NW Natural®

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Portland, OR 97204

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nwnatural.com

December 29, 2023 NWN OPUC Advice No. 23-30 / UG 490

VIA ELECTRONIC FILING AND HAND DELIVERY

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

Re: UG 490 – Application of NW Natural for a General Rate Revision

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"). Per the Public Utility Commission of Oregon ("Commission") Staff's request, fifteen (15) copies of the non-confidential, redacted Executive Summary, Direct Testimonies, and Exhibits are included with this filing. 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.

On December 20, 2023, the Court of Appeals of the State of Oregon concluded that the Climate Protection Program, OAR 340-271-0010 to 340-271-9000, is invalid.[1] This decision was issued after NW Natural's Application was finalized and printed. NW Natural will address the impact, if any, of this decision on the Company's Application through the pendency of the proceeding.

Please note the filing contains some confidential information that represents business-sensitive, non-public information. Confidential information and Highly Confidential or Sensitive Security information will be provided subject to a General Protective Order and Modified Protective Order, respectively.

Included with this filing are revisions to Tariff, P.U.C. Or. 25 (as Exhibit NW Natural/1717, Walker), stated to become effective with service on and after **November 1, 2024**. 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.

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[1] N.W. Natural Gas Co. v. Environ. Quality Comm., 329 Or App 648 (2023).

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

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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, 2024
OPUC Advice No. 23-30; UG 490 Compliance Filing

Schedule Title	**Proposed Sheet**
Schedule H – Large Volume Non-Residential High Pressure Gas Service (HPGS) Rider	Sixth Revision of Sheet H-5
Schedule X Distribution Facilities Extensions for Applicant-Requested Services and Mains	Second Revision of Sheet X-5
Schedule X Distribution Facilities Extensions for Applicant-Requested Services and Mains	First Revision of Sheet X-7
Rate Schedule 2 - Residential Sales Service	Sixteenth Revision of Sheet 2-1
Rate Schedule 3 - Basic Firm Sales Service – Non-Residential	Fifteenth Revision of Sheet 3-4
Rate Schedule 4 - Residential Multi-Family Service	Fourth Revision of Sheet 4-1
Rate Schedule 15 - Charges for Special Metering Equipment, Rental Meters, and Metering Services (Optional)	Fifth Revision of Sheet 15-1
Rate Schedule 15 - Charges for Special Metering Equipment, Rental Meters, and Metering Services (Optional)	Fifth Revision of Sheet 15-2
Rate Schedule 27 - Residential Heating Dry-Out Service	Thirteenth Revision of Sheet 27-1
Rate Schedule 31 - Non-Residential Firm Sales and Firm Transportation Service	Fifteenth Revision of Sheet 31-11
Rate Schedule 31 - Non-Residential Firm Sales and Firm Transportation Service	Thirteenth Revision of Sheet 31-12
Rate Schedule 32 - Large Volume Non-Residential Sales and Transportation Service	Thirteenth Revision of Sheet 32-12
Rate Schedule 32 - Large Volume Non-Residential Sales and Transportation Service	Fifteenth Revision of Sheet 32-13
Rate Schedule 32 - Large Volume Non-Residential Sales and Transportation Service	Thirteenth Revision of Sheet 32-14
Schedule 167 - General Adjustments to Rates	Fifth Revision of Sheet 167-1
Schedule 175 - Amortization of Horizon 1 Start-Up Cost Deferral	First Revision of Sheet 175-1
Schedule 182 - Rate Adjustment for Environmental Cost Recovery	Third Revision of Sheet 182-1
Schedule 190 - Partial Decoupling Mechanism	Fifteenth Revision of Sheet 190-1
Schedule 190 - Partial Decoupling Mechanism	Thirteenth Revision of Sheet 190-2
Schedule 195 - Weather Adjusted Rate Mechanism (WARM Program)	Fifth Revision of Sheet 195-3
Schedule 195 - Weather Adjusted Rate Mechanism (WARM Program)	Ninth Revision of Sheet 195-4

Schedule 195 - Weather Adjusted Rate Mechanism (WARM Program)	Thirteenth Revision of Sheet 195-5
Schedule 196 - Adjustment for Certain Excess Deferred Income Taxes Related to the 2017 Federal Tax Cuts and Jobs Act	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	Fifth Revision of Sheet 196-2
Schedule 196 (cancelled reserved for future use)	Third Revision of Sheet 196-3
Schedule 197 - Amortization of Pension Balancing Account	Third Revision of Sheet 197-2
Schedule 198 - Renewable Natural Gas Adjustment Mechanism	Second Revision of Sheet 198-1
Schedule 198 - Renewable Natural Gas Adjustment Mechanism	First Revision of Sheet 198-2
Schedule 330 - Residential Bill Discount Program – Optional for Qualifying Customers	First Revision of Sheet 330-1

NW Natural

UG 490

NOTICE OF APPLICATION FOR
GENERAL RATE REVISION

December 29, 2023

<u>To All Parties Who Participated in UG 435:</u>
Please be advised that on December 29, 2023, 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 490 ADVICE 23-30, 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 435, 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 Application within 25 days of service of this notice or seek to intervene in the proceeding. The granting of this General Rate Revision Application will authorize a change in rates.

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CERTIFICATE OF SERVICE

UG 490

I hereby certify that on December 29, 2023, I have served by electronic and/or hand delivery non-confidential, redacted copies of UG 490 ADVICE 23-30, 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 435

UG 435

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DATED December 29, 2023, Portland, Oregon.

/s/ Erica Lee-Pella
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BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UG 490

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, 2024. With this filing, the Company requests a revision to customer rates that will increase the Company's annual Oregon jurisdictional revenues by $154.9 million, or an approximately 16.62 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 approximately 708 thousand customer accounts in Oregon, consisting of approximately 644 thousand residential, 62 thousand commercial, and 840 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:

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III. CASE SUMMARY

A. The Test Year

The Company's test year in this case is the 12-months ending October 31, 2025 ("Test Year"). NW Natural provides information for a historical base year of the 12-months ending December 31, 2023 ("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, 2024. 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 50 percent common equity and 50 percent long-term debt, a requested 10.1 percent return on equity ("ROE"), and a resulting overall rate of return ("ROR") on rate base of 7.406 percent. The Company's current authorized ROE is 9.4 percent. As described in the testimony of James M. Coyne and Jennifer E. Nelson, a reasonable ROE range for NW Natural is 9.80 percent to 10.40 percent using a combination of models and alternative input assumptions. Based on the results of the four methods analyzed, James M. Coyne and Jennifer E. Nelson recommend that 10.10 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 costs due to inflation, 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. These improvements to NW Natural's operations include:

- **Capital Investment:** The capital investment includes the construction of safe, seismically resilient regional resource centers; addressing capacity constraints on the system; information technology and services ("IT&S") systems and applications becoming obsolete and the need to modernize those systems to cloud-based architecture; complying with the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") requirements; and the routine systematic replacement of assets that have reached the end of their useful lives.
- **Meter Modernization Program:** NW Natural is embarking on 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. The MMP has been designed to mitigate long delays in procurement arising from supply chain issues by first depleting NW Natural's existing stock of mechanical meters with ERTs attached, fulfilling existing purchase orders, and then strategically

implementing a new metering technology—ultrasonic meters. NW Natural will install ultrasonic meters in select areas that will benefit most from the new safety technology, which includes shutoff capability and alerts related to high flow and high temperature. The Company also will replace the current end-of-life meter reading software and upgrade the software to new technology in order to ensure meter reading continuity and appropriately utilize the ultrasonic meter technology.

- **Modernizing IT&S Systems:** NW Natural continues to modernize its IT&S infrastructure. In its previous general rate proceeding (UG 435), the Company described the successful completion of its Horizon 1 project, where NW Natural upgraded its existing enterprise resource planning ("ERP") software that manages and integrates many of NW Natural's essential business functions. In this proceeding, NW Natural is seeking cost recovery of additional projects to further modernize its IT&S infrastructure and transition to cloud-based IT&S architecture. These upgrades are largely in response to cyber-security advancements, existing software reaching end of life and end of support, and developers exclusively providing cloud-based solutions. NW Natural is also beginning to move towards the second phase of the Horizon project, "H2: Vista," to comprehensively update the Company's outdated customer information system ("CIS") and other customer-facing functions and related services. Although NW Natural is not seeking cost recovery of H2: Vista in this proceeding, it is seeking cost recovery of four incremental employees to backfill our current CIS team while those current CIS employees move to full-time H2: Vista development.

- **Seismically Secure Regional Resource Centers:** 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. In this case, the Company is seeking cost recovery for several facility projects that further enhance our seismic resiliency and the continuity of our operations. Specifically, NW Natural is constructing an office building and warehouse as part of Phase 2 of its Central Resource Center project in central Portland to: 1) provide workspace for emergency response crews, 2) provide storage for equipment, parts, and materials, and 3) provide parking for Company vehicles. NW Natural is also seismically upgrading the Sunset Resource Center in Hillsboro and the Sherwood Data Center, as well as enhancing the physical security at its facilities and field infrastructure in response to direction from the United States Department of Homeland Security's Transportation Security Administration ("TSA") and increasing potential threats. Finally, the Company has completed several necessary upgrades to the Miller Station Control Building located at NW Natural's Mist Gas Storage Facility to address seismic and other safety concerns, resolve space constraints, and improve inadequate facilities.
- **Distribution System & Storage Operations:** The Company continues to make improvements to our distribution system and storage facilities in order to keep our system safe, reliable, and economical. The distribution system projects include a system reinforcement in the areas of Astoria, Warrenton and Cannon Beach (North

Coast Feeder Uprate Project), and the rebuilding of the SE Gate Station in the southeast Portland area to address end-of-life, undersized, corroded and difficult to operate equipment. At our Mist storage facility, we are acquiring a gas generator, a power turbine and standby parts for each of the two turbine compressor units, which have experienced unplanned outages. Other projects at our Mist storage facility include replacing and upgrading primary electrical components, replacing end-of-life injection systems at wellhead locations, replacing and upgrading instrumentation and controls equipment, and continuing our annual Mist Well Rework Program in compliance with PHMSA requirements. Projects at our liquefied natural gas ("LNG") plant in Portland include replacing and upgrading valves and controls, boil-off compressors and pretreatment processes. At our Newport LNG facility, we are making improvements to the tank.

- **Depreciation Rates:** The Company is filing an updated depreciation study performed by Gannett Fleming, and the results of the depreciation study are one of the key drivers to the increase requested in the Company's revenue requirement.
- **Cybersecurity:** Additionally, NW Natural is complying with a recent cybersecurity directive from the TSA, which has resulted in the Company investing significant resources protecting the Company's operations.

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. Bill Discount Proposal

NW Natural carefully considered the energy burden experienced by its customers and is proposing modifications to its residential bill discount program. Under the current program, customers with income less than 60 percent of Oregon state median income can currently qualify for up to a 40 percent discount on their monthly bill based on household size and income. In this proceeding, NW Natural is seeking to increase this discount from 40 percent to 80 percent for customers with income less than 15 percent of the state median. It is also seeking to increase the discount from 25 percent to 40 percent for customers with incomes less than 30 percent of the state median income. With these changes, NW Natural is targeting to reduce participating customers' gas usage-related energy burden to 3 percent or less.

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 how NW Natural is serving the needs of our customers and the communities we serve, broadening and expanding our low-income programs, and working with its Community Equity Advisory Group. Their testimony also describes NW Natural's vision and progress in our transition to a low-carbon economy, and the Company's proposals for responsible customer growth while balancing the Company's obligations to reduce emissions for all of its residential, commercial and industrial customers under the current Oregon Department of Environmental Quality's Climate Protection Plan ("CPP"). In addition, they describe the Company's overall operating environment, as well as the Company's current efforts and goals, and provide a high-level overview of the Company's application for a general rate revision.

- In NW Natural/200, **Cecelia J. Tanaka**, Community Partnerships Manager, describes the Company's initiatives and priorities regarding equity and inclusion, and provides an update regarding the Company's Low-Income Needs Assessment and low-income assistance offerings.
- In NW Natural/300, **Brody J. Wilson**, Interim Chief Financial Officer, Vice President, Treasurer, Chief Accounting Officer and Controller, provides testimony about the Company's cost of capital. His testimony provides information about the costs of the Company's long-term debt during the Test Year. Mr. Wilson's testimony explains that the Company continues to adhere to its policy of balancing long-term debt and equity financing by targeting a 50/50 capital structure. Mr. Wilson requests to maintain our most recently Commission-approved capital structure of 50 percent common equity and 50 percent long-term debt, resulting in an ROR on rate base of 7.406 percent.
- In NW Natural/400, **James M. Coyne**, Senior Vice President, and **Jennifer E. Nelson**, Assistant Vice President, of Concentric Energy Advisors, Inc., a firm with expertise on utility finance and required rates of return for regulated companies, 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. Their testimony provides an analysis of NW Natural's cost of equity, and a range of return on equity that NW Natural should be given the opportunity to earn in order to attract capital. The testimony supports a reasonable range for the Company's cost of equity between 9.8 percent and 10.4 percent, and Mr. Coyne and Ms. Nelson recommend that NW Natural be allowed an opportunity to earn a 10.1 percent return on equity in the revenue requirement authorized in this proceeding.

- In NW Natural/500, **Daniel B. Kizer**, Engineering Senior Director, provides testimony about some of the major improvements to our distribution system and storage facilities that the Company has undertaken in order to keep our system safe, reliable, and economical. Mr. Kizer also discusses NW Natural's ongoing plans for safety-driven system projects and programs, in connection with the Company's 2024 Safety Project Plan filed in docket UM 1900.
- In NW Natural/600, **Wayne K. Pipes**, Director of Facilities, Security and Emergency Management, describes the Company's execution of our long-term plan to update our regional resource centers for a variety of reasons, including upgrading them seismically, improving emergency response times, ensuring compliance with applicable requirements, making mechanical and electrical upgrades, resolving space constraints and improving inadequate facilities. Mr. Pipes also details our recent projects to protect the safety of our critical infrastructure in light of a wave of recent incidents targeting utility and energy infrastructure.

- In NW Natural/700, **Jim R. Downing**, Vice President and Chief Information Officer, describes NW Natural's ongoing IT&S context and strategic approach, provides a preview of H2: Vista, and details the Company's cost-recovery requests with respect to major projects and crucial hiring needs. In NW Natural/800 (Sensitive Security Information), **Mr. Downing** sponsors separate testimony describing the Company's response to the emergency mandatory federal regulatory requirements in TSA Security Directive Pipeline-2021-02.
- In NW Natural/900, **Joe S. Karney**, Vice President of Engineering and Utility Operations, presents 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. Finally, Ms. Rogers 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, **Brody J. Wilson and Nikki R. Sparley**, Treasury & Investor Relations Director, discuss the factors that are causing significant changes to uncollectible expense and provide the Company's proposal for forecasting uncollectible expense in this rate case.
- In NW Natural/1400, **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/1500, **Zachary D. Kravitz** and **Anna K. Chittum**, Director of Renewable Resources, provide an update on our decarbonization efforts under the CPP and propose updates to the Company's renewable natural gas automatic adjustment clause.
- In NW Natural/1600, **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/1700, **Kyle T. Walker**, Senior Manager of Rates and Regulatory Affairs, provides the calculation of the Company's revenue requirement, proposed changes to the Decoupling mechanism, and Tariffs, which represents the annual dollars needed to recover prudently incurred costs of operating the utility business, enhancements to Decoupling and presentation of Tariffs.

- In NW Natural/1800, **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. Mr. Wyman also proposes a new fixed charge for new residential customers, and he proposes creating a separate fixed charge for residential multifamily customers reflecting a lower cost to serve those customers compared to single family residential customers.
- In NW Natural/1900, **Gregg H. Therrien**, Vice President at Concentric Energy Advisors, updates NW Natural's line extension allowance ("LEA"). In support of the Company's request, Mr. Therrien presents a revised discounted cash flow analysis (with supporting calculations) and a revised LEA tariff. His testimony also supports the incremental costs and benefits of adding a new customer to the natural gas distribution system, consistent with the Commission's directives regarding the LEA issued in Order No. 22-388 of docket UG 435 in the Company's last rate case.

V. <u>CONCLUSION</u>

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 sheet.

DATED: December 29th, 2023

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 29, 2023

Total Revenues Collected Under Proposed Rates:		$1,090,799,131
Revenue Change Requested:		$154,909,690
Revenues Net of any Credits from Federal Agencies:		$1,090,799,131
Percentage Change in Revenue Requested:		16.62 %
Percentage Change in Revenues Net of any Credits from Federal Agencies:		16.62 %
Test Period:	November 1, 2024 to October 31, 2025	
Requested Over Rate of Return		7.406%
Requested Rate of Return on Equity:		10.10%
Proposed Rate Base:		$2,136,360,766
Results of Operation		
Before Proposed Rate Change		
Utility Operating Income:		$49,268,419
Average Rate Base:		$2,136,360,766
Rate of Return on Capital:		2.306%
Rate of Return on Equity:		-0.10%
After Proposed Rate Change		
Utility Operating Income:		$158,218,878
Average Rate Base:		$2,136,360,766
Rate of Return on Capital:	7.406%	
Rate of Return on Equity:		10.10%

The $154.9 million of revenue requirement and $4.4 million of Plant EDIT 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 - Residential	$79.43	$93.81	$14.38	18.1%
Schedule 2 – Multi Family	$79.43	$91.82	$12.39	15.6%
Schedule 2 – New Premise	N/A	$66.54	N/A	N/A
Schedule 2 – Multi Family, New Premise	N/A	$63.92	N/A	N/A
Schedule 3 - Commercial	$284.45	$332.83	$48.38	17.0%
Schedule 3 - Industrial	$1,342.67	$1,462.82	$120.15	8.9%
Schedule 27 - Dry Out	$59.58	$71.17	$11.59	19.5%
Schedule 31 - Firm Sales - Commercial	$2,506.40	$2,760.37	$253.97	10.1%
Schedule 31 - Firm Transportation - Commercial	$1,697.73	$1,935.61	$237.88	14.0%
Schedule 31 - Firm Sales - Industrial	$4,254.66	$4,581.13	$326.47	7.7%
Schedule 31 - Firm Transportation - Industrial	$1,978.29	$2,254.78	$276.49	14.0%
Schedule 32 - Firm Sales - Commercial	$5,664.85	$6,133.27	$468.42	8.3%
Schedule 32 - Firm Sales - Industrial	$13,738.43	$14,352.29	$613.86	4.5%
Schedule 32 - Firm Transportation - Commercial	$3,367.16	$3,900.49	$533.33	15.8%
Schedule 32 - Firm Transportation - Industrial	$7,233.46	$8,435.00	$1,201.54	16.6%
Schedule 32 - Interruptible Sales - Commercial	$28,530.42	$29,930.67	$1,400.25	4.9%
Schedule 32 - Interruptible Sales - Industrial	$26,742.30	$28,010.81	$1,268.51	4.7%
Schedule 32 - Interruptible Transportation - Commercial	$11,702.38	$13,256.32	$1,553.94	13.3%
Schedule 32 - Interruptible Transportation - Industrial	$12,131.93	$13,878.28	$1,746.35	14.4%
Schedule 33 - Firm and Interruptible Transp Svcs	$38,250.00	$38,250.00	-	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 490

NW Natural

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

POLICY
EXHIBIT 100

December 29, 2023

EXHIBIT 100 - DIRECT TESTIMONY - POLICY

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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 served as President of NW Natural's affiliate, NW Natural Water Company, LLC, since 2018. 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 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. 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.

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 the cost and business drivers that necessitated and led to NW Natural making this request.

Q. Please summarize your testimony.

A. First, we discuss the current operating environment for NW Natural and discuss some of our challenges and opportunities. Specifically, we discuss the importance of the gas system to the overall energy system in Oregon, and why we must continue to maintain and invest in a safe system.

Second, in addition to its traditional role as a gas utility, NW Natural is being directed to address the emissions for all of its residential, commercial and industrial customers under the current Oregon Department of Environmental Quality ("ODEQ") Climate Protection Plan ("CPP"). As discussed below, the CPP is not a "cap and trade" program; it does not have an allowance-based auction framework, and given the stringency of the cap, no market exists in which to trade compliance instruments. Additionally, covered entities have a limited ability to acquire offset-like instruments called Community Climate Investment ("CCI") credits. As it stands now, to comply with the CPP will require NW Natural to change its business model. To meet the emissions reductions associated with the CPP, NW Natural must pursue a number of actions simultaneously, including enhancing energy efficiency, obtaining decarbonized fuels, and purchasing CCI credits. In addition, the Company will pursue strategic decarbonization efforts to leverage the capacity value of the existing gas system in the winter, while seeking operational efficiencies between the gas and electric systems during milder months in the fall and spring.

Third, we describe the key drivers of our request for a general rate revision, such as inflationary pressures across our system and continued investments that ensure safe and reliable service to our customers. 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.

Fourth, we discuss near-term and longer-term changes to the Company's business model that will allow NW Natural to serve its current and future customers in a manner that promotes energy efficiency and carbon emission reductions, adapting to the rapid changes in the energy industry. We want to support customer growth in a manner that protects our existing customer base from potential risks, but also allows new customers to have the same opportunities to choose their energy provider and to have the resiliency and affordability benefits provided by the gas system. Additionally, we consider the customer benefits of utilizing a multi-year rate plan in the Company's next rate case.

Fifth, we provide an update on several important equity initiatives that were described in the Policy Testimony in our previous general rate case (UG 435), including completing our first Low-Income Needs Assessment ("LINA"), establishing a bill discount program, and implementing a Community Equity Advisory Group ("CEAG"). The Company has carefully considered the energy burden experienced by its customers and has proposed changes to the bill discount program to mitigate these impacts. We are proud of the progress we have made in these new endeavors and are eager to share additional details in this testimony.

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

II. NW NATURAL AND ITS CURRENT OPERATING ENVIRONMENT

Q. What is NW Natural's mission statement?

A. We provide safe, reliable and affordable utility services and renewable energy in a sustainable way to better the lives of the communities we serve.

Q. Please describe the business of Northwest Natural.

A. NW Natural has provided gas service in the Pacific Northwest for 164 years. To effectively provide this service, NW Natural operates more than 14,000 miles of transmission and distribution pipelines and over 20 billion cubic feet of natural gas storage at our three storage operations. Currently, NW Natural is the largest standalone gas utility in the Pacific Northwest, serving approximately 2.5 million people in Oregon and Southwest Washington. In Oregon, we provide service in 126 cities in 15 different counties. Our employee base of approximately 1,200 serve over two million people in Oregon, with approximately 708 thousand customer accounts, which represents approximately 88 percent of our total gas system customer base.

Q. Please discuss NW Natural's ongoing role as an energy services provider.

A. 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 will continue to prudently invest in our system to ensure the safe and reliable delivery of energy to homes and businesses in Oregon.

Concurrent with this operational work, NW Natural must adapt to a rapidly evolving technology environment, including maintaining a cyber-security program in accordance with federal regulations and moving to cloud-based technologies. All of these activities must happen simultaneously while we ensure that we equitably serve our diverse customer base.

Q. Please summarize NW Natural's overall role in Oregon's energy system.

A. NW Natural's role in the state's overall energy system can hardly be overstated. NW Natural provides more energy to Oregonians than any other utility—gas or electric. In Oregon, the gas and electric systems have a concurrent peak in winter. During this concurrent peak, the gas system delivers about twice as much energy as the electric system itself—with even more available. Despite this vast amount of energy delivered, NW Natural's residential and commercial customers' use accounts for less than 7 percent of the state's overall emissions, while the electric sector is at 29 percent.

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.

Recently, on December 22, 2022, we experienced one of these very cold mornings in Oregon resulting in record throughput on our system. We commissioned an energy consultant, ICF, to analyze the impact to the electric system if all, or portions of, our residential gas load was electrified on that 17-degree day. The analysis shows that between 8:00 and 9:00 a.m., we delivered approximately 23 million cubic feet of natural gas to serve residential end uses.

Using conservative assumptions, to electrify that load would increase electric consumption by over 80 percent or about 3.4 GW of new load. To put that number in perspective, Portland General Electric's peak during the morning of December 22, 2022 was 4.1 GW, which is very close to its all-time peak of 4.45 GW. The cost to serve that amount of peak load with renewable energy, particularly where solar generating capacity is low during a December morning and wind generation is highly variable, could reach into the tens of billions of dollars. In fact, ICF estimates it would require approximately 14 GW of renewables and battery storage capacity to be assured of meeting this increased load, given the intermittency of renewable generation and the limitations of battery technology. Even this amount of capacity would not fully replace the value of NW Natural's system because the Company also, of course, serves commercial and industrial customers and given current technology, many industrial uses of natural gas simply cannot be electrified at any price.

Q. Please explain how NW Natural will change as decarbonization of the natural gas system begins to accelerate.

A. As the decarbonization of the natural gas system begins to accelerate, NW Natural will undergo fundamental change. While still retaining our trusted responsibility as an energy services provider, the Company will pursue increasing decarbonization efforts that use all cost-effective available means to reduce the greenhouse gas emissions associated with the energy we provide. In short, NW Natural must continue to be focused on providing safe, affordable, and reliable energy as it has done for 164 years while also undergoing the transformative change necessary to decarbonize.

Q. Please describe NW Natural's role in decarbonization.

A. Environmental stewardship is a core value at NW Natural, and we are a leader on environmental issues among natural gas utilities across North America. Historically, the actions that we have taken to reduce our customers' emissions have been voluntary, such as our Smart Energy program and acquiring renewable natural gas ("RNG") under Senate Bill 98.[1] Now, however, our decarbonization actions are mandatory. In 2022, the ODEQ adopted the CPP; this rule applies to the state's covered fuel suppliers, including NW Natural. The CPP requires emissions covered by the program to be cut in half by 2035 and reduced by 90 percent by 2050. For NW Natural, these "covered emissions" are the emissions that result from its sales customers' and transport customers' use of natural gas.

Q. How does the CPP reduce covered emissions?

A. The CPP sets a declining limit, or cap, on covered emissions. The initial cap for 2022 is set at covered entities' average greenhouse gas emissions from the years 2017-2019. This initial cap represents the number of compliance instruments that ODEQ allocates at no cost in 2022. Each compliance instrument is equivalent to one metric ton of covered emissions. Every year after 2022, the cap (i.e., the number of compliance instruments allocated at no cost) is reduced. By 2035, the

[1] ORS 757.390-398.

number of compliance instruments is cut in half. By 2050, the number of compliance instruments is reduced by 90 percent.

Q. For its covered emissions to not exceed the cap, what is the equivalent amount of therms that will require compliance under the CPP?

A. For each year from 2023 to 2035, NW Natural will need to incrementally reduce its emissions of conventional natural gas by approximately 41.7 million therms in order to not exceed the declining cap.

Q. Must NW Natural's covered emissions not exceed the cap in order to comply with the CPP?

A. There is a declining amount of compliance instruments allocated that effectively offset a portion of NW Natural's covered emissions. To demonstrate compliance with the CPP, NW Natural must ensure that its total amount of compliance instruments, plus CCI credits, equals its covered emissions over each three-year compliance period.

Q. What are CCI credits?

A. CCI credits are compliance tools created by ODEQ that are unique to the CPP. CCI credits are defined as: "money paid by a covered fuel supplier [e.g., NW Natural] to a community climate investment entity to support implementation of community climate investment projects and any interest that accrues on the money while it is held by a CCI entity or subcontractor."[2] In exchange for this money, covered fuel suppliers like NW Natural will receive CCI credits that they can use

[2] OAR 340-271-0020(8).

for compliance. NW Natural cannot purchase an unlimited number of CCI credits. During the first three-year CPP compliance period (2022-2024), NW Natural may purchase CCI credits for up to 10 percent of its CPP compliance obligation. During the second three-year compliance period (2025-2027), this amount increases to 15 percent and for every three-year compliance period thereafter the amount is 20 percent.

Q. How does the price of CCI credits compare to the price of emission allowances in the United States and Canada?

A. As shown in Table 1 below, CCI credits are starting out roughly twice as expensive as the most expensive emission allowances in the United States and Canada, and the costs increase each year.

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TABLE 1

State(s)	Climate Program	Cost ($ per ton)
Oregon	Climate Protection Program	**$123** ($1+CPI ea. yr.)
Washington	Climate Commitment Act (cap & trade)	**$63** (Q3 auction)
California & Quebec	Western Climate Initiative (cap & trade)	**$35** (Q3 auction)
BC Canada	Carbon Tax	**$65**
Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, Virginia, New York, Pennsylvania, Rhode Island, Vermont	Regional Greenhouse Gas Initiative (RGGI)	**$13** (Q3 auction)

The high price of these CCI credits compared to emission allowances in other markets makes decarbonization more expensive for Oregonians relative to residents and businesses of other states, especially for industrial customers. Industrial customers in Washington and California, for example, have "energy/emissions intensive, trade exposed" ("EITE") designations for their respective greenhouse gas ("GHG") reduction programs, which seeks to lower the cost of the program in order to prevent these customers from shifting their operations to other states without GHG reduction programs. In other words, EITE designations help ensure that a state's GHG reduction program does not merely result in emissions moving (or "leaking") to another state or country. The CPP lacks this designation, increasing the cost of the program on Oregon industrial customers relative to other, higher GHG emitting jurisdictions.

Q. Given CPP requirements, how can NW Natural comply with the CPP?

A. NW Natural intends to use all available tools allowed to comply with the CPP. NW Natural will continue to pursue cost-effective energy efficiency and new technologies to reduce throughput and, therefore, its compliance obligation. In addition to acquiring CCI credits, the Company will reduce its covered emissions by acquiring decarbonized fuels, such as RNG and hydrogen. We also intend to offer customized industrial decarbonization services to all our large customers, which will include a variety of technologies well-suited to our largest users, such as pre-combustion carbon capture via methane pyrolysis.

We are studying the costs and technical viability of dual-fuel solutions in different applications to determine if certain forms of electric/gas combinations would be beneficial to our customers. In particular, we believe that hybrid heating, where an air source heat pump is paired with a gas furnace, could reduce natural gas throughput, as well as address continuing resource adequacy and reliability concerns on the electric grid. This solution also eliminates the need to rely on higher emitting and more costly electric resistance back up heat. Installing ground-source heat pumps is an additional opportunity to reduce natural gas throughput. NW Natural believes that these types of strategic solutions could maximize the strengths of both the natural gas and electric utility systems while recognizing the inherent limitations of attempting to decarbonize both systems in isolation from each other.

Q. Is NW Natural seeking to recover any costs associated with meeting a projected CPP compliance gap in this proceeding?

A. No, we are not. However, NW Natural is taking this opportunity to raise these issues now given that the first compliance period (2022-2024) is likely the only compliance period where NW Natural can meet its full compliance needs with legally valid CCI credits without needing incremental sources, such as RNG. Due to the uncertainties associated with weather volatility, which will drive our compliance obligations from year to year, NW Natural expects to take additional compliance actions in the near future.[3] Going forward, NW Natural expects that it will have to use all of the compliance methods mentioned above to comply with the CPP, and likely others, as technologies continue to evolve and mature.

III. NW NATURAL'S APPLICATION FOR GENERAL RATE REVISION

Q. Can you please summarize the Company's requested rate increase?

A. NW Natural is seeking to increase revenues from base rates by $154.9 million. The rate increase requested in our application would result in approximately a 16.62 percent increase to revenues collected from customers' base rates. The request is based on a capital structure of 50 percent common equity and 50 percent long-term debt and a requested 10.1 percent return on equity ("ROE"), resulting in an overall rate of return ("ROR") on rate base of 7.406 percent.

[3] NW Natural/1500, Kravitz-Chittum.

Q. Can you please comment on the considerations NW Natural undertook before filing this general rate revision?

A. We recognize that any request to increase rates is difficult and that there is never a good time to raise rates. At its core, this rate case is about seeking to recover costs that are increasing due to inflation, as well as the costs of our long-planned investments to continue to support our utility service to customers. We understand that natural gas plays an essential role in our customers' lives, and we do not take lightly the prospect of increasing our customers' rates.

We determined, however, that NW Natural would need to file this application with the Commission seeking to revise its rates to recognize an increased revenue requirement related to its provision of utility service. Without the requested increase in base rates, NW Natural's gas distribution utility would expect the overall ROR to be 2.306 percent, with a corresponding ROE of –0.10 percent, well below the proposed ROR and ROE in this case of 7.406 percent and 10.1 percent, respectively. The Company, therefore, needs to increase its rates in order to maintain an ability to 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. Can you describe the significant factors that are driving the need to file this rate case?

A. Yes, the single biggest factor is that we have continued to make substantial investments in the safety and reliability of our distribution system and operations, including a significant effort to modernize customer meters throughout our system.

The capital investment is driven by the construction of safe, seismically resilient regional resource centers; addressing capacity constraints on the system; information technology and services ("IT&S") systems and applications becoming obsolete and the need to modernize those systems to cloud-based architecture; complying with the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") requirements; and the routine systematic replacement of assets that have reached the end of their useful lives.

Q. Please describe the meter modernization program.

A. As detailed in the Direct Testimony of Joe S. Karney (NW Natural/900, Karney), Vice President of Engineering and Utility Operations, NW Natural is embarking on 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. The MMP has been designed to mitigate long delays in procurement arising from supply chain issues by first depleting NW Natural's existing stock of mechanical meters with ERTs attached, fulfilling existing purchase orders, and then strategically implementing a new metering technology—ultrasonic meters. NW Natural will install ultrasonic meters in select areas that will benefit most from the new safety technology, which includes shutoff capability and alerts related to high flow and high temperature. The Company also will replace the current end-of-life meter reading software and upgrade the software to new technology in order to ensure meter reading continuity and appropriately utilize the ultrasonic meter technology.

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

A. The Company continues to modernize its IT&S infrastructure. In its previous general rate proceeding (UG 435), the Company described the successful completion of its Horizon 1 project, where NW Natural upgraded its existing enterprise resource planning ("ERP") software that manages and integrates many of NW Natural's essential business functions. In this proceeding, NW Natural is seeking cost recovery of additional projects to further modernize its IT&S infrastructure and transition to cloud-based IT&S architecture. These upgrades are largely in response to cyber-security advancements, existing software reaching end of life and end of support, and developers exclusively providing cloud-based solutions.

NW Natural is also beginning to move towards the second phase of the Horizon project, "H2: Vista." As part of H2: Vista, NW Natural will comprehensively update the Company's outdated customer information system ("CIS") and other customer-facing functions and related services. Although NW Natural is not seeking cost recovery of H2: Vista in this proceeding, it is seeking cost recovery of four incremental employees to backfill our current CIS team while those current CIS employees move to full-time H2: Vista development.

The Direct Testimony of Jim R. Downing (NW Natural/700, Downing), the Company's Vice President and Chief Information Officer, provides a comprehensive explanation of the Company's IT&S projects, including a preview of H2: Vista.

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. We are methodically evaluating our facilities, including our resource centers across our service territory, to mitigate the risk that a seismic event or tsunami could make our facilities inoperable. In previous general rate proceedings, we addressed moving our operational headquarters to a seismically resilient building in downtown Portland, constructed a seismically resilient resource center in Vancouver, Washington, and completed relocation of resource centers in Lincoln City and Warrenton near the Oregon Coast. Our resource centers provide emergency response services, customer field services, construction, transmission maintenance, leakage inspection, and other operations services.

As explained in the Direct Testimony of Wayne K. Pipes (NW Natural/600, Pipes), Director of Facilities, Security and Emergency Management, we are seeking cost recovery for several facility projects that further enhance our seismic resiliency and the continuity of our operations. Specifically, NW Natural is constructing an office building and warehouse as part of Phase 2 of its Central Resource Center project in Southeast Portland, which provides NW Natural more efficient dispatch capabilities in a densely populated area in our service territory. NW Natural is also seismically upgrading the Sunset Resource Center in Hillsboro and the Sherwood Data Center, as well as enhancing the physical security at its facilities and field infrastructure in response to direction from the United States. Department of Homeland Security's Transportation Security Administration ("TSA") and increasing potential threats. Finally, the Company has completed several necessary upgrades to the Miller Station Control Building located at NW Natural's Mist Gas Storage Facility to address seismic and other safety concerns, resolve space constraints, and improve inadequate facilities.

Q. Please describe the significant distribution system and storage facility projects that are included in this case.

A. We continue to make improvements to our distribution system and storage facilities in order to keep our system safe, reliable, and economical. The distribution system projects include a system reinforcement in the areas of Astoria, Warrenton and Cannon Beach (North Coast Feeder Uprate Project), and the rebuilding of the SE Gate Station in the southeast Portland area to address end-of-life, undersized, corroded and difficult to operate equipment.

At our Mist storage facility, we are acquiring a gas generator, a power turbine and standby parts for each of the two turbine compressor units, which have recently experienced unplanned outages. We are also introducing our longer-term, holistic solution to addressing those outages. Other projects at our Mist storage facility include replacing and upgrading primary electrical components, replacing end-of-life injection systems at wellhead locations, replacing and upgrading instrumentation and controls equipment, and continuing our annual Mist Well Rework Program in compliance with PHMSA requirements. Projects at our liquefied natural gas ("LNG") plant in Portland include replacing and upgrading valves and controls, boil-off compressors and pretreatment processes. At our Newport LNG facility, we are making improvements to the tank.

Our Senior Director of Engineering, Daniel B. Kizer, includes details of each of these projects in his Direct Testimony (NW Natural/500, Kizer), and also describes the Company's safety-related projects on its distribution system and at its storage facilities.

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

A. In recent years, the environment in which NW Natural and investors operate in has changed. In 2022, the Federal Reserve increased interest rates at the fastest pace in 35 years. The 10-year treasury rate, a bellwether for utility equities, was at 1.52 percent at the end of 2021, compared to 4.58 percent on November 7, 2023. These higher yields on government bonds indicate the cost of capital has increased for all companies. Higher yields on longer-term treasury bonds, like the 10-year treasury rate referenced above, provide investors a more attractive risk-free alternative to utility stocks. In addition, the environmental policy focus in the Pacific Northwest for gas utilities over the past two years 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. In this case, the Company is filing an updated depreciation study performed by Gannett Fleming. The results of the depreciation study are one of the key drivers to the increase requested in the Company's revenue requirement.[4] Applying the depreciation rates from the depreciation study to Test Year plant balances results in an increase to depreciation expense of $62.4 million.

Q. In the Company's most recently filed depreciation study (Docket No. UM 2214), the Commission requested that NW Natural address the issue of accelerated depreciation when it files its next depreciation study. How is NW Natural approaching this issue?

A. In Order No. 22-322 (at page 3), the Commission stated the following:

> In adopting this stipulation, we are mindful that prior to the company's next depreciation study, to be filed no later than December 31, 2027, NW Natural, Staff, and stakeholders will be engaged in significant work towards the company reducing emissions in response to the Oregon Department of Environmental Quality's Climate Protection Program or other policy and regulatory directives. We anticipate that parties may seek to evaluate accelerated depreciation or other adjustments to asset depreciation schedules as one tool to mitigate uncertainty about decarbonization pathways and manage potential future risks to customers. We ask that the company include in its next depreciation filing testimony addressing its consideration of this approach.

First and foremost, we only need to look back one year to December 22, 2022 to underscore the importance of the gas system to the overall energy system in Oregon. Second, customers continue to choose gas service due to its efficiency, reliability, resiliency, and affordability. Third, our research indicates 70 percent of likely voters want to retain the ability to choose the energy system and products they install in their homes in the areas we serve. In this respect, we believe it is

[4] NW Natural/1602, Spanos.

inadvisable to make wholesale conclusions about the future of the gas system and the need to make changes to the Company's asset lives on the basis of future policies that do not exist now.

However, to be responsive to the Commission's directive, we have filed a depreciation study with this rate case, rather than wait until NW Natural is obligated to file another study—December 31, 2027.[5] We believe it is very important to have our depreciation rates reflect the actual operations and depreciable lives of the assets on our system. While, in theory, depreciation rates should already reflect the assets' useful life, in practice this has not been the case because of reasonable efforts to mitigate near-term rate pressures. Previously NW Natural, its stakeholders, and the Commission have lowered revenue requirement through downward adjustments to depreciation rates, or, in other words, authorizing NW Natural to recover depreciation expense over a length of time that is greater than the projected life of its assets in the Company's depreciation study.[6] If this historical approach persists, it would compound the issue so that when each new depreciation study is filed, the resulting depreciation rates would require significantly more adjustment to regain alignment with the actual operational and financial needs of our system. In sum, while this approach was a reasonable short

[5] *In the Matter of Northwest Natural Gas Company dba NW Natural, Updated Depreciation Study Pursuant to OAR 860-027-0350,* Docket No. UM 2214, Order No. 22-322, at 3 (Sep. 7, 2022).

[6] *Id.* at 2 ("The revised depreciation rates under the stipulation will result in an annual depreciation expense of about $106.85 million, an approximate $9.36 million decrease from the annual depreciation expense proposed in NW Natural's initial filing.").

term rate mitigation tool, it is incompatible in an environment where we are being asked to evaluate considerations for accelerated depreciation.

For this reason, the Company has updated its depreciation study, which will require a higher revenue requirement. If we can reset these rates to reflect the actual results of our depreciation study, we can then begin to discuss the justifications for, and impacts of, accelerated depreciation. For example, certain investments in our system are relatively short-lived, especially in the cloud-based IT&S environment. This is part of the changing nature of the utility industry, which is driving more frequent rate cases and higher depreciation expense. On the other hand, service and main lines are longer lived assets, have large plant balances, and any policy driven change to these lives would cause customers' bills to rise.

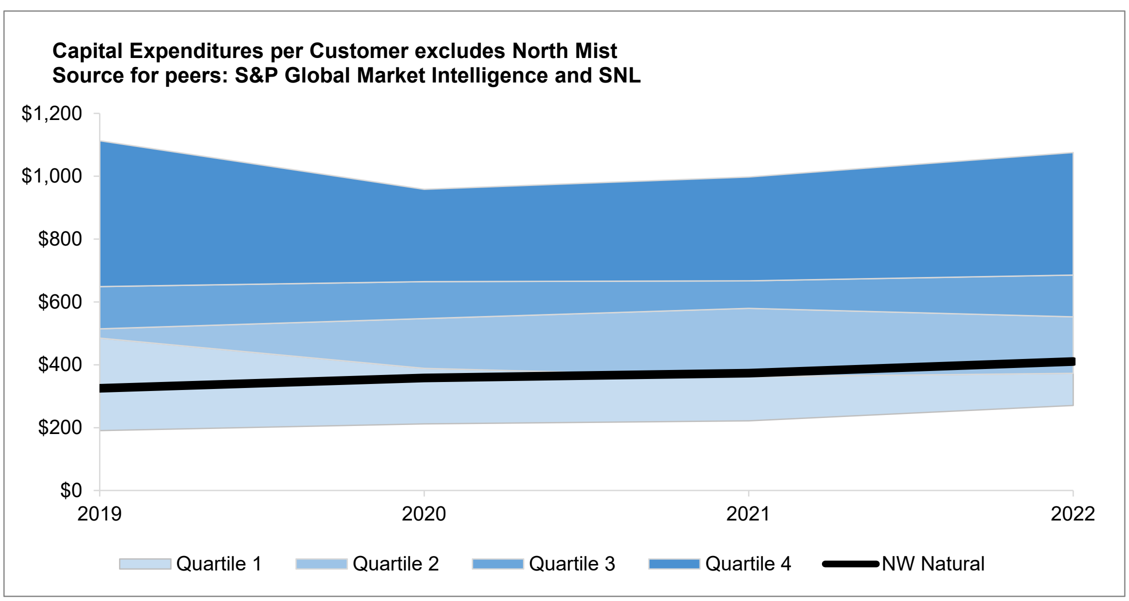
Q. Is the Company proposing accelerated depreciation in this case?

A. No. Given the near-term rate pressure associated with NW Natural's proposal to increase its depreciation expense to reflect the useful life of its assets, we do not believe that further increases to depreciation expense are appropriate to mitigate the potential future risks of certain decarbonization pathways that the Company may pursue. However, we are not attempting to foreclose that discussion. As we move to multi-year rate plans, we should have more flexibility to smooth out rate increases annually rather than the volatile increases that come with the traditional rate case model. In such a filing, we can consider whether a disciplined approach to gradually increase depreciation expense to mitigate potential future uncertainties—while balancing intergenerational equity between today's customers and tomorrow's customers—is a reasonable approach for NW Natural and its customers.

Q. Given the recent investments in NW Natural's system that are driving this rate case, can you describe how the Company compares to other peer utilities' capital expenditures?

A. NW Natural's capital expenditures are significantly lower than other comparable utilities. To make a relevant comparison, the Direct Testimony of Tobin F. Davilla (NW Natural/1400, Davilla), Senior Manager of Financial Planning and Budget, evaluated capital expenditures per customer. Chart 1 below, described in more detail in Mr. Davilla's testimony, provides a comparison of the Company's capital expenditures per customer with a panel of similar gas utilities for the 2019- 2022 period. NW Natural excluded investment in the North Mist expansion project. The panel includes nine peer companies and shows that NW Natural is in the bottom of the second quartile of capital expenditure per customer.

Chart 1



These metrics indicate that NW Natural implements effective cost management procedures, while keeping its system safe and reliable.

Q. How does NW Natural's operations and maintenance ("O&M") costs compare to peer utilities?

A. Mr. Davilla also compared NW Natural's O&M per customer expense with a panel of similar gas utilities, as shown below in Chart 2. For comparability purposes, NW Natural excludes expenses related to the environmental docket (UM 1635, Order No. 15-049), and production, transmission and pension (non-service costs) expenses are excluded for the peer group and NW Natural.

Chart 2

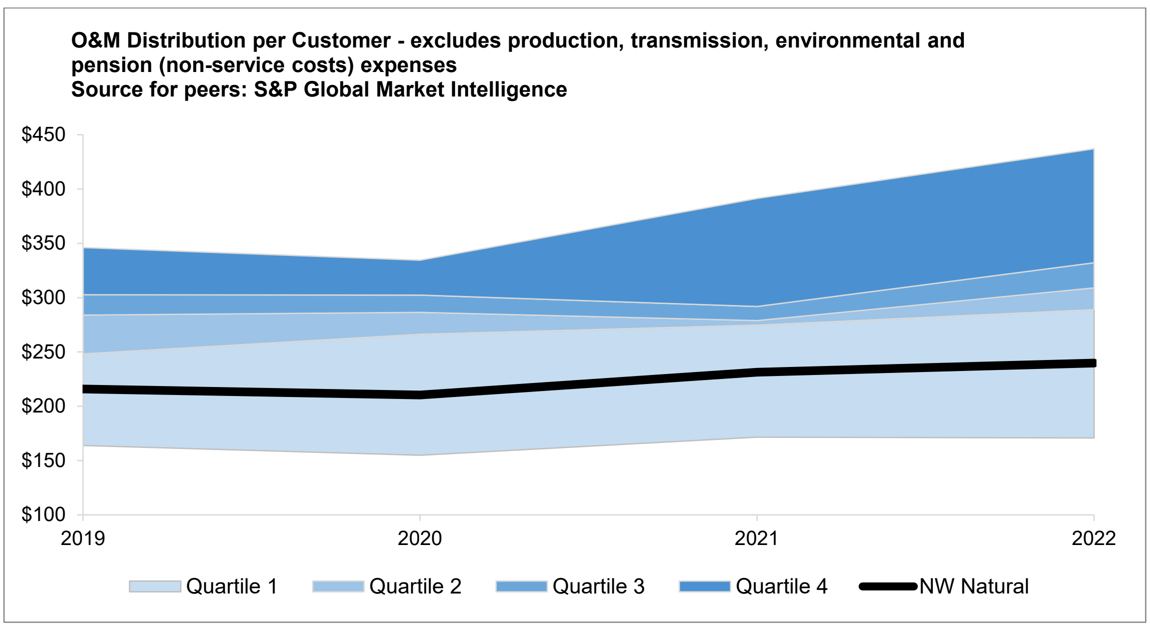


Chart 2, described in more detail in Mr. Davilla's testimony, shows that NW Natural is consistently a top performer in O&M expense management in the first quartile through the sample period. The panel uses customer counts and costs for those companies with FERC Form 2 information available in research findings posted by Regulatory Research Associates, a group within S&P Global Market Intelligence, and includes seven peer companies. This information shows that NW Natural performs well in managing its O&M expense to keep rates low for customers and provide the high-quality service our customers have come to expect from our Company.

Finally, we recognize that not all households and businesses have natural gas service, and customers have other options for serving their energy needs. This means that, even as a regulated utility, we compete for business with other energy providers, and therefore, we are always motivated to keep natural gas rates as low as possible while still being able to provide excellent customer service, exceed safety standards, and maintain financial integrity as a Company.

IV. CHANGES TO REGULATORY MECHANISMS

Q. Can you describe the Company's strategy for growth?

A. NW Natural is committed to providing energy service to customers who want to connect their homes and businesses to the gas system. This is not just a commitment. We have an obligation to our current and future customers to serve them. We do recognize, however, that this obligation to serve must be performed safely and reliably—and without discrimination.

To meet our customers' needs, we must fully support and invest in delivering energy to our customers. There are no short-cuts to keeping our energy system safe and reliable. It takes a well-trained and committed workforce, ongoing maintenance and investment in our distribution and storage systems, safe facilities and resource centers to dispatch our construction and technician teams, and the modernization of our metering and IT&S infrastructure—all of which require significant resources to ensure that we can meet the energy needs of homes and businesses on system peak days like December 22, 2022. We have been able to affordably provide this service by spreading the costs of these investments over a growing customer base.

At the same time, NW Natural is facing new ODEQ rules mandating that we significantly reduce carbon emissions. As such, we are now required to be both a decarbonization company and an energy provider. To meet the demands of the CPP, we will need to rapidly hire new teams and create new systems within our Company to respond. Those teams will need to ramp-up our operational capabilities to deliver on our compliance and decarbonization requirements. To plan, develop and execute these new activities will require additional staffing resources and ongoing Company investments, including the expertise to procure or develop renewable resources necessary to decarbonize and comply with the CPP.

Our new customers also continue to want gas service at their homes and businesses, which expands our distribution system. Historically, customer growth has always been viewed favorably because each new customer who is connected to our system is simultaneously helping to spread fixed costs over a growing customer base. For example, we have been on a multi-year plan to make our facilities seismically-sound to ensure their resiliency in the event of an earthquake. When we can add more customers to the system, the cost of these facilities will be lower for each customer. The emerging complexity is that customer growth also adds incremental emissions under the CPP that will create compliance pressures due to the decreasing cap on emissions. It is important to point out that this dynamic is not limited to gas utilities. Electric utilities face a similar dilemma—where each customer addition puts more pressure on meeting the emissions targets set in HB 2021.[7]

Q. In the face of this changing environment, how does the Company propose to grow?

A. NW Natural will continue to grow, but we are proposing certain modifications to our regulatory mechanisms that ensure responsible and planful growth. We understand that all energy systems are evolving, including the gas delivery system. We expect a future where customers are using less of our product through hybrid space-heating systems (e.g., electric heat pumps backed-up by gas furnaces), but customers will continue to rely on the gas system for the resiliency benefits of fireplaces, water heaters, cooktops, and back-up generators. While overall gas delivery throughput will decrease—driven by less usage in times where heat pumps can operate efficiently—the full strength of the system, including NW Natural's three on-system storage operations, will continue to be vital during winter peaks when hybrid systems switch to gas furnace space-heating. As such, the

[7] HB 2021 requires retail electric providers to reduce greenhouse gas emissions associated with electricity sold to Oregon consumers to 80 percent below baseline emissions levels by 2030, 90 percent below baseline emissions levels by 2035, and 100 percent below baseline emissions levels by 2040. The baseline is set at the average annual emissions of greenhouse gas for the years 2010-2012. HB 2021 is available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled.

Pacific Northwest will need to continue to rely on the gas system during the coldest winter mornings of the year.

Under this responsible growth strategy, we are proposing two main adjustments to our tariffed services:

- **New Customer Fixed Charge**: An increased fixed charge for customers joining the system on or after November 1, 2024, to reflect new customers' lower usage compared to our existing customer base, and thereby protecting against intraclass subsidies through the decoupling mechanism.
- **Updated Line Extension Allowance:** An updated line extension allowance ("LEA") for new customers that is responsive to current policy and the changing nature of how customers are using our system, which derives a higher allowance for lower-use customers.

We will discuss both of these issues in this testimony. We believe that these near-term regulatory actions will have long-term benefits for our customers.

Q. Please explain the Company's proposal to charge a higher monthly fixed customer charge for residential customers added to the distribution system on or after November 1, 2024.

A. The Company proposes to include a higher monthly fixed charge for new customers added to the system on or after the effective date of rates for this proceeding. Specifically, the Company plans to charge new customers (i.e., new premises added to the system) $26.25 per month. This fixed charge is $16.25 more per month than the proposed fixed charge for existing residential customers.

Q. Why is the Company seeking to increase the monthly fixed charge for new customers?

A. The proposed fixed charge for new customers is designed to address intra-class equity concerns between our existing and new residential customers, which is a component of our responsible growth strategy. This proposal developed out of our most recent rate case, in which Staff provided testimony describing the intent and history of the Company's decoupling mechanism.[8] In its analysis, Staff was concerned that the use per customer ("UPC") of new residential customers joining the system is materially lower than the decoupling baseline UPC for existing residential customers.[9] As part of that case, NW Natural committed to providing updated data on UPCs of new residential customers.[10]

In evaluating that data, it is clear that new residential customers are using less gas than our overall residential customer base. On average, new residential customers are using approximately 210 therms less than our existing residential customer base (660 therms per year). Under the existing decoupling mechanism, new customers would be decoupled to the 660 therm baseline, meaning that the differential between their actual usage and the baseline would be collected in the decoupling deferral each year and recovered from all decoupled customers. While ratemaking is never perfect, we strive to make our rate mechanisms as fair and

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[8] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision,* Docket No. UG 435, Exhibit Staff/1300, Scala at 16-17 (Apr. 22, 2022).

[9] Id. at 19-20.

[10] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision,* Docket No. UG 435, Second Partial Stipulation (June 29, 2022).

equitable to our customers as practicable. Given the differential between existing and new customer usage, we are concerned that our existing customer base is subsidizing our new customers through the decoupling mechanism.

As a result of this analysis, the new monthly fixed charge is set to reflect the difference in the UPC for new customers compared to existing customers. The fixed charge will ensure that new customers as a group are contributing equivalent contributions for their cost of service as existing customers, while preserving the decoupling mechanism, which has been central to our conservation efforts for two decades.

Q. Please describe NW Natural's proposal to update its LEA.

A. NW Natural is proposing a first of its kind LEA that provides a higher line extension allowance for customers that use less natural gas. Customers that use a higher amount of natural gas will receive a reduced line extension allowance. The new proposed LEA aligns with our vision for the future of the gas system where customers consume less throughout the year, but still rely on it for the winter peak performance of gas furnaces and fireplaces, and other customer preference features like gas cooktops and tankless water heaters—all with models that can operate in a power outage. Lower usage also results in lower emissions, which aligns with NW Natural's and the state's climate goals.

Q. Please provide background on NW Natural's current LEA.

A. Gas and electric utilities evaluate the addition of new customers by comparing the incremental revenue from a new customer to the incremental investment cost to connect them to the system, inclusive of the utility's fair rate of return.

Fundamentally, it is a financial transaction between the utility and the new customer. If the incremental revenues do not exceed the incremental cost, then the new customer will be required to pay for the difference. This methodology, which is commonly accepted, is specifically designed to prevent subsidies.

In our prior rate case (UG 435), NW Natural's former LEA was challenged because NW Natural had not incorporated CPP compliance costs into the financial LEA model. The theory was that new customers will be less beneficial to the system because those new customers' emissions will bring more costs to the system. While NW Natural disputed a proposal to phase out and eliminate the LEA, the issue was ultimately decided by the Commission. The Commission ordered NW Natural to reset its LEA to represent a "five times margin" approach, which reduced the available LEA to $2,300. The Commission directed that the LEA would be phased down to "four times margin" and "three times margin" over the following two years. As of November 1, 2023, our maximum available LEA for a residential customer is $1,840. In its Order, the Commission provided NW Natural an opportunity to propose changes to its LEA with the expectation that NW Natural would address, among other things, the costs of the CPP in the LEA and the changing policy environment.

Q. Please describe NW Natural's updated LEA proposal.

A. By incorporating the CPP costs into the LEA model, while also factoring in the benefits to spreading future fixed costs of the distribution system to new customers, the model produces an LEA that decreases with more expected throughput. This is because under the current CPP, compliance costs increase with each expected therm of gas consumed. In other words, customers are still producing a benefit for the system, but the benefit diminishes with increased use.

Based on the results of the LEA model, we are proposing four levels of LEA determined by the expected usage at the residence. For low use customers (between 0-250 therms annually), the LEA will be set at $3,600. For typical new customers (between 251-450 therms), the LEA will be set at $3,100. For higher use customers (between 451-650 therms), the LEA will be set at $2,600. For the highest use customers (651 therms and higher), the LEA will be set at $1,800 (based on 1,000 therms).

The proposed LEA model is responsive to a lower-use future by sending price signals to consumers associated with their expected usage.

Q. Are there other changes to our current regulatory mechanisms that NW Natural intends to propose in a subsequent general rate case?

A. Yes. We believe that further changes to our regulatory mechanisms should occur in response to the pressing demands on NW Natural. We view multi-year rate plans as an important vehicle to allow NW Natural to effectuate these changes, and to do so in a manner that eases the rate impacts over steady, annual rate changes compared to single year, “lumpy” rate cases.

Q. Please describe what a multi-year rate plan is and why NW Natural intends to pursue such a plan in its next general rate proceeding.

A. A multi-year rate plan would set rates over a period of several years. Multi-year rate plans typically use an index or forecasts (or some combination thereof) that allow for rate changes over the course of the plan. The multi-year rate plan would also include a stay-out provision, which ensures that a utility could not file a general rate case that seeks to otherwise change rates during the term of the multi-year rate plan. In contrast, rates in Oregon are typically set based on costs incurred during a single forward Test Year, resulting in utilities often having to file another rate case within, or soon after, the rate case Test Year.

Q. Why does NW Natural anticipate proposing a multi-year rate plan in its next general rate proceeding?

A. NW Natural anticipates proposing a multi-year plan for several reasons. First, it anticipates increasing costs associated with scaling a decarbonization platform, modernizing IT&S and migrating to the cloud, and maintaining a safe and reliable natural gas system. Given these increasing costs, NW Natural would likely file a series of general rate proceedings over the next several years absent a multi-year plan.

Second, a multi-year plan will smooth out rate impacts for customers. When a utility does not file annual rate cases, the difference between the costs that are recovered in rates and the utility's actual costs will increase with time. While customers often benefit from that lag between rate cases, when the rates are eventually reset the entirety of that difference will be recovered in one rate change. With a multi-year plan, annual rate changes will incrementally adjust for the utility's costs. This will allow for customers to be better prepared for their utility costs because the volatility in rates should be mitigated by annual changes.

Third, while filing annual rate cases could also address rate-smoothing, rate cases are highly resource intensive proceedings that strain the Commission, rate case intervenors and the utility. A multi-year rate plan would reduce the workload of all interested participants compared to having several sequential general rate cases over the same span of time.

Fourth, a multi-year rate plan avoids systemic regulatory lag that benefits both NW Natural and its customers. NW Natural would benefit from being able to add capital investments to rate base as they enter service over the course of the multi-year plan, thereby avoiding regulatory lag. Additionally, a multi-year plan would include opportunities for stakeholders to review and audit capital investments after they enter service. Customers would also benefit because existing net plant would be reduced each year, all else equal, whereas this benefit only currently occurs immediately after a general rate case.

Q. Given these advantages, why isn't NW Natural proposing a multi-year rate plan as part of this proceeding?

A. While there are advantages to a multi-year rate plan, there are a number of issues that must be addressed, such as how to determine expense levels and rate base beyond the first year the plan is in effect (i.e., beyond the scope of a typical Oregon rate case). Additionally, there should be appropriate procedures in place for audits to ensure that capital investments are placed in-service by a designated time. By signaling that NW Natural intends to propose a multi-year rate plan in the future, NW Natural seeks to engage with Staff and intervenors within the context and timing of this general rate case to address—or at least identify—these important issues prior to making such a filing in its next rate case.

Q. Does NW Natural have any preliminary thoughts on these issues?

A. Yes. Given that NW Natural is not proposing a multi-year rate plan in this proceeding, we are only conceptually discussing the mechanics of a multi-year rate plan at a high level. That said, NW Natural anticipates that multi-year rate plans could be set for three to four years. Rates set beyond the typical forward Test Year would include inflationary adjustments for expenses similar to the current treatment of many types of expenses. The actual rate used for inflationary adjustments can be updated prior to changing rates each year. Similarly, NW Natural can set rates for cost increases or decreases due to other known factors. For example, cloud services costs often escalate each year pursuant to contract.

For capital investments beyond the typical Oregon forward Test Year, rate base would be set by demonstrating a capital forecast with reliable categories of anticipated expenditures (e.g., public works, vehicles and equipment, transmission and distribution integrity management). For larger, discrete projects, NW Natural would specifically identify these projects, provide sufficient evidence to justify prudency, the project costs and expected in-service dates. To the extent there were material updates to the costs, timing, or status of a project, NW Natural would provide updates through the pendency of the rate case or through a determined process prior to resetting rates after the first-year rate change.

We look forward to exploring these issues with the parties and the Commission throughout this proceeding.

V. EQUITY

Q. In Policy Testimony in its last rate case, NW Natural highlighted several important equity initiatives. Please describe these initiatives.

A. In Policy Testimony in our last rate case (UG 435, NW Natural/100, Anderson-Kravitz), we described our plans to develop a CEAG, perform a LINA, and establish a residential bill discount program. The Direct Testimony of Cecelia J. Tanaka in this rate case (NW Natural/200, Tanaka) discusses the Company's equity initiatives in detail.

Q. Did NW Natural develop a CEAG?

A. Yes. NW Natural formed the CEAG as planned in 2022. The CEAG is integrated into many initiatives across the Company, including low-income programs, renewable resource development, and philanthropic investment. To form the CEAG, NW Natural engaged community-based organizations ("CBOs") that have not been involved in energy planning and Company program planning opportunities, especially those CBOs that serve an identity, community and underrepresented/underserved population present within NW Natural's service territory in Oregon and Washington.

Q. Please summarize how NW Natural is advancing equity through the CEAG.

A. NW Natural conducts quarterly meetings of the CEAG, focusing on concrete, actionable issues, such as how to improve NW Natural's outreach strategies. Like any consultant, CEAG members are compensated for their time. CEAG members receive $5,000 per year, which reflects a 30-hour annual commitment at $160 per hour. This amount is on par with similar types of consulting services. NW Natural has also hired a third-party consultant to lead meetings, advise and ensure responsiveness and accountability.

Q. Did NW Natural conduct a LINA?

A. Yes. A third party, Applied Energy Group ("AEG"), completed a LINA in 2022. Broadly speaking, the LINA identified barriers to participating in energy efficiency programs, such as affordability and lack of awareness of the Company's offerings. AEG recommended that NW Natural increase awareness of its energy efficiency programs, including low or no cost options. The LINA also mapped customers' energy burden by census block and provided recommendations on streamlining program participation.

Q. Regarding the LINA, please briefly summarize NW Natural's next steps.

A. NW Natural is in the process of scoping our second LINA, where NW Natural will require a third-party consultant to create an income propensity model so the Company can learn more about where its low-income customers reside to provide education and assistance accessing various programs. This model will be more granular than the assessment conducted in the first LINA, which focused on census blocks. NW Natural is also working to implement recommendations from the original LINA.

Q. Has NW Natural established a residential bill discount program?

A. Yes. NW Natural began its residential bill discount program on November 1, 2022. Under the current program, customers with income less than 60 percent of Oregon state median income can currently qualify for up to a 40 percent discount on their monthly bill based on household size and income. In this proceeding, NW Natural is seeking to increase this discount from 40 percent to 80 percent for customers with income less than 15 percent of the state median. It is also seeking to increase the discount from 25 percent to 40 percent for customers with incomes less than 30 percent of the state median income. With these changes, NW Natural is targeting to reduce participating customers' gas usage-related energy burden to 3 percent or less.

Q. Since its inception, has NW Natural seen increased participation in the residential bill discount program?

A. Yes. When the program was launched, over 11,000 customers who had previously received energy assistance within the past two years were auto-enrolled into the program. Enrollments have grown steadily, and through October 2023, the cumulative number of participants is 37,222, which represents 5.84 percent of all residential customers. NW Natural's bill assistance programs, including the Oregon Low-Income Gas Assistance Program, the Gas Assistance Program, and the residential bill discount program, are fully described in the Direct Testimony of Cecelia J. Tanaka.

VII. SUMMARY OF WITNESSES

Q. Can you briefly describe the testimony provided by other witnesses in this case?

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

Cecelia J. Tanaka, Community Partnerships Manager, describes the Company's initiatives and priorities regarding equity and inclusion, provides an update regarding the Company's LINA and low-income assistance offerings, proposes enhancements to the bill discount program targeting reduced energy burdens for customers most in need, and demonstrates that the Company's low-income assistance offerings continue to provide relief for energy-burdened customers. NW Natural/200, Tanaka.

Brody J. Wilson, Interim Chief Financial Officer, Vice President, Treasurer, Chief Accounting Officer and Controller, provides testimony about the Company's cost of capital. His testimony provides information about the costs of the Company's long-term debt during the Test Year. Mr. Wilson's testimony explains that the Company continues to adhere to its policy of balancing long-term debt and equity financing by targeting a 50/50 capital structure. Mr. Wilson requests to maintain our most recently Commission-approved capital structure of 50 percent common equity and 50 percent long-term debt, resulting in an ROR on rate base of 7.406 percent. Natural/300, Wilson.

James M. Coyne, Senior Vice President, and **Jennifer E. Nelson**, Assistant Vice President, of Concentric Energy Advisors, Inc., a firm with expertise on utility finance and required rates of return for regulated companies, 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. Their testimony provides an analysis of NW Natural's cost of equity, and a range of return on equity that NW Natural should be given the opportunity to earn in order to attract capital. The testimony supports a reasonable range for the Company's cost of equity between 9.8 percent and 10.4 percent, and Mr. Coyne and Ms. Nelson recommend that NW Natural be allowed an opportunity to earn a 10.1 percent return on equity in the revenue requirement authorized in this proceeding. NW Natural/400, Coyne-Nelson.

Daniel B. Kizer, Engineering Senior Director, provides testimony about some of the major improvements to our distribution system and storage facilities that the Company has undertaken in order to keep our system safe, reliable, and economical. Mr. Kizer also discusses NW Natural's ongoing plans for safety-driven system projects and programs, in connection with the Company's 2024 Safety Project Plan filed in docket UM 1900. NW Natural/500, Kizer.

Wayne K. Pipes, Director of Facilities, Security and Emergency Management, describes the Company's execution of our long-term plan to update our regional resource centers for a variety of reasons, including upgrading them seismically, improving emergency response times, ensuring compliance with applicable requirements, making mechanical and electrical upgrades, resolving space constraints and improving inadequate facilities. Mr. Pipes also details our recent projects to protect the safety of our critical infrastructure in light of a wave of recent incidents targeting utility and energy infrastructure. NW Natural/600, Pipes.

Jim R. Downing, Vice President and Chief Information Officer, describes NW Natural's ongoing IT&S context and strategic approach, provides a preview of H2: Vista, and details the Company's cost-recovery requests with respect to major projects and crucial hiring needs. NW Natural/700, Downing. Mr. Downing 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, Downing (Sensitive Security Information).

Joe S. Karney, Vice President of Engineering and Utility Operations, presents 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. Finally, Ms. Rogers sets forth 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.

Brody J. Wilson and **Nikki R. Sparley**, Treasury and Investor Relations Director, discuss the factors that are causing significant changes to uncollectible expense and provide the Company's proposal for forecasting uncollectible expense in this rate case. NW Natural/1300, Wilson-Sparley.

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/1400, Davilla.

Zachary D. Kravitz and **Anna K. Chittum**, Director of Renewable Resources, provide an update on our decarbonization efforts under the CPP and propose updates to the Company's renewable natural gas automatic adjustment clause. NW Natural/1500, Kravitz-Chittum.

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/1600, 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, enhancements to the decoupling mechanism and presentation of tariffs. NW Natural/1700, 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. Mr. Wyman also proposes a new fixed charge for new residential customers, and proposes creating a separate fixed charge for residential multi-family customers, reflecting a lower cost to serve those customers compared to single family residential customers. NW Natural/1800, Wyman.

Gregg H. Therrien, Vice President at Concentric Energy Advisors, updates NW Natural's LEA. In support of the Company's request, Mr. Therrien presents a revised discounted cash flow analysis (with supporting calculations) and a revised LEA tariff. His testimony also supports the incremental costs and benefits of adding a new customer to the natural gas distribution system, consistent with the Commission's directives regarding the LEA issued in Order No. 22-388 of docket UG 435 in the Company's last rate case. NW Natural/1900, Therrien.

As described by these witnesses in greater detail, NW Natural is requesting to revise the rates we charge to reflect continued investment in our distribution system and increasing costs. While we recognize that rate increases can be difficult for our customers, the recovery of the critical investments in our system will ultimately benefit our customers because it supports NW Natural's ability to operate a financially sound natural gas utility that will continue to provide safe and reliable service.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Direct Testimony of Cecelia J. Tanaka

EQUITY
EXHIBIT 200

December 29, 2023

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 Community Partnerships Manager 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. Prior to NW Natural, I have 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 low-income needs assessment and low-income assistance offerings.

Q. Please summarize your testimony.

A. In my testimony, I describe the Company's Community Equity Advisory Group ("CEAG"), including providing background and context for the formation of the CEAG and the Company's engagement with the CEAG to help inform the consideration of equity in the Company's proposals. I also describe the Company's recent Low-Income Needs Assessment ("LINA"), and detail the lessons learned from this assessment and the Company's plans for additional studies. I explain the Company's existing bill assistance offerings and how the Company is proposing deeper discounts to mitigate energy burden for customers. I describe the Company's Oregon Low Income Energy Efficiency ("OLIEE") Program, and the Company's recent major projects performed under this program. I also explain how the Company is mitigating energy burden in this rate case and how the Company proposes to continue examining refinements to its existing programs. Finally, I describe the Company's efforts to address diversity, equity, and inclusion within the Company and in the community.

II. 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. Climate change disproportionately impacts the very communities least likely to be involved in energy planning and decision making—low-income communities, people of color, rural residents and seniors are prime examples of this disconnect. Through deeper community engagement via the CEAG, NW Natural will be positioned to uncover and understand barriers to equitable participation; and, in turn, formulate strategies to address those barriers and center equity in our work ensuring that diversity, equity and inclusion are not merely convenient add-ons, but catalysts for change.

Q. Why was the CEAG established?

A. The CEAG was established to bridge this divide and place equity and environmental justice principles at the forefront of decision-making conversations and practices at NW Natural. The purpose of the CEAG is to provide NW Natural direct feedback, recommendations, advice, and review on areas related to (a) system planning and renewable resource development, (b) low-income programs, (c) arrearage programs, (d) Company-sponsored philanthropic investments, and (e) other areas as determined by the CEAG and NW Natural. Specific deliverables may include developing a CEAG plan, drafting guidelines for engaging diverse stakeholders, and coordinating with other NW Natural technical working and/or advisory groups to evaluate recommended strategies for improving energy equity.

Q. Was the CEAG formed in response to a statute or direction from the Commission?

A. No. The CEAG was initially identified as a need by the NW Natural Integrated Resource Plan team, but we see the advisory group's influence and impact extending beyond system planning decisions and being integrated into other efforts throughout the Company, including (but not limited to) low-income programs, renewable resource development, and philanthropic investment.

NW Natural embarked on the development of its CEAG voluntarily and in the absence of policy guidelines and parameters—as such, we are drawing on best practices from peer utilities and other stakeholders, including Puget Sound Energy, City of Portland, City of Gresham, Port of Portland, and Portland General Electric Company ("PGE"), and soliciting input from our third-party consultant, Traci Simmons. Ms. Simmons has a long and distinguished career facilitating diversity, equity, inclusion, and belonging priorities at large institutions—with special attention to newly formed groups. These credentials demonstrate a deep understanding of the responsibilities of public-facing organizations in addressing service and participation disparities in underserved communities and a well-established track record of navigating complex environments. Ms. Simmons currently serves as the Associate Vice President of Diversity, Equity and Inclusion at Mt. Hood Community College.

Q. How did NW Natural recruit CEAG participants?

A. CEAG recruitment focused on community-based organizations ("CBOs") that serve an identity, community, and underrepresented/underserved population present within the NW Natural service territory in Oregon and Washington — prioritizing organizations that had not participated in energy planning and Company program planning opportunities in the past.

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.

Examples of how we are fulfilling this commitment include:

- Centering quarterly meetings on concrete, actionable asks of the advisory group—an approach that demands clear expectations, thoughtful planning, and ongoing dialogue.
- Compensating organizations for their time, expertise, and engagement; organizations receive $5,000 per year and the estimated time requirement for the year is 30 hours (rate of $160/hour which is on par with similar types of consulting services).
- Hiring a third-party consultant to lead meetings, advise, and ensure responsiveness and accountability; NW Natural utilizes best practices and guidance from the third-party consultant to develop processes of

documentation and response to advisory items brought forward by the CEAG.

- Formalizing feedback and accountability measures with respect to CEAG input: at each CEAG meeting, NW Natural provides a detailed report to the CEAG on topics such as the concrete actions, deliverables, and milestones achieved that were undertaken or achieved since the last meeting and under the recommendations from CEAG members.
- Sourcing meeting topics based on feedback from CEAG members.
- Recruiting culturally specific organizations not currently involved in the energy justice sphere.

Q. Please provide an example of a topic addressed through the CEAG.

A. The first official CEAG meeting—with representation from all external members, internal departments, the core CEAG team, and our third-party consultant---focused on bill discount outreach. We dedicated the first half-day meeting to outreach strategies to better understand how partner organizations effectively reach and communicate with the individuals they serve, what strategies they employ and have identified to be the most impactful for awareness and action—to inform our outreach strategies on the bill discount program and beyond. The first CEAG meeting preceded the launch of the bill discount program by approximately five weeks, which allowed our planning teams to incorporate the following feedback from the CEAG before the program went live on November 1, 2022:

- Toolkit: Development of a communications and outreach toolkit for community partners, which included printable resources, digital materials and customizable content to streamline outreach efforts and allow for easy integration into existing channels of communication (an online version was also developed).
- Plain language review: A new step in the content creation process included two rounds of a Plain Language[1] review—a consulting service to edit and adapt content for greater accessibility and readability to a 6-8th grade reading level. This was provided by The Next Door,[2] a Hood River-based nonprofit partner, grantee, and CEAG member.
- A QR code and two sets of contact numbers, (503) and (800), were included in outreach materials.
- A bill discount program poster for waiting rooms, events and shared spaces.
- Information on the ease of application was included in outreach materials, messaging and the application homepage.

Feedback from the CEAG implemented (after the November 1 launch) includes:

[1] The Next Door, Inc., Consulting Services Flyer, "Diversity Training and Language Services of The Next Door, Inc." available at: https://nextdoorinc.org/wp-content/uploads/2017/10/Consulting-Services-Flyer.pdf (Sept. 11, 2017).

[2] The Next Door, Inc., Plain Language Training, available at: https://nextdoorinc.org/events/plain-language-training-3/ (Jul. 30, 2020).

- Ad spots on Spanish language radio.
- Informational sessions. For example, in June 2023, NW Natural sent three representatives to a community event at Lents Elementary School, a SUN school where Spanish is the predominant language among families; two of the NW Natural representatives were bilingual (Spanish/English) and came from NW Natural's Customer Contact Center.

III. LOW-INCOME NEEDS ASSESSMENT

Q. Has NW Natural performed a low-income needs assessment?

A. Yes, in 2022, the Company engaged Applied Energy Group ("AEG") to perform a LINA to provide insight into customer and community characteristics, eligible populations, penetration of current Energy Assistance offerings, and barriers and opportunities for current or future Energy Assistance offerings. The Company's completed LINA is attached as Exhibit NW Natural/201, Tanaka. To complete this assessment, AEG combined NW Natural data with publicly available secondary sources to provide a granular geographic picture of NW Natural's Oregon and Washington service areas; and then used this information to survey NW Natural's income-qualified residential customers.

Q. What was the scope of the LINA?

A. The scope of the LINA spanned: general awareness of income-based programs, program interest, barriers to participation and other behavioral insights among the low-income survey population. The LINA also included a tool that mapped energy burden and income throughout NW Natural's territory—AEG was able to calculate each household's energy burden based on actual billing data from NW Natural, estimated electric costs from United States Department of Agriculture's Rural-Urban Commuting Areas Codes and reported income submitted through the survey.

Q. Please describe the results of the LINA.

A. The LINA serves as an early step in better understanding our lower income customer base. It helped to uncover areas of opportunity for greater engagement, household characteristics and preferences and high priority needs; as well as topics and survey questions to include in a next LINA. The LINA survey targeted customers with a high probability of being eligible for income-based assistance programs.

The LINA identified barriers to participation in energy efficiency ("EE") programs, provided specific recommendations regarding EE programs and more generalized recommendations to enhance participation in energy assistance programs. Some of the barriers to participation in EE programs were:

- Affordability of EE products
- Unaware of EE products
- Credibility of EE products' effectiveness
- Complexity of paperwork to participate

The overall recommendations included:

- Addressing cost barriers/affordability of EE products – Over 60 percent of survey respondents indicated they cannot afford energy efficient equipment purchases with or without rebates. While there is a lack of knowledge by customers as to what EE measures NW Natural offers free of charge, the identified cost barriers can be addressed. AEG recommended a few ways to address reducing the cost barriers for EE upgrades for income-qualified customers, many of which the Company already is doing through the OLIEE Program.
- Increasing customer awareness and education – Survey results indicated low awareness of NW Natural's energy assistance programs. AEG notes that the Company has a significant opportunity to increase participation in EE measures and energy assistance through robust outreach and education of such programs.
- Discount program design and streamlining program participation – Survey results showed over 60 percent of customers preferred a discount program over bill forgiveness or time payment arrangement. AEG recommended that the Company offer between 15 percent and 25 percent bill discounts to income-eligible customers. Survey results also showed that customers prefer instant discounts on EE products.
- Building trust through testimonials – Of those surveyed, 25 percent of customers do not believe installing EE measures in their home will add

benefit. AEG suggested reinforcing the benefits of EE measures by promoting testimonials from customers who have participated in NW Natural's programs. AEG also commented that focusing on increased comfort and reducing energy bills will resonate well with income-eligible customers.

- Mapped energy burden analysis by census block group[3] – AEG provided a mapping tool that identified areas of higher-than-average energy burden based on average natural gas bills and analysis estimating an average electric bill. The map showed overlays of zip code, county, and energy burden over NW Natural's service territory. The mapping provides an opportunity to target marketing to income-eligible areas.

Other survey findings included:

- One barrier to program participation relates to lack of knowledge of NW Natural energy assistance and EE programs. Approximately 25 percent of respondents were aware of program offerings (both income-based energy efficiency and energy assistance programs).
- Of those surveyed, homes reporting an income of less than $30,000 are likely to be energy burdened – above 6 percent of annual income dedicated to utility costs.

[3] Used residential building stock assessment estimated the average annual electricity usage for natural gas heated homes and average and applied electric rates (from Clark Public Utility District and PGE) to get an estimated average annual electric cost.

- Discount programs ranked higher than forgiveness programs and time arrangement payments. More than 25 percent have heating systems that are near the end of their useful life.
- Over 40 percent have manual thermostats, which provides a significant opportunity for outreach to customers and offering free thermostats.

Customers are very interested in free products, installation, and audits, as well as point of purchase discounts. It may be difficult for certain customers to purchase energy efficient equipment, even if a rebate is offered, and accordingly, there is a preference for free services and equipment.

Q. What else was provided in the LINA?

A. Besides the survey, which was valuable in itself, AEG performed a basic energy burden analysis which also included a mapping tool to identify low-income and energy burdened customers in NW Natural's service territory at the census block level. Although the mapping tool is based on census block information using average income information by block, it did not identify how many NW Natural customers were in each census block.

Q. How have the lessons learned from the LINA informed NW Natural's plans for a second LINA?

A. In the next LINA, NW Natural will require an income propensity model so the Company can learn more about where its low-income customers reside to provide education and assistance accessing various programs. As explained above, the AEG-provided mapping tool, by census block group, did not reveal specific information about our customers. Some other lessons learned from the LINA study are:

- Customers are unaware of NW Natural energy assistance or weatherization services.
- Customers will participate in a program that can help lower monthly bill payments or connect customers to free weatherization services.
- Customers stated a 15 percent discount on their monthly NW Natural bill would have meaningful impact on their household finances and overall well being.
- Customers trust NW Natural as a source of information about energy assistance.
- Increasing customer education on the benefits of energy-efficient products may increase customers' adoption and participation in NW Natural programs.

Q. Does NW Natural plan to conduct another LINA in the near term?

A. Yes. In late fall 2023, Commission Staff informed the Company of its plan to ask utilities to provide updated LINAs by mid-2024 as part of a work stream led by Staff in the UM 2211 proceeding. NW Natural looks forward to actively participating in the UM 2211 proceeding to develop our second LINA.

IV. INCOME-BASED BILL ASSISTANCE PROGRAMS

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

A. NW Natural offers the Oregon Low-Income Gas Assistance Program ("OLGA") and the supplemental low-income assistance program, the Gas Assistance Program ("GAP"), to assist income eligible residential customers with energy costs. Additionally, NW Natural launched its residential bill discount program for qualifying residential customers in late 2022.

Q. What is OLGA?

A. OLGA addresses the needs of low-income Oregonians and makes it possible for these households to stay warm throughout the coldest months of the year. OLGA steps in to provide funding where the federal Low-Income Home Energy Assistance Program ("LIHEAP") cannot, due to lack of monies available outside of the winter months. Although NW Natural can access LIHEAP from December to April, recently, more and more customers are needing assistance outside of the main heating season and into the shoulder and summer months. Without assistance, many low-income households will turn off their gas after the winter because they cannot afford the bills they have received. Customers face the inability to turn their gas heating back on in the fall when temperatures drop because they have been unable to catch up with payments. OLGA steps in to fill the need from April to December and ensure these customers who would otherwise fall through the cracks are able to receive assistance and access fall and winter heating.

Q. What is GAP?

A. Separately, GAP is a program that exists to provide funds to low-income households to assist with heating bills. GAP is funded by NW Natural shareholders, employees, retirees, and customers through a donation-match program. NW Natural shareholders match the first $60,000 in donations received; GAP benefits from community donations and fundraising that NW Natural promotes through bill inserts, newsletters, social media, and community events. Additionally, GAP receives funds through state funding grants.

Q. What is the residential bill discount program?

A. NW Natural launched its 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 and self-certification of income eligibility by customers and a tiered discount structure that provides larger discounts to households with lower incomes. Customers with income less than 60 percent of Oregon state median income qualify for some level of assistance within the program's tiered discounts. Customers can qualify for up to a 40 percent discount on their monthly bill based on household size and income.

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

A. Yes. LIHEAP is a federally funded program that provides grants to eligible customers to assist with their energy bills.

Q. How many customers have been participating in NW Natural's OLGA and GAP?

A. NW Natural's bill assistance programs, OLGA and GAP, have seen steady participation over their 20-year histories. For the 2022-2023 program year, OLGA provided 7,553 residential customers with assistance. This resulted in about $3.7 million in payments to customers. GAP has helped 1,525 customers in the 2022-2023 program year by providing over $195,000 in assistance to these households. As the Company expands outreach through a variety of avenues, it expects to see additional participation by eligible customers.

Q. How has enrollment increased over the first year of the bill discount program?

A. NW Natural has seen a three-fold increase in enrollment since the program was launched. NW Natural's residential bill discount program began on November 1, 2022. At the time of program launch, over 11,000 customers who had previously received energy assistance within the past two years were auto-enrolled into the program. Enrollments have grown steadily, and through October 2023, the cumulative number of participants reached 37,222, which represents 5.84 percent of all residential customers. Table 1 provides a summary of the number of households that have been served by NW Natural's bill assistance programs over the past five program years.

Table 1. Households Served by Income-Based Bill Assistance Programs

	October 1 - September 30 Program Years				October 31 Count	
	OLGA	**OLIEE**	**GAP**	**LIHEAP**	**Bill Discount**	**Totals**
2018-19	7,685	260	1,366	1,789	n/a	11,100
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
	32,310	1,189	6,071	11,296	37,222	88,088

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

A. NW Natural has informed customers about its programs through a variety of avenues, including targeted outreach, direct engagement, and paid ads.

Q. How is NW Natural leveraging relationships with community partners to promote outreach and engagement regarding energy assistance and bill discount offerings?

A. 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 were especially meaningful and allowed 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. Our outreach efforts included the development of an Outreach & Communications Toolkit which includes printable resources, digital materials and other customizable content to streamline outreach efforts and allow for easy integration into existing channels of communication—allowing for organizations to choose what works best for who they serve and how.

The Company has provided its community partners information and resources to pass on to its clientele. Examples of such information and resources include PowerPoints discussing programs and unique URLs to allow easy access to information, program and enrollment details to be disseminated, talking points to keep community partners informed and able to assist enrollment, language and graphics to be used on social media, text messages, and newsletters to allow digital outreach, and brochures and posters that can be posted prominently to inform customers. In addition to working with these partners, the Company is performing direct outreach through non-profit led channels, including check-in calls with homebound seniors, brochures inserted in food boxes at schools and food pantries, and information mailers and social media posts. The Company has successfully partnered with hundreds of distinct community partners to disseminate information in over 80 neighborhood newsletters, more than 100 city and library homepages, 17 county agencies, 835 schools in over 100 school districts, and over 100 public libraries. The Company has also partnered with federal and state agencies to make this information available and has distributed over 35,000 brochures with information on assistance programs. NW Natural leads additional outreach through in-person events, such as preparing a vendor table at community events (IRCO Sun School utility, Coos County Farmer's Market, Housing Oregon annual conference, TriMet Annual Servicer Change & Fare Proposal open houses, Community Action weatherization open houses, OECA Conference, CUB, Mid-Willamette Valley Community Action Agency weatherization Open House), housing conferences, stakeholder network meetings, local farmers' markets, and community open houses.

Q. What are examples of targeted outreach NW Natural is conducting for the bill discount program.

A. On top of the activities detailed above, the Company has piloted several data-informed, targeted outreach initiatives to amplify its efforts and reach especially vulnerable populations, including:

1) *Low-income, energy burdened households*. Cross-referencing data on pockets of high poverty and energy burden rates (identified through the LINA), the Company is conducting additional outreach in those areas with disproportionately low bill discount enrollment rates despite high probability of energy burden and income poverty.

2) *Families eligible for free or reduced meals*. The Company is redoubling outreach to Title I Schools and Head Start centers to get program information directly to households that meet income guidelines[4] that align with those of the bill discount program.

3) *Manufactured Home Park residents*. Home to roughly one in twelve Oregon residents, manufactured home parks ("MHP") shelter large

[4] Oregon Department of Education, Child Nutrition Program, Online Free and Reduced Meal Applications, available at: https://www.ode.state.or.us/apps/FRLApp/Default/Apply#:~:text=Children%20participating%20in%20their%20school%27s,are%20eligible%20for%20free%20meals.&text=Children%20who%20meet%20the%20definition,are%20eligible%20for%20free%20meals

populations of low-income, senior and immigrant homeowners with median annual incomes of less than $30,000—less than half of the national average of $64,000. MHP residents also face significantly higher energy costs and rates of energy burden due to the inefficient infrastructure of manufactured homes built before 1980. The American Council for Energy-Efficiency Economy (ACEEE) reports that older manufactured homes consume 53 percent more energy than the average home and that energy costs per square foot in manufactured homes are double those in site-built homes. These factors depict an especially vulnerable and often isolated population—and one highly in need of some reprieve from their energy bills.

NW Natural also conducted direct outreach to Title 1 schools and others with high percentages of families eligible for free and reduced meals; as well as dozens of Head Start programs throughout the Company's territory to get program information directly to the households and families served by these institutions.

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

A. Yes. In addition to the direct outreach described above, the Company has sponsored paid ads on local radio stations, including Spanish-language ads, to inform customers of its low-income programs. The Company has also purchased digital ads across other websites and social media platforms. Finally, the Company has dedicated its public service announcement budget entirely to notifying eligible customers about the bill discount program. NW Natural's efforts are the result of a developed, targeted outreach plan that aims to spread awareness of these programs in order to reach the demographics that could greatly benefit from participation.

Q. Is NW Natural proposing any changes to its income-based bill discount program at this time?

A. Yes, we propose to increase the discounts offered to more specifically address and mitigate the energy burden experienced by the Company's lower income customers.

Q. What is energy burden?

A. Energy burden is defined as the percentage of gross household income spent on energy costs.[5] If a household spends more than 6 percent of their income on energy costs, they are considered energy burdened, and if a household spends more than 10 percent of their income on energy costs, they are considered extremely energy burdened.[6]

Q. How will NW Natural's proposal reflect consideration of energy burden?

A. The Company proposes to increase the bill discount percentages for Tier 1 and Tier 0 to target a participant's bill with discount as a percentage of income to be at or near 3 percent. In doing so, we are using a participant's bill with discount as a percentage of income as a proxy for a customer's energy burden related to their natural gas bill. The intent of targeting 3 percent is to minimize the energy burden

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[5] Or. Housing and Community Services, Statewide Housing Plan: Definitions Appendix at 2 (Feb. 2019) (available at https://www.oregon.gov/ohcs/Documents/swhp/swhp-appendices-20181015.pdf).

[6] *Id.*

related to natural gas service to less than half of the 6 percent that is commonly understood as the indicator of energy-burdened customers.

Q. Please explain why an update to the bill discount program is being proposed at this time.

A. When the bill discount program was being designed in 2022, the income tiers were determined in a collaborative manner among the Company, Commission Staff, and low-income advocates through a series of workshops and comments in docket ADV 1390. At that time, bill discount programs for Oregon investor-owned utilities were in a nascent stage and NW Natural, Staff and stakeholders worked together to determine a reasonable starting point for the discount tiers. As we had discussed throughout the ADV 1390 regulatory process, NW Natural has reviewed the discount tiers of the bill discount program using experience and data gained since the launch of the program and guidance from the LINA to arrive at the proposed changes intended to better reduce the energy burden of those customers most in need.

In addition to targeting the 3 percent energy burden related to natural gas service, we have updated our analysis of the discount tiers to include rates as proposed in this case and, importantly, made an adjustment to consider the mid-point of an income range when calculating the average annual bill with discount as a percentage of income instead of using the max of the income range. NW Natural used the max of the income range when initially designing the tiers in ADV 1390. Using the mid-point of the income range to determine the bill discount percentage for each tier provides better coverage of reduced energy burden throughout the tier. In addition, updating the analysis to include the rates proposed in this case and current income eligibility tables along with using the mid-point of the income range results in changing the Tier 1 discount from 25 percent to 40 percent and changing the Tier 0 discount from 40 percent to 80 percent. The analysis shows that the current discount percentages in Tiers 3 and 2 are adequate to achieve the target of 3 percent or less.

Tables 2 and 3 below provide a comparison of the current discount tier and the proposed discount tier and illustrate the changes in the average annual bill, income eligibility tables, use of mid-point versus max-point income for each tier and the proposed change to discount percentages.

Table 2 - Current Bill Discount Tiers

Bill Discount Program Impacts, Assuming Household of 4:				
	SMI 60%	**SMI 45%**	**SMI 30%**	**SMI 15%**
	Tier 3 - 15%	**Tier 2 - 20%**	**Tier 1 - 25%**	**Tier 0 -40%**
Income max of tier	$56,430	$42,323	$28,215	$14,108
Average annual bill	$758.35	$758.35	$758.35	$758.35
Bill as % income before discount	1.3%	1.8%	2.7%	5.4%
Bill discount	$113.75	$151.67	$189.59	$303.34
Bill after discount	$644.60	$606.68	$568.76	$455.01
Bill as % income after discount	1.1%	1.4%	2.0%	3.2%

Note that this table reflects the rates and income eligibility tables that were assumed at the time of the design of the bill discount program in 2022.

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Table 3 - Proposed Bill Discount Tiers

Bill Discount Program Impacts, Assuming Household of 4:	SMI 60% Tier 3 - 15%	SMI 45% Tier 2 - 20%	SMI 30% Tier 1 - 40%	SMI 15% Tier 0 - 80%
Income mid-point of tier	$56,246	$40,176	$24,106	$8,035
Average annual bill	$1,124.87	$1,124.87	$1,124.87	$1,124.87
Bill as % income before discount	2.0%	2.8%	4.7%	14.0%
Bill discount	$168.73	$224.97	$449.95	$899.90
Bill after discount	$956.14	$899.90	$674.92	$224.97
Bill as % income after discount	1.7%	2.2%	2.8%	2.8%

Note that this table reflects the rates for Residential Schedule 2 proposed in this case and income eligibility tables for 2023-2024.

Designing the discount tiers in this way, by targeting a participant's gas usage-related energy burden to 3 percent or less, is consistent with findings from the LINA surveys that found that homes reporting an income of less than $30,000 are likely to be energy burdened. For the 2023-2024 season, the max of the Tier 1 income at 30 percent SMI is $32,141. As can be seen in the table above, an average customer at the mid-point of the income in Tier 1 would receive a 40 percent discount rate that has been set to target a percentage of gas bill to income of 2.8 percent.

V. <u>OREGON LOW-INCOME ENERGY EFFICIENCY</u>

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-efficient 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. Please describe the OLIEE program changes resulting from the settlement agreement in docket UG 435.

A. The OLIEE program changes resulting from agreements in the UG 435 rate case included an increase in flexible funds that increased project caps by $4,000. These flexible funds were made available for additional energy efficiency measures, health and safety measures, or administrative costs. Since those changes, our agencies spent $400 thousand more in energy efficiency upgrades in the 2022-2023 program year as compared to the previous program year. Increased funds were mostly spent on health and safety measures and much needed coverage of agency administrative costs. The increased spend on health and safety measures opened the door to address health and safety issues in the home that would not have been addressed under the older cap, such as mold, ventilation, electrical panels and tankless water heaters to resolve combustion/venting issues. Increased emphasis on energy education funding for our agencies also provided increased outreach and visibility for OLIEE. Some examples of these energy education funds in action this past program year include:

- Washington County Agency – held an Open House providing greater overview and thorough view into their weatherization process.
- Mid-Willamette Valley Agency (Salem)- provided a Weatherization Day event in Salem where NW Natural participated as a sponsor and customers were able to sign up for weatherization services on the spot.
- Homes for Good (Eugene) – created instructional videos in multiple languages regarding eligibility and their weatherization program process.
- YCAP (Yamhill County) Agency - launched targeted postcards and outreach materials directed at NW Natural customers. They launched their online energy education portal that provides greater accessibility to their clients through quizzes and opportunities to win raffle prizes.

Q. Have there been any other recent updates to the OLIEE?

A. Yes. In 2021, NW Natural embarked on a year-long process to restore delivery of the Open Solicitation Program. While NW Natural had previously funded OSP projects (2016-2018), the program had been inactive for a few years in an effort to refine reporting and process document practices, enable higher transparency and establish staffing capacity to lead the program. Renewed attention to the OSP spurred new conversations and created the opportunity to reimagine the program and its potential for impact; optimize activities and offerings; increase take-up; tap unspent funds and establish a clear process for awarding, delivering and evaluating program funds moving forward.

In 2021, the Community Partnership Program Manager position was hired with the intention of increasing engagement with community partners and to reopen this funding program. Since the relaunch of the program, OSP has delivered $2.8 million in energy efficiency and weatherization funding and served roughly 630 low-income households and families.

An example of an OSP-funded project is a partnership model with Oregon Energy Fund ("OEF") and Habitat for Humanity Portland Region. This project will provide full building energy retrofits for 14 owner-occupied, condominium units in the Agape Square community, located in North Portland's Cully neighborhood. Home to approximately 40 residents, the building complex is part of the Habitat for Humanity Portland Region housing portfolio. All Agape Square units are connected to NW Natural service lines; and homeowners are NW Natural customers. The upgrades are projected to reduce energy bills by 13 percent.

Resident engagement was critical to the success of this project and included multiple in-person meetings with community members. The initial meeting engaged the complex's Home Owners' Association ("HOA") officers to introduce the opportunity and share information about the funding program. The HOA officers expressed interest in participating and voted to move forward and bring the proposal to the broader Agape community. A second session was hosted by Habitat for Humanity at its headquarters office in North Portland; 11 of the 14 homeowners attended the meeting (including 3 officers), along with representation from NW Natural, OEF and Burch Energy. The informational session concluded with unanimous support by all residents to move forward. Homeowners also received an application package that consists of a statement of ownership, a liability waiver and a request for demographic information. These materials are necessary for work to commence, as well as ensure data collection and tracking protocols are in place.[7]

Q. Does NW Natural plan to update the OLIEE in the near term?

A. Yes. We have been working with our OLIEE Advisory Committee to develop changes to Schedule 320 to expand the reach to customers and provide more support for projects and to ease the administrative burden of the agencies that administer OLIEE projects. A tariff filing to enact these changes is expected in early 2024.

[7] A short video on the project can be accessed here https://www.youtube.com/watch?v=v_12cgyLHIQ.

VI. MITIGATING ENERGY BURDEN IN THIS CASE

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

A. NW Natural is aware of the potential impact that this rate case can have on customers at a time of rising consumer costs. NW Natural has increasingly been monitoring the impact of the tools we have, such as low-income weatherization (OLIEE) and the bill discount program, to mitigate this impact.

Q. How does NW Natural propose to mitigate the rate impact for customers experiencing higher energy burdens?

A. As I discussed in my testimony above, the Company carefully considered energy burden when developing its updated bill discount program offering and has proposed program enhancements aimed at reducing energy burden by increasing participation and providing greater benefit to participants. NW Natural's key proposal is to substantially increase bill discounts for the top tiers of the bill discount program to reduce energy burdens for those customers.

Q. Are the energy assistance and bill discount programs offered by NW Natural an effective tool to mitigate energy burden?

A. Yes. The following examples illustrate the effectiveness of NW Natural's energy assistance and bill discount programs. As shown in Table 4 below, these benefits can be stacked to provide impactful relief to customers and reduce energy burden.

Table 4 - Examples of Bill Discount and Energy Assistance Benefits

EA Programs	Scenarios
OLGA	**Scenario 1 – New enrollment in bill discount with new energy assistance pledged/committed** Account: 272xxxx-0 • Balance on 9/8/23 bill is $72.57 and includes $26.36 past due and declined card payment fee. • Community Services Consortium pledged a $610.00 OLGA commitment on 9/7. Customer was auto-enrolled in the Bill Discount Program on 9/9 to receive the first discount on the 10/10 bill.
LIHEAP & OLGA	**Scenario 2 – Enrolled in bill discount with new energy assistance pledged/committed** Account: 545xxx-2 • Balance on 9/20/23 bill of $7.04 - current Auto Pay customer. • Impact NW-Multnomah County provided a $390.00 LIHEAP commitment on 9/5/23. • IRCO-Multnomah County provided a $390.00 LIHEAP commitment on 9/8/23. • Customer self-enrolled in the Bill Discount Program on 3/17 via Web form and received the first discount on the 3/24 bill in the amount of $26.35. • Next bill discount on 10/20 bill.
LIHEAP	**Scenario 3 – New enrollment in bill discount with new energy assistance posted to ledger (3 examples: LIHEAP, OLGA and a combination of both)** Account: 340xxxx-9 • Balance on 8/24/23 bill of $364.18 includes $323.29 past due. • NAYA-Multnomah County provided a $750.00 LIHEAP on 7/23. • $750 LIHEAP grant posted on 9/7 leaving a credit balance of $385.82. • Customer was auto-enrolled in the Bill Discount Program on 9/9 to receive the first discount on the 9/22 bill.
OLGA	Account: 424xxx-7 • Balance on 8/24/23 bill of $16.80. • Clackamas County Social Services provided a $365.00 OLGA commitment on 8/14. • Customer paid $16.80 on 9/6 and $365.00 OLGA grant posted on 9/7. • Customer was auto-enrolled in the Bill Discount Program to receive the first discount on the 9/25 bill.

LIHEAP & OLGA	Account: 441xxxx-4 • Balance on 8/16/23 bill $31.44 includes $22.66 past due. • Pending transfer of $368.40 balance from prior account and pending $390 LIHEAP commitment provided by Multnomah County on 6/2/23 once balance is transferred. • SEI-Multnomah County provided a $330.00 OLGA commitment on 9/6/23. • Customer auto-enrolled in the Bill Discount Program on 9/6 to receive the first discount on the 9/14 bill.
LIHEAP	**Scenario 4 – Enrolled in bill discount and new energy assistance posted to ledger** Account: 254xxxx-3 • Balance on 8/30/23 bill of $110.13 includes $95.98 past due. • IRCO-Multnomah County provided a $365.00 LIHEAP commitment on 8/31/23. • $365.00 LIHEAP grant posted on 9/21/23 leaving credit balance of $254.87. • Customer signed up for the Bill Discount Program on 11/4/22 by a CSR and received the first discount of $11.67 on the 12/1 bill. • Next bill discount on 9/29 bill.

Further, analyzing the impact that stacking these benefits has on energy burden is summarized in Table 5, below. Table 5 shows that we are continuing to have effective mitigation tools to help reduce energy burden, thus helping to insulate the impacts of rate changes on customers most in need.

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Table 5 - Energy Burden Analysis of Example Bill Discount and Energy Assistance Benefits

	Scenario 2	Scenario 3 LIHEAP	Scenario 3 OLGA	Scenario 4
NW Natural bill discount tier	20%	15%	15%	40%
annual usage	680	893	494	204
annual bill	$1,073.06	$1,379.12	$805.81	$389.12
Mid point of income for the tier	$40,176	$56,246	$56,246	$8,035
Assistance programs				
NW Natural bill discount	$214.61	$206.87	$120.87	$155.65
LIHEAP	$780.00	$750.00		
NW Natural OLGA			$365.00	$365.00
	$994.61	$956.87	$485.87	$520.65
Annual Bill as a % of income before programs	2.7%	2.5%	1.4%	4.8%
Annual Bill as a % of income after programs	0.2%	0.8%	0.6%	-1.6%

Note that this table reflects the rates for Residential Schedule 2 in effect at the time the bills in the scenarios were issued.

Q. How is NW Natural continuing to study and refine its programs for mitigating energy burden for its customers?

A. As mentioned previously in this testimony, NW Natural expects to begin work soon on its next LINA as part of the UM 2211 proceeding. The Company expects that the new LINA will provide further insight on potential program improvements, new programs, and improved outreach to customers that would benefit the most from our bill discount and energy assistance programs. The Company will also continue to engage its stakeholders, including the CEAG, on these important topics.

VII. 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, we believe that focusing on diversity, equity and inclusion is not just the right thing to do; it is the path to excellence and innovation. We know that we all benefit when we amplify underrepresented voices, celebrate our differences and create an environment where everyone can contribute, thrive and prosper. In 2022, NW Natural adopted its NW Natural Holding Company Human Rights Policy ("Human Rights Policy"). The Human Rights Policy reflects the Company's belief that human rights are fundamental rights, freedoms, and standards of treatment to which all people are entitled. In accordance with the Human Rights Policy, the Company fosters diversity, equity, and inclusion through business practices and community service.

NW Natural is committed to fostering an inclusive culture and ensuring equity in all aspects of our work, from the way we hire and operate every day, to the biggest decisions we make as a business.

As a reflection of this commitment, NW Natural has focused efforts on expanding the diversity of our supplier network and increasing our purchasing from businesses owned by minorities, women, veterans and other traditionally disadvantaged groups. We encourage our suppliers to use diverse subcontractors while performing work on NW Natural's behalf. In 2022, we laid the foundation for improvements that helped us double the percentage of our purchasing spend with diverse suppliers in 2023. Through our Sustainable Purchasing Program, we form strategic partnerships that help us build a more diverse supplier base. These relationships reflect and support the communities we serve. Due to these efforts, in 2022, NW Natural purchased about $23.7 million in goods and services from verified minority-, women- or veteran-owned business and about $202.3 million from small businesses.

NW Natural is committed to doing our part to create equity in our community. For example, we recently announced $600,000 in support toward family- and children-focused nonprofits 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. Please describe NW Natural's efforts to address diversity, equity and inclusion within the Company.

A. NW Natural's leadership team has continued to advance the effectiveness of its diversity, equity and inclusion work. The executive Chief Human Resources Officer role was recast to Chief Human Resources and Diversity Officer in 2018, currently held by Melinda Rogers, to ensure direct and clear accountability for our diversity, equity and inclusion work. A new Strategy Committee, comprised of 4 officers, 3 senior leaders and the co-chairs of the Company's Diversity, Equity and Inclusion Council, has also created governance and oversight for the work being undertaken throughout the Company.

We have a longstanding commitment to safety, environmental stewardship, and taking care of our employees and communities. 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"). These 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. About 23 percent of our employees are connected to an ERG. The Company additionally has created various groups and committees to allow employees to connect and address sustainability and environmental justice issues and offers opportunities for employees to engage in equity training.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Cecelia J. Tanaka

EQUITY
EXHIBIT 201

December 29, 2023

EXHIBIT 201 – EQUITY

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AEG

NW Natural Low Income Needs Assessment

Prepared for: NW Natural

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Date: September 2022

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1

INTRODUCTION

NW Natural and its delivery partners currently offer a number of Energy Assistance programs for income-eligible customers in its Oregon [1]and Washington[2] service areas, designed to decrease energy costs and energy burden and to improve residents' health, safety, and comfort. NW Natural is exploring ways to amplify its portfolio of Energy Assistance programs in each state and is interested in understanding additional opportunities to serve its low-income customers' needs, either through increased participation in current offerings or through new or revamped Energy Assistance.

On December 18, 2020, NW Natural filed a general rate case with the Washington Utilities and Transportation Commission (WUTC), docketed as UG-200994. An all-party settlement was reached and submitted to the WUTC for approval. Order 05 was issued on October 21, 2021, which approved the stipulation and resolved all the issues in the case. As part of the stipulation and in compliance with Order 05, NW Natural agreed to work in consultation with the GREAT Advisory Group to produce a Low-income Needs Assessment (LINA) to determine the need for low-income Energy Assistance for the Company's Washington customers. The assistance may come in the form of low-income weatherization, other energy assistance measures, or low-income Energy Assistance programs. The AG and NW Natural LINA should both align with the goal of increasing equitable service.

NW Natural engaged Applied Energy Group (AEG) to perform the LINA and meet the needs of previous rate case orders by providing insight into customer and community characteristics, eligible populations, penetration of current Energy Assistance offerings, and barriers and opportunities for current or future Energy Assistance offerings. To complete this assessment, AEG combined NW Natural data with publicly available secondary sources to provide a granular geographic picture of NW Natural's Oregon and Washington service areas; and then used this information to survey NW Natural's income-qualified residential customers. The assessment also created a robust analysis framework that can be updated and enhanced, as necessary, to answer new questions about NW Natural's income-qualified customers and offerings.

AEG's methodology, data sources, and assessment results are described in the remaining sections of this report:

- **Section 2: Community Characterization and Survey Sample Frame Development** presents the data sources and methodology AEG used to characterize communities within NW Natural's service area, followed by the results of this characterization and a description of the sample that was used to implement the customer survey.
- **Section 3: Customer Survey** describes the implementation of the customer survey and presents key findings related to Energy Assistance. The survey instrument is included in Survey Instrument A, with detailed survey responses in Survey Responses B.
- **Section 4: Additional Analyses** describes two additional analyses that AEG performed as part of this assessment:
    - An assessment of average energy burden within Census block groups within NW Natural's Oregon and Washington service territories, and
    - A penetration analysis of the percent of customers eligible for Energy Assistance currently participating in NW Natural programs.

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[1] Oregon Energy Assistance programs: Low Income Home Energy Assistance Program (LIHEAP), Oregon Low-Income Gas Assistance (OLGA), and Gas Assistance Plan (GAP), Arrearage Management Program (AMP – available during COVID, currently discontinued), Residential Bill Discount Program.

[2] Washington Energy Assistance Program: Low Income Home Energy Assistance Program (LIHEAP), Gas Residential Energy Assistance Tariff (GREAT), and Gas Assistance Plan (GAP), COVID Assistance Program (CAP – available during COVID, currently discontinued)

- **Section 5: Barriers and Recommendations** synthesizes the results of the previous sections to identify barriers to participation in existing NW Natural Energy Assistance offerings and provides recommendations on how the reach of these, or future offerings, could be increased.

2

COMMUNITY CHARACTERIZATION AND SURVEY SAMPLE FRAME DEVELOPMENT

Community Characterization

To provide deeper insight into NW Natural's residential customer base and to inform the implementation of the customer survey described in the next section of this report, AEG performed a granular analysis within the communities NW Natural serves in Oregon and Washington. The goal of this analysis was to characterize communities based on two metrics: 1) the probability that a NW Natural customer residing in the area qualifies for Energy Assistance, and 2) whether the community was urban or non-urban.

The data sources and process used to characterize communities on these metrics are described below, along with the results of the analysis.

Data Sources

To perform the community characterization, AEG relied on the following key data sources:

- NW Natural billing and location data for active customers,
- NW Natural customer Energy Assistance program participation identifiers,
- The 2020 American Community Survey (ACS), which provides average characteristics at the Census block group level,[3] and
- State-specific income guidelines for Energy Assistance, shown in Table 2-1 below. As shown, income guidelines for Energy Assistance are more restrictive for common household sizes in Washington than in Oregon.

Table 2-1 Income Guidelines for Oregon and Washington, Program Year 2022[4]

	Annual Gross Income*	
Household Size (Residents)	Oregon Requirement: 60% State Median Income (SMI)	WA Requirement: 150% Federal Poverty Level (FPL)
1	$29,334	$19,320
2	$38,373	$26,130
3	$47,402	$32,940
4	$56,430	$39,750
5	$65,459	$46,560
6	$74,488	$53,370
7	$76,181	$60,180
8	$77,874	$66,990
9	$79,567	$73,800

[3] Block groups are statistical divisions of census tracts, generally defined to contain between 600 and 3,000 people: https://www.census.gov/programs-surveys/geography/about/glossary.html#

[4] Current scope for the sampling and low-income probability was based on the 2022 income guidelines. Updated guidelines for 2023 are available for future LINAs. [Federal Poverty Guidelines for FFY 2023 | The LIHEAP Clearinghouse (hhs.gov)]

10	$81,260	$80,610
11	$82,953	$87,420
12	$84,645	$94,230
Each Additional Member	$1,692	$6,810

** Gross Income refers to all household income before any deductions*

- Urban and non-urban designations are based on the USDA's Rural-Urban Commuting Areas Codes, which classify Census tracts using measures of population density, urbanization, and daily commuting. Each Census tract is given a 1 to 10 score to delineate metropolitan, micropolitan, small town, and rural commuting areas based on the size and direction of the primary (largest) commuting flow. For this analysis, AEG defined Census tracts with a score of 1-3 as "urban" and Census tracts with a 4-10 as "non-urban."

Because NW Natural does not gather income or household size information from its customers, AEG was not able to assess Energy Assistance eligibility at a customer level. Rather, AEG mapped each customer's service address to a Census block group, aggregated customer counts to the Census block group level, and then merged these counts with income and household size information from the ACS.

AEG employed ACS's margin of error data to determine probability distribution for each block group and estimate the likelihood of Energy Assistance eligibility. This methodology is more rigorous than using only median income and household size from the ACS, which would have created an overly limiting, binary assessment of each block group.

Data Cleaning

Table 2-2 shows the data cleaning and screening steps AEG took to develop the preliminary residential sampling frame (i.e., the group of customers eligible for the low-income designation), and the proportion of customers remaining after each data processing step. As shown, this cleaning process removed roughly 17% of provided accounts.

1. Filtered out non-residential customers and reclassified customers with missing building types to single family.
2. Removed customers with 0 or negative annual natural gas usage.
3. Removed customers with missing ZIP codes.
4. Removed customers in the bottom 15% of natural gas usage to increase the likelihood of reaching customers who have natural gas heat and water heating.

Table 2-2 Sample Attrition - NW Natural Residential Customer Data

	Number of Households	% Original Accounts
Original Database	718,117	100%
Remove Non-Residential & Reclassify Nulls	716,128	99.7%
Remove Missing Service Zip Codes	708,669	98.7%
Remove 0 or Negative Annual Usage	704,950	98.2%
Only Top 85% of Annual Usage	594,070	82.7%
Sample Frame Total	**594,070**	**82.7%**

Energy Assistance Eligibility

After cleaning the data, AEG matched each remaining customer's service address to the appropriate Census block group to apply the low-income probabilities developed above. Table 2-3 shows the distribution of NW

Natural residential customers in each state based on the block group-level probability of eligibility for Energy Assistance programs. Key findings from this analysis include:

- In both states, most customers reside in communities where less than 13% of households are expected to qualify for Energy Assistance:
  - In Oregon, 80% of customers reside in these communities
  - In Washington, 99% of customers reside in these communities
- In both states, a small percentage of customers reside in communities where over 90% of households are expected to qualify for Energy Assistance:
  - In Oregon, about 3% of customers reside in these communities
  - In Washington, no customers reside in these communities
- In Washington, few customers (~100) reside in communities with a probability of over 30% Energy Assistance eligibility.
- The distribution of customers by low-income probability likely creates additional challenges for NW Natural in ensuring eligible customers are aware of Energy Assistance offerings.

Table 2-3 NW Natural Customers by Low-Income Probability, by State

Low Income Probability	Oregon Customers	Washington Customers
96 – 100%	8,614	0
91 – 95%	3,484	0
86 – 90%	2,178	44
81 – 85%	1,846	0
71 – 80%	4,281	0
61 – 70%	5,821	0
51 – 60%	5,865	25
41 – 50%	8,622	38
31 – 40%	16,244	1
21 – 30%	18,715	155
11 – 20%	28,079	352
1 – 10%	417,866	71,840
Total	**521,615**	**72,455**

Survey Sample Design

Because eligibility for Energy Assistance could not be determined at the customer level, AEG aimed to sample high-probability areas in both states to increase the likelihood of reaching eligible customers with the survey. While this methodology created a sufficiently large sample for Oregon, as discussed and shown above, few such customers were identified in Washington, so an alternate approach was required.

To develop the Washington sample, AEG identified customers who had participated in an Energy Assistance program from 2017–2019,[5] then created a geographic radius area around these participants' service locations

[5] Because new OLGA program eligibility requirements were introduced during the COVID-19 pandemic (2020-2022), this time period was used to identify customers who qualified under the original program eligibility requirements.

(250 feet for urban customers, 1,320 [one-quarter mile] feet for non-urban customers);[6] the hypothesis was that customers residing near known participants would be more likely to qualify for Energy Assistance programs. This methodology identified roughly 8,000 Washington residential customers to include in the survey sample who might qualify for Energy Assistance programs.

With the eligible sample developed, AEG merged urban and non-urban designations to inform the final survey sample design. Table 2-4shows the urban/non-urban designation overlayed with the low-income probability for the Oregon service area.

Table 2-4 Oregon Residential Customers by Low Income Probability and Urban/Non-Urban Designation

Low Income Probability	Urban	Non-Urban
96 – 100%	6,581	2,033
91 – 95%	2,747	737
86 – 90%	1,616	562
81 – 85%	1,673	173
71 – 80%	3,251	1,030
61 – 70%	4,433	1,388
51 – 60%	4,909	956
41 – 50%	6,187	2,435
31 – 40%	14,070	2,174
21 – 30%	15,013	3,702
11 – 20%	24,580	3,499
01 – 10%	390,444	27,422

Final Sample Design

The final sample frame consists of Oregon customers with an 86% or higher probability of being a low-income customer and all Washington customers that were qualified to receive the survey through the method described above. The distribution of customers by each dimension is presented in Table 2-5, with details on the number of customers who were recruited to complete the survey presented in the following section.

Table 2-5 Residential Sample by Eligibility and Urban/Non-Urban Designations

State	Low Income Indicator	Urban Designation	Universe N	Universe %
Oregon	86 – 100% Probability	Urban	10,944	76.6%
		Non-Urban	3,332	23.4%
Washington	Qualified	Urban	7,705	97.1%
		Non-Urban	309	2.9%
Total Qualified Sample			***22,290***	

[6] AEG used an initial radius on rural identified homes of 1,000 feet for initial survey recruitment, then increased the rural buffer for Washington to 1,320 feet to increase the number of responses.

3

CUSTOMER SURVEY

AEG used the sample frame above to recruit NW Natural residential customers to participate in a survey to learn more about customers who may qualify for Energy Assistance programs and to identify barriers to participation to make these programs, or potential new offerings, more effective. The survey targeted low-income households with the goal of completing surveys with 400 Oregon and 100 Washington income-qualified customers.

Survey Implementation

Data collection took place from May 27 to July 20, 2022. As discussed above, AEG was not able to identify qualifying customers directly, which created challenges for hitting quotas, particularly in Washington. To try to get as large a set of responses as possible, AEG implemented a multi-stage recruitment effort:

1. A postcard survey invitation was mailed to 4,520 Oregon customers (3,900 urban and 620 non-urban) and 1,233 Washington customers (1,000 urban and 233 non-urban) based on the established quotas. The postcard included both English and Spanish instructions for accessing the survey online, including the survey URL and a passcode. It also offered the first 500 customers who qualified and completed the survey a $25 gift card incentive. To qualify for the survey, customers had to have a natural gas heating system and meet the state-specific low-income program requirements shown in **Error! Reference source not found.**

   A week after the initial mailing, a second invitation postcard was sent to the same sample.

2. Because the response rate and the number of customers who qualified for the survey were lower than expected, AEG mailed the invitation to an additional 1,000 Washington customers in the sample frame.
3. Finally, AEG emailed the survey to Oregon and Washington NW Natural Residential Insight Panel members, regardless of whether they were likely to qualify for the survey.

Figure 3-1 Postcard Invitation

A total of 1,616 customers completed the screening portion of the survey. Of those, 307 Oregon customers and 63 Washington[7] customers qualified and completed the survey. The +/- at the 90% confidence interval is 5% for Oregon and 10% for Washington.

[7] Due to the small number of responses in the Washington service territory caution should be taken when interpreting the survey results. The most accurate way to interpret the percentages cited in the report for Washington is as a 10% range in both directions. That is, if it is reported that 50% of Washington customers answered yes to a question, that should be interpreted as 40 – 60% of Washington customers answered yes.

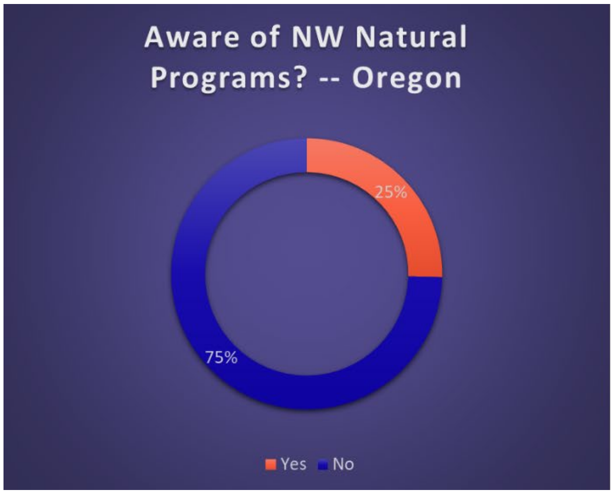
Key Survey Findings

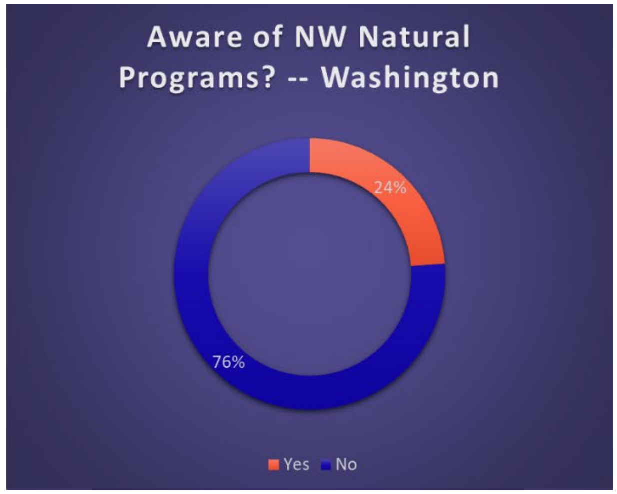
The survey included questions regarding household characteristics, natural gas service, energy efficiency behavior, NW Natural programs, and barriers to program participation. The key findings as they relate to program interest and energy efficiency opportunities are discussed below.

Energy Assistance Programs

Roughly a quarter of respondents in both states are aware of at least one NW Natural program that can lower monthly bill payments or connect customers to free weatherization services (Figure 3-1).

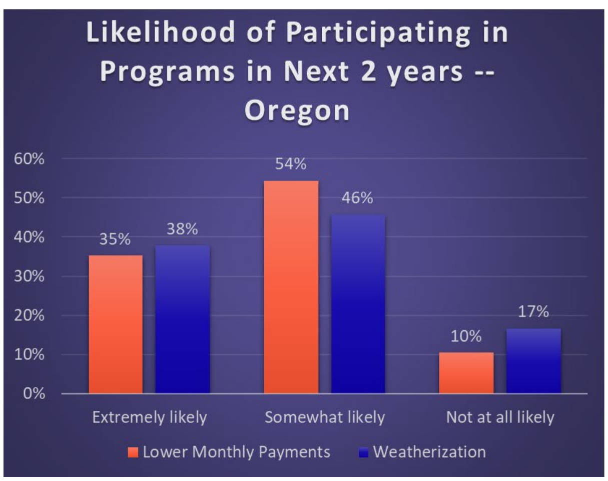
Figure 3-1 Awareness of NW Natural Energy Assistance or Weatherization Programs (QP1)

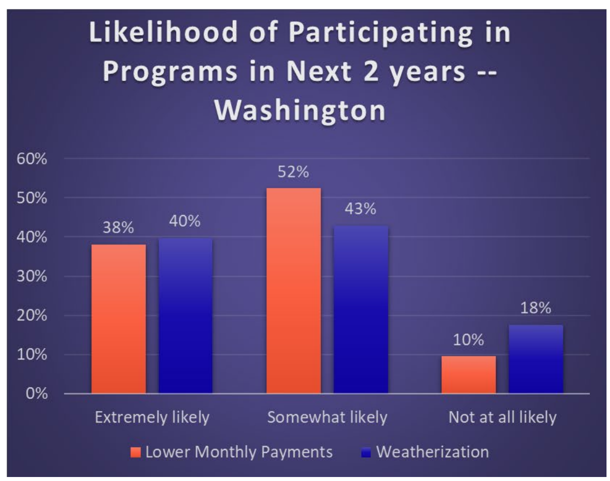




Twenty-three percent of Oregon and 13% of Washington respondents had participated in a program; however, a large majority say they are at least somewhat likely to participate in a program that can help lower monthly bill payments or connect customers to free weatherization services (Figure 3-2).

Figure 3-2 Likelihood of Participating in a NW Natural Energy Assistance or Weatherization Program (QP3a)





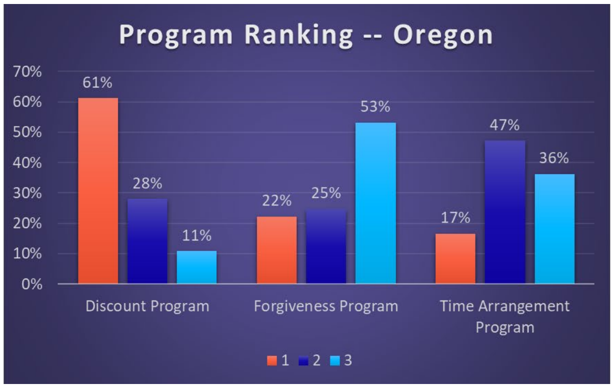
Customers were asked to rank three types of potential Energy Assistance programs in order of preference:

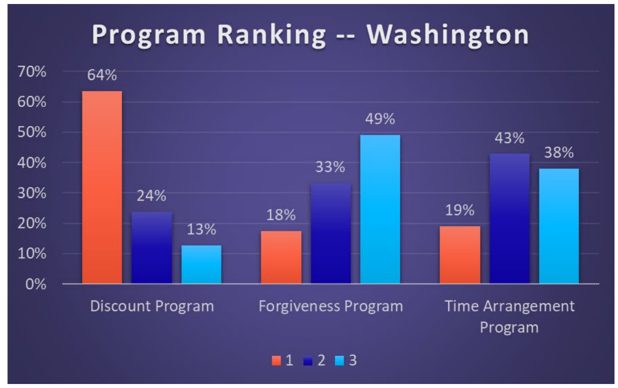
- A discount program that provides a percentage discount on their monthly NW Natural bill,

- A forgiveness program that eliminates or reduces their prior unpaid bills to NW Natural, and
- A time payment arrangement program where they negotiate a contract with NW Natural to pay a fixed amount for natural gas service over a specific period of time (one to two years).

Discount programs are the most popular, with 61% of Oregon respondents and 64% of Washington respondents ranking discount programs first - ahead of forgiveness or time arrangement programs (Figure 3-3).

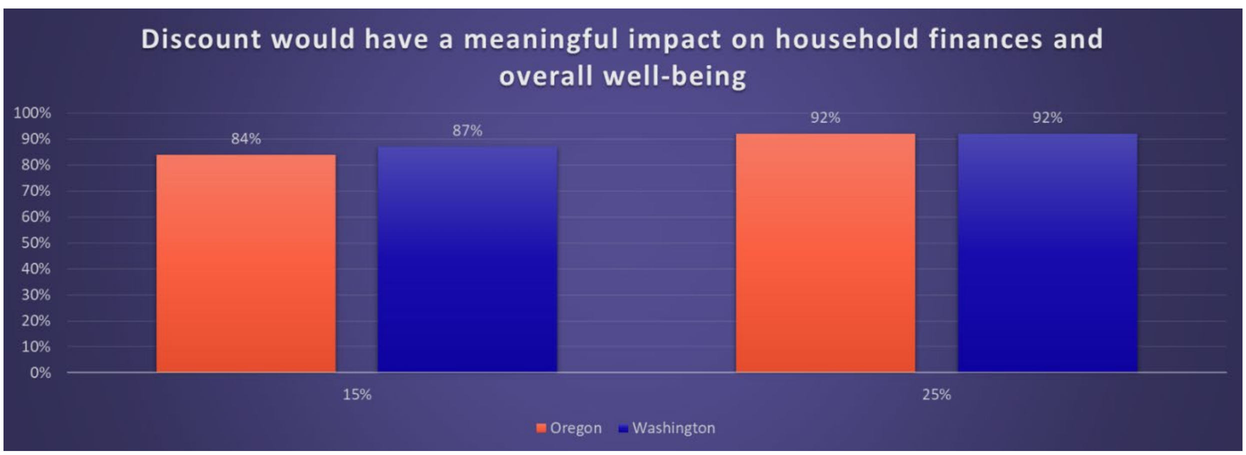
Figure 3-3 Ranking of Potential Energy Assistance Options (QP5)





Next, respondents were asked about the impacts of specific bill discount levels. A large percentage of respondents say a 15% discount program would have a meaningful impact on their household finances and overall well-being. That metric increases by only 5 - 8% when the discount is increased to 25% (Figure 3-4).[8]

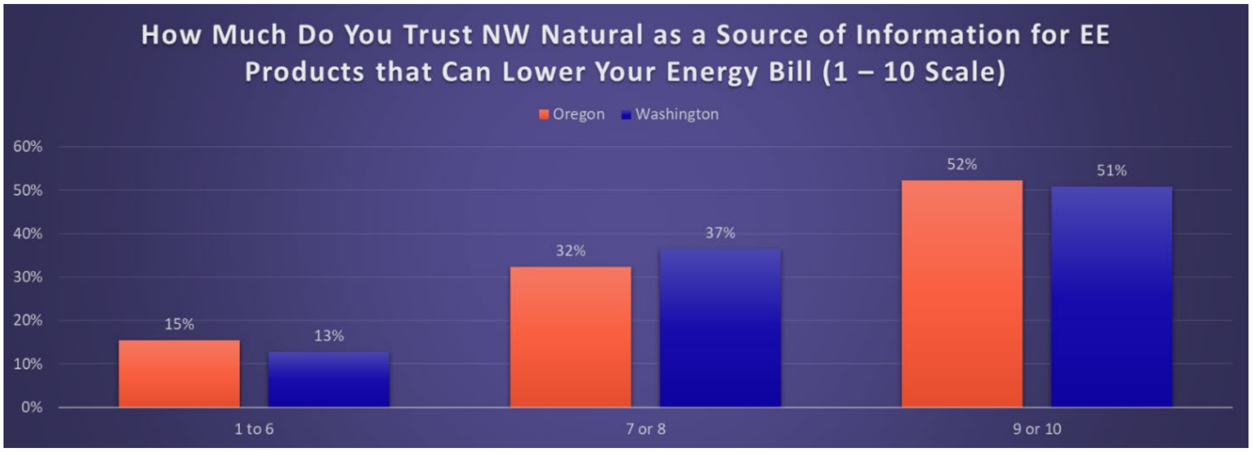
Figure 3-4 Customer Response to Discount Programs (QP6 – QP7)



Respondents view NW Natural as a trusted source of information about Energy Assistance, with 84% of Oregon respondents and 88% of Washington respondents giving the statement "*How much do you trust NW Natural as a source of information for energy efficiency products that can lower your energy bill*?" a rating of seven or higher on a 10-point scale (Figure 3-5).

[8] If customers indicated a 15% discount would be meaningful, they were not asked about a 25% discount, as it was assumed that these customers would also find a higher discount meaningful.

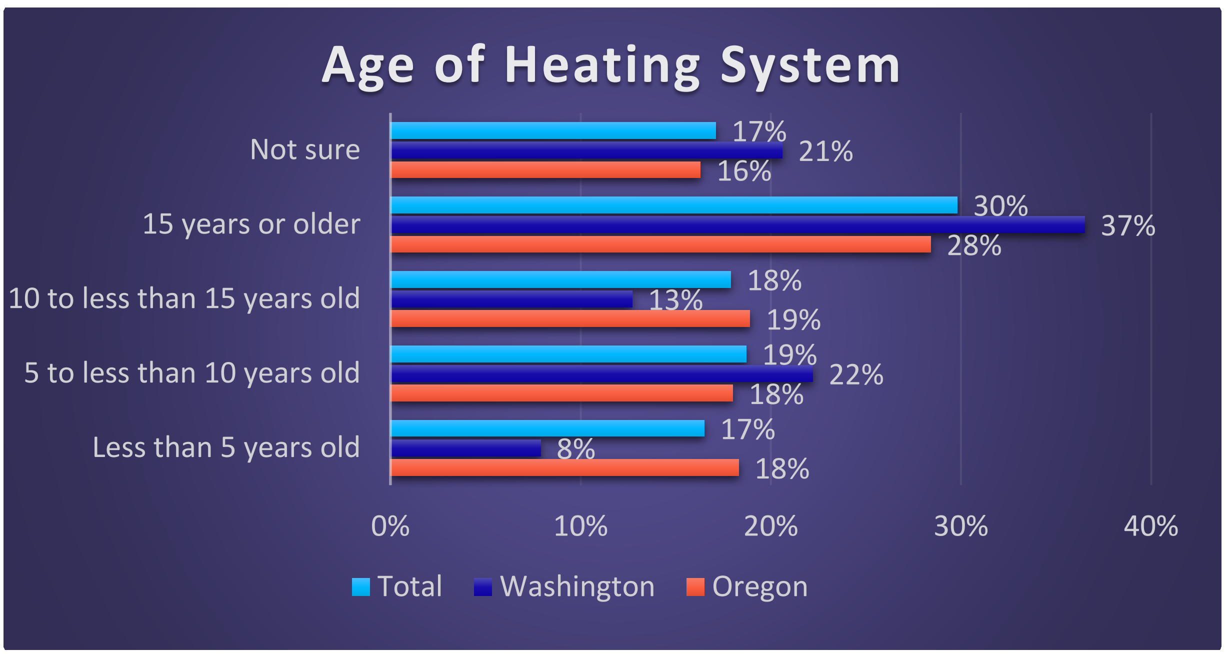
Figure 3-5 Trust in NW Natural (QEE3)



Energy Efficiency

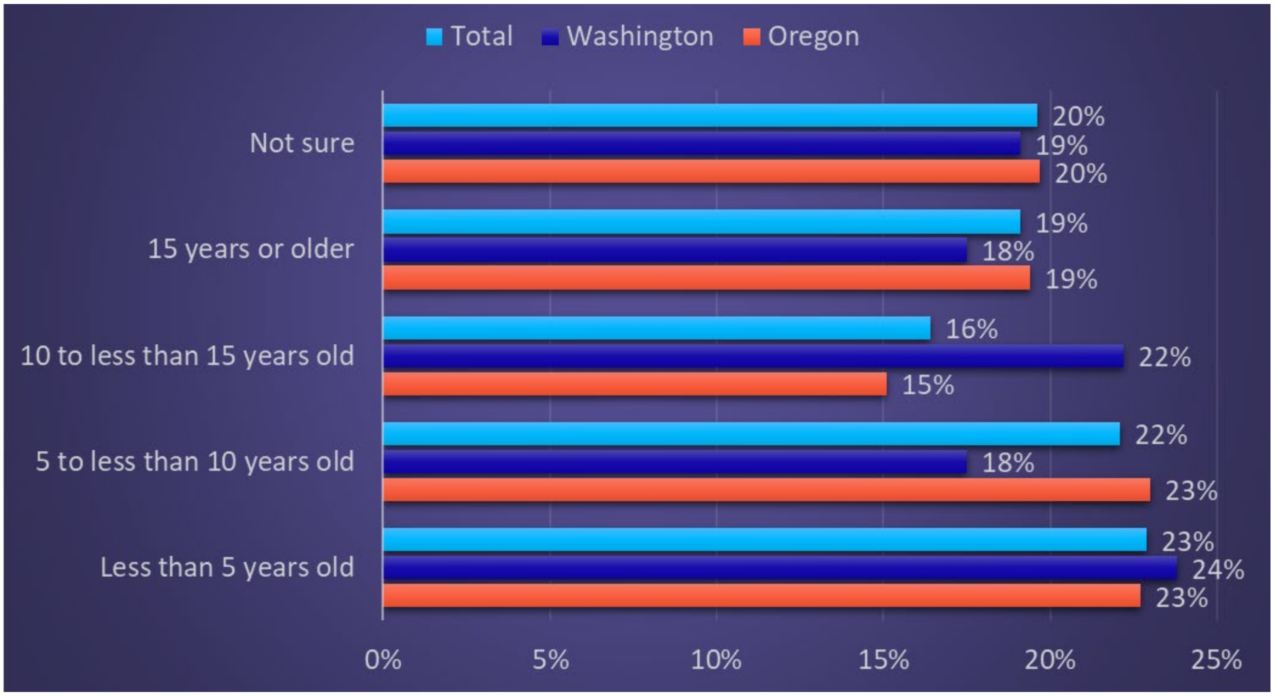
In terms of natural gas equipment in customers' homes, the survey identified an opportunity for energy efficiency upgrades. More than a quarter of Oregon respondents and more than a third of Washington respondents have natural gas heating systems that are nearing the end of their useful lives (15 years or older, Figure 3-6)

Figure 3-6 Age of Heating System (QH2)



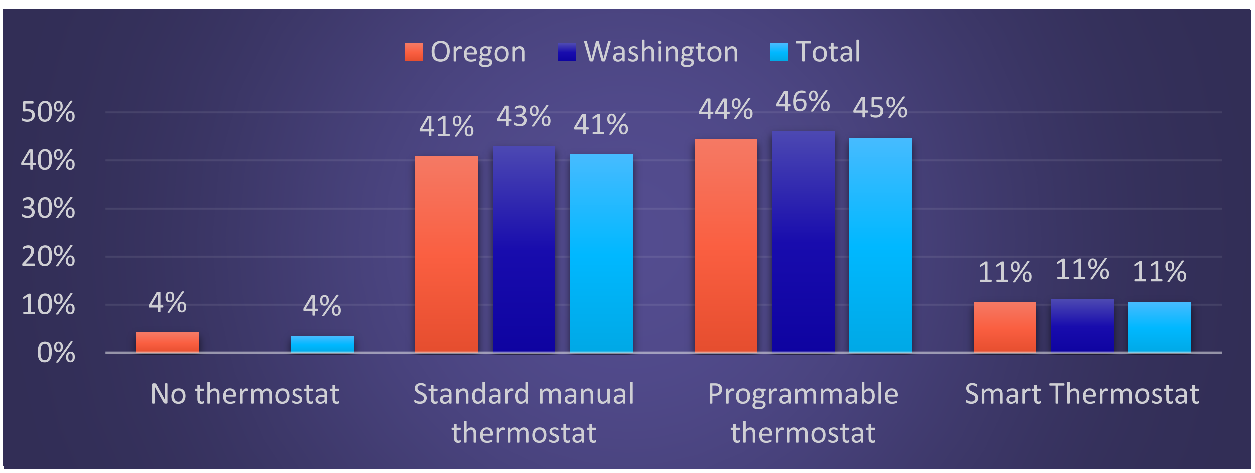
A smaller but still significant proportion of customers in both states have water heating systems that are 15 years or older (Figure 3-7).

Figure 3-7 Age of Water Heating System (QH6)



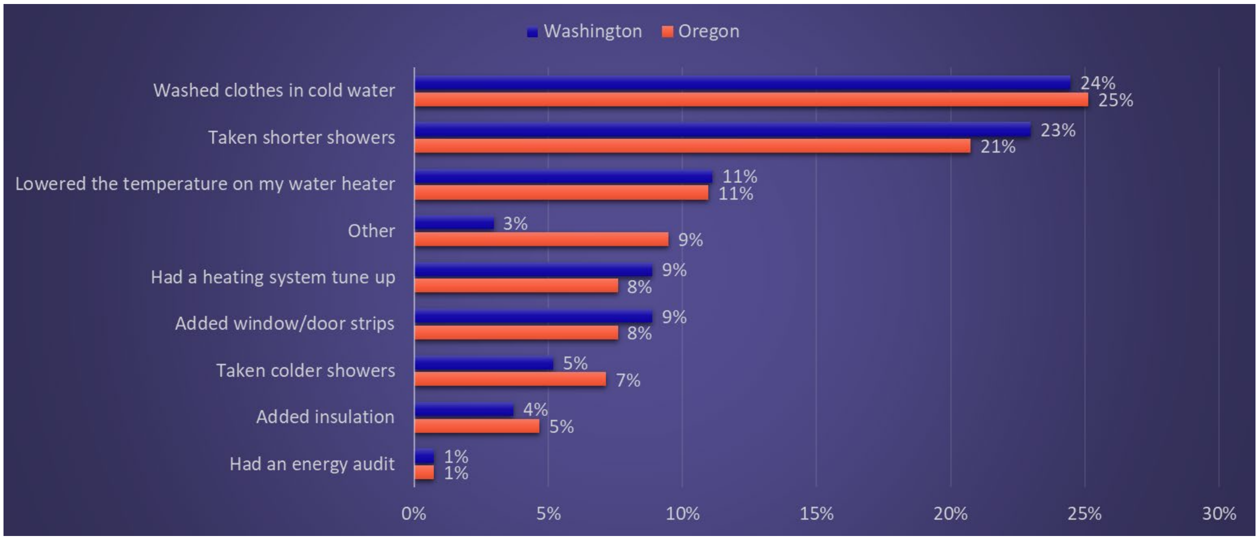
41% percent of Oregon respondents and 43% of Washington respondents have a manual thermostat (Figure 3-8).

Figure 3-8 Type of Thermostat (QH3)



Few Oregon and Washington respondents have taken actions to lower their natural gas bills. Among those that have the actions are mainly behavioral (Figure 3-9).

Figure 3-9 Actions Taken to Lower Natural Gas Bills (QB2)



Additional survey responses related to energy burden and program barriers and opportunities are presented in Sections 4 and Section 5, respectively. Results for all survey responses are provided in Appendix B.

4

ADDITIONAL ANALYSES

In addition to the community characterization and customer surveys, to provide insight into Energy Assistance opportunities and barriers to participation, AEG performed two separate analyses as part of this project:

1. An assessment of average energy burden within Census block groups within NW Natural's Oregon and Washington service territories, and
2. A penetration analysis of the percent of customers eligible for Energy Assistance currently participating in NW Natural programs.

The methods and results of these analyses are described in detail below.

Energy Burden Analysis

Energy Burden Methodology

Energy burden is defined as the percent of household income spent on energy bills.[9] A household is typically considered energy burdened when energy-related expenditures exceed 6% of the household's annual income. As part of this assessment, NW Natural wanted to understand the level of energy burden within its service area to identify geographic areas and communities where Energy Assistance could be particularly impactful. To perform this energy burden analysis, AEG performed the following steps:

1. **Calculated average natural gas bills for each NW Natural residential customer.** AEG used historical billing data and current NW Natural base charges and volumetric rates to calculate average annual natural gas bills for each customer.
2. **Estimate average electricity bills.** When calculating energy burden, it is important to include both natural gas and electricity costs. As a natural gas utility, NW Natural does not have access to electricity billing data for its customers, so AEG needed to use secondary sources to estimate average electricity bill amounts. To perform this estimation, AEG calculated average annual electricity consumption for natural gas-heated homes in the Northwest Energy Efficiency Alliance's 2016 Residential Building Stock Assessment (RBSA) by state and housing type.[10] AEG then applied electric consumption rates from Portland General Electric (Oregon) and Clark Public Utilities (Washington)[11] to average annual electric usage by building type to get an average annual electric cost for single-family and multifamily households by state.
3. **Estimate average total energy-related costs.** AEG combined estimated annual gas costs by customer with estimated RBSA average annual electric costs by state and building type to estimate total annual energy-related costs for each NW Natural customer. AEG then calculated the median energy-related cost of all customers within each Census block group.
4. **Calculate average energy burden by Census block group.** For each block group, AEG divided median annual energy-related costs by median household income to calculate the average energy burden for each Census block group.

[9] *Ten Year Plan: Reducing the Energy Burden in Oregon Affordable Housing,* p. 1. Available at the following URL https://www.oregon.gov/energy/Get-Involved/Documents/2018-BEEWG-Ten-Year-Plan-Energy-Burden.pdf

[10] The RBSA sample of homes in NW Natural's service territory was not sufficient to calculate reliable averages, so AEG averaged all-natural gas-heated homes in each state, regardless of provider.

[11] Based on discussion with NW Natural, AEG used rates from the most prevalent electric provider within NW Natural's service area in each state.

Energy Burden Results

Although this averaging method does not provide an estimate of the number of NW Natural customers that are energy burdened in each Census block group, it does provide insight into the typical energy burden across NW Natural's service area and how this varies by geography. This variation is illustrated in maps of select areas of NW Naturals Oregon and Washington service territory below; the shaded areas represent block groups with an average energy burden of **over 3%.** For comparison, AEG calculated average statewide energy burdens of 2.25% and 1.86% for NW Natural's Oregon and Washington service areas, respectively.

Figure 4-1 Portland, Oregon (East)

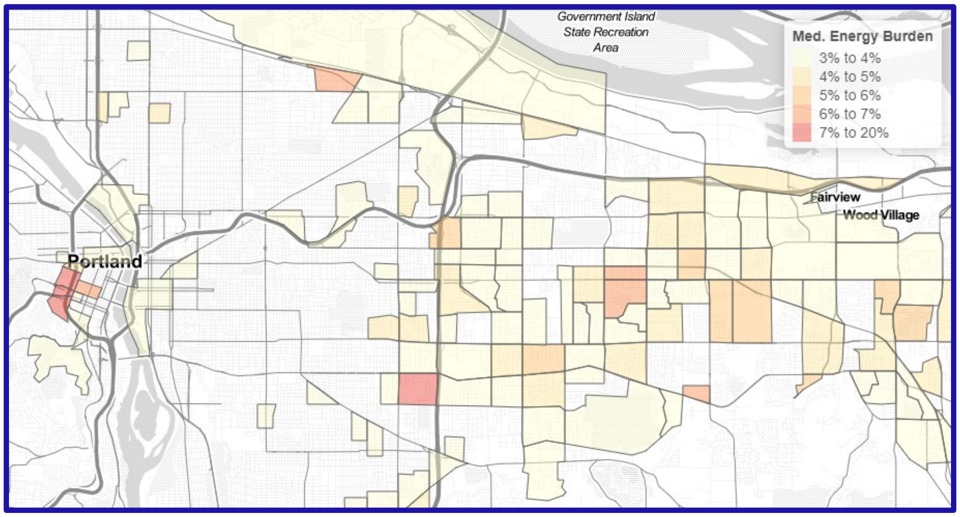


Figure 4-2 Eugene, Oregon

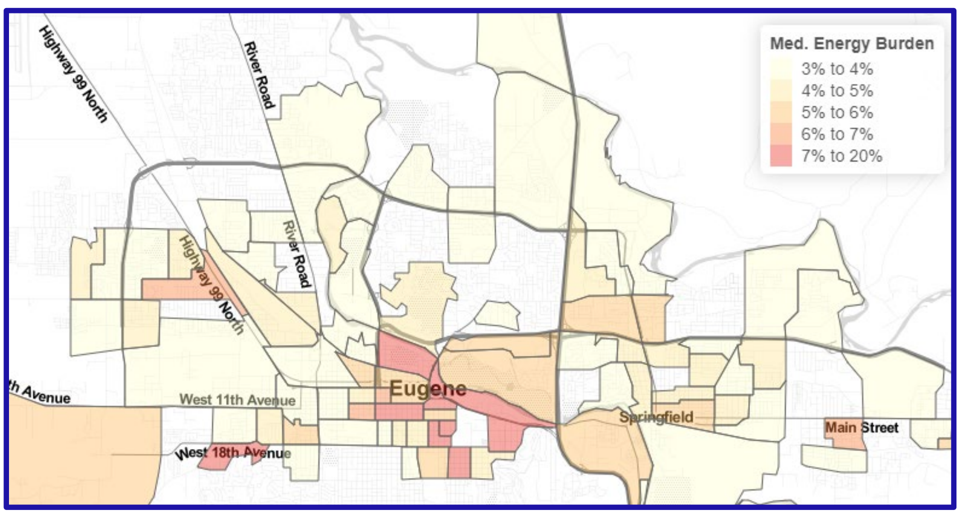


Figure 4-3 Salem, Oregon

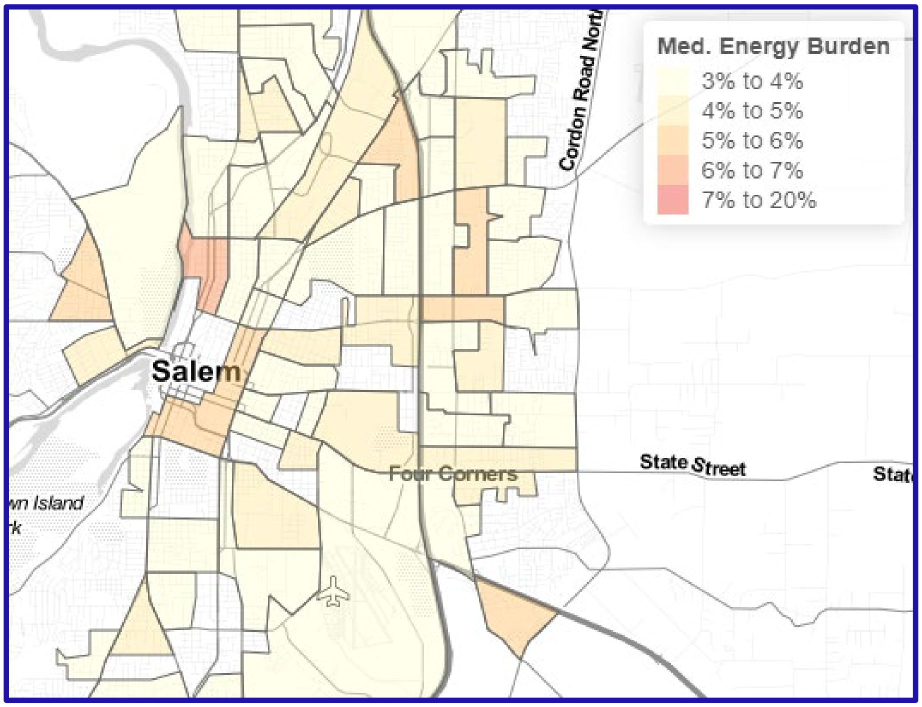
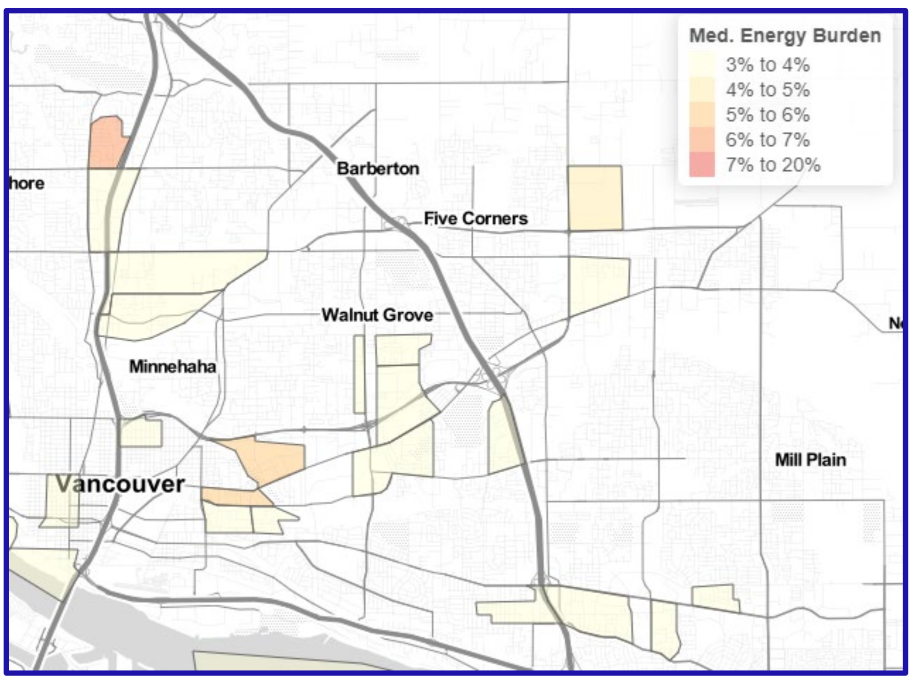


Figure 4--3 Vancouver, Washington

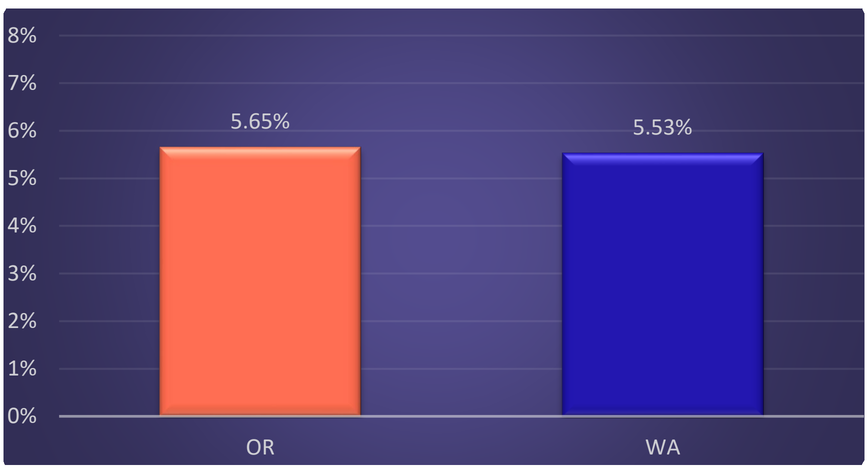


Energy Burden Among Survey Respondents

Of the 370 survey responses, AEG was able to calculate each household's energy burden based on calculated natural gas costs from NW Natural billing data, estimated electric costs from RBSA, and reported income submitted through the survey. In the survey, AEG requested household income by bucketed groups encompassing a range of incomes – such as $35,000 to $39,999. The figures below show energy burden across different metrics, separated by state. Note that average energy burdens from survey respondents are higher than statewide averages, which is to be expected because only customers eligible for Energy Assistance were qualified to take the survey.

Based on the survey responses, there is little variability between states, urban communities, and market segments. Due to the limited number of responses, AEG is unable to draw conclusions from the survey data pertaining to rural Washington communities, as only one respondent was classified as rural[12]. However, the survey responses indicate that single-family homes are more likely to be energy burdened compared to multifamily units. In addition, for Oregon, the energy burden between homeowners and renters is negligible for both single-family and multifamily homes, while Washington single-family and multifamily homeowners are slightly more burdened than renters.

Figure 4-4 Survey Respondents' Average Energy Burden by State



[12] AEG only received one Rural Washington completed survey and this household is estimating 11% energy burden based on our analysis.

Figure 4-5 Survey Respondents' Average Energy Burden by State & Community

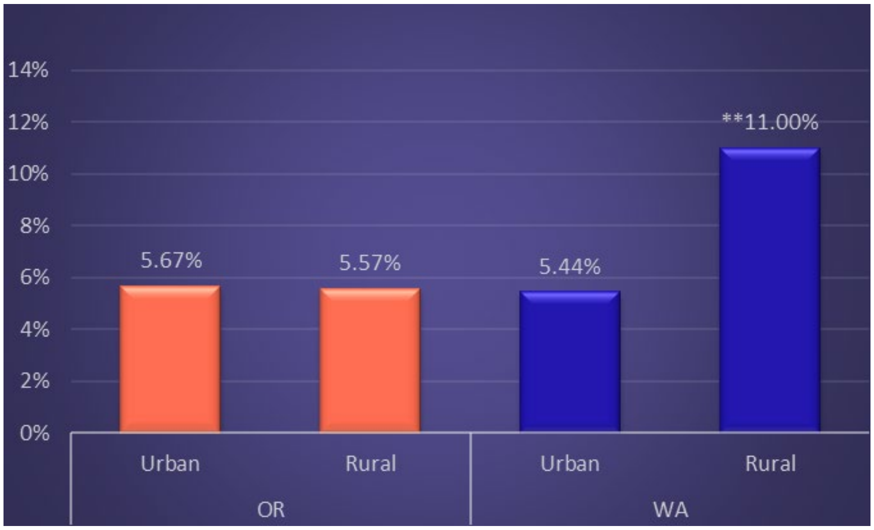


Figure 4-6 Survey Respondents' Average Energy Burden by State and Market Segment

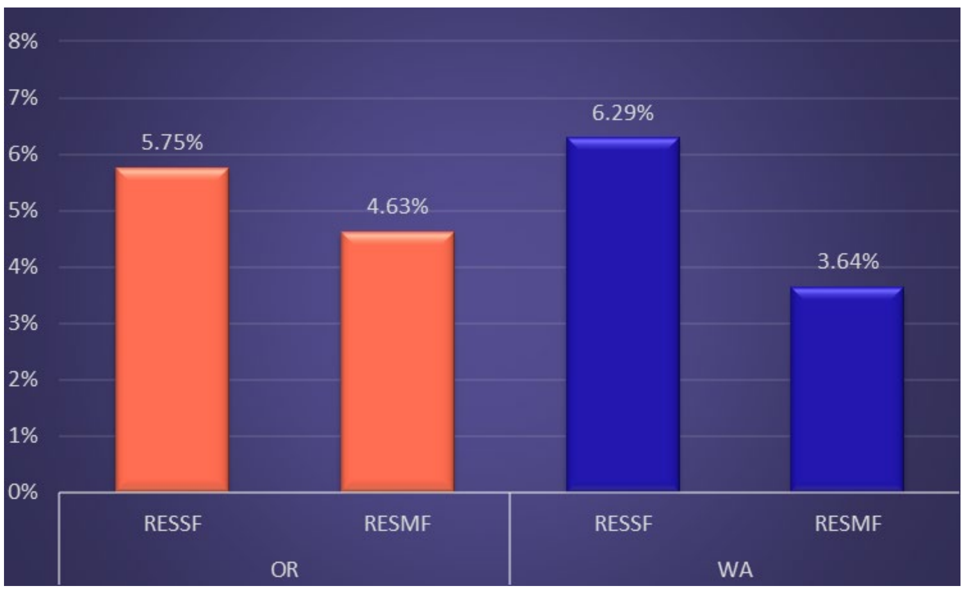
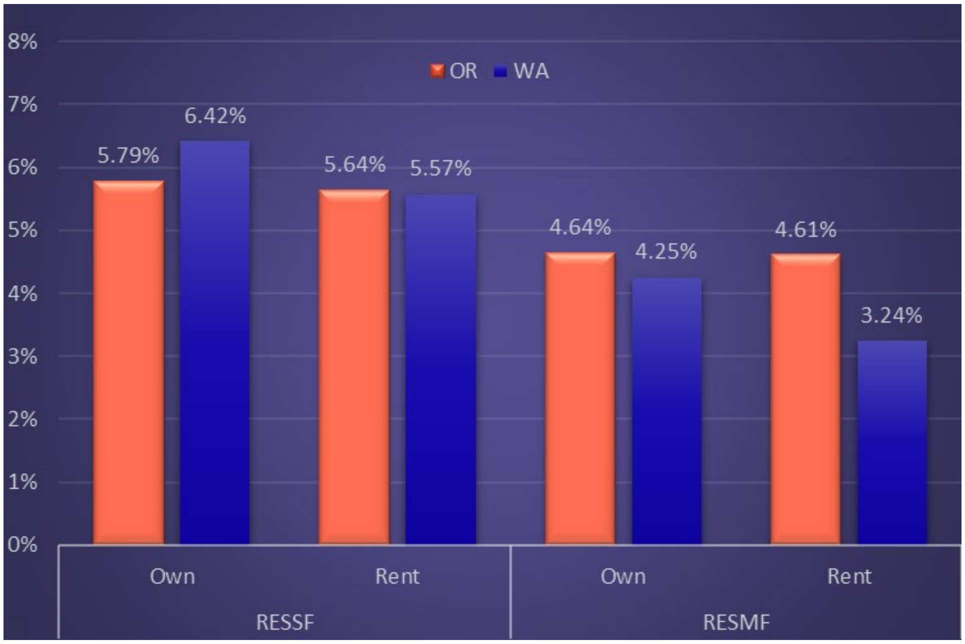


Figure 4-7 Survey Respondents' Average Energy Burden by Ownership and Market Segment



Survey responses indicate that, across NW Natural's service territory, homes reporting an income of less than $30,000 are likely to be energy burdened – above 6% of annual income dedicated to utility costs. Note that while household size is a factor in determining eligibility for Energy Assistance, it is not a component of energy burden. However, survey responses did not indicate that energy burden necessarily increases with household size, though this may be a function of using a single average electricity cost which does not vary by household size.

Figure 4-8 Survey Respondents' Average Energy Burden by Reported Income

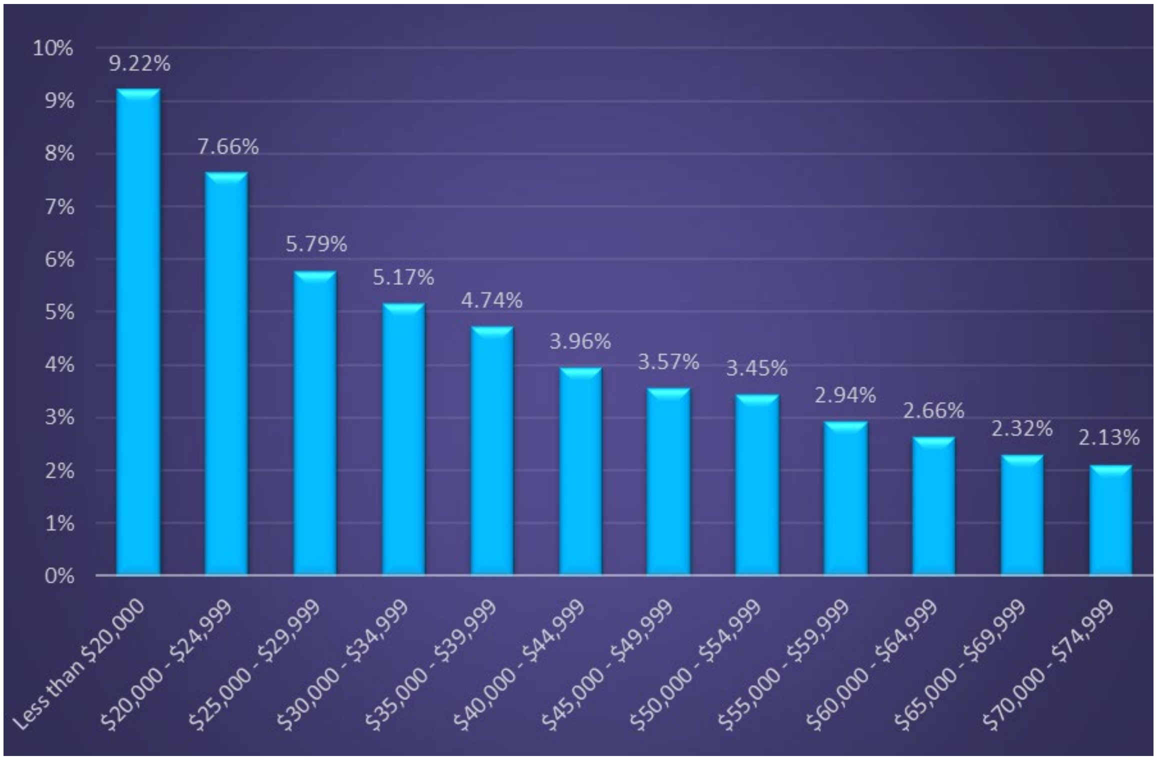
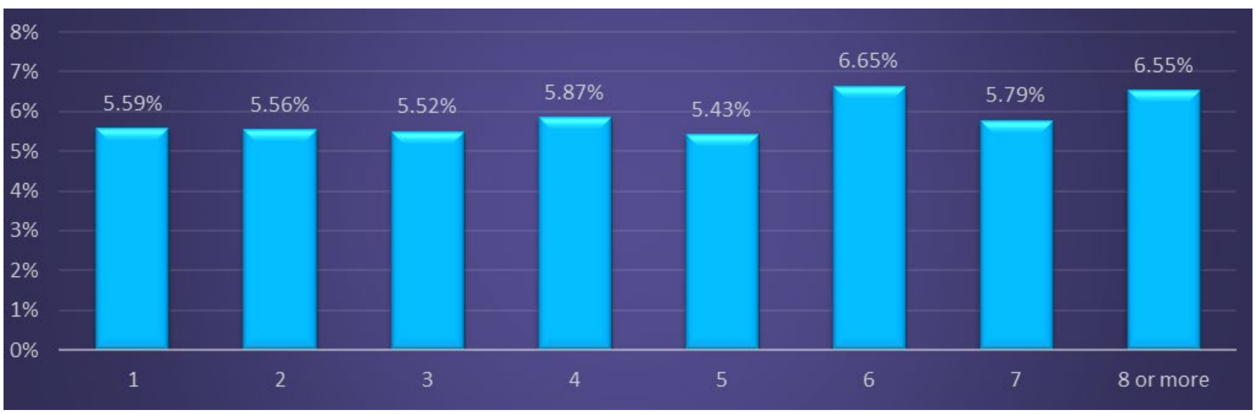


Figure 4-9 Survey Respondents' Average Energy Burden by Household Size



Energy Burdened Households Receiving Energy Assistance

Out of 370 survey responses, 39 responses were identified as receiving some amount of Energy Assistance between 2017 and 2022:

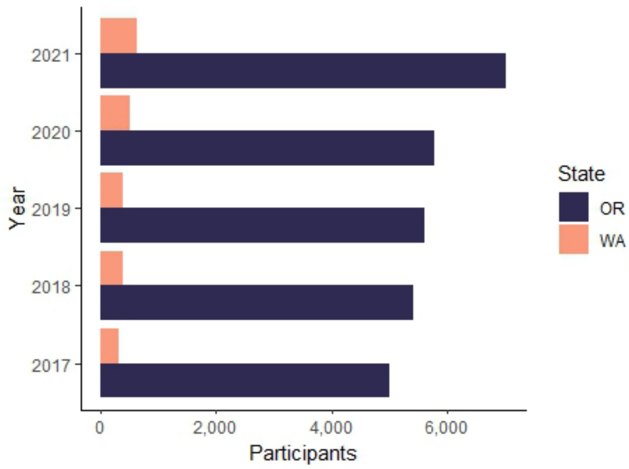
- **Pre-COVID** (2017-2019), 30 survey respondents received some monetary support through an Energy Assistance program. Of those 30 respondents who received pre-COVID assistance, the average energy burden, based on their current reported income, was **6.03%**.
- During **COVID** (determined as 2020-2022), 27 survey respondents received some monetary support through an Energy Assistance program. Of those 27 respondents who received assistance during COVID, the average energy burden, based on their current reported income, was **5.75%**.

As stated earlier, new Energy Assistance eligibility requirements were introduced during COVID, allowing households with higher reported incomes to receive assistance; this is reflected in the slight drop in average energy burden during COVID compared to pre-COVID. However, this analysis does not consider historically reported income as AEG did not receive information regarding customers' annual reported income from historical years.

Energy Assistance Penetration Analysis

To assess the penetration of existing NW Natural Energy Assistance programs, AEG compared customer-level participation data provided by NW Natural, to the number of estimated eligible residential customers, with eligibility determined by household size and income. The number of recent participating premises in NW Natural's existing Energy Assistance programs, by state, is shown in Figure 4-10. As shown, the number of participants has steadily increased in both states over the past several years, with a larger increase in 2021 when eligibility requirements were relaxed to help customers navigate the COVID-19 pandemic.

Figure 4-10 Energy Assistance Program Participation

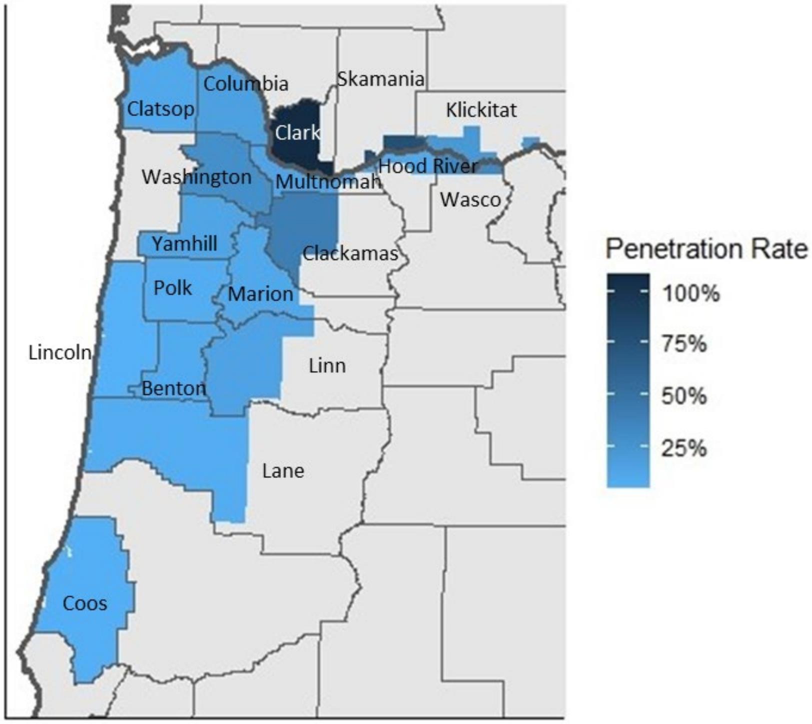


AEG used the participation and eligibility information to investigate program penetration by geography within NW Natural's Oregon and Washington service territories. Through this analysis, AEG noted the following challenges in calculating Energy Assistance penetration rates:

- Participation is based on actual NW Natural data, but the estimated eligible households are based on populations at the Census's Block Group level.
- Program participation is based on eligibility in each year, but population eligibility estimates were based on the most current information from the American Community Survey.
- Because participation was tied to premises, when residents moved, the new residents may or may not have continued to receive Energy Assistance.

Because of these challenges, the calculated values may not be reflective of current program penetration; however, the relative penetration across different geographies is expected to be more reliable and can help NW Natural identify areas that existing programs have underserved. Figure 4-11 illustrates this variation across counties served by NW Natural in Oregon and Washington (shaded areas represent the portion of each county served by NW Natural). As shown, AEG estimates that NW Natural has achieved the highest Energy Assistance penetration in Clark County, WA, though this may be a function of having few qualified customers in the service area, as discussed in Section 2.

Figure 4-11 Energy Assistance Program Penetration by County



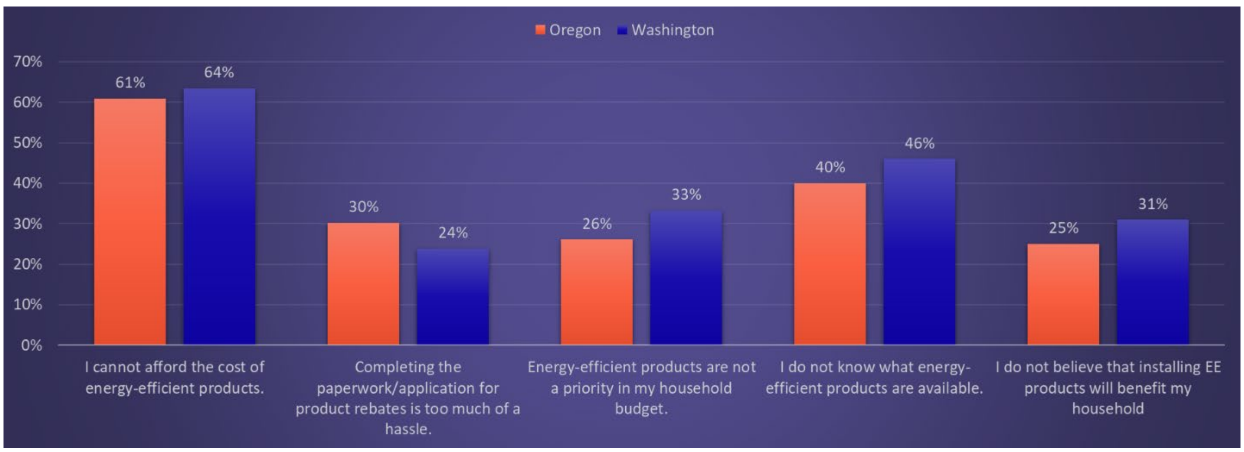
5

BARRIERS AND RECOMMENDATIONS

Identified Barriers

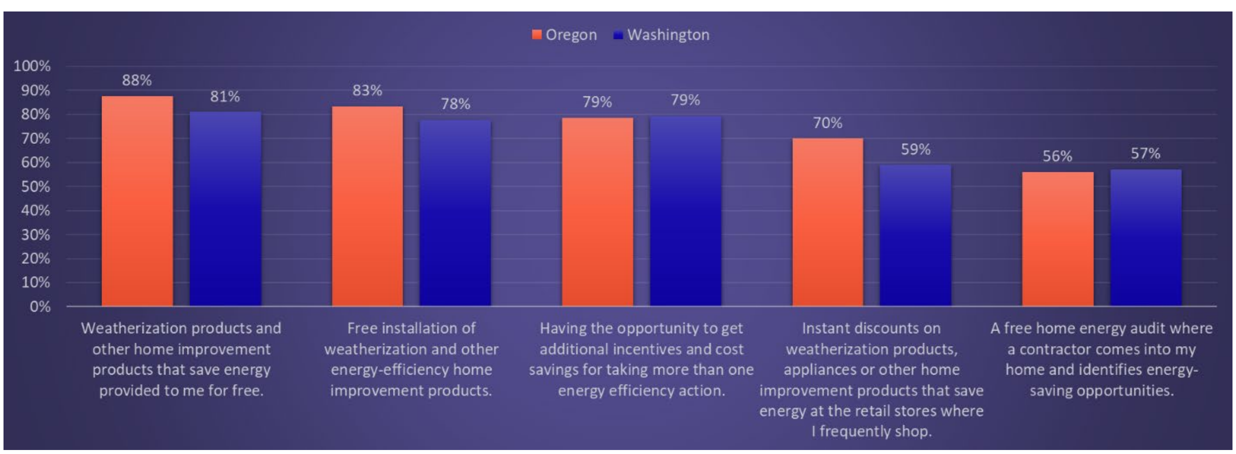
The survey included questions on common barriers to seeking Energy Assistance and purchasing energy-efficient products through energy-efficient rebate programs, and features that would make it easier for customers to find Energy Assistance and participate in rebate programs. The questions focused on cost, awareness/education, the type of Energy Assistance that can impact their household, and trust barriers to learn more about the most significant factors in the customer decision-making process when seeking Energy Assistance or purchasing energy-efficient products. As shown in Figure 5-1, the cost of energy-efficient products was the most commonly cited barrier in both states, followed by a lack of energy efficiency and Energy Assistance program awareness.

Figure 5-1 Barriers to Energy Efficiency



Respondents indicated that programmatic features that can help overcome barriers include free products, subsidized installation, and audits, as well as point of purchase discounts. These features are likely to increase participation in utility programs that offer rebates for the purchase and installation of energy efficient products.

Figure 5-2 Features that Will Make Customers More Likely to Participate in an EE Program (QP4)



Recommendations

Based on survey responses and additional analysis performed through this project, AEG offers the following recommendations to address key barriers to Energy Assistance and energy efficiency program participation.

The 2022 LINA provides an analysis structure and baseline customer survey responses to build on in future years. Using 2022 survey responses, future LINA's can pinpoint communities where income-eligible customers live, which will increase the number of income-eligible customers the survey reaches and potentially the response rate. NW Natural can also measure the change in survey responses on program participation, barriers to participation, customers' awareness, and other baseline metrics that have been established through the 2022 survey. This will allow NW Natural to measure their success in implementing new programs, awareness campaigns, and Energy Assistance benefits to serve the income- eligible population more effectively in Oregon and Washington.

Addressing Cost Barriers

61% of survey respondents in Oregon and 64% in Washington indicate that they cannot afford energy-efficient purchases. NW Natural (through the Energy Trust of Oregon) currently offers rebates for a number of energy efficiency home upgrades, but the price of these upgrades remain cost prohibitive for many of the survey respondents. The following AEG recommendations are focused on removing the cost barrier for energy efficiency upgrades for income-qualified customers:

- 88% of Oregon respondents and 81% of Washington respondents are interested in **free weatherization and other energy efficiency home improvement products**. Weather stripping, LED bulbs, and low-flow showerheads are common low-cost upgrades utilities have provided to customers in the past. Explore opportunities to continue or increase these offerings for income-qualified customers. NW Natural can also look at providing these products through direct install programs in combination with a free home energy audit.
- **Offering increased incentives on HVAC and water heating equipment or zero-cost replacement programs for income-qualified customers.** Survey results indicate that there is a significant opportunity to replace old HVAC and water heating equipment in income-qualified customer homes. 30% of survey respondents in Oregon and 37% in Washington have natural gas space heating equipment that is 15 years or older, while close to 20% of respondents between the two states have natural gas water heaters that are approaching 15 years or older. This provides NW Natural with an opportunity to target equipment replacement in income-qualified homes that is nearing end-of-life, and bundle HVAC (including smart thermostats) and water heating equipment if it results in larger incentive offerings (see "bundling" recommendation below). Partnering with other Energy Assistance organizations or funding opportunities would also be an effective way to remove the cost barrier for these customers.
- 79% percent of survey respondents in Oregon and Washington are interested in **bundling energy-efficient upgrades for a larger incentive**. This provides NW Natural with an opportunity to have customers participate in more than one energy efficiency program to improve the efficiency of their home if an increased incentive from bundling is available to lower the cost to the customer. NW Natural could also explore partnerships with other community programs that provide additional home services to income-qualified customers.

Increasing Customer Awareness and Education

Survey results indicate that low awareness is impacting participation in Energy Assistance programs in both Oregon and Washington. A quarter of respondents in both states are aware of NW Natural programs that can lower monthly bill payments or connect customers to free weatherization services, while only 23% of Oregon and 13% of Washington respondents had participated in a program in the past.

Oregon and Washington customer interest suggests that there are opportunities to increase participation in NW Natural Energy Assistance and weatherization programs. 54% of Oregon and 52% of Washington respondents are 'somewhat likely' to participate in a program that lowers monthly payments in the next two years, while 46% of Oregon and 43% of Washington respondents are 'somewhat likely' to participate in a weatherization program.

There is greater awareness of energy efficiency products in both states; however, increasing customer education on the benefits of energy-efficient products may increase customers' adoption and participation in NW Natural programs. 40% of survey respondents in Oregon and 46% in Washington indicate that awareness of energy-efficient products is a barrier to purchasing energy-efficient products and participating in rebate programs.

The following AEG recommendations focus on increasing awareness and education of Energy Assistance and energy efficiency products and programs.

- **Targeted Community Marketing** is directed to communities that are identified as having a high number of income-qualified customers. AEG's community characterization estimates the average median income within a block group and the number of households that are eligible for Energy Assistance programs based on a low-income probability score for each block group. These block groups have been included on interactive maps that visually show where these low-income communities are throughout NW Natural's Oregon and Washington service territory. The maps provide NW Natural with an opportunity to implement targeted marketing campaigns that reach income-qualified residents, with the hope that providing education and awareness of Energy Assistance programs and the benefits of energy-efficient products will increase participation in NW Natural programs. Partnering with organizations that provide services to income- qualified customers, such as food banks or health and educational services, can also be an effective way of increasing customer touch points within these communities.
- **Prioritizing educational resources** with each NW Natural customer interaction that increases awareness of available Energy Assistance and the benefits of energy-efficient products and programs. Leave behind brochures, links to online resources, or one-on-one information exchanges are all ways to educate customers on where to find Energy Assistance and how to lower bills by way of improving energy efficiency in a home. Coordinating with NW Natural customer service departments and field staff increases the opportunity to reach customers who are not initially contacting the utility for energy efficiency related or Energy Assistance inquiries.

Discount Program Design and Streamlining Program Participation

Survey recipients were asked to rank the type of Energy Assistance options in order of their preference. Discount programs ranked higher than forgiveness programs and time arrangement payments, with a preference from 61% of Oregon and 64% of Washington survey respondents.

30% of survey respondents in Oregon and 24% in Washington indicate that completing rebate program paperwork is overly burdensome and is a barrier to energy efficiency program participation.

The following recommendations focus on the type of Energy Assistance customers are most interested in and how to streamline participation in energy efficiency rebate programs.

- **Offer bill discounts for income-eligible customers in the 15%-25% range.** A significant number of respondents in Oregon and Washington say a 15%-25% bill discount would have a meaningful impact on their household finances and overall well-being.
- **Offer midstream incentives and point of purchase discounts.** 70% of respondents in Oregon and 59% in Washington would be interested in instant discounts on energy-efficient products and services at their local retailers. Midstream rebates with local retailers eliminate customer rebate paperwork and potentially increase the number of discounted energy-efficiency products that are offered. Recruiting retailers who serve higher populations of income-qualified customers, are located in high probability low-income areas, or are located near mass transit could also increase energy efficiency rebate accessibility for these customers.

Building Trust Through Testimonials

- **Customer testimonials** can reinforce the benefits of energy-efficient upgrades and NW Natural's support through program participation. 25% of respondents in Oregon and 31% in Washington reported that they do not believe installing energy-efficient measures in their home will add benefit. Promoting testimonials from customers who have participated in NW Natural programs can be a useful tool in removing this "trust" barrier. Testimonials that reference increased comfort or a reducing energy bill cost will likely resonate the strongest with income-qualified customers who are looking for ways to reduce energy use.

Reducing Energy Burden

AEG's analysis identified areas of NW Natural's service territory with higher-than-average energy burden. Although this analysis could be improved with actual electricity bill information, the information should be valuable for NW Natural in targeting Energy Assistance offerings to communities with high energy burden. This analysis framework can also be updated over time based on new billing and ACS data.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Direct Testimony of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 300

REDACTED

December 29, 2023

EXHIBIT 300 – DIRECT TESTIMONY– COST OF CAPITAL

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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 Brody J. Wilson. I am Vice President, Treasurer, Chief Accounting Officer, and Controller at NW Natural. In addition, on July 28, 2023, I was appointed as Interim Chief Financial Officer of Northwest Natural Holding Company ("NW Natural Holdings") and NW Natural.

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 explain the Company's financing strategy and how that leads to a financially healthy utility that benefits our customers. More specifically, the Company's financing strategy is to maintain a balance of long-term debt and equity financing by targeting a capital structure of 50 percent common equity and 50 percent long-term debt. This balance supports our strong credit ratings, which provides us access to capital markets. We work to manage interest rate risk and secure low-cost capital to fund utility growth and operations. To do this, we intend to maintain a strong balance sheet and focus on financing our ongoing long-term assets of the Company through a balance of long-term debt and equity financing.

Q. Please summarize your testimony.

A. To further explain our financing strategy, my testimony:

- Describes NW Natural's request for a capital structure of 50 percent common equity and 50 percent long-term debt, with an overall rate of return ("ROR") on rate base of 7.406 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 (i.e., November 1, 2024 through October 31, 2025); 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 ratemaking capital structure and overall ROR?

A. In UG 435, 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. 22-388

Component	Ratio	Cost	Weighted Cost
Long-term Debt	50%	4.271%	2.135%
Common Equity	50%	9.40%	4.7%
Total	**100%**		**6.836**

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

A. NW Natural is requesting a continued capital structure of 50 percent equity and 50 percent long-term debt, with an overall ROR on rate base of 7.406 percent, based upon a 4.712 percent embedded cost of long-term debt and a 10.1 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	50%	4.712%	2.356%
Common Equity	50%	10.1%	5.050%
Total	**100%**		**7.406%**

Q. Does NW Natural always maintain exactly a 50/50 capital structure?

A. No. Although NW Natural's target capital structure has for a long time been, and continues to be, 50/50, there is a natural fluctuation in this ratio on a temporary basis over time. The fluctuation does not, however, represent a meaningful departure from our targeted capital structure. For example, NW Natural forecasts the Test Year to have an average equity ratio slightly lower than 50 percent (49.04 percent to be precise using a 13-month average) but that number will fluctuate throughout the year.

Q. Why is it important to NW Natural to maintain a 50/50 capital structure at the utility?

A. Maintaining a 50 percent utility common equity ratio is important for several reasons. 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.

The converse is true, too. Generally, companies with higher debt ratios are considered riskier. By maintaining a long-term debt ratio at 50 percent, the Company is maintaining its risk profile in line with its historical risk profile and with those of the natural gas peer group. If the Company were to increase its debt ratio beyond 50 percent, it is likely that the rating agencies would view such an action negatively. In the event our ratings were downgraded, the Company could face more difficulty accessing capital markets and higher costs of debt – potentially causing detriment to both our customers and our shareholders.

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

A. The Company's proposed capital structure has a significantly lower equity to capital ratio than the average of our peer group identified by Dr. James M. Coyne and Jennifer E. Nelson in the Company's Return on Equity Direct Testimony (NW Natural/400, Coyne-Nelson). Our peer group has an average equity ratio of 54.45 percent over the last three years, and the Combined Proxy Group has a three-year average common equity ratio of 53.10 percent. (NW Natural/400, Coyne-Nelson/61.)

Q. What is NW Natural's plan to maintain the target utility common equity ratio of 50 percent over the next few years?

A. The Company's plan relies on retained earnings growth each year, as well as continuing to request equity infusions from our parent company, as needed.

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	YTD[1] 2023
$93 million	$ -	$116 million	$179.4 million	$30 million

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 ($1,479,700,000) and the corresponding weighted average cost (4.712 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.

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

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]**

IV. CREDIT RATINGS

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

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

Table 8. Current Ratings

	Moody's	S&P
Corporate	n/a	A+
Secured	A2	AA-
Commercial Paper	P-2	A-1
Outlook	Stable	Negative

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 435)?

A. No, there have not been any changes to NW Natural's credit ratings since the last general rate case, UG 435. However, as shown in the above table, there has been a change to the outlook issued by S&P. Specifically, in the report issued for NW Natural on October 9, 2023, S&P downgraded the outlook for NW Natural from stable to negative. 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 negative outlook?

A. As context, in October 2023 S&P provided the first credit rating for NW Natural Holdings. At the same time, S&P also reviewed NW Natural's ratings. After its review, S&P gave two primary reasons for the negative outlook for both entities. 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 and potential gas bans. (NW Natural/301, Wilson).

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 NW Natural's financial forecast, as a consolidated company, for the 2023 year-end ("YE") period.

Table 9 – Moody's Benchmarks

Ratio	Moody's "A" Benchmark	NW Natural's 2023 YE Forecast	Comment
Pre-tax Interest Coverage	4.5x to 6.0x	4.2x	Out of range for "A" rating but within the "Baa" rating
Debt Leverage	40%-50%	50.0%	Within "A" rating band
CFO Pre-W/C to Debt	19% to 27%	14.9%	Out of range for "A" rating but within the "Baa" rating
Retained Cash Flow	15% to 23%	9.1%	Out of range for "A" rating but within the "Baa" rating

Table 10 – S&P's Benchmarks

Ratio	S&P "A" Benchmark	NW Natural's 2023 YE Forecast	Comment
FFO/Debt	13% - 23%	15.4%	Within "A" rating band
Debt/EBITDA (x)	3x – 4x	4.4x	Within "BBB" rating band

FFO = Funds From Operations
EBITDA = Earnings Before Interest, Taxes, Depreciation and Amortization
CFO = Cash Flow from Operations

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 low 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. Does this conclude your direct testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibits of Brody J. Wilson

COST OF CAPITAL
EXHIBITS 301 – 305

December 29, 2023

EXHIBITS 301-305 – COST OF CAPITAL

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UG 490

NW Natural

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COST OF CAPITAL
EXHIBIT 301

December 29, 2023

S&P Global
Ratings

RatingsDirect®

Research Update:

Northwest Natural Holding Co. Rated 'A+' With Negative Outlook; Subsidiary Ratings Affirmed; Outlook Revised To Negative

October 9, 2023

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Rating Action Overview

- Northwest Natural Holding Co.'s (NWNH) consolidated financial measures are weak for the current rating and remain below our downgrade threshold.
- We assigned our 'A+' long-term issuer credit ratings (ICR) to Portland, Oregon-based natural gas utility holding company, NWNH. The outlook is negative.
- At the same time, we affirmed our ratings on subsidiary Northwest Natural Gas Co. (NWNG), including the 'A+' long-term ICR, 'A+' unsecured debt rating, 'AA-' senior secured debt rating with a '1+' recovery rating, and 'A-1' short-term rating. However, we revised our outlook to negative from stable.
- The negative outlook on the group reflects a potential for the ratings to be lowered over the next 12-24 months if NWNH does not improve its financial measures and its funds from operations (FFO) to debt remains below 15%. In addition, the negative outlook also reflects a gradual increase in business risk due to ongoing energy transition risks in Oregon and Washington due to decarbonization mandates and potential gas bans, a potential weakening of the company's management of regulatory risk, or an inability to consistently earn its authorized return on equity (ROE).

Rating Action Rationale

The negative outlook reflects NWNH's weak financial measures and the possibility that they will remain below our downgrade threshold for the current rating along with a potential increase in business risk. Since 2020, NWNH's FFO to debt has remained consistently below our 15% downgrade threshold. The company's historical underperformance reflects its higher 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 headwinds stemming from the COVID-19 pandemic, higher bad debt expenses, elevated capital spending, and inflationary pressures, including higher operating costs.

We expect the company's financial measures will remain challenged due to its elevated capital spending plan, including acquisition of water utilities, investments in renewable natural gas (RNG) projects, and ongoing infrastructure replacements. The company's financial measures could deteriorate further if it funds its elevated capital investment plan primarily with debt or experiences any material disallowance in future rate cases.

Furthermore, the negative outlook also reflects a potential gradual weakening of business risk due to ongoing energy transition risks in Oregon and Washington due to implementation of decarbonization mandates and potential gas bans that may result in higher operating risk within its service territories. In addition, over the past few years, the company's earned ROEs have been modestly weaker than authorized ROEs, reflecting a potential weakening of management's ability to manage regulatory risk.

We assigned our 'A+' long-term ICR to NWNH, the parent company of NWNG. Our rating largely reflects its operating subsidiary NWNG's operations, which account for about 96% of consolidated EBITDA. NWNG provides natural gas service to approximately 795,000 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 mitigate regulatory lag.

NWNH, through its operating subsidiaries, owns and operates several regulated water distribution and wastewater services utilities. NWNH continues to grow its water and wastewater services operations by acquiring several small water and wastewater utilities close to the existing operations. The strategy to diversify its business operations by acquiring small water utilities could negatively impact financial measures if these acquisitions are largely funded with debt. Given the low-risk nature of water utilities, we view NWNH's entry into the regulated water utility space as a modest positive for its business risk profile. However, the water utilities operations do not have a meaningful impact on the overall credit quality of the company because they do not contribute any meaningful EBITDA.

Furthermore, NWNH, through its operating subsidiary NW Natural Renewable Holdings LLC (NWNR), plans to invest and grow its competitive RNG assets. NWNR partnered with EDL Energy to construct two landfill RNG facilities and plans to invest about $50 million. Typically, we consider investments in nonregulated operations as higher risk compared to regulated utility operations. However, the competitive RNG operations do not materially impact the overall credit quality as they do not contribute any meaningful EBITDA, and the company has signed long-term fixed-volume offtake agreements with investment grade counterparties that alleviates some of these risks.

We assess NWNH's financial risk profile as intermediate. We assess the company'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 incorporate our assumptions, including continued use of regulatory mechanisms and rate riders to effectively manage regulatory risk, annual capital spending averaging about $390 million, and annual dividends averaging about $70 million. We expect FFO to debt to be constrained in 2023 at about 14.8% and improve to about 15%-16% for 2024-2025.

Outlook

The negative outlook reflects NWNH's current weaker financial performance and the possibility that the financial measures could weaken further if regulatory risk persists. Our base case assumes FFO to debt at about 15%-16% over the next 12-24 months.

Downside scenario

We could lower our ratings on NWNH and NWNG over the next 12-24 months if FFO to debt remains consistently below 15%. We could also lower our ratings on NWNH and NWNG if business risk increases. This could reflect a higher operating risk in its service territories 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 revise our outlook on NWNH and NWNG back to stable over the next 12-24 months if FFO to debt remains consistently above 15%, 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 795,000 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 $390 million over our forecast period.
- Small tuck-in regulated water utilities acquisitions funded in a credit supportive manner.
- Annual dividends averaging about $70 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 $390 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 $137.8 million;
- Credit facility of about $600 million; and
- Cash FFO estimated of about $280 million.

Principal liquidity uses

- Debt maturities, including commercial paper outstanding of about $281 million;
- Capital expenditure (capex) of about $390 million; and
- Dividend payments of about $70 million.

Environmental, Social, And Governance

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

Group Influence

Under our group rating methodology, we view NWNH as the parent of the group with NWNG as its subsidiary. NWNH's group credit profile is 'a+', leading to an issuer credit rating of 'A+'.

We consider NWNG a core subsidiary of parent NWNH. This core status reflects our view that NWNG is highly unlikely to be sold, is integral to the group's overall strategy, possesses a strong, long-term commitment from senior management, and is closely linked to the parent's name and reputation. Given its core subsidiary status and NWNH's GCP of 'a+', the issuer credit rating on NWNG is 'A+'.

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 June 30, 2023, NWNG's capital structure consists of approximately $1.3 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.

Foreign currency issuer credit rating: A+/Negative/--

Local currency 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: Satisfactory (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a+

Northwest Natural Gas Co.:

Foreign currency issuer credit rating: A+/Negative/A-1

Local currency issuer credit rating: A+/Negative/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: Satisfactory (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a+

Related Criteria

- 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: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, 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: Methodology: Management And Governance Credit Factors For Corporate

Entities, Nov. 13, 2012

- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings List

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

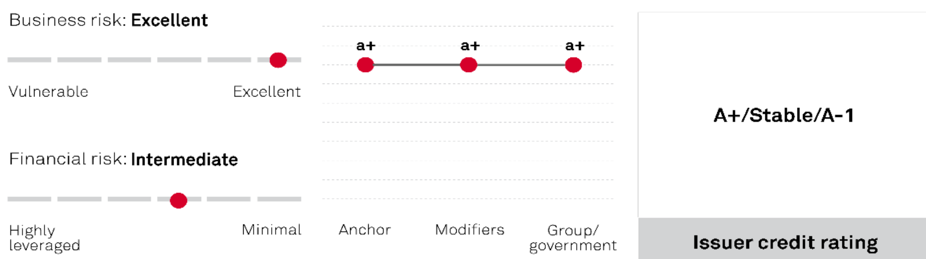
S&P Global
Ratings

RatingsDirect®

Northwest Natural Gas Co.

June 16, 2023

Ratings Score Snapshot



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Credit Highlights

Overview

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

Northwest Natural Gas Co. (NWNG) is exposed to various decarbonization initiatives announced in Oregon and Washington. The state of Washington recently enacted legislation, the Climate Commitment Act (CCA), which establishes a comprehensive program that provides an overall limit for GHG emissions from major sources in the state that begins on Jan. 1, 2023 and declines yearly to 95% below 1990 levels by 2050. Similarly, the State of Oregon recently introduced the Climate Protection Program (CPP), which outlines GHG emissions reduction goals of 50% by 2035 and 90% by 2050 from a 1990 baseline. The company will require additional resources and tools to comply with CPP in Orgon and CCA in Washington which may result in additional costs. Furthermore, some local jurisdictions within the company's service territories are considering building codes that disallows natural gas in residential or commercial new construction or conversions. Recently, the Eugene City council passed an ordinance that prohibits the use of natural gas in low-rise residential buildings beginning with permits submitted after June 2023. The Eugene ordinance has been referred to the ballot for vote in November 2023. These initiatives further restrict future growth and elevates the risk of recovery of investments. At this stage, the company expects to track and recover the costs of compliance with CCA and CCP in rates. We continue to monitor future developments and the assess the potential impact of these risks.

NWNG is implementing various initiatives and investments in decarbonization initiatives. The company plans to invest in various renewable natural gas (RNG) facilities and procure additional RNG supply to serve its customers. In addition, NWNG has successfully executed series of hydrogen blend tests and made progress on turquoise hydrogen pilot project. Furthermore, the company has also filed integrated resource planning within its service territories that includes comprehensive analysis to support implementation of the transformative climate policies adoption. At this time, these initiatives partially offset the elevated decarbonization initiative risks.

NWNG will effectively manage its regulatory risk under credit-supportive regulatory frameworks in Washington and Oregon. We expect NWNG will continue to benefit from this. It will get timely cost recovery for its investments through rate case filings and other regulatory mechanisms, including purchased gas adjustment and environmental cost recovery. We expect it to maintain credit measures consistent with our rating. Specifically, we expect funds from operations (FFO) to debt of about 17%-19% throughout our forecast period.

Outlook

The stable rating outlook on NWNG reflects S&P Global Ratings' expectation of strong financial and operating performance and effective management of regulatory risk. We expect the company to maintain FFO to debt of 15%-17% over the next two years.

Downside scenario

Ratings pressure could occur over the next two years if FFO to debt consistently drops below 15%. This could occur if the company relies heavily on external financing to fund cash shortfalls, investments in nonregulated operations exceed our expectations, or mismanagement of regulatory risk impairs cash flow.

Upside scenario

Although we consider an upgrade unlikely over the next two years, we could raise the ratings if the company improves financial measures on a sustained basis, including FFO to debt of more than 23%. This could occur through strengthened operating cash flow or reduced leverage.

Our Base-Case Scenario

Assumptions

- Modest customer growth and continued use of regulatory mechanisms.
- Continued negative discretionary cash flow.
- Annual capital spending averaging about $283 million over our forecast period.
- Annual dividends averaging about $73 million.
- All debt maturities refinanced.

Key metrics

Northwest Natural Gas Co.--Key Metrics*

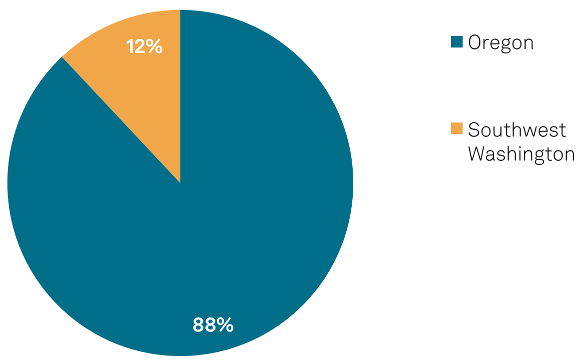
Mil. $	2022a	2023e	2024f
Debt to EBITDA (x)	4.8	4.0-4.5	4.0-4.5
FFO to debt (%)	16.9	17.0-19.0	17.0-19.0

*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 795,000 residential, commercial, and industrial natural gas customers in Oregon and Southwest Washington through 14,200 miles of pipeline systems. Approximately 88% of customers are in Oregon and 12% are in southwest Washington.

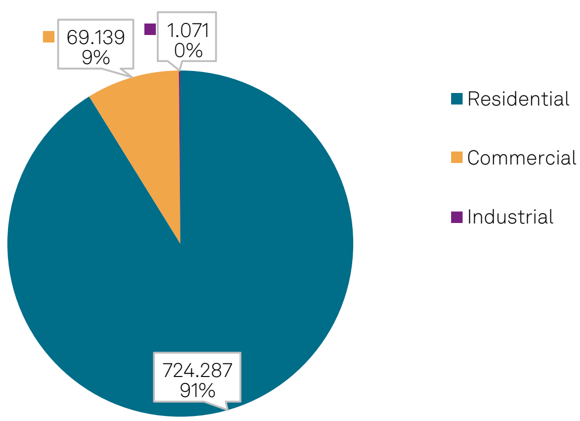
Customers based on geography



Source: Company filings.

Number of customers based on NGD segment as of Dec. 31, 2022

(000's)



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.
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	2022-12-31	2022-12-31	2022-09-30	2022-12-31
Mil.	$	$	$	$
Revenue	1,014	2,555	4,202	2,124
EBITDA	292	574	1,511	698
Funds from operations (FFO)	236	410	1,234	535
Interest	52	81	122	146
Cash interest paid	51	97	261	140
Operating cash flow (OCF)	146	1,544	994	508
Capital expenditure	319	605	2,432	858
Free operating cash flow (FOCF)	(173)	939	(1,438)	(350)
Discretionary cash flow (DCF)	(236)	802	(1,814)	(350)
Cash and short-term investments	13	10	52	0
Gross available cash	13	10	52	0
Debt	1,397	2,644	8,022	3,751
Equity	1,191	2,584	9,419	3,673
EBITDA margin (%)	28.8	22.5	36.0	32.9
Return on capital (%)	7.2	5.9	5.8	6.8
EBITDA interest coverage (x)	5.6	7.1	12.4	4.8
FFO cash interest coverage (x)	5.6	5.2	5.7	4.8
Debt/EBITDA (x)	4.8	4.6	5.3	5.4
FFO/debt (%)	16.9	15.5	15.4	14.3
OCF/debt (%)	10.5	58.4	12.4	13.6
FOCF/debt (%)	(12.4)	35.5	(17.9)	(9.3)
DCF/debt (%)	(16.9)	30.3	(22.6)	(9.3)

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 focus customer base, and effective management of regulatory risks. NWNG provides natural gas service to approximately 795,000 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 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.

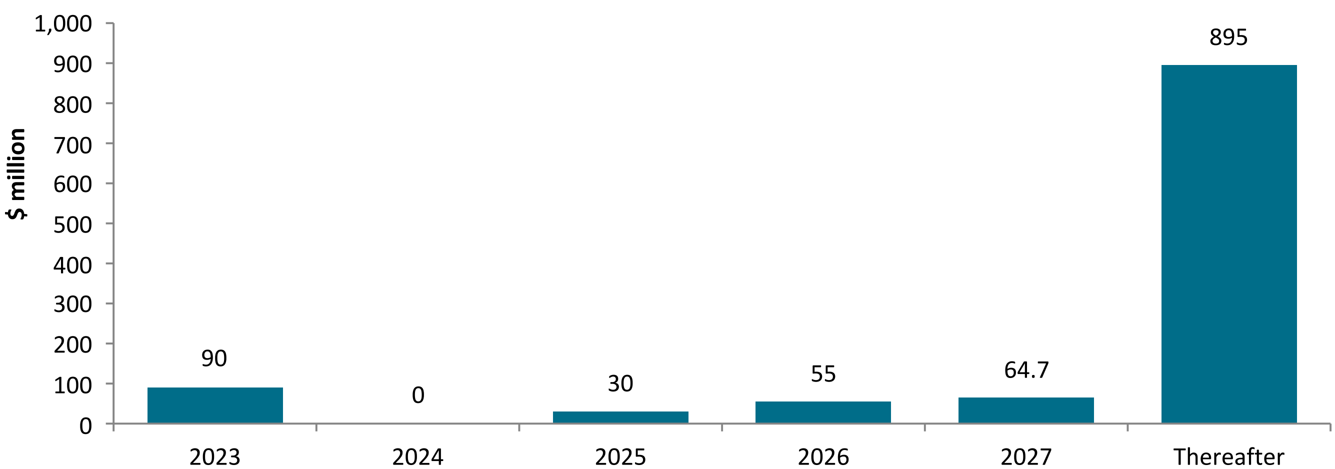
Financial Risk

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 continued use of regulatory mechanisms and rate riders to effectively manage regulatory risk, annual capital spending averaging about $283 million, and annual dividends averaging about $73 million. We expect FFO to debt in the middle of the intermediate financial risk profile range, with FFO to debt about 17%-19% throughout the outlook period.

Our base-case forecast includes Washington Utilities and Transportation Commission's (WUTC) October 2021 order concluding NWNG's general rate case filed in December 2020. The WUTC order allows NWNG to implement a revenue increase of about $5 million from November 2021 and up to $3 million for two years from November 2022. In addition, NWNG got the approval of increasing revenue of about $59.4 million for general rate case filed with Oregon Public Utility Commission in November 2022.

Debt maturities

NWNG debt maturity schedule



Source: Company filings.

Northwest Natural Gas Co.--Financial Summary

Period ending	Dec-31-2017	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022
Reporting period	2017a	2018a	2019a	2020a	2021a	2022a
Display currency (mil.)	$	$	$	$	$	$
Revenues	762	706	740	759	843	1,014
EBITDA	248	226	245	257	286	292
Funds from operations (FFO)	191	157	202	207	211	236
Interest expense	45	43	41	44	49	52
Cash interest paid	41	41	40	44	48	51
Operating cash flow (OCF)	206	173	191	148	143	146
Capital expenditure	211	214	240	274	280	319
Free operating cash flow (FOCF)	(5)	(41)	(50)	(126)	(137)	(173)
Discretionary cash flow (DCF)	(61)	(80)	(103)	(182)	(193)	(236)
Cash and short-term investments	3	8	6	10	12	13
Gross available cash	3	8	6	10	12	13
Debt	1,009	1,121	1,066	1,353	1,379	1,397
Common equity	743	716	822	835	978	1,191
Adjusted ratios						
EBITDA margin (%)	32.5	32.0	33.0	33.9	33.9	28.8
Return on capital (%)	9.5	8.0	8.3	7.4	7.5	7.2
EBITDA interest coverage (x)	5.5	5.3	5.9	5.9	5.9	5.6
FFO cash interest coverage (x)	5.6	4.8	6.0	5.7	5.4	5.6
Debt/EBITDA (x)	4.1	5.0	4.4	5.3	4.8	4.8
FFO/debt (%)	19.0	14.0	18.9	15.3	15.3	16.9
OCF/debt (%)	20.4	15.4	17.9	10.9	10.3	10.5
FOCF/debt (%)	(0.5)	(3.7)	(4.6)	(9.3)	(9.9)	(12.4)
DCF/debt (%)	(6.1)	(7.1)	(9.6)	(13.4)	(14.0)	(16.9)

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-31-2022									
Company reported amounts	1,296	1,191	1,014	282	169	46	292	145	63	319
Cash taxes paid	-	-	-	-	-	-	(6)	-	-	-
Cash interest paid	-	-	-	-	-	-	(45)	-	-	-
Lease liabilities	80	-	-	-	-	-	-	-	-	-

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
Operating leases	-	-	-	7	6	6	(6)	1	-	-
Postretirement benefit obligations/ deferred compensation	121	-	-	-	-	-	-	-	-	-
Accessible cash and liquid investments	(13)	-	-	-	-	-	-	-	-	-
Share-based compensation expense	-	-	-	3	-	-	-	-	-	-
Nonoperating income (expense)	-	-	-	-	2	-	-	-	-	-
Debt: other	(86)	-	-	-	-	-	-	-	-	-
Total adjustments	101	-	-	10	8	6	(57)	1	-	-
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	1,397	1,191	1,014	292	177	52	236	146	63	319

Liquidity

As of March 31, 2023, we assess NWNG'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 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, and our belief that the company can lower its high capital spending (averaging about $283 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 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 the company to proactively address this maturity well in advance of its scheduled due date.

Principal liquidity sources

- Cash and cash equivalents of about $129.7 million as of March 31, 2023;
- Credit facility of about $400 million; and
- Cash FFO estimated of about $280 million.

Principal liquidity uses

- Debt maturities of about $90 million;
- Capital expenditure of about $304 million;
- Working capital outflow of about $45 million; and
- Dividend payments of about $67 million.

Environmental, Social, And Governance

ESG Credit Indicators

E-1	**E-2**	E-3	E-4	E-5	S-1	**S-2**	S-3	S-4	S-5	G-1	**G-2**	G-3	G-4	G-5

ESG credit indicators provide additional disclosure and transparency at the entity level and reflect S&P Global Ratings' opinion of the influence that environmental, social, and governance factors have on our credit rating analysis. They are not a sustainability rating or an S&P Global Ratings ESG Evaluation. The extent of the influence of these factors is reflected on an alphanumerical 1-5 scale where 1 = positive, 2 = neutral, 3 = moderately negative, 4 = negative, and 5 = very negative. For more information, see our commentary "ESG Credit Indicator Definitions And Applications," published Oct. 13, 2021.

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

Group Influence

Under our group rating methodology, we view NWNG as the parent and the ultimate rated entity. As a result, NWNG's group and stand-alone credit profile are the same, 'a+'.

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 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 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	Satisfactory (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	**a+**

Related Criteria

- 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
- ARCHIVE | General Criteria: Group Rating Methodology, Nov. 19, 2013
- ARCHIVE | Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, 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: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- ARCHIVE | General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Ratings Detail (as of June 15, 2023)*

Northwest Natural Gas Co.	
Issuer Credit Rating	A+/Stable/A-1
Commercial Paper	
Local Currency	A-1
Senior Secured	AA-
Issuer Credit Ratings History	
25-Jan-2010	A+/Stable/A-1
19-Dec-2008	AA-/Negative/A-1+
28-Feb-2006	AA-/Stable/A-1+

*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
INVESTORS SERVICE

CREDIT OPINION
19 July 2023

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.

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Northwest Natural Gas Company

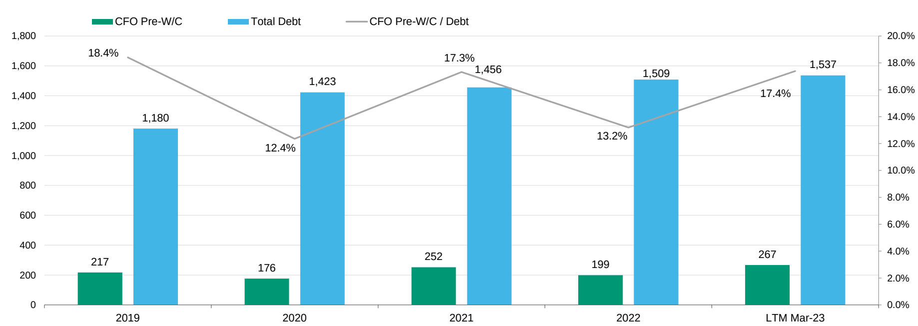
Update to credit analysis

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 consistent cash flow generation and financial metrics.

The utility has typically sustained credit metrics, including a cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio, in the high teens over the last several years only declining to low teens in 2020 and 2022 as a result of one time events. The years of financial decline were driven by the coronavirus pandemic (2020) and an increase in commodity prices in 2022, which drove an increase in gas cost deferrals. Favorably, the utility was authorized full recovery of its gas cost beginning in 2023, thereby driving the improvement in the utility's credit metrics. As of the last twelve months ending 31 March 2021, the CFO pre-WC to debt ratio was 17.4% much improved from the weak 13.2% at year-end 2022. We expect credit metrics to sustain in the mid-teens percent range 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 consistent 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.

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. 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]

	Dec-19	Dec-20	Dec-21	Dec-22	LTM Mar-23
CFO Pre-W/C + Interest / Interest	5.5x	4.5x	5.8x	4.4x	5.2x
CFO Pre-W/C / Debt	18.4%	12.4%	17.3%	13.2%	17.4%
CFO Pre-W/C – Dividends / Debt	13.9%	8.5%	13.5%	9.0%	13.2%
Debt / Capitalization	51.2%	55.2%	52.5%	49.3%	48.6%

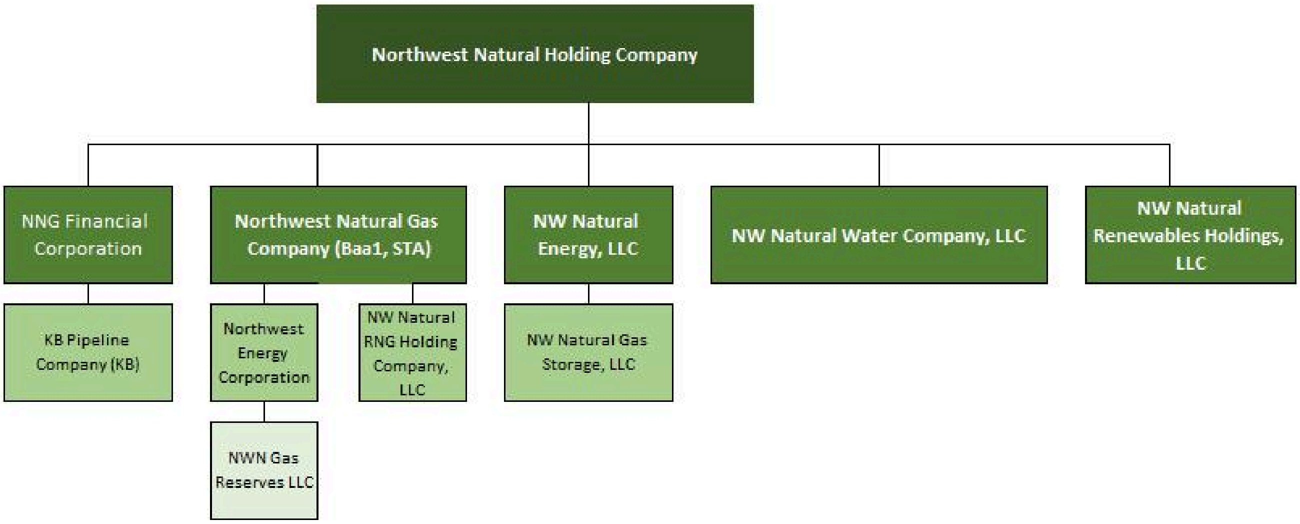
[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

Profile

Northwest Natural Gas Company (NW Natural) is a natural gas local distribution company (LDC), serving over 795,000 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, not rated), is a holding company headquartered in Portland, Oregon and owns NW Natural, NW Natural Water Company, LLC (NWN Water, not rated), 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

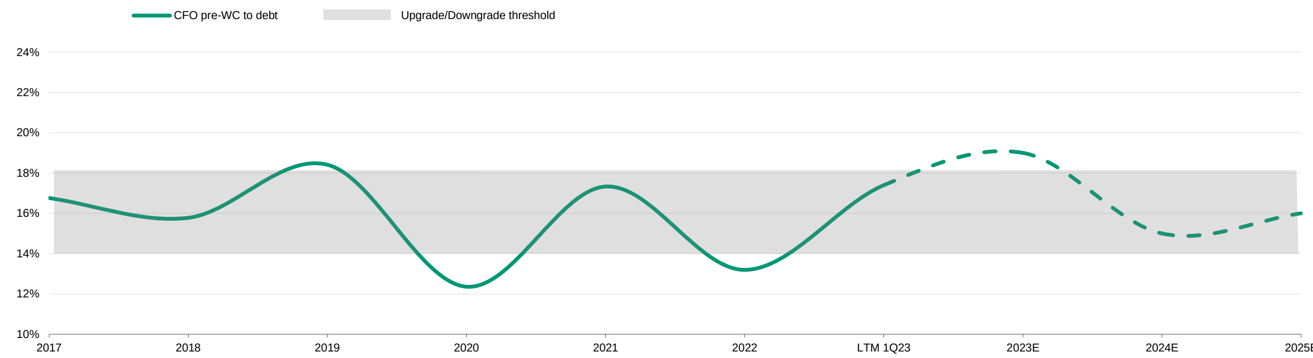
Detailed credit considerations

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 $170 million in cash flow from operations, which resulted in CFO pre-WC to debt ratio averaging about 16% from 2017 to 2022. 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. This lead to a year-end CFO pre-WC to debt ratio of 12.4%. The pandemic-related debt was subsequently repaid in 2021, and due to the stronger economic activity - including better than expected connections within commercial and industrial (C&I) customers - the utility's credit metrics improved to about 17% at the end of 2021.

In 2022, NW Natural's credit metrics ended the year at 13.2%. The weak ratio was 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. Although natural gas cost is a pass-through to customers, NW Natural must first file to recover the cost through its annual purchase gas adjustment mechanism (PGA). NW Natural typically files its annual PGA in the third quarter with rates effective 1 November of the same year. However, for 2022, to help limit customer bill impact during a higher usage period, NW Natural requested to delay the PGA effective date until 1 March 2023. Although there was a delay in the effective date, the utility was authorized to recover the full cost deferral within a year, a credit positive. NW Natural had about $194.2 million in gas cost deferral at year-end 2022. The collection of the deferral in 2023 supports the cash flow improvement that will lead to an improvement of the CFO pre-WC to debt ratio. We expect the ratio at about 19% in 2023 and sustain between 15% and 16% over the next several years.

Exhibit 4
Credit metrics expected to sustain in the mid-teens percent range over the next several years
Historical and forecast 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 Investors Service

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.

NW Natural's most recent general rate case resulted in a multi-party settlement that was approved by the OPUC on On 24 October 2022. In the settlement, NW Natural was authorized a $59.4 million revenue increase, $1.76 billion rate base and the same 9.4% ROE and 50% equity layer as previously authorized in a 2020 rate case. We view this as a constructive outcome and compares favorably to NW Natural's original filing (filed on 17 December 2021) which requested a $73.5 million base rate increase premised on a 50% equity layer, 9.5% ROE and $1.73 billion rate base. The general rate case filing was driven by overall system investment including several projects related to technology upgrades, cybersecurity, system resiliency and reliability and resource center facility renovations. The settlement also approved the recovery of $10.5 million coronavirus pandemic deferral over two years starting 1 November 2022 when new rates became effective.

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 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.

Washington

On 21 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 is 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

NW Natural's ESG Credit Impact Score is CIS-3 (Moderately Negative)

Exhibit 5
ESG Credit Impact Score

CIS-3
Moderately Negative

NEGATIVE IMPACT
POSITIVE IMPACT

For an issuer scored CIS-3 (Moderately Negative), 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 negative influence of the overall ESG attributes on the rating is more pronounced compared to an issuer scored CIS-2.

Source: Moody's Investors Service

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 moderately negative exposure to environmental and social risks balanced with a neutral to low exposure to governance risks.

Exhibit 6
ESG Issuer Profile Scores

ENVIRONMENTAL	SOCIAL	GOVERNANCE
E-3	**S-3**	**G-2**
Moderately Negative	Moderately Negative	Neutral-to-Low

Source: Moody's Investors Service

Environmental

NW Natural's **E-3** issuer profile score is driven by its moderately negative carbon transition and physical climate risks. These risks are offset by a neutral to low exposure to water management, waste and pollution and natural capital. 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 this 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

The utility'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 Natrual'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 NW Natural are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for NW Natural 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 2023, NW Natural's internal liquidity included about $130 million of cash on hand and produced about $182 million in cash flow from operations; this compares to about $318 million in capital expenditures and $65 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 2023, 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 2023 (51.4%).

NW Natural's debt maturity is manageable, with the next debt maturities due in August 2023 when $50 million of first mortgage bonds are due and November 2023 when $40 million of first mortgage bonds are due.

Rating methodology and scorecard factors

Exhibit 7

Methodology Scorecard Factors

Northwest Natural Gas Company

Regulated Electric and Gas Utilities Industry Scorecard [1][2]	Current LTM 3/31/2023		Moody's 12-18 Month Forward View As of Date Published [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	Aa	Aa
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)	5.1x	A	4.5x - 5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	16.0%	Baa	15% - 19%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	11.8%	Baa	10% - 13%	Baa
d) Debt / Capitalization (3 Year Avg)	50.6%	Baa	48% - 50%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching		0		0
a) Scorecard-Indicated Outcome		A3		A3
b) Actual Rating Assigned		Baa1		Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2023(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	Dec-19	Dec-20	Dec-21	Dec-22	LTM Mar-23
As Adjusted					
FFO	**219**	**184**	**227**	**207**	**256**
+/- Other	-2	-8	25	-8	12
CFO Pre-WC	**217**	**176**	**252**	**199**	**267**
+/- ΔWC	-20	-3	-105	-53	-84
CFO	**198**	**173**	**148**	**146**	**183**
- Div	53	55	56	63	65
- Capex	226	267	280	320	320
FCF	**-82**	**-149**	**-189**	**-237**	**-202**
(CFO Pre-W/C) / Debt	18.4%	12.4%	17.3%	13.2%	17.4%
(CFO Pre-W/C - Dividends) / Debt	13.9%	8.5%	13.5%	9.0%	13.2%
FFO / Debt	18.6%	12.9%	15.6%	13.7%	16.6%
RCF / Debt	14.1%	9.0%	11.8%	9.5%	12.4%
Revenue	740	759	843	1,014	1,122
Interest Expense	48	51	53	59	63
Net Income	81	75	85	86	102
Total Assets	3,321	3,599	3,898	4,453	4,301
Total Liabilities	2,505	2,764	2,921	3,262	3,050
Total Equity	816	835	978	1,191	1,250

[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 Baa1 (Stable)			Berkshire Gas Company A3 (Stable)			Wisconsin Gas LLC A3 (Stable)			Southwest Gas Corporation Baa1 (Stable)		
(In US millions)	FYE Dec-21	FYE Dec-22	LTM Mar-23	FYE Dec-21	FYE Dec-22	LTM Mar-23	FYE Dec-20	FYE Dec-21	FYE Dec-22	FYE Dec-21	FYE Dec-22	LTM Mar-23
Revenue	843	1,014	1,122	85	102	103	574	687	917	1,522	1,935	2,173
CFO Pre-W/C	252	199	267	11	18	18	135	161	170	463	449	467
Total Debt	1,456	1,509	1,537	73	80	78	889	943	1,081	3,182	3,648	4,119
CFO Pre-W/C + Interest / Interest	5.8x	4.4x	5.2x	4.6x	6.3x	6.3x	6.4x	7.3x	8.9x	5.4x	4.6x	4.4x
CFO Pre-W/C / Debt	17.3%	13.2%	17.4%	15.4%	21.9%	23.5%	15.1%	17.0%	15.7%	14.6%	12.3%	11.3%
CFO Pre-W/C – Dividends / Debt	13.5%	9.0%	13.2%	15.4%	9.5%	23.5%	7.3%	13.9%	10.2%	11.1%	9.0%	8.3%
Debt / Capitalization	52.5%	49.3%	48.6%	30.8%	31.5%	29.9%	41.6%	41.6%	42.0%	50.1%	52.9%	54.9%

[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 Investors Service

REPORT NUMBER 1370715

MOODY'S
INVESTORS SERVICE

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 302

December 29, 2023

NW Natural
UG 490 - Exhibit 302
NW Natural Credit Ratings 2018 - 2023

Debt Rating History

Standard & Poors

Rating Type	7/20/2018	3/23/2021	6/15/2022	Current
Outlook	Stable	Stable	Stable	Negative
Senior Secured LT Deb	AA-	AA-	AA-	AA-
Corporate Credit Ratii	A+	A+	A+	A+
Short-Term	A-2	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	Current
Outlook	Negative	Negative	Stable	Stable	Stable	Stable
Senior Secured LT Deb	A1	A1	A2	A2	A2	A2
Corporate Credit Ratii	A3	A3	Baa1	Baa1	Baa1	Baa1
Short-Term	P-2	P-2	P-2	P-2	P-2	P-2

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 303

REDACTED

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December 29, 2023

NORTHWEST NATURAL GAS COMPANY
EMBEDDED COST OF LONG-TERM DEBT CAPITAL AT
October 31, 2025

#	Coupon Rate	Description of Issue	Date Issued	Maturity Date	10/31/2025 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 Out-standing Debt
		(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Medium-Term Notes																
		First Mortgage Bonds:																
1	6.520%	6.520% Series	12/1/1995	12/1/2025	0.1	10,000,000	10,000,000	0	0.00	62,500	0.625	27,646	0.28	9,909,854	99.099	30	6.589%	658,900
2	7.050%	7.050% Series	10/15/1996	10/15/2026	1.0	20,000,000	20,000,000	0	0.00	125,000	0.625	50,940	0.25	19,824,060	99.120	30	7.121%	1,424,200
3	3.211%	3.211% Series	12/5/2016	12/5/2026	1.1	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
4	7.000%	7.000% Series	5/20/1997	5/21/2027	1.6	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
5	2.822%	2.822% Series	9/13/2017	9/13/2027	1.9	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
6	6.650%	6.650% Series	11/10/1997	11/10/2027	2.0	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
7	6.650%	6.650% Series	6/1/1998	6/1/2028	2.6	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
8	3.141%	3.141% Series	6/17/2019	6/15/2029	3.6	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
9	7.740%	7.740% Series	8/29/2000	8/29/2030	4.8	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
10	7.850%	7.850% Series	9/6/2000	9/1/2030	4.8	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
11	5.820%	5.820% Series	9/24/2002	9/24/2032	6.9	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
12	5.660%	5.660% Series	2/25/2003	2/25/2033	7.3	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
13	5.250%	5.250% Series	6/21/2005	6/21/2035	9.6	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
14	4.000%	4.000% Series	10/30/2012	10/31/2042	17.0	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
15	4.136%	4.136% Series	12/5/2016	12/5/2046	21.1	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
16	3.685%	3.685% Series	9/13/2017	9/13/2047	21.9	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
17	4.110%	4.110% Series	9/10/2018	9/10/2048	22.9	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
18	3.869%	3.869% Series	6/17/2019	6/15/2049	23.6	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
19	3.600%	3.600% Series	3/31/2020	3/15/2050	24.4	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
20	3.078%	3.078% Series	11/15/2021	12/1/2051	26.1	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
21	4.780%	4.780% Series	9/30/2022	9/30/2052	26.9	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
22	5.430%	5.430% Series	1/6/2023	1/6/2053	27.2	100,000,000	100,000,000	0	0.00	248,409	0.248	233,316	0.23	99,518,275	99.518	30	5.463%	5,463,000
23	5.750%	5.750% Series	3/8/2023	3/8/2033	7.4	100,000,000	100,000,000	(220,000)	0.22	625,000	0.625	439,925	0.44	98,715,075	98.715	10	5.922%	5,922,000
24	5.180%	5.180% Series	8/4/2023	8/4/2034	8.8	80,000,000	80,000,000	0	0.00	232,253	0.290	117,576	0.15	79,650,171	99.563	11	5.233%	4,186,400
25	5.230%	5.230% Series	8/4/2023	8/4/2038	12.8	50,000,000	50,000,000	0	0.00	158,036	0.316	61,371	0.12	49,780,592	99.561	15	5.273%	2,636,500
Confidential Forecast																		
[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
						$1,479,700,000	$1,479,700,000	-$818,500		$8,631,448		$7,390,654		$1,462,859,398			4.712%	$69,727,458
						$69,727,458	$1,479,700,000	EQUALS =	4.712%									

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 490

NW Natural

Exhibit of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 304

December 29, 2023

NW Natural
UG 490 - Exhibit 304
Market Implied Treasury Forwards

Market Implied Treasury Forwards

	2023	2024				2025			
Indices	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
Fed Funds Effective (Avg.)	5.43	5.38	5.13	4.77	4.34	3.88	3.57	3.37	3.17
3-Month SOFR	5.42	5.32	5.07	4.73	4.35	3.97	3.72	3.50	3.28
5-Year UST Note	4.50	4.29	4.05	3.83	3.65	3.56	3.45	3.42	3.40
10-Year UST Note	4.46	4.28	4.09	3.91	3.77	3.69	3.62	3.60	3.58
30-Year UST Note	4.65	4.51	4.34	4.16	4.02	3.92	3.88	3.89	3.90

Source: Bloomberg, as of October 23, 2023

NW Natural's Calculation

	2023	2024				2025			
Implied 20-Year UST Note	4.56	4.40	4.22	4.04	3.90	3.81	3.75	3.75	3.74

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 305

REDACTED

Per Commission's General Protective Order, this exhibit is confidential in its entirety and has been redacted.

December 29, 2023

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Direct Testimony of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 400

December 29, 2023

EXHIBIT 400 - DIRECT TESTIMONY – RETURN ON EQUITY

Table of Contents

I. INTRODUCTION AND SUMMARY

Q. Mr. Coyne, please state your name, affiliation, and business address.

A. My name is James M. Coyne. I am a Senior Vice President at Concentric Energy Advisors, Inc. ("Concentric"). Concentric is a management consulting and economic advisory firm, focused on the North American energy industry. Based in Marlborough, Massachusetts and with offices in Washington D.C. and Calgary, Alberta, 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 provide expert testimony before federal, state, and Canadian provincial agencies on matters pertaining to economics, finance, and public policy in the energy industry. I regularly advise utilities, generating companies, public bodies, and private equity investors on business issues pertaining to the utility industry. This work includes calculating the cost of capital for the purpose of ratemaking and providing expert testimony and studies on matters pertaining to rate policy, valuation, capital costs, fuels, and power markets. I have authored numerous articles on the energy industry, lectured on utility regulation for regulatory commission staff, and provided testimony before the Federal Energy Regulatory Commission ("FERC") as well as state and provincial jurisdictions in the U.S. and Canada. I hold a Bachelor of Science in Business Administration from Georgetown

University and a Master of Science in Resource Economics from the University of New Hampshire. My educational and professional background is summarized more fully in Exhibit NW Natural/401, Coyne-Nelson.

Q. Ms. Nelson, please state your name, affiliation, and business address.

A. My name is Jennifer E. Nelson. I am an Assistant Vice President at Concentric. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. Please describe your professional background and education.

A. I have 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 have 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/402, Coyne-Nelson.

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

A. We are appearing on behalf of Northwest Natural Gas Company dba NW Natural ("NW Natural" or "the Company").

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of our 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. Our analyses and conclusions are supported by the data presented in Exhibit NW Natural/403 to Exhibit NW Natural/411, which have been prepared by us or under our direction.

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

A. Our ROE recommendation is based on the results from the Discounted Cash Flow ("DCF") model, the Bond Yield Plus Risk Premium method ("Risk Premium"), the Capital Asset Pricing Model ("CAPM"), and the Expected Earnings approach. The use of multiple models mitigates the impacts of market factors that may unduly influence any one model's results. Our application of the DCF model is based on reputable third-party growth rate projections, as well as market-based information on current annualized dividends and recent stock prices. The Risk Premium model is based on a current average and projected risk-free rate and the relationship between actual authorized ROEs 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.

In addition to the analyses discussed above, we also consider the Company's capital expenditure program, the risks associated with electrification and energy transition, and NW Natural's significantly smaller size relative to a group of proxy companies to assist with determining the appropriate ROE. In a recent credit report downgrading NW Natural's credit outlook to "Negative", S&P Global Ratings ("S&P") noted that a gradual weakening of business risk associated with ongoing energy transition risks in Oregon and Washington was a factor that contributed to the Negative outlook.[2]

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

A. The ROE results presented in our Direct Testimony indicate that a reasonable ROE range for NW Natural is 9.80 percent to 10.40 percent using a combination of models and alternative input assumptions. Based on the results of all four methods (DCF, Risk Premium, CAPM, and Expected Earnings) and considering the business risks of NW Natural relative to the proxy group, combined with our

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

[2] S&P Global Ratings, "Northwest Natural Holding Co. Rated 'A+' With Negative Outlook; Subsidiary Ratings Affirmed; Outlook Revised To Negative," at 1-2 (October 9, 2023).

observations pertaining to capital market conditions, it is our opinion that 10.10 percent is a reasonable, if not conservative, estimate of the Company's cost of equity.

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

A. We support NW Natural's requested capital structure of 50.00 percent common equity and 50.00 percent long-term debt as reasonable relative to the range of capital structures for the operating companies held by the proxy group companies.

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

A. The balance of our Direct Testimony is organized as follows: Section III provides background on the regulatory principles behind making an ROE determination in general. Section IV presents a review of current and projected economic and capital market conditions and their impacts on utility cost of capital. Section V describes the criteria and approach for selecting a proxy group of comparable companies. Section VI provides the details and results of the DCF, CAPM, Risk Premium, and Expected Earnings analyses. Section VII provides an assessment of the business risk factors we have considered in arriving at an appropriate cost of equity estimate for NW Natural. Section VIII assesses the reasonableness of NW Natural's proposed capital structure in the context of the proxy group. Section IX summarizes our results, conclusions, and recommendations.

III. REGULATORY PRINCIPLES

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.[3]

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, preferred equity, and long-term debt to finance their permanent 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, debt and equity, are weighted by their respective book values. 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.

However, the ROE cannot be derived solely through quantitative metrics and models. To properly estimate the ROE, the financial, regulatory, and economic

[3] 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 (Dec. 18, 2020).

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 mechanistically 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.

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.[4] 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

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

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 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. EFFECTS OF ECONOMIC AND CAPITAL MARKET CONDITIONS

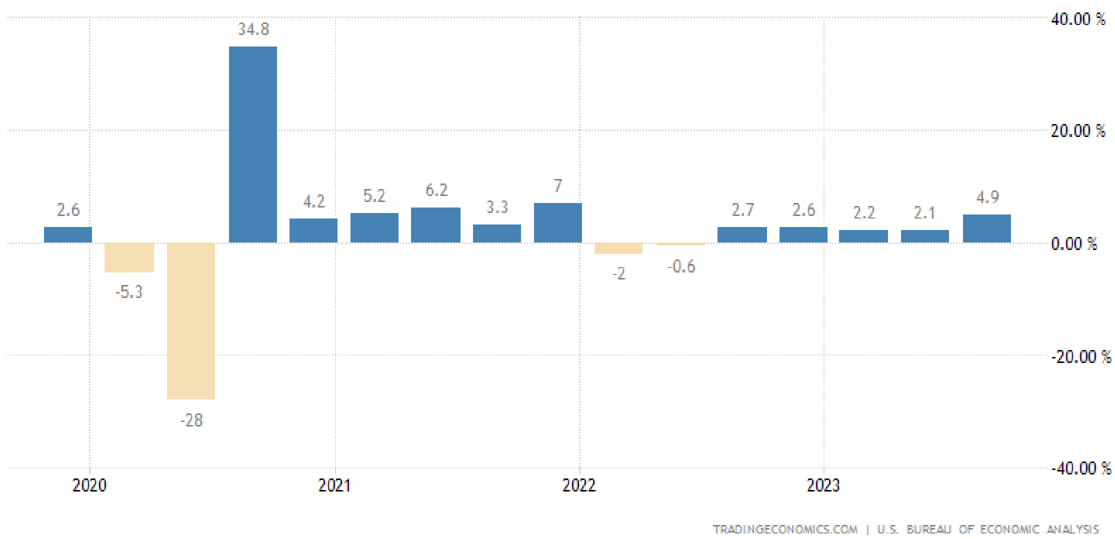
Q. Why is it important to consider the effects of prevailing economic and capital market conditions when setting the ROE?

A. Consistent with ratemaking jurisprudence, the required cost of capital, including the ROE, is a function of prevailing and expected conditions in the general economy and in capital markets. The standard ROE estimation tools, such as the DCF, CAPM, Risk Premium, and Expected Earnings models, each reflect the state of the general economy and financial markets by incorporating specific economic and financial data. These inputs are, however, only samples of the various economic and market forces that may affect a utility's ROE going forward. Consideration must be given to whether the assumptions relied on in the current or projected data are sustainable over the period that the recommended ROE will be in effect. If investors do not expect current market conditions to be sustained in the future, it is possible that the ROE estimation models will not provide an accurate estimate of investors' required return. Therefore, an assessment of fluctuating market conditions is integral to any ROE recommendation.

Q. Please discuss economic and capital market conditions.

A. Economic and capital market conditions have been unsettled due to increasing inflationary pressure and the prospects for weaker economic growth or recession as the Federal Reserve tightens monetary policy. After experiencing steady economic growth from 2017-2019, the consequences of COVID-19 forced the U.S. economy into a sharp recession in 2020. Gross Domestic Product ("GDP") has tracked unevenly since then, as shown in Figure 1.

Figure 1: U.S. Real GDP Growth[5]



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

A. The U.S. Federal Reserve (the "Fed") has engaged in more restrictive monetary policy to combat higher than expected inflation. Specifically, the Fed has raised the discount rate eleven times since March 2022, with the federal funds rate increasing from 0.00 to 0.25 percent in March 2022 to the current range of 5.25 – 5.50 percent set in July 2023. The Fed has indicated that it expects a policy rate of between 5.50 and 5.75 percent by the end of 2023,[6] although at its most recent meeting it held the current 5.25 to 5.50 percent range.[7] Higher short-term interest rates have contributed to an increase in long-term interest rates on both

[5] Source: https://tradingeconomics.com/united-states/gdp-growth, accessed November 17, 2023.

[6] Federal Open Market Committee ("FOMC"), Summary of Economic Projections, September 20, 2023, at 4.

[7] https://www.federalreserve.gov/newsevents/pressreleases/monetary20231101a.htm.

government and utility bonds, which translates to a higher cost of capital for utilities such as NW Natural.

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 utility companies is being affected by several key factors in current and prospective capital markets, including: (1) the interest rate environment; (2) central bank monetary policy in response to persistent inflationary pressures; and (3) increased Beta coefficients for utilities since January 2020 (demonstrating greater sector risk in the eyes of investors). In this section, we discuss how each of these factors affects the models used to estimate the cost of equity for regulated utilities.

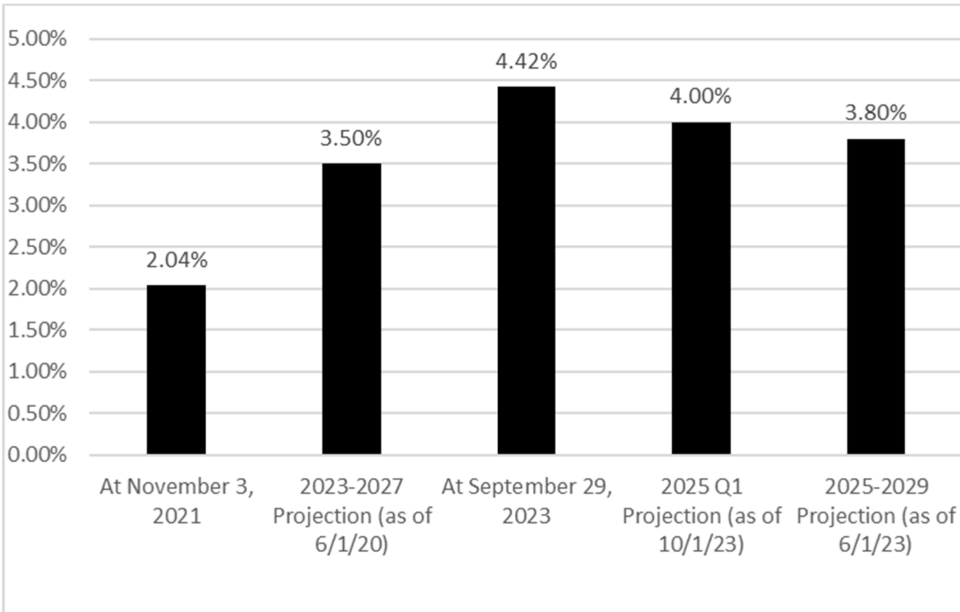
Q. Please discuss the path of government bond yields and explain the implications for equity investors considering the utility sector.

A. The 30-day average yield on 30-year Treasury bonds was 2.04 percent as of November 3, 2021 when the Fed signaled it would begin tapering its asset purchases and begin normalizing monetary policy. This was one month prior to when NW Natural filed its last rate general case on December 17, 2021. The Commission ultimately approved a stipulation agreement setting the Company's ROE at 9.4 percent.[8] As shown in Figure 2, as of September 29, 2023, the 30-day average 30-year Treasury bond yield was 4.42 percent. This represents an

[8] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Order No. 22-388, at p. 6 (Oct. 24, 2022).

increase of 238 basis points in the average 30-year Treasury bond yield since November 2021.

Figure 2: Comparison of U.S. Treasury Bond Yields[9]



All else equal, higher yields on government bonds indicate that the cost of capital has increased for all companies, including utilities. Higher yields on long-term Treasury bonds present investors with a more attractive return on a "risk-free" alternative, and utility dividend yields must also increase for companies to continue to attract equity capital. Figure 2 shows that Treasury bond yields are projected to be approximately 3.80 percent through 2029. Because current and projected yields on government bonds are similar, we have considered both as the risk-free rate in the CAPM and Risk Premium models.

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[9] Sources: Bloomberg Professional and Blue Chip Financial Forecasts, as of June 1, 2020, October 1, 2023, and June 1, 2023.

Q. Please discuss the effect of inflation on the cost of equity for regulated utilities such as NW Natural.

A. As shown in Figure 3, inflation as measured by the consumer price index ("CPI") for the 12 months ending in September 2023 was 3.7 percent, after reaching an annualized rate of 9.1 percent in June 2022, the highest level in 40 years. Although the pace of inflation has subsided in recent months, year-over-year inflation has remained above the Fed's target.

Figure 3: Consumer Price Index – All Urban, Not Seasonally Adjusted[10]

In response, the Federal Reserve has been aggressively tightening monetary policy since March 2022 to combat much higher than anticipated inflation. The Federal Reserve has been targeting inflation of around 2.0 percent for many years. In its press release following the November 1, 2023 FOMC

[10] Source: https://tradingeconomics.com/united-states/inflation-cpi, accessed October 31, 2023.

meeting, the Federal Reserve continued to emphasize that it "is strongly committed to returning inflation to its 2 percent objective" and is "prepared to adjust the stance of monetary policy as appropriate if risks emerge that could impede the attainment of the Committee's goals."[11]

Looking forward, the inflation risks in the market are twofold: 1) either inflation becomes embedded in the economy if the Federal Reserve does not move aggressively enough in tightening monetary policy, or 2) the Federal Reserve responds to inflationary pressure by raising short-term interest rates to a level that causes a slowdown in economic growth or a recession. The October 2023 issue of Blue Chip Financial Forecasts ("Blue Chip") reports the results of a survey of leading economists and market analysts taken in September 2023. Blue Chip reports that 46 percent of those surveyed expect that a recession will start in the U.S. in the next 12 months, and they expect the terminal federal funds rate to peak at 5.45 percent.[12]

Q. What is your conclusion regarding how higher interest rates and inflation affect the cost of equity for utilities such as NW Natural?

A. After reaching historical lows in July 2020, interest rates on government and utility bonds have been steadily increasing, as inflation levels that peaked at levels not seen in over 40 years remain above the Fed's target inflation rate. It is important

[11] Federal Reserve Board of Governors, Press Release, November 1, 2023. https://www.federalreserve.gov/newsevents/pressreleases/monetary20231101a.htm

[12] Blue Chip Financial Forecast, Vol. 42, Issue No. 10, October 1, 2023, at 14.

to recognize that there has been a fundamental change in market conditions. Increases in interest rates, inflation, and utility sector risk (as illustrated by Beta coefficients) indicate higher cost of equity capital for utilities. While capital markets are generally efficient in terms of pricing in changes in economic indicators, the current environment remains fluid and investors are uncertain whether the Federal Reserve will be able to bring down inflation without causing a recession. This uncertainty is reflected in ongoing market volatility, after sharp declines in equity prices in 2022 and continued volatility in 2023.

Q. Please discuss the Beta coefficients for utility companies.

A. The Beta coefficient is a measure of market risk in the Capital Asset Pricing Model, as discussed in more detail in Section VI of our Direct Testimony. Utilities have traditionally been considered less risky than the broader market and viewed by investors as a safe haven during recessions and other periods of market uncertainty. As such, Beta coefficients for regulated utilities have historically averaged around 0.75. Figure 4 demonstrates that since January 2020, there has been a meaningful shift in investor perceptions regarding the relative risk of utilities as compared with the broad market. While utilities remain less risky than the broad market, the natural gas utilities in our Gas Proxy Group have been trading more in line with the S&P 500 Index, and Beta coefficients for natural gas utilities have increased to the range of 0.80 to 0.95. Notably, these elevated Beta coefficients have been in place since the onset of the COVID-19 pandemic more than three years ago, indicating this is not temporary.

Figure 4: Beta Coefficients for the Gas Proxy Group

	January 2020	September 2023
Value Line Beta	0.64	0.88
Bloomberg Beta	0.60	0.84

In summary, utility Beta coefficients have increased substantially since January 2020, indicating that, in contrast to prior periods, investors now perceive the utility sector as having higher market risk relative to the broad market. This perception is further evidence that the cost of equity for regulated utilities such as NW Natural has increased in recent years.

Q. What is your conclusion regarding the effect of capital market conditions on the cost of equity for NW Natural in this proceeding?

A. Our primary conclusion is that the cost of capital for both debt and equity has increased for utilities, including NW Natural. This is reflected in the results of the models used to estimate the cost of equity. In particular, the DCF model results are higher as utility dividend yields have necessarily increased to keep pace with higher government bond yields. The CAPM and Risk Premium results have also increased with government bond yields and utility Beta coefficients.

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 in our 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 795,000 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.[13] NW Natural's long-term issuer rating is A+ from S&P. The Company's senior unsecured shelf rating from Moody's Investor Services ("Moody's") is (P)Baa1.[14]

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[13] Northwest Natural Holding Company, 2022 SEC Form 10-K, at 9.

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

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

A. As explained below, we have developed two proxy groups: a Gas Proxy Group and a Combined Proxy Group. The Gas Proxy Group is utilized to develop our recommendation. The Combined Proxy Group is utilized to inform, verify, and support our recommendation. To develop the Gas Proxy Group, we first began with the nine companies that Value Line classifies as "Natural Gas Utilities" and then screened companies according to the following criteria, as all of them would apply to NW Natural and narrow the field of potential proxy group members:

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"), Thomson First Call (as reported by Yahoo! Finance), and Zacks Investment Research ("Zacks");
5. Regulated net operating income makes up more than 60 percent of the consolidated company's net operating income, on average, for the three years ended 2022;

6. Natural gas distribution net operating income makes up more than 60 percent of the consolidated company's net operating income, on average, for the three years ended 2022;
7. Is not involved in a merger or other transformative transaction for an approximate six-month period prior to our analysis.

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

A. Based on the screening criteria discussed above, we arrived at a proxy group consisting of six publicly traded natural gas utilities shown in Figure 5.

Figure 5: 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/404, Coyne-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, our 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. Moreover, a larger proxy group does not necessarily improve the representative nature of the proxy group. In our opinion, 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, it is our opinion that our proxy group is reasonably comparable to NW Natural and is an appropriate basis for the ROE estimation process.

Q. Please describe your Combined Proxy Group 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 our 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, we recognize that it may be appropriate to develop a larger proxy group to evaluate the reasonableness of Gas Proxy Group's ROE model results. Therefore, we developed a Combined Proxy Group consisting of the six natural gas utilities contained in the Gas Proxy Group, supplemented with a group of 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, we 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, Thomson First Call (as reported by Yahoo! Finance), and ZacksZacks;
5. Regulated net operating income makes up more than 60 percent of the consolidated company's net operating income, on average, for the three years ended 2022;
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 2022;
7. Is not involved in a merger or other transformative transaction for an approximate six-month period prior to our analysis.

Based on this screening criteria, eleven electric utilities were added to the six gas proxy companies to produce a Combined Proxy Group consisting of the following 17 companies (see also Exhibit NW Natural/404, Coyne-Nelson):

Figure 6: 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
CenterPoint Energy, Inc.	CNP
CMS Energy Corporation	CMS
DTE Energy Company	DTE
MGE Energy, Inc.	MGEE
NorthWestern Corporation	NWE
Public Service Enterprise Group Inc.	PEG
Southern Company	SO
Wisconsin Energy Corporation	WEC

Q. Did you include Northwest Natural Holding Company ("NWNH" or "NW Natural Holdings") in your proxy groups?

A. No. It is our 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. 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, we 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. We have considered the results of four ROE estimation models, specifically, the constant growth and multistage 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. We 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 September 29, 2023;
2. Annualized dividend per share as of September 29, 2023; and
3. Company-specific earnings growth forecasts from Value Line, Yahoo! Finance, and Zacks as of September 29, 2023.

Our application of the Constant Growth DCF model is provided in Exhibit NW Natural/405, Coyne-Nelson.

Q. Why did you use 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. In our view, 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. We have used the consensus analyst five-year growth estimates in earnings per share ("EPS") from Thomson First Call (reported by Yahoo! Finance) and Zacks, as well as 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, in order 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 estimated dividend growth available to investors?

A. Yes, although that does not mean that investors incorporate such estimates into their investment evaluations. Academic studies suggest that investors base their investment decisions on analysts' expectations of growth in earnings.[15] In addition, the only forward-looking growth rates that are available on a consensus basis are analysts' EPS growth rates. The fact that earnings growth projections are the only widely reported estimates of growth further supports using 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. We calculated the Mean High DCF result using the maximum growth rate (*i.e.*, the maximum of the Value Line, Zacks, and First Call EPS growth rates) in combination with the expected dividend yield for each of the proxy group companies. We 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/405, Coyne-Nelson and summarized in Figure 7 below.

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[15] *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 7: Constant Growth DCF Results

	Mean Low	Mean	Mean High
Gas Proxy Group			
30-day average	9.20%	10.34%	11.86%
90-day average	9.07%	10.21%	11.72%
180-day average	8.97%	10.11%	11.62%
Combined Proxy Group			
30-day average	8.93%	9.80%	10.80%
90-day average	8.76%	9.63%	10.63%
180-day average	8.67%	9.53%	10.54%

2. Multi-Stage DCF Model

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

A. Yes, we have. We understand that the Commission has given substantial weight to the Multi-Stage DCF model in prior decisions.[16] Therefore, we 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 First Call forecasts used in the Constant Growth

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[16] 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 (Dec. 18, 2020).

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 2030-2034.[17] 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.[18]

The results of the Multi-Stage DCF analysis are shown in Figure 8 below (see also Exhibit NW Natural/406, Coyne-Nelson).

Figure 8: Multi-Stage Growth DCF Results

	Gas Proxy Group	Combined Proxy Group
30-day average	8.95%	8.81%
90-day average	8.78%	8.61%
180-day average	8.67%	8.50%

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

[18] 4.24% = (1 + 2.0%)(1+ 2.2%) – 1

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).[19] As shown in Equation [2], the CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \qquad [2]$$

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 MRP. According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by the Beta coefficient, which is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \quad [3]$$

[19] 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.

where:

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

The variance of the market return, noted in Equation [3], 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. We applied two estimates of the risk-free rate. First, we considered the current 30-day average yield on 30-year Treasury bonds (4.42 percent). However, since both the DCF and CAPM models assume long-term investment horizons, we also considered Blue Chip Financial Forecast's projected yield on 30-year Treasury bonds for 2025-2029 of 3.80 percent.[20] Using the 5-year forecast of 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

[20] Blue Chip Financial Forecasts, Volume No. 42, Issue No. 6, June 1, 2023, at 14.

> 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.[21]

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

A. We considered two measures of the Beta coefficient for the proxy group companies: (1) the calculated beta from Bloomberg (which is calculated using 60 months of weekly data against the S&P 500 Index); and (2) the reported Beta coefficient from Value Line (which is calculated using 60 months of weekly data against the NYSE Composite Index). The Beta coefficients in our CAPM analysis are shown in Exhibit NW Natural/407, Coyne- Nelson.

Q. What MRP did you use in your CAPM analysis?

A. We considered both a forward-looking MRP and the long-term historical average MRP. For our forward-looking market return estimate, we used the Constant Growth DCF formula to estimate the total market return for the S&P 500 Index. We 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 of September 29, 2023, the average expected total market return from these three sources is 15.03 percent, as shown in Figure 9 (see also Exhibit NW Natural/407).

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

Figure 9: DCF-Based Expected Market Return

Source	Market Return
S&P Earnings & Estimates	14.70%
Bloomberg Professional	16.21%
Value Line	14.19%
Average	15.03%

A forward-looking MRP is calculated by subtracting the risk-free rates from the 15.03 percent average expected total market return shown in Figure 9. To moderate the effect of the forward-looking market return, we averaged the forward looking MRP with the long-term average historical MRP of 7.17 percent between 1926 and 2022 as reported by Kroll (formerly Duff & Phelps). As shown in Exhibit NW Natural/407, Coyne-Nelson, averaging the forward and historical MRPs yields a blended MRP of 8.89 percent using the current risk-free rate of 4.42 percent. Using the projected risk-free rate of 3.80 percent, the blended MRP is 9.20 percent.

Q. Did you also perform a CAPM analysis using only the historical MRP?

A. Yes. Although the estimation of the cost of equity is a forward-looking analysis, we also performed a CAPM analysis using only the current long-term historical average MRP of 7.17 percent based on data published by Kroll for the period from 1926-2022.

Q. What are the results of your CAPM analyses?

A. The CAPM results are shown in Exhibit NW Natural/407, Coyne-Nelson and summarized below in Figure 10 and Figure 11.

Figure 10: CAPM Results for the Gas Proxy Group

Bloomberg Beta Coefficients	**Blended MRP**	**Historical MRP**
Current Average Risk-Free Rate (R_f = 4.42%)	11.87%	10.43%
Projected Risk-Free Rate (R_f = 3.80%)	11.51%	9.81%
Value Line Beta Coefficients		
Current Average Risk-Free Rate (R_f = 4.42%)	12.20%	10.69%
Projected Risk-Free Rate (R_f = 3.80%)	11.85%	10.07%
Average Bloomberg & Value Line CAPM (R_f = 4.42%)	12.04%	10.56%
Average Bloomberg & Value Line CAPM (R_f = 3.80%)	11.68%	9.94%

Figure 11: CAPM Results for the Combined Proxy Group

Bloomberg Beta Coefficients	**Blended MRP**	**Historical MRP**
Current Average Risk-Free Rate (R_f = 4.42%)	12.16%	10.66%
Projected Risk-Free Rate (R_f = 3.80%)	11.81%	10.04%
Value Line Beta Coefficients		
Current Average Risk-Free Rate (R_f = 4.42%)	12.37%	10.83%
Projected Risk-Free Rate (R_f = 3.80%)	12.03%	10.21%
Average Bloomberg & Value Line CAPM (R_f = 4.42%)	12.26%	10.74%
Average Bloomberg & Value Line CAPM (R_f = 3.80%)	11.92%	10.13%

C. Risk Premium Analysis

Q. Please describe the Risk Premium approach that you used.

A. In general terms, this approach recognizes that equity is riskier than debt because equity investors bear the residual risk associated with ownership. Equity investors, therefore, require a greater return (i.e., a premium) than would a bondholder. The

Risk Premium approach estimates the cost of equity as the sum of the Equity Risk Premium and the yield on a particular class of bonds.

$$ROE = RP + Y \qquad [4]$$

Where:

RP = Risk Premium (difference between allowed ROE and the 30-Year Treasury Yield) and

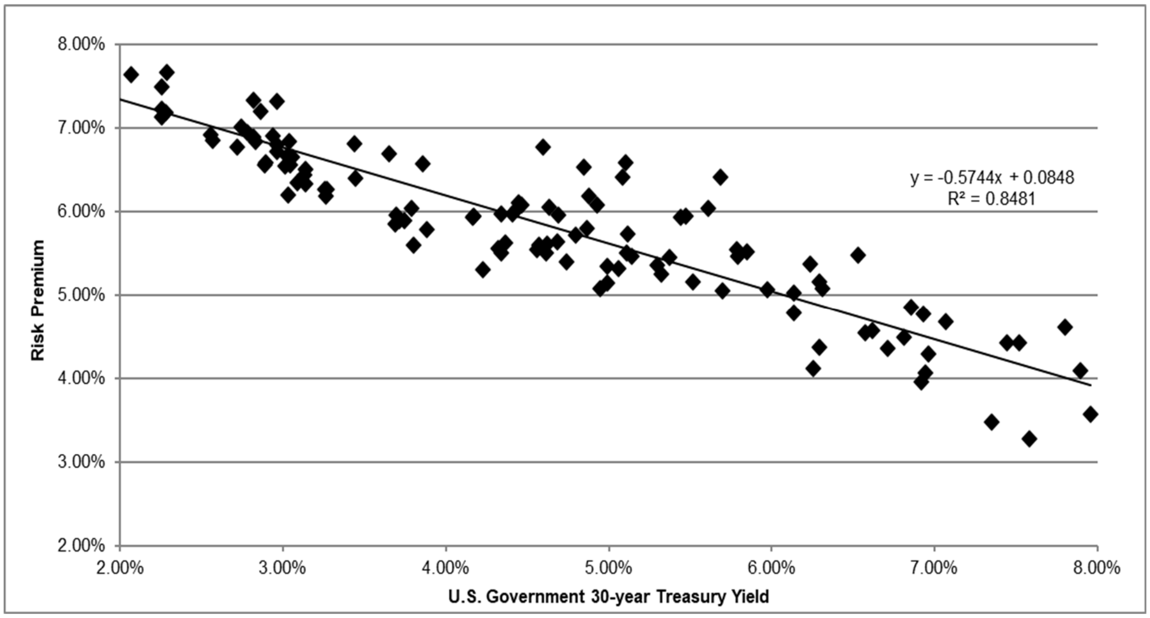
Y = Applicable bond yield.

Since the equity risk premium is not directly observable, it is typically estimated using a variety of approaches, some of which incorporate *ex-ante*, or forward-looking, estimates of the cost of equity and others that consider historical, or *ex-post*, estimates. For our Risk Premium analysis, we have relied on authorized returns from a large sample of natural gas utility companies.

Q. What did your Risk Premium analysis reveal?

A. We conducted two Risk Premium analyses. Our first risk premium analysis examines the relationship between quarterly average allowed ROEs for natural gas distribution utilities and the respective 30-year Treasury bond yield from the relevant quarter. Data regarding allowed ROEs were provided by Regulatory Research Associates. The data includes 765 natural gas rate cases from 1992 through September 29, 2023. The results of that regression are detailed in Figure 12.

Figure 12: Gas Risk Premium Regression Results vs. 30-Year Treasury Yield



Our second Risk Premium analysis performs the same analysis instead using ROEs authorized in 932 electric rate decisions over the same period, as shown in Figure 13 below.

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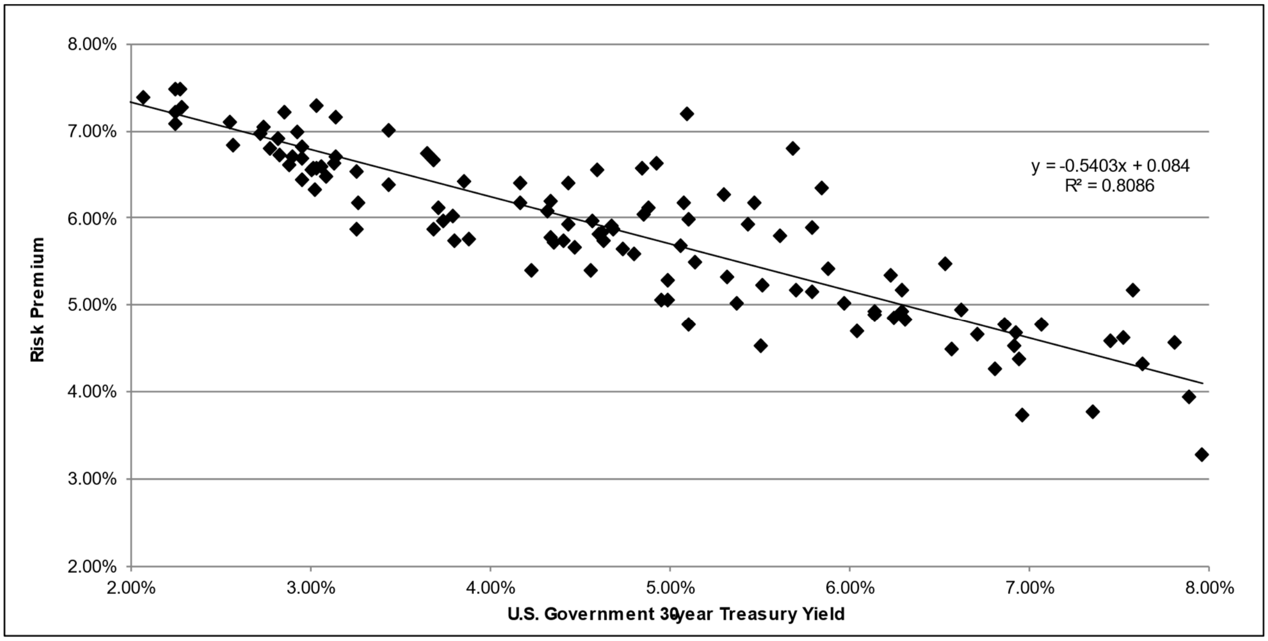
Figure 13: Electric Risk Premium Regression Results vs. 30-Year Treasury Yield



As illustrated by Figure 12 and Figure 13, the risk premium varies inversely with the level of the bond yield, and generally increases as bond yields decrease, and vice versa. Our analysis considers three estimates of the 30-year Treasury yield, including the current 30-day average (4.42 percent), a "Near-Term" Blue Chip consensus forecast for Q1 2024 – Q1 2025 (4.16 percent), and a "Long-Term" Blue Chip consensus forecast for 2025-2029 (3.80 percent). Based on the regression coefficients in Exhibit NW Natural/408, Coyne-Nelson, which estimate the risk premium at varying bond yields, the results of our analyses are shown in Figure 14 and Figure 15 below.

Figure 14: Gas Risk Premium Results Using 30-Year Treasury Yield

	Current Yield on 30-Year Treasury Bond	Near-Term Forecast for Yield on 30-Year Treasury Bond[22]	Long-Term Forecast for Yield 30-Year Treasury Bond[23]
Yield	4.42%	4.16%	3.80%
Risk Premium	5.95%	6.09%	6.30%
Resulting ROE	10.36%	10.25%	10.10%

Figure 15: Electric Risk Premium Results Using 30-Year Treasury Yield

	Current Yield on 30-Year Treasury Bond	Near-Term Forecast for Yield on 30-Year Treasury Bond[24]	Long-Term Forecast for Yield 30-Year Treasury Bond[25]
Yield	4.42%	4.16%	3.80%
Risk Premium	6.02%	6.16%	6.35%
Resulting ROE	10.43%	10.32%	10.15%

While our Risk Premium analysis produces three ROE estimates, we rely only on the results using current and long-term projected bond yields in our ultimate ROE recommendation.

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.

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[22] Blue Chip consensus forecast for Q1 2024 – Q1 2025, as of October 1, 2023.

[23] Blue Chip consensus forecast for 2025 – 2029, as of June 1, 2023.

[24] Blue Chip consensus forecast for Q1 2024 – Q1 2025, as of October 1, 2023.

[25] Blue Chip consensus forecast for 2025 – 2029, as of June 1, 2023.

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 improperly depressed ROE 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 of our Direct Testimony, NW Natural expects to invest approximately $1.4 billion in infrastructure in the 2023-2027 period, or approximately 62 percent of the Company's net utility plant. This underscores the importance of maintaining 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 natural gas companies in the Gas Proxy Group and Combined Proxy Group, we rely on the Gas Risk Premium results using current and long-term projected 30-year Treasury bond yields (10.36 percent, and 10.10 percent, respectively). For the electric utilities in the Combined Proxy Group, we use the Electric Risk Premium results using current and long-term projected 30-year Treasury bond yields (10.43 percent, and 10.15 percent, respectively). The proxy group average Risk Premium estimates we relied on are shown in Figure 16 below.

Figure 16: Risk Premium ROE Estimates

	Gas Proxy Group	Combined Proxy Group
Current bond yield (4.42%)	10.36%	10.41%
Long-Term Projected bond yield (3.80%)	10.10%	10.13%

D. Expected Earnings Analysis

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

A. Yes. We 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. We relied on the projected ROE for the proxy companies as reported by Value Line for the period from 2026-2028. We 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/409, Coyne-Nelson (and summarized in Figure 17), the Expected Earnings analysis produces mean and median return estimates between 9.58 percent and 10.65 percent.

Figure 17: Expected Earnings Results

	Gas Proxy Group	Combined Proxy Group
Mean	9.61%	10.65%
Median	9.58%	10.36%

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. We recognize that the Commission has traditionally not given weight to the Expected Earnings approach,[26] in part citing to the FERC, and we 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

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

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 subjective inputs.

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, especially in volatile market environments, which have been experienced recently.

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.[27]

For these reasons, we believe the Expected Earnings approach is reasonable and should be given equal consideration.

E. 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. We have placed equal weight on the results of the DCF, CAPM, Bond Yield Risk Premium, and Expected Earnings analyses. Our ROE recommendation is ultimately based on the average produced by these four methodologies, providing

[27] Roger A. Morin, Ph.D., *New Regulatory Finance*, at 394-395 (2006).

equal weight to each reflecting the validity of each model. As shown in Figure 18 below (see also Exhibit NW Natural/403, Coyne-Nelson), we derive an average ROE estimate range of approximately 9.80 percent to 10.40 percent for the Gas Proxy Group. The low end of the range reflects the four-model average using more conservative CAPM inputs (i.e., projected interest rates and the historical MRP), while the high end of the range reflects the four-model average using current interest rates and an average of the forward-looking and historical MRP. The average of the various four-model averages for the Gas Proxy Group is 10.10 percent. Similarly, applying the same approaches to the Combined Proxy Group indicates an ROE range of approximately 10.00 percent to 10.60 percent, with an average of 10.33 percent (rounded to 10.30 percent).

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Figure 18: Analytical Model Results

	Current Interest Rates	Long-Term Projected Interest Rates
Gas Proxy Group		
Average DCF (Avg of Mean CGDCF & MSDCF)	9.51%	9.51%
Average CAPM (Blended MRP)	12.04%	11.68%
Average CAPM (Historical MRP)	10.56%	9.94%
Risk Premium	10.36%	10.10%
Expected Earnings	9.61%	9.61%
4-model Average ROE (Blended MRP CAPM)	10.38%	10.23%
4-model Average ROE (Historical MRP CAPM)	10.01%	9.79%
Average	**10.10%**	
Combined Proxy Group		
Average DCF (Avg of Mean CGDCF & MSDCF)	9.15%	9.15%
Average CAPM (Blended MRP)	12.26%	11.92%
Average CAPM (Historical MRP)	10.74%	10.13%
Risk Premium	10.41%	10.13%
Expected Earnings	10.65%	10.65%
4-model Average ROE (Blended MRP CAPM)	10.62%	10.46%
4-model Average ROE (Historical MRP CAPM)	10.24%	10.01%
Average	**10.33%**	

In our 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, we recommend an ROE of 10.10 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 and need to maintain access to capital, (2) the risk associated with decarbonization efforts and electrification, and (3) the Company's relatively small size. These factors increase NW Natural's risk relative to the proxy group. While we have not made an explicit adjustment to our 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. Capital Expenditure Plan 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, we do. As a capital-intensive enterprise, the allowed 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.[28] 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 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 2023-2027 it will invest approximately $1.4 billion in capital, or about $290 million per year.[29] 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 ("RNG") projects, and customer growth. In total, these capital expenditures are equal to approximately 62 percent of the Company's total net utility plant in service as of December 31, 2022, of $2.26 billion.[30]

[28] Source: Value Line, accessed September 8, 2023.

[29] Source: Northwest Natural Investor Presentation, June 2023, slide 15.

[30] Commission Docket No. RG 40, *NW Natural's Earnings Review for the 12 Months Ended December 31, 2022* (April 27, 2023); Washington Utilities & Transportation Commission Docket No. UG-230297, *NW Natural's Annual Commission Basis Report for the 12 Months Ended December 31, 2022 with Workpapers* (April 28, 2023).

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 for the benefit of both customers and shareholders. 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.

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 according to public policy and jurisdiction. Addressing climate change is an increasing area of focus for federal, state, and local governments. The Biden administration is targeting a 50 percent reduction in greenhouse gas ("GHG") emissions relative to 2005 by 2030, and net zero emissions economy-wide by 2050. As shown in Figure 19 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.[31] As shown in Figure 19, Oregon is among the states with "aggressive"

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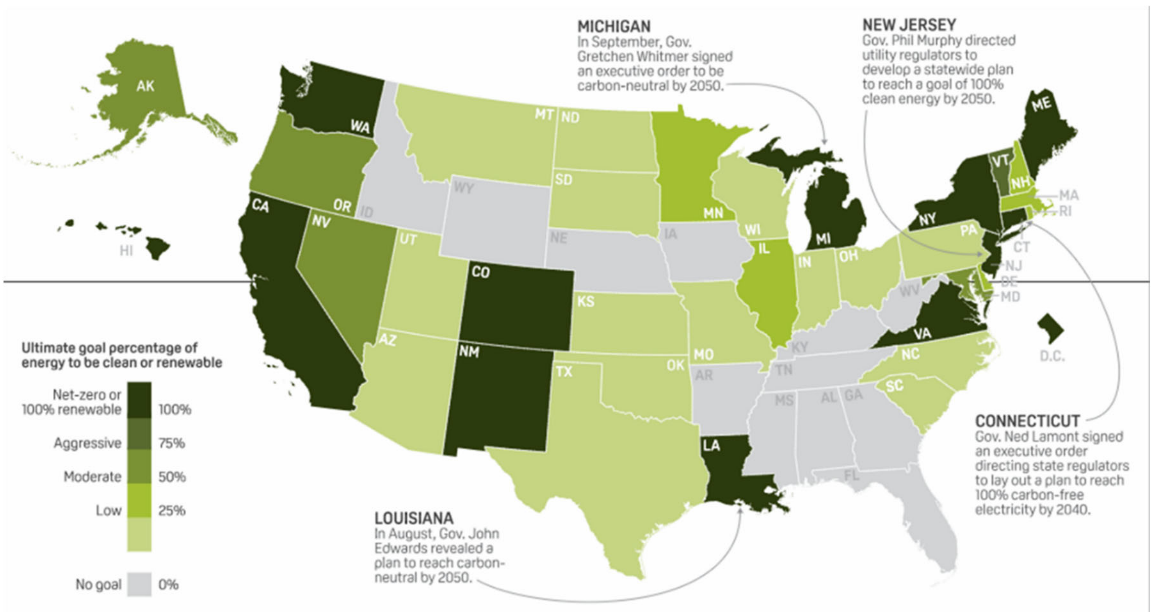
[31] EO-20-04, at 5.

clean energy or renewable goals.[32]

Figure 19: U.S. Renewable Targets[107]



Declining 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.[33]

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[32] NW Natural also operates in Washington, which is ranked in the category with the most aggressive decarbonization goals shown in Figure 19.

[33] The Brattle Group, "The Future of Gas Utilities Series: Transition Gas Utilities To A Decarbonized Future," Part 1 of 3, August 2021, at 9.

Investor Environmental, Sustainability, and Governance ("ESG") concerns are already affecting capital markets, as illustrated by S&P's analysis of the financing costs of North American oil and gas companies relative to their environmental impact. Specifically, S&P grouped North American energy companies into quartiles based on the carbon intensity of their revenue as measured by the annual metric tons of carbon emissions per million dollars of annual revenue. S&P concluded that it saw "evidence that issuers with lower carbon intensity were able to issue longer-dated debt at lower financing costs than their more carbon-intense peers."[34]

Investment advisor Wells Fargo recently noted:

> Even with the steps being taken to decarbonize, it is yet to be seen whether the LDC [(local distribution company)] decarbonization story will ultimately resonate with ESG-minded investors. We expect the answer will be influenced by (1) the pace at which LDCs clean-up the gas molecules and reduce overall emissions, which likely requires technological advancements to drive down the costs of RNG and hydrogen and (2) the level of local policy support.[35]

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."[36] Additionally, S&P has observed that the "'electrification' movements

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[34] S&P Global Ratings, "The Energy Transition: ESG Concerns Are Starting to Present Capital Market Challenges to North American Energy Companies," June 14, 2021, at 4.

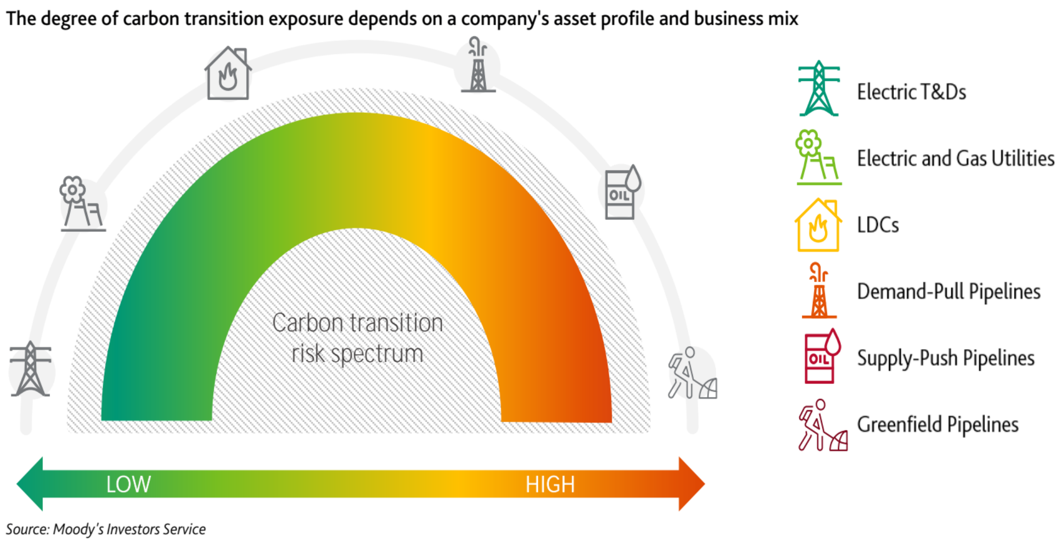
[35] Wells Fargo Securities, "Gas Utility 2021 Outlook," January 6, 2021, at 4.

[36] Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 1.

in states like California, Massachusetts, New York and Washington are raising questions about the future of gas utilities in the U.S."[37]

According to Moody's, the degree of carbon transition exposure depends on a company's asset profile and business mix. Figure 20 shows that gas LDCs are considered to have higher carbon transition risk than either electric transmission and distribution companies or combination electric and gas utilities.

Figure 20: Carbon Transition Risk Spectrum[38]



The Moody's report also reached the following conclusions regarding the relative risk of gas distribution companies vs. electric utilities:[39]

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[37] S&P Global Market Intelligence, "RRA Regulatory Focus: 2021 Energy Utility Regulatory Focus," February 11, 2021, at 10.

[38] Moody's Investors Service, "Shifting environmental agendas raise long-term credit risk for natural gas investments," September 30, 2020, at 10.

[39] Moody's Investors Service, "Shifting environmental agendas raise long-term credit risk for natural gas investments," September 30, 2020, at 10.

- Company-specific factors to determine credit impact: Demand-pull pipelines and **LDCs will be most sensitive** to the aforementioned geographical influences, such as local and state politics, weather characteristics and relative consumer costs.
- Political and strategic agendas impact LDC growth in some areas: The political and legislative push for lower carbon emissions will impact more than just the fuel source of electric generation units. In some pockets of the US, local distribution companies (LDCs) are facing early-stage challenges to sales growth, where limited upstream expansion for supply or local restrictions on new gas services will have a greater impact on the business in the coming years.
- Pace of transition depends on technology, related costs, and ultimately public policy: Certain technological advancements, including the prolific use of RNG or hydrogen gas blending, could help to support the use of existing natural gas infrastructure, whereas competing technologies such as battery storage and hydrogen gas storage for electric generation could accelerate electrification efforts and the decline of gas assets. In either case, the ability of consumers to absorb the cost of implementing any such changes will likely be a key factor in determining the pace and magnitude of asset replacement. **Full decarbonization efforts aimed at achieving net-zero emissions will likely come at a hefty cost, ultimately to be borne by utility customers.**

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.

Q. Have the credit rating agencies noted energy transition risk as a specific risk for NW Natural?

A. Yes. For example, on October 9, 2023, S&P put the Company on "Negative" outlook, noting that the negative outlook reflected, in part, "a gradual increase in business risk due to ongoing energy transition risks in Oregon and Washington due to decarbonization mandates and potential gas bans".[40] 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.[41] 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."[42] 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 RNG investments.

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[40] S&P Global Ratings, "Northwest Natural Holding Co. Rated 'A+' With Negative Outlook; Subsidiary Ratings Affirmed; Outlook Revised To Negative," at 1 (October 9, 2023).

[41] Moody's Investors Service, "Credit Opinion: Northwest Natural Gas Company," at 2 (July 18, 2023).

[42] Moody's Investors Service, "Credit Opinion: Northwest Natural Gas Company," at 2 (July 18, 2023).

> 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 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.[43]

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."[44] In other words, regulatory support is critical to the Company's ability to mitigate energy transition risks the Company faces.

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[43] Moody's Investors Service, "Credit Opinion: Northwest Natural Gas Company," at 4-5 (July 18, 2023). Emphasis added.

[44] Moody's Investors Service, "Credit Opinion: Northwest Natural Gas Company," at 6 (July 18, 2023).

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. For example, Atmos Energy, NiSource, ONEGas, and Spire operate in jurisdictions with "low" to no renewable energy targets shown in Figure 19 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?

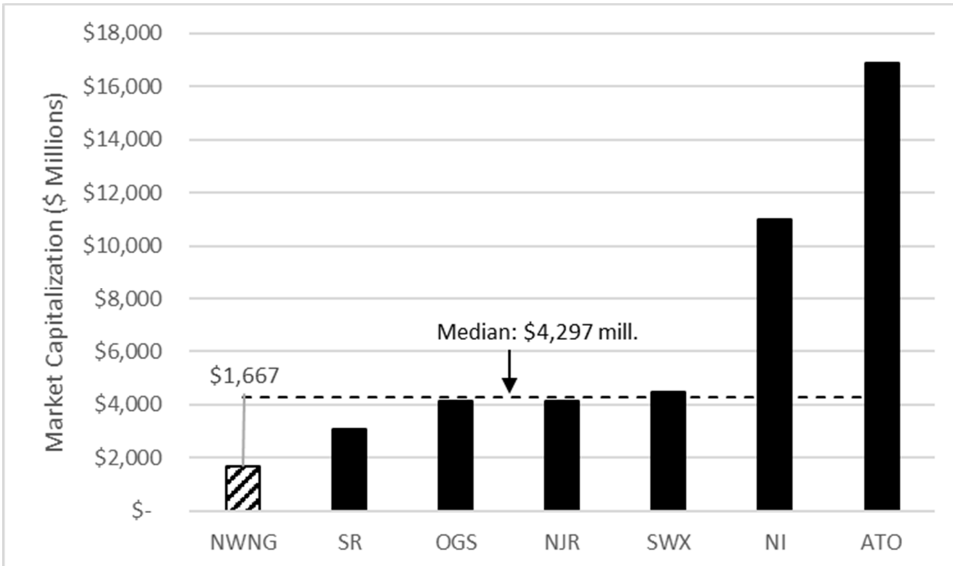
A. While energy transition is a risk for all utilities, as a natural gas-only utility that operates in jurisdictions with more aggressive decarbonization policies, NW Natural is more exposed to the long-term threats to the natural gas utility business. It is critical that supportive regulation enables NW Natural to meet its decarbonization goals while maintaining access to capital in order to mitigate its risk.

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.[45] Figure 21 below shows NW Natural's market capitalization relative to the Gas Proxy Group.

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 electricity or 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.

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[45] See, e.g. "Firm Size and Return," Ibbotson SBBI 2015 Classic Yearbook, at 99-100.

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/410, Coyne-Nelson, the Combined Proxy Group median market capitalization of $4.3 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 0.58 percent (or 58 basis points). The implied market capitalization for NW Natural is approximately $1.67 billion,[46] which falls within the sixth decile and corresponds to a size premium of 1.16 percent (or 116 basis points). The difference between those size premiums is 58 basis points (1.16 percent – 0.58 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[47] typically hold larger numbers of shares in each of their investments for management efficiency.

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[46] $1.67 billion = NW Natural's rate base of approximately $2.14 billion x equity ratio of 50% x the Gas Proxy Group median market-to-book ratio of 1.56.

[47] 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.[48]

[48] 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, we analyzed three measures of liquidity for the publicly traded 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.

NW Natural Holdings' trading volume is significantly lower than the Gas Proxy Group companies on average. As Figure 22 below shows, NW Natural Holdings' average daily trading volume has been 18.84 percent of the Gas Proxy Group's trading volume. We also calculated the average daily share turnover of NW Natural Holdings' 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). Lower trading volume and share turnover indicate lower liquidity, which is an underlying factor of the size premium. NW Natural Holdings' average daily share turnover is approximately 89 percent of the Gas Proxy Group's average daily share turnover.

Figure 22: Market Capitalization, Trading Volume, and Share Turnover Percentage[49]

	NW Natural Holdings	Gas Proxy Group Average	NWNH % of Proxy Group
Market Capitalization ($ Million)	$1,391	$7,280	19.11%
Average Daily Volume	216,736	1,150,437	18.84%
Average Daily Share Turnover	0.62%	0.69%	89.36%

[49] Source: S&P Capital IQ Pro. 30-trading day average ended September 29, 2023.

Next, we measured the relative difference in the average spread between the bid price and ask price in NW Natural Holdings' 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.[50] Dr. Damodaran cites to studies demonstrating the bid-ask spread as a percentage of a stock's price increased as firm size decreased.[51] Similarly, Amihud and Mendelson found that "[a]sset illiquidity is inversely related to the bid-ask spread."[52] In a 1989 study, Amihud and Mendelson concluded that the annual expected return increased by 0.24 percent to 0.26 percent for every 1 percent increase in the bid-ask spread as a percent of the stock price.[53] Figure 23 below summarizes the average bid-ask spread as a percentage of the average stock price for NW Natural Holding and the companies in the Gas Proxy Group.

Figure 23: Bid-Ask Spread as a Percent of Stock Price[54]

	30-day Average	90-day Average	180-day Average	YTD 2023 Average
NW Natural Holdings	0.0627%	0.0625%	0.0658%	0.0647%
Gas Proxy Group (Avg)	0.0286%	0.0306%	0.0317%	0.0323%
Difference	2.19x	2.04x	2.07x	2.00x

[50] 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

[51] 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

[52] Yakov Amihud and Haim Mendelson, "Liquidity, Asset Prices and Financial Policy," Financial Analysts Journal, Vol. 47, No. 6 (Nov-Dec 1991), at 57.

[53] 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.

[54] Source: Bloomberg Professional as of September 29, 2023.

As Figure 23 shows, the bid-ask spread as a percentage of the stock price for NW Natural Holdings is approximately 2.0x higher than the Gas Proxy Group companies on average. Both the analyses shown in Figure 22 and Figure 23 indicate that NW Natural Holdings 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 a specific risk adjustment to your ROE recommendation of 10.10 percent to reflect NW Natural's small size?

A. No. While we have quantified a 58-basis point premium associated with the Company's small size, we did not explicitly factor it into our 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 financial profile is more acute because they may have a greater impact on revenues and expenses. While we have not made an explicit adjustment for the risk factors, they should be considered when determining the appropriate ROE 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 50.00 percent common equity and 50.00 percent long-term debt, as discussed in the testimony of Company witness Brody J. Wilson (NW Natural/300, Wilson).

Q. How does NW Natural's proposed capital structure compare to those of the proxy group companies?

A. As shown in Exhibit NW Natural/411, Coyne-Nelson, NW Natural's proposed capital structure is consistent with, 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 2022, we calculated the common equity, long-term debt, and preferred equity ratios at the regulated utility operating company level for the two proxy groups. We then "rolled 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 54.45 percent over the last three years, and the Combined Proxy Group has a three-year average common equity ratio of 53.10 percent. NW Natural's proposed 50 percent common equity ratio is below these proxy group averages. Although this places equity holders at greater risk, we have not made an adjustment to our recommended ROE as a result of the proposed capital structure.

IX. SUMMARY AND CONCLUSIONS

Q. Please summarize your ROE recommendation based on this range of results.

A. Based on our analyses of four widely used analytical approaches applied to a proxy group of six natural gas utilities, we estimate that the Company's cost of equity is within a range of 9.80 percent to 10.40 percent. Within that range, we conclude that 10.10 percent is reasonable. Given the small size of the proxy group of natural gas utilities, we evaluated the reasonableness of our recommendation by applying the same analytical approaches to an expanded proxy group that added eleven 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 10.00 percent to 10.60 percent, with an average ROE of 10.30 percent. Therefore, it is our opinion that an ROE of 10.10 percent based on the model results for the Gas Proxy Group is reasonable.

Additionally, we 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. While we do not propose an explicit adjustment in our ROE recommendation to account for these risks, we conclude that our 10.10 percent ROE recommendation is on the conservative side.

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

A. We support NW Natural's requested capital structure of 50.00 percent common equity and 50.00 percent long-term debt as reasonable relative to the range of capital structures for the operating companies held by the proxy group companies.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibits of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBITS 401-411

December 29, 2023

EXHIBITS 401 – 411 – RETURN ON EQUITY

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RETURN ON EQUITY
EXHIBIT 401

December 29, 2023

CONCENTRIC ENERGY ADVISORS

JAMES M. COYNE
SENIOR VICE PRESIDENT

Mr. Coyne provides financial, regulatory, strategic, and litigation support services to clients in the natural gas, power, and utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, and matters pertaining to rate and regulatory policy. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. He has authored numerous articles on the energy industry and provided testimony and expert reports before federal, state and provincial jurisdictions in the U.S. and Canada. Mr. Coyne holds a B.S. in Business from Georgetown University and an M.S. in Resource Economics from the University of New Hampshire.

AREAS OF EXPERTISE

Energy Regulation

- Rate policy
- Cost of capital
- Incentive regulation
- Fuels and power markets

Management and Business Strategy

- Fuels and power market assessments
- Investment feasibility
- Corporate and business unit planning
- Benchmarking and productivity analysis

Financial and Economic Advisory

- Valuation analysis
- Due diligence
- Buy and sell-side advisory

Litigation Support and Expert Testimony

- Rate and regulatory policy
- Fuels and power markets
- Contract litigation
- Valuation and damages

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2006 – Present)
Senior Vice President
Vice President

FTI Consulting (Lexecon) (2002 – 2006)
Senior Managing Director – Energy Practice

Arthur Andersen LLP (2000 – 2002)
Managing Director, Andersen Corporate Finance – Energy and Utilities

Navigant Consulting, Inc. (1996 – 2000)
Managing Director, Financial Services Practice
Senior Vice President, Strategy Practice

TotalFinaElf (1990 – 1996)
Manager, Corporate Planning and Development
Manager, Investor Relations
Manager of Strategic Planning and Vice President, Natural Gas Division

Arthur D. Little, Inc. (1989 – 1990)
Senior Consultant – International Energy Practice

DRI/McGraw-Hill (1984 – 1989)
Director, North American Natural Gas Consulting
Senior Economist, U.S. Electricity Service

Massachusetts Energy Facilities Siting Council (1982 – 1984)
Senior Economist – Gas and Electric Utilities

Maine Office of Energy Resources (1981 – 1982)
State Energy Economist

EDUCATION

University of New Hampshire
M.S., Resource Economics, *with honors*, 1981

Georgetown University
B.S., Business Administration and Economics, *cum laude*, 1975

DESIGNATIONS AND AFFILIATIONS

Community Rowing Inc., Board of Directors, 2015 - 2019

Georgetown University, Alumni Admissions Interviewer, 1988 – current

NASD General Securities Representative and Managing Principal (Series 7, 63 and 24 Certifications), 2001

American Petroleum Institute, CEO's Liaison to Management and Policy Committees, 1994-1996

National Petroleum Council, Regulatory and Policy Task Forces, 1992

President, International Association for Energy Economics, Dallas Chapter, 1995

Gas Research Institute, Economics Advisory Committee, 1990-1993

NARUC, Advanced Regulatory Studies Program, Michigan State University, 1984

PUBLICATIONS AND RESEARCH

"Advancing FERC's Methodology for Determining Allowed ROEs for Electric Transmission Companies," submitted to FERC on behalf of EEI, James Coyne, Joshua Nowak and Julie Lieberman, May, 2020.

"Regulator Rationale for Ratepayer-Funded Electricity and Natural Gas Innovation", James M. Coyne, Robert C. Yardley, Jr. and Jessalyn G. Pryciak, Energy Regulation Quarterly, Volume 6, Issue 3, 2018.

"Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers" (with Robert Yardley), prepared for the Canadian Gas Association and Canadian Electricity Association, May 2015.

"Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010

"A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June 2007

"Do Utilities Mergers Deliver?" (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006

"Winners and Losers: Utility Strategy and Shareholder Return" (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004

"Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance" (with Prescott Hartshorne), white paper distributed to clients and press, August 2003

"The New Generation Business," commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001

Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992

"Natural Gas Outlook," articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989

SELECTED SPEAKING ENGAGEMENTS

"The Market Risk Premium: An In-Depth Review", Society of Utility and Regulatory Financial Analysts 53rd Financial Forum, Richmond, VA, April 28,2022

"Energy Sector in Transition", Ontario Energy Association, Toronto, ON, September 24, 2018.

"Understanding Regulated Utilities in Today's Capital Markets", NARUC Annual Meeting, La Quinta, CA, November 14, 2016.

"Rate of Return: Where the Regulatory Rubber Meets the Road," CAMPUT Annual Conference, Montreal, Quebec, May 17, 2016.

"Innovations in Utility Business Models and Regulation", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2015 Energy Regulation Course, Queens University, Kingston, Ontario, June 2015

"M&A and Valuations," Panelist at Infocast Utility Scale Solar Summit, September 2010

"The Use of Expert Evidence," The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010

"A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008

"Nuclear Power on the Verge of a New Era," moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005

"The Investment Implications of the Repeal of PUCHA," Skadden Arps Client Conference, New York, NY, October 2005

"Anatomy of the Deal," First Annual Energy Transactions Conference, Newport, RI, May 2005

"The Outlook for Wind Power," Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005

"Direction of U.S. M&A Activity for Utilities," Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002

"Outlook for U.S. Merger & Acquisition Activity," Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001

"Investor Perspectives on Emerging Energy Companies," Panel Moderator at Energy Venture Conference, Boston, MA, June 2001

"Electric Generation Asset Transactions: A Practical Guide," workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999

"New Strategic Options for the Power Sector," Electric Utility Business Environment Conference, Denver, CO, May 1999

"Electric and Gas Industries: Moving Forward Together," New England Gas Association Annual Meeting, November 1998

"Opportunities and Challenges in the Electric Marketplace," Electric Power Research Institute, July 1998

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Alberta Beverage Container Management Board				
Alberta Beverage Container Management Board	2016 2019	Expert for the Board	N/A	Return Margin on Bottle Depots
Alberta Utilities Commission				
ATCO Utilities Group	2008 2009	ATCO Gas; ATCO Pipelines Ltd.; ATCO Electric Ltd.	Application No. 1578571 / Proceeding ID. 85	2009 Generic Cost of Capital Proceeding (Gas & Electric)
Enmax Power Corporation	2017	Enmax	22570	Cost of Common Equity
Enmax Power Corporation	2020	Enmax	24110	2021 Generic Cost of Capital
Enmax Power Corporation	2023	Enmax	27084	2024 and Beyond Cost of Capital Parameters
American Arbitration Association				
TransCanada Corporation	2004	TransCanada Corporation	AAA Case No. 50T 1810018804	Valuation of Natural Gas Pipeline
British Columbia Utilities Commission				
FortisBC	2012	FortisBC Utilities	G-20-12	Cost of Capital Adjustment Mechanisms
FortisBC	2015 2016	FortisBC Utilities	G-129-16	Cost of Capital (Gas and Electric Distribution)
FortisBC	2022	FortisBC Utilities	G-217-22	Cost of Capital (Gas and Electric Distribution)
California Public Utilities Commission				
San Diego Gas & Electric Company	2019	San Diego Gas & Electric Company	A-19-04-014	Cost of Capital (Electric & Gas Distribution)
San Diego Gas & Electric Company	2021	San Diego Gas & Electric Company	A-21-08-014	Cost of Capital (Electric & Gas Distribution)
Southern California Gas Company	2022	Southern California Gas Company	A-22-04-011	Cost of Capital (Gas Distribution)
San Diego Gas & Electric Company	2022	San Diego Gas & Electric Company	A-22-04-012	Cost of Capital (Electric & Gas Distribution)
Canada Energy Regulator				
Enbridge Pipelines Inc.	2021	Enbridge Pipelines Inc.	RH-001-2020	Cost of Capital (Oil Pipeline)
Connecticut Department of Public Utility Control				
Aquarion Water Company of CT/ Macquarie Securities	2007	Aquarion Water Company of CT	DPUC Docket No. 07-05-19	Return on Equity (Water)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Federal Energy Regulatory Commission				
Atlantic Power Corporation	2007	Atlantic Path 15, LLC	ER08-374-000	Return on Equity (Electric)
Atlantic Power Corporation	2010	Atlantic Path 15, LLC	ER11-2909-000	Return on Equity (Electric)
Atlantic Power Corporation	2011	Atlantic Path 15, LLC	ER11-2909 and EL11-29	Rate of Return (Electric Transmission)
Startrans IO, LLC	2012	Startrans IO, LLC	ER-13-272-000	Cost of Capital (Electric Transmission)
Startrans IO, LLC	2015	Startrans IO, LLC	ER-16-194-000 and EL16-25-000	Cost of Capital (Electric Transmission)
Northern States Power Company	2019	Northern States Power Company	ER20-26-000	Cost of Capital (Electric Transmission)
PPL Electric Utilities Corp.	2020	PP&l Industrial Customer Alliance v. PPL Electric	EL20-48-000	Answering Testimony in Response to a Section 206 ROE Complaint
South First Energy Operating Companies	2020	South First Energy Operating Companies	ER21-253-000	Cost of Capital (Electric Transmission)
DCR Transmission, L.L.C.	2023	DCR Transmission, L.L.C.	ER23-___-000	Cost of Capital (Electric Transmission)
Florida Public Service Commission				
Florida Power & Light Company	2021	Florida Power & Light Company	Docket No. 20210015-EI	Cost of Capital (Electric)
Georgia Public Service Commission				
Georgia Power Company	2022	Georgia Power Company	44280	Cost of Capital (Electric)
Hawaii Public Utility Commission				
The Gas Company	2017	The Gas Company	Docket No. 2017-0105	Cost of Capital (Gas Distribution)
Maine Public Utilities Commission				
Bangor Hydro Electric Company	1998	Bangor Hydro Electric Company	MPUC Docket No. 98-820	Transaction-Related Financial Advisory Services, Valuation
Central Maine Power Company	2007	Central Maine Power Company	MPUC Docket No. 2007-215	Sales Forecast
Enmax Corporation	2019	Enmax Corporation	2019-00097	Regulatory Approval of Emera Maine Acquisition

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Versant Power	2021	Versant Power	MPUC Docket No. 2020-00316	Cost of Capital (Electric)
Versant Power	2022	Versant Power	2022-00255	Cost of Capital (Electric)
Maryland State Board of Contract Appeals				
Green Planet Power Solutions	2018	Green Planet Power Solutions and Maryland Bio Energy LLC v. Maryland Department of General Services	MSBCA 3061	Contract Litigation, Power Purchase Agreement, Damages Analysis
Massachusetts Superior Court				
Burncoat Pond Watershed District	2010	Central Water District v. Burncoat Pond Watershed District	WDCV 2001-0105	Valuation/Eminent Domain
Minnesota Public Utilities Commission				
Northern States Power Company	2015 2016	Northern States Power Company	E-002-GR-15-826	Cost of Capital (Electric)
Northern States Power Company	2017	Northern States Power Company	E002/M-17-797 G002/M-17-787 E002/M-17-818	Cost of Capital (Electric and Gas Rate Riders for Transmission, Renewable Generation and Gas Distribution)
New Brunswick Energy and Utilities Board				
Liberty Utilities (Gas New Brunswick) LP	2021	Liberty Utilities (Gas New Brunswick) LP	491	Cost of Capital (Gas)
Newfoundland and Labrador Board of Commissioners of Public Utilities				
Newfoundland Power	2016	Newfoundland Power	2016 GRA	Cost of Capital (Electric)
Newfoundland Power	2018	Newfoundland Power	2018 GRA	Cost of Capital (Electric)
Newfoundland Power	2021	Newfoundland Power	2021 GRA	Cost of Capital (Electric)
Newfoundland Power	2023	Newfoundland Power		Cost of Capital (Electric)
New Jersey Board of Public Utilities				
Conectiv	2000-2001	Atlantic City Electric Company	NJBPU Docket No. EM00020106	Transaction-Related Financial Advisory Services

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
North Carolina Utilities Commission				
Duke Energy Carolinas, LLC	2023	Duke Energy Carolinas, LLC	E-7, Sub 1276	Return on Equity (Electric)
Nova Scotia Utility and Review Board				
Nova Scotia Power Inc.	2012	Nova Scotia Power Inc.	2013 GRA	Return on Equity/Business Risk (Electric)
Nova Scotia Power Inc.	2022	Nova Scotia Power Inc.	2022 GRA	Return on Equity/Business Risk (Electric)
Eastward Energy Inc.	2023	Eastward Energy Inc.	M10960	Return on Equity/Business Risk (Gas)
Public Utility Commission of Ohio				
Duke Ohio, Inc.	2022	Duke Ohio, Inc.	22-507-GA-AIR	Return on Equity (Gas)
Ontario Energy Board				
Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	2009	Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	EB-2009-0084	Ontario Energy Board's 2009 Consultative Process on Cost of Capital Review (Gas & Electric)
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study and Cost of Capital (Gas Distribution)
Enbridge Gas Distribution	2014	Enbridge Gas Distribution	EB-2012-0459	Incentive Regulation Plan and Industry Productivity Study
Ontario Power Generation	2016	Ontario Power Generation	EB-2016-0152	Cost of Capital (Electric Generation)
Ontario Power Generation	2020	Ontario Power Generation	EB-2020-0290	Capital Structure (Electric Generation)
Enbridge Gas Distribution	2022	Enbridge Gas Distribution	EB-2022-0200	Capital Structure and Business Risk
Prince Edward Island Regulatory and Appeals Commission				
Maritime Electric Company	2015	Maritime Electric Company	UE20942	Return on Capital (Electric)
Maritime Electric Company	2022	Maritime Electric Company	UE20946	Return on Capital (Electric)
Public Utilities Commission of Ohio				
Duke Energy Ohio, Inc.	2022	Duke Energy Ohio, Inc.	2022-00372	Cost of Capital (Gas Distribution)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Duke Energy Ohio, Inc.	2023	Duke Energy Ohio, Inc.	22-507-GA-AIR	Cost of Capital (Gas)
Régie de l'énergie du Québec				
Gaz Métro	2012	Gaz Métro	R-3809-2012	Return on Equity/Business Risk/ Capital Structure (Gas Distribution)
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2013	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3842-2013	Return on Equity/Business Risk (Electric)
Hydro-Québec Distribution	2014	Hydro-Québec Distribution	R-3905-2014	Remuneration of Deferral Accounts
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2015-2017	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3897-2014	Performance-Based Ratemaking
South Carolina Public Service Commission				
Piedmont Natural Gas Company	2022	Piedmont Natural Gas Company	2022-89-G	Return on Equity (Gas Distribution)
Duke Energy Progress	2022	Duke Energy Progress	Docket No. 2022-254-E	Return on Equity (Electric)
South Dakota Public Service Commission				
Northern States Power Company-MN	2012	Northern States Power Company-MN	EL 11-019	Return on Equity
Texas Public Utility Commission				
Texas New Mexico Power Company	2004	Texas New Mexico Power Company	PUC Docket No. 29206	Auction Process and Stranded Cost Recovery
U.S. Department of Commerce				
Government of Québec	2017	Duty Investigation of Uncoated Groundwood Paper from Canada	PUC Docket No. 29206	Contracting for Renewable Resources, Market Analysis, Damages Analysis
Vermont Public Service Board				
Vermont Gas Systems, Inc.	2006	Vermont Gas Systems, Inc.	VPSB Docket No. 7109	Models of Incentive Regulation
Vermont Gas Systems, Inc.	2012	Vermont Gas Systems, Inc.	Docket No. 7803A	Cost of Capital (Gas Distribution)
Green Mountain Power Corporation	2013	Green Mountain Power Corporation	Docket No. 8191	Return on Equity (Electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Vermont Gas Systems, Inc.	2016	Vermont Gas Systems, Inc.	Docket No. 8698/8710	Return on Equity (Gas Distribution)
Green Mountain Power Corporation	2017	Green Mountain Power Corporation	Docket No. Tariff-8677	Return on Equity (Electric)
Green Mountain Power Corporation	2018	Green Mountain Power Corporation	18-0974	Return on Equity (Electric)
State Corporation of Virginia				
Dominion Energy Virginia	2021	Virginia Electric and Power Company	PUR-2021-00058	Cost of Capital (Electric)
Wisconsin Public Service Commission				
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-170	Return on Equity (Electric)
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-171	Return on Equity (Electric)
Northern States Power Company	2011	Northern States Power Company	PSCW Docket No. 4220-UR-117	Return on Equity (Electric)
Northern States Power Company	2013	Northern States Power Company	PSCW Docket No. 4220-UR-119	Return on Equity (Gas & Electric)
Northern States Power Company	2015	Northern States Power Company	PSCW Docket No. 4220-UR-121	Return on Equity (Gas & Electric)
Northern States Power Company	2017 2019	Northern States Power Company	PSCW Docket No. 4220-UR-123, 4220-UR-124	Return on Equity (Gas & Electric)
Northern States Power Company	2021	Northern States Power Company	4220-UR-125	Cost of Capital (Electric, Affidavit)
Northern States Power Company	2023	Northern States Power Company	4220-UR-126	Cost of Capital (Electric & Gas)
Yukon Utilities Board				
ATCO Electric Yukon	2016	ATCO Electric Yukon	2016-2017 GRA	Return on Equity (Electric)

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 402

December 29, 2023

JENNIFER E. NELSON
ASSISTANT VICE PRESIDENT

Ms. Nelson is a Certified Rate of Return Analyst with 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 the Arkansas Public Service Commission, the New Hampshire Public Utilities Commission, the New Mexico Public Regulation Commission, and the Public Utilities Commission of Texas regarding the cost of capital.
- Submitted expert testimony on behalf of natural gas utilities before regulatory commissions in Florida, North Carolina, Ohio, 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 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
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				
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
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 Utilities Commission of South Carolina				
Dominion Energy South Carolina	04/23	Dominion Energy South Carolina	2023-70-G	Cost of Capital
Public Utilities Commission of Texas				
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

PUBLIC UTILITY COMMISSION OF OREGON

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Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 403

December 29, 2023

SUMMARY OF ROE MODEL RANGES AND ROE RECOMMENDATION

	[1]	[2]	[3]
Gas Proxy Group Mean	4-model Average (Blended MRP CAPM)	4-model Average (Hist MRP CAPM)	Midpoint of Range
Results at Current Interest Rates	10.38%	10.01%	
Results at Projected Interest Rates	10.23%	9.79%	
Range of Results (Min & Max, rounded)	**9.80%**	**10.40%**	**10.10%**

Combined Proxy Group Mean	4-model Average (Blended MRP CAPM)	4-model Average (Hist MRP CAPM)	Midpoint of Range
Results at Current Interest Rates	10.62%	10.24%	
Results at Projected Interest Rates	10.46%	10.01%	
Range of Results (Min & Max, rounded)	**10.00%**	**10.60%**	**10.30%**

Point ROE Recommendation	**10.10%**

COMBINED DCF, CAPM, RISK PREMIUM AND EXPECTED EARNINGS RESULTS - CURRENT INTEREST RATES

Company	Ticker	Mean Constant DCF	Mean Multi-Stage DCF	CAPM BB Beta (Blended MRP)	CAPM VL Beta (Blended MRP)	CAPM BB Beta (Historical MRP)	CAPM VL Beta (Historical MRP)	AVG DCF	AVG CAPM (Blended MRP)	AVG CAPM (Historical MRP)	Risk Premium	Expected Earnings	4-model Average (Blend CAPM)	4-model Average (Hist MRP CAPM)
Atmos Energy Corporation	ATO	9.93%	7.61%	11.56%	11.98%	10.17%	10.51%	8.77%	11.77%	10.34%	10.36%	10.36%	10.31%	9.96%
New Jersey Resources Corporation	NJR	9.50%	8.66%	11.90%	12.87%	10.45%	11.23%	9.08%	12.38%	10.84%	10.36%	12.00%	10.96%	10.57%
NiSource Inc.	NI	11.58%	9.23%	12.09%	12.42%	10.60%	10.87%	10.41%	12.26%	10.74%	10.36%	10.51%	10.88%	10.50%
ONE Gas, Inc.	OGS	9.01%	8.25%	11.70%	11.53%	10.29%	10.15%	8.63%	11.61%	10.22%	10.36%	8.80%	9.85%	9.50%
Southwest Gas Holding	SWX	10.42%	9.15%	12.14%	12.42%	10.65%	10.87%	9.78%	12.28%	10.76%	10.36%	7.71%	10.04%	9.65%
Spire, Inc.	SR	10.88%	9.91%	11.85%	11.98%	10.41%	10.51%	10.39%	11.91%	10.46%	10.36%	8.29%	10.24%	9.88%
Ameren Corporation	AEE	9.45%	8.04%	11.80%	11.98%	10.37%	10.51%	8.74%	11.89%	10.44%	10.43%	10.31%	10.34%	9.98%
Avista Corporation	AVA	11.55%	10.48%	11.73%	12.42%	10.31%	10.87%	11.02%	12.08%	10.59%	10.43%	7.70%	10.31%	9.93%
Black Hills Corporation	BKH	7.93%	8.72%	13.25%	13.31%	11.54%	11.59%	8.33%	13.28%	11.56%	10.43%	8.21%	10.06%	9.63%
CenterPoint Energy, Inc.	CNP	9.74%	7.65%	14.09%	14.20%	12.22%	12.30%	8.69%	14.15%	12.26%	10.43%	10.29%	10.89%	10.42%
CMS Energy Corporation	CMS	10.20%	8.50%	11.75%	11.53%	10.33%	10.15%	9.35%	11.64%	10.24%	10.43%	12.40%	10.96%	10.61%
DTE Energy Company	DTE	8.84%	8.32%	12.53%	12.87%	10.96%	11.23%	8.58%	12.70%	11.09%	10.43%	12.87%	11.15%	10.75%
MGE Energy, Inc.	MGEE	7.70%	6.88%	10.65%	11.09%	9.44%	9.80%	7.29%	10.87%	9.62%	10.43%	12.15%	10.18%	9.87%
NorthWestern Energy Group, Inc.	NWE	8.98%	9.39%	12.99%	12.87%	11.33%	11.23%	9.19%	12.93%	11.28%	10.43%	8.15%	10.18%	9.76%
Public Service Enterprise Group Inc.	PEG	8.83%	8.49%	12.70%	12.87%	11.10%	11.23%	8.66%	12.78%	11.16%	10.43%	13.30%	11.29%	10.89%
Southern Company	SO	10.11%	9.13%	12.30%	12.42%	10.78%	10.87%	9.62%	12.36%	10.82%	10.43%	14.74%	11.79%	11.40%
Wisconsin Energy Corporation	WEC	9.44%	8.50%	11.65%	11.53%	10.25%	10.15%	8.97%	11.59%	10.20%	10.43%	13.21%	11.05%	10.70%
GAS PROXY GROUP MEAN		10.22%	8.80%	11.87%	12.20%	10.43%	10.69%	9.51%	12.04%	10.56%	10.36%	9.61%	10.38%	10.01%
COMBINED PROXY GROUP MEAN		9.65%	8.64%	12.16%	12.37%	10.66%	10.83%	9.15%	12.26%	10.74%	10.41%	10.65%	10.62%	10.24%

COMBINED DCF, CAPM, RISK PREMIUM AND EXPECTED EARNINGS RESULTS - PROJECTED INTEREST RATES

Company		Mean Constant DCF	Mean Multi-Stage DCF	CAPM BB Beta (Blended MRP)	CAPM VL Beta (Blended MRP)	CAPM BB Beta (Historical MRP)	CAPM VL Beta (Historical MRP)	AVG DCF	AVG CAPM (Blended MRP)	AVG CAPM (Historical MRP)	Risk Premium	Expected Earnings	4-model Average (Blend CAPM)	4-model Average (Hist MRP CAPM)
Atmos Energy Corporation	ATO	9.93%	7.61%	11.19%	11.62%	9.56%	9.89%	8.77%	11.40%	9.73%	10.10%	10.36%	10.16%	9.74%
New Jersey Resources Corporation	NJR	9.50%	8.66%	11.54%	12.54%	9.83%	10.61%	9.08%	12.04%	10.22%	10.10%	12.00%	10.81%	10.35%
NiSource Inc.	NI	11.58%	9.23%	11.74%	12.08%	9.99%	10.25%	10.41%	11.91%	10.12%	10.10%	10.51%	10.73%	10.28%
ONE Gas, Inc.	OGS	9.01%	8.25%	11.33%	11.16%	9.67%	9.54%	8.63%	11.25%	9.60%	10.10%	8.80%	9.69%	9.28%
Southwest Gas Holding	SWX	10.42%	9.15%	11.79%	12.08%	10.03%	10.25%	9.78%	11.94%	10.14%	10.10%	7.71%	9.88%	9.43%
Spire, Inc.	SR	10.88%	9.91%	11.49%	11.62%	9.79%	9.89%	10.39%	11.56%	9.84%	10.10%	8.29%	10.08%	9.66%
Ameren Corporation	AEE	9.45%	8.04%	11.44%	11.62%	9.75%	9.89%	8.74%	11.53%	9.82%	10.15%	10.31%	10.18%	9.76%
Avista Corporation	AVA	11.55%	10.48%	11.37%	12.08%	9.70%	10.25%	11.02%	11.72%	9.97%	10.15%	7.70%	10.15%	9.71%
Black Hills Corporation	BKH	7.93%	8.72%	12.94%	13.00%	10.92%	10.97%	8.33%	12.97%	10.95%	10.15%	8.21%	9.91%	9.41%
CenterPoint Energy, Inc.	CNP	9.74%	7.65%	13.81%	13.92%	11.60%	11.69%	8.69%	13.87%	11.64%	10.15%	10.29%	10.75%	10.19%
CMS Energy Corporation	CMS	10.20%	8.50%	11.39%	11.16%	9.71%	9.54%	9.35%	11.27%	9.62%	10.15%	12.40%	10.79%	10.38%
DTE Energy Company	DTE	8.84%	8.32%	12.19%	12.54%	10.34%	10.61%	8.58%	12.37%	10.47%	10.15%	12.87%	10.99%	10.52%
MGE Energy, Inc.	MGEE	7.70%	6.88%	10.25%	10.70%	8.82%	9.18%	7.29%	10.47%	9.00%	10.15%	12.15%	10.01%	9.65%
NorthWestern Energy Group, Inc.	NWE	8.98%	9.39%	12.67%	12.54%	10.71%	10.61%	9.19%	12.60%	10.66%	10.15%	8.15%	10.02%	9.54%
Public Service Enterprise Group Inc.	PEG	8.83%	8.49%	12.37%	12.54%	10.48%	10.61%	8.66%	12.46%	10.55%	10.15%	13.30%	11.14%	10.66%
Southern Company	SO	10.11%	9.13%	11.96%	12.08%	10.16%	10.25%	9.62%	12.02%	10.21%	10.15%	14.74%	11.63%	11.18%
Wisconsin Energy Corporation	WEC	9.44%	8.50%	11.28%	11.16%	9.63%	9.54%	8.97%	11.22%	9.58%	10.15%	13.21%	10.89%	10.48%
GAS PROXY GROUP MEAN		10.22%	8.80%	11.51%	11.85%	9.81%	10.07%	9.51%	11.68%	9.94%	10.10%	9.61%	10.23%	9.79%
COMBINED PROXY GROUP MEAN		9.65%	8.64%	11.81%	12.03%	10.04%	10.21%	9.15%	11.92%	10.13%	10.13%	10.65%	10.46%	10.01%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 404

December 29, 2023

PROXY GROUP SELECTION

		[1]	[2]	[3]	[4]	[5]	[6]
Company		Pays Dividends (Yes/No)	S&P Rating	Positive Earnings Growth by more than one Analyst (Yes/No)	% Regulated Net Operating Income / Total Net Operating Income (2020-2022)	% Natural Gas Distribution Net Operating Income / Total Net Operating Income (2020-2022)	Involved in Merger (Yes/No)
Atmos Energy Corporation	ATO	Yes	A-	Yes	100%	66%	No
New Jersey Resources Corporation	NJR	Yes	[7]	Yes	66%	61%	No
NiSource Inc.	NI	Yes	BBB+	Yes	100%	66%	No
ONE Gas, Inc.	OGS	Yes	A-	Yes	100%	100%	No
Southwest Gas Holding	SWX	Yes	BBB-	Yes	77%	77%	No
Spire, Inc.	SR	Yes	A-	Yes	89%	89%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	100%	15%	No
Avista Corporation	AVA	Yes	BBB	Yes	100%	26%	No
Black Hills Corporation	BKH	Yes	BBB+	Yes	99%	53%	No
CenterPoint Energy, Inc.	CNP	Yes	BBB+	Yes	100%	45%	No
CMS Energy Corporation	CMS	Yes	BBB+	Yes	88%	30%	No
DTE Energy Company	DTE	Yes	BBB+	Yes	100%	22%	No
MGE Energy, Inc.	MGEE	Yes	AA-	Yes	73%	19%	No
NorthWestern Energy Group, Inc.	NWE	Yes	BBB	Yes	100%	15%	No
Public Service Enterprise Group Inc.	PEG	Yes	BBB+	Yes	90%	21%	No
Southern Company	SO	Yes	BBB+	Yes	95%	18%	No
Wisconsin Energy Corporation	WEC	Yes	A-	Yes	99%	39%	No

[1] Source: Bloomberg Professional
[2] Source: S&P Capital IQ Pro
[3] Source: Value Line, Zacks and Yahoo Finance
[4] Source: Company 10-K reports, average of three most recent years
[5] Source: Company 10-K reports, average of three most recent years
[6] Source: Bloomberg Professional
[7] New Jersey Natural Gas Co is rated A1 by Moody's

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 405

December 29, 2023

30-DAY CONSTANT GROWTH DCF

Company		Annualized Dividend [1]	Stock Price [2]	Dividend Yield [3]	Expected Dividend Yield [4]	Value Line Earnings Growth [5]	Yahoo! Finance Earnings Growth [6]	Zacks Earnings Growth [7]	Average Growth [8]	Low DCF ROE [9]	Mean DCF ROE [10]	High DCF ROE [11]
Atmos Energy Corporation	ATO	$2.96	$113.74	2.60%	2.70%	7.00%	7.50%	7.30%	7.27%	9.69%	9.96%	10.20%
New Jersey Resources Corporation	NJR	$1.68	$42.32	3.97%	4.08%	5.00%	6.00%	6.00%	5.67%	9.07%	9.75%	10.09%
NiSource Inc.	NI	$1.00	$26.62	3.76%	3.90%	9.50%	6.70%	7.00%	7.73%	10.58%	11.63%	13.43%
ONE Gas, Inc.	OGS	$2.60	$73.50	3.54%	3.63%	6.50%	5.00%	5.00%	5.50%	8.63%	9.13%	10.15%
Southwest Gas Holding	SWX	$2.48	$62.47	3.97%	4.10%	10.00%	4.00%	5.00%	6.33%	8.05%	10.43%	14.17%
Spire, Inc.	SR	$2.88	$58.75	4.90%	5.05%	8.00%	n/a	4.20%	6.10%	9.21%	11.15%	13.10%
Ameren Corporation	AEE	$2.52	$79.24	3.18%	3.28%	6.50%	5.90%	6.40%	6.27%	9.17%	9.55%	9.78%
Avista Corporation	AVA	$1.84	$33.48	5.50%	5.67%	6.50%	6.30%	6.30%	6.37%	11.97%	12.04%	12.17%
Black Hills Corporation	BKH	$2.50	$54.34	4.60%	4.68%	3.00%	5.40%	2.20%	3.53%	6.85%	8.22%	10.12%
CenterPoint Energy, Inc.	CNP	$0.76	$28.10	2.70%	2.80%	6.50%	negative	7.50%	7.00%	9.29%	9.80%	10.31%
CMS Energy Corporation	CMS	$1.95	$56.01	3.48%	3.60%	6.50%	5.87%	7.80%	6.72%	9.45%	10.32%	11.42%
DTE Energy Company	DTE	$3.81	$104.07	3.66%	3.76%	4.50%	5.10%	6.00%	5.20%	8.24%	8.96%	9.77%
MGE Energy, Inc.	MGEE	$1.71	$72.95	2.34%	2.41%	n/a	5.40%	5.30%	5.35%	7.71%	7.76%	7.81%
NorthWestern Energy Group, Inc.	NWE	$2.56	$50.69	5.05%	5.15%	3.50%	3.66%	5.20%	4.12%	8.64%	9.27%	10.38%
Public Service Enterprise Group Inc.	PEG	$2.28	$60.26	3.78%	3.88%	4.00%	5.50%	5.50%	5.00%	7.86%	8.88%	9.39%
Southern Company	SO	$2.80	$68.23	4.10%	4.23%	6.50%	7.30%	4.00%	5.93%	8.19%	10.16%	11.55%
Wisconsin Energy Corporation	WEC	$3.12	$84.45	3.69%	3.80%	6.00%	5.50%	5.80%	5.77%	9.30%	9.57%	9.81%
GAS PROXY GROUP MEAN				3.79%	3.91%	7.67%	5.84%	5.75%	6.43%	9.20%	10.34%	11.86%
COMBINED PROXY GROUP MEAN				3.81%	3.92%	6.22%	5.68%	5.68%	5.87%	8.93%	9.80%	10.80%

Notes
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of September 30, 2023
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth	Low DCF ROE	Mean DCF ROE	High DCF ROE
Atmos Energy Corporation	ATO	$2.96	$116.46	2.54%	2.63%	7.00%	7.50%	7.30%	7.27%	9.63%	9.90%	10.14%
New Jersey Resources Corporation	NJR	$1.68	$45.13	3.72%	3.83%	5.00%	6.00%	6.00%	5.67%	8.82%	9.49%	9.83%
NiSource Inc.	NI	$1.00	$27.05	3.70%	3.84%	9.50%	6.70%	7.00%	7.73%	10.52%	11.57%	13.37%
ONE Gas, Inc.	OGS	$2.60	$76.77	3.39%	3.48%	6.50%	5.00%	5.00%	5.50%	8.47%	8.98%	10.00%
Southwest Gas Holding	SWX	$2.48	$63.06	3.93%	4.06%	10.00%	4.00%	5.00%	6.33%	8.01%	10.39%	14.13%
Spire, Inc.	SR	$2.88	$61.87	4.66%	4.80%	8.00%	n/a	4.20%	6.10%	8.95%	10.90%	12.84%
Ameren Corporation	AEE	$2.52	$81.71	3.08%	3.18%	6.50%	5.90%	6.40%	6.27%	9.07%	9.45%	9.68%
Avista Corporation	AVA	$1.84	$37.19	4.95%	5.10%	6.50%	6.30%	6.30%	6.37%	11.40%	11.47%	11.61%
Black Hills Corporation	BKH	$2.50	$58.20	4.30%	4.37%	3.00%	5.40%	2.20%	3.53%	6.54%	7.91%	9.81%
CenterPoint Energy, Inc.	CNP	$0.76	$28.88	2.63%	2.72%	6.50%	negative	7.50%	7.00%	9.22%	9.72%	10.23%
CMS Energy Corporation	CMS	$1.95	$58.30	3.34%	3.46%	6.50%	5.87%	7.80%	6.72%	9.31%	10.18%	11.28%
DTE Energy Company	DTE	$3.81	$108.41	3.51%	3.61%	4.50%	5.10%	6.00%	5.20%	8.09%	8.81%	9.62%
MGE Energy, Inc.	MGEE	$1.71	$75.93	2.25%	2.31%	n/a	5.40%	5.30%	5.35%	7.61%	7.66%	7.71%
NorthWestern Energy Group, Inc.	NWE	$2.56	$54.60	4.69%	4.79%	3.50%	3.66%	5.20%	4.12%	8.27%	8.91%	10.01%
Public Service Enterprise Group Inc.	PEG	$2.28	$61.47	3.71%	3.80%	4.00%	5.50%	5.50%	5.00%	7.78%	8.80%	9.31%
Southern Company	SO	$2.80	$69.71	4.02%	4.14%	6.50%	7.30%	4.00%	5.93%	8.10%	10.07%	11.46%
Wisconsin Energy Corporation	WEC	$3.12	$87.43	3.57%	3.67%	6.00%	5.50%	5.80%	5.77%	9.17%	9.44%	9.68%
GAS PROXY GROUP MEAN				3.66%	3.77%	7.67%	5.84%	5.75%	6.43%	9.07%	10.21%	11.72%
COMBINED PROXY GROUP MEAN				3.65%	3.75%	6.22%	5.68%	5.68%	5.87%	8.76%	9.63%	10.63%

Notes
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of September 30, 2023
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

Company		Annualized Dividend [1]	Stock Price [2]	Dividend Yield [3]	Expected Dividend Yield [4]	Value Line Earnings Growth [5]	Yahoo! Finance Earnings Growth [6]	Zacks Earnings Growth [7]	Average Growth [8]	Low DCF ROE [9]	Mean DCF ROE [10]	High DCF ROE [11]
Atmos Energy Corporation	ATO	$2.96	$115.49	2.56%	2.66%	7.00%	7.50%	7.30%	7.27%	9.65%	9.92%	10.16%
New Jersey Resources Corporation	NJR	$1.68	$48.28	3.48%	3.58%	5.00%	6.00%	6.00%	5.67%	8.57%	9.25%	9.58%
NiSource Inc.	NI	$1.00	$27.37	3.65%	3.80%	9.50%	6.70%	7.00%	7.73%	10.48%	11.53%	13.33%
ONE Gas, Inc.	OGS	$2.60	$78.23	3.32%	3.41%	6.50%	5.00%	5.00%	5.50%	8.41%	8.91%	9.93%
Southwest Gas Holding	SWX	$2.48	$62.15	3.99%	4.12%	10.00%	4.00%	5.00%	6.33%	8.07%	10.45%	14.19%
Spire, Inc.	SR	$2.88	$66.00	4.36%	4.50%	8.00%	n/a	4.20%	6.10%	8.66%	10.60%	12.54%
Ameren Corporation	AEE	$2.52	$84.07	3.00%	3.09%	6.50%	5.90%	6.40%	6.27%	8.99%	9.36%	9.59%
Avista Corporation	AVA	$1.84	$39.68	4.64%	4.78%	6.50%	6.30%	6.30%	6.37%	11.08%	11.15%	11.29%
Black Hills Corporation	BKH	$2.50	$61.64	4.06%	4.13%	3.00%	5.40%	2.20%	3.53%	6.30%	7.66%	9.57%
CenterPoint Energy, Inc.	CNP	$0.76	$29.18	2.60%	2.70%	6.50%	negative	7.50%	7.00%	9.19%	9.70%	10.20%
CMS Energy Corporation	CMS	$1.95	$59.71	3.27%	3.38%	6.50%	5.87%	7.80%	6.72%	9.23%	10.10%	11.19%
DTE Energy Company	DTE	$3.81	$109.99	3.46%	3.55%	4.50%	5.10%	6.00%	5.20%	8.04%	8.75%	9.57%
MGE Energy, Inc.	MGEE	$1.71	$75.17	2.27%	2.34%	n/a	5.40%	5.30%	5.35%	7.64%	7.69%	7.74%
NorthWestern Energy Group, Inc.	NWE	$2.56	$56.17	4.56%	4.65%	3.50%	3.66%	5.20%	4.12%	8.14%	8.77%	9.88%
Public Service Enterprise Group Inc.	PEG	$2.28	$61.43	3.71%	3.80%	4.00%	5.50%	5.50%	5.00%	7.79%	8.80%	9.31%
Southern Company	SO	$2.80	$69.40	4.03%	4.15%	6.50%	7.30%	4.00%	5.93%	8.12%	10.09%	11.48%
Wisconsin Energy Corporation	WEC	$3.12	$90.42	3.45%	3.55%	6.00%	5.50%	5.80%	5.77%	9.05%	9.32%	9.55%
GAS PROXY GROUP MEAN				3.56%	3.68%	7.67%	5.84%	5.75%	6.43%	8.97%	10.11%	11.62%
COMBINED PROXY GROUP MEAN				3.55%	3.66%	6.22%	5.68%	5.68%	5.87%	8.67%	9.53%	10.54%

Notes
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of September 30, 2023
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 406

December 29, 2023

30-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	$2.96	$113.74	7.27%	6.76%	6.26%	5.76%	5.25%	4.75%	4.24%	7.65%
New Jersey Resources Corporation	NJR	$1.68	$42.32	5.67%	5.43%	5.19%	4.96%	4.72%	4.48%	4.24%	8.95%
NiSource Inc.	NI	$1.00	$26.62	7.73%	7.15%	6.57%	5.99%	5.41%	4.83%	4.24%	9.30%
ONE Gas, Inc.	OGS	$2.60	$73.50	5.50%	5.29%	5.08%	4.87%	4.66%	4.45%	4.24%	8.39%
Southwest Gas Holding	SWX	$2.48	$62.47	6.33%	5.99%	5.64%	5.29%	4.94%	4.59%	4.24%	9.15%
Spire, Inc.	SR	$2.88	$58.75	6.10%	5.79%	5.48%	5.17%	4.86%	4.55%	4.24%	10.23%
Ameren Corporation	AEE	$2.52	$79.24	6.27%	5.93%	5.59%	5.26%	4.92%	4.58%	4.24%	8.15%
Avista Corporation	AVA	$1.84	$33.48	6.37%	6.01%	5.66%	5.31%	4.95%	4.60%	4.24%	11.07%
Black Hills Corporation	BKH	$2.50	$54.34	3.53%	3.65%	3.77%	3.89%	4.01%	4.13%	4.24%	9.03%
CenterPoint Energy, Inc.	CNP	$0.76	$28.10	7.00%	6.54%	6.08%	5.62%	5.16%	4.70%	4.24%	7.72%
CMS Energy Corporation	CMS	$1.95	$56.01	6.72%	6.31%	5.90%	5.48%	5.07%	4.66%	4.24%	8.65%
DTE Energy Company	DTE	$3.81	$104.07	5.20%	5.04%	4.88%	4.72%	4.56%	4.40%	4.24%	8.46%
MGE Energy, Inc.	MGEE	$1.71	$72.95	5.35%	5.17%	4.98%	4.80%	4.61%	4.43%	4.24%	6.94%
NorthWestern Energy Group, Inc.	NWE	$2.56	$50.69	4.12%	4.14%	4.16%	4.18%	4.20%	4.22%	4.24%	9.71%
Public Service Enterprise Group Inc.	PEG	$2.28	$60.26	5.00%	4.87%	4.75%	4.62%	4.50%	4.37%	4.24%	8.54%
Southern Company	SO	$2.80	$68.23	5.93%	5.65%	5.37%	5.09%	4.81%	4.53%	4.24%	9.20%
Wisconsin Energy Corporation	WEC	$3.12	$84.45	5.77%	5.51%	5.26%	5.01%	4.75%	4.50%	4.24%	8.65%
GAS PROXY GROUP MEAN											8.95%
COMBINED PROXY GROUP MEAN											8.81%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 30-day average as of September 30, 2023
[3] Source: Exhibit NW Natural/405
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Sources: Blue Chip Financial Forecasts 2030-2034 Real GDP growth (2.0%) and projected Inflation (2.2%) = ((1+GDP) x (1+ CPI)) - 1
[10] Internal rate of return

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	$2.96	$116.46	7.27%	6.76%	6.26%	5.76%	5.25%	4.75%	4.24%	7.57%
New Jersey Resources Corporation	NJR	$1.68	$45.13	5.67%	5.43%	5.19%	4.96%	4.72%	4.48%	4.24%	8.66%
NiSource Inc.	NI	$1.00	$27.05	7.73%	7.15%	6.57%	5.99%	5.41%	4.83%	4.24%	9.22%
ONE Gas, Inc.	OGS	$2.60	$76.77	5.50%	5.29%	5.08%	4.87%	4.66%	4.45%	4.24%	8.21%
Southwest Gas Holding	SWX	$2.48	$63.06	6.33%	5.99%	5.64%	5.29%	4.94%	4.59%	4.24%	9.11%
Spire, Inc.	SR	$2.88	$61.87	6.10%	5.79%	5.48%	5.17%	4.86%	4.55%	4.24%	9.93%
Ameren Corporation	AEE	$2.52	$81.71	6.27%	5.93%	5.59%	5.26%	4.92%	4.58%	4.24%	8.03%
Avista Corporation	AVA	$1.84	$37.19	6.37%	6.01%	5.66%	5.31%	4.95%	4.60%	4.24%	10.38%
Black Hills Corporation	BKH	$2.50	$58.20	3.53%	3.65%	3.77%	3.89%	4.01%	4.13%	4.24%	8.70%
CenterPoint Energy, Inc.	CNP	$0.76	$28.88	7.00%	6.54%	6.08%	5.62%	5.16%	4.70%	4.24%	7.63%
CMS Energy Corporation	CMS	$1.95	$58.30	6.72%	6.31%	5.90%	5.48%	5.07%	4.66%	4.24%	8.48%
DTE Energy Company	DTE	$3.81	$108.41	5.20%	5.04%	4.88%	4.72%	4.56%	4.40%	4.24%	8.29%
MGE Energy, Inc.	MGEE	$1.71	$75.93	5.35%	5.17%	4.98%	4.80%	4.61%	4.43%	4.24%	6.83%
NorthWestern Energy Group, Inc.	NWE	$2.56	$54.60	4.12%	4.14%	4.16%	4.18%	4.20%	4.22%	4.24%	9.31%
Public Service Enterprise Group Inc.	PEG	$2.28	$61.47	5.00%	4.87%	4.75%	4.62%	4.50%	4.37%	4.24%	8.46%
Southern Company	SO	$2.80	$69.71	5.93%	5.65%	5.37%	5.09%	4.81%	4.53%	4.24%	9.09%
Wisconsin Energy Corporation	WEC	$3.12	$87.43	5.77%	5.51%	5.26%	5.01%	4.75%	4.50%	4.24%	8.50%
GAS PROXY GROUP MEAN											8.78%
COMBINED PROXY GROUP MEAN											8.61%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of September 30, 2023
[3] Source: Exhibit NW Natural/405
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Sources: Blue Chip Financial Forecasts 2030-2034 Real GDP growth (2.0%) and projected Inflation (2.2%) = ((1+GDP) x (1+ CPI)) - 1
[10] Internal rate of return

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	$2.96	$115.49	7.27%	6.76%	6.26%	5.76%	5.25%	4.75%	4.24%	7.60%
New Jersey Resources Corporation	NJR	$1.68	$48.28	5.67%	5.43%	5.19%	4.96%	4.72%	4.48%	4.24%	8.37%
NiSource Inc.	NI	$1.00	$27.37	7.73%	7.15%	6.57%	5.99%	5.41%	4.83%	4.24%	9.17%
ONE Gas, Inc.	OGS	$2.60	$78.23	5.50%	5.29%	5.08%	4.87%	4.66%	4.45%	4.24%	8.14%
Southwest Gas Holding	SWX	$2.48	$62.15	6.33%	5.99%	5.64%	5.29%	4.94%	4.59%	4.24%	9.18%
Spire, Inc.	SR	$2.88	$66.00	6.10%	5.79%	5.48%	5.17%	4.86%	4.55%	4.24%	9.57%
Ameren Corporation	AEE	$2.52	$84.07	6.27%	5.93%	5.59%	5.26%	4.92%	4.58%	4.24%	7.93%
Avista Corporation	AVA	$1.84	$39.68	6.37%	6.01%	5.66%	5.31%	4.95%	4.60%	4.24%	10.00%
Black Hills Corporation	BKH	$2.50	$61.64	3.53%	3.65%	3.77%	3.89%	4.01%	4.13%	4.24%	8.45%
CenterPoint Energy, Inc.	CNP	$0.76	$29.18	7.00%	6.54%	6.08%	5.62%	5.16%	4.70%	4.24%	7.59%
CMS Energy Corporation	CMS	$1.95	$59.71	6.72%	6.31%	5.90%	5.48%	5.07%	4.66%	4.24%	8.38%
DTE Energy Company	DTE	$3.81	$109.99	5.20%	5.04%	4.88%	4.72%	4.56%	4.40%	4.24%	8.23%
MGE Energy, Inc.	MGEE	$1.71	$75.17	5.35%	5.17%	4.98%	4.80%	4.61%	4.43%	4.24%	6.86%
NorthWestern Energy Group, Inc.	NWE	$2.56	$56.17	4.12%	4.14%	4.16%	4.18%	4.20%	4.22%	4.24%	9.16%
Public Service Enterprise Group Inc.	PEG	$2.28	$61.43	5.00%	4.87%	4.75%	4.62%	4.50%	4.37%	4.24%	8.46%
Southern Company	SO	$2.80	$69.40	5.93%	5.65%	5.37%	5.09%	4.81%	4.53%	4.24%	9.11%
Wisconsin Energy Corporation	WEC	$3.12	$90.42	5.77%	5.51%	5.26%	5.01%	4.75%	4.50%	4.24%	8.36%
GAS PROXY GROUP MEAN											8.67%
COMBINED PROXY GROUP MEAN											8.50%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 180-day average as of September 30, 2023
[3] Source: Exhibit NW Natural/405
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Sources: Blue Chip Financial Forecasts 2030-2034 Real GDP growth (2.0%) and projected Inflation (2.2%) = ((1+GDP) x (1+ CPI)) - 1
[10] Internal rate of return

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 407

December 29, 2023

MARKET RISK PREMIUM DERIVED FROM S&P EARNINGS AND ESTIMATE REPORT

[1] S&P's estimate of the S&P 500 Dividend Yield	1.63%
[2] S&P's estimate of the S&P 500 Growth Rate	12.96%
[3] S&P 500 Estimated Required Market Return	14.70%

Notes:
[1] Source: S&P Dow Jones Indices, S&P 500 Earnings and Estimate Report,September 29, 2023
[2] Source: S&P Dow Jones Indices, S&P 500 Earnings and Estimate Report, September 29, 2023
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]

MARKET RISK PREMIUM CALCULATION USING CAP. WEIGHTED BLOOMBERG GROWTH RATES

[4] Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.60%
[5] Cap. Weighted Estimate of the S&P 500 Growth Rate	14.49%
[6] Cap. Weighted S&P 500 Estimated Required Market Return	16.21%

Notes:
[4] Source: Bloomberg Professional, as of September 30, 2023
[5] Source: Bloomberg Professional, as of September 30, 2023
[6] Equals ([4] x (1 + (0.5 x [5]))) + [5]

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Bloomberg Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
LyondellBasell Industries NV	LYB	324.20	94.70	5.28	10.50	30,701.46	0.09%	0.46%	0.92%
American Express Co	AXP	736.46	149.19	1.61	11.89	109,872.32	0.31%	0.50%	3.71%
Verizon Communications Inc	VZ	4204.04	32.41	8.21	n/a	0.00	0.00%	0.00%	
Broadcom Inc	AVGO	412.74	830.58	2.22	12.40	342,810.27	0.97%	2.16%	12.07%
Boeing Co/The	BA	603.20	191.68	n/a	n/a	0.00	0.00%		
Caterpillar Inc	CAT	510.14	273.00	1.90	15.00	139,269.04	0.40%	0.75%	5.93%
JPMorgan Chase & Co	JPM	2906.09	145.02	2.90	-0.50	421,440.45	1.20%	3.47%	-0.60%
Chevron Corp	CVX	1867.25	168.62	3.58	14.77	314,854.85	0.89%	3.20%	13.20%
Coca-Cola Co/The	KO	4324.35	55.98	3.29	7.19	242,076.83	0.69%	2.26%	4.94%
AbbVie Inc	ABBV	1765.05	149.06	3.97	2.48	263,097.91	0.75%	2.97%	1.85%
Walt Disney Co/The	DIS	1829.78	81.05	n/a	22.27	148,303.59	0.42%		9.38%
FleetCor Technologies Inc	FLT	73.96	255.34	n/a	12.30	18,884.18	0.05%		0.66%
Extra Space Storage Inc	EXR	211.28	121.58	2.01	1.27	25,687.06	0.07%	0.15%	0.09%
Exxon Mobil Corp	XOM	4003.19	117.58	3.10	18.41	470,695.43	1.34%	4.14%	24.60%
Phillips 66	PSX	445.29	120.15	3.50	13.02	53,501.35	0.15%	0.53%	1.98%
General Electric Co	GE	1088.38	110.55	0.29	7.00	120,320.19	0.34%	0.10%	2.39%
HP Inc	HPQ	988.27	25.70	4.09	-5.48	25,398.51	0.07%	0.29%	-0.39%
Home Depot Inc/The	HD	1000.07	302.16	2.77	3.44	302,179.94	0.86%	2.37%	2.95%
Monolithic Power Systems Inc	MPWR	47.78	462.00	0.87	n/a	0.00	0.00%	0.00%	
International Business Machines Corp	IBM	911.01	140.30	4.73	3.35	127,814.14	0.36%	1.72%	1.22%
Johnson & Johnson	JNJ	2401.49	155.75	3.06	4.00	374,031.29	1.06%	3.25%	4.25%
McDonald's Corp	MCD	728.76	263.44	2.31	10.40	191,985.32	0.55%	1.26%	5.67%
Merck & Co Inc	MRK	2537.52	102.95	2.84	49.31	261,237.79	0.74%	2.10%	36.57%
3M Co	MMM	551.99	93.62	6.41	10.00	51,677.49	0.15%	0.94%	1.47%
American Water Works Co Inc	AWK	194.67	123.83	2.29	8.00	24,105.86	0.07%	0.16%	0.55%
Bank of America Corp	BAC	7946.37	27.38	3.51	-5.00	217,571.67	0.62%	2.17%	-3.09%
Pfizer Inc	PFE	5645.96	33.17	4.94	-3.70	187,276.49	0.53%	2.63%	-1.97%
Procter & Gamble Co/The	PG	2356.89	145.86	2.58	6.38	343,776.56	0.98%	2.52%	6.23%
AT&T Inc	T	7149.00	15.02	7.39	2.44	107,377.98	0.30%	2.25%	0.74%
Travelers Cos Inc/The	TRV	228.94	163.31	2.45	14.92	37,388.52	0.11%	0.26%	1.58%
RTX Corp	RTX	1455.52	71.97	3.28	9.12	104,753.41	0.30%	0.98%	2.71%
Analog Devices Inc	ADI	498.31	175.09	1.96	6.50	87,249.80	0.25%	0.49%	1.61%
Walmart Inc	WMT	2691.56	159.93	1.43	8.00	430,461.83	1.22%	1.74%	9.78%
Cisco Systems Inc	CSCO	4054.86	53.76	2.90	7.50	217,989.17	0.62%	1.80%	4.64%
Intel Corp	INTC	4188.00	35.55	1.41	0.83	148,883.40	0.42%	0.59%	0.35%
General Motors Co	GM	1375.91	32.97	1.09	0.36	45,363.59	0.13%	0.14%	0.05%
Microsoft Corp	MSFT	7429.76	315.75	0.95	16.62	2,345,947.98	6.66%	6.33%	110.70%
Dollar General Corp	DG	219.48	105.80	2.23	-0.10	23,220.56	0.07%	0.15%	-0.01%
Cigna Group/The	CI	295.98	286.07	1.72	9.80	84,671.00	0.24%	0.41%	2.36%
Kinder Morgan Inc	KMI	2228.17	16.58	6.82	2.00	36,942.98	0.10%	0.71%	0.21%
Citigroup Inc	C	1925.70	41.13	5.15	-8.06	79,204.12	0.22%	1.16%	-1.81%
American International Group Inc	AIG	711.90	60.60	2.38	10.00	43,141.14	0.12%	0.29%	1.22%
Altria Group Inc	MO	1774.61	42.05	9.32	6.00	74,622.35	0.21%	1.98%	1.27%
HCA Healthcare Inc	HCA	271.99	245.98	0.98	7.57	66,903.61	0.19%	0.19%	1.44%
International Paper Co	IP	346.00	35.47	5.22	-2.00	12,272.58	0.03%	0.18%	-0.07%
Hewlett Packard Enterprise Co	HPE	1282.87	17.37	2.76	3.34	22,283.37	0.06%	0.17%	0.21%
Abbott Laboratories	ABT	1735.36	96.85	2.11	2.18	168,069.42	0.48%	1.01%	1.04%
Aflac Inc	AFL	594.06	76.75	2.19	5.98	45,594.26	0.13%	0.28%	0.77%
Air Products and Chemicals Inc	APD	222.15	283.40	2.47	10.27	62,957.03	0.18%	0.44%	1.83%
Royal Caribbean Cruises Ltd	RCL	256.17	92.14	n/a	124.32	23,603.78	0.07%		8.33%
Hess Corp	HES	307.06	153.00	1.14	n/a	0.00	0.00%	0.00%	
Archer-Daniels-Midland Co	ADM	536.10	75.42	2.39	-6.10	40,432.81	0.11%	0.27%	-0.70%
Automatic Data Processing Inc	ADP	411.99	240.58	2.08	16.00	99,115.83	0.28%	0.58%	4.50%
Verisk Analytics Inc	VRSK	145.03	236.24	0.58	11.58	34,261.18	0.10%	0.06%	1.13%
AutoZone Inc	AZO	18.16	2539.99	n/a	13.72	46,116.06	0.13%		1.80%
Avery Dennison Corp	AVY	80.58	182.67	1.77	7.00	14,720.10	0.04%	0.07%	0.29%
Enphase Energy Inc	ENPH	136.36	120.15	n/a	20.38	16,383.05	0.05%		0.95%
MSCI Inc	MSCI	79.09	513.08	1.08	15.26	40,578.98	0.12%	0.12%	1.76%
Ball Corp	BALL	315.06	49.78	1.61	10.30	15,683.64	0.04%	0.07%	0.46%
Axon Enterprise Inc	AXON	74.76	198.99	n/a	n/a	0.00	0.00%		
Ceridian HCM Holding Inc	CDAY	155.61	67.85	n/a	n/a	0.00	0.00%		
Carrier Global Corp	CARR	837.63	55.20	1.34	10.65	46,237.07	0.13%	0.18%	1.40%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Bloomberg Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Bank of New York Mellon Corp/The	BK	778.78	42.65	3.94	10.00	33,215.05	0.09%	0.37%	0.94%
Otis Worldwide Corp	OTIS	411.75	80.31	1.69	n/a	0.00	0.00%	0.00%	
Baxter International Inc	BAX	506.41	37.74	3.07	0.66	19,111.72	0.05%	0.17%	0.04%
Becton Dickinson & Co	BDX	290.11	258.53	1.41	9.36	75,001.88	0.21%	0.30%	1.99%
Berkshire Hathaway Inc	BRK/B	1308.07	350.30	n/a	n/a	0.00	0.00%		
Best Buy Co Inc	BBY	217.64	69.47	5.30	3.21	15,119.31	0.04%	0.23%	0.14%
Boston Scientific Corp	BSX	1464.22	52.80	n/a	12.10	77,310.97	0.22%		2.65%
Bristol-Myers Squibb Co	BMY	2089.10	58.04	3.93	2.55	121,251.54	0.34%	1.35%	0.88%
Brown-Forman Corp	BF/B	310.14	57.69	1.42	7.04	17,891.75	0.05%	0.07%	0.36%
Coterra Energy Inc	CTRA	755.05	27.05	2.96	23.02	20,423.99	0.06%	0.17%	1.33%
Campbell Soup Co	CPB	297.95	41.08	3.60	3.17	12,239.58	0.03%	0.13%	0.11%
Hilton Worldwide Holdings Inc	HLT	261.51	150.18	0.40	17.14	39,274.17	0.11%	0.04%	1.91%
Carnival Corp	CCL	1119.45	13.72	n/a	n/a	0.00	0.00%		
Qorvo Inc	QRVO	97.91	95.47	n/a	2.83	9,347.47	0.03%		0.08%
UDR Inc	UDR	329.48	35.67	4.71	7.46	11,752.55	0.03%	0.16%	0.25%
Clorox Co/The	CLX	123.83	131.06	3.66	17.90	16,228.64	0.05%	0.17%	0.82%
Paycom Software Inc	PAYC	60.47	259.27	0.58	n/a	0.00	0.00%	0.00%	
CMS Energy Corp	CMS	291.73	53.11	3.67	7.50	15,493.62	0.04%	0.16%	0.33%
Colgate-Palmolive Co	CL	826.69	71.11	2.70	7.85	58,786.07	0.17%	0.45%	1.31%
EPAM Systems Inc	EPAM	57.96	255.69	n/a	4.70	14,820.05	0.04%		0.20%
Comerica Inc	CMA	131.78	41.55	6.84	-6.12	5,475.33	0.02%	0.11%	-0.10%
Conagra Brands Inc	CAG	477.87	27.42	5.11	1.07	13,103.11	0.04%	0.19%	0.04%
Airbnb Inc	ABNB	426.36	137.21	n/a	19.34	58,500.72	0.17%		3.21%
Consolidated Edison Inc	ED	344.92	85.53	3.79	4.33	29,501.35	0.08%	0.32%	0.36%
Corning Inc	GLW	852.98	30.47	3.68	6.58	25,990.36	0.07%	0.27%	0.49%
Cummins Inc	CMI	141.65	228.46	2.94	n/a	0.00	0.00%	0.00%	
Caesars Entertainment Inc	CZR	215.29	46.35	n/a	n/a	0.00	0.00%		
Danaher Corp	DHR	738.35	219.91	0.49	-0.26	162,373.50	0.46%	0.23%	-0.12%
Target Corp	TGT	461.61	110.57	3.98	2.51	51,039.66	0.14%	0.58%	0.36%
Deere & Co	DE	288.00	377.38	1.43	18.05	108,685.82	0.31%	0.44%	5.57%
Dominion Energy Inc	D	836.77	44.67	5.98	-3.05	37,378.65	0.11%	0.63%	-0.32%
Dover Corp	DOV	139.87	139.51	1.46	13.00	19,513.82	0.06%	0.08%	0.72%
Alliant Energy Corp	LNT	252.72	48.45	3.74	6.00	12,244.24	0.03%	0.13%	0.21%
Steel Dynamics Inc	STLD	165.64	107.22	1.59	-16.43	17,760.35	0.05%	0.08%	-0.83%
Duke Energy Corp	DUK	771.00	88.26	4.65	6.06	68,048.46	0.19%	0.90%	1.17%
Regency Centers Corp	REG	171.00	59.44	4.37	5.02	10,164.42	0.03%	0.13%	0.14%
Eaton Corp PLC	ETN	399.00	213.28	1.61	15.00	85,098.72	0.24%	0.39%	3.62%
Ecolab Inc	ECL	285.03	169.40	1.25	14.10	48,284.76	0.14%	0.17%	1.93%
Revvity Inc	RVTY	124.14	110.70	0.25	46.45	13,741.74	0.04%	0.01%	1.81%
Emerson Electric Co	EMR	571.50	96.57	2.15	14.90	55,189.76	0.16%	0.34%	2.33%
EOG Resources Inc	EOG	582.26	126.76	2.60	11.33	73,807.40	0.21%	0.55%	2.37%
Aon PLC	AON	202.87	324.22	0.76	9.17	65,773.54	0.19%	0.14%	1.71%
Entergy Corp	ETR	211.46	92.50	4.63	6.22	19,559.68	0.06%	0.26%	0.35%
Equifax Inc	EFX	122.72	183.18	0.85	11.23	22,479.85	0.06%	0.05%	0.72%
EQT Corp	EQT	411.26	40.58	1.48	22.19	16,688.93	0.05%	0.07%	1.05%
IQVIA Holdings Inc	IQV	183.12	196.75	n/a	13.16	36,029.25	0.10%		1.35%
Gartner Inc	IT	78.83	343.61	n/a	7.22	27,085.06	0.08%		0.56%
FedEx Corp	FDX	251.42	264.92	1.90	14.50	66,606.19	0.19%	0.36%	2.74%
FMC Corp	FMC	124.73	66.97	3.46	8.00	8,353.44	0.02%	0.08%	0.19%
Brown & Brown Inc	BRO	283.61	69.84	0.66	11.55	19,807.53	0.06%	0.04%	0.65%
Ford Motor Co	F	3931.37	12.42	4.83	10.96	48,827.67	0.14%	0.67%	1.52%
NextEra Energy Inc	NEE	2023.71	57.29	3.26	8.75	115,938.58	0.33%	1.07%	2.88%
Franklin Resources Inc	BEN	498.98	24.58	4.88	-6.13	12,264.88	0.03%	0.17%	-0.21%
Garmin Ltd	GRMN	191.45	105.20	2.78	5.60	20,140.75	0.06%	0.16%	0.32%
Freeport-McMoRan Inc	FCX	1433.64	37.29	1.61	n/a	0.00	0.00%	0.00%	
Dexcom Inc	DXCM	387.87	93.30	n/a	30.96	36,188.46	0.10%		3.18%
General Dynamics Corp	GD	273.04	220.97	2.39	10.90	60,334.31	0.17%	0.41%	1.87%
General Mills Inc	GIS	581.28	63.99	3.69	8.00	37,196.04	0.11%	0.39%	0.84%
Genuine Parts Co	GPC	140.44	144.38	2.63	8.95	20,276.44	0.06%	0.15%	0.52%
Atmos Energy Corp	ATO	148.46	105.93	2.79	7.50	15,726.58	0.04%	0.12%	0.33%
WW Grainger Inc	GWW	50.00	691.84	1.08	n/a	0.00	0.00%	0.00%	
Halliburton Co	HAL	898.55	40.50	1.58	23.40	36,391.11	0.10%	0.16%	2.42%
L3Harris Technologies Inc	LHX	189.13	174.12	2.62	2.50	32,931.84	0.09%	0.24%	0.23%
Healthpeak Properties Inc	PEAK	547.05	18.36	6.54	1.38	10,043.91	0.03%	0.19%	0.04%
Insulet Corp	PODD	69.82	159.49	n/a	36.33	11,135.75	0.03%		1.15%
Catalent Inc	CTLT	180.27	45.53	n/a	n/a	0.00	0.00%		
Fortive Corp	FTV	352.02	74.16	0.38	7.93	26,106.10	0.07%	0.03%	0.59%
Hershey Co/The	HSY	149.85	200.08	2.38	9.50	29,982.79	0.09%	0.20%	0.81%
Synchrony Financial	SYF	418.18	30.57	3.27	64.00	12,783.85	0.04%	0.12%	2.32%
Hormel Foods Corp	HRL	546.48	38.03	2.89	n/a	0.00	0.00%	0.00%	
Arthur J Gallagher & Co	AJG	215.51	227.93	0.97	12.74	49,120.28	0.14%	0.13%	1.78%
Mondelez International Inc	MDLZ	1360.42	69.40	2.45	8.04	94,413.01	0.27%	0.66%	2.16%
CenterPoint Energy Inc	CNP	629.43	26.85	2.98	n/a	0.00	0.00%	0.00%	
Humana Inc	HUM	123.91	486.52	0.73	12.32	60,283.23	0.17%	0.12%	2.11%
Willis Towers Watson PLC	WTW	104.82	208.96	1.61	10.92	21,903.81	0.06%	0.10%	0.68%
Illinois Tool Works Inc	ITW	302.39	230.31	2.43	3.94	69,643.44	0.20%	0.48%	0.78%
CDW Corp/DE	CDW	134.05	201.76	1.17	13.10	27,045.52	0.08%	0.09%	1.01%
Trane Technologies PLC	TT	228.40	202.91	1.48	11.68	46,344.24	0.13%	0.19%	1.54%
Interpublic Group of Cos Inc/The	IPG	384.94	28.66	4.33	5.20	11,032.24	0.03%	0.14%	0.16%
International Flavors & Fragrances Inc	IFF	255.25	68.17	4.75	19.22	17,400.60	0.05%	0.23%	0.95%
Generac Holdings Inc	GNRC	62.24	108.96	n/a	4.50	6,782.00	0.02%		0.09%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Bloomberg Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
NXP Semiconductors NV	NXPI	257.80	199.92	2.03	20.50	51,539.78	0.15%	0.30%	3.00%
Kellanova	K	342.35	55.84	4.30	4.51	19,116.66	0.05%	0.23%	0.24%
Broadridge Financial Solutions Inc	BR	117.62	179.05	1.79	n/a	0.00	0.00%	0.00%	
Kimberly-Clark Corp	KMB	338.19	120.85	3.91	9.71	40,869.66	0.12%	0.45%	1.13%
Kimco Realty Corp	KIM	619.89	17.59	5.23	3.47	10,903.90	0.03%	0.16%	0.11%
Oracle Corp	ORCL	2739.38	105.92	1.51	14.45	290,154.71	0.82%	1.24%	11.90%
Kroger Co/The	KR	719.32	44.75	2.59	4.55	32,189.39	0.09%	0.24%	0.42%
Lennar Corp	LEN	250.15	112.23	1.34	-3.15	28,074.56	0.08%	0.11%	-0.25%
Eli Lilly & Co	LLY	949.30	537.13	0.84	22.03	509,894.82	1.45%	1.22%	31.89%
Bath & Body Works Inc	BBWI	227.38	33.80	2.37	11.38	7,685.48	0.02%	0.05%	0.25%
Charter Communications Inc	CHTR	149.67	439.82	n/a	14.90	65,828.30	0.19%		2.78%
Loews Corp	L	225.51	63.31	0.39	n/a	0.00	0.00%	0.00%	
Lowe's Cos Inc	LOW	577.12	207.84	2.12	20.64	119,947.58	0.34%	0.72%	7.03%
IDEX Corp	IEX	75.60	208.02	1.23	10.00	15,726.73	0.04%	0.05%	0.45%
Marsh & McLennan Cos Inc	MMC	493.95	190.30	1.49	10.66	93,999.45	0.27%	0.40%	2.85%
Masco Corp	MAS	224.93	53.45	2.13	6.74	12,022.29	0.03%	0.07%	0.23%
S&P Global Inc	SPGI	318.20	365.41	0.99	13.72	116,273.46	0.33%	0.33%	4.53%
Medtronic PLC	MDT	1330.53	78.36	3.52	3.17	104,260.64	0.30%	1.04%	0.94%
Viatris Inc	VTRS	1199.53	9.86	4.87	-2.18	11,827.39	0.03%	0.16%	-0.07%
CVS Health Corp	CVS	1284.40	69.82	3.47	7.13	89,676.74	0.25%	0.88%	1.82%
DuPont de Nemours Inc	DD	459.06	74.59	1.93	12.85	34,241.36	0.10%	0.19%	1.25%
Micron Technology Inc	MU	1095.30	68.03	0.68	-11.00	74,513.40	0.21%	0.14%	-2.33%
Motorola Solutions Inc	MSI	167.02	272.24	1.29	n/a	0.00	0.00%	0.00%	
Cboe Global Markets Inc	CBOE	105.52	156.21	1.41	6.53	16,482.81	0.05%	0.07%	0.31%
Laboratory Corp of America Holdings	LH	88.60	201.05	1.43	n/a	0.00	0.00%	0.00%	
Newmont Corp	NEM	794.80	36.95	4.33	11.86	29,367.71	0.08%	0.36%	0.99%
NIKE Inc	NKE	1225.07	95.62	1.42	16.07	117,141.58	0.33%	0.47%	5.34%
NiSource Inc	NI	413.26	24.68	4.05	7.50	10,199.13	0.03%	0.12%	0.22%
Norfolk Southern Corp	NSC	227.02	196.93	2.74	4.34	44,706.06	0.13%	0.35%	0.55%
Principal Financial Group Inc	PFG	241.72	72.07	3.61	7.38	17,420.40	0.05%	0.18%	0.37%
Eversource Energy	ES	349.09	58.15	4.64	4.99	20,299.35	0.06%	0.27%	0.29%
Northrop Grumman Corp	NOC	151.30	440.19	1.70	4.06	66,600.75	0.19%	0.32%	0.77%
Wells Fargo & Co	WFC	3667.70	40.86	3.43	13.41	149,862.22	0.43%	1.46%	5.71%
Nucor Corp	NUE	248.72	156.35	1.30	n/a	0.00	0.00%	0.00%	
Occidental Petroleum Corp	OXY	884.68	64.88	1.11	-13.00	57,398.17	0.16%	0.18%	-2.12%
Omnicom Group Inc	OMC	197.57	74.48	3.76	6.41	14,715.09	0.04%	0.16%	0.27%
ONEOK Inc	OKE	582.47	63.43	6.02	7.08	36,946.26	0.10%	0.63%	0.74%
Raymond James Financial Inc	RJF	208.84	100.43	1.67	13.95	20,974.00	0.06%	0.10%	0.83%
PG&E Corp	PCG	2091.24	16.13	n/a	9.45	33,731.72	0.10%		0.91%
Parker-Hannifin Corp	PH	128.51	389.52	1.52	14.56	50,057.22	0.14%	0.22%	2.07%
Rollins Inc	ROL	484.10	37.33	1.39	13.72	18,071.34	0.05%	0.07%	0.70%
PPL Corp	PPL	737.09	23.56	4.07	5.20	17,365.82	0.05%	0.20%	0.26%
ConocoPhillips	COP	1197.49	119.80	0.50	-0.50	143,459.42	0.41%	0.20%	-0.20%
PulteGroup Inc	PHM	219.45	74.05	0.86	-3.91	16,249.90	0.05%	0.04%	-0.18%
Pinnacle West Capital Corp	PNW	113.31	73.68	4.70	6.46	8,348.83	0.02%	0.11%	0.15%
PNC Financial Services Group Inc/The	PNC	398.26	122.77	5.05	-0.12	48,893.77	0.14%	0.70%	-0.02%
PPG Industries Inc	PPG	235.51	129.80	2.00	11.30	30,569.59	0.09%	0.17%	0.98%
Progressive Corp/The	PGR	585.10	139.30	0.29	38.67	81,504.43	0.23%	0.07%	8.95%
Public Service Enterprise Group Inc	PEG	499.11	56.91	4.01	6.73	28,404.41	0.08%	0.32%	0.54%
Robert Half Inc	RHI	107.08	73.28	2.62	0.78	7,846.97	0.02%	0.06%	0.02%
Cooper Cos Inc/The	COO	49.52	318.01	0.02	7.00	15,749.13	0.04%	0.00%	0.31%
Edison International	EIX	383.29	63.29	4.66	4.80	24,258.36	0.07%	0.32%	0.33%
Schlumberger NV	SLB	1421.19	58.30	1.72	27.56	82,855.14	0.24%	0.40%	6.48%
Charles Schwab Corp/The	SCHW	1770.22	54.90	1.82	5.31	97,185.08	0.28%	0.50%	1.47%
Sherwin-Williams Co/The	SHW	257.15	255.05	0.95	8.49	65,585.85	0.19%	0.18%	1.58%
West Pharmaceutical Services Inc	WST	73.86	375.21	0.20	n/a	0.00	0.00%	0.00%	
J M Smucker Co/The	SJM	102.14	122.91	3.45	6.09	12,554.27	0.04%	0.12%	0.22%
Snap-on Inc	SNA	52.92	255.06	2.54	4.87	13,497.01	0.04%	0.10%	0.19%
AMETEK Inc	AME	230.71	147.76	0.68	9.74	34,090.01	0.10%	0.07%	0.94%
Southern Co/The	SO	1091.52	64.72	4.33	6.08	70,642.85	0.20%	0.87%	1.22%
Truist Financial Corp	TFC	1331.98	28.61	7.27	4.13	38,107.83	0.11%	0.79%	0.45%
Southwest Airlines Co	LUV	595.63	27.07	2.66	20.35	16,123.81	0.05%	0.12%	0.93%
W R Berkley Corp	WRB	257.52	63.49	0.69	12.50	16,350.14	0.05%	0.03%	0.58%
Stanley Black & Decker Inc	SWK	153.23	83.58	3.88	n/a	0.00	0.00%	0.00%	
Public Storage	PSA	175.83	263.52	4.55	3.73	46,334.46	0.13%	0.60%	0.49%
Arista Networks Inc	ANET	309.58	183.93	n/a	19.35	56,941.23	0.16%		3.13%
Sysco Corp	SYY	504.93	66.05	3.03	n/a	0.00	0.00%	0.00%	
Corteva Inc	CTVA	709.52	51.16	1.25	17.92	36,298.84	0.10%	0.13%	1.85%
Texas Instruments Inc	TXN	907.97	159.01	3.27	7.80	144,375.67	0.41%	1.34%	3.20%
Textron Inc	TXT	198.07	78.14	0.10	11.73	15,477.27	0.04%	0.00%	0.52%
Thermo Fisher Scientific Inc	TMO	385.95	506.17	0.28	n/a	0.00	0.00%	0.00%	
TJX Cos Inc/The	TJX	1144.08	88.88	1.50	10.00	101,685.92	0.29%	0.43%	2.89%
Globe Life Inc	GL	94.82	108.73	0.83	n/a	0.00	0.00%	0.00%	
Johnson Controls International plc	JCI	680.32	53.21	2.78	13.81	36,199.83	0.10%	0.29%	1.42%
Ulta Beauty Inc	ULTA	49.23	399.45	n/a	6.54	19,664.52	0.06%		0.37%
Union Pacific Corp	UNP	609.46	203.63	2.55	6.50	124,103.53	0.35%	0.90%	2.29%
Keysight Technologies Inc	KEYS	177.58	132.31	n/a	2.52	23,494.95	0.07%		0.17%
UnitedHealth Group Inc	UNH	926.31	504.19	1.49	11.90	467,033.72	1.33%	1.98%	15.77%
Blackstone Inc	BX	709.75	107.14	2.95	10.52	76,042.62	0.22%	0.64%	2.27%
Marathon Oil Corp	MRO	605.69	26.75	1.50	-10.00	16,202.13	0.05%	0.07%	-0.46%
Bio-Rad Laboratories Inc	BIO	24.00	358.45	n/a	6.00	8,604.23	0.02%		0.15%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Bloomberg Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Ventas Inc	VTR	402.38	42.13	4.27	8.12	16,952.19	0.05%	0.21%	0.39%
VF Corp	VFC	388.87	17.67	6.79	11.54	6,871.30	0.02%	0.13%	0.23%
Vulcan Materials Co	VMC	132.87	202.02	0.85	22.92	26,841.59	0.08%	0.06%	1.75%
Weyerhaeuser Co	WY	730.75	30.66	2.48	n/a	0.00	0.00%	0.00%	
Whirlpool Corp	WHR	54.82	133.70	5.24	-1.35	7,329.17	0.02%	0.11%	-0.03%
Williams Cos Inc/The	WMB	1216.42	33.69	5.31	3.50	40,981.22	0.12%	0.62%	0.41%
Constellation Energy Corp	CEG	321.59	109.08	1.03	23.30	35,079.26	0.10%	0.10%	2.32%
WEC Energy Group Inc	WEC	315.44	80.55	3.87	6.40	25,408.29	0.07%	0.28%	0.46%
Adobe Inc	ADBE	455.30	509.90	n/a	14.66	232,157.47	0.66%		9.66%
AES Corp/The	AES	669.63	15.20	4.37	n/a	0.00	0.00%	0.00%	
Amgen Inc	AMGN	534.90	268.76	3.17	5.00	143,759.99	0.41%	1.29%	2.04%
Apple Inc	AAPL	15634.23	171.21	0.56	10.57	2,676,736.86	7.60%	4.26%	80.31%
Autodesk Inc	ADSK	213.76	206.91	n/a	13.86	44,229.91	0.13%		1.74%
Cintas Corp	CTAS	101.93	481.01	1.12	11.86	49,027.91	0.14%	0.16%	1.65%
Comcast Corp	CMCSA	4115.69	44.34	2.62	8.65	182,489.65	0.52%	1.36%	4.48%
Molson Coors Beverage Co	TAP	200.96	63.59	2.58	7.07	12,779.05	0.04%	0.09%	0.26%
KLA Corp	KLAC	136.32	458.66	1.13	9.27	62,525.45	0.18%	0.20%	1.64%
Marriott International Inc/MD	MAR	298.24	196.56	1.06	16.65	58,622.05	0.17%	0.18%	2.77%
Fiserv Inc	FI	609.62	112.96	n/a	14.35	68,862.11	0.20%		2.81%
McCormick & Co Inc/MD	MKC	251.10	75.64	2.06	7.01	18,993.20	0.05%	0.11%	0.38%
PACCAR Inc	PCAR	522.81	85.02	1.27	12.00	44,448.88	0.13%	0.16%	1.51%
Costco Wholesale Corp	COST	442.79	564.96	0.72	13.06	250,160.33	0.71%	0.51%	9.27%
Stryker Corp	SYK	379.78	273.27	1.10	7.26	103,781.93	0.29%	0.32%	2.14%
Tyson Foods Inc	TSN	285.55	50.49	3.80	-22.91	14,417.42	0.04%	0.16%	-0.94%
Lamb Weston Holdings Inc	LW	145.67	92.46	1.21	10.89	13,468.37	0.04%	0.05%	0.42%
Applied Materials Inc	AMAT	836.53	138.45	0.92	3.73	115,818.13	0.33%	0.30%	1.23%
American Airlines Group Inc	AAL	653.36	12.81	n/a	n/a	0.00	0.00%		
Cardinal Health Inc	CAH	246.35	86.82	2.31	n/a	0.00	0.00%	0.00%	
Cincinnati Financial Corp	CINF	156.86	102.29	2.93	17.66	16,044.80	0.05%	0.13%	0.80%
Paramount Global	PARA	610.40	12.90	1.55	5.71	7,874.15	0.02%	0.03%	0.13%
DR Horton Inc	DHI	338.30	107.47	0.93	-8.43	36,356.78	0.10%	0.10%	-0.87%
Electronic Arts Inc	EA	270.91	120.40	0.63	5.64	32,617.80	0.09%	0.06%	0.52%
Fair Isaac Corp	FICO	24.86	868.53	n/a	n/a	0.00	0.00%		
Expeditors International of Washington Inc	EXPD	147.90	114.63	1.20	n/a	0.00	0.00%	0.00%	
Fastenal Co	FAST	571.33	54.64	2.56	n/a	0.00	0.00%	0.00%	
M&T Bank Corp	MTB	165.95	126.45	4.11	11.10	20,984.25	0.06%	0.25%	0.66%
Xcel Energy Inc	XEL	551.53	57.22	3.64	6.15	31,558.72	0.09%	0.33%	0.55%
Fifth Third Bancorp	FITB	680.89	25.33	5.53	25.00	17,246.92	0.05%	0.27%	1.22%
Gilead Sciences Inc	GILD	1246.01	74.94	4.00	2.15	93,376.29	0.27%	1.06%	0.57%
Hasbro Inc	HAS	138.74	66.14	4.23	8.64	9,176.33	0.03%	0.11%	0.22%
Huntington Bancshares Inc/OH	HBAN	1447.88	10.40	5.96	-5.65	15,057.97	0.04%	0.25%	-0.24%
Welltower Inc	WELL	518.73	81.92	2.98	10.72	42,494.28	0.12%	0.36%	1.29%
Biogen Inc	BIIB	144.82	257.01	n/a	0.06	37,220.96	0.11%		0.01%
Northern Trust Corp	NTRS	207.00	69.48	4.32	13.00	14,382.64	0.04%	0.18%	0.53%
Packaging Corp of America	PKG	89.92	153.55	3.26	3.00	13,806.45	0.04%	0.13%	0.12%
Paychex Inc	PAYX	361.23	115.33	3.09	7.00	41,660.89	0.12%	0.37%	0.83%
QUALCOMM Inc	QCOM	1116.00	111.06	2.88	-5.69	123,942.96	0.35%	1.01%	-2.00%
Ross Stores Inc	ROST	338.63	112.95	1.19	10.00	38,248.48	0.11%	0.13%	1.09%
IDEXX Laboratories Inc	IDXX	83.01	437.27	n/a	17.57	36,298.66	0.10%		1.81%
Starbucks Corp	SBUX	1145.40	91.27	2.50	19.71	104,540.66	0.30%	0.74%	5.85%
KeyCorp	KEY	935.92	10.76	7.62	7.48	10,070.49	0.03%	0.22%	0.21%
Fox Corp	FOXA	253.68	31.20	1.67	6.24	7,914.94	0.02%	0.04%	0.14%
Fox Corp	FOX	235.58	28.88	1.80	6.24	6,803.58	0.02%	0.03%	0.12%
State Street Corp	STT	318.64	66.96	4.12	1.31	21,336.13	0.06%	0.25%	0.08%
Norwegian Cruise Line Holdings Ltd	NCLH	425.42	16.48	n/a	n/a	0.00	0.00%		
US Bancorp	USB	1556.97	33.06	5.81	8.00	51,473.26	0.15%	0.85%	1.17%
A O Smith Corp	AOS	124.59	66.13	1.81	n/a	0.00	0.00%	0.00%	
Gen Digital Inc	GEN	639.44	17.68	2.83	n/a	0.00	0.00%	0.00%	
T Rowe Price Group Inc	TROW	224.30	104.87	4.65	-0.18	23,521.82	0.07%	0.31%	-0.01%
Waste Management Inc	WM	405.06	152.44	1.84	9.80	61,747.19	0.18%	0.32%	1.72%
Constellation Brands Inc	STZ	183.30	251.33	1.42	9.73	46,069.04	0.13%	0.19%	1.27%
DENTSPLY SIRONA Inc	XRAY	211.72	34.16	1.64	9.78	7,232.22	0.02%	0.03%	0.20%
Zions Bancorp NA	ZION	148.15	34.89	4.70	-3.00	5,168.78	0.01%	0.07%	-0.04%
Alaska Air Group Inc	ALK	127.22	37.08	n/a	4.62	4,717.47	0.01%		0.06%
Invesco Ltd	IVZ	448.62	14.52	5.51	4.26	6,513.98	0.02%	0.10%	0.08%
Intuit Inc	INTU	280.26	510.94	0.70	18.84	143,195.53	0.41%	0.29%	7.66%
Morgan Stanley	MS	1656.97	81.67	4.16	3.76	135,324.49	0.38%	1.60%	1.44%
Microchip Technology Inc	MCHP	544.33	78.05	2.10	12.06	42,485.27	0.12%	0.25%	1.45%
Chubb Ltd	CB	410.74	208.18	1.65	14.50	85,506.81	0.24%	0.40%	3.52%
Hologic Inc	HOLX	244.94	69.40	n/a	-14.09	16,998.97	0.05%		-0.68%
Citizens Financial Group Inc	CFG	472.29	26.80	6.27	-6.14	12,657.48	0.04%	0.23%	-0.22%
O'Reilly Automotive Inc	ORLY	60.26	908.86	n/a	12.13	54,766.09	0.16%		1.89%
Allstate Corp/The	ALL	261.57	111.41	3.20	-4.00	29,141.96	0.08%	0.26%	-0.33%
Equity Residential	EQR	379.03	58.71	4.51	5.68	22,252.97	0.06%	0.29%	0.36%
BorgWarner Inc	BWA	235.06	40.37	1.09	5.31	9,489.49	0.03%	0.03%	0.14%
Keurig Dr Pepper Inc	KDP	1397.26	31.57	2.72	6.35	44,111.47	0.13%	0.34%	0.79%
Organon & Co	OGN	255.57	17.36	6.45	7.34	4,436.66	0.01%	0.08%	0.09%
Host Hotels & Resorts Inc	HST	711.61	16.07	4.48	n/a	0.00	0.00%	0.00%	
Incyte Corp	INCY	224.09	57.77	n/a	65.18	12,945.56	0.04%		2.40%
Simon Property Group Inc	SPG	327.19	108.03	7.04	1.70	35,346.44	0.10%	0.71%	0.17%
Eastman Chemical Co	EMN	118.56	76.72	4.12	5.43	9,095.62	0.03%	0.11%	0.14%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Bloomberg Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
AvalonBay Communities Inc	AVB	142.02	171.74	3.84	10.30	24,389.83	0.07%	0.27%	0.71%
Prudential Financial Inc	PRU	363.00	94.89	5.27	11.13	34,445.07	0.10%	0.52%	1.09%
United Parcel Service Inc	UPS	723.28	155.87	4.16	-4.03	112,737.03	0.32%	1.33%	-1.29%
Walgreens Boots Alliance Inc	WBA	863.26	22.24	8.63	-6.57	19,198.92	0.05%	0.47%	-0.36%
STERIS PLC	STE	98.78	219.42	0.95	n/a	0.00	0.00%	0.00%	
McKesson Corp	MCK	134.90	434.85	0.57	10.03	58,662.13	0.17%	0.09%	1.67%
Lockheed Martin Corp	LMT	251.83	408.96	2.93	6.98	102,988.81	0.29%	0.86%	2.04%
Cencora Inc	COR	202.18	179.97	1.08	9.44	36,385.43	0.10%	0.11%	0.98%
Capital One Financial Corp	COF	381.44	97.05	2.47	-2.91	37,018.85	0.11%	0.26%	-0.31%
Waters Corp	WAT	59.10	274.21	n/a	5.79	16,206.63	0.05%		0.27%
Nordson Corp	NDSN	57.01	223.17	1.22	n/a	0.00	0.00%	0.00%	
Dollar Tree Inc	DLTR	220.01	106.45	n/a	7.37	23,419.64	0.07%		0.49%
Darden Restaurants Inc	DRI	120.32	143.22	3.66	10.45	17,231.51	0.05%	0.18%	0.51%
Evergy Inc	EVRG	229.58	50.70	4.83	4.70	11,639.86	0.03%	0.16%	0.16%
Match Group Inc	MTCH	278.09	39.18	n/a	62.00	10,894.06	0.03%		1.92%
Domino's Pizza Inc	DPZ	35.09	378.79	1.28	13.94	13,293.26	0.04%	0.05%	0.53%
NVR Inc	NVR	3.26	5963.30	n/a	-3.60	19,464.21	0.06%		-0.20%
NetApp Inc	NTAP	208.79	75.88	2.64	7.40	15,843.06	0.04%	0.12%	0.33%
DXC Technology Co	DXC	205.17	20.83	n/a	6.84	4,273.77	0.01%		0.08%
Old Dominion Freight Line Inc	ODFL	109.27	409.14	0.39	4.80	44,705.91	0.13%	0.05%	0.61%
DaVita Inc	DVA	91.30	94.53	n/a	15.78	8,630.59	0.02%		0.39%
Hartford Financial Services Group Inc/The	HIG	305.82	70.91	2.40	7.00	21,685.48	0.06%	0.15%	0.43%
Iron Mountain Inc	IRM	291.85	59.45	4.37	4.00	17,350.60	0.05%	0.22%	0.20%
Estee Lauder Cos Inc/The	EL	232.30	144.55	1.83	8.40	33,578.53	0.10%	0.17%	0.80%
Cadence Design Systems Inc	CDNS	271.79	234.30	n/a	19.00	63,680.40	0.18%		3.43%
Tyler Technologies Inc	TYL	42.08	386.14	n/a	n/a	0.00	0.00%		
Universal Health Services Inc	UHS	62.14	125.73	0.64	8.91	7,812.86	0.02%	0.01%	0.20%
Skyworks Solutions Inc	SWKS	159.39	98.59	2.76	4.99	15,714.56	0.04%	0.12%	0.22%
Quest Diagnostics Inc	DGX	112.24	121.86	2.33	-0.67	13,676.96	0.04%	0.09%	-0.03%
Activision Blizzard Inc	ATVI	786.80	93.63	1.06	7.00	73,667.90	0.21%	0.22%	1.46%
Rockwell Automation Inc	ROK	114.86	285.87	1.65	15.59	32,835.03	0.09%	0.15%	1.45%
Kraft Heinz Co/The	KHC	1228.30	33.64	4.76	3.92	41,319.84	0.12%	0.56%	0.46%
American Tower Corp	AMT	466.16	164.45	3.94	13.29	76,659.35	0.22%	0.86%	2.89%
Regeneron Pharmaceuticals Inc	REGN	106.74	822.96	n/a	3.33	87,843.57	0.25%		0.83%
Amazon.com Inc	AMZN	10317.75	127.12	n/a	51.21	1,311,592.51	3.72%		190.72%
Jack Henry & Associates Inc	JKHY	72.94	151.14	1.38	7.52	11,023.40	0.03%	0.04%	0.24%
Ralph Lauren Corp	RL	40.39	116.09	2.58	10.82	4,688.64	0.01%	0.03%	0.14%
Boston Properties Inc	BXP	156.87	59.48	6.59	3.79	9,330.33	0.03%	0.17%	0.10%
Amphenol Corp	APH	596.45	83.99	1.00	5.46	50,096.17	0.14%	0.14%	0.78%
Howmet Aerospace Inc	HWM	412.21	46.25	0.43	19.27	19,064.62	0.05%	0.02%	1.04%
Pioneer Natural Resources Co	PXD	233.14	229.55	3.21	-0.73	53,517.52	0.15%	0.49%	-0.11%
Valero Energy Corp	VLO	353.13	141.71	2.88	-7.69	50,042.48	0.14%	0.41%	-1.09%
Synopsys Inc	SNPS	152.08	458.97	n/a	16.27	69,801.99	0.20%		3.22%
Etsy Inc	ETSY	123.01	64.58	n/a	8.15	7,944.24	0.02%		0.18%
CH Robinson Worldwide Inc	CHRW	116.44	86.13	2.83	5.00	10,028.89	0.03%	0.08%	0.14%
Accenture PLC	ACN	630.80	307.11	1.68	10.00	193,723.45	0.55%	0.92%	5.50%
TransDigm Group Inc	TDG	55.18	843.13	n/a	26.65	46,526.44	0.13%		3.52%
Yum! Brands Inc	YUM	280.21	124.94	1.94	11.45	35,009.56	0.10%	0.19%	1.14%
Prologis Inc	PLD	923.86	112.21	3.10	8.95	103,666.56	0.29%	0.91%	2.63%
FirstEnergy Corp	FE	573.36	34.18	4.80	-6.66	19,597.51	0.06%	0.27%	-0.37%
VeriSign Inc	VRSN	103.13	202.53	n/a	12.30	20,887.73	0.06%		0.73%
Quanta Services Inc	PWR	145.20	187.07	0.17	8.00	27,162.38	0.08%	0.01%	0.62%
Henry Schein Inc	HSIC	130.59	74.25	n/a	5.16	9,695.94	0.03%		0.14%
Ameren Corp	AEE	262.48	74.83	3.37	n/a	0.00	0.00%	0.00%	
ANSYS Inc	ANSS	86.79	297.55	n/a	11.14	25,824.66	0.07%		0.82%
FactSet Research Systems Inc	FDS	38.15	437.26	0.90	10.45	16,679.72	0.05%	0.04%	0.49%
NVIDIA Corp	NVDA	2470.00	434.99	0.04	35.00	1,074,425.30	3.05%	0.11%	106.77%
Sealed Air Corp	SEE	144.41	32.86	2.43	0.93	4,745.31	0.01%	0.03%	0.01%
Cognizant Technology Solutions Corp	CTSH	505.04	67.74	1.71	12.00	34,211.48	0.10%	0.17%	1.17%
Intuitive Surgical Inc	ISRG	351.36	292.29	n/a	16.12	102,697.55	0.29%		4.70%
Take-Two Interactive Software Inc	TTWO	169.83	140.39	n/a	54.11	23,842.57	0.07%		3.66%
Republic Services Inc	RSG	316.33	142.51	1.50	9.26	45,079.62	0.13%	0.19%	1.19%
eBay Inc	EBAY	532.16	44.09	2.27	6.50	23,462.80	0.07%	0.15%	0.43%
Goldman Sachs Group Inc/The	GS	329.67	323.57	3.40	9.00	106,671.65	0.30%	1.03%	2.72%
SBA Communications Corp	SBAC	108.38	200.17	1.70	8.00	21,695.03	0.06%	0.10%	0.49%
Sempra	SRE	629.31	68.03	3.50	4.49	42,811.76	0.12%	0.43%	0.55%
Moody's Corp	MCO	183.50	316.17	0.97	13.87	58,017.20	0.16%	0.16%	2.28%
ON Semiconductor Corp	ON	431.53	92.95	n/a	8.50	40,110.62	0.11%		0.97%
Booking Holdings Inc	BKNG	35.69	3083.95	n/a	20.00	110,072.34	0.31%		6.25%
F5 Inc	FFIV	59.31	161.14	n/a	10.19	9,556.57	0.03%		0.28%
Akamai Technologies Inc	AKAM	151.71	106.54	n/a	10.72	16,163.50	0.05%		0.49%
Charles River Laboratories International Inc	CRL	51.27	195.98	n/a	11.00	10,048.09	0.03%		0.31%
MarketAxess Holdings Inc	MKTX	37.68	213.64	1.35	n/a	0.00	0.00%	0.00%	
Devon Energy Corp	DVN	640.70	47.70	4.11	-4.00	30,561.39	0.09%	0.36%	-0.35%
Bio-Techne Corp	TECH	158.24	68.07	0.47	n/a	0.00	0.00%	0.00%	
Alphabet Inc	GOOGL	5933.00	130.86	n/a	18.01	776,392.38	2.20%		39.70%
Teleflex Inc	TFX	46.99	196.41	0.69	7.03	9,229.70	0.03%	0.02%	0.18%
Bunge Ltd	BG	150.64	108.25	2.45	-5.14	16,307.00	0.05%	0.11%	-0.24%
Allegion plc	ALLE	87.78	104.20	1.73	5.43	9,146.68	0.03%	0.04%	0.14%
Netflix Inc	NFLX	443.15	377.60	n/a	32.28	167,332.31	0.48%		15.33%
Agilent Technologies Inc	A	292.59	111.82	0.80	11.00	32,717.08	0.09%	0.07%	1.02%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Bloomberg Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Warner Bros Discovery Inc	WBD	2437.38	10.86	n/a	n/a	0.00	0.00%		
Elevance Health Inc	ELV	235.65	435.42	1.36	12.13	102,605.85	0.29%	0.40%	3.53%
Trimble Inc	TRMB	248.32	53.86	n/a	n/a	0.00	0.00%		
CME Group Inc	CME	359.75	200.22	2.20	8.61	72,028.34	0.20%	0.45%	1.76%
Juniper Networks Inc	JNPR	321.36	27.79	3.17	7.89	8,930.59	0.03%	0.08%	0.20%
BlackRock Inc	BLK	149.30	646.49	3.09	9.20	96,522.90	0.27%	0.85%	2.52%
DTE Energy Co	DTE	206.11	99.28	3.84	n/a	0.00	0.00%	0.00%	
Nasdaq Inc	NDAQ	491.32	48.59	1.81	2.68	23,873.04	0.07%	0.12%	0.18%
Celanese Corp	CE	108.85	125.52	2.23	3.07	13,663.10	0.04%	0.09%	0.12%
Philip Morris International Inc	PM	1552.35	92.58	5.62	6.04	143,716.10	0.41%	2.29%	2.46%
Salesforce Inc	CRM	973.00	202.78	n/a	21.67	197,304.94	0.56%		12.14%
Ingersoll Rand Inc	IR	404.40	63.72	0.13	n/a	0.00	0.00%	0.00%	
Roper Technologies Inc	ROP	106.71	484.28	0.56	n/a	0.00	0.00%	0.00%	
Huntington Ingalls Industries Inc	HII	39.87	204.58	2.42	40.00	8,156.20	0.02%	0.06%	0.93%
MetLife Inc	MET	752.02	62.91	3.31	13.07	47,309.70	0.13%	0.44%	1.76%
Tapestry Inc	TPR	227.44	28.75	4.87	15.00	6,538.87	0.02%	0.09%	0.28%
CSX Corp	CSX	2006.33	30.75	1.43	3.91	61,694.65	0.18%	0.25%	0.68%
Edwards Lifesciences Corp	EW	607.92	69.28	n/a	10.65	42,116.42	0.12%		1.27%
Ameriprise Financial Inc	AMP	102.63	329.68	1.64	17.59	33,833.74	0.10%	0.16%	1.69%
Zebra Technologies Corp	ZBRA	51.34	236.53	n/a	n/a	0.00	0.00%		
Zimmer Biomet Holdings Inc	ZBH	208.96	112.22	0.86	9.48	23,449.94	0.07%	0.06%	0.63%
CBRE Group Inc	CBRE	309.84	73.86	n/a	n/a	0.00	0.00%		
Camden Property Trust	CPT	106.77	94.58	4.23	7.34	10,098.40	0.03%	0.12%	0.21%
Mastercard Inc	MA	934.85	395.91	0.58	18.18	370,115.67	1.05%	0.61%	19.10%
CarMax Inc	KMX	158.67	70.73	n/a	15.54	11,222.59	0.03%		0.50%
Intercontinental Exchange Inc	ICE	594.94	110.02	1.53	9.87	65,454.86	0.19%	0.28%	1.83%
Fidelity National Information Services Inc	FIS	592.47	55.27	3.76	2.68	32,745.54	0.09%	0.35%	0.25%
Chipotle Mexican Grill Inc	CMG	27.59	1831.83	n/a	26.95	50,536.53	0.14%		3.87%
Wynn Resorts Ltd	WYNN	113.94	92.41	1.08	n/a	0.00	0.00%	0.00%	
Live Nation Entertainment Inc	LYV	230.15	83.04	n/a	n/a	0.00	0.00%		
Assurant Inc	AIZ	53.02	143.58	1.95	13.79	7,613.04	0.02%	0.04%	0.30%
NRG Energy Inc	NRG	229.12	38.52	3.92	4.03	8,825.59	0.03%	0.10%	0.10%
Regions Financial Corp	RF	938.38	17.20	5.58	2.08	16,140.08	0.05%	0.26%	0.10%
Monster Beverage Corp	MNST	1047.52	52.95	n/a	15.05	55,466.08	0.16%		2.37%
Mosaic Co/The	MOS	332.28	35.60	2.25	22.93	11,829.17	0.03%	0.08%	0.77%
Baker Hughes Co	BKR	1009.65	35.32	2.27	57.62	35,660.98	0.10%	0.23%	5.83%
Expedia Group Inc	EXPE	137.84	103.07	n/a	17.50	14,207.27	0.04%		0.71%
CF Industries Holdings Inc	CF	192.95	85.74	1.87	44.50	16,543.36	0.05%	0.09%	2.09%
Leidos Holdings Inc	LDOS	137.35	92.16	1.56	6.45	12,658.27	0.04%	0.06%	0.23%
APA Corp	APA	307.27	41.10	2.43	-3.33	12,628.59	0.04%	0.09%	-0.12%
Alphabet Inc	GOOG	5801.00	131.85	n/a	18.01	764,861.85	2.17%		39.11%
First Solar Inc	FSLR	106.83	161.59	n/a	35.70	17,262.82	0.05%		1.75%
TE Connectivity Ltd	TEL	313.94	123.53	1.91	3.10	38,780.88	0.11%	0.21%	0.34%
Discover Financial Services	DFS	249.95	86.63	3.23	7.04	21,653.00	0.06%	0.20%	0.43%
Linde PLC	LIN	487.95	372.35	1.37	9.20	181,686.69	0.52%	0.71%	4.75%
Visa Inc	V	1606.79	230.01	0.78	14.91	369,577.31	1.05%	0.82%	15.64%
Mid-America Apartment Communities Inc	MAA	116.68	128.65	4.35	3.79	15,010.50	0.04%	0.19%	0.16%
Xylem Inc/NY	XYL	240.83	91.03	1.45	n/a	0.00	0.00%	0.00%	
Marathon Petroleum Corp	MPC	399.84	151.34	1.98	83.00	60,512.39	0.17%	0.34%	14.26%
Tractor Supply Co	TSCO	108.81	203.05	2.03	10.00	22,093.46	0.06%	0.13%	0.63%
Advanced Micro Devices Inc	AMD	1615.67	102.82	n/a	26.26	166,123.29	0.47%		12.38%
ResMed Inc	RMD	147.07	147.87	1.30	7.83	21,747.39	0.06%	0.08%	0.48%
Mettler-Toledo International Inc	MTD	21.87	1108.07	n/a	9.75	24,227.95	0.07%		0.67%
Jacobs Solutions Inc	J	125.92	136.50	0.76	9.26	17,187.81	0.05%	0.04%	0.45%
Copart Inc	CPRT	957.36	43.09	n/a	n/a	0.00	0.00%		
VICI Properties Inc	VICI	1013.43	29.10	5.70	10.67	29,490.75	0.08%	0.48%	0.89%
Albemarle Corp	ALB	117.35	170.04	0.94	31.93	19,953.68	0.06%	0.05%	1.81%
Fortinet Inc	FTNT	785.34	58.68	n/a	18.00	46,083.58	0.13%		2.36%
Moderna Inc	MRNA	380.59	103.29	n/a	-60.35	39,311.45	0.11%		-6.74%
Essex Property Trust Inc	ESS	64.18	212.09	4.36	9.80	13,612.57	0.04%	0.17%	0.38%
CoStar Group Inc	CSGP	408.34	76.89	n/a	20.00	31,397.03	0.09%		1.78%
Realty Income Corp	O	708.79	49.94	6.15	7.00	35,396.87	0.10%	0.62%	0.70%
Westrock Co	WRK	256.40	35.80	3.07	5.00	9,179.23	0.03%	0.08%	0.13%
Westinghouse Air Brake Technologies Corp	WAB	179.13	106.27	0.64	11.33	19,036.15	0.05%	0.03%	0.61%
Pool Corp	POOL	39.05	356.10	1.24	-4.92	13,906.42	0.04%	0.05%	-0.19%
Western Digital Corp	WDC	321.90	45.63	n/a	-22.46	14,688.11	0.04%		-0.94%
PepsiCo Inc	PEP	1376.58	169.44	2.99	8.64	233,247.88	0.66%	1.98%	5.72%
Diamondback Energy Inc	FANG	178.82	154.88	2.17	8.97	27,695.33	0.08%	0.17%	0.71%
Palo Alto Networks Inc	PANW	308.60	234.44	n/a	20.50	72,347.01	0.21%		4.21%
ServiceNow Inc	NOW	204.00	558.96	n/a	30.00	114,027.84	0.32%		9.71%
Church & Dwight Co Inc	CHD	246.05	91.63	1.19	5.85	22,545.29	0.06%	0.08%	0.37%
Federal Realty Investment Trust	FRT	81.52	90.63	4.81	6.85	7,388.43	0.02%	0.10%	0.14%
MGM Resorts International	MGM	350.89	36.76	n/a	n/a	0.00	0.00%		
American Electric Power Co Inc	AEP	515.18	75.22	4.41	n/a	0.00	0.00%	0.00%	
SolarEdge Technologies Inc	SEDG	56.56	129.51	n/a	26.91	7,324.83	0.02%		0.56%
Invitation Homes Inc	INVH	611.96	31.69	3.28	7.47	19,392.89	0.06%	0.18%	0.41%
PTC Inc	PTC	118.83	141.68	n/a	16.99	16,836.26	0.05%		0.81%
JB Hunt Transport Services Inc	JBHT	103.35	188.52	0.89	15.00	19,482.60	0.06%	0.05%	0.83%
Lam Research Corp	LRCX	132.51	626.77	1.28	12.20	83,054.55	0.24%	0.30%	2.88%
Mohawk Industries Inc	MHK	63.68	85.81	n/a	-1.83	5,464.55	0.02%		-0.03%
GE HealthCare Technologies Inc	GEHC	454.84	68.04	0.18	8.93	30,947.18	0.09%	0.02%	0.78%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Bloomberg Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Pentair PLC	PNR	165.11	64.75	1.36	6.14	10,691.07	0.03%	0.04%	0.19%
Vertex Pharmaceuticals Inc	VRTX	258.10	347.74	n/a	13.72	89,749.96	0.25%		3.49%
Amcor PLC	AMCR	1446.44	9.16	5.35	2.20	13,249.36	0.04%	0.20%	0.08%
Meta Platforms Inc	META	2222.58	300.21	n/a	27.44	667,241.64	1.89%		51.98%
T-Mobile US Inc	TMUS	1176.46	140.05	1.86	5.00	164,762.80	0.47%	0.87%	2.34%
United Rentals Inc	URI	68.28	444.57	1.33	20.04	30,356.57	0.09%	0.11%	1.73%
Honeywell International Inc	HON	663.96	184.74	2.34	9.50	122,660.16	0.35%	0.81%	3.31%
Alexandria Real Estate Equities Inc	ARE	173.03	100.10	4.96	4.05	17,320.10	0.05%	0.24%	0.20%
Delta Air Lines Inc	DAL	643.42	37.00	1.08	28.63	23,806.47	0.07%	0.07%	1.94%
Seagate Technology Holdings PLC	STX	207.39	65.95	4.25	1.21	13,677.57	0.04%	0.16%	0.05%
United Airlines Holdings Inc	UAL	326.73	42.30	n/a	n/a	0.00	0.00%		
News Corp	NWS	191.84	20.87	0.96	8.00	4,003.64	0.01%	0.01%	0.09%
Centene Corp	CNC	541.48	68.88	n/a	8.43	37,297.07	0.11%		0.89%
Martin Marietta Materials Inc	MLM	61.80	410.48	0.72	19.03	25,369.31	0.07%	0.05%	1.37%
Teradyne Inc	TER	154.01	100.46	0.44	15.00	15,472.25	0.04%	0.02%	0.66%
PayPal Holdings Inc	PYPL	1098.04	58.46	n/a	15.96	64,191.24	0.18%		2.91%
Tesla Inc	TSLA	3173.99	250.22	n/a	34.50	794,196.78	2.25%		77.80%
Arch Capital Group Ltd	ACGL	372.95	79.71	n/a	14.50	29,728.16	0.08%		1.22%
Dow Inc	DOW	703.08	51.56	5.43	2.78	36,250.55	0.10%	0.56%	0.29%
Everest Group Ltd	EG	43.40	371.67	1.88	33.24	16,131.96	0.05%	0.09%	1.52%
Teledyne Technologies Inc	TDY	47.08	408.58	n/a	6.36	19,233.90	0.05%		0.35%
News Corp	NWSA	379.59	20.06	1.00	8.00	7,614.48	0.02%	0.02%	0.17%
Exelon Corp	EXC	994.30	37.79	3.81	n/a	0.00	0.00%	0.00%	
Global Payments Inc	GPN	259.99	115.39	0.87	13.63	30,000.71	0.09%	0.07%	1.16%
Crown Castle Inc	CCI	433.68	92.03	6.80	n/a	0.00	0.00%	0.00%	
Aptiv PLC	APTV	282.82	98.59	n/a	12.44	27,883.62	0.08%		0.98%
Align Technology Inc	ALGN	76.53	305.32	n/a	17.54	23,367.36	0.07%		1.16%
Illumina Inc	ILMN	158.30	137.28	n/a	-32.22	21,731.42	0.06%		-1.99%
Kenvue Inc	KVUE	1914.89	20.08	3.98	n/a	0.00	0.00%	0.00%	
Targa Resources Corp	TRGP	223.71	85.72	2.33	15.00	19,176.59	0.05%	0.13%	0.82%
LKQ Corp	LKQ	267.56	49.51	2.22	n/a	0.00	0.00%	0.00%	
Zoetis Inc	ZTS	460.32	173.98	0.86	10.91	80,085.95	0.23%	0.20%	2.48%
Equinix Inc	EQIX	93.57	726.26	1.88	15.43	67,952.52	0.19%	0.36%	2.98%
Digital Realty Trust Inc	DLR	302.71	121.02	4.03	6.59	36,633.84	0.10%	0.42%	0.69%
Molina Healthcare Inc	MOH	58.30	327.89	n/a	11.74	19,115.99	0.05%		0.64%
Las Vegas Sands Corp	LVS	764.45	45.84	1.75	n/a	0.00	0.00%	0.00%	

MARKET RISK PREMIUM CALCULATION USING CAP. WEIGHTED VALUE LINE GROWTH RATES

[7] Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.64%
[8] Cap. Weighted Estimate of the S&P 500 Growth Rate	12.44%
[9] Cap. Weighted S&P 500 Estimated Required Market Return	14.19%

Notes:
[7] Source: Bloomberg Professional, as of September 30, 2023
[8] Source: Value Line, as of September 30, 2023
[9] Equals ([7] x (1 + (0.5 x [8]))) + [8]

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
LyondellBasell Industries NV	LYB	324.20	94.70	5.28	2.00	30,701.46	0.09%	0.46%	0.17%
American Express Co	AXP	736.46	149.19	1.61	8.50	109,872.32	0.31%	0.50%	2.63%
Verizon Communications Inc	VZ	4204.04	32.41	8.21	1.50	136,252.94	0.38%	3.15%	0.58%
Broadcom Inc	AVGO	412.74	830.58	2.22	30.00	342,810.27	0.97%	2.14%	28.98%
Boeing Co/The	BA	603.20	191.68	n/a		0.00	0.00%		
Caterpillar Inc	CAT	510.14	273.00	1.90	13.50	139,269.04	0.39%	0.75%	5.30%
JPMorgan Chase & Co	JPM	2906.09	145.02	2.90	8.50	421,440.45	1.19%	3.44%	10.09%
Chevron Corp	CVX	1867.25	168.62	3.58	21.50	314,854.85	0.89%	3.18%	19.07%
Coca-Cola Co/The	KO	4324.35	55.98	3.29	7.50	242,076.83	0.68%	2.24%	5.12%
AbbVie Inc	ABBV	1765.05	149.06	3.97	2.00	263,097.91	0.74%	2.94%	1.48%
Walt Disney Co/The	DIS	1829.78	81.05	n/a	65.00	148,303.59	0.42%		27.16%
FleetCor Technologies Inc	FLT	73.96	255.34	n/a	13.50	18,884.18	0.05%		0.72%
Extra Space Storage Inc	EXR	211.28	121.58	2.01	5.00	25,687.06	0.07%	0.15%	0.36%
Exxon Mobil Corp	XOM	4003.19	117.58	3.10	7.00	470,695.43	1.33%	4.11%	9.28%
Phillips 66	PSX	445.29	120.15	3.50	15.50	53,501.35	0.15%	0.53%	2.34%
General Electric Co	GE	1088.38	110.55	0.29	26.00	120,320.19	0.34%	0.10%	8.81%
HP Inc	HPQ	988.27	25.70	4.09	12.50	25,398.51	0.07%	0.29%	0.89%
Home Depot Inc/The	HD	1000.07	302.16	2.77	6.50	302,179.94	0.85%	2.36%	5.53%
Monolithic Power Systems Inc	MPWR	47.78	462.00	0.87	15.00	22,073.44	0.06%	0.05%	0.93%
International Business Machines Corp	IBM	911.01	140.30	4.73	3.00	127,814.14	0.36%	1.70%	1.08%
Johnson & Johnson	JNJ	2401.49	155.75	3.06	5.00	374,031.29	1.05%	3.22%	5.27%
McDonald's Corp	MCD	728.76	263.44	2.31	10.50	191,985.32	0.54%	1.25%	5.68%
Merck & Co Inc	MRK	2537.52	102.95	2.84	8.50	261,237.79	0.74%	2.09%	6.26%
3M Co	MMM	551.99	93.62	6.41	4.50	51,677.49	0.15%	0.93%	0.66%
American Water Works Co Inc	AWK	194.67	123.83	2.29	3.00	24,105.86	0.07%	0.16%	0.20%
Bank of America Corp	BAC	7946.37	27.38	3.51	0.00	217,571.67	0.61%	2.15%	0.00%
Pfizer Inc	PFE	5645.96	33.17	4.94	2.00	187,276.49	0.53%	2.61%	1.06%
Procter & Gamble Co/The	PG	2356.89	145.86	2.58	5.50	343,776.56	0.97%	2.50%	5.33%
AT&T Inc	T	7149.00	15.02	7.39	1.50	107,377.98	0.30%	2.24%	0.45%
Travelers Cos Inc/The	TRV	228.94	163.31	2.45	7.50	37,388.52	0.11%	0.26%	0.79%
RTX Corp	RTX	1455.52	71.97	3.28	15.00	104,753.41	0.30%	0.97%	4.43%
Analog Devices Inc	ADI	498.31	175.09	1.96	11.50	87,249.80	0.25%	0.48%	2.83%
Walmart Inc	WMT	2691.56	159.93	1.43	6.50	430,461.83	1.21%	1.73%	7.88%
Cisco Systems Inc	CSCO	4054.86	53.76	2.90	8.50	217,989.17	0.61%	1.78%	5.22%
Intel Corp	INTC	4188.00	35.55	1.41		0.00	0.00%	0.00%	
General Motors Co	GM	1375.91	32.97	1.09	8.50	45,363.59	0.13%	0.14%	1.09%
Microsoft Corp	MSFT	7429.76	315.75	0.95	12.50	2,345,947.98	6.61%	6.28%	82.63%
Dollar General Corp	DG	219.48	105.80	2.23	5.50	23,220.56	0.07%	0.15%	0.36%
Cigna Group/The	CI	295.98	286.07	1.72	10.00	84,671.00	0.24%	0.41%	2.39%
Kinder Morgan Inc	KMI	2228.17	16.58	6.82	17.50	36,942.98	0.10%	0.71%	1.82%
Citigroup Inc	C	1925.70	41.13	5.15	3.50	79,204.12	0.22%	1.15%	0.78%
American International Group Inc	AIG	711.90	60.60	2.38	4.00	43,141.14	0.12%	0.29%	0.49%
Altria Group Inc	MO	1774.61	42.05	9.32	6.00	74,622.35	0.21%	1.96%	1.26%
HCA Healthcare Inc	HCA	271.99	245.98	0.98	12.50	66,903.61	0.19%	0.18%	2.36%
International Paper Co	IP	346.00	35.47	5.22	6.00	12,272.58	0.03%	0.18%	0.21%
Hewlett Packard Enterprise Co	HPE	1282.87	17.37	2.76	7.50	22,283.37	0.06%	0.17%	0.47%
Abbott Laboratories	ABT	1735.36	96.85	2.11	4.50	168,069.42	0.47%	1.00%	2.13%
Aflac Inc	AFL	594.06	76.75	2.19	8.00	45,594.26	0.13%	0.28%	1.03%
Air Products and Chemicals Inc	APD	222.15	283.40	2.47	10.50	62,957.03	0.18%	0.44%	1.86%
Royal Caribbean Cruises Ltd	RCL	256.17	92.14	n/a		0.00	0.00%		
Hess Corp	HES	307.06	153.00	1.14	23.50	46,980.33	0.13%	0.15%	3.11%
Archer-Daniels-Midland Co	ADM	536.10	75.42	2.39	7.50	40,432.81	0.11%	0.27%	0.85%
Automatic Data Processing Inc	ADP	411.99	240.58	2.08	11.00	99,115.83	0.28%	0.58%	3.07%
Verisk Analytics Inc	VRSK	145.03	236.24	0.58	8.00	34,261.18	0.10%	0.06%	0.77%
AutoZone Inc	AZO	18.16	2539.99	n/a	13.00	46,116.06	0.13%		1.69%
Avery Dennison Corp	AVY	80.58	182.67	1.77	9.50	14,720.10	0.04%	0.07%	0.39%
Enphase Energy Inc	ENPH	136.36	120.15	n/a	27.50	16,383.05	0.05%		1.27%
MSCI Inc	MSCI	79.09	513.08	1.08	12.50	40,578.98	0.11%	0.12%	1.43%
Ball Corp	BALL	315.06	49.78	1.61	13.00	15,683.64	0.04%	0.07%	0.57%
Axon Enterprise Inc	AXON	74.76	198.99	n/a	24.00	14,876.49	0.04%		1.01%
Ceridian HCM Holding Inc	CDAY	155.61	67.85	n/a		0.00	0.00%		
Carrier Global Corp	CARR	837.63	55.20	1.34	13.00	46,237.07	0.13%	0.17%	1.69%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Bank of New York Mellon Corp/The	BK	778.78	42.65	3.94	7.00	33,215.05	0.09%	0.37%	0.66%
Otis Worldwide Corp	OTIS	411.75	80.31	1.69	11.00	33,067.24	0.09%	0.16%	1.02%
Baxter International Inc	BAX	506.41	37.74	3.07	6.00	19,111.72	0.05%	0.17%	0.32%
Becton Dickinson & Co	BDX	290.11	258.53	1.41	5.00	75,001.88	0.21%	0.30%	1.06%
Berkshire Hathaway Inc	BRK/B	1308.07	350.30	n/a	6.00	458,216.92	1.29%		7.75%
Best Buy Co Inc	BBY	217.64	69.47	5.30	3.00	15,119.31	0.04%	0.23%	0.13%
Boston Scientific Corp	BSX	1464.22	52.80	n/a	13.00	77,310.97	0.22%		2.83%
Bristol-Myers Squibb Co	BMY	2089.10	58.04	3.93		0.00	0.00%	0.00%	
Brown-Forman Corp	BF/B	310.14	57.69	1.42	12.50	17,891.75	0.05%	0.07%	0.63%
Coterra Energy Inc	CTRA	755.05	27.05	2.96		0.00	0.00%	0.00%	
Campbell Soup Co	CPB	297.95	41.08	3.60	5.00	12,239.58	0.03%	0.12%	0.17%
Hilton Worldwide Holdings Inc	HLT	261.51	150.18	0.40		0.00	0.00%	0.00%	
Carnival Corp	CCL	1119.45	13.72	n/a		0.00	0.00%		
Qorvo Inc	QRVO	97.91	95.47	n/a	14.50	9,347.47	0.03%		0.38%
UDR Inc	UDR	329.48	35.67	4.71	15.50	11,752.55	0.03%	0.16%	0.51%
Clorox Co/The	CLX	123.83	131.06	3.66	11.00	16,228.64	0.05%	0.17%	0.50%
Paycom Software Inc	PAYC	60.47	259.27	0.58	19.50	15,677.28	0.04%	0.03%	0.86%
CMS Energy Corp	CMS	291.73	53.11	3.67	6.50	15,493.62	0.04%	0.16%	0.28%
Colgate-Palmolive Co	CL	826.69	71.11	2.70	8.50	58,786.07	0.17%	0.45%	1.41%
EPAM Systems Inc	EPAM	57.96	255.69	n/a	20.50	14,820.05	0.04%		0.86%
Comerica Inc	CMA	131.78	41.55	6.84	4.00	5,475.33	0.02%	0.11%	0.06%
Conagra Brands Inc	CAG	477.87	27.42	5.11	4.50	13,103.11	0.04%	0.19%	0.17%
Airbnb Inc	ABNB	426.36	137.21	n/a		0.00	0.00%		
Consolidated Edison Inc	ED	344.92	85.53	3.79	6.00	29,501.35	0.08%	0.31%	0.50%
Corning Inc	GLW	852.98	30.47	3.68	17.50	25,990.36	0.07%	0.27%	1.28%
Cummins Inc	CMI	141.65	228.46	2.94	10.00	32,360.67	0.09%	0.27%	0.91%
Caesars Entertainment Inc	CZR	215.29	46.35	n/a		0.00	0.00%		
Danaher Corp	DHR	738.35	219.91	0.49	11.00	162,373.50	0.46%	0.22%	5.03%
Target Corp	TGT	461.61	110.57	3.98	12.00	51,039.66	0.14%	0.57%	1.73%
Deere & Co	DE	288.00	377.38	1.43	13.50	108,685.82	0.31%	0.44%	4.13%
Dominion Energy Inc	D	836.77	44.67	5.98	2.50	37,378.65	0.11%	0.63%	0.26%
Dover Corp	DOV	139.87	139.51	1.46	6.50	19,513.82	0.05%	0.08%	0.36%
Alliant Energy Corp	LNT	252.72	48.45	3.74	6.50	12,244.24	0.03%	0.13%	0.22%
Steel Dynamics Inc	STLD	165.64	107.22	1.59	2.00	17,760.35	0.05%	0.08%	0.10%
Duke Energy Corp	DUK	771.00	88.26	4.65	5.00	68,048.46	0.19%	0.89%	0.96%
Regency Centers Corp	REG	171.00	59.44	4.37	10.50	10,164.42	0.03%	0.13%	0.30%
Eaton Corp PLC	ETN	399.00	213.28	1.61	12.00	85,098.72	0.24%	0.39%	2.88%
Ecolab Inc	ECL	285.03	169.40	1.25	10.00	48,284.76	0.14%	0.17%	1.36%
Revvity Inc	RVTY	124.14	110.70	0.25	-1.50	13,741.74	0.04%	0.01%	-0.06%
Emerson Electric Co	EMR	571.50	96.57	2.15	6.50	55,189.76	0.16%	0.33%	1.01%
EOG Resources Inc	EOG	582.26	126.76	2.60	15.00	73,807.40	0.21%	0.54%	3.12%
Aon PLC	AON	202.87	324.22	0.76	9.50	65,773.54	0.19%	0.14%	1.76%
Entergy Corp	ETR	211.46	92.50	4.63	0.50	19,559.68	0.06%	0.26%	0.03%
Equifax Inc	EFX	122.72	183.18	0.85	12.00	22,479.85	0.06%	0.05%	0.76%
EQT Corp	EQT	411.26	40.58	1.48		0.00	0.00%	0.00%	
IQVIA Holdings Inc	IQV	183.12	196.75	n/a	14.50	36,029.25	0.10%		1.47%
Gartner Inc	IT	78.83	343.61	n/a	10.50	27,085.06	0.08%		0.80%
FedEx Corp	FDX	251.42	264.92	1.90	7.00	66,606.19	0.19%	0.36%	1.31%
FMC Corp	FMC	124.73	66.97	3.46	10.00	8,353.44	0.02%	0.08%	0.24%
Brown & Brown Inc	BRO	283.61	69.84	0.66	6.50	19,807.53	0.06%	0.04%	0.36%
Ford Motor Co	F	3931.37	12.42	4.83	45.50	48,827.67	0.14%	0.66%	6.26%
NextEra Energy Inc	NEE	2023.71	57.29	3.26	9.50	115,938.58	0.33%	1.07%	3.10%
Franklin Resources Inc	BEN	498.98	24.58	4.88	2.00	12,264.88	0.03%	0.17%	0.07%
Garmin Ltd	GRMN	191.45	105.20	2.78	5.00	20,140.75	0.06%	0.16%	0.28%
Freeport-McMoRan Inc	FCX	1433.64	37.29	1.61	12.50	53,460.29	0.15%	0.24%	1.88%
Dexcom Inc	DXCM	387.87	93.30	n/a		0.00	0.00%		
General Dynamics Corp	GD	273.04	220.97	2.39	9.50	60,334.31	0.17%	0.41%	1.62%
General Mills Inc	GIS	581.28	63.99	3.69	4.50	37,196.04	0.10%	0.39%	0.47%
Genuine Parts Co	GPC	140.44	144.38	2.63	9.00	20,276.44	0.06%	0.15%	0.51%
Atmos Energy Corp	ATO	148.46	105.93	2.79	7.00	15,726.58	0.04%	0.12%	0.31%
WW Grainger Inc	GWW	50.00	691.84	1.08	11.00	34,592.69	0.10%	0.10%	1.07%
Halliburton Co	HAL	898.55	40.50	1.58	30.00	36,391.11	0.10%	0.16%	3.08%
L3Harris Technologies Inc	LHX	189.13	174.12	2.62	19.50	32,931.84	0.09%	0.24%	1.81%
Healthpeak Properties Inc	PEAK	547.05	18.36	6.54	14.50	10,043.91	0.03%	0.18%	0.41%
Insulet Corp	PODD	69.82	159.49	n/a		0.00	0.00%		
Catalent Inc	CTLT	180.27	45.53	n/a	21.00	8,207.78	0.02%		0.49%
Fortive Corp	FTV	352.02	74.16	0.38	16.00	26,106.10	0.07%	0.03%	1.18%
Hershey Co/The	HSY	149.85	200.08	2.38	9.50	29,982.79	0.08%	0.20%	0.80%
Synchrony Financial	SYF	418.18	30.57	3.27	47.00	12,783.85	0.04%	0.12%	1.69%
Hormel Foods Corp	HRL	546.48	38.03	2.89	7.50	20,782.67	0.06%	0.17%	0.44%
Arthur J Gallagher & Co	AJG	215.51	227.93	0.97	22.00	49,120.28	0.14%	0.13%	3.05%
Mondelez International Inc	MDLZ	1360.42	69.40	2.45	10.00	94,413.01	0.27%	0.65%	2.66%
CenterPoint Energy Inc	CNP	629.43	26.85	2.98	6.50	16,900.25	0.05%	0.14%	0.31%
Humana Inc	HUM	123.91	486.52	0.73	12.50	60,283.23	0.17%	0.12%	2.12%
Willis Towers Watson PLC	WTW	104.82	208.96	1.61	9.50	21,903.81	0.06%	0.10%	0.59%
Illinois Tool Works Inc	ITW	302.39	230.31	2.43	11.00	69,643.44	0.20%	0.48%	2.16%
CDW Corp/DE	CDW	134.05	201.76	1.17	7.00	27,045.52	0.08%	0.09%	0.53%
Trane Technologies PLC	TT	228.40	202.91	1.48	13.00	46,344.24	0.13%	0.19%	1.70%
Interpublic Group of Cos Inc/The	IPG	384.94	28.66	4.33	8.50	11,032.24	0.03%	0.13%	0.26%
International Flavors & Fragrances Inc	IFF	255.25	68.17	4.75	8.00	17,400.60	0.05%	0.23%	0.39%
Generac Holdings Inc	GNRC	62.24	108.96	n/a	19.00	6,782.00	0.02%		0.36%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
NXP Semiconductors NV	NXPI	257.80	199.92	2.03	8.50	51,539.78	0.15%	0.29%	1.23%
Kellanova	K	342.35	55.84	4.30	3.00	19,116.66	0.05%	0.23%	0.16%
Broadridge Financial Solutions Inc	BR	117.62	179.05	1.79	8.50	21,060.04	0.06%	0.11%	0.50%
Kimberly-Clark Corp	KMB	338.19	120.85	3.91	7.00	40,869.66	0.12%	0.45%	0.81%
Kimco Realty Corp	KIM	619.89	17.59	5.23	11.00	10,903.90	0.03%	0.16%	0.34%
Oracle Corp	ORCL	2739.38	105.92	1.51	10.00	290,154.71	0.82%	1.24%	8.18%
Kroger Co/The	KR	719.32	44.75	2.59	6.00	32,189.39	0.09%	0.24%	0.54%
Lennar Corp	LEN	250.15	112.23	1.34	3.50	28,074.56	0.08%	0.11%	0.28%
Eli Lilly & Co	LLY	949.30	537.13	0.84	19.00	509,894.82	1.44%	1.21%	27.30%
Bath & Body Works Inc	BBWI	227.38	33.80	2.37	26.50	7,685.48	0.02%	0.05%	0.57%
Charter Communications Inc	CHTR	149.67	439.82	n/a	12.50	65,828.30	0.19%		2.32%
Loews Corp	L	225.51	63.31	0.39	25.50	14,276.97	0.04%	0.02%	1.03%
Lowe's Cos Inc	LOW	577.12	207.84	2.12	8.00	119,947.58	0.34%	0.72%	2.70%
IDEX Corp	IEX	75.60	208.02	1.23	8.00	15,726.73	0.04%	0.05%	0.35%
Marsh & McLennan Cos Inc	MMC	493.95	190.30	1.49	9.00	93,999.45	0.26%	0.40%	2.38%
Masco Corp	MAS	224.93	53.45	2.13	6.50	12,022.29	0.03%	0.07%	0.22%
S&P Global Inc	SPGI	318.20	365.41	0.99	7.50	116,273.46	0.33%	0.32%	2.46%
Medtronic PLC	MDT	1330.53	78.36	3.52	7.50	104,260.64	0.29%	1.03%	2.20%
Viatris Inc	VTRS	1199.53	9.86	4.87		0.00	0.00%	0.00%	
CVS Health Corp	CVS	1284.40	69.82	3.47	8.50	89,676.74	0.25%	0.88%	2.15%
DuPont de Nemours Inc	DD	459.06	74.59	1.93	9.50	34,241.36	0.10%	0.19%	0.92%
Micron Technology Inc	MU	1095.30	68.03	0.68	9.50	74,513.40	0.21%	0.14%	1.99%
Motorola Solutions Inc	MSI	167.02	272.24	1.29	11.00	45,469.52	0.13%	0.17%	1.41%
Cboe Global Markets Inc	CBOE	105.52	156.21	1.41	12.50	16,482.81	0.05%	0.07%	0.58%
Laboratory Corp of America Holdings	LH	88.60	201.05	1.43	1.00	17,813.03	0.05%	0.07%	0.05%
Newmont Corp	NEM	794.80	36.95	4.33	8.00	29,367.71	0.08%	0.36%	0.66%
NIKE Inc	NKE	1225.07	95.62	1.42	18.00	117,141.58	0.33%	0.47%	5.94%
NiSource Inc	NI	413.26	24.68	4.05	9.50	10,199.13	0.03%	0.12%	0.27%
Norfolk Southern Corp	NSC	227.02	196.93	2.74	8.50	44,706.06	0.13%	0.35%	1.07%
Principal Financial Group Inc	PFG	241.72	72.07	3.61	5.50	17,420.40	0.05%	0.18%	0.27%
Eversource Energy	ES	349.09	58.15	4.64	6.50	20,299.35	0.06%	0.27%	0.37%
Northrop Grumman Corp	NOC	151.30	440.19	1.70	9.50	66,600.75	0.19%	0.32%	1.78%
Wells Fargo & Co	WFC	3667.70	40.86	3.43	12.00	149,862.22	0.42%	1.45%	5.07%
Nucor Corp	NUE	248.72	156.35	1.30	2.00	38,887.68	0.11%	0.14%	0.22%
Occidental Petroleum Corp	OXY	884.68	64.88	1.11	17.00	57,398.17	0.16%	0.18%	2.75%
Omnicom Group Inc	OMC	197.57	74.48	3.76	7.00	14,715.09	0.04%	0.16%	0.29%
ONEOK Inc	OKE	582.47	63.43	6.02	12.00	36,946.26	0.10%	0.63%	1.25%
Raymond James Financial Inc	RJF	208.84	100.43	1.67	15.00	20,974.00	0.06%	0.10%	0.89%
PG&E Corp	PCG	2091.24	16.13	n/a	7.50	33,731.72	0.10%		0.71%
Parker-Hannifin Corp	PH	128.51	389.52	1.52	14.50	50,057.22	0.14%	0.21%	2.05%
Rollins Inc	ROL	484.10	37.33	1.39	10.50	18,071.34	0.05%	0.07%	0.53%
PPL Corp	PPL	737.09	23.56	4.07	8.00	17,365.82	0.05%	0.20%	0.39%
ConocoPhillips	COP	1197.49	119.80	0.50	9.00	143,459.42	0.40%	0.20%	3.64%
PulteGroup Inc	PHM	219.45	74.05	0.86	8.00	16,249.90	0.05%	0.04%	0.37%
Pinnacle West Capital Corp	PNW	113.31	73.68	4.70	2.50	8,348.83	0.02%	0.11%	0.06%
PNC Financial Services Group Inc/The	PNC	398.26	122.77	5.05	7.50	48,893.77	0.14%	0.70%	1.03%
PPG Industries Inc	PPG	235.51	129.80	2.00	3.00	30,569.59	0.09%	0.17%	0.26%
Progressive Corp/The	PGR	585.10	139.30	0.29	12.00	81,504.43	0.23%	0.07%	2.76%
Public Service Enterprise Group Inc	PEG	499.11	56.91	4.01	4.00	28,404.41	0.08%	0.32%	0.32%
Robert Half Inc	RHI	107.08	73.28	2.62	9.50	7,846.97	0.02%	0.06%	0.21%
Cooper Cos Inc/The	COO	49.52	318.01	0.02	12.00	15,749.13	0.04%	0.00%	0.53%
Edison International	EIX	383.29	63.29	4.66	4.50	24,258.36	0.07%	0.32%	0.31%
Schlumberger NV	SLB	1421.19	58.30	1.72	26.00	82,855.14	0.23%	0.40%	6.07%
Charles Schwab Corp/The	SCHW	1770.22	54.90	1.82	9.00	97,185.08	0.27%	0.50%	2.46%
Sherwin-Williams Co/The	SHW	257.15	255.05	0.95	7.00	65,585.85	0.18%	0.18%	1.29%
West Pharmaceutical Services Inc	WST	73.86	375.21	0.20	17.00	27,713.39	0.08%	0.02%	1.33%
J M Smucker Co/The	SJM	102.14	122.91	3.45	6.00	12,554.27	0.04%	0.12%	0.21%
Snap-on Inc	SNA	52.92	255.06	2.54	6.00	13,497.01	0.04%	0.10%	0.23%
AMETEK Inc	AME	230.71	147.76	0.68	10.00	34,090.01	0.10%	0.07%	0.96%
Southern Co/The	SO	1091.52	64.72	4.33	6.50	70,642.85	0.20%	0.86%	1.29%
Truist Financial Corp	TFC	1331.98	28.61	7.27	6.00	38,107.83	0.11%	0.78%	0.64%
Southwest Airlines Co	LUV	595.63	27.07	2.66		0.00	0.00%	0.00%	
W R Berkley Corp	WRB	257.52	63.49	0.69	15.00	16,350.14	0.05%	0.03%	0.69%
Stanley Black & Decker Inc	SWK	153.23	83.58	3.88	1.00	12,806.96	0.04%	0.14%	0.04%
Public Storage	PSA	175.83	263.52	4.55	7.50	46,334.46	0.13%	0.59%	0.98%
Arista Networks Inc	ANET	309.58	183.93	n/a	13.00	56,941.23	0.16%		2.09%
Sysco Corp	SYY	504.93	66.05	3.03	18.50	33,350.36	0.09%	0.28%	1.74%
Corteva Inc	CTVA	709.52	51.16	1.25	13.50	36,298.84	0.10%	0.13%	1.38%
Texas Instruments Inc	TXN	907.97	159.01	3.27	3.00	144,375.67	0.41%	1.33%	1.22%
Textron Inc	TXT	198.07	78.14	0.10	16.00	15,477.27	0.04%	0.00%	0.70%
Thermo Fisher Scientific Inc	TMO	385.95	506.17	0.28	9.50	195,356.31	0.55%	0.15%	5.23%
TJX Cos Inc/The	TJX	1144.08	88.88	1.50	17.00	101,685.92	0.29%	0.43%	4.87%
Globe Life Inc	GL	94.82	108.73	0.83	9.00	10,309.78	0.03%	0.02%	0.26%
Johnson Controls International plc	JCI	680.32	53.21	2.78	11.50	36,199.83	0.10%	0.28%	1.17%
Ulta Beauty Inc	ULTA	49.23	399.45	n/a	13.50	19,664.52	0.06%		0.75%
Union Pacific Corp	UNP	609.46	203.63	2.55	6.50	124,103.53	0.35%	0.89%	2.27%
Keysight Technologies Inc	KEYS	177.58	132.31	n/a	13.00	23,494.95	0.07%		0.86%
UnitedHealth Group Inc	UNH	926.31	504.19	1.49	12.00	467,033.72	1.32%	1.96%	15.79%
Blackstone Inc	BX	709.75	107.14	2.95	15.00	76,042.62	0.21%	0.63%	3.21%
Marathon Oil Corp	MRO	605.69	26.75	1.50	22.50	16,202.13	0.05%	0.07%	1.03%
Bio-Rad Laboratories Inc	BIO	24.00	358.45	n/a	11.50	8,604.23	0.02%		0.28%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Ventas Inc	VTR	402.38	42.13	4.27	23.50	16,952.19	0.05%	0.20%	1.12%
VF Corp	VFC	388.87	17.67	6.79	9.00	6,871.30	0.02%	0.13%	0.17%
Vulcan Materials Co	VMC	132.87	202.02	0.85	9.50	26,841.59	0.08%	0.06%	0.72%
Weyerhaeuser Co	WY	730.75	30.66	2.48	-2.50	22,404.73	0.06%	0.16%	-0.16%
Whirlpool Corp	WHR	54.82	133.70	5.24	-1.50	7,329.17	0.02%	0.11%	-0.03%
Williams Cos Inc/The	WMB	1216.42	33.69	5.31	10.50	40,981.22	0.12%	0.61%	1.21%
Constellation Energy Corp	CEG	321.59	109.08	1.03		0.00	0.00%	0.00%	
WEC Energy Group Inc	WEC	315.44	80.55	3.87	6.00	25,408.29	0.07%	0.28%	0.43%
Adobe Inc	ADBE	455.30	509.90	n/a	11.00	232,157.47	0.65%		7.20%
AES Corp/The	AES	669.63	15.20	4.37	14.00	10,178.36	0.03%	0.13%	0.40%
Amgen Inc	AMGN	534.90	268.76	3.17	6.00	143,759.99	0.41%	1.28%	2.43%
Apple Inc	AAPL	15634.23	171.21	0.56	10.50	2,676,736.86	7.54%	4.23%	79.20%
Autodesk Inc	ADSK	213.76	206.91	n/a	10.00	44,229.91	0.12%		1.25%
Cintas Corp	CTAS	101.93	481.01	1.12	14.00	49,027.91	0.14%	0.16%	1.93%
Comcast Corp	CMCSA	4115.69	44.34	2.62	9.00	182,489.65	0.51%	1.35%	4.63%
Molson Coors Beverage Co	TAP	200.96	63.59	2.58	35.00	12,779.05	0.04%	0.09%	1.26%
KLA Corp	KLAC	136.32	458.66	1.13	13.50	62,525.45	0.18%	0.20%	2.38%
Marriott International Inc/MD	MAR	298.24	196.56	1.06	17.50	58,622.05	0.17%	0.17%	2.89%
Fiserv Inc	FI	609.62	112.96	n/a	9.50	68,862.11	0.19%		1.84%
McCormick & Co Inc/MD	MKC	251.10	75.64	2.06	4.50	18,993.20	0.05%	0.11%	0.24%
PACCAR Inc	PCAR	522.81	85.02	1.27	5.00	44,448.88	0.13%	0.16%	0.63%
Costco Wholesale Corp	COST	442.79	564.96	0.72	10.50	250,160.33	0.70%	0.51%	7.40%
Stryker Corp	SYK	379.78	273.27	1.10	7.00	103,781.93	0.29%	0.32%	2.05%
Tyson Foods Inc	TSN	285.55	50.49	3.80	6.00	14,417.42	0.04%	0.15%	0.24%
Lamb Weston Holdings Inc	LW	145.67	92.46	1.21	15.50	13,468.37	0.04%	0.05%	0.59%
Applied Materials Inc	AMAT	836.53	138.45	0.92	5.50	115,818.13	0.33%	0.30%	1.79%
American Airlines Group Inc	AAL	653.36	12.81	n/a		0.00	0.00%		
Cardinal Health Inc	CAH	246.35	86.82	2.31	6.50	21,388.45	0.06%	0.14%	0.39%
Cincinnati Financial Corp	CINF	156.86	102.29	2.93	10.50	16,044.80	0.05%	0.13%	0.47%
Paramount Global	PARA	610.40	12.90	1.55	1.50	7,874.15	0.02%	0.03%	0.03%
DR Horton Inc	DHI	338.30	107.47	0.93	5.00	36,356.78	0.10%	0.10%	0.51%
Electronic Arts Inc	EA	270.91	120.40	0.63	16.00	32,617.80	0.09%	0.06%	1.47%
Fair Isaac Corp	FICO	24.86	868.53	n/a	16.00	21,589.05	0.06%		0.97%
Expeditors International of Washington Inc	EXPD	147.90	114.63	1.20	10.00	16,953.43	0.05%	0.06%	0.48%
Fastenal Co	FAST	571.33	54.64	2.56	6.50	31,217.64	0.09%	0.23%	0.57%
M&T Bank Corp	MTB	165.95	126.45	4.11	6.50	20,984.25	0.06%	0.24%	0.38%
Xcel Energy Inc	XEL	551.53	57.22	3.64	6.00	31,558.72	0.09%	0.32%	0.53%
Fifth Third Bancorp	FITB	680.89	25.33	5.53	4.50	17,246.92	0.05%	0.27%	0.22%
Gilead Sciences Inc	GILD	1246.01	74.94	4.00	13.50	93,376.29	0.26%	1.05%	3.55%
Hasbro Inc	HAS	138.74	66.14	4.23	8.50	9,176.33	0.03%	0.11%	0.22%
Huntington Bancshares Inc/OH	HBAN	1447.88	10.40	5.96	10.50	15,057.97	0.04%	0.25%	0.45%
Welltower Inc	WELL	518.73	81.92	2.98	12.00	42,494.28	0.12%	0.36%	1.44%
Biogen Inc	BIIB	144.82	257.01	n/a	-1.00	37,220.96	0.10%		-0.10%
Northern Trust Corp	NTRS	207.00	69.48	4.32	5.50	14,382.64	0.04%	0.17%	0.22%
Packaging Corp of America	PKG	89.92	153.55	3.26	9.00	13,806.45	0.04%	0.13%	0.35%
Paychex Inc	PAYX	361.23	115.33	3.09	9.50	41,660.89	0.12%	0.36%	1.12%
QUALCOMM Inc	QCOM	1116.00	111.06	2.88	5.50	123,942.96	0.35%	1.01%	1.92%
Ross Stores Inc	ROST	338.63	112.95	1.19	14.00	38,248.48	0.11%	0.13%	1.51%
IDEXX Laboratories Inc	IDXX	83.01	437.27	n/a	10.50	36,298.66	0.10%		1.07%
Starbucks Corp	SBUX	1145.40	91.27	2.50	16.00	104,540.66	0.29%	0.74%	4.71%
KeyCorp	KEY	935.92	10.76	7.62	7.50	10,070.49	0.03%	0.22%	0.21%
Fox Corp	FOXA	253.68	31.20	1.67	8.50	7,914.94	0.02%	0.04%	0.19%
Fox Corp	FOX	235.58	28.88	1.80		0.00	0.00%	0.00%	
State Street Corp	STT	318.64	66.96	4.12	9.00	21,336.13	0.06%	0.25%	0.54%
Norwegian Cruise Line Holdings Ltd	NCLH	425.42	16.48	n/a		0.00	0.00%		
US Bancorp	USB	1556.97	33.06	5.81	4.00	51,473.26	0.15%	0.84%	0.58%
A O Smith Corp	AOS	124.59	66.13	1.81	9.50	8,239.14	0.02%	0.04%	0.22%
Gen Digital Inc	GEN	639.44	17.68	2.83	10.50	11,305.28	0.03%	0.09%	0.33%
T Rowe Price Group Inc	TROW	224.30	104.87	4.65	2.00	23,521.82	0.07%	0.31%	0.13%
Waste Management Inc	WM	405.06	152.44	1.84	6.50	61,747.19	0.17%	0.32%	1.13%
Constellation Brands Inc	STZ	183.30	251.33	1.42	5.50	46,069.04	0.13%	0.18%	0.71%
DENTSPLY SIRONA Inc	XRAY	211.72	34.16	1.64	12.00	7,232.22	0.02%	0.03%	0.24%
Zions Bancorp NA	ZION	148.15	34.89	4.70	6.50	5,168.78	0.01%	0.07%	0.09%
Alaska Air Group Inc	ALK	127.22	37.08	n/a		0.00	0.00%		
Invesco Ltd	IVZ	448.62	14.52	5.51	6.50	6,513.98	0.02%	0.10%	0.12%
Intuit Inc	INTU	280.26	510.94	0.70	14.50	143,195.53	0.40%	0.28%	5.85%
Morgan Stanley	MS	1656.97	81.67	4.16	7.50	135,324.49	0.38%	1.59%	2.86%
Microchip Technology Inc	MCHP	544.33	78.05	2.10	10.00	42,485.27	0.12%	0.25%	1.20%
Chubb Ltd	CB	410.74	208.18	1.65	15.00	85,506.81	0.24%	0.40%	3.61%
Hologic Inc	HOLX	244.94	69.40	n/a	25.00	16,998.97	0.05%		1.20%
Citizens Financial Group Inc	CFG	472.29	26.80	6.27	7.50	12,657.48	0.04%	0.22%	0.27%
O'Reilly Automotive Inc	ORLY	60.26	908.86	n/a	12.00	54,766.09	0.15%		1.85%
Allstate Corp/The	ALL	261.57	111.41	3.20	10.50	29,141.96	0.08%	0.26%	0.86%
Equity Residential	EQR	379.03	58.71	4.51	-5.00	22,252.97	0.06%	0.28%	-0.31%
BorgWarner Inc	BWA	235.06	40.37	1.09	7.00	9,489.49	0.03%	0.03%	0.19%
Keurig Dr Pepper Inc	KDP	1397.26	31.57	2.72	12.50	44,111.47	0.12%	0.34%	1.55%
Organon & Co	OGN	255.57	17.36	6.45		0.00	0.00%	0.00%	
Host Hotels & Resorts Inc	HST	711.61	16.07	4.48	51.00	11,435.49	0.03%	0.14%	1.64%
Incyte Corp	INCY	224.09	57.77	n/a	32.00	12,945.56	0.04%		1.17%
Simon Property Group Inc	SPG	327.19	108.03	7.04	3.50	35,346.44	0.10%	0.70%	0.35%
Eastman Chemical Co	EMN	118.56	76.72	4.12	6.00	9,095.62	0.03%	0.11%	0.15%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
AvalonBay Communities Inc	AVB	142.02	171.74	3.84	6.00	24,389.83	0.07%	0.26%	0.41%
Prudential Financial Inc	PRU	363.00	94.89	5.27	3.00	34,445.07	0.10%	0.51%	0.29%
United Parcel Service Inc	UPS	723.28	155.87	4.16	7.50	112,737.03	0.32%	1.32%	2.38%
Walgreens Boots Alliance Inc	WBA	863.26	22.24	8.63	1.00	19,198.92	0.05%	0.47%	0.05%
STERIS PLC	STE	98.78	219.42	0.95	10.00	21,674.53	0.06%	0.06%	0.61%
McKesson Corp	MCK	134.90	434.85	0.57	9.00	58,662.13	0.17%	0.09%	1.49%
Lockheed Martin Corp	LMT	251.83	408.96	2.93	7.00	102,988.81	0.29%	0.85%	2.03%
Cencora Inc	COR	202.18	179.97	1.08	9.00	36,385.43	0.10%	0.11%	0.92%
Capital One Financial Corp	COF	381.44	97.05	2.47	4.00	37,018.85	0.10%	0.26%	0.42%
Waters Corp	WAT	59.10	274.21	n/a	10.00	16,206.63	0.05%		0.46%
Nordson Corp	NDSN	57.01	223.17	1.22	9.00	12,723.81	0.04%	0.04%	0.32%
Dollar Tree Inc	DLTR	220.01	106.45	n/a	9.00	23,419.64	0.07%		0.59%
Darden Restaurants Inc	DRI	120.32	143.22	3.66	15.00	17,231.51	0.05%	0.18%	0.73%
Evergy Inc	EVRG	229.58	50.70	4.83	7.50	11,639.86	0.03%	0.16%	0.25%
Match Group Inc	MTCH	278.09	39.18	n/a	16.50	10,894.06	0.03%		0.51%
Domino's Pizza Inc	DPZ	35.09	378.79	1.28	12.00	13,293.26	0.04%	0.05%	0.45%
NVR Inc	NVR	3.26	5963.30	n/a	3.50	19,464.21	0.05%		0.19%
NetApp Inc	NTAP	208.79	75.88	2.64	8.00	15,843.06	0.04%	0.12%	0.36%
DXC Technology Co	DXC	205.17	20.83	n/a	9.00	4,273.77	0.01%		0.11%
Old Dominion Freight Line Inc	ODFL	109.27	409.14	0.39	9.00	44,705.91	0.13%	0.05%	1.13%
DaVita Inc	DVA	91.30	94.53	n/a	7.00	8,630.59	0.02%		0.17%
Hartford Financial Services Group Inc/The	HIG	305.82	70.91	2.40	8.00	21,685.48	0.06%	0.15%	0.49%
Iron Mountain Inc	IRM	291.85	59.45	4.37	4.00	17,350.60	0.05%	0.21%	0.20%
Estee Lauder Cos Inc/The	EL	232.30	144.55	1.83	8.00	33,578.53	0.09%	0.17%	0.76%
Cadence Design Systems Inc	CDNS	271.79	234.30	n/a	12.00	63,680.40	0.18%		2.15%
Tyler Technologies Inc	TYL	42.08	386.14	n/a	10.50	16,248.00	0.05%		0.48%
Universal Health Services Inc	UHS	62.14	125.73	0.64	6.00	7,812.86	0.02%	0.01%	0.13%
Skyworks Solutions Inc	SWKS	159.39	98.59	2.76	3.50	15,714.56	0.04%	0.12%	0.15%
Quest Diagnostics Inc	DGX	112.24	121.86	2.33	4.00	13,676.96	0.04%	0.09%	0.15%
Activision Blizzard Inc	ATVI	786.80	93.63	1.06	13.50	73,667.90	0.21%	0.22%	2.80%
Rockwell Automation Inc	ROK	114.86	285.87	1.65	9.50	32,835.03	0.09%	0.15%	0.88%
Kraft Heinz Co/The	KHC	1228.30	33.64	4.76	6.00	41,319.84	0.12%	0.55%	0.70%
American Tower Corp	AMT	466.16	164.45	3.94	5.00	76,659.35	0.22%	0.85%	1.08%
Regeneron Pharmaceuticals Inc	REGN	106.74	822.96	n/a	1.50	87,843.57	0.25%		0.37%
Amazon.com Inc	AMZN	10317.75	127.12	n/a	19.50	1,311,592.51	3.70%		72.07%
Jack Henry & Associates Inc	JKHY	72.94	151.14	1.38	7.00	11,023.40	0.03%	0.04%	0.22%
Ralph Lauren Corp	RL	40.39	116.09	2.58	12.50	4,688.64	0.01%	0.03%	0.17%
Boston Properties Inc	BXP	156.87	59.48	6.59	-1.00	9,330.33	0.03%	0.17%	-0.03%
Amphenol Corp	APH	596.45	83.99	1.00	12.50	50,096.17	0.14%	0.14%	1.76%
Howmet Aerospace Inc	HWM	412.21	46.25	0.43	12.00	19,064.62	0.05%	0.02%	0.64%
Pioneer Natural Resources Co	PXD	233.14	229.55	3.21	8.50	53,517.52	0.15%	0.48%	1.28%
Valero Energy Corp	VLO	353.13	141.71	2.88	1.50	50,042.48	0.14%	0.41%	0.21%
Synopsys Inc	SNPS	152.08	458.97	n/a	15.00	69,801.99	0.20%		2.95%
Etsy Inc	ETSY	123.01	64.58	n/a	10.00	7,944.24	0.02%		0.22%
CH Robinson Worldwide Inc	CHRW	116.44	86.13	2.83	6.00	10,028.89	0.03%	0.08%	0.17%
Accenture PLC	ACN	630.80	307.11	1.68	12.50	193,723.45	0.55%	0.92%	6.82%
TransDigm Group Inc	TDG	55.18	843.13	n/a	26.00	46,526.44	0.13%		3.41%
Yum! Brands Inc	YUM	280.21	124.94	1.94	11.50	35,009.56	0.10%	0.19%	1.13%
Prologis Inc	PLD	923.86	112.21	3.10	2.50	103,666.56	0.29%	0.91%	0.73%
FirstEnergy Corp	FE	573.36	34.18	4.80	4.00	19,597.51	0.06%	0.26%	0.22%
VeriSign Inc	VRSN	103.13	202.53	n/a	13.00	20,887.73	0.06%		0.77%
Quanta Services Inc	PWR	145.20	187.07	0.17	15.00	27,162.38	0.08%	0.01%	1.15%
Henry Schein Inc	HSIC	130.59	74.25	n/a	9.00	9,695.94	0.03%		0.25%
Ameren Corp	AEE	262.48	74.83	3.37	6.50	19,641.00	0.06%	0.19%	0.36%
ANSYS Inc	ANSS	86.79	297.55	n/a	8.50	25,824.66	0.07%		0.62%
FactSet Research Systems Inc	FDS	38.15	437.26	0.90	10.50	16,679.72	0.05%	0.04%	0.49%
NVIDIA Corp	NVDA	2470.00	434.99	0.04	40.00	1,074,425.30	3.03%	0.11%	121.10%
Sealed Air Corp	SEE	144.41	32.86	2.43	7.50	4,745.31	0.01%	0.03%	0.10%
Cognizant Technology Solutions Corp	CTSH	505.04	67.74	1.71	8.00	34,211.48	0.10%	0.17%	0.77%
Intuitive Surgical Inc	ISRG	351.36	292.29	n/a	12.50	102,697.55	0.29%		3.62%
Take-Two Interactive Software Inc	TTWO	169.83	140.39	n/a		0.00	0.00%		
Republic Services Inc	RSG	316.33	142.51	1.50	12.50	45,079.62	0.13%	0.19%	1.59%
eBay Inc	EBAY	532.16	44.09	2.27	9.50	23,462.80	0.07%	0.15%	0.63%
Goldman Sachs Group Inc/The	GS	329.67	323.57	3.40	5.00	106,671.65	0.30%	1.02%	1.50%
SBA Communications Corp	SBAC	108.38	200.17	1.70	23.50	21,695.03	0.06%	0.10%	1.44%
Sempra	SRE	629.31	68.03	3.50	7.00	42,811.76	0.12%	0.42%	0.84%
Moody's Corp	MCO	183.50	316.17	0.97	16.00	58,017.20	0.16%	0.16%	2.62%
ON Semiconductor Corp	ON	431.53	92.95	n/a	13.00	40,110.62	0.11%		1.47%
Booking Holdings Inc	BKNG	35.69	3083.95	n/a	22.00	110,072.34	0.31%		6.82%
F5 Inc	FFIV	59.31	161.14	n/a	10.00	9,556.57	0.03%		0.27%
Akamai Technologies Inc	AKAM	151.71	106.54	n/a	5.00	16,163.50	0.05%		0.23%
Charles River Laboratories International Inc	CRL	51.27	195.98	n/a	8.00	10,048.09	0.03%		0.23%
MarketAxess Holdings Inc	MKTX	37.68	213.64	1.35	10.50	8,049.31	0.02%	0.03%	0.24%
Devon Energy Corp	DVN	640.70	47.70	4.11	10.50	30,561.39	0.09%	0.35%	0.90%
Bio-Techne Corp	TECH	158.24	68.07	0.47	13.00	10,771.40	0.03%	0.01%	0.39%
Alphabet Inc	GOOGL	5933.00	130.86	n/a		0.00	0.00%		
Teleflex Inc	TFX	46.99	196.41	0.69	10.00	9,229.70	0.03%	0.02%	0.26%
Bunge Ltd	BG	150.64	108.25	2.45	1.50	16,307.00	0.05%	0.11%	0.07%
Allegion plc	ALLE	87.78	104.20	1.73	10.50	9,146.68	0.03%	0.04%	0.27%
Netflix Inc	NFLX	443.15	377.60	n/a	13.00	167,332.31	0.47%		6.13%
Agilent Technologies Inc	A	292.59	111.82	0.80	13.50	32,717.08	0.09%	0.07%	1.24%

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Warner Bros Discovery Inc	WBD	2437.38	10.86	n/a		0.00	0.00%		
Elevance Health Inc	ELV	235.65	435.42	1.36	12.50	102,605.85	0.29%	0.39%	3.61%
Trimble Inc	TRMB	248.32	53.86	n/a	5.50	13,374.62	0.04%		0.21%
CME Group Inc	CME	359.75	200.22	2.20	7.50	72,028.34	0.20%	0.45%	1.52%
Juniper Networks Inc	JNPR	321.36	27.79	3.17	10.50	8,930.59	0.03%	0.08%	0.26%
BlackRock Inc	BLK	149.30	646.49	3.09	7.50	96,522.90	0.27%	0.84%	2.04%
DTE Energy Co	DTE	206.11	99.28	3.84	4.50	20,462.50	0.06%	0.22%	0.26%
Nasdaq Inc	NDAQ	491.32	48.59	1.81	6.00	23,873.04	0.07%	0.12%	0.40%
Celanese Corp	CE	108.85	125.52	2.23	6.50	13,663.10	0.04%	0.09%	0.25%
Philip Morris International Inc	PM	1552.35	92.58	5.62	5.00	143,716.10	0.40%	2.27%	2.02%
Salesforce Inc	CRM	973.00	202.78	n/a	18.00	197,304.94	0.56%		10.01%
Ingersoll Rand Inc	IR	404.40	63.72	0.13	12.00	25,768.30	0.07%	0.01%	0.87%
Roper Technologies Inc	ROP	106.71	484.28	0.56	8.00	51,678.00	0.15%	0.08%	1.16%
Huntington Ingalls Industries Inc	HII	39.87	204.58	2.42	10.00	8,156.20	0.02%	0.06%	0.23%
MetLife Inc	MET	752.02	62.91	3.31	7.50	47,309.70	0.13%	0.44%	1.00%
Tapestry Inc	TPR	227.44	28.75	4.87	12.00	6,538.87	0.02%	0.09%	0.22%
CSX Corp	CSX	2006.33	30.75	1.43	8.50	61,694.65	0.17%	0.25%	1.48%
Edwards Lifesciences Corp	EW	607.92	69.28	n/a	10.50	42,116.42	0.12%		1.25%
Ameriprise Financial Inc	AMP	102.63	329.68	1.64	11.00	33,833.74	0.10%	0.16%	1.05%
Zebra Technologies Corp	ZBRA	51.34	236.53	n/a	1.50	12,142.98	0.03%		0.05%
Zimmer Biomet Holdings Inc	ZBH	208.96	112.22	0.86	6.50	23,449.94	0.07%	0.06%	0.43%
CBRE Group Inc	CBRE	309.84	73.86	n/a	8.50	22,884.63	0.06%		0.55%
Camden Property Trust	CPT	106.77	94.58	4.23	-3.00	10,098.40	0.03%	0.12%	-0.09%
Mastercard Inc	MA	934.85	395.91	0.58	16.00	370,115.67	1.04%	0.60%	16.69%
CarMax Inc	KMX	158.67	70.73	n/a	-3.50	11,222.59	0.03%		-0.11%
Intercontinental Exchange Inc	ICE	594.94	110.02	1.53	6.00	65,454.86	0.18%	0.28%	1.11%
Fidelity National Information Services Inc	FIS	592.47	55.27	3.76	23.50	32,745.54	0.09%	0.35%	2.17%
Chipotle Mexican Grill Inc	CMG	27.59	1831.83	n/a	20.00	50,536.53	0.14%		2.85%
Wynn Resorts Ltd	WYNN	113.94	92.41	1.08	27.00	10,528.83	0.03%	0.03%	0.80%
Live Nation Entertainment Inc	LYV	230.15	83.04	n/a		0.00	0.00%		
Assurant Inc	AIZ	53.02	143.58	1.95	10.50	7,613.04	0.02%	0.04%	0.23%
NRG Energy Inc	NRG	229.12	38.52	3.92	-2.50	8,825.59	0.02%	0.10%	-0.06%
Regions Financial Corp	RF	938.38	17.20	5.58	11.50	16,140.08	0.05%	0.25%	0.52%
Monster Beverage Corp	MNST	1047.52	52.95	n/a	11.00	55,466.08	0.16%		1.72%
Mosaic Co/The	MOS	332.28	35.60	2.25	1.50	11,829.17	0.03%	0.07%	0.05%
Baker Hughes Co	BKR	1009.65	35.32	2.27		0.00	0.00%	0.00%	
Expedia Group Inc	EXPE	137.84	103.07	n/a		0.00	0.00%		
CF Industries Holdings Inc	CF	192.95	85.74	1.87	9.00	16,543.36	0.05%	0.09%	0.42%
Leidos Holdings Inc	LDOS	137.35	92.16	1.56	7.00	12,658.27	0.04%	0.06%	0.25%
APA Corp	APA	307.27	41.10	2.43	21.00	12,628.59	0.04%	0.09%	0.75%
Alphabet Inc	GOOG	5801.00	131.85	n/a	10.50	764,861.85	2.16%		22.63%
First Solar Inc	FSLR	106.83	161.59	n/a	27.50	17,262.82	0.05%		1.34%
TE Connectivity Ltd	TEL	313.94	123.53	1.91	10.50	38,780.88	0.11%	0.21%	1.15%
Discover Financial Services	DFS	249.95	86.63	3.23	4.00	21,653.00	0.06%	0.20%	0.24%
Linde PLC	LIN	487.95	372.35	1.37	8.50	181,686.69	0.51%	0.70%	4.35%
Visa Inc	V	1606.79	230.01	0.78	13.50	369,577.31	1.04%	0.81%	14.06%
Mid-America Apartment Communities Inc	MAA	116.68	128.65	4.35	-12.50	15,010.50	0.04%	0.18%	-0.53%
Xylem Inc/NY	XYL	240.83	91.03	1.45	6.00	21,922.66	0.06%	0.09%	0.37%
Marathon Petroleum Corp	MPC	399.84	151.34	1.98	14.50	60,512.39	0.17%	0.34%	2.47%
Tractor Supply Co	TSCO	108.81	203.05	2.03	13.50	22,093.46	0.06%	0.13%	0.84%
Advanced Micro Devices Inc	AMD	1615.67	102.82	n/a	25.50	166,123.29	0.47%		11.94%
ResMed Inc	RMD	147.07	147.87	1.30	9.50	21,747.39	0.06%	0.08%	0.58%
Mettler-Toledo International Inc	MTD	21.87	1108.07	n/a	11.00	24,227.95	0.07%		0.75%
Jacobs Solutions Inc	J	125.92	136.50	0.76	11.00	17,187.81	0.05%	0.04%	0.53%
Copart Inc	CPRT	957.36	43.09	n/a	7.00	41,252.47	0.12%		0.81%
VICI Properties Inc	VICI	1013.43	29.10	5.70	8.00	29,490.75	0.08%	0.47%	0.66%
Albemarle Corp	ALB	117.35	170.04	0.94	-4.50	19,953.68	0.06%	0.05%	-0.25%
Fortinet Inc	FTNT	785.34	58.68	n/a	24.00	46,083.58	0.13%		3.12%
Moderna Inc	MRNA	380.59	103.29	n/a	-20.00	39,311.45	0.11%		-2.22%
Essex Property Trust Inc	ESS	64.18	212.09	4.36	2.00	13,612.57	0.04%	0.17%	0.08%
CoStar Group Inc	CSGP	408.34	76.89	n/a	14.00	31,397.03	0.09%		1.24%
Realty Income Corp	O	708.79	49.94	6.15	5.50	35,396.87	0.10%	0.61%	0.55%
Westrock Co	WRK	256.40	35.80	3.07	8.50	9,179.23	0.03%	0.08%	0.22%
Westinghouse Air Brake Technologies Corp	WAB	179.13	106.27	0.64	10.50	19,036.15	0.05%	0.03%	0.56%
Pool Corp	POOL	39.05	356.10	1.24	14.00	13,906.42	0.04%	0.05%	0.55%
Western Digital Corp	WDC	321.90	45.63	n/a	3.00	14,688.11	0.04%		0.12%
PepsiCo Inc	PEP	1376.58	169.44	2.99	5.50	233,247.88	0.66%	1.96%	3.61%
Diamondback Energy Inc	FANG	178.82	154.88	2.17		0.00	0.00%	0.00%	
Palo Alto Networks Inc	PANW	308.60	234.44	n/a		0.00	0.00%		
ServiceNow Inc	NOW	204.00	558.96	n/a	61.00	114,027.84	0.32%		19.60%
Church & Dwight Co Inc	CHD	246.05	91.63	1.19	6.00	22,545.29	0.06%	0.08%	0.38%
Federal Realty Investment Trust	FRT	81.52	90.63	4.81	2.50	7,388.43	0.02%	0.10%	0.05%
MGM Resorts International	MGM	350.89	36.76	n/a	25.00	12,898.68	0.04%		0.91%
American Electric Power Co Inc	AEP	515.18	75.22	4.41	6.50	38,751.54	0.11%	0.48%	0.71%
SolarEdge Technologies Inc	SEDG	56.56	129.51	n/a	27.00	7,324.83	0.02%		0.56%
Invitation Homes Inc	INVH	611.96	31.69	3.28		0.00	0.00%	0.00%	
PTC Inc	PTC	118.83	141.68	n/a	15.00	16,836.26	0.05%		0.71%
JB Hunt Transport Services Inc	JBHT	103.35	188.52	0.89	9.00	19,482.60	0.05%	0.05%	0.49%
Lam Research Corp	LRCX	132.51	626.77	1.28	8.00	83,054.55	0.23%	0.30%	1.87%
Mohawk Industries Inc	MHK	63.68	85.81	n/a	2.50	5,464.55	0.02%		0.04%
GE HealthCare Technologies Inc	GEHC	454.84	68.04	0.18		0.00	0.00%	0.00%	

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Pentair PLC	PNR	165.11	64.75	1.36	12.00	10,691.07	0.03%	0.04%	0.36%
Vertex Pharmaceuticals Inc	VRTX	258.10	347.74	n/a	12.00	89,749.96	0.25%		3.03%
Amcor PLC	AMCR	1446.44	9.16	5.35	13.00	13,249.36	0.04%	0.20%	0.49%
Meta Platforms Inc	META	2222.58	300.21	n/a	9.00	667,241.64	1.88%		16.92%
T-Mobile US Inc	TMUS	1176.46	140.05	1.86	20.00	164,762.80	0.46%	0.86%	9.29%
United Rentals Inc	URI	68.28	444.57	1.33	17.00	30,356.57	0.09%	0.11%	1.45%
Honeywell International Inc	HON	663.96	184.74	2.34	11.00	122,660.16	0.35%	0.81%	3.80%
Alexandria Real Estate Equities Inc	ARE	173.03	100.10	4.96	11.00	17,320.10	0.05%	0.24%	0.54%
Delta Air Lines Inc	DAL	643.42	37.00	1.08		0.00	0.00%	0.00%	
Seagate Technology Holdings PLC	STX	207.39	65.95	4.25	7.00	13,677.57	0.04%	0.16%	0.27%
United Airlines Holdings Inc	UAL	326.73	42.30	n/a		0.00	0.00%		
News Corp	NWS	191.84	20.87	0.96		0.00	0.00%	0.00%	
Centene Corp	CNC	541.48	68.88	n/a	10.00	37,297.07	0.11%		1.05%
Martin Marietta Materials Inc	MLM	61.80	410.48	0.72	12.00	25,369.31	0.07%	0.05%	0.86%
Teradyne Inc	TER	154.01	100.46	0.44	12.50	15,472.25	0.04%	0.02%	0.54%
PayPal Holdings Inc	PYPL	1098.04	58.46	n/a	12.00	64,191.24	0.18%		2.17%
Tesla Inc	TSLA	3173.99	250.22	n/a	26.00	794,196.78	2.24%		58.18%
Arch Capital Group Ltd	ACGL	372.95	79.71	n/a	21.00	29,728.16	0.08%		1.76%
Dow Inc	DOW	703.08	51.56	5.43	7.00	36,250.55	0.10%	0.55%	0.72%
Everest Group Ltd	EG	43.40	371.67	1.88	10.00	16,131.96	0.05%	0.09%	0.45%
Teledyne Technologies Inc	TDY	47.08	408.58	n/a	9.50	19,233.90	0.05%		0.51%
News Corp	NWSA	379.59	20.06	1.00		0.00	0.00%	0.00%	
Exelon Corp	EXC	994.30	37.79	3.81		0.00	0.00%	0.00%	
Global Payments Inc	GPN	259.99	115.39	0.87	13.50	30,000.71	0.08%	0.07%	1.14%
Crown Castle Inc	CCI	433.68	92.03	6.80	7.00	39,911.48	0.11%	0.76%	0.79%
Aptiv PLC	APTV	282.82	98.59	n/a	33.50	27,883.62	0.08%		2.63%
Align Technology Inc	ALGN	76.53	305.32	n/a	17.00	23,367.36	0.07%		1.12%
Illumina Inc	ILMN	158.30	137.28	n/a	6.50	21,731.42	0.06%		0.40%
Kenvue Inc	KVUE	1914.89	20.08	3.98		0.00	0.00%	0.00%	
Targa Resources Corp	TRGP	223.71	85.72	2.33		0.00	0.00%	0.00%	
LKQ Corp	LKQ	267.56	49.51	2.22	13.00	13,246.70	0.04%	0.08%	0.49%
Zoetis Inc	ZTS	460.32	173.98	0.86	9.00	80,085.95	0.23%	0.19%	2.03%
Equinix Inc	EQIX	93.57	726.26	1.88	15.00	67,952.52	0.19%	0.36%	2.87%
Digital Realty Trust Inc	DLR	302.71	121.02	4.03	-3.00	36,633.84	0.10%	0.42%	-0.31%
Molina Healthcare Inc	MOH	58.30	327.89	n/a	11.50	19,115.99	0.05%		0.62%
Las Vegas Sands Corp	LVS	764.45	45.84	1.75		0.00	0.00%	0.00%	

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE, BLENDED MRP, & VL BETA

$K = Rf + \beta (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	30-day Average of 30-Year U.S. Treasury Bond Yield	Beta (β)	Forward Market Return (Rm)	Average Forward and Historical Market Risk Premium (Rm − Rf)	ROE (K)
Atmos Energy Corporation	ATO	4.42%	0.85	15.03%	8.89%	11.98%
New Jersey Resources Corporation	NJR	4.42%	0.95	15.03%	8.89%	12.87%
NiSource Inc.	NI	4.42%	0.90	15.03%	8.89%	12.42%
ONE Gas, Inc.	OGS	4.42%	0.80	15.03%	8.89%	11.53%
Southwest Gas Holding	SWX	4.42%	0.90	15.03%	8.89%	12.42%
Spire, Inc.	SR	4.42%	0.85	15.03%	8.89%	11.98%
Ameren Corporation	AEE	4.42%	0.85	15.03%	8.89%	11.98%
Avista Corporation	AVA	4.42%	0.90	15.03%	8.89%	12.42%
Black Hills Corporation	BKH	4.42%	1.00	15.03%	8.89%	13.31%
CenterPoint Energy, Inc.	CNP	4.42%	1.10	15.03%	8.89%	14.20%
CMS Energy Corporation	CMS	4.42%	0.80	15.03%	8.89%	11.53%
DTE Energy Company	DTE	4.42%	0.95	15.03%	8.89%	12.87%
MGE Energy, Inc.	MGEE	4.42%	0.75	15.03%	8.89%	11.09%
NorthWestern Energy Group, Inc.	NWE	4.42%	0.95	15.03%	8.89%	12.87%
Public Service Enterprise Group Inc.	PEG	4.42%	0.95	15.03%	8.89%	12.87%
Southern Company	SO	4.42%	0.90	15.03%	8.89%	12.42%
Wisconsin Energy Corporation	WEC	4.42%	0.80	15.03%	8.89%	11.53%
Gas Proxy Group Mean			0.88			12.20%
Combined Proxy Group Mean			0.89			12.37%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line, as of September 29, 2023
[3] Source: Average of MRPs presented in Exh. 407 page 1-15
[4] Equals Average of ([3] - [1], 7.17%)
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE, BLENDED MRP, & BLOOMBERG BETA

$K = Rf + \beta (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	30-day Average of 30-Year U.S. Treasury Bond Yield	Beta (β)	Forward Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Atmos Energy Corporation	ATO	4.42%	0.803	15.03%	8.89%	11.56%
New Jersey Resources Corporation	NJR	4.42%	0.841	15.03%	8.89%	11.90%
NiSource Inc.	NI	4.42%	0.863	15.03%	8.89%	12.09%
ONE Gas, Inc.	OGS	4.42%	0.819	15.03%	8.89%	11.70%
Southwest Gas Holding	SWX	4.42%	0.869	15.03%	8.89%	12.14%
Spire, Inc.	SR	4.42%	0.836	15.03%	8.89%	11.85%
Ameren Corporation	AEE	4.42%	0.830	15.03%	8.89%	11.80%
Avista Corporation	AVA	4.42%	0.822	15.03%	8.89%	11.73%
Black Hills Corporation	BKH	4.42%	0.994	15.03%	8.89%	13.25%
CenterPoint Energy, Inc.	CNP	4.42%	1.088	15.03%	8.89%	14.09%
CMS Energy Corporation	CMS	4.42%	0.825	15.03%	8.89%	11.75%
DTE Energy Company	DTE	4.42%	0.912	15.03%	8.89%	12.53%
MGE Energy, Inc.	MGEE	4.42%	0.701	15.03%	8.89%	10.65%
NorthWestern Energy Group, Inc.	NWE	4.42%	0.964	15.03%	8.89%	12.99%
Public Service Enterprise Group Inc.	PEG	4.42%	0.932	15.03%	8.89%	12.70%
Southern Company	SO	4.42%	0.887	15.03%	8.89%	12.30%
Wisconsin Energy Corporation	WEC	4.42%	0.813	15.03%	8.89%	11.65%
Gas Proxy Group Mean			0.84			11.87%
Combined Proxy Group Mean			0.87			12.16%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 5-Year Betas as of September 29, 2023
[3] Source: Average of MRPs presented in Exh. 407 page 1-15
[4] Equals Average of ([3] - [1], 7.17%)
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE, BLENDED MRP, & VL BETA
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2025 - 2029)	Beta (β)	Forward Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Atmos Energy Corporation	ATO	3.80%	0.85	15.03%	9.20%	11.62%
New Jersey Resources Corporation	NJR	3.80%	0.95	15.03%	9.20%	12.54%
NiSource Inc.	NI	3.80%	0.90	15.03%	9.20%	12.08%
ONE Gas, Inc.	OGS	3.80%	0.80	15.03%	9.20%	11.16%
Southwest Gas Holding	SWX	3.80%	0.90	15.03%	9.20%	12.08%
Spire, Inc.	SR	3.80%	0.85	15.03%	9.20%	11.62%
Ameren Corporation	AEE	3.80%	0.85	15.03%	9.20%	11.62%
Avista Corporation	AVA	3.80%	0.90	15.03%	9.20%	12.08%
Black Hills Corporation	BKH	3.80%	1.00	15.03%	9.20%	13.00%
CenterPoint Energy, Inc.	CNP	3.80%	1.10	15.03%	9.20%	13.92%
CMS Energy Corporation	CMS	3.80%	0.80	15.03%	9.20%	11.16%
DTE Energy Company	DTE	3.80%	0.95	15.03%	9.20%	12.54%
MGE Energy, Inc.	MGEE	3.80%	0.75	15.03%	9.20%	10.70%
NorthWestern Energy Group, Inc.	NWE	3.80%	0.95	15.03%	9.20%	12.54%
Public Service Enterprise Group Inc.	PEG	3.80%	0.95	15.03%	9.20%	12.54%
Southern Company	SO	3.80%	0.90	15.03%	9.20%	12.08%
Wisconsin Energy Corporation	WEC	3.80%	0.80	15.03%	9.20%	11.16%
Gas Proxy Group Mean			0.88			11.85%
Combined Proxy Group Mean			0.89			12.03%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023 at 14
[2] Source: Value Line, as of September 29, 2023
[3] Source: Average of MRPs presented in Exh. 407 page 1-15
[4] Equals Average of ([3] - [1], 7.17%)
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE, BLENDED MRP, & BLOOMBERG BETA
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2025 - 2029)	Beta (β)	Forward Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Atmos Energy Corporation	ATO	3.80%	0.803	15.03%	9.20%	11.19%
New Jersey Resources Corporation	NJR	3.80%	0.841	15.03%	9.20%	11.54%
NiSource Inc.	NI	3.80%	0.863	15.03%	9.20%	11.74%
ONE Gas, Inc.	OGS	3.80%	0.819	15.03%	9.20%	11.33%
Southwest Gas Holding	SWX	3.80%	0.869	15.03%	9.20%	11.79%
Spire, Inc.	SR	3.80%	0.836	15.03%	9.20%	11.49%
Ameren Corporation	AEE	3.80%	0.830	15.03%	9.20%	11.44%
Avista Corporation	AVA	3.80%	0.822	15.03%	9.20%	11.37%
Black Hills Corporation	BKH	3.80%	0.994	15.03%	9.20%	12.94%
CenterPoint Energy, Inc.	CNP	3.80%	1.088	15.03%	9.20%	13.81%
CMS Energy Corporation	CMS	3.80%	0.825	15.03%	9.20%	11.39%
DTE Energy Company	DTE	3.80%	0.912	15.03%	9.20%	12.19%
MGE Energy, Inc.	MGEE	3.80%	0.701	15.03%	9.20%	10.25%
NorthWestern Energy Group, Inc.	NWE	3.80%	0.964	15.03%	9.20%	12.67%
Public Service Enterprise Group Inc.	PEG	3.80%	0.932	15.03%	9.20%	12.37%
Southern Company	SO	3.80%	0.887	15.03%	9.20%	11.96%
Wisconsin Energy Corporation	WEC	3.80%	0.813	15.03%	9.20%	11.28%
Gas Proxy Group Mean			0.838			11.51%
Combined Proxy Group Mean			0.870			11.81%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023 at 14
[2] Source: Bloomberg Professional, 5-Year Betas as of September 29, 2023
[3] Source: Average of MRPs presented in Exh. 407 page 1-15
[4] Equals Average of ([3] - [1], 7.17%)
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE, HISTORICAL MRP, & VL BETA
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Atmos Energy Corporation	ATO	4.42%	0.85	11.59%	7.17%	10.51%
New Jersey Resources Corporation	NJR	4.42%	0.95	11.59%	7.17%	11.23%
NiSource Inc.	NI	4.42%	0.90	11.59%	7.17%	10.87%
ONE Gas, Inc.	OGS	4.42%	0.80	11.59%	7.17%	10.15%
Southwest Gas Holding	SWX	4.42%	0.90	11.59%	7.17%	10.87%
Spire, Inc.	SR	4.42%	0.85	11.59%	7.17%	10.51%
Ameren Corporation	AEE	4.42%	0.85	11.59%	7.17%	10.51%
Avista Corporation	AVA	4.42%	0.90	11.59%	7.17%	10.87%
Black Hills Corporation	BKH	4.42%	1.00	11.59%	7.17%	11.59%
CenterPoint Energy, Inc.	CNP	4.42%	1.10	11.59%	7.17%	12.30%
CMS Energy Corporation	CMS	4.42%	0.80	11.59%	7.17%	10.15%
DTE Energy Company	DTE	4.42%	0.95	11.59%	7.17%	11.23%
MGE Energy, Inc.	MGEE	4.42%	0.75	11.59%	7.17%	9.80%
NorthWestern Energy Group, Inc.	NWE	4.42%	0.95	11.59%	7.17%	11.23%
Public Service Enterprise Group Inc.	PEG	4.42%	0.95	11.59%	7.17%	11.23%
Southern Company	SO	4.42%	0.90	11.59%	7.17%	10.87%
Wisconsin Energy Corporation	WEC	4.42%	0.80	11.59%	7.17%	10.15%
Gas Proxy Group Mean			0.88			10.69%
Combined Proxy Group Mean			0.89			10.83%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line, as of September 29, 2023
[3] Equals [1] + [4]
[4] Source: Kroll, arithmetic average MRP 1926-2022
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE, HISTORICAL MRP, & BLOOMBERG BETA
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Atmos Energy Corporation	ATO	4.42%	0.803	11.59%	7.17%	10.17%
New Jersey Resources Corporation	NJR	4.42%	0.841	11.59%	7.17%	10.45%
NiSource Inc.	NI	4.42%	0.863	11.59%	7.17%	10.60%
ONE Gas, Inc.	OGS	4.42%	0.819	11.59%	7.17%	10.29%
Southwest Gas Holding	SWX	4.42%	0.869	11.59%	7.17%	10.65%
Spire, Inc.	SR	4.42%	0.836	11.59%	7.17%	10.41%
Ameren Corporation	AEE	4.42%	0.830	11.59%	7.17%	10.37%
Avista Corporation	AVA	4.42%	0.822	11.59%	7.17%	10.31%
Black Hills Corporation	BKH	4.42%	0.994	11.59%	7.17%	11.54%
CenterPoint Energy, Inc.	CNP	4.42%	1.088	11.59%	7.17%	12.22%
CMS Energy Corporation	CMS	4.42%	0.825	11.59%	7.17%	10.33%
DTE Energy Company	DTE	4.42%	0.912	11.59%	7.17%	10.96%
MGE Energy, Inc.	MGEE	4.42%	0.701	11.59%	7.17%	9.44%
NorthWestern Energy Group, Inc.	NWE	4.42%	0.964	11.59%	7.17%	11.33%
Public Service Enterprise Group Inc.	PEG	4.42%	0.932	11.59%	7.17%	11.10%
Southern Company	SO	4.42%	0.887	11.59%	7.17%	10.78%
Wisconsin Energy Corporation	WEC	4.42%	0.813	11.59%	7.17%	10.25%
Gas Proxy Group Mean			0.84			10.43%
Combined Proxy Group Mean			0.87			10.66%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 5-Year Betas as of September 29, 2023
[3] Equals [1] + [4]
[4] Source: Kroll, arithmetic average MRP 1926-2022
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE, HISTORICAL MRP, & VL BETA
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2025 - 2029)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Atmos Energy Corporation	ATO	3.80%	0.85	11.59%	7.17%	9.89%
New Jersey Resources Corporation	NJR	3.80%	0.95	11.59%	7.17%	10.61%
NiSource Inc.	NI	3.80%	0.90	11.59%	7.17%	10.25%
ONE Gas, Inc.	OGS	3.80%	0.80	11.59%	7.17%	9.54%
Southwest Gas Holding	SWX	3.80%	0.90	11.59%	7.17%	10.25%
Spire, Inc.	SR	3.80%	0.85	11.59%	7.17%	9.89%
Ameren Corporation	AEE	3.80%	0.85	11.59%	7.17%	9.89%
Avista Corporation	AVA	3.80%	0.90	11.59%	7.17%	10.25%
Black Hills Corporation	BKH	3.80%	1.00	11.59%	7.17%	10.97%
CenterPoint Energy, Inc.	CNP	3.80%	1.10	11.59%	7.17%	11.69%
CMS Energy Corporation	CMS	3.80%	0.80	11.59%	7.17%	9.54%
DTE Energy Company	DTE	3.80%	0.95	11.59%	7.17%	10.61%
MGE Energy, Inc.	MGEE	3.80%	0.75	11.59%	7.17%	9.18%
NorthWestern Energy Group, Inc.	NWE	3.80%	0.95	11.59%	7.17%	10.61%
Public Service Enterprise Group Inc.	PEG	3.80%	0.95	11.59%	7.17%	10.61%
Southern Company	SO	3.80%	0.90	11.59%	7.17%	10.25%
Wisconsin Energy Corporation	WEC	3.80%	0.80	11.59%	7.17%	9.54%
Gas Proxy Group Mean			0.88			10.07%
Combined Proxy Group Mean			0.89			10.21%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023 at 14
[2] Source: Value Line, as of September 29, 2023
[3] Equals [1] + [4]
[4] Source: Kroll, arithmetic average MRP 1926-2022
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE, HISTORICAL MRP, & BLOOMBERG BETA
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2025 - 2029)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Atmos Energy Corporation	ATO	3.80%	0.803	11.59%	7.17%	9.56%
New Jersey Resources Corporation	NJR	3.80%	0.841	11.59%	7.17%	9.83%
NiSource Inc.	NI	3.80%	0.863	11.59%	7.17%	9.99%
ONE Gas, Inc.	OGS	3.80%	0.819	11.59%	7.17%	9.67%
Southwest Gas Holding	SWX	3.80%	0.869	11.59%	7.17%	10.03%
Spire, Inc.	SR	3.80%	0.836	11.59%	7.17%	9.79%
Ameren Corporation	AEE	3.80%	0.830	11.59%	7.17%	9.75%
Avista Corporation	AVA	3.80%	0.822	11.59%	7.17%	9.70%
Black Hills Corporation	BKH	3.80%	0.994	11.59%	7.17%	10.92%
CenterPoint Energy, Inc.	CNP	3.80%	1.088	11.59%	7.17%	11.60%
CMS Energy Corporation	CMS	3.80%	0.825	11.59%	7.17%	9.71%
DTE Energy Company	DTE	3.80%	0.912	11.59%	7.17%	10.34%
MGE Energy, Inc.	MGEE	3.80%	0.701	11.59%	7.17%	8.82%
NorthWestern Energy Group, Inc.	NWE	3.80%	0.964	11.59%	7.17%	10.71%
Public Service Enterprise Group Inc.	PEG	3.80%	0.932	11.59%	7.17%	10.48%
Southern Company	SO	3.80%	0.887	11.59%	7.17%	10.16%
Wisconsin Energy Corporation	WEC	3.80%	0.813	11.59%	7.17%	9.63%
Gas Proxy Group Mean			0.838			9.81%
Combined Proxy Group Mean			0.870			10.04%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023 at 14
[2] Source: Bloomberg Professional, 5-Year Betas as of September 29, 2023
[3] Equals [1] + [4]
[4] Source: Kroll, arithmetic average MRP 1926-2022
[5] Equals [1] + [2] x [4]

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 408

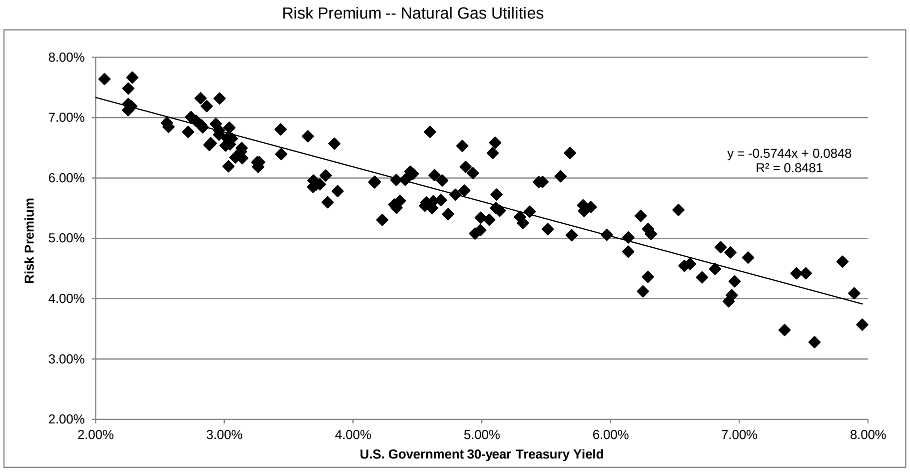
December 29, 2023

Risk Premium -- Natural Gas Utilities

	[1]	[2]	[3]
	Average Authorized Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
1992.1	12.42%	7.80%	4.62%
1992.2	11.98%	7.89%	4.09%
1992.3	11.87%	7.45%	4.42%
1992.4	11.94%	7.52%	4.42%
1993.1	11.75%	7.07%	4.68%
1993.2	11.71%	6.86%	4.85%
1993.3	11.39%	6.31%	5.07%
1993.4	11.16%	6.14%	5.02%
1994.1	11.12%	6.57%	4.55%
1994.2	10.84%	7.35%	3.48%
1994.3	10.87%	7.58%	3.28%
1994.4	11.53%	7.96%	3.57%
1995.2	11.00%	6.94%	4.06%
1995.3	11.07%	6.71%	4.35%
1995.4	11.61%	6.23%	5.37%
1996.1	11.45%	6.29%	5.16%
1996.2	10.88%	6.92%	3.96%
1996.3	11.25%	6.96%	4.29%
1996.4	11.19%	6.62%	4.58%
1997.1	11.31%	6.81%	4.49%
1997.2	11.70%	6.93%	4.77%
1997.3	12.00%	6.53%	5.47%
1997.4	10.92%	6.14%	4.78%
1998.2	11.37%	5.85%	5.52%
1998.3	11.41%	5.47%	5.94%
1998.4	11.69%	5.10%	6.59%
1999.1	10.82%	5.37%	5.44%
1999.2	11.25%	5.79%	5.46%
1999.4	10.38%	6.25%	4.12%
2000.1	10.66%	6.29%	4.36%
2000.2	11.03%	5.97%	5.06%
2000.3	11.33%	5.79%	5.55%
2000.4	12.10%	5.69%	6.41%
2001.1	11.38%	5.44%	5.93%
2001.2	10.75%	5.70%	5.05%
2001.4	10.65%	5.30%	5.35%
2002.1	10.67%	5.51%	5.15%
2002.2	11.64%	5.61%	6.03%
2002.3	11.50%	5.08%	6.42%
2002.4	11.01%	4.93%	6.08%
2003.1	11.38%	4.85%	6.53%
2003.2	11.36%	4.60%	6.76%
2003.3	10.61%	5.11%	5.50%
2003.4	10.84%	5.11%	5.73%
2004.1	11.06%	4.88%	6.18%
2004.2	10.57%	5.32%	5.25%
2004.3	10.37%	5.06%	5.31%
2004.4	10.66%	4.86%	5.79%
2005.1	10.65%	4.69%	5.96%
2005.2	10.54%	4.47%	6.07%
2005.3	10.47%	4.44%	6.03%
2005.4	10.32%	4.68%	5.63%
2006.1	10.68%	4.63%	6.05%
2006.2	10.60%	5.14%	5.46%
2006.3	10.34%	4.99%	5.34%
2006.4	10.14%	4.74%	5.40%
2007.1	10.52%	4.80%	5.72%
2007.2	10.13%	4.99%	5.14%
2007.3	10.03%	4.95%	5.08%
2007.4	10.12%	4.61%	5.50%
2008.1	10.38%	4.41%	5.97%
2008.2	10.17%	4.57%	5.60%

Risk Premium -- Natural Gas Utilities

	[1]	[2]	[3]
	Average Authorized Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
2008.3	10.55%	4.44%	6.11%
2008.4	10.34%	3.65%	6.69%
2009.1	10.24%	3.44%	6.81%
2009.2	10.11%	4.17%	5.94%
2009.3	9.88%	4.32%	5.56%
2009.4	10.31%	4.34%	5.97%
2010.1	10.24%	4.62%	5.61%
2010.2	9.99%	4.36%	5.62%
2010.3	10.43%	3.86%	6.57%
2010.4	10.09%	4.17%	5.93%
2011.1	10.10%	4.56%	5.54%
2011.2	9.85%	4.34%	5.51%
2011.3	9.65%	3.69%	5.96%
2011.4	9.88%	3.04%	6.84%
2012.1	9.63%	3.14%	6.50%
2012.2	9.83%	2.93%	6.90%
2012.3	9.75%	2.74%	7.01%
2012.4	10.06%	2.86%	7.19%
2013.1	9.57%	3.13%	6.44%
2013.2	9.47%	3.14%	6.33%
2013.3	9.60%	3.71%	5.89%
2013.4	9.83%	3.79%	6.04%
2014.1	9.54%	3.69%	5.85%
2014.2	9.84%	3.44%	6.39%
2014.3	9.45%	3.26%	6.19%
2014.4	10.28%	2.96%	7.32%
2015.1	9.47%	2.55%	6.91%
2015.2	9.43%	2.88%	6.55%
2015.3	9.75%	2.96%	6.79%
2015.4	9.68%	2.96%	6.72%
2016.1	9.48%	2.72%	6.76%
2016.2	9.42%	2.57%	6.85%
2016.3	9.47%	2.28%	7.19%
2016.4	9.67%	2.83%	6.84%
2017.1	9.60%	3.04%	6.56%
2017.2	9.47%	2.90%	6.58%
2017.3	10.14%	2.82%	7.32%
2017.4	9.70%	2.82%	6.88%
2018.1	9.68%	3.02%	6.66%
2018.2	9.43%	3.09%	6.34%
2018.3	9.71%	3.06%	6.65%
2018.4	9.53%	3.27%	6.26%
2019.1	9.55%	3.01%	6.54%
2019.2	9.73%	2.78%	6.94%
2019.3	9.95%	2.29%	7.66%
2019.4	9.74%	2.25%	7.48%
2020.1	9.35%	1.89%	7.46%
2020.2	9.55%	1.38%	8.17%
2020.3	9.52%	1.37%	8.15%
2020.4	9.50%	1.62%	7.88%
2021.1	9.71%	2.07%	7.64%
2021.2	9.48%	2.25%	7.22%
2021.3	9.43%	1.93%	7.50%
2021.4	9.59%	1.94%	7.65%
2022.1	9.38%	2.25%	7.12%
2022.2	9.23%	3.03%	6.19%
2022.3	9.52%	3.26%	6.26%
2022.4	9.66%	3.88%	5.78%
2023.1	9.64%	3.74%	5.89%
2023.2	9.40%	3.80%	5.60%
2023.3	9.53%	4.23%	5.30%
AVERAGE	10.39%	4.48%	5.91%
MEDIAN	10.28%	4.47%	5.94%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.92097
R Square	0.84819
Adjusted R Square	0.84693
Standard Error	0.00398
Observations	123

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.0107	0.0107	676.0392	0.0000
Residual	121	0.0019	0.0000		
Total	122	0.0126			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.0848	0.00105	80.56117	0.00000	0.08275	0.08692
30-Year Treasury Bond Yield	-0.5744	0.02209	-26.00075	0.00000	-0.61818	-0.53070

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.42%	5.95%	10.36%
Blue Chip Near-Term Projected Forecast (Q1 2024 - Q1 2025) [5]	4.16%	6.09%	10.25%
Blue Chip Long-Term Projected Forecast (2025-2029) [6]	3.80%	6.30%	10.10%
AVERAGE			10.24%

Notes:
[1] Source: Regulatory Research Associates, rate cases through September 29, 2023
[2] Source: Bloomberg Professional, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional, 30-day average as of September 29, 2023
[5] Source: Blue Chip Financial Forecasts, Vol. 42, No. 10, October 1, 2023 at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023 at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.084834 + (-0.574439 x Column [7])
[9] Equals Column [7] + Column [8]

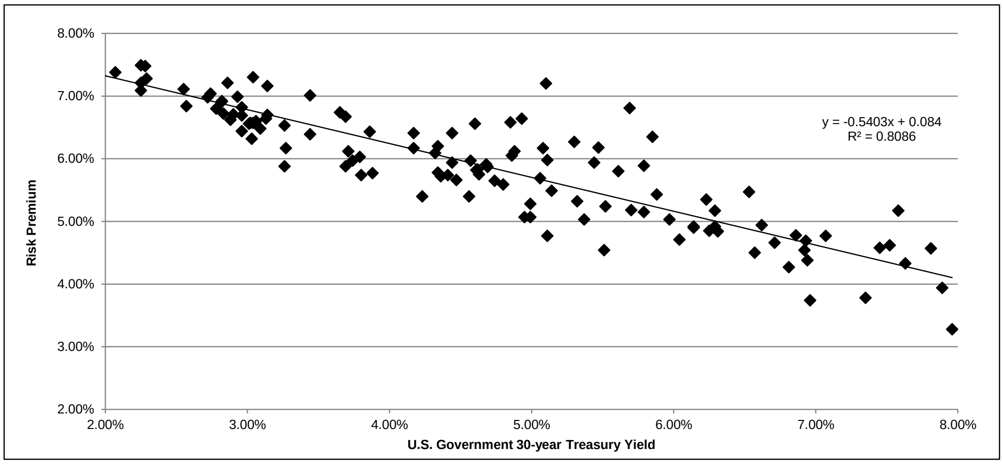
Risk Premium -- Electric Utilities (US)

	[1] Average Authorized Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1992.1	12.38%	7.81%	4.57%
1992.2	11.83%	7.89%	3.94%
1992.3	12.03%	7.45%	4.58%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.77%
1993.2	11.64%	6.86%	4.78%
1993.3	11.15%	6.31%	4.84%
1993.4	11.04%	6.14%	4.90%
1994.1	11.07%	6.57%	4.50%
1994.2	11.13%	7.35%	3.78%
1994.3	12.75%	7.58%	5.17%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.33%
1995.2	11.32%	6.94%	4.38%
1995.3	11.37%	6.71%	4.66%
1995.4	11.58%	6.23%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.96%	3.74%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.81%	4.27%
1997.2	11.62%	6.93%	4.69%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.14%	4.92%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.47%	6.18%
1998.4	12.30%	5.10%	7.20%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.79%	5.15%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.25%	4.85%
2000.1	11.21%	6.29%	4.92%
2000.2	11.00%	5.97%	5.03%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.44%	5.94%
2001.2	10.88%	5.70%	5.18%
2001.3	10.76%	5.52%	5.24%
2001.4	11.57%	5.30%	6.27%
2002.1	10.05%	5.51%	4.54%
2002.2	11.41%	5.61%	5.80%
2002.3	11.25%	5.08%	6.17%
2002.4	11.57%	4.93%	6.64%
2003.1	11.43%	4.85%	6.58%
2003.2	11.16%	4.60%	6.56%
2003.3	9.88%	5.11%	4.77%
2003.4	11.09%	5.11%	5.98%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.32%	5.32%
2004.3	10.75%	5.06%	5.69%
2004.4	10.91%	4.86%	6.05%
2005.1	10.56%	4.69%	5.87%
2005.2	10.13%	4.47%	5.66%
2005.3	10.85%	4.44%	6.41%
2005.4	10.59%	4.68%	5.91%
2006.1	10.38%	4.63%	5.75%
2006.2	10.63%	5.14%	5.49%
2006.3	10.06%	4.99%	5.07%
2006.4	10.39%	4.74%	5.65%
2007.1	10.39%	4.80%	5.59%
2007.2	10.27%	4.99%	5.28%
2007.3	10.02%	4.95%	5.07%
2007.4	10.43%	4.61%	5.82%
2008.1	10.15%	4.41%	5.74%
2008.2	10.54%	4.57%	5.97%
2008.3	10.38%	4.44%	5.94%
2008.4	10.39%	3.65%	6.74%
2009.1	10.45%	3.44%	7.01%
2009.2	10.58%	4.17%	6.41%
2009.3	10.41%	4.32%	6.09%
2009.4	10.54%	4.34%	6.20%
2010.1	10.45%	4.62%	5.83%
2010.2	10.08%	4.36%	5.72%
2010.3	10.29%	3.86%	6.43%
2010.4	10.34%	4.17%	6.17%
2011.1	9.96%	4.56%	5.40%
2011.2	10.12%	4.34%	5.78%
2011.3	10.36%	3.69%	6.67%
2011.4	10.34%	3.04%	7.30%
2012.1	10.30%	3.14%	7.16%

Risk Premium -- Electric Utilities (US)

	[1] Average Authorized Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
2012.2	9.92%	2.93%	6.99%
2012.3	9.78%	2.74%	7.04%
2012.4	10.07%	2.86%	7.21%
2013.1	9.77%	3.13%	6.64%
2013.2	9.84%	3.14%	6.70%
2013.3	9.83%	3.71%	6.12%
2013.4	9.82%	3.79%	6.03%
2014.1	9.57%	3.69%	5.88%
2014.2	9.83%	3.44%	6.39%
2014.3	9.79%	3.26%	6.53%
2014.4	9.78%	2.96%	6.82%
2015.1	9.66%	2.55%	7.11%
2015.2	9.50%	2.88%	6.62%
2015.3	9.40%	2.96%	6.44%
2015.4	9.65%	2.96%	6.69%
2016.1	9.70%	2.72%	6.98%
2016.2	9.41%	2.57%	6.84%
2016.3	9.76%	2.28%	7.48%
2016.4	9.55%	2.83%	6.72%
2017.1	9.61%	3.04%	6.57%
2017.2	9.61%	2.90%	6.71%
2017.3	9.73%	2.82%	6.91%
2017.4	9.74%	2.82%	6.92%
2018.1	9.59%	3.02%	6.57%
2018.2	9.57%	3.09%	6.48%
2018.3	9.66%	3.06%	6.60%
2018.4	9.44%	3.27%	6.17%
2019.1	9.57%	3.01%	6.56%
2019.2	9.58%	2.78%	6.80%
2019.3	9.57%	2.29%	7.28%
2019.4	9.74%	2.25%	7.49%
2020.1	9.45%	1.89%	7.56%
2020.2	9.52%	1.38%	8.14%
2020.3	9.34%	1.37%	7.97%
2020.4	9.32%	1.62%	7.70%
2021.1	9.45%	2.07%	7.38%
2021.2	9.46%	2.25%	7.21%
2021.3	9.37%	1.93%	7.44%
2021.4	9.36%	1.94%	7.42%
2022.1	9.34%	2.25%	7.09%
2022.2	9.35%	3.03%	6.32%
2022.3	9.14%	3.26%	5.88%
2022.4	9.65%	3.88%	5.77%
2023.1	9.71%	3.74%	5.97%
2023.2	9.54%	3.80%	5.74%
2023.3	9.63%	4.23%	5.40%
AVERAGE	10.49%	4.54%	5.95%
MEDIAN	10.39%	4.57%	5.97%

Risk Premium -- Electric Utilities (US)



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.899258063
R Square	0.808665064
Adjusted R Square	0.807134385
Standard Error	0.004329513
Observations	127

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.009902904	0.009902904	528.3046324	1.02346E-46
Residual	125	0.002343086	1.87447E-05		
Total	126	0.01224599			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.084035246	0.001133709	74.12420169	3.6199E-105	0.081791496	0.086279
30-Year Treasury Bond Yield	-0.540306164	0.023507027	-22.98487834	1.02346E-46	-0.586829489	-0.4937828

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.42%	6.02%	10.43%
Blue Chip Near-Term Projected Forecast (Q1 2024 - Q1 2025) [5]	4.16%	6.16%	10.32%
Blue Chip Long-Term Projected Forecast (2025-2029) [6]	3.80%	6.35%	10.15%
AVERAGE			10.30%

Notes:
[1] Source: Regulatory Research Associates, rate cases through September 29, 2023
[2] Source: Bloomberg Professional, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional, 30-day average as of September 29, 2023
[5] Source: Blue Chip Financial Forecasts, Vol. 42, No. 10, October 1, 2023 at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023 at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.084035 + (-0.540306 x Column [7])
[9] Equals Column [7] + Column [8]

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 409

December 29, 2023

EXPECTED EARNINGS ANALYSIS

Company	Ticker	[1] Value Line ROE 2026-2028	[2] Value Line Total Capital 2022	[3] Value Line Common Equity Ratio 2022	[4] Total Equity 2022	[5] Value Line Total Capital 2026-2028	[6] Value Line Common Equity Ratio 2026-2028	[7] Total Equity 2026-2028	[8] Compound Annual Growth Rate	[9] Adjustment Factor	[10] Adjusted Return on Common Equity
Atmos Energy Corporation	ATO	10.00%	15,180	62.10%	9,427	22,500	60.00%	13,500	7.45%	1.036	10.36%
New Jersey Resources Corporation	NJR	11.50%	4,303	42.20%	1,816	6,250	45.00%	2,813	9.15%	1.044	12.00%
NiSource Inc.	NI	10.00%	17,099	31.60%	5,403	22,500	40.00%	9,000	10.74%	1.051	10.51%
ONE Gas, Inc.	OGS	8.50%	5,246	49.30%	2,586	7,500	49.00%	3,675	7.28%	1.035	8.80%
Southwest Gas Holding	SWX	7.50%	7,621	42.20%	3,216	9,500	45.00%	4,275	5.86%	1.028	7.71%
Spire, Inc.	SR	8.00%	5,777	44.60%	2,577	8,200	45.00%	3,690	7.45%	1.036	8.29%
Ameren Corporation	AEE	10.00%	24,193	43.40%	10,500	29,500	48.50%	14,308	6.38%	1.031	10.31%
Avista Corporation	AVA	7.50%	4,710	49.60%	2,336	6,000	50.50%	3,030	5.34%	1.026	7.70%
Black Hills Corporation	BKH	8.00%	6,602	45.40%	2,997	8,425	46.00%	3,876	5.27%	1.026	8.21%
CenterPoint Energy, Inc.	CNP	10.00%	24,878	37.10%	9,230	28,000	44.00%	12,320	5.95%	1.029	10.29%
CMS Energy Corporation	CMS	12.00%	20,205	33.60%	6,789	24,300	39.00%	9,477	6.90%	1.033	12.40%
DTE Energy Company	DTE	12.50%	25,158	37.00%	9,308	32,200	39.00%	12,558	6.17%	1.030	12.87%
MGE Energy, Inc.	MGEE	12.00%	1,684	64.20%	1,081	2,000	61.00%	1,220	2.45%	1.012	12.15%
NorthWestern Energy Group, Inc.	NWE	8.00%	5,148	51.80%	2,667	6,200	52.00%	3,224	3.87%	1.019	8.15%
Public Service Enterprise Group Inc.	PEG	13.00%	30,224	45.40%	13,722	37,600	46.00%	17,296	4.74%	1.023	13.30%
Southern Company	SO	14.50%	80,558	36.50%	29,404	93,500	37.00%	34,595	3.31%	1.016	14.74%
Wisconsin Energy Corporation	WEC	13.00%	25,368	44.40%	11,263	29,800	44.50%	13,261	3.32%	1.016	13.21%
Gas Proxy Group Mean											9.61%
Gas Proxy Group Median											9.58%
Combined Proxy Group Mean											10.65%
Combined Proxy Group Median											10.36%

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Source: Value Line
[4] Equals [2] x [3]
[5] Source: Value Line
[6] Source: Value Line
[7] Equals [5] x [6]
[8] Equals ([7] / [4]) ^ (1/5) - 1
[9] Equals 2 x (1 + [8]) / (2 + [8])
[10] Equals [1] x [9]

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 410

December 29, 2023

Small Size Premium

	[1] ($Mil)
NW Natural Gas Equity	$1,070.00
Median Market to Book for Proxy Group	1.56
NW Natural's Implied Market Capitalization	$1,666.69

Company Name	Ticker	[2] Market Cap ($Mil)	[3] Market to Book Ratio
Atmos Energy Corporation	ATO	$16,887	1.58
New Jersey Resources Corporation	NJR	$4,129	2.07
NiSource Inc.	NI	$11,002	1.81
ONE Gas, Inc.	OGS	$4,116	1.54
Southwest Gas Holding	SWX	$4,456	1.37
Spire, Inc.	SR	$3,090	1.15
MEDIAN		$4,292.07	1.56
MEAN		$7,280	1.58

Market Capitalization ($Mil) [4]			
Decile	Low	High	Size Premium
1	$ 31,549.077	$ 2,203,381.29	-0.26%
2	$ 12,372.885	$ 31,316.513	0.45%
3	$ 5,918.981	$ 12,323.854	0.57%
4	$ 3,770.176	$ 5,916.017	0.58%
5	$ 2,365.425	$ 3,769.877	0.93%
6	$ 1,389.851	$ 2,365.076	1.16%
7	$ 789.019	$ 1,389.118	1.37%
8	$ 377.076	$ 782.383	1.18%
9	$ 218.389	$ 373.879	2.15%
10	$ 2.015	$ 218.227	4.83%
Proxy Group Median		$ 4,292.068	0.58%
6th Decile Size Premium		$ 1,666.688	1.16%
Difference from Proxy Group Median			0.58%

Notes:
[1] Source: Company provided data. NW Natural's rate base of $2.14 billion x 50% equity ratio
[2] Source: S&P Capital IQ, 30-day average as of 9/29/2023
[3] Source: S&P Capital IQ, 30-day average as of 9/29/2023
[4] Source: Duff & Phelps Cost of Capital Navigator as of December 31, 2022

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 411

December 29, 2023

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	Average
Atmos Energy Corporation	ATO	52.91%	51.03%	58.31%	54.09%
New Jersey Resources Corporation	NJR	53.98%	55.19%	55.45%	54.88%
NiSource Inc.	NI	54.17%	54.85%	54.43%	54.48%
ONE Gas, Inc.	OGS	58.24%	61.09%	60.04%	59.79%
Southwest Gas Holding	SWX	43.96%	50.70%	47.66%	47.44%
Spire, Inc.	SR	54.32%	55.30%	58.47%	56.03%
Ameren Corporation	AEE	53.36%	53.39%	52.69%	53.15%
Avista Corporation	AVA	51.06%	50.79%	50.99%	50.95%
Black Hills Corporation	BKH	47.62%	46.99%	49.32%	47.98%
CenterPoint Energy, Inc.	CNP	48.71%	46.71%	46.96%	47.46%
CMS Energy Corporation	CMS	49.69%	52.17%	51.05%	50.97%
DTE Energy Company	DTE	50.52%	50.28%	49.87%	50.22%
MGE Energy, Inc.	MGEE	60.91%	60.44%	62.28%	61.21%
NorthWestern Energy Group, Inc.	NWE	50.34%	47.82%	47.17%	48.44%
Public Service Enterprise Group Inc.	PEG	55.16%	55.17%	54.54%	54.96%
Southern Company	SO	54.98%	54.42%	54.69%	54.70%
Wisconsin Energy Corporation	WEC	55.15%	56.19%	56.36%	55.90%
GAS PROXY GROUP MEAN		52.93%	54.70%	55.73%	54.45%
COMBINED PROXY GROUP MEAN		52.65%	53.09%	53.55%	53.10%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2022	2021	2020	Average
Atmos Energy Corporation	ATO	52.91%	51.03%	58.31%	54.09%
New Jersey Natural Gas Company	NJR	53.98%	55.19%	55.45%	54.88%
Columbia Gas of Kentucky, Inc.	NI	54.91%	53.87%	54.68%	54.49%
Columbia Gas of Maryland, Inc.	NI	51.96%	55.26%	54.95%	54.06%
Columbia Gas of Ohio, Inc.	NI	50.67%	50.79%	50.45%	50.64%
Columbia Gas of Pennsylvania, Inc.	NI	56.64%	56.05%	55.68%	56.12%
Columbia Gas of Virginia, Inc.	NI	44.25%	44.52%	43.69%	44.15%
Northern Indiana Public Service Company LLC	NI	56.92%	58.59%	58.01%	57.84%
Kansas Gas Service Company, Inc.	OGS	58.37%	61.37%	60.33%	60.02%
Oklahoma Natural Gas Company	OGS	58.26%	60.99%	59.85%	59.70%
Texas Gas Service Company, Inc.	OGS	58.13%	60.98%	59.99%	59.70%
Southwest Gas Corporation	SWX	43.96%	48.05%	47.66%	46.56%
Spire Alabama Inc.	SR	61.18%	58.51%	64.20%	61.30%
Spire Gulf Inc.	SR	51.61%	49.48%	40.55%	47.21%
Spire Mississippi Inc.	SR	NA	NA	NA	NA
Spire Missouri Inc.	SR	51.46%	53.96%	56.68%	54.03%
Ameren Illinois Company	AEE	55.39%	55.51%	54.80%	55.23%
Union Electric Company	AEE	51.54%	51.50%	50.81%	51.29%
Alaska Electric Light and Power Company	AVA	60.89%	60.49%	60.15%	60.51%
Avista Corporation	AVA	50.65%	50.35%	50.57%	50.52%
Black Hills Colorado Electric, Inc.	BKH	47.92%	46.55%	49.78%	48.08%
Black Hills Energy Arkansas, Inc.	BKH	47.26%	43.66%	51.98%	47.63%
Black Hills Power, Inc.	BKH	50.13%	49.96%	48.12%	49.41%
Black Hills Wyoming Gas, LLC	BKH	NA	47.36%	49.74%	48.55%
Cheyenne Light, Fuel and Power Company	BKH	42.85%	46.37%	47.64%	45.62%
CenterPoint Energy Houston Electric, LLC	CNP	44.55%	42.04%	41.98%	42.86%
Indiana Gas Company, Inc.	CNP	57.54%	57.05%	58.36%	57.65%
Southern Indiana Gas and Electric Company	CNP	56.48%	56.38%	56.63%	56.50%
Vectren Energy Delivery of Ohio, Inc.	CNP	57.69%	50.94%	49.86%	52.83%
Consumers Energy Company	CMS	49.69%	52.17%	51.05%	50.97%
Citizens Gas Fuel Company	DTE	NA	NA	NA	NA
DTE Electric Company	DTE	50.41%	49.83%	49.45%	49.90%
DTE Gas Company	DTE	50.82%	51.99%	51.45%	51.42%
Madison Gas and Electric Company	MGEE	60.91%	60.44%	62.28%	61.21%
NorthWestern Energy Group, Inc.	NWE	50.34%	47.82%	47.17%	48.44%
Public Service Electric and Gas Company	PEG	55.16%	55.17%	54.54%	54.96%
Alabama Power Company	SO	52.22%	51.60%	51.55%	51.79%
Georgia Power Company	SO	56.05%	55.60%	56.05%	55.90%
Mississippi Power Company	SO	55.67%	55.40%	55.31%	55.46%
Atlanta Gas Light Company	SO	59.05%	59.17%	59.30%	59.17%
Chattanooga Gas Company	SO	52.54%	52.54%	52.54%	52.54%
Northern Illinois Gas Company	SO	56.35%	54.68%	54.94%	55.32%
Virginia Natural Gas	SO	55.37%	54.17%	55.52%	55.02%
Michigan Gas Utilities Corporation	WEC	57.89%	55.30%	52.41%	55.20%
North Shore Gas Company	WEC	55.36%	55.15%	57.07%	55.86%
The Peoples Gas Light and Coke Company	WEC	52.04%	52.34%	53.90%	52.76%
Upper Michigan Energy Resources Corporation	WEC	54.50%	54.72%	52.10%	53.77%
Wisconsin Electric Power Company	WEC	55.65%	58.33%	56.70%	56.89%
Wisconsin Gas LLC	WEC	60.13%	57.18%	61.08%	59.46%
Wisconsin Public Service Corporation	WEC	54.77%	56.24%	56.71%	55.91%

Notes:
[1] Ratios are weighted by actual common capital, preferred capital and long-term debt of Operating Subsidiaries.
[2] Spire Mississippi and Citizens Gas Fuel Company are financed with 100% 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	2022	2021	2020	Average
Atmos Energy Corporation	ATO	47.09%	48.97%	41.69%	45.91%
New Jersey Resources Corporation	NJR	46.02%	44.81%	44.55%	45.12%
NiSource Inc.	NI	45.83%	45.15%	45.57%	45.52%
ONE Gas, Inc.	OGS	41.76%	38.91%	39.96%	40.21%
Southwest Gas Holding	SWX	56.04%	49.30%	52.34%	52.56%
Spire, Inc.	SR	45.68%	44.70%	41.53%	43.97%
Ameren Corporation	AEE	46.09%	46.00%	46.56%	46.22%
Avista Corporation	AVA	48.94%	49.21%	49.01%	49.05%
Black Hills Corporation	BKH	52.38%	53.01%	50.68%	52.02%
CenterPoint Energy, Inc.	CNP	51.29%	53.29%	53.04%	52.54%
CMS Energy Corporation	CMS	50.13%	47.62%	48.72%	48.83%
DTE Energy Company	DTE	49.48%	49.72%	50.13%	49.78%
MGE Energy, Inc.	MGEE	39.09%	39.56%	37.72%	38.79%
NorthWestern Energy Group, Inc.	NWE	49.66%	52.18%	52.83%	51.56%
Public Service Enterprise Group Inc.	PEG	44.84%	44.83%	45.46%	45.04%
Southern Company	SO	45.02%	45.12%	44.82%	44.99%
Wisconsin Energy Corporation	WEC	44.69%	43.63%	43.46%	43.93%
GAS PROXY GROUP MEAN		47.07%	45.30%	44.27%	45.55%
COMBINED PROXY GROUP MEAN		47.30%	46.82%	46.36%	46.83%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2022	2021	2020	Average
Atmos Energy Corporation	ATO	47.09%	48.97%	41.69%	45.91%
New Jersey Natural Gas Company	NJR	46.02%	44.81%	44.55%	45.12%
Columbia Gas of Kentucky, Inc.	NI	45.09%	46.13%	45.32%	45.51%
Columbia Gas of Maryland, Inc.	NI	48.04%	44.74%	45.05%	45.94%
Columbia Gas of Ohio, Inc.	NI	49.33%	49.21%	49.55%	49.36%
Columbia Gas of Pennsylvania, Inc.	NI	43.36%	43.95%	44.32%	43.88%
Columbia Gas of Virginia, Inc.	NI	55.75%	55.48%	56.31%	55.85%
Northern Indiana Public Service Company LLC	NI	43.08%	41.41%	41.99%	42.16%
Kansas Gas Service Company, Inc.	OGS	41.63%	38.63%	39.67%	39.98%
Oklahoma Natural Gas Company	OGS	41.74%	39.01%	40.15%	40.30%
Texas Gas Service Company, Inc.	OGS	41.87%	39.02%	40.01%	40.30%
Southwest Gas Corporation	SWX	56.04%	51.95%	52.34%	53.44%
Spire Alabama Inc.	SR	38.82%	41.49%	35.80%	38.70%
Spire Gulf Inc.	SR	48.39%	50.52%	59.45%	52.79%
Spire Mississippi Inc.	SR	NA	NA	NA	NA
Spire Missouri Inc.	SR	48.54%	46.04%	43.32%	45.97%
Ameren Illinois Company	AEE	44.17%	44.00%	44.51%	44.23%
Union Electric Company	AEE	47.80%	47.78%	48.39%	47.99%
Alaska Electric Light and Power Company	AVA	39.11%	39.51%	39.85%	39.49%
Avista Corporation	AVA	49.35%	49.65%	49.43%	49.48%
Black Hills Colorado Electric, Inc.	BKH	52.08%	53.45%	50.22%	51.92%
Black Hills Energy Arkansas, Inc.	BKH	52.74%	56.34%	48.02%	52.37%
Black Hills Power, Inc.	BKH	49.87%	50.04%	51.88%	50.59%
Black Hills Wyoming Gas, LLC	BKH	NA	52.64%	50.26%	51.45%
Cheyenne Light, Fuel and Power Company	BKH	57.15%	53.63%	52.36%	54.38%
CenterPoint Energy Houston Electric, LLC	CNP	55.45%	57.96%	58.02%	57.14%
Indiana Gas Company, Inc.	CNP	42.46%	42.95%	41.64%	42.35%
Southern Indiana Gas and Electric Company	CNP	43.52%	43.62%	43.37%	43.50%
Vectren Energy Delivery of Ohio, Inc.	CNP	42.31%	49.06%	50.14%	47.17%
Consumers Energy Company	CMS	50.13%	47.62%	48.72%	48.83%
Citizens Gas Fuel Company	DTE	NA	NA	NA	NA
DTE Electric Company	DTE	49.59%	50.17%	50.55%	50.10%
DTE Gas Company	DTE	49.18%	48.01%	48.55%	48.58%
Madison Gas and Electric Company	MGEE	39.09%	39.56%	37.72%	38.79%
NorthWestern Energy Group, Inc.	NWE	49.66%	52.18%	52.83%	51.56%
Public Service Electric and Gas Company	PEG	44.84%	44.83%	45.46%	45.04%
Alabama Power Company	SO	47.78%	46.96%	46.88%	47.21%
Georgia Power Company	SO	43.95%	44.40%	43.95%	44.10%
Mississippi Power Company	SO	44.33%	44.60%	44.69%	44.54%
Atlanta Gas Light Company	SO	40.95%	40.83%	40.70%	40.83%
Chattanooga Gas Company	SO	47.46%	47.46%	47.46%	47.46%
Northern Illinois Gas Company	SO	43.65%	45.32%	45.06%	44.68%
Virginia Natural Gas	SO	44.63%	45.83%	44.48%	44.98%
Michigan Gas Utilities Corporation	WEC	42.11%	44.70%	47.59%	44.80%
North Shore Gas Company	WEC	44.64%	44.85%	42.93%	44.14%
The Peoples Gas Light and Coke Company	WEC	47.96%	47.66%	46.10%	47.24%
Upper Michigan Energy Resources Corporation	WEC	45.50%	45.28%	47.90%	46.23%
Wisconsin Electric Power Company	WEC	43.94%	41.22%	42.82%	42.66%
Wisconsin Gas LLC	WEC	39.87%	42.82%	38.92%	40.54%
Wisconsin Public Service Corporation	WEC	45.23%	43.76%	43.29%	44.09%

Notes:
[1] Ratios are weighted by actual common capital, preferred capital and long-term debt of Operating Subsidiaries.
[2] Spire Mississippi and Citizens Gas Fuel Company are financed with 100% 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

PREFERRED EQUITY RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	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 Holding	SWX	0.00%	0.00%	0.00%	0.00%
Spire, Inc.	SR	0.00%	0.00%	0.00%	0.00%
Ameren Corporation	AEE	0.55%	0.61%	0.75%	0.64%
Avista Corporation	AVA	0.00%	0.00%	0.00%	0.00%
Black Hills Corporation	BKH	0.00%	0.00%	0.00%	0.00%
CenterPoint Energy, Inc.	CNP	0.00%	0.00%	0.00%	0.00%
CMS Energy Corporation	CMS	0.18%	0.21%	0.22%	0.21%
DTE Energy Company	DTE	0.00%	0.00%	0.00%	0.00%
MGE Energy, Inc.	MGEE	0.00%	0.00%	0.00%	0.00%
NorthWestern Energy Group, Inc.	NWE	0.00%	0.00%	0.00%	0.00%
Public Service Enterprise Group Inc.	PEG	0.00%	0.00%	0.00%	0.00%
Southern Company	SO	0.00%	0.46%	0.49%	0.32%
Wisconsin Energy Corporation	WEC	0.16%	0.18%	0.19%	0.17%
GAS PROXY GROUP MEAN		0.00%	0.00%	0.00%	0.00%
COMBINED PROXY GROUP MEAN		0.05%	0.09%	0.10%	0.08%

PREFERRED EQUITY RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2022	2021	2020	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, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Maryland, Inc.	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, Inc.	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%
Southwest Gas Corporation	SWX	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%
Ameren Illinois Company	AEE	0.44%	0.48%	0.69%	0.54%
Union Electric Company	AEE	0.66%	0.71%	0.80%	0.72%
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	NA	0.00%	0.00%	0.00%
Cheyenne Light, Fuel and Power Company	BKH	0.00%	0.00%	0.00%	0.00%
CenterPoint Energy Houston Electric, LLC	CNP	0.00%	0.00%	0.00%	0.00%
Indiana Gas Company, Inc.	CNP	0.00%	0.00%	0.00%	0.00%
Southern Indiana Gas and Electric Company	CNP	0.00%	0.00%	0.00%	0.00%
Vectren Energy Delivery of Ohio, Inc.	CNP	0.00%	0.00%	0.00%	0.00%
Consumers Energy Company	CMS	0.18%	0.21%	0.22%	0.21%
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%
Madison Gas and Electric Company	MGEE	0.00%	0.00%	0.00%	0.00%
NorthWestern Energy Group, Inc.	NWE	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%	1.43%	1.56%	1.00%
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	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	0.41%	0.45%	0.47%	0.44%
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 and Citizens Gas Fuel Company are financed with 100% 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.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Direct Testimony of Daniel B. Kizer

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS EXHIBIT 500

December 29, 2023

EXHIBIT 500 – DIRECT TESTIMONY – DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

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 Daniel B. Kizer. I am the Engineering Senior Director for 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. 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. What is the purpose of your testimony?

A. The primary purpose of my testimony is to describe major distribution system and storage facility projects serving Oregon customers that are included in this rate case. I also discuss the Company's ongoing plans for safety-driven system projects and programs. These projects are discussed in the Company's 2024 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, Underground Storage Facilities – Well Integrity Program, Seismic Projects, Proactive Excess Flow Valve ("EFV") Installation Program, Probabilistic Distribution Risk Model Project and Other Safety Projects and Programs.

II. 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 2022 rate case (docket UG 435)?

A. Yes. In its last rate case, the Company sought cost recovery for the E04 – 6 and 8 inch ILI Conversion Project, the Natural Forces Projects, the Newport Switchgear Replacement Project, the Portland Liquefied Natural Gas ("Portland LNG" or "PLNG") Boil Off Compressor Project, the TBD1845 Fire System Upgrade Project (subsequently renamed the Mist Fire System Upgrade Project), and the Mist GC 500 Human-Machine Interface ("HMI") and Controls Upgrade Project. As part of the Multi-Party Stipulation in docket UG 435, NW Natural agreed to remove these projects from its request because the projects were not scheduled to be placed in-service by October 31, 2022. By its Order No. 22-388, entered on October 24, 2022, the Public Utility Commission of Oregon ("Commission") approved and adopted the Multi-Party Stipulation that removed the costs of these projects from revenue requirement for purposes of calculating rates as set forth in the Company's attestation filed in docket UG 435 on October 24, 2022.

Q. Please provide an update of these six projects.

A. The Company completed and placed in service the E04 – 6 and 8 inch ILI Conversion Project in December 2023, the Mist Fire System Upgrade Project in December 2023, the Newport Switchgear Replacement Project in July 2023 and the Mist GC 500 HMI and Controls Upgrade Project in May 2023. The Natural Forces Projects triggered the P30 Willis Creek Horizonal Directional Drilling ("HDD") Install Project that I discuss in my testimony. The PLNG Boil Off Compressor Project is scheduled to be completed and in-service by the rate effective date in this case and is discussed in my 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;
- A public works project, namely the Tualatin-Sherwood Road Grading Project (the actual costs exceeding those already being recovered in rates);
- P30 Willis Creek HDD Install Project;
- SE Gate Station Rebuild Project; and
- 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 Liquefied Natural Gas ("Newport LNG" or "NLNG") storage facilities.

- Projects related to the Mist GC500 and GC600 turbine compressor units, specifically the Mist GC500 and GC600 Turbine Compressors Cold Spare Projects;
- Other Mist projects, specifically the Electrical Upgrades Project (Phase 2), Mist Upgrade Methanol Injection at Injection/Withdrawal ("I/W") Wells Project, and Mist Instruments & Controls Project (Phase 3);
- Portland LNG projects, specifically the PLNG Valve and Controls Replacement Project, the PLNG Boil-Off Compressor Project and the PLNG Pretreatment Improvements Project; and
- A Newport LNG project, specifically the T-1 Tank Improvements Project.

A. Major Distribution System Projects

1. North Coast Feeder Uprate Project

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 Integrated Resource Plan ("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 Electronic Portable Pressure Recorders ("EPPR"). 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 0 pounds per square inch guage ("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 non-pipeline alternatives ("NPAs"), 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 needs 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." (Docket No. LC 71, Staff's Opening Comments, page 6). 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 I stated earlier, the Company appropriately analyzed alternatives (including NPAs) 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 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?

A. The North Coast Feeder Uprate Project – Section A is expected to be placed in service in September 2024. Project design is substantially complete, jurisdictional and environmental permits have been obtained, and construction began in September 2022. Section B of the North Coast Feeder Uprate Project is expected to be completed in December 2025.

Q. What is the estimated total cost to complete the North Coast Feeder Uprate Project?

A. The total cost to complete the North Coast Feeder Uprate Project – Section A is expected to be approximately $8.2 million. The total cost to complete the North Coast Feeder Uprate Project – Section B is expected to be approximately $6.4 million.

2. Public Works Project - Tualatin-Sherwood Road Grading Project

Q. Please describe the Tualatin-Sherwood Road Grading Project.

A. The Tualatin-Sherwood Road Grading Project relocated approximately 6,400 feet of six-inch high-pressure main, approximately 11,000 feet of four-inch main, three district regulators and two telemetry facilities on Tualatin-Sherwood Road.

Q. Why did the Company conduct the Tualatin-Sherwood Road Grading Project?

A. Washington County widened Tualatin-Sherwood Road from three lanes to five lanes from Teton Avenue to Langer Farms Parkway in the City of Sherwood, a distance of approximately 3.5 miles. The County's project conflicted with the

Company's mainline running along Tualatin-Sherwood Road, and the County required the Company to mitigate the conflict. The Company had no alternative to undertaking this public works project.

Q. Is the Tualatin-Sherwood Road Grading Project completed and in service?

A. Yes. The Company completed the Sherwood-Road Grading Project in October 2022 and it is in service.

Q. Was the Tualatin-Sherwood Road Grading Project included in the Company's last rate case (UG 435)?

A. Yes. The Company listed the Tualatin-Sherwood Road Grading Project in its attestation filed on October 5, 2022, and October 24, 2022 in UG 435, and the Commission-authorized revenue requirement in that case included a certain level of project costs.

Q. Did the Commission-authorized revenue requirement in UG 435 include all costs associated with the Tualatin-Sherwood Road Grading Project?

A. No. Pursuant to Paragraph 3.d of the Multi-Party Stipulation in UG 435 adopted by Order No. 22-388, the Company agreed that the amount added to rate base for each of the completed and in-service projects identified in the attestation was the lower of the actual cost stated in the attestation or the forecasted amount included in Appendix C to the Multi-Party Stipulation. The forecasted amount included in Appendix C to the Multi-Party Stipulation was $2.6 million and the actual cost stated in the attestation was $7.0 million, so the Company included only $2.6 million in the rate base used to generate the revenue requirement in UG 435.

Q. Was $7.0 million the final actual cost of the Tualatin-Sherwood Road Grading Project?

A. No. The final actual cost of the Tualatin-Sherwood Road Grading Project is approximately $9.1 million.

Q. Please explain why the Tualatin-Sherwood Road Grading Project cost approximately $9.1 million when the amount the Company forecasted in UG 435 was approximately $2.6 million.

A. NW Natural had been coordinating utility relocation with Washington County as early as 2020. However, the final impact to NW Natural facilities and the scope of such relocation was not known during the processing of UG 435. Material changes to the County's roadway design and schedule led to numerous, significant changes that affected the scope, schedule, and costs of our gas main installation. Subsequently, several other issues outside the Company's control drove increased construction costs for the Tualatin-Sherwood Road Grading Project. ***First,*** initial relocation plans submitted to the County showed that the gas mains would be located in a County-provided public utility easement that would be outside the existing and new roadway. Due to conflict with other utilities, the County ultimately did not permit NW Natural to install the mains in the public utility easement. The design change required the new mains to be located within the existing roadway resulting in significantly higher costs for traffic control measures, pavement removal, excavation and backfill quantities of approximately $3.4 million. ***Second,*** the approximately $1.2 million cost to relocate the three district regulators and two telemetry facilities was not included in the $2.6 million forecasted amount. ***Third,*** Washington County changed its preliminary pavement restoration requirement of a temporary two-inch asphalt patch to full depth restoration, resulting in significantly higher costs for pavement removal and restoration of approximately $1.1 million. ***Fourth,*** the Company faced the following additional construction issues: it incurred additional construction costs to excavate rock of approximately $0.3 million; and the contractor encountered multiple unmarked utilities that led to delays and some damages that increased costs to avoid or repair by approximately $0.4 million.

Q. What is the Company requesting in this rate case regarding cost recovery of the Tualatin-Sherwood Road Grading Project?

A. The Company is requesting recovery of $6.5 million, which is the difference between the initial amount estimated and included in the revenue requirement in UG 435 and the total actual costs incurred by the Company to complete the Tualatin-Sherwood Road Grading Project and place it in service.

3. 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 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 is getting redesigned with a scheduled construction timeframe of Summer 2024.

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 $3.5 million.

4. SE Gate Station Rebuild Project

Q. Please describe the SE Gate Station Rebuild Project.

A. The SE Gate Station is a key delivery point in the southeast Portland area. Several significant issues at the gate station need to be addressed: difficulty of operation, inoperable and passing valves, an end-of-life line heater, corrosion, an undersized pressure regulator that also has shown evidence of extreme wear during inline inspection, and outdated and out-of-place telemetry and control devices. The SE

Gate Station Rebuild Project involves replacing piping, valves, the line heater, and station regulation, updating telemetry and controls, and installing a check meter and coalescing filter in order to improve the gate station's operation, safety, efficiency, and compliance.

Q. Did the Company consider alternatives to performing the SE Gate Station Rebuild Project?

A. Yes. The Company considered doing nothing, but that approach would not remedy any of the operational, safety, efficiency or compliance concerns referenced above. The Company also determined that demand side management was not a viable option because the issues are not related to supply. Further, a satellite LNG facility would have been inadequate to handle the demand in the southeast Portland area.

Q. What is the timing of the SE Gate Station Rebuild Project?

A. The Company expects to complete the SE Gate Station Rebuild Project in October 2024.

Q. What is the estimated total cost of the SE Gate Station Rebuild Project?

A. The total cost of the SE Gate Station Rebuild Project is expected to be approximately $2.3 million.

B. Major Storage Facility Projects

Q. Please identify the Company's storage facilities.

A. The Company has three storage facilities: Portland LNG, Newport LNG and Mist. This rate case includes projects related to all three storage facilities.

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.[1] This facility was constructed by Chicago Bridge and Iron and commissioned in 1977.

Q. Please describe the Mist Storage Facility.

A. NW Natural operates the Mist Storage Facility located in Mist, Oregon, which features a natural gas storage field consisting of seven different underground pools and a total of 21 injection/withdrawal wells. 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

[1] 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.

process equipment for conveying natural gas between the wells and utility pipelines, including the natural gas compression and dehydration systems. I will provide further detail about the compressor units later in my testimony related to the Mist GC500 and GC600 Turbine Compressor Unit Projects.

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 ("Mist Storage Facility Assessment") and identified a number of needed improvements to the facility to improve site reliability, resulting in the Mist Reliability Program. Since completing the Mist Storage Facility Assessment, the Company has conducted several other studies of the Mist Storage Facility that I will reference later in my testimony. Without acting upon many of the upgrades addressed in the Mist Storage Facility Assessment and subsequent studies, Miller Station and the Mist storage operation will likely experience equipment failures, increased operations and maintenance costs, cyber threats, and other risks over the next 10 years. Going forward, the Company expects to continually assess Miller Station and the Mist storage operations and to adapt the projects discussed in my testimony to the findings of those future assessments.

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.

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 evenly 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 89.01 percent. The Direct Testimony of Kyle T.

Walker (NW Natural/1700, Walker) addresses the topic of allocation factors and their associated methodology.

1. Mist GC500 and GC600 Turbine Compressor Units Projects

Q. Please describe the compressor units at Miller Station of the Mist Storage Facility.

A. Miller Station has four compressor units, totaling 15,400 horsepower ("hp"): two smaller reciprocating units ("GC300" and "GC400") and two larger turbine units ("GC500" and "GC600"). The GC300 and GC400 units, each rated at 1,350 hp and installed in 1988, are intended for operations when flow rate demands are low or during peak times when the site requires all compressors operating at their respective maximum capacities. 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 interstate storage service (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 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 compressor units perform after the Company completed the 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 current 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 had to be taken out of operation several times to address cracked vanes, failed combustion air seals, bleed valve failures, and oil leaks. The GC300 and GC400 reciprocating units underwent unplanned outages as well such as power piston failures, combustion system failures, main compressor bearings, and compressor crosshead failure.

Q. What caused those failures and outages?

A. The Company completed a study of the compressor units in June 2020 ("AECOM Compressor Study") and a focused turbine compressor study in December 2022 ("Burns and McDonnell Turbine Compressor Study" or "Turbine Compressor Study"). The two compressor studies found that the issues with the compressor units were caused by age, outdated and unsupported systems, mechanical fatigue, and non-ideal operation. The AECOM Compressor Study recommended upgrading the existing GC300 and GC400 reciprocating units, 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"), the Burns and McDonnell Turbine Compressor Study recommended replacing the end-of-life GC500 and GC600 turbines all together.

Q. Has the Company upgraded the GC300 and GC400 reciprocating units?

A. Yes. The Company upgraded the GC300 and GC400 reciprocating units through numerous projects, including the Mist 300 and 400 Compressor Controls Upgrade Project completed in September 2021 that I discussed in my testimony filed in the Company's most recent rate case, UG 435, NW Natural/400, Kizer/15-16. The Mist 300 and 400 Compressor Controls Upgrade Project replaced and modernized the control systems of the reciprocating compressors to obtain more useful life out of that aging equipment. Doing so has relieved the inefficient usage rates on the turbine engine driven centrifugal compressors at the Mist Storage Facility, which in turn has lowered the need to operate the turbines when flows are lower.

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 55,000 hours of operation over 25 years and the GC600 unit has 47,000 hours of operation over 21 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, which leads to 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, has the Company reevaluated and updated the AECOM Compressor Study?

A. Yes. In December 2022, the Company completed the Turbine Compressor Study. Through the Turbine Compressor Study, NW Natural has become much more informed about the vulnerability operating the existing turbine compressor units to supply storage gas to its customers. As a result of the Turbine Compressor Study, the Company is implementing 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. Through the Mist GC500 and GC600 Turbine Compressors Cold Spare Projects, the Company is acquiring a gas generator, a power turbine and standby spare parts from Siemens for each of the GC500 and GC600 turbine compressor units. At this time, the Company does not have a need for – and thus has not included in the scope of these projects – spares of the third major component of the compressor unit, the centrifugal compressor, because that component operates closer to ambient temperatures and in less demanding conditions and it was overhauled in 2022 with spare parts included. 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 will mitigate the risk of prolonged outages down to less than a month (from a current average downtime of three to six months) and will improve resiliency at the Miller Station, and it is the most cost-effective and viable option for the 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 a longer-term solution can be pursued. I will describe the Company's proposed longer-term solution later in my testimony.

Q. What is the timing and status of the Mist GC500 and GC600 Turbine Compressors Cold Spare Projects?

A. The Company expects to complete the Mist GC600 Turbine Compressor Cold Spare Project in January 2024 and expects to complete the Mist GC500 Turbine Compressor Cold Spare Project in October 2024. Neither project requires the Company to undertake an extensive and lengthy permitting process, as would have several of the alternatives that I discuss next in my testimony.

Q. What are the Company's most recent cost estimates for the Mist GC600 Turbine Compressor Cold Spare Project and the Mist GC500 Turbine Compressor Cold Spare Project?

A. The Company's most recent total cost estimate for the GC600 Turbine Compressor Cold Spare Project is approximately $1.2 million for core utility service, which is approximately $1.1 million on an Oregon-allocated basis. The Company's most recent total cost estimate for the Mist GC500 Turbine Compressor Cold Spare Project is approximately $4.1 million, or approximately $3.7 million on an Oregon-allocated basis.

Q. Did the Company consider alternatives to the Mist GC500 and GC600 Turbine Compressors Cold Spare Projects?

A. Yes. The Company considered three alternatives for each of the GC500 and GC600 units: (1) replace the existing GC500 unit with a Siemens SGT-100 equivalent driver and re-wheel the existing compressor, and replace the existing GC600 unit with a new similar driver ("Alternative 1"); (2) do nothing ("Alternative 2"); and (3) replace the existing GC500 and GC600 units each with a new equivalent turbine compressor unit provided by Solar Turbines that are configured exactly the same as each other ("Alternative 3").

Q. Why did the Company decide to not proceed with Alternative 1 as the selected option for either or both the GC500 and GC600 units?

A. Compared with the Mist GC500 and GC600 Turbine Compressors Cold Spare Projects, Alternative 1 would have taken much longer to implement for the GC500 and GC600 units, would have cost several times more for the GC500 and GC600 unitsl and would have offered only a partial, short-term solution for the GC500 and GC600 units. Alternative 1 would not have been an immediate implementation solution because it would have required an amendment to the facility's State of Oregon Energy Facility Siting Council ("EFSC") permit, and modifications to the air permit, which would have involved a minimum 12- to 18-month process. In addition, Alternative 1 would not have provided a long-term solution for NW Natural due to the unreliability and unavailability of the remaining major components of the existing gas turbine compressor units, as well as lack of response from the OEM, lack of spare parts, and extended lead times. Alternative 1 also only would have offered a partial solution because maintenance and failure issues would have continued with the major components that would not have been replaced based on the historical experience with a similar model that the operations team has used for decades.

Q. Why did the Company decide to not proceed with Alternative 2 as the selected option?

A. Quite simply, Alternative 2, or doing nothing, would not have addressed the root causes of major structural component failures, meaning that failures and outages would continue, and their impact, duration and unpredictability only would become more acute.

Q. Why did the Company decide to not proceed with Alternative 3 as the selected option?

A. Alternative 3 is not an immediate implementation alternative, even though it is the Company's long-term solution, as I will discuss next in my testimony. Alternative 3 is a much higher-cost solution, mainly regarding the cost of the turbine compressor and design, material, and construction cost due to the necessary modifications to accommodate the new equipment. Such modifications include, but are not limited to installing new inlet piping, valves, and fittings to accommodate a new turbine compressor; installing a new electrical system to accommodate a new turbine compressor; installing a new fuel gas conditioning skid; replacing and relocating the existing lube oil tank; expanding the existing compressor building; and replacing the existing gas cooler. Further, Alternative 3 would require a long implementation lead time for the EFSC permit process, which will be started soon. Notwithstanding, the Company expects that this alternative will be proposed separately in the future as the long-term solution.

Q. Why does the Company expect that Alternative 3 will be proposed separately in the future as the long-term solution to the failures and outages experienced by the GC500 and GC600 turbine compressor units?

A. There are several important reasons why the Company believes that Alternative 3 is the long-term solution to the failures and outages experienced by the GC500 and GC600 turbine compressor units. Replacing the existing GC500 and GC600 units each with a new equivalent turbine compressor unit will resolve operational issues and other issues, including OEM unresponsiveness and lack of spare parts. It also will allow for an emergency core exchange swap time of approximately 14 days, whereas Siemens does not provide a core exchange program for the existing GC500 and GC600 compressors. The new turbine unit has a proven time between overhaul of 41,000 hours (compared with the 15,000- to 30,000-hour overhaul frequency of the current units), there are about 2,000 such units configured exactly the same as each other, and there are many of the exact same units along the West Coast.

Q. If the Company expects to implement Alternative 3 for both the GC500 and GC600 units, then why is the Company executing the Mist GC500 and GC600 Turbine Compressors Cold Spare Projects now?

A. The Mist GC500 and GC600 Turbine Compressors Cold Spare Projects are needed now to continue to operate Miller Station resiliently. As discussed above, failures and outages to the GC500 and GC600 units are occurring. Alternative 3 is a long-lead solution that cannot be implemented for several winter heating seasons. At the same time, the GC500 and GC600 Turbine Compressors Cold Spare Projects can be implemented for the upcoming winter heating seasons but will not solve the issues as holistically as Alternative 3. For these reasons, the GC500 and GC600 Turbine Compressors Cold Spare Projects are needed now and Alternative 3 is needed in the future. The Company will provide detailed information about Alternative 3 in its IRP Update to be filed in August 2024.

2. Other Mist Projects

a. Mist Electrical Upgrades Project (Phase 2)

Q. What is the condition of the electrical infrastructure at Miller Station?

A. In furtherance of the Mist Storage Facility Assessment, a Company engineering consultant completed a study of the Miller Station electrical infrastructure in April 2021. That study identified deficiencies in the existing electrical distribution system and prepared a list of recommendations to bring the Miller Station electrical system into compliance with current codes and standards and to add electrical capacity to this currently constrained site.

Q. Please describe the Mist Electrical Upgrades Project.

A. The Mist Electrical Upgrades Project is implementing the recommendations of the study by replacing and upgrading a number of primary electrical components at Miller Station. The Mist Electrical Upgrades Project addresses all power availability concerns, improves safety with modern equipment designed to have lower arc flash and improved safety functions, and has minor impact to operations. Phase 1, which added electrical capacity, a new power distribution center and a new Motor Control Center, was completed and in-service in October 2022, and its costs are included in rates established in UG 435. Phase 2 continues to implement system improvements to the Miller Station electrical infrastructure.

Q. Did the Company consider alternatives to performing the Mist Electrical Upgrades Project?

A. Yes. Not performing the Mist Electrical Upgrades Project would have severely limited operations at Miller Station with end-of-life electrical equipment that pose higher safety risks and are not constructed to modern code requirements. The Mist Electrical Upgrades Project addresses new Code requirements that have driven more process and safety features, and it provides additional electrical capacity needed at Miller Station. The Company also considered whether it could reduce energy consumption by upgrading to more energy efficient equipment. However, most of the equipment at Miller Station already has been upgraded to be more energy efficient and the energy reduction could not be achieved through future equipment upgrades.

Q. What is the expected timing of the Mist Electrical Upgrades Project (Phase 2)?

A. The Company expects to complete the Mist Electrical Upgrades Project (Phase 2), which will replace additional end-of-life equipment (e.g., certain motor control centers, conductors, switchboard), replace cables with missing or deteriorated labels, upgrade power feeds, perform arc-flash studies and add disconnect switches, in October 2024.

Q. What is the Company's most recent cost estimate for the Mist Electrical Upgrades Project (Phase 2)?

A. The Company's most recent total cost estimate for the Mist Electrical Upgrades Project (Phase 2) is approximately $2.3 million for core utility service, which is approximately $2.0 million on an Oregon-allocated basis.

b. Mist Upgrade Methanol Injection at I/W Wells Project

Q. What is the condition of the methanol systems at Mist wellhead locations?

A. The existing methanol tanks and injection systems at 14 Mist wellhead locations have reached the end of their operational lifespan, resulting in the more frequent formation of hydrates in flow control valves, instrumentation supply lines, controllers and other equipment. These hydrates cause equipment to plug up, particularly with flow control valves, leading to the blockage of gas flow. When equipment becomes plugged, it must be isolated, blown down, and manually treated with methanol. Several iterations of this procedure may be necessary to unplug equipment and restore flow or functionality. The problem has been worsening rapidly due to the end-of-life methanol injection system. The pumps often experience vapor lock, and flow switches have begun to fail, resulting in insufficient methanol injection that will increase the frequency of hydrate plugs. Recently, when pulling gas from the Busch reservoir on peak deliveries, the control valve accumulated hydrates and in a short period plugged off the flow of storage gas to customers, and full control of the control valve was not regained at that location until it fully thawed. These thawing efforts can take serval hours.

Q. Please describe the Mist Upgrade Methanol Injection at I/W Wells Project.

A. The Mist Upgrade Methanol Injection at I/W Wells Project will replace the end-of-life methanol tanks and injection systems at the 14 wellhead locations with new systems. The new systems will include the use of heat trace in targeted areas and possibly additional separation to eliminate hydrates forming in the flow control valves or instrumentation supply lines. Most importantly, elimination of hydrate formations mitigates freezing and plugging those lines or devices ultimately resulting in loss of operational control.

Q. Did the Company consider alternatives to the Mist Upgrade Methanol Injection at I/W Wells Project?

A. Yes. Not performing the Mist Upgrade Methanol Injection at I/W Wells Project would have severely limited operations at Miller Station with end-of-life methanol systems that result in more frequent formation of hydrates that can damage flow control valves, instrumentation supply lines, controllers, and other equipment. Damaged equipment creates unplanned downtime and manual intervention, which adversely impacts delivery of storage gas to customers. The Company also considered a phased implementation of the Mist Upgrade Methanol Injection at I/W Wells Project, but determined that it would be difficult to predict which locations should be prioritized because all the above-referenced equipment have reached the end of their operational lifespan. Ultimately, the Company concluded that the Mist Upgrade Methanol Injection at I/W Wells Project was the least-cost, least-risk alternative.

Q. What is the expected timing of the Mist Upgrade Methanol Injection at I/W Wells Project?

A. The Company expected to complete the Mist Upgrade Methanol Injection at I/W Wells Project in August 2024.

Q. What is the Company's most recent cost estimate of the Mist Upgrade Methanol Injection at I/W Wells Project?

A. The Company's most recent total cost estimate for the Mist Upgrade Methanol Injection at I/W Wells Project is approximately $4.6 million for core utility service, which is approximately $4.1 million on an Oregon-allocated basis.

c. Mist Instruments & Controls Project (Phase 3)

Q. Please describe the Mist Instrument and Controls Project (Phase 3).

A. In furtherance of the Mist Storage Facility Assessment, a Company engineering consultant completed an assessment report of the Miller Station instrumentation and controls equipment in June 2023 that recommended replacing certain equipment. The Mist Instrument and Controls Project (Phase 3) will replace failing, functionally-reduced and end-of-life equipment, including flow transmitters, moisture analyzers, ultrasonic flow transmitters, chromatographs and temperature and pressure sensors with new industry and Company standard units. The new standard units provide greater reliability, better accuracy, improved functionality and less required maintenance. The project also involves updating as-built drawings to facilitate the creation of a master instrument index to aid in maintenance activities and equipment troubleshooting and to maintain compliance with Title 49, Part 192 of the Code of Federal Regulations.

Q. Did the Company consider alternatives to performing the Mist Instrument and Controls Project (Phase 3)?

A. The Company determined that there were no alternatives to the Mist Instrument and Controls Project (Phase 3) because this project is end-of-life equipment replacement for critical infrastructure.

Q. What is the expected timing of the Mist Instrument and Controls Project (Phase 3)?

A. The Company expects to complete the Mist Instrument and Controls Project (Phase 3) in October 2024.

Q. What is the Company's most recent cost estimate for the Mist Instrument and Controls Project?

A. The Company's most recent total cost estimate for the Mist Instrument and Controls Project is approximately $2.2 million for core utility service, which is approximately $2.0 million on an Oregon-allocated basis.

3. Portland LNG Projects

a. PLNG Valve and Controls Replacement Project

Q. What is the condition of the valves and controls at the Portland LNG facility?

A. A Company engineering consultant completed an assessment report of the Portland LNG facility, including its valves and controls. The report provided a list of leaking and end-of-life valves and instrumentation associated with the valves that need to be replaced. The report prioritized those plant components that posed the greatest potential to disrupt plant operation or impact plant reliability, operability, and capacity within the next five years.

Q. Please describe the PLNG Valve and Controls Replacement Project.

A. The PLNG Valve and Controls Replacement Project is replacing the Portland LNG facility components prioritized in the report.

Q. Did the Company consider alternatives to performing the PLNG Valve and Controls Replacement Project?

A. The Company considered replacing older valves as they fail, but that reactive approach would pose safety and operational risks to the facility. As it is, the PLNG Valve and Controls Replacement Project is replacing only those components prioritized in the report, with the disposition of other components being determined at a later time as part of a future project.

Q. What is the expected timing of the PLNG Valve and Controls Replacement Project?

A. The Company expects that the PLNG Valve and Controls Replacement Project will be completed and in service in December 2023 or January 2024.

Q. What is the Company's most recent cost estimate for the PLNG Valve and Controls Replacement Project?

A. The Company's most recent total cost estimate for the PLNG Valve and Controls Replacement Project is approximately \$4.3 million, or approximately \$3.8 million on an Oregon-allocated basis.

b. PLNG Boil-Off Compressor Project

Q. Please describe the PLNG Boil-Off Compressor Project.

A. This project will augment boil off gas compressor capacity at the Portland LNG facility. Boil-off compressors maintain the tank pressure during liquefaction and holding operations. Existing boil-off compressor C2 was constructed in 1967 and overhauled in 2000, and compressor C3 was constructed in 1986. This project will evaluate and replace compression capacity to ensure continued reliable service.

Q. Did the Company include the PLNG Boil-Off Compressor Project in its 2022 rate case (UG 435)?

A. Yes. The Company included the PLNG Boil-Off Compressor Project in UG 435, at NW Natural/400, Kizer/24-25. In its attestation filed in docket UG 435 on October 24, 2022, the Company removed $1.1 million of gross 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, 2022.

Q. What is the expected timing of the PLNG Boil-Off Compressor Project?

A. The Company expects that the PLNG Boil-Off Compressor Project will be completed and placed in service in October 2024.

Q. What is the Company's most recent cost estimate for the PLNG Boil-Off Compressor Project?

A. The Company's most recent total cost estimate for the PLNG Boil-Off Compressor Project is approximately $4.8 million, or approximately $4.2 million on an Oregon-allocated basis.

Q. What factors have caused the cost increase of the PLNG Boil-Off Compressor Project?

A. After the Company completed the design engineering, it determined that the new C-4 boil-off compressor should be a different type of compressor to be installed in a new location adjacent to the existing boil-off compressors C-2 and C-3, rather than a replacement of an existing compressor. This selected location will result in reduced downtime during construction and the new type of compressor will allow improved compression capabilities, automation, and safety features. During detailed design, the final costs for the heat exchangers exceeded original estimates because the existing heat exchangers were undersized and, therefore, a new ambient heat exchanger for the inlet boil-off gas was designed and procured, including associated valves, equipment. and foundations. Final design for the glycol cooling water capacity for the new compressor exceeded the capacity of the existing glycol system, requiring additional glycol coolers, pumps and associated piping and foundations. The Company also incurred additional costs for environmental remediation not included in the original estimate resulting from the final design size of excavations and soil removal required for foundations. Finally, after the Company completed the geotechnical analysis, it determined that it needed to install 15 additional driven piles, which increased the cost over the original foundation designs. City of Portland permitting delays and additional engineering activities also are expected to affect final project schedule and overall project cost.

Q. Despite the cost increase, is the PLNG Boil-Off Compressor Project still the least-cost, least-risk option?

A. Yes. The ability to manage tank pressure with a boil-off compressor is critical to the safe operation of the Portland LNG facility. The Company needs to address the age of the existing compressors, and installing a third compressor is the least-cost, least-risk option to complement the existing two compressors for redundancy purposes.

c. PLNG Pretreatment Improvements Project

Q. Please describe generally the production of LNG at the Portland LNG facility.

A. At the Portland LNG facility, the production of LNG occurs in two phases: pretreatment and liquefaction. Pretreatment removes contaminants, namely water, odorant, and carbon dioxide, from feed gas entering the plant. Liquefaction then cools and condenses the gas to a -260°F liquid suitable for the onsite storage.

Q. Please describe the pretreatment phase in more detail.

A. As gas is processed in the pretreatment phase, the pretreatment vessel adsorbent media becomes saturated with the contaminants. One set of vessels dehydrates the incoming gas and removes odorant, and a second set of vessels removes carbon dioxide. Once saturated, the media is regenerated with hot natural gas which carries the contaminants away for consumption by blending them into the distribution system outside the plant.

Q. Is the pretreatment phase at the Portland LNG facility operating effectively?

A. No. A Company engineering consultant completed an assessment report of the Portland LNG facility, including its pretreatment phase. The existing regeneration process is not effectively removing contaminants. In particular, the pretreatment system is not fully regenerating the molecular sieve adsorbing beds, which should be processing and cleaning up gas as it enters the facility. This problem leads to contaminant carryover to the liquefaction system where the contaminants freeze and plug the heat exchangers and rotating equipment in the liquefaction system. As a result, the liquefaction system shuts down and is unable to produce LNG to refill the tank while the heat exchangers and rotating equipment are thawed.

Q. Please describe the PLNG Pretreatment Improvements Project.

A. The PLNG Pretreatment Improvements Project will improve the performance of the regeneration process during the pretreatment phase of LNG production at the Portland LNG facility. The objective of this project is to replace the end-of-life molecular sieve media in two (2) carbon dioxide removal vessels and two (2) dehydration vessels, review and replace end-of-life pressure relief valves and obsolete equipment, modernize control logic and programming for the plant automation system to increase safety and reliability, and remove obsolete sulfur vessel V-1.

Q. Did the Company consider alternatives to performing the PLNG Pretreatment Improvements Project?

A. Yes. The Company considered a full pre-treatment system replacement, as well as not taking any action. The expected cost of replacing the full pre-treatment system would have been an order of magnitude greater than the PLNG Pretreatment Improvements Project, with similar benefits. Doing nothing would not improve plant operation or employee safety. The Company selected the PLNG Pretreatment Improvements Project as the least-cost, least-risk alternative.

Q. When does the Company expect to complete the PLNG Pretreatment Improvements Project?

A. The Company expects that the PLNG Pretreatment Improvements Project will be completed in October 2024.

Q. What is the Company's most recent cost estimate for the PLNG Pretreatment Improvements Project?

A. The Company's most recent total cost estimate for the PLNG Pretreatment Improvements Project is approximately $2.6 million, or approximately $2.3 million on an Oregon-allocated basis.

4. Newport LNG Project

a. T-1 Tank Improvements Project

Q. Please describe the Newport LNG T-1 Tank Improvements Project.

A. As I mentioned earlier, Newport LNG was constructed and commissioned in 1977. The plant has one LNG tank. The LNG tank is largely original. As part of a separate project, NW Natural is planning to repaint the LNG storage tank. To help facilitate this work, Occupational Safety and Health Administration (OSHA) regulations require new worker tie-off points to be installed onto the tank to provide safe working conditions. Additionally, the relief valves on the tank are original equipment, and are planned for end-of-life replacement. This project will improve the tank to facilitate access to the dome, install tie offs and retrofit tank appurtenances to bring them into current standards or industry practices, provide the highest assurance of continued system deliverability, and address components in poor condition and at end-of-life. Some of the necessary improvements must be performed while the tank is offline (that is, offline but not drained). Performing the work over one planned outage is more efficient, cost effective and less disruptive. The Newport LNG T-1 Tank Improvements Project implements the recommendations made in the Newport LNG Tank Study Report submitted by NW Natural's engineering consultant on July 20, 2022.

Q. Did the Company consider alternatives to performing the Newport LNG T-1 Tank Improvements Project?

A. The Company considered taking no action, but that would fail to address any of the issues that I just mentioned. NW Natural also considered limiting the scope of the project solely to the safety issues, but deferring repair of components in poor condition would fail to address these components that are at the end-of-life. For example, the Davit system[2] is at end of life, and is a necessary tool to move equipment to the top of the tank. The electrical grounding system for the tank requires updating to current Code compliance, and the overfill piping is missing structural supports. Including these repairs under one mobilization and outage will be the most efficient, rather than to piecemeal the necessary repairs.

Q. When does the Company expect to complete the Newport LNG T-1 Tank Improvements Project?

A. The Company expects to complete the Newport LNG T-1 Tank Improvements Project in October 2024.

Q. What is the Company's most recent cost estimate for the Newport LNG T-1 Tank Improvements Project?

A. The Company's most recent total cost estimate for the Newport LNG T-1 Tank Improvements Project is approximately $3.5 million, or approximately $3.2 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

[2] Davit systems are commonly used to raise, lower, and suspend personnel performing routine work duties or to facilitate rescues in vertical confined space applications such as vaults, manholes, and pump stations.

are also discussed in the Company's 2024 SPP,[3] filed in docket UM 1900 on September 27, 2023. NW Natural estimates for 2024 that it will invest approximately $17.5 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.[4] For discussion in my testimony, significant projects and programs include:

- ILI Conversion Projects;
- Underground Storage Facilities – Well Integrity Program;
- Seismic Projects;
- Proactive EFV Installation Program;
- Probabilistic Distribution Risk Model Project; 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.

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[3] The dollar amounts stated in this section of my testimony (III. Safety-Related Projects) are project costs before construction overhead costs are added.

[4] The Company also expects to incur approximately $4.7 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 cost, 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. Which ILI Conversion Projects are you addressing in your testimony?

A. One of the ILI Conversion Projects completed in 2022, the P31/P75 McMinnville Trans ILI Project, incurred significant additional costs after it went in service that are included in this rate case. Further, in 2024, NW Natural expects to change the assessment methodology of the following pipelines to ILI to continue to comply with PHMSA's seven-year inspection requirement: S36 Willamette Valley Feeder ILI Project, S24 Granger Trans ILI Project, and S22 Albany Trans ILI Project.

Q. Please describe the P31/P75 McMinnville Trans ILI Project.

A. The P31/P75 McMinnville Project changed the ECDA assessment methodology to ILI for the McMinnville/Lafayette transmission line, which is approximately 13 miles of six-inch pipeline routed along Oregon Highway 99W that serves the City of McMinnville and surrounding areas. This project was completed and placed in service in October 2022 and was included in the Company's 2022 rate case (UG 435), at an actual total cost of $3.5 million.

Q. Why is the Company addressing the P31/P75 McMinnville Trans ILI Project in this case?

A. After the Company placed the P31/P75 McMinnville Trans ILI Project in service, it incurred trailing charges in several subsequent months, totaling $1.4 million, to address and remediate three locations of unidentified and unpiggable sites. These sites were discovered during the cleaning of the line in preparation for smart tool pigging. In September 2022, the first cleaning tool was inserted into the line but was not received at the end of the line, and it was discovered to be lodged into a construction fitting that was installed in 1999. This construction fitting was documented incompletely in the 1999 as-build information and thus not initially discovered in the original documentation review that is conducted prior to in-line inspection projects. Once this initial fitting was discovered, two additional fittings as part of this 1999 project were discovered to be unpiggable and needed to be addressed. Cleaning and smart tool inspection were successfully completed in March 2023. The report from the smart tool run was issued in May 2023 and resulted in one immediate anomaly and three prudent operator digs. All digs and repairs were completed by September 2023. The Company is requesting recovery of those incremental costs in this rate case.

Q. Please describe the S36 Mid-Willamette Valley Feeder ILI Project.

A. The S36 Mid-Willamette Valley Feeder ILI Project changes the ECDA assessment methodology to ILI for this approximately 32 miles of 12-inch pipeline from Christensen Bridle to NW Independence Highway and US Highway 20. The Company expects to complete this project and place it in service in October 2024, at an estimated total cost of $2.1 million.

Q. Please describe the S24 Granger Trans ILI Project.

A. The S24 Granger Trans ILI Project changes the ECDA assessment methodology to ILI for this approximately 4.5 miles of six-inch pipeline from Corvallis Granger Regional Station to the valve bridle on the north side of Highway 20, west of Rondo Road. The Company expects to complete this project and place it in service in October 2024, at an estimated total cost of $2.2 million.

Q. Please describe the S22 Albany Trans ILI Project.

A. The S22 Albany Trans ILI Project changes the ECDA assessment methodology to ILI for this approximately 12 miles of 10-inch pipeline from the Albany Gate Station to the Corvallis Granger Regional Station. The Company expects to complete this project and place it in service in October 2024, at an estimated total cost of $2.2 million.

B. Underground Storage Facilities – Well Integrity Program

Q. Please describe the regulatory framework behind the Company's Underground Storage Facilities – Well Integrity Program.

A. In December 2016, PHMSA adopted an interim final rule establishing regulations for underground gas storage facilities. The regulations responded to Section 12 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016, which was enacted following the serious natural gas leak at the Aliso Canyon facility in California on October 23, 2015. In February 2020, PHMSA published its Underground Storage Facilities final rule, which incorporated the American Petroleum Institute ("API") Recommended Practices ("RP"), API RP 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs." The Underground Storage Facilities rule addresses critical safety issues related to downhole facilities, including wells, wellbore tubing, and casing, at underground natural gas storage facilities through integrity management techniques, such as risk models, inspections, and remediation activities.

Q. Please describe the Company's Underground Storage Facilities – Well Integrity Program.

A. In compliance with the Underground Storage Facilities rule, NW Natural developed a storage well integrity program for its operations at the Mist Storage Facility. NW Natural completed the development of its Well Integrity Plan and accelerated the development of a Risk Management Plan for the underground storage fields at

Mist that included a schedule to rework the storage wells over the federally mandated eight-year guideline. The Mist Well Rework Program for 2023 involved the plug and abandonment of one (1) underground utility storage well and baseline casing inspections of ten (10) underground utility storage wells within the Mist storage fields and ensured their functional integrity complies with the Company's Risk Management Plan and PHMSA requirements.

Q. What is the scope of the Mist Well Rework Program for 2024?

A. In accordance with the rule, NW Natural is running baseline casing inspection logs on each of its active gas storage wells prior to the March 13, 2027, deadline. The Company has completed its initial assessment of most of its wells. As such, the Mist Well Rework Program for 2024 involves the initial baseline casing inspection of only one (1) underground utility storage well within the Mist storage fields and ensures that its functional integrity complies with the Company's Risk Management Plan and PHMSA requirements. Going forward, additional assessments of underground utility storage wells within the Mist storage fields will be conducted at a time and in a manner determined through the Company's initial assessments.

Q. When does the Company expect to complete the Mist Well Rework Program for 2024?

A. The Company expects to complete the Mist Well Rework Program for 2024 in June 2024.

Q. What is the Company's most recent cost estimate for the Mist Well Rework Program for 2024?

A. The Company's most recent total cost estimate for the Mist Well Rework Program for 2024 is approximately $0.3 million for core utility service, which is approximately $0.29 million on an Oregon-allocated basis. Similar annual costs are expected to continue for the life of the facility.

C. Seismic Projects

Q. Is the Company assessing the impact of seismic forces on its system?

A. Yes. In 2023, NW Natural worked with an engineering consultant to develop a risk model of the Company's transmission and high-pressure distribution system utilizing the regulations in the PHMSA Rupture Mitigation Valve ("RMV") Rule and a seismic study created in 2020. This risk model prioritized transmission and high-pressure distribution segments based on a risk score. In 2024, NW Natural is working to implement the results of this risk analysis to select critical valve locations that need RMV technology based on risk. To do so, the Company estimates that it will spend approximately $1.6 million, or approximately $1.5 million on an Oregon-allocated basis.

D. 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 296,000 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 2024, we expect to invest approximately $3.4 million, or approximately $3.0 million on an Oregon-allocated basis, as part of our DIMP budget on EFV retrofits in high consequence areas.

E. 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 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. This risk model is a five-year program that is scheduled to begin implementation in 2024. In 2024, we expect to invest approximately $0.97 million, or approximately $0.87 million on an Oregon-allocated basis, in connection with our probabilistic distribution risk model project.

F. 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 2024 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. I briefly will describe each of them. In 2024, we expect to invest approximately $1.5 million, or approximately $1.4 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.

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 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.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Direct Testimony of Wayne K. Pipes

FACILITIES
EXHIBIT 600

December 29, 2023

EXHIBIT 600 – DIRECT TESTIMONY – FACILITIES

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 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 major facilities projects that are included in this rate case. Specifically, I discuss Phase 2 of the Central Resource Center ("RC") construction; upgrades to the Sunset RC, the Sherwood Data Center, and the Miller Station complex that supports NW Natural's Mist Gas Storage Facility (the "Mist Facility"); and physical security upgrades the Company is undertaking at various sites. I also preview the planned future relocation of The Dalles RC and the remodel of the Coos Bay RC and Albany RC, which are not included in this case and will be included in a future rate case.

Q. Please summarize your testimony.

A. This general rate case includes five important facilities projects, which will improve the resiliency of the Company's facilities and support ongoing safe and efficient operations.

First, in Phase 2 of the Central RC project, NW Natural will complete construction of an office building and warehouse at the site to serve as a base for its utility field operations in central Portland. Among other benefits, this new RC will improve emergency response times and support the Company's ongoing operations following a significant seismic event that affects the bridges over the Willamette River.

Second, NW Natural will seismically upgrade the Sunset RC in Hillsboro so that the building meets basic life safety performance objectives. At the same time, the Company will install a decanter system and truck scale at the RC to increase efficiency of operations and ensure compliance with applicable requirements.

Third, the Company completed several necessary upgrades to the Miller Station Control Building located at the Mist Facility. To support the reliable operation of the critical Mist Facility, the Company upgraded the Control Building to address seismic and other safety concerns, resolve space constraints, and improve inadequate facilities.

Fourth, NW Natural is completing seismic and other mechanical and electrical system upgrades to the Sherwood Data Center to increase reliability and reduce outages at this critical facility, which is one of the Company's two data centers and hosts 98 percent of its applications.

Fifth, the Company will enhance physical security at its facilities and field infrastructure—first through a five-site pilot project to determine the most efficient and effective approach and then through a broader, 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.

In the future, NW Natural plans to continue its efforts to increase safety, resiliency, and efficiency by relocating The Dalles RC and upgrading the Coos Bay and Albany RCs, and the Company will seek recovery for these projects in a future case.

Q. Have you prepared exhibits to accompany your testimony?

A. Yes. The following exhibits accompany my testimony:

- Exhibit NW Natural/601, Pipes – KPFF Report – Sunset RC
- Exhibit NW Natural/602, Pipes – Tier 1 Seismic Evaluation – Miller Station
- Exhibit NW Natural/603, Pipes – KPFF Report – Sherwood Data Center
- Exhibit NW Natural/604, Pipes – Glumac Assessment of Sherwood Data Center

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II. DISCUSSION OF PROJECTS INCLUDED IN THIS CASE

Q. Before discussing the specific projects in this case, please provide some background regarding NW Natural's efforts to address the resiliency of Company facilities, with a focus on seismic vulnerabilities.

A. The specific projects addressed in my testimony represent a continuation of NW Natural's efforts to identify and address seismic vulnerabilities in its facilities. As I explained in my testimony in the Company's last two rate cases, dockets UG 388 and UG 435, there has been a greater awareness and understanding of the risk of a major earthquake in the Pacific Northwest in recent years. In response, a series of legislative mandates and state plans, including the Oregon Seismic Safety Policy Advisory Commission's Oregon Resilience Plan, have provided recommendations on making Oregon's energy infrastructure seismically resilient.[1] These State-led efforts required NW Natural to assess the seismic resiliency of its facilities and to mitigate the seismic vulnerabilities discovered.[2]

To comply with these requirements, the Company hired KPFF Consulting Engineers ("KPFF"), a multi-state engineering firm, to perform seismic evaluations of its facilities. The study concluded that none of the Company's resource centers met the current standards for seismic performance, with varying degrees of non-compliance. These seismic assessments factored significantly into NW Natural's

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[1] *See, e.g.*, 2011 House Resolution 3; Oregon Resilience Plan, *available at* https://www.oregon.gov/oem/Documents/Oregon_Resilience_Plan_Final.pdf; Oregon Senate Bill 33 (2013); Senate Bill 33 Implementation of the Oregon Resilience Plan, Report to the 77th Legislative Assembly From the Governor's Task Force on Resilience Plan Implementation (Oct. 1, 2014) *available at* https://www.oregon.gov/oem/Documents/2014_ORTF_report.pdf.

[2] *See* Oregon Resilience Plan at 175.

decision-making process that led it to undertake the seismic projects described in my testimony.

Q. Aside from the seismic element, do the projects discussed in this testimony include other elements that you discussed in prior rate cases?

A. Yes. In my testimony in docket UG 435 regarding resource center upgrade projects, I explained that NW Natural is installing decant systems, fueling stations, and truck scales at all of its resource centers to support the Company's efficient operations and its resiliency objectives. Some of the projects I discuss below involve adding these elements to existing RCs. In addition, the Central Phase 2 project is a continuation of the development of the Central RC—Phase 1 of which was approved in docket UG 435.

A. Central Resource Center Phase 2

Q. Please provide an overview of the Central RC Project.

A. I presented much of the background of the Central RC, planning for construction, and details of Phase 1 in my testimony in docket UG 435 (NW Natural/500, Pipes), which can be referenced for additional context. The Central RC is a medium-sized resource center located in SE Portland at approximately SE 11th and SE Clinton. The Company owns the 4.35-acre site, which it previously used for business offices up until 2013. In 2013, the Tri-County Metropolitan Transportation District of Oregon ("Tri-Met") threatened condemnation to accommodate Tri-Met's plans to expand its Metropolitan Area Express ("MAX") light rail route and create the Orange Line. In response, the Company relocated its office space and removed buildings that had been on the property. Thereafter, the Company began using the remainder of the property for Company storage and vehicle parking.

NW Natural initiated planning for the Central RC in September 2017 and is completing construction in phases. During Phase 1, NW Natural completed site work and constructed outbuildings such as covered pipe storage, specialty equipment garages, a fueling station, and a decant system with spoils bins. Phase 2 construction began in February 2023 and includes a one-story office building with an attached warehouse. Upon completion of Phase 2, the Company plans to use this property to house workspace for emergency response crews. The Central RC will also contain storage for equipment, parts, and materials and will provide parking for Company vehicles.

With these additions, the Company will use the Central RC as its base for utility field operations in and around Portland's central city. These operations include emergency response, customer field services, construction, transmission maintenance, leakage inspection, system operations, and field engineering.

Q. Please provide more detail regarding what Phase 2 of the Central RC involves.

A. From inception, the Company planned to use the Central RC as an office building that also houses emergency response crews. Phase 2 will include construction of that office building and an attached warehouse. The office building will contain space for offices for the emergency response crews and other staff noted above. The warehouse will be large enough to keep supplies accessible to the team. The construction plans also include installation of a new generator, a new transformer, and a new trash enclosure. The Phase 2 construction ensures the buildings comply with modern seismic requirements so that the Central RC can be operational in the event of an earthquake.

Q. Please describe the role the Central RC will play upon completion of Phase 2 construction.

A. The Central RC will enable the Company to improve response times for emergencies in the central business district and in the central east side of Portland. The Company tracks emergency call data, allowing it to pinpoint areas of the city that initiate a high volume of emergency calls. Using this data, the Company determined Portland's central east side regularly produces a high rate of emergency calls. For example, since January 2017, the Company has seen 14.4 percent of all emergency calls come from within a 7-mile radius of the Central RC's location. As such, the Company concluded it could use the Central RC to improve response times in the area. As the east side of Portland continues to see developments and increases in population density, the Company anticipates an increase in emergency calls. Moreover, the Company is preparing for potential emergencies in the area, due to natural disasters or construction mishaps that may affect gas lines.

Upon completion of Phase 2, the Central RC will provide office space for emergency response crews, operations crews, construction and field service supervisors, and leak detection staff and engineers. Housing these employees at the Central RC will improve the Company's response time for emergency and service calls in the area. For example, the location of the Central RC will permit emergency teams to arrive downtown 17 to 26 minutes faster than a team dispatched from a different resource center location. Currently, emergency service response teams are housed in the Company's resource centers located in Sherwood, Sunset, Parkrose, and Mt. Scott. Table 1 below shows that a response team dispatched from the new Central RC will arrive significantly sooner than a response team dispatched from these other RCs.

Table 1. Response Times from NW Natural Resource Centers

Company Facility	Miles	Mid-Morning Travel Times (mins.)
Sherwood	16	34
Sunset	13.3	27
Parkrose	10.1	25
Mt. Scott	7.8	28
Central	1.8	8

Locating emergency response crews at the Central RC will also permit the Company to maintain operations on the east side of Portland in the event the City's bridges are impassable at any point in time. The ability to maintain operations on both sides of the Willamette River is key for the Company's seismic preparedness.

Q. Why is the Central RC Phase 2 Project necessary?

A. Phase 2 is necessary to better serve customers, improve facility safety for employees, and meet the Company's increasing emergency response needs. Specifically, the Central RC will house emergency response crews and will enable the Company to respond to emergencies much faster than it can currently. The Phase 2 construction is also designed to ensure the buildings and structures that make up the Central RC can remain functional in the event of a significant seismic event.

Q. How will the new Central RC improve day-to-day operations in the central city area?

A. Upon completion, the Central RC will house operations supervisor and team member offices that will improve service to the Company's customers. Specifically, the Company anticipates that service technicians working out of the Central RC will be able to arrive at service appointments more quickly, shortening appointment windows for customers. The Central RC will also increase operational efficiencies by reducing travel time required to access critical construction and restoration materials.

Finally, the Central RC will provide other services that meet other important needs, such as providing freeze-protection storage to prevent damage to specialized equipment; providing space for monthly safety meetings and for on-site training and testing to meet regulatory operator qualification requirements; and providing shelter for employees to help the Company comply with Occupational Safety and Health Administration heat-illness prevention and wildfire-smoke exposure requirements.

Q. How will the new Central RC improve emergency response in the central city area?

A. About 14 percent of the emergency calls NW Natural received in 2017 were within a 7-mile radius of the new Central RC. With emergency response crews located close to those calls, the Company expects response times to improve significantly, thereby improving safety and service to its customers. As I noted previously in Table 1, the Central RC's location will permit an emergency response crew to arrive in downtown Portland within approximately 8 minutes of an emergency call. This response time is significantly quicker than from a team dispatched from one of the other Portland area RCs. Because the Company sees a high volume of emergency calls in the area surrounding the Central RC, operating emergency response crews out of the Central RC is crucial to cutting response times in that area as well.

Q. How is the Central RC Project important to the Company's business continuity planning?

A. The Central RC will further the Company's business continuity objectives by providing a facility on the east side of the Willamette River designed to be operational following a significant seismic event. In 2018, Governor Kate Brown adopted Oregon's *Resiliency 2025* plan that identified Critical Energy Infrastructure Hub goals for energy facilities to assess seismic vulnerabilities and develop information to mitigate risks relating to seismic activity.[3] In accordance with these goals, the Company identified a need to operate emergency response crews on the east side of the Willamette River to serve that area following a significant seismic event. The Central RC will provide a base for emergency

[3] State of Oregon, Office of the Governor, *Resiliency 2025: Improving Our Readiness for the Cascadia Earthquake and Tsunami*, p. 15 (Oct. 16, 2018) (available at https://www.oregon.gov/lcd/NH/Documents/Apx_9.2.5_Resiliency2025.pdf).

response crews and will permit them to reach vital service areas should the bridges over the Willamette River become compromised.

Q. How did the Company decide to construct the Central RC?

A. The Company determined in 2016 that it needed to reestablish an operating facility in the central Portland region to meet emergency response and general customer service needs. In response to this need, the Company began relocating a small group of construction and field service employees to this area by placing them in the Company's Exley building and other temporary facilities. However, this approach did not meet the Company's need to provide a permanent facility in the Central Eastside designed to accommodate both office employees and field crews and their related equipment, and to remain operational and allow for mobilization of emergency response personnel after a major seismic event, so the Company began considering alternatives.

Q. What alternatives did the Company consider to the Central RC Project?

A. As I explained in my testimony in docket UG 435, first, the Company considered retrofitting either its Exley or Appliance Center facilities but determined these were not viable options because both buildings were too small to accommodate the activities and staffing the Company envisions for the Central RC. Furthermore, there was increased risk associated with retrofitting older concrete buildings compared with constructing new buildings, and retrofitting the Appliance Center would have required the Company to relocate Appliance Center activities to another facility. Additionally, employees working at Exley or the Appliance Center facilities would have had to cross busy Ninth Avenue to access vehicles and equipment parked at the Central RC location, which would have created safety concerns.

Second, the Company searched for real estate on which to construct a new facility on the east side of the Willamette River, but there were no options available that met the Company's needs. The Company expanded its search to the west side of the river and identified potentially suitable properties, but these properties did not meet the Company's objective of establishing a seismically sound facility on the east side of the river in case of bridge collapse during a major seismic event.

Third, the Company considered utilizing one of its other existing Portland resource centers, such as Parkrose or Mt. Scott, but these sites were too small to accommodate the Company's needs, and locating at these facilities would not meet the Company's goal of decreasing response times to the Central Eastside.

Fourth, the Company considered utilizing the second floor of its offices at 250 Taylor but rejected this option because 250 Taylor does not have yard space or adequate on-site parking and would not satisfy the Company's goal of establishing a resource center in the Central Eastside.

Finally, the Company considered—and ultimately selected—the Central RC Project as described above because it was the one available option for building a resource center in the Central Eastside that met the Company's size and operational requirements. Furthermore, this option allows the Company to make use of a Company-owned property, thereby reducing overall project cost.

Q. Will the Phase 2 construction cause any disruption in the Company's use of the Central RC?

A. No. The area undergoing construction is separated from the rest of the site, so daily operations have not experienced any significant impacts as a result of the Phase 2 construction.

Q. When did Phase 2 of the Central RC begin, and when does the Company expect to place Phase 2 in service?

A. Phase 2 construction began on February 20, 2023. The Company expects Phase 2 construction to be completed in late December 2023.

Q. What is the Company's cost estimate for completing Phase 2?

A. At this time, the Company's cost estimate is $9.2 million to complete Phase 2 of the Central RC for our Oregon customers.

B. Sunset Resource Center

Q. Please summarize the upgrades NW Natural is making to the Sunset RC.

A. NW Natural is making seismic upgrades to the Sunset RC to address the resiliency of critical equipment and known seismic vulnerabilities. At the same time, the Company is installing a new decanter system and truck scale to enable more efficient operations and ensure compliance with applicable requirements. Conducting these upgrades at the same time is more efficient and cost-effective than undertaking them separately and will improve the resiliency and functionality of the Sunset RC.

Q. Where is the Sunset RC located?

A. The Sunset RC is located at 22605 NE Walker Road in Hillsboro, Oregon. The facilities, equipment, and employees at the Sunset RC support NW Natural's provision of safe and reliable service to the Beaverton and Hillsboro areas. The services provided out of this location include customer field services, construction, emergency response, transmission maintenance, leakage inspection, system operations, and field engineering. The Sunset RC also provides storage for vehicles, equipment, parts, and materials.

Q. Please describe the existing facilities at the Sunset RC prior to the upgrades.

A. The Sunset RC is comprised of an office and warehouse building with multiple other outbuildings. The office and warehouse were originally constructed around 1964, and NW Natural remodeled the building's interior in 2011. In 2016, a seismic assessment completed by KPFF Engineering (NW Natural/601, Pipes) determined that the building did not meet basic life safety performance objectives for existing buildings. This lack of seismic resiliency creates safety concerns for employees and could impede NW Natural's ability to respond to a major natural disaster.

Q. Did the Company consider alternatives to undertaking seismic upgrades at the existing Sunset RC?

A. Yes. The Company considered buying a new site for the RC and either constructing or retrofitting a seismically resilient building. However, NW Natural determined that this option would almost certainly be more expensive than upgrading the existing Sunset RC because it would involve acquiring the land in addition to the necessary construction. The Company also considered doing nothing, but this was not a viable alternative or the least-risk approach because, as noted above, the building does not meet basic life safety performance objectives. For these reasons, NW Natural determined that a seismic retrofit of the existing facility was the best way to ensure the Sunset RC will not endanger employees' lives if a significant seismic event occurs.

Q. Please explain how the upgraded Sunset RC will support NW Natural's business continuity planning and ongoing safe and reliable operation.

A. The upgraded Sunset RC will meet basic life safety standards, which will maintain employees' safety during a significant seismic event. Keeping employees safe from significant harm will help NW Natural respond and continue operating after such an event. Moreover, the upgrades will increase the chance that the Sunset RC will remain usable, for at least some of its current functions, following such an event.

Q. Please provide detail regarding the decant system that will be installed.

A. The decant system separates liquids from soils removed during excavation work (also called "spoils") completed for utility operations. The spoils are placed in the decant system, which is a sloped containment bin that enables liquids to separate from the soil through settling of the heavier solid materials and evaporation and draining of the liquids. Once removed, the liquid is filtered through a filtration system before it passes into a stormwater drain. Finally, the dry residue is disposed of at an appropriate site. NW Natural can dispose of dry residue more efficiently because there are more sites available for dry residue disposal.

Q. Why is the decant system necessary?

A. The decant system is important to NW Natural's field operations because the Company cannot conduct construction projects that involve vacuum excavation and horizontal directional drilling operations (*e.g.*, large capital projects, system reinforcement projects, main extensions, new service installations, customer relocates, and cut and abandons) unless it has an appropriate way to dispose of the spoils. Environmental compliance requirements have reduced the availability of disposal sites for spoils, and the remaining sites are overcrowded. As a result, these sites pose safety concerns for our employees when entering and exiting sites and during spoil disposal. Additionally, due to the increasingly limited availability of sites accepting spoils, NW Natural has recently needed to haul spoils from Hillsboro to a remote location in Sherwood, which is an inefficient use of resources in terms of both fuel and employee time. Due to these issues, NW Natural is in the process of installing decant systems at all resource centers.

Q. Please provide detail regarding the truck scale that will be installed and explain why it is necessary.

A. The truck scale is used to weigh NW Natural's semitrucks and trailers before they leave the facility for a delivery. This is an important compliance and safety measure to ensure that NW Natural's trucks and trailers meet applicable weight limitations and to avoid over-loading trucks with equipment and materials. NW Natural uses its trucks and trailers daily to haul excavation equipment and job supplies to job sites.

Q. Did the Company consider alternatives to installing the new decanter and truck scale?

A. Yes. As discussed above, NW Natural considered acquiring a new site for the Sunset RC but determined that doing so would simply add the land acquisition costs to the cost of the necessary upgrades, as it is very unlikely that a suitable site exists that already has a decanter and truck scale. The Company also considered not installing these upgrades but rejected that alternative because it would not fulfill the operational needs and objectives discussed above.

Q. What is the Company's current forecasted cost for the Sunset RC project?

A. At this time, the Company's cost estimate is $4.1 million to complete all the upgrades at the Sunset RC for our Oregon customers.

Q. When will the upgrades to the Sunset RC begin, and when does the Company expect to place them in service?

A. Work on the Sunset RC upgrades is scheduled to begin in April 2024, and the anticipated in-service month is October 2024.

C. Miller Station Tenant Improvements

Q. Please provide an overview of the Miller Station location.

A. Miller Station is located at the Mist Facility in Mist, Oregon. Miller Station contains an operations center designed to house employees at the site, as well as buildings for gas operations and equipment. The Mist Facility—including Miller Station—is a critical site for NW Natural because the Mist Facility contains a significant amount of underground reservoirs the Company uses to store natural gas. The Mist Facility also contains infrastructure important to the Company's operations, including compressor stations and a gas transmission pipeline. Thus, the Mist Facility is vital to the Company's provision of natural gas to its customers. Miller Station's operations center is known as the Control Building, which currently houses between 25 and 30 employees who work at the Mist Facility on a day-to-day basis. The Control Building was originally constructed in 1979 and underwent several expansions in the decades that followed.

Q. Please summarize the changes NW Natural is making to Miller Station.

A. The Company is expanding the existing office space into the warehouse to accommodate more employees and is making structural improvements to address seismic deficiencies (NW Natural/602, Pipes), increase the resiliency of the building, and make the location safer for the employees on-site. NW Natural is also updating and repairing outdated elements of the building. Specifically, the electrical, mechanical, and plumbing systems serving the building are past their usable life and in need of replacement. The construction will update these systems by installing new lighting fixtures, branch circuits, data cabling, heating and cooling systems, water supply and drain lines, sinks, toilets, and showers. The construction will also update the ductwork and exhaust systems.

In addition, the Company identified safety concerns for its employees at the Control Building. Specifically, the Company has determined that uncontrolled storm water runs under the foundation of the Control Building. If the stormwater is not properly diverted, it could undermine the structural integrity of the Control Building. The Company's improvements will address this issue by remodeling and constructing new employee offices, and installing a new water filtration system, as recommended by NW Natural's well consultants. The Company is also installing drains to discharge the stormwater and will divert the stormwater around the building.

Finally, the Company is refreshing the building to add standard amenities, making it more functional for employees who work on-site. The Control Building was initially designed to house only eight employees, but there are currently between 25 and 30 employees on-site on any given day. The Control Building contains very limited restroom facilities that must be shared between all employees. The planned construction will expand office spaces, add additional restrooms and showers, and create a new, larger kitchen facility to accommodate the number of employees regularly using the building. The construction will also allow the Company to update the building for its current uses by adding a library for technical manuals and constructing an exercise room for employee use. NW Natural will also refresh the paint on the building and update the floor coverings that are approximately 40 years old.

Q. Why is the Miller Station Tenant Improvement Project necessary?

A. The Miller Station Tenant Improvement Project is necessary to meet the needs of the Company's employees who provide service functions critical for customers. As I detailed above, Miller Station was not designed to comfortably house the number of employees currently using the facility.

In addition to the lack of space and adequate facilities for employees, the Company identified structural issues that may put employees at risk if not addressed. A significant portion of the building does not meet basic life safety seismic standards.[4] In addition, as I indicated previously, stormwater drainage under the building is undermining its structural integrity. The Company must address these issues in a timely manner to protect its employees and continue to provide reliable service to customers.

Q. Please explain how upgrading Miller Station will support NW Natural's business continuity planning and ongoing safe and reliable operation.

A. After the upgrades, the entire operations center at Miller Station will meet basic life safety standards, which will maintain employees' safety during a significant seismic event. Keeping employees safe from significant harm will help NW Natural respond and continue operating after such an event. Moreover, the upgrades will increase the chance that the operations center will remain at least partially usable following such an event.

Q. How will the Miller Station Tenant Improvement Project improve day-to-day operations at the Mist Facility?

A. The improvements will provide employees with safe and adequate office accommodations and a more comfortable working environment, which will allow employees to better focus on day-to-day tasks.

Q. Did NW Natural consider alternatives to the Miller Station Tenant Improvement Project?

A. Yes, the Company analyzed many alternative actions, including extending the Miller Station buildings and doing a complete tear-down and rebuild. The

[4] The lunch/meeting room added in 2001, multi-purpose room added in 2013, and new controller room added in 2017 meet current seismic standards, but the remainder of the building does not.

Company's analysis prioritized time of completion and cost effectiveness. Pursuant to this analysis, the Company determined that renovating Miller Station was the most cost-effective and timely alternative.

Q. What alternatives did the Company consider?

A. The Company considered a number of alternatives to address ongoing issues in the Control Building.

First, the Company considered bringing in a modular trailer to provide additional office space for employees. The Company quickly determined that there were topographical challenges to bringing in this trailer, namely, that the gradation of the property would make it difficult to place a trailer without issue. The Company also found that electrical and plumbing lines would need to be placed to accommodate the trailer's use. Although the Company determined that bringing in a trailer could be feasible, it would only provide a temporary solution and would require significant investment, which would be better applied to permanent solutions to the issues.

Second, the Company considered extending the size of the Control Building. However, the Company determined that there was insufficient space for a proper extension, and further, that the ground was not level, which would present difficulties for expansion efforts. The Company also found that the cost of a building expansion would be exorbitant because the expansion would require the Company to reroute underground electrical, gas, and signal wiring. As a result, the Company did not pursue the option of extending the building.

Third, the Company considered tearing down the existing Control Building and creating a new building on the site. However, the Company did some minor reconstruction in 2017, adding a new control room and data room to the Control Building. These new structures could not be demolished because such construction would require taking the plant offline, which would interfere with day-to-day operations at the Mist Facility. Further, removing the building around the newer rooms would cause structural integrity issues. The Company considered completing this construction in the summer months when the Mist Facility is not used to supply natural gas to customers. However, this option was also unworkable, because the Company needs to access the Mist Facility during the summer months to inject natural gas to store it until the high demand of the winter months. The Company concluded the construction could not be completed in the short time frame during which it would be feasible to have the Mist Facility offline and inaccessible. As a result, this alternative presented issues with both time of construction and cost effectiveness, and the Company determined it was not a workable option.

Fourth, the Company considered bringing in a restroom trailer to address the lack of facilities for employees. However, this alternative only addressed a discrete portion of the identified issues at the Control Building and did not resolve the other issues employees face, including safety issues. In addition, locating a restroom trailer at the site presented the same challenges discussed above in the modular trailer analysis. The Company also concluded that a restroom trailer would not provide a viable option in the winter as it was likely the pipes in the trailer would freeze, making the trailer unusable. As a result, the Company determined this option was not an effective alternative.

Finally, the Company considered looking for a separate site at its North Mist property. However, the Company found that North Mist presented separate logistical issues, in that North Mist is not configured to allow employees control of the Mist Facility. As a result, the Company determined it would have to install new fiber lines to North Mist, the cost of which would exceed the projected cost of the renovations of Miller Station. The Company also considered that North Mist is not as easily accessible to employees, especially during the winter months. Accordingly, NW Natural determined this option was not a viable alternative.

After consideration of all these alternative approaches and rejecting them for the reasons explained, the Company concluded that renovating Miller Station was the most time-efficient and cost-effective solution to the issues presented at the location.

Q. What is the timing associated with the Miller Station Tenant Improvement Project?

A. Construction of the improvements began in May 2023 and finished in mid-November 2023.

Q. Did the construction cause any disruption in the Company's use of the Mist Facility?

A. NW Natural experienced very limited disruption as a result of the construction, which was completed prior to the very busy heating season.

Q. What is the Company's current forecasted cost for the Miller Station Tenant Improvement Project?

A. The Company estimates that it will cost $3.2 million to complete all of the planned renovations at Miller Station, or $2.8 million on an Oregon-allocated basis.

D. Sherwood Data Center

Q. Please summarize the upgrades NW Natural is making to the Sherwood Data Center.

A. To make the Sherwood Data Center more reliable and less vulnerable to failure, NW Natural is upgrading the electrical system, the HVAC system, and the fire alarm system, and is adding a remote monitoring system. In addition, NW Natural will undertake seismic upgrades to enable the facility to better withstand a major seismic event.

Please note that the Data Center is housed at NW Natural's main operations facility in Sherwood, which also includes a resource center and many other components. However, my testimony in this case is specific to the Data Center.

Q. Please explain the function of the Sherwood Data Center.

A. The Sherwood Data Center is one of NW Natural's two primary data centers in Oregon, and it plays a critical role for the Company.[5] The Sherwood Data Center hosts 98 percent of the Company's applications, including critical business systems such as the customer information system and the system used for all building and asset management. In addition, the Sherwood Data Center houses

[5] The Company's other primary data center is located in Bend.

the servers that receive and compile 90 percent of the data from the Company's Supervisory Control and Data Acquisition ("SCADA") system, which is used to monitor the gas distribution system.

Q. Why does the Sherwood Data Center need to be upgraded?

A. Sherwood has experienced numerous incidents that impacted the reliability of the Data Center. An outage at the Sherwood Data Center would cause customer service issues and interrupt many aspects of the Company's business. But the biggest risk for the Company is the potential for its Gas Control department to lose visibility to the SCADA system. SCADA presents operators in the Gas Control department with data it compiles from a number of sources, such as remote-control valves, input/output modules, and pressure transmitters—thereby allowing the operators to view data in a single location and control operations based on that information.

In recent years, the Data Center has experienced at least two outages resulting from a single-point-of-failure in the power system. Specifically, in 2017, a Comcast contractor dug through the power line feeding one of the Data Center buildings, and the entire Data Center had to be taken offline to complete repairs. And in 2021, when Portland General Electric Company lost power to the site, the Data Center's Uninterruptible Power Supply ("UPS")—which activates to provide power after a loss of power until the generator starts up—failed, resulting in an outage.

In addition, the existing HVAC system is inadequate for current conditions. In the summer months, NW Natural frequently resorts to propping open the doors and using portable fans to mitigate overheating. And during the 2020 wildfires, the Data Center's fire suppression system had to be manually disabled to prevent the sprinklers from automatically activating due to the smoke. As a result, NW Natural had to post someone to watch for fires around the clock until the systems could be re-enabled.

Finally, the Data Center has known seismic vulnerabilities (NW Natural/603, Pipes), which must be mitigated to bring the facility to an "immediate occupancy" level, which means that the structure may experience light overall damage but will retain original strength such that it is likely occupancy will be able to occur after a seismic event.

For all these reasons, the Data Center currently poses a high risk of failure, which would have a significant negative impact on the Company's operations.

Q. How did NW Natural determine what upgrades were necessary?

A. NW Natural commissioned Glumac, a mechanical, electrical, and plumbing engineering consulting firm, to assess the Data Center and make recommendations regarding current operations and potential upgrades. Glumac's assessment occurred in August 2020 (NW Natural/604, Pipes), and concluded that several systems at the Data Center are in a highly vulnerable state with a high risk of down time. Specifically, Glumac used the Uptime Institute's Tier Rating system, which includes four tiers of reliability with Tier 4 being the highest reliability and

Tier 1 the lowest.[6] Glumac concluded that several systems at the Data Center achieve only a Tier 1 rating, even though most commercial data centers achieve a minimum of Tier 2 or 3 rating.

Glumac recommended that NW Natural complete the upgrades discussed in this testimony, which will bring the Data Center to the level of a Tier 2+ rating.

Q. Please provide more detail regarding the specific electrical upgrades at the Data Center.

A. To improve electrical reliability, NW Natural split the building's existing electrical system into two independent critical power paths to the computer and HVAC equipment. This configuration allows for maintenance of equipment and fault tolerance—*i.e.*, one failure or maintenance procedure will not shutdown the system, as long as all computer equipment is dual corded, which it will be. In addition, NW Natural installed a second, redundant UPS, which will prevent outages like the one that occurred in 2021 when the UPS failed, and added a new connection box that will allow the Company to connect a temporary rental generator to the Data Center's electrical system in case the main generator fails or has to be down for service.

Q. Please provide more detail regarding the HVAC upgrades at the Data Center.

A. NW Natural upgraded the HVAC system so that it automatically shuts down outside ventilation air in case of poor outdoor air quality—such as when there is

[6] The Uptime Institute is a think tank and professional-services organization based in Santa Fe, New Mexico. Their rating system is the industry standard method for rating data centers. https://uptimeinstitute.com/tier-certification

smoke from forest fires. The upgrades also include adding headers to the ductwork, adding temperature sensors to identify hot spots and to monitor hot-side containment for servers, creating a load profile to optimize the energy required to provide cooling, restoring economizer and heat recovery system functionality, adjusting operating parameters, replacing an outdated controller, and ductwork modifications to improve air distribution in the room. Finally, the Company will add communications to improve temperature and humidity control and monitoring and address pressurization issues in the room.

Q. Please provide more detail regarding the upgrades to the alarm and monitoring systems at the Data Center.

A. NW Natural modified the fire alarm system so that it is less likely to falsely activate the fire suppression system. Now, one of the smoke-sensing systems is ultra-sensitive, but rather than shutting down the system or activating sprinklers when it senses smoke, it instead alerts operations staff. Only if the situation continues or worsens will the alarm trigger more extreme measures.

NW Natural also added a remote monitoring system that alarms and notifies operations staff of pre-failure and failure of critical equipment, such as the emergency generator and UPS systems.

Q. Please provide more detail regarding the seismic upgrades planned for the Data Center.

A. NW Natural increased the amount of shear wall to compensate for the load, properly connected the shear walls and diaphragm, infilled window openings to reach safe proportions, installed additional connections between tilt panels, and connected the tilt panels to the foundation. The Company improved seismic anchoring by securing all mechanical, electrical, and plumbing infrastructure to the structure. NW Natural also braced critical equipment such as the utility transformer by securing it to structure.

Q. Did the Company consider alternatives to upgrading the Data Center?

A. NW Natural considered moving important functions to a new location, such as a new data center, but it would not be feasible to re-route all the telemetry equipment for the SCADA to a new location, even if NW Natural could identify and acquire an alternative location that would be more cost-effective than upgrading the existing location. At a high level, re-routing would require migrating older point-to-point circuits to newer multi-protocol label switching (MPSL) circuits and installing numerous repeaters to allow microwave and radio data from throughout the Company's service territory to reach the new location. As such, NW Natural did not identify any viable alternatives to implementing the proposed upgrades at the Sherwood Data Center in order to maintain the safe and reliable operation of the Company's gas distribution system.

NW Natural also considered whether to undertake additional upgrades at the Data Center to bring the facility to the level of a Tier 3 rating. However, the additional upgrades required—such as a second generator and a second, redundant source of power to the facility—would have more than doubled the cost of this project. For this reason, NW Natural determined that upgrading to a Tier 2+ level provided the appropriate balance at this time between cost and needed redundancy.

Q. What is the Company's current forecasted cost for the Data Center project?

A. The current projected cost for all the upgrades at the Data Center is $3.0 million, or $2.7 million on an Oregon-allocated basis.

Q. When did the upgrades to the Sherwood Data Center begin, and when does the Company expect to place them in service?

A. Work at the Sherwood Data Center began in March 2023, and the expected in-service date for the electrical, mechanical, and alarm system work is December 2023. The seismic work will be completed in the summer of 2024.

E. Security Upgrades

Q. Please summarize the security upgrades NW Natural is undertaking.

A. In response to increasing threats and new direction from TSA, NW Natural is 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 is a pilot program to complete upgrades at five, high-priority sites in 2023.

After the pilot concludes, NW Natural will develop a plan for upgrading the remaining sites and will begin implementing security upgrades more broadly in 2024. The Company anticipates completing multiple sites per year over the next four or five years. Currently, NW Natural anticipates that all security upgrades will be completed by 2028, although the timing could change following completion of the pilot.

Q. How did NW Natural determine that security upgrades are necessary?

A. A variety of emerging threats and new requirements over the last six 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.[7] 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.[8]

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

[7] Transportation Security Administration, *Pipeline Security Guidelines* (March 2018; updated April 2021), *available at* https://www.tsa.gov/sites/default/files/pipeline_security_guidelines.pdf.

[8] *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 will also inform the Company's planned upgrades during the pilot and at other sites.

Finally, the United States in general has seen a recent uptick in attacks on the energy system, including intentional destruction of critical infrastructure, and the Company has experienced a rash of break-ins and theft at the Company's resource centers. For all these reasons, NW Natural decided to address physical security upgrades in a comprehensive way—first by pursuing a pilot and then a broader program.

Q. Please provide additional detail regarding the pilot program.

A. 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 will help the Company learn about costs, supply chain issues, and equipment that may 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.

The Company's facilities and field infrastructure include more than 1,200 sites, and because security upgrades can be costly, it is not feasible to complete every recommended upgrade at each site. Instead, the pilot includes more limited upgrades at each site—for example, installing an anti-climb attachment to an existing fence rather than installing an entirely new anti-climb fence; using automated fence monitoring that can sense human movement; employing uncuttable fencing materials; and using key cards along with security codes for access to sensitive information. Following the pilot, NW Natural will evaluate the general contractor used and overall project implementation to determine the most efficient and effective approach to security upgrades more broadly. The Company's focus will be on choosing durable materials and mechanisms that result in stronger physical and cyber security.

Q. Who is the general contractor for the pilot program, and how did NW Natural select them?

A. The general contractor is Essex Construction, and NW Natural selected them through a request for proposals process in which they achieved the highest score and were the lowest cost. Essex Construction has experience working with other utilities in this type of work.

Q. What specific sites does the pilot include?

A. The pilot includes five sites:

- A plant,
- A telemetry site,
- Two gate stations, and
- A resource center.

Q. Please provide specific examples of the types of security upgrades that will be undertaken at the pilot program sites.

A. At one or more of the five sites, NW Natural is installing new fencing, anti-climb fencing, lighting, video surveillance systems, intelligent intrusion detection systems, enhanced gates, gate alarms, and/or radar stations.

Q. How will the security upgrades provide benefits?

A. Security upgrades provide several benefits: They improve employee safety, protect property, plant and equipment, and improve cyber security at locations that are connected to our gas control system. They also ensure NW Natural is compliant with requirements from regulators—specifically the TSA. And they help ensure the Company's system can continue providing safe and reliable service to customers without interruption.

Q. What is the Company's current forecasted cost for the security upgrades?

A. The current projected cost for the pilot is $1.8 million in Oregon. After the pilot is completed, the Company estimates it will complete an additional $5 million in upgrades (predominantly in Oregon) annually from 2024 through 2028.

Q. When will the security upgrades begin, and when does the Company expect to place them in service?

A. The pilot program is underway and is expected to be complete in January 2024. The broader upgrade program will commence after the pilot is complete and is expected to continue for several years, with security upgrades being placed in service on a rolling basis as they are completed.

III. PREVIEW OF FUTURE PROJECTS

A. The Dalles Resource Center

Q. Please summarize the Company's plans to relocate The Dalles RC.

A. NW Natural is currently looking for a new location in The Dalles to retrofit an existing facility or construct a new resource center. The current resource center is located on a very small parcel that NW Natural leases, and the existing buildings lack the functionality and amenities that are standard in the Company's resource centers. For example, there are no showers or changing room—employees must change in the warehouse. There also is no fueling station, truck wash system, specialty equipment garages, covered pipe storage, decant system, or truck scale at The Dalles RC. Once the Company's real estate broker identifies an appropriate property and NW Natural completes its due diligence, NW Natural intends to retrofit an existing building or purchase land and construct a new resource center.

Q. What is the planned timeline for this project?

A. NW Natural hopes to complete due diligence and purchase the property in 2024, conduct design and permitting in 2025, and construct the new facility in 2026. However, the project cannot proceed until the broker identifies an appropriate property, and the process of retrofitting an existing facility or acquiring the land and planning and permitting the new facility will take time. Given the urgent need for upgrades to the current resource center, the Company hopes to have the project completed before the end of 2026.

B. Coos Bay Resource Center

Q. Please summarize the retrofit NW Natural is undertaking at the Coos Bay RC and explain why the upgrades are necessary.

A. NW Natural is retrofitting the Coos Bay RC building, which is almost 60 years old and is lacking the functionality required in a resource center. The retrofit began with a minor remodel in 2018, which included the interior office space at the resource center. In the next phase, NW Natural will complete the remaining upgrades required to make the building safe and fully functional, including covered pipe and equipment storage, specialty equipment garages, decant system, fueling station, and truck scale. In addition, the remodel will include seismic upgrades to enable the facility to better withstand a major seismic event.

Q. What is the Company's current forecasted cost and timing for the Coos Bay RC project?

A. Planning and permitting for the work are scheduled to be completed in 2024 with construction scheduled for 2026. The current projected cost for all the upgrades at the Coos Bay RC in Oregon is $5.5 million.

C. Albany Resource Center

Q. Please summarize the retrofit NW Natural plans to undertake at the Albany RC and explain why it is necessary.

A. The Albany RC supports NW Natural's provision of safe and reliable service to NW Natural's service territory from south of Salem to north of Eugene. The resource center was originally constructed in 1961, and an auditorium was added in 2006. The office building has not been seismically retrofitted, and the yard lacks the required functionality that is now standard at NW Natural resource centers. Therefore, the Albany RC remodel will include seismic upgrades to enable the facility to better withstand a major seismic event and will also involve installing facilities such as covered spoils bins, decant tanks, a truck scale, and a fuel tank in the yard.

Q. What is the Company's current forecasted cost and timing for the Albany RC project?

A. Planning and permitting for the work are scheduled to be completed in 2024 with construction scheduled for 2025. The current projected cost for all the upgrades at the Albany RC in Oregon is $6.7 million.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibits of Wayne K. Pipes

FACILITIES
EXHIBITS 601-604

December 29, 2023

EXHIBITS 601-604 – FACILITIES

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December 29, 2023

kpff

ASCE 41-13 Tier 1 Seismic Evaluation of

NW Natural – Sunset Service Center

21605 NW Amberwood Drive
Hillsboro, OR 97124

August 5, 2016
KPFF Project No. 1600122

NW Natural – Sunset 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 Sunset Service Center located at 21605 NW Amberwood Drive in Hillsboro, 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 Sunset Service Center located in Hillsboro, Oregon. This evaluation is based on a site visit that was completed on April 20, 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 Sunset Service Center is an existing one-story building located at 21605 NW Amberwood Drive in Hillsboro, Oregon. The original construction date is circa 1964. The overall building measures approximately 115 feet in the east-west direction by 72 feet in the north-south direction with a small “notch” measuring approximately 25 feet by 18 feet at the northeast corner. The building is approximately 7,800 square feet. The roof level is approximately 17’-0” above the ground floor. There is a small mechanical mezzanine with a “pop-up” roof located at the interior of the building.

The roof framing consists of wood-chord/metal web trusses supporting ¾” plywood roof sheathing. The exterior bearing walls consist of 6 inch concrete tilt-up walls. At the interior of the building, the roof trusses are supported by a combination of glu-lam beams with steel pipe columns, CMU bearing walls, and wood stud bearing walls. The interior mechanical mezzanine is framed with a flat concrete slab supported by CMU bearing walls. The pop-up portion of the roof if framed with wood stud bearing walls that that rest on top of the CMU bearing walls at the mezzanine level. The ground floor is a concrete slab on grade. The foundations consist of conventional concrete strip footings at the bearing walls and conventional spread footings at the columns. The lateral force resisting system consists of the wood roof diaphragm and the concrete tilt-up walls acting as shear walls.

In 2011, a voluntary seismic upgrade was completed for the building. The seismic upgrade work consisted of strengthening the out-of-plane connections between the roof diaphragm and the exterior concrete tilt-up walls. Additional work that was completed as part of this renovation includes providing new openings in the existing tilt-up walls, infilling openings in the existing tilt-up walls, adding new CMU partitions, and a new canopy.

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
$S_{X1,\ BSE\text{-}1E}$	0.347 g	Design spectral response acceleration parameter at 1 second for the BSE-1E seismic hazard level. (Includes the minimum of 75% of BSE-1N values)
$S_{XS,\ BSE\text{-}1E}$	0.554 g	Design short-period (0.2 seconds) spectral response acceleration parameter for the BSE-1E seismic hazard Level. (Includes the minimum of 75% of BSE-1N values)
T	0.170 s	Building fundamental period, as defined in Section 4.5.2.4.
S_a	0.554 g	Response spectral acceleration parameter. S_a = Minimum of ($S_{XS,\ BSE\text{-}1E}$ and $S_{X1,\ BSE\text{-}1E}$ / T)

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 the BSE-1E, or 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	Wood Ledgers	A.5.1.2	The connection between the wood diaphragm and the CMU walls induces cross-grain bending on the existing wood ledgers. While the 2011 upgrade work did strengthen this connection, we believe that the retrofitting connection would still not perform well and may be susceptible to damage.
2	Diagonally Sheathed and Unblocked Diaphragms	A.4.2.3	The diaphragms are un-blocked and span more than 40 feet. This may result in the roof diaphragm being over-stressed.
3	Pre-Cast Wall Panels	A.5.3.6	The exterior concrete tilt-up walls are not positively attached to the foundation. This could result in the walls becoming dislodged from the foundations during strong ground shaking.
4	Girders	A.5.4.2	The glu-lam girder to concrete wall connection does not have ties engaging the anchor bolts. This could lead to the anchor bolts pulling out of the wall and a loss of vertical support of the girder.

Note: While the structural deficiencies are identified in the table above, the following is a list of structural unknowns that may contain noncompliant items if evaluation was possible.

Structural Unknowns

No.	Item	Tier 1 Ref.	Comments
1	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.

No.	Item	Tier 1 Ref.	Comments
2	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 "low" landslide hazard.
3	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 immediately adjacent to the site.

Nonstructural Deficiencies

No.	Item	Tier 1 Ref.	Comments
1	Flexible Couplings	A.7.15.4	It was noted that the gas lines do not have flexible couplings.
2	Industrial Storage Racks	A.7.11.1	Some instances of tall storage racks over 12 feet tall that were not braced were observed.
3	Tall Narrow Contents	A.7.11.2	Some instances of tall, narrow contents were observed. These elements are susceptible to over-turning.
4	Fall-Prone Contents	A.7.11.3	Some instances of contents were observed on high shelves that were not restrained.
5	Fall-Prone Equipment	A.7.12.4	Some instances of equipment were observed on high shelves that were not restrained.

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	Heavy Partitions Supported by Ceilings	A.7.2.1	The interior CMU partitions are relatively tall. While they are not braced by the ceiling system, the existing drawings indicate that a small light gage clip is used to brace the top of the wall. This condition should be investigated to ensure that the connection is adequate.

Conceptual Seismic Upgrade Work

The primary structure generally met the acceptance criteria for life safety. The retrofit work that we would recommend includes:

1. Providing a tension strap at the connection between the wood diaphragms and the CMU walls. We believe that the L3x3 that was added as part of the 2011 retrofit (reference detail 3/S202) will not sufficiently prevent the cross-grain bending on the wood ledger. A strap that connects the L3x3 to the underside of the diaphragm would mitigate this deficiency.

2. Strengthening the plywood diaphragm to adequately resist the required seismic forces. Please note that a more detailed analysis may show that the diaphragm in its current state is, in fact, adequate.

3. Provide a positive connection between the exterior concrete tilt-up walls and the foundations.

4. Provide a positive connection between the glu-lam girders and the concrete tilt-up walls.

To meet the life safety objective, we would recommend the following retrofit work for the non-structural elements:

1. Anchor or otherwise brace the tall, narrow contents, equipment, and storage racks that pose a risk of over-turning.

2. Install flexible coupling on the gas lines.

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 less than approximately $15 – $20 per square foot. This does not include costs associated with nonstructural deficiencies, soft costs, impacts to architectural or mechanical, electrical, and plumbing (M/E/P) systems, business interruption, 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 – Sunset Service Center. It was found that the aforementioned building, in its current state, does not completely 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. The structural retrofit work required to mitigate the existing deficiencies would be fairly conventional for a building of this nature.

The building also does not achieve the desired seismic performance objective for Life Safety Nonstructural Performance at the same seismic hazard as stated above. Most of the nonstructural seismic upgrade work would relate to bracing and/or restraint of non-structural components and contents.

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 - Sunset Service Center
Date: 8/3/16
Building Address: 21605 NW Amberwood Dr., Hillsboro, OR
Latitude: 45.5382
Longitude: -122.8990
By: MWT

Year Built: circa 1964
Year(s) Remodeled: 2011
Original Design Code: Unknown
Area (sf): 7,800
Length (ft): 115
Width (ft): 72
No. of Stories: 1
Story Height: approx. 17
Total Height: approx. 17

USE ☐ Industrial ☑ Office ☑ Warehouse ☐ Hospital ☐ Residential ☐ Educational ☐ Other: ____________

CONSTRUCTION DATA

Gravity Load Structural System: Tilt-Up
Exterior Transverse Walls: Tilt-Up Concrete — Openings? Yes
Exterior Longitudinal Walls: Tilt-Up Concrete — Openings? Yes
Roof Materials/Framing: Glu-lam beams, wood roof trusses, plywood sheathing
Intermediate Floors/Framing: N/A
Ground Floor: Slab on grade
Columns: Some interior steel pipe columns — Foundation: spread / strip
General Condition of Structure: Good
Levels Below Grade? None
Special Features and Comments: None

LATERAL-FORCE-RESISTING SYSTEM

	Longitudinal	Transverse
System:	PC1 - Pre-Cast Concrete	PC1 - Pre-Cast Concrete
Vertical Elements:	Concrete Tilt-Up Walls	Concrete Tilt-Up Walls
Diaphragms:	Plywood Sheathed	Plywood Sheathed
Connections:	Yes	Yes

EVALUATION DATA

Soil Factors: Class= D
BSE-1E Spectral Response Accelerations: S_{XS}= 0.554 S_{X1}= 0.347
Level of Seismicity: High
Performance Level: Life Safety
Building Period: T= 0.17
Spectral Acceleration: S_a= 0.554
Modification Factor: $C_mC_1C_2$= C = 1.4
Building Weight: W= 500 k
Pseudo Lateral Force: $V= C_mC_1C_2S_aW$= 390 k

BUILDING CLASSIFICATION: PC1

REQUIRED TIER 1 CHECKLISTS

	Yes	No
Basic Configuration Checklist	☑	☐
Building Type PC1 Structural Checklist	☑	☐
Nonstructural Component Checklist	☑	☐

FURTHER EVALUATION REQUIREMENT: ____________

ASCE 41-13 Tier 1 Checklists

FIRM:	KPFF Consulting Engineers
PROJECT NAME:	NW Natural - Sunset
SEISMICITY LEVEL:	High
PROJECT NUMBER:	1600122
COMPLETED BY:	MWT
DATE COMPLETED:	August 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 - Sunset
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)	
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)	Connections were provided as part of the previous seismic upgrade work.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sunset
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)	
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)	
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)	Mezzanine is supported by CMU walls.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sunset
Project Number 1600122

Building Configuration

RATING				DESCRIPTION	COMMENTS
C ☒	NC ☐	N/A ☐	U ☐	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)	
C ☒	NC ☐	N/A ☐	U ☐	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)	
C ☒	NC ☐	N/A ☐	U ☐	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)	
C ☒	NC ☐	N/A ☐	U ☐	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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sunset
Project Number 1600122

C	NC	N/A	U		
☒	☐	☐	☐	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)	
☒	☐	☐	☐	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)	Based on a review of DOGAMI's hazard maps.
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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sunset
Project Number 1600122

C	NC	N/A	U		
☒	☐	☐	☐	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)	Based on a review of DOGAMI's hazard maps.

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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sunset
Project Number 1600122

ASCE 41-13 Tier 1 Checklists

FIRM:	KPFF Consulting Engineers
PROJECT NAME:	NW Natural - Sunset
SEISMICITY LEVEL:	High
PROJECT NUMBER:	1600122
COMPLETED BY:	MWT
DATE COMPLETED:	August 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 - Sunset
Project Number 1600122

16.12LS Life Safety Structural Checklist for Building Types PC1: Precast or Tilt-Up Concrete Shear Walls with Flexible Diaphragms and PC1A: Precast or Tilt-Up Concrete Shear Walls with Stiff Diaphragms

Low Seismicity

Connections

C	NC	N/A	U	DESCRIPTION	COMMENTS
☒	☐	☐	☐	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)	Connections added/reinforced as part of the previous seismic upgrade work.

Moderate Seismicity

Seismic-Force-Resisting System

C	NC	N/A	U	DESCRIPTION	COMMENTS
☒	☐	☐	☐	REDUNDANCY: The number of lines of shear walls in each principal direction is greater than or equal to 2. (Commentary: Sec. A.3.2.1.1. Tier 2: Sec. 5.5.1.1)	
☒	☐	☐	☐	WALL SHEAR STRESS CHECK: The shear stress in the precast panels, calculated using the Quick Check procedure of Section 4.5.3.3, is less than the greater of 100 lb/in.^{2} or $2\sqrt{f'_c}$. (Commentary: Sec. A.3.2.3.1. Tier 2: Sec. 5.5.3.1.1)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

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C	NC	N/A	U	DESCRIPTION	COMMENTS
☒	☐	☐	☐	REINFORCING STEEL: The ratio of reinforcing steel area to gross concrete area is not less than 0.0012 in the vertical direction and 0.0020 in the horizontal direction. (Commentary: Sec. A.3.2.3.2. Tier 2: Sec. 5.5.3.1.3)	Per existing structural drawings.
☒	☐	☐	☐	WALL THICKNESS: Thicknesses of bearing walls shall not be less than 1/40 the unsupported height or length, whichever is shorter, nor less than 4 in. (Commentary: Sec. A.3.2.3.5. Tier 2: Sec. 5.5.3.1.2)	

Diaphragms

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	TOPPING SLAB: Precast concrete diaphragm elements are interconnected by a continuous reinforced concrete topping slab with a minimum thickness of 2 in. (Commentary: Sec. A.4.5.1. Tier 2: Sec. 5.6.4)	None present.

Connections

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☒	☐	☐	WOOD LEDGERS: The connection between the wall panels and the diaphragm does not induce cross-grain bending or tension in the wood ledgers. (Commentary: Sec. A.5.1.2. Tier 2: Sec. 5.7.1.3)	The detail that was implemented as part of the previous seismic upgrade work is questionable it its ability to preclude cross-grain bending.

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RATING				DESCRIPTION	COMMENTS
C ☒	NC ☐	N/A ☐	U ☐	TRANSFER TO SHEAR WALLS: Diaphragms are connected for transfer of seismic forces to the shear walls. (Commentary: Sec. A.5.2.1. Tier 2: Sec. 5.7.2)	
C ☐	NC ☐	N/A ☒	U ☐	TOPPING SLAB TO WALLS OR FRAMES: Reinforced concrete topping slabs that interconnect the precast concrete diaphragm elements are doweled for transfer of forces into the shear wall or frame elements. (Commentary: Sec. A.5.2.3. Tier 2: Sec. 5.7.2)	None present.
C ☒	NC ☐	N/A ☐	U ☐	GIRDER–COLUMN CONNECTION: There is a positive connection using plates, connection hardware, or straps between the girder and the column support. (Commentary: Sec. A.5.4.1. Tier 2: Sec. 5.7.4.1)	Based on one location observed.

High Seismicity

Seismic-Force-Resisting System

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	DEFLECTION COMPATIBILITY FOR RIGID DIAPHRAGMS: Secondary components have the shear capacity to develop the flexural strength of the components. (Commentary: Sec. A.3.1.6.2. Tier 2: Sec. 5.5.2.5.2)	Diaphragms are flexible.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

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C	NC	N/A	U	Description	Comments
☒	☐	☐	☐	WALL OPENINGS: The total width of openings along any perimeter wall line constitutes less than 75% of the length of any perimeter wall when the wall piers have aspect ratios of less than 2-to-1. (Commentary: Sec. A.3.2.3.3. Tier 2: Sec. 5.5.3.3.1)	

Diaphragms

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☒	☐	☐	☐	CROSS TIES IN FLEXIBLE DIAPHRAGMS: There are continuous cross ties between diaphragm chords. (Commentary: Sec. A.4.1.2. Tier 2: Sec. 5.6.1.2)	Sub-diaphragms provided as part of previous seismic upgrade work.
☐	☐	☒	☐	STRAIGHT SHEATHING: All straight sheathed diaphragms have aspect ratios less than 2-to-1 in the direction being considered. (Commentary: Sec. A.4.2.1. Tier 2: Sec. 5.6.2)	Plywood sheathing added as part of previous seismic upgrade.
☒	☐	☐	☐	SPANS: All wood diaphragms with spans greater than 24 ft consist of wood structural panels or diagonal sheathing. (Commentary: Sec. A.4.2.2. Tier 2: Sec. 5.6.2)	Plywood sheathing added as part of previous seismic upgrade.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

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Project Number 1600122

C	NC	N/A	U	DESCRIPTION	COMMENTS
☐	☒	☐	☐	DIAGONALLY SHEATHED AND UNBLOCKED DIAPHRAGMS: All diagonally sheathed or unblocked wood structural panel diaphragms have horizontal spans less than 40 ft and aspect ratios less than or equal to 4-to-1. (Commentary: Sec. A.4.2.3. Tier 2: Sec.5.6.2)	Plywood sheathing added as part of previous seismic upgrade. Likely that a Tier 2 analysis would show this is OK.
☒	☐	☐	☐	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)	Plywood sheathing added as part of previous seismic upgrade.

Connections

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☒	☐	☐	☐	MINIMUM NUMBER OF WALL ANCHORS PER PANEL: There are at least two anchors from each precast wall panel into the diaphragm elements. (Commentary: Sec. A.5.1.3. Tier 2: Sec. 5.7.1.4)	
☐	☒	☐	☐	PRECAST WALL PANELS: Precast wall panels are connected to the foundation. (Commentary: Sec. A.5.3.6. Tier 2: Sec. 5.7.3.4)	Existing drawings indicate that there is no direct connection between the tilt-up panels and the foundations.

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C	NC	N/A	U	Statement	Comments
☐	☐	☒	☐	UPLIFT AT PILE CAPS: Pile caps have top reinforcement, and piles are anchored to the pile caps. (Commentary: Sec. A.5.3.8. Tier 2: Sec. 5.7.3.5)	None present.
☐	☒	☐	☐	GIRDERS: Girders supported by walls or pilasters have at least two ties securing the anchor bolts unless provided with independent stiff wall anchors with adequate strength to resist the connection force calculated in the Quick Check procedure of Section 4.5.3.7. (Commentary: Sec. A.5.4.2. Tier 2: Sec. 5.7.4.2)	Existing drawings do not indicate that ties are present.

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ASCE 41-13 Tier 1 Checklists

FIRM:	KPFF Consulting Engineers
PROJECT NAME:	NW Natural - Sunset
SEISMICITY LEVEL:	
PROJECT NUMBER:	1600122
COMPLETED BY:	MWT
DATE COMPLETED:	August 3, 2016
REVIEWED BY:	IKE
REVIEW DATE:	August 5, 2016

Project Name NW Natural - Sunset
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)	None present.
☐	☐	☒	☐	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)	None present.
☒	☐	☐	☐	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)	Generator is anchored.
☐	☐	☒	☐	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)	None present.

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C ☐	NC ☐	N/A ☒	U ☐	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)	None present.
C ☐	NC ☐	N/A ☒	U ☐	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)	None present.
C ☐	NC ☐	N/A ☒	U ☐	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)	None present.

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C	NC	N/A	U	Item	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)	None present.
☒	☐	☐	☐	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)	Per conversation with facility staff.
☐	☒	☐	☐	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)	Per conversation with staff.
☐	☐	☒	☐	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)	None present.

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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)	None present.
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)	Condition was covered and we were not able to observe. The existing drawings indicate a light-gage clip supports the top of the CMU partitions. We would recommend investigating this condition further.
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)	None present.
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.

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C	NC	N/A	U	Description	Comments
☐	☐	☒	☐	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)	None present.
☐	☐	☒	☐	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)	None present.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

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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.
☐	☐	☒	☐	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.
☐	☐	☒	☐	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.
☐	☐	☒	☐	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)	Lights appear to weigh same or less.
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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Project Number 1600122

Cladding and Glazing

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	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)	No cladding present.
C ☐	NC ☐	N/A ☒	U ☐	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)	None present.
C ☐	NC ☐	N/A ☒	U ☐	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)	None present.
C ☐	NC ☐	N/A ☒	U ☐	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)	None present.

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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)	None present.
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)	None present.
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)	None present.

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)	None present.

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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)	None present.
☐	☐	☒	☐	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)	None present.
☐	☐	☒	☐	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)	None present.
☐	☐	☒	☐	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)	None present.

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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)	None present.
☐	☐	☒	☐	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)	None present.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

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C	NC	N/A	U	Description	Comments
☒	☐	☐	☐	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)	New light-weight canopy added as part of the previous seismic upgrade work. Appears adequately anchored.
☐	☐	☒	☐	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)	None present.
☐	☐	☒	☐	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)	None present.

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)	None present.

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C	NC	N/A	U	Description	Comments
☐	☐	☒	☐	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)	None present.

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)	None present.
☐	☐	☒	☐	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)	Not a moment frame structure.

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)	Some observed.

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C	NC	N/A	U	Check	Comment
☐	☒	☐	☐	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)	Some observed.
☐	☒	☐	☐	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)	Some observed.
☐	☐	☒	☐	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.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

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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)	Some observed (for example, unbraced heater)
☐	☐	☒	☐	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)	None observed
☐	☐	☒	☐	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)	None observed

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

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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.
C	NC	N/A	U		
☐	☐	☒	☐	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.
C	NC	N/A	U		
☐	☐	☒	☐	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.
C	NC	N/A	U		
☐	☐	☒	☐	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.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

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Rating				Description	Comments
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 ☐	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.
C ☐	NC ☐	N/A ☒	U ☐	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)	None present.
☐	☐	☒	☐	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)	None present.
☐	☐	☒	☐	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	Check	Comment
☐	☐	☒	☐	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.
☐	☐	☒	☐	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.
☐	☐	☒	☐	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.
☐	☐	☒	☐	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.
C	NC	N/A	U		
☐	☐	☒	☐	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 490

NW Natural

Exhibit of Wayne K. Pipes

FACILITIES
EXHIBIT 602

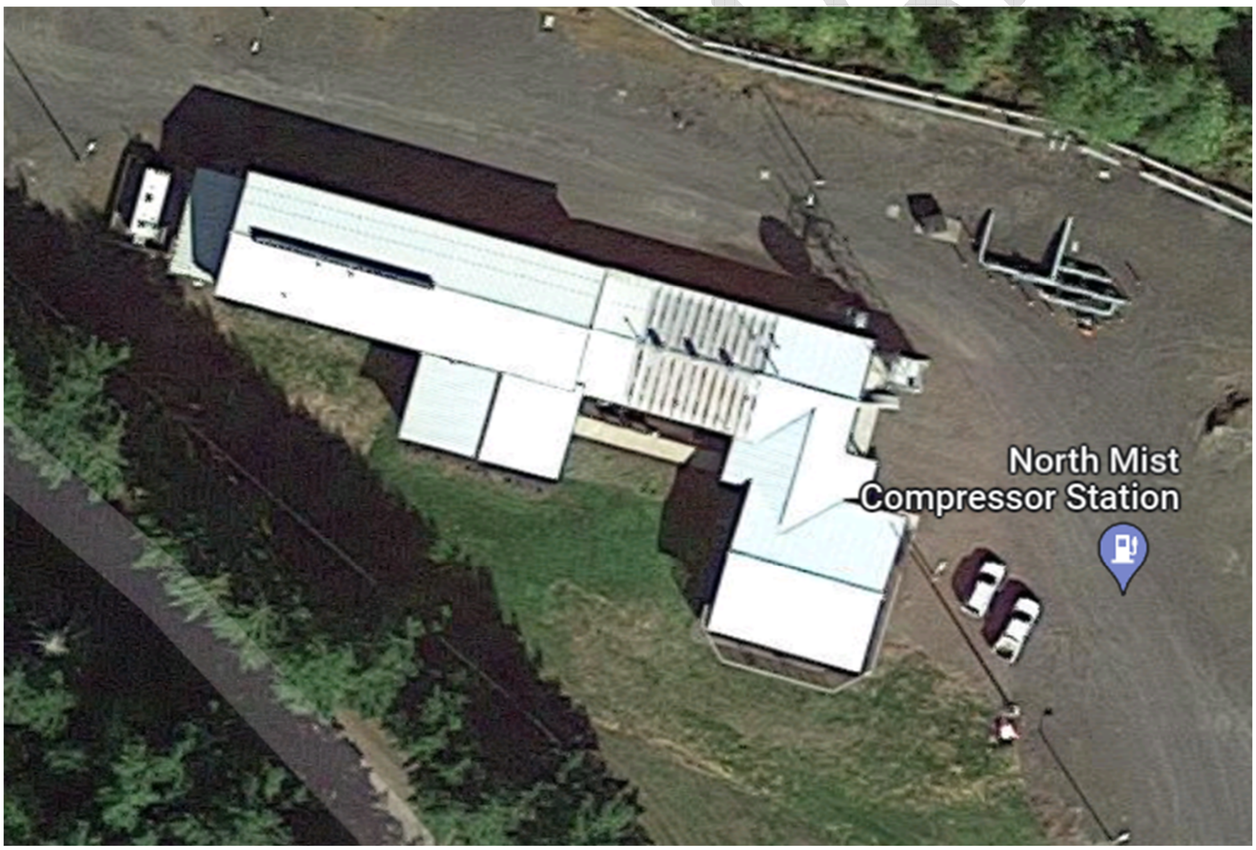
December 29, 2023

MILLER
CONSULTING
ENGINEERS

ASCE 41-17 TIER 1 SEISMIC EVALUATION

NW Natural – Miller Station
14750 Miller Station Rd
Clatskanie, OR 97016

April 1, 2022
MCE Project No. 211635
Prepared For: LRS Architects



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INTRODUCTION

This report summarizes the findings of our seismic evaluation of the NW Natural Miller Station Control Building located at 14750 Miller Station Rd, Clatskanie, OR. Please note this evaluation is based on visual observations and existing building drawings provided by the client. It only relates to the seismic performance of the structure.

Based on the existing building information provided, it has been determined that the current control building is a conglomerate of five different phases. Image 1 below provides a visual representation of the five different phases. Phase 1 is the original pre-engineered metal building (PEMB) and was designed in 1979. It currently includes the electrical room, 2 bathrooms, a data room, 2 private offices, a water treatment room, a kitchen, and a portion of the lunch/meeting room. For the purposes of this report, the Phase 1 building will be called Building 1. Phase 2 is also a PEMB, and the date of design is unknown. It currently includes 2 private offices, covered parking, and a maintenance/storage area. For the purposes of this report, the Phase 2 building will be called Building 2. Phase 3 is an addition to the lunch/meeting room and was designed in 2001. This portion of the building is not included in this seismic evaluation report, as it meets the Benchmark Building criteria. Phase 4 is a multi-purpose room addition to the south of the covered parking area and was designed in 2013. This portion of the building is not included in this seismic evaluation report, as it meets the Benchmark Building criteria and is seismically separated from Building 2. Phase 5 is a new controller room that was designed in 2016 by Miller Consulting Engineers. This portion of the building is not included in this seismic evaluation report, as it meets the Benchmark Building Criteria.

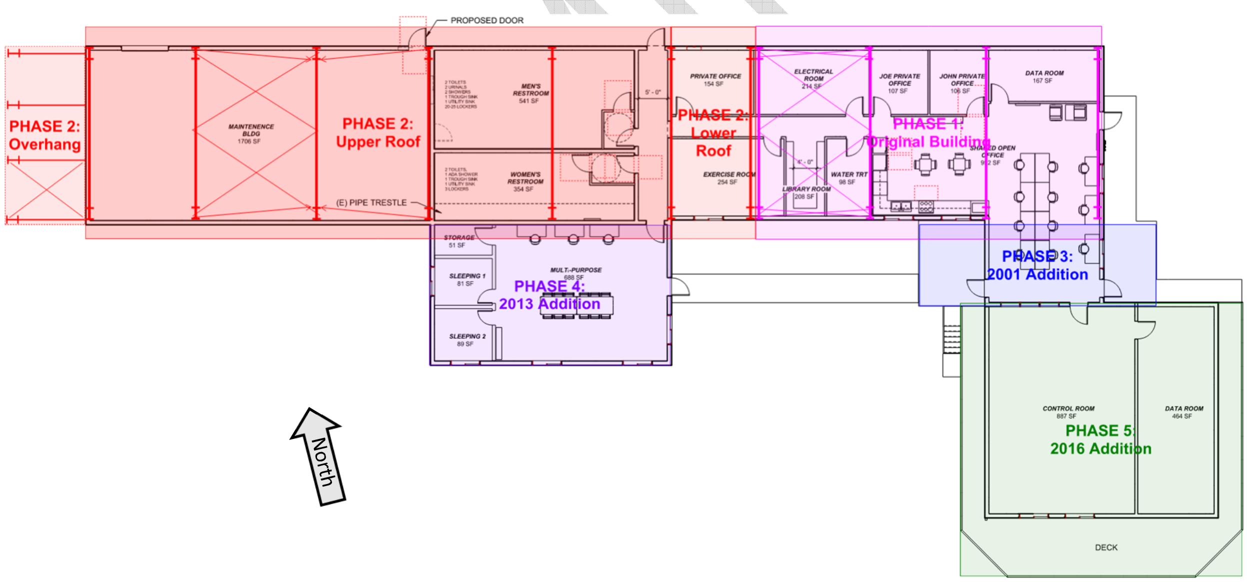

Image 1: Control Building Phases

SCOPE AND INTENT

Miller Consulting Engineers was contracted to perform a Tier 1 seismic evaluation of the NW Natural Miller Station located in Clatskanie, OR. This evaluation is based on a site visit conducted by Kylean Gunhus, PE on March 10, 2022 and upon the procedures of ASCE 41-17 "Seismic Evaluations 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 IV building. Therefore, the BPOE requires meeting the Life Safety structural performance and the Hazards Reduced nonstructural performance at the BSE-2E seismic hazard level. Life Safety, Hazards Reduced, and BSE-2E are defined as follows:

- Life Safety is defined as the post-earthquake damage state in which a structure has damaged components but retains a margin of safety against the onset of partial or total collapse.
- Hazards Reduced is defined as the post-earthquake damage state in which non-structural components are damaged and could potentially create falling hazards, but high-hazard non-structural components are secured to prevent falling into areas of public assembly or those falling hazards from those components could pose a risk to life safety for many people. Preservation of egress, protection of fire suppression systems, and similar life-safety issues are not addressed in this nonstructural performance level.
- BSE-2E is a seismic hazard level that represents an earthquake that has a 5% probability of exceedance in a 50 year period.

SITE AND BUILDING DATA

Building 1 of the Miller Station control building is an existing pre-engineered metal frame building designed in 1979. Building 1 measures approximately 60 feet east-west by 30 feet north-south and has an approximate mean roof height of 11 feet. Its main use is office space. The main lateral force resisting system of Building 1 is comprised of four moment frames in the North-South direction and tension bracing in the East-West direction.

Building 2 of the Miller Station control building is an existing pre-engineered metal frame building of an unknown design date. Building 2 measures approximately 125 feet east-west by 30 feet north-south and has an approximate mean roof height of 18 feet. At the eastern most end of Building 2 it has a framing bay with a lower roof that makes it appear to be part of Building 1. Upon investigation, there appears to be a seismic gap between Building 1 and Building 2. At the western most end of Building 2, there is an exterior overhang that extends approximately 10 feet from the west wall with a roof height of approximately 10 ft. The overhang has bracing that is tied back the main lateral force resisting system. At the interior of Building 2, there is a storage mezzanine that is not attached to the main lateral force resisting system and is not braced independently. The main lateral force resisting system of Building 2 is comprised of seven moment frames in the North-South direction and tension bracing in the East-West direction.

LIST OF CRITERIA USED FOR ANALYSIS

It was assumed that the classification of soils at the site are Site Class D (Default). Table 1 below indicates the ground motions that were used for analysis.

Table 1: Ground Motions Used for Analysis

Parameter	Value	Comments
$S_{X1,\ BSE\text{-}2E}$	0.849 g	Site-modified spectral response acceleration at a 1 second period for the BSE-2E seismic hazard level. Need not exceed $S_{X1,\ BSE\text{-}2N}$.
$S_{X1,\ BSE\text{-}2N}$	1.164 g	
$S_{XS,\ BSE\text{-}2E}$	0.651 g	Site-modified spectral response acceleration at a short period (0.2 seconds) for the BSE-2E seismic hazard level. Need not exceed $S_{XS,\ BSE\text{-}2N}$.
$S_{XS,\ BSE\text{-}2N}$	0.901 g	
$T_{BUILDING\ 1}$	0.121 s	Building fundamental period. See Equation 4-4 of ASCE 41-17.
$S_{a,\ BUILDING\ 1}$	0.849 g	See Equation 4-3 of ASCE 41-17. Not to exceed S_{XS}.
$T_{BUILDING\ 2}$	0.175 s	Building fundamental period. See Equation 4-4 of ASCE 41-17.
$S_{a,\ BUILDING\ 2}$	0.849 g	See Equation 4-3 of ASCE 41-17. Not to exceed S_{XS}.
$S_{1,\ BSE\text{-}2N}$	0.970 g	Spectral response acceleration parameter at a 1 second period for the BSE-2N seismic hazard level. Used to determine the Level of Seismicity in Section 2.5 of ASCE 41-17.
$S_{S,\ BSE\text{-}2N}$	0.501 g	Spectral response acceleration parameter at a short period (0.2 seconds) for the BSE-2N seismic hazard level. Used to determine the Level of Seismicity in Section 2.5 of ASCE 41-17.

The Level of Seismicity for the site is “High” as defined by Table 2-4 of ASCE 41-17.

FINDINGS

Based on the Tier 1 checklists, Building 1 does not meet the BPOE previously defined. Table 2a summarizes the structural deficiencies for Building 1. Table 2b summarizes the structural unknowns for Building 1. Table 2c summarizes the nonstructural uknowns for Building 1. Refer to Appendix A for the full Tier 1 checklists for Building 1.

Table 2a: Building 1 Structural Deficiencies

No.	Item	Tier 1 Ref.	Comments
1	Overturning	A.6.2.1	The ratio of the least horizontal dimension of the seismic-force-resisting system to the building height is less than $0.6S_a$.
2	Wall Brace Axial Stress	A.3.3.1.2	Axial stress in the ¼” diameter diagonal tension bracing is greater than $0.5F_y$.
3	Roof Brace Axial Stress	A.3.3.1.2	Axial stress in the ¼” diagonal tension bracing is greater than $0.5F_y$.
4	Moment Resisting Connections	A.3.1.3.4	5/8” diameter bolts and plate bending are overstressed.

Table 2b: Building 1 Structural Unknowns

No.	Item	Tier 1 Ref.	Comments
1	Liquefaction	A.6.1.1	It is not known if the geotechnical investigation by GeoEngineers for their geotechnical report dated February 6, 2017 looked into this.
2	Slope Failure	A.6.1.2	It is not known if the geotechnical investigation by GeoEngineers for their geotechnical report dated February 6, 2017 looked into this.
3	Surface Fault Rupture	A.6.1.3	It is not known if the geotechnical investigation by GeoEngineers for their geotechnical report dated February 6, 2017 looked into this.

Note: Once further information becomes available, structural unknowns may become deficiencies.

Table 2c: Building 1 Nonstructural Unknowns

No.	Item	Tier 1 Ref.	Comments
1	Fire Suppression Piping	A.7.13.1	
2	Flexible Couplings	A.7.13.2	
3	Emergency Power	A.7.12.1	
4	Sprinkler Ceiling Clearance	A.7.13.3	
5	Emergency Lighting	A.7.3.1	
6	Hazardous Material Equipment	A.7.12.2	
7	Hazardous Material Storage	A.7.15.1	
8	Hazardous Material Distibution	A.7.13.4	
9	Shutoff Valves	A.7.13.3	
10	Flexible Couplings	A.7.15.4	
11	Piping/Ducts Crossing Seismic Joints	A.7.13.6	
12	Tops	A.7.1.4	
13	Suspended Gypsum Board	A.7.2.3	
14	Edge Clearance	A.7.2.4	
15	Seismic Joints	A.7.2.7	
16	Independent Support	A.7.3.2	
17	Pendant Supports	A.7.3.3	
18	Lens Covers	A.7.3.4	
19	Fall-Prone Contents	A.7.11.3	
20	Suspended Contents	A.7.11.6	
21	Fall-Prone Equipment	A.7.12.4	
22	In-Line Equipment	A.7.12.5	
23	Tall Narrow Equipment	A.7.12.6	
24	Suspended Equipment	A.7.12.8	
25	Vibration Isolators	A.7.12.9	
26	Heavy Equipment	A.7.12.10	
27	Electrical Equipment	A.7.12.11	
28	Conduit Couplings	A.7.12.12	
29	Flexible Couplings	A.7.13.2	
30	Fluid and Gas Piping	A.7.13.4	
31	C-Clamps	A.7.13.5	
32	Piping Crossing Seismic Joints	A.7.13.6	
33	Duct Support	A.7.14.3	
34	Ducts Crossing Seismic Joints	A.7.14.4	

Note: Once further information becomes available, nonstructural unknowns may become deficiencies.

Based on the Tier 1 checklists, Building 2 does not meet the BPOE previously defined. Table 3a summarizes the structural deficiencies for Building 2. Table 3b summarizes the structural unknowns for Building 1. Table 3c summarizes the nonstructural unknowns for Building 2. Refer to Appendix B for the full Tier 1 checklists for Building 2.

Table 3a: Building 2 Structural Deficiencies

No.	Item	Tier 1 Ref.	Comments
1	Mezzanines	A.2.1.3	Storage mezzanine does not appear to be independently braced or attached to the seismic-force-resisting system.
2	Overturning	A.6.2.1	The ratio of the least horizontal dimension of the seismic-force-resisting system to the building height is less than $0.6S_a$.
3	Wall Brace Axial Stress	A.3.3.1.2	Axial stress in the ¾" diameter diagonal tension bracing is greater than $0.5F_y$.
4	Roof Brace Axial Stress	A.3.3.1.2	Axial stress in the ¾" diameter diagonal tension bracing is greater than $0.5F_y$.
5	Moment Resisting Connections	A.3.1.3.4	5/8" diameter bolts and plate bending are overstressed.

Table 3b: Building 2 Structural Unknowns

No.	Item	Tier 1 Ref.	Comments
1	Liquefaction	A.6.1.1	It is not known if the geotechnical investigation by GeoEngineers for their geotechnical report dated February 6, 2017 looked into this.
2	Slope Failure	A.6.1.2	It is not known if the geotechnical investigation by GeoEngineers for their geotechnical report dated February 6, 2017 looked into this.
3	Surface Fault Rupture	A.6.1.3	It is not known if the geotechnical investigation by GeoEngineers for their geotechnical report dated February 6, 2017 looked into this.
4	Ties Between Foundation Elements	A.6.2.2	The existing foundation appears to be a pedestal that is discontinuous from the slab on grade. Requires further investigation.

Note: Once further information becomes available, structural unknowns may become deficiencies.

Table 3c: Building 2 Nonstructural Unknowns

No.	Item	Tier 1 Ref.	Comments
1	Fire Suppression Piping	A.7.13.1	
2	Flexible Couplings	A.7.13.2	
3	Emergency Power	A.7.12.1	
4	Sprinkler Ceiling Clearance	A.7.13.3	
5	Emergency Lighting	A.7.3.1	
6	Hazardous Material Equipment	A.7.12.2	
7	Hazardous Material Storage	A.7.15.1	
8	Hazardous Material Distibution	A.7.13.4	
9	Shutoff Valves	A.7.13.3	
10	Flexible Couplings	A.7.15.4	
11	Piping/Ducts Crossing Seismic Joints	A.7.13.6	
12	Independent Support	A.7.3.2	
13	Pendant Supports	A.7.3.3	
14	Lens Covers	A.7.3.4	
15	Industrial Storage Racks	A.7.11.1	
16	Tall Narrow Contents	A.7.11.2	
17	Fall-Prone Contents	A.7.11.3	
18	Suspended Contents	A.7.11.6	
19	Fall-Prone Equipment	A.7.12.4	
20	In-Line Equipment	A.7.12.5	
21	Tall Narrow Equipment	A.7.12.6	
22	Mechanical Doors	A.7.12.7	
23	Suspended Equipment	A.7.12.8	
24	Vibration Isolators	A.7.12.9	
25	Heavy Equipment	A.7.12.10	
26	Electrical Equipment	A.7.12.11	
27	Conduit Couplings	A.7.12.12	
28	Flexible Couplings	A.7.13.2	
29	Fluid and Gas Piping	A.7.13.4	
30	C-Clamps	A.7.13.5	
31	Piping Crossing Seismic Joints	A.7.13.6	

Note: Once further information becomes available, nonstructural unknowns may become deficiencies.

CONCEPTUAL SEISMIC UPGRADE WORK

Structural deficiencies for Building 1 are listed in the previous section and the complete Tier 1 checklists for Building 1 are included in Appendix A. The following is a list of potential solutions to mitigate the known deficiencies.

1. Overturning – Increase size of foundation elements to prevent uplift. Provide new post-installed anchor bolts to the foundation.
2. Wall Brace Axial Stress – Replace existing wire rope tension bracing with larger diameter, higher strength wire rope tension bracing.
3. Roof Brace Axial Stress – Replace existing wire rope tension bracing with larger diameter, higher strength wire rope tension bracing.
4. Moment Resisting Connection – Increase strength of bolts at the moment connections. Reinforce plates at the moment connections.

Structural deficiencies for Building 2 are listed in the previous section and the complete Tier 1 checklists for Building 2 are included in Appendix B. The following is a list of potential solutions to mitigate the known deficiencies.

1. Mezzanines – Provide diagonal bracing to independently support the mezzanine.
2. Overturning – Increase size of foundation elements to prevent uplift. Provide new post-installed anchor bolts to the foundation.
3. Wall Brace Axial Stress – Replace existing tension rod bracing with larger diameter, higher strength tension rod bracing.
4. Roof Brace Axial Stress – Replace existing tension rod bracing with larger diameter, higher strength tension rod bracing.
5. Moment Resisting Connection – Increase strength of bolts at the moment connections. Reinforce plates at the moment connections.

SUMMARY

This ASCE 41-17 Tier 1 seismic evaluation report was prepared for the NW Natural Miller Station Control Building. It was found that the building, in its current state, does not meet the desired seismic structural performance objective and likely does not meet the desired seismic nonstructural performance objective for a BSE-2E seismic hazard level.

The information contained in this report is for the exclusive use of the Client. Miller Consulting Engineers, Inc., assumes no responsibility or liability for any use of this report by other parties. This report relates solely to the stated purpose of this investigation; and no representations concerning other aspects (if any) of the circumstance, structure or site are included. The conclusions (if any) are based on the above stated visual observations, and no destructive testing or monitoring was performed. Specific construction details exceed the scope of this report. No guarantee or warranty, expressed or implied, is provided.

APPENDIX A

ASCE 41-17 Tier 1 Checklists
Building 1

Table 17-1. Very Low Seismicity Checklist

Status				Evaluation Statement		Tier 1 Reference
C	NC	N/A	U	LOAD PATH:	The structure contains 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.	A.2.1.1
C	NC	N/A	U	WALL ANCHORAGE:	Exterior concrete or masonry walls that are dependent of 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 have adequate strength to resist the connection force calculated in the Quick Check procedure of Section 4.4.3.7	A.5.1.1

Table 17-2. Collapse Prevention Basic Configuration Checklist

Status				Evaluation Statement		Tier 1 Reference
Low Seismicity						
Building System - General						
C	NC	N/A	U	LOAD PATH:	The structure contains 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.	A.2.1.1
C	NC	N/A	U	ADJACENT BUILDINGS:	The clear distance between the building being evaluated and any adjacent building is greater than 0.25% of the height of the shorter building in low seismicity, 0.5% in moderate seismicity, and 1.5% in high seismicity.	A.2.1.2
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.	A.2.1.3
Building System - Building Configuration						
C	NC	**N/A**	U	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.	A.2.2.2
C	NC	**N/A**	U	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 of the three stories above.	A.2.2.3
C	NC	N/A	U	VERTICAL IRREGULARITIES:	All vertical elements in the seismic-force-resisting system are continuous to the foundation.	A.2.2.4
C	NC	**N/A**	U	GEOMETRY:	There are not 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.	A.2.2.5
C	NC	**N/A**	U	MASS:	There is no change in effectice mass of more than 50% from one story to the next. Light roofs, penthouses, and mezzanines need not be considered.	A.2.2.6
C	NC	N/A	U	TORSION:	The estimated distance between the story center of mass and story center of rigidity is less than 20% of the building width in either plan dimension.	A.2.2.7
Moderate Seismicity (Complete the Following Items in Addition to the Items for Low Seismicity)						
Geologic Site Hazards						
C	NC	N/A	**U**	LIQUEFACTION:	Liquefaction-susceptible, saturated, loose granular soils that could jeopardize the building's seismic performance do not exist in the foundation soils at depths within 50 ft under the building.	A.6.1.1
C	NC	N/A	**U**	SLOPE FAILURE:	The building site is located away from potential earthquake-induced slope failures or rockfalls so that it is unaffected by such failures or is capable of accomodating any predicted movements without failure.	A.6.1.2
C	NC	N/A	**U**	SURFACE FAULT RUPTURE:	Surface fault rupture and surface displacement at the building site are not anticipated.	A.6.1.3
High Seismicity (Complete the Following Items in Addition to the Items for Moderate Seismicity)						
Foundation Configuration						
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 0.6Sa.	A.6.2.1
C	NC	N/A	U	TIES BETWEEN FOUNDATION ELEMENTS:	The foundation has ties adeqaute to resist the seismic forces where footings, piles, and piers are not restrained by beams, slabs, or soils classified as Site Class A, B, or C.	A.6.2.2

Table 17-12. Collapse Prevention Structural Checklist for Building Type S3

Status				Evaluation Statement		Tier 1 Reference
Low and Moderate Seismicity						
Seismic-Force-Resisting System						
C	NC	N/A	U	BRACE AXIAL STRESS CHECK:	The axial stress in the diagonals, calculated using the Quick Check procedure of Section 4.4.3.2, is less than 0.50Fy.	A.3.3.1.2
C	NC	N/A	U	TRANSFER TO STEEL FRAMES:	Diaphragms are connected for transfer of seismic forces to the steel moment frames.	A.5.2.2
C	NC	N/A	U	STEEL COLUMNS:	The columns in seismic-force-resisting frames are anchored to the building foundation.	A.5.3.1
High Seismicity (Complete the Following Items in Addition to the Items for Low and Moderate Seismicity)						
Seismic-Force-Resisting System						
C	NC	N/A	U	MOMENT-RESISTING CONNECTIONS:	All moment connections are able to develop the elastic moment (FyS) of the adjoining members.	A.3.1.3.4
C	NC	N/A	U	COMPACT MEMBERS:	All frame elements meet compact section requirements in accordance with AISC 360, Table B4.1.	A.3.1.3.8
C	NC	N/A	U	OTHER DIAPHRAGMS:	Diaphragms do not consist of a system other than wood, metal deck, concrete, or horizontal bracing.	A.4.7.1
C	NC	N/A	U	ROOF PANELS:	Where considered as diaphragm elements for lateral resistance, metal, plastic, or cementitious roof panels are positively attached to the roof framing to resist seismic forces.	A.5.5.1
C	NC	N/A	U	WALL PANELS:	Where considered as shear elements for lateral resistance, metal, fiberglass, or cementitious wall panels are positively attached to the framing and foundation to resist seismic forces.	A.5.5.2

Table 17-38. Nonstructural Checklist

Status				Evaluation Statement		Tier 1 Reference
Life Safety Systems						
C	NC	N/A	U	FIRE SUPPRESSION PIPING:	Fire suppression piping is anchored and braced in accordance with NFPA-13.	A.7.13.1
C	NC	N/A	U	FLEXIBLE COUPLINGS:	Fire suppression piping has flexible couplings in accordance with NFPA-13.	A.7.13.2
C	NC	N/A	U	EMERGENCY POWER:	Equipment used to power control Life Safety systems is anchored or braced.	A.7.12.1
C	NC	N/A	U	STAIR AND SMOKE DUCTS:	Stair pressurization and smoke control ducts are braced and have flexible connections at seismic joints.	A.7.14.1
C	NC	N/A	U	SPRINKLER CEILING CLEARANCE:	Penetrations through panelized ceiling for fire suppression devices provide clearances in accordance with NFPA-13.	A.7.13.3
C	NC	N/A	U	EMERGENCY LIGHTING:	Emergency and egress lighting equipment is anchored or braced.	A.7.3.1
Hazardous Materials						
C	NC	N/A	U	HAZARDOUS MATERIAL EQUIPMENT:	Equipment mounted on vibration isolators and containing hazardous material is equipped with restraints or snubbers.	A.7.12.2
C	NC	N/A	U	HAZARDOUS MATERIAL STORAGE:	Breakable containers that hold hazardous material, including gas cylinders, are restrained by latched doors, shelf lips, wires, or other methods.	A.7.15.1
C	NC	N/A	U	HAZARDOUS MATERIAL DISTRIBUTION:	Piping or ductwork conveying hazardous materials is braced or otherwise protected from damage that would allow for hazardous material release.	A.7.13.4
C	NC	N/A	U	SHUTOFF VALVES:	Piping containing hazardous material, including natural gas, has shutoff valves or other devices to limit spills or leaks.	A.7.13.3
C	NC	N/A	U	FLEXIBLE COUPLINGS:	Hazardous material ductwork and piping, including natural gas piping, have flexible couplings.	A.7.15.4
C	NC	N/A	U	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.	A.7.13.6
Partitions						
C	NC	N/A	U	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.	A7.1.1
C	NC	N/A	U	HEAVY PARTITIONS SUPPORTED BY CEILINGS:	The tops of masonry or hollow-clay tile partitions are not laterally supported by an integrated ceiling system.	A.7.2.1
C	NC	N/A	U	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.	A.7.1.2
C	NC	N/A	U	LIGHT PARTITIONS SUPPORTED BY CEILINGS:	The tops of gypsum board partitions are not laterally supported by an integrated ceiling system.	A.7.2.1
C	NC	N/A	U	STRUCTURAL SEPARATIONS:	Partitions that cross structural separations have seismic or control joints.	A.7.1.3
C	NC	N/A	U	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.	A.7.1.4

Table 17-38. Nonstructural Checklist (Continued)

Status				Evaluation Statement		Tier 1 Reference
Ceilings						
C	NC	N/A	U	SUSPENDED LATH AND PLASTER:	Suspended lath and plaster ceilings have attachments that resist seismic forces for every 12 ft^2 of area.	A.7.2.3
C	NC	N/A	U	SUSPENDED GYPSUM BOARD:	Suspended gypsum board ceilings have attachments that resist seismic forces for every 12 ft^2 of area.	A.7.2.3
C	NC	N/A	U	INTEGRATED CEILINGS:	Integrated suspended ceilings with continuous areas greater than 144 ft^2 and ceilings of smaller area that are not surrounded by restraining partitions are laterally restrained at a spacing no greater than 12 ft^2 with members attached to the structures above. Each restraint location has a minimum of four diagonal wires and compressive struts, or diagonal members capable of resisting compression.	A.7.2.2
C	NC	N/A	U	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, 2 in.	A.7.2.4
C	NC	N/A	U	CONTINUITY ACROSS:	The ceiling system does not cross any seismic joint and is not attached to multiple independent structures.	A.7.2.5
C	NC	N/A	U	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.	A.7.2.6
C	NC	N/A	U	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.	A.7.2.7
Light Fixtures						
C	NC	N/A	U	INDEPENDENT SUPPORT:	Light fixtures that weigh more per square foot than the ceiling they penetrate are supported independent of the gride ceiling suspension system by a minimum of two wires at diagonally opposite corners of each fixture.	A.7.3.2
C	NC	N/A	U	PENDANT SUPPORTS:	Light fixtures on pendant supports are attached at a spacing equal to or less than 6 ft. Unbraced suspended fixtures are free to allow a 360-degree range of motion at an angle not less than 45 degrees from horizontal without contacting adjacent components. Alternatively, if rigidly supported and/or braced, they are free to move with the structure to which they are attached without damaging adjoining components. Additionally, the connection to the structure is capable of accommodating the movement without failure.	A.7.3.3
C	NC	N/A	U	LENS COVERS:	Lens covers on light fixtures are attached with safety devices.	A.7.3.4

Table 17-38. Nonstructural Checklist (Continued)

Status				Evaluation Statement		Tier 1 Reference
Cladding and Glazing						
C	NC	N/A	U	CLADDING ANCHORS:	Cladding components weighing more than 10 lb/ft2 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 and seismicity, 4 ft.	A.7.4.1
C	NC	N/A	U	CLADDING ISOLATION:	For steel or concrete moment-frame buildings, panel connections are detailed to accommodate a story drift ratio by use of rods attached to framing with oversized holes or slotted holes 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, and the rods have a length-to-diameter ratio of 4 or less.	A.7.4.3
C	NC	N/A	U	MULTI-STORY PANELS:	For multi-story panels attached at more than one floor level, panel connections are detailed to accommodate a story drift ratio by use of rods attached to framing with oversized holes or slotted holes 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, and the rods have a length-to-diameter ratio of 4 or less.	A.7.4.4
C	NC	N/A	U	THREADED RODS:	Threaded rods for panel connections detailed to accommodate drift by bending of the rod have length-to-diameter ratio greater than 0.06 times the story height in inches for a Life Safety in Moderate Seismicity and 0.12 times the story height in inches for Life Safety in High Seismicity and Position Retention in any seismicity.	A.7.4.9
C	NC	N/A	U	PANEL CONNECTIONS:	Cladding panels are acnhored for out of plane with a minimum number of connection for each wall panel, as follows: for Life Safety in Moderate Seismicity, 2 connections, for Life Safety in High Seismicity and for Position Retention, 4 connections.	A.7.4.5
C	NC	N/A	U	BEARING CONNECTIONS:	Where bearing connections are used, there is a minimum of two bearing connections for each cladding panel.	A.7.4.6
C	NC	N/A	U	INSERTS:	Where concrete cladding components use inserts, the inserts have positive anchorage or are anchored to reinforcing steel.	A.7.4.7
C	NC	N/A	U	OVERHEAD GLAZING:	Glazing panes of any size in curtain walls and individual interior or exterior panes more than 16 ft^2 in area are laminated annealed or laminated heat-strengthened glass and are detailed to remain in the frame when cracked.	A.7.4.8
C	NC	N/A	U	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 Moderate Seismicity, 36 in; for Life Safety in High Seismicity and for Position Retention in any seismicity, 24 in.	A.7.5.1
C	NC	N/A	U	SHELF ANGLES:	Masonry veneer is supported by shelf angles or other elements at each floor above the ground floor.	A.7.5.2
C	NC	N/A	U	WEAKENED PLANES:	Masonry veneer is anchored to the backup adjacent to weakened planes, such as at the locations of flashing.	A.7.5.3
C	NC	N/A	U	UNREINFORCED MASONRY BACKUP:	There is no unreinforced masonry backup.	A.7.7.2
C	NC	N/A	U	STUD TRACKS:	For veneer with cold-formed steel stud backup, stud tracks are fastened to the structure at a spacing equal to or less than 24 in on center.	A.7.6.1
C	NC	N/A	U	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.	A.7.7.1
C	NC	N/A	U	WEEP HOLES:	In veneer anchored to stud walls, the veneer has functioning weep holes and base flashing.	A.7.5.6
C	NC	N/A	U	OPENINGS:	For veneer with cold-formed steel stud backup, steel studs frame window and door openings.	A.7.6.2

Table 17-38. Nonstructural Checklist (Continued)

Status				Evaluation Statement		Tier 1 Reference
Parapets, Cornices, Ornamentation, and Appendages						
C	NC	N/A	U	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.	A.7.8.1
C	NC	N/A	U	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.	A.7.8.2
C	NC	N/A	U	CONCRETE PARAPETS:	Concrete parapets with height-to-thickness ratios greater than 2.5 have vertical reinforcement.	A.7.8.3
C	NC	N/A	U	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. The evaluation statement item does not apply to parapets or cornices covered by other evaluation statements.	A.7.8.4
Masonry Chimneys						
C	NC	N/A	U	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 and seismicity, 2 times the least dimension of the chimney.	A.7.9.1
C	NC	N/A	U	ANCHORAGE:	Masonry chimneys are anchored at each floor level, at the topmost ceiling level, and at the roof.	A.7.9.2
Stairs						
C	NC	N/A	U	STAIR ENCLOSURES:	Hollow-clay tile or unreinforced masonry walls around stair enclosures are restrained out of plane and have height-to-thickness rations 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.	A.7.10.1
C	NC	N/A	U	STAIR DETAILS:	The connection between the stairs and the structure does not rely on post-installed anchors in the concrete or masonry, and the stair details are capable of accommodating the drift calculated using the Quick Check procedure of Section 4.4.3.1 for moment-frame structures or 0.5 in for all other structures without including any lateral stiffness contribution from the stairs.	A.7.10.2
Contents and Furnishings						
C	NC	N/A	U	INDUSTRIAL STORAGE RACKS:	Industrial storage racks or pallet racks more than 12 ft high meet the requirements of ANSI/RMI MH 16.1 as modified by ASCE 7, Chapter 15.	A.7.11.1
C	NC	N/A	U	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.	A.7.11.2
C	NC	N/A	U	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.	A.7.11.3
C	NC	N/A	U	ACCESS FLOORS:	Access floors more than 9 in high are braced.	A.7.11.4
C	NC	N/A	U	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.	A.7.11.5
C	NC	N/A	U	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.	A.7.11.6

Table 17-38. Nonstructural Checklist (Continued)

Status				Evaluation Statement		Tier 1 Reference
Mechanical and Electrical Equipment						
C	NC	N/A	U	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.	A.7.12.4
C	NC	N/A	U	IN-LINE EQUIPMENT:	Equipment installed in line with a duct or piping system, with an operating weight more than 75lb, is supported and laterally braced independent of the duct or piping system.	A.7.12.5
C	NC	N/A	U	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.	A.7.12.6
C	NC	N/A	U	MECHANICAL DOORS:	Mechanically operated doors are detailed to operate with a story drift ratio of 0.01.	A.7.12.7
C	NC	N/A	U	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.	A.7.12.8
C	NC	N/A	U	VIBRATION ISOLATORS:	Equipment mounted on vibration isolators is equipped with horizontal restraints or snubbers and with vertical restraints to resist overturning.	A.7.12.9
C	NC	N/A	U	HEAVY EQUIPMENT:	Floor-supported or platform-supported equipment weighing more than 400 lb is anchored to the structure.	A.7.12.10
C	NC	N/A	U	ELECTRICAL EQUIPMENT:	Electrical equipment is laterally braced to the structure.	A.7.12.11
C	NC	N/A	U	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.	A.7.12.12
Piping						
C	NC	N/A	U	FLEXIBLE COUPLINGS:	Fluid and gas piping has flexible couplings.	A.7.13.2
C	NC	N/A	U	FLUID AND GAS PIPING:	Fluid and gas piping is anchored and braced to the structure to limit spills or leaks.	A.7.13.4
C	NC	N/A	U	C-CLAMPS:	One-sided C-clamps that support piping larger than 2.5 in in diameter are restrained.	A.7.13.5
C	NC	N/A	U	PIPING CROSSING SEISMIC JOINTS:	Piping that crosses seismic joints or isolation planes or is connected to independent structures has couplings or other details to acccomodate the relative seismic displacements.	A.7.13.6
C	NC	N/A	U	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.	A.7.14.2
C	NC	N/A	U	DUCT SUPPORT:	Ducts are not supported by piping or electrical conduit.	A.7.14.3
C	NC	N/A	U	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.	A.7.14.4

Table 17-38. Nonstructural Checklist (Continued)

Status				Evaluation Statement		Tier 1 Reference
Elevators						
C	NC	N/A	U	RETAINER GUARDS:	Sheaves and drums have cable retainer guards.	A.7.16.1
C	NC	N/A	U	RETAINER PLATE:	A retainer plate is present at the top and bottom of both car and counterweight.	A.7.16.2
C	NC	N/A	U	ELEVATOR EQUIPMENT:	Equipment, piping, and other components that are part of the elevator system are anchored.	A.7.16.3
C	NC	N/A	U	SEISMIC SWITCH:	Elevators capable of operating at speeds of 150ft/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% acceleration of gravity in other directions.	A.7.16.4
C	NC	N/A	U	SHAFT WALLS:	Elevator shaft walls are anchored and reinforced to prevent toppling into the shaft during strong shaking.	A.7.16.5
C	NC	N/A	U	COUNTERWEIGHT RAILS:	All counterweight rails and divider beams are sized in accordance with ASME A17.1.	A.7.16.6
C	NC	N/A	U	BRACKETS:	The brackets that tie the car rails and the counterweight rail to the structure are sized in accordance with ASME A17.1.	A.7.16.7
C	NC	N/A	U	SPREADER BRACKET:	Spreader brackets are not used to resist seismic forces.	A.7.16.8
C	NC	N/A	U	GO-SLOW ELEVATORS:	The building has a go-slow elevator system.	A.7.16.9

APPENDIX B

ASCE 41-17 Tier 1 Checklists
Building 2

Table 17-1. Very Low Seismicity Checklist

Status				Evaluation Statement		Tier 1 Reference
C	NC	N/A	U	LOAD PATH:	The structure contains 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.	A.2.1.1
C	NC	N/A	U	WALL ANCHORAGE:	Exterior concrete or masonry walls that are dependent of 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 have adequate strength to resist the connection force calculated in the Quick Check procedure of Section 4.4.3.7	A.5.1.1

Table 17-2. Collapse Prevention Basic Configuration Checklist

Status				Evaluation Statement		Tier 1 Reference
Low Seismicity						
Building System - General						
C	NC	N/A	U	LOAD PATH:	The structure contains 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.	A.2.1.1
C	NC	N/A	U	ADJACENT BUILDINGS:	The clear distance between the building being evaluated and any adjacent building is greater than 0.25% of the height of the shorter building in low seismicity, 0.5% in moderate seismicity, and 1.5% in high seismicity.	A.2.1.2
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.	A.2.1.3
Building System - Building Configuration						
C	NC	**N/A**	U	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.	A.2.2.2
C	NC	**N/A**	U	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 of the three stories above.	A.2.2.3
C	NC	N/A	U	VERTICAL IRREGULARITIES:	All vertical elements in the seismic-force-resisting system are continuous to the foundation.	A.2.2.4
C	NC	**N/A**	U	GEOMETRY:	There are not 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.	A.2.2.5
C	NC	**N/A**	U	MASS:	There is no change in effective mass of more than 50% from one story to the next. Light roofs, penthouses, and mezzanines need not be considered.	A.2.2.6
C	NC	N/A	U	TORSION:	The estimated distance between the story center of mass and story center of rigidity is less than 20% of the building width in either plan dimension.	A.2.2.7
Moderate Seismicity (Complete the Following Items in Addition to the Items for Low Seismicity)						
Geologic Site Hazards						
C	NC	N/A	**U**	LIQUEFACTION:	Liquefaction-susceptible, saturated, loose granular soils that could jeopardize the building's seismic performance do not exist in the foundation soils at depths within 50 ft under the building.	A.6.1.1
C	NC	N/A	**U**	SLOPE FAILURE:	The building site is located away from potential earthquake-induced slope failures or rockfalls so that it is unaffected by such failures or is capable of accomodating any predicted movements without failure.	A.6.1.2
C	NC	N/A	**U**	SURFACE FAULT RUPTURE:	Surface fault rupture and surface displacement at the building site are not anticipated.	A.6.1.3
High Seismicity (Complete the Following Items in Addition to the Items for Moderate Seismicity)						
Foundation Configuration						
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 0.6Sa.	A.6.2.1
C	NC	N/A	**U**	TIES BETWEEN FOUNDATION ELEMENTS:	The foundation has ties adeqaute to resist the seismic forces where footings, piles, and piers are not restrained by beams, slabs, or soils classified as Site Class A, B, or C.	A.6.2.2

Table 17-12. Collapse Prevention Structural Checklist for Building Type S3

Status				Evaluation Statement		Tier 1 Reference
Low and Moderate Seismicity						
Seismic-Force-Resisting System						
C	NC	N/A	U	BRACE AXIAL STRESS CHECK:	The axial stress in the diagonals, calculated using the Quick Check procedure of Section 4.4.3.4, is less than 0.50Fy.	A.3.3.1.2
C	NC	N/A	U	TRANSFER TO STEEL FRAMES:	Diaphragms are connected for transfer of seismic forces to the steel moment frames.	A.5.2.2
C	NC	N/A	U	STEEL COLUMNS:	The columns in seismic-force-resisting frames are anchored to the building foundation.	A.5.3.1
High Seismicity (Complete the Following Items in Addition to the Items for Low and Moderate Seismicity)						
Seismic-Force-Resisting System						
C	NC	N/A	U	MOMENT-RESISTING CONNECTIONS:	All moment connections are able to develop the elastic moment (FyS) of the adjoining members.	A.3.1.3.4
C	NC	N/A	U	COMPACT MEMBERS:	All frame elements meet compact section requirements in accordance with AISC 360, Table B4.1.	A.3.1.3.8
C	NC	N/A	U	OTHER DIAPHRAGMS:	Diaphragms do not consist of a system other than wood, metal deck, concrete, or horizontal bracing.	A.4.7.1
C	NC	N/A	U	ROOF PANELS:	Where considered as diaphragm elements for lateral resistance, metal, plastic, or cementitious roof panels are positively attached to the roof framing to resist seismic forces.	A.5.5.1
C	NC	N/A	U	WALL PANELS:	Where considered as shear elements for lateral resistance, metal, fiberglass, or cementitious wall panels are positively attached to the framing and foundation to resist seismic forces.	A.5.5.2

Table 17-38. Nonstructural Checklist

Status				Evaluation Statement		Tier 1 Reference
Life Safety Systems						
C	NC	N/A	U	FIRE SUPPRESSION PIPING:	Fire suppression piping is anchored and braced in accordance with NFPA-13.	A.7.13.1
C	NC	N/A	U	FLEXIBLE COUPLINGS:	Fire suppression piping has flexible couplings in accordance with NFPA-13.	A.7.13.2
C	NC	N/A	U	EMERGENCY POWER:	Equipment used to power control Life Safety systems is anchored or braced.	A.7.12.1
C	NC	N/A	U	STAIR AND SMOKE DUCTS:	Stair pressurization and smoke control ducts are braced and have flexible connections at seismic joints.	A.7.14.1
C	NC	N/A	U	SPRINKLER CEILING CLEARANCE:	Penetrations through panelized ceiling for fire suppression devices provide clearances in accordance with NFPA-13.	A.7.13.3
C	NC	N/A	U	EMERGENCY LIGHTING:	Emergency and egress lighting equipment is anchored or braced.	A.7.3.1
Hazardous Materials						
C	NC	N/A	U	HAZARDOUS MATERIAL EQUIPMENT:	Equipment mounted on vibration isolators and containing hazardous material is equipped with restraints or snubbers.	A.7.12.2
C	NC	N/A	U	HAZARDOUS MATERIAL STORAGE:	Breakable containers that hold hazardous material, including gas cylinders, are restrained by latched doors, shelf lips, wires, or other methods.	A.7.15.1
C	NC	N/A	U	HAZARDOUS MATERIAL DISTRIBUTION:	Piping or ductwork conveying hazardous materials is braced or otherwise protected from damage that would allow for hazardous material release.	A.7.13.4
C	NC	N/A	U	SHUTOFF VALVES:	Piping containing hazardous material, including natural gas, has shutoff valves or other devices to limit spills or leaks.	A.7.13.3
C	NC	N/A	U	FLEXIBLE COUPLINGS:	Hazardous material ductwork and piping, including natural gas piping, have flexible couplings.	A.7.15.4
C	NC	N/A	U	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.	A.7.13.6
Partitions						
C	NC	N/A	U	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.	A7.1.1
C	NC	N/A	U	HEAVY PARTITIONS SUPPORTED BY CEILINGS:	The tops of masonry or hollow-clay tile partitions are not laterally supported by an integrated ceiling system.	A.7.2.1
C	NC	N/A	U	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.	A.7.1.2
C	NC	N/A	U	LIGHT PARTITIONS SUPPORTED BY CEILINGS:	The tops of gypsum board partitions are not laterally supported by an integrated ceiling system.	A.7.2.1
C	NC	N/A	U	STRUCTURAL SEPARATIONS:	Partitions that cross structural separations have seismic or control joints.	A.7.1.3
C	NC	N/A	U	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.	A.7.1.4

Table 17-38. Nonstructural Checklist (Continued)

Status					Evaluation Statement	Tier 1 Reference
Ceilings						
C	NC	N/A	U	SUSPENDED LATH AND PLASTER:	Suspended lath and plaster ceilings have attachments that resist seismic forces for every 12 ft^2 of area.	A.7.2.3
C	NC	N/A	U	SUSPENDED GYPSUM BOARD:	Suspended gypsum board ceilings have attachments that resist seismic forces for every 12 ft^2 of area.	A.7.2.3
C	NC	N/A	U	INTEGRATED CEILINGS:	Integrated suspended ceilings with continuous areas greater than 144 ft^2 and ceilings of smaller area that are not surrounded by restraining partitions are laterally restrained at a spacing no greater than 12 ft^2 with members attached to the structures above. Each restraint location has a minimum of four diagonal wires and compressive struts, or diagonal members capable of resisting compression.	A.7.2.2
C	NC	N/A	U	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, 2 in.	A.7.2.4
C	NC	N/A	U	CONTINUITY ACROSS:	The ceiling system does not cross any seismic joint and is not attached to multiple independent structures.	A.7.2.5
C	NC	N/A	U	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.	A.7.2.6
C	NC	N/A	U	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.	A.7.2.7
Light Fixtures						
C	NC	N/A	U	INDEPENDENT SUPPORT:	Light fixtures that weigh more per square foot than the ceiling they penetrate are supported independent of the gride ceiling suspension system by a minimum of two wires at diagonally opposite corners of each fixture.	A.7.3.2
C	NC	N/A	U	PENDANT SUPPORTS:	Light fixtures on pendant supports are attached at a spacing equal to or less than 6 ft. Unbraced suspended fixtures are free to allow a 360-degree range of motion at an angle not less than 45 degrees from horizontal without contacting adjacent components. Alternatively, if rigidly supported and/or braced, they are free to move with the structure to which they are attached without damaging adjoining components. Additionally, the connection to the structure is capable of accommodating the movement without failure.	A.7.3.3
C	NC	N/A	U	LENS COVERS:	Lens covers on light fixtures are attached with safety devices.	A.7.3.4

Table 17-38. Nonstructural Checklist (Continued)

Status					Evaluation Statement	Tier 1 Reference
Cladding and Glazing						
C	NC	N/A	U	CLADDING ANCHORS:	Cladding components weighing more than 10 lb/ft2 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 and seismicity, 4 ft.	A.7.4.1
C	NC	N/A	U	CLADDING ISOLATION:	For steel or concrete moment-frame buildings, panel connections are detailed to accommodate a story drift ratio by use of rods attached to framing with oversized holes or slotted holes 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, and the rods have a length-to-diameter ratio of 4 or less.	A.7.4.3
C	NC	N/A	U	MULTI-STORY PANELS:	For multi-story panels attached at more than one floor level, panel connections are detailed to accommodate a story drift ratio by use of rods attached to framing with oversized holes or slotted holes 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, and the rods have a length-to-diameter ratio of 4 or less.	A.7.4.4
C	NC	N/A	U	THREADED RODS:	Threaded rods for panel connections detailed to accommodate drift by bending of the rod have length-to-diameter ratio greater than 0.06 times the story height in inches for a Life Safety in Moderate Seismicity and 0.12 times the story height in inches for Life Safety in High Seismicity and Position Retention in any seismicity.	A.7.4.9
C	NC	N/A	U	PANEL CONNECTIONS:	Cladding panels are acnhored for out of plane with a minimum number of connection for each wall panel, as follows: for Life Safety in Moderate Seismicity, 2 connections, for Life Safety in High Seismicity and for Position Retention, 4 connections.	A.7.4.5
C	NC	N/A	U	BEARING CONNECTIONS:	Where bearing connections are used, there is a minimum of two bearing connections for each cladding panel.	A.7.4.6
C	NC	N/A	U	INSERTS:	Where concrete cladding components use inserts, the inserts have positive anchorage or are anchored to reinforcing steel.	A.7.4.7
C	NC	N/A	U	OVERHEAD GLAZING:	Glazing panes of any size in curtain walls and individual interior or exterior panes more than 16 ft^2 in area are laminated annealed or laminated heat-strengthened glass and are detailed to remain in the frame when cracked.	A.7.4.8
C	NC	N/A	U	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 Moderate Seismicity, 36 in; for Life Safety in High Seismicity and for Position Retention in any seismicity, 24 in.	A.7.5.1
C	NC	N/A	U	SHELF ANGLES:	Masonry veneer is supported by shelf angles or other elements at each floor above the ground floor.	A.7.5.2
C	NC	N/A	U	WEAKENED PLANES:	Masonry veneer is anchored to the backup adjacent to weakened planes, such as at the locations of flashing.	A.7.5.3
C	NC	N/A	U	UNREINFORCED MASONRY BACKUP:	There is no unreinforced masonry backup.	A.7.7.2
C	NC	N/A	U	STUD TRACKS:	For veneer with cold-formed steel stud backup, stud tracks are fastened to the structure at a spacing equal to or less than 24 in on center.	A.7.6.1
C	NC	N/A	U	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.	A.7.7.1
C	NC	N/A	U	WEEP HOLES:	In veneer anchored to stud walls, the veneer has functioning weep holes and base flashing.	A.7.5.6
C	NC	N/A	U	OPENINGS:	For veneer with cold-formed steel stud backup, steel studs frame window and door openings.	A.7.6.2

Table 17-38. Nonstructural Checklist (Continued)

Status				Evaluation Statement		Tier 1 Reference
Parapets, Cornices, Ornamentation, and Appendages						
C	NC	N/A	U	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.	A.7.8.1
C	NC	N/A	U	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.	A.7.8.2
C	NC	N/A	U	CONCRETE PARAPETS:	Concrete parapets with height-to-thickness ratios greater than 2.5 have vertical reinforcement.	A.7.8.3
C	NC	N/A	U	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. The evaluation statement item does not apply to parapets or cornices covered by other evaluation statements.	A.7.8.4
Masonry Chimneys						
C	NC	N/A	U	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 and seismicity, 2 times the least dimension of the chimney.	A.7.9.1
C	NC	N/A	U	ANCHORAGE:	Masonry chimneys are anchored at each floor level, at the topmost ceiling level, and at the roof.	A.7.9.2
Stairs						
C	NC	N/A	U	STAIR ENCLOSURES:	Hollow-clay tile or unreinforced masonry walls around stair enclosures are restrained out of plane and have height-to-thickness rations 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.	A.7.10.1
C	NC	N/A	U	STAIR DETAILS:	The connection between the stairs and the structure does not rely on post-installed anchors in the concrete or masonry, and the stair details are capable of accommodating the drift calculated using the Quick Check procedure of Section 4.4.3.1 for moment-frame structures or 0.5 in for all other structures without including any lateral stiffness contribution from the stairs.	A.7.10.2
Contents and Furnishings						
C	NC	N/A	U	INDUSTRIAL STORAGE RACKS:	Industrial storage racks or pallet racks more than 12 ft high meet the requirements of ANSI/RMI MH 16.1 as modified by ASCE 7, Chapter 15.	A.7.11.1
C	NC	N/A	U	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.	A.7.11.2
C	NC	N/A	U	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.	A.7.11.3
C	NC	N/A	U	ACCESS FLOORS:	Access floors more than 9 in high are braced.	A.7.11.4
C	NC	N/A	U	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.	A.7.11.5
C	NC	N/A	U	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.	A.7.11.6

Table 17-38. Nonstructural Checklist (Continued)

Status				Evaluation Statement		Tier 1 Reference
Mechanical and Electrical Equipment						
C	NC	N/A	U	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.	A.7.12.4
C	NC	N/A	U	IN-LINE EQUIPMENT:	Equipment installed in line with a duct or piping system, with an operating weight more than 75lb, is supported and laterally braced independent of the duct or piping system.	A.7.12.5
C	NC	N/A	U	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.	A.7.12.6
C	NC	N/A	U	MECHANICAL DOORS:	Mechanically operated doors are detailed to operate with a story drift ratio of 0.01.	A.7.12.7
C	NC	N/A	U	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.	A.7.12.8
C	NC	N/A	U	VIBRATION ISOLATORS:	Equipment mounted on vibration isolators is equipped with horizontal restraints or snubbers and with vertical restraints to resist overturning.	A.7.12.9
C	NC	N/A	U	HEAVY EQUIPMENT:	Floor-supported or platform-supported equipment weighing more than 400 lb is anchored to the structure.	A.7.12.10
C	NC	N/A	U	ELECTRICAL EQUIPMENT:	Electrical equipment is laterally braced to the structure.	A.7.12.11
C	NC	N/A	U	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.	A.7.12.12
Piping						
C	NC	N/A	U	FLEXIBLE COUPLINGS:	Fluid and gas piping has flexible couplings.	A.7.13.2
C	NC	N/A	U	FLUID AND GAS PIPING:	Fluid and gas piping is anchored and braced to the structure to limit spills or leaks.	A.7.13.4
C	NC	N/A	U	C-CLAMPS:	One-sided C-clamps that support piping larger than 2.5 in in diameter are restrained.	A.7.13.5
C	NC	N/A	U	PIPING CROSSING SEISMIC JOINTS:	Piping that crosses seismic joints or isolation planes or is connected to independent structures has couplings or other details to acccomodate the relative seismic displacements.	A.7.13.6
C	NC	N/A	U	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.	A.7.14.2
C	NC	N/A	U	DUCT SUPPORT:	Ducts are not supported by piping or electrical conduit.	A.7.14.3
C	NC	N/A	U	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.	A.7.14.4

Table 17-38. Nonstructural Checklist (Continued)

Status				Evaluation Statement		Tier 1 Reference
Elevators						
C	NC	N/A	U	RETAINER GUARDS:	Sheaves and drums have cable retainer guards.	A.7.16.1
C	NC	N/A	U	RETAINER PLATE:	A retainer plate is present at the top and bottom of both car and counterweight.	A.7.16.2
C	NC	N/A	U	ELEVATOR EQUIPMENT:	Equipment, piping, and other components that are part of the elevator system are anchored.	A.7.16.3
C	NC	N/A	U	SEISMIC SWITCH:	Elevators capable of operating at speeds of 150ft/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% acceleration of gravity in other directions.	A.7.16.4
C	NC	N/A	U	SHAFT WALLS:	Elevator shaft walls are anchored and reinforced to prevent toppling into the shaft during strong shaking.	A.7.16.5
C	NC	N/A	U	COUNTERWEIGHT RAILS:	All counterweight rails and divider beams are sized in accordance with ASME A17.1.	A.7.16.6
C	NC	N/A	U	BRACKETS:	The brackets that tie the car rails and the counterweight rail to the structure are sized in accordance with ASME A17.1.	A.7.16.7
C	NC	N/A	U	SPREADER BRACKET:	Spreader brackets are not used to resist seismic forces.	A.7.16.8
C	NC	N/A	U	GO-SLOW ELEVATORS:	The building has a go-slow elevator system.	A.7.16.9

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Wayne K. Pipes

FACILITIES
EXHIBIT 603

December 29, 2023

ASCE 41-13 Tier 1 Seismic Evaluation of

NW Natural – Sherwood Service Center

20285 SW Cipole Road
Sherwood, OR 97140

August 5, 2016
KPFF Project No. 1600122

NW Natural – Sherwood Service Center
ASCE 41-13 Tier 1 Seismic Evaluation

Table of Contents

Introduction

This report is to summarize the findings of our seismic evaluation of two buildings located at the NW Natural Service Center located at 20285 SW Cipole Rd, in Sherwood, OR. The two buildings are identified as Building A and B. Building A contains a training facility, warehouse, and office. Building B is used as an automobile service center and warehouse. 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 and does not address issues related to gravity framing.

Scope and Intent

KPFF Consulting Engineers was contracted to perform a Tier 1 seismic evaluation of two buildings at the NW Natural Service Center located in Sherwood, Oregon. This evaluation is based on a site visit that was completed on June 10, 2016, the existing remodel drawings dated April 3, 2013 and June 5, 2012 for Buildings A and B respectively, 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 IV building (i.e. an Immediate Occupancy) as defined by the International Building Code and the Oregon Structural Specialty Code. Therefore, the BPOE requires meeting the Immediate Occupancy Structural Performance level at the BSE-1E seismic hazard level, and the Position Retention 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. Immediate Occupancy, BSE-1E, and BSE-1N are defined as follows:

- Immediate Occupancy is a structural performance level in which a structure has light overall damage with no permanent drift and substantially retains original strength and stiffness. It is likely that occupancy will be able to occur after the seismic event.

- 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.

<u>Site and Building Data</u>

Building A:
Building A at the NW Natural Service Center in Sherwood, OR is two seismically separated structures located directly adjacent to each other. The eastern structure is a 2 story concrete tilt-up office building with a wood framed roof and second floor. The western structure is a large single story steel framed warehouse with vertical diagonal tension rod bracing in the east-west direction and moment frame in the north-south direction. Diagonal tension rod bracing in the roof plane transfers lateral loads to the moment frames and vertical diagonal tension rod bracing.

The two structures of Building A were seismically upgraded to an Essential Facility in 2013. The drawings for this upgrade identify both structural and nonstructural items are to be upgraded.

The overall building is measures approximately 300 feet in the north-south direction by 380 feet in the east-west direction with total area of approximately 120,000 square feet. The office portion is approximately 260' in the north-south direction and 80' in the east-west direction and 30 feet tall. The warehouse portion is approximately 300' square in plan and 30 feet tall.

Building B:

Building B is a one story structure consisting of a small office area and a large warehouse area. The office area is a wood framed structure with wood roof trusses which are supported by wood framed walls. The exterior walls of the office area are sheathed in plywood and act as shear walls. The warehouse portion is a steel framed metal building with horizontal tension rod cross bracing in the roof plane which transfers loads to the vertical lateral force resisting elements. The vertical lateral force resisting is horizontal tension rod cross bracing in the east-west direction and steel moment frames in the north-south direction.

Building B was renovated in 2011 and did not include any seismic upgrade work.

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
$S_{X1,\ BSE\text{-}1E}$	0.258g	Design spectral response acceleration parameter at 1 second for the BSE-1E seismic hazard level.
$S_{XS,\ BSE\text{-}1N}$	0.706 g	Design short-period (0.2 seconds) spectral response acceleration parameter for the BSE-1N seismic hazard Level.
T	0.275 s	Building fundamental period, as defined in Section 4.5.2.4.
S_a	0.530 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 at Office Portion of Building A

No.	Item	Tier 1 Ref.	Comments
1	Wall Shear Stress Check	A.3.2.3.1	Shear stress in shear walls exceeds the allowable limit.
2	Transfer To Shear Walls	A.5.2.1	The connection between the diaphragm and shear walls do not develop the shear strength of the diaphragm.
3	Wall Openings	A.3.2.3.3	The width of the openings along the perimeter exceeds 50% of the length of the wall.
4	Panel-to-Panel Connections	A.3.2.3.4	The connections between panels do not appear sufficient to transfer overturning between panels.
5	Precast Wall Panel	A.5.3.6	Tilt Panels are not connected to the foundation.

Structural Deficiencies at Warehouse Portion of Building A

No.	Item	Tier 1 Ref.	Comments
1	Brace Axial Stress Check	A.3.3.1.2	Axial Stress in Braces exceeds the allowable limit.
2	Flexural Stress Check	A.3.1.3.3	Flexural Stress in Moment Frame Columns exceeds the allowable limit.
3	Moment-Resisting Connections	A.3.1.3.4	Moment Resisting Connections are not able to develop the strength of the adjoining members.
4	Compact Members	A.3.2.3.4	All Frame elements are not compact.

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	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 site has areas of "low" and "moderate" landslide hazard.
2	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 site has a "low" landslide hazard.
3	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.

Nonstructural Deficiencies of Building A

No.	Item	Tier 1 Ref.	Comments
1	Edge Clearance Of Suspended Ceilings	A.7.2.4	The suspended ceilings do not have ¾" clearance from the enclosing walls and partitions.
2	Edge Support	A.7.2.6	Suspended ceiling edge angles are less than 2" wide

No.	Item	Tier 1 Ref.	Comments
3	Tall Narrow Contents	A7.11.2	Not all contents more than 6 feet high with a height-to-depth or height-to-width ratio greater than 3-to-1 are anchored to the structure or each other (i.e. refrigerators, cabinets, racks.
4	Fall-Prone Contents	A7.11.3	Heavy items (weighing more than 20 pounds) located on storage racks at a height of more than 4 feet above the adjacent floor do not appear to be anchored to the racks.
5	Mechanical Doors	A7.12.7	Mechanical roll up doors do not appear adequate to operate at a 1% story drift ratio.
6	Heavy Equipment	A7.12.10	Rooftop equipment does not appear adequately fastened to structure for seismic forces.
7	Conduit Couplings	A.7.12.12	Electrical conduit crosses seismic joint between buildings with no observable flexible couplings.
8	Piping Crossing Seismic Joints	A.7.13.6	Piping crosses seismic joint between buildings with no observable flexible couplings
9	Duct Bracing	A.7.14.2	The spacing of the transverse bracing of large ductwork in Warehouse exceeds 30 feet.

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 of Building A

No.	Item	Tier 1 Ref.	Comments
1	Overhead Glazing	A.7.4.8	Glass is heat strengthened. It is unknown if the glass is detailed to remain in the framed when cracked.
2	Flexible Couplings	A.7.13.2	It is unknown if all fluid and gas lines have flexible couplings.
3	Elevator Equipment	A.7.16.3	It is unknown if elevator equipment is anchored.
4	Seismic Switch	A.7.16.4	It is unknown if the elevator requires or has a seismic switch.
5	Shaft Walls	A.7.16.5	The detailing of the elevator shaft walls is unknown.
6	Brackets	A.7.16.7	It is unknown if the brackets are sized in accordance with ASME A17.1
7	Spreader Bracket	A.7.16.8	It is unknown if Spreader Brackets are used to resist seismic forces
8	Go-Slow Elevators	A.7.16.9	It is unknown if elevator system is "Go-Slow".

Conceptual Seismic Upgrade Work

Structural deficiencies are identified in the Tier 1 Checklists, and are listed in the Structural Deficiencies table previously shown in this report. The following is a list of potential solutions to mitigate those deficiencies:

Office:

1. Shear Wall Stress Ratio: Increase the amount of concrete shear wall at the perimeter of the office portion of the building by infilling windows on the ground floor.
2. Transfer to Shear Walls: Provide additional nailing between the plywood and ledger and additional bolting between the ledger and the concrete walls.
3. Wall Openings: Infill existing window openings to achieve 50% length of wall.
4. Panel to Panel Connections: Install additional connection between tilt panels.
5. Precast Wall Panel: Connect Tilt Panels to foundations with epoxy dowels

Warehouse:

1. Brace Axial Stress Check: Replace braces with larger braces that have greater axial capacity.
2. Flexural Stress Check: reinforce moment frame columns with additional steel.
3. Moment Resisting Connections: reinforce moment connections between beams and columns.
4. Compact Members: Add web doublers or stiffeners to create compact moment frame members.

Nonstructural deficiencies and items which are unknown are identified in the Tier 1 Checklists, and are listed in the Nonstructural Deficiencies and Unknown tables previously shown in this report. The following is a list of potential solutions to mitigate those deficiencies:

1. Edge Clearance of Suspended Ceilings: Add proper clearance to perimeter of large suspended ceilings.
2. Edge Support: Replace edge support angles with ones with proper width.
3. Overhead Glazing: Identify type of overhead glazing at the skylights and the entryway. Replace with laminated annealed or laminated heat-strengthened glass if they are not already.
4. Industrial Storage Racks: Determine if tall storage racks meet ANSI/MH 16.1. Update the racks if they do not meet the requirements.
5. 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.
6. Fall-Prone Contents: Brace or restrain contents on storage racks/shelves/etc., that weight more than 20 pounds, and are located more than 4 feet above the adjacent floor level.
7. Mechanical Doors: Replace roll-up doors which are required to function after an earthquake with doors which are rated for the purpose.
8. Heavy Equipment: Anchor Rooftop equipment and supporting structure for seismic forces.
9. Conduit Couplings: Replace couplings for conduit which crosses the seismic joints with flexible couplings which can accommodate the seismic drift.

10. Flexible Couplings: Have a mechanical contractor inventory fluid and gas piping fittings and determine if they are flexible.
11. Duct Bracing: Brace large ductwork to resist seismic forces.
12. Piping Crossing Seismic Joints: Replace fittings for piping which crosses the seismic joint with flexible fittings which can accommodate the seismic drift.
13. Elevator: Work with elevator supplier or maintenance company to determine if Tier 1 deficiencies exist and should be retrofitted.

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 $5 - $10 per square foot. This does not include costs associated with geotechnical work, 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 and unknowns.

Summary

This ASCE 41-13 Tier 1 seismic evaluation was prepared for the two buildings at the NW Natural – Sherwood Service Center. It was found that these buildings, in their current state, do not achieve the desired seismic performance objective for Immediate Occupancy 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 of Position Retention for Nonstructural Performance at the seismic hazard as stated above.

A Tier 2 Deficiency-Based Evaluation and Retrofit Procedure is recommended for Building A to further investigate the deficiencies identified in this Tier 1 screening procedure. The Tier 2 Evaluation yields less conservative results than the Tier 1 Procedure. Only the structural deficiencies identified during the Tier 1 screening need be evaluated as part of the Tier 2 evaluation. The result of the Tier 2 Evaluation can be used to create retrofit drawings which may be used for pricing or construction.

Appendix

ASCE 41-13 Summary Data Sheet and Checklists

Appendix C: Summary Data Sheet

BUILDING DATA

Building Name: NW Natural Sherwood Service Center — Date: August 2, 2016

Building Address: 20285 SW Cipole Road, Sherwood, Oregon

Latitude: 45.37318 — Longitude: -122.81172 — By: EK

Year Built: 1998 — Year(s) Remodeled: 2013 — Original Design Code: 1997 UBC

Area (sf): 120,000 — Length (ft): 400' — Width (ft): 300'

No. of Stories: 2 (office), 1 (warehouse) — Story Height: 15' — Total Height: 30'

USE

☐ Industrial ☑ Office ☑ Warehouse ☐ Hospital ☐ Residential ☐ Educational ☐ Other: ______

CONSTRUCTION DATA

Gravity Load Structural System: Wood framed floor framing (office), prefab steel building (warehouse)

Exterior Transverse Walls: Precast concrete tilt (office), metal panel (warehouse) — Openings? Yes

Exterior Longitudinal Walls: Precast concrete tilt (office), metal panel (warehouse) — Openings? Yes

Roof Materials/Framing: Wood framed (office), metal joists (warehouse)

Intermediate Floors/Framing: Wood framed

Ground Floor: Slab-on-grade

Columns: Steel — Foundation: Concrete footings

General Condition of Structure: Good

Levels Below Grade? None

Special Features and Comments: Seismic joint added between office & warehouse in remodel, seismically upgraded to occupancy Category IV in 2013

LATERAL-FORCE-RESISTING SYSTEM

	Longitudinal	Transverse
System:	Precast wall (office), steel moment frame (warehouse)	Precast wall (offfice), steel braced frames (warehouse)
Vertical Elements:	Concrete walls & steel columns	Concrete walls & steel columns
Diaphragms:	Plywood (office), tension rod bracing (warehouse)	Plywood (office), tension rod bracing (warehouse)
Connections:	Varies	Varies

EVALUATION DATA

BSE-1N Spectral Response Accelerations: S_{Ds}= See report — S_{D1}= See report

Soil Factors: Class= See report — F_a= See report — F_v= See report

BSE-1E Spectral Response Accelerations: S_{XS}= See report — S_{X1}= See report

Level of Seismicity: High — Performance Level: Immediate occupancy

Building Period: T= 0.275 seconds

Spectral Acceleration: S_a= 0.53 g

Modification Factor: $C_mC_1C_2$= 1.1 — Building Weight: W= 310k (office), 2209k (warehouse)

Pseudo Lateral Force: $V= C_mC_1C_2S_aW$= 180k (office), 1288k (warehouse)

BUILDING CLASSIFICATION: PC1 (office), S3 (warehouse)

REQUIRED TIER 1 CHECKLISTS

	Yes	No
Basic Configuration Checklist	☑	☐
Building Type PC1 S3 Structural Checklist	☑	☐
Nonstructural Component Checklist	☑	☐

FURTHER EVALUATION REQUIREMENT: Recommend Tier 2 for office & warehouse

ASCE 41-13 Tier 1 Checklists

FIRM:	KPFF Consulting Engineers
PROJECT NAME:	NW Natural - Sherwood
SEISMICITY LEVEL:	High
PROJECT NUMBER:	10021600122
COMPLETED BY:	EK
DATE COMPLETED:	August 2, 2016
REVIEWED BY:	IKE
REVIEW DATE:	August 5, 2016

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

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)	
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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

16.1.2IO Immediate Occupancy Basic Configuration Checklist

Very 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)	
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)	
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)	Mezzanines have own lateral system

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

Building Configuration

RATING				DESCRIPTION	COMMENTS
C ☒	NC ☐	N/A ☐	U ☐	WEAK STORY: The sum of the shear strengths of the seismic-force-resisting system in any story in each direction shall not be less than 80% of the strength in the adjacent story above. (Commentary: Sec. A.2.2.2. Tier 2: Sec. 5.4.2.1)	
C ☒	NC ☐	N/A ☐	U ☐	SOFT STORY: The stiffness of the seismic-force-resisting system in any story shall not be 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)	
C ☒	NC ☐	N/A ☐	U ☐	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)	
C ☒	NC ☐	N/A ☐	U ☐	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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

C	NC	N/A	U		
☒	☐	☐	☐	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)	
C	NC	N/A	U		
☒	☐	☐	☐	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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

Low 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)	
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)	
C ☐	NC ☐	N/A ☐	U ☒	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)	

Moderate and 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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

C	NC	N/A	U		
☐	☐	☐	☒	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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

ASCE 41-13 Tier 1 Checklists

FIRM:	KPFF Consulting Engineers
PROJECT NAME:	NW Natural - Sherwood
SEISMICITY LEVEL:	High
PROJECT NUMBER:	10021600122
COMPLETED BY:	EK
DATE COMPLETED:	August 2, 2016
REVIEWED BY:	IKE
REVIEW DATE:	August 5, 2016

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

16.6IO Immediate Occupancy Structural Checklist for Building Type S3: Steel Light Frames

Very Low and Low 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)	
C ☐	NC ☒	N/A ☐	U ☐	FLEXURAL STRESS CHECK: The average flexural stress in the moment frame columns and beams, calculated using the Quick Check procedure of Section 4.5.3.9, is less than F_y. (Commentary: Sec. A.3.1.3.3. Tier 2: Sec. 5.5.2.1.2)	Beams ok. Column flexure exceeds yield strength.

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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

C	NC	N/A	U	Description	Comments
☒	☐	☐	☐	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)	

Moderate 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)	

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)	
☒	☐	☐	☐	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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

Diaphragms

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	PLAN IRREGULARITIES: There is tensile capacity to develop the strength of the diaphragm at reentrant corners or other locations of plan irregularities. (Commentary: Sec. A.4.1.7. Tier 2: Sec. 5.6.1.4)	No reentrant corners.
C ☐	NC ☐	N/A ☒	U ☐	DIAPHRAGM REINFORCEMENT AT OPENINGS: There is reinforcing around all diaphragm openings larger than 50% of the building width in either major plan dimension. (Commentary: Sec. A.4.1.8. Tier 2: Sec. 5.6.1.5)	No large openings
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)	Consists of horizontal bracing.

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 strength of the adjoining members or panel zones. (Commentary: Sec. A.3.1.3.4. Tier 2: Sec. 5.5.2.2.1)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

C	NC	N/A	U	Statement	Comment
☐	☒	☐	☐	COMPACT MEMBERS: All frame elements 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)	
☐	☐	☒	☐	BEAM PENETRATIONS: All openings in frame-beam webs are less than one quarter of the beam depth and are located in the center half of the beams. (Commentary: Sec. A.3.1.3.9. Tier 2: Sec. 5.5.2.2.5)	
☒	☐	☐	☐	OUT-OF-PLANE BRACING: Beam–column joints are braced out-of-plane. (Commentary: Sec. A.3.1.3.11. Tier 2: Sec. 5.5.2.2.7)	
☒	☐	☐	☐	BOTTOM FLANGE BRACING: The bottom flanges of beams are braced out-of-plane. (Commentary: Sec. A.3.1.3.12. Tier 2: Sec. 5.5.2.2.8)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

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, and the connections are able to develop the lesser of the strength of the frames or the diaphragms. (Commentary: Sec. A.5.2.2. Tier 2: Sec. 5.7.2)	
C ☒	NC ☐	N/A ☐	U ☐	STEEL COLUMNS: The columns in seismic-force-resisting frames are anchored to the building foundation, and the anchorage is able to develop the least of the tensile capacity of the column, the tensile capacity of the lowest level column splice (if any), or the uplift capacity of the foundation. (Commentary: Sec. A.5.3.1. Tier 2: Sec. 5.7.3.1)	(4) 1' diameter A307 bolt tension strength exceeds uplift capacity of footings (6.5 x 6.5 x 19" thick).

Foundation System

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	DEEP FOUNDATIONS: Piles and piers are capable of transferring the seismic forces between the structure and the soil. (Commentary: Sec. A.6.2.3.)	
C ☐	NC ☐	N/A ☒	U ☐	SLOPING SITES: The difference in foundation embedment depth from one side of the building to another does not exceed one story high. (Commentary: Sec. A.6.2.4)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

ASCE 41-13 Tier 1 Checklists

FIRM:	KPFF Consulting Engineers
PROJECT NAME:	NW Natural - Sherwood
SEISMICITY LEVEL:	High
PROJECT NUMBER:	10021600122
COMPLETED BY:	EK
DATE COMPLETED:	August 2, 2016
REVIEWED BY:	IKE
REVIEW DATE:	August 5, 2016

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

16.12IO Immediate Occupancy Structural Checklist for Building Types PC1: Precast or Tilt-Up Concrete Shear Walls with Flexible Diaphragms and PC1A: Precast or Tilt-Up Concrete Shear Walls with Stiff Diaphragms

Very Low Seismicity

Foundation System

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	DEEP FOUNDATIONS: Piles and piers are capable of transferring the lateral forces between the structure and the soil. (Commentary: Sec. A.6.2.3.)	
C ☐	NC ☐	N/A ☒	U ☐	SLOPING SITES: The difference in foundation embedment depth from one side of the building to another does not exceed one story high. (Commentary: Sec. A.6.2.4)	

Connections

RATING				DESCRIPTION	COMMENTS
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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

Seismic-Force-Resisting System

RATING				DESCRIPTION	COMMENTS
C ☒	NC ☐	N/A ☐	U ☐	REDUNDANCY: The number of lines of shear walls in each principal direction is greater than or equal to 2. (Commentary: Sec. A.3.2.1.1. Tier 2: Sec. 5.5.1.1)	
C ☐	NC ☒	N/A ☐	U ☐	WALL SHEAR STRESS CHECK: The shear stress in the precast panels, calculated using the Quick Check procedure of Section 4.5.3.3, is less than the greater of 100 lb/in.^{2} or $2\sqrt{f'_c}$. (Commentary: Sec. A.3.2.3.1. Tier 2: Sec. 5.5.3.1.1)	
C ☒	NC ☐	N/A ☐	U ☐	REINFORCING STEEL: The ratio of reinforcing steel area to gross concrete area is not less than 0.0012 in the vertical direction and 0.0020 in the horizontal direction. The spacing of reinforcing steel is equal to or less than 18 in. (Commentary: Sec. A.3.2.3.2. Tier 2: Sec. 5.5.3.1.3)	

Diaphragms

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	TOPPING SLAB: Precast concrete diaphragm elements are interconnected by a continuous reinforced concrete topping slab with a minimum thickness of 2 in. (Commentary: Sec. A.4.5.1. Tier 2: Sec. 5.6.4)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

Connections

RATING				DESCRIPTION	COMMENTS
C ☒	NC ☐	N/A ☐	U ☐	WOOD LEDGERS: The connection between the wall panels and the diaphragm does not induce cross-grain bending or tension in the wood ledgers. (Commentary: Sec. A.5.1.2. Tier 2: Sec. 5.7.1.4)	
C ☐	NC ☒	N/A ☐	U ☐	TRANSFER TO SHEAR WALLS: Diaphragms are connected for transfer of seismic forces to the shear walls, and the connections are able to develop the lesser of the shear strength of the walls or diaphragms. (Commentary: Sec. A.5.2.1. Tier 2: Sec. 5.7.2)	A35 clips do not match strength of adjacent roof sheathing.
C ☐	NC ☐	N/A ☒	U ☐	TOPPING SLAB TO WALLS OR FRAMES: Reinforced concrete topping slabs that interconnect the precast concrete diaphragm elements are doweled for transfer of forces into the shear wall or frame elements, and the dowels are able to develop the least of the shear strength of the walls, frames, or slabs. (Commentary: Sec. A.5.2.3. Tier 2: Sec. 5.7.2)	
C ☒	NC ☐	N/A ☐	U ☐	GIRDER–COLUMN CONNECTION: There is a positive connection using plates, connection hardware, or straps between the girder and the column support. (Commentary: Sec. A.5.4.1. Tier 2: Sec. 5.7.4.1)	

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Project Name NW Natural - Sherwood
Project Number 10021600122

Low, Moderate, and High Seismicity

Seismic-Force-Resisting System

RATING				DESCRIPTION	COMMENTS
C ☒	NC ☐	N/A ☐	U ☐	DEFLECTION COMPATIBILITY FOR RIGID DIAPHRAGMS: Secondary components shall have the shear capacity to develop the flexural strength of the components. (Commentary: Sec. A.3.1.6.2. Tier 2: Sec. 5.5.2.5.2)	
C ☐	NC ☒	N/A ☐	U ☐	WALL OPENINGS: The total width of openings along any perimeter wall line constitutes less than 50% of the length of any perimeter wall when the wall piers have aspect ratios of less than 2-to-1. (Commentary: Sec. A.3.2.3.3. Tier 2: Sec. 5.5.3.3.1)a	
C ☐	NC ☒	N/A ☐	U ☐	PANEL-TO-PANEL CONNECTIONS: Adjacent wall panels are interconnected to transfer overturning forces between panels by methods other than welded steel inserts. (Commentary: Sec. A.3.2.3.4. Tier 2: Sec. 5.5.3.3.3)	Butterfly clips originally. Bolts added in retrofit do not appear adequate to resist overturning.
C ☒	NC ☐	N/A ☐	U ☐	WALL THICKNESS: Thicknesses of bearing walls shall not be less than 1/25 the unsupported height or length, whichever is shorter, nor less than 4 in. (Commentary: Sec. A.3.2.3.5. Tier 2: Sec. 5.5.3.1.2)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

Diaphragms

RATING				DESCRIPTION	COMMENTS
C ☒	NC ☐	N/A ☐	U ☐	CROSS TIES FOR FLEXIBLE DIAPHRAGMS: There are continuous cross ties between diaphragm chords. (Commentary: Sec. A.4.1.2. Tier 2: Sec. 5.6.1.2)	
C ☒	NC ☐	N/A ☐	U ☐	PLAN IRREGULARITIES: There is tensile capacity to develop the strength of the diaphragm at reentrant corners or other locations of plan irregularities. (Commentary: Sec. A.4.1.7. Tier 2: Sec. 5.6.1.4)	
C ☐	NC ☐	N/A ☒	U ☐	DIAPHRAGM REINFORCEMENT AT OPENINGS: There is reinforcing around all diaphragm openings larger than 50% of the building width in either major plan dimension. (Commentary: Sec. A.4.1.8. Tier 2: Sec. 5.6.1.5)	No large openings.
C ☐	NC ☐	N/A ☒	U ☐	STRAIGHT SHEATHING: All straight sheathed diaphragms have aspect ratios less than 1-to-1 in the direction being considered. (Commentary: Sec. A.4.2.1. Tier 2: Sec. 5.6.2)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

C	NC	N/A	U	Description	Comments
☒	☐	☐	☐	SPANS: All wood diaphragms with spans greater than 12 ft consist of wood structural panels or diagonal sheathing. (Commentary: Sec. A.4.2.2. Tier 2: Sec. 5.6.2)	
☐	☐	☒	☐	DIAGONALLY SHEATHED AND UNBLOCKED DIAPHRAGMS: All diagonally sheathed or unblocked wood structural panel diaphragms have horizontal spans less than 30 ft and aspect ratios less than or equal to 3-to-1. (Commentary: Sec. A.4.2.3. Tier 2: Sec. 5.6.2)	
☒	☐	☐	☐	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)	

Connections

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☒	☐	☐	☐	MINIMUM NUMBER OF WALL ANCHORS PER PANEL: There are at least two anchors from each precast wall panel into the diaphragm elements. (Commentary: Sec. A.5.1.3. Tier 2: Sec. 5.7.1.4)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

C	NC	N/A	U	Statement	Comments
☐	☒	☐	☐	PRECAST WALL PANELS: Precast wall panels are connected to the foundation, and the connections are able to develop the strength of the walls. (Commentary: Sec. A.5.3.6. Tier 2: Sec. 5.7.3.4)	Tilt panels are connected to the slab.
☐	☐	☒	☐	UPLIFT AT PILE CAPS: Pile caps shall have top reinforcement, and piles are anchored to the pile caps; the pile cap reinforcement and pile anchorage are able to develop the tensile capacity of the piles. (Commentary: Sec. A.5.3.8. Tier 2: Sec. 5.7.3.5)	
☒	☐	☐	☐	GIRDERS: Girders supported by walls or pilasters have at least two ties securing the anchor bolts unless provided with independent stiff wall anchors with adequate strength to resist the connection force calculated in the Quick Check procedure of Section 4.5.3.7. (Commentary: Sec. A.5.4.2. Tier 2: Sec. 5.7.4.2)	

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 - Sherwood
SEISMICITY LEVEL:	High
PROJECT NUMBER:	10021600122
COMPLETED BY:	EK
DATE COMPLETED:	August 2, 2016
REVIEWED BY:	IKE
REVIEW DATE:	August 5, 2016

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

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				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☒	☐	☐	☐	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)	
C	NC	N/A	U		
☒	☐	☐	☐	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)	
C	NC	N/A	U		
☒	☐	☐	☐	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)	
C	NC	N/A	U		
☐	☐	☒	☐	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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

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)	
☒	☐	☐	☐	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)	

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)	
☒	☐	☐	☐	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)	Chained back to structure

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

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)	
☒	☐	☐	☐	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)	
☒	☐	☐	☐	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)	
☐	☐	☒	☐	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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

Partitions

RATING C	NC	N/A	U	DESCRIPTION	COMMENTS
☐	☐	☒	☐	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)	
☐	☐	☒	☐	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)	
☐	☐	☒	☐	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)	
☒	☐	☐	☐	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)	

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Project Name NW Natural - Sherwood
Project Number 10021600122

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)	
C ☐	NC ☐	N/A ☒	U ☐	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)	

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)	
C ☐	NC ☐	N/A ☒	U ☐	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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

C	NC	N/A	U	Statement	Comments
☒	☐	☐	☐	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)	
☐	☒	☐	☐	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)	
☒	☐	☐	☐	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)	
☐	☒	☐	☐	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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

C	NC	N/A	U	Description	Comments
☐	☐	☒	☐	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)	

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)	
☒	☐	☐	☐	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)	
☒	☐	☐	☐	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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

Cladding and Glazing

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	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)	
C ☐	NC ☐	N/A ☒	U ☐	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)	
C ☐	NC ☐	N/A ☒	U ☐	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)	
C ☐	NC ☐	N/A ☒	U ☐	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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

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)	
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)	
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)	Unknown if detailed to remain in frame when cracked.

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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

C	NC	N/A	U	Statement	Comments
☐	☐	☒	☐	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)	
☐	☐	☒	☐	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)	
☐	☐	☒	☐	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)	
☐	☐	☒	☐	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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
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C ☐	NC ☐	N/A ☒	U ☐	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)	
C ☐	NC ☐	N/A ☒	U ☐	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)	
C ☐	NC ☐	N/A ☒	U ☐	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)	

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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

C	NC	N/A	U	Description	Comments
☐	☐	☒	☐	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)	No canopies
☒	☐	☐	☐	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)	
☐	☐	☒	☐	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)	

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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
Project Number 10021600122

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)	

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)	
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)	

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)	

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Project Name NW Natural - Sherwood
Project Number 10021600122

C	NC	N/A	U	Description	Comments
☐	☒	☐	☐	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)	Storage shelving unsupported
☐	☒	☐	☐	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)	
☐	☐	☒	☐	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)	
☐	☐	☒	☐	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)	

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Project Name NW Natural - Sherwood
Project Number 10021600122

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)	

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)	
☒	☐	☐	☐	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)	
☒	☐	☐	☐	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)	

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C	NC	N/A	U	Item	Comments
☐	☒	☐	☐	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)	Roll up door at perimeter of warehouse.
☒	☐	☐	☐	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)	
☐	☐	☒	☐	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)	No vibration isolated equipment in building.
☐	☒	☐	☐	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)	Rooftop units on warehouse restrained with screws and light gauge clips. Supporting frame does not appear designed for immediate occupancy level seismic forces.

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Project Name NW Natural - Sherwood
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C	NC	N/A	U	Description	Comments
☒	☐	☐	☐	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)	
☐	☒	☐	☐	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)	Conduit crossing seismic joint does not always have flexible couplings.

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)	
☒	☐	☐	☐	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)	

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RATING				DESCRIPTION	COMMENTS
C ☒	NC ☐	N/A ☐	U ☐	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)	
C ☐	NC ☒	N/A ☐	U ☐	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)	Pipes are bolted to tilt panel office walls and continue to the warehouse portion.

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)	Duct in warehouse.
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)	

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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)	

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)	
C ☐	NC ☐	N/A ☒	U ☐	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)	
C ☐	NC ☐	N/A ☐	U ☒	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)	

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - Sherwood
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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)	
☐	☐	☐	☒	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)	
☐	☐	☒	☐	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)	
☐	☐	☐	☒	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)	

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Project Name NW Natural - Sherwood
Project Number 10021600122

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)	
C	NC	N/A	U		
☐	☐	☐	☒	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)	

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Wayne K. Pipes

FACILITIES
EXHIBIT 604

December 29, 2023

GLUMAC A TETRA TECH COMPANY
engineers for a sustainable future™

MEMORANDUM

To: Philip Zlatnik
NW Natural – Sr. Project Manager
philip.zlatnik@nwnatural.com
503.610.7197

Date: December 1, 2022
From: Phillip Cunningham, PE
cc:

Subject: NW Natural Sherwood Data Center - Facility Assessment Summary

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GLUMAC, a full service Mechanical, Electrical, and Plumbing engineering consulting firm based in Portland, OR was requested to provide an assessment of the data hall located in the NWN Operations and Training Center in Sherwood, OR. These assessments occurred in August of 2020 and included site observations of existing conditions, reviews of record documents and analysis of trending data from the building management systems. The culmination of these assessments was a report published September 29, 2020 which included a list of observed deficiencies, prioritization based on risk, and recommendations for remediations.

The assessments and reports reference the Uptime Institute's Data Hall Tier Rating system, which defines four tiers of reliability. This is an industry standard for describing the risk of downtime due to equipment failure. There are many categories of the rating system, such as generator, UPS, and cooling systems. It is common for some systems and components to have a higher or lower rating based on a variety of factors such as data hall type, first costs, and site limitations.

Our assessments concluded that several systems at the Sherwood location achieve only a Tier 1 rating, the lowest and most vulnerable state with the highest risk of down time. Tier 1 systems are characterized by multiple single points of failure, where any one piece of failed equipment will shut down the entire data hall. They also lack concurrent maintainability, the ability to keep the data hall running while providing routine or emergency maintenance on individual components.

It is common for commercial data halls to achieve a minimum of Tier 2 or 3 ratings. Critical infrastructure and utilities will typically be a minimum of Tier 3 or higher. These data halls are characterized by redundant equipment, arranged in parallel, to allow one 'path' to remain operational should the other fail.

Many of our findings and recommendations were focused on improving the electrical system reliability, notably improvements to the generator, UPS, and main electrical feeders. Other improvements included upgrades to the mechanical cooling system that is needed to keep the servers running without overheating. These would bring the data hall in line with a Tier 2 equivalent rating. Below is a few of the recommendations made in our assessment:

- Improving electrical reliability by splitting the existing single electrical system into two independent critical power paths to the computer and HVAC equipment. This allows for maintenance of equipment and fault tolerance – i.e. one failure or maintenance procedure will not shutdown the system. (As long as all computer equipment is dual corded.)
- Improving seismic anchoring and bracing of critical equipment
- Adding ability to connect a temporary rental generator in case the main generator fails or has to be down for service
- Adding function to automatically shutdown outside ventilation air in case of poor outdoor air quality – as in the case of local forest fires
- Revising the fire alarm system to be less likely to falsely activate a shutdown. This was done by making one of the fire alarm smoke sensing systems be ultra sensitive to alert ops staff but not cause a shutdown unless the situation worsens and continues.
- Addition of a remote monitoring system that alarms and notifies ops staff of pre-failure and failure of critical equipment.

Additional modifications would be necessary to be fully Tier III. Some of these include:

- A second, fully redundant generator
- A second, fully redundant UPS
- Dual-Source power to all equipment including HVAC.

GLUMAC
A TETRA TECH COMPANY
engineers for a sustainable future™

Data Hall Infrastructure Reliability & Assessment Report

NW Natural Operations & Training Center
Sherwood, OR

Prepared for

NW Natural
c/o Wayne K. Pipes
NW Natural – Director of Facilities, Security & Emergency Management

22085 SW Cipole Rd, Sherwood OR 97140

September 29, 2020

TABLE OF CONTENTS

❖ EXECUTIVE SUMMARY

Overview

Glumac was requested to provide an assessment of the data hall located in the NWN Operations and Training Center in Sherwood, OR. The scope of our assessment is to review the existing conditions, available documents, and trending data and provide statements and recommendations regarding the current operations and potential upgrades.

The contents of this report are based on information collected including

- Mechanical Site Observation August 25, 2020
- Electrical & Fire Protection Site Observation September 24, 2020
- Record Drawing of Original building (prior to data hall build out)
- Record Controls Drawings prepared by Environmental Controls, dated 02/01/2014
- Sequence of Operations (SOO) rev 7 (October 5, 2016)
- Trending Data (from August 23rd to 25th)

Detailed explanation of our findings and recommendations follow below which include priority and ROM fee opinions. These include:

- Improvement of data hall airflow patterns to provide better temperature control
- Additional sensors to improve monitoring, control, and reliability
- Restoring economizer and heat recovery functionality to conserve energy
- Updating sequences of operation to improve control
- Improving electrical reliability

❖ OVERALL DATA HALL RELIABILITY RATING

Tier Rating Standard

- The Uptime Institute, a think tank and professional-services organization based in Santa Fe, New Mexico, has defined four levels of Data hall reliability. Their rating system has become the industry standard method for rating Data halls. The levels describe the availability of data from the hardware at a site location. The higher the tier, the greater the availability. The levels are:

	Tier I	Tier II	Tier III	Tier IV
ANNUAL DOWNTIME & (9'S)	28.8 hours & 99.9% (3)	22.0 hours & 99.99% (4)	1.6 hours & 99.9999% (5-6)	0.4 hours & 99.99999% (7-8)
CHARACTERISTICS	• BASIC • Extremely vulnerable to inclement weather conditions • Generally unable to sustain more than a 10-minute power outage	• REDUNDANT COMPONENTS • Minimal thought to site selection • Vapor barrier	• CONCURRENTLY MAINTAINABLE • Careful site selection planning	• FAULT TOLERANT • Stringent site selection criteria • High level of physical security
ROOM SEPARATION	NO	YES • Formal data room separate from other areas	YES • One-hour fire rating	YES • Minimum two-hour fire rating
UPS	• None or Single Module	• Single Module System	• Redundant UPS	• Dual Bus • Redundant UPS
GENERATOR	• No generator if UPS has 8 minutes of backup time • If has one it is single	• Generator backup • Able to sustain 24-hour power outage • Redundant	• Able to sustain 72-hour power outage • Redundant	• Able to sustain 96-hour power outage • Redundant
MAINTENANCE	• Shutdown required	• Shutdown required	• Allows for concurrent maintenance	• 24/7 onsite maintenance staff
REDUNDANT COMPONENTS	N • Numerous single points of failure in all aspects of design	N+1 • Some redundancy in power and cooling systems	N+1 • Redundant power and cooling systems • Redundant service providers	2N • 2N power and cooling systems

ELECTRICAL DISTRIBUTION			• **Main and feeder breakers should be drawout type.** • UL891 or UL1558 construction	• Main and feeder breakers should be drawout type • Breakers should be individually mounted in separate sections. • Switchgear per UL 1558 with proper barriers to minimize/eliminate arc flash distribution between sections. This gear is typically deeper and requires rear access.

NW Natural Data Hall Tier Rating

The data hall is rated Tier 1, the lowest. Additional details of the evaluation are included in Appendix. For the critical functionality desired for the data, it is recommended that the Data hall be enhanced to Tier 3 level. However, based on capital cost budget limitations that may not be feasible.

RECOMMENDATIONS AND PRIORITY LEVELS

Recommendations for improving the various Data hall infrastructure systems are driven by two goals: The first is to enhance the reliability, redundancy and maintainability of the Data hall as a 7x24 critical facility. The second is to provide improvements in the energy usage in the facility.

Costs noted are range of magnitude (ROM) based on educated guesses without any design input. These numbers shall not be used to determine actual construction budgets since they are not bid numbers and could be off by greater than 50%. Recommendations are not in any specific order.

Recommendations have three main components: Priority; Cost and whether or not a computer system shutdown is required to implement the recommendation.

Color Legend:

- RED= High Priority (8-10) (Improve or Remediate Critical issues) , High Cost (>$100K), or Downtime Required
- YELLOW= Medium Priority (5-7) (Good Idea), Medium Cost ($15-100K)
- GREEN= Low Priority (1-4) (“Low hanging fruit”), Low Cost (<$15K), No Downtime Required

❖ EXISTING MECHANICAL CONDITIONS & RECOMMENDATIONS

Overview

The approximately 1,500 square feet data hall is located within the Operation and Training Center and was constructed in 2014. The servers are arranged in two rows with the rear of the racks facing the center aisle. It is a high bay space with no ceiling. The servers are in enclosures with ducted containment (chimneys) off the top. Cooling and dehumidification is provided by two rooftop mounted nominal 40-ton Aaon units (AC-6 & AC-7) arranged in an N+1 configuration. The supply air is individually ducted overhead, flooding the data hall. The return is headered together above the containment. Each air handler is equipped with an inline steam humidifier located outside the data hall. The data hall is backed by UPS located within the data hall and diesel generator. A VESDA system provides smoke detection. According to facilities, there have been no recent changes to connected IT loads.

Phillip Cunningham, PE provided the mechanical assessment on August 25th . At this time, unit AC-6 was offline and having repairs made. During this outage, the data hall experienced temperature and humidity fluctuations significant enough to generate alarms. Protemp (mechanical contractor) and Environmental Controls (controls contractor) were on site making adjustments to correct this situation, which appears to have been resolved. However, the fluctuations do raise concerns over the reliability to maintain the data hall with only one rooftop unit operating.

Airflow Patterns

The general airflow pattern in the data hall is a high (~12') over head supply and ducted chimney returns over the servers. The supply mains coming off of AC-6 and AC-7 are not headered together, each unit serves half the room. During our visit, with one unit out of operation, there were noticeable areas with elevated temperatures. Temperature alarms prior to our visit also suggest uneven air distribution when one unit is operating.

Trending data indicates an average supply air temperature of 62.4°F while the room is reading at 68°F. The room readings are not representative of the server inlets. Generally, measurements taken at the face of the servers should be no more then 2-3°F above discharge air temperature. Any more temperature degradation suggests poor containment of server heat. Cold air should discharge directly over the intake side of the servers, directed down to the face of the servers. Lateral discharge and attempting to mix or flood the entire data hall with cold air will result in increased server inlet temperature and higher rates of cold air bypassing containment and going directly into the return duct.

Recommendations:

- **M1:** Adjust airflow patterns to ensure that air is delivered to the front side of server racks and is not blowing directly on temperature sensors.

Priority: Med	Cost: Low ~$5K	Downtime Required: Yes

- **M2:** Remove any obstructions or constrictions between the front and back side of server racks. Utilize blank off panels in cabinets in all unused positions in all racks.

Priority: High	Cost: Low <$5K	Downtime Required: No

- **M3:** Distribute high-density, high performance servers evenly throughout the space

Priority: Med	Cost: Low <$5K	Downtime Required: Possible

- **M4:** Combine the supply headers to allow better room circulation when only one rooftop unit is operating.

Priority: High	Cost: Low $20K	Downtime Required: Yes

Temperature

Air conditioning efficiency is maximized when the discharge air temperature is highest. Lowering discharge air temperature requires increased compressor energy and causes increased coil condensation, meaning sensible cooling capacity is lost to latent heat transfer. Discharge air setpoint should be no lower than that required to maintain desired server intake temperature.

Currently data hall temperature setpoint is set to 68°F. Trending data indicates an average supply air temperature of 62.4°F and average return plenum temperature of 75.3°F. This operating condition is on the low end of the A1 range[1] and there are energy saving opportunities to operate at warmer temperatures (reduces cooling demand, increases cooling capacity) and a larger temperature differential across the servers (higher delta T means lower airflow volume, and reduced fan energy consumption). Raising discharge air temperature increases economizer availability, further improving energy performance. Manufacturer's ratings for servers should be followed and their anticipated failure rate at varying operating conditions. There is a correlation between running servers at warmer temperatures and their failure rate, however many facilities find the economics of reduced energy consumption offset this replacement cost.

Recommendations:

[1] ASHRAE TC 9.9 Thermal Guidelines for Data Processing environments lists Class A1 space dry bulb range as 59°F to 89.6°F.

- **M5:** Review facility standard for acceptable operating temperatures and rated performance of equipment. Operate at the warmest possible discharge supply temperature that satisfies server inlet temperature.

Priority: High	Cost: Low $1K	Downtime Required: Yes

Temperature Sensor Monitoring

There is a wall mounted temperature sensor for AC-6 near the entrance and another sensor for AC-7 located in the opposite corner of the room. With AC-7 disabled during our visit, we were unable to quantify any discrepancy between the sensors. But it was noted by facilities that temperature fluctuations were observed until the AC-6 sensor was recalibrated. We observed that the AC-6 sensor is directly in the supply airflow path, whereas AC-7 is in a more protected location. According to the SOO, AC-6 and AC-7 are controlling to discharge air temperature, not room temperature which is monitored only. When one unit is not operating, temperature control for the entire space is reduced to one discharge air sensor which is not a good representation of the entire space.

We generally recommend sensors that control critical setpoints, such as discharge air temperature, have 2N redundancy and monitoring sensors, such as room sensors, have at least N+1 redundancy or more to provide accurate coverage. This allows enough data to isolate a faulty sensor, provide backup to a failed sensor, and create a temperature profile of the data hall to identify hot spots.

It was not apparent during our visual inspection if there are return air temperature sensors located in the hot-side containment. The controls drawing indicate one sensor each for AC-6 and AC-7, which is inadequate to identify hot spots within the server racks.

Recommendations:

- **M6:** Install one additional discharge air sensor each at AC-6 and AC-7 for reliability.

Priority: High	Cost: Low $2K	Downtime Required: No

- **M7:** Add two additional room sensors (or more) within the data hall to identify hot spots. Locate sensors closer to server inlets to get more representative information of the air entering the servers.

Priority: Med	Cost: Low $2K	Downtime Required: No

- **M8:** Add dispersed temperature sensors in the hot-side containment to ensure server loads are evenly distributed.

Priority: Med	Cost: Low $5K	Downtime Required: No

- **M9:** Modify the sequence of operation to evaluate for potentially faulty sensor readings and utilize temperature sensor averaging.

Priority: Med	Cost: Low $1K	Downtime Required: No

Capacity

Each rooftop unit is a nominal 40-ton capacity unit. Over the three-day trending period, data shows supply fan operation at 90% and average supply air to return air delta T of 12.8°F which indicates a cooling demand of roughly 20-tons. Further trending and additional measurements would be necessary to fully understand the load profile of the data hall, but it is apparent each unit has the capacity to handle the entire server load and provide N+1 redundancy. Observed temperature fluctuations would therefore be caused by airflow patterns and containment in the data hall or control issues.

Recommendations:

- **M10:** Further analysis should be performed to understand the data hall load profile, airflow patterns, containment, and controls.
- **M11:** This analysis should also be performed prior to adding new or additional loads.

Priority: Med	Cost: Low $5K	Downtime Required: No

Economizer Control

Economization is a duct and damper arrangement with an automatic control system that together allow a cooling system to supply outdoor air to reduce or eliminate the need for mechanical cooling during mild or cold weather. Providing economization over a narrow supply temperature range, with little or no change in data hall temperature, is the most common and reliable (regarding hardware failure rate) approach. Maximizing economizer runtime requires adequately mixing return air to warm the air or partially loading compressors to cool the air and maintain consistent supply air discharge into the data hall. Economization also requires a means of relieving excess air from the data hall to maintain acceptable pressurization levels. The data hall should be slightly positive relative to adjacent spaces and the return plenum should exert the least back pressure as possible on server fans. In other words, the pressure differential from the front to the back of the servers should be as low as possible, allowing the server fans to operate without influence by the HVAC system. Economization control should also factor indoor and outdoor humidity (enthalpy), as operating the system based on temperature only will cause humidify fluctuations in the data hall and increased humidification or dehumidification loads

During our site visit, we were informed the economizer operation had been disabled for an extended period of time due to controllability issues. In reviewing the SOO, the cause of these issues is apparent. The economizer mode was programmed to maintain a fixed 70°F discharge air temperature without factoring humidity. The pressure relief fan is designed to maintain a fixed differential pressure between the room and return plenum (i.e., across the severs) of 0.15" w.g., which is excessive.

Recommendations:

- **M12:** As an energy saving measure, restore economizer functionality
    - Review basis of design setpoints for economization control to align with facility standards and server tolerances
    - Update SOO to include humidity, as well as temperature, to determine economizer availability
    - If not already present, install an enthalpy (or wet bulb) sensor to monitor outside air humidity.
    - Add differential pressure sensing between the data hall and corridor and modulate supply fan speed to maintain the room at a +0.05" w.g. pressure. The exhaust/relief fan should maintain the return plenum at the lowest possible setting within the sensor's accuracy range, typically -0.05" w.g. This will effectively decouple the room pressurization control from the server fans operation.
    - Commission the economizer system to ensure sensors are calibrated and dampers are actuating properly.

Priority: High	Cost: Low $10K	Downtime Required: No

Humidity Control

Humidification is provided by two steam units which inject steam into the supply air ducts just before they enter the data hall. Dehumidification is provided by the rooftop units and hot gas bypass is available for dehumidification cycles. The minimum humidity setpoint is 30% RH and the maximum setpoint is 80%. This operating range aligns with the ASHRAE A1 classification and recommended range[2]. It should be noted that, because the data hall operates on the lower end of the dry bulb range, it is expected to experience relative humidity on the upper end of the acceptable range. Nuisance alarms for high relative humidity may be reduced simply by increasing data hall temperature as described above.

The SOO describing the humidification sequence lacks details, although the actual programming may have more information than is shown in the SOO. It does not describe any relationship or priority between the humidification modes and economization. As mentioned above, the economizer may operate regardless of the impact on humidification loads. As it reads now, the unit could be simultaneously economizing and dehumidifying, thereby exhausting dehumidified air to the outdoors,

[2] ASHRAE TC 9.9 Thermal Guidelines for Data Processing environments lists Class A1 space humidity range between 8% and 80%, but the recommended range is between 10% and 60%.

which is a costly energy penalty. Conversely, the unit could go into a dehumidification sequence utilizing hot gas bypass when simply mixing in more return air from the data hall would adequately raise supply air relative humidity. Again, this is an energy saving opportunity. The sequence defines no deadband ranges to prevent one humidifier operating while the other air handler is dehumidifying. This wasteful condition would not be readily apparent as conditions in the data hall would be within their operating range.

Recommendations:

- **M13:** Update the SOO to factor humidity loads when economizing and utilize outside air and return air as a first measure to maintain humidity in the space before actively dehumidifying/humidifying.
    - Update the sequence to minimize the use of hot gas bypass as much as possible.
    - Update the sequence to prevent simultaneous humidification/dehumidification.
    - Use a +/-5% deadband between humidifiers

Priority: High	Cost: Low $1K	Downtime Required: No

Heat Recovery

The system was designed with a heat recovery bypass that was intended to allow warm air from the data hall to be relieved to the adjacent warehouse for heating instead of exhausted to the outdoors. This system is described in the SOO but no control sequence is provided. We were informed during our site visit that this system has never operated correctly and was disabled due to issues with pressurization control. In reviewing the duct configuration and submittals for the rooftop units, it is apparent this system will not work as installed. The return air bypass tees off of the return air plenum between the servers and rooftop units, which have exhaust fans pulling air from the data hall. This section of ductwork operates at a lower pressure relative to the data hall, which is positive relative to the warehouse. When the return air bypass damper opens and the exhaust fan is on, air will move in the wrong direction, from warehouse to rooftop unit, therefore no heat recovery is taking place. This would also change the airflow balance between data hall and warehouse and disrupt pressurization control. It may have been intended to operate with the exhaust fan at a very low speed or off thereby allowing the server fans to push air into the warehouse, but this is not recommended. The server fans should not be used to overcome any external static friction.

Disabling the heat recovery system is a significant lost opportunity for energy savings, but as installed it is not functional.

Recommendations:

- **M14:** Modify the heat recovery system to make it functional.

- This could be achieved by adding an additional fan in the return air bypass or adding ductwork and dampers on the roof to direct exhaust air into the warehouse.
- Perform calculations to confirm heat is of high enough grade to utilize for heating adjacent spaces.
- Provide a sequence of operation to control this system.
- Provide commission to validate the system works as designed.

Priority: Low	Cost: Med $20K+	Downtime Required: Possible.

Controls

The building is equipped with an Allerton building management system. There is a central global controller for the entire building that ties into a network of MS/TP and ethernet connected local controllers. The rooftop units have their own local controllers, which include the humidifiers, that communicate to the global controller via ethernet. These local controllers are UPS backed allowing the data hall HVAC systems to remain concurrently maintainable in the event of a loss of communication or power outage to the global controller. This is a robust configuration. However, in discussions with the controls contractor, they indicated this hardware is dated and they have seen elevated failure rates associated with these older controllers and that new software will have improved functionality and security features

Recommendations:

- **M15:** Consider replacing outdated controller hardware and software for improved reliability, functionality, and security. Any additional controls added should either connect to the local RTU controllers or integrated with new redundant controllers to allow concurrent maintainability. The global controller is a single point of failure.

Priority: High	Cost: Med $15K	Downtime Required: No.

Mechanical Summary

The data hall is being operated and maintained in alignment with industry standard recommend ranges for temperature and humidity. It was apparent during our assessment that facility operators and managers were well informed about conditions within the data hall and were attentive and responsive to any abnormalities or alarms.

The HVAC system in place is fairly robust, but reliability and potential for expansion should be further evaluated. In addition, there are numerous energy savings opportunities that could be implemented.

❖ EXISTING ELECTRICAL CONDITIONS & RECOMMENDATIONS

Overview

Review of Electrical & Fire protection systems was performed by Larry Hengesh, P.E.

UPS System Recommendations

Overview: There are several possible groups of options for improving the Tier Rating of the facility. Some will raise the rating to Tier 3 but will require a higher capital expense. Other combinations will raise the rating to Tier 2 but may still have single-points-of-failures and other reliability issues. The following are some, not all, of the possible options. These UPS system recommendations require a detailed discussion of cost-vs-benefits and NW Natural's desired outcome. All require detailed electrical engineering that is beyond the scope of this report.

U1: Install an Additional UPS System: The existing 7-year old PowerWare 9395 UPS system is a solid, well-respected workhorse of the industry, with an additional 8-13 years of life. However, there is only one UPS unit, i.e. no redundancy and as such is considered a single-point-of-failure (SPOF). A failure of the inverter, rectifier or its batteries will result in a shutdown of the Data hall. A second UPS unit will increase ride-thru time if the generator does not start, will allow concurrent maintenance of the UPS system and raises the Tier Rating to Tier 3. There are many choices of UPS units that will be energy efficient and fit your application. Two possible alternatives are to choose a smaller modular unit since the existing load is only 65KVA and to move one of the two existing battery strings to serve the new UPS. Additional electrical engineering will need to be performed to design a new system. Refer to U2 since a new UPS unit will require new distribution equipment. This is noted as Priority 7 – since it is a large capital expenditure if choosen.

Priority:	Med. 7	Cost:	High >$100K for new UPS, use one existing battery string and new electrical feeds.	Downtime Required:	Yes

U2: Reconfigure the UPS Bypass Feeder: The existing UPS distribution design has the UPS input and static bypass served from one feeder. A fault on the UPS system will probably trip the input breaker which would also shut down the static bypass function. The existing maintenance bypass feeder is manual operation only and thus does not come into play during a short-circuit event. Reconfiguring the existing bypass feeder to also connect to the UPS static bypass input will improve short-circuit resiliency. However, due to having only one UPS system there are short circuit coordination limitations that would thus not guarantee that it would prevent a shutdown. See recommendation for additional UPS unit. This would require electrical engineering services to design.

Priority:	High 9	Cost:	Low ~$?K	Downtime Required:	Yes

U3: Install Battery Monitoring System Remote Annunciation: Since batteries can fail at any time during their lifetime, it is critical to be consistently monitoring the existing Eaton Cellwatch battery monitoring system. This can be accomplished in two ways:

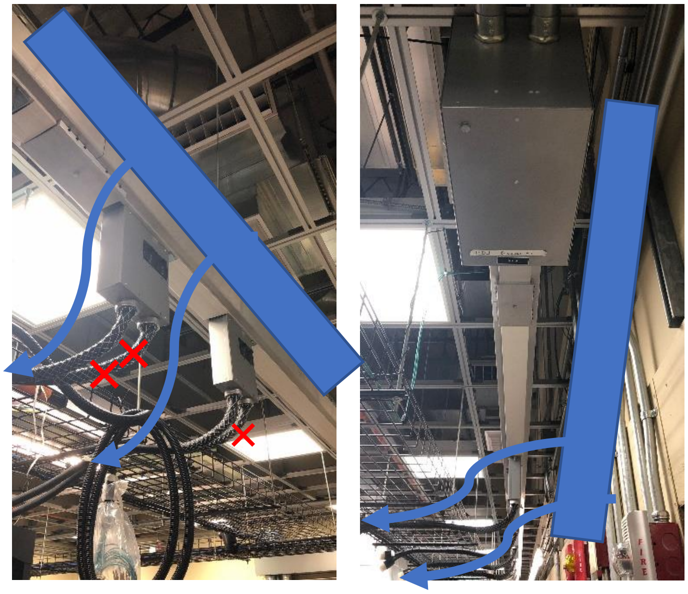
- Manually running a weekly report from the computer next to the UPS batteries and logging it in. The report will notify the user of which cells are trending toward failure.
- Adding a hard-wired monitoring system connection to the alarm contacts on the Cellwatch system. This contact will activate on any battery system alarm or trouble condition.
- The recommended solution is to do both. (Be proactive vs. waiting for an alarm)

Priority:	High 9	Cost:	Low from being just a single monitoring point perspective but a remote monitoring system is required first. See Monitoring System item	Downtime Required:	No

U4: Perform Full PM on UPS: If it hasn't been done yet, the UPS is due for capacitor replacement. They are usually only good for 7-10 years. It is usually possible to replace them while operating on mainteance bypass. Also the UPS user screen showed several warnings that need to be addressed immediately.

Priority:	High 9	Cost:	Low ~$9K	Downtime Required:	No?

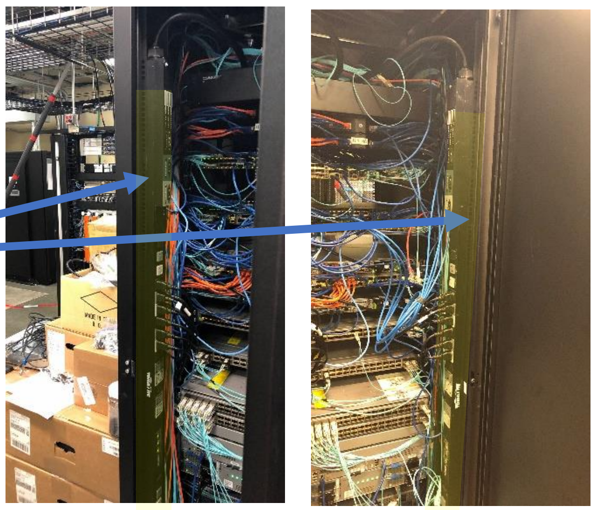
U5: Provide Redundant Power Path for UPS Output Distribution to Rack: The existing distribution system has many single-point-of-failures (SPOF) where just about any major fault will likely shutdown the entire system. Luckily faults are rare. There are two 400A breakers serving the data hall via two runs of overhead plug-in busway. One run serves one lineup of racks. The issue is that both plug-ins serving the two rack distribution units (RDU) (vertical plug strips in back of each cabinet) are both plugged into its respective single busway. This prevents concurrent maintenance and greatly increases the likelihood of inadvertent shutdown. By adding a parallel run of busway next to each of the two busways and thereby creating a true "A" & "B" distribution system the overall reliability, resiliency and maintainability will be increased to Tier 3 (this component only).



Priority:	High 10	Cost:	Med ~$??K	Downtime Required:	No

U6: Provide Color Coding for Dual Power Paths: Following up on U5, both the "A" & the "B" power pathways should be color coded: Orange for "A" and Blue for "B". This insures that each server is fed from two diverse power feeds. This would involve adding:

- Colored nameplates for each breaker in the PDU
- Colored tape on each dual cord serving the servers
- Colored tape on each RDU cord
- Large Colored stickers on each busway plug-in and on sides of busway.



Priority:	High 10	Cost:	Low ~$K	Downtime Required:	No

U7: Install A Surge Suppressor on The UPS System: The existing UPS output PDU may not have a surge suppression device. This device helps protect against damage to electronics adjacent to ones that fail.

Priority:	Low 4	Cost:	Low ~$2K	Downtime Required:	Yes

U8: Determine EPO system Issues, if any, & Upgrade If Required: The existing EPO system was not verified for its design and integrity. Based on Glumac's experience, the EPO system is one system that has caused quite a few inadvertent shutdowns due to fail-off design (vs. fail-safe) improper button safeguards, disgruntled employees, water leaks, etc.. Glumac has designs that are appropriate for this Data hall and includes items such as monitoring, guards, improved wiring.

Priority: High 9	Cost: Low ~$4K	Downtime Required: Yes

U9: Install Metering on Starline Busways: Meters on the input to each Starline busway is recommended to make sure busways are balanced, not overloaded and redundant. The meters may already be installed in the black PDU. However, this needs to be reviewed consistently to make sure there are no unbalance or overloading issues.

Priority: Med 7	Cost: Low ~$4K	Downtime Required: Yes

Generator System Recommendations

G1: Install an Additional Generator Starting Battery System: The existing SPOF generator relies on a single set of very inexpensive starting batteries. Batteries are the weakest link in any generator system and if the generator doesn't start, the Data hall will shut-down after only a few minutes. Starting batteries should be replaced every three years. Providing a new second battery set, second battery charger and a best-battery diode system will greatly improve the generator reliability.

Priority: High 10	Cost: Low ~$7K	Downtime Required: No

G2: Install an Industrial Diesel Fuel/ Water Separator System: The existing generator only has the standard factory fuel filter without the ability to ascertain dirtiness level or allow changing the filter while operating on an extended utility failure. A good industrial fuel/ water filter will allow for better protection from dirty fuel and/or water in the fuel. Priority is medium if the fuel is cleaned at least twice per year or a fuel polisher is added. Otherwise it is high priority.

Priority:	HighMed. 8	Cost:	Low ~$2K	Downtime Required:	No

G3: Install an Industrial Diesel Fuel Polisher System: The existing generator base fuel tank does not have fuel polishing system. This system removes water, algae/ other biological growths and other particles. A polisher is highly recommended since diesel fuel only has a 1-year shelf life then additives need to be added to preserve it.

Priority:	High 10	Cost:	Low ~$9K	Downtime Required:	No

G4: Add Diesel Fuel Level to Remote Monitoring: On possible long utility outages knowing the remaining runtime of the diesel fuel and when to re-order fuel is critical.

Priority:	High 10	Cost:	Low ~$2K	Downtime Required:	No

G5: Replace Existing Diesel Fuel: Fuel system companies can come and pump out the old fuel and replace with a fresh batch. This is recommended if the fuel has been sitting for greater than 5-7 years since it has had many doses of additives to keep it fresh. Additives can only go so far. The cost is not the same as new only.

Priority:	Med 7	Cost:	Low ~$?K	Downtime Required:	No

G6: Install Battery Pack and New Lights by Generator: The code requires battery powered lights around and inside a generator to allow staff to access it in the event the generator does not start. There existing lights inside the generator are connected to house power only – i.e. no battery backup.

Priority:	Med 7	Cost:	Low ~$2K	Downtime Required:	No

G7: Reinstall Generator EPO button inside Adjacent Transfer Switch Enclosure: The code requires a generator emergency power off (EPO) button to allow staff to push it in the event of a generator fire. The risk of this is extremely low but the risk of inadvertent pushing of this EPO is higher. An alternative is to put a locked cover over it with an engraved sign – keyed the same as the padlock to the transfer switch. As a minimum it should be pushed and then verified that it is annunciated on the generator remote annunciator.

Priority:	Low 3	Cost:	Low ~$2K	Downtime Required:	No

G8: Upgrade the Generator Remote Annunciator System: The existing generator remote annunciator panel (GRAP) is incorrectly located in the main electrical room where it is not monitored 24x7, as required by code. The system could have a problem, and someone may not hear the buzzer. The best solution is to connect the generator control panel to the new monitoring system via a digital gateway.

Priority:	High 10	Cost:	Low ~$K when added to the monitoring system	Downtime Required:	No

Remote Monitoring System Recommendations

Overview: Installation of a Data Hall Monitoring System: One of the main causes of downtime is not being aware of an imminent or occurring alarm condition. This facility has only a single temp/ humidity sensor and fire alarm remote annunciation. The central facility monitoring system is intended to provide users with real-time information about the condition of the existing support systems, which their critical equipment is so dependent upon.

M1: Monitoring System: This system would encompass alarm notification, monitoring and historical trending/ databasing of selected power distribution equipment within the Data hall, as well as status of:

- Utility power feed
- Environmental conditions such as temperature and humidity
- Operational conditions of critical HVAC equipment
- Life safety equipment (Fire Alarm and Sprinkler)
- Emergency power source (Generator, fuel levels, Automatic Transfer Switch status).
- UPS system

Again, the purpose of this recommendation is to improve the emergency response time, operability and maintainability of the Data hall by providing the on-site and remote / off-duty staff with immediate feedback of the entire environment surrounding and supporting the IT equipment. The monitoring system would most likely be the existing Allerton BMS system since it is the lowest cost way to implement this recommendation.

The system could be implemented in phases:

- Software to remotely monitor and alarm the UPS unit
- Software to remotely monitor and alarm the meters on the individual Starline busways. This is critical to insure redundancy on the A & B busways.
- Monitoring of servers inlet air temperatures from the server themselves and put into databases for alarming on over-temperature conditions.
- Pull all systems into one comprehensive system to allow monitoring and alarming of all equipment from one software platform.

Priority:	High 10	Cost:	Medium ~$50+K.	Downtime Required:	No

M2: UPS Monitoring System: The UPS unit comes with software for remote monitoring of the equipment. As a minimum this software should be installed on the facilty manager's computer and monitored on a regular basis. It only requires an Ethernet cable to be plugged into the UPS comm. Card. However, ideally the UPS system would be tied into a central monitoring system.

ELECTRICAL SYSTEM RECOMMENDATIONS

E1: Verify and Upgrade All Seismic Anchorage & Bracing Systems: The following pieces of equipment should be evaluated for adequate seismic bracing and upgraded if required by adding additional engineered bracing:

- Main Switchboard – It may be anchored on the inside – just need to confirm
- UPS Busway serving racks
- Telecom Cable tray
- The Generator and UPS Unit appear to be adequately braced
- The utility transformer is not anchored at all and would shear off the conductors in an seismic event.

Priority:	High 10	Cost:	Low ~$2+K	Downtime Required:	No

E2: Install Fused Disconnects for Less Critical Equipment: The entire building is backed up by the generator which means non-critical equipment is shared with critical equipment. Any fault in a non-critical piece of equipment could trip a critical breaker. This recommendation would take field work to see where it makes sense to separate out critical from non-critical. Using fuses in lieu of circuit breakers allows the fault to clear with an increased margin of safety from having the upstream breaker clear as well – possibly shutting down critical equipment.

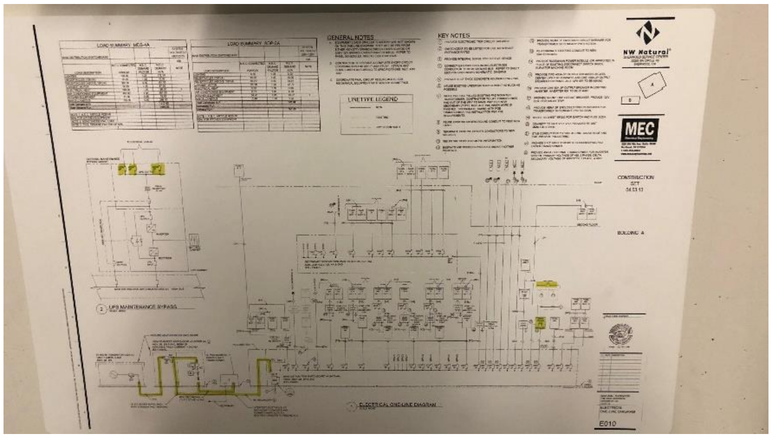
Priority: High 8	Cost: Med ~$500	Downtime Required: But possibly not critical equipment Yes

E3: Verify Electrical Circuit Breaker Coordination Settings: Similar to the above where any electrical fault in a non-critical piece of equipment could trip a critical breaker. This recommendation would be to review/ update the original circuit breaker coordination report, or create a new one, to confirm the circuit breakers are selectively coordinated, so that only the breaker closest to the fault will trip while allowing the other upstream breakers to continue operation. We have seen a 20A circuit breaker trip the main breaker due to wrong settings.

Priority: High 8	Cost: Low <$5K	Downtime Required: But possibly not critical equipment Yes

E4: Install Large Foam Core Mounted Single-line in Electrical Rms: Adding large wall mounted single-line diagrams in the electrical and data hall will help to more quickly trouble-shoot electrical issues. Facility staff should be trained on understanding the single line diagram.

Priority: Low 1	Cost: Low <$100	Downtime Required: No



E5: Preventative Maintenance of Major Electrical Equipment: It is probably time to do a thorough PM on all electrical systems, including: Torqueing bolted electrical connections, Utility transformer Oil Testing, Grounding Verification.

Priority:	High 8	Cost:	Low <$3K	Downtime Required:	No

Fire Protection Systems Recommendations

F1: Program Time Delay in VESDA System to Slow Trigger of Gaseous Fire Protection System: The existing VESDA system is very sensitive to smoke and a single very small smoke event (like server power supply failure) can reach the alarm/ shutdown level and trigger the gas release. Adding a separate conventional smoke detection zone or programming the maximum allowable time delay in the VESDA system will help prevent inadvertent shutdown of the HVAC system and release of the Ecaro-25 gas.

Priority:	High 9	Cost:	Low <$1K	Downtime Required:	No

F2: Add Manual Maintenance disconnect Switch for Fire Alarm Testing: The existing fire alarm system does not have a manual maintenance isolation switch to allow testing of the shutdown of the HVAC system and release of the Ecaro-25 gas. This simple switch insures no inadvertent dumping of the gas.

Priority:	High 9	Cost:	Low <$1K	Downtime Required:	No

F3: Add Remote Monitoring of the Fire Alarm & VESDA Systems: These systems can shutdown the data hall and as such they should be remotely monitored. All levels of alarms should be transmitted to the facilites group.

Priority:	High 10	Cost:	Low <$1K See Monitoring option	Downtime Required:	No

F4: Reconfigure VESDA System: The existing VESDA system serving the chimney racks does not appear to be installed correctly. A typical VESDA system can't have pressure differences between the monitoed space and the VESDA fan unit. The chimney racks are under negative pressure and the fan unit is in the room therefore there is probably no flow on the piping. It is recommended to add two single zone VESDA units, one for each run of racks with the exhaust port pied into the respective enclosues to maintain the correct pressure relationship. Most of the existing rack piping can be reused. The finished design needs to be thouroughly commissioned.

Priority:	High 10	Cost:	Low <$15K	Downtime Required:	No

Facility Operations Training Recommendations

T1: Staff Training on Operating & Trouble-Shooting Facility Issues: The reliability of the data Hall is directly related to the training of the staff. There are many instances where quick actions will keep the data hall in operation or where inadequate training will quickly escalate into an avoidable shutdown. Training should be videotaped and every new staff should be required to review video and pass competency test on a semi-annual basis. Training shall include:

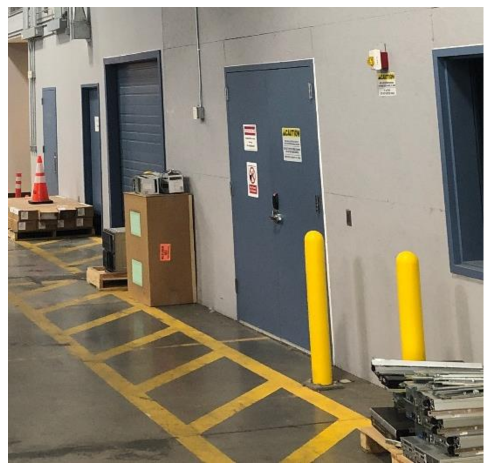
- UPS system Operation
- UPS Battery Monitoring System Operation
- UPS Maintenance Bypass Transfer Operation
- Main Switchboard Operation.
- Generator System Operation
- Transfer Switch Operation
- Fire Protection Systems Operation: VESDA, Fire Alarm & Gaseous Fire Suppression Agent
- Central Monitoring System
- Required Responses to anticipated events
- Logging in of scheduled, consistent reviews of equipment status:
    - UPS Battery Monitoring Software
    - UPS System
    - Generator system preventative maintenance

Priority:	High 10	Cost:	Low <$4K	Downtime Required:	No

ARCHITECTURAL RECOMMENDATIONS

A1: Install Data Hall Wall Waterproofing: It appears the existing wall and doors into the data hall will not prevent water ingress from the outside of the room. A simple caulked baseboard addition would prevent possible sprinkler water from going under the wall and into the data hall. Destruction and removal/ reinstallation of gypsum wall board would be a disruptive to the data hall.

Priority:	Low 1	Cost:	Low <$1K	Downtime Required:	No



A2: Install Concrete Filled Bollards: Critical equipment should be protected with bollards, spaced approximately 6' apart. The utility transformer and possibly the generator would benefit from additional protection.

Priority:	Med 5	Cost:	Med <$10K	Downtime Required:	No

A3: Add Bollard and/or Reflective Marking on the Utility Power Poles: The existing utilit power pole is very close to the road and can be easily hit. Adding bollards and/or reflective markings would add protecxtion/ awareness of the pole. City will probably need to be involved in adding bollard or guard rail.

Priority: High 9	Cost: Low <$7K	Downtime Required: No

A4: Vandal Protection: It appears that several enclosures would benefit from the addition of padlocks to prevent vandalism. The outdoor utility transfer switch enclosure, the generator doors should be locked. A monitored/ card reader key storage safe is recommended by the guard's desk to make sure quick access to keys is possible.

Priority: Low 1	Cost: Low <$2K	Downtime Required: No

Digital Communications Systems Recommendations

C1: Install Diverse Telecom Pathways and Service providers: Having two or more fiber providers and diverse entry locations/ street vault will improve uptime of facility.

Priority:	High 8	Cost:	Med >$50K	Downtime Required:	No?

❖ ELECTRICAL & FIRE PROTECTION SYSTEMS SUMMARY

The data hall is supported by a mix of high-quality, industry-approved equipment with many years of life remaining. However, it is the small details and some existing non-ideal configurations that lowers the possible overall resiliency, concurrent maintainability and redundancy of the facility and increases the likelihood of inadvertent shutdowns. Implementing the recommended upgrades will improve the electrical Tier Rating of the facility from Tier 1 to Tier 2 or better.

Inadequate training of staff can nullify the best of infrastructure reliability by either overlooking worsening conditions or by implementing wrong trouble-shooting procedures or acting on incorrect remediation decisions. Providing adequate remote monitoring and regular training will also improve the reliability rating of the facility.

❖ END OF REPORT

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Direct Testimony of Jim R. Downing

INFORMATION TECHNOLOGY & SERVICES
EXHIBIT 700

December 29, 2023

EXHIBIT 700 – DIRECT TESTIMONY – INFORMATION TECHNOLOGY & SERVICES

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 "Company").

A. My name is Jim R. Downing. My title is Vice President and Chief Information 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 received a Bachelor of Science degree in Business Science Information Systems from University of Phoenix in 2007 and a Master of Business Administration from Tulane in 2011. I earned my Microsoft Certified Systems Engineer credential and am a Cisco Certified Design Associate. I have been employed as an IT&S professional since 1995. Prior to NW Natural, I worked as a Customer Contact and Help Desk consultant at Siemens, helped consolidate European Help Desk services for Compaq, and provided IT&S leadership support for major international oil and gas companies for 17 years. I joined NW Natural in 2017. In 2019, I was recognized by Governor Kate Brown for helping to evaluate and create a multi-year IT strategy for the State of Oregon. In 2023, I was also awarded the "2023 Oregon CIO of the Year" by the Society for Information Management, which recognizes outstanding technology leadership and community contributions.

Q. What is the purpose of your testimony?

A. My testimony summarizes NW Natural's dynamic IT&S environment, provides key strategic updates, details major IT&S projects that will be completed prior to the rate effective date in this rate case, and explains the Company's increased staffing needs.

Q. Please summarize your testimony.

A. In my testimony, I describe NW Natural's ongoing IT&S context and strategic approach, provide an update on major IT&S initiatives, and detail the Company's cost-recovery requests with respect to major projects and crucial hiring needs. These projects are designed to improve customers' online experience, increase transparency in Company operations, and modernize the IT&S infrastructure—all while accommodating the increasingly cloud-based software environment and strengthening NW Natural's cybersecurity posture.

In brief, my testimony addresses the following major points:

- <u>IT&S Environment and Strategy:</u> NW Natural is in the middle of a crucial IT&S infrastructure upgrade and replacement phase. As technology systems have become central to utility operations, a combination of security, customer service, and operational demands have driven a transition to more modern and strategic IT&S solutions. These solutions are increasingly offered only as cloud-based solutions, which carry important benefits but also change the landscape for product lifecycle management.
- <u>Horizon Program:</u> At the core of NW Natural's IT&S infrastructure upgrade process is the two-phase, multi-year Horizon Program. NW Natural

successfully completed the first phase of the transformational effort ("Horizon 1") in 2022, by upgrading the Company's backbone enterprise resource planning ("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: Horizon 2: Vista ("H2: Vista"). H2: Vista will comprehensively update the Company's outdated customer information system ("CIS") and other customer-facing functions and related services, and is currently in development. While H2: Vista itself is not presented for cost recovery in this case, we are seeking cost recovery of four incremental employees who must be brought on board now in order to enable the H2: Vista's development, as described in Section V, below. I also take this opportunity to preview this important program's development as part of the context for the Company's comprehensive IT&S upgrade effort.

- <u>IQGeo Upgrade Project:</u> NW Natural upgraded its central field and web mapping platform, IQGeo. The Company's prior software version was no longer fully supported. By migrating to a fully supported version, the Company is also better able to integrate this mapping system with NW Natural's other ongoing mapping projects. As part of this project, and consistent with its broader cloud-based strategy, the Company also re-platformed IQGeo to a new, more cybersecure cloud environment and established automated testing to facilitate the ongoing upgrade and maintenance process.

- MapFrame Replacement Project: The MapFrame Replacement Project transitions the Company away from an existing end-of-life software system and develops equivalent functionality in the Company's IQGeo platform.
- Composition 2.0 Project: The Composition 2.0 Project modernizes the Company's electronic and printed documents for customers, including bills, notices, letters, welcome packages, and refund checks. Composition 2.0 is the second stage in the Company's broader modernization effort for customer-facing documents and will create more accessible and consistent documentation across the Company's electronic and printed materials.
- Genesys Re-platform Project: The Genesis Re-platform Project migrates the Company's advanced call routing software services from the current, on-premises, end-of-life Genesys PureConnect software, to the Genesys Cloud CX platform.
- Start-Stop-Transfer Project: The Start-Stop-Transfer Project is a major new feature to Web Portals that allows customers to initiate, terminate, or transfer the location of their service with NW Natural, entirely through the Company's website. This project responds to customer feedback indicating that the majority of customers seeking to use the existing online tools are unable to successfully start, stop, or transfer their service without reaching out to a customer care representative.
- Clevest Optimization Project: NW Natural undertook a new project to improve the performance and function of the Company's mobile workforce management software. Responding to key performance issues and functionality gaps, this

project helps facilitate user-friendly functionality and timely customer responses.

- Identity Governance and Administration (“IGA”) Automation Project: The IGA Automation Project provides an automated mechanism to track and manage the security access and identity management for Company personnel, which are currently handled manually. This project provides important security improvements to the Company’s operations in a manner that facilitates the Company’s compliance with Department of Homeland Security’s Transportation Security Administration Security Directive 2 requirements.
- Telemetry Refresh Projects: The Telemetry Refresh Projects involve surveying, permitting, and deploying new equipment to the Company’s remote monitoring and control sites. These projects replace outdated monitoring and control equipment to ensure crucial reliability and safety of the gas supply system.
- Utilities International (“UI”) Planner Re-platform Project: NW Natural’s industry-standard financial and regulatory planning system is no longer supported as an on-premises solution, and the Company is therefore migrating to the available cloud-based software platform. This project includes re-platforming to the cloud environment and integrating the new version of the UI Planner tool.
- PowerPlan Project: The PowerPlan Project transitions a key accounting function, known as the capital settlement process, from the Company’s existing PowerPlan tool and into the broader SAP ERP system.

- SAP[1] Treasury Project: NW Natural implemented an industry-standard software tool to automate and manage the Company's treasury functions—such as financial tracking and payment approval systems. The new tool provides consolidated and comprehensive visibility into the Company's financial risk management, replacing previous manual, spreadsheet-based processes.
- IT&S Staffing Needs: NW Natural is hiring eight new full-time equivalent ("FTE") positions to fill vital gaps in IT&S staffing. These new FTEs will provide skillsets necessary to support the Company's more sophisticated technological capabilities, while ensuring reliable, customer-friendly, and secure operations.

II. OVERVIEW OF THE IT&S ENVIRONMENT

Q. Please describe NW Natural's current IT&S environment.

A. NW Natural's IT&S environment remains dynamic, as software systems and platforms are an increasingly central part of utility operations. As a result, 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. With these goals in mind, NW Natural works to balance the growing need for technological innovation, while preserving and extending the useful life of existing IT&S platforms and programs.

[1] SAP (Systeme, Anwendungen und Produkte in der Datenverarbeitung) is a German software company and international leader in enterprise software programs.

Q. How does NW Natural ensure reliable service while incorporating evolving technologies?

A. NW Natural seeks to provide both modernization and reliability by focusing on proven new technological solutions. By prioritizing proven modern software, the Company can prudently incorporate more effective, transparent, and accurate tools while mitigating risks associated with early technology adoption.

Q. What is the Company's overarching strategic goal in this complex and dynamic IT&S environment?

A. NW Natural's overarching strategic goal is to reduce complexity for the benefit of our customers, while maintaining a current, secure, and compliant IT&S ecosystem. Specifically, the Company is in the process of consolidating and streamlining the number of applications and vendors in our portfolio and using off-the-shelf (rather than custom-developed) software when reasonably possible. By focusing the Company's effort on a tighter number of reliable software providers, NW Natural seeks to simultaneously advance the Company's performance and service, while also enhancing resilience, reliability, and security.

Q. Are customer needs and expectations for the Company's IT&S services changing?

A. Yes. NW Natural's customers increasingly rely on web and mobile technology-based service, and reasonably expect the Company to engage with them smoothly across platforms. This engagement encompasses service support, bill payment, outage and emergency notifications, and program enrollment, among others.

Q. Does the Company's IT&S environment continue to include adoption of cloud-based solutions?

A. Yes. As I discussed in my previous testimonies in UG 435 and UG 388, cloud-based solutions are becoming industry standard for large enterprises. Moving IT&S solutions to the cloud allows the Company to become more agile and responsive to customer service and internal business demands by leveraging modern technologies more quickly. Indeed, over the last several years, the Company has successfully migrated an array of IT&S solutions and platforms to Microsoft's enterprise-wide Azure cloud platform. Consolidating the Company's tools in the cloud is also consistent with NW Natural's overarching goal of simplifying IT&S solutions.

Q. What is the Company's strategy for adopting cloud-based solutions?

A. The Company's strategy for cloud-based solutions was developed in partnership with IT&S consultant Deloitte. Through this partnership, the Company undertook a comprehensive data center cloud strategy, to determine which IT&S systems and applications should move to the cloud, and to develop a detailed application migration strategy. Based on this detailed assessment, NW Natural determined that most of the Company's IT&S systems and applications should be hosted in the cloud.

Q. What are the advantages of hosting the Company's IT&S systems and applications in the cloud?

A. There are major advantages to hosting the Company's IT&S systems and applications in the cloud:

- **First,** cloud-based solutions support enhanced disaster recovery and reliability because they do not depend on on-premises servers.
- **Second,** the cloud-based software options are generally better quality and include more features than available on-premises versions, including software enhancements and automatic security upgrades.
- **Third,** software vendors are increasingly migrating the Company's existing tools to solely cloud-based options—meaning that migration is necessary to avoid transitioning to a new software system or tool. For instance, SAP SuccessFactors, which is used for human resources management, is available only via the cloud, while other software vendors such as Genesys have announced terminating support deadlines for on-premises solutions.
- **Fourth,** once established, cloud-based systems can be more quickly updated to respond to modern technologies, thus allowing the Company to cost-effectively maintain a more up-to-date software portfolio.

Q. Does moving to cloud-based solutions entail a migration process?

A. Yes. In order to adopt a cloud-based solution, the Company must migrate existing on-premises solutions to the cloud. This process is not as simple as flipping a switch, and can require substantial work to ensure a smooth and successful transition. This work includes architecture planning, implementation, data migration, and rigorous testing to ensure that the migrated tools function as intended and maintain the security of the Company's data.

Q. Aside from the nature of the software products themselves, how do cloud-based solutions differ from traditional on-premises tools?

A. The central difference between traditional on-premises and the new cloud-based software solutions is the ownership model. Rather than purchasing an on-site solution up front, cloud-based software entails ongoing subscription fees and continuing upgrades, which generally occur every one to three years. Given the cost of migrating to new solutions, the ongoing subscription model can create some risk of price increases. In order to minimize any cost risk to customers, NW Natural seeks to negotiate longer-term service contracts with software vendors.

Q. Does moving to cloud-based solutions also create new financial pressures?

A. Yes. Given that cloud-based solutions entail ongoing subscriptions, moving to more cloud-based tools increases the Company's annual incremental operations and maintenance ("O&M") spending. As a result, the Company's cloud-based software costs have increased $2.5 million on a system basis, or $2.2 million on an Oregon-allocated basis, due mainly to increases in Azure cloud platform costs and ongoing costs of other cloud software licensing. At the same time, we are still experiencing cost increases for our non-cloud-based software tools, due to growth in user and device counts and general inflationary increases, of $1.8 million on a system basis, or $1.6 million on an Oregon-allocated basis. The impacts of this incremental O&M increase on overall rates are discussed in the Direct Testimony of Tobin F. Davilla (NW Natural/1400, Davilla).

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 through the second phase of the Horizon Program, the Company will effectively consolidate its systems on cloud-based platforms, leveraging the reliability and flexibility benefits described above.

III. HORIZON PROGRAM

Q. Please briefly describe the Horizon Program.

A. As I described in UG 388 and UG 435, 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 H2: Vista, is driven by a significant keystone project to upgrade a major piece of software using new software tools—both developed by a single developer, SAP.

Q. What are the keystone projects for Horizon 1 and H2: Vista?

A. Horizon 1 involved upgrading the Company's central software backbone governing basic business functions, which integrates various other software tools and solutions including finance, human capital management, and enterprise asset management, among other functions. H2: Vista's central project involves upgrading and replacing the Company's decades-old CIS platform. CIS is the integrated framework that manages essential customer-facing functions and integrates with the Company's suite of billing and customer field services. Both projects depend on a series of smaller prerequisite projects that support or integrate with the keystone project for each phase.

Q. How did NW Natural develop the Horizon Program?

A. NW Natural developed the Horizon Program with the support of outside experts, industry surveys, and extensive communications (including site visits) with other utilities that had already implemented or were in the process of implementing similar foundational IT&S upgrades. As part of this process, NW Natural collaborated with top-tier vendors with extensive utility industry experience to analyze the Company's core software platforms, identify strategic options, and create a roadmap for the program's development. Based on this rigorous study and planning process, the Company began Horizon 1 prework in late 2020, with the goal to go live on the project in late 2022.

Q. What is the status of Horizon 1 now?

A. Horizon 1 was successfully implemented in September 2022, having entered service on time and on budget. I want to highlight that Horizon 1's successful deployment is a major achievement for the IT&S team as a whole. NW Natural's IT&S personnel worked incredibly hard to deliver on-time and on-budget results for the Company's customers.

Q. What is the next step for the Horizon Program?

A. The Company is now in the initial planning stage of H2: Vista, which involves a comprehensive framing study to confirm the sequence and scope of various prerequisite and component projects. This careful preliminary analysis is crucial to minimize risk in the larger implementation components of H2: Vista. As with Horizon 1, the Company has developed a governance review process to ensure that projects proceed on-time and at a reasonable cost, with oversight and review checks at each stage in H2: Vista's development.

Q. Is NW Natural seeking cost recovery for H2: Vista project costs in this case?

A. No. NW Natural does not seek recovery for H2: Vista project costs in this rate case. Rather, I provide this update as part of NW Natural's ongoing efforts to transparently inform the Commission and relevant stakeholders regarding the Company's mission critical efforts and investments, and to provide context for the Company's need for additional staff support. As I explain below, the Company is requesting recovery of the costs associated with four new IT&S FTEs, who (as described more fully below) are necessary to ensure adequate personnel support for H2: Vista's CIS upgrade. In 2024, the Company likely will be seeking a deferral order to defer expenses associated with H2: Vista.

Q. Please explain why NW Natural would request a deferral order rather than seeking recovery of these costs in this or a future rate case.

A. The Company expects in 2024 to begin incurring a significant amount of non-routine, one-time O&M expense associated with the planning and development of

H2: Vista. In other words, there are several key aspects of the project that cannot be capitalized and result in significant O&M expense increases over discrete periods of time. These costs are not appropriate to be included in base rates, however, because we know that the costs will not be recurring. Accordingly, NW Natural expects to seek a deferral order to defer such expenses associated with H2: Vista for later recovery.

IV. MAJOR IT&S PROJECTS

Q. Please explain how this section of your testimony is organized.

A. In this section of my testimony, I describe the Company's major IT&S projects. My testimony is organized as follows:

First, I address field and web mapping projects:

- IQGeo Upgrade Project
- MapFrame Replacement Project

Second, I describe key customer-facing projects:

- Composition 2.0 Project
- Genesys Re-platform Project
- Start-Stop-Transfer Project

Third, I detail the other remaining projects driven by security or operational needs:

- Clevest Optimization Project
- Identity Governance and Administration Project
- Telemetry Refresh Projects
- UI Planner Re-platform Project

- PowerPlan Project
- SAP Treasury Project

For each of these projects, I explain the need for and benefits of the project, as well as considered alternatives, project status, and anticipated costs.

A. IQGeo Upgrade Project

Q. Please provide some context on how the IQGeo Upgrade Project fits into the Company's field and web mapping program.

A. 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 tools 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 online and offline representations of NW Natural facilities and assets, which they use for various business purposes, including inspection compliance programs. IQGeo is a key piece of this consolidation and transition project and serves as the Company's new field and web mapping operations hub. IQGeo is a user-friendly, map-based tool that provides field and office personnel with the information they need to improve data accuracy and safety. IQGeo was first licensed in 2019, was implemented in 2020, and is gradually being supplemented with additional functionalities (known as "use cases") over time. In UG 435, for instance, the Company implemented new use cases to provide end users "view access" to engineering records, the ability to collect inspection information in support of compliance programs, and the tools to create as-built drawings and generate PDF records.

Q. Please describe the current IQGeo Upgrade Project.

A. The current IQGeo Upgrade Project is a multi-part effort that builds on the new system by (a) upgrading to a newer, fully supported version of IQGeo, (b) re-platforming IQGeo to Azure's enterprise-wide cloud environment, and (c) establishing automated testing for the IQGeo application.

Q. Why is it necessary to upgrade IQGeo?

A. It is necessary to upgrade IQGeo to mitigate risks of technical failures for the Company's essential field and web mapping system. As with other software products, IQGeo requires periodic upgrades to address bug fixes, incorporate product improvements, and maintain support services from the software vendor. In this case, the Company's current software version 6.1 is out of date. The software vendor discontinued full support for version 6.1 in June 2022. As a result, upgrading now is critical to ensure that ongoing bug fixes, security patches, and other support are available for the smooth operation of this essential system.

Additionally, NW Natural is in the process of upgrading and replacing other legacy mapping applications that rely on or integrate with IQGeo. The current version 6.1 of IQGeo is not compatible with these other projects, further supporting the need to undertake the upgrade.

Q. Why is it necessary to re-platform IQGeo?

A. Re-platforming IQGeo to the Company's enterprise-wide Azure cloud reflects best practices in technology management and aligns with NW Natural's broader strategic goal of consolidating the Company's cloud environments. IQGeo was originally built in one of the Company's first cloud environments, which have since been superseded by the consolidated Azure cloud. In addition to the efficiency of consolidating NW Natural's technologies, the Azure environment is more secure, provides more robust disaster recovery, and has more support capability that will improve the Company's ability to manage IQGeo.

Q. What is the benefit of establishing automated testing for IQGeo?

A. Establishing automated testing for IQGeo will help streamline the testing process required as part of periodic IQGeo software upgrades and migrations. NW Natural has found that the testing portion of implementing new software upgrades can constitute a considerable share of the effort. Given that software upgrades are relatively routine and foreseeable, implementing testing automation work into the broader upgrade and re-platforming process will reduce both near-term and long-term effort, while improving system performance.

Q. What is the current status of the IQGeo Upgrade Project?

A. NW Natural has completed the upgrade and testing automation work and is in the process of migrating IQGeo to the Azure cloud environment. The Company expects to place the IQGeo Upgrade Project in service by January 2024.

Q. What cost recovery is NW Natural requesting for the IQGeo Upgrade Project in this case?

A. NW Natural seeks to recover its capital investment of approximately $1.71 million on a system basis, or $1.5 million on an Oregon-allocated basis.

B. MapFrame Replacement Project

Q. Please provide some background on the MapFrame Replacement Project.

A. The MapFrame Replacement Project is part of the broader field and web mapping program, described above. Stated briefly, the Company is phasing out current end-of-life software tools and transitioning to a consolidated set of modern systems—including IQGeo, which provides an up-to-date visual interface with NW Natural's operational assets. Part of the goal with implementing IQGeo is to consolidate the Company's field and web mapping functions in a smaller set of technologies, including by replacing MapFrame.

Q. Please describe the MapFrame Replacement Project.

A. The MapFrame Replacement Project transitions the Company away from an existing end-of-life software system and develops equivalent functionality in the Company's IQGeo platform. Currently, MapFrame is used as a general map viewer and as a map correction tool, which allows the Company to:

- View gas facility location and asset information;
- Document changes to field conditions and mapping errors; and
- Create personal map notes for users to document information.

None of the above functionalities are currently available in NW Natural's other field and web mapping software tools. Thus, NW Natural intends to transition the above functionalities to IQGeo, which involves CIS integration to view customer information, creating location widgets to display locational information, implementing a design interface to allow for map corrections, enabling users to generate personal notes tied to maps, and facilitating map printing from mobile devices. All of these features are part of developing a new set of "use cases" in IQGeo, consistent with the goal for IQGeo's development as a central operations hub.

Q. Why is the MapFrame Replacement Project necessary?

A. The MapFrame Replacement Project is necessary because the current MapFrame software is end-of-life, and indeed has not received a software update from its developer since 2015. As a result, transitioning away from this product is important to ensure continuity of NW Natural's operations. Transitioning MapFrame's current functions to IQGeo is also a prerequisite for other field and web mapping transition efforts, which are designed to integrate with IQGeo's more modern system.

Q. Are there any additional benefits of the MapFrame Replacement Project?

A. Yes. By transitioning MapFrame's current map viewing and map correction functions into IQGeo, the Company can also streamline the Company's IT&S product suite. This consolidation is consistent with NW Natural's broader strategy of simplifying its IT&S portfolio to benefit customers.

Q. Did NW Natural consider alternatives to the MapFrame Replacement Project?

A. Yes, NW Natural considered two alternatives to the MapFrame Replacement Project. **First,** the Company considered implementing an alternative mapping solution to replace MapFrame. This option was not selected because it would involve implementing a new—non-IQGeo—mapping solution, which would complicate the Company's IT&S environment, delay implementation of a new solution, and increase licensing, implementation, and maintenance costs.

Second, the Company considered maintaining the existing MapFrame solution. This option was not selected because it would undermine reliability of the Company's mapping functions in the short-term, would require NW Natural to pay to maintain two software systems instead of one, and would merely delay identifying a replacement option in the long-term because the current MapFrame tool is already end-of-life. In addition, delaying a transition away from MapFrame would delay the other geospatial projects that depend on IQGeo taking on MapFrame's current map-viewing functionalities.

Q. What is the status of the MapFrame Replacement Project?

A. The MapFrame Replacement Project is underway and on track to be complete by end of Summer 2024.

Q. What cost recovery is NW Natural requesting for the MapFrame Replacement Project?

A. NW Natural seeks to recover its capital investment of $5.5 million on a system basis, or $4.8 million on an Oregon-allocated basis.

C. Composition 2.0 Project

Q. Please describe the Composition 2.0 Project.

A. The Composition 2.0 Project modernizes the Company's electronic and printed documents for customers, including bills, notices, letters, welcome packages, and refund checks. Composition 2.0 is the second phase in the Composition overhaul project. In phase one ("Composition 1.0"), the Company implemented the OpenText platform that is the basis for the Company's broader document modernization effort. Currently, Composition software is used to produce digital bill PDFs, which are then used by Paymentus to produce customers' digital bills. These PDFs are also archived for recordkeeping. With the implementation of the OpenText software as part of Composition 1.0, NW Natural is now in a position to fully modernize additional customer-facing documents, as well as more comprehensively redesign and standardize document presentation in Composition 2.0. This redesign is the first time that NW Natural has comprehensively updated its bill presentation for customers in more than 26 years.

Q. What are the benefits of the Composition 2.0 Project?

A. The Composition 2.0 Project brings important benefits both to customers and to internal Company operations. For customers, redesigning these customer-facing documents provides a wide array of benefits, by:

- Making it easier for customers to locate key information by enabling NW Natural to highlight important aspects of a customer's bill;
- Including answers to frequently asked questions on customer-facing documents;
- Allowing for multi-language document development;
- Including useful context for customers regarding their bills, such as comparing a customer's gas usage to the same month in prior years;
- Explaining potential monthly bill fluctuations by providing information on factors that may be driving a month-to-month difference, such as the number of days in the billing cycle and average temperature variances from normal;

- Emphasizing online payment and self-service account options accessible with a QR code;
- Highlighting contact information for any remaining customer questions;
- Enabling geographically segmented information, thus allowing Oregon customers to see only Oregon-specific information; and
- Providing greater clarity concerning customer payment plans.

In addition to creating more modern and user-friendly electronic and printed documents, Composition 2.0 provides three important benefits for the Company's internal operations: **First,** Composition 2.0 will allow the Company to eliminate residual reliance on a legacy print generation function known as Advanced Function Printing, which is no longer supported by the vendor, IBM. **Second,** the project reduces risk associated with H2: Vista. By removing aspects of document presentment from the CIS now, the Company will have fewer issues to resolve in H2: Vista. **Third,** the project standardizes document sizes. Historically, NW Natural's documents have been printed on smaller-than-standard paper. Switching to standard sizes substantially improves the printing and delivery process by:

- Reducing supply chain issues with procuring specialty paper products;
- Improving efficiency of the print-and-mail vendor by avoiding the daily need to set up custom settings to handle custom sizes; and
- Enabling automated process controls, which can detect bill insertion issues when papers are standard sizes.

Q. How did the Company develop its redesigned customer-facing documents?

A. The Company developed the redesigned documents through both a qualitative and quantitative information gathering process. On a qualitative level, the Company solicited feedback from 39 employees in customer-facing teams, including the Contact Center, Rates and Regulatory, Customer Lifecycle Management, and Account Services. These teams were able to identify key customer concerns that could be effectively and proactively addressed through revisions to customer documents.

From a quantitative perspective, NW Natural then distributed an online survey to over two thousand customers across the Company's service territory to validate the new design direction and to expand on identified questions or concerns. This survey yielded 736 responses and over 500 narrative responses. These responses indicated strong support for the proposed redesign, with 86 percent of respondents liking the redesigned documents. Based on this data and the extensive customer feedback, NW Natural developed a list of "frequently asked questions" and responsive answers to include on customer-facing documents.

Q. What is the status of the Composition 2.0 Project?

A. The Composition 2.0 Project is currently under development and is on track to be placed in service in September 2024.

Q. What cost recovery is NW Natural requesting for the Composition 2.0 Project in this case?

A. NW Natural seeks to recover its capital investment of approximately $4.4 million on a system basis, or $3.9 million on an Oregon-allocated basis, and $87 thousand in incremental ongoing O&M ($77 thousand Oregon-allocated) for hardware and software licensing.

D. Genesys Re-platform Project

Q. As an initial matter, can you please provide some background on Genesys' role within NW Natural?

A. Genesys is the Company's existing advanced call routing software provider. Specifically, the Company employs Genesys PureConnect, an on-premises solution, to serve 7 groups and 300 combined agents across NW Natural, including Customer Support and the Customer Contact Center. Due to the centrality of Genesys' role in NW Natural's communications operations, the Genesys PureConnect software is considered a critical infrastructure system that must be available 24 hours a day, 365 days a year. As a result, reliability issues with this system are unacceptable for public health and safety.

Q. Please describe the Genesys Re-platform Project.

A. The Genesys Re-platform Project transitions the Genesys call routing solution to a cloud environment, in response to the impending termination of Genesys' software support for the PureConnect platform by the software provider.

Q. Why is the Genesys Re-platform Project necessary?

A. The Genesys Re-platform Project is necessary to maintain the integrity and reliability of the Company's communications with customers. Fundamentally, this project is driven by the sunset of the Genesys PureConnect on-premises software. Genesys is phasing out the availability of and support for the PureConnect system, first by ceasing to offer new support agreements in January 2024, and then by fully ceasing support and operation of the system on July 31, 2025. Thus, while Genesys PureConnect has been an integral part of handling NW Natural's customer interactions and support experience, the Company must now initiate a transition to a different call routing solution.

Q. What are the benefits of the Genesys Re-platform Project?

A. In addition to preventing outages on this critical part of NW Natural's communications infrastructure, the Genesys Re-platform Project will reduce the risk of product downtime and support integration with other software solutions. A cloud-hosted call-routing software can greatly minimize outages compared to on-premises options, which can be subject to location-specific service interruptions. Similarly, Genesys Cloud supports integrations with a wide range of other software solutions, which could facilitate future integrations across other technologies and platforms.

Q. Did NW Natural consider alternatives to re-platforming the Genesys software?

A. Yes. NW Natural explored deploying a new contact center solution, but doing so would have been more costly, more labor-intensive, and would not have provided assurance of superior service. Moreover, integrating a new software solution with the Company's other software systems would have introduced additional reliability risks.

Q. What is the status of the Genesys Re-platform Project?

A. The Genesys Re-platform Project is underway and is on track to be placed in service by October 2024.

Q. What cost recovery is NW Natural requesting for the Genesys Re-platform Project in this case?

A. NW Natural seeks to recover its capital investment of approximately $2.3 million on a system basis, or $2.0 million on an Oregon-allocated basis, and $289 thousand in incremental ongoing O&M ($254 thousand Oregon-allocated) for software licensing.

E. Start-Stop-Transfer Project

Q. Please describe the Start-Stop-Transfer Project.

A. The Start-Stop-Transfer Project provides a new web-based tool that will allow customers to seamlessly initiate, terminate, or relocate their service with NW Natural using the Company's website. This project will replace and expand on the existing manual entry forms currently found on the Company's website.

Q. Why is the Start-Stop-Transfer Project necessary?

A. The Start-Stop-Transfer Project is necessary to address customer dissatisfaction with the existing web-based interface for modifying their service with NW Natural. Based on the Company's web tracking, in 2022, only 28 percent of initiated forms to start, stop, or transfer service were successfully completed—resulting in approximately 100,000 customers that were unable to complete their service request online. This pattern corresponds to the prevalence of calls into the Company's Customer Care Center ("CCC"), where requests to start, stop, or transfer service constituted the single most common reason for customer calls in 2022. Based on feedback from the CCC team, the Company understands that customers struggle to complete the online forms for a range of reasons, including

(a) difficulty locating relevant account information; (b) confusion regarding which form to use for which circumstance; (c) the need for precise address information to complete a service request; and (d) lack of customer understanding regarding the importance of required information. The new Start-Stop-Transfer Project is designed to address all of these concerns through a new web-based tool, which will also integrate with the Company's back-end CIS.

Q. What are the benefits of the Start-Stop-Transfer Project?

A. The central benefit of the Start-Stop-Transfer Project is that it enables customers to seamlessly initiate, terminate, and relocate their service with NW Natural, at their convenience and without the need to seek assistance by phone. The project improves the customer experience by implementing a user-friendly interface, which includes:

- a simplified road map for customers, along with easy navigation markers;
- clear indicators of required form fields using accessible color coding;
- explanatory "question mark" features to help customers understand the need for required information;
- existing account validation and automatic provision of customer-specific information, such as accounts numbers, when starting a service request;
- a modernized address entry field with assisted entry to reduce customer input errors; and
- increased access to self-service controls for customers renting properties.

Taken together, these new features will help customers control their service at times that are most convenient for them—including when the CCC may not be available. The project is also expected to reduce overall CCC call volume, thus reducing wait times for other customers seeking CCC support.

Q. Were there viable alternatives to Start-Stop-Transfer Project?

A. Yes, NW Natural considered two alternatives to the Start-Stop-Transfer Project described above. **First,** NW Natural considered pursuing an incremental approach, whereby the Company would improve only the address entry field portion of the feature. Based on CCC staff feedback, inaccurate address information has been one barrier to customers successfully using NW Natural's online start-stop-transfer forms, because the existing tool does not auto-propose correct addresses and cannot process a request if the address includes errors. NW Natural therefore evaluated whether to modify only this aspect of the online forms as an incremental improvement. However, the Company concluded that this option was not preferable because (1) it would be more costly in the long term, as each new incremental improvement would require re-engaging an outside vendor, with associated start-up costs, and (2) there was no assurance that the address input improvement alone would significantly improve the customer experience. Given the range of issues described with the existing online forms and the need to bring in outside vendor support, the Company concluded that resolving the other prominent customer complaints simultaneously would best serve customers and would be most cost-effective.

Second, the Company considered automating the start-stop-transfer service forms into the Company's CIS, rather than maintaining a separate web-based system. While this option would have improved integration of the feature with the Company's back-end systems and improved allocation of staff time, it would not have addressed customer concerns with the online, self-service experience.

Q. What is the status of the Start-Stop-Transfer Project?

A. NW Natural recently issued a request for proposals ("RFP") to identify a vendor to develop the Start-Stop-Transfer Project. The Company received several bids and is now in the process of evaluating and finalizing the procurement details. Initial project bids for this project remained in line with the Company's anticipated budget estimates and the project is on-track to be completed by October 2024.

Q. What cost recovery is NW Natural requesting for the Start-Stop-Transfer Project?

A. NW Natural seeks to recover its capital investment of $2.7 million on a system basis, or $2.4 million on an Oregon-allocated basis.

F. Clevest Optimization Project

Q. Please provide some background on the Clevest Optimization Project.

A. Clevest is NW Natural's new mobile workforce management software used to schedule, dispatch and complete all work in the field—ranging from emergency response to routine maintenance work. Clevest replaced NW Natural's previous end-of-life application, PragmaCad ("P-CAD"), and was developed and implemented as part of the Horizon 1 Project. Clevest was fully deployed in 2022 and has since served as NW Natural's mobile workforce management tool.

Q. Please describe the Company's Clevest Optimization Project.

A. The Clevest Optimization Project is an incremental new effort to optimize and improve the Clevest mobile work management system, including (1) resolving post-deployment issues identified in the product's performance ("stabilization") and (2) adding new functionalities that were initially not included but, following the product's launch, turned out to be critical ("optimization"). By expeditiously stabilizing and optimizing the Clevest software, the Company can ensure that the tool continues to provide the best value for the Company and its customers.

Q. Why is post-deployment stabilization necessary?

A. While effective in a testing environment, Clevest proved to have difficulty accommodating the complexity of NW Natural's operations. As a result, when the platform was deployed and used, the Company encountered issues such as slowed response times. For instance, system input requests would have long lag times, often ranging from 3-5 minutes, and even up to 30 minutes. While the system was operable, these significant lag times created delays in work order processing and customer response times. A new dedicated workstream was necessary to address the post-deployment project performance issues.

Q. Why is post-deployment optimization necessary?

A. As part of streamlining NW Natural's IT&S infrastructure, NW Natural initially determined that certain features and functions of the Clevest platform were non-essential and could be deprioritized. For instance, while work orders could be viewed in sequence, the platform did not allow users to view all work orders tied to a certain location. In practice, the absence of these features and functions resulted in dissatisfaction for both field employees and customers. For instance, without the ability to alert a field worker that multiple work requests were scheduled at the same location, multiple visits would be scheduled—resulting in an ineffective allocation of employee time and confusing customers. Based on this feedback from Clevest users, NW Natural identified a list of mission-critical and high-priority functionalities necessary to optimize Clevest's performance.

Q. How did NW Natural initially select Clevest as the Company's mobile work management platform?

A. NW Natural selected Clevest through a competitive solicitation process. The Company retained a third-party consultant, Deloitte, to help design a competitive RFP that would accommodate the Company's various mobile scheduling, dispatch, and work order processing functions. NW Natural then evaluated the different software vendors' proposals based on cost, as well as three operational factors: (1) functionalities offered; (2) ease of use; and (3) integration capability with NW Natural's remaining system. Clevest received the highest score across the operational factors and was also the lowest overall cost option.

In addition to this quantitative analysis, NW Natural also consulted with several other enterprises that successfully implemented the Clevest product. For instance, SoCalGas reported having evaluated dozens of vendor candidates before selecting Clevest, though its project entailed a narrower range of functional uses.

Q. Did NW Natural attempt to avoid and mitigate post-deployment problems in the initial Clevest procurement process?

A. Yes. NW Natural sought to avoid and minimize any development and deployment issues with Clevest by bringing in an implementation expert, Accenture, to help manage the implementation process. NW Natural coordinated meetings with Accenture and the Clevest vendor, including regular meetings with senior leaders and executives at each company. NW Natural also committed a dedicated business lead and project manager to focus on Clevest work, with twice-daily status updates to maintain progress and momentum.

Q. What options did NW Natural consider before proceeding with the Clevest Optimization Project?

A. NW Natural considered four main options before deciding to proceed with the new Clevest Optimization Project: (1) addressing only basic stabilization issues (such as lagging response times), without pursuing further optimizations or enhancements; (2) addressing stabilization issues and a subset of new functionalities deemed mission-critical, but not addressing other priority features; (3) addressing stabilization issues as well as mission-critical and high-priority functionalities and features; and (4) addressing stabilization issues and the full list of all functionalities and features identified by Clevest users. Of these, NW Natural selected the third option.

Q. Why did the Company decide not to restrict its efforts to basic stabilization issues?

A. The Company decided not to restrict the project to minimal stabilization issues for two reasons. **First,** declining to proactively address known gaps in performance would result in ongoing technical debt as known issues accrued over time. **Second,** failing to address the functional issues experienced by Clevest users would have undermined the value of the overall Clevest investment. Addressing mission-critical functionality gaps was essential to ensure NW Natural's successful provision of service and to avoid significant customer dissatisfaction. For instance, due to Clevest's inconsistent performance in assigning fieldwork out into the future, work assignments needed to be manually reviewed each morning to ensure that pre-work had been correctly assigned. By optimizing this functionality, the Company can ensure proper distribution of work among field resources and better meet scheduling commitments to customers.

Q. Why did the Company decide not to pursue only stabilization and mission-critical functionality improvements?

A. The Company decided not to pursue only stabilization and mission-critical functionality improvements because addressing the high-priority issues did not significantly impact the overall project cost. These additional functionality improvements are relatively high-impact, low-effort new features. For instance, as originally implemented, Clevest displayed phone numbers but did not allow these numbers to be copied or clicked to trigger a call. A simple improvement will display phone numbers as hyperlinks, thus allowing the number to be clicked to trigger an outbound call. Similarly, construction crews interfacing with Clevest need to select the type of equipment (e.g., pipe size) required for various projects. However, as deployed, Clevest did not display products in a clearly discernible order and did not allow products to be filtered. New functionality added in the Clevest Optimization Project will present equipment in a more logical order and allow for type-ahead functionality, which quickly highlights the needed equipment for selection. By incorporating these kinds of low-investment features, the Company can facilitate more accurate recordkeeping and enable construction crews to spend less time interacting with the Clevest platform and more time serving customers.

Q. Why did the Company decide not to pursue the full suite of functionality improvements?

A. The Company decided not to pursue the full suite of functionality improvements to include medium- and low-priority features for two reasons: **First,** expanding the project to include medium- and low-priority features would have substantially increased the overall project costs. **Second,** the medium- and low-priority features required additional upgrades to the Clevest software in order to enable the new features. However, such upgrades are not yet available, and would thus have significantly delayed optimizing the Clevest product. Due to these combined cost and delay factors, the Company decided to focus on the mission-critical and high-priority features instead.

Q. Were there additional alternatives that were rejected as not viable at this stage?

A. Yes. NW Natural identified three alternatives to the Clevest Optimization Project but determined they were not viable under the circumstances: (1) accepting the Clevest product without modification or improvement; (2) implementing a new mobile work management option; and (3) reverting to the original P-CAD tool.

Q. Why was it not viable to simply continue to use Clevest as it was deployed?

A. Continuing to rely on Clevest as deployed without any stabilization or optimization was deemed unacceptable due to the significant delays associated with the tool, which made it challenging for field employees and caused delays in processing orders. As deployed, the product also encountered unexpected data access restrictions, extensive user interface demands, and other functionality issues. The Company's mobile work management tool is a key aspect of the Company's day-to-day operations and customer engagement. Declining to address key issues in the product's performance was not an acceptable option.

Q. Why did NW Natural not consider switching to an entirely different mobile work management platform?

A. Following Clevest's deployment, NW Natural did not consider switching to a wholly new mobile work management platform due to concerns regarding cost, delay, lack of clearly preferable alternative tools, and ongoing strengths with Clevest:

- <u>Cost:</u> Any mobile work management platform requires considerable expense to design, develop, deploy, and integrate. Even significant investment in optimizing/enhancing an existing system cannot reasonably compare to the cost of starting the process from scratch with a whole new mobile work management tool.

- Delay: Implementing a new product option would take years to complete. NW Natural is currently using Clevest as the Company's mobile work management tool and requires prompt improvements to the tool's functionality. Identifying and deploying a brand-new tool would require significantly more time without alleviating the immediate need for tool enhancements.
- Alternative Tools: Current market offerings for mobile work management tools are limited. As a result, even if NW Natural sought to identify and implement an alternate vendor's tool, other deployment issues could arise.
- Clevest Usefulness: As designed, Clevest remains a used and useful product and continues to offer the potential for substantially improved user experience over the previous P-CAD tool.

Q. Given the post-deployment issues, why did NW Natural not consider reverting, even temporarily, to the P-CAD tool?

A. Reverting to the previous P-CAD tool was not possible as that tool was already end-of-life. While P-CAD has rolled out a new mobile workforce management system offering, this new system is a wholly new software platform—and its use would thus require the same comprehensive deployment effort described above.

Q. What is the current status of the Clevest Optimization Project?

A. The Clevest Optimization Project is underway and is on track to be complete by October 2024.

Q. What cost recovery is NW Natural requesting for the Clevest Optimization Project in this case?

A. NW Natural seeks to recover its capital investment of approximately $7.5 million on a system basis, or $6.6 million on an Oregon-allocated basis.

G. Identity Governance and Administration Automation Project

Q. Please describe the IGA Automation Project.

A. The IGA Automation Project involves implementing a comprehensive new software solution to track and manage the security access and identity management for Company personnel, particularly during onboarding, transfers, and offboarding. Currently, security access and other privileges are handled manually, with no centralized control point. As a result, there is currently no mechanism to certify that an individual's access to security and other functions has been removed following offboarding or other role changes. By implementing a new IGA automated system, NW Natural aims to increase Company security of both customer and Company data while streamlining the staff management process. Additionally, cloud technologies rely more heavily on identities to protect data and workloads compared to on premises technologies.[2]

[2] National Security Agency, Cybersecurity & Infrastructure Security Agency, "Identity and Access Management Recommended Best Practices for Administrators" (Mar. 21, 2023) available at: https://media.defense.gov/2023/Mar/21/2003183448/-1/-1/0/ESF%20IDENTITY%20AND%20ACCESS%20MANAGEMENT%20RECOMMENDED%20BEST%20PRACTICES%20FOR%20ADMINISTRATORS%20PP-23-0248_508C.PDF.

Q. Why is robust security access and privilege management important?

A. Robust security access and privilege management is essential to ensure that critical information is protected and that no single individual has end-to-end access for key decision-making pathways. Indeed, secure access controls are a key part of complying with the Sarbanes-Oxley Act of 2002. This legislation requires NW Natural and other public companies to implement, among a range of other security-related controls, mechanisms to ensure that unauthorized individuals cannot access sensitive financial information.[3]

Q. Why is a dedicated IGA software solution necessary?

A. A dedicated IGA software solution is necessary to ensure consistent, secure monitoring and control of access and permissions across the Company. To be clear, monitoring and controlling security access and permissions is more complicated than merely turning a switch on or off. **First,** since there are a range of applications with different access points, there is currently no one centralized mechanism to remove security access for a given individual. **Second,** updated access and permissions may also be triggered by changed positions and roles, meaning that maintaining accurate and up-to-date security controls requires nuanced control. **Third,** an individual's access to any given system or piece of information cannot be viewed in isolation, but rather as a complete picture of that individual's security access and permissions across the Company. This visibility

[3] Sarbanes-Oxley Sections 302.2, 404.

is important to ensure that individuals do not have too much access to sensitive information.

Q. Why has the Company not previously implemented an IGA software tool?

A. NW Natural has not previously implemented an automated IGA tool because the Company was endeavoring to maximize the utility of the existing, less costly manual system. Historically, NW Natural has manually removed security and permissions access for departing personnel as part of the offboarding process and has attempted to improve and strengthen this system over time. However, even an enhanced manual system carries greater risk of failure and security gaps than an automated system. NW Natural therefore determined to move forward with identifying and implementing a centralized IGA software tool.

Q. What software system did NW Natural select for the IGA Automation Project and how was this tool selected?

A. The IGA Automation Project is implementing a software system called IdentityNow, developed by a third-party vendor, SailPoint. NW Natural selected SailPoint's IdentityNow tool through a multi-step, multi-factor evaluation process. **First,** the Company collaborated with an independent consultant, Forrester, to establish initial parameters for IGA software and system needs. Forrester also provided a list of possible system integrators, which are third parties with deep subject matter expertise that can help guide the selection and implementation of specific software tools. **Second,** NW Natural conducted a competitive RFP process to select a system integrator, evaluating each for cost-competitiveness and industry experience. This process resulted in NW Natural selecting Integral Partners as the system integrator. **Third,** Integral Partners worked with NW Natural to develop a detailed picture of minimum system requirements for an IGA solution. Integral Partners used this assessment to prepare a scoring system for different IGA solutions, allowing a side-by-side comparison of each option's technical environment, useability, integration capabilities, auditing functions, types of security controls provided, and other key factors. **Fourth,** Integral Partners then scored IGA tools from 18 different vendors to identify a subset of reasonable options for more detailed consideration. This process yielded three software options that the system integrator considered to be reasonably in line with NW Natural's system requirements and operational needs: SailPoint's IdentityNow, SailPoint's IdentityIQ ("IIQ"), and Saviynt's Enterprise Identity Cloud ("EIC"). For each of these options, Integral Partners also provided cost estimates. **Fifth,** NW Natural assessed each of the three options and conducted its own assessment of available alternatives.

Q. Why did NW Natural select SailPoint's IdentityNow?

A. NW Natural selected SailPoint's IdentityNow software tool because it offers the best, most cost-effective solution to serve long-term customer needs. SailPoint's IdentityNow scored the highest in Integral Partners' scoring system, and offers a comprehensive, user-friendly, and secure IGA solution. SailPoint also has a strong vendor reputation and industry recognition, readily integrates with NW Natural's other IT&S systems, and provides good long-term cost-effectiveness.

Q. Was the IdentityNow solution the least-cost long-term option overall?

A. Yes. IdentityNow's annual subscription costs of $250,000 per year were similar to the other IGA options -- which ranged from an estimated $225,000 (for Saviynt's EIC) to $300,000 (for SailPoint's IIQ) per year – while also providing substantially greater alignment to NW Natural's system. The slightly less expensive annual subscription option, Saviynt's EIC, lacked built-in integrations with other applications in NW Natural's IT&S environment, and would therefore have required substantial more investment to integrate and maintain. As a result, accounting for the implementation and maintenance costs, SailPoint's IdentityNow solution presented the most cost-effective long-term option to provide these important security protections for customers.

Q. What is the current status of the IGA Automation Project?

A. The Company is on track to place the IGA Automation Project in service by June 2024.

Q. What cost recovery is NW Natural requesting for the IGA Automation Project in this case?

A. NW Natural seeks to recover its capital investment of approximately $3.0 million on a system basis, or $2.6 million on an Oregon-allocated basis, and $113 thousand in incremental ongoing O&M ($99 thousand Oregon-allocated) for software licensing.

H. Telemetry Refresh Projects

Q. Please describe the Telemetry Refresh Projects.

A. The Telemetry Refresh Projects involve surveying, permitting, and deploying new equipment to the Company's remote monitoring and control sites. NW Natural manages its network of physical systems 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.[4] These telemetry systems include a range of equipment, such as data acquisition receiver transmitters ("DART"), pressure transmitters, actuators, and communications equipment. The specific nature of the telemetry equipment varies by location, depending in part on the site's accessibility, and has historically included radio, leased analog circuits called "4-wire," cellular connections, and other transmission technologies. Of these, 4-wire was the most common legacy solution for receiving telemetry data and sending pipeline control signals. Communication to and from these telemetry sites was then transmitted to multiple centralized locations—including, for instance, 31 telemetry sites that transmitted to the basement of the Company's former headquarters at One Pacific Square ("OPS") in downtown Portland (collectively, "OPS 4-Wire Sites"). The Telemetry Refresh Projects replace decades-old

[4] The term "telemetry" refers to the process of measuring data (such as pressure, speed, or temperature) using electrical devices and transmitting the results to distant stations.

SCADA technologies with modern equipment, organized to reflect different locations' interconnection:

1. OPS 4-Wire Sites: 32 locations;
2. Coburg Ridge Sites: 8 locations;
3. Healy Heights Sites: 7 locations; and
4. The Dalles Sites: 5 locations.

While each of the above projects is crucial, the OPS 4-Wire Sites are prioritized in order to avoid the need to renew the OPS basement site lease. As a result, the Company separately tracks the costs associated with the OPS 4-Wire 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. The Company's legacy 4-wire and DART technology is more than 30 years old and is end-of-life, challenging the telemetry system's reliability and accuracy. 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 the gas pipeline system.

Q. What are the benefits of the Telemetry Refresh Projects?

A. The new telemetry equipment provides fast, accurate, and reliable monitoring and control over NW Natural's distribution system. These lifecycle management upgrades are essential to ensuring the safe and reliable provision of service. In addition to ensuring essential reliability, promptly upgrading the OPS 4-Wire Sites and related DART sites will remove the need to consider further OPS lease extensions.

Q. Were there any viable alternatives to the Telemetry Refresh Projects?

A. No. As I explain above, the existing telemetry equipment was end-of-life and no longer adequately reliable. While the Company examined the possibility of installing portable pressure recorders (instead of new hard-wired systems), this option was not viable because it would not allow for real-time monitoring and control—thus increasing outages and delaying response times. In light of the Company's core reliability duty to customers, portable pressure recorders were excluded as a viable option.

Q. What is the current status of the Telemetry Refresh Projects?

A. The Company is on track to complete the Telemetry Refresh Projects described here by October 2024.

Q. What cost recovery is NW Natural requesting for the Telemetry Refresh Projects in this case?

A. NW Natural seeks to recover its capital investment of approximately $6.8 million on a system basis, or $6.0 million on an Oregon-allocated basis. Of this amount, $4.1 million is associated with the OPS 4-Wire Sites, or $3.6 million Oregon-allocated.

I. Utilities International Planner Re-platform Project

Q. Please describe the UI Planner Re-platform Project.

A. The UI Planner Re-platform Project entails migrating the Company's UI planning system into the cloud. UI Planner is NW Natural's corporate financial and regulatory finance planning system and is also used by most of the Company's utility peers to perform complex, iterative forecasts and problem-solving. The Company's legacy version of UI Planner was first implemented in 2014 and will no longer be supported by the software provider after 2023. In order to continue using the UI Planner software, the system must be re-platformed to the modern cloud-based environment—which also requires integrating UI Planner's new cloud-based software product.

Q. What alternatives did NW Natural consider to re-platforming the UI Planner software?

A. The only available alternative to UI Planner is Excel's manual spreadsheet functionality, which the Company used prior to UI Planner. Thus, the Company considered foregoing the UI Planner re-platform and reverting to Excel. However, this option was not considered to be reasonably viable for several reasons. **First,** Excel does not have the functionality to run complex models, meaning that any forecasting analysis would require sequenced and interrelated model runs that take significantly longer and yield less reliable results. **Second,** Excel requires laborious manual entry that is both error-prone and costly. **Third,** Excel models must still be built, requiring significant up-front and ongoing maintenance labor.

Q. Are there other benefits of re-platforming UI Planner besides maintaining existing functionality?

A. Yes. The new UI product comes with additional benefits not available in the legacy, on-premises model, including significantly faster model run times, greater modeling transparency, and alternative financial statement methods—which are important for GAAP (Generally Accepted Accounting Principles) forecasting.

Q. What is the current status of the UI planner Re-platform Project?

A. The Company is on track to complete the UI planner re-platform project by August 2024.

Q. What cost recovery is NW Natural requesting for the UI Planner Re-platform project in this case?

A. NW Natural seeks to recover its capital investment of approximately $1.8 million on a system basis, or $1.6 million on an Oregon-allocated basis, and $208 thousand in incremental ongoing O&M ($183 thousand Oregon-allocated) for software licensing.

J. PowerPlan Project

Q. Please describe the PowerPlan Project.

A. The PowerPlan Project transitions a key accounting function, known as the capital settlement process, from the Company's existing PowerPlan tool and into the broader SAP ERP system. The capital settlement process tracks costs accumulated under work orders and projects and allocates those costs to various accounts in PowerPlan.

Q. Why is the PowerPlan Project necessary?

A. The PowerPlan Project is necessary because there has been a lack of visibility of information between PowerPlan and SAP, which has proved to be quite problematic. SAP cannot distinguish the settlement charges in PowerPlan from other charges, meaning that SAP's automated reports indicate that total charges on any given capital project net to $0.00—because charges incurred are offset by the returning settlement charge. Additionally, by performing the capital settlement process outside of SAP in PowerPlan, project managers and others have less visibility into the capital settlement process. Without this visibility, project managers and others have less opportunity to detect and correct errors, which has sometimes caused delays in issuing reports. NW Natural has therefore been relying on manual overrides to accurately track the capital settlements process, which is an unsustainably labor-intensive process.

Q. What are the benefits of the PowerPlan Project?

A. By transitioning the Company's capital settlements process to SAP, the PowerPlan Project improves the accuracy of the Company's capital projects tracking and reporting data, enables effective allocation of Company accounting staff time, and provides project managers and others with visibility into the capital settlements process and with detailed cost-allocation information.

Q. Were there viable alternatives to the PowerPlan Project?

A. No. The only other alternative was to continue to use PowerPlan—which, as I have explained, requires cumbersome workarounds and increases the potential of reporting errors for capital project tracking. As a result, maintaining the status quo did not address the Company's core need for a reliable, transparent capital settlements process, and there were no other viable alternative means of providing this function.

Q. What is the status of the PowerPlan Project?

A. The PowerPlan Project is underway and is on track to be placed in service by October 2024.

Q. What cost recovery is NW Natural requesting for the PowerPlan Project?

A. NW Natural seeks to recover its capital investment of $1.7 million on a system-wide basis, or $1.5 million on an Oregon-allocated basis.

K. SAP Treasury Project

Q. Please describe the SAP Treasury Project.

A. The SAP Treasury Project implements an industry-standard software tool to automate and manage the Company's treasury functions—such as financial tracking and payment approval systems. The new tool provides consolidated and comprehensive visibility into the Company's financial risk management using the necessary subset of SAP's "Treasury Track" software functionalities.

Q. Why is the SAP Treasury Project necessary?

A. The SAP Treasury Project is necessary to address the risks and inefficiencies of the Company's existing manual processes. Currently, the Company relies on predominantly manual, Excel-based tools for its treasury processes, including cash-flow tracking (e.g., daily cash position report generation), bank account tracking, and analyzing liquidity needs. These functions are essential for managing financial risk and ensuring the successful functioning of the utility as a whole.

Q. Why is it important to transition away from manual tools for the Company's treasury processes?

A. It is important to transition away from manual tools for two reasons: (1) because they entail significant employee time that could be more effectively allocated; and (2) because manual entry yields less reliable and accurate data. As a result, most peer utilities have already automated treasury functions, such as by using SAP's Treasury Track software.

Q. Did NW Natural consider any alternatives to the SAP Treasury Project for automating the Company's treasury processes?

A. Yes. NW Natural considered two alternatives to the chosen SAP Treasury Project: (1) exploring a non-SAP software solution; and (2) incorporating the full SAP Treasury Track software suite—rather than the selected limited functionalities.

Q. Why did NW Natural choose SAP as the software provider?

A. NW Natural chose to rely on SAP as the software provider because NW Natural's treasury processes must integrate smoothly with the Company's broader enterprise platform and data systems. Since NW Natural recently transitioned to SAP's S/4 HANA platform to provide this underlying enterprise platform, utilizing SAP's Treasury Track software enables smooth integration with NW Natural's data systems and other departments. Additionally, consolidating and streamlining the number of applications and vendors in our portfolio is consistent with NW Natural's broader strategy of simplifying its IT&S portfolio for the benefit of customers.

Q. Why did NW Natural choose not to incorporate the full SAP Treasury Track software suite?

A. NW Natural chose not to take on the full SAP Treasury Track software suite because this comprehensive software bundle provides functions beyond the minimum viable product needed to meet NW Natural's treasury process needs, while increasing overall costs. The full SAP Treasury Track bundle would have included functions such as multi-bank connectivity, market and credit risk modules, and reporting tools that are either unnecessary or already incorporated in other software tools. Given the higher incremental license and implementation costs, NW Natural selected a subset of the SAP Treasury Track functionality instead.

Q. What are the other benefits of the SAP Treasury Project?

A. In addition to addressing risk and non-optimal use of employee time, the SAP Treasury Project will provide a wide array of additional benefits, including: (1) granular visibility into the Company's payment processing; (2) automated bank account tracking; (3) real-time visibility into market interest rate data; and (4) automated development of amortization and interest rate schedules.

Q. What is the current status of the SAP Treasury Project?

A. The Company placed the SAP Treasury Project in service in November 2023.

Q. What cost recovery is NW Natural requesting for the SAP Treasury Project in this case?

A. NW Natural seeks to recover its capital investment of approximately $2.9 million on a system basis, or $2.5 million on an Oregon-allocated basis.

V. <u>IT&S STAFFING NEEDS</u>

Q. What is NW Natural's strategy for IT&S staffing?

A. NW Natural's IT&S staffing strategy supports the provision of safe, secure, and reliable service by ensuring that: (1) critical areas of IT&S are not dependent on a single individual employee; (2) there are adequate staff resources to support essential business and customer support functions; (3) staff have the skillsets to use necessary modern technologies; and (4) staff are equipped to maintain rigorous cybersecurity practices.

Q. Does NW Natural discuss its overall incremental FTE recovery request elsewhere in testimony?

A. Yes. NW Natural's company-wide incremental FTE recovery request is addressed in detail in the Direct Testimony of Tobin F. Davilla (NW Natural/1400, Davilla) and Melinda B. Rogers (NW Natural/1000, Rogers).

Q. Is NW Natural seeking cost recovery for new FTE positions to support IT&S in particular?

A. Yes. NW Natural is seeking cost recovery for eight new IT&S-related FTEs. These FTEs include four application positions, three operational technology positions, and one security position, as shown in Table 1, below:

Table 1

Department	Role
Applications	CIS Senior Developer
Applications	CIS Developer
Applications	CIS System Analyst 1
Applications	CIS System Analyst 2
Operational Technology	IT&S Engineer
Operational Technology	IT&S Engineer
Operational Technology	Applications Engineer 3
Security	Information Security Specialist

Q. Please explain generally the need for four new CIS-related FTEs.

A. These four new CIS-related FTEs are needed to enable the Company to adequately staff H2: Vista. Existing personnel will need to be available to develop, test, and implement H2: Vista, meaning that existing CIS support capacity will be substantially under-resourced. In order to effectively support NW Natural's ongoing CIS needs, new personnel need substantial lead times—between 18 and 24 months—to be educated and integrated. As a result, while the full H2: Vista implementation effort does not begin in 2024, the new FTEs need to be brought on board quickly in order for these individuals to effectively back-fill existing NW Natural personnel during the H2: Vista effort and support reliable customer service.

Q. Please explain the new CIS Senior Developer's role.

A. The CIS Senior Developer will be responsible for technical design, development, and configuration of the NW Natural CIS application and associated third-party tools. The NW Natural CIS Senior Developer will provide full meter-to-cash operational support, including customer service and billing, and contribute to daily CIS development team activities and production support. This position will work closely with the IT management team, system analysts, and IT&S development teams to ensure that the CIS solution effectively supports reliable customer service.

Q. Please explain the new CIS Developer's role.

A. The CIS Developer will be responsible for development and technical configuration of the NW Natural CIS application and associated third-party tools. The NW Natural CIS Developer will provide full meter-to-cash operational production support and contribute to daily CIS development team activities. This position will work closely with the CIS leadership team, system analysts, and IT&S development teams to ensure that the CIS solution effectively supports reliable customer service.

Q. Please explain the new CIS System Analyst 1's role.

A. The CIS System Analyst will be responsible for providing subject matter expertise for the NW Natural CIS application and associated third-party tools. The NW

Natural CIS System Analyst will provide full meter-to-cash operational production support and contribute to daily CIS application team activities, providing testing, documentation, and overall functional knowledge and expertise. This position will work closely with business stakeholders, CIS leadership team, developers, and other IT&S development teams to ensure that the CIS solution effectively supports reliable customer service.

Q. Please explain the new CIS System Analyst 2's role.

A. The CIS System Analyst will be responsible for providing subject matter expertise for the NW Natural CIS application and associated third-party tools. The NW Natural CIS System Analyst will provide full meter-to-cash operational production support and contribute to daily CIS application team activities, providing testing, documentation, and overall functional knowledge and expertise. This position will work closely with business stakeholders, CIS leadership team, developers, and other IT&S development teams to ensure that the CIS solution effectively supports reliable customer service.

Q. Please explain the need for two new IT&S Engineers.

A. Two additional IT&S Engineers are needed to support the remote SCADA telemetry sites that span our entire gas pipeline distribution system. We have commissioned around 40 new remote SCADA telemetry sites along the gas pipeline as a result of the Company's focus on pipeline situational awareness. Supporting this system requires travel to these remote sites to support engineering design, construction, and commissioning activities. The complexity and increase in the number of SCADA telemetry instrumentation that this team is required to support has the existing team of two employees working overtime every week to keep up. Two additional engineers are needed to support Engineering, Gas Control, security directives, 24x7x365 incident support, and life cycle management programs.

Q. Please explain the IT&S Engineer's role.

A. The IT&S Engineer leads, engineers, designs, tests, and commissions field SCADA telemetry instrumentation for the pipeline control systems, in support of gas control operations. They are responsible for the Operation Technology Equipment Life Cycle Management of control equipment and other instrumentation, and they support the electronic technicians. There has been an increased number of new SCADA telemetry sites supporting pressure monitoring, rupture mitigation with remote control capability, and metering, among other initiatives, which requires this addition of another gas management system engineer.

Q. Please explain the new Applications Engineer 3's role.

A. The Application Engineer 3 will be responsible for design, development, and maintenance of OT applications for the pipeline control systems, in support of gas control operations. This position will also be responsible for OT Application Life Cycle Management. The employee will provide 24x7x365 tier one support for gas control. There has been an increased number of new SCADA telemetry sites supporting pressure monitoring, rupture mitigation with remote control capability and metering, among other initiatives, which requires this addition of another gas management system application engineer.

Q. Please explain the need for a new Information Security Specialist position.

A. As I explained above, the IGA Automation Project is implementing a complex application to track and manage the security access and identity management for Company employees and contractors, particularly during onboarding, transfers, and offboarding. This position will maintain and monitor the identity governance administration solution. Further, the employee will design, develop, test, implement, and document the solution to meet program and various project requirements.

VI. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Direct Testimony of Jim R. Downing

TSA PROJECTS
EXHIBIT 800

REDACTED

Subject to Commission's Modified Protective Order, this exhibit is contains SENSITIVE SECURITY INFORMATION and is HIGHLY CONFIDENTIAL in its entirety and has been redacted.

December 29, 2023

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Direct Testimony of Joe S. Karney

METER MODERNIZATION
EXHIBIT 900

December 29, 2023

EXHIBIT 900 – DIRECT TESTIMONY– METER MODERNIZATION

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 Joe S. Karney. I am the Vice President of Engineering and Utility Operations. 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 testimony?

A. The purpose of my testimony is to explain the Company's Meter Modernization Program ("MMP"), including the background and drivers for the MMP, NW Natural's evaluation of technology options, MMP deployment plans, and new employees associated with the MMP. I also describe the Company's cost recovery proposal for the MMP.

Q. Please provide a summary of your testimony.

A. NW Natural has an immediate need to replace portions of its aging metering system, and it is embarking on a multi-year process to replace metering infrastructure nearing end of life, including both Periodic Cause for Change ("PCC") meters, which are meter families that have been tested and are determined to run fast, and failing Encoder Receiver Transmitter ("ERT") devices. The MMP has been designed to maximize cost-efficiency and mitigate long delays in procurement arising from supply chain issues by first depleting NW Natural's existing stock of mechanical meters with ERTs attached, fulfilling existing purchase orders, and then strategically implementing a new metering technology—ultrasonic meters—in select areas that will benefit most from the new technology. Additionally, the current meter reading software requires updating. The four primary components of the MMP are as follows:

1. ERT Replacement: Due to ERTs in the Company's service territory reaching the end of their approximately 20-year battery life, a replacement program is needed for approximately 500,000 ERTs over the coming 4-year period (now through 2027). NW Natural will continue utilizing current technology (500G ERTs).
2. PCC Meter Replacement: As part of the PCC meter replacement program, NW Natural will exhaust the current mechanical meter inventory (including purchase order commitments) and selectively place ultrasonic meters with shutoff capability where they have the potential to improve safety. NW Natural needs to change out approximately 90,000 PCC identified meters over the coming four-year period (now through 2027).
3. FCS replacement with Temetra: The current meter reading software in use, FCS, is being retired by the vendor, Itron, meaning that it will not be supported beyond the coming three- to four-year period. As part of the MMP, we will upgrade to the new technology in order to ensure meter reading continuity and appropriately utilize the ultrasonic meter technology.

4. Ultrasonic meters: NW Natural will gradually begin adding ultrasonic meters to its meter complement. The key reasons for adding ultrasonic meters include: meter diversification and preparing for an eventual transition away from mechanical meters; supply chain issues creating lead times for ultrasonic meters of 30 weeks compared to 85 weeks for mechanical meters; safety related benefits such as shutoff capability; alerts/alarms related to high flow and high temperature; and reduction of ERT purchasing needs due to ultrasonic meters not requiring ERTs.

The Company plans to implement the MMP beginning in 2023 and continuing through 2027.

II. BACKGROUND REGARDING NW NATURAL'S METERING SYSTEM

Q. Please describe NW Natural's existing metering system.

A. NW Natural operates a metering system containing a mix of residential, commercial, and industrial meters. The meters are located on the premises of the customer, and system-wide are a mix of diaphragm, rotary, and turbine meters, which are all mechanical meters.[1]

Q. What types of meters are used for residential customers?

A. For most residential and commercial customers, NW Natural uses primarily mechanical diaphragm meters. These meters use a flexible membrane, or diaphragm, to measure the volume of gas passing through the meter. As gas flows

[1] Although there are other technology options, in the form of ultrasonic meters, there are currently only four ultrasonic meters in service, which are used in commercial applications. Ultrasonic meters are discussed in greater detail in Section III.

through the meter, it causes the diaphragm to flex, which moves a set of gears that drive the mechanical counter. The index displays the amount of gas that has passed through the meter in cubic meters or cubic feet.

Q. How does NW Natural collect usage data from its mechanical meters?

A. For mechanical meters, the meter data is collected and transmitted through the use of an Encoder Receiver Transmitter device, or ERT. ERT devices are lithium battery powered devices that electronically record and transmit metered gas consumption data from meters via radio frequency protocol. The radio frequency signals from these devices are picked up via data receiving devices placed in NW Natural's trucks, which allows the Company to pick up meter readings as the trucks drive by the premises. NW Natural's meter reading system uses automated meter reading ("AMR") technology.

Q. What is the typical life of the lithium battery within the ERT?

A. The lithium battery within an ERT carries a typical life of approximately 20 years. However, the batteries within the ERTs may begin to perform poorly earlier than 20 years—and by year 17 or 18, the failure rate may begin to increase, requiring the Company to plan for replacement several years before the end of the 20-year life.

Q. Does NW Natural have a significant number of ERTs that are approaching the age at which a replacement is required?

A. Yes. As shown in Figure 1 below, many ERTs across our service territory are entering their 18th year post-installation and starting in 2024, there is a significant uptick in ERT change outs required.

Figure 1. End-of-Life ERTs (18-Year Life)

Q. What timing considerations are relevant to replacing end-of-life ERTs?

A. There are three key timing considerations relevant to the replacement of these ERTs: (1) replacing ERTs early enough to avoid malfunction; (2) optimizing ERT replacement on a geographic basis for efficiency; and (3) navigating supply chain issues resulting in procurement delays. Regarding the risk of malfunction, NW Natural needs to be proactive about ERT change outs and begin installations during the 18th year of an ERT's lifespan, as they begin to start failing in meaningful quantities after 17.5 years. Additionally, to optimize ERT replacement on a geographic basis, NW Natural plans to replace ERTs strategically in geographically organized batches across its service territory rather than responding to individual ERT failures as they occur. As a result, the Company will be able to deploy its resources more efficiently. Finally, regarding supply chain issues, the current lead time for the ERTs used by the Company—Itron 500G AMR

ERTs—is approximately 1 year, meaning ERT purchase orders must be made approximately 1.5 to 2 years prior to installation.

Q. In addition to replacing end-of-life ERTs, are there other metering issues driving NW Natural's Meter Modernization Program?

A. Yes. Through routine testing, the Company has identified certain meters requiring a "periodic cause for change."

Q What meters are identified as requiring a "periodic cause for change"?

A. Periodic cause for change meters are meter families that have been tested and are determined to run fast. Because the problem is associated with the family of meters (meters of the same manufacture, model, and vintage), the entire family of meters needs to be replaced.

Q. What does it mean when NW Natural identifies a "fast" meter?

A. A "fast" meter is a meter that inaccurately measures consumption. Instead of capturing the gas volume within the accurate range, the meter is instead producing a number higher than the actual metered volume. NW Natural defines a "fast" meter as one that is reading at 102 percent of the actual metered volume or more.

Q. How does NW Natural define an "accurate" meter?

A. Consistent with NW Natural's tariff Schedule M, "Meter Testing Procedures," for existing meters in service, NW Natural considers an "accurate" meter to be one that captures the metered volume within 2 percentage points from the true metered volume. NW Natural assesses the true metered volume by using a calibrated meter-proving device. As long as the meter is between 98 percent to 102 percent of the true metered volume, NW Natural considers that meter to be "accurate."

However, for all new meters, NW Natural requires the meter be measuring at 99 – 101 percent to be "accurate," and NW Natural rejects meters outside of that range and returns them to the supplier.

Q. How does NW Natural test the accuracy of its meters and identify PCC meters?

A. NW Natural has a Meter Sampling Program[2] to evaluate the accuracy of its in-service diaphragm meters. Each in-service meter is part of a group of meters, referred to as a "family." NW Natural aims to group meters into "families" based on several criteria, one of which is performance records. Families allow NW Natural to pull a random sampling of similarly performing meters to assess a group of similar meters more efficiently.

NW Natural typically groups meter families based on manufacture date or date placed in service. For example, for all meter sets prior to 2020, a family is created based on manufacturer, meter size, meter type, and installation year. For all meters from 2020 onward, a family is created solely based on the meter manufacture date. NW Natural can modify these families based on performance of certain meters to ensure similarly performing meters are in the same family. Similarly, some families have sub-families according to additional criteria. Sub-families permit NW Natural to remove underperforming meters without affecting the performance of the larger family.

[2] NW Natural's Meter Sampling Program is described in its tariff Schedule M – Meter Testing Procedures, pursuant to OAR 860-023-0015(3).

At least once per year, NW Natural takes a random sample from meters in a specific family. Any meter in the family is eligible to be used in the random sample. Meters selected for sampling are removed from service and tested in accordance with the relevant standards, ANSI B109.1 and B109.2 (2000 version). Because the sampling is intended to be an evaluation of working meters, NW Natural excludes data on meters which are damaged, meters which do not register, meters which do not pass gas, and meters that measure either less than 90.0 percent or more than 110.0 percent on the accuracy scale. NW Natural keeps records of and refers to the samples taken from the past five years to make calculations relating to the accuracy of the meter family and whether the meter family should be categorized as “fast” or “not fast.”

Q. What are the criteria for meter replacement?

A. For all meters, NW Natural uses the sampling acquired either through the Meter Sampling Program or per the schedule applicable to that meter type and calculates whether a proportion of 80 percent of the family results in “accurate” readings and at least 90 percent of the family is not “fast.” To make this determination, NW Natural first compares the sampling measurements to threshold levels of a control meter and takes into account the size of the family. Second, NW Natural determines whether the meter family’s performance meets a satisfactory level based on the control standards. Third, NW Natural determines the accuracy of the family, then the proportion of meters that are “not fast.” If the results of these calculations exceed the control, an additional random sample is obtained for families that are more than 10 years old. Based on where the samples fall within the control standards, NW Natural determines whether the sample readings are satisfactory, at or below limits, or insufficient.

Meters in families that are acceptable—or satisfactory—will remain in service and be tested again during the next period for sampling. If a meter family passes the "not fast" test but fails on "accuracy" it is determined to be slow and under-recording usage. NW Natural has the option to remove these meters based on economic and operating factors. NW Natural may also leave the meters in service and continue to test the meters during the next period for sampling. Meters that fail the sampling, are not accurate, and are fast are ripe for being changed out by NW Natural. The performance and status of each meter family is reported to the Commission in the annual Meter Sampling Program Report, which is provided in Docket RG 41.

Q. What is the timeline for replacement of meters identified for change-out?

A. Meters that are identified as needing to be replaced will be changed out by December 31st of the year following the year in which the applicable Meter Sampling Program Report was issued. However, in the case where in any given year the number of meters identified for change-out exceeds 3 percent of the total population of meters in the Meter Sampling Program, NW Natural may extend the timeline so that the meter family is changed within four years from the issuance of the Meter Sampling Program Report.

Q. Has NW Natural filed any regulatory reports detailing the number of meters identified for replacement as part of the Meter Sampling Program?

A. Yes, NW Natural filed its most recent annual Meter Sampling Program Report for 2022 on February 22, 2023, in Docket RG 41. The Meter Sampling Program Report details the number of meters tested and identified for change-out. As detailed in the 2023 Report, 70,251 meters as part of 18 meter families were identified as not conforming to control standards and as needing to be changed out. These meters account for 8.9 percent of the total population, and therefore, they have been placed on a list for removal by December 2026, or four years from the date of the 2022 Meter Sampling Program Report. These meters identified for change-out join the list of 96,231 non-conforming meters identified from 2019 – 2022 that are flagged to be replaced.

Q. How many PCC meters has the Company identified across its service territory?

A. As shown in Figure 2, below, there are almost 90,000 currently identified PCC eligible meters across NW Natural's service territory that must be replaced between 2024 and 2026.

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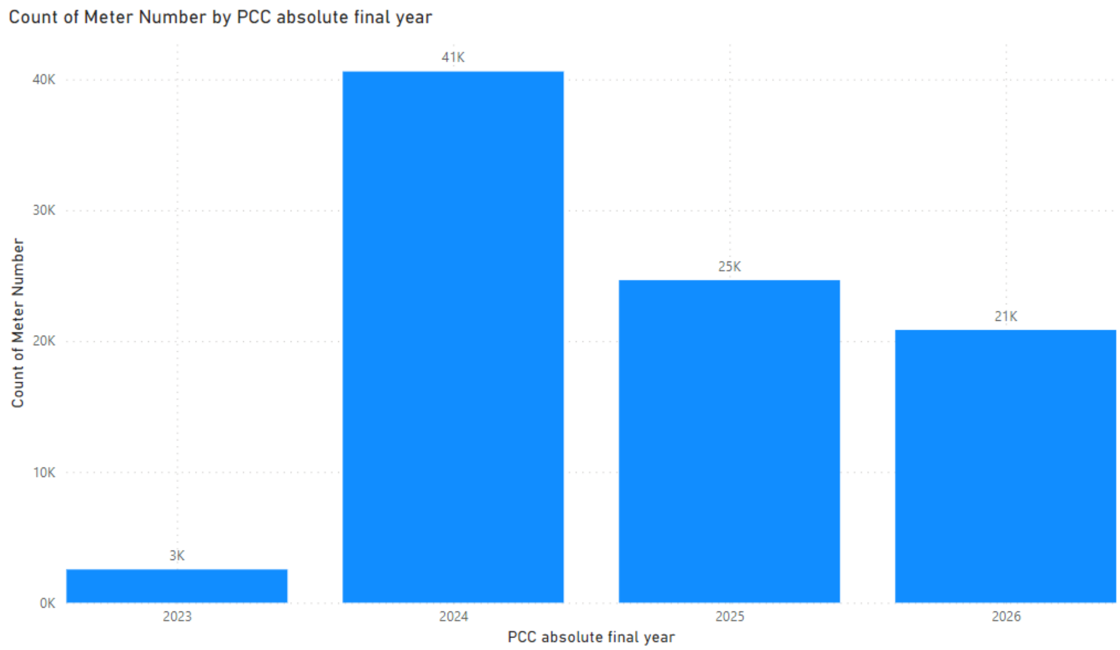
Figure 2. PCC Meters

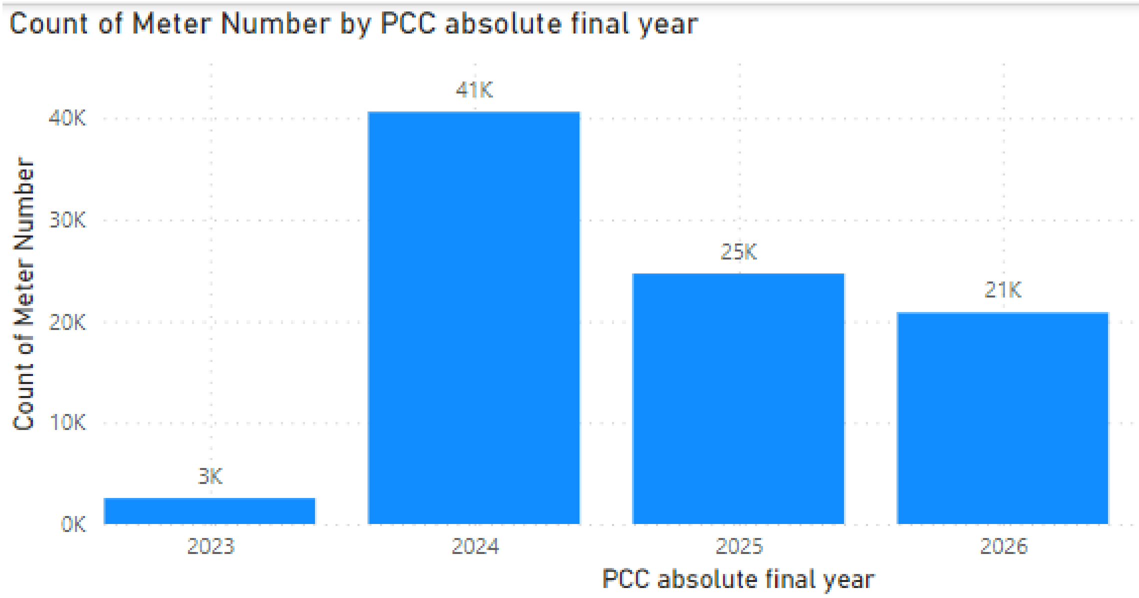


The graphic in Figure 2 depicts PCC figures by the year in which the PCC meters must be replaced (within four years of the date identified) and shows there has been a significant uptick in PCC meters that must be replaced in the next several years.

Q. Is there any overlap among the PCC meters and the meters requiring ERT replacements?

A. Yes. The PCC meters shown above in Figure 2 also fall into the ERT replacement timeline during the 2023 – 2026 years, as shown below in Figure 3. Thus, regardless of PCC status, over 99 percent of these meters would require ERT replacement, independent of being identified as a PCC meter.

Figure 3. Timing for Replacement of PCC Meters Also Requiring ERT Replacement



Q. Beyond the need to replace the end-of-life ERTs and PCC meters, are there other issues that are informing NW Natural's meter modernization strategy?

A. A key issue informing the meter modernization strategy has been the lack of available supply from vendors for both mechanical meters as well as ERTs. The current mechanical meter lead times have stretched to approximately 85 weeks, while ERT lead times are approximately 52-60 weeks. Over the past three years, the warehouse team has expressed concern regarding the possibility of NW Natural entirely depleting its stock of meters during periods of peak supply chain issues—and as a result, the Company has established a minimum safety stock metric of 9,800 meters. In April 2019, meter stock reached a low of around 3,000 meters systemwide. At this inventory level, Sherwood (central warehouse headquarters) did not hold any meters, as any available meters were held at satellite warehouses across the Company's service territory.

Q. Under normal circumstances—meaning without the supply chain issues that have been experienced recently—how quickly does NW Natural replace PCC meters?

A. Prior to 2018, NW Natural would typically determine as eligible for replacement PCC volumes of approximately 5,000 per year and the PCC meters would be replaced in the year after they were identified through the meter sampling process. However, more recently, volumes have been in the 15,000 to 40,000 yearly range for meters that have been identified as part of the PCC sample testing process. The maximum number of meters changed out internally during a one-year period was 26,000 meters during the COVID-19 pandemic as a number of other work orders had ceased due to COVID-19 restrictions. Coupled with supply chain issues, NW Natural has instead targeted a four-year window to change out these meters, as described above.

Q. For meters that are running too fast as determined by the Meter Sampling Program, does NW Natural apply a rate credit to customer bills?

A. Yes. In accordance with the Company's tariff Schedule M, NW Natural provides rate credits to customers whose meters are replaced as determined by the Meter Sampling Program. These credits appear on the customer bill when the meter tests outside the acceptable "accuracy" range. Customers receive these credits from the date NW Natural determined the meter family must be replaced up until the meter is replaced and tested, which could be four years from the date of the Meter Sampling Program Report. Credits are based on the accuracy of the specific meter determined at change out.

Q. Even with the flexibility to make adjustments to customer bills through the Company's Schedule M, why is it important for NW Natural to have fully functional metering equipment?

A. Having fully functional metering equipment is a best utility practice and key to ensuring accurate billing. NW Natural's metering equipment is an essential component of the Company's system, and thus must work properly. We do not think we should delay the replacement program simply because we offer four years of credits. Additionally, while it may be possible to make billing adjustments to account for a meter running fast or slow, if the ERT is at end-of-life, that means that there is no way for the Company to obtain data from the meter without replacing the ERT.

Q. Are there other aspects of NW Natural's metering system that require updating?

A. Yes. The Company's current meter reading technology (FCS) is set to be removed from service by the vendor, Itron. In order to ensure the Company can retain a functional meter reading system, the Company must implement a new software solution (Temetra).

III. <u>ULTRASONIC METERS</u>

Q. Is NW Natural's current system primarily comprised of mechanical meters?

A. Yes—as shown in Figure 4, below, the vast majority of NW Natural's Oregon meter system across all customer classes is comprised of mechanical meters, which include diaphragm, rotary, and turbine meters.

Figure 4. Oregon Meter Types by Customer Class

OREGON ONLY		
Customer Class	**Meter Type**	**Count**
Residential	Diaphragm	630910
	Rotary	47
Commercial	Diaphragm	57369
	Rotary	4939
	Turbine	6
	Ultrasonic	4
Industrial	Diaphragm	215
	Rotary	818
	Turbine	10
		694318

Q. What other technology options are available for NW Natural's metering system?

A. Ultrasonic meters use a metering technology option that has been available on the U.S. market since the 1980s and was initially used primarily in industrial applications but has not been widely adopted for residential application until recently. Many utilities in the U.S. are moving toward the use of ultrasonic meters as they need to replace meters on their system, and although NW Natural currently only has four ultrasonic meters in place on its Oregon system as shown in Figure 4, above, NW Natural expects to further integrate this technology into its metering system in the coming years. In particular, Southwest Gas, CenterPoint, Spire, NiSource, Northwestern Energy, and Dominion are using ultrasonic metering technology.

Q. How do ultrasonic meters measure the flow of gas?

A. Ultrasonic meters use sound waves to measure gas flow. Specifically, ultrasonic sound waves are transmitted through the gas flowing through the meter and then the measurement is produced by recording the time it takes for the sound waves to travel between two transducers placed in the pipe. The difference in the time it takes for the sound waves to travel upstream and downstream gives an accurate measurement of the gas flow rate.

Q. How is the ultrasonic meter different from the mechanical meter?

A. While a diaphragm gas meter uses mechanical components to measure the flow of gas, an ultrasonic gas meter uses non-invasive sound waves to make its measurements. As a result, ultrasonic gas meters are generally more accurate and have fewer moving parts, which means they require less maintenance. Additionally, ultrasonic gas meters are suitable for a wider range of applications, including corrosive or dirty gas environments, where mechanical meters may be less reliable. Ultrasonic meters also have a number of operational and safety benefits in comparison with mechanical meters. The Itron Intelis meters have been tested with renewable natural gas and hydrogen blends preparing NW Natural for a higher capacity of blended gas flowing through to customers.

Q. Do ultrasonic meters require the use of an external 500G ERT?

A. No. The recording and transmitting equipment is included as an integral component of the ultrasonic meters, and thus these meters do not require the use of an external ERT (as the ERT is embedded within the meter) to enable the collection and transmission of usage data.

Q. How do ultrasonic meters transmit data?

A. Ultrasonic meters are designed to use either radio frequency or cellular technology to transmit meter data. At this time, the cellular ultrasonic meters are not yet in production, though they are expected to begin to be produced in 2024.

Q. Are the ultrasonic meters compatible with NW Natural's data collection system?

A. Yes, the Company expects that ultrasonic meters will integrate seamlessly with Temetra, the Company's new system for collecting customer usage data. The Itron Intelis in AMR mode can integrate with the current meter reading system (FCS) and will be installed once the Company receives supply from Itron in the first quarter of 2024.

Q. What are the safety-related benefits associated with ultrasonic meters?

A. Ultrasonic meters include the following features that are not available through mechanical meters:

- Automatic high temperature and high flow shut off;
- Additional tamper alarms (examples: air in pipe, valve status, communication error); and
- 70 percent smaller in size, a lighter meter size for reduced field worker injuries.

Q. Please describe the operational benefits of ultrasonic meters.

A. Ultrasonic meters provide measures to a higher degree of precision and are less likely to drift and require re-calibration. The meters also contain self-diagnostic equipment, and their electronic design enables some self-diagnosis. The ultrasonic meters are also approximately 70 percent smaller than the mechanical meters, which allows more flexibility in storage and shipping of meters as well as our ability to optimize our multi-family installs with smaller meter sets.

Additionally, it is easier to forecast end of life for ultrasonic meters because there is only one device (the ultrasonic meter) rather than two devices (mechanical meter and ERT), and when those meters reach end-of-life, ultrasonic meters are less complex than mechanical meters, and thus allow for easier and faster meter change outs.

Q. What is the typical life span for an ultrasonic meter?

A. The typical life span of an Itron Intelis meter is 20 years.

Q. What is the cost difference at between a mechanical meter and an ultrasonic meter?

A. In March 2023, at the time NW Natural was performing its analysis in support of the MMP, a mechanical meter with an ERT was approximately $164 per unit, and an ultrasonic meter with radio frequency (AMR) capabilities was $200 per unit.

Q. Do the ultrasonic meters have similar supply chain issues as the mechanical meters?

A. While there are supply chain issues for ultrasonic meters, the delays are not as long in comparison with mechanical meters. There is currently an approximate 30-week lead time for ultrasonic AMR meters, as compared to an 85-week lead time for mechanical meters. Additionally, as manufacturers are adding capacity to ultrasonic gas meter supply faster than they are to the mechanical meter supply, NW Natural expects that the supply chain issues for ultrasonic meters will further abate and will not be as problematic as for mechanical meters.

IV. OVERVIEW OF MMP

Q. What is NW Natural's Meter Modernization Program, or MMP?

A. NW Natural is initiating a multi-year process to replace end-of-life ERTs and PCC meters. The MMP has been designed to maximize cost-efficiency and mitigate supply chain issues by first depleting NW Natural's existing stock of mechanical meters with ERTs attached, fulfilling existing purchase orders, and then strategically implementing a new metering technology—ultrasonic meters—in select areas that will benefit most from the new technology. The MMP will help modernize and maintain our current metering system, including maintenance of our existing assets, enable the integration of a more diverse meter complement and facilitate an expanded array of backhaul options into our billing system. This new complement will help us alleviate supply chain challenges and leave us in a less homogenized metering position.

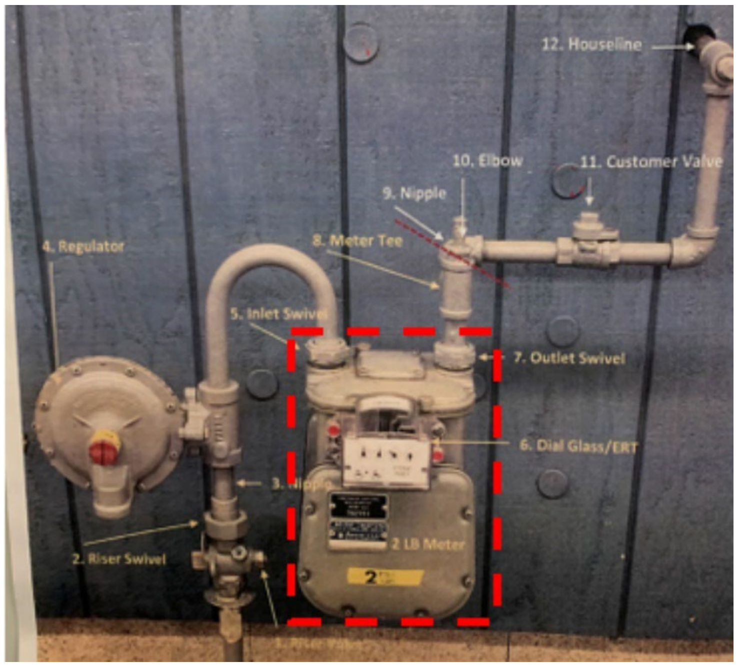
Q. What components of a meter will be replaced under the PCC program versus the ERT replacement program?

A. Figure 5, below, shows the components of a mechanical meter. The MMP includes both the meter and ERT device as outlined in the red dashed box in Figure 5.

- **Meter Replacement.** When a meter is changed out, the entire meter and ERT is removed and replaced with a new meter and ERT combination or an ultrasonic meter (containing communication device built in).

- **ERT Replacement.** An ERT change out does not impact the meter itself; instead, the plastic ERT covering is removed and the ERT device gets removed for recycling.

Figure 5. Photograph of Mechanical Meter



Q. How long has NW Natural been planning ERT replacements?

A. The Company initiated planning for the replacement of ERTs in 2019. NW Natural's current meter data collection solutions are approaching end of life. NW Natural worked with contract subject matter experts to produce a comprehensive strategy designed to assist NW Natural in the alignment of the wide variety of business and technological needs that must be addressed over the next five years. The output of this strategic recommendation requires a series of diverse and complex projects that will have numerous interdependencies. This strategy requires integrated technical designs, impacts a large number of business stakeholders, and requires coordinated communications to our impacted customers and our regulators as well as capital funding coordination.

Q. Did NW Natural's plans for the MMP change over time?

A. Yes. Prior to the MMP, NW Natural initially developed a plan for the replacement of ERTs that would include the installation of an advanced metering infrastructure ("AMI") Mesh Network and would be deployed over the timeframe 2020-2049. At the outset of the COVID-19 pandemic, NW Natural put its planning for the ERT replacements on hold, and then in 2022 reinitiated planning. This pause provided NW Natural an opportunity to reassess the project, which led to two significant changes in project scope, ultimately resulting in lower costs to customers. Specifically, NW Natural reevaluated the prior decision to use AMI technology, and NW Natural combined the ERT replacement project with the PCC replacement project to capture operational efficiencies. Those two decisions were the foundation of the current MMP.

Q. Please describe NW Natural's reevaluation of AMR and AMI technologies.

A. NW Natural studied scenarios including AMR and ultrasonic, AMI (network), and AMI (cellular). NW Natural has used AMR technology for nearly 20 years. AMR eliminated the need for manual meter reading (physical visits to the meter to record gas usage) by transmitting usage through a radio frequency signal. Trucks are rolled across NW Natural's service territory with data collector devices that pick up the radio frequency signal being transmitted from the AMR ERTs. In an AMI system, these truck rolls would not be needed for meter reading as the usage can be backhauled via cellular transmission, through a mesh network, or through cellular enabled access points. Ultimately, as described below, an AMR system is a lower cost than other solutions and provides NW Natural with the necessary data required for billing.

Q. Why did NW Natural decide to combine the PCC meter replacement program with the ERT replacement program to create the MMP?

A. As noted above, the combination of these two programs created operational efficiencies, resulting in lower costs to customers. The PCC meter replacement program is a daily operational activity requiring the change out of meters across the Company's service territory. The ERT replacement program is also a daily operational activity centered around replacing end-of-life ERTs with replacement ERTs. Each of these two projects requires a visit to the premise with an asset replacement of either the meter, the ERT, or both. During NW Natural's strategic planning for each of these projects, we calculated an approximate $10 million cost reduction by combining these two projects into the MMP, reducing the need to touch a meter premise twice for one customer.

Q. What were the estimated costs of the MMP associated with the different ERT technologies?

A. For the AMR and ultrasonic technologies, the estimated costs ranged from $90-120 million; for the AMI (network) technology, the estimated costs ranged from $150-180 million; and for the AMI (cellular) technology, the estimated costs ranged from $160-190 million.

Q. Why is NW Natural initiating the MMP at this time?

A. NW Natural has an immediate need to replace ERTs nearing the end of their useful lives, and to replace PCC meters. Critically, this a multi-year project, and due to the age of the ERTs and the number of ERTs that are reaching end-of-life in 2024, work must begin on this project. The resources for this project need to be onboarded in the third quarter of 2023, while the field work to be performed by the external installation vendor is expected to commence in the first quarter of 2024.

Q. You had previously mentioned that the four key elements of the MMP include the replacement of PCC meters, gradual transition to ultrasonic meters, replacement of end-of-life ERTs, and installation of the new software system. Please elaborate on the Company's decision-making regarding the selection of these resources.

A. In the testimony that follows, I will describe the selection of the ERTs, meters (including exhausting existing inventory and integration of ultrasonic meters), and software, in turn.

A. Selection of ERTs used in MMP

Q. What ERT technologies are currently available?

A. In general, there are three types of ERTs available for purchase at present, as shown in Table 1, below.

Table 1. Available ERT Technologies

	AMR – Radio Frequency	AMI –Mesh Network	AMI – Cellular
500G	Current technology. Read through radio frequency drive by reads.	Read through a network of end points. NW Natural considered with solar powered access points	Read through cellular backhaul via sim card within the ERT

Q. Why did the Company select the 500G AMR ERT technology?

A. NW Natural has been using the 500G AMR ERTs since 2019, which are capable of storing 40 days of hourly data and more interval data. We selected this technology as the least cost option and because it allows for maintaining billing functionality. In order to ensure we received a fair and reasonable quote for ERTs, we issued a request for information for ERTs to five ERT vendors (Honeywell, Landis & Gyr, Itron, Sensus, Aclara). A decision was made to choose Itron for ERT purchases due to the reasonable price and ease of software integration.

B. Selection of Meters Used in MMP

Q. What meter technology options are currently available?

A. As shown in Table 2 below, the two primary technology options are mechanical and ultrasonic, with variations in AMI and AMR meter reading capabilities. As discussed above, the current technology used by NW Natural is mechanical meters with AMR that allows for radio frequency drive-by reads.

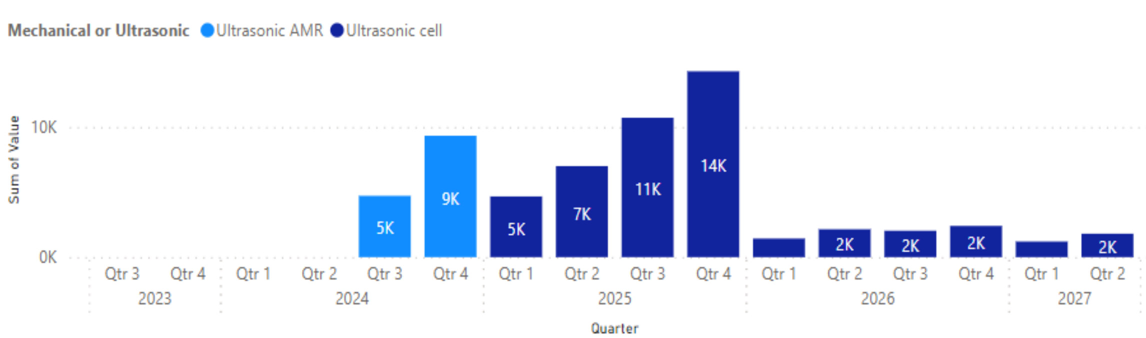
Table 2. Available Meter Technologies

	AMR – Radio Frequency	AMI – Radio Frequency	AMI – Mesh Network	AMI – Cellular
Mechanical	Mechanical (AMR – Radio Frequency)	Mechanical (AMI – Radio Frequency)	Mechanical (AMI – Mesh network) – with 500G mesh network ERTs and solar power access points	Mechanical (AMI – cellular) – with 500G cellular ERTs
Ultrasonic	Ultrasonic (AMR – Radio Frequency)	Ultrasonic (AMI – Radio Frequency)		Ultrasonic (AMI – Cellular) – embedded communication device with cellular backhaul capability

Q. What technology did NW Natural select for the MMP?

A. NW Natural plans to replace the PCC meters with 50,000 mechanical and 50,000 ultrasonic meters—and of the ultrasonic meters, 15,000 will use AMR and 35,000 will use cellular technology as shown in Figure 6 below. As ultrasonic cellular meters are not currently available for purchase, this figure relies on the Itron product roadmap.

Figure 6. Ultrasonic Meter Deployment (dependent on Itron supply)



Q. How did NW Natural decide to use a combination of mechanical meters and ultrasonic meters in the MMP?

A. NW Natural carries approximately 30,000 mechanical meters at our warehouse within inventory at present. We have currently committed to firm purchase orders for an additional 20,000 meters from two separate vendors, and we will continue to replace mechanical meters with replacement mechanical meters in the short-term. As part of our meter diversity efforts, we are planning to diversify away from the exclusive use of mechanical meters. Additionally, the industry appears to be adding capacity for the manufacturing of ultrasonic meters, while moving away from mechanical meters. In fact, our current ERT supplier, Itron, made mechanical meters but has since stopped production to focus on ultrasonic meters. The additional safety and operational benefits provided by ultrasonic meters contributed to our decision to begin purchasing these meters. We need to ensure we are moving where the industry is moving so our hardware does not become obsolete with regards to replacement.

Q. In light of the changes in the industry toward the adoption of ultrasonic meters, did NW Natural evaluate a fully ultrasonic MMP?

A. Yes, early in the MMP study process, in 2019, the Company modeled a budget for a scenario with ultrasonic meters—and even considered replacing our entire meter population in the short-term (800,000 meters) with ultrasonic meters. The Company ultimately determined that the approach of replacing the entire meter population with ultrasonic meters over a short period of time would be far too burdensome on our customers. The Company also believes that there will be benefits in moving towards ultrasonic meters gradually over a longer time horizon and will ensure we are providing the best possible service at an appropriate cost. Importantly, the plan to use a combination of ultrasonic meters and mechanical meters will allow the Company to make use of its existing inventory and committed contracts while taking steps towards diversifying its metering system.

Q. Why is NW Natural including ultrasonic meters in the MMP instead of simply replacing the PCC meters entirely with mechanical meters?

A. The key reasons for including ultrasonic meters include additional meter diversity, supply chain issue curtailment, safety related benefits, and operational improvements.

Q. Please elaborate on the meter diversity rationale.

A. Diversifying beyond mechanical meters supports meter diversity amongst NW Natural's meter population. This is particularly important because the large volumes of PCCs we have been seeing since 2018 have a direct correlation with purchasing and installing large populations of the same meter families at the same time. By diversifying our meter complement, we protect ourselves in this way from what happens if we only have one or two types of meters and they have issues.

Q. Did NW Natural consider any other alternatives in light of the supply chain issues?

A. Due to the significant lead times associated with acquiring meters, NW Natural considered purchasing refurbished meters under a worst-case scenario. However, the refurbished meters have approximately 52-week long lead times, and thus do not mitigate the supply chain issues. Moreover, refurbished meters may be a costlier alternative due to their shorter lifespan and additional expense required in the event the refurbished meter needs to be promptly replaced.

C. Selection of Software to be Implemented in MMP

Q. Please describe the software updates that are included as part of the MMP.

A. As detailed above, the current meter reading technology will become obsolete within the next five years. Accordingly, the Company is updating to Temetra, which is supported by the vendor Itron and will continue to be supported for the foreseeable future.

Q. What are the primary features provided by Temetra?

A. Temetra supports meter reading for drive-by and cellular enabled devices, and with certain meter types (ultrasonic meters) provides capability for over-the-air upgrades and for remote disconnection using cellular connection. An additional benefit of the Temetra system is that the user experience for internal field force will not be significantly impacted.

Q. Did the Company consider alternatives to updating to Temetra?

A. Yes. The Company also considered UIQ, which is an alternative service offering for Itron. UIQ provides an architectural pattern that supports the ability to diversify the ultrasonic meter population, meaning that different types of meters could be incorporated into the system, whereas Temetra supports only Itron meters. UIQ also supports internet of things devices (such as nest thermostats, etc.) and third-party services, such as cathodic protection and methane detection. Finally, UIQ supports integration with an Itron-enabled mesh network (with solar powered battery access points). However, UIQ is significantly more expensive than Temetra and is not a necessary system at present.

Q. What is the cost of Temetra in comparison with UIQ?

A. Temetra costs approximately $250,000, whereas UIQ would cost $2.5 million annually with increased implementation costs compared to Temetra. As a result of this, and the lack of needing a more complicated head-end system in the near-term, we decided to implement the lower cost option for meter reading software, replacing the end-of-life FCS system.

Q. After deploying Temetra, are there additional software modifications needed to accommodate ultrasonic meters?

A. No. For the ultrasonic AMR meters that are installed, they will be compatible with the Company's current AMR-meter reading technology until the system is replaced. The vendor for the current system, Itron, stated they will be discontinuing the system used by the Company for meter reading, which will be replaced by Temetra. The installation of Temetra will be needed to accommodate ultrasonic cellular meters. In sum, the update to Temetra will accommodate both the AMR and cellular ultrasonic meters.

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D. Consideration of Calibration Factor

Q. You mentioned that NW Natural is currently applying a rate credit to adjust customer bills for meters in the PCC category. Did NW Natural consider continuing to apply a rate credit for an extended period instead of procuring additional meters?

A. Yes, NW Natural considered that option, however, the Company ruled it out because the ERTs would eventually fail in the PCC meters—and in particular, nearly 99 percent of the PCC meters have also been identified as requiring a new ERT. Because it would not be possible to apply a rate credit if the ERT is not functioning at all, NW Natural determined that moving forward with replacing the PCC meters would be the best course of action.

Q. In Docket UG 461, Avista recently proposed the use of a calibration adjustment instead of replacing its fast meters.[3] What is a calibration adjustment?

A. A calibration adjustment can be performed by conducting an analysis designed to measure the "drift" of the meter family—or how far off the meters within a particular family are from an accurate reading. The meters within the family can then be "adjusted" for the calibration factor for purposes of invoicing.

[3] *In the Matter of Avista Corp., dba Avista, Request for a General Rate Revision,* Docket No. UG 461, Avista/1100, Webb/13 (Mar. 1, 2023).

Q. Did Staff support Avista's proposal to use a calibration adjustment rather than replacing the meters that are not properly functioning and have begun to drift?

A. No. Staff raised a number of concerns about Avista's proposal, noting that it was not clear how Avista calculates its adjustment, the adjustment is not transparent to customers, the defective meters are left in the field, the calibration adjustment is applied to the entire meter family, and Avista's meter testing may be inadequate and inconsistent with Commission rules.[4] Staff recommended denying Avista's proposal to use the calibration adjustment, requiring Avista to bring its testing program into compliance, and filing annual reports on Avista's meter testing program for 15 years.[5]

Q. How was this issue resolved in the Avista case?

A. The parties in the Avista proceeding ultimately settled this issue in their Second Stipulation, which provided that Avista would replace Oregon meters using the calibration adjustment as soon as practicable, but no later than 2028, make modifications to its meter testing program, use best efforts to pursue recovery of meter costs through applicable warranties, and annually file the results of its meter testing program.[6]

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[4] *In the Matter of Avista Corp., dba Avista, Request for a General Rate Revision,* Docket No. UG 461, Staff/1300, Nottingham-Shearer-Stevens/11 -13 (July 7, 2023).

[5] *Id*. at 14.

[6] *In the Matter of Avista Corp., dba Avista, Request for a General Rate Revision,* Docket No. UG 461, Second Stipulation at 11-12 (Aug. 3, 2023) (approved in Order No. 23-384, (Oct. 26, 2023)).

Q. Did NW Natural consider applying a calibration adjustment instead of replacing its PCC eligible meters?

A. No. Due to the overlap with the PCC-eligible meters and the end-of-life ERTs, NW Natural would not be able apply a calibration factor. As explained above, if the ERT fails, the Company cannot record usage data at all, and thus would not be able to correct usage via a calibration adjustment. Additionally, applying a calibration factor on a meter-by-meter basis tends to be resource intensive. With NW Natural's resource constraints, the burden of continually calculating an appropriate calibration factor would require additional resources. Finally, given the scale and scope of the Company's meter update needs, the Company concluded that replacing its PCC-eligible meters will provide a more durable solution than a calibration adjustment.

E. FTEs Required for the MMP

Q. Will additional employee resources be required to implement the MMP?

A. Yes. NW Natural will need significant resources to complete the MMP. Three of these resources will be incremental NW Natural full-time employees. The majority of the resources are not proposed to be recovered in base rates because they are short-term contractors that we do not intend to keep beyond the duration of the MMP. I will address the full-time employees here.

Q. Please describe the additional full-time resources for the MMP.

A. The three positions are:

1. Itron Applications Suite Application Engineer 2: Because the MMP scope includes implementing new hardware and software from Itron, it is

necessary to add a fully dedicated resource to manage the Itron suite of applications that will continue to grow in complexity as the MMP onboards new metering types. This role will maintain all metering-related technology and is responsible for technical configuration and application administration of Itron-related apps (Temetra, Temetra Mobile).

2. Metering and Network System Engineer: The MMP requires a fully dedicated resource to monitor and manage the future and expanding AMI network. This role will work closely with the Metering Business Lead and Itron Applications Suite Application Engineer 2 to support the modernization of the gas network. This role will monitor performance of the overall system, identify risks/issues, and mitigate them accordingly.

3. Metering Business Lead: This role is responsible for the MMP and all related/dependent projects or workstreams, supporting long-term MMP strategy, managing scope, budget, and program outcomes, and ensuring integration with other critical transformation programs such as H2: Vista.

Q. What is the status of these roles?

A. Two of these positions are currently in active recruitment, and the third position has been filled by an internal employee and that person's prior position has been backfilled.

V. MMP DEPLOYMENT

Q. What steps have been taken to procure the ERT hardware?

A. As discussed above, the Company will use 500G ERTs to replace ERTs with end-of-life batteries. The Company executed a $28.8 million agreement with Itron on

December 31, 2022 to facilitate hardware purchases over the coming 5-year period. Entering into the agreement with Itron was intended to support supply and reduce constraints. The Company expects to deploy approximately 400,000 500G AMR ERTs that will be supplied by Itron.

Q. What steps have been taken to procure the meter hardware?

A. The Company will deplete its existing supply of meters and will also purchase new meters (a combination of both mechanical and ultrasonic) to replace PCC-eligible meters. NW Natural has an outstanding purchase order for 15,000 ultrasonic AMR meters in addition to Sensus and Honeywell mechanical meter purchase orders totaling approximately 15,000 meters. The Company expects to deploy:

- Approximately, 40,000 mechanical meters with ERTs attached;
- Approximately, 50,000 ultrasonic meters in AMR and cellular mode (to be supplied by Itron).

Q. How does NW Natural plan to roll out the MMP?

A. The installations will be divided into 6 distinct batches based on proximity and ERT battery failure date, with a preliminary Batch 0 to be completed by internal field force. The first and second batches will focus on urban areas that will not benefit as much from ultrasonic cellular meters (Eugene, Corvallis). Rural and coastal areas will be the focus of the third and fourth batches to account for Itron's ultrasonic cellular production timeline. The last two batches will be focused solely on installing new ERTs and PCCs in the Portland Metro area.

Q. Why are rural and coastal areas targeted for ultrasonic cellular meters?

A. The more remote areas of the Company's system are harder to reach for the Company's field operations force, and thus will benefit most from the additional safety benefits of the ultrasonic meters. In particular, these areas will benefit from the high temperature / high flow automatic shutoff, and remote shut off capability in the event of wildfires or tsunamis.

Q. Who will deploy the MMP?

A. The program team will use an external installation vendor to deploy the majority of ERTs in the field and approximately half of the PCC meters. NW Natural used a request for proposals ("RFP") to identify the installation vendor.

Q. Please describe the RFP process and the results of the RFP.

A. In March 2023, NW Natural issued an RFP requesting support for installation services for meters and ERTs. We identified three targeted vendors after a rigorous process to vet potential vendors considering safety metrics, diversity scores, and ability to deliver on the work requested. NW Natural sent the RFP to three vendors, namely Sparus Holdings (Southern Cross Inc.) and two other vendors. One of those two vendors declined to bid due to their lack of comfort and expertise with the type of installs requested. The other one of those two vendors declined to bid due to conflicted timing on other projects. The bid received from Sparus Holdings (through their subsidiary Southern Cross Inc.) came in below forecast spend. Through our analysis of Southern Cross, we confirmed that their previous credentials are in-line with the work we have asked them to complete.

Q. What is the expected timing of the costs to update meter hardware?

A. The majority of ERT battery failures are expected between 2024 and 2027 and, as such, require the MMP infrastructure to perform change outs at such scale. Additionally, there are estimated PCC meters that may be identified during the period of the MMP that are beyond currently modeled financial estimates. Per the NW Natural engineering team, there may be an additional 30,000 meters that are identified as PCC eligible during the 2023 – 2027 period.

VI. COST RECOVERY PROPOSAL

Q. How is the Company seeking to recover the costs of the MMP?

A. The MMP is a very sizeable project for NW Natural. The total capital cost of the project, on a system basis, is approximately $83.9 million. As discussed previously, this is a four-year project and we expect to recover the capital investments and ongoing O&M through rate cases. In this rate case, we are proposing to recover the capital investments for the period beginning at the start of the project through the forward test year, which ends October 31, 2025. On an Oregon allocated basis, the capital investment is $69.2 million. In following rate cases, the Company will recover the remainder of the capital investments to complete the MMP.

Q. Is the MMP similar to a traditional capital project from a cost recovery perspective?

A. No. There are two main differences between the MMP and traditional capital projects. The first difference is that the MMP has significant structural lag associated with the timing of the daily installations. For most of NW Natural's major capital projects, the work is performed during the summer construction season, and the projects are placed in service in the fall, prior to the winter heating season, which aligns with our typical rate effective date of November 1. The timing of the construction work with the regulatory proceeding thus minimizes the amount of regulatory lag that the Company experiences for these projects. The MMP, on the other hand, involves daily installation of meters and ERTs over a four-year period. After installation, the meters and ERTs are used and useful, but the Company will experience significantly more lag on recovery due to the daily deployment of the MMP. This type of project can drive the need for annual rate cases, but can also be addressed through multi-year rate plans as described in the Direct Testimony of Justin B. Palfreyman and Zachary D. Kravitz (NW Natural/100, Palfreyman-Kravitz).

The second difference is that the MMP has a significant amount of non-routine, one-time O&M expense associated with the deployment of the MMP. In other words, there are several key aspects of the project that cannot be capitalized and result in lumpy O&M expense increases over a short period. These costs are not appropriate to be included in base rates, however, because we know that the costs will immediately drop off at the conclusion of the project and, consequently, would result in the Company unnecessarily over-recovering its costs at that time. For these reasons, NW Natural is deferring these one-time costs for later recovery.

Q. Has the Company made any other regulatory filings concerning cost recovery for the MMP?

A. Yes, as detailed above, the MMP will involve a significant amount of limited duration O&M expense incurred over the four-year term of the project. Because the O&M expense will only be incurred during the term of the MMP and will include an initial ramp up at the beginning of the project and a ramp down at the end of the project, the Company does not propose building this O&M expense into rates. Instead, concurrent with the filing of this case, the Company filed a request for a deferral for the one-time O&M expense incurred for the limited duration of this project, which NW Natural estimates will be approximately $14.2 million. NW Natural expects that it will seek reauthorization of the deferral over the four-year term of the project.

Q. What is included as O&M expense in the deferral?

A. The preliminary estimate for Oregon-allocated costs that cannot be capitalized and are included within the O&M deferral include the following categories:

i) Meter and ERT replacement: $5.0 million. Southern Cross' installation labor costs for approximately 30 field-techs and supporting positions working across NW Natural's service territory to replace PCC meters and end-of-life ERTs.

ii) ERT and PCC Hardware Recycling: $2.6 million: 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.

iii) Incremental Non-field Labor: $4.1 million: Includes incremental resource costs (non-field) to support the MMP. These positions will provide support in customer call support with increased customer touch points, scheduling support, billing support, internal 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 four-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.

iv) Other external expenses: $0.54 million. Includes bill inserts and door hangers related to the socialization of MMP to our customer base. Due to the increased presence of field workers during the four-year deployment, we will need to inform customers of the reasoning for trucks and field technicians being in their neighborhoods.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Direct Testimony of Melinda B. Rogers

COMPENSATION & BENEFITS
EXHIBIT 1000

REDACTED

December 29, 2023

EXHIBIT 1000 – DIRECT TESTIMONY– COMPENSATION & BENEFITS

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 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 2024 through October 2025 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 2023, 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 contract. As with any labor negotiations, trade-offs are negotiated for other terms and conditions in the contract.

Q. What is the current status of the contract for BU employees?

A. The current contract for BU employees is set to expire on May 31, 2024. NW Natural is currently in negotiations with the BU, **[HIGHLY CONFIDENTIAL BEGINS**] [redacted]. [**HIGHLY CONFIDENTIAL ENDS]**

Q. How has the Company determined BU employees' base pay in this case?

A. **[HIGHLY CONFIDENTIAL BEGINS]** [redacted]. **[HIGHLY CONFIDENTIAL ENDS]**.

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	**[HIGHLY CONFIDENTIAL BEGINS] [redacted] [HIGHLY CONFIDENTIAL ENDS]**
NBU Employees	$65,924,691
Officers	$4,982,411
Total	**[HIGHLY CONFIDENTIAL BEGINS] [redacted] [HIGHLY CONFIDENTIAL ENDS]**

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 2023) and escalating them by 5.30 percent in 2024 and 4.85 percent in 2025. This reflects a 4.50 percent and 4.25 percent merit increase, respectively, and an additional 0.80 percent in 2024 and 0.60 percent in 2025 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. In addition, the percentage increases are influenced by increases in inflation as forecasted by the Consumer Price Index W (CPI-W urban wage earners and clerical workers) for the western United States in 2022 (6.3 percent) and 12 months ended October 2023 (3.1 percent).

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, **[HIGHLY CONFIDENTIAL BEGINS]** [redacted]. **[HIGHLY CONFIDENTIAL ENDS]**.

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 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 industries, rather than adding this pay directly to base pay. For general industry on average, 86 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. Given the sizeable increase to revenues requested in this rate case, 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 at this time. 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 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. In the most recent Collective Bargaining Agreement (“CBA”), NW Natural and the union agreed to eliminate pay-at-risk compensation as a component of total compensation for BU employees. **[HIGHLY CONFIDENTIAL BEGINS]** [redacted]

[redacted]. **[HIGHLY CONFIDENTIAL ENDS]**.

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 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 and by representing the Company positively through community involvement. 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, and existing customers benefit from growth because the Company's fixed costs are shared among a larger customer base.

- The public safety goal has two components—damage call response time and odor call response time. Both are measured in percent 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 four years. 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.

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 $9,340,431 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. Starting in 2022, the Company provides medical and pharmacy insurance to its NBU employees and officers through Regence and Kaiser Permanente. In the most recent CBA, NW Natural and the union agreed that BU employees will 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. As previously stated, the current CBA for BU employees is set to expire on May 31, 2024, and NW Natural is currently in negotiations with the BU regarding a new CBA. **[HIGHLY CONFIDENTIAL BEGINS]** [redacted] **[HIGHLY CONFIDENTIAL ENDS].**

Q. What is the medical benefits expense proposed for recovery in this case?

A. The Company has included $19.9 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.

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 7.10 percent increase in costs for 2023 and is expected to be 9.5 percent for 2024. 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 during the last few years (see NW Natural/1004, Rogers). In the case of BU employees, **[HIGHLY CONFIDENTIAL BEGINS]** [redacted] **[HIGHLY CONFIDENTIAL ENDS].**

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 2022 Clinical Utilization Reports, we know that NW

Natural's average age under the pre-65 covered NBU participants in 2022 was 50 years old, compared to their overall databases that indicated an average age of 45 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 learn 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 2.0 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 2023, Parker, Smith & Feek completed an analysis of the Company's medical benefits in 2022 relative to 34 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 34 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 Equal to the 34 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:

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Table 3
Utility Employee Medical Benefits
(Oregon Allocated FTEs)

Type of Utility Employee	Test Year
Bargaining Unit (BU) Employees	**[HIGHLY CONFIDENTIAL BEGINS]** [redacted] **[HIGHLY CONFIDENTIAL ENDS]**
NBU Employees[1]	$9,985,300

VI. RETIREMENT BENEFITS

Q. Please provide an overview of your retirement benefits.

A. Table 4 shows the retirement income benefits programs, which provide market median retirement offerings to employees:

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[1] Including officers.

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 **[HIGHLY CONFIDENTIAL BEGINS]** [redacted] **[HIGHLY CONFIDENTIAL ENDS]** 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 company into "Enhanced" account-no employee contribution required Contribution is 5 percent for NBU; **[HIGHLY CONFIDENTIAL BEGINS]** [redacted] **[HIGHLY CONFIDENTIAL ENDS]** 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.

Q. Are there any significant changes that NW Natural has made since the Company's last rate case?

A. For NBU employees, the Company is proposing no changes to retirement benefits for this case. For BU employees, **[HIGHLY CONFIDENTIAL BEGINS]** [redacted]

[redacted]. **[HIGHLY CONFIDENTIAL ENDS]**.

Q. How do NW Natural's retirement benefits compare to the retirement benefits provided by other companies?

A. In 2023, 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 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 shown to be Worse when compared to the Utility database.

Q. Please explain the total retirement benefits included for recovery in the Test Year.

A. Table 5 shows the amount requested for recovery in the Test Year.

Table 5
Utility Retirement Benefits
(Oregon Allocated FTE)

Component	Test Year
RKSP-Matching Contribution	$5,720,000
RKSP-Enhanced Contribution	$4,588,300
Western States Pension-withdrawal liability	$497,100
Total	**$9,493,600**

VII. EMPLOYEE HEADCOUNT

Q. What is NW Natural's FTE count at the end of the Base Year (calendar year 2023)?

A. On a system level, our FTE count at the end of the Base Year is projected to be 1,233.7. The FTE projection is based on actual FTEs as of September 30, 2023, and is then adjusted based on projected FTE attrition and projected FTE hires for the final three months of 2023. 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 1,233.7 FTEs does not include the 77 positions that are projected to be unfilled at the end of the Base Year.

Q. Is the Company requesting additional FTE above the FTE count at the end of the Base Year?

A. Yes, the Company is requesting an additional 13 employees that it expects to hire in the first half of 2024. The Direct Testimony of Jim R. Downing (NW Natural/700, Downing) provides the background, descriptions, and hiring status of eight of the FTEs. The Direct Testimony of Zachary D. Kravitz and Anna K. Chittum (NW Natural/1500, Kravitz-Chittum) provides the background, description, and hiring status of the other five FTEs.

Q. In seeking rate recovery, did NW Natural adjust its system level count of 1,246.7 FTEs?

A. Yes. NW Natural has removed 63.7 FTEs that are allocated to non-utility activities. After these FTEs are removed, NW Natural has 1,183 gas utility FTEs at the start of 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 1,183 FTEs?

A. Yes. NW Natural is seeking cost recovery of employees' compensation and benefits based on the 1,183 gas utility FTEs that NW Natural projects to have at the end of the Base Year.

Since the Company serves customers in Oregon and Washington, it allocates a certain percentage (approximately 89 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/1700, 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 490

NW Natural

Exhibits of Melinda B. Rogers

COMPENSATION & BENEFITS
EXHIBITS 1001 - 1006

December 29, 2023

EXHIBITS 1001-1006 – COMPENSATION & BENEFITS

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS
EXHIBIT 1001

December 29, 2023

Exhibit 1001 Base Pay Analysis

2023 Salary Structure - Base Pay Analysis

2023 Salary Structure		
NWN Grade	**NWN 2023 Midpoint**	**NWN Midpoint vs. Market Median**
14	$60,700	118.1%
15	$65,550	105.7%
16	$70,800	103.9%
17	$77,150	104.4%
18	$84,100	104.3%
19	$91,650	104.8%
20	$101,750	102.0%
21	$112,950	102.6%
22	$126,500	102.2%
23	$141,700	99.9%
24	$158,700	101.2%
25	$177,750	103.5%
26	$199,100	109.1%
	Overall	**104.7%**

Data Source: NW Natural Market Analysis 2023

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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NW Natural

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS
EXHIBIT 1002

December 29, 2023

Pay Governance®
Advisory Services to Compensation Committees

NW Natural Gas Company & NW Natural Holding Company

Executive Compensation Review

Organization and Executive Compensation Committee Meeting – February 2023

Key Findings

1. Similar to last year, total direct compensation in aggregate for NW Natural is competitive with the Peer Group, broader energy industry, and general industry.
2. Officers positioned below competitive TDC levels (-20% or more) should be reviewed for continued movement toward competitive compensation
   — Currently, TDC levels for the Officers are generally within the competitive range ± 20%.
3. Salaries are generally aligned with the NW Natural philosophy of targeting median.
4. EAIP targets are generally competitive.
5. NW Natural internal equity generally aligns with the ranking of CEO and highest paid executives at energy industry companies (see p. 17).

	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	8%	-4%	-10%	9%	-5%	-21%	10%	-8%	-21%
Target Total Cash	11%	-1%	-10%	26%	-2%	-23%	18%	-7%	-23%
Long-term Incentives	48%	-17%	-30%	234%	24%	-37%	270%	41%	-37%
Target Total Direct	22%	-8%	-19%	58%	5%	-28%	52%	4%	-28%

Note: Competitiveness is more commonly referred to as a range around the intended level : base salary: ±10% of the 50th percentile; cash compensation: ±15% of the 50th percentile; total direct compensation: ±20% of the 50th percentile

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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NW Natural

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS
EXHIBIT 1003

REDACTED

Per Commission's General Protective Order, this exhibit is confidential in its entirety and has been redacted.

December 29, 2023

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

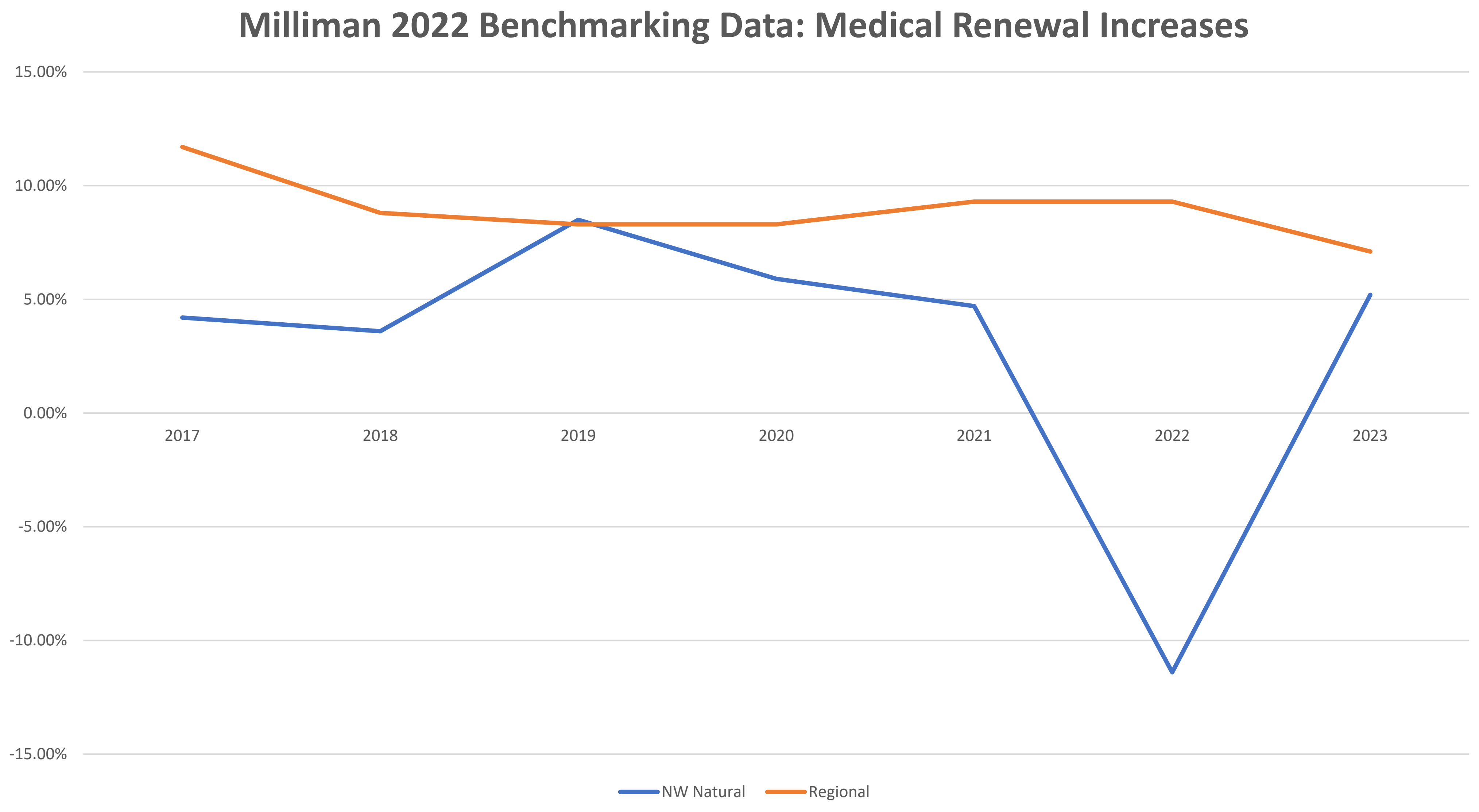
UG 490

NW Natural

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS EXHIBIT 1004

December 29, 2023


Milliman 2022 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
NW Natural
Regional

BEFORE THE

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UG 490

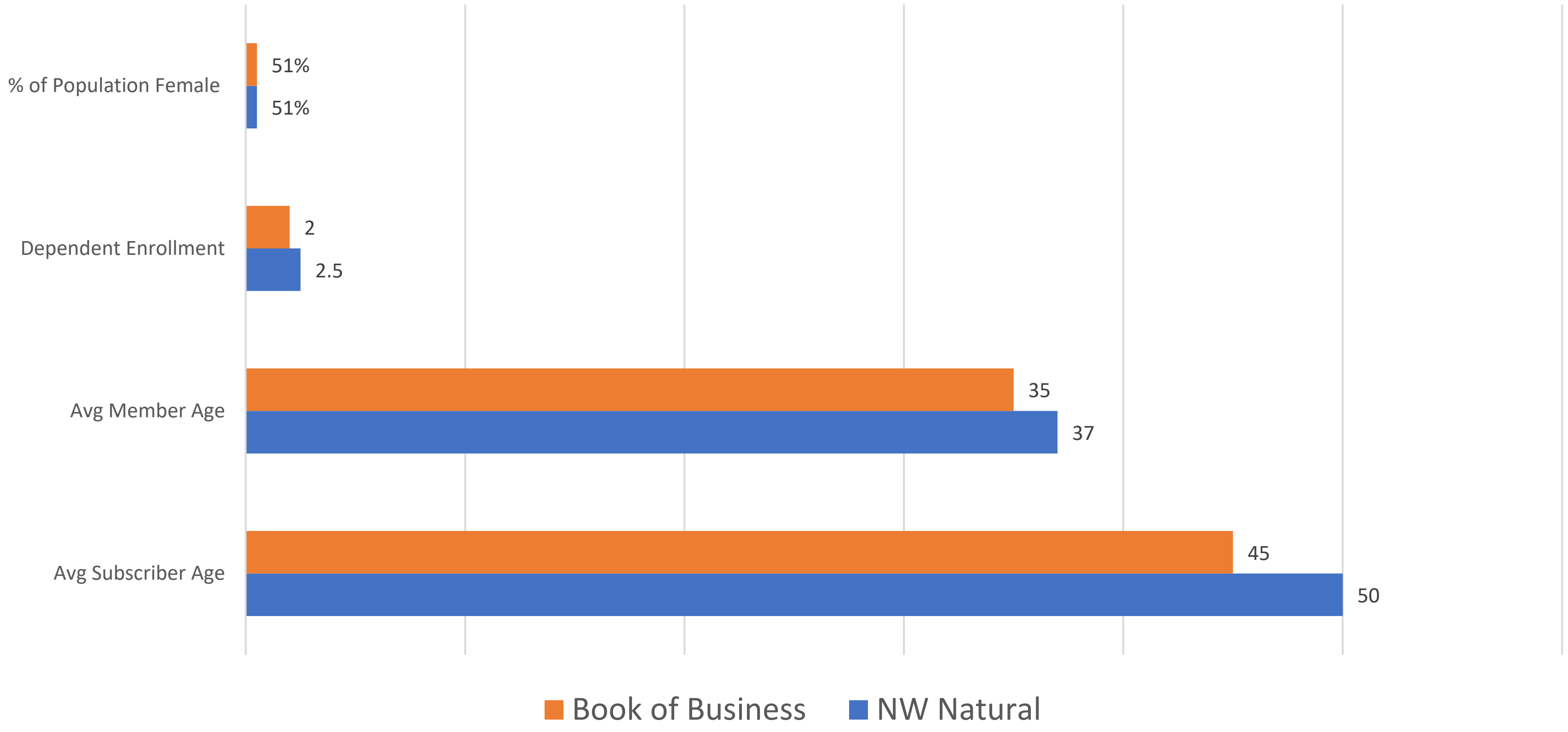
NW Natural

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS
EXHIBIT 1005

December 29, 2023

Kaiser and Regence 2022 Demographic Benchmarking Data



BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS
EXHIBIT 1006

December 29, 2023

Milliman 2022 Benchmarking Data

Medical	Ranking as compared to 34 Utilities in the PNW
Deductible	Equal
Out of Pocket Maximum	Equal
Office Visit – Primary	Equal
Office Visit – Specialist	Equal
Telehealth Visit	Equal
Alternative Care	Better
Pharmacy	Worse

Vision and Dental	Ranking as compared to 34 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 2022 Benchmarking Data

Long-term Disability	Ranking as compared to 34 Utilities in the PNW
Benefit Percentage	Equal
Monthly Maximum	Equal
Elimination Period	Equal

Short-term Disability	Ranking as compared to 34 Utilities in the PNW
Benefit Percentage	Better
Elimination Period	Better
Maximum Benefit Period	Better

Life Insurance	Ranking as compared to 34 Utilities in the PNW
Employee Coverage	Worse
Dependent Coverage	Equal
Voluntary Buy-up	Equal

Other	Ranking as compared to 34 Utilities in the PNW
Flexible Spending Accounts	Equal
Employee Assistance Program	Better

Defined Contribution	Ranking as compared to 34 Utilities in the PNW
Company Match	Equal
Enhanced (Non-Match)	Worse

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Direct Testimony of Cory A. Beck

CUSTOMER COMMUNICATIONS
EXHIBIT 1100

December 29, 2023

EXHIBIT 1100 - DIRECT TESTIMONY - CUSTOMER COMMUNICATIONS

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 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 2024 through October 2025 (the "Test Year") and explain that such proposed level is just three cents more per customer than the level presumed just and reasonable under Oregon Administrative Rule ("OAR") 860-026-0022(3)(a); and

- Present the Company's Test Year Category B (safety-related communications) 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 $1,354,530 for Category A communications based on forecasted revenues and customer count, which is equivalent to about $1.92 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 $1.95 per customer, nearly equal to the rate derived using the level presumed just and reasonable under OAR 860-026-0022(3)(a).

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;
- Energy and money-saving tips and resources;
- The efficient use of natural gas;
- 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); 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 and streaming media.

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 almost entirely 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. Safety-related communications are legally mandated messages intended to ensure that NW Natural's customers, contractors, public officials, emergency officials and the general public within the NW Natural service territory know how to use natural gas safely, have emergency preparedness awareness, 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. Each year, the Company executes a robust Public Safety Awareness Program supported by paid media, customer communications, public relations, targeted mailings and community events. The Company 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. Third-party damages to NW Natural pipelines still pose a significant threat to our system and public safety. The Company's Test Year damage prevention effort includes paid media across multiple channels, including TV, streaming media, radio, print, digital, social media and community events.

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 ("RP-1162"), and OAR 860-024-0020. 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. 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. What Category B communications expenses are included in the Test Year?

A. The Company has included $975,000 for Category B communications and media expenses in the Test Year, which is an increase of about $250,000 to the Base Year spending level.

Q. Why is the Company requesting an increase to the Base Year spending level?

A. The Company delivers many of its safety communications and advertising in Spanish. We have plans for 2024 to expand the website to offer multi-language content and to develop and execute broader multi-lingual content and media for the Test Year to ensure safety messages are more accessible for a wider audience and more closely match our diverse customer base. Similar to the multi-language communications presented to income-qualified customers about bill discounts and payment programs, the Company has engaged its media planning and buying agency to recommend a multi-language communication strategy that fits the needs of our customer base. The plan outlines the development for a multi-media approach based upon the media channels most effective with Spanish, Chinese, Vietnamese and Russian customers. The proposal, which I provide as exhibit NW Natural/1101, Beck, recommends a tailored approach offing a mix of non-English media channels:

- Broadcast and cable TV
- Radio
- Digital display advertising
- Streaming media
- Targeted email marketing
- Cultural print advertising
- Cultural event sponsorships
- Social media

The Company believes that this proposal is aligned with the Commission's ongoing diversity, equity and inclusion efforts.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Cory A. Beck

CUSTOMER COMMUNICATIONS
EXHIBIT 1101

December 29, 2023

EXHIBIT 1101 – CUSTOMER COMMUNICATIONS

Table of Contents

k.mann MARKETING

NW Natural®

Media Suggestions
2024-2025

Presented to Cory Beck, Director, Customer Experience Services, NW Natural
Presented by Kellie Mann kellie@kmannmarketing.com 503.819.4366

Introduction

The landscape for the American consumer is constantly changing, and marketing strategies must evolve to stay in step. Those changes are prevalent in the growth of the multicultural audience in the United States with population numbers expected to grow by 2.3 million people annually reaching a majority status by 2044 according to the US Census. This audience is not only growing by scope but by purchasing power as well.

In all forms of marketing, it is imperative to focus on the ability to target, engage, and connect with multicultural audiences like never before, however, this journey should not be designed with the same pathways in mind. Building an authentic audience relationship is essential to forge whether it be in the auto, health, travel or utility industry.

The best way to make that connection is to truly understand the people you are targeting — to empathize with them, comprehend their challenges and speak to them in a way that makes them feel heard.

Understanding NW Natural's goal to design a multi-language safety-related campaign focusing on the Hispanic, Russian and Chinese audiences, we will be outlining different mediums on how to reach each of these audiences effectively and efficiently.

When honing in on the Oregon population for these ethnic groups, we find that Hispanic community is approximately 558,000, Russian is 100,000+ and Chinese 57,000+.

In Vancouver, Washington, these featured audience populations are Hispanic 27,000+, Russian 14,000+, and Chinese 1,475+.

Since the majority of our target audience is the Hispanic population, a good portion of the proposal details how this group is consuming media. The other two languages will be identified in the mediums that make the most sense when it comes to specific targeting tactics.

The following pages outline a media outreach for the Hispanic, Russian and Chinese languages in Oregon and SW Washington.

Oregon 2020 Census, Zip Atlas

Media Suggestions

1. **United States Hispanic Population Statistics**

2. **Best Media to Reach the Hispanic Audience**

3. **Broadcast TV - Univision**
   a. Audience Statistics
   b. News and Event Sponsorships
   c. Email Marketing

4. **Cable TV**
   a. Audience Statistics

5. **Broadcast Radio - El Rey**
   a. Radio and/or Event Sponsorships

6. **Streaming Audio**

7. **Digital: Display, Pre-Roll, Connected TV**

8. **Social Media: Facebook, Instagram, YouTube**

9. **Zip Code Percentages in Oregon/SW Washington and Eugene for the Russian, Latino and Chinese Languages**

10. **Suggested Media Investment**

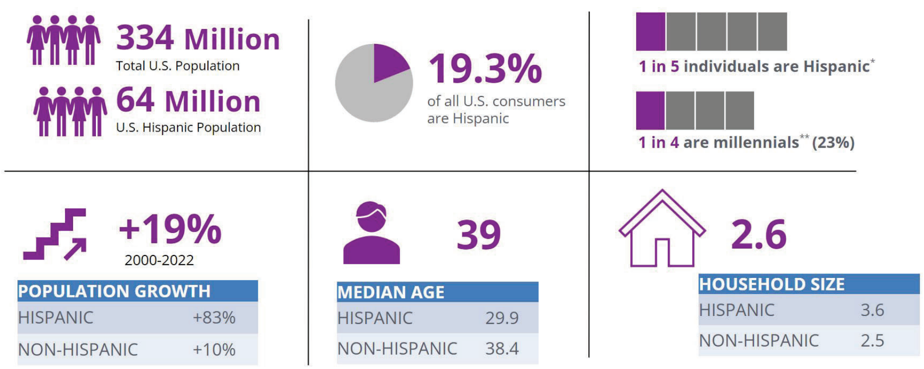
Hispanic US Population Statistics

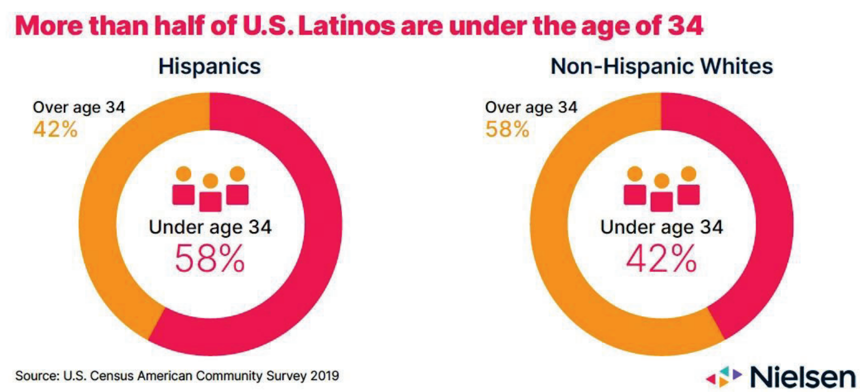
Pew Research states that 64 million Hispanics make up almost 20% of the current U.S. population, which accounts for 51% of all new population growth. Amazing to think that 58% of this audience is under the age of 34!

Given this growth in population, spending is expected to grow to $2.8 trillion by 2026, which will represent 20% of that total US buying power.

Many Hispanics are immersed in both American and Latino culture in the United States, and they are largely bilingual and bicultural, with 75% speaking Spanish at home.

According to the Kantar 2021 U.S. Monitor report, 88% of U.S. Hispanics say they appreciate businesses that speak to them in Spanish, and 87% feel businesses that make a sincere effort to be part of or invest in their communities deserve their loyalty.





Pew Research, Claritas, Adweek, Kantar

Best Media to Reach the Hispanic Audience

1). Mobile

- According to YouGov research cited by eMarketer, 87% of U.S. Hispanic Internet users have a smartphone compared with 84% of non-Hispanic white Internet users.

2). Digital Video

- U.S. Hispanic adults also over-index on YouTube use compared to the total population, at 78% using YouTube vs. 73% of all adults who use Youtube, respectively.
- Preference for streaming digital video also extends into online TV streaming services.

3). Connected TV

- In total, it's estimated that 79% of U.S. Hispanic adults use Netflix, compared to 62% of non-Hispanics, and 39% of Latinos are Hulu users, compared to 26% of non-Hispanics.
- According to Nielsen, 43.6% of Hispanic viewers spend their TV time watching streamed content, resulting in 33.5 billion minutes viewed.
- Nine in 10 Hispanics use connected TV platforms or services, and 83% watch video content online. The top channels watched on CTV are ESPN, TNT, Fox News, CNN, TBS, and HGTV.

4). Digital Audio

- 85% of US Hispanics are using digital streaming services for their music. The survey showed Pandora (25%) and Spotify (20%) are the most commonly used apps.

5). Social Media

- 71% of Hispanics are more likely to use social media to connect with friends and family compared to 63% of Caucasian adults and 60% of African American adults.

Pew Research, YouGov, eMarketer, H Code

Hispanic Media Usage

Watched broadcast TV last 7 days	Listened to the radio	HHLD Subscribe to cable/satellite	Use the Internet	Use a smartphone to access internet	Use social media	HHLD have a TV streaming media devices
84%	89%	41%	97%	88%	87%	50%

Portland Hispanic Broadcast TV

Here, we start with linear TV as a media suggestion.

As for broadcast, Spanish language TV continues to be an incredibly powerful platform for advertisers to connect with the U.S. Hispanic community.

According to Nielsen, 24 of the top 25 entertainment shows among U.S. bilingual adults are watching Spanish-language TV.

There are a variety of ways to advertise to the Hispanic audience through Univision in the Portland Metro area:

1). Broadcast TV
2). News Sponsorship
3). Soccer Sponsorship
4). Outdoor Initiative Sponsorship
3). Email Marketing

The following pages outline the Portland Hispanic broadcast TV market with statistics, sponsorship opportunities and email marketing.

Portland Hispanic TV Market

MARKET FACTS

#30	National Hispanic Market Rank (Ranking by TV HHs)
134,100	Hispanic TV Households
10.4%	of DMA TV Households
479,186	Hispanic Total Viewership
14.7%	of DMA Population

HISPANIC DEMO SHARE

Adults 18-34 % Hispanic	32%	151,682
Adults 18-49 % Hispanic	54%	257,949
Adults 25-54 % Hispanic	46%	217,732

- ✓ Hispanic viewing audiences skew younger than general market.
- ✓ More than half of Hispanic viewing comes from Adults 18-49.

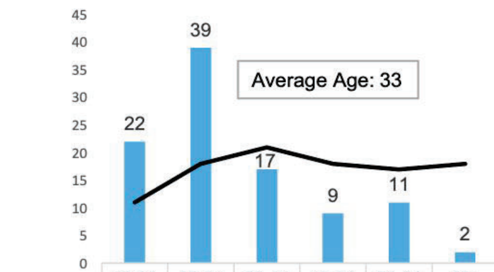
UNIVISION PORTLAND

Source: Nielsen 2022-2023 Universe Estimates; Portland DMA Hispanic TV HH and Persons.

KUNP Reaches Viewers With Highly Sought Characteristics

35.8% 64.2%

Married 48%



	18-24	25-34	35-44	45-54	55-64	65+
KUNP	22	39	17	9	11	2
A18+	11	18	21	18	17	18

Children at Home 76%

< Age 5: 23%
Age 6-11: 58%
Age 12-17: 50%

Ethnicity:

White:	68%
Hispanic:	83%
Non-White:	31%

40% Own Their Home

Average Home Value: $351K

Any college 35%

Post Grad 6%

Average Income $43K

20% $50-$75K

14% $75-$150K

26% $100K+

Employed Full/Part Time: 40%
Two+ Income Family: 53%
Net Worth $100K+: 45%

Univision Portland

Source: Scarborough Prime Lingo Portland, Or Release 1 Total (Jan 2021 - Jan 2022). Watched KUNP past week.

KUNP's audience tends t be much younger than typical broadcast TV.

- ✓ *Active,*
- ✓ *employed,*
- ✓ *homeowners,*
- ✓ *acquisition phase*
- ✓ *families*

UNIVISION PORTLAND

Univision News Products

- **Noticiero Univision Edicion Noctura,** 5:30a-6a
- **Despierta America,** 7a – 11a Monday thru Friday and Sunday
- **Noticiero Univision Edicion Digital,** 12p-12:30p
- **Noticias Noroeste**, Only local Spanish News in the Portland DMA, weekdays at 6 & 11p

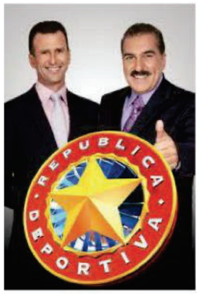
KUNP-TV, Univision Portland Facts:

✓ The <u>only</u> TV station providing Local News in Spanish in the marketplace.
✓ Univision Portland Local & National News provide the day's headlines, with a story focus of utmost importance to Hispanic and Latino Americans.
✓ Univision Noticiero Univision is the most watched Spanish language network newscast in the United States, regularly beating its nearest rival, Telemundo's Noticiero Telemundo.
✓ Key demographic Adults 18-49 – at least 10 years younger than the average age of English language evening news competitors.
✓ Established and rooted in the Latino Community (12+ years), a reputable and accountable source of local news.
✓ Univision Portland signal reaches about 75% of the Latinos in the state Oregon and SW Washington
✓ Bicultural journalism presenting news stories that matter to the community
✓ News Sponsorship opportunities are available.

The only local TV Newscast in Spanish language serving the growing Hispanic community in Oregon & SW Washington.

Bicultural journalism presenting news stories that matter to the community.

SOCCER SPONSORSHIP OPPORTUNITY



Quarterly Sponsorship

Reach the Hispanic Audience during Soccer Programming, the **most watched** programming on the Univision network, the #1 Spanish Language Network targeting Hispanics in America.

As a soccer package sponsor, NW Natural spot will be guaranteed to run during Futbol Liga MX weekly games and/or other high-profile soccer games which are normally sold out. In addition, NW Natural spot will be placed inside weekly soccer programming such as Futbol Central, Republica Deportive and Contacto Deportivo. The package includes a stand-alone promo schedule highlighting NW Natural partnership by having a graphic and audio mention of NW Natural.

Station Quarterly Deliverables:

- Campaign total of 26x :15/:15 or :30 second spots to run two times (2x) weekly during **Univision soccer games.**
- Campaign total of 26x :15/:15 or :30 second spots to run two times (2x) weekly during **Univision soccer programming: Republica Deportiva, Futbol Central or Contacto Deportivo**.
- Campaign total of 65x :15 second tune in promos to run five times (5x) weekly, Tuesday – Saturday, 7:00a-11:30p.
- Production of 1x tune in :15 second stand-alone NW Natural sponsorship promo.
- Pre-empted soccer game spots will be placed in primetime or soccer programming if network cancels soccer games unexpectedly.
- **Campaign Investment: $11,375 Gross**

Nuestro Noroeste "Our Northwest" is KUNP-TV Univision living green, nature, and outdoors Initiative. It is a station branded communications campaign with the purpose of creating awareness about the richness and diversity of the outdoors in the Pacific Northwest Region. **Sponsorship includes:**

In-content: Univision Portland will air one (1) Nuestro Noroeste news story each month. Content is at the full discretion of the news department with primary focus on covering outdoor living, recreation, and sustainability related topics. Sponsor to receive logo and mention adjacent to each story (6pm and 11pm local news).

Broadcast: Production of a series of 60- and 30-second Nuestro Noroeste messages presented by Sponsor to air on Univision Portland (KUNP-TV). Custom quarterly schedule valued at **$10,000**. Specific timing and placements dependent upon topic and communication strategy.

Digital: Video embedded messages targeted to reach your desired audience(s). Targeting may include demographic, geographic and behavioral criteria, total 100,000 impressions per month to be delivered across all digital platforms and Univisionportland.com.

All messages available for viewing on UnivisionPortland.com in the Nuestro Noroeste section.

Production: Production of one (1) 60- and one (1) 30-second message per quarter is included. Univision Portland creative services team will collaborate with Sponsor regarding content. Please note content must be in line with Nuestro Noroeste initiative objectives to qualify. Production of all digital assets included.

Promos: Sponsorship of a 15-second station branded message, promoting Nuestro Noroeste to air 20x per month, 60x per quarter. Sponsor logo and mention included.

12-month Sponsorship Investment: $46,720

GROW YOUR BUSINESS WITH EMAIL MARKETING

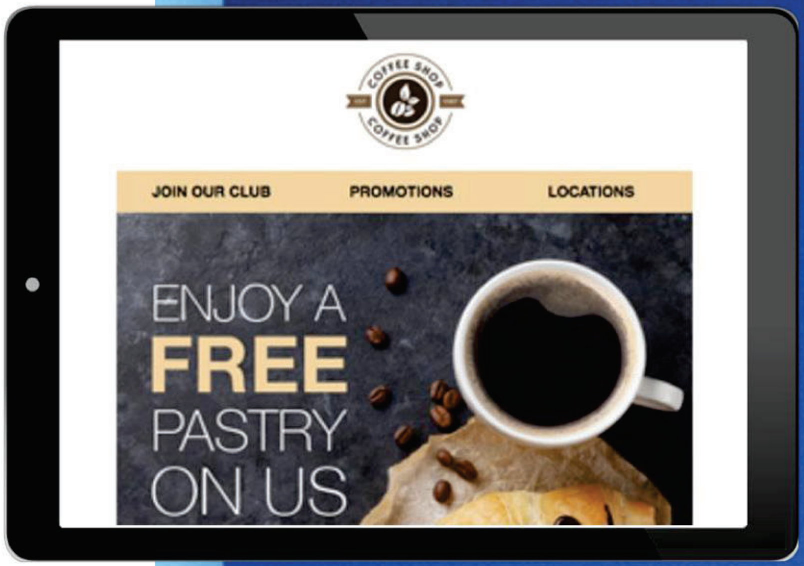
TELL YOUR STORY

Send customized messages to a defined target audience and grow new customers, promote events, extend special offers, and generate awareness of your products and services. It is a large format that is suitable for telling a complex story.

Features Include

- In-house graphic design team
- Templated designs or custom HMTL available
- 200 million+ database with extensive verification and opt-in processes that is appended monthly
- 2% CTR Guarantee
- Spanish Language Campaigns available to NW Natural to reach Spanish Language Customers
- Detailed reporting provided 7-9 business days after deployment

univision



90%
of internet users engage in email activities.

Cable TV

While trends continue with households "cutting the cord" across all demos, there is still a solid percentage of homes that access the content they love via their local cable provider especially with live programming such as news and sports. Below are the top 10 US Hispanic/Latino TV networks as of last year.

Top 10 U.S. Hispanic/Latino TV Networks Year-to-Date 2022

(by Hispanic Household Average Audience) *Highest value in each column highlighted in Green*

NETWORK RANK	NETWORK	RATING %	AVERAGE AUDIENCE	INDEX
1	Univision	2.7	383,111	635
2	Telemundo	2.0	275,912	633
3	UniMas	0.7	98,288	632
4	TUDN	0.5	63,836	645
5	Estrella TV	0.3	47,463	644
6	Galavision	0.3	39,271	639
7	UNIVERSO	0.3	36,189	637
8	Discovery Channel en Espanol	0.2	28,952	657
9	ESPN Deportes	0.2	23,276	648
10	FOX Deportes	0.1	20,291	649

Network Average Audience (Cable) YTD Average: 67,588*

Source: Comscore TV National, Hispanic/Latino Networks only, Hispanic Ethnicity HHLD Live, 1/1/2022 – 8/31/22, U.S.

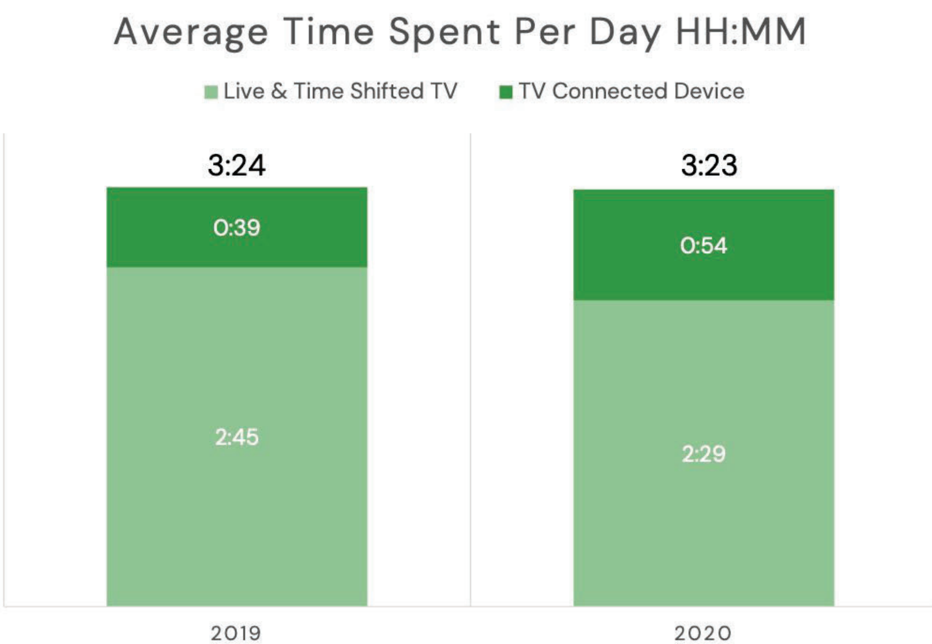
*Cable TV average audience benchmark based on an average across 248 networks, HHLD Live, 1/1/22 – 8/31/22

comscore

The following pages outline the Portland Hispanic Cable TV market with statistics.

effectv

HISPANIC TV VIEWERSHIP SHIFTING, BUT STILL CONSUMED ON THE BIG SCREEN

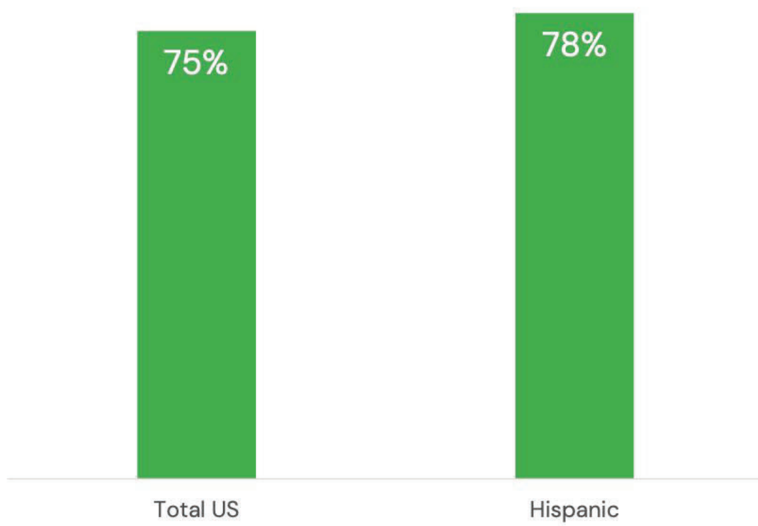


Time spent with TV **remains the same,** but **shifts slightly** to TV connected devices year over year

Source: Nielsen Total Audience Report published March 2021, Average Time Spent Per Adults 18+ Per Day, Q3 2020 vs. Q3 2019.
TV Connected Devices includes Internet Connected Devices.

HISPANICS HAVE NEARLY UBIQUITOUS ADOPTION OF STREAMING

% of HHs with Streaming Service[1]

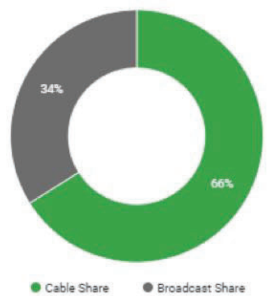


Hispanic adults spend
26%
of their streaming time with ad-supported VOD[2]

Sources:
1. Nielsen "Cultural Connectivity Transformed." August 2020
2. Nielsen Total Audience Report published March 2021, Share of Streaming Among Streaming Capable Homes, Jan 2021.

HISPANIC VIEWING HABITS IN THE PORTLAND MARKET

Cable-Broadcast Share

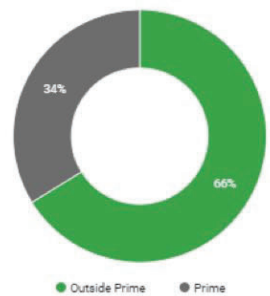


11
Nets Watched

66%
Viewing Outside Prime

68%
Watch VOD

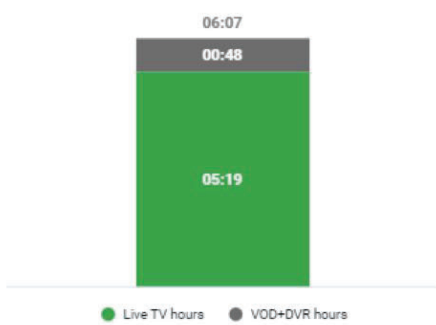
Viewing by Time of Day



6:07
Daily Time Spent

87%
Watched Live

Daily Time Spent



66%
Cable Share

1.9X
More Time with Cable

Source: Comcast Internal Data, Q1'21 Targets as listed. Market: Miami DMA, zones as listed. Target: Hispanic as defined by Experian.

Spanish Radio

Latinos are 20% more likely than Non-Hispanics to stream AM /FM broadcast radio stations online.

The Nielsen analysis shows that AM/FM radio continues to lead all media, including all broadcast, streaming and digital platforms, in building broad reach with Hispanic adults.

As of Spring 2022, Nielsen data shows:

- 97% of all Latinos 18+ listen to AM/FM radio on a monthly basis, compared to 59% of all streaming music services, combined.
- Although radio listenership increases with age, a full 95% of Hispanics 18-34 (Millennials and Gen Z) can be reached through AM/FM radio. This compares to 65% reach for all streaming music services and 29% for the leading platform, Spotify.
- While streaming audio lags AM/FM radio in reach, share of listening time doubled among Hispanic adults since Q2 2020, from 5% to 10% of total AQH.
- When added to the mix of audio platforms, radio achieves an additional 64% in incremental reach in brand's Hispanic media plan

El Rey - 93.1 El Rey (KRYP-FM) landed in the Portland market in 2007 as the first Mexican Regional Music station; reaching a large, growing and untapped Hispanic listener-base.

El Rey's audience comprises of families and young people who become loyal to the station and its advertisers. Over the years, El Rey has seen proven success in the Portland area and continues to lead the market in its format.

Monthly broadcast schedule 6 month sample - $20,000

Stations	Spots	Unit Rate	Total Cost	Average Rating	CPP	GRPs	% of GRPs	% of Total Cost	% Reach	Net Reach	Frequency	GIs	CPM
Radio Total	541	$37.05	$20,045.00	0.3%	$126.23	158.8	100%	100%	7.7%	81,500	21.2	1,728,900	$11.58
KRYP-FM	541	$37.05	$20,045.00	0.3%	$126.23	158.8	100%	100%	7.7%	81,500	21.2	1,728,900	$11.58

Spanish Radio Events

A Salem riverfront concert in August with over 7,000 attendees.

- 250 x promotional mentions (shared :30) that include your name as the title sponsor of the concert, along with KRYP – El Rey
- 75x :30 commercials from 5A-10P to air during the month of August
- Signage throughout the venue, and in high profile arena locations
- Booth space in a high visibility location
- Stage thank you on the day of the event (done by station talent)
- 1 one-hour van hit at the client location prior to event
- Sponsor logo and link on the El Rey website and mobile app
- Inclusion in station social media posts leading up to and during the event
- El Rey digital retargeting
- **Investment: $10,000**

Mochilazo de El Rey" Remote

- 2-hour remote with on-air talent and promotions team,where we will bring 100 backpacks filled with school supplies to give out to elementary school aged kids at your business location.
- Remote sponsorship opportunity with promotional on air mentions, sponsor logo on ElRey website and mobile app, inclusion in social media posts and commercial spots.
- **Investment: $5,000**

JUGETAZO

- A holiday event aiding children in need during the holidays.
- 50 Pre-Recorded Promo's
- 20 x Live mentions
- 35 :60 commercials
- 1 two hour remote with on air personality
- **Investment: $4,000**

Digital Display/Connected TV

In addition to their buying power and the cultural significance of the Spanish language within the Hispanic community, Latinos are also leading digital transformation as tech aficionados.

- 88% watched streaming content vs. 79% for non-Hispanics and 56% spend between 1-3 hours watching Over The Top services
- Connected TV streaming consumption has also been consistently growing among the U.S. Hispanic population, with content made by and for Hispanics increasing alongside this trend.
- Netflix recently launched their "Con Todo" channel on Instagram highlighting all things #LatinXcellence, in addition to launching a new podcast titled "Brown Love" to highlight Latinx content and experiences.
- Pantaya, Lionsgate, and Hemisphere Media's Netflix-style streaming service, recently launched to target the Latino community. They offer premium content and original programming specifically for the Hispanic market.
- Pluto TV, Viacom's free, ad-supported streaming service, added a Latino category featuring 11 linear Spanish and Portuguese-language channels, with content ranging from movies, comedy, music, true crime, reality, sports and telenovelas.

When it comes to tech device ownership, Hispanics also over-index across the board:

- 62% owned an internet-connected device, making them 29% more likely when compared to the general population.
- Two-thirds of Hispanics own an enabled Smart TV, which makes them 25% more likely compared to the total U.S. population.
- The group is also 15% more likely to own a game console, 13% more likely to own a computer, and 4% more likely to own a smartphone.
- The pandemic has further fueled Hispanic digital use, especially when it comes to streaming video.
- Compared to the non-Hispanic population at 55%, 70% of U.S. Latinos report that they have increased the amount of time spent watching movies or shows using a streaming service, and increased their weekly viewing time by roughly 8 hours as the pandemic took place.

Take into account that these above statistics reflect the Hispanic audience. Overall, all of the US population has increased tech device purchases and usage, including the Russian and Chinese communities.

Digital Display and Connected TV will have the ability to target these audiences specifically in the Portland and Eugene DMAs. Perhaps one of the best mediums to utilize for this multicultural campaign.

Nielsen, eMarketer

Digital Display/CTV Portland

For the digital portion of this campaign, we would use the following tactics @ $4,100 a month:

- Digital Display
- Connected TV

Portland ***Digital Display*** - 160x600, 300x250, 728x90, 320x50, 300x50, 300x600, 320x480	**Spanish/Latino/Hispanic** audience	1,200,000 Impressions	$5 CPM	$500/MO
	Chinese audience	600,000 Impressions	$5 CPM	$250/MO
	Russian audience	240,000 Impressions	$5 CPM	$100/MO
Portland ***CTV*** - 15 or :30 second Video	**Spanish/Latino/Hispanic** audience	857,143 Impressions	$35 CPM	$2500/MO
	Chinese audience	171,429 Impressions	$35 CPM	$500/MO
	Russian audience	85,714 Impressions	$35 CPM	$250/MO

Digital Display/CTV Eugene

For the digital portion of this campaign, we would use the following tactics @ $1,700 a month:

- Digital Display - Addressable Geo-Fencing to Audience Curated Demos
- Connected TV - Addressable Geo-Fencing to Audience Curated Demos

Eugene ***Digital Display*** - 160x600, 300x250, 728x90, 320x50, 300x50, 300x600, 320x480	**Spanish/Latino/Hispanic** audience	600,000 Impressions	$5 CPM	$250/MO
	Chinese audience	240,000 Impressions	$5 CPM	$100/MO
	Russian audience	240,000 Impressions	$5 CPM	$100/MO
Eugene ***CTV-*** :15 or :30 second Video	**Spanish/Latino/Hispanic** audience	257,143 Impressions	$35 CPM	$750/MO
	Chinese audience	85,714 Impressions	$35 CPM	$250/MO
	Russian audience	85,714 Impressions	$35 CPM	$250/MO

Connected TV DMA Households

Spanish/Latino/Hispanic	Portland, OR Metro (Includes Vancouver)	82,887 Parcels
Ages 18+, Spanish Language, OR Hispanic Ethnicity	Eugene, OR Metro	10,859 Parcels
Chinese	Portland, OR Metro (Includes Vancouver)	6,182 Parcels
Ages 18+, Chinese Language	Eugene, OR Metro	458 Parcels
Russian	Portland, OR Metro (Includes Vancouver)	3,751 Parcels
Ages 18+, Russian Language	Eugene, OR Metro	120 Parcels
	Total	**104,257 Parcels**

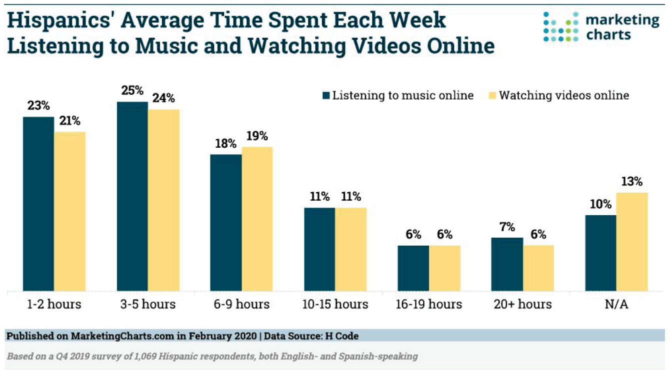
Streaming Audio/Podcast

The Nielsen analysis shows that AM/FM radio continues to lead all media, including all broadcast, streaming and digital platforms, in building broad reach with Hispanic adults.

As of Spring 2022 Nielsen data shows:

- 65% reach for all streaming music services and 29% for the leading platform, Spotify.
- Streaming audio share of listening time doubled among Hispanic adults since Q2 2020, from 5% to 10% of total AQH.
- Podcast listenership has also grown with Hispanic adults over the last two years, with 60% saying they listen more often and 62% saying they listen to more podcasts.

Streaming audio has the ability to target consumers by age, location, and interest, allowing for impressions to be served without waste. Streaming publishes like Pandora, iHeart, Sonos, SoundCloud, and dozens more are at the fingertips of ever consumer on their phones, in their cars, on their job sites, and in their homes on smart speakers and computers in both music and podcast formats. Creative can be 30 or 15 in length.



Nielsen, Marketing Charts

Streaming Audio/Podcast

As an example for streaming audio, here are the audience targets available through iHeart Media:

- Asian ethnicity
- Spanish format/Genre
- Hispanic
- Latino
- Spanish Speakers

Please note that a Spanish language audio spot can ONLY run on Spanish Genre, not on Hispanic/Latino/Spanish speakers

For podcast audio, iHeart has psychographic networks that will align with a couple of your key demos:

- Trajectory-Asians, A25-44, tech savvy, highly educated, early tech adapters, financial investments, active lifestyle/travel
- Progressive-Hispanic, parents, A25-54, Shop at Costco, Target, online shoppers, etc.

Monthly budget: $1,000

Portland DMA Audience Information:

Spanish Speakers- 129,004
Russian Speakers- 7,189
Chinese Speakers- 13,118
Hispanic Ethnicity- 337,797
Russian Ethnicity- 32,012
Chinese Ethnicity- 57,929

Social Media

Hispanic social media marketing is the same in this aspect, but it goes a step further to specifically reach and connect with Hispanic audiences across social platforms.

Since most social people spend the majority of their social media time on their mobile devices, social media marketing is a great way to boost your mobile marketing strategy.

Overall, social media use has never been higher, according to eMarketer, 79% of U.S. Hispanic adults say they now spend an additional two or more hours on social media than they did prior to the pandemic, and 42% use social media to stay up-to-date with news more than they did previously.

Tied to the importance of mobile among Hispanic consumers is their love of social media platforms. According to Culture Marketing Council research, U.S. Hispanics are much more likely than both white and Black Americans to say that they are on social networks from the moment they wake up to the moment they go to sleep, spending many of their waking hours on their favorite social media apps.

The survey also found that:

- 47% of U.S. Hispanics ages 13-17 self-identify as heavy social media users versus 32% of non-Hispanic blacks and 24% of non-Hispanic whites.
- 37% of U.S. Hispanics ages 18-34 self-identify as heavy social media users versus 30% of non-Hispanic blacks and 28% of non-Hispanic whites.
- 29% of U.S. Hispanics ages 35-49 self-identify as heavy social media users versus 20% of non-Hispanic blacks and 19% of non-Hispanic whites.

FB/Insta/YouTube Monthly Budget for Portland and Eugene DMAs: $6,500

eMarketer, Culture Marketing Council

**Facebook/Instagram/YouTube Audience Target:
High Income/Home Owners**

Adults, 35 - 54

Portland/Eugene DMA Zips

Interests > Additional Interests
Russian Language
Chinese Language
Hispanic Language
Home Owner

and MUST ALSO match at least ONE of the following

Demographics > Financial > Income

Household income: top 10% of ZIP codes (US)
Household income: top 10%-25% of ZIP codes (US)

**Facebook/Instagram/YouTube Audience Target:
Low Income**

Adults, 25 - 54

Portland/Eugene DMA Zips

Interests > Additional Interests
Russian Language
Chinese Language
Hispanic Language

and MUST ALSO match at least ONE of the following

Demographics > Financial > Income

Household income: top 25%-100% of ZIP codes (US)

Russian Audience Estimate

Audience definition

Your audience is defined.

Specific Broad

Estimated audience size: 60,800 - 71,600

Estimates may vary significantly over time based on your targeting selections and available data.

Latino Audience Estimate

Audience definition

Your audience is defined.

Specific Broad

Estimated audience size: 163,400 - 192,200

Estimates may vary significantly over time based on your targeting selections and available data.

Chinese Audience Estimate

Audience definition

Your audience is defined.

Specific Broad

Estimated audience size: 51,000 - 60,000

Estimates may vary significantly over time based on

Meta - Russian	FB/Insta	Impressions 300,000-1.1M	Est CPM $7.21-13.20	$1,200-$2,500/Mo
Meta - Hispanic	FB/Insta	Impressions 480,000-1.8M	Est CPM $3.39-$12.50	$1,500-$4,000/Mo
Meta - Chinese	FB/Insta	Impressions 165,000-990,000	Est CPM $6.06-$17.21	$750-$1,700/Mo

Meta - Russian	YouTube	Impressions 5,000-210,000	Est CPM $6.18-$12.50	$1,000-$2,000/Mo
Meta - Hispanic	YouTube	Impressions 210,000-480,000	Est CPM $6.10-$13.90	$1,500-$3,000/Mo
Meta - Chinese	YouTube	Impressions 16,000-58,000	Est CPM $8.10-$15	$4500-$1,500/Mo

Cultural Papers

El Latino de Hoy is an Hispanic newspaper serving Oregon and the surrounding region, specifically the cities of Portland, Salem and Eugene along with Vancouver, Washington. Circulating over 25,000 weekly to the Spanish speaking Oregonian in over 33 cities. B&W and Color available in full page $2,064-$2,580, half page $1038-$1,290, quarter page $516-$645 pricing.

Portland Chinese Times publishes every Friday since 1997 is active on FB, WeChat/PDX Now and PCTTV online. Distributes over 20,000 copies weekly in Oregon and Washington to the Chinese/Asian community. B&W and Color available in full page $800-$1,000, half page $420-$600, quarter page $220-$350 pricing.

Russian City magazine is the most widely read Russian-language publication in America, including in Portland. This is a monthly magazine for a very wide audience from 18 years old and ... to infinity. This popular project was based on the idea of creating a source of useful and exciting information in Russian. As a result, the pages of the magazine are full of exciting and interesting publications: entertaining and informative articles, exclusive interviews, news, tips, success stories and much more. At the same time, the magazine has very important functions - to maintain language contact, to bring people together, to give a feeling of something dear and close. This is a territory of communication, search for like-minded people and, of course, progress towards success. Banner advertising on website only $400-$500 a month.

Cultural Events

Cultural events around Portland, Vancouver and Eugene with sponsorship opportunities:

Hispanic:
- Portland - Cinco de Mayo Fiesta - May
- Vancouver - ¡VIVA VANCOUVER! - August
- Eugene - Fiesta Cultural Kickoff at the First Friday ArtWalk - September

Chinese:
- Portland - Lunar New Year Celebrations
    - Chinese New year Cultural Fair - January
    - Chinese New Year at Lan Su Garden - January
- Portland - Jade International Night Market - August
- Eugene - Asian Celebration with Obon and Taiko Festival - July

Russian:
- Portland - Slavic Festival - July

Zip Codes - Oregon & Washington

Zip codes with the highest percentage of Hispanic/Russian/Chinese Population in Portland, Oregon

Hispanic or Latino	Russian	Chinese
97233 - 24.2%	97233 - 4.15%	97266 - 8.42%
97236 - 20.8%	97216 - 3.55%	97201 - 7.62%
97230 - 19.0%	97236 - 3.31%	97216 - 7.52%
97218 - 18.2%	97210 - 2.56%	97229 - 7.21%
97216 - 17.0%	97205 - 2.49%	97209 - 4.63%
97203 - 15.1%	97201 - 2.46%	97239 - 3.37%
97204 - 14.9%	97221 - 2.41%	97236 - 3.34%
97266 - 13.3%	97232 - 2.08%	97206 - 3.25%
97222 - 12.7%	97239 - 1.95%	97219 - 3.19%
97232 - 12.2%	97214 - 1.91%	97221- 3.07%

*Zip Atlas

Zip codes with the highest percentage of Hispanic/Russian/Chinese Population in Vancouver, Washington

Hispanic or Latino	Russian	Chinese
98661 - 19.7%	98664 - 3.69%	98683 - 4.76%
98665 - 14.7%	98682 - 3.06%	98686 - 3.24%
98664 - 14.3%	98860 - 2.78%	98660 - 2.43%
98683 - 13.4%	98684 - 2.22%	98685 - 2.27%
98663 - 12.7%	98661 - 1.92%	98663 - 2.16%
98684 - 12.3%	98662 - 1.87%	98684 - 1.44%
98682 - 11.2%	98663 - 1.73%	98662 - 1.12%
98660 - 9.7%	98683 - 1.70%	98682 - 0.92%
98662 - 9.7%	98685 - 1.65%	98665 - 0.86%
98686 - 8.8%	98665 - 1.55%	98664 - 0.58%

*Zip Atlas

Zip codes with the highest percentage of Hispanic/Chinese Population in Eugene, Oregon

Russian population not registered

Hispanic or Latino	Asian
97402 - 15.5%	97401 - 6.6%
97401 - 9.2%	97403 - 5.3%
97404 - 8.4%	97405 - 3.5%
97403 - 8.0%	97408 - 3.3%
97408 - 7.5%	97404 - 3.0%

*Zip Atlas

Suggested Media Investment

June 2024-2025

- Broadcast TV - Univision TV Schedule & Email Marketing: $3,000 a month = $36,000
- Portland & Eugene Cable - Comcast = $2,000 a month = $24,000
- Broadcast Radio Schedule - El Rey = $20,000 (April - September) = $20,000
- Digital
  - Display, Connected TV = $5,800 a month = $69,600
- Streaming Audio - iHeart Media = $1,000 a month = $12,000
- Cultural Print (half page ad in El Latino and half page ad in Portland Chinese Times) = $3,000
- Cultural Events = TBD
- Social Media (FB/Insta) & YouTube = $6,500 a month = $78,000

Total 12 Month Investment: $242,600

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Direct Testimony of Kathryn M. Williams

EXPENSES FOR POLITICAL ACTIVITIES
EXHIBIT 1200

December 29, 2023

EXHIBIT 1200 - DIRECT TESTIMONY – EXPENSES FOR POLITICAL ACTIVITIES

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 "Political Activities" expenses in Section IV.B.3.b of its

Order No. 22-388 in the Company's most recent general rate case, UG 435, as it applies to this general rate case.

II. COMMISSION ORDER NO. 22-388 – RESOLUTION OF "POLITICAL ACTIVITIES" EXPENSES

Q. Please summarize the development and Commission resolution of "Political Activities" expenses in the Company's most recent general rate case, UG 435.

A. NW Natural's application in UG 435 included specific cost allocations (inclusive of salaries and overheads) for employees (e.g., Community and Government Affairs) engaged in political activities, which were allocated to non-recoverable expenses along with costs of production of materials and communications. In other words, such allocated expenses were paid for by shareholders and not by customers. All the parties in UG 435, except for the Coalition,[1] filed a stipulation including a provision reducing revenue requirement associated with salaries, wages and benefits by $5.25 million, which included such costs for employees in Community and Government Affairs. The Coalition sought to disallow the entire budget of salary expenses for the Company's Community and Governmental Affairs employees.

The Commission concluded in Order No. 22-388, at pages 21-24, that it was "not clear" from the record how much of test year expenses were associated with political activities and found that the Company had not provided "any expense

[1] The "Coalition" in UG 435 was comprised of the Coalition of Communities of Color, Climate Solutions, Verde, Columbia Riverkeeper, Oregon Environmental Council, Community Energy Project and Sierra Club.

information detailed enough to separate out" political activities expenses from non-political activities expenses and that it was "unlikely" that all political activities expenses were in fact removed from test year expenses. The Commission signaled that, "[g]oing forward, we expect NW Natural to provide detailed expense information that clearly categorizes its [political] activity." At the same time, the Commission noted that:

> "Our adjustment does not reflect an assumption about what proportion of NW Natural's activity may in the future qualify as political in nature. It merely reflects our hesitation to disallow NW's [sic] Natural's entire Government and Community Affairs budget, despite NW Natural not meeting its burden of proof to adequately delineate political activity, because we are aware that some proportion of the department's work involves informational engagement and education for local governments for which ratepayer support is appropriate."

III. EXPENSES FOR POLITICAL ACTIVITIES

Q. After the Commission issued its Order No. 22-388 in UG 435, what actions did the Company take to meet the Commission's going-forward expectation that NW Natural provide detailed expense information that clearly categorizes its political activities?

A. The Company updated its time-tracking policy for political activities, or activities intended to influence a legislative body, through exception time reporting. Effective January 1, 2023, employees have been entering into the Company's time tracking system, called "WorkForce," exception time spent each working day on such activities. The Company created a "Time Charging Procedures – Political Activities" ("General Procedure") to help its employees with the exception time reporting function. A copy of the General Procedure is attached as Confidential NW Natural/1201, Williams.

Q. How does NW Natural define a "legislative body" for this purpose?

A. A "legislative body" is a congress, tribal government, federal or state legislature, local council or public initiative process to put a measure on a ballot. A legislative body is not a judicial, executive or administrative body (e.g., Department of Environmental Quality, Department of Energy, Treasury, school boards, housing authorities, sewer and water districts, zoning boards), whether elected or appointed.

Q. How does NW Natural describe an "intent to influence" a legislative body?

A. An "intent to influence" a legislative body is an effort undertaken to influence the legislative body through a "lobbying communication."

Q. How does NW Natural describe a "lobbying communication"?

A. A "lobbying communication" is any communication with any member or employee of a legislative body, or with any governmental official or employee who may participate in the formulation of legislation. A lobbying communication includes communications intended to influence the general public, or any segment, with respect to elections, legislation, or initiatives/referendums. This includes attempts to urge or encourage the public to contact members of a legislative body for the purpose of proposing, supporting or opposing legislation. A lobbying communication must include an attempt to influence and does not include communications intended to educate or inform (unless that communication also includes support or opposition).

Q. How do employees determine whether they are spending time on activities intended to influence a legislative body that require exception time reporting?

A. Employees who spend time on activities intended to influence a legislative body, such as some members of the Public Affairs team, may also spend other time on core utility functions. As the Commission stated in Order No. 22-388 and I quoted earlier in my testimony, "we are aware that some proportion of the [Community and Government Affairs] department's work involves informational engagement and education for local governments for which ratepayer support is appropriate." The intent of each employee is critical in determining which of those roles is being performed at a particular time.

In certain cases, an employee's primary role is as a subject matter expert for the utility, where they provide information to elected officials or their staff or the general public regarding NW Natural as a utility and any utility-related data the public or its officials may need. This engagement is a core utility function, and the Company considers it to be appropriate for cost recovery. No exception time reporting is required in these circumstances. Confidential NW Natural/1201, Williams, provides examples of core utility functions.

In other cases, an employee's role is as an advocate for the Company intended to influence a legislative body. In the advocate role of intending to influence a legislative body, the Company allocates that time to non-recoverable cost centers. Exception time reporting is required in these circumstances.

Confidential NW Natural/1201, Williams, provides examples of activities intended to influence a legislative body.

Q. What guidance does the Company use to determine which activities are intended to influence a legislative body?

A. The Company's accountants have informed me that NW Natural takes guidance from the scope of activities described in 18 Code of Federal Regulations ("CFR") Section 367.4264 for the Federal Energy Regulatory Commission ("FERC"). 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.

The Commission cited this CFR section in Order No. 22-388 (page 22) in NW Natural's last rate case when it stated that the Commission's precedent that "utilities are not permitted to recover expenses associated with political lobbying" is "similar to FERC's regulations prohibiting political activities and lobbying."

Q. Does the General Procedure provide detailed instructions for exception time reporting of activities intended to influence a legislative body?

A. Yes. Exception time is to be reported in half-hour increments daily, in the cost center identified in the General Procedure (Confidential NW Natural/1201, Williams). The General Procedure provides illustrative examples for use in exception time reporting and step-by-step screen shots of the "WorkForce" time entry system.

Q. For the avoidance of any doubt, how have employees been treating their time spent on potential "gas bans" in the Company's service territories such as the City of Eugene?

A. Employees are instructed to exception time report all of their activities spent on potential "gas bans" in the Company's service territories such as the City of Eugene, including the Company's referendum campaign to bring Eugene's related ordinance to a ballot measure last year. As a result, customers do not pay for our employees' time spent on such activities.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kathryn M. Williams

EXPENSES FOR POLITICAL ACTIVITIES
EXHIBIT 1201

REDACTED

Per Commission's General Protective Order, this exhibit is confidential in its entirety and has been redacted.

December 29, 2023

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Direct Testimony of Brody J. Wilson and Nikki R. Sparley

UNCOLLECTIBLE EXPENSE
EXHIBIT 1300

December 29, 2023

EXHIBIT 1300 – DIRECT TESTIMONY – UNCOLLECTIBLE EXPENSE

Table of Contents

I. INTRODUCTION AND SUMMARY

Q. Please state your names and positions with Northwest Natural Gas Company dba NW Natural ("NW Natural" or "Company").

A. My name is Brody J. Wilson. My current position is Vice President, Treasurer, Chief Accounting Officer, and Controller at NW Natural. In addition, on July 28, 2023, I was appointed as Interim Chief Financial Officer of Northwest Natural Holding Company ("NW Natural Holdings") and NW Natural. My name is Nikki R. Sparley. My current position is Treasury & Investor Relations Director at NW Natural.

Q. Mr. Wilson, please summarize your educational background and business experience.

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. In 2013, I was appointed as Controller and Chief Accounting Officer of NW Natural and its subsidiaries. In 2016, I also became Treasurer.

Q. Ms. Sparley, please summarize your educational background and business experience.

A. I received a Bachelor of Science in Accounting and English from Minnesota State University in 2005 and a Master of Science in Writing from Portland State University in 2012. From 2005 to 2007, I worked at the public accounting firm Eide Bailly LLP as a Senior Associate, and from 2007 to 2011, I was a Senior Financial and Accounting Analyst and Team Lead over several accounting areas at

Standard Insurance Company. I joined NW Natural in 2011 as a Financial Analyst and became its Financial Reporting Manager in 2014 and its Director of Investor Relations in 2015. I was promoted to my current role in May 2021.

Q. What is the purpose of your testimony regarding uncollectible expense?

A. Our testimony explains what uncollectible expense is and how NW Natural calculated it using a historical average in the revenue requirement for past rate cases. We then discuss the factors that are causing significant changes to uncollectible expense and explain that, as a result, a historical average is not an accurate or reliable method for forecasting uncollectible expense in the Test Year (November 1, 2024 through October 31, 2025) for this case. Finally, we provide NW Natural's proposal for forecasting uncollectible expense in this rate case and support the Test Year forecast amount of $4.49 million.

Q. Please summarize your testimony.

A. NW Natural's goal is to forecast uncollectible expense accurately so that it collects in rates an amount that is as close as possible to the actual expense the Company writes off as uncollectible from customers. With the onset of the COVID-19 pandemic in March 2020 and the resulting disconnection moratorium, the level of uncollectible expense increased to an unprecedented level. Although pandemic conditions improved and the moratorium was lifted for some customers in late 2021, the level of uncollectible expense has remained much higher into 2023 than it was pre-pandemic. Also, in 2022, NW Natural agreed to permanently stop collecting deposits from residential customers, and the Commission adopted many changes to its Division 21 rules strengthening customer protections concerning disconnections. The Company expects that these changes will cause the uncollectible rate to remain higher than pre-pandemic levels, and that the rate will remain volatile over the next several years given current economic conditions.

For all of these reasons, NW Natural proposes to depart from its past approach of using a three-year historical average and instead use an itemized forecast approach, which yields a proposed uncollectible rate of 0.491 percent.

II. BACKGROUND

Q. What is uncollectible expense?

A. Uncollectible expense is the amount owed to NW Natural from customers that cannot be collected and the Company writes off. Because the revenue NW Natural collects each year varies, uncollectible expense is expressed as a percentage of revenue—the uncollectible rate.

Q. When does NW Natural write off amounts as uncollectible?

A. The Company writes off only those unpaid amounts that are significantly past due and deemed uncollectible. In order to deem an amount uncollectible, the Company follows a strict communication process with the customer. First, the Company provides a shut-off notice when a bill is 35 days past due, followed about 10 days later by a phone call informing the customer that their service will be shut off if the customer does not make a payment or enter into a payment arrangement. Within a week after the phone call, a service technician can knock on the customer's door to attempt to collect payment and shut off service if a payment arrangement is not made. Once the account is closed, NW Natural issues a final bill, a reminder notice, and a pre-collection letter over the course of the next two months. If, despite all of these efforts, the outstanding amounts have not been collected within 30 days after the pre-collection letter was sent, then NW Natural writes off the amount owed and sends the account to a collection agency.

Q. Does NW Natural account for amounts recovered via collections when calculating uncollectible expense?

A. Yes. The write-off amounts used in the Company's calculations and discussed in this testimony are net of recoveries. Before the COVID-19 pandemic, collection agencies were able to successfully recover approximately 53 percent of the amounts owed. Today, about 27 percent are recovered.

Q. How did NW Natural forecast uncollectible expense in its past rate cases?

A. In past rate cases, NW Natural used a historical three-year average to forecast the uncollectible rate using the base year for the rate case and the two preceding years. However, in the Company's last rate case filed December 17, 2021, in docket UG 435, the Company made an adjustment to this approach due to the impacts of the COVID-19 pandemic in the three-year historical average. Rather than use the base year 2021 and the two preceding years for the average, the Company used a three-year historical average from March 2017 through February 2020 to avoid including months affected by the COVID-19 pandemic. The resulting uncollectible rate was 0.097 percent. NW Natural used the pre-COVID 19 amounts because the Company expected that the uncollectible rate would begin to return to pre-pandemic levels in the test year of that rate case (November 1, 2022 through October 31, 2023). However, for the reasons explained below, the Company's prior expectation is no longer supportable, and a further methodology change is needed.

III. CHANGES AFFECTING UNCOLLECTIBLE EXPENSE

Q. Please summarize how recent events have affected or are expected to affect the uncollectible rate.

A. Several recent events have resulted in an uncollectible rate that is much higher than it was pre-pandemic and have made it necessary to pivot from using a historical three-year average to using more recent collections experience coupled with forecasted factors. A three-year historical view does not account for factors such as: NW Natural's agreement to stop collecting residential customer deposits, significant changes to the collections and disconnection process adopted in the Division 21 rules, current macroeconomic factors such as inflation and higher interest rates, and federal regulation changes for collection agencies.

Q. How did the COVID-19 pandemic affect the amount of uncollectible expense?

A. In March 2020, NW Natural stopped sending notices[1] and disconnecting accounts—first voluntarily and then pursuant to a Stipulation adopted and subsequently revised by the Commission.[2] As a result, the Company's accounts receivable aged more than 150 days grew to an unprecedented level of nearly $8 million, as shown in Table 1 below.

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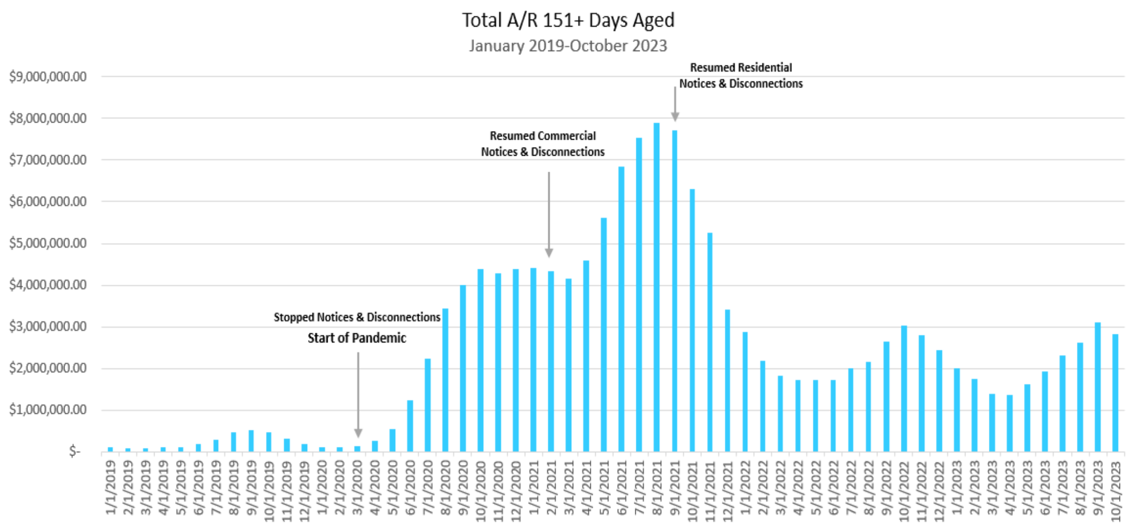
[1] The Company sends both a "reminder notice" and an "urgent final shutoff notice."

[2] *In the Matter of Public Utility Commission of Oregon, Investigation into the Effects of the COVID-19 Pandemic on Utility Customers*, Docket No. UM 2114, Order No. 20-401, App. A at 2-3 (Nov. 5, 2020); Docket No. UM 2114, Order No. 21-057, App. A at 1 (Feb. 24, 2021); Docket No. UM 2114, Order No. 21-164 at 1 & App. A at 4 (May 25, 2021).

<u>TABLE 1</u>



This record deterioration occurred despite NW Natural's efforts to advocate for additional funding for customers (for example the federal Low-Income Home Energy Assistance Program, or LIHEAP, and the Company's Arrearage Management Program, or "AMP"), to connect customers with assistance, and to implement flexible payment arrangements (for example, the Company moved from 12-month arrangements to 24-month arrangements).

Q. Did the amount of aged accounts receivable improve after the disconnection moratorium ended?

A. Yes, but as shown in Table 1, it still remains much higher than pre-pandemic levels. In Fall 2021, NW Natural gradually resumed notices and disconnections—first for commercial accounts and then for most residential accounts. While a protected class of customers was still excluded from having their gas service disconnected,[3] NW Natural was nevertheless able to make progress and reduce the amount of aged accounts receivable. However, in October 2023, the amount of accounts receivable aged more than 150 days was still *six times higher* than it was in October 2019.

In summary, even though the COVID-19 pandemic has formally ended, the current environment remains fundamentally different than pre-pandemic, and NW Natural continues to observe a significantly higher uncollectible rate.

Q. Please explain why NW Natural stopped collecting residential customer deposits.

A. Under the second partial stipulation in NW Natural's last rate case, docket UG 435, NW Natural agreed to stop collecting customer deposits from new residential customers and customers that self-certify as low income or who are currently enrolled in an energy assistance program.[4] During the pandemic, NW Natural had agreed to temporarily stop collecting deposits under the docket UM 2114 stipulation,[5] and the docket UG 435 stipulation made this change permanent.

[3] *In the Matter of Revisions to Division 21 Rules to Strengthen Customer Protections Concerning Disconnections,* Docket No. AR 653, Order No. 22-353 (Sep. 29, 2022*).*

[4] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Order No. 22-388 at 28-30 (Oct. 24, 2022).

[5] *In the Matter of Public Utility Commission of Oregon, Investigation into the Effects of the COVID-19 Pandemic on Utility Customers*, Docket No. UM 2114, Order No. 20-401, App. A at 3-4 (Nov. 5, 2020).

Q. How does not collecting deposits affect the uncollectible expense?

A. Lack of deposits increases the uncollectible expense because NW Natural no longer has funds available to apply to past-due amounts when a customer closes their account. In a pre-pandemic year, NW Natural would collect $1.3 million in deposits on average from its Oregon residential gas customers, but even after applying the $1.3 million in deposits, the Company would still write-off $1.4 million on average from its residential customer base.

Q. Please summarize the recent changes to the Division 21 rules affecting disconnections and collections.

A. The revised Division 21 rules, which took effect in November 2022, made several changes to the collections and disconnection process that have increased uncollectible expense for all customer classes. Specifically, the new rules added winter weather and air quality moratoriums on disconnections, reduced the time available for collection activities in the field, and increased the minimum time from when a customer receives an Urgent Final Shut-Off Notice to disconnection from 15 days to 20 days.

Q. Please explain how the new Division 21 rules impact the amount of time Company employees can spend in the field working to recover past-due amounts.

A. The Division 21 rules now prohibit disconnections for nonpayment after 2:00 PM, whereas 4:00 PM was previously the cut-off time. The rules also prohibit disconnections when temperatures are, or are forecasted to be, less than 32 degrees, when a winter storm warning indicating weather conditions pose a threat to life or property, when a residential or commercial customer is under a level 2 or 3 evacuation notice due to wildfires, or when the Air Quality Index ("AQI") is 100 or above. These changes combine to reduce the amount of time NW Natural personnel can complete "field credit orders." A field credit order is when a NW Natural representative contacts a customer at their home to request payment or set up a payment plan. If an arrangement is not made, the representative can shut off service. There is a direct correlation between the number of field credit orders NW Natural completes and the amount of aged accounts receivable, and the new rules permit less time in the field.

Q. How do the revised Division 21 rules affect the disconnection process?

A. Because the rules require five additional days between the notice and disconnection, NW Natural revised its process to remove the call-ahead that previously occurred three days before disconnection. Now, there is only a single call-ahead one day before the disconnection. With the decreased number of touch points with the customer, NW Natural expects to be less successful at collecting payments prior to disconnection.

Q. Please explain the bill assistance that was available during the pandemic through the AMP and when it ended.

A. The pandemic-era AMP provided over $9 million in grants to qualifying NW Natural customers and allowed NW Natural to automatically credit a struggling customer's account to reduce or eliminate the amount due. The AMP program started in May 2021, and the Company continued initiating grants to qualifying customers through

July 2022. The AMP funds were recovered through the COVID-19 deferral. NW Natural expects that the end of the AMP will increase the uncollectible rate.

Q. Did the COVID-19 deferral have other effects on the amount of uncollectible expense NW Natural recovered?

A. Yes. While the COVID-19 deferral was in place, NW Natural deferred uncollectible expense above the amount approved in rates in docket UG 435. Now that the deferral for uncollectible expense has ended, NW Natural does not have a mechanism in place to recover the difference if the actual uncollectible expense significantly exceeds the amount in rates.

Q. Please explain how NW Natural expects current economic conditions to impact the uncollectible rate.

A. The current macro-economic environment is weaker than in the pre-COVID-19 timeframe of 2017 through early 2020, when NW Natural calculated the historical average uncollectible rate used in its last rate case.

In 2022 the Federal Reserve increased interest rates at the fastest pace in 35 years. The 10-year treasury rate was at 1.52 percent at the end of 2021, compared to 4.58 percent on November 7, 2023. Oregon Office of Economic Analysis in its most recent forecast on page 6 states, "Looking forward, the economy will cool some due to higher interest rates."[6] The report goes on to reflect on page 7, "...national job growth has slowed, and the unemployment rate has risen from 3.4 percent in April 2023 to 3.9 percent in October 2023. Such a move

[6] https://www.oregon.gov/das/oea/Documents/OEA-Forecast-1223.pdf.

up in the unemployment rate only tends to happen heading into recession." Employment growth in Q3 2023 slipped below 2 percent in Oregon, with job losses in manufacturing and higher initial claims for unemployment insurance still a cause for concern based on data from the Oregon Employment Department.

In addition, according to the Federal Reserve Economic Data ("FRED"), the Personal Saving Rate was 6.4 percent in December 2019, whereas in September 2023 it was nearly half that at 3.4 percent; the consumer price index was 2.3 percent in December 2019, reached a high of 9.1 percent in June 2022 according to the Bureau of Labor Statistics, and is still above the Federal Reserve's targeted 2 percent inflation rate in September 2023 with a rate of 3.7 percent. Further, the national delinquency rate on credit card loans has increased to 2.98 percent from a low in the third quarter of 2021 of 1.55 percent and the fourth quarter of 2019's rate of 2.62 percent, according to FRED.

In sum, the risk of a recession remains elevated heading into 2024 as falling savings, continued pressure from higher interest rates, a cooling labor market, and higher than targeted inflation create a weaker macroeconomic environment today compared to our baseline period of 2017-2019. These conditions make using a historical average to determine the uncollectible rate no longer an accurate option.

IV. TEST YEAR FORECAST

Q. How did NW Natural forecast Test Year uncollectible expense for this case?

A. NW Natural began with the uncollectible rate from docket UG 435, which reflects the rate in strong economic conditions, as a baseline, and then the Company made several adjustments to account for various factors that have affected and are expected to continue affecting the rate. This methodology more accurately reflects the uncollectible rate expected during the Test Year than using a three-year-historical-average approach. Please see Figure 1 for an overview of the Company's calculation of the proposed uncollectible rate for the Test Year.

FIGURE 1

Baseline Uncollectible Rate 2017-2019	0.097%
Weaker Economic Conditions	0.100%
Deposits No Longer Collected	0.137%
Division 21: Temperature/Weather/Wildfire/AQI/Shortened Day	0.029%
Division 21: Customer Notice Change 15 to 20 Days	0.007%
Collection Agency Reduced Recoveries	0.071%
Discontinued Arrearage Management Program	0.050%
	0.491%

Q. Please describe the Company's Weaker Economic Conditions adjustment shown in Figure 1.

A. In NW Natural's experience, uncollectible expense typically increases during times of economic downturns. To estimate the impact of weaker economic conditions on our uncollectible rate, we averaged the uncollectible rates during previous technical economic recessions and arrived at 0.40 percent, which is 0.15 percent higher than the average uncollectible rate experienced in non-recessionary periods. Because the economy is weaker but not in a technical recession today, we used a 0.10 percent impact on the uncollectible rate. We will continue to monitor economic factors and evaluate this evolving situation during the rate case. However, it is important to adjust for this factor because, with our uncollectible rate set in docket UG 435 at 0.097 percent, increases in the rate due to an economic downtown have the potential to more than double our yearly uncollectible expense.

Q. Please describe the Company's adjustment for Deposits No Longer Collected shown in Figure 1.

A. As we explained above, NW Natural permanently stopped collecting deposits from new residential or low-income customers as a result of the stipulation adopted in docket UG 435 by Order No. 22-388. Prior to that, residential customers that were deemed high risk based on factors such as a history of delayed payments, prior bankruptcy filing, or theft of gas were charged a deposit. The practice of collecting deposits offered customers a safety net and also helped the Company mitigate write-offs. When a customer closed their account, any deposit that was held was credited back on their closing bill, helping reduce the closing bill. Lower closing bill amounts result in lower write-offs if the closing bill was not paid. NW Natural collected an annual average of $1.4 million per year in deposits from our Oregon Residential customers in 2017 through 2019. During that time, NW Natural refunded on average $600,000 in deposits on customers closing bills, meaning that customer deposits assisted the customers and reduced potential write-offs by $600,000 per year on average, or 0.137 percent of the annual residential gas revenues for that time period. Therefore, it is reasonable to expect that going forward, NW Natural's lack of deposits will increase the uncollectible rate by 0.137 percent.

Q. Please describe the Company's adjustment for Division 21: Temperature/Weather/Wildfire/AQI/Shortened Day shown in Figure 1.

A. The revised Division 21 rule that took effect on September 30, 2022 created many changes to NW Natural's accounts receivable collection processes and procedures. These changes included shorter time frames for our technicians to visit customers and collect payments, new weather moratoriums, and a longer notification timeframe. They create less time for our technicians to collect on accounts in the field, which results in a higher uncollectible rate.

Prior to the Division 21 rule changes being implemented, NW Natural's technicians would work field credit orders from approximately 8:00 AM until 4:00 PM. The new rules state that technicians need to stop completing field credit orders by 2:00 PM. That is a time reduction of 25 percent to complete field credit orders each day, which equates to approximately 52 days a year that are lost due to this rule.

In addition, there were two weather moratoriums imposed as part of the revised Division 21 rules. First, the cold weather moratorium prohibits NW Natural from disconnecting customers if the weather is or is forecasted to be less than 32 degrees or when there is a winter storm warning indicating weather conditions pose a threat to life or property. This weather moratorium resulted in approximately 28 days of inability to complete field credit orders in one or more areas in our territory during the winter of 2022 - 2023. Second, the new Air Quality moratorium prohibits NW Natural from completing field credit orders if the AQI is

100 or above. This resulted in approximately four days of inability to complete field credit orders in 2022.

As a result, NW Natural on average is unable to complete credit field orders approximately 84 days per year. Field credit orders are an important part of a Company's collections process because they allow our technicians to talk to customers and make payment arrangements, collect money, or disconnect service. The longer a customer is allowed to continue using gas service without payment, results in a higher bill and eventually leads to a higher uncollectible expense. We conservatively used the 2022 net write-off rate and 2023 budgeted residential revenues to calculate that our daily net write-off amount is $3,723, which equates to $313 thousand of incremental write-offs for the reduction of 84 days for field credit orders. Translating the $313 thousand to a percent of total 2023 budgeted revenues provides the 0.029 percent increase in our uncollectible expense that we anticipate from the lost time in the field to complete credit orders.

Q. Please describe the Company's adjustment for Division 21: Customer Notice Change 15 to 20 Days shown in Figure 1.

A. The revised Division 21 rules also require NW Natural to provide more notice time to customers before interruption of service. Specifically, the required notice period increased from 15 days to 20 days. In order to comply with this requirement in the most effective and efficient manner, NW Natural needed to forgo our three-day call-ahead that the Company previously provided to customers. Historically the Company provided a call-ahead to the customer three days and one day prior to disconnection. Now, the Company still provides the one-day call-ahead but has eliminated the three-day call-ahead. NW Natural historically received payment from about 20 percent of the customers it reached out to with the three-day call ahead. We took the September 2023 account balance aged 60+ days of $6.8 million and multiplied it by the 20 percent to reach $1.4 million of accounts receivable that we would expect to collect from the three-day call ahead. Of that $1.4 million, we typically see 6 percent of accounts receivables turn into delinquent accounts that are deemed uncollectible and written off. The $1.4 million multiplied by 6 percent equates to $81 thousand of incremental uncollectible expense. To convert that to a percentage, we took the $81 thousand divided by the $1.1 billion of 2023 budgeted total revenues. Therefore, with the reduction in payments resulting from the removal of the three-day call-ahead, NW Natural expects it will see an increase in uncollectible expense of 0.007 percent.

Q. Please describe the Company's adjustment for Collection Agency Reduced Recoveries shown in Figure 1.

A. When NW Natural writes off an account balance, it is sent to a collection agency that will try to recover the balance on behalf of NW Natural. Post-pandemic, NW Natural has seen a decline in the number of recoveries received from collection agencies. One factor is due to the Consumer Financial Protection Bureau (CFPB) amending Regulation F (12 C.F.R. § 1006 and following). As of November 30, 2021, under these changes, consumers have more control over how debt collectors communicate with them, while collectors have new restrictions on how they collect debts. For NW Natural, pre-pandemic, recoveries for 2014-2019 averaged 53 percent. Post-pandemic, the Company received only 27 percent recovery, on average, for 2022 and through October 2023. When the Company applied that 27 percent reduction in recoveries to our write-offs, it increased the uncollectible expense by 0.071 percent.

Q. Please describe the Company's adjustment for the Discontinued Arrearage Management Program shown in Figure 1.

A. As discussed above, during the pandemic, NW Natural provided over $9 million in grants to customers in need of payment assistance due to the pandemic under the AMP. NW Natural started giving out grants to customers under the program in May 2021 and initiated its last grants in July 2022. Without the AMP program, NW Natural would have had a higher uncollectible expense due to higher customer balances. In the months of May 2021 through December 2022,[7] NW Natural wrote off $4,704,000. Of that amount, approximately $1.2 million in write offs were associated with accounts that had received AMP funds. If we apply our post-pandemic collection agency recovery rate of 27 percent to the write offs on accounts that received AMP funds, it results in a net write off of approximately $900,000. If the Company were to restate our annual net write-offs to include this amount of $900,000 for the AMP program years, we would see an increase to our uncollectible expense of 0.05 percent. Therefore, we project the uncollectible rate to be 0.05 percent higher in the absence of the AMP.

[7] The timeframe ended in December 2022 was used in order to capture write-offs that occurred after the last grants were initiated in July 2022.

Q. As a comparison, what would the uncollectible rate be if NW Natural had continued to use its prior three-year-historical-average approach?

A. The three-year historical average rate for years October 2021 through October 2023 is 0.182 percent, which is much lower than the rate the Company has observed in 2023 and expects in the Test Year and going forward.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Direct Testimony of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 1400

December 29, 2023

EXHIBIT 1400 – 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 2023 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, 2025 ("Test Year");

- Discuss the Company's performance in managing O&M expense; 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 $237.1 million. This compares to a Company total of $265.4 million of O&M for the Test Year, which is adjusted for state allocations, uncollectible accounts expense (NW Natural/1300, Wilson-Sparley) and amounts that represent O&M for which the Company is not seeking cost recovery in this case. Exhibit NW Natural/1401, Davilla shows the Base Year O&M expense and Exhibit NW Natural/1402, 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 2023. How did NW Natural establish Base Year O&M costs given that this filing is being made in December 2023?

A. The Company used the actual expenses for January through September 2023 and forecast the expenses for the remaining three months of 2023 to develop the total Base Year O&M expenses. The total Company Base Year O&M, excluding uncollectible accounts expense, is forecast to be $221.0 million, or $197.7 million on an Oregon-allocated basis. The Company adopted the calendar year 2023 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 435.

Q. How did NW Natural determine the forecasted costs for October through December 2023?

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 2023. 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 2023 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 West Region Urban Consumer Price Index ("CPI") as reported in the September 2023 Oregon Economic and Revenue Forecast, published by the Oregon Office of Economic Analysis ("OEA").[1] Other O&M cost adjustments were calculated specifically for

[1] NW Natural/1403, Davilla/54.

the Test Year. Base Year payroll costs were also adjusted for increases through the Test Year.

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 2023 Base Year forecast includes 1,170 gas-regulated FTEs. These 1,170 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 2023 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 but expected to be hired prior to the rate effective date (i.e., November 1, 2024). These FTE are to provide skillsets necessary to support the Company's more sophisticated technological capabilities, while ensuring reliable, customer-friendly, and secure operations (NW Natural/700, Downing) and necessary to ensure that the Company can efficiently comply with the Climate Protection Program (NW Natural/1500, Kravitz-Chittum).

Q. Did the projected FTE count consider vacancies and FTEs allocated to non-utility activities?

A. Yes. NW Natural does not seek to recover in rates costs for 64.3 vacant FTE positions and 63.7 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	1,311.0
Unfilled FTE Adjustment	(64.3)
Hired FTEs	1,246.7
Non-regulated FTE Removal	(63.7)
Regulated FTEs	**1,183.0**

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 63.7 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)
Affiliate Activity	(33.1)
North Mist Storage	(8.8)
Interstate Storage	(6.2)
Other Non-Regulated Activity	(7.4)
Non-Regulated FTE Removal	**(63.7)**

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 2022 Affiliated Interest Report and Cost Allocation Manual*, Docket No. RG 8, Exhibit B, Page 4 (April 27, 2023).

commenced on December 1, 2019, and will run through May 31, 2024.[3] NW Natural is currently in negotiations with the bargaining unit. The Direct Testimony of Melinda B. Rogers (NW Natural/1000, Rogers) discusses BU payroll costs used in this case.

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, 2024, and 4.25 percent on March 1, 2025. Based on historical trends, the Company also assumes an additional 0.80 in 2024 and 0.60 percent in 2025 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 these 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 their time to capital. In the second approach, employees who are generally supportive of both capital and O&M projects, such as human resources,

[3] See NW Natural/1404, Davilla.

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 64.9 percent. The Company calculated this allocation using the historical O&M allocation for the trailing 12-month period ended September 2023 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 West Region Urban CPI as reported in the September 2023 Oregon Economic and Revenue Forecast, published by the OEA.[4] These escalation factors were applied on January 1, 2024, and January 1, 2025. The Company also identified several items where the growth projection was greater or lesser than using CPI and adjusted these items with their specific increase or decrease.

[4] See NW Natural/1403, Davilla/54.

Q. Why did NW Natural use the West Region Urban CPI as the escalator for these accounts instead of the U.S. All-Urban CPI?

A. NW Natural specifically selected the West Region Urban CPI because a regional CPI provides a better measure of aggregate price changes experienced by the Company than a national CPI. This is because most of the Company's non-payroll expenses (*e.g.,* office supplies, utilities, repairs and maintenance, contractors, professional services) are regional purchases (*i.e.*, purchases made within Oregon or southwest Washington). Therefore, a regional CPI is more representative of the price changes experienced by the Company.

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 Headquarter Lease Expense (FERC 931) 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 expense in the Test Year. The total expense adjustment decrease in the Test Year is $186 thousand, and the Oregon-allocated amount after administrative transfer is $107 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 revises 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 capitalizable. Beginning in 2024, NW Natural will begin its first rig-based casing 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 re-assessment work is an O&M expense. The total expense increase in the Test Year is $625 thousand, and the Oregon-allocated amount is $556 thousand.

- Advertising Adjustment (FERC 913 & 909): The Company included advertising costs for Category A equivalent to $1.95 per customer, and $975,000 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 $527 thousand, and the Oregon-allocated amount is $463 thousand.
- Contracted Customer Payment Processing Fees (FERC 903): The Company entered into an agreement with Paymentus[5] to provide electronic bill payment services in March of 2019 that went into effect in October 2020. The Company expects to sign a contract amendment and extension in the near term. In addition to the impacts of the new amendment, the Company has experienced 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. The total expense increase in the Test Year is $1.46 million, and the Oregon-allocated amount is $1.29 million.
- Contracted Locating 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.

[5] See NW Natural/1405, Davilla (Confidential).

The Company entered into a new amended agreement with Heath Consultants effective September 1, 2023.[6] This agreement runs through December 31, 2026. Prior to this agreement, locating and marking services was provided by Locating, Inc. throughout most of the Base Year. 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. The total expense increase in the Test Year is $3.2 million, and the Oregon-allocated amount is $2.9 million.

- Contracted Survey Services (FERC 874): The Company entered into a new amended agreement with Heath Consultants on September 1, 2023[7] and running through December 31, 2026, to 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 a 3 percent annual increase throughout the contract. The

[6] See NW Natural/1406, Davilla (Confidential).

[7] *Id.*

total expense increase in the Test Year is $1.0 million, and the Oregon-allocated amount is $915 thousand.

- Information Technology and Services ("IT&S") (FERC 921): The Direct Testimonies of Jim R. Downing (NW Natural/700 and 800, Downing*)* discuss in more detail the largest components of the IT&S O&M expense increase. The total expense increase in the Test Year is $6.0 million, and the Oregon-allocated amount after administrative transfer is $4.5 million.
- Insurance (FERC 924): The Company has incurred insurance premiums for the fiscal period 2023-2024 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 projects the Test Year expense to increase by ten percent. The total expense increase in the Test Year is $910 thousand, and the Oregon-allocated amount is $804 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 23.5 percent to the payroll charges.[8] The Oregon-allocated credit amount after administrative transfer during the Test Year is $512 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, non-payroll and a 23.5 percent overhead applied to payroll is credited through a mechanism described in more detail in the CAM.[9] The Oregon-allocated indirect non-payroll allocated amount and 23.5 percent administrative overhead credited to the utility during the Test Year is $490 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.

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[8] See *NW Natural's 2022 Affiliated Interest Report and Cost Allocation Manual*, Docket No. RG 8, Exhibit B, Page 6 (April 27, 2023).

[9] *Id.*, Page 7.

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 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) OR 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: $24.3 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: $7.7 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: $903 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 $1.1 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 $73 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 $1.0 million, or $903 thousand Oregon-allocated. This cost is expensed as an O&M expense.
- Pension Non-Service: $4.6 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 $8.5 million. This is made up of a service component and a non-service component. The system service expense forecasted in the Test Year is $3.4 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 $5.1 million, or $4.6 million Oregon-allocated. This non-service portion of pension is expensed as O&M.

- Claims and Damages: $139 thousand expense – This expense is based on a three-year historical average.
- Severance: $103 thousand expense – This expense is based on a three-year historical average.
- Stock expense: $1.1 million 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: $130 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 $25.1 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/1700, Walker).

III. O&M EXPENSE MANAGEMENT AND COMPANY PERFORMANCE

Q. Does NW Natural have cost control protocols and practices in place?

A. Yes. Under the direction of the Interim 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 new customer payment processing contract and locating and survey service contract.

Furthermore, as described more in the Direct Testimony of Jim R. Downing (NW Natural/700, Downing), 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.

Q. Have you compared NW Natural's O&M expense per customer to O&M expenses per customer at comparable utilities?

A. Yes. Chart 1, which is also seen in the Direct Testimony of Justin B. Palfreyman and Zachary D. Kravitz (NW Natural/100, Palfreyman-Kravitz), provides a comparison of the Company's O&M per customer expense with a panel of similar gas utilities. For comparability purposes, NW Natural excludes expenses related to the environmental docket (UM 1635, Order No. 15-049) and non-service pension expense, and production and transmission expenses are excluded for the peer group and NW Natural.

<u>Chart 1</u>

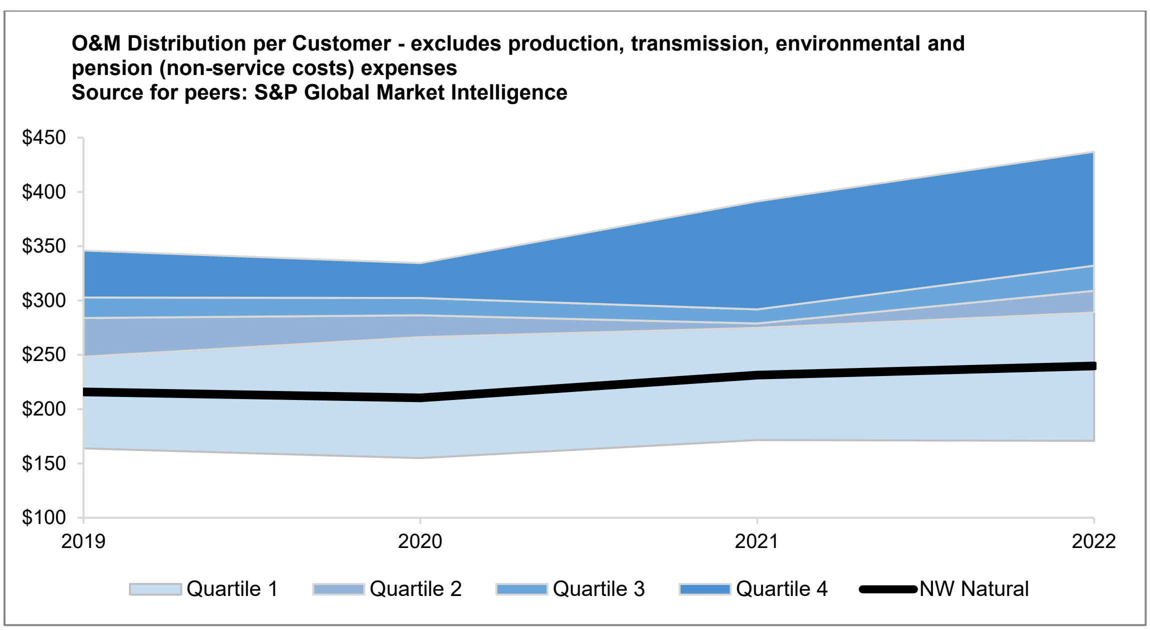


Chart 1 shows that NW Natural is consistently a top performer in O&M expense management. The panel uses customer counts and costs for those companies with FERC Form 2 information available in S&P Global Market Intelligence, and includes the following companies: Atmos, Avista, Cascade Natural Gas, National Fuel Gas, New Jersey Gas, and Washington Gas and Light.

Again, this information shows that NW Natural performs well in managing its O&M expense to keep rates low for customers while providing the high-quality service our customers expect.

IV. 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 2023 are $328 million, for 2024 are $375 million, and for 2025 are $363 million. The capital expenditures forecasted for the Test Year are $361.7 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 435, that will be used and useful as of the rate effective date of this case—November 1, 2024. 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. Could you define the difference between "discrete" and "non-discrete" expenditures?

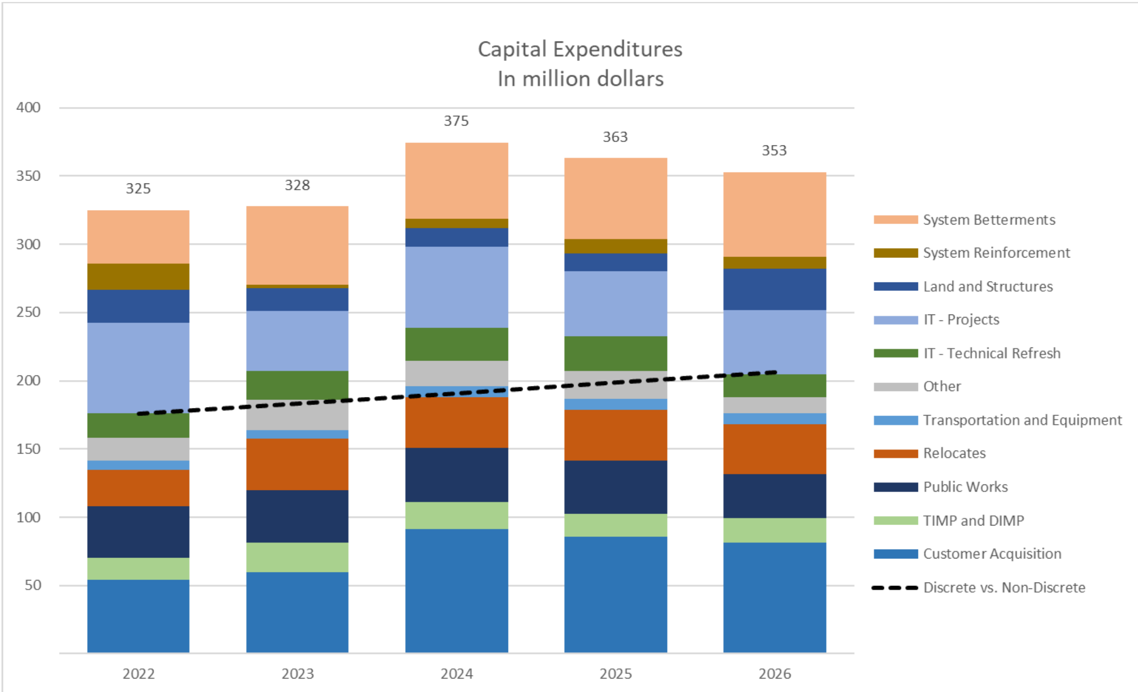
A. The Company's capital expenditures can be thought of as falling into one of two categories. The first category consists of "discrete investments" that the Company has proposed and planned to implement to fulfill a specific operational aim, or to address a specific system issue. These discrete projects 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 widely 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, (*e.g.*, Data Reporting and Analytics Project) 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.

Figure 1



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 (NW Natural/500, Kizer), Wayne K. Pipes (NW Natural/600, Pipes), and Jim R. Downing (NW Natural/700 and 800, Downing).

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[10] on the Company's system.

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[10] 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".

- ***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 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

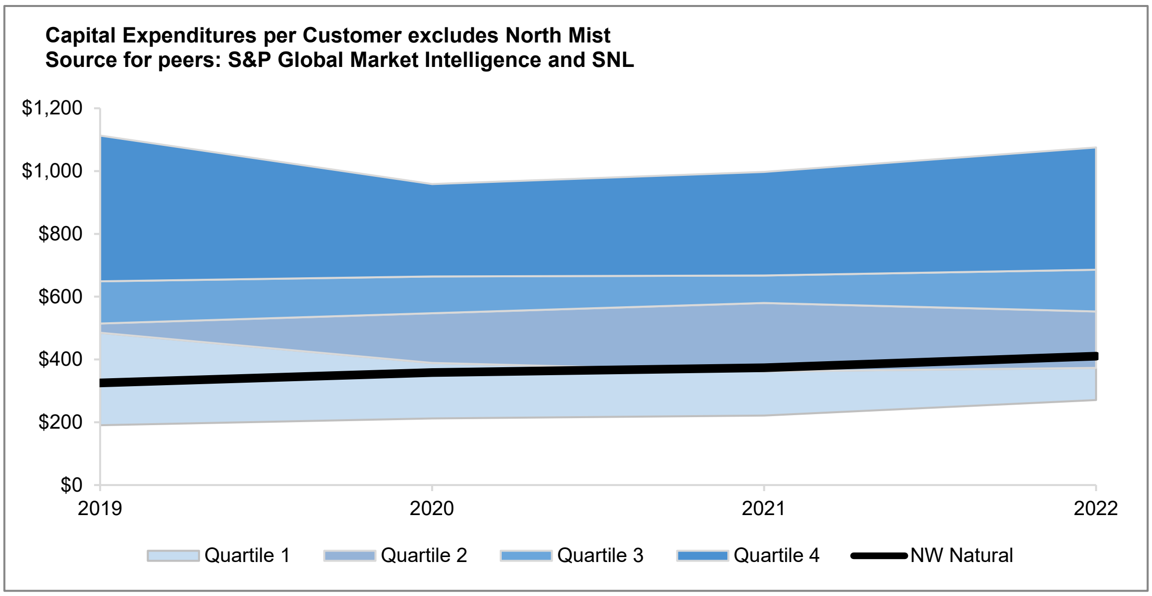
on annual trends, the Company's inventories, safety needs, and best practices for replacement of equipment at the end of its useful life. *Leakage* – Leakage costs represent replacements of services and mains that result from leaks on the Company's system. Like damage and public works projects, these 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. Have you compared NW Natural's capital expenditures to capital expenditures of comparable utilities?

A. Yes. NW Natural's capital expenditures are historically lower than comparable utilities. To make a relevant comparison, we evaluated capital expenditures per customer. Chart 2 below, which is also seen in the Direct Testimony of Justin B. Palfreyman and Zachary D. Kravitz (NW Natural/100, Palfreyman-Kravitz), provides a comparison of the Company's capital expenditures per customer with a panel of similar gas utilities for the 2019-2022 period. NW Natural excluded investment in the North Mist expansion project. The panel includes the following companies: National Fuel Gas, South Jersey Gas, New Jersey Natural Gas, NiSource Inc., Atmos, Chesapeake Utilities, Southwest Gas, Spire, and One Gas.

Chart 2



Again, these metrics indicate that NW Natural implements effective cost management procedures, while keeping its system safe and reliable.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibits of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBITS 1401 - 1406

December 29, 2023

EXHIBITS 1401 – 1406 – OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES

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PUBLIC UTILITY COMMISSION OF OREGON

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NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 1401

December 29, 2023

NW Natural
Base Year Twelve Months Ended December 31, 2023
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**	$535,401	$480,675
5	818	**Compressor Station Expense**	292,297	260,174
6	819	**Compressor Station Fuel**	40,618	36,154
`	820	**Measuring and Regulator Station Expense**	3,051,592	2,716,306
7	821	**Purification Expense**	-	-
8		**Maintenance**		
9	832	**Wells Expense**	291,340	259,321
10	834	**Compressor Station Expense**	1,565,966	1,393,867
11		**Total Underground Storage Expense**	5,777,214	5,146,497
12		**Other Storage Expense**		
13		**Operation**		
14	840	**Supervision and Engineering**	176,482	157,087
15		**Total Other Storage Expense**	176,482	157,087
16		**Liquified Natural Gas Expense**		
17		**Operation**		
18	844	**Supervision and Engineering**	1,783,060	1,587,102
19	845	**LNG Fuel**	(156,047)	(138,898)
20		**Maintenance**		
21	847	**Supervision and Engineering**	1,796,310	1,598,896
22		**Total Liquified Natural Gas Expense**	3,423,324	3,047,100
23		**Total Natural Gas Storage**	9,377,019	8,350,684
24		**Transmission Expense**		
25		**Operation**		
26	856	**Mains Expense**	4,107,220	4,056,748
27		**Maintenance**		
28	863	**Maintenance of Mains**	27,959	27,614
29		**Total Transmission Expense**	4,135,179	4,084,362
30		**Distribution Expense**		
31		**Operation**		
32	870	**Supervision and Engineering**	3,662,586	3,378,837
33	874	**Mains and Services Expense**	18,694,209	16,572,616
34	875	**Measuring and Regulator Station Expense - G**	341,059	309,981
35	877	**Measuring and Regulator Station Expense - Ci**	667,892	606,317
36	878	**Meter and House Regulator Expense**	4,266,747	3,750,044
37	879	**Customer Installation Expense**	22,138,711	19,457,611
38	880	**Other Expense**	1,455,697	1,285,938
39	881	**Rents**	274,341	237,333
40		**Maintenance**		
41	885	**Supervision and Engineering**	5,725,244	5,242,291
42	887	**Mains**	5,265,706	4,855,308
43	889	**Measuring and Regulator Station Expense - G**	2,212,602	2,009,413
44	891	**Measuring and Regulator Station Expense - Ci**	126,414	115,387
45	892	**Services**	537,750	472,655
46	893	**Meters and House Regulators**	2,817,101	2,483,229
47	894	**Other Equipment**	14,151	12,439
48		**Total Distribution Expense**	68,200,211	60,789,398
49		**Customer Accounts Expense**		
50		**Operation**		
51	901	**Supervision**	2,192,590	1,927,067
52	902	**Meter Reading Expenses**	570,630	501,527
53	903	**Customer Records and Collection Expense**	21,940,623	19,310,829
54	904	**Uncollectible Accounts**	-	-
55		**Total Customer Accounts Expense**	24,703,843	21,739,423
56		**Customer Service and Informational**		
57		**Operation**		
58	907	**Supervision**	-	-
59	908	**Customer Assistance Expense**	2,282,925	2,017,730
60	909	**Customer Information Expense**	2,430,291	2,135,983
61	910	**Miscellaneous Customer Service Expense**	186,763	163,829
62		**Total Customer Service and Informational**	4,899,980	4,317,542
63		**Sales Expense**		
64		**Operation**		
65	911	**Supervision**	210,882	185,344
66	912	**Demonstration and Selling Expense**	1,531,247	1,348,431
67	913	**Advertising**	980,002	861,324
68	916	**Miscellaneous Sales Expense**	-	-
69		**Total Sales Expense**	2,722,132	2,395,100
70		**Administrative and General Expense**		
71		**Operation**		
72	921	**Office Supplies and Expense**	96,714,065	85,232,136
73	922	**Administrative Expenses Transferred - Credit**	(31,867,028)	(28,135,701)
74	924	**Property Insurance Premium**	5,104,380	4,510,230
75	925	**Injuries and Damages**	196,151	173,319
76	926	**Employee Pensions and Benefits**	9,610,502	9,336,099
77	928	**Regulatory Commission Expense**	-	-
78	930	**Miscellaneous General Expense**	4,963,081	4,560,973
79	931	**Rents**	10,565,934	9,336,533
80		**Maintenance**		
81	932	**Maintenance of General Plant**	6,703,560	6,031,654
82		**Total Administrative and General Expense**	101,990,645	91,045,242
83		**Total Operations and Maintenance Expense**	216,029,010	192,721,751
84	407	**Environmental Rider**	5,000,000	5,000,000
85		**Total O&M Expense including Environmental Rider**	221,029,010	197,721,751

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 1402

December 29, 2023

NW Natural
Test Year Twelve Months Ended October 31, 2025
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	$223,299	$200,475
5	818	Compressor Station Expense	309,948	275,885
6	819	Compressor Station Fuel	42,722	38,027
`	820	Measuring and Regulator Station Expense	2,684,578	2,389,616
7	821	Purification Expense	-	-
8		Maintenance		
9	832	Wells Expense	939,825	836,538
10	834	Compressor Station Expense	1,641,510	1,461,108
11		Total Underground Storage Expense	5,841,882	5,201,649
12		Other Storage Expense		
13		Operation		
14	840	Supervision and Engineering	207,217	184,444
15		Total Other Storage Expense	207,217	184,444
16		Liquified Natural Gas Expense		
17		Operation		
18	844	Supervision and Engineering	2,021,911	1,799,703
19	845	LNG Fuel	(166,352)	(148,069)
20		Maintenance		
21	847	Supervision and Engineering	2,044,959	1,820,218
22		Total Liquified Natural Gas Expense	3,900,519	3,471,852
23		Total Natural Gas Storage	9,949,617	8,857,944
24		Transmission Expense		
25		Operation		
26	856	Mains Expense	4,463,283	4,408,436
27		Maintenance		
28	863	Maintenance of Mains	32,445	32,045
29		Total Transmission Expense	4,495,729	4,440,481
30		Distribution Expense		
31		Operation		
32	870	Supervision and Engineering	4,280,643	3,949,011
33	874	Mains and Services Expense	24,948,078	22,116,738
34	875	Measuring and Regulator Station Expense	388,935	353,494
35	877	Measuring and Regulator Station Expense	754,217	684,683
36	878	Meter and House Regulator Expense	4,977,440	4,374,672
37	879	Customer Installation Expense	25,861,108	22,729,207
38	880	Other Expense	1,707,241	1,508,148
39	881	Rents	291,272	251,980
40		Maintenance		
41	885	Supervision and Engineering	6,752,914	6,183,272
42	887	Mains	6,039,880	5,569,144
43	889	Measuring and Regulator Station Expense	2,552,959	2,318,513
44	891	Measuring and Regulator Station Expense	139,569	127,394
45	892	Services	608,480	534,823
46	893	Meters and House Regulators	3,281,330	2,892,440
47	894	Other Equipment	16,565	14,560
48		Total Distribution Expense	82,600,629	73,608,080
49		Customer Accounts Expense		
50		Operation		
51	901	Supervision	2,589,030	2,275,498
52	902	Meter Reading Expenses	671,554	590,229
53	903	Customer Records and Collection Expense	26,223,978	23,080,783
54	904	Uncollectible Accounts	-	-
55		Total Customer Accounts Expense	29,484,562	25,946,509
56		Customer Service and Informational		
57		Operation		
58	907	Supervision	-	-
59	908	Customer Assistance Expense	2,699,948	2,386,310
60	909	Customer Information Expense	3,282,434	2,884,932
61	910	Miscellaneous Customer Service Expense	220,786	193,674
62		Total Customer Service and Informational	6,203,169	5,464,915
63		Sales Expense		
64		Operation		
65	911	Supervision	249,228	219,046
66	912	Demonstration and Selling Expense	1,759,202	1,549,170
67	913	Advertising	(0)	(0)
68	916	Miscellaneous Sales Expense	-	-
69		Total Sales Expense	2,008,430	1,768,217
70		Administrative and General Expense		
71		Operation		
72	921	Office Supplies and Expense	113,041,240	99,620,942
73	922	Administrative Expenses Transferred - Cre	(36,860,295)	(32,544,304)
74	924	Property Insurance Premium	6,325,360	5,589,088
75	925	Injuries and Damages	198,213	175,141
76	926	Employee Pensions and Benefits	19,031,456	17,714,424
77	928	Regulatory Commission Expense	-	-
78	930	Miscellaneous General Expense	5,414,275	4,977,707
79	931	Rents	11,024,949	9,742,139
80		Maintenance		
81	932	Maintenance of General Plant	7,435,413	6,690,152
82		Total Administrative and General Expense	125,610,609	111,965,290
83		Total Operations and Maintenance Expense	260,352,744	232,051,435
84	407	Environmental Rider	5,000,000	5,000,000
85		Total O&M Expense including Environmental Rider	265,352,744	237,051,435

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 1403

December 29, 2023

DAS
DEPARTMENT OF ADMINISTRATIVE SERVICES

Oregon Economic and Revenue Forecast

September 2023

Volume XLIII, No. 3
Release Date: August 30th, 2023

Department of Administrative Services
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DAS Director
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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. It is the basis for much of the budgeting in state government.

The report is issued four times a year; in 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, while 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 in turn 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 telephone at 503-378-3405.

Berri Leslie

Berri Leslie
DAS Director
Chief Operating
Officer

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Executive Summary

September 2023

The economy continues to be in an inflationary boom. Growth is outpacing expectations. The good news is inflation has slowed considerably in the past year. The consensus of economic forecasters is now that the economic soft landing is the most likely scenario. The challenge today is twofold. First, there are emerging signs that the economy is reaccelerating which means inflation could re-heat at some point in the quarters ahead. Second, this leaves the Federal Reserve in a tough position of trying to thread the needle of raising interest rates just enough to cool the economy and bring inflation down, but not too much that chokes off growth. The initial descent appears to have gone as good as can be expected. However, navigating the crosswinds of waiting for the full impact of past interest rate increases to slow growth even as inflation remains above target is challenging.

Oregon's economic outlook remains effectively unchanged from last quarter. The labor market is tight, albeit less so than during the reopening phase of the cycle. And as inflation slows, income gains are once again outpacing price increases, leading to rising living standards. With the economy at full employment, future growth will come from labor force gains driven by a return of positive net migration in the years ahead, along with productivity gains driven by capital investment. The combination of the post-pandemic rise in start-up activity, large increase in federal investment, including in semiconductors, and the potential of generative AI should all help to boost productivity in the years ahead. Oregon is well-positioned to benefit.

After several quarters of unexpectedly rapid growth in tax collections, Oregon's state revenue outlook appears to have stabilized. Collections in recent months have tracked closely with the May forecast. Even so, Oregon has yet to go through its first personal income tax filing season of the biennium, and as such, everything remains at risk.

This revenue forecast represents the last look at the 2021-23 biennium and reveals the Close of Session (COS) forecast for the current 2023-25 biennium. The Close of Session forecast sets the bar for Oregon's constitutionally required balanced budget, as well as its unique kicker law. The COS incorporates any legislative changes enacted during the legislative session that impact General Fund revenues and folds them into the mid-session (May) revenue forecast that covers the next two years, and forms the basis of the legislatively adopted budget. This session's legislative changes were relatively modest in scope, totaling a reduction of $48.6 million in expected General Fund revenues relative to the May forecast.

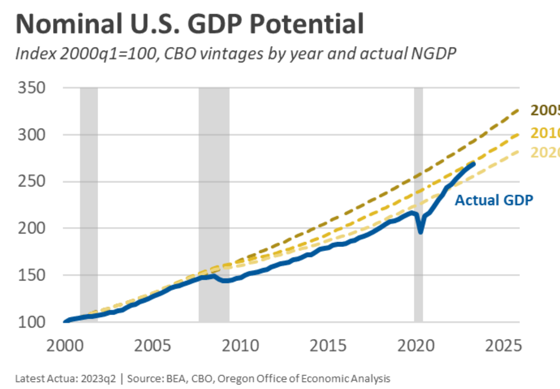
Total General Fund resources in 2023-25 are increased $437 million compared to the Close of Session forecast. Most of the increase can be attributed to collections of corporate income taxes, which continue to outstrip underlying profit earnings. Additionally, a larger beginning balance increases resources, a direct result of a larger ending balance last biennium as the accountants closed the books this summer. That increase in revenues at the end of 2021-23 does result in a larger personal income kicker than previously estimated. Our office will certify the kicker in the coming weeks, but currently $5.6 billion will be returned to Oregon taxpayers next filing season. The median, or typical Oregonian is expected to receive a $980 credit.

Economic Outlook

Macroeconomic Setting

Stepping back and examining the pandemic business cycle to date shows that the U.S. economy is on a much different trajectory than expected. At nearly every point since the shutdowns, the economy has outpaced expectations. So much so that when comparing the actual size of the U.S. economy today, not only is it above what economists thought the potential would be, it is starting to make up a lot of the lost ground from last decade when the slow, steady, and subpar recovery from the Great Financial Crisis was thought to have permanently scared the economy. This is a reminder that the potential size, and growth of the economy is not fixed. The combination, and contributions from labor and capital can, and do change, in part driven by public policy. As an example, the strong pandemic recovery has largely been driven by the very large, federal fiscal response, both initially and in subsequent legislation.

Now, of course this cycle has been an inflationary economic boom. On a real, or inflation-adjusted basis the gains are more in line with pre-pandemic expectations. Ultimately it is those real gains that matter when measuring growth and living standards. However, we live our lives in the nominal world. In that sense, incomes, consumer spending, business revenue, and tax collections all outpace expectations in recent years.

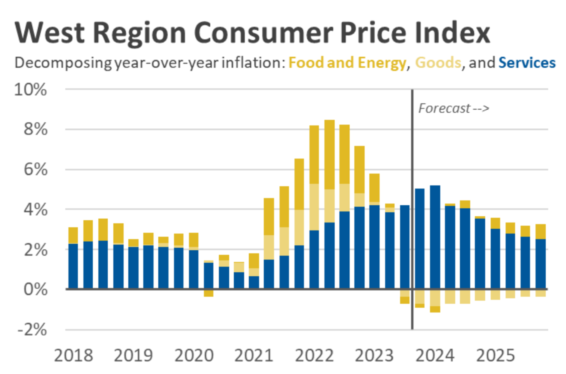


Inflation is Slowing, Now the Hard Part

Inflation Outlook

The good news is inflation has slowed considerably in the past year. On a year-over-year basis, the Consumer Price Index (CPI) last summer was running at a nine percent pace. This summer, CPI is running between three and four percent. Much of this slowdown in inflation is tied to supply side healing in the global economy, meaning supply chain struggles have eased, and food and energy prices have come off the boil. Expectations are inflation will remain relatively low in the months ahead as both autos and shelter inflation weigh on the overall index.

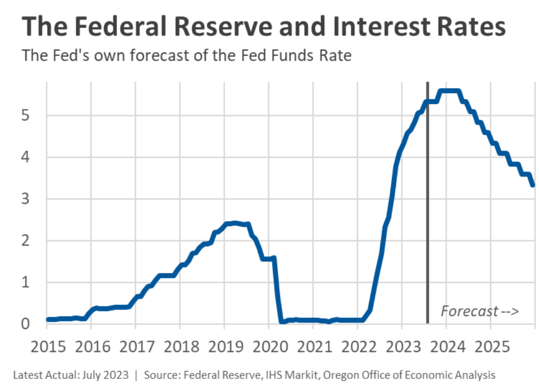
The bad news is even with all of the good news, inflation remains above the Federal Reserve's two percent target. And with the underlying growth in the economy reaccelerating today, inflation may re-heat as well in the not-too-distant future. To be clear, the baseline outlook remains for inflation to continue to broadly slow, with a multiyear period required to fully get back to the Fed's target on a sustainable basis. But risks remain that inflation may pick back up later this year or next.



Federal Reserve Policy

The current state of the economy leaves the Federal Reserve in a tough position. The reacceleration in growth appears to have caught the Fed, and many economists, a bit off-guard. Expectations were for the economy to continue to slow, alleviating pressure that results in inflation continuing to subside. This may very well be the case, and remains the theoretical lynchpin to the soft landing scenario. The renewed strength in the economy today may prove temporary. In fact the Fed is counting on that.

Historically the impact of past interest rate increases takes anywhere from 6 to 18 months to be felt in the real economy, even as financial markets react immediately. As Milton Friedman famously said the impacts of monetary policy are long and variable. There is some indication that in today's world of increased access to information in real time, the lags are shorter. Even so, the Fed has raised interest rates more than five percentage points in the past 18 months. Some additional slowdown in the economy should still be expected as the higher rates work their way into everyday business and household decisions. The question is how much slowing will there actually be?

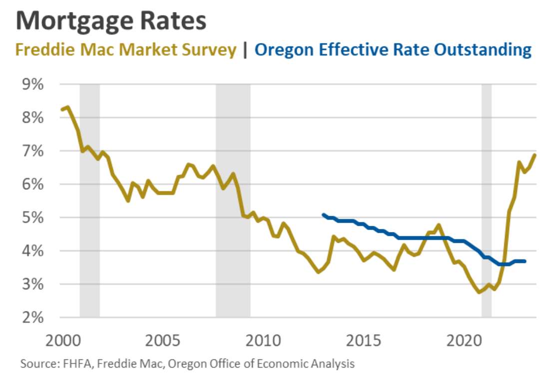


Moving forward the Federal Reserve believes its policy is restrictive. Based on their latest forecast, the Fed expects to raise interest rates one more time and hold them at a relatively high level until inflation slows further. Once that occurs, the Fed expects to cut interest rates so that the real, or inflation-adjusted rate remains relatively constant. While most private forecasters follow the general contours of the Fed's own outlook, expectations are starting to increase for even more interest rate increases, and/or the Fed holding rates steady for an even longer period of time. Such an outcome would keep with the "higher for longer" view of the economy given the strength and elevated inflation. There is a possibility that the economy is simply stronger than many believed, and therefore higher interest rates are needed to truly cool inflation.

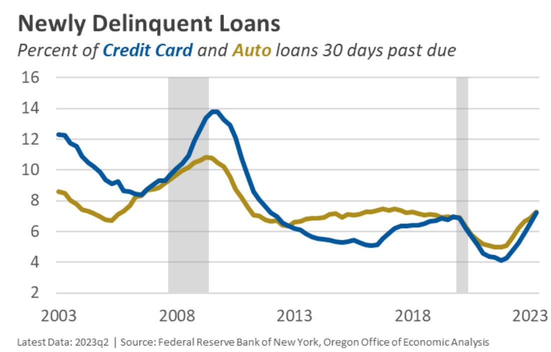
Impacts of Higher Interest Rates

Traditionally, higher interest rates slow economic growth through credit-sensitive sectors in the economy. With higher financing costs, businesses will expand and invest at a slower rate, and households will take on less debt, slowing consumer spending in the process. Today, a broad slowdown in the economy is not seen in the data, or at least not yet. The latest tracking estimates for real GDP growth this quarter are running at more than five percent according to the Federal Reserve Bank of Atlanta. Growth appears to be above trend, even with interest rates the highest they have been in decades.

Clearly higher rates are slowing some sectors in the economy. In addition to higher interest rates, banks are also tightening lending standards according to the Federal Reserve's Senior Loan Officer Opinion Survey (SLOOS). As such, it is more difficult for, generally smaller, businesses to get new loans. Large companies are better able to access deeper capital markets and rely less on traditional banking relationships. And many types of construction are taking more of a wait and see approach, with the expectations that rates will be lower in the years ahead. These actions do, or will slow overall growth.



All of that said, higher interest rates today do not appear to be packing the same punch, certainly compared to last decade. First, household balance sheets are strong. Income and wage growth is faster, household savings is higher, and the dominant type of debt households have – mortgages – is locked in at low, fixed rates. Two-thirds of Oregon households with a mortgage, have an interest rate below four percent. Moody's Analytics estimates that just 10-20 percent of all household debt is at adjustable interest rates, meaning today's higher rates will only slowly be repriced into household balance sheets over a period of years. There is unlikely to be a big slowdown in consumer spending due to rates alone.



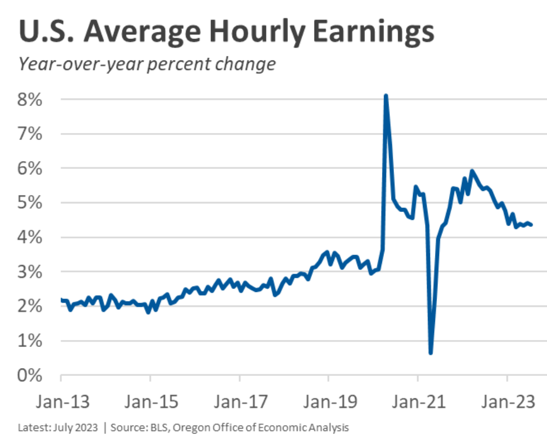
Of course this masks the differences between the macro and micro impacts. Households with more credit card debt, or those needing to buy an automobile today and the like are much more impacted, and likely struggling financially as a result, even if the economywide statistics are very strong. In recent quarters, national delinquency rates on both credit cards and automobile loans have increased off their record lows and are now back to pre-pandemic numbers. It is likely these delinquencies will rise higher in the quarters ahead, even as it is yet to be seen just how high they go this cycle.

Second, business balance sheets are strong as well. Revenues are up, driven by strong consumer spending, and according to Goldman Sachs, about half of all debt held by S&P 500 companies is set to mature in 2030 or later. As such, firms – at least the large, publicly traded ones – are less sensitive to today's higher rates as much of their debt is likewise locked in at lower rates for an extended period of time. Another consideration is that manufacturing, and goods-producing industries more broadly are capital intensive. Therefore, they are likely more sensitive to higher interest rates. But as the U.S. economy continues to evolve and become more service-oriented, the impact of higher rates on goods producers represents a smaller share of the economy than in the past.

Third, in terms of sectors of the economy most likely to be impacted, it may be the Federal Government. According to the Wall Street Journal, approximately three-quarters of federal debt is set to mature (come due) in the next five years. As that debt will need to be rolled over at higher rates, the impact will be to slow federal spending on public services, increase taxes to pay for it, or to increase the annual deficits, and overall debt. Given the commitments of increased federal investment in the years ahead (more on that later in the forecast), a reduction in overall federal spending appears unlikely. According to the Congressional Budget Office's latest long-term outlook, federal interest payments measured as a share of GDP is set to rise from 2.5 percent last year to 3.2 percent in 2030, which was the previous historic high reached in 1991. The CBO expects further interest payment increases over the long-term.

Now, this does not mean the federal debt is big threat to the economy. It is just an acknowledgement that the federal budget will be more impacted by the higher rates than the private sector in the short-term. Keep in mind that countries with their own currency, and independent monetary policy do not default on their debt (although the political brinkmanship around the U.S.' artificial debt ceiling may prove otherwise at some point). But sometime in the (distant) future, higher interest payments are likely to impact either direct federal spending, or the ability for fiscal policy to help during recessions.

Labor Market Crosscurrents



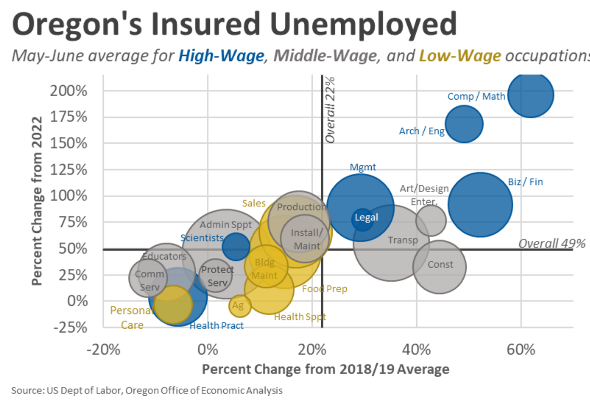
When it comes to the labor market, it remains very strong. Many indicators show the labor market has cooled some from the reopening highs, but remains tighter than last decade. In fact if we focus on job openings, and average hourly earnings, the U.S. labor market is roughly halfway back to pre-pandemic patterns. Job openings have declined some as employers have staffed back up and are less desperate to hire today. And wage growth has slowed as well. To date this combination of a declining job openings, slowing inflation, but unemployment remaining at or near record lows is being referred to as the immaculate cooling. As such, the likelihood of the economic soft landing is rising and is now the consensus outlook for forecasters. However, with average hourly earnings currently increasing at a 4-5 percent annual rate, it is unlikely to be consistent with the Fed's two percent inflation target over time.

Labor Market is Still Tight, but Less So

Here in Oregon the labor market data reveals more pronounced trends than in the national data. Job growth and personal income tax withholdings slowed noticeably early in 2023. And as of June 2023, job openings in the state are now back to pre-pandemic levels. Additionally, the number of Oregonians filing for and receiving unemployment insurance increased as well. And while UI claims have not spiraled upward like they do heading into a recession, they remain at higher levels than in the years leading up to the pandemic. Oregon's labor market looks to be a little less tight than it was, but still somewhere at or near full employment.

The largest increases in unemployment insurance claims have been among workers coming from high-wage occupations. In particular, increases among Computer and Math, and Architecture and Engineering occupations, followed by other high-wage occupations including Management, Legal, Business and Finance has seen the largest percentage changes. Some of these increases are likely tied to the large number of high-tech layoffs announced in the past year – particularly the Computer and Math, and Architecture and Engineering jobs. At the time of the announcements, and even in the ensuing months, it was difficult to see an impact on the overall economy. However, by looking at the characteristics of the unemployed, it shows there was a clear impact for some workers.

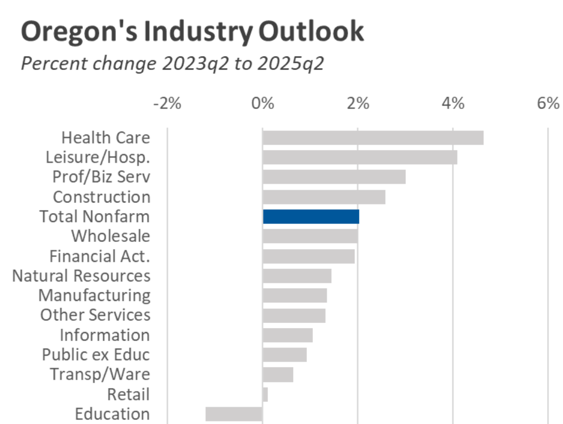
Additionally, more interest rate sensitive occupations like Construction, and Transportation have seen larger increases in unemployment as well. These changes are likely tied to the goods and freight cycle the U.S. economy has gone through in the past year. Overall, consumer spending on goods has held strong after the big pandemic era increases. However, as supply caught up to demand, inventories did accumulate for retailers and home improvement stores, among others. As those businesses have worked through their inventory, new orders and the associated production and logistics needed to get the new products to retailers did slow down, resulting in some layoffs. Now those cyclical swings are turning up. With inventories now leaner, production is increasing, and the freight recession is over and starting to improve. That is part of the reacceleration story in the short-term.



Oregon Industry Forecast

Labor is still hard to come by. The economy remains cyclical strong as evidenced by a low unemployment rate, and high employment rates among working-age cohorts. Most Oregonians who want a job, have a job, or at least there are plentiful job opportunities. But the labor market is also structurally tight for demographic reasons. The large Baby Boomer generation is retiring in recent years and will continue to do so in the decade ahead. Annual retirements nationwide are expected to be at least one million per year, and here in Oregon around 15,000 per year. To keep total employment stable, all of those soon-to-be retirees with a lifetime of experience and skills will need to be replaced by new hires.

Looking forward, job growth will slow noticeably from the pandemic reopening highs. In fact given high employment rates today, combined with the demographics, job gains may come in below expectations even as total labor income continues to grow quickly. Even so, the composition of job growth in the state is expected to shift as well. During the pandemic and initial recovery, many goods-producing industries and associated supply chain segments outpaced the overall economy, while in-person services lagged. With the relative slowdown in goods spending, sectors like transportation and warehousing, retail, even manufacturing and construction were expected to take a backseat in terms of overall gains. And with continued strong growth from households for things like going out to eat, and on vacations, and the like, service sectors are expected to add jobs at a faster rate during the 2023-25 biennium.



Some of these gains are more about the industries playing catchup to the overall economy. For example, leisure and hospitality has yet to fully regain the total number of jobs it had pre-pandemic. Clearly there have been some structural changes in the industry, be it the lack of daily cleanings for hotel rooms, or more kiosk ordering at restaurants and the like. On a per capita basis, or an inflation-adjusted revenue per employee basis, the industry is likely to never return to where it was in 2019. However, with a growing economy, and increased consumer demand, job gains should continue. The demand for workers is there. The risks to the industry employment forecast are that these structural changes are larger than are built into the forecast. Plus it is hard to find workers, especially for low-paying industries. As a result, more job growth may occur in the higher-paying, higher-productivity industries in the years ahead. Such an outcome would be a boon for the overall economy, albeit partially at the expense of the lower-paying industries looking for staff today.

Additionally, recent developments in financial markets may dampen future construction activity more than anticipated. The residential construction industry appeared to have found a bottom and was adjusting to mortgage rates in the 6-7 percent range. Recent weeks have now pushed mortgage rates closer to 7.5 percent. Should these higher rates persist more than a few days or weeks, they will slow future sales, and building activity. These developments are too new to build into this forecast but are substantial enough to warrant a mention as a potential risk. Similarly, commercial real estate is likely to slow as well given higher construction costs, including financing costs make new projects challenging to pencil out. On the other hand, should private sector activity slow more than anticipated, the increase in federal investment, see the next section, will make up for some of the slack, and compete less, or crowd out other types of activities.

Capital Investment Drives Productivity Gains

Economic growth is driven by the combination of labor and capital. Investment in the various forms of capital – financial, human, natural, physical, and social – drive productivity gains, meaning workers are able to produce more for every hour of work. Higher productivity raises the overall speed limit of the economy. Better productivity also helps alleviate inflationary pressures, the key macroeconomic issue facing the economy today.

So far during the pandemic, Oregon's overall economic growth compared to other states has been strongest in terms of productivity, above average in terms of income, and slightly below average when it comes to jobs and population gains. This pattern, and contributions to growth differs from Oregon's modern experience, as discussed in greater detail last quarter.

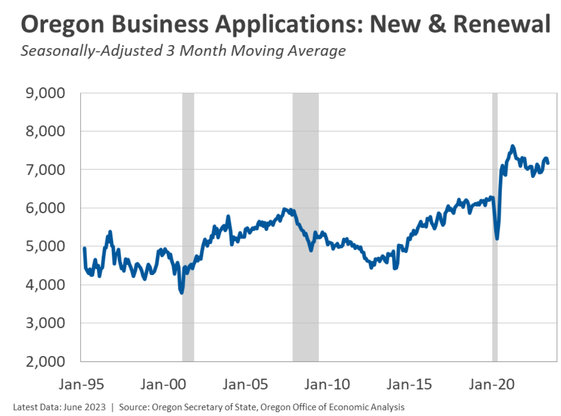
More broadly, productivity growth in the U.S. economy in recent decades has been slow. The exact reasons why is not fully understood by economists, but aging demographics, the slowdown in federal investment, and dearth of start-ups are all thought to be key factors.

Moving forward there are a few reasons to be more optimistic about productivity gains, including the Millennials aging into their prime working years, which also so happen to be peak entrepreneurship years as well, in addition to big increases in federal investment, and the more speculative potential of generative AI. Oregon stands to benefit as much, if not more than the typical state as a result.

Start-Ups

As discussed in greater detail in the May 2023 forecast[1], there has been a substantial increase in new business formation during and after the pandemic. New firms typically bring new ideas and products, and improve efficiencies compared to existing firms. This process, sometimes referred to creative destructive, raises economywide productivity.

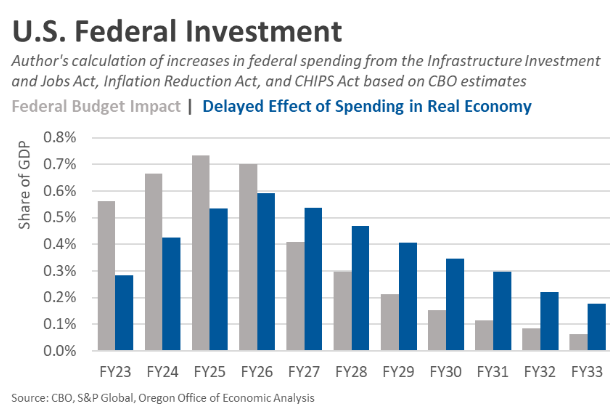
While there were some initial caveats or qualms that the increase in start-ups may have been just to access pandemic aid programs, or due to IRS changes and the like, the fact that business formation remains strong for the past three years is encouraging.



While tighter financial conditions in the economy may dampen start-up activity in the near future as it is harder to get loans, and for entrepreneurs to tap into their home equity at higher interest rates, there are also upside risks in the form of demographics. Research from the Census Bureau[2] shows that entrepreneurship rates peak in ones late 30s through early 40s. In the decade ahead the large Millennial generation will age into their peak entrepreneurship years, likely providing a long-lasting demographic tailwind to start-up activity in the years ahead. Now, simply having more businesses does not necessarily lead to increased business investment and productivity gains, but it is an encouraging signal about the possibilities in the years ahead.

Federal Investment

In recent years the federal government has passed major legislation that will increase federal investment in the economy. The combination of the Infrastructure Investment and Jobs Act (2021), Inflation Reduction Act (2022), and Chips and Science Act (2022) is a big boost to federal spending. Some of these increases in direct investment were offset by increases in revenue, or cost savings elsewhere in the budget, but the direct investment increases amount to more than half a percent of GDP per year over the next few years.



In terms of the economic impact, timing matters. It is one thing for the money to be approved to be spent, but when it comes to many of these projects, it takes time to design them, go through the RFP process, and ultimately build them. As such, much of the initial spending in the federal budget has gone

[1] See page 6: https://digital.osl.state.or.us/islandora/object/osl%3A1010830/datastream/OBJ/view
[2] https://www.census.gov/content/dam/Census/library/working-papers/2018/adrm/carra-wp-2018-03.pdf

to seed loan and grant programs, and to other agencies to fund projects in the years ahead. Using a 2021 Congressional Budget Office analysis on the timing of actual infrastructure spending as a guide, the increase in federal investment will ramp up over the next few years, with the peak economic impact occurring during fiscal year 2026.

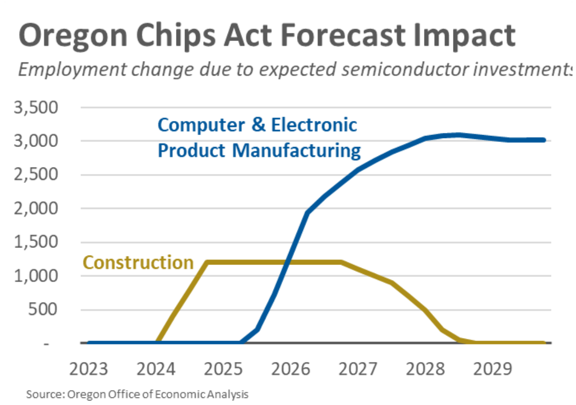
In the short-run it is possible that the increase in federal investment could be inflationary. The economy only has so much construction and production capacity, so the increases could compete with other potential projects for labor and materials and the like. This competition could lead to higher construction costs. However in the long-run these investments should be disinflationary overall, and a boost to productivity once completed.

Oregon and the Chips and Science Act

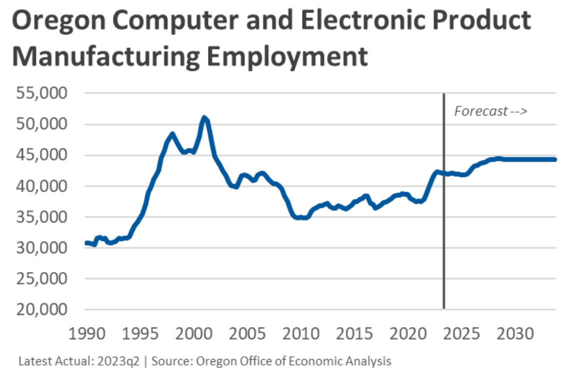
Included in the recent federal legislation was a big incentive program to increase domestic semiconductor manufacturing. In recent years there have been a handful of large, semiconductor announcements in states like Arizona, New York, Ohio, Texas and the like. To date none of the big announcements have been in Oregon, although that is set to change in the near future by all accounts. Our office is now building in some realistic placeholder assumptions about the growth in Oregon's high-tech sector in the years ahead.

To date, the State of Oregon has received more than a dozen applications for newly passed state incentives that should result in tens of billions of dollars of investment, and associated construction activity. There will also be local semiconductor job gains as well. The details of these projects are not public. However the combination of the federal and state programs, and momentum behind onshoring given the chip shortages during the pandemic, the increasing likelihood of sizable projects in the state is too big to ignore from a forecasting perspective.

Specifically the forecast now includes an increase of about 3,000 additional Computer and Electronic Product manufacturing jobs over the next five years, in addition to just over 1,000 construction jobs that phase in and out over the same time period. The actual construction impact is expected to be larger than that, but some of the labor will likely shift from other projects in the region, resulting in a smaller net increase in total construction jobs. For now these forecast changes are more of placeholder values. As our office learns more about the potential projects, and ultimately which ones do or do not get built, we will adjust the forecast accordingly.

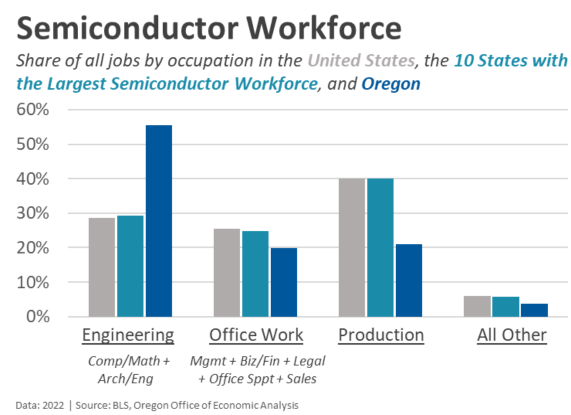


Our March 2022 forecast discusses the high-tech manufacturing outlook in more detail, but a few aspects are worth noting. First, the industry is a pillar of Oregon's economy. Its importance is hard to overstate. Second, industry employment held relatively steady (or down) for much of recent decades. Third, given the chip shortage and increased demand during the pandemic, local job gains increased by more than 3,000 jobs even without any of the major announcements seen elsewhere in the nation. This increase is the equivalent of adding one or one and a half new fabs. Fourth, the Oregon semiconductor workforce is significantly different than elsewhere in the country.



Oregon is 1.2 percent of all jobs nationwide. Oregon is 9 percent of the nation's semiconductor jobs (NAICS 3344). Oregon is 17 percent of the nation's engineering type jobs within the semiconductor industry. This means 55 percent of the workers in Oregon's semiconductor industry today work in Computer and Math, and Architecture and Engineering occupations. The national figure is 29 percent, as is it among the Top 10 states with the largest semiconductor workforces. Those states from largest to tenth largest are California, Texas, Oregon, Arizona, New York, Florida, Massachusetts, Michigan, Illinois, and Minnesota. Only Arizona at 43 percent engineering jobs is somewhat similar to Oregon's occupational structure.

What this means is Oregon is a key location within the nation for the research and design of semiconductors. Now, Oregon is still an integral location for the actual manufacturing of semiconductors as well, with about 7,000 production jobs which ranks 4th highest nationally, but as a share of the overall industry, Oregon's production jobs account for 21 percent compared to 40 percent nationally, and among the other large states. It is our high concentration of engineering jobs, and what that means for the overall industry, that makes Oregon standout compared to other staes.



Growth in semiconductors is likely to increase overall productivity in the economy because the sector is, well, highly productive. Looking at the average value-added per employee from state GDP data, Computer and Electronic Products are three times as productive as the average worker in the economy. And Oregon Computer and Electronic Product workers are 20-30 percent more productive than the average such worker nationwide. As such, local growth in the industry is expected to help boost economywide statistics in the years ahead.

Generative AI and Your State

Generative AI is a type of artificial intelligence that can create new content such as text, images, audio, and video without human intervention. It works by learning from a large dataset of existing examples and identifying patterns that it can use to generate new content that is similar to the examples it has learned from. Generative AI models are incredibly diverse and can take in various types of content, including images, longer text formats, emails, social media content, voice recordings, program code, and structured data. They can output new content, translations, answers to questions, sentiment analysis, summaries, and even videos. Generative AI has applications in art, design, music, business, marketing, and more, and it primarily helps automate the create process.

That paragraph was written by Perplexity AI, a ChatGPT like program trained on OpenAI's API. The prompt given was to write one paragraph on what generative AI is. Recent reports from McKinsey[3], Goldman Sachs, and OpenAI[4] all highlight the potential impacts of generative AI on the economy.

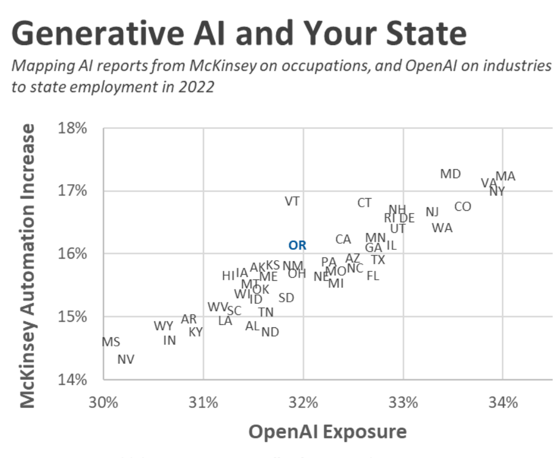
At a base level, the expectations are that generative AI will automate some tasks for workers, allowing them to spend more time on more productive tasks. In some ways, the impacts are similar to past trends in automation in the economy but differ in important ways.

First, the reports highlight that generative AI should be a net positive for the economy. It is unlikely to automate away many jobs, but rather make existing jobs more productive. This differs some from the trends in recent decades with the outright decline in manufacturing jobs due to automation, technological change, and offshoring.

Second, the types of workers most likely to be impacted is different than past automation trends. With generative AI, it will be jobs in industries and occupations largely held by college graduates where more of the routine research and writing tasks, among other, will be impacted. This means white-collar, and office-based jobs, as opposed to manufacturing and clerical jobs should see the biggest changes.

Among occupational groups, McKinsey estimates that educators, business, legal, and scientific, technical, engineering, and math are expected to see the largest increases in automation. Conversely agriculture, construction, installation and repair, food services, and production jobs will see the smallest increases. At the industry level, OpenAI estimates that high-tech, financial activities, professional and technical services will be the most impacted, while social assistance, food services, and most types of manufacturing the least impacted.

Taking both of these reports and mapping the potential changes to each state's occupational and industrial structure reveals the nearby scatterplot. A few things stand out. First, the relatively tight linear fit indicates that the two reports have similar impacts, or at least similar distributional impacts on workers in different types of jobs.



Second, the absolute variation across states is fairly minimal. The range of exposure is a few percentage points. This is an indication that generative AI can best be thought of as a macro or economywide impact, given

[3] https://www.mckinsey.com/capabilities/mckinsey-digital/our-insights/the-economic-potential-of-generative-AI-the-next-productivity-frontier - key-insights
[4] https://arxiv.org/pdf/2303.10130.pdf

these types of jobs are everywhere. It is an open question whether the *development* of AI programs and tools will have a localized impact in existing tech hubs or similar locations, but in terms of the *impact* it will be broad based.

Third, that said, there are some relative patterns across states with tech-heavy states, financial centers, and Maryland and Virginia, both near Washington D.C. likely more exposed to AI, and resource states less exposed. Oregon falls in the middle of the pack, ranking 17th most exposed based on an occupational basis, and 26th most exposed based on an industrial structure basis. Keep in mind that exposure, in this context, means the potential to raise productivity among these types of workers, and the economy overall.

Update on Population Growth and Upcoming Data Releases

Data Release Schedule

Unfortunately demographic and population data lags considerably. However in the months ahead new, important data will be released. On September 14th, Census is set to release the published tables for the 2022 American Community Survey (ACS). The ACS is the best source for things like household income, poverty, employment by race and ethnicity, homeownership, working from home, and the socio-economic characteristics of migrants, among others. This will be the first look at any details regarding Oregon's population loss last year. As of today all that is available are total estimates, but none of the details. Our office will post summaries of the most important topics on our website in the weeks ahead, and include a summary in our next quarterly forecast.

Additionally, 2023 population estimates will be released this winter. In November, Portland State University's estimates should be available, followed by Census' estimates in December. This will provide the first look at 2023 data, although analysts will have to wait until Fall 2024 before the details of those estimates are known.

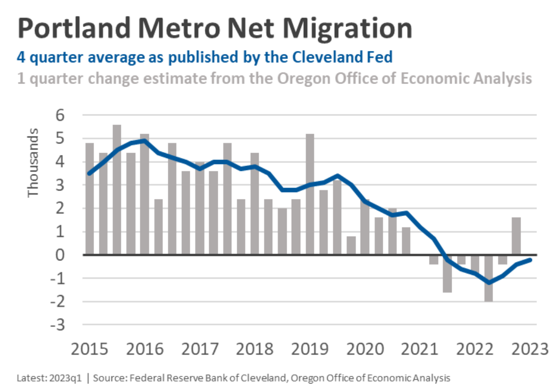
Update on Population Growth

While we wait for the official estimates to be released, there are three data points worth mentioning.

First, Oregon's population is in natural decline. Deaths outnumber births. Oregon's future population gains will come entirely from net migration, should it return as expected. When it comes to the underlying changes in Oregon's population, the preliminary data for the number of deaths and births appears to be slightly less negative than our office's forecast. Deaths have slowed noticeably from their pandemic highs, and are reverting toward the expected long-run trend of a growing, aging population. Births continue to decline further. So far the number of Oregonians aged 0 to 4 years old have fallen 10 percent in recent years. Looking forward, the state's K-12 education population (ages 5 to 17 years old) is expected to decline by 10 percent as well. Should the state's total fertility rate, which ranks 5th lowest nationwide in recent years, not stabilize or rebound some, further declines in young Oregonians should be expected.

Second, the number of surrendered drive licenses at Oregon DMVs continues to be in line with pre-pandemic figures, albeit slightly above. This is one indication that in-migration to Oregon continues, and has not shifted noticeably lower. However the data does miss out-migration, which could be the primary cause of Oregon's slower population gains, or losses.

Third, new data from the Federal Reserve Bank of Cleveland based on consumer credit reports shows that many large metro areas nationwide continue to lose population. Portland is the only Oregon metro included in the analysis, but some of the recent trends in the data are encouraging, or at least have a silver lining. At the metro level, Portland continues to see net out-migration. However, it is getting less negative, and trending toward the positive direction.



Importantly, the data the Cleveland Fed publishes is a four quarter average. This is very helpful to know what has happened over the past twelve months. But what our office really wants to know is what is happening today, and whether the pandemic era patterns are continuing or if things are starting to change. Given the data is a four quarter average, one can back out estimates of what the individual quarters that add up to the four quarters are. These calculations are somewhat sensitive to assumptions made. But the upshot is it is mathematically impossible for net migration to the Portland metro area to be entirely negative in recent quarters. The improvements in the twelve month change, as reported by the Cleveland Fed, mean that at least one of, and possibly all three of the three most recent quarters saw positive migration for the region.

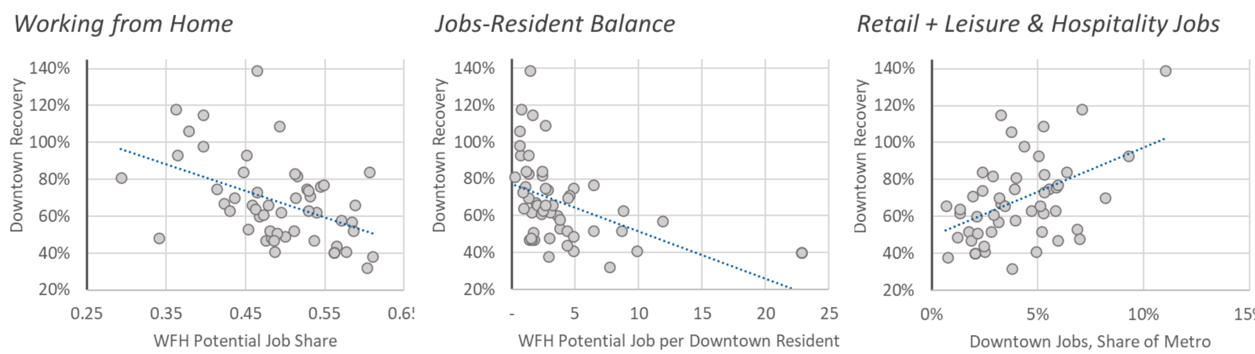
Overall, our office does expect Oregon's population to grow in the years ahead. A modest rebound in migration will drive the gains, given deaths are expected to outnumber births for decades to come. With surrendered driver licenses at Oregon DMVs holding steady, and the possibility that the Portland regions' population has bottomed out, stronger statewide numbers appear likely in the year(s) ahead. To the extent population growth does not rebound as expected, our office is continuing to develop a zero migration alternative scenario. The previous May 2023 forecast included some exploratory findings of this scenario and our office will publish a more complete report in the coming months.

Downtown Recoveries

Included in the Federal Reserve Bank of Cleveland migration update was the fact that many urban cores nationwide continue to lose population. While the Portland metro population may be stabilizing, there are ongoing declines in the urban core neighborhoods based on the same credit report data.

When it comes to big cities and downtown areas there are a few important things to keep in mind. First, downtowns are distinct. There is no relationship between changes in jobs, income, or population at the metro level and the strength of the downtown recoveries. Second, the demand to be downtown has to come from somewhere. As seen in the charts below, it is the combination of commuters, local residents, and visitors all factor into the strength of any downtown.

Downtowns' economic structure does matter



Source: BLS, Census, DowntownRecovery.com, Oregon Office of Economic Analysis

On the left, the larger the share of downtown jobs that can be done remotely (working from home, or WFH), the weaker the downtown recovery. In post-pandemic world where working from home a couple days a week is more common, that downtown demand must be replaced. The middle chart looks at the relative balance between the number of WFH downtown jobs and the number of local residents who live downtown. Areas with comparatively larger downtown populations, have seen stronger recoveries. Finally the chart on the right looks at the importance of downtowns in attracting visitors. These may be city and metro residents coming downtown to go out to eat or take in a show, or out of town tourists and business travelers. But regions where downtowns matter more, by having a larger concentration of shopping and eating places, have seen stronger recoveries. In other words, downtowns need to continue to evolve and be an attractive place for people to work, live, and play.

Lastly, downtown definitions matter considerably. The most commonly cited data, and the data used in the charts above, comes from researchers at the University of Toronto[5]. It tracks cell phone data at the zip code level. The challenge is not all zip codes are created equal, and therefore the definition of “downtown” varies considerably when trying to compare cities. For some cities, like Portland and San Francisco, the zip codes used provide tight geographic definitions focused on the office building areas. For other cities, like San Diego, the downtown zip code includes both the airport and the zoo in addition to the office buildings.

Given the geographic variations, it is problematic to simply rank cities based on this data. The comparisons are apples to oranges based on how each city’s physical layout and zip codes interact. As a result, our office is no longer using it to refer to Portland’s relative ranking nationwide. However, on the other hand, these somewhat different definitions of downtowns do provide more variation in the composition of downtowns and the changes seen during the pandemic. As such, the broad findings of the economic structure of downtowns likely hold up, even if the specifics of one city versus another city are problematic.

[5] https://downtownrecovery.com/

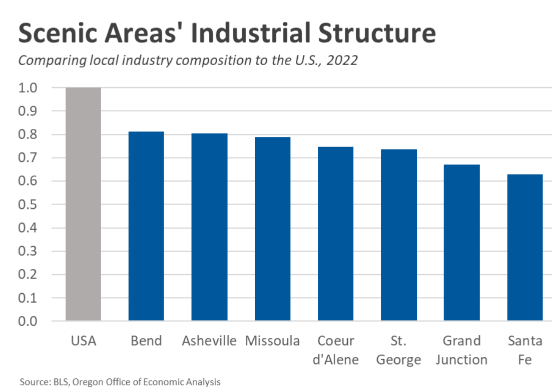
Scenic Areas, Wealth, and Industrial Structure

Scenic areas around the country have local economies with a larger travel and tourism component. If people from outside the area come to visit, they are going to need places to stay, food to eat, activities to do and so on. However, many scenic areas are also highly desirable places to live. As such they have significantly worse housing affordability, and also things like higher rates of working from home even before the pandemic. There is clearly a wealth effect in many scenic areas where not only are there households with very high incomes, but also housing values relative to local incomes or the size of the local economy are materially higher than elsewhere in the country.

Back in 2019, Brookings released a report on so-called wealth work[6], which focused on a dozen occupations that, generally speaking, provide services to those who can afford to have their lawns taken care of, go out to eat, get their taxes done, and so on. One reason this research caught the attention of our office is that the Bend metro area (Deschutes County) stood out as having a much larger share of local jobs in the wealth work occupations. While Bend, and Central Oregon more broadly do have a larger travel and tourism industry, that is not the whole story of the regional economy.

Our office recently updated the Brookings work with the latest available data. All Oregon metros have more housing wealth than the typical metro nationwide – the flipside of bad housing affordability, is a lot of housing wealth. But once again, Bend stood out. Among all metros nationwide, Bend ranks 17th highest for the share of all jobs in the wealth work occupations, and 15th highest for housing wealth. In trying to find similar metros to Bend, a handful of generally smaller, generally fast-growing areas in the intermountain west stood out.

Compared to the nation as a whole, Bend, and these other popular scenic areas do have a lot more jobs in leisure and hospitality, construction, and retail. This is typical given the increase in demand from tourism, and desire to live in these places. However, compared to the other scenic areas, Bend's underlying industrial structure stands out for having relatively more professional and business service jobs, in addition to a larger manufacturing basis. Furthermore, Bend does have a larger share of jobs in financial activities, which is mostly banks, insurance and real estate agents, but also does include the last Blockbuster on earth.



Using a more formal calculation to examine a region's industrial structure finds that among these scenic areas, Bend is the most similar to the nation overall. Bend's economy is more diverse than these other scenic areas.

Now, industry specialization is not necessarily bad. If a local economy relies more on one industry and that industry is booming – think timber in Oregon in the 1960s and 1970s, or high-tech in the Bay Area in the 1990s, or oil in North Dakota in recent decades – than the overall

[6] https://www.brookings.edu/articles/whos-employed-by-the-lifestyles-of-the-rich-and-famous/

economy booms alongside it. Issues arise when that industry faces challenges. As such, a more diversified regional economy can generally be better able to withstand different types of cycles as the economic base is more evenly distributed and less vulnerable to any particular shock.

For more on Scenic Areas, Wealth, and Industrial Structure, including a complete set of slides, please see our office's website[7]*.*

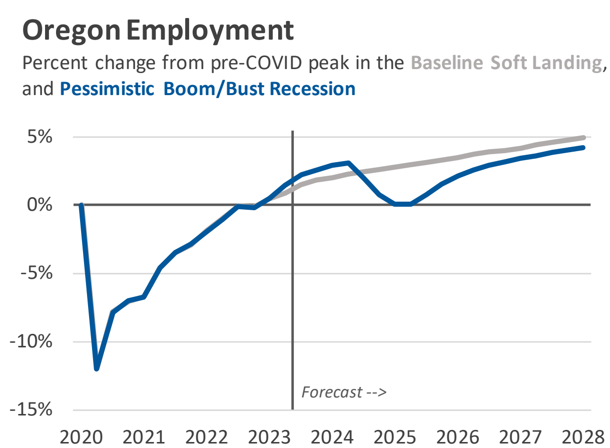
Alternative Scenario

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. Inflation is likely to remain above the Federal Reserve's target for the foreseeable future. As such, the Fed likely will need to raise interest rates further to cool the economy. The combination of high inflation, rising interest rates, and slowing economic growth is problematic. The risk of a recession in the future remains very real. The alternative scenario below is not the lower bound of all outcomes, but rather one plausible scenario modeled on realistic assumptions. For the revenue implications, see page 30.

<u>Boom/Bust Scenario: Moderate Recession</u>

Given the recession concerns and risks in the past year or so, the thinking was that if a recession did come, it would be mild. Inflation expectations remain well anchored, businesses are likely to hoard labor given how hard it is to find workers, and households continue to have strong balance sheets.

Alternative Scenario **Sep 2023**



	2022	2023	2024	2025	2026	2027
Employment						
Base: Soft Landing	3.8%	2.0%	1.2%	0.7%	0.7%	0.7%
Pes: Boom/Bust	3.8%	2.5%	0.5%	-1.6%	2.1%	1.0%
Unemployment Rate						
Base: Soft Landing	4.1%	3.9%	3.9%	4.1%	4.1%	4.1%
Pes: Boom/Bust	4.1%	4.2%	5.9%	6.5%	5.3%	4.7%
Personal Income						
Base: Soft Landing	2.0%	5.9%	6.2%	5.2%	5.0%	5.0%
Pes: Boom/Bust	2.0%	6.7%	4.4%	2.3%	6.2%	5.3%

All of those dynamics are still true today, however the longer the cycle lasts, the more things can change. And today, the ongoing strength in the economy, and slower inflation likely push any potential recession further into the future. One possibility is that today's strong household savings could be spent down in the quarters ahead, leaving somewhat weaker consumers when a recession does come,

[7] https://oregoneconomicanalysis.com/2023/08/03/scenic-areas-wealth-and-industrial-structure/

which would lead to larger layoffs and the so on. As such, the boom/bust alternative scenario this forecast is for a moderate sized recession beginning in the second half of 2024.

The nature of the moderate recession is based on the impacts of higher interest rates, which will impact goods-producing industries to a greater degree than service-providing industries. And the severity of the cycle is close to the average recession Oregon has experienced since World War II, excluding the severe cycles in the early 1980s, the Great Recession, and the COVID recession. Looking specifically at the recessions beginning in 1957, 1960, 1969, 1973, 1990, and 2001, Oregon's average employment change has been a decline lasting three quarters and totaling 2.7 percent, followed by a four quarter recovery period to regain the lost jobs.

The 2024 moderate recession scenario is for a three quarter decline in employment totaling 3.0 percent, followed by a six quarter recovery period, more inline with the so-called jobless recoveries following the 1990 and 2001 cycles, compared to the faster recoveries in the 1950s, 1960s, and 1970s. The three percent decline in employment is a loss of 60,000 jobs. No industry is spared, but goods-producing ones see relatively larger losses at 4.5 percent, while services see slightly fewer losses at 2.8 percent, and the somewhat more stable public sectors experiences job losses of 2.3 percent. The unemployment rate increases to nearly 7 percent by early 2025. Nominal income does not fall outright but growth slows considerably. Income in Oregon is 2.5 percent below the baseline.

Oregon's Agricultural Economy

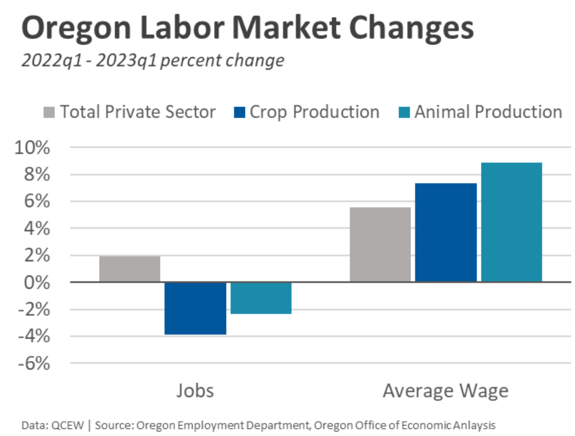
Last year, the Oregon Legislature passed HB 4002 (2022) which establishes maximum hour and overtime compensation requirements for agricultural workers. The law goes into effect starting this year, in 2023. Moving forward, our office will analyze and monitor the economic and labor market data to assess any impacts from the law. Our office will work to incorporate these changes, if any, in the broader context of the state's agricultural economy. It will take some time before data is available to assess any impacts.

Even so, our office has been highlighting the importance of agriculture to the state's economy in recent quarters. We have dug into farm employment, income, and sales at the state and county level, in addition to international exports. Additionally we discussed how ag fits in with the broader food economy in the state and nation, and also the outlook for consumer spending on food and price forecasts related to revenues and costs.

Last quarter we highlighted QCEW data, the nearly real-time data coming from businesses submitting records for unemployment insurance purposes. Of note was the fact that agricultural data was very seasonal given harvest, and that crop production had been on a slight downward trend in 2021 and 2022, possibly in part due to lower global commodity prices.

This quarter we have our first glimpse at the 2023 first quarter QCEW data. At a high level, when comparing the first quarter of this year to last year, employment for both crop production and animal production have declined, compared to job gains for the state's private sector overall. Average wages per worker have increased more for agricultural workers than for all private sector workers. At first blush, this pattern of weaker employment and strong wage gains likely fits the expected patterns of what the impact of the new law would be.

Keep in mind that this is preliminary data, and is just one quarter. It is far from enough information to make any real assessments of how the law is impacting the state economy. It is also at a high level, using a simple year-over-year comparison. Further analysis looking at the number of hours worked per employee is needed to better gauge the impacts.



Moving forward, our office will work with other state agencies to gather and analyze the available data. Future quarterly forecasts will include updates to the underlying ag economy, when available, and any such analysis of the impacts of the new law.

Longer-Term Forecast Risks

The economic and revenue forecast is never certain. Our office will continue to monitor and recognize the potential impacts of risk factors on the Oregon economy. Although far from comprehensive, we have identified several major risks now facing the Oregon economy in the list below:

- U.S. Economy. While Oregon is usually more volatile than the nation overall, the state has never missed a U.S. recession or a U.S. expansion. In fact, Oregon's business cycle is perfectly aligned with the nation's when measuring peak and trough dates for total nonfarm employment.
- Housing Affordability. New housing supply has not kept pace with demand in either the ownership or rental markets. Oregon has underbuilt housing by 140,000 units in recent decades[8]. To the extent home prices and rents rise significantly faster than incomes, it is a clear risk to the outlook. Worse housing affordability hurts Oregonians as they need to devote a larger share of their household budget to the basic necessities. Furthermore, while not the baseline outlook, worse affordability may dampen future growth as fewer people can afford to live here, lowering net in-migration, and the size of the labor force in the years ahead.
- Global Spillovers. The international list of risks seems to change by the day. Right now there is an ongoing war in Europe, and the risk of war in Southeast Asia has been uncomfortably high in recent years. Longer-term concerns regarding commodity price spikes in Emerging Markets, or the strength of the Chinese economy – the top destination for Oregon exports – are top of mind.
- Federal Fiscal Policy. Changes in national spending impact regional economies. In terms of federal revenues, spending, and employment Oregon is generally in the middle of the pack across states. Oregon does see larger impacts related to land management and forest policies, including direct federal employment. Oregon ranks below average in terms of military-dependent industries and lacks a substantial military presence within the state.

[8] https://www.oregon.gov/ohcs/about-us/Documents/RHNA/RHNA-Technical-Report.pdf

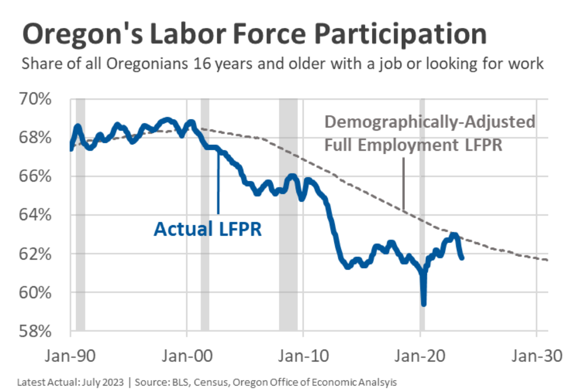
- Climate and Natural Disasters. While the severity, duration, and timing of catastrophic events like earthquakes, wildfires, and droughts are difficult to predict, we know they impact regional economies. Fires damage forests with long-term impacts, and short-term disrupt tourism. Droughts impact our agricultural sector and rural economies to a greater degree. Whenever Cascadia, the big earthquake, hits, we know our economy and infrastructure will be crippled. Some economic modeling suggests that Cascadia's impact on Oregon will be similar to Hurricane Katrina's on New Orleans. Longer-term issues like the potential impact of climate change on migration patterns are hard to predict and generally thought to be outside our office's forecast horizon. Even so, it is a reasonable expectation that migration flows remain strong as the rest of the country becomes less habitable over time.
- Initiatives, Referendums, and Referrals. Generally, the ballot box and legislative changes bring a number of unknowns that could have sweeping impacts on the Oregon economic and revenue picture.

Extended Outlook

Oregon typically outperforms most states over the entire economic cycle. This time is no different, however the expectations are that the relative growth advantage may be a bit smaller than it has been historically. The primary reason being slower population, and labor force growth than in decades past. Our office is a bit more bullish on Oregon's economic and population growth than IHS Markit is, but our office overall agrees with the relative patterns nationwide. From 2023 to 2028, IHS expects Oregon's real GDP growth to rank 14th fastest among all states, while employment growth ranks 25th fastest, and population gains are the 16th fastest.

Over the extended forecast horizon our office has identified four main avenues of growth that are important to continue to monitor: the state's dynamic labor supply, the state's industrial structure, productivity, and the current number of start-ups, or new businesses formed.

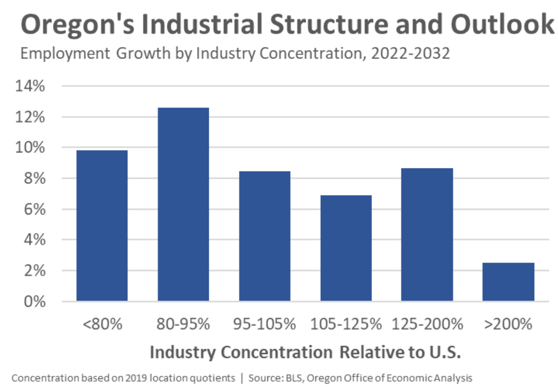
Labor Supply. Oregon has typically benefited from an influx of households from other states, including an ample supply of skilled workers. Households at least used to continue to move to Oregon even when local jobs are scarce, as long as the economy is equally bad elsewhere, particularly in California. Relative housing prices also contribute to migration flows in and out of the state. For 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.



The good news today is that Oregon's labor force has never been larger, and the labor force participation rate has been higher that it was before the pandemic began, at least until the last couple months of data. Even in this sometimes noisy, and unrevised data, the strength of Oregon's labor market is clear.

Moving forward, overall labor force participation rates will decline, simply due to the aging of the population. As more Baby Boomers enter into their retirement years, the share of all adults working or looking for work will fall as a result. As such, comparing Oregon's participation rates against a demographically-adjusted measure is important. Here, too, the current strength of the Oregon's labor market is evident, and encouraging.

The challenge moving forward is twofold. First, is overall population growth and whether that rebounds as expected in the years ahead. Second, whenever the next recession (or two) does come, maintaining a high participation rate and not seeing larger numbers of discouraged workers drop out of the labor force like they did following both the dotcom and housing busts. It was only once the economy became strong again in the late 2010s and early 2020s have some of those losses begun to be regained.



Industrial Structure. Oregon's industrial structure is very similar to the U.S. overall. However, Oregon's manufacturing industry is relatively larger, and weighted more toward semiconductors and wood products, compared to the nation which is more concentrated in transportation equipment (aerospace, and automobiles). However, industries like timber and high-tech, which have been Oregon's strength in both the recent past and historically, are now expected to grow the slowest moving forward. Productivity and output from the state's technology producers is expected to continue growing quickly, however employment is not likely to follow suit. 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.

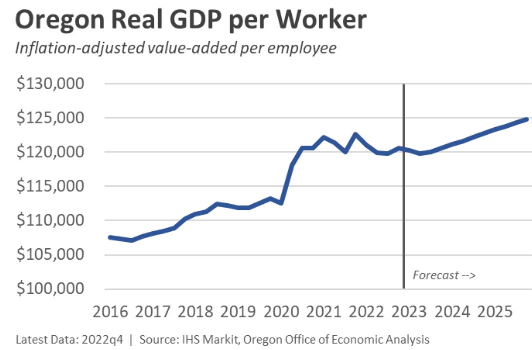
With that being said, certainly not all hope is lost. Those top industries in which Oregon has a local concentration at least twice the national average comprise approximately 4 percent of all statewide employment. Slower growth moving forward is not a weight, but rather more of a lack of a boost.

Many industries in which Oregon has a larger concentration that then typical state are expected to perform quite well over the coming decade. These industries include management of companies, food and beverage manufacturing, published software along with some health care related firms.

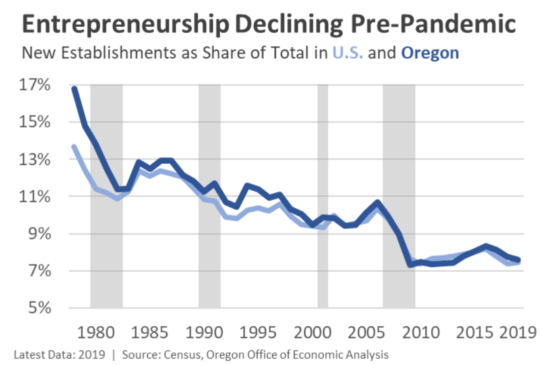
The state's real challenges and opportunities will come in industries in which Oregon does not have a relatively large concentration. These industries, like consulting, computer system design, financial investment, and scientific R&D, are expected to grow quickly in the decade ahead. To the extent that Oregon is behind the curve, then the state may not fully realize these gains if they rely more on clusters and concentrations of similar firms that may already exist elsewhere around the country.

Capital and Productivity. Ultimately, the economy's industrial structure combined with capital will result in increasing productivity. Higher productivity allows firms to produce and sell more products, and pay higher wages to its workers. Capital can come in many different forms including financial, natural, phsyical, human, and social. All can help raise firm productivity, benefiting the economy more broadly.

Today, the economy desparately needs better productivity, which has been sluggish this century. Early in the pandemic, productivity perked up as firms had to make due with reduced workforces at the same time consumer demand remained strong. However, as employment has rebounded, these productivity increases not only have not held, but have eroded. The current outlook for producivity is more or less back to the pre-pandemic trend, if slightly above it. Increasing the stock and use of Oregon's capital would boost the economy overall.

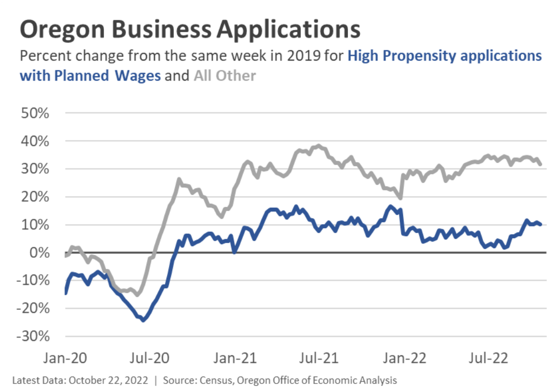


New Business Formation. New businesses are generally considered the primary source of innovation. New ideas, products, and services help propel future economic growth. Unfortunately in the decades leading up to the pandemic, start-up activity was declining. New businesses as a share of all businesses were at or near record lows in 2019. Employment at start-ups follow a similar pattern.



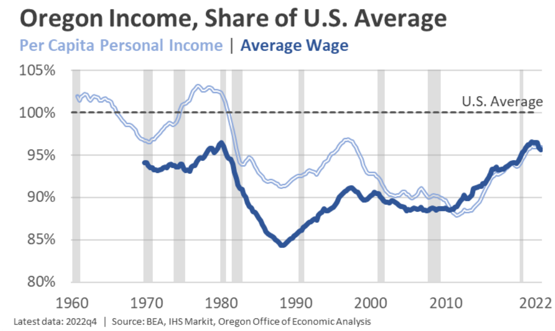
To the extent the low levels of entrepreneurship continue, and R&D more broadly is not being undertaken, slower productivity gains and overall economic growth is to be expected. However, to the extent that larger firms that have won out in today's marketplace are investing in R&D and making those investments themselves, then the worries about the number of start-ups today is overstated. It can be hard to say which is the correct view. That said, actual, realized productivity in the economy has been sluggish in recent decades.

Encouragingly, new business applications during the pandemic actually accelerated, stopping the long-run decline. Applications from what Census calls high-propensity business with planned wages, which are the most likely to eventually turn into real firms that employ workers, have been higher in 2021 and so far in 2022 than back in 2019. New business applications of all other types, including self-employment, are up even further.

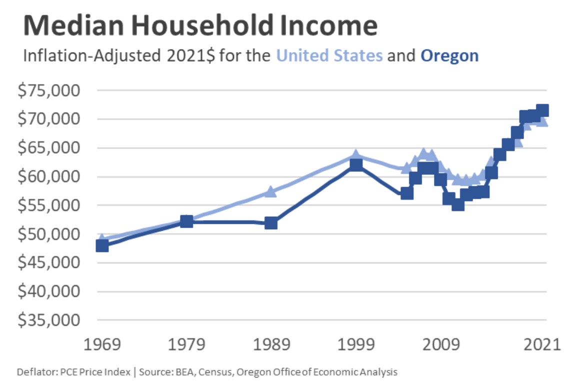


These gains provide some hope for future economic growth should some of these new firms bring new ideas, products, and efficiencies to market. Even if the per firm probability of success remains the same, having more ping pong balls in the lottery increases the overall probability that a few will survive and succeed tremendously.

<u>Oregon Income Relative to U.S</u>. One long-standing concern for some policymakers and analysts had been Oregon's relatively low income and wage compared to the rest of the nation. Encouragingly, the strong economic growth last decade did translate into meaningful increases in Oregon's per capita income and average wage. Today Oregon's per capita income relative to the U.S. is at its highest point since the dotcom bust two decades ago, and the state's average wage is at its highest relative point since the timber industry restructured and the mills started closing in the early 1980s.



Oregon's median household income in recent years has reach historic highs, even after adjusting for inflation. More importantly, it now stands 2.6 percent higher than the U.S. overall as of 2021. In recent years, this marks the first time in more than 50 years that Oregonian incomes for the typical household or family are higher than the nation. The fact that the strong regional growth translated into more money in the pockets of Oregonians, and regained the ground lost decades ago is one of the most important economic trends in recent generations. 2022 data will be released by the Census Bureau on September 14th. Our office will update on our website at that time, and in the next quarterly forecast.



Revenue Outlook

Revenue Summary

After several quarters of unexpectedly rapid growth in tax collections, Oregon's state revenue outlook appears to have stabilized. A consensus of economic forecasters has converged on a baseline scenario in which monetary policymakers are able to navigate a soft landing, cooling inflation without large job and income losses. Although this economic outlook remains highly uncertain, it appears on track for now. The same can be said for the state revenue outlook. Collections in recent months have tracked closely with the May forecast. Even so, Oregon has yet to go through its first personal income tax filing season of the biennium, and as such, everything remains at risk.

This revenue forecast represents the last look at the 2021-23 biennium and reveals the Close of Session (COS) forecast. The Close of Session forecast sets the bar for Oregon's constitutionally required balanced budget, as well as its unique kicker law. The COS incorporates any legislative changes enacted during the legislative session that impact General Fund revenues and folds them into the mid-session (May) revenue forecast that covers the next two years, and forms the basis of the legislatively adopted budget.

This session's legislative changes were relatively modest in scope when compared to the changes that have been made in recent years. After recent transformational changes to Oregon's revenue system, which have shifted the state toward a more consumption-focused revenue base, the legislative changes made during the 2023 session were relatively minor. All told, law changes during the 2023 session resulted in a reduction of $48.6 million in expected General Fund revenue during the current biennium.

2023-25 General Fund Revenues

Gross General Fund revenues for the 2023-25 biennium are expected to reach $25,663 million. This represents an increase of $354 million from the May 2023 forecast, and an increase of $403 million relative to the Close of Session forecast. Most of the increase can be attributed to collections of corporate income taxes, which continue to outstrip underlying profit earnings. Total available resources in the current 2023-25 biennium are increased $437 million after accounting for a bigger beginning balance which was the result of a larger ending balance in the previous 2021-23 biennium after it closed this summer.

Table R.1

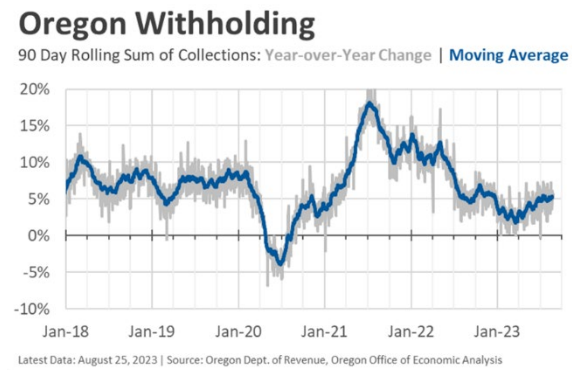
2023-25 General Fund Forecast Summary

(Millions)	2023 COS Forecast	May 2023 Forecast	September 2023 Forecast	Change from Prior Forecast	Change from COS Forecast
Structural Revenues					
Personal Income Tax	$21,019.7	$21,088.3	$21,063.6	-$24.7	$43.9
Corporate Income Tax	$2,228.9	$2,245.0	$2,549.9	$304.8	$320.9
All Other Revenues	$2,011.3	$1,975.3	$2,049.5	$74.2	$38.2
Gross GF Revenues	$25,259.9	$25,308.6	$25,663.0	$354.4	$403.1
Offsets, Transfers, and Actions[1]	-$437.0	-$439.4	-$545.6	-$106.2	-$108.6
Beginning Balance	$7,493.5	$7,002.1	$7,636.2	$634.1	$142.8
Net Available Resources	**$32,316.4**	**$31,871.4**	**$32,753.7**	**$882.3**	**$437.3**
Appropriations	$31,873.6	NA	$31,873.6	NA	$0.0
Ending Balance	**$442.8**	**NA**	**$880.1**	**NA**	**$437.3**
Confidence Intervals					
67% Confidence	+/- 9.0%		$2,302.0	$23.36B to $27.97B	
95% Confidence	+/- 17.9%		$4,604.0	$21.06B to $30.27B	

1 Reflects personal and corporate tax transfers, cost of cashflow management actions (TANS), and Rainy Day Fund tranfer

Personal Income Tax

Growth in withholdings has picked back up in recent weeks, and are not growing at an annual rate of around 5%, in range with what is typically seen when Oregon's economy is expanding. Although there are other factors involved (e.g. retirement income, bonuses, and stock options), withholdings are mostly driven by wages and salaries. While usually wage acceleration would be welcome news, today's labor market needs to cool down. If the labor market continues to heat up at the national level, monetary policymakers may need to clamp down harder going forward.



As always, the most difficult components of personal income taxes to predict are nonwage forms of income such as capital gains. Unlike labor income, taxpayers have flexibility over when they realize capital gains for tax purposes. After setting records during 2022, realized capital gains declined by nearly 50% this year matching expectations. These declines have an outsized impact on tax collections given that most are claimed by high-income households. The drag on revenues will persist in going forward due to losses carried forward into future tax years.

Calculation of Oregon's Personal Income Kicker Credit

Article IX, Section 14 of the Oregon Constitution establishes personal and corporate "kicker" tax rebates. The law is codified in Oregon Revised Statute 291.249, which governs the calculation and certification of the rebates.

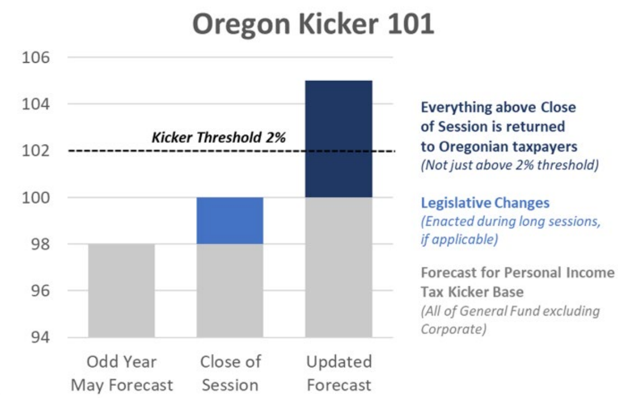
The personal tax rebate is a tax credit refunding a surplus of all General Fund revenues excluding corporate income and excise taxes. The surplus is calculated as the difference between actual revenues for the biennium in question less the forecast issued two years prior that formed the basis of the legislatively adopted budget. The refunding is triggered if actual revenues are more than two percent larger than forecasted revenues.

The Department of Administrative Services is required to tabulate General Fund revenues for the preceding biennium, determine whether they have exceeded the two-percent threshold, and certify the surplus and income tax credit percentage to the Department of Revenue by October 1.

Determining the Kicker Threshold

The personal kicker threshold is set two percent higher than General Fund revenues (excluding corporate income and excise taxes) were expected to be when the budget was drafted. According to ORS 291 349:

"*The Oregon Department of Administrative Services shall base its estimate on the last forecast given to the Legislative Assembly before adjournment sine die of the odd-numbered year regular session on which the printed, adopted budget prepared in the Oregon Department of Administrative Services is based, adjusted only insofar as necessary to reflect changes in laws adopted at that session."*



In practice, the last forecast presented to the Legislature is typically delivered around May 15 during odd-numbered years. Any statutory changes made during the session that impact revenues are folded into the May outlook using revenue impact estimates developed by the Legislative Revenue Office. This forecast is commonly referred to as the Close of Session forecast and is first reported in the September quarterly economic and revenue outlook report (Table B.1). The Close of Session forecast and resulting kicker threshold remain unchanged over the remainder of the biennium, unless the Legislature chooses to revise the estimate with a 2/3rds vote.9

Determining General Fund Revenues

Unlike most state accounts, General Fund resources used in the kicker calculation are accounted for on a cash basis. According to Article IX, Section 14: *"As soon as is practicable after the end of the biennium, the Governor shall cause actual collections of revenues received by the General Fund for that biennium to be determined."* With few exceptions1011, revenues are counted at the time they are deposited into the General Fund, not when they are remitted by taxpayers or generated in the

9 Article IX, Section 14: (6)(a) Prior to the close of a biennium for which an estimate described in subsection (1) of this section has been made, the Legislative Assembly, by a two-thirds majority vote of all members elected to each House, may enact legislation declaring an emergency and increasing the amount of the estimate prepared pursuant to subsection (1) of this section.

[10] According to LC opinion, any revenue that was understood to be part of the General Fund when the kicker rebate was written into the Constitution (fiscal year 2000) must be included in the kicker calculation even if that revenue is no longer deposited into the General Fund. For the 2021-23 biennium, this included income tax carve-outs for the Greenlight film and video credit, the Gain Share transfer to counties, and reimbursements for investment in Regionally Significant Industrial sites. These, along with a transfer to the PERS UAL out of estate tax collections, are added back into General Fund revenues for the purposes of the kicker calculation.

[11] Some withholdings of personal income taxes that are collected in July are accrued to June due to a rule known as the 30-day number. This accrual is explained in an addendum.

marketplace. As such, all deposits into the General Fund occurring between July 1 of the first year of the biennium, and June 30 of the last year of the biennium are included in revenues. For the 2021-23 biennium the personal income tax surplus has been estimated to be $5.6 billion.

Given the strict cash basis, agency financial statements cannot be used for kicker certification. Instead, the several thousand individual deposits into the General Fund over the course of the biennium must be summed together to reach a total revenue figure. A query of the Statewide Financial Management System identifies all such deposits. Any unusual transactions are reviewed with the DAS Statewide Accounting and Reporting Section and agency financial personnel for verification and potential correction.

Determining the Personal Income Tax Credit Percentage

The kicker rebate is distributed as a refundable income tax credit in the first tax year of the biennium. This size of this credit is based on the taxpayer's personal income tax liability in the previous year.

The Department of Administrative Services is required to calculate the total kicker rebate (actual General Fund revenues less the Close of Session forecast) as a percentage of personal income tax liability for the previous tax year (less credits for taxes paid to other states).

The October 1 certification deadline arrives before liability data for the previous tax year is complete. The extension filing deadline arrives two weeks later, when many of the most complicated and highest-income returns are filed. As a result, the liability figure used in the tax credit percentage represents an estimate based on all collections and returns filed to date, together with historical arrival rates for reported income. After the Department of Administrative Services certifies the income tax credit percentage, the Department of Revenue is allowed to adjust the percentage to account for administrative costs.

Income Group	Adjusted Gross Income*	Rough Estimate of Kicker Size**
Bottom 20%	< $11,400	$60
Second 20%	$11,400 - $28,900	$440
Middle 20%	$28,900 - $52,400	$1,000
Fourth 20%	$52,400 - $96,200	$1,900
Next 15%	$96,200 - $201,300	$3,800
Next 4%	$201,300 - $466,700	$9,200
Top 1%	> $466,700	$44,600
Average	$69,400	$2,100
Median	$35-40,000	$980

* Based on 2020 actual tax returns
** Based on 2020 actual tax returns, PIT kicker amount ($5.6 billion) and the Oregon Office of Economic Analysis' forecast tax liability

Addendum: The 30-day Number

Oregon's General Fund revenues are counted on a pure cash basis with few exceptions. The primary exception is the 30-day accrual of July withholding receipts:

In 1981, Budget and Management recommended instituting a 10 working-day accrual for July 1981. This moved personal income tax withholdings that were related to June activity back into the 1979-81 biennium even though they were received after the biennium ended. Prior to that time, everything was on a cash basis. The motive was to help balance the 1979-81 budget as well as build the 1981-83 budget.

In 1995, the Department of Administrative Services went to a 30-day accrual. This was in response to a Governmental Accounting Standards Board (GASB) recommended change for all states. Most all were making the change because of the one-time revenue gain.

OAM 20.50.00, section 106, describes the 30-day number: *For each biennium ending June 30, the Department of Revenue will record in the biennium then ended net personal income tax withholding receipts received in July related to June (and prior), less any withholding related refunds (errors or adjustments) that occur in July that relate to June (and prior). This is an exception to the cash basis budgetary accounting used for other types of General Fund revenue. For purposes of the General Fund "kicker" calculation, this amount is the "30-day number."*

Corporate Excise Tax

Oregon's traditional corporate income and excise tax collections have continued to outstrip expectations, as well as underlying corporate profits. The current inflationary environment is one factor supporting recent corporate tax collections. With underlying demand so strong, businesses have largely been able to pass cost increases along to their customers. Profits and earnings have skyrocketed. Even so, growth in corporate tax payments has been far faster than has growth in underlying business income.

The surge in tax collections relative to underlying profits began around the same time as the federal tax reforms included in the Tax Cuts and Jobs Act. Among many other things, the reforms encouraged corporations to realize more of their income domestically, potentially increasing the tax base for states. With more than four years of post-reform data now available, the federal reforms are now incorporated in the corporate tax model. This has led to a stronger outlook for collections throughout the forecast horizon.

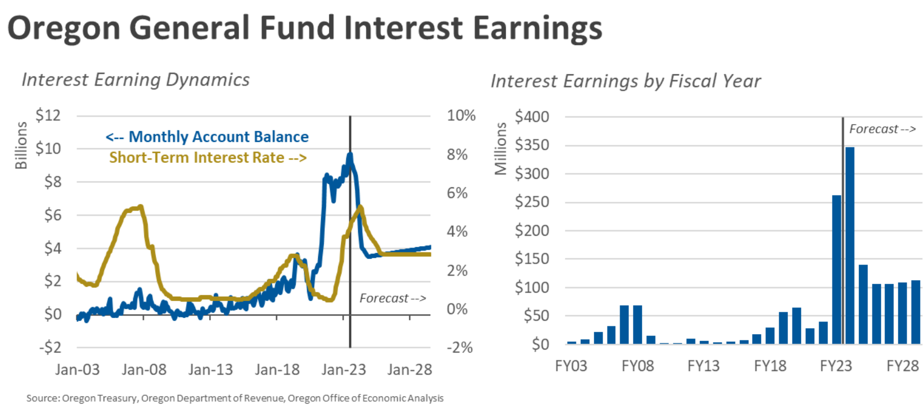
Other Sources of Revenue

Non-personal and non-corporate revenues in the General Fund usually account for approximately six or seven percent of the total. In the newly started 2023-25 biennium they account for nearly eight percent (largely driven by the record personal income tax kicker being paid out which reduces overall Genearl Fund revenues.) The largest such source are estate taxes, followed by interest earnings, liquor revenues, and judicial revenues.

The 2023-25 Close of Session forecast is increased nearly two percent from the May forecast due to legislative actions. The largest change comes from SB 1049 which transfers $40.6 million from Other Funds to the General Fund. Additionally, liquor revenues transferred to the General Fund were increased $5.2 million due to the combination of increased revenues (HB 3308) from home delivery sales, and other cost savings in the agency budget. These gains were partially offset by SB 498 which reduces

Estate Taxes by $8.0 million this biennium, as a new natural resource property exemption is implemented. Additionally, Criminal Fine Account revenues transferred to the General Fund are lowered after account for increased revenues from photo radar expansion and increased expenditures in other programs that receive CFA revenues.

Relative to the new Close of Session forecast, these other revenue sources are raised $38.2 million (+1.9%). Insurance Taxes are increased $20.1 million, Interest Earnings are raised $13.9 million, Estate Taxes are increased $5.4 million, while Securities Fees are lowered $1.1 million.
Looking forward, these revenues are raised $20.0 million (+1.2%) in the next biennium 2025-27, by $14.0 million in 2027-29 (+0.8%), by $9.8 million (+0.5%) in 2029-31, and by $4.2 million (+0.2%) in 2031-33.



One key revenue sources that continues to stand out relative to history is General Fund interest earnings. The combination of high fund balances today – the result of the inflationary economic boom outpacing forecast expectations – and high interest rates, means public sector interest earnings are now substantial. In the just completed Fiscal Year 2023, Oregon saw $262.5 million in interest earnings, which is more than the state received in the previous 10 years combined. The forecast for interest earnings in the current Fiscal Year 2024 are expected to total $346.7 million.

The outlook for interest earnings is somewhat uncertain given potential timing issues. Today, fund balances are more than $6 billion higher than back in 2019. Next spring the record kicker will be returned to taxpayers, which is expected to reduce the balances from today's high-water mark. To the extent the timing of the kicker credits being paid out differ from expectations, or that short-term interest rates shift with broader changes in the financial markets, then the state's interest earnings will differ from this forecast.

Extended General Fund Outlook

Table R.2 exhibits the long-run forecast for General Fund revenues through the 2029-31 biennium. Users should note that the potential for error in the forecast increases substantially the further ahead we look.

Revenue growth in Oregon and other states will face considerable downward pressure over the 10-year extended forecast horizon. As the baby boom population cohort works less and spends less, traditional state tax instruments such as personal income taxes and general sales taxes will become less effective, and revenue growth will fail to match the pace seen in the past.

Table R.2

General Fund Revenue Forecast Summary (Millions of Dollars, Current Law)

Revenue Source	Forecast 2023-25 Biennium	% Chg	Forecast 2025-27 Biennium	% Chg	Forecast 2027-29 Biennium	% Chg	Forecast 2029-31 Biennium	% Chg	Forecast 2031-33 Biennium	% Chg
Personal Income Taxes	21,063.6	-18.0%	30,171.1	43.2%	35,122.7	16.4%	39,838.6	13.4%	44,702.9	12.2%
Corporate Income Taxes	2,549.9	-19.2%	2,898.8	13.7%	3,208.3	10.7%	3,481.5	8.5%	3,840.5	10.3%
All Others	2,049.5	5.7%	1,744.6	-14.9%	1,842.3	5.6%	1,960.6	6.4%	2,096.6	6.9%
Gross General Fund	25,663.0	-16.6%	34,814.5	35.7%	40,173.4	15.4%	45,280.6	12.7%	50,640.0	11.8%
Offsets and Transfers	*(274.3)*		*(191.1)*		*(210.3)*		*(191.0)*		*(10.1)*	
Net Revenue	25,388.7	-17.0%	34,623.4	36.4%	39,963.1	15.4%	45,089.6	12.8%	50,629.9	12.3%

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. A summary of actions taken during the 2023 Legislative Session can be found in Appendix B Table B.3. For a detailed treatment of the components of the 2023 Legislatively Enacted Budget, see:

Legislative Fiscal Office's 2023-25 Budget Summary[12]

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 Report13 together with more timely updates produced by the Legislative Revenue Office.

[12] https://www.oregonlegislature.gov/lfo/Documents/2023-25%20Legislatively%20Adopted%20Budget%20-%20General%20Fund%20and%20Lottery%20Funds%20Summary.pdf
[13] https://www.oregon.gov/DOR/programs/gov-research/Pages/research-tax-expenditure.aspx

General Fund 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.

The near-term outlook is particularly uncertain right now. The probability of the soft landing, no recession is rising but the odds of a recession in coming years remains uncomfortably high. Our office's economic alternative scenario (see page 15) is a Boom/Bust cycle with a recession beginning in the second half of 2024. This does mean the revenue impact will be felt in both the current 2023-25 biennium and the next 2025-27 biennium.

Looking at the current 2023-25 biennium, in the pessimistic scenario, General Fund revenues in Oregon would be $1.6 billion lower than in the baseline. Revenues in 2025-27 would be recovering but still $1.1 billion below the current baseline outlook.

Boom/Bust Alternative Scenario

	$ Millions from Baseline				
	23-25	25-27	27-29	29-31	31-33
General Fund Total	-1,648	-1,122	-223	-125	-102
Other Revenues	$ Millions from Baseline				
	23-25	25-27	27-29	29-31	31-33
Lottery	-24	-59	-47	-41	-24
Corporate Activity Tax	-258	-192	-49	-20	-18
Marijuana Tax	-4	-11	-9	-9	-5
Total	-286	-262	-105	-69	-47
	$ Millions from Baseline				
	23-25	25-27	27-29	29-31	31-33
Total Sum	-1,934	-1,384	-328	-194	-149

Changes would also be seen outside of the General Fund among Oregon's consumption-based revenues as well. Such taxes are generally less volatile than income taxes and help to stabilize Oregon's overall revenue base.

Specifically in 2023-25, the Corporate Activity Tax would be $258 million lower than the baseline, while Lottery is expected to be $24 million lower, and Marijuana revenues $4 million lower.

In 2025-27, the Corporate Activity Tax would be $192 million lower than the baseline, while Lottery would be $59 million, and Marijuana $11 million. Over time the economy and state revenues would make up the recessionary lost ground and nearly converge with the baseline outlook. However, recessions tend to leave scars, and the Boom/Bust scenario never fully regains all of the lost ground economically or in terms of state revenues.

Corporate Activity Tax

The 2019 Legislature enacted the corporate activity tax (CAT)14, a new tax on gross receipts that went into effect January 2020. While taxpayers were required to file on a calendar year basis for tax year 2020, a law change allowed taxpayers to switch to a fiscal year basis beginning with tax year 2021. While a full snapshot of 2021 tax returns won't be available for a few months, an estimate of tax liability is well known. The estimate for 2022 liability will continue to evolve during the extension filing season in the Fall. Given lower-than-expected refund activity in recent months, this estimate has been lowered

[14] 0122 (oregonlegislature.gov)

modestly since the May forecast. Otherwise, the forecast remains little changed in line with the economic outlook presented earlier in this publication. Available resources for the 2023-25 biennium have been revised upward by $29.9 million, primarily buoyed by a larger beginning balance, while legislatively adopted allocations were reduced well below the levels anticipated in the prior forecast. This results in a projected ending balance of $220.7 million in the Fund for Student Success.

These revenues are dedicated to spending on education. The legislation also included personal income tax rate reductions, reducing General Fund revenues. The net impact of HB 3427 was designed to generate approximately $1 billion per year in new state resources, or $2 billion per biennium.

In terms the macroeconomic effects of a major new tax, the Office of Economic Analysis starts with the Legislative Revenue Office's (LRO) impact statement and any Oregon Tax Incidence Model (OTIM) results LRO found. At the top line, OTIM results find minimal macroeconomic impacts across Oregon due to the new tax. Personal income, employment, population, investment and the like are less than one-tenth of a percent different under the new tax relative to the baseline. The model results also show that price levels (inflation) will increase above the baseline as some of the CAT is pushed forward onto consumers. Of course these top line, statewide numbers mask the varying experiences that individual firms and different industries will experience. There are likely to be some businesses or sectors that experience large impacts from the CAT, or where pyramiding increases prices to a larger degree, while other businesses or sectors see relatively few impacts.

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.

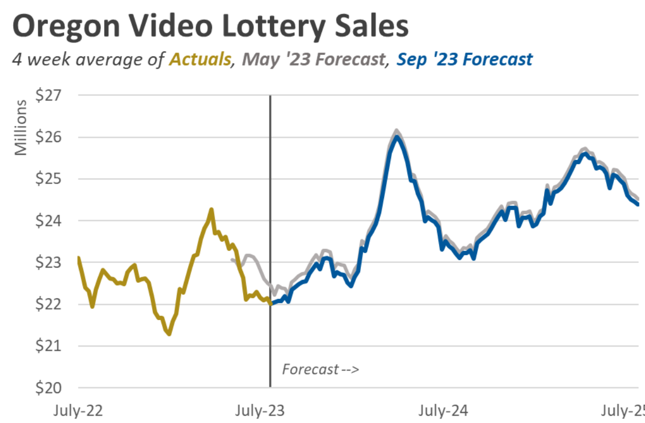
Lottery Forecast

In keeping with a stable economic outlook in terms of income, jobs, population, and spending, the overall lottery forecast is relatively unchanged as well. Resources in the current 2023-25 biennium are raised $9.5 million (+0.5%), while resources in 2025-27 and beyond are all lowered by approximately one half of one percent, or $11 to $15 million per biennium.

The primary change made to the outlook is slight reduction in the sales outlook for video lottery. Sales have tracked low in recent months. This is carried forward into the forecast, when combined with stable income and spending forecasts. It remains an open question to what extent the sharper slowdown in video sales recently is temporary, or a sign of something more permanent. On one hand, sales slowed in other states, but less so than in Oregon. On the other hand, households may be struggling with continued high inflation which could crimp their spending on discretionary items to a greater degree. Or conversely, with increased travel and the high cost of vacations today, consumers may be choosing to spend their money on other entertainment options to a greater degree.

But overall, sales remain much stronger than pre-pandemic, and are tracking closer to the previous forecast in recent weeks than they were a couple of months ago. And comparing the entire cycle to date, Oregon video sales are right in the middle of the pack for sales growth in slots or video seen in other states.

One additional factor impacting sales next year is the record $5.6 billion personal income tax kicker that will be return to taxpayers. While video lottery sales are only approximately 0.45 percent of Oregon personal income, such a large increase in disposable income is likely to result in higher consumer spending statewide, including on discretionary items like video lottery. The result is expectations are sales next spring to regain the pandemic reopening highs, followed by slightly lower sales the following year when there will be no kicker paid out.



Besides the changes made to the video lottery forecast, there are two other impacts to revenues in the current 2023-25 biennium. High jackpots continue to drive traditional Lottery sales above forecast. Additionally, following the close out of the previous biennium, Oregon Lottery was able to transfer $9.2 million in administrative savings this past quarter, raising available resources in the current biennium.

Risks to the Outlook

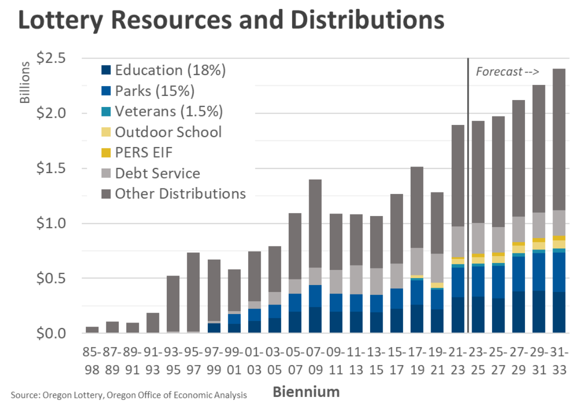
Risks to the outlook abound and vary depending upon the timeframe. In the very near-term, risks lie primarily to the upside. Consumer spending remains robust and sales could outstrip the expectations of an economic soft landing. Conversely, should inflation begin to take a toll on households, discretionary purchases may be cut back, similar to what appears to have happened in recent weeks.

Over the medium term, risks are balanced. Sales may outpace expectations, or the economy may fall into a recession. Looking back historically, Lottery held up well in both the 1990 and 2001 recessions. However Oregon also did not have line games back then, which makes comparing historical periods more challenging to today. To the extent that player behavior for line games differs than overall consumer spending, discretionary spending, or even gaming in a broad sense, sales could under- or overperform as a result.

Over the long term a few sets of risks stand out. Our office expects increased competition for household entertainment dollars, increased competition within the gaming industry, and potentially shifts in generational preferences and tastes when it comes to gaming.

As discussed in depth in the March 2023 forecast, the structural impact of aging has been fully absorbed and has minimal impact moving forward as the Millennials are now entering their peak lottery years. As such, our outlook for video lottery sales is continued growth, however at a rate that is slightly slower than overall personal income growth. Lottery sales will continue to increase as Oregon's population and economy grows, however video lottery sales will likely be a slightly smaller slice of the overall pie. This outlook has been revised up some, so the relative decline is smaller than in previous forecasts due to the updated player demographic work.

However, longer run upside risks remain as well. While it is true that spending on video lottery grew slightly slower than income and spending last decade, that had reversed in the past couple of years. Some of the strong sales since reopening are due to pent-up demand, strong household finances, and the fact that other entertainment options were either not available initially (concerts, spectator sports) or possibly less desirable due to the virus (long distance travel, movie theaters). Even so, the relative strength in video sales could point toward some more permanent and not just pandemic or temporary changes in player behavior.



The full extended outlook for lottery earnings can be found in Table B.9 in Appendix B.

Budgetary Reserves

The state currently administers two general reserve accounts, the Oregon Rainy Day Fund15 (ORDF) and the Education Stability Fund16 (ESF). This section updates balances and recalculates the outlook for these funds based on the December revenue forecast.

As of this forecast the two reserve funds currently total a combined $2.1 billion. At the end of the current 2023-25 biennium, they will total $2.9 billion, which is equal to 11.3 percent of current revenues. Including the currently projected $880 million ending balance in the General Fund, the total effective reserves at the end of the current 2023-25 biennium are projected to be $3.8 billion, or 14.8 percent of current revenues.

The forecast for the ORDF includes two deposits for this biennium relating to the General Fund ending balance from the previous biennium (2021-23). A deposit of $271.3 million will be made in early 2024 after the accountants closed the books on last biennium. Additionally, a $91.6 million deposit relating to the increased corporate taxes from Measure 67 is expected at the end of the biennium in June 2025. This exact transfer amount is subject to some revision as corporate filings are processed, however the transfer itself will occur. At the end of 2023-25 the ORDF will total $1.9 billion.

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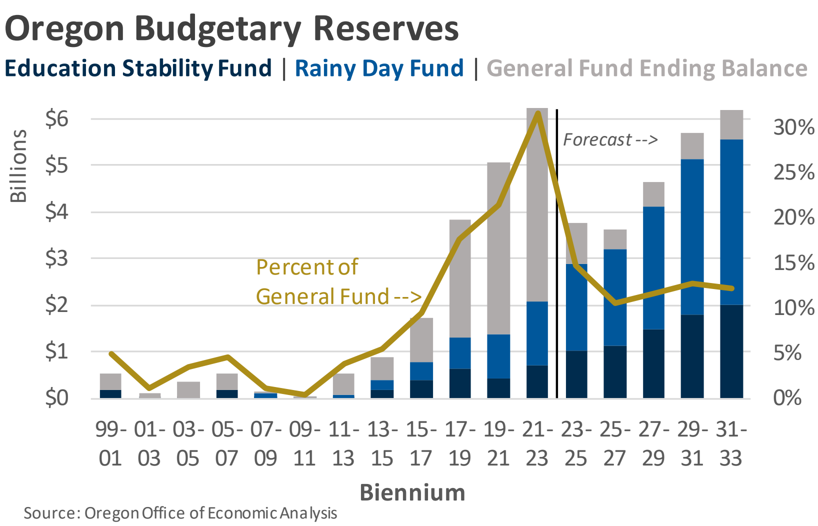
[15] The ORDF is funded from ending balances each biennium, up to one percent of appropriations. The Legislature can deposit additional funds, as it did in first populating the ORDF with surplus corporate income tax revenues from the 2005-07 biennium. The ORDF also retains interest earnings. Withdrawals 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 three-fifths vote. 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 percent of General Fund revenues in the prior biennium.

[16] The ESF gained its current reserve structure and mechanics via constitutional amendment in 2002. The ESF receives 18 percent 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 five percent of General Fund revenues collected in the prior biennium.

Looking ahead to the 2025-27 biennium, the ORDF is projected to hit its cap of 7.5 percent of revenues early in calendar year 2026. At that time, should the forecast prove accurate, the ending balance transfer related to 2023-25 would not be made, and those revenues would be retained in the General Fund. The ORDF would once again hit is cap in fiscal year 2031 based on the current outlook.
The ESF will receive an expected $298.5 million in deposits in the current 2023-25 biennium based on the current lottery forecast. At the end of current 2023-25 biennium the ESF will stand at $1.0 billion. The ESF is projected to hit its cap of 5 percent of revenues early in calendar year 2026, when the deposits will then accrue to the Capital Matching Account.

Together, the ORDF and ESF are projected to have a combined balance of $2.9 billion at the close of the 2023-25 biennium, or 11.3 percent of current revenues. At the close of 2025-27 the combined balance will be $3.2 billion, or 9.2 percent of revenues. Such levels of reserve balances are larger than Oregon has been able to accumulate in past cycles, and should help stabilize the budget when the next recession hits.



Effective Reserves ($ millions)

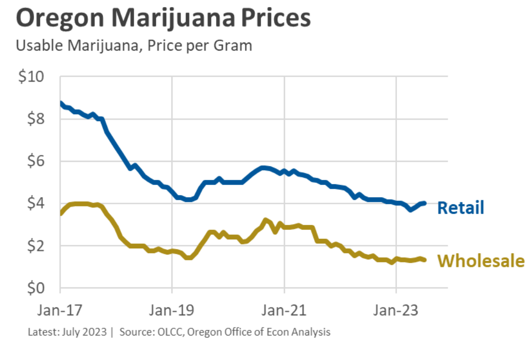
	Current Jul-23	*End of 2023-25*
ESF	$713	$1,009
RDF	$1,358	$1,863
Reserves	$2,071	$2,872
Ending Balance	$880	$880
Total	**$2,952**	**$3,752**
% of GF	11.6%	14.8%

With a potential recession in year ahead, the state is expected to meet the trigger for withdrawals should the recession come and should policymakers choose to. In particular the reserve fund trigger of two consecutive quarters of employment declines would be expected to be met based on our office's alternative scenario of a moderate recession. The other triggers may or may not be met. If revenues come in below forecast this biennium, that could trigger a potential withdrawal. And for the ESF only, not the ORDF, a Governor's declaration of emergency could also trigger a potential withdrawal. Finally, these are the technical considerations for using the reserve funds in the upcoming 2023-25 biennium. Ultimately policymakers will decide whether to use the funds or not. Regardless of the trigger(s) met, the Legislature would need a three-fifths vote in each chamber to approve an ESF reserve fund withdrawal and a simple majority vote in each chamber to approve an ORDF withdrawal.

B.10 in Appendix B provides more details for Oregon's budgetary reserves.

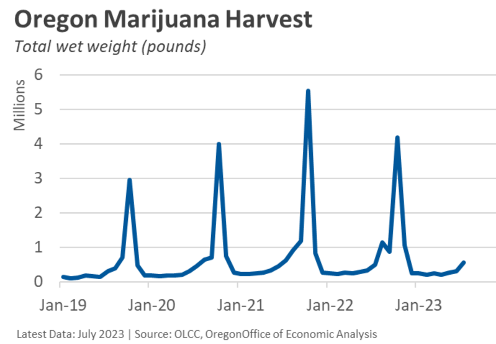
Recreational Marijuana Forecast

The underlying recreational marijuana forecast remains effectively unchanged. Revenues in the current 2023-25 biennium are lowered $2.8 million (-0.9%) compared to the Close of Session forecast. Revenues remain unchanged in both 2025-27 and 2027-29, while being lowered $1.3 million in 2029-31.



The primary reason for the stable outlook is largely tracking as expected following the large downward forecast adjustment made back in the March 2023 forecast.

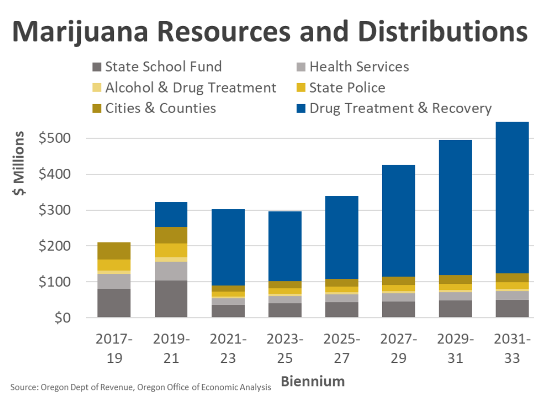
Encouragingly, the underlying market dynamics appear to be stabilizing. Harvest levels are down, sales are stable to rising, and average prices are firming. Given the market saturation, low prices that make it difficult for businesses to be profitable, and the fact that the large, outdoor harvest is about to begin, it remains an open question to whether today's stabilizing market dynamics are temporary or represent a true bottom.



Moving forward the crux of the issue remains the low prices, not only for firms but for tax collections given Oregon levies its recreational marijuana tax based on the price of the product. The forecast calls for better market balance, meaning lower levels of harvest and supply, combined with rising demand.

That said the low-hanging fruit for demand growth is behind us. Marijuana usage rates are steady in recent years, after increase considerably in the past decade. Many former black market consumers have converted to the legal market, and those that remain may be harder to switch. And underlying population growth has slowed during the pandemic, with only a modest rebound expected in the outlook.

Overall, expectations are the market will stabilize in the not too distant future. Sales and tax collections will remain relatively steady this year and next. Overall revenue and resources will be unchanged from last biennium (2021-23) to the current 2023-25 biennium. As supply and demand are expected to get into better balance, some pricing power and profitability will return to the market. Overall sales and taxes will increase with a growing population and economy in the decade ahead. Usage rates and consumption as share of income are expected to hold steady in the longer-run. Both upside and downside risks abound to this outlook.



See Table B.11 in Appendix B for a full breakdown of revenues and associated distributions to recipient programs.

Psilocybin Forecast

Ballot Measure 109 which voters passed in 2020 and legalized psilocybin, tasked our office with the revenue forecasting responsibilities. The current forecast remains unchanged from last quarter. The first quarterly tax returns were recently due. As more returns and data become available in the quarters ahead, our office will adjust the outlook accordingly.

After speaking with other state agencies and private businesses entering the psilocybin industry there are a few important items to note up front.

First, the overall cost of a session to a customer is expected to be in the hundreds, and even thousands of dollar range. Second, the state's 15 percent retail sales tax which was part of BM109 only applies to the product itself and not the overall cost of the session. Third, by all accounts the cost of the product is relatively small compared to the overall cost of a session, where the vast majority of the revenue will go to cover the operational costs of the service center and facilitator.

This newly legal industry is just getting started. The Oregon Health Authority has recently issued some of the first licenses in the state. Once the industry is up and running, OHA will gather data, including the number of sessions, product prices and the like. Unfortunately for now there is no data and our office's initial forecasts are based entirely on assumptions. Those assumptions are as follows.

OHA estimates they will license 28 service centers in the first year. Assuming 20 customers per day, the equivalent of one large class, all year long results in 204,000 individual customers or session over the course of the first year. Some service center centers will accommodate many more customers while others may focus on smaller, more in-depth sessions. Anecdotal information to date indicates the first couple of service centers are serving just a handful of customers per week currently.

As uncertain as those projections are, the average product price assumption is even more so. Service centers may charge customers whatever price they want to for the actual product. There are two main ways to think through these possibilities, and for now our office is taking a middle ground approach.

On one hand, service centers may charge customers the traditional retail price that includes a markup over wholesale cost which largely relates to production, testing, and distribution costs. Whether the sales tax piece would be an additional charge on top of the session costs overall, or already factored that price is unknown. Tax revenues are estimated to be $1-2 million per year under these scenarios.

On the other hand, service center may charge customers a minimal product cost of $1 or $10, even if that is below their wholesale or acquisition costs. The benefit to 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. This is more likely to be the case if the sales tax is folded into the total session price initially and not an add-on fee when the customer pays. Tax revenues are estimated to be tens of thousands or hundreds of thousands of dollars a year under these scenarios.

For now, given the uncertainty of a newly legal industry our office is taking a middle ground approach and assuming a $10 average product price per session. The state is likely to receive a bit more than $600,000 in the current 2023-25 biennium based on the assumptions discussed above. We know that business practices will vary and time will tell what ultimately becomes the industry standard. Our office will continue to update these estimates as we learn more. Expectations are by this fall there will be useful data to help guide these estimates and they will not be made entirely upon assumptions.

Oregon Psilocybin Retail Sales Tax Revenue

Average	Biennial Revenue (millions)			
Product Price	2023-25	2025-27	2027-29	2029-31
$1	$0.062	$0.064	$0.067	$0.068
$10	$0.618	$0.643	$0.666	$0.679
$25	$1.545	$1.608	$1.664	$1.698
$50	$3.091	$3.215	$3.329	$3.396

Population and Demographic Outlook

Population and Demographic Summary

Oregon's resident population count on April 1, 2020 was 4,237,256. This is from the newly released decennial census data administered by the U.S. Census Bureau. During the past decade, Oregon gained 406,182 residents or 10.6 percent. The gain was substantial enough that yielded one additional congressional seat for the state. Oregon now has a total of six members in the House of Representatives. We have been predicting this rare gain for a long time. This is rare because it took 40 years for Oregon to gain this seat and only five states gained one additional seat each and Texas gained two seats following the 2020 Census.

In Historical context, Oregon's population growth rate between the 2010 and 2020 censuses was the second lowest since the first census count in Oregon in 1860 after gaining statehood. The lowest growth rate was recorded between the 1980 and 1990 censuses, a decade characterized by a major recession. Oregon's population increased by 441 percent in the last century spanning 1920-2020. The gain of 406,182 persons in the last decade alone was nearly the same as the total population count of Oregon in the year 1900 when state's population was 413,536. Oregon's population growth of 10.6 percent in the last decade was 11th highest in the nation, excluding Washington D.C. Still, our growth rate for the decade lagged all our neighboring states, except California. During the prior decade between 2000 and 2010, Oregon's population growth rate ranked 18th highest in the nation when Oregon was hit hard by the double recessions during the decade. As a result of such economic downturn during the Great Recession and sluggish recovery that followed, Oregon's population increased at a slow pace between 2000 and 2010 decade. However, Oregon's population was showing moderately strong growth since then because of state's strong economic recovery. The recent COVID-19 pandemic has caused dire economic and employment situations and has caused slow population growth. The population growth is expected to rebound after the year 2023. However, current economic turmoil is likely to slow the pace of expected growth. The average population growth between 2021 and 2023 was lowest since 1985-86. Oregon's population is expected to reach 4.575 million in the year 2032 with an annual rate of growth of 0.66 percent between 2022 and 2032. The projected population of 2030 is 141,500 less than our March 2020 forecast released just before the COVID hit. The lower projection is due to the lingering COVID-19 effect resulting in higher deaths, lower births, and fewer net-migration, and 2020 Census count coming lower than expected.

Oregon's economic condition 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 market. 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 comes from net in-migration. The COVID-19 pandemic has left noticeable impact on demographic processes. Due to the declining births and rising deaths, past forecasts projected natural increase (births minus deaths) to turn negative after the year 2025. However, Oregon's natural increase has already turned negative because of the COVID effect. Even during this pandemic, Oregon has gained people through net-migration as the workers are able to work from home in many sectors. Working-age adults come to Oregon as long as we have favorable economic conditions and offers better quality of life. During the 1980s, which included a major recession and a net loss of population during the early years, net migration contributed to 22 percent of the population change. On the other extreme of the economic cycle, net migration accounted for 73 percent of the population change during the booming economy of early 1990s. This share of migration to population change declined to 25 percent in 2010-11 as a result of the economic recession, lowest since early 1980s when we had negative net migration for several years. As a sign of slow to modest economic gain and declining natural increase (excess of deaths over births), the ratio of net migration-to-population change has registered at 90 percent in 2020. As a result of 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 2032 and beyond. So, in the future, all of Oregon's population growth and more will come from the net migration due to the combination of continued positive net migration, well below replacement level fertility, and the rise in the number of deaths associated with the increase in the elderly population. Thus, migration will be solely responsible for Oregon's future population growth. Without the gain due to migration, Oregon's population will start to decline. Oregon's negative natural increase caused by excess of deaths over births is expected to continue. However, under a few scenarios this trend may reverse itself. Such reversal can happen if the women start to have more children due to behavioral or motivational factors, or mortality and life expectancy improve suddenly resulting in fewer deaths or large number of women in childbearing age move into Oregon. Since all the states in the country are already experiencing below replacement level fertility (2.1 children per woman), the natural increase will eventually turn negative nationwide even if the trend is mitigated for the short term because of the large number of women in childbearing age.

Age structure and its change affect employment, state revenue, and expenditure as the demand for 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 history of decades past do impact the current age-sex structure. Growth in many age groups will show the effects of the baby-boom and their echo generations during the forecast period of 2022-2032. It will also reflect demographics impacted by the depression era smaller birth cohort combined with changing migration of working age population and elderly retirees through history. After a period of relatively slow growth during the 1990s and early 2000s, the elderly population (65+) has picked up a faster pace of growth since 2005. This population group will maintain the high growth as the tail end of the baby-boom generation continue to enter this age group combined with the attrition of small depression era birth cohort due to death. This age cohort, however, has hit the plateau of high growth rates exceeding 4 percent annually between 2011 and 2019. The group will experience continued high but diminishing rate of growth. The average annual growth of the elderly population will be 1.8 percent during the 2022-2032 forecast period. Different age groups among the elderly population show quite varied and fascinating growth trends. The youngest elderly (aged 65-74), which was growing at an extremely fast pace in the recent past averaging 5.1 percent annually between 2010 and 2020 due to the direct impact of the baby-boom generation entering and smaller pre-baby boom cohort exiting this 65-74 age group. This fast-paced growth rate will taper off to negative growth by the end of the forecast period of 2022-2032 as a sign of the end of the baby-boom generation transitioning to elderly age group. This high growth transitioning into a net loss of this youngest elderly population resulting in -0.3 percent annual average loss in the coming ten years. The next older generation of population aged 75-84 has seen several years of slow growth and a period of shrinking until a decade ago. The elderly aged 75-84 started to show growth as the effect of depression era birth-cohort matured out of this age group. An unprecedented fast pace of growth of population in this age group has already started as the baby-boom generation is maturing from the youngest elderly into this 75-84 age group. Annual growth rate during the forecast period of 2022-2032 is expected to be unusually high 4.4 percent. However, for most of the forecast period, the annual growth rate will exceed 4 percent per year. After a period of slow growth, the oldest elderly (aged 85+) will resume growth at a strong rate steadily gaining momentum due to the combination of cohort change, continued positive net migration, and improving longevity. The average annual rate of growth for this oldest elderly over the forecast horizon will be 4.2 percent. An unprecedented growth in oldest elderly will commence near the end of the forecast horizon as the fast growing 75-84 age group population transition into this oldest elderly age cohort. As a sign of massive demographic structural change of Oregon’s population, starting in 2023 the number of elderly will exceed the number of children under the age of 18. 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.

The oldest working age population aged 45-64 also has seen the dramatic demographic impact as the baby-boom generation matures out of the oldest working-age cohort which is replaced by smaller baby-bust cohort or Gen X. As the effect of this demographic transition combined with slowing net migration, the once fast-paced growth of population aged 45-64 has gradually tapered off to below zero percent rate of growth by 2012 and has remained and will remain at slow or below zero growth phase for a few more years. The size of this older working-age population will see about 0.8 percent annualized rate of change over the forecast horizon of next ten years. The younger working-age population of 25-44 age group has recovered from several years of declining and slow growing trend. The decline in the past was mainly due to the exiting baby-boom cohort. This age group has seen positive but slow growth starting in the year 2004 and has gained steam since 2013. This group will increase by 0.5 percent annual average rate during the forecast horizon mainly because of the exiting smaller birth (baby-bust) cohort being replaced by larger baby-boom-echo cohort. The young adult population (aged 18-24) will see only a small change over the forecast period due to the combination of negative and slow growth years. Although the slow growth of college-age population (age 18-24), in general, tend to ease the pressure on public spending on higher education, but college enrollment typically goes up during the time of very competitive job market, high unemployment, and scarcity of well-paying jobs when even the older people flock back to colleges to better position themselves in a tough job market. The growth in K-12 population (aged 5-17) has been very slow or negative in the past and is expected to decline through the forecast 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 -1.0 percent 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 to decline in the near future due to the sharp decline in the number of births. We expect a rebound in the number of births in the forecast period due to a small increase in fertility rate and increase in the women in the child-bearing ages. During the forecast horizon, the children under the age of five will increase at the rate of 0.6 percent annually. Although the number of children under the age of five declined in the recent years, the demand for childcare services and pre-Kindergarten program will be additionally determined by the labor force participation and poverty rates of the parents.

Overall, 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. Oregon's estimated population of July 1, 2020 based on the most recent decennial census is the base for the forecast. To explain the cohort-component projection procedure very briefly, the forecasting 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. Further iterations subject the in-and-out migrants to the same mortality and fertility rates. Hence, the age-sex group we start with become one year older the next year accounting for the deaths during the year, births to the women in childbearing ages, and add/subtract net migration for that age during the year.

The U.S. Census Bureau just released the age-sex details of the resident population count of April 1, 2020 for the states. This is the crucial information as the base for all future postcensal population estimates and projections. The 2020 census population total and age-sex detail are used to determine the error of closure, which is the difference between the actual census enumeration and the estimate based on the previous census of 2010. Again, the error of closure is used to correct and adjust all previous annual postcensal estimates for the time between 2011 and 2019. OEA has estimated the total intercensal population for Oregon based on 2010 and 2020 census counts and postcensal estimates of Population Research Center, Portland State University. Therefore, Oregon's *intercensal* population estimates for the years 2011 through 2029 in this forecast shown in Appendix C are different from prior *postcensal* numbers and PSU's original estimates. The Bureau released age-sex detail of the census population in June of this year. OEA has produce preliminary readjusted intercensal estimates by age and sex for each of the years from 2011 through 2019. The numbers of births and deaths through 2022 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 2020 and this rate is projected to 1.5 children per woman by 2032 which is well below the replacement level fertility of 2.1 children per woman. Oregon's fertility level is tracking below the national level.

Life Table survival rates are developed for the year 2020. Male and female life expectancies for the 2020-2032 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 births of 77.3 and the female life expectancy of 81.8 in 2010. Due to the effect 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 respectively for males and females. This is expected to improve to 79.5 years for women and 83.5 years for men by 2032.

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 take into account Oregon's employment, unemployment rates, income/wage data from Oregon and neighboring states, past trends and migration to population ratio. Distribution of migrants by age and sex is based on detailed data from the American Community Survey. In the recent past, slowdown in Oregon's economy resulted in smaller net migration and slow population growth. Estimated population growth and net migration rates in 2010-2011 were the lowest in over two decades. Migration is intrinsically related to economy and employment situation of the state. Still, high unemployment and job loss in the recent past have impacted net migration and population growth, but not to the extent in the early 1980s. Main reason for this is the fact that other states of potential destination for Oregon out-migrants were not faring any better either, limiting the potential destination choices. The role of net migration in Oregon's population growth will get more prominence as the natural increase has begun to turn negative. The increasing excess of deaths over births will continue due to the rapid increase in the number of deaths associated with the aging population and relatively fewer number of births largely due to the decline in fertility rate associated with life-style choices. Such a trend was expected, but the COVID-19 has hastened the process. The annual net migration is expected to be low due to the after-effect of COVID-19 and economic slowdown. However, the migration is expected to recover after 2024. Between 2022 and 2033 net migration is expected to be in the range of 19,280 to 40,740, averaging 33,860 persons annually with net migration rate ranging between 4.5 to 8.9 per thousand population.

Appendix A: Economic Forecast Detail

Table A.1 – Employment Forecast Tracking

Total Nonfarm Employment, 2nd quarter 2023

(Employment in thousands, Annualized Percent Change)

	Preliminary Estimate		Forecast		Forecast Error		Y/Y Change
	level	% ch	level	% ch	level	%	% ch
Total Nonfarm	1,980.3	1.7	1,989.0	1.3	(8.7)	(0.4)	1.9
Total Private	1,676.4	1.6	1,685.6	1.1	(9.2)	(0.5)	1.6
Mining and Logging	6.3	9.0	6.3	(1.4)	(0.0)	(0.7)	(1.1)
Construction	120.0	2.6	120.3	(0.6)	(0.3)	(0.2)	4.2
Manufacturing	192.8	(0.4)	194.5	(0.0)	(1.7)	(0.9)	(0.5)
Durable Goods	135.9	(0.3)	136.3	(0.9)	(0.4)	(0.3)	0.2
Wood Product	22.8	(0.3)	23.3	0.7	(0.5)	(2.2)	(3.0)
Metals and Machinery	38.4	0.6	38.5	(0.9)	(0.1)	(0.3)	0.7
Computer and Electronic Product	42.1	(1.9)	40.5	(5.2)	1.5	3.8	2.1
Transportation Equipment	10.7	1.2	11.2	8.9	(0.5)	(4.2)	(1.6)
Other Durable Goods	22.0	0.4	22.8	0.7	(0.8)	(3.6)	(0.3)
Nondurable Goods	56.9	(0.6)	58.2	2.1	(1.3)	(2.3)	(1.9)
Food	27.8	(5.5)	29.2	3.8	(1.3)	(4.6)	(3.3)
Other Nondurable Goods	29.0	4.4	29.0	0.4	0.0	0.0	(0.6)
Trade, Transportation & Utilities	364.5	(1.7)	368.3	0.3	(3.7)	(1.0)	(0.9)
Retail Trade	209.5	(2.3)	210.4	0.2	(0.9)	(0.4)	(0.6)
Wholesale Trade	76.2	(4.9)	78.7	0.7	(2.5)	(3.2)	(1.3)
Transportation, Warehousing & Utilities	78.9	3.0	79.1	0.5	(0.2)	(0.3)	(1.3)
Information	36.5	7.9	37.0	0.3	(0.4)	(1.2)	(1.1)
Financial Activities	104.6	3.6	106.9	0.7	(2.3)	(2.2)	(1.0)
Professional & Business Services	267.3	2.4	269.9	0.8	(2.6)	(1.0)	1.2
Educational & Health Services	314.1	3.4	312.4	3.6	1.8	0.6	3.8
Educational Services	35.0	7.3	35.4	4.3	(0.4)	(1.1)	0.7
Health Services	279.2	2.9	277.0	3.5	2.1	0.8	4.2
Leisure and Hospitality	204.7	1.2	206.2	2.2	(1.5)	(0.7)	4.0
Other Services	65.4	6.1	63.7	0.5	1.6	2.5	6.9
Government	303.9	2.3	303.4	2.1	0.5	0.2	3.9
Federal	28.0	(2.3)	28.4	2.8	(0.4)	(1.3)	0.3
State	44.7	3.1	44.4	9.6	0.3	0.7	4.5
State Education	1.3	12.2	1.3	(4.8)	0.1	3.9	20.9
Local	231.2	2.7	230.7	0.7	0.5	0.2	4.3
Local Education	133.6	5.3	131.9	0.2	1.7	1.3	5.1

Table A.2 – Short-Term Oregon Economic Summary

Oregon Forecast Summary

	Quarterly					Annual					
	2023:2	2023:3	2023:4	2024:1	2024:2	2022	2023	2024	2025	2026	2027
Personal Income ($ billions)											
Nominal Personal Income	279.9	284.9	289.0	294.0	298.0	266.6	282.5	299.8	315.3	331.1	347.7
% change	5.8	7.4	5.8	7.1	5.6	2.0	5.9	6.2	5.2	5.0	5.0
Real Personal Income (base year=2012)	220.3	222.7	224.1	226.7	228.3	217.0	221.5	229.1	235.6	242.4	249.5
% change	2.8	4.4	2.5	4.7	2.9	(4.1)	2.0	3.4	2.8	2.9	2.9
Nominal Wages and Salaries	142.2	145.2	147.1	148.9	150.9	136.5	143.7	151.8	159.1	166.8	174.8
% change	5.7	8.6	5.4	5.0	5.3	8.1	5.3	5.6	4.9	4.8	4.8
Other Indicators											
Per Capita Income ($1,000)	65.2	66.3	67.2	68.2	69.1	62.3	65.7	69.5	72.6	75.7	79.0
% change	5.4	7.0	5.4	6.6	5.1	1.5	5.6	5.7	4.5	4.3	4.3
Average Wage rate ($1,000)	71.4	72.3	73.0	73.7	74.5	69.5	71.8	74.9	78.1	81.3	84.6
% change	4.7	5.2	4.0	4.2	4.4	4.1	3.3	4.3	4.2	4.1	4.1
Population (Millions)	4.3	4.3	4.3	4.3	4.3	4.28	4.30	4.32	4.34	4.37	4.40
% change	0.4	0.4	0.4	0.4	0.5	0.4	0.3	0.5	0.6	0.7	0.7
Housing Starts (Thousands)	19.3	19.4	19.5	19.8	19.9	19.9	19.3	20.1	21.0	21.1	21.2
% change	6.0	3.2	2.9	4.7	3.5	(1.4)	(3.3)	4.2	4.3	0.5	0.6
Unemployment Rate	3.8	3.5	3.6	3.7	3.8	4.1	3.9	3.9	4.1	4.1	4.1
Point Change	(0.9)	(0.3)	0.1	0.1	0.1	(1.1)	(0.3)	(0.0)	0.2	0.0	0.0
Employment (Thousands)											
Total Nonfarm	1,980.3	1,992.1	1,999.4	2,003.2	2,007.7	1,947.2	1,985.9	2,009.2	2,022.3	2,037.2	2,051.3
% change	1.7	2.4	1.5	0.8	0.9	3.8	2.0	1.2	0.7	0.7	0.7
Private Nonfarm	1,676.4	1,687.2	1,694.8	1,699.0	1,703.9	1,652.4	1,682.1	1,705.4	1,719.2	1,733.4	1,746.6
% change	1.6	2.6	1.8	1.0	1.2	3.9	1.8	1.4	0.8	0.8	0.8
Construction	120.0	120.4	120.1	120.2	121.0	115.8	119.9	121.4	123.2	123.7	123.8
% change	2.6	1.1	(0.7)	0.3	2.5	4.0	3.6	1.2	1.5	0.4	0.0
Manufacturing	192.8	193.9	194.7	195.3	195.6	193.3	193.6	195.7	195.6	196.4	196.3
% change	(0.4)	2.4	1.7	1.1	0.7	3.5	0.2	1.1	(0.0)	0.4	(0.1)
Durable Manufacturing	135.9	136.2	136.3	136.7	136.8	135.5	136.1	136.9	136.6	137.6	137.3
% change	(0.3)	0.7	0.3	1.3	0.3	4.9	0.5	0.6	(0.2)	0.7	(0.2)
Wood Product Manufacturing	22.8	22.7	22.7	22.7	22.7	23.3	22.8	22.7	22.9	23.2	23.1
% change	(0.3)	(0.3)	(0.3)	(0.5)	(0.2)	2.5	(2.4)	(0.3)	0.9	1.4	(0.5)
High Tech Manufacturing	42.1	42.0	42.0	42.0	42.0	41.3	42.1	42.0	42.0	43.3	44.0
% change	(1.9)	(0.3)	(0.8)	0.6	(0.0)	8.9	1.9	(0.3)	0.1	3.1	1.7
Transportation Equipment	10.7	11.0	11.0	11.1	11.2	10.8	10.8	11.3	11.7	11.8	11.6
% change	1.2	10.0	1.1	5.0	3.8	1.1	0.1	4.2	3.7	1.2	(1.9)
Nondurable Manufacturing	56.9	57.8	58.5	58.5	58.8	57.8	57.5	58.8	59.0	58.8	59.0
% change	(0.6)	6.3	5.0	0.6	1.5	0.4	(0.5)	2.3	0.3	(0.2)	0.3
Private nonmanufacturing	1,483.6	1,493.3	1,500.1	1,503.7	1,508.3	1,459.1	1,488.4	1,509.8	1,523.6	1,536.9	1,550.3
% change	1.8	2.6	1.8	1.0	1.2	4.0	2.0	1.4	0.9	0.9	0.9
Retail Trade	209.5	209.8	209.7	209.7	209.7	210.7	209.9	209.7	209.7	209.7	209.7
% change	(2.3)	0.5	(0.1)	(0.0)	(0.0)	0.7	(0.4)	(0.1)	0.0	0.0	(0.0)
Wholesale Trade	76.2	77.5	77.6	77.6	77.7	77.1	77.1	77.7	77.8	78.0	78.2
% change	(4.9)	7.2	0.3	0.3	0.3	2.8	0.0	0.8	0.0	0.3	0.4
Information	36.5	36.2	36.9	36.9	36.7	36.7	36.4	36.6	36.9	37.0	37.1
% change	7.9	(4.0)	7.8	0.5	(2.2)	4.6	(0.9)	0.8	0.7	0.2	0.2
Professional and Business Services	267.3	269.9	272.4	273.1	273.8	264.1	268.8	273.9	275.9	280.4	286.2
% change	2.4	4.0	3.8	1.0	1.1	5.0	1.8	1.9	0.7	1.6	2.0
Health Services	279.2	281.6	283.3	284.6	286.6	269.5	280.3	287.0	292.7	297.4	302.1
% change	2.9	3.6	2.4	1.8	2.8	0.9	4.0	2.4	2.0	1.6	1.6
Leisure and Hospitality	204.7	206.6	207.8	209.1	210.4	198.3	205.8	210.6	213.3	215.0	216.5
% change	1.2	3.6	2.4	2.5	2.5	13.3	3.8	2.3	1.3	0.8	0.7
Government	303.9	304.9	304.6	304.3	303.8	294.8	303.9	303.8	303.2	303.9	304.7
% change	2.3	1.4	(0.5)	(0.4)	(0.6)	3.2	3.1	(0.0)	(0.2)	0.2	0.3

Table A.3 – Oregon Economic Forecast Change

Oregon Forecast Change (Current vs. Last)

	Quarterly					Annual					
	2023:1	2023:2	2023:3	2023:4	2024:1	2022	2023	2024	2025	2026	2027
Personal Income ($ billions)											
Nominal Personal Income	279.9	284.9	289.0	294.0	298.0	266.6	282.5	299.8	315.3	331.1	347.7
% change	(0.5)	0.0	0.1	0.2	0.3	0.2	(0.2)	0.3	0.3	0.2	0.0
Real Personal Income (base year=2012)	220.3	222.7	224.1	226.7	228.3	217.0	221.5	229.1	235.6	242.4	249.5
% change	(0.4)	0.3	0.2	0.4	0.4	0.2	(0.1)	0.5	0.3	0.1	(0.1)
Nominal Wages and Salaries	142.2	145.2	147.1	148.9	150.9	136.5	143.7	151.8	159.1	166.8	174.8
% change	(1.3)	(0.6)	(0.8)	(0.8)	(0.8)	0.3	(1.0)	(0.8)	(0.9)	(0.9)	(0.9)
Other Indicators											
Per Capita Income ($1,000)	65.2	66.3	67.2	68.2	69.1	62.3	65.7	69.5	72.6	75.7	79.0
% change	(0.5)	(0.0)	0.0	0.1	0.3	0.1	(0.3)	0.3	0.3	0.1	(0.0)
Average Wage rate ($1,000)	71.4	72.3	73.0	73.7	74.5	69.5	71.8	74.9	78.1	81.3	84.6
% change	(0.6)	(0.5)	(0.7)	(0.7)	(0.7)	0.4	(0.7)	(0.7)	(0.8)	(0.8)	(0.8)
Population (Millions)	4.29	4.30	4.30	4.3	4.3	4.28	4.30	4.32	4.34	4.37	4.40
% change	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0
Housing Starts (Thousands)	19.3	19.4	19.5	19.8	19.9	19.9	19.3	20.1	21.0	21.1	21.2
% change	(2.2)	(0.9)	(0.8)	(0.8)	(2.2)	(0.1)	(2.1)	(1.5)	(0.5)	0.1	0.1
Unemployment Rate	3.8	3.5	3.6	3.7	3.8	4.1	3.9	3.9	4.1	4.1	4.1
Point Change	(0.3)	(0.5)	(0.4)	(0.4)	(0.4)	0.0	(0.3)	(0.3)	(0.1)	(0.1)	(0.1)
Employment (Thousands)											
Total Nonfarm	1,980.3	1,992.1	1,999.4	2,003.2	2,007.7	1,947.2	1,985.9	2,009.2	2,022.3	2,037.2	2,051.3
% change	(0.4)	(0.1)	(0.0)	(0.1)	(0.1)	(0.1)	(0.3)	(0.1)	(0.1)	(0.1)	(0.2)
Private Nonfarm	1,676.4	1,687.2	1,694.8	1,699.0	1,703.9	1,652.4	1,682.1	1,705.4	1,719.2	1,733.4	1,746.6
% change	(0.5)	(0.2)	(0.2)	(0.3)	(0.2)	(0.2)	(0.4)	(0.2)	(0.2)	(0.2)	(0.2)
Construction	120.0	120.4	120.1	120.2	121.0	115.8	119.9	121.4	123.2	123.7	123.8
% change	(0.2)	0.1	0.0	0.0	0.3	(0.1)	(0.3)	0.5	1.0	1.0	0.8
Manufacturing	192.8	193.9	194.7	195.3	195.6	193.3	193.6	195.7	195.6	196.4	196.3
% change	(0.9)	(0.7)	(0.6)	(0.4)	(0.1)	(0.3)	(0.8)	(0.0)	0.3	0.9	1.1
Durable Manufacturing	135.9	136.2	136.3	136.7	136.8	135.5	136.1	136.9	136.6	137.6	137.3
% change	(0.3)	(0.2)	(0.1)	0.1	0.2	(0.1)	(0.3)	0.3	0.6	1.6	2.0
Wood Product Manufacturing	22.8	22.7	22.7	22.7	22.7	23.3	22.8	22.7	22.9	23.2	23.1
% change	(2.2)	(2.4)	(2.6)	(2.8)	(3.0)	(0.3)	(2.3)	(3.1)	(3.3)	(2.7)	(2.9)
High Tech Manufacturing	42.1	42.0	42.0	42.0	42.0	41.3	42.1	42.0	42.0	43.3	44.0
% change	3.8	3.6	3.6	3.7	3.7	0.4	3.5	3.8	4.5	8.2	10.4
Transportation Equipment	10.7	11.0	11.0	11.1	11.2	10.8	10.8	11.3	11.7	11.8	11.6
% change	(4.2)	(1.7)	(1.6)	(1.4)	(1.3)	(0.5)	(2.5)	(1.3)	(1.1)	(0.8)	(0.8)
Nondurable Manufacturing	56.9	57.8	58.5	58.5	58.8	57.8	57.5	58.8	59.0	58.8	59.0
% change	(2.3)	(2.1)	(1.7)	(1.4)	(0.9)	(0.8)	(1.9)	(0.9)	(0.4)	(0.7)	(0.8)
Private nonmanufacturing	1,483.6	1,493.3	1,500.1	1,503.7	1,508.3	1,459.1	1,488.4	1,509.8	1,523.6	1,536.9	1,550.3
% change	(0.5)	(0.2)	(0.1)	(0.2)	(0.2)	(0.1)	(0.4)	(0.2)	(0.3)	(0.3)	(0.4)
Retail Trade	209.5	209.8	209.7	209.7	209.7	210.7	209.9	209.7	209.7	209.7	209.7
% change	(0.4)	(0.3)	(0.4)	(0.4)	(0.4)	(0.0)	(0.2)	(0.4)	(0.3)	(0.3)	(0.2)
Wholesale Trade	76.2	77.5	77.6	77.6	77.7	77.1	77.1	77.7	77.8	78.0	78.2
% change	(3.2)	(1.1)	(0.9)	(0.9)	(0.7)	(0.4)	(1.8)	(0.6)	(0.5)	(0.4)	(0.4)
Information	36.5	36.2	36.9	36.9	36.7	36.7	36.4	36.6	36.9	37.0	37.1
% change	(1.2)	(2.3)	(1.3)	(1.5)	(1.7)	(0.5)	(1.9)	(1.7)	(1.6)	(1.4)	(1.2)
Professional and Business Services	267.3	269.9	272.4	273.1	273.8	264.1	268.8	273.9	275.9	280.4	286.2
% change	(1.0)	(0.3)	(0.1)	(0.2)	(0.1)	(0.2)	(0.7)	(0.1)	(0.2)	(0.2)	(0.2)
Health Services	279.2	281.6	283.3	284.6	286.6	269.5	280.3	287.0	292.7	297.4	302.1
% change	0.8	0.8	0.5	0.1	0.0	0.2	0.8	(0.0)	(0.2)	(0.3)	(0.4)
Leisure and Hospitality	204.7	206.6	207.8	209.1	210.4	198.3	205.8	210.6	213.3	215.0	216.5
% change	(0.7)	(0.4)	(0.4)	(0.4)	(0.4)	(0.2)	(0.5)	(0.4)	(0.6)	(0.8)	(1.1)
Government	303.9	304.9	304.6	304.3	303.8	294.8	303.9	303.8	303.2	303.9	304.7
% change	0.2	0.8	0.8	0.7	0.6	0.1	0.5	0.6	0.4	0.2	0.0

Table A.4 – Annual Economic Forecast

Sept 2023 - Personal Income

(Billions of Current Dollars)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Personal Income*												
Oregon	222.3	241.8	261.5	266.6	282.5	299.8	315.3	331.1	347.7	365.2	383.6	402.6
% Ch	5.1	8.8	8.2	2.0	5.9	6.2	5.2	5.0	5.0	5.0	5.0	5.0
U.S.	18,587.0	19,832.3	21,294.8	21,777.2	22,892.3	24,001.9	25,106.7	26,238.8	27,459.9	28,694.2	29,928.2	31,202.1
% Ch	5.1	6.7	7.4	2.3	5.1	4.8	4.6	4.5	4.7	4.5	4.3	4.3
Wage and Salary												
Oregon	112.9	115.8	126.3	136.5	143.7	151.8	159.1	166.8	174.8	183.1	191.7	200.7
% Ch	5.3	2.5	9.1	8.1	5.3	5.6	4.9	4.8	4.8	4.8	4.7	4.7
U.S.	9,324.6	9,457.4	10,290.1	11,189.6	11,777.1	12,323.3	12,842.5	13,398.8	14,009.9	14,628.9	15,239.4	15,873.4
% Ch	4.8	1.4	8.8	8.7	5.3	4.6	4.2	4.3	4.6	4.4	4.2	4.2
Other Labor Income												
Oregon	27.6	28.6	30.5	32.2	34.1	36.3	38.2	40.1	42.1	44.1	46.3	48.5
% Ch	5.3	3.5	6.6	5.5	6.0	6.4	5.3	5.1	4.9	4.8	4.8	4.8
U.S.	1,472.9	1,476.2	1,550.3	1,612.5	1,676.7	1,748.3	1,822.0	1,900.9	1,987.6	2,075.4	2,162.0	2,252.0
% Ch	2.8	0.2	5.0	4.0	4.0	4.3	4.2	4.3	4.6	4.4	4.2	4.2
Nonfarm Proprietor's Income												
Oregon	18.9	20.7	21.8	22.9	24.1	25.9	27.2	28.7	30.6	32.5	34.5	36.5
% Ch	1.4	9.8	5.3	5.1	5.2	7.5	5.0	5.7	6.3	6.2	6.4	5.7
U.S.	1,572.3	1,597.9	1,702.2	1,756.6	1,824.2	1,858.9	1,907.5	1,988.7	2,082.3	2,179.5	2,288.2	2,406.8
% Ch	2.1	1.6	6.5	3.2	3.9	1.9	2.6	4.3	4.7	4.7	5.0	5.2
Dividend, Interest and Rent												
Oregon	44.9	45.4	46.8	49.4	53.0	57.6	61.2	63.8	66.6	69.4	72.4	75.5
% Ch	5.2	1.2	3.1	5.6	7.3	8.6	6.2	4.4	4.3	4.3	4.3	4.3
U.S.	3,817.2	3,815.3	3,926.2	4,125.8	4,393.6	4,753.8	5,052.3	5,267.7	5,484.3	5,690.7	5,892.4	6,100.8
% Ch	7.8	(0.1)	2.9	5.1	6.5	8.2	6.3	4.3	4.1	3.8	3.5	3.5
Transfer Payments												
Oregon	42.7	56.8	63.4	54.9	58.6	61.4	64.3	67.9	71.7	75.9	80.5	85.1
% Ch	6.0	33.1	11.6	(13.5)	6.8	4.8	4.7	5.5	5.7	5.9	6.0	5.8
U.S.	3,089.7	4,187.1	4,546.4	3,839.6	4,024.9	4,168.2	4,361.0	4,602.0	4,855.2	5,124.3	5,395.2	5,664.0
% Ch	5.6	35.5	8.6	(15.5)	4.8	3.6	4.6	5.5	5.5	5.5	5.3	5.0
Contributions for Social Security												
Oregon	19.6	20.1	21.5	23.2	24.7	26.3	27.6	28.9	30.2	31.7	33.2	34.8
% Ch	5.3	2.7	6.8	8.1	6.4	6.4	4.8	4.8	4.7	4.8	4.8	4.8
U.S.	773.9	790.9	842.7	909.8	963.0	1,010.7	1,053.5	1,098.3	1,137.3	1,185.5	1,235.5	1,287.4
% Ch	5.0	2.2	6.6	8.0	5.9	5.0	4.2	4.3	3.5	4.2	4.2	4.2
Residence Adjustment												
Oregon	(5.5)	(5.7)	(6.0)	(6.4)	(6.8)	(7.2)	(7.6)	(7.9)	(8.2)	(8.6)	(9.0)	(9.4)
% Ch	6.8	4.4	4.7	7.5	5.8	6.0	4.6	4.5	4.4	4.4	4.4	4.4
Farm Proprietor's Income												
Oregon	0.3	0.3	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
% Ch	26.9	(15.0)	(36.1)	120.7	(7.3)	(5.3)	18.0	4.4	(0.4)	1.7	3.1	2.3
Per Capita Income (Thousands of $)												
Oregon	52.7	57.0	61.3	62.3	65.7	69.5	72.6	75.7	79.0	82.3	85.8	89.4
% Ch	4.1	8.0	7.7	1.5	5.6	5.7	4.5	4.3	4.3	4.3	4.2	4.1
U.S.	56.2	59.8	64.1	65.2	68.2	71.2	74.1	77.0	80.2	83.4	86.5	89.7
% Ch	4.5	6.3	7.2	1.9	4.6	4.3	4.1	4.0	4.1	4.0	3.8	3.7

* Personal Income includes all classes of income minus Contributions for Social Security

Sept 2023 - Employment By Industry

(Oregon - Thousands, U.S. - Millions)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Nonfarm												
Oregon	1,954.3	1,830.8	1,875.9	1,947.2	1,985.9	2,009.2	2,022.3	2,037.2	2,051.3	2,065.4	2,077.8	2,091.0
% Ch	1.6	(6.3)	2.5	3.8	2.0	1.2	0.7	0.7	0.7	0.7	0.6	0.6
U.S.	150.9	142.2	146.3	152.6	156.1	156.6	156.3	156.5	157.1	157.9	158.7	159.4
% Ch	1.3	(5.8)	2.9	4.3	2.3	0.3	(0.2)	0.1	0.4	0.5	0.5	0.5
Private Nonfarm												
Oregon	1,655.9	1,546.2	1,590.2	1,652.4	1,682.1	1,705.4	1,719.2	1,733.4	1,746.6	1,759.8	1,771.3	1,782.9
% Ch	1.7	(6.6)	2.8	3.9	1.8	1.4	0.8	0.8	0.8	0.8	0.7	0.7
U.S.	128.3	120.2	124.3	130.4	133.4	133.7	133.2	133.3	133.8	134.5	135.1	135.7
% Ch	1.5	(6.3)	3.4	4.9	2.3	0.2	(0.3)	0.1	0.4	0.5	0.5	0.4
Mining and Logging												
Oregon	6.9	6.6	6.6	6.3	6.2	6.2	6.4	6.5	6.6	6.6	6.6	6.7
% Ch	(4.4)	(4.8)	(0.1)	(4.5)	(0.9)	0.5	2.0	2.0	1.4	0.4	0.2	0.5
U.S.	0.7	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
% Ch	(0.0)	(17.5)	(6.5)	8.0	5.3	0.5	2.9	5.3	3.7	1.3	(0.2)	(1.4)
Construction												
Oregon	109.6	108.4	111.3	115.8	119.9	121.4	123.2	123.7	123.8	123.0	122.6	122.7
% Ch	3.9	(1.1)	2.6	4.0	3.6	1.2	1.5	0.4	0.0	(0.6)	(0.3)	0.0
U.S.	7.5	7.3	7.4	7.7	7.9	7.9	7.9	7.9	8.0	8.1	8.2	8.2
% Ch	2.8	(3.2)	2.5	4.2	2.2	(0.2)	(0.3)	0.6	0.6	1.1	1.1	1.1
Manufacturing												
Oregon	198.1	185.5	186.7	193.3	193.6	195.7	195.6	196.4	196.3	196.3	196.4	196.3
% Ch	1.5	(6.4)	0.6	3.5	0.2	1.1	(0.0)	0.4	(0.1)	0.0	0.0	(0.1)
U.S.	12.8	12.2	12.4	12.8	13.0	12.7	12.4	12.2	12.1	11.9	11.8	11.8
% Ch	1.0	(5.1)	1.6	3.8	1.1	(2.3)	(2.4)	(1.5)	(1.0)	(1.0)	(0.8)	(0.5)
Durable Manufacturing												
Oregon	137.1	128.4	129.1	135.5	136.1	136.9	136.6	137.6	137.3	136.7	136.3	135.8
% Ch	1.1	(6.3)	0.5	4.9	0.5	0.6	(0.2)	0.7	(0.2)	(0.4)	(0.3)	(0.3)
U.S.	8.0	7.6	7.7	8.0	8.1	7.9	7.7	7.5	7.4	7.3	7.3	7.2
% Ch	1.2	(5.8)	1.4	3.8	1.5	(2.4)	(3.0)	(1.6)	(1.2)	(1.4)	(1.1)	(0.6)
Wood Products												
Oregon	23.2	22.0	22.7	23.3	22.8	22.7	22.9	23.2	23.1	22.9	22.9	23.1
% Ch	(1.4)	(5.3)	3.5	2.5	(2.4)	(0.3)	0.9	1.4	(0.5)	(0.7)	0.0	0.6
U.S.	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5
% Ch	0.7	(3.1)	3.5	4.6	(1.3)	(6.8)	4.1	8.3	3.5	1.0	0.8	1.7
Metal and Machinery												
Oregon	40.2	36.6	36.3	38.1	38.4	38.6	38.2	37.5	36.9	36.6	36.5	36.2
% Ch	2.2	(8.9)	(0.8)	4.9	0.8	0.6	(1.0)	(1.9)	(1.7)	(0.6)	(0.4)	(0.7)
U.S.	3.0	2.8	2.8	2.9	2.9	2.9	2.8	2.8	2.7	2.7	2.7	2.6
% Ch	1.1	(6.8)	(0.2)	4.0	1.5	(2.1)	(3.0)	(0.8)	(1.0)	(1.6)	(1.1)	(0.7)
Computer and Electronic Products												
Oregon	38.6	38.0	37.9	41.3	42.1	42.0	42.0	43.3	44.0	44.4	44.3	44.3
% Ch	1.8	(1.7)	(0.1)	8.9	1.9	(0.3)	0.1	3.1	1.7	0.8	(0.1)	(0.1)
U.S.	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.0
% Ch	2.0	(1.2)	(0.3)	2.7	1.2	(0.1)	(0.1)	(0.6)	(1.0)	(1.4)	(1.4)	(1.2)
Transportation Equipment												
Oregon	12.6	11.0	10.7	10.8	10.8	11.3	11.7	11.8	11.6	11.3	11.2	11.1
% Ch	3.8	(13.0)	(2.4)	1.1	0.1	4.2	3.7	1.2	(1.9)	(2.2)	(1.2)	(1.3)
U.S.	1.7	1.6	1.6	1.7	1.8	1.8	1.7	1.6	1.5	1.5	1.5	1.4
% Ch	1.6	(8.0)	3.4	4.9	4.7	(2.3)	(5.5)	(5.8)	(3.3)	(2.1)	(2.0)	(1.7)
Other Durables												
Oregon	22.4	20.9	21.4	22.0	22.0	22.3	21.8	21.7	21.7	21.5	21.3	21.2
% Ch	(0.7)	(6.6)	2.2	2.6	0.3	1.3	(2.4)	(0.3)	(0.3)	(0.9)	(0.6)	(0.5)
U.S.	2.2	2.1	2.2	2.3	2.2	2.2	2.1	2.1	2.1	2.1	2.1	2.1
% Ch	0.6	(4.9)	2.9	3.5	(0.6)	(4.1)	(2.4)	0.2	(0.2)	(0.6)	(0.2)	0.5
Nondurable Manufacturing												
Oregon	61.1	57.1	57.6	57.8	57.5	58.8	59.0	58.8	59.0	59.5	60.1	60.4
% Ch	2.4	(6.5)	0.9	0.4	(0.5)	2.3	0.3	(0.2)	0.3	0.9	0.9	0.5
U.S.	4.8	4.6	4.7	4.9	4.9	4.8	4.7	4.6	4.6	4.6	4.6	4.6
% Ch	0.8	(3.9)	1.8	3.8	0.3	(2.0)	(1.5)	(1.3)	(0.6)	(0.4)	(0.3)	(0.2)
Food Manufacturing												
Oregon	29.9	28.0	28.5	28.7	28.3	29.1	29.3	29.4	29.5	29.7	30.0	30.2
% Ch	0.1	(6.2)	1.7	0.7	(1.4)	2.9	0.7	0.1	0.3	0.7	1.1	0.8
U.S.	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.8	1.8
% Ch	1.5	(1.8)	1.4	3.6	1.6	(0.6)	(0.2)	0.0	0.8	1.0	1.1	1.1
Other Nondurable												
Oregon	31.2	29.1	29.1	29.1	29.2	29.7	29.7	29.5	29.6	29.9	30.1	30.2
% Ch	4.7	(6.8)	0.1	0.0	0.3	1.7	(0.1)	(0.6)	0.3	1.1	0.7	0.3
U.S.	3.1	3.0	3.0	3.2	3.1	3.1	3.0	2.9	2.9	2.9	2.8	2.8
% Ch	0.4	(5.0)	1.9	3.9	(0.5)	(2.7)	(2.2)	(2.0)	(1.5)	(1.2)	(1.1)	(1.1)
Trade, Transportation, and Utilities												
Oregon	357.2	349.6	361.5	367.0	365.9	366.5	366.9	367.6	368.3	368.8	368.8	368.7
% Ch	1.3	(2.1)	3.4	1.5	(0.3)	0.1	0.1	0.2	0.2	0.1	(0.0)	(0.0)
U.S.	27.7	26.6	27.7	28.7	28.9	28.5	27.9	27.7	27.6	27.5	27.3	27.1
% Ch	0.4	(3.7)	3.9	3.6	0.8	(1.2)	(2.1)	(0.8)	(0.3)	(0.6)	(0.7)	(0.5)

Sept 2023 - Employment By Industry

(Oregon - Thousands, U.S. - Millions)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Retail Trade												
Oregon	210.1	200.9	209.2	210.7	209.9	209.7	209.7	209.7	209.7	209.8	209.6	209.5
% Ch	(0.7)	(4.4)	4.1	0.7	(0.4)	(0.1)	0.0	0.0	(0.0)	0.0	(0.1)	(0.0)
U.S.	15.6	14.8	15.3	15.5	15.6	15.1	14.4	14.1	14.0	13.9	13.9	13.9
% Ch	(1.1)	(4.7)	3.0	1.5	0.4	(3.0)	(4.5)	(2.0)	(0.7)	(0.7)	(0.5)	0.1
Wholesale Trade												
Oregon	76.6	74.3	75.0	77.1	77.1	77.7	77.8	78.0	78.2	78.5	78.6	78.7
% Ch	1.2	(3.0)	1.0	2.8	0.0	0.8	0.0	0.3	0.4	0.3	0.2	0.1
U.S.	5.9	5.6	5.7	6.0	6.1	6.1	6.2	6.2	6.2	6.2	6.1	6.0
% Ch	0.8	(4.3)	1.4	4.5	1.5	1.2	0.6	0.3	0.2	(0.7)	(1.1)	(1.2)
Transportation and Warehousing, and Utilities												
Oregon	70.6	74.5	77.3	79.2	78.9	79.1	79.4	79.9	80.3	80.6	80.6	80.5
% Ch	7.5	5.5	3.8	2.5	(0.3)	0.2	0.5	0.5	0.5	0.3	0.1	(0.1)
U.S.	6.2	6.2	6.7	7.2	7.3	7.3	7.4	7.4	7.4	7.4	7.3	7.3
% Ch	3.9	(0.6)	8.3	7.8	1.1	0.5	0.6	0.6	(0.0)	(0.5)	(0.7)	(0.9)
Information												
Oregon	35.1	33.3	35.1	36.7	36.4	36.6	36.9	37.0	37.1	37.3	37.5	37.6
% Ch	2.2	(5.1)	5.4	4.6	(0.9)	0.8	0.7	0.2	0.2	0.8	0.6	0.2
U.S.	2.9	2.7	2.9	3.1	3.1	3.1	3.2	3.1	3.1	3.1	3.1	3.1
% Ch	0.9	(5.0)	5.0	7.6	0.6	0.5	2.4	(1.0)	(1.5)	(0.3)	0.1	(0.3)
Financial Activities												
Oregon	103.5	102.5	104.2	105.1	104.9	106.4	106.7	107.3	107.4	107.2	106.8	106.2
% Ch	1.3	(1.0)	1.6	0.9	(0.2)	1.4	0.3	0.5	0.1	(0.1)	(0.4)	(0.6)
U.S.	8.8	8.7	8.8	9.0	9.1	9.2	9.3	9.4	9.5	9.5	9.4	9.3
% Ch	1.9	(0.6)	1.2	2.7	1.0	1.0	0.9	1.0	0.7	(0.1)	(0.4)	(0.9)
Professional and Business Services												
Oregon	254.7	243.6	251.6	264.1	268.8	273.9	275.9	280.4	286.2	293.0	299.4	305.9
% Ch	2.0	(4.3)	3.3	5.0	1.8	1.9	0.7	1.6	2.0	2.4	2.2	2.2
U.S.	21.3	20.4	21.4	22.6	23.1	23.2	23.1	23.1	23.3	24.0	24.6	25.1
% Ch	1.6	(4.5)	5.0	5.6	2.2	0.5	(0.5)	(0.0)	1.2	2.7	2.5	2.4
Education and Health Services												
Oregon	312.1	296.7	299.1	304.0	315.3	322.4	328.0	332.7	337.2	340.7	343.8	347.3
% Ch	2.1	(4.9)	0.8	1.6	3.7	2.3	1.7	1.4	1.4	1.0	0.9	1.0
U.S.	24.2	23.3	23.6	24.4	25.3	25.8	25.9	26.0	26.1	26.3	26.4	26.6
% Ch	2.2	(3.7)	1.6	3.0	3.9	2.1	0.5	0.2	0.6	0.6	0.4	0.5
Educational Services												
Oregon	36.6	31.5	32.1	34.5	35.0	35.4	35.3	35.2	35.1	35.0	35.0	34.9
% Ch	0.3	(13.9)	1.7	7.6	1.4	1.2	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
U.S.	3.7	3.5	3.6	3.8	3.9	4.0	4.0	4.0	4.1	4.1	4.1	4.1
% Ch	0.7	(7.1)	3.1	5.9	3.9	1.8	0.0	0.2	0.7	0.8	0.2	(0.2)
Health Care and Social Assistance												
Oregon	275.5	265.2	267.1	269.5	280.3	287.0	292.7	297.4	302.1	305.6	308.9	312.4
% Ch	2.3	(3.7)	0.7	0.9	4.0	2.4	2.0	1.6	1.6	1.2	1.1	1.1
U.S.	20.4	19.8	20.1	20.6	21.3	21.8	21.9	22.0	22.1	22.2	22.3	22.5
% Ch	2.5	(3.1)	1.4	2.4	3.9	2.1	0.6	0.2	0.6	0.6	0.5	0.6
Leisure and Hospitality												
Oregon	213.9	162.1	175.0	198.3	205.8	210.6	213.3	215.0	216.5	218.8	220.9	222.8
% Ch	1.2	(24.2)	7.9	13.3	3.8	2.3	1.3	0.8	0.7	1.1	0.9	0.9
U.S.	16.6	13.1	14.1	15.9	16.6	16.6	16.8	17.0	17.1	17.1	17.1	17.2
% Ch	1.8	(20.8)	7.7	12.0	4.5	0.2	1.0	1.2	0.5	0.0	0.4	0.2
Other Services												
Oregon	64.8	57.8	59.2	61.9	65.1	65.7	66.3	66.8	67.4	68.0	68.4	68.9
% Ch	0.6	(10.8)	2.5	4.4	5.2	0.9	0.9	0.8	0.9	0.8	0.6	0.7
U.S.	5.9	5.3	5.5	5.7	5.9	6.0	6.1	6.2	6.3	6.4	6.5	6.5
% Ch	1.0	(9.6)	2.4	4.6	3.1	2.2	1.6	1.6	1.4	1.4	1.0	0.6
Government												
Oregon	298.4	284.7	285.7	294.8	303.9	303.8	303.2	303.9	304.7	305.6	306.5	308.2
% Ch	1.2	(4.6)	0.4	3.2	3.1	(0.0)	(0.2)	0.2	0.3	0.3	0.3	0.5
U.S.	22.6	22.0	22.0	22.2	22.7	22.9	23.1	23.2	23.3	23.5	23.6	23.8
% Ch	0.7	(2.8)	(0.1)	0.9	2.3	1.0	0.7	0.6	0.5	0.5	0.5	0.7
Federal Government												
Oregon	28.5	29.2	28.5	27.8	28.1	28.0	27.9	27.8	27.8	27.7	27.6	28.3
% Ch	1.4	2.5	(2.3)	(2.3)	0.9	(0.2)	(0.4)	(0.3)	(0.3)	(0.3)	(0.2)	2.4
U.S.	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0
% Ch	1.1	3.6	(1.6)	(0.6)	1.4	0.2	0.0	0.0	0.0	0.0	0.0	2.3
State Government, Oregon												
State Total	40.9	41.4	42.6	43.0	45.0	45.2	44.9	45.2	45.6	46.2	46.6	47.0
% Ch	3.6	1.1	2.8	1.0	4.8	0.3	(0.5)	0.5	1.0	1.3	0.9	0.8
State Education	0.9	0.9	1.0	1.2	1.3	1.3	1.3	1.3	1.3	1.2	1.2	1.2
% Ch	7.2	4.1	11.3	18.6	13.8	(0.5)	(1.8)	(2.2)	(2.0)	(1.9)	(1.7)	(1.8)
Local Government, Oregon												
Local Total	228.9	214.1	214.6	223.9	230.8	230.6	230.3	230.9	231.3	231.8	232.3	232.9
% Ch	0.8	(6.5)	0.2	4.3	3.0	(0.1)	(0.1)	0.2	0.2	0.2	0.2	0.2
Local Education	133.0	121.9	122.2	128.6	133.0	132.1	131.2	130.5	129.6	128.6	128.1	127.7
% Ch	0.3	(8.3)	0.2	5.2	3.4	(0.6)	(0.7)	(0.5)	(0.8)	(0.7)	(0.4)	(0.3)

Sept 2023 - Other Economic Indicators

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GDP (Bil of 2012 $),												
Chain Weight (in billions of $)	19,036.1	18,509.1	19,609.8	20,014.1	20,384.2	20,623.3	20,933.8	21,293.6	21,680.9	22,070.2	22,453.5	22,850.0
% Ch	2.3	(2.8)	5.9	2.1	1.8	1.2	1.5	1.7	1.8	1.8	1.7	1.8
Price and Wage Indicators												
GDP Implicit Price Deflator,												
Chain Weight U.S., 2012=100	112.3	113.8	118.9	127.2	132.2	135.8	139.0	142.0	145.2	148.4	151.7	155.1
% Ch	1.8	1.3	4.5	7.0	3.9	2.7	2.3	2.2	2.2	2.2	2.2	2.2
Personal Consumption Deflator,												
Chain Weight U.S., 2012=100	109.9	111.1	115.6	122.9	127.5	130.9	133.8	136.6	139.4	142.1	144.8	147.6
% Ch	1.5	1.1	4.0	6.3	3.8	2.6	2.3	2.1	2.0	2.0	1.9	1.9
CPI, Urban Consumers,												
1982-84=100												
West Region	270.3	275.1	287.5	310.5	324.2	335.9	345.7	354.2	362.7	370.9	379.1	387.7
% Ch	2.7	1.7	4.5	8.0	4.4	3.6	2.9	2.5	2.4	2.3	2.2	2.3
U.S.	255.7	258.9	271.0	292.6	304.7	312.8	320.8	328.1	335.6	342.9	349.9	357.2
% Ch	1.8	1.3	4.7	8.0	4.1	2.7	2.6	2.3	2.3	2.2	2.1	2.1
Oregon Average Wage												
Rate (Thous $)	57.4	62.9	66.8	69.5	71.8	74.9	78.1	81.3	84.6	88.0	91.6	95.3
% Ch	3.9	9.5	6.1	4.1	3.3	4.3	4.2	4.1	4.1	4.1	4.1	4.1
U.S. Average Wage												
Wage Rate (Thous $)	61.8	66.5	70.3	73.3	75.4	78.7	82.2	85.6	89.2	92.6	96.1	99.6
% Ch	3.4	7.7	5.7	4.2	2.9	4.3	4.4	4.2	4.1	3.9	3.7	3.7
Housing Indicators												
FHFA Oregon Housing Price Index												
1991 Q1=100	434.9	470.8	556.6	615.6	613.2	624.2	649.5	680.5	707.8	734.3	762.1	791.6
% Ch	4.8	8.2	18.2	10.6	(0.4)	1.8	4.1	4.8	4.0	3.7	3.8	3.9
FHFA National Housing Price Index												
1991 Q1=100	268.8	289.9	338.5	386.2	396.8	396.2	400.7	405.6	409.9	414.8	421.2	429.4
% Ch	5.1	7.9	16.8	14.1	2.8	(0.1)	1.1	1.2	1.1	1.2	1.5	1.9
Housing Starts												
Oregon (Thous)	20.7	18.1	20.2	19.9	19.3	20.1	21.0	21.1	21.2	21.4	21.5	21.6
% Ch	5.7	(12.7)	11.9	(1.4)	(3.3)	4.2	4.3	0.5	0.6	1.1	0.1	0.9
U.S. (Millions)	1.3	1.4	1.6	1.6	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
% Ch	3.6	8.2	14.9	(3.4)	(9.2)	(3.9)	3.7	(0.5)	(1.0)	(0.2)	(0.1)	(0.6)
Other Indicators												
Unemployment Rate (%)												
Oregon	3.7	7.6	5.2	4.1	3.9	3.9	4.1	4.1	4.1	4.1	4.1	4.1
Point Change	(0.3)	3.9	(2.4)	(1.1)	(0.3)	(0.0)	0.2	0.0	0.0	0.0	0.0	0.0
U.S.	3.7	8.1	5.4	3.6	3.6	4.0	4.6	4.8	4.7	4.6	4.5	4.4
Point Change	(0.2)	4.4	(2.7)	(1.7)	(0.1)	0.5	0.5	0.2	(0.1)	(0.1)	(0.1)	(0.1)
Industrial Production Index												
U.S, 2012 = 100	102.4	95.1	99.2	102.6	102.7	102.4	103.0	104.1	105.3	106.7	108.0	109.2
% Ch	(0.7)	(7.2)	4.4	3.4	0.1	(0.3)	0.6	1.1	1.1	1.4	1.2	1.1
Prime Rate (Percent)	5.3	3.5	3.3	4.9	8.2	8.2	6.6	5.8	5.8	5.8	5.8	5.8
% Ch	7.7	(32.9)	(8.3)	49.3	69.3	(0.3)	(19.5)	(12.5)	(0.3)	(0.0)	(0.0)	(0.0)
Population (Millions)												
Oregon	4.21	4.24	4.26	4.28	4.30	4.32	4.34	4.37	4.40	4.43	4.47	4.50
% Ch	0.9	0.7	0.5	0.4	0.3	0.5	0.6	0.7	0.7	0.7	0.8	0.8
U.S.	330.5	331.9	332.5	333.8	335.5	337.3	339.0	340.7	342.5	344.2	346.0	347.7
% Ch	0.6	0.4	0.2	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Timber Harvest (Mil Bd Ft)												
Oregon	3,541.3	3,624.7	3,880.5	3,652.0	3,637.2	3,599.1	3,633.6	3,682.8	3,734.6	3,734.5	3,723.2	3,715.5
% Ch	(12.9)	2.4	7.1	(5.9)	(0.4)	(1.0)	1.0	1.4	1.4	(0.0)	(0.3)	(0.2)

Appendix B: Revenue Forecast Detail

Table B.1a – General Fund Revenues – 2021-23

Table B.1a
General Fund Revenue Statement -- 2021-23

	Estimate at COS 2021	Forecasts Dated: 5/17/2023 2021-22	2022-23	Total 2021-23	Forecasts Dated: 9/1/2023 2021-22	2022-23	Total 2021-23	Difference 09/1/2023 Less 5/15/2023	09/1/2023 Less COS
Taxes									
Personal Income Taxes	20,628,060,000	12,482,887,000	13,176,596,000	25,659,483,000	12,462,886,000	13,274,254,000	25,737,140,000	77,657,000	5,109,080,000
Transfers & Offsets	(40,583,000)	(16,409,000)	(10,814,000)	(27,223,000)	(26,237,000)	(27,398,000)	(53,635,000)	(26,412,000)	(13,052,000)
Corporate Income Taxes	1,343,966,000	1,539,051,000	1,622,101,000	3,161,152,000	1,538,497,000	1,618,518,000	3,157,015,000	(4,137,000)	1,813,049,000
Transfer to Rainy Day Fund (Minimum Tax)	(56,001,000)	0	(128,983,000)	(128,983,000)	0	(128,600,000)	(128,600,000)	383,000	(72,599,000)
Insurance Taxes	135,086,000	86,214,000	61,457,000	147,671,000	86,214,000	96,048,000	182,262,000	34,591,000	47,176,000
Estate Taxes	443,848,000	325,468,000	264,175,000	589,643,000	325,468,000	297,572,000	623,040,000	33,397,000	179,192,000
Transfer to PERS UAL	(74,916,000)	0	(89,003,000)	(89,003,000)	0	0	0	89,003,000	74,916,000
Cigarette Taxes	44,903,000	24,396,000	21,976,000	46,372,000	24,396,000	21,361,000	45,757,000	(615,000)	854,000
Other Tobacco Products Taxes	65,129,000	30,320,000	30,234,000	60,554,000	30,320,000	29,440,000	59,760,000	(794,000)	(5,369,000)
Other Taxes	1,786,000	1,007,000	898,000	1,905,000	1,007,000	845,000	1,852,000	(53,000)	66,000
Fines and Fees									
State Court Fees	136,147,000	52,488,000	54,566,000	107,054,000	52,488,000	52,526,000	105,014,000	(2,040,000)	(31,133,000)
Secretary of State Fees	82,185,000	42,949,000	44,099,000	87,048,000	42,949,000	46,684,000	89,633,000	2,585,000	7,448,000
Criminal Fines & Assessments	27,202,000	792,000	6,068,000	6,860,000	792,000	66,000	858,000	(6,002,000)	(26,344,000)
Securities Fees	26,538,000	15,575,000	14,365,000	29,940,000	15,575,000	13,997,000	29,572,000	(368,000)	3,034,000
Central Service Charges	12,746,000	6,373,000	6,373,000	12,746,000	6,373,000	6,373,000	12,746,000	0	0
Liquor Apportionment	347,137,000	160,020,000	197,552,000	357,572,000	160,020,000	172,335,000	332,355,000	(25,217,000)	(14,782,000)
Interest Earnings	35,000,000	39,984,000	277,683,000	317,667,000	39,984,000	262,484,000	302,468,000	(15,199,000)	267,468,000
Miscellaneous Revenues	12,000,000	8,490,000	7,600,000	16,090,000	8,490,000	9,240,000	17,730,000	1,640,000	5,730,000
One-time Transfers	58,677,000	94,681,000	58,677,000	153,358,000	94,681,000	40,851,476	135,532,476	(17,825,524)	76,855,476
Gross General Fund Revenues	23,400,410,000	14,910,695,000	15,844,420,000	30,755,115,000	14,890,140,000	15,942,594,476	30,832,734,476	77,619,476	7,432,324,476
Total Transfers	(171,500,000)	(16,409,000)	(228,800,000)	(245,209,000)	(26,237,000)	(155,998,000)	(182,235,000)	62,974,000	(85,651,000)
Net General Fund Revenues	23,228,910,000	14,894,286,000	15,615,620,000	30,509,906,000	14,863,903,000	15,786,596,476	30,650,499,476	140,593,476	7,346,673,476
Plus Beginning Balance	3,025,585,699			4,082,489,264			4,082,489,264	0	1,056,903,565
Less Anticipated Administrative Actions*	(21,472,000)			0			0	0	21,472,000
Less Statutory Transfers**	(224,612,788)			(222,880,647)			(220,722,881)	2,157,766	3,889,907
Available Resources	26,008,410,911			34,369,514,617			34,512,265,859	142,751,242	8,503,854,948
Appropriations	25,445,991,039			27,367,410,483			27,130,627,861	(236,782,622)	1,684,636,822
Less Estimated Reversions***				0			(254,596,034)	(254,596,034)	(254,596,034)
Projected Expenditures	25,445,991,039			27,367,410,483			26,876,031,827	(491,378,656)	1,430,040,788
Estimated Ending Balance	562,419,872			7,002,104,134			7,636,234,032	634,129,898	7,073,814,160

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 occurred for the 2021-23 biennium.
** "Statutory Transfers" include the Rainy Day Fund transfer for 2021-23 only.
*** "Estimated Reversions" equals the amount assumed by the Legislative Fiscal Office at LAB.

Table B.1b – General Fund Revenues – 2023-25 Close of Session

Table B.1b
General Fund Revenue Statement -- 2023-25 -- Close of Session

	Forecasts Dated: 5/17/2023			Forecasts Dated: Close of Session (COS)			Difference
	2023-24	2024-25	Total 2023-25	2023-24	2024-25	Total 2023-25	COS Less 5/15/2021
Taxes							
Personal Income Taxes	8,712,640,000	12,375,653,000	21,088,293,000	8,681,640,000	12,338,053,000	21,019,693,000	(68,600,000)
Transfers & Offsets	(17,520,000)	(19,510,000)	(37,030,000)	(17,520,000)	(19,510,000)	(37,030,000)	0
Corporate Income Taxes	1,136,036,000	1,109,009,000	2,245,045,000	1,144,336,000	1,084,609,000	2,228,945,000	(16,100,000)
Transfer to Rainy Day Fund (Minimum Tax)	0	(91,604,000)	(91,604,000)	0	(91,604,000)	(91,604,000)	0
Insurance Taxes	71,825,000	73,186,000	145,011,000	71,825,000	73,186,000	145,011,000	0
Estate Taxes	270,366,000	277,366,000	547,732,000	268,366,000	271,366,000	539,732,000	(8,000,000)
Transfer to PERS UAL	0	0	0	0	0	0	0
Cigarette Taxes	21,847,000	21,297,000	43,144,000	21,847,000	21,297,000	43,144,000	0
Other Tobacco Products Taxes	30,684,000	30,619,000	61,303,000	30,684,000	30,619,000	61,303,000	0
Other Taxes	898,000	898,000	1,796,000	898,000	898,000	1,796,000	0
Fines and Fees							
State Court Fees	60,398,000	62,919,000	123,317,000	60,398,000	62,919,000	123,317,000	0
Secretary of State Fees	50,642,000	49,358,000	100,000,000	51,641,600	50,162,400	101,804,000	1,804,000
Criminal Fines & Assessments	9,695,000	9,695,000	19,390,000	7,757,000	7,757,000	15,514,000	(3,876,000)
Securities Fees	15,442,000	16,153,000	31,595,000	15,442,000	16,153,000	31,595,000	0
Central Service Charges	8,050,000	8,050,000	16,100,000	8,050,000	8,050,000	16,100,000	0
Liquor Apportionment	191,943,000	204,634,000	396,577,000	194,482,000	207,340,000	401,822,000	5,245,000
Interest Earnings	348,920,000	124,405,000	473,325,000	348,920,000	124,405,000	473,325,000	0
Miscellaneous Revenues	8,000,000	8,000,000	16,000,000	8,000,000	8,000,000	16,000,000	0
One-time Transfers	0	0	0	220,000	40,614,635	40,834,635	40,834,635
Gross General Fund Revenues	10,937,386,000	14,371,242,000	25,308,628,000	10,914,506,600	14,345,429,035	25,259,935,635	(48,692,365)
Total Transfers	(17,520,000)	(111,114,000)	(128,634,000)	(17,520,000)	(111,114,000)	(128,634,000)	0
Net General Fund Revenues	10,919,866,000	14,260,128,000	25,179,994,000	10,896,986,600	14,234,315,035	25,131,301,635	(48,692,365)
Plus Beginning Balance			7,002,104,134			7,493,482,790	491,378,656
Less Anticipated Administrative Actions*			0			0	0
Less Legislatively Adopted Actions**			(310,743,560)			(308,375,734)	2,367,826
Available Resources			31,871,354,575			32,316,408,692	*445,054,117*
Appropriations			N/A			31,873,575,550	*NA*
Estimated Ending Balance			N/A			442,833,142	*NA*

Table B.1c – General Fund Revenues – 2023-25

Table B.1c
General Fund Revenue Statement -- 2023-25

		Forecasts Dated: 5/17/2023			Forecasts Dated: 9/1/2023			Difference	
	Estimate at COS 2023	2023-24	2024-25	Total 2023-25	2023-24	2024-25	Total 2023-25	09/1/2023 Less 5/15/2023	09/1/2023 Less COS
Taxes									
Personal Income Taxes	21,019,693,000	8,712,640,000	12,375,653,000	21,088,293,000	8,558,736,000	12,504,858,000	21,063,594,000	(24,699,000)	43,901,000
Transfers & Offsets	(37,030,000)	(17,520,000)	(19,510,000)	(37,030,000)	(33,251,000)	(70,340,000)	(103,591,000)	(66,561,000)	(66,561,000)
Corporate Income Taxes	2,228,945,000	1,136,036,000	1,109,009,000	2,245,045,000	1,204,234,000	1,345,657,000	2,549,891,000	304,846,000	320,946,000
Transfer to Rainy Day Fund (Minimum Tax)	(91,604,000)	0	(91,604,000)	(91,604,000)	0	(110,175,000)	(110,175,000)	(18,571,000)	(18,571,000)
Insurance Taxes	145,011,000	71,825,000	73,186,000	145,011,000	81,440,000	83,666,000	165,106,000	20,095,000	20,095,000
Estate Taxes	539,732,000	270,366,000	277,366,000	547,732,000	271,050,000	274,080,000	545,130,000	(2,602,000)	5,398,000
Transfer to PERS UAL	0	0	0	0	(60,503,000)	0	(60,503,000)	(60,503,000)	(60,503,000)
Cigarette Taxes	43,144,000	21,847,000	21,297,000	43,144,000	21,847,000	21,297,000	43,144,000	0	0
Other Tobacco Products Taxes	61,303,000	30,684,000	30,619,000	61,303,000	30,684,000	30,619,000	61,303,000	0	0
Other Taxes	1,796,000	898,000	898,000	1,796,000	898,000	898,000	1,796,000	0	0
Fines and Fees									
State Court Fees	123,317,000	60,398,000	62,919,000	123,317,000	60,398,000	62,919,000	123,317,000	0	0
Secretary of State Fees	101,804,000	50,642,000	49,358,000	100,000,000	51,642,000	50,162,000	101,804,000	1,804,000	0
Criminal Fines & Assessments	15,514,000	9,695,000	9,695,000	19,390,000	7,757,000	7,757,000	15,514,000	(3,876,000)	0
Securities Fees	31,595,000	15,442,000	16,153,000	31,595,000	14,930,000	15,536,000	30,466,000	(1,129,000)	(1,129,000)
Central Service Charges	16,100,000	8,050,000	8,050,000	16,100,000	8,050,000	8,050,000	16,100,000	0	0
Liquor Apportionment	401,822,000	191,943,000	204,634,000	396,577,000	194,482,000	207,340,000	401,822,000	5,245,000	0
Interest Earnings	473,325,000	348,920,000	124,405,000	473,325,000	346,668,000	140,513,000	487,181,000	13,856,000	13,856,000
Miscellaneous Revenues	16,000,000	8,000,000	8,000,000	16,000,000	8,000,000	8,000,000	16,000,000	0	0
One-time Transfers	40,834,635	0	0	0	220,000	40,615,000	40,835,000	40,835,000	365
Gross General Fund Revenues	25,259,935,635	10,937,386,000	14,371,242,000	25,308,628,000	10,861,036,000	14,801,967,000	25,663,003,000	354,375,000	403,067,365
Total Transfers	(128,634,000)	(17,520,000)	(111,114,000)	(128,634,000)	(93,754,000)	(180,515,000)	(274,269,000)	(145,635,000)	(145,635,000)
Net General Fund Revenues	25,131,301,635	10,919,866,000	14,260,128,000	25,179,994,000	10,767,282,000	14,621,452,000	25,388,734,000	208,740,000	257,432,365
Plus Beginning Balance	7,493,482,790			7,002,104,134			7,636,234,032	634,129,898	142,751,242
Less Anticipated Administrative Actions*	0			0			0	0	0
Less Statutory Transfers**	(308,375,734)			(310,743,560)			(271,306,279)	39,437,281	37,069,455
Available Resources	32,316,408,692			31,871,354,575			32,753,661,754	882,307,179	437,253,062
Appropriations	31,873,575,550			*N/A*			31,873,575,550	*N/A*	0
Estimated Ending Balance	442,833,142			*N/A*			880,086,204	*N/A*	437,253,062

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 RDF transfer for the COS and September forecasts. The BM 110 Transfer that was included for the May 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 $37,069,455 in FY 2025.

Table B.2 – General Fund Revenues by Fiscal Year

TABLE B.2

General Fund Revenue Forecast — **September 2023**

($Millions)

Fiscal Years	2019-20 Fiscal Year	2020-21 Fiscal Year	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	7,212.5	12,794.0	12,436.6	13,246.9	8,558.7	12,504.9	14,637.4	15,533.7	16,914.1	18,208.7	19,351.9	20,486.7	21,695.9	23,007.0
Film & Video, Gain Share, Industrial Lands	(20.5)	(21.4)	(26.2)	(27.4)	(33.3)	(70.3)	(32.8)	(33.0)	(35.6)	(36.1)	(30.6)	(10.0)	(8.2)	(2.0)
Corporate Excise & Income	488.3	1,478.6	1,538.5	1,618.5	1,204.2	1,345.7	1,406.1	1,492.8	1,573.0	1,635.3	1,701.0	1,780.4	1,870.9	1,969.6
Transfer to RDF & PERS UAL	0.0	(74.5)	0.0	(128.6)	0.0	(110.2)	0.0	(125.3)	0.0	(138.6)	0.0	(150.4)	0.0	0.0
Insurance	75.3	83.9	86.2	96.0	81.4	83.7	84.7	85.4	92.9	94.7	96.5	98.3	100.2	102.2
Estate	113.8	410.3	325.5	297.6	271.0	274.1	278.4	285.3	288.1	295.6	305.6	314.0	326.5	339.6
Transfer toPERS UAL	0.0	0.0	0.0	0.0	(60.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cigarette	30.5	24.6	24.4	21.4	21.8	21.3	20.7	20.3	19.9	19.6	19.3	19.0	18.7	18.4
Other Tobacco Products	30.9	30.4	30.3	29.4	30.7	30.6	30.6	30.8	30.7	30.9	31.0	30.9	30.8	30.8
Other Taxes	0.4	0.6	1.0	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Other Revenues														
Licenses and Fees	135.3	114.1	111.8	113.3	134.7	136.4	138.3	137.6	139.7	138.9	140.8	140.0	142.4	141.5
Charges for Services	5.7	5.7	6.4	6.4	8.1	8.1	8.7	8.7	9.4	9.4	10.0	10.0	10.7	10.7
Liquor Apportionment	162.1	178.8	160.0	172.3	194.5	207.3	187.2	197.6	209.7	223.2	238.5	253.7	269.9	287.2
Interest Earnings	64.5	28.5	40.0	262.5	346.7	140.5	106.3	106.2	109.3	112.5	115.9	119.3	122.7	126.5
Others	20.4	165.4	103.2	50.1	8.2	48.6	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Gross General Fund	8,339.8	15,314.8	14,863.9	15,915.2	10,861.0	14,802.0	16,907.3	17,907.1	19,395.7	20,777.7	22,019.4	23,261.3	24,597.7	26,042.4
Net General Fund	8,319.3	15,218.9	14,837.7	15,759.2	10,767.3	14,621.4	16,874.6	17,748.8	19,360.1	20,602.9	21,988.8	23,100.8	24,589.5	26,040.4

Biennial Totals	2019-21 BN	Change (%)	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	20,006.5	6.3%	25,683.5	28.4%	21,063.6	-18.0%	30,171.1	43.2%	35,122.7	16.4%	39,838.6	13.4%	44,702.9	12.2%
Corporate Excise & Income	1,966.9	11.2%	3,157.0	60.5%	2,549.9	-19.2%	2,898.8	13.7%	3,208.3	10.7%	3,481.5	8.5%	3,840.5	10.3%
Insurance	159.2	-0.7%	182.3	14.5%	165.1	-9.4%	170.1	3.0%	187.6	10.3%	194.8	3.8%	202.4	3.9%
Estate Taxes	524.1	37.5%	623.0	18.9%	545.1	-12.5%	563.6	3.4%	583.8	3.6%	619.6	6.1%	666.1	7.5%
Cigarette	55.1	-16.0%	45.8	-17.0%	43.1	-5.7%	41.0	-5.0%	39.6	-3.4%	38.4	-3.1%	37.2	-3.1%
Other Tobacco Products	61.3	-3.6%	59.8	-2.5%	61.3	2.6%	61.4	0.2%	61.7	0.4%	61.8	0.3%	61.6	-0.4%
Other Taxes	1.0	-49.4%	1.9	85.4%	1.8	-3.0%	1.8	0.0%	1.8	0.0%	1.8	0.0%	1.8	0.0%
Other Revenues														
Licenses and Fees	249.4	-3.7%	225.1	-9.7%	271.1	20.4%	275.9	1.8%	278.5	0.9%	280.9	0.8%	283.9	1.1%
Charges for Services	11.5	5.5%	12.7	11.1%	16.1	26.3%	17.4	8.1%	18.7	7.5%	20.0	7.0%	21.3	6.5%
Liquor Apportionment	340.9	15.8%	332.4	-2.5%	401.8	20.9%	384.8	-4.2%	432.9	12.5%	492.2	13.7%	557.2	13.2%
Interest Earnings	92.9	6.6%	302.5	225.5%	487.2	61.1%	212.5	-56.4%	221.8	4.4%	235.1	6.0%	249.1	6.0%
Others	185.8	1121.7%	153.3	-17.5%	56.8	-62.9%	16.0	-71.8%	16.0	0.0%	16.0	0.0%	16.0	0.0%
Gross General Fund	23,654.6	7.9%	30,779.1	30.1%	25,663.0	-16.6%	34,814.5	35.7%	40,173.4	15.4%	45,280.6	12.7%	50,640.0	11.8%
Net General Fund	23,538.2	8.0%	30,596.9	30.0%	25,388.7	-17.0%	34,623.4	36.4%	39,963.1	15.4%	45,089.6	12.8%	50,629.9	12.3%

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 — **OREGON PERSONAL INCOME TAX REVENUE FORECAST - QUARTERLY COLLECTIONS**

Thousands of Dollars - Not Seasonally Adjusted — **September 2023**

	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	2,620,742	2,717,988	2,836,667	2,670,067	10,845,464	2,656,138	2,811,262	2,993,014	2,796,631	11,257,044
%CHYA	4.4%	2.9%	5.8%	3.9%	4.3%	1.4%	3.4%	5.5%	4.7%	3.8%
EST. PAYMENTS	498,682	240,875	288,002	668,711	1,696,270	483,653	425,653	520,287	765,563	2,195,155
%CHYA	-24.4%	-66.2%	-49.9%	-15.3%	-38.0%	-3.0%	76.7%	80.7%	14.5%	29.4%
FINAL PAYMENTS[1]	170,298	286,802	172,119	470,484	1,099,702	105,500	149,468	244,804	1,563,996	2,063,768
%CHYA	4.7%	12.2%	-50.8%	-71.6%	-54.7%	-38.0%	-47.9%	42.2%	232.4%	87.7%
REFUNDS	359,217	347,069	2,446,104	1,933,794	5,086,184	389,133	902,145	1,001,102	734,637	3,027,016
%CHYA	22.6%	-37.9%	197.4%	168.5%	112.4%	8.3%	159.9%	-59.1%	-62.0%	-40.5%
OTHER	(284,139)	-	-	287,622	3,483	(287,622)	-	-	303,529	15,907
TOTAL	2,646,365	2,898,596	850,684	2,163,090	8,558,736	2,568,537	2,484,238	2,757,002	4,695,081	12,504,858
%CHYA	-7.3%	-5.0%	-69.4%	-52.8%	-35.5%	-2.9%	-14.3%	224.1%	117.1%	46.1%

Note: "Other" includes July withholding accrued to June.

Tax law impacts are reflected in the collections numbers to produce more meaningful projections.

TABLE B.4 **OREGON PERSONAL INCOME TAX REVENUE FORECAST - QUARTERLY COLLECTIONS**

Thousands of Dollars - Not Seasonally Adjusted **September 2023**

	2025:3	2025:4	2026:1	2026:2	FY 2026	2026:3	2026:4	2027:1	2027:2	FY 2027
WITHHOLDING	2,803,031	2,966,731	3,146,152	2,938,089	11,854,003	2,944,834	3,116,821	3,340,453	3,124,188	12,526,297
%CHYA	5.5%	5.5%	5.1%	5.1%	5.3%	5.1%	5.1%	6.2%	6.3%	5.7%
EST. PAYMENTS	553,703	487,302	593,484	842,840	2,477,328	609,595	536,491	652,690	916,986	2,715,761
%CHYA	14.5%	14.5%	14.1%	10.1%	12.9%	10.1%	10.1%	10.0%	8.8%	9.6%
FINAL PAYMENTS[1]	162,673	259,099	285,251	1,784,630	2,491,653	173,206	280,554	294,213	1,883,834	2,631,807
%CHYA	54.2%	73.3%	16.5%	14.1%	20.7%	6.5%	8.3%	3.1%	5.6%	5.6%
REFUNDS	164,090	354,529	940,236	742,083	2,200,938	172,626	373,027	1,013,957	800,772	2,360,382
%CHYA	-57.8%	-60.7%	-6.1%	1.0%	-27.3%	5.2%	5.2%	7.8%	7.9%	7.2%
OTHER	(303,529)	-	-	318,882	15,353	(318,882)	-	-	339,081	20,199
TOTAL	3,051,787	3,358,603	3,084,651	5,142,359	14,637,399	3,236,127	3,560,839	3,273,399	5,463,317	15,533,682
%CHYA	18.8%	35.2%	11.9%	9.5%	17.1%	6.0%	6.0%	6.1%	6.2%	6.1%

	2027:3	2027:4	2028:1	2028:2	FY 2028	2028:3	2028:4	2029:1	2029:2	FY 2029
WITHHOLDING	3,131,301	3,314,165	3,545,004	3,314,575	13,305,046	3,322,133	3,516,144	3,754,791	3,509,908	14,102,975
%CHYA	6.3%	6.3%	6.1%	6.1%	6.2%	6.1%	6.1%	5.9%	5.9%	6.0%
EST. PAYMENTS	663,221	583,687	711,873	1,025,147	2,983,928	741,450	652,534	792,145	1,088,510	3,274,639
%CHYA	8.8%	8.8%	9.1%	11.8%	9.9%	11.8%	11.8%	11.3%	6.2%	9.7%
FINAL PAYMENTS[1]	179,471	296,602	354,109	2,174,656	3,004,838	217,477	351,663	394,921	2,408,385	3,372,447
%CHYA	3.6%	5.7%	20.4%	15.4%	14.2%	21.2%	18.6%	11.5%	10.7%	12.2%
REFUNDS	185,364	401,878	1,014,140	799,017	2,400,399	185,802	401,385	1,103,595	871,829	2,562,611
%CHYA	7.4%	7.7%	0.0%	-0.2%	1.7%	0.2%	-0.1%	8.8%	9.1%	6.8%
OTHER	(339,081)	-	-	359,744	20,663	(359,744)	-	-	380,944	21,200
TOTAL	3,449,548	3,792,575	3,596,846	6,075,106	16,914,076	3,735,515	4,118,956	3,838,262	6,515,918	18,208,650
%CHYA	6.6%	6.5%	9.9%	11.2%	8.9%	8.3%	8.6%	6.7%	7.3%	7.7%

	2029:3	2029:4	2030:1	2030:2	FY2030	2030:3	2030:4	2031:1	2031:2	FY 2031
WITHHOLDING	3,517,921	3,723,368	3,973,495	3,714,011	14,928,796	3,722,495	3,939,890	4,203,118	3,928,450	15,793,953
%CHYA	5.9%	5.9%	5.8%	5.8%	5.9%	5.8%	5.8%	5.8%	5.8%	5.8%
EST. PAYMENTS	787,278	692,866	840,654	1,148,763	3,469,562	830,857	731,219	887,397	1,215,608	3,665,080
%CHYA	6.2%	6.2%	6.1%	5.5%	6.0%	5.5%	5.5%	5.6%	5.8%	5.6%
FINAL PAYMENTS[1]	241,662	389,432	426,145	2,569,801	3,627,041	260,327	417,865	456,940	2,721,690	3,856,823
%CHYA	11.1%	10.7%	7.9%	6.7%	7.5%	7.7%	7.3%	7.2%	5.9%	6.3%
REFUNDS	201,657	437,477	1,149,632	906,886	2,695,652	210,267	455,244	1,222,196	964,741	2,852,447
%CHYA	8.5%	9.0%	4.2%	4.0%	5.2%	4.3%	4.1%	6.3%	6.4%	5.8%
OTHER	(380,944)	-	-	403,096	22,152	(403,096)	-	-	426,370	23,274
TOTAL	3,964,260	4,368,189	4,090,663	6,928,786	19,351,898	4,200,316	4,633,731	4,325,259	7,327,378	20,486,684
%CHYA	6.1%	6.1%	6.6%	6.3%	6.3%	6.0%	6.1%	5.7%	5.8%	5.9%

	2031:3	2031:4	2032:1	2032:2	FY2032	2032:3	2032:4	2033:1	2033:2	FY 2033
WITHHOLDING	3,937,426	4,167,374	4,441,517	4,150,708	16,697,026	4,160,199	4,403,159	4,695,146	4,388,039	17,646,543
%CHYA	5.8%	5.8%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%
EST. PAYMENTS	879,203	773,768	939,075	1,286,992	3,879,038	930,833	819,206	994,197	1,362,204	4,106,440
%CHYA	5.8%	5.8%	5.8%	5.9%	5.8%	5.9%	5.9%	5.9%	5.8%	5.9%
FINAL PAYMENTS[1]	279,733	446,109	485,528	2,875,874	4,087,243	297,632	473,201	514,334	3,047,576	4,332,742
%CHYA	7.5%	6.8%	6.3%	5.7%	6.0%	6.4%	6.1%	5.9%	6.0%	6.0%
REFUNDS	223,121	483,961	1,276,981	1,007,456	2,991,518	233,511	505,697	1,322,293	1,042,981	3,104,482
%CHYA	6.1%	6.3%	4.5%	4.4%	4.9%	4.7%	4.5%	3.5%	3.5%	3.8%
OTHER	(426,370)	-	-	450,493	24,122	(450,493)	-	-	476,251	25,758
TOTAL	4,446,871	4,903,290	4,589,139	7,756,611	21,695,911	4,704,661	5,189,868	4,881,384	8,231,090	23,007,003
%CHYA	5.9%	5.8%	6.1%	5.9%	5.9%	5.8%	5.8%	6.4%	6.1%	6.0%

Note: "Other" includes July withholding accrued to June. Tax law impacts are reflected in the collections numbers to produce more meaningful projections.

Table B.5 – Corporate Income Tax Forecast

TABLE B.5 **OREGON CORPORATE INCOME TAX REVENUE FORECAST - QUARTERLY COLLECTIONS**

Thousands of Dollars - Not Seasonally Adjusted **September 2023**

	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	851,620	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	421,356
%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	378,703	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	122,284	106,374	358,150	736,786	254,198	184,839	98,980	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	554,935
%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	623,976
%CHYA	70.1%	47.4%	-29.0%	71.6%	27.9%	-15.3%	2.7%	68.7%	76.6%	24.9%
TOTAL	230,132	204,694	112,816	287,429	835,071	312,814	222,543	174,185	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	466,218	1,869,087
%CHYA	36.8%	30.9%	15.5%	9.3%	22.6%	20.1%	14.8%	40.9%	11.9%	20.1%
FINAL PAYMENTS	56,491	96,179	115,111	261,579	529,360	72,368	50,907	83,324	260,902	467,501
%CHYA	-50.7%	-2.2%	46.9%	-0.7%	-4.6%	28.1%	-47.1%	-27.6%	-0.3%	-11.7%
REFUNDS	49,631	255,602	197,775	44,052	547,060	116,377	247,875	320,324	205,888	890,464
%CHYA	-20.6%	0.6%	28.4%	-71.3%	-12.3%	134.5%	-3.0%	62.0%	367.4%	62.8%
TOTAL	363,352	335,513	205,882	634,304	1,539,051	384,025	371,192	169,675	521,232	1,446,124
%CHYA	16.2%	50.8%	18.2%	29.0%	28.1%	5.7%	10.6%	-17.6%	-17.8%	-6.0%

	2023:3	2023:4	2024:1	2024:2	FY 2024	2024:3	2024:4	2025:1	2025:2	FY 2025
ADVANCE PAYMENTS	389,931	472,931	279,762	383,409	1,526,032	356,407	459,882	287,153	406,180	1,509,621
%CHYA	-8.9%	-16.8%	-31.2%	-17.8%	-18.4%	-8.6%	-2.8%	2.6%	5.9%	-1.1%
FINAL PAYMENTS	99,551	81,876	98,204	287,500	567,131	101,524	229,474	183,341	318,255	832,593
%CHYA	37.6%	60.8%	17.9%	10.2%	21.3%	2.0%	180.3%	86.7%	10.7%	46.8%
REFUNDS	74,362	373,113	266,500	174,955	888,930	122,471	391,660	288,817	193,609	996,558
%CHYA	-36.1%	50.5%	-16.8%	-15.0%	-0.2%	64.7%	5.0%	8.4%	10.7%	12.1%
TOTAL	415,120	181,694	111,465	495,954	1,204,234	335,460	297,695	181,676	530,826	1,345,657
%CHYA	8.1%	-51.1%	-34.3%	-4.8%	-16.7%	-19.2%	63.8%	63.0%	7.0%	11.7%

TABLE B.5 **OREGON CORPORATE INCOME TAX REVENUE FORECAST - QUARTERLY COLLECTIONS**

Thousands of Dollars - Not Seasonally Adjusted **September 2023**

	2025:3	2025:4	2026:1	2026:2	FY 2026	2026:3	2026:4	2027:1	2027:2	FY 2027
ADVANCE PAYMENTS	381,894	492,218	307,860	435,103	1,617,075	409,568	528,569	330,062	466,824	1,735,023
%CHYA	7.2%	7.0%	7.2%	7.1%	7.1%	7.2%	7.4%	7.2%	7.3%	7.3%
FINAL PAYMENTS	104,752	262,082	185,228	324,806	876,868	102,954	265,927	189,099	338,382	896,362
%CHYA	3.2%	14.2%	1.0%	2.1%	5.3%	-1.7%	1.5%	2.1%	4.2%	2.2%
REFUNDS	137,432	444,439	302,885	203,103	1,087,859	144,095	464,937	316,913	212,690	1,138,634
%CHYA	12.2%	13.5%	4.9%	4.9%	9.2%	4.8%	4.6%	4.6%	4.7%	4.7%
TOTAL	349,214	309,861	190,203	556,806	1,406,084	368,427	329,560	202,248	592,516	1,492,751
%CHYA	4.1%	4.1%	4.7%	4.9%	4.5%	5.5%	6.4%	6.3%	6.4%	6.2%

	2027:3	2027:4	2028:1	2028:2	FY 2028	2028:3	2028:4	2029:1	2029:2	FY 2029
ADVANCE PAYMENTS	439,777	567,410	349,042	494,205	1,850,433	466,081	602,188	365,461	518,497	1,952,227
%CHYA	7.4%	7.3%	5.8%	5.9%	6.7%	6.0%	6.1%	4.7%	4.9%	5.5%
FINAL PAYMENTS	103,474	270,380	189,963	344,971	908,787	100,309	269,668	191,585	350,429	911,992
%CHYA	0.5%	1.7%	0.5%	1.9%	1.4%	-3.1%	-0.3%	0.9%	1.6%	0.4%
REFUNDS	151,006	487,221	327,789	220,187	1,186,203	156,496	505,722	338,713	227,963	1,228,894
%CHYA	4.8%	4.8%	3.4%	3.5%	4.2%	3.6%	3.8%	3.3%	3.5%	3.6%
TOTAL	392,245	350,569	211,215	618,988	1,573,018	409,894	366,135	218,334	640,963	1,635,325
%CHYA	6.5%	6.4%	4.4%	4.5%	5.4%	4.5%	4.4%	3.4%	3.6%	4.0%

	2029:3	2029:4	2030:1	2030:2	FY 2030	2030:3	2030:4	2031:1	2031:2	FY 2031
ADVANCE PAYMENTS	489,630	633,822	385,462	547,744	2,056,658	517,928	671,476	408,628	581,406	2,179,438
%CHYA	5.1%	5.3%	5.5%	5.6%	5.3%	5.8%	5.9%	6.0%	6.1%	6.0%
FINAL PAYMENTS	97,527	271,861	194,106	357,974	921,469	95,005	274,416	197,035	367,174	933,630
%CHYA	-2.8%	0.8%	1.3%	2.2%	1.0%	-2.6%	0.9%	1.5%	2.6%	1.3%
REFUNDS	162,221	525,242	352,298	237,349	1,277,109	169,082	547,877	367,679	247,995	1,332,633
%CHYA	3.7%	3.9%	4.0%	4.1%	3.9%	4.2%	4.3%	4.4%	4.5%	4.3%
TOTAL	424,936	380,441	227,271	668,370	1,701,018	443,851	398,015	237,984	700,585	1,780,436
%CHYA	3.7%	3.9%	4.1%	4.3%	4.0%	4.5%	4.6%	4.7%	4.8%	4.7%

	2031:3	2031:4	2032:1	2032:2	FY 2032	2032:3	2032:4	2033:1	2033:2	FY 2033
ADVANCE PAYMENTS	544,974	699,814	320,792	452,732	2,018,313	425,191	547,041	330,624	466,774	1,769,630
%CHYA	5.2%	4.2%	-21.5%	-22.1%	-7.4%	-22.0%	-21.8%	3.1%	3.1%	-12.3%
FINAL PAYMENTS	96,164	282,070	75,743	382,762	836,738	134,851	118,871	84,195	411,544	749,461
%CHYA	1.2%	2.8%	-61.6%	4.2%	-10.4%	40.2%	-57.9%	11.2%	7.5%	-10.4%
REFUNDS	175,390	563,969	146,356	98,436	984,150	69,980	226,153	151,434	101,889	549,455
%CHYA	3.7%	2.9%	-60.2%	-60.3%	-26.1%	-60.1%	-59.9%	3.5%	3.5%	-44.2%
TOTAL	465,748	417,915	250,179	737,058	1,870,901	490,062	439,759	263,386	776,429	1,969,636
%CHYA	4.9%	5.0%	5.1%	5.2%	5.1%	5.2%	5.2%	5.3%	5.3%	5.3%

Table B.6 – Cigarette and Tobacco Tax Distribution

TABLE B.6 — September 2023

Cigarette & Tobacco Tax Distribution (Millions of $)

	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
Distribution Forecast															
2021-22	**363.6**	24.4	93.0	16.3	197.1	3.7	21.7	7.4	**56.5**	30.3	23.5	2.6	**35.9**	32.3	3.6
2022-23	**328.0**	21.4	84.5	14.8	177.5	3.4	19.7	6.7	**55.0**	29.4	23.0	2.6	**31.9**	28.7	3.2
2021-23 Biennium	**691.6**	45.8	177.5	31.1	374.6	7.1	41.4	14.2	**111.5**	59.8	46.6	5.2	**67.8**	61.0	6.8
2023-24	**330.7**	21.8	85.1	14.9	178.7	3.4	19.9	6.8	**57.0**	30.7	23.7	2.6	**29.9**	26.9	3.0
2024-25	**322.4**	21.3	83.0	14.5	174.2	3.3	19.4	6.6	**56.9**	30.6	23.6	2.6	**30.2**	27.1	3.0
2023-25 Biennium	**653.0**	43.1	168.1	29.4	353.0	6.7	39.2	13.4	**113.9**	61.3	47.3	5.3	**60.1**	54.1	6.0
2025-26	**313.0**	20.7	80.6	14.1	169.2	3.2	18.8	6.4	**56.9**	30.6	23.6	2.6	**30.4**	27.4	3.0
2026-27	**307.0**	20.3	79.1	13.8	166.0	3.2	18.4	6.3	**57.2**	30.8	23.7	2.6	**30.7**	27.6	3.1
2025-27 Biennium	**620.1**	41.0	159.7	27.9	335.2	6.4	37.2	12.7	**114.1**	61.4	47.4	5.3	**61.1**	55.0	6.1
2027-28	**301.8**	19.9	77.7	13.6	163.1	3.1	18.1	6.2	**57.1**	30.7	23.7	2.6	**30.9**	27.8	3.1
2028-29	**297.1**	19.6	76.5	13.4	160.6	3.1	17.8	6.1	**57.4**	30.9	23.9	2.7	**31.2**	28.0	3.1
2027-29 Biennium	**598.9**	39.6	154.2	27.0	323.7	6.2	36.0	12.3	**114.5**	61.7	47.6	5.3	**62.1**	55.9	6.2
2029-30	**292.5**	19.3	75.3	13.2	158.1	3.0	17.6	6.0	**57.5**	31.0	23.9	2.7	**31.4**	28.3	3.1
2030-31	**288.0**	19.0	74.2	13.0	155.7	3.0	17.3	5.9	**57.4**	30.9	23.8	2.7	**31.6**	28.5	3.2
2029-31 Biennium	**580.5**	38.4	149.5	26.2	313.8	6.0	34.9	11.9	**114.9**	61.8	47.7	5.3	**63.0**	56.7	6.3
2031-32	**283.6**	18.7	73.0	12.8	153.3	2.9	17.0	5.8	**57.3**	30.8	23.8	2.6	**31.9**	28.7	3.2
2032-33	**279.2**	18.4	71.9	12.6	150.9	2.9	16.8	5.7	**57.1**	30.8	23.7	2.6	**32.1**	28.9	3.2
2031-33 Biennium	**562.8**	37.2	144.9	25.3	304.2	5.8	33.8	11.6	**114.4**	61.6	47.5	5.3	**64.0**	57.6	6.4

[1] Includes the cigarette floor tax in FY21 of $27.7 million and FY22 of $1.6 million

[2] Old and New refere to pre- and post-Measure 108 (2020) taxes and programs

Table B.7 – Liquor Apportionment and Revenue Distribution to Local Government

TABLE B.7 **September 2023**

Liquor Apportionment and Revenue Distribution to Local Governments (Millions of $)

	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]
2021-22	311.292	176.701	10.675	0.359	56.163	39.314	95.476	28.081		7.419
2022-23	325.841	186.102	8.430	0.307	59.546	41.682	101.229	29.773		6.742
2021-23 Biennium	637.133	362.804	19.104	0.666	115.709	80.996	196.705	57.854		14.161
2023-24	341.572	194.482	10.019	0.376	62.134	43.494	105.628	31.067		6.792
2024-25	364.155	207.340	10.681	0.401	66.242	46.369	112.611	33.121		6.621
2023-25 Biennium	705.726	401.822	20.700	0.777	128.376	89.863	218.239	64.188		13.414
2025-26	342.792	187.199	11.516	0.429	65.295	45.706	111.001	32.647		6.430
2026-27	361.105	197.622	11.826	0.443	68.733	48.114	116.847	34.366		6.307
2025-27 Biennium	703.897	384.821	23.342	0.872	134.028	93.820	227.848	67.014		12.736
2027-28	382.134	209.662	12.168	0.458	72.657	50.860	123.517	36.328		6.199
2028-29	405.481	223.216	12.518	0.474	76.942	53.860	130.802	38.471		6.103
2027-29 Biennium	787.615	432.878	24.687	0.933	149.599	104.720	254.319	74.799		12.301
2029-30	431.759	238.477	12.930	0.493	81.754	57.228	138.983	40.877		6.009
2030-31	457.982	253.725	13.330	0.511	86.553	60.587	147.140	43.276		5.916
2029-31 Biennium	889.741	492.202	26.260	1.003	168.307	117.815	286.123	84.153		11.924

[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 May 2023 Forecast

Table B.8 Track Record for the May 2023 Forecast

(Quarter ending June 30, 2023)

Personal Income Tax

(Millions of dollars)	Forecast Comparison: Actual Revenues	Latest Forecast	Percent Difference	Year/Year Change: Prior Year	Percent Change
Withholding	$2,569.2	$2,532.7	1.4%	$2,467.7	4.1%
Dollar difference		$36.5			
Estimated Payments*	$789.4	$845.8	-6.7%	$904.7	-12.7%
Dollar difference		-$56.4			
Final Payments*	$1,658.3	$1,612.3	2.8%	$2,116.0	-21.6%
Dollar difference		$45.9			
Refunds	-$720.3	-$674.1	6.9%	-$960.6	-25.0%
Dollar difference		-$46.2			
Total Personal Income Tax	**$4,296.7**	**$4,316.8**	**-0.5%**	**$4,527.8**	**-5.1%**
Dollar difference		-$20.1			

Corporate Income Tax

(Millions of dollars)	Forecast Comparison: Actual Revenues	Latest Forecast	Percent Difference	Year/Year Change: Prior Year	Percent Change
Advanced Payments	$466.2	$447.4	4.2%	$416.8	11.9%
Dollar difference		$18.8			
Final Payments	$260.9	$297.1	-12.2%	$261.6	-0.3%
Dollar difference		-$36.2			
Refunds	-$205.9	-$47.4	334.8%	-$44.1	367.4%
Dollar difference		-$158.5			
Total Corporate Income Tax	**$521.2**	**$697.2**	**-25.2%**	**$634.3**	**-17.8%**
Dollar difference		-$176.0			

Total Income Tax

(Millions of dollars)	Forecast Comparison: Actual Revenues	Latest Forecast	Percent Difference	Year/Year Change: Prior Year	Percent Change
Corporate and Personal Tax	**$4,817.9**	**$5,014.0**	**-3.9%**	**$5,162.1**	**-6.7%**
Dollar difference		-$196.1		-$344.2	

* Data separating estimated and other personal income tax payments is no longer available. Tracking represents estimates based on banking data.

Table B.9 – Lottery Forecast

TABLE B.9
Summary of Lottery Resources

Sep 2023 Forecast

(in millions of dollars)	2023-25 Current Forecast	2023-25 Change from May-23	2023-25 Change from COS 2023	2025-2027 Current Forecast	2025-2027 Change from May-23	2027-29 Current Forecast	2027-29 Change from May-23	2029-31 Current Forecast	2029-31 Change from May-23	2031-33 Current Forecast	2031-33 Change from May-23
LOTTERY EARNINGS											
Traditional Lottery	175.423	*11.728*	*11.728*	161.007	*(0.364)*	160.728	(0.880)	160.719	(0.898)	160.759	(0.916)
Video Lottery	1,612.728	*(12.256)*	*(12.256)*	1,758.521	*(10.698)*	1,906.694	(12.353)	2,041.688	(13.227)	2,186.685	(14.167)
Sports Betting[1]	45.221	*0.906*	*0.906*	47.643	*0.000*	50.146	0.000	52.594	0.000	55.162	0.000
Administrative Actions	9.152	*9.152*	*9.152*	0.000	*0.000*	0.000	0.000	0.000	0.000	0.000	0.000
Total Available to Transfer	**1,842.525**	*9.530*	*9.530*	**1,967.171**	*(11.062)*	**2,117.568**	(13.232)	**2,255.002**	(14.125)	**2,402.606**	(15.083)
ECONOMIC DEVELOPMENT FUND											
Beginning Balance	84.396	*(0.000)*	*0.000*	0.000	*0.000*	0.000	0.000	0.000	0.000	0.000	0.000
Transfers from Lottery	1,842.525	*9.530*	*9.530*	1,967.171	*(11.062)*	2,117.568	(13.232)	2,255.002	(14.125)	2,402.606	(15.083)
Other Resources[2]	2.000	*0.000*	*0.000*	2.000	*0.000*	2.000	0.000	2.000	0.000	2.000	0.000
Total Available Resources	**1,928.921**	*9.530*	*9.530*	**1,969.171**	*(11.062)*	**2,119.568**	(13.232)	**2,257.002**	(14.125)	**2,404.606**	(15.083)
ALLOCATION OF RESOURCES											
Constitutional Distributions											
Education Stability Fund[3]	331.654	*1.715*	*1.715*	130.809	(0.664)	381.130	(2.382)	353.683	51.467	376.674	74.458
Oregon Capital Matching Fund[3]	0.000	*0.000*	*0.000*	186.068	(1.106)	0.000	0.000	43.365	(44.684)	0.000	(88.049)
Parks and Natural Resources Fund[4]	276.379	*1.430*	*1.430*	295.076	(1.659)	317.635	(1.985)	338.250	(2.119)	360.391	20.022
Veterans' Services Fund[5]	27.638	*0.143*	*0.143*	29.508	(0.166)	31.764	(0.198)	33.825	(0.212)	36.039	2.002
Other Distributions											
Outdoor School Education Fund[6]	56.406	*(0.000)*	*0.000*	60.534	0.174	65.006	0.414	69.807	0.687	74.963	0.997
County Economic Development	59.982	*(2.320)*	*0.000*	67.422	(0.410)	73.103	(0.474)	78.278	(0.507)	83.838	5.052
HECC Collegiate Athletic & Scholarships[7]	18.330	*(0.000)*	*0.000*	19.672	(0.111)	21.176	(0.132)	22.550	(0.141)	24.026	1.335
Gambling Addiction [7]	18.330	*(0.000)*	*0.000*	19.672	(0.111)	21.176	(0.132)	22.550	(0.141)	24.026	1.335
County Fairs	3.828	*0.000*	*0.000*	3.828	0.000	3.828	0.000	3.828	0.000	3.828	0.000
Other Legislatively Adopted Allocations[8]	1,061.945	*827.645*	*0.000*	234.300	0.000	234.300	0.000	234.300	0.000	234.300	0.000
Employer Incentive Fund (PERS)[1]	29.620	*0.594*	*1.433*	32.107	(0.000)	32.847	0.000	34.656	(0.215)	37.412	2.541
Total Distributions	**1,884.112**	*829.207*	*4.721*	**1,078.995**	(4.053)	**1,181.963**	(4.890)	**1,235.093**	4.135	**1,255.496**	19.693
Ending Balance/Discretionary Resources	**44.809**	*(819.677)*	*4.809*	**890.176**	(7.009)	**937.605**	(8.343)	**1,021.909**	(18.260)	**1,149.110**	113.786

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: Budgetary Reserve Summary and Outlook **Sep 2023**

Rainy Day Fund

(Millions)	2021-23	2023-25	2025-27	2027-29	2029-31	2031-33
Beginning Balance	$962.2	$1,353.5	$1,862.7	$2,072.7	$2,658.0	$3,337.2
Interest Earnings	$44.1	$146.4	$112.8	$128.2	$162.8	$190.7
Deposits[1]	$347.2	$362.9	$97.1	$457.1	$516.4	$0.0
Triggered Withdrawals	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Ending Balance[2]	**$1,353.4**	**$1,862.8**	**$2,072.7**	**$2,658.0**	**$3,337.2**	**$3,527.9**

Education Stability Fund[3]

(Millions)	2021-23	2023-25	2025-27	2027-29	2029-31	2031-33
Beginning Balance	$414.6	$710.8	$1,009.3	$1,127.0	$1,470.0	$1,788.3
Interest Earnings[4]	$21.9	$82.9	$66.0	$73.2	$93.0	$108.2
Deposits[5]	$294.0	$298.5	$117.7	$343.0	$318.3	$339.0
Distributions	$19.8	$85.3	$66.0	$73.2	$93.0	$215.9
Oregon Education Fund	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Oregon Opportunity Grant	$19.8	$85.3	$66.0	$73.2	$93.0	$215.9
Withdrawals	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Ending Balance	**$710.8**	**$1,009.3**	**$1,127.0**	**$1,470.0**	**$1,788.3**	**$2,019.7**

Total Reserves

(Millions)	2021-23	2023-25	2025-27	2027-29	2029-31	2031-33
Ending Balances	**$2,064.2**	**$2,872.0**	**$3,199.6**	**$4,128.0**	**$5,125.5**	**$5,547.6**
Percent of General Fund Revenues	6.7%	11.3%	9.2%	10.3%	11.4%	11.0%

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
Summary of Marijuana Resources

Sep 2023

	2023-25			2025-27		2027-29		2029-31		20231-33	
(in millions of dollars)	**Current Forecast**	*Change from May-23*	*Change from COS 2023*	**Current Forecast**	*Change from May-23*	**Current Forecast**	*Change from May-23*	**Current Forecast**	*Change from May-23*	**Current Forecast**	*Change from May-23*
MARIJUANA EARNINGS											
+ Tax Revenue [1]	314.083	*(2.777)*	*(2.777)*	357.522	*0.000*	412.880	0.000	470.206	(0.858)	520.176	NA
+ Medical Marijuana Tax Revenue [2]	0.000	*0.000*	*0.000*	0.000	*0.000*	31.817	(0.080)	43.625	(0.416)	45.041	NA
- Administrative Costs [3]	18.374	*0.000*	*0.000*	18.746	*0.000*	19.144	0.000	19.571	0.000	20.027	NA
Net Available to Transfer	**295.709**	*(2.777)*	*(2.777)*	**338.776**	*0.000*	**393.736**	*(0.080)*	**494.260**	*(1.273)*	**545.190**	*NA*
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	NA
Revenue Transfers	295.709	*(2.777)*	*(2.777)*	338.776	*0.000*	425.553	(0.080)	494.260	(1.273)	545.190	NA
Other Resources	0.000	*0.000*	*0.000*	0.000	*0.000*	0.000	0.000	0.000	0.000	0.000	NA
Total Available Resources	**295.709**	*(2.777)*	*(2.777)*	**338.776**	*0.000*	**425.553**	*(0.080)*	**494.260**	*(1.273)*	**545.190**	*NA*
ALLOCATION OF RESOURCES [4]											
Drug Treatment & Recovery	193.833	*(2.777)*	*(2.777)*	230.228	*(0.025)*	311.773	(0.445)	375.441	(1.672)	421.386	NA
State School Fund	40.751	*0.000*	*0.000*	43.419	*0.010*	45.512	0.146	47.528	0.159	49.522	NA
Mental Health, Alcoholism, & Drug Services	20.375	*(0.000)*	*0.000*	21.710	*0.005*	22.756	0.073	23.764	0.080	24.761	NA
State Police	15.281	*(0.000)*	*0.000*	16.282	*0.004*	17.067	0.055	17.823	0.060	18.571	NA
Cities	10.188	*0.000*	*0.000*	10.855	*0.002*	11.378	0.037	11.882	0.040	12.380	NA
Counties	10.188	*0.000*	*0.000*	10.855	*0.002*	11.378	0.037	11.882	0.040	12.380	NA
Alcohol & Drug Abuse Prevention, Intervention & Treatment	5.094	*(0.000)*	*0.000*	5.427	*0.001*	5.689	0.018	5.941	0.020	6.190	NA
Total Distributions	**295.709**	*(2.777)*	*(2.777)*	**338.776**	*(0.000)*	**425.553**	*(0.080)*	**494.260**	*(1.273)*	**545.190**	*NA*
Ending Balance	**0.000**	*0.000*	*0.000*	**0.000**	*0.000*	**0.000**	0.000	**0.000**	0.000	**0.000**	NA

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 — **September 2023**

Summary of Corporate Activity Tax Resources

(in millions of dollars)	2021-23 Actuals	2021-23 *Change from May-23*	2021-23 *Change from COS 2021*	2023-25 Current Forecast	2023-25 *Change from May-23*	2023-25 *Change from COS 2023*	2025-27 Current Forecast	2025-27 *Change from May-23*	2027-29 Current Forecast	2027-29 *Change from May-23*	2029-31 Current Forecast	2029-31 *Change from May-23*
Corporate Activity Tax												
+ Tax Revenue	2,555.067	13.690	*186.770*	2,782.494	3.396	*3.396*	3,135.094	*24.228*	3,488.941	*14.587*	3,884.772	*(3.312)*
- Administrative Costs	15.894	(3.306)	*(3.306)*	21.312	0.000	*0.000*	23.656	*0.000*	26.259	*0.000*	28.689	*0.000*
Net Available to Transfer	**2,539.173**	16.996	**190.076**	**2,761.182**	**3.396**	3.396	**3,111.438**	24.228	**3,462.682**	14.587	**3,856.083**	(3.312)
Fund for Student Success												
Beginning Balance	200.557	0.000	*0.000*	345.006	26.478	*26.478*	220.718	*220.718*	0.000	*0.000*	0.000	*0.000*
Revenue Transfers	2,539.173	16.996	*190.076*	2,761.182	3.396	*3.396*	3,111.438	*24.228*	3,462.682	*14.587*	3,856.083	*(3.312)*
Other Resources	0.000	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	**2,739.730**	16.996	**190.076**	**3,106.187**	**29.875**	29.875	**3,332.156**	244.945	**3,462.682**	14.587	**3,856.083**	(3.312)
ALLOCATION OF RESOURCES												
State School Fund	722.288	(9.483)	*36.610*	711.112	9.157	*9.157*	796.084	*4.190*	915.028	*6.371*	1,025.784	*9.774*
Student Investment Account	891.938	0.000	*(0.339)*	1,087.179	(100.000)	*0.000*	1,268.036	*120.378*	1,273.827	*4.108*	1,415.149	*(6.543)*
Statewide Education Initiative Account	382.930	0.000	*10.028*	557.396	(154.911)	*0.000*	760.822	*72.227*	764.296	*2.465*	849.090	*(3.926)*
Early Learning Account	397.568	0.000	*(38.539)*	529.783	54.911	*0.000*	507.214	*48.151*	509.531	*1.643*	566.060	*(2.617)*
Total Distributions	**2,394.724**	(9.483)	**7.761**	**2,885.470**	**(190.843)**	9.157	**3,332.156**	244.945	**3,462.682**	14.587	**3,856.083**	(3.312)
Ending Balance	**345.006**	26.478	**182.315**	**220.718**	**220.718**	20.718	**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 $8.82 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 | **Corporate Activity Tax Collections By Quarter** | **Sep-23**

(thousands)	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

	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

	2023:3	2023:4	2024:1	2024:2	FY 2024	2024:3	2024:4	2025:1	2025:2	FY 2025
Estimated Payments	292,440	392,881	257,324	303,438	1,246,082	304,593	411,036	270,387	321,702	1,307,719
Final Payments	50,519	66,479	63,882	179,929	360,809	52,948	70,791	66,035	181,106	370,879
Refunds	-31,059	-180,059	-20,815	-22,257	-254,191	-29,919	-176,587	-20,425	-21,873	-248,804
Total	311,899	279,300	300,391	461,110	1,352,700	327,622	305,240	315,997	480,935	1,429,794

	2025:3	2025:4	2026:1	2026:2	FY 2026	2026:3	2026:4	2027:1	2027:2	FY 2027
Estimated Payments	323,241	436,630	287,195	339,987	1,387,053	341,720	461,209	303,317	358,777	1,465,024
Final Payments	53,463	70,930	68,091	191,617	384,102	56,393	75,378	72,108	202,299	406,178
Refunds	-29,427	-173,763	-20,355	-22,589	-246,134	-30,964	-184,662	-21,605	-23,897	-261,128
Total	347,277	333,796	334,932	509,016	1,525,020	367,149	351,926	353,820	537,178	1,610,074

	2027:3	2027:4	2028:1	2028:2	FY 2028	2028:3	2028:4	2029:1	2029:2	FY 2029
Estimated Payments	360,275	486,216	319,783	378,510	1,544,783	380,117	513,036	337,429	399,320	1,629,902
Final Payments	59,558	79,539	76,052	213,276	428,425	62,793	83,849	80,211	225,034	451,888
Refunds	-32,702	-194,854	-22,794	-25,201	-275,551	-34,478	-205,413	-24,033	-26,583	-290,507
Total	387,131	370,901	373,041	566,585	1,697,657	408,432	391,472	393,607	597,772	1,791,284

	2029:3	2029:4	2030:1	2030:2	FY 2030	2030:3	2030:4	2031:1	2031:2	FY 2031
Estimated Payments	401,012	541,223	355,983	421,399	1,719,617	423,253	571,238	375,780	444,984	1,815,256
Final Payments	66,252	88,478	84,628	237,398	476,756	69,893	93,337	89,295	250,532	503,057
Refunds	-36,377	-216,753	-25,359	-28,045	-306,534	-38,376	-228,657	-26,753	-29,594	-323,380
Total	430,887	412,949	415,253	630,751	1,889,839	454,770	435,918	438,321	665,923	1,994,933

	2031:3	2031:4	2032:1	2032:2	FY 2032	2032:3	2032:4	2033:1	2033:2	FY 2033
Estimated Payments	446,886	603,160	396,751	469,561	1,916,358	471,553	636,411	418,462	494,312	2,020,738
Final Payments	73,758	98,504	94,262	264,530	531,054	77,877	104,012	99,494	279,117	560,500
Refunds	-40,499	-241,315	-28,237	-31,242	-341,293	-42,760	-254,807	-29,812	-32,973	-360,352
Total	480,145	460,349	462,776	702,848	2,106,119	506,670	485,615	488,144	740,456	2,220,886

Appendix C: Population Forecast Detail

Table C.1 – Oregon's Population Forecast and Components of Change

Year (July 1)	Population	Population Change Number	Population Change Percent	Births Number	Births Rate/1000	Deaths Number	Deaths Rate/1000	Natural Increase	Net Migration Number	Net Migration 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	3,854,500	17,200	0.45	45,381	11.80	32,437	8.43	12,944	4,256	1.11
2011-2012	3,878,200	23,700	0.61	44,897	11.61	32,804	8.48	12,093	11,607	3.00
2012-2013	3,910,900	32,700	0.84	44,969	11.55	33,168	8.52	11,801	20,899	5.37
2013-2014	3,952,000	41,100	1.05	45,447	11.56	33,731	8.58	11,716	29,384	7.47
2014-2015	4,000,400	48,400	1.22	45,660	11.48	35,318	8.88	10,342	38,058	9.57
2010-2015		**163,100**		**226,354**		**167,458**		**58,896**	**104,204**	
2015-2016	4,060,100	59,700	1.49	45,647	11.33	35,339	8.77	10,308	49,392	12.26
2016-2017	4,122,000	61,900	1.52	44,602	10.90	36,773	8.99	7,829	54,071	13.22
2017-2018	4,173,200	51,200	1.24	42,906	10.34	36,268	8.74	6,638	44,562	10.74
2018-2019	4,211,400	38,200	0.92	42,220	10.07	36,622	8.74	5,598	32,602	7.78
2019-2020	4,243,959	32,559	0.77	40,920	9.68	37,821	8.95	3,099	29,460	6.97
2015-2020		**243,559**		**216,295**		**182,823**		**33,472**	**210,087**	
2020-2021	4,263,581	19,622	0.46	39,654	9.32	41,893	9.85	-2,239	21,861	5.14
2021-2022	4,281,851	18,270	0.43	40,446	9.47	46,304	10.84	-5,858	24,128	5.65
2022-2023	4,296,800	14,949	0.35	40,510	9.44	44,841	10.45	-4,331	19,280	4.49
2023-2024	4,316,700	19,900	0.46	40,962	9.51	45,124	10.48	-4,162	24,062	5.59
2024-2025	4,342,800	26,100	0.60	41,325	9.54	45,534	10.52	-4,209	30,309	7.00
2020-2025		**98,841**		**202,897**		**223,696**		**-20,799**	**119,640**	
2025-2026	4,371,800	29,000	0.67	41,786	9.59	46,059	10.57	-4,273	33,273	7.64
2026-2027	4,402,700	30,900	0.71	42,262	9.63	46,697	10.64	-4,434	35,334	8.05
2027-2028	4,434,800	32,100	0.73	42,786	9.68	47,423	10.73	-4,638	36,738	8.31
2028-2029	4,468,800	34,000	0.77	43,335	9.73	48,114	10.81	-4,779	38,778	8.71
2029-2030	4,503,900	35,100	0.79	43,947	9.80	48,672	10.85	-4,725	39,825	8.88
2025-2030		**161,100**		**214,116**		**236,965**		**-22,849**	**183,948**	
2030-2031	4,539,200	35,300	0.78	44,274	9.79	49,248	10.89	-4,974	40,274	8.91
2031-2032	4,574,600	35,400	0.78	44,637	9.80	49,976	10.97	-5,339	40,739	8.94
2030-2032		**70,700**		**88,911**		**99,224**		**-10,312**	**81,012**	
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		**406,659**		**442,649**		**350,281**		**92,368**	**314,291**	7.81
2020-2030		**259,941**		**417,013**		**460,661**		**-43,648**	**303,589**	6.97
2030-2032		**70,700**		**88,911**		**99,224**		**-10,312**	**81,012**	1.78

Sources: 1990-1999 population - U.S. Census Bureau; 2000-2019 intercensal population estimates by Office of Economic Analysis based on postcensal estimates by Population Research Center, PSU; 2020-2022 population by PRC/PSU; births and deaths 1990-2022: 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 Forecast by Age and Sex

	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	112,011	106,985	218,996	108,666	103,520	212,186	106,579	101,393	207,973	104,997	99,903	204,900
5- 9	121,563	116,455	238,018	124,747	118,498	243,245	123,837	117,750	241,587	122,364	116,360	238,724	120,326	114,362	234,688
10-14	124,611	118,821	243,432	132,309	125,225	257,534	132,412	125,104	257,515	131,719	124,013	255,733	130,372	122,407	252,779
15-19	131,215	124,664	255,879	130,658	125,672	256,330	130,753	124,261	255,015	132,444	125,261	257,704	134,302	126,950	261,253
20-24	128,737	124,919	253,656	135,238	132,221	267,459	135,835	133,971	269,806	136,171	134,637	270,808	135,981	133,963	269,945
25-29	133,819	131,522	265,341	145,729	142,132	287,860	142,728	139,065	281,793	140,395	136,457	276,852	138,956	134,908	273,864
30-34	131,483	128,253	259,736	152,805	149,031	301,836	155,224	150,855	306,079	157,324	152,299	309,623	157,761	152,269	310,030
35-39	128,103	123,715	251,818	150,399	148,210	298,609	151,617	148,909	300,526	152,625	149,506	302,131	153,770	150,205	303,975
40-44	125,961	122,930	248,891	138,274	136,608	274,883	141,917	140,797	282,714	144,994	144,474	289,468	147,255	147,443	294,698
45-49	130,755	132,549	263,304	130,153	127,426	257,579	128,938	126,672	255,610	129,368	127,773	257,142	131,519	130,311	261,830
50-54	135,069	141,566	276,635	125,650	125,882	251,533	128,315	127,999	256,314	130,101	129,398	259,499	130,564	129,667	260,231
55-59	132,995	140,775	273,769	128,444	134,806	263,250	125,645	131,315	256,960	122,890	127,880	250,770	120,887	125,154	246,042
60-64	115,186	121,047	236,233	130,455	143,111	273,566	129,404	142,001	271,406	127,989	140,487	268,476	126,501	138,490	264,991
65-69	81,837	87,957	169,794	125,244	139,324	264,568	126,016	141,153	267,169	125,867	141,776	267,643	124,898	141,296	266,194
70-74	56,945	63,006	119,950	103,012	114,579	217,592	107,556	120,135	227,690	109,758	123,446	233,204	111,183	126,097	237,280
75-79	40,954	50,138	91,091	65,368	75,617	140,985	68,876	79,838	148,713	73,719	85,459	159,178	78,787	91,449	170,236
80-84	30,391	42,761	73,152	38,064	46,702	84,766	39,844	48,938	88,782	41,928	51,719	93,647	44,690	55,211	99,901
85+	26,767	51,389	78,156	31,812	51,557	83,370	32,310	51,405	83,715	32,388	50,887	83,275	32,889	51,074	83,962
Total	1,898,693	1,938,607	3,837,300	2,100,373	2,143,586	4,243,959	2,109,892	2,153,689	4,263,581	2,118,623	2,163,228	4,281,851	2,125,639	2,171,161	4,296,800
Mdn. Age	37.2	39.4	38.3	38.9	40.8	39.8	39.1	41.1	40.1	39.3	41.4	40.4	39.6	41.7	40.6

	2024			2025			2026			2027			2028		
Age	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total
0-4	104,290	99,102	203,392	104,569	99,418	203,987	105,820	100,579	206,399	106,910	101,584	208,494	108,209	102,794	211,002
5- 9	117,977	112,034	230,010	115,089	108,859	223,948	111,968	105,508	217,476	110,115	103,514	213,629	108,876	102,255	211,131
10-14	129,259	121,229	250,487	128,666	120,659	249,325	128,093	120,114	248,207	126,930	118,899	245,829	125,385	117,155	242,540
15-19	135,762	128,160	263,922	136,982	129,113	266,095	137,608	129,430	267,038	137,383	128,719	266,102	136,644	127,566	264,209
20-24	135,643	132,801	268,444	135,225	130,973	266,198	135,810	130,031	265,842	138,074	131,620	269,695	140,857	134,229	275,087
25-29	139,011	135,235	274,247	139,942	137,157	277,099	141,170	139,484	280,654	142,124	140,671	282,795	142,727	140,747	283,474
30-34	156,938	151,129	308,068	155,041	149,050	304,091	152,915	146,550	299,464	151,512	144,532	296,044	151,439	143,933	295,371
35-39	155,582	151,537	307,119	158,215	153,511	311,726	161,251	155,845	317,096	163,933	157,765	321,697	165,555	158,570	324,125
40-44	149,274	149,770	299,043	151,174	151,388	302,562	152,664	152,518	305,182	153,938	153,555	307,493	155,501	154,911	310,412
45-49	134,673	133,872	268,545	138,434	138,329	276,763	142,325	142,843	285,168	145,698	146,862	292,561	148,411	150,399	298,810
50-54	129,971	129,046	259,017	128,779	127,925	256,703	127,789	127,420	255,209	128,466	128,797	257,263	130,934	131,726	262,660
55-59	120,716	124,430	245,146	122,782	126,044	248,827	125,637	128,503	254,140	127,696	130,290	257,987	128,528	131,064	259,592
60-64	125,109	136,306	261,415	123,215	133,662	256,877	120,777	130,556	251,332	118,485	127,556	246,041	116,977	125,403	242,380
65-69	123,586	140,341	263,928	122,645	139,545	262,190	121,949	138,817	260,765	121,064	137,798	258,862	120,146	136,443	256,589
70-74	112,867	129,092	241,959	114,375	131,827	246,202	115,335	133,788	249,122	115,670	134,765	250,435	115,312	134,820	250,132
75-79	83,324	96,989	180,313	88,060	102,825	190,885	92,066	107,941	200,007	94,393	111,314	205,707	96,094	114,147	210,241
80-84	47,438	58,827	106,265	49,749	62,024	111,773	52,558	65,625	118,183	56,732	70,715	127,447	61,088	76,142	137,231
85+	33,757	51,623	85,380	34,944	52,605	87,549	36,355	54,160	90,516	38,169	56,452	94,621	40,455	59,361	99,816
Total	2,135,176	2,181,524	4,316,700	2,147,885	2,194,916	4,342,800	2,162,090	2,209,711	4,371,800	2,177,292	2,225,408	4,402,700	2,193,137	2,241,663	4,434,800
Mdn. Age	39.8	42.0	40.9	40.0	42.3	41.1	40.2	42.5	41.4	40.4	42.8	41.6	40.5	43.0	41.8

	2029			2030			2031			2032		
Age	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total
0-4	109,537	104,036	213,573	110,970	105,382	216,352	112,312	106,646	218,958	113,583	107,845	221,428
5- 9	108,463	101,650	210,113	108,957	102,109	211,066	110,407	103,396	213,803	111,647	104,498	216,145
10-14	123,400	115,013	238,414	120,659	111,902	232,560	117,576	108,554	226,130	115,768	106,568	222,336
15-19	136,024	126,753	262,777	135,743	126,420	262,163	135,379	126,031	261,410	134,325	124,896	259,221
20-24	143,094	136,202	279,296	144,812	137,651	282,463	145,778	138,293	284,070	145,766	137,753	283,519
25-29	143,031	140,180	283,211	142,987	138,643	281,630	143,869	137,905	281,774	146,467	139,783	286,250
30-34	152,699	145,133	297,832	154,493	147,744	302,238	156,423	150,655	307,078	157,916	152,238	310,154
35-39	165,680	158,086	323,766	164,325	156,345	320,671	162,556	154,029	316,585	161,416	152,136	313,552
40-44	157,693	156,822	314,515	160,596	159,211	319,807	163,844	161,882	325,726	166,697	164,064	330,761
45-49	150,823	153,219	304,042	153,007	155,168	308,175	154,715	156,538	311,253	156,156	157,761	313,917
50-54	134,368	135,649	270,017	138,335	140,385	278,721	142,391	145,135	287,525	145,902	149,354	295,256
55-59	128,277	130,859	259,136	127,355	130,007	257,363	126,586	129,709	256,295	127,432	131,281	258,713
60-64	117,195	125,166	242,361	119,501	127,136	246,637	122,522	129,879	252,402	124,725	131,886	256,610
65-69	119,251	134,801	254,053	117,770	132,538	250,308	115,711	129,732	245,442	113,752	126,977	240,729
70-74	114,576	134,366	248,942	114,086	133,953	248,039	113,774	133,545	247,320	113,247	132,817	246,064
75-79	97,987	117,259	215,246	99,667	120,072	219,739	100,839	122,148	222,987	101,457	123,321	224,778
80-84	64,986	81,140	146,126	68,963	86,292	155,255	72,376	90,841	163,217	74,575	94,038	168,613
85+	42,907	62,474	105,380	45,232	65,482	110,715	48,047	69,177	117,225	52,068	74,487	126,555
Total	2,209,991	2,258,809	4,468,800	2,227,460	2,276,440	4,503,900	2,245,105	2,294,095	4,539,200	2,262,898	2,311,702	4,574,600
Mdn. Age	40.7	43.3	42.0	40.9	43.5	42.2	41.1	43.7	42.4	41.3	43.9	42.6

Table C.3 Population of Oregon

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	3,854,500	17,200	0.45%
2012	3,878,200	23,700	0.61%
2013	3,910,900	32,700	0.84%
2014	3,952,000	41,100	1.05%
2015	4,000,400	48,400	1.22%
2016	4,060,100	59,700	1.49%
2017	4,122,000	61,900	1.52%
2018	4,173,200	51,200	1.24%
2019	4,211,400	38,200	0.92%
2020	4,243,959	32,559	0.77%
2021	4,263,581	19,622	0.46%
2022	4,281,851	18,270	0.43%
2023	4,296,800	14,949	0.35%
2024	4,316,700	19,900	0.46%
2025	4,342,800	26,100	0.60%
2026	4,371,800	29,000	0.67%
2027	4,402,700	30,900	0.71%
2028	4,434,800	32,100	0.73%
2029	4,468,800	34,000	0.77%
2030	4,503,900	35,100	0.79%
2031	4,539,200	35,300	0.78%
2032	4,574,600	35,400	0.78%

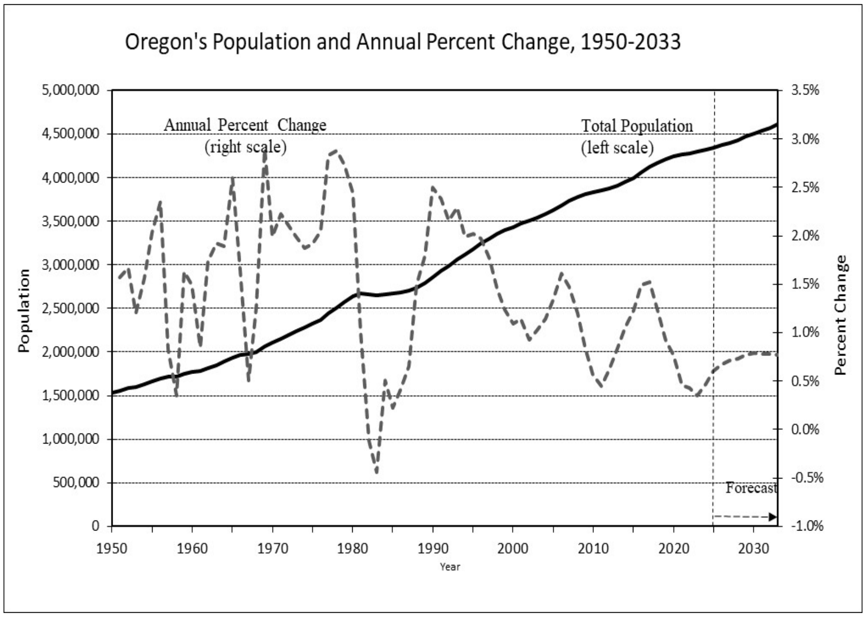


Table C.4 Children: Ages 0-4 / Table C.5 School Age Population: Ages 5-17 / Table C.6 Young Adult Population: Ages 18-24

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	235,911	-2,532	-1.06%	629,794	-1,337	-0.21%	360,835	982	0.27%
2012	232,406	-3,506	-1.49%	631,284	1,489	0.24%	362,832	1,997	0.55%
2013	229,470	-2,936	-1.26%	633,903	2,619	0.41%	366,162	3,330	0.92%
2014	228,491	-979	-0.43%	636,663	2,760	0.44%	368,698	2,535	0.69%
2015	228,530	38	0.02%	639,405	2,741	0.43%	370,335	1,638	0.44%
2016	229,939	1,409	0.62%	642,777	3,373	0.53%	371,121	786	0.21%
2017	230,713	774	0.34%	646,608	3,831	0.60%	373,452	2,331	0.63%
2018	228,576	-2,137	-0.93%	647,996	1,387	0.21%	375,357	1,905	0.51%
2019	224,371	-4,206	-1.84%	649,539	1,543	0.24%	374,840	-517	-0.14%
2020	218,996	-5,374	-2.40%	651,951	2,412	0.37%	372,617	-2,222	-0.59%
2021	212,186	-6,810	-3.11%	652,057	106	0.02%	371,866	-751	-0.20%
2022	207,973	-4,214	-1.99%	649,895	-2,162	-0.33%	373,075	1,209	0.33%
2023	204,900	-3,073	-1.48%	645,416	-4,478	-0.69%	373,248	173	0.05%
2024	203,392	-1,508	-0.74%	640,050	-5,367	-0.83%	372,813	-435	-0.12%
2025	203,987	595	0.29%	632,545	-7,505	-1.17%	373,021	208	0.06%
2026	206,399	2,412	1.18%	623,414	-9,131	-1.44%	375,148	2,127	0.57%
2027	208,494	2,095	1.02%	615,695	-7,719	-1.24%	379,560	4,412	1.18%
2028	211,002	2,508	1.20%	608,826	-6,869	-1.12%	384,140	4,580	1.21%
2029	213,573	2,571	1.22%	603,315	-5,511	-0.91%	387,284	3,144	0.82%
2030	216,352	2,779	1.30%	598,619	-4,697	-0.78%	389,634	2,350	0.61%
2031	218,958	2,607	1.20%	594,584	-4,035	-0.67%	390,829	1,196	0.31%
2032	221,428	2,469	1.13%	590,977	-3,607	-0.61%	390,243	-586	-0.15%

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 (July 1)	C.7 Population	C.7 % Change from previous decade/yr. Number	C.7 Percent	C.8 Population	C.8 % Change from previous decade/yr. Number	C.8 Percent	C.9 Population	C.9 % Change from previous decade/yr. Number	C.9 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	651,180	-2,178	-0.33%	1,027,906	2,120	0.21%	1,055,385	5,444	0.52%
2012	652,390	1,211	0.19%	1,032,603	4,697	0.46%	1,049,595	-5,790	-0.55%
2013	657,293	4,903	0.75%	1,040,709	8,106	0.78%	1,045,648	-3,947	-0.38%
2014	664,759	7,466	1.14%	1,051,331	10,622	1.02%	1,047,081	1,433	0.14%
2015	673,701	8,941	1.35%	1,063,996	12,664	1.20%	1,051,826	4,745	0.45%
2016	685,321	11,621	1.72%	1,083,602	19,607	1.84%	1,058,830	7,003	0.67%
2017	697,303	11,981	1.75%	1,107,682	24,080	2.22%	1,060,299	1,469	0.14%
2018	705,507	8,204	1.18%	1,129,825	22,143	2.00%	1,056,891	-3,407	-0.32%
2019	711,574	6,068	0.86%	1,147,437	17,612	1.56%	1,050,482	-6,409	-0.61%
2020	714,828	3,253	0.46%	1,163,188	15,750	1.37%	1,045,927	-4,555	-0.43%
2021	716,157	1,330	0.19%	1,171,112	7,924	0.68%	1,040,290	-5,637	-0.54%
2022	718,958	2,800	0.39%	1,178,073	6,961	0.59%	1,035,887	-4,402	-0.42%
2023	720,771	1,813	0.25%	1,182,567	4,494	0.38%	1,033,094	-2,793	-0.27%
2024	722,937	2,166	0.30%	1,188,477	5,909	0.50%	1,034,123	1,029	0.10%
2025	725,404	2,467	0.34%	1,195,479	7,002	0.59%	1,039,169	5,047	0.49%
2026	728,755	3,351	0.46%	1,202,397	6,918	0.58%	1,045,849	6,680	0.64%
2027	733,025	4,270	0.59%	1,208,029	5,632	0.47%	1,053,851	8,002	0.77%
2028	737,222	4,197	0.57%	1,213,382	5,354	0.44%	1,063,441	9,590	0.91%
2029	740,528	3,306	0.45%	1,219,324	5,942	0.49%	1,075,556	12,115	1.14%
2030	742,361	1,833	0.25%	1,224,345	5,021	0.41%	1,090,895	15,339	1.43%
2031	744,005	1,644	0.22%	1,231,163	6,818	0.56%	1,107,476	16,580	1.52%
2032	745,890	1,885	0.25%	1,240,717	9,554	0.78%	1,124,496	17,020	1.54%

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	544,668	2.35%	300,679	3.77%	164,699	0.28%	79,290	1.45%
2012	569,480	4.56%	323,020	7.43%	166,250	0.94%	80,210	1.16%
2013	595,007	4.48%	344,941	6.79%	169,092	1.71%	80,974	0.95%
2014	619,735	4.16%	364,915	5.79%	173,464	2.59%	81,356	0.47%
2015	646,309	4.29%	386,254	5.85%	178,545	2.93%	81,510	0.19%
2016	673,830	4.26%	406,961	5.36%	184,772	3.49%	82,098	0.72%
2017	703,246	4.37%	428,081	5.19%	192,909	4.40%	82,256	0.19%
2018	734,554	4.45%	447,292	4.49%	204,711	6.12%	82,552	0.36%
2019	764,731	4.11%	465,467	4.06%	216,593	5.80%	82,671	0.14%
2020	791,279	3.47%	482,160	3.59%	225,750	4.23%	83,370	0.84%
2021	816,070	3.13%	494,859	2.63%	237,495	5.20%	83,715	0.41%
2022	836,947	2.56%	500,847	1.21%	252,825	6.45%	83,275	-0.53%
2023	857,574	2.46%	503,474	0.52%	270,137	6.85%	83,962	0.83%
2024	877,845	2.36%	505,887	0.48%	286,578	6.09%	85,380	1.69%
2025	898,599	2.36%	508,392	0.50%	302,658	5.61%	87,549	2.54%
2026	918,593	2.23%	509,888	0.29%	318,190	5.13%	90,516	3.39%
2027	937,072	2.01%	509,297	-0.12%	333,154	4.70%	94,621	4.54%
2028	954,009	1.81%	506,721	-0.51%	347,471	4.30%	99,816	5.49%
2029	969,747	1.65%	502,995	-0.74%	361,372	4.00%	105,380	5.57%
2030	984,056	1.48%	498,347	-0.92%	374,994	3.77%	110,715	5.06%
2031	996,190	1.23%	492,762	-1.12%	386,204	2.99%	117,225	5.88%
2032	1,006,739	1.06%	486,793	-1.21%	393,391	1.86%	126,555	7.96%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 1404

December 29, 2023

Collective Bargaining Agreement

A vested interest in a successful future.

Effective: December 1, 2019 — May 31, 2024

2019 Collective Bargaining Agreement
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COLLECTIVE BARGAINING AGREEMENT

THIS COLLECTIVE BARGAINING AGREEMENT, hereinafter called “Agreement,” is entered into on December 1, 2019, 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
- Champion 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 to 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 continues to value input from our employees and the Union, which we believe contributes to productivity, satisfaction, engagement, and success.

1.3.1 The Union and the Company agree to work collaboratively on those items that are mandatory subjects under the law and on those items identified by the Company for Union involvement which the law would allow an Employer to change unilaterally.

1.3.2 The Company, Union and employee involvement may include, as examples:

- Representation through Union Representatives, Stewards, Chief Stewards, and Union approved Subject Matter Experts,
- Feedback on proposals, and
- Participation in, and use of, Issue Resolution process and the Labor/Management Committee.

1.3.3 The Company will, not later than the first quarter of each year meet with the 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 regular 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 November 30, 2018. 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.

1.4.3 The Company agrees to meet with the Union if it is considering laying off bargaining unit employees for any reason such as new technologies, new processes, redesign, elimination or sale of a business line, regulatory or legislative changes, or other factors outside of the Company's control.

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

2.1.1.1 This Agreement applies to and covers individuals who are employed in the jobs shown in the Job Titles by Group list of this Agreement as to areas and properties now served or owned by the Company. The terms of this Agreement do not extend to any NW Natural affiliate.

2.1.1.2 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, a task, or a job.

2.1.1.3 The Union and the Company agree to a standard process by which new jobs will be evaluated for inclusion in the bargaining unit.

2.1.1.3.1 This process applies to newly created jobs that do not exist at the Company as of December 1, 2019. This does not apply to the creation of additional numbers of existing jobs (or positions).

When the Company determines there is a need to add new jobs, it will consider the definitions described in the National Labor Relations Act (NLRA) found on the website www.nlrb.gov.

2.1.1.3.2 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., Engineers, 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. Other types of confidentiality might also be identified.

2.1.1.3.3 The Company will meet with the Union to review its analysis of the new jobs and to obtain the Union's input.

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 NW Natural whose job is within the bargaining unit as defined in Section 2.1.1 to this Article.

2.1.2.2 **Regular Employee**

A regular employee is an employee who is employed by NW Natural to work on a full or part-time basis.

2.1.2.2.1 A Full-Time regular employee is a regular employee who is employed by NW Natural to work an average of forty (40) or more hours per work week.

2.1.2.2.2 A Part-Time regular employee is a regular employee who is employed by NW Natural to fill a continuing work requirement that averages less than forty (40) hours per work week.

2.1.2.2.3 A Job-Share employee is a part-time regular employee who is employed by NW Natural to share the responsibilities of one (1) full-time position with one (1) other job-share employee.

2.1.2.2.3.1 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.

2.1.2.2.3.2 Both job-share employees must meet the bidding and performance qualifications for the shared position.

2.1.2.2.3.3 Work schedules will be agreed to between the job-share employees and will be subject to approval by the workgroup Supervisor.

2.1.2.2.3.4 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 his or her first year of employment (three hundred and sixty-five [365] calendar days) with NW Natural. Probationary employees who are regular employees retain all rights and benefits of regular employees under the Collective Bargaining Agreement; except as limited in Article 4.3.2 and Article 20.1 within this Agreement.

Probationary employees who are term employees retain only the rights and benefits provided to term employees.

2.1.2.3.1 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 his or her Term Employment Agreement. Term employees have only those benefits and rights expressly defined in their Term Employment Agreement.

2.1.2.4.1 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 use its best efforts to 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.

2.1.2.4.2 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.

2.1.2.4.3 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 ninety (90) 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 ninety (90) calendar days requires the mutual agreement of the Union and the Company. 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.

2.1.2.5.1 Any person covered by the Agreement as a temporary worker must obtain a working permit from the Union after each thirty (30) days worked.

2.1.3 **Recognition**

The Company recognizes the Union as the exclusive bargaining agent for the employees covered by this Agreement.

2.1.4 **Union Membership Requirements**

2.1.4.1 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.

2.1.4.2 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.

2.1.4.3 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 his or her 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 expressly 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.

Management's right to contract work out is further described in Article 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 Article 1.3 within this Agreement.

Section 2.3 No Strike, No Lockout

2.3.1 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.

2.3.2 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 Section 2.3.1 to 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

2.4.1 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.

2.4.2 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 Compliance with Laws Governing the Workplace

2.5.1 NW Natural is an Equal Employment Opportunity Employer. The Company prohibits discrimination, harassment or retaliation on the basis of race, age, color, religion, gender, national origin, disability, marital status, sexual orientation, gender identity, eligible veteran status, or any other status or characteristic protected by applicable law. The Union shares the Company’s commitment to maintaining a business environment free from discrimination, harassment or retaliation and supports business and workplace decisions promoting diversity.

2.5.1.1 The Company agrees not to discriminate against any member of the Union for his or her activity on behalf of or because of membership in the Union.

2.5.2 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.

2.5.3 The parties strive to comply with all applicable laws, rules and regulations governing the workplace, including but not limited to laws addressing discrimination in employment. To the extent such provisions include exceptions applicable to parties in a collectively bargained relationship, this provision does not address or waive the application of such exceptions.

Section 2.6 Modifications and Agreements

2.6.1 In the past, the Union and the Company have reserved 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. The Union and the Company continue to reserve this right during this Agreement. Amendments to this Agreement are made by a Memorandum of Agreement (MOA), must be in writing, agreed to, and signed by both parties.

2.6.1.1 Additionally, during the life of this Agreement, memorandums may be made, but the language described above does not have the intention of opening the entire Collective Bargaining Agreement for negotiations.

2.6.2 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.

2.6.3 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 in the Agreement or related terms and conditions of employment of covered Employees. 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.

2.6.4 Except as expressly noted otherwise, this Agreement supersedes all prior Joint Accords, Joint Accord Guidelines (JAGs), Interpretations, Agreements, and other understandings between the parties. To the extent the terms of this Agreement were to conflict with any Interpretation, Agreement, or other understandings between the parties, the terms of this Agreement control.

Section 2.7 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 Committee shall meet as mutually agreed and with an outlined agenda set by the LMC Co-Chairs.

The Committee may adopt bylaws governing the operations of meetings and the range of issues to be discussed. Decisions will be made by consensus.

The Committee shall consider only those contract issues which are mutually agreed upon or otherwise designated in the contract or the bylaws of the Committee.

ARTICLE 3
SENIORITY

Section 3.1 Company Seniority

3.1.1 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.

3.1.2 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 Employee Seniority

3.4.1 Term employees do not establish or accumulate any seniority while in term employment. For those term employees who are subsequently hired as regular employees with no break in service refer to Section 3.4.2 and Section 3.4.3 to this Article.

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 employee.

3.4.3 Company seniority is established on the date of hire as a term 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 work days 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 terminates 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, with the exception of an LTSA in the same job or Line of Progression as 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) continue to earn seniority in their regular job, and in accordance with Article 4.5.1 to this Agreement.

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 Defining the Work, Positions and Job Descriptions

Job and position descriptions will be maintained for all jobs and positions in the bargaining unit. The Company has the right to change and create job and position descriptions.

Section 4.3 Postings and Consideration of Bids

4.3.1 When a position posting 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 position 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.

4.3.2.1 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.

4.3.3 The Union and the Company 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.

4.3.4 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

4.4.1 Seniority and qualifications will be considerations in awarding a posted position. With agreement between the Union and the Company, 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.

4.4.2 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.

4.4.2.1 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.

4.4.2.2 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 (14^{th}) calendar day from the employee’s acceptance of the award.

4.4.3 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).

4.4.3.1 **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.

4.4.3.2 **Line of Progression (LoP) Jobs**

A LoP is a sequence of specifically related positions that require successively higher skills to advance sequentially to the next higher position. The following are the currently recognized LoPs:

- Construction
- Customer Field Service

LoP positions may be added to, 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.

4.4.3.3 **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/positions 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
- Semi & Crane

4.4.3.4 **Jobs Involving Progression without Bidding**

Employees will progress based on meeting the qualifications and performance standards for the higher-level position. Positions may be added, 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:

- Accounts Payable = Accounting 2 to 3
- Account Billing = Accounting 2 to 3
- Communications & Control Technician 1 to 2
- Customer Contact Center = Customer Service 2 to 3
- GIS = Graphics 1 to 2; 2 to 3
- Specialty Construction 1 to 2
- Storage plants = Gas Storage 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 and business need.

4.4.3.5 **Job Family**

A Job Family is a group of jobs that are related because of similar job content, skill requirements, and/or career paths.

4.4.3.6 **General Job Description Content**

Job descriptions shall include language pertaining to working down levels of the Job Family.

4.4.3.7 **General Task Bar**

A “general task bar” consists of one or more tasks that everyone in a Job Family at a higher level than the general task bar can be expected to perform with training as needed. Additional tasks could be introduced by the Company at various levels depending on business need. The General Task Bar tasks are maintained by the Company.

4.4.4 **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

4.5.1 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. 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 Union and the Company.

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.

4.5.2 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 his or her 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 (e.g., Construction 4) 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

4.9.1.1 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 Union and the Company.

The Chief Stewards will be notified by management no later than the start of any Short-Term Assignment expected to last longer than seven (7) calendar days.

4.9.1.2 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.

4.9.1.3 Employees will continue to accumulate Job or Line of Progression seniority in their regular position during such assignments.

4.9.1.4 An employee returning from an authorized 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 Union and the Company. All LTSAs are subject to the following:

4.9.2.1 An LTSA is not a replacement for a vacant regular position. Recurring LTSAs will be reviewed by the Union and the Company to determine whether there is a need for a regular position. The term “voluntary,” as used here, means that either the employee or the Company may end the LTSA at any time for any reason.

4.9.2.2 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.

4.9.2.3 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.

4.9.2.4 If there are no qualified bidders, the position will be temporarily assigned based on this Article.

4.9.3 **Assignment to Non-Bargaining Position**

An employee may be assigned to a non-bargaining position, either exempt or non-exempt; and in accordance with Section 4.5.1 to this Article. The Company’s non-bargaining unit processes apply with respect to the assignment; however, the employee will continue to retain Union membership status (including benefits) and pay Union dues. The Company will notify the Chief Stewards 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 five (5) following processes:

5.1.1 Failure to Qualify During Qualifying Period

5.1.2 Failure to Maintain Performance Qualifying Standards

5.1.3 Field Operations Testing Failure to Qualify

5.1.4 Arc Welding Procedure to Recertify

5.1.5 Oxy-Acetylene 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.

5.2.1.1 Employees may exercise their right to return per Article 4.5 within this Agreement.

5.2.1.2 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.

5.2.1.3 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 Article 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, which may include a loss of job skill(s) at any time.

For failure to qualify situations involving Operator Qualifications or welding, refer to the Field Operations Testing Failure to Qualify process within this Article, Arc Welding Procedure to Recertify within this Article, or the Oxy-Acetylene 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:

5.3.2.1.1 The changes that must occur for the employee to meet standards;

5.3.2.1.2 The time line 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. DAPs longer than one hundred and eighty (180) calendar days must be signed by the Manager and Union Representative.); and

5.3.2.1.3 Consequences if the employee does not meet the requirements of the DAP.

5.3.2.2 The employee may:

5.3.2.2.1 Unless restricted by a DAP or other disciplinary action, bid on any open positions (if any are available) for which they meet bidding qualifications; and/or

5.3.2.2.2 Apply for a position waiver in accordance with Article 4.6 within this Agreement.

5.3.3 If the employee does not successfully complete the DAP:

5.3.3.1 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

5.3.3.2 The employee will use Paid Time Off (PTO) until PTO is exhausted; then the employee will be placed on leave without pay; and

5.3.3.3 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:

5.4.1.1.1 The consequences after each failure of a required test;

5.4.1.1.2 The criteria that must be met before an employee can attempt to retest;

5.4.1.1.3 The time intervals between testing opportunities; and

5.4.1.1.4 The resources available to the employee.

5.4.1.2 This process does not apply to:

5.4.1.2.1 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

5.4.1.2.2 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

5.4.1.2.3 Weld testing (Refer to the Oxy-Acetylene Welding Procedure to Recertify or the Arc 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.

5.4.1.4 This process does not apply to or override any department-level guidelines or processes.

5.4.1.5 It is the employee's responsibility to actively participate in this process.

5.4.2 **Process**

At any point during this process, the regular employee has the option to do any of the following, if applicable:

5.4.2.1 Bid to an open position, if available, for which they meet bidding Qualifications unless otherwise specified in a DAP;

5.4.2.2 Apply for a Waiver per Article 4.6 within this Agreement, as available, or

5.4.2.3 Exercise their right to return to a former position per Article 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:

5.4.3.3.1 Employee may be afforded additional time to prepare (e.g., receive training or study) for retesting, as necessary.

5.4.3.3.2 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 **<u>Second Failure</u>**

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 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 **<u>Third Failure</u>**

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:

5.4.5.2.1 Following third failure of a required test for requalification (i.e., employee has previously passed testing and was "qualified"):

5.4.5.2.1.1 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.

5.4.5.2.1.2 Employee will use all accrued and banked PTO until PTO is exhausted; then employee will continue on leave without pay.

5.4.5.2.1.3 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.

5.4.5.2.2 Following third failure of a required test on a new task or content area introduced to an incumbent's position:

5.4.5.2.2.1 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.

5.4.5.2.2.2 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.

5.4.5.2.2.3 Employee will use all accrued and banked PTO until PTO is exhausted; then the employee will continue on leave without pay.

5.4.5.2.2.4 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.

5.4.5.2.2.5 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.

5.4.5.2.2.6 Employee will not be eligible for preferential bidding, redeployment, or bumping as a result of this process.

5.4.5.2.2.7 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 Arc Welding Procedure to Recertify

5.5.1 Application

This procedure applies to all regular employees who are required to maintain Arc Welding qualifications. This procedure covers failure on any of the following Arc Welding tests:

- Requalification Testing
- Probable Cause Testing

It is the employee's responsibility to actively participate in this process.

5.5.2 First Failure

5.5.2.1 Employee is immediately restricted from performing the task.

5.5.2.2 Use standard Documented Verbal Warning.

5.5.2.3 No days toward experienced rate, if at entry rate.

5.5.2.4 Minimum of eight (8) hours of formal, paid, documented training is provided.

5.5.2.5 Minimum time to retest is second (2^{nd}) 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

5.5.3.1 Restriction from performing the task continues.

5.5.3.2 Initiate "Failure to Maintain Performance Qualifying Standards" or "Failure to Qualify During Qualifying Period" process. Use standard DAP.

5.5.3.3 Employees at the experienced rate go back to Step 4 of the In-Training rate.

5.5.3.4 Minimum of eight (8) hours of formal, paid, documented training is provided.

5.5.3.5 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**

5.5.4.1 Initiate "Failure to Maintain Performance Qualifying Standards" or "Failure to Qualify During Qualifying Period" processes within this Article.

5.5.4.2 Loss of position.

5.5.4.3 One (1) year minimum from loss of position to bid on open Arc Welding position.

Section 5.6 Oxy-Acetylene Welding Procedure to Recertify

5.6.1 **Application**

This procedure applies to all regular employees who are required to maintain an Oxy-Acetylene Weld qualification, including:

- Employees who hold a Construction 1 position, who hold oxy-acetylene weld qualifications;
- Employees who hold a Construction 2 position;
- Employees who hold a Construction 3 position for a minimum of one (1) year from position award; and
- Employees, as determined by business need.

Employees who voluntarily elect to maintain their Oxy-Acetylene Welding qualification and subsequently fail a test may opt out of the qualification process, and are not subject to this Article.

This procedure covers failure on any of the following Oxy-Acetylene Weld tests:

- Requalification Testing
- Random Testing

- Probable Cause Testing

Note: If this is third "first failure" in four consecutive tests, go directly to "second failure."

It is the employee's responsibility to actively participate in this process.

5.6.2 **First Failure**

5.6.2.1 Employee is immediately restricted from performing the task.

5.6.2.2 Use standard Oxy-Acetylene Welding Documented Verbal Warning.

5.6.2.3 No days toward rate retention.

5.6.2.4 An employee (Construction 2 or higher) at experienced rate will go back to entry rate in the same grade.

5.6.2.5 An employee (Construction 2 or higher) at entry rate will go back to experienced rate in the next lower grade in the Line of Progression.

5.6.2.6 Construction 1 or 2 cannot work up in the Line of Progression.

5.6.2.7 Construction 3 or 4 at experienced rate can continue to crew lead.

5.6.2.8 Two (2) hours of formal, paid, documented training is provided.

5.6.2.9 Minimum time to retest is fourteen (14) calendar days (can be waived for the first time ever failure since January 21, 2005). Maximum time to retest is thirty (30) calendar days. Any exceptions to minimum or maximum time to retest must be approved by Management.

5.6.3 **Second Failure**

5.6.3.1 Restriction from performing the task continues.

5.6.3.2 Initiate "Failure to Maintain Performance Qualifying Standards" or "Failure to Qualify During Qualifying Period" process within this Article. Use standard Oxy-Acetylene Welding DAP.

5.6.3.3 Employees (Construction 2 or higher) will go back to experienced Construction 1 rate.

5.6.3.4 Construction 1 or 2 cannot work up in the Line of Progression.

5.6.3.5 Construction 3 and 4 at experienced pay rate can continue to crew lead and will be paid at entry Construction 3 or 4 rate when crew leading, as appropriate. When not crew leading, they will be paid at experienced Construction 1 pay rate.

5.6.3.6 Two (2) hours of formal, paid, documented training is provided.

5.6.3.7 Minimum time to retest is thirty (30) calendar days. Maximum time to retest is sixty (60) calendar days. Any exceptions to minimum or maximum time to retest must be approved by Management.

5.6.4 **Third Failure**

5.6.4.1 Initiate "Failure to Maintain Performance Qualifying Standards" or "Failure to Qualify During Qualifying Period" processes within this Article.

5.6.4.2 Loss of position (Sign position waiver in accordance with Article 4.6 within this Agreement).

5.6.4.3 Loss of rate retention and qualification.

5.6.4.4 Must bid to open Construction 1 position (or other position) where available.

5.6.4.5 If no Construction 1 position is available or employee chooses not to bid, employee may be assigned to varying locations based on business need.

5.6.4.6 Two (2) hours of formal, paid, documented training is provided.

5.6.4.7 One (1) year minimum from loss of position to retest. The opportunity to retest will require Management approval and will be based on business need.

5.6.4.8 If employee successfully retests after one (1) year, employee can start working up as Construction 2, as needed, and can bid on Construction 2 position where available.

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 **<u>General Definitions and Rules</u>**

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: A regular full-time schedule will typically be five (5) workdays of eight (8) hours duration; including two (2) consecutive days off in most instances. Alternate schedules 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.

6.1.1.3 Workday: Each employee's workday begins at the start of his or her shift and continues for twenty-four (24) hours or until the beginning of his or her 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 Shift	06:00 p.m. – 5:59 a.m.

6.1.1.6 The Company and the Union agree that there shall be a minimum of eight (8) hour rest period between scheduled shifts.

6.1.1.7 An employee who reports for work on a regularly scheduled workday and is then sent home for lack of work shall be paid for his or her scheduled shift at the rate such employee would have received.

6.1.1.8 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, holidays, floating holidays, and PTO used.

6.1.1.9 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.

6.1.2 **<u>Flexible Schedules/Work Arrangements</u>**

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 his or her shift, and/or make up lost time in his or her 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 <u>Telework</u>. An employee may request to telework, which establishes a reporting location off Company property, typically the employee's residence. An employee who is teleworking must log in to the appropriate Company software systems and be ready to work at the employee's scheduled start time. Under this method, the telework location is not considered a fixed official work location/station. Not every telework arrangement option will be available for every work group, position, or employee, and approval of teleworking will be at the Manager's discretion. Company policies and department guidelines will define specific and/or additional requirements for teleworking.

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 to be afforded a rest under Section 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.

- 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.

- If the work abuts the start of the employee's next shift and there is less than twelve (12) hours notification prior to start of the next shift.

- If the completion of a Call-In is two (2) hours or less before the start of the regularly scheduled shift, the Call-In will be considered to abut the shift. The employee will continue to work until the start of the regularly scheduled shift and hours worked will be paid at the Call-In rate. Once the regularly scheduled shift starts, the shift will be considered an Unplanned Shift Change and ending time will be adjusted accordingly. Pay will be at the Unplanned Shift Change pay rate for the remainder of hours worked.

- When the work alters the original shift start time with less than twelve (12) hours notification prior to the start of the new shift.

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 under the following circumstances:

6.1.3.4.1 An employee already at the reporting location up to one (1) hour before the employee's scheduled shift may be assigned to an earlier start time. The shift for that employee will be moved to one (1) hour earlier from the start of the employee's regular shift and such change is not considered an Unplanned Shift Change or a Call-In. Employees may be required to work through to the end of their original shift and may be required to work additional overtime.

6.1.3.4.2 An employee in the process of commuting in an assigned Company vehicle to or from the reporting location may be assigned an extended shift and such change is not considered an Unplanned Shift Change or Call-In. If commuting away from the reporting location, the time from the end of the shift to the time of the request is considered time worked.

6.1.3.4.3 Short duration work on a scheduled day off will be paid at a minimum of two (2) hours at the appropriate overtime rate.

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 Section 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.

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 Article 11.6.2 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 within the same workday 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 do not abut a regularly scheduled shift, hours worked on the Call-In will be paid at the Call-In pay rate.

6.1.5.3 If the completion of a Call-In is two (2) hours or less before the start of the regularly scheduled shift, the Call-In will be considered to abut the shift. The employee will continue to work until the start of the regularly scheduled shift and hours worked will be paid at the Call-In rate. Once the regularly scheduled shift starts, the shift will be considered an Unplanned Shift Change and the ending time will be adjusted accordingly. Pay will be at the Unplanned Shift Change pay rate for the remainder of hours worked.

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 commuting in an assigned Company vehicle per Section 6.1.3.4.2 to this Article, except for an Employee on an On-Call Assignment per Section 6.1.4.2 to this Article;
- An employee is on site within one (1) hour of start of shift and requested to start his or her shift early per Section 6.1.3.4.1 to this Article;
- 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.

6.1.5.7 For immediate response (unplanned), paid time for the Call-In begins when the employee is in transit to the reporting location. In transit status will be established by telephonic or electronic notification to the Company that the employee is traveling to the reporting location.

6.1.5.8 For non-immediate response (planned), paid time for the Call-in begins when the employee arrives at the reporting location, unless an employee is assigned a Company vehicle during this time period, in which case time starts when the employee is in transit. In transit status will be established by telephonic or electronic notification to the Company that the employee is traveling to the reporting location.

6.1.5.9 Call-Ins that do not abut 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 his or her 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 **Time Excused Due to Extended Work**

6.1.6.1 The employee will be afforded the opportunity of taking eight (8) hours of non-worked time and returning to complete the remainder of the scheduled shift when within the twelve (12) hour period before the start of the regularly scheduled shift the employee works:

- A total of six (6) or more hours duration (consecutive or aggregate); or
- Three (3) or more Call-Ins and the employee has less than eight (8) hours of non-worked time immediately prior to the start of the employee's next scheduled shift.

6.1.6.2 **Time Not Excused Due to Extended Work.** The employee will not be afforded the opportunity of taking eight (8) hours of non-worked time:

- If employee's start time was moved to an earlier time due to an Unplanned Shift Change, employee is not eligible for a paid rest period.
- If employee's Call-In ends with eight (8) hours or more before the start of the scheduled shift.

6.1.6.3 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

Time excused or worked for the remainder of the regular shift shall be paid at the straight-time rate and shall be counted as time worked for the purpose of calculating overtime.

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.

6.2.2.1 **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 <u>Company vehicle or other transportation is provided</u>.

6.2.3 **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 his or her scheduled start time. Additionally, the employee must be at the employee's reporting location at the end of his or her shift, unless otherwise directed. Under this method, the Company-based location is not considered the fixed official work location/station.

6.2.4 **Travel When Jobsite Reporting**

For jobsite reporting, the region is defined as the geographic area within a fifty (50) 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 practices, which include providing appropriate personnel and equipment to meet health and safety obligations. Changes to protective gear allowances provided by the Company shall be in accordance with Article 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 and/or work locations.

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. Prior to work redesign, the Company will involve the Union to discuss the impact of the redesign and identify issues that must be resolved prior to 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 the Employer 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 work days) from point of notification to make his/her 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 Article 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 Article 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 Union and the Company 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 Union and the Company will meet to determine the method by which they may meet the challenges of the unforeseen event(s). Prior to the Company initiating any forced reduction in available work hours, the Union and the Company will endeavor to use as many voluntary means they deem appropriate and which 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 Section 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),
- Redeployment resulting from Failure to Qualify During Qualifying Period (refer to the Redeployment Process in accordance with Article 5 within this Agreement), and
- Company-declared lack of work.

7.5.1 **General Bumping Principles**

An employee:

7.5.1.1 Cannot bump an employee who has more Company seniority.

7.5.1.2 Cannot bump into a higher graded job.

7.5.1.3 Cannot bump into a job for which bidding qualifications are not met as defined in Article 4 within this Agreement.

7.5.1.4 Cannot bump into a previously declined job at any location due to Work Redesign.

7.5.1.5 Cannot bump into a previously declined job at that specific location due to assignment in redeployment.

7.5.1.6 Can decline to bump into positions that change their employment status (FT, PT>20, PT<20). In such cases, the Union and the Company 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.

7.5.1.7 Can bump into a different employment status (FT, PT>20, PT<20), but must elect to change employment status accordingly.

Section 7.6 Layoff

7.6.1 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 Article 1.4 within this Agreement.

7.6.2 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 is responsible for maintaining an appraisal system to measure a regular employee's level of performance and provide feedback. Performance qualifying standards will be established by Management with appropriate Union involvement. The results of the appraisal process will determine if performance requirements have been or continue to be satisfied for:

- Probationary period,
- Qualifying period,
- Incumbent's ongoing performance appraisal, at least annually, and
- Advancement to the Experienced pay rate for the position (see Article 11.1.3 within this Agreement)

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.

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 should ask Supervisors for a Performance Development Plan in order to ensure that they can meet the standards.

8.2.3 **Relationship to the Disciplinary Process**

The Performance Development Plan **cannot** be construed as the first step in the disciplinary process. All disciplinary action must be conducted as described in Article 20 within this Agreement. Each Supervisor has the right and responsibility to determine a course of action for a regular employee not meeting an essential function standard. If, in the view of the Supervisor, the failure of the regular employee to meet standards is of significant consequence and needs immediate action (Examples: Creates an untenable working environment, severely affects working processes, involves a Company policy, safety or Code of Ethics violation, etc.), the Supervisor may choose to use a disciplinary process for the regular employee; in accordance with Article 20 of this Agreement; rather than work through a Performance Development Plan. It is not required that the Supervisor first use the Performance Development Plan when working with a regular employee to improve performance.

8.2.4 **Relationship to Pay**

8.2.4.1 Regular employees are entitled to pay progression if they are not on an active Performance Development Plan and they meet the requirements defined under Article 11.1.3 within this Agreement.

8.2.4.2 The new pay will commence with the completion of the Performance Development Plan and satisfactory Performance Appraisal.

8.2.4.3 Successful completion of the Performance Development Plan does not change anniversary dates for pay progression timelines.

8.2.5 **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 8.3 Statement of Expectations

8.3.1 A Statement of Expectations is a non-disciplinary coaching tool a Manager or Supervisor may use to outline and help an employee understand the Manager's or Supervisor's expectations of the employee.

8.3.2 At times a Manager or 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 for no more than four (4) years, unless otherwise agreed to between the Company and Union.

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 Union and the Company 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), or relevant leave laws.
    - Discipline or retaliation based on an employee's use of protected leave is not permitted. 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 supervisory 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 might 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 Protected leave is applied prior to absences being 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.

9.3.1.4 **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 his or her 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.
- 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. Employees may be required to substantiate the reason(s) for their absence in order for the time away to be considered approved.

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 Section 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 patterns of unapproved absence do not replace supervisory and management judgment when reviewing employees' attendance and any mitigating circumstances involved. 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 to be a No Call/No Show when the employee fails to report for work without contacting his or her 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

10.2.1 **Step One**

Prior to filing a formal issue, the employee and the Supervisor should first meet informally to discuss and attempt to resolve the issue(s).

10.2.2 **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

10.3.1 **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.

10.3.1.1 An Issue Resolution Committee is organized on an ad hoc 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.

10.3.1.2 The Committee shall be comprised of two (2) bargaining unit members appointed by the Union and two (2) management employees appointed by the Company. These Committee members shall be selected from the list of Labor/Management Committee members by the LMC Co-Chairs.

10.3.1.3 For any single topic the Committee may meet for up to three (3) hours total.

10.3.2 The Committee shall consider only those contract issues which are mutually agreed upon or otherwise designated in the Agreement or bylaws of the Committee.

10.3.3 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.

10.3.4 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.

10.3.5 All timelines above may be extended by mutual agreement of the Union and the Company. 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.

10.3.6 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

<u>Section 11.1 Compensation</u>

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) work days or more, the Company may, at its sole discretion, extend the two hundred and sixty (260) day timeframe by the same number of work days missed.

- The qualifying period for the position.

- Receive satisfactory performance evaluation(s).

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

- Pipe Fuser (Construction 1)

- 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 Section 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.

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.

11.2.1 An employee’s rate of pay shall be adjusted depending upon the employee’s current rate of pay as follows

- Effective December 1, 2019 all bargaining unit employees shall first be moved to the base rate for their job group in accordance with “Schedule A – Job Titles by Pay Group” to this Agreement. If a bargaining unit employee is currently paid above their job group, they will be held at their current pay rate.

- Effective December 1, 2019 all bargaining unit employees shall receive an increase, to their base rate of one and one-half percent (1.5%) and as set forth in "Schedule B – Wage Scale" within this Agreement. If a bargaining unit employee is paid above the base rate plus the one and one-half percent (1.5%) they will be held at their current rate of pay except as specified in Section 11.2.3 and Section 11.4 within this Article.

- Effective June 1, 2020 all bargaining unit employees shall receive an increase of two percent (2%) and as set forth in "Schedule B – Wage Scale" within this Agreement. If a bargaining unit employee is paid above the base rate plus two percent (2%) they will be held at their current rate of pay except as specified in Section 11.2.3 and Section 11.4 within this Article.

- Effective June 1, 2021 all bargaining unit employees shall receive an increase to their current wage rate of three and a half percent (3.5%) and as set forth in "Schedule B – Wage Scale" within this Agreement. If a bargaining unit employee is paid above the base rate plus the three and one-half percent (3.5%) they will be held at their current rate of pay except as specified in Sections 11.2.3 and Section 11.4 within this Article.

- Effective June 1, 2022 all bargaining unit employees shall receive an increase to their current wage rate of three and a half percent (3.5%) and as set forth in "Schedule B – Wage Scale" within this Agreement. If a bargaining unit employee is paid above the base rate plus three and one-half percent (3.5%) they will be held at their current rate of pay except as specified in Section 11.2.3 and Section 11.4 within this Article.

- Effective June 1, 2023 all bargaining unit employees shall receive an increase to their current wage rate of three and a half percent (3.5%) and as set forth in "Schedule B – Wage Scale" within this Agreement. If bargaining unit employee is paid above the base rate plus three and one-half percent (3.5%) they will be held at their current rate of pay except as specified in Section 11.2.3 and Section 11.4 within this Article.

- Employees in positions covered by pay guarantees in Article 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**
December 1, 2019	1.5 %
June 1, 2020	2.0 %
June 1, 2021	3.5 %
June 1, 2022	3.5 %
June 1, 2023	3.5 %

11.2.3 Employees whose current rate of pay remains above the Wage Scale prior to the Scheduled Annual Increase shall receive increases when the:

- Wage rate remains more than three percent (3%) above that contained in the Wage Scale prior to the Scheduled Annual Increase. The Employee shall receive a one percent (1%) increase in the Employee's current wage rate plus a lump sum* equivalent to the difference between the one percent (1%) wage increase and the Scheduled Annual Increase.

- Wage rate remains less than three percent (3%) above that contained in the Wage Scale prior to the Scheduled Annual Increase. The Employee shall receive that percentage amount of the Scheduled Annual Increase necessary added to the Employee's current wage rate to achieve the rate of pay equal to that amount specified in the Wage Scale. The difference between the percentage amount received and the Scheduled Annual increase, shall be in a lump sum* amount.

*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) month period prior to the increase, and shall be paid on the employee's second pay check in the month the increase was issued.

Section 11.3 Job Compensation and Approval Process

11.3.1 **Human Resources Professional Review Request**

When a new bargaining unit job is established or if there is a substantive change 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. This Section does not prevent the process described in Section 11.3.2 within this Article.

11.3.2 **Department/Employee Review Request**

The LMC 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. The LMC LT reserves the right to bring in subject matter experts to inform their decisions; by mutual agreement between the Union and the Company.

11.3.3 Changes and additions of a significant nature to “Position Specific Essential Functions” and/or requests for reevaluation of placement in a job family; and level; will follow these steps:

(1) Employee(s) shall submit the Job Compensation Evaluation to their department Manager for consideration. The employee's department shall so notify the employee(s) in writing within ten (10) working days or as practicable; if they agree or disagree with the request.

a. Management will submit the “Request to Existing Bargaining Unit Job/Position Description or Placement” form to Human Resources.

b. Upon notice for the Job Compensation Evaluation, the LMC Co-Chairs will notify the employee and the Manager within twenty (20) business days or as practicable as to whether the position warrants market review.

(2) Human Resources will review and create a revised job description as appropriate; within thirty (30) days, or as practicable, of receipt on the Job Compensation Evaluation request.

a. Human Resources will present results, findings, and recommendations to the LMC LT.

(3) 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.

<u>Section 11.4 Honored Pay Rate Employees</u>

11.4.1 Effective December 1, 2019 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 Key Goals

11.5.1 For plan year 2019, the Key Goals opportunity between zero (0) and three percent (3%) will be based upon Key Goals measures as determined by the Key Goals Committee. Any opportunity for awards above three percent (3%) will be determined by profits above the budgeted earnings per share target for the year as determined by the Company.

11.5.2 The maximum annual 2019 Key Goals award will be no greater than seven percent (7%) of eligible earnings and is only attainable if the Company has an exceptional year. The Key Goals Program contains definitions of eligible earnings and employee eligibility.

11.5.3 After the 2019 Key Goals award there will be no Key Goals program for the life of this Agreement.

Section 11.6 Premium Pay Rates

11.6.1 **Overtime Pay**

11.6.1.1 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 Section 11.6.1.2 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.

11.6.1.2 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 Article 6.1.5 within this Agreement.

- All hours worked on holidays as provided for in Article 14.5 within this Agreement.

11.6.2 **Pay for On-Call Assignment**

- Fifty-eight dollars ($58.00) for each On-Call Assignment on an employee's regularly scheduled workday,

- Eighty-seven dollars ($87.00) for each On-Call Assignment on an employee's scheduled days off, and

- One Hundred Thirteen dollars ($113.00) for each On-Call Assignment that begins on an actual (not an Observed) holiday as defined in Article 14.1 within this Agreement.

Effective June 1, 2020 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 Section 11.2.2 to this Article.

11.6.3 **Recognition for On-Call Assignments**

11.6.3.1 Employees who have ninety (90) to one hundred fourteen (114) 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.

11.6.3.2 Employees who have one hundred fifteen (115) 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.

11.6.3.3 Call-In pay is in addition to On-Call Assignment pay as provided in Article 6.1.5 within this Agreement. On-Call Assignment periods are not to be counted as time worked for the purpose of calculating overtime.

11.6.4 **Schedule Based Premium Pay**

11.6.4.1 **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 two dollars and seventy-five cents ($2.75) per hour.

11.6.4.2 **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 one dollar and fifty cents ($1.50) per hour.

11.6.5 **Skill Based Premium Pay**

11.6.5.1 **HAZWOPER Work Pay.** Employees trained to perform duties identified by the Company as HAZWOPER (Hazardous Waste Operations and Emergency Response) will receive an additional two dollars and fifty cents ($2.50) per hour when performing such duties.

11.6.5.2 **Bilingual Pay.** All hours worked by an employee who is qualified for and participating in an approved Bilingual Program shall be compensated an additional one dollar ($1.00) per hour.

11.6.5.3 **High Angle Work Pay.** Employees identified, trained and certified in high angle work and rescue skills shall be paid an additional two dollars and fifty cents ($2.50) 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.

ARTICLE 12
PAID TIME OFF (PTO)

Section 12.1 General

12.1.1 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.

12.1.2 **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:

- Include signatures of the department Manager and the Union Representative.

- Include date the guidelines were completed or reviewed.

- Be posted in such places as is normal.

- 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.

12.1.3 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.

12.1.4 Employees will be required to take a minimum number of PTO hours annually (Annual Minimum Usage) as described in Section 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.).

12.1.5. **Previously Approved PTO Scheduling When Awarded a Position**

Once a position has been awarded, the awarding group will attempt to accommodate the PTO requests that were previously approved, but it is still 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, but it is still subject to availability and returning Supervisor approval.

12.1.6 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.

12.1.7 **Annual Minimum PTO Usage Exceptions**

12.1.7.1 Employees are responsible to schedule and take annual minimum PTO within department guidelines.

12.1.7.2 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.

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
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 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 or term 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 his or her 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).

12.4.1 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.

12.4.2 All PTO buy back shall be in accordance with IRS rules and Company guidelines.

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 Article 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.

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 Regular employees who have completed the probationary period of employment with the Company 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 Article 12.5 within this Agreement.

ARTICLE 14
HOLIDAYS

Section 14.1 Holidays Defined

14.1.1 **Paid Holidays**

New Year's Day
Memorial Day
Independence Day
Labor 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 either be observed on another day or be paid at the employee's regular straight-time pay as determined by the Manager (Observed Holiday). 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).

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.

Examples of floating days typically requested by employees include:

Martin Luther King's Birthday
Presidents' Day
Veterans Day
Employee's Birthday

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 Section 14.2.2 within this Article.

Section 14.4 Additional Designated Holiday

14.4.1 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.

14.4.2 Scheduled additional designated holidays qualify as a holiday for pay.

Section 14.5 Holiday Allowance for Work on a Holiday

14.5.1 Employees who work during a holiday, 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 a holiday allowance of eight (8) hours pay or may select a day off mutually agreed to by the Supervisor and the employee.

14.5.2 Employees whose scheduled workday is on the actual date of the holiday (not the observed holiday) shall be paid at two (2) times the employee's regular rate and be granted either the eight (8) hours pay or an alternate day off, and will receive regular pay for working a scheduled workday on the observed holiday.

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 the days before or 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 day before or the day after the scheduled holiday(s) and the absence is unapproved, and in accordance with Article 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; i.e., it shall either be observed on another day off in lieu of or be paid at the employee's regular straight-time pay as determined by the Manager.

ARTICLE 15
DISABILITY

<u>Section 15.1 Non-Industrial Disability</u>

15.1.1 **Short-Term Disability (Non-Industrial)**

15.1.1.1 Short-Term Disability (STD) benefits are available to eligible regular employees. Regular employees are to use PTO to cover each absence for the same non-industrial illness or injury lasting up to four (4) consecutive or non-consecutive workdays in a consecutive fourteen (14) calendar day period.

15.1.1.2 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.

15.1.1.3 STD income replacement is based on a regular employee's Length of Service, as defined in Article 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%

15.1.1.4 STD benefits are provided to eligible regular employees for as long as they have an accepted disability claim as 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 a qualified healthcare provider's release to return to work when directed by the third-party STD Plan Administrator.

15.1.1.5 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.

15.1.1.6 For more details regarding STD, including eligibility requirements, refer to the STD Plan summary plan description or contact Human Resources.

15.1.2 **Long-Term Disability (Non-Industrial)**

15.1.2.1 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.

15.1.2.2 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.

15.1.2.3 A regular employee whose employment has ended as described in Section 15.1.2.2 to 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 must contact his or her 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 Section 15.1.1 and Section 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 him or her from returning to his or her current regular job, the Union and the Company 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 his or her pay administered as an Honored Pay Rate Employee subject to provisions in Article 11.4 within this Agreement.

15.4.4 A regular employee whose employment is ended per Section 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)

15.5.1 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 does not restart or extend this Consecutive Disability Period.

15.5.2 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 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 Article 2.5 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 Section 16.1.1.3 and Section 16.1.1.5 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 Union and the Company.

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, 2020 and for the term of the Agreement, eligible employees shall be responsible for twenty percent (20%) of the cost of the premium. However, if an eligible employee completes the annual health risk assessment and biometric screening prior to the open enrollment period for each year, the employee will only be responsible for fifteen percent (15%) of the total premium. In both cases, the Company will be responsible for the remaining portion of the premium.

16.1.1.4 **Health Risk Assessment and Biometric Screenings**

The Company will provide employees with (4) options for Biometric Screenings and Health Risk Assessments:

- Onsite screenings at the following Company resource centers: Albany, Mt. Scott, Salem, Appliance Center, One Pacific Square or HQ 250 Taylor, Sherwood, Clark County, Parkrose, Sunset and Eugene.

- A lab voucher and physician form (for assessment through healthcare provider).

- E-Screen
- Home Test Kits

16.1.1.5 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.

16.1.1.6 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 Section 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 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, under the Retirement Plan and **(ii)** enrolls in retiree coverage through the Welfare Trust Fund. A covered retiree may enroll his or her 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 is to make payments to the Welfare Trust Fund for retiree medical coverage end on May 31, 2024

16.2.1.1 Effective January 1, 2019, 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 his or her 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 is to make payments to the Welfare Trust Fund for retiree medical coverage end on May 31, 2024

16.2.2 Effective January 1, 2020, and for 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.

Retirees with Spouses or Partners Eligible for Company Paid Benefits

16.2.4 Effective January 1, 2015, 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 Section 16.1.3 to this Article.

16.2.5 **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.

ARTICLE 17
OTHER BENEFITS

Section 17.1 Meal Allowance

17.1.1 An employee shall be provided a meal allowance for:

- Working three (3) or more hours beyond the normal shift duration (minimum eight [8] hour shift), except while on per diem;
- Each four (4) hours of continuous overtime beyond the original three (3) hours;
- Unplanned Shift Change without at least three (3) hours advance notice to provide for a meal, unless the employee is already at the reporting location or in the process of commuting in an assigned Company vehicle; or,
- After four (4) consecutive hours of work on a Call-In.

17.1.2 Employees who work beyond the minimum overtime required to earn a meal allowance shall be paid for one-half (½) hour to eat the meal. The one-half (½) hour will be paid one (1) time per continuous work period whether the employee breaks to eat the meal or works straight through to complete the work.

17.1.3 Effective December 1, 2019, the meal allowance is twenty-two dollars and ninety cents ($22.90). The meal allowance 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 Section 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 allowances are not provided when the employee receives per diem.

17.2.2 Effective December 1, 2019, the per diem rate is sixty-four dollars ($64.00). The per diem rate will be adjusted annually by averaging the Government Services Administration's State of Oregon rates as published on the web site (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 Union and the Company.

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 Article 6.1.3 within this Agreement).

a. Paid travel at a time other than the employee's regular scheduled working hours must be pre-approved by Management.

b. Paid travel time shall be counted as time worked for the calculation of overtime. To determine appropriate pay, refer to Article 11.6.1 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.

c. Paid travel time is eligible for applicable premium pay.

d. 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].

e. When applicable, mileage reimbursement will be paid in accordance with the Company's Mileage Reimbursement Policy.

f. 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.

a. 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.

b. 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.

c. 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.

a. All travel arrangements, including scheduled travel day, and itinerary, are to be mutually agreed to by the employee and Management prior to travel.

b. 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.

c. Travel time is only those hours spent in transit to or from the travel destination.

d. 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 work days, 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).

17.4.2 Parking

The Company has no obligation to provide employee parking, but will make parking available to the extent possible.

17.4.3 Transit Passes

Headquarters-based bargaining unit employees shall be provided transit passes (TriMet passes for Oregon residents and C-Tran passes for Washington residents who commute using C-Tran), at no cost to the employee.

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 Benefits

Regular employees who have completed one (1) year of service and are regularly scheduled to work twenty (20) or more hours per week are eligible for Paid Parental Leave following the birth or adoption of a child. Eligible full-time employees qualify for one hundred and twenty (120) hours of Paid Parental Leave.

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.

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 Article 12.5 within this Agreement.

Section 17.8 Personal Protective Equipment (PPE)

17.8.1 **FR (Fire Resistant) Clothing Allowance**

Newly hired or rehired field employees who are required to wear FR clothing shall receive one thousand eight hundred dollars ($1,800.00) for the purchase of approved FR clothing.

17.8.2 All field employees who are required to wear FR clothing shall receive an allowance, to be spent annually, of seven hundred and fifty dollars ($750.00) for the purchase of approved FR clothing, effective January 1, 2020.

17.8.3 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.

17.8.4 Footwear Protection Allowance

Employees required to wear safety footwear shall be provided up to two hundred and fifty dollars ($250.00) per calendar year for either purchase or refurbishment of boots (e.g., boot rebuilds or toe guards).

17.8.5 Prescription Safety Glasses

Employees requiring prescription safety glasses receive up to four hundred dollars ($400.00) 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 dollars ($200.00) for replacement prescription safety glasses.

ARTICLE 18
RETIREMENT PLANS

Section 18.1 Bargaining Unit Employees' Retirement Plan (Retirement Plan)

The Company shall continue to maintain the 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.

Section 18.2 Retirement K Savings Plans (RKSP 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.

18.2.1.1 During the term of this Agreement, beginning with the first pay period of 2020, 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.

18.2.1.2 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 Retirement 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 reserves the right to discipline or terminate any employee for just cause and to determine the appropriate level of discipline based on the facts and circumstances presented. The employee has the right to Union representation in disciplinary matters. 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 his or her 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.

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.

20.2.2.1 **Suspension**

A disciplinary suspension is unpaid and may be used by a Manager or Supervisor in conjunction with a Disciplinary Action Plan (DAP).

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.

Five (5) 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 In case of a suspension or termination, 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 to this Article. Employees are entitled to Union representation at such meetings.

20.4.4 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 to this Article.

Section 20.5 Distribution of Documents

Copies of DVWs, DAPs, Suspensions, and Terminations will be provided to the employee, Steward, Chief Steward and the Union Office.

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 to 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 deadlines under this Article, the day which triggers the deadline (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 in a class grievance or in a non-class grievance, and the appropriate Company representative at each step.

21.2.1 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 Grievance

A written grievance shall 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:

21.3.1 The statement of the grievance/response and the facts upon which it is based;

21.3.2 Signed by the grievant and the represented parties involved;

21.3.3 A statement of the specific provision(s) of the Agreement that is (are) the basis of the grievance/response;

21.3.4 The manner in which the provision is purported to have been violated, misapplied, or misinterpreted (or in which the provision supports the response);

21.3.5 The date or dates on which the alleged violation, misinterpretation, or misapplication occurred; and

21.3.6 The specific remedy sought or offered.

Section 21.4 Grievance Process

21.4.1 A grievance can be initiated in the following ways:

21.4.1.1 If the concern is about discipline, it should start at Level 1 in the grievance process.

21.4.1.2 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.

21.4.1.3 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.

21.4.2 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.

21.4.3 **Level 1 – Process**

Participants: Employee, Steward(s) or representative of the Union, and the first line Supervisor or their designee.

Procedure: The Union Steward has ten (10) 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 five (5) working days of receiving the documented grievance to potentially resolve the grievance. Resolved and unresolved outcomes of the grievance resolution meeting will be documented.

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.

21.4.4 **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.

21.4.5 **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.

21.4.6 All timelines above may be extended by mutual agreement of the Union and the Company. 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

21.5.1 If the grievance cannot be resolved at Level 3, the Union and the Company 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.

21.5.2 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.

21.5.3 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, 2024, 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, 2024, or prior to any May 31st thereafter stating that it desires to negotiated modifications or to terminate this Agreement.

IN WITNESS WHEREOF, the parties have caused this Agreement to be executed in duplicate by their respective officers, thereunto duly authorized.

NORTHWEST NATURAL GAS COMPANY

By ______________________
Larry R. Buchanan

____
Cari L. Colton

____
Cliff L. Crawford

____
James C. Hart

____
Jon G. Huddleston

____
Mark J. Lilly

____
Darcy D. Noxon

____
Kerry F. Shampine

____
Joseph S. Karney, LMC Executive Sponsor

____
Kathryn G. Beyerchen, LMC Co-Chair

____
Melinda B. Rogers, LMC Executive Sponsor
Vice President, Human Resources

____
David Anderson
President and Chief Executive Officer

____
MardiLyn Saathoff
Senior Vice President and General Counsel

OFFICE & PROFESSIONAL EMPLOYEES INTERNATIONAL UNION, LOCAL-11, AFL-CIO

By ______________________
Howard D. Bell

____
Richard C. Brown

____
Bryce L. Forge

____
John G. Goebel

____
Michael K. Jamison

____
Curtis L. Pearce

____
Ernest H. Pech

____
Lorelei M. Ricketts

____
Aron P. Ruljancich

____
Karyn S. Morrison, LMC Co-Chair

____
Maureen M. Colvin, LMC Executive Sponsor
Executive Secretary-Treasurer

Schedule A – Job Titles by Pay Group

Pay Group	Job Title *(Position Title)*
A	Comms & Control Technician 2
	Construction 4 *(Transmission Foreman/woman)*
	Journeyman Electrician
B	Comms & Control Technician 1
	Construction 3 *(Distribution Foreman/woman)*
	*Corrosion Technician
	Customer Field Service 4 *(Industrial Tech)*
	Gas Storage 2 *(Chief Operator)*
	System Ops 2
	Transmission Maintenance 2
	*Weld & Fab 4 *(Mechanic Welder)*
C	Customer Field Service 3 *(Commercial Tech)*
	Field Support 3 *(Field Engineering Tech)*
	General Services 4 *(Sr Machinist)*
	Leakage Inspector
	Transportation 4 *(Auto Shop Foreman/Woman)*
D	*Customer Field Service 2 *(Service Tech)*
	Field Support 2 *(Field Measurement Tech)*
	Gas Storage 1 *(Plant Operator)*
	General Services 3 *(Machinist)*
	Specialty Construction 2
	Weld & Fab 3 *(Sr Fabricator)*
E	Construction 2 *(Pipe Welder Fitter)*
	Field Support 1 *(Field Data Tech)*
	Fire & Safety Technician
	General Services 2 *(Maintenance Tech)*
	Graphics 3
	Meter & Reg Shop 3
	Semi & Crane
	System Ops 1
	Transmission Maintenance 1
	Transportation 3 *(Auto Mechanic)*
	Weld & Fab 2 *(Fabricator)*
F	Accounting 4
	*Construction 1 *(Pipe Fuser)*
	Customer Service 4
	Meter & Reg Shop 2
	Specialty Construction 1
	Stores 3 *(Head Storekeeper)*
	Stores 3 *(Storekeeper - Delivery)*
	Stores 3 *(Storekeeper - Transportation)*
G	Building Maintenance Technician
	Graphics 2
	Stores 2 *(Storekeeper)*
	Technical Coordinator 3
	Weld & Fab 1 *(Body Repair Tech)*
H	Accounting 3
	Computer Support 1
	Customer Field Service 1 Honored
	Customer Service 3
	Graphics 1
	Meter & Reg Shop 1
	Technical Coordinator 2
	Transportation 2 (Lube Tech Specialist)
	Utility Support 3 *(Field Maint Worker)*
I	Operational Support 3
J	Accounting 2
	Customer Service 2
	Office Services 2
K	Operational Support 2
	Transportation 1 *(Garage Attendant)*
L	Accounting 1
	General Services 1 *(Delivery Driver)*
	Office Services 1
	Stores 1 *(Warehouse Worker)*
M	Customer Service 1
	Operational Support 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 Scale

Pay Group	Step Description	Dec 2019 Wage Rate Structure Move	Dec 2019 Wage Rate with 1.5% Increase	June 2020 Wage Rate with 2.0% Increase	June 2021 Wage Rate with 3.5% Increase	June 2022 Wage Rate with 3.5% Increase	June 2023 Wage Rate with 3.5% Increase
A	Experienced	$46.40	$47.09	$48.03	$49.71	$51.45	$53.25
A	Entry	$44.54	$45.20	$46.10	$47.71	$49.38	$51.11
B	Experienced	$43.57	$44.22	$45.10	$46.68	$48.31	$50.00
B	Entry	$41.82	$42.45	$43.29	$44.81	$46.37	$48.00
B	3 - Training	$39.21	$39.79	$40.59	$42.00	$43.47	$44.99
B	2 – Training	$37.03	$37.58	$38.33	$39.66	$41.05	$42.49
B	1 – Training	$34.85	$35.37	$36.08	$37.33	$38.64	$39.99
C	Experienced	$40.92	$41.53	$42.36	$43.84	$45.38	$46.97
C	Entry	$39.28	$39.86	$40.66	$42.08	$43.56	$45.08
C	3 - Training	$36.82	$37.37	$38.12	$39.45	$40.83	$42.25
C	2 – Training	$34.78	$35.30	$36.00	$37.26	$38.56	$39.90
C	1 – Training	$32.73	$33.22	$33.88	$35.07	$36.29	$37.56
D	Experienced	$38.43	$39.00	$39.78	$41.17	$42.61	$44.10
D	Entry	$36.89	$37.44	$38.18	$39.52	$40.90	$42.33
D	3 - Training	$34.58	$35.10	$35.80	$37.05	$38.34	$39.69
D	2 – Training	$32.66	$33.15	$33.81	$34.99	$36.21	$37.48
D	1 – Training	$30.74	$31.20	$31.82	$32.93	$34.08	$35.28
E	Experienced	$36.09	$36.63	$37.36	$38.67	$40.02	$41.42
E	Entry	$34.64	$35.16	$35.86	$37.12	$38.41	$39.76
F	Experienced	$33.89	$34.39	$35.07	$36.30	$37.57	$38.88
F	Entry	$32.53	$33.01	$33.66	$34.84	$36.06	$37.32
F	3 - Training	$30.50	$30.95	$31.56	$32.66	$33.80	$34.98
F	2 – Training	$28.80	$29.23	$29.80	$30.84	$31.92	$33.03
F	1 – Training	$27.11	$27.51	$28.05	$29.03	$30.04	$31.09
G	Experienced	$31.83	$32.30	$32.94	$34.09	$35.29	$36.52
G	Entry	$30.25	$30.68	$31.29	$32.39	$33.52	$34.69
H	Experienced	$29.75	$30.19	$30.79	$31.87	$32.98	$34.14
H	Entry	$28.26	$28.68	$29.25	$30.27	$31.33	$32.43

continued on next page

Pay Group	Step Description	Dec 2019 Wage Rate Structure Move	Dec 2019 Wage Rate with 1.5% Increase	June 2020 Wage Rate with 2.0% Increase	June 2021 Wage Rate with 3.5% Increase	June 2022 Wage Rate with 3.5% Increase	June 2023 Wage Rate with 3.5% Increase
I	Experienced	$27.80	$28.21	$28.77	$29.78	$30.82	$31.90
I	Entry	$26.42	$26.79	$27.33	$28.29	$29.28	$30.30
J	Experienced	$25.97	$26.35	$26.87	$27.81	$28.78	$29.79
J	Entry	$24.69	$25.03	$25.52	$26.41	$27.34	$28.29
K	Experienced	$24.05	$24.41	$24.89	$25.76	$26.66	$27.60
K	Entry	$22.86	$23.18	$23.64	$24.47	$25.32	$26.21
L	Experienced	$22.27	$22.60	$23.05	$23.86	$24.69	$25.56
L	Entry	$21.16	$21.47	$21.89	$22.66	$23.45	$24.27
M	Experienced	$20.62	$20.92	$21.31	$22.08	$22.85	$23.65
M	Entry	$19.58	$19.87	$20.26	$20.96	$21.69	$22.44
N	Experienced	$19.09	$19.37	$19.75	$20.44	$21.15	$21.89
N	Entry	$18.13	$18.40	$18.76	$19.41	$20.09	$20.79
O	Experienced	$17.67	$17.93	$18.28	$18.92	$19.58	$20.27
O	Entry	$16.79	$17.03	$17.36	$17.96	$18.59	$19.23

MEMORANDUM OF AGREEMENT
BETWEEN THE
NW NATURAL GAS COMPANY
AND THE
OFFICE & PROFESSIONAL EMPLOYEES INTERNATIONAL UNION LOCAL 11

This Memorandum of Agreement is entered into between the NW Natural Gas Company and the Office & Professional Employees International Union, Local 11 with the intent to allow proper communication between the parties listed above and in accordance with Article 11/Wages and Schedule "B" Wage Schedule within the Collective Bargaining Agreement.

It is mutually agreed by all parties that in consideration of inflation and impacts to bargaining unit employees an additional one percent (1%) one-time non-precedent setting cost of living increase shall be applied to the current scheduled annual increase of three and a half percent (3.5%) for the 2023 calendar year and the wage scheduled shall be adjusted accordingly; and as attached to this memorandum.

Be it further agreed that Employees whose current rate of pay remains above the Wage Scale shall have the additional one percent (1%) one-time non-precedent setting cost of living increase applied in accordance with Article 11.2.3 within the Collective Bargaining Agreement.

This Memorandum of Agreement shall be pursuant to the terms of Article 10/Issue Resolution and Article 21/Grievance and Mediation Arbitration Process should there be any dispute regarding the interpretation and/or application of this memorandum.

Agreed on this 14 day of February 2023

Melinda B Rogers

Melinda Rogers, NW Natural Gas Company
Vice President, Chief Human Resources and Diversity Officer

Maureen Goldberg, OPEIU Local 11
Executive Secretary-Treasurer

SCHEDULE "B" WAGE RATES		
Pay Group	**Step Description**	**June 2023 3.5% Increase Plus a 1% COLA**
A	Experienced	$53.78
A	Entry	$51.62
B	Experienced	$50.50
B	Entry	$48.48
B-3	Training	$45.44
B-2	Training	$42.91
B-1	Training	$40.39
C	Experienced	$47.44
C	Entry	$45.53
C-3	Training	$42.67
C-2	Training	$40.30
C-1	Training	$37.94
D	Experienced	$44.54
D	Entry	$42.75
D-3	Training	$40.09
D-2	Training	$37.85
D-1	Training	$35.63
E	Experienced	$41.83
E	Entry	$40.16
F	Experienced	$39.27
F	Entry	$37.69
F-3	Training	$35.33
F-2	Training	$33.36
F-1	Training	$31.40
G	Experienced	$36.89
G	Entry	$35.04
H	Experienced	$34.48
H	Entry	$32.75
I	Experienced	$32.22
I	Entry	$30.60
J	Experienced	$30.09
J	Entry	$28.57
K	Experienced	$27.88
K	Entry	$26.47
L	Experienced	$25.82
L	Entry	$24.51
M	Experienced	$23.89
M	Entry	$22.66
N	Experienced	$22.11
N	Entry	$21.00
O	Experienced	$20.47
O	Entry	$19.42

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 1405

REDACTED

Per Commission's General Protective Order, this exhibit is confidential in its entirety and has been redacted.

December 29, 2023

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 1406

REDACTED

Per Commission's General Protective Order, this exhibit is confidential in its entirety and has been redacted.

December 29, 2023

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Direct Testimony of Zachary D. Kravitz and Anna K. Chittum

DECARBONIZATION PLANNNING & RENEWABLE NATURAL GAS AUTOMATIC ADJUSTMENT CLAUSE EXHIBIT 1500

December 29, 2023

EXHIBIT 1500 – DIRECT TESTIMONY – DECARBONIZATION PLANNING & RENEWABLE NATURAL GAS AUTOMATIC ADJUSTMENT CLAUSE

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 Zachary D. Kravitz. My position at NW Natural is Vice President of Rates and Regulatory Affairs. 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. 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 of the department. I assumed my current position in 2022. 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.

My name is Anna K. Chittum. I am the Director of Renewable Resources at NW Natural. I have worked for the Company since 2017. My responsibilities include developing renewable natural gas ("RNG") projects for the Company, purchasing RNG from other market participants, driving renewables strategy and goals for the Company, and managing the Renewables team here at NW Natural. I received my Bachelor's degree in Economics from Gonzaga University and a Master of Science degree in Urban Planning from Columbia University. I was also a Fulbright Fellow in Denmark during the 2013-2014 academic year. From June

2006 to March 2008, I worked as Manager of Client Services at the New York City Mayor's Office of Industrial and Manufacturing Businesses. From March 2008 to June 2014, I worked as a Senior Researcher and later a Visiting Fellow at The American Council for an Energy Efficient Economy. Since 2017, I have worked at NW Natural, where I am now the Director of Renewable Resources.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to:

- Briefly summarize Schedule 198, Renewable Natural Gas Recovery Mechanism ("Schedule 198"), which is an automatic adjustment clause ("AAC") that is designed to recover NW Natural's investments in RNG infrastructure;
- Explain what the Climate Protection Program ("CPP") is and its requirements;
- Describe how the Company intends to use a least cost/least risk framework to comply with the CPP that includes the acquisition of Community Climate Investment ("CCI") credits, as well as pursuing other tools to comply with the CPP, such as the acquisition of RNG.
- Propose two changes to Schedule 198, which would: 1) permit deferrals between the in-service date of an RNG project and the rate effective date, and 2) set the earnings test at NW Natural's authorized return on equity ("ROE").

- Explain NW Natural's request to recover the costs of five additional full-time employees ("FTEs") that are focused on decarbonization and CPP compliance.

II. BACKGROUND

Q. Please describe Schedule 198.

A. The Commission approved Schedule 198 in the Company's last general rate case (UG 435). Schedule 198 is an AAC, which is defined in ORS 757.210(1)(b) as "a provision of a rate schedule that provides for rate increases or decreases or both, without prior hearing, reflecting increases or decreases or both in costs incurred, taxes paid to units of government or revenues earned by a utility . . ." More specifically, Schedule 198 authorizes NW Natural to recover the costs of RNG investments outside of a general rate case.

Q. Why did NW Natural originally propose Schedule 198?

A. NW Natural originally filed Schedule 198 in late 2020. This docket, ADV 1215, was eventually consolidated into NW Natural's last general rate case—UG 435—which was filed approximately a year later. Schedule 198 is designed to recover NW Natural's "qualified investments" in RNG infrastructure pursuant to ORS 757.390-398 ("SB 98"). Under SB 98, NW Natural is authorized to acquire RNG up to the portfolio targets set in ORS 757.396. The targets start at 5 percent of Oregon sales load from 2020 to 2024 and gradually escalate to 30 percent from 2045 to 2050.

Q. Since NW Natural first proposed Schedule 198 in late 2020, have there been subsequent regulatory changes that have affected RNG procurement?

A. Yes. In late 2021, the Oregon Department of Environmental Quality ("ODEQ") adopted the Climate Protection Program ("CPP"). Under the CPP, the ODEQ requires that covered entities, such as NW Natural, reduce the greenhouse gas ("GHG") emissions for which the CPP deems them to be responsible. For NW Natural, these "covered emissions" are the emissions that result from its sales customers' and transport customers' use of natural gas.

Q. Please describe how the CPP is structured.

A. Under the CPP, ODEQ distributes to NW Natural an allocation of compliance instruments on an annual basis. Each compliance instrument equals one metric ton of covered emissions. The amount of compliance instruments NW Natural receives is set at its average covered emissions from years 2017-2019 and declines every year.[1] By 2035, the number of compliance instruments is cut in half. By 2050, the number of compliance instruments is reduced by 90 percent. NW Natural must demonstrate compliance with the CPP every three years. At the end of each three-year compliance period, NW Natural must retire compliance instruments and CCI credits that are equal to its covered emissions over the compliance period.

[1] OAR 340-271-9000, Table 4.

Q. What are CCI credits?

A. CCI credits are offset-like compliance instruments unique to the CPP. CCI credits are defined as: “money paid by a covered fuel supplier (e.g., NW Natural) to a community climate investment entity to support implementation of community climate investment projects and any interest that accrues on the money while it is held by a CCI entity or subcontractor.”[2] In exchange for this money, covered fuel suppliers, like NW Natural, will receive CCI credits that they can use for compliance. NW Natural, however, cannot purchase an unlimited number of CCI credits. During the first three-year CPP compliance period (2022-2024), NW Natural may purchase CCI credits for up to 10 percent of its CPP compliance obligation.[3] During the second three-year compliance period (2025-2027), this amount increases to 15 percent, and for every three-year compliance period thereafter, the amount is 20 percent.[4]

Q. What are the penalties if NW Natural fails to comply with the CPP?

A. In addition to being a regulatory requirement that NW Natural must follow, the potential magnitude of penalties associated with not complying with the CPP is large. If NW Natural fails to meet its obligations under the CPP, it faces penalties of up to $12,000 per metric ton of any covered emissions that exceed the cumulative amount of compliance instruments and CCI credits that it retired during the compliance period.

[2] OAR 340-271-0020(8).

[3] OAR 340-271-9000, Table 6.

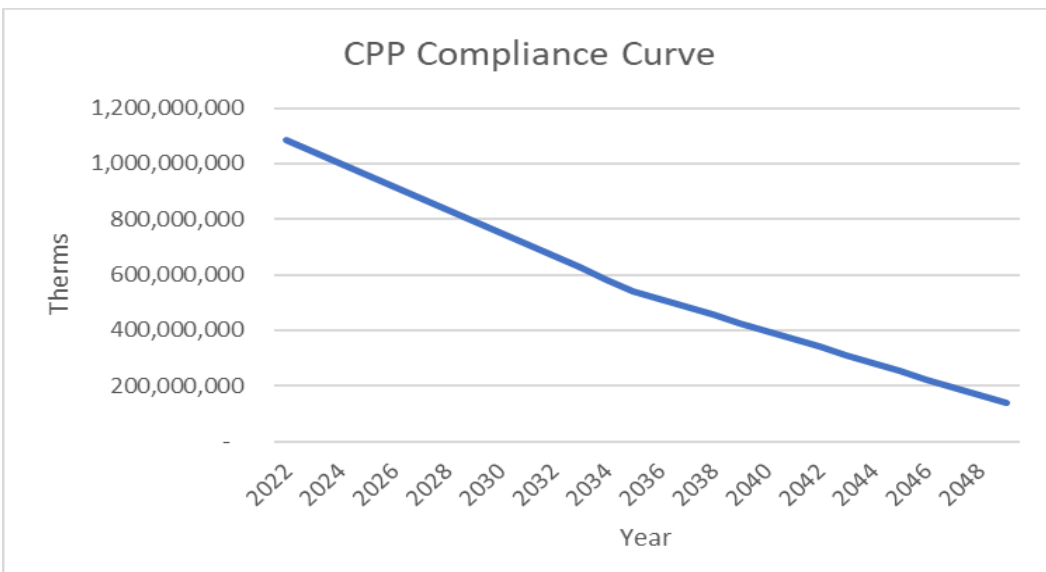
[4] *Id.*

Q. Will NW Natural have to take aggressive action to comply with the CPP?

A. Yes. To meet its CPP obligations solely with the compliance instruments allocated to it by ODEQ, NW Natural would have to reduce its supply of conventional natural gas to customers by approximately 41.7 million therms[5] each year from 2023 to 2035. From 2035 to 2050, NW Natural would have to reduce its supply of conventional natural gas to customers by approximately 28.9 million therms each year to satisfy its CPP obligations with only compliance instruments allocated to it by ODEQ.

Table 1 below shows the reduction in compliance instruments on a therm basis.

TABLE 1



[5] One therm is equal to 0.00531148 MT CO2e, resulting in an annual reduction of 221,537 MT CO2e from 2023 to 2035, and an annual reduction of 153,599 MT CO2e from 2035 to 2050. See also OAR 340-271-9000, Table 4, showing the annual reduction in compliance instruments in MT CO2e.

Q. What is the first compliance action that NW Natural intends to take?

A. NW Natural intends to purchase the maximum amount of legally valid and available CCI credits allowed for each three-year compliance period. During the first three-year compliance period (2022-2024), NW Natural expects to purchase approximately $220 million of CCI credits.[6] In NW Natural's most recent Integrated Resource Plan ("IRP") proceeding (docket LC 79), there was broad agreement among stakeholders that CCI credits are currently the least cost compliance option.[7]

Q. Is purchasing the maximum amount of CCI credits necessary for CPP compliance in the first compliance period (2022-2024)?

A. Although purchasing the maximum amount of CCI credits is not strictly necessary for CPP compliance in the first compliance period (2022-2024), it leverages this least cost option to mitigate costs in future compliance periods. By retiring all of the CCI credits it purchases in the first compliance period, NW Natural will retain some of the compliance instruments allocated to it during that period for use in future compliance periods.[8] If NW Natural only were to purchase the amount of CCI credits strictly necessary for CPP compliance in the first compliance period

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[6] As of the date of this testimony, CCI credits are not yet available for purchase, but they are expected to be available in 2024.

[7] *In the Matter of Northwest Natural Gas Co., dba NW Natural, 2022 Integrated Resource Plan*, Docket No. LC 79, Order No. 23-281, at 5-6, 9-10 (Aug. 2, 2023).

[8] Per OAR 340-271-0430, CPP compliance instruments do not expire unless they are retired for compliance purposes or NW Natural ceases being a covered fuel supplier.

and not carry over any compliance instruments, it would be forced to take more expensive actions in future compliance periods in order to comply with the CPP.

Q. Are there any complicating factors that make CPP compliance planning difficult?

A. Yes. Weather variability is a major issue that will significantly impact CPP compliance planning.

Q. Please explain how weather variability impacts CPP compliance planning.

A. Residential and commercial use of natural gas is highly dependent on weather. Relative to normalized weather, natural gas use can increase by nearly 20 percent in cold weather and decrease by a similar amount in warm weather. Since CPP compliance is not weather normalized, these changes in use (i.e., substantial increases or decreases in covered emissions) will have a material effect on CPP compliance. Compounding this effect is that NW Natural's service territory often experiences consecutive years of cold or warm weather. Table 2 below indicates residential and commercial gas use relative to normalized weather since 1987, where percentages greater than 100 indicate higher gas use in response to colder weather, and percentages less than 100 indicate lower gas use in response to warmer weather.

TABLE 2

	Residential %	Commercial %
1987	92.2%	91.8%
1988	98.6%	98.1%
1989	101.1%	101.6%
1990	99.3%	99.5%
1991	98.6%	98.3%
1992	81.9%	80.8%
1993	105.0%	105.9%
1994	95.1%	94.9%
1995	85.4%	84.2%
1996	102.4%	102.3%
1997	92.6%	92.8%
1998	94.5%	93.8%
1999	100.8%	100.4%
2000	101.9%	102.0%
2001	103.4%	103.4%
2002	100.1%	99.8%
2003	92.4%	91.9%
2004	92.2%	91.9%
2005	98.6%	98.2%
2006	102.8%	102.9%
2007	109.0%	109.4%
2008	117.7%	118.7%
2009	111.6%	112.8%
2010	96.4%	95.4%
2011	113.2%	114.0%
2012	104.2%	104.3%
2013	109.2%	110.1%
2014	86.1%	85.8%
2015	80.0%	79.0%
2016	81.2%	79.9%
2017	107.9%	108.6%
2018	92.7%	92.2%
2019	104.7%	105.5%
2020	96.4%	96.3%

As shown in Table 2 above, NW Natural's residential and commercial customers have experienced colder weather, and therefore higher gas use, relative to normalized weather as recently as 2019 and experienced colder-than-normal weather for four years in a row between 2006-2009. Conversely, NW Natural experienced three warm years in a row between 2014-2016.

Q. How will weather influence NW Natural's CPP compliance?

A. For the first compliance period (2022-2024), weather will have a limited effect on NW Natural's compliance. During this period, assuming legally valid CCI credits are available, NW Natural can likely satisfy its CPP compliance obligation by solely purchasing such credits, and, to carryover compliance instruments to future compliance periods, as explained above. This strategy is intended to limit, at least to some extent, the effects of colder-than-normal weather on CPP compliance in the future. It should also reduce the need to take more costly compliance actions to some degree, but additional compliance actions will nonetheless become necessary during the second compliance period (2025-2027).

Weather throughout the remainder of the first compliance period will have a material effect on how many compliance instruments NW Natural can carry forward for use in future compliance periods. Under our current compliance plan, NW Natural currently expects to carry forward approximately 1.1 million compliance instruments from the first compliance period, assuming normalized weather through the end of calendar year 2024 (the end of the first compliance period). If weather is colder than normal, then this carry over amount could be reduced to about 476,000 compliance instruments.

Going into the second compliance period (2025-2027), NW Natural will not be able to rely solely on CCI credits absent prolonged warmer-than-normal weather. NW Natural, however, cannot base its compliance strategy on warmer-than-normal weather. Instead, it will have to take incremental actions in order to ensure compliance with the CPP, even in colder-than-normal weather.

Q. Please describe the actions that NW Natural is considering taking to reduce covered emissions.

A. NW Natural will pursue least cost/least risk CPP compliance actions as available. However, given the amount of covered emissions it must reduce, NW Natural will have to pursue a number of actions simultaneously, such as acquiring decarbonized fuels, like RNG, and taking actions to reduce throughput. Reducing throughput, however, has become more difficult in the aftermath of the COVID-19 pandemic. Even after the pandemic, many people continue to work from home, increasing their natural gas use. Since the start of the pandemic, use per residential customer has increased from 630 therms a year to 660 therms. Additional action will be necessary just to reduce residential customer use to pre-pandemic levels, let alone reduce usage beyond that. Nonetheless, wider adoption of hybrid heating, where an air source heat pump is paired with a gas furnace that provides heating on the coldest days, would reduce customers' natural gas use. In addition, transport customers have not historically been a part of the Company's energy efficiency programs, but that will change under the CPP, which may lead to future reductions in throughput.

None of these decarbonization solutions should be thought of as binary choices that the Company needs to make. Rather, to comply with the CPP, NW Natural will have to pursue all possible compliance actions under available laws. Initially, and pursuant to Commission guidance, NW Natural will maximize the lowest cost action first—currently purchasing CCI credits—before moving to other actions that are more expensive at this time.[9] In making its decisions, the Company will examine all potential ways to reduce costs, such as potentially taking advantage of Inflation Reduction Act tax credits for RNG projects that materially begin construction in 2024 and potentially other RNG tax credits that may become available in the coming years. However, while RNG will be a vital part of our CPP compliance, it must be understood that NW Natural needs to pursue all compliance actions to assure compliance during future cold-weather compliance periods.

III. SHIFT IN APPROACH IN ACQUIRING RNG

Q. Please describe NW Natural's recent approach to acquiring RNG.

A. NW Natural has aligned its RNG acquisition goals with the RNG targets of the State of Oregon established in SB 98. Since the passage of this law, NW Natural has pursued RNG to prudently meet the acquisition targets in SB 98. NW Natural has gone to great lengths to evaluate RNG offtakes and investments on an apples-to-apples basis by proposing an RNG evaluation methodology in its IRP (docket LC 71) and subsequently in a stand-alone docket where that evaluation methodology was approved, UM 2030. Following that methodology, the Company has pursued a mix of RNG offtakes and its own development projects through its affiliates, working to prudently secure RNG resources. Specifically, NW Natural has developed RNG projects at two Tyson facilities in Nebraska. These affiliates

[9] *In the Matter of Northwest Natural Gas Co., dba NW Natural, 2022 Integrated Resource Plan*, Docket No. LC 79, Order No. 23-281, at 11-12 (Aug. 2, 2023).

sell RNG produced at the facilities to NW Natural, but NW Natural's investment in these facilities—made through its affiliates—are part of its rate base. Additionally, NW Natural has executed three different offtake agreements for RNG from owners of other RNG projects around the country.

Q. How has the CPP changed the Company's approach to acquiring RNG?

A. In its recent IRP, the Commission did not acknowledge NW Natural's proposed RNG acquisitions to meet SB 98 targets,[10] causing the Company to re-evaluate its CPP compliance strategy. Although the Company continues to believe that SB 98 authorizes it, under the construct provided in that law, to acquire RNG up to SB 98 targets, it is no longer planning an SB 98-first approach for CPP compliance. Rather, NW Natural will start by maximizing CCI credits and pursue multiple, simultaneous compliance actions in the coming years to assure CPP compliance even during cold weather.

Q. Is NW Natural also pursuing changes to simplify how it acquires RNG?

A. Yes. In addition to taking other compliance actions, such as maximizing CCI credits, NW Natural will also need to acquire substantial amounts of RNG to comply with the CPP. To facilitate the acquisition of RNG, the Company is seeking to apply a simpler framework for its RNG investments that is designed to lead to faster regulatory approvals. The Company's Dakota City and Lexington investments have complex structures involving affiliates and multiple dockets. Parties have raised concerns about this approach, and the resulting rate treatment

[10] *Id.* at 7.

hinders the Company from operating these projects as efficiently as possible, as fully explained in the next section of our testimony. Therefore, absent a compelling reason to do otherwise, NW Natural will begin developing projects through the utility without using a subsidiary affiliate to house the investment. While we continue to believe using subsidiaries benefits customers, those benefits are outweighed by the Commission's lingering concern with this type of structure.[11] We have strived to be as transparent as possible with these arrangements. The Commission, however, clearly views this structuring as a riskier approach for customers, indicating continued use of the affiliate structure may require additional risk sharing than what was agreed to in the Lexington and Dakota City dockets.[12] As such, absent a compelling reason to do otherwise, NW Natural will not pursue this structure going forward. This should also benefit the parties to our RNG dockets in that it will eliminate an affiliated interest transaction that, by law, requires review and decision within 90 days of filing at the Commission.

IV. PROPOSED REVISIONS TO SCHEDULE 198

Q. Please summarize the Company's proposed revisions to Schedule 198.

A. The Company proposes to revise Schedule 198 to: 1) address regulatory treatment prior to RNG investments being included in rates, and 2) remove disincentives in the Schedule 198 earnings test that inadvertently inhibit higher than forecasted

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[11] *In the Matter of Northwest Natural Gas Co., dba NW Natural, Renewable Natural Gas Adjustment Mechanism- Dakota City*, Docket No. UG 462, Order No. 23-367 (Oct. 16, 2023).

[12] *Id.*

RNG production. The revised Schedule 198 is included in the Direct Testimony of Kyle Walker, NW Natural/1717, Walker.

Q. What is the current regulatory treatment of RNG investments prior to being included in rates?

A. Currently, NW Natural is not permitted to defer, for later cost recovery, the costs of its RNG investments between the investment's in-service date and the rate effective date. This type of regulatory lag prevents the Company from fully recovering its costs associated with complying with mandatory ODEQ regulations (the CPP).

Q. Why does the Company believe that it should be allowed to defer these costs?

A. As stated above, the Company plans to make these investments for compliance with the CPP. Since the CPP is a mandatory ODEQ regulation, the Company must make investments to lower the emissions that are attributed to it under the CPP.

Q. Has the Commission previously approved deferrals for projects that are necessary to comply with regulatory requirements?

A. Yes. Electric utilities have Renewable Adjustment Clauses ("RACs") that permit them to defer the cost of renewable electric generation projects between the in-service date and the rate effective date to meet the state's renewable portfolio standard.[13] Like the CPP for NW Natural, the state's renewable portfolio standard is a requirement that the state's electric utilities must satisfy.

Q. Didn't NW Natural raise this issue in its last general rate case and the Commission found that a deferral was not appropriate?

A. Yes, but the Commission reasoned that if NW Natural received rate treatment that was too favorable, then it may seek to pursue RNG projects at the expense of other decarbonization projects.[14] However, as we have previously explained, NW Natural will pursue CPP compliance on a least cost/least risk basis using tools that are available to us. The Company intends to demonstrate its commitment to this plan planning by purchasing $220 million worth of CCI credits over the first compliance period (2022-2024), to the extent legally valid CCI credits are available, in order to fully maximize their value across multiple compliance periods, which will limit (but not eliminate) the amount of RNG that NW Natural will have to acquire in the coming years. While NW Natural will still need to acquire a substantial amount of RNG to comply with the CPP, especially due to weather variability, it is implementing least cost/least risk CPP compliance by planning for

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[13] See e.g., Portland Gen. Elec. Schedule 122, available at: https://assets.ctfassets.net/416ywc1laqmd/66KKFjiBXfAq7uOjpYUfcY/b9e32d3f3ceb7e5a548d09209cc1a624/Sched_122.pdf.

[14] *In the Matter of Northwest Natural Gas Co., dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Order No. 22-388 at 81, 83 (Oct. 24, 2022). ("It is possible that a prudent strategy may include RNG, but this will depend on the costs and risks relative to alternatives. We are concerned about the potential incentive created by the availability of an AAC to skew the company's analysis of costs and risks of alternative CPP compliance measures towards RNG projects." Given these concerns, the Commission ultimately found a deferral was not appropriate, stating "given our concerns about the interactions between the CPP and the AAC described above, it is appropriate to require a rate change to be implemented before the company can recognize revenues from the recovery for RNG projects.").

purchases of CCI credits. Further, the amount that NW Natural intends to spend on CCI credits ($220 million over the first compliance period) greatly exceeds the revenue requirement of the Company's current RNG investments of approximately $4.8 million per year, thereby showing that the Company is not seeking this deferral so that it can acquire more RNG than necessary. Rather, it is seeking rate treatment that balances the interests of the Company and customers while also recognizing that NW Natural must acquire RNG to meet CPP requirements.

Q. Is NW Natural seeking to guarantee cost recovery by proposing to defer costs between the project's in-service date and the rate effective date?

A. No. In seeking a deferral between the commercial operation date and the rate effective date of the facility, the Company is not seeking guaranteed cost recovery. Instead, the Company is only seeking the opportunity to recover prudently incurred costs that are necessary to comply with state regulations (the CPP). Without a deferral, the Company would not have the ability to demonstrate that these costs are prudent and should be included in rates, resulting in no opportunity for recovery.

Q. Is there another way to address the Company's concern without granting a deferral?

A. Yes. Currently, Schedule 198 requires NW Natural to make a filing to include new RNG projects in rates by February 28. Instead of only having a single date where NW Natural can make this filing, it can be revised so that the Company can time its filing so that rates go into effect shortly after the project goes into service. This type of treatment largely addresses the Company's concern without the need for a deferral, although we believe that a deferral is a more straightforward approach that would continue a predictable cadence of annual Schedule 198 filings throughout the year.

Q. What is the earnings test in Schedule 198?

A. Under Schedule 198, NW Natural forecasts the revenue requirement of its RNG investments for the coming year, beginning on November 1. These forecasted costs are compared to actual costs incurred at the end of the year. Any difference in costs (positive or negative) is recovered through a true-up mechanism in Schedule 198 subject to an earnings test. The earnings test sets a deadband at 50 basis points below and 50 basis points above authorized ROE. If NW Natural's ROE is within this deadband, there is no truing-up in order to recover actual costs incurred. Rather, NW Natural recovers its forecasted costs for the year.

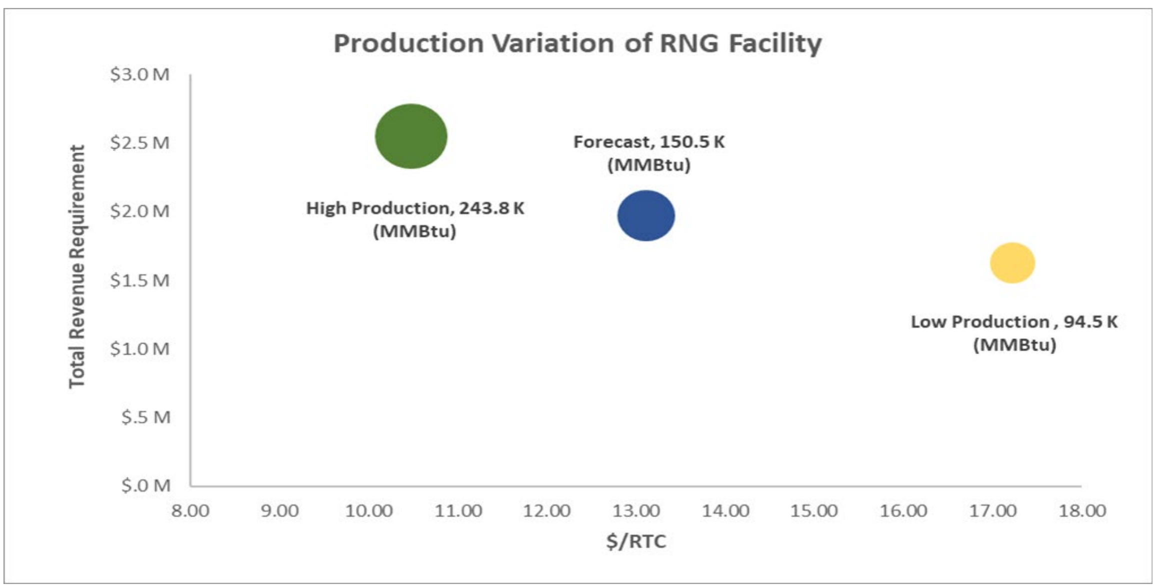
Q. Does the earnings test inadvertently inhibit higher than forecasted RNG production?

A. Yes. If NW Natural's ROE is within the earnings test deadband, it will only recover its forecasted costs for the year, not its actual costs. The problem with this approach is that higher than forecasted RNG production increases the project's overall revenue requirement, even though per-unit costs decline. For instance, the more RNG that is produced, the more that is paid to the supplier of the raw biogas, since the contract with the raw biogas owner is typically on a volumetric or per-mmbtu basis. Payments that are tied to the production of raw biogas are beneficial to customers because it encourages the supplier to produce as much raw biogas as possible, lowering the per-unit cost as fixed costs are spread over a larger amount of RNG. However, these payments also increase the overall revenue requirement. Nonetheless, the Company believes that the earnings test should not discourage NW Natural from producing as much RNG as possible at the lowest per-unit cost regardless of the increase to overall revenue requirement.

Q. Using a hypothetical example, can you demonstrate how the earnings test may inadvertently inhibit RNG production?

A. Table 3 below shows that, as RNG production increases, increased O&M costs—such as increased payments to the raw biogas owner for greater production—push up the project's annual revenue requirement, even though per-unit costs decline. This increase in production, which reduces per-unit costs, should be encouraged. However, under the current Schedule 198, there is no way to recover the increase in total costs, even though per-unit costs decline.

TABLE 3



Q. How does NW Natural propose addressing this issue?

A. NW Natural proposes to set the earnings test at its authorized ROE, removing the deadband. In other words, the earnings test would only trigger if:

1) NW Natural's actual ROE was at or above its authorized ROE, and

2) its actual Schedule 198 costs exceeded its annual forecast.

Although such treatment may still result in NW Natural not fully recovering its costs, even if those costs were driving per-unit costs down, the earnings test would only come into play if NW Natural was earning at or above its authorized ROE. Therefore, NW Natural believes that its proposal strikes a reasonable balance between the Company and its customers' interests.

V. NEW DECARBONIZATION EMPLOYEES

Q. The Direct Testimony of Justin B. Palfreyman and Zachary D. Kravitz (NW Natural/100, Palfreyman-Kravitz) discuss the need for additional expertise associated with decarbonization and compliance with the CPP. Will NW Natural hire additional FTEs that are focused on these issues?

A. Yes. NW Natural plans to hire five additional FTEs that are focused on decarbonization and CPP compliance. Three of these new FTEs will be part of NW Natural's Renewables Department: Decarbonization Services Analyst, Decarbonization Services Operations Support, and Decarbonization Portfolio Manager. In addition, the Rates & Regulatory Affairs Department will hire a Decarbonization Compliance Rates Analyst and the Strategic Planning Department will hire a Peak Load Management Analyst. NW Natural anticipates that all of these roles will be filled by the rate effective date—November 1, 2024.

Q. Please describe the Decarbonization Services Analyst position.

A. The Decarbonization Analyst will research and analyze new and emerging technologies and develop business cases for new decarbonization services, including district energy and geothermal energy in both residential and commercial and industrial applications, as well as negotiating agreements with large customers in hard-to-decarbonize sectors for siting hydrogen and carbon capture projects. Given the CPP requirement to cut covered emissions in half by 2035 and 90 percent by 2050, district energy and ground-source heat pumps, which is a specific type of electrification, will be important compliance tools. Therefore, having an FTE focused on these tools is imperative for the successful rollout of these new service options for customers. Similarly, carbon capture and hydrogen projects for the hard-to-decarbonize industrial sector will be a critical large-scale CPP compliance solution that the Company must pursue to decarbonize effectively. Transitioning these large users of natural gas to hydrogen—or otherwise storing the carbon associated with their energy use—will result in a correspondingly large amount of emissions savings. This position will include significant direct outreach to customers to understand their current energy usage characteristics and support the evaluation of new technologies.

Q. Please describe the Decarbonization Services Operations Support position.

A. The Decarbonization Services Operations Support position will collect and manage details supporting operational contracts and finances for the Company's decarbonization projects. This work includes managing invoices for parts and services for the Company's RNG projects and other decarbonization projects, such as district energy, geothermal, carbon capture, and hydrogen. Due to the Company's decarbonization portfolio growth in response to CPP requirements, this role will be vital in ensuring the efficient management of these projects, the accurate accounting and reporting of their performance, and integration into the company's financial planning and reporting activities.

Q. Please describe the Decarbonization Portfolio Manager position.

A. The Decarbonization Portfolio Manager will play a key role in shaping the transformation of NW Natural as the energy industry decarbonizes. Specifically, the Decarbonization Portfolio Manager will manage the overall CPP decarbonization portfolio. These activities include coordinating a multi-disciplinary, multi-department decarbonization team, tracking and monitoring the Company's ongoing compliance workstreams, forecasting resource requirements, and recommending compliance actions. The Decarbonization Portfolio Manager will also act as a subject matter expert for the Company's decarbonization portfolio and represent NW Natural in various forums including with regulatory bodies, such as the Commission and ODEQ.

Q. Please describe the Decarbonization Compliance Rates Analyst position.

A. The Decarbonization Compliance Rates Analyst will focus on providing ongoing regulatory analytical support for the Company's decarbonization efforts, including developing analytical models for ratemaking and bill impact analysis, recommending decarbonization actions to management, and preparing documents and analyses for regulatory proceedings.

Q. Please describe the Peak Load Management Analyst position.

A. The Peak Load Management Analyst will perform research, data collection, quantitative data analysis, and reporting tasks to support demand-side management ("DSM") programs and support analysis, including demand response potential or planning studies, and DSM program and policy evaluations. Focusing on DSM is critical in order maximize the existing system in order to minimize investments in the expansion of the distribution system while still providing safe and reliable utility service. This focus on demand-side management was evident in the Company's recent IRP, where the Commission stated that it "expect[ed] companies to take very seriously our expectation that they mitigate growth where they reasonably can [to] avoid distribution system capital investments" while "taking very seriously the company's continuing obligation to maintain safe and reliable service."[15]

Q. Does this conclude your direct testimony?

A. Yes.

[15] *In the Matter of Northwest Natural Gas Co., dba NW Natural, 2022 Integrated Resource Plan*, Docket No. LC 79, Order No. 23-281, at 14 (Aug. 2, 2023).

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

DIRECT TESTIMONY OF JOHN J. SPANOS

DEPRECIATION
EXHIBIT 1600

December 29, 2023

EXHIBIT 1600 – DIRECT TESTIMONY– DEPRECIATION

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I. INTRODUCTION

Q. Please state your name and address.

A. John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. 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 37 years of depreciation experience which includes giving expert testimony in more than 440 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 800 other depreciation or valuation assignments. Please refer to NW Natural/1601, 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 dba NW Natural (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, 2022, 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, 2022.

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, 498.10, 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, "2022 Depreciation Study – Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2022", which has been marked Exhibit NW Natural/1602, 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 2022. 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. 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 67-R3 indicates an average service life of 67 years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a moderate height, 3, 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. Each of the life spans result in probable retirement years that are years into the future but included as part of the Company's future expectations. As a result, the retirements of these facilities are not yet subject to specific management plans. 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 $5,000 regulator will include not only the $5,000 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 10 percent (($50 - $550)/$5,000).

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 2022 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 2020-2022 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, 2022.

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, 498.10, 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 approximately 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. DESCRIPTION OF REPORT

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 25 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 2022 and analyzed for periods that best represent the overall service life of this property. The life tables for the 1919-2022, 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 $2,306,351 retired during age interval 0.5-1.5 with $983,469,927 exposed to retirement at the beginning of the interval. Consequently, the retirement ratio is 0.0023 ($2,306,351/$983,469,927) 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 99.66 percent. This process continues for the remaining age intervals for which plant was exposed to retirement during the period 1919-2022. The resultant life table, or original survivor curve, is plotted along with the estimated smooth survivor curve, the 65-R1.5 on page VII-101.

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 2022. The 30-year period experienced $51,864,733 (($108,345)-$51,756,388) in negative net salvage for $445,620,241 plant retired. The result is negative net salvage of 114 percent ($51,864,733/$45,620,241) on the statistics for the account for the entire 30-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 110 percent.

My calculation of the annual depreciation related to the original cost of Account 380.00, Services, as of December 31, 2022, is presented on pages IX-73 through IX-75 of the report. The calculation is based on the 65-R1.5 survivor curve, 110 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/1602, Spanos. In my opinion, these are reasonable and appropriate depreciation accrual rates for the Company.

Q. Does this complete your direct testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibits of John J. Spanos

DEPRECIATION
EXHIBITS 1601– 1602

December 29, 2023

EXHIBITS 1601 – 1602 – DEPRECIATION

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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-	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. Com.	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. Com.	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.	2020	NJ BPU	Docket No. ER20020146	Jersey Central Power & Light Company	Depreciation
331.	2020	PA PUC	Docket No. R-2020-3018835	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
332.	2020	PA PUC	Docket No. R-2020-3019369	Pennsylvania-American Water Company	Depreciation
333.	2020	PA PUC	Docket No. R-2020-3019371	Pennsylvania-American Water Company	Depreciation
334.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
335.	2020	NM PRC	Case No. 20-00104-UT	El Paso Electric Company	Depreciation
336.	2020	MD PSC	Case No. 9644	Columbia Gas of Maryland, Inc.	Depreciation
337.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
338.	2020	VA St CC	Case No. PUR-2020-00095	Virginia Natural Gas Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
339.	2020	SC PSC	Docket No. 2020-125-E	Dominion Energy South Carolina, Inc.	Depreciation
340.	2020	WV PSC	Case No. 20-0745-G-D	Hope Gas, Inc. d/b/a Dominion Energy West Virginia	Depreciation
341.	2020	VA St CC	Case No. PUR-2020-00106	Aqua Virginia, Inc.	Depreciation
342.	2020	PA PUC	Docket No. R-2020-3020256	City of Bethlehem – Bureau of Water	Depreciation
343.	2020	NE PSC	Docket No. NG-109	Black Hills Nebraska	Depreciation
344.	2020	NY PSC	Case No. 20-E-0428 & 20-G-0429	Central Hudson Gas & Electric Corporation	Depreciation
345.	2020	FERC	ER20-598	Duke Energy Indiana	Depreciation
346.	2020	FERC	ER20-855	Northern Indiana Public Service Company	Depreciation
347.	2020	OR PSC	UE 374	PacifiCorp	Depreciation
348.	2020	MD PSC	Case No. 9490 Phase II	Potomac Edison – Maryland	Depreciation
349.	2020	IN URC	Case No. 45447	Southern Indiana Gas and Electric Company	Depreciation
350.	2020	IN URC	IURC Cause No. 45468	Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery of	Depreciation
351.	2020	KY PSC	Case No. 2020-00349	Kentucky Utilities Company	Depreciation
352.	2020	KY PSC	Case No. 2020-00350	Louisville Gas and Electric Company	Depreciation
353.	2020	FERC	Docket No. ER21- 000	South FirstEnergy Operating Companies	Depreciation
354.	2020	OH PUC	Case Nos 20-1651-EL-AIR, 20-1652-EL-AAM & 20-1653-EL-ATA	Dayton Power and Light Company	Depreciation
355.	2020	OR PSC	UG 388	Northwest Natural Gas Company	Depreciation
356.	2020	MO PSC	Case No. GR-2021-0241	Ameren Missouri Gas	Depreciation
357.	2021	KY PSC	Case No. 2021-00103	East Kentucky Power Cooperative	Depreciation
358.	2021	MPUC	Docket No. 2021-00024	Bangor Natural Gas	Depreciation
359.	2021	PA PUC	Docket No. R-2021-3024296	Columbia Gas of Pennsylvania, Inc.	Depreciation
360.	2021	NC Util. Com.	Doc. No. G-5, Sub 632	Public Service of North Carolina	Depreciation
361.	2021	MO PSC	ER-2021-0240	Ameren Missouri	Depreciation
362.	2021	PA PUC	Docket No. R-2021-3024750	Duquesne Light Company	Depreciation
363.	2021	KS PSC	21-BHCG-418-RTS	Black Hills Kansas Gas	Depreciation
364.	2021	KY PSC	Case No. 2021-00190	Duke Energy Kentucky	Depreciation
365.	2021	OR PSC	Docket UM 2152	Portland General Electric	Depreciation
366.	2021	ILL CC	Docket No. 20-0810	North Shore Gas Company	Depreciation
367.	2021	FERC	ER21-1939-000	Duke Energy Progress	Depreciation
368.	2021	FERC	ER21-1940-000	Duke Energy Carolina	Depreciation
369.	2021	KY PSC	Case No. 2021-00183	NiSource Columbia Gas of Kentucky	Depreciation
370.	2021	MD PSC	Case No. 9664	NiSource Columbia Gas of Maryland	Depreciation
371.	2021	OH PUC	Case No. 21-0596-ST-AIR	Aqua Ohio	Depreciation
372.	2021	PA PUC	Docket No. R-2021-3026116	Hanover Borough Municipal Water Works	Depreciation
373.	2021	OR PSC	UM-2180	Idaho Power Company	Depreciation
374.	2021	ID PUC	Case No. IPC-E-21-18	Idaho Power Company	Depreciation
375.	2021	WPSC	6690-DU-104	Wisconsin Public Service Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
376.	2021	PAPUC	Docket No. R-2021-3026116	Borough of Hanover	Depreciation
377.	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
378.	2021	TX PUC	Texas PUC Docket No. 52195; SOHA Docket No. 473-21-2606	El Paso Electric	Depreciation
379.	2021	MO PSC	Case No. GR.2021-0108	Spire Missouri	Depreciation
380.	2021	WV PSC	Case No. 21-0215-WS-P	West Virginia American Water Company	Depreciation
381.	2021	FERC	ER21-2736	Duke Energy Carolinas	Depreciation
382.	2021	FERC	ER21-2737	Duke Energy Progress	Depreciation
383.	2021	IN URC	Cause #45621	Northern Indiana Public Service Company	Depreciation
384.	2021	PA PUC	Docket No. R-2021-3026682	City of Lancaster	Depreciation
385.	2021	OH PUC	Case No. 21-887-EL-AIR; Case No. 21-888-EL-ATA; Case No. 889-El-AAM	Duke Energy Ohio	Depreciation
386.	2021	AK PSC	Docket No. 21-097-U	Black Hills Energy Arkansas, Inc.	Depreciation
387.	2021	OK CC	Cause No. PUD202100164	Oklahoma Gas & Electric	Depreciation
388.	2021	FERC	Case ER-22-392-001	El Paso Electric	Depreciation
389.	2021	FERC	Case ER-21-XXX	MidAmerican Electric	Depreciation
390.	2021	PA PUC	Docket Nos. R-2021-3027385, R-2021-3027386	Aqua Pennsylvania, Inc. Aqua Pennsylvania Wastewater, Inc.	Depreciation
391.	2022	FERC	Case ER-22-282-000	El Paso Electric	Depreciation
392.	2022	ILL CC	Docket No. 22-0154	MidAmerican Gas	Depreciation
393.	2022	MO PSC	Case No. ER-2022-0129	Evergy Metro	Depreciation
394.	2022	MO PSC	Case No. ER-2022-0130	Evergy Missouri West	Depreciation
395.	2022	PA PUC	Docket No. R-2022-3031211	NiSource Columbia Gas of Pennsylvania, Inc.	Depreciation
396.	2022	MA DPU	D.P.U. 22-20	The Berkshire Gas Company	Depreciation
397.	2022	PA PUC	R-2022-3031672; R-2022-	Pennsylvania-American Water Company	Depreciation
398.	2022	SD PUC	Docket No. NG22-	MidAmerican Gas	Depreciation
399.	2022	MD PSC	Case No. 9680	NiSource Columbia Gas of Maryland	Depreciation
400.	2022	WYPSC	Docket No. 20003-214-ER-22	Black Hills Energy – Cheyenne Light, Fuel and Power Company	Depreciation
401.	2022	MA DPU	D.P.U. 22.22	NSTAR Electric Company d/b/a Eversource Energy	Depreciation
402.	2022	NC Util Com	Docket No. W-218, Sub 573	Aqua North Carolina, Inc.	Depreciation
403.	2022	OR PUC	UM2213	Northwest Natural Gas	Depreciation
404.	2022	OR PUC	UM2214	Northwest Natural Gas	Depreciation
405.	2022	ME PUC	Docket No. 2022-00152	Central Maine Power	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
406.	2022	SC PSC	Docket No. 2022-254-E	Duke Energy Progress	Depreciation
407.	2022	NC Util Com	Docket No. E-2, SUB 1300	Duke Energy Progress	Depreciation
408.	2022	IN URC	Cause #45772	Northern Indiana Public Service Company	Depreciation
409.	2022	PA PUC	R-2022-3031340	The York Water Company	Depreciation
410.	2022	PA PUC	R-2022-3032806	The York Water Company	Depreciation
411.	2022	PA PUC	R-2022-3031704	Borough of Ambler	Depreciation
412.	2022	MO PSC	ER-2022-0337	Ameren Missouri	Depreciation
413.	2022	OH PUC	Case No. 22-507-GA-AIR	Duke Energy Ohio	Depreciation
414.	2022	PA PUC	R-2022-3035730	National Fuel Gas Distribution Corporation – PA Division	Depreciation
415.	2022	WY PSC	20003-214-ER-22	Cheyenne Light, Fuel and Power Company	Depreciation
416.	2022	NJ BPU	BPU Docket No. ER2303144	Jersey Central Power & Light Company	Depreciation
417.	2022	KY PSC	Case No. 2022-00372	Duke Energy Kentucky	Depreciation
418.	2022	TX PUC	SOAH Docket No. 473-23-04521	Aqua Texas, Inc.	Depreciation
419.	2022	NC Util Com	Docket No. E-7, Sub 1276	Duke Energy Carolinas, LLC	Depreciation
420.	2022	KY PSC	Case No. 2022-00432	Bluegrass Water	Depreciation
421.	2023	ILL CC	Docket No. 23-0069	The Peoples Gas Light and Coke Company	Depreciation
422.	2023	ILL CC	Docket No. 23-0068	North Shore Gas Company	Depreciation
423.	2023	WV PSC	Case No. 23-0030-E-D	Monongahela Power Company and The Potomac Edison Company	Depreciation
424.	2023	ID PUC	AVU-E-23-01; AVU-G-23-01	Avista Corporation	Depreciation
425.	2023	ILL CC	Docket No. 23-0066	Northern Illinois Gas Company d/b/a Nicor Gas Company	Depreciation
426.	2023	SC PSC	Docket No. 2023-70-G	Dominion Energy South Carolina, Inc.	Depreciation
427.	2023	FERC	Docket No. ER23-xxx-00	Duke Energy Ohio, Inc.	Depreciation
428.	2023	WY PSC	Docket No. 30036-78-GR-23	Black Hills Wyoming Gas Company d/b/a Black Hills Energy	Depreciation
429.	2023	PSC MD	Case No. 9695	The Potomac Edison Company	Depreciation
430.	2023	OR PUC	Case No. UM2277	Avista Corporation	Depreciation
431.	2023	FERC	Docket No. ER23-xxx-000	PPL Electric Utilities	Depreciation
432.	2023	OH PUC	Case No. 23-0154-GA-AIR	Northeast Ohio Natural Gas Corporation	Depreciation
433.	2023	DE PSC	PSC Docket No. 23-0601	Artesian Water Company	Depreciation
434.	2023	CO PUC	No. 23AL-0231G	Black Hills Colorado d/b/a Black Hills Energy	Depreciation
435.	2023	NH PUC	Docket No. DE 23-039	Granite State Electric d/b/a Liberty Utilities	Depreciation
436.	2023	MD PSC	Case No. 9701	Columbia Gas of Maryland	Depreciation
437.	2023	NY PSC	Case Nos. 23-E-0418; 23-G-0419	Central Hudson Gas and Electric	Depreciation
438.	2023	FERC	Docket No. ER23-xxx-000	Central Maine Power Company	Depreciation
439.	2023	SD PUC	Docket Number EL23-016	Northwestern Energy	Depreciation
440.	2023	CT PURA	Docket No. 23-08-32	Connecticut Water Company	Depreciation
441.	2023	OH PUC	Case 23-0894-GA-AIR	The East Ohio Gas Company d/b/a Dominion Energy Ohio	Depreciation
442.	2023	IN URC	Cause No. 45911	Indianapolis Power & Light	Depreciation
443.	2023	IN URC	Cause No. 45967	Northern Indiana Public Service Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
444.	2023	PA PUC	Docket No. R-2023-3043189 and Docket No. R-2023-3043190	Pennsylvania-American Water Company	Depreciation
445.	2023	IN URC	Cause No. 45988	Citizens Energy Group	Depreciation

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of John J. Spanos

DEPRECIATION
EXHIBIT 1602

December 29, 2023

NW Natural®

2022 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO GAS PLANT
AS OF DECEMBER 31, 2022

Prepared by:

GANNETT FLEMING

Excellence Delivered As Promised

NORTHWEST NATURAL GAS COMPANY
Portland, Oregon

2022 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO GAS PLANT
AS OF DECEMBER 31, 2022

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 5, 2023

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, 2022. 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:jmr

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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, 2022. 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 to the detailed accumulated depreciation reserve due to recording of Removal Work in Progress (RWIP) based on Order No. 20-364.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to gas plant in service as of December 31, 2022 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 $158.2 million when applied to depreciable plant balances as of December 31, 2022. 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, 2022	PROPOSED RATE	PROPOSED EXPENSE
Intangible Plant	$ 248,530,403.19	12.46	$ 30,967,174
Oil Gas Facilities	21,398.00	-	(5,997)
Other Production Facilities	628,802.00	-	(2,330)
Underground Storage Plant	214,857,527.38	2.12	4,545,886
Local Storage Plant	102,047,489.49	4.08	4,162,110
Transmission Plant	395,412,904.63	1.92	7,589,944
Distribution Plant	2,721,404,755.58	3.16	85,861,554
General Plant	363,152,755.30	6.86	24,901,872
General Plant Reserve Amortization	-	-	184,588
Total	**$4,046,056,035.57**	**3.91**	**$158,213,128**

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, 2022. 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, 2022

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 2022, 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.

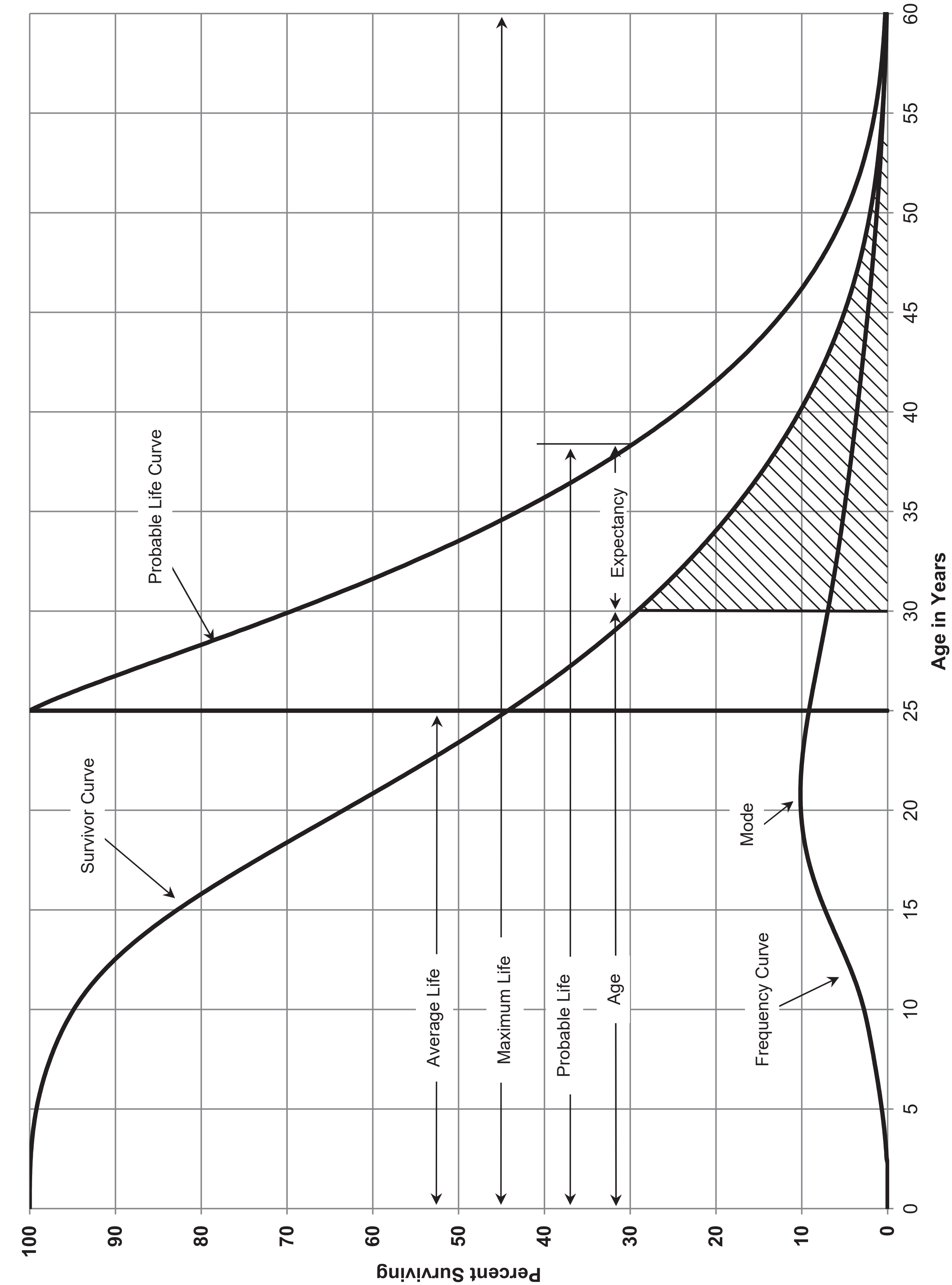

FIGURE 1. TYPICAL SURVIVOR CURVE AND DERIVED CURVES

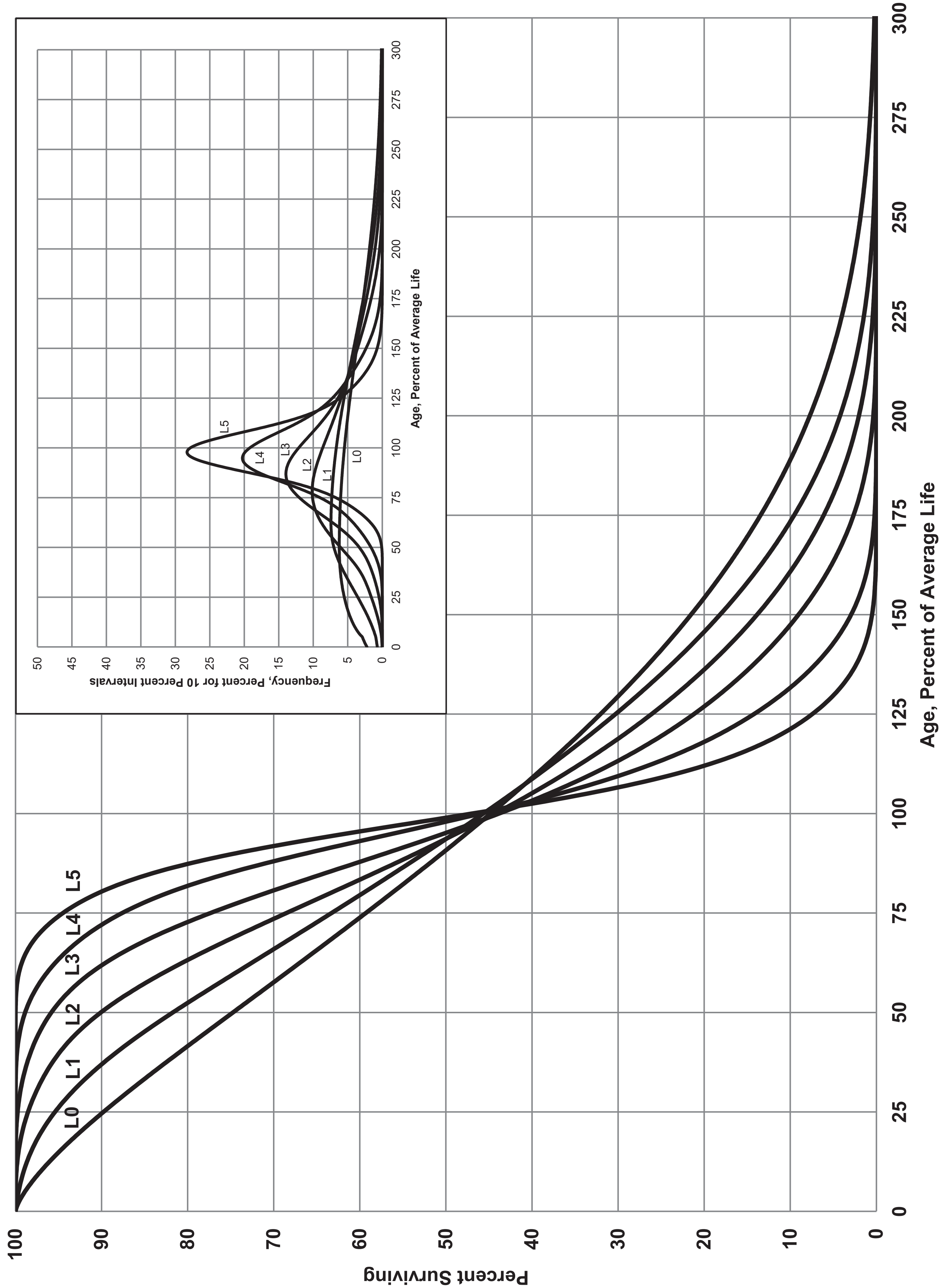

FIGURE 2. LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

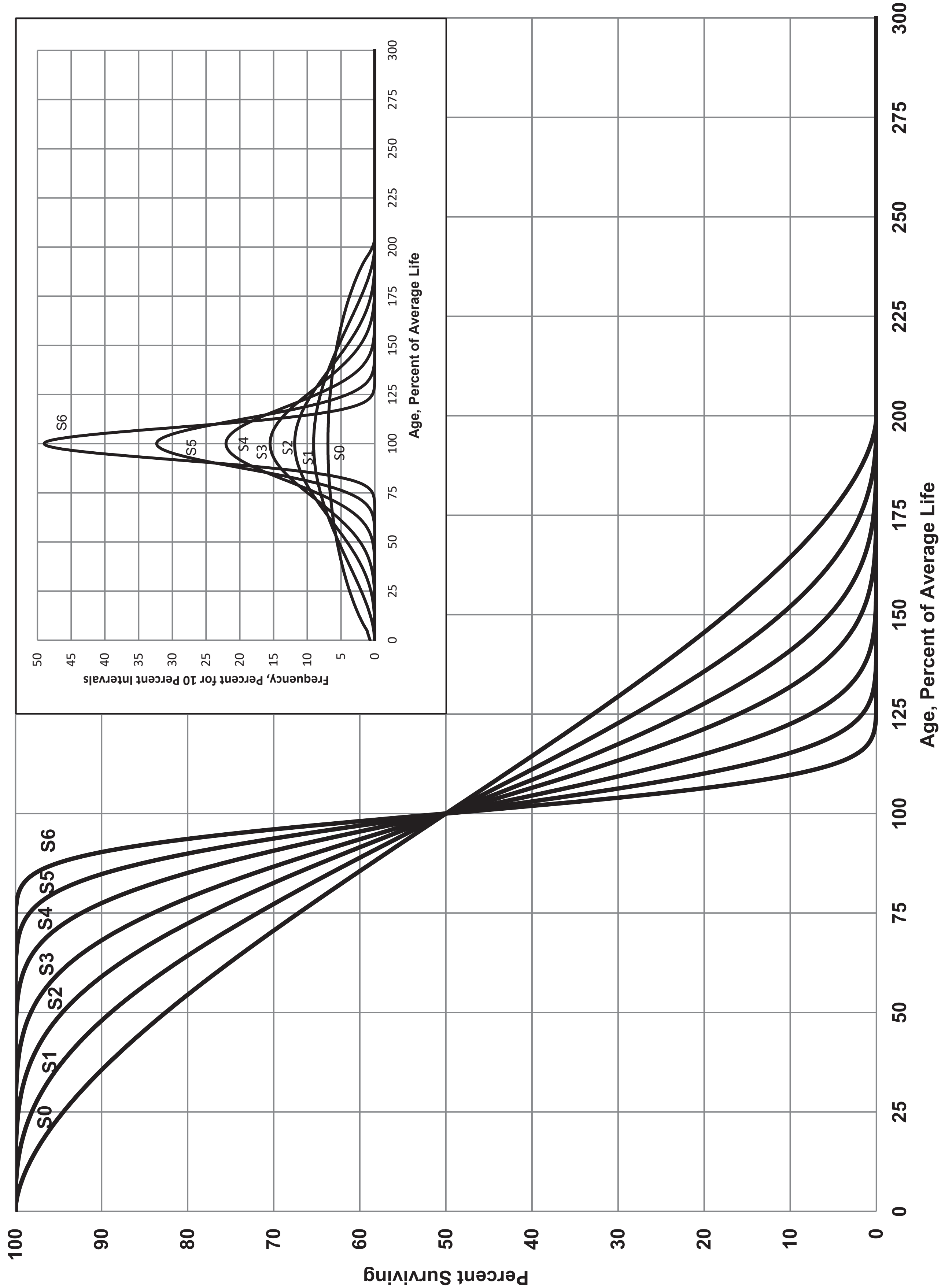

FIGURE 3. SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

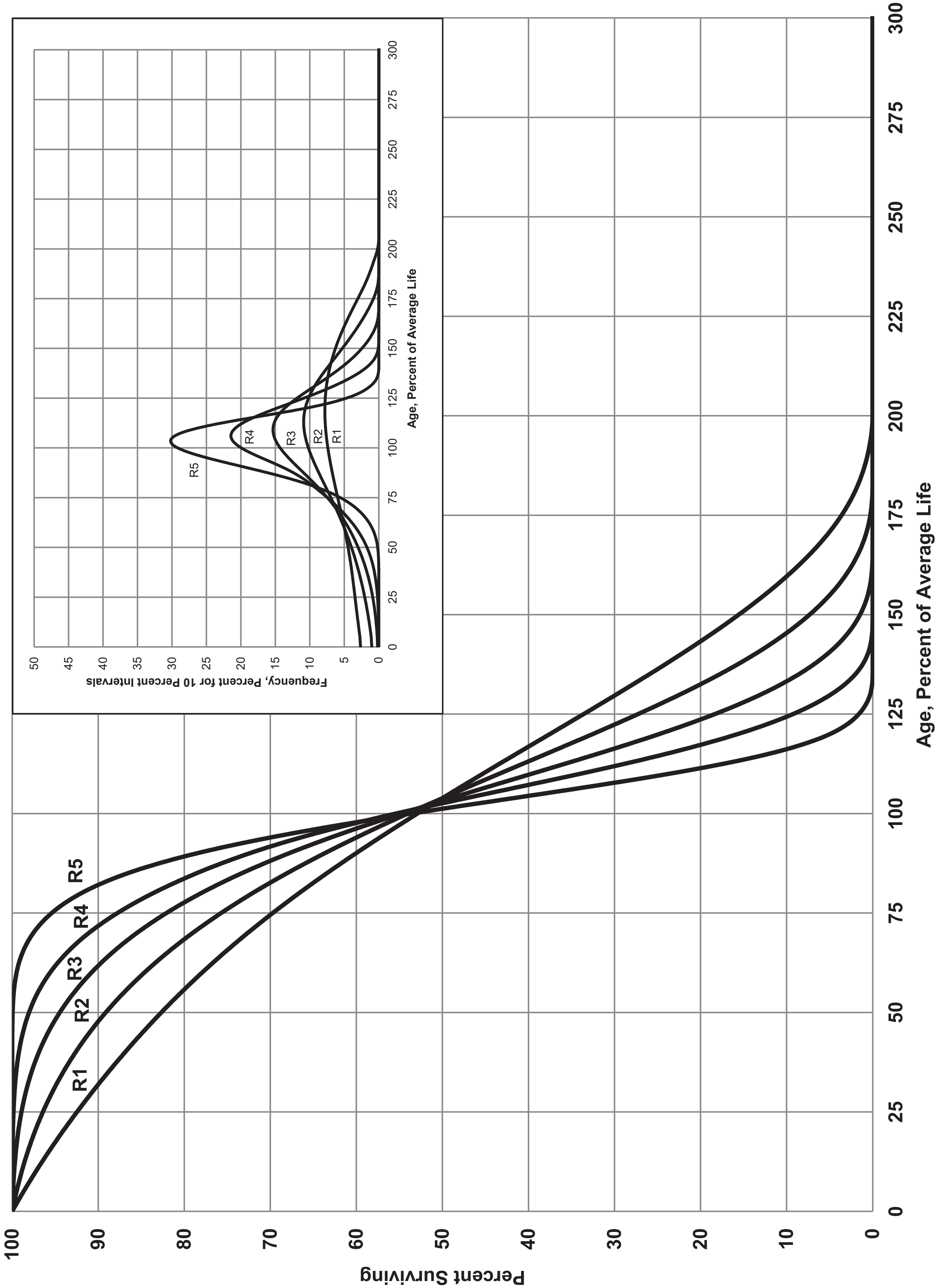

FIGURE 4. RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

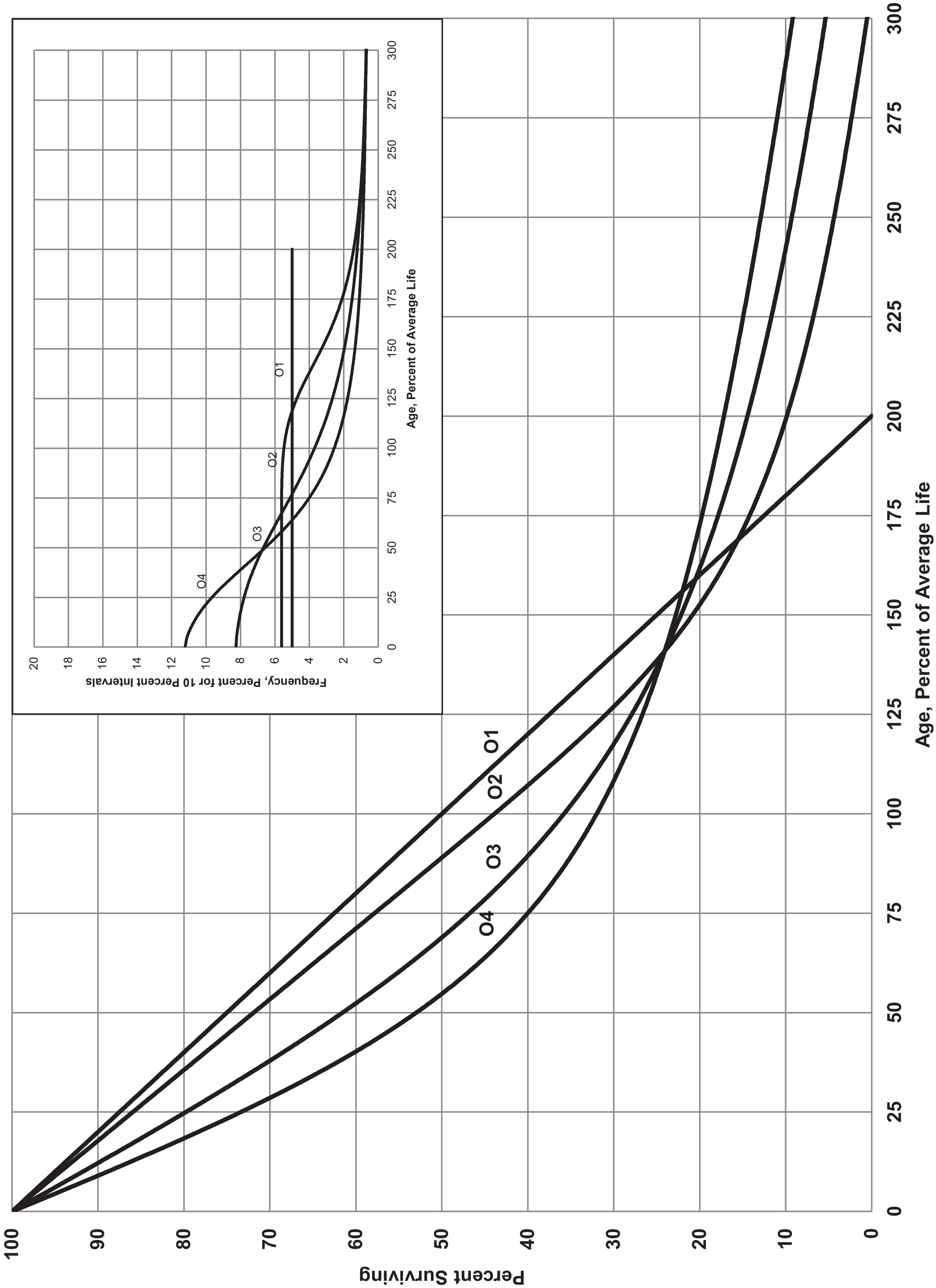

FIGURE 5. ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES

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 2013-2022 for which there were placements during the years 2008-2022. 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 2008 were retired in 2013. 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 2013 retirements of 2008 installations and ending with the 2022 retirements of the 2017 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 2013-2022
SUMMARIZED BY AGE INTERVAL

Experience Band 2013-2022 | Placement Band 2008-2022

Year Placed	Retirements, Thousands of Dollars During Year 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total During Age Interval	Age Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2008	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2009	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2010	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2011	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2012	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2013	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2014		5	11	12	13	14	15	16	18	20	113	7½-8½
2015			6	12	13	15	16	17	19	19	124	6½-7½
2016				6	13	15	16	17	19	19	131	5½-6½
2017					7	14	16	17	19	20	143	4½-5½
2018						8	18	20	22	23	146	3½-4½
2019							9	20	22	25	150	2½-3½
2020								11	23	25	151	1½-2½
2021									11	24	153	½-1½
2022										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2013-2022
SUMMARIZED BY AGE INTERVAL

Experience Band 2013-2022 Placement Band 2008-2022

Year Placed (1)	2013 (2)	2014 (3)	2015 (4)	2016 (5)	2017 (6)	2018 (7)	2019 (8)	2020 (9)	2021 (10)	2022 (11)	Total During Age Interval (12)	Age Interval (13)
	Acquisitions, Transfers and Sales, Thousands of Dollars — During Year											
2008	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2009	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2010	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2011	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2012	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2013	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2014		-	-	-	-	-	-	-	-	-	6	7½-8½
2015			-	-	-	-	-	-	-	-	-	6½-7½
2016				-	-	-	-	(12)[b]	-	-	-	5½-6½
2017					-	-	-	-	22[a]	-	-	4½-5½
2018						-	-	(19)[b]	-	-	10	3½-4½
2019							-	-	-	-	-	2½-3½
2020								-	-	(102)[c]	(121)	1½-2½
2021									-	-	-	½-1½
2022											-	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 2013 through 2022 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 2018 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 2013-2022
SUMMARIZED BY AGE INTERVAL

Experience Band 2013-2022 Placement Band 2008-2022

Year Placed	Exposures, Thousands of Dollars – Annual Survivors at the Beginning of the Year 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total at Beginning of Age Interval	Age Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2008	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2009	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2010	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2011	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2012	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2013	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2014		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2015			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2016				580[a]	574	561	546	530	501	482	3,057	5½-6½
2017					660[a]	653	639	623	628	609	3,789	4½-5½
2018						750[a]	742	724	685	663	4,332	3½-4½
2019							850[a]	841	821	799	4,955	2½-3½
2020								960[a]	949	926	5,719	1½-2½
2021									1,080[a]	1,069	6,579	½-1½
2022										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 2013-2022, 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 2013-2022 Placement Band 2008-2022

(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

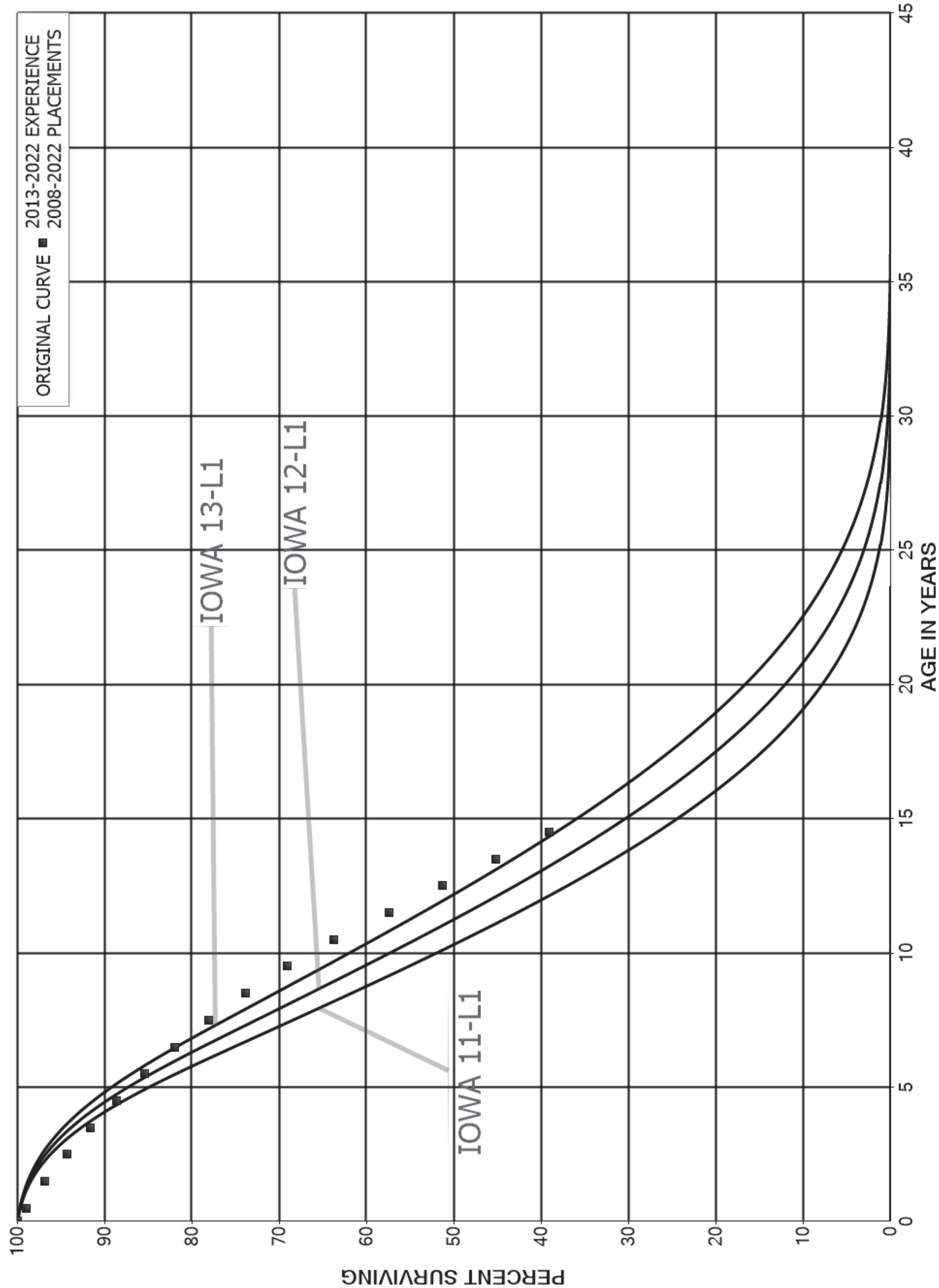


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

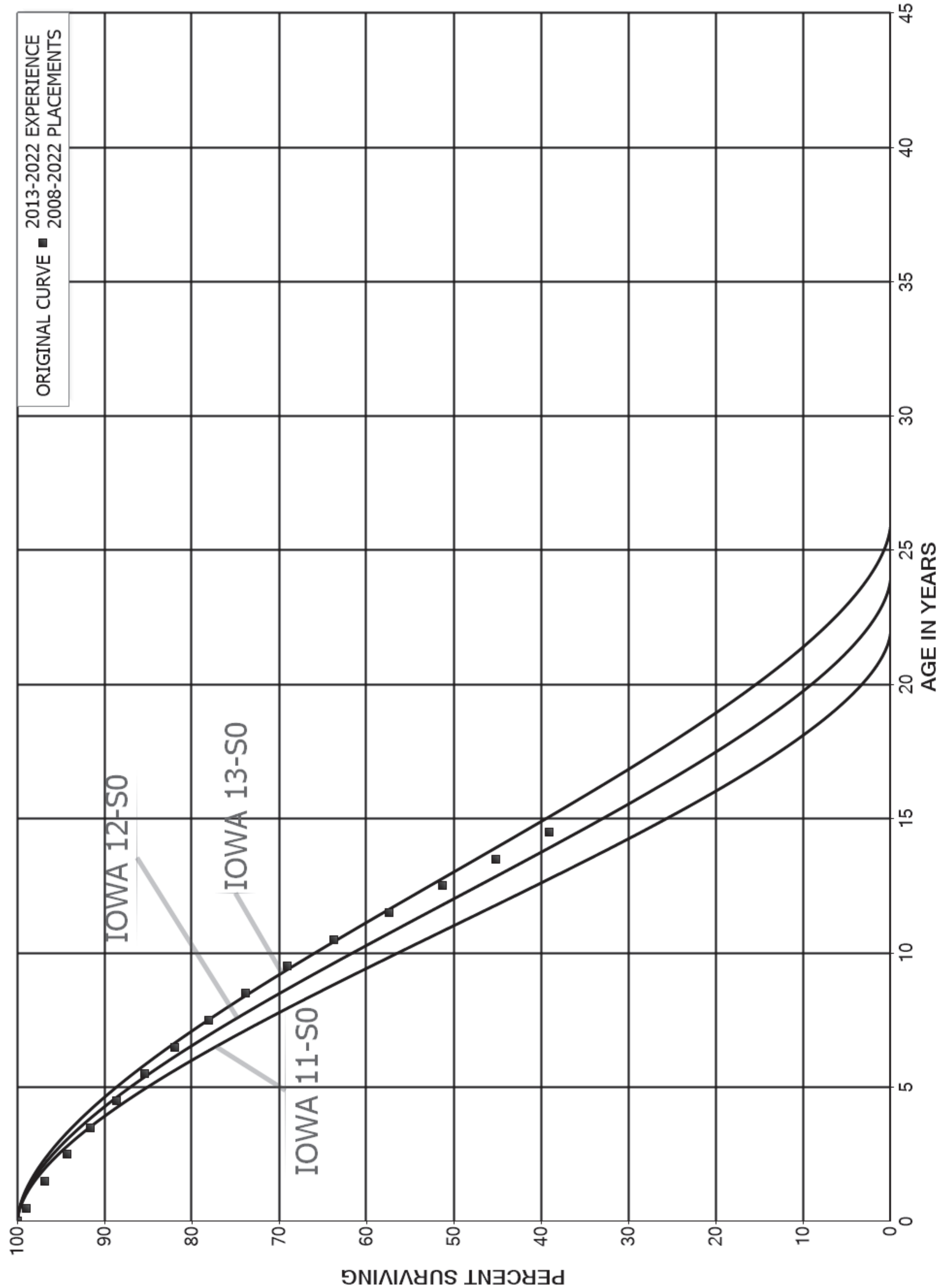


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

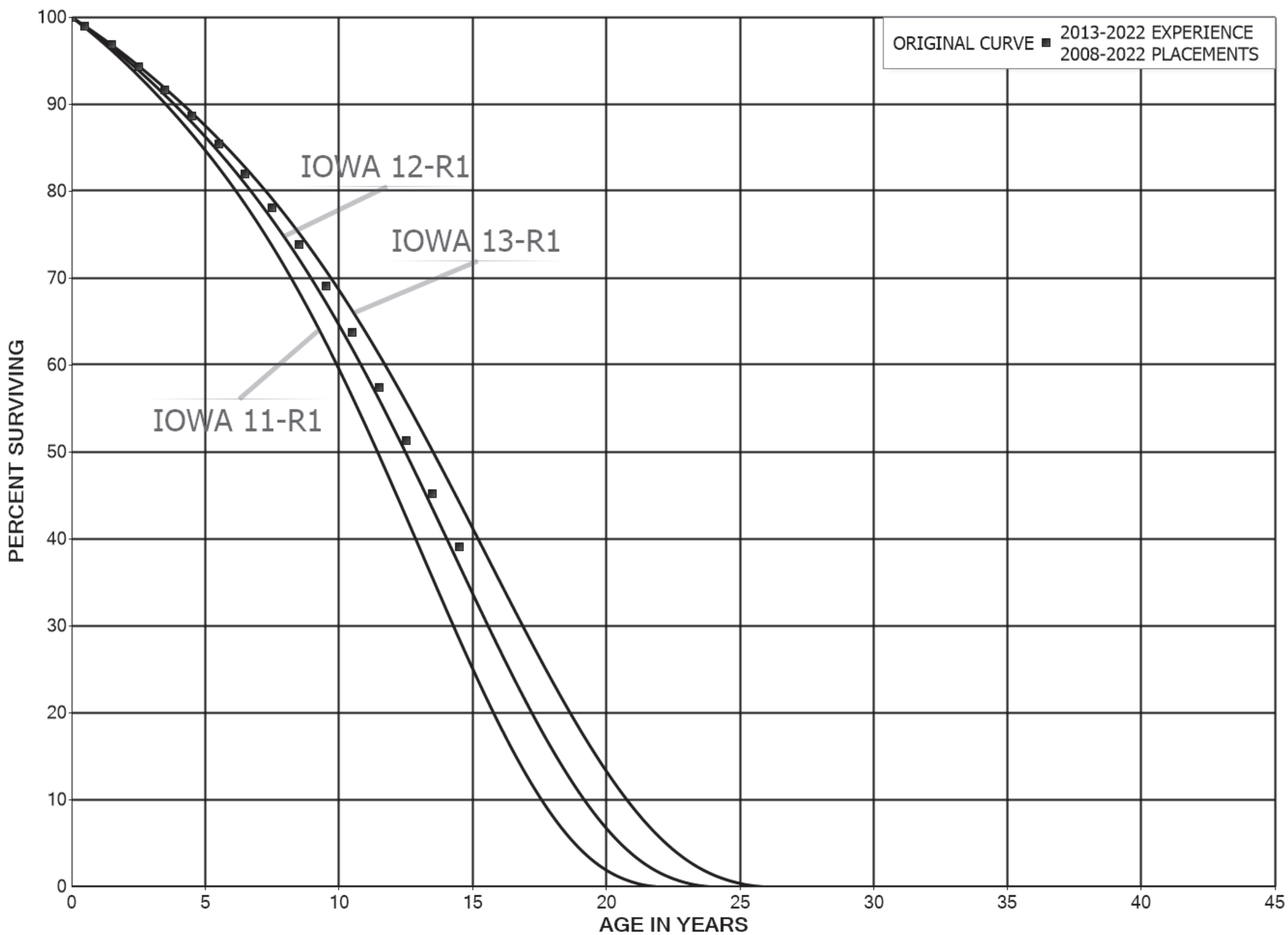
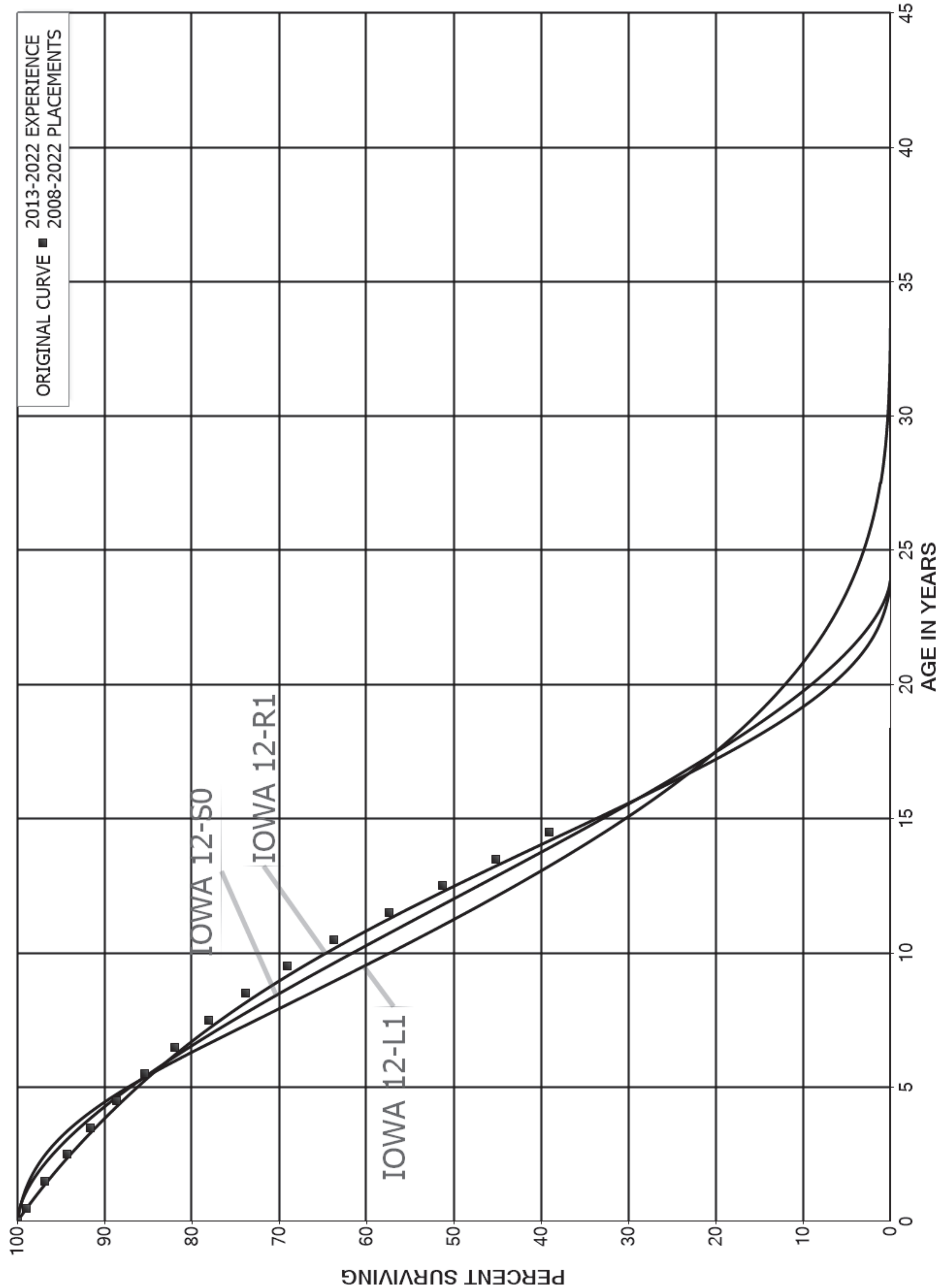


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



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 72 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

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 36 percent of the total depreciable plant. Aged plant accounting data have been compiled for the years 1910 through 2022. 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 2022 and 1961 through 2022. The Iowa 67-R3 is an excellent fit of the original survivor curve. The 67-year service life is within the typical service life range of 55 to 70 years for mains. The 67-year life reflects the Company’s plans and practices of the past and next few years. The previous estimate was the Iowa 68-R3.

The survivor curve estimate for Account 380, Services, is based on the statistical analyses of historical retirement experience for the periods 1919-2022, 1976-2015 and 1981-2015. The 65-R1.5 estimate for Account 380, Services, is a good fit of the original survivor curve developed from historical plant retirements for the period 1919 through 2022. 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 65-R1.5 survivor curve sets forth the constant rates of retirement through approximately age 76. The 65-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-R2

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 2022.

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 2022. 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 2022 contributed significantly toward the net salvage estimates for 11 plant accounts, representing 71 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 2022 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 2020-20220 periods were computed to smooth the annual amounts.

Cost of removal fluctuated considerably during the 30-year period, 1993-2022. 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 390 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 19 percent gross salvage reflects moderate salvage value for pipe.

The net salvage percent based on the overall period 1993 through 2022 is 95 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 75 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.

<u>Single Unit of Property</u>

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, 2022, 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, 2022, 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	5
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, 2022, 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, 2022. For most plant accounts, the application of such rates to future balances that reflect additions subsequent to December 31, 2022, 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, 2022, 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, 2022 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, 2022

DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2022	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	116,460,287.26	22,267,386	94,192,901	18,980,427	16.30	5.0
303.11 MISCELLANEOUS INTANGIBLE PLANT - HORIZON		10-SQ	0	47,100,838.00	813,380	46,287,458	4,872,364	10.34	9.5
303.12 MISCELLANEOUS INTANGIBLE PLANT - SECURITY DIRECTIVE		5-SQ	0	6,653,764.00	221,249	6,432,515	1,429,448	21.48	4.5
303.20 MISCELLANEOUS INTANGIBLE PLANT - CUSTOMER INFORMATION SYSTEM		15-SQ	0	32,409,597.11	32,398,798	10,799	1,661	0.01	6.5
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	15,263,454.19	5,820,831	9,442,623	2,684,448	17.59	3.5
303.71 MISCELLANEOUS INTANGIBLE PLANT - CLOUD-BASED SOFTWARE HORIZON		10-SQ	0	23,987,694.00	793,126	23,194,568	2,441,533	10.18	9.5
303.72 MISCELLANEOUS INTANGIBLE PLANT - CLOUD-BASED SOFTWARE TSA SECURITY DIRECTIVE		5-SQ	0	2,507,817.63	0	2,507,818	557,293	22.22	4.5
TOTAL INTANGIBLE PLANT				**248,530,403.19**	**66,461,721**	**182,068,682**	**30,967,174**	**12.46**	
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		20-L0.5	(5)	4,033.00	8,066	(3,831)	0	-	-
311.80 LIQUEFIED PETROLEUM GAS EQUIPMENT		20-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	36,703	72,922	1,547	1.41	47.1
351.00 STRUCTURES AND IMPROVEMENTS		60-R3	0	9,151,549.93	3,451,565	5,699,985	137,196	1.50	41.5
352.00 WELLS		50-S3	0	57,617,342.25	19,349,053	38,268,289	1,080,688	1.88	35.4
352.10 STORAGE LEASEHOLDS AND RIGHTS		55-S2.5	0	3,939,511.52	2,005,825	1,933,687	63,530	1.61	30.4
352.20 RESERVOIRS		55-S2.5	0	10,834,054.54	4,363,031	6,471,024	189,171	1.75	34.2
352.30 NONRECOVERABLE GAS		60-R4	0	6,440,889.82	3,961,845	2,479,045	81,957	1.27	30.2
353.00 LINES		55-S2.5	(15)	12,135,600.15	4,628,445	9,327,495	247,119	2.04	37.7
354.10 COMPRESSOR STATION EQUIPMENT - TURBINE 1		50-R3	(10)	4,154,699.66	2,400,497	2,169,673	104,583	2.52	20.7
354.20 COMPRESSOR STATION EQUIPMENT - TURBINE 2		50-R3	(10)	4,154,699.00	2,445,528	2,124,641	105,076	2.53	20.2
354.30 COMPRESSOR STATION EQUIPMENT - TURBINE 3		50-R3	(10)	14,640,514.36	6,099,608	10,004,958	346,508	2.37	28.9
354.40 COMPRESSOR STATION EQUIPMENT - TURBINE 4		50-R3	(10)	16,399,249.42	5,262,814	12,776,360	380,508	2.32	33.6
354.50 COMPRESSOR STATION EQUIPMENT - TURBINE 5		50-R3	(10)	3,739,476.97	880,290	3,233,135	85,291	2.28	37.9
354.60 COMPRESSOR STATION EQUIPMENT - TURBINE 6		50-R3	(10)	260,041.78	37,572	248,474	5,820	2.24	42.7
355.00 MEASURING AND REGULATING EQUIPMENT		45-S2	(10)	37,208,515.78	8,739,540	32,189,827	888,636	2.39	36.2
356.00 PURIFICATION EQUIPMENT		45-S2.5	(5)	28,809,985.05	1,156,666	29,093,818	690,858	2.40	42.1
357.00 OTHER EQUIPMENT		35-R4	0	5,261,772.21	1,272,416	3,989,356	137,398	2.61	29.0
TOTAL UNDERGROUND STORAGE PLANT				**214,857,527.38**	**66,091,398**	**160,082,689**	**4,545,886**	**2.12**	

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, 2022

DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2022	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)
LOCAL STORAGE PLANT										
361.00 STRUCTURES AND IMPROVEMENTS										
LINNTON	06-2036	60-R2.5	*	(5)	12,254,779.35	4,431,605	8,435,913	634,063	5.17	13.3
NEWPORT	06-2042	60-R2.5	*	(5)	12,196,541.26	4,708,351	8,098,017	429,910	3.52	18.8
OTHER		60-R2.5		(5)	26,757.00	13,776	14,319	404	1.51	35.4
TOTAL STRUCTURES AND IMPROVEMENTS					24,478,077.61	9,153,732	16,548,249	1,064,377	4.35	15.6
362.00 GAS HOLDERS										
LINNTON	06-2036	60-R3	*	(20)	4,556,064.35	2,934,624	2,532,653	197,638	4.34	12.8
NEWPORT	06-2042	60-R3	*	(20)	5,927,103.82	6,422,031	690,494	42,580	0.72	16.2
OTHER		60-R3		(20)	1,600.14	1,297	623	15	0.94	41.5
TOTAL GAS HOLDERS					10,484,768.31	9,357,952	3,223,770	240,233	2.29	13.4
363.10 LIQUEFACTION EQUIPMENT										
LINNTON	06-2036	55-R2	*	(5)	3,911,724.33	2,839,591	1,267,720	96,611	2.47	13.1
NEWPORT	06-2042	55-R2	*	(5)	22,533,332.49	7,757,409	15,902,590	858,897	3.81	18.5
TOTAL LIQUEFACTION EQUIPMENT					26,445,056.82	10,597,000	17,170,310	955,508	3.61	18.0
363.20 VAPORIZING EQUIPMENT										
LINNTON	06-2036	40-R4	*	(5)	4,458,618.00	2,557,302	2,124,247	177,740	3.99	12.0
NEWPORT	06-2042	40-R4	*	(5)	6,718,208.96	995,368	6,058,751	321,164	4.78	18.9
TOTAL VAPORIZING EQUIPMENT					11,176,826.96	3,552,670	8,182,998	498,904	4.46	16.4
363.30 COMPRESSOR EQUIPMENT										
LINNTON	06-2036	35-R1.5	*	(5)	412,186.22	212,017	220,779	17,115	4.15	12.9
NEWPORT	06-2042	35-R1.5	*	(5)	5,578,397.69	2,252,798	3,604,520	204,833	3.67	17.6
TOTAL COMPRESSOR EQUIPMENT					5,990,583.91	2,464,815	3,825,299	221,948	3.70	17.2
363.40 MEASURING AND REGULATING EQUIPMENT										
LINNTON	06-2036	50-R4	*	(5)	5,494,974.35	1,190,349	4,579,374	353,632	6.44	12.9
NEWPORT	06-2042	50-R4	*	(5)	14,186,433.04	418,832	14,476,923	748,428	5.28	19.3
TOTAL MEASURING AND REGULATING EQUIPMENT					19,681,407.39	1,609,181	19,056,297	1,102,060	5.60	17.3
363.50 CNG REFUELING FACILITIES		31-R3		(5)	3,051,295.49	1,751,707	1,452,153	77,148	2.53	18.8
363.60 LNG REFUELING FACILITIES		45-S2.5		(5)	739,473.00	740,065	36,382	1,932	0.26	18.8
TOTAL LOCAL STORAGE PLANT					**102,047,489.49**	**39,227,122**	**69,495,458**	**4,162,110**	**4.08**	
TRANSMISSION PLANT										
365.20 LAND RIGHTS		75-R4		0	6,455,176.86	2,516,465	3,938,712	83,184	1.29	47.3
366.30 STRUCTURES AND IMPROVEMENTS		55-R3		0	1,546,072.61	466,982	1,079,091	26,854	1.74	40.2
367.00 MAINS		70-R3		(40)	219,580,954.30	42,473,126	264,940,210	4,360,905	1.99	60.8
367.21 MAINS - NORTH MIST		70-R3		(40)	1,994,582.39	1,313,728	1,478,687	32,812	1.65	45.1
367.22 MAINS - SOUTH MIST		70-R3		(40)	14,949,264.00	11,958,827	8,970,143	230,497	1.54	38.9
367.23 MAINS - SOUTH MIST		70-R3		(40)	34,881,341.36	17,269,532	31,564,346	657,160	1.88	48.0
367.24 MAINS - 11.7M S MIST		70-R3		(40)	17,466,181.89	7,506,282	16,946,373	330,403	1.89	51.3
367.25 MAINS - 12M NORTH S MIST		70-R3		(40)	18,613,651.15	7,703,372	18,355,740	354,915	1.91	51.7
367.26 MAINS - 38M NORTH S MIST		70-R3		(40)	68,232,675.58	28,417,009	67,108,737	1,298,108	1.90	51.7
368.00 COMPRESSOR STATION EQUIPMENT		45-R3		(5)	7,723,454.21	3,215,299	4,894,328	157,020	2.03	31.2
369.00 MEASURING AND REGULATING EQUIPMENT		50-R2.5		(10)	3,969,550.28	1,990,173	2,376,332	58,086	1.46	40.9
TOTAL TRANSMISSION PLANT					**395,412,904.63**	**124,830,795**	**421,652,699**	**7,589,944**	**1.92**	

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, 2022

DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2022	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)
DISTRIBUTION PLANT									
374.20 LAND RIGHTS		75-R3	0	1,886,180.64	1,722,154	164,027	2,498	0.13	65.7
375.00 STRUCTURES AND IMPROVEMENTS		35-S0	0	1,519,558.28	183,826	1,335,732	57,132	3.76	23.4
376.11 MAINS - HP 4" AND LESS		67-R3	(85)	703,204,530.08	386,134,235	914,794,146	19,684,854	2.80	46.5
376.12 MAINS - HP 4" AND OVER		67-R3	(85)	752,871,136.38	285,873,611	1,106,937,991	22,032,850	2.93	50.2
377.00 COMPRESSOR STATION EQUIPMENT		30-S3	(5)	818,380.00	710,080	149,219	12,808	1.57	11.7
378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL		55-R2.5	(25)	49,852,298.35	15,051,134	47,264,239	1,086,633	2.18	43.5
379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE		50-R2	(25)	21,362,517.65	4,057,325	22,645,822	507,268	2.37	44.6
380.00 SERVICES		65-R1.5	(110)	954,703,727.69	470,394,277	1,534,483,551	30,191,891	3.16	50.8
381.00 METERS		30-L1	0	113,008,940.35	19,526,342	93,482,598	4,447,427	3.94	21.0
381.10 METERS - ELECTRIC		16-S4	0	1,696,938.46	1,425,093	271,845	36,150	2.13	7.5
381.20 METERS - ERT		14-R0.5	0	40,620,035.75	16,825,416	23,794,620	3,143,943	7.74	7.6
382.00 METER INSTALLATIONS		26-L1	0	63,039,649.54	4,657,901	58,381,749	3,856,770	6.12	15.1
382.10 METER INSTALLATIONS - ELECTRIC		14-L3	0	481,019.77	247,267	233,753	45,655	9.49	5.1
382.20 METER INSTALLATIONS - ERT		18-R3	0	12,014,009.73	6,187,216	5,826,794	555,956	4.63	10.5
383.00 HOUSE REGULATORS		35-S2	0	2,820,768.52	622,862	2,197,907	80,662	2.86	27.2
386.00 OTHER PROPERTY ON CUSTOMERS' PREMISES		10-S6	0	1,162,110.41	634,047	528,063	117,347	10.10	4.5
387.10 OTHER EQUIPMENT - CATHODIC PROTECTION TESTING		30-S3	0	173,858.98	149,168	24,691	1,710	0.98	14.4
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				**2,721,404,755.58**	**1,214,571,049**	**3,812,516,747**	**85,861,554**	**3.16**	
GENERAL PLANT									
390.00 STRUCTURES AND IMPROVEMENTS		48-S0	(5)	135,703,280.39	18,819,682	123,668,762	2,895,955	2.13	42.7
390.10 STRUCTURES AND IMPROVEMENTS - SOURCE CONTROL PLANT		48-S0	(5)	23,033,564.87	7,007,847	17,177,396	420,545	1.83	40.8
391.10 OFFICE FURNITURE AND EQUIPMENT		20-SQ	0	17,962,724.22	5,451,054	12,511,670	897,344	5.00	13.9
391.20 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS		5-SQ	0	44,259,126.85	24,520,664	19,738,463	8,849,891	20.00	2.2
391.21 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS HORIZON		10-SQ	0	2,198,614.00	109,931	2,088,683	219,861	10.00	9.5
391.22 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS TSA SECURITY DIRECTIVE		5-SQ	0	24,886,345.00	2,488,634	22,397,711	4,977,269	20.00	4.5
392.00 TRANSPORTATION EQUIPMENT		13-L2	15	57,491,560.78	18,993,988	29,873,839	3,339,066	5.81	8.9
393.00 STORES EQUIPMENT		FULLY ACCRUED		119,406.00	119,406	0	0	-	-
394.00 TOOLS, SHOP AND GARAGE EQUIPMENT		25-SQ	0	18,690,183.15	6,616,238	12,073,945	747,605	4.00	16.2
396.00 POWER OPERATED EQUIPMENT		15-L1.5	20	16,114,047.55	3,027,114	9,864,124	893,114	5.54	11.0
397.00 COMMUNICATION EQUIPMENT		15-SQ	0	49,718.14	31,488	18,230	3,315	6.67	5.5
397.10 COMMUNICATION EQUIPMENT - MOBILE		10-SQ	0	4,286,109.04	1,495,841	2,790,268	428,610	10.00	6.5
397.20 COMMUNICATION EQUIPMENT - NON-MOBILE AND TELEMETER		15-SQ	0	9,957.65	6,306	3,652	664	6.67	5.5
397.30 COMMUNICATION EQUIPMENT - TELEMETER OTHER		15-SQ	0	11,912,893.50	2,476,276	9,436,618	794,196	6.67	11.9
397.40 COMMUNICATION EQUIPMENT - TELEMETER MICROWAVE		15-SQ	0	5,969,596.82	1,722,641	4,246,956	398,156	6.67	10.7
397.50 COMMUNICATION EQUIPMENT - TELEPHONE		10-SQ	0	340,671.19	280,126	60,545	34,067	10.00	1.8
398.10 MISCELLANEOUS EQUIPMENT - PRINT SHOP		15-SQ	0	4,359.31	3,633	726	290	6.67	2.5
398.20 MISCELLANEOUS EQUIPMENT - KITCHEN		15-SQ	0	28,864.84	13,352	15,513	1,924	6.67	8.1
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	-	-
TOTAL GENERAL PLANT				**363,152,755.30**	**93,275,953**	**265,967,101**	**24,901,872**	**6.86**	

NORTHWEST NATURAL GAS COMPANY

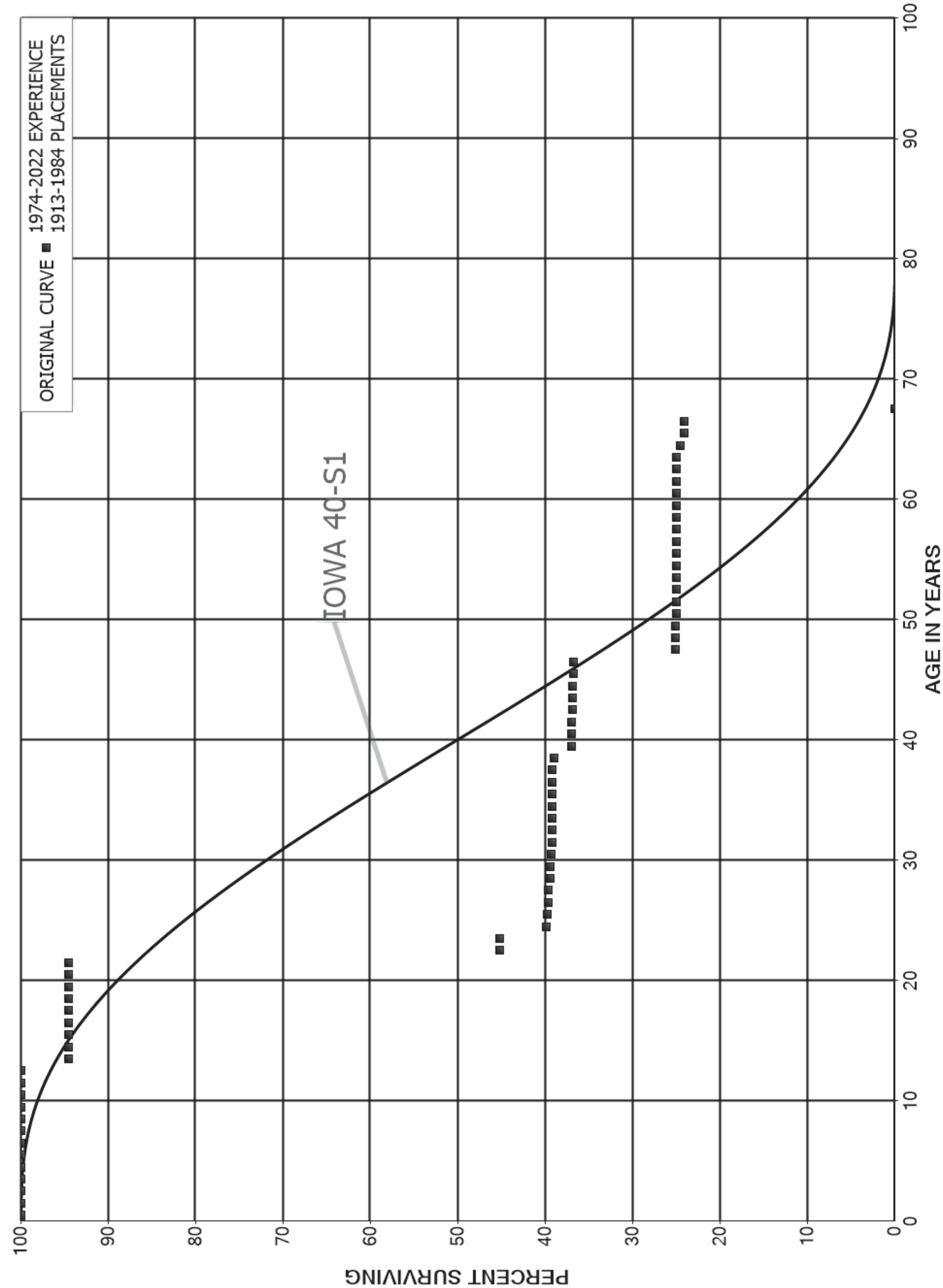
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2022

DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2022	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					1,698,555		(339,711) **		
391.20 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS					(1,045,429)		209,086 **		
391.21 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS HORIZON					(1,129)		226 **		
391.22 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS TSA SECURITY DIRECTIVE					(1,424,288)		284,858 **		
394.00 TOOLS, SHOP AND GARAGE EQUIPMENT					681,126		(136,225) **		
395.00 LABORATORY EQUIPMENT					(39)		8 **		
397.00 COMMUNICATION EQUIPMENT					5,096		(1,019) **		
397.10 COMMUNICATION EQUIPMENT - MOBILE					(90,729)		18,146 **		
397.20 COMMUNICATION EQUIPMENT - NON-MOBILE AND TELEMETER					(65,129)		13,026 **		
397.30 COMMUNICATION EQUIPMENT - TELEMETER OTHER					(426,912)		85,382 **		
397.40 COMMUNICATION EQUIPMENT - TELEMETER MICROWAVE					(329,456)		65,891 **		
397.50 COMMUNICATION EQUIPMENT - TELEPHONE					77,743		(15,549) **		
398.10 MISCELLANEOUS EQUIPMENT - PRINT SHOP					(1,248)		250 **		
398.20 MISCELLANEOUS EQUIPMENT - KITCHEN					(1,093)		219 **		
TOTAL RESERVE ADJUSTMENT FOR AMORTIZATION					**(922,932)**		**184,588**		
TOTAL DEPRECIABLE GAS PLANT				**4,046,056,035.57**	**1,604,226,143**	**4,911,775,049**	**158,213,128**	**3.91**	
NONDEPRECIABLE GAS PLANT									
301.00 ORGANIZATION				1,174.00					
302.00 FRANCHISES AND CONSENTS				83,621.00					
304.10 LAND				24,998.00					
350.10 LAND				106,549.00					
360.11 LAND - LNG LINNTON				83,598.00					
360.12 LAND - LNG NEWPORT				536,433.00	(242)				
360.20 LAND - OTHER				106,557.00					
365.10 LAND				1,015,597.00					
374.10 LAND				211,692.00					
389.00 LAND				13,118,401.00	487,235				
ROU UTILITY LEASE					13,274,179				
FIN UTILITY LEASE					132,879				
TOTAL NONDEPRECIABLE GAS PLANT				**15,288,620.00**	**13,894,051**				
TOTAL GAS PLANT IN SERVICE				**4,061,344,655.57**	**1,618,120,194**				

* 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 1974-2022

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	85,197	4,325	0.0508	0.9492	38.90

NORTHWEST NATURAL GAS COMPANY

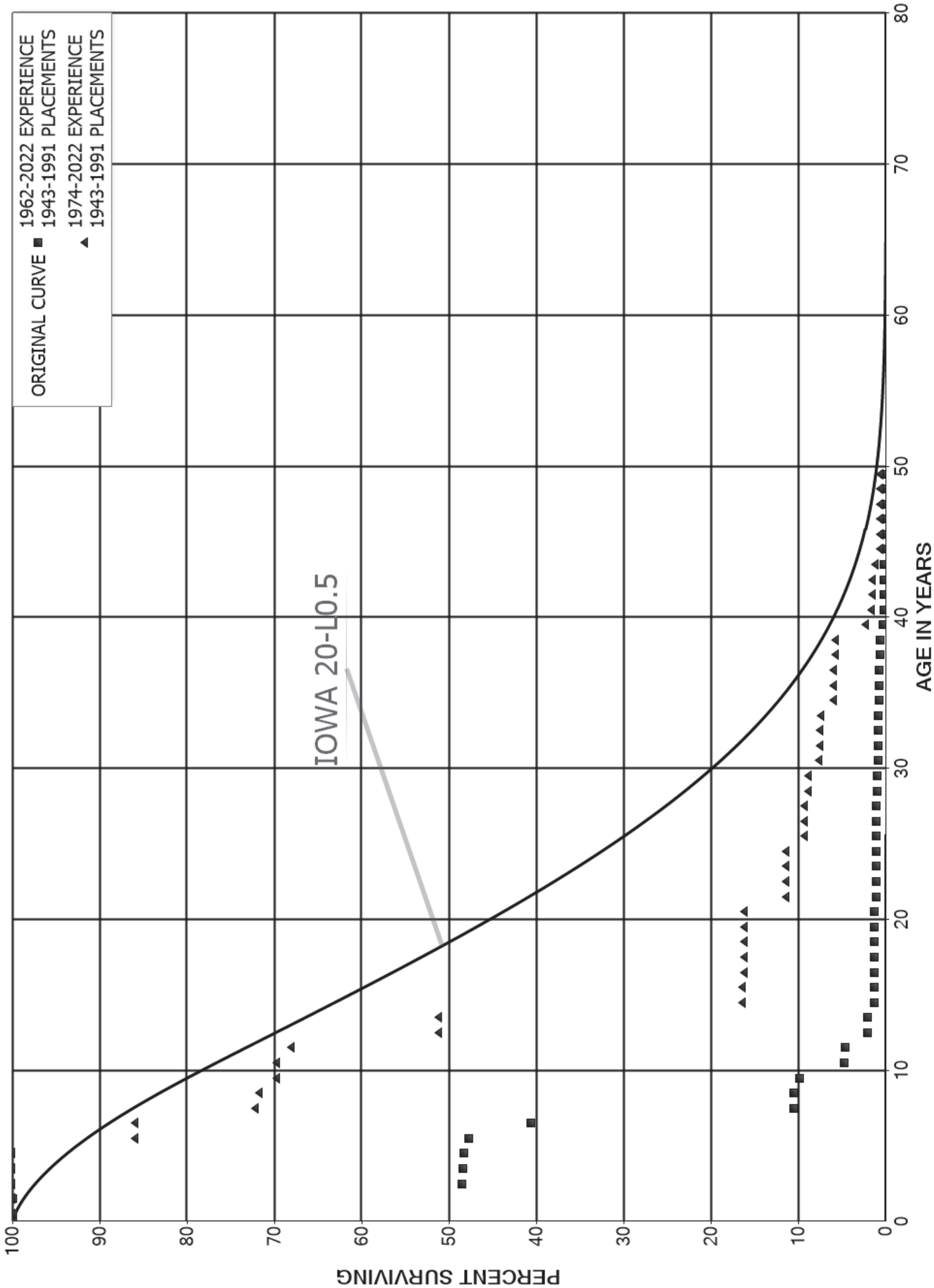
ACCOUNTS 305.11, 305.17 AND 305.50 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1913-1984 EXPERIENCE BAND 1974-2022

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	36.93
40.5	80,872		0.0000	1.0000	36.93
41.5	80,872	90	0.0011	0.9989	36.93
42.5	83,479		0.0000	1.0000	36.89
43.5	83,749	49	0.0006	0.9994	36.89
44.5	83,700	273	0.0033	0.9967	36.86
45.5	83,427		0.0000	1.0000	36.74
46.5	80,730	25,553	0.3165	0.6835	36.74
47.5	55,177		0.0000	1.0000	25.11
48.5	55,239		0.0000	1.0000	25.11
49.5	55,239	270	0.0049	0.9951	25.11
50.5	54,969		0.0000	1.0000	24.99
51.5	54,969		0.0000	1.0000	24.99
52.5	54,969		0.0000	1.0000	24.99
53.5	54,969		0.0000	1.0000	24.99
54.5	54,986	62	0.0011	0.9989	24.99
55.5	54,924		0.0000	1.0000	24.96
56.5	54,924		0.0000	1.0000	24.96
57.5	55,941		0.0000	1.0000	24.96
58.5	56,791		0.0000	1.0000	24.96
59.5	48,471		0.0000	1.0000	24.96
60.5	54,110	17	0.0003	0.9997	24.96
61.5	54,093		0.0000	1.0000	24.95
62.5	54,093		0.0000	1.0000	24.95
63.5	54,093	1,017	0.0188	0.9812	24.95
64.5	51,053	850	0.0166	0.9834	24.49
65.5	50,203		0.0000	1.0000	24.08
66.5	5,639	5,639	1.0000		24.08
67.5					

NORTHWEST NATURAL GAS COMPANY
ACCOUNTS 311.70 AND 311.80 LIQUEFIED PETROLEUM GAS EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 311.70 AND 311.80 LIQUEFIED PETROLEUM GAS EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1943-1991 EXPERIENCE BAND 1962-2022

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 1962-2022

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	4,033		0.0000	1.0000	0.05
48.5	4,033		0.0000	1.0000	0.05
49.5	627		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	403		0.0000	1.0000	0.05
59.5					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 1974-2022

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

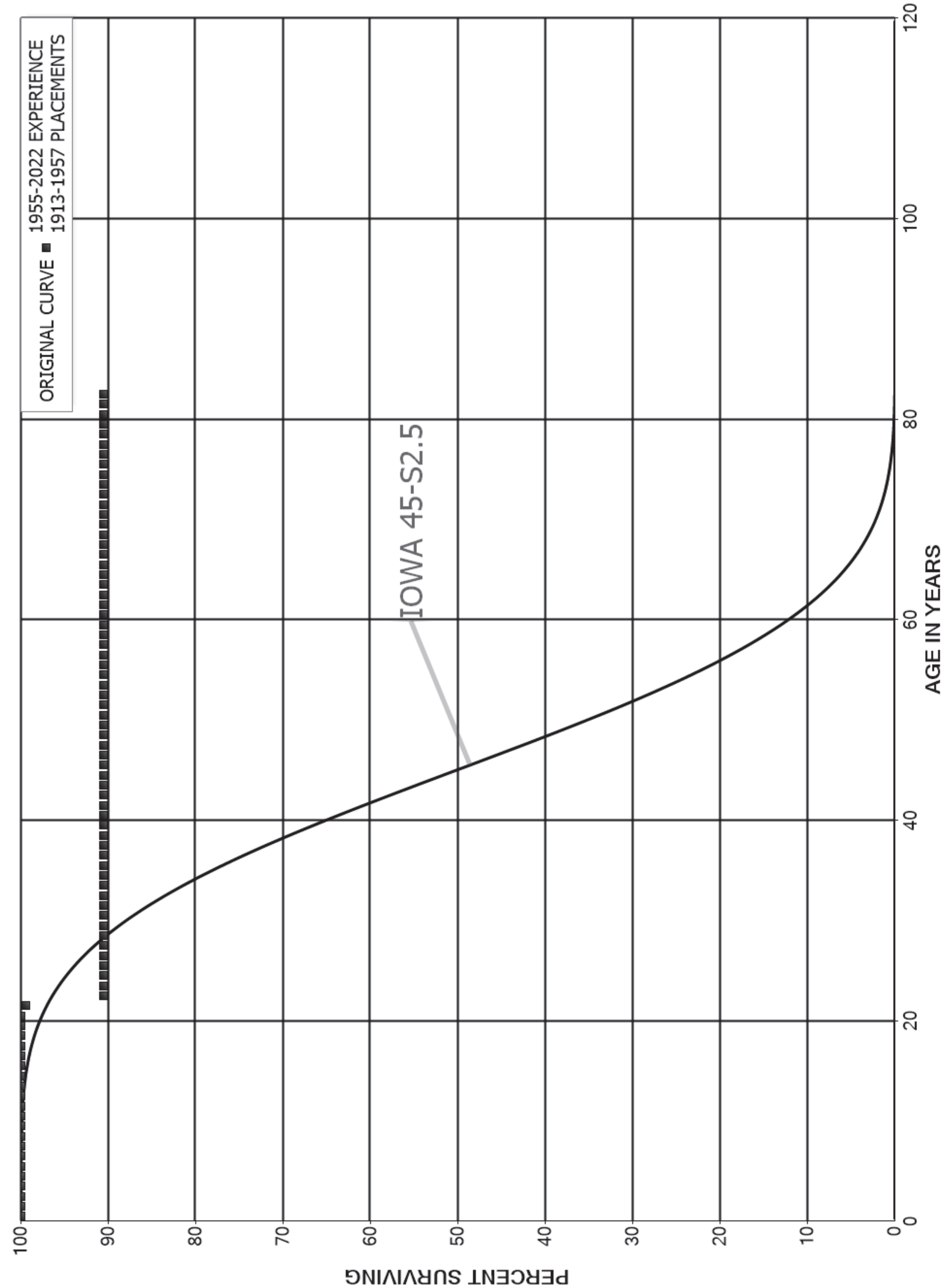
ACCOUNTS 311.70 AND 311.80 LIQUEFIED PETROLEUM GAS EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1943-1991 EXPERIENCE BAND 1974-2022

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	4,033		0.0000	1.0000	0.47
48.5	4,033		0.0000	1.0000	0.47
49.5	627		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	403		0.0000	1.0000	0.47
59.5					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 1955-2022

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	3,189		0.0000	1.0000	100.00
0.5	10,049		0.0000	1.0000	100.00
1.5	136,338		0.0000	1.0000	100.00
2.5	151,712		0.0000	1.0000	100.00
3.5	179,823		0.0000	1.0000	100.00
4.5	194,359		0.0000	1.0000	100.00
5.5	194,950		0.0000	1.0000	100.00
6.5	201,811		0.0000	1.0000	100.00
7.5	259,718		0.0000	1.0000	100.00
8.5	259,718		0.0000	1.0000	100.00
9.5	259,718		0.0000	1.0000	100.00
10.5	267,855		0.0000	1.0000	100.00
11.5	319,464		0.0000	1.0000	100.00
12.5	319,464		0.0000	1.0000	100.00
13.5	384,746		0.0000	1.0000	100.00
14.5	408,285		0.0000	1.0000	100.00
15.5	408,285		0.0000	1.0000	100.00
16.5	408,285		0.0000	1.0000	100.00
17.5	408,285	263	0.0006	0.9994	100.00
18.5	408,022		0.0000	1.0000	99.94
19.5	408,022		0.0000	1.0000	99.94
20.5	408,022	2,294	0.0056	0.9944	99.94
21.5	405,728	36,343	0.0896	0.9104	99.37
22.5	369,385		0.0000	1.0000	90.47
23.5	369,385		0.0000	1.0000	90.47
24.5	369,385		0.0000	1.0000	90.47
25.5	369,385		0.0000	1.0000	90.47
26.5	369,385		0.0000	1.0000	90.47
27.5	369,385		0.0000	1.0000	90.47
28.5	376,125		0.0000	1.0000	90.47
29.5	376,125		0.0000	1.0000	90.47
30.5	376,125		0.0000	1.0000	90.47
31.5	384,419		0.0000	1.0000	90.47
32.5	384,419		0.0000	1.0000	90.47
33.5	384,419		0.0000	1.0000	90.47
34.5	384,419		0.0000	1.0000	90.47
35.5	384,419		0.0000	1.0000	90.47
36.5	384,419		0.0000	1.0000	90.47
37.5	384,419		0.0000	1.0000	90.47
38.5	384,419		0.0000	1.0000	90.47

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 318.30 AND 318.50 RESIDUAL REFINING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1913-1957 EXPERIENCE BAND 1955-2022

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	384,419		0.0000	1.0000	90.47
40.5	384,419		0.0000	1.0000	90.47
41.5	388,447		0.0000	1.0000	90.47
42.5	388,447		0.0000	1.0000	90.47
43.5	388,447		0.0000	1.0000	90.47
44.5	388,447		0.0000	1.0000	90.47
45.5	388,447		0.0000	1.0000	90.47
46.5	388,447		0.0000	1.0000	90.47
47.5	388,447		0.0000	1.0000	90.47
48.5	388,447		0.0000	1.0000	90.47
49.5	388,447		0.0000	1.0000	90.47
50.5	388,447		0.0000	1.0000	90.47
51.5	388,447		0.0000	1.0000	90.47
52.5	388,447		0.0000	1.0000	90.47
53.5	388,447		0.0000	1.0000	90.47
54.5	388,447		0.0000	1.0000	90.47
55.5	388,447		0.0000	1.0000	90.47
56.5	388,447		0.0000	1.0000	90.47
57.5	388,447		0.0000	1.0000	90.47
58.5	388,447		0.0000	1.0000	90.47
59.5	388,447		0.0000	1.0000	90.47
60.5	388,447		0.0000	1.0000	90.47
61.5	388,447		0.0000	1.0000	90.47
62.5	388,447		0.0000	1.0000	90.47
63.5	388,447		0.0000	1.0000	90.47
64.5	388,447		0.0000	1.0000	90.47
65.5	387,494		0.0000	1.0000	90.47
66.5	387,331		0.0000	1.0000	90.47
67.5	385,521		0.0000	1.0000	90.47
68.5	380,955		0.0000	1.0000	90.47
69.5	291,009		0.0000	1.0000	90.47
70.5	275,635		0.0000	1.0000	90.47
71.5	247,524		0.0000	1.0000	90.47
72.5	232,988		0.0000	1.0000	90.47
73.5	232,397		0.0000	1.0000	90.47
74.5	225,536		0.0000	1.0000	90.47
75.5	167,629		0.0000	1.0000	90.47
76.5	167,629		0.0000	1.0000	90.47
77.5	167,629		0.0000	1.0000	90.47
78.5	159,492		0.0000	1.0000	90.47

NORTHWEST NATURAL GAS COMPANY

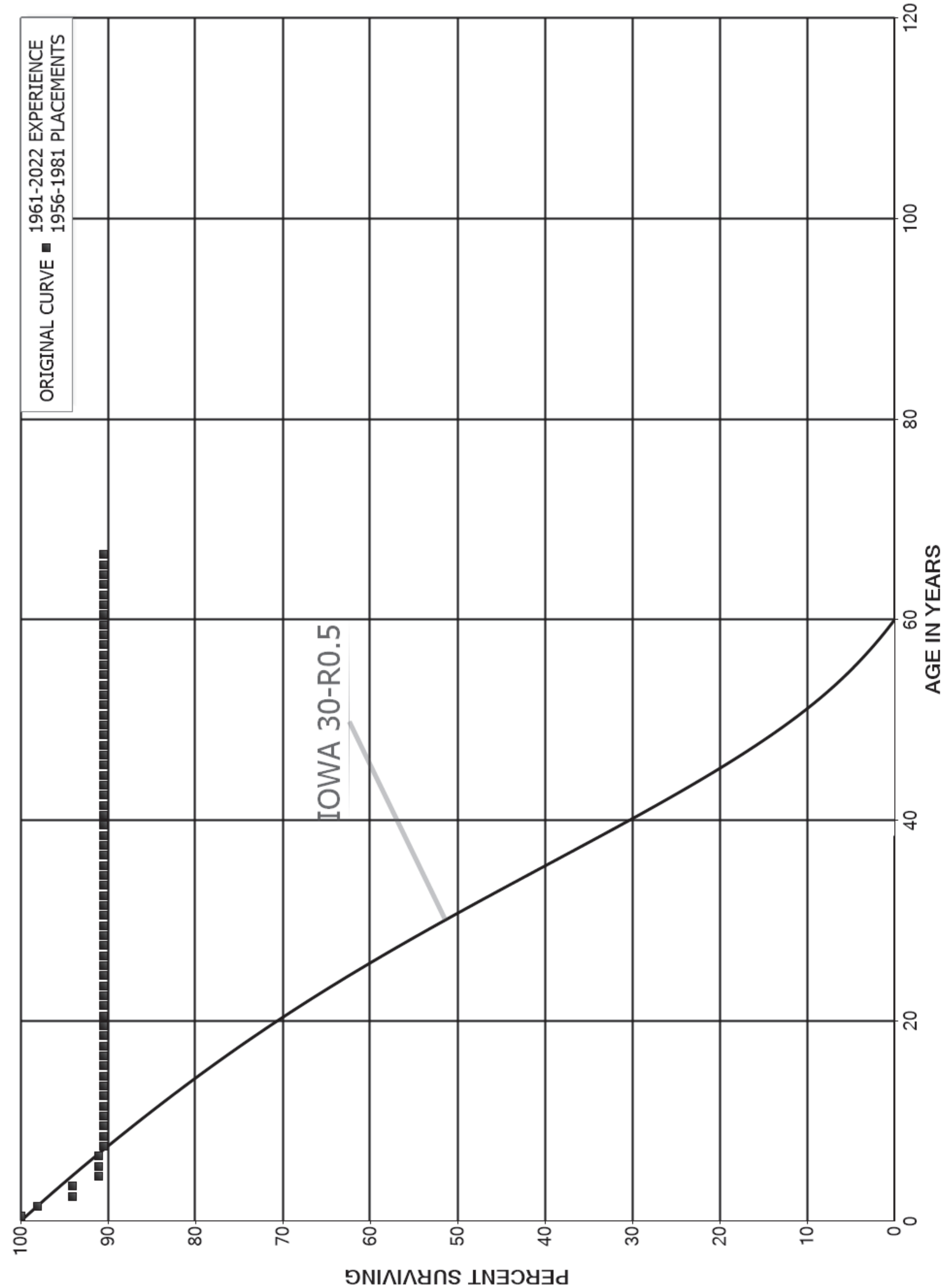
ACCOUNTS 318.30 AND 318.50 RESIDUAL REFINING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1913-1957 EXPERIENCE BAND 1955-2022

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	107,883		0.0000	1.0000	90.47
80.5	107,883		0.0000	1.0000	90.47
81.5	42,601		0.0000	1.0000	90.47
82.5	19,062		0.0000	1.0000	90.47
83.5	19,062		0.0000	1.0000	90.47
84.5	19,062		0.0000	1.0000	90.47
85.5	19,062		0.0000	1.0000	90.47
86.5	19,062		0.0000	1.0000	90.47
87.5	19,062		0.0000	1.0000	90.47
88.5	19,062		0.0000	1.0000	90.47
89.5	19,062		0.0000	1.0000	90.47
90.5	19,062		0.0000	1.0000	90.47
91.5	19,062		0.0000	1.0000	90.47
92.5	19,062		0.0000	1.0000	90.47
93.5	19,062		0.0000	1.0000	90.47
94.5	19,062		0.0000	1.0000	90.47
95.5	19,062		0.0000	1.0000	90.47
96.5	12,322		0.0000	1.0000	90.47
97.5	12,322		0.0000	1.0000	90.47
98.5	12,322		0.0000	1.0000	90.47
99.5	4,028		0.0000	1.0000	90.47
100.5	4,028		0.0000	1.0000	90.47
101.5	4,028		0.0000	1.0000	90.47
102.5	4,028		0.0000	1.0000	90.47
103.5	4,028		0.0000	1.0000	90.47
104.5	4,028		0.0000	1.0000	90.47
105.5	4,028		0.0000	1.0000	90.47
106.5	4,028		0.0000	1.0000	90.47
107.5	4,028		0.0000	1.0000	90.47
108.5	4,028		0.0000	1.0000	90.47
109.5					90.47

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 1961-2022

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

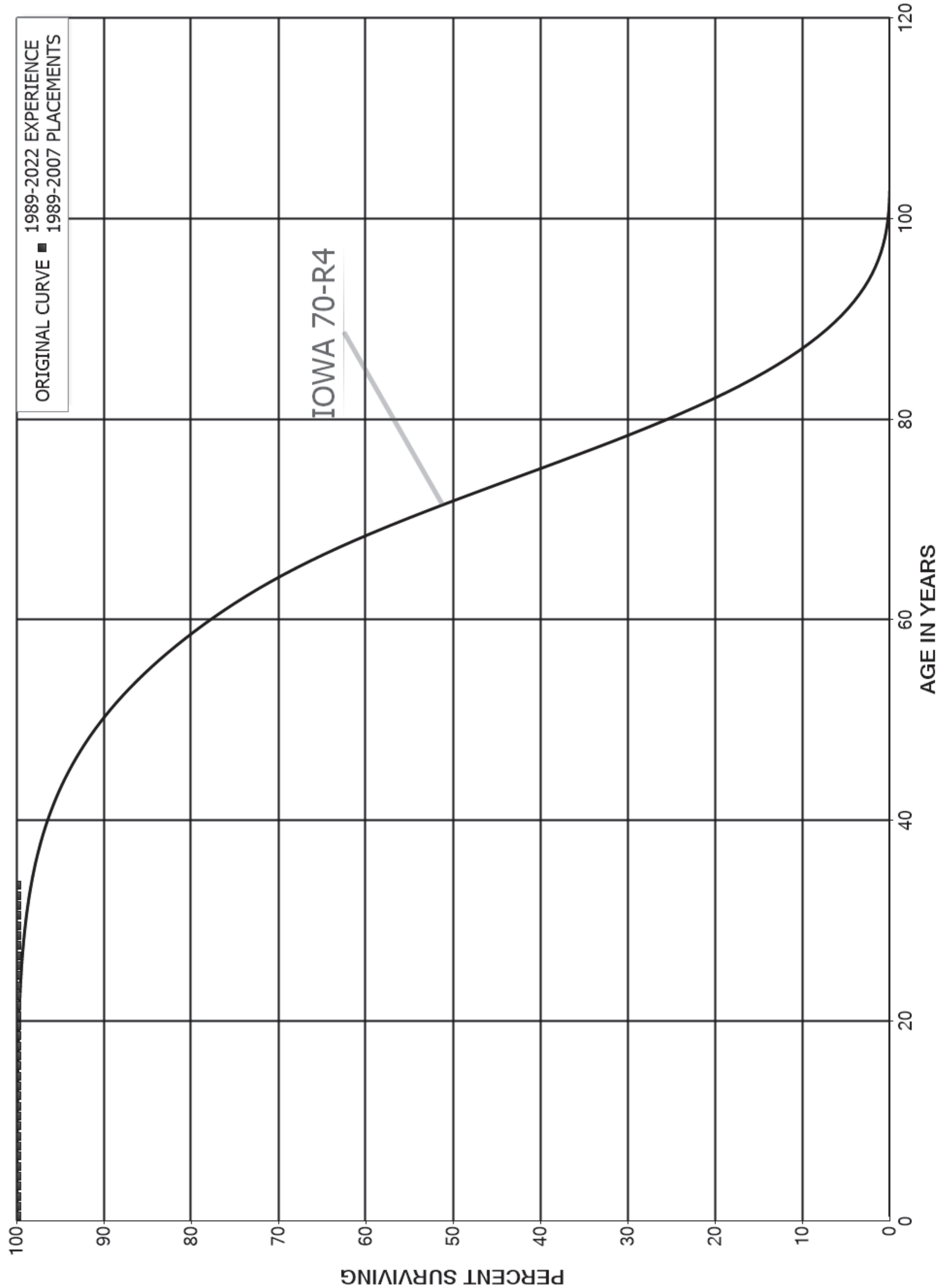
ACCOUNT 319.00 GAS MIXING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-1981 EXPERIENCE BAND 1961-2022

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	181,891		0.0000	1.0000	90.54
42.5	169,470		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	169,381		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	168,460		0.0000	1.0000	90.54
59.5	168,460		0.0000	1.0000	90.54
60.5	166,793		0.0000	1.0000	90.54
61.5	166,793		0.0000	1.0000	90.54
62.5	166,516		0.0000	1.0000	90.54
63.5	166,299		0.0000	1.0000	90.54
64.5	160,563		0.0000	1.0000	90.54
65.5	145,043		0.0000	1.0000	90.54
66.5					90.54

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 350.20 LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

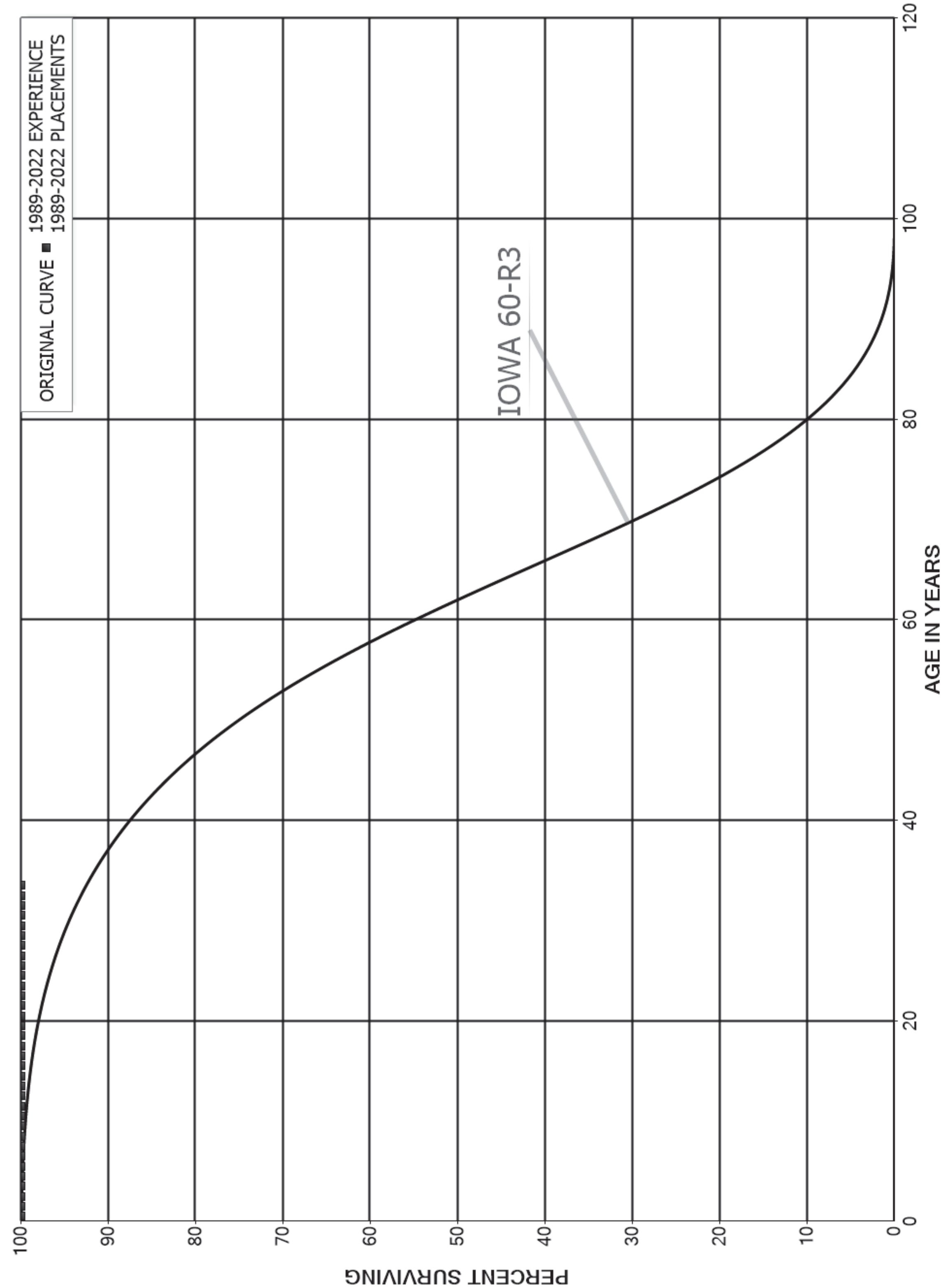
ACCOUNT 350.20 LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2007 EXPERIENCE BAND 1989-2022

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	51,122		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	47,318		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	46,690		0.0000	1.0000	100.00
25.5	46,505		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	46,105		0.0000	1.0000	100.00
29.5	40,841		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					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 351.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

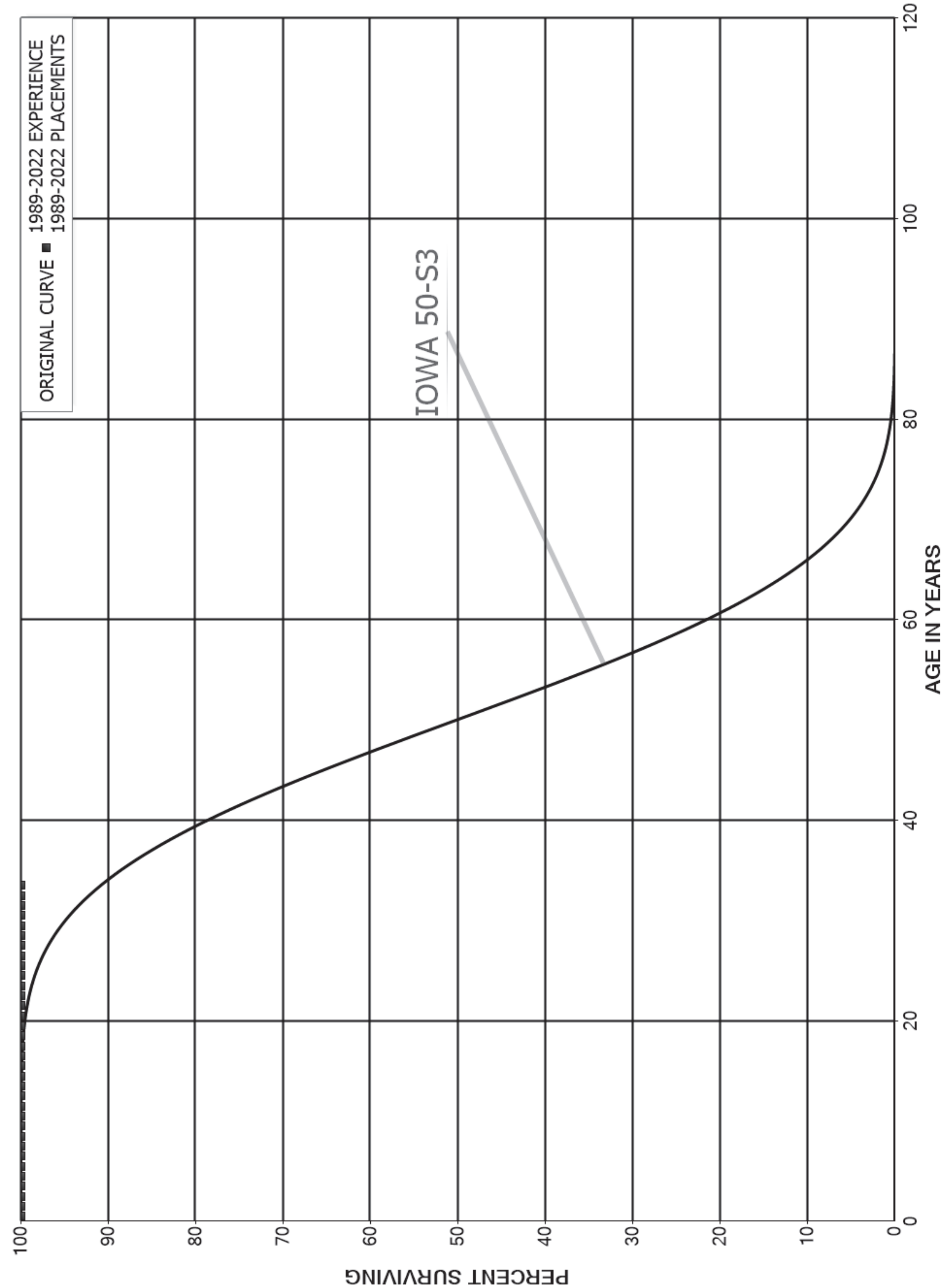
ACCOUNT 351.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2022 EXPERIENCE BAND 1989-2022

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	9,167,746		0.0000	1.0000	100.00
0.5	8,935,718		0.0000	1.0000	100.00
1.5	8,634,151		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	7,382,069		0.0000	1.0000	100.00
5.5	7,208,245		0.0000	1.0000	100.00
6.5	7,208,245		0.0000	1.0000	100.00
7.5	7,141,840		0.0000	1.0000	100.00
8.5	6,715,064		0.0000	1.0000	100.00
9.5	6,715,064		0.0000	1.0000	100.00
10.5	6,555,425		0.0000	1.0000	100.00
11.5	6,555,425		0.0000	1.0000	100.00
12.5	6,542,426		0.0000	1.0000	100.00
13.5	6,538,592		0.0000	1.0000	100.00
14.5	6,247,670		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	6,247,546		0.0000	1.0000	100.00
18.5	6,173,312		0.0000	1.0000	100.00
19.5	6,156,413		0.0000	1.0000	100.00
20.5	5,913,514		0.0000	1.0000	100.00
21.5	5,029,273		0.0000	1.0000	100.00
22.5	4,996,462		0.0000	1.0000	100.00
23.5	4,991,499		0.0000	1.0000	100.00
24.5	2,516,340		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	2,480,692		0.0000	1.0000	100.00
28.5	2,467,430		0.0000	1.0000	100.00
29.5	2,464,204		0.0000	1.0000	100.00
30.5	2,422,299		0.0000	1.0000	100.00
31.5	2,146,801		0.0000	1.0000	100.00
32.5	2,101,010		0.0000	1.0000	100.00
33.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 352.00 WELLS
ORIGINAL AND SMOOTH SURVIVOR CURVES



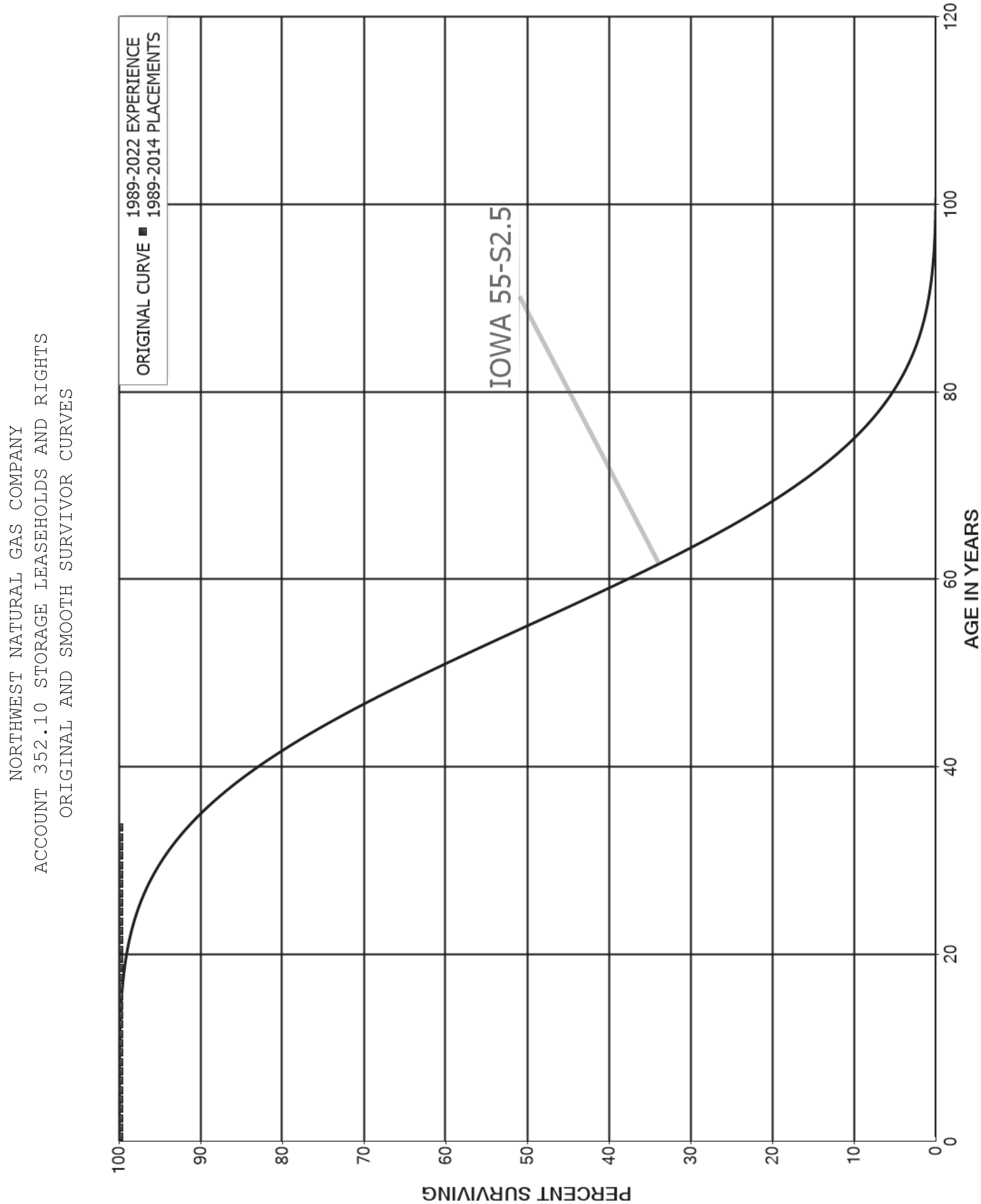
NORTHWEST NATURAL GAS COMPANY

ACCOUNT 352.00 WELLS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2022 EXPERIENCE BAND 1989-2022

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	59,428,554		0.0000	1.0000	100.00
0.5	52,423,569		0.0000	1.0000	100.00
1.5	48,256,749		0.0000	1.0000	100.00
2.5	43,804,325		0.0000	1.0000	100.00
3.5	40,316,037		0.0000	1.0000	100.00
4.5	36,987,527		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	36,970,027		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	36,138,659		0.0000	1.0000	100.00
14.5	36,138,659		0.0000	1.0000	100.00
15.5	27,363,189		0.0000	1.0000	100.00
16.5	27,363,189		0.0000	1.0000	100.00
17.5	23,510,122		0.0000	1.0000	100.00
18.5	18,383,091		0.0000	1.0000	100.00
19.5	18,338,288		0.0000	1.0000	100.00
20.5	18,338,288		0.0000	1.0000	100.00
21.5	18,138,203		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	11,810,679		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	11,808,321		0.0000	1.0000	100.00
29.5	11,625,429		0.0000	1.0000	100.00
30.5	11,474,852		0.0000	1.0000	100.00
31.5	9,469,844		0.0000	1.0000	100.00
32.5	8,933,762		0.0000	1.0000	100.00
33.5					100.00


NORTHWEST NATURAL GAS COMPANY
ACCOUNT 352.10 STORAGE LEASEHOLDS AND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE ■ 1989-2022 EXPERIENCE
1989-2014 PLACEMENTS
IOWA 55-S2.5
PERCENT SURVIVING
100
90
80
70
60
50
40
30
20
10
0
AGE IN YEARS
0
20
40
60
80
100
120

NORTHWEST NATURAL GAS COMPANY

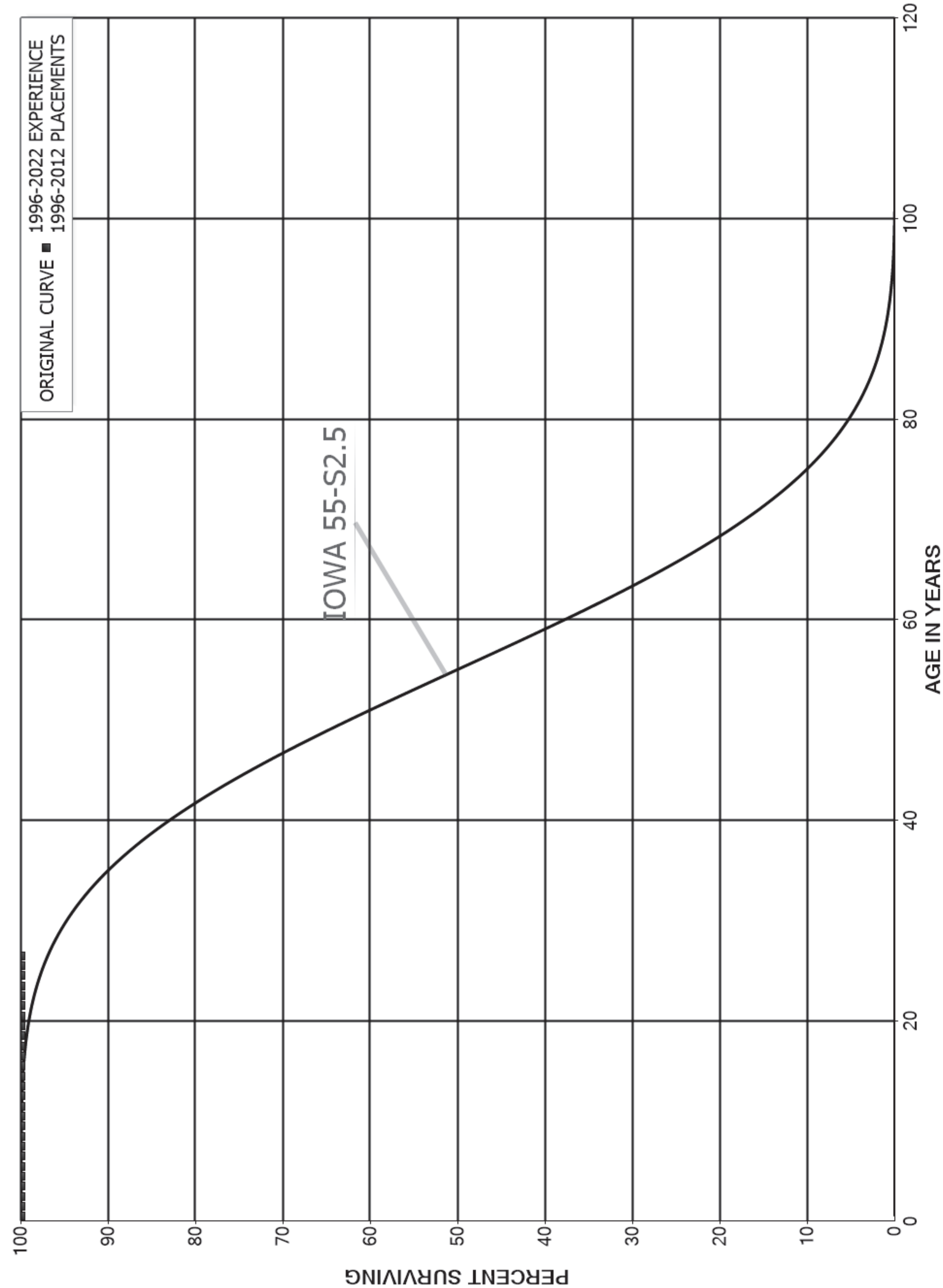
ACCOUNT 352.10 STORAGE LEASEHOLDS AND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2014 EXPERIENCE BAND 1989-2022

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	3,539,512		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	3,538,491		0.0000	1.0000	100.00
19.5	3,538,491		0.0000	1.0000	100.00
20.5	3,535,500		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	3,530,407		0.0000	1.0000	100.00
24.5	3,038,080		0.0000	1.0000	100.00
25.5	1,448,101		0.0000	1.0000	100.00
26.5	1,210,801		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	1,210,800		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					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 352.20 RESERVOIRS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

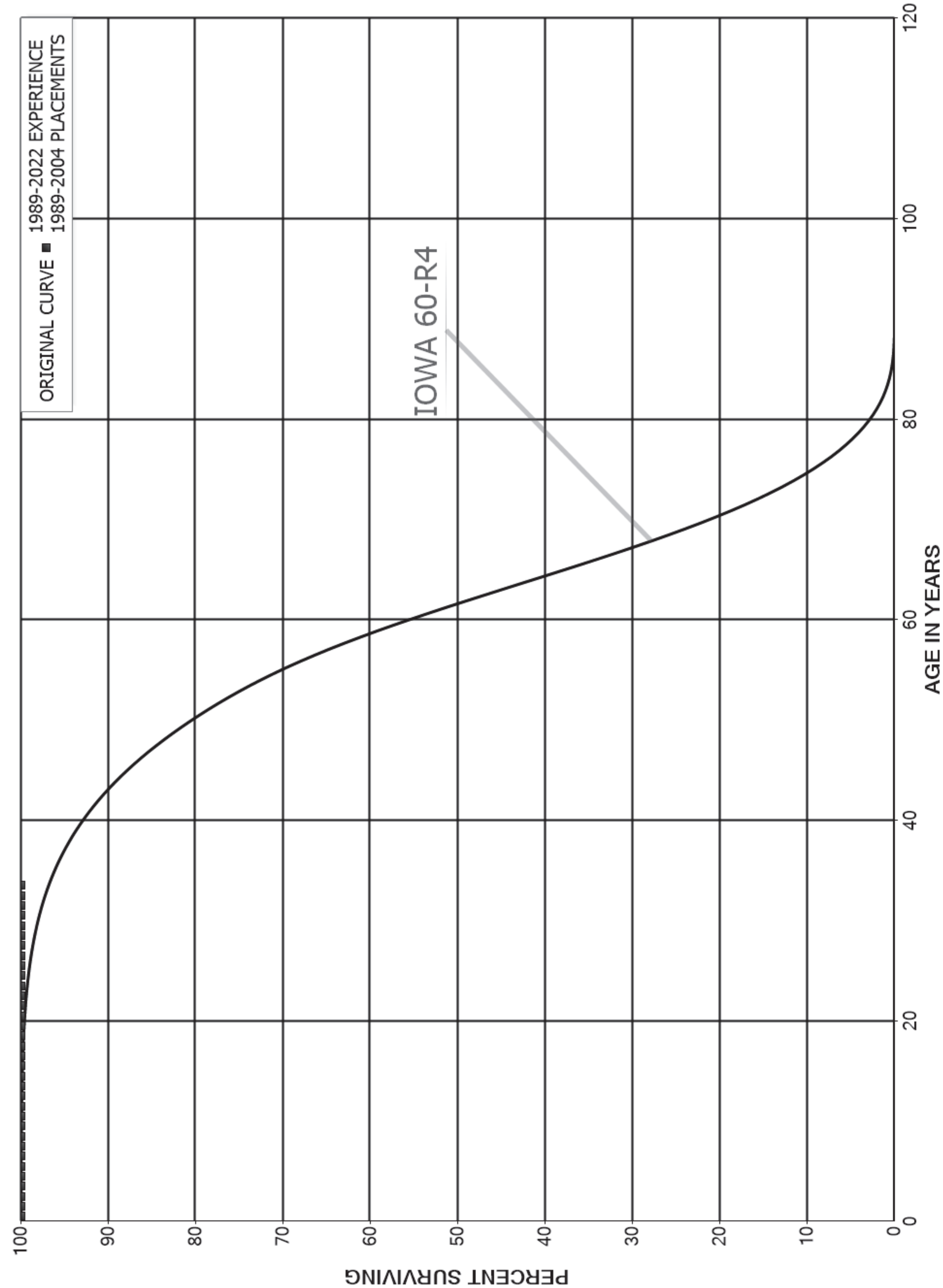
ACCOUNT 352.20 RESERVOIRS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1996-2012 EXPERIENCE BAND 1996-2022

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	10,816,555		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	8,371,537		0.0000	1.0000	100.00
18.5	7,159,166		0.0000	1.0000	100.00
19.5	7,159,166		0.0000	1.0000	100.00
20.5	4,161,435		0.0000	1.0000	100.00
21.5	4,161,435		0.0000	1.0000	100.00
22.5	3,685,094		0.0000	1.0000	100.00
23.5	3,679,091		0.0000	1.0000	100.00
24.5	1,679,184		0.0000	1.0000	100.00
25.5	1,679,184		0.0000	1.0000	100.00
26.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 352.30 NONRECOVERABLE GAS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

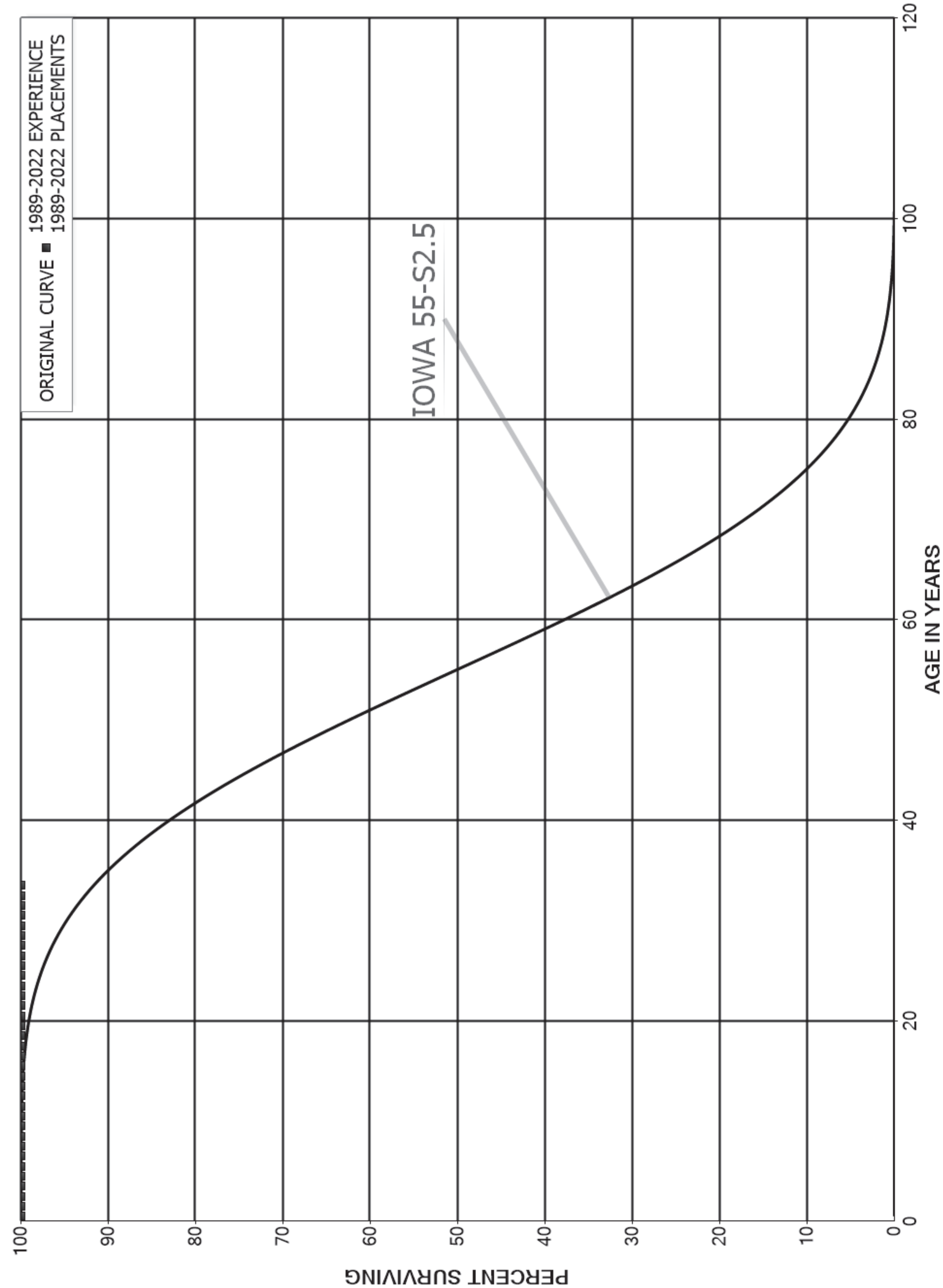
ACCOUNT 352.30 NONRECOVERABLE GAS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2004 EXPERIENCE BAND 1989-2022

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	6,375,402		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	6,312,953		0.0000	1.0000	100.00
25.5	6,312,953		0.0000	1.0000	100.00
26.5	4,057,953		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	4,057,952		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					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 353.00 LINES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

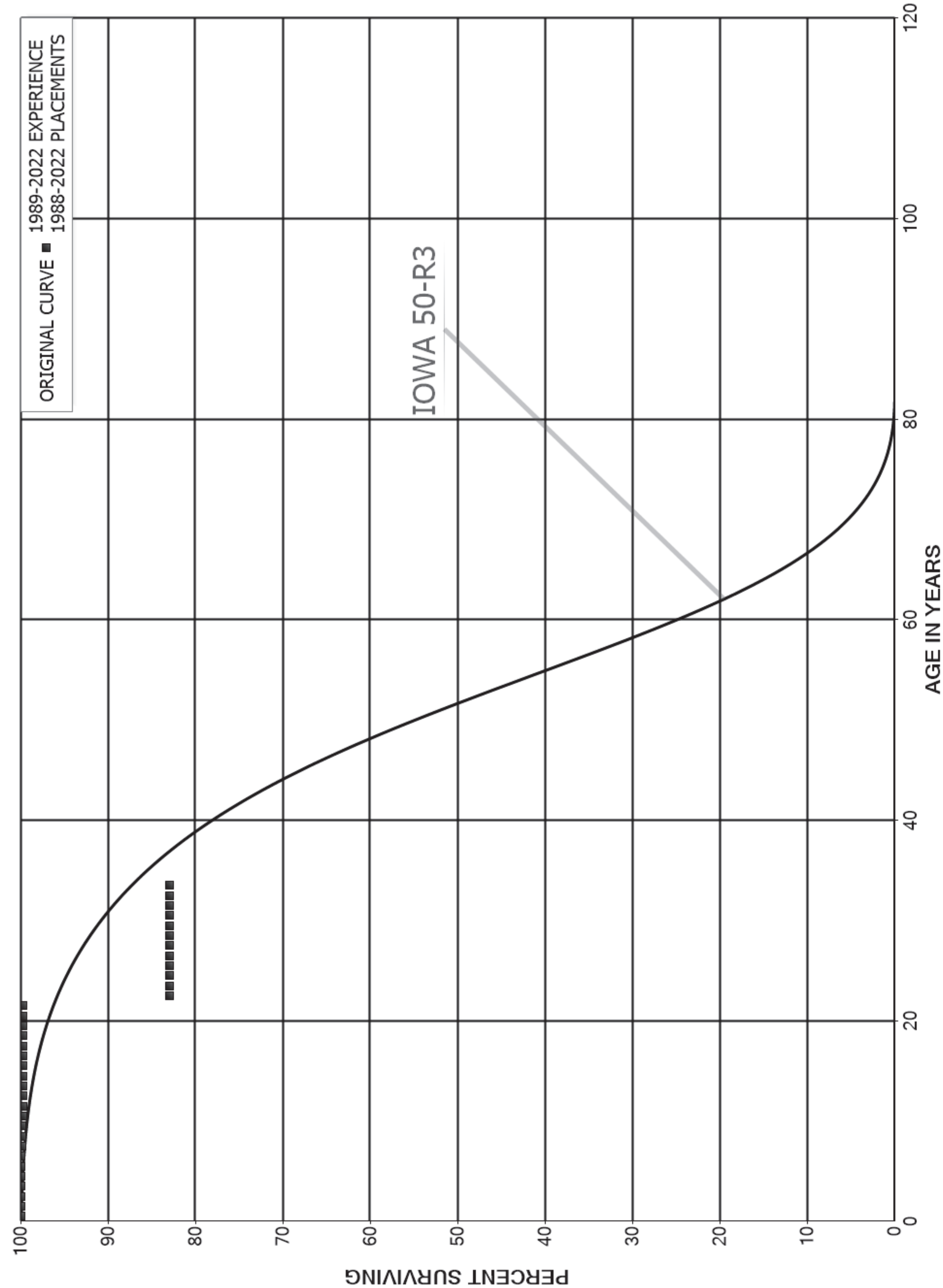
ACCOUNT 353.00 LINES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2022 EXPERIENCE BAND 1989-2022

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	12,167,087		0.0000	1.0000	100.00
0.5	10,822,416		0.0000	1.0000	100.00
1.5	10,790,148		0.0000	1.0000	100.00
2.5	10,673,228		0.0000	1.0000	100.00
3.5	9,535,478		0.0000	1.0000	100.00
4.5	8,201,964		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	7,641,810		0.0000	1.0000	100.00
16.5	7,641,810		0.0000	1.0000	100.00
17.5	7,137,450		0.0000	1.0000	100.00
18.5	6,453,175		0.0000	1.0000	100.00
19.5	6,445,334		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	6,392,472		0.0000	1.0000	100.00
24.5	2,538,843		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	2,538,842		0.0000	1.0000	100.00
30.5	2,538,842		0.0000	1.0000	100.00
31.5	2,521,353		0.0000	1.0000	100.00
32.5	2,521,353		0.0000	1.0000	100.00
33.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNTS 354.10 THROUGH 354.60 COMPRESSOR STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

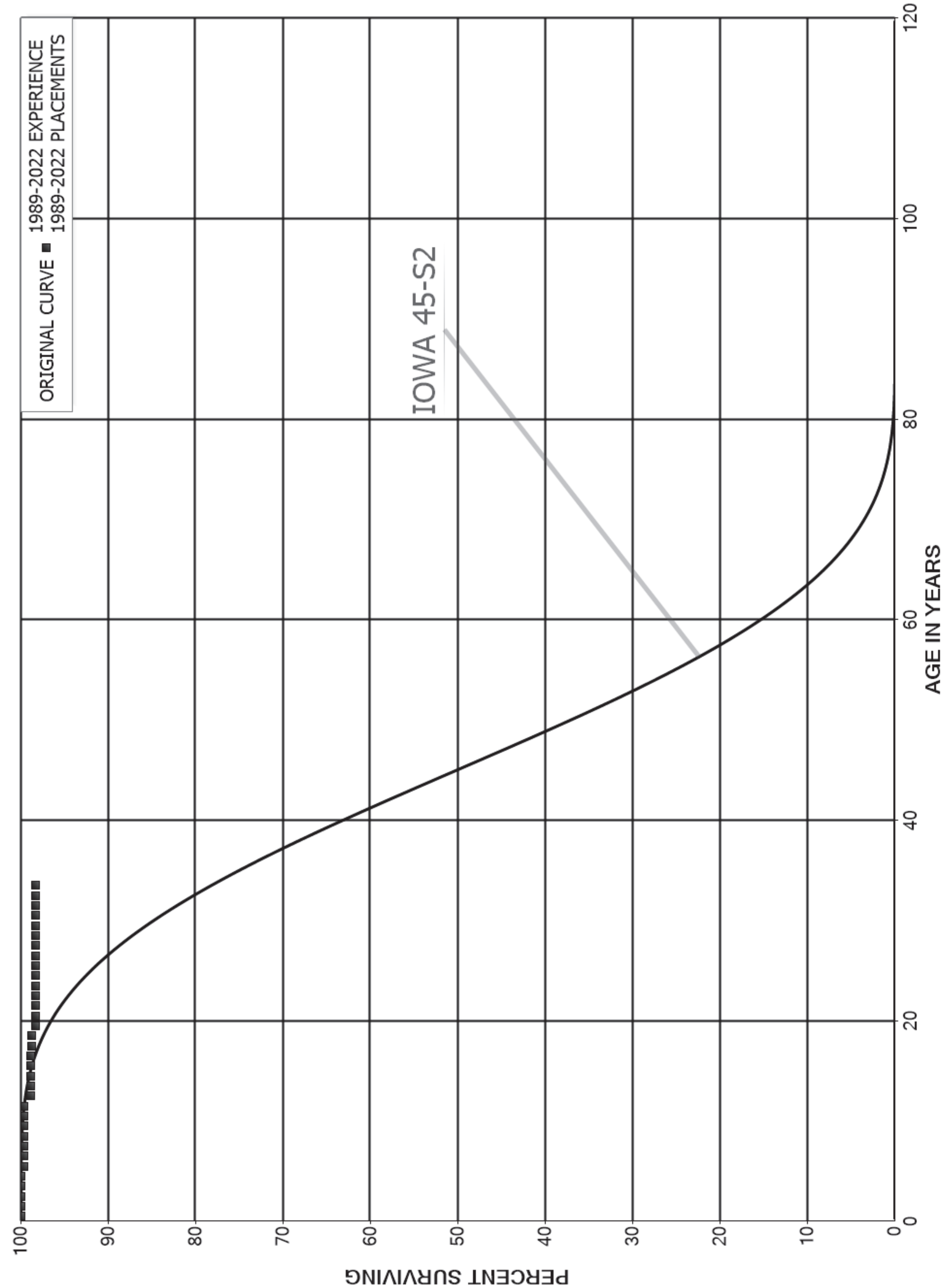
ACCOUNTS 354.10 THROUGH 354.60 COMPRESSOR STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1988-2022 EXPERIENCE BAND 1989-2022

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	38,937,797		0.0000	1.0000	100.00
0.5	36,057,854		0.0000	1.0000	100.00
1.5	36,863,881	31,012	0.0008	0.9992	100.00
2.5	35,120,846		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	45,822,356		0.0000	1.0000	99.92
6.5	45,776,479	51,212	0.0011	0.9989	99.92
7.5	45,465,090		0.0000	1.0000	99.80
8.5	44,683,528		0.0000	1.0000	99.80
9.5	43,916,201	23,443	0.0005	0.9995	99.80
10.5	43,875,258		0.0000	1.0000	99.75
11.5	42,737,646		0.0000	1.0000	99.75
12.5	42,700,357		0.0000	1.0000	99.75
13.5	42,622,975		0.0000	1.0000	99.75
14.5	41,766,032		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	39,069,867		0.0000	1.0000	99.75
19.5	39,065,888		0.0000	1.0000	99.75
20.5	38,943,483		0.0000	1.0000	99.75
21.5	29,681,689	5,000,000	0.1685	0.8315	99.75
22.5	16,906,902		0.0000	1.0000	82.95
23.5	16,812,180		0.0000	1.0000	82.95
24.5	8,143,343		0.0000	1.0000	82.95
25.5	8,124,254		0.0000	1.0000	82.95
26.5	8,121,118		0.0000	1.0000	82.95
27.5	8,004,748		0.0000	1.0000	82.95
28.5	7,997,100		0.0000	1.0000	82.95
29.5	7,993,959		0.0000	1.0000	82.95
30.5	7,952,213		0.0000	1.0000	82.95
31.5	7,813,027		0.0000	1.0000	82.95
32.5	7,702,081		0.0000	1.0000	82.95
33.5					82.95

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 355.00 MEASURING AND REGULATING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

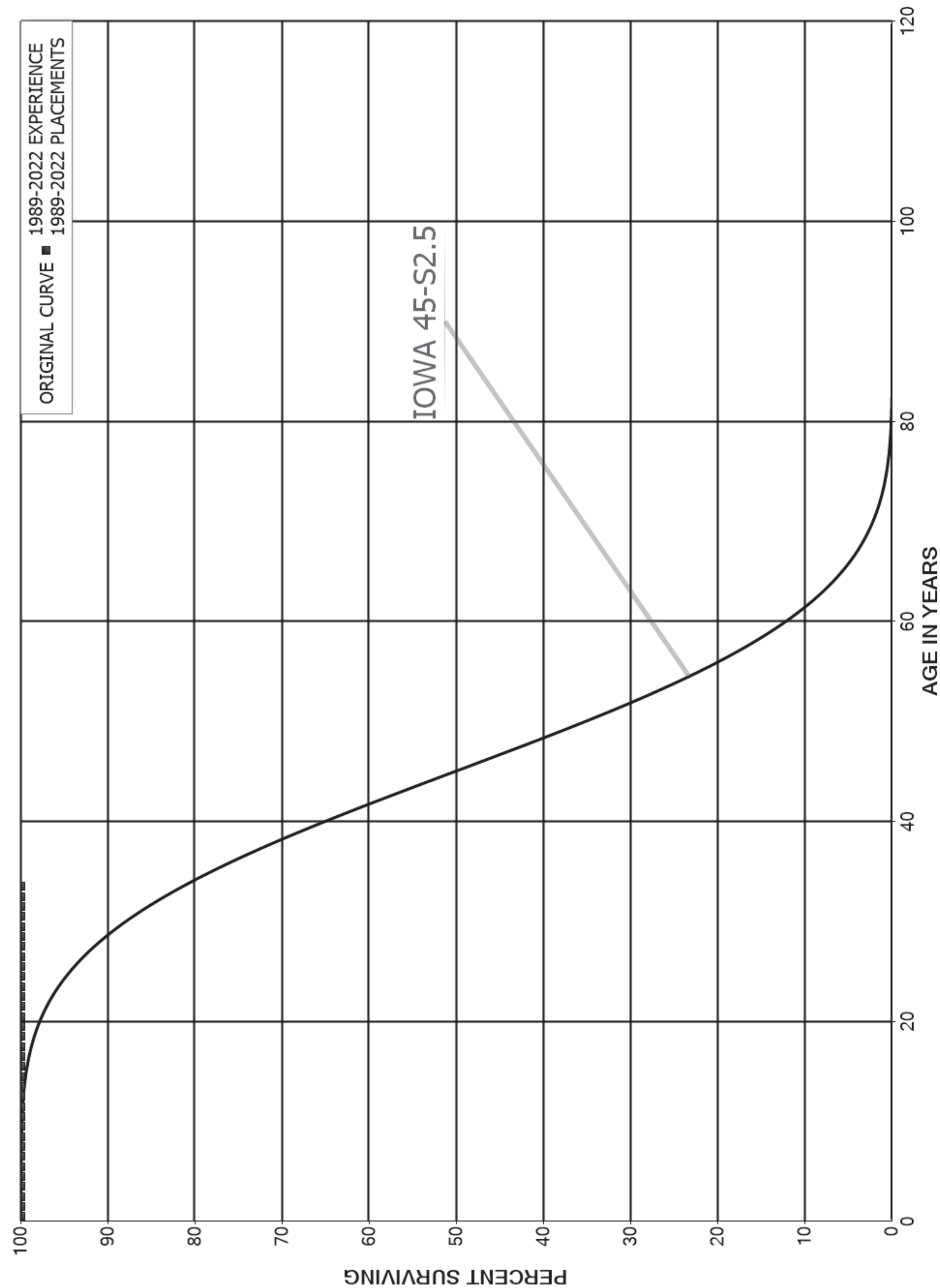
ACCOUNT 355.00 MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2022 EXPERIENCE BAND 1989-2022

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	37,721,066		0.0000	1.0000	100.00
0.5	27,546,415		0.0000	1.0000	100.00
1.5	17,883,613		0.0000	1.0000	100.00
2.5	16,304,356		0.0000	1.0000	100.00
3.5	16,621,758		0.0000	1.0000	100.00
4.5	16,956,436	58,779	0.0035	0.9965	100.00
5.5	16,292,883		0.0000	1.0000	99.65
6.5	16,168,075		0.0000	1.0000	99.65
7.5	16,158,003		0.0000	1.0000	99.65
8.5	16,158,003		0.0000	1.0000	99.65
9.5	16,086,849		0.0000	1.0000	99.65
10.5	16,069,349		0.0000	1.0000	99.65
11.5	15,633,832	122,683	0.0078	0.9922	99.65
12.5	15,511,149		0.0000	1.0000	98.87
13.5	14,469,437		0.0000	1.0000	98.87
14.5	13,868,686		0.0000	1.0000	98.87
15.5	9,699,149		0.0000	1.0000	98.87
16.5	9,556,019	15,249	0.0016	0.9984	98.87
17.5	7,749,151		0.0000	1.0000	98.71
18.5	6,918,523	32,310	0.0047	0.9953	98.71
19.5	6,886,213		0.0000	1.0000	98.25
20.5	6,688,016		0.0000	1.0000	98.25
21.5	6,639,166		0.0000	1.0000	98.25
22.5	4,935,004		0.0000	1.0000	98.25
23.5	4,696,363		0.0000	1.0000	98.25
24.5	3,606,243		0.0000	1.0000	98.25
25.5	3,606,243		0.0000	1.0000	98.25
26.5	3,590,871		0.0000	1.0000	98.25
27.5	3,581,013		0.0000	1.0000	98.25
28.5	3,580,978		0.0000	1.0000	98.25
29.5	3,579,193		0.0000	1.0000	98.25
30.5	3,561,374		0.0000	1.0000	98.25
31.5	3,539,964		0.0000	1.0000	98.25
32.5	3,473,015		0.0000	1.0000	98.25
33.5					98.25

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 356.00 PURIFICATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

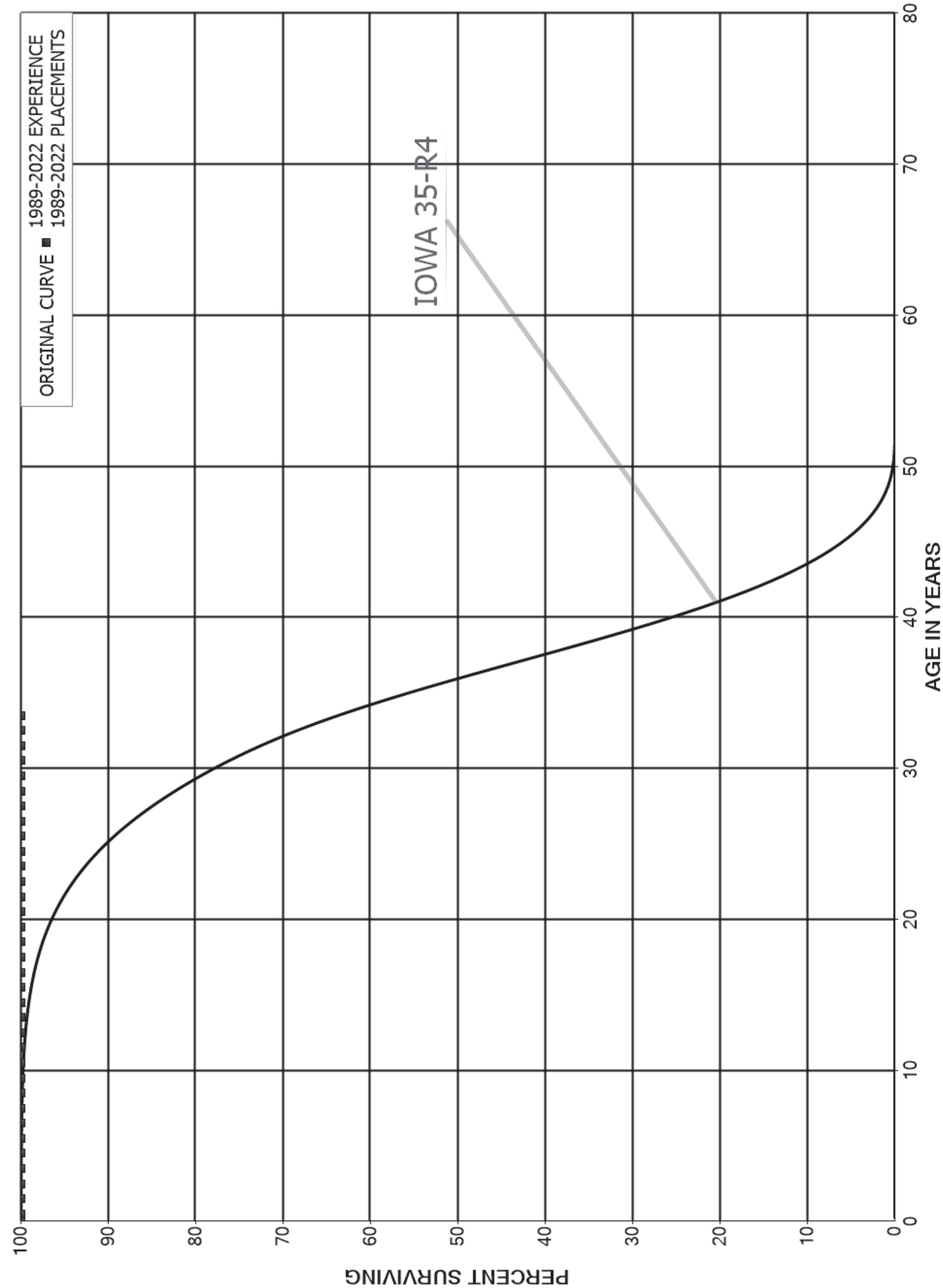
ACCOUNT 356.00 PURIFICATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2022 EXPERIENCE BAND 1989-2022

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	28,796,465		0.0000	1.0000	100.00
0.5	28,542,130		0.0000	1.0000	100.00
1.5	28,542,130		0.0000	1.0000	100.00
2.5	363,765		0.0000	1.0000	100.00
3.5	363,765		0.0000	1.0000	100.00
4.5	297,363		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	294,282		0.0000	1.0000	100.00
25.5	294,282		0.0000	1.0000	100.00
26.5	245,456		0.0000	1.0000	100.00
27.5	171,575		0.0000	1.0000	100.00
28.5	171,575		0.0000	1.0000	100.00
29.5	168,697		0.0000	1.0000	100.00
30.5	152,757		0.0000	1.0000	100.00
31.5	152,757		0.0000	1.0000	100.00
32.5	139,942		0.0000	1.0000	100.00
33.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 357.00 OTHER EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

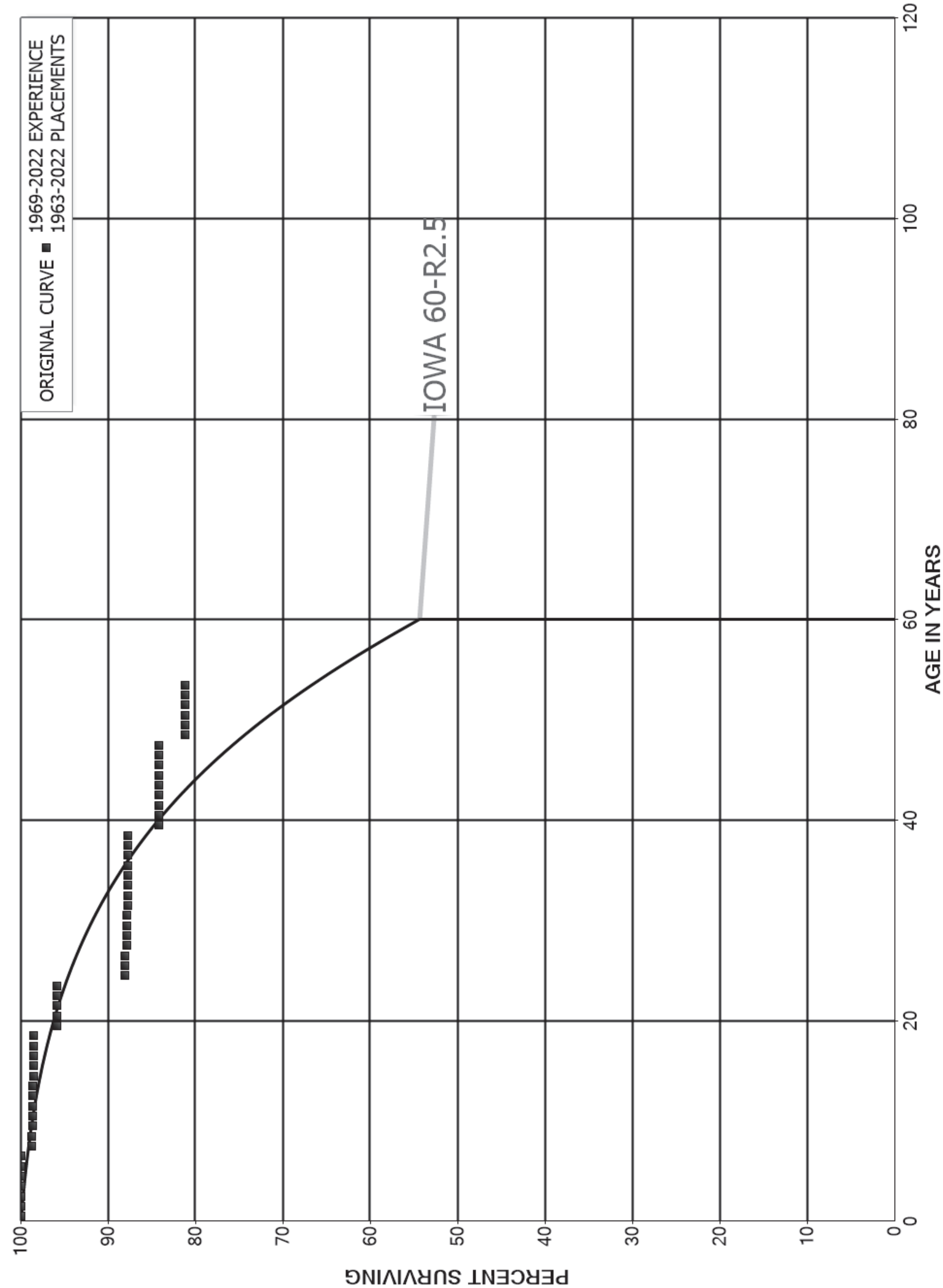
ACCOUNT 357.00 OTHER EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2022 EXPERIENCE BAND 1989-2022

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	5,141,896		0.0000	1.0000	100.00
1.5	4,666,683		0.0000	1.0000	100.00
2.5	2,422,822		0.0000	1.0000	100.00
3.5	2,422,822		0.0000	1.0000	100.00
4.5	1,395,285		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	1,332,029		0.0000	1.0000	100.00
14.5	702,587		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	646,258		0.0000	1.0000	100.00
24.5	82,037		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	76,057		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					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 1963-2022 EXPERIENCE BAND 1969-2022

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	25,433,163	44	0.0000	1.0000	100.00
0.5	23,982,076		0.0000	1.0000	100.00
1.5	23,532,775		0.0000	1.0000	100.00
2.5	23,361,127		0.0000	1.0000	100.00
3.5	23,193,204		0.0000	1.0000	100.00
4.5	15,681,596	44	0.0000	1.0000	100.00
5.5	12,828,703		0.0000	1.0000	100.00
6.5	9,280,825	123,196	0.0133	0.9867	100.00
7.5	9,103,804		0.0000	1.0000	98.67
8.5	9,050,517	4,058	0.0004	0.9996	98.67
9.5	9,046,459		0.0000	1.0000	98.63
10.5	8,942,963		0.0000	1.0000	98.63
11.5	8,661,178		0.0000	1.0000	98.63
12.5	7,912,962		0.0000	1.0000	98.63
13.5	6,562,103	6,596	0.0010	0.9990	98.63
14.5	5,296,524		0.0000	1.0000	98.53
15.5	4,864,332		0.0000	1.0000	98.53
16.5	3,854,896		0.0000	1.0000	98.53
17.5	3,659,257	1,150	0.0003	0.9997	98.53
18.5	3,639,683	97,968	0.0269	0.9731	98.50
19.5	3,541,714		0.0000	1.0000	95.85
20.5	3,414,287		0.0000	1.0000	95.85
21.5	3,334,846		0.0000	1.0000	95.85
22.5	3,292,618		0.0000	1.0000	95.85
23.5	3,107,432	253,844	0.0817	0.9183	95.85
24.5	2,786,531		0.0000	1.0000	88.02
25.5	2,594,384		0.0000	1.0000	88.02
26.5	2,483,579	5,060	0.0020	0.9980	88.02
27.5	2,395,109	478	0.0002	0.9998	87.84
28.5	2,143,139		0.0000	1.0000	87.82
29.5	2,074,412		0.0000	1.0000	87.82
30.5	1,927,592	2,147	0.0011	0.9989	87.82
31.5	1,838,391	568	0.0003	0.9997	87.72
32.5	1,813,495		0.0000	1.0000	87.70
33.5	1,729,977		0.0000	1.0000	87.70
34.5	1,682,462		0.0000	1.0000	87.70
35.5	1,673,588		0.0000	1.0000	87.70
36.5	1,664,262		0.0000	1.0000	87.70
37.5	1,644,107		0.0000	1.0000	87.70
38.5	1,643,837	66,938	0.0407	0.9593	87.70

NORTHWEST NATURAL GAS COMPANY

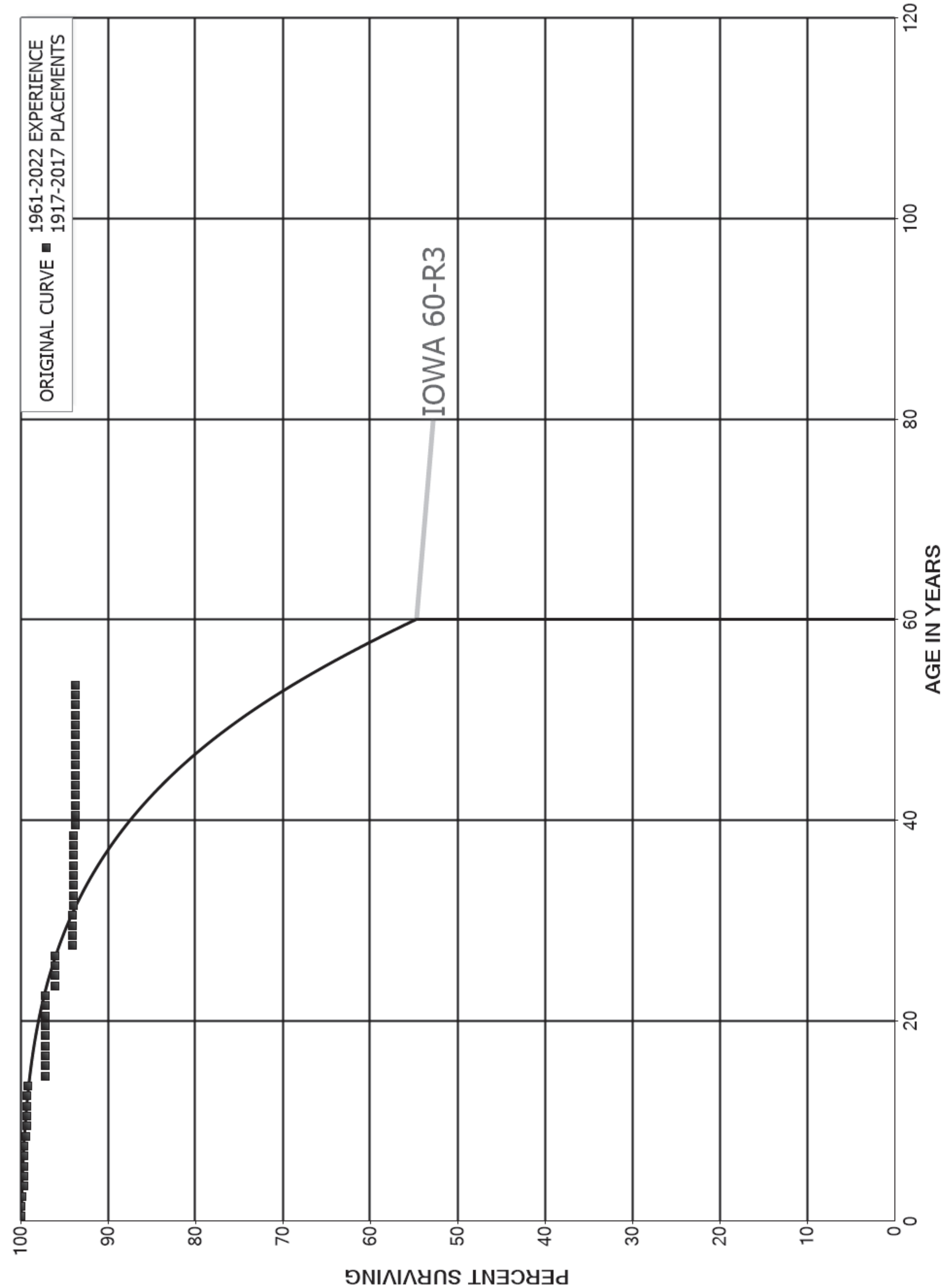
ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1963-2022 EXPERIENCE BAND 1969-2022

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	84.12
40.5	1,516,207		0.0000	1.0000	84.12
41.5	1,515,190		0.0000	1.0000	84.12
42.5	1,515,190		0.0000	1.0000	84.12
43.5	1,499,105		0.0000	1.0000	84.12
44.5	1,457,539		0.0000	1.0000	84.12
45.5	746,366		0.0000	1.0000	84.12
46.5	731,809		0.0000	1.0000	84.12
47.5	722,166	25,020	0.0346	0.9654	84.12
48.5	91,537		0.0000	1.0000	81.21
49.5	91,537		0.0000	1.0000	81.21
50.5	91,537		0.0000	1.0000	81.21
51.5	91,537		0.0000	1.0000	81.21
52.5	65,448		0.0000	1.0000	81.21
53.5	6,036		0.0000	1.0000	81.21
54.5	5,509		0.0000	1.0000	81.21
55.5	5,509		0.0000	1.0000	81.21
56.5	5,509		0.0000	1.0000	81.21
57.5	4,009		0.0000	1.0000	81.21
58.5	4,009		0.0000	1.0000	81.21
59.5					81.21

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 1961-2022

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	10,695,129		0.0000	1.0000	100.00
0.5	10,768,044	954	0.0001	0.9999	100.00
1.5	10,727,563	20,788	0.0019	0.9981	99.99
2.5	10,733,167	24,257	0.0023	0.9977	99.80
3.5	10,734,121		0.0000	1.0000	99.57
4.5	10,733,944		0.0000	1.0000	99.57
5.5	10,362,210		0.0000	1.0000	99.57
6.5	8,675,277		0.0000	1.0000	99.57
7.5	8,621,453	12,049	0.0014	0.9986	99.57
8.5	8,576,872	11,416	0.0013	0.9987	99.43
9.5	8,573,429	472	0.0001	0.9999	99.30
10.5	8,573,608		0.0000	1.0000	99.29
11.5	8,551,119		0.0000	1.0000	99.29
12.5	8,551,119	8,994	0.0011	0.9989	99.29
13.5	8,813,824	174,892	0.0198	0.9802	99.19
14.5	8,813,824		0.0000	1.0000	97.22
15.5	8,813,824	2,066	0.0002	0.9998	97.22
16.5	8,448,084		0.0000	1.0000	97.20
17.5	8,444,380		0.0000	1.0000	97.20
18.5	8,444,380		0.0000	1.0000	97.20
19.5	8,442,780		0.0000	1.0000	97.20
20.5	8,442,780		0.0000	1.0000	97.20
21.5	8,442,709		0.0000	1.0000	97.20
22.5	8,442,031	96,759	0.0115	0.9885	97.20
23.5	8,345,123		0.0000	1.0000	96.09
24.5	8,345,123	1,431	0.0002	0.9998	96.09
25.5	8,345,123		0.0000	1.0000	96.07
26.5	8,206,631	174,892	0.0213	0.9787	96.07
27.5	8,028,102		0.0000	1.0000	94.02
28.5	7,954,233		0.0000	1.0000	94.02
29.5	7,935,242		0.0000	1.0000	94.02
30.5	7,932,289	1,200	0.0002	0.9998	94.02
31.5	7,930,072		0.0000	1.0000	94.01
32.5	7,930,072		0.0000	1.0000	94.01
33.5	7,930,072		0.0000	1.0000	94.01
34.5	7,922,701		0.0000	1.0000	94.01
35.5	7,931,283		0.0000	1.0000	94.01
36.5	7,931,283		0.0000	1.0000	94.01
37.5	7,931,283		0.0000	1.0000	94.01
38.5	7,311,305	18,053	0.0025	0.9975	94.01

NORTHWEST NATURAL GAS COMPANY

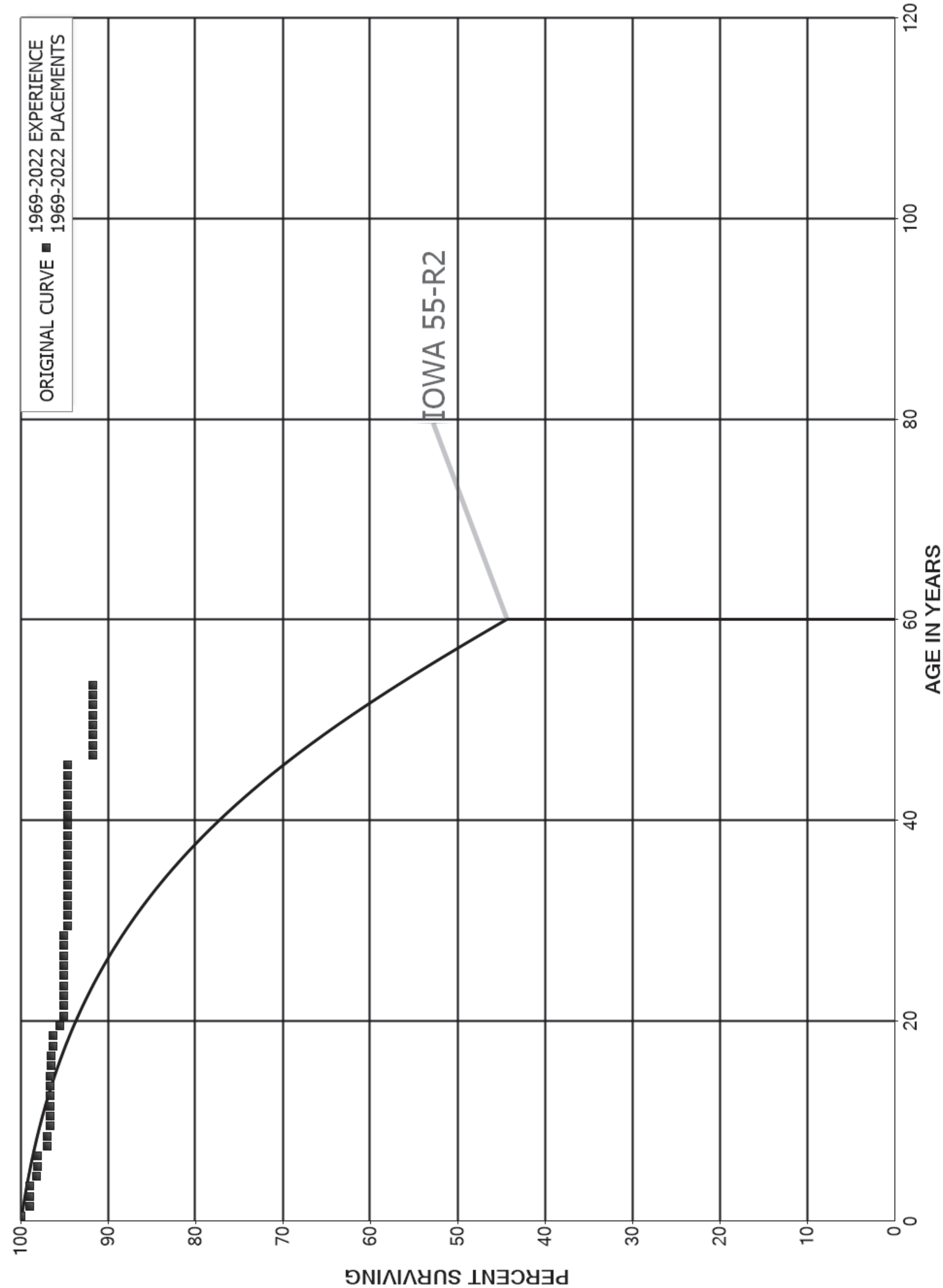
ACCOUNT 362.00 GAS HOLDERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1917-2017 EXPERIENCE BAND 1961-2022

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	7,292,283		0.0000	1.0000	93.78
40.5	7,292,283		0.0000	1.0000	93.78
41.5	7,292,283		0.0000	1.0000	93.78
42.5	7,292,283		0.0000	1.0000	93.78
43.5	7,292,380		0.0000	1.0000	93.78
44.5	7,282,078		0.0000	1.0000	93.78
45.5	1,730,784		0.0000	1.0000	93.78
46.5	1,730,784		0.0000	1.0000	93.78
47.5	1,730,784	602	0.0003	0.9997	93.78
48.5	1,729,367		0.0000	1.0000	93.74
49.5	1,729,367		0.0000	1.0000	93.74
50.5	1,729,367		0.0000	1.0000	93.74
51.5	1,729,367		0.0000	1.0000	93.74
52.5	1,729,367		0.0000	1.0000	93.74
53.5	8,858		0.0000	1.0000	93.74
54.5	8,858		0.0000	1.0000	93.74
55.5	8,858		0.0000	1.0000	93.74
56.5	8,858		0.0000	1.0000	93.74
57.5	8,858		0.0000	1.0000	93.74
58.5	8,858		0.0000	1.0000	93.74
59.5	8,858		0.0000	1.0000	93.74
60.5	97		0.0000	1.0000	93.74
61.5	97		0.0000	1.0000	93.74
62.5	97		0.0000	1.0000	93.74
63.5	97		0.0000	1.0000	93.74
64.5	97		0.0000	1.0000	93.74
65.5	97		0.0000	1.0000	93.74
66.5	97		0.0000	1.0000	93.74
67.5	97		0.0000	1.0000	93.74
68.5					93.74

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 1969-2022 EXPERIENCE BAND 1969-2022

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	27,012,639	28,598	0.0011	0.9989	100.00
0.5	20,439,803	199,635	0.0098	0.9902	99.89
1.5	20,140,001		0.0000	1.0000	98.92
2.5	19,794,898		0.0000	1.0000	98.92
3.5	19,563,714	146,338	0.0075	0.9925	98.92
4.5	14,568,815	18,698	0.0013	0.9987	98.18
5.5	10,875,424		0.0000	1.0000	98.05
6.5	10,472,636	114,090	0.0109	0.9891	98.05
7.5	10,304,721		0.0000	1.0000	96.98
8.5	9,947,870	34,692	0.0035	0.9965	96.98
9.5	9,758,855		0.0000	1.0000	96.65
10.5	9,685,872		0.0000	1.0000	96.65
11.5	9,685,872		0.0000	1.0000	96.65
12.5	9,685,872	434	0.0000	1.0000	96.65
13.5	9,615,025		0.0000	1.0000	96.64
14.5	9,552,647	13,425	0.0014	0.9986	96.64
15.5	9,495,419		0.0000	1.0000	96.51
16.5	9,339,565	18,523	0.0020	0.9980	96.51
17.5	9,272,709	3,226	0.0003	0.9997	96.31
18.5	8,974,436	74,502	0.0083	0.9917	96.28
19.5	8,768,268	34,032	0.0039	0.9961	95.48
20.5	8,665,232		0.0000	1.0000	95.11
21.5	8,199,959		0.0000	1.0000	95.11
22.5	8,111,837		0.0000	1.0000	95.11
23.5	7,783,304		0.0000	1.0000	95.11
24.5	7,234,849		0.0000	1.0000	95.11
25.5	6,950,150		0.0000	1.0000	95.11
26.5	6,757,315	399	0.0001	0.9999	95.11
27.5	6,754,705		0.0000	1.0000	95.11
28.5	6,737,997	35,128	0.0052	0.9948	95.11
29.5	6,686,673		0.0000	1.0000	94.61
30.5	6,605,144		0.0000	1.0000	94.61
31.5	6,501,938		0.0000	1.0000	94.61
32.5	6,412,166		0.0000	1.0000	94.61
33.5	6,390,407		0.0000	1.0000	94.61
34.5	6,390,407		0.0000	1.0000	94.61
35.5	6,313,086		0.0000	1.0000	94.61
36.5	6,298,223		0.0000	1.0000	94.61
37.5	6,286,698		0.0000	1.0000	94.61
38.5	6,264,779		0.0000	1.0000	94.61

NORTHWEST NATURAL GAS COMPANY

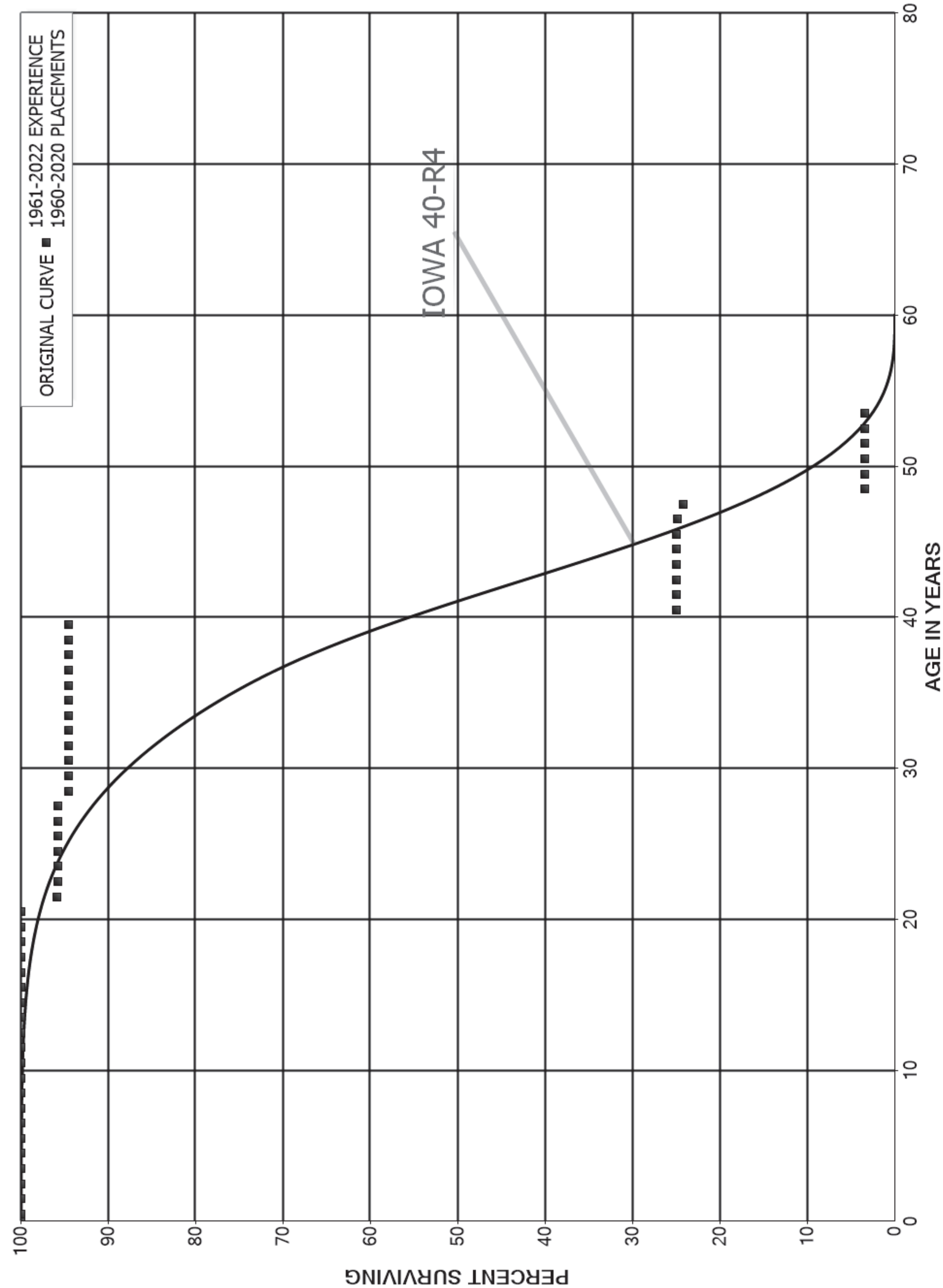
ACCOUNT 363.10 LIQUEFACTION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2022 EXPERIENCE BAND 1969-2022

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	94.61
40.5	6,264,779		0.0000	1.0000	94.61
41.5	6,264,779		0.0000	1.0000	94.61
42.5	6,164,100		0.0000	1.0000	94.61
43.5	6,158,562		0.0000	1.0000	94.61
44.5	6,142,214		0.0000	1.0000	94.61
45.5	905,417	27,318	0.0302	0.9698	94.61
46.5	852,144		0.0000	1.0000	91.76
47.5	851,876		0.0000	1.0000	91.76
48.5	849,919		0.0000	1.0000	91.76
49.5	849,919		0.0000	1.0000	91.76
50.5	845,658		0.0000	1.0000	91.76
51.5	844,045		0.0000	1.0000	91.76
52.5	828,857		0.0000	1.0000	91.76
53.5					91.76

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 1960-2020 EXPERIENCE BAND 1961-2022

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	13,820,840		0.0000	1.0000	100.00
0.5	13,820,840	602	0.0000	1.0000	100.00
1.5	14,023,474		0.0000	1.0000	100.00
2.5	11,055,638	1,415	0.0001	0.9999	100.00
3.5	11,055,638		0.0000	1.0000	99.98
4.5	11,055,638		0.0000	1.0000	99.98
5.5	6,584,958		0.0000	1.0000	99.98
6.5	6,584,958	1,983	0.0003	0.9997	99.98
7.5	6,436,057		0.0000	1.0000	99.95
8.5	6,436,057	2,322	0.0004	0.9996	99.95
9.5	6,433,834		0.0000	1.0000	99.92
10.5	6,433,834		0.0000	1.0000	99.92
11.5	5,320,819		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	4,999,612		0.0000	1.0000	99.92
17.5	4,999,612		0.0000	1.0000	99.92
18.5	4,931,166		0.0000	1.0000	99.92
19.5	4,931,166		0.0000	1.0000	99.92
20.5	4,930,986	200,000	0.0406	0.9594	99.92
21.5	4,730,986	8,350	0.0018	0.9982	95.86
22.5	4,722,636		0.0000	1.0000	95.69
23.5	4,722,636	455	0.0001	0.9999	95.69
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	4,710,261	59,483	0.0126	0.9874	95.67
28.5	4,618,017		0.0000	1.0000	94.46
29.5	4,618,016		0.0000	1.0000	94.46
30.5	4,615,790		0.0000	1.0000	94.46
31.5	4,429,354		0.0000	1.0000	94.46
32.5	3,273,347		0.0000	1.0000	94.46
33.5	3,273,347		0.0000	1.0000	94.46
34.5	3,273,347		0.0000	1.0000	94.46
35.5	3,095,885		0.0000	1.0000	94.46
36.5	3,083,807		0.0000	1.0000	94.46
37.5	3,083,807		0.0000	1.0000	94.46
38.5	3,083,807		0.0000	1.0000	94.46

NORTHWEST NATURAL GAS COMPANY

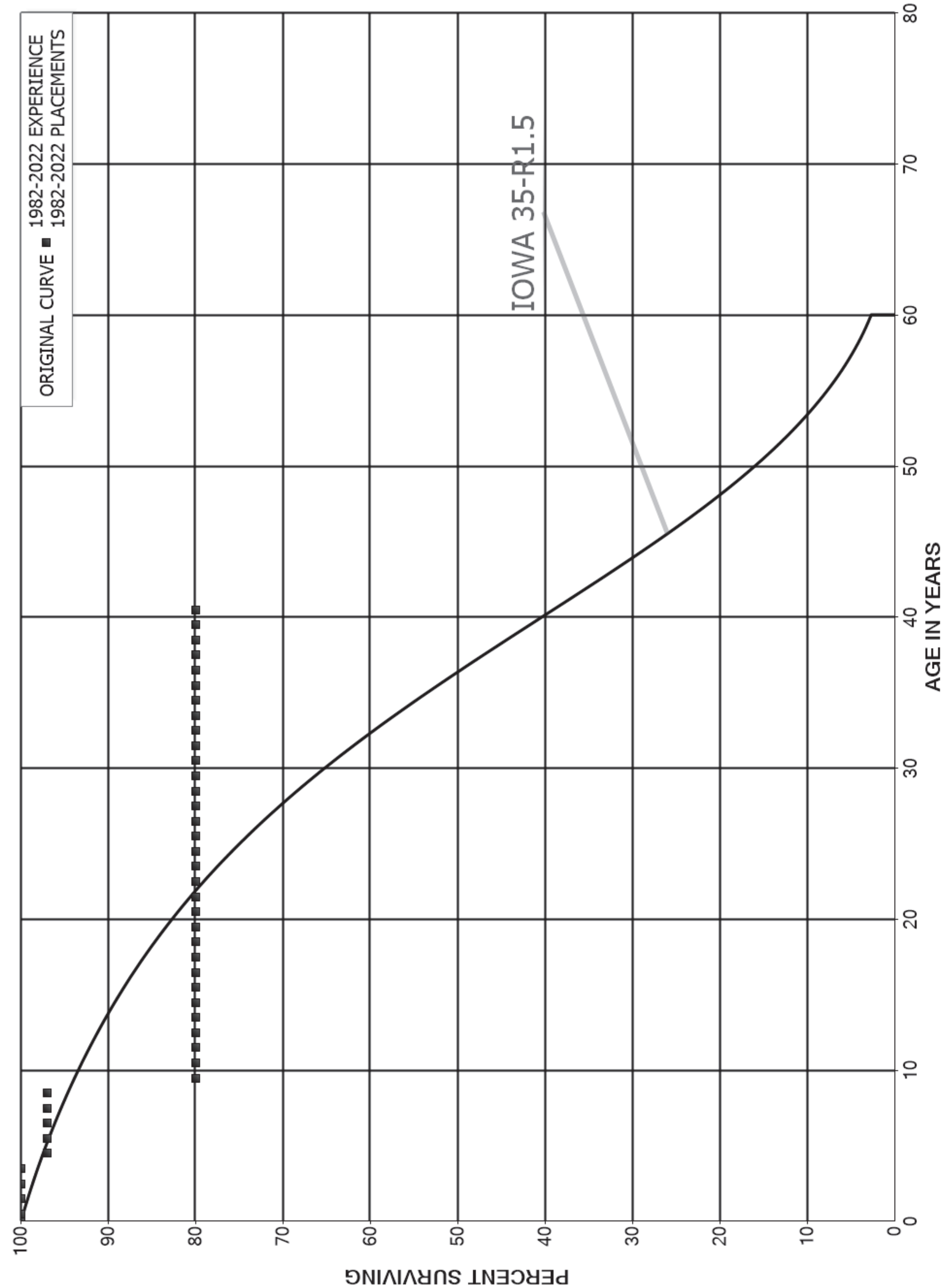
ACCOUNT 363.20 VAPORIZING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2020 EXPERIENCE BAND 1961-2022

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	94.46
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	753,468	4,062	0.0054	0.9946	24.94
46.5	362,742	9,122	0.0251	0.9749	24.81
47.5	353,351	303,259	0.8582	0.1418	24.18
48.5	47,833		0.0000	1.0000	3.43
49.5	34,582		0.0000	1.0000	3.43
50.5	32,214		0.0000	1.0000	3.43
51.5	18,960		0.0000	1.0000	3.43
52.5	18,960		0.0000	1.0000	3.43
53.5					3.43

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 363.30 COMPRESSOR EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



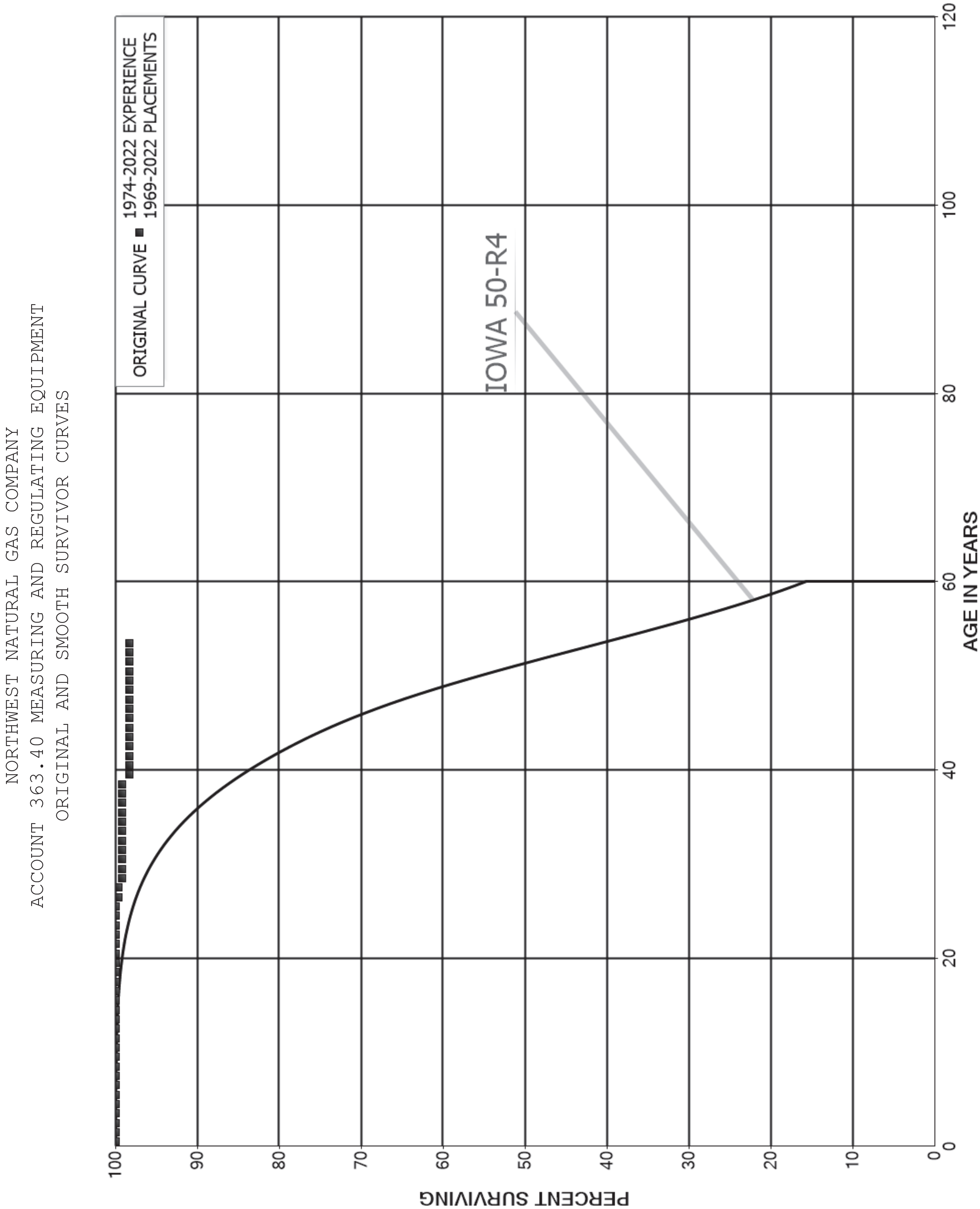
NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.30 COMPRESSOR EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1982-2022 EXPERIENCE BAND 1982-2022

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	6,207,702		0.0000	1.0000	100.00
0.5	5,961,554		0.0000	1.0000	100.00
1.5	5,161,937		0.0000	1.0000	100.00
2.5	5,040,754	273	0.0001	0.9999	100.00
3.5	5,040,481	151,425	0.0300	0.9700	99.99
4.5	4,632,459		0.0000	1.0000	96.99
5.5	4,134,653		0.0000	1.0000	96.99
6.5	1,867,683		0.0000	1.0000	96.99
7.5	1,867,683		0.0000	1.0000	96.99
8.5	481,854	84,841	0.1761	0.8239	96.99
9.5	397,013		0.0000	1.0000	79.91
10.5	397,013		0.0000	1.0000	79.91
11.5	397,013		0.0000	1.0000	79.91
12.5	397,013		0.0000	1.0000	79.91
13.5	397,013		0.0000	1.0000	79.91
14.5	343,850		0.0000	1.0000	79.91
15.5	343,850		0.0000	1.0000	79.91
16.5	343,850		0.0000	1.0000	79.91
17.5	327,070		0.0000	1.0000	79.91
18.5	327,070		0.0000	1.0000	79.91
19.5	148,568		0.0000	1.0000	79.91
20.5	148,568		0.0000	1.0000	79.91
21.5	148,568		0.0000	1.0000	79.91
22.5	148,568		0.0000	1.0000	79.91
23.5	148,568		0.0000	1.0000	79.91
24.5	148,568		0.0000	1.0000	79.91
25.5	127,741		0.0000	1.0000	79.91
26.5	108,320		0.0000	1.0000	79.91
27.5	108,320		0.0000	1.0000	79.91
28.5	108,320		0.0000	1.0000	79.91
29.5	108,320		0.0000	1.0000	79.91
30.5	108,320		0.0000	1.0000	79.91
31.5	108,320		0.0000	1.0000	79.91
32.5	108,320		0.0000	1.0000	79.91
33.5	108,320		0.0000	1.0000	79.91
34.5	108,320		0.0000	1.0000	79.91
35.5	108,320		0.0000	1.0000	79.91
36.5	86,804		0.0000	1.0000	79.91
37.5	86,804		0.0000	1.0000	79.91
38.5	86,804		0.0000	1.0000	79.91
39.5	85,687		0.0000	1.0000	79.91
40.5					79.91


NORTHWEST NATURAL GAS COMPANY
ACCOUNT 363.40 MEASURING AND REGULATING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE ■ 1974-2022 EXPERIENCE
1969-2022 PLACEMENTS
IOWA 50-R4
PERCENT SURVIVING
100
90
80
70
60
50
40
30
20
10
0
AGE IN YEARS
0
20
40
60
80
100
120

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.40 MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2022 EXPERIENCE BAND 1974-2022

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	19,059,447		0.0000	1.0000	100.00
0.5	13,805,464		0.0000	1.0000	100.00
1.5	13,286,310		0.0000	1.0000	100.00
2.5	12,980,119		0.0000	1.0000	100.00
3.5	12,872,234		0.0000	1.0000	100.00
4.5	12,752,913		0.0000	1.0000	100.00
5.5	1,362,034		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	1,002,125		0.0000	1.0000	100.00
9.5	850,563		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	682,272		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	653,998		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	636,675		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	628,091		0.0000	1.0000	99.18
31.5	607,580		0.0000	1.0000	99.18
32.5	560,097		0.0000	1.0000	99.18
33.5	555,322		0.0000	1.0000	99.18
34.5	545,620		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	541,958		0.0000	1.0000	99.18
38.5	541,958	4,721	0.0087	0.9913	99.18

NORTHWEST NATURAL GAS COMPANY

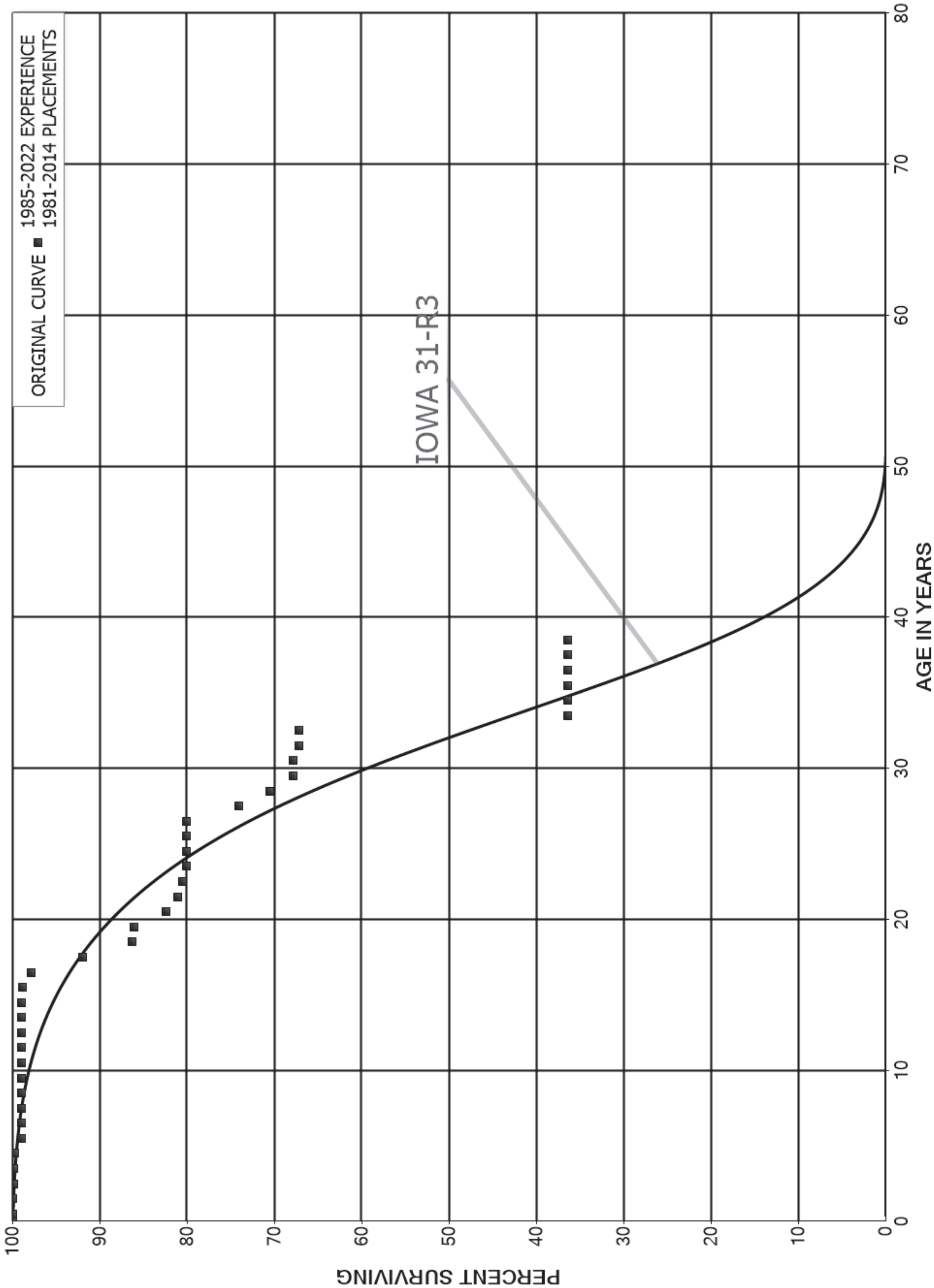
ACCOUNT 363.40 MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2022 EXPERIENCE BAND 1974-2022

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	482,034		0.0000	1.0000	98.32
46.5	482,034		0.0000	1.0000	98.32
47.5	481,660		0.0000	1.0000	98.32
48.5	480,333		0.0000	1.0000	98.32
49.5	480,333		0.0000	1.0000	98.32
50.5	474,008		0.0000	1.0000	98.32
51.5	464,177		0.0000	1.0000	98.32
52.5	461,537		0.0000	1.0000	98.32
53.5					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 1981-2014 EXPERIENCE BAND 1985-2022

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	3,397,353		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	2,068,805		0.0000	1.0000	99.00
9.5	1,945,791		0.0000	1.0000	99.00
10.5	1,828,161		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	1,544,374	4,067	0.0026	0.9974	86.32
19.5	1,540,307	66,855	0.0434	0.9566	86.09
20.5	1,472,152	22,396	0.0152	0.9848	82.36
21.5	1,449,756	10,299	0.0071	0.9929	81.10
22.5	1,439,457	8,819	0.0061	0.9939	80.53
23.5	1,426,354		0.0000	1.0000	80.03
24.5	1,397,519		0.0000	1.0000	80.03
25.5	1,349,534		0.0000	1.0000	80.03
26.5	1,121,383	84,323	0.0752	0.9248	80.03
27.5	743,701	35,635	0.0479	0.9521	74.02
28.5	359,682	13,528	0.0376	0.9624	70.47
29.5	284,944	25	0.0001	0.9999	67.82
30.5	265,212	2,421	0.0091	0.9909	67.81
31.5	210,584		0.0000	1.0000	67.19
32.5	147,105	67,435	0.4584	0.5416	67.19
33.5	79,670		0.0000	1.0000	36.39
34.5	79,670		0.0000	1.0000	36.39
35.5	79,670		0.0000	1.0000	36.39
36.5	72,652		0.0000	1.0000	36.39
37.5	71,186		0.0000	1.0000	36.39
38.5	30,743		0.0000	1.0000	36.39

NORTHWEST NATURAL GAS COMPANY

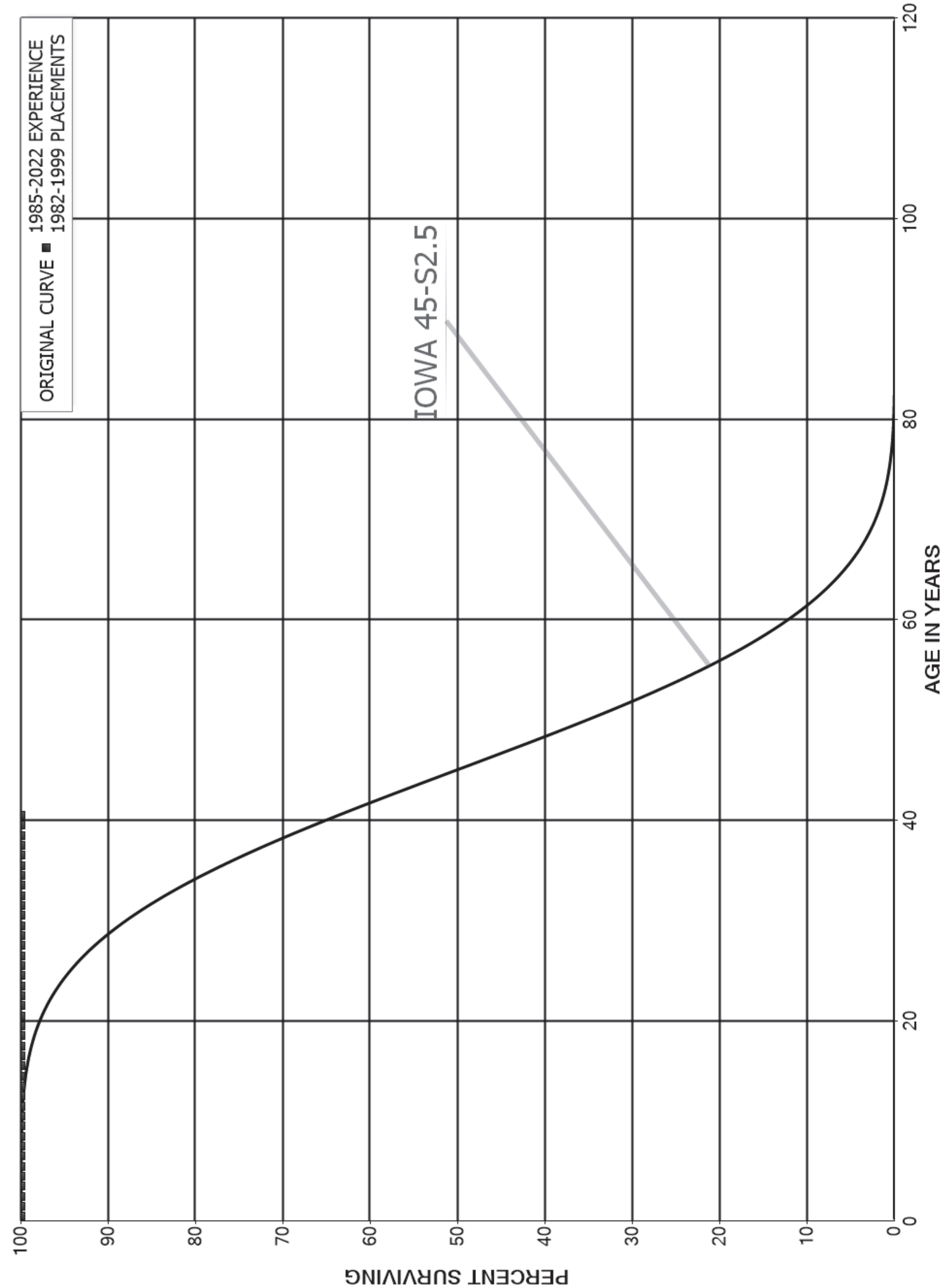
ACCOUNT 363.50 CNG REFUELING FACILITIES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1981-2014 EXPERIENCE BAND 1985-2022

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	29,180		0.0000	1.0000	36.39
40.5	19,620		0.0000	1.0000	36.39
41.5					36.39

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 363.60 LNG REFUELING FACILITIES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

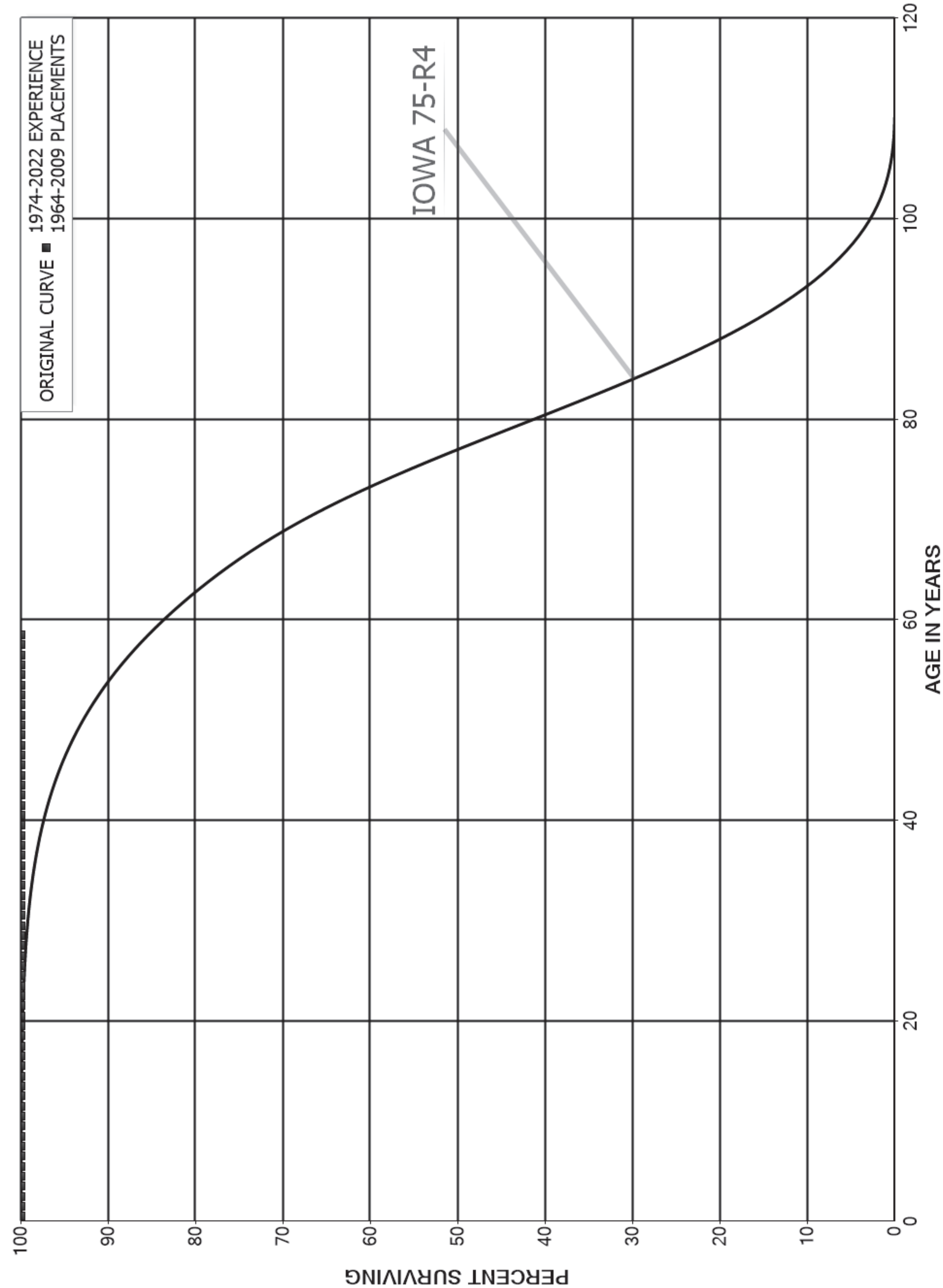
ACCOUNT 363.60 LNG REFUELING FACILITIES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1982-1999 EXPERIENCE BAND 1985-2022

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	730,990		0.0000	1.0000	100.00
24.5	730,990		0.0000	1.0000	100.00
25.5	725,680		0.0000	1.0000	100.00
26.5	712,293		0.0000	1.0000	100.00
27.5	666,615		0.0000	1.0000	100.00
28.5	628,397		0.0000	1.0000	100.00
29.5	573,929		0.0000	1.0000	100.00
30.5	460,040		0.0000	1.0000	100.00
31.5	459,105		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	458,997		0.0000	1.0000	100.00
37.5	453,824		0.0000	1.0000	100.00
38.5	411,057		0.0000	1.0000	100.00
39.5	349,437		0.0000	1.0000	100.00
40.5					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 1974-2022

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	6,270,968		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	4,195,148		0.0000	1.0000	100.00
19.5	3,013,374		0.0000	1.0000	100.00
20.5	2,617,946		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	2,604,197		0.0000	1.0000	100.00
31.5	2,461,137		0.0000	1.0000	100.00
32.5	2,060,125		0.0000	1.0000	100.00
33.5	1,244,309		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

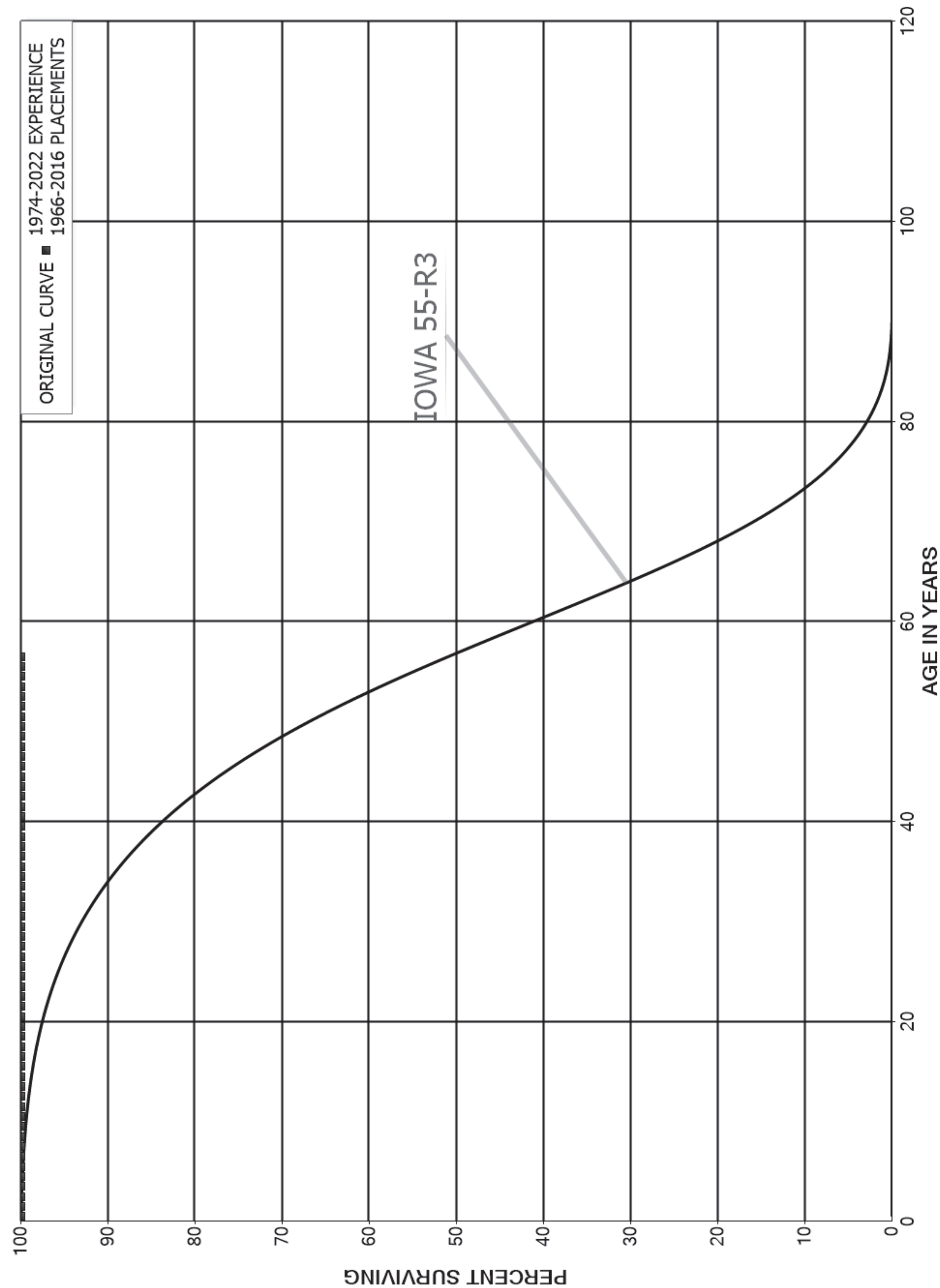
ACCOUNT 365.20 LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1964-2009 EXPERIENCE BAND 1974-2022

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	1,238,350		0.0000	1.0000	100.00
42.5	1,238,350		0.0000	1.0000	100.00
43.5	1,229,163		0.0000	1.0000	100.00
44.5	1,229,163		0.0000	1.0000	100.00
45.5	1,217,081		0.0000	1.0000	100.00
46.5	1,189,050		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	1,168,447		0.0000	1.0000	100.00
55.5	1,009,167		0.0000	1.0000	100.00
56.5	539,190		0.0000	1.0000	100.00
57.5	94,094		0.0000	1.0000	100.00
58.5					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 1974-2022

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	955,999		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	984,166		0.0000	1.0000	100.00
18.5	85,985		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

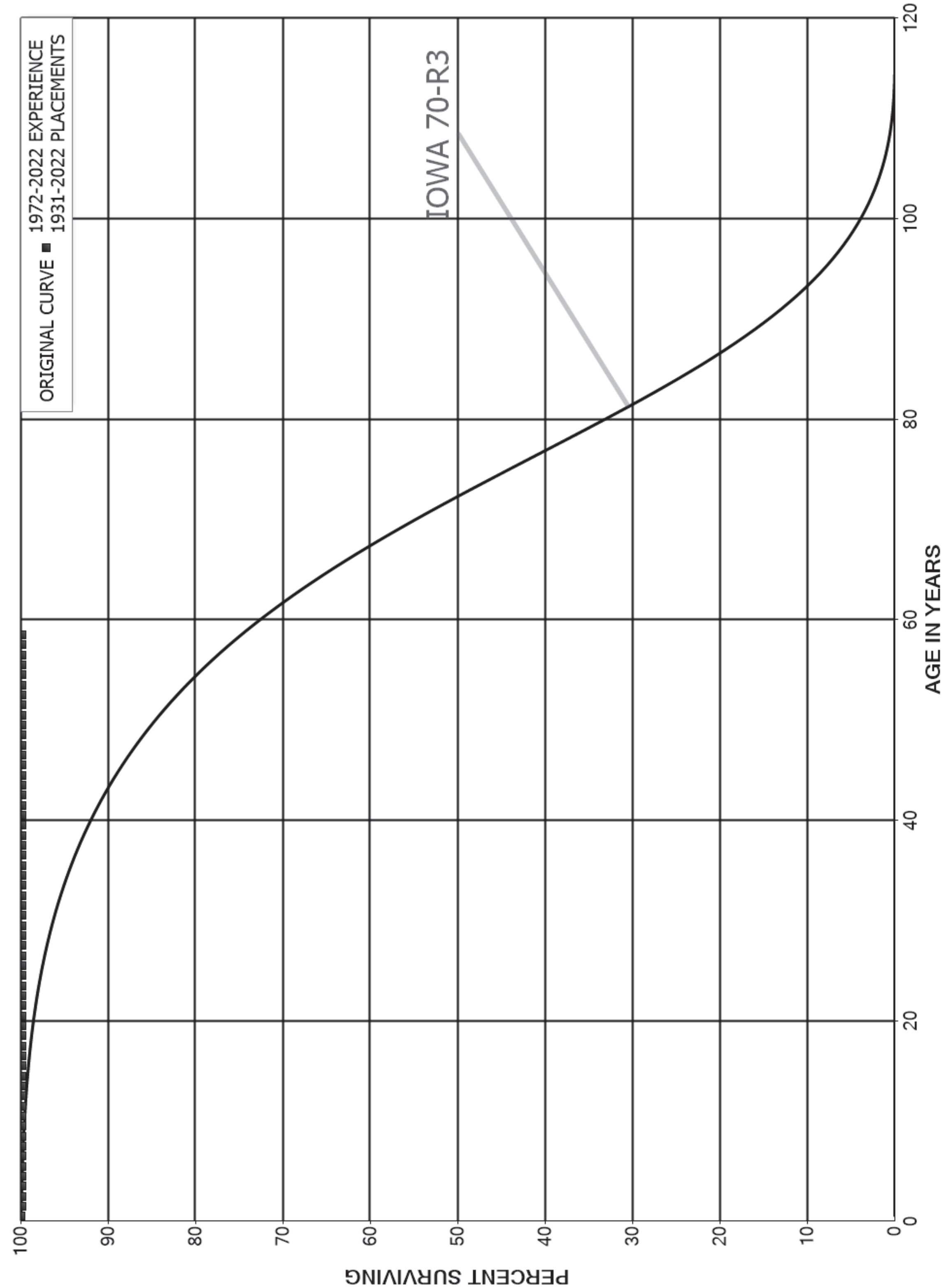
ACCOUNT 366.30 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2016 EXPERIENCE BAND 1974-2022

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					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 1931-2022 EXPERIENCE BAND 1972-2022

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	287,019,381		0.0000	1.0000	100.00
0.5	291,288,392	532,003	0.0018	0.9982	100.00
1.5	338,372,157		0.0000	1.0000	99.82
2.5	328,016,371		0.0000	1.0000	99.82
3.5	318,100,931	38,942	0.0001	0.9999	99.82
4.5	304,406,889		0.0000	1.0000	99.81
5.5	304,985,714		0.0000	1.0000	99.81
6.5	302,922,387		0.0000	1.0000	99.81
7.5	297,564,960	1,086	0.0000	1.0000	99.81
8.5	279,320,700		0.0000	1.0000	99.80
9.5	229,655,960	1,086	0.0000	1.0000	99.80
10.5	198,884,560	16,355	0.0001	0.9999	99.80
11.5	190,822,564		0.0000	1.0000	99.80
12.5	171,475,182		0.0000	1.0000	99.80
13.5	166,874,669		0.0000	1.0000	99.80
14.5	166,874,669		0.0000	1.0000	99.80
15.5	166,808,732	2,603	0.0000	1.0000	99.80
16.5	166,806,129		0.0000	1.0000	99.79
17.5	166,792,438	541	0.0000	1.0000	99.79
18.5	128,793,642		0.0000	1.0000	99.79
19.5	61,949,897		0.0000	1.0000	99.79
20.5	61,694,305	1,756	0.0000	1.0000	99.79
21.5	61,155,910		0.0000	1.0000	99.79
22.5	61,091,777		0.0000	1.0000	99.79
23.5	27,575,643		0.0000	1.0000	99.79
24.5	27,575,643		0.0000	1.0000	99.79
25.5	27,575,643	481	0.0000	1.0000	99.79
26.5	27,575,162		0.0000	1.0000	99.79
27.5	27,573,648		0.0000	1.0000	99.79
28.5	27,441,077	388	0.0000	1.0000	99.79
29.5	27,295,904		0.0000	1.0000	99.79
30.5	27,295,904		0.0000	1.0000	99.79
31.5	27,292,423		0.0000	1.0000	99.79
32.5	26,995,509		0.0000	1.0000	99.79
33.5	10,178,290		0.0000	1.0000	99.79
34.5	10,178,290		0.0000	1.0000	99.79
35.5	10,178,290		0.0000	1.0000	99.79
36.5	10,160,853		0.0000	1.0000	99.79
37.5	10,131,532		0.0000	1.0000	99.79
38.5	10,131,532		0.0000	1.0000	99.79

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 367.00 THROUGH 367.26 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1931-2022 EXPERIENCE BAND 1972-2022

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	99.79
40.5	9,969,318		0.0000	1.0000	99.79
41.5	9,458,671		0.0000	1.0000	99.79
42.5	9,424,544		0.0000	1.0000	99.79
43.5	9,424,544		0.0000	1.0000	99.79
44.5	9,411,932		0.0000	1.0000	99.79
45.5	9,406,964		0.0000	1.0000	99.79
46.5	8,179,539		0.0000	1.0000	99.79
47.5	8,179,539		0.0000	1.0000	99.79
48.5	8,179,539		0.0000	1.0000	99.79
49.5	8,179,539		0.0000	1.0000	99.79
50.5	8,160,658		0.0000	1.0000	99.79
51.5	8,160,658		0.0000	1.0000	99.79
52.5	8,161,199		0.0000	1.0000	99.79
53.5	8,144,175		0.0000	1.0000	99.79
54.5	8,139,304		0.0000	1.0000	99.79
55.5	8,041,218		0.0000	1.0000	99.79
56.5	4,791,489		0.0000	1.0000	99.79
57.5	632,284		0.0000	1.0000	99.79
58.5	541		0.0000	1.0000	99.79
59.5	541		0.0000	1.0000	99.79
60.5	541		0.0000	1.0000	99.79
61.5	541		0.0000	1.0000	99.79
62.5	541		0.0000	1.0000	99.79
63.5	541		0.0000	1.0000	99.79
64.5	541		0.0000	1.0000	99.79
65.5	541		0.0000	1.0000	99.79
66.5	541		0.0000	1.0000	99.79
67.5	541		0.0000	1.0000	99.79
68.5	541		0.0000	1.0000	99.79
69.5	541		0.0000	1.0000	99.79
70.5	541		0.0000	1.0000	99.79
71.5	541		0.0000	1.0000	99.79
72.5	541		0.0000	1.0000	99.79
73.5	541		0.0000	1.0000	99.79
74.5	541		0.0000	1.0000	99.79
75.5	541		0.0000	1.0000	99.79
76.5	541		0.0000	1.0000	99.79
77.5	541		0.0000	1.0000	99.79
78.5	541		0.0000	1.0000	99.79

NORTHWEST NATURAL GAS COMPANY

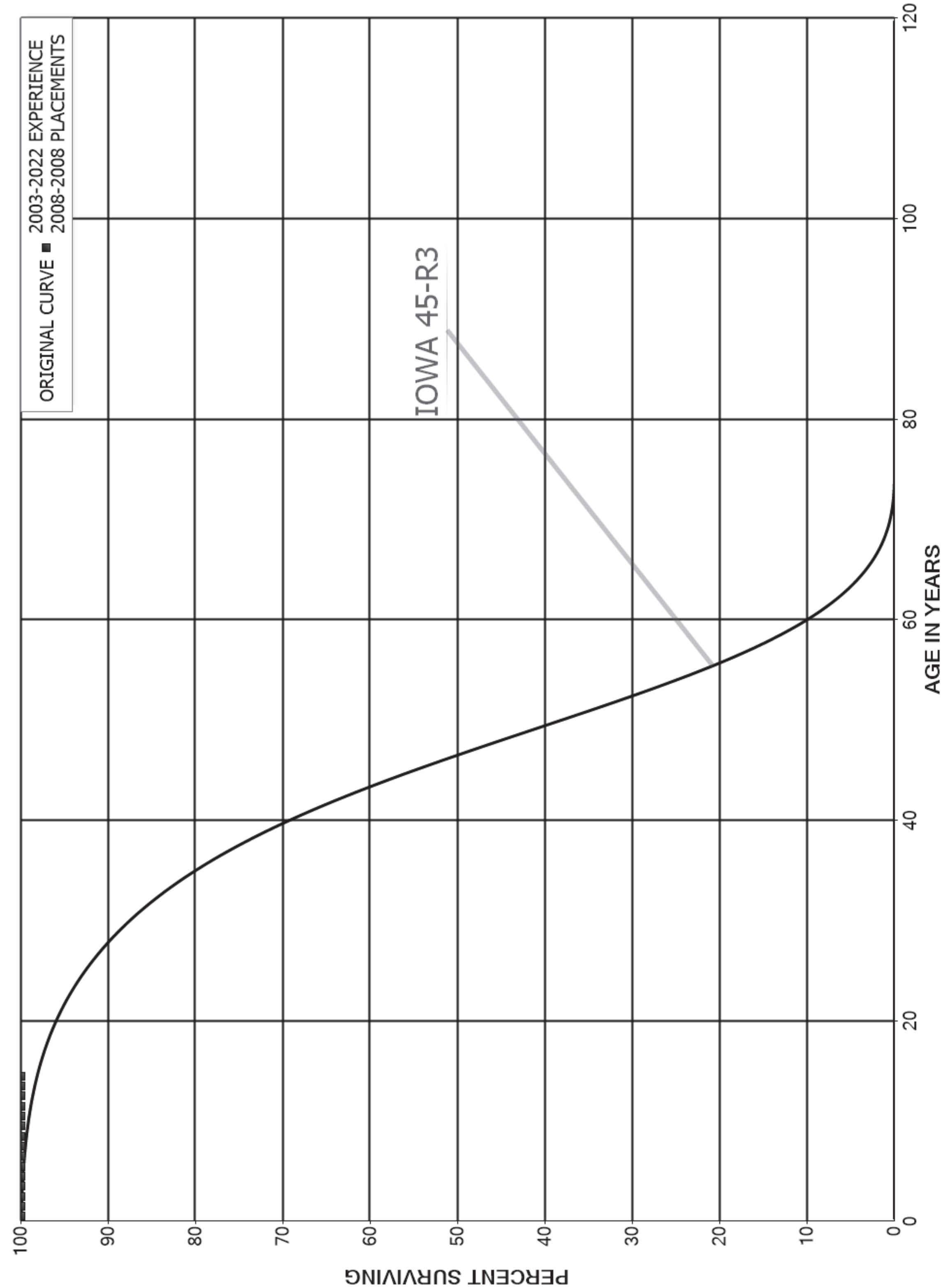
ACCOUNTS 367.00 THROUGH 367.26 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1931-2022 EXPERIENCE BAND 1972-2022

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	99.79
80.5	541		0.0000	1.0000	99.79
81.5	541		0.0000	1.0000	99.79
82.5	541		0.0000	1.0000	99.79
83.5	541		0.0000	1.0000	99.79
84.5	541		0.0000	1.0000	99.79
85.5	541		0.0000	1.0000	99.79
86.5	541		0.0000	1.0000	99.79
87.5	541		0.0000	1.0000	99.79
88.5	541		0.0000	1.0000	99.79
89.5	541		0.0000	1.0000	99.79
90.5	541		0.0000	1.0000	99.79
91.5					99.79

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 368.00 COMPRESSOR STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

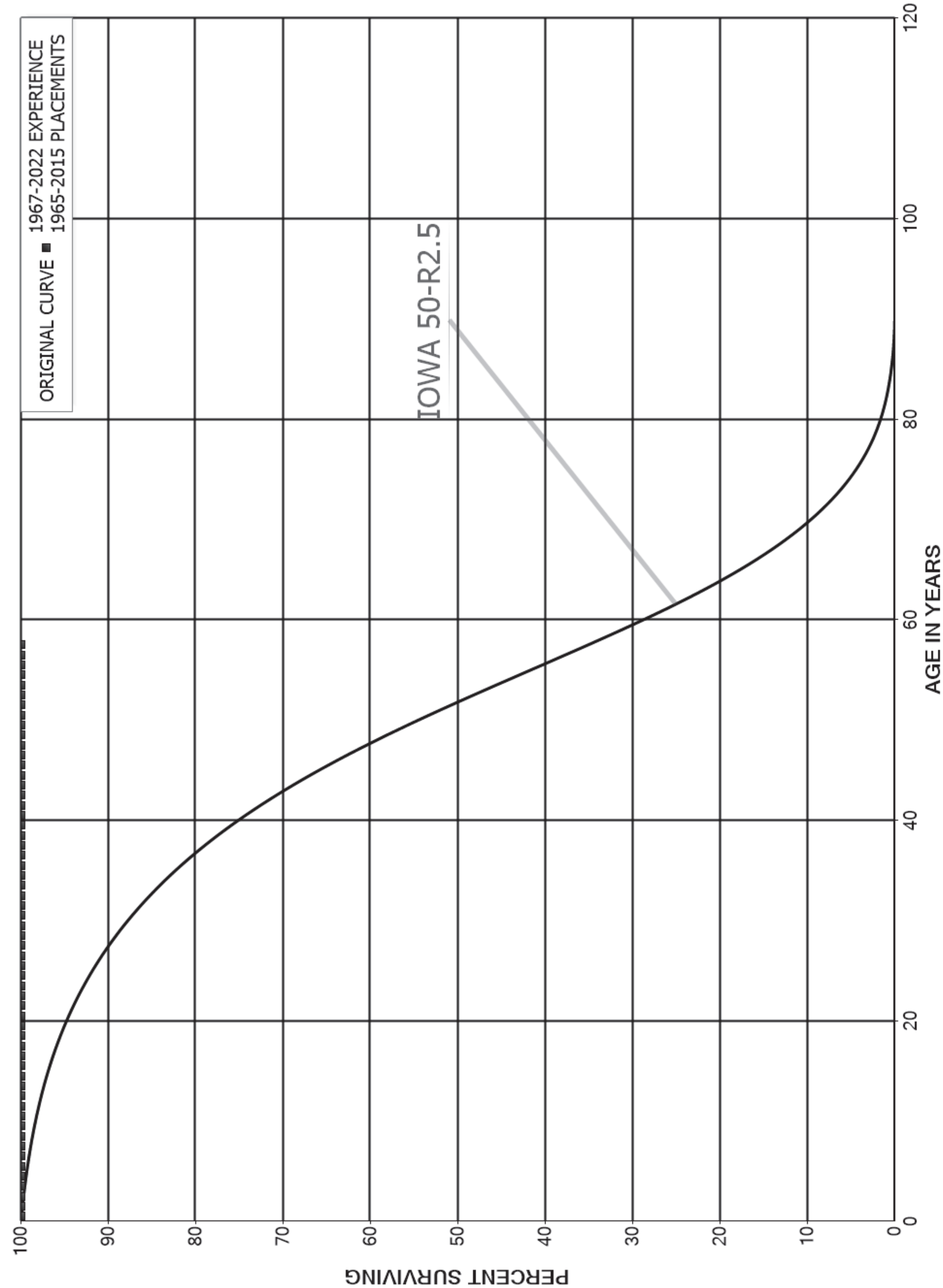
ACCOUNT 368.00 COMPRESSOR STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 2008-2008 EXPERIENCE BAND 2003-2022

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					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 1967-2022

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	3,875,501	638	0.0002	0.9998	99.98
8.5	3,768,413		0.0000	1.0000	99.97
9.5	575,963		0.0000	1.0000	99.97
10.5	542,079		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	408,765		0.0000	1.0000	99.97
17.5	408,765		0.0000	1.0000	99.97
18.5	396,697		0.0000	1.0000	99.97
19.5	207,616		0.0000	1.0000	99.97
20.5	195,625		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	118,019		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	91,081		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

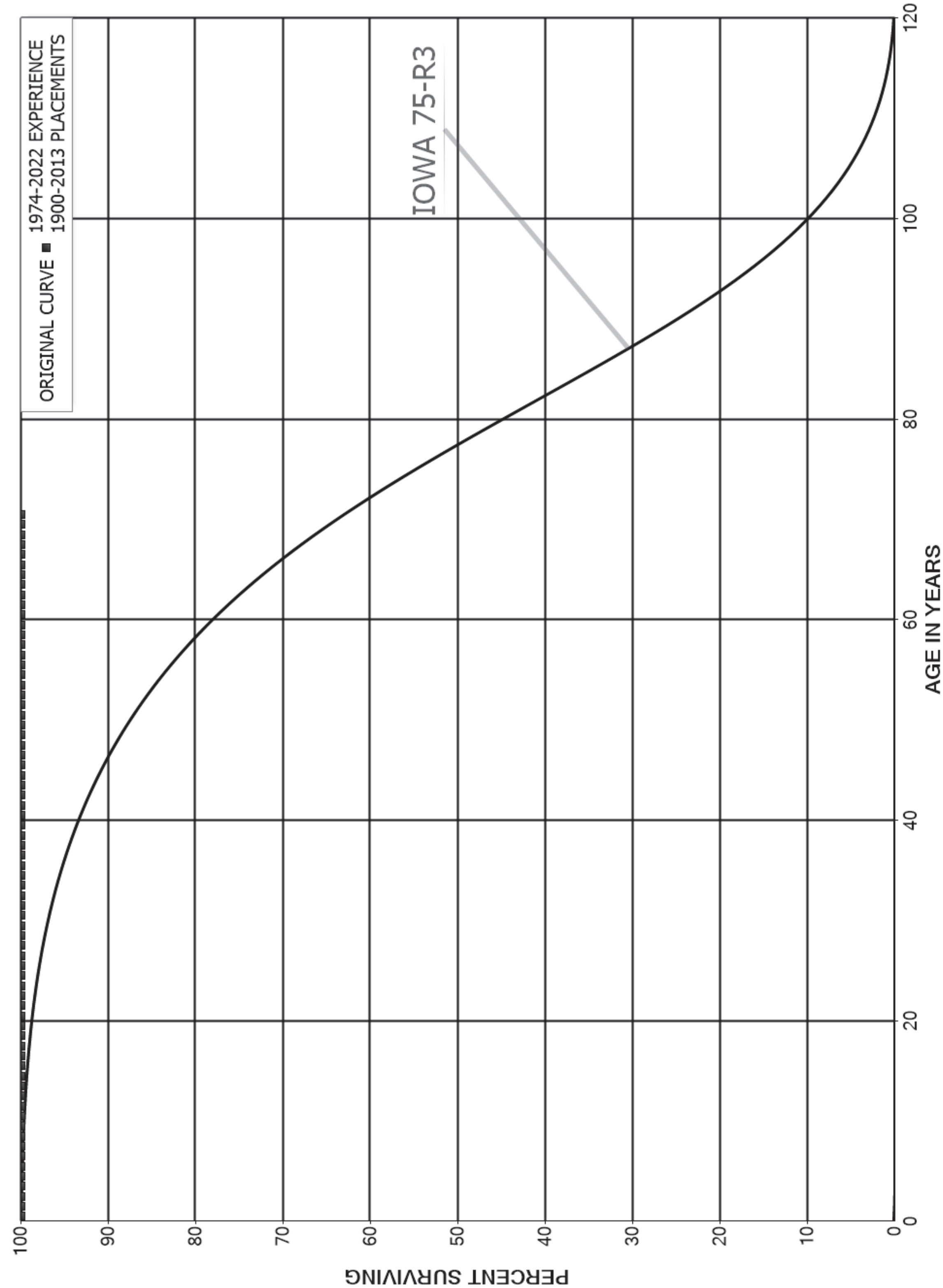
ACCOUNT 369.00 MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1967-2022

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	45,638		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	40,610		0.0000	1.0000	99.97
56.5	14,697		0.0000	1.0000	99.97
57.5					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 1974-2022

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	1,204,705		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	1,185,830		0.0000	1.0000	100.00
13.5	1,183,628		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	893,294		0.0000	1.0000	100.00
20.5	770,286		0.0000	1.0000	100.00
21.5	717,371		0.0000	1.0000	100.00
22.5	702,613		0.0000	1.0000	100.00
23.5	680,493		0.0000	1.0000	100.00
24.5	665,368		0.0000	1.0000	100.00
25.5	629,536		0.0000	1.0000	100.00
26.5	611,427		0.0000	1.0000	100.00
27.5	498,713		0.0000	1.0000	100.00
28.5	455,477		0.0000	1.0000	100.00
29.5	425,600		0.0000	1.0000	100.00
30.5	360,634		0.0000	1.0000	100.00
31.5	175,569		0.0000	1.0000	100.00
32.5	165,563		0.0000	1.0000	100.00
33.5	90,569		0.0000	1.0000	100.00
34.5	86,667		0.0000	1.0000	100.00
35.5	76,934		0.0000	1.0000	100.00
36.5	73,182		0.0000	1.0000	100.00
37.5	68,403		0.0000	1.0000	100.00
38.5	67,639		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 1974-2022

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	67,387		0.0000	1.0000	100.00
40.5	66,348		0.0000	1.0000	100.00
41.5	57,628		0.0000	1.0000	100.00
42.5	56,063		0.0000	1.0000	100.00
43.5	54,474		0.0000	1.0000	100.00
44.5	47,629		0.0000	1.0000	100.00
45.5	37,352		0.0000	1.0000	100.00
46.5	36,548		0.0000	1.0000	100.00
47.5	32,908		0.0000	1.0000	100.00
48.5	29,604		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	27,097		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	17,428		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	16,678		0.0000	1.0000	100.00
59.5	13,253		0.0000	1.0000	100.00
60.5	13,153		0.0000	1.0000	100.00
61.5	13,153		0.0000	1.0000	100.00
62.5	12,953		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	1,813		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					100.00
71.5					
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 1974-2022

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

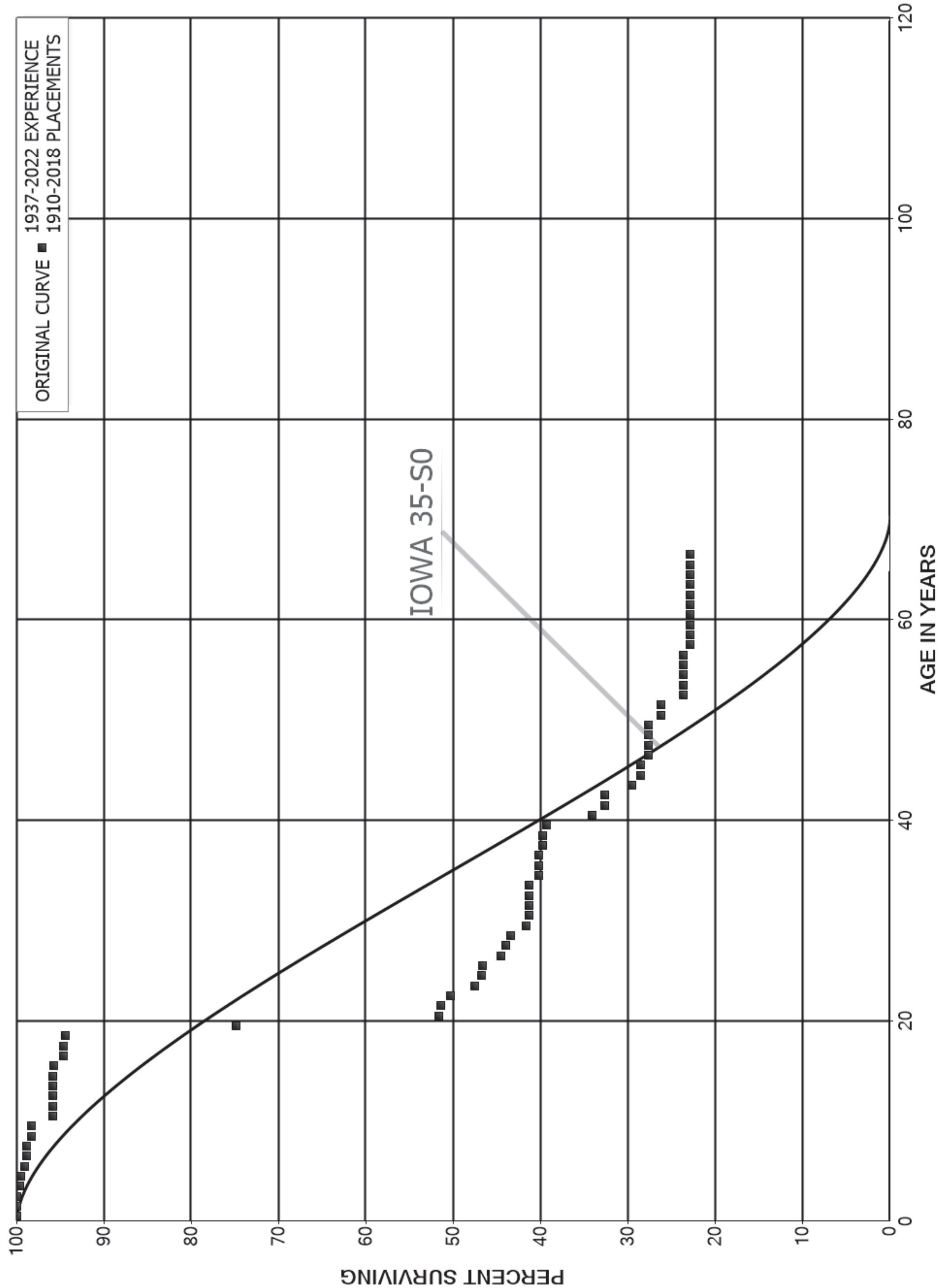
ACCOUNT 374.20 LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1974-2022

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					

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 1910-2018 EXPERIENCE BAND 1937-2022

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	1,548,149		0.0000	1.0000	100.00
0.5	1,548,149	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	1,464,971	5,302	0.0036	0.9964	99.45
5.5	1,464,971	3,403	0.0023	0.9977	99.09
6.5	108,808		0.0000	1.0000	98.86
7.5	108,808	611	0.0056	0.9944	98.86
8.5	108,808		0.0000	1.0000	98.31
9.5	110,952	2,752	0.0248	0.9752	98.31
10.5	110,952		0.0000	1.0000	95.87
11.5	110,952		0.0000	1.0000	95.87
12.5	110,952		0.0000	1.0000	95.87
13.5	110,952		0.0000	1.0000	95.87
14.5	110,952	170	0.0015	0.9985	95.87
15.5	99,983	1,206	0.0121	0.9879	95.72
16.5	99,983		0.0000	1.0000	94.57
17.5	99,983	167	0.0017	0.9983	94.57
18.5	99,983	20,760	0.2076	0.7924	94.41
19.5	99,553	30,809	0.3095	0.6905	74.81
20.5	99,553	506	0.0051	0.9949	51.66
21.5	99,553	2,221	0.0223	0.9777	51.39
22.5	99,553	5,411	0.0544	0.9456	50.25
23.5	99,403	1,664	0.0167	0.9833	47.52
24.5	99,403	118	0.0012	0.9988	46.72
25.5	99,403	4,717	0.0475	0.9525	46.67
26.5	99,403	1,209	0.0122	0.9878	44.45
27.5	99,403	1,250	0.0126	0.9874	43.91
28.5	99,403	4,092	0.0412	0.9588	43.36
29.5	93,680	588	0.0063	0.9937	41.57
30.5	93,092		0.0000	1.0000	41.31
31.5	93,092		0.0000	1.0000	41.31
32.5	67,622	23	0.0003	0.9997	41.31
33.5	67,622	1,870	0.0277	0.9723	41.30
34.5	65,874		0.0000	1.0000	40.16
35.5	65,874		0.0000	1.0000	40.16
36.5	65,874	639	0.0097	0.9903	40.16
37.5	65,874	150	0.0023	0.9977	39.77
38.5	65,874	588	0.0089	0.9911	39.68

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1937-2022

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	39.32
40.5	57,179	2,300	0.0402	0.9598	34.03
41.5	54,879	167	0.0030	0.9970	32.66
42.5	54,879	5,090	0.0927	0.9073	32.56
43.5	54,757	1,928	0.0352	0.9648	29.54
44.5	52,840		0.0000	1.0000	28.50
45.5	52,840	1,623	0.0307	0.9693	28.50
46.5	52,840	107	0.0020	0.9980	27.63
47.5	52,840	4	0.0001	0.9999	27.57
48.5	52,840		0.0000	1.0000	27.57
49.5	52,840	2,607	0.0493	0.9507	27.57
50.5	52,840		0.0000	1.0000	26.21
51.5	58,646	5,806	0.0990	0.9010	26.21
52.5	52,840		0.0000	1.0000	23.61
53.5	52,840		0.0000	1.0000	23.61
54.5	52,840		0.0000	1.0000	23.61
55.5	52,840		0.0000	1.0000	23.61
56.5	52,840	1,625	0.0308	0.9692	23.61
57.5	52,542		0.0000	1.0000	22.89
58.5	52,542		0.0000	1.0000	22.89
59.5	52,542		0.0000	1.0000	22.89
60.5	49,800		0.0000	1.0000	22.89
61.5	49,074		0.0000	1.0000	22.89
62.5	42,091		0.0000	1.0000	22.89
63.5	41,220		0.0000	1.0000	22.89
64.5	37,913		0.0000	1.0000	22.89
65.5	37,913		0.0000	1.0000	22.89
66.5	4,985		0.0000	1.0000	22.89
67.5	4,985		0.0000	1.0000	22.89
68.5	4,985		0.0000	1.0000	22.89
69.5	4,971		0.0000	1.0000	22.89
70.5	4,971		0.0000	1.0000	22.89
71.5	4,971		0.0000	1.0000	22.89
72.5	4,971		0.0000	1.0000	22.89
73.5	4,971		0.0000	1.0000	22.89
74.5	4,971		0.0000	1.0000	22.89
75.5	4,971		0.0000	1.0000	22.89
76.5	4,971		0.0000	1.0000	22.89
77.5	4,971		0.0000	1.0000	22.89
78.5	4,971		0.0000	1.0000	22.89

NORTHWEST NATURAL GAS COMPANY

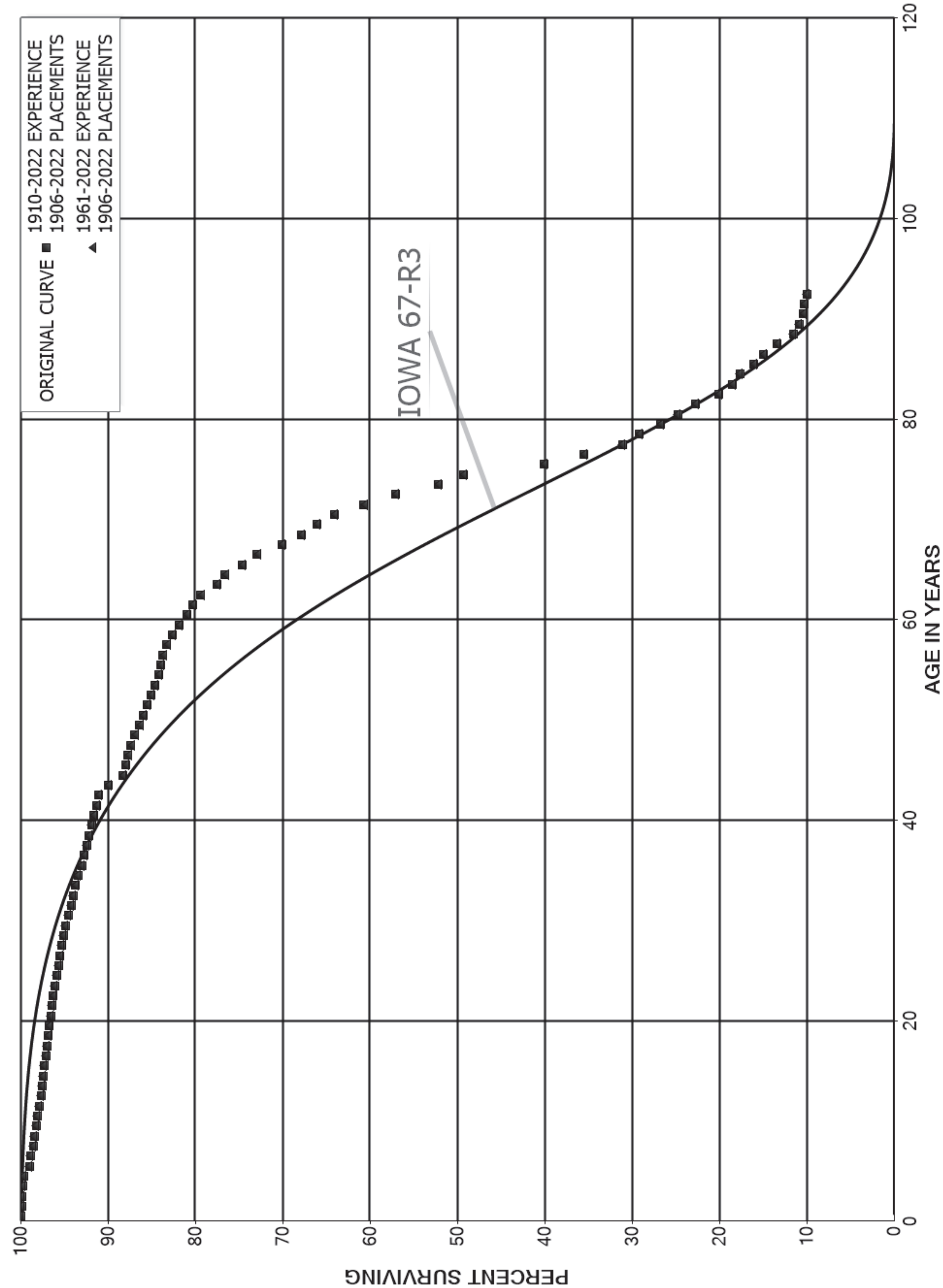
ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1937-2022

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	22.89
80.5	4,971		0.0000	1.0000	22.89
81.5	4,971		0.0000	1.0000	22.89
82.5	4,971		0.0000	1.0000	22.89
83.5	4,971		0.0000	1.0000	22.89
84.5	4,971		0.0000	1.0000	22.89
85.5	4,971		0.0000	1.0000	22.89
86.5	4,971		0.0000	1.0000	22.89
87.5	4,971		0.0000	1.0000	22.89
88.5	4,971		0.0000	1.0000	22.89
89.5	4,971		0.0000	1.0000	22.89
90.5	4,971		0.0000	1.0000	22.89
91.5	4,971		0.0000	1.0000	22.89
92.5	4,971		0.0000	1.0000	22.89
93.5	4,971		0.0000	1.0000	22.89
94.5	4,971		0.0000	1.0000	22.89
95.5	2,827		0.0000	1.0000	22.89
96.5	2,827		0.0000	1.0000	22.89
97.5	2,827		0.0000	1.0000	22.89
98.5	2,827		0.0000	1.0000	22.89
99.5	2,827		0.0000	1.0000	22.89
100.5	2,827		0.0000	1.0000	22.89
101.5	2,827		0.0000	1.0000	22.89
102.5	2,827		0.0000	1.0000	22.89
103.5	2,827		0.0000	1.0000	22.89
104.5	2,827		0.0000	1.0000	22.89
105.5	2,827		0.0000	1.0000	22.89
106.5	2,827		0.0000	1.0000	22.89
107.5	2,827		0.0000	1.0000	22.89
108.5	2,827		0.0000	1.0000	22.89
109.5					22.89

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 1906-2022 EXPERIENCE BAND 1910-2022

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	1,508,616,614	464,552	0.0003	0.9997	100.00
0.5	1,434,170,209	1,223,485	0.0009	0.9991	99.97
1.5	1,387,528,085	1,055,291	0.0008	0.9992	99.88
2.5	1,316,236,590	1,261,170	0.0010	0.9990	99.81
3.5	1,256,895,489	1,479,978	0.0012	0.9988	99.71
4.5	1,194,714,577	7,295,018	0.0061	0.9939	99.59
5.5	1,148,461,605	1,571,442	0.0014	0.9986	98.99
6.5	1,106,445,926	4,140,131	0.0037	0.9963	98.85
7.5	1,068,139,863	1,373,460	0.0013	0.9987	98.48
8.5	1,030,817,447	1,449,815	0.0014	0.9986	98.35
9.5	990,629,730	1,865,006	0.0019	0.9981	98.22
10.5	953,750,926	1,912,878	0.0020	0.9980	98.03
11.5	929,772,730	1,644,232	0.0018	0.9982	97.83
12.5	907,077,126	1,255,821	0.0014	0.9986	97.66
13.5	886,759,410	1,285,128	0.0014	0.9986	97.53
14.5	856,637,639	976,397	0.0011	0.9989	97.39
15.5	820,092,847	1,488,090	0.0018	0.9982	97.27
16.5	782,823,143	1,371,895	0.0018	0.9982	97.10
17.5	744,197,097	1,017,820	0.0014	0.9986	96.93
18.5	708,548,393	874,847	0.0012	0.9988	96.80
19.5	660,555,333	1,023,147	0.0015	0.9985	96.68
20.5	629,084,633	855,878	0.0014	0.9986	96.53
21.5	600,818,516	993,959	0.0017	0.9983	96.39
22.5	568,518,252	1,165,198	0.0020	0.9980	96.24
23.5	538,017,442	1,053,988	0.0020	0.9980	96.04
24.5	506,419,781	1,088,951	0.0022	0.9978	95.85
25.5	469,130,714	839,343	0.0018	0.9982	95.64
26.5	432,987,178	902,448	0.0021	0.9979	95.47
27.5	402,511,170	831,090	0.0021	0.9979	95.27
28.5	371,661,350	761,930	0.0021	0.9979	95.08
29.5	342,085,177	1,278,561	0.0037	0.9963	94.88
30.5	314,754,087	1,019,653	0.0032	0.9968	94.53
31.5	291,481,433	832,748	0.0029	0.9971	94.22
32.5	273,699,815	681,003	0.0025	0.9975	93.95
33.5	255,802,305	761,395	0.0030	0.9970	93.72
34.5	240,200,723	1,128,018	0.0047	0.9953	93.44
35.5	226,220,292	707,258	0.0031	0.9969	93.00
36.5	209,809,221	589,746	0.0028	0.9972	92.71
37.5	193,203,789	527,437	0.0027	0.9973	92.45
38.5	175,587,200	591,042	0.0034	0.9966	92.20

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 376.11 AND 376.12 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2022 EXPERIENCE BAND 1910-2022

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	163,520,045	530,107	0.0032	0.9968	91.89
40.5	151,754,092	505,980	0.0033	0.9967	91.59
41.5	138,960,094	376,228	0.0027	0.9973	91.28
42.5	127,054,323	1,549,950	0.0122	0.9878	91.04
43.5	114,475,502	2,120,145	0.0185	0.9815	89.93
44.5	103,516,518	301,124	0.0029	0.9971	88.26
45.5	97,799,607	365,782	0.0037	0.9963	88.00
46.5	92,562,066	343,747	0.0037	0.9963	87.67
47.5	87,782,271	421,547	0.0048	0.9952	87.35
48.5	81,837,152	537,597	0.0066	0.9934	86.93
49.5	75,389,683	328,431	0.0044	0.9956	86.36
50.5	70,120,739	344,260	0.0049	0.9951	85.98
51.5	64,236,972	364,098	0.0057	0.9943	85.56
52.5	59,086,277	303,588	0.0051	0.9949	85.07
53.5	53,486,182	258,448	0.0048	0.9952	84.64
54.5	47,825,078	138,332	0.0029	0.9971	84.23
55.5	42,992,257	156,625	0.0036	0.9964	83.98
56.5	36,453,676	182,307	0.0050	0.9950	83.68
57.5	30,801,792	226,324	0.0073	0.9927	83.26
58.5	25,012,158	240,265	0.0096	0.9904	82.65
59.5	20,244,402	218,697	0.0108	0.9892	81.85
60.5	18,779,675	156,493	0.0083	0.9917	80.97
61.5	15,305,825	174,141	0.0114	0.9886	80.30
62.5	11,740,391	272,083	0.0232	0.9768	79.38
63.5	9,407,915	115,500	0.0123	0.9877	77.54
64.5	7,392,481	189,928	0.0257	0.9743	76.59
65.5	6,070,389	138,582	0.0228	0.9772	74.62
66.5	3,710,446	142,533	0.0384	0.9616	72.92
67.5	3,472,660	111,159	0.0320	0.9680	70.12
68.5	3,333,945	89,931	0.0270	0.9730	67.87
69.5	3,219,691	95,887	0.0298	0.9702	66.04
70.5	3,078,877	163,508	0.0531	0.9469	64.08
71.5	2,893,833	170,852	0.0590	0.9410	60.67
72.5	2,704,977	232,397	0.0859	0.9141	57.09
73.5	2,453,105	136,254	0.0555	0.9445	52.19
74.5	2,285,103	427,449	0.1871	0.8129	49.29
75.5	1,707,702	194,340	0.1138	0.8862	40.07
76.5	1,480,494	183,626	0.1240	0.8760	35.51
77.5	1,281,663	79,645	0.0621	0.9379	31.10
78.5	1,208,968	101,880	0.0843	0.9157	29.17

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 376.11 AND 376.12 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2022 EXPERIENCE BAND 1910-2022

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	1,106,596	80,711	0.0729	0.9271	26.71
80.5	1,014,007	85,060	0.0839	0.9161	24.76
81.5	923,844	108,546	0.1175	0.8825	22.69
82.5	786,271	61,510	0.0782	0.9218	20.02
83.5	718,007	32,179	0.0448	0.9552	18.46
84.5	687,305	62,266	0.0906	0.9094	17.63
85.5	602,882	42,757	0.0709	0.9291	16.03
86.5	555,828	57,255	0.1030	0.8970	14.89
87.5	481,138	66,475	0.1382	0.8618	13.36
88.5	404,180	22,665	0.0561	0.9439	11.51
89.5	381,209	18,140	0.0476	0.9524	10.87
90.5	364,667	3,707	0.0102	0.9898	10.35
91.5	336,605	10,887	0.0323	0.9677	10.25
92.5	266,554	768	0.0029	0.9971	9.91
93.5	278,387	306	0.0011	0.9989	9.89
94.5	259,964	511	0.0020	0.9980	9.88
95.5	246,335	252	0.0010	0.9990	9.86
96.5	217,484	460	0.0021	0.9979	9.85
97.5	188,590	3,122	0.0166	0.9834	9.82
98.5	179,814	4,135	0.0230	0.9770	9.66
99.5	157,019	913	0.0058	0.9942	9.44
100.5	119,032	4,783	0.0402	0.9598	9.39
101.5	98,112	5,719	0.0583	0.9417	9.01
102.5	85,763	4,399	0.0513	0.9487	8.48
103.5	79,101	1,475	0.0186	0.9814	8.05
104.5	75,228	1,580	0.0210	0.9790	7.90
105.5	71,951	1,018	0.0141	0.9859	7.73
106.5	60,708	170	0.0028	0.9972	7.62
107.5	56,397		0.0000	1.0000	7.60
108.5	58,625		0.0000	1.0000	7.60
109.5	37,145	331	0.0089	0.9911	7.60
110.5	36,708	946	0.0258	0.9742	7.53
111.5	35,621		0.0000	1.0000	7.34
112.5	15,210		0.0000	1.0000	7.34
113.5	38		0.0000	1.0000	7.34
114.5	38		0.0000	1.0000	7.34
115.5	38		0.0000	1.0000	7.34
116.5					7.34

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 376.11 AND 376.12 MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1906-2022 EXPERIENCE BAND 1961-2022

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	1,484,362,926	464,552	0.0003	0.9997	100.00
0.5	1,414,170,582	1,223,485	0.0009	0.9991	99.97
1.5	1,370,645,513	1,055,291	0.0008	0.9992	99.88
2.5	1,302,619,934	1,261,170	0.0010	0.9990	99.81
3.5	1,245,625,857	1,479,978	0.0012	0.9988	99.71
4.5	1,187,700,702	7,295,018	0.0061	0.9939	99.59
5.5	1,141,719,380	1,571,442	0.0014	0.9986	98.98
6.5	1,099,879,212	4,140,131	0.0038	0.9962	98.84
7.5	1,061,789,205	1,373,460	0.0013	0.9987	98.47
8.5	1,024,708,215	1,449,815	0.0014	0.9986	98.34
9.5	984,665,779	1,865,006	0.0019	0.9981	98.20
10.5	947,898,693	1,912,878	0.0020	0.9980	98.02
11.5	924,009,488	1,644,232	0.0018	0.9982	97.82
12.5	901,456,676	1,255,821	0.0014	0.9986	97.65
13.5	881,503,848	1,285,128	0.0015	0.9985	97.51
14.5	851,497,954	976,397	0.0011	0.9989	97.37
15.5	814,984,686	1,487,865	0.0018	0.9982	97.26
16.5	777,751,887	1,371,895	0.0018	0.9982	97.08
17.5	739,154,109	1,017,820	0.0014	0.9986	96.91
18.5	703,526,017	874,847	0.0012	0.9988	96.77
19.5	655,566,675	1,023,147	0.0016	0.9984	96.65
20.5	624,124,308	855,878	0.0014	0.9986	96.50
21.5	595,887,717	993,959	0.0017	0.9983	96.37
22.5	563,621,779	1,165,198	0.0021	0.9979	96.21
23.5	533,149,676	1,053,988	0.0020	0.9980	96.01
24.5	501,573,335	1,088,951	0.0022	0.9978	95.82
25.5	464,301,985	839,343	0.0018	0.9982	95.61
26.5	428,201,372	902,448	0.0021	0.9979	95.44
27.5	397,734,476	831,090	0.0021	0.9979	95.24
28.5	366,962,188	761,930	0.0021	0.9979	95.04
29.5	337,528,294	1,278,561	0.0038	0.9962	94.84
30.5	310,332,970	1,019,653	0.0033	0.9967	94.48
31.5	287,148,860	832,748	0.0029	0.9971	94.17
32.5	269,510,754	681,003	0.0025	0.9975	93.90
33.5	251,771,798	761,395	0.0030	0.9970	93.66
34.5	236,443,917	1,128,018	0.0048	0.9952	93.38
35.5	222,985,922	707,258	0.0032	0.9968	92.93
36.5	206,804,354	589,746	0.0029	0.9971	92.64
37.5	190,469,929	527,437	0.0028	0.9972	92.37
38.5	173,244,243	591,042	0.0034	0.9966	92.12

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 376.11 AND 376.12 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2022 EXPERIENCE BAND 1961-2022

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	161,334,861	530,107	0.0033	0.9967	91.80
40.5	149,666,571	505,980	0.0034	0.9966	91.50
41.5	136,926,836	376,228	0.0027	0.9973	91.19
42.5	125,080,073	1,549,950	0.0124	0.9876	90.94
43.5	112,515,523	2,120,145	0.0188	0.9812	89.82
44.5	101,608,507	301,124	0.0030	0.9970	88.12
45.5	96,026,558	365,782	0.0038	0.9962	87.86
46.5	90,844,694	343,747	0.0038	0.9962	87.53
47.5	86,176,097	421,547	0.0049	0.9951	87.20
48.5	80,491,037	537,597	0.0067	0.9933	86.77
49.5	74,562,739	328,431	0.0044	0.9956	86.19
50.5	70,120,739	344,260	0.0049	0.9951	85.81
51.5	64,236,972	364,098	0.0057	0.9943	85.39
52.5	59,086,277	303,588	0.0051	0.9949	84.91
53.5	53,486,182	258,448	0.0048	0.9952	84.47
54.5	47,825,078	138,332	0.0029	0.9971	84.06
55.5	42,992,257	156,625	0.0036	0.9964	83.82
56.5	36,453,676	182,307	0.0050	0.9950	83.51
57.5	30,801,792	226,324	0.0073	0.9927	83.10
58.5	25,012,158	240,265	0.0096	0.9904	82.48
59.5	20,244,402	218,697	0.0108	0.9892	81.69
60.5	18,779,675	156,493	0.0083	0.9917	80.81
61.5	15,305,825	174,141	0.0114	0.9886	80.14
62.5	11,740,391	272,083	0.0232	0.9768	79.22
63.5	9,407,915	115,500	0.0123	0.9877	77.39
64.5	7,392,481	189,928	0.0257	0.9743	76.44
65.5	6,070,389	138,582	0.0228	0.9772	74.47
66.5	3,710,446	142,533	0.0384	0.9616	72.77
67.5	3,472,660	111,159	0.0320	0.9680	69.98
68.5	3,333,945	89,931	0.0270	0.9730	67.74
69.5	3,219,691	95,887	0.0298	0.9702	65.91
70.5	3,078,877	163,508	0.0531	0.9469	63.95
71.5	2,893,833	170,852	0.0590	0.9410	60.55
72.5	2,704,977	232,397	0.0859	0.9141	56.98
73.5	2,453,105	136,254	0.0555	0.9445	52.08
74.5	2,285,103	427,449	0.1871	0.8129	49.19
75.5	1,707,702	194,340	0.1138	0.8862	39.99
76.5	1,480,494	183,626	0.1240	0.8760	35.44
77.5	1,281,663	79,645	0.0621	0.9379	31.04
78.5	1,208,968	101,880	0.0843	0.9157	29.11

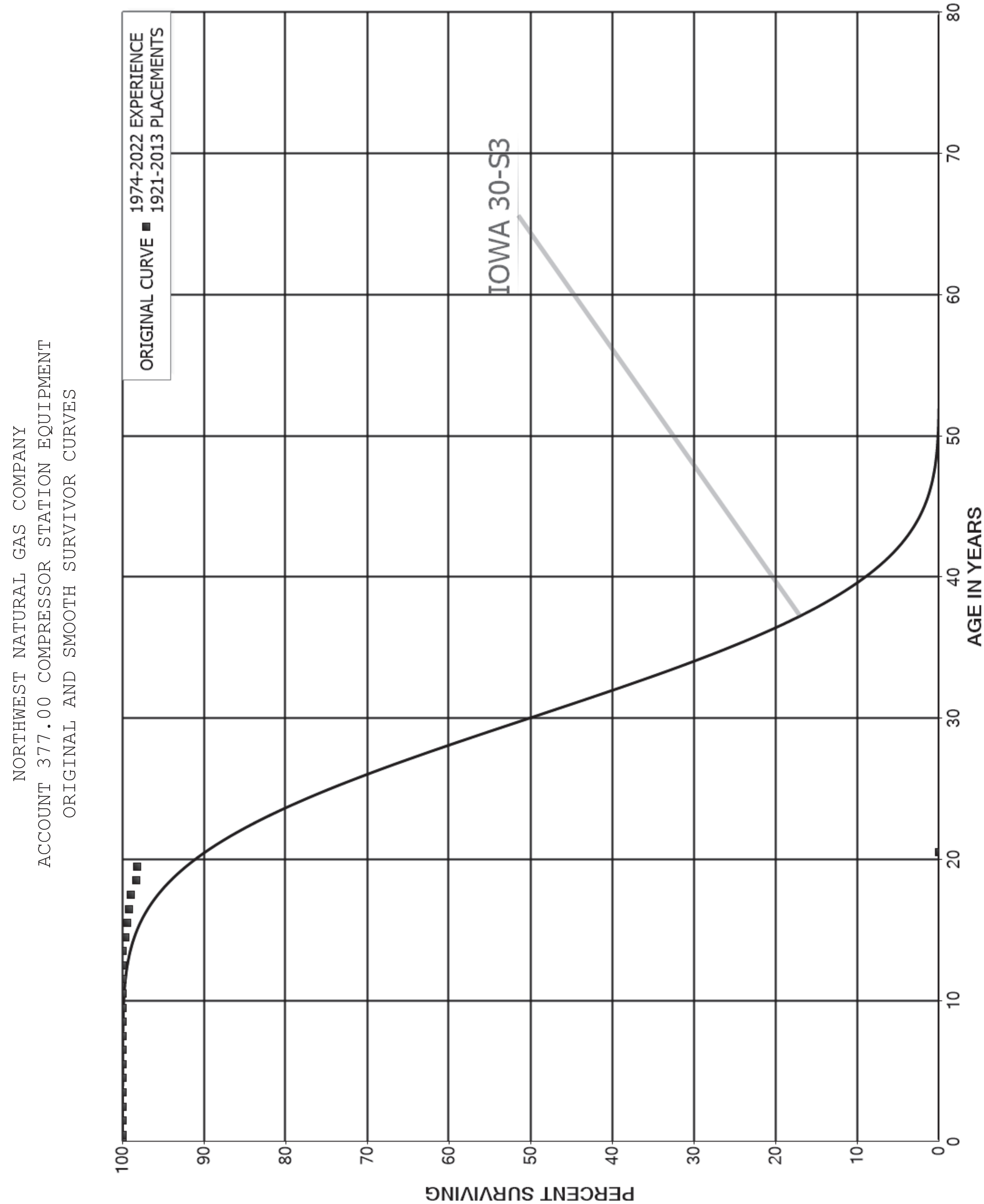
NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 376.11 AND 376.12 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2022 EXPERIENCE BAND 1961-2022

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	1,106,596	80,711	0.0729	0.9271	26.66
80.5	1,014,007	85,060	0.0839	0.9161	24.72
81.5	923,844	108,546	0.1175	0.8825	22.64
82.5	786,271	61,510	0.0782	0.9218	19.98
83.5	718,007	32,179	0.0448	0.9552	18.42
84.5	687,305	62,266	0.0906	0.9094	17.59
85.5	602,882	42,757	0.0709	0.9291	16.00
86.5	555,828	57,255	0.1030	0.8970	14.86
87.5	481,138	66,475	0.1382	0.8618	13.33
88.5	404,180	22,665	0.0561	0.9439	11.49
89.5	381,209	18,140	0.0476	0.9524	10.85
90.5	364,667	3,707	0.0102	0.9898	10.33
91.5	336,605	10,887	0.0323	0.9677	10.23
92.5	266,554	768	0.0029	0.9971	9.89
93.5	278,387	306	0.0011	0.9989	9.87
94.5	259,964	511	0.0020	0.9980	9.86
95.5	246,335	252	0.0010	0.9990	9.84
96.5	217,484	460	0.0021	0.9979	9.83
97.5	188,590	3,122	0.0166	0.9834	9.81
98.5	179,814	4,135	0.0230	0.9770	9.64
99.5	157,019	913	0.0058	0.9942	9.42
100.5	119,032	4,783	0.0402	0.9598	9.37
101.5	98,112	5,719	0.0583	0.9417	8.99
102.5	85,763	4,399	0.0513	0.9487	8.47
103.5	79,101	1,475	0.0186	0.9814	8.03
104.5	75,228	1,580	0.0210	0.9790	7.88
105.5	71,951	1,018	0.0141	0.9859	7.72
106.5	60,708	170	0.0028	0.9972	7.61
107.5	56,397		0.0000	1.0000	7.59
108.5	58,625		0.0000	1.0000	7.59
109.5	37,145	331	0.0089	0.9911	7.59
110.5	36,708	946	0.0258	0.9742	7.52
111.5	35,621		0.0000	1.0000	7.32
112.5	15,210		0.0000	1.0000	7.32
113.5	38		0.0000	1.0000	7.32
114.5	38		0.0000	1.0000	7.32
115.5	38		0.0000	1.0000	7.32
116.5					7.32


NORTHWEST NATURAL GAS COMPANY
ACCOUNT 377.00 COMPRESSOR STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE ■ 1974-2022 EXPERIENCE
1921-2013 PLACEMENTS
IOWA 30-S3
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 377.00 COMPRESSOR STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1921-2013 EXPERIENCE BAND 1974-2022

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	969,942		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	6,243	6,243	1.0000		98.22
20.5					
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

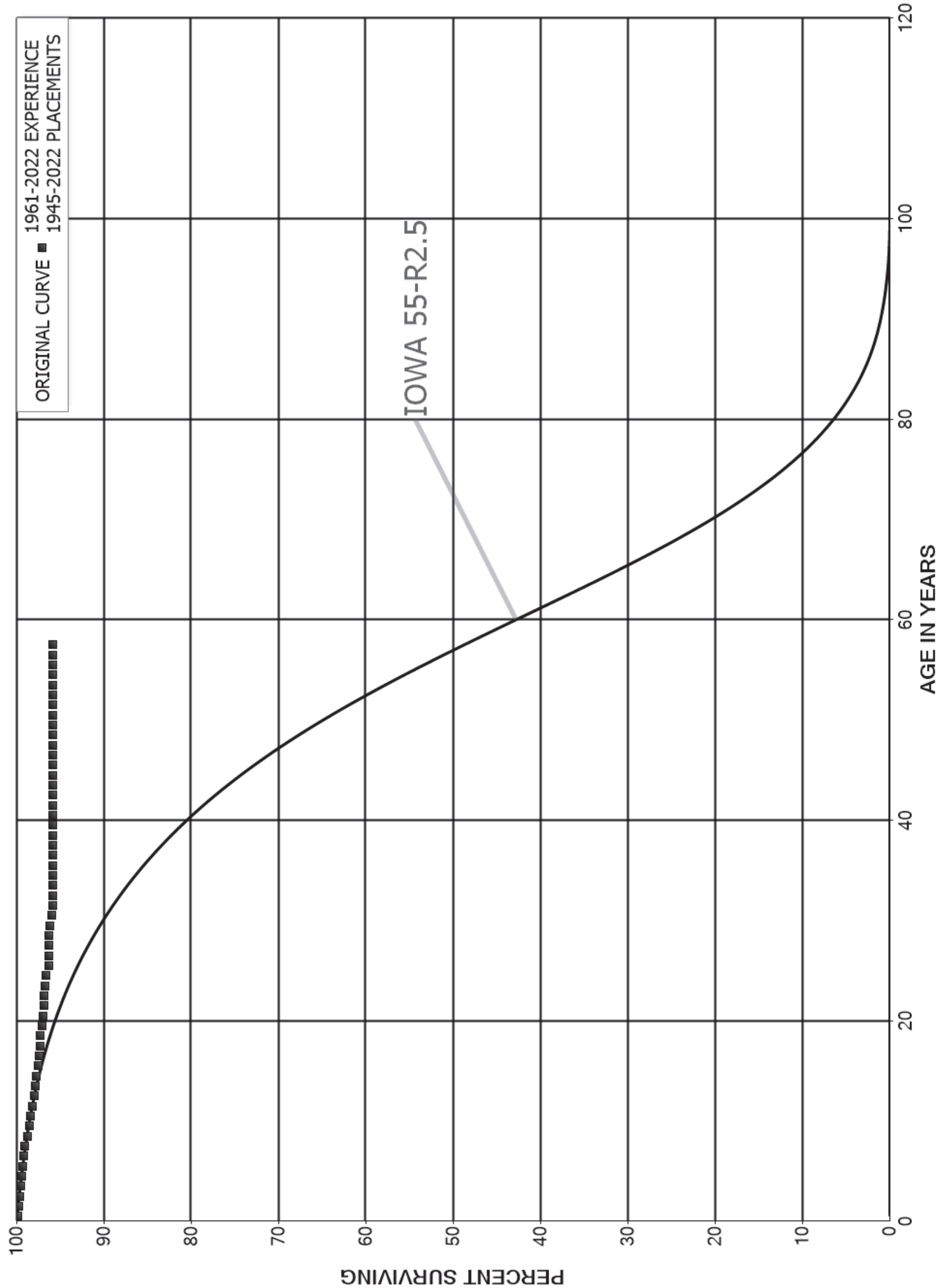
ACCOUNT 377.00 COMPRESSOR STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1921-2013 EXPERIENCE BAND 1974-2022

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
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

ORIGINAL LIFE TABLE

PLACEMENT BAND 1945-2022 EXPERIENCE BAND 1961-2022

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	50,337,670	96,154	0.0019	0.9981	100.00
0.5	46,102,957	50,408	0.0011	0.9989	99.81
1.5	41,272,252	23,346	0.0006	0.9994	99.70
2.5	38,308,250	35,463	0.0009	0.9991	99.64
3.5	37,169,416	48,116	0.0013	0.9987	99.55
4.5	34,469,213	35,988	0.0010	0.9990	99.42
5.5	33,620,256	60,968	0.0018	0.9982	99.32
6.5	31,725,054	40,407	0.0013	0.9987	99.14
7.5	30,899,433	86,601	0.0028	0.9972	99.01
8.5	27,501,860	56,131	0.0020	0.9980	98.73
9.5	23,233,766	44,542	0.0019	0.9981	98.53
10.5	21,673,253	45,263	0.0021	0.9979	98.34
11.5	20,308,238	30,746	0.0015	0.9985	98.14
12.5	18,521,939	22,749	0.0012	0.9988	97.99
13.5	17,492,381	28,527	0.0016	0.9984	97.87
14.5	16,432,029	29,471	0.0018	0.9982	97.71
15.5	15,492,276	27,254	0.0018	0.9982	97.54
16.5	15,125,375	8,958	0.0006	0.9994	97.36
17.5	14,684,742	11,154	0.0008	0.9992	97.31
18.5	13,723,878	21,303	0.0016	0.9984	97.23
19.5	13,130,549	21,145	0.0016	0.9984	97.08
20.5	12,380,939	7,411	0.0006	0.9994	96.92
21.5	12,288,157	10,221	0.0008	0.9992	96.87
22.5	11,335,109	7,084	0.0006	0.9994	96.79
23.5	10,546,350	15,025	0.0014	0.9986	96.73
24.5	9,930,889	26,495	0.0027	0.9973	96.59
25.5	9,039,964	3,146	0.0003	0.9997	96.33
26.5	7,901,812	2,495	0.0003	0.9997	96.30
27.5	7,225,158	2,674	0.0004	0.9996	96.27
28.5	6,646,560	6,125	0.0009	0.9991	96.23
29.5	6,367,211	15,335	0.0024	0.9976	96.14
30.5	5,887,790	2,392	0.0004	0.9996	95.91
31.5	5,345,449		0.0000	1.0000	95.87
32.5	5,102,925		0.0000	1.0000	95.87
33.5	4,802,540		0.0000	1.0000	95.87
34.5	4,532,569		0.0000	1.0000	95.87
35.5	4,224,783		0.0000	1.0000	95.87
36.5	3,853,186		0.0000	1.0000	95.87
37.5	3,582,955		0.0000	1.0000	95.87
38.5	2,986,536		0.0000	1.0000	95.87

NORTHWEST NATURAL GAS COMPANY

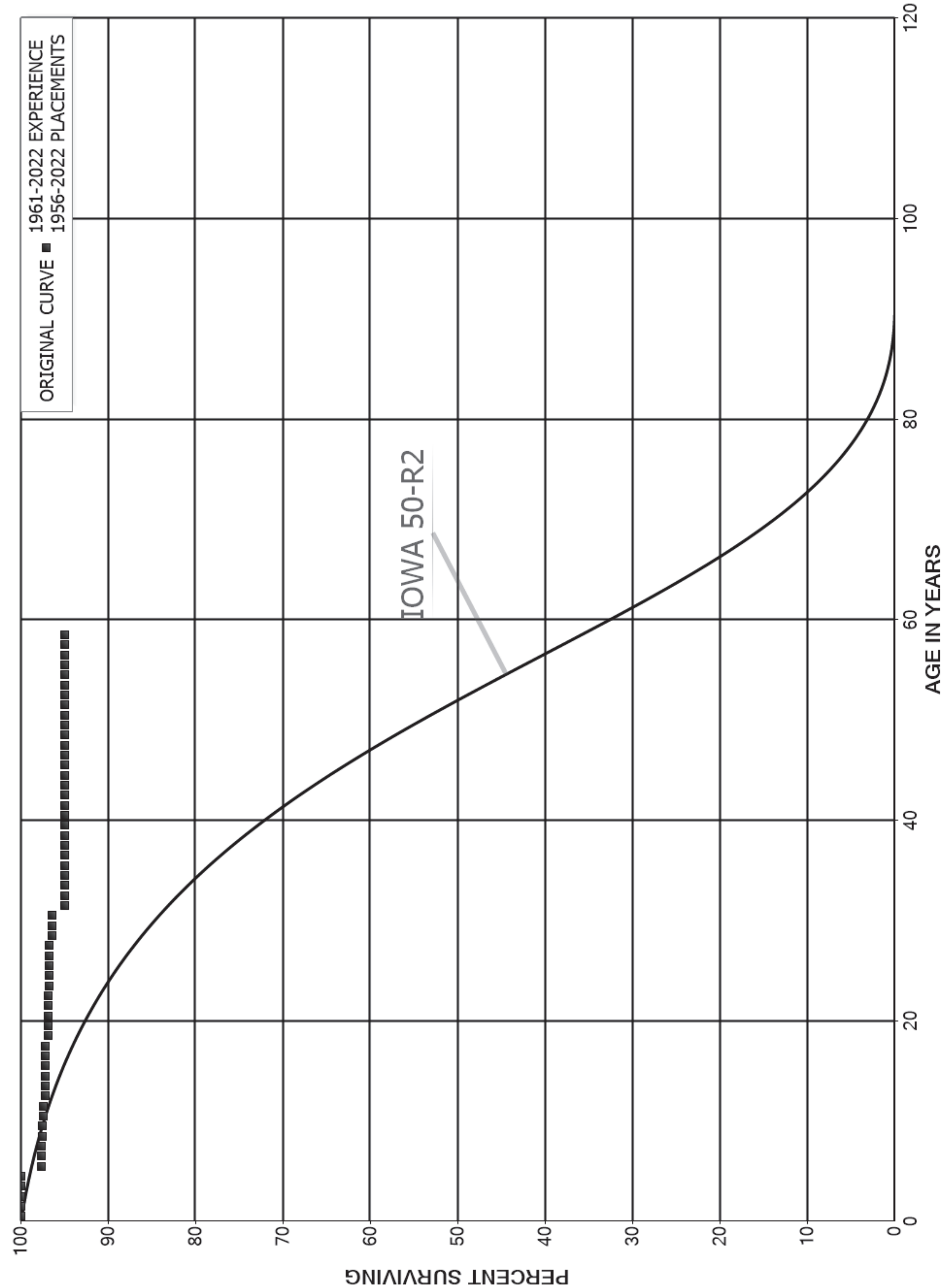
ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1945-2022 EXPERIENCE BAND 1961-2022

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	2,741,832		0.0000	1.0000	95.87
40.5	2,495,298		0.0000	1.0000	95.87
41.5	2,373,003		0.0000	1.0000	95.87
42.5	2,213,567		0.0000	1.0000	95.87
43.5	2,054,315		0.0000	1.0000	95.87
44.5	2,011,767		0.0000	1.0000	95.87
45.5	1,802,340		0.0000	1.0000	95.87
46.5	1,755,842		0.0000	1.0000	95.87
47.5	1,708,116		0.0000	1.0000	95.87
48.5	1,639,403		0.0000	1.0000	95.87
49.5	1,511,705		0.0000	1.0000	95.87
50.5	1,357,468		0.0000	1.0000	95.87
51.5	1,253,312		0.0000	1.0000	95.87
52.5	1,208,496		0.0000	1.0000	95.87
53.5	1,104,792		0.0000	1.0000	95.87
54.5	987,855		0.0000	1.0000	95.87
55.5	892,844		0.0000	1.0000	95.87
56.5	725,427		0.0000	1.0000	95.87
57.5	570,056		0.0000	1.0000	95.87
58.5	487,461		0.0000	1.0000	95.87
59.5	420,586		0.0000	1.0000	95.87
60.5	376,889		0.0000	1.0000	95.87
61.5	310,232		0.0000	1.0000	95.87
62.5	203,029		0.0000	1.0000	95.87
63.5	166,720		0.0000	1.0000	95.87
64.5	123,845		0.0000	1.0000	95.87
65.5	93,005		0.0000	1.0000	95.87
66.5	44,547		0.0000	1.0000	95.87
67.5	31,141		0.0000	1.0000	95.87
68.5	27,206		0.0000	1.0000	95.87
69.5	19,633		0.0000	1.0000	95.87
70.5	15,732		0.0000	1.0000	95.87
71.5	15,732		0.0000	1.0000	95.87
72.5	13,147		0.0000	1.0000	95.87
73.5					95.87

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 1956-2022 EXPERIENCE BAND 1961-2022

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	21,294,974	110	0.0000	1.0000	100.00
0.5	19,945,331	235	0.0000	1.0000	100.00
1.5	18,542,876	1,228	0.0001	0.9999	100.00
2.5	16,894,039	4,769	0.0003	0.9997	99.99
3.5	14,335,724	4,411	0.0003	0.9997	99.96
4.5	11,665,098	273,564	0.0235	0.9765	99.93
5.5	8,313,909	1,235	0.0001	0.9999	97.59
6.5	5,748,614	838	0.0001	0.9999	97.57
7.5	4,850,180	881	0.0002	0.9998	97.56
8.5	4,017,874	1,074	0.0003	0.9997	97.54
9.5	1,927,572	1,551	0.0008	0.9992	97.52
10.5	1,850,955		0.0000	1.0000	97.44
11.5	1,791,679	4,000	0.0022	0.9978	97.44
12.5	1,652,581		0.0000	1.0000	97.22
13.5	1,524,539		0.0000	1.0000	97.22
14.5	1,524,539		0.0000	1.0000	97.22
15.5	1,524,539		0.0000	1.0000	97.22
16.5	1,524,539	1,383	0.0009	0.9991	97.22
17.5	1,367,849	3,498	0.0026	0.9974	97.13
18.5	1,367,547		0.0000	1.0000	96.88
19.5	1,367,547		0.0000	1.0000	96.88
20.5	1,367,327	831	0.0006	0.9994	96.88
21.5	1,325,857	116	0.0001	0.9999	96.83
22.5	1,118,933	520	0.0005	0.9995	96.82
23.5	1,118,413		0.0000	1.0000	96.77
24.5	1,118,413		0.0000	1.0000	96.77
25.5	1,118,413		0.0000	1.0000	96.77
26.5	1,089,712		0.0000	1.0000	96.77
27.5	1,089,712	4,292	0.0039	0.9961	96.77
28.5	1,085,420		0.0000	1.0000	96.39
29.5	1,084,441		0.0000	1.0000	96.39
30.5	1,082,611	15,797	0.0146	0.9854	96.39
31.5	1,031,855		0.0000	1.0000	94.98
32.5	1,029,117		0.0000	1.0000	94.98
33.5	1,024,179		0.0000	1.0000	94.98
34.5	992,184		0.0000	1.0000	94.98
35.5	979,664		0.0000	1.0000	94.98
36.5	895,551		0.0000	1.0000	94.98
37.5	895,551		0.0000	1.0000	94.98
38.5	866,500		0.0000	1.0000	94.98

NORTHWEST NATURAL GAS COMPANY

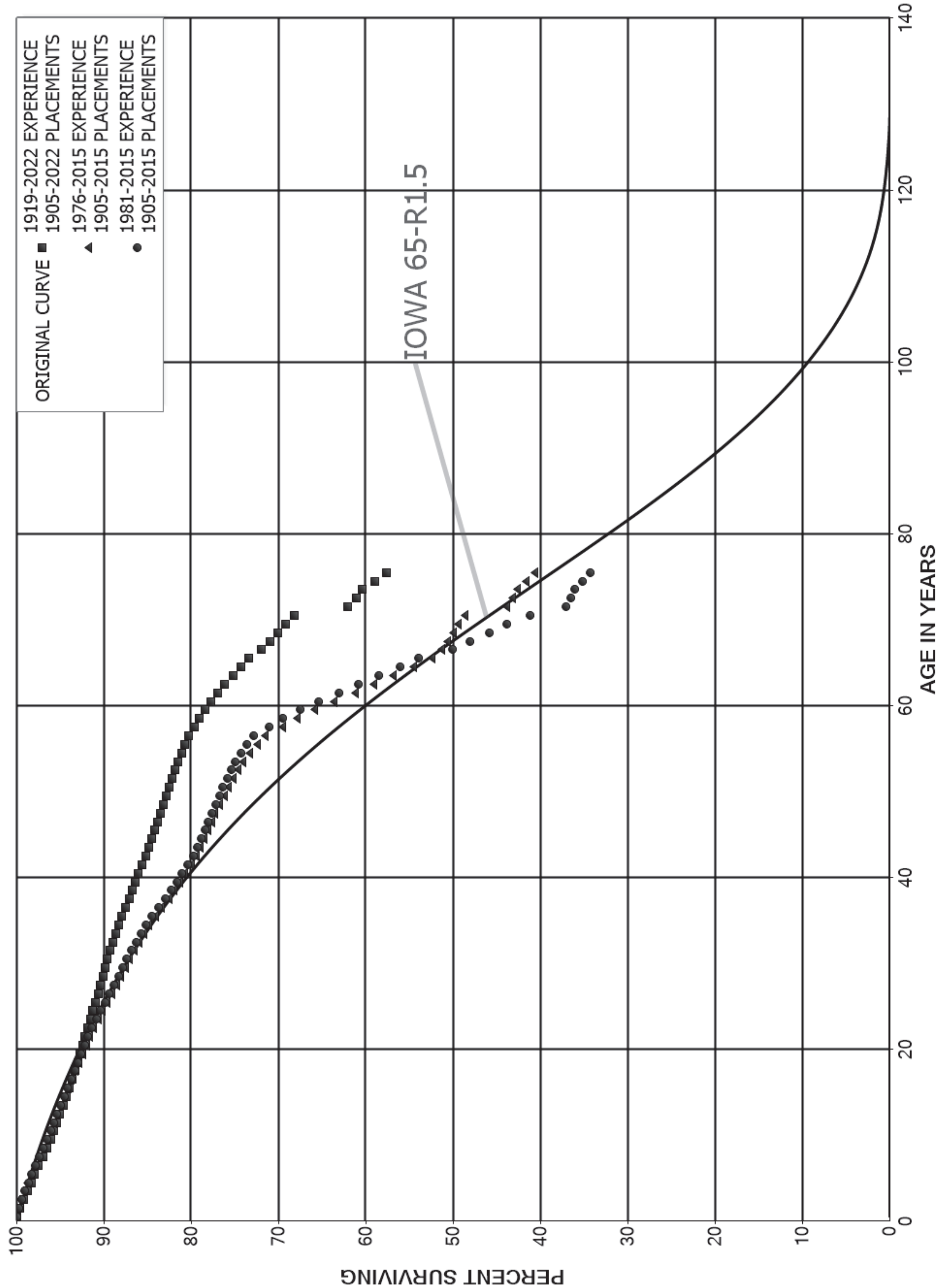
ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2022 EXPERIENCE BAND 1961-2022

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	859,527		0.0000	1.0000	94.98
40.5	830,451		0.0000	1.0000	94.98
41.5	793,737		0.0000	1.0000	94.98
42.5	696,182		0.0000	1.0000	94.98
43.5	696,182		0.0000	1.0000	94.98
44.5	696,182		0.0000	1.0000	94.98
45.5	648,984		0.0000	1.0000	94.98
46.5	629,219		0.0000	1.0000	94.98
47.5	617,455		0.0000	1.0000	94.98
48.5	608,726		0.0000	1.0000	94.98
49.5	580,682		0.0000	1.0000	94.98
50.5	495,890		0.0000	1.0000	94.98
51.5	466,037		0.0000	1.0000	94.98
52.5	456,050		0.0000	1.0000	94.98
53.5	420,982		0.0000	1.0000	94.98
54.5	408,617		0.0000	1.0000	94.98
55.5	400,659		0.0000	1.0000	94.98
56.5	380,063		0.0000	1.0000	94.98
57.5	323,399		0.0000	1.0000	94.98
58.5	259,255		0.0000	1.0000	94.98
59.5	241,009		0.0000	1.0000	94.98
60.5	232,890		0.0000	1.0000	94.98
61.5	223,874		0.0000	1.0000	94.98
62.5	97,566		0.0000	1.0000	94.98
63.5	97,426		0.0000	1.0000	94.98
64.5	90,855		0.0000	1.0000	94.98
65.5	90,440		0.0000	1.0000	94.98
66.5					94.98

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 1905-2022 EXPERIENCE BAND 1919-2022

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	1,020,053,364	1,032,416	0.0010	0.9990	100.00
0.5	983,469,927	2,306,351	0.0023	0.9977	99.90
1.5	937,222,718	4,513,769	0.0048	0.9952	99.66
2.5	894,042,233	4,139,212	0.0046	0.9954	99.18
3.5	850,799,641	3,539,810	0.0042	0.9958	98.73
4.5	813,730,576	3,287,284	0.0040	0.9960	98.31
5.5	778,674,100	3,604,171	0.0046	0.9954	97.92
6.5	745,854,170	3,823,457	0.0051	0.9949	97.46
7.5	715,273,817	3,425,291	0.0048	0.9952	96.96
8.5	686,577,272	2,886,886	0.0042	0.9958	96.50
9.5	659,248,876	2,609,902	0.0040	0.9960	96.09
10.5	638,320,816	2,354,072	0.0037	0.9963	95.71
11.5	619,874,514	2,249,356	0.0036	0.9964	95.36
12.5	607,160,161	2,249,239	0.0037	0.9963	95.01
13.5	585,244,492	2,502,896	0.0043	0.9957	94.66
14.5	563,053,311	1,974,726	0.0035	0.9965	94.26
15.5	541,328,578	1,893,059	0.0035	0.9965	93.93
16.5	516,839,757	1,778,154	0.0034	0.9966	93.60
17.5	493,509,603	1,533,426	0.0031	0.9969	93.28
18.5	468,431,725	1,515,087	0.0032	0.9968	92.99
19.5	441,676,278	1,320,981	0.0030	0.9970	92.69
20.5	416,223,108	1,217,591	0.0029	0.9971	92.41
21.5	391,951,852	1,123,554	0.0029	0.9971	92.14
22.5	367,832,359	1,305,258	0.0035	0.9965	91.87
23.5	340,477,244	1,012,806	0.0030	0.9970	91.55
24.5	315,431,137	1,116,397	0.0035	0.9965	91.28
25.5	289,488,696	922,935	0.0032	0.9968	90.95
26.5	265,657,093	799,663	0.0030	0.9970	90.66
27.5	244,666,504	763,728	0.0031	0.9969	90.39
28.5	222,083,481	660,784	0.0030	0.9970	90.11
29.5	200,055,486	608,789	0.0030	0.9970	89.84
30.5	180,117,837	563,167	0.0031	0.9969	89.57
31.5	160,940,163	574,772	0.0036	0.9964	89.29
32.5	143,254,580	507,980	0.0035	0.9965	88.97
33.5	127,746,294	478,980	0.0037	0.9963	88.65
34.5	115,841,436	500,617	0.0043	0.9957	88.32
35.5	105,297,195	486,582	0.0046	0.9954	87.94
36.5	95,120,255	471,647	0.0050	0.9950	87.53
37.5	84,596,832	355,631	0.0042	0.9958	87.10
38.5	75,944,384	317,397	0.0042	0.9958	86.73

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2022 EXPERIENCE BAND 1919-2022

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	69,199,124	261,567	0.0038	0.9962	86.37
40.5	63,099,224	316,376	0.0050	0.9950	86.04
41.5	55,506,088	258,146	0.0047	0.9953	85.61
42.5	48,090,495	193,057	0.0040	0.9960	85.21
43.5	42,191,969	166,448	0.0039	0.9961	84.87
44.5	37,404,487	155,040	0.0041	0.9959	84.54
45.5	34,015,991	133,755	0.0039	0.9961	84.19
46.5	31,189,244	120,076	0.0038	0.9962	83.86
47.5	28,911,992	120,571	0.0042	0.9958	83.53
48.5	26,418,402	103,820	0.0039	0.9961	83.18
49.5	23,622,029	86,220	0.0036	0.9964	82.86
50.5	20,990,431	92,691	0.0044	0.9956	82.55
51.5	18,616,086	80,259	0.0043	0.9957	82.19
52.5	16,534,835	65,653	0.0040	0.9960	81.84
53.5	14,497,110	74,250	0.0051	0.9949	81.51
54.5	12,700,604	64,227	0.0051	0.9949	81.09
55.5	11,048,595	56,113	0.0051	0.9949	80.68
56.5	9,400,318	75,741	0.0081	0.9919	80.27
57.5	7,957,163	53,528	0.0067	0.9933	79.63
58.5	6,740,552	57,646	0.0086	0.9914	79.09
59.5	5,734,306	48,065	0.0084	0.9916	78.41
60.5	4,912,407	50,314	0.0102	0.9898	77.76
61.5	4,130,385	44,317	0.0107	0.9893	76.96
62.5	3,453,322	42,717	0.0124	0.9876	76.14
63.5	3,142,240	38,909	0.0124	0.9876	75.19
64.5	3,056,222	36,786	0.0120	0.9880	74.26
65.5	2,827,948	53,808	0.0190	0.9810	73.37
66.5	2,552,199	35,907	0.0141	0.9859	71.97
67.5	2,500,865	32,506	0.0130	0.9870	70.96
68.5	2,454,912	29,497	0.0120	0.9880	70.04
69.5	2,346,137	33,605	0.0143	0.9857	69.20
70.5	2,299,263	206,564	0.0898	0.9102	68.20
71.5	2,041,155	33,519	0.0164	0.9836	62.08
72.5	1,987,044	22,736	0.0114	0.9886	61.06
73.5	1,940,349	45,378	0.0234	0.9766	60.36
74.5	1,877,339	41,222	0.0220	0.9780	58.95
75.5	392,956	14,035	0.0357	0.9643	57.65
76.5	331,806	17,460	0.0526	0.9474	55.59
77.5	291,878	11,346	0.0389	0.9611	52.67
78.5	262,540	8,774	0.0334	0.9666	50.62

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2022 EXPERIENCE BAND 1919-2022

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	248,589	6,032	0.0243	0.9757	48.93
80.5	220,518	6,482	0.0294	0.9706	47.74
81.5	199,198	6,888	0.0346	0.9654	46.34
82.5	179,490	6,825	0.0380	0.9620	44.74
83.5	154,317	3,675	0.0238	0.9762	43.04
84.5	136,167	3,757	0.0276	0.9724	42.01
85.5	123,880	3,913	0.0316	0.9684	40.85
86.5	114,157	2,455	0.0215	0.9785	39.56
87.5	104,740	1,288	0.0123	0.9877	38.71
88.5	103,850	1,377	0.0133	0.9867	38.23
89.5	100,031	795	0.0079	0.9921	37.73
90.5	91,781	17,359	0.1891	0.8109	37.43
91.5	62,420	3,612	0.0579	0.9421	30.35
92.5	54,356	1,691	0.0311	0.9689	28.59
93.5	48,619	2,161	0.0444	0.9556	27.70
94.5	43,697	4,384	0.1003	0.8997	26.47
95.5	39,081	1,361	0.0348	0.9652	23.82
96.5	33,147	625	0.0189	0.9811	22.99
97.5	24,666	423	0.0171	0.9829	22.55
98.5	18,774	388	0.0207	0.9793	22.17
99.5	17,057	570	0.0334	0.9666	21.71
100.5	15,736	489	0.0311	0.9689	20.98
101.5	15,286	447	0.0292	0.9708	20.33
102.5	12,461	256	0.0205	0.9795	19.74
103.5	9,967	328	0.0329	0.9671	19.33
104.5	7,975	239	0.0300	0.9700	18.70
105.5	7,736	109	0.0141	0.9859	18.14
106.5	7,627	321	0.0421	0.9579	17.88
107.5	7,299	104	0.0143	0.9857	17.13
108.5	7,024	87	0.0124	0.9876	16.88
109.5	6,901	83	0.0120	0.9880	16.67
110.5	5,713	29	0.0051	0.9949	16.47
111.5	5,683	38	0.0066	0.9934	16.39
112.5	2,838	0	0.0000	1.0000	16.28
113.5	2,785	22	0.0079	0.9921	16.28
114.5	1,588		0.0000	1.0000	16.15
115.5	1,588	19	0.0118	0.9882	16.15
116.5	1,436	45	0.0310	0.9690	15.96
117.5					15.47

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

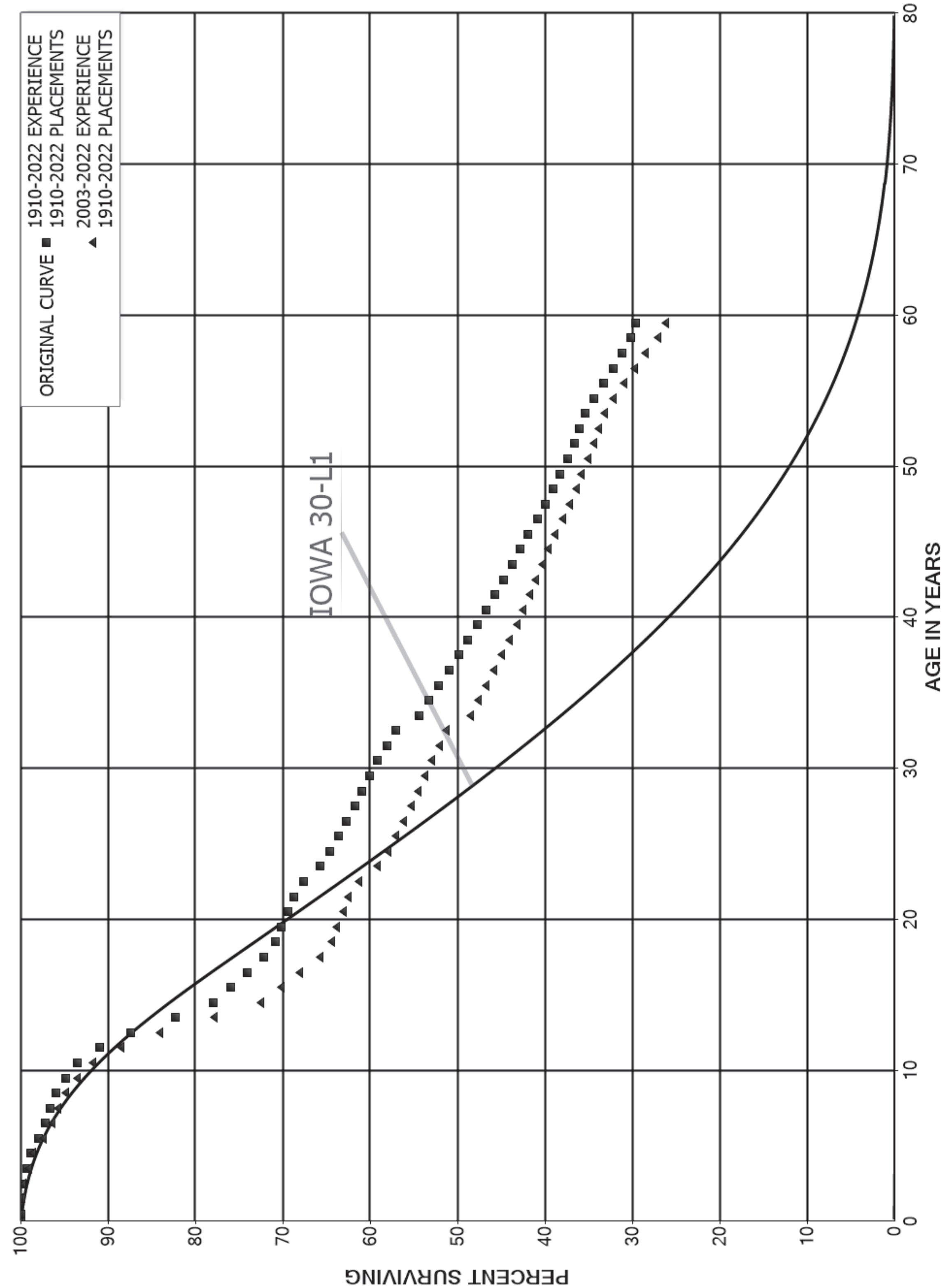
ACCOUNT 380.00 SERVICES

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 1910-2022 EXPERIENCE BAND 1910-2022

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	143,826,164	12,947	0.0001	0.9999	100.00
0.5	141,382,277	38,641	0.0003	0.9997	99.99
1.5	111,451,565	286,740	0.0026	0.9974	99.96
2.5	108,725,296	501,548	0.0046	0.9954	99.71
3.5	103,402,128	372,295	0.0036	0.9964	99.25
4.5	98,439,597	929,182	0.0094	0.9906	98.89
5.5	91,332,278	722,128	0.0079	0.9921	97.96
6.5	90,619,372	518,235	0.0057	0.9943	97.18
7.5	87,024,752	614,229	0.0071	0.9929	96.63
8.5	83,545,617	947,386	0.0113	0.9887	95.94
9.5	79,042,733	1,152,351	0.0146	0.9854	94.86
10.5	72,887,040	1,973,473	0.0271	0.9729	93.47
11.5	70,978,832	2,756,415	0.0388	0.9612	90.94
12.5	68,333,755	3,999,415	0.0585	0.9415	87.41
13.5	64,032,215	3,389,223	0.0529	0.9471	82.29
14.5	56,784,285	1,491,303	0.0263	0.9737	77.94
15.5	50,432,917	1,225,363	0.0243	0.9757	75.89
16.5	42,866,708	1,113,923	0.0260	0.9740	74.05
17.5	41,510,097	712,672	0.0172	0.9828	72.12
18.5	37,951,043	408,418	0.0108	0.9892	70.89
19.5	34,785,443	348,691	0.0100	0.9900	70.12
20.5	32,556,174	334,634	0.0103	0.9897	69.42
21.5	30,442,343	503,712	0.0165	0.9835	68.71
22.5	28,679,930	772,505	0.0269	0.9731	67.57
23.5	26,486,699	466,441	0.0176	0.9824	65.75
24.5	24,695,883	368,089	0.0149	0.9851	64.59
25.5	23,102,119	340,210	0.0147	0.9853	63.63
26.5	21,592,875	325,911	0.0151	0.9849	62.69
27.5	20,149,649	276,230	0.0137	0.9863	61.75
28.5	18,830,756	262,123	0.0139	0.9861	60.90
29.5	17,522,632	257,771	0.0147	0.9853	60.05
30.5	16,136,968	296,931	0.0184	0.9816	59.17
31.5	15,217,043	274,336	0.0180	0.9820	58.08
32.5	13,751,456	624,510	0.0454	0.9546	57.03
33.5	12,389,953	251,826	0.0203	0.9797	54.44
34.5	11,658,353	262,755	0.0225	0.9775	53.34
35.5	11,368,152	249,124	0.0219	0.9781	52.13
36.5	10,366,721	227,916	0.0220	0.9780	50.99
37.5	9,788,257	209,028	0.0214	0.9786	49.87
38.5	9,335,313	206,244	0.0221	0.9779	48.80

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2022 EXPERIENCE BAND 1910-2022

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	8,952,604	190,048	0.0212	0.9788	47.73
40.5	8,164,392	180,118	0.0221	0.9779	46.71
41.5	7,249,705	152,044	0.0210	0.9790	45.68
42.5	6,661,128	155,955	0.0234	0.9766	44.72
43.5	6,025,474	115,629	0.0192	0.9808	43.68
44.5	5,643,974	122,538	0.0217	0.9783	42.84
45.5	5,241,298	130,943	0.0250	0.9750	41.91
46.5	5,127,585	115,171	0.0225	0.9775	40.86
47.5	4,995,019	108,251	0.0217	0.9783	39.94
48.5	4,505,899	85,789	0.0190	0.9810	39.08
49.5	4,119,360	95,457	0.0232	0.9768	38.33
50.5	3,364,184	70,863	0.0211	0.9789	37.45
51.5	3,014,459	50,268	0.0167	0.9833	36.66
52.5	2,662,098	50,575	0.0190	0.9810	36.05
53.5	2,435,688	69,170	0.0284	0.9716	35.36
54.5	2,097,358	63,569	0.0303	0.9697	34.36
55.5	1,708,692	56,884	0.0333	0.9667	33.32
56.5	1,506,137	48,408	0.0321	0.9679	32.21
57.5	1,207,982	40,117	0.0332	0.9668	31.17
58.5	994,762	18,537	0.0186	0.9814	30.14
59.5	800,819	11,095	0.0139	0.9861	29.57
60.5	620,774	4,602	0.0074	0.9926	29.17
61.5	497,734	852	0.0017	0.9983	28.95
62.5	489,771	549	0.0011	0.9989	28.90
63.5	489,136	539	0.0011	0.9989	28.87
64.5	474,497	117	0.0002	0.9998	28.84
65.5	452,972	345	0.0008	0.9992	28.83
66.5	433,130	128	0.0003	0.9997	28.81
67.5	432,187	140	0.0003	0.9997	28.80
68.5	431,797	15	0.0000	1.0000	28.79
69.5	431,251		0.0000	1.0000	28.79
70.5	430,870	12,553	0.0291	0.9709	28.79
71.5	418,251	72	0.0002	0.9998	27.95
72.5	404,432	8	0.0000	1.0000	27.94
73.5	404,424	2,962	0.0073	0.9927	27.94
74.5	401,289		0.0000	1.0000	27.74
75.5	130,447	615	0.0047	0.9953	27.74
76.5	128,674	680	0.0053	0.9947	27.61
77.5	127,994	649	0.0051	0.9949	27.46
78.5	127,345	8	0.0001	0.9999	27.32

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2022 EXPERIENCE BAND 1910-2022

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	127,308	1	0.0000	1.0000	27.32
80.5	127,307	377	0.0030	0.9970	27.32
81.5	126,930	2,255	0.0178	0.9822	27.24
82.5	124,675		0.0000	1.0000	26.76
83.5	124,675	2,534	0.0203	0.9797	26.76
84.5	122,141		0.0000	1.0000	26.21
85.5	122,141		0.0000	1.0000	26.21
86.5	122,141		0.0000	1.0000	26.21
87.5	122,141		0.0000	1.0000	26.21
88.5	122,141		0.0000	1.0000	26.21
89.5	122,141	87	0.0007	0.9993	26.21
90.5	122,054	148	0.0012	0.9988	26.19
91.5	121,906	320	0.0026	0.9974	26.16
92.5	121,585	1,451	0.0119	0.9881	26.09
93.5	120,134	1,246	0.0104	0.9896	25.78
94.5	118,888	1,739	0.0146	0.9854	25.51
95.5	117,149	3,869	0.0330	0.9670	25.14
96.5	113,280	9,143	0.0807	0.9193	24.31
97.5	104,137	6,898	0.0662	0.9338	22.35
98.5	97,239	2,496	0.0257	0.9743	20.87
99.5	94,743	2,878	0.0304	0.9696	20.33
100.5	91,864	1,720	0.0187	0.9813	19.71
101.5	90,145	1,660	0.0184	0.9816	19.35
102.5	88,485	2,410	0.0272	0.9728	18.99
103.5	86,075	2,640	0.0307	0.9693	18.47
104.5	83,436	1,770	0.0212	0.9788	17.91
105.5	81,666	1,380	0.0169	0.9831	17.53
106.5	80,286	2,030	0.0253	0.9747	17.23
107.5	78,256	1,800	0.0230	0.9770	16.79
108.5	76,456	1,630	0.0213	0.9787	16.41
109.5	74,826	6,630	0.0886	0.9114	16.06
110.5	68,196	2,180	0.0320	0.9680	14.64
111.5	66,016	1,590	0.0241	0.9759	14.17
112.5					13.83

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2022 EXPERIENCE BAND 2003-2022

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	105,675,114	363	0.0000	1.0000	100.00
0.5	105,093,713	26,481	0.0003	0.9997	100.00
1.5	77,199,819	268,587	0.0035	0.9965	99.97
2.5	76,113,610	476,388	0.0063	0.9937	99.63
3.5	72,554,403	338,725	0.0047	0.9953	99.00
4.5	69,188,356	863,977	0.0125	0.9875	98.54
5.5	64,090,909	689,413	0.0108	0.9892	97.31
6.5	64,934,613	454,063	0.0070	0.9930	96.26
7.5	62,853,531	555,455	0.0088	0.9912	95.59
8.5	60,630,369	887,878	0.0146	0.9854	94.75
9.5	57,537,879	1,072,594	0.0186	0.9814	93.36
10.5	52,733,999	1,849,493	0.0351	0.9649	91.62
11.5	52,098,679	2,600,936	0.0499	0.9501	88.40
12.5	50,756,334	3,806,029	0.0750	0.9250	83.99
13.5	47,394,925	3,206,048	0.0676	0.9324	77.69
14.5	40,846,555	1,328,159	0.0325	0.9675	72.44
15.5	34,942,257	1,079,313	0.0309	0.9691	70.08
16.5	28,272,848	963,728	0.0341	0.9659	67.92
17.5	27,668,142	541,299	0.0196	0.9804	65.60
18.5	24,667,829	247,518	0.0100	0.9900	64.32
19.5	21,893,179	228,847	0.0105	0.9895	63.67
20.5	20,534,097	190,680	0.0093	0.9907	63.01
21.5	19,604,114	390,553	0.0199	0.9801	62.42
22.5	18,608,175	640,936	0.0344	0.9656	61.18
23.5	17,258,223	366,036	0.0212	0.9788	59.07
24.5	15,943,016	243,973	0.0153	0.9847	57.82
25.5	14,860,157	231,761	0.0156	0.9844	56.93
26.5	13,730,845	220,590	0.0161	0.9839	56.05
27.5	12,497,952	174,455	0.0140	0.9860	55.15
28.5	11,955,899	168,529	0.0141	0.9859	54.38
29.5	11,240,914	156,543	0.0139	0.9861	53.61
30.5	10,744,397	195,197	0.0182	0.9818	52.86
31.5	10,508,434	149,927	0.0143	0.9857	51.90
32.5	9,590,106	521,246	0.0544	0.9456	51.16
33.5	8,715,430	155,613	0.0179	0.9821	48.38
34.5	8,455,456	168,873	0.0200	0.9800	47.52
35.5	8,665,672	166,012	0.0192	0.9808	46.57
36.5	8,097,298	155,040	0.0191	0.9809	45.68
37.5	7,981,507	155,085	0.0194	0.9806	44.80
38.5	7,919,394	147,845	0.0187	0.9813	43.93

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2022 EXPERIENCE BAND 2003-2022

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	7,888,743	140,397	0.0178	0.9822	43.11
40.5	7,371,468	127,023	0.0172	0.9828	42.34
41.5	6,669,558	111,890	0.0168	0.9832	41.61
42.5	6,108,042	118,118	0.0193	0.9807	40.92
43.5	5,489,135	90,501	0.0165	0.9835	40.12
44.5	5,132,066	99,837	0.0195	0.9805	39.46
45.5	4,752,401	110,895	0.0233	0.9767	38.70
46.5	4,668,076	95,080	0.0204	0.9796	37.79
47.5	4,537,408	88,646	0.0195	0.9805	37.02
48.5	4,050,622	67,344	0.0166	0.9834	36.30
49.5	3,667,863	79,053	0.0216	0.9784	35.70
50.5	2,917,862	54,611	0.0187	0.9813	34.93
51.5	2,572,712	38,636	0.0150	0.9850	34.27
52.5	2,224,885	44,031	0.0198	0.9802	33.76
53.5	2,001,874	64,233	0.0321	0.9679	33.09
54.5	1,665,949	59,612	0.0358	0.9642	32.03
55.5	1,279,621	50,361	0.0394	0.9606	30.88
56.5	1,079,267	47,151	0.0437	0.9563	29.67
57.5	781,401	39,343	0.0503	0.9497	28.37
58.5	568,129	18,032	0.0317	0.9683	26.94
59.5	373,918	10,714	0.0287	0.9713	26.09
60.5	193,753	4,450	0.0230	0.9770	25.34
61.5	71,026	686	0.0097	0.9903	24.76
62.5	65,463	407	0.0062	0.9938	24.52
63.5	64,945	464	0.0071	0.9929	24.37
64.5	50,381	58	0.0012	0.9988	24.19
65.5	28,914	290	0.0100	0.9900	24.16
66.5	9,127	51	0.0056	0.9944	23.92
67.5	8,261	54	0.0065	0.9935	23.79
68.5	7,881		0.0000	1.0000	23.63
69.5	7,315		0.0000	1.0000	23.63
70.5	6,934		0.0000	1.0000	23.63
71.5	6,955		0.0000	1.0000	23.63
72.5	6,795		0.0000	1.0000	23.63
73.5	7,135		0.0000	1.0000	23.63
74.5	6,962		0.0000	1.0000	23.63
75.5	6,680	609	0.0912	0.9088	23.63
76.5	5,623	680	0.1209	0.8791	21.48
77.5	5,722	649	0.1134	0.8866	18.88
78.5	5,541	8	0.0014	0.9986	16.74

NORTHWEST NATURAL GAS COMPANY

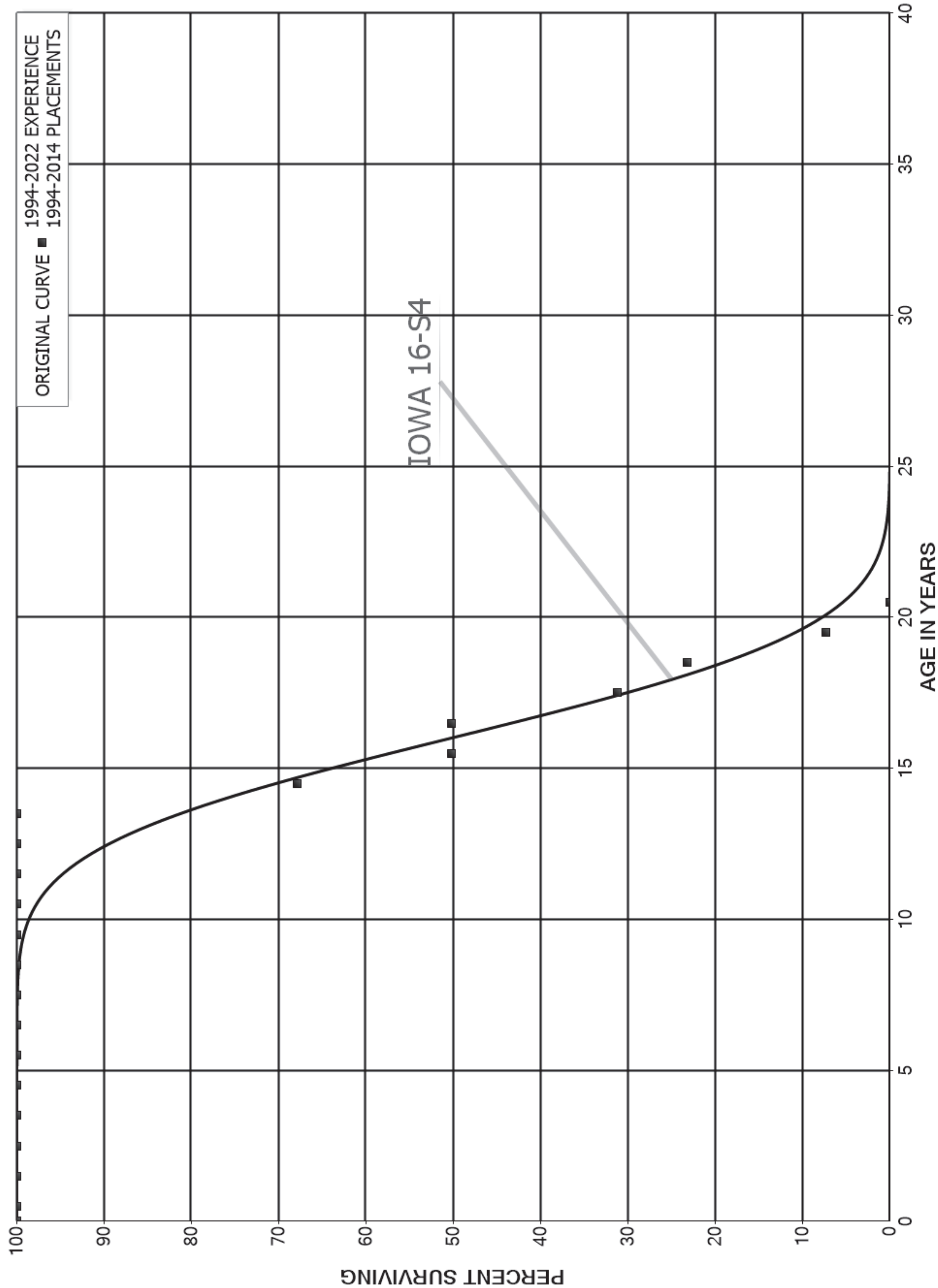
ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2022 EXPERIENCE BAND 2003-2022

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	5,920	1	0.0002	0.9998	16.72
80.5	5,919	377	0.0637	0.9363	16.71
81.5	5,542	2,255	0.4069	0.5931	15.65
82.5	3,326		0.0000	1.0000	9.28
83.5	3,326	34	0.0102	0.9898	9.28
84.5	3,313		0.0000	1.0000	9.19
85.5	3,313		0.0000	1.0000	9.19
86.5	3,313		0.0000	1.0000	9.19
87.5	3,370		0.0000	1.0000	9.19
88.5	3,399		0.0000	1.0000	9.19
89.5	3,399	87	0.0256	0.9744	9.19
90.5	3,312	148	0.0448	0.9552	8.95
91.5	3,164	320	0.1013	0.8987	8.55
92.5	121,585	1,451	0.0119	0.9881	7.68
93.5	120,134	1,246	0.0104	0.9896	7.59
94.5	118,888	1,739	0.0146	0.9854	7.51
95.5	117,149	3,869	0.0330	0.9670	7.40
96.5	113,280	9,143	0.0807	0.9193	7.16
97.5	104,137	6,898	0.0662	0.9338	6.58
98.5	97,239	2,496	0.0257	0.9743	6.15
99.5	94,743	2,878	0.0304	0.9696	5.99
100.5	91,864	1,720	0.0187	0.9813	5.81
101.5	90,145	1,660	0.0184	0.9816	5.70
102.5	88,485	2,410	0.0272	0.9728	5.59
103.5	86,075	2,640	0.0307	0.9693	5.44
104.5	83,436	1,770	0.0212	0.9788	5.27
105.5	81,666	1,380	0.0169	0.9831	5.16
106.5	80,286	2,030	0.0253	0.9747	5.07
107.5	78,256	1,800	0.0230	0.9770	4.95
108.5	76,456	1,630	0.0213	0.9787	4.83
109.5	74,826	6,630	0.0886	0.9114	4.73
110.5	68,196	2,180	0.0320	0.9680	4.31
111.5	66,016	1,590	0.0241	0.9759	4.17
112.5					4.07

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 381.10 METERS - ELECTRIC
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

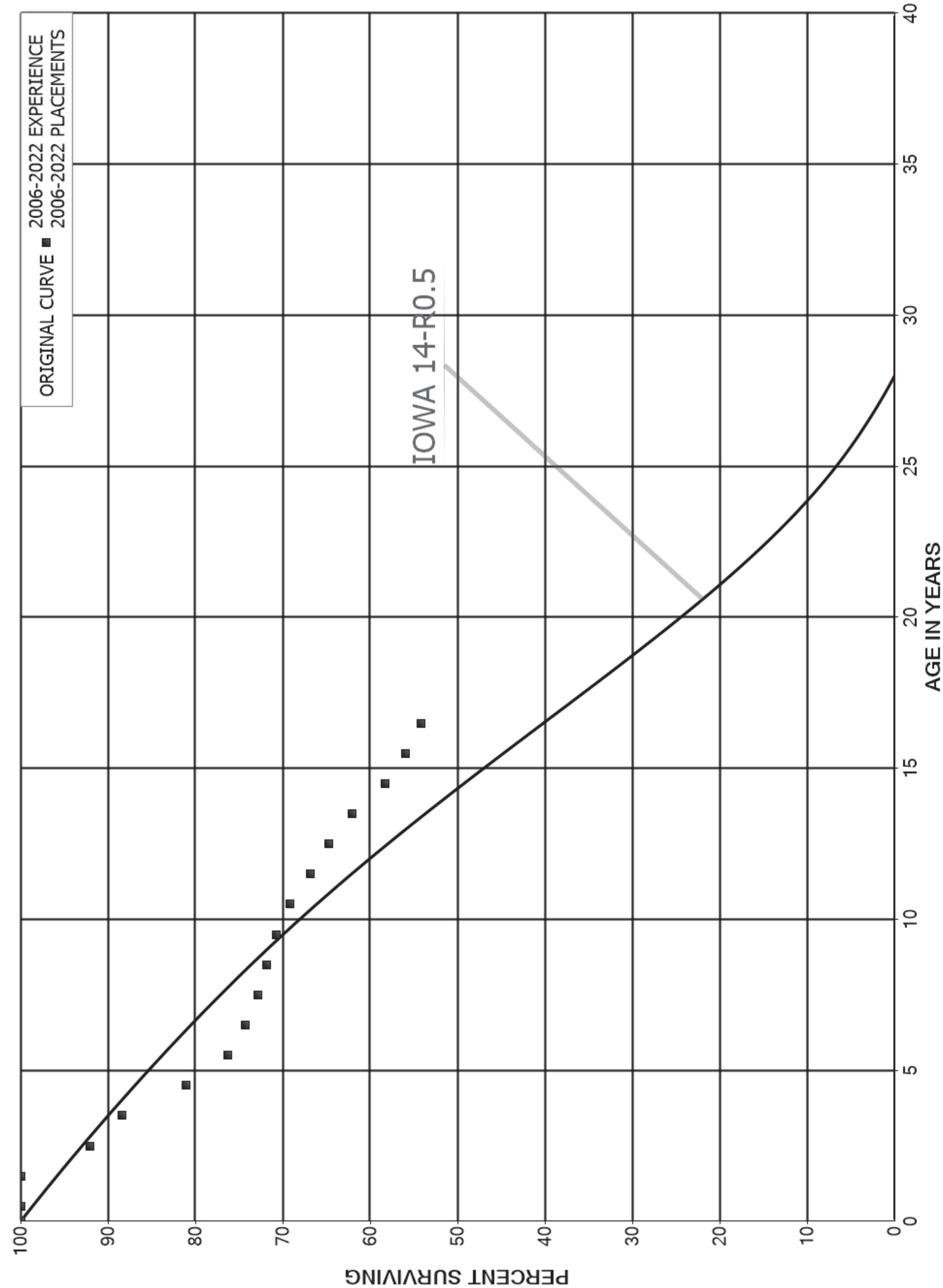
ACCOUNT 381.10 METERS - ELECTRIC

ORIGINAL LIFE TABLE

PLACEMENT BAND 1994-2014 EXPERIENCE BAND 1994-2022

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	507,007		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



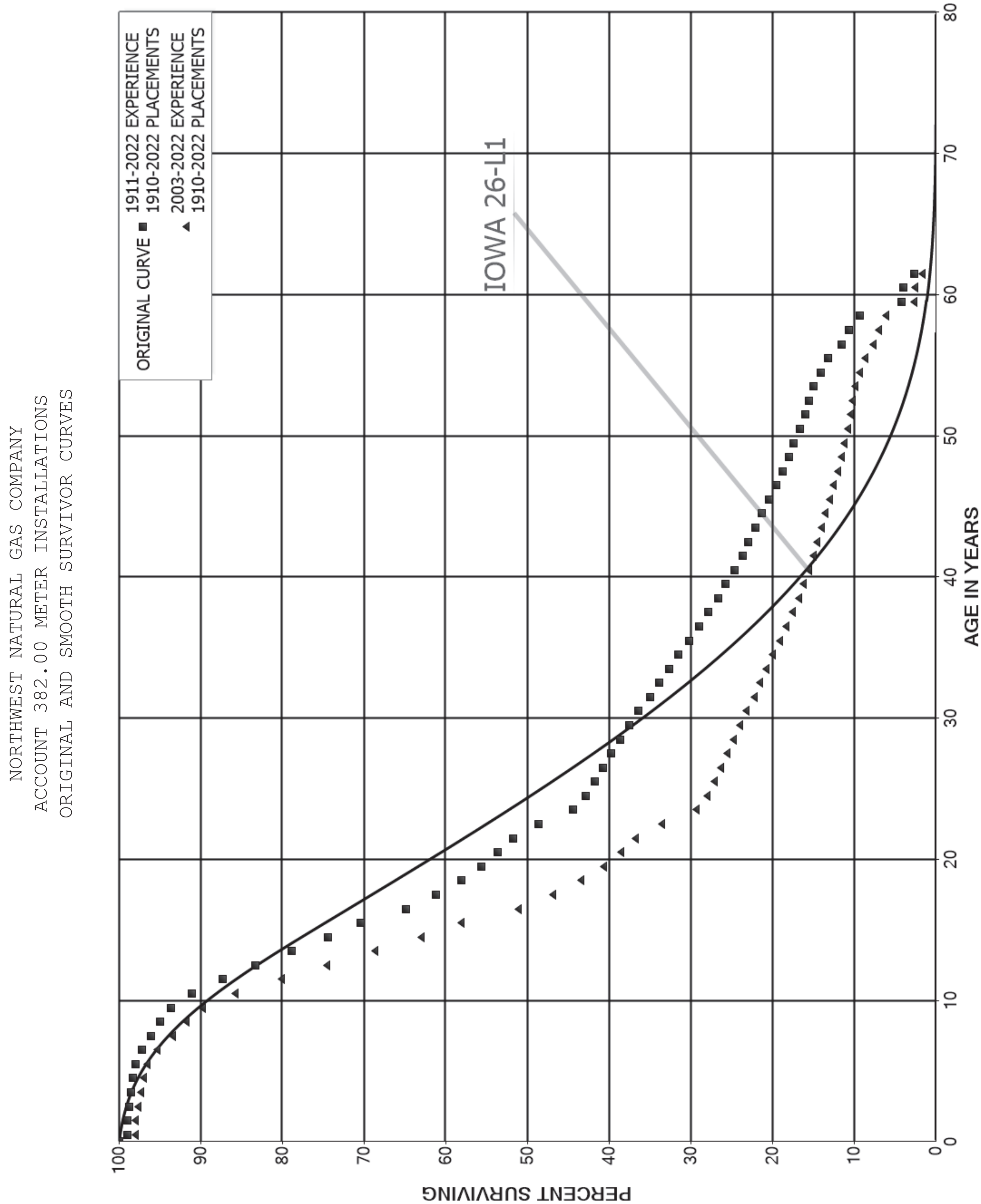
NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.20 METERS - ERT

ORIGINAL LIFE TABLE

PLACEMENT BAND 2006-2022 EXPERIENCE BAND 2006-2022

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	61,183,751		0.0000	1.0000	100.00
0.5	59,713,691	18,697	0.0003	0.9997	100.00
1.5	55,234,952	4,338,344	0.0785	0.9215	99.97
2.5	49,314,271	1,992,852	0.0404	0.9596	92.12
3.5	45,939,944	3,797,990	0.0827	0.9173	88.39
4.5	41,944,971	2,483,292	0.0592	0.9408	81.09
5.5	39,025,566	1,008,737	0.0258	0.9742	76.29
6.5	38,016,829	764,390	0.0201	0.9799	74.31
7.5	37,252,439	489,321	0.0131	0.9869	72.82
8.5	36,763,118	594,698	0.0162	0.9838	71.86
9.5	33,485,222	737,071	0.0220	0.9780	70.70
10.5	32,119,352	1,051,945	0.0328	0.9672	69.14
11.5	30,570,483	997,332	0.0326	0.9674	66.88
12.5	28,999,277	1,191,622	0.0411	0.9589	64.70
13.5	18,866,985	1,126,647	0.0597	0.9403	62.04
14.5	11,844,498	473,590	0.0400	0.9600	58.33
15.5	8,595,807	286,686	0.0334	0.9666	56.00
16.5					54.13


NORTHWEST NATURAL GAS COMPANY
ACCOUNT 382.00 METER INSTALLATIONS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE ■ 1911-2022 EXPERIENCE
1910-2022 PLACEMENTS
▲ 2003-2022 EXPERIENCE
1910-2022 PLACEMENTS
IOWA 26-L1
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2022 EXPERIENCE BAND 1911-2022

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	121,079,997	1,244,242	0.0103	0.9897	100.00
0.5	114,747,369	66,493	0.0006	0.9994	98.97
1.5	103,262,583	234,252	0.0023	0.9977	98.92
2.5	103,051,795	230,434	0.0022	0.9978	98.69
3.5	98,865,222	213,788	0.0022	0.9978	98.47
4.5	95,634,686	355,688	0.0037	0.9963	98.26
5.5	90,367,921	678,566	0.0075	0.9925	97.89
6.5	89,714,474	1,055,779	0.0118	0.9882	97.16
7.5	86,350,145	962,961	0.0112	0.9888	96.01
8.5	83,298,208	1,141,109	0.0137	0.9863	94.94
9.5	79,182,140	2,177,521	0.0275	0.9725	93.64
10.5	73,153,547	3,055,702	0.0418	0.9582	91.07
11.5	70,152,726	3,201,838	0.0456	0.9544	87.26
12.5	67,054,505	3,565,452	0.0532	0.9468	83.28
13.5	63,595,091	3,572,899	0.0562	0.9438	78.85
14.5	60,130,070	3,217,311	0.0535	0.9465	74.42
15.5	55,592,400	4,429,618	0.0797	0.9203	70.44
16.5	51,219,896	2,854,089	0.0557	0.9443	64.83
17.5	48,323,537	2,481,686	0.0514	0.9486	61.21
18.5	41,595,267	1,793,015	0.0431	0.9569	58.07
19.5	39,809,441	1,419,913	0.0357	0.9643	55.57
20.5	38,319,004	1,331,558	0.0347	0.9653	53.59
21.5	34,562,264	2,081,794	0.0602	0.9398	51.72
22.5	30,591,058	2,652,144	0.0867	0.9133	48.61
23.5	27,251,809	950,795	0.0349	0.9651	44.39
24.5	26,314,630	692,761	0.0263	0.9737	42.85
25.5	25,409,614	626,318	0.0246	0.9754	41.72
26.5	24,800,481	618,417	0.0249	0.9751	40.69
27.5	23,590,860	607,297	0.0257	0.9743	39.67
28.5	23,004,318	675,609	0.0294	0.9706	38.65
29.5	22,343,927	666,533	0.0298	0.9702	37.52
30.5	20,319,589	804,436	0.0396	0.9604	36.40
31.5	18,864,456	576,983	0.0306	0.9694	34.96
32.5	16,027,924	577,335	0.0360	0.9640	33.89
33.5	13,727,793	482,844	0.0352	0.9648	32.67
34.5	12,242,186	521,750	0.0426	0.9574	31.52
35.5	11,725,147	457,764	0.0390	0.9610	30.18
36.5	10,160,671	406,580	0.0400	0.9600	29.00
37.5	9,758,850	411,880	0.0422	0.9578	27.84
38.5	9,350,947	340,295	0.0364	0.9636	26.66

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2022 EXPERIENCE BAND 1911-2022

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	8,575,944	375,963	0.0438	0.9562	25.69
40.5	7,712,739	287,081	0.0372	0.9628	24.57
41.5	6,557,977	210,496	0.0321	0.9679	23.65
42.5	5,538,283	210,646	0.0380	0.9620	22.89
43.5	5,340,193	187,867	0.0352	0.9648	22.02
44.5	4,632,288	180,704	0.0390	0.9610	21.25
45.5	4,464,102	192,565	0.0431	0.9569	20.42
46.5	4,028,576	164,894	0.0409	0.9591	19.54
47.5	3,871,344	156,261	0.0404	0.9596	18.74
48.5	3,512,953	121,719	0.0346	0.9654	17.98
49.5	3,104,197	131,998	0.0425	0.9575	17.36
50.5	2,308,415	90,699	0.0393	0.9607	16.62
51.5	2,112,176	54,307	0.0257	0.9743	15.97
52.5	1,860,782	66,920	0.0360	0.9640	15.56
53.5	1,796,447	110,494	0.0615	0.9385	15.00
54.5	1,371,367	89,472	0.0652	0.9348	14.07
55.5	963,311	121,618	0.1262	0.8738	13.16
56.5	715,237	57,869	0.0809	0.9191	11.50
57.5	521,141	64,830	0.1244	0.8756	10.57
58.5	374,081	205,927	0.5505	0.4495	9.25
59.5	168,378	10,272	0.0610	0.9390	4.16
60.5	158,278	52,494	0.3317	0.6683	3.90
61.5	104,551	951	0.0091	0.9909	2.61
62.5	97,732	113	0.0012	0.9988	2.59
63.5	79,833	68	0.0009	0.9991	2.58
64.5	61,644	86	0.0014	0.9986	2.58
65.5	24,124	14	0.0006	0.9994	2.58
66.5	17,970	29	0.0016	0.9984	2.58
67.5	17,941	66	0.0037	0.9963	2.57
68.5	17,889	14	0.0008	0.9992	2.56
69.5	17,882		0.0000	1.0000	2.56
70.5	17,882		0.0000	1.0000	2.56
71.5	17,882		0.0000	1.0000	2.56
72.5	17,882	7	0.0004	0.9996	2.56
73.5	17,875		0.0000	1.0000	2.56
74.5	17,875		0.0000	1.0000	2.56
75.5	17,875		0.0000	1.0000	2.56
76.5	17,875		0.0000	1.0000	2.56
77.5	17,875		0.0000	1.0000	2.56
78.5	17,875		0.0000	1.0000	2.56

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2022 EXPERIENCE BAND 1911-2022

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	2.56
80.5	17,875		0.0000	1.0000	2.56
81.5	17,875		0.0000	1.0000	2.56
82.5	17,875		0.0000	1.0000	2.56
83.5	17,875		0.0000	1.0000	2.56
84.5	17,875		0.0000	1.0000	2.56
85.5	17,875		0.0000	1.0000	2.56
86.5	17,875		0.0000	1.0000	2.56
87.5	17,875		0.0000	1.0000	2.56
88.5	17,875		0.0000	1.0000	2.56
89.5	17,875	7	0.0004	0.9996	2.56
90.5	17,868		0.0000	1.0000	2.56
91.5	17,868		0.0000	1.0000	2.56
92.5	17,868		0.0000	1.0000	2.56
93.5	17,868	69	0.0039	0.9961	2.56
94.5	17,799	188	0.0105	0.9895	2.55
95.5	17,611	808	0.0459	0.9541	2.52
96.5	16,804	1,136	0.0676	0.9324	2.41
97.5	15,668		0.0000	1.0000	2.24
98.5	15,668	850	0.0542	0.9458	2.24
99.5	14,818	13,591	0.9172	0.0828	2.12
100.5	1,227	830	0.6762	0.3238	0.18
101.5	398	398	1.0000		0.06
102.5					

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2022 EXPERIENCE BAND 2003-2022

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	57,461,304	1,232,850	0.0215	0.9785	100.00
0.5	56,197,331	30,004	0.0005	0.9995	97.85
1.5	47,631,129	149,900	0.0031	0.9969	97.80
2.5	50,125,736	180,180	0.0036	0.9964	97.49
3.5	48,766,537	133,653	0.0027	0.9973	97.14
4.5	48,755,069	223,415	0.0046	0.9954	96.88
5.5	47,002,327	618,679	0.0132	0.9868	96.43
6.5	49,804,836	974,201	0.0196	0.9804	95.16
7.5	49,119,624	887,907	0.0181	0.9819	93.30
8.5	48,638,899	1,069,337	0.0220	0.9780	91.62
9.5	46,927,301	2,063,856	0.0440	0.9560	89.60
10.5	43,374,336	2,868,103	0.0661	0.9339	85.66
11.5	42,927,510	3,028,933	0.0706	0.9294	80.00
12.5	42,401,075	3,358,511	0.0792	0.9208	74.35
13.5	41,201,423	3,398,907	0.0825	0.9175	68.46
14.5	39,324,020	3,078,731	0.0783	0.9217	62.82
15.5	35,859,526	4,310,407	0.1202	0.8798	57.90
16.5	33,305,711	2,720,978	0.0817	0.9183	50.94
17.5	31,574,372	2,331,032	0.0738	0.9262	46.78
18.5	25,753,866	1,656,074	0.0643	0.9357	43.32
19.5	24,712,766	1,295,571	0.0524	0.9476	40.54
20.5	24,355,801	1,159,024	0.0476	0.9524	38.41
21.5	22,355,781	1,934,492	0.0865	0.9135	36.58
22.5	19,908,540	2,503,634	0.1258	0.8742	33.42
23.5	17,640,229	822,319	0.0466	0.9534	29.22
24.5	17,745,664	550,341	0.0310	0.9690	27.85
25.5	17,449,218	515,545	0.0295	0.9705	26.99
26.5	17,310,064	509,437	0.0294	0.9706	26.19
27.5	16,334,141	492,830	0.0302	0.9698	25.42
28.5	16,558,412	549,640	0.0332	0.9668	24.65
29.5	16,618,455	546,146	0.0329	0.9671	23.84
30.5	15,599,080	650,400	0.0417	0.9583	23.05
31.5	14,817,500	456,662	0.0308	0.9692	22.09
32.5	12,474,529	469,435	0.0376	0.9624	21.41
33.5	10,559,230	391,058	0.0370	0.9630	20.61
34.5	9,641,153	443,790	0.0460	0.9540	19.84
35.5	9,653,763	390,331	0.0404	0.9596	18.93
36.5	8,554,525	356,420	0.0417	0.9583	18.16
37.5	8,591,912	369,567	0.0430	0.9570	17.41
38.5	8,545,963	312,844	0.0366	0.9634	16.66

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2022 EXPERIENCE BAND 2003-2022

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	8,059,044	350,163	0.0434	0.9566	16.05
40.5	7,429,430	263,149	0.0354	0.9646	15.35
41.5	6,353,264	196,722	0.0310	0.9690	14.81
42.5	5,405,741	196,606	0.0364	0.9636	14.35
43.5	5,227,172	175,693	0.0336	0.9664	13.83
44.5	4,538,672	167,929	0.0370	0.9630	13.36
45.5	4,408,255	179,481	0.0407	0.9593	12.87
46.5	3,987,556	150,893	0.0378	0.9622	12.34
47.5	3,832,917	142,674	0.0372	0.9628	11.88
48.5	3,476,005	107,876	0.0310	0.9690	11.43
49.5	3,069,544	120,576	0.0393	0.9607	11.08
50.5	2,277,101	79,422	0.0349	0.9651	10.64
51.5	2,084,445	46,196	0.0222	0.9778	10.27
52.5	1,836,246	61,863	0.0337	0.9663	10.05
53.5	1,774,299	106,955	0.0603	0.9397	9.71
54.5	1,350,783	86,996	0.0644	0.9356	9.12
55.5	943,854	119,846	0.1270	0.8730	8.53
56.5	696,446	56,927	0.0817	0.9183	7.45
57.5	502,613	64,245	0.1278	0.8722	6.84
58.5	355,618	205,584	0.5781	0.4219	5.97
59.5	150,034	10,001	0.0667	0.9333	2.52
60.5	140,033	52,366	0.3740	0.6260	2.35
61.5	86,266	799	0.0093	0.9907	1.47
62.5	79,509		0.0000	1.0000	1.46
63.5	61,702		0.0000	1.0000	1.46
64.5	43,581		0.0000	1.0000	1.46
65.5	6,140		0.0000	1.0000	1.46
66.5					1.46
67.5					
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

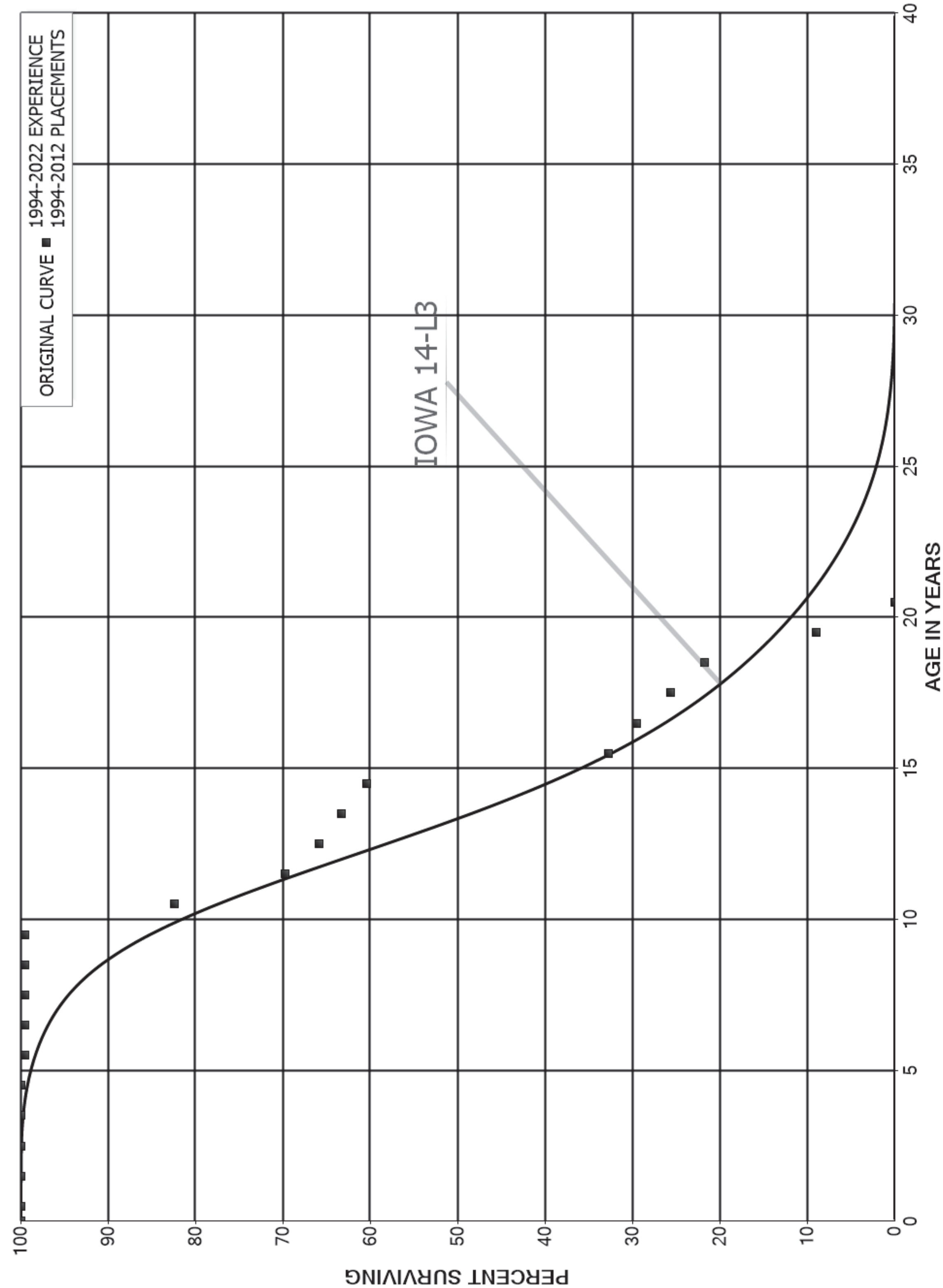
ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2022 EXPERIENCE BAND 2003-2022

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	7		0.0000		
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	14		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	17,868		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



NORTHWEST NATURAL GAS COMPANY

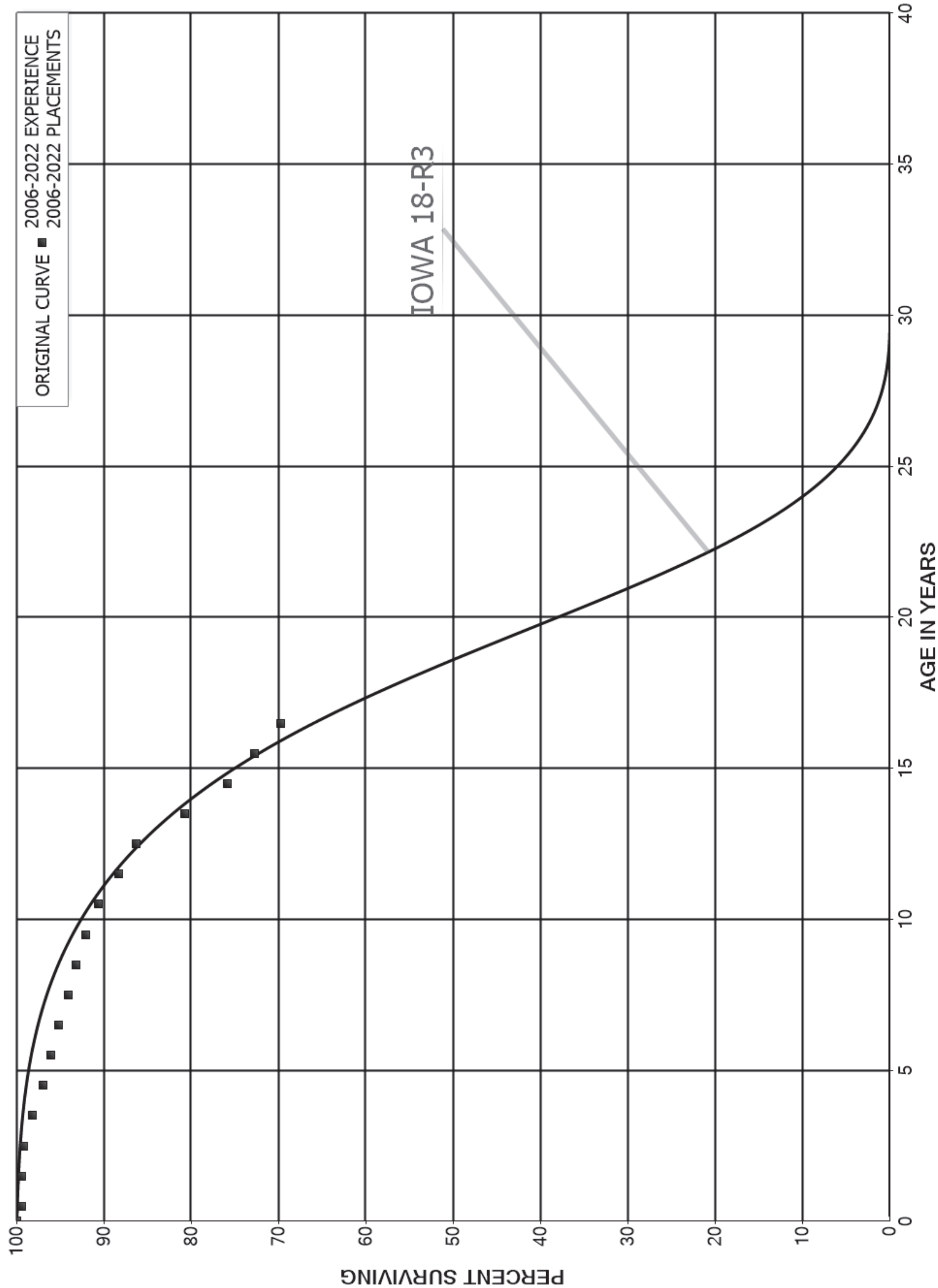
ACCOUNT 382.10 METER INSTALLATIONS - ELECTRIC

ORIGINAL LIFE TABLE

PLACEMENT BAND 1994-2012 EXPERIENCE BAND 1994-2022

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	342,147	52,429	0.1532	0.8468	82.37
11.5	289,718	16,259	0.0561	0.9439	69.74
12.5	273,459	10,720	0.0392	0.9608	65.83
13.5	262,739	11,880	0.0452	0.9548	63.25
14.5	250,859	114,955	0.4582	0.5418	60.39
15.5	135,904	13,170	0.0969	0.9031	32.72
16.5	122,734	16,477	0.1342	0.8658	29.55
17.5	106,257	15,824	0.1489	0.8511	25.58
18.5	90,433	53,374	0.5902	0.4098	21.77
19.5	37,059	37,059	1.0000		8.92
20.5					

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 382.20 METER INSTALLATIONS - ERT
ORIGINAL AND SMOOTH SURVIVOR CURVES



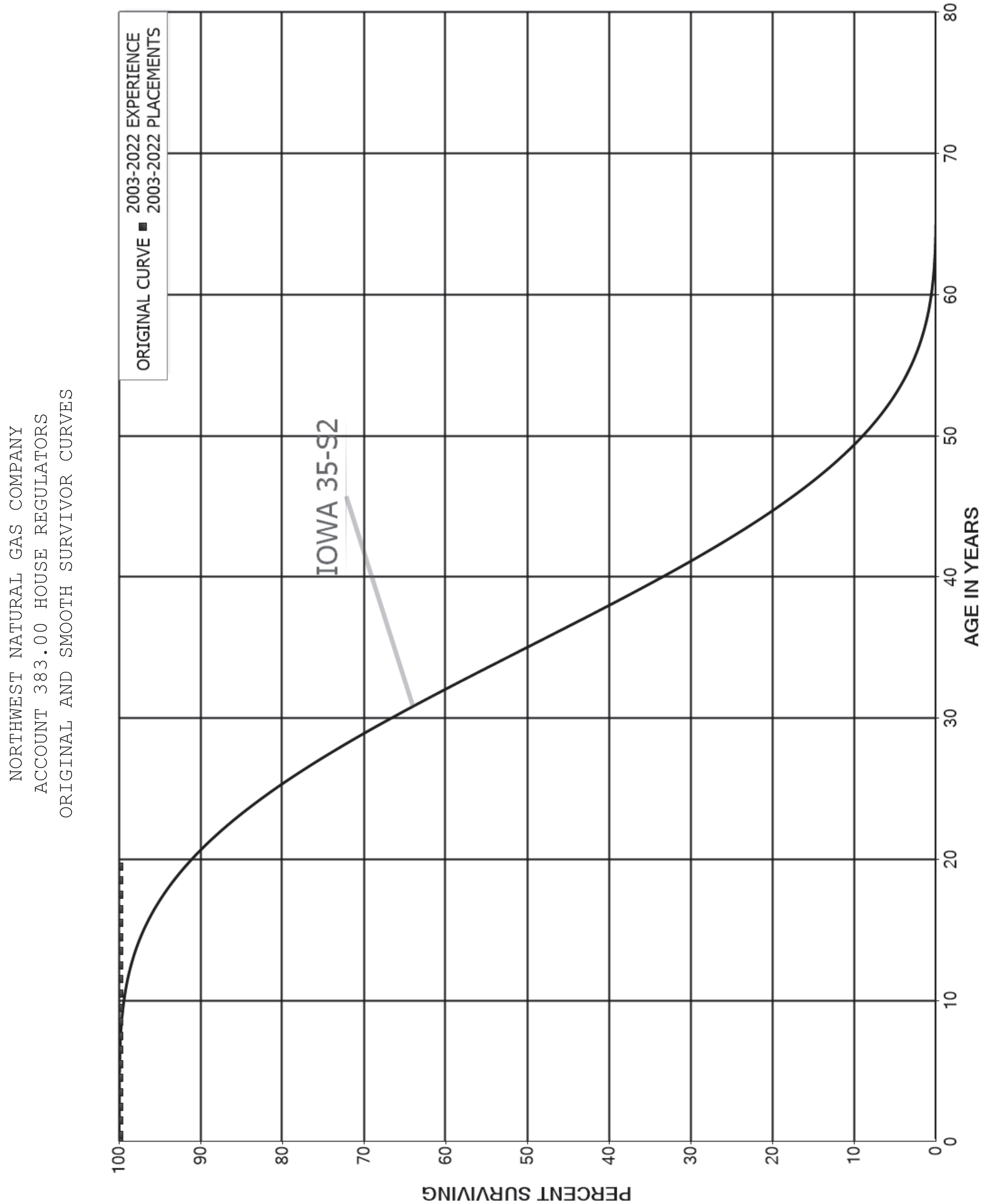
NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.20 METER INSTALLATIONS - ERT

ORIGINAL LIFE TABLE

PLACEMENT BAND 2006-2022 EXPERIENCE BAND 2006-2022

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	14,050,833	84,095	0.0060	0.9940	100.00
0.5	11,529,986	4,140	0.0004	0.9996	99.40
1.5	10,543,892	22,592	0.0021	0.9979	99.37
2.5	9,954,361	93,865	0.0094	0.9906	99.15
3.5	9,860,496	129,762	0.0132	0.9868	98.22
4.5	9,730,734	87,139	0.0090	0.9910	96.93
5.5	9,643,595	92,939	0.0096	0.9904	96.06
6.5	9,550,657	103,554	0.0108	0.9892	95.13
7.5	9,447,103	96,509	0.0102	0.9898	94.10
8.5	9,350,594	107,272	0.0115	0.9885	93.14
9.5	9,243,321	143,695	0.0155	0.9845	92.07
10.5	9,099,626	231,746	0.0255	0.9745	90.64
11.5	8,867,880	210,110	0.0237	0.9763	88.33
12.5	4,046,349	258,619	0.0639	0.9361	86.24
13.5	3,787,730	229,843	0.0607	0.9393	80.73
14.5	2,486,865	103,150	0.0415	0.9585	75.83
15.5	925,982	37,794	0.0408	0.9592	72.68
16.5					69.72


NORTHWEST NATURAL GAS COMPANY
ACCOUNT 383.00 HOUSE REGULATORS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE ■ 2003-2022 EXPERIENCE
2003-2022 PLACEMENTS
IOWA 35-S2
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70
80

NORTHWEST NATURAL GAS COMPANY

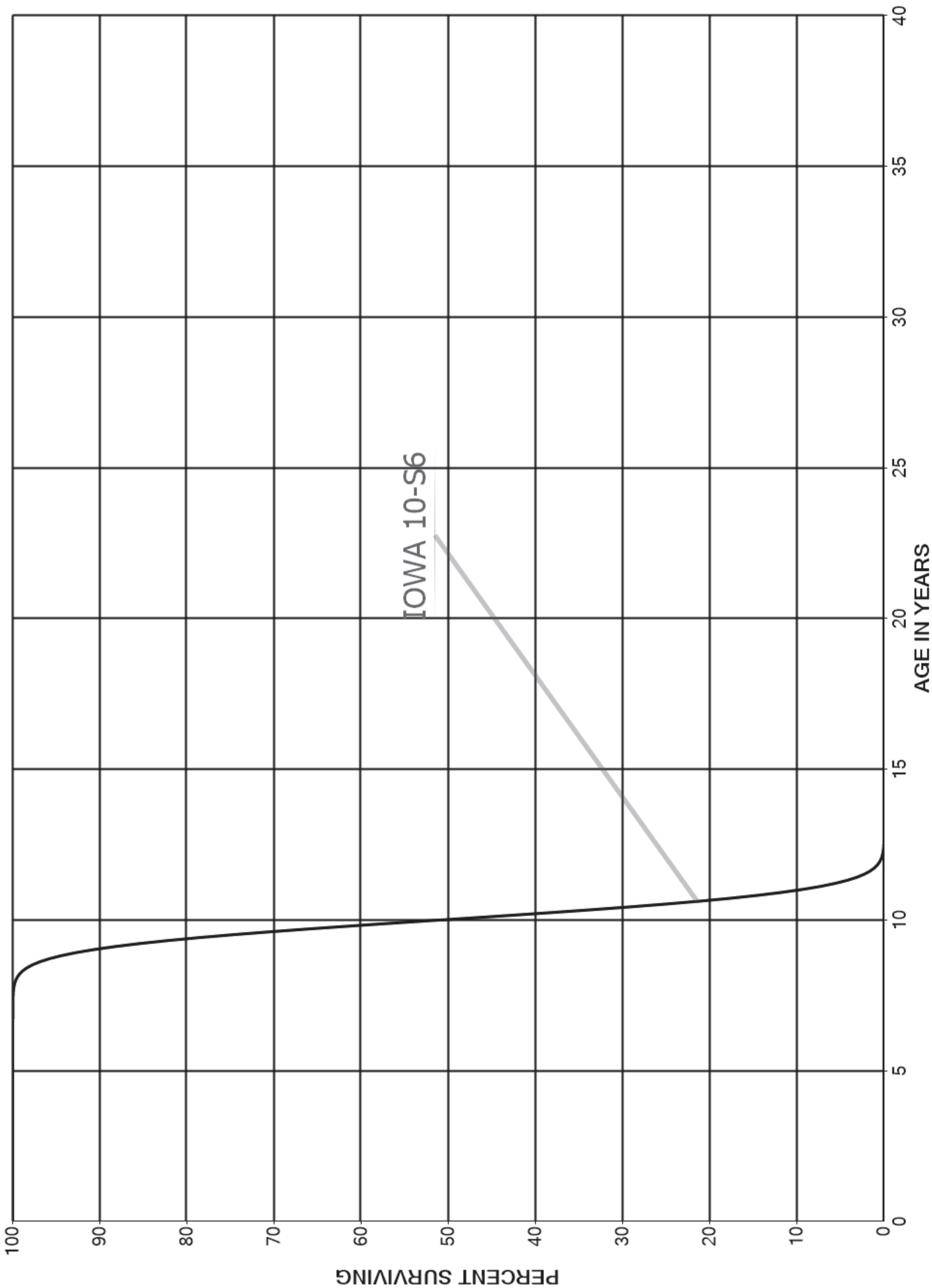
ACCOUNT 383.00 HOUSE REGULATORS

ORIGINAL LIFE TABLE

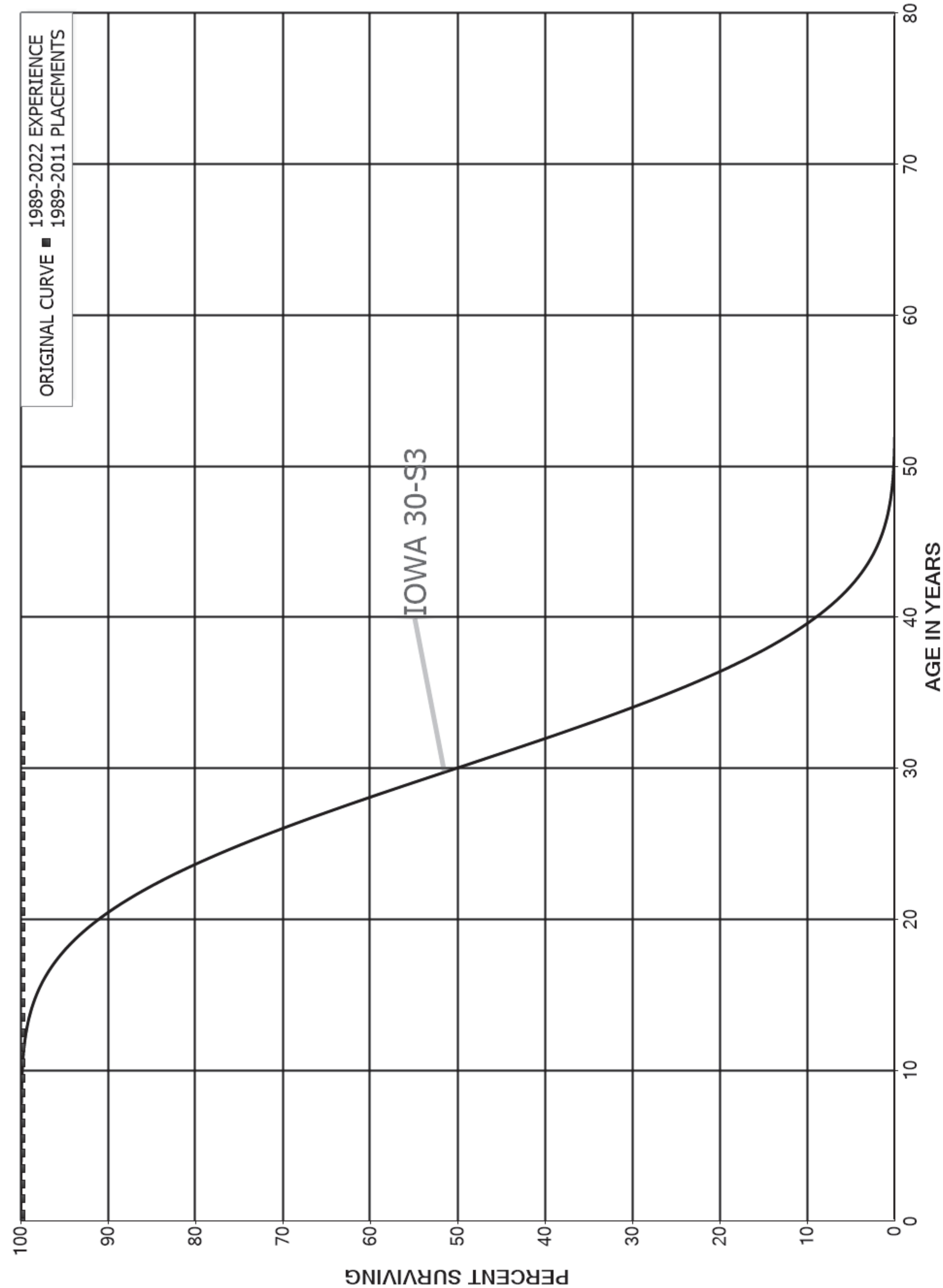
PLACEMENT BAND 2003-2022 EXPERIENCE BAND 2003-2022

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	2,820,769		0.0000	1.0000	100.00
0.5	2,679,217		0.0000	1.0000	100.00
1.5	2,553,748		0.0000	1.0000	100.00
2.5	2,419,709		0.0000	1.0000	100.00
3.5	2,199,701		0.0000	1.0000	100.00
4.5	1,877,440		0.0000	1.0000	100.00
5.5	1,678,311		0.0000	1.0000	100.00
6.5	1,500,612		0.0000	1.0000	100.00
7.5	1,280,026		0.0000	1.0000	100.00
8.5	1,110,626		0.0000	1.0000	100.00
9.5	775,208		0.0000	1.0000	100.00
10.5	619,596		0.0000	1.0000	100.00
11.5	569,858		0.0000	1.0000	100.00
12.5	487,625		0.0000	1.0000	100.00
13.5	451,511		0.0000	1.0000	100.00
14.5	369,806		0.0000	1.0000	100.00
15.5	263,639		0.0000	1.0000	100.00
16.5	163,930		0.0000	1.0000	100.00
17.5	52,920		0.0000	1.0000	100.00
18.5	1,945		0.0000	1.0000	100.00
19.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 386.00 OTHER PROPERTY ON CUSTOMERS' PREMISES
SMOOTH SURVIVOR CURVE



NORTHWEST NATURAL GAS COMPANY
ACCOUNT 387.10 OTHER EQUIPMENT - CATHODIC PROTECTION TESTING
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

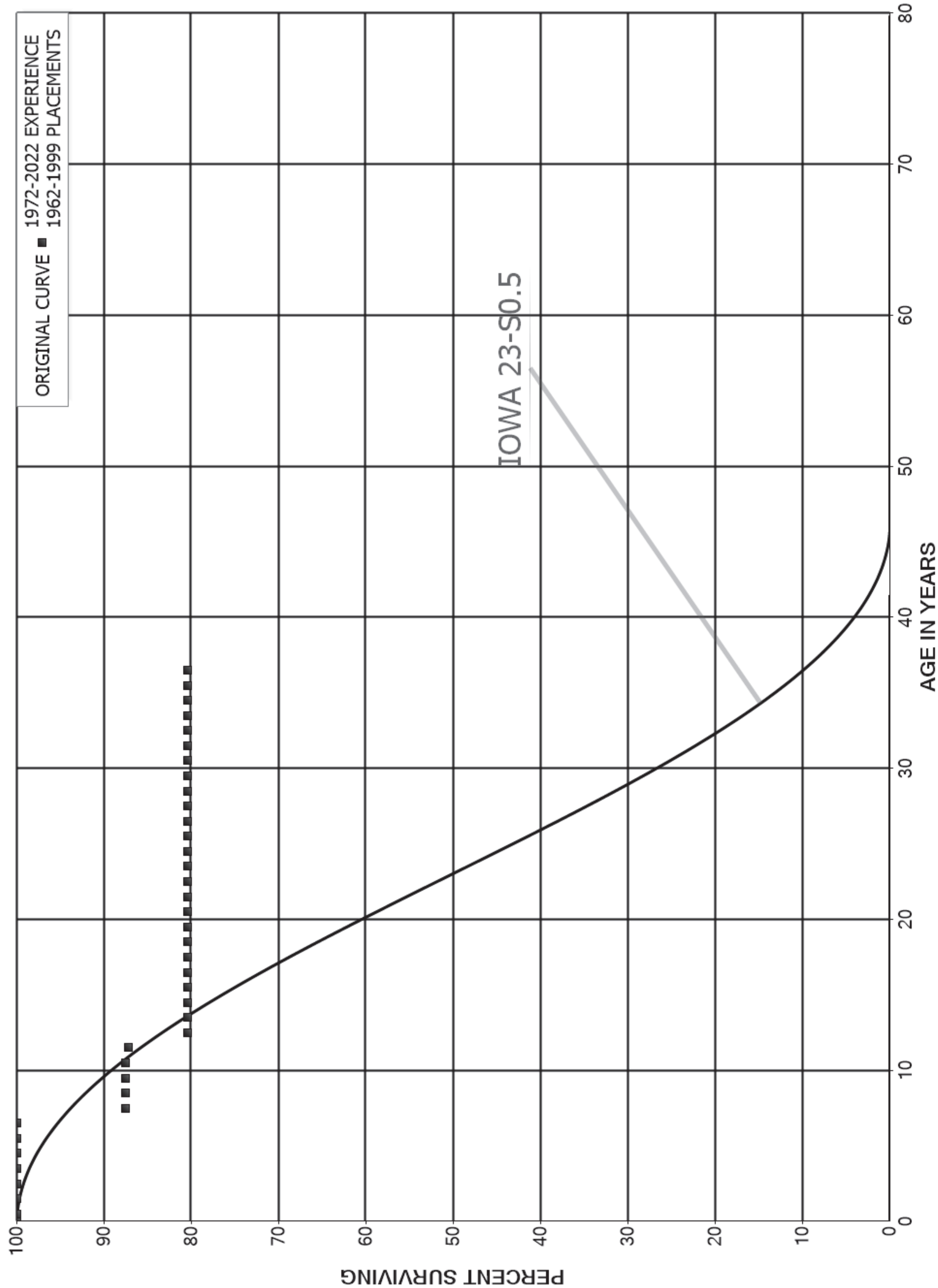
ACCOUNT 387.10 OTHER EQUIPMENT - CATHODIC PROTECTION TESTING

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2011 EXPERIENCE BAND 1989-2022

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	138,950		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	129,084		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	46,148		0.0000	1.0000	100.00
31.5	27,929		0.0000	1.0000	100.00
32.5	18,825		0.0000	1.0000	100.00
33.5					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 1972-2022

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	93,709		0.0000	1.0000	80.39
24.5	89,269		0.0000	1.0000	80.39
25.5	76,317		0.0000	1.0000	80.39
26.5	73,945		0.0000	1.0000	80.39
27.5	71,691		0.0000	1.0000	80.39
28.5	64,033		0.0000	1.0000	80.39
29.5	59,167		0.0000	1.0000	80.39
30.5	59,167		0.0000	1.0000	80.39
31.5	37,876		0.0000	1.0000	80.39
32.5	37,624		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	11,859		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

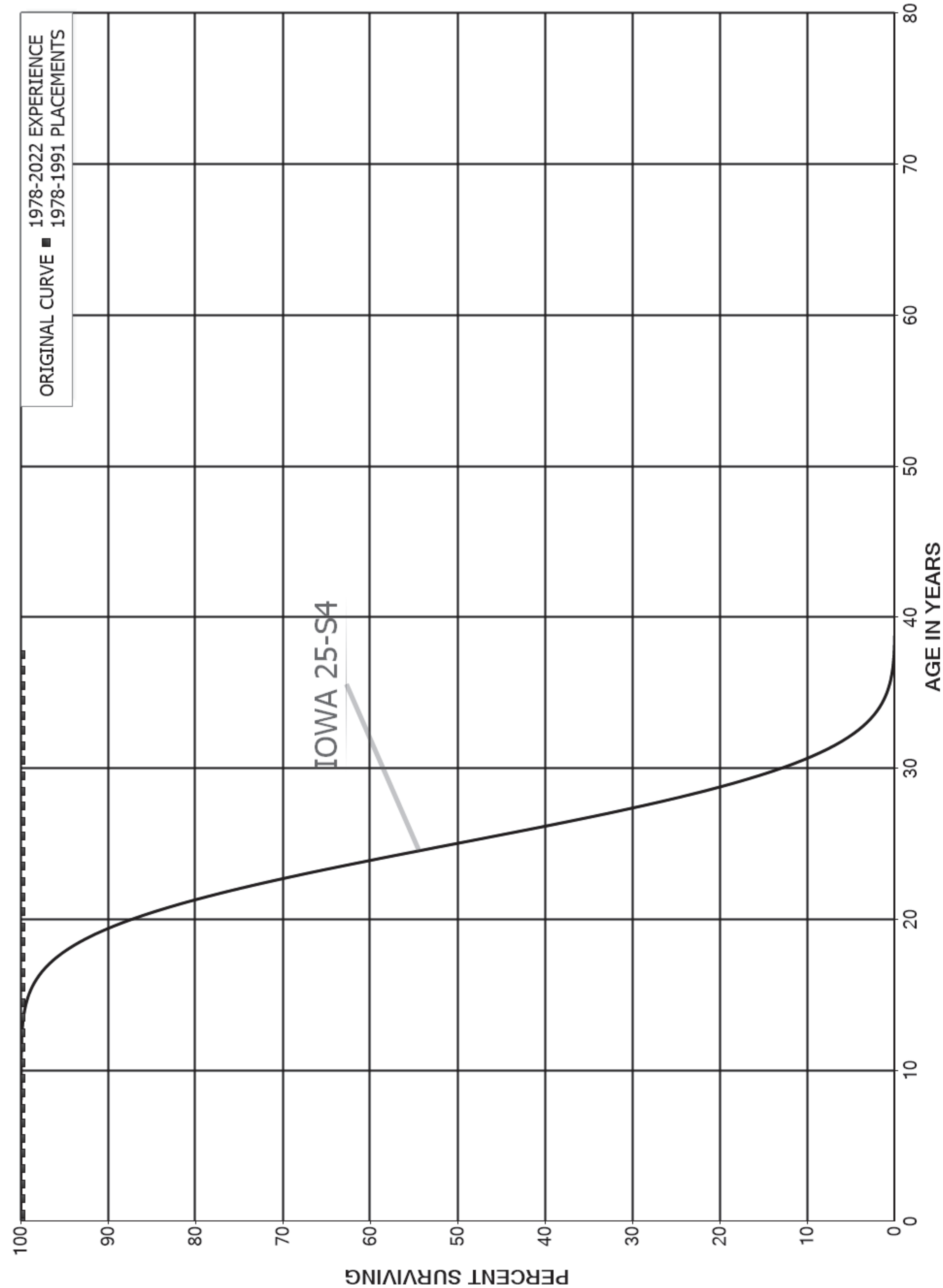
ACCOUNT 387.20 OTHER EQUIPMENT - CALORIMETERS AT GATE STATION

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1962-1999 EXPERIENCE BAND 1972-2022

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	865		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					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 1978-2022

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	60,776		0.0000	1.0000	100.00
32.5	60,170		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	58,537		0.0000	1.0000	100.00
36.5	57,190		0.0000	1.0000	100.00
37.5	16,792		0.0000	1.0000	100.00
38.5	15,567		0.0000	1.0000	100.00

NORTHWEST NATURAL GAS COMPANY

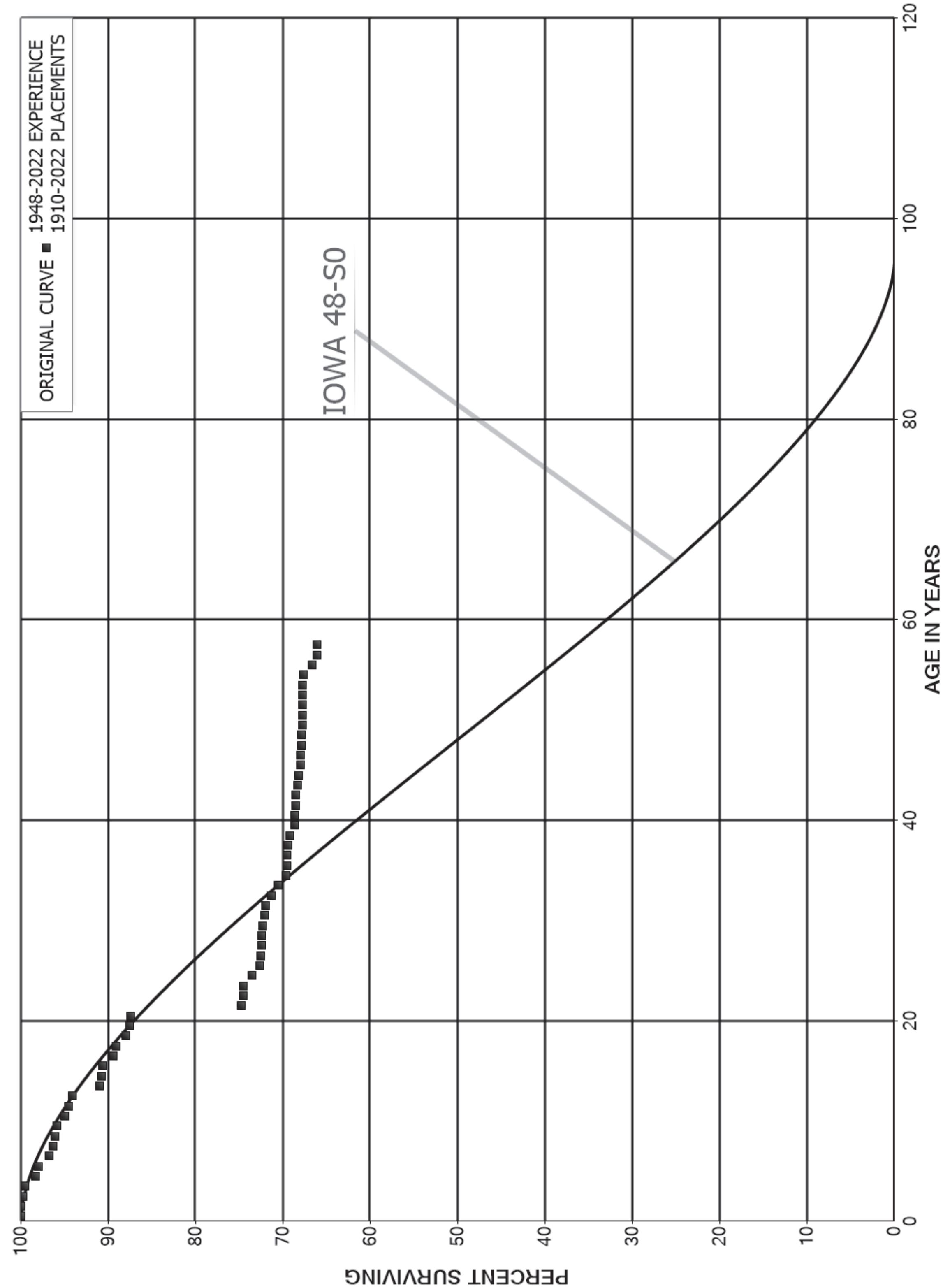
ACCOUNT 387.30 OTHER EQUIPMENT - METER TESTING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1978-1991 EXPERIENCE BAND 1978-2022

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	6,819		0.0000	1.0000	100.00
44.5					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 1910-2022 EXPERIENCE BAND 1948-2022

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	174,162,473	39,299	0.0002	0.9998	100.00
0.5	147,598,117	63,712	0.0004	0.9996	99.98
1.5	111,485,634	278,632	0.0025	0.9975	99.93
2.5	110,183,903	192,359	0.0017	0.9983	99.68
3.5	106,290,536	1,337,593	0.0126	0.9874	99.51
4.5	93,046,023	300,827	0.0032	0.9968	98.26
5.5	91,998,872	1,097,379	0.0119	0.9881	97.94
6.5	86,938,974	475,026	0.0055	0.9945	96.77
7.5	84,507,720	126,822	0.0015	0.9985	96.24
8.5	73,850,373	163,031	0.0022	0.9978	96.10
9.5	39,842,603	393,305	0.0099	0.9901	95.89
10.5	30,551,283	154,142	0.0050	0.9950	94.94
11.5	26,750,099	99,411	0.0037	0.9963	94.46
12.5	25,579,355	873,148	0.0341	0.9659	94.11
13.5	23,982,862	38,768	0.0016	0.9984	90.90
14.5	23,651,107	24,337	0.0010	0.9990	90.75
15.5	23,461,297	317,423	0.0135	0.9865	90.66
16.5	21,612,768	100,550	0.0047	0.9953	89.43
17.5	19,655,575	246,103	0.0125	0.9875	89.01
18.5	15,086,407	69,123	0.0046	0.9954	87.90
19.5	13,739,866	23,841	0.0017	0.9983	87.50
20.5	12,782,976	1,843,884	0.1442	0.8558	87.35
21.5	10,194,040	27,089	0.0027	0.9973	74.75
22.5	9,535,112	4	0.0000	1.0000	74.55
23.5	8,915,290	118,594	0.0133	0.9867	74.55
24.5	8,391,931	110,670	0.0132	0.9868	73.56
25.5	7,957,388	11,605	0.0015	0.9985	72.59
26.5	7,716,659	9,618	0.0012	0.9988	72.48
27.5	7,680,732	3,094	0.0004	0.9996	72.39
28.5	7,666,084	2,415	0.0003	0.9997	72.36
29.5	7,496,646	27,872	0.0037	0.9963	72.34
30.5	7,225,944	6,135	0.0008	0.9992	72.07
31.5	7,083,917	70,812	0.0100	0.9900	72.01
32.5	6,845,824	74,315	0.0109	0.9891	71.29
33.5	6,673,802	84,148	0.0126	0.9874	70.51
34.5	6,446,785	7,153	0.0011	0.9989	69.63
35.5	6,365,143	5,915	0.0009	0.9991	69.55
36.5	6,214,996	6,901	0.0011	0.9989	69.48
37.5	6,083,290	18,930	0.0031	0.9969	69.41
38.5	6,024,480	53,995	0.0090	0.9910	69.19

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 390.00 AND 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2022 EXPERIENCE BAND 1948-2022

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	5,817,842	710	0.0001	0.9999	68.57
40.5	5,302,278	3,798	0.0007	0.9993	68.56
41.5	4,942,800	3,567	0.0007	0.9993	68.51
42.5	4,844,565	9,794	0.0020	0.9980	68.46
43.5	4,800,998	12,969	0.0027	0.9973	68.32
44.5	3,994,531	8,014	0.0020	0.9980	68.14
45.5	3,910,493	786	0.0002	0.9998	68.00
46.5	2,226,868	4,086	0.0018	0.9982	67.99
47.5	2,191,591	622	0.0003	0.9997	67.87
48.5	1,780,908	3,943	0.0022	0.9978	67.85
49.5	1,544,601	450	0.0003	0.9997	67.70
50.5	1,463,003	28	0.0000	1.0000	67.68
51.5	1,440,456		0.0000	1.0000	67.67
52.5	1,423,614		0.0000	1.0000	67.67
53.5	1,404,153	418	0.0003	0.9997	67.67
54.5	1,345,542	20,908	0.0155	0.9845	67.65
55.5	1,299,940	10,091	0.0078	0.9922	66.60
56.5	642,425	558	0.0009	0.9991	66.09
57.5	373,084	3,476	0.0093	0.9907	66.03
58.5	239,103		0.0000	1.0000	65.41
59.5	231,803	435	0.0019	0.9981	65.41
60.5	226,079		0.0000	1.0000	65.29
61.5	218,905		0.0000	1.0000	65.29
62.5	216,762		0.0000	1.0000	65.29
63.5	215,225		0.0000	1.0000	65.29
64.5	262,448	38,544	0.1469	0.8531	65.29
65.5	220,085	9,030	0.0410	0.9590	55.70
66.5	164,997		0.0000	1.0000	53.42
67.5	147,143		0.0000	1.0000	53.42
68.5	147,080	8,917	0.0606	0.9394	53.42
69.5	126,631		0.0000	1.0000	50.18
70.5	97,411		0.0000	1.0000	50.18
71.5	87,330		0.0000	1.0000	50.18
72.5	87,082		0.0000	1.0000	50.18
73.5	78,739		0.0000	1.0000	50.18
74.5	75,677		0.0000	1.0000	50.18
75.5	68,896		0.0000	1.0000	50.18
76.5	68,703		0.0000	1.0000	50.18
77.5	67,941		0.0000	1.0000	50.18
78.5	67,910		0.0000	1.0000	50.18

NORTHWEST NATURAL GAS COMPANY

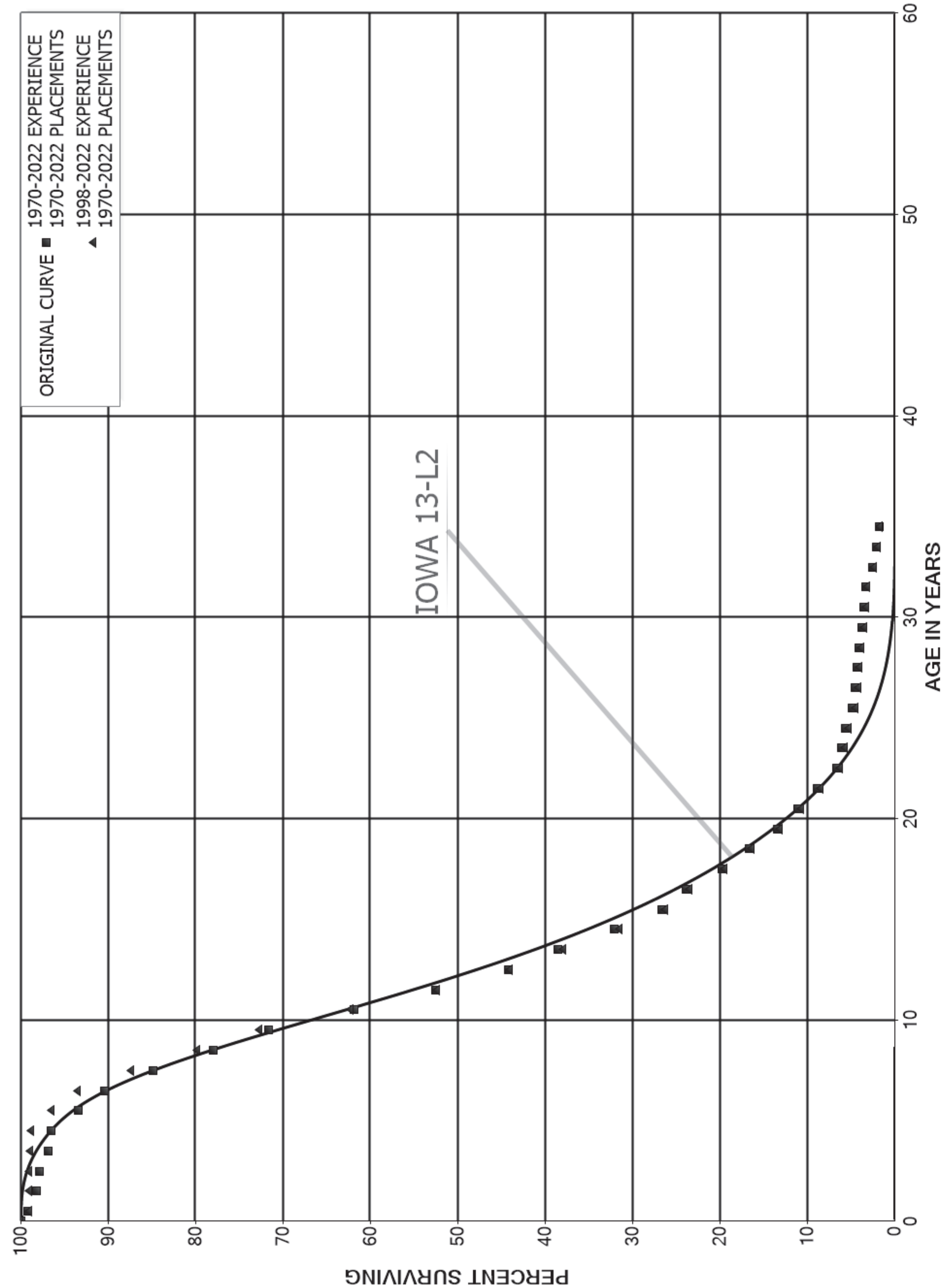
ACCOUNTS 390.00 AND 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2022 EXPERIENCE BAND 1948-2022

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	64,852		0.0000	1.0000	50.18
80.5	64,341		0.0000	1.0000	50.18
81.5	62,997		0.0000	1.0000	50.18
82.5	62,902		0.0000	1.0000	50.18
83.5	62,795		0.0000	1.0000	50.18
84.5	61,850		0.0000	1.0000	50.18
85.5	61,614	416	0.0068	0.9932	50.18
86.5	61,165		0.0000	1.0000	49.84
87.5	61,165		0.0000	1.0000	49.84
88.5	61,165		0.0000	1.0000	49.84
89.5	61,165		0.0000	1.0000	49.84
90.5	61,165		0.0000	1.0000	49.84
91.5	61,165	4,535	0.0741	0.9259	49.84
92.5	56,453		0.0000	1.0000	46.14
93.5	56,453		0.0000	1.0000	46.14
94.5	56,453	5,153	0.0913	0.9087	46.14
95.5	50,755		0.0000	1.0000	41.93
96.5	50,755		0.0000	1.0000	41.93
97.5	50,663		0.0000	1.0000	41.93
98.5	50,652		0.0000	1.0000	41.93
99.5	50,585		0.0000	1.0000	41.93
100.5	50,075		0.0000	1.0000	41.93
101.5	50,075		0.0000	1.0000	41.93
102.5	49,651		0.0000	1.0000	41.93
103.5	49,651		0.0000	1.0000	41.93
104.5	49,651		0.0000	1.0000	41.93
105.5	49,651		0.0000	1.0000	41.93
106.5	49,651		0.0000	1.0000	41.93
107.5	49,479		0.0000	1.0000	41.93
108.5	49,479		0.0000	1.0000	41.93
109.5					41.93

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 1970-2022 EXPERIENCE BAND 1970-2022

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	101,978,179	810,292	0.0079	0.9921	100.00
0.5	98,858,830	1,043,743	0.0106	0.9894	99.21
1.5	93,686,650	277,244	0.0030	0.9970	98.16
2.5	88,430,294	913,832	0.0103	0.9897	97.87
3.5	80,114,522	295,923	0.0037	0.9963	96.86
4.5	53,358,733	1,693,484	0.0317	0.9683	96.50
5.5	51,640,698	1,679,914	0.0325	0.9675	93.44
6.5	49,787,734	3,081,630	0.0619	0.9381	90.40
7.5	46,517,221	3,726,898	0.0801	0.9199	84.80
8.5	41,108,369	3,379,210	0.0822	0.9178	78.01
9.5	33,292,230	4,519,063	0.1357	0.8643	71.59
10.5	25,638,786	3,889,078	0.1517	0.8483	61.88
11.5	20,844,256	3,296,502	0.1581	0.8419	52.49
12.5	15,827,896	2,045,593	0.1292	0.8708	44.19
13.5	13,488,322	2,237,165	0.1659	0.8341	38.48
14.5	10,612,785	1,798,172	0.1694	0.8306	32.10
15.5	8,469,482	895,995	0.1058	0.8942	26.66
16.5	7,418,724	1,277,769	0.1722	0.8278	23.84
17.5	6,060,716	972,045	0.1604	0.8396	19.73
18.5	4,751,887	895,469	0.1884	0.8116	16.57
19.5	3,635,823	651,801	0.1793	0.8207	13.45
20.5	2,890,106	564,780	0.1954	0.8046	11.03
21.5	2,217,486	553,251	0.2495	0.7505	8.88
22.5	1,626,793	137,289	0.0844	0.9156	6.66
23.5	1,352,079	113,735	0.0841	0.9159	6.10
24.5	1,117,569	146,339	0.1309	0.8691	5.59
25.5	936,069	70,523	0.0753	0.9247	4.86
26.5	776,182	34,821	0.0449	0.9551	4.49
27.5	610,941	30,978	0.0507	0.9493	4.29
28.5	457,386	42,868	0.0937	0.9063	4.07
29.5	414,518	19,394	0.0468	0.9532	3.69
30.5	399,466	20,433	0.0512	0.9488	3.52
31.5	369,187	86,154	0.2334	0.7666	3.34
32.5	261,737	51,947	0.1985	0.8015	2.56
33.5	209,790	32,157	0.1533	0.8467	2.05
34.5	147,565	6,956	0.0471	0.9529	1.74
35.5	140,028	12,235	0.0874	0.9126	1.65
36.5	127,793		0.0000	1.0000	1.51
37.5	127,793	9,128	0.0714	0.9286	1.51
38.5	116,321	9,517	0.0818	0.9182	1.40

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1970-2022 EXPERIENCE BAND 1970-2022

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	79,458	3,518	0.0443	0.9557	1.29
40.5	75,940		0.0000	1.0000	1.23
41.5	75,940		0.0000	1.0000	1.23
42.5	75,940		0.0000	1.0000	1.23
43.5	75,940		0.0000	1.0000	1.23
44.5	75,940		0.0000	1.0000	1.23
45.5	75,940		0.0000	1.0000	1.23
46.5	69,477		0.0000	1.0000	1.23
47.5	69,477		0.0000	1.0000	1.23
48.5	69,477		0.0000	1.0000	1.23
49.5	69,477		0.0000	1.0000	1.23
50.5					1.23

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2022 EXPERIENCE BAND 1998-2022

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	80,656,228	810,292	0.0100	0.9900	100.00
0.5	80,097,551		0.0000	1.0000	99.00
1.5	78,337,579	21,443	0.0003	0.9997	99.00
2.5	75,069,870	89,870	0.0012	0.9988	98.97
3.5	69,696,869	119,912	0.0017	0.9983	98.85
4.5	44,814,723	1,041,494	0.0232	0.9768	98.68
5.5	44,421,650	1,389,968	0.0313	0.9687	96.39
6.5	44,011,072	2,870,241	0.0652	0.9348	93.37
7.5	41,902,224	3,636,855	0.0868	0.9132	87.28
8.5	37,330,313	3,306,433	0.0886	0.9114	79.71
9.5	30,244,998	4,356,427	0.1440	0.8560	72.65
10.5	23,196,153	3,702,113	0.1596	0.8404	62.18
11.5	18,591,491	2,954,460	0.1589	0.8411	52.26
12.5	14,509,544	2,032,133	0.1401	0.8599	43.95
13.5	12,390,274	2,099,737	0.1695	0.8305	37.80
14.5	9,793,903	1,624,133	0.1658	0.8342	31.39
15.5	7,925,404	855,914	0.1080	0.8920	26.19
16.5	6,972,644	1,170,066	0.1678	0.8322	23.36
17.5	5,832,456	955,076	0.1638	0.8362	19.44
18.5	4,560,526	895,469	0.1964	0.8036	16.26
19.5	3,471,860	651,801	0.1877	0.8123	13.06
20.5	2,750,994	564,780	0.2053	0.7947	10.61
21.5	2,084,837	553,251	0.2654	0.7346	8.43
22.5	1,494,144	137,289	0.0919	0.9081	6.19
23.5	1,249,498	100,018	0.0800	0.9200	5.63
24.5	1,031,082	146,339	0.1419	0.8581	5.18
25.5	921,872	70,523	0.0765	0.9235	4.44
26.5	766,665	34,821	0.0454	0.9546	4.10
27.5	610,941	30,978	0.0507	0.9493	3.91
28.5	457,386	42,868	0.0937	0.9063	3.72
29.5	414,518	19,394	0.0468	0.9532	3.37
30.5	399,466	20,433	0.0512	0.9488	3.21
31.5	369,187	86,154	0.2334	0.7666	3.05
32.5	261,737	51,947	0.1985	0.8015	2.34
33.5	209,790	32,157	0.1533	0.8467	1.87
34.5	147,565	6,956	0.0471	0.9529	1.58
35.5	140,028	12,235	0.0874	0.9126	1.51
36.5	127,793		0.0000	1.0000	1.38
37.5	127,793	9,128	0.0714	0.9286	1.38
38.5	116,321	9,517	0.0818	0.9182	1.28

NORTHWEST NATURAL GAS COMPANY

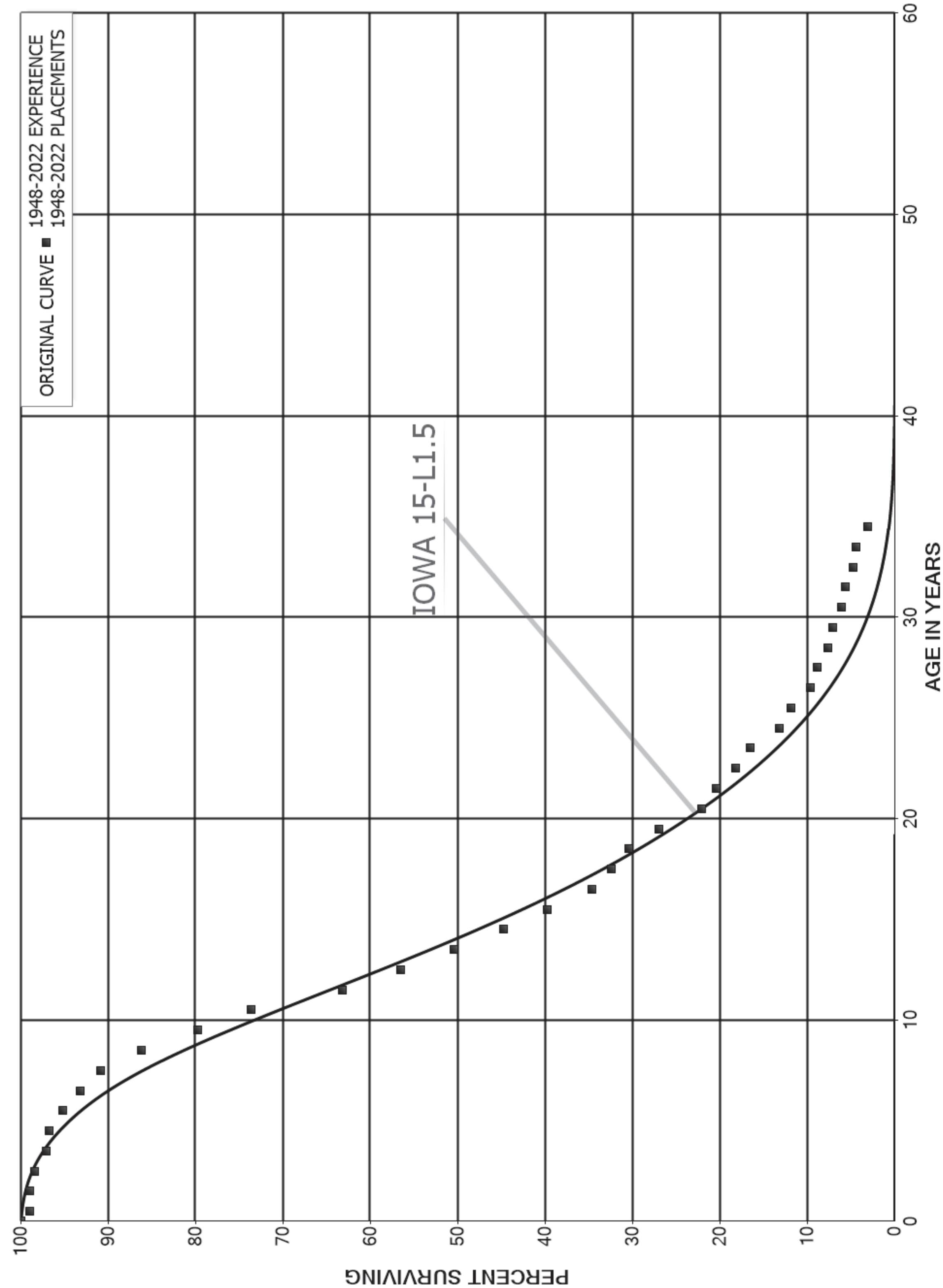
ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1970-2022 EXPERIENCE BAND 1998-2022

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	79,458	3,518	0.0443	0.9557	1.18
40.5	75,940		0.0000	1.0000	1.12
41.5	75,940		0.0000	1.0000	1.12
42.5	75,940		0.0000	1.0000	1.12
43.5	75,940		0.0000	1.0000	1.12
44.5	75,940		0.0000	1.0000	1.12
45.5	75,940		0.0000	1.0000	1.12
46.5	69,477		0.0000	1.0000	1.12
47.5	69,477		0.0000	1.0000	1.12
48.5	69,477		0.0000	1.0000	1.12
49.5	69,477		0.0000	1.0000	1.12
50.5					1.12

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 1948-2022 EXPERIENCE BAND 1948-2022

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	26,082,813	288,089	0.0110	0.9890	100.00
0.5	24,273,046		0.0000	1.0000	98.90
1.5	22,102,238	124,142	0.0056	0.9944	98.90
2.5	20,280,089	268,514	0.0132	0.9868	98.34
3.5	18,198,583	66,342	0.0036	0.9964	97.04
4.5	12,259,701	198,255	0.0162	0.9838	96.68
5.5	12,034,695	252,087	0.0209	0.9791	95.12
6.5	11,866,127	297,998	0.0251	0.9749	93.13
7.5	11,594,547	594,677	0.0513	0.9487	90.79
8.5	10,935,385	807,883	0.0739	0.9261	86.13
9.5	9,381,140	722,486	0.0770	0.9230	79.77
10.5	8,259,975	1,177,004	0.1425	0.8575	73.63
11.5	6,345,278	666,155	0.1050	0.8950	63.13
12.5	5,563,550	606,769	0.1091	0.8909	56.51
13.5	4,918,015	543,883	0.1106	0.8894	50.34
14.5	4,296,572	481,182	0.1120	0.8880	44.78
15.5	3,772,064	488,233	0.1294	0.8706	39.76
16.5	2,954,150	189,717	0.0642	0.9358	34.62
17.5	2,262,150	139,493	0.0617	0.9383	32.39
18.5	2,033,532	229,824	0.1130	0.8870	30.39
19.5	1,741,136	318,213	0.1828	0.8172	26.96
20.5	1,264,001	94,624	0.0749	0.9251	22.03
21.5	1,144,741	122,544	0.1070	0.8930	20.38
22.5	1,022,197	97,196	0.0951	0.9049	18.20
23.5	907,124	180,554	0.1990	0.8010	16.47
24.5	642,305	68,335	0.1064	0.8936	13.19
25.5	579,885	105,633	0.1822	0.8178	11.79
26.5	449,969	40,160	0.0893	0.9107	9.64
27.5	370,429	50,808	0.1372	0.8628	8.78
28.5	307,031	22,348	0.0728	0.9272	7.58
29.5	306,400	41,139	0.1343	0.8657	7.02
30.5	260,912	19,501	0.0747	0.9253	6.08
31.5	231,569	37,953	0.1639	0.8361	5.63
32.5	193,616	12,255	0.0633	0.9367	4.70
33.5	166,701	49,370	0.2962	0.7038	4.41
34.5	117,331		0.0000	1.0000	3.10
35.5	117,331		0.0000	1.0000	3.10
36.5	117,331		0.0000	1.0000	3.10
37.5	54,944		0.0000	1.0000	3.10
38.5	54,944		0.0000	1.0000	3.10

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1948-2022 EXPERIENCE BAND 1948-2022

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	3.10
40.5	54,944		0.0000	1.0000	3.10
41.5	30,054		0.0000	1.0000	3.10
42.5	30,054	20,334	0.6766	0.3234	3.10
43.5	1,025		0.0000	1.0000	1.00
44.5	1,025		0.0000	1.0000	1.00
45.5	1,025		0.0000	1.0000	1.00
46.5	1,025		0.0000	1.0000	1.00
47.5	1,025	1,025	1.0000		1.00
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-
TOTAL	40,904,415	39,459,249	96	706,328	2	38,752,921-	95-

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-
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-

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							
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-
FIVE-YEAR AVERAGE							
18-22	439,144	1,710,595	390	81,599	19	1,628,996-	371-

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-
TOTAL	45,620,241	51,756,388	113	108,345-	0	51,864,733-	114-

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-
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-

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							
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-
FIVE-YEAR AVERAGE							
18-22	1,477,888	3,237,244	219		0	3,237,244-	219-

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
TOTAL	29,273,847		0	157,098	1	157,098	1

THREE-YEAR MOVING AVERAGES

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
99-01	188,775		0	2,945	2	2,945	2
00-02	178,136		0	645	0	645	0

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

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							
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
FIVE-YEAR AVERAGE							
18-22	3,156,774		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	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2014	507,007		0		0		0
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
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							
FIVE-YEAR AVERAGE							
18-22							

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
TOTAL	21,353,213		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
FIVE-YEAR AVERAGE							
18-22	3,496,460		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
TOTAL	54,105,279	58,535	0	8,699	0	49,836-	0

THREE-YEAR MOVING AVERAGES

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
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

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

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							
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
FIVE-YEAR AVERAGE							
18-22	3,158,828		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							
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							
FIVE-YEAR AVERAGE							
18-22							

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.20 METER INSTALLATIONS - 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	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
TOTAL	2,037,361		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
FIVE-YEAR AVERAGE							
18-22	256,024		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							
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
99-01	284,411		0		0		0
00-02	284,411		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							
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
FIVE-YEAR AVERAGE							
18-22	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	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	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
TOTAL	44,413,459		0	6,177,252	14	6,177,252	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
05-07	1,643,185		0	219,775	13	219,775	13
06-08	1,272,301		0	183,235	14	183,235	14

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							
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
FIVE-YEAR AVERAGE							
18-22	1,924,879		0	373,105	19	373,105	19

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 396.00 POWER OPERATED 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
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
TOTAL	10,086,092		0	2,409,489	24	2,409,489	24

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE 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
03-05	425,805		0	72,788	17	72,788	17
04-06	559,692		0	73,979	13	73,979	13

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 396.00 POWER OPERATED 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
THREE-YEAR MOVING AVERAGES							
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
FIVE-YEAR AVERAGE							
18-22	603,810		0	205,823	34	205,823	34

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, 2022

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			
2004	277,949.84	277,950	277,950			
2005	1,431,678.94	1,431,679	1,431,679			
2006	714,428.00	714,428	714,428			
2007	1,629,484.94	1,629,485	1,629,485			
2008	6,001,745.25	5,801,707	1,910,436	4,091,309	0.50	4,091,309
2009	13,177,131.70	11,859,419	3,905,171	9,271,961	1.50	6,181,307
2010	2,523,983.52	2,103,311	692,596	1,831,388	2.50	732,555
2011	3,084,332.46	2,364,665	778,657	2,305,675	3.50	658,764
2012	1,959,821.13	1,371,875	451,743	1,508,078	4.50	335,128
2013	2,749,147.78	1,741,118	573,330	2,175,818	5.50	395,603
2014	4,136,153.78	2,343,834	771,798	3,364,356	6.50	517,593
2015	4,345,986.68	2,172,993	715,542	3,630,445	7.50	484,059
2016	5,169,336.07	2,240,028	737,616	4,431,720	8.50	521,379
2017	5,258,816.60	1,928,250	634,951	4,623,866	9.50	486,723
2018	12,198,059.13	3,659,418	1,205,004	10,993,055	10.50	1,046,958
2019	9,600,094.98	2,239,990	737,603	8,862,492	11.50	770,651
2020	15,205,971.51	2,534,379	834,542	14,371,430	12.50	1,149,714
2021	8,300,511.67	830,051	273,327	8,027,185	13.50	594,606
2022	14,867,295.37	495,527	163,171	14,704,124	14.50	1,014,078
	116,460,287.26	51,568,464	22,267,386	94,192,901		18,980,427

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.0   16.30

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 303.11 MISCELLANEOUS INTANGIBLE PLANT - HORIZON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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	47,100,838.00	2,355,042	813,380	46,287,458	9.50	4,872,364
	47,100,838.00	2,355,042	813,380	46,287,458		4,872,364

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.5   10.34

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, 2022

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	6,653,764.00	665,376	221,249	6,432,515	4.50	1,429,448
	6,653,764.00	665,376	221,249	6,432,515		1,429,448

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.5 21.48

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, 2022

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)
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	183,918	190,259			
2013	1,267,786.82	802,927	1,267,787			
2014	246,002.37	139,402	235,203	10,799	6.50	1,661
	32,409,597.11	31,831,796	32,398,798	10,799		1,661

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.5 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, 2022

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, 2022

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	4,264,625.00	2,132,312	2,633,202	1,631,423	2.50	652,569
2021	7,406,959.82	2,222,088	2,744,067	4,662,893	3.50	1,332,255
2022	3,591,869.37	359,187	443,562	3,148,307	4.50	699,624
	15,263,454.19	4,713,587	5,820,831	9,442,623		2,684,448

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.5   17.59

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, 2022

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	23,987,694.00	1,199,385	793,126	23,194,568	9.50	2,441,533
	23,987,694.00	1,199,385	793,126	23,194,568		2,441,533

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.5   10.18

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 303.72 MISCELLANEOUS INTANGIBLE PLANT - CLOUD-BASED TSA SECURITY DIRECTIVE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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	2,507,817.63	250,782		2,507,818	4.50	557,293
	2,507,817.63	250,782		2,507,818		557,293

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.5 22.22

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, 2022

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	7,461	8,736			
	8,320.00	7,461	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, 2022

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	42,441	46,792			
1958	2,023.00	1,895	4,454	2,330-		
	46,587.00	44,336	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, 2022

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	9,159	13,814			
	13,156.00	9,159	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, 2022

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 20-L0.5						
NET SALVAGE PERCENT.. -5						
1963	403.00	349	423			
1964	224.00	193	235			
1973	3,406.00	2,752	7,408	3,832-		
	4,033.00	3,294	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, 2022

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 20-L0.5						
NET SALVAGE PERCENT.. -5						
1975	4,209.00	3,352	6,585	2,166-		
	4,209.00	3,352	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, 2022

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	66,185	68,546			
1943	3,000.00	3,016	3,150			
1947	11,000.00	10,862	11,550			
1950	14,536.00	14,164	15,263			
1951	28,111.00	27,267	29,517			
1952	15,110.00	14,589	15,866			
1953	1.00	1	1			
1956	163.00	154	171			
1957	953.00	899	1,000			
	144,896.00	144,214	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, 2022

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	23,969	24,716			
1943	48,609.00	48,862	51,039			
1944	8,137.00	8,143	8,544			
1947	46,907.00	46,319	49,252			
1948	6,861.00	6,746	7,204			
1949	591.00	578	621			
1952	264.00	255	277			
1953	89,945.00	86,446	94,442			
1954	4,566.00	4,368	4,794			
1955	1,810.00	1,723	1,902			
	243,551.00	240,347	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, 2022

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	943	967			
1967	89.00	87	93			
1980	12,421.00	9,786	13,042			
1981	3,557.00	2,751	3,735			
	185,448.00	190,450	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, 2022

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	19,125	19,596	21,245	37.22	571
1993	5,264.00	2,185	2,239	3,025	40.95	74
1994	400.00	161	165	235	41.90	6
1997	185.00	67	69	116	44.78	3
1998	628.00	218	223	405	45.74	9
2001	3,804.00	1,160	1,189	2,615	48.66	54
2007	58,502.94	12,904	13,222	45,281	54.56	830
	109,624.94	35,820	36,703	72,922		1,547

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 47.1 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, 2022

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-R3						
NET SALVAGE PERCENT.. 0						
1989	2,101,010.00	1,070,822	1,265,247	835,763	29.42	28,408
1990	45,791.00	22,720	26,845	18,946	30.23	627
1991	275,498.00	132,975	157,119	118,379	31.04	3,814
1992	41,905.00	19,653	23,221	18,684	31.86	586
1993	3,226.00	1,468	1,735	1,491	32.69	46
1994	13,262.00	5,851	6,913	6,349	33.53	189
1995	35,648.00	15,222	17,986	17,662	34.38	514
1998	2,475,159.00	950,461	1,123,032	1,352,127	36.96	36,584
1999	4,963.00	1,833	2,166	2,797	37.84	74
2000	32,811.00	11,637	13,750	19,061	38.72	492
2001	884,241.00	300,492	355,051	529,190	39.61	13,360
2002	242,899.00	78,901	93,227	149,672	40.51	3,695
2003	16,898.54	5,236	6,187	10,712	41.41	259
2004	74,234.66	21,875	25,847	48,388	42.32	1,143
2005	123.98	35	41	83	43.24	2
2008	290,921.56	67,785	80,092	210,830	46.02	4,581
2009	3,834.31	833	984	2,850	46.96	61
2010	12,998.94	2,621	3,097	9,902	47.90	207
2012	159,638.62	27,139	32,066	127,573	49.80	2,562
2014	426,776.29	58,968	69,675	357,101	51.71	6,906
2015	66,404.73	8,101	9,572	56,833	52.68	1,079
2017	173,824.60	15,587	18,417	155,408	54.62	2,845
2018	1,252,081.82	92,028	108,737	1,143,345	55.59	20,567
2021	285,370.88	7,040	8,318	277,053	58.52	4,734
2022	232,028.00	1,896	2,240	229,788	59.51	3,861
	9,151,549.93	2,921,179	3,451,565	5,699,985		137,196

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 41.5   1.50

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 352.00 WELLS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. IOWA 50-S3
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)
1989	8,933,762.00	5,594,322	6,157,778	2,775,984	18.69	148,528
1990	536,082.00	327,975	361,008	175,074	19.41	9,020
1991	2,005,008.00	1,196,990	1,317,550	687,458	20.15	34,117
1992	150,577.00	87,576	96,397	54,180	20.92	2,590
1993	182,892.00	103,480	113,902	68,990	21.71	3,178
1994	2,358.00	1,296	1,427	931	22.52	41
1998	6,327,524.00	3,042,274	3,348,690	2,978,834	25.96	114,747
2001	200,085.00	85,156	93,733	106,352	28.72	3,703
2003	44,802.88	17,357	19,105	25,698	30.63	839
2004	5,127,030.63	1,887,773	2,077,908	3,049,123	31.59	96,522
2005	3,853,067.17	1,343,950	1,479,312	2,373,755	32.56	72,904
2007	8,775,470.65	2,715,131	2,988,597	5,786,874	34.53	167,590
2009	831,368.14	224,303	246,895	584,473	36.51	16,009
2012	17,500.00	3,675	4,045	13,455	39.50	341
2018	3,328,509.28	299,566	329,738	2,998,771	45.50	65,907
2019	3,488,288.60	244,180	268,774	3,219,515	46.50	69,237
2020	4,552,032.47	227,602	250,526	4,301,506	47.50	90,558
2021	4,166,820.20	125,005	137,595	4,029,225	48.50	83,077
2022	5,094,164.23	50,942	56,073	5,038,091	49.50	101,780
	57,617,342.25	17,578,553	19,349,053	38,268,289		1,080,688

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.4 1.88

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 352.10 STORAGE LEASEHOLDS AND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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-S2.5						
NET SALVAGE PERCENT.. 0						
1989	1,210,800.00	681,571	768,282	442,518	24.04	18,408
1993	1.00	1	1			
1996	237,300.00	109,763	123,727	113,573	29.56	3,842
1997	1,589,979.00	710,578	800,980	788,999	30.42	25,937
1998	492,327.00	212,237	239,239	253,088	31.29	8,088
1999	5,093.00	2,114	2,383	2,710	32.17	84
2002	2,991.00	1,094	1,233	1,758	34.89	50
2004	1,020.52	338	381	640	36.76	17
2014	400,000.00	61,744	69,599	330,401	46.51	7,104
	3,939,511.52	1,779,440	2,005,825	1,933,687		63,530

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 30.4 1.61

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 352.20 RESERVOIRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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-S2.5						
NET SALVAGE PERCENT.. 0						
1996	1,679,184.00	776,707	826,240	852,944	29.56	28,855
1998	1,999,907.00	862,140	917,121	1,082,786	31.29	34,605
1999	6,003.00	2,492	2,651	3,352	32.17	104
2000	476,341.00	190,017	202,135	274,206	33.06	8,294
2002	2,997,731.00	1,096,090	1,165,991	1,831,740	34.89	52,500
2004	1,212,371.25	402,071	427,712	784,659	36.76	21,345
2005	2,445,017.29	768,616	817,633	1,627,384	37.71	43,155
2012	17,500.00	3,335	3,548	13,952	44.52	313
	10,834,054.54	4,101,468	4,363,031	6,471,024		189,171

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 34.2 1.75

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 352.30 NONRECOVERABLE GAS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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	4,057,952.00	2,191,984	2,700,486	1,357,466	27.59	49,201
1993	1.00			1	31.18	
1996	2,255,000.00	978,670	1,205,704	1,049,296	33.96	30,898
1998	62,449.00	25,136	30,967	31,482	35.85	878
2004	65,487.82	20,039	24,688	40,800	41.64	980
	6,440,889.82	3,215,829	3,961,845	2,479,045		81,957

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 30.2 1.27

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 353.00 LINES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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-S2.5						
NET SALVAGE PERCENT.. -15						
1989	2,521,353.00	1,632,189	1,703,700	1,195,856	24.04	49,744
1991	17,489.00	10,773	11,245	8,867	25.54	347
1993	1.00	1	1			
1998	3,853,629.00	1,910,450	1,994,153	2,437,520	31.29	77,901
1999	52,862.00	25,234	26,340	34,451	32.17	1,071
2003	7,841.06	3,145	3,283	5,734	35.82	160
2004	684,275.05	260,973	272,407	514,509	36.76	13,996
2005	504,360.29	182,333	190,321	389,693	37.71	10,334
2007	560,153.49	180,138	188,031	456,146	39.62	11,513
2018	1,333,513.81	125,474	130,971	1,402,570	50.50	27,774
2019	1,137,750.13	83,267	86,915	1,221,498	51.50	23,718
2020	116,919.92	6,111	6,379	128,079	52.50	2,440
2021	782.00	25	26	873	53.50	16
2022	1,344,670.40	14,057	14,673	1,531,698	54.50	28,105
	12,135,600.15	4,434,170	4,628,445	9,327,495		247,119

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.7   2.04

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, 2022

SURVIVOR CURVE.. IOWA 50-R3
NET SALVAGE PERCENT.. -10

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1989	3,547,382.00	2,324,103	2,088,050	1,814,070	20.22	89,717
1990	110,946.00	70,857	63,660	58,381	20.97	2,784
1991	139,186.00	86,596	77,801	75,304	21.72	3,467
1992	41,746.00	25,266	22,700	23,221	22.49	1,033
1993	3,141.00	1,848	1,660	1,795	23.26	77
1994	7,648.00	4,366	3,923	4,490	24.05	187
1995	116,370.00	64,388	57,848	70,159	24.85	2,823
1996	3,136.00	1,679	1,508	1,942	25.66	76
1997	19,089.09	9,877	8,874	12,124	26.48	458
1998	166,055.57	82,892	74,473	108,188	27.31	3,961
	4,154,699.66	2,671,872	2,400,497	2,169,673		104,583

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.7   2.52

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, 2022

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	2,721,993	2,445,528	2,124,641	20.22	105,076
	4,154,699.00	2,721,993	2,445,528	2,124,641		105,076

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.2   2.53

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, 2022

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	4,244,418	3,813,324	5,539,735	27.31	202,846
1999	94,722.00	45,533	40,908	63,286	28.15	2,248
2000	3,218,557.00	1,486,973	1,335,945	2,204,468	29.00	76,016
2001	1,699,551.00	753,037	676,554	1,192,952	29.86	39,952
2002	122,405.06	51,892	46,621	88,025	30.73	2,864
2008	131,264.60	40,112	36,038	108,353	36.11	3,001
2009	69,541.41	19,843	17,828	58,668	37.03	1,584
2010	20,130.52	5,332	4,790	17,354	37.96	457
2014	781,561.86	142,025	127,600	732,118	41.74	17,540
	14,640,514.36	6,789,165	6,099,608	10,004,958		346,508

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.9   2.37

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, 2022

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	2,104,978	1,891,181	3,120,672	29.00	107,609
2001	6,176,092.83	2,736,503	2,458,564	4,335,138	29.86	145,182
2004	2,147,487.86	827,255	743,233	1,619,004	32.49	49,831
2012	17,500.00	3,912	3,515	15,735	39.84	395
2013	767,326.56	155,645	139,836	704,223	40.78	17,269
2022	2,734,611.85	29,479	26,485	2,981,588	49.51	60,222
	16,399,249.42	5,857,772	5,262,814	12,776,360		380,508

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 33.6 2.32

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, 2022

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	614,175	551,795	972,970	29.86	32,584
2003	3,978.82	1,611	1,447	2,930	31.60	93
2004	29,546.20	11,382	10,226	22,275	32.49	686
2011	1,167,361.91	285,327	256,348	1,027,750	38.89	26,427
2016	42,248.74	5,893	5,294	41,180	43.66	943
2017	145,612.11	17,235	15,485	144,688	44.62	3,243
2020	779,535.40	42,188	37,903	819,586	47.54	17,240
2022	185,043.79	1,995	1,792	201,756	49.51	4,075
	3,739,476.97	979,806	880,290	3,233,135		85,291

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.9 2.28

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, 2022

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	41,820	37,572	248,474	42.69	5,820
	260,041.78	41,820	37,572	248,474		5,820

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 42.7 2.24

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 355.00 MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. IOWA 45-S2
NET SALVAGE PERCENT.. -10

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1989	3,473,015.20	2,392,359	2,535,214	1,285,103	16.82	76,403
1990	66,949.00	45,201	47,900	25,744	17.38	1,481
1991	21,410.00	14,152	14,997	8,554	17.96	476
1992	17,819.00	11,517	12,205	7,396	18.56	398
1993	1,785.00	1,127	1,194	770	19.18	40
1994	35.00	22	23	16	19.82	1
1995	9,858.00	5,909	6,262	4,582	20.48	224
1996	15,372.00	8,962	9,497	7,412	21.15	350
1998	1,090,120.00	597,695	633,385	565,747	22.57	25,066
1999	238,641.00	126,585	134,144	128,361	23.30	5,509
2000	1,704,161.55	872,297	924,385	950,193	24.06	39,493
2001	48,850.00	24,073	25,510	28,225	24.84	1,136
2002	198,196.98	93,795	99,396	118,621	25.64	4,626
2003	0.07					
2004	830,627.56	359,592	381,064	532,626	27.29	19,517
2005	1,791,619.55	737,939	782,004	1,188,778	28.15	42,230
2006	143,130.10	55,910	59,249	98,194	29.02	3,384
2007	4,611,549.49	1,701,030	1,802,604	3,270,100	29.91	109,331
2008	207,002.45	71,751	76,035	151,668	30.82	4,921
2009	993,447.65	322,013	341,242	751,550	31.74	23,678
2011	435,517.72	121,046	128,274	350,795	33.63	10,431
2012	17,500.00	4,453	4,719	14,531	34.59	420
2013	71,153.62	16,419	17,399	60,870	35.56	1,712
2015	10,072.05	1,842	1,952	9,127	37.52	243
2016	124,808.02	19,800	20,982	116,307	38.51	3,020
2017	124,297.12	16,681	17,677	119,050	39.51	3,013
2018	369,594.51	40,655	43,083	363,471	40.50	8,975
2019	76,345.99	6,532	6,922	77,059	41.50	1,857
2020	1,857,532.18	113,525	120,304	1,922,981	42.50	45,247
2021	9,662,801.94	354,267	375,422	10,253,660	43.50	235,716
2022	8,995,303.03	109,932	116,496	9,778,337	44.50	219,738
	37,208,515.78	8,247,081	8,739,540	32,189,827		888,636

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 36.2 2.39

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 356.00 PURIFICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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	95,804	60,076	86,863	15.66	5,547
1990	12,815.00	8,594	5,389	8,067	16.26	496
1992	15,940.00	10,217	6,407	10,330	17.53	589
1993	2,878.00	1,800	1,129	1,893	18.20	104
1995	73,881.00	43,769	27,447	50,128	19.61	2,556
1996	48,826.00	28,094	17,617	33,650	20.34	1,654
1998	3,081.00	1,662	1,042	2,193	21.88	100
2018	66,401.79	6,972	4,372	65,350	40.50	1,614
2020	28,191,885.97	1,644,658	1,031,326	28,570,154	42.50	672,239
2022	254,334.29	2,967	1,861	265,190	44.50	5,959
	28,809,985.05	1,844,537	1,156,666	29,093,818		690,858

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 42.1 2.40

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 357.00 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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	63,301	75,230	827	5.87	141
1992	5,980.00	4,670	5,550	430	7.67	56
1998	564,221.00	371,257	441,220	123,001	11.97	10,276
1999	56,329.00	35,793	42,538	13,791	12.76	1,081
2008	629,441.85	256,995	305,426	324,016	20.71	15,645
2009	63,256.08	24,092	28,632	34,624	21.67	1,598
2018	1,027,537.43	131,823	156,665	870,872	30.51	28,544
2020	2,250,170.09	160,730	191,020	2,059,150	32.50	63,358
2021	475,212.76	20,368	24,206	451,007	33.50	13,463
2022	113,567.00	1,623	1,929	111,638	34.50	3,236
	5,261,772.21	1,070,652	1,272,416	3,989,356		137,398

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.0   2.61

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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	50,185	51,976	10,407	10.85	959
1970	26,089.00	21,933	22,716	4,678	10.98	426
1974	183.00	151	156	36	11.46	3
1975	8,525.00	6,988	7,237	1,714	11.57	148
1976	14,557.00	11,868	12,291	2,993	11.67	256
1978	9,671.00	7,797	8,075	2,079	11.86	175
1981	1,017.00	805	834	234	12.11	19
1982	46,738.00	36,763	38,075	11,000	12.19	902
1985	20,155.00	15,529	16,083	5,080	12.39	410
1986	6,343.00	4,851	5,024	1,636	12.45	131
1987	6,731.00	5,107	5,289	1,778	12.51	142
1988	30,340.00	22,835	23,650	8,207	12.56	653
1991	27,819.00	20,386	21,113	8,097	12.70	638
1992	4,998.00	3,626	3,755	1,493	12.75	117
1993	42,483.00	30,499	31,587	13,020	12.79	1,018
1994	37,310.00	26,493	27,438	11,737	12.83	915
1995	45,530.00	31,962	33,103	14,704	12.86	1,143
1996	20,875.00	14,470	14,986	6,932	12.90	537
1997	22,876.00	15,651	16,209	7,810	12.93	604
2000	10,951.00	7,162	7,418	4,081	13.02	313
2001	30,731.00	19,750	20,455	11,813	13.05	905
2002	60,440.00	38,116	39,476	23,986	13.08	1,834
2004	6,103.00	3,692	3,824	2,584	13.12	197
2005	185,610.40	109,577	113,487	81,404	13.15	6,190
2006	961,819.17	553,320	573,064	436,846	13.17	33,170
2007	432,192.31	241,622	250,244	203,558	13.19	15,433
2008	892,383.17	483,268	500,513	436,490	13.21	33,042
2009	1,097,712.30	574,328	594,822	557,776	13.22	42,192
2010	113,303.89	56,980	59,013	59,956	13.24	4,528
2011	221,064.76	106,336	110,130	121,988	13.26	9,200
2012	71,983.47	32,957	34,133	41,450	13.27	3,124
2015	53,824.55	20,106	20,823	35,692	13.31	2,682
2016	484,828.69	164,867	170,750	338,320	13.32	25,399
2017	14,238.78	4,308	4,462	10,489	13.34	786
2018	5,604,150.24	1,463,616	1,515,843	4,368,515	13.35	327,230
2020	43,051.42	7,025	7,276	37,928	13.37	2,837
2021	86,705.20	9,073	9,397	81,644	13.37	6,107
2022	1,452,034.00	54,917	56,877	1,467,759	13.38	109,698
	12,254,779.35	4,278,919	4,431,605	8,435,913		634,063

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

NEWPORT
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5
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)
1965	1,500.00	1,230	1,348	227	12.79	18
1974	605,426.00	465,140	509,702	125,995	14.99	8,405
1977	711,173.00	533,480	584,589	162,142	15.61	10,387
1978	31,895.00	23,723	25,996	7,494	15.81	474
1979	16,085.00	11,864	13,001	3,889	15.99	243
1982	13,954.00	10,020	10,980	3,672	16.50	223
1984	270.00	190	208	75	16.80	4
1986	2,983.00	2,059	2,256	876	17.08	51
1987	2,143.00	1,464	1,604	646	17.20	38
1988	17,175.00	11,602	12,714	5,320	17.33	307
1989	83,518.00	55,779	61,123	26,571	17.44	1,524
1990	24,328.00	16,054	17,592	7,952	17.55	453
1991	59,235.00	38,609	42,308	19,889	17.65	1,127
1992	141,822.00	91,239	99,980	48,933	17.75	2,757
1993	26,244.00	16,656	18,252	9,304	17.84	522
1994	214,182.00	133,972	146,807	78,084	17.93	4,355
1995	37,880.00	23,335	25,571	14,203	18.02	788
1996	89,930.00	54,522	59,745	34,681	18.10	1,916
1997	169,271.00	100,916	110,584	67,150	18.17	3,696
1998	67,057.09	39,276	43,039	27,371	18.24	1,501
1999	164,083.00	94,281	103,313	68,974	18.31	3,767
2000	31,277.00	17,610	19,297	13,544	18.38	737
2001	48,710.00	26,838	29,409	21,736	18.44	1,179
2002	66,987.31	36,057	39,511	30,825	18.50	1,666
2003	0.04		0			
2004	12,320.82	6,297	6,900	6,037	18.61	324
2005	10,028.06	4,978	5,455	5,075	18.66	272
2006	47,617.22	22,899	25,093	24,905	18.71	1,331
2008	366,599.53	163,961	179,669	205,260	18.80	10,918
2009	253,147.32	108,576	118,978	146,827	18.84	7,793
2010	636,411.98	260,597	285,563	382,669	18.88	20,268
2011	60,719.61	23,600	25,861	37,895	18.92	2,003
2012	31,512.46	11,563	12,671	20,417	18.95	1,077
2014	53,287.83	16,942	18,565	37,387	19.02	1,966
2016	3,063,049.39	802,475	879,355	2,336,847	19.07	122,540
2017	2,859,549.08	658,904	722,029	2,280,497	19.10	119,398
2018	1,907,457.63	374,529	410,410	1,592,420	19.13	83,242

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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						
2019	167,922.77	26,783	29,349	146,970	19.15	7,675
2020	27,918.13	3,322	3,640	25,674	19.17	1,339
2021	71,870.99	5,369	5,883	69,581	19.19	3,626
	12,196,541.26	4,296,711	4,708,351	8,098,017		429,910
OTHER						
SURVIVOR CURVE.. IOWA 60-R2.5						
NET SALVAGE PERCENT.. -5						
1963	4,009.00	3,187	3,619	591	14.57	41
1968	527.00	396	450	104	17.08	6
1975	1,118.00	760	863	311	21.16	15
1999	21,103.00	7,789	8,844	13,314	38.91	342
	26,757.00	12,132	13,776	14,319		404
	24,478,077.61	8,587,762	9,153,732	16,548,249		1,064,377

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.5 4.35

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 362.00 GAS HOLDERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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	1,680,077	1,649,239	415,372	10.54	39,409
1974	815.00	775	761	217	11.31	19
1983	969.00	872	856	307	12.27	25
1991	1,017.00	857	841	379	12.77	30
1993	18,991.00	15,674	15,386	7,403	12.87	575
2006	362,872.63	239,783	235,382	200,065	13.26	15,088
2009	488,646.40	293,411	288,025	298,350	13.32	22,399
2015	53,824.55	23,059	22,636	41,954	13.40	3,131
2016	1,686,933.32	658,127	646,047	1,378,273	13.41	102,779
2017	221,486.45	76,862	75,451	190,333	13.42	14,183
	4,556,064.35	2,989,497	2,934,624	2,532,653		197,638
NEWPORT INTERIM SURVIVOR CURVE.. IOWA 60-R3 PROBABLE RETIREMENT YEAR.. 6-2042 NET SALVAGE PERCENT.. -20						
1977	5,551,294.00	4,829,026	6,167,553	493,999	15.35	32,182
1978	10,302.00	8,882	11,344	1,018	15.59	65
1994	72,915.00	52,568	67,139	20,359	18.08	1,126
1996	138,492.00	96,786	123,614	42,577	18.25	2,333
2006	900.36	498	636	444	18.90	23
2017	153,200.46	40,515	51,745	132,095	19.28	6,851
	5,927,103.82	5,028,275	6,422,031	690,494		42,580
OTHER SURVIVOR CURVE.. IOWA 60-R3 NET SALVAGE PERCENT.. -20						
2003	1,600.14	595	1,297	623	41.41	15
	1,600.14	595	1,297	623		15
	10,484,768.31	8,018,367	9,357,952	3,223,770		240,233

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.4 2.29

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.10 LIQUEFACTION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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 55-R2						
PROBABLE RETIREMENT YEAR.. 6-2036						
NET SALVAGE PERCENT.. -5						
1969	828,857.00	695,431	870,300			
1970	15,188.00	12,684	15,947			
1971	1,613.00	1,341	1,694			
1972	4,261.00	3,525	4,474			
1974	1,957.00	1,603	2,055			
1975	268.00	218	281			
1976	25,955.00	21,032	27,253			
1980	100,679.00	79,749	103,916	1,797	11.62	155
1986	715.00	544	709	42	12.09	3
1987	68,778.00	51,899	67,626	4,591	12.16	378
1990	86,886.00	63,912	83,280	7,951	12.34	644
1991	51,422.00	37,466	48,820	5,174	12.40	417
1992	77,450.00	55,884	72,819	8,504	12.45	683
1994	15,589.00	11,009	14,345	2,023	12.55	161
1995	2,211.00	1,543	2,011	311	12.60	25
1996	6,143.00	4,235	5,518	932	12.64	74
1997	132,937.00	90,460	117,873	21,711	12.68	1,712
1998	157,516.00	105,694	137,723	27,669	12.72	2,175
1999	78,997.00	52,215	68,038	14,909	12.76	1,168
2000	88,122.00	57,311	74,678	17,850	12.80	1,395
2001	284,485.00	181,866	236,978	61,731	12.83	4,811
2002	44,801.00	28,104	36,621	10,421	12.87	810
2003	131,666.14	80,960	105,494	32,756	12.90	2,539
2004	219,028.75	131,776	171,709	58,271	12.93	4,507
2005	46,627.74	27,392	35,693	13,266	12.96	1,024
2006	127,298.03	72,848	94,924	38,739	12.99	2,982
2007	8,445.29	4,700	6,124	2,743	13.01	211
2009	70,412.91	36,653	47,760	26,173	13.06	2,004
2012	72,983.52	33,244	43,318	33,315	13.13	2,537
2015	53,824.55	20,038	26,110	30,406	13.18	2,307
2016	402,787.76	136,343	177,660	245,267	13.20	18,581
2017	111,506.66	33,597	43,778	73,304	13.22	5,545
2019	55,575.58	11,916	15,527	42,827	13.25	3,232
2020	75,214.89	12,274	15,993	62,982	13.26	4,750
2021	461,522.51	47,999	62,544	422,054	13.28	31,781
	3,911,724.33	2,207,465	2,839,591	1,267,720		96,611

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.10 LIQUEFACTION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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 55-R2						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
1977	5,236,797.00	3,908,431	4,390,626	1,108,011	14.81	74,815
1978	16,348.00	12,103	13,596	3,569	15.00	238
1979	5,538.00	4,065	4,567	1,248	15.19	82
1984	21,919.00	15,370	17,266	5,749	16.05	358
1985	11,525.00	8,002	8,989	3,112	16.20	192
1986	14,148.00	9,722	10,921	3,934	16.35	241
1987	8,543.00	5,808	6,525	2,446	16.49	148
1989	21,759.00	14,461	16,245	6,602	16.76	394
1990	2,886.00	1,895	2,129	902	16.89	53
1991	51,784.00	33,575	37,717	16,656	17.01	979
1992	4,079.00	2,611	2,933	1,350	17.12	79
1993	16,196.00	10,222	11,483	5,523	17.24	320
1994	1,119.00	696	782	393	17.34	23
1996	186,692.00	112,594	126,485	69,542	17.54	3,965
1997	151,762.28	89,961	101,060	58,291	17.64	3,304
1998	390,938.46	227,725	255,820	154,665	17.72	8,728
1999	249,536.00	142,574	160,164	101,849	17.81	5,719
2001	180,788.00	99,056	111,277	78,551	17.97	4,371
2002	30,345.79	16,248	18,253	13,611	18.04	754
2004	76,018.79	38,642	43,409	36,410	18.18	2,003
2005	1,705.00	842	946	844	18.25	46
2006	28,555.27	13,659	15,344	14,639	18.31	800
2007	35,357.72	16,333	18,348	18,778	18.37	1,022
2008	62,378.35	27,739	31,161	34,336	18.43	1,863
2014	356,850.62	112,869	126,794	247,899	18.72	13,242
2017	3,561,611.76	817,759	918,648	2,821,044	18.83	149,816
2018	4,848,560.74	948,400	1,065,407	4,025,582	18.87	213,332
2019	174,662.05	27,751	31,175	152,220	18.90	8,054
2021	221,992.66	16,552	18,594	214,498	18.97	11,307
2022	6,562,936.00	169,796	190,744	6,700,339	19.00	352,649
	22,533,332.49	6,905,461	7,757,409	15,902,590		858,897
	26,445,056.82	9,112,926	10,597,000	17,170,310		955,508

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.0 3.61

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.20 VAPORIZING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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	19,097	19,422	486	1.63	298
1971	13,254.00	13,176	13,400	517	2.13	243
1972	2,368.00	2,338	2,378	109	2.39	46
1973	13,251.00	12,988	13,209	705	2.66	265
1974	2,259.00	2,198	2,235	137	2.93	47
1975	269.00	260	264	18	3.21	6
1976	386,664.00	370,574	376,879	29,118	3.49	8,343
1986	12,078.00	10,322	10,498	2,184	7.40	295
1987	177,462.00	149,266	151,806	34,529	7.89	4,376
1990	1,140,108.00	912,595	928,122	268,991	9.30	28,924
1991	181,570.00	142,962	145,394	45,254	9.72	4,656
1993	1.00	1	1			
1994	32,761.00	24,551	24,969	9,430	10.81	872
1995	11,181.00	8,239	8,379	3,361	11.12	302
2006	321,206.91	188,010	191,209	146,058	12.98	11,253
2015	53,824.46	20,254	20,599	35,917	13.41	2,678
2017	2,091,400.63	637,688	648,538	1,547,433	13.44	115,136
	4,458,618.00	2,514,519	2,557,302	2,124,247		177,740
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 40-R4						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
1977	60,825.00	57,815	38,498	25,368	3.79	6,693
1990	15,899.00	12,410	8,264	8,430	10.24	823
1991	4,866.00	3,714	2,473	2,636	10.88	242
1992	2,226.00	1,660	1,105	1,232	11.52	107
2002	180.00	103	69	120	16.71	7
2004	68,445.68	36,793	24,500	47,368	17.35	2,730
2011	1,113,015.02	443,088	295,045	873,620	18.75	46,593
2015	95,076.50	28,051	18,679	81,152	19.14	4,240

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.20 VAPORIZING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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	554,160	369,007	2,129,237	19.26	110,552
2020	2,967,835.97	356,216	237,199	2,879,029	19.37	148,633
2021	10,560.25	796	530	10,558	19.40	544
	6,718,208.96	1,494,806	995,368	6,058,751		321,164
	11,176,826.96	4,009,325	3,552,670	8,182,998		498,904

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.4 4.46

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.30 COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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	69,605	89,971			
1983	1,117.00	899	1,173			
1986	21,516.00	16,806	22,592			
1996	19,421.00	13,428	20,392			
2008	51,410.22	27,362	53,981			
2022	233,035.00	8,601	23,908	220,779	12.90	17,115
	412,186.22	136,701	212,017	220,779		17,115
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 35-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
1997	20,827.00	12,795	21,033	836	13.70	61
2003	178,502.00	94,501	155,342	32,085	15.33	2,093
2005	16,780.44	8,346	13,719	3,900	15.79	247
2014	1,385,829.26	434,295	713,900	741,220	17.30	42,845
2016	2,266,969.59	583,821	959,693	1,420,625	17.54	80,993
2017	497,806.37	112,672	185,212	337,485	17.65	19,121
2018	256,596.34	49,448	81,283	188,143	17.75	10,600
2020	121,183.04	14,188	23,322	103,920	17.93	5,796
2021	820,790.65	60,070	98,744	763,086	18.02	42,347
2022	13,113.00	334	549	13,220	18.10	730
	5,578,397.69	1,370,470	2,252,798	3,604,520		204,833
	5,990,583.91	1,507,171	2,464,815	3,825,299		221,948

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.2 3.70

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.40 MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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						
1969	461,537.00	428,825	351,598	133,016	5.75	23,133
1970	2,640.00	2,435	1,996	776	6.07	128
1971	9,831.00	8,996	7,376	2,947	6.41	460
1972	6,325.00	5,740	4,706	1,935	6.76	286
1974	1,327.00	1,183	970	423	7.49	56
1975	374.00	330	271	122	7.87	16
1985	3,662.00	2,919	2,393	1,452	11.19	130
1988	3,818.00	2,954	2,422	1,587	11.78	135
1990	33,747.00	25,570	20,965	14,469	12.09	1,197
2002	17,323.00	11,046	9,057	9,132	13.16	694
2006	28,273.59	16,405	13,451	16,237	13.31	1,220
2009	168,291.28	88,583	72,630	104,076	13.39	7,773
2013	151,561.74	65,793	53,944	105,195	13.45	7,821
2014	359,909.59	146,340	119,986	257,919	13.45	19,176
2017	1,203,718.97	365,774	299,902	964,003	13.48	71,514
2018	426,268.10	112,021	91,847	355,734	13.48	26,390
2020	366,277.42	60,131	49,302	335,289	13.49	24,855
2021	330,436.66	34,720	28,467	318,491	13.49	23,609
2022	1,919,653.00	72,039	59,066	1,956,570	13.49	145,039
	5,494,974.35	1,451,804	1,190,349	4,579,374		353,632
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 50-R4						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
1977	55,203.00	46,842	7,540	50,423	9.57	5,269
1988	5,884.00	4,225	680	5,498	15.12	364
1989	4,775.00	3,375	543	4,470	15.50	288
1990	13,736.00	9,553	1,538	12,885	15.86	812
1991	20,511.00	14,030	2,258	19,278	16.20	1,190
1992	3,371.00	2,268	365	3,174	16.51	192
2017	10,187,159.88	2,358,368	379,640	10,316,878	19.41	531,524
2018	154,590.07	30,537	4,916	157,404	19.42	8,105
2019	116,849.50	18,674	3,006	119,686	19.44	6,157

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.40 MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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						
2020	101,306.78	12,116	1,950	104,422	19.45	5,369
2021	188,716.81	14,180	2,283	195,870	19.46	10,065
2022	3,334,330.00	87,666	14,112	3,486,934	19.47	179,093
	14,186,433.04	2,601,834	418,832	14,476,923		748,428
	19,681,407.39	4,053,638	1,609,181	19,056,297		1,102,060

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.3 5.60

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.50 CNG REFUELING FACILITIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. IOWA 31-R3
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)
1981	19,620.00	18,800	20,601			
1982	9,560.00	9,076	10,038			
1983	1,563.00	1,470	1,641			
1984	40,443.00	37,657	42,465			
1985	1,466.00	1,351	1,539			
1986	7,018.00	6,392	7,369			
1990	63,479.00	54,655	63,703	2,950	5.58	529
1991	52,207.00	44,172	51,485	3,332	6.02	553
1992	19,707.00	16,360	19,068	1,624	6.49	250
1993	61,210.00	49,779	58,020	6,250	6.99	894
1994	348,384.00	277,067	322,936	42,867	7.52	5,700
1995	293,359.00	227,641	265,328	42,699	8.09	5,278
1996	228,151.00	172,482	201,037	38,522	8.68	4,438
1997	47,984.57	35,285	41,126	9,258	9.29	997
1998	28,835.82	20,579	23,986	6,292	9.93	634
1999	4,283.40	2,960	3,450	1,048	10.60	99
2002	1,300.00	804	937	428	12.74	34
2004	49,674.00	28,165	32,828	19,330	14.26	1,356
2012	117,630.32	39,803	46,392	77,120	21.01	3,671
2013	123,013.59	37,832	44,095	85,069	21.92	3,881
2014	1,532,406.79	423,544	493,663	1,115,364	22.84	48,834
	3,051,295.49	1,505,874	1,751,707	1,452,153		77,148

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.8 2.53

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.60 LNG REFUELING FACILITIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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	268,985	366,909			
1983	61,620.00	46,757	64,701			
1984	42,767.00	31,973	44,905			
1985	5,173.00	3,807	5,432			
1986	108.00	78	113			
1991	935.00	613	914	68	16.88	4
1992	113,889.00	72,999	108,805	10,778	17.53	615
1993	54,468.00	34,061	50,768	6,423	18.20	353
1994	38,218.00	23,284	34,704	5,425	18.89	287
1995	45,678.00	27,061	40,334	7,628	19.61	389
1996	13,387.00	7,703	11,481	2,575	20.34	127
1997	5,310.00	2,961	4,414	1,162	21.10	55
1999	8,483.00	4,418	6,585	2,322	22.68	102
	739,473.00	524,700	740,065	36,382		1,932

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.8 0.26

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 365.20 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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	67,559	70,370	23,724	21.15	1,122
1965	445,096.00	315,248	328,367	116,729	21.88	5,335
1966	469,977.00	328,293	341,955	128,022	22.61	5,662
1967	159,280.00	109,669	114,233	45,047	23.36	1,928
1968	20,603.00	13,980	14,562	6,041	24.11	251
1976	28,031.00	16,628	17,320	10,711	30.51	351
1977	12,082.00	7,032	7,325	4,757	31.35	152
1979	9,187.00	5,136	5,350	3,837	33.07	116
1981	5,959.00	3,193	3,326	2,633	34.81	76
1989	815,816.00	357,874	372,766	443,050	42.10	10,524
1990	401,012.00	170,883	177,994	223,018	43.04	5,182
1991	143,060.00	59,170	61,632	81,428	43.98	1,851
1992	13,749.00	5,512	5,741	8,008	44.93	178
2002	395,428.00	107,450	111,921	283,507	54.62	5,191
2003	1,181,773.75	305,689	318,410	863,364	55.60	15,528
2004	2,075,820.15	509,552	530,757	1,545,063	56.59	27,303
2009	184,208.96	33,060	34,436	149,773	61.54	2,434
	6,455,176.86	2,415,928	2,516,465	3,938,712		83,184

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 47.3 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, 2022

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	69,711	75,174	10,811	10.41	1,039
2004	898,180.86	287,580	310,118	588,063	37.39	15,728
2005	57,818.26	17,556	18,932	38,886	38.30	1,015
2016	504,088.49	58,197	62,758	441,330	48.65	9,072
	1,546,072.61	433,044	466,982	1,079,091		26,854

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 40.2 1.74

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 367.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. IOWA 70-R3
NET SALVAGE PERCENT.. -40

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1931	541.00	685	707	50	6.69	7
1964	631,743.00	626,564	646,687	237,753	20.41	11,649
1965	4,159,205.00	4,073,517	4,204,346	1,618,541	21.03	76,963
1966	3,249,729.00	3,141,195	3,242,080	1,307,541	21.67	60,339
1967	98,086.00	93,534	96,538	40,782	22.32	1,827
1968	4,871.00	4,581	4,728	2,091	22.98	91
1969	17,024.00	15,781	16,288	7,546	23.65	319
1972	18,881.00	16,721	17,258	9,175	25.72	357
1976	1,227,425.00	1,016,070	1,048,703	669,692	28.61	23,408
1977	4,968.00	4,039	4,169	2,786	29.35	95
1978	12,612.00	10,062	10,385	7,272	30.11	242
1980	34,127.00	26,182	27,023	20,755	31.64	656
1981	510,647.00	383,804	396,131	318,775	32.42	9,833
1982	162,214.00	119,389	123,223	103,877	33.20	3,129
1985	29,321.00	20,173	20,821	20,228	35.60	568
1986	17,437.00	11,711	12,087	12,325	36.42	338
1989	522,156.00	324,675	335,103	395,915	38.91	10,175
1990	139,805.00	84,581	87,297	108,430	39.75	2,728
1991	940.00	553	571	745	40.60	18
1993	136,072.00	75,330	77,749	112,752	42.32	2,664
1994	132,571.00	71,085	73,368	112,231	43.19	2,599
1995	1,514.00	785	810	1,310	44.07	30
2001	536,035.70	220,310	227,386	523,064	49.45	10,578
2002	255,592.00	100,396	103,620	254,209	50.36	5,048
2003	145,757.63	54,543	56,295	147,766	51.29	2,881
2004	102,958.14	36,632	37,809	106,332	52.21	2,037
2007	65,936.81	19,755	20,389	71,923	55.02	1,307
2009	4,600,512.66	1,204,414	1,243,096	5,197,622	56.91	91,331
2010	19,347,382.59	4,697,583	4,848,455	22,237,881	57.86	384,339
2011	8,045,641.26	1,800,647	1,858,478	9,405,420	58.81	159,929
2012	31,403,683.70	6,425,068	6,631,422	37,333,735	59.77	624,623
2013	48,073,769.43	8,912,973	9,199,230	58,104,047	60.73	956,760
2014	17,931,560.05	2,976,603	3,072,202	22,031,982	61.70	357,082
2015	5,312,454.39	778,774	803,786	6,633,650	62.67	105,850
2016	4,539,331.08	577,421	595,966	5,759,098	63.64	90,495
2017	3,119,026.03	336,231	347,030	4,019,606	64.61	62,213
2018	14,893,908.12	1,313,643	1,355,833	19,495,638	65.59	297,235
2019	9,883,982.95	679,978	701,817	13,135,759	66.56	197,352

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 367.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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						
2020	9,993,194.34	491,625	507,414	13,483,058	67.54	199,631
2021	5,441,231.52	161,039	166,211	7,451,513	68.52	108,749
2022	24,777,106.90	242,816	250,615	34,437,335	69.51	495,430
	219,580,954.30	41,151,468	42,473,126	264,940,210		4,360,905

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 60.8 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, 2022

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	889,447	1,135,384	867,243	38.91	22,288
1990	81,695.00	49,425	63,091	51,282	39.75	1,290
1991	2,019.00	1,187	1,515	1,312	40.60	32
2004	181.00	64	82	171	52.21	3
2013	480,239.39	89,037	113,656	558,679	60.73	9,199
	1,994,582.39	1,029,160	1,313,728	1,478,687		32,812

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 45.1 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, 2022

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	9,242,758	11,893,515	8,916,946	38.91	229,168
1990	75,414.00	45,625	58,710	46,870	39.75	1,179
1991	522.00	307	395	336	40.60	8
1993	8,713.00	4,824	6,207	5,991	42.32	142
	14,949,264.00	9,293,514	11,958,827	8,970,143		230,497

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.9 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, 2022

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	14,995,051	16,885,496	30,037,092	47.63	630,634
2000	64,133.00	27,526	30,996	58,790	48.54	1,211
2001	603.00	248	279	565	49.45	11
2003	382,180.95	143,014	161,044	374,009	51.29	7,292
2013	918,290.41	170,253	191,717	1,093,890	60.73	18,012
	34,881,341.36	15,336,092	17,269,532	31,564,346		657,160

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 48.0 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, 2022

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	6,535,950	7,506,282	16,946,373	51.29	330,403
	17,466,181.89	6,535,950	7,506,282	16,946,373		330,403

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 51.3 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, 2022

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	4,029,419	4,560,438	10,514,647	51.29	205,004
2004	7,746,047.21	2,756,013	3,119,216	7,725,250	52.21	147,965
2005	16,294.30	5,495	6,219	16,593	53.14	312
2013	83,391.98	15,461	17,499	99,250	60.73	1,634
	18,613,651.15	6,806,388	7,703,372	18,355,740		354,915

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 51.7 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, 2022

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	14,250,403	16,212,422	37,101,968	51.29	723,376
2004	30,150,968.21	10,727,594	12,204,587	30,006,768	52.21	574,732
	68,232,675.58	24,977,997	28,417,009	67,108,737		1,298,108

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 51.7 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, 2022

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	2,492,332	3,215,299	4,894,328	31.17	157,020
	7,723,454.21	2,492,332	3,215,299	4,894,328		157,020

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.2   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, 2022

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	13,260	16,167			
1966	25,913.00	23,185	28,504			
1967	5,028.00	4,460	5,531			
1977	45,443.00	35,801	49,987			
1987	26,938.00	17,601	29,632			
1992	77,606.00	44,664	85,367			
2002	11,991.00	4,838	10,955	2,235	31.66	71
2003	189,080.78	72,838	164,938	43,051	32.49	1,325
2004	12,068.68	4,426	10,022	3,254	33.33	98
2006	133,313.77	43,906	99,423	47,222	35.03	1,348
2012	33,883.82	7,231	16,374	20,898	40.30	519
2013	3,180,851.99	615,813	1,394,477	2,104,460	41.20	51,079
2014	106,367.62	18,463	41,809	75,195	42.11	1,786
2015	106,367.62	16,334	36,987	80,017	43.02	1,860
	3,969,550.28	922,820	1,990,173	2,376,332		58,086

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 40.9 1.46

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 374.20 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. IOWA 75-R3
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)
1900	208,257.00	205,398	208,257			
1952	1,813.00	1,393	1,813			
1956	11,140.00	8,232	11,140			
1960	200.00	141	200			
1962	100.00	69	100			
1963	3,425.00	2,334	3,425			
1964	750.00	505	750			
1968	9,669.00	6,152	9,669			
1971	2,507.00	1,524	2,507			
1974	3,304.00	1,910	3,304			
1975	3,640.00	2,068	3,640			
1976	804.00	449	804			
1977	10,277.00	5,629	10,277			
1978	6,845.00	3,678	6,845			
1979	1,589.00	837	1,589			
1980	1,565.00	808	1,565			
1981	8,720.00	4,409	8,720			
1982	1,039.00	514	1,039			
1983	252.00	122	252			
1984	764.00	361	764			
1985	4,779.00	2,209	4,779			
1986	3,752.00	1,692	3,752			
1987	9,733.00	4,280	9,733			
1988	3,902.00	1,672	3,902			
1989	74,994.00	31,278	74,994			
1990	10,006.00	4,060	10,006			
1991	185,065.00	72,940	185,065			
1992	64,966.00	24,851	64,966			
1993	29,877.00	11,082	29,877			
1994	43,236.00	15,525	43,236			
1995	112,714.00	39,149	112,714			
1996	18,109.00	6,072	18,109			
1997	35,832.00	11,591	35,832			
1998	15,125.00	4,709	15,125			
1999	23,933.00	7,161	23,933			
2000	14,758.00	4,237	14,758			
2001	52,915.00	14,541	52,915			
2002	123,008.00	32,293	123,008			
2003	301,674.10	75,458	301,674			

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 374.20 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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-R3						
NET SALVAGE PERCENT.. 0						
2009	2,201.96	385	2,019	183	61.89	3
2010	23,150.32	3,753	19,680	3,470	62.84	55
2013	455,790.26	56,336	295,417	160,373	65.73	2,440
	1,886,180.64	671,807	1,722,154	164,027		2,498

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 65.7   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, 2022

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-S0						
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	31,714	20,208	12,720	1.29	9,860
1958	3,307.00	3,116	1,985	1,322	2.02	654
1959	871.00	811	517	354	2.40	148
1960	6,983.00	6,430	4,097	2,886	2.77	1,042
1961	726.00	661	421	305	3.15	97
1962	2,742.00	2,466	1,571	1,171	3.52	333
1965	298.00	258	164	134	4.66	29
1990	25,470.00	14,518	9,251	16,219	15.05	1,078
1993	1,907.00	1,011	644	1,263	16.44	77
2016	1,356,163.12	210,395	134,062	1,222,101	29.57	41,329
2018	83,178.16	9,292	5,921	77,257	31.09	2,485
	1,519,558.28	285,657	183,826	1,335,732		57,132

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 23.4   3.76

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, 2022

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 67-R3						
NET SALVAGE PERCENT.. -85						
1906	38.00	70	70			
1910	1,486.00	2,729	2,665	84	0.49	84
1911	33.00	61	61			
1912	33.00	60	59	2	0.70	2
1913	846.84	1,546	1,510	57	0.90	57
1914	389.00	707	690	30	1.14	26
1915	258.22	468	457	21	1.36	15
1916	203.00	367	358	18	1.61	11
1917	91.00	164	160	8	1.83	4
1918	420.08	753	735	42	2.08	20
1919	2,922.01	5,219	5,097	309	2.32	133
1920	530.00	943	921	60	2.57	23
1921	1,394.00	2,470	2,412	167	2.82	59
1922	3,143.77	5,549	5,419	397	3.08	129
1923	824.00	1,449	1,415	109	3.32	33
1924	92.28	162	158	13	3.58	4
1925	10,444.49	18,215	17,789	1,533	3.84	399
1926	3,628.84	6,303	6,156	557	4.10	136
1927	3,028.90	5,240	5,117	486	4.35	112
1928	3,793.38	6,535	6,382	636	4.61	138
1929	598.77	1,027	1,003	105	4.87	22
1930	2,212.07	3,779	3,691	401	5.13	78
1931	736.11	1,252	1,223	139	5.38	26
1932	1,984.41	3,362	3,283	388	5.64	69
1933	404.00	682	666	81	5.90	14
1934	1,805.82	3,034	2,963	378	6.16	61
1935	105.33	176	172	23	6.42	4
1936	4,979.21	8,292	8,098	1,114	6.69	167
1937	1,098.10	1,821	1,778	253	6.95	36
1938	6.66	11	11	1	7.23	
1939	832.67	1,368	1,336	204	7.51	27
1940	4,948.84	8,091	7,902	1,253	7.79	161
1941	2,439.72	3,969	3,876	637	8.08	79
1942	9,590.13	15,523	15,160	2,582	8.38	308
1943	988.17	1,591	1,554	274	8.69	32
1944	2,042.04	3,270	3,193	585	9.01	65
1945	1,205.00	1,919	1,874	355	9.33	38
1946	23,985.29	37,968	37,080	7,293	9.67	754
1947	16,463.98	25,903	25,297	5,161	10.02	515
1948	545.40	853	833	176	10.38	17
1949	16,924.00	26,281	25,666	5,643	10.76	524
1950	17,887.98	27,585	26,940	6,153	11.15	552
1951	21,257.02	32,546	31,785	7,540	11.55	653

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, 2022

SURVIVOR CURVE.. IOWA 67-R3
NET SALVAGE PERCENT.. -85

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1952	18,288.79	27,795	27,145	6,689	11.96	559
1953	24,932.17	37,595	36,715	9,410	12.39	759
1954	14,568.02	21,790	21,280	5,671	12.83	442
1955	12,004.04	17,806	17,389	4,818	13.28	363
1956	244,289.23	359,189	350,786	101,149	13.75	7,356
1957	594,438.11	865,978	845,719	253,992	14.24	17,837
1958	525,118.92	757,747	740,020	231,450	14.74	15,702
1959	768,621.85	1,098,300	1,072,606	349,344	15.25	22,908
1960	997,905.59	1,411,326	1,378,309	467,816	15.78	29,646
1961	1,279,087.08	1,789,925	1,748,050	618,261	16.32	37,884
1962	4,974.67	6,886	6,725	2,478	16.87	147
1963	1,778,638.69	2,433,969	2,377,027	913,455	17.44	52,377
1964	2,844,548.43	3,847,036	3,757,036	1,505,379	18.02	83,539
1965	2,942,418.08	3,931,494	3,839,518	1,603,955	18.61	86,188
1966	3,647,121.65	4,811,613	4,699,047	2,048,128	19.22	106,562
1967	2,837,391.13	3,694,788	3,608,350	1,640,824	19.84	82,703
1968	3,036,699.92	3,901,516	3,810,242	1,807,653	20.47	88,307
1969	3,384,253.20	4,288,257	4,187,935	2,072,933	21.11	98,197
1970	3,065,153.15	3,828,007	3,738,452	1,932,081	21.77	88,750
1971	2,894,920.40	3,561,851	3,478,523	1,877,080	22.44	83,649
1972	2,918,072.63	3,536,352	3,453,620	1,944,814	23.11	84,155
1973	3,625,904.83	4,325,135	4,223,950	2,483,974	23.80	104,369
1974	2,977,929.66	3,494,632	3,412,876	2,096,294	24.50	85,563
1975	2,900,641.60	3,347,052	3,268,749	2,097,438	25.21	83,199
1976	3,803,646.91	4,314,441	4,213,506	2,823,241	25.92	108,921
1977	4,337,635.82	4,832,751	4,719,691	3,304,935	26.65	124,013
1978	6,039,037.82	6,604,905	6,450,386	4,721,834	27.39	172,393
1979	8,194,318.15	8,794,777	8,589,027	6,570,462	28.13	233,575
1980	8,538,983.73	8,985,560	8,775,346	7,021,774	28.89	243,052
1981	7,547,532.11	7,783,777	7,601,679	6,361,255	29.65	214,545
1982	7,042,007.75	7,112,741	6,946,341	6,081,373	30.42	199,914
1983	7,271,090.25	7,187,549	7,019,399	6,432,118	31.20	206,158
1984	9,839,249.81	9,511,593	9,289,073	8,913,539	31.99	278,635
1985	10,764,113.92	10,170,877	9,932,933	9,980,678	32.78	304,475
1986	10,466,331.47	9,655,411	9,429,526	9,933,187	33.59	295,719
1987	9,528,105.90	8,576,767	8,376,117	9,250,879	34.40	268,921
1988	9,729,775.17	8,537,980	8,338,237	9,661,847	35.22	274,328
1989	12,204,374.64	10,433,111	10,189,032	12,389,061	36.04	343,759
1990	12,997,727.88	10,813,395	10,560,420	13,485,377	36.87	365,755
1991	14,474,840.15	11,706,469	11,432,601	15,345,853	37.71	406,944
1992	17,011,904.29	13,359,244	13,046,710	18,425,313	38.56	477,835
1993	18,888,240.48	14,384,037	14,047,528	20,895,717	39.42	530,079
1994	20,633,836.22	15,223,613	14,867,462	23,305,135	40.28	578,578

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, 2022

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 67-R3						
NET SALVAGE PERCENT.. -85						
1995	17,284,532.15	12,337,129	12,048,507	19,927,877	41.15	484,274
1996	16,715,533.16	11,529,606	11,259,875	19,663,861	42.02	467,964
1997	16,915,777.67	11,256,520	10,993,178	20,301,011	42.90	473,217
1998	18,876,819.06	12,097,719	11,814,698	23,107,417	43.79	527,687
1999	17,871,835.41	11,009,614	10,752,048	22,310,848	44.69	499,236
2000	16,434,681.94	9,720,210	9,492,810	20,911,352	45.58	458,784
2001	13,934,148.86	7,891,215	7,706,603	18,071,572	46.49	388,720
2002	12,945,020.05	7,005,832	6,841,933	17,106,354	47.40	360,894
2003	17,190,351.82	8,866,758	8,659,324	23,142,827	48.32	478,949
2004	16,299,606.63	7,992,993	7,806,000	22,348,272	49.24	453,864
2005	12,936,950.52	6,011,820	5,871,176	18,062,182	50.17	360,020
2006	16,100,008.40	7,068,282	6,902,922	22,882,094	51.10	447,790
2007	14,626,410.06	6,045,761	5,904,323	21,154,536	52.03	406,583
2008	8,439,780.90	3,267,145	3,190,711	12,422,884	52.98	234,483
2009	14,507,517.74	5,239,492	5,116,916	21,721,992	53.92	402,856
2010	4,351,213.15	1,457,326	1,423,232	6,626,512	54.87	120,767
2011	11,466,149.47	3,539,709	3,456,899	17,755,478	55.82	318,085
2012	17,096,675.88	4,824,665	4,711,794	26,917,056	56.78	474,059
2013	13,370,741.24	3,418,745	3,338,765	21,397,106	57.74	370,577
2014	14,730,793.42	3,375,974	3,296,994	23,954,974	58.70	408,092
2015	17,355,189.74	3,512,517	3,430,343	28,676,758	59.67	480,589
2016	21,710,291.04	3,812,772	3,723,574	36,440,464	60.64	600,931
2017	18,923,614.37	2,816,449	2,750,559	32,258,128	61.61	523,586
2018	22,810,439.53	2,777,559	2,712,579	39,486,734	62.59	630,879
2019	23,834,293.70	2,263,757	2,210,798	41,882,645	63.56	658,947
2020	19,757,953.86	1,342,197	1,310,797	35,241,418	64.54	546,040
2021	23,928,674.80	977,881	955,004	43,313,044	65.52	661,066
2022	19,972,210.67	270,094	263,775	36,684,815	66.51	551,568
	703,204,530.08	395,384,091	386,134,235	914,794,146		19,684,854

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.5   2.80

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, 2022

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 67-R3						
NET SALVAGE PERCENT.. -85						
1909	15,171.92	28,068	28,068			
1910	18,924.68	34,755	30,208	4,803	0.49	4,803
1911	107.55	198	172	27	0.47	27
1912	73.85	135	117	20	0.70	20
1913	20,767.30	37,904	32,946	5,474	0.90	5,474
1915	4,079.00	7,393	6,426	1,120	1.36	824
1916	10,173.75	18,369	15,966	2,855	1.61	1,773
1917	2,712.00	4,880	4,242	775	1.83	423
1918	4,687.00	8,402	7,303	1,368	2.08	658
1919	80.00	143	124	24	2.32	10
1920	9,605.00	17,088	14,853	2,916	2.57	1,135
1921	15,536.41	27,533	23,931	4,811	2.82	1,706
1922	37,159.00	65,584	57,005	11,739	3.08	3,811
1923	17,836.00	31,362	27,259	5,738	3.32	1,728
1924	5,562.00	9,740	8,466	1,824	3.58	509
1925	19,177.00	33,444	29,069	6,408	3.84	1,669
1926	36,316.09	63,074	54,823	12,362	4.10	3,015
1927	10,785.00	18,657	16,216	3,736	4.35	859
1928	13,629.16	23,479	20,408	4,806	4.61	1,043
1929	512.68	880	765	183	4.87	38
1930	56,369.00	96,298	83,701	20,582	5.13	4,012
1931	22,611.66	38,472	33,439	8,393	5.38	1,560
1932	220.60	374	325	83	5.64	15
1934	8,805.18	14,792	12,857	3,433	6.16	557
1935	5,966.83	9,981	8,675	2,364	6.42	368
1937	13,738.29	22,779	19,799	5,617	6.95	808
1939	5,571.02	9,151	7,954	2,352	7.51	313
1940	204.00	334	290	87	7.79	11
1941	2,385.00	3,880	3,372	1,040	8.08	129
1942	1,951.00	3,158	2,745	864	8.38	103
1945	4,704.00	7,491	6,511	2,191	9.33	235
1946	10,534.00	16,675	14,494	4,994	9.67	516
1947	133,674.27	210,314	182,801	64,496	10.02	6,437
1948	30,663.40	47,939	41,668	15,059	10.38	1,451
1949	5,025.44	7,804	6,783	2,514	10.76	234
1952	27,604.00	41,951	36,463	14,604	11.96	1,221
1953	8,981.10	13,542	11,770	4,845	12.39	391
1954	14,182.88	21,214	18,439	7,799	12.83	608
1955	83,723.80	124,188	107,942	46,947	13.28	3,535
1956	1,977,027.61	2,906,909	2,526,636	1,130,865	13.75	82,245
1957	537,549.99	783,103	680,660	313,807	14.24	22,037
1958	1,405,566.79	2,028,233	1,762,906	837,393	14.74	56,811
1959	1,333,005.20	1,904,760	1,655,585	810,475	15.25	53,146

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, 2022

SURVIVOR CURVE.. IOWA 67-R3
NET SALVAGE PERCENT.. -85

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1960	2,417,524.52	3,419,076	2,971,803	1,500,617	15.78	95,096
1961	2,065,022.94	2,889,746	2,511,718	1,308,574	16.32	80,182
1962	1,298,743.16	1,797,705	1,562,535	840,140	16.87	49,801
1963	2,820,805.50	3,860,117	3,355,148	1,863,342	17.44	106,843
1964	2,776,712.70	3,755,293	3,264,037	1,872,881	18.02	103,933
1965	2,559,974.71	3,420,495	2,973,036	1,762,917	18.61	94,730
1966	2,796,121.84	3,688,897	3,206,327	1,966,498	19.22	102,315
1967	1,920,831.87	2,501,265	2,174,057	1,379,482	19.84	69,530
1968	2,430,809.70	3,123,075	2,714,524	1,782,474	20.47	87,077
1969	2,044,666.70	2,590,839	2,251,913	1,530,720	21.11	72,512
1970	1,772,751.02	2,213,952	1,924,330	1,355,259	21.77	62,254
1971	2,739,194.38	3,370,249	2,929,363	2,138,147	22.44	95,283
1972	1,979,812.94	2,399,295	2,085,427	1,577,227	23.11	68,249
1973	2,349,121.43	2,802,133	2,435,567	1,910,308	23.80	80,265
1974	2,675,203.26	3,139,379	2,728,695	2,220,431	24.50	90,630
1975	1,602,030.21	1,848,583	1,606,757	1,356,999	25.21	53,828
1976	1,156,683.17	1,312,015	1,140,381	999,483	25.92	38,560
1977	1,169,960.47	1,303,504	1,132,984	1,031,443	26.65	38,703
1978	2,906,507.57	3,178,852	2,763,004	2,614,035	27.39	95,438
1979	2,907,127.91	3,120,155	2,711,986	2,666,201	28.13	94,781
1980	3,064,189.87	3,224,442	2,802,630	2,866,121	28.89	99,208
1981	4,858,075.88	5,010,139	4,354,728	4,632,712	29.65	156,247
1982	4,260,449.08	4,303,243	3,740,306	4,141,525	30.42	136,145
1983	4,289,416.52	4,240,133	3,685,452	4,249,969	31.20	136,217
1984	7,345,237.69	7,100,634	6,171,751	7,416,939	31.99	231,852
1985	5,441,494.56	5,141,600	4,468,992	5,597,773	32.78	170,768
1986	5,293,392.32	4,883,266	4,244,452	5,548,324	33.59	165,178
1987	3,764,678.86	3,388,793	2,945,481	4,019,175	34.40	116,836
1988	5,190,153.46	4,554,414	3,958,619	5,643,165	35.22	160,226
1989	5,079,560.68	4,342,346	3,774,294	5,622,893	36.04	156,018
1990	4,070,149.01	3,386,140	2,943,175	4,586,601	36.87	124,399
1991	7,827,885.95	6,330,771	5,502,599	8,978,990	37.71	238,106
1992	9,227,712.32	7,246,412	6,298,458	10,772,810	38.56	279,378
1993	9,950,514.03	7,577,655	6,586,369	11,822,082	39.42	299,901
1994	9,348,646.75	6,897,418	5,995,119	11,299,877	40.28	280,533
1995	12,319,839.38	8,793,495	7,643,157	15,148,546	41.15	368,130
1996	18,556,167.02	12,799,190	11,124,839	23,204,070	42.02	552,215
1997	19,387,197.32	12,901,114	11,213,430	24,652,885	42.90	574,659
1998	11,699,351.16	7,497,845	6,517,000	15,126,800	43.79	345,440
1999	11,787,786.84	7,261,648	6,311,701	15,495,705	44.69	346,738
2000	14,910,274.76	8,818,607	7,664,984	19,919,024	45.58	437,012
2001	13,523,650.64	7,658,741	6,656,848	18,361,906	46.49	394,965
2002	17,591,699.95	9,520,610	8,275,153	24,269,492	47.40	512,015

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, 2022

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 67-R3						
NET SALVAGE PERCENT.. -85						
2003	30,009,368.10	15,478,787	13,453,899	42,063,432	48.32	870,518
2004	18,472,504.72	9,058,538	7,873,528	26,300,606	49.24	534,131
2005	24,463,760.56	11,368,346	9,881,174	35,376,783	50.17	705,138
2006	19,846,959.00	8,713,281	7,573,436	29,143,438	51.10	570,322
2007	21,160,821.12	8,746,730	7,602,509	31,545,010	52.03	606,285
2008	20,580,851.80	7,967,105	6,924,873	31,149,703	52.98	587,952
2009	4,702,280.46	1,698,262	1,476,101	7,223,118	53.92	133,960
2010	16,824,292.46	5,634,859	4,897,724	26,227,217	54.87	477,988
2011	10,916,634.19	3,370,069	2,929,207	17,266,566	55.82	309,326
2012	18,094,439.06	5,106,233	4,438,251	29,036,461	56.78	511,385
2013	25,627,873.20	6,552,752	5,695,541	41,716,024	57.74	722,480
2014	21,486,386.65	4,924,207	4,280,037	35,469,778	58.70	604,255
2015	17,178,699.14	3,476,797	3,021,973	28,758,620	59.67	481,961
2016	18,902,601.79	3,319,684	2,885,413	32,084,400	60.64	529,096
2017	20,107,462.58	2,992,644	2,601,155	34,597,651	61.61	561,559
2018	36,968,771.74	4,501,576	3,912,693	64,479,535	62.59	1,030,189
2019	34,545,597.36	3,281,106	2,851,882	61,057,473	63.56	960,627
2020	50,462,741.93	3,428,035	2,979,590	90,376,483	64.54	1,400,317
2021	28,902,206.99	1,181,132	1,026,619	52,442,464	65.52	800,404
2022	54,506,793.03	737,123	640,695	100,196,872	66.51	1,506,493
	752,871,136.38	328,894,977	285,873,611	1,106,937,991		22,032,850

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 50.2   2.93

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 377.00 COMPRESSOR STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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	525,607	710,080	149,219	11.65	12,808
	818,380.00	525,607	710,080	149,219		12,808

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.7   1.57

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, 2022

SURVIVOR CURVE.. IOWA 55-R2.5
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	14,345	15,671	763	6.99	109
1950	2,585.00	2,806	3,065	166	7.24	23
1952	3,901.00	4,189	4,576	300	7.75	39
1953	7,573.00	8,086	8,833	633	8.02	79
1954	3,935.00	4,177	4,563	356	8.29	43
1955	13,406.00	14,146	15,454	1,304	8.57	152
1956	48,458.00	50,815	55,512	5,060	8.86	571
1957	30,840.00	32,129	35,099	3,451	9.16	377
1958	42,875.00	44,366	48,467	5,127	9.47	541
1959	36,309.00	37,299	40,747	4,639	9.80	473
1960	107,203.00	109,299	119,402	14,602	10.14	1,440
1961	66,657.00	67,429	73,662	9,659	10.49	921
1962	43,697.00	43,836	47,888	6,733	10.86	620
1963	66,875.00	66,511	72,659	10,935	11.24	973
1964	82,595.00	81,413	88,938	14,306	11.63	1,230
1965	155,371.00	151,698	165,720	28,494	12.04	2,367
1966	167,417.00	161,823	176,781	32,490	12.47	2,605
1967	95,011.00	90,886	99,287	19,477	12.91	1,509
1968	116,937.00	110,638	120,864	25,307	13.37	1,893
1969	103,704.00	96,987	105,952	23,678	13.85	1,710
1970	44,816.00	41,414	45,242	10,778	14.34	752
1971	104,156.00	95,042	103,827	26,368	14.85	1,776
1972	154,237.00	138,919	151,760	41,036	15.37	2,670
1973	127,698.00	113,477	123,966	35,656	15.90	2,243
1974	68,713.00	60,187	65,750	20,141	16.46	1,224
1975	47,726.00	41,196	45,004	14,654	17.02	861
1976	46,498.00	39,523	43,176	14,946	17.60	849
1977	209,427.00	175,157	191,347	70,437	18.20	3,870
1978	42,548.00	35,005	38,241	14,944	18.80	795
1979	159,252.00	128,777	140,680	58,385	19.42	3,006
1980	159,436.00	126,606	138,308	60,987	20.06	3,040
1981	122,295.00	95,335	104,147	48,722	20.70	2,354
1982	246,534.00	188,488	205,910	102,258	21.36	4,787
1983	244,704.00	183,360	200,308	105,572	22.03	4,792
1984	596,419.00	437,690	478,146	267,378	22.71	11,774
1985	270,231.00	194,077	212,016	125,773	23.40	5,375
1986	371,597.00	260,963	285,084	179,412	24.10	7,444
1987	307,786.00	211,184	230,704	154,028	24.81	6,208
1988	269,971.00	180,820	197,534	139,930	25.53	5,481
1989	300,385.00	196,208	214,344	161,137	26.26	6,136
1990	242,524.00	154,333	168,598	134,557	27.00	4,984
1991	539,949.00	334,397	365,306	309,630	27.75	11,158
1992	464,086.00	279,507	305,342	274,766	28.50	9,641

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, 2022

SURVIVOR CURVE.. IOWA 55-R2.5
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)
1993	273,224.00	159,775	174,543	166,987	29.27	5,705
1994	575,924.00	326,578	356,764	363,141	30.05	12,085
1995	674,159.00	370,324	404,554	438,145	30.83	14,212
1996	1,135,006.00	603,100	658,846	759,912	31.62	24,033
1997	864,430.00	443,615	484,619	595,918	32.42	18,381
1998	600,436.00	297,081	324,541	426,004	33.23	12,820
1999	781,675.00	372,185	406,587	570,507	34.05	16,755
2000	942,827.00	431,343	471,213	707,321	34.87	20,285
2001	85,371.00	37,447	40,908	65,806	35.70	1,843
2002	729,133.00	305,908	334,184	577,232	36.54	15,797
2003	572,105.94	229,100	250,276	464,856	37.38	12,436
2004	933,123.87	355,648	388,521	777,884	38.23	20,347
2005	448,837.66	162,294	177,295	383,752	39.09	9,817
2006	341,438.24	116,708	127,496	299,302	39.96	7,490
2007	921,693.36	296,831	324,268	827,849	40.83	20,276
2008	1,038,546.13	313,693	342,688	955,495	41.71	22,908
2009	1,015,593.77	286,448	312,925	956,567	42.59	22,460
2010	1,776,089.88	465,003	507,984	1,712,128	43.48	39,377
2011	1,339,039.11	323,194	353,067	1,320,732	44.38	29,760
2012	1,530,066.81	338,011	369,254	1,543,330	45.28	34,084
2013	4,230,410.08	847,986	926,367	4,361,646	46.18	94,449
2014	3,336,812.27	599,875	655,322	3,515,693	47.09	74,659
2015	810,260.45	128,720	140,618	872,208	48.01	18,167
2016	1,873,752.16	258,484	282,376	2,059,814	48.93	42,097
2017	845,963.08	99,020	108,173	949,281	49.85	19,043
2018	2,723,320.39	261,200	285,343	3,118,807	50.78	61,418
2019	1,166,726.01	87,242	95,306	1,363,102	51.71	26,361
2020	2,955,890.46	157,881	172,474	3,522,389	52.65	66,902
2021	4,744,404.91	153,126	167,279	5,763,227	53.58	107,563
2022	4,236,554.77	45,278	49,463	5,246,230	54.53	96,208
	49,852,298.35	13,777,641	15,051,134	47,264,239		1,086,633

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 43.5 2.18

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, 2022

SURVIVOR CURVE.. IOWA 50-R2
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)
1956	90,440.00	96,183	113,050			
1957	415.00	438	519			
1958	6,571.00	6,883	8,214			
1959	140.00	145	174	1	8.43	
1960	126,308.00	130,192	156,149	1,736	8.77	198
1961	9,016.00	9,217	11,055	215	9.11	24
1962	8,119.00	8,227	9,867	282	9.47	30
1963	18,246.00	18,324	21,977	830	9.83	84
1964	64,144.00	63,807	76,529	3,651	10.21	358
1965	56,664.00	55,828	66,959	3,871	10.59	366
1966	20,596.00	20,086	24,091	1,654	10.99	151
1967	7,958.00	7,681	9,212	736	11.39	65
1968	12,365.00	11,805	14,159	1,297	11.81	110
1969	35,068.00	33,104	39,704	4,131	12.24	338
1970	9,987.00	9,318	11,176	1,308	12.68	103
1971	29,853.00	27,517	33,003	4,313	13.13	328
1972	84,792.00	77,161	92,545	13,445	13.60	989
1973	28,044.00	25,191	30,214	4,841	14.07	344
1974	8,729.00	7,734	9,276	1,635	14.56	112
1975	11,764.00	10,276	12,325	2,380	15.06	158
1976	19,765.00	17,013	20,405	4,301	15.57	276
1977	47,198.00	40,012	47,989	11,008	16.09	684
1980	97,555.00	78,702	94,393	27,551	17.73	1,554
1981	36,714.00	29,096	34,897	10,996	18.30	601
1982	29,076.00	22,621	27,131	9,214	18.88	488
1983	6,973.00	5,320	6,381	2,335	19.48	120
1984	29,051.00	21,730	26,062	10,252	20.08	511
1986	84,113.00	60,309	72,333	32,808	21.32	1,539
1987	12,520.00	8,777	10,527	5,123	21.96	233
1988	31,995.00	21,917	26,287	13,707	22.60	607
1989	4,938.00	3,301	3,959	2,214	23.26	95
1990	2,738.00	1,784	2,140	1,282	23.93	54
1991	34,959.00	22,199	26,625	17,074	24.60	694
1992	1,830.00	1,130	1,355	932	25.29	37
1993	979.00	588	705	519	25.98	20
1996	28,701.00	15,692	18,821	17,055	28.13	606
2000	206,808.00	97,717	117,200	141,310	31.10	4,544
2001	40,639.00	18,420	22,093	28,706	31.87	901
2002	220.00	95	114	161	32.64	5
2004	302.39	119	143	235	34.21	7
2005	155,306.30	58,201	69,805	124,328	35.01	3,551
2009	128,042.07	37,580	45,073	114,980	38.26	3,005
2010	135,098.10	36,848	44,195	124,678	39.09	3,190

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, 2022

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						
NET SALVAGE PERCENT.. -25						
2011	59,276.55	14,923	17,898	56,198	39.93	1,407
2012	76,366.14	17,621	21,134	74,324	40.77	1,823
2013	2,090,302.12	437,396	524,602	2,088,276	41.63	50,163
2014	832,210.86	156,456	187,650	852,614	42.48	20,071
2015	898,196.35	149,325	179,097	943,648	43.35	21,768
2016	2,565,294.90	370,685	444,591	2,762,028	44.22	62,461
2017	3,101,387.30	380,695	456,597	3,420,137	45.09	75,851
2018	2,742,492.22	276,306	331,395	3,096,720	45.97	67,364
2019	2,555,967.51	200,643	240,646	2,954,313	46.86	63,046
2020	1,699,020.09	95,570	114,624	2,009,151	47.75	42,076
2021	1,485,514.96	50,136	60,132	1,796,762	48.65	36,932
2022	1,491,748.79	16,782	20,128	1,844,558	49.55	37,226
	21,362,517.65	3,384,826	4,057,325	22,645,822		507,268

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 44.6 2.37

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. IOWA 65-R1.5
NET SALVAGE PERCENT.. -110

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	2,730	2,898	24	4.27	6
1906	133.00	260	276	3	4.53	1
1908	1,175.00	2,277	2,417	50	5.01	10
1909	53.00	102	108	3	5.23	1
1910	2,807.67	5,401	5,733	163	5.46	30
1912	1,105.60	2,111	2,241	81	5.91	14
1913	35.43	67	71	3	6.13	
1914	170.72	323	343	16	6.37	3
1915	7.13	13	14	1	6.60	
1918	1,664.41	3,101	3,292	203	7.34	28
1919	2,237.74	4,150	4,405	294	7.60	39
1920	2,462.15	4,545	4,824	347	7.86	44
1922	784.36	1,434	1,522	125	8.40	15
1923	1,329.26	2,419	2,568	223	8.67	26
1924	5,469.48	9,906	10,515	971	8.94	109
1925	7,855.78	14,155	15,025	1,472	9.23	159
1926	4,572.61	8,198	8,702	900	9.51	95
1927	232.27	414	439	49	9.79	5
1928	2,761.01	4,899	5,200	598	10.08	59
1929	4,046.62	7,141	7,580	918	10.38	88
1930	4,569.31	8,020	8,513	1,083	10.67	101
1931	12,146.35	21,202	22,505	3,002	10.97	274
1932	7,589.08	13,171	13,980	1,957	11.28	173
1933	2,507.36	4,327	4,593	672	11.58	58
1934	3,282.62	5,633	5,979	915	11.89	77
1935	6,961.46	11,873	12,603	2,016	12.21	165
1936	5,810.08	9,849	10,454	1,747	12.53	139
1937	8,530.14	14,372	15,255	2,658	12.85	207
1938	14,474.44	24,233	25,722	4,674	13.18	355
1939	18,347.87	30,522	32,398	6,133	13.51	454
1940	12,820.67	21,187	22,489	4,434	13.85	320
1941	14,837.77	24,352	25,849	5,310	14.20	374
1942	22,039.62	35,923	38,131	8,152	14.55	560
1943	5,176.70	8,377	8,892	1,979	14.91	133
1944	17,992.51	28,908	30,684	7,100	15.27	465
1945	22,468.24	35,830	38,032	9,151	15.64	585
1946	47,115.36	74,557	79,139	19,803	16.02	1,236
1947	35,625.43	55,937	59,375	15,438	16.40	941
1948	17,632.27	27,463	29,151	7,877	16.79	469
1949	23,991.40	37,058	39,335	11,047	17.19	643
1950	20,894.57	31,998	33,964	9,915	17.60	563
1951	51,671.82	78,445	83,266	25,245	18.01	1,402
1952	13,269.00	19,964	21,191	6,674	18.43	362

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. IOWA 65-R1.5
NET SALVAGE PERCENT.. -110

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1953	79,278.96	118,180	125,443	41,043	18.86	2,176
1954	13,446.55	19,853	21,073	7,165	19.30	371
1955	15,426.24	22,552	23,938	8,457	19.75	428
1956	221,940.70	321,233	340,974	125,101	20.20	6,193
1957	205,110.95	293,825	311,881	118,852	20.66	5,753
1958	52,344.56	74,190	78,749	31,175	21.13	1,475
1959	277,125.61	388,484	412,358	169,606	21.61	7,848
1960	642,526.56	890,744	945,483	403,823	22.09	18,281
1961	741,048.63	1,015,360	1,077,757	478,445	22.59	21,180
1962	795,504.29	1,077,126	1,143,319	527,240	23.09	22,834
1963	968,673.41	1,295,632	1,375,253	658,961	23.60	27,922
1964	1,179,677.31	1,558,038	1,653,784	823,538	24.12	34,143
1965	1,389,622.29	1,811,973	1,923,325	994,882	24.64	40,377
1966	1,614,933.80	2,077,616	2,205,292	1,186,069	25.18	47,104
1967	1,628,549.26	2,066,712	2,193,718	1,226,235	25.72	47,676
1968	1,749,254.44	2,188,816	2,323,326	1,350,108	26.27	51,394
1969	1,997,570.25	2,463,370	2,614,752	1,580,146	26.83	58,895
1970	2,031,609.91	2,468,613	2,620,317	1,646,064	27.39	60,097
1971	2,306,742.44	2,760,444	2,930,082	1,914,077	27.96	68,458
1972	2,568,299.07	3,025,282	3,211,195	2,182,233	28.54	76,462
1973	2,718,692.74	3,150,652	3,344,270	2,364,985	29.13	81,187
1974	2,399,117.08	2,734,554	2,902,601	2,135,545	29.72	71,855
1975	2,189,117.76	2,452,762	2,603,492	1,993,655	30.32	65,754
1976	2,734,409.30	3,009,805	3,194,767	2,547,493	30.93	82,363
1977	3,272,931.45	3,537,064	3,754,428	3,118,728	31.55	98,850
1978	4,657,010.39	4,939,542	5,243,093	4,536,629	32.17	141,020
1979	5,748,365.48	5,980,013	6,347,504	5,724,064	32.80	174,514
1980	7,195,890.52	7,339,441	7,790,473	7,320,897	33.43	218,992
1981	7,315,027.89	7,307,340	7,756,400	7,605,159	34.08	223,156
1982	5,874,667.89	5,747,099	6,100,277	6,236,526	34.72	179,623
1983	6,473,638.28	6,194,942	6,575,641	7,018,999	35.38	198,389
1984	8,339,171.30	7,802,412	8,281,895	9,230,365	36.04	256,114
1985	10,083,628.88	9,216,265	9,782,634	11,392,987	36.71	310,351
1986	9,723,597.81	8,676,677	9,209,887	11,209,668	37.38	299,884
1987	10,119,775.67	8,807,909	9,349,183	11,902,346	38.06	312,726
1988	11,459,835.75	9,722,525	10,320,005	13,745,650	38.74	354,818
1989	15,037,565.10	12,422,502	13,185,905	18,392,982	39.43	466,472
1990	17,153,072.49	13,782,528	14,629,509	21,391,943	40.13	533,066
1991	18,661,923.19	14,572,816	15,468,362	23,721,677	40.83	580,986
1992	19,354,548.87	14,675,935	15,577,818	25,066,735	41.53	603,581
1993	21,484,580.20	15,797,934	16,768,768	28,348,850	42.24	671,138
1994	21,950,960.59	15,630,577	16,591,126	29,505,891	42.96	686,822
1995	20,303,949.40	13,985,360	14,844,805	27,793,489	43.68	636,298

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. IOWA 65-R1.5
NET SALVAGE PERCENT.. -110

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1996	23,045,528.70	15,337,537	16,280,078	32,115,532	44.40	723,323
1997	25,032,859.37	16,069,819	17,057,361	35,511,644	45.13	786,874
1998	24,159,346.64	14,939,319	15,857,388	34,877,240	45.86	760,515
1999	26,302,156.24	15,635,790	16,596,660	38,637,868	46.60	829,139
2000	23,078,593.98	13,167,469	13,976,652	34,488,395	47.34	728,525
2001	23,121,345.17	12,639,306	13,416,032	35,138,793	48.08	730,840
2002	24,233,724.82	12,660,110	13,438,115	37,452,707	48.83	767,002
2003	25,334,363.36	12,613,169	13,388,289	39,813,874	49.59	802,861
2004	23,648,102.81	11,200,546	11,888,856	37,772,160	50.34	750,341
2005	21,702,250.34	9,746,155	10,345,088	35,229,638	51.10	689,425
2006	22,751,785.18	9,651,307	10,244,411	37,534,338	51.87	723,623
2007	19,972,152.56	7,975,180	8,465,280	33,476,240	52.64	635,947
2008	19,847,826.62	7,432,039	7,888,762	33,791,674	53.41	632,684
2009	19,857,772.97	6,941,602	7,368,186	34,333,137	54.18	633,687
2010	10,680,779.52	3,464,482	3,677,386	18,752,251	54.96	341,198
2011	16,289,369.66	4,873,226	5,172,701	29,034,975	55.74	520,900
2012	18,461,646.05	5,052,048	5,362,512	33,406,945	56.53	590,960
2013	24,642,592.60	6,114,197	6,489,934	45,259,510	57.32	789,594
2014	27,229,519.71	6,061,291	6,433,777	50,748,214	58.11	873,313
2015	27,021,365.04	5,316,427	5,643,138	51,101,729	58.91	867,454
2016	29,453,632.54	5,033,567	5,342,896	56,509,732	59.71	946,403
2017	32,037,750.87	4,647,652	4,933,265	62,346,012	60.51	1,030,342
2018	33,824,888.32	4,021,847	4,269,002	66,763,263	61.32	1,088,768
2019	39,366,850.03	3,649,898	3,874,196	78,796,189	62.13	1,268,247
2020	38,919,168.87	2,577,772	2,736,185	78,994,070	62.95	1,254,870
2021	43,937,289.64	1,745,716	1,852,996	90,415,312	63.77	1,417,835
2022	35,590,853.91	471,614	500,596	74,240,197	64.59	1,149,407
	954,703,727.69	443,160,629	470,394,277	1,534,483,551		30,191,891

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 50.8   3.16

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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-L1						
NET SALVAGE PERCENT.. 0						
1910	64,426.44	64,426	64,426			
1943	29.00	26	17	12	2.81	4
1946	1,158.03	1,029	669	489	3.33	147
1947	735.00	649	422	313	3.50	89
1948	173.00	152	99	74	3.68	20
1950	160.00	139	90	70	4.03	17
1951	66.00	57	37	29	4.22	7
1952	381.00	325	211	170	4.40	39
1953	566.00	479	312	254	4.59	55
1954	326.00	274	178	148	4.77	31
1955	815.00	680	442	373	4.96	75
1956	19,496.93	16,150	10,505	8,992	5.15	1,746
1957	21,443.00	17,619	11,460	9,983	5.35	1,866
1958	14,099.78	11,496	7,478	6,622	5.54	1,195
1959	145.04	117	76	69	5.74	12
1960	7,237.98	5,805	3,776	3,462	5.94	583
1961	118,514.85	94,258	61,311	57,204	6.14	9,317
1962	169,556.67	133,724	86,982	82,575	6.34	13,024
1963	176,360.63	137,856	89,670	86,691	6.55	13,235
1964	174,578.69	135,241	87,969	86,610	6.76	12,812
1965	251,395.10	192,988	125,531	125,864	6.97	18,058
1966	151,760.32	115,440	75,089	76,671	7.18	10,678
1967	327,450.31	246,678	160,454	166,996	7.40	22,567
1968	271,864.29	202,811	131,920	139,944	7.62	18,365
1969	178,980.90	132,208	85,996	92,985	7.84	11,860
1970	309,350.80	226,238	147,158	162,193	8.06	20,123
1971	290,605.36	210,302	136,793	153,812	8.29	18,554
1972	671,329.45	480,672	312,657	358,672	8.52	42,098
1973	315,980.94	223,819	145,585	170,396	8.75	19,474
1974	398,466.09	279,058	181,516	216,950	8.99	24,132
1975	36,402.30	25,202	16,393	20,009	9.23	2,168
1976	1,501.02	1,027	668	833	9.47	88
1977	301,503.71	203,817	132,574	168,930	9.72	17,380
1978	288,106.78	192,360	125,122	162,985	9.97	16,348
1979	515,434.09	339,841	221,052	294,382	10.22	28,805
1980	470,329.44	306,029	199,059	271,270	10.48	25,885
1981	771,720.89	495,445	322,266	449,455	10.74	41,849
1982	621,957.20	393,699	256,085	365,872	11.01	33,231
1983	195,947.83	122,336	79,574	116,374	11.27	10,326
1984	253,176.22	155,703	101,278	151,898	11.55	13,151
1985	362,639.61	219,760	142,945	219,695	11.82	18,587
1986	758,418.15	452,267	294,181	464,237	12.11	38,335
1987	31,272.11	18,357	11,940	19,332	12.39	1,560

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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-L1						
NET SALVAGE PERCENT.. 0						
1988	483,011.11	278,857	181,385	301,626	12.68	23,788
1989	738,750.11	419,115	272,617	466,133	12.98	35,912
1990	1,194,883.79	665,945	433,170	761,714	13.28	57,358
1991	628,996.42	344,269	223,933	405,063	13.58	29,828
1992	1,134,824.80	609,401	396,390	738,435	13.89	53,163
1993	1,054,102.00	554,806	360,878	693,224	14.21	48,784
1994	1,059,351.95	546,276	355,330	704,022	14.53	48,453
1995	1,179,089.23	595,440	387,309	791,780	14.85	53,319
1996	1,251,072.12	617,617	401,734	849,338	15.19	55,914
1997	1,304,342.29	629,567	409,507	894,835	15.52	57,657
1998	1,403,612.34	661,101	430,019	973,593	15.87	61,348
1999	1,440,722.63	661,767	430,452	1,010,271	16.22	62,286
2000	1,273,954.67	570,311	370,964	902,991	16.57	54,496
2001	1,801,510.85	784,252	510,123	1,291,388	16.94	76,233
2002	1,899,162.31	803,972	522,950	1,376,212	17.30	79,550
2003	2,772,798.89	1,138,705	740,680	2,032,119	17.68	114,939
2004	2,883,270.72	1,147,542	746,428	2,136,843	18.06	118,319
2005	294,931.04	113,548	73,858	221,073	18.45	11,982
2006	6,419,429.38	2,383,727	1,550,516	4,868,913	18.86	258,161
2007	4,956,971.23	1,772,960	1,153,237	3,803,734	19.27	197,391
2008	3,992,437.41	1,369,406	890,742	3,101,695	19.71	157,367
2009	439,742.81	143,941	93,628	346,115	20.18	17,151
2011	1,979.67	580	377	1,603	21.21	76
2012	5,048,717.03	1,383,348	899,810	4,148,907	21.78	190,492
2013	3,580,551.06	909,460	591,566	2,988,985	22.38	133,556
2014	2,878,498.88	668,762	435,002	2,443,497	23.03	106,101
2015	3,100,226.68	650,025	422,814	2,677,413	23.71	112,923
2017	6,206,258.51	993,001	645,906	5,560,353	25.20	220,649
2018	4,603,849.83	613,831	399,272	4,204,578	26.00	161,715
2019	4,830,668.54	508,814	330,962	4,499,707	26.84	167,649
2020	2,443,899.74	186,543	121,338	2,322,562	27.71	83,817
2021	29,266,678.83	1,355,925	881,974	28,384,705	28.61	992,125
2022	2,894,781.53	45,361	29,505	2,865,277	29.53	97,029
	113,008,940.35	29,984,734	19,526,342	93,482,598		4,447,427

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.0 3.94

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.10 METERS - ELECTRIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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	899,377	1,425,093	271,845	7.52	36,150
	1,696,938.46	899,377	1,425,093	271,845		36,150

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.5   2.13

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.20 METERS - ERT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. IOWA 14-R0.5
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)
2006	8,309,121.42	5,400,929	4,979,944	3,329,177	4.90	679,424
2007	2,775,100.71	1,716,594	1,582,791	1,192,310	5.34	223,279
2008	5,895,840.23	3,449,067	3,180,223	2,715,617	5.81	467,404
2009	8,940,669.43	4,923,716	4,539,928	4,400,741	6.29	699,641
2010	573,874.12	295,953	272,884	300,990	6.78	44,394
2011	496,924.53	237,813	219,276	277,649	7.30	38,034
2012	628,798.68	277,571	255,935	372,864	7.82	47,681
2013	2,683,198.53	1,079,021	994,916	1,688,283	8.37	201,706
2016	0.22					
2017	436,112.85	103,734	95,648	340,465	10.67	31,909
2018	196,983.35	38,552	35,547	161,436	11.26	14,337
2019	1,381,474.71	211,172	194,712	1,186,763	11.86	100,064
2020	625,674.35	68,824	63,459	562,215	12.46	45,122
2021	6,206,202.29	412,278	380,143	5,826,059	13.07	445,758
2022	1,470,060.33	32,547	30,010	1,440,050	13.69	105,190
	40,620,035.75	18,247,771	16,825,416	23,794,620		3,143,943

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.6   7.74

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. IOWA 26-L1
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)
1956	6,139.96	5,467	1,249	4,891	2.85	1,716
1957	37,441.00	33,092	7,558	29,883	3.02	9,895
1958	18,120.95	15,891	3,629	14,492	3.20	4,529
1959	17,807.17	15,492	3,538	14,269	3.38	4,222
1960	5,957.43	5,142	1,174	4,783	3.56	1,344
1961	1,401.59	1,200	274	1,128	3.74	302
1964	82,750.46	69,065	15,774	66,976	4.30	15,576
1965	136,905.37	113,263	25,869	111,036	4.49	24,730
1966	127,561.94	104,601	23,891	103,671	4.68	22,152
1967	319,933.27	259,885	59,357	260,576	4.88	53,397
1968	316,560.96	254,711	58,176	258,385	5.08	50,863
1969	84.19	67	15	69	5.28	13
1970	202,003.24	159,427	36,413	165,590	5.48	30,217
1971	113,233.06	88,452	20,202	93,031	5.69	16,350
1972	671,866.92	519,407	118,632	553,235	5.90	93,769
1973	298,584.58	228,417	52,170	246,415	6.11	40,330
1974	214,238.39	162,161	37,037	177,201	6.32	28,038
1975	5,896.92	4,414	1,008	4,889	6.54	748
1976	255,224.00	188,866	43,137	212,087	6.76	31,374
1978	531,412.46	383,845	87,670	443,742	7.22	61,460
1979	1,074.42	767	175	899	7.45	121
1980	822,262.99	579,383	132,331	689,932	7.68	89,835
1981	881,116.31	612,711	139,943	741,173	7.92	93,582
1982	497,064.73	341,061	77,898	419,167	8.16	51,369
1983	442,127.24	299,117	68,318	373,809	8.41	44,448
1984	1,174.82	784	179	996	8.66	115
1985	918.50	604	138	780	8.91	88
1986	1,109,975.85	718,498	164,104	945,872	9.17	103,149
1988	1,008,122.72	632,012	144,351	863,772	9.70	89,049
1989	1,729,005.61	1,066,001	243,474	1,485,532	9.97	149,000
1990	2,267,450.92	1,373,554	313,719	1,953,732	10.25	190,608
1991	659,095.10	392,162	89,569	569,526	10.53	54,086
1992	1,367,484.77	798,406	182,355	1,185,130	10.82	109,531
1995	608,807.91	334,613	76,425	532,383	11.71	45,464
1997	225,924.86	118,785	27,130	198,795	12.33	16,123
1999	700,347.81	350,713	80,103	620,245	12.98	47,785
2000	1,895,559.61	924,445	211,142	1,684,418	13.32	126,458
2001	2,437,542.08	1,156,906	264,236	2,173,306	13.66	159,100
2002	78,803.23	36,340	8,300	70,503	14.01	5,032
2003	1,106.41	495	113	993	14.36	69
2004	4,271,037.88	1,851,324	422,841	3,848,197	14.73	261,249
2005	76,055.16	31,885	7,283	68,772	15.10	4,554
2007	1,390,594.65	542,332	123,868	1,266,727	15.86	79,869

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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 26-L1						
NET SALVAGE PERCENT.. 0						
2012	3,895,714.86	1,183,713	270,359	3,625,356	18.10	200,296
2013	2,999,717.13	849,160	193,948	2,805,769	18.64	150,524
2014	2,109,296.89	549,219	125,441	1,983,856	19.23	103,165
2015	2,333,393.18	550,144	125,652	2,207,741	19.87	111,109
2017	4,952,573.32	899,090	205,352	4,747,221	21.28	223,084
2018	3,070,080.75	466,407	106,527	2,963,554	22.05	134,402
2019	3,983,765.27	479,566	109,533	3,874,232	22.87	169,402
2021	11,024,942.07	589,393	134,616	10,890,326	24.61	442,516
2022	2,834,388.63	51,246	11,705	2,822,684	25.53	110,563
	63,039,649.54	20,393,701	4,657,901	58,381,749		3,856,770

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.1   6.12

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.10 METER INSTALLATIONS - ELECTRIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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-L3						
NET SALVAGE PERCENT.. 0						
2012	481,019.77	305,106	247,267	233,753	5.12	45,655
	481,019.77	305,106	247,267	233,753		45,655

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.1   9.49

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.20 METER INSTALLATIONS - ERT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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-R3						
NET SALVAGE PERCENT.. 0						
2006	888,188.47	671,080	752,683	135,505	4.40	30,797
2007	1,457,732.76	1,055,238	1,183,554	274,179	4.97	55,167
2008	1,071,021.59	738,405	828,194	242,828	5.59	43,440
2010	4,611,421.05	2,828,323	3,172,244	1,439,177	6.96	206,778
2020	566,940.00	76,854	86,200	480,740	15.56	30,896
2021	981,953.28	80,196	89,948	892,005	16.53	53,963
2022	2,436,752.58	66,328	74,393	2,362,360	17.51	134,915
	12,014,009.73	5,516,424	6,187,216	5,826,794		555,956

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.5 4.63

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 383.00 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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-S2						
NET SALVAGE PERCENT.. 0						
2003	1,944.74	987	984	961	17.23	56
2004	50,974.78	24,818	24,752	26,223	17.96	1,460
2005	111,010.40	51,668	51,530	59,480	18.71	3,179
2006	99,709.20	44,185	44,067	55,642	19.49	2,855
2007	106,166.87	44,590	44,471	61,696	20.30	3,039
2008	81,705.03	32,379	32,292	49,413	21.13	2,339
2009	36,113.86	13,424	13,388	22,726	21.99	1,033
2010	82,233.28	28,500	28,424	53,809	22.87	2,353
2011	49,737.69	15,959	15,916	33,822	23.77	1,423
2012	155,612.57	45,839	45,716	109,897	24.69	4,451
2013	340,537.54	91,165	90,921	249,617	25.63	9,739
2014	169,400.03	40,753	40,644	128,756	26.58	4,844
2015	215,465.95	45,864	45,741	169,725	27.55	6,161
2016	177,698.56	32,849	32,761	144,938	28.53	5,080
2017	199,129.42	31,235	31,151	167,978	29.51	5,692
2018	322,261.36	41,343	41,232	281,029	30.51	9,211
2019	220,007.55	22,001	21,942	198,066	31.50	6,288
2020	134,038.69	9,574	9,549	124,490	32.50	3,830
2021	125,469.00	5,378	5,363	120,106	33.50	3,585
2022	141,552.00	2,023	2,018	139,534	34.50	4,044
	2,820,768.52	624,534	622,862	2,197,907		80,662

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.2 2.86

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, 2022

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 10-S6						
NET SALVAGE PERCENT.. 0						
2017	1,162,110.41	639,161	634,047	528,063	4.50	117,347
	1,162,110.41	639,161	634,047	528,063		117,347

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.5   10.10

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, 2022

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.. 0						
1989	18,825.00	15,863	18,825			
1990	9,104.00	7,575	9,104			
1991	18,219.00	14,952	17,975	244	5.38	45
1992	82,936.00	67,068	80,629	2,307	5.74	402
2005	9,866.13	5,528	6,646	3,220	13.19	244
2011	34,908.85	13,300	15,989	18,920	18.57	1,019
	173,858.98	124,286	149,168	24,691		1,710

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.4   0.98

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, 2022

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	22,135	25,765			
1990	252.00	201	252			
1991	21,291.00	16,681	21,291			
1993	4,866.00	3,660	4,866			
1994	7,658.00	5,637	7,658			
1995	2,254.00	1,622	2,254			
1996	2,372.00	1,667	2,372			
1997	12,952.00	8,875	12,952			
1998	4,440.00	2,965	4,440			
1999	2,715.00	1,765	2,715			
	96,424.00	77,067	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, 2022

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	1,186	1,225			
1985	40,398.00	38,944	40,398			
1986	1,347.00	1,292	1,347			
1987	1,633.00	1,559	1,633			
1990	606.00	567	606			
1991	11,895.00	11,053	11,895			
	72,671.00	70,168	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, 2022

SURVIVOR CURVE.. IOWA 48-S0
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)
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	569	572			
1930	177.00	181	186			
1936	33.00	32	35			
1937	236.00	228	248			
1938	945.00	904	992			
1939	107.00	102	112			
1940	95.00	89	100			
1941	1,344.00	1,253	1,411			
1942	511.00	472	537			
1943	3,058.00	2,800	3,188	23	6.15	4
1944	31.00	28	32	1	6.53	
1945	762.00	685	780	20	6.92	3
1946	193.00	172	196	7	7.31	1
1947	6,781.00	5,979	6,808	312	7.69	41
1948	3,062.00	2,674	3,045	170	8.08	21
1949	8,343.00	7,214	8,214	546	8.47	64
1950	248.00	212	241	19	8.86	2
1951	10,081.00	8,543	9,727	858	9.26	93
1952	29,220.00	24,513	27,910	2,771	9.65	287
1953	11,532.00	9,573	10,900	1,209	10.05	120
1954	63.00	52	59	7	10.45	1
1955	17,854.00	14,509	16,520	2,227	10.85	205
1956	46,058.00	37,026	42,157	6,204	11.25	551
1957	3,819.00	3,036	3,457	553	11.66	47
1958	2,256.00	1,774	2,020	349	12.06	29
1959	1,537.00	1,195	1,361	253	12.47	20
1960	2,315.00	1,779	2,026	405	12.88	31
1961	7,174.00	5,447	6,202	1,331	13.29	100
1962	5,289.00	3,967	4,517	1,036	13.71	76
1963	7,300.00	5,410	6,160	1,505	14.12	107
1964	130,505.00	95,521	108,758	28,272	14.54	1,944
1965	269,207.00	194,568	221,530	61,137	14.96	4,087
1966	652,577.00	465,652	530,180	155,026	15.38	10,080
1967	28,680.00	20,195	22,994	7,120	15.81	450
1968	58,260.00	40,476	46,085	15,088	16.24	929
1969	24,007.00	16,453	18,733	6,474	16.67	388

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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						
1970	16,934.00	11,446	13,032	4,749	17.10	278
1971	22,591.00	15,053	17,139	6,582	17.54	375
1972	82,143.00	53,943	61,418	24,832	17.98	1,381
1973	232,553.00	150,476	171,328	72,853	18.42	3,955
1974	410,099.00	261,411	297,636	132,968	18.86	7,050
1975	35,275.00	22,138	25,206	11,833	19.31	613
1976	674,980.00	416,967	474,748	233,981	19.76	11,841
1977	71,654.00	43,559	49,595	25,642	20.21	1,269
1978	794,352.00	474,903	540,713	293,357	20.67	14,192
1979	34,675.00	20,381	23,205	13,204	21.13	625
1980	90,623.00	52,355	59,610	35,544	21.59	1,646
1981	357,050.00	202,605	230,681	144,222	22.06	6,538
1982	254,992.00	142,069	161,756	105,986	22.53	4,704
1983	29,883.00	16,336	18,600	12,777	23.01	555
1984	23,017.00	12,341	14,051	10,117	23.49	431
1985	50,285.00	26,432	30,095	22,704	23.97	947
1986	104,994.00	54,066	61,558	48,686	24.46	1,990
1987	70,133.00	35,362	40,262	33,378	24.95	1,338
1988	73,630.00	36,320	41,353	35,958	25.45	1,413
1989	92,458.00	44,597	50,777	46,304	25.95	1,784
1990	164,888.00	77,730	88,501	84,631	26.45	3,200
1991	128,634.00	59,203	67,407	67,659	26.96	2,510
1992	247,197.00	110,961	126,337	133,220	27.48	4,848
1993	153,692.00	67,241	76,559	84,818	28.00	3,029
1995	18,867.50	7,813	8,896	10,915	29.07	375
1996	88,757.78	35,705	40,653	52,543	29.61	1,775
1997	208,311.11	81,294	92,559	126,168	30.16	4,183
1998	372,706.61	140,965	160,499	230,843	30.71	7,517
1999	394,922.00	144,528	164,556	250,112	31.27	7,998
2000	181,017.49	63,990	72,857	117,211	31.84	3,681
2001	409,332.12	139,504	158,836	270,963	32.42	8,358
2002	196,636.83	64,521	73,462	133,007	33.00	4,031
2003	902,838.01	284,394	323,804	624,176	33.60	18,577
2004	4,167,289.98	1,258,001	1,432,328	2,943,326	34.20	86,062
2005	1,213,206.76	350,046	398,554	875,313	34.81	25,145
2006	1,174,466.05	322,689	367,406	865,783	35.44	24,430
2007	88,023.67	22,971	26,154	66,271	36.07	1,837
2008	240,284.56	59,343	67,566	184,733	36.71	5,032
2009	661,837.93	153,899	175,226	519,704	37.37	13,907
2010	716,899.25	156,194	177,839	574,905	38.04	15,113
2011	3,586,892.63	728,127	829,027	2,937,210	38.72	75,858
2012	8,807,856.10	1,653,124	1,882,205	7,366,044	39.42	186,861
2013	15,918,360.62	2,740,473	3,120,233	13,594,046	40.13	338,750

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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						
2014	9,852,047.32	1,538,767	1,752,001	8,592,649	40.86	210,295
2015	2,147,511.53	300,171	341,767	1,913,120	41.61	45,977
2016	895,762.62	110,120	125,380	815,171	42.38	19,235
2017	539,011.32	56,947	64,838	501,124	43.17	11,608
2018	11,924,207.41	1,048,585	1,193,893	11,326,525	43.98	257,538
2019	2,733,856.88	190,777	217,214	2,653,336	44.81	59,213
2020	1,032,966.80	52,419	59,683	1,024,932	45.68	22,437
2021	35,763,860.80	1,118,676	1,273,696	36,278,358	46.57	779,007
2022	25,863,856.71	277,273	315,696	26,841,354	47.51	564,962
	135,703,280.39	16,535,788	18,819,682	123,668,762		2,895,955

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 42.7 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, 2022

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	3,085,628	5,943,767	12,875,625	40.13	320,848
2014	667,063.96	104,187	200,693	499,724	40.86	12,230
2016	3,119,876.16	383,539	738,801	2,537,069	42.38	59,865
2017	216,141.91	22,836	43,989	182,960	43.17	4,238
2019	507,450.98	35,411	68,211	464,613	44.81	10,369
2022	599,800.97	6,430	12,386	617,405	47.51	12,995
	23,033,564.87	3,638,031	7,007,847	17,177,396		420,545

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 40.8 1.83

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 391.10 OFFICE FURNITURE AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2002	150,625.11	150,625	150,625			
2003	318,220.88	310,265	306,792	11,429	0.50	11,429
2004	900,507.14	832,969	823,645	76,862	1.50	51,241
2005	156,461.63	136,904	135,372	21,090	2.50	8,436
2006	86,514.39	71,374	70,575	15,939	3.50	4,554
2007	161,293.83	125,003	123,604	37,690	4.50	8,376
2008	262,606.27	190,390	188,259	74,347	5.50	13,518
2009	16,197.81	10,934	10,812	5,386	6.50	829
2010	610,092.81	381,308	377,040	233,053	7.50	31,074
2012	915,653.06	480,718	475,337	440,316	9.50	46,349
2013	1,290,726.41	613,095	606,233	684,493	10.50	65,190
2014	1,073,795.73	456,363	451,255	622,541	11.50	54,134
2015	526,655.66	197,496	195,285	331,371	12.50	26,510
2016	228,667.97	74,317	73,485	155,183	13.50	11,495
2017	614,673.90	169,035	167,143	447,531	14.50	30,864
2018	357,096.50	80,347	79,448	277,648	15.50	17,913
2019	221,915.36	38,835	38,400	183,515	16.50	11,122
2020	8,934,077.08	1,116,760	1,104,260	7,829,817	17.50	447,418
2021	917,853.23	68,839	68,068	849,785	18.50	45,934
2022	219,089.45	5,477	5,416	213,673	19.50	10,958
	17,962,724.22	5,511,054	5,451,054	12,511,670		897,344

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.9   5.00

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, 2022

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						
2016	0.14					
2018	5,918,084.50	5,326,276	5,132,655	785,430	0.50	785,430
2019	16,124,026.13	11,286,818	10,876,520	5,247,506	1.50	3,498,337
2020	15,425,944.20	7,712,972	7,432,591	7,993,353	2.50	3,197,341
2021	2,202,453.81	660,736	636,717	1,565,737	3.50	447,353
2022	4,588,618.07	458,862	442,181	4,146,437	4.50	921,430
	44,259,126.85	25,445,664	24,520,664	19,738,463		8,849,891

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.2   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, 2022

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	2,198,614.00	109,931	109,931	2,088,683	9.50	219,861
	2,198,614.00	109,931	109,931	2,088,683		219,861

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.5   10.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 391.22 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS TSA SECURITY DIRECTIVE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. 5-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)
2022	24,886,345.00	2,488,634	2,488,634	22,397,711	4.50	4,977,269
	24,886,345.00	2,488,634	2,488,634	22,397,711		4,977,269

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.5   20.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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			
1990	21,296.00	16,974	18,102			
1991	9,846.00	7,738	8,369			
1994	122,576.04	91,928	104,190			
1995	130,420.96	96,190	110,858			
1996	89,364.25	64,741	75,960			
1997	35,160.27	25,012	29,416	470	2.12	222
1998	117,858.83	82,302	96,792	3,388	2.32	1,460
1999	137,426.00	94,078	110,642	6,170	2.53	2,439
2000	22,937.00	15,372	18,078	1,418	2.75	516
2001	52,722.00	34,541	40,622	4,192	2.98	1,407
2002	76,191.06	48,771	57,358	7,404	3.21	2,307
2003	215,707.91	134,694	158,409	24,943	3.45	7,230
2004	340,901.61	207,293	243,790	45,976	3.70	12,426
2005	69,026.34	40,845	48,036	10,636	3.95	2,693
2006	50,063.92	28,806	33,878	8,676	4.20	2,066
2007	143,928.24	80,461	94,627	27,712	4.45	6,227
2008	370,999.30	201,338	236,786	78,563	4.70	16,716
2009	16,819.11	8,864	10,425	3,871	4.94	784
2010	1,505,950.82	770,006	905,576	374,482	5.18	72,294
2011	514,464.34	254,641	299,474	137,821	5.43	25,381
2012	2,905,836.56	1,386,982	1,631,179	838,782	5.70	147,155
2013	3,783,385.76	1,729,145	2,033,585	1,182,293	6.01	196,721
2014	1,458,675.13	631,381	742,544	497,330	6.38	77,951
2016	2,522.59	924	1,087	1,057	7.40	143
2018	26,401,558.61	7,163,944	8,425,257	14,016,068	8.85	1,583,736
2019	7,424,678.82	1,606,901	1,889,818	4,421,159	9.69	456,260
2020	4,979,112.48	787,833	926,542	3,305,704	10.58	312,448
2021	4,077,052.92	394,547	464,013	3,001,482	11.52	260,545
2022	2,309,447.91	75,498	88,790	1,874,241	12.50	149,939
	57,491,560.78	16,171,535	18,993,988	29,873,839		3,339,066

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.9   5.81

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 393.00 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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						
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, 2022

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	479,744	479,744	53,305	2.50	21,322
2001	494,438.80	425,217	425,217	69,222	3.50	19,778
2002	479,727.82	393,377	393,377	86,351	4.50	19,189
2003	546,830.13	426,528	426,528	120,302	5.50	21,873
2004	857,542.25	634,581	634,581	222,961	6.50	34,302
2005	731,631.02	512,142	512,142	219,489	7.50	29,265
2006	382,098.07	252,185	252,185	129,913	8.50	15,284
2007	212,322.56	131,640	131,640	80,683	9.50	8,493
2008	419,885.67	243,534	243,534	176,352	10.50	16,795
2009	236,537.99	127,731	127,731	108,807	11.50	9,461
2010	79,462.62	39,731	39,731	39,732	12.50	3,179
2011	286,576.95	131,825	131,825	154,752	13.50	11,463
2012	1,673,154.33	702,725	702,725	970,429	14.50	66,926
2013	944,985.54	359,095	359,095	585,891	15.50	37,799
2014	431,652.65	146,762	146,762	284,891	16.50	17,266
2015	360,232.86	108,070	108,070	252,163	17.50	14,409
2016	1,360,659.75	353,772	353,772	1,006,888	18.50	54,426
2017	1,829,211.61	402,427	402,427	1,426,785	19.50	73,168
2018	1,359,422.40	244,696	244,696	1,114,726	20.50	54,377
2019	1,205,137.21	168,719	168,719	1,036,418	21.50	48,205
2020	2,501,680.54	250,168	250,168	2,251,513	22.50	100,067
2021	1,157,247.24	69,435	69,435	1,087,812	23.50	46,290
2022	606,696.19	12,134	12,134	594,562	24.50	24,268
	18,690,183.15	6,616,238	6,616,238	12,073,945		747,605

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.2   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, 2022

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	44,220	40,539	9,370	1.71	5,480
1989	14,660.73	9,915	9,090	2,639	2.32	1,138
1991	9,842.00	6,477	5,938	1,936	2.66	728
1994	12,590.00	7,910	7,252	2,820	3.22	876
1995	39,380.00	24,342	22,316	9,188	3.41	2,694
1996	6,962.00	4,225	3,873	1,697	3.62	469
1998	55,390.23	32,348	29,655	14,657	4.05	3,619
1999	17,877.00	10,221	9,370	4,932	4.28	1,152
2002	123,482.15	65,791	60,314	38,472	5.01	7,679
2003	62,542.82	32,489	29,785	20,249	5.26	3,850
2004	90,637.99	45,827	42,012	30,498	5.52	5,525
2005	501,185.16	246,451	225,936	175,012	5.78	30,279
2006	301,830.38	144,234	132,228	109,236	6.04	18,085
2007	11,235.18	5,207	4,774	4,214	6.31	668
2008	38,685.54	17,393	15,945	15,003	6.57	2,284
2010	126,667.32	53,099	48,679	52,655	7.14	7,375
2011	702,206.22	282,753	259,216	302,549	7.45	40,611
2012	307,231.72	118,142	108,308	137,477	7.79	17,648
2013	499,901.68	181,832	166,696	233,225	8.18	28,512
2014	63,570.81	21,665	19,862	30,995	8.61	3,600
2018	5,863,004.82	1,232,028	1,129,470	3,560,934	11.06	321,965
2019	1,761,607.76	296,894	272,180	1,137,106	11.84	96,039
2020	1,698,007.01	210,105	192,615	1,165,791	12.68	91,939
2021	2,222,191.84	169,473	155,365	1,622,388	13.57	119,557
2022	1,520,970.34	38,937	35,696	1,181,080	14.52	81,342
	16,114,047.55	3,301,978	3,027,114	9,864,124		893,114

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.0   5.54

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 397.00 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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	31,488	31,488	18,230	5.50	3,315
	49,718.14	31,488	31,488	18,230		3,315

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.5   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, 2022

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	24,964	24,964	30,511	5.50	5,547
2019	4,161,405.21	1,456,492	1,456,492	2,704,913	6.50	416,140
2020	40,009.64	10,002	10,002	30,008	7.50	4,001
2021	29,219.34	4,383	4,383	24,836	8.50	2,922
	4,286,109.04	1,495,841	1,495,841	2,790,268		428,610

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.5   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, 2022

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	9,957.65	6,306	6,306	3,652	5.50	664
	9,957.65	6,306	6,306	3,652		664

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.5 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, 2022

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						
2007	53,241.79	53,242	53,242			
2008	153,747.85	148,623	146,269	7,479	0.50	7,479
2009	47,988.32	43,189	42,505	5,483	1.50	3,655
2010	188,278.98	156,899	154,414	33,865	2.50	13,546
2011	562,402.09	431,177	424,347	138,055	3.50	39,444
2012	264,234.41	184,964	182,034	82,200	4.50	18,267
2013	135,620.33	85,892	84,531	51,089	5.50	9,289
2014	386,407.83	218,966	215,497	170,911	6.50	26,294
2015	2,309.81	1,155	1,137	1,173	7.50	156
2018	94,316.84	28,295	27,847	66,470	10.50	6,330
2019	436,457.88	101,839	100,226	336,232	11.50	29,238
2020	4,370,817.24	728,484	716,944	3,653,873	12.50	292,310
2021	2,379,868.92	237,987	234,217	2,145,652	13.50	158,937
2022	2,837,201.21	94,564	93,066	2,744,135	14.50	189,251
	11,912,893.50	2,515,276	2,476,276	9,436,618		794,196

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.9   6.67

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 397.40 COMMUNICATION EQUIPMENT - TELEMETER MICROWAVE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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						
2007	61,119.78	61,120	61,120			
2010	71,274.98	59,396	58,171	13,104	2.50	5,242
2011	44,683.87	34,258	33,551	11,133	3.50	3,181
2013	177,219.97	112,239	109,923	67,297	5.50	12,236
2014	371,736.68	210,652	206,306	165,431	6.50	25,451
2015	76,277.45	38,139	37,352	38,925	7.50	5,190
2017	1,206,002.15	442,205	433,082	772,920	9.50	81,360
2019	2,763,921.53	644,906	631,602	2,132,320	11.50	185,419
2020	861,088.57	143,518	140,557	720,532	12.50	57,643
2022	336,271.84	11,208	10,977	325,295	14.50	22,434
	5,969,596.82	1,757,641	1,722,641	4,246,956		398,156

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.7   6.67

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 397.50 COMMUNICATION EQUIPMENT - TELEPHONE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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	209,296	209,296	36,935	1.50	24,623
2015	94,440.13	70,830	70,830	23,610	2.50	9,444
	340,671.19	280,126	280,126	60,545		34,067

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.8   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, 2022

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	3,633	3,633	726	2.50	290
	4,359.31	3,633	3,633	726		290

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.5   6.65

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 398.20 MISCELLANEOUS EQUIPMENT - KITCHEN

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

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	10,677	10,677	2,135	2.50	854
2020	16,052.40	2,675	2,675	13,377	12.50	1,070
	28,864.84	13,352	13,352	15,513		1,924

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.1   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, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
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, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
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, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
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			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Direct Testimony of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1700

December 29, 2023

EXHIBIT 1700 – DIRECT TESTIMONY – DECOUPLING / 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 early 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 2023 (“Base Year”) and the test year of November 1, 2024 to October 31, 2025 (“Test Year”);
- Propose modifications to the Company’s Decoupling mechanism along with routine updates to our weather adjustment rate mechanism (“WARM”) and Decoupling mechanism;
- Present the revenue requirement needed to yield NW Natural’s proposed overall rate of return (“ROR”) of 7.406 percent and return on equity (“ROE”) of 10.1 percent, and detail the increase required;
- Present the adjusted results of operations for the Test Year 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; and
- Present Company tariffs that are proposed to change due to the filing of this general rate case.

Q. Please provide a brief overview of the elements of revenue requirement, and why the determination of revenue requirement is principal 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 gas costs.[1] Operating and maintenance costs include payroll and other non-capital costs of serving customers. Revenue-related costs are primarily comprised of franchise taxes, but also include 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] The ROE is the amount of return that shareholders of the Company are expecting, given the Company's risk and how it compares to alternative investments.

Investment costs are related to our rate base, which includes a number of components, but is primarily net plant. Net plant represents the assets that have been acquired or constructed by the Company for purposes of serving its

[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.

customers, and which are being financed by the Company. Rate base also includes certain other items that are financed, such as gas in storage, cash working capital, and 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 of these components, represents the amount that requires financing from shareholders and bondholders.

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 have the opportunity to earn its authorized return on equity.

Q. Can you please describe how the testimony presented in this rate case establishes NW Natural's revenue requirement?

A. Yes. NW Natural's required return on rate base is established in the testimonies of Brody J. Wilson, Interim Chief Financial Officer, Vice President, Treasurer, Chief Accounting Officer and Controller (NW Natural/300, Wilson), and James M. Coyne and Jennifer E. Nelson, Senior Vice President and Assistant Vice President of

Concentric Energy Advisors, Inc., respectively (NW Natural/400, Coyne-Nelson). Mr. Wilson's testimony 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. Mr. Coyne and Ms. Nelson's testimony provides evidence of the returns that NW Natural should pay shareholders to continue to attract their investment in the Company through purchasing common stock.

Along with my description of taxes, the following pieces of testimony establish our operating expenses: Melinda B. Rogers, Vice President and Chief Human Resources and Diversity Officer (NW Natural/1000, Rogers); Cory A. Beck, Director of Customer Experience Services (NW Natural/1100, Beck); Daniel B. Kizer, Engineering Senior Director (NW Natural/500, Kizer); Wayne K. Pipes, Director of Facilities, Security and Emergency Management (NW Natural/600, Pipes); Jim R. Downing, Vice President and Chief Information Officer (NW Natural/700, Downing and NW Natural/800, Downing); Joe S. Karney, Vice President of Engineering and Utility Operations (NW Natural/900, Karney); Brody J. Wilson and Nikki R. Sparley, Treasury & Investor Relations Director (NW Natural/1300, Wilson-Sparley); Zachary D. Kravitz, Vice President of Rates and Regulatory Affairs, and Anna K. Chittum, Director of Renewable Resources (NW Natural/1500, Kravitz-Chittum); Tobin F. Davilla, Senior Manager of Financial Planning and Budget (NW Natural/1400, Davilla); and John J. Spanos, President of Gannet Fleming Valuation and Rate Consultants, Inc. (NW Natural/1600, Spanos).

Ms. Rogers' testimony 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 describes the costs associated with our customer communications. Mr. Kizer's testimony describes the operating expenses associated with the Company's safety and other regulatory compliance projects and programs. Mr. Pipes' testimony describes the operating expenses associated with the Company's facilities. Mr. Downing's two pieces of testimony 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 security directives, respectively. Mr. Karney's testimony describes the operating expenses associated with the Company's Meter Modernization Program. Mr. Wilson's and Ms. Sparley's testimony describe the Company's uncollectible expense. Mr. Kravitz's and Ms. Chittum's testimony describe operating expenses related to the Company's decarbonization efforts. Mr. Davilla's testimony describes all other operations and maintenance expense, and the total level of expense the Company will incur in the Test Year. Mr. Spanos's testimony 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.

With respect to our capital investments, the testimonies of Messrs. Kizer, Pipes, Downing and Karney describe the Company's recent projects related to NW

Natural's distribution and storage infrastructure, facilities, IT&S systems, and meter replacement, respectively. In conjunction with these pieces of testimony, my calculations demonstrate NW Natural's rate base that is used in serving our Oregon customers.

My testimony provides the summation of all these costs, and the calculations of revenue requirement in accordance with established methodologies for calculating the Company's revenue requirement for the Test Year.

II. BASE YEAR AND TEST YEAR

Q. Why did NW Natural use calendar year 2023 as the Base Year?

A. The Company chose calendar year 2023 as the Base Year because it is the most recent calendar year ahead of the Company's filing. While the last three months of 2023 shown in this filing are forecast data, the actual information will be available within a few months of our filing.

Q. Why did NW Natural choose the period of November 1, 2024 to October 31, 2025 as the Test Year in this case?

A. The Company chose the 12-month period from November 1, 2024 to October 31, 2025 because it best reflects the conditions expected when new rates from this rate case will be in effect. Given a filing date of December 2023 for the rate case, the normal timeline for the rate case process would mean that rates would be expected to be effective by November 1, 2024. This matches the Test Year used to calculate the revenue requirement in this case, and also coincides with the effective date of the annual PGA rate change, which minimizes the frequency of rate changes for customers.

III. DECOUPLING

Q. Please provide some background information on NW Natural's Decoupling mechanism.

A. NW Natural's Decoupling mechanism was put in place in 2002. The Decoupling mechanism removes the link between customer usage of natural gas and NW Natural's revenues across specific rate schedules. Under Decoupling, NW Natural is made financially indifferent to the consumption patterns and energy efficiency adoption of its residential and small- to mid-sized commercial customers.

The Decoupling mechanism is important because it allows NW Natural to support increased energy efficiency by allowing it to avoid the negative financial consequences that would otherwise occur as customers reduce their natural gas consumption. Furthermore, it helps ensure the Company recovers its cost of service consistent with the last general rate case that set customer rates.

Since Decoupling's inception in 2002,[3] NW Natural has collected a public purpose charge from decoupled rate classes to provide funding for enhanced energy efficiency programs developed and administered by Energy Trust of Oregon, as well as low-income energy efficiency activities, and low-income bill payment assistance.

NW Natural believes that the Decoupling mechanism serves a very important function and is committed to continuing its strong support of energy

[3] *In the Matter of the Application of Northwest Natural for the Public Purposes Funding and Distribution Margin Normalization*, Docket No. UG 143, Order No. 02-634 (Sept. 12, 2002).

efficiency measures and lowering the carbon emissions related to natural gas usage.

Q. What customers are currently covered by NW Natural's Decoupling mechanism?

A. The current Decoupling mechanism applies to residential, small commercial and mid-sized commercial firm sales customers taking service under rate schedules 2, 3 and 31, respectively.

Q. Will you describe the calculations that take place under the current Decoupling mechanism?

A. Yes, the monthly Decoupling calculation starts by determining the actual customer counts and usage for each customer class. Customer counts and usage are identified during the accounting close process that occurs for NW Natural each month. Counts and usage are determined by customer class and broken down into eight separate weather zones across Oregon.

Next, a weather adjustment is added or subtracted (depending on if weather was warmer or colder than normal) from the actual usage, resulting in an adjusted usage figure that represents usage under normal weather.[4] Last, the baseline

[4] The Decoupling weather adjustment uses the same normal degree days (25-year daily average) and statistical usage coefficients as the WARM program. For the shoulder months of November, April and May, the weather adjustment simply takes the WARM mechanism's calculated therms as the weather adjustment. In the months of December through March, the weather adjustment calculation is done in full, and is therefore identical to the WARM mechanism, except that it includes opt-outs. In colder than normal months, the weather adjustment will reduce therms. In warmer than normal months, the weather adjustment will increase therms.

usage[5] multiplied by the actual customer counts per class is subtracted from the total weather adjusted therms for the month, by customer class, to determine the non-weather therm variance for the month. The non-weather therms are then multiplied by the customer class margin rate to derive the Decoupling revenue. This Decoupling revenue represents the amount of revenues that are lost (or gained) from variations in usage per customer, for reasons other than weather. For an example of the current Decoupling calculation, please see NW Natural/1701, Walker.

Q. Please summarize Staff's concerns with the residential Decoupling mechanism from NW Natural's latest general rate case, UG 435.

A. Staff stated that new customers use less gas than established, or existing, customers on a weather normalized average use-per-customer ("UPC") basis. With declining UPC's and increasing number of customers, Staff was concerned that the Company may over-collect revenue.[6]

Q. Did Staff have a residential Decoupling modification proposal in UG 435 that would mitigate the risk of over-collection?

A. Yes. Staff proposed to bifurcate the residential Decoupling calculation between established customers and new customers that join the system after each rate case.[7] Staff requested that the Company reevaluate the UPCs for both new and

[5] Baseline usage is the use per customer used in rate spread calculations in rate cases.

[6] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Staff/1300, Scala at 19 (April 22, 2022).

[7] *Id*. at 24-28.

existing customer groups as part of each rate case filing and move the formerly new customer group into the established customer tranche for the purposes of calculating the Decoupling customer baselines.

Furthermore, Staff proposed that the mechanism be bifurcated after the difference between normal and actual heating degree days (i.e., after the weather adjustment during the December through March time period). The calculation would then take the difference in the weather adjusted therms and the Decoupling baseline that represents the UPC for each set of customers, existing and new.[8] Staff found that it would be "prudent for the Company to modify the decoupling mechanism to distinguish baseline use-per-customer for new versus existing customers. Doing so would more accurately reflect lower usage associated with new customers and mitigate the risk of over-collection from the Company."[9]

Q. What was the conclusion on Decoupling in UG 435?

A. The stipulating parties of the second partial stipulation agreed upon requirements that the Commission adopted in Order No. 22-388.

Q. What are the Decoupling requirements from the adopted second partial stipulation in UG 435?

A. As part of the second partial stipulation approved by Commission Order No. 22-388, the Company agreed to present UPC data that will include the Company's UPCs for existing residential customers and ten years of data to develop a UPC

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[8] *Id*. at 27.

[9] *Id*. at 26.

for customers taking service at new residential premises. Furthermore, the Company agreed to include the number of new residential customers forecasted within this rate case filing and to not argue in this rate case filing that implementing a two-part (existing customers/new customers) decoupling mechanism is not technically feasible.

Q. Has NW Natural presented UPC data in this case?

A. Yes. Please refer to NW Natural/1800, Wyman. Furthermore, as part of the proposal below, the UPC information that creates the Decoupling baselines can be viewed in NW Natural/1702, Walker.

Q. Has the Company included the number of new residential customers within this rate case filing?

A. Yes. The number of customers at the end of September 2023 was 635,748 residential customers. Between October 1, 2023 and the rate effective date (November 1, 2024), customers are forecasted to grow by 3,273 residential customers. For the Test Year, the Company is forecasting an additional 4,226 residential customers.

Q. Is the Company proposing any modifications to its Decoupling mechanism?

A. Yes. The Company proposes to bifurcate existing residential customers from new premise residential customers, as of the rate effective date of this docket (November 1, 2024), for the Decoupling calculation. As further described in NW Natural/1800, Wyman, the new premise residential customers' decoupling baseline was based off usage data from the five-year period of January 2018 to December 2022, and is 449.4 therms per year. Each new premise residential customer that gets added to the gas system after November 1, 2024 will be decoupled at this new baseline.

Q. Why is the Company proposing this modification to its Decoupling mechanism?

A. The Company agrees with Staff's recommendation from UG 435 to bifurcate two sets of residential customers due to the large difference in average usage between the two groups. Furthermore, the Company must comply with Oregon Department of Environmental Quality's Climate Protection Program ("CPP"). Under the CPP, the ODEQ requires that covered entities, such as NW Natural, reduce the greenhouse gas ("GHG") emissions for which the CPP deems them to be responsible. For NW Natural, these GHG emissions are the result of its sales customers' and transport customers' use of natural gas. One potential way the Company can comply with the CPP is if customers consume less natural gas. The Decoupling mechanism will hold the Company financially harmless while residential customers reduce their usage.

Q. How is NW Natural going to calculate a new premise residential customer's decoupling amounts?

A. NW Natural is going to calculate a new premise residential customer's decoupling amounts in the same way existing residential customers are decoupled today, except the new premise residential customer's actual usage will be compared to the lower baseline. Specifically, the Company's customer information system will provide our accounting department with a monthly report of new premise residential customer counts (residential customers that joined the system past the rate effective date), with that group's usage for the particular month. The actual usage will be compared with the new premise residential customer baseline to determine the therm usage to be decoupled. After the therm usage to be decoupled is identified, then that amount will be multiplied by the Schedule 2 per therm margin rate to determine the dollars to be decoupled. Because the new premise residential customer and existing residential customers are in the same class and on the same rate schedule, they will share the same decoupled amount per therm. Sharing the same decoupled amount per therm is appropriate because customers with higher usage will pay or receive more of the decoupling balance versus customers with lower use. Please see NW Natural/1703, Walker for an example of the proposed Decoupling calculation.

Q. How will weather adjustments during the winter months be made within the proposed Decoupling calculation?

A. The weather adjustments will be made in the proposed Decoupling calculation in the same way as the existing mechanism works today with one minor modification. The heating coefficient that converts heating degree days to therms will be a weighted average of the two sets of residential customers, existing and new premise.[10] This will decrease the weather adjustment because new premises do not have as strong of usage response to weather.

[10] See NW Natural/1702, Walker for the proposed coefficients.

Q. Does the coefficient used in the proposed Decoupling calculation impact the WARM?

A. Yes. The proposed Decoupling mechanism and WARM use the same heating statistical coefficient and normalized heating degree days (HDD) that are established in Mr. Wyman's models as discussed in NW Natural/1800, Wyman. 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 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/1702, Walker. The Company is not proposing any other modifications to the WARM.

Q. Does NW Natural have an updated Decoupling tariff that describes the modifications proposed in your testimony?

A. Yes. Please see NW Natural/1717, Walker for an updated Schedule 190 that reflects the proposed modifications.

III. <u>TEST YEAR REVENUE REQUIREMENT</u>

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 7.406 percent in the Test Year, a revenue requirement increase of $154.9 million, or 16.7 percent, 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 requested rate increase?

A. At current rate levels, the Company's ROE would be *negative* 0.10 percent. This is significantly below the 10.1 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/1704, Walker shows a side-by-side comparison of the results of operations from UG 435, the Company's last case in 2022[11] and the Test Year results from this rate case. Of particular note in this detailed comparison are four specific areas:

1) Line 6 shows a growth in margins (revenues net of cost of gas) of $24.5 million during the period;
2) Line 9 shows total operating and maintenance expenses increasing by $53.3 million;
3) Line 14 shows an increase in depreciation expense of $62.4 million; and
4) Line 19 shows an increase in net plant of $375.4 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.

[11] UG 435 was completed, and rates became effective November 1, 2022.

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.[12] See testimony NW Natural/1800, Wyman on cost-of-service schedule changes.

IV. 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 in the Test Year. This testimony and the related exhibits explain how these adjustments are reflected in the Test Year revenue requirement.

[12] Gas reserves are included in the weighted average cost of gas, but it has no effect on incremental revenue requirement.

Q. Have you prepared NW Natural's Oregon-allocated results of operations for the Test Year?

A. Yes. See NW Natural/1705, Walker for a summary of NW Natural's Oregon-allocated Results of Operations for the Test Year.

Q. Please describe Exhibit NW Natural/1705, Walker.

A. Column "a" of NW Natural/1705, 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/1705, Walker.

These adjustments are calculated as the difference between Base Year and Test Year volumes and customers multiplied by current rates.[13]

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, 2023, as well as a forecast for the remaining three months of 2023, multiplied by rates that were effective during the applicable months. This calculation is shown in NW Natural/1706, 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/1800, Wyman.

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 UPCs, effectively normalizing usage that will become the baseline for the decoupling mechanism at the rate effective date of this proceeding. The revenue requirement uses UPC's for existing residential customers at the 660

[13] Current rates became effective November 1, 2023, which include the most recent PGA and base rates from UG 435 and UG 462 (Renewable Natural Gas Adjustment Mechanism – Dakota City).

therms per year level while new premise residential customers use UPC's at 450 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/1705, Walker, and in detail on NW Natural/1707, Walker. The Company has proposed an adjustment that represents the difference between the Base Year and a three-year average ending September 30, 2023. 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/1707, Walker. Cost of service related to Schedule H, curtailment and entitlement revenues,[14] 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/1705, 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 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/1705, Walker in summary, and in detail in NW Natural/1708, Walker. The

[14] Curtailment and entitlement revenues are now given back to customers on Schedule 168 and do not impact miscellaneous revenues (see Order No. 20-364).

Direct Testimony of Brody J. Wilson and Nikki R. Sparley (NW Natural/1300, Wilson-Sparley) explains the uncollectible rate methodology.

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/1709, Walker/1-2*,* for Test Year in NW Natural/1709, Walker/3-4*,* and in summary at line 9 of NW Natural/1705, Walker. The Direct Testimony of Tobin F. Davilla (NW Natural/1400, 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/1705, 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/1710, 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 are included in NW Natural/1711, 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 of 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 of 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 Test Year income tax expense the same annual dollar amounts documented in Order No. 22-388?

A. Yes. The annual Plant EDIT amortization dollar amounts included in the Test Year income tax expense have remained the same as those documented in Order No. 22-388 providing the same annual benefit to customers.

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/1705, Walker. The supporting calculation is disclosed in NW Natural/1712, Walker. The Base Year property tax expense equals the Oregon property taxes paid (cash basis) in November 2023, 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 2021, 2022 and 2023. This average rate (1.375 percent) is then applied to net plant for year-end 2024 and 2025 to provide forecasted property tax assessments for 2024 and 2025, respectively. The forecasted assessments for the two years were then combined at a ratio of eight months of 2024 and four months of 2025 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/1705, Walker. This adjustment was calculated as follows for the different categories within Other Taxes, the detail of which is shown in NW Natural/1712, Walker:

- Franchise fees were derived by applying the effective rate of 2.309 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 0.430 percent multiplied by total revenues for both 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 Base Year and Test Year gross revenue was multiplied by 0.116% 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 last rate case proceeding, 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 2023, 2022, and 2021 amounts. The amounts for the 12-months ended September 30, 2023 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 88.36 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/1705, Walker and in detail in NW Natural/1713, 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, 2023, as a base and increasing plant accounts for capital expenditures from October 2023 through the end of the Test Year. Applicable account balances were then decreased for expected retirements. Gross asset balances multiplied by the proposed depreciation rates generate depreciation expense.

Q. Please describe how depreciation rates for each asset category were determined.

A. The Company's current depreciation rates were implemented as the same time as rates from our last rate case in UG 435. In this rate case, the Company is requesting to update depreciation rates. The Company is filing an updated depreciation study, NW Natural/1602, Spanos, performed by Gannett Fleming Valuation and Rate Consultants, LLC, and presented by its President, John J. Spanos, NW Natural/1600, Spanos. The updated depreciation study recommends an increase to depreciation expense of approximately $34.3 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.[15] 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/1714, Walker for

[15] FERC order in docket No. AI20-1-000, dated December 20, 2019.

the cloud-based assets that are projected to be in FERC 303.7 during the Test Year.

V. RATE BASE

Q. Describe the calculation of rate base.

A. The components of rate base are shown in NW Natural/1705, Walker at lines 18-28 and at NW Natural/1713, 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 (including an EDIT Rate Base Adjustment). These components are described in detail below.

Q. How were amounts for Utility Plant in Service calculated?

A. The Company starts with actual plant account balances as of September 30, 2023. We then forecast additions, retirements and transfers 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. 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. Consistent with mass-asset accounting, both the gross plant and accumulated depreciation amounts are lowered to reflect forecasted asset retirements. Detail on the various capital projects that are included in the plant projection are described in the Direct Testimonies of Daniel B. Kizer (NW Natural/500, Kizer), Wayne K. Pipes (NW Natural/600, Pipes), Jim

R. Downing (NW Natural/700, Downing and NW Natural/800, Downing), and Joe S. Karney (NW Natural/900, Karney).

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, 2023 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, 2023 balance as a proxy.
- **Gas Inventory –** This component of rate base includes a 13-month average of monthly averages ("AMA")[16] of stored gas supplies and is composed of two elements. The first element, cushion gas, assumes a continuation of the September 30, 2023 balance. The second element, working gas inventory, was derived by starting with October 2023 storage volume and price balances and then by modeling injections and withdrawals on a monthly basis through the end of the Test Year. Withdrawals reflected the PGA pattern of cycling the gas facilities.

[16] Average rate base balances were calculated by utilizing monthly forecast amounts to construct a 13-month AMA for all rate base components.

Injections of gas volumes were priced at a mix of forward prices and IHS Markit Ltd. forecasts in October 2023. Monthly balances of the two categories were projected for the Test Year to calculate the 13-month AMA included in rate base.

- **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 –** We compared the methodologies used in UG 388 and UG 435 to see which method most closely forecasted actuals through September 2023. To do this, we used actuals through September 2021 and forecasted the September 2023 values using the respective methodologies. The UG 435 method takes a 13-month AMA of month-over-month percent change ended September 30, 2021 and escalated to September 30, 2023 using this average change. The UG 388 method uses trended amounts based on 57 months of historical balances beginning September 30, 2021. The UG 388 forecasting method produced results most similar to actual Material and Supplies balances observed through September 30, 2023. Accordingly, the Test Year amount of $16.5 million is derived using trended amounts based on historic balances of actual Material and Supplies inventory. A 13-month AMA of balances is used for Test Year.

- **Cash Working Capital –** The Test Year amount for cash working capital, $22 million, was derived using a lead-lag study for days of cash led or lagged in calendar year 2022 (with certain noted exceptions) combined with the Test Year forecast of revenues and expenses. The lead-lag study is included as Exhibit NW Natural/1715, Walker. I discuss the Cash Working Capital component of rate base in greater detail next in my testimony.
- **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, 2022, and forecasting 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, 2023 through October 31, 2024. For the other utility federal and state deferred taxes, projections were made for various sub-categories of utility operations.
- **EDIT Rate Base Adjustment** – Due to re-measurement of deferred income taxes following the 2017 federal income tax reform, EDIT amortization is being flowed through to benefit customers. This amortization reduces the EDIT regulatory liability and has an increasing

effect on rate base. The adjustment included in the Test Year is $3.1 million to rate base and represents one-half of two years of amortization.

- **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.

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 booked and actual 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/1715, Walker. The results of the study show that NW Natural's average daily cash working capital requirements in Oregon for the Test Year is $22.16 million with a cash working capital factor of 2.9 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/1715, Walker/1 summaries the lead-lag study results for NW Natural. The net lag days, 10.6 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 2022. 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 month or about 15.5 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 2022 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 25.34 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/1715, Walker/2, the Company has an average operating revenue lag of 40.84 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 40.86 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 15.5 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 40.5 days (i.e., 15.5 days + 25 days = 40.5 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 11.4 days. Annual incentive pay is paid once a year, after the end of the year. For this analysis we used 2022 as the service period and July 2nd, 2022 as the midpoint date. The payment was made to employees on February 28, 2023 and therefore there is a 241 day lag. On a weighted average basis, the average payroll lag is 27.4 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 (HAS), 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 11.4 days. The second group was calculated by summarizing the invoice date and payment days for each of the vendors we pay for benefits costs. For the second group, we analyzed employee benefits data for the 12-months ended September 30, 2023 (rather than for calendar year 2022) because our current accounting system that went in service in September 2022 has better functionality than our previous accounting system. The Company's average employee benefits lag was determined to be 1.3 days. Therefore, the total lag for employee benefits is 12.8 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 171.8 days.

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 216 days. The Company does not forecast prepaid IT because it is not a usual revenue requirement item; therefore, the Test Year amount used for prepaid IT is calendar year 2022.

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 90.7 days.

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 110 different entities. The fees were analyzed based on service period and payment dates, which results in an average lag of 89.9 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 31,151 items, which results in a lag of 36.7 days. As with employee benefits costs, Other O&M was analyzed using data from October 1, 2022 to September 30, 2023.

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 was used for pay day payments. The total lag for payroll taxes is 76.6 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 days. For this analysis, we used calendar year 2023 figures. 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, 2022 thru June 30, 2023 tax year, taxes were paid on November 15, 2022. The total lead (or negative lag) for property taxes is 45 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 $22.16 million with a cash working capital factor of 2.9 percent. The Test Year revenue requirement amount is 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 (10.6 days) represents the average number of days the Company must fund operation expenses before they receive the appropriate revenues for those expenses. Please see Exhibit NW Natural/1715, Walker for a summary of the lead/lag study.

VI. 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/1716, 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 are fully considered in the PGA filing process, gas costs have not been an issue in general rate cases, and gas costs at the time of the rate case filing have been accepted as appropriate for inclusion in the general rate case revenue requirement.

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, 2023. 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/1400, 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.

VII. 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, Public Purposes Schedules, Adjustment Schedules, and Rate Schedules. NW Natural/1717, Walker includes the proposed Tariff changes.

Q. Which General Schedules are affected by the proposals in this case?

A. General Schedule X, related to NW Natural's line extension allowance, is discussed in detail in NW Natural/1900, Therrien. General Schedule H, related to compressed natural gas service, is being updated for the cost of capital inputs and is discussed in NW Natural/1800, Wyman.

Q. Which Public Purposes Schedule is affected by the proposals in this case?

A. Schedule 330, related to the Company's Residential Bill Discount Program, is discussed in detail in NW Natural/200, Tanaka.

Q. Which Adjustment Schedules are affected by the proposals in this case?

A. Schedule 167 shows the base rate changes proposed in this case. Schedule 175, 182, 196 and 197 are changing due solely to the billing determinants in this case. Schedule 190 captures the modifications proposed to the Company's Decoupling mechanism. Schedule 195 updates the routine inputs needed for the WARM. Schedule 198 modifies the RNG automatic adjustment clause, as fully described in NW Natural/1500, Kravitz-Chittum.

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	Schedule 33

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE

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UG 490

NW Natural

Exhibits of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS EXHIBITS 1701-1717

December 29, 2023

EXHIBITS 1701-1717 – DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS

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NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS EXHIBIT 1701

December 29, 2023

NW Natural
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Exhibit 1701
Example of Current Monthly Decoupling Calculation for February

Line	Description	Amount	
1	**Total Customer Counts by Schedule:**		
2	Schedule 2 - Residential	646,061	
3			
4	**Actual Therm Usage by Schedule:**		
5	Schedule 2 - Residential	67,187,973	
6			
7	**Schedule 2 Customer Counts by Weather Zone:**		
8	Albany	41,225	
9	Astoria	12,649	
10	Coos Bay	1,489	
11	Eugene	39,433	
12	Lincoln City	10,279	
13	Portland	442,654	
14	Salem	93,037	
15	The Dalles	5,295	
16			
17	**WEATHER ADJUSTMNET:**		
18			
19	**Schedule 2 Normal Degree Days by Weather Zone:**		
20	Albany	464.7	
21	Astoria	438.8	
22	Coos Bay	361.1	
23	Eugene	471.0	
24	Lincoln City	392.7	
25	Portland	451.4	
26	Salem	462.6	
27	The Dalles	558.5	
28			
29	**Schedule 2 Actual Degree Days by Weather Zone:**		
30	Albany	437.0	
31	Astoria	456.0	
32	Coos Bay	336.0	
33	Eugene	448.5	
34	Lincoln City	423.5	
35	Portland	515.5	
36	Salem	451.0	
37	The Dalles	672.0	
38			
39	**Schedule 2 Degree Day Variance by Weather Zone:**		
40	Albany	27.7	
41	Astoria	-17.2	
42	Coos Bay	25.1	
43	Eugene	22.5	
44	Lincoln City	-30.8	
45	Portland	-64.1	
46	Salem	11.6	
47	The Dalles	-113.5	
48			
49			
50	**Schedule 2 Therm Adjustment by Weather Zone:**		
51	Albany	170,469	Statistical Coefficient
52	Astoria	(32,582)	Schedule 2:
53	Coos Bay	5,576	0.14942
54	Eugene	132,503	
55	Lincoln City	(47,380)	
56	Portland	(4,236,684)	
57	Salem	161,630	
58	The Dalles	(89,779)	
59	TOTAL	(3,936,246)	
60			
61	**Schedule 2 Total Normalized Therms:**	**63,251,727**	
62			
63			
64	**DECOUPLING REVENUE CALCULATION:**		
65			

Line		Baseline Use Per Customer	Actual Customer Count
66			
67	**Schedule 2 - Residential**	95.1	646,061
68			
69			

Line	Baseline Total Usage	Normalized Therms	Variance	Margin Rate Per Therm	Decoupling Revenue to Defer
70					
71	61,414,559	63,251,727	(1,837,168)	$ 0.68627	$ (1,260,793)

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UG 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1702

December 29, 2023

NW Natural
UG 490 - Exhibit 1702
Decoupling and WARM Updates

Decoupling Usage Baselines

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
02- Existing Residential	Base	20.4	19.5	18.7	17.6	16.2	16.0	14.0	11.9	12.9	14.0	15.3	17.8	194.4
	Heat	86.1	75.6	58.6	39.1	16.3	5.7	2.7	2.1	4.1	26.0	60.9	88.6	465.8
	Total	106.4	95.1	77.3	56.7	32.6	21.7	16.7	14.0	17.0	40.0	76.2	106.5	**660.2**
02- New Premise Residential	Base	16.7	14.0	13.5	12.5	10.2	8.7	7.7	6.7	7.1	7.6	10.0	14.2	128.9
	Heat	58.3	49.9	40.1	27.4	12.6	5.3	1.7	1.5	4.0	19.7	41.1	58.9	320.5
	Total	75.0	63.9	53.5	39.9	22.8	13.9	9.5	8.2	11.0	27.4	51.2	73.1	**449.4**
03 - Small Commerical	Base	99.4	95.1	87.5	64.4	50.3	46.4	34.5	28.3	40.8	53.5	58.7	74.7	733.7
	Heat	360.1	322.7	261.6	191.3	109.5	70.0	63.6	54.7	49.7	121.3	262.9	372.4	2,239.8
	Total	459.5	417.9	349.1	255.7	159.8	116.4	98.1	83.1	90.5	174.8	321.5	447.1	**2,973.5**
31CSF - Commerical	Base	1,422.8	1,336.3	1,342.2	1,066.4	832.2	611.1	346.0	267.1	409.0	720.7	987.0	1,218.0	10,558.7
	Heat	3,729.5	3,416.8	2,842.3	2,199.3	1,293.4	837.5	715.6	623.6	604.8	1,424.9	2,784.0	3,804.8	24,276.6
	Total	5,152.4	4,753.1	4,184.5	3,265.6	2,125.6	1,448.6	1,061.6	890.7	1,013.7	2,145.7	3,771.0	5,022.8	**34,835.4**

WARM and Decoupling Coefficients

02 - Residential	0.15533
03 - Small Commercial	0.65004
31CFS - Commerical	6.69582

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NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS EXHIBIT 1703

December 29, 2023

NW Natural
UG 490
Exhibit 1703
Example of Proposed Monthly Decoupling Calculation for February

Line	EXISTING RESIDENTIAL CUSTOMERS		NEW PREMISE RESIDENTIAL CUSTOMERS	
1	**Total Customer Counts by Schedule:**		**Total Customer Counts by Schedule:**	
2	Schedule 2 - Residential	646,061	Schedule 2 - Residential	1,429
3				
4	**Actual Therm Usage by Schedule:**		**Actual Therm Usage by Schedule:**	
5	Schedule 2 - Residential	67,187,973	Schedule 2 - Residential	101,562
6				
7	**Schedule 2 Customer Counts by Weather Zone:**		**Schedule 2 Customer Counts by Weather Zone:**	
8	Albany	41,225	Albany	91
9	Astoria	12,649	Astoria	28
10	Coos Bay	1,489	Coos Bay	3
11	Eugene	39,433	Eugene	87
12	Lincoln City	10,279	Lincoln City	23
13	Portland	442,654	Portland	979
14	Salem	93,037	Salem	206
15	The Dalles	5,295	The Dalles	12
16				
17	**WEATHER ADJUSTMNET:**		**WEATHER ADJUSTMNET:**	
18				
19	**Schedule 2 Normal Degree Days by Weather Zone:**		**Schedule 2 Normal Degree Days by Weather Zone:**	
20	Albany	464.7	Albany	464.7
21	Astoria	438.8	Astoria	438.8
22	Coos Bay	361.1	Coos Bay	361.1
23	Eugene	471.0	Eugene	471.0
24	Lincoln City	392.7	Lincoln City	392.7
25	Portland	451.4	Portland	451.4
26	Salem	462.6	Salem	462.6
27	The Dalles	558.5	The Dalles	558.5
28				
29	**Schedule 2 Actual Degree Days by Weather Zone:**		**Schedule 2 Actual Degree Days by Weather Zone:**	
30	Albany	437.0	Albany	437.0
31	Astoria	456.0	Astoria	456.0
32	Coos Bay	336.0	Coos Bay	336.0
33	Eugene	448.5	Eugene	448.5
34	Lincoln City	423.5	Lincoln City	423.5
35	Portland	515.5	Portland	515.5
36	Salem	451.0	Salem	451.0
37	The Dalles	672.0	The Dalles	672.0
38				
39	**Schedule 2 Degree Day Variance by Weather Zone:**		**Schedule 2 Degree Day Variance by Weather Zone:**	
40	Albany	27.7	Albany	27.7
41	Astoria	-17.2	Astoria	-17.2
42	Coos Bay	25.1	Coos Bay	25.1
43	Eugene	22.5	Eugene	22.5
44	Lincoln City	-30.8	Lincoln City	-30.8
45	Portland	-64.1	Portland	-64.1
46	Salem	11.6	Salem	11.6
47	The Dalles	-113.5	The Dalles	-113.5
48				
49				
50	**Schedule 2 Therm Adjustment by Weather Zone:**		**Schedule 2 Therm Adjustment by Weather Zone:**	
51	Albany	177,212	Albany	392
52	Astoria	(33,871)	Astoria	(75)
53	Coos Bay	5,797	Coos Bay	13
54	Eugene	137,744	Eugene	305
55	Lincoln City	(49,254)	Lincoln City	(109)
56	Portland	(4,404,257)	Portland	(9,742)
57	Salem	168,023	Salem	372
58	The Dalles	(93,330)	The Dalles	(206)
59	TOTAL	(4,091,937)	TOTAL	(9,051)
60				
61	**Schedule 2 Total Normalized Therm:**	**63,096,036**	**Schedule 2 Total Normalized Ther**	**92,511**

Statistical Coefficient
Schedule 2:
0.1553

62
63
64 **DECOUPLING REVENUE CALCULATION:**

Line		Baseline Use Per Customer	Actual Customer Count		Baseline Use Per Customer	Actual Customer Count
66	**Sch. 2 - Residential**	95.1	646,061	**Sch. 2 - Residential**	63.9	1,429

67
68

Line	Baseline Total Usage	Normalized Therms	Variance	Margin Rate Per Therm	Decoupling Revenue to Defer	Baseline Total Usage	Normalized Therms	Variance	Margin Rate Per Therm	Decoupling Revenue to Defer
70	61,414,559	63,096,036	(1,681,478)	$ 0.91084	$ (1,531,557)	91,356	92,511	(1,155)	$ 0.91084	$ (1,052)

71
72
73 **DECOUPLED AMOUNT TO BE INCLUDED IN RESIDENTIAL DEFERRAL:**
74

Line		
75	**February Residential Decoupling Deferral Entry**	**$ (1,532,609)**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1704

December 29, 2023

NW Natural
UG 490 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2025
Base Year Twelve Months Ended December 31, 2023
Comparison of Test Year to Prior Rate Case
($000)

Line No.		UG 435 Order 22-388	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)	$485,621	$509,947	$24,325
2	Transportation	17,010	16,609	(400)
3	Decoupling	0	0	0
4	WARM	0	0	0
5	Miscellaneous Revenues	3,400	4,005	606
6	Total Operating Revenues	506,031	530,561	24,531
	Operating Revenue Deductions			
7	Uncollectible Accrual for Gas Sales	770	4,494	3,724
8	Other Operating & Maintenance Expenses	187,434	237,051	49,617
9	Total Operating & Maintenance Expense	188,204	241,545	53,341
10	Federal Income Tax	19,659	(2,432)	(22,091)
11	State Excise	12,888	4,863	(8,024)
12	Property Taxes	27,066	31,795	4,730
13	Other Taxes	29,747	34,701	4,954
14	Depreciation & Amortization	108,449	170,820	62,371
15	Total Operating Revenue Deductions	386,012	481,293	95,280
16	Net Operating Revenues	$120,018	$49,268	($70,750)
	Average Rate Base			
17	Utility Plant in Service	3,566,576	4,120,671	554,095
18	Accumulated Depreciation	(1,460,030)	(1,638,721)	(178,691)
19	Net Utility Plant	2,106,546	2,481,950	375,404
20	Aid in Advance of Construction	(7,268)	(6,499)	770
21	Customer Deposits	(292)	(755)	(463)
22	Gas Inventory	38,198	43,889	5,691
23	Leasehold Improvements	22,307	18,596	(3,711)
24	Materials & Supplies	15,396	21,810	6,414
25	Accumulated Deferred Income Taxes	(419,208)	(444,789)	(25,581)
26	Cash Working Capital	0	22,159	22,159
27	Total Rate Base	$1,755,679	$2,136,361	$380,682

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1705

December 29, 2023

NW Natural
UG 490 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2025
Base Year Twelve Months Ended December 31, 2023
Increase in Revenue Requirement
($000)

Line No.		Base Year at Present Rates (a)	Adjustments to Base Year (b)	Test Year at Present Rates (c)	Required Increase (d)	Proposed Total (e)
	Operating Revenues					
1	**Sale of Gas**	$910,328	$4,947	$915,275	$154,910	$1,070,185
2	**Transportation**	17,056	(447)	16,609	0	16,609
3	**Decoupling**	1,818	(1,818)	0	0	0
4	**WARM**	(12,610)	12,610	0	0	0
5	**Miscellaneous Revenues**	4,346	(341)	4,005	0	4,005
6	**Total Operating Revenues**	920,938	14,951	935,889	154,910	1,090,799
		516,117		530,561		685,471
	Operating Revenue Deductions					
7	**Gas Purchased**	404,822	506	405,328	0	405,328
8	**Uncollectible Accrual for Gas Sales**	3,088	1,406	4,494	757	5,251
9	**Other Operating & Maintenance Expenses**	197,722	39,330	237,051	0	237,051
10	**Total Operating & Maintenance Expense**	605,631	41,243	646,874	757	647,631
11	**Federal Income Tax**	16,399	(18,831)	(2,432)	28,962	26,530
12	**State Excise**	12,052	(7,189)	4,863	11,997	16,860
13	**Property Taxes**	27,868	3,927	31,795	0	31,795
14	**Other Taxes**	33,604	1,097	34,701	4,243	38,944
15	**Depreciation & Amortization**	112,729	58,091	170,820	0	170,820
16	**Total Operating Revenue Deductions**	808,284	78,337	886,621	45,959	932,580
17	**Net Operating Revenues**	$112,654	($63,386)	$49,268	$108,950	$158,219
	Average Rate Base					
18	**Utility Plant in Service**	3,608,816	511,855	4,120,671	0	4,120,671
19	**Accumulated Depreciation**	(1,464,792)	(173,930)	(1,638,721)	0	(1,638,721)
20	**Net Utility Plant**	2,144,025	337,925	2,481,950	0	2,481,950
21	**Aid in Advance of Construction**	(6,517)	19	(6,499)	0	(6,499)
22	**Customer Deposits**	(677)	(78)	(755)	0	(755)
23	**Gas Inventory**	63,623	(19,735)	43,889	0	43,889
24	**Leasehold Improvements**	21,314	(2,717)	18,596	0	18,596
25	**Materials & Supplies**	19,452	2,358	21,810	0	21,810
26	**EDIT Adjustment to Rate Base**	3,100	0	3,100	0	3,100
27	**Accumulated Deferred Income Taxes**	(438,056)	(9,833)	(447,889)	0	(447,889)
28	**Cash Working Capital**	19,852	2,307	22,159	0	22,159
28	**Total Rate Base**	$1,826,116	$310,245	$2,136,361	$0	$2,136,361
29	**Rate of Return**	6.169%		2.306%		7.406%
30	**Return on Common Equity**	7.64%		-0.10%		10.10%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1706

December 29, 2023

NW Natural
UG 490 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2025
Base Year Twelve Months Ended December 31, 2023 (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**	415,840,977	1.37519	$571,858,301	425,260,256	1.37492	$584,697,334
2	**Commercial**	257,264,397	1.07525	$276,623,429	251,922,343	1.07525	$270,880,550
3	**Industrial Firm**	37,572,067	0.77899	$29,268,217	37,906,427	0.77885	$29,523,506
4	**Interruptible**	59,710,782	0.54560	$32,578,098	55,585,659	0.54283	$30,173,471
5	**Total Sales of Gas Revenues**	770,388,223		$910,328,044	770,674,686		$915,274,861
	Transportation Volumes and Revenues						
6	**Firm**	95,431,272	0.09614	$9,174,380	98,431,545	0.09093	$8,949,954
7	**Interruptible**	184,237,319	0.03367	$6,202,959	181,335,352	0.03318	$6,016,204
8	**Special Contracts - Firm**	62,197,161	0.02218	$1,379,351	57,069,285	0.02354	$1,343,392
9	**Special Contracts - Interruptible**	13,603,232	0.02202	$299,569	14,340,441	0.02089	$299,588
10	**Total Transportation**	355,468,984		$17,056,260	351,176,622		$16,609,139
11	**Total Deliveries and Revenues**	1,125,857,207		$927,384,304	1,121,851,309		$931,884,000
12	**Decoupling Base Period**			$1,818,109			
13	**WARM Base Period**			($12,610,294)			
14	**Total Revenue**			$916,592,120			$931,884,000
	Gas Costs						
15	**Demand Charges**			$69,926,237			$70,308,208
16	**Commodity Charges**			334,895,465			335,019,992
17	**Total Cost of Gas**			$404,821,702			$405,328,200
18	**Total Margin**			$511,770,418			$526,555,800

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1707

December 29, 2023

NW Natural

UG 490 - Oregon Jurisdictional Rate Case
Miscellaneous Revenues Detail
Twelve Months Ended September 2021, 2022 & 2023

Line No.		12 Months Ended September 2021 (a)	12 Months Ended September 2022 (b)	12 Months Ended September 2023 (c)	Test Year (d)
1	FORFEITED DISCOUNTS-LATE PAYMENT CHARGE	1,976,581	2,009,100	2,987,712	2,987,712
2	MISC SERV REV- Scheduled CNG Main Rev	10,411	12,412	14,390	-
3	MISC SERV REV- Unscheduled CNG Main Rev	21,255	2,235	1,654	-
4	MISC SERVICE REVENUES-AUTOMATED PAYMENT	938	-	-	-
5	MISC SERVICE REVENUES-FIELD COLLECTION C	25,060	(2,740)	116,440	46,253
6	MISC SERVICE REVENUES-GAS DIVERSIONS	24,350	40,238	47,272	47,272
7	MISC SERVICE REVENUES-RECONN CHG-CR-AFTE	100	80	-	-
8	MISC SERVICE REVENUES-RECONN CHG-CR-DURI	6,460	11,250	40,690	40,690
9	MISC SERVICE REVENUES-RECONN CHG-SEAS-AF	-	-	-	-
10	MISC SERVICE REVENUES-RECONN CHG-SEAS-DU	4,290	900	1,410	2,200
11	MISC SERVICE REVENUES-DELINQ RECONN FEE	4,200	4,100	82,320	30,207
12	MISC SERVICE REVENUES-SEAS RECONN FEE	800	800	6,100	6,100
13	MISC SERVICE REVENUES-RETURNED CHECK CHA	260,675	345,270	446,010	446,010
14	MISC SERVICE REVENUES-SUMMARY BILL SVCS	13,010	11,751	12,125	12,295
15	RENT FROM GAS PROPERTY-RENT - UTILITY PR	72,324	73,834	75,827	75,827
16	RENT FROM GAS PROP - Schedule H CNG Reve	198,116	184,924	214,071	-
17	OTHER GAS REV-LNG SALES & OTHER MISC REV	41,760	121,341	92,603	85,234
18	OTHER GAS REVENUES-METER RENTALS	166,974	168,922	165,605	167,167
20	OTHER GAS REVENUES-CNG METER RENTALS	910	838	835	-
21	Non-AMR Install/Remove Charge	1,204	344	516	688
22	Non-AMR Read Charge	6,584	7,301	7,885	7,885
23	OTHER GAS REVENUES-MULTIPLE CALL OUT FEE	55,951	61,034	32,717	49,901
	Total Miscellaneous Revenues	**2,891,951**	**3,053,934**	**4,346,182**	**4,005,442**

Note: Excludes Billing Amortization Offsets, WARM deferrals, Washington Misc Revenues

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1708

December 29, 2023

NW Natural
UG 490 - Oregon Jurisdictional Rate Case
Uncollectible Accounts Adjustments
($000)

Line No.	Test Year Uncollectible Expense	
1	Uncollectible Rate in Strong Economic Conditions	0.097%
2	Impact of Mild Recession	0.100%
3	No Longer Charging Deposits	0.137%
4	Division 21: Weather/Shortened Day	0.030%
5	Division 21: Notices 15-20 Day	0.008%
6	Add: Collection Agency Reduced Recoveries	0.069%
7	Add: AMP	0.050%
8	Weighted Total	0.491%
9	Oregon Normalized Revenues (Test Year)	
10	Residential	584,697
11	Commercial	270,881
12	Industrial	29,524
13	Interruptible	30,173
14	Total	915,275
15	Normalized Uncollectible	
16	Residential	$2,871
17	Commercial	$1,330
18	Industrial	$145
19	Interruptible	$148
20	Total Normalized Uncollectible	$4,494
21	In Base O&M	$0
22	Uncollectible expense in Test Year	$4,494
23	Uncollectible rate for normalizaing adjustments	0.491%
24	Uncollectible expense in Base Year (estimated)	$3,088

12 Months Ended September Amounts	2023 Actual (d)
Gas Revenues	
Residential	679,699
Commercial	331,581
Industrial	35,659
Interruptible	41,147
Total	1,088,086
Net Write-Offs	
Residential	2,659
Commercial	424
Industrial	4
Interruptible	-
Total	3,088
Residential	0.391%
Commercial	0.128%
Industrial	0.013%
Interruptible	0.000%
Total	0.284%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1709

December 29, 2023

NW Natural
UG 490 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2025
Base Year Twelve Months Ended December 31, 2023
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	$535,401	$480,675
5	818	Compressor Station Expense	292,297	260,174
6	819	Compressor Station Fuel	40,618	36,154
7	820	Measuring and Regulator Station Expense	3,051,592	2,716,306
8	821	Purification Expense	-	-
9		Maintenance		
10	832	Wells Expense	291,340	259,321
11	834	Compressor Expense	1,565,966	1,393,867
		Total Underground Storage Expense	5,777,214	5,146,497
12		Other Storage Expense		
13		Operation		
14	840	Supervision and Engineering	176,482	157,087
15		Total Other Storage Expense	176,482	157,087
16		Liquified Natural Gas Expense		
17		Operation		
18	844	Supervision and Engineering	1,783,060	1,587,102
19	845	LNG Fuel	(156,047)	(138,898)
20		Maintenance		
21	847	Supervision and Engineering	1,796,310	1,598,896
22		Total Liquified Natural Gas Expense	3,423,324	3,047,100
23		Total Natural Gas Storage	9,377,019	8,350,684
24		Transmission Expense		
25		Operation		
26	856	Mains Expense	4,107,220	4,056,748
27		Maintenance		
28	863	Maintenance of Mains	27,959	27,614
29		Total Transmission Expense	4,135,179	4,084,362
30		Distribution Expense		
31		Operation		
32	870	Supervision and Engineering	3,662,586	3,378,837
33	874	Mains and Services Expense	18,694,209	16,572,616
34	875	Measuring and Regulator Station Expense - General	341,059	309,981
35	877	Measuring and Regulator Station Expense - City Gate	667,892	606,317
36	878	Meter and House Regulator Expense	4,266,747	3,750,044
37	879	Customer Installation Expense	22,138,711	19,457,611
38	880	Other Expense	1,455,697	1,285,938
39	881	Rents	274,341	237,333

NW Natural
UG 490 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2025
Base Year Twelve Months Ended December 31, 2023
Operations and Maintenance Expense

Line No.	FERC Acct.	Description	BASE YEAR System (a)	BASE YEAR Oregon (b)
40		Maintenance		
41	885	Supervision and Engineering	5,725,244	5,242,291
42	887	Mains	5,265,706	4,855,308
43	889	Measuring and Regulator Station Expense - General	2,212,602	2,009,413
44	891	Measuring and Regulator Station Expense - City Gate	126,414	115,387
45	892	Services	537,750	472,655
46	893	Meters and House Regulators	2,817,101	2,483,229
47	894	Other Equipment	14,151	12,439
48		Total Distribution Expense	68,200,211	60,789,398
49		Customer Accounts Expense		
50		Operation		
51	901	Supervision	2,192,590	1,927,067
52	902	Meter Reading Expenses	570,630	501,527
53	903	Customer Records and Collection Expense	21,940,623	19,310,829
54	904	Uncollectible Accounts (per adjustment calculation)	-	-
55		Total Customer Accounts Expense	24,703,843	21,739,423
56		Customer Service and Informational		
57		Operation		
58	907	Supervision	-	-
59	908	Customer Assistance Expense	2,282,925	2,017,730
60	909	Customer Information Expense	2,430,291	2,135,983
61	910	Miscellaneous Customer Service Expense	186,763	163,829
62		Total Customer Service and Informational	4,899,980	4,317,542
63		Sales Expense		
64		Operation		
65	911	Supervision	210,882	185,344
66	912	Demonstration and Selling Expense	1,531,247	1,348,431
67	913	Advertising	980,002	861,324
68	916	Miscellaneous Sales Expense	-	-
69		Total Sales Expense	2,722,132	2,395,100
70		Administrative and General Expense		
71		Operation		
72	921	Office Salaries and Expense	96,714,065	85,232,136
73	922	Administrative Expenses Transferred - Credit	(31,867,028)	(28,135,701)
74	924	Property Insurance Premium	5,104,380	4,510,230
75	925	Injuries and Damages	196,151	173,319
76	926	Employee Pensions and Benefits	9,610,502	9,336,099
77	928	Regulatory Commission Expense	-	-
78	930	Miscellaneous General Expense	4,963,081	4,560,973
79	931	Rents	10,565,934	9,336,533
80		Maintenance		
81	932	Maintenance of General Plant	6,703,560	6,031,654
82		Total Administrative and General Expense	101,990,645	91,045,242
83		Total O&M Expense	216,029,010	192,721,751
84	407	Environmental Rider	5,000,000	5,000,000
85		Total O&M Expense including Environmental Rider	221,029,010	197,721,751

NW Natural
UG 490 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2025
Base Year Twelve Months Ended December 31, 2023
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	$223,299	$200,475
5	818	Compressor Station Expense	309,948	275,885
6	819	Compressor Station Fuel	42,722	38,027
7	820	Measuring and Regulator Station Expense	2,684,578	2,389,616
8	821	Purification Expense	-	-
9		Maintenance		
10	832	Wells Expense	939,825	836,538
11	834	Compressor Expense	1,641,510	1,461,108
		Total Underground Storage Expense	5,841,882	5,201,649
12		Other Storage Expense		
13		Operation		
14	840	Supervision and Engineering	207,217	184,444
15		Total Other Storage Expense	207,217	184,444
16		Liquified Natural Gas Expense		
17		Operation		
18	844	Supervision and Engineering	2,021,911	1,799,703
19	845	LNG Fuel	(166,352)	(148,069)
20		Maintenance		
21	847	Supervision and Engineering	2,044,959	1,820,218
22		Total Liquified Natural Gas Expense	3,900,519	3,471,852
23		Total Natural Gas Storage	9,949,617	8,857,944
24		Transmission Expense		
25		Operation		
26	856	Mains Expense	4,463,283	4,408,436
27		Maintenance		
28	863	Maintenance of Mains	32,445	32,045
29		Total Transmission Expense	4,495,729	4,440,481
30		Distribution Expense		
31		Operation		
32	870	Supervision and Engineering	4,280,643	3,949,011
33	874	Mains and Services Expense	24,948,078	22,116,738
34	875	Measuring and Regulator Station Expense - General	388,935	353,494
35	877	Measuring and Regulator Station Expense - City Gate	754,217	684,683
36	878	Meter and House Regulator Expense	4,977,440	4,374,672
37	879	Customer Installation Expense	25,861,108	22,729,207
38	880	Other Expense	1,707,241	1,508,148
39	881	Rents	291,272	251,980

NW Natural
UG 490 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2025
Base Year Twelve Months Ended December 31, 2023
Operations and Maintenance Expense

			TEST YEAR	
Line No.	FERC Acct.	Description	System	Oregon
			(a)	(b)
40		Maintenance		
41	885	Supervision and Engineering	6,752,914	6,183,272
42	887	Mains	6,039,880	5,569,144
43	889	Measuring and Regulator Station Expense - General	2,552,959	2,318,513
44	891	Measuring and Regulator Station Expense - City Gate	139,569	127,394
45	892	Services	608,480	534,823
46	893	Meters and House Regulators	3,281,330	2,892,440
47	894	Other Equipment	16,565	14,560
48		Total Distribution Expense	82,600,629	73,608,080
49		Customer Accounts Expense		
50		Operation		
51	901	Supervision	2,589,030	2,275,498
52	902	Meter Reading Expenses	671,554	590,229
53	903	Customer Records and Collection Expense	26,223,978	23,080,783
54	904	Uncollectible Accounts (calculated separately)	-	-
55		Total Customer Accounts Expense	29,484,562	25,946,509
56		Customer Service and Informational		
57		Operation		
58	907	Supervision	-	-
59	908	Customer Assistance Expense	2,699,948	2,386,310
60	909	Customer Information Expense	3,282,434	2,884,932
61	910	Miscellaneous Customer Service Expense	220,786	193,674
62		Total Customer Service and Informational	6,203,169	5,464,915
63		Sales Expense		
64		Operation		
65	911	Supervision	249,228	219,046
66	912	Demonstration and Selling Expense	1,759,202	1,549,170
67	913	Advertising	(0)	(0)
68	916	Miscellaneous Sales Expense	-	-
69		Total Sales Expense	2,008,430	1,768,217
70		Administrative and General Expense		
71		Operation		
72	921	Office Salaries and Expense	113,041,240	99,620,942
73	922	Administrative Expenses Transferred - Credit	(36,860,295)	(32,544,304)
74	924	Property Insurance Premium	6,325,360	5,589,088
75	925	Injuries and Damages	198,213	175,141
76	926	Employee Pensions and Benefits	19,031,456	17,714,424
77	928	Regulatory Commission Expense	-	-
78	930	Miscellaneous General Expense	5,414,275	4,977,707
79	931	Rents	11,024,949	9,742,139
80		Maintenance		
81	932	Maintenance of General Plant	7,435,413	6,690,152
82		Total Administrative and General Expense	125,610,609	111,965,290
83		Total O&M Expense	260,352,744	232,051,435
84	407	Environmental Rider	5,000,000	5,000,000
85		Total O&M Expense including Environmental Rider	265,352,744	237,051,435

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1710

December 29, 2023

NW Natural
UG 490 - Oregon Jurisdictional Rate Case
Tax Provision
Test Year Twelve Months Ended October 31, 2025
Base Year Twelve Months Ended December 31, 2023
($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	$920,938	$920,938	$935,889	$935,889
2	Operating Revenue Deductions	605,631	605,631	646,874	646,874
3	Property & Other Taxes	61,472	61,472	66,496	66,496
4	Book Depreciation	112,729	112,729	170,820	170,820
5	Interest (Rate Base * Cost of Debt)	42,877	42,877	50,333	50,333
6	Remove Equity Flotation				
7	State Tax Deduction	0	12,052	0	4,863
8	Subtotal	98,229	86,176	1,367	-3,496
9	Permanent Differences 1/	7,074	7,074	7,074	7,074
10	Taxable Income	105,303	93,250	8,442	3,578
11	Tax Rate	7.60%	21.00%	7.600%	21.000%
12	Tax Before Credits	8,003	19,583	642	751
13	Tax Credits & EDIT Amortization 2/	4,049	(3,183)	4,222	(3,183)
14	Total Tax	$12,052	$16,399	$4,863	($2,432)

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 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1711

December 29, 2023

NW Natural
UG 490 - Oregon Jurisdictional Rate Case
Proforma 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%	4.696%	2.348%	50.0%	4.712%	2.356%
2	Common Stock	50.0%	9.400%	4.700%	50.0%	10.100%	5.050%
3	Total	100.0%		7.048%	100.0%		7.406%
Revenue Sensitive Costs							
4	Gas Sales		98.85%			97.80%	
5	Transportation		1.85%			1.77%	
6	Other		-0.70%			0.43%	
7	Subtotal		100.00%			100.00%	
8	O & M - Uncollectible		0.49%			0.49%	
9	Franchise Taxes at		2.31%			2.31%	
10	OPUC Fee		0.430%			0.430%	
11	State Taxable Income		96.77%			96.77%	
12	State Income Tax		7.35%			7.35%	
13	Federal Taxable Income		89.42%			89.42%	
14	Federal Income Tax		18.78%			18.78%	
15	Utility Operating Income		70.64%			70.64%	
16	Total Revenue Sensitive Costs		29.36%			29.36%	
17	Net-to-gross factor		141.57%			141.57%	
18	Rate of Return on Equity		9.40%			10.10%	
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		2.309%			2.309%	
23	Uncollectible Accounts		0.491%			0.491%	
24	Regulatory Fees		0.430%			0.430%	
25	Interest Coordination Factor		2.348%			2.356%	

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1712

December 29, 2023

NW Natural
UG 490 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2025
Base Year Twelve Months Ended December 31, 2023 (Actual and Estimate)
Forecast of Other Taxes

Line No.		Actual 2021	Actual 2022	Actual/Forecast 2023	Weighted Average	Test Year Normalized	Base Year Normalized
		(b)	(c)	(d)	(e)	(f)	(g)
	Property Taxes						
1	Taxes Paid	24,955,215	27,195,294	28,541,184			27,868,239
2	Net Plant December 31 of prior year	1,839,299,862	1,910,467,332	2,120,091,125			
3	Effective Rate on Prior Year-End Net Plant	1.357%	1.423%	1.346%	1.375%		
4	Net Plant 12/31/23					2,237,877,681	
5	2024 Payment Forecast (line 4 * line 3e)					30,763,628	
6	Net Plant 12/31/24					2,463,008,403	
7	2025 Payment Forecast (line 6 * line 3e)					33,858,452	
8	Test Period Expense 1/					31,795,236	
9	Other Taxes						
10	Franchise					21,612,334	21,516,292
11	Payroll					7,758,059	6,783,911
12	Regulatory Fee					4,024,325	4,006,441
13	Department of Energy					1,090,285	1,085,440
14	Other					215,888	212,104
15	Other Taxes Excluding Property Taxes					34,700,891	33,604,188
16	1/ eight twelfths is taken from year 2020 and four twelfths from 2021						

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1713

December 29, 2023

NW Natural
UG 490 - Oregon Jurisdictional Rate Case
Rate Base & Depreciation Expense - Oregon and System
Test Year Twelve Months Ended October 31, 2025
Base Year Twelve Months Ended December 31, 2023 (Actual and Estimate)
($000)

Line No.	Rate Base	Test Year Oregon (a)	Test Year System (b)	Base Year Oregon (c)	Base Year System (d)
1	Utility Plant in Service	4,120,671	4,665,889	3,608,816	4,077,902
2	Accumulated Depreciation	(1,638,721)	(1,834,526)	(1,464,792)	(1,638,760)
3	Net Utility Plant	2,481,950	2,831,363	2,144,025	2,439,142
4	Aid in Advance of Construction	(6,499)	(10,902)	(6,517)	(10,739)
5	Customer Deposits	(755)	(859)	(677)	(770)
6	Gas Inventory (Working and Cushion)	43,889	49,307	63,623	71,479
7	Leasehold Improvemets	18,596	21,046	21,314	24,121
8	Materials & Supplies	21,810	25,496	19,452	22,740
9	Accumulated Deferred Income Taxes - Depreciation	(441,529)	(484,777)	(429,494)	(471,607)
10	Accumulated Deferred Income Taxes - Other	(6,360)	(7,071)	(8,562)	(9,426)
11	EDIT Rate Base Adjustment	3,100	3,563	3,100	3,563
12	Cash Working Capital	22,159	24,738	19,852	22,163
13	Total Rate Base	2,136,361	2,451,905	1,826,116	2,090,666

1/ Test Year Depreciation DTL per Proration Methodology

Line No.	Depreciation Expense	Test Year Oregon	Test Year System	Base Year Oregon	Base Year System
14	Intangible - Software	47,558	54,110	17,425	19,826
15	Transmission	5,533	5,732	4,210	4,285
16	Distribution	85,613	98,484	62,727	71,815
17	General	21,116	24,020	20,091	22,867
18	Storage and Storage Transmission	11,001	12,439	8,276	9,378
19	Subtotal	170,820	194,784	112,729	128,171
20					
21					
22	Total	170,820	194,784	112,729	128,171

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1714

REDACTED

December 29, 2023

NW Natural
UG 490
Exhbit 1714 - Cloud Based Software

Project Description	Contract Life (Years)	Depreciation Rate	Capitalized Date	Gross Plant Balance
Tech Refr LgSvrs-2019-MicrosoftLic	5	20.00%	Jan-20	$ 104,109
Success Factors Recruiting Mgmt Impl	5	20.00%	Jan-20	$ 794,670
Tech Refr LgSvrs-2019-MicrosoftLic	0	0.00%	Sep-23	$ 1,882
Success Factors Recruiting Mgmt Impl	0	0.00%	Sep-23	$ 22,729
SAP Concur	5	20.00%	Jun-20	$ 756,130
Execution Leak & Inspection - Cloud Based SW	0	0.00%	Sep-23	$ 201,084
Digital Portal - Cloud Based SW	3	33.33%	Oct-20	$ 427,270
SAP Asset Manager - Cloud Based SW	3	33.33%	Oct-20	$ 854,135
SAP LMS - Cloud Based SW	5	20.00%	Nov-20	$ 1,184,315
SAP LMS - Phase 2 - Cloud Based SW	5	20.00%	Apr-21	$ 830,935
Planview - Cloud Based SW	5	20.00%	Apr-21	$ 1,526,203
Slalom Execution Phase - Cloud Based SW	3	33.33%	Apr-21	$ 789,864
Cloud Based SAP SF EC&OnBoarding	5	20.00%	Aug-21	$ 3,162,495
Slalom Execution Phase - Cloud Based SW	3	33.33%	Aug-21	$ 311,239
Slalom Execution Phase - Cloud Based SW	3	33.33%	Sep-21	$ 199,324
Execution Leak & Inspection - Cloud Based SW Azure	3	33.33%	Dec-21	$ 423,954
Slalom Execution Phase - Cloud Based SW	3	33.33%	Dec-21	$ 192,037
Slalom Execution Phase - Cloud Based SW	3	33.33%	Mar-22	$ 303,550
Azure DevOpps 2019 - Cloud Based SW	3	33.33%	Jul-22	$ 18,601
QA Inspection Tool - Cloud Based SW	3	33.33%	Jun-24	$ 624,501
Slalom Execution Phase - Cloud Based SW	3	33.33%	Jul-22	$ 152,413
IT&S Execution Labor External (Cap)	10	10.00%	Sep-22	$ 33,915
Labor External (Capital)	10	10.00%	Sep-22	$ 185,012
Labor External (Capital)	10	10.00%	Sep-22	$ 23
Labor External (Capital)	10	10.00%	Sep-22	$ 18
Labor External (Capital)	10	10.00%	Sep-22	$ 19
Labor External (Capital)	10	10.00%	Sep-22	$ 15,937
DecSecOps Labor Inter (Cap)	10	10.00%	Sep-22	$ 9,293
Labor External (Capital)	10	10.00%	Sep-22	$ 260,646
Labor External (Capital)	10	10.00%	Sep-22	$ 20
Labor External (Capital)	10	10.00%	Sep-22	$ 29
Labor External (Capital)	10	10.00%	Sep-22	$ 71,625
Labor External (Capital)	10	10.00%	Sep-22	$ 39
Labor External (Capital)	10	10.00%	Sep-22	$ 29
Labor External (Capital)	10	10.00%	Sep-22	$ 28
Labor External (Capital)	10	10.00%	Sep-22	$ 13
Labor External (Capital)	10	10.00%	Sep-22	$ 32,577
Labor External (Capital)	10	10.00%	Sep-22	$ 78,474
Labor External (Capital)	10	10.00%	Sep-22	$ 6
DATA Labor Internal (C)	10	10.00%	Sep-22	$ 14,159
Labor External (Capital)	10	10.00%	Sep-22	$ 381,179
Labor External (Capital)	10	10.00%	Sep-22	$ 12
Labor External (Capital)	10	10.00%	Sep-22	$ 8
Mobility Test & QA Proc Labor Inter (C)	10	10.00%	Sep-22	$ 3,492
Labor External (Capital)	10	10.00%	Sep-22	$ 117,593
Labor External (Capital)	10	10.00%	Sep-22	$ 29
Project Management (Allocate)	10	10.00%	Sep-22	$ 73,691
Execution Labor Internal (Capital)	10	10.00%	Sep-22	$ 8,668
Execution Labor External (Capital)	10	10.00%	Sep-22	$ 939,113
EAM Labor Internal (Capital)	10	10.00%	Sep-22	$ 560,354
Accenture Labor External (Capital)	10	10.00%	Sep-22	$ 1,519,700
External Labor Other (Capital)	10	10.00%	Sep-22	$ 195,195
Supply Chain Labor Internal (Capital)	10	10.00%	Sep-22	$ 326,662
Accenture Labor External (Capital)	10	10.00%	Sep-22	$ 653,579
External Labor Other (Capital)	10	10.00%	Sep-22	$ 83,137
Finance Labor Internal (Capital)	10	10.00%	Sep-22	$ 349,957
Accenture Labor External (Capital)	10	10.00%	Sep-22	$ 2,051,134
External Labor Other (Capital)	10	10.00%	Sep-22	$ 32,055
IT&S Horizon 1 Labor Internal (Capital)	10	10.00%	Sep-22	$ 878,328
Accenture Labor External (Capital)	10	10.00%	Sep-22	$ 360,186
External Labor Other (Capital)	10	10.00%	Sep-22	$ 554,753
HCM Rel 1 Labor Internal (Capital)	10	10.00%	Sep-22	$ 16,074
Accenture Labor External (Capital)	10	10.00%	Sep-22	$ 279,106
HCM Rel 2 Labor Internal (Capital)	10	10.00%	Sep-22	$ 76,115
Accenture Labor External (Capital)	10	10.00%	Sep-22	$ 903,747
External Labor Other (Capital)	10	10.00%	Sep-22	$ 93,626
Accenture Labor External (Capital)	10	10.00%	Sep-22	$ 148,264

Project Description	Contract Life (Years)	Depreciation Rate	Capitalized Date	Gross Plant Balance
External Labor Other (Capital)	10	10 00%	Sep-22	$ 36,934
Data Migration Labor Internal (Capital)	10	10 00%	Sep-22	$ 33,351
Accenture Labor External (Capital)	10	10 00%	Sep-22	$ 178,674
External Labor Other (Capital)	10	10 00%	Sep-22	$ 86,544
Mobility Labor Internal (Capital)	10	10 00%	Sep-22	$ 50,367
Accenture Labor External (Capital)	10	10 00%	Sep-22	$ 29,257
Reporting & Analytics Labor Inter (Cap)	10	10 00%	Sep-22	$ 19,480
Accenture Labor External (Capital)	10	10 00%	Sep-22	$ 160,448
External Labor Other (Capital)	10	10 00%	Sep-22	$ 843,659
Security Labor Inter (Cap)	10	10 00%	Sep-22	$ 13,502
Accenture Labor External (Capital)	10	10 00%	Sep-22	$ 230,194
External Labor Other (Capital)	10	10 00%	Sep-22	$ 103,650
Dev Training Materials Labor Internal	10	10 00%	Sep-22	$ 10,002
Accenture Labor External (Capital)	10	10 00%	Sep-22	$ 332,763
External Labor Other (Capital)	10	10 00%	Sep-22	$ 294,367
Program Mgmt Labor Inter (Cap)	10	10 00%	Sep-22	$ 114,547
Accenture Labor External (Capital)	10	10 00%	Sep-22	$ 982,673
External Labor Other (Capital)	10	10 00%	Sep-22	$ 966,550
Development Labor Inter (Cap)	10	10 00%	Sep-22	$ 84,790
Accenture Labor External (Capital)	10	10 00%	Sep-22	$ 302,429
Testing Labor Internal (Cap)	10	10 00%	Sep-22	$ 65,771
Accenture Labor External (Capital)	10	10 00%	Sep-22	$ 231,312
External Labor Other (Capital)	10	10 00%	Sep-22	$ 319,972
Tech Arch Labor Internal (Cap)	10	10 00%	Sep-22	$ 129,576
Accenture Labor External (Capital)	10	10 00%	Sep-22	$ 275,196
External Labor Other (Capital)	10	10 00%	Sep-22	$ 7,248
Travel (Capital)	10	10 00%	Sep-22	$ 106,585
PWC (Capital)	10	10 00%	Sep-22	$ 205,774
On Prem SW SAP (Capital)	10	10 00%	Sep-22	$ 1,087,978
On Prem Clevest (Capital)	10	10 00%	Sep-22	$ 331,926
On Prem PowerPlan (Capital)	10	10 00%	Sep-22	$ 619,527
On Prem Other (Capital)	10	10 00%	Sep-22	$ 73,175
Cloud Based SAP (Capital)	10	10 00%	Sep-22	$ 1,016,295
Cloud Based Clevest (Capital)	10	10 00%	Sep-22	$ 138
Cloud Based PowerPlan (Capital)	10	10 00%	Sep-22	$ 61,534
Cloud Based SW Accenture (Capital)	10	10 00%	Sep-22	$ 15,392
Cloud Based SW Azure (Capital)	10	10 00%	Sep-22	$ 430,281
Cloud Other (Capital)	10	10 00%	Sep-22	$ 2,874
On Prem SW Maint SAP (Capital)	10	10 00%	Sep-22	$ 350,757
On Prem SW Maint Clevest (Capital)	10	10 00%	Sep-22	$ 110,377
On Prem SW Maint PowerPlan (Capital)	10	10 00%	Sep-22	$ 319,739
Cloud Based SW Maint Other (Capital)	10	10 00%	Sep-22	$ 153
Hardware (Capital)	10	10 00%	Sep-22	$ 109,116
Misc (Capital)	10	10 00%	Sep-22	$ 284,843
SLA Credit (Capital)	10	10 00%	Sep-22	$ (10,818)
IQGEO (Capital)	10	10 00%	Sep-22	$ 732,643
Execution Labor Internal (Capital)	3	33 33%	Oct-22	$ 33,981
Execution Labor External (Capital)	3	33 33%	Oct-22	$ 283,598
Planning Labor Internal (Capital)	3	33 33%	Oct-22	$ 133,475
Planning Labor External (Capital)	3	33 33%	Oct-22	$ 886,527
Planning Software (Capital)	3	33 33%	Oct-22	$ 698
Planning Hardware (Capital)	3	33 33%	Oct-22	$ 13,745
Execution Labor Internal (Capital)	3	33 33%	Oct-22	$ 187,666
Execution Labor External (Capital)	3	33 33%	Oct-22	$ 1,399,231
Execution Software (Capital)	3	33 33%	Oct-22	$ 63,766
Execution Hardware (Capital)	3	33 33%	Oct-22	$ 134
Planning Labor External (Capital)	3	33 33%	Oct-22	$ 83,146
Execution Labor External (Capital)	3	33 33%	Oct-22	$ 125,327
Planning Labor External (Capital)	3	33 33%	Oct-22	$ 5,940
Planning Software (Capital)	3	33 33%	Oct-22	$ 241,599
Execution Labor External (Capital)	3	33 33%	Oct-22	$ 1,748
Execution Other (Capital)	10	10 00%	Sep-22	$ 2,339
Cloud Software (Capital)	3	33 33%	Oct-22	$ 145,007
Cloud Software (Capital)	3	33 33%	Oct-22	$ 590,418
Accenture Travel (Capital)	10	10 00%	Sep-22	$ (1,930)
Accenture Change Orders (Capital)	10	10 00%	Oct-22	$ 36,693
COMPUTER SOFTWARE	3	33 33%	Sep-22	$ 33,102
COMPUTER SOFTWARE	3	33 33%	Sep-22	$ 340
Internal Labor Azure	3	33 33%	Sep-22	$ 229
Cloud SW Asset #2 (Nov) 3 year	3	33 33%	Dec-22	$ 167,126
NMEP Cloud Asset Nov (3 year)	3	33 33%	Dec-22	$ 733
Cloud SW Asset (Nov) 3 year	3	33 33%	Dec-22	$ (1,126)
Cloud Asset Nov	3	33 33%	Dec-22	$ 8,046
Cloud SW Asset Dec	3	33 33%	Dec-22	$ (435,871)
NMEP SW Asset Dec	3	33 33%	Dec-22	$ (3,660)
Cloud SW Asset Dec	3	33 33%	Dec-22	$ 67
Cloud SW Asset Dec	3	33 33%	Dec-22	$ 3,860
COMPUTER SOFTWARE	3	33 33%	Oct-22	$ 518,219
COMPUTER SOFTWARE	3	33 33%	Oct-22	$ 6,261
COMPUTER SOFTWARE	3	33 33%	Oct-22	$ 86,304
COMPUTER SOFTWARE	3	33 33%	Oct-22	$ 737,316
COMPUTER SOFTWARE	3	33 33%	Oct-22	$ 19,026
COMPUTER SOFTWARE	3	33 33%	Oct-22	$ 11,974
Q3 & Q4 2022 Sprints (Capital)	3	33 33%	Jan-23	$ 536,024
Plan Cloud Roll Out 1 Labor Inter(Cap)	3	33 33%	Feb-23	$ 91,666
Labor External (Capital)	3	33 33%	Feb-23	$ 1,291,714
Execute Cloud MVC (Capital)	3	33 33%	Feb-23	$ 18,369
Labor External (Capital)	3	33 33%	Feb-23	$ 21,255
COMPUTER SOFTWARE	10	10 00%	Sep-22	$ 71,699
COMPUTER SOFTWARE	10	10 00%	Sep-22	$ 9
COMPUTER SOFTWARE	10	10 00%	Sep-22	$ 144,094
COMPUTER SOFTWARE	10	10 00%	Sep-22	$ 14,353
COMPUTER SOFTWARE	10	10 00%	Oct-22	$ 753,448

Project Description	Contract Life (Years)	Depreciation Rate	Capitalized Date	Gross Plant Balance
[redacted]				
10/31/25 TOTAL				$ 102,419,531

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1715

December 29, 2023

NW Natural - UG 490, Exhibit 1715 Page 1
Test Year Twelve Months Ended October 31, 2025
Lead-Lag Test Year Summary

			Revenue Requirement	Revenue	Expense	Net		
1			Revenue Requirement	Revenue	Expense	Net		
2			$	Lag (Lead) Days	Lag (Lead) Days	Lag (Lead) Days		Weighted $
3	**Total Revenue Lag**			40.86				
4								
5	**Operations and Maintenance Expense**							
6	Purchased Gas	$	405,328,200	40.86	40.50	0.36	$	145,514,871
7	Labor - Payroll	$	96,616,791	40.86	27.39	13.47	$	1,301,048,177
8	Employee Benefits	$	30,664,931	40.86	12.78	28.07	$	860,892,374
9	Prepaid Insurance	$	6,708,372	40.86	-171.83	212.69	$	1,426,819,327
10	Prepaid IT	$	7,603,047	40.86	-216.04	256.90	$	1,953,224,659
11	Regulatory Fees	$	4,024,325	40.86	-90.69	131.55	$	529,409,950
12	Municipal Franchise Fees	$	21,612,334	40.86	89.86	-49.00	$	(1,058,984,036)
13	Other O&M	$	104,769,713	40.86	36.74	4.12	$	432,047,231
14								
15	**Payroll Taxes**	$	7,758,059	40.86	76.56	-35.70	$	(276,931,642)
16								
17	**Other Taxes**							
18	Federal/State	$	43,390,123	40.86	36.50	4.36	$	189,137,765
19	CAT	$	4,221,850	40.86	75.00	-34.14	$	(144,138,146)
20	Property Taxes	$	31,795,236	40.86	-45.00	85.86	$	2,729,907,338
21								
22	**Net of Revenue less Expense Lag**	**$**	**764,492,981**	**40.86**	**30.28**	10.58	**$**	**8,087,947,868**
23						Days		365
24	**Aver Daily Cash Working Capital Requirements - Oregon**						**$**	**22,158,761**
25	**Aver Daily Cash Working Capital Requirements - System**						**$**	**24,738,041**
26								
27	**Cash Working Capital Factor**							**2.90%**

NW Natural - UG 490, Exhibit 1715 Page 2
Test Year Twelve Months Ended October 31, 2025
Revenue Test Year Summary

		Revenues Billed	Lag (Lead) Days	Weighted Revenues
1		Revenues Billed	Lag (Lead) Days	Weighted Revenues
2	Sale of Gas	$ 1,070,184,550		
3	Transportation Revenues	$ 16,609,139		
4	Service Lag		15.50	
5	Billing Lag		0.00	
6	Collection Lag		25.34	
7	**Grand Total Revenues**	**$ 1,086,793,689**	**40.84**	**$ 44,388,722,331**
8	Misc Revenues	$ 4,005,442		
9	Service Lag		15.00	
10	Billing Lag		0.00	
11	Collection Lag		30.00	
12	**Total Other Revenues**	**$ 4,005,442**	**45.00**	**$ 180,244,890**
13				
14	**Total Revenue Lag**	**$ 1,090,799,131**	**40.86**	**$ 44,568,967,221**

NW Natural - UG 490, Exhibit 1715 Page 3
Test Year Twelve Months Ended October 31, 2025
Expense Test Year Summary

1						
2			Revenue Requirement $	Lag (Lead) Days		Weighted $
3	**Operations and Maintenance Expense**					
4	Purchased Gas	$	405,328,200	40.50	$	16,415,792,100
5	Service Lag			15.50		
6	Payment Lag			25.00		
7	Labor - Payroll	$	96,616,791	27.39	$	2,646,617,789
8	Employee Benefits [1]	$	30,664,931	12.78	$	392,046,197
9	Prepaid Insurance	$	7,555,492	-171.83	$	(1,298,285,361)
10	Prepaid IT [2]	$	7,603,047	-216.04	$	(1,642,571,716)
11	Regulatory Fees	$	4,024,325	-90.69	$	(364,980,050)
12	Municipal Franchise Fees	$	21,612,334	89.86	$	1,942,042,497
13	Other O&M [1]	$	104,769,713	36.74	$	3,848,738,994
14	**TOTAL O&M**	**$**	**573,405,120**	**38.26**	**$**	**19,733,233,172**
15						
16	**Payroll Taxes**	$	7,758,059	76.56	$	593,918,221
17						
18	**Other Taxes**					
19	Federal/State	$	43,390,123	36.50	$	1,583,739,487
20	CAT	$	4,221,850	75.00	$	316,638,720
21	Property Taxes	$	31,795,236	(45.00)	$	(1,430,785,625)
22						
23	**TOTAL TAXES**	**$**	**82,943,418**	**12.82**	**$**	**746,872,084**
24						
25	**TOTAL REQUIRMENT**	**$**	**656,348,538**	**35.05**	**$**	**20,480,105,255**
26						
27	[1] Lag days is based on TTM September 30, 2023					
28	[2] Revenue Requirement $ is the Base Year amount					

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1716

December 29, 2023

NW Natural
UG 490 - Oregon Jurisdictional Rate Case
State Allocation Factors

Line No.	Allocation Factors - Summary	Oregon	Washington
1	Customers-all	87.890%	12.11%
2	Customers-Residential	87.720%	12.28%
3	Customers-Commercial	89.690%	10.31%
4	Customers-Industrial	92.460%	7.54%
5	Customers-The Dalles	74.860%	25.14%
6	3-factor	88.360%	11.64%
7	firm volumes	89.010%	10.99%
8	sales volumes	89.660%	10.34%
9	sendout volumes	91.250%	8.75%
10	sales/sendout volumes	90.460%	9.54%
11	Payroll	88.984%	11.02%
12	Admin Transfer	88.102%	11.90%
13	Employee Cost	88.305%	11.69%
14	Regulatory	70.000%	30.00%
15	Telemetering	88.462%	11.54%
16	Direct-Wa	0.000%	100.00%
17	Direct-Or	100.000%	0.00%
18	Gross plant direct assign	87.780%	12.22%
19	Transmission	98.765%	1.23%
20	Accumulated Depreciation	89.266%	10.73%
21	Rate Base	87.131%	12.87%
22	Distribution	85.543%	14.46%
23	Perimeter	93.750%	6.25%
24	Environmental Admin Costs	96.680%	3.32%
25	Accumulated Depreciation	89.327%	10.67%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1717

December 29, 2023

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

Sixth Revision of Sheet H-5
Cancels Fifth Revision of Sheet H-5

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, 2024		
Year	**No Bonus Depreciation**	**With Bonus Depreciation**
Year 1	21.5%	21.0%
Year 2	20.1%	19.2%
Year 3	18.7%	18.0%
Year 4	17.4%	16.9%
Year 5	16.2%	15.8%
Year 6	15.0%	14.8%
Year 7	13.9%	13.8%
Year 8	12.8%	12.8%
Year 9	11.8%	11.8%
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)

Issued December 29, 2023
NWN OPUC Advice No. 23-30

Effective with service on
and after November 1, 2024

SCHEDULE X
DISTRIBUTION FACILITIES EXTENSIONS
FOR APPLICANT-REQUESTED SERVICES AND MAINS
(continued)

REQUIREMENTS FOR NEW CONSTRUCTION AND PLANNED DEVELOPMENT INSTALLATIONS (continued):
The installation schedule for a Company provided utility pathway will be determined between the Company and the Applicant. If the Company fails to meet the agreed installation schedule, the Company will pay to the Applicant the service guarantee credit specified in **Schedule C.**

CONSTRUCTION ALLOWANCE:
The Construction Allowance is based upon the Customer classification. The customer classifications are:
(1) Residential (Single-Family or Multi-Family Dwellings), and
(2) Non-Residential (Commercial and Industrial) and Planned Developments.

An Applicant is subject to the conditions set forth in the "GENERAL CONDITIONS OF SERVICE" provision of this Schedule if the Applicant fails to install the equipment associated with the Construction Allowance afforded to the Applicant under this Schedule.

The Construction Allowances for each Customer classification follow:

Residential

The Construction Allowance per residential dwelling will be equal to the amount in the table below for (C)
each tier of estimated annual usage. To qualify for an allowance under the range 0-250 annual therms, (C)
two natural gas appliances must be installed in the qualified dwelling. The Calculation of the estimated (C)
therm usage assumes usage in a permanent structure occupied 12 months per year and may be adjusted where service is requested where occupancy is known or expected to be less than 12 months per year.
The estimated therm usage is determined from the type and number of appliances to be installed. For (C)
example, a perspective customer installing water heat, backup furnace and a cooktop would have an (C)
estimated annual usage of 214 therms and would qualify them for $3,600 construction allowance. (C)

Tier	Estimated Annual Therm Usage	Allowance
Tier 1	0-250	$3,600
Tier 2	251-450	$3,100
Tier 3	451-650	$2,600
Tier 4	651+	$1,800

(N)
(N)

(continue to Sheet X-6)

SCHEDULE X
DISTRIBUTION FACILITIES EXTENSIONS
FOR APPLICANT-REQUESTED SERVICES AND MAINS
(continued)

SERVICE AGREEMENTS:
A Service Agreement may be required, at the sole discretion of the Company, in the following circumstances:

1. Whenever a Main Extension is required.
2. For service to Planned Developments.
3. When the cost of construction is greater than $50,000.
4. When the Company's investment analysis requires a guarantee of margin revenue as a condition of the investment.

REFUNDS OF CONSTRUCTION CONTRIBUTIONS:
When the installation requires a Main Extension, any Construction Contribution paid may be subject to refund. A refund opportunity exists only when a new Service Line installation is added along the Main Extension within thirty-six (36) months from the date that the Main Extension was installed.

The Company will review Main Extension activity at the end of the thirty-six (36) month period to determine whether a refund of a Construction Contribution is due. The Company will perform a refund calculation prior to the end of the refund period upon specific request from the original contributor.

To determine the amount available for refund, the construction cost and the Construction Allowance will be updated. The construction cost will equal the actual construction cost of the original installation plus the cost of the subsequent connection. The Construction Allowance will equal the original Construction Allowance plus the Construction Allowance afforded the subsequent Applicant. If the resulting Construction Contribution is less than the Construction Contribution paid by the original contributor, then a refund equal to such difference will be issued to the original contributor. Example Calculation for a single original contributor:

Cost	Allowance	Contribution	Description	
$ 6,900			Cost of original Main Extension with 1 Service Line	
	$ 3,600		Less Original Construction Allowance	(C)
		$3,300	Original Construction Contribution Paid	(C)
$ 2,042			Add cost of new connection to Main Extension	
$ 8,942			Updated cost of Main Extension and 2 Service Lines	
	$ 7,200		Less Construction Allowance on 2 Service Lines	(C)
	$ 1,742		Revised Construction Allowance (updated cost less updated Construction Allowance)	(C)
		$ 1,558	Refund to Original Contributor (original contribution less updated Construction Allowance	(C)

In no event will a refund exceed the amount of the original Construction Contribution.

(continue to Sheet X-8)

NORTHWEST NATURAL GAS COMPANY

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, 2024 (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. "Connected" shall mean when the premise was connected to the natural gas system. "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 ths Rate Schedule 2. (N)

(N)

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 (Connected prior to 11/1/2024)	$10.00	$0.90649	$0.00435	$0.10025	$0.44732	$0.06135	**$1.51976**	(N)
Residential Multi-Family (Connected prior to 11/1/2024)	$8.00	$0.90649	$0.00435	$0.10025	$0.44732	$0.06135	**$1.51976**	
Residential Single-Family (Connected after 11/1/2024)	$26.25	$0.90649	$0.00435	$0.10025	$0.44732	$0.06135	**$1.51976**	
Residential Multi-Family (Connected after 11/1/2024)	$24.25	$0.90649	$0.00435	$0.10025	$0.44732	$0.06135	**$1.51976**	(N)

(continue to Sheet 2-2)

RATE SCHEDULE 3
BASIC FIRM SALES SERVICE - NON-RESIDENTIAL
(continued)

MONTHLY RATE: Effective: November 1, 2024 (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 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	$0.74971	$0.00435	$0.10025	$0.44732	($0.01882)	**$1.28281**	(I)
Industrial	$0.53332	$0.00435	$0.10025	$0.44732	$0.06884	**$1.15408**	(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.

RATE SCHEDULE 4
RESIDENTIAL MULTI-FAMILY SERVICE

APPLICABLE:
To Residential tenants that reside in a Participant Multi-Family Building.

MONTHLY RATE: $**10.33** Effective: November 1, 2024 (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.

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 rent supplementary displacement type meters from the Company at the following rates:

Diaphragm Meters: Effective: November 1, 2024 (C)
The currently available meter sizes and associated monthly charges are shown below:

Meter Size (Cubic Feet/hour)	Monthly Charge	
250	$3.01	(I)
630	$7.70	|
1000	$10.87	(I)

Rotary Meters: Effective: November 1, 2024 (C)

Meter Size	Meter Capacity (Cubic Feet/hour)	Monthly Charge	
1.5M175/15C175	1500	$26.23	(R)
3M175	3000	$40.41	(I)
5M175	5000	$49.34	|
7M175	7000	$51.50	|
11M175	11000	$89.68	|
16M175	16000	$108.53	|
23M175	23000	$142.55	|
38M175	38000	$274.53	(I)

(continue to 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 have been grandfathered for billing purposes. These meters/charges are not available to new meter rental requests.

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 have been grandfathered for billing purposes. These meters/charges are not available to new meter rental requests.

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	$55.01	(I)
Remote Index	---	$50.00	$4.00	
Pulse Output	---	$100.00	$8.00	
Administrative Set-Up/Consultation Fee (all meters)	$100.00	---	---	
Technical Assistance (Rotary meters only)	$100.00	---	---	

[1]Site specific engineering design costs for AAMR will be added to the installation charge if needed.

(continue to Sheet 15-3)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Thirteenth Revision of Sheet 27-1
Cancels Twelfth 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, 2024 (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)	$0.73852	$0.00435	$0.10025	$0.44732	$0.03969	**$1.33013**	(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.

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Fifteenth Revision of Sheet 31-11
Cancels Fourteenth 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, 2024 (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	$0.49260	$0.00435	$0.44732	$0.00500	**$0.94927**	(I)
Block 2: All additional therms	$0.45823	$0.00435	$0.44732	$0.00328	**$0.91318**	(I)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10025**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.48**	
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	$0.33448	$0.00435		$0.01874	**$0.35757**	(I)
Block 2: All additional therms	$0.30578	$0.00435		$0.01702	**$0.32715**	(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 dependen 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)

RATE SCHEDULE 31
NON-RESIDENTIAL FIRM SALES AND FIRM TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR INDUSTRIAL CUSTOMER CLASS: Effective: November 1, 2024 (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	$0.39571	$0.00435	$0.44732	$0.06165	**$0.90903**	(I)
Block 2: All additional therms	$0.36661	$0.00435	$0.44732	$0.06031	**$0.87859**	(I)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10025**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.48**	
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	$0.28416	$0.00435		$0.01499	**$0.30350**	(I)
Block 2: All additional therms	$0.25684	$0.00435		$0.01346	**$0.27465**	(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 Thirteenth Revision of Sheet 32-12
Cancels Twelfth Revision of Sheet 32-12

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES: **Effective: November 1, 2024** (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	$0.32211	$0.00435	$0.44732	$0.06080	**$0.83458**
Block 2: Next 20,000 therms	$0.28752	$0.00435	$0.44732	$0.05874	**$0.79793**
Block 3: Next 20,000 therms	$0.23011	$0.00435	$0.44732	$0.05533	**$0.73711**
Block 4: Next 100,000 therms	$0.17248	$0.00435	$0.44732	$0.05190	**$0.67605**
Block 5: Next 600,000 therms	$0.13107	$0.00435	$0.44732	$0.04944	**$0.63218**
Block 6: All additional therms	$0.11145	$0.00435	$0.44732	$0.04827	**$0.61139**
32 ISF Volumetric Charges (per therm):					
Block 1: 1st 10,000 therms	$0.25491	$0.00435	$0.44732	$0.05252	**$0.75910**
Block 2: Next 20,000 therms	$0.23082	$0.00435	$0.44732	$0.05182	**$0.73431**
Block 3: Next 20,000 therms	$0.19057	$0.00435	$0.44732	$0.05061	**$0.69285**
Block 4: Next 100,000 therms	$0.15045	$0.00435	$0.44732	$0.04942	**$0.65154**
Block 5: Next 600,000 therms	$0.12244	$0.00435	$0.44732	$0.04858	**$0.62269**
Block 6: All additional therms	$0.10834	$0.00435	$0.44732	$0.04817	**$0.60818**
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):					**$0.10025**
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV per month):					**$1.48**

(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 Fifteenth Revision of Sheet 32-13
Cancels Fourteenth Revision of Sheet 32-13

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES (continued): **Effective: November 1, 2024** (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]:					**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	$0.18569	$0.00435	$0.44732	$0.05827	**$0.69563**	(I)
Block 2: Next 20,000 therms	$0.15864	$0.00435	$0.44732	$0.05712	**$0.66743**	
Block 3: Next 20,000 therms	$0.11348	$0.00435	$0.44732	$0.05519	**$0.62034**	
Block 4: Next 100,000 therms	$0.06830	$0.00435	$0.44732	$0.05325	**$0.57322**	
Block 5: Next 600,000 therms	$0.04119	$0.00435	$0.44732	$0.05209	**$0.54495**	
Block 6: All additional therms	$0.02137	$0.00435	$0.44732	$0.05124	**$0.52428**	(I)
Interruptible Pipeline Capacity Charge (per therm):					**$0.01193**	
32 ISI Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	$0.16891	$0.00435	$0.44732	$0.05593	**$0.67651**	(I)
Block 2: Next 20,000 therms	$0.14445	$0.00435	$0.44732	$0.05521	**$0.65133**	
Block 3: Next 20,000 therms	$0.10365	$0.00435	$0.44732	$0.05398	**$0.60930**	
Block 4: Next 100,000 therms	$0.06283	$0.00435	$0.44732	$0.05278	**$0.56728**	
Block 5: Next 600,000 therms	$0.03835	$0.00435	$0.44732	$0.05204	**$0.54206**	
Block 6: All additional therms	$0.02042	$0.00435	$0.44732	$0.05150	**$0.52359**	(I)
Interruptible Pipeline Capacity Charge (per therm):					**$0.01193**	

[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 Thirteenth Revision of Sheet 32-14
Cancels Twelfth Revision of Sheet 32-14

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES (continued): **Effective: November 1, 2024** (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	$0.15382	$0.00435		$0.00423	**$0.16240**	(I)
Block 2: Next 20,000 therms	$0.13070	$0.00435		$0.00338	**$0.13843**	
Block 3: Next 20,000 therms	$0.09230	$0.00435		$0.00198	**$0.09863**	
Block 4: Next 100,000 therms	$0.05384	$0.00435		$0.00058	**$0.05877**	
Block 5: Next 600,000 therms	$0.03074	$0.00435		($0.00027)	**$0.03482**	
Block 6: All additional therms	$0.01543	$0.00435		($0.00084)	**$0.01894**	
Industrial						
Block 1: 1st 10,000 therms	$0.14768	$0.00435		$0.00345	**$0.15548**	
Block 2: Next 20,000 therms	$0.12551	$0.00435		$0.00279	**$0.13265**	
Block 3: Next 20,000 therms	$0.08860	$0.00435		$0.00169	**$0.09464**	
Block 4: Next 100,000 therms	$0.05172	$0.00435		$0.00058	**$0.05665**	
Block 5: Next 600,000 therms	$0.02952	$0.00435		($0.00009)	**$0.03378**	
Block 6: All additional therms	$0.01483	$0.00435		($0.00052)	**$0.01866**	(I)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (32 CTI or ITI) [3]:						
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	$0.13652	$0.00435		$0.00240	**$0.14327**	(I)
Block 2: Next 20,000 therms	$0.11605	$0.00435		$0.00183	**$0.12223**	
Block 3: Next 20,000 therms	$0.08193	$0.00435		$0.00087	**$0.08715**	
Block 4: Next 100,000 therms	$0.04779	$0.00435		($0.00007)	**$0.05207**	
Block 5: Next 600,000 therms	$0.02731	$0.00435		($0.00065)	**$0.03101**	
Block 6: All additional therms	$0.01371	$0.00435		($0.00102)	**$0.01704**	
Industrial						
Block 1: 1st 10,000 therms	$0.13832	$0.00435		$0.00307	**$0.14574**	
Block 2: Next 20,000 therms	$0.11756	$0.00435		$0.00247	**$0.12438**	
Block 3: Next 20,000 therms	$0.08301	$0.00435		$0.00145	**$0.08881**	
Block 4: Next 100,000 therms	$0.04841	$0.00435		$0.00045	**$0.05321**	
Block 5: Next 600,000 therms	$0.02768	$0.00435		($0.00016)	**$0.03187**	
Block 6: All additional therms	$0.01387	$0.00435		($0.00056)	**$0.01766**	(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.

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NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

Fifth Revision of Sheet 167-1
Cancels Fourth Revision of Sheet 167-1

SCHEDULE 167
GENERAL ADJUSTMENTS TO RATES

PURPOSE:
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 435 initiated following a Company request to change rates due to increases or decreases in the cost of general utility operations.

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, 2024 (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	$2.00	$0.22457	03 CSF	$0.00	$0.19528	(I) (I) (I)
02MF	$0.00	$0.22457	03 ISF	$0.00	$0.09578	(N)(N) (I)
02NP	$18.25	$0.22457				(N)(N)
02NPMF	$16.25	$0.22457				(N)(N)
27	$0.00	$0.24408				(I)

Schedule	Block	Amount	Schedule	Block	Amount	Schedule	Block	Amount	
31 CSF	Cust. Charge	$0.00	32 CSF	Cust. Charge	$0.00	32 CSI	Cust. Charge	$0.00	
	Block 1	$0.08982		Block 1	$0.06302		Block 1	$0.03908	(I)(I)(I)
	Block 2	$0.08195		Block 2	$0.05319		Block 2	$0.03300	(I)
31CTF	Cust. Charge	$0.00		Block 3	$0.03689		Block 3	$0.02284	
	Block 1	$0.06254		Block 4	$0.02052		Block 4	$0.01268	(I)
	Block 2	$0.05717		Block 5	$0.00875		Block 5	$0.00658	(I)
31ISF	Cust. Charge	$0.00		Block 6	$0.00318		Block 6	$0.00212	(I)(I)
	Block 1	$0.06457	32 ISF	Cust. Charge	$0.00	32 ISI	Cust. Charge	$0.00	(I)
	Block 2	$0.05821		Block 1	$0.03158		Block 1	$0.03665	(I)(I)(I)
31 ITF	Cust. Charge	$0.00		Block 2	$0.02666		Block 2	$0.03094	(I)
	Block 1	$0.04999		Block 3	$0.01844		Block 3	$0.02141	(I)
	Block 2	$0.04519		Block 4	$0.01025		Block 4	$0.01188	
				Block 5	$0.00453		Block 5	$0.00617	
				Block 6	$0.00165		Block 6	$0.00198	(I)(I)
			32 CTF	Cust. Charge	$0.00	32 CTI	Cust. Charge	$0.00	
				Block 1	$0.02915		Block 1	$0.01856	(I)(I)
				Block 2	$0.02477		Block 2	$0.01578	
				Block 3	$0.01749		Block 3	$0.01114	
				Block 4	$0.01020		Block 4	$0.00650	
				Block 5	$0.00583		Block 5	$0.00371	
				Block 6	$0.00293		Block 6	$0.00187	(I)(I)
			32 ITF	Cust. Charge	$0.00	32 ITI	Cust. Charge	$0.00	
				Block 1	$0.02519		Block 1	$0.02031	(I)(I)
				Block 2	$0.02140		Block 2	$0.01725	
				Block 3	$0.01511		Block 3	$0.01219	
				Block 4	$0.00882		Block 4	$0.00711	
				Block 5	$0.00504		Block 5	$0.00406	
				Block 6	$0.00253		Block 6	$0.00203	(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.

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25 First Revision of Sheet 175-1
Cancels Original 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, 2024 (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	Block	Adjustment	
2R		$0.00165					
2MF		$0.00165					(N)
2NP		$0.00165		31 CSF	Block 1	$0.00065	(N)(R)
2NPmf		$0.00165			Block 2	$0.00061	(N)(R)
03 CSF		$0.00136		31 CTF	Block 1	$0.00067	(I)
03 ISF		$0.00076			Block 2	$0.00061	(I) (R)
27		$0.00145		31 ISF	Block 1	$0.00053	(R)(I)
					Block 2	$0.00049	
				31 ITF	Block 1	$0.00057	
					Block 2	$0.00051	
				32 CSI	Block 1	$0.00028	
32 CSF	Block 1	$0.00047			Block 2	$0.00024	(R)
	Block 2	$0.00042			Block 3	$0.00018	(R)
	Block 3	$0.00033			Block 4	$0.00011	(I)
	Block 4	$0.00025			Block 5	$0.00007	
	Block 5	$0.00019			Block 6	$0.00004	(I)
	Block 6	$0.00017		32 ISI	Block 1	$0.00008	(I)
32 ISF	Block 1	$0.00006			Block 2	$0.00007	(R)
	Block 2	$0.00005			Block 3	$0.00005	(R)
	Block 3	$0.00004			Block 4	$0.00003	
	Block 4	$0.00003			Block 5	$0.00002	(I) (I)
	Block 5	$0.00003			Block 6	$0.00001	
	Block 6	$0.00003		32 CTI	Block 1	$0.00006	(I)
32 CTF	Block 1	$0.00009			Block 2	$0.00005	
	Block 2	$0.00008			Block 3	$0.00003	(R)
	Block 3	$0.00006			Block 4	$0.00002	(I)
	Block 4	$0.00003			Block 5	$0.00001	
	Block 5	$0.00002			Block 6	$0.00001	
	Block 6	$0.00001		32 ITI	Block 1	$0.00006	
32 ITF	Block 1	$0.00007			Block 2	$0.00005	(I)
	Block 2	$0.00006			Block 3	$0.00004	(I)
	Block 3	$0.00004			Block 4	$0.00002	
	Block 4	$0.00003			Block 5	$0.00001	(I)
	Block 5	$0.00002			Block 6	$0.00001	(I)
	Block 6	$0.00001		33		$0.00002	(I)

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Issued by: NORTHWEST NATURAL GAS COMPANY
d.b.a. NW Natural

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25 Third Revision of Sheet 182-1

Cancels Second 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

(C)

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2024

The Adjustment amounts shown below are calculated based on equal percent of margin by Rate Schedule and Customer class, and the rate allocation adopted in Docket UG 221. 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	
2R		$0.00844				(I)
2MF		$0.00844				(N)
2NP		$0.00844	31 CSF	Block 1	$0.00475	(I)
2NPmf		$0.00844		Block 2	$0.00442	(N) (I)
03 CSF		$0.00631	31 ISF	Block 1	$0.00359	(I) (R)
03 ISF		$0.00426		Block 2	$0.00333	(R) (R)
27		$0.00706	31 CTF	Block 1	$0.00380	(I) (I)
				Block 2	$0.00348	(I)
			31 ITF	Block 1	$0.00305	(R)
				Block 2	$0.00276	(R)
			32 CSI	Block 1	$0.00167	(I)
32 CSF	Block 1	$0.00168		Block 2	$0.00143	(R)
	Block 2	$0.00150		Block 3	$0.00104	(R)
	Block 3	$0.00121		Block 4	$0.00064	(R)
	Block 4	$0.00091		Block 5	$0.00040	(I)
	Block 5	$0.00070		Block 6	$0.00023	(I)
	Block 6	$0.00060	32 ISI	Block 1	$0.00155	(I)
32 ISF	Block 1	$0.00081		Block 2	$0.00133	(R)
	Block 2	$0.00074		Block 3	$0.00097	(R)
	Block 3	$0.00061		Block 4	$0.00060	(R)
	Block 4	$0.00049		Block 5	$0.00038	(I)
	Block 5	$0.00040		Block 6	$0.00022	(I) (I)
	Block 6	$0.00035	32 CTI	Block 1	$0.00115	(I) (R)
32 CTF	Block 1	$0.00147		Block 2	$0.00099	(R)(R)
	Block 2	$0.00125		Block 3	$0.00071	(R)
	Block 3	$0.00090		Block 4	$0.00043	(R)
	Block 4	$0.00054		Block 5	$0.00026	
	Block 5	$0.00033		Block 6	$0.00015	(I)
	Block 6	$0.00018	32 ITI	Block 1	$0.00124	(R)
32 ITF	Block 1	$0.00114		Block 2	$0.00106	
	Block 2	$0.00097		Block 3	$0.00076	
	Block 3	$0.00070		Block 4	$0.00046	(R)
	Block 4	$0.00042		Block 5	$0.00028	
	Block 5	$0.00025		Block 6	$0.00016	(R) (I)
	Block 6	$0.00014	33 (all)		$0.00009	(I)

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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; and Commission Order XX-XXX in Docket UG 490; (b) identify the adjustment applicable to rates under the Rate Schedules listed below. (T) (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, 2024** (C)
The Temporary Adjustments for Residential and Commercial Customers taking service on the above-listed Rate Schedules includes the following adjustment:

Residential Rate Schedules:	$0.00566
Commercial Rate Schedule 3:	($0.04545)
Commercial Rate Schedule 31:	($0.01571)

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 November 1, 2024 and for those connected on or after November 1, 2024. The resulting usage differential shall be multiplied by the per therm distribution margin for the applicable customer group. (C) (C)

   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)

SCHEDULE 190
PARTIAL DECOUPLING MECHANISM
(continued)

PARTIAL DECOUPLING DEFERRAL ACCOUNT (continued):

2. The baseline use-per-customer is:

   Residential (premise connected prior to November 1, 2024): 660.21 (N)
   Residential (premise connected on or after November 1, 2024): 449.38 (N)

   Commercial (Schedule 3): 2,973.46 (C)
   Commercial (Schedule 31): 34,835.37 (C)

3. Weather-normalized usage is calculated using the approach to weather normalization adopted in the Company's last general rate case, Docket UG 490. The weather data is taken from the stations identified in **Rule 24**.

   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 .15533 for Residential variances, .65004 for Commercial (Schedule 3) variances, and 6.69582 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, 2024 is $0.91084 per therm for Residential customers and $0.75406 per therm for Commercial (Schedule 3) customers and $0.47945 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.

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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.

<u>WARM FORMULA</u>:

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, 2024 are: (C)

Rate Schedule 2:	0.15533	Rate Schedule 3:	0.65004

(I)(I)

(continue to Sheet 195-4)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

Ninth Revision of Sheet 195-4
Cancels Eighth 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, 2024 are: (C)

Rate Schedule 2:	$0.91084	Rate Schedule 3:	$0.75406

(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	0.1553	$0.14		0.6500	$0.49
5	0.7767	$0.71		3.2502	$2.45
10	1.5533	$1.41		6.5004	$4.90
15	2.33	$2.12		9.7506	$7.35
20	3.1066	$2.83		13.0008	$9.80
25	3.8833	$3.54		16.251	$12.25
30	4.6599	$4.24		19.5012	$14.71
35	5.4366	$4.95		22.7514	$17.16
40	6.2132	$5.66		26.0016	$19.61
45	6.9899	$6.37		29.2518	$22.06
50	7.7665	$7.07		32.502	$24.51

(I)(I)
(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)

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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 $1.51976 cents per therm, the HDD variance is 50 HDDs colder than normal, (I)
and the monthly therm usage is 129 therms:

HDD Differential:	Normal HDDs:	600 HDDs	
	Actual HDDs:	650 HDDs	
	HDD variance:	600 – 650 = -50 HDDs	
Equivalent Therms:	HDD variance:	-50 HDDs	
	Statistical coefficient:	0.15533	(C)
	Equivalent therms:	-50 x 0.15533 = -7.7665 therms	(C)
Total Warm Adjustment:	Equivalent therms:	-7.7665 therms	(C)
	Margin Rate:	$0.90649	(I)
	Total WARM Adj.:	-7.7665 x $0.90649 = ($7.04025)	(R)
Total WARM Adjustment converted to cents per therm:	Total WARM Adj.	($7.04025)	(R)
	Monthly usage:	129 therms	
	Cent/therm Adj.:	($7.04025) / 129 = ($0.05458)	(R)
Billing Rate per therm:	Current Rate/therm:	$1.51976	(I)
	WARM cent/therm Adj.	($0.05458)	(R)
	WARM Billing Rate:	$1.51976 + ($0.05458) = $1.46518	(I)
Total WARM Bill:	Customer Charge:	$10.00	(I)
	Usage Charge:	$1.46518	(I)
	Total	(129 x $1.46518) + $10.00 = $197.01	(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.

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, Order No. 22-388 in docket (N)
UG 435 entered on October 24, 2022, and Order No. XX-XXX in docket UG 490 entered on XXXX (N)
XX, 2024.

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 (T)(D)
from the 2017 federal Tax Cuts and Jobs Act (TCJA). (D)

The adjustment to Customer rates for the amortization of the portion of EDIT associated with Plant (T)
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 $3.1 million per year, prior to full (C)
revenue gross up.

This rate adjustment first became effective commencing November 1, 2024. (C)

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)

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, 2024** (C)
The effect of this adjustment is included in the temporary rate and base rate for Plant. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED (T)(D)

The volumetric adjustment applicable to each Rate Schedule is shown in the table below: (D)

Rate Schedule	Block	Rate Adjustment (per therm)		Rate Schedule	Block	Rate Adjustment (per therm)
2R		($0.00732)				
2MF		($0.00732)				
2NP		($0.00732)		32 ITF	Block 1	($0.00071)
2NPmf		($0.00732)			Block 2	($0.00061)
03 CSF		($0.00553)			Block 3	($0.00043)
03 ISF		($0.00271)			Block 4	($0.00025)
27		($0.00691)			Block 5	($0.00014)
31 CSF	Block 1	($0.00254)			Block 6	($0.00007)
	Block 2	($0.00232)		32 CSI	Block 1	($0.00111)
31 CTF	Block 1	($0.00177)			Block 2	($0.00093)
	Block 2	($0.00162)			Block 3	($0.00065)
31 ISF	Block 1	($0.00183)			Block 4	($0.00036)
	Block 2	($0.00165)			Block 5	($0.00019)
31 ITF	Block 1	($0.00142)			Block 6	($0.00006)
	Block 2	($0.00128)		32 ISI	Block 1	($0.00104)
32 CSF	Block 1	($0.00178)			Block 2	($0.00088)
	Block 2	($0.00151)			Block 3	($0.00061)
	Block 3	($0.00104)			Block 4	($0.00034)
	Block 4	($0.00058)			Block 5	($0.00017)
	Block 5	($0.00025)			Block 6	($0.00006)
	Block 6	($0.00009)		32 CTI	Block 1	($0.00053)
32 ISF	Block 1	($0.00089)			Block 2	($0.00045)
	Block 2	($0.00075)			Block 3	($0.00032)
	Block 3	($0.00052)			Block 4	($0.00018)
	Block 4	($0.00029)			Block 5	($0.00011)
	Block 5	($0.00013)			Block 6	($0.00005)
	Block 6	($0.00005)		32 ITI	Block 1	($0.00057)
32 CTF	Block 1	($0.00083)			Block 2	($0.00049)
	Block 2	($0.00070)			Block 3	($0.00034)
	Block 3	($0.00050)			Block 4	($0.00020)
	Block 4	($0.00029)			Block 5	($0.00012)
	Block 5	($0.00016)			Block 6	($0.00006)
	Block 6	($0.00008)		33 (all)		$0.00000

(M)
(R)
(N)
(N) (R)
(N)
(I)
(I)
(R)
(I)
(R)
(I)
(R)
(I)
(R)
(R)
(M) (R)

(M) Moved from sheet 196.3.

(continue to Sheet 196-3)

SCHEDULE 196

(K)

—CANCELLED—

—Sheet 196-3 IS RESERVED FOR FUTURE USE—

(K) Transferred to sheet 196.2

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

Third Revision of Sheet 197-2
Cancels Second 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	
2R		$0.01204					(I)
2MF		$0.01204					(N)
2NP		$0.01204		31 CSF	Block 1	$0.00677	(N) (I)
2NPmf		$0.01204			Block 2	$0.00630	(N)
03 CSF		$0.00900		31 ISF	Block 1	$0.00512	(I)
03 ISF		$0.00607			Block 2	$0.00475	(R) (I)
27		$0.01007		31 CTF	Block 1	$0.00543	(I) (R)
					Block 2	$0.00497	
				31 ITF	Block 1	$0.00435	
					Block 2	$0.00394	(R)
				32 CSI	Block 1	$0.00238	(I)
32 CSF	Block 1	$0.00240			Block 2	$0.00204	(R)
	Block 2	$0.00214			Block 3	$0.00148	(R)
	Block 3	$0.00172			Block 4	$0.00091	(R)
	Block 4	$0.00130			Block 5	$0.00057	(I)
	Block 5	$0.00099			Block 6	$0.00032	(I)
	Block 6	$0.00085		32 ISI	Block 1	$0.00221	(I)
32 ISF	Block 1	$0.00116			Block 2	$0.00190	(R)
	Block 2	$0.00105			Block 3	$0.00138	(R)
	Block 3	$0.00087			Block 4	$0.00086	(R)
	Block 4	$0.00069			Block 5	$0.00055	(I)
	Block 5	$0.00057			Block 6	$0.00032	(I) (I)
	Block 6	$0.00051		32 CTI	Block 1	$0.00164	(I) (R)
32 CTF	Block 1	$0.00209			Block 2	$0.00141	(R)
	Block 2	$0.00179			Block 3	$0.00101	
	Block 3	$0.00128			Block 4	$0.00061	
	Block 4	$0.00077			Block 5	$0.00037	(R)
	Block 5	$0.00046			Block 6	$0.00021	(I)
	Block 6	$0.00026		32 ITI	Block 1	$0.00177	(R)
32 ITF	Block 1	$0.00163			Block 2	$0.00152	(R)
	Block 2	$0.00139			Block 3	$0.00109	(R)
	Block 3	$0.00099			Block 4	$0.00066	(R)
	Block 4	$0.00060			Block 5	$0.00040	
	Block 5	$0.00036			Block 6	$0.00023	(R) (I)
	Block 6	$0.00021		33 (all)		$0.00013	(I) (I)

Issued December 29, 2023
NWN OPUC Advice No. 23-30

Effective with service on
and after November 1, 2024

SCHEDULE 198
RENEWABLE NATURAL GAS ADJUSTMENT MECHANISM

PURPOSE:
The purpose of this Schedule is to identify adjustments to rates in the Rate Schedules listed below for the recovery of the revenue requirement of qualified investments, as defined by ORS 757.392(5), in renewable natural gas (RNG) infrastructure.

This adjustment mechanism will recover the revenue requirement associated with the prudently incurred qualified investments that contribute to the Company meeting the targets set forth in ORS 757.396. For purposes of this Schedule, “qualified investment” has the meaning given that term in ORS 757.392. This Adjustment Schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210 and Oregon Senate Bill 98 (2019) codified as ORS 757.396.

APPLICABLE:
To All Customers on the Rate Schedules of this Tariff listed below:

Rate Schedule 2	Rate Schedule 31	Rate Schedule 60A/60
Rate Schedule 3	Rate Schedule 32	
Rate Schedule 27	Rate Schedule 33	

Application to Rates:

The per-therm Base Adjustment in the applicable Rate Schedules include the following adjustment:

	All Customers	Effective Date:
Schedule 198 amortization	$0.00435	November 1, 2024

(C)

SPECIAL CONDITIONS:
1. The Company will file this Schedule by August 1 of each year as necessary to update all charges already included on this schedule as needed. Updating of charges will include updating for the relevant vintage of the revenue requirement for previously included investments and a true-up for actual costs and volumes of previously included costs. This updating of charges will be supported by a deferral application (Schedule 198 Deferral) that will apply to costs recovered through this Schedule 198. The amortization of the Schedule 198 Deferral amount will be subject to an earnings test that is set at the Company’s authorized ROE. (N) (N)

(continue to Sheet 198-2)

SCHEDULE 198
RENEWABLE NATURAL GAS ADJUSTMENT MECHANISM
(continued)

2. In addition, the Company will file this Schedule on or before February 28 as necessary for proposed charges relating to new qualified investments in anticipation of the expected in-service date of the RNG project and providing time for stakeholder review. When the Company anticipates that a new qualified investment will commence operation, the Company may file a deferral request by the in-service date (RNG Project Deferral). The RNG Project Deferral will include any start-up operating and maintenance costs incurred prior to the project being placed in service and the revenue requirements of the qualified investment beginning on the project's in-service date. Amounts will be deferred until the qualified investment can be placed in rates through Schedule 198. NW Natural will make a filing to amortize these deferred amounts under this Schedule 198. The amortization of the RNG Project Deferral amount will not be subject to the provisions of ORS 757.259(5). (N)

3. The Company will provide in its Schedule 198 RNG project application filings a draft procedural schedule to accommodate stakeholder review and feedback, and may also include a technical workshop, depending on the size and complexity of the RNG project.

4. NW Natural will change rates under this schedule concurrent with annual Purchased Gas Adjustment on November 1.

5. NW Natural will propose a cost allocation methodology consistent with Commission guidance, including Order No. 22-388 and any subsequent Commission precedent. For the Lexington RNG project, costs are allocated in accordance with Order No. 22-388, including the costs associated with the project that NW Natural deferred consistent with that order ("Lexington Deferral").

6. For purposes of this Schedule, only applications for RNG Project(s) exceeding $5 million individually or in aggregate will be eligible for recovery under this mechanism.

7. Within three years of the effective date of this tariff, NW Natural will convene a meeting with the parties in consolidated docket UG 411/UG 435 to meet and confer in good faith regarding a comprehensive review of Schedule 198. Any changes in Schedule 198 as a result of this review would apply prospectively to new RNG projects.

8. The provisions listed in the special conditions above may be modified if approved by the Commission.

QUALIFIED INVESTMENT COST RECOVERY:
The revenue requirement associated with qualified investments in RNG includes incremental depreciation expense, property and other taxes, return on investment, income taxes, operating and maintenance costs, and other costs relating to the Company's qualified investment. The capital structure and the cost of capital to be used in the calculation of return on rate base will be that adopted by the Commission in the Company's most recent general rate case.

(continue to Sheet 198-3)

SCHEDULE 330
RESIDENTIAL BILL DISCOUNT PROGRAM – OPTIONAL FOR QUALIFYING CUSTOMERS

PURPOSE:
The purpose of this schedule is to implement an optional bill discount program for income-qualifying residential customers.

APPLICABLE:
To all income-qualified Residential Customers taking service under Rate Schedule 2 of this Tariff. Income-qualified is defined as Customers with gross household income at or below 60% of Oregon State Median Income (SMI), adjusted for household size. For customers in single-person households, eligibility is extended to those with gross household incomes the greater of 60% SMI or full-time wages at Oregon minimum wage rates for Portland Metro area.

Pending operational readiness, this program will begin as early as October 1, 2022 and no later than November 1, 2022.

BILL DISCOUNT:
Participating income-qualified Customers will receive the following credit on their monthly bill:

	Income Qualifying	Bill Discount Percentage	
Tier 0	0-15% SMI	80%	(C)
Tier 1	16-30% SMI	40%	(C)
Tier 2	31%-45% SMI	20%	
Tier 3*	46%-60% SMI	15%	

* For customers in single-person households, Tier 3 eligibility is extended to those with gross household income that is the greater of 60% SMI or full-time wages at Oregon minimum wage rates for Portland Metro area.

SPECIAL CONDITIONS:
1. An Applicant for this bill assistance program must be the account holder and is required to provide an application that includes a self-declaration of household size and income. Household size reflects all permanent residents in the home, including adults and children. Qualifying income refers to total gross annual income, both taxable and nontaxable, from all sources for all persons in the applicant's household.
2. Renewal of a Customer's enrollment is required every two years. It is the customer's responsibility to notify the Company if there is a change in income qualification status.
3. NW Natural may also auto-enroll eligible customers that have received energy assistance or have participated in any of the Company's low-income programs with a Tier 3 bill discount. Auto-enrolled customers may provide additional information to qualify for higher tier discounts and must re-enroll every two years.
4. Participants that were not auto-enrolled may be subject to post-enrollment verification audit sampling, which may include a showing of proof of household size and income. Bill discounts may be suspended for Customers found to be ineligible or non-responsive during post-enrollment audits. Customers may re-apply for this program upon providing verification of eligibility.

(continue to Sheet 330-2)

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Direct Testimony of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD EXHIBIT 1800

December 29, 2023

EXHIBIT 1800 – DIRECT TESTIMONY – CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD

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 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 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 8 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.

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/1700, 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 rate classes for the test year of November 1, 2024, through October 31, 2025 ("Test Year"). I also explain how the Company derived Test Year revenues for the Industrial rate class.

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, RS 3 Basic Non-Residential (Commercial), 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 435.

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 across all rate classes. I describe the following three-step proposal in full later in my testimony. First, for RS 2 Residential, RS 3 Commercial, and RS 27 Dry-Out, NW Natural proposes 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. 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 1.75[1] in addition to the Transportation rate class. 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 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 1.75 or the Transportation rate class. 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 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. 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

[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.

such that the rate classes as a whole are moved closer to parity based on their indicated cost causation. The proposal described above is an incremental approach; it moves all rate classes closer to parity, but does so in a manner that works to minimize rate shock.

Next, I discuss proposed changes to rate design. The Company proposes to increase the residential fixed monthly charge from $8.00 to $10.00. I then address two requirements of the Company regarding rate design that came out of the Company's last general rate case, UG 435. I present a proposal to bifurcate the Company's residential fixed monthly charge based on premise dwelling type. Specifically, I propose a multi-family residential fixed monthly charge of $8.00, which is $2.00 lower than the proposed $10.00 single-family residential fixed monthly charge. The proposed fixed monthly charges are for residential premises connected prior to November 1, 2024. I also present a fixed monthly charge for new residential premises that join the system on or after the expected rate effective date of this proceeding, November 1, 2024.

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 1801, 1802, 1803, and 1804. NW Natural/1801, Wyman is a summary of the Company's long-run incremental cost study by rate schedule. NW Natural/1802, Wyman presents the rate spread allocation proposal methodology. NW Natural/1803, Wyman indicates the incremental revenue requirement allocation by rate schedule, as well as the bill impact and rate increase by rate schedule. NW Natural/1804, 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/1703, 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 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, 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 rate classes on a per customer basis. The forecast relies on the relationship between weather (including temperature which is translated into heating degree days, or "HDDs", as well as other variables such as precipitation and wind speed) and load by rate schedule and time of year (measured in daily increments).[2] The UPC Forecast was developed as described below:

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[2] The degree day is a unit of measurement based on the difference between the average temperature for a day and a base set point. Degree days are additive in that the sum of the daily degree days over the course of the month is taken to represent that month's weather. The degree day is a common unit of measurement that allows for an analysis of increasing usage as a function of increasingly colder weather.

- 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, 1998 through May 31, 2023 for two purposes. The first was to have recent actual weather data to statistically analyze against recent actual usage, and the second 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 normal degree days using a simple linear regression which estimates the relationship between temperature readings at like stations.
- I matched actual therm usage and actual HDDs for the period of January 2012 through May 2023. As part of this process, I used load data on a billing cycle basis, and matched actual weather observations with the days between cycle meter read dates. This process ensures actual usage recorded for each billing period is appropriately matched to the observed weather for the same period. I then created a weighting of the number of days, customers, and HDDs associated with each billing cycle for each schedule in the Residential and Commercial customer classes. I used a 59-degree Fahrenheit base for residential schedules and a 58-degree Fahrenheit base for Commercial

schedules as our temperature set points to convert temperature observations to HDDs.[3]

- After aggregating therm usage and weights on a monthly basis, I used these aggregates to regress therm use per premise per day against HDDs per day, using a type of econometric time series model specification. I created a model estimation for every firm sales schedule in the Residential and Commercial customer classes, as well as two class-wide estimations. 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 (4) temporal effects on usage from prior periods.
- Normal daily HDD amounts were developed using daily HDD values derived from the benchmark 25-year weather data set.
- Finally, the estimated coefficients were used to build the weather normalized UPC Forecast on a daily basis using the 25-year HDD benchmark.

[3] The set point is taken 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.

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 two Oregon general rate cases, UG 388 and UG 435. In both proceedings, 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

[4] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Exhibit Staff/400, Bain/4, lines 4-16 (April 22, 2022).

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]

Q. In NW Natural's most recent rate case (UG 435), did the Commission Staff recommend modifications to the UPC Forecast model specification?

A. Yes. Staff requested the Company, in future filings, continue to examine how impacts of the COVID-19 global pandemic relate to the UPC Forecast.

Q. Did other intervenors to UG 435 recommend modifications to the UPC Forecast model specification?

A. Yes. Witness Sudeshna Pal of the Oregon Citizens' Utility Board ("CUB") suggested the Company explore three modifications to the UPC Forecast model:

- The use of a composite weather variable, especially for residential and small commercial customers, as opposed to simply using HDDs as a proxy for weather patterns;
- including HDDs in multiple explanatory variables; and
- controlling for days of the week effect.[6]

Q. Did the Company apply these Staff and CUB recommendations to the ARIMA model specification and indicator variable selection process in this case?

A. Yes. As I describe below, I reviewed and decided to use each of these recommended modifications to the ARIMA model specification and indicator

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[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 435, Exhibit CUB/300, Pal/3, lines 14-19 (April 22, 2022).

variable selection process in this case, although with a different approach regarding the use of a composite weather variable.

Q. Please describe the changes in the UPC Forecast methodology from NW Natural's latest rate case, UG 435.

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.

CUB suggested I explore the use of a composite weather variable, which is one variable that accounts for multiple weather indicators such as temperature, wind speed, and precipitation, and employ a forecasting methodology similar to one presented by National Grid, a London-based multinational natural gas and electric utility.[7] After examining this methodology against the data available to me, I found that using a composite weather variable approach did not improve model efficacy relative to other model specifications I tested. I did find, however, that including additional weather variables such as those employed in the Company's Integrated Resource Plan ("IRP") long-term load forecast marginally improves the UPC Forecast model.

Also, per CUB's recommendation, I now include observed HDDs in multiple explanatory variables within the model. CUB suggested that use of multiple

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[7] *Gas Demand Forecasting Methodology*. National Grid. November 2016. Document is available at: https://www.nationalgrid.com/gas-transmission/document/132516/download.

variables that measure HDDs "can capture the dynamic nature of heat loss."[8] 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 found that including such observations can make small improvements to the model forecast. Further, I modified my model indicator variables to account for not just month, but number of weekend and holiday days within each month. Controlling for weekend and holiday days can help 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 more likely to be spent at home).

Per Staff's recommendation, I included 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.

Finally, I included a variable to forecast demand side management ("DSM") savings in the ARIMA model based on reported actual energy efficiency measures that have been deployed, rather than use a post-estimation adjustment based on anticipated programmatic savings.

[8] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Exhibit CUB/300, Pal/6, lines 11-14 and Pal/7, lines 1-7 (April 22, 2022).

Q. Please describe the additional weather variables included in the UPC Forecast in this case.

A. In addition to the standard HDDs that I have included in iterations of the forecast in prior cases, I now also include 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 IRP long-term resource planning forecast models.[9]

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.[10] 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 to be 14 degrees Celsius, or about 57.2 degrees Fahrenheit.[11]

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[9] 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.

[10] 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.

[11] *Ibid*.

A composite weather variable is created by using a formula to combine multiple weather variables into one variable. As noted above, I found that using a composite weather variable approach did not improve model efficacy relative to other model specifications I tested. Using these weather variables 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 now are included in multiple explanatory variables within the UPC Forecast using interaction effects.

A. I now include explanatory variables that have interactive effects between the additional weather variables and effective temperature HDDs, in addition to the standard HDD variable employed in prior model iterations. 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 now controls for weekend and holiday days.

A. In prior model iterations, I used a simple indicator variable for each month to control for differences in base load demand throughout the year. I now include 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. This can help control for changes to the elasticity of demand (especially residential demand) throughout the year as additional holiday days can signal periods when people take additional time off of work beyond the federally designated day(s), (e.g., taking additional days off around the Thanksgiving holiday). Each additional holiday day above the standard monthly amount of non-working days does not necessarily create the same demand as the last, however, as more days off can signal a higher rate of out-of-state travel and vacation time away from home.

Q. Please explain why the Company does not include a constant term in the UPC Forecast.

A. 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. 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 we 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).

Q. Please describe how the UPC Forecast now estimates DSM savings.

A. In UG 435 Opening Testimony, I wrote: “While we recognize that the UPC Forecast ARIMA regression model does account for declining usage due to energy efficiency measures over time, the model cannot fully capture that decline at the Test Year because it cannot anticipate future programmatic energy efficiency projects that have been planned and budgeted."[12] For that filing, I created a post-estimation adjustment to the UPC Forecast to account for DSM savings after the rate effective date.

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. 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 the Company's ARIMA model specification selection process.

A. The choice of model specification, in this case the ARIMA(p,d,q) terms, is one of the final steps in the UPC Forecast methodology. For every rate schedule modeled, I relied foremost on Durbin-Watson test statistics, r-squared values, and root mean squared error results to assess model efficacy and choose appropriate

[12] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision,* Docket No. UG 435, Exhibit NW Natural/1400, Wyman/13 (Dec. 17, 2021).

ARIMA *p* and *q* terms.[13] 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.[14]

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 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 outcome of this model specification selection process.

A. For all of the rate schedules I modeled, I found that optimal test statistics were achieved with one lagged autoregressive *p* term, and either no or between one

[13] 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.

[14] 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.

and two moving average *q* term(s).[15] For each rate schedule model, the Augmented Dickey-Fuller test indicated model stationarity using the selected *p* and *q* terms. Inclusion of the differencing *d* term degraded all or nearly all test statistics, and therefore I did not employ the *d* term in any model specification.

Q. 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 weekend-holiday indicator variables, weather-temperature interaction term variables, and COVID-19 and DSM variables in order to optimize model estimation. For all but one rate schedule, I used a weekend-holiday indicator variable for every month and dropped the constant term. Based on my analysis of the test statistics, I found that use of weekend-holiday indicator variables for non-winter months and a combined indicator for remaining months performed the best for the lower-load and largely heating-based consumption RS 27 Dry-Out rate schedule. Further, based on test statistics, I did not apply the COVID-19 variable to the RS 27 Dry-Out rate schedule. Finally, I only applied the DSM variable to the RS 2 Residential rate schedule, also based on test statistics.

[15] I use the word “optimal” instead of adjectives such as “larger” or “smaller” because not every test statistic is evaluated based on magnitude. The Durbin-Watson test statistic, which is a test for autocorrelation, takes a value from 0 to 4. The optimal value, which indicates no autocorrelation, is 2.

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 is able to estimate actual known out-of-sample values using historical data. The Company 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.

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 discussed above.

Q. How are the results of the ARIMA model interpreted and evaluated?

A. The monthly weekend-holiday indicator variables represent customer base load 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. I used statistical software to evaluate the model estimation output against the 25-year daily normal HDD values in order to derive a normalized use per customer per day by month.[16] 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.

Q. Please summarize the results of the UPC Forecast.

A. The estimated ARIMA coefficients produced a Test Year UPC of 660.2 therms for the Residential class and 3,997.2 therms for the Commercial class. The UPC for the Commercial class was further defined for each of the rate schedules within the class, to allow for the calculation of normalized revenues using rates from each rate schedule.

Q. Have you calculated a UPC for a subset of residential premises that represent new service connections ("New Premise UPC") for purposes of creating a bifurcated baseline for the Company's Decoupling mechanism?

A. Yes. I calculated a New Premise UPC for the Company's bifurcated Decoupling mechanism baseline proposal as outlined in NW Natural/1700, Walker.

Q. Please describe the New Premise UPC parameters and your methodology.

A. I queried the Company's Customer Information System ("CIS") for all bills generated for Oregon residential premises that had a service connection initiated over a 10-year period (beginning January 2013 through December 2022). For calculation of the New Premise UPC, I limited the analysis to only new connections

[16] 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.

initiated after January 1, 2018. Additionally, 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 so I did not include bills issued immediately after connection in my analysis. I used an ARIMA model specification nearly identical to the model used to derive the weather normalized UPC Forecast for the Residential rate class as described earlier in my testimony.

Q. Why is there generally a delay between service initialization 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. The gap between service initialization and full habitation, and the timing of my analysis in mid-2023, is also the reason why I did not include any premise data after 2022.

Q. Why did the Company use five years of usage data to establish the New Premise UPC?

A. The Company chose to include services initiated in the five years prior to January 2023 because the model requires data from multiple winter heating seasons to adequately interpret the load response of a customer class (or a subset thereof) to observed weather. If the Company did not use a large enough sample, I would not have enough data points to produce model coefficients that are statistically significant, nor would test statistics suggest the model specification is producing a reasonable prediction of weather normalized load. In the analysis the Company presented during the UG 435 rate case proceeding, I used a period of ten years to calculate the New Premise UPC. Staff took the position that a ten-year period was too long and captured premises it did not consider "new."[17] In response to Staff's concern, I have reduced the analysis period to five years which was the shortest modeling period that produced statistically significant model coefficients and acceptable test statistics.

Q. If the analysis uses five years of usage data, what is the median service age of the premises in the New Premise UPC?

A. The use of the five-year historical period translates into a weighted average service age of the evaluated new residential premises of just over two and a half years. Of all the new services evaluated, roughly one-fifth has an age of five years, roughly one-fifth has an age of four years (etc.), and roughly one-fifth has an age of just one year or less. Since the data captures premises initiated through December 2022, the median service in this analysis was connected in April 2020 (i.e., half were connected between January 2018 and April 2020 and half were connected between April 2020 and the end of December 2022).

[17] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Exhibit Staff/1300, Scala/20, lines 8-20 (April 22, 2022).

Q. What is the Company's weather normalized New Premise UPC estimated by this analysis?

A. The five-year analysis period produces a weather normalized New Premise UPC of 449.4 therms annually for purposes of the Company's bifurcated Decoupling mechanism baseline proposal.

Q. How is the customer forecast and UPC Forecast used to create Test Year volumes that generate revenues at existing rates for the proposed revenue requirement?

A. Residential and Commercial class Test Year monthly volumes were calculated by multiplying the weather normalized forecasted UPCs for each rate schedule by the forecasted monthly end-of-period customer counts.

Q. How are Test Year volumes built for the Industrial Sales and Transportation classes?

A. Test Year volumes for the Industrial Sales and 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/1703, Walker and is shown in summary at NW Natural/1702, 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/1700, 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.[18] The statistical coefficients to be used in the

[18] NW Natural Tariff OR 25, Schedule 195, Fourth Revision of Sheet 195-3.

calculation of the WARM Adjustment Factor, defined in Schedule 195 as β, are 0.15533 for RS 2 Residential and 0.65004 for RS 3 Commercial. These statistical coefficients, along with that of RS 31 Commercial Firm Sales, 6.69582, are used as outputs for the Company's Decoupling mechanism, as described in Schedule 190.[19]

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

[19] NW Natural Tariff OR 25, Schedule 190, Twelfth Revision of Sheet 190-2.

utility service.[20] By understanding the long run incremental costs by rate 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*

[20] 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 historic 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.

Optimality.[21] 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

[21] *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, 2025.

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; (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/1801, 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 435?

A. Generally, NW Natural's LRIC study methodology is similar to the methodology used in the Company's last rate case filing, UG 435. There are two notable modifications, both of which are based on Staff recommendations. I describe these changes in more detail later in this testimony. The modifications are updates to:

- The maximum daily delivered volume ("MDDV") calculation for design day load factor development, in order to account for changing incremental customer counts through time; and

- The system core main allocation, which now includes interruptible peak day deliveries, adjusted with a fifty percent credit, to calculate weighted peak day deliveries for all rate schedules as a basis for core main cost assignment.

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 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.[22]

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 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 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.

[22] 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.

Finally, I took the average aggregate MDDV value from the period January 2019 through September 2023. This value is the basis for the design day load factor denominator.

Q. Did the Company update how the MDDVs were estimated in the design day factor calculation?

A. Yes. Staff asserted, in its UG 435 Opening Testimony, that my method for estimating MDDVs overestimated capacity factors for some rate schedules because my averaging method essentially did not account for the full peak demand generated by new customers because it assumed zero demand for the years prior to their taking service. Overestimating capacity factors, as Staff noted, underestimates the capacity burden that some rate schedules may put on the system during peak times.[23] I updated my methodology to weight each year's MDDV values by Test Year customer counts for each rate schedule, as described above, which was Staff's preferred approach.[24] I note that this approach is only valid when using customer counts incremental to the Test Year; simply using year-to-year customer count differences would risk overestimating the capacity burden

[23] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Exhibit Staff/1600, Gibbens/6-13 (April 22, 2022).

[24] *Id*. at 11, lines 11-22.

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 30.1 percent, with a firm load factor of 26.5 percent and a transportation load factor of 58.7 percent. The RS 2 Residential load factor is about 23.7 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 23.4 percent, while the large Commercial rate schedules have estimated load factors ranging from 24.6 percent to 59.2 percent; the Industrial rate schedules have estimated load factors ranging from 35.5 percent to 68.5 percent.

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 4 inches in diameter, and those 4 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 six calendar years (2017 – 2022) 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 six years of job orders data, I used a main extension forecast for 2023 that is produced annually by the Company's Business Analytics team. This forecast uses three categories of extensions: Commercial mains, Residential mains, and system expansion main extensions. The latter 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 6-year median cost per foot and median main length installed by market segment. Additionally, I used the same dataset to calculate the 6-year median cost per foot and median main length installed by pipe size (less than 4 inches, or greater than or equal to 4 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 weighted using three data sources ("Inflation Index").[25] 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

[25] I weighted inflation forecasts from three sources: (1) IHS Markit Power Planner Table A20: *Cost Trends of Gas Utility Construction: Pacific Region*. Mains; plastic value. Second Quarter, 2019. (2) The Company's long-term inflation assumption used in its 2022 IRP, Docket No. LC 79. (3) Oregon Economic and Revenue Forecast, Table Other Economic Indicators: CPI Urban Consumers. Page 50, September 2023.

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 6-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 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 4 inches and greater than or equal to 4 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.[26] 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 4 inches and equal to or greater than 4 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

[26] 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.

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.

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 system design day load factor (i.e., the "average") and distributes costs across all schedules. The firm demand allocator is based on one minus the system design day load factor (i.e., the "excess") and similarly distributes costs across all rate schedules.

Q. Did the Company update how system core mains are allocated?

A. Yes. The system core main allocation now includes interruptible peak day deliveries, adjusted with a fifty percent credit. Staff, in its UG 435 Opening Testimony, 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.[27] The Company

[27] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Exhibit Staff/1600, Gibbens/13, lines 11-14 (April 22, 2022).

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, including an allocation to interruptible customers at fifty percent of the standard firm demand allocation as Staff recommended is reasonable.

c. System Reinforcements

Q. 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 five years of historical system reinforcement capital spend (2018 – 2022). For each year, the system reinforcement capital investment was multiplied 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 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.[28] 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. I halved this ratio for interruptible sales customers to

[28] Note that the UG 435 LRIC study did not apportion any system reinforcement costs to interruptible rate schedules.

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 8 years of historical accounting data of Oregon services job orders (2015 – 2022) 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) and 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 a eight-year median 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.

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 2021, and again in 2023, to reflect current operations and Accounts Services functions. Both the 2021 and 2023 updates were 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/1801, 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 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 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/1700, 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 RS 2 Residential, RS 3 Commercial, 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. The LRIC study indicates that the RS 2 Residential and RS 3 Commercial rate schedules are at a similar level of parity.

Table 1
LRIC Study Parity Ratio at Present Rates, by Rate Schedule

RATE SCHEDULE	02R	03C	03I	27R	31CSF	31CTF	31ISF	31ITF
LRIC Study Determined Parity Ratio	**0.96**	**0.95**	**1.21**	**0.82**	**1.66**	**1.95**	**1.63**	**2.34**
RATE SCHEDULE	32CSF	32ISF	32CTF	32ITF	32CSI	32ISI	32CTI	32ITI
LRIC Study Determined Parity Ratio	**1.61**	**1.91**	**2.22**	**1.65**	**1.30**	**1.46**	**2.64**	**1.25**

The class-wide LRIC study indicated parity ratios are as follow: 0.96 for the Residential schedule; 0.95 for the Small Commercial schedule; 1.59 for Large Commercial Sales schedules; and 1.53 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 filed study, as part of UG 435, 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 half of these schedules have moved closer to parity.

Both studies also indicate that RS 2 Residential and RS 3 Commercial customers are paying less than their determined cost of service. The RS 2 Residential parity ratio is slightly higher than the UG 435 indicated ratio (while still underpaying the determined cost of service, the LRIC study indicates the gap has narrowed). The RS 3 Commercial parity ratio is roughly the same. 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 435.

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, as well as the capital investment cost and O&M assumptions, of its cost of service analysis for tariff Schedule 4 – Residential Multi-Family Service ("Schedule 4").[29]

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.

[29] The Company also has updated the cost of capital components, as well as the capital investment cost and O&M assumptions, of its cost of service analysis for tariff Schedule 15 – Charges for Special Metering Equipment, Rental Meters, and Metering Services, and Schedule H – Large Volume Non-Residential High Pressure Gas Service Rider.

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 cost of service analysis also updates the service shut-off valve cost, from $46 to reflect recent average costs of $52 per unit. The analysis also updates the annual O&M expense to reflect the 2023 Meter-to-Cash study described earlier in my testimony.

Q. Please summarize the results of this analysis.

A. The results of the analysis increase the Schedule 4 base monthly rate from $10.30 to $11.54, an increase of 12.0 percent.

IV. RATE DESIGN & RATE SPREAD

Q. What is the purpose of the rate design and rate spread section?

A. The purpose of this section is to:

- Present the Company's proposal to increase its Residential fixed monthly charge;
- Address two requirements of the Company regarding rate design that are set forth in the Commission's order adopting the Multi-Party Stipulation Regarding Revenue Requirement, Rate Spread, and Certain Other Issues in UG 435 ("UG 435 First Stipulation");
- Present the Company's New Premise Customer Charge;
- 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. What is the Company's proposal for its Residential fixed monthly charge?

A. The Company proposes to increase the fixed monthly charge for RS 2 Residential from $8.00 to $10.00 in order to collect more of its fixed costs on a per-customer, per-month basis.

Q. Why is the Company proposing to increase the fixed monthly charge for RS 2 Residential?

A. The fixed monthly charge is one piece of the RS 2 Residential rate mechanism the Company uses to collect a portion of the fixed cost component of its overall authorized revenue requirement for that class. The other piece is the volumetric rate, which is used to collect the remainder of the fixed cost component as well as the variable component of the overall authorized revenue requirement. In fact, a significant portion of the Company's fixed costs are collected on the volumetric rate. The LRIC study's indicated fixed monthly charge for the Residential class at the proposed rates in this proceeding is an estimated $37.06 per customer per month. At the current rate of $8.00, the Company would only collect only about one-fifth of its fixed costs through the fixed charge component of its Residential rate, relying on collection of the remaining four-fifths through the volumetric rate component that produces revenues that vary year-to-year based on weather. The

Company's proposal of $10.00 results in a more reasonable level of fixed cost recovery that is not contingent on weather at a higher, level of 27.0 percent of its total fixed costs.

Q. How does the Company's existing Residential fixed monthly charge compare to peer utilities?

A. Table 2, which I present later in my testimony, shows the monthly Residential fixed charges for the Company's peer utilities. As shown in Table 2, the Company's existing monthly Residential fixed charge ranks near the bottom of all peer utilities.

Q. Is this the Company's only proposal with regards to the fixed monthly charge for the Residential class?

A. No. As I explain later in my testimony, the Company proposes additional changes to the fixed monthly charge for its Residential class.

Q. What are the two requirements of the Company regarding rate design in the UG 435 First Stipulation that you are addressing in this general rate case?

A. The first requirement relates to commercial service on Rate Schedule 3 (Basic Firm Sales Service – Non-Residential) ("RS 3C"). Specifically, in Section III.11 of the UG 435 First Stipulation, the Company agreed to "develop a cost study analysis examining whether to bifurcate Commercial RS 3," "consult with SBUA [Small Business Utility Advocates] prior to conducting cost study," "present its findings to the Stipulating Parties prior to the Company's next general rate case" and "address whether to bifurcate Commercial RS 3 in its opening testimony in its next general rate case."[30] [31]

The second requirement relates to the customer charge for multi-family versus single-family dwellings. Specifically, in Section III.12 of the UG 435 First Stipulation, the Company agreed to "host a workshop with the Stipulating Parties relating to the difference in fixed cost for multi-family vs. single-family dwellings" and, [i]n advance of the workshop, [to] confer with the Stipulating Parties regarding the scope of the workshop."[32]

Q. Did the Company comply with Section III.11 of the UG 435 First Stipulation with regards to a cost study analysis of Commercial Rate Schedule 3 ("RS 3C Cost Study")?

A. Yes. The Company consulted with SBUA on the parameters of the RS 3C Cost Study and presented preliminary results to SBUA on June 26, 2023. The Company presented its final findings to the Stipulating Parties on October 18, 2023. My testimony addresses why the Company proposes to not bifurcate Commercial RS 3 as a result of the RS 3C Cost Study.

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[30] The Stipulating Parties to the UG 435 First Stipulation are Staff, CUB, SBUA, and the Alliance of Western Energy Consumers ("AWEC").

[31] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Order No. 22-388, Appendix A, page 11, lines 3-5 (Oct. 24, 2022).

[32] *Id*. at 11, lines 6-11.

Q. Did the Company comply with Section III.12 of the UG 435 First Stipulation with regards to the fixed monthly customer charge for multi-family versus single-family dwellings ("Customer Charge Workshop")?

A. Yes. The Company conferred with the Stipulating Parties with regards to the scope of the Customer Charge Workshop on February 14, 2023. The Company hosted the Customer Charge Workshop with the Stipulating Parties on October 18, 2023. My testimony addresses the Company's proposal resulting from its findings presented at the Customer Charge Workshop.

Q. Is NW Natural proposing any changes to its rate structure as a result of the Customer Charge Workshop?

A. Yes. Below, I present a proposal to bifurcate the residential fixed monthly charge based on premise dwelling type as a result of the Customer Charge Workshop. In summary, the Company proposes a multi-family residential fixed monthly charge of $8.00, which is $2.00 lower than the proposed $10.00 single-family residential fixed monthly charge.

a. Rate Schedule 3C Cost Study

Q. Please summarize the issue that the Company agreed to address in the RS 3C Cost Study.

A. The Company agreed to develop a cost study analysis examining whether to bifurcate its RS 3C tariff rate based on the size of the meter connected to each service on the rate schedule. In UG 435 Opening Testimony, SBUA noted that an estimated 10.7 percent of NW Natural's RS 3C customers are connected to large capacity meters, which SBUA defined as having capacity above 1,000 MBH (BTUs per hour).[33] The weighted average cost of these meters, as calculated in the Company's LRIC Study in UG 435 ("UG 435 LRIC Study"), is noticeably higher than the cost of sub-1,000 MBH meters, which are connected to the remaining 89.3 percent of RS 3C customers. SBUA argued that the cost differences lead to an upward tilted cross subsidy, such that the RS 3C customers that are lower volume users purportedly are subsidizing the costs of the higher volume RS 3C customers.[34] SBUA proposed bifurcation of the Company's LRIC Study in its UG 435 Opening Testimony.[35] The Company agreed to examine whether there such a subsidy exists and, if so, whether it warrants bifurcation of the RS 3C rate schedule into two sub-schedules based on meter size.

Q. How did the Company examine this issue?

A. The Company queried and analyzed data for customers taking service on RS 3C, broken down by meter type and size and bifurcated its UG 435 LRIC Study to determine how both revenues and expenses would be allocated to a new commercial rate schedule for customers with larger meter sets given their usage profiles.

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[33] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Exhibit SBUA/100, Kermode/9 (April 22, 2022).

[34] *Id*. at 10.

[35] *Id.* at 13.

Q. How do you respond to SBUA's proposal to bifurcate the Company's RS 3C tariff schedule based solely on meter size at each connection?

A. Meter costs are just one of many categories of costs that are allocated in the LRIC study. For instance, in the UG 435 LRIC study, capitalized meter and meter-related net plant balances were 8.2 percent of total net plant. Meter and meter-related O&M expenses were about 5.6 percent of total O&M expense. Meter costs are just one (relatively small) component of all the allocable costs driving the LRIC Study parity ratios.

The fact that a RS 3C customer is connected to a larger-sized meter does not necessarily mean that the customer consistently is a large volume user. For instance, sometimes a former larger customer could have been at the premise prior and the meter set remained connected for the RS 3C customer. Some customers need to have the ability to ramp up usage under certain conditions (freeze protection, emergency backup). Operationally, NW Natural's objective is to deliver 100 percent capacity on gas equipment needs regardless of when or how often that need arises. Finally, I note that meter size does not always equate to capacity. Due to space constraints (for instance, a small building setback), the Company may install a smaller meter but run a higher pressure through it to increase its capacity. For these reasons, meter size should not be a sole determinant of service rate schedule.

Q. Please summarize the results of the RS 3C Cost Study.

A. I found that RS 3C customers with large meter sets do, on average, use more load on a per customer basis compared to RS 3C customers with meter sets of sub-

1,000 MBH capacity. The larger meter set group had a UPC of just under five times that of the smaller meter set group. Despite this higher UPC, on average, these customers would pay higher bills if they were to elect service on the Company's other commercial rate classes, RS 31C (Non-Residential Firm Sales and Firm Transportation Service) and RS 32C (Large Volume Non-Residential Firm and Interruptible Transportation Service).

RS 3C larger meter set customers, because of their higher average usage, contribute more margin revenue to the RS 3C schedule compared to customers with smaller meter sets. On the cost side, for the larger meter set customers, I used weighted average meter costs calculated by SBUA,[36] as well as assumed service line, mains, O&M, capacity investment, and storage costs commensurate to industrial and commercial customers with similar load profiles. When accounting for the higher revenues and higher costs, I found that the larger meter size customers as a RS 3C sub-class overpay their cost to serve relative to smaller meter size customers on that schedule. Therefore, moving larger meter RS 3C customers to a sub-schedule or to a completely new schedule would be detrimental to smaller meter size customers.

Q. Please comment on the findings of the RS 3C Cost Study.

A. It is bad policy to set rate design on the basis of one type of service characteristic (e.g., meter size), especially when the basis for that design (e.g., placing customers with higher loads on a bifurcated rate schedule) does not hold valid, as

[36] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Exhibit SBUA/103, Kermode/1 (April 22, 2022).

explained above. Meter size is not indicative of a subset of commercial services with common characteristics in terms of load (e.g., heating vs non-heating, peaking vs flat), equipment type, or capacity requirements.

For these reasons, and based on the results of the RS 3C Cost Study, the Company is not proposing to bifurcate its RS 3C tariff rate in this rate case.

b. Single-Family vs Multi-Family Customer Charge Workshop

Q. Please summarize the issue that the Company agreed to address in the Customer Charge Workshop.

A. NW Natural agreed to host a workshop relating to the difference in fixed cost for serving multi-family residential premises compared to single-family residential premises. In UG 435 Opening Testimony, Staff indicated interest "in exploring whether or not the Company should separate pricing for multi-family residential customers" based on distinctions that could make the fixed costs of serving multi-family premises lower relative to single-family premises.[37] These distinctions are based largely on economic and spatial efficiencies associated with serving customers that are generally clustered, and are located in higher density urban areas within the Company's service territory. Hypothetically, such efficiencies may be due to lower marginal distribution costs on a per multi-family premise basis as it requires fewer average feet of main, for instance, to serve each premise relative to single-family premises due to spatial clustering. Economic efficiencies in marginal O&M expenses may be observed as well, for items such as meter reading

[37] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Exhibit Staff/1300, Scala/48, lines 18-19 (April 22, 2022).

and field technician expense or accounts opening and closing processes (e.g., it takes fewer miles of travel to serve denser areas, and multi-family premises have more transitory accounts compared to single-family premises). Staff expressed interest in understanding these efficiencies and whether they drive significant enough variation in the fixed costs between premises types to pursue a modification to the residential base monthly charge.[38]

Q. Have other Oregon utilities adopted separate base monthly charges for single-family and multi-family residential premises?

A. Yes. Portland General Electric Company ("PGE") and PacifiCorp d/b/a Pacific Power ("Pacific Power") currently have separate base monthly charges for single-family and multi-family residential premises for electric customers. Avista Corporation dba Avista Utilities ("Avista") will have separate base monthly charges for single-family and multi-family natural gas residential customers beginning April 1, 2024.

Q. Please summarize the types of multi-family residential premises that the Company serves and their associated rate schedules.

A. Multi-family residential premises on the Company's system can fall under different rate schedules depending upon the circumstances of the dwelling and service type:

- Schedule 2 Residential Sales Service (RS 2 Residential) for individually metered customers;

[38] *Id*. at 49, lines 2-4.

- Schedule 3 Basic Firm Sales Service Non-Residential (RS 3 Commercial), which includes residents of a multi-family building with natural gas service that is master metered under a commercial rate schedule and, therefore, are not directly charged by the utility and are not utility customers; and
- Schedule 4 Residential Multi-Family Service (RS 4 Multi-Family) for customers that reside in a particular type of multi-family building.
- Additionally, NW Natural also serves master-metered multi-family buildings where a single meter serves the entire building. These multi-family buildings may have several residences served by the single meter, but the customer account and billing are associated with a property management company or landlord. These customers are typically RS 3 Commercial, and as explained below, NW Natural is not proposing any rate design changes for these RS 3 Commercial customers.

Q. What was the outcome of the Company's conference with the Stipulating Parties in advance of the Customer Charge Workshop?

A. At the outset of the analysis, the Company did not have a complete survey of billing-quality data that identified multi-family residential premises in its CIS. The Company agreed to acquire the necessary data. The Stipulating Parties agreed on an analysis framework whereby the Company would examine how economic and spatial efficiencies result in cost differences between premise types for distribution piping (e.g., mains), meters and services, and O&M categories such as meter reading and field work.

For purposes of the analysis, the Company defined multi-family residential premises as attached dwelling units of two or more attached units including duplexes, apartments, condos, or townhomes that are individually metered on RS 2 Residential. The Company also agreed to examine the scale of the sub-set of residential master metered premises on RS 3 Commercial. Finally, the Company excluded all premises on RS 4 Multi-Family from the analysis.[39]

Q. Please describe the Company's data collection methodology for this issue.

A. The Company engaged a third-party data analytics vendor to identify and verify both multi-family residential dwelling units and master metered buildings (such as apartment buildings without individually metered units) within its service territory. The goal of this work was to enhance the Company's CIS with active residential premise data with a field indicating dwelling type: single-family or multi-family. The vendor used an address matching algorithm to append third-party data to NW Natural's CIS dataset to increase the number of features available for classifying multi-family premises. Features include information such as a unit number or other parcel grouping identifiers (e.g., common tax lot number or address for multiple premises). The vendor also used public and private real estate data sources to visually verify samplings of dwelling unit types. Using this process, the vendor was able to identify and validate residential dwelling types, including buildings served

[39] The Company offers a separate multi-family residential fixed monthly charge rate for eligible new construction multi-family developments through its Residential Multi-Family Service tariff (RS 4). The charge rate for this schedule is based on a separate cost of service analysis for a specific type of eligible new construction multi-family development and is not applicable to premises taking service on RS 2 Residential.

by master meters. These data are meant to supplement and improve the accuracy of NW Natural's CIS customer dataset.

Q. Please describe the Company's analysis methodology in preparation of the Customer Charge Workshop.

A. I worked across Company departments, notably with the Company's GIS team, to conduct a spatial efficiency analysis to understand how differences in geographic densities of multi-family premises relative to single-family premises may drive differences in distribution system design and therefore cost of service efficiencies. Using GIS software, we mapped every Oregon residential premise by dwelling type, along with the distribution system (mains and services) directly serving each premise riser for a radius of one hundred feet (about three-quarters of an acre). This analysis did not assign transmission or large capacity mains to any single premise since these parts of the distribution system serve many connections, both residential and non-residential, and cannot be assigned to any specific premise. We used GIS data analysis tools to identify and assign total feet of distribution mains by premise type to understand the extent to which multi-family premises are served by fewer feet of the distribution system relative to single-family premises. After calculating the differences in distribution system densities by premise type, I bifurcated the UG 435 LRIC Study to adjust the distribution cost allocation for single-family and multi-family premises in order to estimate a measure of cost of service efficiency for the premise type with the lower assigned distribution cost.

Q. Please summarize the analysis results presented at the Customer Charge Workshop.

A. The Company's vendor identified roughly 10.7 percent of the Company's residential premises as multi-family. The Company's distribution system is designed such that these premises from the riser to an area within three-quarters of an acre, according to the GIS analysis, require about 23.9 percent fewer feet of piping. We find no difference, however, in services and meters requirements nor have we found a difference in O&M expense on a per customer basis.

Assigning these lower distribution system needs to the multi-family premises, the bifurcated UG 435 LRIC Study suggests that the fixed cost rate component for these premises could be roughly 18.6 to 23.8 percent lower compared to the fixed cost rate for single-family residential premises based on two scenarios: A customer using 450 and 350 therms annually, respectively. This difference is owing not just to the lower assigned distribution cost, but also to lower storage and capacity costs that the bifurcated UG 435 LRIC Study assigns to the lower use multi-family premises. Together, these factors drive this measure of cost of service efficiency.

Q. Has the Company examined the demographics of the premises identified as multi-family?

A. Yes. The Company does not have extensive detailed demographic data on its customers residing at multi-family premises. Using GIS analysis, however, we estimate that a higher proportion of multi-family premises in the Company's service territory are located in low-income Census Tracts as defined by the US Census

Bureau relative to single-family premises (28.5 percent vs 21.7 percent).[40] Further, a higher proportion of customers residing at multi-family premises are enrolled in Schedule 330 (the Company's Residential Bill Discount Program) relative to customers residing at single-family premises (7.9 percent vs 4.5 percent).

Q. What is the Company's proposal in response to the results presented at the Customer Charge Workshop?

A. The Company proposes a lower fixed monthly charge for multi-family premises relative to single-family premises. The Company is making this proposal in response to the spatial and economic fixed cost efficiencies suggested by the results of this analysis, to be consistent with responses of peer utilities to similar analyses, and because the likelihood that customers residing in multi-family premises live in low (or lower) income households is slightly higher than that of customers residing in single-family premises.

Specifically, the Company proposes a multi-family residential fixed monthly charge of $8.00, which is $2.00 lower than the proposed $10.00 single-family residential fixed monthly charge.

Q. Please explain why the Company is making this proposal.

A. The Company's proposal recognizes the results presented at the Customer Charge Workshop by assigning multi-family premises a lower portion of fixed costs

[40] Note that being located in a low-income Census Tract does not signify that a customer residing at a premise in that Census Tract lives in a low-income household, just that there is a higher likelihood that the customer lives in a low (or lower) income household.

for each monthly bill and provides cost savings for customers who may be more likely to live in low or lower income households.

The midpoint of the results presented at the Customer Charge Workshop shows a 21.2 percent reduction on the fixed cost rate component (the average of 18.6 to 23.8 percent).[41] As a practical matter, the Company's proposal represents a 20.0 percent reduction ($2.00 less than the proposed $10.00 monthly single-family fixed charge), which is used to maintain a rounded fixed charge amount for both premise types.

Q. How does the Company's existing and proposed fixed monthly charges compare to peer utilities?

A. Table 2 below is a comparison of the Company's existing fixed monthly charge and its proposal compared to peer utilities in the Pacific Northwest:

[41] Note that this reduction is based on the fixed cost rate component only, and not the entire $37.06 fixed monthly cost amount referenced earlier in my testimony.

Table 2
Fixed Monthly Charges for
Single-Family and Multi-Family Residential Customers,
Comparison of Peer Utility Residential Rate Tariffs

		Fixed Monthly Charge	
Utility	**Service Type^**	**Single-Family**	**Multi-Family**
Puget Sound Energy	NG	$ 12.50	*N/A*
Avista*	NG	$ 11.25	$ 9.75
PGE	E	$ 11.00	$ 8.00
Pacific Power	E	$ 11.00	$ 8.00
NW Natural (*Proposed*)	NG	$ 10.00	$ 8.00
NW Natural (*Current*)	NG	$ 8.00	*N/A*
Cascade	NG	$ 6.00	*N/A*

* Avista rates indicated above are for new rates effective April 1, 2024.
^ Service Type: NG=Natural Gas; E=Electric.

Per Table 2, the Company currently has one of the lowest fixed residential monthly charges relative to its peer utilities. NW Natural's proposal would still result in a single-family residential premise charge among the lowest in its peer group, but will align its multi-family residential premise charge with that of PGE and Pacific Power. As I explained earlier in my testimony, the proposal results in a reasonable collection of its fixed costs on a monthly basis and still sends a conservation price signal on its volumetric rate.

Q. How does the Company propose to implement its proposal?

A. The single-family and multi-family fixed monthly charges will be bifurcated and be included on the existing RS 2 Residential tariff. The Company intends to work internally to validate the multi-family premise data from now until the rate effective date of this rate case. The Company will implement a process whereby customers may inquire whether they are on the correct bifurcated fixed charge.

Q. Has the Company examined the scale of the sub-set of residential master-metered premises on RS 3 Commercial?

A. Yes, but more analysis is needed to determine which master-metered premises are serving individual residential dwelling units, how many are being served, and for what purposes. For instance, some master-meters may be serving common area clubhouses and pools instead of residential space and/or water heating needs. Further, while we do know that master-meter premises with a residential designation make up just two-tenths of one percent of all residential premise types, the Company does not currently have data to ascertain how many residential units (such as individual apartments) are being served at each meter. Finally, more analysis is also needed to understand whether any geographic distinction exists within these premises (e.g., what types of services master-metered buildings in suburban areas use compared to those in more denser areas). We note that these premises are billed on RS 3C with a fixed monthly charge of $15.00; any fixed cost efficiencies (if they exist) would be applied to the bill of the account holder (such as a property management company or landlord), and then that amount would be spread among the multiple, if not dozens, of residential units on that premise resulting in very little practical change to residents' utility expense.

c. New Premise Customer Charge

Q. Please summarize the Company's proposal for a New Premise Customer Charge.

A. The Company proposes to include a higher fixed monthly charge for new customers added to the system on or after the effective date of rates for this proceeding (November 1, 2024). The Company plans to charge new residential customers (i.e., new residential premises added to the system) $26.25 per month. This fixed charge is $16.25 more per month than the proposed fixed monthly charge for existing residential customers.

Q. Why is the Company seeking to increase the fixed monthly charge for new residential customers?

A. As explained in NW Natural/100, Palfreyman-Kravitz, the proposed fixed charge for new customers is designed to address intra-class equity concerns between our existing and new residential customers. Earlier in my testimony I presented the Company's weather normalized New Premise UPC of 449.4 therms annually. This UPC is roughly 210.8 therms lower than the existing residential weather normalized UPC of 660.2 therms annually. Under the Company's existing decoupling mechanism, new residential customers would be decoupled to the 660.2 therm baseline, meaning that the differential between their actual usage and the baseline would be collected in the decoupling deferral each year and recovered from all decoupled customers.

Q. Please explain how the proposed fixed charge for new residential customers promotes fairness and equity in residential rate design.

A. The new fixed monthly charge is set to reflect the difference in the UPC for new customers compared to existing customers. Without the higher new premise fixed charge, the Company's decoupling deferral, which is amortized through the volumetric rate, would be higher. The higher volumetric rate would impact higher users the most, including those users who are least able to respond in the short-run to higher price signals with energy efficiency measures such as new appliance purchases and home weatherization.

The new residential premise fixed charge will ensure that new residential customers as a group are providing equivalent contributions for their cost of service as existing residential customers.

Q. Does the Company's proposal include a lower fixed charge for new multi-family residential premises?

A. Yes. The Company proposes to apply the same $2.00 reduction to the fixed charge for existing multi-family residential customers to new multi-family residential customers. Therefore, the new multi-family residential fixed monthly charge would be $24.25.

Q. Please explain how the New Premise Customer Charge is calculated.

A. First, I apportioned the Test Year Residential class customer count and volumes among the four residential sub-groups: existing single-family, existing multi-family, new premise single-family, and new premise multi-family. Using the class-wide incremental revenue requirement determined through the Company's rate spread proposal, as explained below, I solved for new premise single- and multi-family fixed monthly charges that would maintain the same volumetric rate across all sub-classes.[42] This calculation results in roughly the same normalized expected revenues per customer between existing and new premise single-family residential

[42] This calculation indicated a fixed monthly charge of $26.35 ($24.35 for multi-family premises), which I rounded down to the nearest quarter-dollar.

customers (as well as the same between existing and new premise multi-family residential customers).

Q. How does your proposal constitute sound rate design?

A. The Company's proposal maintains the same volumetric price signal for the residential rate class in order to promote a fair apportionment of revenue requirement across the Residential rate class, while avoiding different volumetric price signals on an intra-class level. The Company's proposal is responsive to the principle of fairness presented as "Attributes of a Sound Rate Structure" developed by James C. Bonbright ("Bonbright Principles"). The sixth principle seeks to avoid "arbitrariness and capriciousness" while attaining equity in three dimensions: "(1) Horizonal (i.e., equals treated equally); (2) vertical (i.e., unequals treated unequally); and (3) anonymous (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant)."[43] The Company's proposal avoids arbitrariness in the volumetric price signal on an intra-class basis while maintaining equity between premises of different vintages (existing vs new) while also apportioning rates that recognize differing costs of service across premise types (single-family vs multi-family).

2. Rate Spread

Q. What is NW Natural's total incremental revenue requirement?

A. NW Natural has filed for an incremental revenue requirement of $154.9 million in this case. See NW Natural/1700, Walker.

[43] See: Bonbright, James C., Albert L. Danielsen, David R. Kamerschen. *Principles of Public Utility Rates* (Second Edition, 1988). Public Utilities Reports, pages 383-384.

Q. Is any of the $154.9 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 3 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 3 equals the full incremental revenue requirement in this case of $154.9 million. The values in this table are derived at line 19b of the LRIC Summary of Results, Exhibit NW Natural/1801, Wyman.

Table 3
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	$123,499,971	$40,572,937	$156,562	$388,359	($2,213,094)	($384,457)	($712,473)	($70,153)
RATE SCHEDULE	32CSF	32ISF	32CTF	32ITF	32CSI	32ISI	32CTI	32ITI
LRIC Study Determined Target Revenue	($2,754,881)	($1,189,393)	($416,116)	($1,462,665)	($17,839)	($336,921)	($263,122)	$192,973

As seen in Table 3 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 21.0 percent and 19.5 percent for the RS 2 Residential and RS 3 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 Transportation 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 large 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."[44] 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.[45]

The Company understands that rate design principles, such as the Bonbright Principles, taken together, can be overlapping in nature and they do not

[44] *Id*. at 383.

[45] *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. I describe the Company's rate spread methodology in detail below. First, for RS 2 Residential, RS 3 Commercial, and RS 27 Dry-Out, NW Natural proposes to use a separate cap for each 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. 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 1.75 in addition to the Transportation rate class. 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 1.75 or the Transportation rate class. 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 and RS 32 Commercial Sales, RS 31 Industrial Sales Firm, and RS 32 Industrial Sales 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. 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.

Q. Please describe the methodology NW Natural proposes to use to spread the $154.9 million incremental revenue requirement.

A. NW Natural proposes a multi-step process for spreading the $154.9 million incremental revenue requirement:

1. Apply a cap equal to 1.04 times the overall incremental margin increase of 29.3 percent to RS 2 Residential. This cap is equal to a 30.5 percent margin increase.
2. Apply a cap equal to 1.05 times the overall incremental margin increase to RS 3 Commercial. This cap is equal to a 30.8 percent margin increase.
3. Apply a cap equal to 1.22 times the overall incremental margin increase to RS 27 Dry-Out. This cap is equal to a 35.7 percent margin increase.
4. Apply a floor equal to 0.50 times the overall incremental margin increase of 29.3 percent to the Transportation rate class plus any other rate schedules with a LRIC study indicated parity ratio above 1.75. This floor is equal to a roughly 14.6 percent margin increase.

5. After the caps and floor have been applied, allocate the remaining revenue requirement on an equal percent of margin basis among the remaining rate schedules, which include RS 3 Industrial, RS 31 and RS 32 Commercial Sales, RS 31 Industrial Sales Firm, and RS 32 Industrial Sales Interruptible. This step results in the same proposed margin increase for each of the remaining schedules, equal to roughly a 20.3 percent increase. The effect of this step would be the same as applying a floor equal to 0.69 times the overall incremental margin increase in this case.

The caps of 1.04 for the Residential class, 1.05 for RS 3C, and 1.22 for RS 27 Dry-Out represent an approximation of the inverse mathematical relationship between the parity ratio of each rate class and schedule and unit parity of 1.00. For instance, Residential class (0.96 parity ratio): 1.00/0.96≈1.04.

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/1802, 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, RS 3 Commercial, and RS 27 Dry-Out rate schedules will receive a revenue spread slightly greater than an equal percent of margin share calculated across all rate schedules. The Transportation rate class as well as RS 32 Industrial Sales Firm (with a parity ratio above 1.75) 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 higher rate relative to the Transportation rate class.

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). The Parity Ratio at Proposed Rates is presented at line 26b of the LRIC Study Summary of Results, Exhibit NW Natural/1801, Wyman.

Q. Are there any components of the $154.9 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 $4.4 million from the $154.9 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. We propose 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 $154.9 million has been applied?

A. No. There are no other base adjustment components or temporary rate components that are addressed as part of the rate spread proposal in this proceeding.

Q. As part of this rate spread methodology, is the Company proposing to make changes to its fixed monthly charges?

A. Yes. As I explain earlier in my testimony, the Company proposes four Residential fixed monthly charges based on premise vintage and type, as summarized below:

- Existing single-family: $10.00
- Existing multi-family: $8.00
- New Premise single-family: $26.25
- New Premise multi-family: $24.25

The Company does not propose any changes to its fixed monthly charges for its Commercial and Industrial rate classes, or RS 27 Dry-Out.

V. RESULTS AND BILL IMPACTS

Q. What is the rate impact to firm sales customers for all of the revenue requirement components presented in this case combined?

A. Table 4 below shows the combined incremental revenue requirement of $154.9 million net of the $4.4 million plant EDIT credit with average bill increase presented in this case for firm sales customers. These impacts are also presented in Exhibit NW Natural/1803, Wyman.

Table 4
Combined Incremental Revenue Requirement
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	$ 109,872,388	17.8%
27	$ 212,003	19.5%
03 C	$ 34,870,187	17.0%
03 I	$ 488,805	8.9%
31 C Firm Sales	$ 2,041,479	10.1%
31 I Firm Sales	$ 704,711	7.7%
32 C Firm Sales	$ 2,848,675	8.3%
32 I Firm Sales	$ 537,107	4.5%
Total All Schedules**	$ 154,909,651	

* 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/1700, 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/1803, 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 4 above. NW Natural/1804, 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 490

NW Natural

Exhibits of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD EXHIBITS 1801-1804

December 29, 2023

EXHIBITS 1801-1804 – CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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NW Natural

Exhibit of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST,
LONG-RUN INCREMENTAL COSTS,
AND RATE DESIGN/SPREAD
EXHIBIT 1801

December 29, 2023

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2025
Long-Run Incremental Cost Study
Summary of Results
Exhibit NW Natural/1801, 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	2023 TY ANNUAL THERM DELIVERIES *(excl. special contract)*	1,050,441,583	425,260,256	178,565,073	5,103,413	868,581	23,789,903	2,813,111	11,708,097	496,097	48,698,787	21,094,918	6,166,007	88,956,330	24,461,851	31,123,809	7,185,488	174,149,864	0	71,409,726
2	2023 TY AVG CUSTOMERS - END OF PERIOD	708,012	644,228	60,059	339	1,524	682	59	181	7	546	83	26	99	45	60	3	71	0	7
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER	1,484	660	2,973	15,054	570	34,894	47,680	64,686	70,871	89,192	254,156	237,154	898,549	539,667	518,730	2,450,478	2,450,478	0	10,201,389
	AVERAGE WINTER SALES	123,537,690	57,027,021	23,190,454	578,209	125,384	3,062,942	366,590	1,195,866	55,912	5,828,862	2,010,196	688,479	8,393,658	2,629,365	2,750,252	717,685	14,916,816	0	
	AVERAGE SUMMER SALES	51,542,771	14,060,877	6,702,107	264,114	19,917	870,017	98,159	798,265	26,296	2,217,240	1,578,942	323,094	6,367,349	1,391,162	2,415,532	471,275	13,938,426	0	
4	ESTIMATED DESIGN DAY LOAD FACTOR	30.1%	23.7%	23.4%	35.5%	17.0%	24.6%	46.3%	46.0%	40.8%	29.3%	68.5%	55.6%	62.5%	54.9%	51.8%	59.2%	57.7%	0.0%	
	4a Average Daily Deliveries	2,877,922	1,165,097	489,219	13,982	2,380	65,178	7,707	32,077	1,359	133,421	57,794	16,893	243,716	67,019	85,271	19,686	477,123	0	
	4b Peak Day Deliveries	9,534,229	4,925,598	2,093,049	39,351	13,977	265,260	16,634	69,779	3,334	455,196	84,327	30,374	390,019	122,139	164,558	33,280	827,355	0	
	LRIC Cost Allocation Factors - Capital Cost Indirect Allocators																			
5	Distribution Main Design Day Peak & Average	100.00%	48.29%	20.46%	0.43%	0.13%	2.63%	0.20%	0.85%	0.04%	4.73%	1.22%	0.40%	5.41%	1.60%	2.10%	0.45%	11.06%	0.00%	0.00%
6	System Core Mains	100.00%	50.84%	21.55%	0.45%	0.14%	2.76%	0.21%	0.87%	0.04%	4.95%	1.25%	0.41%	5.53%	1.15%	1.50%	0.63%	7.72%	0.00%	0.00%
7	Capacity Incremental (System Reinforcement)	100.00%	52.25%	21.94%	0.63%	0.00%	0.00%	0.00%	1.44%	0.06%	5.98%	2.59%	0.76%	10.93%	1.50%	1.91%	0.00%	0.00%	0.00%	0.00%
8	Transmission Mains	100.00%	50.46%	21.32%	0.50%	0.09%	1.80%	0.14%	1.05%	0.05%	5.22%	1.69%	0.52%	7.29%	1.42%	1.84%	0.36%	6.26%	0.00%	0.00%
9	Storage Winter Sales / Summer Sales Excess Ratio	100.00%	63.85%	24.50%	0.47%	0.16%	3.26%	0.00%	0.59%	0.00%	5.37%	0.64%	0.00%	0.00%	0.92%	0.25%	0.00%	0.00%	0.00%	0.00%
10	Service Lines	100.00%	80.01%	17.53%	0.36%	0.10%	0.66%	0.06%	0.18%	0.01%	0.61%	0.08%	0.03%	0.14%	0.06%	0.06%	0.00%	0.11%	0.00%	0.00%
11	Meters Average Installed Cost	100.00%	77.82%	17.43%	0.40%	0.18%	1.08%	0.10%	0.36%	0.01%	1.24%	0.28%	0.08%	0.30%	0.18%	0.20%	0.01%	0.33%	0.00%	0.00%
12	Account Service Cost per Customer	100.00%	90.16%	8.49%	0.05%	0.22%	0.40%	0.03%	0.11%	0.00%	0.32%	0.05%	0.02%	0.06%	0.03%	0.04%	0.00%	0.04%	0.00%	0.00%
13	Common Cost (Administrative, General Plant, etc.)	100.00%	76.66%	18.78%	0.33%	0.15%	0.80%	0.09%	0.31%	0.01%	1.07%	0.24%	0.07%	0.51%	0.21%	0.22%	0.03%	0.51%	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	$26,746,394	$17,241,918	$6,888,601	$99,587	$29,139	$397,089	$34,115	$127,872	$4,571	$628,152	$135,054	$42,492	$420,746	$121,580	$118,870	$25,913	$430,694	$0	$0
	14b Meters & Services Costs	$714,392,414	$460,529,193	$183,993,561	$2,659,958	$778,302	$10,606,200	$911,209	$3,415,442	$122,089	$16,777,848	$3,607,271	$1,134,965	$11,238,070	$3,247,386	$3,175,011	$692,140	$11,503,770	$0	$0
	14c Core Main Costs	$854,210,449	$550,662,130	$220,004,047	$3,180,554	$930,628	$12,682,003	$1,089,547	$4,083,899	$145,984	$20,061,541	$4,313,271	$1,357,096	$13,437,540	$3,882,951	$3,796,411	$827,603	$13,755,242	$0	$0
	14d Transmission Costs	$225,135,754	$145,132,542	$57,984,279	$838,267	$245,276	$3,342,469	$287,161	$1,076,353	$38,476	$5,287,421	$1,136,806	$357,676	$3,541,599	$1,023,391	$1,000,582	$218,123	$3,625,332	$0	$0
	14e Gas Storage Costs	$315,875,754	$211,196,403	$84,378,534	$1,219,844	$356,926	$4,863,951	$0	$1,566,305	$0	$7,694,238	$1,654,276	$0	$0	$1,489,235	$1,456,044	$0	$0	$0	$0
15	**Total Rate Base**	**$2,136,360,766**	**$1,384,762,186**	**$553,249,021**	**$7,998,210**	**$2,340,272**	**$31,891,712**	**$2,322,032**	**$10,269,871**	**$311,120**	**$50,449,200**	**$10,846,678**	**$2,892,229**	**$28,637,955**	**$9,764,543**	**$9,546,918**	**$1,763,780**	**$29,315,038**	**$0**	**$0**
16	**Proposed Rate of Return**	*7.406%*																		
17	**Total Return on Rate Base at** 10.1% **ROE**	**$158,218,878**	**$102,555,487**	**$40,973,622**	**$592,347**	**$173,321**	**$2,361,900**	**$171,970**	**$760,587**	**$23,042**	**$3,736,268**	**$803,305**	**$214,198**	**$2,120,927**	**$723,162**	**$707,045**	**$130,626**	**$2,171,072**	**$0**	**$0**
18	**Revenue at Current Rates** *(incl misc rev)*	$935,889,442	$587,008,625	$208,409,273	$5,120,734	$1,055,526	$22,704,926	$1,140,610	$9,697,979	$156,930	$39,930,829	$14,892,281	$994,454	$6,714,797	$13,483,573	$16,881,514	$515,000	$5,539,411	$0	$1,642,981
	18a Cost of Gas Commodity	$405,328,200	$226,293,737	$95,019,831	$2,715,677	$462,198	$12,659,320	$0	$6,230,228	$0	$25,914,086	$11,225,241	$0	$0	$10,917,326	$13,890,556	$0	$0	$0	$0
	18b O&M and Other Operating Revenue Deductions	$481,292,823	$345,619,833	$101,363,527	$1,936,852	$656,309	$6,240,164	$711,298	$2,241,272	$86,678	$8,504,360	$2,071,063	$502,776	$3,662,557	$1,848,397	$2,069,143	$208,811	$3,569,785	$0	$0
	18c Net Operating Revenues	**$49,268,419**	**$15,095,055**	**$12,025,915**	**$468,205**	**($62,980)**	**$3,805,442**	**$429,312**	**$1,226,480**	**$70,252**	**$5,512,384**	**$1,595,977**	**$491,678**	**$3,052,241**	**$717,849**	**$921,816**	**$306,188**	**$1,969,626**	**$0**	**$1,642,981**
19	**Incremental Net Operating Revenue Deficiency (Sufficiency)**																			
	19a *Net-to-Gross Revenue Sensitive Factor:*	*141.6%*																		
	19b **Component LRIC Target Increase by Schedule**	$154,909,690	$123,499,971	$40,542,937	$156,562	$338,359	($2,213,094)	($384,457)	($712,473)	($70,153)	($2,754,881)	($1,189,393)	($416,116)	($1,462,665)	($17,839)	($336,921)	($263,122)	$192,973	$0	$0
	(incl. Corporate Activity Tax, credit for special contract revenues)																			
20	**Margin Revenue at Current Rates** *(incl misc rev)*	$530,561,242	$360,714,888	$113,389,442	$2,405,057	$593,328	$10,045,606	$1,140,610	$3,467,751	$156,930	$14,016,743	$3,667,040	$994,454	$6,714,797	$2,566,247	$2,990,958	$515,000	$5,539,411	$0	$1,642,981
21	**LRIC Based Target Margin**	**$685,470,931**	**$484,214,859**	**$153,932,379**	**$2,561,619**	**$931,687**	**$7,832,512**	**$756,153**	**$2,755,279**	**$86,777**	**$11,261,862**	**$2,477,647**	**$578,338**	**$5,252,132**	**$2,548,408**	**$2,654,037**	**$251,878**	**$5,732,384**	**$0**	**$1,642,981**
22	Current Revenue to Proposed Cost (Includes Cost of Gas)	**0.86**	**0.83**	**0.84**	**0.97**	**0.76**	**1.11**	**1.51**	**1.08**	**1.81**	**1.07**	**1.09**	**1.72**	**1.28**	**1.00**	**1.02**	**2.04**	**0.97**	**1.00**	**1.00**
23	Current Margin Revenue to LRIC Based Target Margin	**0.77**	**0.74**	**0.74**	**0.94**	**0.64**	**1.28**	**1.51**	**1.26**	**1.81**	**1.24**	**1.48**	**1.72**	**1.28**	**1.01**	**1.13**	**2.04**	**0.97**	**1.00**	**1.00**
	23a **Parity Ratio at Present Rates**	**1.00**	**0.96**	**0.95**	**1.21**	**0.82**	**1.66**	**1.95**	**1.63**	**2.34**	**1.61**	**1.91**	**2.22**	**1.65**	**1.30**	**1.46**	**2.64**	**1.25**	**1.00**	**1.00**
24	Target Increase as Percent of Total Present Revenue	**16.6%**	**21.0%**	**19.5%**	**3.1%**	**32.1%**	**-9.7%**	**-33.7%**	**-7.3%**	**-44.7%**	**-6.9%**	**-8.0%**	**-41.8%**	**-21.8%**	**-0.1%**	**-2.0%**	**-51.1%**	**3.5%**	**0.0%**	**0.0%**
	24a Target Increase as Percent of Present Margin Revenue	**29.3%**	**34.2%**	**35.8%**	**6.5%**	**57.0%**	**-22.0%**	**-33.7%**	**-20.5%**	**-44.7%**	**-19.7%**	**-32.4%**	**-41.8%**	**-21.8%**	**-0.7%**	**-11.3%**	**-51.1%**	**3.5%**	**0.0%**	**0.0%**
	(less special contract revenue)																			
25	Proposed Rate Revenue Increase (see: NW Natural/1800, Wyman)	$154,909,690	$109,872,101	$34,869,999	$488,773	$212,004	$2,041,542	$167,031	$704,742	$22,981	$2,848,586	$537,002	$145,628	$983,316	$521,532	$607,845	$75,417	$811,192	$0	$0
	25a *Proposed Increase as Percent of Present Margin Revenue*	**29.3%**	**30.5%**	**30.8%**	**20.3%**	**35.7%**	**20.3%**	**14.6%**	**20.3%**	**14.6%**	**20.3%**	**14.6%**	**14.6%**	**14.6%**	**20.3%**	**20.3%**	**14.6%**	**14.6%**	**0.0%**	**0.0%**
26	**Margin Revenue at Proposed Rates** *(incl misc rev)*	**$685,470,931**	**$470,586,989**	**$148,259,441**	**$2,893,830**	**$805,333**	**$12,087,148**	**$1,307,641**	**$4,172,493**	**$179,911**	**$16,865,329**	**$4,204,042**	**$1,140,082**	**$7,698,113**	**$3,087,778**	**$3,598,803**	**$590,416**	**$6,350,602**	**$0**	**$1,642,981**
	26a Revenue-to Cost Ratio at Proposed Rates	**1.00**	**0.97**	**0.96**	**1.13**	**0.86**	**1.54**	**1.73**	**1.51**	**2.07**	**1.50**	**1.70**	**1.97**	**1.47**	**1.21**	**1.36**	**2.34**	**1.11**	**1.00**	**1.00**
	26b Parity Ratio at Proposed Rates	**1.00**	**0.97**	**0.96**	**1.13**	**0.86**	**1.54**	**1.73**	**1.51**	**2.07**	**1.50**	**1.70**	**1.97**	**1.47**	**1.21**	**1.36**	**2.34**	**1.11**	**1.00**	**1.00**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD EXHIBIT 1802

December 29, 2023

NW Natural
Oregon Jurisdictional Rate Case - UG 490
Test Year Twelve Months Ended October 31, 2025
Rate Spread Allocation Proposal Methodology - Revenue Requirement Effects
Exhibit NW Natural/1802, Wyman

	Factor	Margin %
02R CAP:	**1.04**	30.5%
03C CAP:	**1.05**	30.8%
27R CAP:	**1.22**	35.7%
FLOOR at 0.5x:	**0.50**	14.6%

								Step 1	**Step 2**	**Step 3**				
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	Apply Caps: Parity Ratio Less than 1.0	Apply Floor: Transportation Class & Parity Ratio Over 1.75	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	02	$ 360,714,888	$ 584,697,334	34.2%	0.96	$ 123,499,971	$ 105,646,251	$ 109,872,101			$ 109,872,101	30.5%	$ 470,586,989	0.97
2	03CSF	$ 113,389,442	$ 207,588,681	35.8%	0.95	$ 40,542,937	$ 33,209,523	$ 34,869,999			$ 34,869,999	30.8%	$ 148,259,441	0.96
3	03ISF	$ 2,405,057	$ 5,088,420	6.5%	1.21	$ 156,562	$ 704,394			$ 488,773	$ 488,773	20.3%	$ 2,893,830	1.13
4	27R	$ 593,328	$ 1,051,370	57.0%	0.82	$ 338,359	$ 173,774	$ 212,004			$ 212,004	35.7%	$ 805,333	0.86
5	31CSF	$ 10,045,606	$ 22,561,649	-22.0%	1.66	$ (2,213,094)	$ 2,942,159			$ 2,041,542	$ 2,041,542	20.3%	$ 12,087,148	1.54
6	31CTF	$ 1,140,610	$ 1,133,412	-33.7%	1.95	$ (384,457)	$ 334,062		$ 167,031		$ 167,031	14.6%	$ 1,307,641	1.73
7	31ISF	$ 3,467,751	$ 9,636,781	-20.5%	1.63	$ (712,473)	$ 1,015,636			$ 704,742	$ 704,742	20.3%	$ 4,172,493	1.51
8	31ITF	$ 156,930	$ 155,940	-44.7%	2.34	$ (70,153)	$ 45,962		$ 22,981		$ 22,981	14.6%	$ 179,911	2.07
9	32CSF	$ 14,016,743	$ 39,678,850	-19.7%	1.61	$ (2,754,881)	$ 4,105,227			$ 2,848,586	$ 2,848,586	20.3%	$ 16,865,329	1.50
10	32ISF	$ 3,667,040	$ 14,798,305	-32.4%	1.91	$ (1,189,393)	$ 1,074,003		$ 537,002		$ 537,002	14.6%	$ 4,204,042	1.70
11	32CTF	$ 994,454	$ 988,178	-41.8%	2.22	$ (416,116)	$ 291,256		$ 145,628		$ 145,628	14.6%	$ 1,140,082	1.97
12	32ITF	$ 6,714,797	$ 6,672,424	-21.8%	1.65	$ (1,462,665)	$ 1,966,631		$ 983,316		$ 983,316	14.6%	$ 7,698,113	1.47
13	32CSI	$ 2,566,247	$ 13,398,486	-0.7%	1.30	$ (17,839)	$ 751,603			$ 521,532	$ 521,532	20.3%	$ 3,087,778	1.21
14	32ISI	$ 2,990,958	$ 16,774,985	-11.3%	1.46	$ (336,921)	$ 875,992			$ 607,845	$ 607,845	20.3%	$ 3,598,803	1.36
15	32CTI	$ 515,000	$ 511,750	-51.1%	2.64	$ (263,122)	$ 150,833		$ 75,417		$ 75,417	14.6%	$ 590,416	2.34
16	32ITI	$ 5,539,411	$ 5,504,455	3.5%	1.25	$ 192,973	$ 1,622,384		$ 811,192		$ 811,192	14.6%	$ 6,350,602	1.11
17	33T	$ 0	$ 0	0.0%	1.00	$ 0	$ 0				$ 0	0.0%	$ 0	1.00
	Total	**$ 528,918,261**	**$ 930,241,019**	**29.3%**		**$ 154,909,690**	**Rev Req Applied:**	**$ 144,954,105**	**$ 2,742,566**	**$ 7,213,019**	**$ 154,909,690**	**29.3%**	**$ 683,827,951**	
		(1)	**(1)**										**(1)**	
Proposed Rev Req:		**$ 154,909,690**					**Rev Req Remainder:**	**$ 9,955,585**	**$ 7,213,019**	**$ 0**				

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

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD EXHIBIT 1803

December 29, 2023

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2025
Proposed Incremental Revenue Requirement Allocation by Rate Schedule - Revenue Requirement Effects
Exhibit NW Natural/1803, Wyman

UG 490 Revenue Requirement Impacts
Impacts of UG 490 Revenue Requirement items, including the application of the Plant EDIT Amortization Credit

				Revenue Requirement	Plant EDIT Credit	Total: Rev. Req. Items			Revenue Requirement Effects		
Line No.	Rate Schedule	Margin Revenue at Present Rates	Total Revenue at Present Rates	Margin Increase ($) (1)	Margin decrease ($) (2)	Margin Increase ($)	Margin Revenue at Proposed Rates	Total Revenue at Proposed Rates	Margin Revenue Increase (%)	Total Revenue Increase (%)	Average Bill Increase (%)
		A	B	C	D	E	F = A+E	G = B+E	H	I	J
1	02R	$ 360,714,887	$ 584,697,334	$ 112,985,293	$ (3,112,905)	$ 109,872,388	$ 470,587,275	$ 694,569,722	30.5%	18.8%	17.8%
2	02R - *SF*	$ 319,667,295	$ 518,161,633	$ 101,315,790	$ (2,765,676)	$ 98,550,113	$ 418,217,408	$ 616,711,746	30.8%	19.0%	18.1%
3	02R - *MF*	$ 39,289,450	$ 63,685,856	$ 10,769,048	$ (339,943)	$ 10,429,105	$ 49,718,555	$ 74,114,961	26.5%	16.4%	15.6%
4	02R - *NP*	$ 1,338,204	$ 2,169,149	$ 699,729	$ (5,566)	$ 694,163	$ 2,032,367	$ 2,863,312	51.9%	32.0%	*N/A*
5	02R - *NP MF*	$ 419,939	$ 680,695	$ 200,726	$ (1,720)	$ 199,006	$ 618,945	$ 879,702	47.4%	29.2%	*N/A*
6	03C	$ 113,389,442	$ 207,588,681	$ 35,857,652	$ (987,465)	$ 34,870,187	$ 148,259,629	$ 242,458,869	30.8%	16.8%	17.0%
7	03I	$ 2,405,057	$ 5,088,420	$ 502,635	$ (13,830)	$ 488,805	$ 2,893,862	$ 5,577,225	20.3%	9.6%	8.9%
8	27R	$ 593,328	$ 1,051,370	$ 218,005	$ (6,002)	$ 212,003	$ 805,332	$ 1,263,374	35.7%	20.2%	19.5%
9	31CSF	$ 10,045,606	$ 22,561,649	$ 2,099,241	$ (57,761)	$ 2,041,479	$ 12,087,085	$ 24,603,128	20.3%	9.0%	10.1%
10	31CTF	$ 1,140,610	$ 1,133,412	$ 171,758	$ (4,730)	$ 167,028	$ 1,307,637	$ 1,300,439	14.6%	14.7%	14.0%
11	31ISF	$ 3,467,751	$ 9,636,781	$ 724,685	$ (19,974)	$ 704,711	$ 4,172,462	$ 10,341,492	20.3%	7.3%	7.7%
12	31ITF	$ 156,930	$ 155,940	$ 23,633	$ (651)	$ 22,982	$ 179,912	$ 178,921	14.6%	14.7%	14.0%
13	32CSF	$ 14,016,743	$ 39,678,850	$ 2,929,216	$ (80,541)	$ 2,848,675	$ 16,865,419	$ 42,527,525	20.3%	7.2%	8.3%
14	32ISF	$ 3,667,040	$ 14,798,305	$ 552,237	$ (15,130)	$ 537,107	$ 4,204,147	$ 15,335,412	14.6%	3.6%	4.5%
15	32CTF	$ 994,454	$ 988,178	$ 149,735	$ (4,136)	$ 145,599	$ 1,140,052	$ 1,133,777	14.6%	14.7%	15.8%
16	32ITF	$ 6,714,797	$ 6,672,424	$ 1,011,210	$ (27,809)	$ 983,401	$ 7,698,198	$ 7,655,825	14.6%	14.7%	16.6%
17	32CSI	$ 2,566,247	$ 13,398,486	$ 536,362	$ (14,796)	$ 521,566	$ 3,087,813	$ 13,920,052	20.3%	3.9%	4.9%
18	32ISI	$ 2,990,958	$ 16,774,985	$ 625,005	$ (17,257)	$ 607,749	$ 3,598,707	$ 17,382,734	20.3%	3.6%	4.7%
19	32CTI	$ 515,000	$ 511,750	$ 77,553	$ (2,139)	$ 75,413	$ 590,413	$ 587,163	14.6%	14.7%	13.3%
20	32ITI	$ 5,539,411	$ 5,504,455	$ 833,871	$ (23,312)	$ 810,559	$ 6,349,970	$ 6,315,014	14.6%	14.7%	14.4%
21	33T	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	0.0%	0.0%	0.0%
	Total (3)	**$ 528,918,261**	**$ 930,241,019**	**$ 159,298,092 (4)**	**$ (4,388,440) (4)**	**$ 154,909,651 (4)**	**$ 683,827,912**	**$ 1,085,150,671**	**29.3%**	**16.7%**	**(5)**

NOTE **(1):** Revenue Requirement spread based on the Company's proposal described in Testimony NW Natural/1800, Wyman.
NOTE **(2):** Plant excess deferred income taxes (EDIT) amortization credit spread to all rate schedules based on the revenue requirement spread noted above.
NOTE **(3):** 02R indicates the entire Residential rate class. Below it are the four proposed Residential sub-classes that make-up the class-wide total. They are as follow. 02R - SF : Existing Single-Family; 02R - MF : Existing Multi-Family; 02R - NP: New Premise Single-Family; 02R - NP MF: New Premise Multi-Family.
NOTE **(4):** 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.
NOTE **(5)**: 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.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD EXHIBIT 1804

December 29, 2023

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2025
Proposed Base and Total Billing Rates by Rate Schedule and Block - Combined Effects
Exhibit NW Natural/1804, Wyman

						Current Tariff	UG 490	Current Tariff Rate						*Includes Plant EDIT* GRC BASE $154,909.7 Revenue Requirement		UG 490 BILLING RATE
								11/1/2023	11/1/2023	11/1/2023	11/1/2023	11/1/2023	11/1/2023			
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	Proposed Increase: Base Rates	**UG 490 Proposed Base Rate**	**UG 490 Proposed Billing Rate**
	A	B	C	D	E	F	G	H	I	J	K	L	M= H…L	N	O=H+N	P=I+J+K+L+O
1	2R		N/A	377,824,648	570,918	$ 8.00	$ 10.00	$0.68192	$0.00435	$0.10025	$0.44732	$0.06135	$ 1.29519	$0.22457	**$0.90649**	**$1.51976**
2	02R - *MF*		N/A	46,440,330	70,170	$ 8.00	$ 8.00	$0.68192	$0.00435	$0.10025	$0.44732	$0.06135	$ 1.29519	$0.22457	**$0.90649**	**$1.51976**
3	02R - *NP*		N/A	760,357	2,390	$ 8.00	$ 26.25	$0.68192	$0.00435	$0.10025	$0.44732	$0.06135	$ 1.29519	$0.22457	**$0.90649**	**$1.51976**
4	02R - *NP MF*		N/A	234,922	750	$ 8.00	$ 24.25	$0.68192	$0.00435	$0.10025	$0.44732	$0.06135	$ 1.29519	$0.22457	**$0.90649**	**$1.51976**
5	3C Firm Sales		N/A	178,565,073	60,059	$ 15.00	$ 15.00	$0.55443	$0.00435	$0.10025	$0.44732	($0.01882)	$ 1.08753	$0.19528	**$0.74971**	**$1.28281**
6	3I Firm Sales		N/A	5,103,413	339	$ 15.00	$ 15.00	$0.43754	$0.00435	$0.10025	$0.44732	$0.06884	$ 1.05830	$0.09578	**$0.53332**	**$1.15408**
7	27 Dry Out		N/A	868,581	1,524	$ 8.00	$ 8.00	$0.49444	$0.00435	$0.10025	$0.44732	$0.03969	$ 1.08605	$0.24408	**$0.73852**	**$1.33013**
8	31C Firm Sales	Block 1	2,000	11,676,852	682	$ 325.00	$ 325.00	$0.30253	$0.00435	$0.00000	$0.44732	$0.00500	$ 0.75920	$0.08982	**$0.39235**	**$0.84902**
9		Block 2	all additional	12,113,051				$0.27603	$0.00435	$0.00000	$0.44732	$0.00328	$ 0.73098	$0.08195	**$0.35798**	**$0.81293**
10	31C Firm Transpt	Block 1	2,000	1,154,921	59	$ 575.00	$ 575.00	$0.27194	$0.00435	$0.00000	$0.00000	$0.01874	$ 0.29503	$0.06254	**$0.33448**	**$0.35757**
11		Block 2	all additional	1,658,190				$0.24861	$0.00435	$0.00000	$0.00000	$0.01702	$ 0.26998	$0.05717	**$0.30578**	**$0.32715**
12	31I Firm Sales	Block 1	2,000	3,645,031	181	$ 325.00	$ 325.00	$0.23089	$0.00435	$0.00000	$0.44732	$0.06165	$ 0.74421	$0.06457	**$0.29546**	**$0.80878**
13		Block 2	all additional	8,063,066				$0.20815	$0.00435	$0.00000	$0.44732	$0.06031	$ 0.72013	$0.05821	**$0.26636**	**$0.77834**
14	31I Firm Transpt	Block 1	2,000	117,271	7	$ 575.00	$ 575.00	$0.23417	$0.00435	$0.00000	$0.00000	$0.01499	$ 0.25351	$0.04999	**$0.28416**	**$0.30350**
15		Block 2	all additional	378,825				$0.21165	$0.00435	$0.00000	$0.00000	$0.01346	$ 0.22946	$0.04519	**$0.25684**	**$0.27465**
16	32C Firm Sales	Block 1	10,000	34,266,943	546	$ 675.00	$ 675.00	$0.15884	$0.00435	$0.00000	$0.44732	$0.06080	$ 0.67131	$0.06302	**$0.22186**	**$0.73433**
17		Block 2	20,000	10,937,767				$0.13408	$0.00435	$0.00000	$0.44732	$0.05874	$ 0.64449	$0.05319	**$0.18727**	**$0.69768**
18		Block 3	20,000	2,211,305				$0.09297	$0.00435	$0.00000	$0.44732	$0.05533	$ 0.59997	$0.03689	**$0.12986**	**$0.63686**
19		Block 4	100,000	1,239,889				$0.05171	$0.00435	$0.00000	$0.44732	$0.05190	$ 0.55528	$0.02052	**$0.07223**	**$0.57580**
20		Block 5	600,000	42,883				$0.02207	$0.00435	$0.00000	$0.44732	$0.04944	$ 0.52318	$0.00875	**$0.03082**	**$0.53193**
21		Block 6	all additional	-				$0.00802	$0.00435	$0.00000	$0.44732	$0.04827	$ 0.50796	$0.00318	**$0.01120**	**$0.51114**
22	32I Firm Sales	Block 1	10,000	7,913,705	83	$ 675.00	$ 675.00	$0.12308	$0.00435	$0.00000	$0.44732	$0.05252	$ 0.62727	$0.03158	**$0.15466**	**$0.65885**
23		Block 2	20,000	7,948,293				$0.10391	$0.00435	$0.00000	$0.44732	$0.05182	$ 0.60740	$0.02666	**$0.13057**	**$0.63406**
24		Block 3	20,000	2,813,868				$0.07188	$0.00435	$0.00000	$0.44732	$0.05061	$ 0.57416	$0.01844	**$0.09032**	**$0.59260**
25		Block 4	100,000	2,175,618				$0.03995	$0.00435	$0.00000	$0.44732	$0.04942	$ 0.54104	$0.01025	**$0.05020**	**$0.55129**
26		Block 5	600,000	243,434				$0.01766	$0.00435	$0.00000	$0.44732	$0.04858	$ 0.51791	$0.00453	**$0.02219**	**$0.52244**
27		Block 6	all additional	-				$0.00644	$0.00435	$0.00000	$0.44732	$0.04817	$ 0.50628	$0.00165	**$0.00809**	**$0.50793**
28	32C Firm Transpt	Block 1	10,000	2,590,573	26	$ 925.00	$ 925.00	$0.12467	$0.00435	$0.00000	$0.00000	$0.00423	$ 0.13325	$0.02915	**$0.15382**	**$0.16240**
29		Block 2	20,000	1,953,763				$0.10593	$0.00435	$0.00000	$0.00000	$0.00338	$ 0.11366	$0.02477	**$0.13070**	**$0.13843**
30		Block 3	20,000	719,396				$0.07481	$0.00435	$0.00000	$0.00000	$0.00198	$ 0.08114	$0.01749	**$0.09230**	**$0.09863**
31		Block 4	100,000	880,187				$0.04364	$0.00435	$0.00000	$0.00000	$0.00058	$ 0.04857	$0.01020	**$0.05384**	**$0.05877**
32		Block 5	600,000	22,088				$0.02491	$0.00435	$0.00000	$0.00000	($0.00027)	$ 0.02899	$0.00583	**$0.03074**	**$0.03482**
33		Block 6	all additional	-				$0.01250	$0.00435	$0.00000	$0.00000	($0.00084)	$ 0.01601	$0.00293	**$0.01543**	**$0.01894**
34	32I Firm Transpt	Block 1	10,000	8,736,363	99	$ 925.00	$ 925.00	$0.12249	$0.00435	$0.00000	$0.00000	$0.00345	$ 0.13029	$0.02519	**$0.14768**	**$0.15548**
35		Block 2	20,000	13,246,592				$0.10411	$0.00435	$0.00000	$0.00000	$0.00279	$ 0.11125	$0.02140	**$0.12551**	**$0.13265**
36		Block 3	20,000	9,131,203				$0.07349	$0.00435	$0.00000	$0.00000	$0.00169	$ 0.07953	$0.01511	**$0.08860**	**$0.09464**
37		Block 4	100,000	21,165,098				$0.04290	$0.00435	$0.00000	$0.00000	$0.00058	$ 0.04783	$0.00882	**$0.05172**	**$0.05665**
38		Block 5	600,000	24,865,776				$0.02448	$0.00435	$0.00000	$0.00000	($0.00009)	$ 0.02874	$0.00504	**$0.02952**	**$0.03378**
39		Block 6	all additional	11,811,298				$0.01230	$0.00435	$0.00000	$0.00000	($0.00052)	$ 0.01613	$0.00253	**$0.01483**	**$0.01866**
40	32C Interr Sales	Block 1	10,000	4,058,178	45	$ 675.00	$ 675.00	$0.13468	$0.00435	$0.00000	$0.44732	$0.05827	$ 0.64462	$0.03908	**$0.17376**	**$0.68370**
41		Block 2	20,000	5,136,344				$0.11371	$0.00435	$0.00000	$0.44732	$0.05712	$ 0.62250	$0.03300	**$0.14671**	**$0.65550**
42		Block 3	20,000	3,110,823				$0.07871	$0.00435	$0.00000	$0.44732	$0.05519	$ 0.58557	$0.02284	**$0.10155**	**$0.60841**
43		Block 4	100,000	6,956,084				$0.04369	$0.00435	$0.00000	$0.44732	$0.05325	$ 0.54861	$0.01268	**$0.05637**	**$0.56129**
44		Block 5	600,000	5,200,422				$0.02268	$0.00435	$0.00000	$0.44732	$0.05209	$ 0.52644	$0.00658	**$0.02926**	**$0.53302**
45		Block 6	all additional	-				$0.00732	$0.00435	$0.00000	$0.44732	$0.05124	$ 0.51023	$0.00212	**$0.00944**	**$0.51235**
46	32I Interr Sales	Block 1	10,000	4,985,895	60	$ 675.00	$ 675.00	$0.12033	$0.00435	$0.00000	$0.44732	$0.05593	$ 0.62793	$0.03665	**$0.15698**	**$0.66458**
47		Block 2	20,000	6,430,643				$0.10158	$0.00435	$0.00000	$0.44732	$0.05521	$ 0.60846	$0.03094	**$0.13252**	**$0.63940**
48		Block 3	20,000	3,474,949				$0.07031	$0.00435	$0.00000	$0.44732	$0.05398	$ 0.57596	$0.02141	**$0.09172**	**$0.59737**
49		Block 4	100,000	9,019,174				$0.03902	$0.00435	$0.00000	$0.44732	$0.05278	$ 0.54347	$0.01188	**$0.05090**	**$0.55535**
50		Block 5	600,000	7,213,148				$0.02025	$0.00435	$0.00000	$0.44732	$0.05204	$ 0.52396	$0.00617	**$0.02642**	**$0.53013**
51		Block 6	all additional	-				$0.00651	$0.00435	$0.00000	$0.44732	$0.05150	$ 0.50968	$0.00198	**$0.00849**	**$0.51166**
52	32C Interr Transpt	Block 1	10,000	1,052,700	3	$ 925.00	$ 925.00	$0.11796	$0.00435	$0.00000	$0.00000	$0.00240	$ 0.12471	$0.01856	**$0.13652**	**$0.14327**
53		Block 2	20,000	1,477,735				$0.10027	$0.00435	$0.00000	$0.00000	$0.00183	$ 0.10645	$0.01578	**$0.11605**	**$0.12223**
54		Block 3	20,000	886,682				$0.07079	$0.00435	$0.00000	$0.00000	$0.00087	$ 0.07601	$0.01114	**$0.08193**	**$0.08715**
55		Block 4	100,000	3,117,615				$0.04129	$0.00435	$0.00000	$0.00000	($0.00007)	$ 0.04557	$0.00650	**$0.04779**	**$0.05207**
56		Block 5	600,000	650,756				$0.02360	$0.00435	$0.00000	$0.00000	($0.00065)	$ 0.02730	$0.00371	**$0.02731**	**$0.03101**
57		Block 6	all additional	-				$0.01184	$0.00435	$0.00000	$0.00000	($0.00102)	$ 0.01517	$0.00187	**$0.01371**	**$0.01704**
58	32I Interr Transpt	Block 1	10,000	5,097,928	71	$ 925.00	$ 925.00	$0.11801	$0.00435	$0.00000	$0.00000	$0.00307	$ 0.12543	$0.02031	**$0.13832**	**$0.14574**
59		Block 2	20,000	8,495,129				$0.10031	$0.00435	$0.00000	$0.00000	$0.00247	$ 0.10713	$0.01725	**$0.11756**	**$0.12438**
60		Block 3	20,000	6,394,205				$0.07082	$0.00435	$0.00000	$0.00000	$0.00145	$ 0.07662	$0.01219	**$0.08301**	**$0.08881**
61		Block 4	100,000	18,961,134				$0.04130	$0.00435	$0.00000	$0.00000	$0.00045	$ 0.04610	$0.00711	**$0.04841**	**$0.05321**
62		Block 5	600,000	36,089,329				$0.02362	$0.00435	$0.00000	$0.00000	($0.00016)	$ 0.02781	$0.00406	**$0.02768**	**$0.03187**
63		Block 6	all additional	99,112,139				$0.01184	$0.00435	$0.00000	$0.00000	($0.00056)	$ 0.01563	$0.00203	**$0.01387**	**$0.01766**
64	33		N/A	-	-	$ 38,000.00	$ 38,000.00	$0.00574	$0.00435	$0.00000	$0.00000	($0.00147)	$ 0.00862	$0.00000	**$0.00574**	**$0.00862**

NOTE**:** The four proposed Residential sub-classes are as follow. 02R : Existing Single-Family; 02R - MF : Existing Multi-Family; 02R - NP: New Premise Single-Family; 02R - NP MF: New Premise Multi-Family.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Direct Testimony of Gregg H. Therrien

LINE EXTENSION ALLOWANCE
EXHIBIT 1900

December 29, 2023

EXHIBIT 1900 – DIRECT TESTIMONY – LINE EXTENSION ALLOWANCE

Table of Contents

I. INTRODUCTION AND SUMMARY

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

A. My name is Gregg H. Therrien, and I am a Vice President at Concentric Energy Advisors ("Concentric"). My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts.

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

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

Q. Please describe your professional background and education.

A. As a consultant with Concentric, I provide regulatory strategy and financial rate case expertise to regulated and unregulated entities in the natural gas, electric, and water industries. Consulting engagements include expert testimony on the subjects of allocated cost of service, rate design, rate consolidation, alternative rate plans, decoupling, revenue requirements, and natural gas infrastructure replacement programs. Prior to entering consulting, I held leadership level positions at Connecticut Natural Gas Corporation and its affiliated companies for over 19 years. I earned a Master of Business Administration from the University of Connecticut and a Bachelor of Science in Finance from Bryant University and am a certified Project Management Professional ("PMP"). My professional qualifications and experience are provided in Exhibit NW Natural/1901, Therrien.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to update NW Natural's Line Extension Allowance ("LEA"). In support of the Company's request, I present a revised discounted cash flow ("DCF") analysis (with supporting calculations). My testimony supports the incremental costs and benefits of adding a new customer to the natural gas distribution system, consistent with the Public Utility Commission of Oregon's ("Commission") directives regarding the LEA issued in Order No. 22-388 of docket UG 435 in the Company's last rate case.[1]

Q. Do you sponsor any exhibits with your Direct Testimony?

A. Yes, I am sponsoring Exhibits NW Natural/1901 through NW Natural/1907, referenced below:

Exhibit NW Natural/1901, Therrien – Curriculum Vitae of Gregg Therrien

Exhibit NW Natural/1902, Therrien – DCF Summary Example

Exhibit NW Natural/1903, Therrien – Existing system revenue requirements

Exhibit NW Natural/1904, Therrien – New system non-growth capital expenditure revenue requirements

Exhibit NW Natural/1905, Therrien – Supporting DCF assumptions

Exhibit NW Natural/1906, Therrien – CPP cost and revenue assumptions

Exhibit NW Natural/1907, Therrien – Year-by-year economic impact on existing customers

[1] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Order No. 22-388 (Oct. 24, 2022).

Q. Please summarize the revised LEA tariff provisions you present and support in your testimony.

A. The revised LEA tariff[2] establishes the framework and quantitative analysis to determine whether a new customer who requests service will receive an LEA, and if so, the amount of the LEA. The proposed four-tiered fixed amounts are based on the analysis contained in Exhibit NW Natural/1902, Therrien, and are intended to remain fixed allowances until the Company's next general rate case. Importantly, the revised LEA tariff aligns NW Natural's responsible growth plan[3] with the decarbonization goals of Oregon by driving low-use customer growth rather than high-use, as is the case with traditional line extension policies.

Further, in Order No. 22-388 in docket UG 435, the Commission directed the Company to address certain issues with a future proposal to revise the LEA tariff. I address the Commission's directives in Order No. 22-388 in Section VI of my direct testimony.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized as follows:

Section II: (1) Provides background and context regarding the purpose of an LEA policy for natural gas utilities generally; and (2) discusses various approaches of LEA policies adopted by natural gas utilities across the U.S.;

[2] The Direct Testimony of Kyle T. Walker presents all the Company's revised tariffs, including the LEA Tariff. NW Natural/1700, Walker.

[3] NW Natural/100, Palfreyman-Kravitz.

Section III: Describes the benefits of adding new customers to NW Natural's gas distribution system and explains why adding new customers should remain an important objective for existing Oregon customers;

Section IV: Provides background on Oregon Department of Environmental Quality's ("ODEQ") Climate Protection Program ("CPP"), summarizes the positions of the parties and the Commission's order regarding the Company's LEA in Docket UG 435, and describes the Company's current LEA tariff. Specifically, the Company is including the full estimated cost of compliance for each new customer in the calculation of the LEA, as directed by the Commission in Order No. 22-288. Further, the Company is factoring in the revenues from each new customer as they contribute to CPP compliance in their rates;

Section V: Presents the proposed LEA tariff, supported through the revised DCF analysis;

Section VI: Responds to the Commission's directives in Order No. 22-388; and

Section VII: Summarizes my conclusions and recommendations.

II. BACKGROUND ON NATURAL GAS UTILITY LINE EXTENSION POLICIES

Q. Please explain the objective of natural gas utility line extension policies.

A. Line extension policies are widely used by natural gas utilities across the U.S. under the principle that extending service to new customers benefits existing customers through the allocation of fixed costs among a larger customer base (thus attaining additional economies of scale), recognizing also that the revenues from new customers support incremental investment by the utility. While the policies vary from utility to utility, the components of line extension policies are similar. The purpose of a line extension policy is to define the rules that govern the extension of natural gas distribution service to new customers and to ensure the consistent application of those rules. A sound line extension policy ensures that existing customers do not subsidize new customers, while allowing a level of investment from the natural gas utility commensurate with the incremental revenues from the new customers.

Q. Please describe the common approaches used by natural gas utilities to calculate an LEA.

A. A typical LEA process begins when a potential new gas customer requests service. At that time, the natural gas utility will perform a financial calculation that compares the expected future revenues of that single new customer to the construction cost to connect that customer over a set period to determine if an allowance is justified, and if the prospective customer must pay a Contribution In Aid of Construction ("CIAC") to join the system. Expected future revenues are calculated based on the applicable existing utility tariff rate and an estimate of the new customer's consumption, which may consider variables such as dwelling size and gas-fired appliance use (e.g., space heat, cooking). Expected construction costs include the service line, meter, and if necessary, gas main extension costs. If the net present value ("NPV") of expected revenues equal or exceed expected construction costs, including the carrying cost (financial return), then an allowance is applied to offset the upfront construction costs equal to either the full amount of the required incremental investment or an amount such that an NPV value of zero is achieved. If expected construction costs exceed the calculated allowance (i.e., an NPV less than zero), then the customer must pay a CIAC to connect to the system. In this respect, existing customers are held harmless from the cost to connect the new customer because the natural gas utility is expected to recover the construction cost to connect the customer through future revenues and the payment of a CIAC, if applicable. Within this simple objective, there are four primary approaches to the financial calculation used by natural gas utilities to estimate an LEA.

1) Footage Allowance: The new customer receives a footage allowance toward construction costs based on the distance from a distribution main. The customer pays the additional cost of construction if the length of service is in excess of the footage allowance, or if other costs such as a main extension are required.
2) Dollar Allowance: The construction allowance is capped at a fixed dollar amount, and the customer pays the construction costs above the fixed cap.
3) Revenue/Margin Multiplier: The construction allowance equals a multiple of annual expected non-fuel base distribution margin revenues. Under this approach, the new customer's expected revenues are calculated based on usage characteristics for the customer class or specific equipment anticipated to be utilized at the new premise.

4) DCF/NPV Analysis: A fourth approach is an investment analysis in which the NPV of expected new customer revenues is netted against the NPV of expected costs related to the line extension over a pre-established period (e.g., 30 years). If the difference is zero or positive, then the extension of service to the new customer is considered economical. If the difference is negative, then the natural gas utility requires a CIAC equal to the amount that would result in discounted costs equaling discounted future revenues (i.e., an NPV equal to zero).

Whether an NPV approach is used explicitly for each customer or performed at a system-level analysis to support the more simplistic approaches 1 through 3 above, the premise of the calculation is that the expected incremental revenues (benefit) will exceed the cost (return of and return on[4] incremental invested capital) on an NPV basis over a prescribed period. The analysis is incremental and customer specific. It does not consider revenues and costs beyond the scope of the line extension construction cost[5] to connect that customer. Because an objective of a line extension policy is to hold existing customers harmless, the perspective of the analysis is appropriately limited to the costs and benefits of connecting that new, individual customer. Lastly, as most gas utility delivery rates include a substantial volumetric revenue recovery, customers with higher expected

[4] The "return on" investment capital is accounted for in the DCF model using a discount rate equal to the natural gas utility's most recently approved overall cost of capital.

[5] "Construction cost" in this context typically includes actual invested capital in plant items (service line, meter, and appurtenances), incremental property tax, and in some cases, a nominal amount of incremental operations and maintenance ("O&M") expense.

gas usage typically receive a higher line extension allowance. In other words, under most line extension policies, higher use customers are generally provided higher allowances, while customers that use less are more likely to be required to provide CIACs.

Q. Which approach does NW Natural use for its current LEA policy?

A. NW Natural's Line Extension Policy is set forth in Schedule X of its tariff. As authorized in Order No. 22-388 in Docket No. UG 435, NW Natural's current LEA policy uses the Revenue/Margin Multiplier approach for new residential customers.[6] As approved in Order No. 22-388, from November 1, 2022 to October 31, 2023, new residential customers were allowed an LEA equal to 5x margin, at a cap of $2,300.[7] As of November 1, 2023, the multiplier was reduced to 4x margin, and will be further reduced to 3x margin on November 1, 2024.[8] The Company uses the NPV investment analysis approach for non-residential customers, where the amount of the LEA is determined on a case-by-case basis.

Prior to the Commission's order in Docket No. UG 435, the Company used an investment analysis approach for new customers in which expected average future revenues and line extension costs were discounted at the Company's Weighted Average Cost of Capital over the coming 30 years.

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6 *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Order No. 22-388, at 51 (Oct. 24, 2022).

7 *Id*.

8 *Id.*

Q. Is an LEA a subsidy for new customers?

A. No, it is not. A subsidy occurs when one class of customers overpays for its standalone cost of service and another class underpays for its standalone cost of service. An LEA is not a subsidy because the prospective customer must bear the full cost of connecting to the system under the Company's proposed LEA calculations. As discussed above, the DCF model for any new customer must achieve at least a zero NPV, which ensures no financial subsidy occurs. The LEA is designed with the objective of avoiding subsidies by comparing the specific cost of connecting the new customer with the new customer's expected revenues, which the Commission recognized in Order No. 22-388.[9] As long as the utility recovers sufficient revenues to cover the customer's cost to join the system, there can be no subsidy from existing customers to new customers. As explained earlier, an overarching purpose of a line extension policy is to ensure equity between existing customers and new customers and to hold existing customers harmless from the cost of extending distribution service to new customers. Under this strict financial construct, the only possible subsidy is provided by new customers that have a positive NPV LEA calculation.

[9] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Order No. 22-388, at 48 (Oct. 24, 2022).

Q. Should line extension policies be revisited in light of recent policy changes in Oregon and the Company's decarbonization goals?

A. The Company believes it is reasonable to consider recent policy changes and decarbonization goals in a utility's planning and operations, including how it adds new customers to its distribution system. An LEA can be structured to accomplish not only the goal of ensuring that no subsidy is created between new and existing customers but is also consistent with the utility's decarbonization transition that recognizes the need for the gas system for winter peak capacity but may ultimately rely on less non-peak gas throughput. As discussed in more detail below, the Company's proposed new LEA model calculation and proposed tariff changes address recent policy changes and includes the costs associated with incremental CPP costs.

III. BENEFITS OF NEW CUSTOMER ADDITIONS

Q. Why is it important to continue to allow NW Natural to add new customers to its distribution system?

A. NW Natural has an obligation to serve existing customers and therefore must continue to invest in its natural gas distribution system to provide safe and reliable service to those existing customers, even if no new customers joined the system. In other words, even if no new customers join NW Natural's system, the Company must make "non-growth" capital investments to continue to provide safe and reliable service on behalf of existing customers. For example, "non-growth" capital investment includes investments for replacing aging infrastructure, modernizing and upgrading metering and billing technology, and fortifying storage and distribution structures against damage. In the absence of customer and sales growth, the recovery of cost of service related to those necessary investments would be borne only by existing customers. All else equal, the incremental cost of new capital investment on a per-customer basis is reduced by adding new customers.

Q. Will adding new customers increase costs that will have to be recovered in the future from existing customers?

A. No. Under the proposed LEA, new customers will, at worst, be both revenue and cost neutral with respect to their effect on the utility and existing customers. System level future cost of service will be spread among a broader customer base along with its higher billing determinants, which will benefit existing customers. For example, if a new customer billing system is required sometime in the future, the overall revenue requirement per customer is lower if new customers have been added to the system, all else being equal.

IV. ODEQ'S CLIMATE PROTECTION PROGRAM AND THE IMPLICATION OF LINE EXTENSION ALLOWANCES FOR THE OREGON NATURAL GAS UTILITIES

Q. Are you familiar with ODEQ's CPP?

A. Yes, I am.

Q. Please briefly summarize your understanding of the CPP as it relates to natural gas utilities such as NW Natural.

A. On March 10, 2020, Governor Brown signed Executive Order ("EO") 20-04 that directed Oregon state agencies to reduce and regulate greenhouse gas ("GHG") emissions. Specifically, EO 20-04 directed the ODEQ to develop new administrative rules that would cap sector specific GHG emissions from fossil fuels and reduce emissions over time.

In response to EO 20-04, the ODEQ established the CPP.[10] The CPP requires that covered entities[11] reduce GHG emissions for which the CPP deems them to be responsible.[12] For NW Natural, these GHG emissions are the result of its sales customers' and transport customers' use of natural gas. Covered entities have a limited ability to acquire offset-like instruments called Community Climate Investment ("CCI") credits.

The amount of compliance instruments NW Natural receives is set at its average covered emissions from years 2017-2019 and declines every year. By 2035, the number of compliance instruments is cut in half. By 2050, the number of compliance instruments is reduced by 90 percent. NW Natural must demonstrate compliance with the CPP every three years. At the end of each three-year compliance period, NW Natural must retire compliance instruments and CCI credits that are equal to its covered emissions over the compliance period.[13]

Currently, NW Natural's annual GHG emissions reduction target follows the schedule shown in Table 1 below.

[10] https://www.oregon.gov/deq/Regulations/rulemaking/RuleDocuments/ghgcr2021overviewFS.pdf

[11] "Covered entities" include natural gas utilities (such as NW Natural) and gasoline, diesel, kerosene, and propane fuel suppliers.

[12] https://www.oregon.gov/deq/Regulations/rulemaking/RuleDocuments/ghgcr2021overviewFS.pdf

[13] OAR 340-271-9000, Table 4.

Table 1: NW Natural's Annual GHG Emission Targets[14]

	Cap in metric tons of CO_2e	% Reduction from Base Emissions
2023	5,538,434	3.85%
2024	5,316,897	7.69%
2025	5,095,359	11.54%
2026	4,873,822	15.38%
2027	4,652,285	19.23%
2028	4,430,747	23.08%
2029	4,209,210	26.92%
2030	3,987,673	30.77%
2031	3,766,135	34.62%
2032	3,544,598	38.46%
2033	3,323,061	42.31%
2034	3,101,523	46.15%
2035	2,879,986	50.00%
2036	2,726,387	52.67%
2037	2,572,787	55.33%
2038	2,419,188	58.00%
2039	2,265,589	60.67%
2040	2,111,990	63.33%
2041	1,958,390	66.00%
2042	1,804,791	68.67%
2043	1,651,192	71.33%
2044	1,497,593	74.00%
2045	1,343,993	76.67%
2046	1,190,394	79.33%
2047	1,036,795	82.00%
2048	883,196	84.67%
2049	729,596	87.33%
2050	575,997	90.00%

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[14] OAR 340-271-9000, Table 4.

Q. Please summarize the positions of the parties regarding NW Natural's LEA in Docket No. UG 435 as it relates to the CPP.

A. In the Company's last rate case, Docket No. UG 435, NW Natural did not propose to change its Line Extension Policy in its initial application. However, the Oregon Citizens' Utility Board ("CUB") and the Coalition proposed significant changes to NW Natural's line extension tariff seeking to reduce or eliminate the LEA.[15]

CUB argued that new customers bring incremental CPP compliance costs, altering the economics underpinning the LEA.[16] Although CUB argued that including CPP costs in NW Natural's LEA analysis at the time would result in a negative LEA, CUB instead proposed to reduce the LEA to $2,200 based on a five-years-of-margin methodology, further reduce the LEA to $1,100 in 2024 (50 percent reduction) and eliminate the LEA entirely in 2025.[17] The Coalition argued that the economic rationales that supported an LEA no longer applied and proposed to eliminate the LEA for residential and non-residential customers immediately.[18]

[15] The Coalition was comprised of the Coalition of Communities of Color, Climate Solutions, Verde, Columbia Riverkeeper, Oregon Environmental Council, Community Energy Project, and Sierra Club. *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Order No. 22-388, at 2 (Oct. 24, 2022).

[16] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, CUB Opening Brief, at 5 (April 22, 2023).

[17] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Order No. 22-388, at 32, citing, CUB/100, Jenks/17; CUB/400, Jenks/11, 33 (Oct. 24, 2022).

[18] *Id.*, citing, Coalition/200, Burgess/4, 29-30; Coalition/500, Burgess/2, 13-14 (Oct. 24, 2022).

In Order No. 22-388, the Commission reduced the Company's LEA to five times margin (or $2,300) for 2022, and further reducing it to four times margin on November 1, 2023 ($1,840) and three times margin on November 1, 2024 ($1,380).[19] Additionally, the Commission directed NW Natural to make the following demonstrations if it requests a modification to its LEA in a future rate request:

- The Company's best reasonable estimate of present and future CPP compliance costs;
- An analysis of how each new customer addition changes the costs of CPP compliance for other customers;
- An explanation of how the proposed LEA incorporates and recognizes the costs of CPP compliance;
- An analysis supporting the Company's assumptions about the expected time frame over which new customers will remain on the system, and how changing policy dynamics were factored in; and
- A demonstration of the expected year-by-year economic impact on existing customers from the addition of new customers under the proposed LEA, such that the "breakeven" year is shown, along with the costs and benefits expected in other years, and a demonstration of when rate-based

[19] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Order No. 22-388, at 48 (Oct. 24, 2022).

investments for customer additions covered by the LEA are depreciated and removed.[20]

I address these directives in Section VI of my direct testimony.

V. PROPOSED LEA TARIFF

Q. How is the Company's current LEA tariff allowance calculated?

A. The Company's current LEA tariff provides for a variable LEA per customer, up to a defined cap, which the Commission set at four times annual margin for the period November 1, 2023 through October 31, 2024, resulting in a cap of $1,840 per residential customer, and is set to be reduced to a three times annual margin approach on November 1, 2024.[21] This approach was based on the Company's LEA tariff prior to 2012, in which the Company utilized a five times annual margin approach. The five times annual margin was derived from a DCF calculation using pre-2012 assumptions for costs to serve and annual margin from new customers.

Q. Is a four times annual margin approach a reasonable substitute for an LEA that is derived from a DCF calculation based on current assumptions of the revenues and costs to add a new customer?

A. No, not when the underlying cost of service is being redefined for new customers. Using an "x times" approach can be an efficient way to administer an LEA in a static regulatory environment but is not appropriate when changes such as the addition of CPP costs to revenue requirements are being implemented. When

[20] *Id*. at 52.

[21] *Id*. at 51.

circumstances change that require revisiting an LEA policy, it is customary to revise the underlying DCF calculation reflecting current costs and revenues, such as what is being proposed here.

Q. Prior to the LEA proposal in this case, how was the DCF calculated?

A. The DCF model included estimated revenues based on then-current tariff rates and estimated new customer consumption. Revenues and costs in the DCF calculation were stated on a real dollar basis, which assumed no relative change between revenues and costs to serve. Under the existing LEA calculation, there was no consideration for potential changes in the real rates customers will be charged in the future, either higher or lower based on projected future capital additions, depreciation, or environmental costs such as CPP costs.

Q. What changes does the Company propose in its new LEA DCF calculation?

A. First, consistent with the Commission's directive in Order No. 22-388, the new DCF calculation recognizes costs of the CPP as an incremental expense that are not currently included in base rates. Additionally, because new customers will be subject to paying annual CPP costs, credit for those revenues is also reflected in the DCF analysis. Accounting for the CPP costs and revenues in the DCF calculation is consistent with the Commission's direction to address the potential for CPP "double counting" issues in a subsequent LEA proposal.[22] Therefore, the first material change to the model recognizes the net impact of a new customer's responsibility for, and payment towards, CPP costs.

[22] *Id*. at 53-54.

The second change the Company is seeking to include in the new DCF analysis is the recognition of future rate changes on a real dollar basis. As stated above, a constant real dollar amount from existing tariffs is included in the DCF calculation. The Company proposes to also recognize: 1) a new customer's contribution to the recovery of costs for new, non-growth capital expenditures, and 2) the new customer's participation in the decline in rates that would occur from the depreciation of the existing distribution system absent any new capital investment. The inclusion of these two rate base elements captures known future effects on existing customers, and like the CPP element, are appropriate to add to the analysis. To account only for the impact of the CPP costs would materially and unfairly disregard other impacts from the addition of new customers.

Third, the new LEA analysis utilizes the updated rate design for new residential customers added to the system after November 1, 2024, which provides a higher fixed monthly customer charge, resulting in higher revenues from all new customers.

Finally, the DCF model as proposed includes a shorter term of 25 years, primarily to respond to concerns about the prior 30-year term.

Exhibit NW Natural/1905, Therrien, provides the supporting DCF assumptions used in this case.

Q. Please elaborate on the significance of the first proposed change, CPP recognition.

A. When utilizing a DCF calculation on a real dollar basis, only known and measurable changes should be included to either the revenue (benefit) or expense (cost) portions of the calculation. It is the net of the benefits and costs that pays for the up-front incremental investment for the new customer. Ignoring known and measurable future adjustments would be a significant shortcoming to a long-term DCF analysis; however, any recognition of changes not already included as part of normal utility operations should be material and truly incremental to the existing cost and rate structure. CPP costs fit this description. Under NW Natural's current LEA, neither the costs of the CPP nor the revenues collected for CPP compliance are explicitly included. The updated DCF model that supports the proposed LEA now includes CPP cost and revenue elements.

Q. Did you review the Company's CPP cost estimates for the DCF calculation?

A. Yes. I understand that the Company assumed that it would maximize the purchase of CCI credits throughout the term of the DCF model. The Company escalated the costs of the CCI credits by increasing the cost per CCI credit by $1 each year and adding an inflation adjustment per OAR 340-271-0820. Next, the Company assumed $22 per dekatherm of renewable natural gas ("RNG") for its needed CPP compliance incremental to CCI credits. To reflect a conservative cost estimate for purposes of building the DCF model, the Company included a higher cost for RNG than the anticipated costs that were in the Company's last IRP, and it did not include the costs for potential lower cost decarbonization solutions such as energy efficiency and industrial decarbonization. The calculations of the CPP dollars included in the proposed DCF are shown in Exhibit NW Natural/1906, Therrien – CPP cost and revenue assumptions.

Q. Please describe the importance of the second proposed change, recognizing changes to future system revenue requirements.

A. Typically, DCF LEA models utilize existing customer tariffs and assume those tariff rates are reflective of future costs of service on a real dollar basis. With the identification of CPP as a new and material component that should be reflected in the revised LEA model, I consulted with the Company to determine if there are other changes in the financial cost to serve that should also be factored in. As a result, we identified two material changes to expected future cost of service on a real dollar basis. First, we recognize that new customers contribute to the recovery of non-revenue generating future capital expenditures. Stated differently, all else being equal, a new customer helps reduce rates to the existing customer base through economies of scale. This is a long-standing and recognized concept, yet was not previously reflected in the DCF analysis used to calculate an LEA. The revised LEA analysis recognizes this benefit. Second, we reviewed the anticipated impact on future rates that may occur as the existing rate base is depreciated over time. This results in a net impact to revenues that reflects the benefit new customers provide to future non-growth capital expenditures (Exhibit NW Natural/1904, Therrien), and the impact in the reduction in the revenue requirement for existing rate base (on a real dollar basis).

In terms of known and measurable components of the analysis, it is important to note that both the CPP costs and net revenue requirements of rate base are fully expected to occur, and while they are material components, their measurement relies on long-term forecasted costs. Other impacts have not been included in the analysis, though they may also be substantial. Those include changes to costs of capital, increased income tax rates, and the net change on all costs from inflation, which would bring O&M increases into the equation. Because all other components have been included on a real cost basis, inflation has been intentionally held neutral to the analysis, except for forecasted inflation for CCI credits.

Q. Please describe the third change to the DCF Model.

A. The third change to the DCF model introduces a new rate to calculate revenues in the DCF model for customers joining the system on or after November 1, 2024. The initial rate design for this tariff is described in the testimony of Company witness Robert J. Wyman (NW Natural/1800, Wyman).

Q. Please describe the fourth change to the DCF Model.

A. The fourth change to the DCF model is the use of a 25-year term as a basis of the DCF. There appeared to be concern in the last rate case about assumptions for depreciation rates as well as the appropriate term of a DCF analysis.[23] In response, the Company now proposes using a 25-year term as compared to the prior 30-year term for the DCF LEA model. Additionally, the DCF analysis does not include a component for depreciation, so the choice of a depreciation rate is not germane to the outcome of the analysis. If the DCF analysis is based on a 25-

[23] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Order No. 22-388, at 34 (Oct. 24, 2022).

year term, the result is based on the requirement that the investment is recovered during that period, as well as the return on the investment over the term.

Q. How does the introduction of a new customer fixed charge factor into the LEA?

A. As described in the Direct Testimony of Robert J. Wyman (NW Natural/1800, Wyman), the volumetric portion of the rate for a new customer added to the system on or after November 1, 2024 is initially set equal to that of the proposed volumetric delivery rate for all existing residential customers in Residential Schedule 2 of $0.90649 per therm.[24] The fixed charge portion for new customers is determined by adding $16.25 to the proposed fixed charge of $10 that will apply to all rate Schedule 2 residential customers. This addition is equal to the difference in the use-per-customer ("UPC") for existing and new customers times the volumetric rate. This rate design, in conjunction with the volumetric impacts of CPP costs and revenues, has the consequence that higher-use new customers will not have a higher LEA compared to lower use / potentially more efficient customers. The introduction of the additional charge means that a new customer using natural gas as a backup fuel to electricity or installing high-efficiency equipment is not going to be unnecessarily burdened by a higher required CIAC.

Q. How is the proposed LEA tariff allowance calculated?

A. The proposed LEA tariff allowance is calculated using a DCF approach like the existing LEA. As described above, the underlying calculation is based on a DCF

[24] Excludes the current "Base Adjustment" and "Temporary Adjustment" volumetric rates.

model that now includes the cost and recovery of CPP, the net benefit/cost of the change in the base distribution system revenue requirements, and the effect of the new customer tariff. Further, the number of years of discounted cash flows is reduced from 30 to 25 years. Table 2 below shows the revised calculation:

Table 2: Proposed LEA DCF Calculation
(Example – 449.4 Therms Per New Customer)

	Rate	Initial Investment	Year 1 (2025)	Year 2	Year 3, etc.
Revenue from New Connection Tariff			722	722	722
CPP Revenue			26	40	161
CPP Cost			(313)	(322)	(989)
Nominal Change in Base Rate Revenue per Customer			0	(14)	(27)
Contribution to New Non-Growth Capex			39	93	139
Operations & Maintenance			(79)	(79)	(79)
Franchise Tax	2.74%		(20)	(20)	(20)
Property Tax	1.50%		(47)	(45)	(43)
Net Before Taxes			328	375	(136)
Income Tax	27.00%		89	101	(37)
Net After Tax			240	274	(99)
Tax Benefit on Interest					
Tax Benefit on Investment			32	61	56
Total Operating Cash (ROR Analysis)		($3,125)	271	335	(43)

		Result	NPV
DCF Result (Line Extension Allowance)	25-year	$3,125	0

In this example, a new customer using 449.4 therms per year would generate sufficient incremental revenues to fund a $3,125 initial capital investment while also covering incremental CPP costs. On a margin multiplier approach, this is equivalent to 4.3 times annual margin. Because of the incremental CPP costs associated with higher usage, the calculation for a higher use-per-customer actually results in a lower LEA. This reflects the cost of marginal CPP costs that increase with higher consumption.

Q. What are the four proposed breakpoints for the new LEA?

A. The Company is proposing a four-tiered, fixed LEA based on anticipated annual usage. These tiers are shown in Table 3 below:

Table 3: LEA Output at Various Consumption Levels (Therms)[25]

Use Per Customer	0 – 250 therms	251 – 450 therms	451 – 650 therms	Over 650 therms[26]
LEA Results	$3,600	$3,100	$2,600	$1,800

Q. How were these usage tiers derived?

A. To assist the Company's proposal, I ran a usage strata analysis for all new residential gas heating customers added in 2022 with 12 full months of usage:

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[25] The LEA Results shown in Table 3 and elsewhere in my testimony are the amounts shown in Exhibit NW Natural/1905, Therrien, as then rounded by the Company.

[26] Value based on 1,000 therms.

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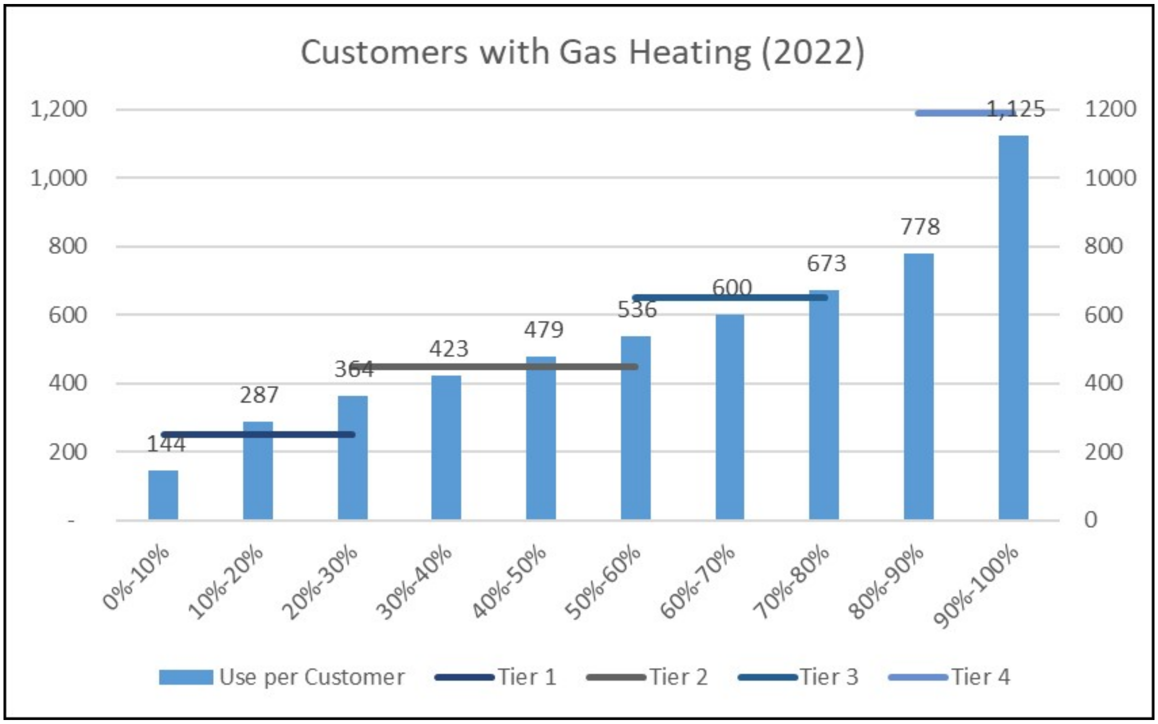
Chart 1: New Customer Usage Strata



As Chart 1 above shows, new customers using 250 annual therms or less account for approximately 20 percent of new customer additions. New customers using between 250 – 450 therms represent approximately the next 30 percent of customers, customers using between 451 – 650 therms represent approximately the next 20 percent of customers, and new customers using equal to or in excess of 651 therms represent the remaining 30 percent of the new customer usage strata. As described in the Direct Testimony of Robert J. Wyman (NW Natural/1800, Wyman), 450 therms is the expected UPC of new customers. This usage represents a reasonable middle-point for the LEA tiers because it will incentivize lower-use customer growth as compared to the current average UPC for new customers. To the extent a lower LEA (higher throughput) does not exceed construction costs, the customer can then make an economic decision to avoid installing a higher-use appliance in the residence, and consequently receive a higher LEA.

After establishing the UPC as the midpoint, the Company established four tiers of LEA. The tiered approach allows for efficiency implementing the LEA so that the Company does not need to run a DCF calculation for every new potential customer. Rather, the Company can determine the expected therm usage from the customer based on the appliances installed in the residence, and then quickly identify the LEA based on which tier the customer is in.

Q. Please elaborate on the specific usage level breakpoints.

A. For Tier 1, (0-250 therms), the Company ran the DCF model with the most conservative (highest) assumption for therm usage at 250 therms. For customers in this tier, the LEA is $3,600. Importantly, this tier would allow a customer to utilize hybrid heating solutions (electric heat pump with natural gas furnace back-up) and appliances with resiliency benefits in the event of power outages like natural gas generators and fireplaces. Additionally, the Company is requiring customers in the first tier to install a minimum of two appliances.

For the second tier (251-450 therms), the Company also used the most conservative (highest) assumption for therm usage at 450 therms. For customers in this tier, the LEA is $3,100. As noted above, the Company chose 450 therms for the breakpoint based on the new customer UPC.

For the third tier (451-650 therms), the Company set the high-end breakpoint at the existing customer UPC (650 therms) and used the most conservative (highest) assumption for therm usage at 650 therms. For customers in this tier, the LEA is $2,600.

Finally, for the fourth tier (651+ therms), the Company set the breakpoint so that the lowest LEA is set at the usage level of NW Natural's existing customer base's UPC. The Company utilized a conservative therm assumption of 1,000 therms for all new customers expected to use more than 650 therms. The fourth tier provides an LEA of $1,800.

VI. RESPONSE TO COMMISSION DIRECTIVES IN ORDER NO. 22-388

Q. Did the Commission require NW Natural to make certain demonstrations if it were to propose a modification to the LEA approved in UG 435?

A. Yes. As noted in Section IV above, the Commission directed the Company in Order No. 22-388 to make five demonstrations[27] if it proposed to modify its LEA. In this section, I respond to each of the Commission's directives.

A. Estimate of Present and Future CPP Compliance Costs and Incorporation of CPP Costs in the LEA Proposal

Q. Does the proposed LEA reflect the Company's best reasonable estimate of present and future CPP compliance costs?

A. Yes. The Company is using its best reasonable estimate of present and future CPP compliance costs. These estimates did not utilize the inputs from the

[27] Two of the five directives are addressed in subsection A.

Company's last integrated resource plan and are not intended to be a substitute for integrated resource planning, which incorporate more assumptions related to decarbonization activities, energy efficiency, and throughput reduction. Rather, the approach for the LEA relies on maximizing CCI credits and then utilizing RNG to meet CPP compliance using conservative cost estimates. Beginning in Year 3 (2027), the Company would increase its purchases of RNG, increasing annual CPP costs from $7.17 per MMBtu in Year 2 to $22.00 per MMBtu in Year 3.[28] This estimate is held flat for the remaining years. Table 4 below summarizes the Company's CPP cost estimate. Finally, for purposes of the revised LEA DCF the costs considered applicable to new customers represent the marginal costs by year.

Table 4: Annual CPP Cost Estimate

Year	$/MMBtu
Year 1	$6.96
Year 2	$7.17
Year 3 - 25	$22.00

Q. Does the proposed LEA incorporate and recognize the costs of CPP compliance?

A. Yes. As explained above, I have incorporated the Company's CPP compliance costs into the revised LEA model, as shown in Exhibit NW Natural/1902, Therrien, Line 3.

[28] MMBtu = Million British Thermal Units. 1 MMBtu = 10 therms.

B. Analysis of Incremental CPP Compliance Cost on Existing Customers

Q. Have you prepared an analysis of how each new customer addition changes the costs of CPP compliance for existing customers?

A. Yes. As discussed above, the proposed LEA analysis incorporates a new customer's cost of CPP compliance. Additionally, because the addition of a new customer increases the Company's CPP compliance requirement in aggregate, the proposed LEA DCF analysis assumes that new customers bear their full CPP compliance cost in each year, whereas existing customers' compliance is phased in over time as outlined by the ODEQ targets. As shown in Table 1 above, in 2025, the Company's emissions reduction target is approximately 11 percent below the baseline; therefore, each existing customer's compliance requirement, on average, is approximately 11 percent of their baseline emissions, whereas new customers' compliance requirement is 100 percent of their 2025 emissions. The DCF model includes 100 percent of the cost for the new customers each year and also a growing amount of offsetting revenues as the new customers participate in the recovery of CPP costs. While the DCF for the LEA does not generate incremental revenue for the level of cost over the amounts recovered for the CPP, the amount of LEA determined by the model ensures that the revenues from the new customer are sufficient to offset those costs. As a result of the DCF modeling, because the LEA accounts for CPP compliance, the cost of CPP compliance over time is not changed for existing customers.

C. Assumptions Regarding How Long New Customers Are Expected to Remain on NW Natural's System

Q. Does the proposed LEA address the expected time frame over which new customers will remain on the system, and how changing policy dynamics were factored in?

A. Yes. The Company is proposing what should be considered a conservative term for the LEA analysis. The updated LEA model assumes a 25-year analysis period for new customers. In consultation with the Company, this assumption is based on a combination of historical experience, appliance lives, and expected future use of the natural gas distribution system. Historically, natural gas services (Residential) remain active for multiple decades, regardless of actual appliance life. This means that when a natural gas appliance requires replacement, new natural gas appliances are chosen by the customer.

With regard to customer preference, CUB has argued that new NW Natural customers may not be as reliably retained for over 30 years if customers choose to convert all of their natural gas appliances to electric appliances.[29] While the Company does not see evidence of this occurring, the use of a 25-year term reflects a change to the Company's historical approach. In prior versions of the Company's DCF model approved by the Commission, the Company included various terms depending on the expected appliances installed at the residence.

[29] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Exhibit CUB/100, Jenks/16.

For space-heating, the Company previously used a 30-year term for the DCF calculation. For the lowest expected use tier (non-space heating), the Company used a 15-year term. Going forward, this framework does not align with the expected use of the gas system. Because the Company expects hybrid systems and other long-term resilience appliances to be installed for low-use customers, it is reasonable to expect that low-use customers will remain on the system beyond 30 years. Additionally, to qualify for Tier 1, the Company is requiring that customers install two appliances so that the life expectancy of the customer is more reliable for the analysis. For these reasons, a 25-year term, which shortens the 30-year term in prior models, is a reasonable balance for purposes of determining an LEA.

With respect to changing policy dynamics, the Company intends to update the LEA in future rate cases. For example, if there were a jurisdictional restriction to adding new customers or replacing gas appliances, the Company would consider revising its LEA for that jurisdiction so that the LEA results in fair outcomes to the Company's existing customer base. There have been no restrictions on adding new customers or using gas appliances anywhere in NW Natural's service territory, and therefore, I have not made any changes to the DCF term at this time. Therefore, it is my opinion that a 25-year analysis period is conservative, yet also recognizes that future policy may dictate a change in the length of time a customer stays on the system.

Q. Are existing customers harmed by the assumption of a 25-year term in the LEA compared to the longer depreciable lives of the assets?

A. No, however, it could potentially result in a timing issue. Using a 25-year term for the analysis does mean that because the book depreciation rate reflects a longer life, there would be book value at the end of the 25 years. Importantly, because the analysis resulted in fully recovering the investment in a shorter timeframe, on a revenue requirement basis it produced higher than sufficient revenues to support the related cost of service, and other customers will have benefitted from that overage. As a consequence, in the event that the new customer leaves the system at the end of the 25 years, other customers would then be required to reverse the earlier benefit and support the remaining net plant book value.

However, in the event that a new customer continues service beyond the assumed 25-year term in the LEA analysis, the customer provides continued (and additional) benefits to existing customers that were not contemplated in the determination of the LEA. Given the Company's experience of customers maintaining service on an extended basis, I conclude that there is a net benefit that is achieved by the continuation of adding customers to the system.

D. Year-by-Year Economic Impact on Existing Customers

Q. What is the Commission's directive regarding the year-by-year economic impact on existing customers under the proposed LEA?

A. The final directive by the Commission required the following:

> A demonstration of the expected year-by-year economic impact on existing customers from the addition of new customers under the proposed LEA, such that the "breakeven" year is shown, along with

the costs and benefits expected in other years, and a demonstration of when rate-based investments for customer additions covered by the LEA are depreciated and removed.[30]

Q. Have you modeled the year-by-year economic impact on existing customers?

A. Yes, I have. Exhibit NW Natural/1907, Therrien models the year-by-year costs and benefits associated with adding a new customer. For a given annual usage assumption (e.g., 250 therms, 450 therms, 650 therms or 1,000 therms), the costs contained in the analysis include: CPP costs, incremental O&M costs, franchise taxes, property taxes, and income taxes. The benefits include an assumption of annual revenue (monthly fixed charge plus variable distribution revenue), CPP revenue, nominal change in base rate revenue per customer, and the contribution to new non-growth capital expenditures. The model sets the LEA equal to the value of construction costs in which the NPV of cash flows (initial outlay of the LEA amount and future annual revenues over the subsequent 25 years) equals zero.

Regarding the costs and benefits to existing customers, the proposed LEA model factors in the full burden of the new customer's CPP compliance costs, recognizing that the addition of new customers increases the Company's CPP compliance costs. Further, the proposed LEA analysis also incorporates the new customer's annual contribution to new non-growth capital expenditures and the nominal change in base rate revenue, which reflect the net benefits to existing customers.

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[30] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Order No. 22-388, at 52 (Oct. 24, 2022).

Q. What is the breakeven year in the proposed LEA analysis?

A. My interpretation of "breakeven year" means the year in which new customer revenues meet (begin to exceed) the corresponding year's revenue requirement. For the LEA model as proposed, using the four different usage levels, Exhibit NW Natural/1907, Therrien shows the base revenues by year as well as the cost of service (revenue requirement) by year, and the net, where positive amounts indicate that the revenues from a new customer at each usage level exceeds the cost of service for that customer in that year. I observe that, as a result of the material change in the CPP in year 3 to $22 per therm that earlier years may have a positive revenue-to-cost comparison, but I have chosen to summarize the first year that revenues exceed cost of service on a remainder of analysis basis. This is summarized in Table 5 as follows:

Table 5: Break-Even Year[31]

UPC (Therms)	250	450	650	1,000
LEA Result	$3,600	$3,100	$2,600	$1,800
Times Margin	6.7	4.3	2.9	1.5
Rev Req B/E Year	**10**	**11**	**11**	**11**

VII. CONCLUSION AND RECOMMENDATION

Q. What is your recommendation regarding NW Natural's proposed LEA?

A. I recommend that the Commission allow the Company to maintain the ability to connect new customers and offer a monetary allowance to offset upfront connection costs when expected revenues and benefits equal or exceed the

[31] LEA Results displayed in Table 5 are rounded, per footnote 25.

construction cost. The proposed LEA addresses several issues raised by parties in the Company's last rate case. Specifically, it incorporates the costs and revenues of CPP compliance, as well as incremental benefits that existing customers receive as new customers are added to the system. Most importantly, the proposed LEA tariff appropriately aligns the incentives for joining NW Natural's gas distribution system with the ODEQ's climate goals, because unlike traditional line extension policies, lower use, more efficient customers will receive a higher LEA than higher use customers.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibits of Gregg H. Therrien

LINE EXTENSION ALLOWANCE
EXHIBITS 1901-1907

December 29, 2023

EXHIBITS 1901-1907 – LINE EXTENSION ALLOWANCE

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PUBLIC UTILITY COMMISSION OF OREGON

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LINE EXTENSION ALLOWANCE
EXHIBIT 1901

December 29, 2023

GREGG H. THERRIEN
VICE PRESIDENT

Mr. Therrien provides regulatory strategy and financial rate case expertise to regulated and unregulated entities in the natural gas, electric, and water industries. Since joining Concentric in 2016, Mr. Therrien has performed a multitude of consulting engagements including expert testimony on the subjects of allocated cost of service, rate design, rate consolidation, alternative rate plans, decoupling, revenue requirements, and natural gas infrastructure replacement programs. Other engagements include merger and acquisition due diligence, electric power plant retirement analysis (including securitization), billing system and rate mechanism audits, natural gas storage rate analysis, solar/renewable project evaluation, line extension policies, power procurement advisory services, interstate pipeline rate settlement assistance and tariff writing and administration.

Prior to entering consulting Mr. Therrien held previous leadership level positions at Connecticut Natural Gas Corporation and its affiliated companies for over 19 years. He formerly served as Director, Gas Construction at Connecticut Natural Gas and The Southern Connecticut Gas Company and Director, Regulatory & Tariffs at UIL Holdings, Inc.

Mr. Therrien holds an M.B.A. from the University of Connecticut, a B.S. in Finance from Bryant University, and is certified Project Management Professional (PMP).

REPRESENTATIVE PROJECT EXPERIENCE

Consultancy

- Allocated Cost of Service for water and natural gas utilities
- Rate design studies (including revenue allocation, rate design and bill impact analyses) for water, gas, and electric utilities
- Regulatory risk assessments and management strategy
- Gas infrastructure replacement program benchmarking, technical and financial analysis, and expert testimony
- Market analysis for international clients
- M&A due diligence (regulatory and financial)
- Gas and Electric distribution alternative rate plan analysis
- Economic Development, Low Income rate development, and large customer tariff development
- Decoupling testimony assistance for a Western Gas LDC
- Decoupling and Rate Design expert witness testimony for a New England Gas LDC
- Revenue Requirements witness for an electric distribution company
- Regulatory rate strategies for a vertically integrated electric utility
- Testified on behalf of a New England gas LDC on the subjects of decoupling, capital trackers and rate design
- Developed an Alternative Rate Plan for a New England gas LDC

- Rate comparison study for the Government of Alberta, Canada
- Established a cost of service-based pricing model for a 10MW fuel cell developer
- Power procurement consultancy for a New England investor-owned water utility
- Rates comparisons for U.S. electric and gas distribution utilities
- Revenue requirements and tariff review of a gas storage facility
- Rate consolidation analysis for gas and water distribution companies
- Renewable project financial evaluation
- Review of natural gas company regulatory and operational performance in response to a commission Show Cause Order
- Led an investigation of billing errors related to a municipal electric, gas, water, and refuse utility in support of a class action lawsuit investigation
- Assessed the impact of and strategy to comply with the Tax Cuts and Jobs Act ("TCJA")
- Reviewed and recommended changes to electric line extension policies
- Evaluated Renewable Natural Gas ("RNG") investments as part of buy-side due diligence
- Modeled alternative time of use ("TOU") tariff structures in support of a utility customer's evaluation of a large customer potential electric system bypass
- Provided regulatory assistance and strategy to a market broker in a state utility investigation of Consumer Choice Aggregation
- Assisted in the development of a lead/lag study for a Southwestern electric utility
- Part of a team that developed a multi-year rate plan regulatory strategy for a Mid-Atlantic natural gas utility
- Co-authored a RNG white paper for a Southern U.S. natural gas company
- Authored a report on behalf of a major U.S. interstate pipeline in support of an ongoing FERC settlement proceeding
- Prepared extensive rate analyses in support of electric transmission and generation project development and acquisition
- Developed a rate design model, performed rate analysis, drafted position papers and data responses for an international electric utility

Regulatory Affairs

- Led the preparation, filing, discovery and implementation of several rate cases
- Designed rates and prepared testimony, and served as the primary rate design witness
- Prepared, testified, and implemented revenue requirement rate mechanisms for new customer growth and pipeline replacement programs
- Prepared gas Integrated Resource Plans
- Prepared assessment of forecast methodology and forecast accuracy of gas demands
- Prepared validation of sales forecast and analysis of declining use per customer
- Proposed, testified, and implemented Connecticut's first gas decoupling mechanism
- Key contributor in settlement negotiations for rate cases and other litigated regulatory matters, including the LDC gas expansion plan
- Prepared testimony and exhibits for bi-annual Purchased Gas Adjustment proceedings

- Prepared biennial Gas LDC Demand and Supply filings
- Prepared testimony and new program tariffs in support of gas unbundling

Business Strategy and Operations

- Led a gas construction organization, leveraging project management practices to plan and execute a $100M annual capital budget
- Responsible for RFP development and bid selection of five-year contracts of local, regional and national gas construction and restoration contractors representing approximately seventy work crews
- Developed and implemented a tablet-based QA/QC inspection program
- Developed annual sales and revenue operating budgets
- Developed rate of return new customer acquisition model
- Guided several process improvement teams
- Successfully negotiated contracts with large cogeneration users avoiding system bypass and obtaining regulatory approval

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2016 – Present)
Vice President (2022-Present)
Assistant Vice President (2016-2021)

AVANGRID and affiliated companies (2016)
Connecticut Natural Gas and The Southern Connecticut Gas Company (2014 – 2016)
Director, Gas Construction

UIL Holdings, Inc. (2010 – 2014)
Director, Regulatory & Tariffs

Iberdrola S.A. / Energy East Corporation / Connecticut Natural Gas and The Southern Connecticut Gas Company (2001 – 2010)
Director, Regulatory & Pricing / Director, Pricing & Analysis

Connecticut Natural Gas Corporation (1997 – 2001)
Manager, Pricing

United Technologies, Inc. – Pratt & Whitney
Turbo Power & Marine Systems (1996 – 1997)
Manager, Financial Planning & Analysis

Pratt & Whitney Aircraft
Business Unit Cell Leader, Overhaul & Repair / Manufacturing – turbine airfoils (1994 – 1996)
Financial Analyst, Commercial Engine Business (1987 – 1994)

EDUCATION

University of Connecticut
M.B.A., Concentration in Finance, 1993

Bryant University (College)
B.S., Finance, 1987

PROFESSIONAL AFFILIATIONS

American Gas Association
Guild of Gas Managers
Northeast Gas Association
Project Management Institute

CERTIFICATIONS

Certified Project Management Professional (PMP)

PUBLICATION

Co-Authored the American Gas Foundation report titled "Regulatory Pathways for Advancing Low-Carbon Gas Resources", February 2023

LEADERSHIP

Connecticut Economic Resource Center (CERC)
Member, Board of Directors 2008 – 2011
Treasurer, 2011 – 2016

Connecticut Power and Energy Society (CPES)
Treasurer and Director 2022 - present
Secretary and Director 2018 – 2022
Member, Board of Directors 2017 – 2018

AGA Executive Leadership Development Program – 2012

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Connecticut Public Utilities Regulatory Authority				
United Illuminating Company	2023	United Illuminating Company Application for a rate increase	Docket No. 22-08-08	Rate design, Economic Development rate
NuPower, LLC	2022	PURA – review of combined heat and power projection solicitation.	Docket No. 18-08-14RE01	Cost of Service analysis for a regulated fuel cell project, as amended
The Connecticut Water Company	2021	The Connecticut Water Company	20-12-30	Allocated Cost of Service, Rate Design and Rate Consolidation
NuPower, LLC	2019	PURA – review of combined heat and power projection solicitation.	Docket No. 18-08-14	Cost of Service analysis for a regulated fuel cell project
Yankee Gas Services (Eversource Energy)	2018	Yankee Gas Services DBA Eversource Energy – amend rate schedules.	Docket No. 18-05-10	Distribution Rate Case Rate design, decoupling, and capital trackers
Connecticut Natural Gas Corporation & Southern Connecticut Gas Company	2016	Connecticut Natural Gas Corporation & Southern Connecticut Gas Company - OCC successfully advocated that the gas utilities should not be allowed to recover certain expenses	Docket No. 16-04-10	State of Connecticut LDC Gas Expansion Plan: System Expansion Reconciliation Capital Expenditures, System Improvement/Reinforcement Projects
Connecticut Natural Gas Corporation & Southern Connecticut Gas Company	2014	Connecticut Natural Gas Corporation & Southern Connecticut Gas Company	Docket No. 13-06-02RE01	State of Connecticut LDC Gas Expansion Plan Settlement Agreement
Connecticut Natural Gas Corporation & Southern Connecticut Gas Company	2013	Connecticut Natural Gas Corporation & Southern Connecticut Gas Company	Docket No. 13-06-02	State of Connecticut LDC Gas Expansion Plan Rates, Hurdle Rate analysis, Demand forecast, Rate Mechanism
Connecticut Natural Gas Corporation	2013	Connecticut Natural Gas Corporation	Docket No. 13-06-08	Distribution Rate Case Revenue Requirements, Cost of Service, Rate Design, Demand Forecast, and Forecasted Revenues; Decoupling, DIMP and System Expansion Reconciliation Rate Mechanisms, Tariffs

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
The Southern Connecticut Gas Company	2013	The Southern Connecticut Gas Company	Docket No. 99-10-25RE01	Firm Transportation Service Agreement and Gas Exchange Agreement - Review of Revenue Requirement Allocation
Connecticut Natural Gas Corporation & Southern Connecticut Gas Company	2011	Connecticut Natural Gas Corporation & Southern Connecticut Gas Company	Docket No. 08-12-06RE02, 08-12-07RE02	Settlement Agreement RE: Resolve Stayed Decisions and Orders from Appealed CNG and SCG Rate Cases, and resolve SCG overearnings
The Southern Connecticut Gas Company	2011	DPUC review Overearnings for SCG	Docket No. 10-12-17	Just and Reasonable Rates – Potential Overearnings Investigation
U.S. Federal Energy Regulatory Commission ("FERC")				
CenterPoint Energy Minnesota Gas	2023	CenterPoint Energy Resources Corporation	Docket No. RP22-1033-000	Prepared and Direct Answering Testimony in Northern Natural Gas Company's rate proceeding
Florida Public Service Commission				
Peoples Gas System, Inc.	2023	Petition for a Rate Increase	Docket No. 20230023-GU	Allocated Cost of Service and Rate Design
Georgia Public Service Commission				
Liberty Utilities Georgia d/b/a/ Peachtree Natural Gas	2020	Liberty Utilities Corp.	Docket 42959	Distribution Rate Case Allocated Cost of Service and Rate Design
Illinois Commerce Commission				
The Peoples Gas Light & Coke Company	2017	ICC vs The Peoples Gas Light & Coke Company	Docket No. 16-0376	Gas Distribution Aging Infrastructure Peer Utility Benchmark Study, Affordability
Maine Public Utilities Commission				
Emera, Maine	2017	Request for approval of rate change Emera	Docket No. 2017-00198	Electric Distribution Revenue Requirements
Massachusetts Department of Public Utilities				
Berkshire Gas Company	2022	The Berkshire Gas Company filed a petition with the Department of Public Utilities for an increase in gas distribution rates.	D.P.U. 22-20	Weather Normalization, Rate Design and Bill Impacts
Boston Gas Company d/b/a National Grid	2020	Boston Gas Company	D.P.U. 20-120	Allocated Cost of Service, Rate Design and Rate Consolidation

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Berkshire Gas Company	2018	The Berkshire Gas Company filed a petition with the Department of Public Utilities for an increase in gas distribution rates.	D.P.U. 18-40	Rate Design, Decoupling and Performance-Based Ratemaking
New Hampshire Public Utilities Commission				
Liberty Utilities – New Hampshire d/b/a/ EnergyNorth Natural Gas	2023	Request for Approval of Revenue Decoupling Adjustment	DG 22-041	Petition for Approval to Recover Revenue Decoupling Adjustment Factor Costs
Liberty Utilities – New Hampshire d/b/a/ Granite State Electric	2023	Granite State Electric - Petition for Permanent and Temporary Rates	DE 23-039	Temporary Rates, Rate Design, and Performance-Based Ratemaking
Liberty Utilities – New Hampshire d/b/a/ Granite State Electric	2022	Request for Approval of Revenue Decoupling Adjustment	DE 22-052	Revenue Decoupling - Compliance
Liberty Utilities – New Hampshire d/b/a/ Granite State Electric	2019	Granite State Electric - Petition for Permanent and Temporary Rates	DE 19-064	Revenue Decoupling
Pennichuck Water Works	2018	Pennichuck Water Works, Inc. – Rate Proceeding	DW 19-084	Allocated Cost of Service
Liberty Utilities – New Hampshire d/b/a/ EnergyNorth Natural Gas	2017	Liberty Distribution Service Rate Case – Request for change in rates	DG 17-048	Revenue Decoupling Rate Design

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Gregg H. Therrien

LINE EXTENSION ALLOWANCE
EXHIBIT 1902

December 29, 2023

			Year 1	Year 2	Year 3	Year 4	Year 5
1	**Revenue from New Connection Tariff**	*Exh 1905*	722	722	722	722	722
2	**CPP Revenue**	*Exh 1906*	26	40	161	178	220
3	**CPP Cost**	*Exh 1906*	(313)	(322)	(989)	(989)	(989)
4	**Nominal Change in Base Rate Revenue per Customer**	*Exh 1903*	0	(14)	(27)	(41)	(54)
5	**Contribution to New Non-Growth Capex**	*Exh 1904*	39	93	139	180	219
6	**Operations & Maintenance**		(79)	(79)	(79)	(79)	(79)
7	**Franchise Tax**	2.74%	(20)	(20)	(20)	(20)	(20)
8	**Property Tax**	1.50%	(47)	(45)	(43)	(41)	(39)
9	**Net Before Taxes**		328	375	(136)	(89)	(20)
10	**Income Tax**	27.00%	89	101	(37)	(24)	(5)
11	**Net After Tax**		240	274	(99)	(65)	(14)
12	**Tax Benefit on Investment**		32	61	56	52	48
13	**Total Operating Cash (ROR Analysis)**	($3,125)	271	335	(43)	(13)	34

		Rate	Year 1	Year 2	Year 3	Year 4	Year 5
1	**Plant**		3,125	3,125	3,125	3,125	3,125
2	**Depreciation (per model term)**	4.000%	(125)	(250)	(375)	(500)	(625)
3	**Net Plant**		3,000	2,875	2,750	2,625	2,500
4	**Deferred Taxes**		(2)	25	48	66	80
5	**Net Rate Base**		3,002	2,850	2,702	2,559	2,420
6	**Average Rate Base**		3,064	2,926	2,776	2,631	2,489
	Basis for interest expense		1,532	1,463	1,388	1,315	1,245

Tax Depreciation			Year 1	Year 2	Year 3	Year 4	Year 5
1	**Tax Depreciation Rate**		3.75%	7.22%	6.68%	6.18%	5.71%
2	**Plant Additions**		3,125				
3	**Total Tax Depreciation**		117	226	209	193	179
4	**Tax Benefit @**	27.00%	32	61	56	52	48

Book Depreciation

			Year 1	Year 2	Year 3	Year 4	Year 5
1	**Book Depreciation Rate**		4.00%	4.00%	4.00%	4.00%	4.00%
2	**Plant Additions**		3,125				
3	**Book Depreciation**		125	125	125	125	125
4	**Total Book Depreciation**		125	125	125	125	125
5	**Total Tax Depreciation**		117	226	209	193	179
6	**Difference**		(8)	101	84	68	54
7	**Deferred Taxes**	27.00%	(2)	27	23	18	14
	20 year MACRS		3.75%	7.22%	6.68%	6.18%	5.71%

			Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
1	Revenue from New Connection Tariff	*Exh 1905*	722	722	722	722	722	722	722	722	722	722
2	CPP Revenue	*Exh 1906*	261	288	331	374	417	460	488	516	544	573
3	CPP Cost	*Exh 1906*	(989)	(989)	(989)	(989)	(989)	(989)	(989)	(989)	(989)	(989)
4	Nominal Change in Base Rate Revenue per Customer	*Exh 1903*	(68)	(81)	(95)	(109)	(122)	(136)	(149)	(163)	(176)	(190)
5	Contribution to New Non-Growth Capex	*Exh 1904*	255	287	319	349	378	405	432	457	480	503
6	Operations & Maintenance		(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
7	Franchise Tax	2.74%	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)
8	Property Tax	1.50%	(38)	(36)	(34)	(32)	(30)	(28)	(26)	(24)	(23)	(21)
9	Net Before Taxes		45	93	155	217	277	336	379	420	461	500
10	Income Tax	27.00%	12	25	42	59	75	91	102	114	124	135
11	Net After Tax		33	68	113	158	202	245	276	307	336	365
12	Tax Benefit on Investment		45	41	38	38	38	38	38	38	38	38
13	Total Operating Cash (ROR Analysis)	($3,125)	77	109	152	196	240	283	314	344	374	402

		Rate	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
1	Plant		3,125	3,125	3,125	3,125	3,125	3,125	3,125	3,125	3,125	3,125
2	Depreciation (per model term)	4.000%	(750)	(875)	(1,000)	(1,125)	(1,250)	(1,375)	(1,500)	(1,625)	(1,750)	(1,875)
3	Net Plant		2,375	2,250	2,125	2,000	1,875	1,750	1,625	1,500	1,375	1,250
4	Deferred Taxes		91	99	103	107	111	115	119	123	127	130
5	Net Rate Base		2,284	2,151	2,022	1,893	1,764	1,635	1,506	1,377	1,248	1,120
6	Average Rate Base		2,352	2,217	2,087	1,957	1,828	1,700	1,571	1,442	1,313	1,184
	Basis for interest expense		1,176	1,109	1,043	979	914	850	785	721	656	592

Tax Depreciation			Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
1	Tax Depreciation Rate		5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%
2	Plant Additions											
3	Total Tax Depreciation		165	153	141	139	139	139	139	139	139	139
4	Tax Benefit @	27.00%	45	41	38	38	38	38	38	38	38	38

Book Depreciation												
1	Book Depreciation Rate		4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
2	Plant Additions											
3	Book Depreciation		125	125	125	125	125	125	125	125	125	125
4	Total Book Depreciation		125	125	125	125	125	125	125	125	125	125
5	Total Tax Depreciation		165	153	141	139	139	139	139	139	139	139
6	Difference		40	28	16	14	14	14	14	14	14	14
7	Deferred Taxes	27.00%	11	7	4	4	4	4	4	4	4	4
	20 year MACRS		5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%

			Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
1	Revenue from New Connection Tariff	*Exh 1905*	722	722	722	722	722	722	722	722	722	722
2	CPP Revenue	*Exh 1906*	601	629	657	685	714	742	770	798	826	855
3	CPP Cost	*Exh 1906*	(989)	(989)	(989)	(989)	(989)	(989)	(989)	(989)	(989)	(989)
4	Nominal Change in Base Rate Revenue per Customer	*Exh 1903*	(204)	(217)	(231)	(244)	(258)	(271)	(285)	(298)	(312)	(326)
5	Contribution to New Non-Growth Capex	*Exh 1904*	524	544	562	580	596	611	625	640	653	666
6	Operations & Maintenance		(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
7	Franchise Tax	2.74%	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)
8	Property Tax	1.50%	(19)	(17)	(15)	(13)	(11)	(9)	(8)	(6)	(4)	(2)
9	Net Before Taxes		537	574	609	643	675	707	738	768	799	828
10	Income Tax	27.00%	145	155	164	174	182	191	199	208	216	224
11	Net After Tax		392	419	444	469	493	516	539	561	583	605
12	Tax Benefit on Investment		38	38	38	38	38	19	0	0	0	0
13	Total Operating Cash (ROR Analysis)	($3,125)	430	456	482	507	531	535	539	561	583	605

		Rate	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
1	Plant		3,125	3,125	3,125	3,125	3,125	3,125	3,125	3,125	3,125	3,125
2	Depreciation (per model term)	4.000%	(2,000)	(2,125)	(2,250)	(2,375)	(2,500)	(2,625)	(2,750)	(2,875)	(3,000)	(3,125)
3	Net Plant		1,125	1,000	875	750	625	500	375	250	125	0
4	Deferred Taxes		134	138	142	146	150	135	101	68	34	0
5	Net Rate Base		991	862	733	604	475	365	274	182	91	0
6	Average Rate Base		1,055	926	797	668	540	420	319	228	137	46
	Basis for interest expense		528	463	399	334	270	210	160	114	68	23

Tax Depreciation			Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
1	Tax Depreciation Rate		4.46%	4.46%	4.46%	4.46%	4.46%	2.23%	0.00%	0.00%	0.00%	0.00%
2	Plant Additions											
3	Total Tax Depreciation		139	139	139	139	139	70	0	0	0	0
4	Tax Benefit @	27.00%	38	38	38	38	38	19	0	0	0	0

Book Depreciation												
1	Book Depreciation Rate		4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
2	Plant Additions											
3	Book Depreciation		125	125	125	125	125	125	125	125	125	125
4	Total Book Depreciation		125	125	125	125	125	125	125	125	125	125
5	Total Tax Depreciation		139	139	139	139	139	70	0	0	0	0
6	Difference		14	14	14	14	14	(55)	(125)	(125)	(125)	(125)
7	Deferred Taxes	27.00%	4	4	4	4	4	(15)	(34)	(34)	(34)	(34)
	20 year MACRS		4.46%	4.46%	4.46%	4.46%	4.46%	2.23%	0.00%	0.00%	0.00%	0.00%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Gregg H. Therrien

LINE EXTENSION ALLOWANCE
EXHIBIT 1903

December 29, 2023

	Description		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
	Revenue Requirement Calculations										
1	Gross Plant		$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation		$ (1,590,754,661)	$ (1,687,260,190)	$ (1,783,765,719)	$ (1,880,271,247)	$ (1,976,776,776)	$ (2,073,282,305)	$ (2,169,787,834)	$ (2,266,293,363)	$ (2,362,798,891)
3	Net Plant		$ 2,412,638,220	$ 2,316,132,691	$ 2,219,627,163	$ 2,123,121,634	$ 2,026,616,105	$ 1,930,110,576	$ 1,833,605,047	$ 1,737,099,519	$ 1,640,593,990
4	Deferred Taxes		$ (435,773,775)	$ (418,342,824)	$ (400,911,873)	$ (383,480,922)	$ (366,049,971)	$ (348,619,020)	$ (331,188,069)	$ (313,757,118)	$ (296,326,167)
5	Average Rate Base (Plant related)		$ 1,976,864,445	$ 1,897,789,867	$ 1,818,715,290	$ 1,739,640,712	$ 1,660,566,134	$ 1,581,491,556	$ 1,502,416,978	$ 1,423,342,401	$ 1,344,267,823
6	Pre-Tax ROR		9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%
7	Return and Taxes		$ 178,979,125	$ 171,819,960	$ 164,660,795	$ 157,501,630	$ 150,342,465	$ 143,183,300	$ 136,024,135	$ 128,864,970	$ 121,705,805
8	Book Depreciation		96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529
9	O&M		539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000
10	Property Taxes	1.5%	36,189,573	34,741,990	33,294,407	31,846,825	30,399,242	28,951,659	27,504,076	26,056,493	24,608,910
11	Franchise Tax and Comm Fees	2.7%	23,992,909	23,750,349	23,507,790	23,265,230	23,022,671	22,780,111	22,537,552	22,294,992	22,052,433
12	Annual Revenue Requirement		$ 875,334,136	$ 866,484,828	$ 857,635,521	$ 848,786,214	$ 839,936,906	$ 831,087,599	$ 822,238,291	$ 813,388,984	$ 804,539,676
13	No. of Customers		652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer		$ 1,341.98	$ 1,328.42	$ 1,314.85	$ 1,301.28	$ 1,287.71	$ 1,274.15	$ 1,260.58	$ 1,247.01	$ 1,233.45
15	YoY Change			$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)
16	Cumulative Change		$ -	$ (13.57)	$ (27.13)	$ (40.70)	$ (54.27)	$ (67.83)	$ (81.40)	$ (94.97)	$ (108.54)
17	Depreciation Expense (based on model term rate)	4.00%	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529
18	Deferred Tax Amortization (based on model term rate)		$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951
19	Net Utility Plant		$ 1,964,464,000								

	Description	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19
	Revenue Requirement Calculations										
1	Gross Plant	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation	$ (2,459,304,420)	$ (2,555,809,949)	$ (2,652,315,478)	$ (2,748,821,007)	$ (2,845,326,535)	$ (2,941,832,064)	$ (3,038,337,593)	$ (3,134,843,122)	$ (3,231,348,651)	$ (3,327,854,179)
3	Net Plant	$ 1,544,088,461	$ 1,447,582,932	$ 1,351,077,403	$ 1,254,571,874	$ 1,158,066,346	$ 1,061,560,817	$ 965,055,288	$ 868,549,759	$ 772,044,230	$ 675,538,702
4	Deferred Taxes	$ (278,895,216)	$ (261,464,265)	$ (244,033,314)	$ (226,602,363)	$ (209,171,412)	$ (191,740,461)	$ (174,309,510)	$ (156,878,559)	$ (139,447,608)	$ (122,016,657)
5	Average Rate Base (Plant related)	$ 1,265,193,245	$ 1,186,118,667	$ 1,107,044,089	$ 1,027,969,511	$ 948,894,934	$ 869,820,356	$ 790,745,778	$ 711,671,200	$ 632,596,622	$ 553,522,045
6	Pre-Tax ROR	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%
7	Return and Taxes	$ 114,546,640	$ 107,387,475	$ 100,228,310	$ 93,069,145	$ 85,909,980	$ 78,750,815	$ 71,591,650	$ 64,432,485	$ 57,273,320	$ 50,114,155
8	Book Depreciation	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529
9	O&M	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000
10	Property Taxes	23,161,327	21,713,744	20,266,161	18,818,578	17,370,995	15,923,412	14,475,829	13,028,246	11,580,663	10,133,081
11	Franchise Tax and Comm Fees	21,809,873	21,567,313	21,324,754	21,082,194	20,839,635	20,597,075	20,354,516	20,111,956	19,869,397	19,626,837
12	Annual Revenue Requirement	$ 795,690,369	$ 786,841,061	$ 777,991,754	$ 769,142,446	$ 760,293,139	$ 751,443,832	$ 742,594,524	$ 733,745,217	$ 724,895,909	$ 716,046,602
13	No. of Customers	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer	$ 1,219.88	$ 1,206.31	$ 1,192.75	$ 1,179.18	$ 1,165.61	$ 1,152.04	$ 1,138.48	$ 1,124.91	$ 1,111.34	$ 1,097.78
15	YoY Change	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)
16	Cumulative Change	$ (122.10)	$ (135.67)	$ (149.24)	$ (162.80)	$ (176.37)	$ (189.94)	$ (203.50)	$ (217.07)	$ (230.64)	$ (244.21)
17	Depreciation Expense (based on model term rate)	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529
18	Deferred Tax Amortization (based on model term rate)	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951
19	Net Utility Plant										

	Description	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
	Revenue Requirement Calculations						
1	Gross Plant	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation	$ (3,424,359,708)	$ (3,520,865,237)	$ (3,617,370,766)	$ (3,713,876,295)	$ (3,810,381,824)	$ (3,906,887,352)
3	Net Plant	$ 579,033,173	$ 482,527,644	$ 386,022,115	$ 289,516,586	$ 193,011,058	$ 96,505,529
4	Deferred Taxes	$ (104,585,706)	$ (87,154,755)	$ (69,723,804)	$ (52,292,853)	$ (34,861,902)	$ (17,430,951)
5	Average Rate Base (Plant related)	$ 474,447,467	$ 395,372,889	$ 316,298,311	$ 237,223,733	$ 158,149,156	$ 79,074,578
6	Pre-Tax ROR	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%
7	Return and Taxes	$ 42,954,990	$ 35,795,825	$ 28,636,660	$ 21,477,495	$ 14,318,330	$ 7,159,165
8	Book Depreciation	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529
9	O&M	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000
10	Property Taxes	8,685,498	7,237,915	5,790,332	4,342,749	2,895,166	1,447,583
11	Franchise Tax and Comm Fees	19,384,278	19,141,718	18,899,159	18,656,599	18,414,040	18,171,480
12	Annual Revenue Requirement	$ 707,197,294	$ 698,347,987	$ 689,498,679	$ 680,649,372	$ 671,800,064	$ 662,950,757
13	No. of Customers	652,270	652,270	652,270	652,270	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer	$ 1,084.21	$ 1,070.64	$ 1,057.08	$ 1,043.51	$ 1,029.94	$ 1,016.38
15	YoY Change	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)
16	Cumulative Change	$ (257.77)	$ (271.34)	$ (284.91)	$ (298.47)	$ (312.04)	$ (325.61)
17	Depreciation Expense (based on model term rate)	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529
18	Deferred Tax Amortization (based on model term rate)	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951
19	Net Utility Plant						

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Gregg H. Therrien

LINE EXTENSION ALLOWANCE
EXHIBIT 1904

December 29, 2023

	Description		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14
1	**Rate Base Calculation**															
2	Capex (MID) (oregon share @90%)		$ 250,200,000	$ 250,200,000	$ 205,200,000	$ 205,200,000	$ 205,200,000	$ 187,200,000	$ 187,200,000	$ 187,200,000	$ 187,200,000	$ 187,200,000	$ 187,200,000	$ 187,200,000	$ 187,200,000	$ 187,200,000
3	Cumulative Capex		$ 250,200,000	$ 500,400,000	$ 705,600,000	$ 910,800,000	$ 1,116,000,000	$ 1,303,200,000	$ 1,490,400,000	$ 1,677,600,000	$ 1,864,800,000	$ 2,052,000,000	$ 2,239,200,000	$ 2,426,400,000	$ 2,613,600,000	$ 2,800,800,000
4	Accumulated Depreciation		(10,008,000)	(30,024,000)	(58,248,000)	(94,680,000)	(139,320,000)	(191,448,000)	(251,064,000)	(318,168,000)	(392,760,000)	(474,840,000)	(564,408,000)	(661,464,000)	(766,008,000)	(878,040,000)
5	Net Plant (Low)		$ 240,192,000	$ 470,376,000	$ 647,352,000	$ 816,120,000	$ 976,680,000	$ 1,111,752,000	$ 1,239,336,000	$ 1,359,432,000	$ 1,472,040,000	$ 1,577,160,000	$ 1,674,792,000	$ 1,764,936,000	$ 1,847,592,000	$ 1,922,760,000
6	Deferred Tax Reserve		168,910	(1,837,065)	(5,682,109)	(10,606,854)	(16,363,667)	(22,736,285)	(29,344,244)	(36,018,616)	(42,791,407)	(49,728,972)	(56,860,080)	(64,203,476)	(71,777,504)	(79,584,525)
7	Year End Rate Base Additions		$ 240,360,910	$ 468,538,935	$ 641,669,891	$ 805,513,146	$ 960,316,333	$ 1,089,015,715	$ 1,209,991,756	$ 1,323,413,384	$ 1,429,248,593	$ 1,527,431,028	$ 1,617,931,920	$ 1,700,732,524	$ 1,775,814,496	$ 1,843,175,475
	Revenue Requirement Calculations															
8	Average Rate Base		$ 120,180,455	$ 354,449,922	$ 555,104,413	$ 723,591,519	$ 882,914,739	$ 1,024,666,024	$ 1,149,503,735	$ 1,266,702,570	$ 1,376,330,989	$ 1,478,339,811	$ 1,572,681,474	$ 1,659,332,222	$ 1,738,273,510	$ 1,809,494,986
9	Pre-Tax ROR		9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%
10	Return and Taxes		$ 10,880,763	$ 32,090,788	$ 50,257,418	$ 65,511,713	$ 79,936,340	$ 92,770,058	$ 104,072,474	$ 114,683,290	$ 124,608,704	$ 133,844,264	$ 142,385,663	$ 150,230,751	$ 157,377,848	$ 163,826,018
11	Book Depreciation	4.0%	10,008,000	20,016,000	28,224,000	36,432,000	44,640,000	52,128,000	59,616,000	67,104,000	74,592,000	82,080,000	89,568,000	97,056,000	104,544,000	112,032,000
12	O&M															
13	Property Taxes	1.5%	3,602,880	7,055,640	9,710,280	12,241,800	14,650,200	16,676,280	18,590,040	20,391,480	22,080,600	23,657,400	25,121,880	26,474,040	27,713,880	28,841,400
14	Annual Revenue Requirement - pre franch		24,491,643	59,162,428	88,191,698	114,185,513	139,226,540	161,574,338	182,278,514	202,178,770	221,281,304	239,581,664	257,075,543	273,760,791	289,635,728	304,699,418
15																
16	Franchise Tax and Comm Fees	2.7%	690,235	1,667,344	2,485,461	3,218,031	3,923,749	4,553,566	5,137,061	5,697,900	6,236,256	6,752,006	7,245,027	7,715,259	8,162,654	8,587,186
17	Annual Revenue Requirement		$ 25,181,878	$ 60,829,772	$ 90,677,159	$ 117,403,545	$ 143,150,289	$ 166,127,903	$ 187,415,575	$ 207,876,669	$ 227,517,560	$ 246,333,670	$ 264,320,570	$ 281,476,049	$ 297,798,382	$ 313,286,603
18	No. of Customers		652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270
19	Rev Req per Cust ("cost avoidance")		$ 38.61	$ 93.26	$ 139.02	$ 179.99	$ 219.46	$ 254.69	$ 287.33	$ 318.70	$ 348.81	$ 377.66	$ 405.23	$ 431.53	$ 456.56	$ 480.30
20	Deferred Taxes:		1	2	3	4	5	6	7	8	9	10	11	12	13	14
21	20-year MACRS		3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%
		Invmt. Yr.														
22	Tax Depreciation	Year 1	9,382,500	18,061,938	16,705,854	15,454,854	14,293,926	13,223,070	12,229,776	11,314,044	11,163,924	11,161,422	11,163,924	11,161,422	11,163,924	11,161,422
23		Year 2		9,382,500	18,061,938	16,705,854	15,454,854	14,293,926	13,223,070	12,229,776	11,314,044	11,163,924	11,161,422	11,163,924	11,161,422	11,163,924
24		Year 3			7,695,000	14,813,388	13,701,204	12,675,204	11,723,076	10,844,820	10,030,176	9,279,144	9,156,024	9,153,972	9,156,024	9,153,972
25		Year 4				7,695,000	14,813,388	13,701,204	12,675,204	11,723,076	10,844,820	10,030,176	9,279,144	9,156,024	9,153,972	9,156,024
26		Year 5					7,695,000	14,813,388	13,701,204	12,675,204	11,723,076	10,844,820	10,030,176	9,279,144	9,156,024	9,153,972
27		Year 6						7,020,000	13,513,968	12,499,344	11,563,344	10,694,736	9,893,520	9,150,336	8,465,184	8,352,864
28		Year 7							7,020,000	13,513,968	12,499,344	11,563,344	10,694,736	9,893,520	9,150,336	8,465,184
29		Year 8								7,020,000	13,513,968	12,499,344	11,563,344	10,694,736	9,893,520	9,150,336
30		Year 9									7,020,000	13,513,968	12,499,344	11,563,344	10,694,736	9,893,520
31		Year 10										7,020,000	13,513,968	12,499,344	11,563,344	10,694,736
32		Year 11											7,020,000	13,513,968	12,499,344	11,563,344
33		Year 12												7,020,000	13,513,968	12,499,344
34		Year 13													7,020,000	13,513,968
35		Year 14														7,020,000
36		Year 15														
37		Year 16														
38		Year 17														
39		Year 18														
40		Year 19														
41		Year 20														
42		Sum	9,382,500	27,444,438	42,462,792	54,669,096	65,958,372	75,726,792	84,086,298	91,820,232	99,672,696	107,770,878	115,975,602	124,249,734	132,591,798	140,942,610
43	Book Depreciation		10,008,000	20,016,000	28,224,000	36,432,000	44,640,000	52,128,000	59,616,000	67,104,000	74,592,000	82,080,000	89,568,000	97,056,000	104,544,000	112,032,000
44	Variance		($625,500)	$7,428,438	$14,238,792	$18,237,096	$21,318,372	$23,598,792	$24,470,298	$24,716,232	$25,080,696	$25,690,878	$26,407,602	$27,193,734	$28,047,798	$28,910,610
45	Deferred Taxes	27.00%	($168,910)	$2,005,975	$3,845,043	$4,924,745	$5,756,813	$6,372,618	$6,607,959	$6,674,371	$6,772,791	$6,937,565	$7,131,109	$7,343,396	$7,574,027	$7,807,021

	Description	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
1	**Rate Base Calculation**											
2	Capex (MID) (oregon share @90%)	$ 187,200,000	$ 187,200,000	$ 187,200,000	$ 187,200,000	$ 187,200,000	$ 187,200,000	$ 187,200,000	$ 187,200,000	$ 187,200,000	$ 187,200,000	$ 187,200,000
3	Cumulative Capex	$ 2,988,000,000	$ 3,175,200,000	$ 3,362,400,000	$ 3,549,600,000	$ 3,736,800,000	$ 3,924,000,000	$ 4,111,200,000	$ 4,298,400,000	$ 4,485,600,000	$ 4,672,800,000	$ 4,860,000,000
4	Accumulated Depreciation	(997,560,000)	(1,124,568,000)	(1,259,064,000)	(1,401,048,000)	(1,550,520,000)	(1,707,480,000)	(1,871,928,000)	(2,043,864,000)	(2,223,288,000)	(2,410,200,000)	(2,604,600,000)
5	Net Plant (Low)	$ 1,990,440,000	$ 2,050,632,000	$ 2,103,336,000	$ 2,148,552,000	$ 2,186,280,000	$ 2,216,520,000	$ 2,239,272,000	$ 2,254,536,000	$ 2,262,312,000	$ 2,262,600,000	$ 2,255,400,000
6	Deferred Tax Reserve	(87,625,142)	(95,898,754)	(104,405,962)	(113,146,163)	(122,119,961)	(131,326,753)	(137,364,108)	(136,971,114)	(130,692,794)	(119,052,964)	(102,286,231)
7	Year End Rate Base Additions	$ 1,902,814,858	$ 1,954,733,246	$ 1,998,930,038	$ 2,035,405,837	$ 2,064,160,039	$ 2,085,193,247	$ 2,101,907,892	$ 2,117,564,886	$ 2,131,619,206	$ 2,143,547,036	$ 2,153,113,769
	Revenue Requirement Calculations											
8	Average Rate Base	$ 1,872,995,166	$ 1,928,774,052	$ 1,976,831,642	$ 2,017,167,938	$ 2,049,782,938	$ 2,074,676,643	$ 2,093,550,570	$ 2,109,736,389	$ 2,124,592,046	$ 2,137,583,121	$ 2,148,330,403
9	Pre-Tax ROR	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%
10	Return and Taxes	$ 169,575,125	$ 174,625,171	$ 178,976,155	$ 182,628,077	$ 185,580,937	$ 187,834,736	$ 189,543,522	$ 191,008,936	$ 192,353,920	$ 193,530,092	$ 194,503,117
11	Book Depreciation	119,520,000	127,008,000	134,496,000	141,984,000	149,472,000	156,960,000	164,448,000	171,936,000	179,424,000	186,912,000	194,400,000
12	O&M											
13	Property Taxes	29,856,600	30,759,480	31,550,040	32,228,280	32,794,200	33,247,800	33,589,080	33,818,040	33,934,680	33,939,000	33,831,000
14	Annual Revenue Requirement - pre franc	318,951,725	332,392,651	345,022,195	356,840,357	367,847,137	378,042,536	387,580,602	396,762,976	405,712,600	414,381,092	422,734,117
15												
16	Franchise Tax and Comm Fees	8,988,851	9,367,650	9,723,582	10,056,647	10,366,845	10,654,177	10,922,983	11,181,765	11,433,988	11,678,288	11,913,697
17	Annual Revenue Requirement	$ 327,940,577	$ 341,760,301	$ 354,745,777	$ 366,897,004	$ 378,213,983	$ 388,696,713	$ 398,503,585	$ 407,944,741	$ 417,146,588	$ 426,059,379	$ 434,647,813
18	No. of Customers	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270
19	Rev Req per Cust ("cost avoidance")	$ 502.77	$ 523.96	$ 543.86	$ 562.49	$ 579.84	$ 595.91	$ 610.95	$ 625.42	$ 639.53	$ 653.20	$ 666.36
20	Deferred Taxes:	15	16	17	18	19	20	21	22	23	24	25
21	20-year MACRS	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	2.231%	0.000%	0.000%	0.000%	0.000%
22	Tax Depreciation	11,163,924	11,161,422	11,163,924	11,161,422	11,163,924	11,161,422	5,581,962	-	-	-	-
23		11,161,422	11,163,924	11,161,422	11,163,924	11,161,422	11,163,924	11,161,422	5,581,962	-	-	-
24		9,156,024	9,153,972	9,156,024	9,153,972	9,156,024	9,153,972	9,156,024	9,153,972	4,578,012	-	-
25		9,153,972	9,156,024	9,153,972	9,156,024	9,153,972	9,156,024	9,153,972	9,156,024	9,153,972	4,578,012	-
26		9,156,024	9,153,972	9,156,024	9,153,972	9,156,024	9,153,972	9,156,024	9,153,972	9,156,024	9,153,972	4,578,012
27		8,350,992	8,352,864	8,350,992	8,352,864	8,350,992	8,352,864	8,350,992	8,352,864	8,350,992	8,352,864	8,350,992
28		8,352,864	8,350,992	8,352,864	8,350,992	8,352,864	8,350,992	8,352,864	8,350,992	8,352,864	8,350,992	8,352,864
29		8,465,184	8,352,864	8,350,992	8,352,864	8,350,992	8,352,864	8,350,992	8,352,864	8,350,992	8,352,864	8,350,992
30		9,150,336	8,465,184	8,352,864	8,350,992	8,352,864	8,350,992	8,352,864	8,350,992	8,352,864	8,350,992	8,352,864
31		9,893,520	9,150,336	8,465,184	8,352,864	8,350,992	8,352,864	8,350,992	8,352,864	8,350,992	8,352,864	8,350,992
32		10,694,736	9,893,520	9,150,336	8,465,184	8,352,864	8,350,992	8,352,864	8,350,992	8,352,864	8,350,992	8,352,864
33		11,563,344	10,694,736	9,893,520	9,150,336	8,465,184	8,352,864	8,350,992	8,352,864	8,350,992	8,352,864	8,350,992
34		12,499,344	11,563,344	10,694,736	9,893,520	9,150,336	8,465,184	8,352,864	8,350,992	8,352,864	8,350,992	8,352,864
35		13,513,968	12,499,344	11,563,344	10,694,736	9,893,520	9,150,336	8,465,184	8,352,864	8,350,992	8,352,864	8,350,992
36		7,020,000	13,513,968	12,499,344	11,563,344	10,694,736	9,893,520	9,150,336	8,465,184	8,352,864	8,350,992	8,352,864
37			7,020,000	13,513,968	12,499,344	11,563,344	10,694,736	9,893,520	9,150,336	8,465,184	8,352,864	8,350,992
38				7,020,000	13,513,968	12,499,344	11,563,344	10,694,736	9,893,520	9,150,336	8,465,184	8,352,864
39					7,020,000	13,513,968	12,499,344	11,563,344	10,694,736	9,893,520	9,150,336	8,465,184
40						7,020,000	13,513,968	12,499,344	11,563,344	10,694,736	9,893,520	9,150,336
41							7,020,000	13,513,968	12,499,344	11,563,344	10,694,736	9,893,520
42		149,295,654	157,646,466	165,999,510	174,350,322	182,703,366	191,054,178	186,805,260	170,480,682	156,174,408	143,807,904	132,310,188
43	Book Depreciation	119,520,000	127,008,000	134,496,000	141,984,000	149,472,000	156,960,000	164,448,000	171,936,000	179,424,000	186,912,000	194,400,000
44	Variance	$29,775,654	$30,638,466	$31,503,510	$32,366,322	$33,231,366	$34,094,178	$22,357,260	($1,455,318)	($23,249,592)	($43,104,096)	($62,089,812)
45	Deferred Taxes	$8,040,618	$8,273,611	$8,507,208	$8,740,202	$8,973,798	$9,206,792	$6,037,354	($392,994)	($6,278,320)	($11,639,830)	($16,766,733)

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Gregg H. Therrien

LINE EXTENSION ALLOWANCE
EXHIBIT 1905

December 29, 2023

1	**General Inputs:**		
2	Start Date:	11/1/2024	*<-- input*
3	Year 1:	2025	*<-- input*
4	UPC Therms - New Customers	449.4	*<-- input*
5	NPV Number of Years:	25	*<-- input*
6	Model depreciation assumption	4.00%	
7	**Distribution Revenue Calculation:**		
8	UPC (therms)	449.4	
9			
10	Customer Charge	**$26.25**	*<-- input (tariff)*
11	Rate per Therm	0.90649	*<-- input (tariff)*
12	**Annual Distribution Revenue (Real $)**	**$722.38**	
13	**NPV**	$1	
14			
15	**Construction Costs**	**$3,125**	***Goal seek to produce 0 NPV***
16	**Times Margin**	4.3	

Model Results at Proposed Consumption Levels (Therms)

UPC (Therms)	250	450	650	1,000
LEA	$3,606	$3,125	$2,644	$1,803
Times Margin	6.7	4.3	2.9	1.5
Rev Req B/E Year	Year 10	Year 11	Year 11	Year 11

17	**Cost of Capital**				
18				**Weighted**	**After-tax**
19		**% of Capital**	**Cost**	**Cost**	**Cost**
20					
21	**Debt**	50.00%	4.271%	2.136%	1.559%
22	**Common Equity**	50.00%	10.100%	5.050%	5.050%
23		100.00%		**7.186%**	**6.609%**

24	**Other Costs:**		
25	**State Tax Rate**	7.60%	*<-- input*
26	**Federal Tax Rate**	21.00%	*<-- input*
27	**Revenue Sensitive Rate (Franchise tax, Comm fee)**	2.741%	*<-- input*
28	**Property Tax Rate**	1.50%	*<-- input*
29	**Incremental O&M**	79.19	*<-- input*

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Gregg H. Therrien

LINE EXTENSION ALLOWANCE
EXHIBIT 1906

December 29, 2023

Growth Rate	0.15%
2022-24 CCI Cap	10.00%
2025-27 CCI Cap	15.00%
Beyond 2027	20.00%

		Source	2024	2025	2026	2027	2028	2029	2030
1	**Normalized Load**	NWN internal data	1,088,444,642	1,090,264,509	1,091,897,976	1,093,353,861	1,094,995,193	1,096,638,989	1,098,285,253
2	**Non-Combustion Exclusion**	NWN internal data	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841
3	**RNG**	NWN internal data	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147
4	**MT CO2e**	NWN internal data	5,609,893	5,619,559	5,628,235	5,635,968	5,644,686	5,653,417	5,662,161
5	**Compliance Curve (MT CO2e)**	NWN internal data	5,316,897	5,095,359	4,873,822	4,652,285	4,430,747	4,209,210	3,987,673
6	**Over (Under) Compliance**		292,996	524,200	754,413	983,683	1,213,939	1,444,207	1,674,488
7	**CCI Cap**		560,989	842,934	844,235	845,395	1,128,937	1,130,683	1,132,432
8	**Over (Under) CCI Cap**		(267,994)	(318,734)	(89,822)	138,288	85,002	313,523	542,056
9	**Accumulated Over (Under) CCI Cap**		(267,994)	(586,728)	(676,550)	(538,263)	(453,261)	(139,738)	402,318
10	**New Customer Therms**	NWN internal data	450	450	450	450	450	450	450
11	**New Customer MT CO2e**	NWN internal data	2.39	2.39	2.39	2.39	2.39	2.39	2.39
12	**CPP Cost of New Customer**	NWN internal data	$ 305.94	$ 313.11	$ 322.67	$ 990.00	$ 990.00	$ 990.00	$ 990.00
13	**CPP Cost per Therm**		$ 0.68	$ 0.70	$ 0.72	$ 2.20	$ 2.20	$ 2.20	$ 2.20
14	**CPP Cost**		$ 305.53	$ 312.69	$ 322.24	$ 988.68	$ 988.68	$ 988.68	$ 988.68
15	**2022 CPP Annual Cap (MT CO2e)**	DEQ Greenhouse Gas Emissions Calculations to supplement rulemaking GHGCR2021, Calculation for proposed OAR 340-271-9000 Table 2: Oregon Climate Protection Program Caps	28,081,335						
16	**CPP Annual Caps (MT CO2e)**	DEQ Greenhouse Gas Emissions Calculations to supplement rulemaking GHGCR2021, Calculation for proposed OAR 340-271-9000 Table 2: Oregon Climate Protection Program Caps	25,921,232	25,763,209	24,637,057	23,510,904	23,013,190	21,842,149	20,671,108
17	**CPP Revenue Multiplier**		-7.69%	-8.26%	-12.27%	-16.28%	-18.05%	-22.22%	-26.39%
18	**CPP Revenue**		$ 23.50	$ 25.81	$ 39.52	$ 160.91	$ 178.44	$ 219.67	$ 260.90

		2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
1	**Normalized Load**	1,099,933,988	1,101,585,198	1,103,238,887	1,104,895,059	1,106,553,717	1,108,214,864	1,109,878,506	1,111,544,645	1,113,213,285	1,114,884,430	1,116,558,083
2	**Non-Combustion Exclusion**	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841
3	**RNG**	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147
4	**MT CO2e**	5,670,918	5,679,688	5,688,472	5,697,269	5,706,079	5,714,902	5,723,738	5,732,588	5,741,451	5,750,327	5,759,217
5	**Compliance Curve (MT CO2e)**	3,766,135	3,544,598	3,323,061	3,101,523	2,879,986	2,726,387	2,572,787	2,419,188	2,265,589	2,111,990	1,958,390
6	**Over (Under) Compliance**	1,904,783	2,135,090	2,365,411	2,595,746	2,826,093	2,988,515	3,150,951	3,313,400	3,475,862	3,638,337	3,800,827
7	**CCI Cap**	1,134,184	1,135,938	1,137,694	1,139,454	1,141,216	1,142,980	1,144,748	1,146,518	1,148,290	1,150,065	1,151,843
8	**Over (Under) CCI Cap**	770,599	999,153	1,227,717	1,456,292	1,684,877	1,845,534	2,006,203	2,166,882	2,327,572	2,488,272	2,648,983
9	**Accumulated Over (Under) CCI Cap**	1,172,917	2,172,070	3,399,786	4,856,078	6,540,955	8,386,490	10,392,693	12,559,575	14,887,147	17,375,418	20,024,402
10	**New Customer Therms**	450	450	450	450	450	450	450	450	450	450	450
11	**New Customer MT CO2e**	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39
12	**CPP Cost of New Customer**	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00
13	**CPP Cost per Therm**	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20
14	**CPP Cost**	$ 988.68	$ 988.68	$ 988.68	$ 988.68	$ 988.68	$ 988.68	$ 988.68	$ 988.68	$ 988.68	$ 988.68	$ 988.68
15	**2022 CPP Annual Cap (MT CO2e)**											
16	**CPP Annual Caps (MT CO2e)**	19,910,424	18,688,088	17,465,752	16,243,416	15,021,080	14,219,956	13,418,831	12,617,707	11,816,583	11,015,459	10,214,334
17	**CPP Revenue Multiplier**	-29.10%	-33.45%	-37.80%	-42.16%	-46.51%	-49.36%	-52.21%	-55.07%	-57.92%	-60.77%	-63.63%
18	**CPP Revenue**	$ 287.68	$ 330.71	$ 373.75	$ 416.79	$ 459.82	$ 488.03	$ 516.23	$ 544.44	$ 572.64	$ 600.85	$ 629.06

		2042	2043	2044	2045	2046	2047	2048	2049
1	**Normalized Load**	1,118,234,249	1,119,912,932	1,121,594,134					
2	**Non-Combustion Exclusion**	20,733,841	20,733,841	20,733,841					
3	**RNG**	11,540,147	11,540,147	11,540,147					
4	**MT CO2e**	5,768,119	5,777,036	5,785,965					
5	**Compliance Curve (MT CO2e)**	1,804,791	1,651,192	1,497,593					
6	**Over (Under) Compliance**	3,963,328	4,125,844	4,288,372					
7	**CCI Cap**	1,153,624	1,155,407	1,157,193					
8	**Over (Under) CCI Cap**	2,809,705	2,970,437	3,131,179					
9	**Accumulated Over (Under) CCI Cap**	22,834,106	25,804,543	28,935,722					
10	**New Customer Therms**	450	450	450	450	450	450	450	450
11	**New Customer MT CO2e**	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39
12	**CPP Cost of New Customer**	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00
13	**CPP Cost per Therm**	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20
14	**CPP Cost**	$ 988.68	$ 988.68	$ 988.68	$ 988.68	$ 988.68	$ 988.68	$ 988.68	$ 988.68
15	**2022 CPP Annual Cap (MT CO2e)**								
16	**CPP Annual Caps (MT CO2e)**	9,413,210	8,612,086	7,810,962	7,009,837	6,208,713	5,407,589	4,606,465	3,805,340
17	**CPP Revenue Multiplier**	-66.48%	-69.33%	-72.18%	-75.04%	-77.89%	-80.74%	-83.60%	-86.45%
18	**CPP Revenue**	$ 657.26	$ 685.47	$ 713.67	$ 741.88	$ 770.09	$ 798.29	$ 826.50	$ 854.70

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Gregg H. Therrien

LINE EXTENSION ALLOWANCE
EXHIBIT 1907

December 29, 2023

NW Natural
Exhibit NW Natural/1907a, Therrien - Year-By-Year Economic Impact on Existing Customers

LEA Determined $3,606

			Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
1	**Depreciation (using book depreciation rates)**	4.00%	144	144	144	144	144	144	144	144	144
2	**O&M**		79	79	79	79	79	79	79	79	79
3	**Property Taxes**		53	51	49	46	44	42	40	38	36
	Taxes on Equity Return										
4	**State**		19	18	17	16	15	14	13	13	12
5	**Federal**		47	45	43	41	39	36	34	32	30
6	**Total Taxes**		66	63	60	57	54	51	48	45	42
	Return on Rate Base										
7	**Debt**		75	72	68	65	61	58	55	51	48
8	**Common Equity**		179	170	162	153	145	137	129	122	114
9	**Total Return**		254	243	230	218	206	195	184	173	162
10	**Subtotal Cost of Service**		596	580	562	545	528	511	495	479	464
11	**Revenue Sensitive Items**		17	16	16	15	15	14	14	14	13
12	**Total Cost of Service**		613	596	578	560	543	526	509	493	477
13	**Cost of CPP ($/Therm)**		0.70	0.72	2.20	2.20	2.20	2.20	2.20	2.20	2.20
14	**UPC (Therms)**		250	250	250	250	250	250	250	250	250
15	**New Customer Cost of CPP**		174	179	550	550	550	550	550	550	550
16	**Less: New Customer Recovery of CPP (re class WACOD)**		-14	-22	-90	-99	-122	-145	-160	-184	-208
17	**Nominal Change in Base Rate Revenue per Customer (Rate Base)**		0	14	27	41	54	68	81	95	109
18	**Less: Contribution to New Non-Growth Capex**		-39	-93	-139	-180	-219	-255	-287	-319	-349
19	**Total Cost of Service (Net)**		734	674	927	872	805	744	693	635	578
20	**New Customer Revenue**		$542	$542	$542	$542	$542	$542	$542	$542	$542
21	**Revenue less cost of service (impact on existing customers)**		($193)	($132)	($385)	($330)	($264)	($202)	($151)	($93)	($37)

NW Natural
Exhibit NW Natural/1907a, Therrien - Year-By-Year Economic Impact on Existing Customers

			Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18
1	**Depreciation (using book depreciation rates)**	4.00%	144	144	144	144	144	144	144	144	144
2	**O&M**		79	79	79	79	79	79	79	79	79
3	**Property Taxes**		34	31	29	27	25	23	21	18	16
	Taxes on Equity Return										
4	**State**		11	10	10	9	8	7	6	6	5
5	**Federal**		28	26	24	22	20	18	16	14	12
6	**Total Taxes**		39	37	34	31	28	26	23	20	17
	Return on Rate Base										
7	**Debt**		45	42	39	36	32	29	26	23	20
8	**Common Equity**		107	99	92	84	76	69	61	54	46
9	**Total Return**		152	141	130	120	109	98	87	77	66
10	**Subtotal Cost of Service**		448	432	417	401	385	370	354	339	323
11	**Revenue Sensitive Items**		13	12	12	11	11	10	10	10	9
12	**Total Cost of Service**		461	444	428	412	396	380	364	348	332
13	**Cost of CPP ($/Therm)**		2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20
14	**UPC (Therms)**		250	250	250	250	250	250	250	250	250
15	**New Customer Cost of CPP**		550	550	550	550	550	550	550	550	550
16	**Less: New Customer Recovery of CPP (re class WACOD)**		-232	-256	-271	-287	-303	-319	-334	-350	-366
17	**Nominal Change in Base Rate Revenue per Customer (Rate Base)**		122	136	149	163	176	190	204	217	231
18	**Less: Contribution to New Non-Growth Capex**		-378	-405	-432	-457	-480	-503	-524	-544	-562
19	**Total Cost of Service (Net)**		523	469	425	381	339	299	259	221	185
20	**New Customer Revenue**		$542	$542	$542	$542	$542	$542	$542	$542	$542
21	**Revenue less cost of service (impact on existing customers)**		$18	$72	$117	$160	$202	$243	$282	$320	$357

NW Natural
Exhibit NW Natural/1907a, Therrien - Year-By-Year Economic Impact on Existing Customers

			Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
1	**Depreciation (using book depreciation rates)**	4.00%	144	144	144	144	144	144	144
2	**O&M**		79	79	79	79	79	79	79
3	**Property Taxes**		14	12	10	8	5	3	1
	Taxes on Equity Return								
4	**State**		4	3	3	2	1	1	0
5	**Federal**		10	8	7	5	4	2	1
6	**Total Taxes**		14	12	9	7	5	3	1
	Return on Rate Base								
7	**Debt**		16	13	10	8	6	3	1
8	**Common Equity**		39	31	24	19	13	8	3
9	**Total Return**		55	45	35	26	19	11	4
10	**Subtotal Cost of Service**		307	292	277	264	253	241	229
11	**Revenue Sensitive Items**		9	8	8	7	7	7	6
12	**Total Cost of Service**		316	300	285	272	260	248	236
13	**Cost of CPP ($/Therm)**		2.20	2.20	2.20	2.20	2.20	2.20	2.20
14	**UPC (Therms)**		250	250	250	250	250	250	250
15	**New Customer Cost of CPP**		550	550	550	550	550	550	550
16	**Less: New Customer Recovery of CPP (re class WACOD)**		-381	-397	-413	-428	-444	-460	-475
17	**Nominal Change in Base Rate Revenue per Customer (Rate Base)**		244	258	271	285	298	312	326
18	**Less: Contribution to New Non-Growth Capex**		-580	-596	-611	-625	-640	-653	-666
19	**Total Cost of Service (Net)**		149	115	83	53	25	-3	-31
20	**New Customer Revenue**		$542	$542	$542	$542	$542	$542	$542
21	**Revenue less cost of service (impact on existing customers)**		$393	$427	$459	$489	$517	$545	$572

NW Natural
Exhibit NW Natural/1907b, Therrien - Year-By-Year Economic Impact on Existing Customers

			LEA Determined		$3,125						
			Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**
1	**Depreciation (using book depreciation rates)**	4.00%	125	125	125	125	125	125	125	125	125
2	**O&M**		79	79	79	79	79	79	79	79	79
3	**Property Taxes**		46	44	42	40	38	37	35	33	31
	Taxes on Equity Return										
4	**State**		16	15	15	14	13	12	12	11	10
5	**Federal**		41	39	37	35	33	32	30	28	26
6	**Total Taxes**		57	55	52	49	47	44	41	39	37
	Return on Rate Base										
7	**Debt**		65	62	59	56	53	50	47	45	42
8	**Common Equity**		155	148	140	133	126	119	112	105	99
9	**Total Return**		220	210	199	189	179	169	159	150	141
10	**Subtotal Cost of Service**		527	513	498	483	468	454	440	426	412
11	**Revenue Sensitive Items**		15	14	14	14	13	13	12	12	12
12	**Total Cost of Service**		542	528	512	496	481	466	452	438	424
13	**Cost of CPP ($/Therm)**		0.70	0.72	2.20	2.20	2.20	2.20	2.20	2.20	2.20
14	**UPC (Therms)**		449	449	449	449	449	449	449	449	449
15	**New Customer Cost of CPP**		313	322	989	989	989	989	989	989	989
16	**Less: New Customer Recovery of CPP (re class WACOD)**		-26	-40	-161	-178	-220	-261	-288	-331	-374
17	**Nominal Change in Base Rate Revenue per Customer (Rate Base)**		0	14	27	41	54	68	81	95	109
18	**Less: Contribution to New Non-Growth Capex**		-39	-93	-139	-180	-219	-255	-287	-319	-349
19	**Total Cost of Service (Net)**		791	731	1,228	1,167	1,085	1,007	947	872	799
20	**New Customer Revenue**		$722	$722	$722	$722	$722	$722	$722	$722	$722
21	**Revenue less cost of service (impact on existing customers)**		($68)	($8)	($505)	($445)	($363)	($285)	($225)	($150)	($76)

NW Natural
Exhibit NW Natural/1907b, Therrien - Year-By-Year Economic Impact on Existing Customers

			Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18
1	**Depreciation (using book depreciation rates)**	4.00%	125	125	125	125	125	125	125	125	125
2	**O&M**		79	79	79	79	79	79	79	79	79
3	**Property Taxes**		29	27	25	23	22	20	18	16	14
	Taxes on Equity Return										
4	**State**		10	9	8	8	7	6	6	5	4
5	**Federal**		25	23	21	19	18	16	14	12	11
6	**Total Taxes**		34	32	29	27	25	22	20	17	15
	Return on Rate Base										
7	**Debt**		39	36	34	31	28	25	23	20	17
8	**Common Equity**		92	86	79	73	66	60	53	47	40
9	**Total Return**		131	122	113	104	94	85	76	67	57
10	**Subtotal Cost of Service**		399	385	372	358	345	331	318	304	290
11	**Revenue Sensitive Items**		11	11	10	10	10	9	9	9	8
12	**Total Cost of Service**		410	396	382	368	354	340	326	313	299
13	**Cost of CPP ($/Therm)**		2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20
14	**UPC (Therms)**		449	449	449	449	449	449	449	449	449
15	**New Customer Cost of CPP**		989	989	989	989	989	989	989	989	989
16	**Less: New Customer Recovery of CPP (re class WACOD)**		-417	-460	-488	-516	-544	-573	-601	-629	-657
17	**Nominal Change in Base Rate Revenue per Customer (Rate Base)**		122	136	149	163	176	190	204	217	231
18	**Less: Contribution to New Non-Growth Capex**		-378	-405	-432	-457	-480	-503	-524	-544	-562
19	**Total Cost of Service (Net)**		726	655	601	547	495	444	394	345	298
20	**New Customer Revenue**		$722	$722	$722	$722	$722	$722	$722	$722	$722
21	**Revenue less cost of service (impact on existing customers)**		($4)	$67	$122	$175	$228	$279	$329	$377	$424

NW Natural
Exhibit NW Natural/1907b, Therrien - Year-By-Year Economic Impact on Existing Customers

			Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
1	**Depreciation (using book depreciation rates)**	4.00%	125	125	125	125	125	125	125
2	**O&M**		79	79	79	79	79	79	79
3	**Property Taxes**		12	10	8	7	5	3	1
	Taxes on Equity Return								
4	**State**		4	3	2	2	1	1	0
5	**Federal**		9	7	6	4	3	2	1
6	**Total Taxes**		12	10	8	6	4	3	1
	Return on Rate Base								
7	**Debt**		14	12	9	7	5	3	1
8	**Common Equity**		34	27	21	16	12	7	2
9	**Total Return**		48	39	30	23	16	10	3
10	**Subtotal Cost of Service**		277	263	251	240	230	219	209
11	**Revenue Sensitive Items**		8	7	7	7	6	6	6
12	**Total Cost of Service**		285	271	258	246	236	226	215
13	**Cost of CPP ($/Therm)**		2.20	2.20	2.20	2.20	2.20	2.20	2.20
14	**UPC (Therms)**		449	449	449	449	449	449	449
15	**New Customer Cost of CPP**		989	989	989	989	989	989	989
16	**Less: New Customer Recovery of CPP (re class WACOD)**		-685	-714	-742	-770	-798	-826	-855
17	**Nominal Change in Base Rate Revenue per Customer (Rate Base)**		244	258	271	285	298	312	326
18	**Less: Contribution to New Non-Growth Capex**		-580	-596	-611	-625	-640	-653	-666
19	**Total Cost of Service (Net)**		252	208	165	124	85	47	8
20	**New Customer Revenue**		$722	$722	$722	$722	$722	$722	$722
21	**Revenue less cost of service (impact on existing customers)**		$470	$515	$557	$598	$637	$676	$714

NW Natural
Exhibit NW Natural/1907c, Therrien - Year-By-Year Economic Impact on Existing Customers

			Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
		LEA Determined		$2,644							
1	**Depreciation (using book depreciation rates)**	4.00%	106	106	106	106	106	106	106	106	106
2	**O&M**		79	79	79	79	79	79	79	79	79
3	**Property Taxes**		39	37	36	34	33	31	29	28	26
	Taxes on Equity Return										
4	**State**		14	13	12	12	11	10	10	9	9
5	**Federal**		35	33	32	30	28	27	25	24	22
6	**Total Taxes**		48	46	44	42	39	37	35	33	31
	Return on Rate Base										
7	**Debt**		55	53	50	48	45	42	40	38	35
8	**Common Equity**		131	125	119	112	106	100	95	89	84
9	**Total Return**		186	178	169	160	151	143	135	127	119
10	**Subtotal Cost of Service**		459	446	433	421	408	396	384	373	361
11	**Revenue Sensitive Items**		13	13	12	12	12	11	11	11	10
12	**Total Cost of Service**		471	459	446	432	420	407	395	383	371
13	**Cost of CPP ($/Therm)**		0.70	0.72	2.20	2.20	2.20	2.20	2.20	2.20	2.20
14	**UPC (Therms)**		650	650	650	650	650	650	650	650	650
15	**New Customer Cost of CPP**		452	466	1,430	1,430	1,430	1,430	1,430	1,430	1,430
16	**Less: New Customer Recovery of CPP (re class WACOD)**		-37	-57	-233	-258	-318	-377	-416	-478	-541
17	**Nominal Change in Base Rate Revenue per Customer (Rate Base)**		0	14	27	41	54	68	81	95	109
18	**Less: Contribution to New Non-Growth Capex**		-39	-93	-139	-180	-219	-255	-287	-319	-349
19	**Total Cost of Service (Net)**		848	788	1,531	1,465	1,367	1,273	1,203	1,111	1,020
20	**New Customer Revenue**		$904	$904	$904	$904	$904	$904	$904	$904	$904
21	**Revenue less cost of service (impact on existing customers)**		$56	$116	($627)	($561)	($463)	($369)	($299)	($207)	($116)

NW Natural
Exhibit NW Natural/1907c, Therrien - Year-By-Year Economic Impact on Existing Customers

			Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18
1	**Depreciation (using book depreciation rates)**	4.00%	106	106	106	106	106	106	106	106	106
2	**O&M**		79	79	79	79	79	79	79	79	79
3	**Property Taxes**		25	23	21	20	18	17	15	13	12
	Taxes on Equity Return										
4	**State**		8	8	7	6	6	5	5	4	4
5	**Federal**		21	19	18	16	15	13	12	11	9
6	**Total Taxes**		29	27	25	23	21	19	17	15	13
	Return on Rate Base										
7	**Debt**		33	31	28	26	24	21	19	17	14
8	**Common Equity**		78	73	67	62	56	51	45	40	34
9	**Total Return**		111	103	96	88	80	72	64	56	48
10	**Subtotal Cost of Service**		350	338	327	315	304	292	281	269	258
11	**Revenue Sensitive Items**		10	10	9	9	9	8	8	8	7
12	**Total Cost of Service**		359	348	336	324	312	301	289	277	265
13	**Cost of CPP ($/Therm)**		2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20
14	**UPC (Therms)**		650	650	650	650	650	650	650	650	650
15	**New Customer Cost of CPP**		1,430	1,430	1,430	1,430	1,430	1,430	1,430	1,430	1,430
16	**Less: New Customer Recovery of CPP (re class WACOD)**		-603	-665	-706	-747	-787	-828	-869	-910	-951
17	**Nominal Change in Base Rate Revenue per Customer (Rate Base)**		122	136	149	163	176	190	204	217	231
18	**Less: Contribution to New Non-Growth Capex**		-378	-405	-432	-457	-480	-503	-524	-544	-562
19	**Total Cost of Service (Net)**		931	843	778	714	651	589	529	470	413
20	**New Customer Revenue**		$904	$904	$904	$904	$904	$904	$904	$904	$904
21	**Revenue less cost of service (impact on existing customers)**		($27)	$61	$126	$191	$253	$315	$375	$434	$492

NW Natural
Exhibit NW Natural/1907c, Therrien - Year-By-Year Economic Impact on Existing Customers

			Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
1	**Depreciation (using book depreciation rates)**	4.00%	106	106	106	106	106	106	106
2	**O&M**		79	79	79	79	79	79	79
3	**Property Taxes**		10	9	7	6	4	2	1
	Taxes on Equity Return								
4	**State**		3	2	2	1	1	1	0
5	**Federal**		8	6	5	4	3	2	1
6	**Total Taxes**		11	9	7	5	4	2	1
	Return on Rate Base								
7	**Debt**		12	10	8	6	4	2	1
8	**Common Equity**		29	23	18	14	10	6	2
9	**Total Return**		41	33	26	19	14	8	3
10	**Subtotal Cost of Service**		246	235	224	215	206	198	189
11	**Revenue Sensitive Items**		7	7	6	6	6	6	5
12	**Total Cost of Service**		253	242	231	221	212	203	195
13	**Cost of CPP ($/Therm)**		2.20	2.20	2.20	2.20	2.20	2.20	2.20
14	**UPC (Therms)**		650	650	650	650	650	650	650
15	**New Customer Cost of CPP**		1,430	1,430	1,430	1,430	1,430	1,430	1,430
16	**Less: New Customer Recovery of CPP (re class WACOD)**		-991	-1,032	-1,073	-1,114	-1,155	-1,195	-1,236
17	**Nominal Change in Base Rate Revenue per Customer (Rate Base)**		244	258	271	285	298	312	326
18	**Less: Contribution to New Non-Growth Capex**		-580	-596	-611	-625	-640	-653	-666
19	**Total Cost of Service (Net)**		356	301	248	197	147	97	48
20	**New Customer Revenue**		$904	$904	$904	$904	$904	$904	$904
21	**Revenue less cost of service (impact on existing customers)**		$548	$603	$656	$708	$758	$807	$857

NW Natural
Exhibit NW Natural/1907d, Therrien - Year-By-Year Economic Impact on Existing Customers

			Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
			LEA Determined		$1,803						
1	**Depreciation (using book depreciation rates)**	4.00%	72	72	72	72	72	72	72	72	72
2	**O&M**		79	79	79	79	79	79	79	79	79
3	**Property Taxes**		26	25	24	23	22	21	20	19	18
	Taxes on Equity Return										
4	**State**		9	9	8	8	8	7	7	6	6
5	**Federal**		24	23	22	20	19	18	17	16	15
6	**Total Taxes**		33	32	30	28	27	25	24	22	21
	Return on Rate Base										
7	**Debt**		38	36	34	32	31	29	27	26	24
8	**Common Equity**		89	85	81	77	73	69	65	61	57
9	**Total Return**		127	121	115	109	103	98	92	87	81
10	**Subtotal Cost of Service**		338	330	321	312	304	295	287	279	271
11	**Revenue Sensitive Items**		10	9	9	9	9	8	8	8	8
12	**Total Cost of Service**		347	339	330	321	312	304	295	287	279
13	**Cost of CPP ($/Therm)**		0.70	0.72	2.20	2.20	2.20	2.20	2.20	2.20	2.20
14	**UPC (Therms)**		1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
15	**New Customer Cost of CPP**		696	717	2,200	2,200	2,200	2,200	2,200	2,200	2,200
16	**Less: New Customer Recovery of CPP (re class WACOD)**		-57	-88	-358	-397	-489	-581	-640	-736	-832
17	**Nominal Change in Base Rate Revenue per Customer (Rate Base)**		0	14	27	41	54	68	81	95	109
18	**Less: Contribution to New Non-Growth Capex**		-39	-93	-139	-180	-219	-255	-287	-319	-349
19	**Total Cost of Service (Net)**		947	888	2,060	1,984	1,858	1,736	1,649	1,527	1,407
20	**New Customer Revenue**		$1,221	$1,221	$1,221	$1,221	$1,221	$1,221	$1,221	$1,221	$1,221
21	**Revenue less cost of service (impact on existing customers)**		$274	$333	($838)	($763)	($637)	($515)	($428)	($306)	($186)

NW Natural
Exhibit NW Natural/1907d, Therrien - Year-By-Year Economic Impact on Existing Customers

			Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18
1	**Depreciation (using book depreciation rates)**	4.00%	72	72	72	72	72	72	72	72	72
2	**O&M**		79	79	79	79	79	79	79	79	79
3	**Property Taxes**		17	16	15	14	12	11	10	9	8
	Taxes on Equity Return										
4	**State**		6	5	5	4	4	4	3	3	2
5	**Federal**		14	13	12	11	10	9	8	7	6
6	**Total Taxes**		20	18	17	16	14	13	11	10	9
	Return on Rate Base										
7	**Debt**		23	21	19	18	16	15	13	11	10
8	**Common Equity**		53	50	46	42	38	35	31	27	23
9	**Total Return**		76	70	65	60	54	49	44	38	33
10	**Subtotal Cost of Service**		264	256	248	240	232	225	217	209	201
11	**Revenue Sensitive Items**		7	7	7	7	7	6	6	6	6
12	**Total Cost of Service**		271	263	255	247	239	231	223	215	207
13	**Cost of CPP ($/Therm)**		2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20
14	**UPC (Therms)**		1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
15	**New Customer Cost of CPP**		2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200
16	**Less: New Customer Recovery of CPP (re class WACOD)**		-927	-1,023	-1,086	-1,149	-1,211	-1,274	-1,337	-1,400	-1,463
17	**Nominal Change in Base Rate Revenue per Customer (Rate Base)**		122	136	149	163	176	190	204	217	231
18	**Less: Contribution to New Non-Growth Capex**		-378	-405	-432	-457	-480	-503	-524	-544	-562
19	**Total Cost of Service (Net)**		1,288	1,170	1,087	1,004	923	844	765	688	612
20	**New Customer Revenue**		$1,221	$1,221	$1,221	$1,221	$1,221	$1,221	$1,221	$1,221	$1,221
21	**Revenue less cost of service (impact on existing customers)**		($67)	$51	$135	$217	$298	$378	$456	$533	$609

NW Natural
Exhibit NW Natural/1907d, Therrien - Year-By-Year Economic Impact on Existing Customers

			Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
1	**Depreciation (using book depreciation rates)**	4.00%	72	72	72	72	72	72	72
2	**O&M**		79	79	79	79	79	79	79
3	**Property Taxes**		7	6	5	4	3	2	1
	Taxes on Equity Return								
4	**State**		2	2	1	1	1	0	0
5	**Federal**		5	4	3	2	2	1	0
6	**Total Taxes**		7	6	5	3	2	1	0
	Return on Rate Base								
7	**Debt**		8	7	5	4	3	2	1
8	**Common Equity**		19	16	12	9	7	4	1
9	**Total Return**		28	22	17	13	9	6	2
10	**Subtotal Cost of Service**		193	185	178	172	166	160	154
11	**Revenue Sensitive Items**		5	5	5	5	5	5	4
12	**Total Cost of Service**		199	191	183	177	171	165	159
13	**Cost of CPP ($/Therm)**		2.20	2.20	2.20	2.20	2.20	2.20	2.20
14	**UPC (Therms)**		1,000	1,000	1,000	1,000	1,000	1,000	1,000
15	**New Customer Cost of CPP**		2,200	2,200	2,200	2,200	2,200	2,200	2,200
16	**Less: New Customer Recovery of CPP (re class WACOD)**		-1,525	-1,588	-1,651	-1,714	-1,776	-1,839	-1,902
17	**Nominal Change in Base Rate Revenue per Customer (Rate Base)**		244	258	271	285	298	312	326
18	**Less: Contribution to New Non-Growth Capex**		-580	-596	-611	-625	-640	-653	-666
19	**Total Cost of Service (Net)**		538	464	393	323	253	184	116
20	**New Customer Revenue**		$1,221	$1,221	$1,221	$1,221	$1,221	$1,221	$1,221
21	**Revenue less cost of service (impact on existing customers)**		$684	$757	$829	$899	$968	$1,037	$1,106