NW Natural®

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October 21, 2022

VIA ELECTRONIC FILING

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

Re: LC 79 – NW Natural's 2022 Integrated Resource Plan: Errata Filing

Northwest Natural Gas Company, dba NW Natural (NW Natural or Company) files herewith an errata of its 2022 Integrated Resource Plan (IRP), which was filed on September 23, 2022. After filing the IRP, NW Natural noticed certain reference errors in several chapters and appendices, and several minor errors, including typographical, spacing, and grammar errors. In addition, we are including Appendix K that the Company previously said it would provide in a supplemental update.

Appendices

Appendix K – Low Emissions Gas Resource Evaluation Methodology was not filed with NW Natural's final 2022 IRP on September 23 but was noted within the IRP that it would be provided in a supplemental update.

Minor Errors Corrected

After converting the 2022 IRP to a pdf format, we noticed some reference errors in Chapters 6, 7, and 8. Attachment A provides a detailed listing of updates and changes.

Next Steps

At the time the Company filed its IRP, it explained that consistent with stakeholder feedback, it was compiling supporting workpapers in a manner that will allow for easy access for stakeholders to work directly with the supporting data. The workpapers will be provided on Monday, October 24, 2022.

To further assist Stakeholders, NW Natural will conduct a workshop on Thursday, October 27, 2022, for the purpose of reviewing the workpapers with stakeholders and answering any clarifying questions.

Conclusion

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Sincerely,

/s/ Rebecca Trujillo

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Attachments

Attachment A

Edit Description	Notes	Chapter; Section(s)	Original Page Number(s)	Original PDF Page Number(s)
Copy Editing	Spacing, referencing, and formatting corrected throughout the document.	1-10	NA	NA
Graphics Edited/Updated	Graphics edited/updated to match following chapters and text descriptions.	1; 1.1.1, 1.2.1, 1.4.1 (Figure 1.1, Infographic, Figure 1.3, Table 1.2)	10, 11, 13, 24	27, 30, 41
Clarification	Clarification provided with minor wording edits, footnote, and/or punctuation.	1; 1.1.2, 1.4, 1.4.2 3: 3.4 6; 6.5.1 (Figure 6.18)	10-13, 22, 27 111 216	28-31, 40, 45 129 234
Graphics Edited/Updated	Legend added.	7; 7.6.3, 7.6.5, (Figures 7.9, 7.11, 7.12, 7.13, 7.14)	360, 361, 362	350, 351, 352
Correction	"Percentage of Annual Sales Demand" graph. Both were modeled as percentage of annuals sales demand and did not need to be broken out by state.	7; 7.4.1 – 7.4.9	264-355	282-344

Edit Description	Notes	Appendix; Section(s)	Original Page Number(s)	Original PDF Page Number(s)
Copy Editing	Spacing, referencing, and formatting corrected throughout the document.	A-K	NA	NA
Missing Copy/ Clarification	Copy added.	B; B.4, B.5	62, 65	464, 467
Section removed	Section indicated to be filed in supplementally.	B; B.7, B.8	66	468
Supplemental Filing	Section indicated to be filed in supplemental update.	K; K.1-K.5	204	606

NW Natural®

2022 NW Natural Integrated Resource Plan

September 2022

nwnatural.com

Forward Looking Statement

This and other presentations made by NW Natural from time to time, may contain forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as "anticipates," "assumes," "intends," "plans," "seeks," "believes," "estimates," "expects", "will", and similar references to future periods. Examples of forward-looking statements include, but are not limited to, statements regarding the following: plans; objectives; assumptions, estimates; expectations; timing; goals; strategies; commitments; future events; investments; models; forecasts; timing and amount of capital expenditures; risks and risk profile; utility system and infrastructure investment; reliability and resiliency; third-party projects; storage, pipeline and other infrastructure investments; commodity costs; competitive advantage; customer service; customer and business growth; forecasts of customers' future energy; capacity and environmental compliance needs; projected demand-side, supply-side, and other resources; resource options; emissions; energy requirements; environmental policy; effects of the global pandemic; economic uncertainty and future economic expectations; population growth; effects of global unrest; natural gas market volatility; weather and weather volatility; local, state and federal requirements relevant to energy or climate change and NW Natural's ability to comply with, and costs related to, such requirements, as well as the efficacy of those requirements in reducing emissions; development and delivery of renewable energy; current and potential changes to building codes; load forecasting methodology; emissions compliance options; population trends; housing trends; gas supply levels, characteristics and areas of origin; natural gas production and market dynamics; renewable natural gas and hydrogen development, availability and markets; ability to use and blend renewable natural gas and hydrogen into existing gas systems; characteristics and feasibility of end-use equipment, and innovation and timing of readiness related thereto; avoided costs; energy efficiency; environmental attributes and availability and markets relating thereto; avoided costs; system planning and modeling; business risk; gas storage development, costs, timing or returns related thereto; financial positions and performance; liquidity, strategic goals, greenhouse gas emissions, carbon savings, gas reserves and investments and regulatory recoveries related thereto, hedge efficacy, cash flows and adequacy thereof, return on equity, capital structure, return on invested capital, revenues and earnings and timing thereof, margins, operations and maintenance expense, dividends, credit ratings and profile, the regulatory environment, effects of regulatory disallowance, timing or effects of future regulatory proceedings or future regulatory approvals, regulatory prudence reviews, effects of legislation, and other statements that are other than statements of historical facts.

Forward-looking statements are based on our current expectations and assumptions regarding our business, the economy and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncertainties, risks and changes in circumstances that are difficult to predict. Our actual results may differ materially from those contemplated by the forward-looking statements, so we caution you against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed by reference to the factors described in Part I, Item 1A "Risk Factors," and Part II, Item 7 and Item 7A "Management's Discussion and Analysis of Financial Condition and Results of Operations," and "Quantitative and Qualitative Disclosure about Market Risk" in the Company's most recent Annual Report on Form 10-K, and in Part I, Items 2 and 3 "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Quantitative and Qualitative Disclosures About Market Risk", and Part II, Item 1A, "Risk Factors", in the Company's quarterly reports filed thereafter.

All forward-looking statements made in this presentation and all subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by these cautionary statements. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to publicly update any forward-looking statement, whether as a result of new information, future developments or otherwise, except as may be required by law.

S&P Global Commodity Insights Gas Price Forecast Disclaimer

A Message from NW Natural President and CEO

President and CEO David H. Anderson at company headquarters and operations center.

It is an exciting time for energy system planning as the energy transition is fully underway. Since we filed our last Integrated Resource Plan (IRP) transformative climate policies have been established in both Oregon and Washington. These policies require emissions reductions from gas utilities and drastically changes the calculus of comparing low emissions resources against traditional resources. While NW Natural has long been a leader amongst gas utilities in planning for a low carbon future, our 2022 IRP is our first comprehensive analysis to support implementation of our obligations under existing climate policies. The outcome of this complex and technical work is a flexible long-term resource acquisition plan, supported by concrete near-term action designed to achieve the emissions reductions needed to support local, state, and federal climate policies at a reasonable cost, while continuing to provide safe and reliable service.

The highlights of this plan include expanding our acquisition of renewable natural gas (RNG) over the next few years and working with the Energy Trust of Oregon to expand energy efficiency (EE) programs that serve our customers within the context of complying with climate policy. To address any compliance obligations not met by RNG and EE before filing our next IRP (expected in 2024), we will acquire emissions compliance instruments made available to covered parties in the climate programs in Oregon and Washington. These compliance instruments include Community Climate Investments in Oregon's Climate Protection Program and emissions allowances and offsets that can be used for compliance in Washington's Cap-and-Invest program. Longer-term, we expect the mix of biofuel-sourced renewable gas we deliver to our customers to be supplemented by renewable hydrogen and synthetic natural gas made from renewable hydrogen. While there is still much to sort out regarding the specific resources we will need going forward as policy, technology, and markets develop, we expect the majority of the energy we deliver to our customers to be from renewable and net zero sources by the late 2030s.

While climate policy has led to a substantial change to our expected resource acquisition, a critical role played by IRPs is the analysis to ensure reliability and resource adequacy. For a gas utility, this means ensuring we have sufficient resources to serve all of our customers' needs during the coldest weather we can experience in our service territory. In this regard, the capacity resources that we need in this IRP are similar to that in our previous IRPs—maintaining our existing energy storage resources, adding storage capacity from our Mist underground storage facility in Northwest Oregon, and a reliance upon non-pipeline solutions (energy efficiency and demand response).

I am extremely proud of the work that has gone into developing our 2022 IRP and want to thank everyone who participated in the public process that helped shape this document. Your feedback and participation in this process has made our IRP better and our plan to move forward more robust. The analysis included in this IRP demonstrates how a natural gas utility can contribute to the energy transition needed to address climate change by rapidly reducing emissions while continuing to deliver safe, reliable, and affordable energy services. I encourage our energy and climate stakeholders in the Pacific Northwest to review the detailed plan we have developed.

David H. Anderson

David H. Anderson
President and Chief Executive Officer

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Glossary

AECO	Alberta Energy Company
AEG	Applied Energy Group
AGA	American Gas Association
AMA	Asset Management Agreement
ARIMA	Autoregressive integrated moving average
AWEC	Alliance of Western Energy Consumers
Baseload demand	Refers to utility customer demand that is constant over the year
Bcf	A billion cubic feet
Biogas	Gaseous fuel, especially methane, produced by fermentation of organic matter
Biomethane	A naturally occurring gas which is produced by anaerobic digestion of organic matter such as dead animal or plant material, manure, sewage, organic waste, etc.
Boiler	A large furnace in which water-filled tubes are heated to produce steam
Book and Claim Accounting	A chain of custody model which recognizes that environmental attributes (e.g., RTCs) can be separated from physical product and possession of environmental attribute can be used to deliver sustainable product
Brown Gas	The physical gas product from an RNG project where the environmental attributes have been separated and the RTC is not included
Btu	British thermal unit
Bundled RNG	RNG including the physical gas molecules and renewable thermal certificate (RTC)
CAGR	Compound Annual Growth Rate
Capacity	The maximum load that a gas pipeline or gas storage facility can carry under existing service conditions
Cap-and-Invest Program	Section of Washington's CCA, regulated by the Department of Ecology, which sets emissions caps, allowances, and trading mechanisms
Carbon cap	A limit on the amount of allowable carbon produced in a given region for a defined time period
Carbon Cap and Trade	A market mechanism to limit carbon emissions. Carbon emissions are capped at a certain level. Allowances are provided to companies and these allowances can be traded. The market sets the price of the allowances, creating a market incentive to reduce carbon emissions

Carbon credits or allowances	A fixed amount of carbon emissions to be produced is set for a period of time, and allowances or credits are allocated to carbon generators. The idea is that entities producing less carbon than their allowed amount can sell their allowances to other parties who are producing more than their allowed credit allowance. Often these can be traded or re-sold
CCA	Washington Climate Commitment Act
CCA allowances	A Cap-and-Invest Program mechanism for covered entities to obtain such allowances to cover emissions not reduced within a particular compliance period
CCI	Community Climate Investment
CCI credit	"an instrument issued by DEQ to track a covered fuel supplier's payment of community climate investment funds, and which may be used in lieu of a compliance instrument, as further provided and limited in this division." Or. Admin. R. 340-271-0020
CD	Contract Demand
CEAG	Community and Equity Advisory Group
CHP	Combined Heat and Power
CIS	Customer Information System
Citygate	The point of delivery at which a local gas distribution company takes custody of gas from an interstate pipeline; Meter stations which serve as designated point(s) on a distribution system where the distributor takes delivery of its gas supply from a pipeline source
Class B (pipeline system)	A pipeline system operating at 60 psig or less
CMM	Customer Management Module
CNG	Compressed natural gas
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
Cogeneration	The use of a single prime fuel source to generate both electrical and thermal energy in order to optimize the efficiency of the fuel used. Usually, the dominant demand is for thermal energy, with any excess electrical energy being transmitted into the lines of local power supply company
Common Carrier Pipeline	A pipeline that is connected to the continent-wide natural gas pipeline grid
Compliance obligation	"Total quantity of covered emissions from a covered fuel supplier rounded to the nearest metric ton of CO_2e." Or. Admin. R. 340-271-0020
Conservation Potential Assessment (CPA)	Analysis preformed to provide an outlook on the potential amount of energy efficiency or energy

	conservation that is available within a given area or territory over a defined period of time
Conversion	An existing residential or commercial building which adds natural gas service to the building and becomes a new NW Natural customer
CPI	Consumer Price Index
CPP	Oregon Climate Protection Program
CUB	Oregon Citizens' Utility Board
Curtailment	A method to balance natural gas requirements with available supply. Usually there is a hierarchy of customers for the curtailment plan. A customer may be required to partially cut back or totally eliminate its take of gas depending on the severity of the shortfall between gas supply and demand and a customer's position in the hierarchy
Degree day	The number of degrees that the average outdoor temperature falls below or exceeds a base value in a given period of time
Demand-side resource	An energy resource such as conservation that is based on how energy is used, not produced
DEQ	Department of Environmental Quality
Deterministic	A defined set of properties, constraints, or equations that explicitly defines the relationship between variables; deterministic solutions provide a single outcome; contrast with stochastic
DR	Demand response; reducing peak demand by either shifting or interrupting load
DSM	Demand-side management
Dth	Dekatherm (or dekatherm)
Discount rate	An interest rate that reflects the value of money over time. In comparing alternatives for a decision, a discount rate is applied to make different monetary stream flows equivalent, in terms of a present value or a levelized value
Distribution/Distribution System	The pipeline system that transports gas from interstate pipelines to customers.
EE	Energy Efficiency; EE is a reduction in energy use, production, or distribution as a result of greater efficiency
EFRC	Energy Frontier Research Center
EIA	U.S. Energy Information Administration
Energy savings	A term used to define the reduced energy usage as a result of energy efficiency initiatives
End-use consumer	Someone who uses energy to run equipment or appliances, such as for space heating and cooling, ventilation, refrigeration, and lighting

EPA	Environmental Protection Agency
EPPR	Electronic Portable Pressure Recorder
ERU	Emission Reduction Unit
ETO	Energy Trust of Oregon
Entitlement	An event during which gas shippers must not take delivery of more than a specified volume of gas in a day
Exogenous (variable)	A variable that is independent or determined outside of the model
FERC	Federal Energy Regulatory Commission
Firm (Sales, Service, Customers)	Service offered to customers under schedules or contracts which anticipate no interruptions. The period of service may be for only a specified part of the year as in off-peak service. Certain firm service contracts may contain clauses which permit unexpected interruption in case the supply to residential customers is threatened during an emergency.
GAP; GASP	Gas Acquisition Plan; Gas Acquisition Strategy and Policies
Gasco	NW Natural's Portland LNG plant
Gas Day	A period of twenty-four consecutive hours, coextensive with a "gas day" as defined in the tariff of the Transporter delivering Gas to the Delivery Point in a particular transaction
GeoTEE	Geographically Targeted Energy Efficiency
GIS	Geographical information system
GHG	Greenhouse gas
GTI	Gas Technology Institute
HDD	Heating degree day
Hedging	Any method of minimizing the risk of price change.
Henry Hub	A natural gas national trading hub typically used for referencing national natural gas prices
Incremental costs	Additional costs that a utility would incur by operating a power plant, the cost of the next MMBtu generated or purchased, or the cost of producing and/or transporting the next available unit of energy above the current base cost previously determined
Interstate pipeline	Pipelines owned and operated by pipeline companies, where 3rd party shippers contract for firm and interruptible capacity

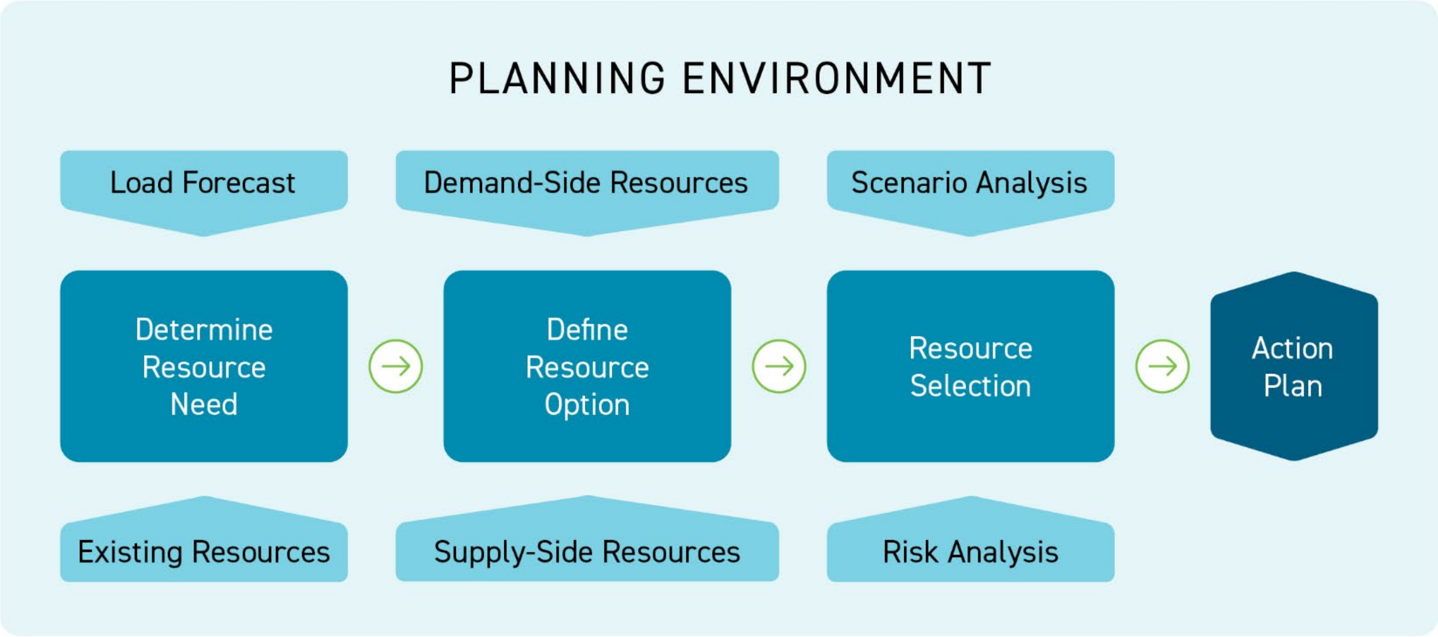
Interruptible (service, i.e., Sales or Transportation and also customers(s) of such service)	A transportation service similar to firm service in operation, but a lower priority for scheduling, subject to interruption if capacity is required for firm service. Interruptible customers trade the risk of occasional and temporary supply interruptions in return for a lower service rate.
IRP	Integrated Resource Plan
Jackson Prairie	A gas storage facility near Centralia, Washington, contracted by NW Natural
LDC	Local distribution company
Least-cost planning	Method of meeting future energy needs by acquiring the lowest cost resources first, considering all possible means of meeting energy needs and all resource costs including construction, operation, transmission, distribution, fuel, waste disposal, end-of-cycle, consumer, and environmental costs
Levelized (cost)	Equal periodic cost where the present value is equivalent to that of an unequal stream of periodic costs (typically expressed as a periodic rate; e.g., levelized cost per year)
LNG	Liquefied natural gas
Load	The demand for energy/power averaged over a specific time period
Load center	Geographical service area or collection of areas defined by NW Natural
Load factor	Ratio of total energy (example: therms) used in a period divided by the possible total energy used within the period, if used at the peak demand during the entire period
MAOP	Maximum allowable operating pressure
MAPE	Mean absolute percentage error
Marginal cost	The cost of producing the marginal, or next, unit
Mbtu	Thousand British thermal unit
Mbtu/ day	Thousand British thermal unit per day
Mcf	A thousand cubic feet
MDDO	Maximum daily delivery obligation
MDT	A thousand dekatherms
MMbtu	A million British thermal unit
MMbtu/ day	A million British thermal unit per day
MMcf	A million cubic feet
MMDT	A million dekatherms
MPH (or mph)	Velocity in miles per hour
MSA	Metropolitan Statistical Area: a geographical area as defined by the U.S. Office of Management and Budget (OMB)

$MTCO_2e$	A metric ton of carbon dioxide equivalent
Monte Carlo (simulation, analysis)	Statistical methods based on repeated sampling to simulate probability-based outcomes
Moving average	A statistical average calculated over a rolling period in time series data
NEEA	Northwest Energy Efficiency Alliance
New Construction	Newly constructed residential or commercial building with natural gas service which become a new NW Natural customer
NGL	Natural gas liquids
Nominations	The process of scheduling gas on the interstate pipeline. The shipper notifies the pipeline the volume and receipt point and the delivering receipt point in accordance with the transportation contract
Non-pipeline alternatives	Strategies to use natural gas more efficiently so that new pipeline capacity is not needed
Normal distribution	Commonly used probability distribution in statistical analysis
Normal weather	Expected weather conditions based on observed historical data
NPVRR (also PVRR)	Net present value revenue requirement
NWEC	NW Energy Coalition
NWIGU	Northwest Industrial Gas Users
NWGA	Northwest Gas Association
NWPCC	Northwest Power and Conservation Council
NWPL	Northwest Pipeline
ODOE	Oregon Department of Energy
OEA	State of Oregon's Office of Economic Analysis
Off-peak	Refers to a period of relatively low demand on a natural gas system. This can also refer to low demand months
OFO	Operational flow orders
OLIEE	Oregon Low Income Energy Efficiency
OPUC	Public Utility Commission of Oregon
Outage	A period, scheduled or unexpected, during which the transmission of power stops or a particular power-producing facility ceases to provide generation
P2G	Power-to-gas
Peak (day, hour)	A period in which a maximum value of a process (e.g., gas demand) occurs or is expected to occur
Peak day shaving	A peak day is the one day (24 hours) of maximum system deliveries of gas during a year. Peak shaving is a load management technique where supplemental supplies, such as LNG or storage gas,

	are used to accommodate seasonal periods of peak customer demand
PGA	Purchased gas adjustment
Planning Horizon	The timeframe which the IRP evaluates the net present value costs and outcomes for resource decisions. For this IRP the planning horizon is 2022-2050.
PLEXOS®	Optimization modeling software used by NW Natural
PSIG	Pounds per square inch gauge
PST	Pacific Standard Time
PVRR (also NPVRR)	Present value of revenue requirement
REC	Renewable energy certificate
Reference Case	An analytical scenario (e.g., forecast scenario) to which other scenarios are compared
RIN	Renewable identification number
RMSE	Root mean squared error
RNG	Renewable natural gas. “RNG” is gas that satisfies the definition of “renewable natural gas” or “renewable hydrogen” in either Oregon or Washington. **Oregon definition per ORS 757.392(7)**: “Renewable natural gas” means any of the following products processed to meet pipeline quality standards or transportation fuel grade requirements: (a) Biogas that is upgraded to meet natural gas pipeline quality standards such that it may blend with, or substitute for, geologic natural gas; (b) Hydrogen gas derived from renewable energy sources; or (c) Methane gas derived from any combination of: a. Biogas; b. Hydrogen gas or carbon oxides derived from renewable energy sources; or c. Waste carbon dioxide. **Washington definitions per RCW 54.04.190(6):** "Renewable natural gas" means a gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters. "Renewable hydrogen" means hydrogen produced using renewable resources both as the source for the hydrogen and the source for the energy input into the production process.
ROW	Right of way
RPS	Renewable portfolio standards

RTC	Renewable thermal certificate An RTC is a *sole* claim to the environmental benefits of a dekatherm of RNG, separate from the physical gas of RNG (i.e., unbundled RNG)
Sales (service, customers)	Service provided whereby NW Natural acquires gas supply and delivers it to customers
SCADA (system)	Supervisory Control and Data Acquisition
SME panel	A panel composed of subject matter experts
Stochastic	The property of being randomly distributed or including a random component; a stochastic variable often feeds into a forecast, property or constraint providing a range of outcomes; contrasts with deterministic
Synergi™	A computer-based model used to simulate the physical natural gas system
T-DSM	Targeted demand-side management
TF-1	Northwest Pipeline's rate schedule designation for firm, year-round transportation service on its system
TF-2	Northwest Pipeline's rate schedule designation for firm transportation service on its system from certain storage facilities (e.g., Jackson Prairie). TF-2 service may have the same scheduling priority as, or may be subordinate/secondary in priority to, TF-1 service
Therm	Unit of measurement: 1 Therm = 29.3 KWh
Transportation (service, customers)	Service provided whereby a customer purchases natural gas directly from a supplier but pays the utility to transport the gas over its distribution system to the customer's facility
UPC	Use per customer
WACOG	Weighted average cost of gas
Weatherization	The use of structural changes, such as storm windows and insulation, in order to decrease use of heating fuel
Weather normalization	A method of averaging energy use under normal conditions. Also known as weather corrected, normalization enables comparison of energy use across periods of time or geography
W & P	Woods & Poole forecasting service
WUTC	Washington Utilities & Transportation Commission

1 Executive Summary



1.1 Overview

1.1.1 About NW Natural

NW Natural is a natural gas local distribution and storage utility headquartered in Portland, Oregon with a 163-year history. NW Natural serves approximately 2.5 million people in Oregon and Washington via nearly 800,000 customer accounts. The service territory includes the Portland-Vancouver metropolitan area, the Willamette Valley, much of the Oregon Coast, and a portion of the Columbia River Gorge. Approximately 89% of NW Natural's customers reside in Oregon, with the other 11% in the state of Washington. Residential customers account for roughly 90% of our customer accounts.

Figure 1.1: NW Natural's Service Territory

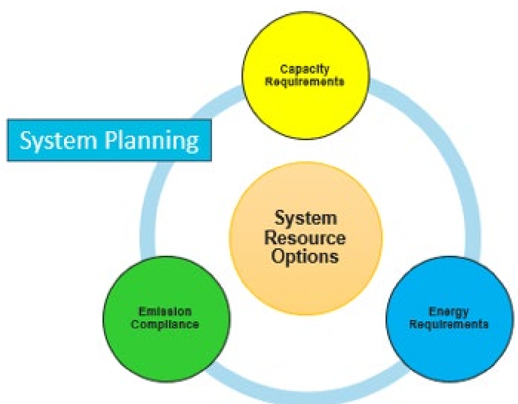
1.1.2 IRP Planning Process

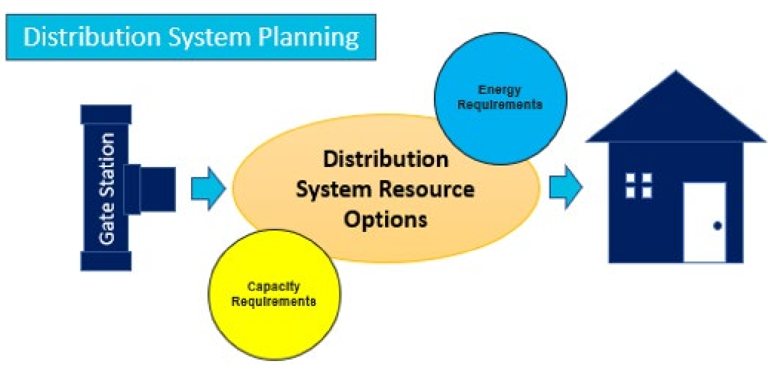
Guided by the economic, political, and technological landscape in which we operate, and consistent with the requirements for Integrated Resource Planning set forth in Oregon Administrative Rule (OAR) 860-027-400 and Washington Administrative Code (WAC) 480-90-238, NW Natural develops a resource acquisition plan (an Integrated Resource Plan, or IRP) on approximately two-year cycles, with this plan looking out to 2050.

The IRP is the result of a rigorous analytical process that follows three broad steps:

1) forecasting our customers' future energy, capacity, and environmental compliance needs;
2) determining the resource options available to meet those needs, inclusive of both resource options that help reduce the amount of gas our customers use (demand-side resources) and options that help us deliver energy and meet emissions compliance obligations (supply-side resources); and finally
3) identifying the portfolio of resources with the best combination of cost and risk for our customers.

NW Natural conducts this involved analytical process to ensure that we have adequate gas supply to meet customer needs on each day and across a year (energy planning) and during the coldest days we might experience (system capacity planning). Additionally, we acquire resources that will allow us to comply with environmental compliance laws and rules (environmental compliance planning). Lastly, the analytical process ensures that we can distribute the gas coming onto our system so that each of our customers can be served reliably (distribution system planning).





Given that IRPs are completed roughly every two year and are updated annually, this IRP should not be viewed as a "set it and forget it" plan, but rather a snapshot of the resource portfolio that shows as the "least-cost- least-risk" way to meet customers' needs going forward with the information currently available. While each IRP has a long planning horizon, the primary output of each IRP is the Action Plan, which details the activities we propose taking before the completion of the next IRP (the next two to four years). As such, the actions detailed in the Action Plan are the near-term activities that are needed to serve customer needs now while allowing the utility to remain on a path that supports longer-term needs, noting that the next IRP will also include an Action Plan that will rely upon updated information, data, and analysis.

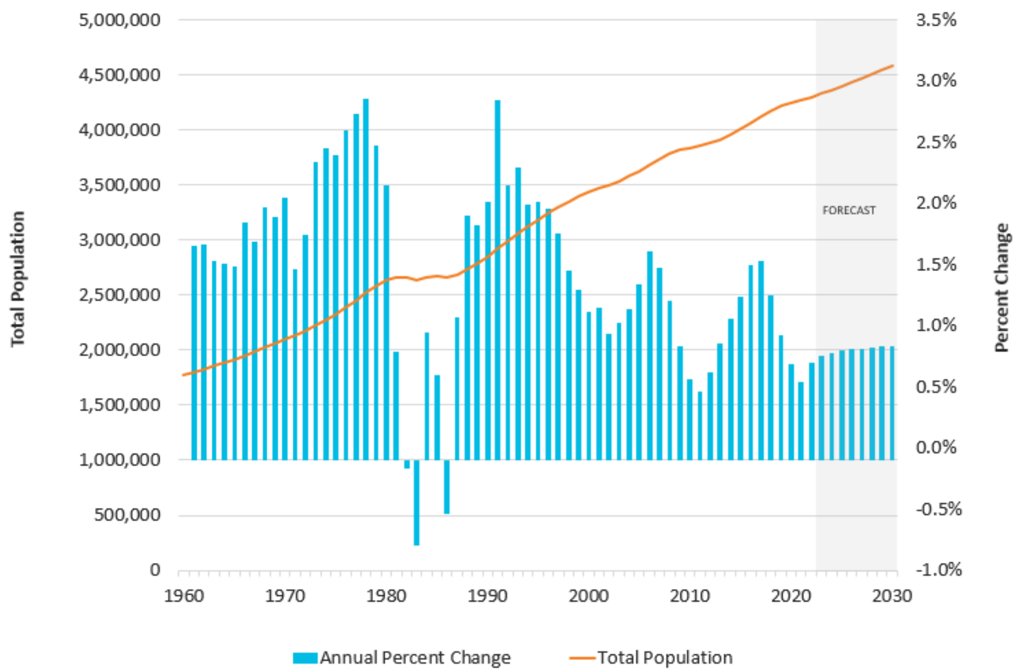
1.2 Planning Environment

Broader market and policy conditions and developments influence our customers' gas needs and the resource options that are suitable for us to serve those needs. While the planning environment presents analytical challenges and uncertainty in every IRP, the combination of the dynamic environmental policy associated with the energy transition in the Pacific Northwest, the current uncertainty in energy markets and the broader economy, and adjustments associated with the COVID-19 pandemic make the current planning environment particularly challenging.

1.2.1 Economic Outlook and Energy Markets

The broader economy is an important driver of the customer growth and gas use of NW Natural customers. When NW Natural completed its last IRP in 2018, our service territory, like the rest of the United States, was roughly a decade into the recovery from the Great Recession of the 2007-2009 period. While the 2018 IRP did not contemplate the COVID-19 pandemic, the current environment of high inflation or the acuteness of the housing shortage in our service territory, the customer growth projected in the 2018 IRP has largely materialized. As we draft this IRP a high level of economic uncertainty has settled on the Pacific Northwest, the United States, and the globe. While employment in NW Natural's service territory has largely recovered to pre-pandemic levels, high inflation, increasing interest rates, housing affordability, a potential recession on the horizon, living preferences, and working options changed by the pandemic all could impact NW Natural customer growth and residential, commercial, and industrial gas usage moving forward. These and other factors have slowed expected population growth in our service territory.

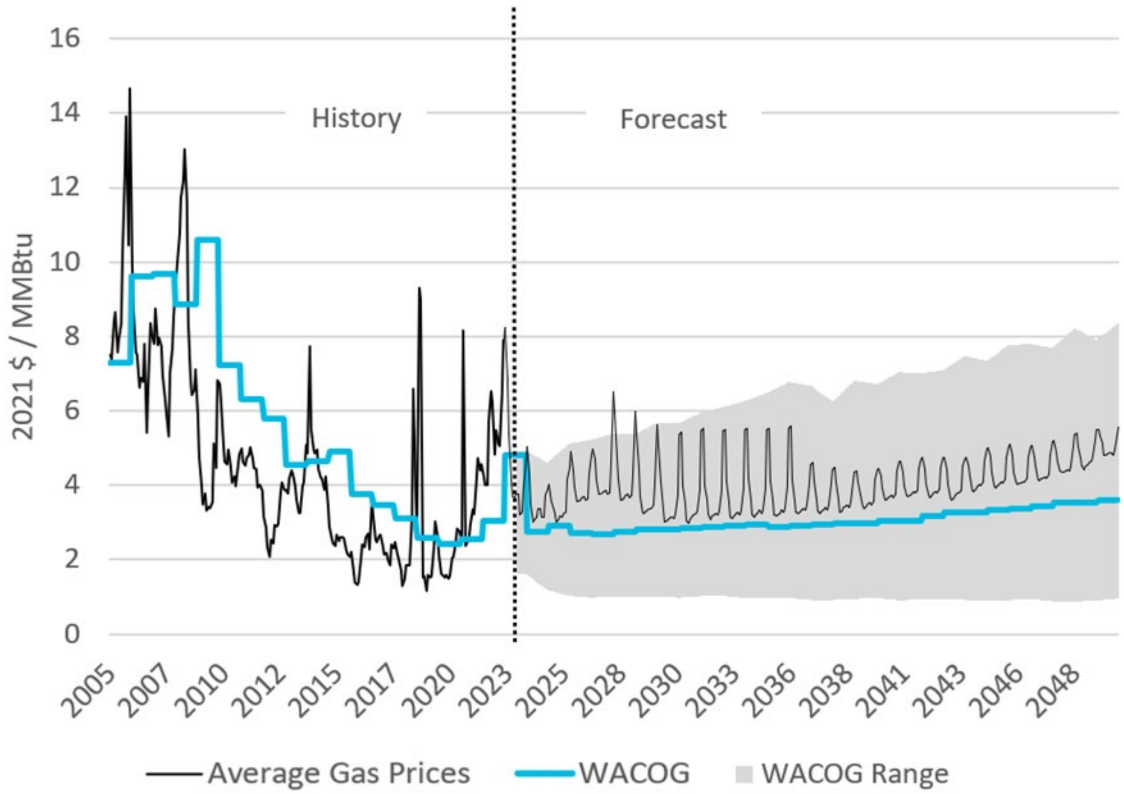
Figure 1.2: Oregon Population Growth Slowing



Source: U.S. Census Bureau, Portland State University Population Research Center, Oregon Office of Economic Analysis.

While the conventional natural gas markets, where NW Natural purchases gas on behalf of our customers, are currently experiencing prices higher than in recent years due primarily to Russia's invasion of Ukraine, prices of conventional gas are expected to return to levels consistent with prices in recent years over the medium- and long-term. However, while long-term expectations in conventional gas prices have not changed substantially compared to the 2018 IRP, limited capacity in regional and national natural gas infrastructure is driving an increase in price *volatility*, particularly during extreme weather events when NW Natural customers' gas needs are highest. Market dynamics suggest this current environment of more volatile prices during extreme weather is likely to continue, even as prices fall back to those in line with recent years.

Figure 1.3: Weighted Average Cost of Gas[1]



1.2.2 Environmental Policy

The single largest driver of change in this IRP is climate policy established in Oregon and Washington in recent years, and uncertainty about potential additional policies that could impact NW Natural's resource planning. NW Natural has implemented changes over recent IRP cycles to assess and evaluate low-GHG emissions supply resources, forecast emissions, and analyze demand- and supply-side resources on an apples-to-apples basis within the context of not only energy needs but also GHG emissions[2]. These innovations, along with new analytical tools developed for this IRP, are needed to evaluate customer needs with NW Natural being a covered entity with compliance obligations under GHG emissions cap programs. Also, while NW Natural plans its resources on a service-territory wide basis for energy and capacity needs to the benefit of customers in both Oregon and Washington, differing climate policy in the two states requires that for the first time our emissions compliance planning be conducted at the state level, resulting in a more complex IRP than in previous years.

[1] The range for the forecasted WACOG is based on the 5th and 95th percentile outputs of a stochastic simulation process optimized through the Resource Planning Optimization Model (i.e., PLEXOS®). The forecasted WACOG is the annual mean of these simulations.

[2] Apples to apples comparison here refers to using the same least cost least risk framework and using PVRR and risk analysis to evaluate portfolio options.

Climate Policy Enacted Since Last IRP - Oregon

1. **Senate Bill 98 (SB 98)**- Passed in 2019 SB 98 encourages the development of renewable natural gas (RNG) and allows natural gas utilities to procure RNG at the following voluntary targets as a percentage of natural gas sales:

Table 1.1: RNG Targets 2020-2050

Year	RNG Target (% of gas sales)
2020-2024	5%
2025-2029	10%
2030-2034	15%
2035-2039	20%
2040-2044	25%
2045-2050	30%

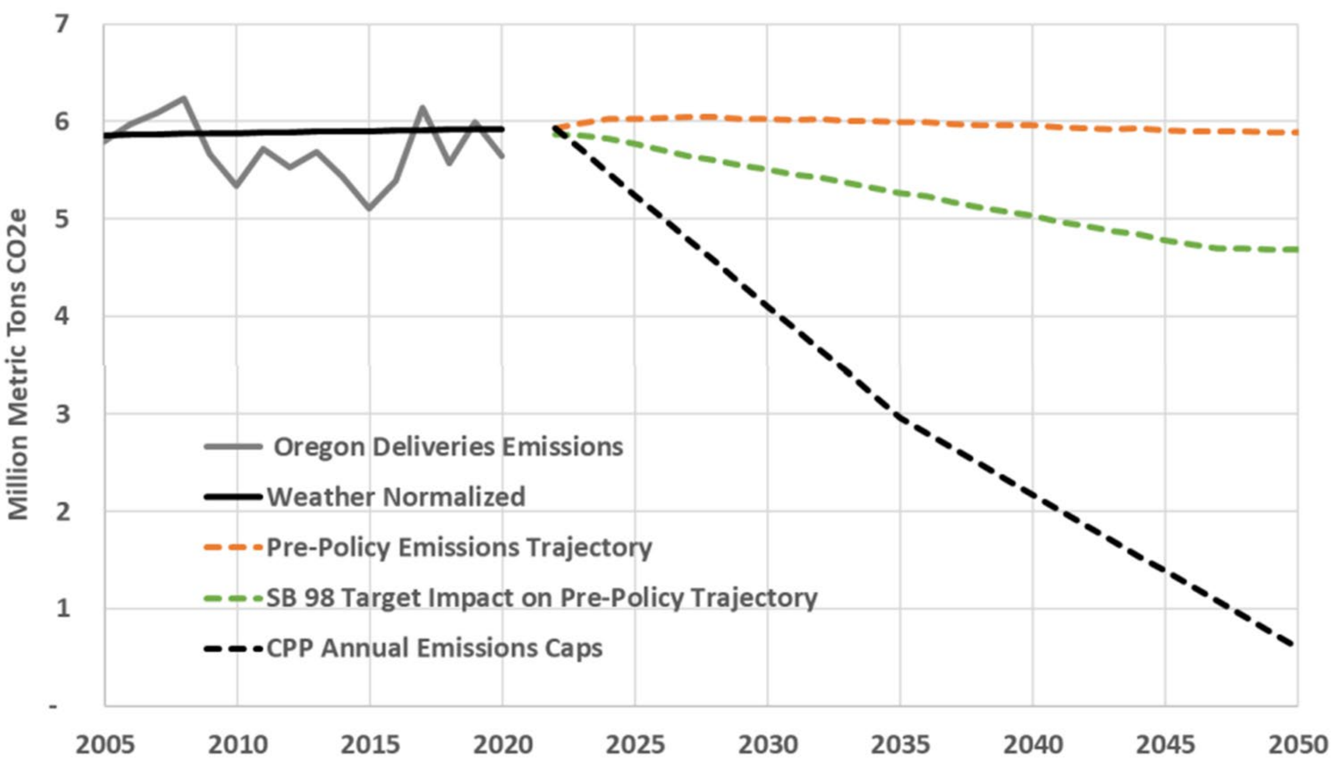
Rules for program implementation were established at the Oregon Public Utility Commission in 2020[3] and NW Natural has begun procuring RNG to meet the targets in SB 98. The law states that it may not be allowed to continue to pursue additional RNG qualified investments if the incremental cost of RNG exceeds 5 percent of total revenue requirement in a given year.

2. **Climate Protection Program (CPP)**- The CPP is a GHG emissions cap program established with an initial compliance year of 2022 administered by the Oregon Department of Environmental Quality (ODEQ). The CPP was established from direction from Executive Order 20-04 issued by Gov. Brown in 2020. The program includes roughly half of the state's emissions and primarily covers the transportation and natural gas utility sectors. The CPP has three-year compliance periods and sets annual emissions compliance limits for natural gas utilities and associated customer emissions. The CPP also establishes gas utilities as the covered party for the emissions associated with the use of gas on utility transportation rate schedules. The CPP is not a typical cap-and-trade system that includes state-sanctioned allowance auctions.

   Figure 1.4 shows the expected impact of SB 98 and the CPP relative to a pre-policy emissions trajectory to show the requirements of the CPP relative to historical trends and details the emissions reduction requirements that are a key driver of the activities in this IRP.

[3] For additional information please see Oregon Docket AR 632

Figure 1.4: NW Natural OR Emissions- Historical Trend and Impact of SB 98 and CPP

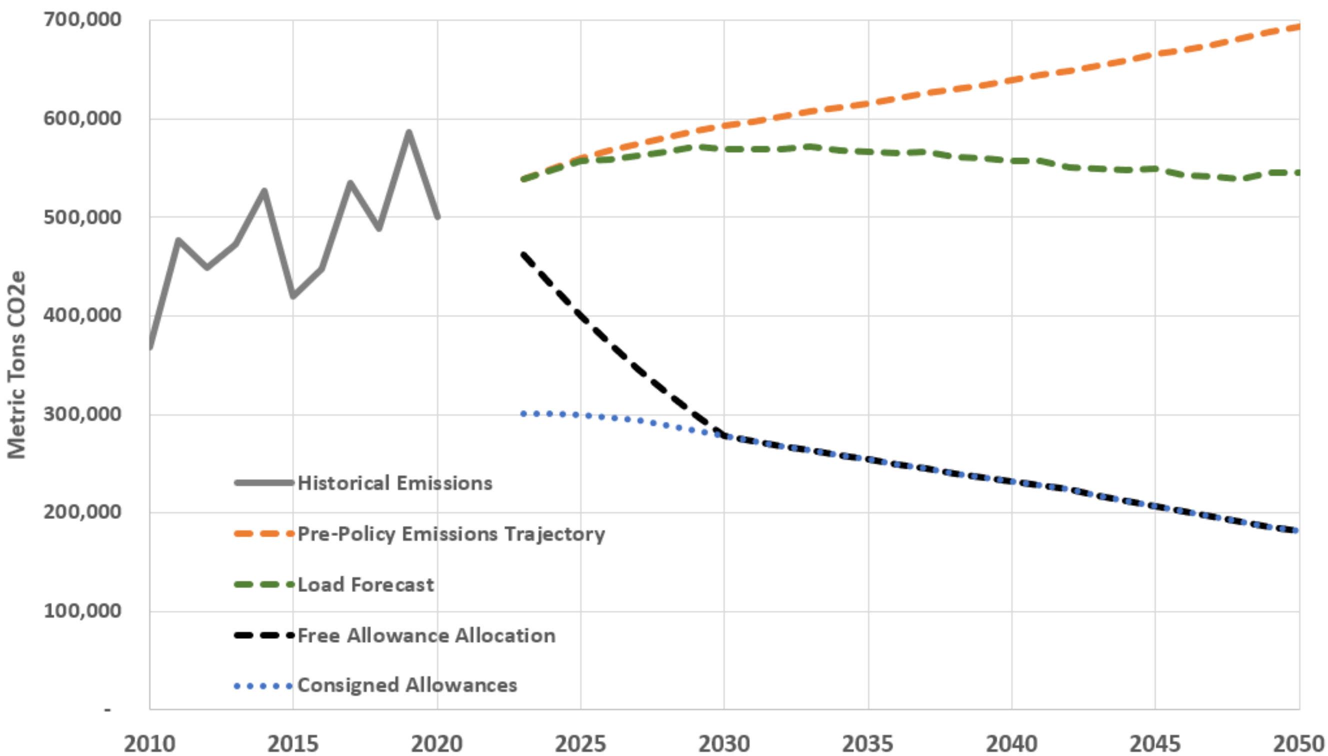


Climate Policy Enacted Since Last IRP - Washington

1. **House Bill 1257 (HB 1257)**- Passed in 2019. Establishes a requirement for natural gas utilities to establish a voluntary renewable natural gas option for customers, conduct energy efficiency forecasts (or conservation potential assessments (CPAs)) with economically incented targets, and use the social cost of carbon for resource planning. Similar to SB 98 in Oregon HB 1257 also declares the value of RNG for reducing emissions and includes a provision that allows natural gas utilities to sell and/or deliver RNG to all customers up to a total cost of 5% of revenue requirement.

2. **Climate Commitment Act (CCA)**- Passed in 2021. Directs establishment of a cap-and-invest program with similar provisions as the trading program currently in practice in California. The cap-and-invest program is currently in rulemaking. Covered parties need to demonstrate they have compliance instruments equal to their emissions over 4-year compliance periods. The program will establish a state-sanctioned allowance trading program and provides free and consigned emissions allowances to natural gas utilities for some of their customers' expected emissions. Gas utilities are also established as the point of regulation for most customers on gas transportation schedules. Figure 1.5 shows the CCA Pre-policy emissions trajectory along with the expected compliance allowances.

Figure 1.5: NW Natural WA Emissions- Historical Trend and Free Allowances in CCA



3. **Building Codes Updates**- Residential building codes were updated in 2018 and commercial codes in 2022. Both updates made it more challenging to meet energy and emissions standards with the most common natural gas equipment installed in homes and businesses today.

For gas utilities the climate policies established since the filing of our last IRP are transformative policies that have generated transformative changes in NW Natural's resource planning and the Action Plan in this IRP. In fact, waiting for the OR-CPP rules to be finalized was the primary driver of NW Natural delaying its IRP until 2022. While these programs have provided certainty by establishing emissions reduction requirements with natural gas utilities as covered parties, they also create substantial uncertainty in resource planning and a heightened focus on resources that can help reduce GHG emissions.

Furthermore, there is still substantial policy uncertainty given that additional local, state, or federal climate policies that are currently being considered could restrict growth and incent electrification. This policy uncertainty manifests in key planning assumptions important to conducting IRP analysis and requires different tools to comprehensively analyze outcomes that represent large changes from current trends.

The climate policies enacted since our last IRP, current uncertainty, and stakeholder feedback through the IRP process were the impetus for the following changes in this IRP:

1. Development of a Community and Equity Advisory Group
    - Recognizing the need to hear additional voices that have been underrepresented in past IRPs, this IRP was the impetus for the formation of NW Natural's Community and Equity Advisory Group (CEAG). This group was recently formed but it is anticipated that the CEAG will assist NW Natural on various programs and processes including the resource planning process.
2. Switching to the PLEXOS® software resource planning optimization
    - The change to the far more flexible PLEXOS® software allowed NW Natural to develop the complex model needed to conduct robust emissions compliance planning to develop appropriate strategies for emissions compliance in both Oregon and Washington.
3. More detailed assumptions about low-GHG emitting resources
    - While NW Natural has analyzed both low carbon supply-side (e.g., RNG, clean hydrogen, etc.) and demand-side (e.g., natural gas heat pumps) resources in prior IRPs, these resources did not show as cost-effective resources in the near term given that we did not have authority to procure these resources if they were more expensive than conventional gas. Emissions cap programs change this dynamic and require these resources as part of the preferred portfolio and the Action Plan.
4. Change in load forecasting methodology
    - Given the transformative emissions policies that have been established and the current policy uncertainty, we have decided it is no longer appropriate to project forward historical trends to project our customers' needs. We have deployed forecasting techniques that project a change from historical trends. Additionally, we have modeled dual-fuel (or hybrid) gas-electric space heating for the first time in this IRP.
5. Including transportation schedule loads in our optimization modeling
    - In previous IRPs NW Natural's gas supply and emissions planning did not include loads on gas transportation rate schedules (though transportation loads were included in distribution system planning) since NW Natural does not need to supply/sell (only distribute) gas to transportation rate schedule customers. However, given that gas utilities were made the point of regulation for transportation schedule emissions in both the OR-CPP and WA-CCA it is required that these loads be included in our resource modeling to appropriately model emissions compliance.
    - Furthermore, given that there are not currently utility affiliated energy efficiency (EE) programs that serve transportation schedule customers there is discussion in both Oregon and Washington about establishing EE programs for transportation schedule customers to be part of the utilities' emissions compliance options. In anticipation that EE programs for transportation customers might be established, and to better

understand what cost-effective EE might be available to contribute to emissions compliance obligations, NW Natural had an independent consultant conduct the CPA for its transportation customers. Like existing energy efficiency programs, this CPA showed meaningful cost-effective savings in the context of compliance with the OR-CPP and WA-CCA.

6. Utilizing stochastic risk analysis as the primary tool for developing the Action Plan
    - While NW Natural has conducted robust risk analysis for numerous IRPs, in past IRPs a single base case was developed, and the Action Plan was constructed primarily using the results from this base case. Given the high degree of uncertainty and the transformative new policies which we are implementing the Action Plan and preferred portfolio in this IRP is based upon a risk-adjusted approach based upon the range of outcomes of our stochastic Monte Carlo simulations.

To assess a prudent path for implementing the climate policies discussed above in the context of a high degree of uncertainty NW Natural developed nine scenarios to understand the least-cost resource portfolio under a wide range of "what if" potential futures to supplement the reference case with input from stakeholders in the IRP process. Complying with the provisions of the OR-CPP and the WA-CCA is required of all scenarios. The results from this scenario analysis were ultimately used to help define the stochastic risk analysis conducted to develop the preferred portfolio in this IRP.

1.3 Determining Resource Needs – Energy, Capacity, and Compliance

On an annual basis, NW Natural's sales load[4] consists predominantly of space heating. During peak conditions, sales load and total deliveries are driven by space heating. Because of the needs for space heating, our loads are very seasonal and have peaks that are much higher than average daily loads. After adjusting for expected energy efficiency acquisition over the planning horizon it is expected that annual load will decline over the planning horizon. While peak load may decline in the long-term in the short- and medium term it is expected that it will continue to rise similar to recent history. While these forecasts represent our risk-adjusted expectations, there is uncertainty in load forecasting – particularly in the later years of the planning horizon – so expected resource decisions are tested for robustness using a wide range of peak capacity and annual load forecasts.

[4] "Sales" load is a bundled service where NW Natural provides a bundled service that includes both the natural gas commodity and delivery services, whereas "transportation" load does not include sale of the natural gas commodity, simply delivery of the gas purchased by another gas supplier

Figure 1.6: Monthly Sales Load by End Use

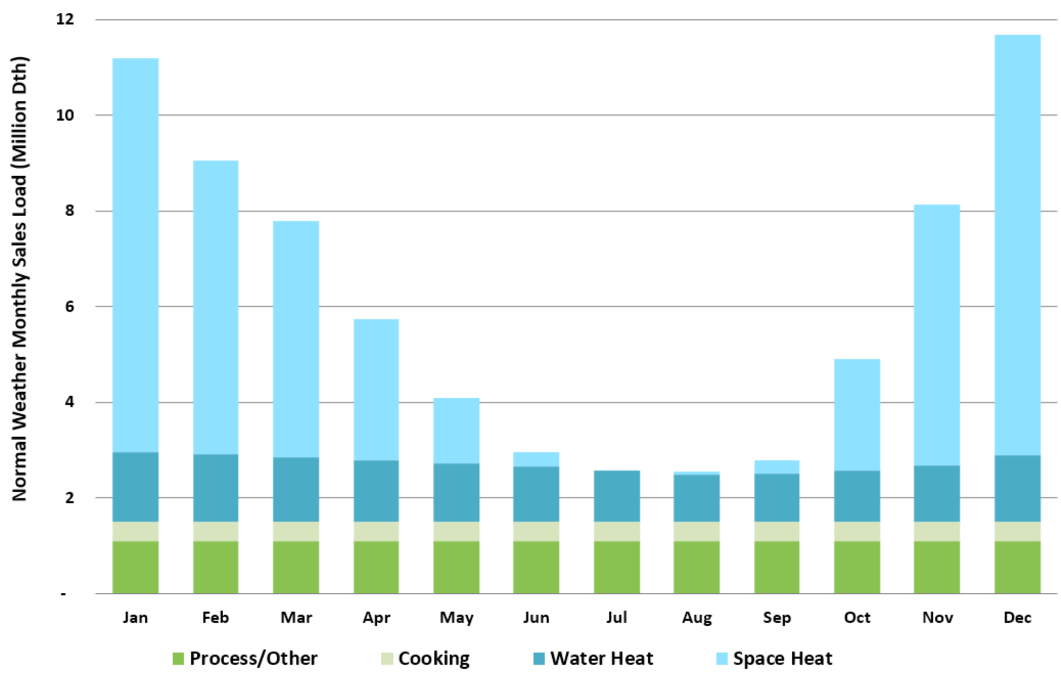
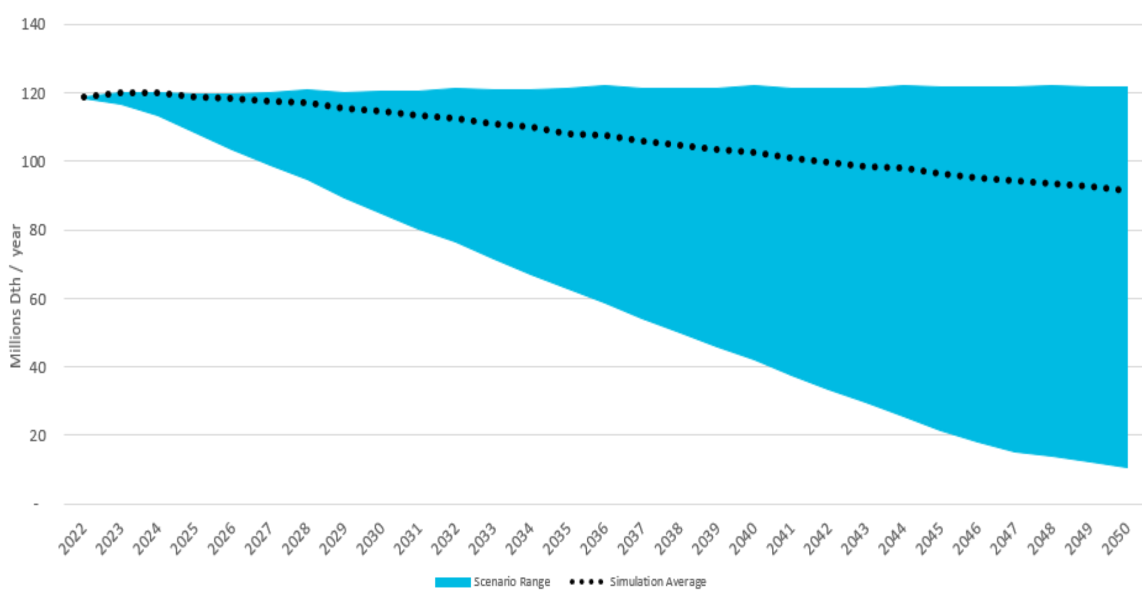
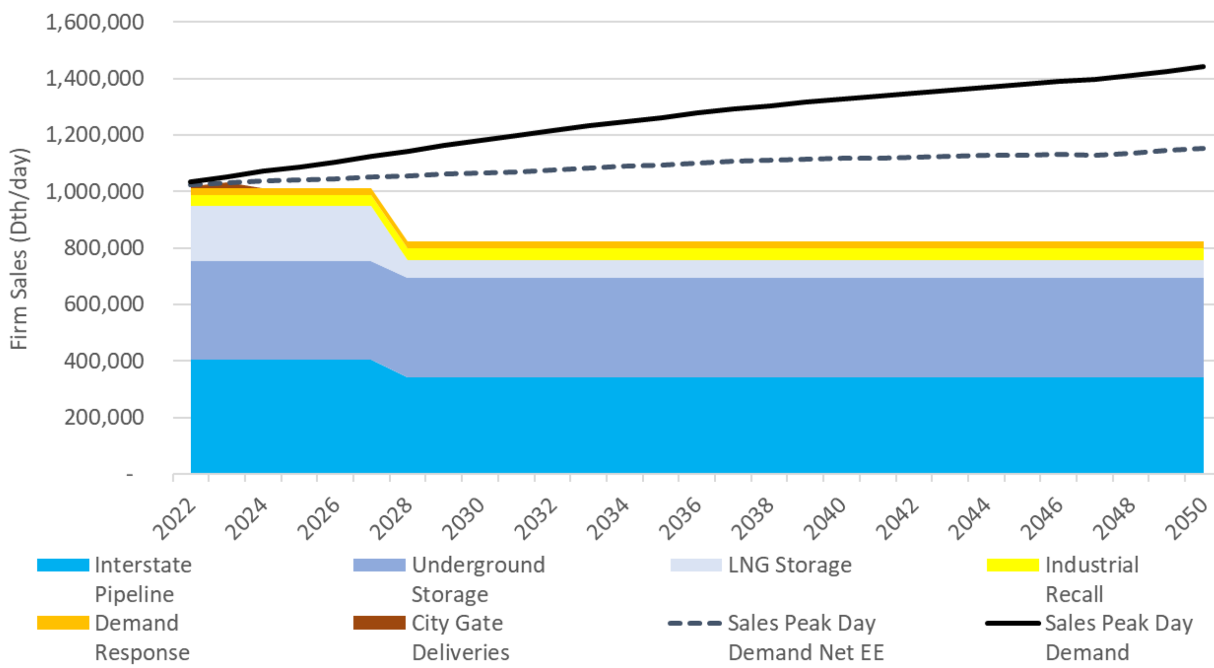


Figure 1.7: Annual Deliveries (Including Transportation) Forecast Range



The risk-adjusted peak load forecast, in coordination with assumptions about the availability of energy efficiency savings shown above translates to the capacity load-resource balance shown in Figure 1.8.

Figure 1.8: Peak Day Load Resource Balance



Along with energy and capacity needs, both customers in Washington and Oregon have compliance needs to meet emission compliance with the environmental policies discussed above.

1.4 Resource Options to Meet Needs

Resource options to meet these needs will vary in each resource's ability and cost to meet these needs.

1.4.1 Energy and Capacity Options

Figure 1.8 shows the peak capacity load resource balance that NW Natural needs to fill to ensure that it can reliably serve customers in the event of an extreme cold event. As the figure shows, without action to replace the Cold Box at the Company's Portland liquified natural gas (LNG) facility a resource that NW Natural relies upon from to serve customers during peak periods would no longer be available and its capabilities would need to be replaced. Table 1.2 below shows the capacity resource options analyzed to fill the resource deficiency depicted in Figure 1.8.

Table 1.2: Capacity Resource Options

Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	As needed Max : 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800[†]
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800[‡]

Notes: Pipeline options are available for selection November 1st of year; storage options are available for selection May 1st in each year. Newport Takeaway options must occur sequentially.

[†] Pressure modeling shows that with this option would allow for additional Mist takeaway and would increase the max Mist Recall to 240,492 Dth/day. 130,800 is used in this table for a direct comparison to the deliverability enabled by the Cold Box alternative.

[‡] Pressure modeling shows that with this option would allow for additional Mist takeaway and would increase the max Mist Recall to 204,422 Dth/day. 130,800 is used in this table for a direct comparison to the deliverability enabled by the Cold Box alternative.

1.4.2 Emissions Policy Compliance Options

Defining and assessing options to reduce emissions is a primary focus of this IRP, and the options that can be used to reduce or offset emissions for compliance vary between the OR-CPP and the WA-CCA. Some forms of energy efficiency and emissions compliance options are more flexible than others and can be procured to and used for emissions compliance on short timeframes, while others require a longer lead time for construction (e.g., development of a new RNG or hydrogen project) or attrition through time (e.g., energy efficiency). Table 1.3 below shows the options evaluated by NW Natural for compliance with the OR-CPP and WA-CCA.

Table 1.3: Emissions Compliance Options

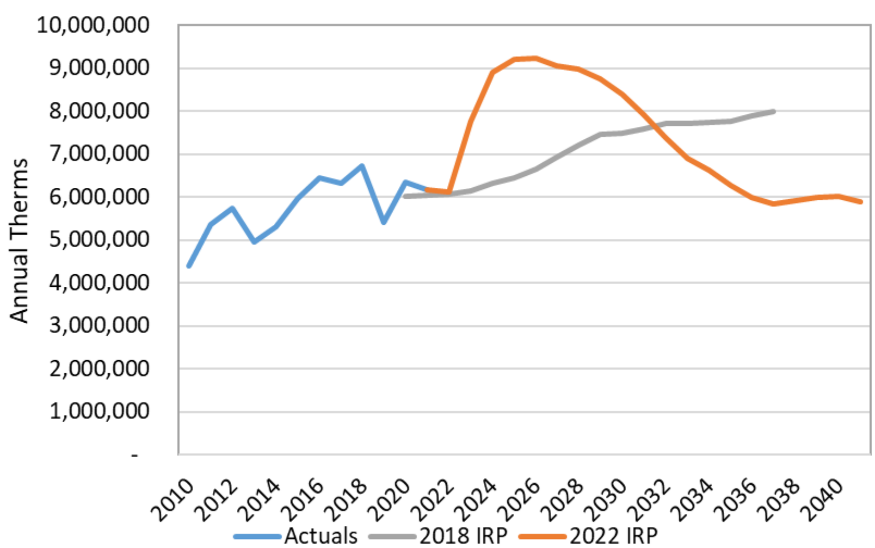
Emissions Compliance Options	Long-term Compliance Option	Short-term Compliance Flexibility
Energy Efficiency	✓	
Development RNG	✓	
RNG offtake from existing project	✓	✓
Development Hydrogen	✓	
Development Synthetic Gas	✓	
Community Climate Investments*	✓	✓
Banking	✓	✓
Allowance Trading Auction**	✓	✓
Bilateral Allowance Trading*	✓	
Offsets**	✓	✓

* Only and option under Oregon Climate Protection Program
** Only and option under Washington Cap-and-Invest

Energy Efficiency

The OR-CPP substantially increased avoided GHG emissions costs compared to the last IRP, leading to a sizeable increase in near- to mid-term energy efficiency expectations from Energy Trust of Oregon programs for customers with a bundled gas sales service, as can be seen in Figure 1.9.

Figure 1.9: Oregon Sales Customer Energy Efficiency Forecast: 2022 vs 2018 IRP



Supply-Side Low GHG Resources

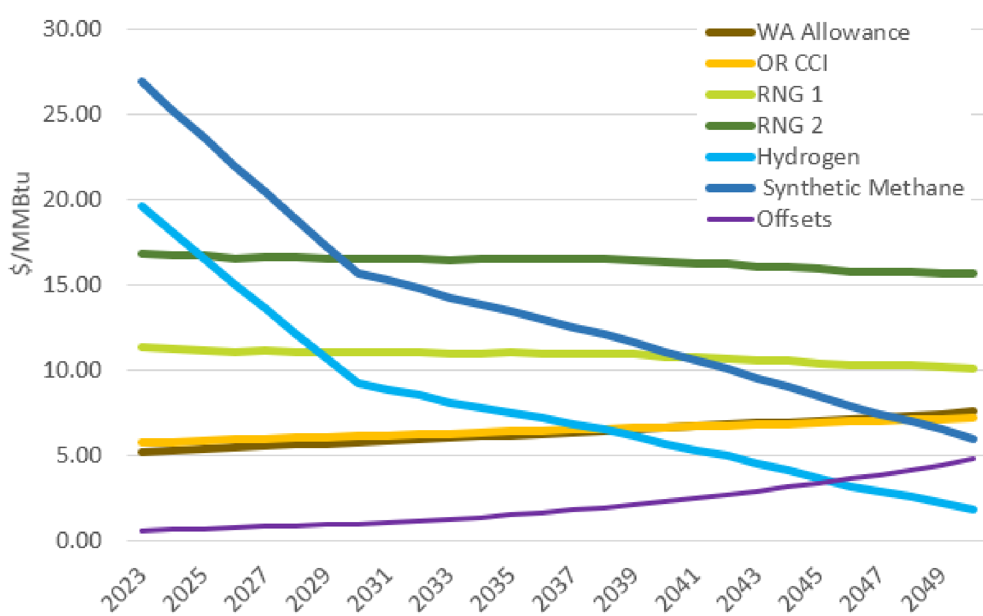
This IRP focuses on assessing the cost and availability of RNG, clean hydrogen and synthetic gas derived from clean hydrogen combined with carbon capture. Independent third parties served as the primary source for establishing many of these assumptions, where NW Natural's experience in the biofuel RNG market served a key role in understanding prices and validating availability.

Compliance Instruments

Both the OR-CPP and the WA-CCA have options that are allowed for compliance which are not direct emissions reductions from NW Natural customers. In simplistic terms, from NW Natural's customers' perspective, these options can be thought of as offsets. In the OR-CPP the purchase of CCIs serve this role, whereas emissions offsets and emissions allowances can be used for compliance in the WA-CCA. Prices for CCIs are set in rule, where offsets need to be acquired by covered parties in the WA-CCA and the allowance trading market, with bounds set in rule, determine the prices of allowances in the program (noting that the Social Cost of Carbon (SCC) replaces the cost of allowances for resource decision-making purposes in complying with the WA-CCA).

Like other key inputs, these prices and availabilities are somewhat uncertain, and ranges for these assumptions are deployed in both scenario and stochastic risk assessment, with the primary cost assumptions for these resources are shown in Figure 1.10.

Figure 1.10: Emissions Compliance Option Cost Trajectories[5]



[5] Costs show the unbundled price. See Chapter 6 for details about bundled vs. unbundled RNG.

1.5 Resource Selection and Preferred Portfolio

Using the newly developed PLEXOS® model, least-cost portfolio optimization was conducted on the nine "what if" scenarios and 500 stochastic simulations (also known as draws) each with a unique set of input assumptions. While there is substantial long-term uncertainty in the levels of capacity needed and what (and how much) emissions reduction resources are the lowest cost options for customers, this work resulted in the emergence of clear paths forward in terms of ensuring reliability (capacity planning) and meeting emissions compliance obligations in the near-term (i.e., the period covered by the action plan in this IRP). In other words, the results show that an Action Plan in this IRP can be developed that represents a low regret path forward.

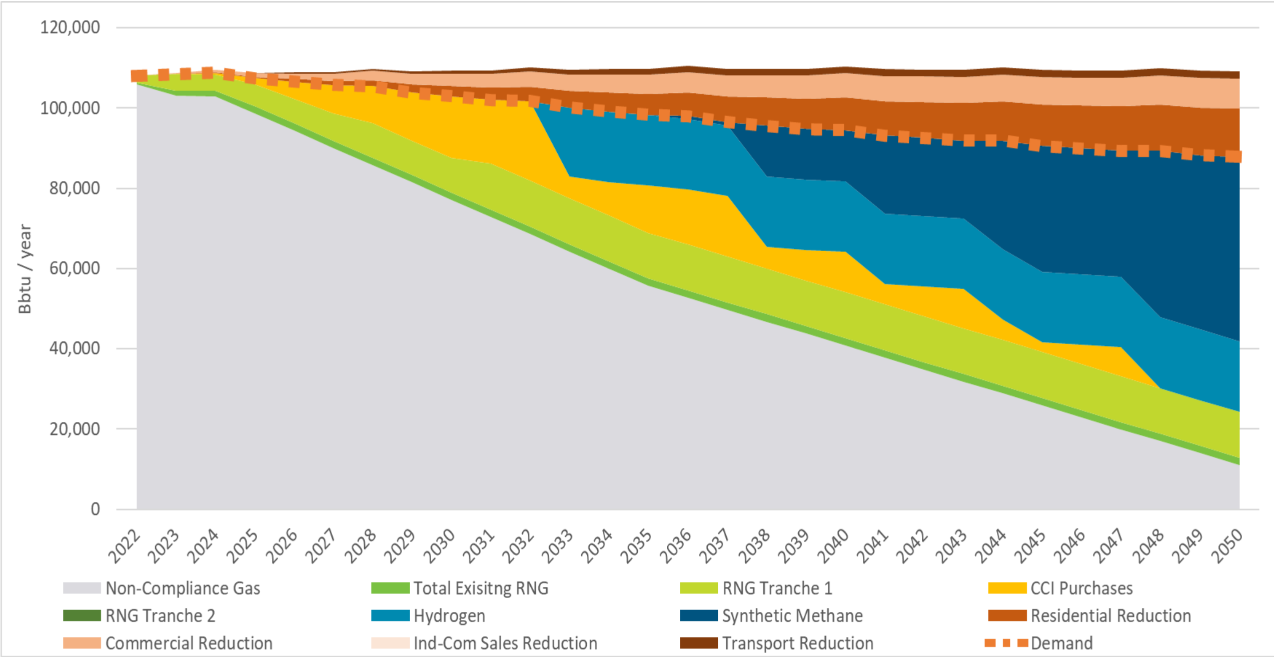
1.5.1 Capacity Results

All scenarios except for the most extreme electrification scenario show that replacing the Cold Box at the Portland LNG facility to retain the plants peaking capabilities moving forward is the cheapest way to serve customer needs. Additionally, all scenarios rely upon recalling deliverability from NW Natural's Mist storage facility to serve and meet expected capacity needs over the planning horizon. While a decision needs to be made now to address a potential shortfall in 2027 if the Portland LNG facility is not retained in the resource portfolio, recalling Mist deliverability is a flexible resource with a short lead time that can be optimized through annual updates to resource planning work.

1.5.2 Emissions Compliance Results

Figure 1.11 and Figure 1.12 show the least-cost compliance options for Scenario 1, which has results that are indicative of most scenarios and representative of the average results of the stochastic simulation work.

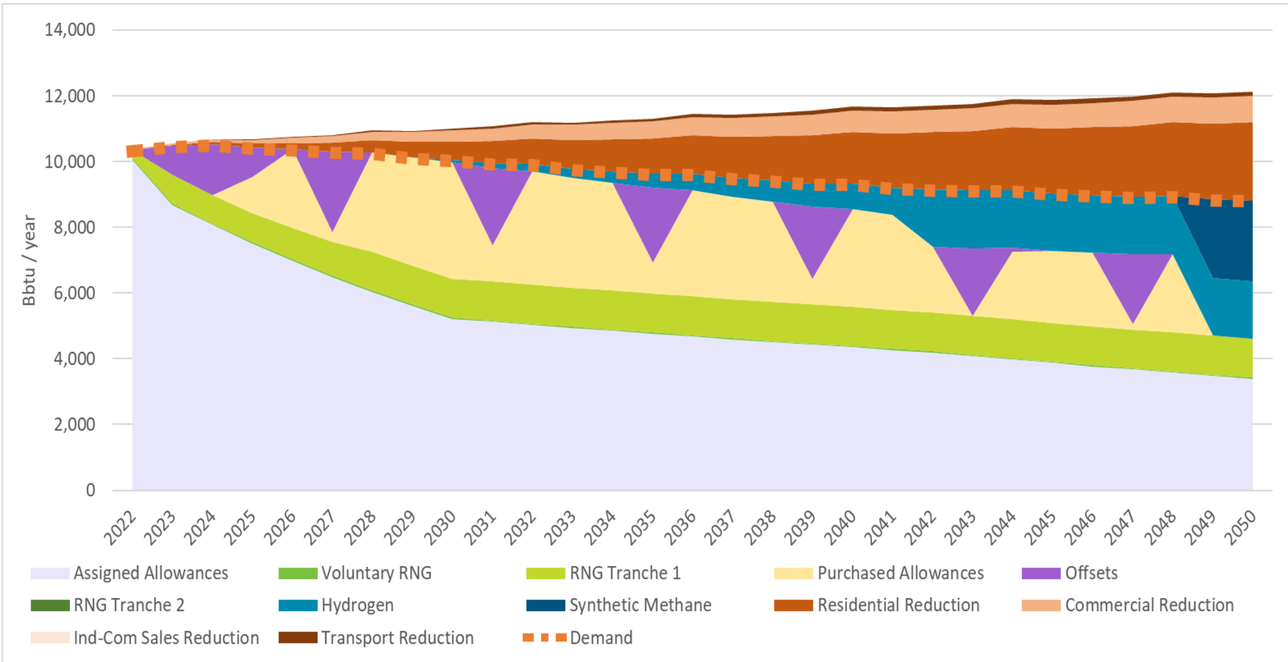
Figure 1.11: Scenario 1 Oregon CPP Compliance Portfolio



The majority of scenarios and simulation draws show that in the OR-CPP's first compliance period (2022-2024) biofuel RNG to meet SB 98 targets make up the majority of the needed compliance action. Depending on weather and other load developments a small amount of the lowest cost incremental option – CCIs – could be needed during the first 3-year compliance period. In no scenario do the CCIs projected approach the limit for CCIs allowed in the first compliance period. Since the amount of RNG needed to achieve SB 98 targets varies by scenario due to differences in load (SB 98 targets are a percentage of sales load), higher load scenarios show more SB 98 RNG and lower load scenarios show smaller amounts SB 98 RNG, though the difference is small given that load cannot change materially from current levels by the end of 2024. Also, even in scenarios with aggressive load reductions going forward, the amount of RNG that aligns with near-term SB 98 targets would be able to be utilized for compliance (i.e., not "wasted" in terms of compliance needs). Furthermore, over the first compliance period it is not anticipated that RNG or clean hydrogen would be cheaper than CCIs, making a strategy of purchasing compliance needs, more than SB 98, a robust option.

Looking at the results across scenarios and simulation draws shows a consistent trend in expected OR-CPP emissions compliance resources through time. In the near-term biofuel RNG is the cheapest option and is used to meet SB 98 targets, whereas renewable hydrogen is expected to become the incremental resource starting around 2030, and once blending limits are reached around 2040, synthetic methane (or methanated renewable hydrogen) becomes the cheapest resource.

Figure 1.12: Scenario 1 Washington Cap-and-Invest Compliance Trajectory



The Washington Cap-and-Invest program the results are similar to the results in Oregon, where biofuel RNG supported by HB 1257 is expected to be a core resource in the near term, one that is supplemented by offsets and allowance purchases. At current price expectations for offsets a strategy of maximizing the offsets allowed in the program shows as the least cost option. However, there is still work that needs to be done to understand what offsets might be available on tribal lands and what they might cost, but if these can be procured at a price lower than the expected price of allowances they would also be acquired for compliance. Allowance purchases show as the lowest cost option to fill in the remaining compliance need over the first compliance period (2023-2027), even if allowance prices are at the price ceiling currently detailed in the draft rule. Consequently, a strategy of purchasing allowances in the quarterly auction adjusting in real time to load expectations and weather over the compliance period is a strategy that is robust across scenarios and simulation draws.

1.6 Action Plan Covering the Next Two to Four Years

The Action Plan turns the results of the IRP analysis into discrete near-term activities that represent the best combination of least cost and least risk over the IRP planning horizon. The action items in this Action Plan are robust in regard to a wide range of potential future outcomes and therefore all represent low regret ways to move forward in the current environment.

Capacity Resource Action Items:

1. Acquire 20,000 Dth/day of deliverability from either recalling Mist, a city gate deal, or a combination of both for the 2023-24 gas year. Based upon updated load forecast in upcoming IRP updates recall Mist capacity as required for the 2024-25 and 2025-26 gas years.
2. Replace the Cold Box at the Portland liquified natural gas (LNG) facility for a targeted in-service date of 2026 at an estimated cost of $7.5 to $15 million.
3. Scope a residential and small commercial demand response program to supplement our large commercial and industrial programs and file by 2024.

Oregon Emissions Compliance Action Items:

4. Working through Energy Trust of Oregon, acquire 5.7 – 7.8 million therms of first year savings in 2023 and 6.7 – 8.9 million therms of first year savings in 2024, or the amount identified by the Energy Trust board.
5. In Oregon, to achieve SB 98 targets, seek to acquire 3.5 million Dths of renewable natural gas (RNG) in 2024 and 4.2 million Dths of RNG in 2025, representing 5% and 6% of normal weather sales load in 2024 and 2025.
6. Work with Energy Trust of Oregon, the Alliance of Western Energy Consumers and other stakeholders to develop energy efficiency programs for transportation schedule customers by 2024.
    - While this item is a part of our compliance strategy, NW Natural is not asking for acknowledgment from the OPUC of this item as we are already pursuing this action.
7. In Oregon, purchase Community Climate Investments representing any additional Climate Protection Plan (CPP) compliance needs for years 2022 and 2023 in Q4 2023 and for year 2024 in Q4 2024 based upon actual emissions to ensure compliance with the 2022-2024 compliance period.

Distribution System Action Item:

8. In Oregon, uprate the Forest Grove Feeder (also known as the McKay Creek Feeder) to be in service for the 2025 gas year at an estimated cost of $3.0 to $7.0 million.

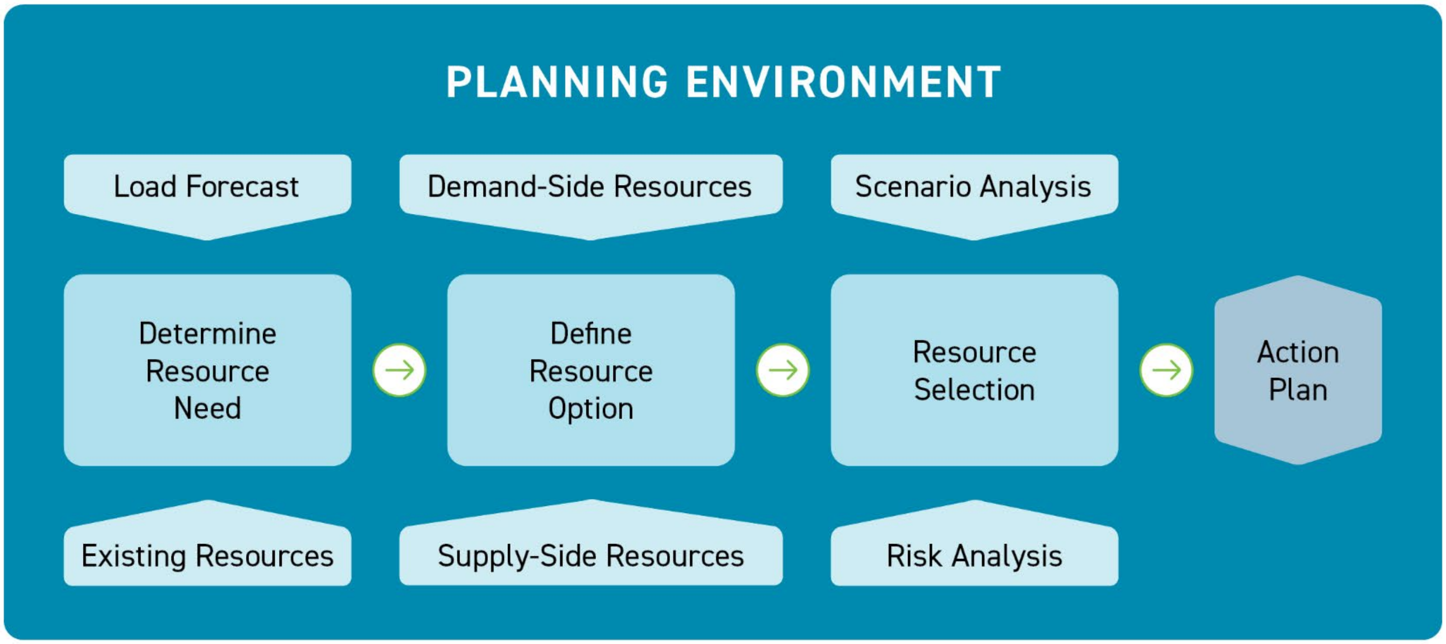
Washington Emissions Compliance Action Items:

9. In Washington, acquire carbon offsets compliant with the Climate Commitment Act's Cap-and-Invest program for 5% of expected weather emissions in year 2023 and 2024. Seek to acquire additional offsets representing 3% of expected weather emissions allowed for CCA compliance on tribal lands, and if they can be acquired for a lower price than the program allowance price floor for years 2023 and 2024, acquire these offsets.

10. In Washington, to support HB 1257, seek to acquire 600,000 Dths of renewable natural gas (RNG) in 2024 and 800,000 Dths of RNG in 2025, representing 6% and 8% of normal weather compliance gas in 2024 and 2025.
11. In Washington, purchase emissions allowances equal to emissions at an estimate of the 95th percentile of need for annual compliance net of voluntary RNG, carbon offsets, and freely allocated but not consigned allowances.
12. Working through Energy Trust of Oregon, acquire 275,000-370,000 therms of first year savings in 2023 and 276,000-310,000 therms of first year savings in 2024, or the amount approved through WUTC Biennial Energy Efficiency Plan.
13. Work with Energy Trust of Oregon, the Alliance of Western Energy Consumers and other stakeholders to develop energy efficiency programs for transportation and industrial sales schedule customers by 2024.

Environmental policy, economic conditions, market forces, and technological change are the backdrop that helps define key assumptions and objectives in an IRP. Chapter 2 lays out this planning environment with a focus on the transformational state greenhouse gas reduction policies that are the drivers of large changes in this IRP.

2 | Planning Environment



2.1 Planning Environment Overview

Fundamental in developing an IRP is an understanding of the planning environment and potential impacts to the plan now and in the future. The planning environment is a holistic review of potential risks, opportunities and important factors that can impact the IRP.

When evaluating the planning environment NW Natural considers:

- Economic and demographic factors
- Commodity price forecast
- Environmental policy
- New technology or game changers
- Load service environment

NW Natural takes these factors into consideration for our load forecast, potential future resources, and risk analysis. These factors are discussed in more detail below.

2.2 Economic and Demographic Factors

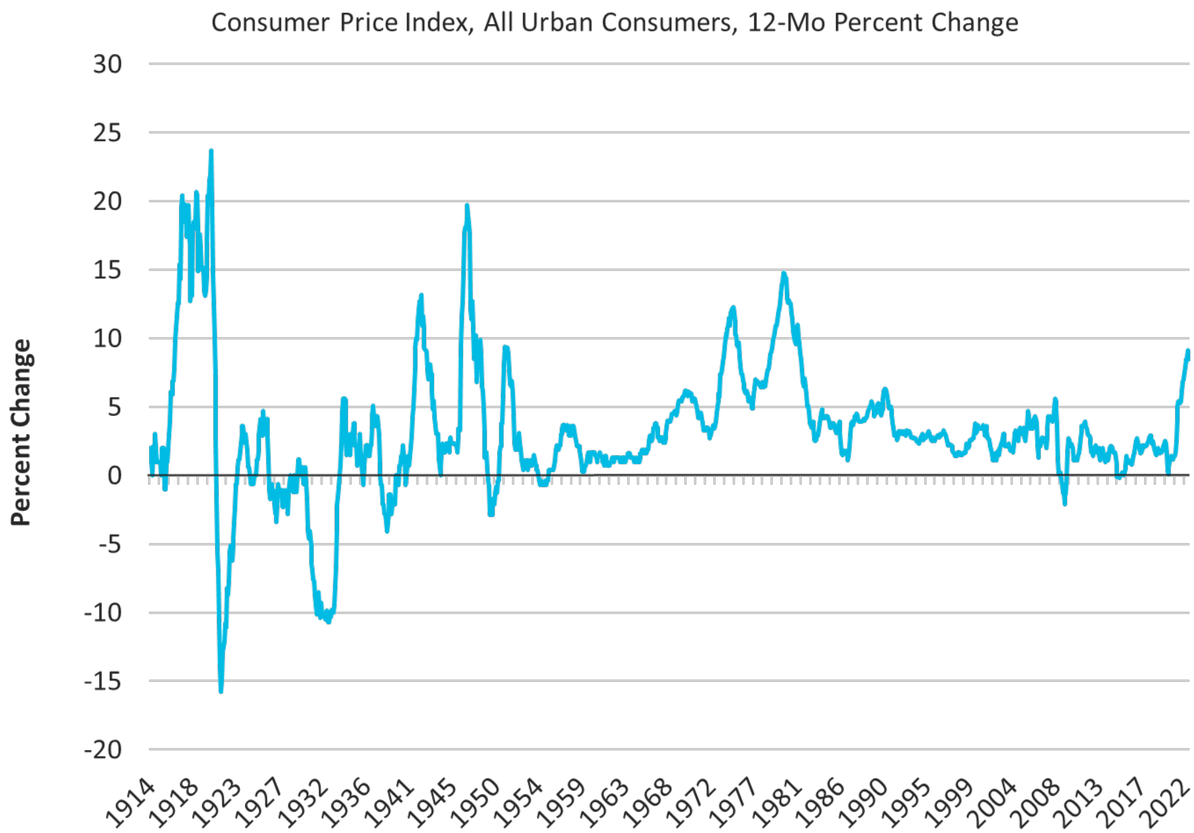
Economic and demographic factors are important underlying drivers of load growth. Changes in customer volume and usage patterns, especially for industrial customers, are impacted by broader trends in the economy and changing demographics.

2.2.1 U.S. Economic and Demographic Outlook

The U.S. economy continues its recovery from the COVID-19 pandemic, but inflation and uncertainty are slowing growth. In July 2022, the unemployment rate was 3.5 percent, the same rate as February 2020 before the COVID-19 pandemic. Similarly, total nonfarm employment in July 2022 was essentially the same as February 2020, with full recovery of total jobs lost during the pandemic. The labor market appears to be back at full employment, and while leisure and hospitality employment is still down 7.1 percent from pre-COVID-19 levels, employment has grown and shifted to other industries like transportation and warehousing, and professional and business services, making up the difference. The labor force participation rate has increased from its April 2020 low, but remains below pre-COVID-19 levels, contributing to the extremely tight labor market.

But the economy is slowing. On one hand, economic growth ought to slow given labor constraints, but beyond the labor market, inflation, supply chain issues, and uncertainty surrounding monetary and fiscal policy, as well as geopolitical risks and energy supply shocks from the war in Ukraine, are putting downward pressure on growth. Massive deficit spending in the wake of COVID-19 and expansionary monetary policy by the Federal Reserve boosted the money supply in the U.S. to unprecedented levels in 2020 and 2021, which led to inflation. Energy price increases caused by the war in Ukraine further exacerbated inflation in early 2022. The Consumer Price Index in July 2022 was 8.5 percent higher year-over-year, following 9.1, 8.6, 8.3, and 8.5 percent increases the previous four months. This is the highest year-over-year inflation since 1981 (Figure 2.1).

Figure 2.1: Inflation at a 41-Year High



Source: U.S. Bureau of Labor Statistics.

The Federal Reserve has the unenviable task of trying to engineer a "soft landing" from this high inflationary environment. Historically, this rarely happens, and it has never happened with inflation this high, and the unemployment rate this low. Nonetheless, the Federal Open Market Committee (FOMC) has begun raising interest rates, with a 25-basis point increase in March 2022, a 50-point hike in May, and 75-point hikes in June and July, the highest increases since 1994. The Fed is also beginning to reduce its holdings of Treasury securities and mortgage-backed securities, shrinking the Fed's balance sheet, and further shifting from a policy of quantitative easing to one of tightening. Forward guidance from the FOMC indicates more rate increases in 2022, up to 50 or 75-basis points at a time.

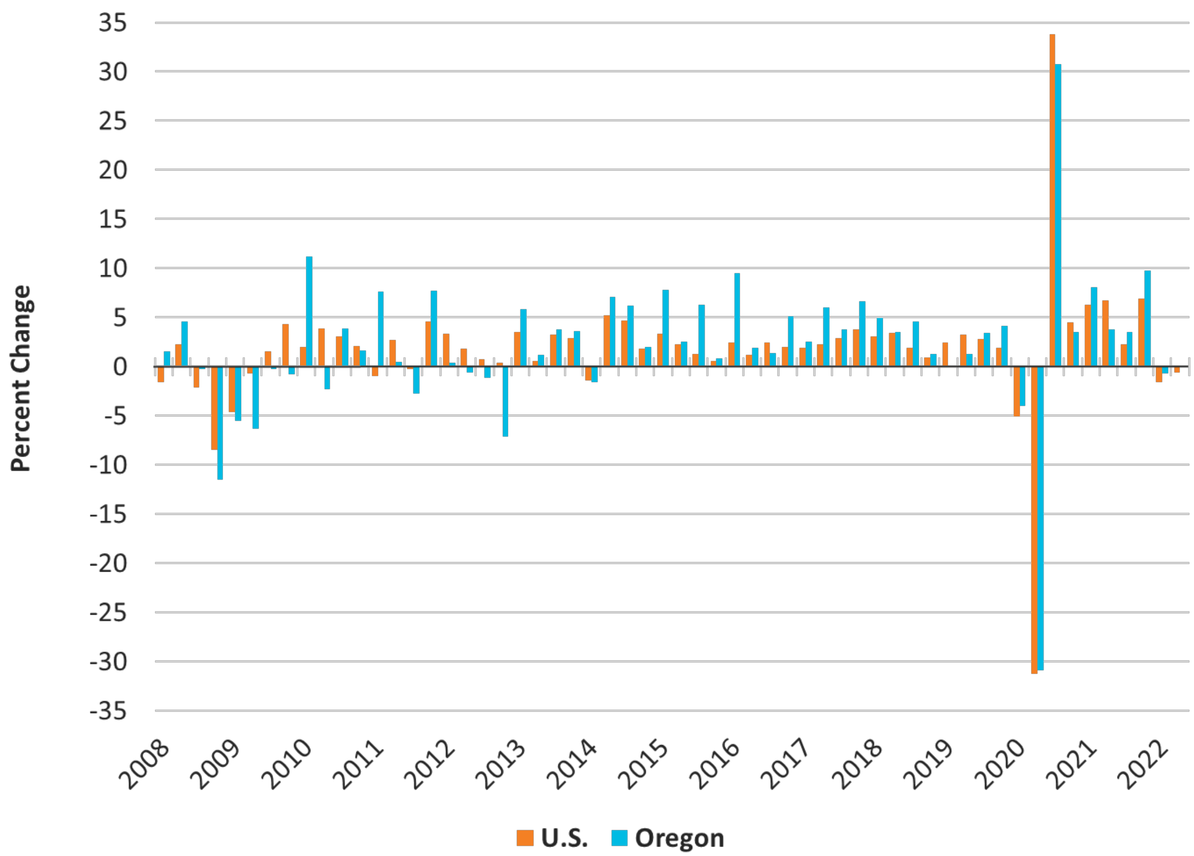
Real GDP declined in the first two quarters of 2022 by 1.6 and 0.9 percent. Two consecutive quarters of decline is a sign the economy may be in recession. GDP has declined due to decreases in government spending and investment, while real consumer spending is being eaten away by high inflation. The labor market remains strong, but unemployment claims are beginning to rise. Economists and business leaders have increased their probability of recession in their forecasting, with the chance of recession over the next 12-24 months as high as 50 percent.[6] The spreads between short and long-term Treasuries have shrunk significantly, another signal of recession. In fact, the yield on two-year Treasuries has been higher than ten-year Treasuries since July 2022 and continued to be through the end of August 2022. The S&P 500 officially fell into bear market (decline of 20 percent or more from previous peak) territory in June 2022. Stagflation – high inflation coupled with little to no economic growth – is a real possibility in the near-term, especially if efforts by the Fed do not lead to significantly lower inflation, but slow growth.

2.2.2 Oregon Economic and Demographic Outlook

During and after the recession of 2008 and 2009, Oregon GDP and employment followed similar trends to past economic cycles of greater loss during recession and greater gains in expansion years (Figure 2.2). Oregon's more cyclical economy is the result of larger-than-average durable goods manufacturing and related industries. Oregon's economy benefits from this industry concentration over time, with stronger GDP growth across cycles than the U.S. The recession caused by COVID-19 was different, though, since job losses were concentrated in industries like leisure and hospitality, air transportation, and retail trade – service industries that most states have in similar concentrations. As a result, negative GDP and employment impacts across states were more similar than a typical recession. Oregon's economic recovery coming out of the COVID-19 pandemic largely mirrors trends nationally.

[6] National Association for Business Economics, "NABE Outlook Survey, May 2022," www.nabe.com, May 23, 2022, https://nabe.com/NABE/Surveys/Outlook_Surveys/May-2022-Outlook-Survey-Summary.aspx; Reade Pickert and Kyungjin Yoo, "U.S. Recession Odds Within the Next Year Now 30%, Survey Shows," www.bloomberg.com, May 13, 2022, https://www.bloomberg.com/news/articles/2022-05-13/odds-of-a-us-recession-within-next-year-now-30-survey-shows#xj4y7vzkg; Prerane Bhat and Indradip Ghosh, "No Respite from Fed Rate Hikes This Year, Chances Rising of Four 50 bps in a Row – Reuters poll," www.reuters.com, June 9, 2022, https://www.reuters.com/markets/us/poll-no-respite-fed-rate-hikes-this-year-chances-rising-four-50-bps-row-2022-06-10/; Isabella Simonetti and Jason Karaian, "'Uncomfortably high': What economists say about the chance of recession," *The New York Times*, June 28, 2022, https://www.nytimes.com/2022/06/28/business/recession-probability-us.html#:~:text=S%26P%20Global%20Ratings%3A%20Beth%20Ann,walking%20out%20of%202023%20unscathed.%E2%80%9D.

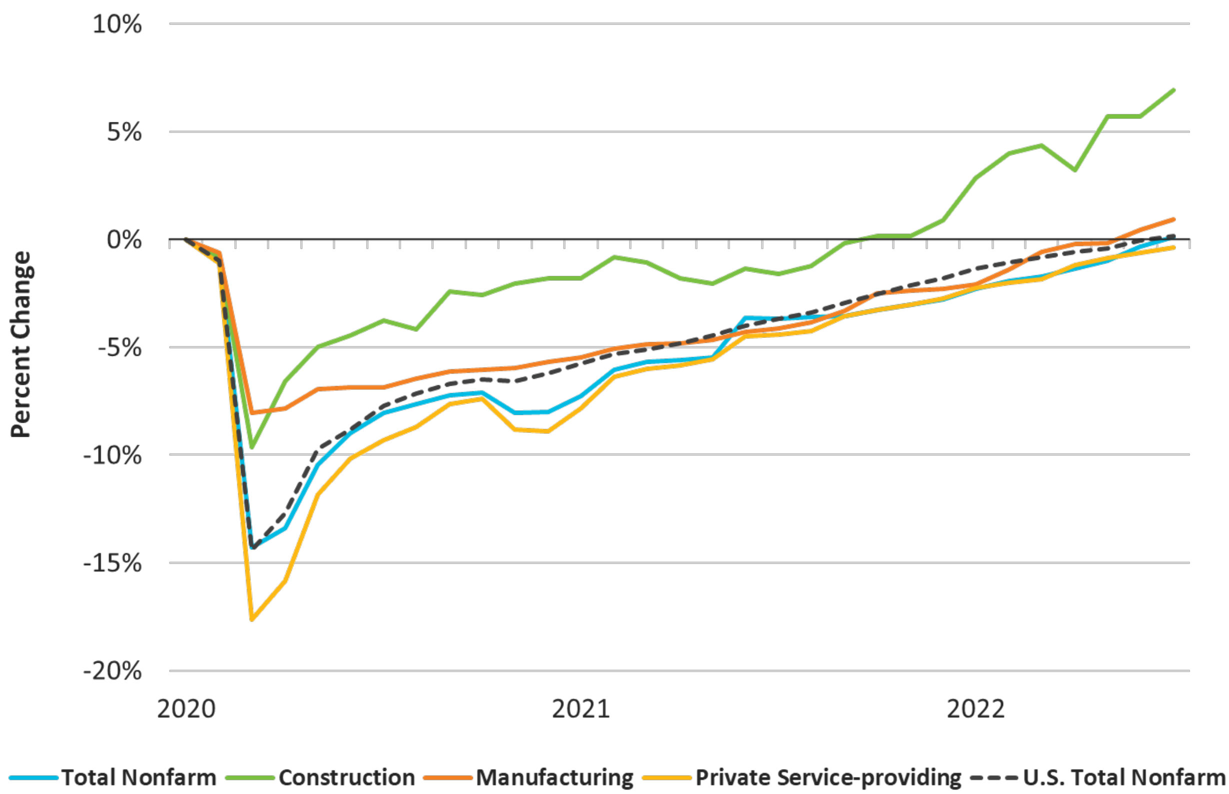
Figure 2.2: Real Gross Domestic Product, Percent Change, Annualized



Source: U.S. Bureau of Economic Analysis.

In August 2022, Oregon total nonfarm employment finally recovered total jobs lost since the beginning of the pandemic (Figure 2.3). Manufacturing employment, which declined 8 percent in April 2020, has also recovered all jobs lost during the pandemic. This is welcome news for Oregon's economy since jobs lost in manufacturing during recessions do not all come back historically. Some amount of structural job loss is typically realized, which reduces hard-to-replace, accessible, middle-wage jobs for Oregonians. Construction employment in Oregon is well above its pre-pandemic peak thanks to a strong rebound in residential building and related specialty trade contractors. Service industries experienced the largest employment declines during the pandemic and have recovered 99 percent of jobs lost since February 2020.

Figure 2.3: Oregon Employment Fully Recovered



Source: Oregon Employment Department, Current Employment Statistics, Official Oregon Series; U.S. Bureau of Labor Statistics.

The Oregon Office of Economic Analysis (OEA) September 2022 forecast projects all major industry sectors in Oregon will regain all jobs lost by the end of 2022, except leisure and hospitality, where employment is projected to return to its pre-pandemic peak in 2026. The baseline forecast, which assumes a "soft landing" by the Fed and no recession, calls for continued growth over the next five years, but at a slower rate. Employment growth is forecasted to be 3.8 percent in 2022, 1.8 percent in 2023, and down to 1.0 percent in 2024. With interest rates on the rise, economic activity is slowing, such as building permits and home sales. So far, the labor market remains solid, but further contractionary monetary policy moves are expected to lead to higher unemployment going forward as the economy cools.

Recent demographic trends in Oregon have created some uncertainty for demographic forecasters in the state. Oregon has enjoyed strong population growth for many years. That changed with COVID-19, and perhaps to a lesser degree, with the perceived lower quality of life experienced by Oregonians in the wake of protests, increased homelessness, and increased crime throughout the state, particularly in Portland. Immigration into the U.S. and migration between states slowed dramatically during the pandemic. Net migration into the U.S. dropped to 247,000 in 2021 – a 48 percent decline from 2020 –

and was down 76 percent from last decade's high in 2016.[7] Similarly, Oregon's number of foreign-born prime working age adults was 90,000 lower in the first half of 2022 than it was in 2016, a decline of nearly one-third.[8] While migration between states will increase with the pandemic largely behind us, it is unclear what immigration into the U.S. will look like going forward due to uncertainty surrounding immigration policies at the federal level. Another wrinkle is the impact of increased remote workers in the U.S. It is an open question whether a larger share of remote workers in the U.S. could have a positive or negative impact on Oregon's population and economy (or no impact at all). Oregon has historically attracted young, educated workers who see Oregon as a lower cost, higher quality of life destination than other places on the west coast. However, Oregon has a high personal income tax that remote workers may want to avoid. It is the 12th most expensive state in the U.S., up 8 spots from 2010 when it ranked 20th, and had the fourth highest increase in prices between 2015 and 2020.[9] That said, California and Washington are still more expensive than Oregon.

The latest demographic forecast from the OEA shows Oregon's population continuing to grow over the next decade, but at a slower rate than it has over the past three decades (Figure 2.4). Factors in the lower growth rate include slower growth trends since 2015, reduced migration during the pandemic, an aging population, and declining birth rate. A slower growing population will constrain potential labor force in Oregon, limiting economic growth as well. One of the potential barriers to higher growth is Oregon's affordability, in particular, its lack of affordable housing.

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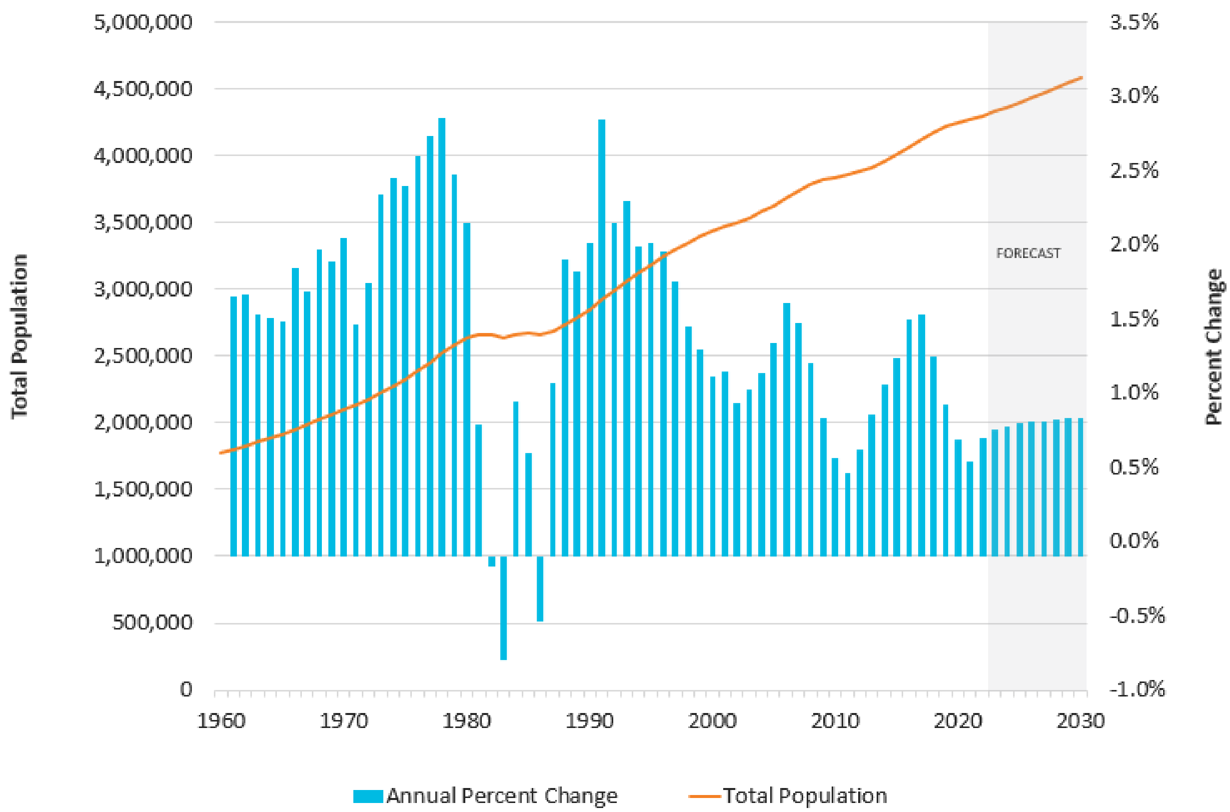
[7] Jason Schachter, Pete Borsella, and Anthony Knapp, "New Population Estimates Show COVID-19 Pandemic Significantly Disrupted Migration Across Borders," U.S. Census Bureau, December 21, 2021, https://www.census.gov/library/stories/2021/12/net-international-migration-at-lowest-levels-in-decades.html.

[8] IPUMS-CPS, University of Minnesota, www.ipus.org, retrieved June 21, 2022.

[9] U.S. Bureau of Economic Analysis, Regional Economic Accounts, Regional Price Parities by state, www.bea.gov, retrieved June 21, 2022.

Figure 2.4: Oregon Population Growth Slowing



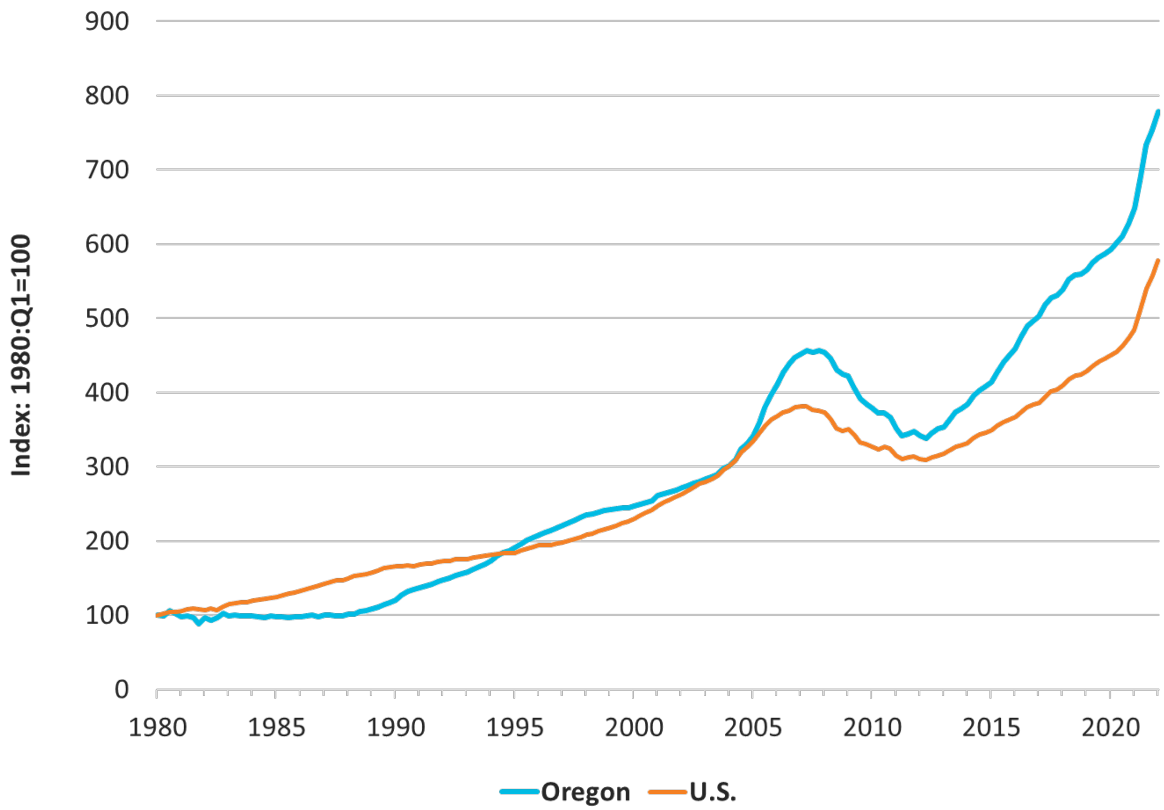
Source: U.S. Census Bureau, Portland State University Population Research Center, Oregon Office of Economic Analysis.

Housing affordability continues to be a problem in Oregon, as supply is not keeping up with demand. Oregon has underproduced about 110,000 housing units as of 2021, which is 19 percent of total units needed in the state.[10] Demand remains strong, with prices at record highs and inventories at record lows.[11] Oregon house prices increased at a much faster rate than prices in the U.S. over the past decade (Figure 2.5). Oregon prices were 20 percent higher in the first quarter of 2022 than they were the year before, which was equal to the highest quarterly year-over-year percent change experienced before the Great Recession in the first quarter of 2006.

[10] ECONorthwest. *Implementing a Regional Housing Needs Analysis Methodology in Oregon: Approach, Results, and Initial Recommendation*. Portland, Oregon: ECONorthwest, 2021. Accessed June 30, 2022. https://www.oregon.gov/ohcs/about-us/Documents/RHNA/RHNA-Technical-Report.pdf.

[11] Realtor.com. Housing Inventory Core Metrics. Accessed June 30, 2022, via Federal Reserve Bank of St. Louis, Federal Reserve Economic Data. https://fred.stlouisfed.org/series/ACTLISCOUOR.

Figure 2.5: Oregon House Prices Increasing Much Faster than U.S.



Source: Federal Housing Finance Agency, FHFA House Price Index.

Growth appears to be slowing, though, as a result of increasing interest rates brought on by the Federal Reserve's actions to tamp down inflation. At the end of August 2022, the 30-year fixed rate mortgage average in the U.S. was 5.6 percent, almost double what it was a year earlier.[12] Market data through July 2022 show that new listings of homes for sale in Oregon are beginning to decline, along with closed sales and the median sale price, while inventory is slowing increasing from historic lows.[13] This trend is likely to continue as further interest rate increases are expected from the Fed in 2022. Single family residential building permits in Oregon have been declining on a year-over-year basis since October 2021 based on three month moving averages. The OEA also expects housing starts in Oregon to decline in 2022. Housing starts are forecasted to grow from 2023 to 2030, but at a slower rate than they did pre-pandemic. Most of the slower growth in starts is tied to slower population growth.

2.2.3 NW Natural System Area Economic and Demographic Outlook

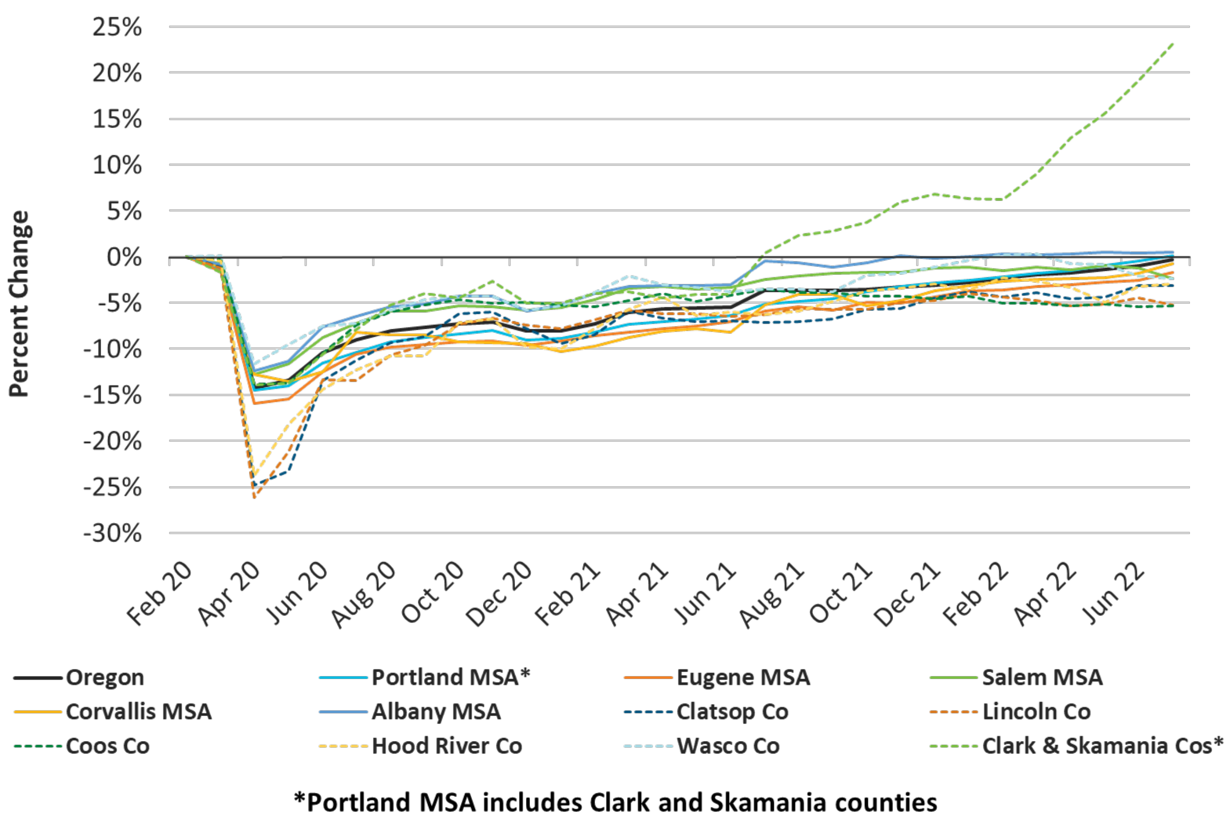
The COVID-19 pandemic impacted cities and counties differently across the Company's service territory. In the service territory, as well as across the U.S., the pandemic had a larger negative impact

[12] Freddie Mac. Primary Mortgage Market Survey. Accessed August 30, 2022, via Federal Reserve Back of St. Louis, Federal Reserve Economic Data. https://fred.stlouisfed.org/series/MORTGAGE30US.

[13] RMLS. "July 2022 Market Action Statistics (Real Talk with RMLS, Episode 61." August 17, 2022. https://rmlscentral.com/podcast/july-2022-market-action-statistics-real-talk-with-rmls-episode-61/.

in communities with above average concentrations of service sector employment in leisure and hospitality, arts, entertainment, and recreation, personal services, and air transportation. Employment in these industries is typically more concentrated in metropolitan areas than rural areas and in areas with significant tourism. Throughout the Company's service territory, employment declined the most in Lincoln, Clatsop, and Hood River counties – rural areas with significant tourism (Figure 2.6). The Portland metro area, which includes Clark and Skamania counties in Washington, and Eugene metro area also experienced larger employment declines than average across the state.

Figure 2.6: Pandemic Employment Impacts Across NW Natural Territory



Source: Oregon Employment Department, Current Employment Statistics, Official Oregon Series.

Within the Portland MSA, employment in Clark and Skamania counties in Southwest Washington has soared in comparison to other areas within the Company's service territory since February 2020 and is 23 percent higher than its pre-pandemic peak. The Albany MSA has eclipsed pre-pandemic total employment, and the Portland MSA has recovered all jobs lost since the beginning of the pandemic as of July 2022. The Eugene and Salem MSAs were still down about 2 percent from their peak. Coos and Lincoln counties were still down 5 percent from their pre-pandemic peaks, while Clatsop and Hood River counties were still down 3 percent. August 2022 data shows Oregon has now recovered all jobs lost during the pandemic. Areas that experienced larger job losses in the most impacted industries will take longer to recover.[14]

The pandemic led to lower rates of migration across the nation and migration out of larger cities. Total population in the Portland metro area declined by about 4,600 in 2021 from 2020. More significantly, Multnomah County's population dropped by 12,500, a decline of 1.5 percent. It remains to be seen how much this population shift out of larger cities and into suburbs and less populated areas will influence growth patterns going forward, but forecasters expect population growth to return to the Portland metro area, albeit at slower rates than experienced over the decade preceding the pandemic.[15] Population forecasts for metro areas and counties in the Company's service territory have not been developed since the onset of the pandemic. Based on the current population forecast for Oregon developed by the OEA, population growth across the service territory will be slower between 2020 and 2030 than it was between 2010 and 2020.

Like Oregon, housing affordability in the service territory is an area of concern. Figure 2.7 shows recent trends in single family building permits in the territory's three largest metro areas and, while growth in permits has continued to rise from lows experienced after the Great Recession, the pace of housing construction does not appear to be meeting increased demand in the area based on price and inventory trends. This was the case before the pandemic, but the situation worsened even more during the pandemic with extraordinarily low mortgage rates, migration out of cities to suburbs, and higher household incomes. Clark County continues to produce housing at a far greater rate than other counties in the Portland MSA, accounting for 37 percent of metro residential building permits in 2021. In 2011, that number was 18 percent. The S&P CoreLogic Case-Shiller Portland Home Price Index increased at an annualized rate of 5.2 percent between April 2010 and April 2020. In the two years since, it increased at a 17.4 percent annualized rate. Increasing mortgage rates, brought on by interest rate increases by the Fed, have begun to dampen sales and prices in region. In the Portland metro area, pending sales were down 27.5 percent in June 2022 from a year ago.[16] The median sale price appears to have topped out as well and inventory is beginning to rise. Similar trends are occurring in Eugene, Salem, and other areas of the service territory.

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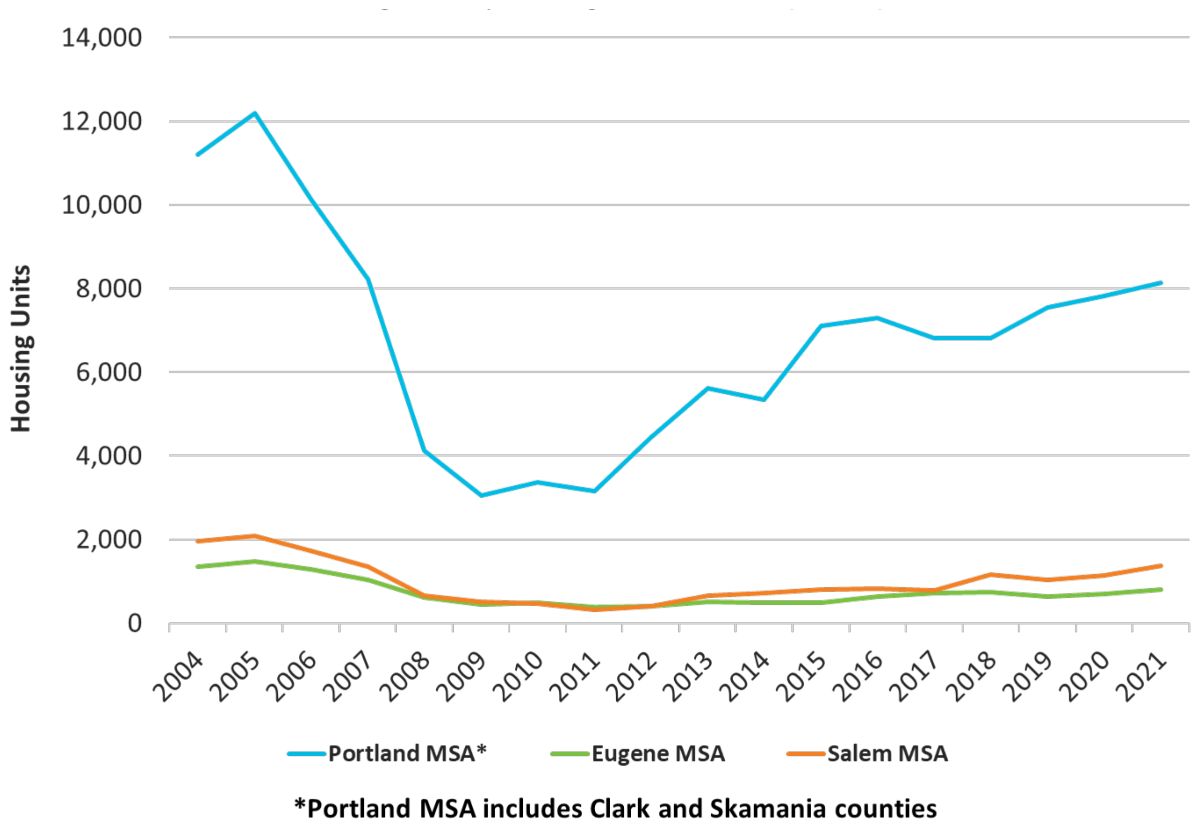
[14] Oregon Office of Economic Analysis, *Oregon Economic and Revenue Forecast, June 2022*. Salem, Oregon: Department of Administrative Services, 2022. Accessed July 6, 2022. https://www.oregon.gov/das/OEA/Documents/forecast0622.pdf.

[15] Metro (MPO), *Portland-area 2045 Population and Housing Forecasts by City and County*. Portland, Oregon: Metro, 2021. Accessed July 5, 2022. https://www.oregonmetro.gov/sites/default/files/2021/03/26/2045-regional-population-housing-forecast-by-city-county.pdf.

[16] RMLS, *Market Action, June 2022*. Portland, Oregon: RMLS, 2022. Accessed July 11, 2022. https://www.rmlsweb.com/v2/public2/loadfile.asp?id=12507.

Figure 2.7: Single Family Building Permits Issued (Annual)



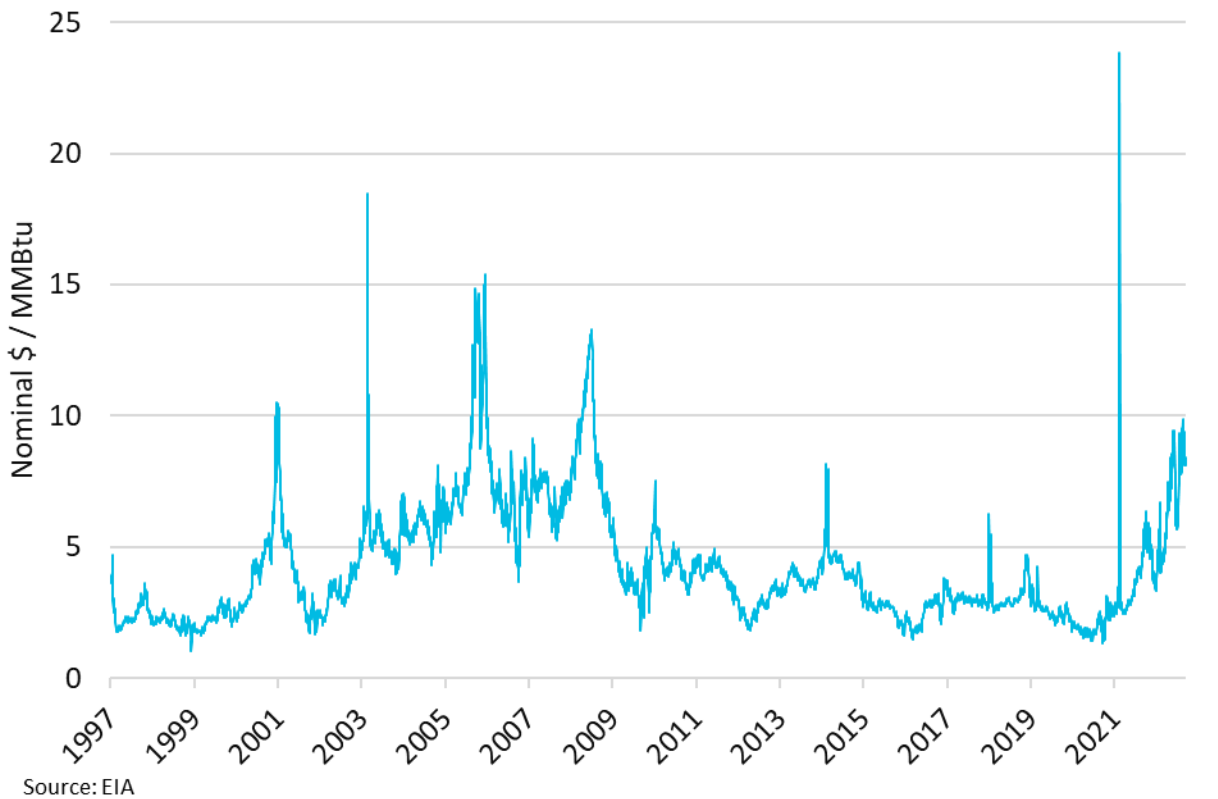
Source: U.S. Census Bureau, Building Permits Survey.

2.3 Natural Gas Prices

Like many commodities, volatility in natural gas prices is influenced by numerous factors, including macro-economic factors, weather, power generation demand, and production constraints and development in new and traditional supplies — such as more efficient extraction technologies or additional access to RNG. Figure 2.8 depicts historical gas prices at Henry Hub and how natural gas prices have been changing over time.[17]

[17] Henry Hub is the US benchmark pricing delivery location for futures contracts on the New York Mercantile Exchange (NYMEX).

Figure 2.8: Historical Daily Natural Gas Prices



2.3.1 Natural Gas Supply Sources

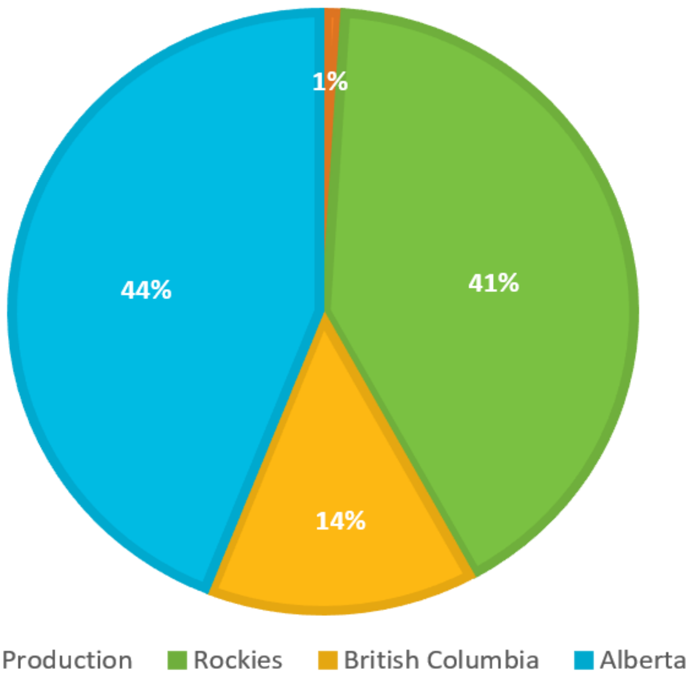
NW Natural purchases natural gas on behalf of all sales customers. Purchasing natural gas from producers located in Canada or the Western US requires the corresponding interstate/interprovincial pipeline capacity rights to ship the gas from the location of production to our service territory. NW Natural, as customer of the interstate/interprovincial pipeline companies, holds capacity contracts that allow us to ship conventional gas that is purchased from out-of-state production basins and deliver it to NW Natural's service territory.

NW Natural's current upstream pipeline capacity contracts allow us to access and buy Canadian natural gas, which is shipped south from British Columbia and Alberta, and natural gas coming out of the Rockies, primarily in Wyoming and Colorado. In 2021, these contracts enabled us to purchase roughly 38% of our supplies from Rockies, 28% from Alberta and 34% from British Columbia (see Figure 2.9).[18]

[18] There is a small amount of gas being produced at Mist that comes onto our system through a third-party producer and new RNG interconnections that began to flow onto our system in 2021.

Looking forward, gas from RNG sources, either with or without environmental attributes, will become a larger share of the Company's supply purchases.[19]

Figure 2.9: Supply Diversity by Location January 2021-December 2021



While our contracts allow us to access various points along the interstate/interprovincial pipelines, the gas prices we pay for gas produced in these basins are closely correlated with three major natural gas trading hubs in the corresponding production areas: AECO (Alberta), Opal (Rockies), and Westcoast Station 2 (British Columbia). Additionally, NW Natural purchases gas at a fourth trading hub at Sumas, which is on the Washington (U.S.)/British Columbia (Canada) border, however, there is no major production operations associated with Sumas.[20]

2.3.2 Natural Gas Price Forecast

NW Natural subscribes to a gas market fundamentals forecasting service through a third-party, IHS Markit.[21] IHS Markit implements a nation-wide supply and demand fundamentals model for the natural gas sector. Using this model IHS Markit publishes a long-term gas price forecasts for numerous natural gas hubs around the U.S. and Canada. The IRP uses these gas price forecasts as the expected gas price for the four natural gas price hubs where the company purchases gas, AECO, Opal (i.e., Rockies), Sumas and West Coast Station 2. Natural gas prices will vary by location and time of year. As

[19] Please see Chapter 6 for more information on RNG

[20] Purchases at Sumas are grouped together with British Columbia in Figure 2.9, however; Sumas is a trading hub and most of the gas being bought and sold at this location is likely being transported from either Alberta or Northern British Columbia.

[21] IHS now owned by S&P Global.

demand increases in a specific region and pipeline capacity to ship gas into that area becomes constrained, prices in the constrained region can spike. Figure 2.10 shows both historical prices and forecasted prices for these four hubs.

Figure 2.10: Historical Natural Gas Prices and Forecasts by Trading Hub[22]

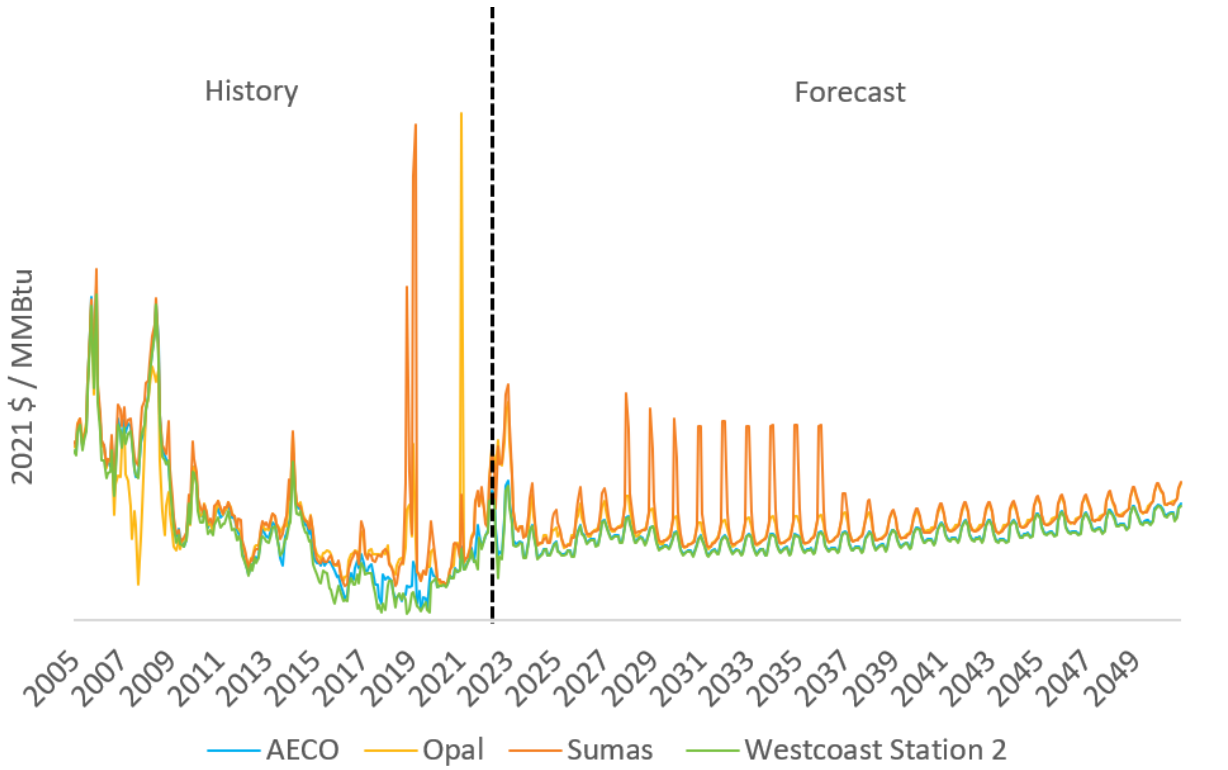
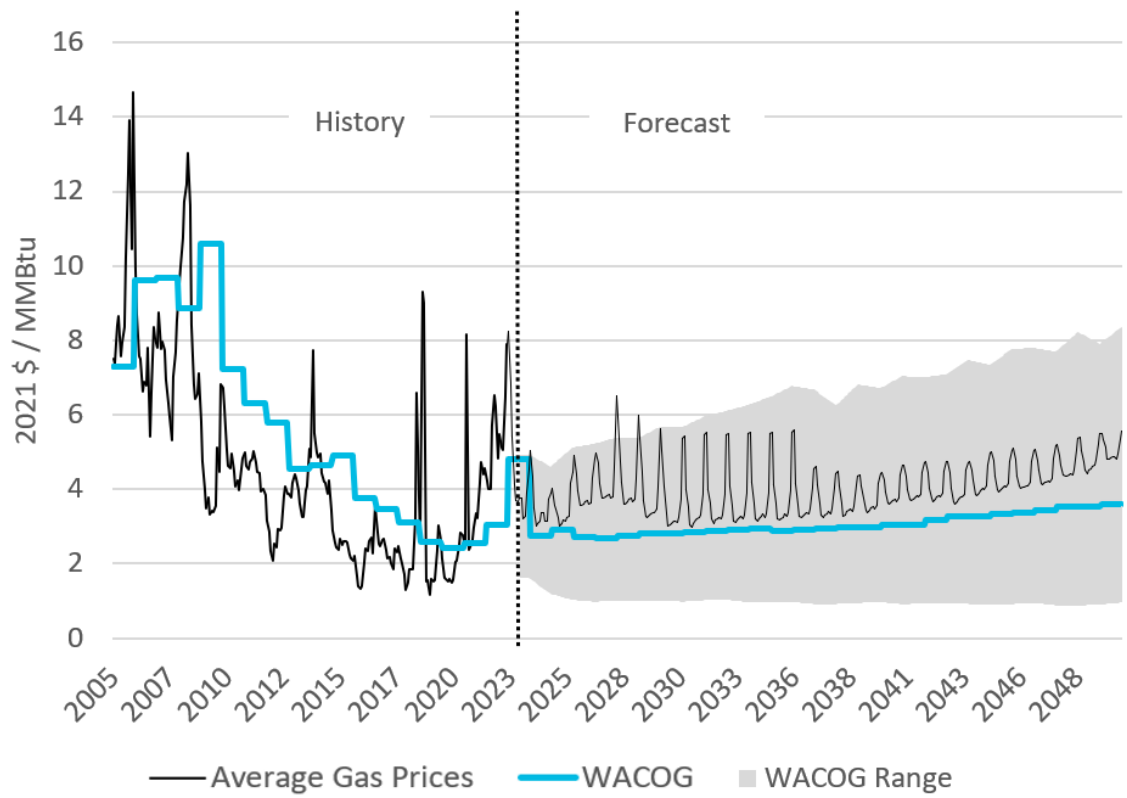


Figure 2.11 shows a historical average gas price, the historical weighted average cost of gas (WACOG), the forecasted WACOG over the planning horizon and the range of potential WACOG into the future. The WACOG is inclusive of fuel and variable charges to ship the gas to NW Natural's system. In practice the WACOG is forecasted in advanced for customers for the upcoming gas year and filed each fall through the purchased gas adjustment (PGA) filing. Any over/under collection of revenues from WACOG is trued up in rates in the following year's PGA.

[22]Source: IHS "North American Natural Gas Long-Term Outlook Market outlook data tables - August 2022," September 2022. Y-axis values were removed to protect proprietary hub specific forecasts provided by IHS for this IRP.

Figure 2.11: Weighted Average Cost of Gas[23]



2.3.3 Current Conditions

While demand has continued to recover following the impact of the COVID-19 pandemic, production growth has lagged as producers have focused on capital discipline. The market has been additionally strained with an increase in LNG and Mexico pipeline exports, strong demand for natural gas generation, and a low storage inventory. Without additional supply to balance demand, the market has faced sustained high prices.

With new LNG export facilities and expansions, the seven big U.S. export plants are expected to have a capacity of 13.8 Bcf/d by the end of 2022. LNG exports have hit record levels due to the capacity additions along with strong global demand as a result of Russia's invasion of Ukraine. While a June 8 fire at Freeport LNG has taken the facility offline until late 2022, the additional 2 Bcf/d of supply added to the market has been swallowed up by strong demand for natural gas generation and injections into storage. LNG exports have increased from an average of 6.5 Bcf/d in 2020 to 9.8 Bcf/d in 2021 to 11.2 Bcf/d for the first half of 2022. The EIA expects LNG exports to increase to 12.7 Bcf/d in 2023.[24] LNG

[23] The range for the forecasted WACOG is based on the 5th and 95th percentile of annual WACOG that is an output of the Monte Carlo process optimized through the Resource Planning Optimization Model (i.e., PLEXOS®). The forecasted WACOG is the annual mean of these simulations. The average gas prices is a weighted average across the 4 purchasing hubs based on 2022 modelled weights.

[24] Source: EIA, Short Term Energy Outlook, July 12, 2022

export growth will be constrained until the Golden Pass LNG Terminal is online in 2024, which will increase export capacity to 16.3 Bcf/d.

Despite high prices, power sector demand for natural gas generation is near record levels from 2020 as gas-to-coal fuel switching for electric generation is less flexible and new renewable generating capacity is facing construction delays due to supply-chain issues.[25] Coal generation is constrained due to low coal stockpiles resulting from low production and increased exports, rail transport issues, and coal plant retirements. More than 100 GW of coal retired across the US over the past 10 years and an estimated 90 GW of retirements have been announced or are planned by 2030.[26] Demand for natural gas in the electric power sector is expected to grow through 2025 even as new renewable energy resources come online.[27]

Storage inventory is expected to head into the winter of 2022-23 below average. The EIA is forecasting that storage will end the 2022 injection season around 6% below the five-year average. This creates anxiety in the market in the event of a colder-than-normal winter.

An increase in crude oil and natural gas prices have contributed to increased drilling activity. Dry gas production is growing in the Haynesville region and the Permian Basin. Associated gas production, which is dependent on the crude oil market, is also expected to grow in the Permian Basin as high oil prices have led to plans to increase oil production. The EIA forecasts that dry natural gas production will increase 2.7 Bcf/d or 3% compared to 2021 and 3.7 Bcf/d or 4% in 2023.[28] Gas production from the Montney region in northern British Columbia and Alberta, Canada has also been increasing. Canadian production is currently just below the April 2006 all-time record high as Canadian producers were in better financial shape than U.S. producers and were able to boost production when prices began to rise.[29]

Volatility has been up due to the continual shifts in the market. Volatility of U.S. natural gas futures prices reached a record-high level in February with the 30-day historical volatility of gas futures reaching 179.1%. Upward price pressure and volatility will remain until supply and demand are balanced.

2.3.4 Natural Gas Price Uncertainty

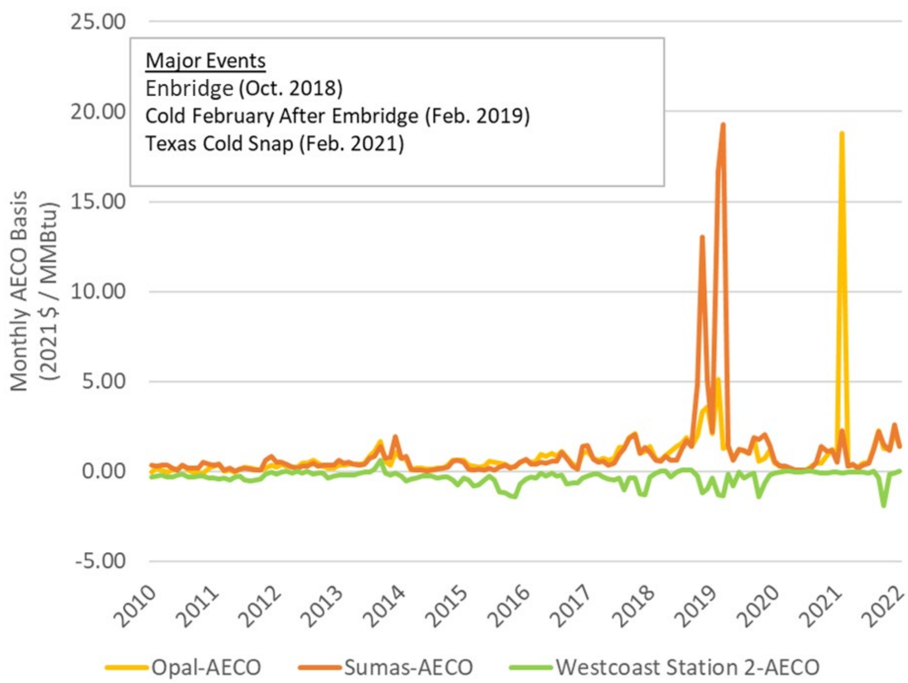
As seen by historical data in Figure 2.8, Figure 2.10, and Figure 2.11, gas prices can be quite volatile. NW Natural has the resources, such as our Mist storage facility, and gas hedging programs that limits rate payer's exposure to short-term price volatile. However, gas prices over the long-term are also uncertain and this uncertainty increases further out into the future (see Figure 2.11). NW Natural

[25] Source: Platts Gas Daily, "Gas demand from US power generators continues at record pace in July", July 11, 2022
[26] Source: IHS Markit, North American Power Market Outlook, July 14, 2022
[27] Source: IHS Markit, North American Natural Gas Short-Term Outlook, June 2022
[28] Source: EIA, Short Term Energy Outlook, July 12, 2022
[29] Source: Platts Gas Daily, "West Canada spot gas prices plummet as production soars to 16-year highs", July 11, 2022

conducts a Monte Carlo simulation of natural gas prices using historical data in combination with the long-term natural gas prices forecast from a third-party consultant (IHS) to simulate natural gas prices. This simulation provides insight into the range of potential short-term and long-term gas prices.[30]

Price simulation for each of the four basins in which NW Natural purchases gas is used in the risk analysis for the IRP (discussed in Chapter 7). Each simulation uses historical annual and monthly prices at each hub (AECO, Opal, Sumas, and Station 2) from 2010 through 2022 to capture cross hub correlation, incorporating potential price spikes at Sumas and Opal, as were recently seen at those locations. Figure 2.12 shows historical price spreads between AECO and the three other gas hubs. This graph demonstrates how long stable periods of gas price spreads can have sudden volatility, primarily due to weather and upstream pipeline capacity constraints.

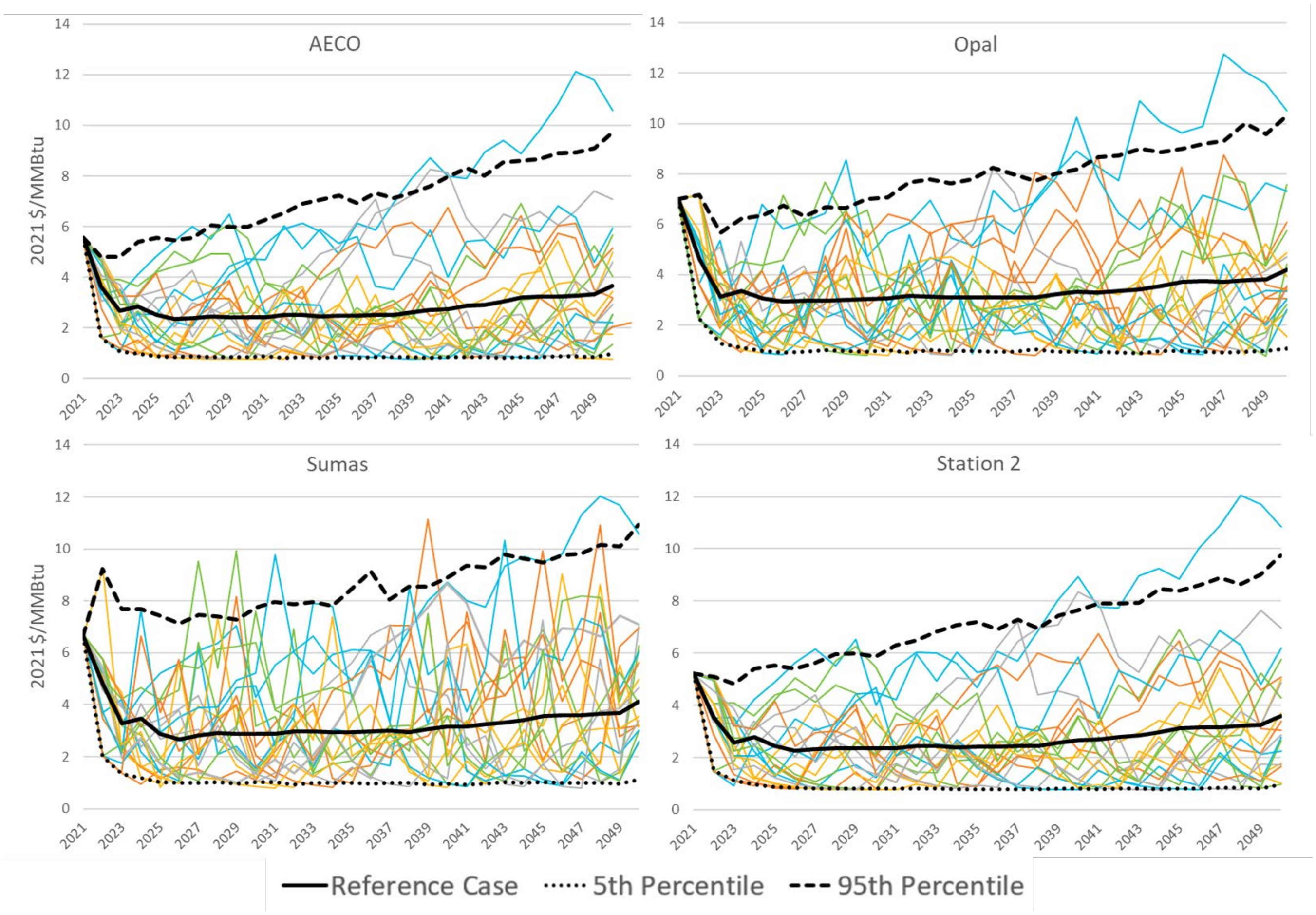
Figure 2.12: Gas Price Basis to AECO



The IRP refers to the gas price forecast from our third-party consultant as the reference case price forecast. Figure 2.13 shows annual average gas price forecasts for each hub along with the 5th percentile, 95th percentile, and a select number of individual simulations.

[30] See Appendix F for more technical details on the gas price simulation.

Figure 2.13: Gas Price Simulations – Annual Averages



2.4 RNG and Hydrogen Markets[31]

The renewable natural gas (RNG) market in the United States has matured significantly over the last several years. Whereas in previous years, most of the financing of new RNG projects came from private equity, this year saw substantial development and acquisition activities from large established players in the oil and natural gas and asset management space, such as Kinder Morgan and BlackRock. As can be seen in Figure 2.14, this year the RNG industry reached the milestone of over 250 operational projects in the U.S. and Canada,[32] up from 100 projects just three years ago in 2019.[33]

[31] Please see Chapter Six for additional information on both RNG and Hydrogen
[32] https://www.rngcoalition.com/media-room
[33] https://www.rngcoalition.com/renewable-natural-gas-market-surpasses-100-project-pinnacle-in-north-america

Figure 2.14: RNG Projects

Source: RNG Coalition. https://www.rngcoalition.com/infographic

The key markets that have historically driven RNG project development are transportation fuel-driven, such as the federal United States Environmental Protection Agency's Renewable Fuel Standard and the California Low Carbon Fuel Standard and Oregon Clean Fuels Program. The value of certain RNG that can qualify for the generation of credits under the federal program has been hovering around \$35/MMBtu, and the value for certain RNG that is selling into the Oregon Clean Fuels Program has been \$50/MMBtu and up, depending on the resource. These revenue opportunities have driven the strong growth in project development and have helped to grow a more established RNG industry. An increasing number of engineering and construction firms now have RNG experience, and NW Natural has seen a growing number of traditional energy project engineering and construction firms building out dedicated RNG teams. This year NW Natural issued an RFP for engineering firms to provide services as "owners engineers" for future RNG projects and received six responses from firms with significant RNG experience and expertise.

To maintain its awareness of current market dynamics and identify new resource opportunities, NW Natural issues annual RFPs for RNG resources. Our 2022 RFP process is currently ongoing, but we received 20 individual bids from RNG developers and brokers and are currently reviewing the bids. There continues to be a strong response to our annual RFPs and a clear interest in selling RNG into markets such as gas utilities that can offer revenue opportunities separate and distinct from the transportation fuel credit markets. Those transportation fuel credit markets, while lucrative, are also highly volatile, and very hard to forecast or hedge against. Utilities, then, represent a steady and reliable source of revenue for RNG projects, and revenue that can help project developers secure project-level financing.

Hydrogen markets continue to be based on the lowest-cost available feedstocks and direct on-site use of the commodity for processes such as liquid fuels refining and fertilizer production. There is minimal large-scale use of non-fossil sources due to costs and limited carbon policies incentivizing lower-carbon sources. For off-site hydrogen use, costs are higher due to liquifying and truck transportation costs.

That said, there are signs the hydrogen market is changing. NW Natural has received responses in its annual RNG RFP for hydrogen at competitive prices, even lower than many RNG sources. Hydrogen developers are finding sources of low-cost electricity in regions outside of Oregon to use for electrolytic hydrogen production. Direct injection of hydrogen into interstate pipelines has yet to become widespread; developers are therefore exploring methanation to produce synthetic methane still at competitive prices. Transmission system hydrogen blending is predicted to become available in the future, at which time these methanation plants can be re-purposed to produce hydrogen at lower production costs.

NW Natural and many other gas utilities are predicting increased hydrogen production in their regions and are preparing for wide-scale hydrogen blending. Hydrogen developers have expressed interest in developing projects in our region and have requested information about how and where they can blend. By preparing for hydrogen blending, NW Natural is positioning itself to accept large volumes of clean hydrogen to reduce the carbon intensity of its energy and potentially enable other segments to decarbonize, such as heavy-duty transport, aviation, and maritime shipping. Economies of scale generated through large hydrogen production projects for utility use can decrease the costs of hydrogen for these other industries.

2.5 Efficient End Use Equipment

To accelerate the development and market adoption of efficient natural gas products, practices, and services, NW Natural partners with the Energy Trust of Oregon and natural gas utilities in Oregon and Washington through the Northwest Energy Efficiency Alliance (NEEA) to create a long-term market transformation strategy to ultimately increase consumer choices for the efficient use of natural gas in the Northwest.

There are three initiatives currently in NEEA's portfolio representing a technical savings potential of over 360 million annual therms in the Northwest. The specific technologies and their associated anticipated savings are outlined below.

2.5.1 Efficient Gas Water Heaters

The Efficient Gas Water Heater program seeks to transform the residential gas water heating market, making gas-fired heat pump water heaters the standard in gas water heating appliances. These units use half the energy of today's standard tanked gas water heaters and therefore represent tremendous savings opportunity. NEEA's 2020-2024 Business Plan[34] indicates a significant market for this product in

[34] NEEA's 2020-2024 Business Plan can be found at: NEEA-2020-2024-Strategic-and-Business-Plans.pdf

the Northwest (1.7 million customers) and a high cumulative savings potential (over 200 million annual therms). NEEA is working to achieve this goal through exploring opportunities to accelerate adoption of currently available efficient products while driving manufacturers to develop and commercialize heat pump water heater technology, and ultimately influencing federal manufacturing standards for natural gas water heaters. Broad commercialization of heat pump water heaters is estimated by 2025.

2.5.2 Efficient Rooftop Units

Rooftop units (RTUs) are heating, and air conditioning appliances fueled by natural gas and are prevalent in low rise commercial buildings in the Northwest. RTUs are often purchased as a like-for-like replacement based on cost and availability and, therefore, strategic efficiency improvements may achieve savings without onerous customer adaptation.

NEEA identified best practices for effectively adopting RTU's with more efficient furnace components. Through additional modeling in 2020, NEEA staff identified several other, commercially available efficiency measures beyond the furnace (heating component of the RTU system) that could provide significant whole system efficiency gains and are not currently valued by existing metrics or widely used by manufacturers.

Current efficiency metrics and specifications focus only on some of the energy used by RTUs; for example, TE (thermal efficiency that measures a gas furnace's efficiency in converting fuel to energy) only accounts for the efficiency of the burner in the gas furnace (which is only one component of the RTU), and does not consider the efficiency of controls, insulation, damper leakage, and performance in different climates. To meet the need for a more comprehensive view of efficiency, updated metrics and specifications for RTUs are needed. To this end, NEEA is developing and promoting a new efficient Gas RTU national specification, comprehensive test procedure and associated Qualified Products List (QPL) that recognizes the efficiency improvements provided by these additional RTU characteristics that voluntary programs can reference and will provide modes to value higher system efficiency in the market. Ultimately, the program aims to lock in this efficiency shift through state codes and Federal Standards to represent a 10% efficiency gain above 2020 standards. This effort has the potential to save over 80 million annual therms in the Northwest.

2.5.3 High-Performance Windows

New technology advancements in ultra-thin glass production and low-conductivity gases that are inserted in between the panes of glass, have created the opportunity for a new caliber of high-performance windows. Designed to be the same width and virtually the same weight as existing double-glazed windows, new triple-paned windows offer a sleek and non-invasive retrofit solution for existing homes with poor-performing windows. They can also help builders in the new construction market reach above-code program targets more easily than other options. NEEA's High-Performance Windows program will focus on stimulating national builder and consumer demand, influencing the ENERGY STAR® specification to reach higher performance levels, and including high-performance windows in building codes. The efficiency of windows is measured in U-Values, the lower the U-Value number, the better the thermal performance of the window.[35] Today ENERGY STAR® rated windows for the northern climate zone have a U-Value of 0.27; the long-term goal of this program is for windows with a 0.20 U-Value, or less, to reach over 50% share of sales in the Northwest which will benefit both natural gas- and electrically-heated homes and have the potential to save over 80 million annual therms in the Northwest.

2.5.4 Other Portfolio Activities

NEEA also recognizes the necessity of other activities to advance the portfolio, such as scanning for new technologies and codes and standards work, the activities for which are closely coordinated with the strategies and activities of the alliance's Market Transformation programs. For additional detail, please refer to NEEA's 2020-2024 Business Plan.[36]

2.6 Environmental Policy- Overview

Both Oregon and Washington have adopted climate policies that call for transformative change in energy systems. While state policy is driving much of the change, federal and local policies continue to influence NW Natural investments. The emission reduction targets in both states are aggressive but the policy structures are quite different. Most notably options for compliance and compliance periods in state carbon goals are not the same across both states. This requires greater differentiation as the company works to decarbonize the system at large and to comply with the laws in both states. Each law is detailed more completely in Sections 2.6.2 and 2.6.7.

In addition to the transformative climate policy that sets carbon emission reduction goals, the environmental policy landscape in each state includes additional important elements including such factors as policy movement in building codes and renewable energy procurement.

2.6.1 Environmental Policy – Federal[37]

At the federal level, greenhouse gas emissions from the natural gas supply chain continue to be a focus of the Environmental Protection Agency (EPA) agenda. Under 40 CFR Part 98, the Greenhouse Gas Reporting Rule, NW Natural reports to EPA the emissions from the use of our product by our customers and the fugitive emissions from our system. Emissions are reported for operations in both Oregon and Washington. At this time, there is not a federal carbon market or cap on emissions. NW Natural emissions are limited by policy at the state level.

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[35] The typical U-Values on windows is **a measurement of heat loss and the rate at which it is lost**. U-Values indicate the overall performance in retaining heat and preventing it from escaping to the outside. U-Values are measure in Watts per square meter Kelvin, or W/m2 K.

[36] https://neea.org/img/documents/NEEA-2020-2024-Strategic-and-Business-Plans.pdf

[37] At the time of this writing, the Inflation Reduction Act was recently passed. Due to the timing of its passage, NW Natural was not able to include it in this section but as the environmental policy space is very dynamic on many levels, we will continue to monitor environmental policy especially as it applies to our action plan.

To spur innovation in alternative fuels there is ongoing work at the federal level for financial incentives for the development of hydrogen and renewable natural gas (RNG). Much like incentives that were provided to alternative electricity generation projects, hydrogen and RNG projects would benefit greatly from federal investments as these markets develop. One example of such investments is the Regional Clean Hydrogen Hub program administered by the US Department of Energy (US DOE). As part of the 2021 Bipartisan Infrastructure Law, $8,000,000,000 was allocated to the US DOE to support the development of at least 4 regional clean hydrogen hubs to improve clean hydrogen production, processing, delivery, storage, and end use.

2.6.2 Environmental Policy / Codes – OR

Oregon Climate Protection Program (CPP)

On March 10th, 2020, Governor Kate Brown issued Executive Order 20-04 directing state agencies to take actions and regulate greenhouse gas emissions. The Climate Protection Program (CPP) was developed as an outcome of this executive order with Department of Environmental Quality (DEQ) as the administrator and regulator. Following a formal rulemaking process, the program went into effect on January 1, 2022.

The CPP sets a declining limit, or cap, on greenhouse gas emissions from fossil fuels used throughout the state of Oregon, including diesel, gasoline, natural gas, and propane, used in transportation, residential, commercial, and industrial settings (the program is not inclusive of fossil fuel used in electric generation). The CPP also regulates site-specific greenhouse gas emissions at large stationary sources, such as emissions from industrial processes. The program baseline is set at average greenhouse gas emissions from covered entities from years 2017-2019. Reductions from this baseline are set at 50% by 2035 and 90% by 2050.

NW Natural is the entity responsible for decarbonizing all load delivered on the company's system. This includes not only sales customers- those customers for whom the company purchases and delivers the commodity but also transportation schedule customers. Transport schedule customers purchase the commodity they use directly from marketers and suppliers and pay NW Natural for delivery via the distribution system. This customer segment has not historically had rate funded energy efficiency programs.

Covered entities emissions are reported annually through the existing DEQ greenhouse gas reporting program and compliance will be demonstrated by each covered entity at the end of each three-year compliance period. To comply, covered entities like NW Natural can work to reduce usage through efficiency measures, introduce renewable and low carbon alternative fuels, trade for additional compliance instruments with other covered entities, or purchase a limited amount of Community Climate Investments (CCI).

CCIs are a unique compliance tool developed by DEQ specifically for the CPP. These tools were designed to focus on funding emission reduction projects benefitting underrepresented communities. In the rulemaking, DEQ established a set dollar amount that a regulated entity must invest in an approved project to earn a credit. The regulated entities using this compliance tool will pay a DEQ designated third party to invest in projects that reduce or remove greenhouse gas emissions in Oregon's communities.

These instruments are not conventional offsets. The program requires all CCI investments be located in Oregon and intends to prioritize investments in environmental justice and other impacted communities. CCIs are not available for purchase in the first year of the CPP as that part of the program and its administration is still under development. CCIs are projected to be available by the first demonstration of compliance. Per the rule making, the price of CCIs will be set at $71/ton for the first compliance period and raise over time. Use of CCIs as a compliance instrument is limited to 10% of the compliance demonstration during the first compliance period (2022-2024), 15% during the second compliance period (2025-2027), and 20% during the subsequent compliance periods (2028-2050).

Senate Bill 98 (SB 98)

NW Natural worked collaboratively with legislators and renewable natural gas (RNG) stakeholders to create SB 98, a groundbreaking bill that was signed into law by Oregon Governor Kate Brown in 2019. In 2020, rulemaking for SB 98 was completed[38] and NW Natural was able to begin procuring RNG for our customers. SB 98 sets the following voluntary targets of 5% RNG for 2020-2024 period, 10% for 2025-2029, 15% by 2030, 20% by 2035, and 30% by 2050. It enables utilities to procure RNG through offtake contracts or invest in and own cleaning and conditioning equipment required to bring raw biogas and landfill gas up to pipeline quality, as well as allowing the facilities to connect to the local distribution system. The rule does contain cost containment measures that only allow for up to 5% of the utility's revenue requirement to be used to cover the incremental cost of investments in RNG infrastructure. The RNG procured under SB 98 may be acquired locally or from sources across the nation.

Status of Oregon Codes

The 2021 Oregon Residential Specialty Code (ORSC) went into effect in April 2021 and is based on the 2018 International Residential Code. The current ORSC is fuel neutral. The next residential code cycle process began in June 2022 and will be effective in the fall of 2023. Review of proposals and the discussion process began in September 2022.

Oregon commercial energy code is currently based on the national ASHRAE 90.1 – 2019 standard. The ASHRAE 90.1 – 2019 standard became effective in 2021 and is fuel neutral. The Oregon Building Codes Division has expressed intent to continue use of the national ASHRAE standard for the next commercial energy code cycle.

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[38] For more information about the rulemaking, please see Oregon PUC docket AR 632

We expect future code cycles to continue to encourage electric heat pump technology adoption with opportunities for hybrid and gas heat pump technologies as well. For example, commercial and industrial gas heat pumps are available now and are comparable in price to their electric counterparts. We fully anticipate residential gas heat pumps, now in late-stage pilots, to be commercially available soon. In turn, we would expect building codes to reflect these high-efficiency options, as they lower emissions while reducing grid reliability risks.

Potential Impacts of Oregon House Bill 3055

Oregon House Bill (HB) 3055, effective September 25, 2021, creates new provisions and amends numerous Oregon Revised Statutes (ORS) including ORS Chapter 757 - Utility Regulation Generally. The majority of HB 3055 focuses on State programs outside of natural gas planning, however, Section 23 creates allowances and pathways for natural gas utilities to recover costs for expenses for investments in infrastructure to support the adoption and service of alternative fuel vehicles if particular conditions are met.[39] Such conditions are as follows:

Allows natural gas utilities to recover costs from investments related to infrastructure to support the adoption and service of alternative fuel vehicles if they can reasonably be expected to:

- *Support vehicles that are powered by renewable natural gas or hydrogen;*
- *Support reductions in transportation sector greenhouse gas emissions over time; and,*
- *Benefit the natural gas utility system; or that revenues from natural gas utilities from fueling alternative forms of transportation vehicles offset utilities' fixed costs that may otherwise be charged to retail natural gas customers*

It is unclear at this point to what extent this legislation will have on the CNG market locally and regionally.

2.6.3 Environmental Policy / Codes – WA

Washington Climate Commitment Act (CCA)

In 2021, the Washington Legislature passed the Climate Commitment Act (or CCA) which establishes a state-wide program to reduce carbon pollution and achieve greenhouse gas limits set in state law (RCW 70A.45.020). The Climate Commitment Act (CCA) caps and sets reduction targets for greenhouse gas emissions from identified emitting sources and industries. The program will start Jan. 1, 2023.

The primary regulator of the CCA is Washington Department of Ecology (Ecology). The agency is in the process, throughout 2022, of developing rules to implement the cap on carbon emissions, including mechanisms for the sale and tracking of tradable emission allowances, along with compliance and accountability measures. Long term, the program is intended to allow for linkage with similar programs in other states/jurisdictions. California has been identified as the most likely first partner.

[39] https://www.oregon.gov/puc/Documents/2021-Legislative-Summary.pdf

The cap-and-invest program works by setting a limit, or 'cap', on greenhouse gas emissions in the state, and then lowering that cap over time to ensure Washington meets the greenhouse gas targets. The program baseline is set at average covered entity greenhouse gas emissions from years 2015-2019. Reductions from this baseline are set at 45% by 2035, 70% reduction by 2050 and 95% by 2050.

When it launches on Jan. 1, 2023, the cap-and-invest program will cover industrial facilities, certain fuel suppliers, in-state electricity generators, electricity importers, and natural gas distributors with annual greenhouse gas emissions above 25,000 metric tons of carbon dioxide equivalent. Over time additional portions of the economy will be moved under the program. On Jan. 1, 2027, the program adds waste-to-energy facilities and on Jan. 1, 2031, the program adds railroad companies.

All participating entities must obtain allowances equal to their covered emissions. The Legislature determined that 'emissions-intensive, trade exposed' entities (EITEs), natural gas utilities, and electric utilities will be issued some allowances at no cost. Businesses can also buy and sell allowances on a secondary market. The total number of allowances issued each year will be equal to the 'emissions cap' and will decrease over time to meet statutory limits.

Most businesses will purchase their allowances at auction (consigned allowances). Ecology will host quarterly emission allowance auctions for covered entities. Funds from the auction of emission allowances are intended to support new investments in climate resiliency programs, lower carbon transportation, and addressing health disparities across the state. Ecology is proposing floor and ceiling prices for allowances to prevent allowance prices from going too high.

A portion of a covered entity's compliance obligation can be covered by credits generated by projects that reduce, remove, or avoid greenhouse gas emissions, called offset projects. Covered entities can meet up to 5% of their obligations with offset credits through 2026 (plus an additional 3% for offset projects on tribal lands), and 4% from 2027 to 2030 (plus an additional 2% for projects on tribal lands). To qualify under the CCA, offset projects must result in greenhouse gas reductions that are real, permanent, quantifiable, verifiable, and enforceable. They must also be in addition to emissions reductions that are required by law.

The cap-and -invest program is still in the final stages of rulemaking and will not be complete before the publication of this plan. As such, it is possible that some details included may shift before implementation.

House Bill 1257 (HB 1257)

House Bill 1257, The Washington Clean Buildings Bill, passed in 2019. HB 1257 adopts energy performance standards, aimed at reducing the energy intensity of Washington's commercial building stock, for commercial buildings exceeding 50,000 square feet. Buildings that fit this category will be required under the law to meet Energy-Use Intensity targets (EUIt) to reduce greenhouse gas emissions.

HB 1257 also includes four provisions that represent meaningful policy changes Washington's natural gas distribution utilities:

1) Requires utilities to identify and acquire all natural gas conservation measures that are available and cost-effective. To achieve this goal, the legislation requires the utilities to establish a conservation acquisition target every two years (also referred to as a biennial energy efficiency plan). To identify all conservation measures the company contracted the consulting firm AEG to conduct a conservation potential assessment (CPA).
2) Requires all Washington natural gas utilities to offer a voluntary renewable natural gas tariff. NW Natural's voluntary renewable natural gas offering was approved by the Washington commission in March of 2022 and went live for customer participation in July of 2022.
3) Permits natural gas utilities to propose a renewable natural gas program for delivery to all retail customers at a total cost of up to 5% of revenue requirement. This is a key provision in this IRP and is used to set targets for RNG acquisition to be delivered to all NW Natural customers in Washington.
4) Requires gas utilities to use the Social Cost of Carbon (SCC), including an assessment of upstream emissions, to make resource planning decisions. NW Natural has included the SCC in its avoided costs in Washington and interprets this provision along with the CCA to mean that NW Natural will use the higher of the SCC or the expected price of allowances in the cap-and-invest system as the price of carbon for the resource planning work in this IRP.

Status of Washington Codes

Washington's new residential code went into effect in February 2021. This change made it more expensive to build a single-family home with gas compared to electric – with the cost deferential varying depending on the home size, equipment choices, and shell measures selected. Despite this change, many homebuilders are opting to build with gas cooking and fireplaces, although some continue to build with gas space heating as well. New residential code development began in May 2022 and includes a prohibition on gas furnaces and water heating for residential new construction but allows for gas heat pumps and hybrid systems. The code draft will not be decided on until after the public comment period, which takes place from September to October 2022. The State Building Codes Council (SBCC) will take action on the new code in November 2022.

Washington commercial code changes were approved in April 2022 by the SBCC (with a final vote scheduled for November 2022) and will prohibit gas space and water heating in new construction and retrofits, with very limited exceptions beginning July 2023.

2.6.4 Environmental Policy – Local

In NW Natural's service territory several local jurisdictions (e.g., cities and counties) have or are in the process of creating Climate Action Plans as a means of addressing and reducing carbon emissions within the jurisdiction. The plans vary across the territory between direct actions that municipal facilities and operations can take to reduce emissions, to plans that encompass the activities of all citizens, institutions, and businesses. Most plans include a focus on a number of activities to reduce the use of fossil fuels in transportation and buildings. Within this spectrum of options, some municipalities consider banning natural gas or in some way limiting the growth of natural gas infrastructure.

2.6.5 Equity and Environmental Justice

In this IRP, there is a greater recognition for the need to hear the voices from communities historically underrepresented in public processes. Environmental justice recognizes that these communities may bear a disproportionate amount of either energy burden and/or negative impacts from climate change and seeks environmental justice through having voices heard, directing benefits to these communities, and/or providing additional supports. These communities typically include but are not limited to communities of color, communities experiencing lower incomes, and tribal communities. As discussed more in Chapter 10, NW Natural has recently created a Community and Equity Advisory Group (CEAG) with the hopes of hearing from more of these voices.

2.6.6 Low Income Needs Assessment

As a result of an all-party settlement agreement in docket UG-200994, NW Natural's 2020 general rate case filed on December 18, 2020, the Company agreed to conduct a Low Income Needs Assessment (LINA). The LINA will consist of a compilation and analysis of relevant data to inform NW Natural's low-income programs in both Oregon and Washington. Some of the broad topics the LINA will be evaluating are eligibility/participation, penetration rate, characteristics of communities, identifying barriers to program participation, and energy burden. The LINA will help NW Natural better understand its customers' needs to design programs that are adapted specifically for the benefit of our customers.

After conducting an RFP, NW Natural contracted with Applied Energy Group (AEG) in February 2022 to estimate the total number of customers eligible to receive energy assistance benefits in its service territory. The Company is aware of the current energy assistance program penetration rate; the goal is to reach those customers that are eligible but have not received energy assistance in the past. AEG conducted a survey of known low-income customers, the results of which will be included in the final report expected in October 2022.

Current NW Natural energy assistance programs consist of the following:

- Oregon Customers - Low Income Home Energy Assistance Program (LIHEAP), Oregon Low-Income Gas Assistance (OLGA), and Gas Assistance Plan (GAP)

- Washington Customers - Low Income Home Energy Assistance Program (LIHEAP), Gas Residential Energy Assistance Tariff (GREAT), and Gas Assistance Plan (GAP)

2.7 Transformative Change for Resource Planning

NW Natural recognizes the climate imperative for society to decarbonize across the energy sector. Equally important is the means to decarbonization by equitably distributing the costs and benefits to utility ratepayers. To this end, NW Natural has taken many actions prior to this IRP to advance the company's decarbonization goals, such as the replacement of all bare steel and cast-iron pipes, developing an opt-in smart energy program, and pushing forward SB 98 legislation to voluntary acquire RNG on the behalf of all sales customers. For several IRPs, NW Natural has evaluated resource decisions inclusive of a forecasted GHG compliance price as an added cost for conventional gas and in the 2018 IRP proposed a concrete, yet flexible, methodology for evaluating renewable energy resources based on the *all-in* costs to serve customers.

The Company's IRP process is accustomed to incorporating new policies and legislation into the long-term planning of resources and their associated risks. At a high-level this IRP uses the same process directed by commission IRP guidelines to incorporate new and known legislation discussed in this chapter into the 2022 IRP. However, what is different is the scale at which, the CPP and the CCA impact resource decisions over the planning horizon relative to previously filed IRPs.

To understand the impact of these transformative policies in the context of the IRP, we develop a reference case that projects forward historical trends of critical drivers that make up total system demand. This includes trends in market share of gas customers in new construction, historical conversion rates, share of the end-use equipment operating in the service territory and the overall efficiency of that equipment found in homes and businesses. Defining a reference case provides a hypothetical construct for the "but for" world where natural gas demand continues in the same trajectory as the past absent decarbonization policies or meaningful changes in end-use equipment efficiency or deployment.[40] Given the planning environment, the likelihood of the reference case occurring is minimal, but establishes a starting point for comparison when forecasting deviations from historical trends into the future.

[40] The reference case focuses on the demand for energy rather than being applied to resource supply assumptions, as we still have the resource optimization model solve the reference case to meet CPP and CCA emissions compliance obligations for comparison to resource optimization for the other scenarios and stochastic futures.

How a reference case is defined may differ across different utilities or from one IRP to the next. For this IRP, we define the reference as the following:

Reference Case – a projection of demand based on historical trends of customer additions and gas usage. The reference case shows what load would look like if all trends embedded in historical data continued over the remainder of the planning horizon to 2050. The reference case is not a base case or preferred portfolio, it is a tool used to show how the scenarios being modeled in the IRP differ from the prior "business-as-usual" state.

In addition to the Reference Case, the IRP conducts several "what-if" scenarios where a few key demand and supply inputs are explicitly modified in-contrast to the Reference Case. The results from these scenarios provide insights to the resource planning impacts, risks, and rate implications from changes specific input assumptions.[41] Separate from the scenario work, the IRP process also employs stochastic simulations, which randomly varies numerous key inputs that have a high level of uncertainty over the planning horizon (such as gas prices). This stochastic process simulates 500 different potential futures for the resources optimization software to solve for the optimal resource portfolio for each of the 500 simulations.

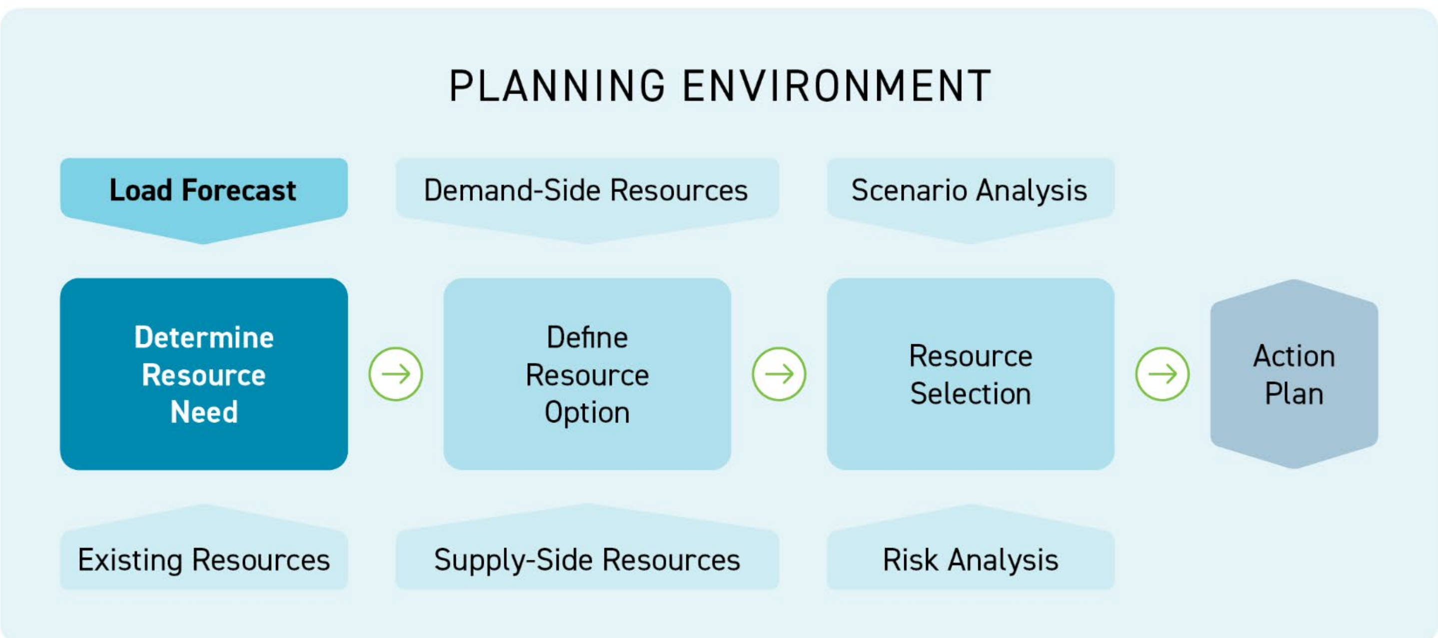
Unlike previous IRPs, this IRP does not define or select any single scenario or set of outcomes as a base case. Typically, a base case consists of a set of assumptions and outcomes, which given the knowledge at a moment in time, represent the Company's best expectations of the future. With these transformative policies, the resources need, and the cost and availability of demand-side and supply-side resources required to meet those needs is very uncertain. Therefore, this IRP does not present a base case, but instead outlines a wide range of potential outcomes through scenario and simulation work. Using this work, we develop an action plan that is robust to the uncertain future.

Per the above, with feedback from stakeholders NW Natural defined 9 scenarios to better understand the impact of changing key assumptions in the context of complying with transformation climate policies. The goal of scenario development is not to predict the future, and it is important not to vary too many variables when comparing one scenario to another, or the primary driver of differing results between scenarios may be hard to untangle. The specific assumptions of each of the scenarios is discussed in more detail throughout this IRP and the key inputs and results by scenario are detailed in Chapter 7.

[41] See Table 7.3: 2022 IRP Scenarios in Chapter 7 for details on supply and demand input assumptions for scenarios.

The first step in determining resource needs is projecting the energy needs of our customers. Chapter 3 describes our load forecasting techniques and shows load projections under a wide range of circumstances. These load forecasts are then used to define the amount of greenhouse gas emissions reduction needed to comply with environmental regulations.

3 | Resource Needs



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This chapter examines the future resource requirements for NW Natural's system. This includes resources needed for capacity, energy, and emissions compliance. Establishing resource need begins with the load (i.e., demand) forecast, which is the focus of this Chapter. The resources needed are ultimately determined by demand specific type of customer. Table 3.1 lays out how system resources are planned to meet capacity, energy, and emissions compliance needs by customer type.

Table 3.1: System Resource Planning by Customer Type

	System Resource Planning		
Customer Type	**Design Winter Weather Energy Requirements**	**Peak Day Capacity Requirements**	**Expected Weather Emissions Compliance**
Firm Sales	✓	✓	✓
Interruptible Sales	✓		✓
Firm Transport			✓
Interruptible Transport			✓

3.1 Overview

Given the planning environment as outlined in the previous chapter, this IRP develops a range of load forecasts over a 28-year planning horizon from 2022 to 2050. The resulting demand and emissions reduction requirements from these load forecasts determine the need for *gas supply and compliance resources*, which include options for both demand-side and supply-side resources and are discussed in detail in the following chapters). Developing a range of load forecasts and understanding the potential uncertainty of the load is a critical first step to determining the resource need.

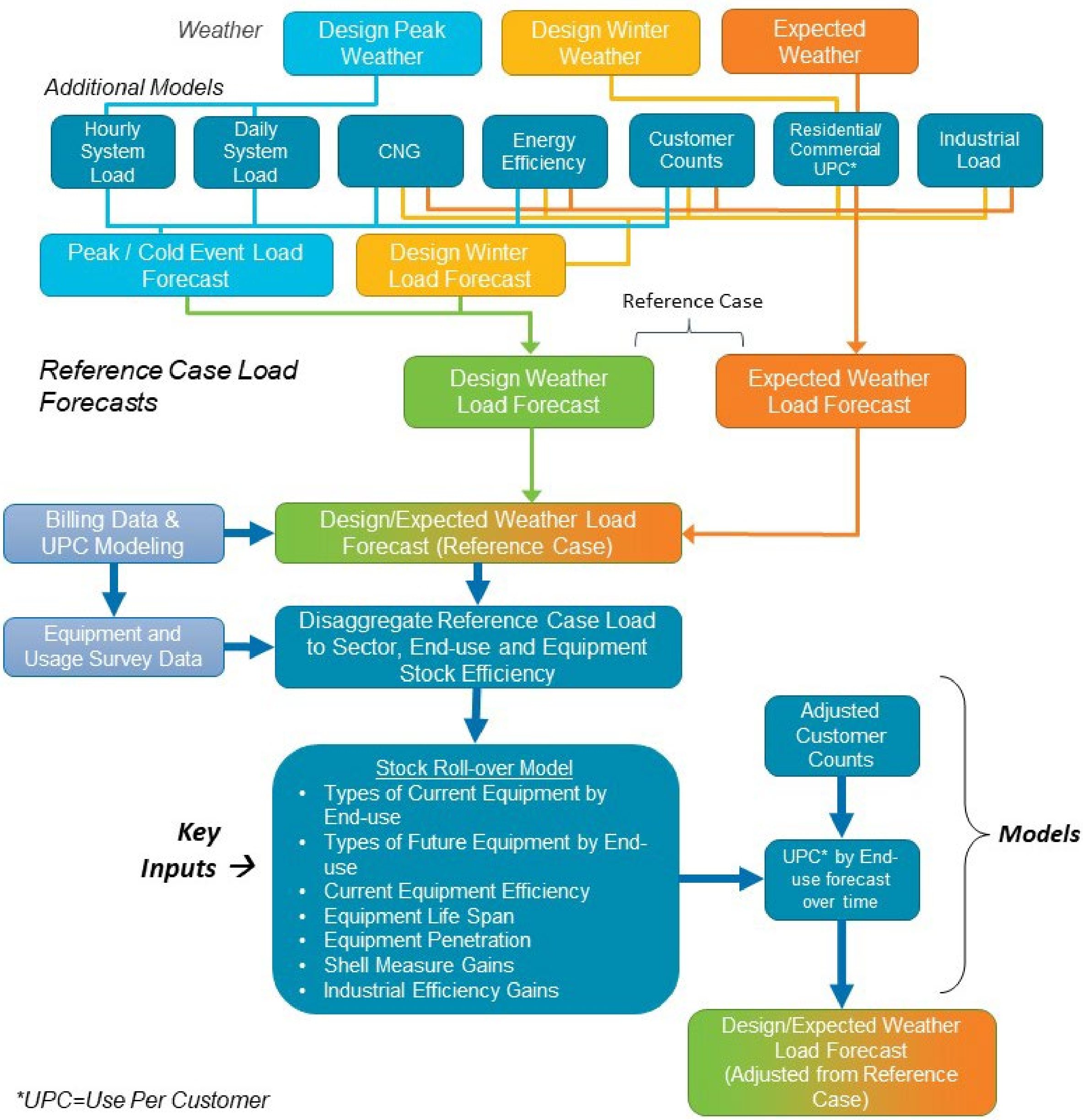
NW Natural's load forecasts are compiled from several bottom-up modeling components including customer count forecast, use per customer modeling, industrial load forecast, and energy efficiency projections, and are combined with a top-down daily/hourly system load modeling approach. Each of these components of the load forecast is done at a selected granularity of time, geography, and customer type and allocated to lower levels where necessary. This component-by-component approach to load forecasting provides a deep understanding of the demand drivers, while balancing model complexity with accuracy and precision.

NW Natural's load forecasts start with historical data, input from subject matter experts (SME), and econometric models to project historical trends into the future. The combination of these historical trend models builds a *reference case* load forecast, which serves as a starting point for developing a range of load forecasts. The reference case represents a business-as-usual perspective, where the future looks like the past. Given the changing policy landscape, the imperative to address climate change, and the company's own carbon commitment goals, load forecasts are likely to deviate from these historical trends. To adequately model changes to these historical trends, NW Natural implements an end-use load forecasting model using the reference case as an anchoring point to adjust for changing expectations. This IRP's scenarios and stochastic forecasts all require the reference case as a starting point.

NW Natural first implemented end-use load forecasting in the 2018 IRP to analyze several scenarios. This IRP expands the use of the end-use load forecasting model to all scenarios (to be discussed in more detail later in this chapter) in combination with Monte Carlo simulations to create a range of potential load forecasts. Figure 3.1 illustrates a high-level flow chart for the various models needed to develop the reference case for a given weather pattern and how it then feeds into the end-use load forecasting model.[42] The rest of this chapter is arranged by following this diagram through the different components of the load forecasting model.

[42] The color patterns correspond to the type of weather being used in the forecast. Light blue is design peak weather (i.e., design cold event, design day or design hours), yellow is design winter weather (November-April), and orange is expected weather. The design weather load forecast is green as it combines both the peak design weather and the design winter weather. Dark blue boxes are various models or combination of models.

Figure 3.1: Load Forecast Model Flow Diagram



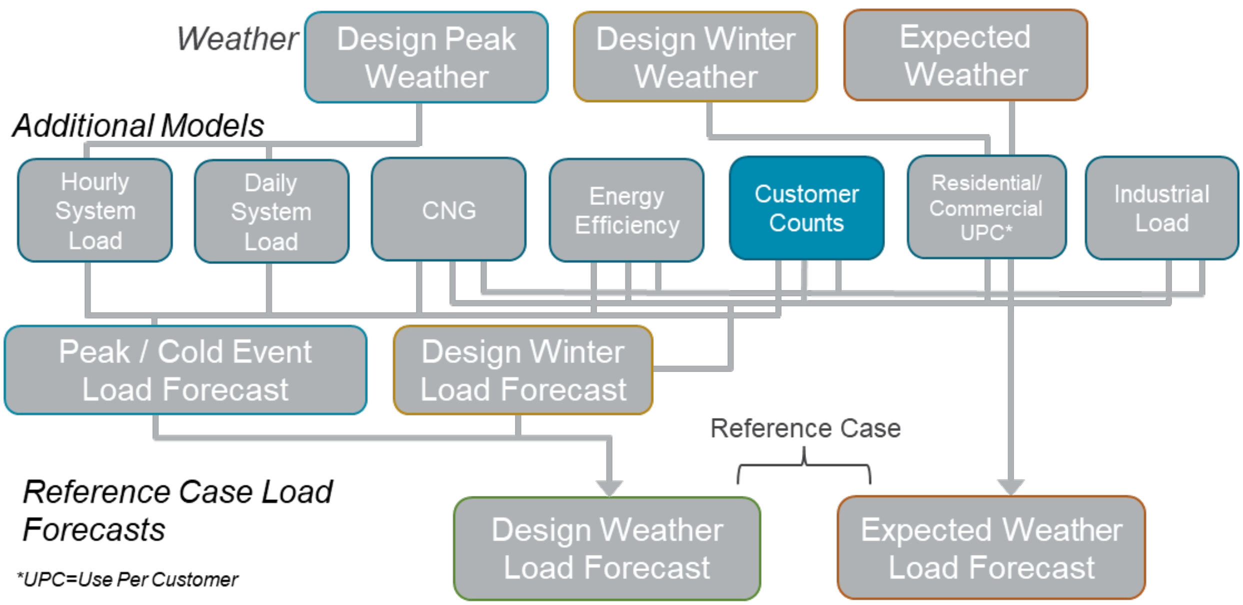
3.2 Reference Case Forecasts

The reference case forecasts rely on historical data to project forward historical trends. This means using statistical regression models and experience from internal subject matter experts to develop the reference case forecasts that enables the application of the stock roll-over model.

3.2.1 Customer Forecast – Reference Case

NW Natural serves a wide variety of homes and businesses where multiple people typically live in a single home and hundreds of consumers may patron a single business. As a common practice, the IRP defines a single customer as a natural gas meter in service. The customer count (i.e., meter count) forecast for residential and commercial customers is a critical input of the load forecast models (see Figure 3.2).

Figure 3.2: Load Forecast Model Flow Diagram – Customer Counts



NW Natural develops separate customer count forecasts for residential customers and commercial customers with four and three sub-classes, respectively. Each sub-class is allocated across ten load centers, which comprise NW Natural's service territory (see Table 3.2). In total, 70 separate customer count series are generated from the sub-class and load center combination. The customer count forecast is developed at this granular level as customer usage profiles are distinctly different across both sub-class and location (e.g., gas usage for the average residential house on the Pacific coast is very different than the average residential home in Portland).

Table 3.2: Customer Count Series

Class	Sub-class
Residential	Existing New Construction - Single Family New Construction - Multi Family Conversions
Commercial	Existing New Construction Conversions

X

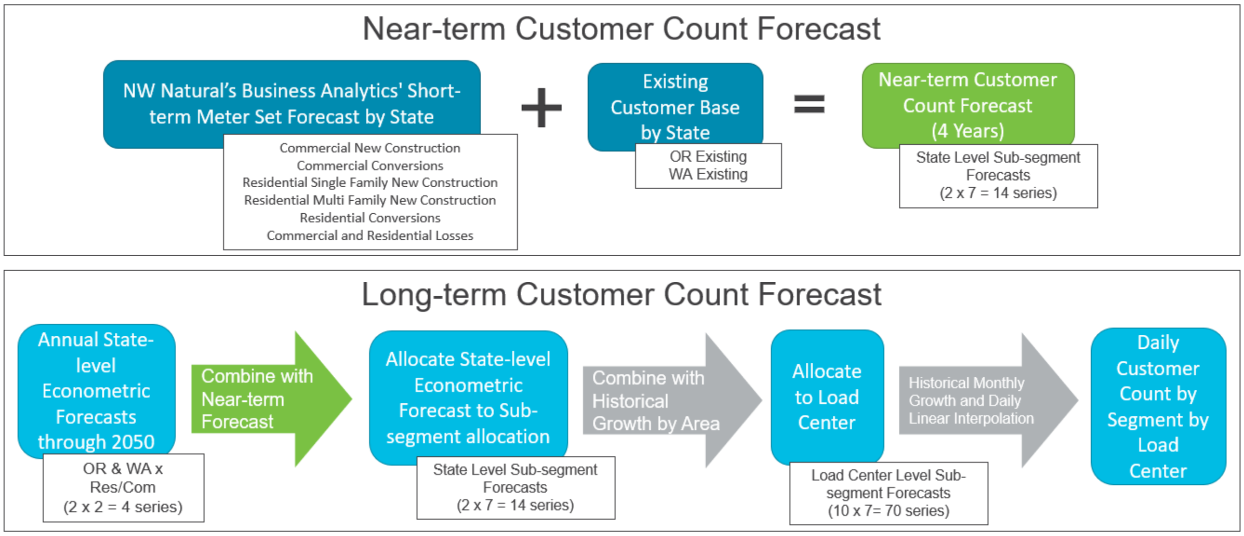
Load Center†
Albany
Astoria
The Dalles OR
The Dalles WA
Coos Bay
Eugene
Lincoln City
Portland
Salem
Vancouver

†The 10 Load centers include a broader area than indicated by its name (e.g., the Vancouver load center includes all of NW Natural's service territory in Clark County).

The IRP customer count forecast for the planning horizon combines a near-term customer count forecast provided by internal subject matter experts (SME), with an econometric model that captures long-term trends. The near-term forecast is projected by state and sub-class, while the econometric model is estimated by class (residential and commercial) and by state. Using historical data and growth rates, these forecasts are combined and allocated to each load center as illustrated in Figure 3.3.[43] Note that the IRP models do not forecast the number of industrial or large commercial customers due to the extreme difference in usage profiles among these customers. Load forecasting for these large usage customers is discussed later in this chapter.

[43] See NW Natural's 2018 IRP, Chapter 3, Section 2.2 in which NW Natural evaluated several alternative bottoms-ups approaches for the customer count forecast including estimating sub-segments (referred to as components in the 2018 IRP) at the load center level. For a variety of reasons, including data availability and predictive power, NW Natural concluded that a top down statewide forecast for residential and commercial customer counts was the appropriate methodology.

Figure 3.3: Customer Count Forecast Process Diagram



Subject Matter Expert Panel

NW Natural's customer forecasts blend two different types of forecasts, that is, econometric method-based long-term trend forecasts as detailed in the following section and near-term forecasts provided by a panel of internal subject matter experts (SME panel). The SME panel is composed of NW Natural employees from multiple departments across the company. The panel meets quarterly to update its previous forecast and prepare a budgetary forecast in the fourth quarter. The panel uses quantitative macroeconomic information such as the number of Oregon housing starts forecasted by Oregon's Office of Economic Analysis (OEA) or state immigration numbers, and qualitative information including up-to-date intel about potential multifamily new construction housing customer additions or information gathered directly from the trade ally community. Using information from departments across the company, the panel develops a near-term annual forecast for residential and commercial customer counts.

Econometric Models

NW Natural used some of the same steps in its approach to developing and evaluating econometric models for customer forecasts in the 2022 IRP as in the 2018 IRP Update #3, 2018 IRP, and 2016 IRP. These include the use of annual data, ensuring stationarity of dependent variables, and evaluating multiple explanatory variables and their transformations.

Annual data is used for two primary reasons. First, a much longer time series is available for customer data at an annual frequency than at a monthly frequency. Second, potential explanatory variables are typically not available at a monthly frequency, but at quarterly or annual frequencies. This is often the case for both historical and forecast values.

NW Natural tested dependent variables for stationarity and differenced where stationarity was not indicated. The Company assessed econometric models with alternative autoregressive integrated moving average (ARIMA) structures for each forecast, generally selecting the structure with the best information criterion value.

NW Natural also evaluated multiple potential explanatory variables for each customer forecast. These included transformations of values, such as differencing, moving averages, leads/lags, and their combinations. The Company eliminated from further consideration explanatory variables with less satisfactory results, such as limited correlation with the dependent variable or an indication of a non-normal distribution of model errors.

Econometric models are developed by class and by state. Table 3.3 shows the explanatory variables and source used in the econometric customer forecasting models. Technical details for the econometric forecast can be found in Appendix B.

Table 3.3: Exogenous Variables used in Econometric Customer Forecast Models

Model	Oregon Models (Source)	Washington Models (Source)
Residential	U.S. Housing Starts (OEA)	U.S. Housing Starts (OEA)
Commercial	Oregon Population (OEA)	Oregon Nonfarm Employment (OEA)

SME and Econometric Blending

Timing requirements of the IRP process are such that NW Natural finalized customer forecasts in the 2022 IRP before 2021 annual data was available. Therefore, the first forecast year is 2021. The Company used the SME panel forecast for years between 2021 and 2023 and as demonstrated in the 2018 IRP the SME panel forecast is arguably more accurate than the econometric forecast in the near term.[44] For year 2024, the Company blends the two types of customer forecasts, with the SME panel forecast and the econometric forecast receiving a one-half weight each. As a standard, the fourth year of the customer count forecast is "blended". For years 2025 forward, the Company added the rate of change from the econometric customer forecast to the value of the customer forecast of the prior year. This merges the state by class econometric model to the state by sub-class SME forecast. Counts are then allocated to load center and daily counts.

Residential and Commercial Customer Count Forecast

As shown in Table 3.2 the customer count forecast models develop 70 separate series by load center and sub-class. Figure 3.4 and Figure 3.5 aggregates those series for the system residential and system commercial counts, respectively. See Appendix B for state specific breakouts.

[44] See NW Natural's 2018 IRP, Chapter 3 pages 3.8-3.10 for a detailed comparison.

Figure 3.4: System Residential Customers – Reference Case

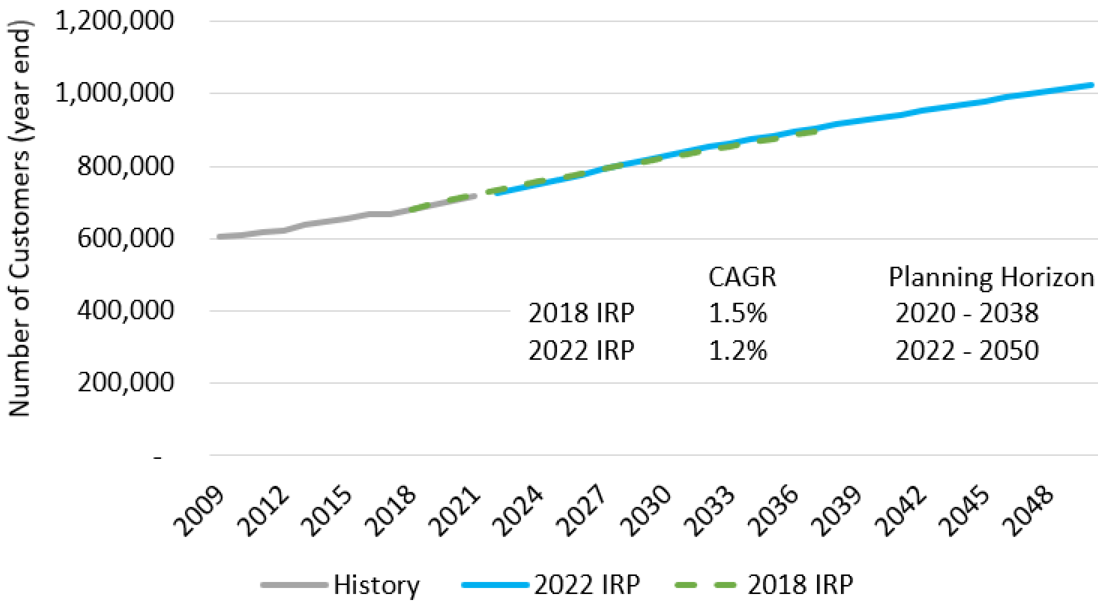
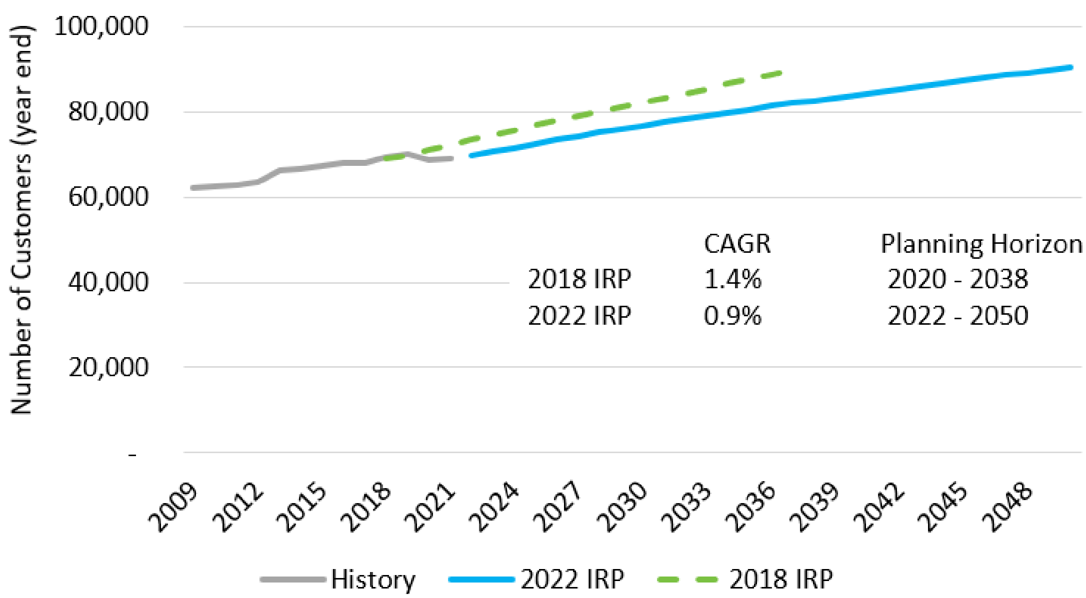


Figure 3.5: System Commercial Customers– Reference Case[45]



[45] Figure 3.5 includes customer counts for large commercial customers on rate schedules 31/32/41/42, but these customer counts are subtracted from the commercial customer count that is used in the use-per-customer model, which estimates small commercial customer usage. This is discussed later in this chapter.

Table 3.4 summarizes the primary similarities and differences between customer forecasts in the 2022 IRP and the 2018 IRP.[46]

Table 3.4: Customer Forecasting Comparison between the 2022 and 2018 IRP

	2022 IRP	2018 IRP Update
Econometric Models	State by Class Oregon Residential Oregon Commercial Washington Residential Washington Commercial	State by Class Oregon Residential Oregon Commercial Washington Residential Washington Commercial
Left-hand side variable	**Right-hand side variable (source)**	
Residential customers (OR)	OR Housing Starts (OEA)	U.S. Housing Starts (OEA)
Residential customers (WA)	U.S. Housing Starts† (OEA)	U.S. Housing Starts (OEA)
Commercial customers (OR)	OR Population‡ (OEA)	OR Population (OEA)
Commercial customers♠ (WA)	OR Nonfarm Employment (OEA)	OR Nonfarm Employment (OEA)
Year of SME panel and econometric forecast blending	Year 4 - 2024	Year 4 - 2020

† Right-hand side variable for WA residential model – US Housing Starts – transformed to log form from level form
‡ Right-hand side variable for OR commercial model – Oregon population – transformed to log form from level form
♠ Autoregressive terms in 2018 WA commercial model no longer statistically significant and were dropped

3.2.2 Climate Change Adjusted Weather Forecasts

Climate change is impacting weather patterns across the globe, including here in the Pacific Northwest. As weather is a primary driver for gas usage and a critical input for forecasting load, the long-term trends in weather are important to consider for NW Natural's long-term resource planning. This section explains how the Company incorporates climate change trends into our load forecast modeling.[47]

[46] These are the same changes made for the 2018 IRP Update #3. There were no changes in methodology between the 2018 IRP Update #3 and the 2022 IRP. Only data was updated.
[47] NW Natural has included climate change models into our long-term load forecasts for several years, but first presented these changes to external stakeholder through the 2018 IRP Update #3.

NW Natural develops weather forecasts, which incorporates data from climate models from the Intergovernmental Panel on Climate Change (IPCC). These climate model predictions are available on a coarse grid of about 300 square kilometers. The coarse grid predictions are further downscaled using a local weather to get weather projections for NW Natural's service territory. The downscaled projections of the IPCC climate models are available through a website maintained by the Lawrence Livermore National Laboratory (LLNL) and are matched to weather stations for each load center.[48] The IPCC publishes numerous models from several different agencies around the world. For a robust outlook of weather trends, the IPCC recommends using an ensemble of climate models. We selected the five climate models to inform the long-term trends in annual HDDs forecasted out to 2050.

IPCC Climate Models
ccsm4.6 cnrm-cm5.1 gfdl-cm3.1 hadgem2-cc.1 miroc5.1

The IRP implements several deterministic and stochastic weather pattern forecasts as inputs into the demand models to establish resource requirements. Table 3.5 describes the three primary deterministic weather patterns.

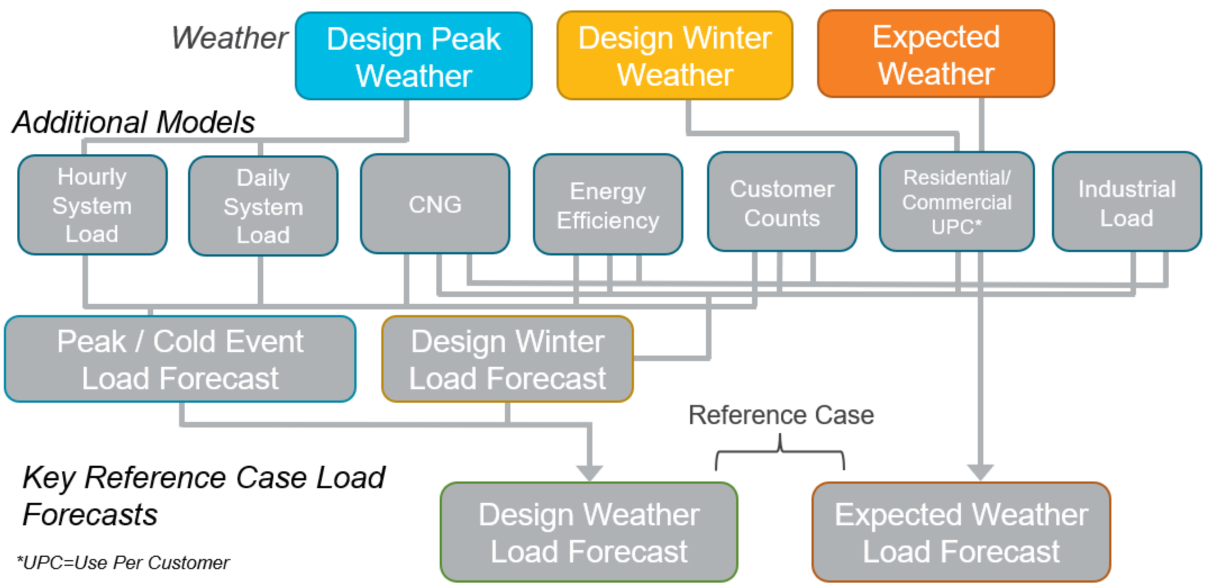
Table 3.5: Planning Standard Descriptions

Weather Pattern	Description	Purpose
Expected Weather	Expected weather is similar to "normal weather" uses in previous IRPs, however; expected weather is now incorporating long-term climate change trends based on cumulative annual HDDs. The expectation into the future is that on average weather would be reflected by expected weather.	Expected weather is the baseline used for emissions compliance planning and resource portfolio evaluation as expected weather will be a primary driver for expected natural gas and compliance costs.
Design Winter Weather	Cold winter weather adjusted from the expected weather based as a 90th percentile severe winter, based on cumulative winter HDDs (November-April).	The design winter weather drives annual energy requirements, ensuring resources are planned adequetly to meet annual energy requirement to sufficiently manage a colder than usual winter.
Design Peak Weather	The design peak day uses historical data to simulate a 1-in-100 year winter event.	Peak day weather drives the system capacity requirement for each forecasted winter in NW Natural's IRP. Peak hour weather drives the distribution capaacity requirement for a specfic area on NW Natural's distribution system.

[48] Downscaling of the IPCC data to NW Natural's service territory if made available by Archive Collaborators (i.e. Bureau of Reclamation, California-Nevada Climate Applications Program, Climate Analytics Group, Cooperative Institute for Research in Environmental Sciences, Lawrence Livermore National Laboratory, National Center for Atmospheric Research, Santa Clara University, Scripps Institution of Oceanography, Southwest Climate Adaptation Science Center, U.S. Army Corps of Engineers, and U.S. Geological Survey). The downscaling tool is free to use and is hosted on a website maintained by Lawrence Livermore National Laboratory (LLNL): https://gdo-dcp.ucllnl.org/downscaled_cmip_projections

Figure 3.6 shows the load forecast flow chart illustrating how different weather inputs are used in demand forecasting models. See Appendix B for technical details on how these weather forecasts are generated.

Figure 3.6: Load Forecast Model Flow Diagram – Weather Patterns



Expected Weather

Since NW Natural's load is primarily driven by heating requirements, the expected weather forecast focuses on the expected level of annual HDDs out to 2050. The expected annual HDDs is based on the average of the annual HDDs from the five selected IPCC climate models for each load center. Intra-year shaping is then applied for each month and then intra-month shaping is applied to each day to generate a daily forecasted temperature. This daily shaping is developed using a representative temperature pattern that is applied to each year in the forecast. In other words, each year in the forecast will have the same shape, but overall temperatures are increasing (i.e., HDDs are decreasing) over the planning horizon. Using a representative weather pattern, creates realistic volatility in daily temperatures, which is important for modeling resource dispatching.

Design Winter Weather

Design winter weather is generated to ensure our resource plan is adequate to serve customers during a colder than normal winter. This is particularly important for storage resource planning, such that the storage facilities maintain a sufficient inventory level to serve customers throughout colder than normal winter. NW Natural uses a 90th percentile design winter planning standard based on cumulative winter (Nov-April) HDDs. The design winter weather is developed as an adjustment to the expected weather forecast for the winter months, thus incorporating climate change trends for those winter months.

Design Peak Weather

Design peak weather includes a five-day cold event where NW Natural's system experiences a peak day on the third day of the five-day cold snap. Temperatures for this design peak weather for each location are based on temperatures from February 3, 1989, where system weighted temperatures fell to 10°F. Note that the peak day sales load forecast is discussed in more detail later in this chapter and is a function of many more drivers than temperature, but the design peak weather describe here is used in combination with the UPC model to allocate system load for the two days prior to the peak, the peak day, and the two days after the peak to each load center. Design peak weather is modeled from February 1st to February 5th and combined with design winter weather to produce the design weather to ensure capacity and energy requirements can be met by NW Natural's resource stack.

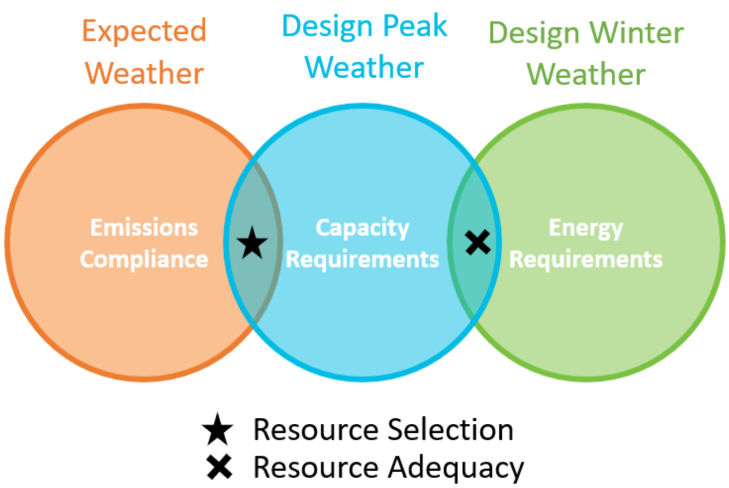
Weather Patterns for Resource Planning

In previous IRPs, NW Natural has used the combination of design winter weather and design peak weather to ensure the selected resource portfolio could meet both capacity requirements and total annual energy requirements. Capacity requirements, specifically the ability to serve customers on a peak day, has been the primary driver for resource selection in previous IRPs. Resource selection for this IRP will need to fulfill an additional emission reduction requirement to comply with the state legislated emissions targets for utilities. Emissions reduction requirements must be based on expected weather. Due to modeling limitations, a single weather pattern, and therefore daily demand profile, must be used per run in the cost minimizing resource selection model.[49]

As emissions compliance and capacity requirements are critical to the long-term resource plan, this IRP uses expected weather with a single design peak day for resource selection. This will ensure that the resource planning optimization model (PLEXOS®) selects a least cost resource portfolio that meets both capacity and emission reduction requirements illustrated by Figure 3.7. The combination of design peak and design winter weather is still used to test the resource adequacy NW Natural's resource stack.

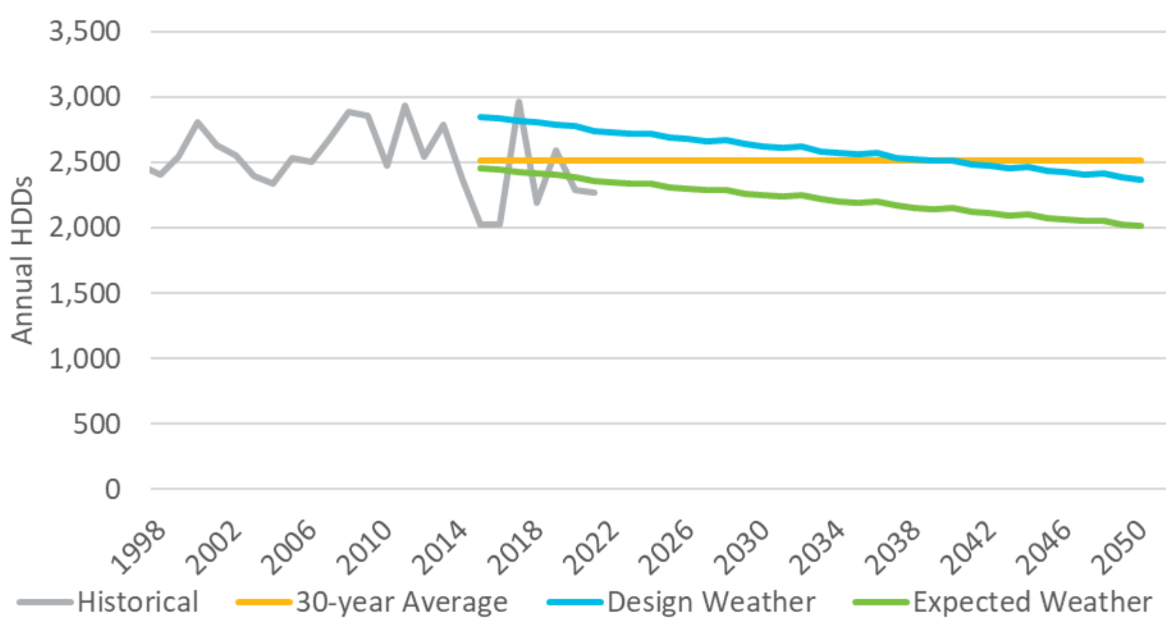
[49] NW Natural generates 500 runs through the Monte Carlo simulation, where weather is a key variable treated as uncertain both year-over-year and within a given forecast year.

Figure 3.7: Weather Patterns for Resource Planning



Embedded in both expected and design weather are the impacts from climate change. The climate change models predict as substantial decrease in annual HDDs over the planning horizon. Figure 3.8 illustrates the annual HDDs for expected weather and design weather for the Portland load center used for this IRP. The 30-year average is simply shown for historical context.

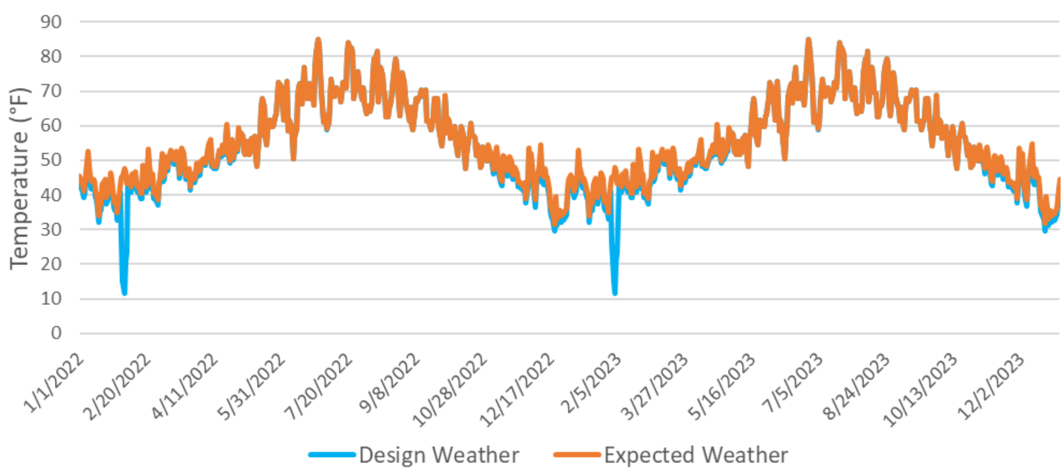
Figure 3.8: Portland Example Annual Expected and Design HDDs



Weather Uncertainty

Thus far we have discussed how specific weather patterns are modeled and implemented for resource planning. For both expected and design weather, the intra-year shape is the same in each forecast year even though cumulative annual HDDs are steadily decreasing over the planning horizon. Figure 3.9 illustrates the intra-year shaping for Portland daily temperatures for both design and expected weather. We use a representative year to get daily temperature volatility within a year; the year-over-year shape is the same.

Figure 3.9: Expected and Design Weather Intra-Year Shaping – Portland Daily Temperatures



The reality is that weather is random, both at a daily level and at an annual level. Some years will be overall colder than expected and have higher cumulative HDDs than expected. It is also possible that the Pacific Northwest experiences consecutive colder years or consecutive warmer years than expected weather. For system resource planning, it is important to understand the bounds of these possibilities, especially now with emissions compliance obligations under the CPP and CCA. Colder years will have higher emissions and warmer years will have lower emissions, but NW Natural's compliance obligation under the CPP is a straight trajectory reduction from the baseline. The CCA has a similar straight-line trajectory for the quantity of assigned allowances to the gas utility. Having a few consecutive cold years will have meaningful consequences for acquiring qualified compliance resources within a compliance period.

The IRP implements a Monte Carlo simulation to understand the potential range of daily, monthly, and annual temperature and HDDs.[50] Relying on both historical data and climate change modeling forecasts from the IPCC, we create a weather simulation for each load center over the planning horizon. This simulation provides different intra-year weather patterns (Figure 3.10) as well as variation in annual cumulative HDDs from one year to the next (Figure 3.11).

[50] See Appendix F for further technical details on the Company's weather simulation.

Figure 3.10: Single Simulation for Three Load Centers

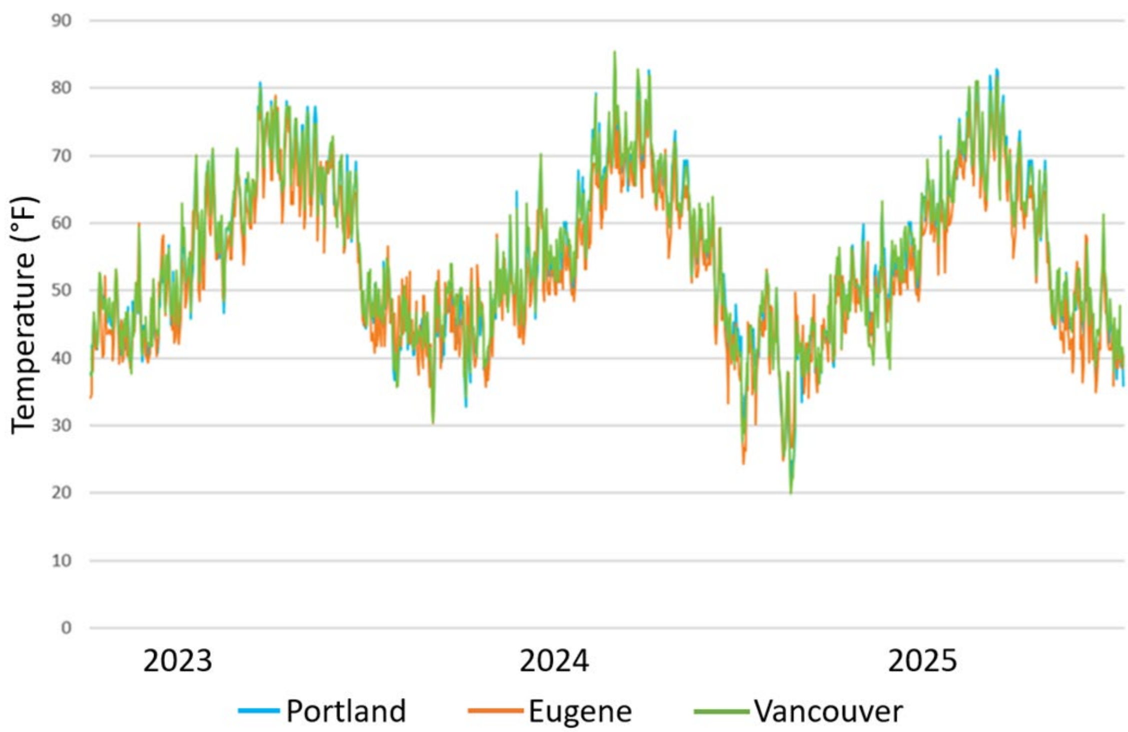
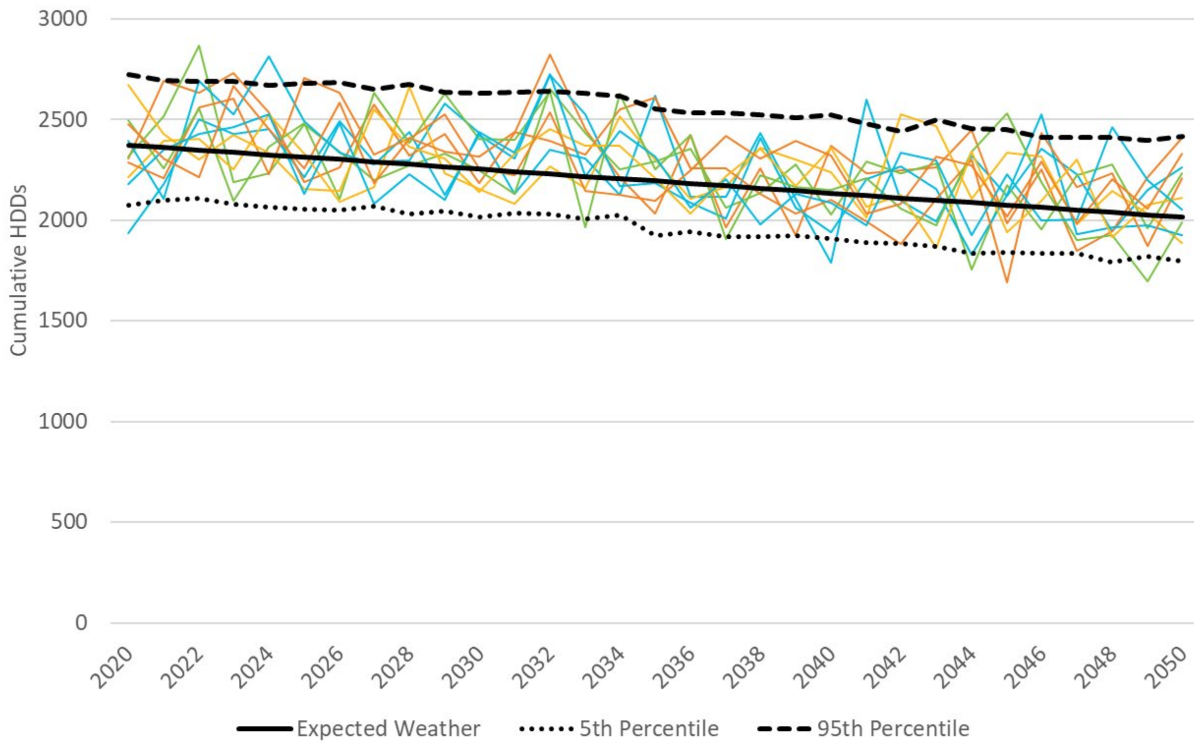


Figure 3.11: Weather Simulation - Cumulative HDDs for Portland (Base 58°F)



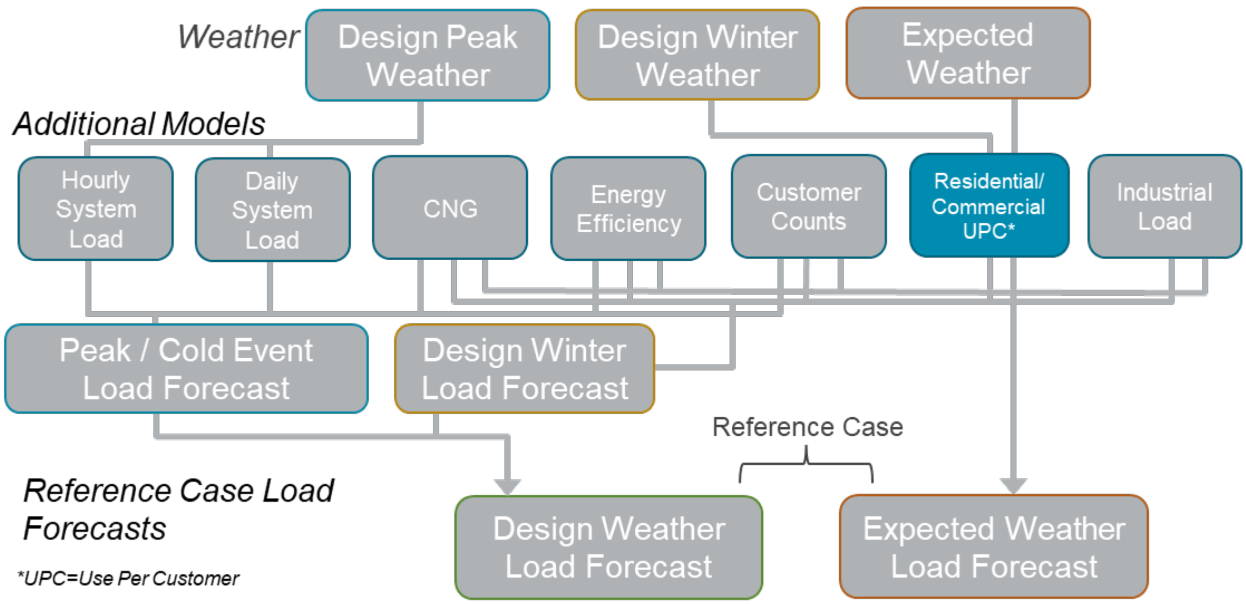
3.2.3 Residential and Small Commercial Use per Customer – Reference Case

The reference case demand for residential and small commercial customers is developed by first modeling daily use per customer (UPC) demand as a function of daily temperatures.[51] UPC models match up historical billing data with historical weather data and are estimated for each sub-class of customer by location. The daily weather patterns then feed into these UPC models (see Figure 3.12) which are then are multiplied by the customer count forecast to create daily residential and commercial load forecasts. Energy efficiency adjustments are made at the state and customer class level to create the reference case demand for residential and small commercial.

[51] Load from large commercial customer on rate schedules 31/32/41/42 and special contracts is estimate along-side the industrial load and is discussed in the industrial load section.

Use per Customer Regression Model

Figure 3.12: Load Forecast Model Flow Diagram – UPC Models



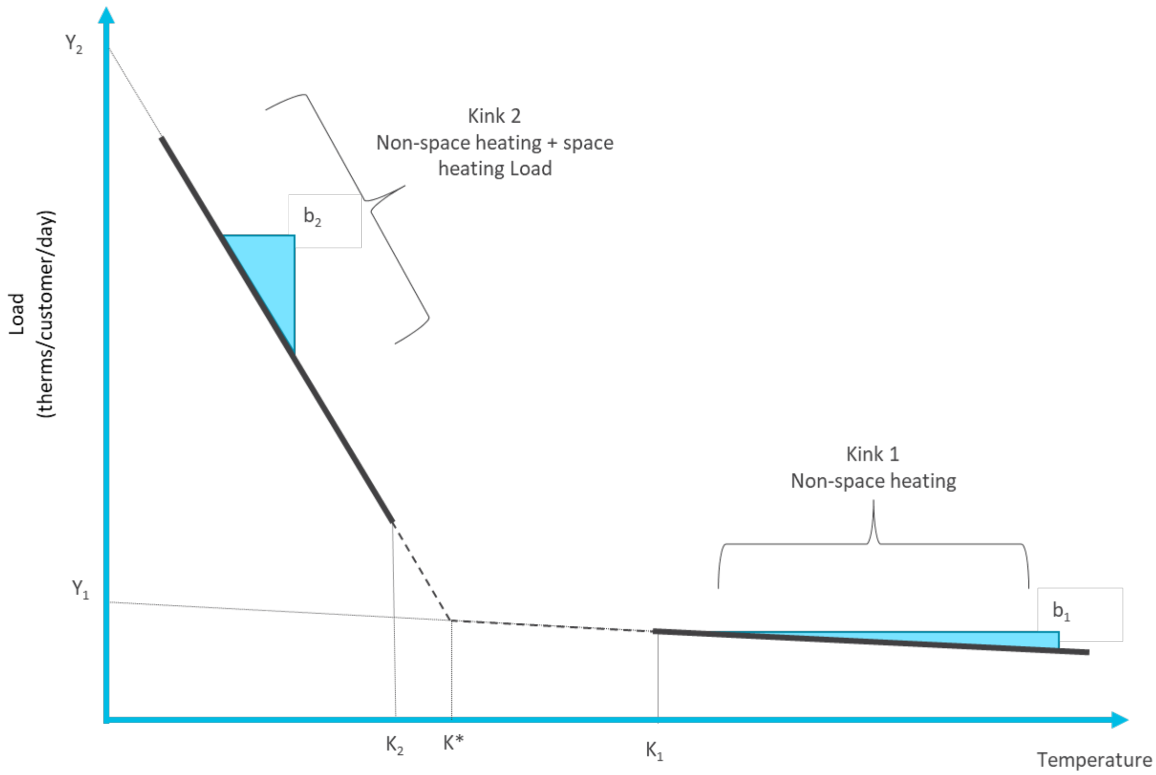
The UPC models estimates a two-segment piece-wise demand function for each customer sub-class and location. Demand functions for existing customers are estimated by load center and demand functions for new construction and conversion customers are estimated by state. Table 3.6 lays out the details of the billing data used in each UPC model.

Table 3.6: UPC Regression Data Details

Sub-class	Bills Used In Regression Model	Geographic Grouping
Residential Existing	All current residential customers	Load Center
Residential Conversion	Residential new construction/conversions since 2018	State
Residential Single-family New Construction		
Residential Multi-family New Construction		
Commercial Existing	All current commercial customers	Load Center
Commercial Conversion	Small commercial new construction/conversions since 2018	State
Commercial New Construction		

The two segments of the piece-wise demand function represent customer demand as 1) non-heating load at warmer temperatures and 2) heating + non-heating load at colder temperatures. A simplified model is illustrated by Figure 3.13.

Figure 3.13: UPC model



The temperature point (K*) for when heating load starts for the average customer varies by location and customer sub-class. K* is calculated based on where the two regression lines intersect.[52] Regression models are used to estimate the parameters b_1, b_2, Y_1, and Y_2 for each of the models outlined by Table 3.2. Given these parameters, use per customer demand as a function of temperature (T) is specified as:

$$\underline{Use\ Per\ Customers\ (UPC)}$$

$$= Y_1 + b_1 * (T) \qquad if\ :\ T \geq K^*$$

$$= Y_2 + b_2 * (T) \qquad if\ :\ T < K^*$$

A table with b_1, b_2, Y_1, Y_2, K_1, K_2, and K* parameters for each model is listed in Appendix B. Figure 3.14 shows the predicted values for four of the residential UPC models as an example.

[52] Due to the nature of the monthly billing data used in the UPC model, data points with temperatures above K_1 are used for kink 1 regressions and data points with temperatures below K_2 are used for kink 2 regressions.

Figure 3.14: UPC Model Predicted Values

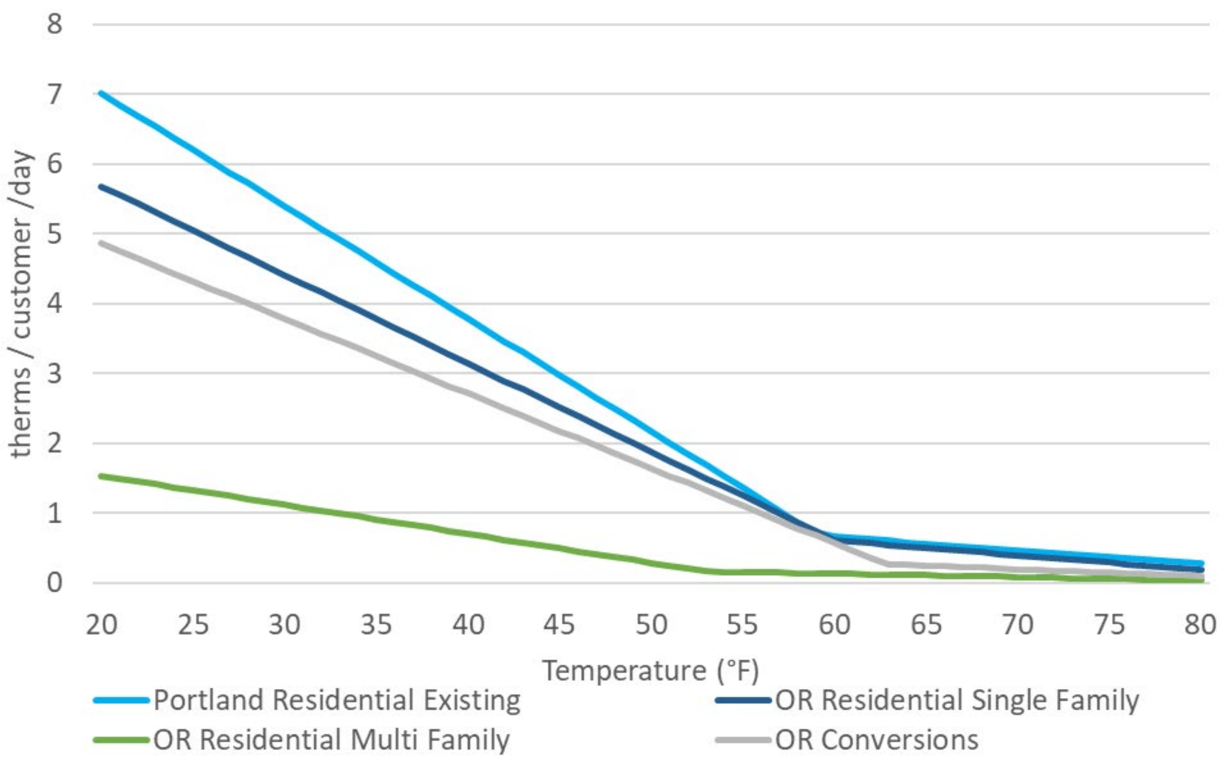


Figure 3.15 and Figure 3.16 show the forecasted first year estimates of usage per customers for residential and commercial customer classes, respectively. While residential existing customer usage has remained almost unchanged over several IRPs, residential conversion, and new construction in the 2022 IRP have seen a reduction of 30% and 41%, respectively, in estimated annual usage compared with the 2016 IRP. In contrast, commercial customer usage is slightly lower (about 9% lower for the commercial conversion customers) between the 2022 and the 2016 IRPs.

Figure 3.15: First Year Residential Annual Usage per Customer

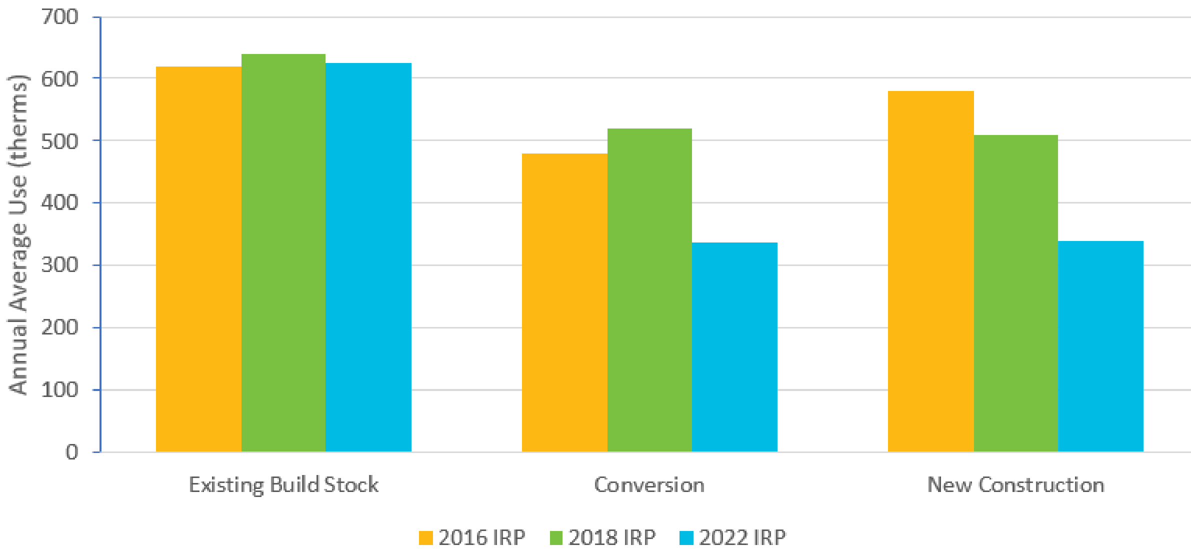
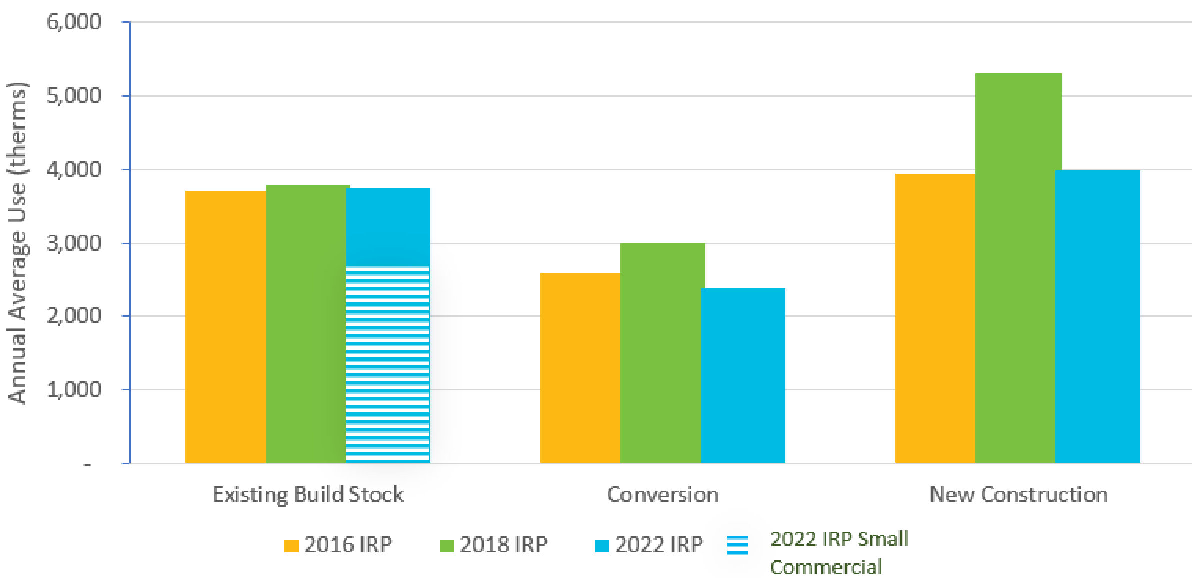


Figure 3.16: First Year Commercial Annual Usage per Customer



By multiplying the customer count forecast by the UPC model conditional on a given weather pattern (i.e., temperature) provides daily load for each sub-class and load center.

Cost-Effective Energy Efficiency

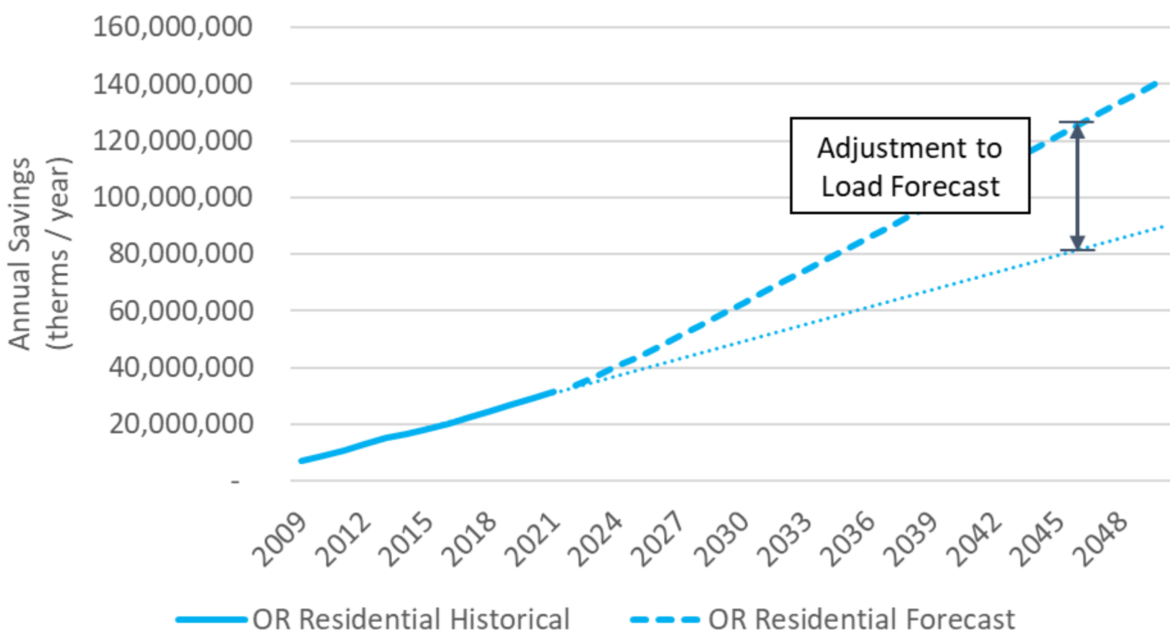
The Energy Trust of Oregon (Energy Trust) currently administers energy efficiency programs for residential, commercial, and industrial sales customers in Oregon and residential and commercial sales customers in Washington. NW Natural is working to establish energy efficiency programs for industrial sales customers in Washington and transportation customers across the system to further the therm savings, and therefore maximize emission reductions from energy efficiency for the whole gas system.

Energy Trust provides NW Natural with a therm savings forecast, known as a resource assessment (RA) or conservation potential assessment (CPA), for the incentive programs currently being offered in Oregon. Additionally, NW Natural hired a third-party consultant, Applied Energy Group (AEG), to conduct a CPA for Washington sales customers. AEG also conducted two high-level CPAs for transport customers in NW Natural's system, one for Oregon and one for Washington. See Chapter 5 for details for these various CPAs.

Customer Type	CPA Developer
Oregon	
Sales	Energy Trust
Residential	
Commercial	
Industrial	
Transport	AEG
Washington	
Sales	AEG
Residential	
Commercial	
Industrial	
Transport	

Historical billing data used in the UPC models will reflect underlining trends in customer usage, but the UPC models by themselves will not reflect forecasted ramping up of incentivized energy efficiency programs. NW Natural uses the CPAs provided by Energy Trust and AEG to adjust output from the UPC models by the difference between the historical energy efficiency trend and the forecast from the CPA for cumulative therm savings. Figure 3.17 illustrates this difference and the adjustment made to the UPC modeled forecast for Oregon residential savings. These adjustments are done by state and customer type. Annual savings predictions are allocated to the day and load center based on load. A similar adjustment is made for design peak day savings to the peak day forecast discussed later in this chapter.

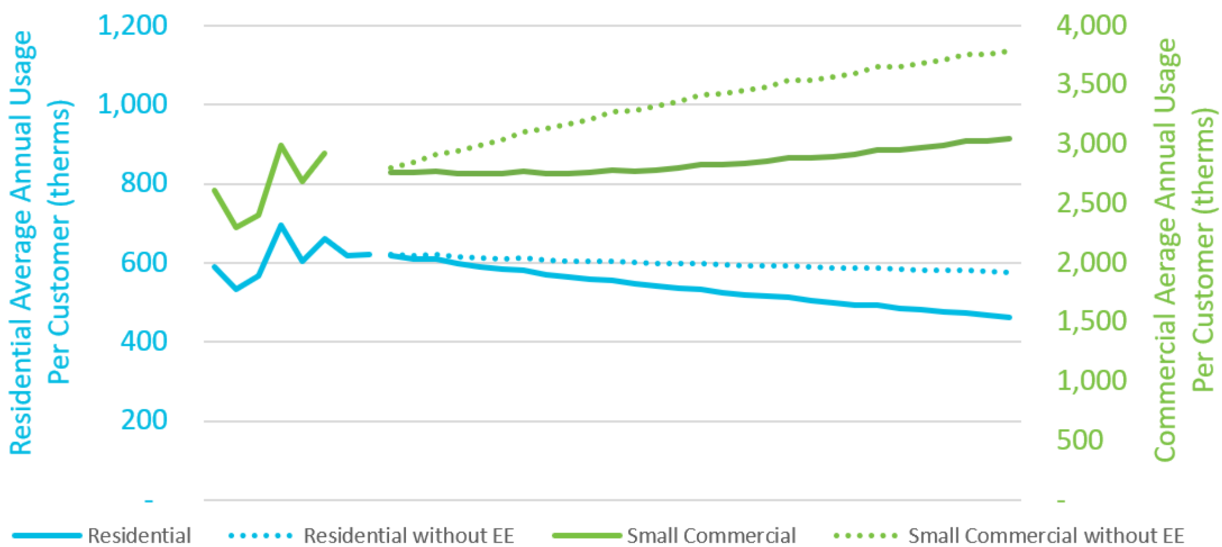
Figure 3.17: OR Residential Cumulative Annual Savings and UPC Adjustment



Residential and Small Commercial Annual Use per Customer and Annual Forecast

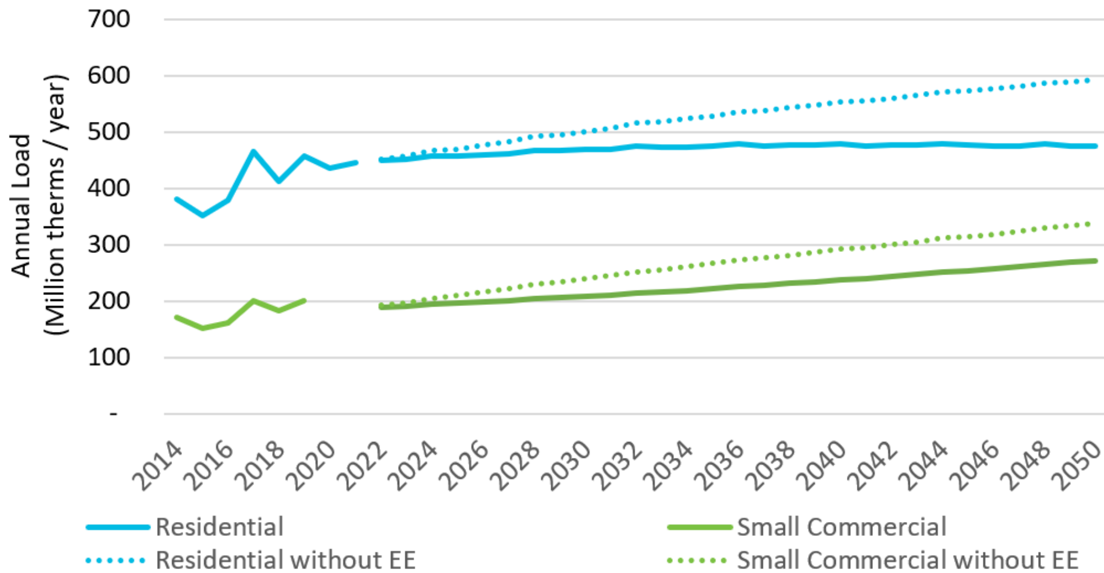
Figure 3.18 shows NW Natural's forecast of average annual use per customer for residential and commercial customers before and after incentivized energy efficiency savings. Residential average annual use per customer for the reference case declines, while commercial average annual use per customer for the reference case increases over the planning horizon. This increase in the reference case commercial UPC is reflective of the new construction commercial customers on average using more gas than existing customers.

Figure 3.18: Trend in Use per Customer With and Without Energy Efficiency – Reference



Multiplying the customer count forecast and the daily use per customer forecast provides a daily residential and small commercial forecast. Aggregating the daily number for each year provides the annual load forecasts for residential and small commercial customers (Figure 3.19). Due to declines in residential UPC and increases in residential customers over the planning horizon, the annual residential reference case demand grows slowly till 2040 before beginning to decline. Small commercial reference case total demand increases throughout the planning horizon driven by increases in commercial customers.

Figure 3.19: Residential and Small Commercial Annual Demand Forecast

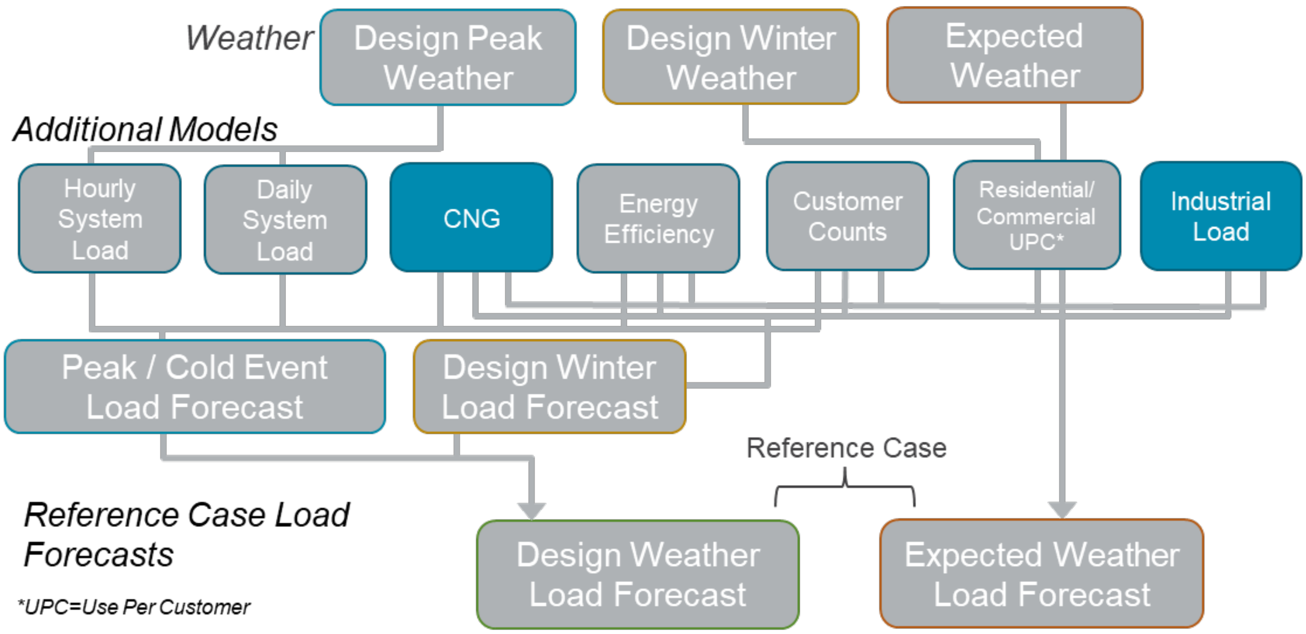


3.2.4 Industrial, Large Commercial and Compressed Natural Gas (CNG) Load Forecast – Reference Case

As noted earlier, NW Natural does not forecast Industrial load by forecasting use per customer and multiplying by forecasted customers due to the extreme differences in usage levels by these customers. Instead, we directly forecast the annual load of all industrial customers and large commercial customers. NW Natural's industrial load can then be allocated into four categories of service: firm sales, firm transportation, interruptible sales, and interruptible transportation.[53] Large commercial sales load is forecasted separately but is include as a part of the industrial load box in the Figure 3.20 flow chart.

[53] There are a few large commercial customers on transportation rate schedules. Load from these customers is included in the industrial load forecast (i.e., not the large commercial sales forecast) and is not separated out from the overall transport load forecast.

Figure 3.20: Load Forecast Model Flow Diagram – Industrial, Large Commercial and CNG Load Forecast



Econometric Forecasts

NW Natural uses methods to develop an econometric forecast of industrial load like the methodology for the long-term econometric models implemented for residential and commercial customer counts, including an ARIMA structure and exogenous variable selection. Forecasting approaches involving separately forecasting loads for each industrial class of service were generally unsuccessful.[54] Therefore, NW Natural forecasts the aggregate industrial load (for all classes of service) and allocates the total to individual classes of service as well as to month and load center. Large commercial sales load is forecasted separately. See Appendix B for technical details related to the econometric models used to forecast industrial load.

SME Panel Forecasts

Similar to customer forecasts, NW Natural also uses an SME panel forecast of industrial load to blend with the econometric forecast discussed above. More specifically, NW Natural uses the SME panel forecast for 2022 and 2023, an equally weighted blend of the two forecasts for 2024, and the econometric forecast for 2025 forward.

Compressed Natural Gas Service

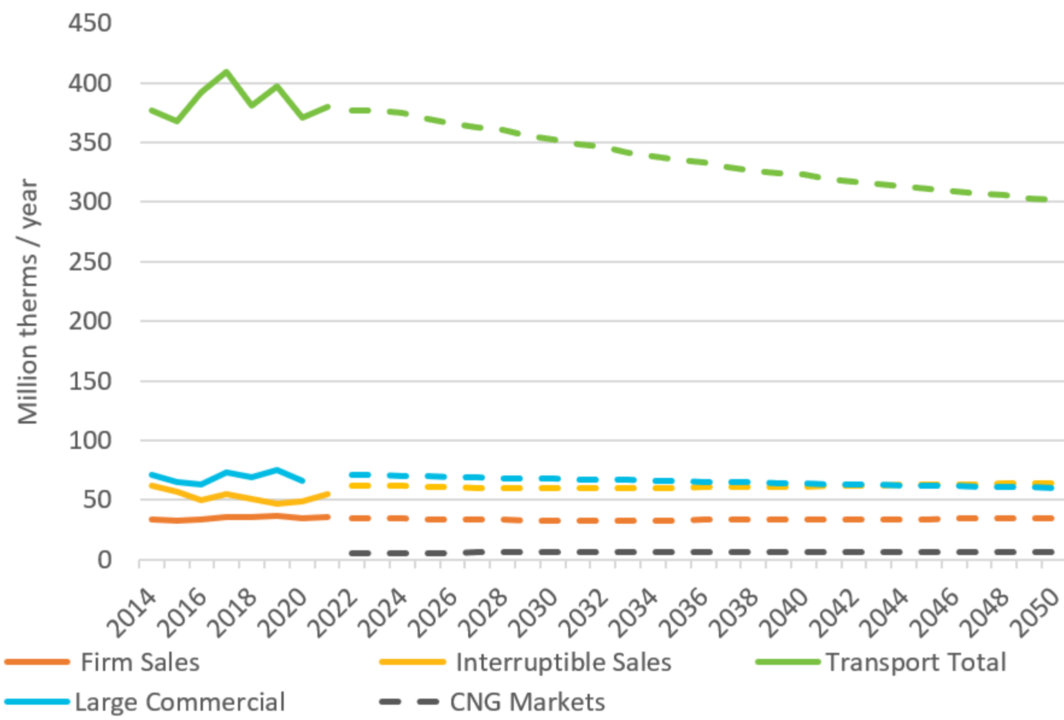
The 2022 IRP load forecast includes a load forecast associated with NW Natural's compressed natural gas (CNG) service, which NW Natural has previously labeled as an emerging market in previous IRPs. NW Natural's relies on SME who work with CNG customers to develop the CNG load forecast. CNG customer load is forecasted to be less than 0.5% of NW Natural's annual throughput for any year over the planning horizon (see Figure 3.24).

[54] The industrial classes of service are firm sales, interruptible sales, firm transportation, and interruptible transportation.

Industrial, Large Commercial Load, and CNG Annual Load Forecast

NW Natural uses the composition of the SME panel industrial load forecast, which is by service category, to allocate the total industrial load to the four classes of service for 2022 forward. Figure 3.21 shows the annual industrial load by service category and large commercial sales load.

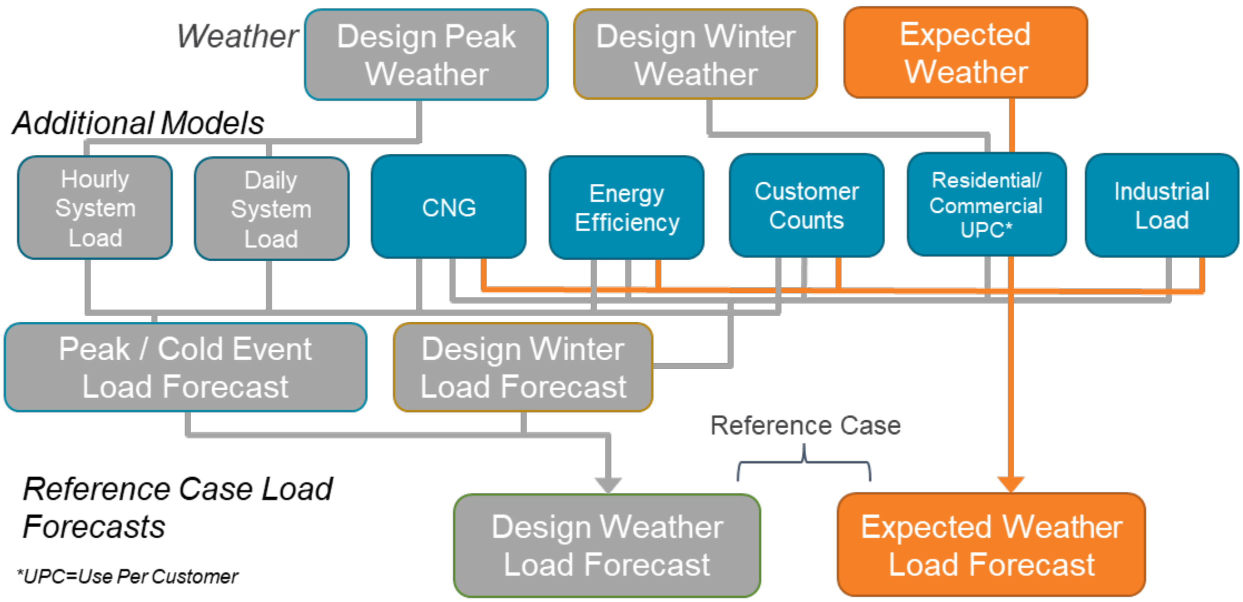
Figure 3.21: System Industrial, Large Commercial and CNG Load by Service – Reference Case



NW Natural uses details provided in the SME panel forecast of industrial load to allocate these load forecasts by service type from annual to monthly and from system totals to load centers.

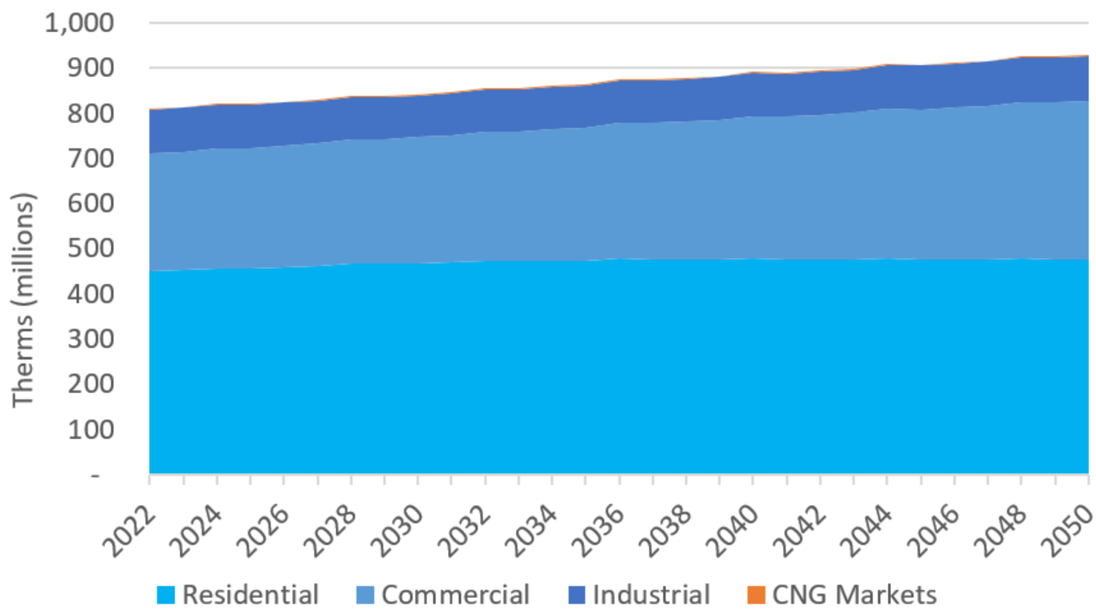
3.2.5 Expected Weather Annual Load Forecast – Reference Case

Figure 3.22: Load Forecast Model Flow Diagram – Expected Annual Load Forecast



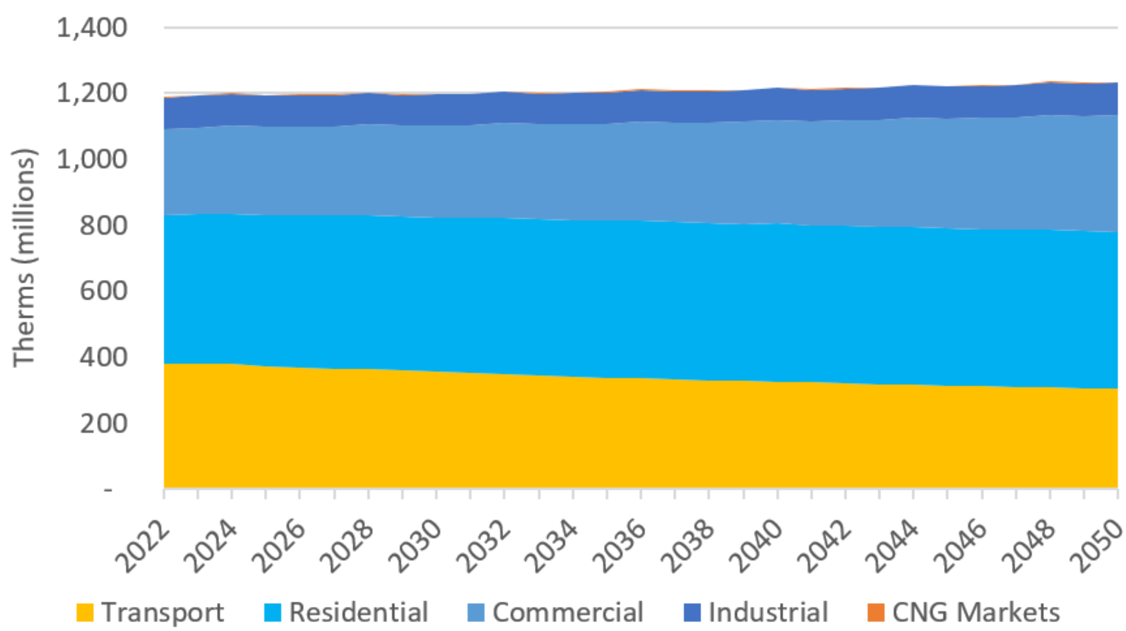
Combining the expected weather, the customer counts, the residential UPC models, the small commercial UPC models, the industrial load, the large commercial sales load, the CNG market forecasts and energy efficiency forecast provides the total reference case expected weather load forecast (Figure 3.23).

Figure 3.23: Expected Weather Annual Sales – Reference Case[55]



Emission compliance will be based on total throughput (i.e., sales load plus transport).

Figure 3.24: Expected Weather Annual Throughput – Reference Case[56]

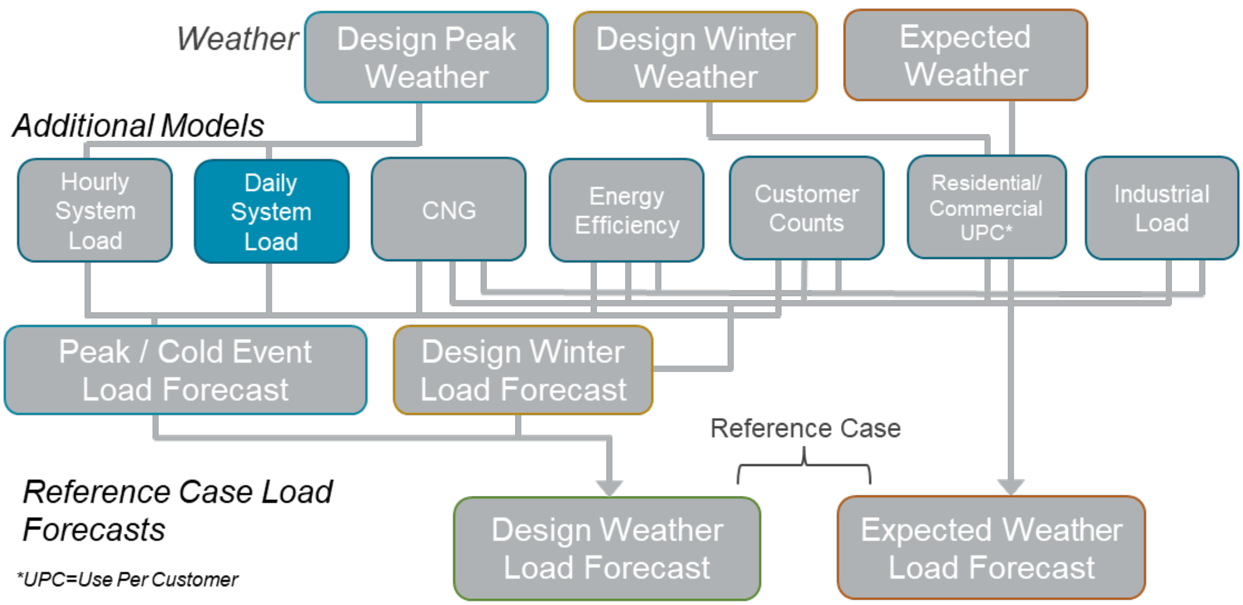


[55] These forecasts are adjusted for energy efficiency forecasts as shown in Figure 3.17.
[56] These forecasts are adjusted for energy efficiency forecasts as shown in Figure 3.17.

3.2.6 Daily System Load Model

The daily system load model is an econometric model that measures the relationship between daily firm sales load and its drivers such as temperature. Using historical data of daily firm sales load and drivers, the model statistically estimates coefficients, which represent the effect of each daily driver.[57] These coefficients are subsequently used as an input into the peak day planning standard, discussed in the next section. The daily system load model for resource planning is used to predict daily firm sales during peak demand conditions created from a combination of several factors. Ultimately, the daily system load model used for the peak day firm sales load forecast that determines the daily capacity requirements for resource planning (see Figure 3.25).

Figure 3.25: Load Forecast Model Flow Diagram – Daily System Load



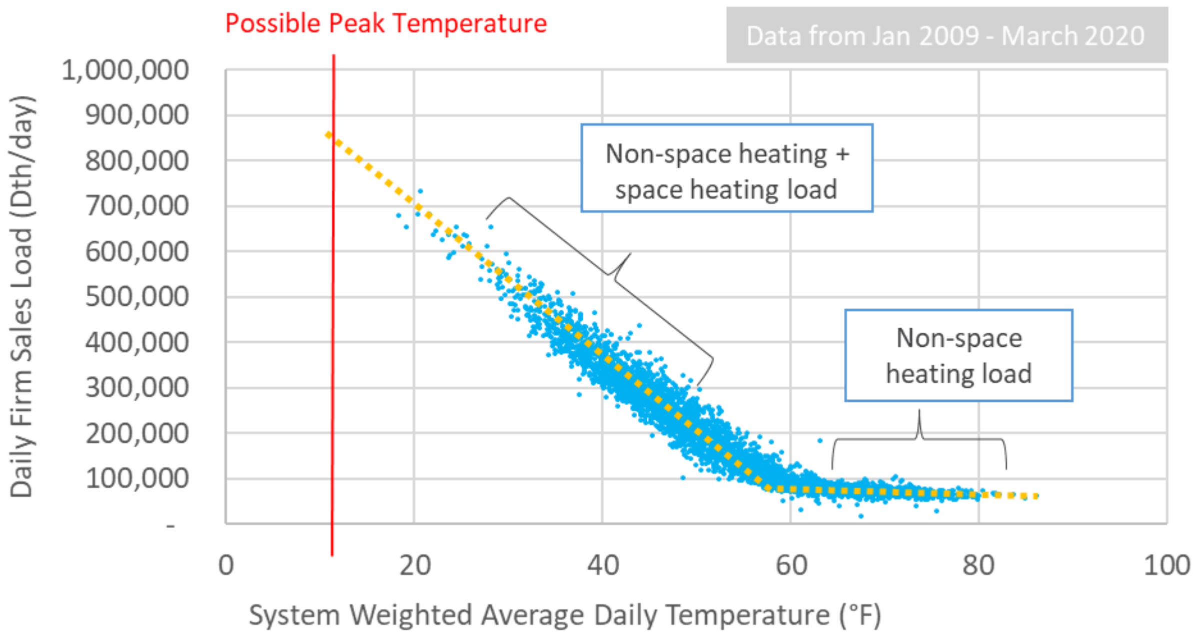
Daily Demand Drivers

The daily system load model includes 11 drivers: temperature, daily lagged temperature, solar radiation, wind speed, snow depth, customer count, day of the week indicator variables, a holiday indicator variable, a time trend, water heater water inlet temperature and an indicator variable for the pandemic shutdown in March of 2020. During peak conditions roughly 84% of NW Natural's sales throughput is used for space heating. Therefore, weather is a prominent driver of peak load and peak conditions. Peak conditions take place on very cold and windy winter weekdays when temperature drops and gas demand for space heating spikes. Figure 3.26 shows a scatter plot of temperature and a daily firm sales load. This figure illustrates that a negative linear relationship exists between daily load

[57] The daily system load model focuses on daily firm sales as NW Natural must buy the gas and have enough capacity resources to bring that gas on system during a peak day. Daily load for a gas day (7 a.m. - 7 a.m.) is used as gas is typically scheduled for an entire day in a day-ahead market. Hourly load is relevant for distribution system planning, but not necessary for supply planning and gas scheduling.

and temperature. There is a structural break in this relationship at 58°F as space heating equipment (e.g., furnaces) kicks on at temperatures less than 58°F. To capture this relationship the daily system load model is estimated in two versions: average daily temperature less than 59°F and average daily temperature greater than 59°F.[58] The coefficients from the less than 59°F model version are used as inputs into the peak day planning standard.

Figure 3.26: Daily Firm Sales Load and Temperature



In addition to temperature, NW Natural includes a daily lagged temperature variable into the model. The necessity of including a temperature lag is due to the physical location of where data is collected and the speed at which gas flows through pipelines. Data on daily flow is collected at NW Natural's gate stations and at our on-system storage locations. Additionally, data is collected at the end use location for interruptible sales and transportation customers who have higher frequency meters that record their daily usage. Non-firm sales customer usage is subtracted coincidently from the flow coming from the gate stations and on-system storage, but these customers could be located far from the gate station. Since gas does not flow instantaneously, there is a delay between when customers use gas and when it flows through the gate stations.[59] Including a lagged temperature variable helps capture this lagged data response to changes in weather.

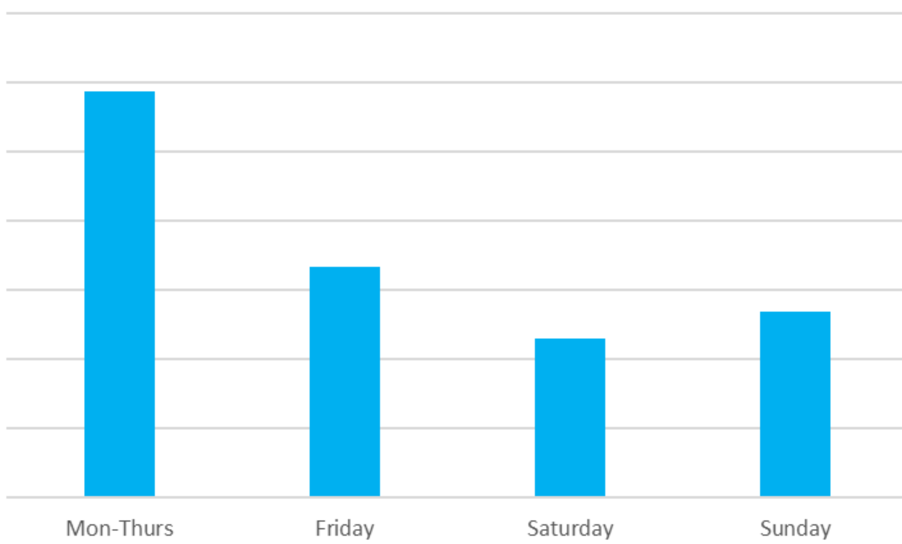
[58] Daily temperatures are calculated as system-weighted daily averages from hourly weather data.

[59] The duration of the delay is dependent on several factors including the pipeline distance from the gate station and the speed of gas flow (which is dependent on the overall demand and pipeline pressure). This delayed response is applicable to all customers, i.e., firm sales customers as well.

Wind and solar radiation have positive and negative impacts on daily load, respectively. High winds cool building structures, which in turn require additional gas to maintain space heating. Conversely, higher solar radiation heats buildings and hence reduces heating demand.

The day of the week also impacts natural gas load. The data shows a statistically significant increase in daily load during a weekday relative to a Saturday or Sunday. This is mainly driven by schools and businesses closing for the weekend. Daily load on Friday also shows a significant decrease in daily load relative to Monday through Thursday.[60] Figure 3.27 shows daily average use for Monday–Thursday, Friday, Saturday, and Sunday. To capture this effect the model includes Friday, Saturday, and Sunday indicator, or dummy, variables.[61] A similar effect is captured by a holiday indicator variable.[62]

Figure 3.27: Average Winter (Nov-Feb) Firm Sales Daily Use by Weekday



Snow depth and water heater inlet temperature were first introduced in the 2018 IRP daily system load model and are used again in the 2022 IRP model. Snow depth is a proxy for business closures and the effect is like the effect of a weekend or holiday. Since snow depth is often correlated with cold weather, this effect is less intuitive. After controlling for other weather drivers, additional snow depth causes more schools and businesses to shut down and has a statistically significant negative impact on load.[63] NW Natural uses Bull Run River water temperature as a proxy for water heater inlet temperature.[64] Colder inlet water temperature requires additional heat to warm and thus has a negative effect on load meaning that load will increase.

[60] For a 7 a.m. - 7 a.m. gas day, Friday includes 7 hours of Saturday. Including these hours into a Friday is a primary reason why Friday is different than other weekdays.
[61] Throughout this section weekday refers to a Monday through Thursday.
[62] Holidays are identified as federal holidays where most business and schools close. If the holiday falls on weekend the following Monday is considered a holiday as this a typical practice for schools and businesses to grant the following Monday as a holiday.
[63] NW Natural initially tried to attain data on school closures but could not find sufficient data.
[64] Portland is NW Natural's largest load center with data on surface water temperature readily available through the U.S. Geological Survey (USGS).

The impact from the COVID-19 economic shutdown was overall negative as school and business closed for social distancing. It is likely that residential usage increased from people spending more time at home, either from unemployment or remote working, but the system data used for this model indicates an overall decrease in firm sales load. As the data for this model ends in March of 2021, the longer-term impacts of COVID-19 on load is yet to be discovered, however; by including an indicator variable for the COVID-19 shutdown we account for its immediate impact during the 2020-2021 winter.

Table 3.7: Driver Variable Impacts on Load Modeling

Driver Variable	Impact on Load
Temperature	(-)
Previous Day Temperature	(-)
Solar Radiation	(-)
Wind Speed	(+)
Snow Depth	(-)
Water Heater Inlet Temperature	(-)
Fri/Sat/Sun or Holiday	(-)
Customer Count	(+)
Time Trend	(-)
COVID 19	(-)

The last two drivers include customer counts and a time trend. Customer growth has increased over the past decade and has a positive impact on NW Natural's daily load.[65] Counter to customer growth, through energy efficiency efforts and changes in customer profiles,[66] use per customer is declining. To account for this change over time the model includes a time trend.

Interaction Effects

Beginning with the 2018 IRP daily system load model, we have been incorporating interaction effects between variables, primarily temperature and other independent variables. The reason for including interaction effects starts with recognizing that a single driver alone fails to sufficiently explain changes in daily demand primarily used for space heating. For example, demand on a warm summer day with no wind will not be very different from demand on a windy summer day. However, the impact of wind greatly increases as temperatures decrease. In other words, demand on a cold windy day will be much greater than demand on a day with the same temperature and no wind. For more technical details on the daily system load model see Appendix B.

[65] A negative impact means that the values of the attribute go in the opposite direction as load. Whereas a positive impact means the values of the attribute go in the same direction as load. As an example, as temperature increases, load decreases and correspondingly, as temperatures drop, load increases.
[66] For example, the addition of higher efficiency new construction homes.

Firm Sales Daily System Load Regression Model

Daily load drivers constitute the independent, or right-hand-side, variables in the econometric model and daily system firm sales is the dependent, or left-hand-side, variable.

$$System\ Firm\ Sales_t = \alpha + \sum_{i=1}^{23} \beta_i\, Drivers_{it} + \epsilon_t$$

Where α is a constant, β_i are the estimated coefficients, *i* is an index for drivers, *t* is a daily index and ε is a random error.

The right-hand-side variables include the previous day's temperature, solar radiation, wind speed, snow depth, customer count, Friday, Saturday, Sunday and holiday dummy variables, a time trend, and the Bull Run River water temperature. Temperature interacts with each dependent variable except for the Bull Run River water temperature. The data shows that the efficiency of insulated water heaters is independent of the outside temperature and therefore an interaction between temperature and the water heater inlet water temperature is not considered in this model.

3.2.7 Capacity Requirement Planning Standard

Developing a planning standard is important for selecting the right mix of resources to cost-effectively serve customers and ensure the reliability of the service under design peak weather conditions. Gas supply capacity requirements refers to the daily maximum volume of gas that the system can deliver to customers. In the 2018 IRP, NW Natural implemented a new planning standard that uses statistics and Monte Carlo simulation of the demand drivers to set a standard that the company's resource capacity can serve the highest firm sales demand day going into each future winter with 99% certainty. This is equivalent to planning for a 1-in-a-100-year weather event. This IRP uses the same planning standard as the 2018 IRP.

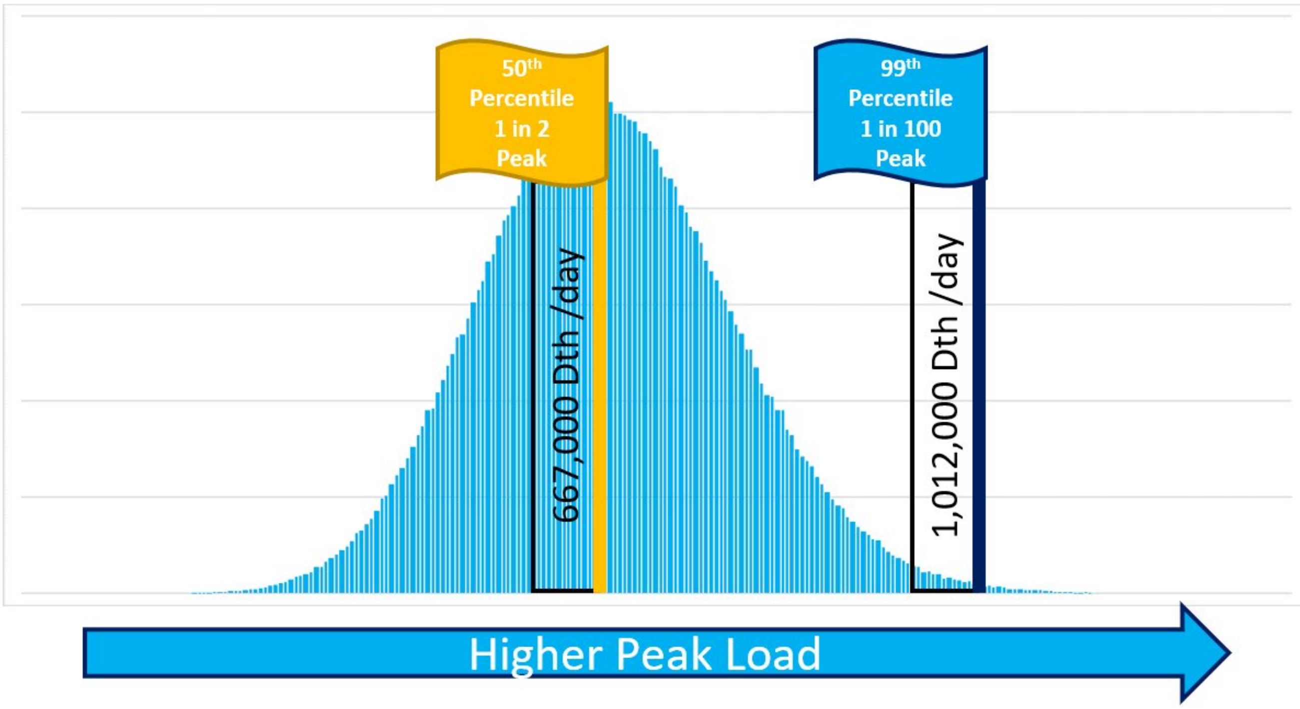
As weather is random, a 1-in-a-100-year event has a probability of occurring more often than once every 100 years. On the other side of the coin, this type of event also has the probability of not occurring within the next 100 years.[67] We plan our system resources to be available to serve firm sales demand during this extremely rare cold winter day. This should not be confused with 1-in-2 peak, which is the expected firm sales peak load that we are likely to see occur each year. In fact, we will see a daily peak load lower than a 1-in-2 peak occur in about half of the winters in the future.

Using the regression coefficients from the firm sales daily system load model and the Monte Carlo simulation of the demand drivers create a distribution of peak day demand under potential peak conditions. Using this distribution and accounting for model error the 99th percentile is pulled from this distribution to establish the firm sales peak load that would occur under a 1-in-a-100-year weather event. Figure 3.28 demonstrates the difference between a 1-in-2 peak (50th percentile) and the 1-in-a-

[67] See the 2018 IRP Chapter 3, Section 7.2 for a detail discussion on this topic.

100-year (99th percentile) firm sales peak load, which we plan our system resources. Note that these percentiles are dynamic as customers counts and a time trend are included as regressors and change over time.

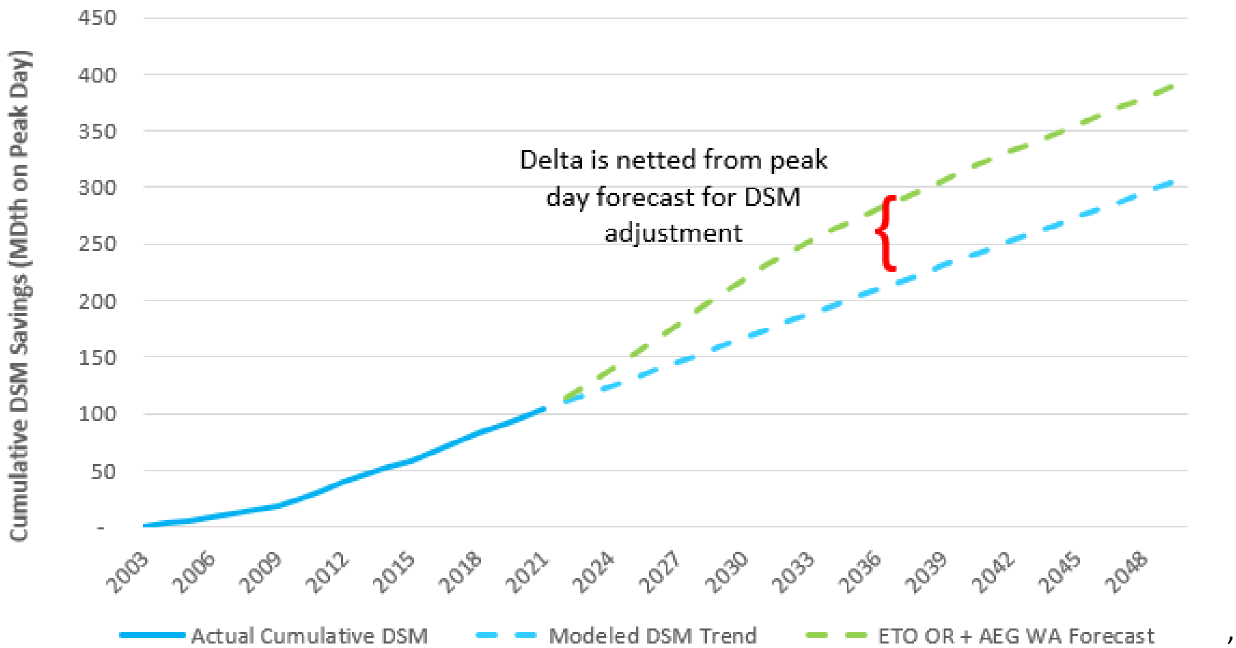
Figure 3.28: 2022 Firm Sales Peak Day Distribution



3.2.8 Design Day Peak Savings from Energy Efficiency

The 99th percentile load requirement includes a time trend capturing underlying trends in the data, part of which is driven by past energy efficiency programs. There is an adjustment to the 99th percentile to account for design peak therm energy savings forecast, similar to the adjustment discussed for annual therm savings. These design peak therm savings are calculated using peak factors estimated by NW Natural for each end-use and are further discussed in Chapter 4, Section 4.3. These factors are applied to the annual sales savings forecasted by the Energy Trust (Oregon sales) and AEG (Washington sales). Figure 3.29 illustrates the adjustment made to the 99th percentile load requirement.

Figure 3.29: DSM Peak Day Savings Trend and Forecast



3.2.9 Peak Day Forecast – Reference Case

The peak day load forecast, which is modeled as the third day of a cold event, combines the customer forecast, peak day therm savings energy efficiency forecast, the daily system load model, and the peak day planning standard.[68] The combination of these models results in a forecast of the gas supply capacity requirements over the planning horizon (see Figure 3.30).[69]

[68] Note that peak day contribution from CNG markets is included in the peak day forecast but are de minimis.

[69] Peak day is defined, per the peak day planning standard, as the firm resource requirement needed to have a 99% chance to be able to meet the highest firm sales demand day in a gas year.

Figure 3.30: Load Forecast Model Flow Diagram – Peak Day Load Forecast

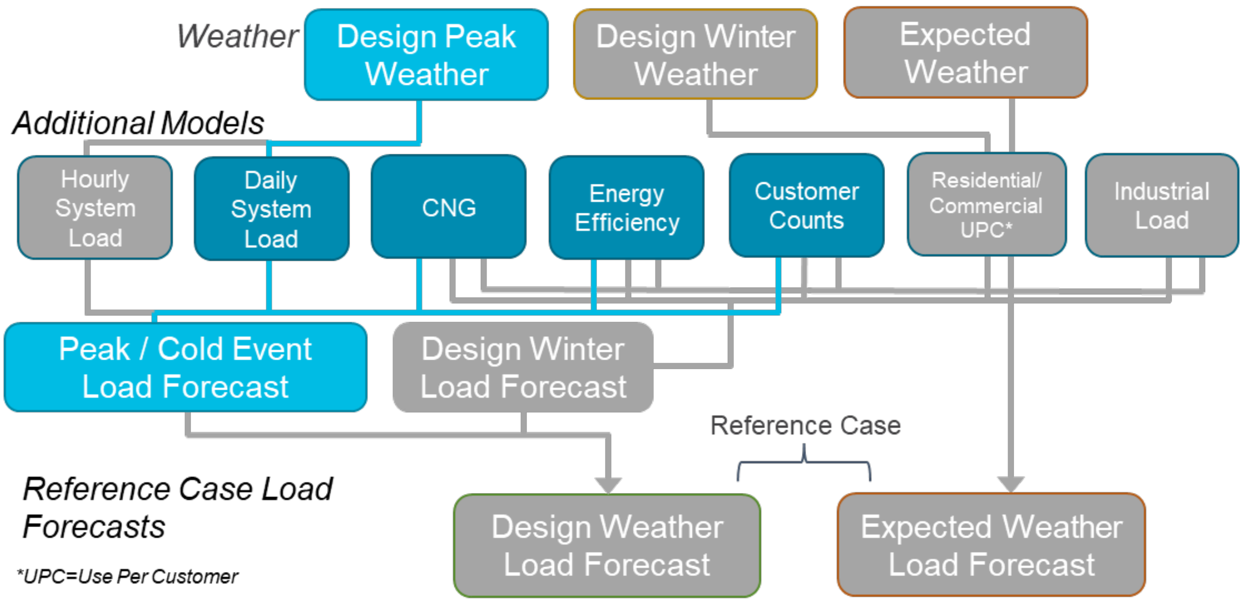
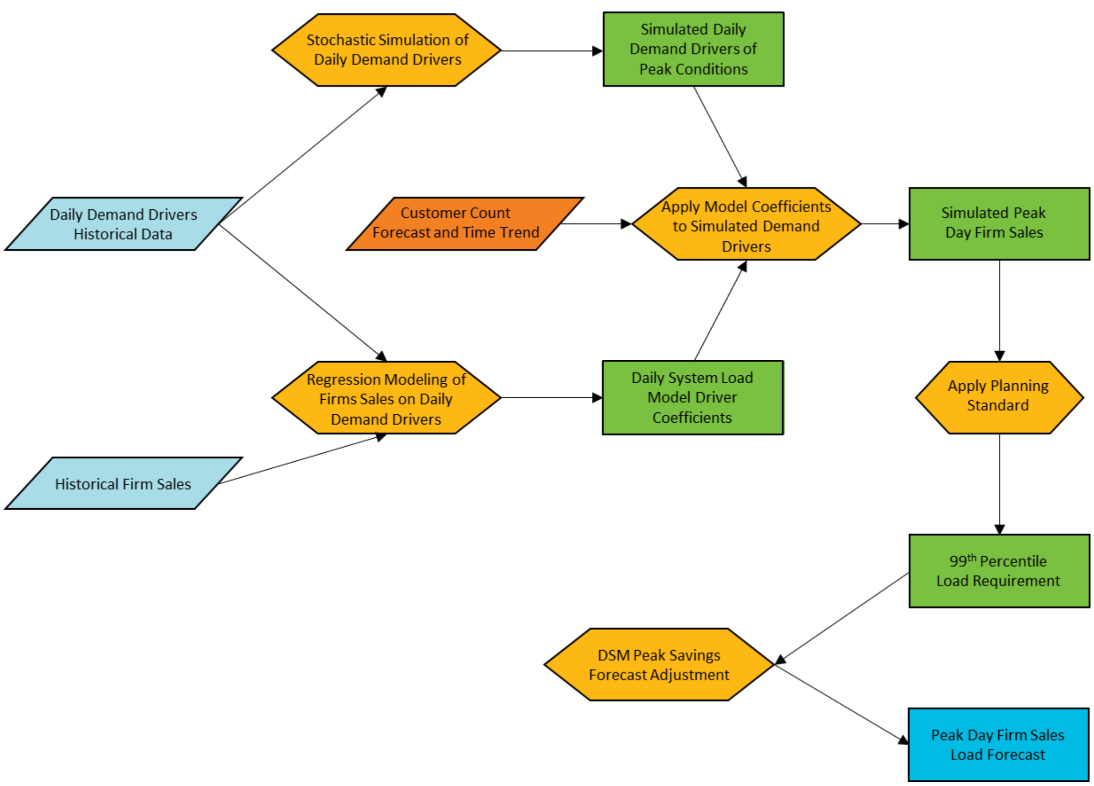


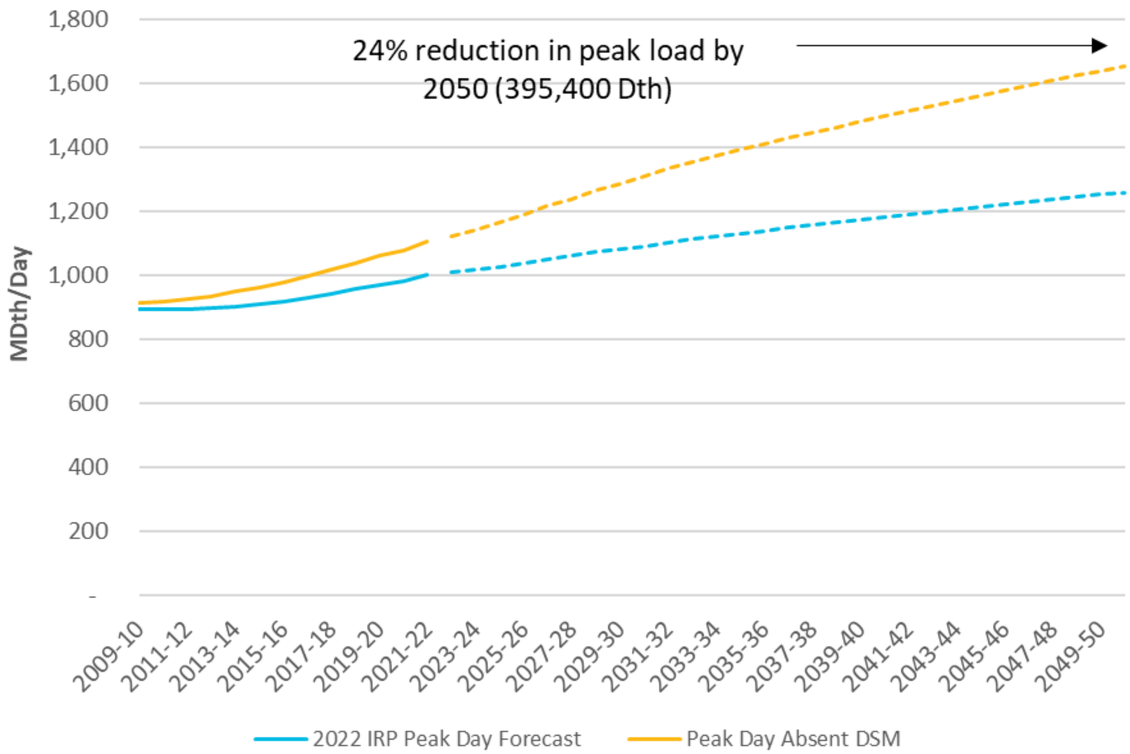
Figure 3.31 illustrates a flow chart for how the daily system load model, forecast of design peak day therm savings, and the planning standard are combined to develop the peak day forecast.

Figure 3.31: Peak Day Load Forecast Flow Chart



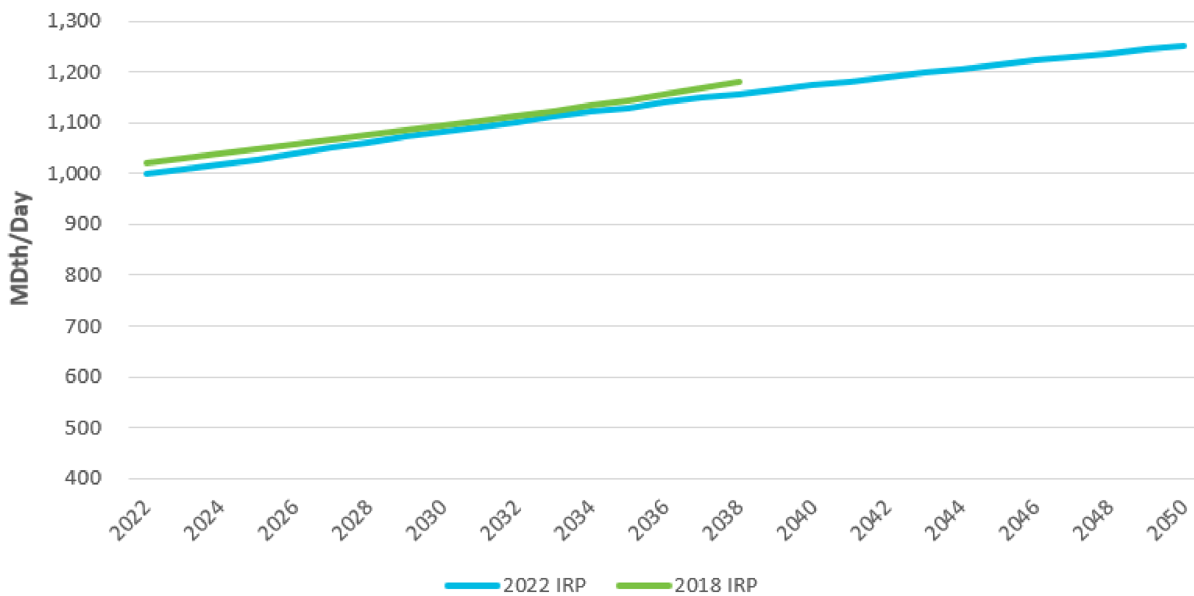
The impact of DSM programs has been and will continue to be a significant way to reduce annual load, but also generates significant savings on peak, particularly measures related to space heating. Figure 3.32 shows the peak day forecast, absent any DSM programs relative to the 2022 IRP peak day forecast adjusted for ETO and AEG's DSM forecast.

Figure 3.32: Peak Day Load Forecast Without DSM



By 2050, DSM programs will reduce peak day load by about 395,400 Dth or 24% of peak load. This is roughly the capacity equivalent of three Portland LNG facilities. Compared to the 2018 IRP, the reference case peak day forecast is lower by 1.5% by in 2038 as shown in Figure 3.33 but extends out to 2050.

Figure 3.33: Peak Day Load Comparison 2018 IRP to 2022 IRP

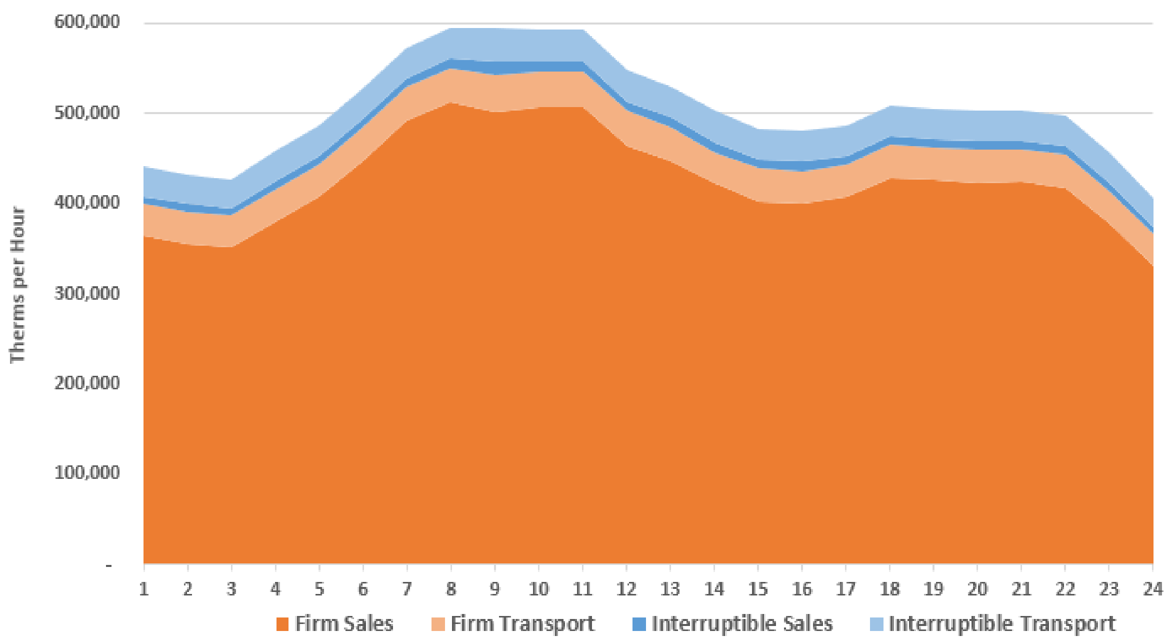


3.2.10 Demand Response

Demand response (DR) is a key resource that can be deployed to reduce peak loads. While there is interaction between DR and energy efficiency programs DR programs should not be thought of as emissions reduction programs given the infrequent use of demand response resources. NW Natural has substantial demand response programs via its interruptible schedules that have been in use for many years.

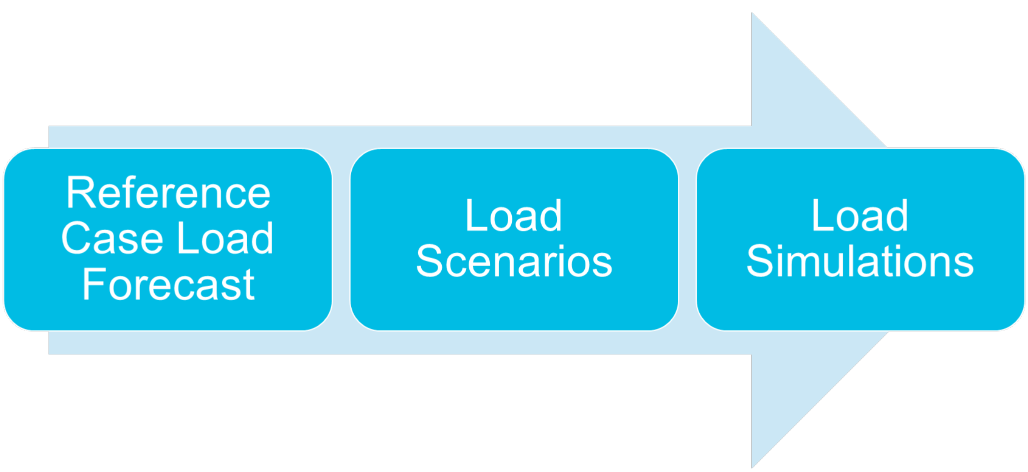
Figure 3.34- Existing Demand Response Impact shows what NW Natural's peak load would be by hour without its interruptible schedules. More than 2% of sales load on a peak day can be interrupted during peak periods, and roughly 9% of deliveries can be interrupted during a peak hour to maintain pressure on the distribution system. Without these DR programs substantial investment would be needed to maintain reliability on peak. While cost effective storage resources (see Chapter 6) make the potential capacity costs avoided from DR programs relatively small for gas utilities compared to electric utilities a confluence of new technologies in metering and smart devices makes potential additional DR peak savings possible from residential and small commercial customers to supplement existing industrial and large commercial programs. NW Natural engaged a third-party consultant to provide a comprehensive demand response potential study (please see Appendix B). Smart thermostats in particular could be a valuable demand response resource, and while the incentive that can be supported by NW Natural's relatively low-capacity avoided costs (see Chapter 4) we propose an Action Item in this IRP to establish a residential and small commercial DR program by 2024.

Figure 3.34- Existing Demand Response Impact



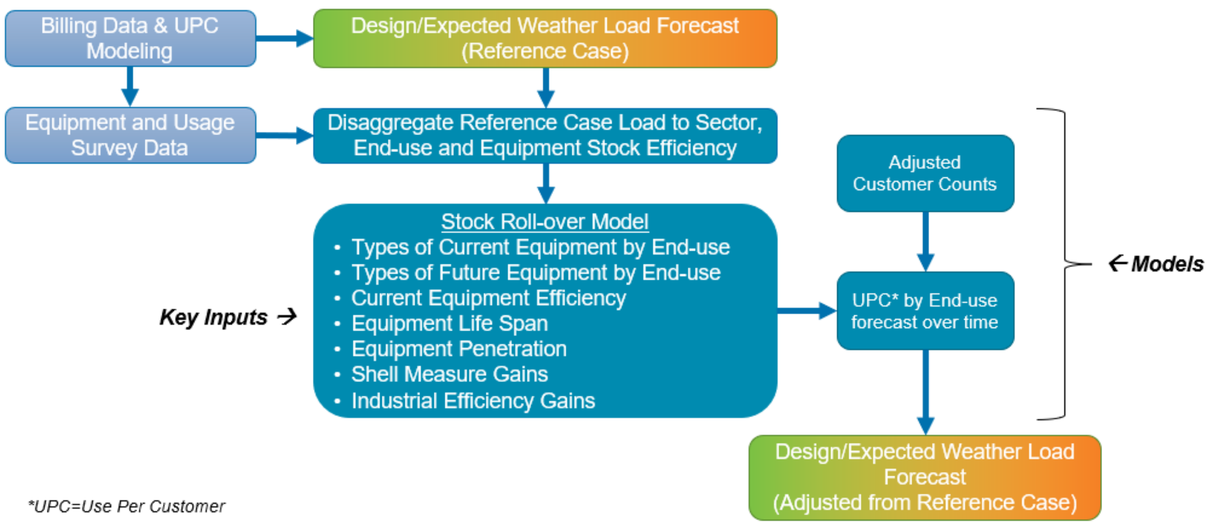
3.3 End Use Load Forecast Model

The statistical models used to the develop the forecasts in Section 3.2 are appropriate to use when historical trends are expected to continue and have been used to develop base case forecasts in NW Natural's prior IRPs. However, they are not appropriate for forecasting structural change like that could be afoot from the transformational climate policies recently established in the Company's service territory.



In order to evaluate potential large-scale changes in end use equipment technology, customer preferences, and/or the policy environment NW Natural developed an end use load forecasting methodology in the 2018 IRP that has been improved and becomes the driver of the key load forecasts used in this IRP (i.e., the forecasts used in each of the scenarios as well as the stochastic Monte Carlo simulation draws). End use load forecasting is not possible without a reference case to model changes against, and those changes are modeled relative to the reference case forecasts detailed in the previous section. While end use load forecasting is more flexible than forecasts derived only from econometric techniques, it has the drawback of being dependent upon user defined assumptions. The end-use load forecasting process is detailed below.

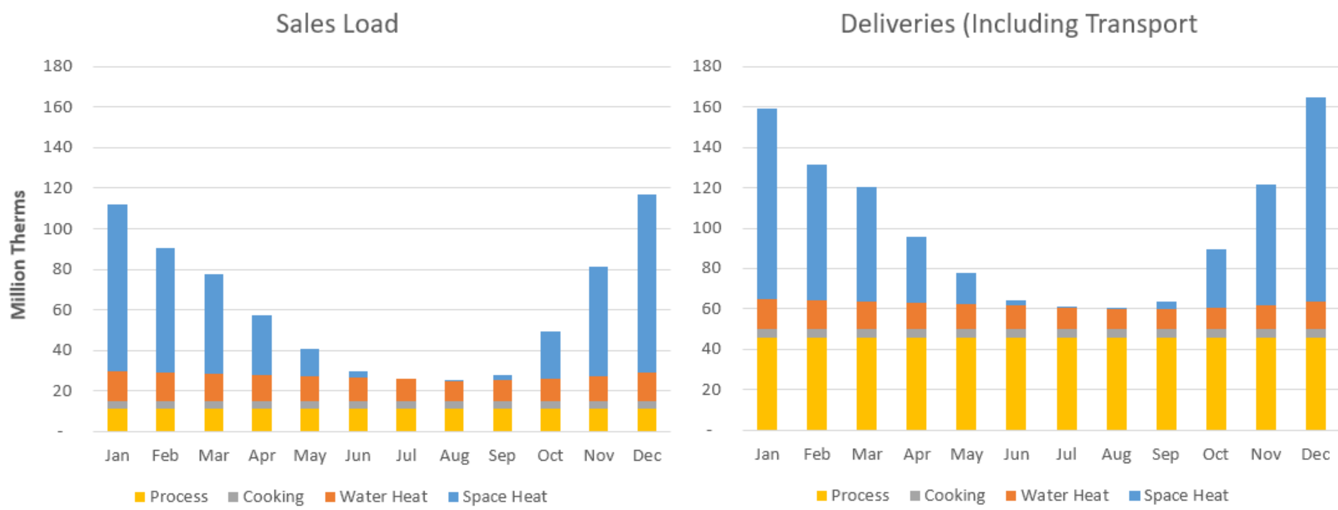
Figure 3.35: End Use Load Forecasting Process



3.3.1 Disaggregating Load by End Use

Forecasting by end use requires breaking down total load into end uses like space heating, water heating, cooking, and industrial applications to forecast each end use separately. The statistical techniques described in Section 3.2 are modified to estimate load by end use. This work shows that NW Natural's sales load is primarily space heating load.

Figure 3.36: Load Breakdown by End Use



Roughly 2/3 of the gas delivered to NW Natural customers is sold as a bundled product by the utility to customers on sales schedules, with the majority of the load on transport schedules being comprised of industrial process loads. While space heating makes up the majority of the load sold on sales schedules throughout the year, it accounts for roughly 90% of the firm sales load that is expected on a peak day or hour.

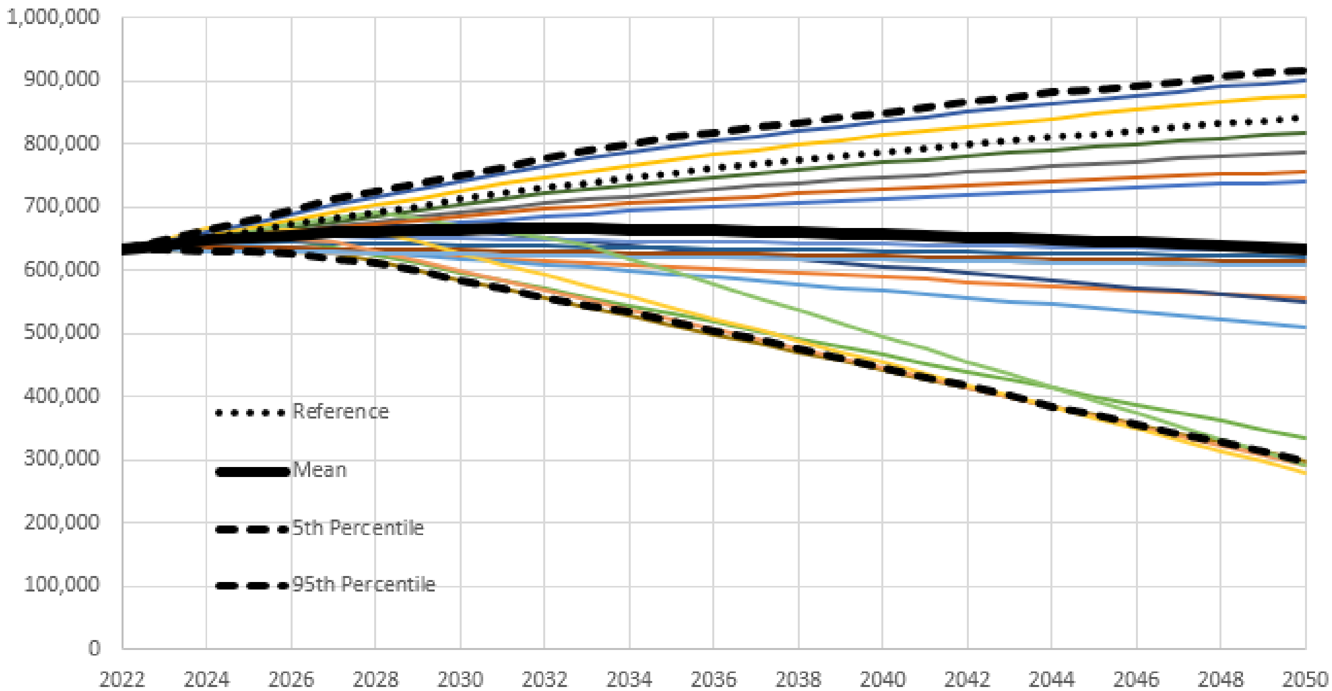
3.3.2 Stock Rollover Model

The relative efficiencies and equipment options available determine how much energy is needed for end use energy services like keeping a home warm or having hot water for a shower. To understand how changing technology or deploying more energy efficient technologies would be expected to impact load the efficiency of the stock of equipment and rate of stock turnover/replacement based upon expected equipment lives needs to be estimated. A key source of information on the efficiencies of equipment in use in NW Natural's service territory are building stock assessments completed by the Northwest Energy Efficiency Alliance, though this information is supplemented by NW Natural's own analysis of customer billing data surveys as well as national building stock assessments. The assumptions about emerging end use equipment deployment are discussed in Section 5.8.

3.4 Customer Count Uncertainty

Six of the nine scenarios utilize the same customer count forecast, whereas the electrification scenario assume varying degrees of customer declines. These scenario help define the residential and commercial customer count stochastic simulation results shown in Figure 3.37.

Figure 3.37: Oregon Residential Customer Count Monte Carlo Results[70]



[70] For graphs showing the mean and dispersion of a Monte Carlo simulation, the colored lines represent individual stochastic draws from that simulation.

3.5 Annual Load Uncertainty

Combining the uncertainty in customer counts, energy efficiency, emerging technology deployment, economic activity, and weather allow total load uncertainty to be developed.

Figure 3.38: Total System Load (Deliveries) by Scenario

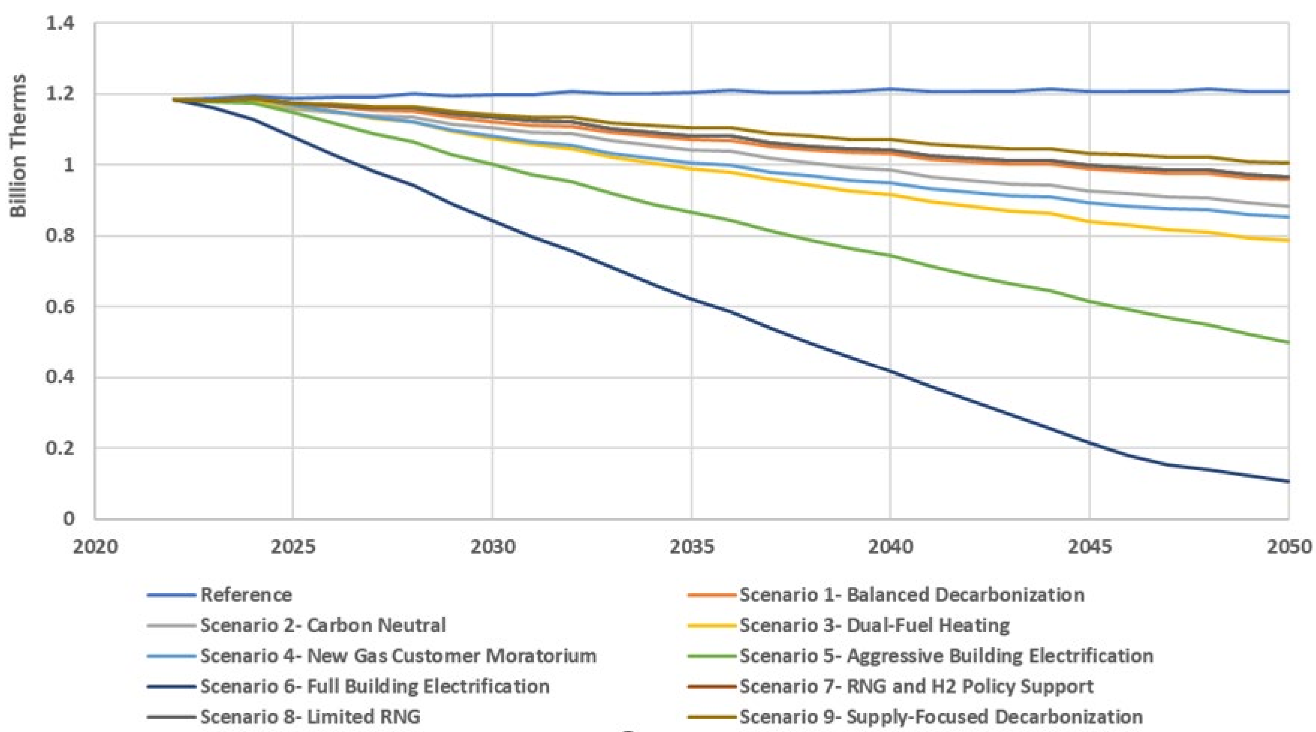


Figure 3.39: Oregon Residential Stochastic Load Results

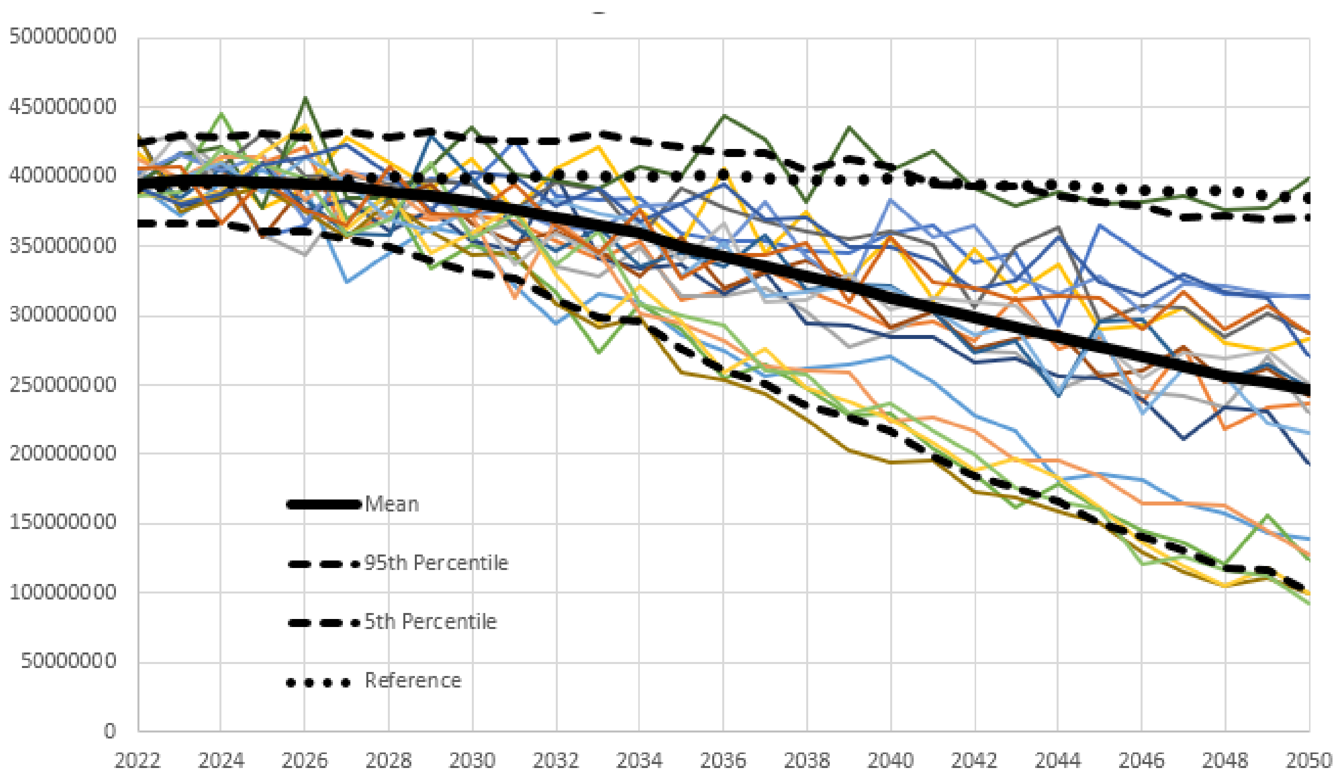
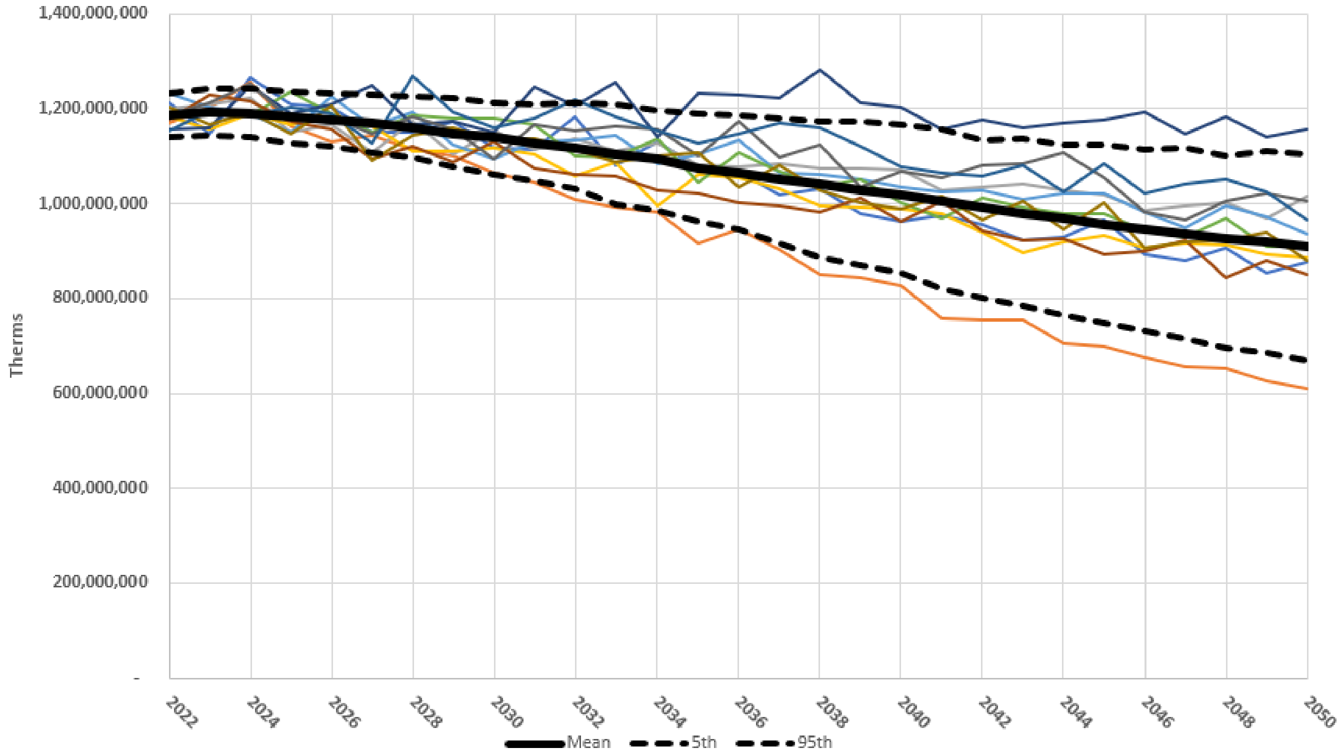


Figure 3.40: Total System Load Stochastic Simulation Results



3.6 Peak Load Uncertainty

The peak loads associated with the load forecasts of each scenario and the results of the stochastic Monte Carlo simulation are shown below.

Figure 3.41: Firm Sales Peak Day Load by Scenario

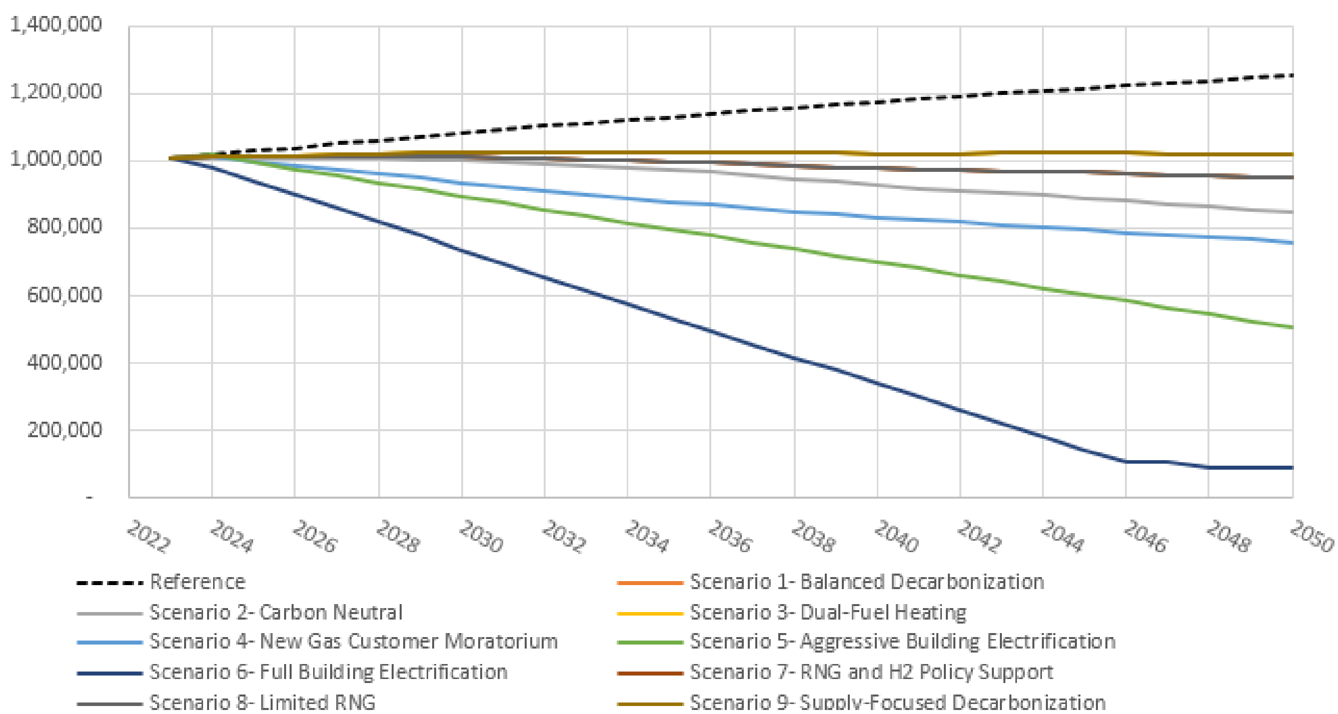
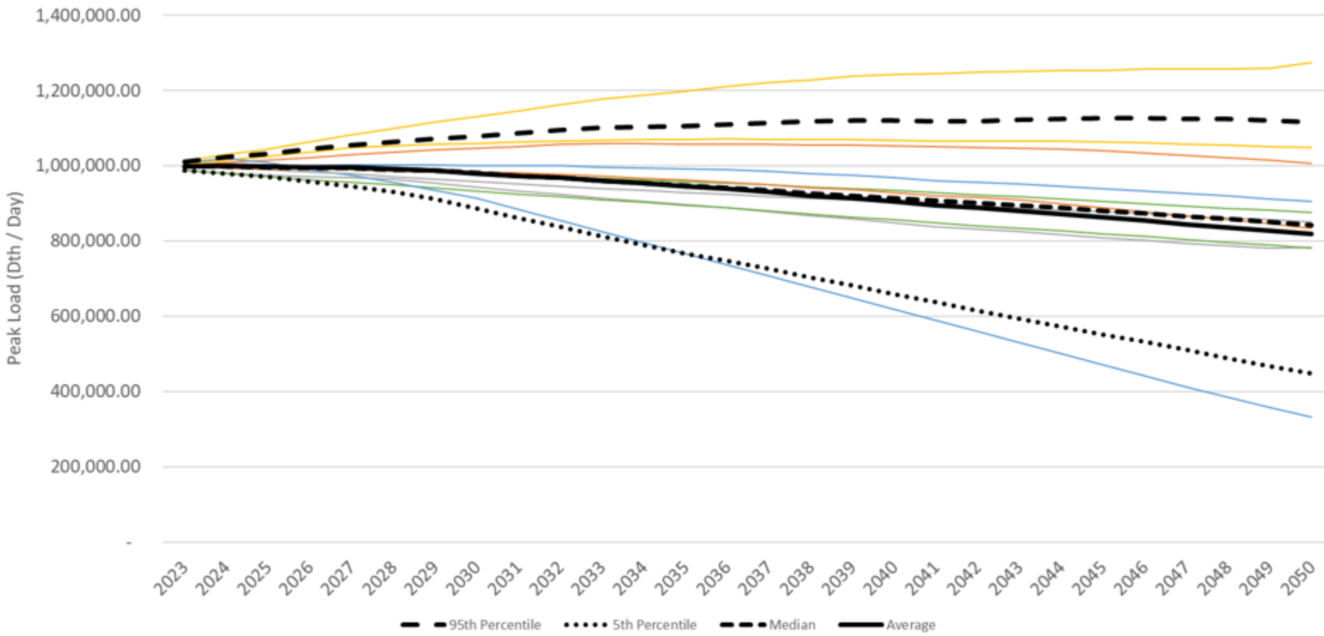


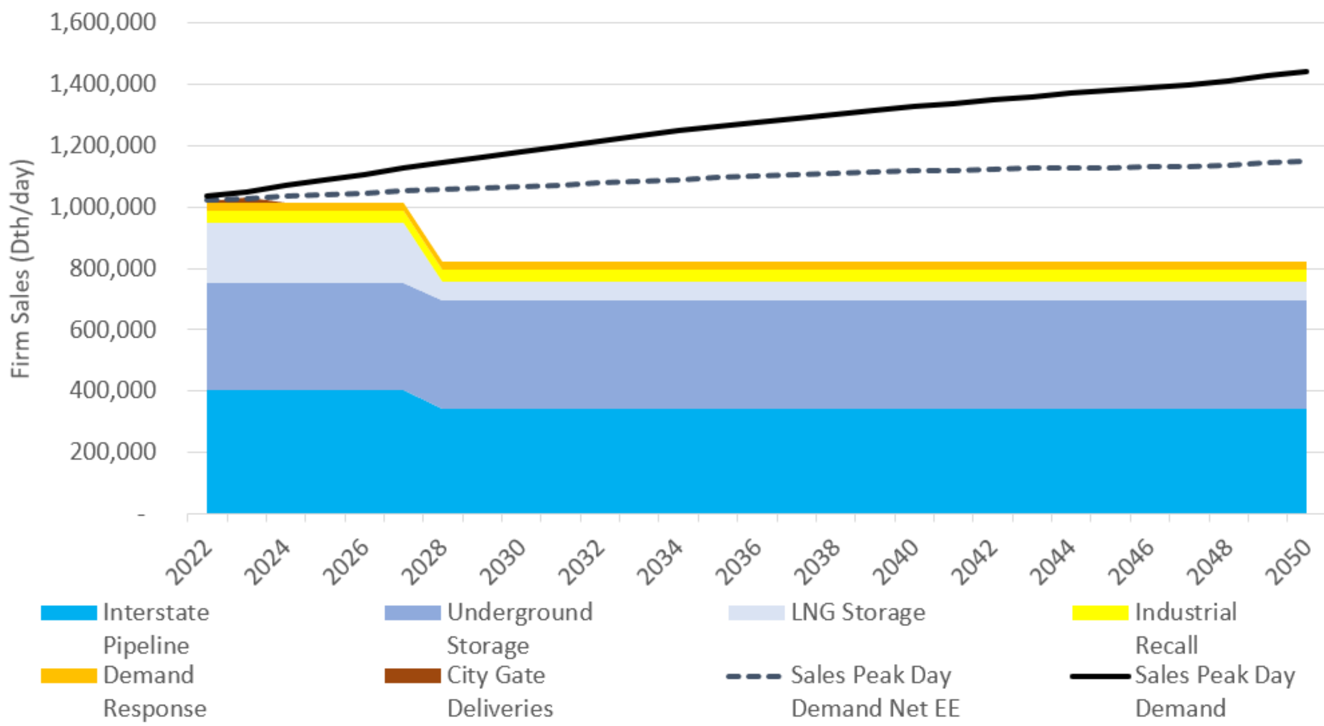
Figure 3.42: System Firm Sales Peak Day Load Stochastic Simulation Results



3.7 Defining Capacity Resource Needs

Figure 3.43 shows an example peak day load-resource balance. The gap between the peak load net of energy efficiency and the expected resources represents the capacity needs to address. The options to fill this gap are discussed in Chapters 5 and 6, and the least cost results for filling the gap for each scenario and across simulation draws are shown in Chapter 7.

Figure 3.43: Peak Day Capacity Load Resource Balance[71]



[71] Scenario 1 load depicted as an example. The peak load resource balance for each scenario can be seen in Chapter 7.

3.8 Defining Compliance Resource Needs

Similar to the capacity needs shown in the previous section, once load is forecasted and the requirements of Oregon's Climate Protection Program and Washington's Cap-and-Invest program defined the emissions reductions required to comply with the programs can be defined.

Figure 3.44: Oregon CPP Emission Compliance Needs

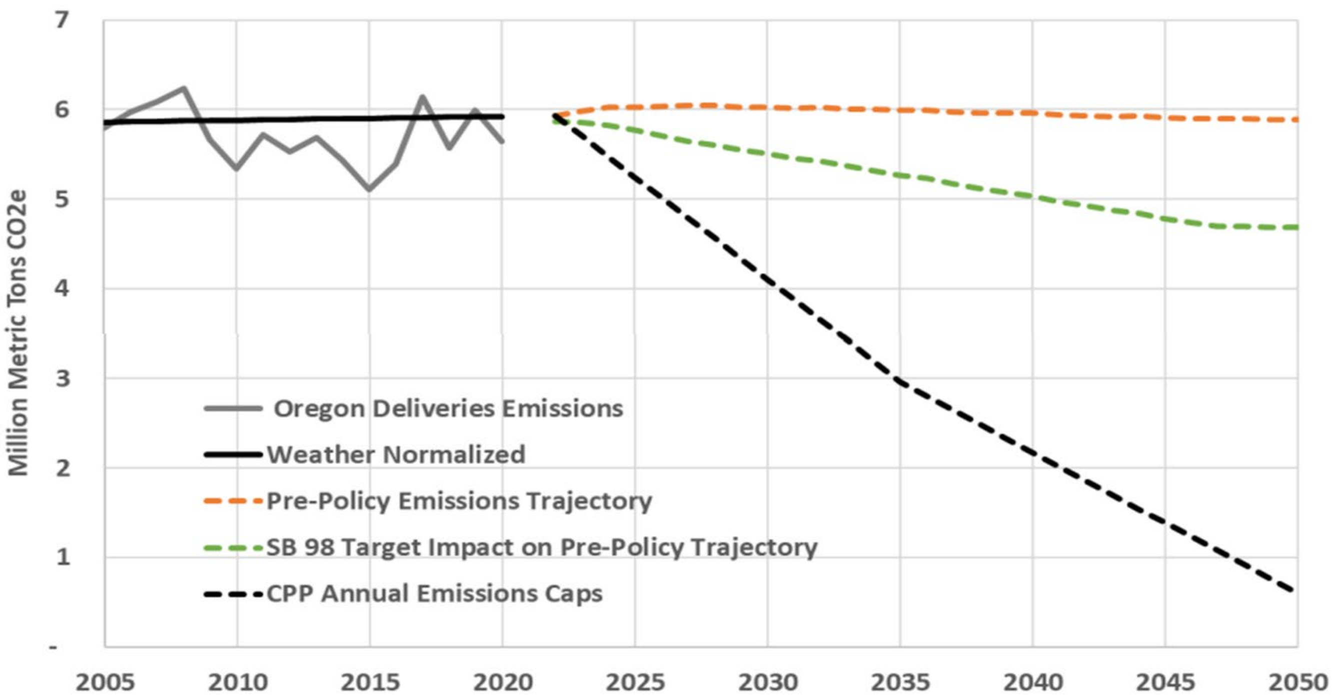
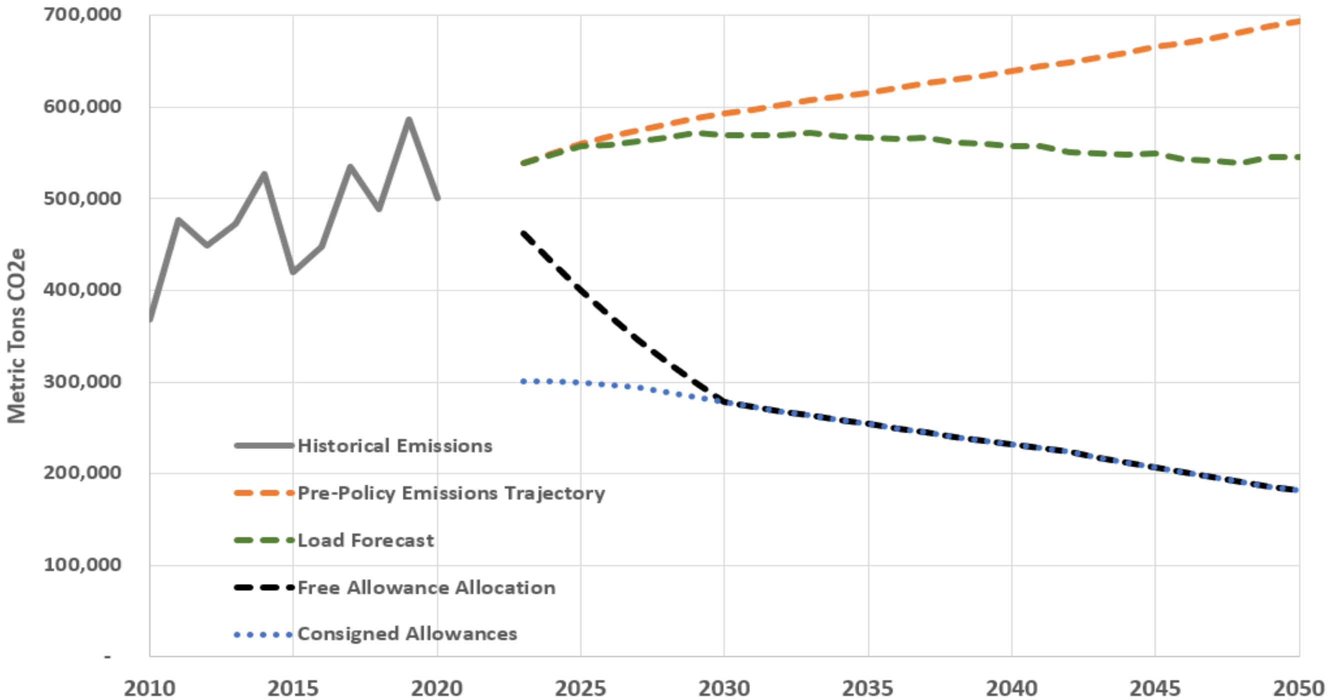


Figure 3.45: Washington Cap-and-Invest Emissions Compliance Situation



Choosing amongst resource options requires understanding the cost tradeoffs amongst resource options. Chapter 4 describes the methodologies used to determine the costs that are avoided when one resource is chosen over the other available options.

4 | Avoided Costs

4.1 Avoided Costs – Overview

As part of the IRP process, NW Natural forecasts avoided costs over the planning horizon. Total avoided cost is an estimate of the cost to serve the marginal unit of demand with conventional supply-side resources. This incremental cost represents the cost that could be avoided if that unit of gas were not demanded, due to efforts such as demand-side management (DSM), or through on-system supply side resources such as locally sourced renewable natural gas.

Therefore, the avoided cost forecast can be used as a guideline for comparing the cost of acquiring gas and supply-side resources to meet demand with other options so that the most cost-effective solutions are identified to meet customer needs. Practically, the avoided cost forecast is a key component of the cost-effectiveness test that is conducted by Energy Trust of Oregon (ETO) and Applied Energy Group (AEG) to determine the DSM savings projections for Oregon (ETO) and Washington (AEG) detailed in Chapter 5.

Chapter 4 details the methodology used to calculate each component of NW Natural's avoided costs. The methodology we used to calculate our avoided cost forecast has seen continued improvement since the 2014 IRP, and we are working with ETO and AEG to make additional improvements implementable within the broader distribution planning and IRP processes. For the 2022 IRP, NW Natural's avoided cost forecast features the following key methodological improvements:

- A new methodology is used to measure the reduction in price risk (hedge value) for avoided cost that is based on the same Monte Carlo gas price simulations and aligns with NW Natural's methodology for evaluating risk of other resources, particularly the methodology being applied for RNG.
- Avoided costs have been applied to more diversified on-system and low carbon supply-side resources so the entire value these resources provide to customers is included when they are evaluated against conventional resources.
- Environmental incremental policy compliance costs for recent Climate Protection Program (CPP) and Community Climate Investments (CCI) for Oregon and Climate Compliance Act (CCA) for Washington have been explicitly included in its portfolio modeling assumptions to generate state-specific avoided costs in NW Natural's territory.
- This is the first time in NW Natural's IRP filing that avoided costs are estimated based on the resource optimization results obtained from the current IRP modeling and filed in the same IRP.

This chapter also presents the avoided costs results for both the demand-side and the supply-side resources to which the concept is applied. NW Natural continues to work on improving its methodologies and internal processes relative to avoided costs in a continuing effort to ensure that all resources, be they demand- or supply-side, are evaluated on a fair and consistent basis in a fully integrated process.

4.2 Avoided Cost Components

Table 4.1 summarizes each of the components of avoided costs and shows which components are included in the evaluation of the different resource options NW Natural considers in its resource planning. Additionally, Table 4.1 shows which values of the avoided costs components vary by end use or supply resource.

Table 4.1: Avoided Costs Components and Application Summary

Costs Avoided		Resource Option Application					
		Demand-Side Resources			Supply-Side Resources		
			Demand Response		Low-Carbon Gas Supply		
		Energy Efficiency	Interruptible Schedules	Other DR	On-System Resources	Off-System Resources	Recall Agreements
Commodity Related Avoided Costs	Natural Gas Purchase and Transport Costs	✓			✓	✓	
	Greenhouse Gas Compliance Costs	✓			✓	✓	
	Commodity Price Risk Reduction Value	✓			✓	✓	
Infrastructure Related Avoided Costs	Supply Capacity Costs	✓	✓	✓	✓		✓
	Distribution System Costs	✓	✓	✓	✓		
Unquantified Conservation Costs	10% Northwest Power & Conservation Council Credit	✓					

4.2.1 Commodity Related Avoided Costs

These avoided costs are those that apply equally on a per unit of natural gas saved or supplied basis. This is to say that for these components it is either irrelevant or somewhat unimportant when the energy is saved or supplied.[72] For example, it is irrelevant from a greenhouse gas (GHG) emissions compliance cost perspective whether the emissions occur during a peak period or any other time of the year.

4.2.2 Gas and Transport Costs

This component represents the cost of the natural gas commodity itself. The main driver of these costs is the natural gas price forecast detailed in Chapter 2, though it also includes the following minor costs: 1) "line losses," or the amount of gas that is used to deliver gas from where it is purchased to where it is consumed; 2) applicable variable transmissions costs; and 3) storage inventory carrying costs. On any given day in the forecast period the avoided gas and transport costs represent the cost of the last unit of gas sold during that particular day,[73] where that unit may be from an expected daily spot purchase

[72] Noting that seasonality of natural gas prices and the storage resources in NW Natural's portfolio make it inaccurate to claim that when the energy is saved or served has no impact on these avoided costs.
[73] Which by cost minimization protocols is the most expensive unit of gas purchased that day.

or a storage withdrawal depending on the load that needs to be served and gas prices on that day. This daily figure comes from the resource planning optimization model and is aggregated to the monthly level. Note that avoided commodity and transport costs varied not only through time but also across end uses since each end use has its own estimate based on the seasonal usage or supply portfolio of that resource and the seasonality of natural gas prices exhibited in the price forecast. The details of this calculation can be found in Appendix C.

4.2.3 Greenhouse Gas Emissions Compliance Costs

NW Natural explicitly includes incremental environmental policy compliance costs for the CPP in Oregon and the CCA in Washington in its portfolio modeling assumptions. This is in addition to the current state and federal policies embedded in the gas price forecasts provided by a third-party consultant. Potential compliance costs are hence separately generated by state to meet environmental policy requirements specific to each state in NW Natural's service territory.

For Oregon, the incremental environmental policy cost is based on the marginal compliance resource needed for compliance with the CPP in Oregon. Potential marginal compliance resources and their costs are discussed in Chapter 6. It should be noted that the avoided GHG compliance costs are CCP specific and do not include compliance resources that are acquired to meet Oregon SB 98 targets, even though these resources could be counted toward emissions compliance.

For Washington, the calculation is slightly more straightforward as House Bill 1257 directs natural gas utilities to use the social cost of carbon inclusive of upstream emissions for planning purposes. It is the Company's interpretation that this bill applies to avoid costs and hence the Company uses the social cost of carbon published on the WUTC's website as the incremental environmental policy cost for Washington.[74]

4.2.4 Commodity Price Risk Reduction Value or the Hedge Value of DSM

While the "cost to achieve natural gas price certainty" is a more descriptive name for this component of avoided costs, this component is more commonly referred to as the "hedge value of DSM."[75] Natural gas prices are volatile and uncertain, particularly when analyzing long-term price forecasts as is necessary to 1) forecast costs in IRPs; and 2) evaluate the cost-effectiveness of resource options that provide energy savings or gas supply for multiple years (and in the case of DSM, sometimes indefinitely). If price hedging is not used to remove or mitigate this price volatility and uncertainty, customers are exposed to changes in the trend of prices in the long-term, and price fluctuations around this long-term trend in the short-term. DSM savings are a type of long-term hedge: if the actual energy savings that are going to be acquired and the costs to obtain those savings are known with

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[74] https://www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act/social-cost-carbon

[75] See OPUC docket No. UM 1622 for a lengthy discussion of the hedge value of DSM in avoided costs. Also, see page 10 and Appendix 1 of NW Natural's reply comments in the Company's 2016 IRP proceeding (OPUC docket No. LC 64) for a detailed history on how the hedge value of DSM came to be included in the NW Natural's avoided costs starting with the 2016 IRP. (https://edocs.puc.state.or.us/efdocs/HAC/lc64hac115929.pdf).

certainty, acquiring demand-side savings removes the price risk associated with unhedged supply resources that would be necessary if energy savings were not acquired. The hedge value of DSM represents the risk premium gas purchasers need to pay (i.e., the cost to fix the price) to obtain a long-term fixed price financial hedge at the time of the IRP analysis.[76]

This IRP applies a new methodology to measure the reduction in price risk (hedge value) for avoided cost that uses a similar risk assessment as the portfolio risk-adjusted present value revenue requirement (rPVRR) and the same methodology is used to determine the risk-adjusted incremental cost of renewable resources and based on data from the same Monte Carlo gas price simulations:

Risk Adjusted Cost of Gas = 75%*Mean Price + 25%* 95th Percentile Stochastic Price

The second term on the right-hand side of the formula represents the risk premium, which is a quantitative valuation of the cost risk associated with a given resource type. This is the risk that a hedge protects against, and hence the risk reduction value is calculated as:

Risk Reduction Value = Risk Adjusted Cost of Gas – Mean Stochastic Price of Gas

When the risk reduction value of DSM is added to the gas and transport costs described above, it represents the fixed price of gas that could be obtained through financial hedging instruments. The same risk reduction value is applied in both states and to all end uses and is the least significant component of avoided costs.

4.2.5 Infrastructure Related Avoided Costs

Infrastructure needs are driven by peak loads. Consequently, the extent to which resources reduce or supply energy on peak determines the infrastructure costs they avoid. To estimate infrastructure costs avoided for any resource there are two pieces that need to be calculated:

1) the incremental cost of serving additional peak load; and
2) the amount energy that would be saved or supplied during a peak

Note that the incremental cost of serving additional peak load is the same for all resources but the energy supplied or saved on peak is resource specific. Take energy efficiency as an example. A significant share of the energy savings achieved through DSM programs comes from large industrial customers, though many of these customers elect to be on interruptible schedules.[77] These customers are interrupted during peak events, so they do not contribute to peak load or the infrastructure designed to serve it. Therefore, savings acquired for interruptible customers avoid commodity related

[76] Inclusive of the costs of assessing and managing counterparty risk of financial hedging.
[77] Note that interruptible customers pay a lower rate than firm customers, with the difference in rate being the estimated infrastructure costs that are saved by interrupting customers during peak events.

costs, but do not avoid infrastructure related costs related to peak planning. On the other hand, DSM measures that target space heating, by contrast, result in relatively pronounced peak day load reductions (recall that space heating represents the vast majority of the peak load) in addition to the energy savings they provide on an annual basis.

There are two infrastructure-related avoided costs components — supply capacity avoided costs and distribution system avoided costs. Supply capacity resources are the resources we use to get gas onto our system of pipelines and are primarily interstate pipeline capacity and storage resources. Distribution system resources are the assets, primarily smaller pipelines, on NW Natural's system that distribute the gas that arrives at NW Natural's system via its supply resources to customers as it is demanded. Note that supply resources are held on a service territory-wide portfolio basis and serve both states, so supply capacity costs avoided per unit of gas are the same in both states. However, distribution assets are separate in Oregon and Washington, so distribution capacity costs avoided differ by state based upon the expected costs of the distribution system in that state. Per Commission guidance and industry best practices, infrastructure resource costs are based upon the costs of the incremental capacity resource (i.e., cost of the marginal resource) needed to meet customer needs.

4.2.6 Supply Capacity Costs

NW Natural's methodology for estimating supply capacity costs has not changed since the last IRP and has been applied to the end uses considered for DSM and the on-system supply resources discussed in Chapter 6.

1) Estimating the incremental infrastructure costs of serving peak day load:

Given the longstanding process of coordination between NW Natural and ETO/AEG (see Figure 4.2 in Section 4.3 for a visual depiction of this coordination) the DSM savings projections provided by ETO and AEG are completed before the supply resource optimization. Therefore, the incremental supply resources that would be saved for each year in the planning horizon with DSM need to be assumed before the supply resource optimization to assign a cost for the supply capacity costs being avoided. The assumptions made about what supply portfolio resources would be acquired in each year were not significantly different from the actual supply resource choices detailed in Chapter 7.[78] For supply-side resources, the supply capacity costs avoided are determined within the resource planning optimization.

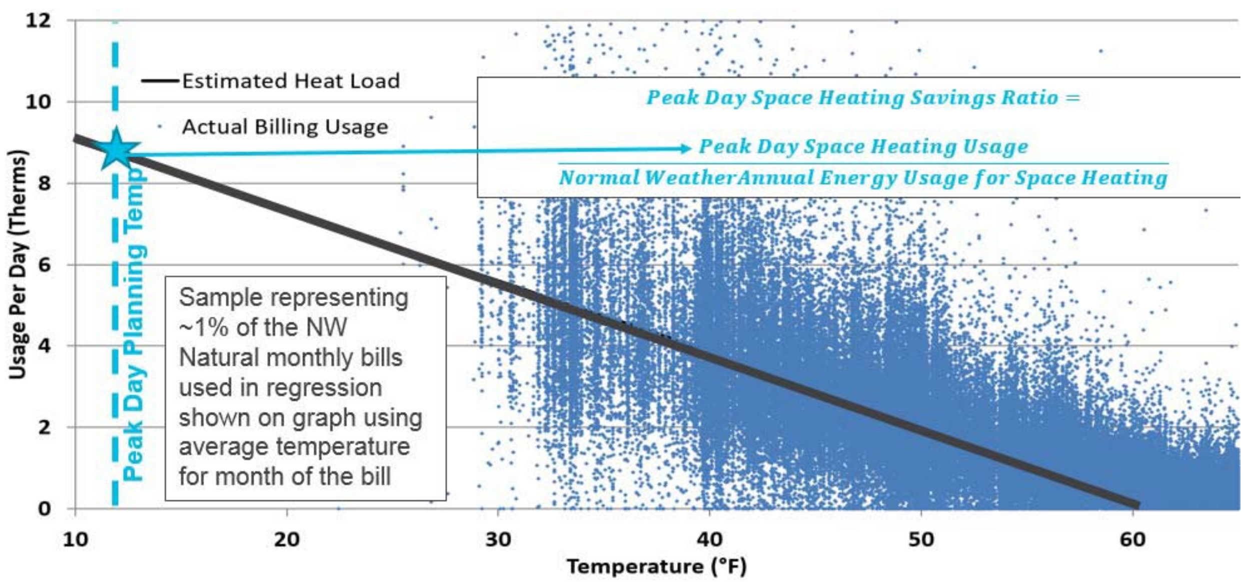
2) Estimating the energy savings or supply on a peak day for each resource option:

To give an idea of how this calculation works, the largest contributor to peak day load — residential space heating — is used as an example. Figure 4.1 shows daily usage for NW Natural residential

[78] Note that the avoided cost figures have been updated and will be used by Energy Trust for budgeting if the avoided costs in the 2018 IRP are acknowledged.

customers who use natural gas to heat their homes.[79] While there is much variation in usage due to differences in customer equipment efficiency, behavior, home type and size, and relative shell efficiency, the average NW Natural residential customer's space heating usage across temperatures is depicted by the black line. As the graph shows, using an estimate of the temperature that corresponds with NW Natural's peak day planning standard (see Chapter 3), an average residential customer would use roughly nine therms of gas for space heating on a peak day.

Figure 4.1: Residential Space Heating Peak Day Savings Estimate and Peak to Annual Ratio



In conjunction with an estimate of the average annual usage for space heating under normal Weather, this peak day usage estimate can be used to determine the share of annual space heating load that occurs on a planning peak day. Assuming the savings shape and the load shape are the same, this ratio can be multiplied by the ETO and AEG's annual savings estimated for each residential space heating measure to estimate the peak savings for that measure. This can then be used to calculate the supply infrastructure avoided costs on an energy basis. Similarly, the peak day to annual usage ratios were calculated for all the end uses considered. These ratios are shown in Table 4.2.

[79] Note that if a thermostat is set to a fixed temperature and the efficiency of the customer's space heating equipment is not a function of temperature (which is generally true of any natural gas space heating equipment currently used by NW Natural customers) usage will be linear in temperature.

Table 4.2: End Use Specific Peak Day Usage/Savings Ratios

Peak DAY Usage to Normal Weather Annual Usage Factors for SUPPLY Costs		Source of Information
Residential Space Heating (Including Hearths and Fireplaces)	**0.01983**	NW Natural Regressions
Commercial Space Heating	**0.01769**	NW Natural Regressions
Water Heating	**0.0033**	NW Natural Regressions and NEEA Water Heater Study
Cooking	**0.00356**	Analysis of ODOE RECS Data
Process Load	**0.00274**	Annual/365

4.2.7 Distribution Capacity Costs

The same general process undertaken for supply resource capacity costs avoided is also completed for avoided distribution capacity costs, with the key metric being the incremental costs associated with enhancing or reinforcing the distribution system to serve peak hour demand, rather than peak day demand.

1) Estimating the incremental infrastructure costs of serving growing peak hour load:

This state-specific calculation relies on historical data of the costs to reinforce NW Natural's distribution system and is based on an average of the revenue requirement of reinforcement projects that were completed over the previous five years. Note that these costs do not include the costs associated with installing new services or meters, operation, and maintenance costs, or with commodity purchases or our supply capacity resources. They represent only the cost-of-service revenue requirement of capital expenditures to reinforce the distribution system so that it is sufficient to reliably serve all our customers. The primary driver of these costs is growing peak hour load. Therefore, to estimate the cost of reinforcing NW Natural's distribution system as peak hour load grows, the growth in peak hour load for each of Oregon and Washington over the same five years was estimated using the peak hour load forecasting technique described in Chapter 8. Dividing the revenue requirement from the sum of the reinforcement projects over the past five years by the growth in peak hour load over the same period, gives an estimate of the cost of incremental peak hour load on a per unit of peak hour load for the two states in our service territory. This is the estimate of the costs that would be avoided by serving or saving a unit of gas on a peak hour. This methodology has been applied since the 2018 IRP.

2) Estimating the energy savings or supply on a peak day for each resource option

For each resource considered, the amount of natural gas it will supply or save on a peak hour is what is determined for each resource evaluated. Given that the peak hour is typically the hour starting at 7 a.m. on the peak day, this is done by estimating the share of peak day savings/supply that will occur during that hour and multiplying this factor by the peak day factors in Table 4.2. Take again the largest contributor to peak hour load — residential space heating — as an example: dividing the peak hour space heating load (7 a.m.) by the total space heating load for the peak day, provides an estimate of the share of peak day load served during the peak hour that distribution system infrastructure is designed to serve. This estimate was made using two sources, NW Natural system hourly flow regressions and the Electric Power Research Institute (EPRI) residential peak space heating load shape. These sources were averaged to calculate the hourly to daily peak hour factor for residential space heating. Using NW Natural's hourly load forecasting methodology described in Chapter 8, subtracting summer loads from peak day loads for each hour of the day provides an estimate of space heating load on a peak day, which can then be turned into the peak hour factor described above. For residential space heating, this factor is 5.79%.[80] Multiplying this factor times the peak day factor in Table 4.2 gives an estimate that the average residential NW Natural customer would use the equivalent of 0.115% of their normal weather *annual* residential space heating load on a peak hour. This figure, along with the peak hour to annual usage ratios for the other end uses considered in this IRP, is shown in Table 4.3.

Table 4.3: End Use Specific Peak Hour Usage/Savings Ratios

Peak HOUR Usage to Normal Weather Annual Usage Factors for DISTRIBUTION System Costs		Source of Information
Residential Space Heating	0.00115	NWN System Hourly Flows & EPRI Load Shape
Hearths and Fireplaces	0.00058	EPRI Load Shape
Commercial Space Heating	0.00139	NWN System Hourly Flows & EPRI Load Shape
Water Heating	0.00026	NWN System Hourly Flows & Ecotope Water Heating Study
Cooking	0.00071	EPRI Load Shape
Process Load	0.00011	Daily/24

Multiplying the factor shown in Table 4.3 by the annual normal weather usage for each end use measure or on-system supply resource gives an estimate of the energy saved or supplied on a peak hour, which can be multiplied by the estimate of the cost of serving an additional unit of peak hour load to estimate the costs avoided by that measure or supply resource.

4.2.8 Ten Percent Northwest Power and Conservation Council Conservation Credit

This credit is applied for DSM and is calculated from a summation of all the components of avoided costs except the hedge value of DSM and the GHG compliance cost components. Note that even though the 10% conservation credit is applied consistently across all DSM resources, the actual credit included in avoided costs varies since some of the avoided costs components vary by state, end use, and/or time. While the credit was originally designed to apply to DSM, it is unclear whether it should also be applied to supply-side resources that also conserve the use of conventional natural gas (most notably renewable natural gas) so that demand- and supply-side resources are treated on a fair and consistent basis per Oregon PUC's IRP guidelines. NW Natural has not included the Conservation Credit in the avoided costs of any resources except DSM in this IRP, but it warrants consideration in future IRPs.

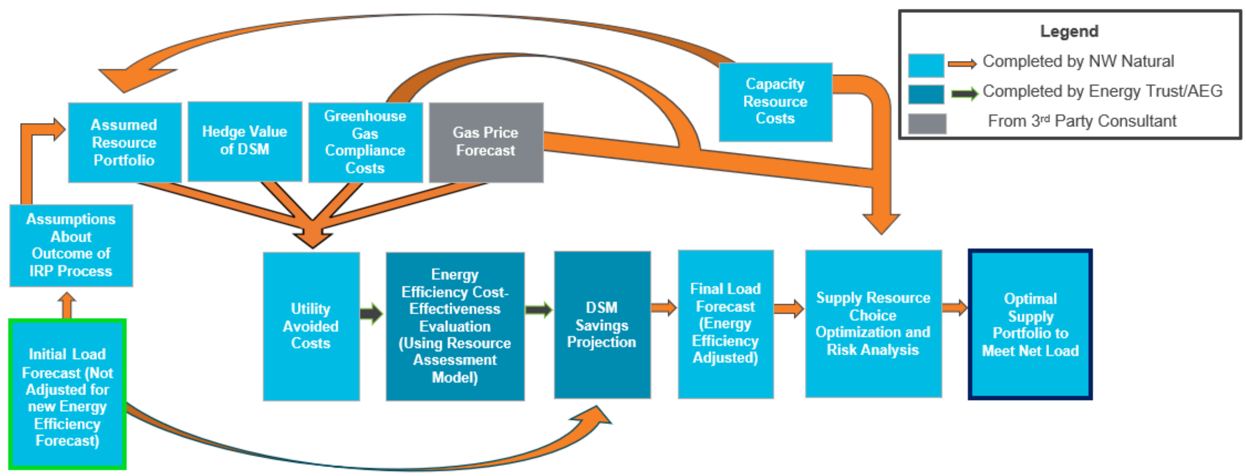
[80] Note that a flat load has a factor of 1/24, or 4.17%.

4.3 Demand-side Applications of Avoided Costs

4.3.1 Avoided Costs and DSM in the Overall IRP Process

Figure 4.2 details how avoided costs and DSM energy savings are integrated into the broader IRP process and shows what work is completed by NW Natural and what work is completed by ETO or AEG. Note that estimating the infrastructure (capacity) costs that can be avoided with DSM complicates the general process of obtaining the DSM savings projections from ETO and AEG. This complexity arises because the DSM savings projection has to be made before supply-side resource choice modeling to net the DSM savings projection out of load and start the supply-side resource optimization. That is, assumptions about what supply-side capacity resources to choose from need to be made before the resource optimization process has begun for ETO and AEG to complete their cost-effectiveness test and savings projections for DSM required by the IRP.[81]

Figure 4.2: NW Natural IRP Process



As shown in Figure 4.2, the optimal supply portfolio to meet net load is obtained during the final stage of the IRP modeling process, which is necessarily after NW Natural provides ETO avoided cost estimates for developing the savings projection found in Chapter 5. However, upon completion of the modeling in the IRP, a more accurate avoided cost estimate can be developed based upon the marginal costs of the supply-side resources from the preferred portfolio developed in Chapter 7. In prior IRPs NW Natural included in the IRP for acknowledgement the avoided costs provided to ETO early in the IRP analysis timeline. However, in this IRP the Company has decided to update the avoided costs based upon final IRP results as they represent the most accurate and up to date estimates of avoided costs at the time of filing the IRP, and those estimates are what is shown in this Chapter.

[81] Note that the work done by ETO and AEG to complete their DSM savings projections, and the projections for this IRP cycle, are the topic of Chapter 5.

4.3.2 Avoided Cost Component Breakdown Through Time

For each end use, avoided costs vary through time (and by state). Figure 4.3 uses Oregon residential space heating as an example to show the component breakdown of avoided costs through time for this end use.[82] It is interesting to note that in contrast to the 2018 IRP, a similar sharp increase in avoided costs is perceived in the 2030s but due to different reasons. In the 2018 IRP the sharp increase in avoided costs was due to supply capacity costs increasing dramatically as the Mist storage was expected to be exhausted in 2030. In this IRP, assumption about Mist Recall has changed: the Mist storage capacity may be recalled and transferred for use by core utility customers so this avoided costs component is forecasted to be small and steady throughout the planning horizon.[83] As shown in Figure 4.3, the sharp increase in avoided costs in Oregon this IRP comes from a significant increase in avoided GHG compliance costs. In Oregon, energy efficiency cannot avoid RNG acquisition to support SB 98, but it can be used for compliance under the Climate Protection Program (CPP), and as such the avoided GHG compliance costs are represented by the marginal emissions reduction activity expected to comply with the CPP in each year. Per Chapter 7[84], the marginal CPP activity is expected to be Community Climate Investments (CCIs) until 2035. However, the limit on the number of CCIs used for compliance will be reached in 2036. At this point in time the marginal cost of emissions reduction from the incremental renewable supply resource in a given year becomes the cost that can be avoided with additional EE savings. It is noticeable in Figure 4.3 that the avoided GHG compliance costs are decreasing over time after 2036, in alignment with the trend in renewable resource costs as described in Chapter 6. It is also worth noting that space heating has the greatest impact on peak loads, so the distribution infrastructure costs avoided are largest for space heating relative to the other end uses.

[82]See Appendix C for the same graph for each end use and also for Washington State.
[83] See Chapter 6 for a more detailed discussion regarding the Mist storage recall.
[84] Marginal resources from Scenario 1 are used to determine avoided costs.

Figure 4.3: Example Avoided Cost Breakdown Through Time – Oregon Residential Space Heating

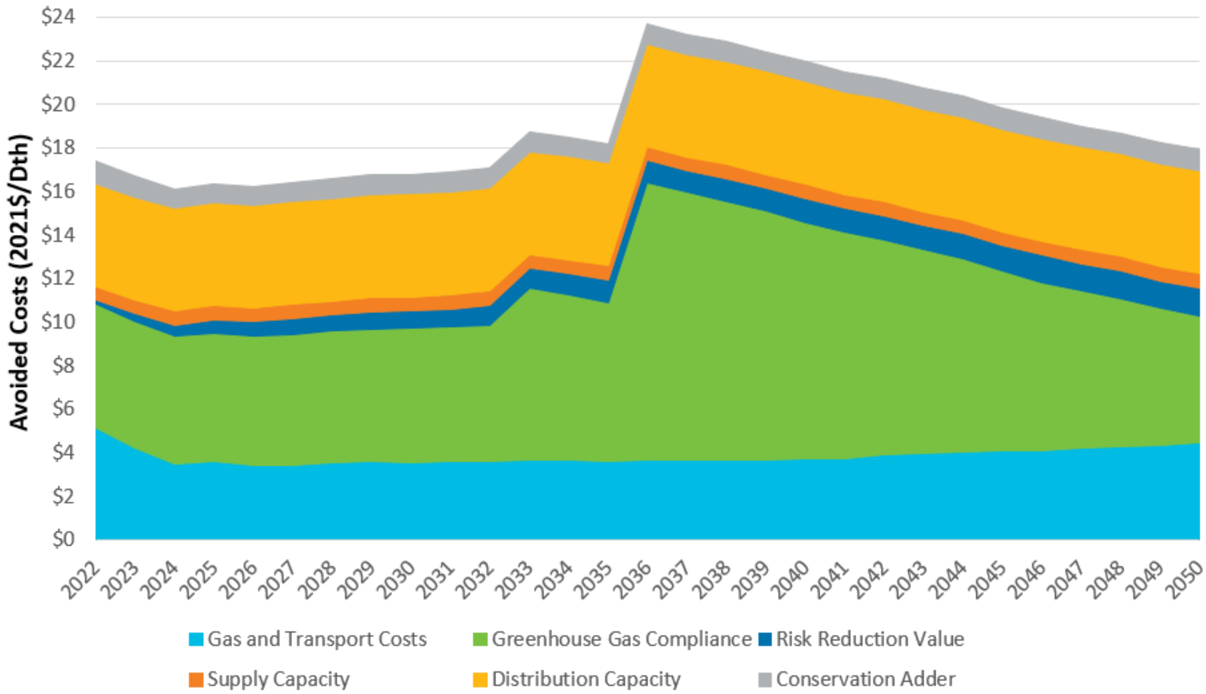


Figure 4.4 (Oregon), Figure 4.5 (Washington) and Table 4.4 summarize the component breakdown of avoided costs by end use and by state. The values are presented in levelized terms to provide a more succinct summary of the results. Note that the first bar (far left) in Figure 4.4 is a levelized representation of the time path shown in Figure 4.3.

Figure 4.4: Oregon 30-year Levelized Avoided Costs by End Use

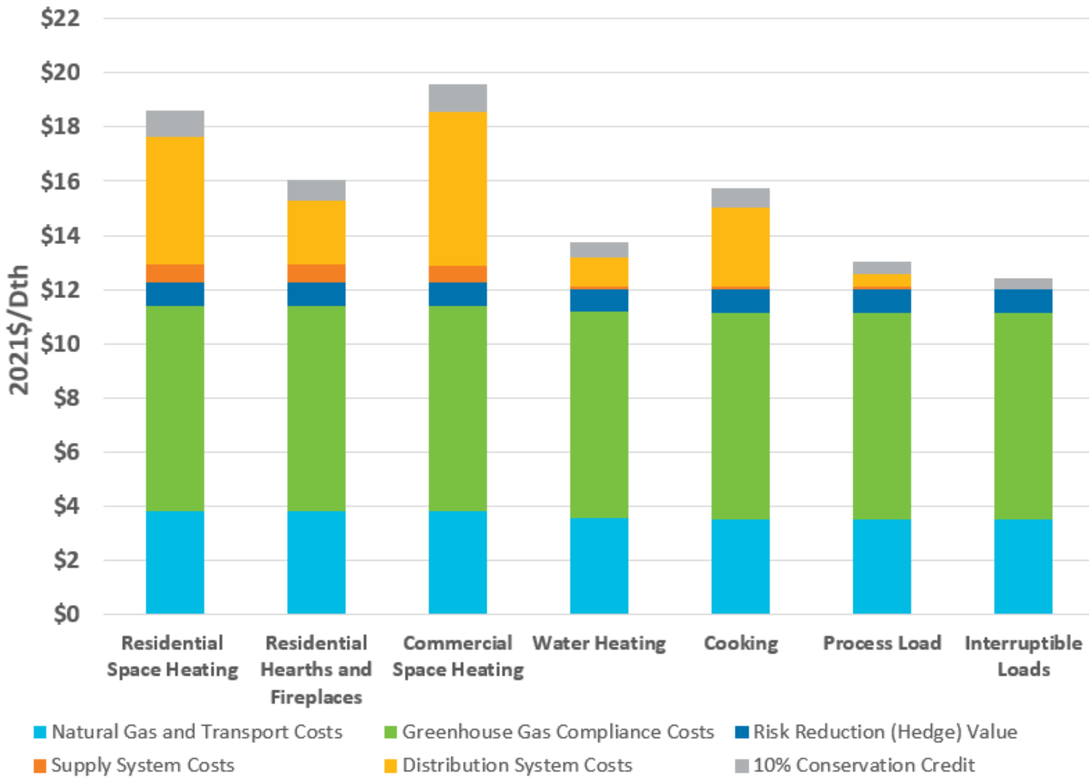


Figure 4.5: Washington 30-year Levelized Avoided Costs by End Use

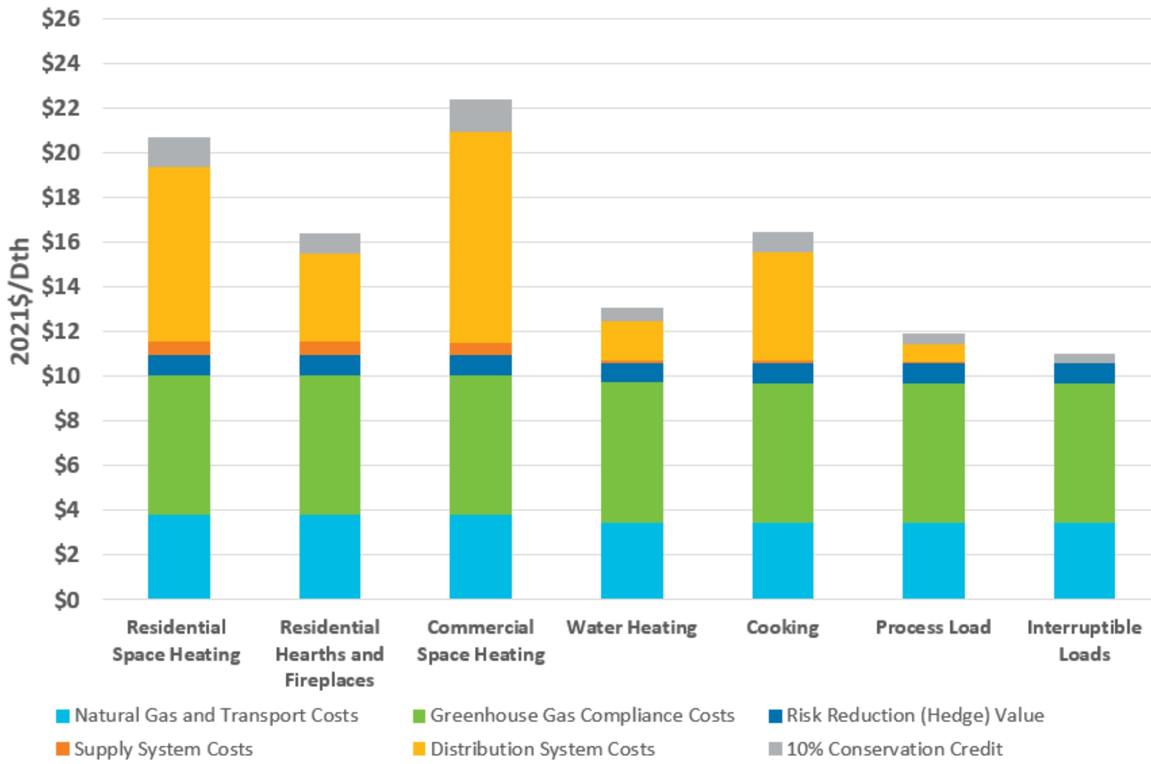


Table 4.4: Energy Efficiency Avoided Cost Summary Results by End Use and State (2021$/Dth)

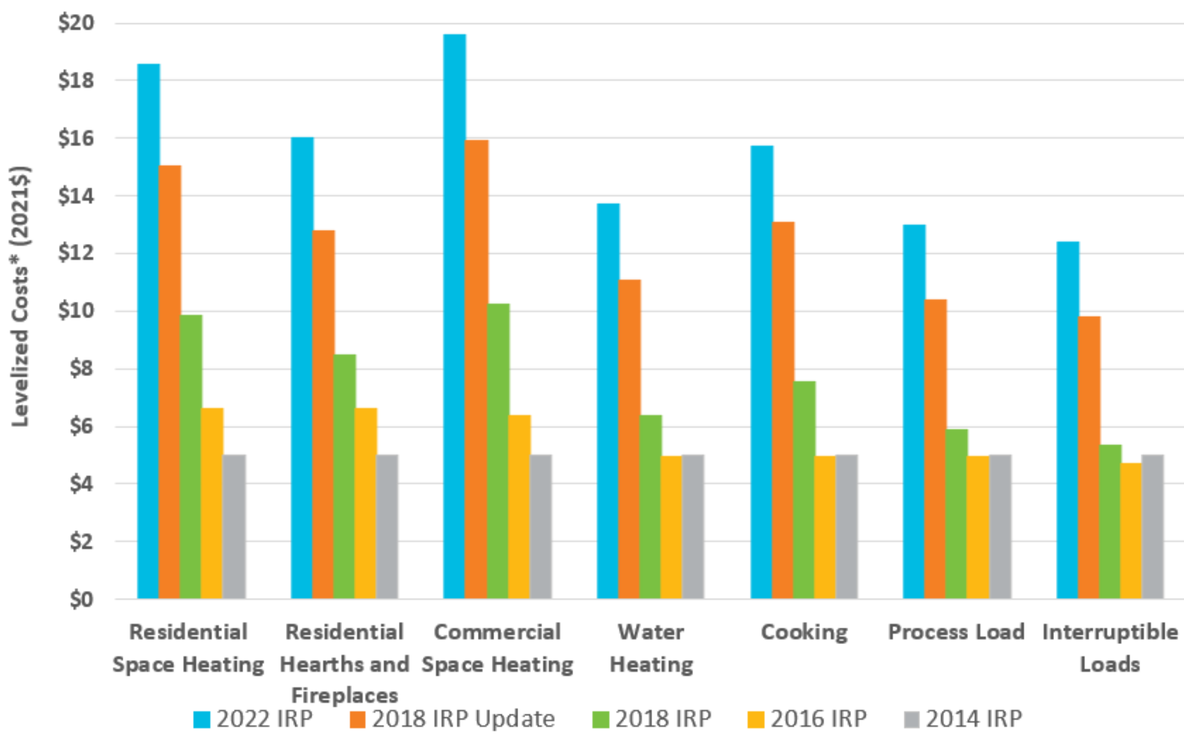
		Commodity Costs			Capacity Costs		10% Conservation Credit	**Total Avoided Costs**
		Natural Gas Commodity and Transport	Greenhouse Gas Compliance Costs	Risk Reduction (Hedge) Value	Supply Capacity Costs Avoided	Distribution System Resources		
Oregon	Residential Space Heating	$3.83			$0.64	$4.72	$0.92	**$18.58**
	Residential Hearths and Fireplaces	$3.83			$0.64	$2.37	$0.68	**$16.00**
	Commercial Space Heating	$3.83			$0.57	$5.69	$1.01	**$19.57**
	Water Heating	$3.58	$7.61	$0.86	$0.11	$1.07	$0.48	**$13.70**
	Cooking	$3.55			$0.12	$2.92	$0.66	**$15.72**
	Process Load	$3.55			$0.09	$0.47	$0.41	**$12.99**
	Interruptible Loads	$3.55			X	X	$0.36	**$12.38**
Washington	Residential Space Heating	$3.83			$0.64	$7.81	$1.23	**$20.64**
	Residential Hearths and Fireplaces	$3.83			$0.64	$3.93	$0.84	**$16.37**
	Commercial Space Heating	$3.83			$0.57	$9.42	$1.38	**$22.33**
	Water Heating	$3.50	$6.26	$0.86	$0.11	$1.77	$0.55	**$13.04**
	Cooking	$3.47			$0.12	$4.84	$0.85	**$16.40**
	Process Load	$3.47			$0.09	$0.78	$0.44	**$11.90**
	Interruptible Loads	$3.47			X	X	$0.36	**$10.95**

Table 4.4 shows that Washington avoided costs are slightly higher than Oregon avoided costs for space heating and cooking, due to the differences in distribution capacity costs across the states. Relative to Oregon, Washington avoided costs are more than 11% higher for residential space heating, 14% higher for commercial space heating, and 4% higher for cooking. However, Washington avoided costs for other end uses appear to be slightly lower than their Oregon counterparts because the difference in GHG compliance costs outweighs the differences in distribution capacity costs across the states.

4.3.3 Avoided Costs Results Across IRPs

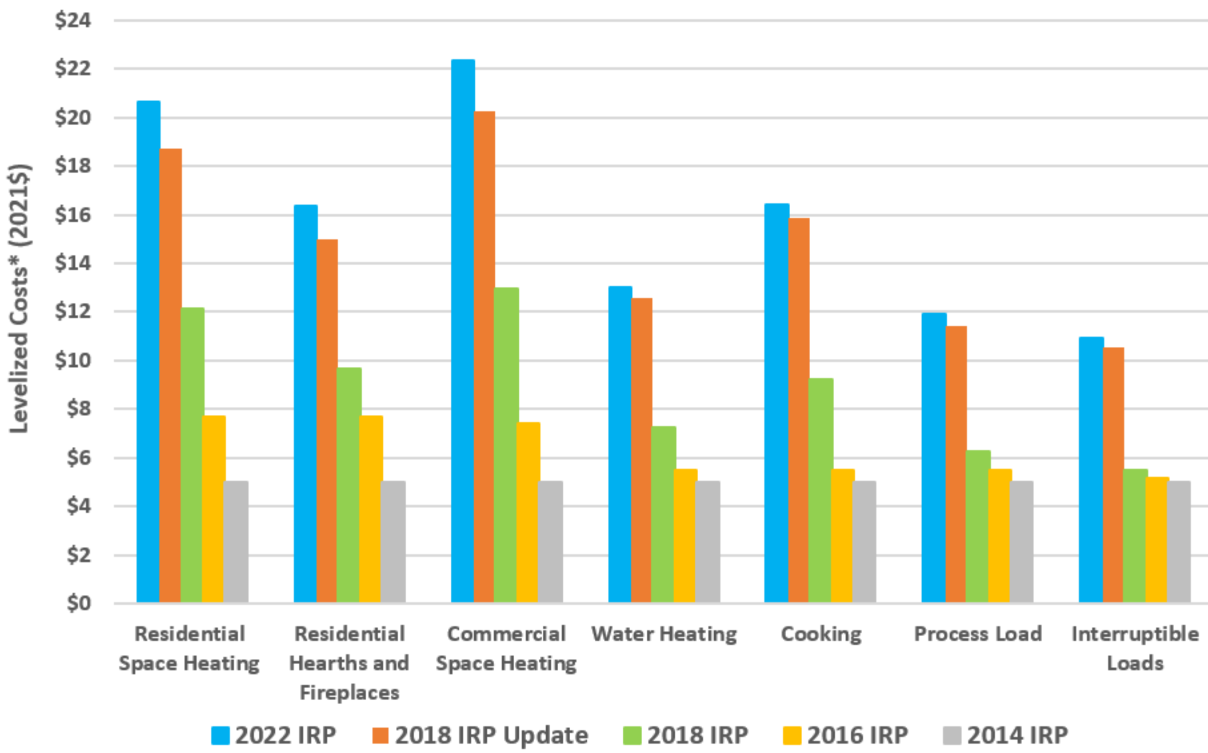
Figure 4.6 and Figure 4.7 show avoided costs for Oregon and Washington, respectively, by end use evaluated in the 2022 IRP, the avoided costs from the 2018 and 2016 IRPs, and those filed in the 2014 IRP (which were constant across end uses). Improvements to NW Natural's methodology for calculating peak savings from DSM are visible in the marked increase in estimated avoided costs for space heating measures.

Figure 4.6: Levelized Avoided Costs: 2022, 2018, 2016, and 2014 IRPs – Oregon



***2022 IRP and 2018 IRP Update are 30-year levelized figures where earlier figures are 20-year levelized figures**

Figure 4.7: Levelized Avoided Costs: 2022, 2018, 2016, and 2014 IRPs – Washington

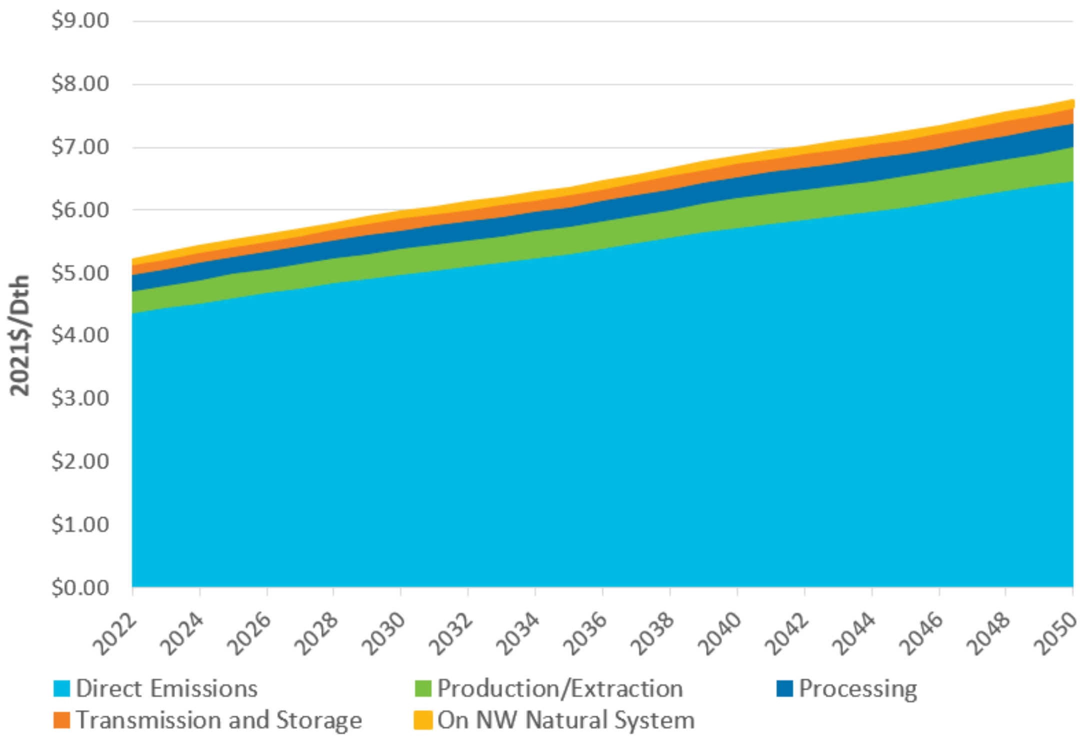


***2022 IRP and 2018 IRP Update are 30-year levelized figures where earlier figures are 20-year levelized figures**

4.3.4 Avoided Costs for Carbon Emissions Reductions

As is discussed in Chapter 2, full compliance with the federal and state climate and environmental policies and regulations is a key requirement for this IRP. Potential GHG emissions compliance costs are consequently an important component of avoided costs. Figure 4.8 shows how avoided costs for emissions reduction across the life cycle of natural gas change over the planning horizon 2022-2050. Note that the avoided costs for GHG emissions reduction come mostly from direct emissions (i.e., combustion of natural gas), accounting for 84 percent of the total. The GHG costs avoided from production/extraction, processing, transportation, and storage, and on NW Natural system are seven, five, three, and one percent in the total, respectively.

Figure 4.8: Avoided Costs by Life Cycle of Natural Gas and Year



4.4 Supply-side Applications of Avoided Costs

Non-conventional supply-side resources can also avoid costs associated with conventional resources. There are two primary examples where this can occur: 1) natural gas supply resources with lower carbon intensities, and 2) natural gas supply resources that are injected directly onto NW Natural's pipeline network ("on-system gas supply"). It is important to note that lower carbon on-system supply resources avoid both GHG compliance costs and the infrastructure costs associated with off-system gas supply.

4.4.1 Avoided Costs of Low Carbon Gas Supply

Natural gas supply alternatives that have a carbon intensity lower than conventional natural gas avoid expected GHG compliance costs, and the costs avoided depend upon the carbon intensity of the resource. For example, if a source of renewable natural gas has a carbon intensity of zero, it would avoid all the expected GHG compliance costs associated with conventional natural gas. The specific avoided cost items applied to these lower carbon gas supply resources are shown in Table 4.5, which shows that GHG compliance costs avoided are applied to all low carbon gas resources. The primary application of avoided costs is in the Low Carbon Gas Evaluation Methodology, which is detailed in the appendix.

Table 4.5: Costs Avoided by Low Carbon Resource Type

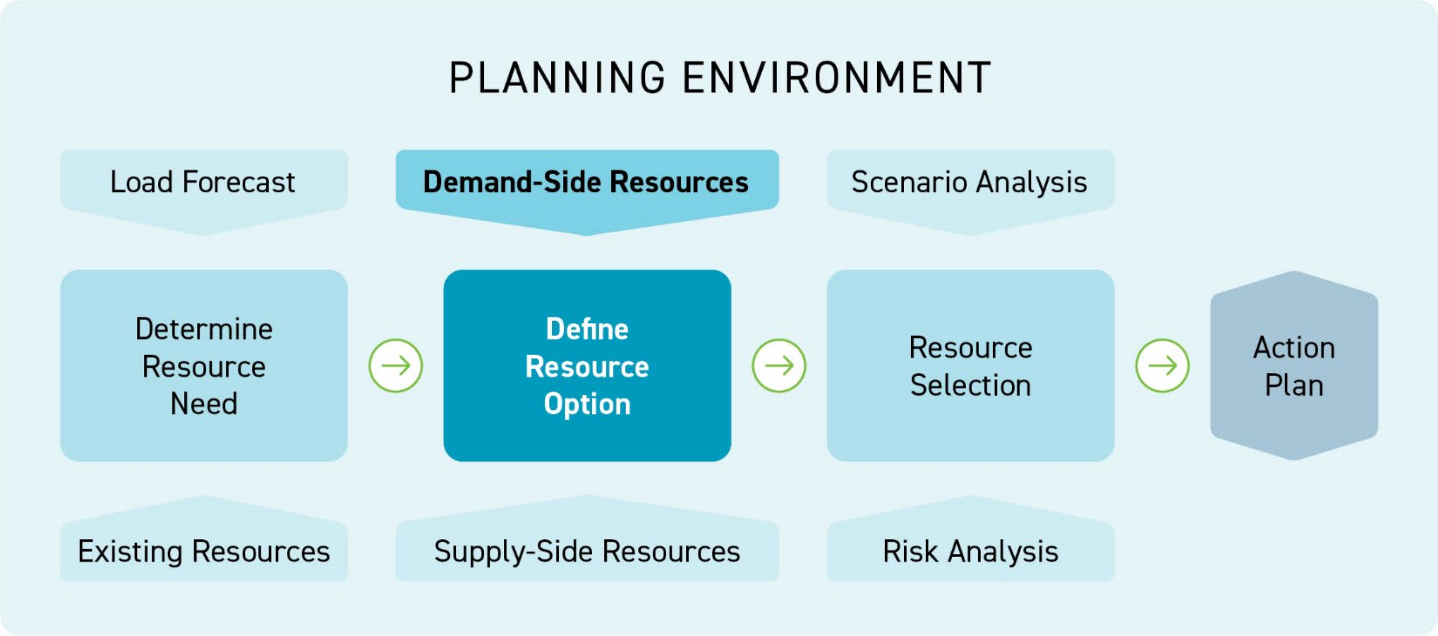
Costs Avoided by Resource Type	Conventional Gas Purchase and Transport Costs	Greenhouse Gas Compliance Costs	Gas Supply Capacity Costs-On-System Dispatch	Gas Supply displacement from bundled product	Distribution Capacity Costs
On-System Bundled RNG Purchase	X	X	X		X
RNG with Delivery to NW Natural- Bundled	X	X	X	X	
RNG with Sale of Brown Gas- Bundled - Choose Sales Hub	X	X			
Unbundled Environmental Attribute Purchase		X			

4.4.2 Avoided Costs of On-System Gas Supply

As described above, on-system natural gas supply avoids the incremental costs associated with serving peak load based upon how much gas is supplied directly onto NW Natural's system during a peak hour and day. The amount of gas supplied during peak times is resource-specific and the more on-system resources can supply gas directly onto NW Natural's system during peak times, the more value the resource provides to NW Natural's system and customers via delayed or avoided infrastructure investments. Like with demand-side resources, avoided supply capacity infrastructure costs from on-system gas supply are determined by multiplying the cost to bring an additional unit of peak day load onto NW Natural's system by the amount of gas the resource is expected to supply on a peak day. Similarly, avoided distribution system enhancement costs are calculated by multiplying the costs to serve an additional unit of peak hour load on NW Natural's distribution system by the amount of gas the resource is expected to supply on a peak hour.

Once resource needs are established it is important to take a wide scope to assess what options are available to meet those needs. Chapter 5 evaluates and forecasts resources that can be deployed to reduce customer energy use throughout the year (energy efficiency) and during the coldest days we experience (demand response).

5 | Demand-Side Resources



5.1 Energy Trust of Oregon

The following section provides was drafted by the Energy Trust of Oregon. Energy Trust is the administrator for NW Natural energy efficiency programs (EE) and completes the cost-effectiveness evaluation of the majority of the EE programs available to NW Natural's customers. Content provided by the Energy Trust territory is shown in maroon text, where the following section is specific to NW Natural's customers in Oregon.[85]

In 2002, as part of an agreement that allowed NW Natural to implement a decoupling mechanism, the Public Utility Commission of Oregon directed the Company to collect a public purpose charge for the funding of its residential and commercial energy efficiency programs and low-income programs, and to transfer the responsibility of energy efficiency programs to a third party.[86]

NW Natural chose Energy Trust as its program administrator. Energy Trust is a non-profit organization that was established as a result of electric direct access legislation adopted in 2002 to administer the Oregon-based, investor-owned electric utilities' energy efficiency programs. Energy Trust began managing NW Natural's residential and commercial program in 2003. The programs are outlined in the Company's Tariff Schedule 350 and funded through the public purpose charge, Schedule 301.

After NW Natural's 2008 IRP[87] identified that cost-effective industrial savings were available, the Company worked with Energy Trust to launch an Industrial demand-side management (DSM) program in Oregon. This program is available to large Firm and Interruptible Sales customers, but not transportation customers. Costs for the program, described in Schedule 360 of the Company's tariff, are deferred for recovery a year later through the charge published annually in Schedule 188.

With the exception of the first few years of the residential and commercial programs in Oregon when gas customers were just learning about the availability of incentives for energy efficient equipment, Energy Trust has been meeting and even exceeding the annual savings targets derived through the biannual IRP analysis of the available, cost-effective DSM potential.

Since October 1, 2009, NW Natural has provided energy efficiency programs to its Washington Residential and Commercial customers in compliance with the direction provided by the WUTC in the Company's 2008 rate case.[88] The programs were developed and continue to evolve under the oversight of the Energy Efficiency Advisory Group (EEAG), which is comprised of interested parties to the Company's 2008 rate case. Energy Trust administers the programs, leveraging the offerings available in Oregon to customers located in Washington.[89]

[85] Energy Trust administers NW Natural's energy efficiency programs in both Oregon and Washington. The methodology and results in this chapter are provided by Energy Trust and are Oregon specific. NW Natural's Washington energy efficiency forecast was performed by a different entity and the results of which are described in a separate section.
[86] See Order No. 02-634 in Docket No. UG 143.
[87] See Docket No. LC 45.
[88] See Order No. 4 in Docket UG-080546.
[89] The program's parameters are provided in the Company's Schedule G and its Energy Efficiency Plan, which by reference is part of the Tariff. The program is funded through a charge collected in accordance with Schedule 215.

5.1.1 Energy Trust Forecast Overview and High-Level Results for Oregon

Energy Trust developed a 20-year DSM resource forecast for NW Natural territory in Oregon using Energy Trust's DSM resource assessment modeling tool (hereinafter 'RA Model') to identify the total 20-year cost effective modeled savings potential. Energy Trust then deploys this cost-effective potential exogenously to the RA model into an annual savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. This final 20-year savings projection is provided to NW Natural for inclusion in the Company's forecasts. The 2022 IRP results show that NW Natural can save 41.2 million therms[90] in Oregon in the next five years from 2022 to 2026 and over 147.1 million therms by 2041.[91] These results represent a 37% and 6% increase respectively in cost-effective DSM potential over the prior IRP in 2018. The two main drivers of this increased potential are:

1) *Increased budgets and program forecast:* NW Natural and Energy Trust coordinated on assumptions associated with accelerating the energy efficiency forecast to reflect increased annual program budgets in the first five years of the IRP.
2) *Measure additions and updates:* Energy Trust added several new emerging technologies to the model and updated measure level assumption for several of the existing measures

Figure 5.1 depicts the full suite of savings potential identified both in the model (Technical, Achievable, Cost-effective achievable) as well as the amount included in the final savings projection by Sector.

[90] The savings discussed in this chapter and appendices, depicted in all tables and the following figures showing savings projections are in gross savings for Oregon unless otherwise explicitly noted. Energy Trust publicly reports its Oregon savings and goals in gross savings as determined in consultation with OPUC and stakeholders in 2019. Energy Trust public reports prior to 2020 included net savings which are adjusted for market effects including free ridership and spillover. Prior Energy Trust DSM chapters for NWN IRP were in gross savings. Gross savings are not adjusted for market effects and most accurately reflect the reductions NW Natural will see on their system.

[91] Includes over 6.6 million therms of market transformation savings resulting from code changes driven by Energy Trust's New Buildings Program. Also includes 4.5 million therms from a large project adder incorporated into the savings forecast; more details on this adder are included later in this chapter.

Figure 5.1: 20-year Savings Potential by Sector and Potential Type - Oregon

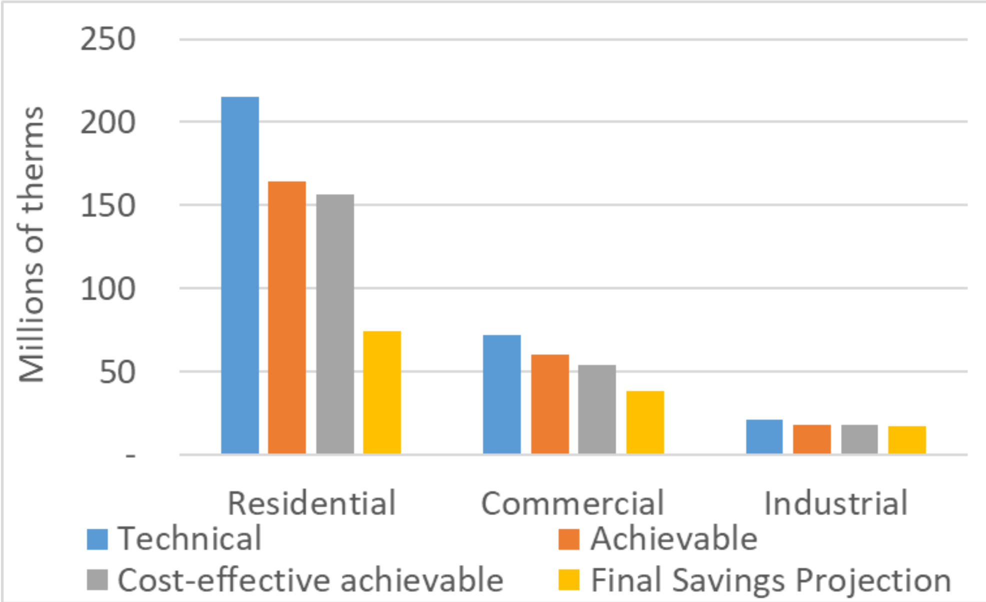
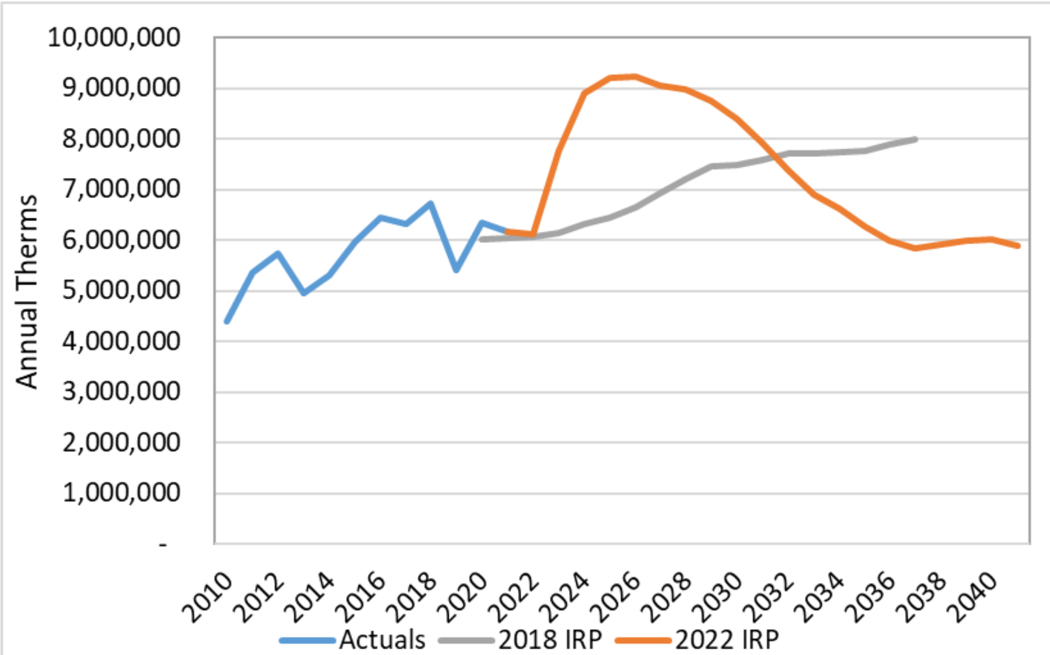


Figure 5.2 links actual historical savings going back to 2010 to the new savings projection for the 2022 IRP. It also compares the 2022 IRP forecast to the 2018 IRP forecast.

Figure 5.2: Annual Savings Projection Comparison for 2018 and 2022 IRPs, with Actual savings since 2010 - Oregon



5.1.2 Energy Trust Resource Assessment Economic Modeling Tool

Energy Trust owns, operates, and maintains a RA Model to perform the complex calculation process to create DSM forecasts for each of the utilities it serves, including NW Natural. The tool estimates the total technical, achievable, and cost-effective achievable potential for acquiring DSM resources in NW Natural's service territory across residential, commercial, and industrial sectors. The model primarily takes a bottom-up approach that begins with estimating available measure level savings and related cost and market penetration assumptions. These measure level savings are scaled up to NW Natural's service territory based on a set of applicability assumptions for each measure adjusted based on NW Natural inputs, such as customer and load forecasts, among others. The product of all these factors results in the total 20-year DSM savings potential available that can be acquired by providing energy efficiency services to NW Natural's customers.

In the intervening years since NW Natural's 2018 IRP, Energy Trust has made several updates and improvements to the RA model. These enhancements contributed to the increase in energy efficiency potential identified in this DSM forecast:

- *Refreshed measure level assumptions* – Measure inputs for measures spanning residential, commercial, and industrial program sectors were reviewed and updated using a combination of Energy Trust primary data review and analysis, regional secondary sources, and engineering analysis. The refreshed assumptions include baseline adjustments, savings and costs updates, as well as density assumptions pertaining to where measures can be installed and existing measure saturation rates.

- *Lost opportunity measures and unconstrained potential to replace failed equipment* – Lost opportunity measures are constrained in each year by the assumed failed equipment burnout rate as a percentage of total stock. Energy Trust has aligned how the RA model treats lost opportunity measures to be consistent with Northwest Power and Conservation Council (NWPCC) methodology, constraining replace on burnout turnover exogenously to the RA model and allowing lost opportunities to recycle throughout the forecast period.
- *Updated achievability assumptions to align with NWPCC methodology* – Energy Trust has updated achievability assumptions to be consistent with what was used in the most recent power plan. Historically achievability rates were assumed to be 85% for all measures. NWPCC has updated these rates for some measures based on market research. At a high level these changes result in greater achievability for market transformation and codes and standards, and lower achievability for shell measures.

Figure 5.3 shows a graphical representation of the three categories of savings potential identified by Energy Trust's RA Model. The following methodology section describes the inputs and methods to calculate each of these potential types in detail.

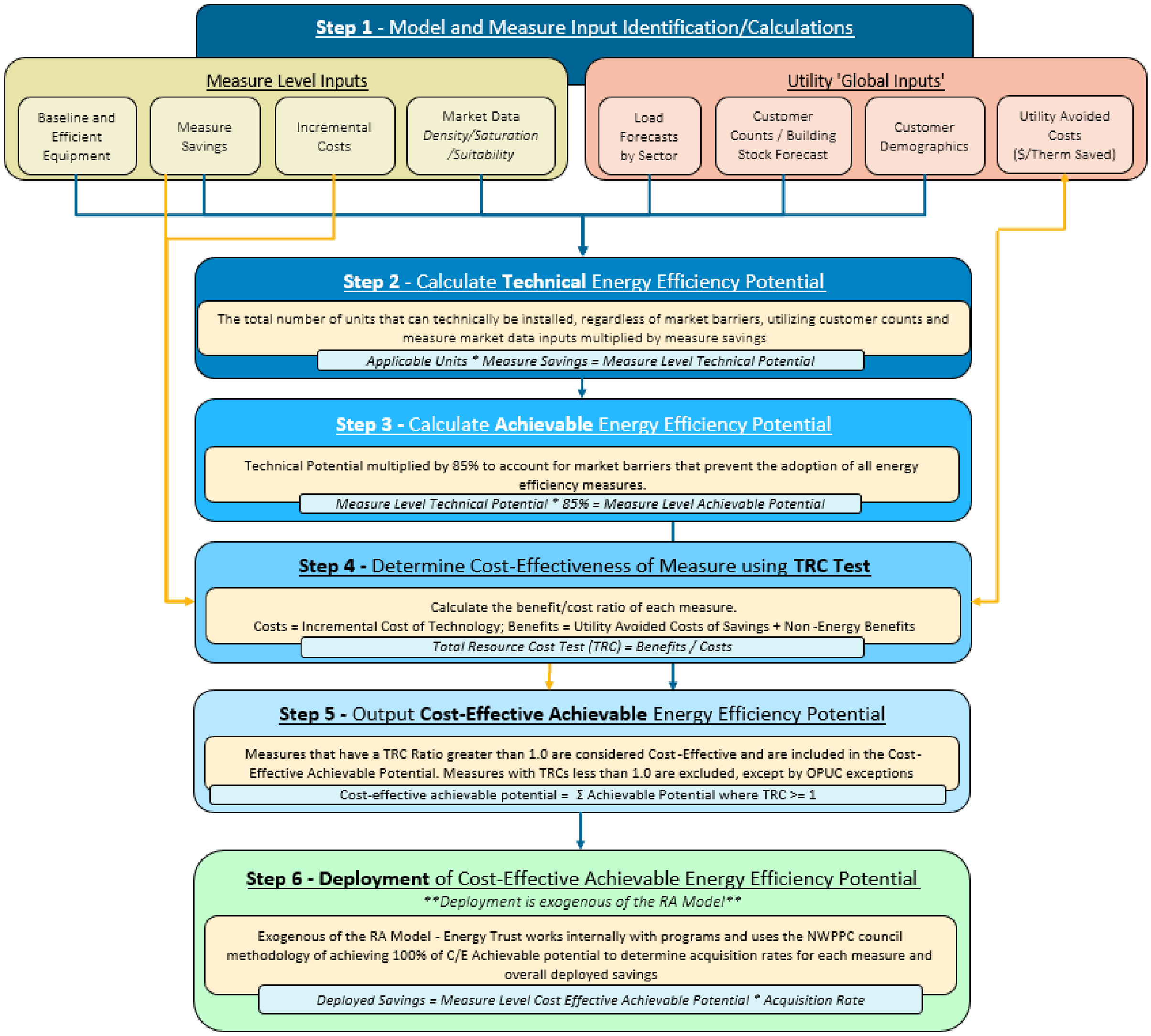
Figure 5.3: Three categories of savings potential identified by RA Model

<table>
<tr><td>Not technically feasible</td><td colspan="3">Technical Potential</td></tr>
<tr><td>Not technically feasible</td><td>Market barriers</td><td colspan="2">Achievable Potential</td></tr>
<tr><td>Not technically feasible</td><td>Market barriers</td><td>Not cost effective</td><td>Cost-Effective Potential</td></tr>
</table>

5.1.3 Methodology for Determining the Cost-Effective DSM Potential

Energy Trust's DSM resource assessment follows six overarching steps from initial calculations to deployed savings, as shown in Figure 5.4. Steps 1 through 5 (Measure Identification/Input Development to Cost Effective Achievable Output) are calculated within Energy Trust's RA Model. This results in the total cost-effective potential that is achievable over the forecast horizon. The actual deployment of these savings (the acquisition percentage of the total potential each year – Step 6 of Figure 5.4 is done exogenously of the RA model and is explained in further detail in the next section. The remainder of this section provides further detail on steps 1 – 5 of the overall methodology shown in Figure 5.4.

Figure 5.4: Energy Trust's 20-Year DSM Forecast Determination Methodology



Step 1: Model and Measure Input Identification/Calculations

The first step of the modeling process is to identify and characterize the list of measures to include in the model, as well as receive and format utility 'global' inputs for use in the model. Energy Trust compiles and loads a list of all commercially available and emerging technology measures for residential, commercial, industrial and agricultural applications installed in new or existing structures. The list of measures is meant to reflect the full suite of measures offered by Energy Trust, plus a spectrum of emerging technologies.[92] Simultaneous to this effort, Energy

[92] An emerging technology is defined as technology that is not yet commercially available but is in some stage of development with a reasonable chance of becoming commercially available within a 20-year timeframe. The model is capable of quantifying costs, potential, and risks associated with uncertain, but high-saving emerging technology measures. The savings from emerging technology measures are reduced by a risk-adjustment factor based on what stage

Trust collects necessary data from the utility to run the model and scale the measure level savings to a given service territory (known as 'global inputs').

- ***Measure Level Inputs:***
  Once the measures to include in the model have been identified, they must be characterized in order to determine their savings potential and cost-effectiveness. The characterization inputs are determined through a combination of Energy Trust primary data analysis, regional secondary sources[93], and engineering analysis. There are over 30 measure level inputs that feed into the model, but on a high level, the inputs are put into the following categories:
  1. *Measure Definition and Equipment Identification*: This is the definition of the efficient equipment and the baseline equipment it is replacing (e.g., a 70+% EF gas storage water heater replacing an 60% EF baseline gas water heater).
  2. *Measure Savings:* the therms savings associated with an efficient measure calculated by comparing the baseline and efficient measure consumptions.
  3. *Incremental Costs:* The incremental cost of an efficient measure over the baseline. The definition of incremental cost depends upon the replacement type of the measure. If a measure is a Retrofit measure, the incremental cost of a measure is the full cost of the equipment and installation. If the measure is a Replace on Burnout or New Construction measure, the incremental cost of the measure is the difference between the cost of the efficient measure and the cost of the baseline measure.
  4. *Market Data:* Market data of a measure includes the density, saturation, and suitability of a measure. A density is the number of measure units that can be installed per scaling basis (e.g., the average number of showers per home for showerhead measures). The saturation is the average saturation of the density that is already efficient (e.g., 50% of the showers already have a low flow showerhead). Suitability of a measure is a percentage input to represent the percent of the density that the efficient measure is actually suitable to be installed in. These data inputs are all generally derived from regional market data sources such as RBSA and CBSA.
- ***Utility Global Inputs:***
  The RA Model requires several utility-level inputs to create the DSM forecast. These inputs include:
  1. *Customer and Load Forecasts:* These inputs are essential to scale the measure level savings to a utility service territory. For example, residential measures are characterized on a scaling basis 'per home', so the measure densities are calculated as the number of measures per home. The model then takes the number of homes that NW Natural serves currently and the forecasted number of homes to scale the measure level potential to their entire service territory.

of development the technology is in. The concept is that the incremental risk-adjusted savings from emerging technology measures will result in a reasonable amount of savings over standard measures for those few technologies that eventually come to market without having to try and pick winners and losers.

[93] Secondary Regional Data sources include: The Northwest Power Planning Council (NWPPC), the Regional Technical Forum (the technical arm of the NWPPC), and market reports such as NEEA's Residential and Commercial Building Stock Assessments (RBSA and CBSA)

2. *Customer Stock Demographics:* These data points are utility specific and identify the percentage of stock that utilize different heating fuels for both space heating and water heating. The RA Model uses these inputs to segment the total stocks to the stocks that are applicable to a measure (e.g., gas storage water heaters are only applicable to customers that have gas water heat).
3. *Utility Avoided Costs:* Avoided costs are the net present value of avoided commodity and commodity-related costs as well as avoided supply-side and demand-side resource costs associated with energy efficiency savings represented as $s per therm saved. Please see Chapter 4 for more detail. Avoided costs are the primary 'benefit' of energy efficiency in the cost effectiveness screen.

Step 2: Calculate Technical Energy Efficiency Potential

Once measures have been characterized and utility data loaded into the model, the next step is to determine the technical potential that could be saved. Technical potential is defined as the total potential of a measure in the service territory that could be achieved regardless of market barriers, representing the maximum potential savings available. The model calculates technical potential by multiplying the number of applicable units for a measure in the service territory by the measure's savings. The model determines the total number of applicable units for a measure utilizing several of the measure level and utility inputs referenced above:

Total applicable units =	*Measure Density * Baseline Saturation * Suitability Factor * Heat Fuel Multipliers (if applicable) * Total Utility Stock (e.g., # of homes)*
Technical Potential =	*Total Applicable Units * Measure Savings*

The measure level technical potential is then summed up to show the total technical potential across all sectors. This savings potential does not take into account the various market barriers that will limit a 100 percent adoption rate.

Step 3: Calculate Achievable Energy Efficiency Potential

Achievable potential is simply a reduction to the technical potential based on each measure's achievability assumption rate, to account for market barriers that prevent total adoption of all cost-effective measures. Historically the achievable potential was defined as 85 percent of the technical potential. The Northwest Power and Conservation Council (NWPCC) updated the achievability assumption for certain measures in the most recent power plan, and Energy Trust has aligned the RA model with these assumptions. Many measures still have 85 percent achievability while market transformation and codes and standards are assumed to be closer to 100% achievable while shell measures are closer to 60% achievable.

Achievable Potential =	*Technical Potential * achievability%*

Step 4: Determine Cost Effectiveness of Measure using TRC Test

The RA Model screens all DSM measures in every year of the forecast horizon using the Total Resource Cost (TRC) test, a benefit-cost ratio (BCR) that measures the cost effectiveness of the investment being made in a DSM measure. This test evaluates the total present value of benefits attributable to the measure divided by the total present value of all costs. A TRC test value equal to or greater than 1.0 means the value of benefits is equal to or exceeds the costs of the measure and is therefore cost-effective and contributes to the total amount of cost-effective potential. The TRC is expressed formulaically as follows:

TRC = Present Value of Benefits / Present Value of Costs

Where the Present Value of Benefits includes the sum of the following two components:

a) Avoided Costs: The present value of natural gas energy saved over the life of the measure, as determined by the total therms saved multiplied by NW Natural's avoided cost per therm.[94] The net present-value of these benefits is calculated based on the measure's expected lifespan using the Company's discount rate.[95]
b) Non-energy benefits are also included when present and quantifiable by a reasonable and practical method (ex. Water savings from low-flow showerheads, Operations and Maintenance (O&M) cost reductions from advanced controls).

Where the *Present Value of Costs* includes:

a) Incentives paid to the participant; and
b) The participant's remaining out-of-pocket costs for the installed cost of the measures after incentives, minus state and federal tax credits.

[94] See Chapter 4 for a discussion of NW Natural's avoided cost.
[95] NW Natural's real after-tax annual discount rates used in the 2018 IRP are 3.83 percent for Oregon. As discussed in Chapter Four, DSM energy savings forecasts need to be completed prior to NW Natural's resource optimization analysis. Therefore, NW Natural provided the 3.83 percent discount rate to ETO in 2021 and updated the discount rate to 3.4 percent in May 2022 and used it in resource optimization to reflect the influence of the recent dynamic economic environment. It is worth noting that the cost of a DSM measure occurs typically in the year of installation while the stream of its benefits lasts over its entire useful life. Therefore, a higher discount rate results in a lower present value for the benefits and so forth a lower cost effectiveness test value. That is, compared to the more recent discount rate of 3.4 percent, the use of a 3.83 percent discount rate could lead to a more conservative DSM savings forecast.

The cost effectiveness screen is a critical component for Energy Trust modeling and program planning because Energy Trust is only allowed to incentivize cost-effective measures unless an exception has been granted by the OPUC.

Step 5: Quantify the Output of Cost-Effective Achievable Energy Efficiency Potential

The RA Model's final output of potential is the quantified cost-effective achievable potential. If a measure passes the TRC test described above, then *achievable savings* from a measure is included in this potential. If the measure does not pass the TRC test above, the measure is not included in cost-effective achievable potential. However, the cost-effectiveness screen is overridden for some measures under two specific conditions: 1) The OPUC has granted an exception to offer non-cost-effective measures under strict conditions or 2) the measure is cost-effective when using blended gas avoided costs[96] and is therefore offered by Energy Trust programs.

Step 6: Deployment of Cost-Effective Achievable Energy Efficiency Potential

After determining the cumulative 20-year[97] cost-effective achievable modeled potential, Energy Trust develops a savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. The savings projection is a 20-year forecast of energy savings that will result in a reduction of load on NW Natural's system. Energy Trust ramp rates are based on Northwest Power and Conservation Council method and ramp rates, but calibrated to be specific to Energy Trust. Retrofit measure potential continues until 100% of the cost-effective achievable potential is acquired and saving potential is exhausted. Lost opportunity measures continue to ramp up to 100% of annual available cost-effective achievable potential at which point all savings are realized annually. Hard to reach measures or emerging technologies do not ramp to 100%. This savings forecast includes savings from program activity for existing measures and emerging technologies, expected savings from market transformation efforts that drive improvements in codes and standards, and a forecast of what Energy Trust is describing as a 'large project adder', savings that account for large unidentified projects that consistently appear in Energy Trust's historical savings record and have been a source of overachievement against IRP targets in prior years. The evolution from modeled technical potential to savings projections is depicted in Figure 5.5.

[96] Energy Trust uses blended avoided costs for measure development and cost-effectiveness screening to provide uniform gas offerings throughout Oregon. Utility specific avoided costs are used in RA modeling to align inputs with utility IRPs.
[97] Energy Trust provided NW Natural with a final savings projection extended to 2050. These results are discussed in section 5.1.6.

Figure 5.5: The Progression to Program Savings Projections

<table>
<tr><td>Not Technically Feasible</td><td colspan="4">Technical Potential</td></tr>
<tr><td>Not Technically Feasible</td><td>Market Barriers</td><td colspan="3">Achievable Potential</td></tr>
<tr><td>Not Technically Feasible</td><td>Market Barriers</td><td>Not Cost Effective</td><td colspan="2">Cost Effective Potential</td></tr>
<tr><td>Not Technically Feasible</td><td>Market Barriers</td><td>Not Cost Effective</td><td>Program Design, Market Penetration</td><td>Final Savings Projection</td></tr>
</table>

5.1.4 RA Model Results and Outputs

The RA Model outputs results by potential type, as well as several other useful outputs, including a supply curve based on the levelized cost of energy efficiency measures. This section discusses the overall model results by potential type and provides an overview of the supply curve.

Forecasted Savings Potential by Type

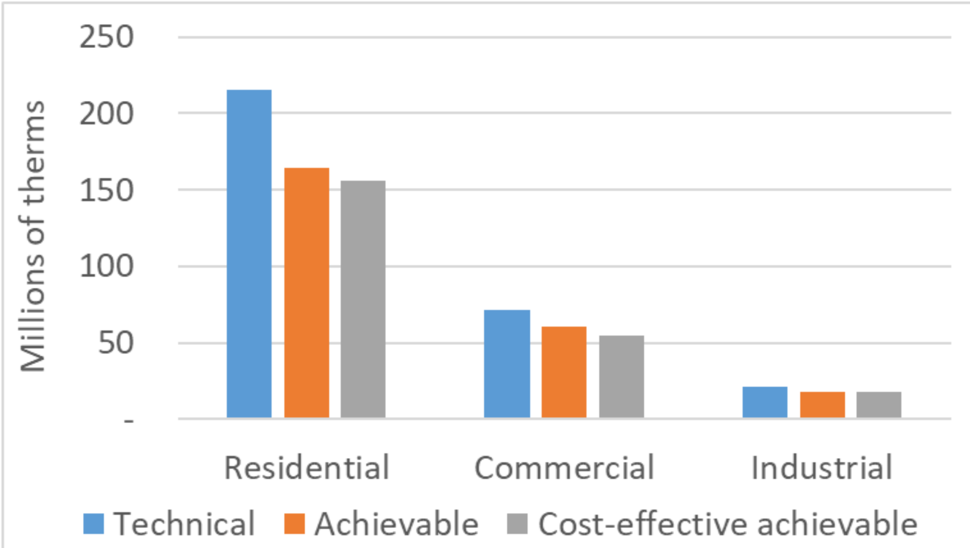
Table 5.1 summarizes the technical, achievable, and cost-effective potential for NW Natural's system in Oregon by market sector. These savings represent the total 20-year cumulative savings potential identified in the RA Model by the three types identified in Figure 5.3. Modeled savings represent the full spectrum of potential identified in Energy Trust's resource assessment model through time, prior to deployment of these savings into the final annual savings projection.

Table 5.1: Summary of Cumulative Modeled Savings Potential - 2022–2041 - Oregon

Sector	Technical Potential (Therms)	Achievable Potential (Therms)	Cost-effective achievable Potential (Therms)
Residential	215,276,957	164,364,887	156,369,194
Commercial	71,737,121	60,455,169	54,208,488
Industrial	21,290,701	18,097,096	18,097,096
Total	**308,304,779**	**242,917,152**	**228,674,778**

Figure 5.6 shows cumulative forecasted savings potential across the three sectors Energy Trust serves, as well as the type of potential identified in NW Natural's Oregon service territory.

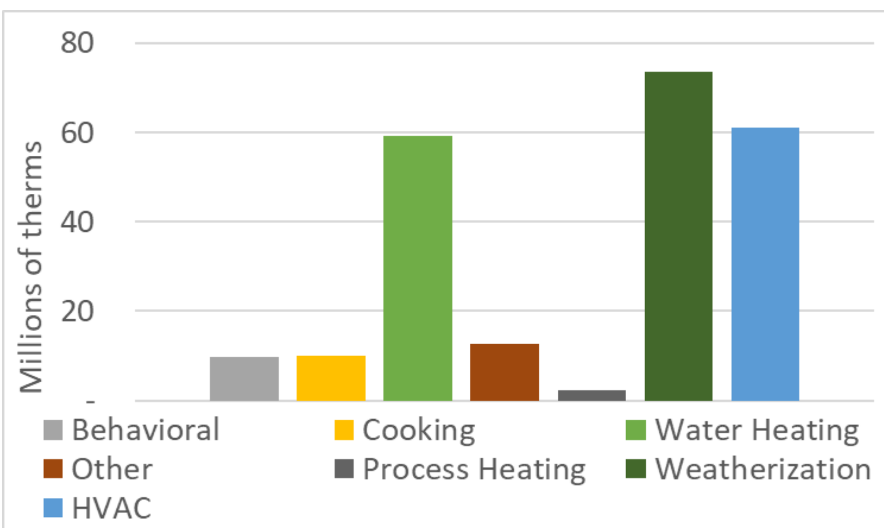
Figure 5.6: Summary of Cumulative Modeled Savings Potential - 2022–2041 - by Sector and type of Potential - Oregon



These results show that for the Residential and Commercial Sectors, approximately 73 and 76 percent of the technical potential identified in the model is found to be cost effective, with the majority of the DSM potential coming from the residential sector. For the Industrial Sector, 85 percent of the achievable potential identified is found to be cost effective.

Figure 5.7 provides a breakdown of NW Natural's 20-year cost-effective DSM savings potential by end use in Oregon.

Figure 5.7: 20-year Cumulative Cost-Effective Potential by End Use - Oregon



The weatherization and HVAC end uses top the list and represent all measures that save space heat. Water heating includes water heating equipment from all sectors. Behavioral consists primarily of potential from Energy Trust's commercial strategic energy management measure, a service where Energy Trust energy experts provide training to facilities teams and staff to develop the skills to identify operations and maintenance changes that make a difference in a building's energy use. The other category consists primarily of a commercial new construction design measure that is 10 percent better than code. Figure 5.18 shows the amount of emerging technology savings within each category of DSM potential, highlighting the contributions of commercially available and emerging technology DSM in Oregon. This graph shows that while over 66 million therms of the DSM technical potential consists of emerging technology, once the cost-effectiveness screen is applied, over 42 million, or 64 percent of that potential remains. For commercially available measures, of the 241 million therms of technical potential, over 185 million, or 77 percent of the potential remains. 19 percent of the total cost-effective potential identified in the model is from emerging technology measures including gas heat pump water heaters for both residential and commercial.

Figure 5.8: Cumulative 20-year potential by savings type, detailing the contributions of commercially available and emerging technology - Oregon

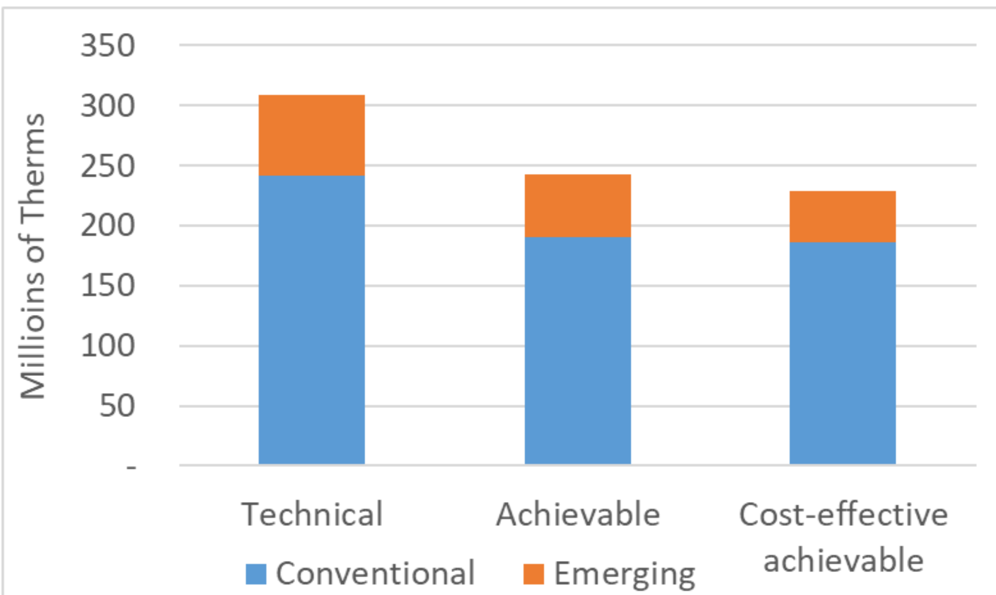


Table 5.2 shows the savings potential for Oregon in the resource assessment model that was added by employing the cost-effectiveness override option in the model. The cost-effectiveness override option forces non-cost-effective potential into the cost-effective potential results and is used when a measure meets one of the following two criteria.

1. The measure is not cost-effective but is offered through Energy Trust programs under an OPUC exception and is expected to be brought into cost-effective compliance in the near future.

2. The measure is cost-effective using Energy Trust's blended gas avoided costs and is currently offered through Energy Trust programs but is not cost-effective when modeled with NW Natural-specific avoided costs.

Table 5.2: Cumulative Cost-Effective Potential (2022-2041) due to use of Cost-effectiveness override (Millions of Therms) - Oregon

Sector	Yes CE Override	No CE Override	Difference
Residential	156.37	125.04	31.33
Commercial	54.21	47.19	7.01
Industrial	18.10	18.10	0
Total	**228.67**	**190.33**	**38.35**

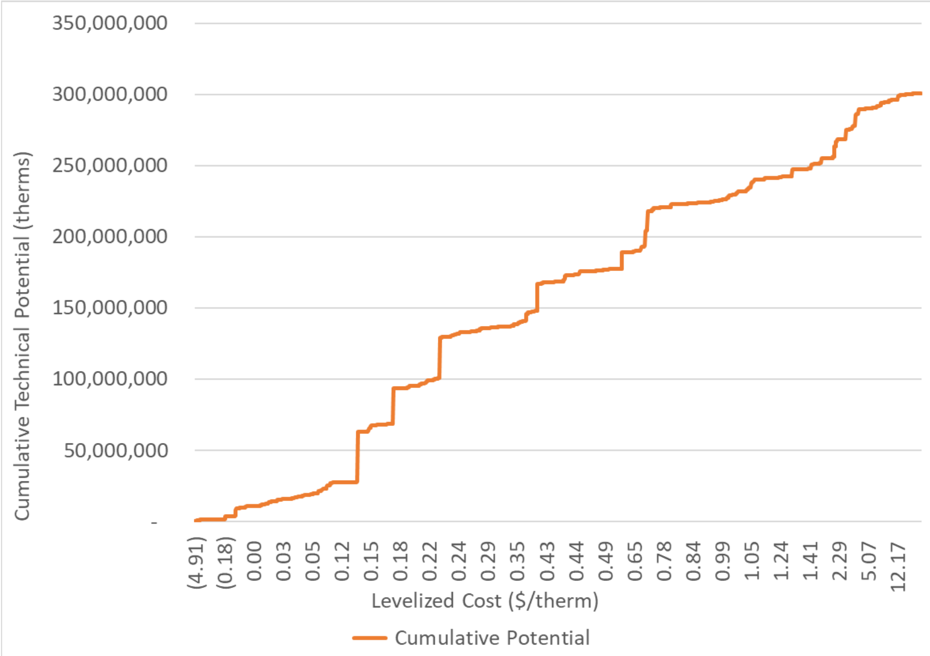
In this IRP, 17 percent of the cost-effective potential identified by the model is due to the use of the cost-effective override for measures with exceptions. The measures that had this option applied to them for measures under OPUC exception included manufactured home replacement, clothes washers, and attic, floor, and wall insulation. Measures overridden due to ETO's use of blended avoided costs are residential whole home new construction measures.

Supply Curve and Levelized Costs

An additional output of the RA Model is a resource supply curve developed from the levelized cost of energy of each measure that graphically depicts the total potential therms that could be saved at various costs for all measures.

The levelized cost for each measure is determined by calculating the present value of the total cost of the measure over its economic life, converted to equal annual payments, per therm of energy savings. The levelized cost calculation starts with the customer's incremental total resource cost (TRC) of a given measure. The total cost is amortized over an estimated measure lifetime using the NW Natural's Oregon discount rate of 3.83 percent. The annualized measure cost is then divided by the annual energy savings, in therms. Figure 5.9 shows the supply curve developed for this IRP that can be used for comparing demand-side and supply-side resources in Oregon.

Figure 5.9: 20-year Gas Supply Curve - Oregon



5.1.5 2022 Oregon Model Results Compared to 2018

Table 5.3 shows the total modeled potential for DSM in this IRP compared to the prior IRP in 2018. The increased potential is primarily found in the residential sector and is primarily driven by emerging technology, new measures that are being offered by programs, and changes in modeling assumptions. This modeled savings amount is mitigated by the amount of savings potential selected for deployment as shown in the final savings projection in Section 5.1.6. Only a portion of the cost-effective potential from lost opportunity measures, such as new construction and replacement of end-of-life equipment, is expected to be acquired given program budgets, incentive levels, and customer decision making preferences. Assumptions based on historical program performance are considered when generating the final annual savings projection. The final savings projection relies on program input and forecasts of what amount of the modeled cost-effective potential Energy Trust anticipates acquiring through programs, code improvements and market transformation.

Table 5.3: Total 2022 IRP Cost-Effective Modeled Potential compared to 2018 and IRP modeled potential by Sector - Oregon

	Total Cost-Effective Potential 2018 OR IRP (Millions of therms) 2018-2037	Total Cost-Effective Potential 2022 IRP (Millions of therms) 2022-2041
Residential	115.8	156.4
Commercial	62.8	54.2
Industrial	16.5	18.1
All DSM	195.1	228.7

Table 5.4 builds off Table 5.3 and details the key factors that drove the change in cost-effective potential for DSM in this IRP compared to the prior IRPs in 2018. The primary emerging technologies, Gas Heat Pump Water Heaters and Gas Fired Heat Pumps, are broken out separately in the table below and make up 13.56 MM therms of the total 23.02 MM therm savings from emerging technologies.

Table 5.4: Key Changes in Model that Increased Potential from 2018 IRP to 2022 IRP - Oregon

Change Component	**Change in DSM Savings (Millions of Therms) from 2018 to 2022 IRPs**	**% Of Total**
Emerging Technology[98]	23.02	69%
Gas Heat Pump Water Heater	*13.11*	
Gas Heat Pump	*0.45*	
New Measures	25.01	75%
Removed Measures	-25.08	-75%
CE override	29.98	89%
Change in Model Assumptions	-21.02	-63%
Total Change from 2018 to 2022 IRP	**33.56**	**95%**

[98] Emerging technology is made up of condensing gas rooftop units, gas absorption heat pump water heaters, gas fired heat pumps, industrial advanced wall insulation, and thin triple pane windows. Gas heat pump water heaters constitute 13.11 million therms of the emerging technology potential. Energy Trust applies a risk adjustment factor to emerging technologies based on market risk, technical risk and data risk ranging from 10% to 90%. Gas heat pump water heaters are assigned an adjustment of 70% to account for market uncertainty. Furthermore, while the total Cost-Effective potential is 13.11 million therms, the Energy Trust deployment process allows emerging technology measures to gradually enter the marketplace and gain market share over conventional measures. The final deployed savings projection for Gas fired heat pump water heaters is 2.5 million therms over the 20-year forecast period.

5.1.6 Oregon Final Savings Projection

The results of the final savings projection show that Energy Trust can save 41.2 million therms across NW Natural's system in Oregon in the next five years from 2022 to 2026 and over 147.1 million therms by 2041.

The final savings projection of 147.1 million therms by 2041 in NW Natural's service territory in Oregon, contains a reduction to the full cost-effective potential shown in Table 5.5. This is due to additional market-related constraints on the ability to capture all market activity in a given year for measures meant to replace equipment that fails, and measures associated with the construction of new homes and buildings, otherwise known as 'lost opportunity' measures. These are measure opportunities that appear in a given year, but if lost, do not reappear again as savings potential until their useful life has passed. These savings are depicted in the savings deployment scenarios beginning on the next page.

Table 5.5 depicts savings projections for NW Natural's Oregon system. The 'Other' sector referenced in the savings projections include the large project adder, Commercial New Buildings market transformation savings, and code savings from several commercial cooking measures that result in a market baseline equivalent to efficient technology. Both Commercial market transformation and cooking savings were forecasted outside of that Sector's standard savings as Energy Trust does not claim those savings.

Table 5.5: 20-Year Cumulative Savings Potential by type, including final savings projection (Millions of Therms) - Oregon

	Technical	Achievable	Cost-effective	Energy Trust Savings Projection [99]
Residential	215.28	164.36	156.37	74.14
Commercial	71.74	60.46	54.21	38.09
Industrial	21.29	18.10	18.10	16.74
Other	0	0	0	18.12
All DSM	308.30	242.92	228.67	147.08

[99] The savings deployment process applies ramp rates to shape forecasted annual cost-effective savings acquisition over the 20-year forecast horizon. The deployment accounts for near term program savings targets and past program activity. In general, deployments follow Power Council principles such that retrofit measures acquire all available cost-effective achievable savings in the 20-year period following a bell-shaped acquisition curve while lost opportunity measures ramp up throughout the modeling period to achieve 100% market annual penetration by the end of the forecast. Some measures assume a lower acquisition rate to reflect market characteristics, such as hard to reach measures including insulation and windows, and emerging technology. Emerging technology measures begin with low rates of forecasted market uptake and often do not ramp to full market penetration by the end of the forecast period. Hard to reach measures are the reason that the Residential savings deployment is proportionally less than the cost-effective achievable savings potential when compared to the projections for commercial and industrial as emerging technologies (primarily gas fired heat pump water heaters) and shell make up a higher share of cost-effective achievable savings potential for this sector.

Figure 5.10 shows the annual savings projection by Sector. The growth in savings from 2022 to 2025 is a result of discussions with NW Natural to increase efficiency spending to accelerate cost effective potential acquisition in the near forecast term. These increases reflect Energy Trust's best attempt to estimate increased savings potential without running these estimates through the more comprehensive planning that accommodates our annual budgeting process. Energy Trust will use these savings targets as a starting point for constructing savings goals for the 2023-2024 budget and presenting the anticipated budget needs that will accompany these savings goals. The eventual savings goals and the revenue needed to fund the budget will be negotiated, per usual practice, as a component of the budget process. Furthermore, the magnitude of the savings increases reflected in the attached savings targets for 2023-2026 are subject to evolving program designs and offerings that will need to be tested to validate their resulting efficacy.

Figure 5.10: 20-Year Annual Savings Projection by Sector - Oregon

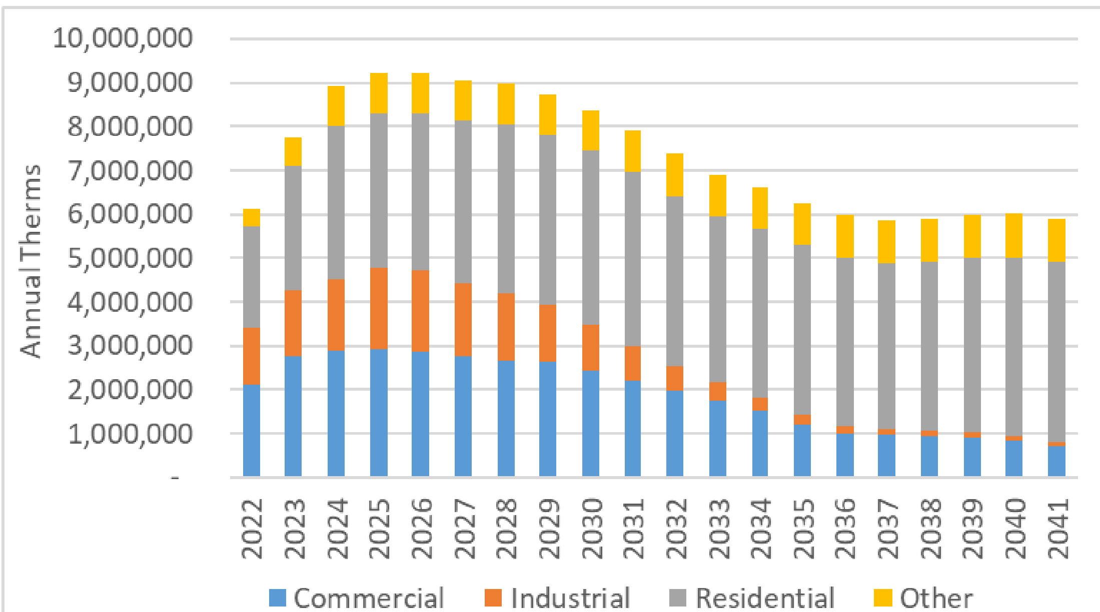
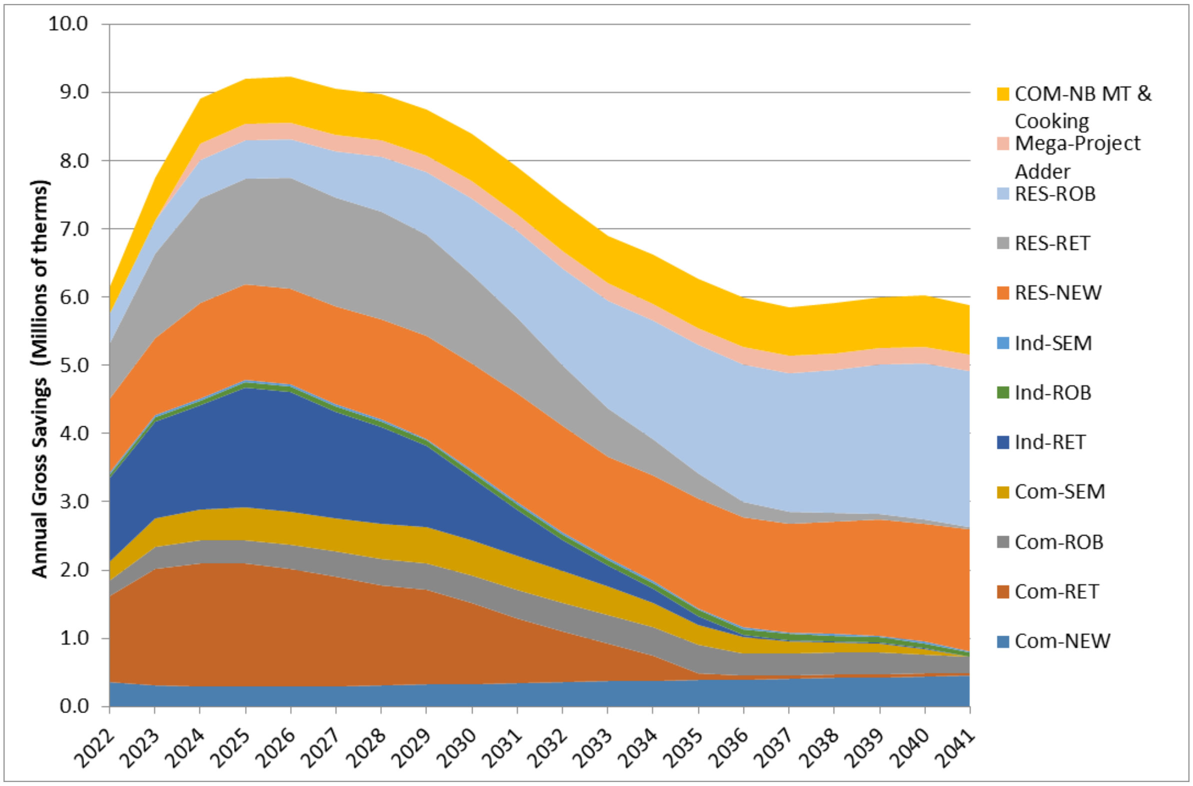


Figure 5.11 shows the annual savings projection by Sector-Measure Type. This view provides greater detail into the types of savings being forecasted and their relative contribution through time.

Figure 5.11: Annual Savings Projection by Sector-Measure Type - Oregon



Oregon Final Savings Projection Extended to 2050

The Energy Trust RA model is configured to calculate savings potential results over a 20-year forecast horizon. Energy Trust then deploys the cost-effective achievable potential exogenously to the RA model as described in Section 5.1.4 above. This deployment methodology has been modified to extend the final savings projection through 2050 to align with NW Natural's IRP horizon by continuing the energy efficiency acquisition curves for the additional nine years. This projection is different depending on the curve that was applied. As stated previously, Energy Trust ramp rates are based on Northwest Power and Conservation Council method and ramp rates but calibrated to be specific to Energy Trust. Retrofit measure potential continues until 100% of the cost-effective achievable potential is acquired and savings potential is exhausted. Lost opportunity measures continue to ramp up to 100% of annual available cost-effective achievable potential at which point all savings are realized annually. Hard to reach measures or emerging technologies do not ramp to 100%.

Table 5.6: 20-year and 29-year Final Savings Projection (Millions of Therms) - Oregon

	20-Year Savings Projection	9-Year Savings Extension	Total Final Savings through 2050
Residential	74.14	35.92	110.05
Commercial	38.09	6.66	44.75
Industrial	16.74	0.21	16.95
Other	18.12	5.86	23.97
All DSM	147.08	48.65	195.73

Figure 5.12: Annual Savings Projection by Sector through 2050 - Oregon

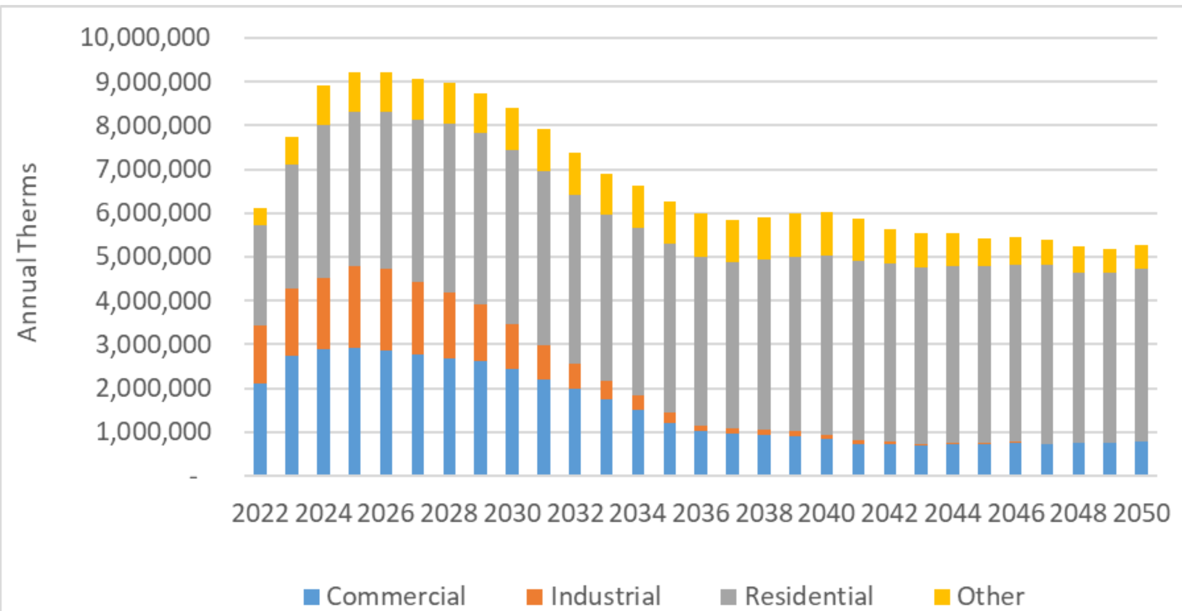
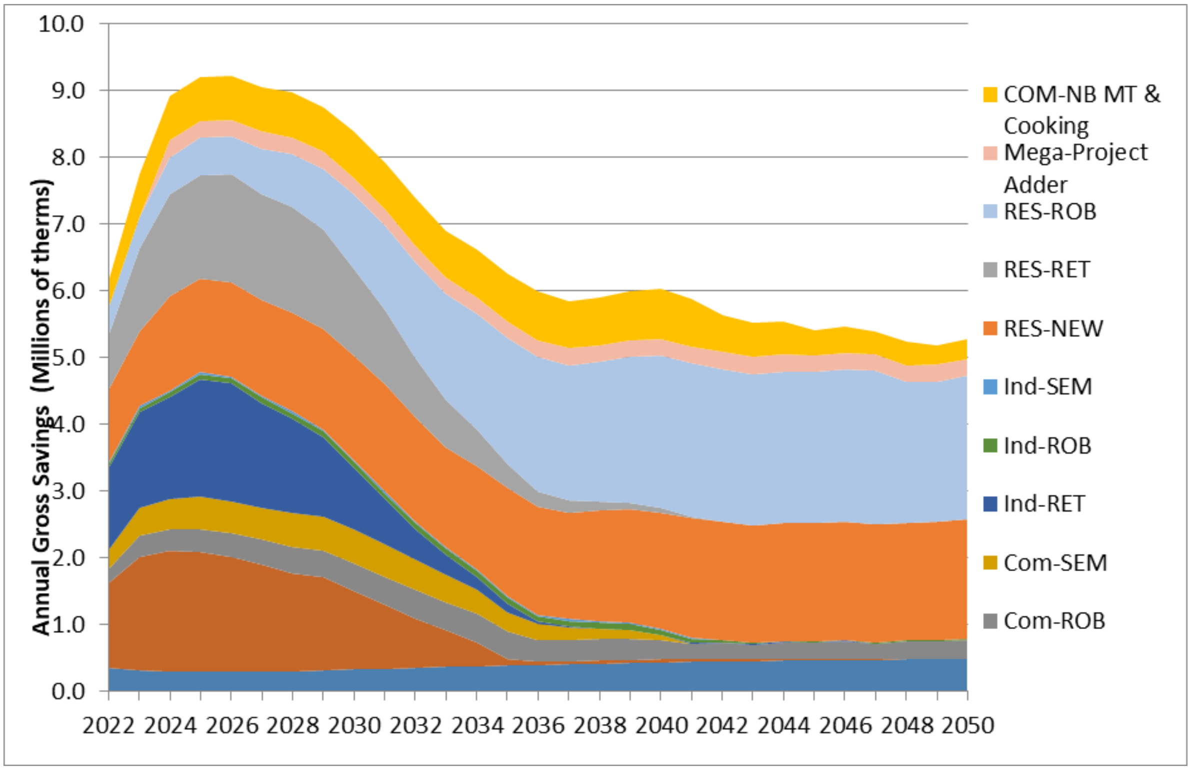


Figure 5.13: Annual Savings Projection by Sector through 2050 - Oregon



Oregon Peak Savings Deployment

Figure 5.14 and Figure 5.15 detail the amount of peak-day and peak-hour savings that Energy Trust forecasts to acquire as calculated from the annual savings projection using peak-day/annual use and peak-hour/annual use coincident load factors developed by NW Natural.

Figure 5.14: NW Natural's Annual Peak-Day Savings Projection by Sector - Oregon

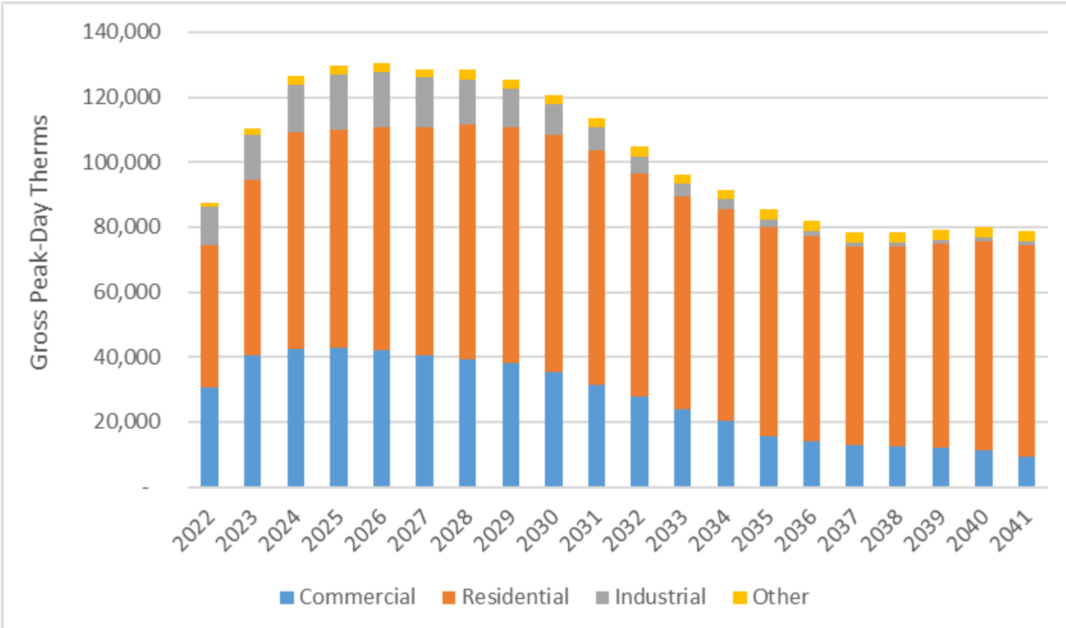
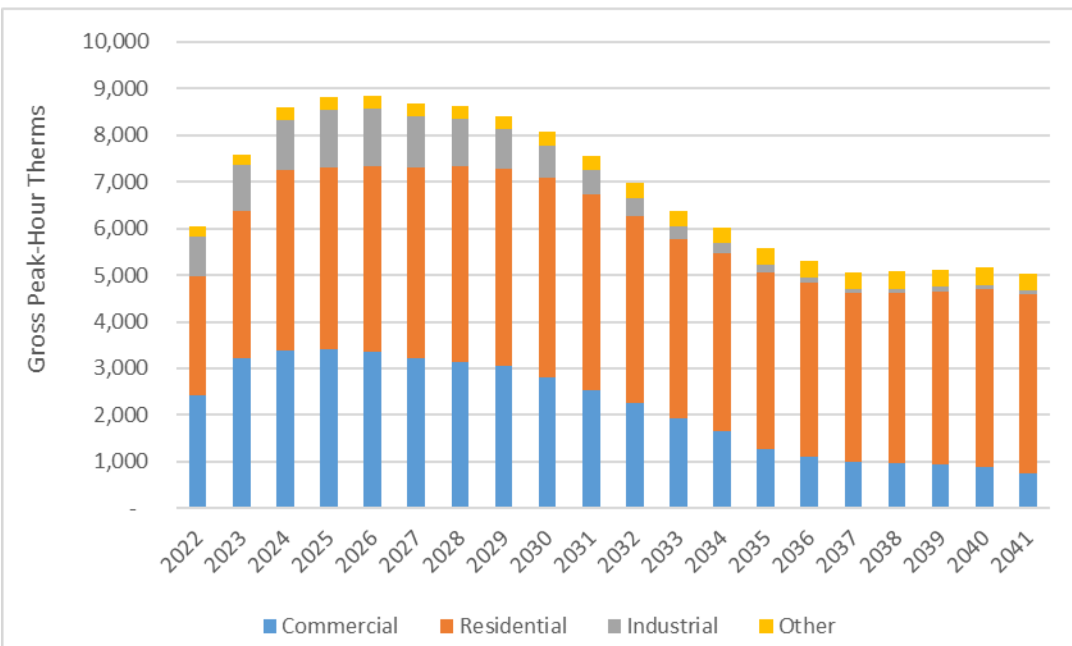


Figure 5.15: NW Natural's Annual Peak-Hour Savings Projection by Sector - Oregon



Residential and Commercial heating measures have the greatest savings coincident with peak, and in this forecast contribute the most peak savings potential. The total peak-day savings over the 20-year savings projection is 2,055,067 therms or 1.4% of the 147.1 million therm savings projection. The total peak-hour savings over the 20-year savings projection is 136,898 therms or 0.09% of the 147.1 million therm savings projection.

Impacts of Changing Market Conditions on Energy Trust Oregon Forecast

The deployment of the cost-effective achievable resource discussed in the chapter up to this point is based on Energy Trust assuming an aggressive market approach to maximize savings acquisition in the next few years in pursuit of carbon reduction objectives. Since Energy Trust originally assembled the forecast discussed in this chapter, Energy Trust's view of market conditions has changed to reflect limitations brought about by emergent supply chain issues and labor shortages that are outcomes of the ongoing impacts of the pandemic on the Oregon economy. Energy Trust's second quarter forecast for 2022 end of year results is showing that we are not on track to achieve 2022 goals. As a result, the 2023 and 2024 savings targets that are reflected in the deployment now seem overly aggressive as it is not possible to know when the market will correct to previous conditions.

Energy Trust and NW Natural discussed whether Energy Trust should update Energy Trust modeling results to reflect this updated market intelligence. Energy Trust and NW Natural jointly concluded that it will be too disruptive to NW Natural's modeling process to update the forecast at this time because NW Natural has already incorporated the previously submitted Energy Trust results into other NW Natural modeling protocols. Moreover, Energy Trust and NW Natural agreed that the long-term impact of the changes in 2023 and 2024 have minimal impact on the savings potential over the forecast horizon and the long-term impacts on NW Natural's system planning.

As an alternative, Energy Trust and NW Natural agreed that the 2023-2024 energy efficiency savings targets in the action plan will be framed by a range of potential energy savings outcomes that are influenced by market conditions. This range is bound on the lower end by the savings targets that reflect decelerated market conditions resulting in the savings goals from the first round of Energy Trust's 2023-2024 budget process. The higher end of the range of conditions included in the deployment earlier in this chapter is bound by the original, and now seemingly aggressive, savings targets associated with accelerated market conditions. Table 5.7 shows the lower bound of Energy Trust savings projection.

Table 5.7: 20-year Lower Bound Cumulative Savings Potential by type, including final savings projection (Millions of Therms) - Oregon

	Technical	Achievable	Cost-effective	Energy Trust Lower Bound Savings Projection
Residential	215.28	164.36	156.37	69.31
Commercial	71.74	60.46	54.21	38.00
Industrial	21.29	18.10	18.10	16.70
Other	0	0	0	18.10
All DSM	308.30	242.92	228.67	142.10

A comparison between the original NW Natural savings targets and the updated lower bound estimate reflecting the 2023-2024 Energy Trust budget is shown in Table 5.10 covering NW Natural's action plan years.

Table 5.8: 2023 and 2024 Annual Energy Trust Savings Projection (Therms) - Oregon

	2023	2024	Total
Upper Bound Reflecting Accelerated Market Conditions	7,750,168	8,910,070	16,660,239
Lower Bound Reflecting Decelerated Market Conditions	5,693,343	6,693,833	12,387,176

Figure 5.16 and Figure 5.17 below show annual lower bound savings projections by sector and by measure type in Oregon.

Figure 5.16: 20-Year Lower Bound Annual Savings Projection by Sector - Oregon

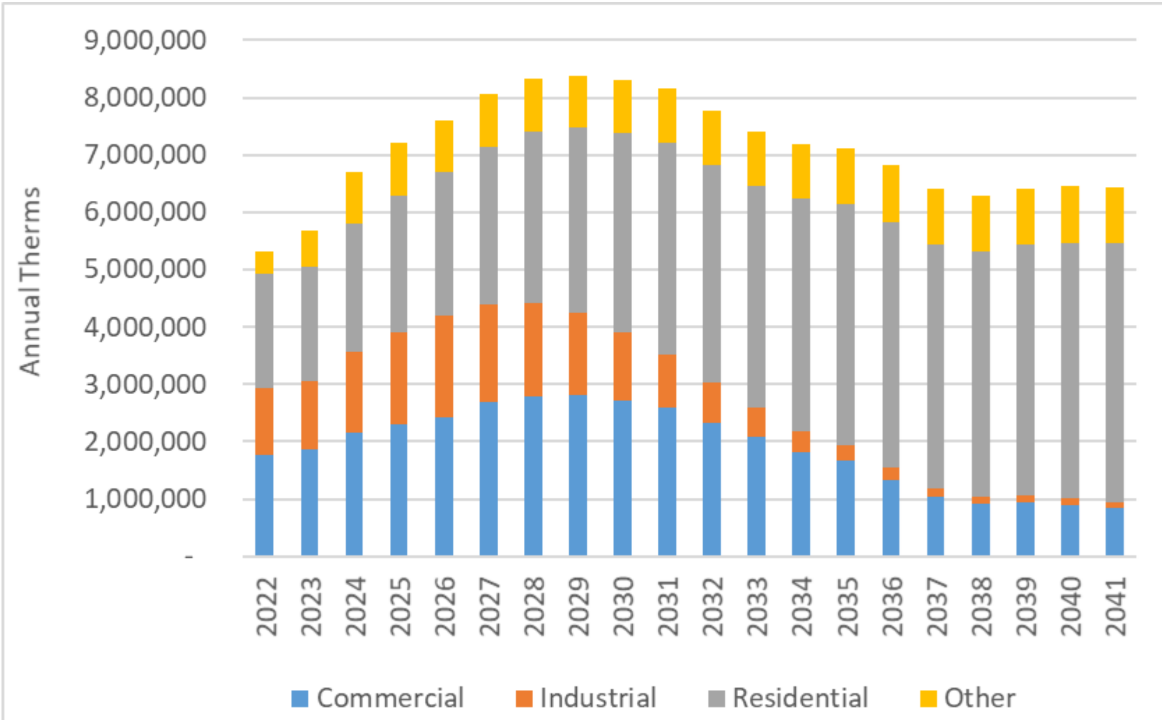
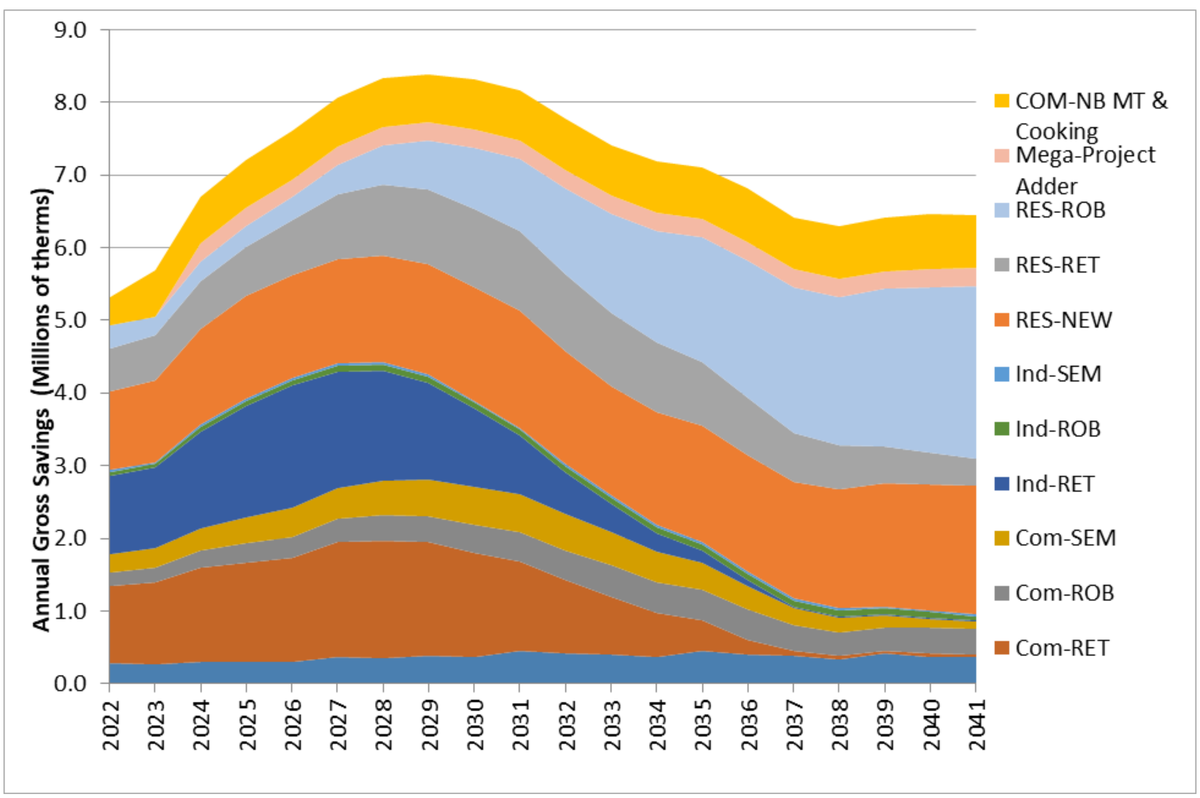


Figure 5.17: Annual Lower Bound Savings Projection by Sector-Measure Type - Oregon



5.2 Conservation Potential Assessment in Washington

This section is extracted and summarized from the final report of the 2021 NW Natural Washington Conservation Potential Assessment submitted by Applied Energy Group (AEG) to NW Natural. [100]

5.2.1 Background

In early 2021, NW Natural contracted with Applied Energy Group (AEG), a consulting firm known for its services to the energy industry including gas utilities, to conduct an assessment of available conservation potential in its Washington service territory. AEG applied standard industry and northwest regional methodologies to develop reliable estimates of technical, achievable technical, and achievable economic potential from two different cost-effectiveness perspectives for the period from 2022-2051. AEG completed the assessment in collaboration with NW Natural and ETO using information specific to NW Natural's customers and existing energy efficiency programs wherever possible and delivered the final study report to NW Natural in July 2021.

5.2.2 Analysis Approach

To perform the conservation potential analysis, AEG used a bottom-up approach following the major steps:

1) Performed a market characterization to describe sector-level natural gas use for the residential, commercial, and industrial sectors for the base year, 2019. This included extensive use of NW Natural data and other secondary data sources from NEEA and the Energy Information Administration (EIA).
2) Developed a baseline projection of energy consumption by sector, segment, end use, and technology for 2022 through 2051.
3) Defined and characterized several hundred EE measures to be applied to all sectors, segments, and end uses.
4) Estimated technical, achievable technical, and achievable economic energy savings at the measure level for 2022-2051. Achievable economic potential was assessed using both the Total Resource Cost (TRC) and Utility Cost Test (UCT) screens.

More specifically, AEG used its Load Management Analysis and Planning tool (LoadMAP™) version 5.0 to develop both the baseline projection and the estimates of potential. Built in Excel, the LoadMAP™ framework possesses key features that embody basic principles of rigorous end-use models, accommodates different levels of segmentation, includes algorithms that independently account for new and existing appliances and building stock, and balances the competing needs of simplicity and robustness. The LoadMAP™ model provides projections of baseline energy use by sector, segment, end

[100] The 2021 Washington Conservation Potential Study is available at the following URL: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=3&year=2021&docketNumber=210773

use, and technology for existing and new buildings. It also provides forecasts of total energy use and energy-efficiency savings associated with the various types of potential.[101]

Three types of potential were analyzed in this AEG study: technical, achievable technical, and achievable economic. Table 5.9 provides detailed definitions on each type of potential.

Table 5.9: Types of Potential and Definitions

Potential Type	Definition
Technical	Everyone chooses the most efficient option regardless of cost at time of equipment replacement or measure adoption.
Achievable Technical	A modified technical potential that accounts for likely measure adoption within the market
Achievable Economic	A subset of achievable technical potential that includes only cost-effective measures

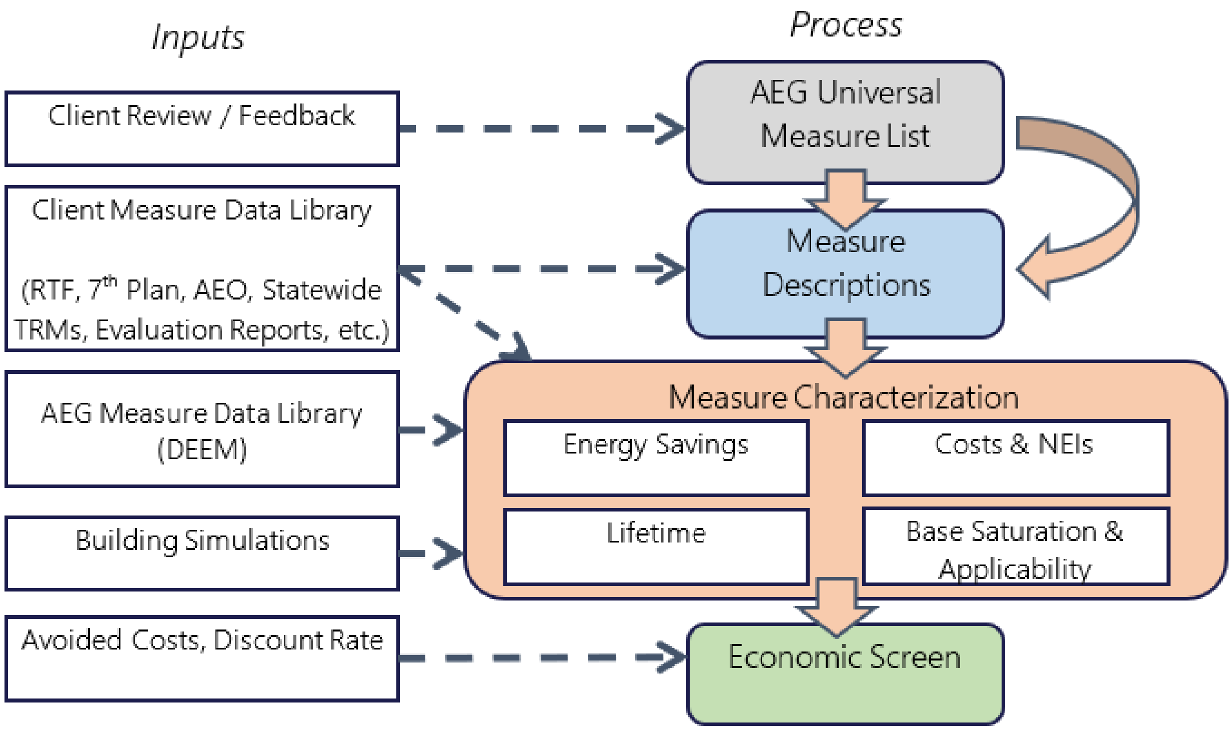
AEG developed the reference baseline in alignment with NW Natural's long-term demand forecast, but some modifications to account for known future conditions were also made. Inputs to the baseline projection include:

1) Current economic and load growth forecasts (i.e., customer growth, climate change assumptions)
2) Trends in fuel shares and equipment saturations
3) Existing and approved changes to building codes and equipment standards

To develop NW Natural's DSM measure list, in addition to its own databases, AEG also used datasets provided by NW Natural and ETO. As shown in Figure 5.18, first, a list of measures is identified; each measure is then assigned an applicability for each market sector and segment and is characterized with appropriate savings, costs, and other attributes; then cost-effectiveness screening is performed. NW Natural provided feedback during each step of the process to ensure measure assumptions and results lined up with real-world programmatic experience.

[101] The model computes energy forecasts for each type of potential for each end use as an intermediate calculation. Annual-energy savings are calculated as the difference between the value in the baseline projection and the value in the potential forecast (e.g., the technical potential forecast).

Figure 5.18: Approach for Energy Efficiency Measure Characterization and Assessment



5.2.3 Baseline Projection

Prior to developing estimates of energy conservation potential, baseline projections of annual natural gas use for 2022 through 2051 by customer segment and end use in the absence of new utility energy-efficiency programs were developed. The savings from past programs are embedded in the forecast, but the baseline projection assumes that those past programs cease to exist in the future to avoid double counting potential opportunities. Thus, the potential analysis captures all possible savings from future programs.

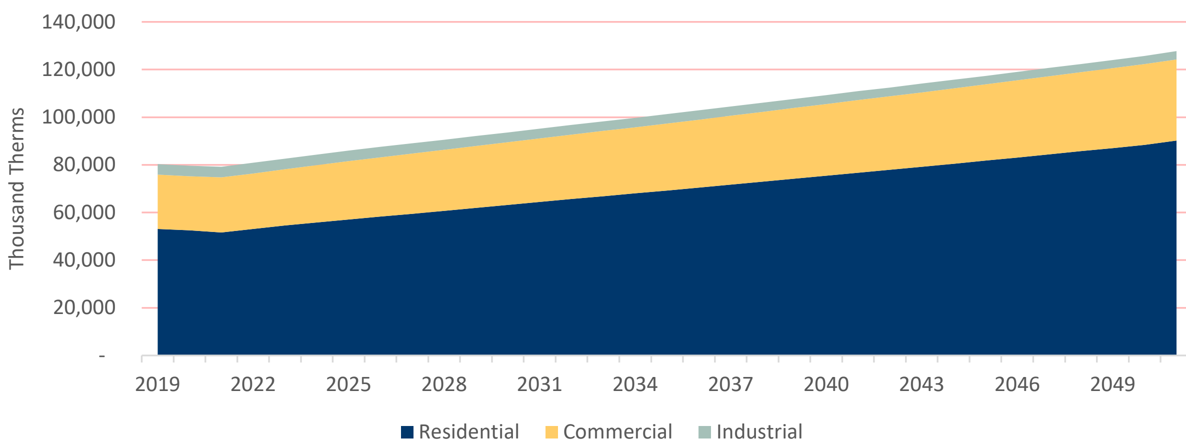
Table 5.10 and Figure 5.19 provide a summary of the baseline projection for annual use by sector for the entire NW Natural Washington service territory. Base year (2019) values[102] are weather normalized using HDD data provided by NW Natural's load forecast department. Years 2021 forward include the impact of climate trends through projected heating degree days (HDDs) supplied by NW Natural. Overall, the forecast shows modest growth in natural gas consumption, at an average rate of about 1.4% per year.

[102] NW Natural also provided 2020 consumption data for AEG's consideration in aligning the baseline projection with NW Natural's forecast

Table 5.10: Baseline Projection Summary by Sector, Selected Years (mTherms) - Washington

Sector	2019	2020	2021	2022	2023	2024	2031	2040	2050	% Change ('19-'50)	Avg. Growth
Residential	53,096	52,500	51,552	53,041	54,507	55,765	64,452	75,477	88,376	66.40%	1.60%
Commercial	22,840	22,754	23,213	23,350	23,623	24,112	26,657	30,083	33,935	48.60%	1.30%
Industrial	4,382	4,379	4,400	4,440	4,450	4,405	4,120	3,753	3,435	-21.60%	-0.80%
Total	**80,319**	**79,633**	**79,166**	**80,831**	**82,581**	**84,282**	**95,229**	**109,312**	**125,747**	**56.60%**	**1.40%**

Figure 5.19: Baseline Projection Summary by Sector - Washington



5.2.4 DSM Potential

Table 5.11 and Figure 5.20 summarize the energy conservation savings in terms of annual energy use for all measures for four levels of potential relative to the baseline projection. Savings are represented in cumulative terms, reflecting the effects of persistent savings in prior years in addition to new savings. This allows for the reporting of annual savings impacts as they actually impact each year of the forecast.

Table 5.11: Summary of Energy Efficiency Potential (mTherms) - Washington

Scenario	2022	2023	2024	2026	2031	2040	2050
Baseline Load Projection (mTherms)	80,831	82,581	84,282	87,530	95,229	109,312	125,747
Cumulative Savings (mTherms)							
TRC Achievable Economic Potential	354	725	1,036	1,827	4,390	9,345	11,392
UCT Achievable Economic Potential	477	992	1,470	2,671	6,523	13,936	16,818
Achievable Technical Potential	874	1,799	2,702	4,808	10,350	19,102	22,321
Technical Potential	2,033	4,189	6,160	10,491	20,957	35,383	42,373
Cumulative Savings (% of Baseline)							
TRC Achievable Economic Potential	0.40%	0.90%	1.20%	2.10%	4.60%	8.50%	9.10%
UCT Achievable Economic Potential	0.60%	1.20%	1.70%	3.10%	6.80%	12.70%	13.40%
Achievable Technical Potential	1.10%	2.20%	3.20%	5.50%	10.90%	17.50%	17.80%
Technical Potential	2.50%	5.10%	7.30%	12.00%	22.00%	32.40%	33.70%

Figure 5.20: Summary of Annual Cumulative Energy Efficiency Potential (mTherms) - Washington

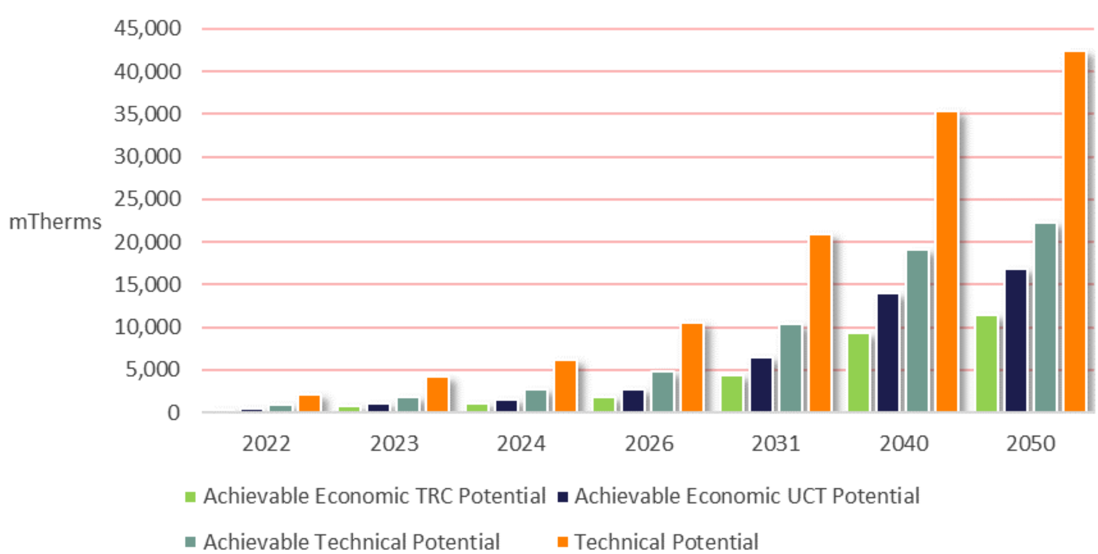


Table 5.12 summarizes TRC achievable potential by market sector for selected years. In general, residential and commercial potential are well balanced and dominant since industrial sales customer consumption represents a small percentage of the baseline and potential for this sector is also relatively small in size. In 2022, TRC achievable economic potential is 182 mTherms, or 0.3% of the

baseline projection for the residential sector, 155 mTherms, or 0.7% of the baseline projection for the commercial sector, and 16 mTherms, or 0.4% of the baseline projection for the industrial sector, respectively. By 2050, cumulative savings are 6,612 mTherms, or 7.5% of the baseline for the residential sector, 4,526 mTherms, or 13.7% of the baseline for the commercial sector, and 254 mTherms, or 7.4% of the baseline for industrial sector, respectively. Overall, in 2022, first-year savings are 354 mTherms, or 0.4% of the baseline projection. Cumulative savings in 2031 are 4,390 mTherms, or 4.6% of the baseline. By 2050 cumulative TRC achievable economic potential reaches 11,392 mTherms, or 9.1% of the baseline.

Table 5.12: Cumulative TRC Achievable Economic Potential by Sector, Selected Years (mTherms) - Washington

Sector	2022	2023	2024	2026	2031	2040	2050
Residential	182	369	478	837	2,250	5,380	6,612
Commercial	155	323	509	908	1,979	3,713	4,526
Industrial	16	33	49	82	162	253	254

Table 5.13 and Table 5.14 present the total reference baseline and potential savings for the peak day and peak hour, respectively. Peak day and hour impacts are estimated using the annual energy savings and conversion factors that relate peak day or hour consumption to annual consumption by end use obtained from NW Natural.

Table 5.13: Peak Day Potential Summary (mTherms) - Washington

Scenario	2022	2023	2024	2026	2031	2040	2050
Peak Day Savings (mTherms)							
TRC Achievable Economic Potential	5	11	16	27	60	124	148
UCT Achievable Economic Potential	7	15	22	38	85	179	208
Achievable Technical Potential	11	23	34	60	127	238	272
Technical Potential	27	55	79	134	265	473	563
Energy Savings (% of Baseline)							
TRC Achievable Economic Potential	0.50%	1.10%	1.40%	2.40%	4.90%	8.90%	9.30%
UCT Achievable Economic Potential	0.70%	1.40%	2.00%	3.40%	6.90%	12.80%	13.00%
Achievable Technical Potential	1.10%	2.20%	3.20%	5.40%	10.30%	17.00%	17.00%
Technical Potential	2.60%	5.20%	7.30%	11.90%	21.60%	33.80%	35.30%

Table 5.14: Peak Hour Potential Summary (mTherms) - Washington

Scenario	2022	2023	2024	2026	2031	2040	2050
Peak Hour Savings (mTherms)							
TRC Achievable Economic Potential	0.4	0.7	1.1	1.9	4.5	9.6	11.5
UCT Achievable Economic Potential	0.5	1	1.5	2.8	6.8	14.5	17.5
Achievable Technical Potential	0.9	1.9	2.8	5	10.9	20.1	23.4
Technical Potential	2.1	4.4	6.5	11.1	22.3	37.4	44.8
Energy Savings (% of Baseline)							
TRC Achievable Economic Potential	0.50%	0.90%	1.30%	2.20%	4.80%	8.80%	9.20%
UCT Achievable Economic Potential	0.60%	1.20%	1.80%	3.20%	7.30%	13.40%	14.00%
Achievable Technical Potential	1.10%	2.30%	3.40%	5.80%	11.60%	18.50%	18.80%
Technical Potential	2.70%	5.40%	7.80%	12.90%	23.60%	34.50%	35.90%

Key opportunities for savings include residential furnace and water heating equipment upgrades and weatherization, as well as behavioral programs and kitchen equipment. For detailed top DSM measures contributing to the potential savings reported above, refer to the 2021 Washington Conservation Potential Study.[103]

5.3 DSM Potential for Oregon Transportation Customers

5.3.1 Background

With the passing of Executive Order 20-04 in March 2020, statewide greenhouse gas emissions from large stationary sources, transportation fuel, and other liquid and gaseous fuels will be limited by new goals from the Oregon Department of Environmental Quality (DEQ). The resulting Climate Protection Program (CPP) formalizes emission reduction requirements for Oregon's natural gas utilities, including the responsibility for on-site emission of natural gas transportation customers.[104] NW Natural's transportation customers have not historically paid into the public purpose charge and thus are currently not eligible to participate in natural gas energy efficiency programs administered by ETO. NW Natural engaged AEG to assess the potential that exists with Oregon transportation customers and inform what DSM programs for transportation customers could look like in the future.

The Washington Conservation Potential Assessment (CPA) that AEG completed for NW Natural in 2021 provided a starting point to assess the potential for energy efficiency to reduce greenhouse gas (GHG) emissions at transportation customer sites.[105] AEG used many of the same data sources from the Washington CPA, updated as appropriate to capture Oregon transportation customer characteristics.

5.3.2 Methodology

AEG began the analysis by characterizing NW Natural's Oregon transportation customers' energy consumption in the base year of the study (2021) using NW Natural customer and sales data. This characterization resulted in energy use distribution by sector, segment, and end use. Using NW Natural load forecasts and measure characterizations from the 2021 Washington CPA, AEG then developed a baseline energy projection over the 30-year study period. Oregon transportation customer equipment specifications were informed by NW Natural's equipment database and vetted with NW Natural Field Technicians. The Northwest Power and Conservation Council (NWPCC) 2021 Power Plan ramp rates informed measure adoption throughout the forecast and were the basis in analyzing the three scenarios provided in this study.

[103] The 2021 Washington Conservation Potential Study is available at the following URL: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=3&year=2021&docketNumber=210773
[104] Transportation customers are non-residential natural gas consumers, typically large industrial users, who purchase natural gas from an alternate supplier, but use NW Natural's distribution system to deliver the fuel to their sites.
[105] The 2021 Washington Conservation Potential Study is available at the following URL: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=3&year=2021&docketNumber=210773

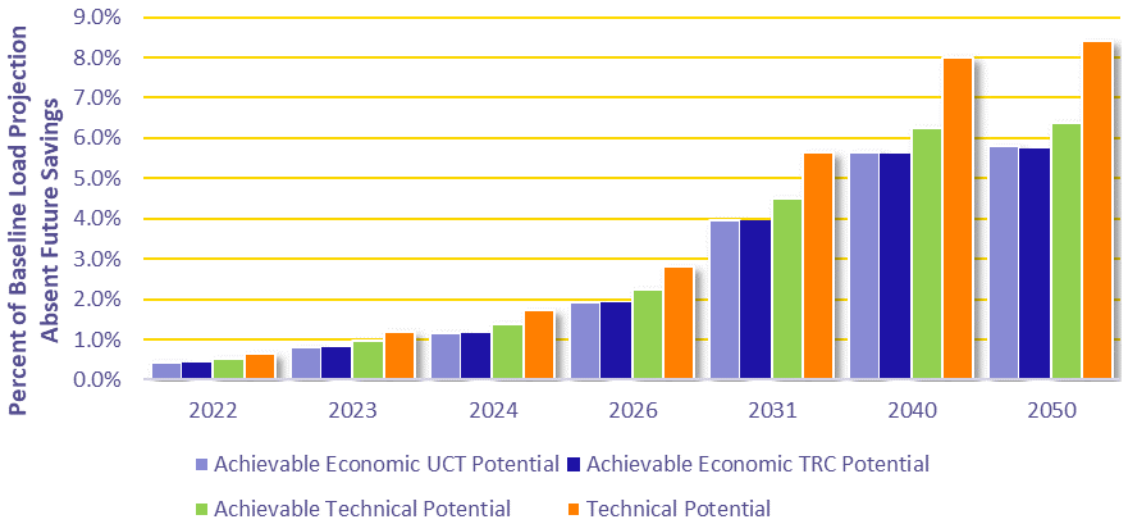
5.3.3 Results Summary

A summary of the identified DSM potential for the reference case at Oregon transportation customer sites is presented in Table 5.15 and Figure 5.21. A majority of the potential can be acquired over 10 years, and almost all over 20 years. Only a small amount of potential remains for acquisition from 2042-2051, primarily for equipment that was not assumed to be upgraded during the first 20 years of the forecast period. More specifically, in 2022, first year TRC achievable economic potential savings are 1,531 mTherms, or 0.43% of the baseline projection. Cumulative savings in 2031 are 13,424 mTherms, or 3.95% of the baseline. By 2050 cumulative TRC achievable economic potential slowly increases to 17,481 mTherms, or 5.75% of the baseline. The top measures identified to help achieve the savings potential over the next 20 years include strategic energy management, steam system efficiency improvements, hot water line insulation, building roof/ceiling insulation, and heated process fluid insulation.

Table 5.15: Summary Potential Results – Reference Case: Oregon Transportation

Scenario	2022	2023	2024	2026	2031	2040	2050
Baseline Load Projection Absent Future Savings (mTherms)	357,025	357,418	355,616	350,191	340,047	323,605	304,190
Cumulative Savings (mTherms)							
TRC Achievable Economic Potential	1,531	2,883	4,155	6,721	13,424	18,166	17,481
UCT Achievable Economic Potential	1,537	2,894	4,170	6,746	13,480	18,287	17,655
Achievable Technical Potential	1,844	3,448	4,929	7,867	15,346	20,220	19,392
Technical Potential	2,291	4,298	6,158	9,842	19,167	25,882	25,622
Cumulative Savings (% of Baseline)							
TRC Achievable Economic Potential	0.43%	0.81%	1.17%	1.92%	3.95%	5.61%	5.75%
UCT Achievable Economic Potential	0.43%	0.81%	1.17%	1.93%	3.96%	5.65%	5.80%
Achievable Technical Potential	0.52%	0.96%	1.39%	2.25%	4.51%	6.25%	6.37%
Technical Potential	0.64%	1.20%	1.73%	2.81%	5.64%	8.00%	8.42%

Figure 5.21: Reference Case Cumulative Potential: Oregon Transportation



5.4 DSM Potential for Washington Transportation Customers

While the DSM potential for Washington transports customers is not included in the final report of the 2021 NW Natural Washington Conservation Potential Assessment submitted by AEG to NW Natural, AEG also conducted the assessment and submitted the summary results to NW Natural in a separate Excel document. The data and methodologies employed by AEG in this assessment have been detailed in subsections 5.3.1 and 5.3.2. The potential cumulative savings in mTherms by sector and case for the transportation customers in Washington in 2050 are summarized in Table 5.16 and Figure 5.22. More detailed achievable economic TRC potential by transportation customer segment from 2022 to 2050 is reported in Table 5.17.

Table 5.16: 2050 Cumulative Savings by Sector and Case in mTherms: Washington Transportation

Sector	UTILITY Cost Effective Potential	SOCIAL Cost-Effective Potential	Achievable Technical Potential	Technical Potential
Commercial Transport	328	350	499	731
Industrial - Firm	578	579	612	750
Industrial - Interruptible	477	481	505	614
Total	**1,384**	**1,410**	**1,615**	**2,095**

Figure 5.22: 2050 Cumulative Savings by Sector and Case: Washington Transportation

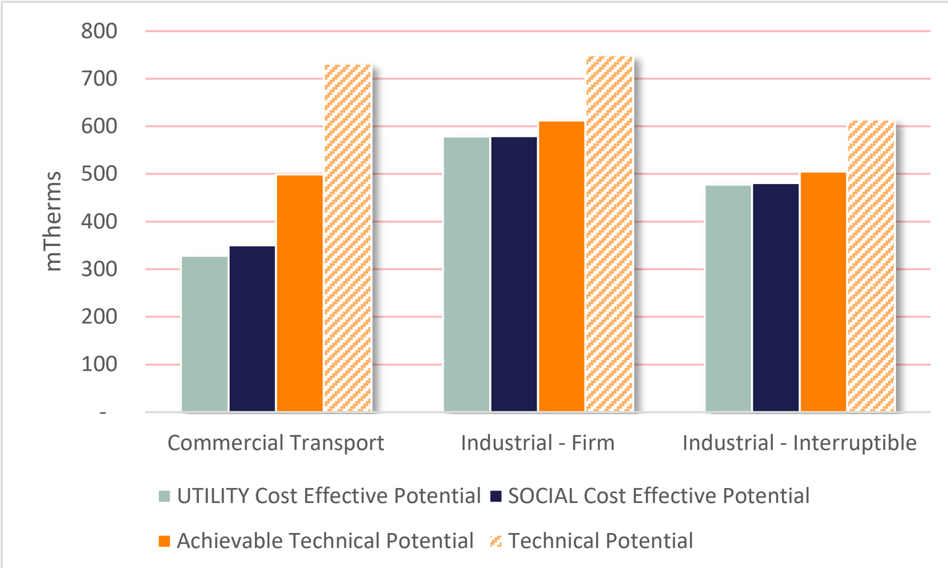


Table 5.17: Cumulative TRC Potential Savings by Customer Segment in mTherms: Washington Transportation

	2022	2023	2024	2026	2031	2040	2050
Commercial Transport	**7.95**	**16.74**	**26.86**	**50.32**	**120.76**	**265.16**	**350.43**
Retail	1.86	3.75	5.73	10.06	21.78	39.70	45.55
Grocery	0.81	1.78	2.95	5.82	14.58	35.15	49.70
Lodging	0.64	1.42	2.38	4.60	10.76	25.08	35.95
Other Health	4.63	9.80	15.79	29.84	73.64	165.24	219.23
Industrial - Firm	**38.05**	**75.93**	**113.62**	**189.12**	**368.64**	**575.46**	**579.45**
Electronics Manufacturing	16.75	33.39	49.96	83.65	168.04	266.83	266.40
Food Processing	19.08	38.09	57.02	94.45	180.04	278.32	282.34
Stone, Clay, Glass	0.62	1.23	1.83	3.03	5.25	6.90	6.92
Other Industrial	1.61	3.21	4.81	7.99	15.31	23.41	23.79
Industrial - Interruptible	**31.71**	**63.24**	**94.64**	**157.75**	**307.45**	**476.01**	**480.56**
Electronics Manufacturing	10.59	21.11	31.57	52.82	105.57	167.19	167.29
Food Processing	4.99	9.96	14.91	24.70	47.05	72.76	73.89
Lumber and Wood Products	3.52	7.02	10.51	17.55	34.79	55.27	55.85
Stone, Clay, Glass	8.50	16.94	25.36	42.28	81.42	122.51	124.33
Other Industrial	4.11	8.21	12.29	20.39	38.62	58.28	59.20
Grand Total	**77.70**	**155.91**	**235.12**	**397.19**	**796.84**	**1,316.63**	**1,410.44**

Table 5.15 shows that most of the achievable economic TRC potential is assumed to be acquired steadily over the next 20 years. This is particularly the case for the industrial firm and interruptible transportation customers: over 99 percent of their TRC potential is projected to be acquired by 2040.

The top measures identified to help achieve the savings potential over the next 20 years include strategic energy management, hot water line insulation, building automation systems, gas boiler stack economizers, roof/ceiling insulation, and gas boiler hot water reset.

5.5 Transportation Energy Efficiency Programs

NW Natural does not currently have energy efficiency programs for our transportation customers in either Oregon or Washington. Given that NW Natural will have compliance obligations for transportation customer's usage under the CPP, the Company recognizes the importance to pursue energy efficiency opportunities. NW Natural is already working on standing up an energy efficiency program for transportation customers and is actively engaging relevant stakeholders.[106] Establishing energy efficiency programs will be a critical part of the Company's compliance strategy in both states and will require engagement from stakeholders to find equitable funding mechanisms for these programs.

5.6 Gas Heat Pumps/Gas Heat Pump Water Heaters

Gas heat pumps are similar to heat pump technology on the electric side but are thermally driven using natural gas. They have the potential to reduce emissions and energy consumption by 40% or greater than existing natural gas furnaces and as they typically do not require back up heating, provide good opportunities for peak load management.

As shown in Figure 5.23[107], GTI identified gas heat pumps that are either on or near the market for both residential and commercial applications. In both markets, gas heat pumps can be used for space heating and cooling, for water heating or as "Combi" systems providing both hot water and space heating.

[106] As a practical matter for the IRP model, we shift the savings projections for transportation customers to start in 2025 to account for this initial ramp up period of a program. NW Natural is hoping to being taking advantage of energy efficiency opportunities prior to this date.
[107] NW Natural 2022 IRP Third Technical Working Group, April 13, 2022. This presentation and others may be found at https://www.nwnatural.com/about-us/rates-and-regulations/resource-planning

Figure 5.23: Gas-Fired Heat Pumps

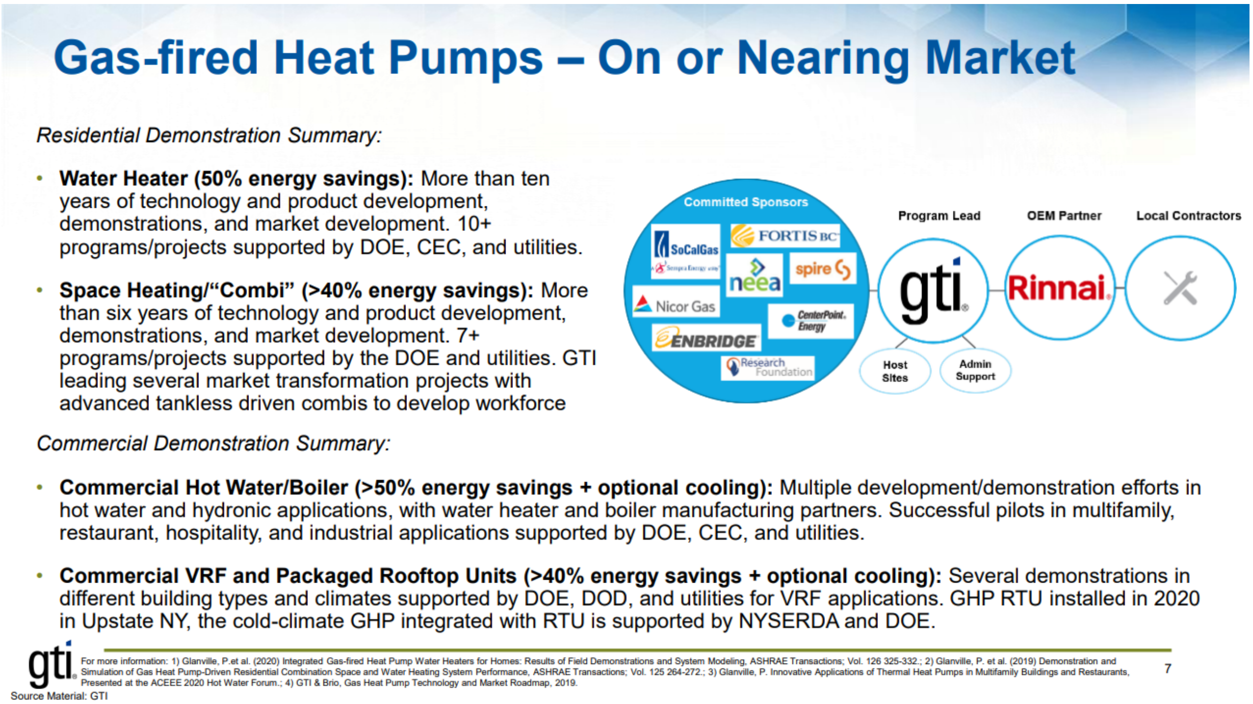


Figure 5.24 also shows the technology readiness of heat pumps from different manufacturers.

Figure 5.24: Gas Heat Pump Technology Readiness by Manufacturer

Technology Readiness

Green: Commercially available in North America

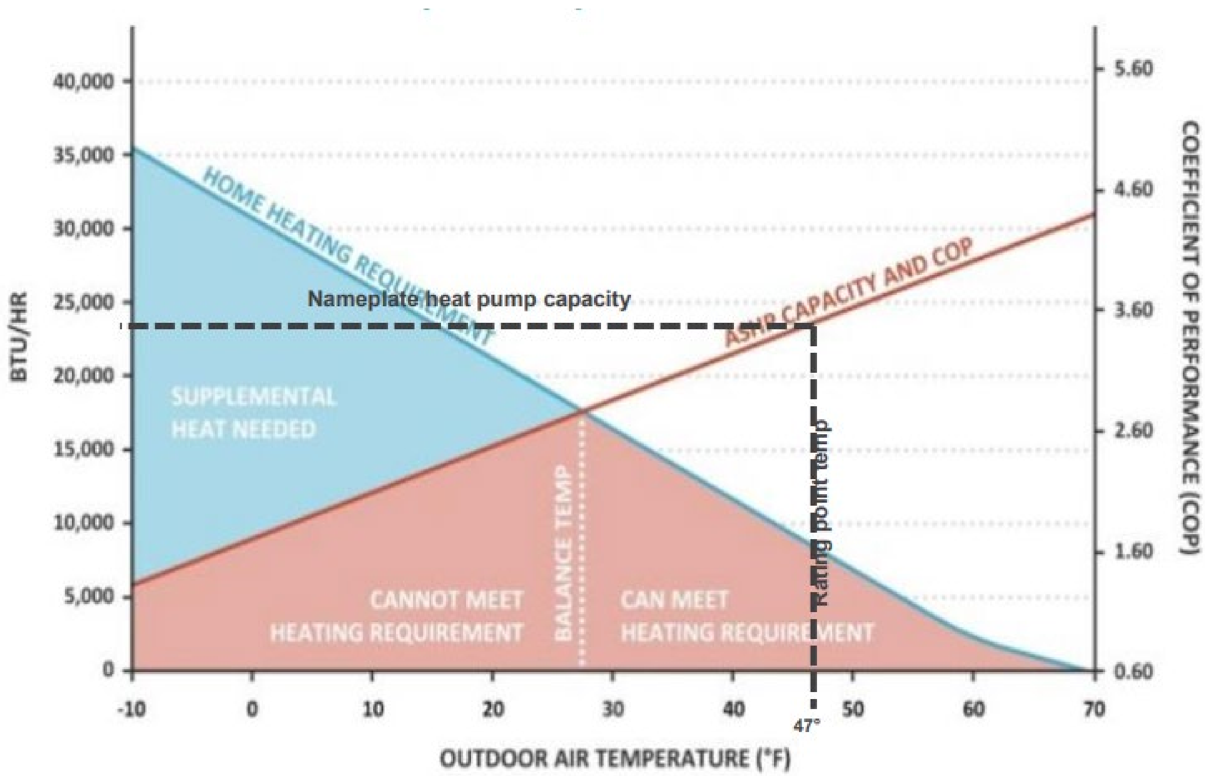
Source: Enbridge, NEEA, GTI

Manufacturer	Type	Primary Applications	Primary Sectors	Technology Readiness for North America
ROBUR	Absorption	Space and DWH heating Cooling (possible)	• Commercial • Residential	• Commercial size unit commercially available • Residential unit available in Europe. Efforts underway to bring it to NA
YANMAR	Engine driven	Space heating and cooling	• Commercial	• Commercially available
SMTI / ANESI	Absorption	Space and DHW heating	• Residential • Small commercial	• Field trials of pre-production unit underway
VICOT	Absorption	Space and DHW heating	• Residential • Commercial	• Commercially available in China • Lab testing and field trials of production unit underway in NA
ThermoLift	Thermal compression	Space heating, cooling and DHW heating	• Residential • Small commercial	• Lab testing and field trials of pre-production unit underway
HeatAmp	Adsorption	Space and DHW heating	• Residential • Small commercial	• Lab testing in Europe
Rinnai	Absorption	DHW heating	• Residential	• Lab testing and field trials planned

5.7 Dual-Fuel (Hybrid) Heating Systems

While not a new technology, dual-fuel (or hybrid) systems use electric heat pumps with direct use natural gas as back up for peak periods. Typically, electric heat pumps use resistance heating as back-up systems to heat pumps to help maintain comfort during cold temperatures. As can be seen in Figure 5.25, electric heat pumps are efficient, but efficiencies decline as temperatures decrease due to the use of resistance back up heating. This contributes to large peaks to utility loads and is expensive to customers.

Figure 5.25: Efficiency of Electric Heat Pumps and Ambient Temperature



Hybrid heating systems consist of using an electric heat pump as the main source of space heating, but it is teamed with a natural gas furnace for back up heat. The benefit of using both energy systems is that it helps with energy system resource adequacy. With the natural gas energy system providing peak heat, these dual-fuel systems serve as demand response for the electric grid and allows the existing seasonal storage infrastructure to serve peak needs in a region that is capacity constrained. By displacing resistance back up heat and using natural gas only in times of cold temperatures not only does this help with resource adequacy but it also supports energy efficiency and decarbonization efforts. Decarbonization efforts are further supported as both energy systems use more renewable energy or low carbon energy.

5.8 Key Demand-Side Input Assumptions

NW Natural's primary driver of our demand-side assumptions are based on the forecasts that are discussed above and have been provided by both ETO and AEG. We adjust our load forecasts for these projections in the recognition that there is also DSM included in our historical data used to train our load forecasting models. These DSM efforts are material and NW Natural expects a reduction of roughly 20% in load in its reference case by 2050 from programs for sales customers. Assuming that DSM programs for our transportation schedule customers begins in 2024, NW Natural expects a reduction of 10% of its transportation load in its reference case by 2050. All load sensitivities and simulation draws adjust for electrification assumptions so that savings are not being claimed from an energy need not served by NW Natural.

The Figure 5.26 and Table 5.18 set forth the key assumptions NW Natural used for emerging end use equipment penetration and costs in both its reference case and scenarios. Figure 5.26 shows the percent of installations per year of gas heat pumps for residential space heating, gas heat pump water heaters for residential water heating, gas heat pumps for commercial space heating, and hybrid heating for both residential and commercial applications.

Figure 5.26: Assumptions on Emerging Technology Adoption Over Time

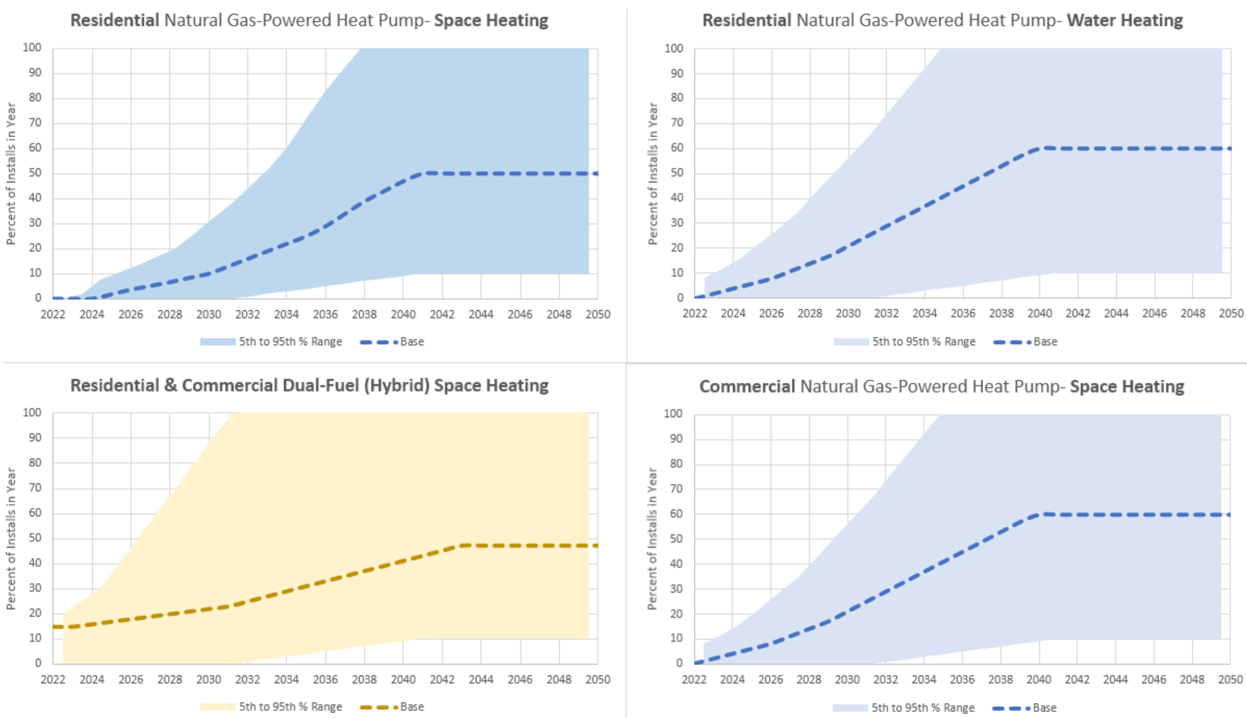


Table 5.18 represents NW Natural's assumptions of cost for these emerging technologies.

Table 5.18: Assumptions on Cost for Emerging Technologies

Incremental Demand-Side Measure Costs	Incentive	Total Cost to Utility	Cost Range (5th and 90th Percentile)
Residential Hybrid Heating Incremental Incentive (2020$/System Install)	$1,200	$1,600	+/-30%
Residential Hybrid Heating Share of Incentive paid by non-CCI funds (%)	25%	$400	+/-50%
Residential Gas Heat Pump Incentive (2020$/System Install)	$3,000	$4,000	+/-40%
Residential Gas Heat Pump Water Heater Incentive (2020$/System Install)	$1,200	$1,600	+/-40%
Commercial Hybrid Heating Incremental Incentive (2020$/System Install)	$3,000	$4,000	+/-30%
Commercial Hybrid Heating Share of Incentive paid by non-CCI funds (%)	25%	$1,000	+/-40%
Commercial Gas Heat Pump Incentive (2020$/System Install)	$10,000	$13,333	+/-30%
First Year Transport Load Savings Cost (2020$/1st year therm saved)		$1.79	+/-100%

5.9 Low Income Programs

5.9.1 Oregon Low-Income Energy Efficiency Program (OLIEE)

Since 2002, a portion of the public purpose funding collected by NW Natural has been allocated for Oregon Low-Income Energy Efficiency (OLIEE) through a surcharge to Oregon Residential and Commercial customers' energy bills. The OLIEE program attempts to provide equitable access to DSM by funding high-efficiency equipment and weatherization measures to income qualified homes. The program consists of two parts: The Community Action Program (CAP), and the Open Solicitation Program (OSP).

The CAP provides energy evaluations of low-income dwellings and funding for qualifying DSM measures. In conjunction with DSM, health, safety, and repair (HSR) projects like improving ventilation may also receive funds through the CAP. The program is administered by 10 CAP agencies throughout the Oregon service territory.

OSP focuses on projects that do not fit into the CAP framework, including but not limited to, new affordable housing or temporary living space retrofits. NW Natural invites proposals that serve low-income qualified customers and allocates funds based on availability. Bi-annual meetings are held with both the CAP agencies and OLIEE Advisory Committee (OAC) to ensure proper implementation of the programs. Historical engagement in the OLIEE program is shown in Table 5.19.

Table 5.19: Homes Served through OLIEE Program

Program Year	Homes	Therms Saved
2015-2016	231	52,817
2016-2017	260	59,232
2017-2018	299	103,708
2018-2019	260	73,441
2019-2020	248	68,320
2020-2021	341	60,394

5.9.2 Washington Low-Income Energy Efficiency Program (WA-LIEE)

In 2009, NW Natural launched a revised low-income program identified as WA-LIEE (Washington Low-Income Energy Efficiency). Modeled after Oregon's low-income CAP program, the WA-LIEE program reimburses administering agencies for installing weatherization measures that are cost-effective when analyzed in aggregate.

In Washington, two agencies co-administer the program. The program is informed by input from NW Natural's Energy Efficiency Advisory Group (EEAG). Homes with gas in SW Washington tend to be newer construction with less of a need for weatherization, and only 2% of NW Natural's customers in Washington qualify as low-income. Barriers such as these limit participation. NW Natural continues to evaluate how to support agencies and adjust the program to increase the number of homes served per year. Table 5.20 shows the historical number of homes treated through the WA-LIEE program.

Table 5.20: Homes Served through WA-LIEE Program

Program Year	Homes	Therms Saved
2016	16	6,132
2017	13	6,048
2018	16	7,578
2019	22	20,170
2020	3	1,132
2021	11	3,568

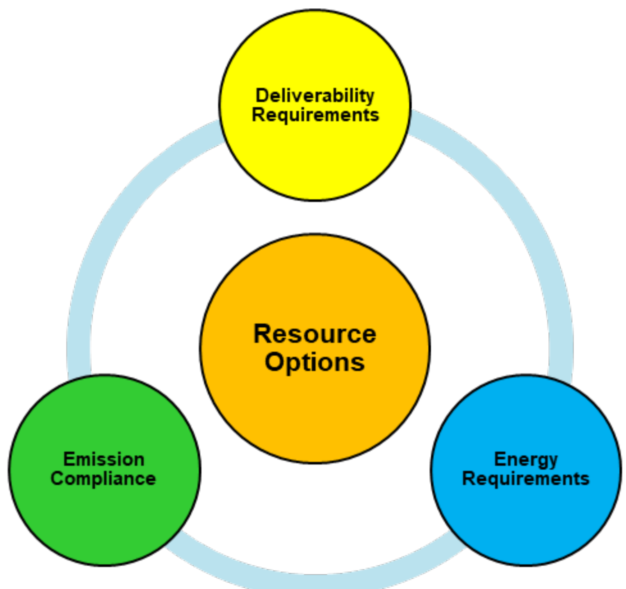
Once customer needs are established it is important to take a wide scope and assess what options are available to meet those needs. Chapter 6 discusses resources that can be used to serve customer energy and emissions needs throughout the year (conventional natural gas, renewable natural gas, and clean hydrogen) and during the coldest days we experience (pipelines and storage facilities).

6 Supply-Side and Compliance Resources

6.1 Overview

This chapter of the IRP discusses both current and potential supply-side resources that NW Natural uses to deliver conventional natural gas and renewable natural gas to customers. Supply-side resources include not only the gas itself, but also the upstream interstate pipeline capacity required to ship the gas, NW Natural's gas storage options, and other on-system resource options. Additionally, agreements for acquiring renewable thermal certificates (RTCs) on the behalf of customers and other emissions compliance resources, such as community climate investments (CCIs) are discussed in this chapter. Meeting compliance obligations in both Oregon and Washington over the planning horizon is a major focus for this IRP. While these compliance resources may not actually provide gas supply to the system, they are discussed in this supply-side resource chapter of this IRP.[108]

This suite of supply-side resources focused on in this chapter are associated with serving customers at the system level and meeting emissions requirements in both Oregon and Washington. Supply-side resource options associated with alleviating constraints in specific areas of the distribution system are discussed in Chapter 8.



All resources vary across three dynamics as to the value for what each resource provides to NW Natural's system; 1) the daily deliverability or capacity value, 2) the overall energy a resource can provide throughout the year, and 3) the contribution to emissions reduction under an emissions constraint. For example, a year-round pipeline capacity contract provides capacity every day of the year but needs to be paired with gas purchases to provide energy. Storage LNG facilities are limited on the amount of energy they can provide but can provide capacity for serving peak demand. Off-system RNG gas contracts provide emissions compliance requirements, but by themselves do not provide capacity to the system. All these different resources also vary in costs, availability, and risks.[109]

The rest of this chapter discusses general types of supply-side resources, NW Natural's current resource portfolio, future emissions compliance resource options, and future capacity resources

[108] Future discussion could help assess if resources needed for emissions compliance should be classified under a separate category as compliance resources such as CCIs do not clearly fall under the binary classification of demand-side or supply-side resources.

[109] Also, as done previously, potential resources are discussed in this chapter that ultimately are deemed too speculative to include in the portfolio choice analysis in Chapter Seven, with explanations for why they ended up on the "cutting room floor."

options available for NW Natural to address resource need. These current and future options are inputs to the resource planning optimization model discussed in Chapter 7. The ability to plan for customer requirement variations while maintaining reliability of service is best accomplished by having a diversity of resources available. The portfolio of supply-side resources available to NW Natural can be categorized under various primary resource types:

Natural gas, RNG, or hydrogen supply contracts – these are contract agreements for natural gas or RNG to be purchased from a producer or gas marketer for a specified volume for a given period and at a specific location known as a receipt point.[110] Natural gas supply contracts are purchased on a term basis, for example baseload contracts- or purchased on the spot (daily) market and must be used in conjunction with other supply-side resources, such as interstate pipeline contracts, to ship the gas from the receipt point to a delivery point connected to NW Natural's system, known as a citygate.[111] See Appendix E for further details about gas purchasing practices. RNG and Hydrogen are discussed in further detail later in this chapter.

Interstate/interprovincial pipeline capacity – NW Natural contracts with pipeline companies in the US and Canada to ship natural gas from receipt points, where gas is injected into the interstate/interprovincial pipeline, to delivery points where NW Natural physically takes custody of the gas. These capacity rights are used to ship gas supplies purchased for NW Natural sales customers to NW Natural's system.[112]

On-system production resources – On-system production resources are non-storage resources that produce gas and inject directly onto NW Natural's system. This primarily consists of injections from renewable methane sources, but also includes a minimal amount of Mist production gas still being collected from producing wells next to the underground Mist storage facility (a.k.a. Miller Station). The current on-system resources from renewable methane sources do not have environmental attributes, or RTCs, associated with the injected gas, however; future on-system renewable methane source could be bundled with the RTCs and used for emissions compliance for NW Natural customers.

Underground storage – There are 387 active underground natural gas storage fields in the Lower 48 states.[113] These facilities utilize depleted oil or gas production wells, natural aquifers, or salt caverns to store gas supplies. The geological properties of each of these underground facilities offers an effective means of storing large amounts of natural gas which can be accessed relatively quickly to meet seasonal demand shifts throughout the year.[114] Utilities, gas marketers, and other shippers of natural gas contract with the storage facility owners for both storage capacity (the total amount of gas stored

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[110] Receipt points are commonly locations or gate stations on an interstate pipeline.
[111] The term ship is use purposefully here to refer to either physically flowing gas or moving gas via displacement on the interstate/interprovincial pipeline, as the pipeline contracts commonly refer to their customers, such as NW Natural as shippers.
[112] Transport customers are responsible for their own capacity and gas purchases upstream of NW Natural's system.
[113] https://www.eia.gov/naturalgas/storagecapacity
[114] For more information: https://www.eia.gov/naturalgas/storage/basics/

underground) and storage deliverability (the amount of gas that can be withdrawn from storage in a day).[115] While the storage capacity is a function of the geological properties of each facility, the storage deliverability is a function of the wells drilled into the formation and the piping and compression infrastructure used to withdraw stored gas. Note that storage capacity helps meet annual energy requirements, whereas storage deliverability helps meet system capacity requirements as discussed at the start of this chapter.

In addition, deliverability from underground storage can be a function of the storage inventory level (i.e., how full the storage facility is at any given time). When the facility is full, the pressure of the gas underground is high and therefore will flow freely out of the ground. As the facility empties, pressure declines and deliverability will also decline. Due to the physics of these facilities, storage contracts often include clauses known as “ratchets”, which specify the deliverability as a function of a customer’s capacity inventory level.

Above-ground LNG storage – Above-ground LNG tanks and facilities super-cool natural gas into a liquid, known as liquefaction, and are an effective way to store more energy per volumetric unit (e.g., cubic foot) compared to its gaseous form. LNG storage facilities reverse the process, known as vaporization, to quickly inject gas back into the system to meet spikes in demand. Compared to underground storage, these facilities have a higher ratio of storage deliverability to their overall storage capacity and are well-suited as “peaker” units to help meet demand spikes when temperatures plumet.

Industrial recall options – NW Natural contracts with several industrial counterparties for recall options wherein we would pay the replacement fuel price for an industrial company to switch to an alternative fuel source to propane, fuel oil or diesel and provide us with the natural gas supplies that they would have otherwise consumed. Note that these contracts are not with sales customers therefore would not be considered demand response. These contracts are agreements that provide additional interstate pipeline capacity and natural gas supplies if called upon. These contracts are limited to the number of days we can call on them in a winter season.

Citygate deliveries – The "citygate" is the point of delivery at which gas is transferred from an interstate or intrastate pipeline to a local distribution company’s custody. Citygate contracts are for gas supplies delivered directly to NW Natural’s service territory by the counterparty utilizing their own NWP pipeline capacity. Such deliveries could be arranged as baseload supplies, or on a swing basis, i.e., delivered or not each day at the option of NW Natural.

NW Natural has utilized citygate delivery agreements, on occasion, when cost effective. Such agreements usually take the form of swing arrangements that allow up to five days’ usage during the period of December through February. As a near-term capacity resource city gate deliveries are relatively inexpensive, but if the option for deliveries is utilized, the commodity price for the delivered volumes is index-based and expected to be extremely high. The long-term reliability of citygate deliveries is very uncertain to be evaluated as a long-term option for IRP analysis, but these options are evaluated as an alternative for meeting design peak demand going into each winter.

6.1.1 Compliance Resource Types

Bundled and unbundled environmental attributes from RNG – unbundled purchases do not provide capacity nor energy to NW Natural's system but are a pathway for reducing carbon emissions or meeting state carbon reduction targets on behalf of NW Natural customers. One example is the purchasing of renewable thermal certificates (RTCs) that confer all the benefits of the RNG emissions reductions to NW Natural's customers. In other words, other parties cannot claim the emissions reductions for RTCs purchased and held by NW Natural. RTCs are generated when a Dth of RNG is injected into a gas pipeline, displacing fossil gas. Bundled purchases give NW Natural ownership of both the gas and the environmental attributes of RNG. A bundled resource could provide capacity and energy if bundled with an on-system production RNG resource or if it is used in combination with pipeline capacity contracts to ship the RNG to NW Natural's system. Alternatively, if the bundled RNG resource is not on-system or capable of utilizing NW Naturals pipeline contracts, NW Natural can unbundle the energy from the environmental attributes and sell the energy from that resource (often referred to as "*brown gas*") and retain the RTC of that RNG to retire on behalf of customers.

Qualified compliance instruments – certain compliance instruments are approved by legislation and qualify to be purchased to meet emissions compliance obligations. These compliance instruments are not tied a volumetric amount of methane but represent a metric ton CO_2e reduction for compliance obligation. The CPP in Oregon allows for CCIs, while in Washington the CCA allows for the purchase of both offset credits and tradable allowances (see Chapter 2 for policy details and section 6.6 of this chapter for modeling details).

6.2 Low Carbon and Zero Carbon Gas

The last few years have seen significant maturation in the technologies and markets around all types of decarbonized gases. Biofuel-based resources (typically referred to as Renewable Natural Gas, or RNG) are one type of low- or zero-carbon gas many are familiar with, as biogas has been used for decades to supply energy via direct heating use or power generation. But new technologies have opened new opportunities for decarbonized gases. Hydrogen generation from a variety of sources has also matured significantly, and projects looking to inject both pure hydrogen into gas lines as well as synthetic methane generated by marrying clean hydrogen with waste CO_2 are being developed today. Below we discuss the main types of low carbon gases NW Natural is currently considering as resources.

6.2.1 Biofuels

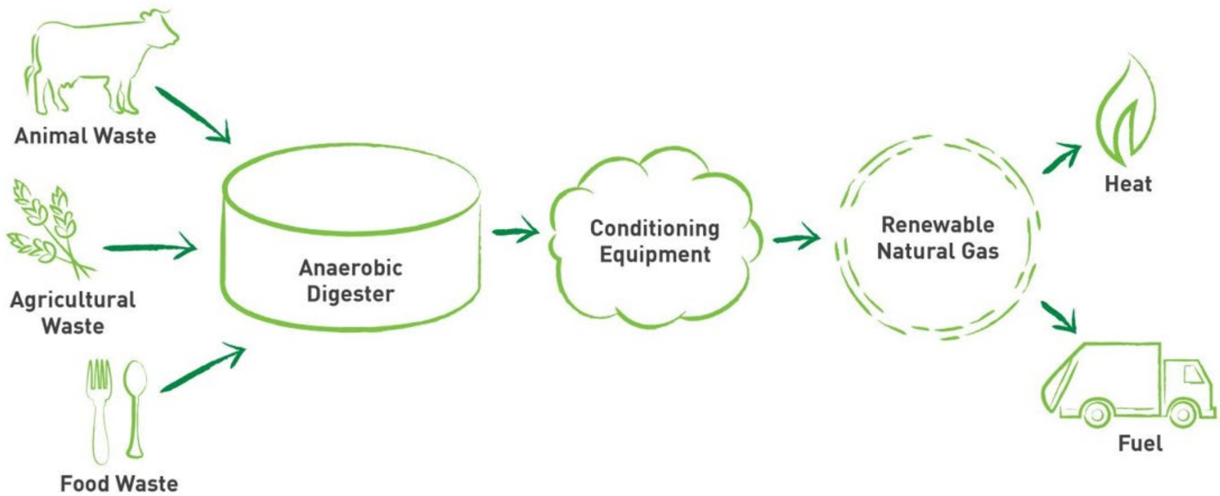
Biofuel gas or Renewable Natural Gas (RNG) is *pipeline-quality gas* derived by cleaning up the raw biogas emitted as organic material chemically breaks down. RNG going directly onto NW Natural's system must meet specified quality standards, be at least 97.3% methane and have an energy content of at least 985 BTUs/SCF. Once on our system, RNG is fully interchangeable with conventional natural gas, and requires no new equipment in customer homes or businesses.

In Oregon, RNG was defined in 2019's Senate Bill 98 as: "any of the following products processed to meet pipeline quality standards or transportation fuel grade requirements: Biogas that is upgraded to meet natural gas pipeline quality standards such that it may blend with, or substitute for, geologic natural gas; Hydrogen gas derived from renewable energy sources; or Methane gas derived from any combination of: Biogas; Hydrogen gas or carbon oxides derived from renewable energy sources; or waste carbon dioxide[116]." Thus, NW Natural takes a broad view of potential RNG resources it can secure on behalf of its Oregon customers.

In Washington, per 2019's House Bill 1257, renewable natural gas "means a gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters." The bill further notes that "the [UTC]

[116] Oregon Senate Bill 98: https://olis.oregonlegislature.gov/liz/2019R1/Downloads/MeasureDocument/SB98/Enrolled

commission may approve inclusion of other sources of gas if those sources are produced without consumption of fossil fuels[117]."



There are many policies that drive NW Natural to procure RNG for its customers. Table 6.1 identifies the key driving policies that establish RNG goals, define RNG, define its role in our emissions compliance activities, and otherwise motivate NW Natural to secure least cost RNG resources on behalf of its customers.

Table 6.1: Policies Driving RNG Acquisitions

Policy	Relevance for RNG
Oregon Senate Bill 98	Volumetric targets for RNG procurement for Oregon sales customers
Oregon Climate Protection Program (CPP)	Compliance will include RNG and hydrogen (above and beyond Senate Bill 98 volumes) when cost-effective to procure
Washington House Bill 1257	Establishes both an option for delivery for RNG to all gas customers as well as a requirement to offer customers voluntary RNG tariff
Washington Climate Commitment Act (CCA)	Sets emission cap that applies to gas utilities, which can use RNG and hydrogen as a compliance tool
Voluntary offerings to customers	Building options for customers in Oregon and Washington to procure greater amounts of RNG and hydrogen

The policy that has had the largest impact to date on NW Natural's procurement of RNG is Oregon Senate Bill 98, which established volumetric targets for RNG that the Company internalized as its own RNG targets after the law passed. The law allows gas utilities to procure RNG and invest in RNG

[117] Washington House Bill 1257: https://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/House%20Passed%20Legislature/1257-S3.PL.pdf?q=20220917151937

projects, provided that the *incremental* cost of such procurement does not exceed 5% of the company's annual revenue requirement. The calculation for what costs are incremental is discussed later in this chapter.

Time Period	Large Gas Utility Volumetric Targets
2020-2024	5%
2025-2029	10%
2030-2034	15%
2035-2039	20%
2040-2044	25%
2045-2050	30%

Under Senate Bill 98 gas utilities can purchase RNG (including hydrogen) for all customers as part of our utility resource mix. This is a significant change, as prior to the passage of the bill, we could only buy the least-cost gas, which was not RNG. It also allows gas utilities to invest in and own the equipment necessary to bring raw biogas and landfill gas up to pipeline quality, as well as the facilities to connect to the local gas distribution system.

Senate Bill 98 has driven the Company to be a leader in the procurement of RNG among gas utilities, and to develop programs and build a team around the development and procurement of RNG. This technical and market knowledge can now be applied to NW Natural's compliance and planning under programs such as the Climate Protection Program, Washington House Bill 1257, and the Washington Climate Commitment Act.

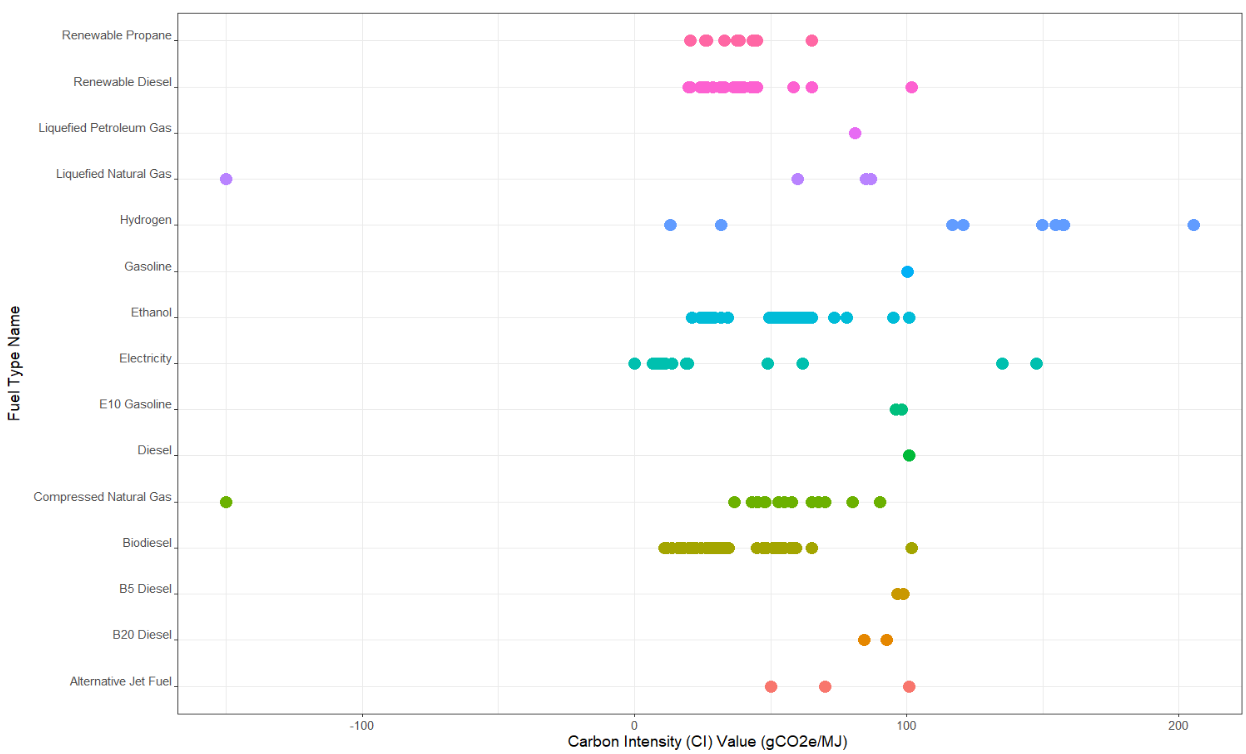
Emissions Benefits of RNG

There are several ways to evaluate the emissions of RNG. Both Oregon and Washington's laws relating specifically to procurement of RNG by gas utilities do not set parameters around prescribed carbon intensity of RNG. NW Natural considers RNG to be carbon neutral because the carbon dioxide that is emitted when RNG is combusted is biogenic – derived from and stored by organic matter – meaning that the combustion of it does not add any additional carbon into the carbon cycle. NW Natural reports its emissions in both states on a "combustion basis," which reflects the view that the carbon in RNG is biogenic, and thus the carbon emitted when combusted is not reported. This same approach is used by the U.S. Environmental Protection Agency, the International Energy Agency, and the Intergovernmental Panel on Climate Change, which all recognize that because the CO_2 in biogas is biogenic, it is appropriate to not report that carbon in RNG when reporting emissions.

There are other programs in the United States that use a different approach to measuring the emissions reduction benefits of RNG. These programs use "lifecycle-based" methodologies, which look at the total emissions embedded in the entire lifecycle of a fuel's production and utilization. These programs are mostly found in transportation fuels, which have several different types of fuels and use the lifecycle-based approach to evaluate these fuels on an "apples to apples" basis. This approach derives a "carbon intensity" of a fuel and includes considerations of the methane emissions that would have occurred had the RNG project not occurred, how efficient the use of the fuel is in the end use (e.g., how efficient is a certain motor?) and other aspects. Each fuel is given a "carbon intensity score" which can vary from month to month or year to year, depending on local policies that address methane emissions, project performance, etc. NW Natural does not use carbon intensity scores to evaluate RNG resources because our compliance environment uses combustion-based emissions treatment. However, NW Natural does record the carbon intensity score of its resources and reports it in its annual Senate Bill 98 reports. Oregon's rules for Senate Bill 98 require annual reporting of the carbon intensity of RNG, and we expect reporting for Washington under RNG delivered as part of a House Bill 1257 program will require similar data.

The carbon intensity of a resource using the lifecycle-based approach will vary depending on the raw feedstock, the process used, the efficiency of the equipment, etc. State-level clean fuels programs are the most advanced programs in evaluating and tracking the carbon intensity of RNG using this approach. Figure 6.1 shows the current carbon intensities of all the fuels currently registered in the Oregon Clean Fuels Program. As can be seen in the "compressed natural gas" fuel type, the carbon intensity score of CNG resources (most of which are RNG-derived) ranges from -150 to a little under 100 grams CO_2/MJ of fuel.[118]

Figure 6.1: Carbon Intensities for Registered Projects in the Oregon Clean Fuels Program



[118] Oregon DEQ's Clean Fuels Program: https://www.oregon.gov/deq/ghgp/cfp/Pages/Clean-Fuel-Pathways.aspx

Appendix E lists all the RNG projects located in Oregon, Washington, and California that are currently generating RNG using feedstocks that are common in the procurement of RNG currently being undertaken by NW Natural.

In Oregon, our compliance under the Climate Protection Program will be measured in part via the data reported in the Oregon Greenhouse Gas Reporting Program. Training provided by the Oregon DEQ notes that "We do not require direct delivery of the biomethane to the supplier, and an equivalent volume of natural gas can be assumed to have been displaced as long as the purchased biomethane was nominated to a natural gas pipeline[119]." This approach – separating the environmental attributes of the RNG from the physical delivered gas – is the standard used throughout the RNG industry, including in the U.S. Environmental Protection Agency's Renewable Fuel Standard, the Oregon Clean Fuels Program, Oregon Senate Bill 98, and the California Low Carbon Fuel Standard. As noted earlier, under SB 98 we are required to report the carbon intensity of all RNG resources utilizing the lifecycle approach, but that approach is not what is used to measure our emissions for purposes of the Climate Protection Program compliance.

Renewable Thermal Certificates (RTCs)

To track the environmental attributes of RNG and ensure that the benefits are not being claimed by multiple parties, the RNG industry has begun using the generation of "renewable thermal certificates" (RTCs) to track and record RNG transactions. Regardless of whether RNG is purchased bundled with or without the underlying physical gas, RTCs are recorded to ensure the environmental attributes of the gas are appropriately tracked.

An RTC is a sole claim to the environmental benefits of a dekatherm of thermal energy from sources such as RNG, hydrogen or synthetic methane, and is separate from the physical gas (i.e., unbundled RNG or hydrogen). RTCs are procured to meet compliance needs, to show how NW Natural is procuring renewable resources on behalf of its customers. The Midwest Renewable Energy Tracking System (MRETs), which has historically tracked the sale of electricity-based renewable energy credits (RECs) has emerged as the leading platform on which RTCs are tracked and recorded.

One RTC is created for every Dth of RNG produced and injected into the "common carrier" network or an LDC's distribution system.

[119] Oregon DEQ's Greenhouse Gas Reporting Training slides: https://www.oregon.gov/deq/ghgp/Documents/3pbC5ngSupplier.pdf and video recording: https://www.youtube.com/watch?v=FlzNhG-v16I

Figure 6.2: Tracking RTCs

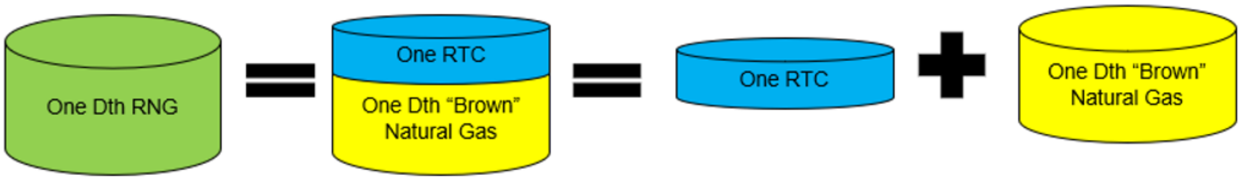
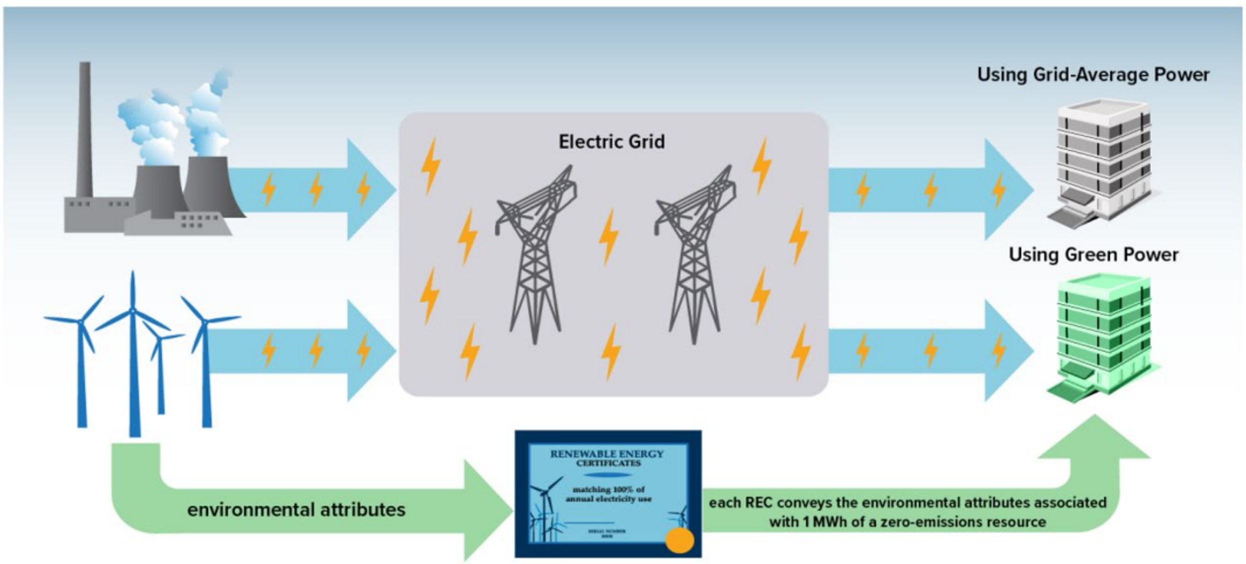


Figure 6.3: Tracking RECs



NW Natural purchases both bundled and unbundled RNG resources. Bundled resources means we are purchasing the physical energy and the RTC together; unbundled means we are just purchasing the RTC. Both are recognized as compliant resources under Senate Bill 98 and the Oregon Climate Protection Program. Contracts for RNG are either contracts for physical gas with special transaction confirmations and other elements that delineate what a producer will deliver RTCs into MRETs as part of their contractual obligations, or they are contracts just for the RTCs or environmental attributes of RNG.

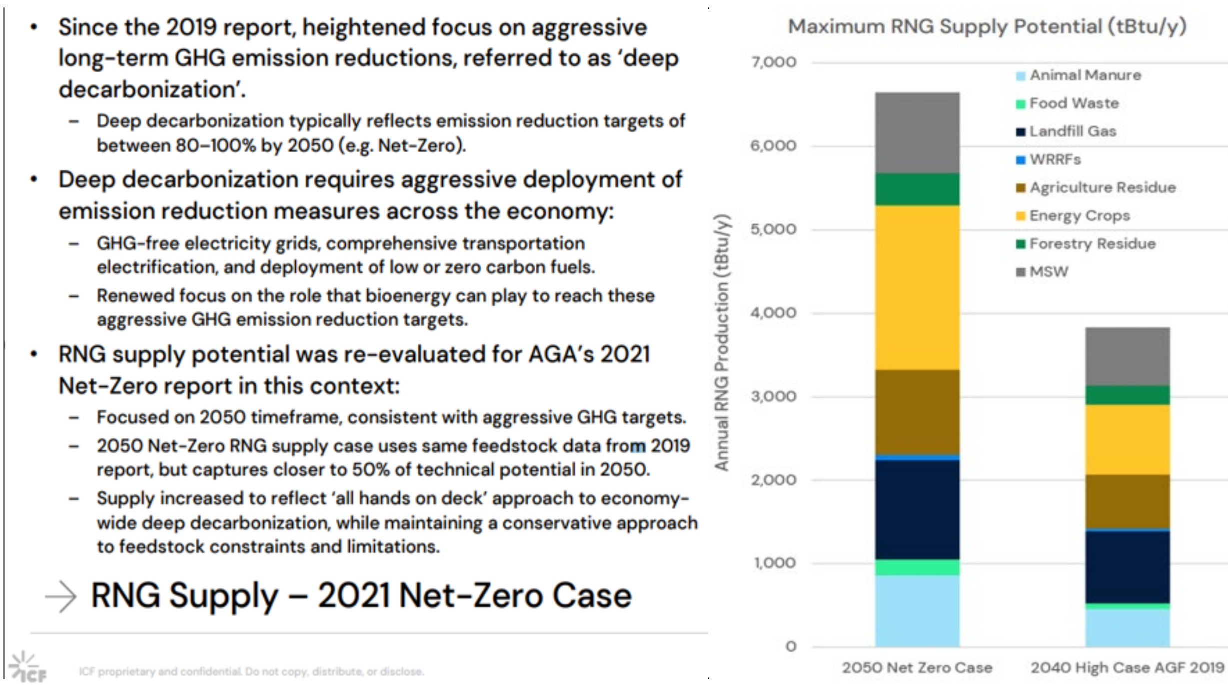
RNG Supply

RNG supply has recently been and continues to be a topic of research and new evaluation, as the industry matures, and more potential buyers seek to understand the type and amount, and economics of available RNG supplies. The American Gas Foundation supported a study by ICF in 2019[120] and the RNG supply potential was re-evaluated by ICF for the American Gas Association's 2021 Net-Zero

[120] https://gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/

report.[121] ICF's updated Net-Zero report articulates that a larger maximum supply potential of RNG will be available with more aggressive decarbonization policies and utility renewable energy development. Figure 6.4 summarizes these findings.

Figure 6.4: ICF 2021 Net Zero Report Key Findings



NW Natural is a leader in RNG procurement and project development among gas utilities in the U.S. and Canada. In previous years, NW Natural considered the transportation fuel sector to be its primary competitor for low-cost RNG, due to the highly lucrative credit markets available to those sectors. However, in recent years other gas utilities and large commercial and industrial gas users have identified RNG as a critical resource for their decarbonization goals and targets and have begun to enter the market and buy RNG under both medium term (5 years) and long term (10 years+) contracts. NW Natural has internal RNG origination resources and has maintained active project origination and development efforts for several years. These activities and our annual RFP process for RNG will continue to help the company identify cost-effective RNG resources in the future. NW Natural continues to be able offer longer term contracts than most other market participants, and its high credit rating allows it to be viewed as a highly low-risk offtaker/purchaser of RNG by RNG project developers and owners.

[121] The results of these reports were presented at one of NW Natural's Technical Working Group #3. For more information, please see TWG 3, https://www.nwnatural.com/about-us/rates-and-regulations/resource-planning

NW Natural responded to concerns from stakeholders that there is not sufficient RNG to meet its goals.[122] In fact, just 1/50th of the updated ICF estimate of the total amount of RNG available in the US would be about 132 million MMBtu, which is nearly twice the total demand of gas by NW Natural sales customers today. While there has been healthy growth in the RNG market in recent years, there is still much more RNG that can be developed than what is already developed.

The costs for RNG reflect the production costs, including financing costs, the capital costs of equipment, the ongoing operating expenses, and development costs such as legal and permitting. The cost of RNG on a $/MMBtu basis is largely impacted by the size of the project. There are tremendous economies of scale in RNG production, as many of the high capital costs increase to some degree with volume, but not in a 1:1 manner. Costs for gas cleaning and conditioning equipment have increased along with all other major equipment in this inflationary period, and NW Natural will continue to evaluate how such cost increases are impacting offtake prices and the costs of RNG project development.

Renewable Natural Gas Procurement

Oregon Senate Bill 98, Washington HB 1257, the Oregon Climate Protection Program, and the Washington Climate Commitment Act all underscore the need for NW Natural to secure low carbon gases, including biofuel-based RNG and hydrogen resources. While each program takes a slightly different view of RNG definitions, cost caps, etc., NW Natural endeavors to secure resources that it believes will work within a variety of policies, regulations, and other programs. Our current assumption, for instance, is that all the RNG we have procured to date under Senate Bill 98 will also offer compliance benefits under the Oregon CPP. As noted earlier, the Oregon DEQ has stated that off-system RNG, which is typically tracked via RTCs, will qualify as a resource under the Oregon CPP.

RNG projects take several years to develop. NW Natural keeps track of projects at a variety of times in their lifespans. For instance, projects are sometimes in very early stages of development, with no definitive agreements or interconnection agreements signed, when they come to our attention. A developer may contact NW Natural about buying the RNG, and we will express interest but convey that we cannot enter true negotiations until the project has a clear pathway toward full development. NW Natural may enter non-binding letters of intent (LOIs) and non-binding term sheets with developers and project owners. Only a small number of these resources become actual contracted resources but entering into these non-binding agreements allows us to learn more about the resource, exercise our due diligence, and assess the costs and benefits of a project. This is similar to how other utility projects are assessed, where there is initial investigation/origination, targeted due diligence, and then recommendations for an investment or resource selection.

[122] See Oregon Docket UG 435, NW Natural's Reply Testimony and Exhibits: https://edocs.puc.state.or.us/efdocs/HTB/ug435htb162723.pdf

Projects must be continually evaluated and worked on, which makes it hard to put specific resources into an IRP. Typically, NW Natural must decide about whether to enter into definitive agreements within a set timeline (e.g., within 90-day exclusivity period, or in response to a formal bid process with a hard deadline). Additionally, all projects, regardless of timing or whether they are identified through the RFP process, are evaluated on the same metrics, which include incremental cost to customers, project risks, volume availability, etc.

NW Natural utilizes in-house origination resources as well as its external relationships in the industry to identify new potential RNG resroruces. An annual request for proposal process is used to evaluate multiple opportunties in the market and understand the breadth of renewable resources that might be available. Figure 6.5 and Table 6.2 summarize the 2021 RFP responses.

Figure 6.5: 2021 RFP by Feedstock

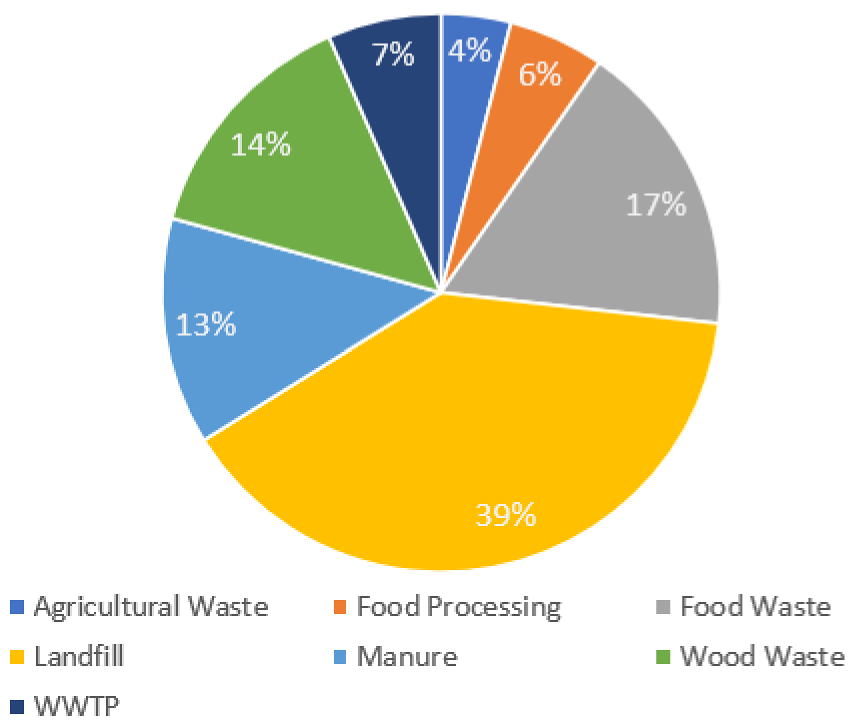


Table 6.2: 2021 RFP Responses- Summary

2021 RFP Response Summary	
Total Responses	27
Average Contract Term	14 years
Average Annual Volume of Resource	597,806 MMbtu
Bundled vs Unbundled	52% / 48%

2022 RNG RFP Procurement and Development Timeline

The 2022 RFP is NW Natural's 3rd annual RFP for RNG resources. The RFP was released on April 14, 2022, with short-listed respondents receiving notification in mid-June. Diligence was conducted on short-listed respondents June throught July and final agreement negotiations began in the third of 2022 and as noted above, NW Natural is in the midst of final negotiations with a small number of respondents and will be likely entering into multiple RNG contracts over the next several months as a result of the 2022 RFP.

Rolling Evalutations

Between rounds of RFPs, NW Natural additionally evalutates resources on a rolling basis. This includes a rolling evalutaion of other offtake resources as well as a rolling evalution of RNG development opportunities. For development opportunities, the following agreements and activities are common during NW Natural's rolling evalution process:

- Non-disclosure agreements signed to collect initial data
- Non-binding term sheets agreed to to explore economic agreements with feedstock owners, developers, project owners, etc.
- Extensive diligence processes undertaken to assess project economics and risks, including technical, legal, regulatory, financial, environmental, etc.

6.2.2 Hydrogen

Hydrogen is evaluated as a compliance resource option as it provides the needed emissions reductions for NW Natural customers. The use of hydrogen has many benefits including: its compatibility with current gas system operations, increasing the diversity of supply sources, the ability to deliver high temperature energy (critical for industrial process loads), the potential to support new vehicle fuel demand (trucking, aviation, marine), and the ability to store energy long term at a low cost.

The Hydrogen Rainbow

Hydrogen can be sourced from many sources and feedstocks, including electrolysis of water (referred to as electrolytic hydrogen or green hydrogen), gasification or pyrolysis of woody biomass, and cracking of imported ammonia. There are many types of hydrogen, and the colors represent the base source and production method, as depicted in Table 6.3. The manner in which different types of hydrogen may qualify for emissions compliance under the CPP and CCA is not entirely clear. To reflect some of the projects currently under consideration, this IRP only considers hydrogen produced through electrolysis (green hydrogen) and synthetic methane (described below) using renewably-generated electricity as a compliance resource. NW Natural is exploring all low-carbon sources of hydrogen inside and outside the region.

Table 6.3: Hydrogen Sources[123]

	Gray Hydrogen	Blue Hydrogen	Turquoise Hydrogen	Green Hydrogen	Pink Hydrogen
Process	Steam methane reforming	Steam methane reforming with carbon capture sequestration	Reforming methane into hydrogen gas and elemental (solid) carbon	Electrolysis, electricity is used to split the molecule into hydrogen and oxygen	Electrolysis, electricity is used to split the molecule into hydrogen and oxygen
Source	Methane	Methane	Methane	Renewably-generated electricity	Nuclear electricity generation

Regardless of the type of hydrogen that is produced or purchased, the hydrogen molecules can be blended into the existing pipeline and used by existing buildings, and commercial appliances. Preliminary studies and testing project a 20%, by volume, blending limit onto a combined system. In addition to the combined systems servicing homes and business, there is potential for hydrogen to have dedicated systems for large industrial processes currently relying on natural gas. These dedicated systems would flow 100% hydrogen that is completely separated from the distribution system delivering the blended hydrogen-methane gas but would provide the required energy for a large industrial customer.

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123 Each source of hydrogen carries a carbon footprint from a lifecycle perspective. Green hydrogen carries the carbon intensity of the energy used to create the electricity and build and maintain the associated generation infrastructure, blue and turquoise sources have up- and mid-stream methane emissions or CO_2 sequestration efficiencies, etc. These carbon intensities depend on a number of design and production factors and can range from near-zero to the hundreds of grams of CO_2 per MJ of energy. The newly passed Inflation Reduction Act provides hydrogen production tax credits (PTCs) based on the carbon intensity of the gas, as measure on a lifecycle basis using the GREET software created by Argonne National Laboratory. The PTCs are highly skewed towards the lowest carbon intensities possible:
Based on carbon intensity ($0.60/kg base credit, **5x** if prevailing wages & apprenticeship requirements met):

- 0.45kgCO_2/kgH_2: 100% ($3.00/kg or $22/MMBtu)
- 0.45-1.5kgCO_2/kgH_2: 33.4% ($1.00/kg or $7.43/MMBtu)
- 1.5-2.5kgCO_2/kgH_2: 25% ($0.75/kg or $5.57/MMBtu)
- 2.5-4.0kgCO_2/kgH_2: 20% ($0.60/kg or $4.46/MMBtu)

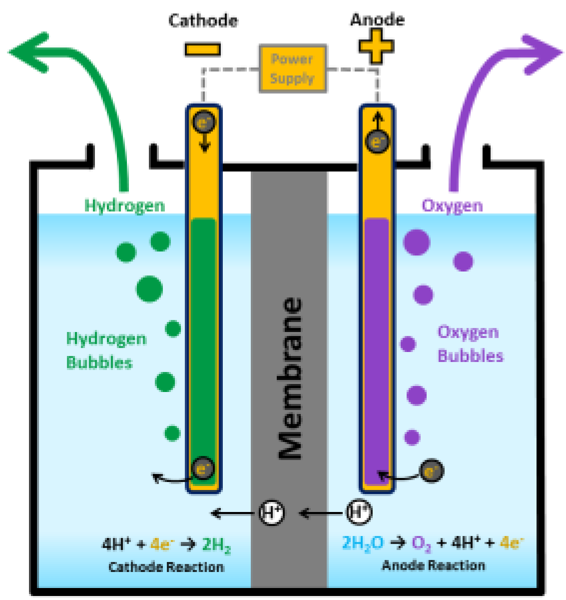
Any given hydrogen production pathway could be anywhere in this range of carbon intensities depending on the capital costs of the project. For example, electrolytic hydrogen using electricity from a coal generation plant could be on the lower end of carbon intensities using significant carbon capture infrastructure. The incentives to minimize the carbon intensity to obtain the maximize PTC are very high, and at a minimum, all hydrogen projects are expected to meet the definition of Clean Hydrogen as outlined in the Inflation Reduction Act, with the highest level being produced with emissions of 4kgCO_2e/kgH_2 or less.

Power-to-gas

Power-to-gas (P2G), also referred to as green hydrogen or electrolytic hydrogen, describes a suite of technologies that use electrolysis in an electrolyzer to separate water molecules into oxygen and hydrogen. P2G produces useful hydrogen that can be used as an energy source onsite (as in a fuel cell) or injected into a gas grid to produce energy that is very similar to typical natural gas. There are limitations in the amount of hydrogen that can be blended into the natural gas system, but current pilots are exploring blending up to 20% hydrogen within existing natural gas grids.[124] A discussion of P2G as a potential resource option is new to NW Natural's IRP process.

Figure 6.6 shows the basic reaction that occurs within an electrolyzer during electrolysis. An electrolyzer uses electricity to conduct this process, and if the electricity is sourced from zero-carbon resources, the entire production of hydrogen and oxygen is virtually zero-emissions.

Figure 6.6: Schematic of Polymer Electrolyte Membrane (PEM) Electrolysis



Source: U.S. Department of Energy. https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis

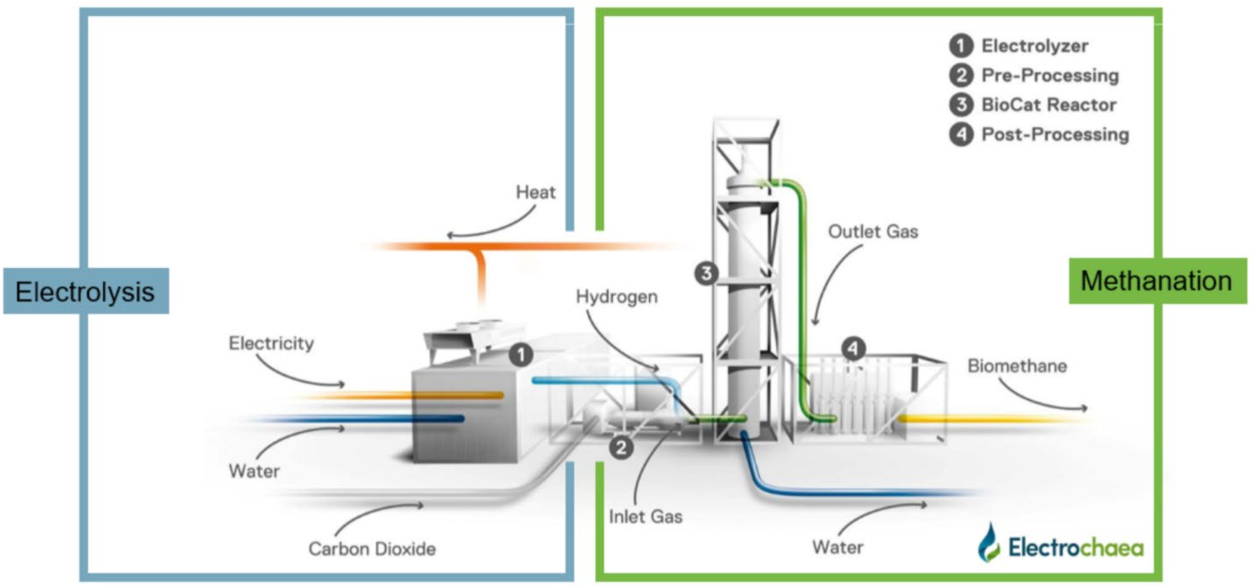
NW Natural is currently considering P2G projects that would blend hydrogen directly into the pipeline, at overall percentages likely far below 20%. NW Natural is reviewing research related to the impacts of varying percentages of hydrogen on system components and end use appliances to better understand the maximum potential of using hydrogen to meet different energy demands on our system with zero emissions.

[124] See, e.g., the HyDeploy project: https://hydeploy.co.uk/.

Synthetic Methane

Green hydrogen can be combined with waste CO_2 to produce synthetic methane (also referred to as synthetic natural gas or methanated hydrogen or power-to-X) using chemical or biological processes, as depicted in Figure 6.7. The molecule is identical to methane molecules sourced from fossil or renewable sources and can be directly injected into natural gas transmission and distribution systems. Unlike hydrogen, synthetic methane does not have a blending limit. Producing synthetic methane uses approximately 15% of the original chemical energy from the hydrogen; however, economies of scale through large production plants can decrease these costs such that they are competitive with small scale distributed hydrogen production.

Figure 6.7: Synthetic Methane Production Process



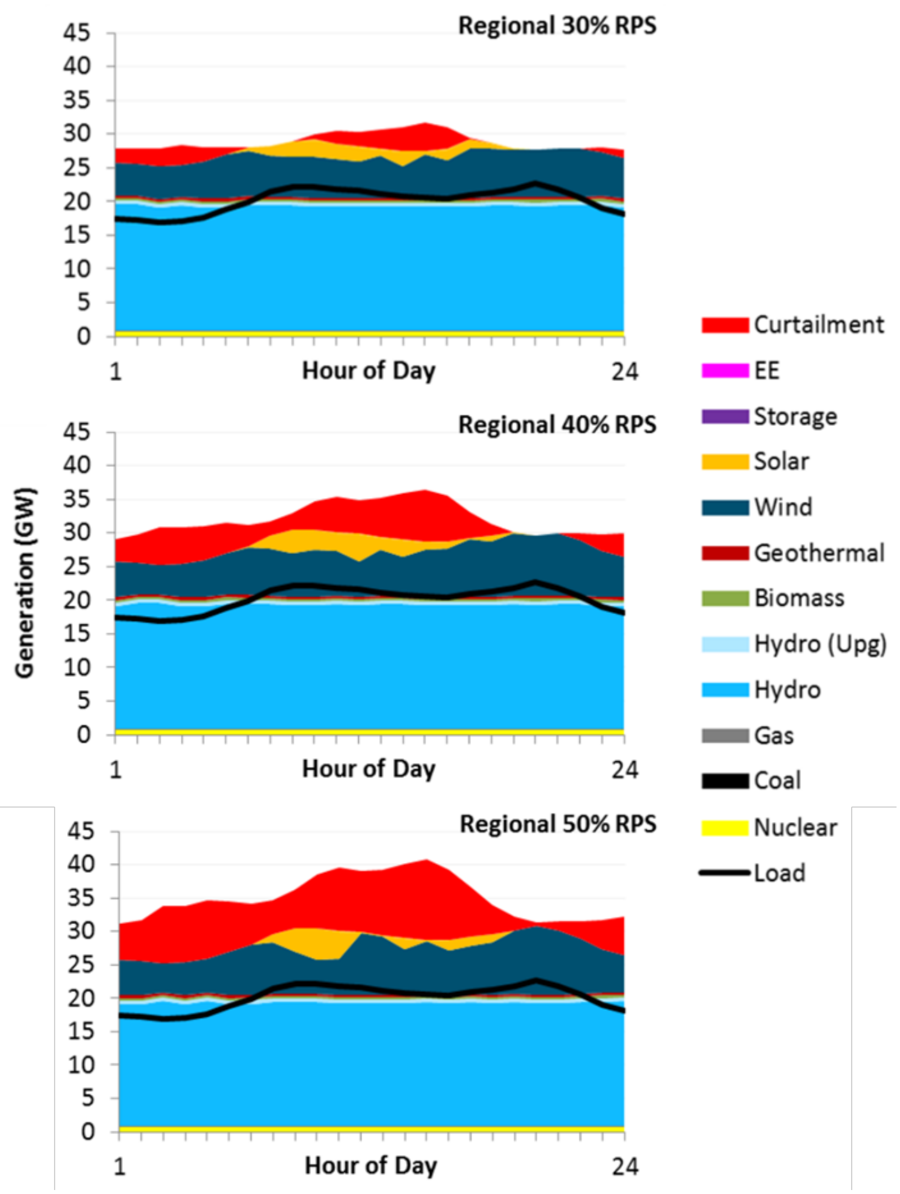
Synthetic methane does not have the energy dilution effects nor possible material compatibility effects that direct hydrogen injection has; therefore, large amounts can be produced and injected much easier as long as a suitable (i.e., low-cost and steady) waste carbon source can be found. NW Natural is pursuing synthetic methane projects where low-cost green hydrogen is available and direct hydrogen blending is not possible.

In addition, RNG projects which have low-cost electricity nearby are also being explored for synthetic methane "bolt-on" projects, as RNG has the requisite low-cost and steady waste CO_2 supply. By adding synthetic methane to RNG projects, almost twice the amount of gas can by produced at the site while leveraging the existing gas interconnect and compression infrastructure.

Power-to-gas and the Need for Seasonal Energy Storage

As renewable electricity goals and targets in the region ramp up over time, the amount of electricity that will need to be curtailed due to oversupply is expected to rise. See Figure 6.8 for one analysis of the impact of rising renewable portfolio standards on the overall amount of curtailed power.

Figure 6.8: Increasing renewable curtailment observed with increasing regional RPS goals[125]



Curtailment events and the consequent energy storage needs are very different in the Pacific Northwest compared to other regions. In our region, excess generation occurs over a longer time period, and is less predictable day-to-day, due to the nature of the region's renewable resources. Thus,

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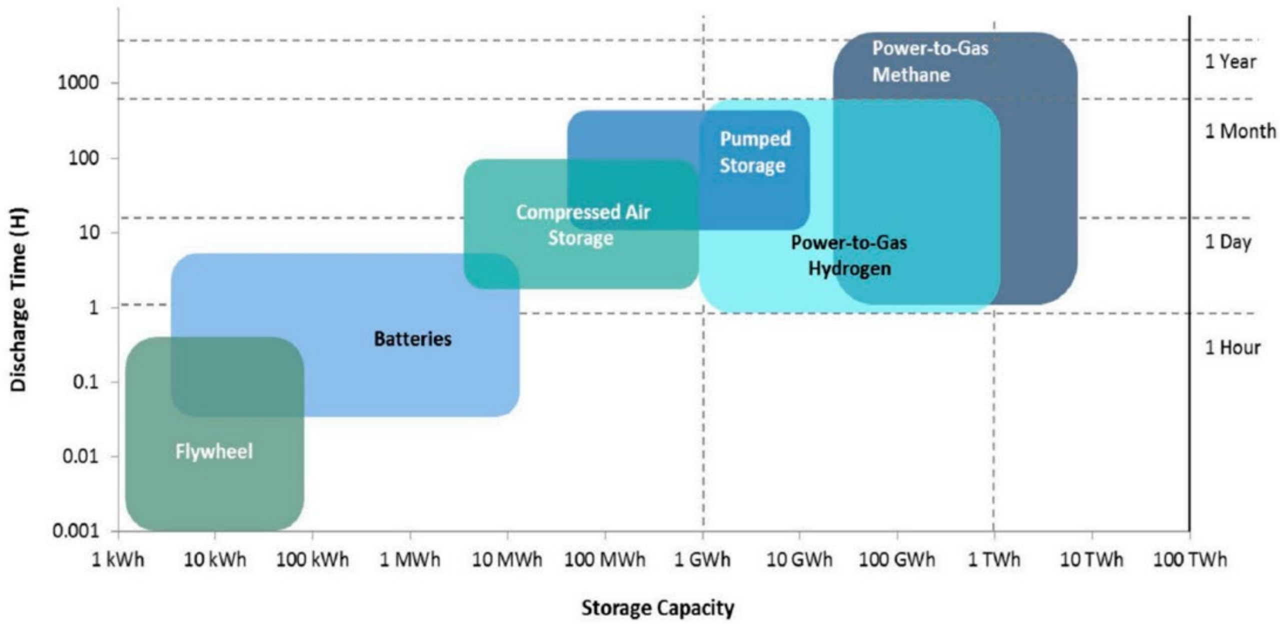
[125] https://www.ethree.com/wp-content/uploads/2018/01/E3_PGP_GHGReductionStudy_2017-12-15_FINAL.pdf

shorter-duration energy storage resources, such as batteries, which are well-equipped to handle energy storage needs over the course of several hours, are less well-suited to handle the energy storage needs we will experience in our region, which will stretch over weeks or perhaps months.[126] For this reason, energy storage resources that can store energy over longer time periods are necessary.

Figure 6.9: Comparative Energy Storage Resources: Size and Duration



Source: https://www.californiahydrogen.org/wp-content/uploads/2018/01/CHBC-Hydrogen-Energy-Storage-White-Paper-FINAL.pdf

As seen in Figure 6.9, power-to-gas is one technology that can help store energy over much longer time periods than batteries and other shorter-duration energy storage resources. Hydrogen generated by excess power can be used immediately in the natural gas system, displacing natural gas purchases, and turning what would otherwise be wasted energy into usable energy. A power-to-gas system can run for days, weeks, and months at a time, providing an energy storage service to the grid for very long durations. The overall amount of energy that can be stored is dependent on the size of the natural gas system to which it is connected, and the available gas storage technologies attached to that system. In the case of NW Natural, energy can be stored and withdrawn from the existing distribution system as well as our significant underground storage resources, including Mist.

[126] See pp. xiii – xv in the Pacific Northwest Low Carbon Scenario Analysis: https://www.ethree.com/wp-content/uploads/2018/01/E3_PGP_GHGReductionStudy_2017-12-15_FINAL.pdf.

Power-to-gas Existing Technologies and Trends

There are three primary electrolyzer technologies that are available today for power-to-gas applications. These are:

- Alkaline
- Proton exchange membrane (PEM)
- Solid oxide (SOE)

Of these technologies, alkaline electrolyzers have been in operation much longer than the other two. They are also less expensive than the other technologies, and more efficient in their production of hydrogen. However, PEM technologies have advantages over alkaline electrolyzers such as faster ramp-up times and a smaller footprint. SOE technology is less developed but offers the distinct advantage of using heat as one of the inputs to generate hydrogen, so it could potentially offer a productive use for existing waste heat resources. The choice of electrolyzer depends on the situation and the way it will be operated.

Today most P2G projects are located in Europe, where P2G has been identified as a critical component of a low-carbon future. In the U.S., several demonstration projects exist, and several projects are being designed in Canada.

The Economics of Power-to-gas for the Direct-use Natural Gas System

When P2G is utilized as a supply-side resource for the direct-use natural gas system, its economics are driven primarily by technology costs (i.e., electrolyzer and methanation facility costs), the price of electricity used as a feedstock, and how often the built facility is used to produce deliverable gas. Additionally, the functional and emissions attributes of the various P2G technologies influence its relative cost effectiveness for a regional natural gas system.

A 2018 report commissioned by NW Natural found recent commercial-scale electrolyzer projects with construction costs between $500 and $1000 per kW of capability, a range consistent with other recent industry estimates. As with most emerging technologies, these costs are expected to decline through time. At a given facility cost level, the ultimate costs of hydrogen delivered to the natural gas system on a per-unit basis depends on the extent to which a built facility is utilized, often referred to as its capacity factor or utilization factor. For illustration, Figure 6.10 and Figure 6.11 isolate the impact of these two factors on the per-unit cost to produce gas. First, Figure 6.10 summarizes a range of per-MMBtu costs associated with varying facility capital costs, assuming a facility with 1 MW capability, 70% efficiency in turning electricity into gas energy, and a 20% capacity factor.

Figure 6.10: Electrolyzer Fixed Cost per MMBtu vs. Facility Capital Costs

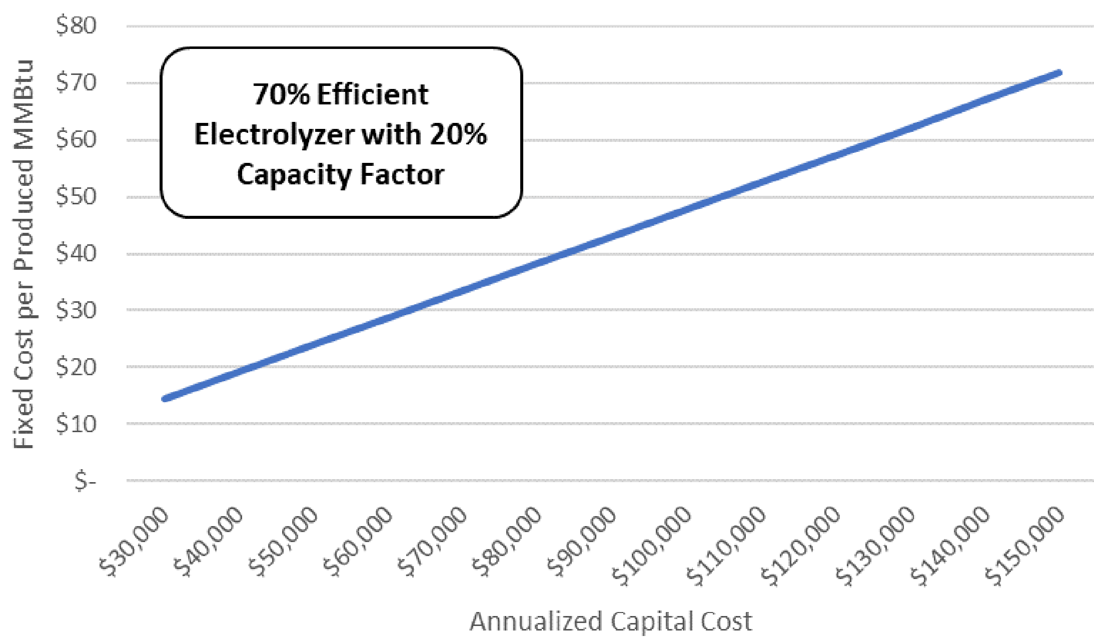
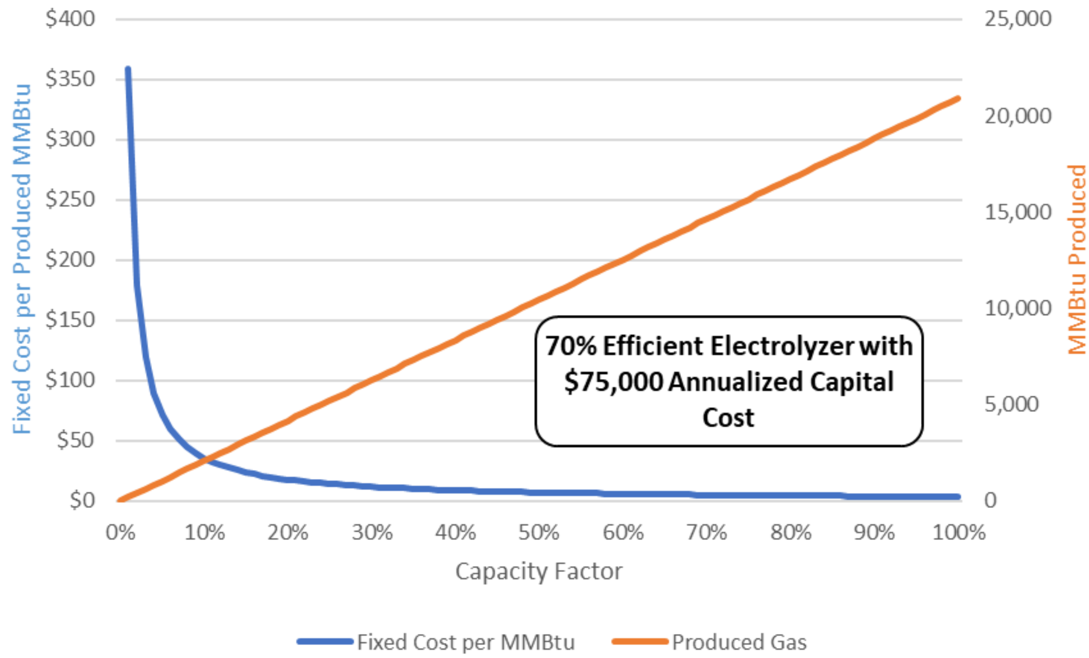


Figure 6.11 illustrates the cost impact of capacity factor on a 70% efficient 1 MW electrolyzer with a $75,000 annualized capital cost. If the facility is operated at capacity for an entire year, the capital (fixed) cost per MMBtu of produced gas would be $3.59. If the facility were operated during only half the hours of the year, this cost would double to $7.18/MMBtu.

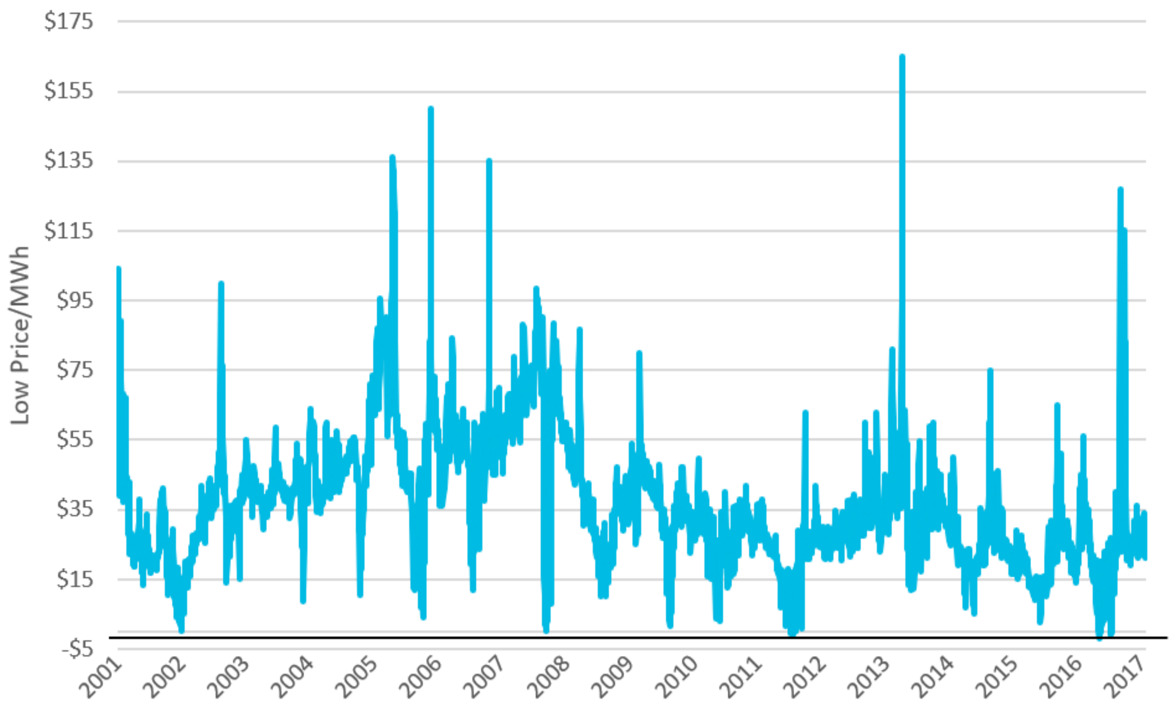
Figure 6.11: Electrolyzer Fixed Cost per MMBtu vs. Utilization Factor



While hydrogen produced by P2G technology must be blended with conventional natural gas to be used directly by most appliances, an additional conversion to methane (methanation) produces gas that is fully interchangeable with pipeline natural gas. Electrolysis may currently have more visibility in research and pilot programs in the U.S. and elsewhere, but several methanation facilities are in use in the U.S. and Europe, and the technology costs associated with this additional step in the P2G process are expected to fall over the coming decades.

For a direct-use natural gas system, P2G is essentially an opportunistic resource — by taking advantage of transitory surpluses in electricity markets, a gas utility can produce low-cost, carbon-neutral fuel for its customers. Thus, the availability of low-cost (or no-cost) electricity directly affects a P2G facility's utilization factor and overall economics. In the Pacific Northwest, electricity prices often fall to very low (and sometimes negative) levels during the spring season, as snowmelt increases hydro flows and electricity demand wanes with warming weather. At the Mid-Columbia power market, for reference, peak wholesale power prices have dropped below $0.01 per kWh on an average of roughly nine days per year over the last decade (Figure 6.12).

Figure 6.12: Mid-Columbia Trading Hub Peak Wholesale Electricity Prices, Daily Low



As the penetration of renewable generation resources increases in the region as a result of both market and policy forces, periods of curtailment (excess generation) are expected to increase in duration and frequency, and both power-to-hydrogen and power-to-methane technologies are recognized as well positioned for large scale and extended-duration storage. For NW Natural, the utilization rates of our power-to-gas facilities used for direct-use energy will likewise depend on this growing availability of low-cost electricity.

Given the opportunistic nature of P2G as a direct-use supply resource for the natural gas system, and limits on the amount of hydrogen that can be blended with conventional gas, it is worth noting that gas storage would likely play a key role in the integration of the two. At modest levels of hydrogen production, the product could be injected directly into local distribution networks; at higher levels, a combination of dispersed production/injection sites and storage would likely be used to incorporate hydrogen gas into the system.

A final but significant contributing factor in the cost-effectiveness of P2G for a natural gas utility is that its value would not be limited to that of the commodity it produces — its energy value. On-system P2G facilities would also serve as capacity resources, providing options for peak day production and delivery, and distribution system support during peak hours of the year, providing similar value to demand-side resources like energy efficiency measures.

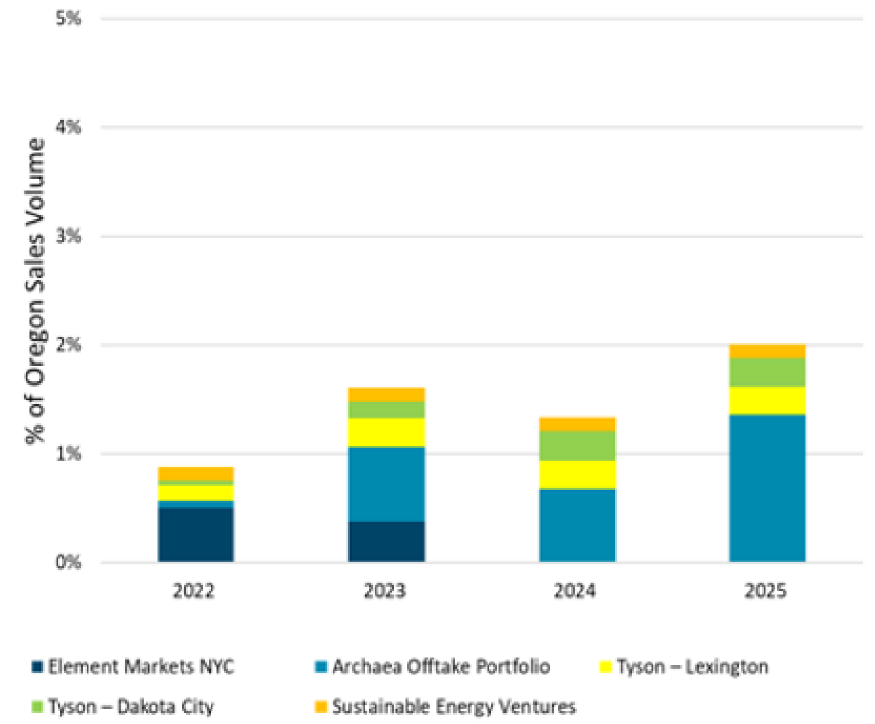
P2G is a relatively new and evolving technology, and as noted above its economics are substantially changing over time. As such, NW Natural draws from existing literature, industry reports, and internal consultants' reports for modeling purposes.

6.3 RNG and Hydrogen Evaluation Methodology

In our 2018 IRP we included the nation's first comprehensive methodology to evaluate the cost-effectiveness of low-carbon gas supply resources and sought acknowledgement of this methodology in Oregon. This request resulted in the OPUC opening a docket (OPUC Docket No. UM 2030) for review of the proposed methodology. This process resulted in a modified methodology that was approved by the OPUC to evaluate low carb gas supply resources. Also, as discussed in Chapter 2, a voluntary renewable gas portfolio standard (SB 98) passed in Oregon, and the resulting rules to implement the program included a placeholder for the evaluation methodology based upon the methodology acknowledged in the most recent IRP. NW Natural has been using this methodology to evaluate the incremental cost of potential resources to comply with climate policy in both Oregon and Washington. As we have gained experience in the RNG market we have made improvements to the methodology and greatly increased the risk evaluation portion of the tool as well as made a process that can align with the realities of the RNG market (in terms of timing and resource types). The updated methodology is included in detail in Appendix K.

Figure 6.13 shows a summary of current committed RNG resources as of March 2022. As our actual experience with RNG grows, we are able to build and refine the supply curve shown in Figure 6.14.

Figure 6.13: Summary of Current Committed RNG Portfolio- Contracted Resources by Opportunity



† For these 5 resources, the weighted risk-adjusted incremental cost is projected to be $7.38/MMbtu

‡ This graph reflects current contracted resources that are actively delivering RNG today. NW Natural has additional contracts in place for future RNG resources that are currently under development, totaling about 3% by 2025

Figure 6.14: Average Cost of RNG

†2020 and 2021 RFP responses, as well as development projects NW Natural is currently evaluating.
‡ Total production represented in chart: 35.3 million Mmbtu/year (about 49% of NW Natural's annual sales in Oregon in 2021.
♠ New RFP issued in 2022.
♦ Proposed supply tranches +/- variability:

- $14.00/Mmbtu
- $19.00/MMbtu

6.4 Current Resources

NW Natural's current portfolio of resources sufficiently meets energy and capacity requirements for customers and are on track to achieve RNG targets outlined by SB 98. This section discusses NW Natural's current resource portfolio.

6.4.1 Gas Supply Contracts

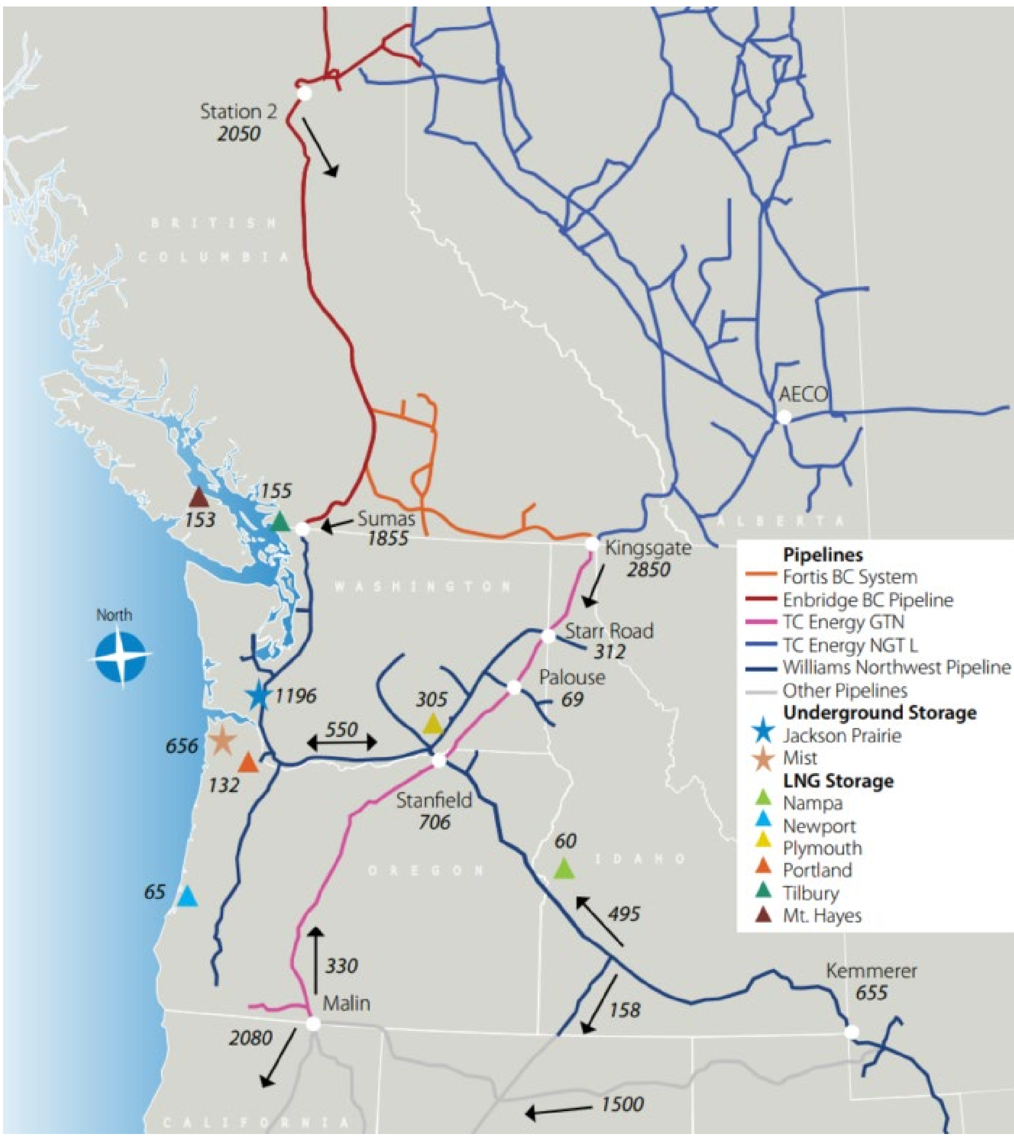
NW Natural has a portfolio of term supply contracts for each year, which are presented and reviewed in the annual purchased gas adjustment (PGA) proceedings in Oregon and Washington. The most recently approved portfolio of term contracts — for the 2021-22 PGA period — is included in Appendix E, Table E.2. Some contracts are designated using the term "Baseload Quantity," which refers to a contractual obligation for daily delivery and payment, while contracts designated as "Swing Supply" mean one party has an option to deliver or receive all, some, or none of the indicated volumes at its sole discretion.

In addition to term contracts, NW Natural buys certain gas volumes on the "spot" market, meaning the volumes, pricing and delivery points are negotiated on a real-time basis for delivery the following day or other near-term period, but no more than a month in advance. NW Natural maintains a diversified array of suppliers from whom gas can be bought on a spot or term basis.

6.4.2 Pipeline Capacity

A map showing the existing natural gas pipeline and storage infrastructure in the Pacific Northwest is shown in Figure 6.15. Total pipeline capacities in the map are shown in thousands of Dths per day (MDth/day).

Figure 6.15: Pacific Northwest Infrastructure and Capacities (MDth/day)



Source: Northwest Gas Association, 2022 Gas Outlook

Firm Pipeline Transport Contracts

NW Natural holds firm transportation contracts for capacity on Williams Northwest Pipeline (NWP), over which all of NW Natural's supplies must flow except for the small amount of natural gas that comes from on-system resources, which are less than 1% of annual purchases.

For gas sourced in the U.S. Rockies, transportation over NWP is all that is needed to bring the supplies to NW Natural's territory.

For gas sourced in British Columbia, purchases are either made directly into the NWP system at the international border (called Sumas on the U.S. side and Huntingdon on the Canadian side) or purchased in Northern British Columbia at a trading hub called Station 2. Extending northward from the international border is the T-South pipeline system (owned by and referred to as Enbridge BC Pipeline in Figure 6.15), which creates a connection between Station 2 and Sumas/Huntington. Purchases made at Station 2 first require transportation by Enbridge before reaching the Sumas/Huntington interconnection point and movement onward by NWP to NW Natural.

For gas sourced in Alberta, purchases are made at the trading hub known as AECO. Gas sourced at the AECO hub reaches the NW Natural system via four pipeline systems, three owned by TC Energy, and the fourth being NWP. Starting in Alberta with NOVA Gas Transmission Limited (NGTL or NOVA), the molecules, then travel along the Foothills pipeline in southeastern British Columbia.[127] The molecules continue south on this pipeline to the international border, at the Kingsgate point in northern Idaho, into Gas Transmission Northwest (GTN) pipeline, which extends southward and connects to NWP at Starr Road, in eastern Washington (near Spokane) and at Stanfield, in northeastern Oregon.

NW Natural has released a small portion of our NWP capacity to one customer but has retained certain heating season recall rights, discussed above as an Industrial recall option. Details of the current portfolio of pipeline transportation contracts are provided in Appendix E, Table E.3.

Since the implementation of the Federal Energy Regulatory Commission's (FERC) Order 636 in 1993, capacity rights on U.S. interstate pipelines have been commoditized, i.e., capacity can be bought and sold like other commodities. These acquisitions and releases occur over electronic bulletin board systems maintained by the pipelines, under rules laid out by FERC. To further facilitate transactional efficiency and a national market, interstate pipelines have standardized many definitions and procedures through the efforts of the industry-supported North American Energy Standards Board (NAESB), with the direction and approval of FERC. Capacity trades can also occur on the Canadian pipelines. In general, Canadian pipeline transactions are consistent with most of the NAESB standards.

Except for a small percentage of on-system supply, all the gas supplied to NW Natural customers must be transported over the NWP system, which is fully subscribed in the areas served by NW Natural.

[127] The small section of Foothills pipeline in southeastern BC is shows as a part of the NGTL system in Figure 6.13

Usage among NWP capacity holders tends to peak in a nearly coincident fashion as cold weather blankets the Pacific Northwest region. Similarly, NWP capacity that may be available during off-peak months tends to be available from many capacity holders at the same time. This means that NW Natural is rarely in a position to release capacity during high value periods of the year, and it would be unusual for capacity to be available for acquisition during peak load conditions.

Given the dynamics of market growth and pipeline expansion, NW Natural will continue to monitor and leverage the capacity release mechanism whenever appropriate, but primarily this will mean continuing to use our asset management agreement (AMA) with a third party to find value-added transactions that benefit customers.

Exposure to Sumas

About 30% of our contracts on the NWP system are sourced from Sumas. We can fill these contracts either with purchases directly at Sumas or with purchases further upstream at West Coast Station 2 (Station 2), which is a supply point where the commodity is being produced. Sumas on the other hand is a trading point where natural gas trading occurs but supplies at Sumas first must be transported there from a production source, such as Station 2. We have long-term Enbridge BC Pipeline (T-South) contracts that allow us to procure about half of the gas we need to ship from Sumas at Station 2. The other half of the supplies we ship from Sumas must be purchased directly at Sumas.

Historically, Sumas has been a high-priced, volatile trading point when compared to other trading points throughout North America. We are expecting this to be further exacerbated in 2027 when the Woodfibre LNG facility is expected to come online. Woodfibre LNG, which is being constructed in Squamish, B.C. will convert about 300,000 Dth of natural gas per day to LNG which will then be shipped overseas. Woodfibre LNG already holds the T-South pipeline capacity they need for their operations and this capacity is currently used to ship Station 2 gas down to Sumas where these supplies are sold.

When the LNG facility is operational, currently forecast to be in 2027, these supplies will be pulled from the Sumas market and used in the liquefaction process. This loss of gas supply equates to approximately 15 percent of the total available winter capacity to Sumas on the T-South system and will represent a fundamental shift in the region's gas supply availability to serve existing demand. It will have significant adverse implications for customers relying on purchasing gas supply at Sumas unless there is an upstream pipeline expansion or another solution that would benefit the market at Sumas. In fact, if a regional peak cold weather event were to occur after Woodfibre is in service and before a solution could be found, we could possibly see supply shortages in the Pacific Northwest.

There are several pipeline solutions that are being marketed as a solution for this supply leaving the market at Sumas and NW Natural will evaluate participation in these projects as the opportunities present themselves. We will also evaluate longer-term physical purchases at Sumas or Mist Recall as solutions for the market disruption at Sumas.

Due to the expectation that Woodfibre LNG will begin operations in late 2027, thus tightening the Sumas market, we do not expect that we will be able to procure large volumes of spot gas during a cold weather event. While we are confident that gas supplies shipped on segmented capacity would flow, our ability to find these supplies will be restricted and that is why we are no longer relying on segmented capacity for a peak day starting in the 2027-28 winter, as is discussed in the segmented capacity section.

Segmented Capacity

Segmented capacity is secondary firm capacity on NWP that is deemed reliable due to the high probability that it will be available during times of peak usage. This reliability assumption is validated every IRP cycle through an analysis of NWP flow data through the Chehalis Compressor Station along the I-5 corridor. The analysis uses the prior three to five winters to validate that there is sufficient North to South capacity available as the weather gets colder. These assumptions are based on current market dynamics as the ability to schedule segmented capacity is more reliable as weather becomes colder (see Appendix E for the Chehalis compressor analysis). For more details on the process of segmentation see Chapter 6, section 3.3 in the 2018 IRP.

For many years now, NW Natural has segmented capacity and flexed the receipt and delivery points to create useful, albeit secondary, firm transportation on the NWP system. This segmented capacity flows from the north (Sumas) in a path that has not experienced constraints, during the coldest weather events in recent years. Utilizing segment capacity does not incur an additional demand charge and only incurs NWP's variable and fuel charges in additional to the Sumas commodity costs. Because of this low opportunity cost, segmented capacity is very valuable resource for customers.

Modeling of segmented capacity began in 2014 with 43,800 Dth/day included in the analysis. Another 16,900 Dth/day of segmented capacity was subsequently created in 2016. This combined amount of 60,700 Dth/day was included in the both the 2016 and 2018 IRPs. This amount remains in the current IRP planning until 2027 when certain constraints in the Sumas market are expected to increase the risk of being able to procure spot gas on a peak day. This IRP does not rely on segmented capacity to meet peak demand starting in the 2027-2028 gas year but does allow it to be used on colder non-peak days at 30,000 Dth/day the rest of the year (see Table 6.4).

Table 6.4: Segmented Capacity Availability Assumption

Timeframe	Design Peak Day Availability	Non-Design Peak Day Availability
2022 – Oct 2027	60,700 Dth/day	60,700 Dth/day when temperature is < 40
Nov 2027 – 2050	0 Dth/day	30,000 Dth/day when temperature is < 40

6.4.3 Storage Assets

NW Natural relies on four existing storage facilities in and around our market area to augment the supplies shipped from British Columbia, Alberta and the U.S. Rockies. These consist of underground storage at Mist and Jackson Prairie, and LNG plants located in Portland and Newport, Oregon.

NW Natural owns and operates Mist, Portland LNG, and Newport LNG, all of which reside within NW Natural's service territory. Hence, gas typically is injected into storage at these facilities during warm periods and withdrawn when needed during cold periods directly onto NW Natural's system.

In contrast, Jackson Prairie underground storage is located about 80 miles north of Portland near Centralia, Washington, i.e., outside NW Natural's service territory. Jackson Prairie has been owned and operated by other parties since its commissioning in the 1970s. NW Natural contracts for Jackson Prairie storage service from NWP. Several separate contracts with NWP provide for the transportation service from Jackson Prairie to the NW Natural citygate.

Table 6.5 shows the maximum storage capacity and deliverability of these four firm storage resources.

Table 6.5: Firm Storage Resources[128]

Facility	Maximum Daily Deliverability (Dth/day)	Maximum Seasonal Storage Working Capacity (Dth)
Mist (reserved for Utility Sales Customers)	305,000	12,213,605 *
Newport LNG	64,500 *	752,500 *
Portland LNG	130,800 *	368,776 *
Jackson Prairie	46,030	1,120,288

Notes: Newport LNG tank maximum capacity currently de-rated pending results of the CO2 removal project, and the available capacity also takes into account a minimum 20% tank level needed for normal operations. Portland LNG maximum capacity currently de-rated due to seismic analysis, and the available capacity also considers a minimum 20% tank level needed for normal operations.

The Mist storage deliverability and seasonal capacity shown in Table 6.5 represents the portion of the facilities reserved for utility service. Mist began storage operations in 1989 and currently has a maximum daily deliverability of 480 million cubic feet[129] per day (MMcf/day) with peak hourly deliverability at a rate of 515 MMcf/day, and a total working gas capacity of 17.3 billion cubic feet (Bcf). These volumetric figures are converted to energy values (Dth) using the heat content of the injected gas. That heat content conversion factor had been relatively constant at 1,010 Btu/cf in prior years but has increased and stabilized at around 1,060 Btu/cf over the past several years.

Storage capacity and deliverability in excess of core needs is made available for the non-utility storage business and AMA activities. As core needs grow, existing storage capacity may be recalled and transferred for use by core utility customers, which NW Natural refers to as Mist recall discussed later in this chapter.

6.4.4 On-system Production Resources

On-system production resources produce methane and do not require upstream capacity resources. In other words, these resources produce and inject gas directly onto NW Natural's system.

[128] The numbers in this table marked with an asterisk (*) originated from volumetric units (e.g., Bcf) and have been converted to energy units (Dth) using the heat content (Btu per cf) of the applicable facility, which may differ very slightly from the assumed heat content factors used in other portions of this IRP. The other numbers in this table do not need to be adjusted for heat content because they originate from contracts (Jackson Prairie) or deliverability calculations (Mist) that are specified in energy units. These values based on the heat content are firm storage resources as of Nov 2021.

[129] All uses of cubic feet in this chapter assume "standard conditions" of gas measurement, i.e., temperature of 60°F and pressure of 14.7 pounds per square inch absolute.

6.4.5 Mist Production

Natural gas wells owned by a third-party in the Mist area continue to produce small quantities of low Btu gas which NW Natural purchases and blends into larger volumes of gas supplies at Miller Station. Over time these wells continue to deplete, and new wells have not been drilled for several years. Unless there is a renewed interest in exploration and production of natural gas in the Mist area, it is expected that these volumes will continue to decline over time.

6.4.6 On-system Production

Two producing RNG projects are interconnected to the NW Natural distribution system and another one is expected to come online later in 2022. Currently, NW Natural only purchases the underlying *brown gas* from these projects and does not have rights to the environmental attributes associated with this RNG. Expected volumes from these projects are still included as gas supplies in the IRP as they do provide a capacity benefit, but not a compliance benefit.

6.4.7 Industrial Recall Options

NW Natural has contracts with three industrial companies located on or near our distribution system wherein we can call on natural gas supplies if needed in the winter. The price of these contracts is tied to an alternate fuel source that the industrial company could use if we were to call on their flowing natural gas supplies. If called upon, these supplies would be delivered to NW Natural at our citygate on the industrial customers' capacity with NWP. Each contract has specific terms outlining when we can call on the capacity and at what volume. Contracts range from 1,000 Dth/day to 30,000 Dth/day.

6.4.8 Existing RNG Contracts

NW Natural has 3 renewable natural gas RTC offtake agreements and 2 development projects, one of which is currently under construction, and one that is operating (see Figure 6.16 for details). In 2021 we officially retired 148,037 RTCs from these project(s) on behalf of customers.

Figure 6.16: Current RNG Contracts

Projects	Feedstock	Type	Projected Volumes (MMBtu/year)		
			2022	2023	2024
Element Markets NYC	Wastewater	Offtake	182,502	365,000	365,000
Archaea Offtake Portfolio	Landfill	Offtake	-	500,000	500,000
Tyson – Lexington[1]	Food & Brewery	Development	86,202	86,000	86,000
Tyson – Dakota City	Food & Brewery	Development	0	113,529	199,219
Wasatch Resource Recovery	Livestock	Offtake	63,606	91,250	91,250

Renewable Natural Gas RTC (Renewable Thermal Certificates) Offtakes

NW Natural has entered into three offtake agreements to purchase RNG from operating RNG projects. Most will be delivered to Oregon customers and will be a part of the Oregon PGA, but some RNG will likely be used for other programs, such as those in Washington and future voluntary tariffs. The following are these offtake agreements:

- Offtake #1
  - Five-year term
  - About 200 Dth/day
  - Organic waste processing facility in Utah
  - Fixed price per RTC; purchase what is delivered

- Offtake #2
  - Two-year term, with option for one year extension
  - About 1,000 Dth/day
  - Wastewater treatment plant in New York plus dairy-based agricultural waste in Wisconsin
  - Fixed price per RTC; only purchase what is delivered

- Offtake #3
  - 21-year term
  - Production ranges from 500,000-1,000,000 Dth/year
  - Landfill facilities (multiple)
  - Fixed price per RTC; only purchase what is delivered; required minimums, damages for failure to deliver

Renewable Natural Gas Development

NW Natural partnered to develop RNG upgrading and conditioning facilities at the Tyson Fresh Meats facilities in Lexington and Dakota City, Nebraska.

Tyson Fresh Meats Facilities:

- Two of the largest beef processing plants in U.S.
- Beef processing and packaging; 7,000 employees across both facilities
- Lexington: newer plant (built in 1990); Dakota City: Tyson purchased in 2001 (built in 1966)
- Processes enough beef daily to feed 18 million people
- Both facilities recently received significant investment in new equipment, wastewater processing facilities, etc.
- Both facilities together expected to produce about 360,000 MMbtu/ year of RNG (about 0.5% of Oregon annual sales)

Scope of RNG Projects:

- Utilize biogas off existing lagoons
- Implement biogas flow balancing control systems
- Address and correct leaks/sources of possible oxygen intrusion
- Invest in upgrading technology (membrane/pressure-swing absorption)
- Invest in interconnection to local gas pipelines
- Buy the RNG and sell *brown gas* locally
- Retire RTCs on behalf of NW Natural customers

Figure 6.17: Tyson Lexington Skid

6.5 Future Compliance Resource Options

As 2022 is the first compliance year for Oregon and 2023 is the first compliance year for Washington, acquiring resources to meet compliance obligations is an immediate issue. This section outlines the various non-demand-side resources available to meet emissions compliance obligations.

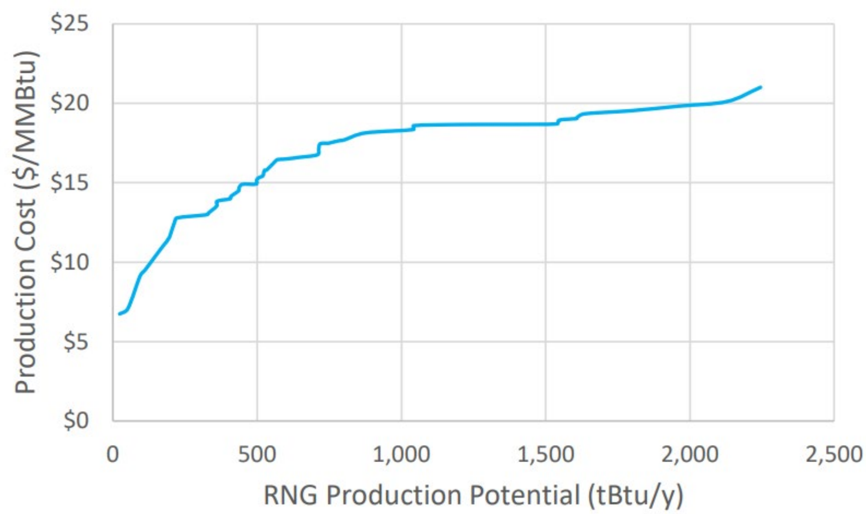
6.5.1 Biofuel RNG

As discussed in detail above and through participation in the RNG market and our annual RFP process, NW Natural maintains a deep understanding of the RNG market. Using information from ICF's AGF 2019 RNG Supply Report and NW Naturals annual request for proposal (RFP) process two RNG supply tranches are developed as a compliance resource for consideration in resource planning optimization. Each tranche represents a portfolio level set of RNG projects with a portfolio average price and associated quantities.

The 2019 ICF study evaluates the technical potential of eight feedstock options including: landfill gas, wastewater, food waste, animal manure, agricultural and forestry residues, and energy crops. The study includes a range of high and low resource potential cases and calculates both the technical potential and an estimate of supply which could be realized. ICF uses a relatively conservative approach in estimating technical potential in both resource potential scenarios. It should be noted that the technical and resource potential are developed independently of policy GHG objectives and illustrates the diversity of RNG supply options available at different price points. On the high end, the study estimated a national technical potential of 14,000 tBtu with roughly 27% or 3,800 tBtu as available for RNG supply. For reference, total US annual direct use natural gas consumption is approximately 18,000-19,000 tBtu.[130]

ICF estimated the majority of RNG produced would be available in the range of $7-$20/MMBtu as plotted in Figure 6.18. These cost estimates reflect the all-in cost to collect, clean, and deliver the RNG up to the point of injection into a common-carrier pipeline. It provides a minimum price point estimate, which RNG developers would need to recoup their costs.

Figure 6.18: Combined RNG Supply Curve in 2040[131]



In addition to the study done by ICF, NW Natural also uses information gathered through our annual RFP for RNG resource acquisition and the prices offered for 2020 and 2021 RFP responses as well as the costs for development projects currently being evaluated (see Figure 6.14 for details).

Since the current RNG market is nascent, dynamic, and these specific resources are not always available throughout the planning horizon, a traditional supply curve would be inappropriate for the IRP. Instead, NW Natural uses a two-tiered portfolio approach for the IRP. The maximum amount of RNG available to NW Natural is 75% of our customers' population weighted share of the national RNG supply potential, estimated by the ICF study. The total amount of RNG available to NW Natural is then split into two traches based on the supply curve as illustrated by Figure 6.19.

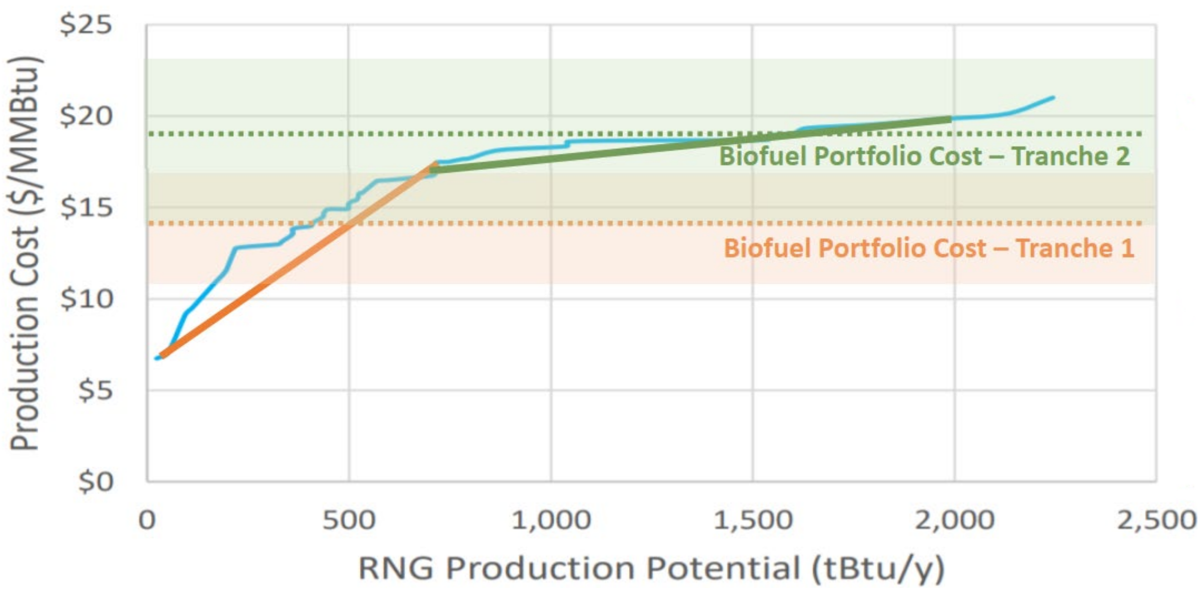
[130] Excludes gas for electric generation and natural gas used in vehicles. Source: https://www.eia.gov/energyexplained/natural-gas/use-of-natural-gas.php#:~:text=The%20United%20States%20used%20about,of%20U.S.%20total%20energy%20consumption.

[131] Source: *Renewable Source of Natural Gas: Supply and Emissions Reduction Assessment*. American Gas Foundation Study Prepared by ICF, 2019.

Tranche 1 (orange in Figure 6.19) represents 1/3 of the total RNG resource available to NW Natural. This is approximately 13 million MMBtu annually. Additionally, most of Tranche 1 represents larger, nearer term projects, such as landfills and can be acquired for a portfolio cost of $14/MMBtu (+/- $3/MMBtu in stochastic simulation).

Tranche 2 (green in Figure 6.19) represents the remaining 2/3 of the resource available to NW Natural, approximately 27 million MMBtu total annual production. This tranche would likely consist of longer term and higher cost projects, such as a new-build solid waste/food digester. Tranche 2 can be acquired for a portfolio cost of $19/MMBtu (+/- $5/MMBtu in stochastic simulation).

Figure 6.19: Biofuels Supply Curve and Tranche 1 & 2 Portfolio Cost[132]



6.5.2 Hydrogen and Synthetic Methane

As discussed in earlier in this chapter, hydrogen can be blended onto the existing system up to 20% by volume and there is potential for dedicated hydrogen systems for large industrial applications. Between the combination of a blended system and the potential for dedicated systems, this IRP uses a 20% of all deliveries by state limitation for hydrogen that can be used for compliance. The use of hydrogen for an LDC to serve its customers is in its infancy and this limitation is uncertain. Therefore, the limitation on hydrogen as a percentage of deliveries is treated as uncertain in the risk analysis of the IRP.

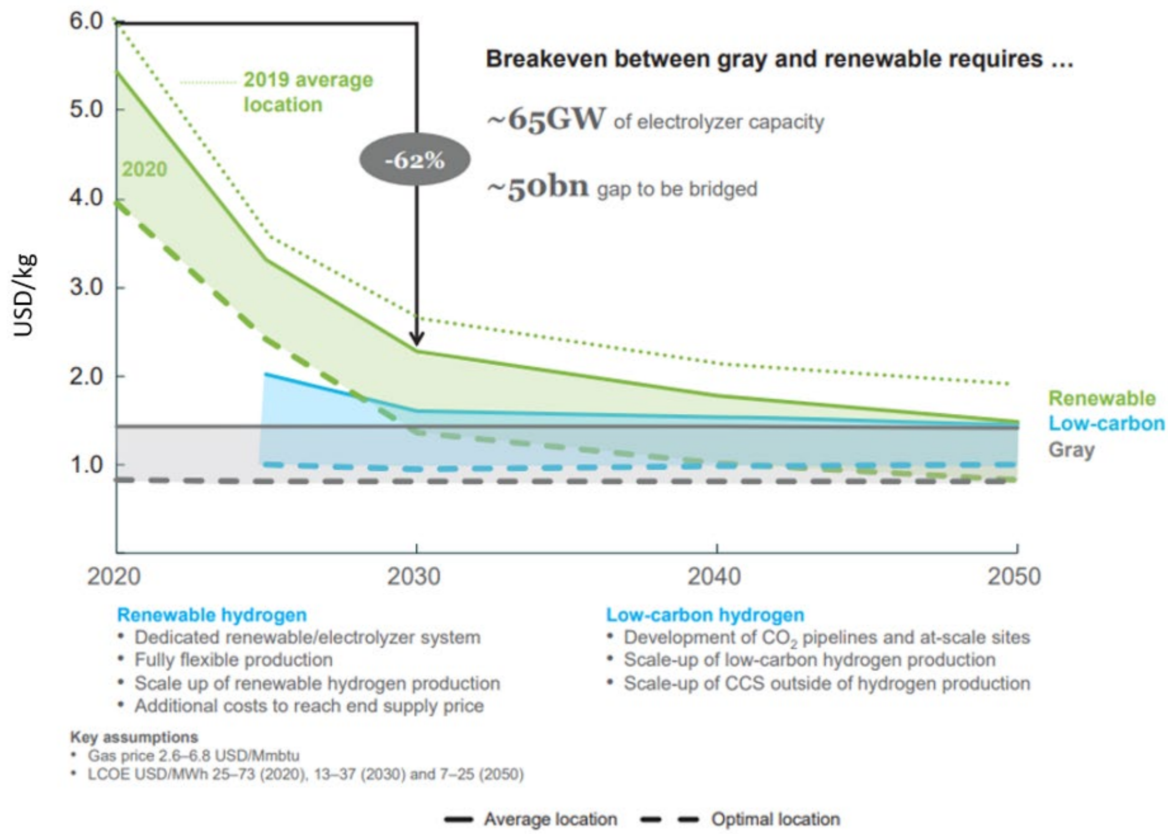
[132] Supply Curve (Blue Line) Source: "Renewable Source of Natural Gas." American Gas Foundation Study Prepared by ICF (2019). RNG supply potential adjusted for update in "Net Zero Emissions Opportunities for Gas Utilities." American Gas Association Prepared by ICF (2022).

Currently, hydrogen sourced from natural gas with carbon capture, low-carbon hydrogen, is the lowest cost resource. Renewable sources are becoming increasingly economically viable and are predicted to lower the production cost of hydrogen over the planning horizon. Specifically, the cost of renewable hydrogen is expected to be on par with the cost of low-carbon hydrogen by 2030, as depicted in Figure 6.19. This decrease in cost is driven by three factors:

1. A forecasted decline in off-peak electricity prices as more renewable generation is available during low demand periods, both at the daily and seasonal level.
2. A decrease in the capital costs of electrolyzer technology as the production of electrolyzers starts benefiting from economies of scale.
3. Capacity factors of hydrogen production at individual hydrogen facilities increase, which spread the fixed capital costs across more hydrogen volumes.

The cost for renewable hydrogen will be highly dependent on the cost of electricity, the growth of renewables and projected overbuild of wind and solar, the share of available biofuel RNG for hydrogen production, and the costs of electrolyzer technology. Due to these factors, the costs of electrolytic hydrogen are expected to decline.

Figure 6.20: Production Cost of Hydrogen[133]



Source: Hydrogen Insights Report 2021; Hydrogen Council, McKinsey & Company

Hydrogen costs are modelled based on the *Hydrogen Insights Report 2021* shown in Figure 6.20. Given the reasons already discussed, hydrogen from renewables is expected to have a relatively steep cost decline in the near term. This rate of cost decline will not continue indefinitely, and the economics will at some point in the future temper the cost decline, like the cost declines seen in wind and solar technology and application. We model the cost of hydrogen starting at roughly $23/MMBtu with higher rate of decline through until 2030 where it pivots to a slower trajectory, but still decreases to roughly $5/MMBtu by 2050. In addition to the forecasted decrease to the prices of hydrogen due to the economics, a hydrogen production tax credit could reduce costs further and help make hydrogen a low-cost resource in the nearer term. This cost trajectory and the potential for a tax credit is uncertain and analyzed as such through the risk analysis.

[133] Multiply USD$/kg$H_2$ by 7.43 to get USD$/MMBtu.

Synthetic methane is another potential compliance resource. Hydrogen, regardless of the feedstock used to produce it, can be combined with waste CO_2 to create synthetic methane. However, the IRP models only synthetic methane created from renewable hydrogen. The synthetic methane molecule is identical to the methane molecules sourced from fossil or renewable sources and can be directly injected into natural gas transmission and distribution systems. Due to this fact, synthetic methane does not have a blending limit and is modelled as a non-bounded quantity.

Producing synthetic methane uses approximately 15% of the original chemical energy from the hydrogen; however, economies of scale through large production plants can decrease these costs such that they are competitive with small scale distributed hydrogen production. Synthetic methane also does not have the energy dilution effects nor possible material compatibility effects that direct hydrogen injection has; therefore, large amounts can be produced and injected much easier as long as a suitable (i.e., low-cost and steady) waste carbon source can be found. NW Natural is pursuing synthetic methane projects where low-cost renewable hydrogen is available and direct hydrogen blending is not possible.

The cost of hydrogen is the primary cost component for creating synthetic methane, but additional costs are determined by the additional capital costs of the methanation equipment and the cost of waste CO_2. We model the costs of synthetic methane through all scenarios and simulations as the price of hydrogen plus an additional adder. This adder starts at $7/MMBtu and decreases over the planning horizon, but the primary driver of the cost decline for synthetic methane is the decline in the cost of hydrogen. We note that this adder for synthetic methane above the price of hydrogen is uncertain and is analyzed in the risk analysis.

6.5.3 Community Climate Investments (CCIs)

As was discussed in Chapter Two, CCIs are a unique compliance tool developed by DEQ specifically for the CPP. These tools were designed to focus on funding emission reduction projects benefitting underrepresented communities. CCIs are projected to be available by the first demonstration of compliance. Per the rule making, the price of CCIs will be set at $71/ton for the first compliance period and raise over time. Use of CCIs as a compliance instrument is limited to 10% of the compliance demonstration during the first compliance period (2022-2024), 15% during the second compliance period (2025-2027), and 20% during the subsequent compliance periods (2028-2050).

6.5.4 Tradable Emission Allowances

Discussed in further detail in Chapter 2, rules are being developed by the Washington Department of Ecology to implement a cap on carbon emissions. Mechanisms for the sale and tracking of tradable emissions allowances are included in that rule making. Long term, the program is intended to link with similar programs in other states/jurisdictions, such as California. The cap-and-invest program works by setting a limit on greenhouse gas emissions in state, and then lowering that cap over time. The program baseline is set at average covered entity greenhouse gas emissions from years 2015-2019. Reductions from this baseline are set at 45% by 2035, 70% reduction by 2050 and 95% by 2050.

NW Natural will be assigned some free allowances over the planning horizon but will be required to hold total allowances equal to the company's covered Washington customer's emissions. This will likely require the utility to purchase allowances at the quarterly allowance auctions. As NW Natural is a relatively small participant in the allowance market, the utility should be able to purchase as many allowances as needed.

6.5.5 Offsets

The CCA allows covered parties to purchase offsets up-to 5% of their emission within the first compliance period. An additional 3% of offsets can be purchased for project on tribal lands. For a total of 8% in the first compliance period (2023-2026). This decreases to 4% of offsets and 2% for projects on tribal lands, total 6% for all subsequent compliance periods. NW Natural is an active participant in the offset market through the Company's Smart Energy Program. We used pricing data from our internal subject matter experts to develop a price forecast for these offsets.

6.5.6 Compliance RNG Resources and Compliance Instruments Comparison

Compliance RNG resources and compliance instruments can be used to meet emissions compliance in both Oregon and Washington. Each type of compliance resource has various quantity limitations, purchasing options, and can be acquired at various costs. Table 6.5 lists the various options that NW Natural can acquire and a summary of their short-term flexibility to help fill in the gap for emissions obligations, which may arise due to year-over-year changes in weather.

Table 6.5: Long-term Compliance vs Short-term Flexibility

Emissions Compliance Options	Long-term Compliance Option	Short-term Compliance Flexibility
Energy Efficiency	✓	
Development RNG	✓	
RNG offtake from existing project	✓	✓
Development Hydrogen	✓	
Development Synthetic Gas	✓	
Community Climate Investments*	✓	✓
Banking	✓	✓
Allowance Trading Auction**	✓	✓
Bilateral Allowance Trading*	✓	
Offsets**	✓	✓

* Only and option under Oregon Climate Protection Program
** Only and option under Washington Cap-and-Invest

We make a distinction between 1) RNG compliance resources, which are ultimately tied to a specific amount of low carbon or zero carbon gas and 2) compliance instruments, which are tied to a specified quantity of emissions which can be deducted from the Company's overall obligation. The costs and quantity limitations for RNG compliance resources employed in the resource planning optimization model are summarized in Table 6.6.[134]

Table 6.6: Renewable Natural Gas Costs and Volumes

Resource	Bundled Price ($/MMBtu)			Volumes Available		
	10th Percentile	Reference	90th Percentile	10th Percentile	Reference	90th Percentile
Biofuels RNG Tranche 1	$10.50	$14.00	$16.50	-50%	11 Million Dth : Oregon 2 Million Dth : Washington	100%
Biofuels RNG Tranche 2	$14.00	$19.00	$24.00	-50%	24 Million Dth : Oregon 3 Million Dth : Washington	100%
Hydrogen				10% Combined	20% combined blending and dedicated systems by state	40% Combined
2022	-20%	$23.00	40%			
2050	-50%	$5.00	70%			
Synthetic Methane				Unlimited		
2022	-20%	$30.00	40%			
2050	-50%	$9.00	70%			

These RNG compliance resources are likely to be longer-term commitments, either through offtake agreements or project development. Therefore, we model these resource options as long-term decisions that if selected as a least cost resource remain throughout the rest of the planning horizon. For example, if the model were to select a hydrogen resource in 2022 for 10 MMBtu per year when the cost of hydrogen is $23 per MMBtu, it incurs a cost of $230 per year for the remainder of the planning horizon, even though the costs of hydrogen decline over time.

To align with the legislation for both Oregon's CPP and Washington's CCA, we model compliance resources from RNG, hydrogen and synthetic methane as having zero anthropogenic carbon dioxide, which is the prevailing approach for evaluating the emissions from biogas-based resources in a combustion-based regulatory framework. This essentially means that each MMBtu or RTC of RNG, hydrogen, or synthetic methane selected in the resource planning optimization model (PLEXOS®) avoids the combustion of one MMBtu of conventional gas in terms of emissions compliance.[135] The PLEXOS® model has the flexibility to assign different carbon intensity scores to different resources if NW Natural's emissions were reported and regulated using a lifecycle accounting basis. NW Natural

[134] Note that the table shows a bundled price, but we subtract out the average price of gas when inputting the costs into the model.

[135] There is a small difference between Oregon and Washington for the carbon intensity score for conventional gas. Washington HB 1257 requires that the IRP account for assumed upstream emissions and results in slightly higher CI score for conventional gas. We account for this difference in the PLEXOS® model.

follows the current guidance on greenhouse gas reporting at the federal and state level in its evaluation of the emissions benefits of RNG, hydrogen, and synthetic methane.

The PLEXOS® model has the flexibility to assign difference carbon intensity scores to difference resources. NW Natural follows the direction of CPP and CCA policies and models carbon intensity scores for RNG that align with these policies in the IRP.

Compliance instruments (CCI, tradable allowances, and offsets) are far more flexible resources to meet emissions obligations. We model these resources as options that can be purchased as needed in each compliance period of the CPP and CCA. As NW Natural is small participant in the tradable allowance market, we do not put any limitations on the amount of the allowances the Company is able to purchase. To align with Washington HB 1257 language to use the SCC for planning, we use the maximum of the SCC and our allowance price forecast to price the tradable allowances in PLEXOS®.[136] This ensures that other compliance resources will be selected if they are ever lower cost than the SCC and required to meet the Company's emission obligation in Washington. This is used for resource selection, but when discussing rate impacts in Chapter 7, we use the allowance price forecast. Quantity limitations on CCIs and offsets are specified by rules for the CPP and CCA. Compliance instrument's costs and volumes are summarized in Table 6.7.

[136] Note that in the Reference Case the SCC is higher than the allowance price forecast over much of the planning horizon. Only in the last few years does the forecasted allowance price increase above the SCC. The allowance price is uncertain and is treated as uncertain in the risk analysis.

Table 6.7: Compliance Instrument Costs and Volumes[137]

Compliance Period	Reference Case Cost		Reference Case Volumes
	$/Metric Tons CO2e	$/Dth	
Oregon : Community Climate Investments (CCI)			
2022-2024	$109	$5.79	10% of OR compliance period deliveries
2025-2027	$112	$5.89	15% of OR compliance period deliveries
2028-2031	$115	$6.10	20% of OR compliance period deliveries
.....	.....	.....	
2049-2051	$135	$7.17	
Washington : Tradable Allowances			
	Max(SCC,Allowance Price Forecast)		No Quantity Limits for NW Natural
2023	$82	$5.11	
2050	$120	$7.63	
Washington : Offsets			
2023-2026	$12	$0.63	8% of WA compliance period deliveries
2027-2030	$16	$0.86	6% of WA compliance period deliveries
.....	.....	.....	
2047-2050	$91	$4.83	

Figure 6.21 and Figure 6.22 shows the reference case price paths for the compliance resources over the planning horizon for Oregon and Washington, respectively.

[137] Prices to vary within a compliance period. The prices indicated are the prices at the start of the compliance period indicated.

Figure 6.21: Reference Case Oregon Compliance Resource Bundled Price Paths

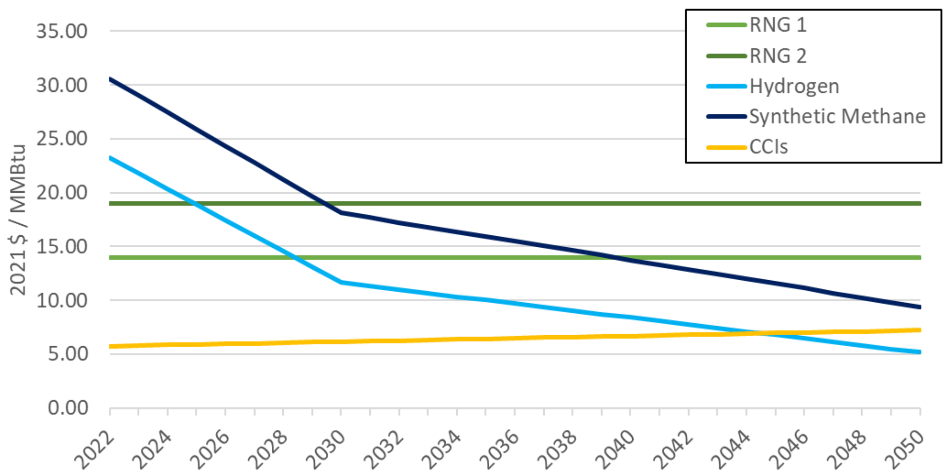
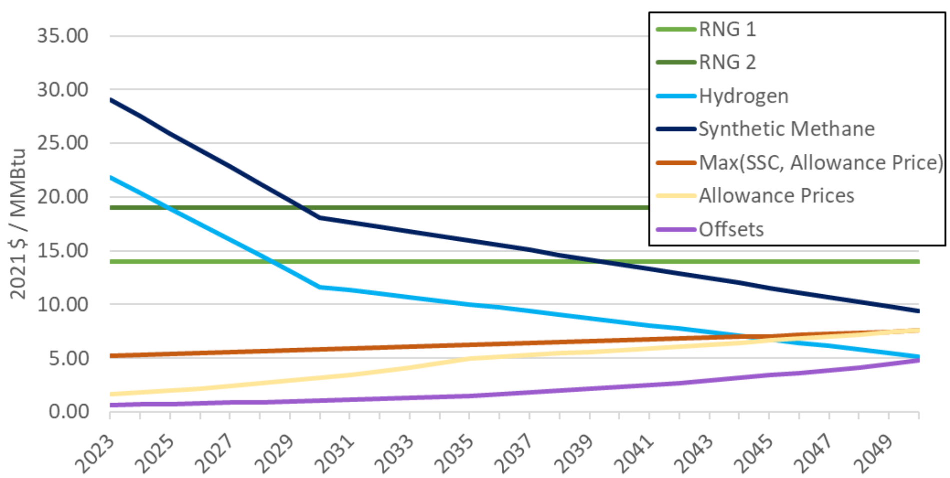


Figure 6.22: Reference Case Washington Compliance Resource Bundled Price Paths



6.6 Future Capacity Resource Options

NW Natural considers additional gas supply resource options including Mist recall, further Mist expansion, and the acquisition of new interstate pipeline capacity. The primary alternatives are described in more detail below.

6.6.1 On-system Production for Capacity

RNG and Hydrogen projects located within NW Natural service territory can inject molecules directly onto the system and provide energy to the system without needing upstream or storage capacity resources. NW Natural is applying for project approval of a 1MW hydrogen electrolyzer using the Senate Bill 844 voluntary emissions reduction program. The electrolyzer would produce approximately 4,300MMBtu of hydrogen to be blended into the natural gas distribution system. This is a small amount of energy that does not significantly impact supply side resource planning today; however, the learnings will be used to enable much larger scale projects connected directly onto NW Natural's system in the coming years.

As we better understand the costs and availability of these utility-scale projects, future IRPs will be able to evaluate them as a potential capacity resource option but are not being considered for capacity in this IRP. Depending on the economics, on-system production resources could be selected as an emissions compliance resource and the value of being on-system and providing capacity is included in the cost evaluation.

6.6.2 Mist Recall

In addition to the existing Mist storage capacity currently reserved for the core utility sales customers (see Table 6.7), NW Natural has developed additional capacity in advance of core customer need. This capacity currently serves the interstate/intrastate storage (ISS) market but could be recalled for service to NW Natural's utility customers as those third-party firm storage agreements expire.

Mist is ideally located in NW Natural's service territory, eliminating the need for upstream interstate pipeline transportation service to deliver the gas during the heating season. Due to its location, Mist is particularly well suited to meet load requirements in the Portland area, which can then free up other capacity resources to meet incremental system requirements.

There are three practical considerations that apply to Mist recall:

1. Recall decisions to transition capacity to the utility portfolio are made roughly a year prior to the core utility's forecasted capacity need. On or about May 1, NW Natural wants to start filling any recalled storage capacity over the summer months to have the maximum inventory in place by the start of the following heating season. Working backwards from May 1, ISS customers need advance notice to empty their gas inventory accounts if their capacity is going to be recalled by NW Natural. NW Natural informs the ISS customer of a recall before the heating season if their contract will not be renewed. Accordingly, we have established the prior summer as the time at which operationally we must make our recall decisions. This timeline is depicted in Figure 6.23.

Figure 6.23: Mist Recall Decision Timeline

Summer This Year	Winter Season	Next Year
Core recall decision made Inform applicable ISS customer(s) if contract will not be renewed	Applicable ISS customer(s) empty inventory if contract is terminating	Core recall is effective May 1 Core injections spring/summer/fall Core withdrawals available Nov. 1

2. Mist ISS contracts are of various durations. While limiting Mist ISS contracts to 1-year terms would maximize the capacity available for recall each year, it also would limit ISS revenues, which utility customer's share in a portion of those revenues. Accordingly, ISS contracts have staggered start dates and durations that create a profile of capacity available for recall that increases over time, in effect mirroring expectations of rising resource requirements.
3. Recalls are rounded (up or down) to the closest 5,000 Dth/day of deliverability. This is done to simplify the administration of recalls and the marketing of ISS service but are modelled as a completely divisible product in the resource planning optimization model discussed in Chapter 7. For scale, 5,000 Dth/day is roughly 0.5% of the current resource stack daily deliverability. The ability to recall Mist in such small increments is a very valuable property that allows customers pay for a capacity resource as needed.

6.6.3 Newport Takeaway Options

As previously mentioned, the daily deliverability of the Newport LNG facility provides 60 MMcf/day (64,500 Dth/day when adjusted for heat content) of system capacity under design peak conditions. This is due to pipeline infrastructure limitations flowing gas out from the central coast back towards Salem. However, the Newport LNG facility has the equipment and permitting necessary to vaporize and deliver up to 100 MMcf/day. To match the pipeline takeaway capability to Newport vaporization capacity of 100 MMcf/day, infrastructure additions would be needed on the Newport to Salem pipeline, known as the Central Coast feeder and other related pipelines. This would provide an incremental 40 MMcf/day (43,000 Dth/day). The 2018 IRP identified a three phased approach that could be done separately and sequentially at various costs to achieve the full 40 MMcf/day of incremental takeaway capability.[138]

1. Newport Takeaway 1 – would increase the maximum pressure rating of 40 miles of the Central Coast Feeder, adding 15 MMcf/day (16,125 Dth/day) at an estimated cost range of $7-16 million.

2. Newport Takeaway 2 –would add a new compressor station near Lincoln City, Oregon, adding 13 MMcf/day (13,975 Dth/day) at an estimated cost of roughly $29-66 million.

3. Newport Takeaway 3 – would boost the Lincoln City compressor horsepower, add another new compressor station to the west of Salem, and make piping improvements between Salem and Albany, all to add 12 MMcf/day (12,900 Dth/day) at an estimated cost of roughly $39-86 million.

The physical gas flow would require that these three improvement projects would have to be undertaken sequentially in the above order. If this were not the case, selection of these projects would

[138] The 2016 IRP and the 2014 IRP evaluated a similar single project call the Christensen Compressor project.

still proceed in this order due to the increase costs of each phase (Table 6.17) for an apples-to-apples cost comparison for resource capacity).

6.6.4 Mist Expansion

The storage currently in service at Mist for core customers, the capacity already developed for future Mist recall that currently serves the ISS market, and the capacity recently developed as North Mist for PGE, collectively do not exhaust the Mist gas field's storage potential. That is, other Mist production reservoirs remain that could be developed by NW Natural into additional storage resources. The primary impediment in doing so is not geological, but the challenges associated with developing new pipeline capacity to move additional gas from a new Mist storage reservoir(s) to NW Natural's load centers.

A Mist expansion project could be developed for core customer use, which would involve 100 MMcf/day (rounded to 106,000 Dth/day) of maximum delivery capacity coupled with a maximum storage capacity of around 4.0 billion cubic feet (4 Bcf, or 4.24 million Dth). Any Mist Expansion would require new compressor stations, additional wells, pipelines and associated infrastructure. If shown to be a least cost least risk resource a Mist expansion would be developed exclusively for utility use.

While design of a new storage facility itself is relatively straightforward, a larger consideration is transporting the stored gas to NW Natural's load centers during the heating season — the "takeaway" pipeline(s). With exhaustion of all available Mist recall capacity, the existing primary takeaway pipelines from Mist will be at their maximum capacities and incapable of transporting additional gas during the heating season.

A Mist expansion project involves expanding the storage capacity and sharing the pipeline constructed for PGE northbound from Mist to the Kelso-Beaver Pipeline (KB Pipeline) and onto NWP's system near Kelso, Washington. NW Natural would contract with NWP for transport to NW Natural's load centers.

The analysis assumes NWP is willing to offer a storage-related transportation service on its mainline, and on the NWP's Grants Pass Lateral (GPL) moving upstream of Molalla, on a firm basis and at a cost reflective of similar offerings that have occurred in the recent past.

NW Natural estimates the investment cost of a Mist expansion with 100 MMcf/day of deliverability and roughly 4 Bcf of storage capacity to be in the range of $150 to $240 million.[139]

[139] A regulatory concern has been raised in the past regarding the utility's direct movement of gas stored at Mist out of Oregon to serve our load centers in Washington; specifically, the concern involves the potential violation of NW Natural's Hinshaw Exemption with FERC. However, preliminary legal analysis has indicated that a viable structure could be created to make this arrangement work without adversely impacting NW Natural's Hinshaw Exemption.

6.6.5 Upstream Pipeline Expansion

NW Natural holds existing contract demand and gate station capacity on: 1) NWP's mainline serving our service areas from Portland to the north coast of Oregon, Clark County in Washington, and various small communities located along or near the Columbia River in both Oregon and Washington; and 2) GPL serving our loads in the Willamette Valley region of Oregon from Portland south to the Eugene area, as well as the central coast (e.g., Lincoln City, Newport) and south coast (e.g., Coos Bay) areas. Therefore, consideration of incremental NWP capacity, separately on the mainline and on the GPL, is a starting point for NW Natural's assessment of incremental interstate pipeline capacity in this IRP.

Since NW Natural effectively is interconnected only to NWP, a subscription to more NWP mainline capacity traditionally has been a prerequisite to holding more upstream capacity of equivalent amounts (e.g., from GTN). There could be exceptions when market dynamics indicate some advantage to holding more or less upstream capacity. For example, as upstream pipelines continue to expand into new supply regions and/or to serve new markets, an evolution of trading hubs may occur; opening up the more liquid trading points while others fade into disuse. The construction of an LNG export terminal in the Pacific Northwest or British Columbia and/or the construction of a new pipeline transporting Arctic gas (either from Alaska or the Mackenzie Delta) are examples of market developments that could cause NW Natural to reconfigure or add to our upstream pipeline contracts. Under these market conditions, it may be beneficial to hold transportation capacity upstream of NWP leading to these new supply points and trading hubs.

The timing for new regional pipelines will be driven by the growth in regional gas demand. From NW Natural's perspective, new regional pipelines could improve gas system resiliency and enhance reliability, which may be particularly important given the convergence and interdependencies of the electric and gas systems. Some proposed projects could provide the additional benefit of mitigating Sumas price risks potentially arising from future British Columbia LNG export terminals. By comparison, meeting regional demand growth via incremental NWP expansions from Sumas essentially "doubles down" on an existing pathway and, at the same time, is a potential lost opportunity to protect customers from a risk management perspective.

In this IRP, NW Natural has evaluated the potential acquisition of interstate pipeline capacity via an expansion of the NWP system between Sumas and Portland. This incremental NWP capacity from Sumas is designed to serve only NW Natural's load growth needs. Accordingly, it would have a relatively small scale and would not benefit from the economies of scale from an expansion built to serve the whole region.[140] Having a NW Natural specific expansion as any option enables the IRP to select the resource at the point in time when customers would be need.

The acquisition of incremental pipeline capacity spans a wide range of lead times. It would be dependent on the length of regulatory permitting times, and the time required to construct the

[140] Such as in the case when a pipeline expansion is being proposed and an open season is held to solicit interest from perspective customers.

required facilities, which could include restrictive periods due to environmental considerations. A pipeline expansion for NW Natural from Sumas to Portland is restricted from being selected for at least 5 years in the resource planning optimization model.

6.6.6 Portland LNG

Portland LNG was constructed by Chicago Bridge & Iron (CB&I) and commissioned in 1968 as one of the first LNG utility facilities used for LNG liquefaction, storage, and LNG vaporization for supplemental winter supply.

The Portland LNG facility’s nominal capacity includes:

- One single containment LNG storage tank with a capacity of 175,000 barrels (7,350,000 gallons) of LNG
- One flow-by-expander liquefaction cycle with a net LNG liquefaction capacity of 2.15 MMCFD (26,000 gpd)
- A net of 15.06 MMCFD tail gas is sent to the distribution system from pretreatment, LNG liquefaction, and vapor recovery operations during LNG liquefaction mode
- Three submerged combustion vaporizers (SCVs) have a combined peak send-out capacity of 120,000 MCFD at 400 psig (130,800 Dth/day after adjusting for the heat content of the gas)
- One LNG truck loading bay using LNG tank pumps with a 506 gpm max rate

Due to its location, Portland LNG is a critical resource for meeting our customer’s peak needs in the Portland Metro Area. As mentioned above, Portland LNG is considered an ‘on-system’ gas supply resource. Gas is typically placed into storage at this facility during off-peak periods, which is also known as ‘liquefaction’ (for the LNG facilities). When needed, this on-system resource does not require further transportation on the NW Pipeline interstate pipeline system, but rather uses vaporization from the LNG facility to supply gas directly to NW Natural’s system. Portland LNG’s central location and proximity to Portland makes it a valuable peaking resource.

Portland LNG needs investment to keep the facility operational and a reliable option to serve customers during cold weather events. NW Natural conducted a comprehensive alternatives analysis to evaluate the options for customers relative to the Portland LNG facility, including demand side management strategies as well as different levels of investment in the facility and options for maintaining reliable service if it were to be taken out of service and decommissioned. The additional demand response or energy efficiency beyond the current demand response and energy efficiency projects were deemed not viable options to replace Portland LNG daily deliverability as a capacity resource. This is due both to the fact that this resource is needed as a system capacity resource and to the timing of the resource need. Thus, the facility investments and the alternatives considered are summarized in Table 6.8.

Table 6.8: Portland LNG Alternatives

Alternative		Sub-Option	Feasible beyond 2027?	Cost of Service	Modeled Option in PLEXOS®
1	Keep Portland LNG Facility	A- Replace Cold Box and upgrade pre-treatment system	Yes		
		B- Replace Cold Box and keep existing pre-treatment system	Yes		✓
		C- Keep existing Cold Box and pre-treatment system	No	N/A	
2	Decommission Portland LNG and enhance Mist takeaway capabilities	A- North Pipeline	No	N/A	
		B- Middle Pipeline	Yes		✓
		C- South Pipeline	No		
3	Decommission Portland LNG and enhance Northwest Pipeline takeaway capabilities		Yes		✓
4	Decommission Portland LNG and complete no replacement alternative		Highly Unlikely		✓

How each of these alternatives was developed and assessed for feasibility and their associated costs is described in the next sections.

Alternative 1- Keep Portland LNG Operational

As mentioned above, the Portland LNG Plant is a liquified natural gas production and storage facility located in Portland, Oregon. The Portland LNG Plant serves as a winter peak shaving facility to address gas supply and system pressure needs on the coldest winter days. This facility in NW Portland is ideally located to assure reliable gas service to Portland area customers and support the rest of NW Natural's system resources under peak demand conditions. The facility provides 130,800 Dth/day of capacity to NW Natural's system and needs investment in a new Cold Box to continue operating as a capacity resource.

Many of the components within the Portland LNG plant are beyond their expected design life and the Portland LNG liquefaction rate has been reduced from its original design capacity due to both age and gas composition changes. Over the last several years NW Natural has engaged LNG industry experts including Braemar, CHIV, and Sanborn Head and Associates (SHA) to assess various options to the liquefaction technology to be considered in the broader IRP. In consultation with SHA the Company uses an approach focused on upgrading critical components which would extend the facility's useful life without requiring a complete replacement of the liquefaction system. SHA performed three studies that looked at modifying the existing liquefaction system, replacing the Cold Box, and a list of other improvements to extend the life of the Portland LNG plant. The reports are summarized as follows:

- Cold Box Replacement FEED Report, Portland LNG Facility
- Pretreatment System Evaluation, Portland LNG Facility
- Facility Assessment Report, Portland LNG Facility

Using the reports from SHA, NW Natural outlined three different scenarios for improving the Portland LNG facility and providing the best value to our customers. Those scenarios are outlined in detail in the following sections.

Replace the Cold Box and upgrade the pre-treatment system

Portland LNG Cold Box

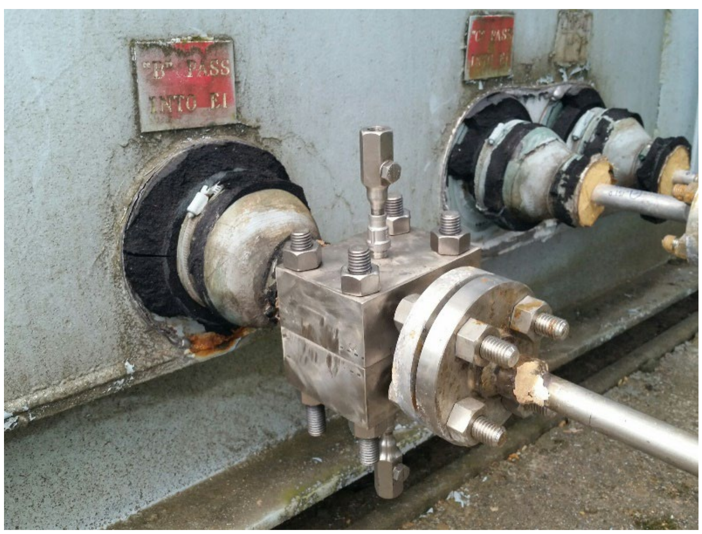
The current Cold Box at Portland LNG is 54 years old. This places it well past its design life and it is currently showing signs of performance issues. Without an investment in the Cold Box the Portland LNG facility would not be able to liquify natural gas to be ready to be withdrawn during a peak event. This investment is critical for the Portland LNG plant to remain in NW Natural's capacity resource stack and is modelled in resources planning optimization model (PLEXOS®) as an option for selection in 2027. Without the Cold Box investment, the Portland LNG facility becomes unavailable. Figure 6.24 shows the existing Portland LNG Cold Box.

Figure 6.24: Portland LNG Cold Box

Over its 54-year life span the Portland LNG Cold Box has developed several natural gas leaks between its outer casing and interconnecting piping. Figure 6.25 shows pitting on the aluminum pipes that has led to holes and leaks on the Cold Box. These leaks have been temporarily remediated using a specialty pipe clamp (Figure 6.26) that encapsulates the hole. However, it is suspected that more leaks exist within the Cold Box itself and cannot be remediated. These leaks derate the capacity of the Cold Box and lead to operational issues. Additionally, the Cold Box is an older design that is purged with natural gas, whereas modern Cold Box designs are purged with nitrogen.

Figure 6.25: Aluminum Pitting

Figure 6.26: Aluminum Pitting Clamp



Sanborn & Head conducted a FEED study to evaluate the Cold Box, assess the replacement effort, and create a cost estimate for the project. SHA outlined the following reasons to replace the Portland LNG Cold Box and summarized them in their FEED Study.

Safety – The Cold Box is purged with natural gas and constantly bleeds, creating an atmosphere around the Cold Box that consistently registers at least 0.5% gas concentration (10% LEL). The new Cold Box will be purged with nitrogen, an inert gas which improves the area safety and offers opportunity for leak detection within the Cold Box.

Fouling of the Cold Box Heat Exchanger Passes – Process modelling identified poor performance as a result of a temperature imbalance between the Cold Box heat exchanger passes. This may be due to loss of heat transfer due to a coating of contaminants within the heat exchanger passes or leaks between passes. Due to the repeated plugging of the heat exchanger passes given the recent history of the feed gas composition exceeding the design capacity of the upstream pretreatment system, contaminant coating may be permanent, and it is possible leaks have developed due to the added stress on the walls.

Age – The existing Cold Box heat exchanger design is outdated. Modern heat exchangers, when operated per manufacturer requirements, are less prone to failure than the older designs. Should one of the heat exchangers fail, repair may not be possible depending upon the severity of the failure causing significant downtime for the liquefier since new heat exchangers have a lead time of at least 1 year without including specification and installation. As identified above, it is possible the heat exchangers already have pass to pass leaks which leads to the belief the equipment has reached the end of its useful life and failure may be imminent.

Temperature Rating – The existing Cold Box heat exchanger maximum temperature rating is 100 °F. This limits liquefaction operation to days when the ambient temperature does not exceed 75-80 °F based upon the current configuration of the E-4 feed cooler and the F-2 water/glycol cooling supply loop. Based on local historical TMY2 ambient temperature data, liquefaction operation may be limited to 90% of the liquefaction season from April 1 through October 1 and as low as 77% of the time in August. The new Cold Box will be rated for 150 °F, mitigating the ambient temperature limit concerns.

In addition to a thorough review of the Cold Box, Sanborn & Head also reviewed what it would take to replace the Portland LNG facility pretreatment system. SHA reviewed several different options to improve the pretreatment system including an option of a total replacement. The pretreatment system replacement options are summarized in the following section.

Pretreatment System

Except for the hot oil heating system, the pretreatment equipment is reaching the end of its useful life and requires system upgrades and/or replacements to improve the safety and availability of the system. The pretreatment system at Portland LNG primarily consists of two original mole sieve dryers D-1 and D-2, and two original CO_2 adsorbers A-1 and A-2. Dryers D-1 and D-2 are internally insulated vessels, designed with an internal bed to contain the molecular sieve for removing water, mercaptans, and other sulfur compounds. The internal bed includes supports, liner, seals, and screens that are designed to support the sieve, prevent gas from bypassing the sieve through the insulation, and prevent sieve carryover. The molecular sieve has not been changed in over 10 years and is more than likely due for replacement. Due to reported sieve carryover, it is suspected that there is some internal support or screen damage. D-1 and D-2 are shown in Figure 6.27.

Figure 6.27: D-1 & D-2

Absorbers A-1 and A-2 are internally insulated vessels, designed with an internal bed to contain the molecular sieve for removing CO_2. The internal bed includes supports, liner, seals, and screens that are designed to support the sieve, prevent gas from bypassing the sieve through the insulation, and prevent sieve carryover. The molecular sieve was changed in 2016. Due to reported sieve carryover and process upsets, it is suspected that there is some internal support or screen damage. A-1 and A-2 are shown in Figure 6.28.

Figure 6.28: A-1 & A-2

Due to the increased CO_2 in the feed gas today as compared to the original design of 0.4 mol% CO_2, the pretreatment system performance does not meet the performance requirements of the existing liquefaction system. Excessive CO_2 in the liquification stream cannot be removed by the Dryers and Adsorbers and results in solid CO_2 within the Cold Box. Solid CO_2 causes plugging of the Cold Box passes during liquification and affects the system availability as the liquefier must be shut down and derimed when plugging occurs.

The existing pretreatment system can remove CO_2 at concentrations up to 0.4 mol% CO_2 in the incoming gas stream. However, the incoming gas frequently has concentrations of CO_2 up to 0.6 mol% and as high as 1 mol% CO_2. This increase marks a change in the composition gas coming to the plant, and a change in treatment methods at the gas production sites that NW Natural cannot control. With these conditions the existing pretreatment system fails to adequality remove CO_2 leading to CO_2 plugging, deriming and plant operations shutdown. The proposed replacement pretreatment system can remove CO_2 up to 1 mol% while still maintaining an LNG production of 2.15 MMSCFD, which is the original design capacity. The cost estimate to replace the Cold Box and the whole pretreatment system is shown in Table 6.9.

Table 6.9: Replace Cold Box and Pretreatment System

Project	Cost
Cold Box Replacement Cost	$11,235,000
Pre-treatment Replacement Cost	$17,300,000
Total:	$28,535,000

Replace the Cold Box and keep the existing pretreatment skid

Sanborn and Head also provided an option for NW Natural in which the Cold Box is replaced but the overall pre-treatment system is not. In this scenario SHA did recommend small, incremental improvements to the pretreatment system to extend its life and increase the safety and reliability of the pretreatment system. These improvements will benefit plant operations and safety but will not improve the LNG production rate of the plant. When CO_2 mol% is higher than 0.4 the plant will temporarily fall below the production rate of 2.15 MMSCFD. The improvements and their costs are summarized in Table 6.10.

Table 6.10: Pretreatment Improvement Cost Estimates

Pretreatment improvement	Cost
Switching valve replacement	$1,300,000
Instrument and controls upgrade	$310,000
E4 relief valve sizing	$10,000
Remove sulfur blimp V-1	$210,000
Replace molecular sieve material in the dryer	$140,000
Replace molecular sieve material in the CO_2 adsorbers	$140,000
Total	$2,110,000

Pretreatment Switching Valves

As the pretreatment system cycles between vessels for adsorption, regeneration heating, and regeneration cooling, switching valves are required to allow for the flow path to be directed properly, prevent clean bed contamination, and controlled pressurization. Pneumatically actuated ball valves are utilized for the switching valves. The valves are standard ball valves. NWN personnel have noted that multiple pretreatment switching valves do not seal completely. This is a common problem with standard quarter turn ball valves in this service due to the seal rubbing and the sieve dust that can break down the seal. Orbit rising stem ball valves, commonly used in modern systems, use a tilt and turn design as they reduce seal rubbing and increase the longevity/reliability of the valve. It is proposed to replace the switching valves that are reported to leak and have unreliable open-closed limit switches.

Pretreatment System Instrumentation and Control

The pretreatment system control is performed by the Facility PLC control system, including dryer and adsorber bed switching, regeneration, flow control, temperature control, and alarms. The HAZOP workshop completed under the Facility Assessment Report identified several findings and recommended enhancements to the existing process controls and interlocks to improve the process safety, if the existing pretreatment systems are maintained.

Sulfur Blimp V-1

The sulfur fuel blimp (V-1) acts as an averaging chamber for the regeneration gas outlet to control the mercaptan spikes in the off-gassing of the pre-treatment sieve. The vessel is only utilized for one hour of the 12-hour dryer cycle, at which time, the regen tail gas is discharged to the 57# system instead of the 85# system. The vessel was originally heat treated to minimize sulfur stress corrosion. As the tank is 50+ years old, the tank should be removed from service or inspected to insure it is fit for service.

E4 Relief Sizing, Mole Sieve Replacement

SHA recommends that the E4 relief valve sizing be verified and possibly replaced if not adequate. SHA also recommends that the mole sieve material in both the dryers and CO_2 adsorbers be replaced. Replacing the mole sieve material was previously identified by NW Natural and budgeted for execution.

Before SHA evaluated any of these options NW Natural had already made plans to execute some of the above line items, including the replacement of the switching valves, upgrades to the instrumentation and controls, and replacement of the mole sieve material. Those improvements are currently being executed under other projects.

With an upgraded Cold Box the plant is predicted to operate safely and reliably for another 15-20 years. The cost estimate to replace the Cold Box and keep the existing pretreatment system is shown in Table 6.11.

Table 6.11: Replace the Cold Box and Keep the Pretreatment System

Project	Cost
Cold Box Replacement Cost	$11,235,000
Pretreatment incremental improvements	$2,110,000
Total:	$13,345,000

Keep the existing Cold Box and the pretreatment systems

The third and final option for Portland LNG evaluated by the SHA team was to keep the existing Cold Box and the existing pretreatment system. If NW Natural continued on this route at a minimum SHA recommends that that the incremental improvements outlined in the previous section be executed. As stated in the above section these incremental improvements will not improve the production of LNG at the plant and the PLNG plant will be susceptible to reduced production and line plugging at CO_2 mol% higher than 0.4%.

If the Cold Box is not replaced, it is anticipated that eventually a failure will occur that would stop production permanently or for an extended period until the Cold Box was replaced. Given the lead time, inclusive of planning, purchasing, permitting, delivery, and construction of a new Cold Box; it is risky to continue to rely on the current Cold Box until failure. A failure of the current Cold Box could lead to managing through 1 or 2 winters seasons without gas from Portland LNG available for a peak event or even as a regional resiliency capacity resource. In the event of a failure of the current Cold Box, the plant would be maintained in a safe condition until the Cold Box replacement was completed.

The cost estimate to keep the Cold Box and the incremental costs required for the existing pretreatment system is shown in Table 6.12.

Table 6.12: Keep the Existing Cold Box and Incremental Improvements to Existing Pretreatment System

Project	Cost
Keep the existing Cold Box	$0
Pretreatment incremental improvements	$2,110,000
Total:	$2,110,000

SHA also performed a facility assessment report that summarizes other recommend improvements to the Portland LNG facility outside of the Cold Box and the pretreatment systems. These upgrades to the plant are intended to increase the life of Portland LNG and improve both safety and operations at the plant. These upgrades are included in the *Facility Assessment Report* for the Portland LNG Facility and included in the appendix of this IRP. These improvements are intended to be executed regardless of which pathway allows for Alternative 1 – Keep Portland LNG Operational.

Option for Inclusion in PLEXOS®

In collaboration with SHA, NW Natural examined several potential pathways for Alternative 1 – Keep Portland LNG Operational. Of these pathways, the option to replace the Cold Box and keep the existing pretreatment system, was the least-cost least-risk pathway in order keep Portland LNG operational and is one of the four high-level alternatives modeled in PLEXOS® as a capacity option for selection.

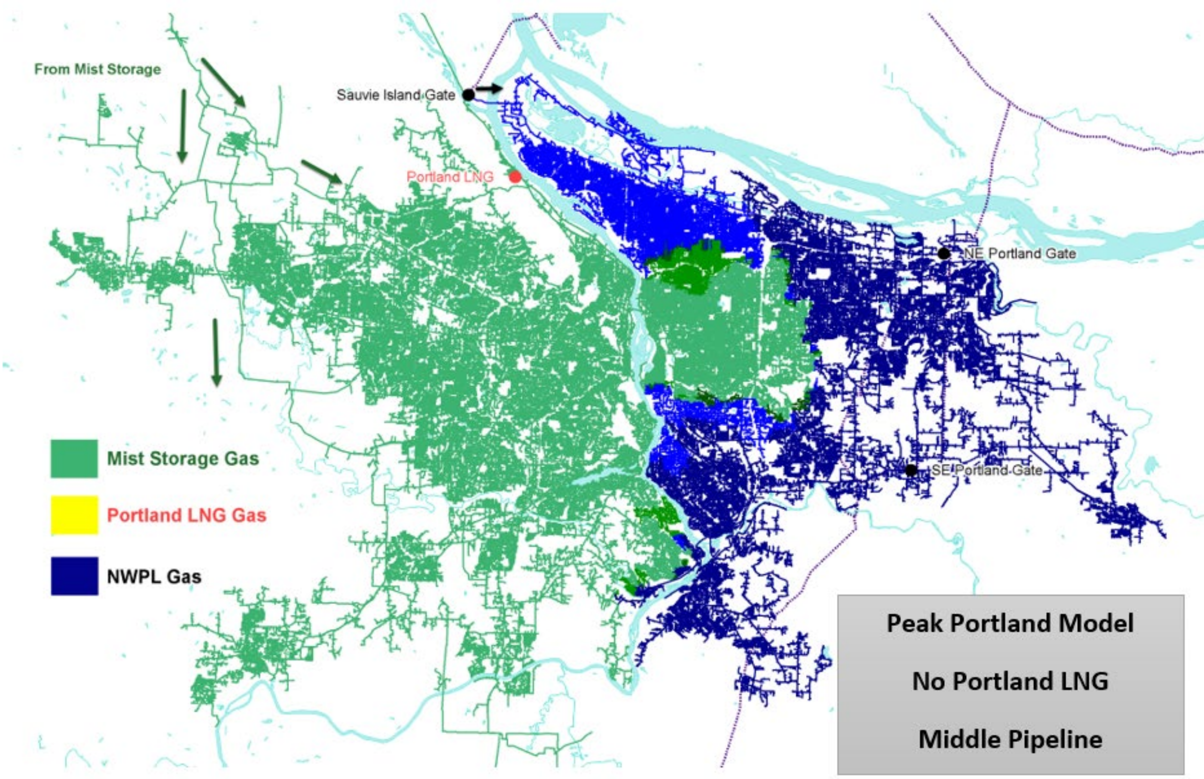
Alternative 2-Decommission Portland LNG and Enhance Mist Takeaway Capabilities

One option to reliably serve firm customer demand on the Portland system without Portland LNG is to install a new pipeline that delivers more Mist gas into Portland. This alternative includes recalling the necessary Mist deliverability to meet system capacity requirements (130,800 Dth/day for full replacement).

The evaluated alternative includes decommissioning Portland LNG and installing a new high-pressure pipeline to support core customers on the distribution system. The proposed high-pressure pipeline, known as the Middle NWN system pipeline, would deliver Mist gas to the East and North Portland replacing Williams and Portland LNG gas. The Middle NWN system pipeline would provide a connection from the 24- inch South Mist Pipeline to the high-pressure system serving Portland. This direct connection would boost pressures in the area with Mist Gas, allowing NW Natural to serve peak demands in Portland if Portland LNG is decommissioned.

Figure 6.29 illustrates the supply distribution after the Middle NWN system pipeline is installed. The green areas represent Mist gas, while the dark blue areas show gas delivered from Williams Pipeline. The lighter blue regions represent a blend of Mist gas and Williams gas. The image shows that the footprint of Mist gas extends further to the East and North Portland with the Middle NWN system pipeline in service.

Figure 6.29: Portland LNG Gas Flow Diagram with Middle Pipeline No LNG



NW Natural conducted an extensive evaluation on the feasibility for the delivery of natural gas supplied from the Mist, Oregon storage facility to meet peak usage demands of the East Portland Region.

NWN's technical team performed system modeling and determined potential options for delivering gas supply from Mist to the Portland, Oregon area by constructing a new natural gas pipeline from the existing South Mist Pipeline Extension (SMPE 24- inch pipeline) to a large transmission pipeline in the Portland, Oregon area. As a result of the modeling the NWN technical team identified the following the three route corridors:

1. Mountaindale Road to Highway 30 Corridor (North Corridor)
2. Scholls to Barbur Corridor (Middle Corridor this also refers to the middle pipeline mentioned above)
3. Wilsonville to Stafford Corridor (South Corridor)

The Southern Corridor was eliminated as an option due to the high risk and costs associated with the installation of a new pipeline under the Willamette River. NW Natural retained HDR and Associates to conduct further analysis of the North Corridor and Middle Corridor. The North Corridor had initially five potential routes evaluated which was later reduced to three, while the Middle Corridor had only one.

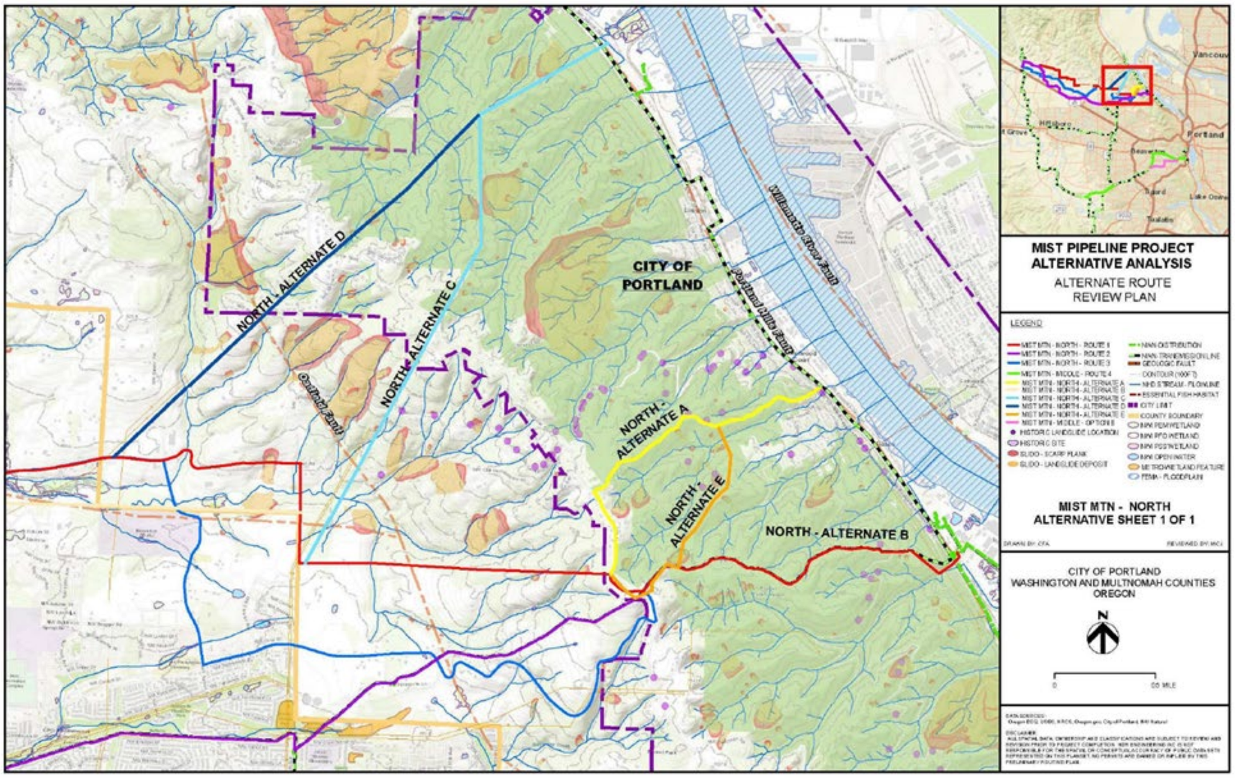
A Phase I evaluation was conducted for three routes of the North Corridor and one route for the Middle Corridor that included the following:

- Natural resources impact
- Rare, threatened, and endangered species
- Proposed mitigation strategies
- Additional environmental considerations
- Geological review
- Land Acquisition
- Permitting
- Constructability, and
- Construction, Operations and Maintenance Costs.

North Corridor

NWN's modeling concluded that the Northern Corridor would require a new 20–inch steel gas pipeline with a 720 PSIG MAOP. The alignments all start at the City of Portland along Hwy 30 and head west northwest to Mountaindale Rd. The first identified obstacle to manage is the City of Portland's Forest Park. Forest Park is a public municipal park that stretches more than 8 miles north and south in length and has over 5,100 acres of property. Five alternatives were identified for analysis and field investigation during the desktop analysis. Figure 6.30 illustrates the five alternatives.

Figure 6.30: North Corridor Route Options



Each alternative was selected to best utilize existing features and infrastructure within Forest Park to minimize the impact to the area. Alternatives A and E are aligned with ridge lines that follow existing water utility easements and hiking trails. Alternatives C and D parallel existing Bonneville Power Administration high voltage easements. Alternative B parallels an existing NWN 16” gas pipeline that runs along the ridgeline Firelane Road 7.

During the field investigation each alternative was further investigated to determine which crossing point would be used. Alternatives A and E looked very promising initially, but the trails and water line easement utilized would require significant land disturbance and clearing just to prepare the site for construction. Alternatives C and D parallel BPA right-of-way (ROW) but unfortunately after conversation with NWN staff being within the BPA ROW would not be feasible from a permission standpoint. This would force the pipelines to have extensive side hill cut conditions for the entire crossing of Forest Park. This would not only increase the impacts to the park but also put the pipeline in additional risk to slope failure in an already unstable area due to the soil conditions and steep slopes. Alternative B that parallels the existing pipeline was much more promising as a crossing location for Forest Park. Due to the historic disturbance of the existing pipeline being built along the pipeline the alternative already lends itself to a usable working space that has an existing NWN easement that is 40 feet wide.

The combination of the existing easement and the use as a fire lane has kept large trees from growing within the easement. There is a significant overhang of canopy and ground vegetation along the easement that would need to be cleared for construction to commence. At the conclusion of the field review the HDR/NWN team identified this as the primary crossing location for Forest Park. Furthermore, because of this determination all Northern Corridor routes utilize this crossing and only deviate once the proposed route hits Skyline Drive. The remaining Northern Corridor analysis starts at Skyline Drive and proceeds to Mountaindale Road. HDR proposed three routes that had specific differences in each.

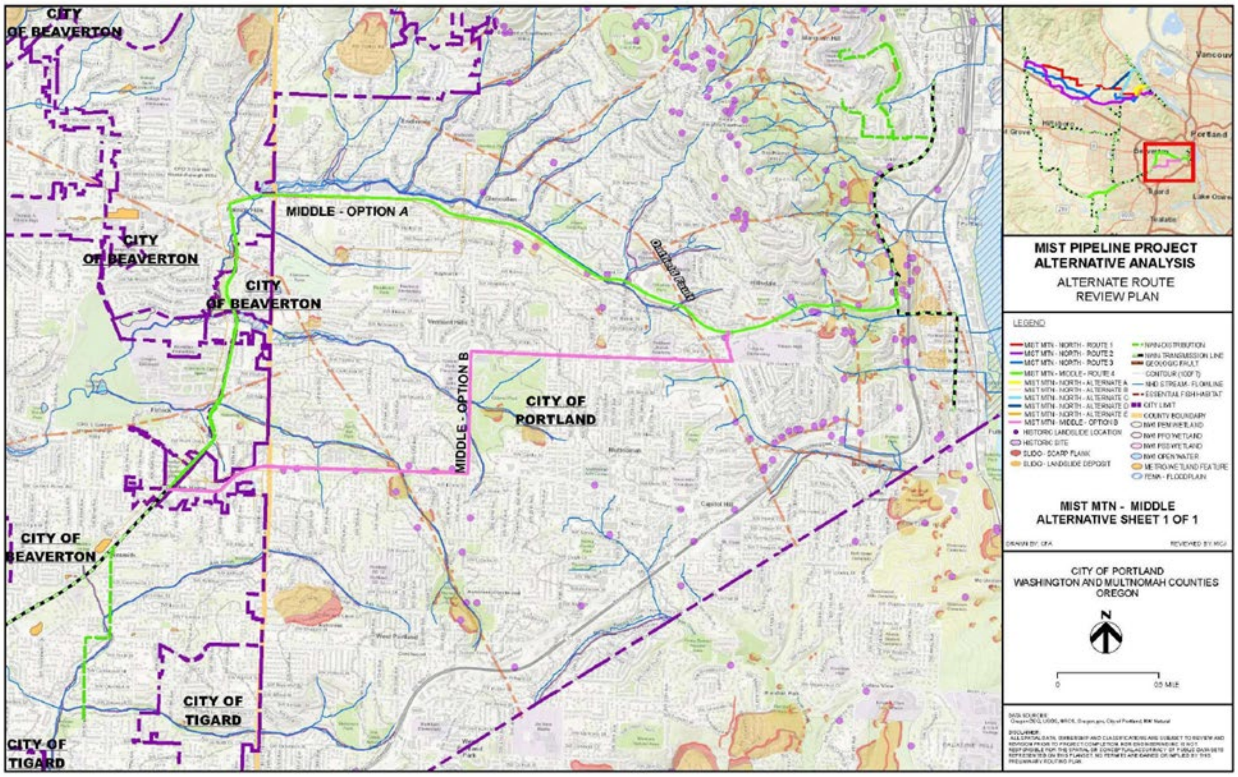
1. Route 1: Greenfield with large portions in open country undeveloped property (Red) – 16.3 mile
2. Route 2: Existing Easement which follows the alignment of NWN's 16 inch pipeline (Purple) - 16.8 miles
3. Route 3: Roadway with all work being within or immediately adjacent to the roadway (Blue) – 16.8 miles

Middle Corridor

NWN's modeling concluded the Middle Corridor[141] would require two new 16-inch steel gas pipelines with the western pipeline operating 720 PSIG MAOP and the eastern pipeline operating at 400 PSIG MAOP. The separation is because an existing 12-inch gas main will be utilized as a bridge between tie-ins. The east side is urban and will require all work to be completed within the roadway. The west side becomes more rural as you continue west but still has significant development along the route. In the East section, HDR looked at two options as shown in Figure 6.31. The Middle Corridor would require a total of 8.4 miles of new pipe. A regulator station will be required near the east side of the route to drop the pressure down to 400 PSIG prior to connecting to the existing 16-inch main.

[141] This is referred to as the Middle pipeline above.

Figure 6.31: Middle Corridor Route Options



Due to the findings of the Phase I Analysis, two routes were selected for a more thorough analysis. Those include Route 3 (Blue Route) from the Northern Corridor and Route 4 from the Middle Corridor.

The main advantage of Route 3 is that NWN can take advantage of the public ROW along the existing network of roadways and only need to secure temporary easements for additional workspace. This will significantly reduce costs for ROW and speed the process for initiating fieldwork during design. The overall permitting risk is moderate, but by using additional avoidance and minimization strategies, it is believed that risk can be mitigated.

Route 4 has the advantages of less permitting risk, fewer trenchless crossings, less ROW to purchase, and half the construction time and cost. Public discontent should also be limited to traffic pattern impacts during construction and not as much long-term environmental damage or spreading development concerns. For the reasons above, the Middle Corridor Route 4 was selected as the alternative to model in PLEXOS®.

In Phase 2, HDR developed more specific route avoidance measures to further mitigate impacts, a route-specific risk matrix for each route, 10% alignment drawings, schedules, and a more specific total incurred cost for each route. A summary of the findings is in Table 6.13.

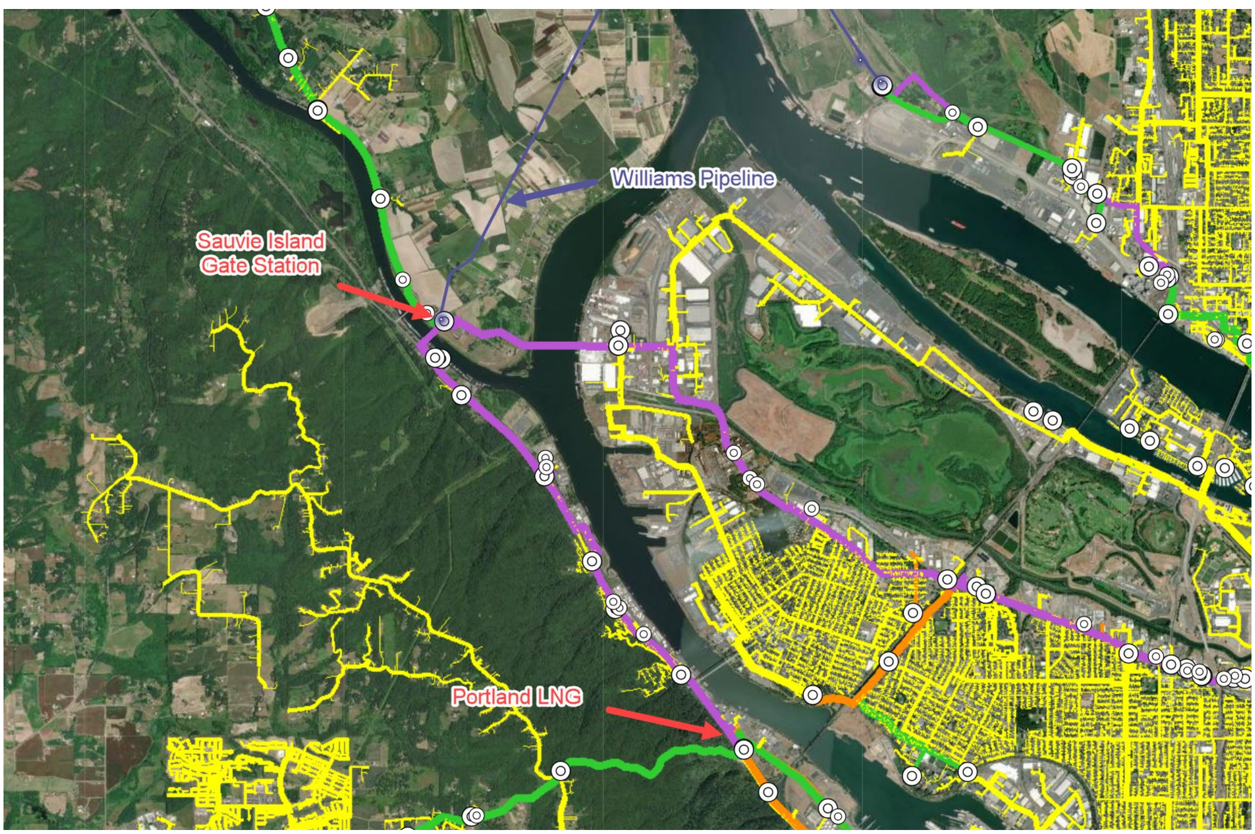
Table 6.13: Phase 2 Results

Route #	Length (miles)	Overall Permit Risk			Number of Trenchless Crossings	Total ROW to Procure		Total Project Duration	Total Installed Cost ($)
		Local	State	Federal		Temp (ac)	Perm (ac)	Days	
3 - North Corridor	16.8	Moderate	Low	Low	8	31.74	0.36	1,025	$127,336,000
4 - Middle Corridor	8.4	Low	Low	Low	2	15.4	0	984	$76,145,000

Alternative 3– Decommission Portland LNG and Enhance NWP Takeaway Capabilities

As shown in Figure 6.32, Sauvie Island Gate Station and Portland LNG feed the same high-pressure system. Provided that there is adequate pressure and flow rates, Sauvie Island Gate Station and Portland LNG are hydraulically interchangeable. Meaning gas from Sauvie Island Gate Station can substitute vaporized gas from Portland LNG because they can supply the same area.

Figure 6.32: Portland LNG Gas Flow Diagram



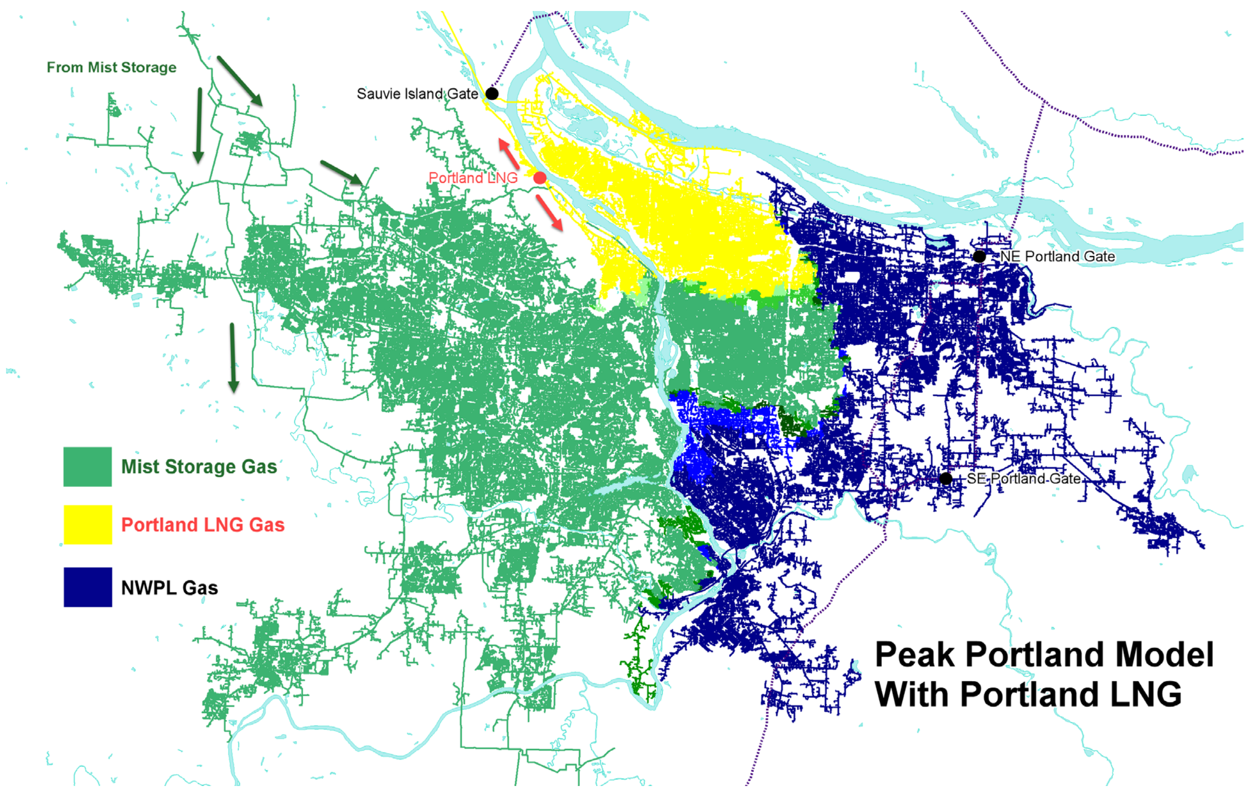
Synergi™ Gas was used to model the volume of gas required from Sauvie Island Gate with Portland LNG offline. The results of the modeling run indicated that NW Natural would require an incremental 38,000 th/hr at Sauvie Island Gate Station to serve firm customers during peak hour conditions. NW Natural approached Williams NW Pipeline to identify the requirements to increase the capacity of the Sauvie Island Gate Station by 38,000 th/hr. Williams NW Pipeline identified an expansion that would allow NW Natural to take more supplies off Sauvie Island Gate Station. Synergi™ modeling results show that we can serve firm customers in Portland if with an interstate pipeline looping option on Williams NW Pipeline that feeds into the Sauvie Island Gate Station.

Alternative	Installation Cost	Additional Resources Required
Interstate Pipeline Looping	$87 Million	Mist Recall

Alternative 4- Decommissions Portland LNG and Complete No Replacement Alternative

During a peak event, the gas being withdrawn from Portland LNG supports the pressures on the distribution system serving North Portland (see yellow area in Figure 6.33).

Figure 6.33: Portland LNG Gas Flow Diagram With LNG



Without Portland LNG, alternative supplies would need to be sourced from either Mist or NWP to replace the LNG gas in the northern portion of Portland. Without a pipeline project, Mist gas would not have adequate pressure to serve the void left by Portland LNG. Additionally, without an expansion on NWP, NW Natural could not take the necessary supplies from Sauvie Island Gate Station to replace the Portland LNG gas. The lack of a reliable supply sources means that there would be unserved demand in the Portland area shown in yellow in Figure 6.33.

Using 2022 forecasted demands, the Synergi™ model does not solve after disabling Portland LNG and limiting the Sauvie Island Gate flows to the current capacity. The unsolved model results from not having adequate supplies to meet demands on the system. During extreme conditions, the lack of supplies would cause system pressures to drop to a point where gas service could be lost to thousands of firm customers.

A Synergi™ analysis was used to determine the maximum firm demand the system could serve if Portland LNG were decommissioned and no other system reinforcement projects were constructed. For this analysis, the Williams supplies were fixed to their current capacities and load was reduced until Synergi™ was able to solve. The model solved after firm demands were reduced by approximately 16% from 2022 forecasted peak demands. This suggest that firm sales peak demand would need to be below 830,000 Dth/day to decommission Portland LNG and not need one of the other alternatives discussed above.

Portland LNG and segmented capacity are the two capacity resources, which fall off the capacity resource stack within the planning horizon. Without these resources, NW Natural has 800,000 Dth/day of capacity. 30,000 Dth/day of Mist Recall would still be required to fill the gap if peak demand were to decline to a point where Alternative 4 is a viable option. We impose a constraint into our resource planning optimization model (PLEXOS®), where Alternative 4 is not available if it selects more than 30,000 Dth/day of Mist Recall.

6.6.7 Capacity Resource Comparison

NW Natural uses cost-of-service modeling, which captures the capital costs, operation and maintenance costs, taxes, construction and overhead, and all other estimated costs associated with an option over the planning horizon. Using the cost-of-service modeling, each option has a present value revenue requirement. These costs become an input into the resource planning optimization model, and they are incurred when a capacity option is selected.

Table 6.14 lists the capacity options, costs in terms of dollars per Dth per day, the daily deliverability, and the years each option is available for selection. These are fixed costs that are incurred everyday throughout the planning horizon if a capacity resource is selected. Note that only Mist Recall is a non-binary option, and the model can select as much Mist Recall as needed in each year. All other options must be selected at the full amount. The model must select the Portland LNG Cold Box or one of the alternatives discussed Section 6.6.6 in the year 2027.[142] While the Cold Box could fail between now and 2027, the year 2027 was selected as this was the earliest timeframe any of the other alternatives could feasibly be constructed. Once an option is selected it remains in the resource stack and incurs the cost for the rest of the planning horizon.[143]

Table 6.14: Capacity Resource Cost and Deliverability

Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	As needed Max : 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800†
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800‡

Notes: Pipeline options are available for selection November 1st of year; storage options are available for selection May 1st in each year. Newport Takeaway options must occur sequentially.

† Pressure modeling shows that with this option would allow for additional Mist takeaway and would increase the max Mist Recall to 240,492 Dth/day. 130,800 is used in this table for a direct comparison to the deliverability enabled by the Cold Box alternative.

‡ Pressure modeling shows that with this option would allow for additional Mist takeaway and would increase the max Mist Recall to 204,422 Dth/day. 130,800 is used in this table for a direct comparison to the deliverability enabled by the Cold Box alternative.

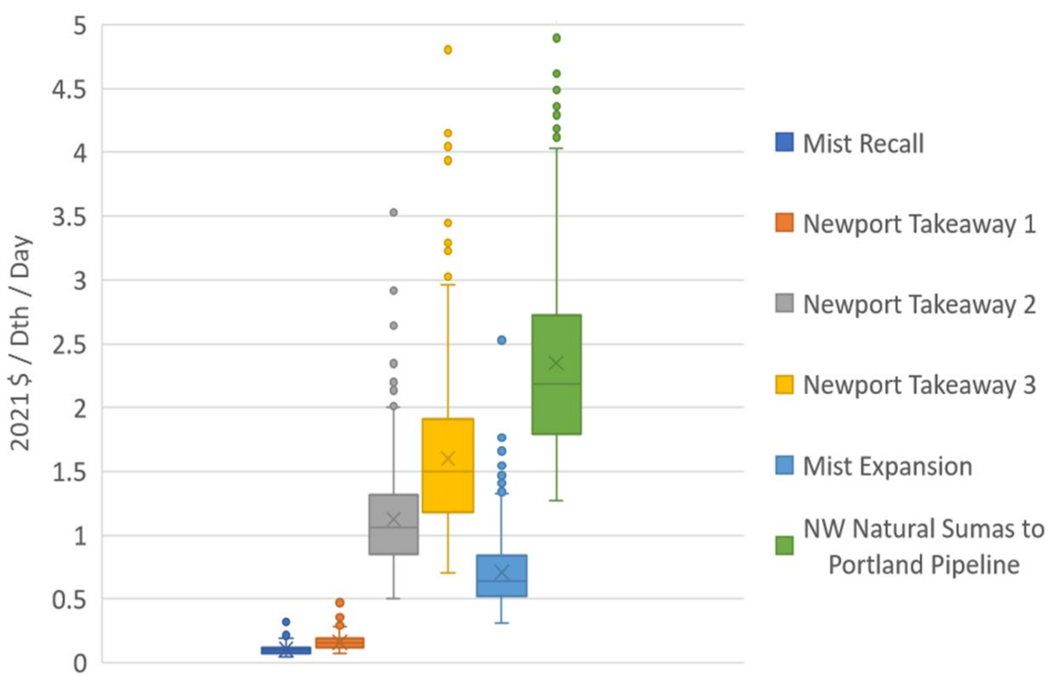
[142] This includes a object in the PLEXOS® model that represents the decommission Portland LNG and complete no replacement alternative.

[143] The only exception to this assumption is the Interstate Pipeline Looping option. This option is an agreement with Williams NW Pipeline that would be if chosen in 2027 would be paid off over the course of 20-years, therefore payments would cease in 2048.

6.6.8 Capacity Resource Cost Uncertainty

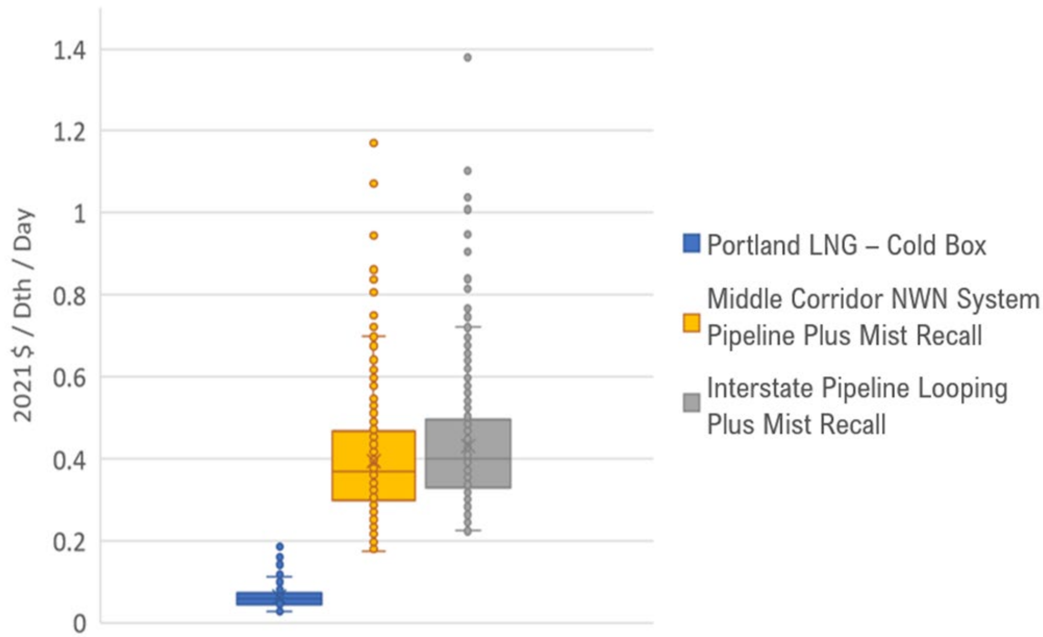
Just like natural gas prices, the price for RNG, the price for hydrogen, and the cost for methanation, the fixed costs for capacity resource options are also uncertain. Many of these costs are associated with construction, material, and labor costs, which can all vary both together and independently; however, since these capacity resources are specific to the natural gas sector, the labor and material costs are likely highly correlated. Additionally, the risk associated with the costs for these capital-intensive resources is not symmetrical with the potential for a much higher, albeit low-probability, over-all project cost. To simulate these fixed costs, we use a log-normal distribution in a Monte Carlo simulation for each capacity resource along with a correlation coefficient to account for correlation across all resources.[144] Figure 6.34 and Figure 6.35 shows the magnitude and range for the capacity resources options considered in resources optimization modelling discussed in the following chapter.[145]

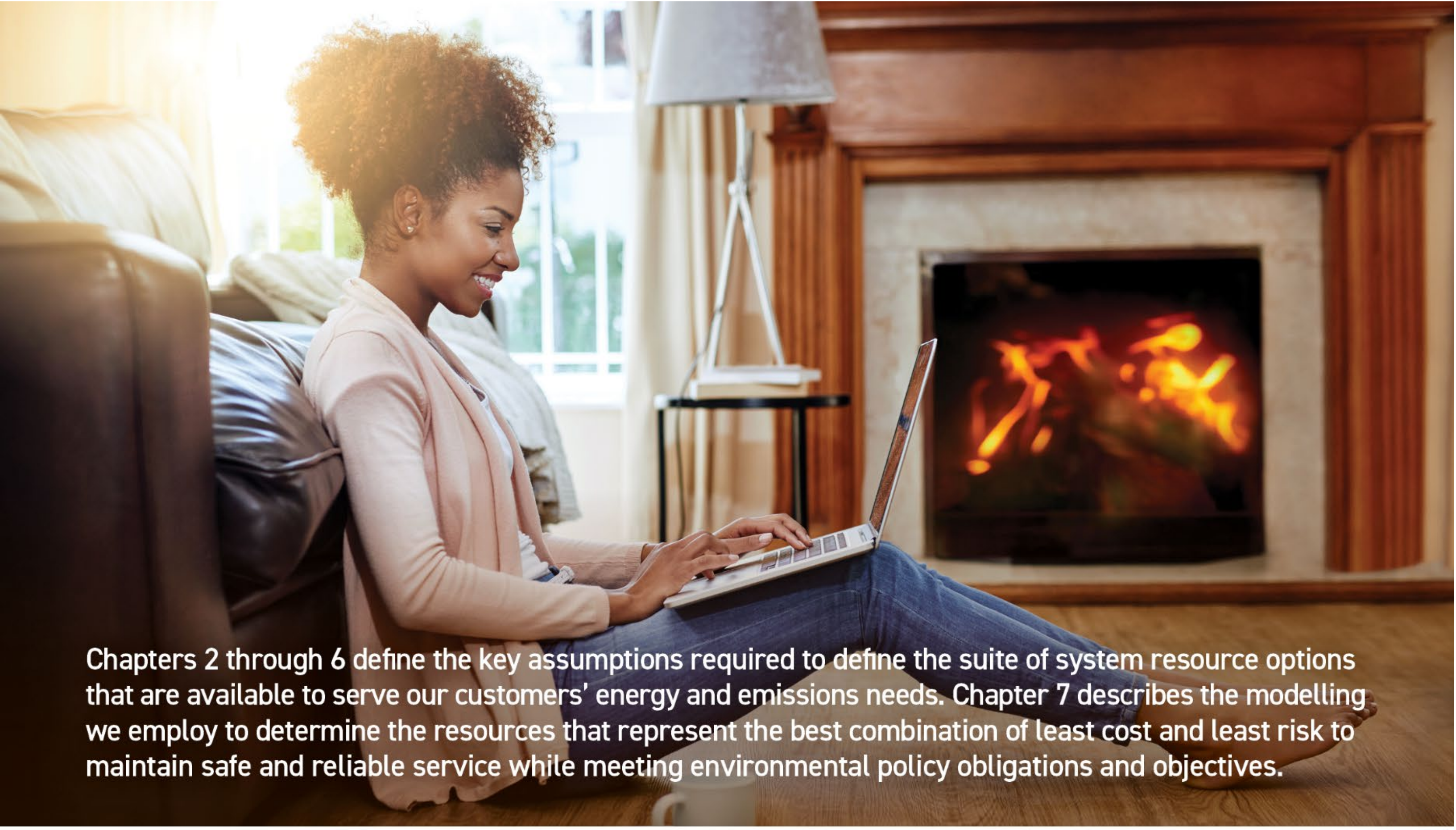
Figure 6.34: Box and Whisker Plot for Capacity Resources



[144] See Appendix F for technical details for capacity resource cost simulation.
[145] Please note the difference in X- axis scale between the two figures

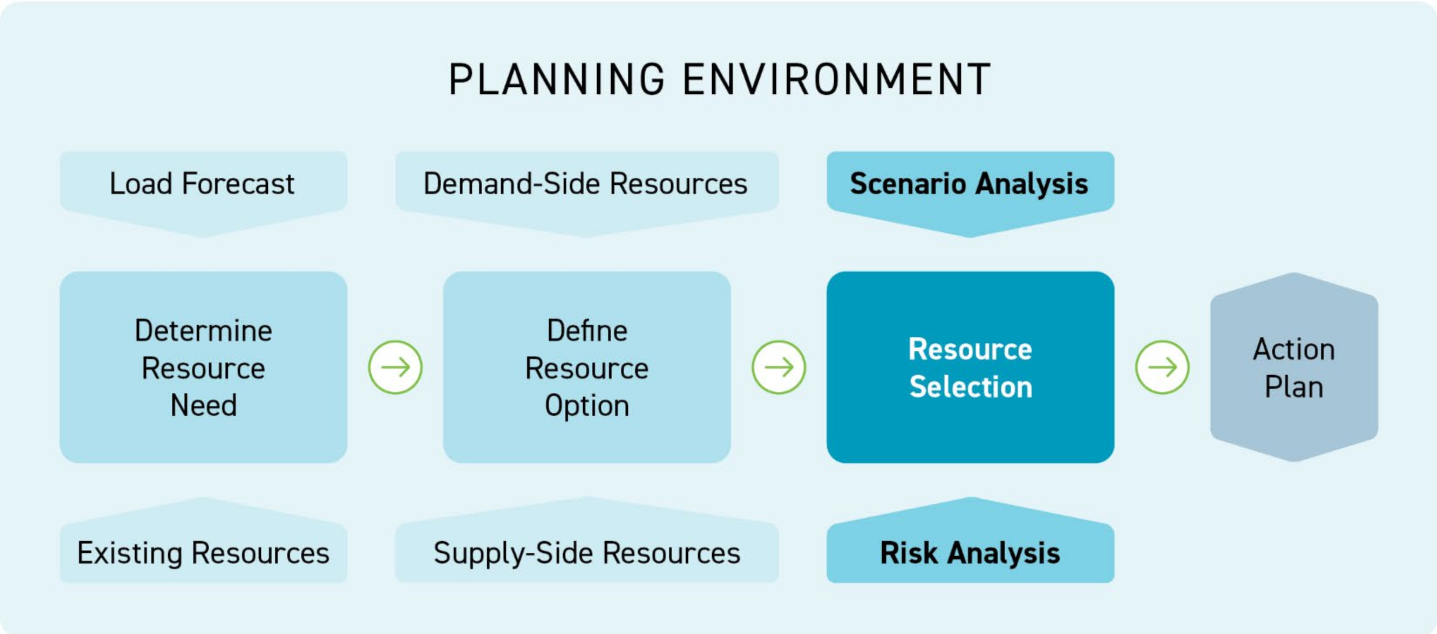
Figure 6.35: Box and Whisker Plot for Portland LNG Alternatives





Chapters 2 through 6 define the key assumptions required to define the suite of system resource options that are available to serve our customers' energy and emissions needs. Chapter 7 describes the modelling we employ to determine the resources that represent the best combination of least cost and least risk to maintain safe and reliable service while meeting environmental policy obligations and objectives.

7 | System Resource Portfolio Optimization and Results



NW Natural®

7.1 Least Cost Least Risk Portfolio Selection – Overview

The IRP is the Company's primary tool to evaluate near-term resource decisions over a long-term planning horizon and understand how those decisions would be viewed under a wide range of circumstances. Some of these near-term decisions involve investments in long lived assets or signing long term contracts, such as an RNG off-take agreement. Understanding the long-term planning outcomes under a variety of futures allows a robust evaluation of any near-term system resource decisions formed within the Action Plan of this IRP. The complex optimization modeling and the results discussed in this chapter help develop system resources Action Plan Items that will be low regret decisions on behalf of customers.

System resource planning must acquire the appropriate mix of resources with the best combination of cost and risk to meet three primary requirements:

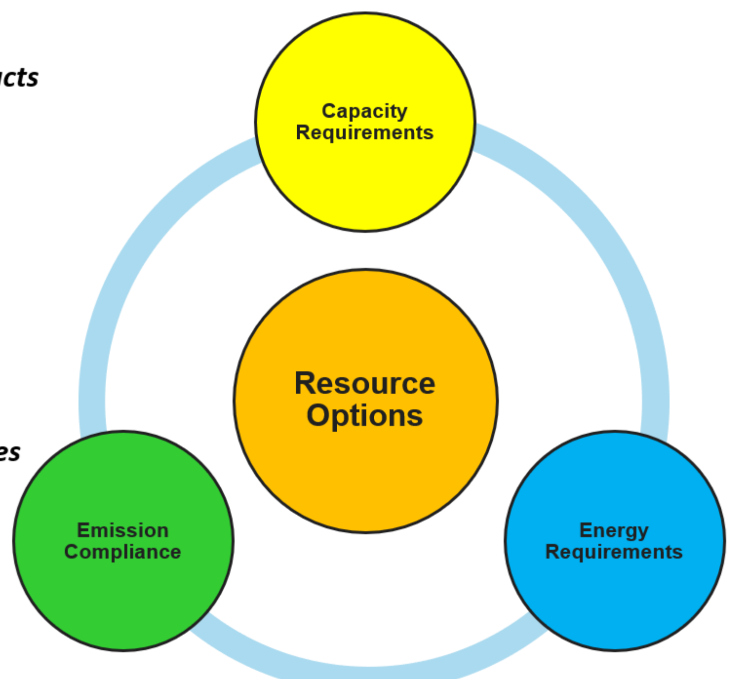
1. Emissions reduction requirements, emission compliance following the rules of the CPP in Oregon, and the CCA in Washington.
2. Capacity requirements, being able to reliably serve customers during a design peak cold event when loss of customer service due to resource constraints occurs at the same time when it is the most dangerous time for customers to lose service.
3. Annual energy requirements, having the resources to reliably serve customers throughout the year.

Figure 7.1: System Resource Planning Requirements and Options

Supply-side Options
Natural gas, RNG, or hydrogen supply contracts
Interstate/interprovincial pipeline capacity
On-system production resources
Underground storage
Above-ground LNG storage
Industrial recall options
Citygate deliveries

Compliance Resource Options
Bundled RNG or hydrogen
Unbundled environmental attribute purchases
Qualified compliance instruments

Demand-side Options
Energy efficiency
Demand response



Resource options offer very different emissions, capacity, and energy contributions. Additionally, resource options all vary in costs, availability, and timing. For example, NW Natural's Newport LNG facility provides a significant amount of capacity, but limited amount of total energy before being completely emptied. On the other hand, upstream pipeline capacity with conventional gas purchases can provide 365 days of both capacity and energy, some of which is needed during the summer to fill NW Natural's storage facilities. Off-system purchases of RNG help meet emission compliance, but do not provide either capacity or energy to the system, whereas an on-system RNG can help meet all three requirements.

Due to the complexity of varying resources and resource requirements, NW Natural must implement an optimization software called PLEXOS® to solve for the least cost mix of resources that complies with emission obligations, while reliably serving customers each day over the planning horizon (2022-2050). Scenario and Monte Carlo simulation is used in the risk analysis to develop the least cost least risk near-term actions for system resources in the Action Plan.

Chapters 2 through 6 lead up to this chapter by discussing all the key load and resource components that become the inputs into the PLEXOS® modelling software. The rest of Chapter 7 discusses the PLEXOS® model, capacity resources needed, a break-out of compliance resources by scenario, and an overview of risk analysis.

7.2 Resource Planning Optimization Model (PLEXOS®)

PLEXOS® implements a mixed integer program (MIP) algorithm, which triangulates a least cost solution of resource acquisition and dispatch that minimizes net present value of total system costs over a specified planning horizon. PLEXOS® is owned and licensed by Energy Exemplar and is a completely new tool for NW Natural's IRPs.[146] The software provides superior flexibility and software technical support over the previous optimization tool used for prior NW Natural's IRP.[147] Most importantly, upgrading to the PLEXOS® software allows NW Natural to implement quantity constraints on emissions and have different the carbon intensities across resources, both critical for modeling compliance with the CPP and CCA.

The software operates by using sophisticated *Operations Research* techniques and algorithms (e.g., linear and non-linear programming) to solve a constrained optimization mathematical problem. Constrained optimization problems start with an *objective function*. The objective function for PLEXOS® is mathematically represented as:

[146] NW Natural only licenses the gas module for PLEXOS®. PLEXOS® has additional modules, such as electric and water, that can be linked for co-optimization of systems. Even after a year of modeling within the gas module, NW Natural is still learning about the full capabilities of the software and may be able to introduce further complexity into the model for future IRPs.

[147] The previous software (SENDOUT) had linear limitations on resource acquisition. The mixed integer program (MIP) algorithm in PLEXOS® are more complex, but allow for integer-based decisions, such as a binary build or not build decisions.

$$Minimize \sum NPV(Cost_t) \ \forall \ daily\ costs\ t = [2022 - 2050]$$

Contextually, this means that model solves for a solution that minimizes the summed net present value (NPV) of all costs incurred each day in the planning horizon; from 2022 through 2050. The algorithm does this by adjusting selection variables, also known as decision variables, but is constrained based on the inputs and parameters of the model. These constraints represent real world limitations, for example daily maximum withdrawal capability from Mist storage. Table 7.1 provides a high-level list of the decision variables and constraints in NW Natural's IRP PLEXOS® model.

Table 7.1: Decision Variables and Constraints

Decision Variable	Constraints
➢ Daily purchases for compliance resources (RNG, hydrogen, synthetic methane) and compliance instruments (CCI, allowances, offsets) ➢ Daily selection of quantity and location to purchase and ship conventional gas ➢ Daily Mist, Jackson Prairie, Portland LNG and Newport storage operations (injections and withdrawals) ➢ Annual acquisition of capacity resources required to serve demand	➢ All demand is served in each load center ➢ NW Natural meets emissions compliance in both Oregon and Washington ➢ Pipeline constraints and costs ➢ Storage constraints and costs ➢ Supply purchasing constraints and costs ➢ Compliance and capacity resource acquisition constraints and costs ➢ Costs are discounted at a rate equal to the Company's real after-tax weighted cost of capital

At its core, the PLEXOS® software is used to create a nodal model that links objects together. Objects can represent, but are not limited to, gas supply contract, gas pipelines, gas storage, and gas demands. Figure 7.2 shows a simple PLEXOS® model with two supply contracts, three pipelines, one storage facility, and two demand areas. All objects can only be connected to other objects through *"node"* objects. Emissions constraints can be placed on any single node or group of nodes. In this simple example there is a constraint placed on all gas flowing from Supply 1 and Supply 2 gas contracts.

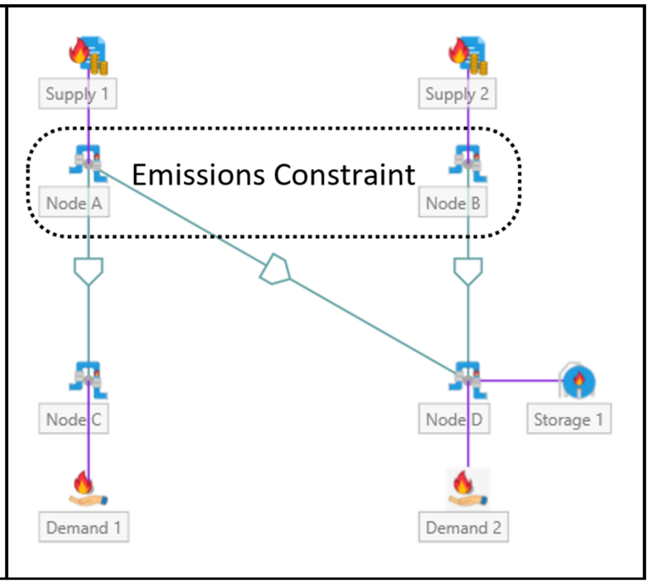
Figure 7.2: PLEXOS® Simple Model Example

In this simple model gas can be purchased from:

- "Supply 1" and put into the system at "Node A"; ***or***
- "Supply 2" and put into the system at "Node B"

3 Pipelines are modeled as directional and

- connect Node A to both Node C and Node D; ***and***
- connect Node B to only Node D
  - Gas from Supply 1 can serve both Demand 1 and 2 and inject into Storage 1
  - Gas from Supply 2 can serve only Demand 2 and inject into Storage 1
  - Gas withdrawn from Storage can only be used to serve Demand 2



For each object numerous properties can be assigned. Additionally, these properties can be dynamic, in other words changing over the planning horizon. Table 7.2 shows seven properties assigned to a single object representing our upstream Foothills pipeline contracts. Properties that are dynamic require a data file with dates and values for a specified time interval (day, month, or year).

Table 7.2: Object Properties Example

Object	Property	Value	Data File	Units
Foothills Pipeline	Max Flow Day		Pipeline MDQ	MMBtu
Foothills Pipeline	Is Bidirectional	No		-
Foothills Pipeline	Flow Charge		Pipeline Variable Charge	$/MMBtu
Foothills Pipeline	Reservation Charge		Pipeline Demand Charge	$/MMBtu/month
Foothills Pipeline	Reservation Volume		Pipeline MDQ	MMBtu
Foothills Pipeline	Loss Rate		Pipeline Fuel Rate	%
Foothills Pipeline	Entitlement Type	Net		-

This IRP is the first NW Natural IRP to implement a PLEXOS® model and the Company built this model from the ground up. Objects in the model include, but are not limited to:

- existing upstream pipeline capacity,
- existing storage facilities,
- existing conventional gas purchasing hubs,
- existing RNG offtake agreement and developments,
- existing on-system production resources,
- future potential capacity resources options,
- future potential compliance resources options and,

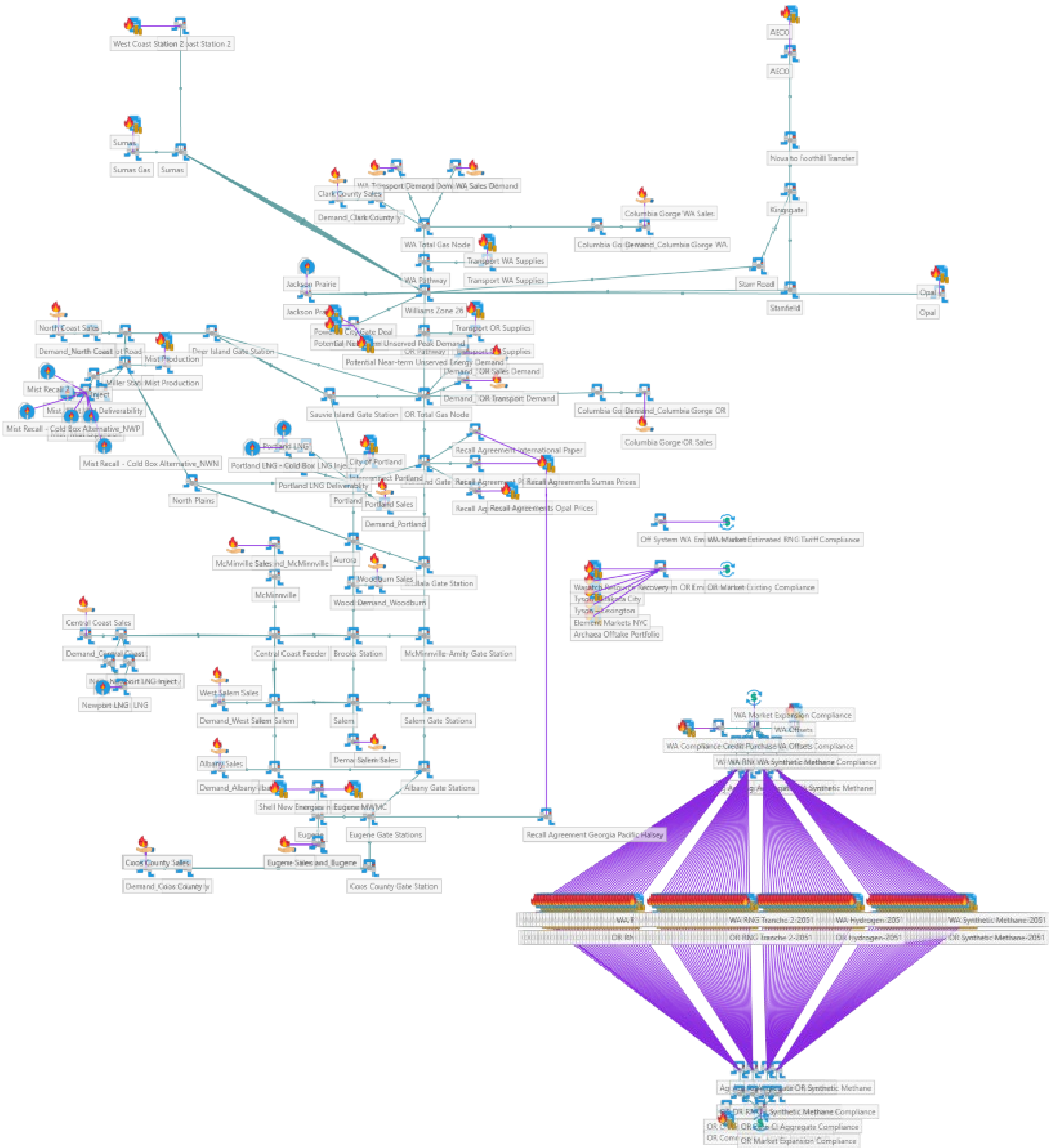
- state specific daily demand by service type (i.e., firm vs interruptible)

In addition to the required properties for each object in the model (example shown in Table 7.2), user defined constraints are developed to ensure that:

- emissions compliance across two separate states,
- least cost qualifying resources are acquired to meet SB 98 targets,
- total cumulative RNG contracts are quantity limited by state,
- hydrogen is less than a specified blending limit by state,
- CCI acquisitions are quantity constrained within each Oregon compliance period,
- offsets are quantity constrained within each Washington compliance period,
- the sequential construction of the potential Newport Takeaway projects,
- potential pipeline resources are selected in November,
- potential storage resources are selected in May and,
- one of the four high-level Portland LNG Alternatives is selected with access to the appropriate level of Mist Recall in May 2027.

This extensive modeling has created a much more complex nodal system model as illustrated by Figure 7.3.

Figure 7.3: 2022 IRP PLEXOS® Model Topography

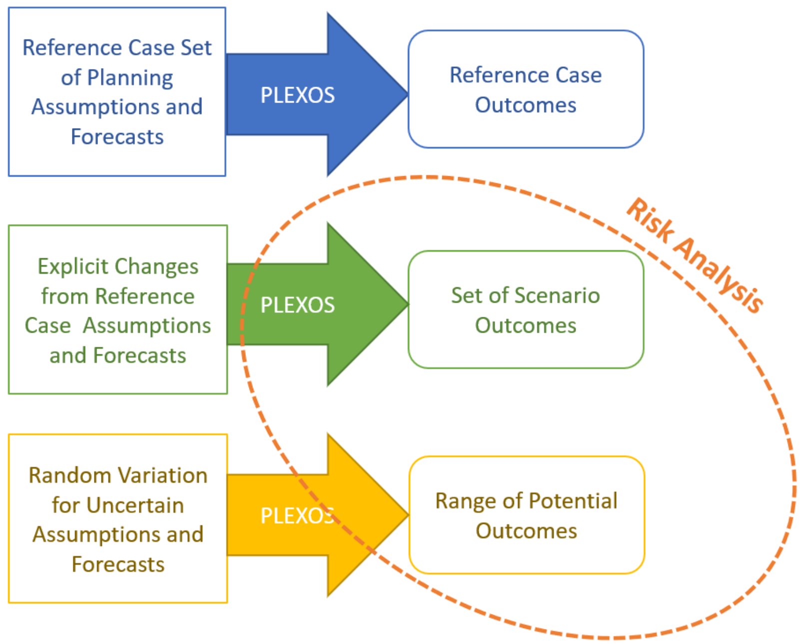


The PLEXOS® model uses the information discussed in chapters 2 through 6. This includes demand forecast, resource options, price forecasts, compliance obligations, etc. Given these inputs, the cost minimization algorithm of the model has perfect foresight of the future and optimizes the resource selection and dispatch across time accordingly. In other words, it can choose to inject into storage in one period to avoid paying high costs in the future.

Unlike the PLEXOS® model, resource planners do not have perfect foresight and face a lot of uncertainty and risk across several factors. Our risk analysis varies the key input component in the mode to understand these risks. An overview of the risk analysis is discussed in the following section.

7.3 Risk Analysis Overview

Unlike previous IRPs, this IRP does not define or select a particular scenario as a base case. Instead, we define a reference case (see Chapter 2, Section 7) and numerous "what-if" scenarios where uncertain key demand and supply inputs are explicitly or stochastically modified in-contrast to the Reference Case. The PLEXOS® takes in all the information and produces a least cost solution for the whole planning horizon. This solution includes, but is not limited to, daily purchases of conventional gas, annual low-GHG supply resource contract decisions, daily storage operations, and capacity resource investments, along with the emissions and costs associated with each of components. The primary output is a least cost resource portfolio that is dynamic through time.



7.3.1 Scenario Analysis Overview

Our risk analysis includes two approaches to testing resource selection. The first approach is to view the world through a specific set of circumstances, known as scenarios. The benefit of using scenarios is it allows stakeholders to understand the implications for resource planning given a specific set of circumstances, for example aggressive building electrification, which can be a bookend set of circumstances. Each scenario makes a few significant deviations from the reference case to understand the implication of that change. For example, Scenario 7 examines the impact of a federal policy aimed at reducing the costs of RNG and Hydrogen. How the future ultimately unfolds will not be a single scenario, but likely a combination of all scenarios.

In addition to the Reference Case, we developed nine other scenarios for the risk analysis. To reference a specific scenario throughout the IRP, we assign numbering and labels to each scenario as shown in Table 7.3. Table 7.3 provides a high-level summary of all the inputs for each scenario. Detailed descriptions of the inputs, outputs, and the reason for a scenario are included as comprehensive standalone sections for each scenario later in this chapter.

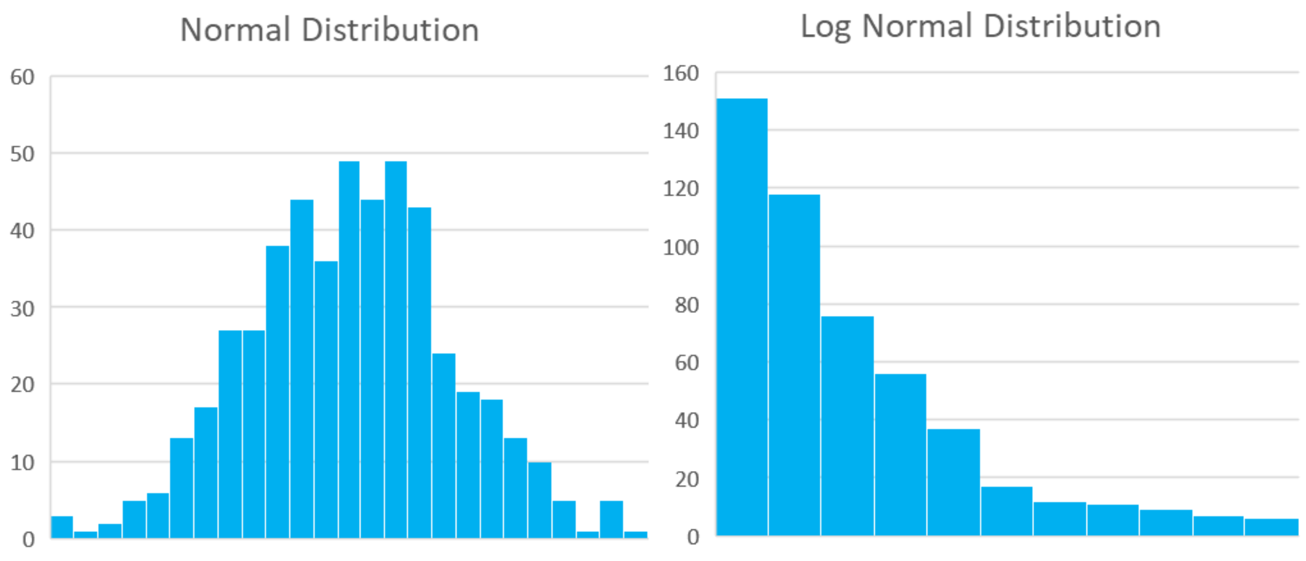
Table 7.3: 2022 IRP Scenarios

2022 IRP Scenarios- Summary Version		Reference (Trend Continuation) Case	1 Balanced Approach	2 Carbon Neutral by 2050	3 Dual-Fuel Heating Systems	4 New Direct Use Gas Customer Moratorium in 2025	5 Aggressive Building Electrification	6 Full Building Electrification	7 RNG and H2 Production Tax Credit	8 Limited RNG Availability	9 Supply-Focused Decarbonization
Demand-Side	Weather	Climate change adjusted expected ("normal") weather in each year									
Demand-Side	Customer Growth	Current expectations				No New Customers After 2025			Current expectations		
Demand-Side	Space and Water Heating Equipment	Current EE expectations	Moderate gas powered heat pump and hybrid heating adoption		All residential and commercial space heating becomes hybrid heating by 2050	Moderate gas heat pump and hybrid adoption for existing customers	High electrification of existing residential and commercial load by 2050	Full electrification of existing residential and commercial load by 2050	Moderate gas heat pump and hybrid heating adoption		No gas powered heat pumps and low levels of hybrid heating
Demand-Side	Industrial Use Efficiency		Consultant projection	High sensitivity	Consultant projection		60% Electrified by 2050	90% Electrified by 2050	Consultant projection		
Demand-Side	Building Shell Improvement		Energy Trust projection	Energy Trust high sensitivity projection	Ajusted Energy Trust projection				Energy Trust projection		
Supply-Side Assumptions	Conventional Gas	Expected pricing in each month									
Supply-Side Assumptions	Capacity Resources	All capacity resources available at expected cost									
Supply-Side Assumptions	Renewable Natural Gas	Expected availability and cost		Higher availability and expected cost	Expected availability and cost				High avail and low cost to customers	Low availability and high cost	Expected availability and cost
Supply-Side Assumptions	Hydrogen	20% Energy maximum (blended and dedicated) and expected cost		40% Energy maximum and expected cost	20% Energy maximum and expected cost				30% energy max and low cost to customers	12% energy max and high cost	35% max and expected cost
Supply-Side Assumptions	Synthetic Methane	No energy max and expected cost							No energy max and low cost to customers	No energy max and high cost	No energy max and expected cost
OR- CCIs		Costs and limits defined in CPP rule									
WA- Allowances & Offsets		Higher of social cost of carbon or California allowance projection in each year									

7.3.2 Monte Carlo Simulation Analysis Overview

The second approach for risk analysis uses stochastic Monte Carlo simulation. Monte Carlo simulation is often used synonymously with stochastic simulation. It is a technique to randomly draw a value from a defined distribution. Figure 7.4 provides an example of a Monte Carlo simulation for 500 draws from a normal distribution and a log normal distribution.

Figure 7.4: Monte Carlo Example - 500 Draws



There is no single distribution or simulation process that is used for the inputs listed in Table 7.4. Some simulations are more complex than others. Some simulations must incorporate critical cross-input or cross-time correlations. For example, the gas price simulation must incorporate both correlation across purchasing hubs and correlation across time. If gas prices increase at AECO they are likely to see a similar increase at Sumas. Also, if markets are facing a high gas price environment in 2027, they are likely to face similar conditions in 2028. To account for these two components, the gas price simulation relies on historical data, both at annual and monthly levels to define the distribution for the gas price Monte Carlo.

How some inputs vary is likely not tied to how other uncertain inputs vary, such as the cost of Mist Recall and Portland's weather. However, some inputs are likely to be correlated. For example, construction cost increases are likely to impact all resources that involve construction and temperature in Oregon and Washington are likely to move together. The co-dependence, or correlation across stochastic simulations (a.k.a. draws) is modeled for known or likely correlated inputs.[148]

NW Natural generates 500 draws for uncertain inputs. Independent inputs are randomly matched to a single draw, whereas correlated inputs are simulated together and matched appropriately to the same draw. While more draws will always be preferred to less draws, computational limits start becoming an

[148] The term draw refers to a random "draw" selected from a defined distribution for uncertain inputs, known as a random variable in statistics

issue at this high threshold of draws. Additional computational costs, both money and time, must be balanced with adding incremental simulation runs.[149] The 500-draw threshold was selected as a sufficient number of random pairings of inputs to produce an adequately wide range of resource portfolio outcomes for a risk analysis and still be able to solve a least costs portfolio for each draw.[150]

Due to the uncertainty of the future, we employ Monte Carlo simulations for numerous factors that are inputs into the PLEXOS® model. Table 7.4 lists the key inputs for which we simulate 500 draws. Most inputs, such as the price for hydrogen or daily temperatures in Portland, are dynamic and change throughout the planning horizon. For dynamic inputs, a dynamic path over the planning horizon is simulated for 500 draws.

Table 7.4: Stochastic Variables for Risk Analysis

Stochastic Variables		
Demand Drivers	**Supply Costs and Prices**	**Capacity Resource Costs**
- Weather Daily Temperatures By Load Center: *Albany, Astoria, Coos Bay, The Dalles, Eugene, Lincoln City, Portland, Salem, Vancouver* - Customer Growth Rates - Growth Moratorium Start Dates - Customer Losses - Gas Heat Pump Penetration - Hybrid Heating Penetration - Building Shell Improvements - Industrial Energy Efficiency	- Price of Conventional Natural Gas By hub: *AECO, Opal, Sumas West Coast Station 2* - Price of RNG Tranche 1 - Price of RNG Tranche 2 - Price Path of Hydrogen - Cost Adder and Path for Methanation - Allowance Prices - Offset Prices **Supply Availability** - Max Allowable Hydrogen Blend - Max Annual Quantity of RNG Tranche 1 - Max Annual Quantity of RNG Tranche 2	- Mist Recall - Newport Takeaway 1 - Newport Takeaway 2 - Newport Takeaway 3 - Upstream Pipeline Expansion - Mist Expansion - Portland LNG Alternative Portland LNG - Cold Box Middle Corridor Mist Takeaway Williams NWP Enhancement

7.4 Scenario Results

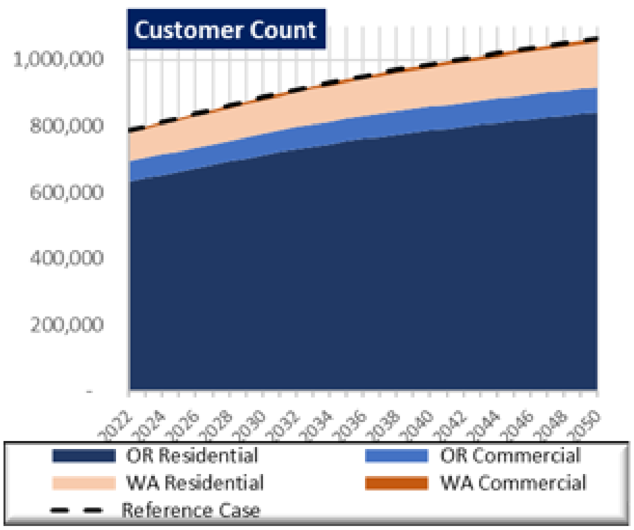
The results of the scenarios discussed throughout the IRP are provided in the following subsections. The key input assumptions and key results of each scenario are compiled as a standalone "booklet" to be able to see how all the key parts fold into the results. The results of the scenarios can then be compared against one another. Each scenario requires compliance with the Oregon Climate Protection Program and the Washington Cap-and-Invest program.

[149] To complete the risk analysis, NW Natural subscribed to 160 computer cores for a 2-month period. Even with this access to additional computer cores the model takes roughly 5 days to complete all 500 draws and significantly more time to troubleshoot and QC the model.

[150] One of the benefits of moving to PLEXOS® is the ability to optimize the resource selection for each individual draw. Due to the limitations of the previous software, prior IRPs ran Monte Carlo simulation of only costs and demand for a fixed resource portfolio. PLEXOS® has the flexibility to input simulations for any key assumption, forecast or constraint and will optimize resource selection for that specific draw. PLEXOS® still has the capability to analyze how a fixed resource portfolio with perform across varying inputs, forecasts, or constraints.

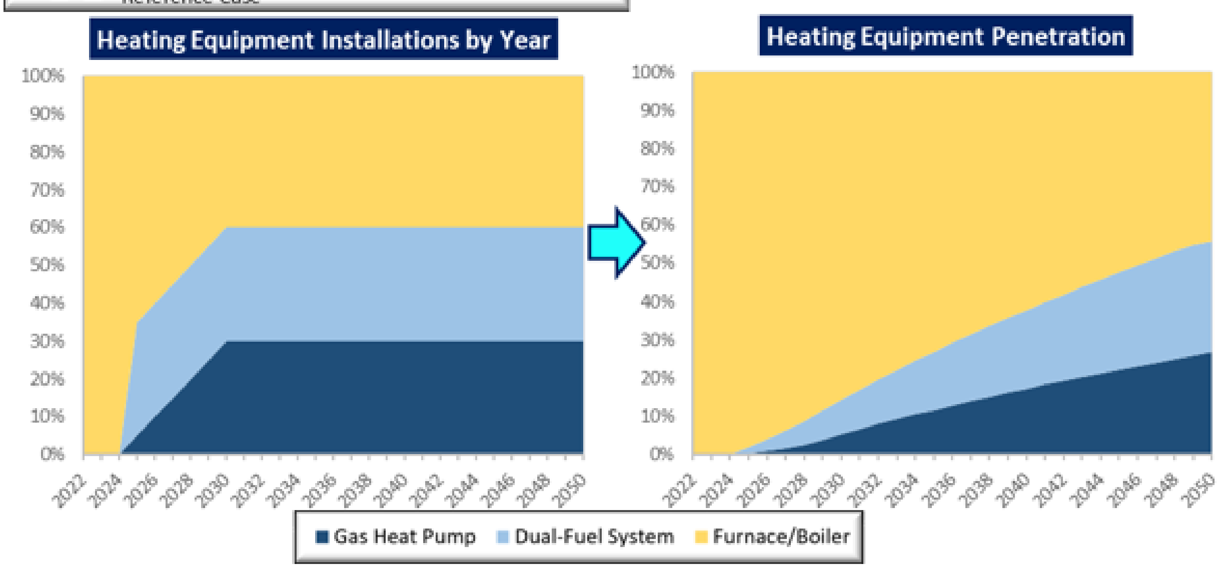
Scenario 1 – Balanced Decarbonization

Scenario 1 represents what NW Natural considers to be a balanced approach to meeting the emissions compliance obligation of Oregon's Climate Protection Program (CPP) and Washington's Cap-and-Invest program. Customer growth is based upon historical trends. It uses the energy efficiency forecasts provided by Energy Trust of Oregon for sales customers and AEG for transport customers. It also deploys a moderate amount of both natural gas heat pump technology for space and water heating and dual-fuel heating systems (electric heat pump with natural gas supplemental/backup heat). It uses our best estimate of the availability and cost of biofuel RNG and a conservative estimate of the amount of renewable hydrogen that is either blended into our system or deployed in pure hydrogen to some customers (20% of deliveries in energy terms). Key assumptions in the other scenarios are varied to be able to compare against Scenario 1.

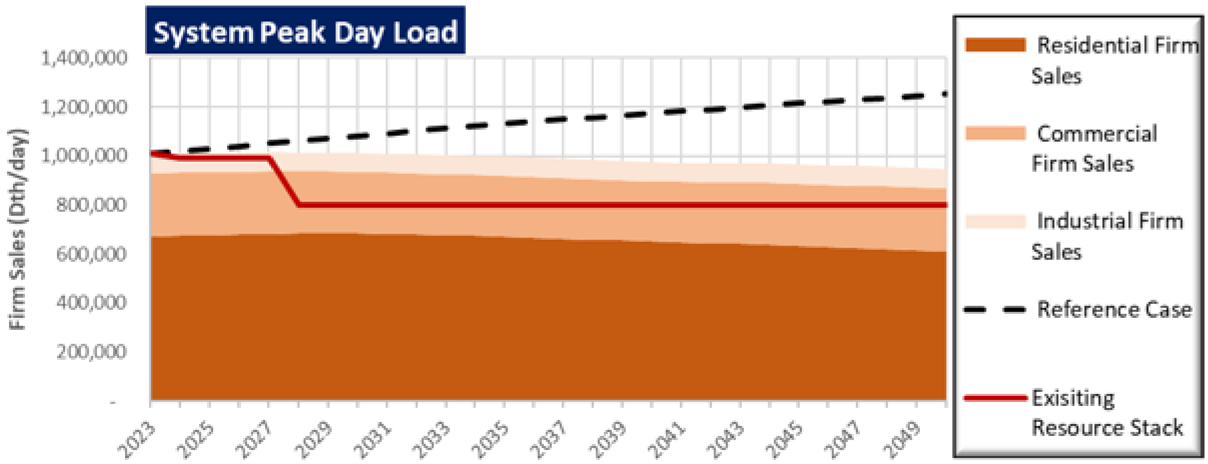


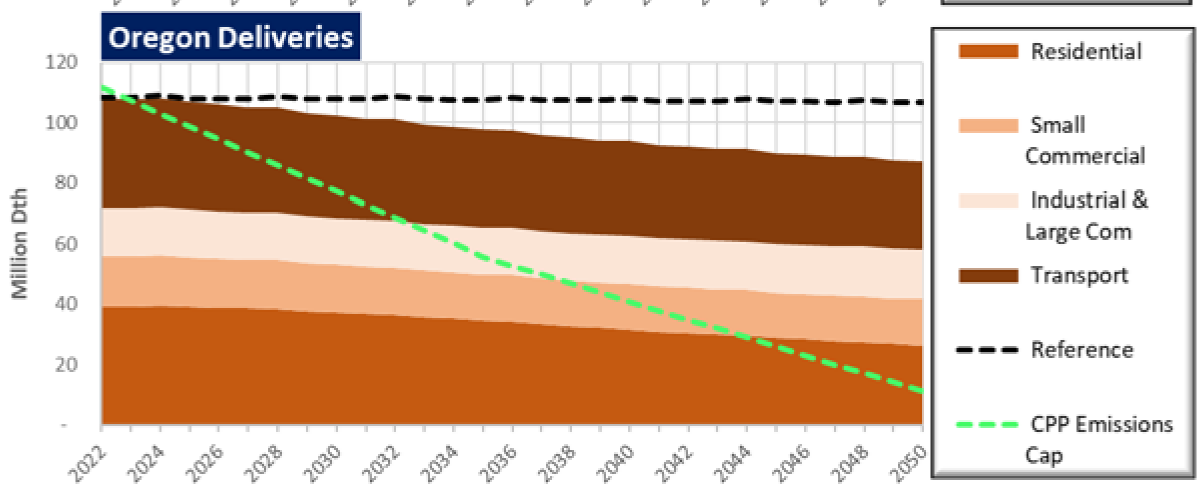
Demand-Side Assumptions

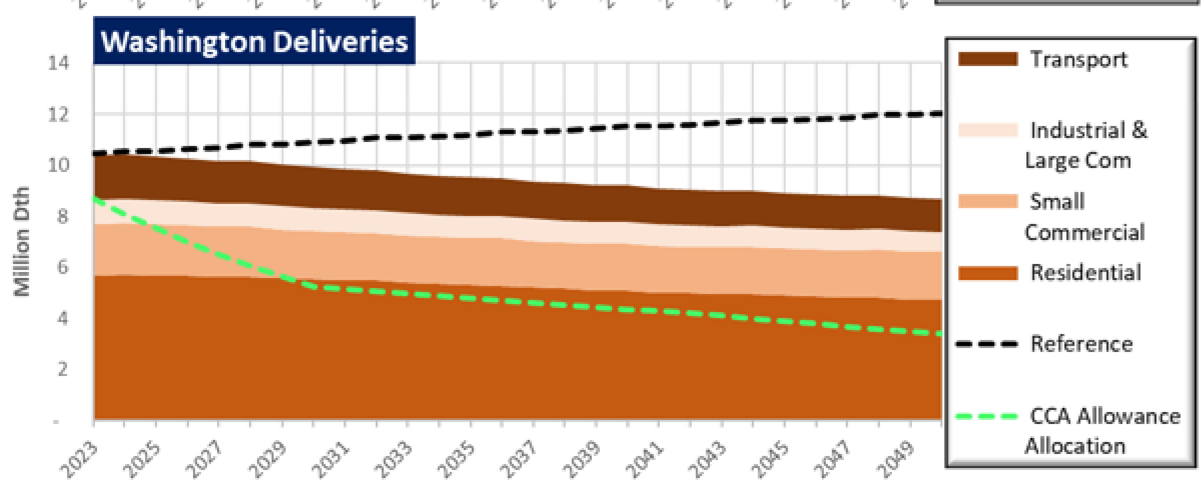
Sales Customer Energy Efficiency	Energy Trust of Oregon projection of savings, at $5.06/therm of first year savings
Transport Customer Energy Efficiency	Applied Energy Group projection of savings at $1.79/therm of first year savings
Gas Heat Pump Cost	$4,000 total cost to utility for a residential heating system, $13,000 for a Commercial heating System; $1600 for residential water heater
Dual-Fuel System Costs	Net cost of $400 to utility



Scenario 1 – Balanced Decarbonization







Scenario 1 – Balanced Decarbonization

Capacity Resource Options

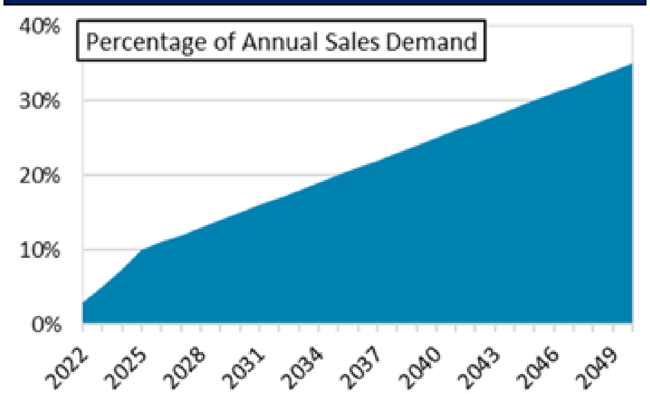
Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	Max: 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800

Compliance Resource Options

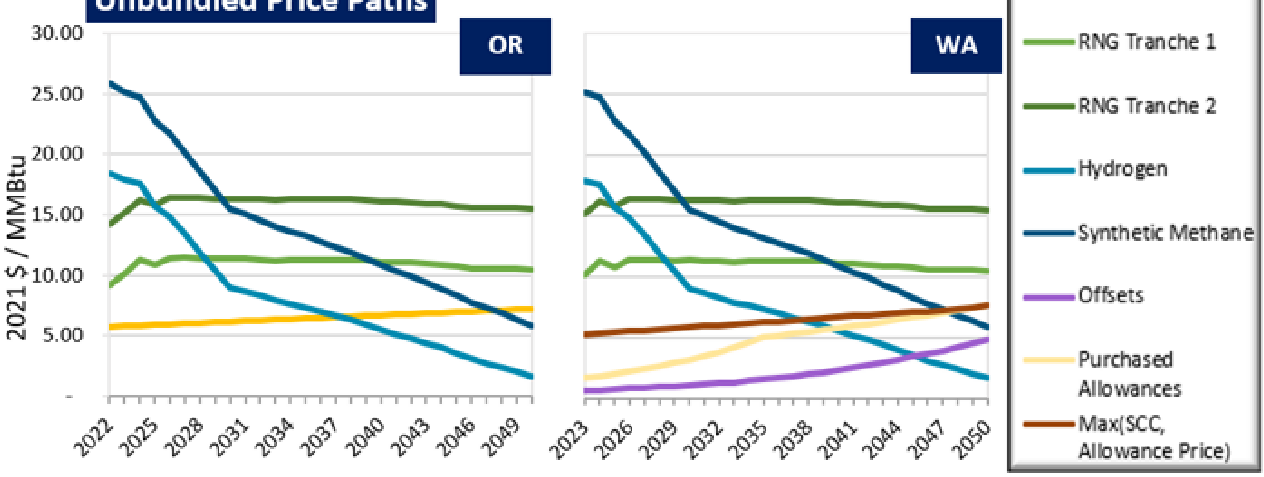
Quantity Available

Option	Limit
RNG Tranche 1	13,000,000 Dth / year
RNG Tranche 2	27,000,000 Dth / year
Hydrogen	20% of Deliveries by Energy
Synthetic Methane	Unbounded
CCIs	OR Compliance Period 1: 10% OR Compliance Period 2: 15% OR Compliance Period >=3: 20%
Allowances	Unbounded
Offsets	WA Compliance Period 1: 6% WA Compliance Period >=2: 8%

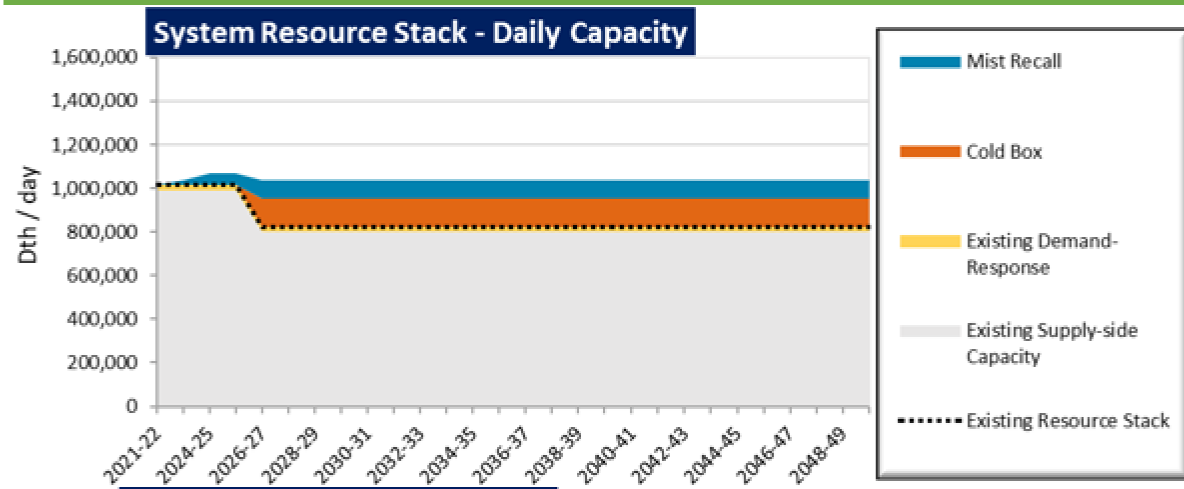
OR SB 98 / WA HB 1257 RNG Targets

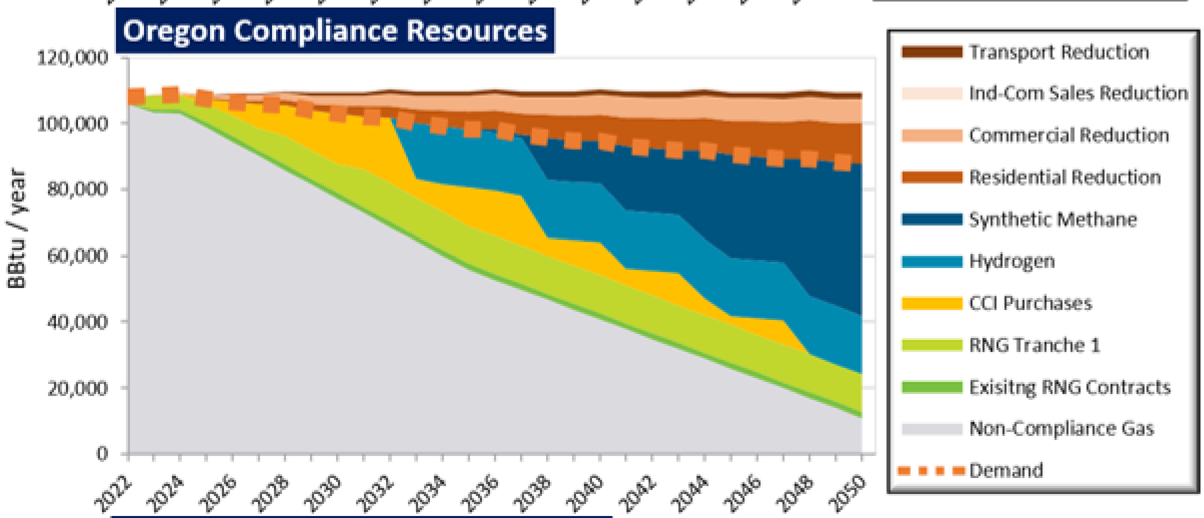


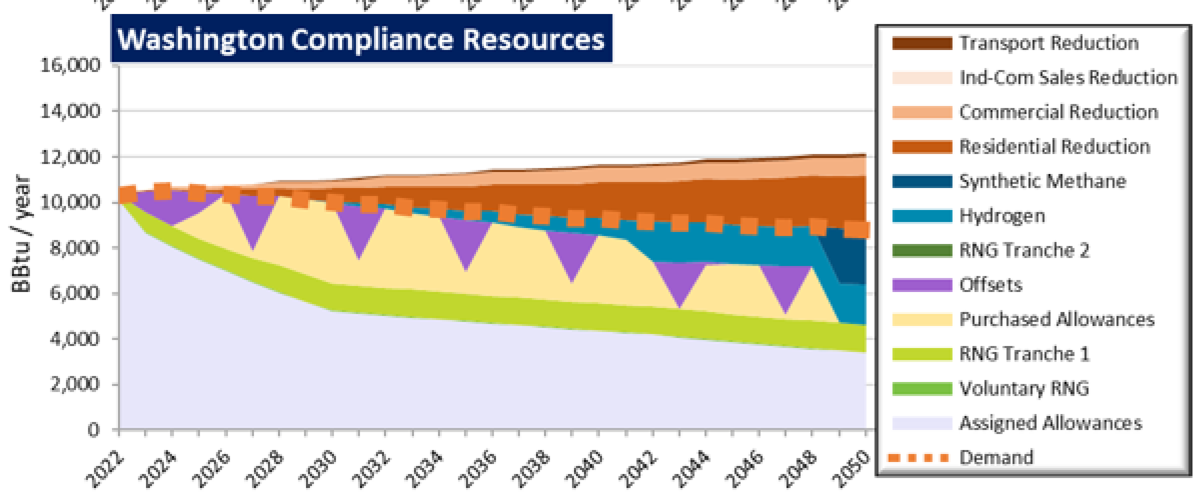
Unbundled Price Paths

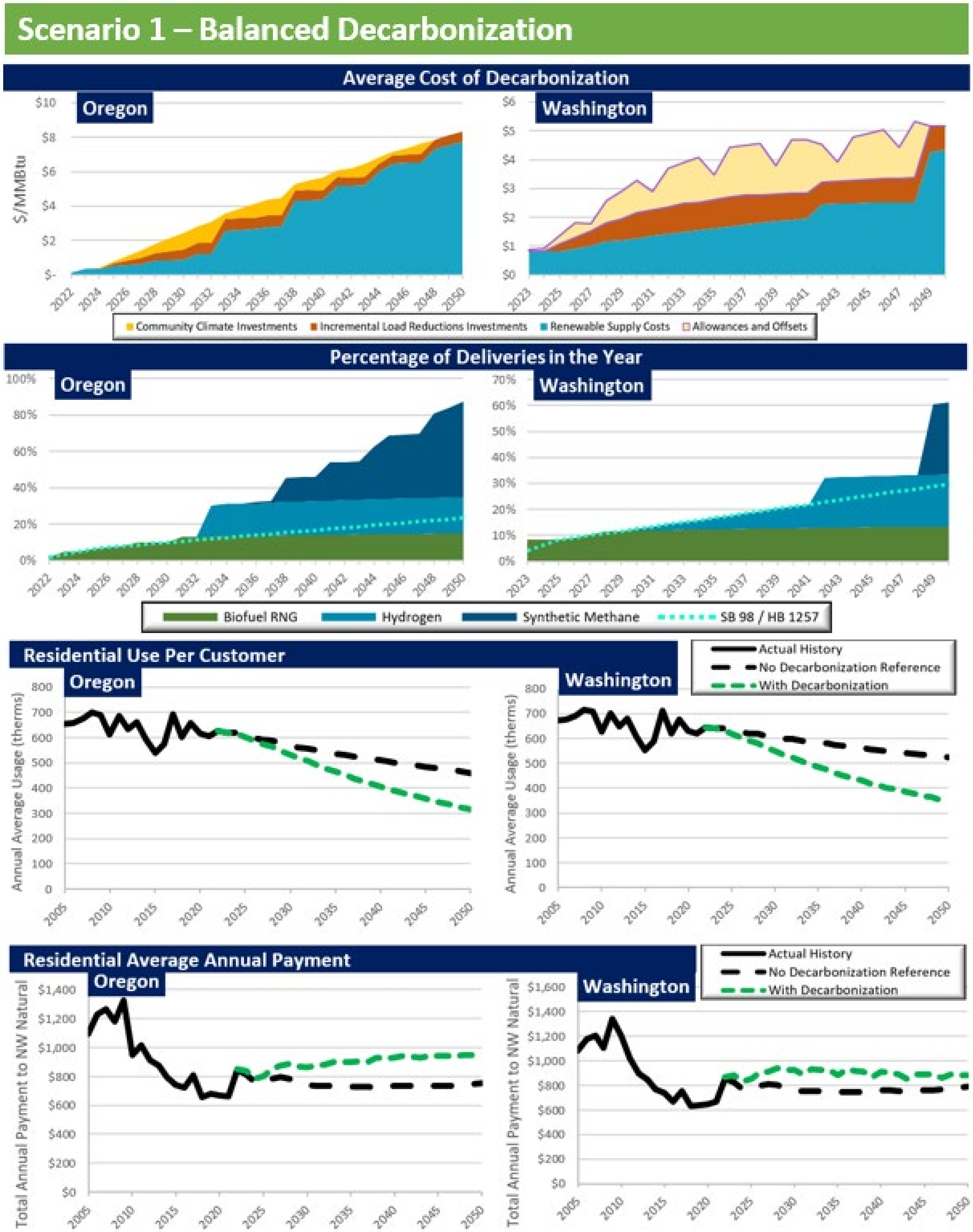


Scenario 1 – Balanced Decarbonization








Scenario 1 – Balanced Decarbonization
Average Cost of Decarbonization
Oregon
Washington
$/MMBtu
Community Climate Investments
Incremental Load Reductions Investments
Renewable Supply Costs
Allowances and Offsets
Percentage of Deliveries in the Year
Oregon
Washington
Biofuel RNG
Hydrogen
Synthetic Methane
SB 98 / HB 1257
Residential Use Per Customer
Oregon
Washington
Annual Average Usage (therms)
Actual History
No Decarbonization Reference
With Decarbonization
Residential Average Annual Payment
Oregon
Washington
Total Annual Payment to NW Natural
Actual History
No Decarbonization Reference
With Decarbonization

Scenario 1 – Balanced Decarbonization

Capacity Takeaways

- Replacing Portland LNG Cold Box shown as least cost solution
- Additional capacity needs served by Mist Recall, with a total recall of 85,000 Dth with the last recall occurring in 2027

Oregon Emissions Takeaways

- Meeting RNG targets for SB 98 represents most of the needed emissions reduction for the first compliance period of the Climate Protection Program; small amounts of Community Climate Investments (CCIs) may be purchased to meet additional requirements depending on weather and other conditions
- Biofuel RNG and CCIs represent the marginal compliance activity in the near- to medium-term, transitioning to renewable hydrogen for blending or dedicated delivery starting in 2032, and then transitioning to synthetic renewable natural gas in 2038
- Renewable supply represents roughly 90% of deliveries in 2050, which is equivalent to roughly ¾ of current gas deliveries in Oregon. Biofuel RNG deliveries represent roughly 10% of current load in 2050
- Decarbonization action to comply with SB 98 and the CPP results in residential gas utility bills being 17% higher in 2030 and 26% higher in 2050 than in a world without these policies

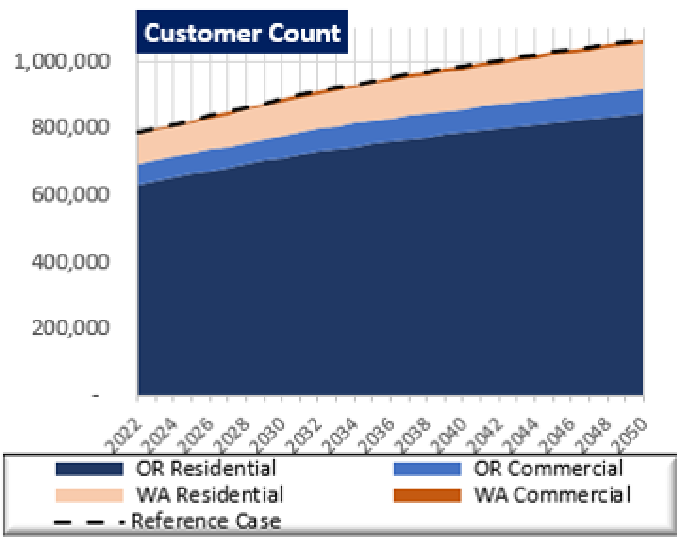
Washington Emissions Takeaways

- Delivering RNG for HB 1257 and utilizing offsets represents the bulk of net near term compliance with Cap-and-Invest, with allowance purchasing filling in any gaps
- Renewable supply represents roughly 60% of deliveries in 2050
- Complying with HB 1257 and Cap-and-Invest results in residential gas utility bills being 22% higher in 2030 and 12% higher in 2050 than in a world without these policies

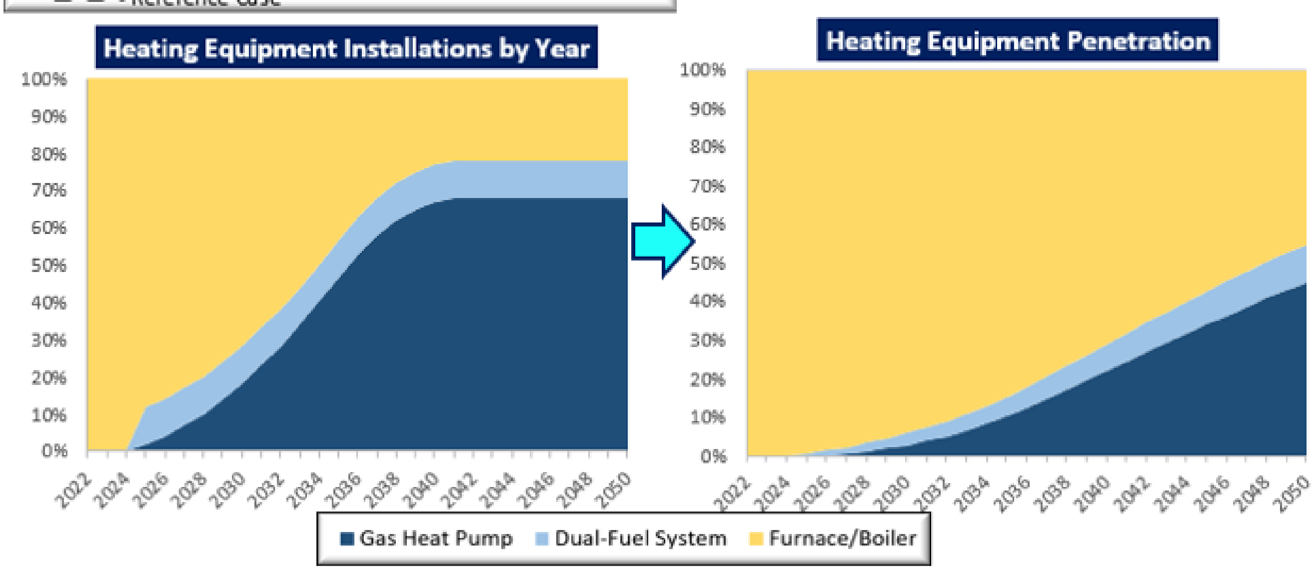
NW Natural®

Scenario 2 – Carbon Neutral

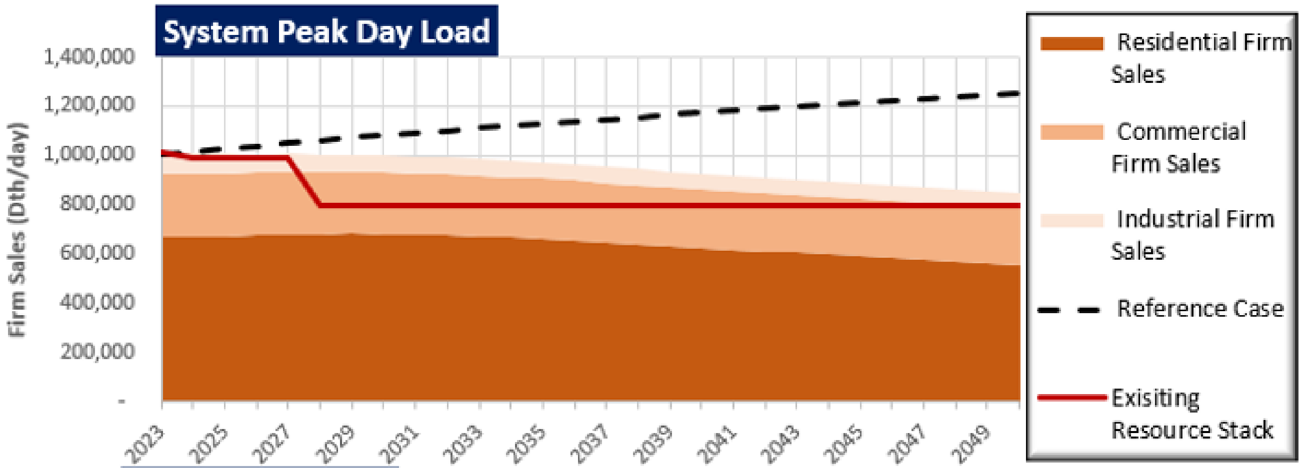
Scenario 2 is the scenario meant to help answer the question "What if NW Natural reduced emissions faster and further than is required by the OR CPP and WA CCA programs?" As such, it is the only scenario that does not use NW Natural's emissions cap in Oregon's CPP program or expected activity to comply with Washington's Cap-and-Invest program as the constraint for emissions. It deploys a requirement that NW Natural's emissions are zero in 2050 without the use of offsets or compliance instruments (like CCIs in OR or emissions allowances in WA). It assumes customer growth based upon historical trends. In order to meet this more aggressive emissions target it deploys a more aggressive deployment of existing Energy Trust EE programs and expected transport schedule EE programs than Scenario 1. It also assumes a more aggressive penetration of natural gas heat pump technology for space and water heating. While the cost and availability of the modeled renewable supply options is the same as Scenario 1 it allows for more pure hydrogen to be blended or dedicated to some customers.

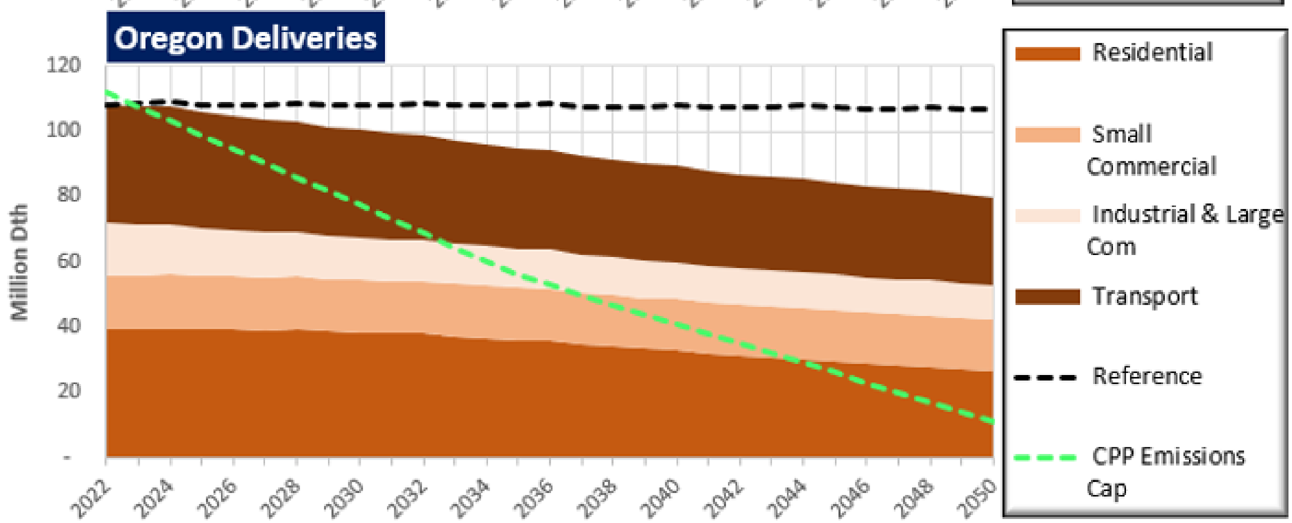


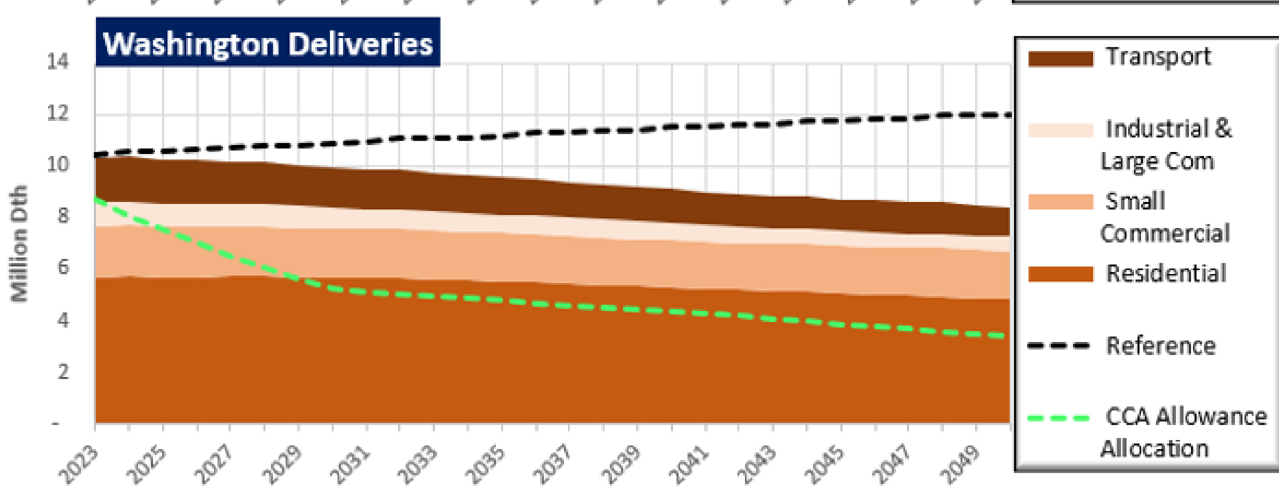
Demand-Side Assumptions	
Sales Customer Energy Efficiency	15% more than ETO projection at $5.06/therm of first year savings
Transport Customer Energy Efficiency	30% more than Applied Energy Group projection of savings at $1.79/therm of first year savings
Gas Heat Pump Cost	$4,000 total cost to utility for a residential heating system, $13,000 for a Commercial heating System; $1,600 for residential water heater
Dual-Fuel System Costs	Net cost of $400 to utility



Scenario 2 – Carbon Neutral







Scenario 2 – Carbon Neutral

Capacity Resource Options

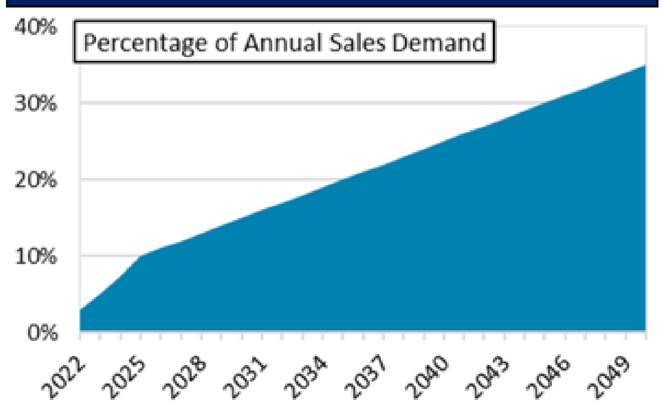
Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	Max: 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800

Compliance Resource Options

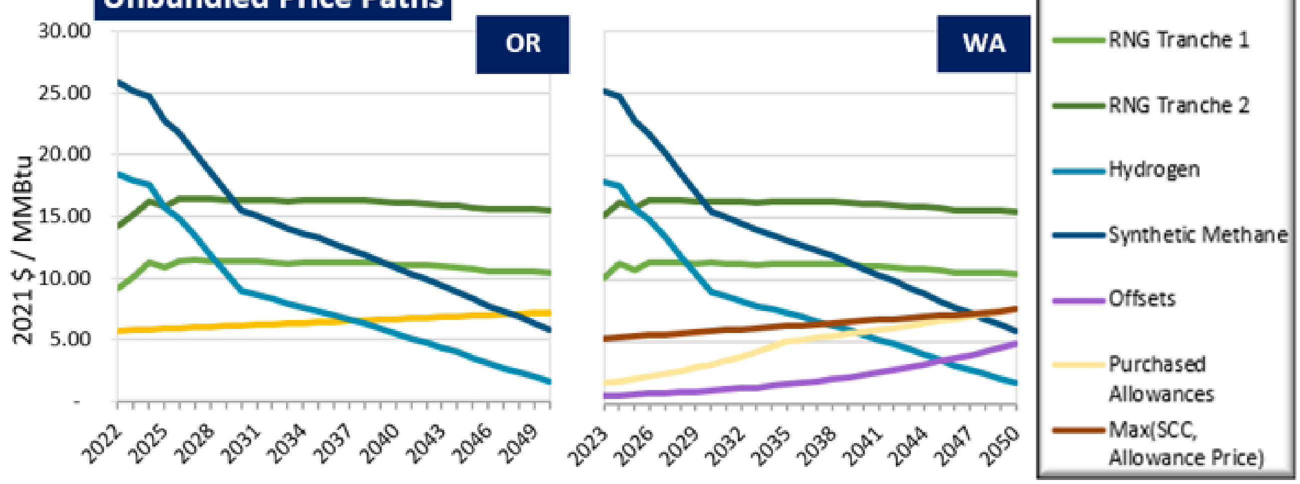
Quantity Available

Option	Limit
RNG Tranche 1	15,000,000 Dth / year
RNG Tranche 2	35,000,000 Dth / year
Hydrogen	40% of Deliveries by Energy
Synthetic Methane	Unbounded
CCIs	OR Compliance Period 1: 10% OR Compliance Period 2: 15% OR Compliance Period >=3: 20%
Allowances	Unbounded
Offsets	WA Compliance Period 1: 6% WA Compliance Period >=2: 8%

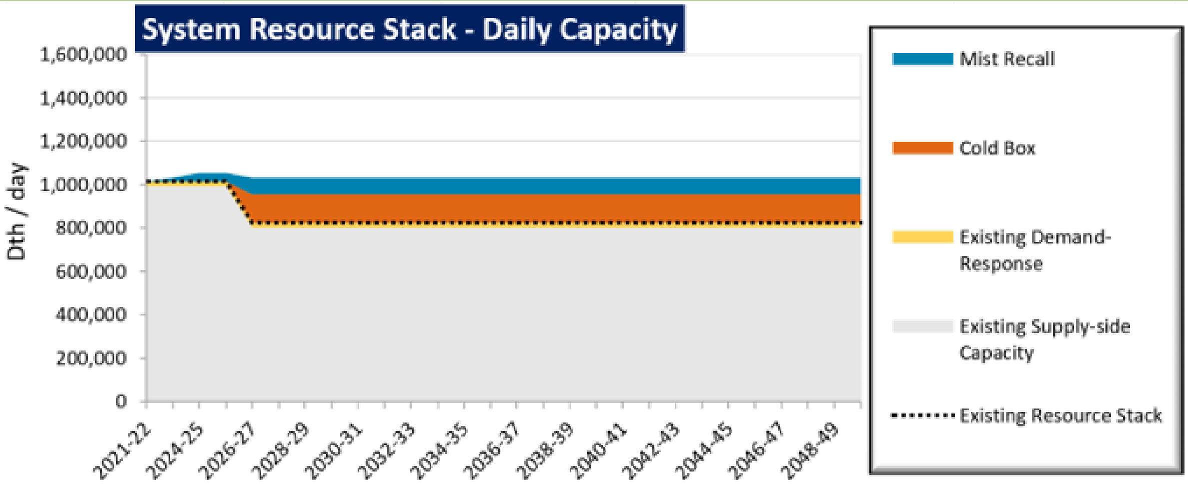
OR SB 98 / WA HB 1257 RNG Targets

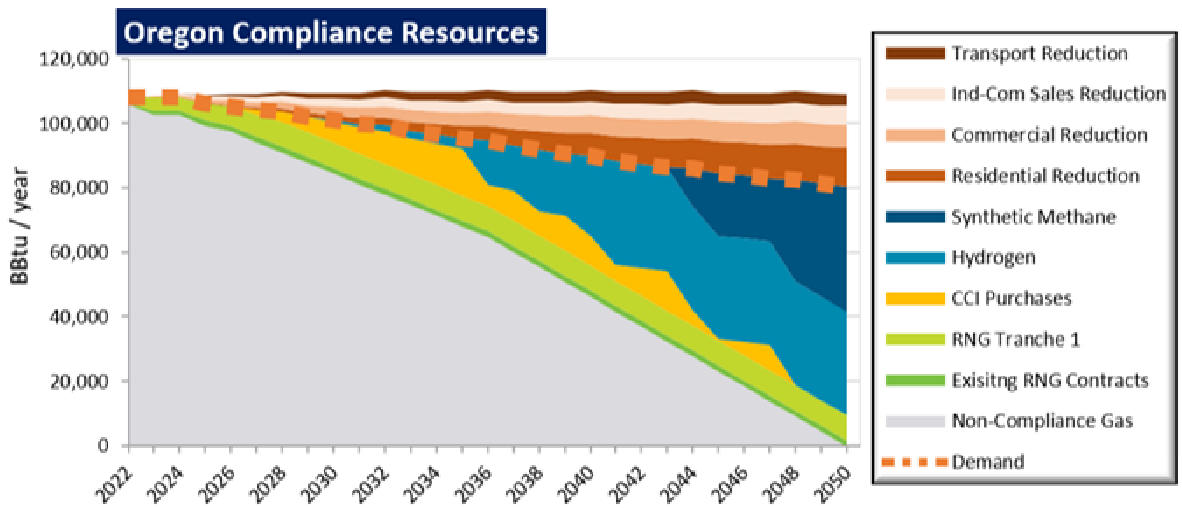


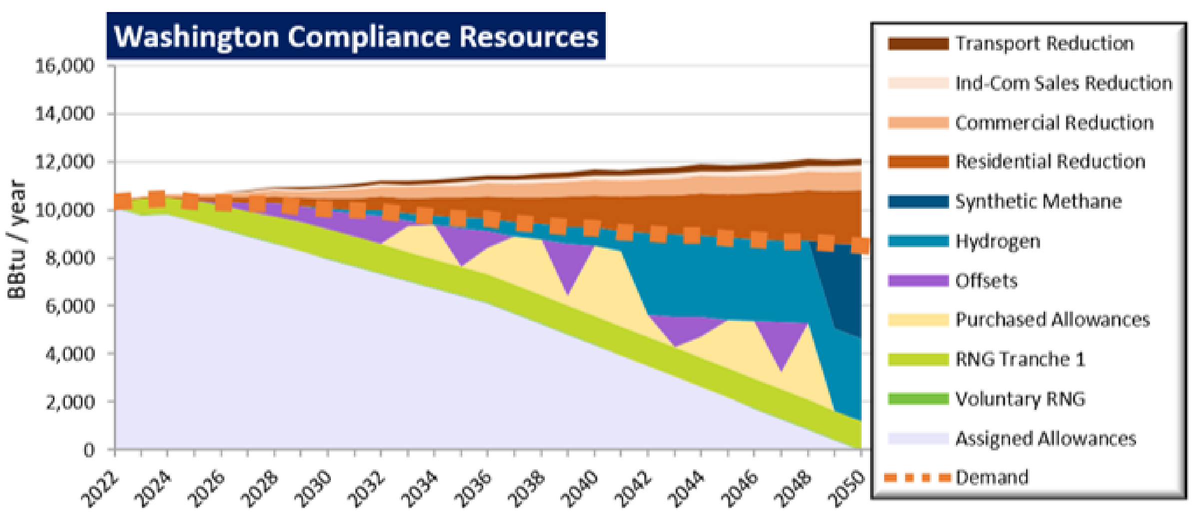
Unbundled Price Paths



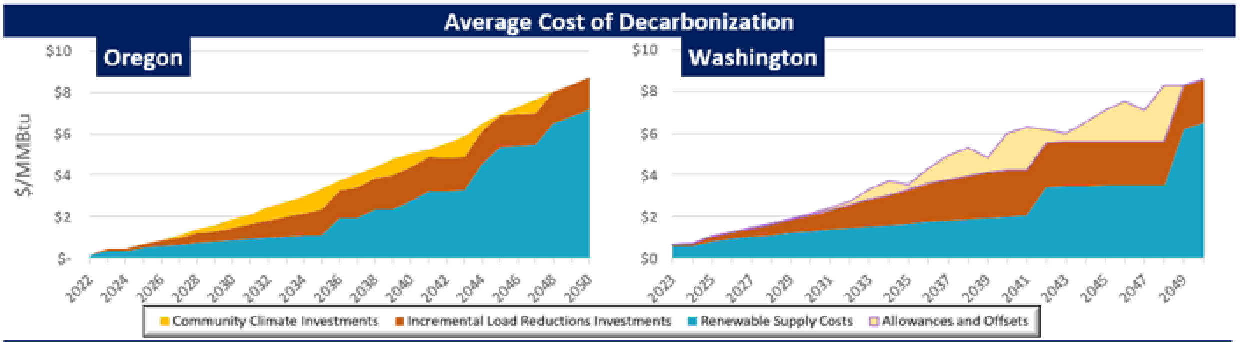
Scenario 2 – Carbon Neutral

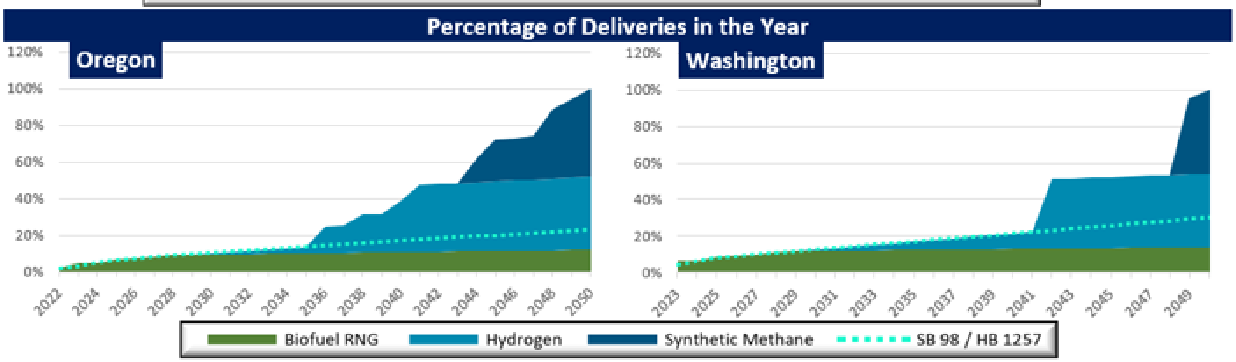


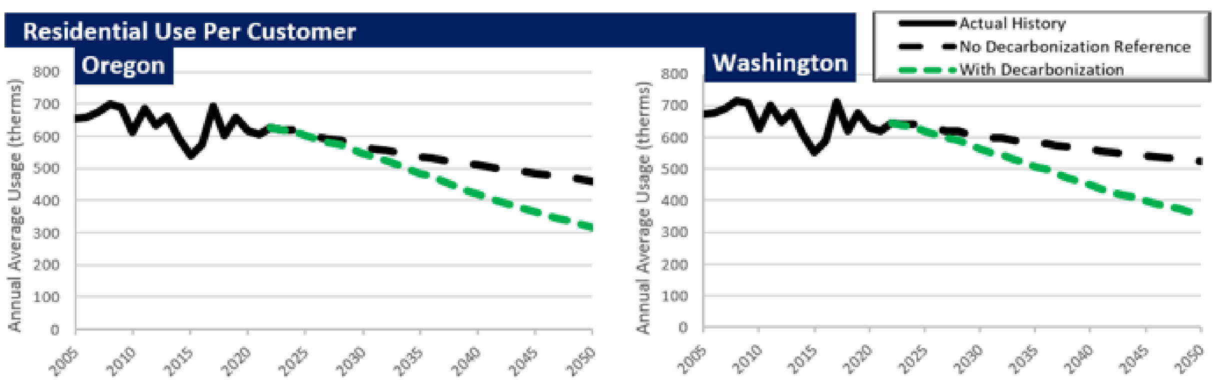


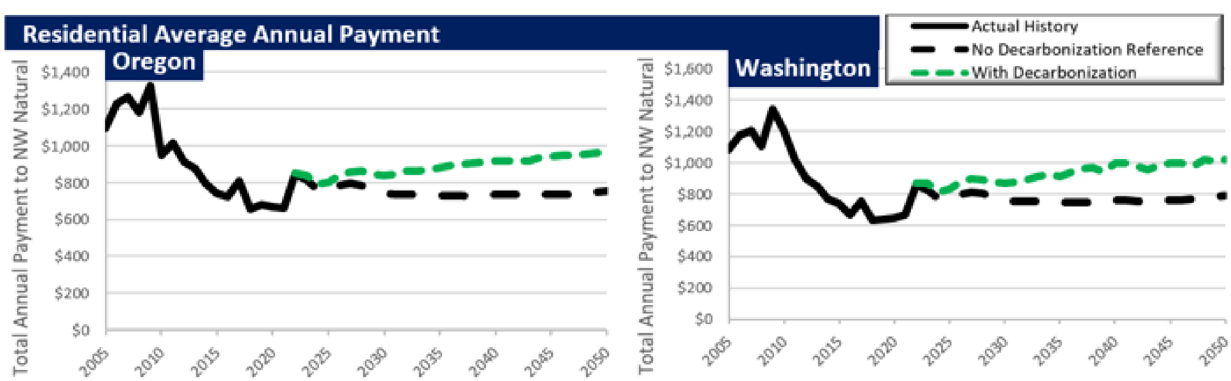


Scenario 2 – Carbon Neutral









Scenario 2 – Carbon Neutral

Capacity Takeaways

- Replacing Portland LNG Cold Box shown as least cost solution
- Additional capacity needs served by Mist Recall, with a total recall of 80,000 Dth with the last recall occurring in 2027

Oregon Emissions Takeaways

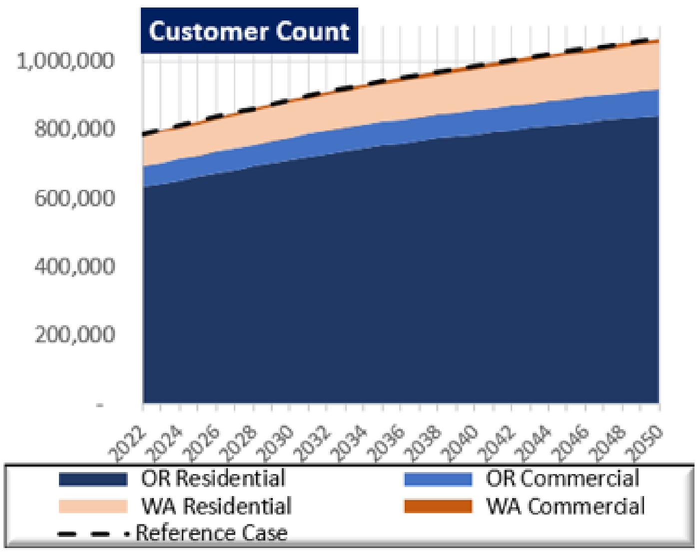
- Meeting RNG targets for SB 98 represents most of the needed emissions reduction for the first compliance period of the Climate Protection Program; small amounts of Community Climate Investments (CCIs) may be purchased to meet additional requirements depending on weather and other conditions
- Biofuel RNG and CCIs represent the marginal compliance activity in the near- to medium-term, transitioning to renewable hydrogen for blending or dedicated delivery starting in 2033, and then transitioning to synthetic renewable natural gas in 2036
- Renewable supply represents 100% of deliveries in 2050, which is equivalent to roughly ¾ of current gas deliveries in Oregon. Biofuel RNG deliveries represent roughly 10% of current load in 2050
- Decarbonization action to comply with SB 98 and the CPP results in residential gas utility bills being 13% higher in 2030 and 28% higher in 2050 than in a world without these policies

Washington Emissions Takeaways

- Delivering RNG for HB 1257 and utilizing offsets represents the bulk of net near term compliance with Cap-and-Invest, with allowance purchasing filling in any gaps
- Renewable supply represents roughly 100% of deliveries in 2050
- Complying with HB 1257 and Cap-and-Invest results in residential gas utility bills being 15% higher in 2030 and 29% higher in 2050 than in a world without these policies

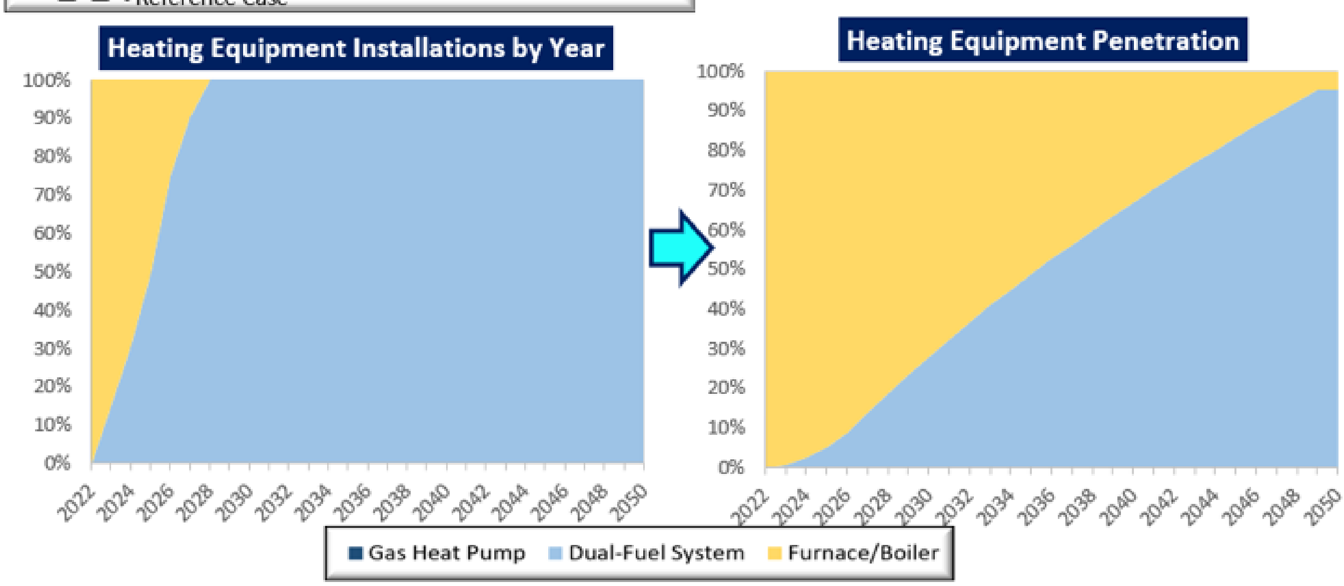
Scenario 3 – Dual-Fuel Heating

Scenario 3 helps to answer the question "What could it mean for gas utility customers if dual-fuel heating (an electric heat pump supplemented by a gas furnace during cold events) becomes the primary equipment to meet heating need in NW Natural's service territory?" It utilizes the same customer growth and supply-side assumptions as Scenario 1, but assumes that by 2028 all heating equipment installations (replacement of existing equipment reaching the end of its life as well as installations in newly constructed buildings) that would be natural gas heating in the reference case become dual-fuel systems, such that by 2050 dual-fuel heating systems predominate in NW Natural's service territory.

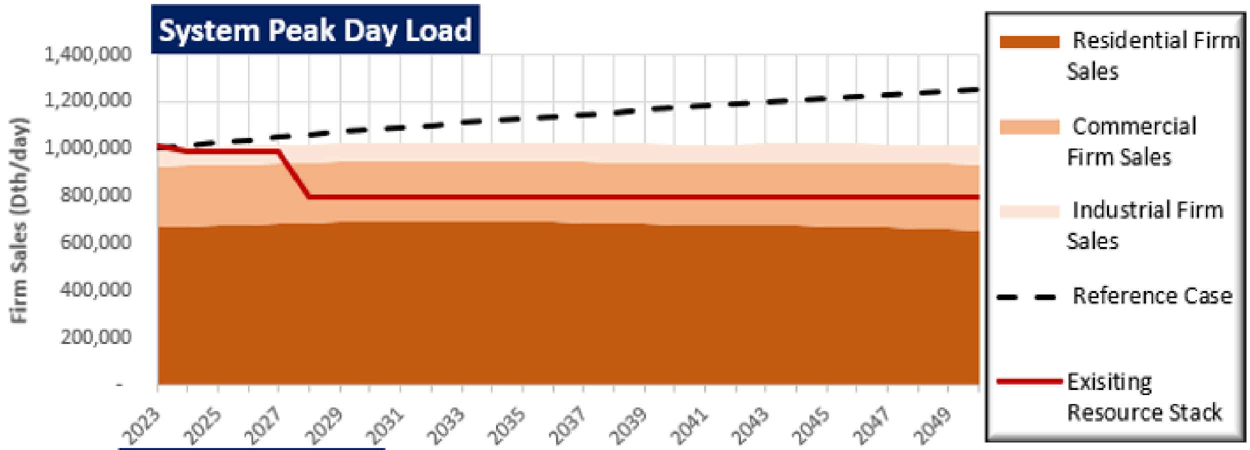


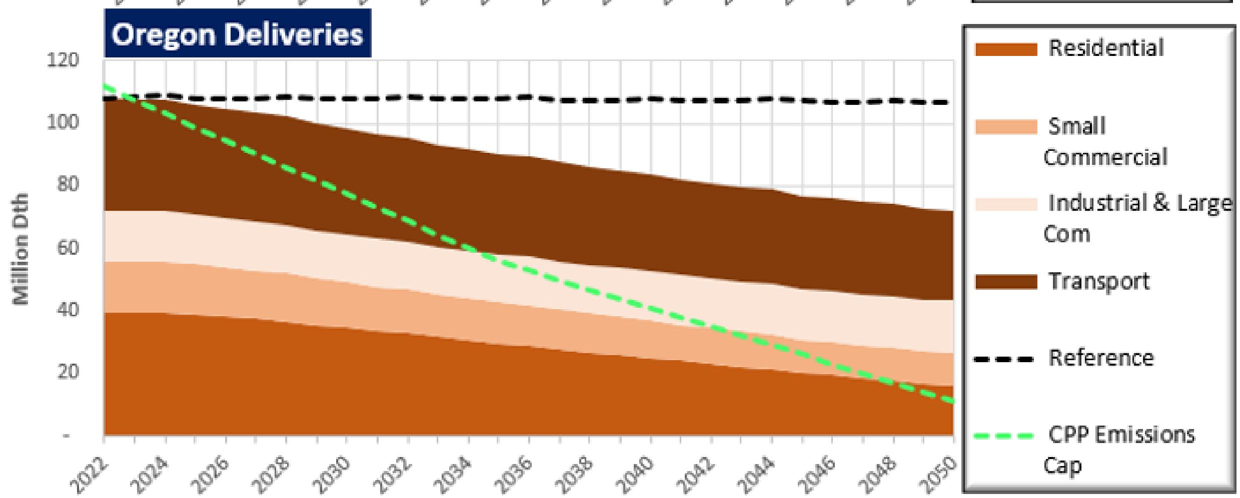
Demand-Side Assumptions

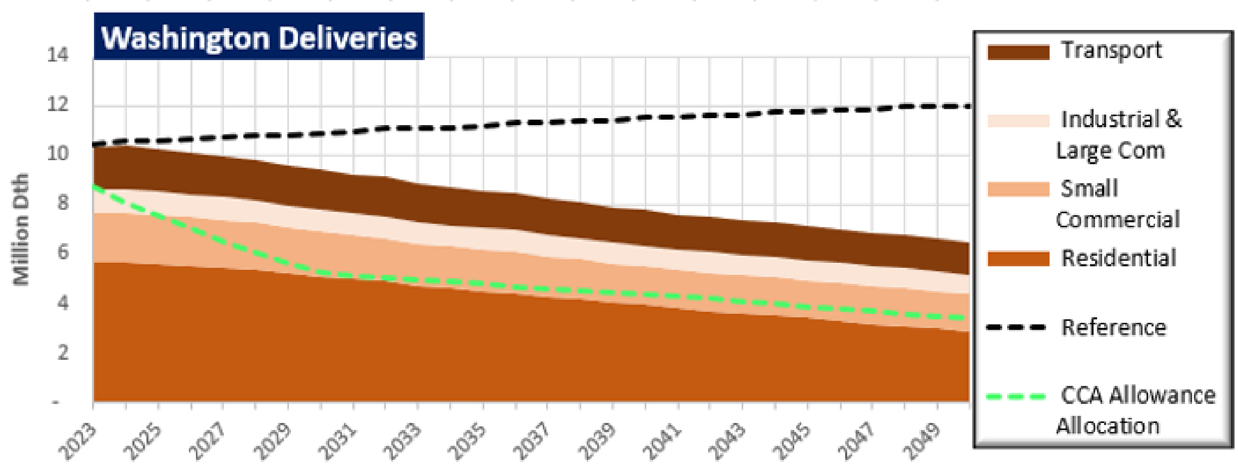
Sales Customer Energy Efficiency	Energy Trust of Oregon projection of savings, at $5.06/therm of first year savings
Transport Customer Energy Efficiency	Applied Energy Group projection of savings at $1.79/therm of first year savings
Gas Heat Pump Cost	$4,000 total cost to utility for a residential heating system, $13,000 for a Commercial heating System; $1,600 for residential water heater
Dual-Fuel System Costs	Net cost of $400 to utility



Scenario 3 – Dual-Fuel Heating







Scenario 3 – Dual-Fuel Heating

Capacity Resource Options

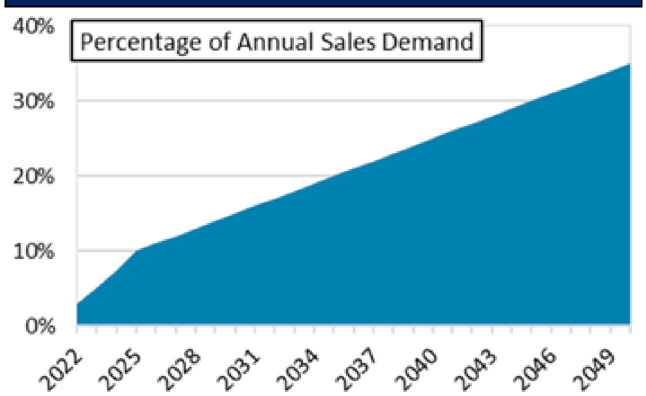
Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	Max: 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800

Compliance Resource Options

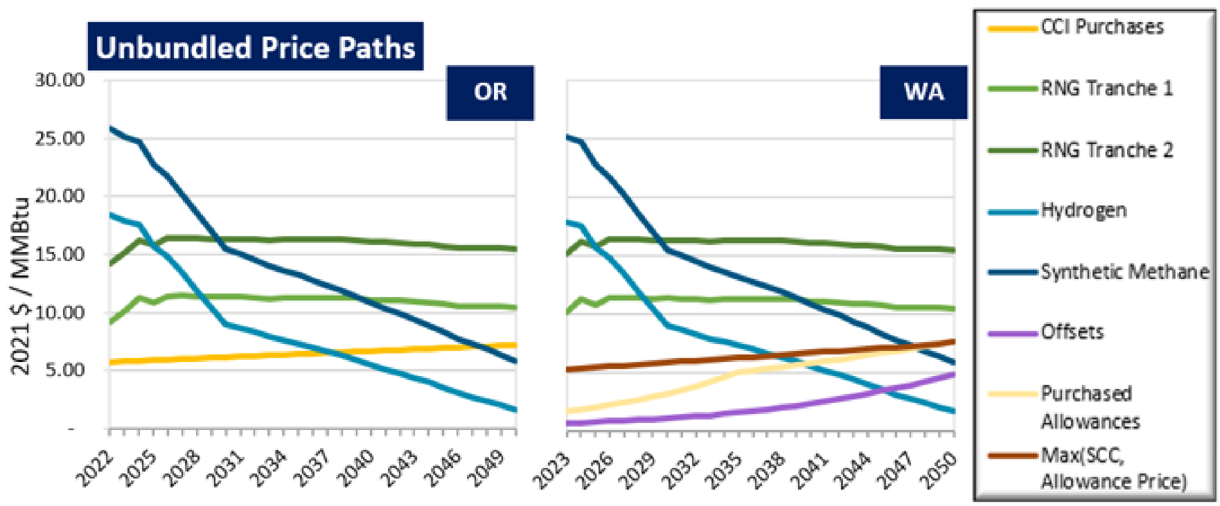
Quantity Available

Option	Limit
RNG Tranche 1	13,000,000 Dth / year
RNG Tranche 2	27,000,000 Dth / year
Hydrogen	20% of Deliveries by Energy
Synthetic Methane	Unbounded
CCIs	OR Compliance Period 1: 10% OR Compliance Period 2: 15% OR Compliance Period >=3: 20%
Allowances	Unbounded
Offsets	WA Compliance Period 1: 6% WA Compliance Period >=2: 8%

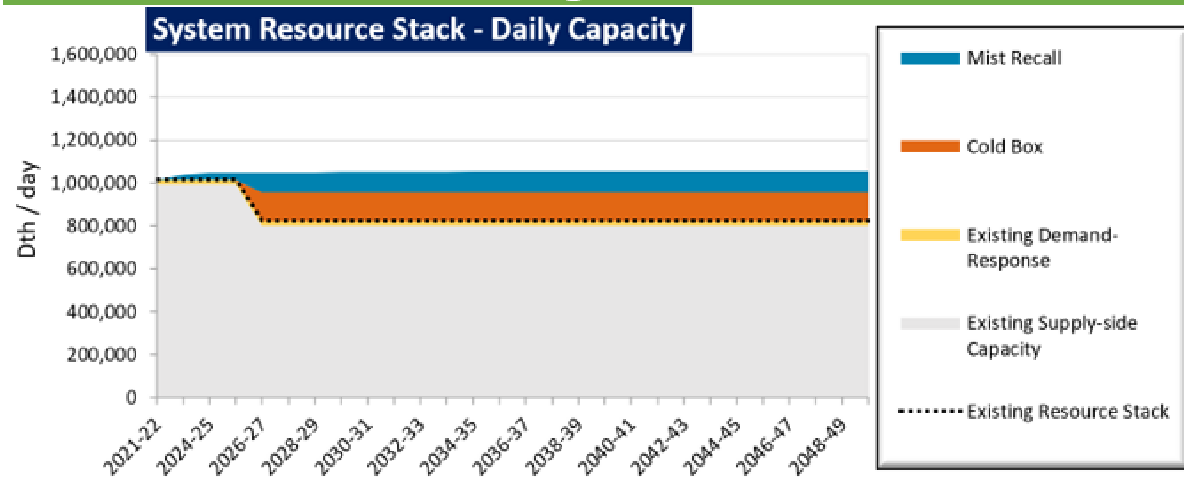
OR SB 98 / WA HB 1257 RNG Targets

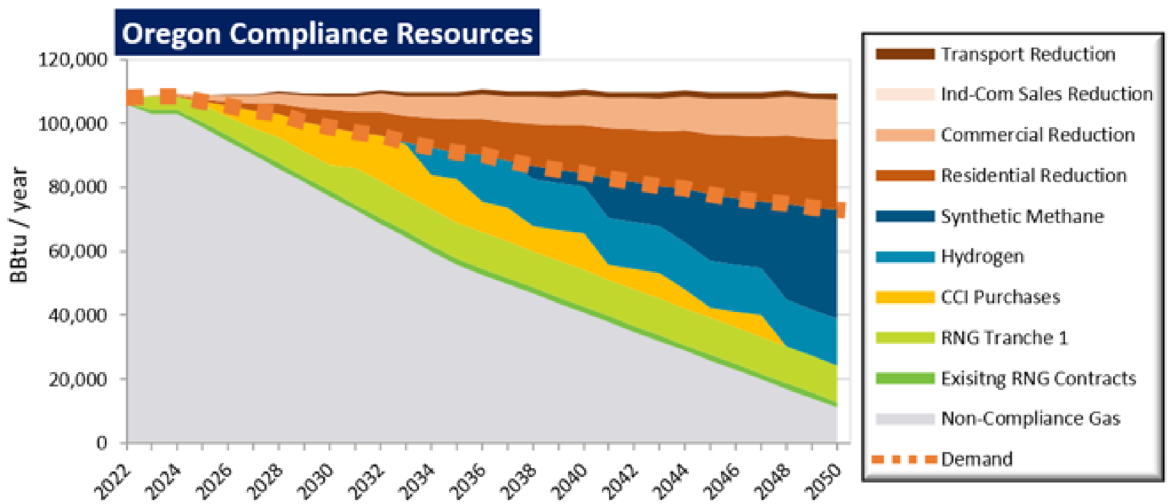


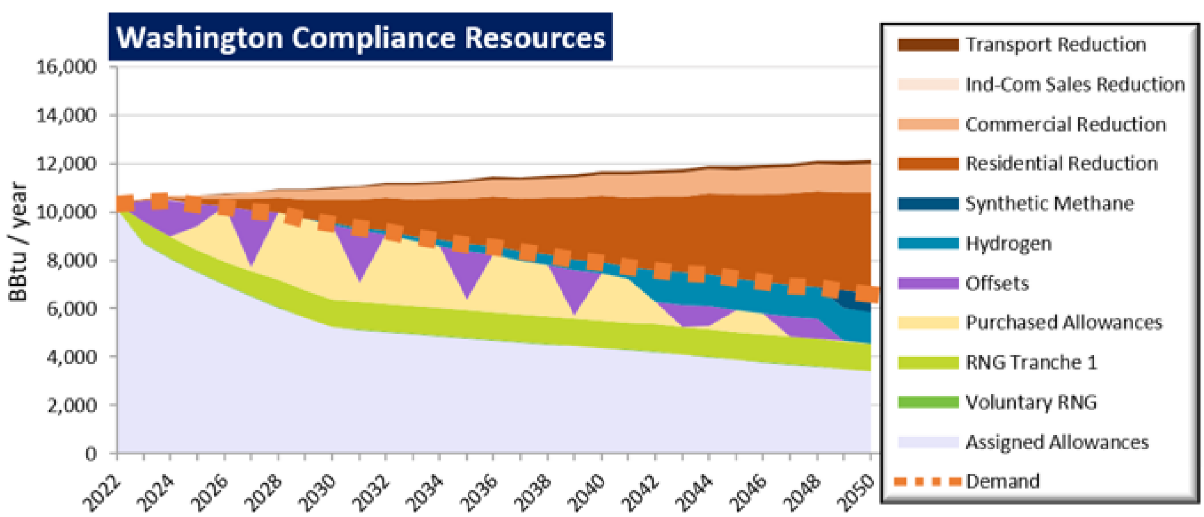
Unbundled Price Paths



Scenario 3 – Dual-Fuel Heating

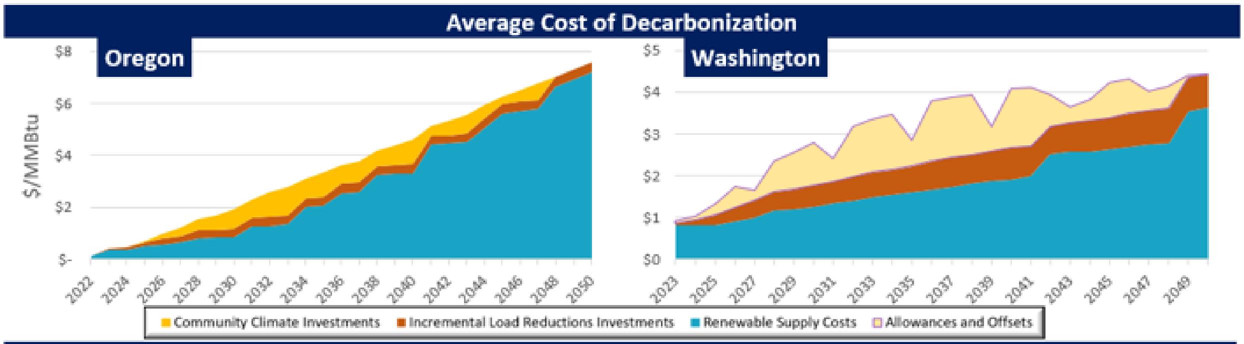


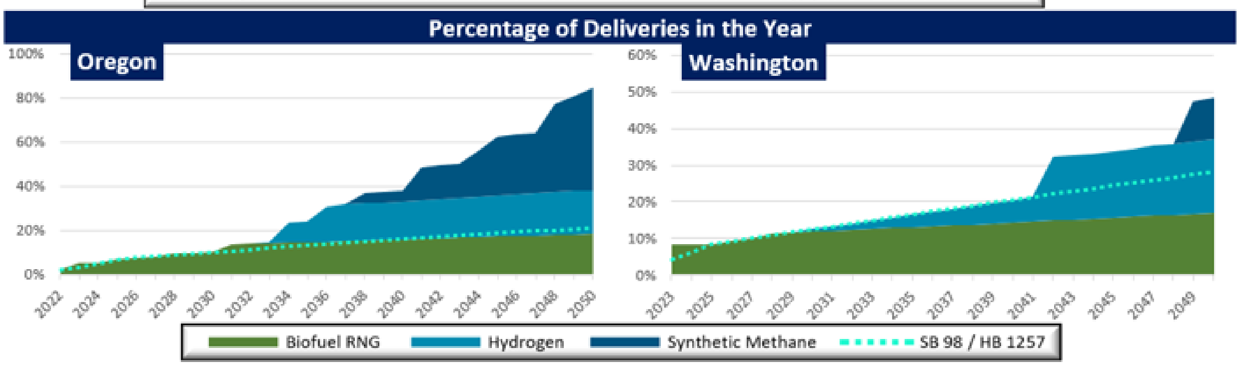


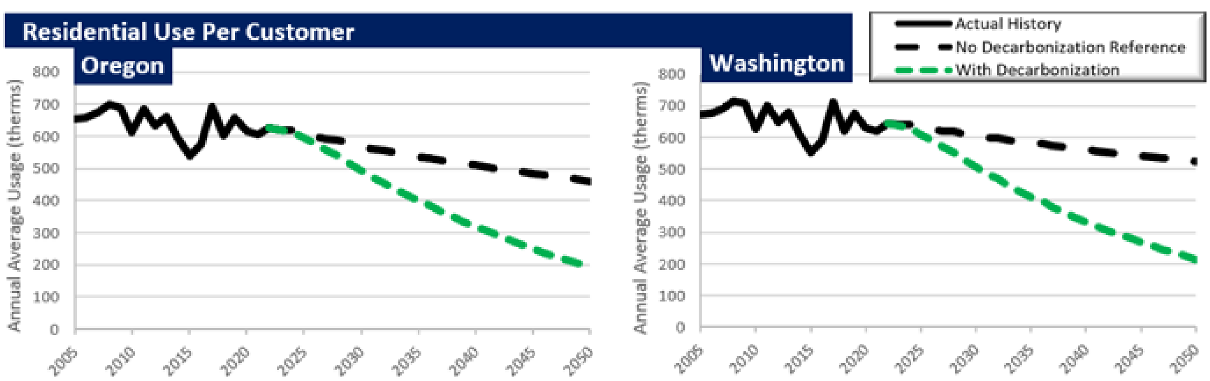


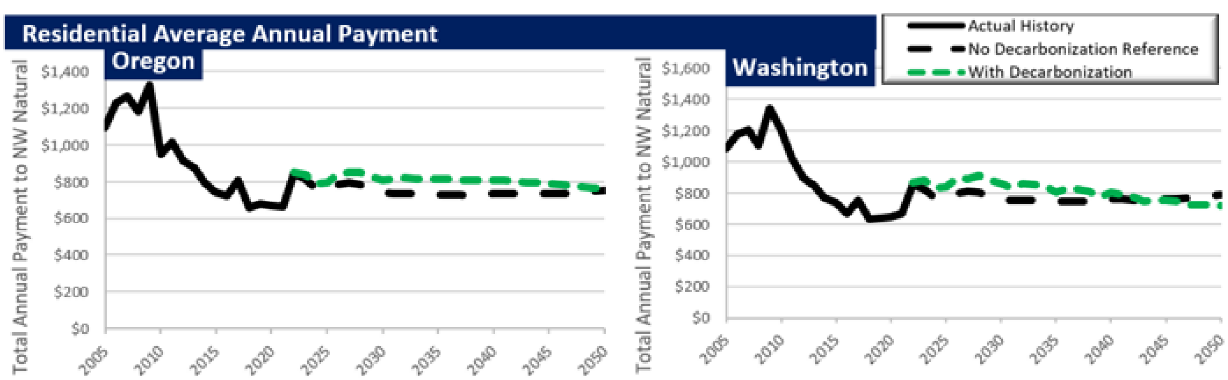
NW Natural®

Scenario 3 – Dual-Fuel Heating









Scenario 3 – Dual-Fuel Heating

Capacity Takeaways

- Replacing Portland LNG Cold Box shown as least cost solution
- Additional capacity needs served by Mist Recall, with a total recall of 100,000 Dth with the last recall occurring in 2035

Oregon Emissions Takeaways

- Meeting RNG targets for SB 98 represents most of the needed emissions reduction for the first compliance period of the Climate Protection Program; small amounts of Community Climate Investments (CCIs) may be purchased to meet additional requirements depending on weather and other conditions
- Biofuel RNG and CCIs represent the marginal compliance activity in the near- to medium-term, transitioning to renewable hydrogen for blending or dedicated delivery starting in 2033, and then transitioning to synthetic renewable natural gas in 2038
- Renewable supply represents roughly 85% of deliveries in 2050, which is equivalent to roughly over half of current gas deliveries in Oregon. Biofuel RNG deliveries represent roughly 10% of current load in 2050
- Decarbonization action to comply with SB 98 and the CPP results in residential gas utility bills being 9% higher in 2030 and 1% higher in 2050 than in a world without these policies. However, this figure can be misleading as most of the heating needs that would otherwise be served by natural gas are served by electricity, so gas service cost per unit of energy served is far greater than in Scenario 1. The cost of heating overall for a customer would need to include estimates of electric service relative to other options

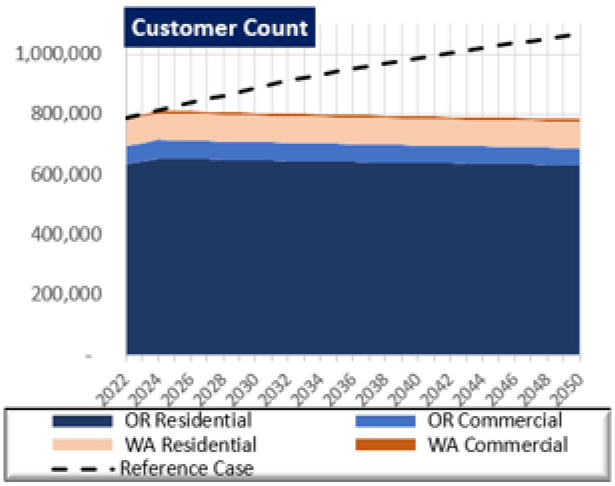
Washington Emissions Takeaways

- Delivering RNG for HB 1257 and utilizing offsets represents the bulk of net near term compliance with Cap-and-Invest, with allowance purchasing filling in any gaps
- Renewable supply represents roughly 50% of deliveries in 2050
- Complying with HB 1257 and Cap-and-Invest results in residential gas utility bills being 15% higher in 2030 and 9% lower in 2050 than in a world without these policies. However, this figure can be misleading as most of the heating needs that would otherwise be served by natural gas are served by electricity, so gas service cost per unit of energy served is far greater than in Scenario 1. The cost of heating overall for a customer would need to include estimates of electric service relative to other options

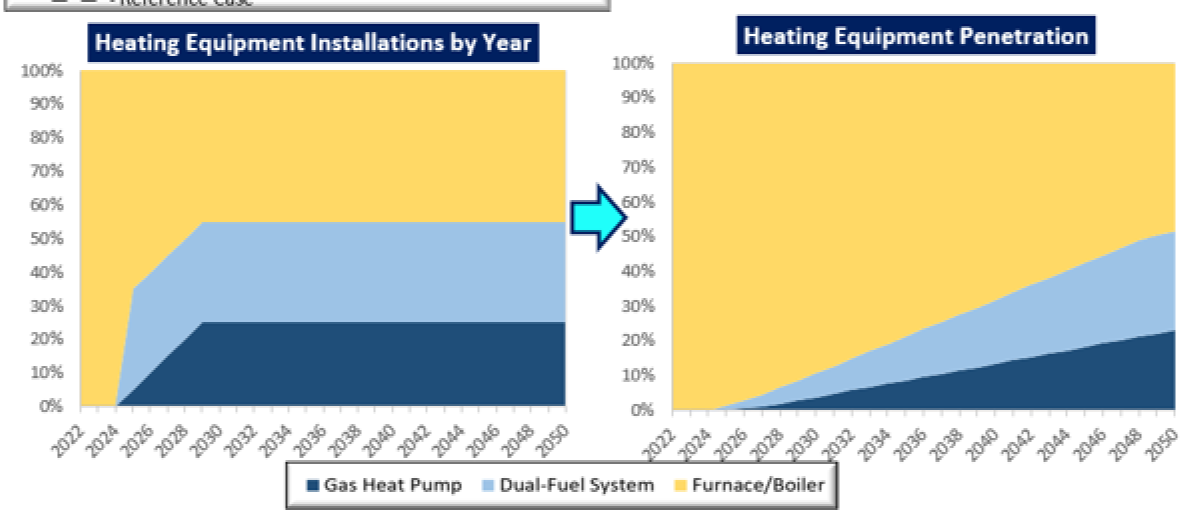
7.4.4 Scenario 4- New Customer Moratorium

Scenario 4 – New Gas Customer Moratorium

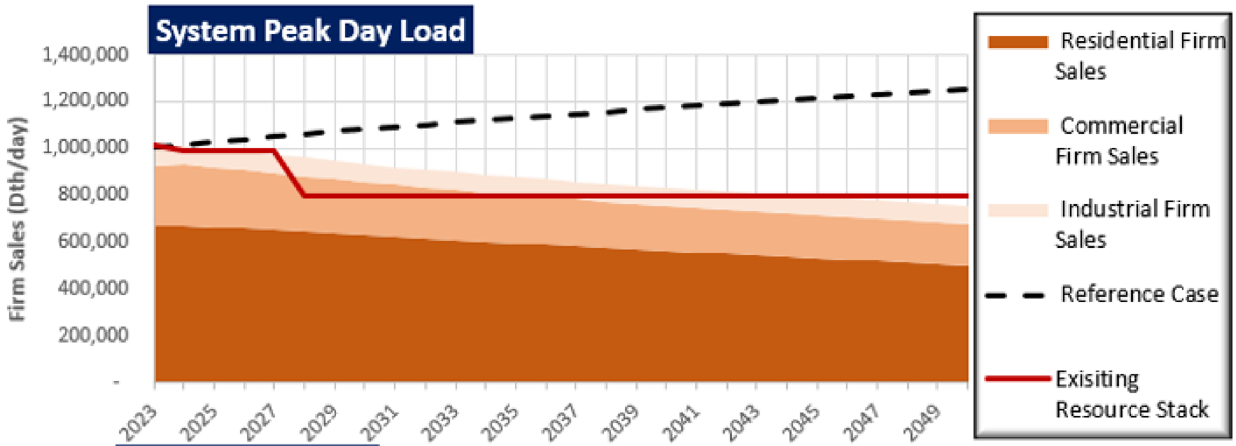
Scenario 4 helps to answer the question "What would be the implications if policy prohibited new customers from connecting to the natural gas grid?" It deploys the same demand and supply-side resource option assumptions as Scenario 1, but assumes that no new customers connect to the gas system starting in 2025. This reduces much of the energy efficiency deployed via Energy Trust programs given that much of the expected savings over the planning horizon come from new construction and conversions.

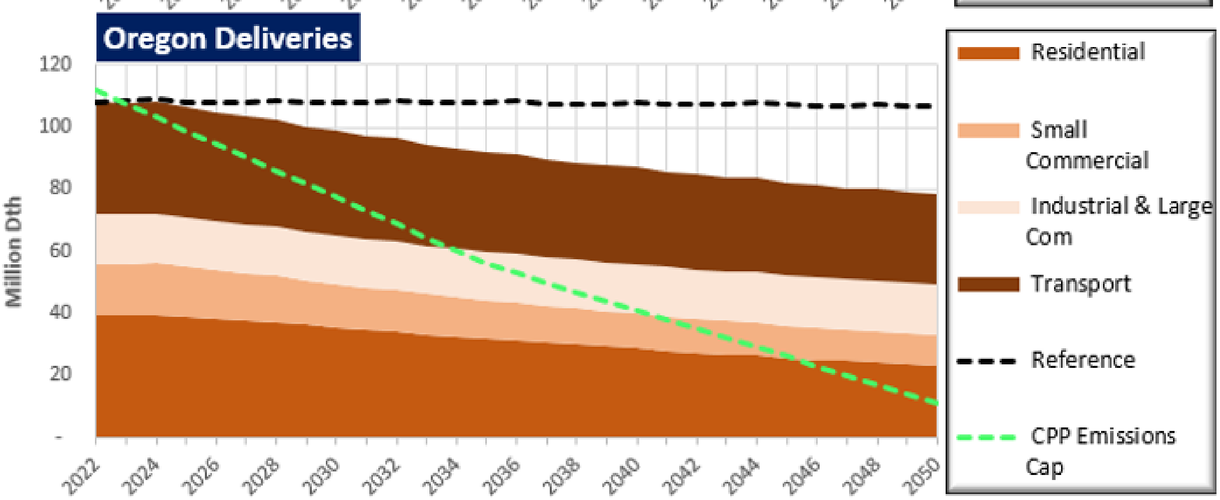


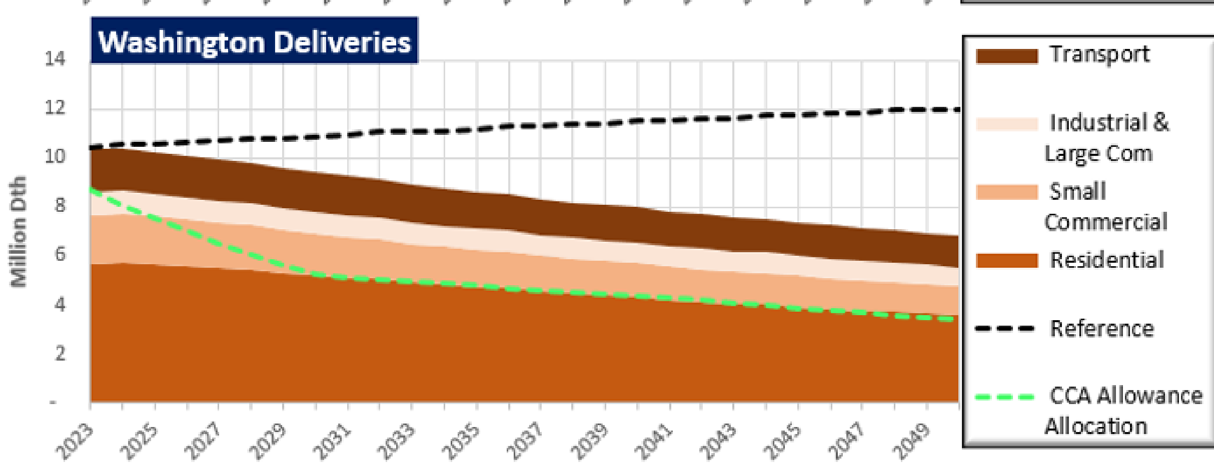
Demand-Side Assumptions	
Sales Customer Energy Efficiency	ETO projection for existing customers at $5.06/therm of first year savings. Expected savings from new buildings are not achieved as new customers are not added.
Transport Customer Energy Efficiency	Applied Energy Group projection of savings at $1.79/therm of first year savings
Gas Heat Pump Cost	$4,000 total cost to utility for a residential heating system, $13,000 for a Commercial heating System; $1,600 for residential water heater
Dual-Fuel System Costs	Net cost of $400 to utility



Scenario 4 – New Gas Customer Moratorium







Scenario 4 – New Gas Customer Moratorium

Capacity Resource Options

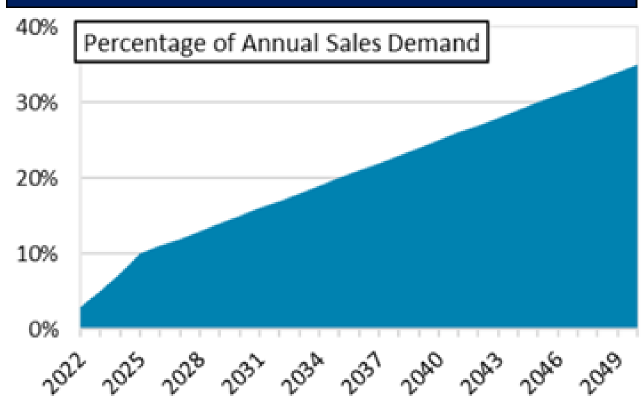
Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	Max: 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800

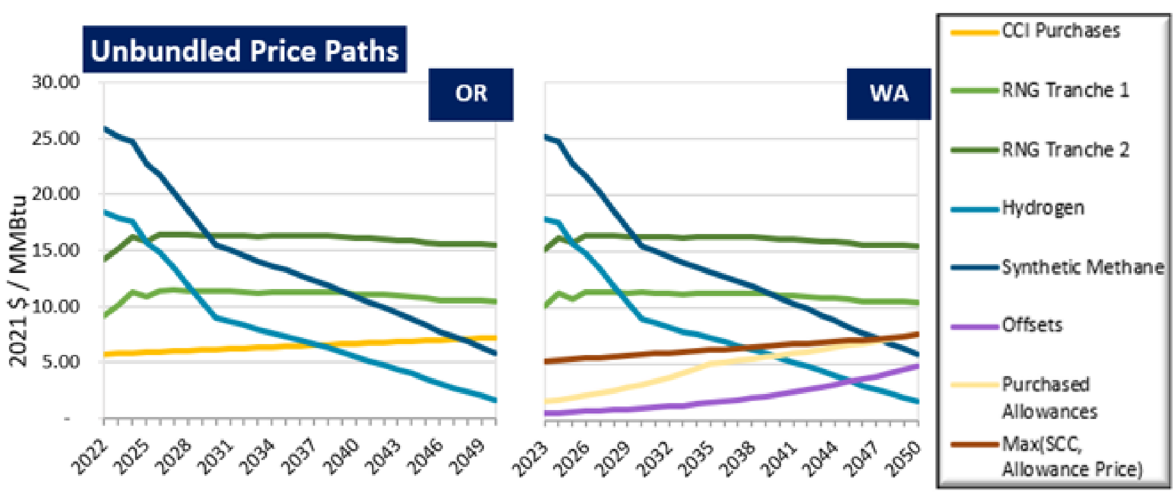
Compliance Resource Options

Quantity Available

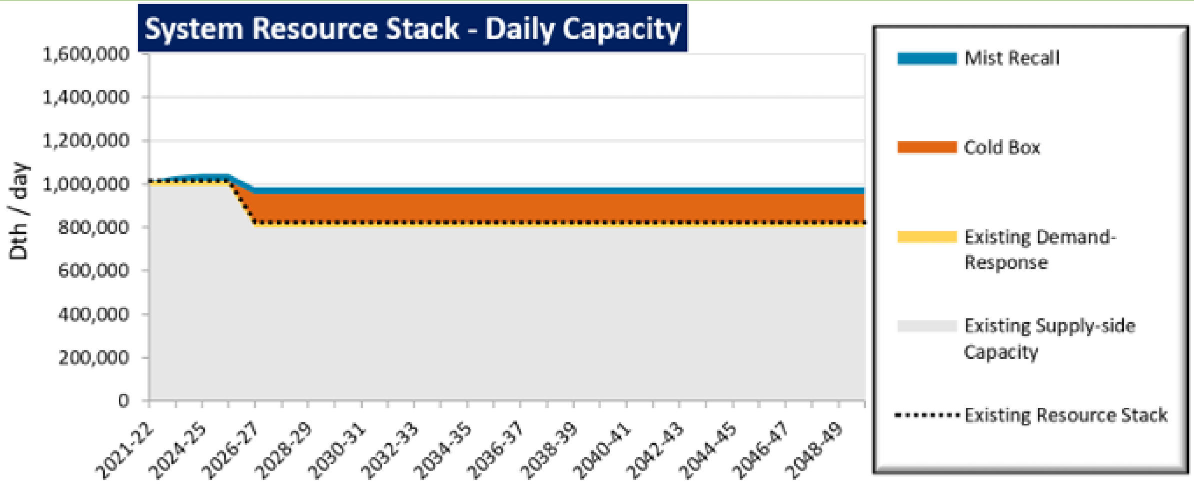
Option	Limit
RNG Tranche 1	13,000,000 Dth / year
RNG Tranche 2	27,000,000 Dth / year
Hydrogen	20% of Deliveries by Energy
Synthetic Methane	Unbounded
CCIs	OR Compliance Period 1: 10% OR Compliance Period 2: 15% OR Compliance Period >=3: 20%
Allowances	Unbounded
Offsets	WA Compliance Period 1: 6% WA Compliance Period >=2: 8%

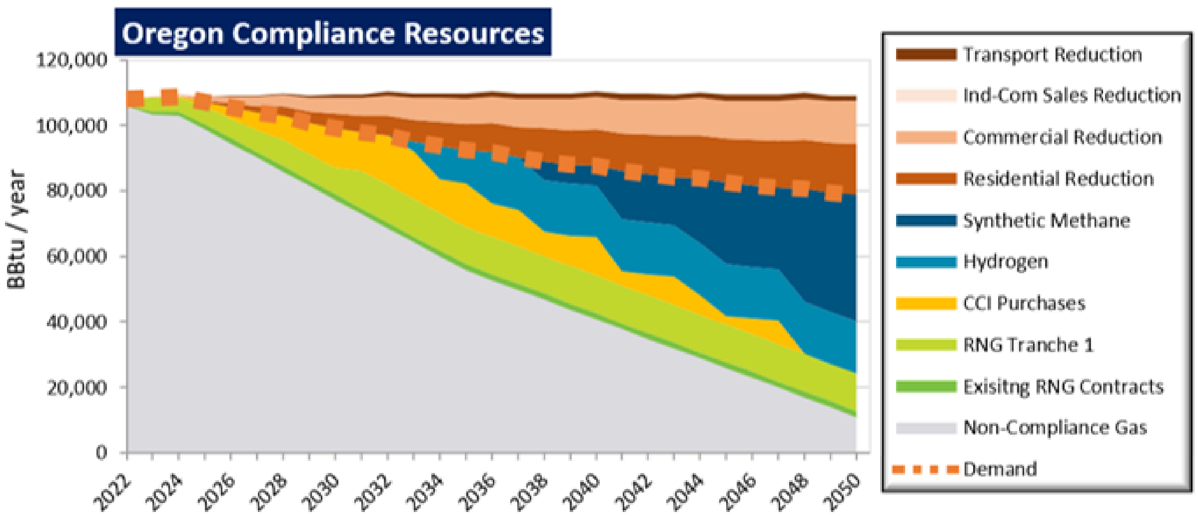
OR SB 98 / WA HB 1257 RNG Targets

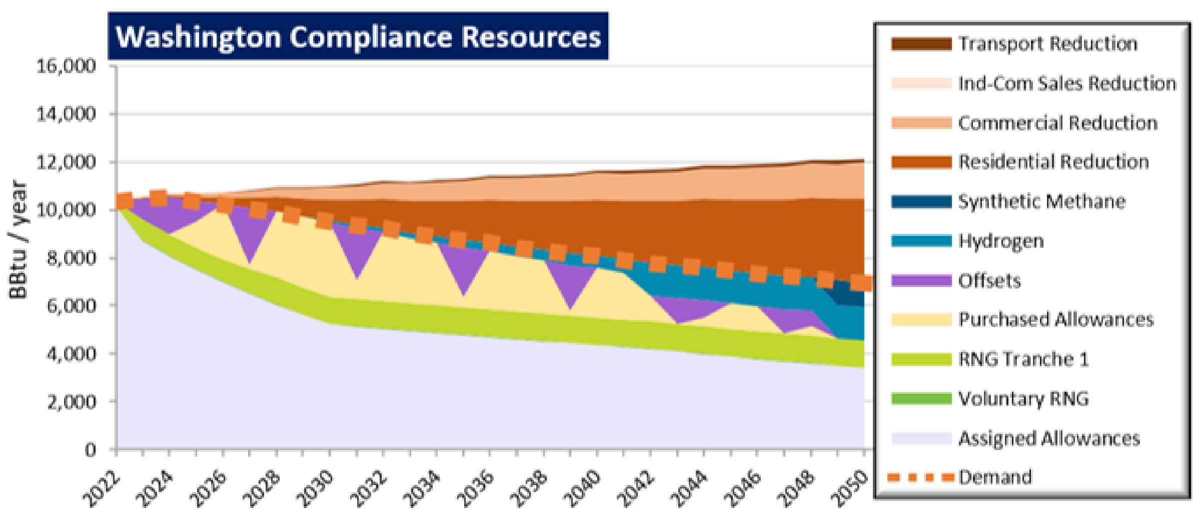




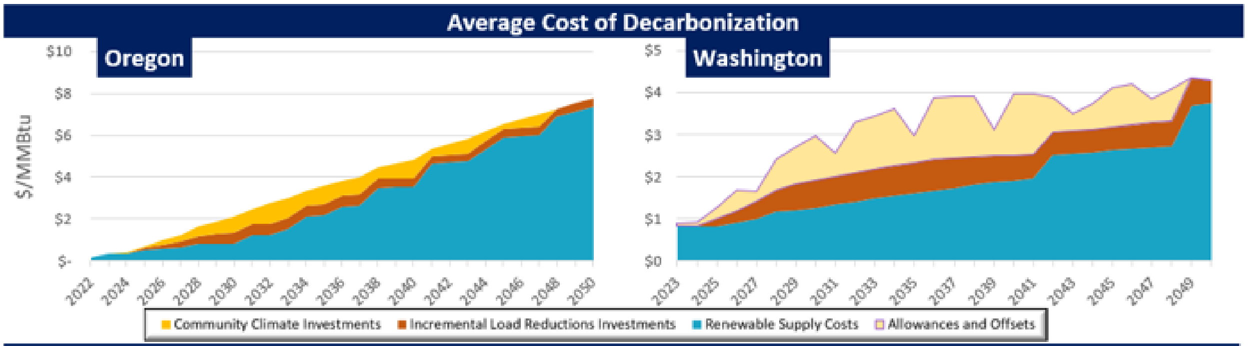
Scenario 4 – New Gas Customer Moratorium

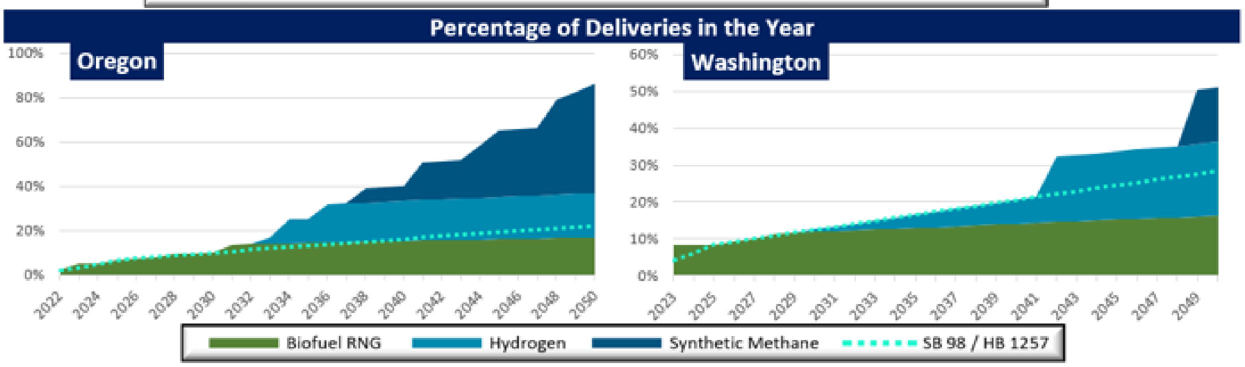


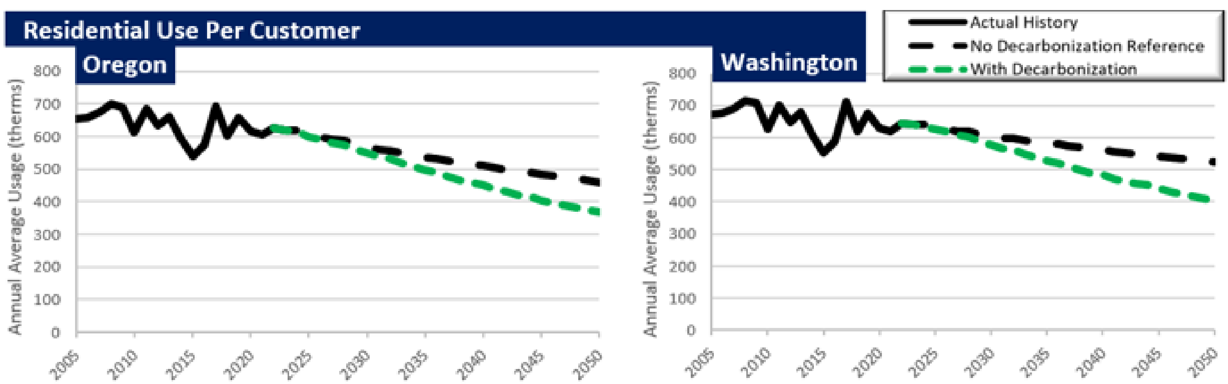


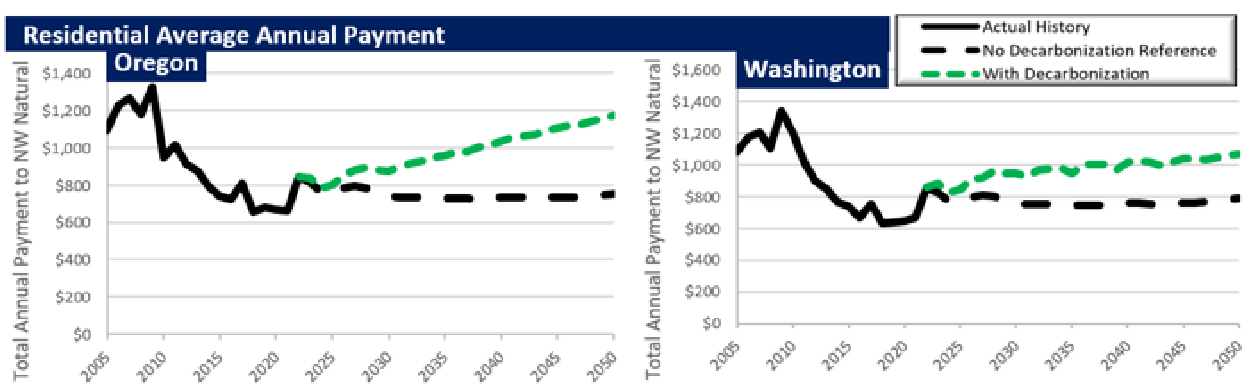


Scenario 4 – New Gas Customer Moratorium









Scenario 4 – New Gas Customer Moratorium

Capacity Takeaways

- Replacing Portland LNG Cold Box shown as least cost solution
- Additional capacity needs served by Mist Recall, with a total recall of 30,000 Dth with the last recall occurring in 2025

Oregon Emissions Takeaways

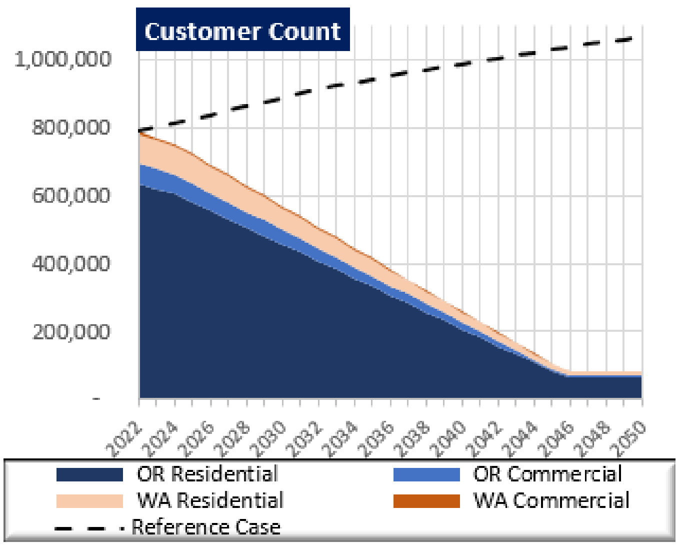
- Meeting RNG targets for SB 98 represents most of the needed emissions reduction for the first compliance period of the Climate Protection Program; small amounts of Community Climate Investments (CCIs) may be purchased to meet additional requirements depending on weather and other conditions
- Biofuel RNG and CCIs represent the marginal compliance activity in the near- to medium-term, transitioning to renewable hydrogen for blending or dedicated delivery starting in 2033, and then transitioning to synthetic renewable natural gas in 2038
- Renewable supply represents roughly 85% of deliveries in 2050, which is equivalent to roughly 2/3 of current gas deliveries in Oregon. Biofuel RNG deliveries represent roughly 10% of current load in 2050
- Decarbonization action to comply with SB 98 and the CPP results in residential gas utility bills being 18% higher in 2030 and 55% higher in 2050 than in a world without these policies

Washington Emissions Takeaways

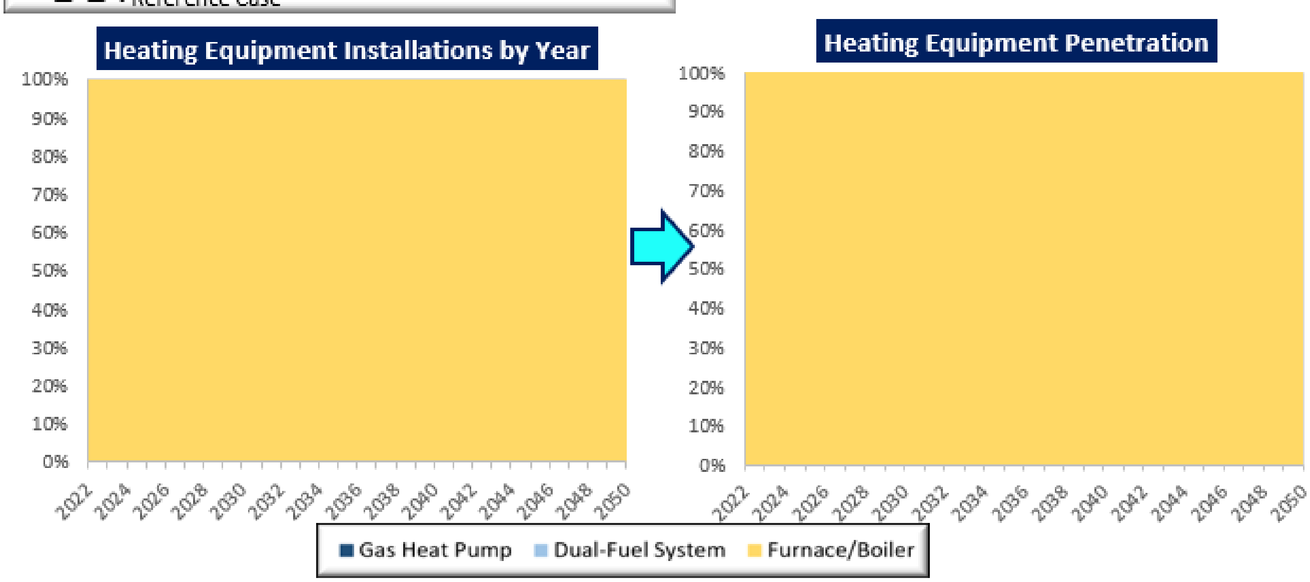
- Delivering RNG for HB 1257 and utilizing offsets represents the bulk of net near term compliance with Cap-and-Invest, with allowance purchasing filling in any gaps
- Renewable supply represents roughly 50% of deliveries in 2050
- Complying with HB 1257 and Cap-and-Invest results in residential gas utility bills being 25% higher in 2030 and 36% higher in 2050 than in a world without these policies

Scenario 5 – Aggressive Building Electrification

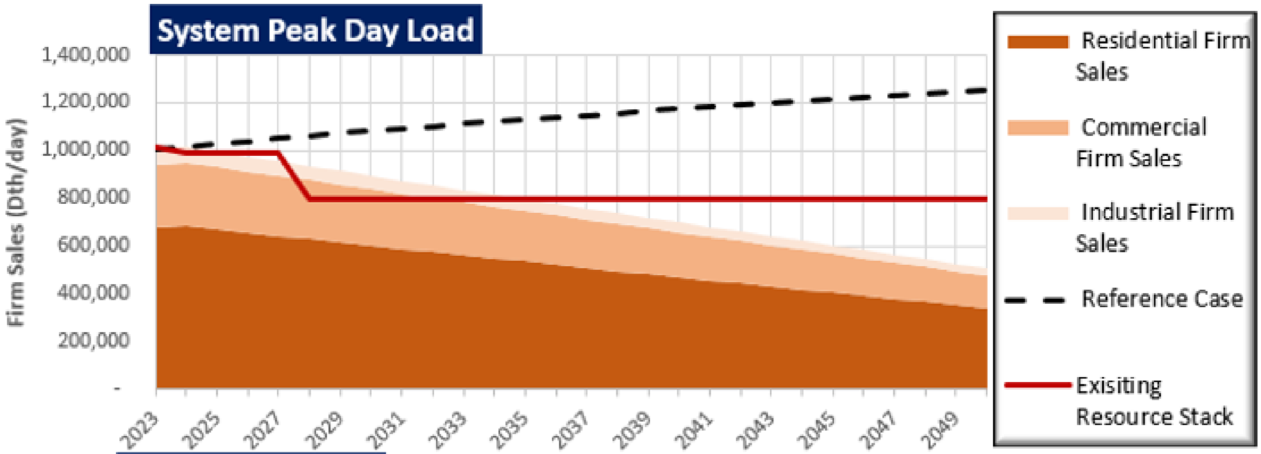
Scenario 5 helps to answer the question "What would it mean if policy prohibited new customers from connecting to the natural gas grid and many existing customers also left the gas system to electrify?" Scenario 5 assumes the same cost and availability of renewable supply as Scenario 1 but assumes no new customers are added to the system starting in 2025, and that half of the customers who replace their existing gas heating equipment in a given year choose to electrify their homes upon that decision and leave the gas system.

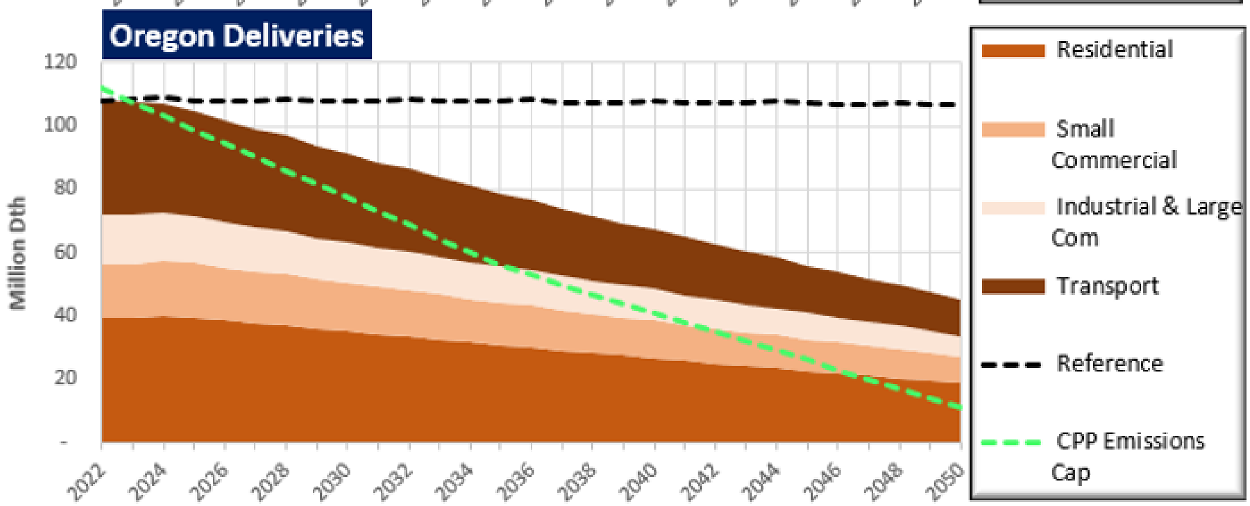


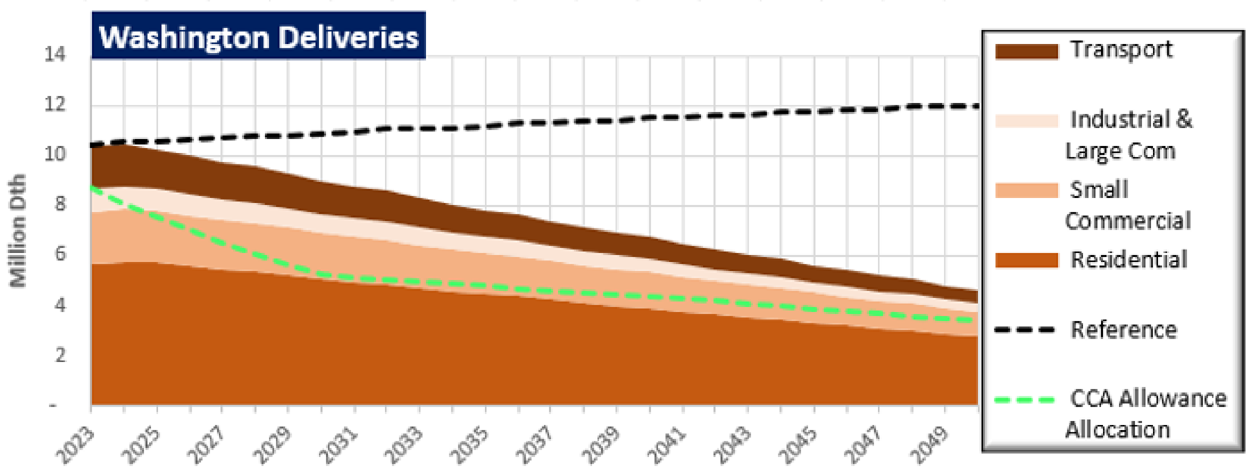
Demand-Side Assumptions	
Sales Customer Energy Efficiency	Gas energy efficiency programs are halted as they are not required to meet emissions goals and cross-subsidize electric customers
Transport Customer Energy Efficiency	
Gas Heat Pump Cost	No Gas Heat Pumps Installed
Dual-Fuel System Costs	No Dual-Fuel System Installed



Scenario 5 – Aggressive Building Electrification







Scenario 5 – Aggressive Building Electrification

Capacity Resource Options

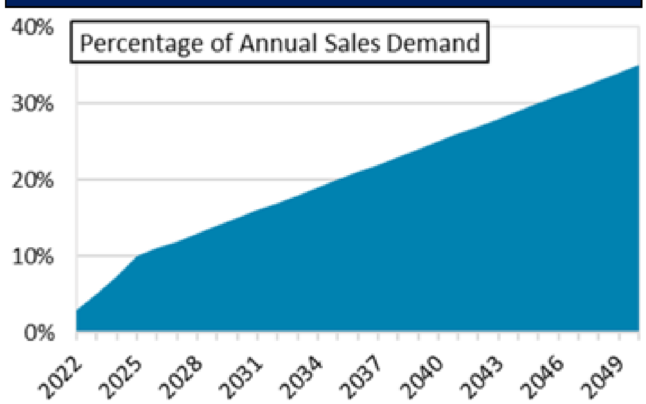
Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	Max: 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800

Compliance Resource Options

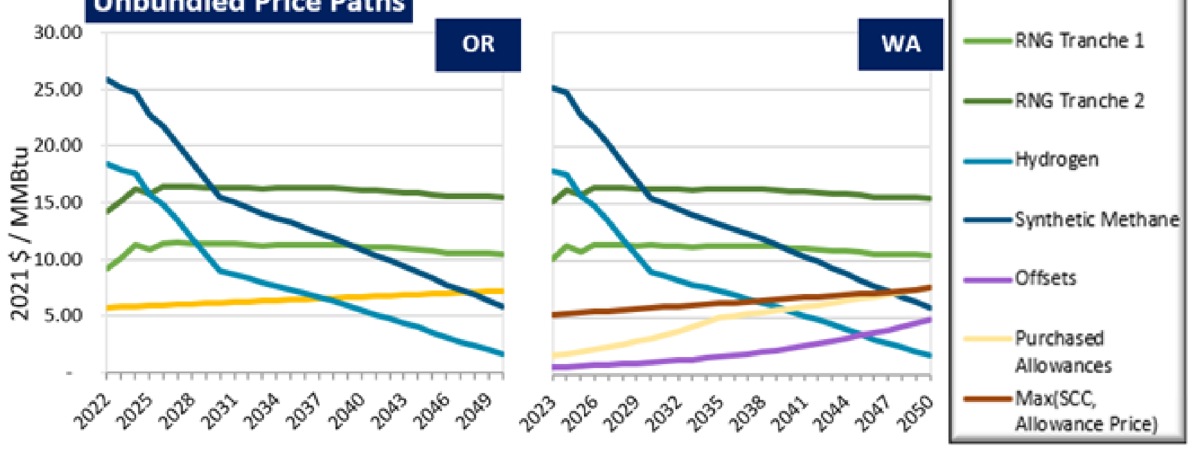
Quantity Available

Option	Limit
RNG Tranche 1	13,000,000 Dth / year
RNG Tranche 2	27,000,000 Dth / year
Hydrogen	20% of Deliveries by Energy
Synthetic Methane	Unbounded
CCIs	OR Compliance Period 1: 10% OR Compliance Period 2: 15% OR Compliance Period >=3: 20%
Allowances	Unbounded
Offsets	WA Compliance Period 1: 6% WA Compliance Period >=2: 8%

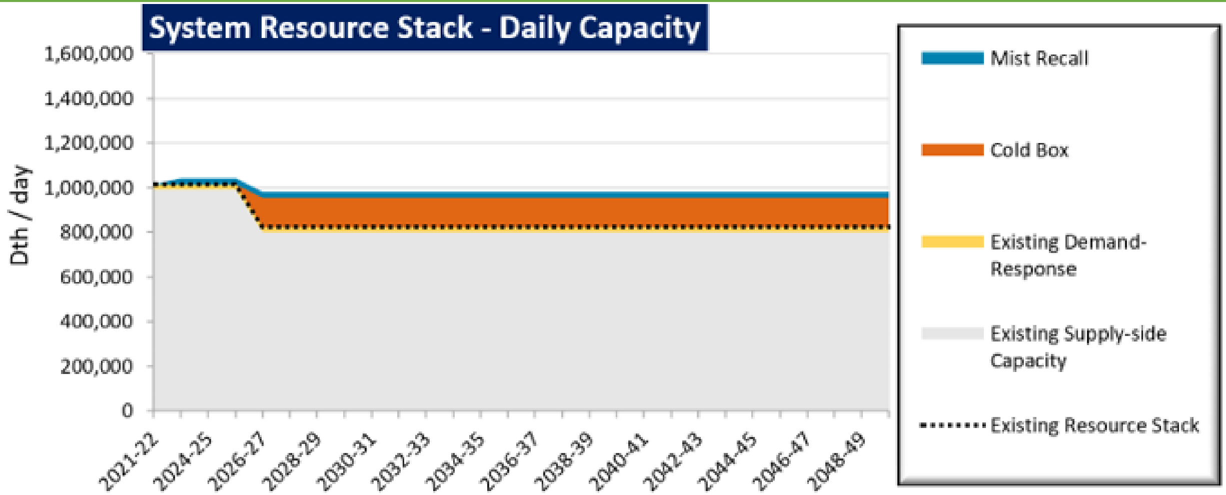
OR SB 98 / WA HB 1257 RNG Targets

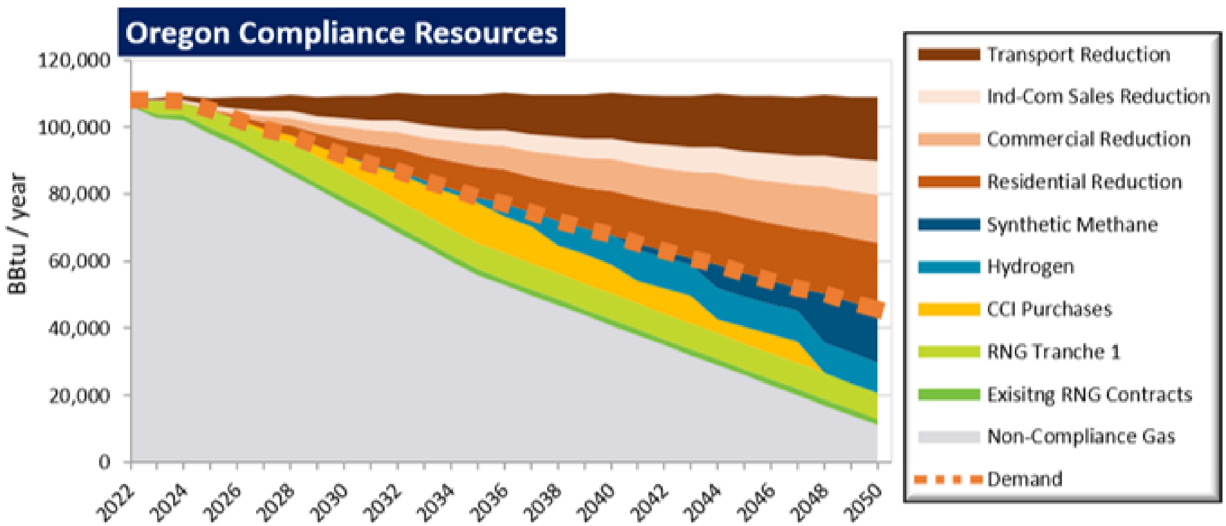


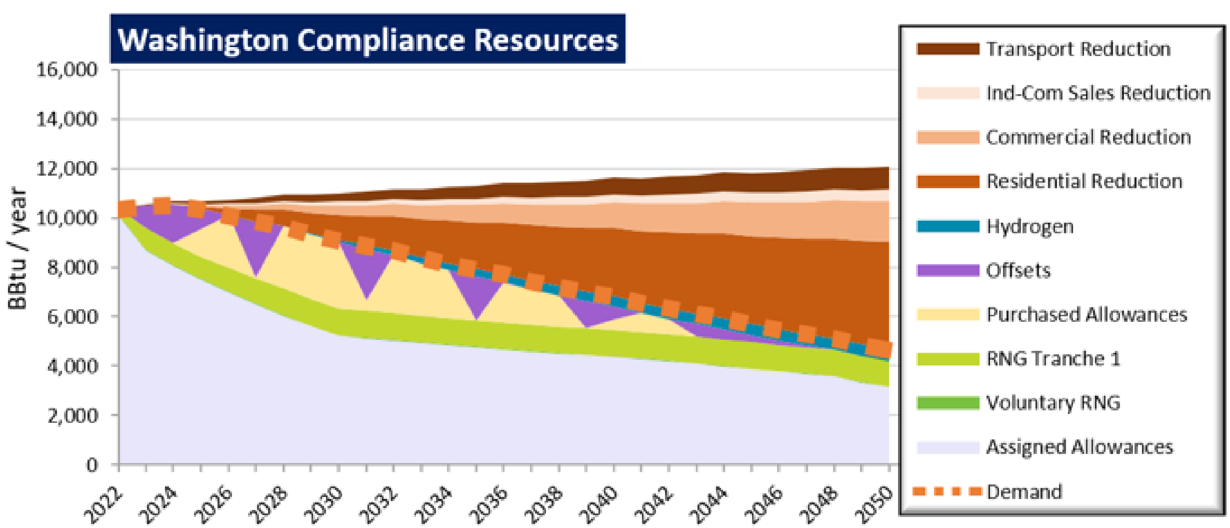
Unbundled Price Paths



Scenario 5 – Aggressive Building Electrification

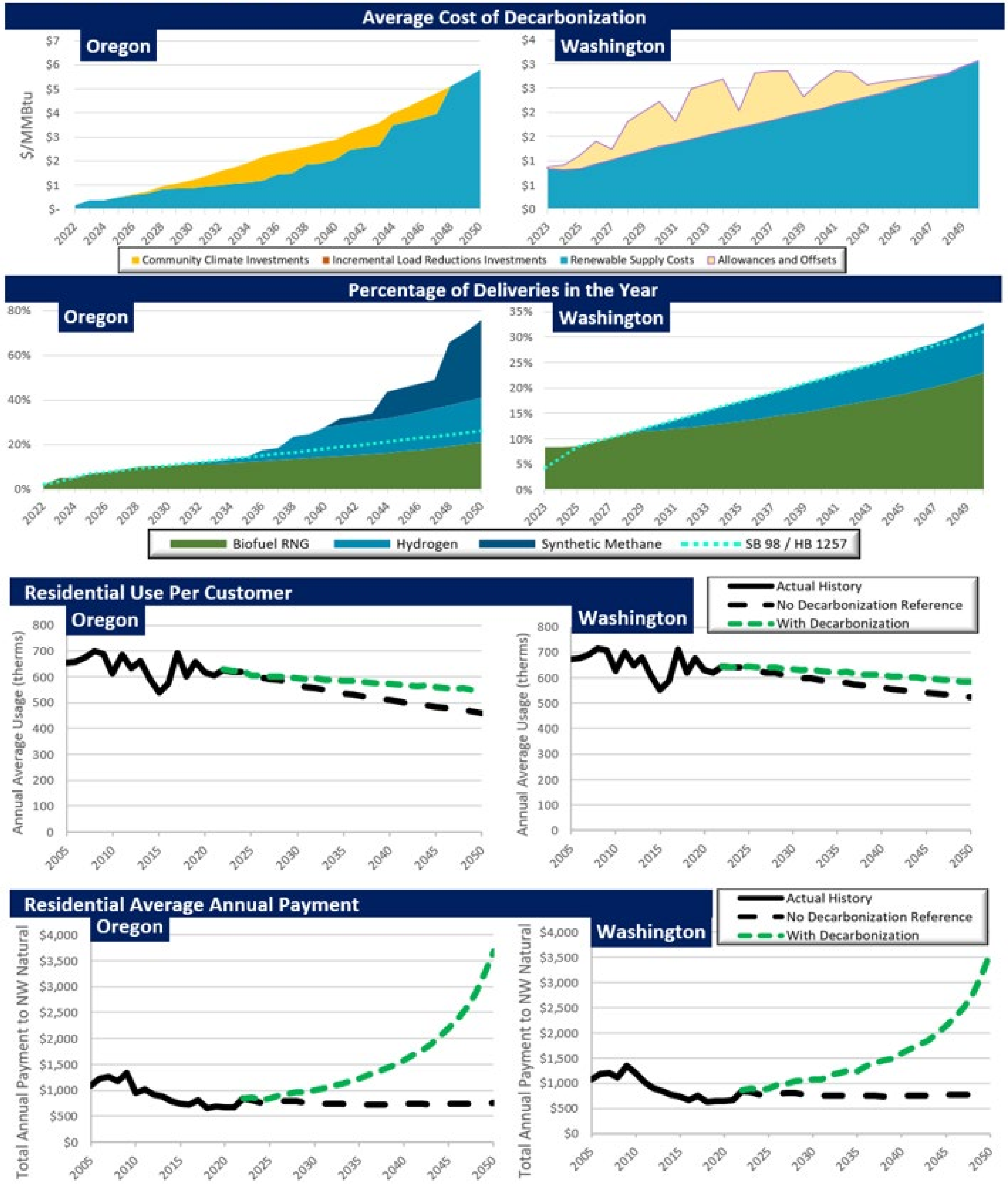






NW Natural®

Scenario 5 – Aggressive Building Electrification



Scenario 5 – Aggressive Building Electrification

Capacity Takeaways

- Replacing Portland LNG Cold Box shown as least cost solution
- Additional capacity needs served by Mist Recall, with a total recall of 30,000 Dth with the last recall occurring in 2023

Oregon Emissions Takeaways

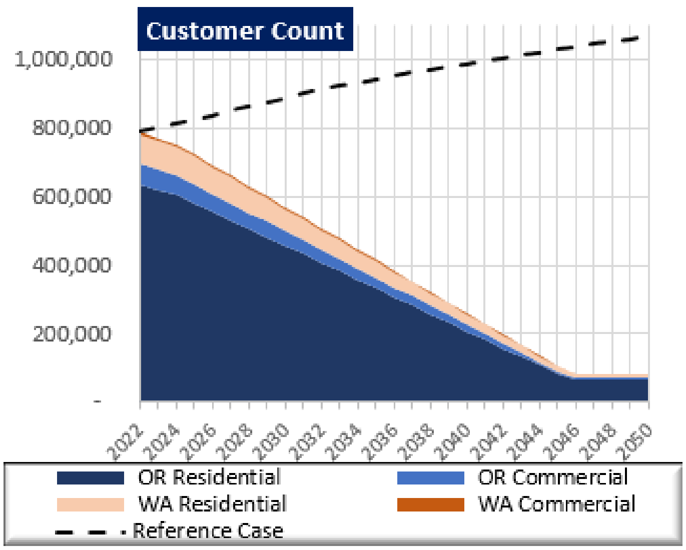
- Meeting RNG targets for SB 98 represents most of the needed emissions reduction for the first compliance period of the Climate Protection Program and far less compliance action is needed due to falling loads
- Renewable supply represents roughly 75% of deliveries in 2050, which is equivalent to roughly 1/3 of current gas deliveries in Oregon. Biofuel RNG deliveries represent roughly 7% of current load in 2050
- Compared to non-electrification scenarios far less decarbonization action is needed from NW Natural to comply with SB 98 and the CPP.
- Customers who remain on the gas system experience 34% higher rates in 2030 and 389% higher in 2050 due to spreading of fixed costs across less energy use

Washington Emissions Takeaways

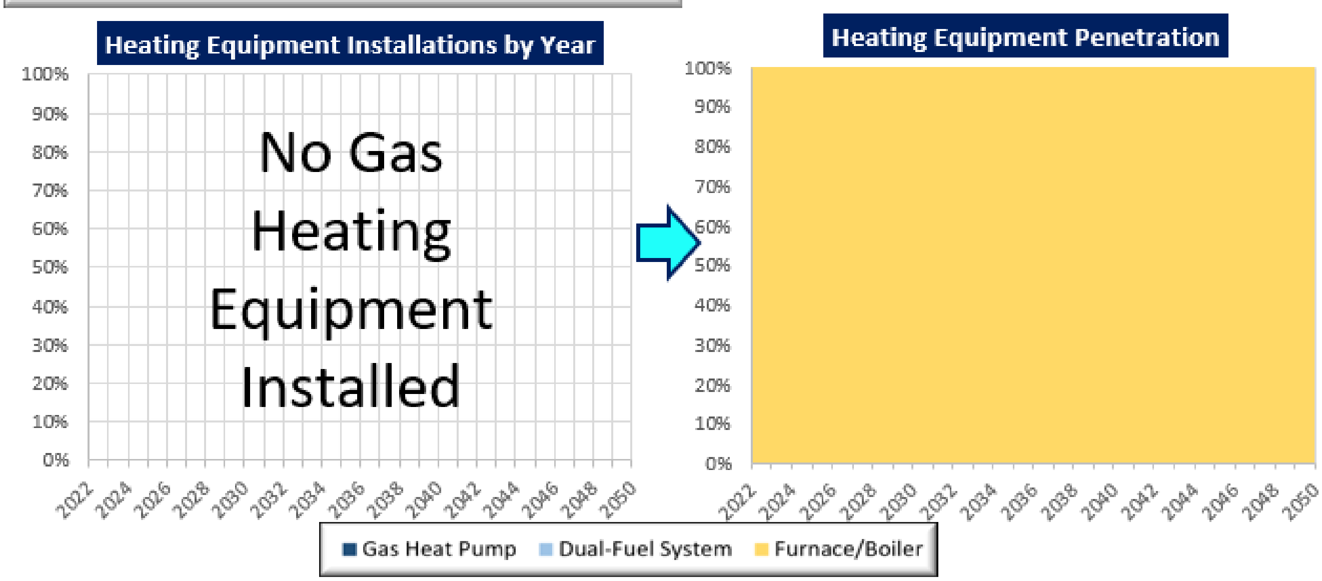
- Delivering RNG for HB 1257 and utilizing offsets represents the bulk of net near term compliance with Cap-and-Invest, with allowance purchasing filling in any gaps
- Renewable supply represents roughly 35% of deliveries in 2050
- Customers who remain on the gas system experience 44% higher rates in 2030 and 352% higher in 2050 due to spreading of fixed costs across less energy use

Scenario 6 – Full Building Electrification

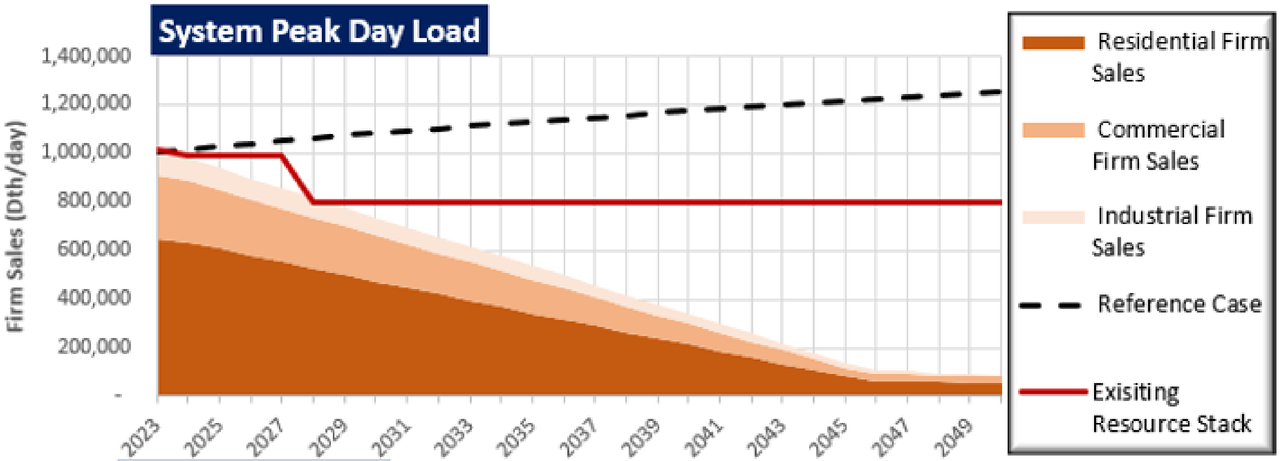
Scenario 6 helps to answer the question “What would it mean if a policy were implemented that required homes and businesses to leave the gas system when they replaced their heating equipment?” This scenario represents the bookend of what the implications could be if the most extreme electrification policy were implemented. While rendered largely moot by the electrification assumption, this scenario assumes the same availability and cost of renewable resources as Scenario 1.

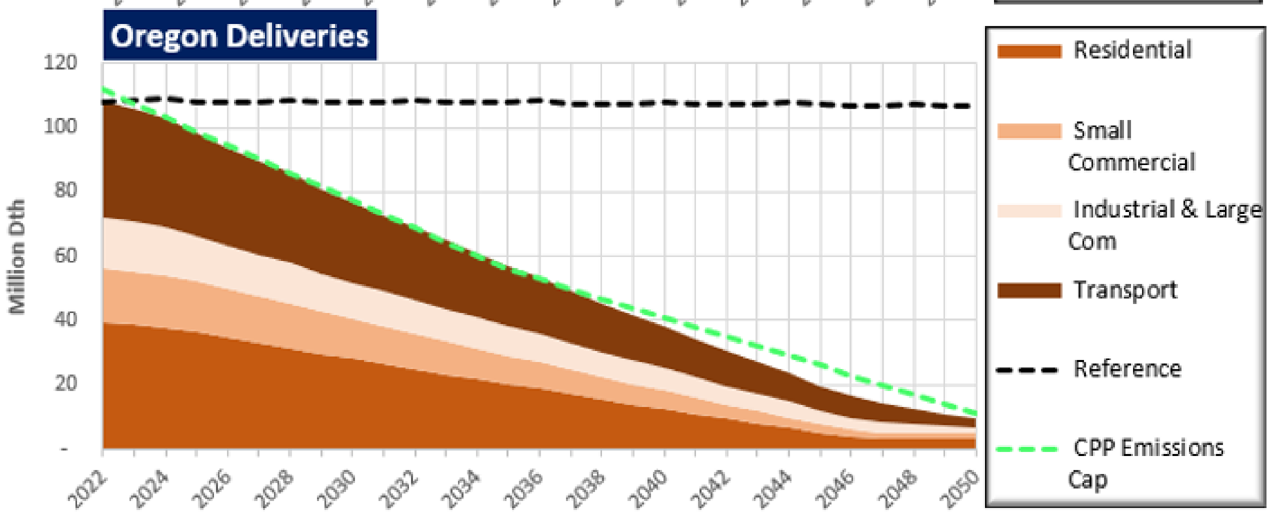


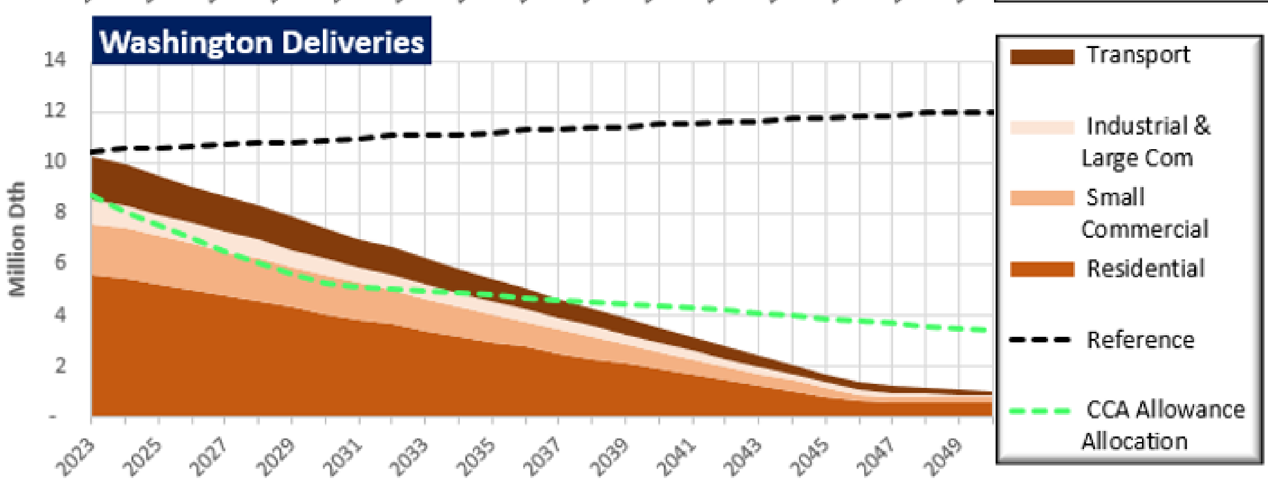
Demand-Side Assumptions	
Sales Customer Energy Efficiency	Gas energy efficiency programs are halted as they are not required to meet emissions goals and cross-subsidize electric customers
Transport Customer Energy Efficiency	
Gas Heat Pump Cost	No Gas Heat Pumps Installed
Dual-Fuel System Costs	No Dual-Fuel System Installed



Scenario 6 – Full Building Electrification







Scenario 6 – Full Building Electrification

Capacity Resource Options

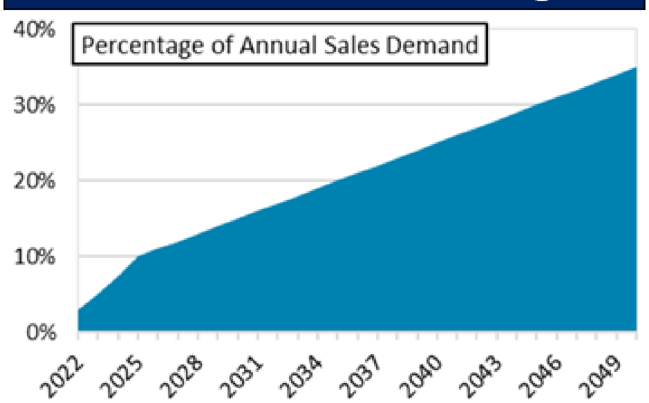
Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	Max: 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800

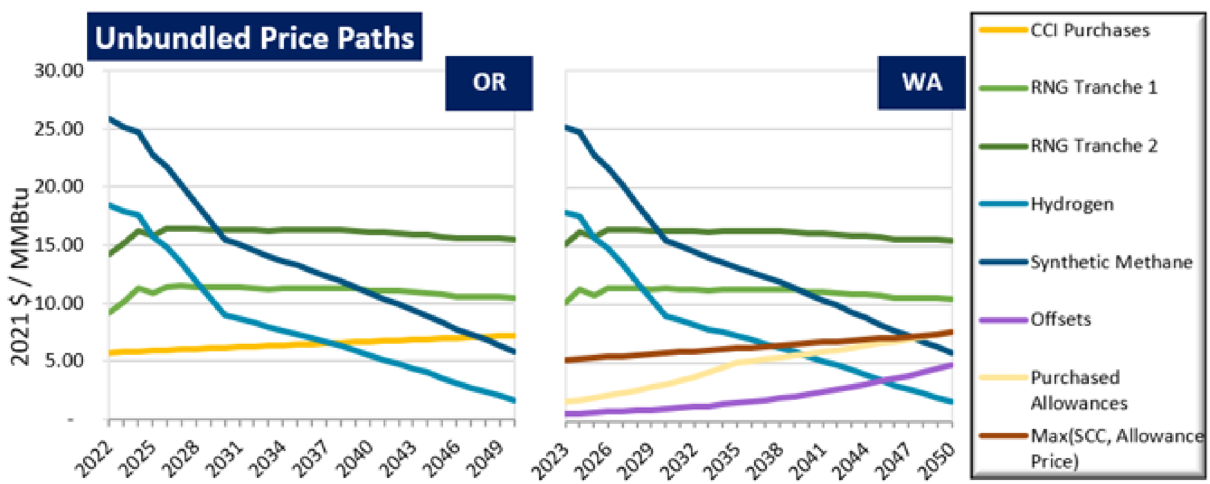
Compliance Resource Options

Quantity Available

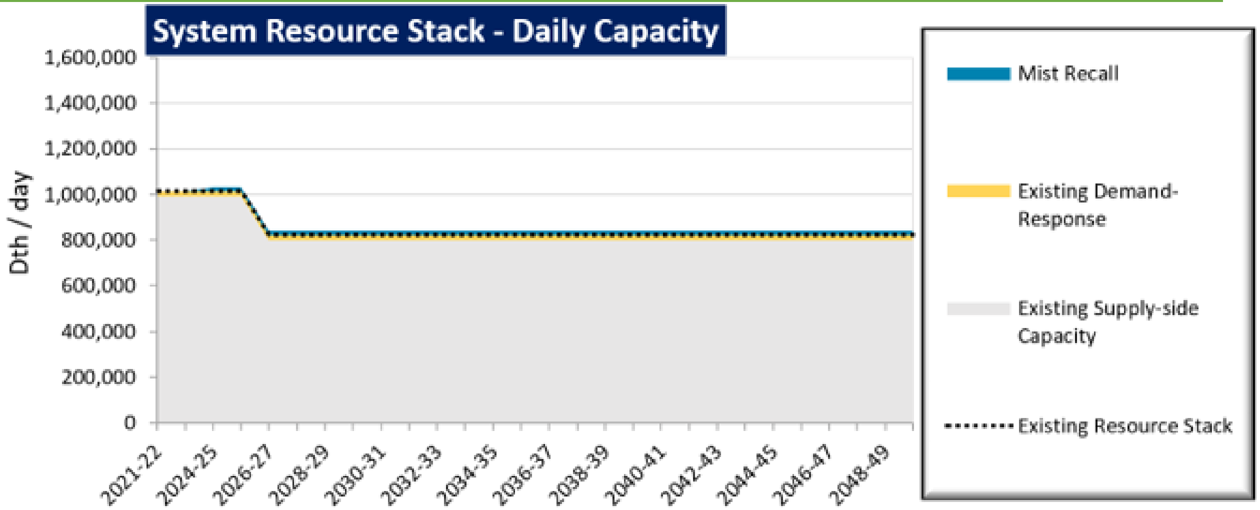
Option	Limit
RNG Tranche 1	13,000,000 Dth / year
RNG Tranche 2	27,000,000 Dth / year
Hydrogen	20% of Deliveries by Energy
Synthetic Methane	Unbounded
CCIs	OR Compliance Period 1: 10% OR Compliance Period 2: 15% OR Compliance Period >=3: 20%
Allowances	Unbounded
Offsets	WA Compliance Period 1: 6% WA Compliance Period >=2: 8%

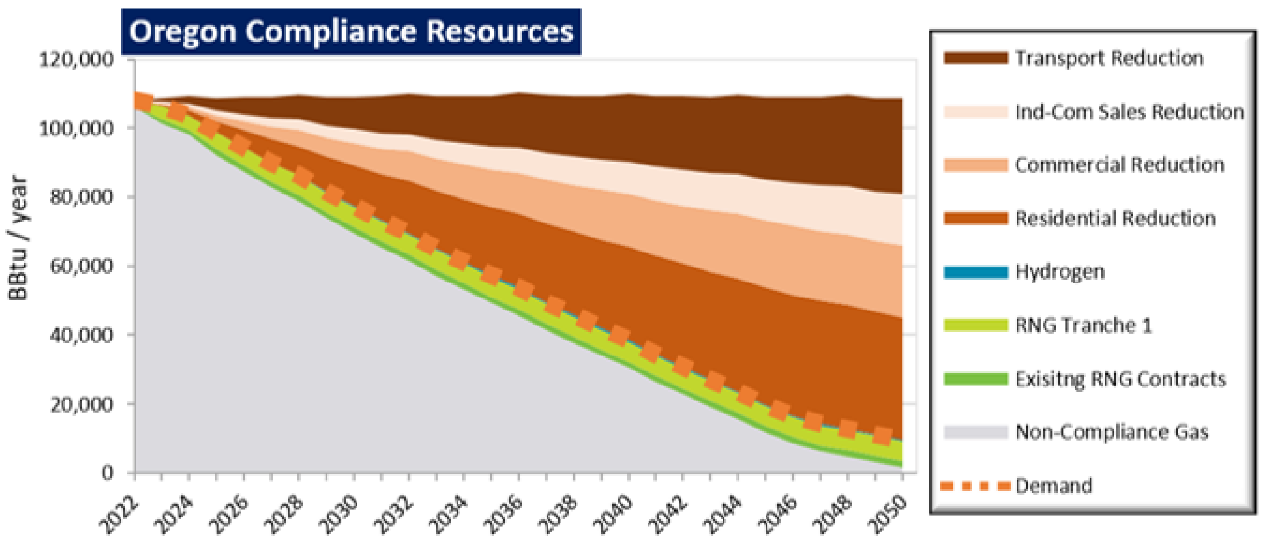
OR SB 98 / WA HB 1257 RNG Targets

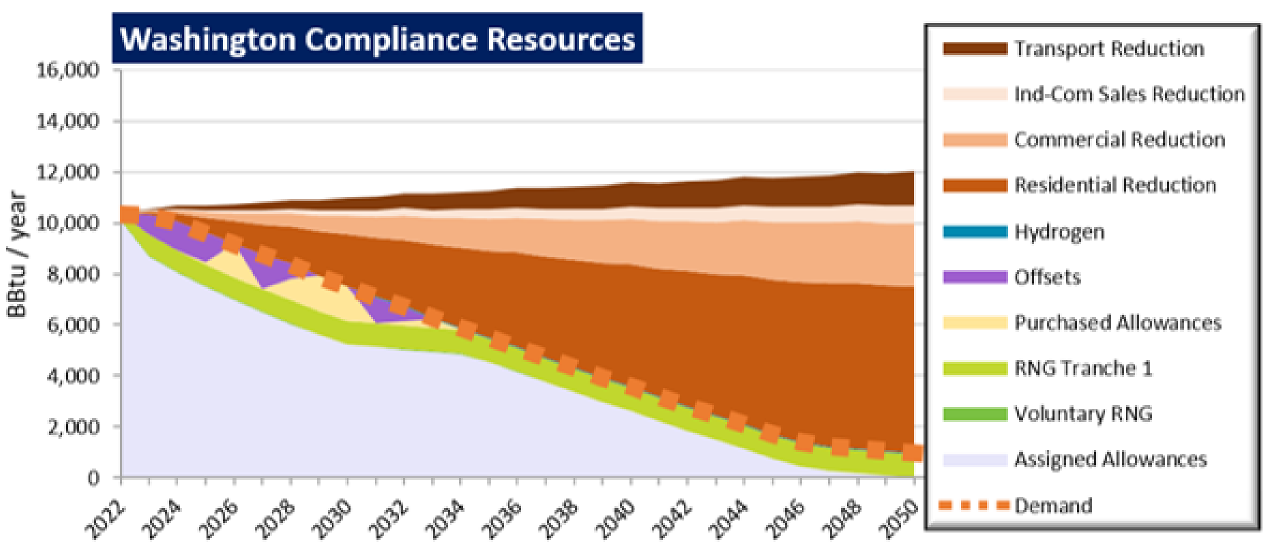




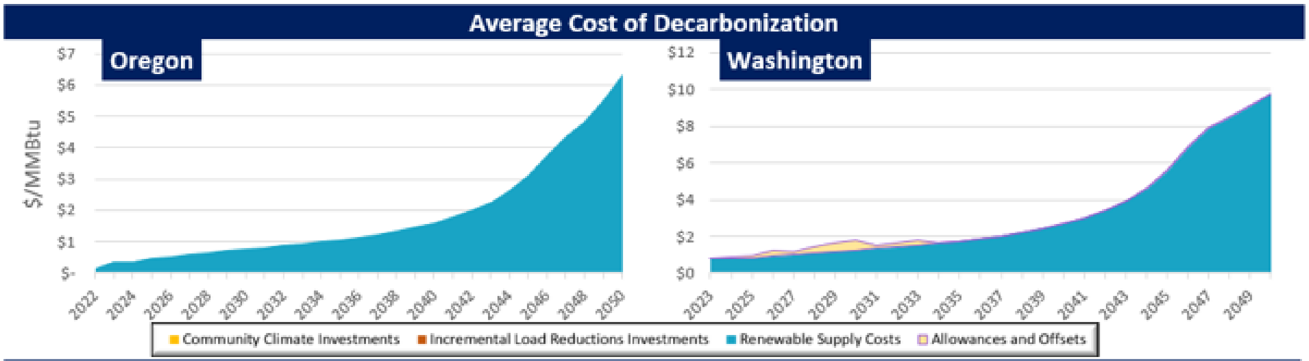
Scenario 6 – Full Building Electrification

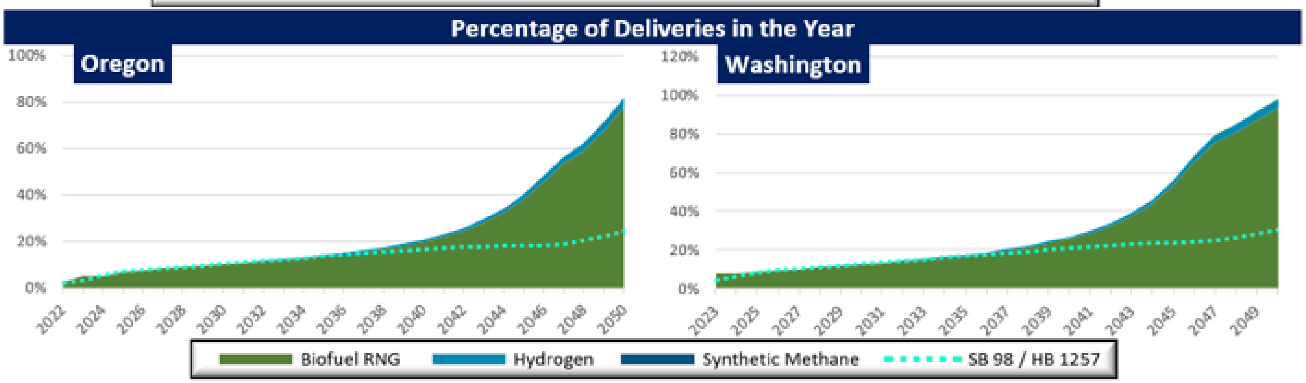


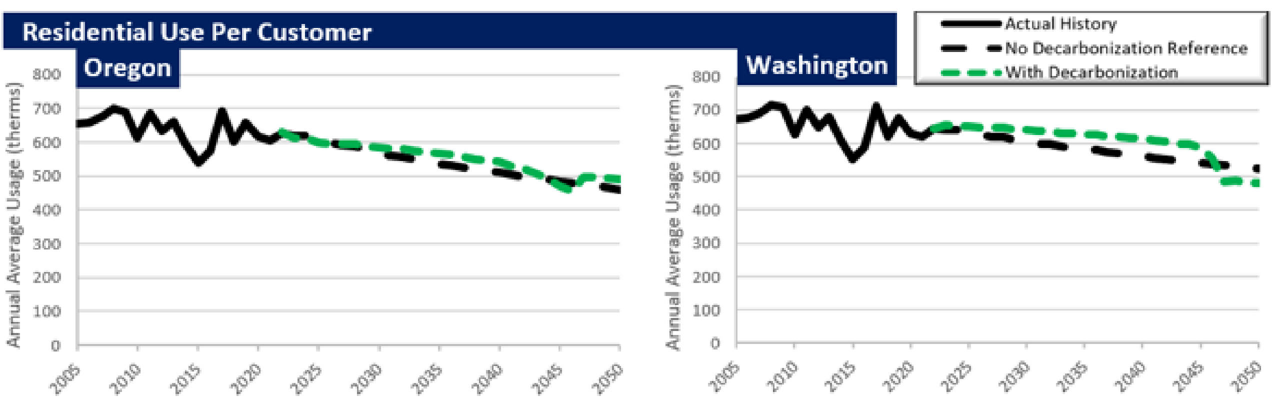


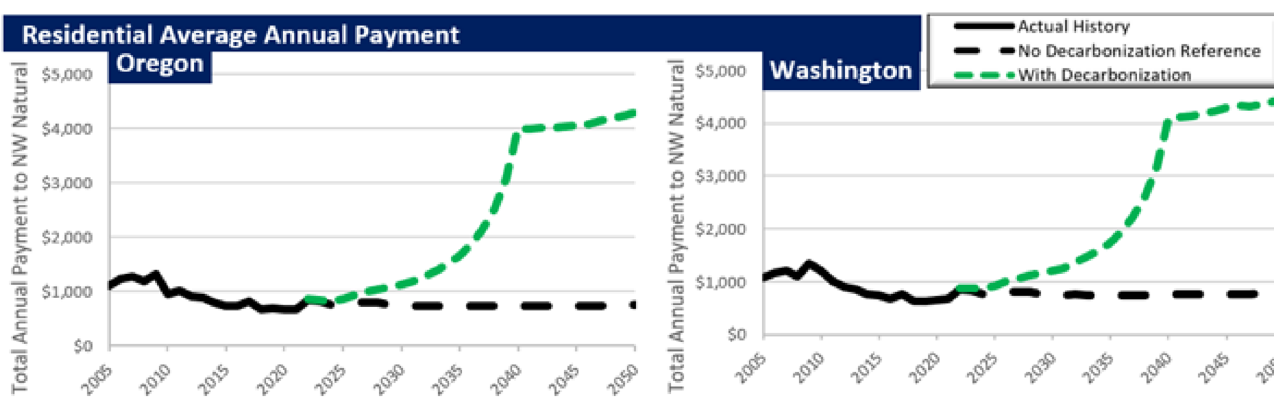


Scenario 6 – Full Building Electrification









Scenario 6 – Full Building Electrification

Capacity Takeaways

- Neither the Portland LNG Cold Box, the Central Pipeline, nor the Interstate Pipeline Looping project were selected
- Additional capacity needs served by Mist Recall, with a total recall of 20,000 Dth with the last recall occurring in 2025

Oregon Emissions Takeaways

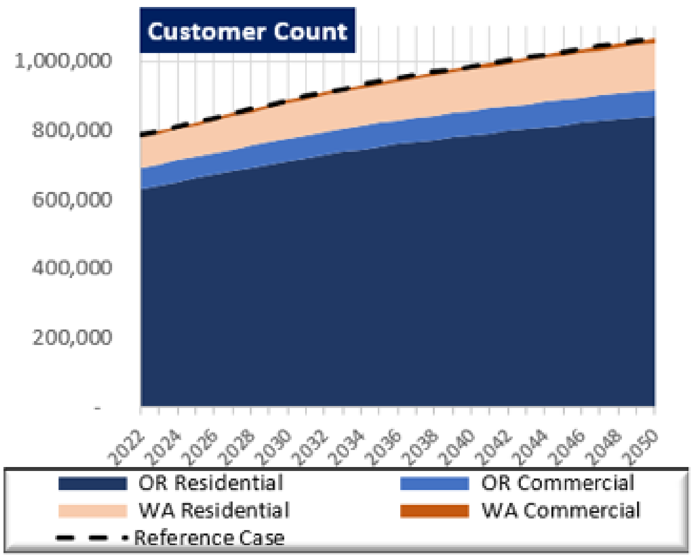
- Meeting RNG targets for SB 98 represents most of the needed emissions reduction for the first compliance period of the Climate Protection Program and far less compliance action is needed due to falling loads
- Renewable supply represents roughly 80% of deliveries in 2050, which is equivalent to roughly 1/3 of current gas deliveries in Oregon. Biofuel RNG deliveries represent roughly 6% of current load in 2050
- Compared to non-electrification scenarios far less decarbonization action is needed from NW Natural to comply with SB 98 and the CPP.
- Customers who remain on the gas system experience 51% higher rates in 2030 and 469% higher in 2050 due to spreading of fixed costs across less energy use

Washington Emissions Takeaways

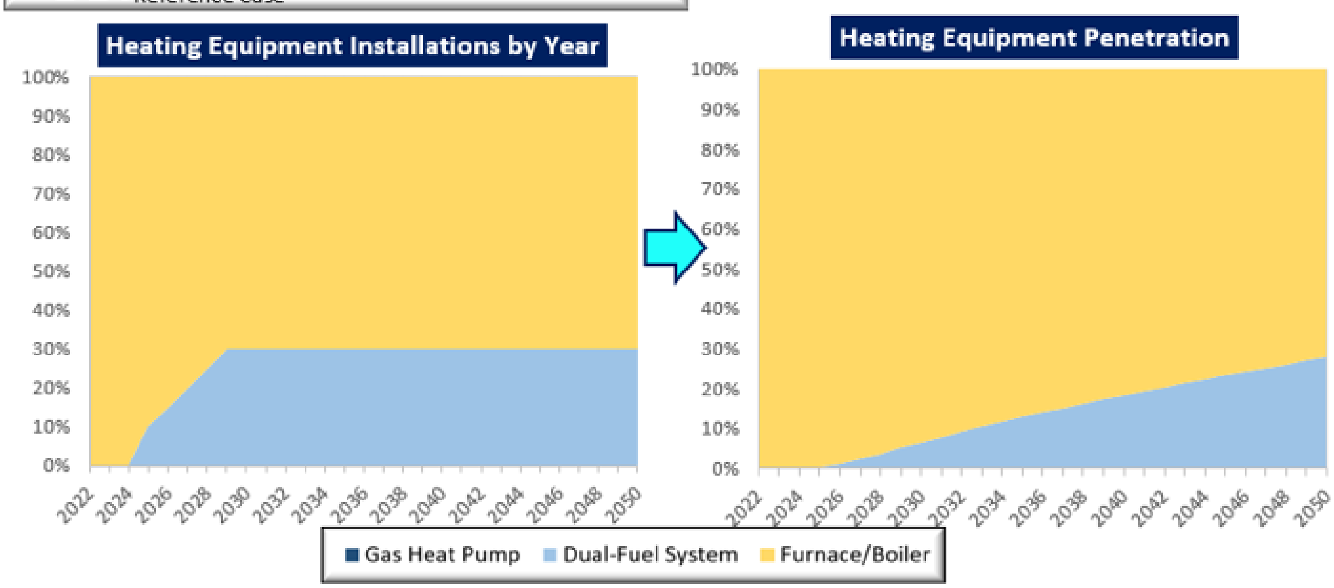
- Delivering RNG for HB 1257 and utilizing offsets represents the bulk of net near term compliance with Cap-and-Invest, with allowance purchasing filling in any gaps
- Renewable supply represents roughly 100% of deliveries in 2050
- Customers who remain on the gas system experience 61% higher rates in 2030 and 459% higher in 2050 due to spreading of fixed costs across less energy use

Scenario 7 – RNG and H2 Policy Support

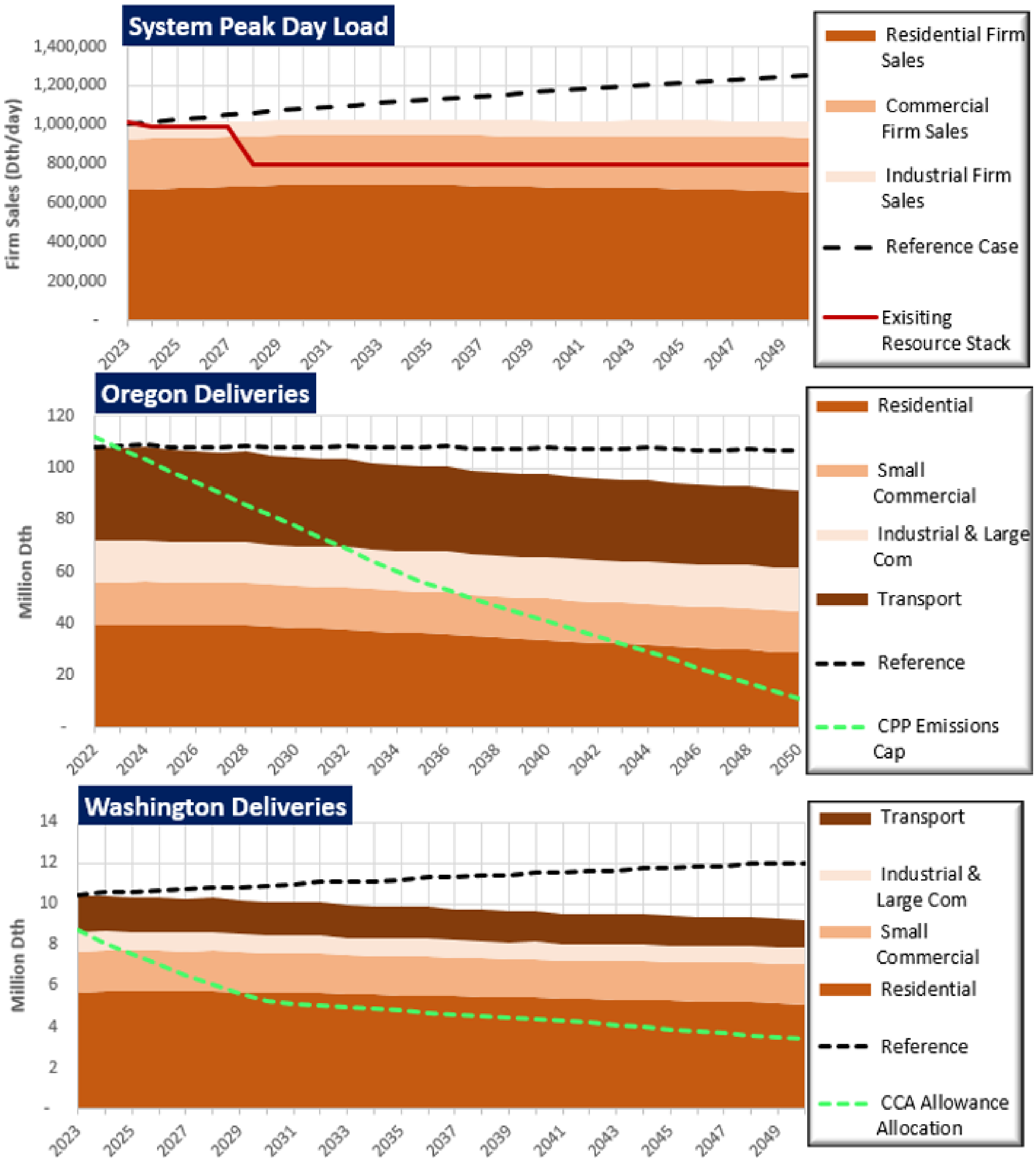
Scenario 7 answers the question "What would it mean if there were federal policy support for renewable natural gas and renewable hydrogen that reduced the cost of these resources to gas utility customers?" This scenario assumes a federal production tax credit of 30% for RNG and H2 similar to policies to support renewable electricity generation. It is assumed that this reduction in the price of these resources also results in a moderate increase in the availability of biofuel RNG. The customer growth demand-side resource assumptions in this scenario are the same as Scenario 1.



Demand-Side Assumptions	
Sales Customer Energy Efficiency	Energy Trust of Oregon projection of savings, at $5.06/therm of first year savings
Transport Customer Energy Efficiency	Applied Energy Group projection of savings at $1.79/therm of first year savings
Gas Heat Pump Cost	$4,000 total cost to utility for a residential heating system, $13,000 for a Commercial heating System; $1,600 for residential water heater
Dual-Fuel System Costs	Net cost of $400 to utility



Scenario 7 – RNG and H2 Policy Support



Scenario 7 – RNG and H2 Policy Support

Capacity Resource Options

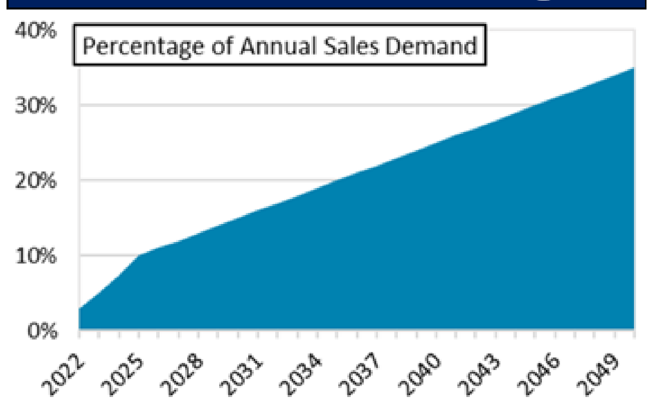
Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	Max: 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800

Compliance Resource Options

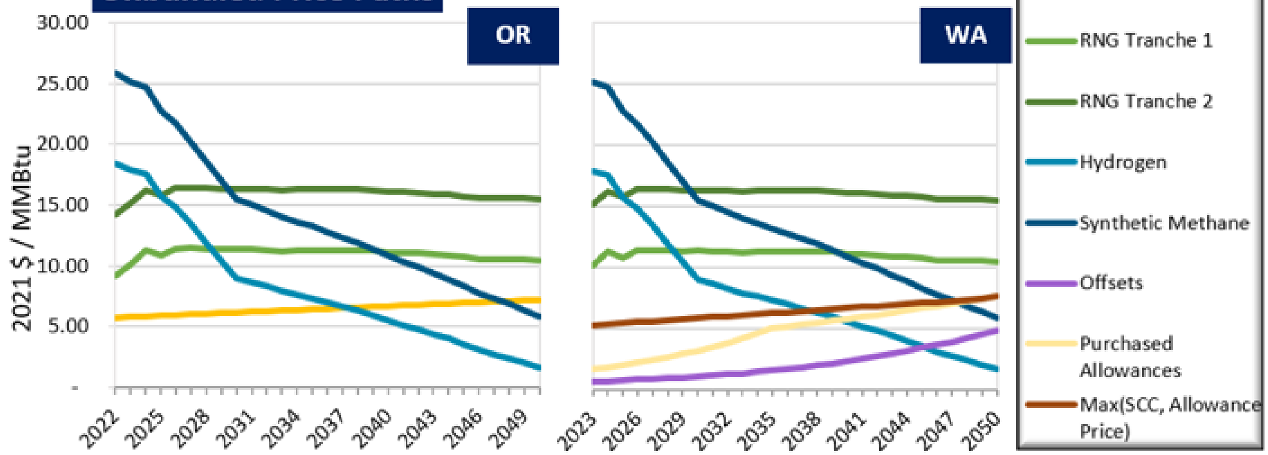
Quantity Available

Option	Limit
RNG Tranche 1	17,000,000 Dth / year
RNG Tranche 2	35,000,000 Dth / year
Hydrogen	30% of Deliveries by Energy
Synthetic Methane	Unbounded
CCIs	OR Compliance Period 1: 10% OR Compliance Period 2: 15% OR Compliance Period >=3: 20%
Allowances	Unbounded
Offsets	WA Compliance Period 1: 6% WA Compliance Period >=2: 8%

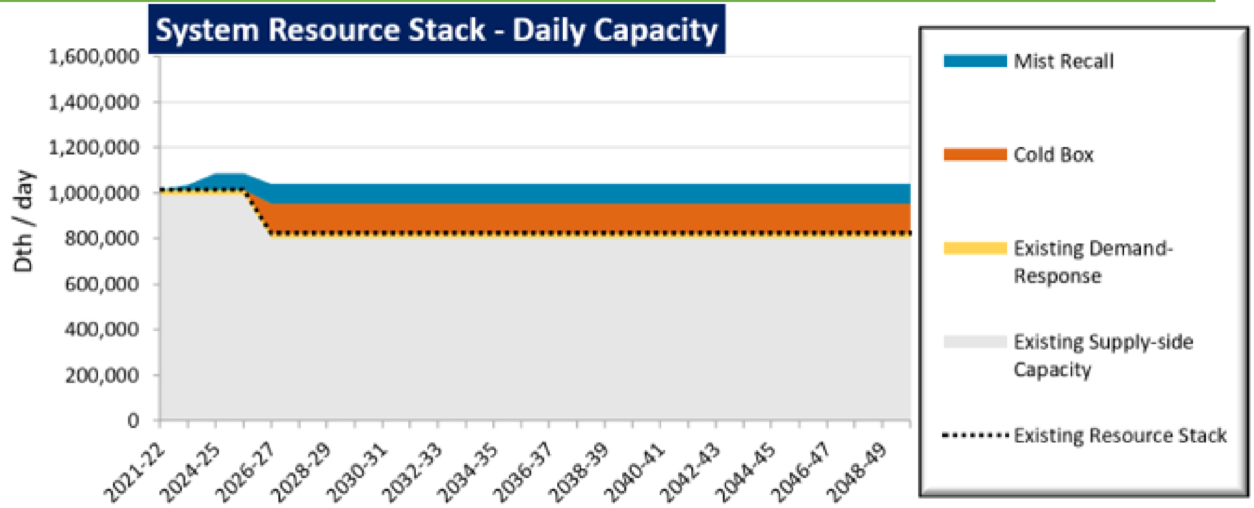
OR SB 98 / WA HB 1257 RNG Targets

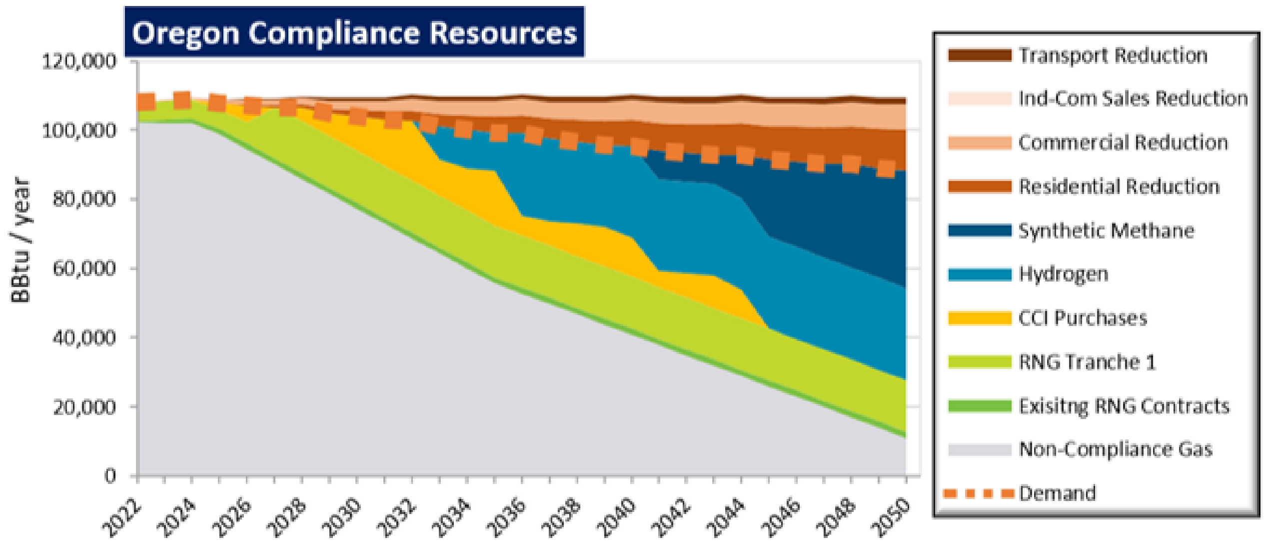


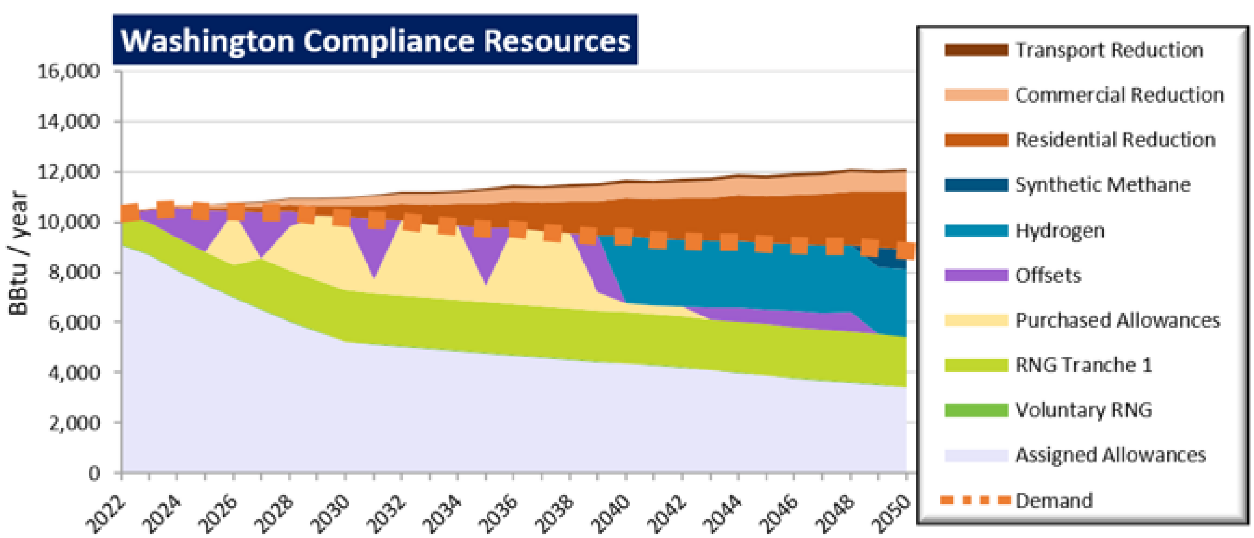
Unbundled Price Paths



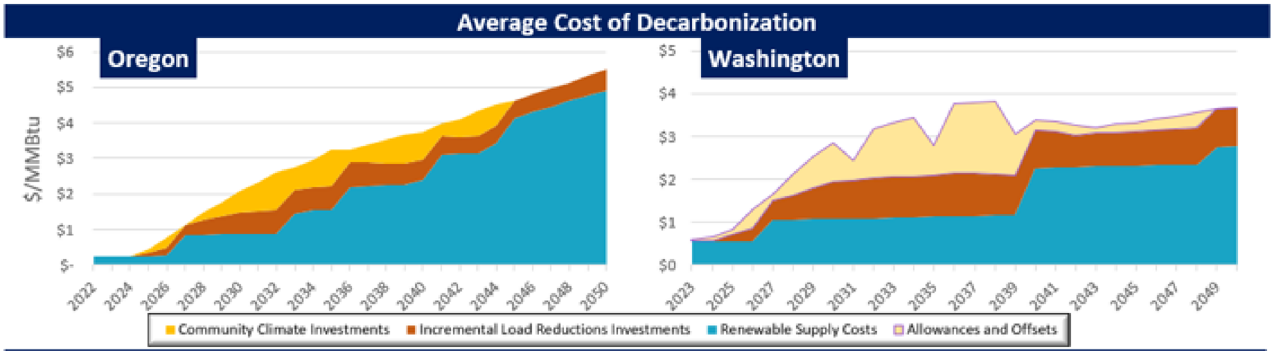
Scenario 7 – RNG and H2 Policy Support

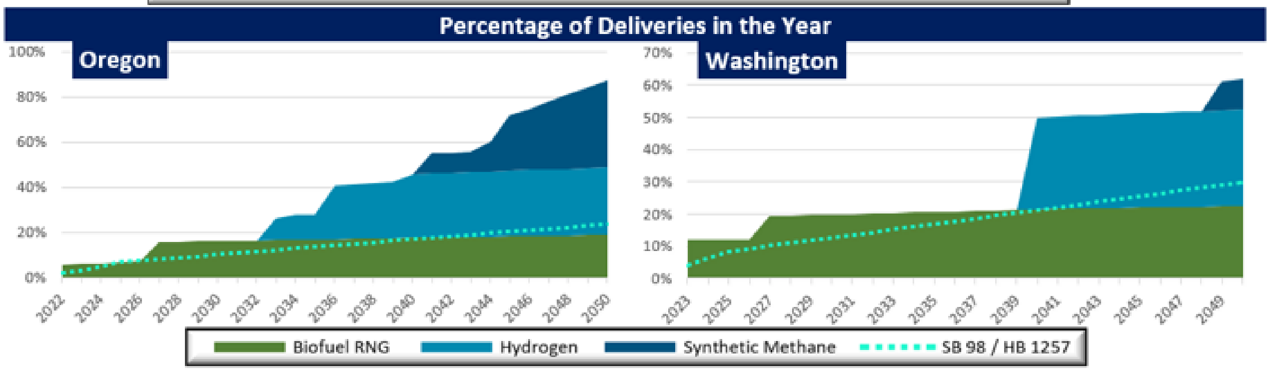


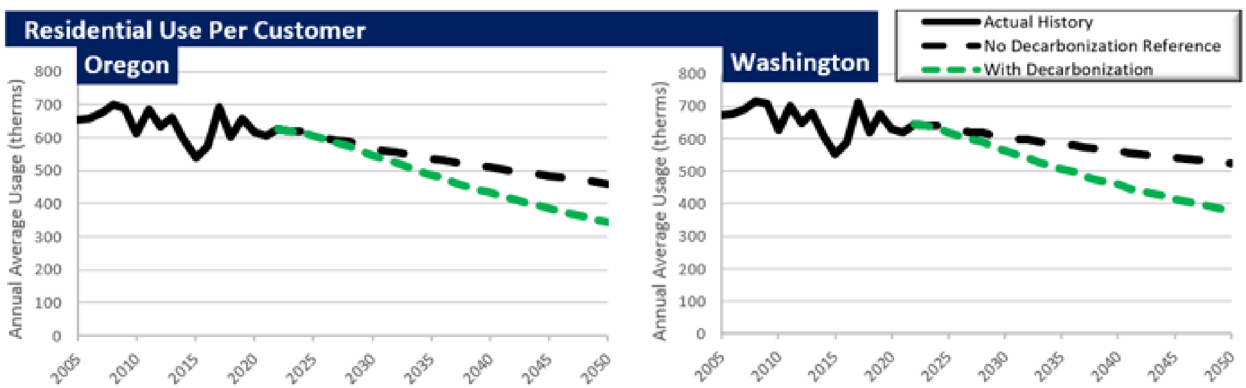


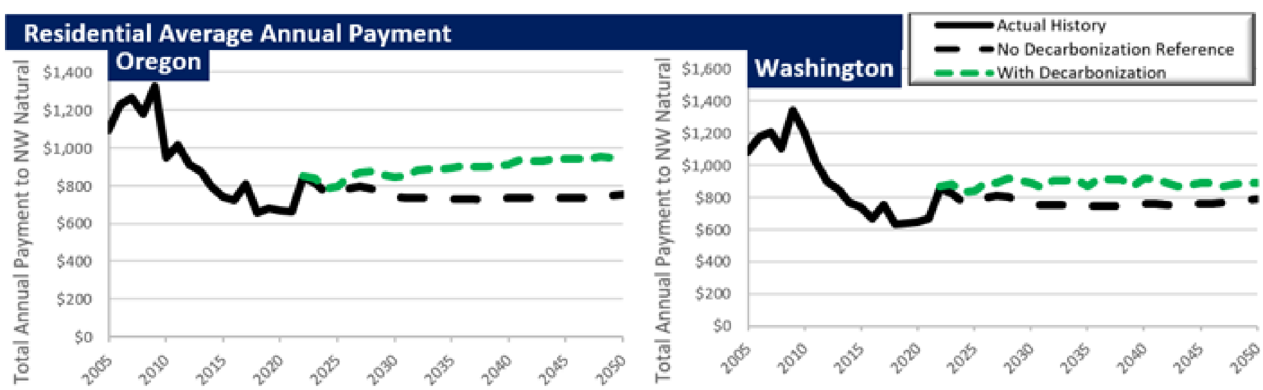


Scenario 7 – RNG and H2 Policy Support









NW Natural®

Scenario 7 – RNG and H2 Policy Support

Capacity Takeaways

- Replacing Portland LNG Cold Box shown as least cost solution
- Additional capacity needs served by Mist Recall, with a total recall of 85,000 Dth with the last recall occurring in 2027

Oregon Emissions Takeaways

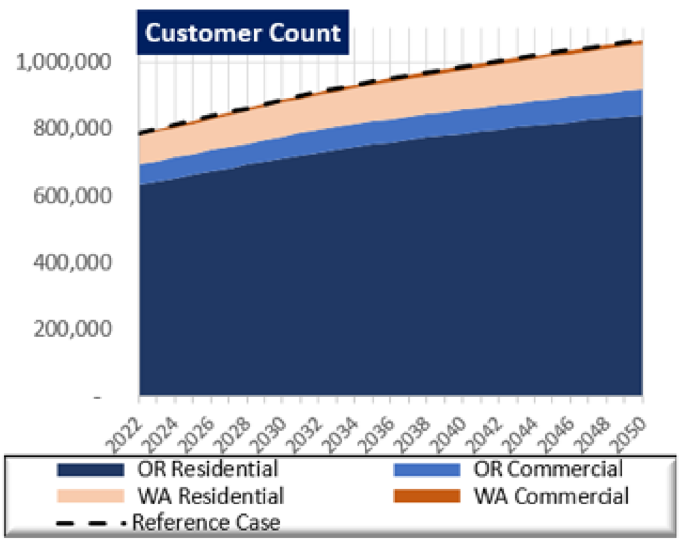
- Meeting RNG targets for SB 98 represents most of the needed emissions reduction for the first compliance period of the Climate Protection Program
- Biofuel RNG represents the marginal compliance activity in the near- to medium-term, transitioning to renewable hydrogen for blending or dedicated delivery starting in 2033, and then transitioning to synthetic renewable natural gas in 2041
- Renewable supply represents roughly 85% of deliveries in 2050, which is equivalent to roughly 2/3 of current gas deliveries in Oregon. Biofuel RNG deliveries represent roughly 14% of current load in 2050
- Decarbonization action to comply with SB 98 and the CPP results in residential gas utility bills being 14% higher in 2030 and 26% higher in 2050 than in a world without these policies

Washington Emissions Takeaways

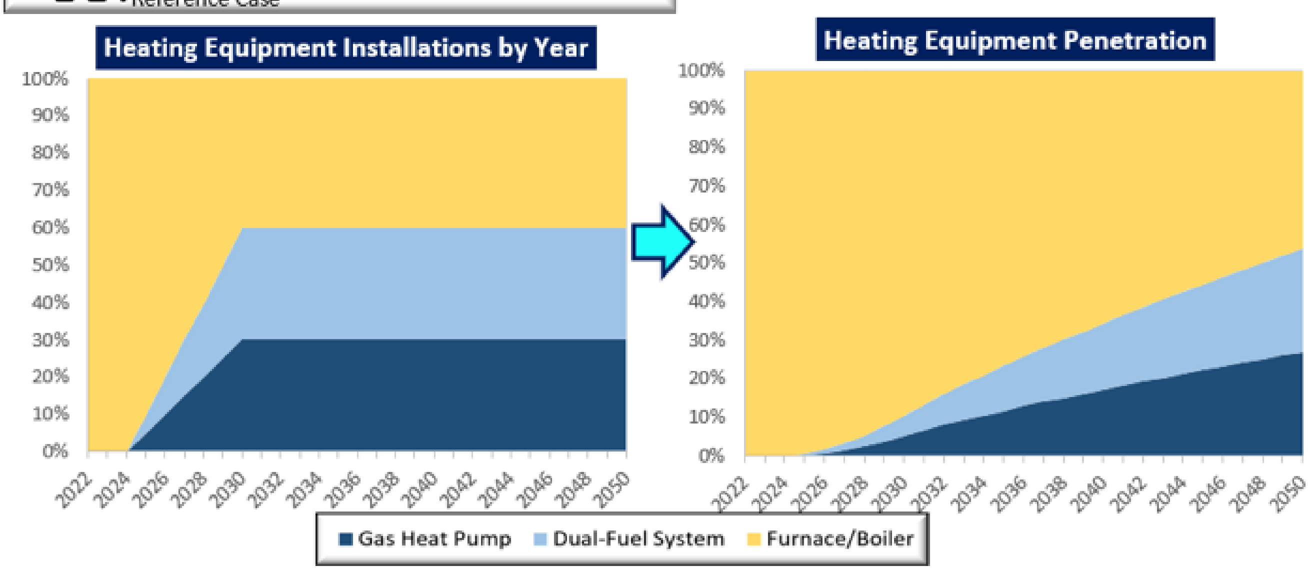
- Delivering RNG for HB 1257 and utilizing offsets represents the bulk of net near term compliance with Cap-and-Invest, with allowance purchasing filling in any gaps
- Renewable supply represents roughly 60% of deliveries in 2050
- Complying with HB 1257 and Cap-and-Invest results in residential gas utility bills being 19% higher in 2030 and 12% higher in 2050 than in a world without these policies

Scenario 8 – Limited RNG

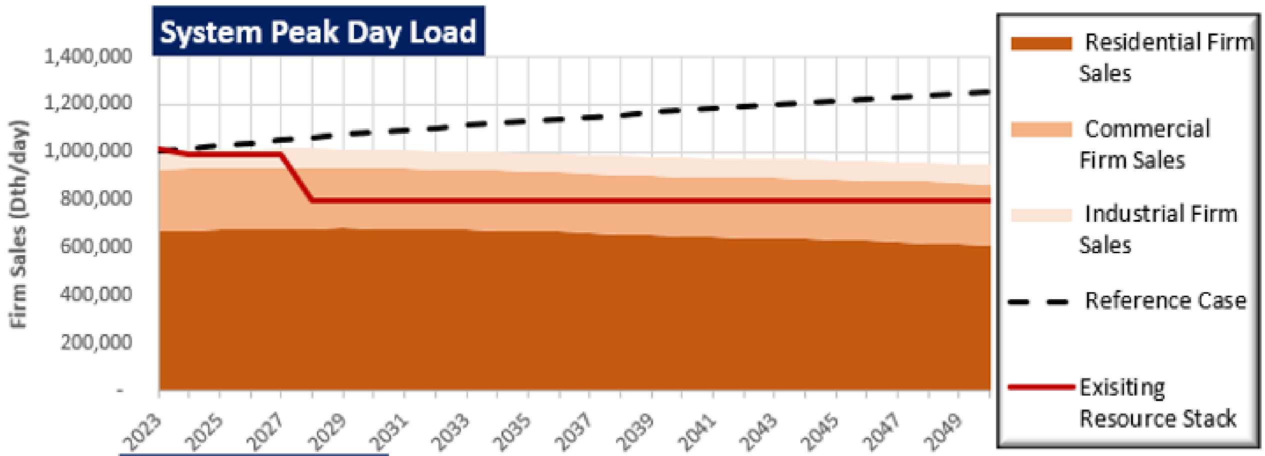
Scenario 8 helps to answer the question "What are the implications if biofuel RNG is less plentiful and more expensive than expected?" This scenario assumes a low resource potential for biofuel RNG (roughly half of the resource assumed in Scenario 1) at a higher cost than can be seen in current markets, and that less hydrogen can be delivered to customers via a combination of blending and dedicated delivery to some customers. Customer growth and demand-side resource assumptions in this Scenario are the same as Scenario 1.

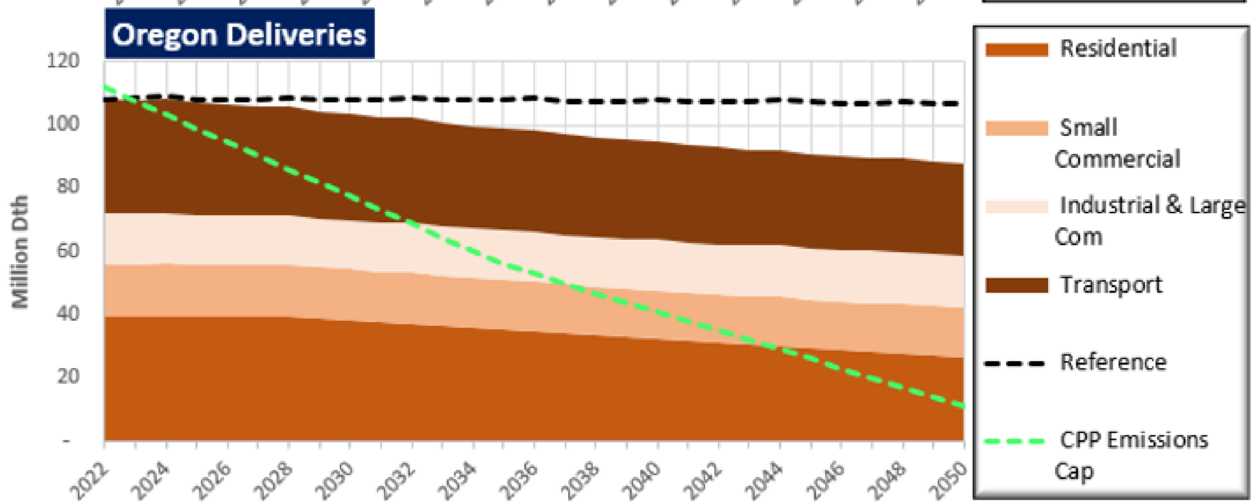


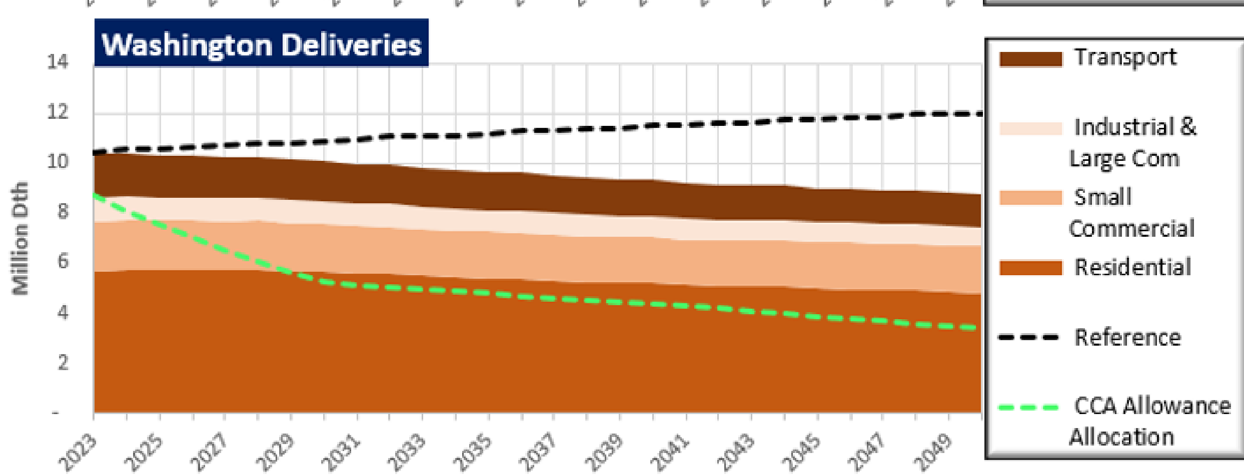
Demand-Side Assumptions	
Sales Customer Energy Efficiency	Energy Trust of Oregon projection of savings, at $5.06/therm of first year savings
Transport Customer Energy Efficiency	Applied Energy Group projection of savings at $1.79/therm of first year savings
Gas Heat Pump Cost	$4,000 total cost to utility for a residential heating system, $13,000 for a Commercial heating System; $1,600 for residential water heater
Dual-Fuel System Costs	Net cost of $400 to utility



Scenario 8 – Limited RNG







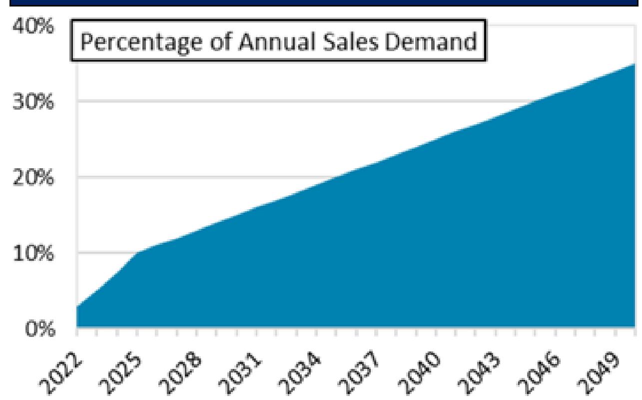
Scenario 8 – Limited RNG

Capacity Resource Options		
Capacity Resource	**Cost ($/Dth/day)**	**Daily Deliverability (Dth/day)**
Mist Recall	$ 0.09	Max: 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800

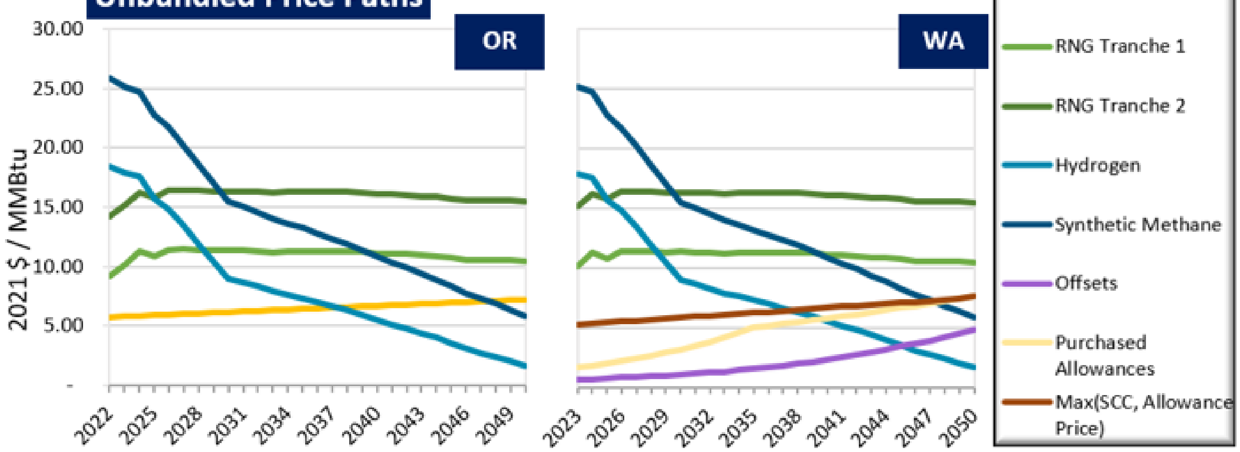
Compliance Resource Options

Quantity Available	
Option	**Limit**
RNG Tranche 1	8,000,000 Dth / year
RNG Tranche 2	13,000,000 Dth / year
Hydrogen	12% of Deliveries by Energy
Synthetic Methane	Unbounded
CCIs	OR Compliance Period 1: 10% OR Compliance Period 2: 15% OR Compliance Period >=3: 20%
Allowances	Unbounded
Offsets	WA Compliance Period 1: 6% WA Compliance Period >=2: 8%

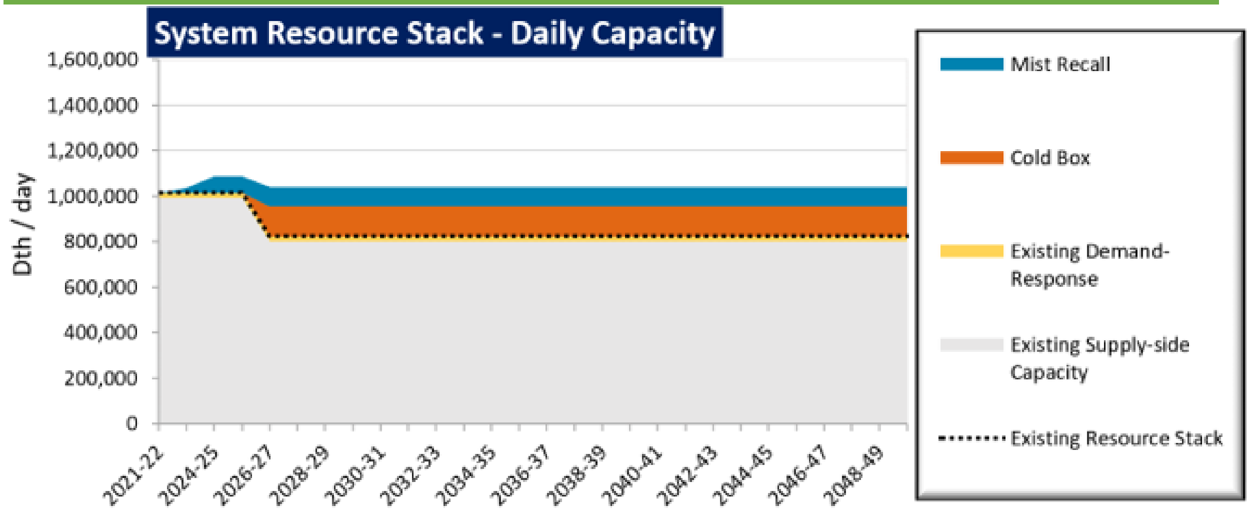
OR SB 98 / WA HB 1257 RNG Targets

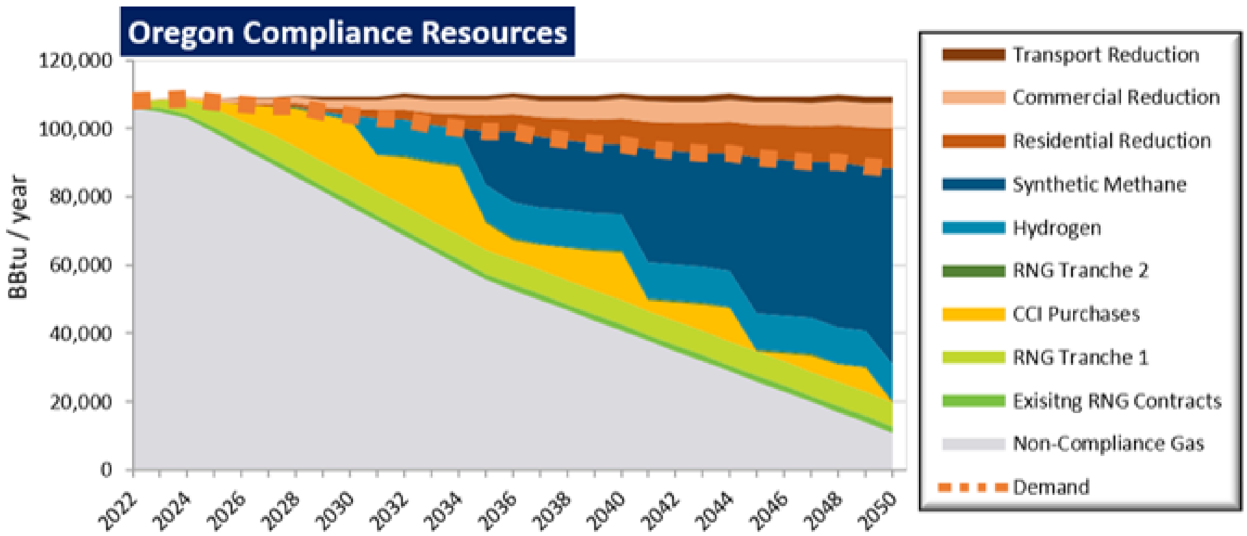


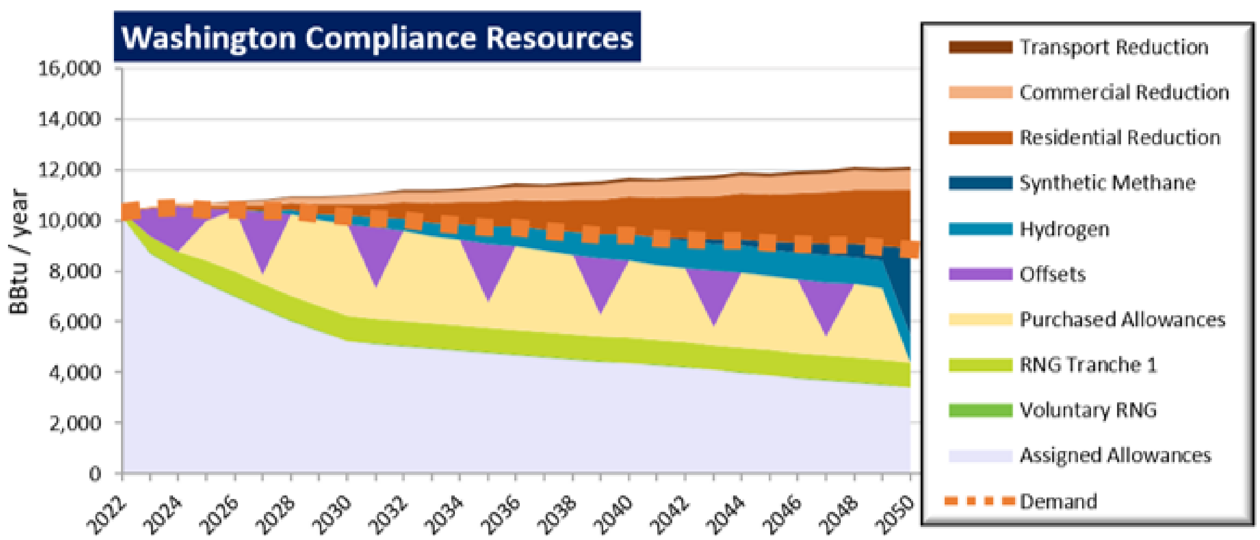
Unbundled Price Paths



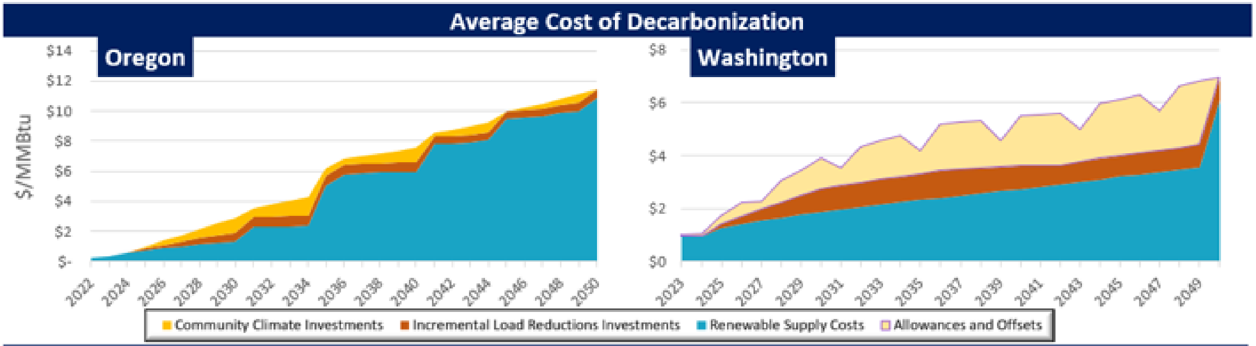
Scenario 8 – Limited RNG

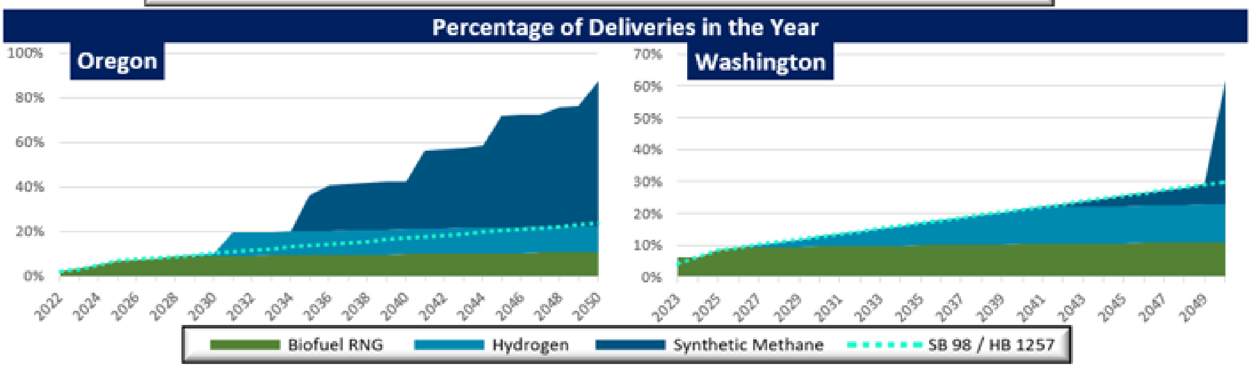


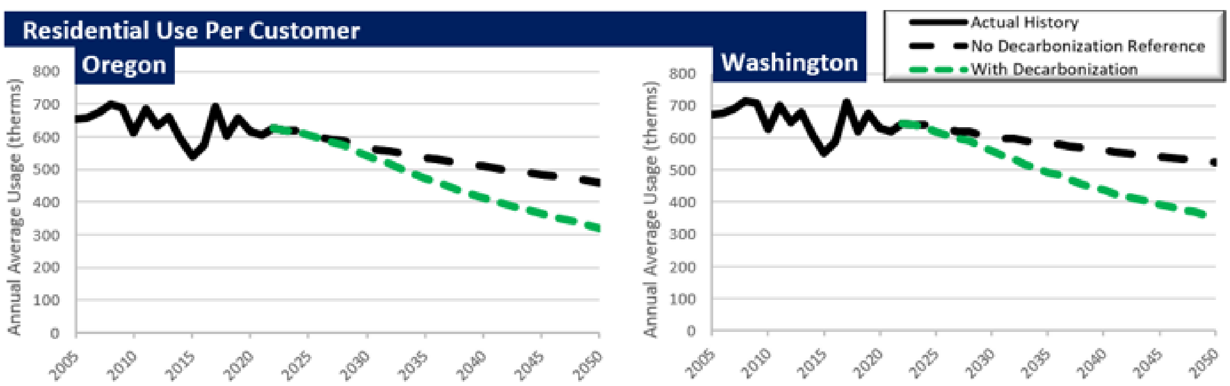


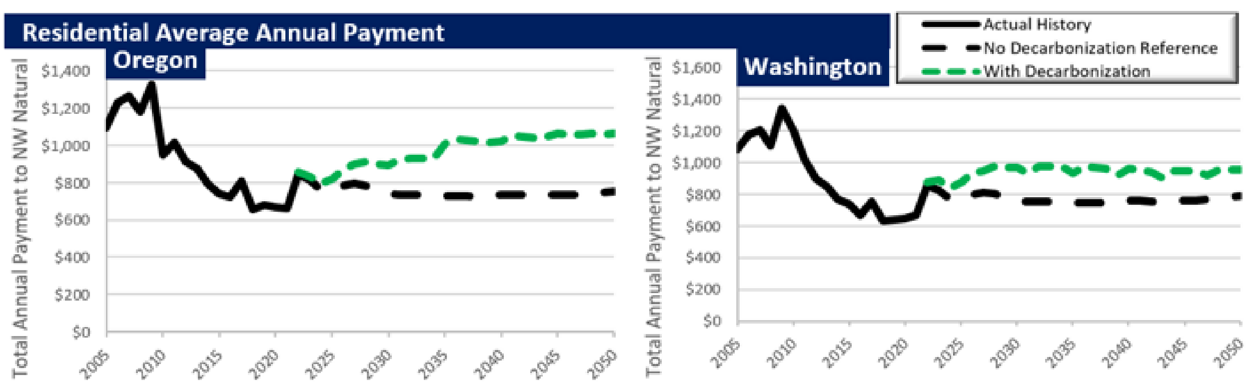


Scenario 8 – Limited RNG









Scenario 8 – Limited RNG

Capacity Takeaways

- Replacing Portland LNG Cold Box shown as least cost solution
- Additional capacity needs served by Mist Recall, with a total recall of 85,000 Dth with the last recall occurring in 2027

Oregon Emissions Takeaways

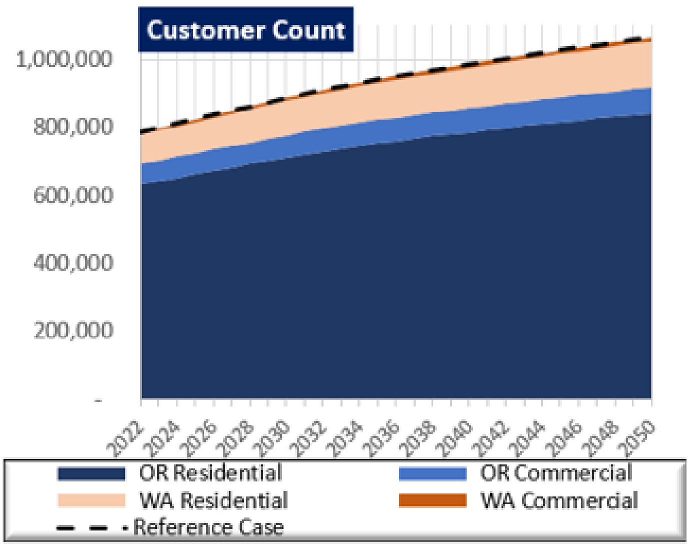
- Meeting RNG targets for SB 98 represents most of the needed emissions reduction for the first compliance period of the Climate Protection Program; small amounts of Community Climate Investments (CCIs) may be purchased to meet additional requirements depending on weather and other conditions
- Biofuel RNG and CCIs represent the marginal compliance activity in the near- to medium-term, transitioning to renewable hydrogen for blending or dedicated delivery starting in 2029, and then transitioning to synthetic renewable natural gas in 2035
- Renewable supply represents roughly 90% of deliveries in 2050, which is equivalent to roughly ¾ of current gas deliveries in Oregon. Biofuel RNG deliveries represent roughly 7% of current load in 2050
- Decarbonization action to comply with SB 98 and the CPP results in residential gas utility bills being 21% higher in 2030 and 41% higher in 2050 than in a world without these policies

Washington Emissions Takeaways

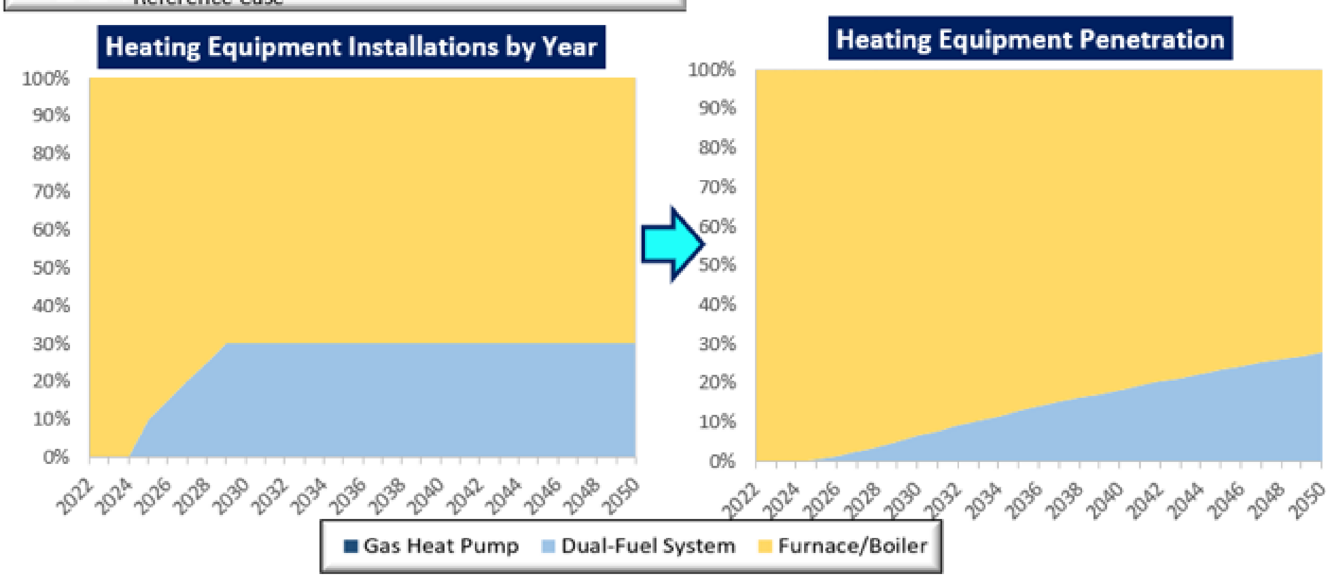
- Delivering RNG for HB 1257 and utilizing offsets represents the bulk of net near term compliance with Cap-and-Invest, with allowance purchasing filling in any gaps
- Renewable supply represents roughly 60% of deliveries in 2050
- Complying with HB 1257 and Cap-and-Invest results in residential gas utility bills being 28% higher in 2030 and 21% higher in 2050 than in a world without these policies

Scenario 9 – Supply-Focused Decarbonization

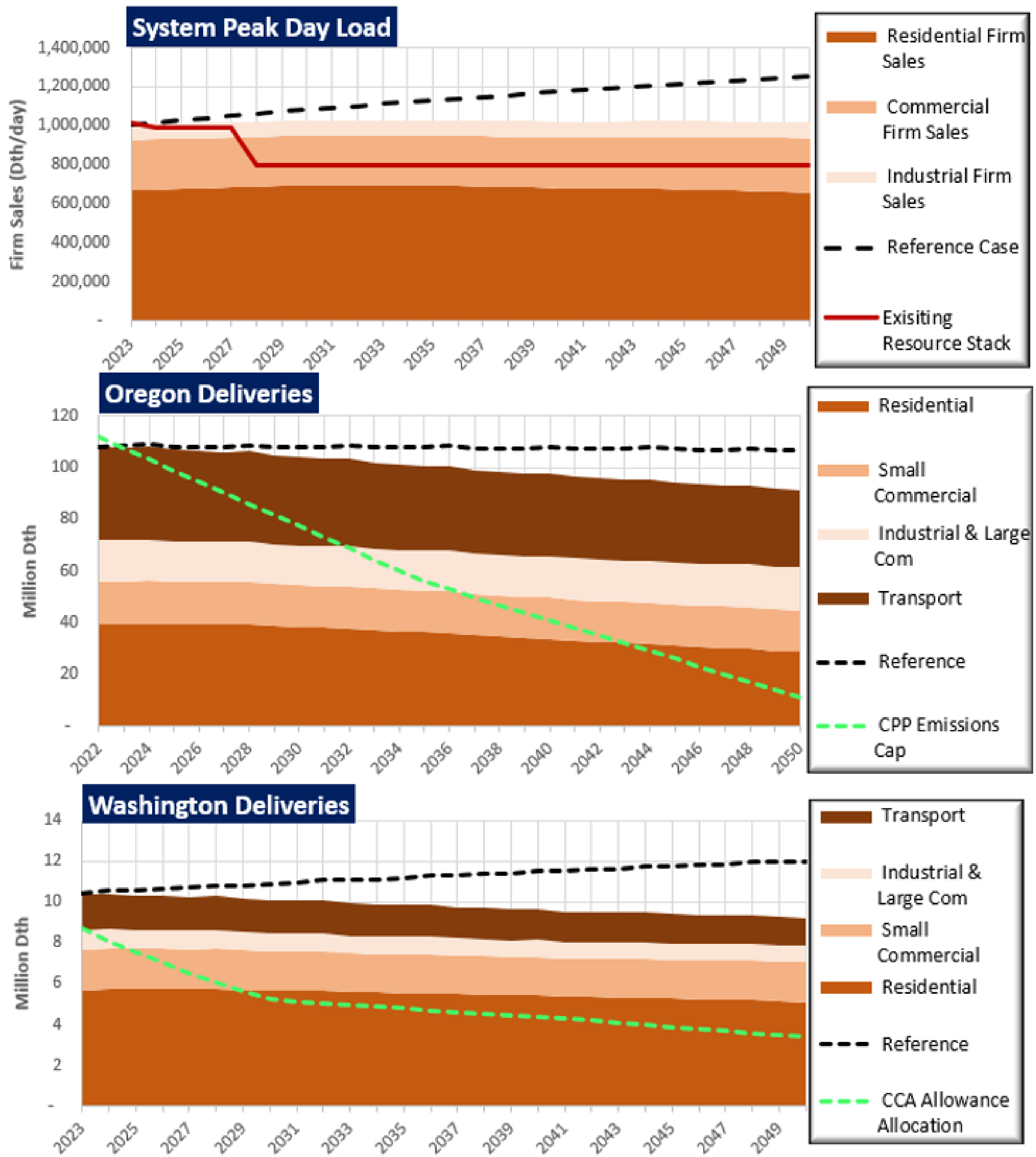
Scenario 9 helps to answer the question "What would it mean if less load can be reduced than is expected?" This scenario assumes less energy efficiency can be achieved than Scenario 1 and assumes that natural gas heat pump technology never becomes available in NW Natural's service territory. This assumption results in a great need for renewable supply to meet the emissions requirements of the OR-CPP and WA-CCA programs. It assumes the same customer growth and price and availability of renewable supply sources (RNG, H2) as Scenario 1.



Demand-Side Assumptions	
Sales Customer Energy Efficiency	Energy Trust of Oregon projection of savings, at $5.06/therm of first year savings
Transport Customer Energy Efficiency	Applied Energy Group projection of savings at $1.79/therm of first year savings
Gas Heat Pump Cost	$4,000 total cost to utility for a residential heating system, $13,000 for a Commercial heating System; $1,600 for residential water heater
Dual-Fuel System Costs	Net cost of $400 to utility



Scenario 9 – Supply-Focused Decarbonization



Scenario 9 – Supply-Focused Decarbonization

Capacity Resource Options

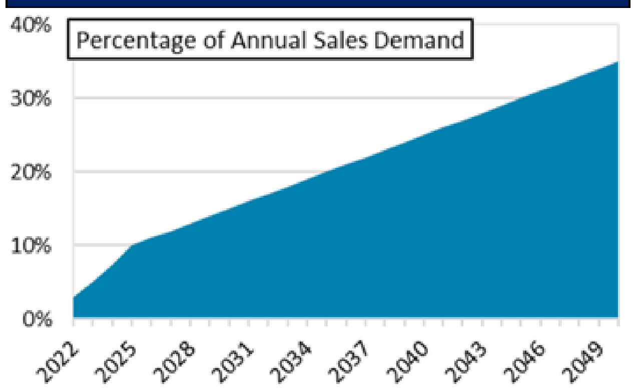
Capacity Resource	Cost ($/Dth/day)	Daily Deliverability (Dth/day)
Mist Recall	$ 0.09	Max: 203,800
Newport Takeaway 1	$ 0.14	16,125
Newport Takeaway 2	$ 1.00	13,975
Newport Takeaway 3	$ 1.41	12,900
Mist Expansion	$ 0.62	106,000
Upstream Pipeline Expansion	$ 2.12	50,000
Portland LNG - Cold Box	$ 0.06	130,800
Interstate Pipeline Looping Plus Required Mist Recall	$ 0.39	130,800
Middle Corridor NWN System Pipeline Plus Required Mist Recall	$ 0.35	130,800

Compliance Resource Options

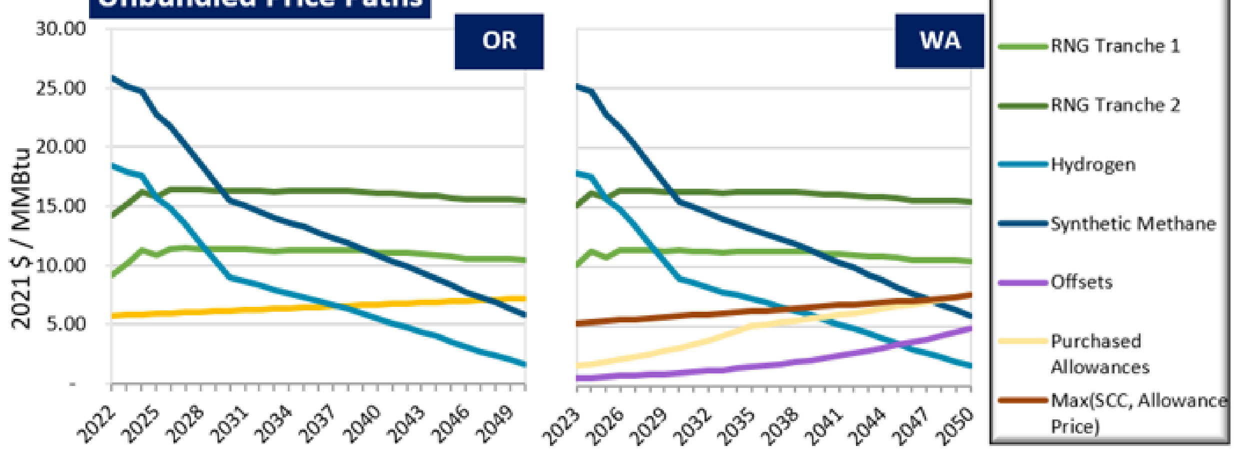
Quantity Available

Option	Limit
RNG Tranche 1	13,000,000 Dth / year
RNG Tranche 2	27,000,000 Dth / year
Hydrogen	35% of Deliveries by Energy
Synthetic Methane	Unbounded
CCIs	OR Compliance Period 1: 10% OR Compliance Period 2: 15% OR Compliance Period >=3: 20%
Allowances	Unbounded
Offsets	WA Compliance Period 1: 6% WA Compliance Period >=2: 8%

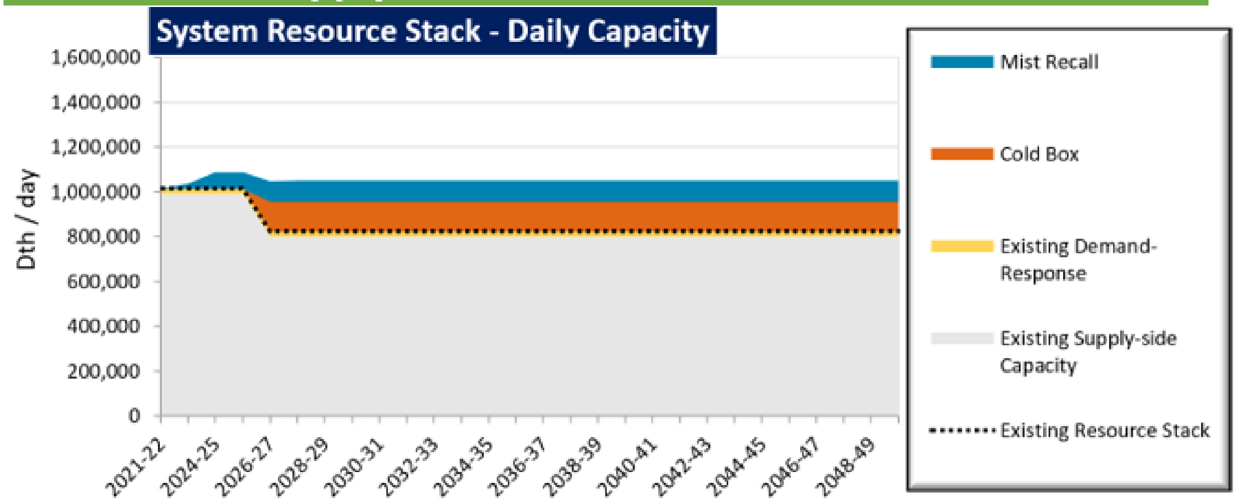
OR SB 98 / WA HB 1257 RNG Targets

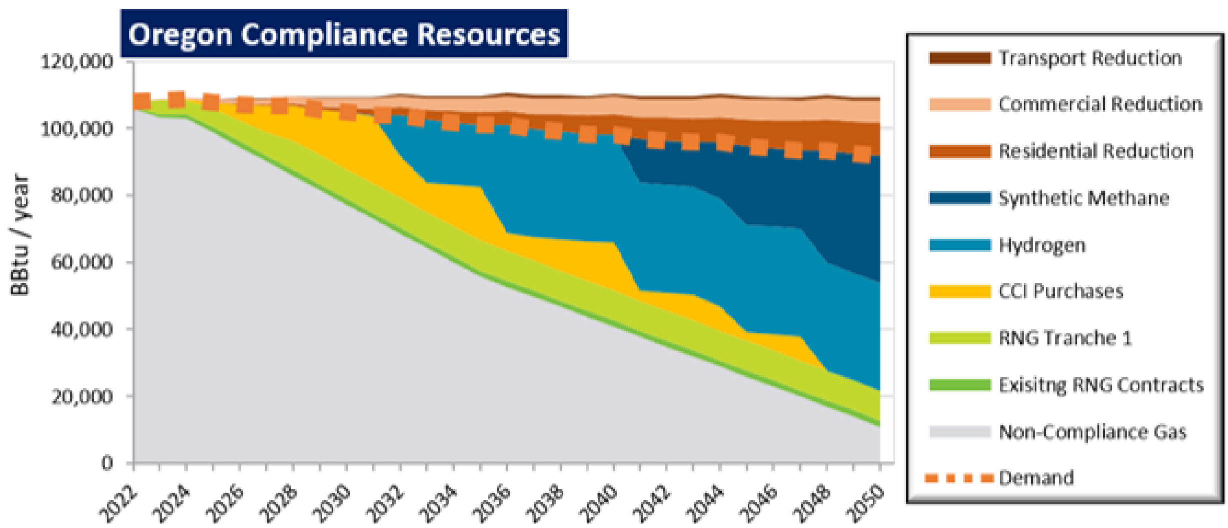


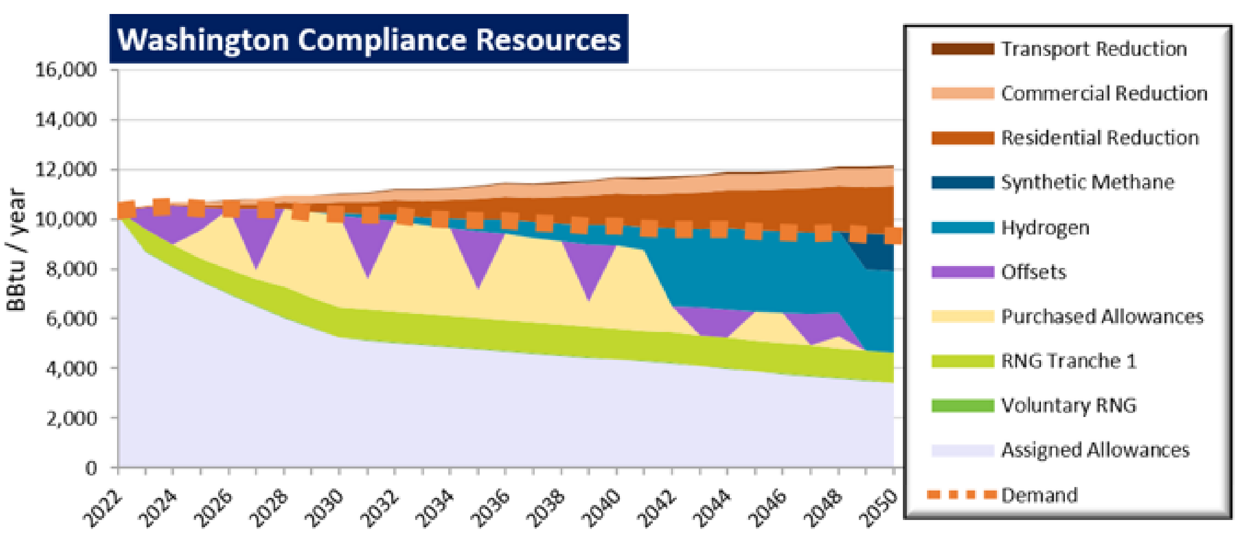
Unbundled Price Paths



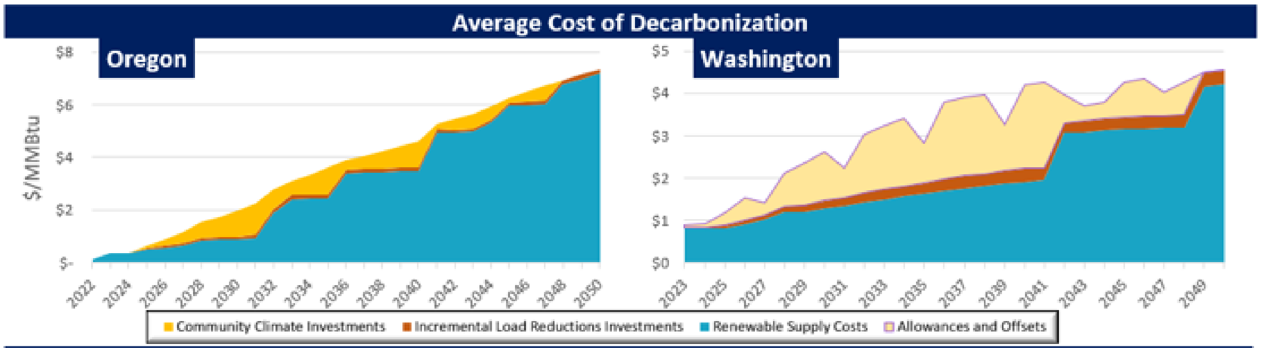
Scenario 9 – Supply-Focused Decarbonization

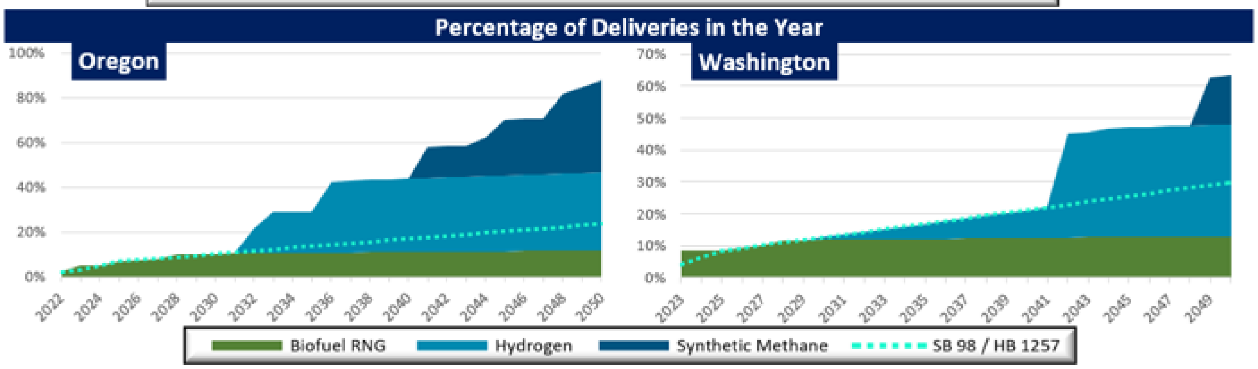


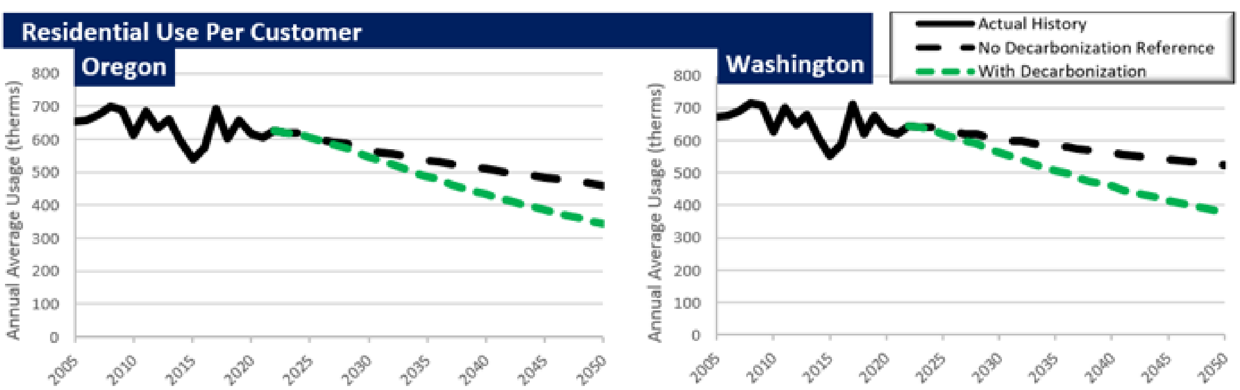


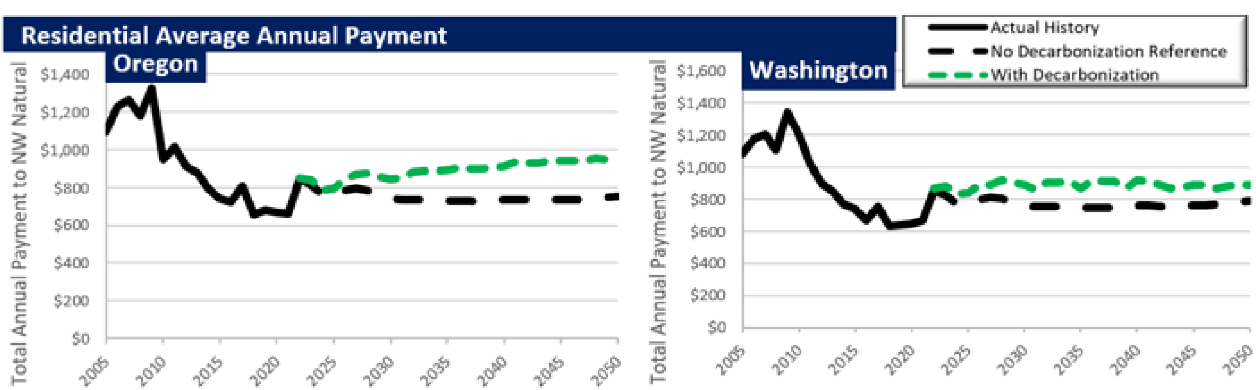


Scenario 9 – Supply-Focused Decarbonization









Scenario 9 – Supply-Focused Decarbonization

Capacity Takeaways

- Replacing Portland LNG Cold Box shown as least cost solution
- Additional capacity needs served by Mist Recall, with a total recall of 100,000 Dth with the last recall occurring in 2031

Oregon Emissions Takeaways

- Meeting RNG targets for SB 98 represents most of the needed emissions reduction for the first compliance period of the Climate Protection Program; small amounts of Community Climate Investments (CCIs) may be purchased to meet additional requirements depending on weather and other conditions
- Biofuel RNG and CCIs represent the marginal compliance activity in the near- to medium-term, transitioning to renewable hydrogen for blending or dedicated delivery starting in 2031, and then transitioning to synthetic renewable natural gas in 2041
- Renewable supply represents roughly 90% of deliveries in 2050, which is equivalent to roughly ¾ of current gas deliveries in Oregon. Biofuel RNG deliveries represent roughly 8% of current load in 2050
- Decarbonization action to comply with SB 98 and the CPP results in residential gas utility bills being 14% higher in 2030 and 26% higher in 2050 than in a world without these policies

Washington Emissions Takeaways

- Delivering RNG for HB 1257 and utilizing offsets represents the bulk of net near term compliance with Cap-and-Invest, with allowance purchasing filling in any gaps
- Renewable supply represents roughly 65% of deliveries in 2050
- Complying with HB 1257 and Cap-and-Invest results in residential gas utility bills being 29% higher in 2030 and 12% higher in 2050 than in a world without these policies

7.5 Scenario Results Takeaways

In all the scenarios, the expected volumes from SB 98 and HB 1257 RNG – of which biofuels are shown as the lowest cost option – make up a significant amount of the needed compliance action in the first compliance periods (CPP:2022-2024, CCA:2023-2027). Similarly, in Oregon CCIs are used to fill in any gaps not served by SB 98 targets in the term, and that NW Natural is not expected to bump up against CCI limits in the CPP until the period around 2030. Since the amount of RNG needed to achieve SB 98 targets varies by scenario due to differences in load (SB 98 targets are a percentage of sales load), higher load scenarios show more SB 98 RNG and lower load scenarios show smaller amounts SB 98 RNG, though the difference is small given that load cannot change materially from current levels by the end of 2024. Also, even in scenarios with aggressive load reductions going forward, the amount of RNG that aligns with near-term SB 98 targets would be able to be utilized for compliance (i.e., not "wasted" in terms of compliance needs). Furthermore, over the first compliance period it is not anticipated that RNG or clean hydrogen would be cheaper than CCIs, making a strategy of purchasing compliance needs in excess of SB 98 a robust option. This strategy is further supported by the flexible nature of CCIs, where they can be purchased for any of the three years compliance period in any of those three years.

Also, when looking across scenarios at compliance with the CPP there is a consistent trend in expected emissions compliance resources through time. In the near-term biofuel RNG is the cheapest option and is used to meet SB 98 targets, whereas renewable hydrogen is expected to become the incremental resource starting around 2030, and once blending limits are reached around 2040, synthetic methane (or methanated renewable hydrogen) becomes the cheapest resource, expected to become cheaper than CCIs and WA allowances in later years in the planning horizon.

For compliance with the Washington Cap-and-Invest program the results show offsets are expected to be the lowest cost compliance option, and if compliance offsets can be procured at prices seen in today's market, they should be acquired to the maximum amount and used for compliance. There is still work that needs to be done to understand what offsets might be available on tribal lands and what they might cost, but if these can be procured at a price lower than the expected price of allowances they would also be acquired for compliance. Allowance purchases show as the lowest cost option to fill in the remaining compliance need over the first compliance period (2023-2027), even if allowance prices are at the price ceiling currently detailed in the draft rule. As such, a strategy of purchasing allowances in the quarterly auction adjusting in real time to load expectations and weather over the compliance period is a strategy that is robust across scenarios.

7.6 Monte Carlo Outcomes

The scenarios provide key insights into how a particular set of inputs can change the outcomes of resource planning. In fact, many key inputs, such as weather, are held constant across all the scenarios to isolate impacts from other key demand-side or supply-side inputs. While the scenario results are very informative, it is certain that the future will not mimic any single scenario. We know that weather will fluctuate from one year to the next, key demand drivers are subject to policy changes, efficiency and technology gains will ebb and flow, and prices and availability for all resources will rise and fall. Therefore, we generate 500 Monte Carlo draws for the key uncertainties as discussed earlier in this chapter (Table 7.4).

The PLEXOS® model imports data files containing these 500 draws for demand, resource prices, and uncertain quantity limitations. The model produces a unique solution for each draw.[151] While the simulation for the inputs has been discussed throughout the IRP, this section presents the outcomes from the PLEXOS® solutions.

7.6.1 Capacity Resource Acquisitions

Table 7.5 summarizes the capacity resource acquisitions across all draws. As anticipated, Mist Recall is the marginal capacity resource selected in the near-term for 99% of the draws. Mist Recall has been the marginal capacity resource for NW Natural for several IRPs now as Mist Recall is relatively cheap capacity and comes with additional storage capacity, which provides ancillary benefits for customers. Given the demand simulations and their implications on peak day demand, only 4% of the draws require an additional capacity resource beyond Mist Recall. In other words, Mist Recall is sufficient to meet customer peak energy requirements over the planning horizon.

Table 7.5: Capacity Resource Monte Carlo Acquisition Summary

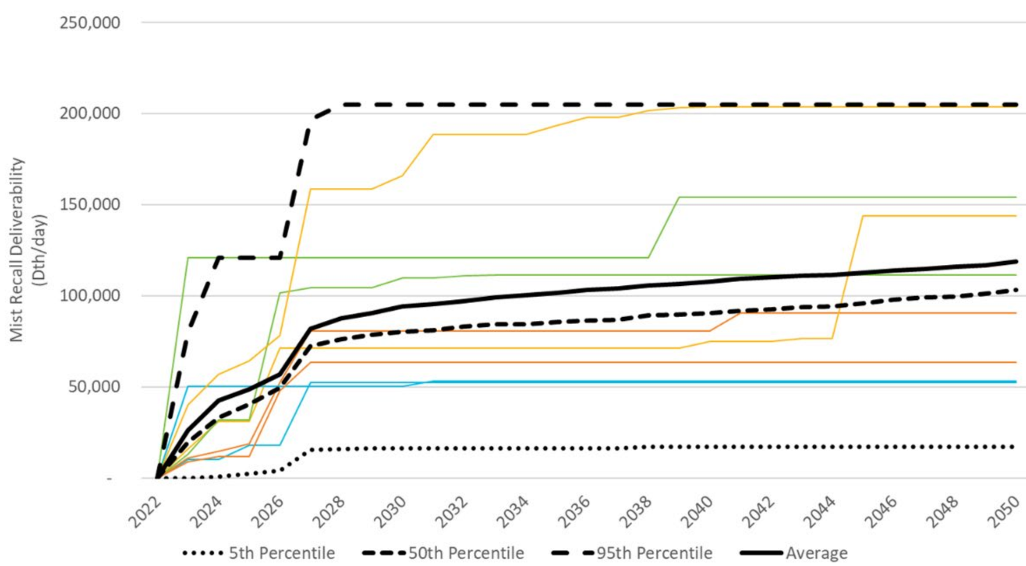
Capacity Resource	Number of Draws where Resource is Selected	If Selected Average Year
Some Mist Recall	496	2023
All Mist Recall	144	2036
Mist Expansion	17	2037
Newport Takeaway 1	21	2036
Newport Takeaway 2	9	2044
Newport Takeaway 3	6	2046
Interstate Pipeline Capacity	3	2043
Portland LNG Cold Box	500	2027†

† Portland LNG Cold Box or an alternative must be selected in 2027

[151] These solutions are not a single data point, but contain a lot of daily data for the system, such as daily conventional gas purchases, daily storage operations, annual capacity resource acquisitions, compliance resources acquisitions, upstream pipeline capacity factors, daily demand, etc…

NW Natural's resource stack is *storage heavy* relative to most other gas LDCs. If the ratio of storage assets to pipeline capacity contracts becomes too lopsided, resource acquisitions could be driven by energy requirements. In other words, given the daily maximum deliverability of pipeline capacity and injection limitations of the storage facilities, there is a threshold where there are simply not enough days in the year to fill up storage capacity as needed to serve load the following winter. As the other resources are generally not selected until after Mist Recall is exhausted, these results suggest that the Company is still well under that storage to pipeline capacity ratio threshold. Figure 7.5 summarizes the results for Mist Recall across the Monte Carlo draws.

Figure 7.5: Monte Carlo Mist Recall Acquisition



From Scenario 6 – *Full Building Electrification*, we see that under reference case prices and costs, Alternative 4 (*Decommission Portland LNG and Complete No Replacement Alternative*) is a least cost and viable solution. Scenario 6 is a bookend case where every piece of natural gas end-use equipment (furnaces, stoves, water heaters, etc.) is replaced with electric appliances beginning today. However, using the 500 simulations, which mixes and matches variation in weather, demand trajectories, and resource costs, 100% of the draws select Alternative 1, keep Portland LNG operational by investing in a new Cold Box.

7.6.2 Compliance Resource Acquisitions and Purchases

Variation in year-over-year weather, uncertainty in the long-term trajectories for demand, the availability of RNG, uncertainty in the limits of hydrogen, and changes in the costs for compliance resources all impact the amount and timing of compliance resource acquisitions. Figure 7.6 summarizes least cost portfolios of RNG compliance resources across all the Monte Carlo draws. Figure 7.7 summarizes the least cost purchases of compliance instruments (CCIs, allowances, and offsets) for compliance with the CPP and CCA.

Figure 7.6: Monte Carlo RNG Compliance Resource Acquisition

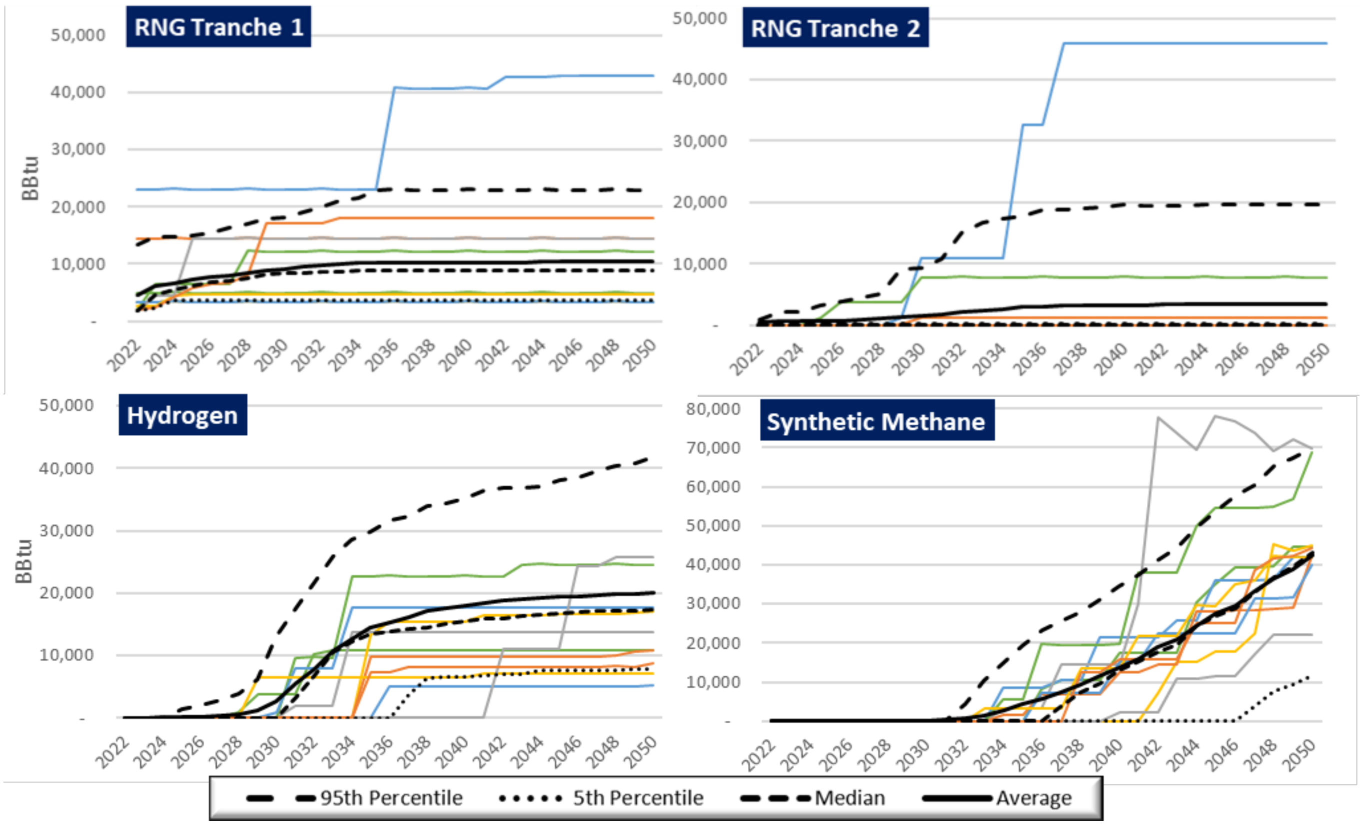
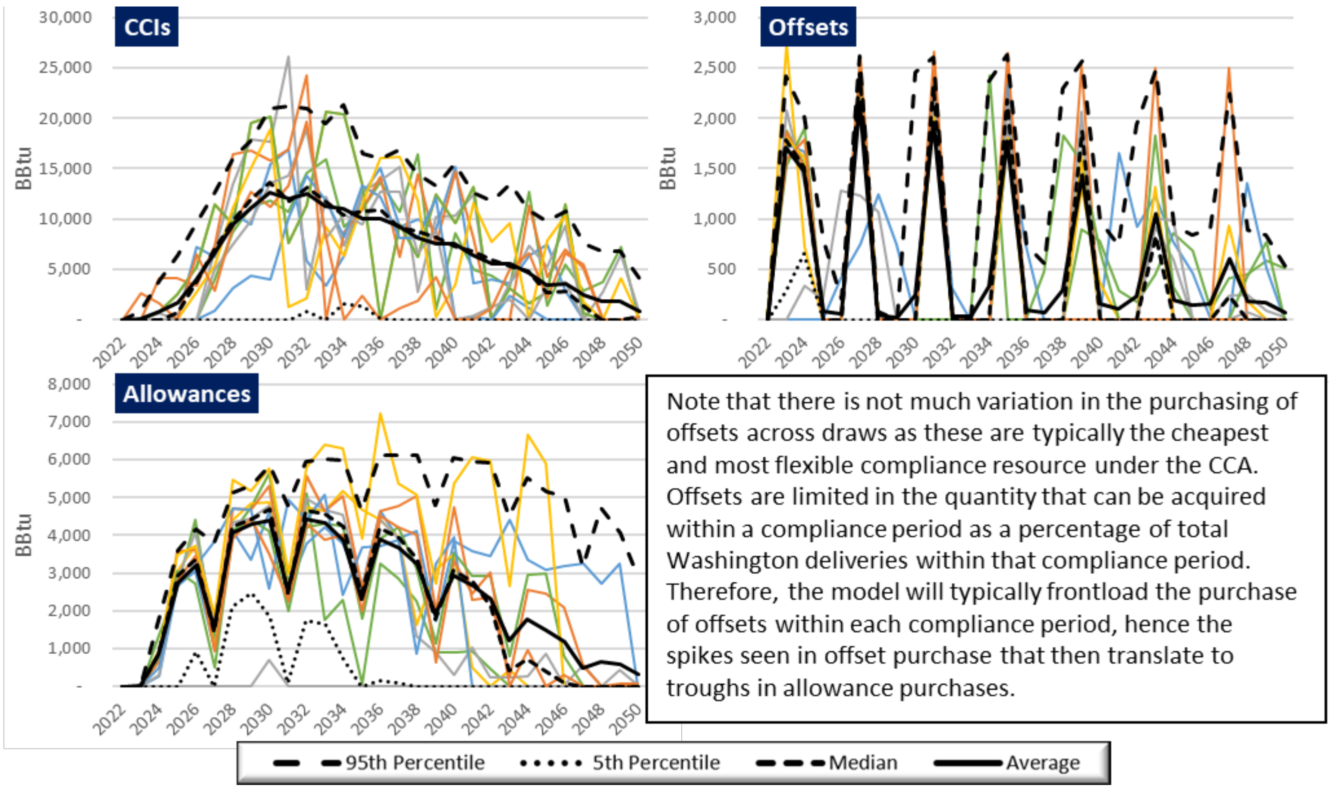


Figure 7.7:Monte Carlo Compliance Instruments Purchases



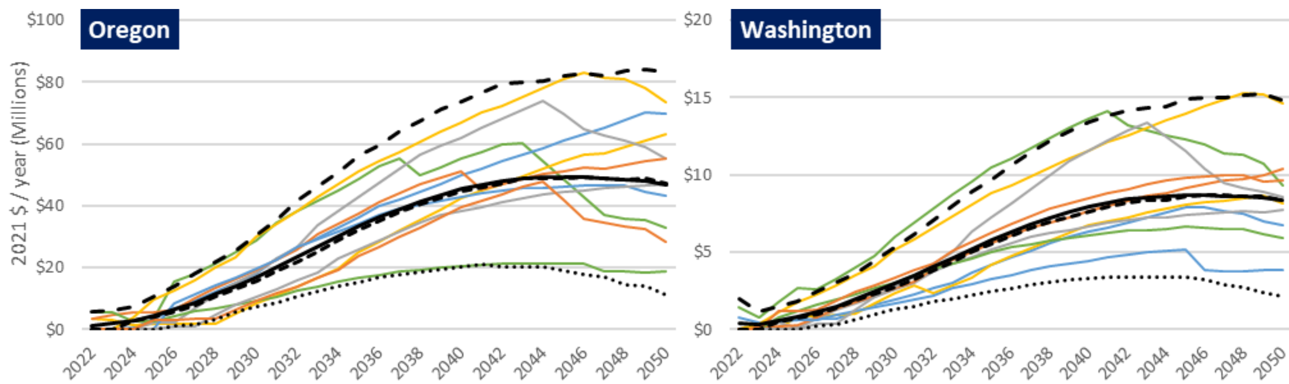
From these results, where the resource planning optimization model selects an average of roughly 5 million Dth of RNG Tranche 1 in the near-term over 500 potential different futures. Hydrogen becomes a significant part of the compliance strategy in the future, but rarely is it selected prior to 2028. Synthetic Methane sees a similar result but is never selected in any draw prior to 2031. Resources that would be represented by the costs and quantities of RNG Tranche 2, generally are not ecumenical over the planning horizon. Of course, NW Natural will be conducting IRPs every few years and as the RNG and hydrogen markets mature we will update cost and availability information as the future unfolds.

Compliance instruments, CCIs, offsets, and allowance purchases are relatively flexible compared to RNG acquisitions and can be used to *fill-in* compliance gaps due variations in weather from one compliance period to the next. Due to this flexibility instruments are often frontloaded or backloaded within a compliance period. This presents as a less smooth and more jagged purchasing strategy relative to the RNG compliance resources. Note that CCIs and allowance purchases see a *hump* shape over the planning horizon. Purchases of these instruments ramp up in the planning horizon but begin to drop off in the future.

7.6.3 Demand Reduction Investments

Demand reduction investments represent incremental investments relative to the reference case that are used for complying with emissions reduction policy. These investments may include incentivizing hybrid heating systems, gas-fired heat pumps, or expanding existing or planned energy efficiency programs.

Figure 7.8: Demand Reduction Investment Totals

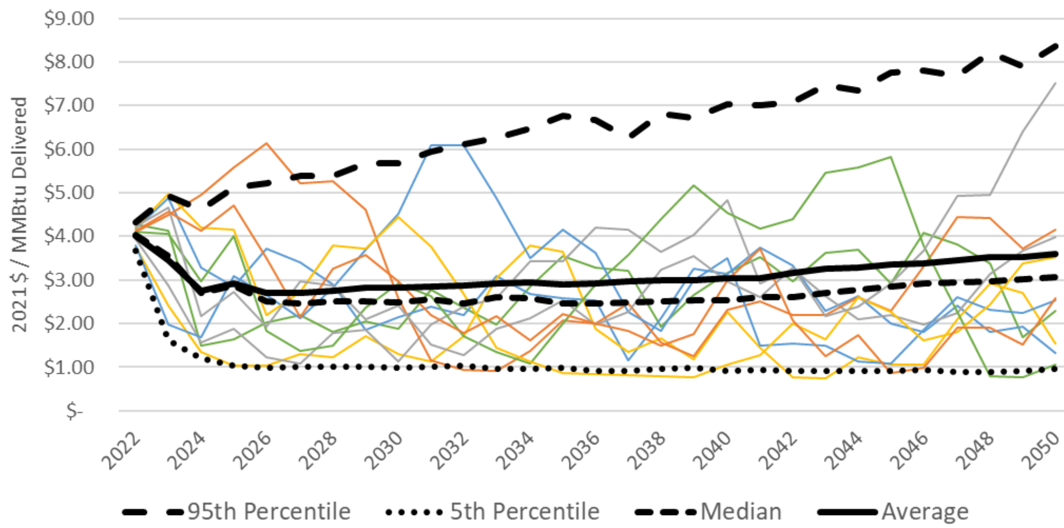


7.6.4 Weighted Average Cost of Gas

The overall gas price environment is stochastic over time, but prices at individual hubs are also stochastic.[152] When NW Natural purchases gas on the behalf of customers, there are variable shipping costs associate with each MMBtu purchased be depending on where the gas bought and what upstream pipelines it must travel along to reach NW Natural service territory. The PLEXOS® model solves the optimal purchasing portfolio or dispatch of gas contracts inclusive of these variable charges. The total dollar amount spent on gas and variable charges in a year divided by the total MMBtus purchased is the weighted average cost of gas (WACOG). Figure 7.10: Monte Carlo WACOG Figure 7.9 summarizes the WACOG that is the output of the PLEXOS® optimization across all resources.

[152] See Chapter 2 for details about natural gas price uncertainty.

Figure 7.9: Monte Carlo WACOG



7.6.5 Weighted Cost of Decarbonization

By looking the quantity of the individual resources acquired that decarbonize the gas system and multiplying those quantities by their respective costs, the Monte Carlo simulation provides the insight into the potential range of costs to decarbonize. We can bucket these costs into three distinct groups, costs from RNG resources acquired, costs from compliance instruments and costs from demand reduction investments. The weighted costs of decarbonization (WACOD) is calculated to summarized the resources that are in these three buckets as illustrated by Figure 7.10, Figure 7.11, and Figure 7.12. The total WACOD for each state is the sum of these buckets, shown by Figure 7.13.

Figure 7.10: Monte Carlo WACOD from Renewable Compliance Resources

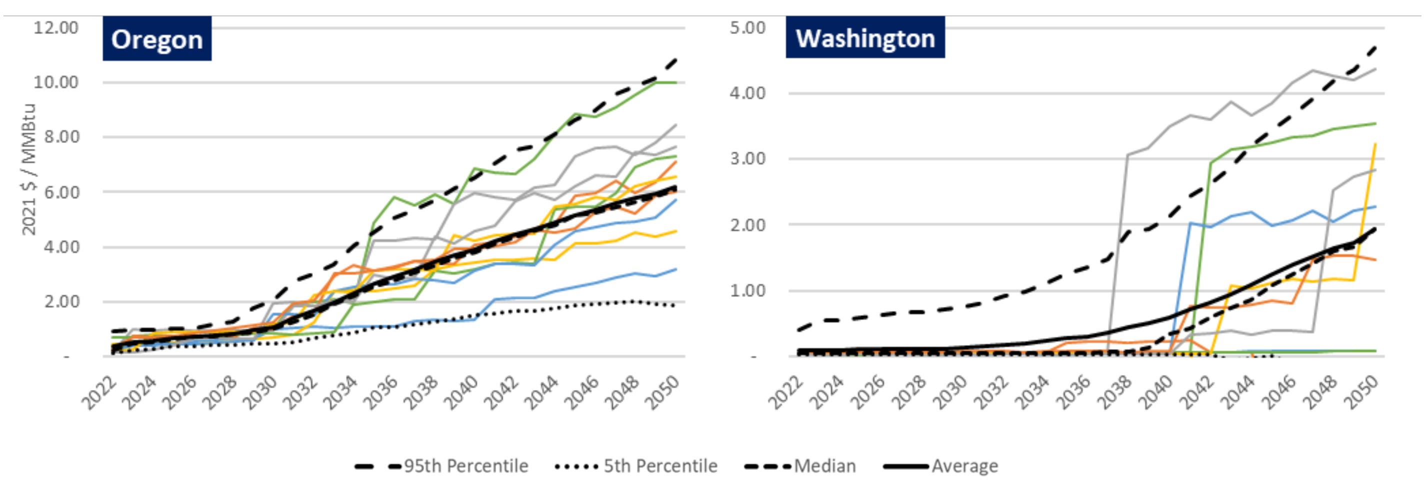


Figure 7.11: Monte Carlo WACOD from Compliance Instruments

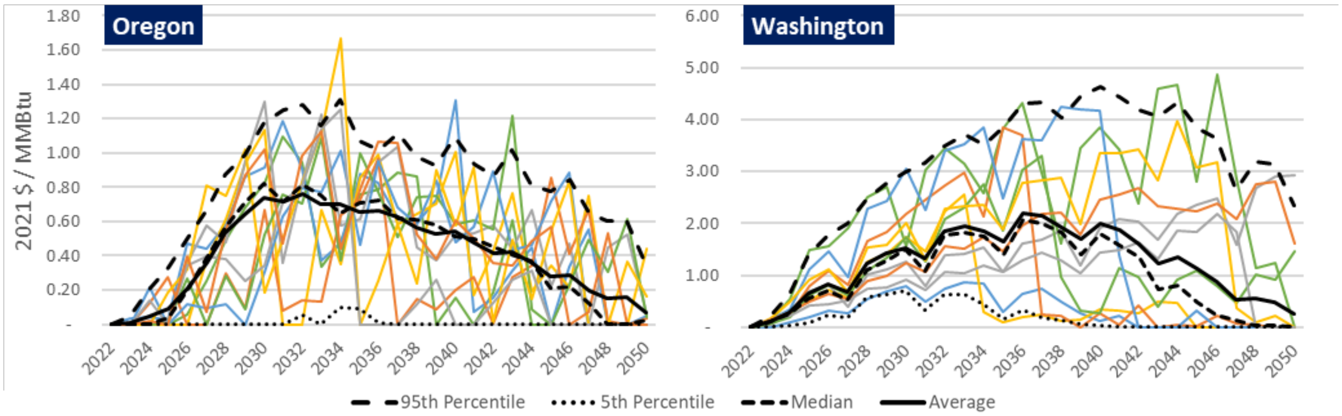


Figure 7.12: Monte Carlo WACOD from Demand Reduction Investments

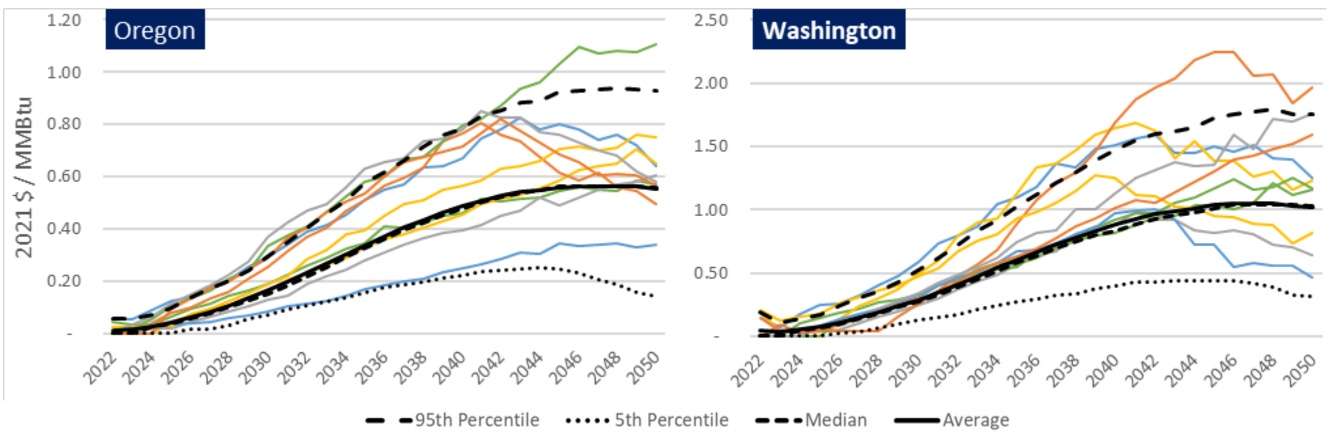
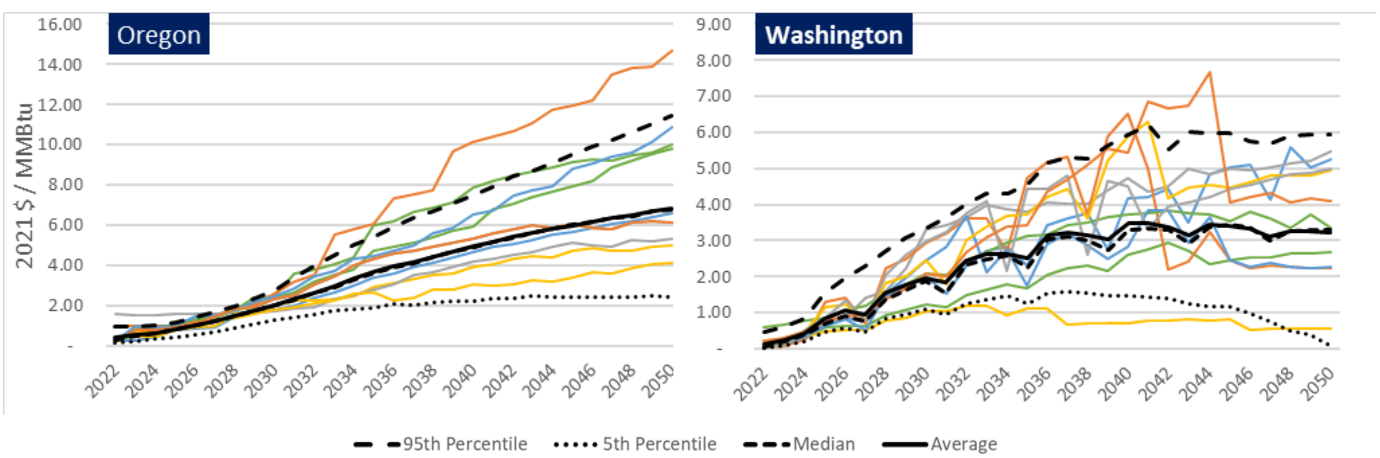
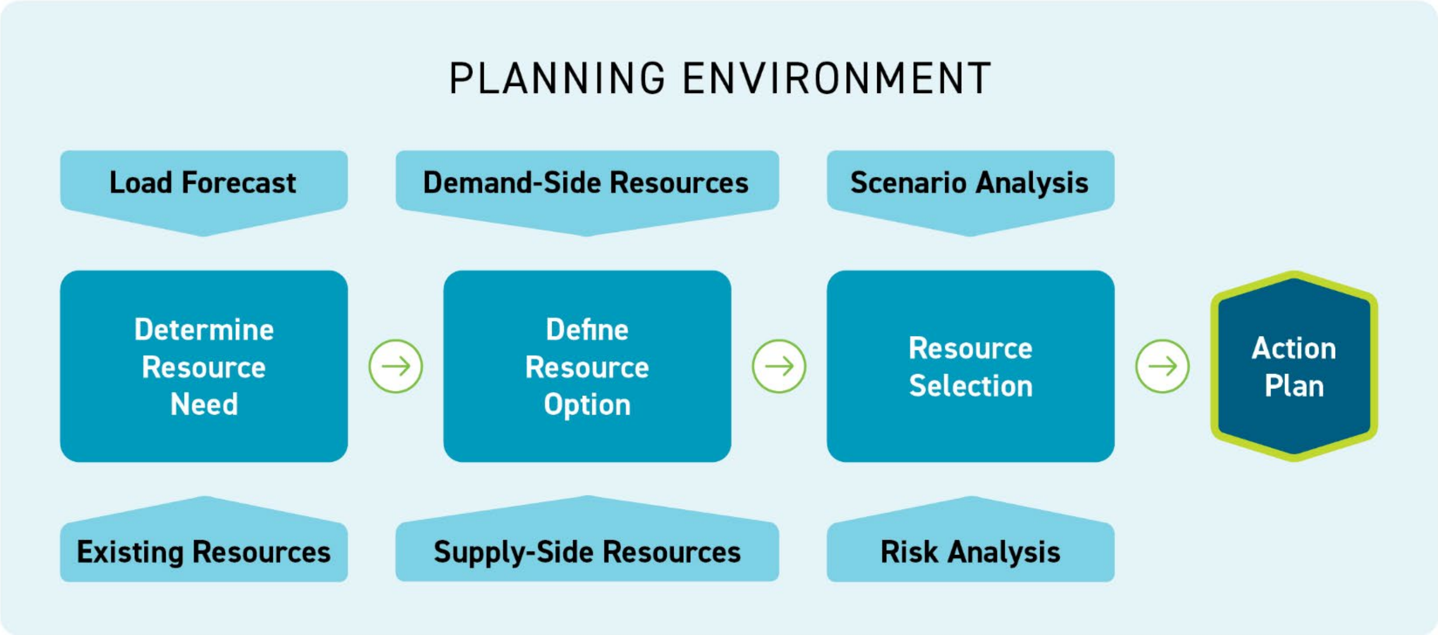


Figure 7.13: Monte Carlo Total WACOD



Chapters 2 through 7 focus on ensuring that we have enough resources to get enough energy on our gas grid every day of the year. Chapter 8 is like its own mini IRP and discusses how we determine needs and options to distribute that gas on so each customer can be served reliably during any weather we could reasonably expect.

8 | Distribution System Planning



8.1 Introduction

Distribution System Planning is an IRP unto itself. It requires a very similar process of identification of needs at the distribution level, identification of resources on both demand-side and distribution supply-side, and then a risk-adjusted resource selection. Some of the unique aspects of distribution system planning include:

- Demand: Forecast peak hour usage for the area in question net of demand-side actions
- Supply: Model distribution system based on actual pipeline alignments and specifications
- Modeling: Use of different software/modeling tools to simulate system under peak conditions and/or use field measurements during cold periods
- Apply system planning criteria to identify areas of concern before planning criteria are exceeded – Ongoing field monitoring of pressures and customer growth informs which areas to investigate

As discussed in TWG No. 5, Distribution System Planning, NW Natural is transitioning from a "just-in-time" distribution system planning process based upon measured criteria violations to a forward-looking distribution system planning process, which will anticipate criteria violation further into the future. Moving from a "just-in-time" to a forward-looking distribution system planning process allows NW Natural to incorporate more non-pipeline demand-side solutions as viable options as these projects take longer to implement and produce reliable peak load reductions. This transition was initiated with NW Natural's Geographically Targeted Energy Efficiency (GeoTEE) pilot and has been a lengthy transition over several years. Once complete and implemented, the process will continue to evolve and improve as we collect more data and adapt to changes in customer usage profiles.

With the transition to a forward-looking distribution system planning process, NW Natural is improving its system modeling. A key component of the system modeling is incorporating a Customer Management Module (CMM) into the Company's pressure system modeling software, Synergi™. CMM provides a link between NW Natural's Geographical Information System (GIS), Customer Information System (CIS), and Synergi™ and is discussed in detail in Section 8.3.2. Incorporating this significant improvement across NW Natural's entire service territory is expected to be completed by the end of 2023.

NW Natural's engineering department annually reviews and updates a 10-year plan for larger projects. The 10-year plan provides budgetary forecasts and a company-wide vision and prioritization to the distribution system planning process and the process itself is discussed in more detail below. The 10-year plan outlines potential improvements for the system, from which NW Natural selects projects from for inclusion in the IRP based on estimated cost, system prioritization needs, supply implications, as well as timing considerations related to the IRP. With the system process improvements with CMM underway but not yet complete, NW Natural is not including the 10-year plan with the 2022 IRP as the completion of the CMM improvement could significantly change the prioritization of projects on the current 10-year plan. Improvements in pressure modeling may indicate areas under observation that are more of a concern or, vice versa, indicate that constrained areas are not as critical as previously modeled. Upon the completion of new Synergi™ models, NW Natural will file a 10-year plan through an IRP Update. We note here that the single distribution system project put forth in the action plan for this IRP is in an area already incorporating the CMM module. Due to the improved modeling, NW Natural was also able to remove another distribution system project that had previously been identified for evaluation in the IRP.

The rest of this chapter discusses NW Natural's distribution system planning process and includes an overview of our needs assessment process and tools including our improved engineering and computer modeling methods that allow for more forward-looking distribution system planning. This is followed by a discussion about our distribution system resources, both existing and future options in addition to pipeline and non-pipeline solutions. The chapter concludes with the identification and discussion of a distribution project included in the action plan.

8.2 Distribution System Planning Process

NW Natural's distribution system planning process ensures that NW Natural:

- Operates a distribution system capable of meeting firm service customers' peak hour demands
- Minimizes system reinforcement costs by selecting the most cost-effective alternative
- Plans for future needs in a timely fashion
- Addresses distribution system needs related to localized customer demand

The goals of distribution system planning are to identify any shortfalls of the distribution system to meet the needs of current firm service customers' gas needs under peak hour conditions[153] and for any new projects, either demand-side or supply-side projects, will be able to serve both current and future firm service energy services. Distribution system planning identifies operational problems or constrained areas in the Company's service territory and develops solutions to address those weaknesses on the system. By knowing where and under what conditions pressure problems may occur, NW Natural can incorporate necessary projects into annual budgets and project planning thereby avoiding costly reactive and potential emergency solutions.

NW Natural collaborates with marketing departments, large customer account representatives, construction crews, external economic development and planning agencies, energy efficiency program administrators and, engineering design and construction firms to develop feasible and reliable solutions. Typical *pipeline* solutions include various forms of reinforcement, replacement, or expansion of NW Natural's distribution system facilities. *Non-pipeline* solutions can be either supply-side

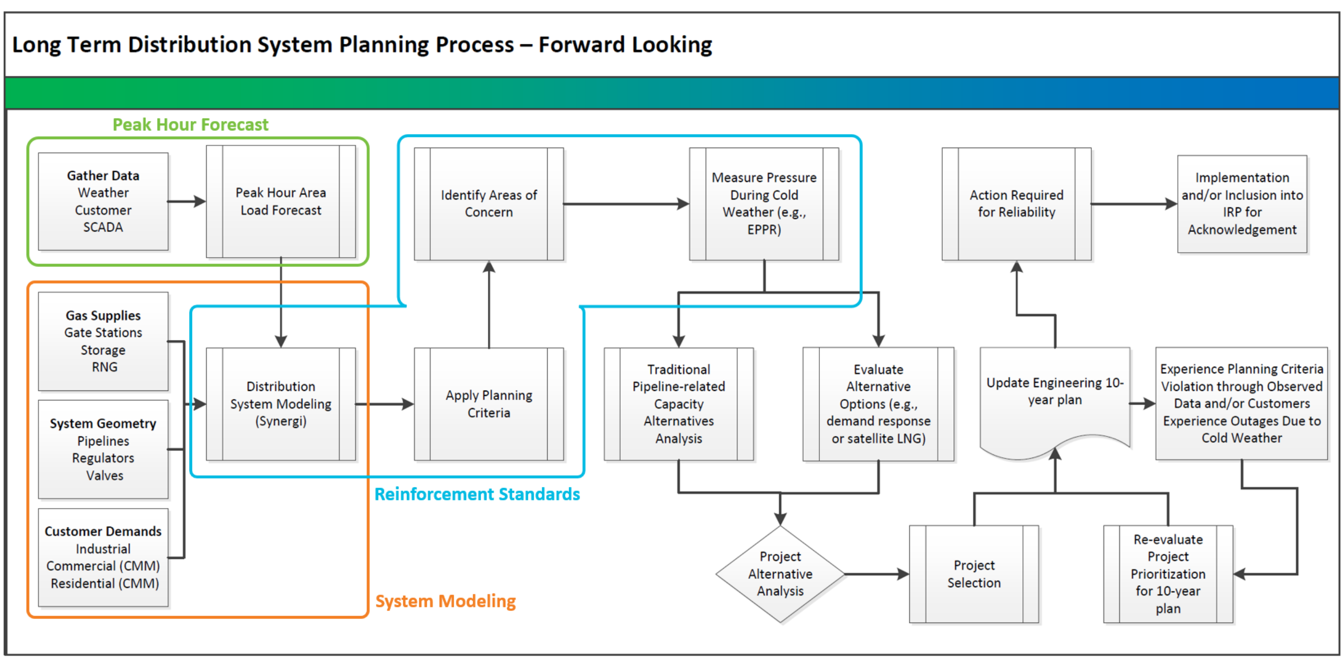
[153] NW Natural uses a peak hour standard for distribution system planning, as usage by firm service customers over a 24-hour period in colder weather has a diurnal pattern that includes an hour in which use is maximal. NW Natural discussed its peak hour standard with stakeholders in the fifth Technical Working Group meeting.

solutions, for example deployment of a mobile CNG supply vehicle, or demand-side solutions, for example geographically targeted interpretability agreements. The costs, timing and reliability varies across each of these options for distribution system planning and the suite of these options is discussed later in this chapter.

Ultimately, distribution system planning follows the same process as the planning for our system resources (see Chapter 8 cover page). The first step requires determining resource need. This starts with forecasting customer peak hour demand, determining potential distribution system constraints based on the existing system, analyzing potential solutions, and assessing the costs and risks of viable alternatives. Planning is ongoing and integrates the requirements associated with known public works projects, customer growth, and other aspects into NW Natural's construction forecasts.

Distribution system planning uses a pressure modeling software, Synergi^{TM}, to model pressure dynamics of actual pipe placement, specifications, and geographic location; along with peak hour usage estimates for the area in question (net of expected energy efficiency savings and demand response resources). Essentially this simulates the system under peak conditions; calibrates this simulation with actual field measurements during cold periods; and applies system planning criteria to identify areas of concern before such planning criteria would be violated by realized peak conditions. Figure 8.1 presents a flow diagram for the distribution system planning process.

Figure 8.1: Distribution System Planning Process



As discussed in the introduction section of this chapter, NW Natural develops a 10-year distribution system plan that outlines areas of the distribution system under observation. These areas are being monitored based on distribution system modeling under peak conditions, where system reinforcement standards are nearing violation.[154] In addition to identifying areas for cold weather observation, the 10-year plan outlines the best (i.e., least-cost least-risk) pipeline solution for each geographic area being monitored[155]. For simplicity, the company prioritizes areas into near-term, medium-term, and long-term evaluations.

Near-term - For areas facing a near-term potential criteria violation (1-to-3-year timeframe), NW Natural completes a planning process that documents the system modeling process and modeling results, identifies the best feasible pipeline solution, estimates the associated high-level cost estimates, and includes an analysis of non-pipeline alternatives, which we discuss later in this chapter.

Medium-term - For areas being monitored that are forecasted to need some action within a 4-to-7-year timeframe NW Natural develops viable pipeline project designs, preliminary modeling documentation, preliminary schedule, and high-level cost estimates.

Long-term - For areas on our radar for needing some action within the 8-to-10-year timeframe NW Natural develops preliminary modeling documentation and a high-level cost estimate for potential pipeline solutions. Project planning associated with issues having this timeframe for resolution is at the conceptual level only and discussion of such projects would not typically included be included in an IRP unless significant investments are indicated.

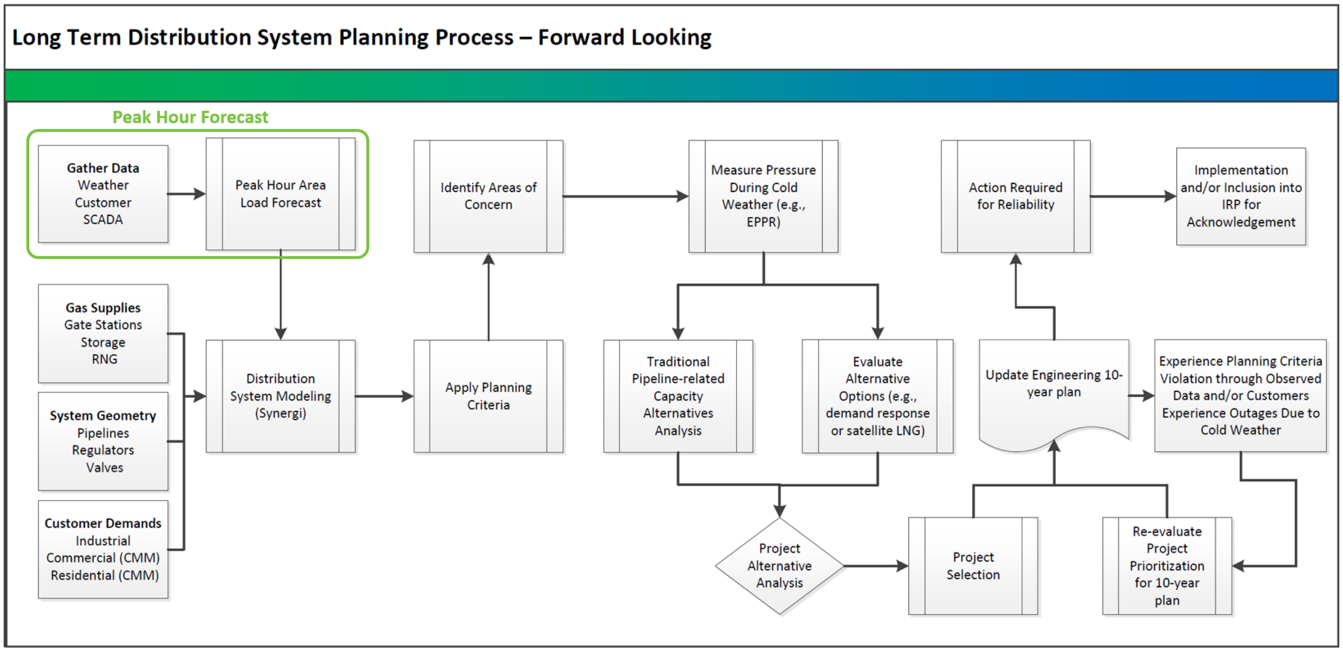
Depending on the scope, magnitude of the investment, or the lead time needed to implement a pipeline solution; any project on the 10-year plan may be included for a full IRP evaluation. Generally, this happens to be the higher priority near-term violation areas being monitored. However, regardless of the lead times needed implement a distribution system solution (either demand-side or supply-side), detailed cost and risk assessments, along with a robust alternatives analysis are conducted for any solutions that would be included into an IRP Action Plan.[156]

8.2.1 Forecasting Peak Hour Load

As can be seen in Figure 8.2, determining peak hour load/demand is a critical part of distribution system planning as it establishes the minimum criterion for meeting customer needs. Firm service peak hour load predictions are the standard which must be met by the Company's distribution system capacity resources for each area of our system.

[154] See Chapter 8, section 8.3.3 for a discussion of system reinforcement standards.
[155] As explained later in this chapter, this also signals an analysis of non-pipeline alternatives as well.
[156] The burden is on NW Natural to decide which projects are brought through the IRP as action items for consideration.

Figure 8.2: Distribution System Planning Process – Peak Hour



Just as NW Natural's peak day load forecast informs our system capacity resource planning, geographically specific peak hour load forecasting provides an input into distribution system planning. Peak hour forecasts augment the daily system load model process with forward-looking, statistically derived forecasts of hourly load in specific areas of NW Natural's service territory. NW Natural included peak hour load forecasts in its 2016 IRP process,[157] redefined its peak planning standard for both peak day and peak hour forecasts in the 2018 IRP and has applied the same peak planning standard in the 2022 IRP. NW Natural monitors, updates, and works to improve NW Natural's peak load forecast models and aspires to synchronize and adapt its peak hour load modeling process to optimally support an overall transition to a fully forward-looking distribution system planning process.

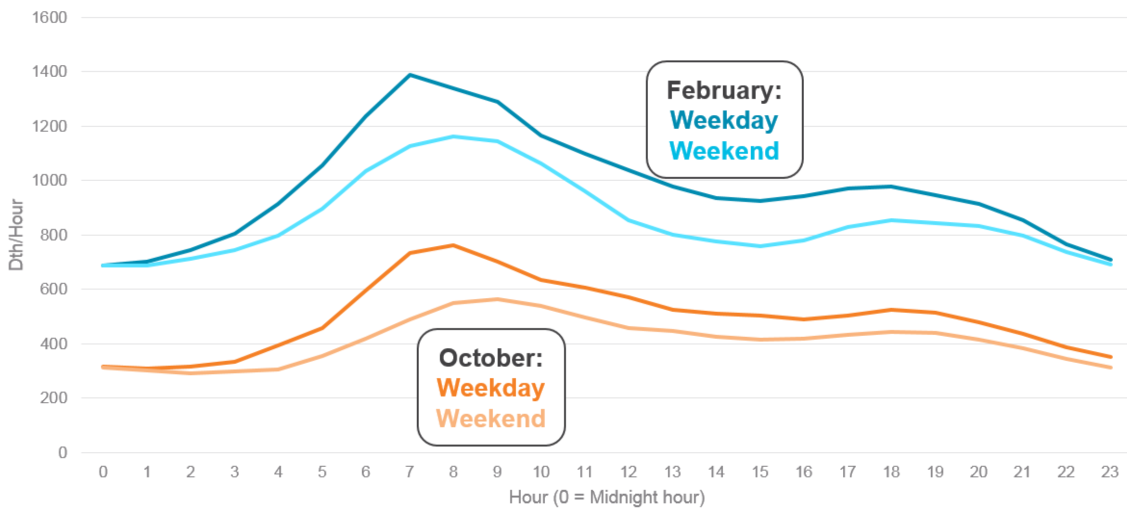
8.2.2 Estimating Peak Hour Load

The peak hour modeling methodology generally follows that of the peak day forecasts while incorporating more granular geographic and time dimensions. Regression analysis is used to establish the statistical relationships between measured firm sales and firm transportation load in a given area with local weather variables—temperature, wind, sunshine, source water temperature, and snow depth—as well as customer counts, day of the week, holiday occurrences, and time trends. Because distribution system planning involves relatively small geographic areas, peak hour load forecasts use similarly localized input data—weather and customer counts, for example. These regression models also derive historical relationships between hourly geographic load and global variables (such as holiday occurrences) that do not vary across locations.

[157] See Chapter 3 and Appendix C in NW Natural's 2016 IRP.

One of the primary differences between peak hour and peak day models is the presence of time-of-day effects. The intraday load shape of the natural gas system typically exhibits an early morning peak followed by a midday taper, before a smaller peak in the late afternoon (see Figure 8.3 as an example). The morning peak is dependent on the day-of-the week and is typically lower and later in the day on weekend days.

Figure 8.3: Hood River Area Intraday Load Shapes



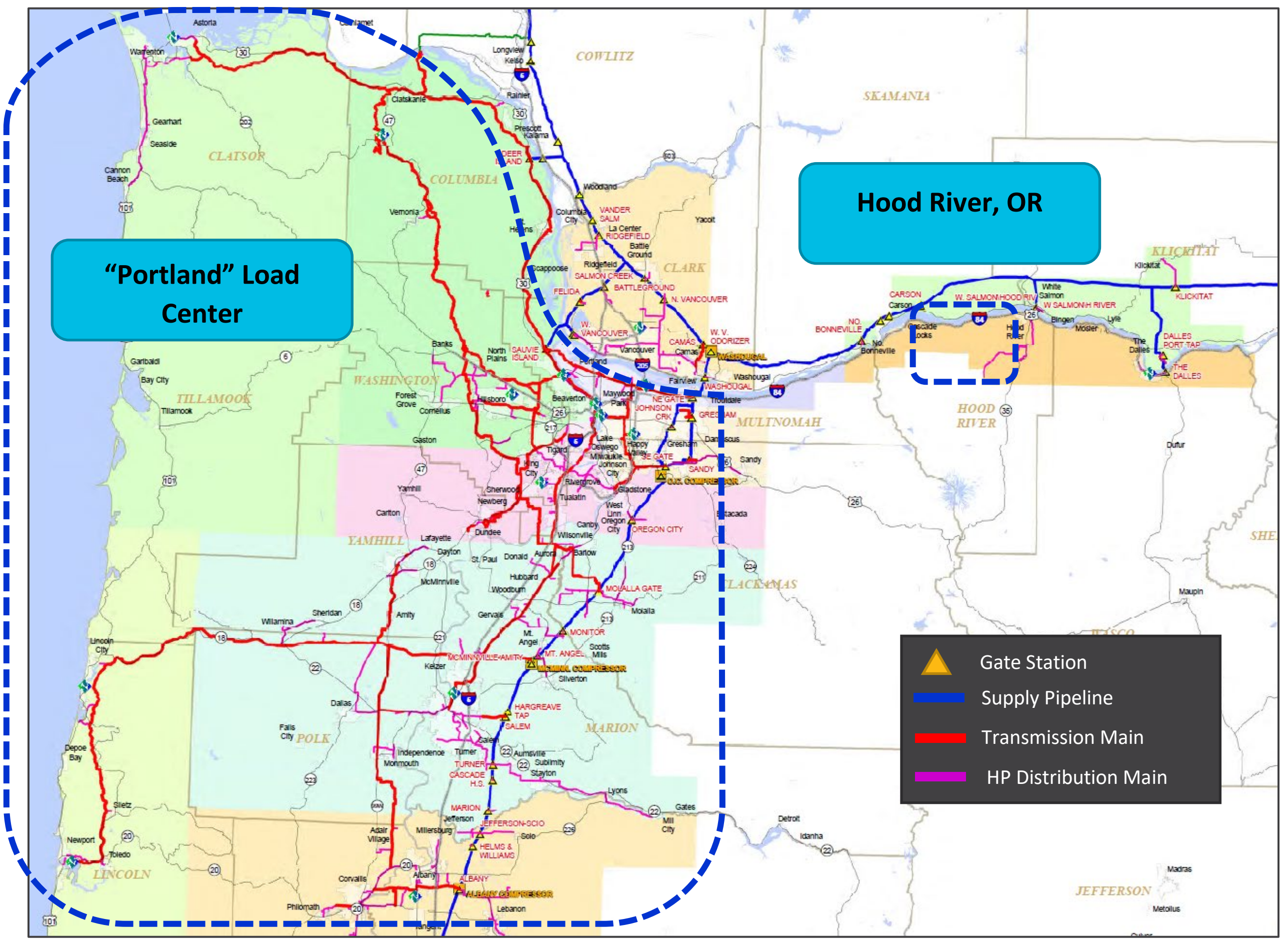
Temperature alters hourly effects, as it does the effects of other weather variables.[158] When temperatures stay cold on average throughout the day—on dark, wintry days in February, for example—the intraday load shape is less pronounced than one during the shoulder season, when midday high temperatures diverge further from nighttime lows and space heating needs fluctuate more substantially. To capture these nuanced dynamics, peak hour load models incorporate effects that are specific to the hour and day of the week (i.e., 72 indicator variables for each hour of a weekday, Saturday, and Sunday), which interact with temperature.

The second unique feature that differentiates peak hour load from peak day load is the narrower geographic relevance of the former concept. Whereas load on a peak day defines the resource capacity required to ensure that adequate gas resources be delivered on NW Natural's system, the ability to deliver gas to customers at any moment depends on very specific segments of NW Natural's distribution system, as outlined earlier in this chapter. Thus, area-specific hourly load and granular weather data is required in place of the system-level inputs of the peak day model. Although gas demand must be met in any given instant, the time dimension granularity is constrained to hourly due to data limitations.[159] The geographic granularity of peak hour modeling is constrained by the

[158] For a full discussion of load forecasting variables and their interactions, please see Chapter 3, Resource Needs.
[159] High frequency meters for customers on interruptible or transportation rate schedules record hourly flows. Additionally, weather data is at best available on an hourly frequency. Hourly data is sufficient for the needs of the distribution system planning process.

availability of data. For example, the area served downstream of the Hood River, Oregon, gate station Figure 8.4 represents a “system within a system” along a single distribution main, where hourly flow measured at the gate station can be isolated from the rest of NW Natural’s distribution system. In contrast, customers in the broader Portland, Oregon, metropolitan area draw gas past multiple SCADA meters at receipt points that also serve other areas of the distribution system (as distant as Salem, Oregon), making it impossible to isolate the hourly load of just those customers within a given neighborhood within the metro area.

Figure 8.4: Hood River and Portland, Oregon, Distribution Systems



At this time, most of NW Natural’s distribution system is oriented and metered more like the Portland metro area than like Hood River. Hood River’s internal interconnectivity, while necessary and beneficial from an operations standpoint, limits the ability to isolate small areas for econometric load forecasting. A summary of peak hour load standards and latest available forecast for the feasible portions of the NW Natural distribution center follows in the next section.

8.2.3 Peak Hour Loads

Generally, the isolatable areas within NW Natural's distribution system are at least as large as (and often larger than) its constituent load centers. However, there are smaller areas for which econometric load forecasting is feasible, such as the area served by the Hood River gate. Forecasts are thus defined by the narrowest possible geography from which hourly data is obtainable. Table 8.1 summarizes the broad areas for which econometric peak hour load forecasting is currently feasible; smaller exceptions are omitted. Note that several load centers are subsumed by a functionally interlinked "Portland" area.

Table 8.1: Areas with a Peak Hour Load Forecast

Area	Description
Vancouver load center	NW Natural's service areas in Clark County Washington
"Portland"	NW Natural service areas in Benton, Clackamas, Clatsop, Columbia, Lincoln, northern Linn, Marion, Multnomah, Polk, Washington, and Yamhill counties in Oregon
Eugene load center	NW Natural's service areas in Lane and southern Linn counties in Oregon
Columbia River Gorge-OR load center	NW Natural service areas in Hood River and Wasco counties in Oregon
Columbia River Gorge-WA load center	NW Natural service areas in Skamania and Klickitat counties in Washington
Coos Bay load center	NW Natural service areas in Coos County Oregon

The conditions that produce peak hour loads across NW Natural's system clearly vary by location, necessitating area-specific peak hour planning standards. Analogous with the statistically based approach of NW Natural's peak day planning standard,[160] an area's peak hour is defined by the level of firm resources that provide a 99% probability of meeting the highest firm hourly load in a gas year. Once area-specific relationships between hourly flow and its driver variables are estimated, they are applied to the area-specific peak planning standard, producing a benchmark that is incorporated into a forward-looking distribution system planning process.

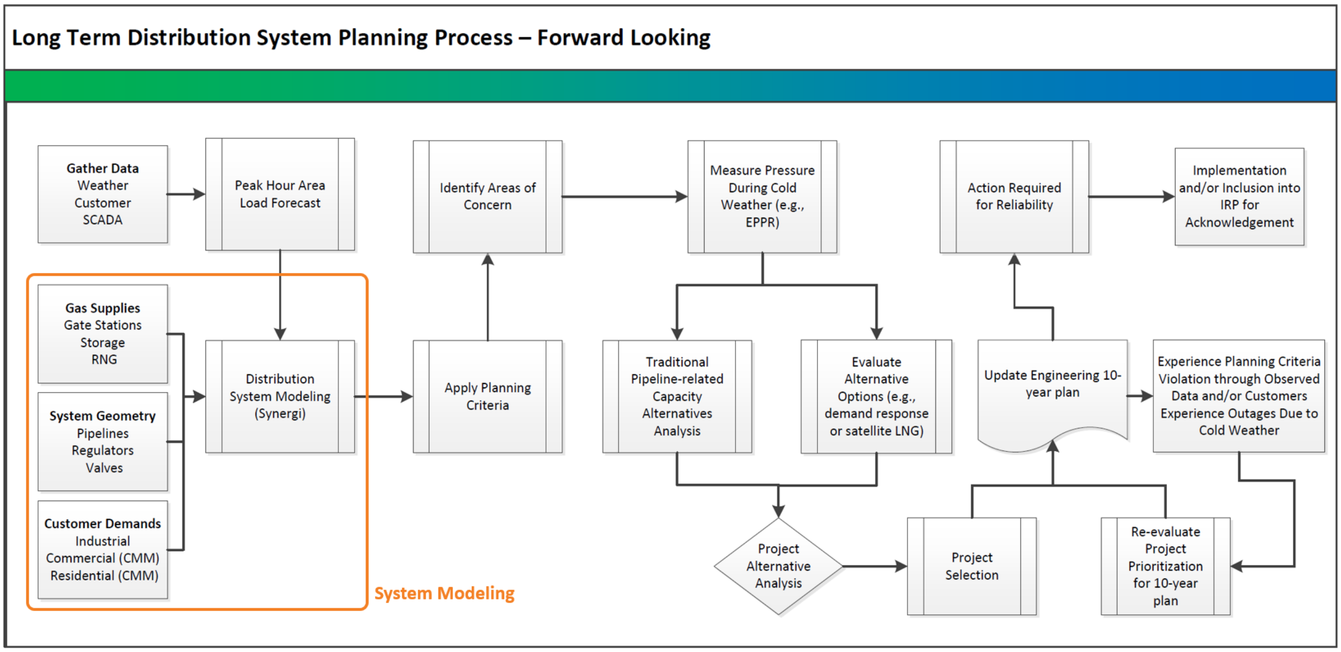
8.3 Distribution System Planning Tools and Standards

8.3.1 System Modeling

As shown in Figure 8.5, system modeling is an important part of the distribution system planning process. Modeling allows accurate simulation of different aspects of NW Natural's system, from the receipt of natural gas from supplies, through NW Natural's pipeline networks, to customer locations.

[160] See Chapter 3 - Resource Needs for a detailed discussion of NW Natural's peak day planning standard.

Figure 8.5: Distribution System Planning Process – System Modeling



As is shown in Figure 8.6, a Synergi Gas™ model contains detailed information regarding a specific portion of NW Natural's system, such as pipe size, length, pipe roughness, and configuration; customer loads; source gas pressures and flow rates; regulator settings and characteristics; and more. The model is based on information from NW Natural's Geographical Information System (GIS) for the piping system configuration and pipe characteristics; from the Customer Information System (CIS) for customer load sizing; and from the Supervisory Control and Data Acquisition (SCADA) system for large customer loads, system pressures, and supply flows and pressures.

Figure 8.6: Data Used in Synergi™ Models

Supply	Pipeline Network	Demand
• Gate Station Supplies (SCADA) • Storage Facility Supplies (SCADA) • Pressure Data (SCADA)	• Pipe Network Topology and Pipe Attributes (GIS) • Customer Location (GIS) • Field As-Built information • Operating Parameters – Regulator Setpoints, Valve Status, etc. • Cold Weather Pressure Survey • Electronic Portable Pressure Recorders (EPPR)	• Largest Customer Demands (SCADA) • Large Customer Demands (Industrial Billing) • Residential and Commercial Demands (Billing Data)

Synergi™ uses mathematical flow equations and an iterative calculation method to evaluate whether the modeled system is balanced. A Synergi™ model shows flows and pressures at every point in the modeled system and, when balanced, the relationship between flows and whether pressures at all points in the modeled system are within tolerances specified by NW Natural's engineering staff. A properly designed Synergi™ model has pressure and flow results closely corresponding with those of the observed actual physical system. As with models used in other contexts, Synergi™ models rely on assumptions about the actual system, and therefore modeling results may vary from actual results. Synergi™ models are a representation of the actual system and the outputs of these models are a static snapshot of expected system conditions under the provided data.

NW Natural will occasionally run a field data collection process called a Cold Weather Survey to collect system pressures during cold weather conditions. Additionally, NW Natural has approximately a dozen Electronic Portable Pressure Recorders (EPPR) which are sited at locations with suspected low pressures. EPPR data includes pressure and temperate reads summarized in hourly intervals. NW Natural uses both EPPR data and Cold Weather Survey pressure data to validate Synergi™ modeled results.

Synergi Gas™ software simulates gas pipeline operations and does not have the ability to perform automated pipeline route selection. Automated route selection for pipeline construction would require data with quality and coverage that are not available at this time. Instead, system planners perform an iterative process incorporating multiple economic, geologic, and infrastructure factors to draft the least cost, feasible route option. An identified route is further refined through field validation and right-of-way acquisition considerations.

Synergi™ simulation capability allows NW Natural to efficiently evaluate distribution system performance in terms of stability, reliability, and safety under conditions ranging from peak hour delivery requirements to both planned and unplanned temporary service interruptions. Synergi™ modeling allows NW Natural to evaluate various scenarios designed to stress test the system's response to alternative demand forecasts, future demand forecasts, emergency situations, new customer demands, customer growth, non-pipeline alternatives, and much more.

8.3.2 Customer Management Module (CMM)

In 2021, NW Natural completed the implementation of the Customer Management Module (CMM). CMM provides a link between NW Natural's Geographical Information System (GIS), Customer Information System (CIS), and Synergi Gas™. CMM is created by DNV, which is the same developer who produces the Synergi Gas™ software. In summary, CMM provides the ability to:

- Import each customer's billing data from CIS and calculate a per customer demand based on daily temperature
- Update customer information such as rate schedule, status (active or inactive), and changes in forecasted consumption
- Assign each customer's load to the closest appropriate facility

Using historical billing, temperature data, and NW Natural GIS systems CMM can tie individual customer demands to their specific geographic location in the model. Previous modeling methods utilized area-specific averages for residential and small commercial customers. For example, residential customers in the Portland metropolitan area were previously assigned the same demand in the Synergi Gas™ models, whereas CMM allows customer-specific usages for each customer in the model based on historical consumption. In short, the benefit of CMM is that it accurately models local system pressures based on historical customer specific usage, rather than localized averages.

Beyond geographically locating customers, the CMM also connects to the CIS system and allows NW Natural to update customer information seamlessly in the Synergi models, including whether customers are identified as active or inactive and their service type (firm vs interruptible). Identifying customer status and rate schedule allows NW Natural to model active customers on the system. Firm customers are included in peak models, whereas interruptible customers are assumed to be curtailed during extreme conditions. The connection to the CIS system provides updates to add or remove demand based on whether the customer is assigned a firm or interruptible rate schedule. CMM allows NW Natural to generate new demands from real-time data if a customer changes their status or service type.

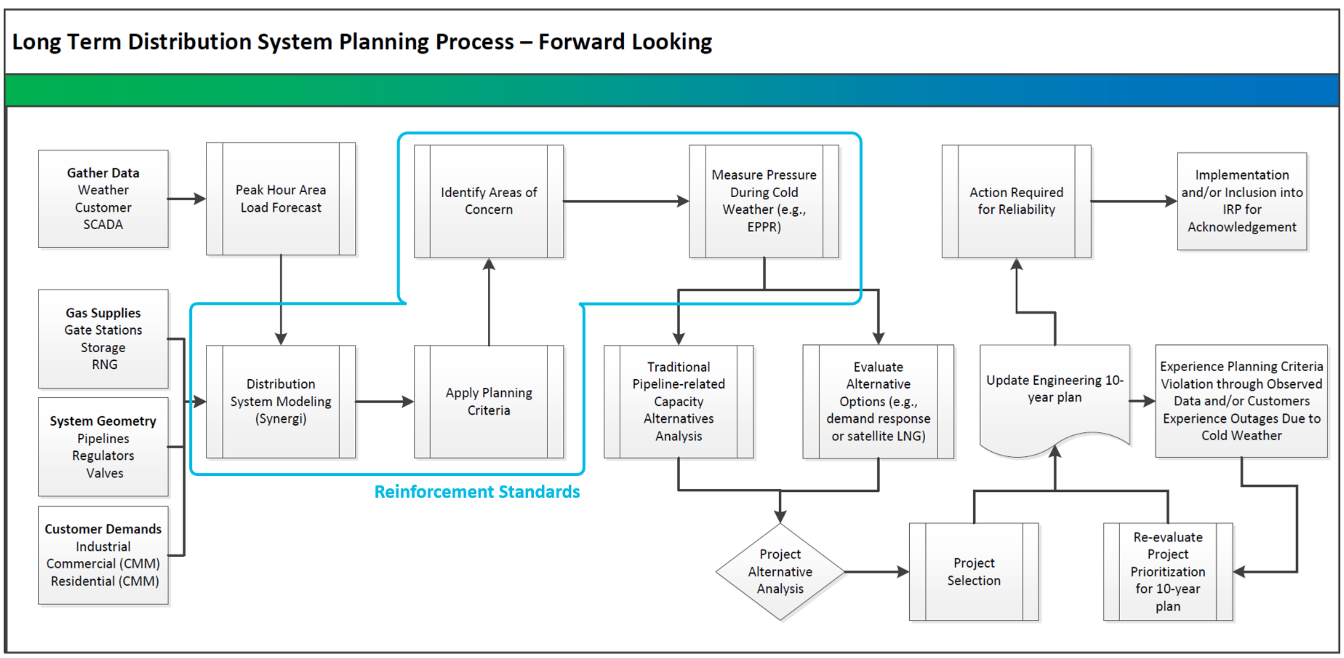
The modeling software requires that customer demands be properly assigned to the correct location in the gas distribution system. When demands are accurately assigned to the correct position in Synergi Gas™, it allows modelers to evaluate localized system pressure conditions. Previous models do not utilize the same coordinated system as the GIS system. CMM based models are required to have the same coordinate system as the GIS system. This requirement makes it mandatory for new models to be developed in order to take advantage of CMM features.

For computational purposes, these CMM models are split geographically across NW Natural's service territory.[161] As mentioned earlier in this chapter, NW Natural is still in the process of developing these models. Model creation using CMM data was prioritized based on locations that were identified to have near-term needs. The distribution planning project introduced later in this chapter was modeled using CMM. NW Natural is in the process of updating all Synergi models to incorporate the benefits provided by CMM.

8.3.3 System Reinforcement Standards

As shown in Figure 8.7, system reinforcement standards are a required component of the distribution system planning process. The standards are based on multiple indicating suboptimal conditions such as a pipeline nearing peak capacity, a regulator near failure, or customers not being served with adequate pressure or volume. The system reinforcement standards represent trigger points indicating systems under stress and in need of imminent attention to reliably serve customers.

Figure 8.7: Distribution System Planning Process – Reinforcement Standards



Transmission and high-pressure distribution systems (systems operating at greater than 60 psig[162]) have different characteristics than other components of NW Natural's distribution system, and design

[161] Previous Synergi™ models were also spilt up geographically across the service territory.
[162] Pounds per square inch gauge: a standard measure of pressure within a pipeline facility.

parameters associated with peak hour load requirements differ as well. System reinforcement parameters for these systems include:

- Experiencing at least a 30% pressure drop over the facility that indicates an investigation will be initiated
- Experiencing or modeling a 40% pressure drop that indicates reinforcing the facility is critical, as a 40% pressure drop equates to an 80% level of capacity utilization
- Considering minimum inlet pressure requirements for proper regulator function in addition to total pressure drop for pipelines that feed other high-pressure systems
- Near-term growth indicated by one or more leading indicators (e.g., new road construction, subdivision, or planned industrial development) may require reinforcing a system that currently has satisfactory performance
- The ability to meet firm service customer delivery requirements (flow or pressure)
- Being identified in the IRP associated with supply requirements or needs

The system reinforcement parameters associated with peak hour load requirements for distribution systems that are not high pressure (systems operating at 60 psig or less) are:

- Experiencing a minimum distribution pressure of 15 psig that indicates an investigation will be initiated
- Experiencing or modeling minimum distribution pressure of 10 psig that indicates reinforcement is critical
- Near-term growth indicated by one or more leading indicators (e.g., new road construction, a new subdivision, or planned industrial development) may require reinforcing a system that currently has satisfactory performance
- Firm service customer delivery requirements (flow or pressure)

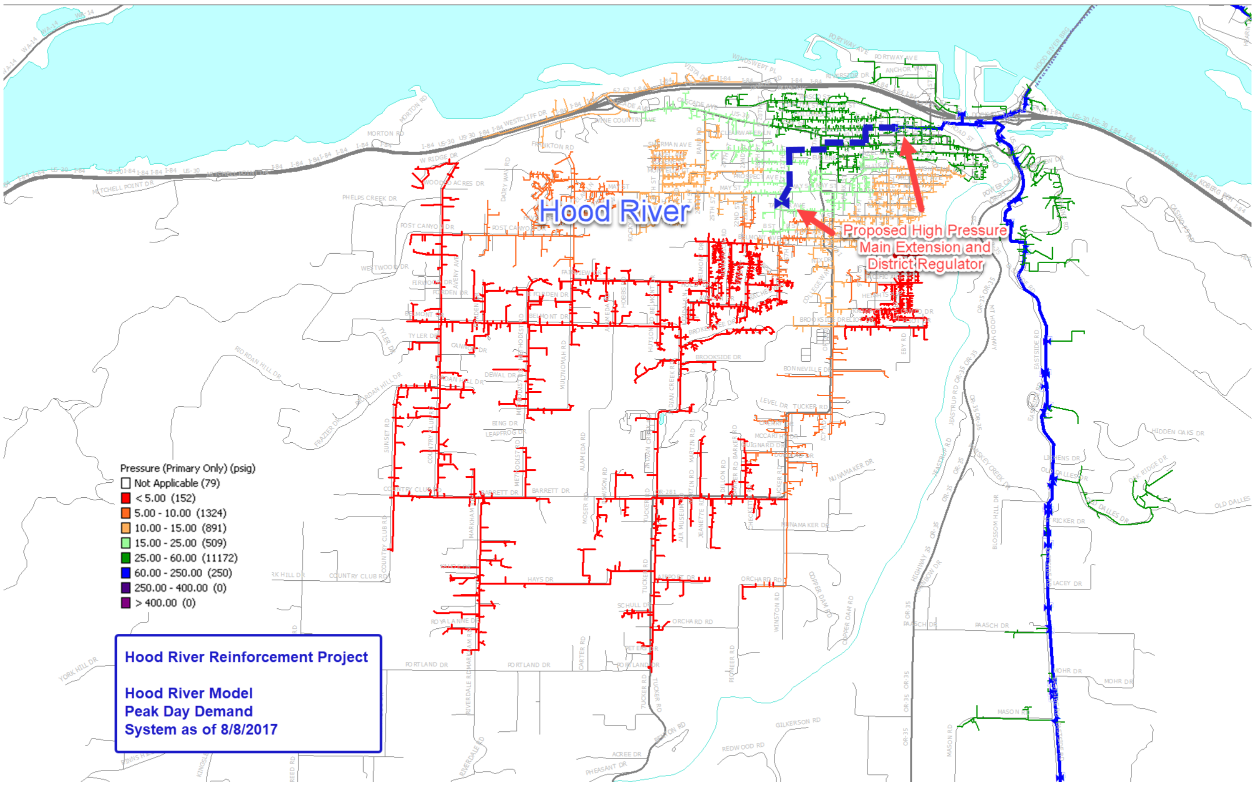
8.3.4 Identification of Distribution System Needs

Accurate modeling and forecasted level of peak hour demand combine to indicate how the distribution system would operate on a peak hour. The system reinforcement standards are then applied to the model results to identify specific areas of NW Natural's system that need reinforcement. Such areas are typically much smaller than the load center in which they are located. In the following example, and as shown in Figure 8.8, an area of the Class B distribution system[163] in Hood River is forecasted, by modeling, to experience low system pressures or outages on a peak hour. This modeling was validated in January of 2017 when several customer outages occurred in the Hood River area under non-peak conditions. Areas with pressure below 10 psig are indicated in orange and red colors, while areas with more satisfactory pressure are indicated with shades of green. Note that the Hood River Class B distribution system is located within the Columbia River Gorge-Oregon load center, is served by a

[163] Class B systems are those operating at 60 psig or less.

single gate station on Northwest Pipeline (NWPL) and is not connected to other parts of NW Natural's distribution system.

Figure 8.8: Illustration of Hood River Area Pressure Issues



8.4 Distribution System Resources

8.4.1 Existing Distribution System

NW Natural's gas distribution system consists of approximately 14.6 thousand miles of transmission and distribution mains, of which approximately 87% are in Oregon with the remaining 13% in Washington.[164]

NW Natural's Oregon service area includes 39 gate stations[165], approximately 954 district regulator stations and 2 renewable natural gas (RNG) production sites. NW Natural owns and operates two liquefied natural gas (LNG) storage plants and the Mist underground storage facility in Oregon, which are discussed in Chapter 6. NW Natural's Washington service area includes 15 gate stations and approximately 78 district regulator stations.

[164] Coos County Pipeline located in Oregon consists of approximately 86 miles of transmission main. Coos County Pipeline is operated by NW Natural on behalf of Coos County.

[165] Gate station values for both Oregon and Washington include all upstream pipeline interconnections, including farm taps.

NW Natural maintains two large compressed natural gas (CNG) trailers, each with a 100 Dth capacity rating, a liquefied natural gas (LNG) trailer rated at 900 Dth capacity, and assorted small CNG trailers rated below 10 Dth capacity. These trailers can be used for short-term and localized use in support of cold weather operations, or while conducting pipeline maintenance procedures.

8.4.2 Geo Current and Future Distribution System Planning Resources

Similar to system planning, alternatives for both demand-side and supply-side are evaluated. Distribution System Planning Resource Options can be seen in Table 8.2.

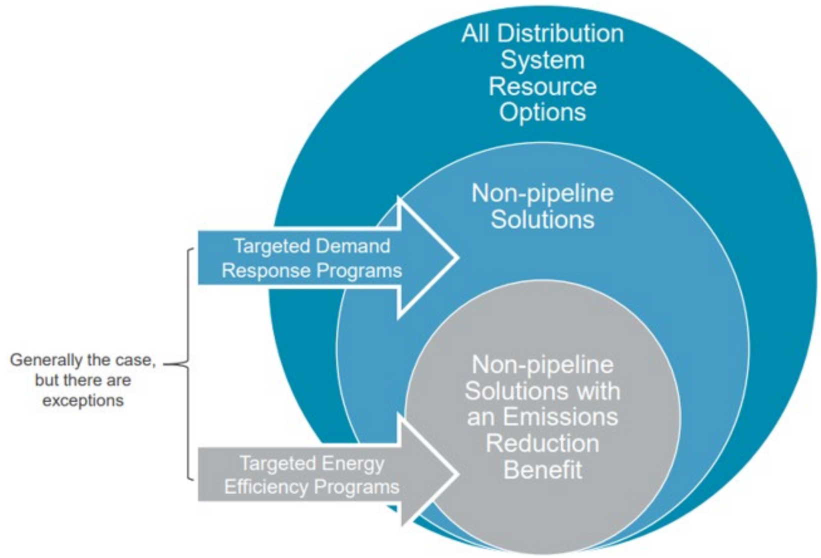
Table 8.2: Distribution System Planning Alternatives

Distribution System Planning Alternatives (not all options are possible or applicable in all situations)				Option Currently Considered for Cost-Effectiveness Evaluation
Supply-Side Alternatives	Pipeline Related Capacity Options		Loop existing pipeline	✓
			Replace existing pipeline	✓
			Install pipeline from different source location into area	✓
			Uprate existing pipeline infrastructure	✓
			Add or upgrade regulator to serve area of weakness	✓
			Gate station upgrades	✓
			Add compression to increase capacity of existing pipelines	✓
	Non-Pipeline Solutions	Distributed Energy Resources (DER)	Mobile/fixed geographically targeted CNG storage	✓
			Mobile/fixed geographically targeted LNG storage	✓
			On-system gas supply (e.g. renewable natural gas, H2)	✓
			Geographically targeted underground storage	✓
Demand-Side Alternatives		Demand Response	Interruptible schedules (DR by rate design)	✓
			Geographically targeted interruptibility agreements	✓
			Geographically targeted Res & Com demand response (GeoDR)	
		Energy Efficiency	Peak hour savings from normal statewide EE programs	✓
			Geographically targeted peak-focused energy efficiency (GeoTEE)	

As shown in both Table 8.2 and Figure 8.9, non-pipeline solutions as distribution resource planning options can be both supply-side and demand-side resources. These solutions must reliably serve customers by helping to either serve or reduce load during a peak event and are evaluated for cost effectiveness along-side other solutions. Often non-pipeline solutions are associated with DSM solutions, but to be clear this is not the case. As shown in Table 8.2 and Figure 8.9, some non-pipeline solutions are supply-side options, for example geographically targeted CNG deployment, whereas other options are demand-side options, for example geographically targeted interruptible agreements.

The purpose of any non-pipeline solution is aimed at serving or reducing peak load in an area and should not be considered a means for emissions reduction.[166]

Figure 8.9: Purpose of Non-pipeline Solutions



Supply-side Options – Pipeline-related Resources

Once NW Natural identifies a distribution system issue, in addition to demand-side alternatives, the Company considers multiple traditional pipeline solutions for addressing the issue. These traditional pipeline solutions may include:

- Pipeline construction
- Equipment addition (district regulators, compressor stations)
- Additional gas supply (gate station changes)
- Operating pressure uprates

The objective is to identify the most efficient, least cost, least risk solution for the identified issue. NW Natural validates the identified solution with models and field testing to verify effectiveness.

Having adequate pressure on the distribution system is crucial for reliably delivering gas to customers. Traditional pipelines are included in the alternative analysis as a solution to improve system pressures in areas with low pressures by installing new distribution pipelines or uprating existing distribution pipelines.

166 Often GeoTEE is mis-conveyed as a solution for emissions reductions. While GeoTEE could provide emission reductions as a secondary impact, this will already be taken into consideration for a cost-effectiveness evaluation of GeoTEE as a distribution system planning option when comparing to the other distribution system options.

Pipelines

One option to remediate low pressures is installing new distribution pipelines to increase the capacity of a distribution system. The proposed distribution pipeline would transport higher pressure gas to areas with weak pressures. A distribution pipeline system reinforcement increases pressures in weak areas, lowering the potential for customer outages.

NW Natural completes pipeline feasibility studies to develop potential pipeline projects to address low pressure areas. The selection criteria include distribution pipeline distance, operating pressure, material, pipeline diameter, load type, and existing network architecture. The three major types of distribution pipeline installations related to system reinforcements are provided below:

1. Distribution Pipeline Extensions – Installation of gas distribution pipeline using a new alignment. A new distribution pipeline delivers higher pressure gas to an area of need, increasing the pressure and reliably of a distribution system. Depending on the relative operating pressures this could also include pressure regulation and overpressure protection equipment.
2. Distribution Pipeline Replacements – Replacing an existing pipeline with a new pipeline. Typically, the replacement distribution pipeline is larger in diameter than the original distribution pipeline, which reduces the pressure drop across the alignment.
3. Distribution Pipeline Looping – A new distribution pipeline that is constructed parallel to an existing distribution pipeline. The looped mains are tied-in, decreasing the flow on the original pipeline, which reduces pressure drop along the original pipeline.

NW Natural considers alternative characteristics for a pipeline solution to the identified issue as a first step in developing supply-side solutions. These alternative characteristics include the path a pipeline solution might take, the size of the pipe, the material used in the pipe, and the probable methods—or combination of methods—of pipeline construction. The feasibility study incorporates all three scenarios as well as these alternative characteristics. The least cost option is provided as an input in the alternatives analysis to address an area in need.

Uprating

Typically, the cost of uprating a portion of a distribution system is generally less than installing a new pipeline. Uprating pipelines is another form of increasing the capacity of a distribution system by operating at a higher Maximum Allowable Operating Pressure (MAOP). Before an uprate can be executed, a pipeline system must comply with Local and Federal Regulations. The uprating effort may include, but is not limited to, key activities such as reviewing records, pressure testing, replacements, field verification, inspections for all pipes and components on the portion of the distribution system being uprated, multiple leakage surveys before, during and after the pressure uprate process. Not all pipelines are eligible to be uprated, a system may have design limitations that prevent a distribution system pipeline from operating at a higher MAOP.

Table 8.3 shows the capacity for a five-mile, six-inch steel pipeline for varying operating pressures. The table shows that a pipeline operating at 600 psig has approximately six times more capacity than a pipeline operating at 100 psig. A major benefit of uprating is that incremental capacity can be provided through existing distribution pipelines by safely operating them at higher pressures.

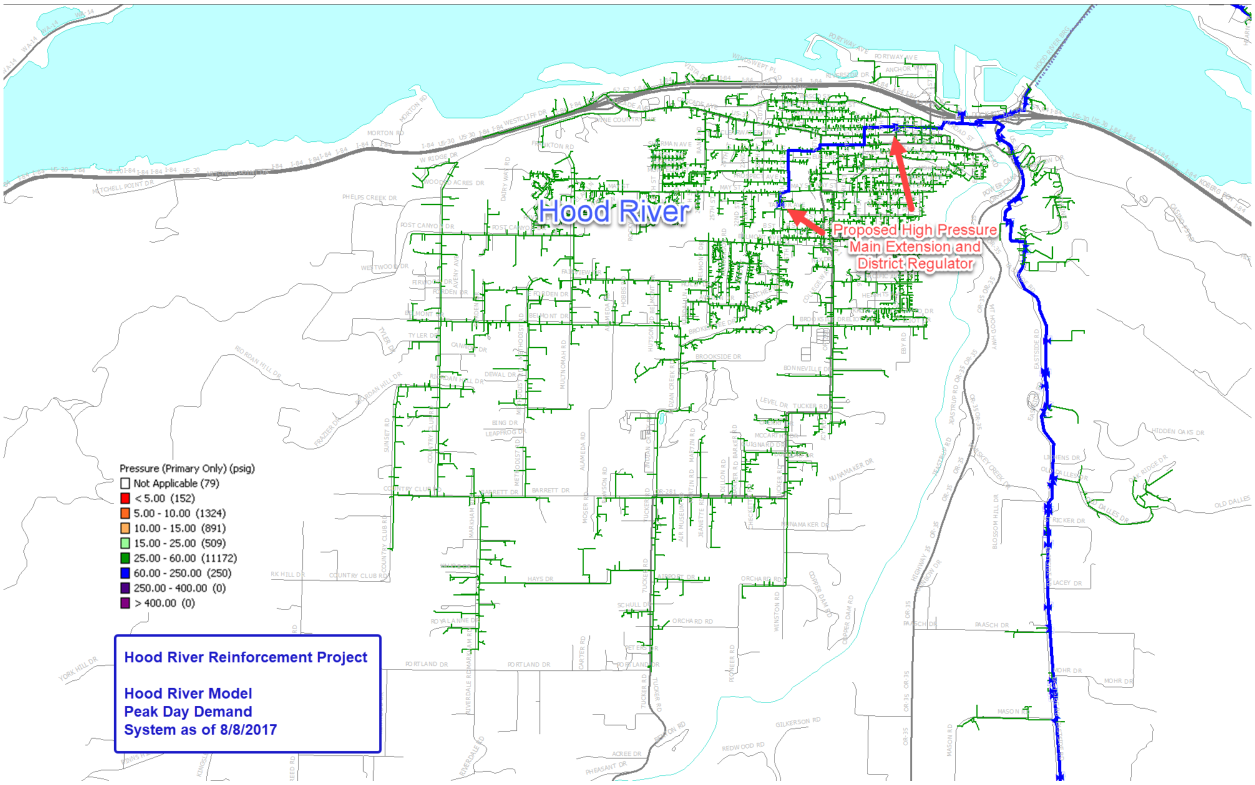
Table 8.3: Pipeline Uprate Capacity Example

Starting Pressure (psig)	Ending Pressure (psig)	Pipeline Capacity* (th/hr)
100	60	1,820
200	120	3,569
300	180	5,341
400	240	7,163
500	300	8,956
600	360	10,800

*Pipeline Capacity Identified by 40% Pressure Drop

In the Hood River example discussed in earlier in this section (8.2), the weakness in the existing system centered around a single point of gas feed from the northeast. This created system bottlenecks, as nearly all gas required by customers must go through a very small number of pipes. The final solution extended the existing high-pressure distribution main on Cascade Street and 6th Street. A new district regulator was installed on the end of the high-pressure main extension reducing the pipeline pressure drop through the bottleneck pipelines in the north. The result was that the system pressures overall were greatly improved (note the red areas in Figure 8.8 are green in Figure 8.10). Effective pipeline routes from the south could have been constructed, but the construction would have been much longer than the identified solution which avoided a costly river crossing.

Figure 8.10: Illustration of Hood River Area Pressure Issues and Resolution



Supply-side Options - Non-pipeline Resources

Non-pipeline supply-side options may be an option when customer demands grow beyond the capacity of the pipeline which currently serves this system. Instead of addressing weak areas with pipeline system reinforcement projects, non-pipeline alternatives are also assessed and include augmenting the capacity of the existing pipeline with a local peaking asset and the use of geo-targeted demand-side management means for reducing the local demand on peak, amongst other possible solutions, in lieu of traditional pipeline solutions. Essentially, non-pipeline supply-side options introduce a new source of gas into a constrained area of the system, thereby propping up pressure in the area to address reliability concerns. The next sections discuss supply side non-pipeline solutions.

GeoRNG

On-system RNG interconnections are a form of distributed resources that can help maintain reliability within NW Natural's distribution system. A strategically located RNG interconnection on NW Natural's system could have a similar impact in a constrained area of the distribution system as any targeted demand-side option. The additional RNG supply would be injected directly onto a weak area of the system which can help avoid or delay a pipeline reinforcement project. The likelihood of an RNG facility providing the biogas needed in the perfect location as a specific alternative to a specific pipeline reinforcement project is small, but possible. Additionally, if more on-system RNG interconnections are developed, then the aggregate of the on-system RNG injections could result in pipeline reinforcement projects that never materialize.

Satellite Storage

A satellite storage facility delivers locally stored gas to the nearby customers, which temporarily reduces the volume of gas that flows on the existing upstream pipeline. Satellite storage works in tandem with existing pipelines to serve customer demand during very cold or peak demand conditions. Unlike the pipeline options, which provide permanent pressure benefits, satellite storage plants are peak shavers which are designed to be dispatched during extreme weather. The satellite storage has a limited supply of gas on site based on the size of the facility and is usually difficult to replenish under peak conditions. Two common types of satellite storage are Liquefied Natural Gas (LNG) and Compressed Natural Gas (CNG).

1. Satellite LNG Facility – LNG is natural gas that has been cooled to a liquid state reducing its volume by about 600 times. A satellite LNG facility is a tank that stores liquified natural gas along with the associated pumping, vaporization, meter, control, fire protection, standby power and odorization systems until the energy is required during peak or emergency conditions. Withdrawal rates are determined by the tank size, vaporizing equipment capacity, and the quantity of gas that can be absorbed by customers and local piping. A satellite LNG facility does not typically include a liquefaction process. LNG is generally brought in via tank trucks or occasionally trains.
2. Satellite CNG Facility – CNG is natural gas that is compressed to less than 1% of the volume it occupies at standard atmospheric pressure. The natural gas is stored in compressed form until dispatched to a lower pressure pipeline system. The storage facility is refilled during non-peak periods when system pressures are not a concern. These facilities normally have compressors to increase the pressure of the gas coming from the pipeline.

The option to site a CNG or LNG storage facility depends on many parameters including cost, flow rates capability, volume, commodity source, permitting requirements and tank size. Typically, the option between LNG and CNG facilities is determined by how much gas is required to serve an area. The biggest advantage of LNG storage is that the total storage capacity is greater than CNG storage. A satellite LNG facility can sustain an area experiencing low pressures for a longer duration. Both options generally require acres of land, and both processes can be noisy, limiting siting and increasing costs to remediate noise generation.

Liquefied natural gas (LNG), compressed natural gas (CNG), underground storage, and propane air facilities have all been used successfully for peaking in various parts of the country. CNG applications do not scale very well and quickly become cost prohibitive. Potentially viable underground storage structures are extremely rare and very expensive to develop. Propane air presents a risk of injecting oxygen into natural gas pipelines and producing a combustible mixture and is a safety risk NW Natural is hesitant to take. NW Natural's experience with LNG as a viable peaking asset facilitates assessment of a satellite LNG facility as an alternative to traditional pipelines. NW Natural has historically utilized mobile CNG and LNG as an emergency or best-efforts measure to support firm customers. Mobile solutions for natural gas delivery have significant risk, capacity, security, and siting issues, and a high cost per therm delivered. Thus, NW Natural routinely examines satellite LNG facilities in the alternatives analysis process and whereas other peaking assets may be considered if deemed appropriate.

Demand-side Resources

Demand-side management (DSM) comes in many forms, but all DSM distribution system resources focus on reducing the peak hour demand within a specific area on NW Natural's system and thereby delaying or avoiding the need for a pipeline reinforcement project or any other supply-side solution.

Lead Times for Non-pipeline Solutions

A primary benefit of moving to a more forward-looking distribution system is to allow for better use of non-pipeline solutions. The early identification of distribution system issues as discussed above is necessary to go beyond supply-side options. More specifically, Figure 8.11 shows the value of the known time component associated with a supply-side solution but also the chunkiness of using this just-in-time supply side solutions.

Figure 8.11: Just in Time Supply-side Solutions

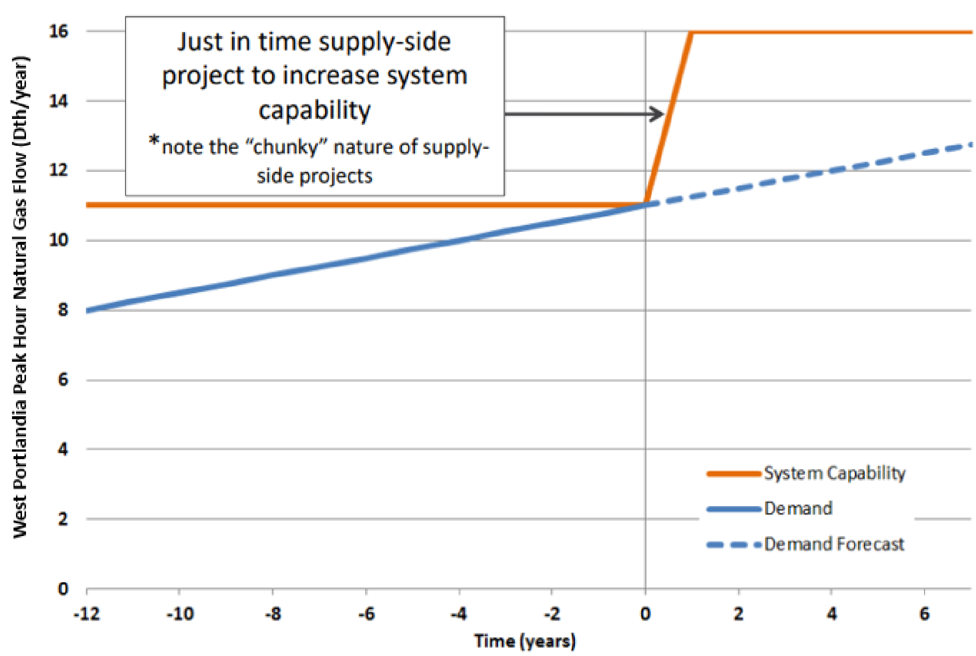
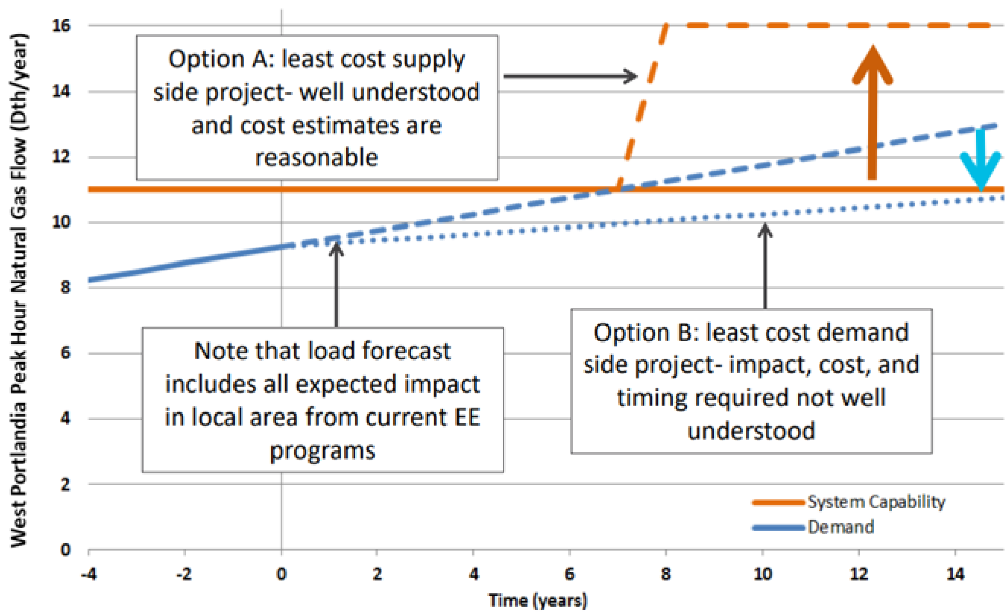


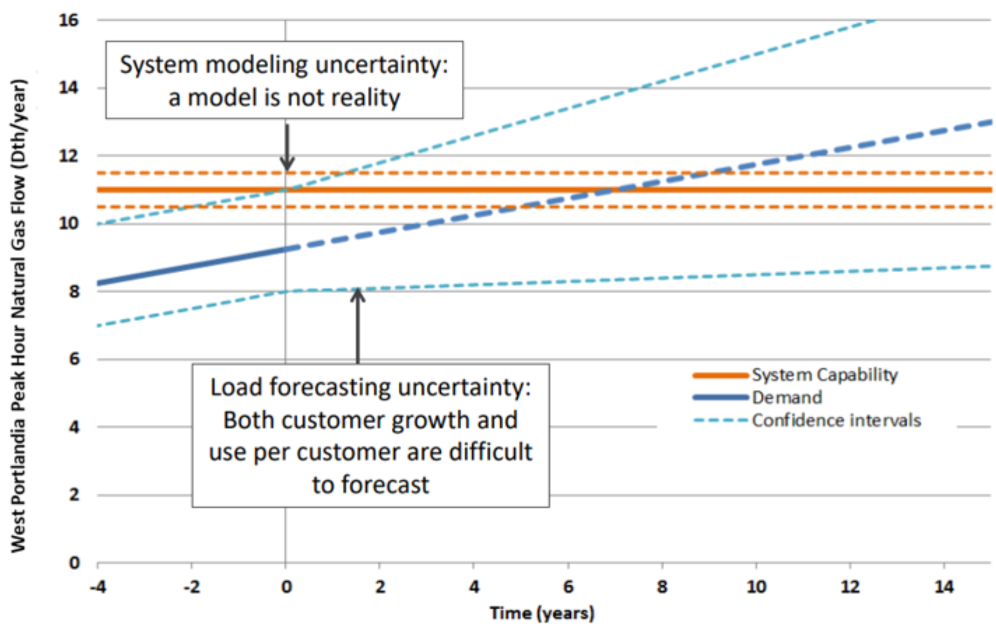
Figure 8.12 shows the timing needed for a demand-side non-pipeline solution.

Figure 8.12: Timing for Demand-side Non-pipeline Solution



As shown in Figure 8.13, the timing needed for demand-side projects is not well understood and there is still quite a bit of uncertainty. This is one of the reasons NW Natural is currently piloting an innovative non-pipeline alternative known as GeoTEE or **Geo**graphically **T**argeted **E**nergy **E**fficiency. Partnering with Energy Trust of Oregon, one of the key objectives of this pilot is to develop the data and ability needed to construct a peak hour energy efficiency supply curve for any given geographic area so that it can be compared for cost-effectiveness against other distribution system capacity options. GeoTEE is discussed in detail below.

Figure 8.13: Distribution System Planning with Uncertainty



Geographically Targeted Interruptible Agreements

NW Natural currently has many large interruptible customers who can be curtailed upon formal notice from NW Natural. This is one form of demand-side management. Another demand-side approach is to contractually arrange for voluntary service curtailment by large firm service customers within the area impacted. NW Natural begins the assessment of this alternative by examining historical loads of current large non-residential firm service customers in the area of influence for the proposed pipeline solution. If the estimated peak hour usage by these customers could be of sufficient volume to defer (or eliminate) the need to implement a supply-side solution, NW Natural would conduct additional analysis regarding whether customer-specific geographically targeted interruptible agreements[167] could be negotiated with these customers. Other demand-side management alternatives may be considered for future projects as new technologies and capabilities evolve. If the alternatives analysis indicates that a more effective and lower cost equivalent solution may be available, the proposed project will be revised to reflect the best alternative. The next sections discuss demand-side non-pipeline solutions.

[167] NW Natural also refers to such agreements as "localized interruptibility agreements."

GeoTEE

GeoTEE stands for **Geo**graphically **T**argeted **E**nergy **E**fficiency, and it is a non-pipeline solution to distribution capacity constraints.[168] More specifically, GeoTEE is defined as savings from offerings that are distinctive to certain locations within a state to achieve additional savings specifically from customers that contribute to the peak load of an area where the distribution system is experiencing weakness and a supply-side project is projected to be needed to meet local peak demand. Geographically targeted DSM savings can be obtained from DSM programs with measures not being offered in other areas of the state or from programs that intensify/accelerate the deployment of measures available elsewhere but different from what is offered in the state at large. Given the current method for evaluating DSM cost-effectiveness, special consideration must be given to the design and deployment of a geographically targeted DSM program to meet the economic/cost-effectiveness criteria.

Specifically, GeoTEE is designed to be achieved by either "accelerating" or "enhancing," or accelerating *and* enhancing, DSM offerings:

"Accelerated" DSM is defined as savings acquired by speeding up the deployment of measures that meet current Energy Trust cost-effectiveness requirements based on statewide avoided costs in an area with location specifically targeted marketing and/or increased incentives. In other words, accelerating DSM is acquiring savings that would be eventually achieved through statewide operations but faster in the locality in question.

"Enhanced" DSM is defined as savings obtained from measures that do not meet current Energy Trust cost-effectiveness requirements based on statewide avoided costs but are cost-effective if location-specific avoided costs[169] are used to represent the value of achieving peak hour savings from DSM in the area that is experiencing a distribution system weakness. In other words, enhancing DSM is savings that are cost-effective based on local avoided costs but are not cost-effective under current statewide avoided costs.

Accelerated and/or Enhanced DSM will be required in a geographically targeted area to achieve the required peak hour savings since the "business as usual" process for acquiring conventional DSM savings is already accounted for in the peak hour distribution system planning that shows additional DSM is needed to address the peak hour demand. The demand-side options to evaluate against supply-side options to address weaknesses in NW Natural's distribution system will be referred to as "geographically targeted DSM via accelerated and/or enhanced offerings" or "Targeted DSM" for short. Allowing for Targeted DSM to be a viable option is breaking new ground for LDCs operating in the

[168] For more information on GeoTEE, please refer to NW Natural's 2016 IRP, Chapter 6, Section 7, https://www.nwnatural.com/about-us/rates-and-regulations/resource-planning

[169] Inclusive of the expected costs of the potential supply-side distribution enhancement.

region and requires major changes to the way NW Natural plans distribution system upgrades and the way Energy Trust evaluates cost-effectiveness and deploys its programs.

Additionally, like supply-side options, if multiple enhanced *and/or* accelerated DSM programs are projected to be cheaper than the best supply-side option, the lowest cost option of the demand-side options would be selected and deployed to meet the best combination of cost and risk planning standard for addressing resource acquisitions.

As part of our 2016 IRP, we proposed the following action item:

Work with Energy Trust of Oregon to further scope a geographically targeted DSM pilot via accelerated and/or enhanced offerings ("Targeted DSM" pilot) to measure and quantify the potential of demand-side resources to cost-effectively avoid/delay gas distribution system reinforcement projects in a timely manner and make a Targeted DSM pilot filing with the Oregon Public Utility Commission in late 2017 or early 2018.

The Public Utility Commission of Oregon (OPUC) acknowledged this item in Order No. 17-059 dated February 21, 2017.[170]

On April 17, 2019, NW Natural filed an update to its 2018 Integrated Resource Plan[171] that included its GeoTEE pilot filing. It also noted at that time that while the filing of the pilot was delayed, the actual pilot was still on schedule.

The objectives of the pilot include:

(1) Develop the data and ability needed to construct a peak hour energy efficiency supply curve for any given geographic area so that it can be compared for cost-effectiveness against other distribution system capacity options.
(2) Determine whether GeoTEE represents a socially desirable tool to serve LDC customers if it shows the potential to be a cost-effective capacity resource in some situations.
(3) Explore and discuss with key stakeholders the appropriate funding mechanism for future GeoTEE projects should they show as a potentially cost-effective way to address distribution system weaknesses.

[170] The Washington Utility and Transportation Commission does not acknowledge specific action plans but did acknowledge that NW Natural's 2016 IRP compliance with WAC 480-90-238in their letter dated December 19, 2016.
[171] https://edocs.puc.state.or.us/efdocs/HAH/lc71hah134047.pdf

Figure 8.14: GeoTEE Phases

To achieve these objectives the pilot is being conducted in Cottage Grove and Creswell, Oregon and using various phases. The phases and anticipated timing are shown in Figure 8.14.

As of this writing, Phase One with increased marketing and outreach has been completed along with Phase Two which involved increased incentives but still within the current cost-effective parameters. Phase Three with the incentives increased even further by applying local avoided costs values for cost effectiveness screening is currently underway and will continue through August 2022. Upon completion of Phase Three, and as shown in Figure 8.14, the reporting and evaluation of the pilot will begin.

Geo-Targeted Demand Response (GeoDR)

Demand response (DR) has proven an effective way for utility companies to balance their supply and demand and prevent service interruptions through extreme weather events. When geographically targeted, DR can help lower peak demand, improve service reliability, and avoid or defer the need for distribution system expansion in the geo-targeted service areas. As discussed in Chapter 3, NW Natural already relies upon substantial demand response resources in the form of interpretability to manage peak loads and save capacity resource costs on its distribution system, where roughly 9% of would-be peak load can be interrupted during peak events. This existing DR resource comes from large commercial and industrial customers, and the cost of serving peak load, on average, is comparatively high. In addition to the DR resources enrolled under the interruptible rate programs, NW Natural commissioned the Brattle Group to explore the potential and opportunities of the technology-enabled DR resources for both Oregon and Washington customers served by the Company. With this exploration as our guide, the Company is proposing to scope a residential and small commercial demand response program to supplement our existing program for large commercial and industrial customers. This exploration will provide the Company with information about cost-effective technologies and program concepts for the customers. The potential emerging technologies under evaluation include Wi-Fi smart thermostats for shaving space heating demand and controlling devices for shaving water heating demand during peak hours for the residential and small commercial customers. The Company is committed to exploring in more detail the program design, to determine if a particular pilot program in an infrastructure constrained area can be successfully implemented.

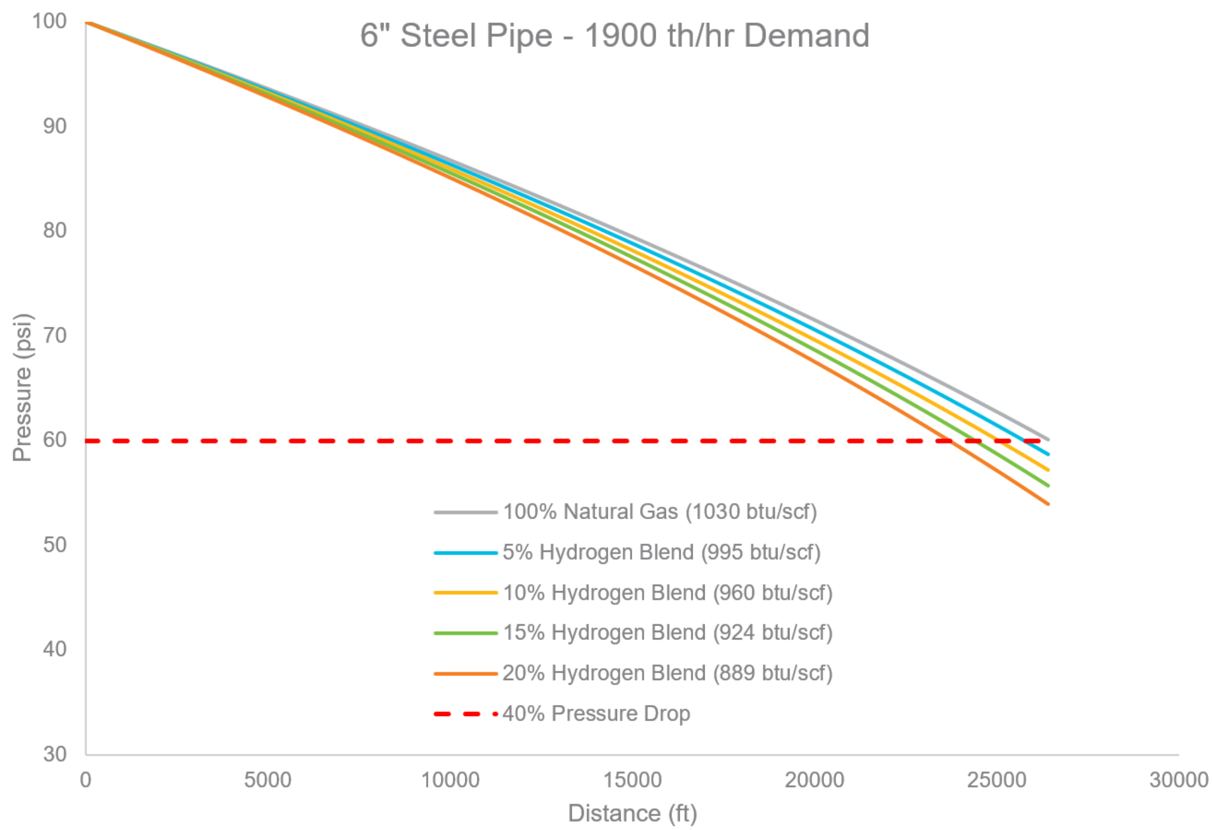
Hydrogen Blended with Natural Gas on the Distribution System

As was discussed in prior sections of the IRP, blending hydrogen into an existing natural gas system has benefits related to emission reductions. Injecting hydrogen into a natural gas stream does not improve pressures on a gas distribution system, and hence is not presented as an option in NW Natural's alternative analysis. In fact, blending natural gas with hydrogen reduces system pressures because it raises the volume of gas required to deliver to customers.

The British thermal units (Btu) Value for gas is defined as the amount of energy release by a unit volume when combusted. NW Natural measures Btu values per a standard cubic foot (Btu/scf). Btu Value on NW Natural's system typically ranges from 985 Btu/scf to 1155 Btu/scf. The Btu Value of hydrogen is approximately 325 Btu/scf. When hydrogen is blended with natural gas, the energy content of the gas stream is lowered because the Btu Value of hydrogen is approximately 1/3 that of natural gas. Btu Value is an important attribute on pipeline system because it determines the volumes of gas required to serve energy needs. Consumption on a natural gas network is determined by the amount of energy consumed, typically expressed in therms or Btus. If the energy needs remain constant while the Btu Value decreases, then it requires a higher volume of gas to meet the same energy demand. Higher volume of gas required equates to additional pressure drop along a pipeline system.

Figure 8.15 illustrates the pressure drop for natural gas compared to hydrogen blends. The graph shows that the pressure drops across a pipeline are proportional to the volume of hydrogen injected into the natural gas stream. Natural gas without hydrogen has less pressure drop than the hydrogen blends because it has a higher Btu Value. As more hydrogen is injected into the gas stream, more pressure drop occurs on the pipeline because the blend has a lower BTU Value. The main takeaway of Figure 8.15 is that it shows that hydrogen blending makes a distribution system with low pressures even weaker.

Figure 8.15: Hydrogen Blending Pressure Drop



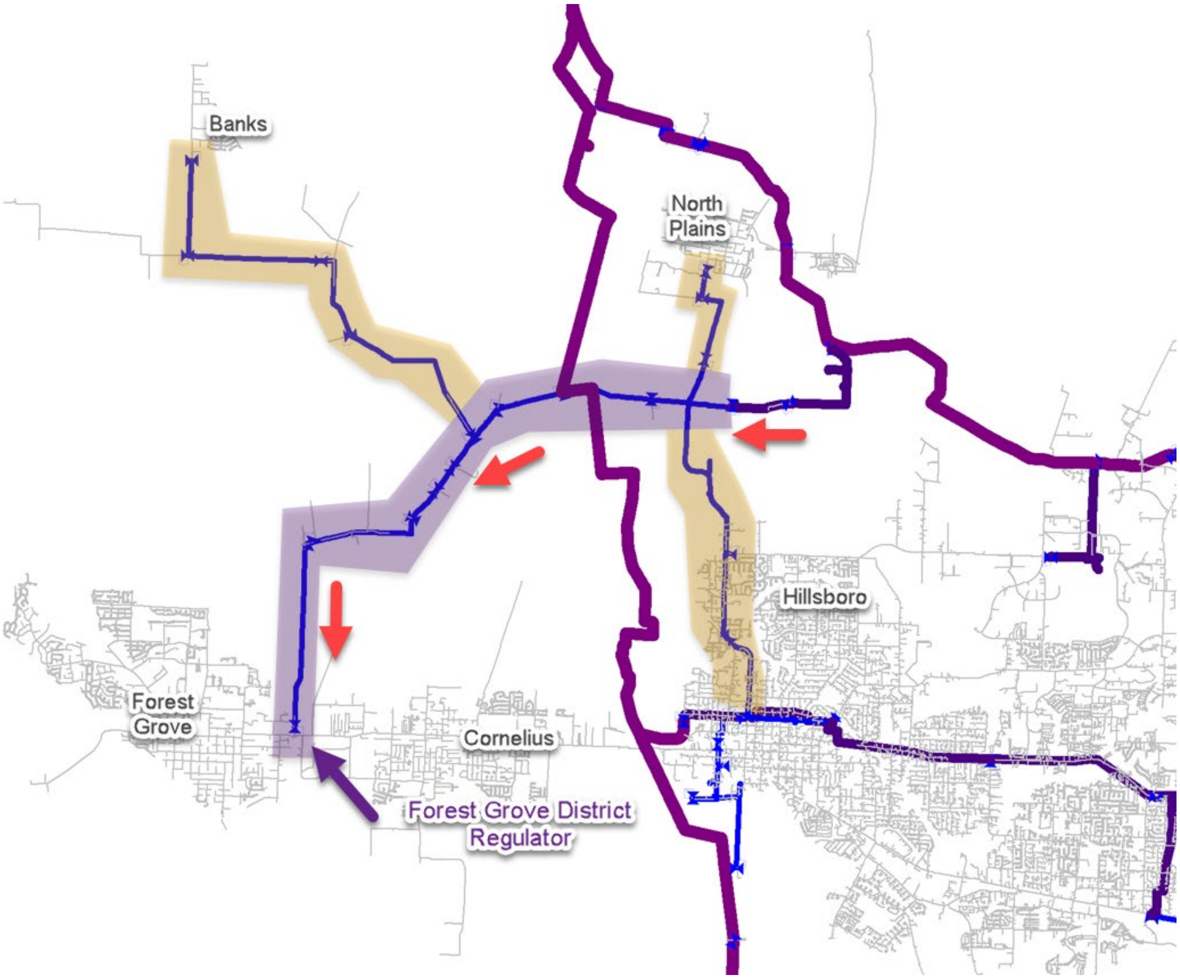
8.5 Distribution System Projects – 2022 IRP Action Item

This section describes a proposed distribution system project, which addresses an area of identified weakness within the distribution system.

8.5.1 Forest Grove Feeder Uprate

The Forest Grove Feeder (also known as the McKay Creek Feeder) is the primary supply pipeline for the western portion of the Portland metropolitan area. Customers in the communities of Hillsboro, Cornelius, Forest Grove, North Plains, and Banks are supplied by this pipeline. The Forest Grove Feeder is fed from the 720 MAOP Rock Creek Feeder and South Mist Feeder and has historically operated at 175 MAOP. Most of this pipeline was constructed in 1989 and other sections were installed in 1994. The segment that serves Banks was installed in 1997. Significant demand growth has occurred in this area and modeling results indicate that this pipeline is operating beyond its design capacity during extreme conditions. The Forest Grove Feeder is shown in Figure 8.16. The section of the Forest Grove Feeder that is operating over the original design capacity is indicated by the purple polygon.

Figure 8.16: Forest Grove Feeder System Identification

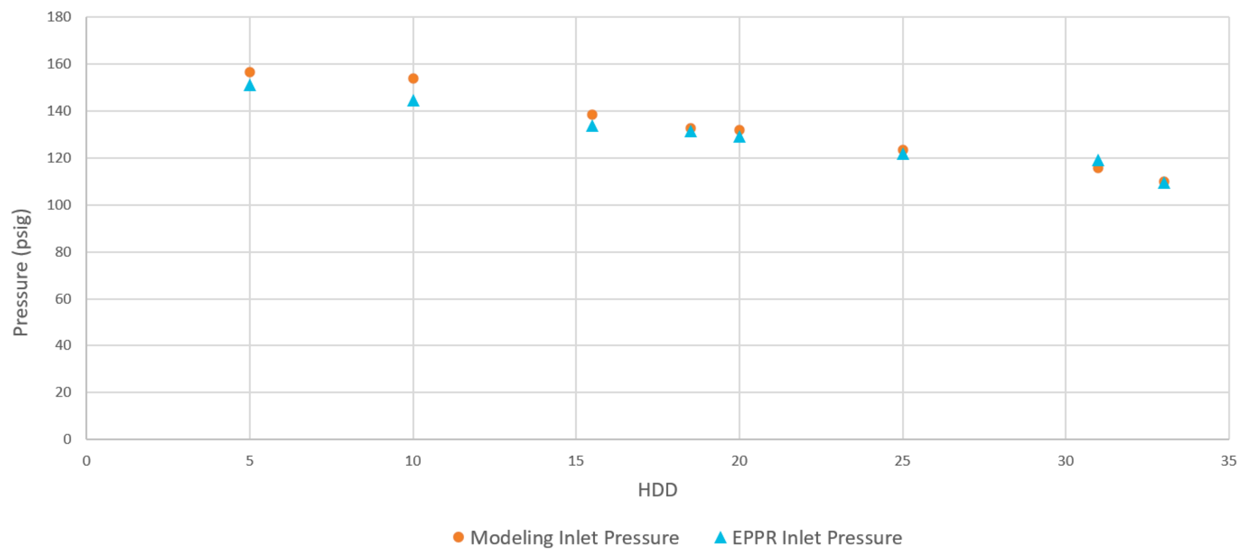


8.5.2 Customer Management Module (CMM)

For the following analysis, residential and commercial customer demands for Cornelius, Forest Grove, North Plains, and Banks were imported using CMM.

Nine data points collected between 2020 to 2022 were used to measure the variances between actual pressure reads from data extracted from an Electronic Portable Pressure Recorders (EPPR) sited at the inlet of the Forest Grove district regulator and the Synergi Gas™ model results. Because curtailments were not issued during the sample period, all interruptible customers remained enabled in Synergi Gas™ models for these data points. Figure 8.17 illustrates the difference between EPPR reads and the Synergi Gas™ model results. The average percent difference for the nine samples is 1.8%. This validation provides supporting data that CMM is producing demands that resemble actual consumption for residential and commercial customers.

Figure 8.17: Forest Grove District Regulator Inlet Pressure - CMM vs EPPR



8.5.3 Analysis

Peak hour analysis assumptions:

- Supplies set at peak hour
    - Customer demands set at Peak Hour
    - Largest customers estimated based on high frequency meter data (SCADA, Industrial Billing System)
- Commercial and residential customers peak hour demand estimated based on CMM Interruptible customers off as requested at peak hour
- Modeled System Configuration and Customers as of August 2021

During peak conditions, a severe pressure drop occurs on the last segment of the Forest Grove Feeder, which is approximately 5.3 miles of 6" steel pipeline operating at 175 MAOP. To force the model to solve during peak conditions, the Forest Grove district regulator had to be bypassed. Bypassing is performed in the model when regulators do not have sufficient inlet pressure to operate correctly. In field operations, bypassing a district regulator is typically performed by an operator who physically opens a valve that connects the district regulator inlet piping to the outlet piping. When bypassing occurs, gas does not flow through the regulator, avoiding pressures losses from the regulator. Figure 8.18 displays the model results for the Forest Grove area. Even with the Forest Grove district regulator bypassed, model results indicate customers may experience outages during a cold event. Customer connected pipes shown in red are those that may experience outages during extreme weather. During a peak hour event, the pressure drop in this segment of the pipeline is so high that Synergi Gas™ provides infeasible solutions. Infeasible solutions occur when the piping network is running out of pressure.

Figure 8.18: Existing System Peak Model

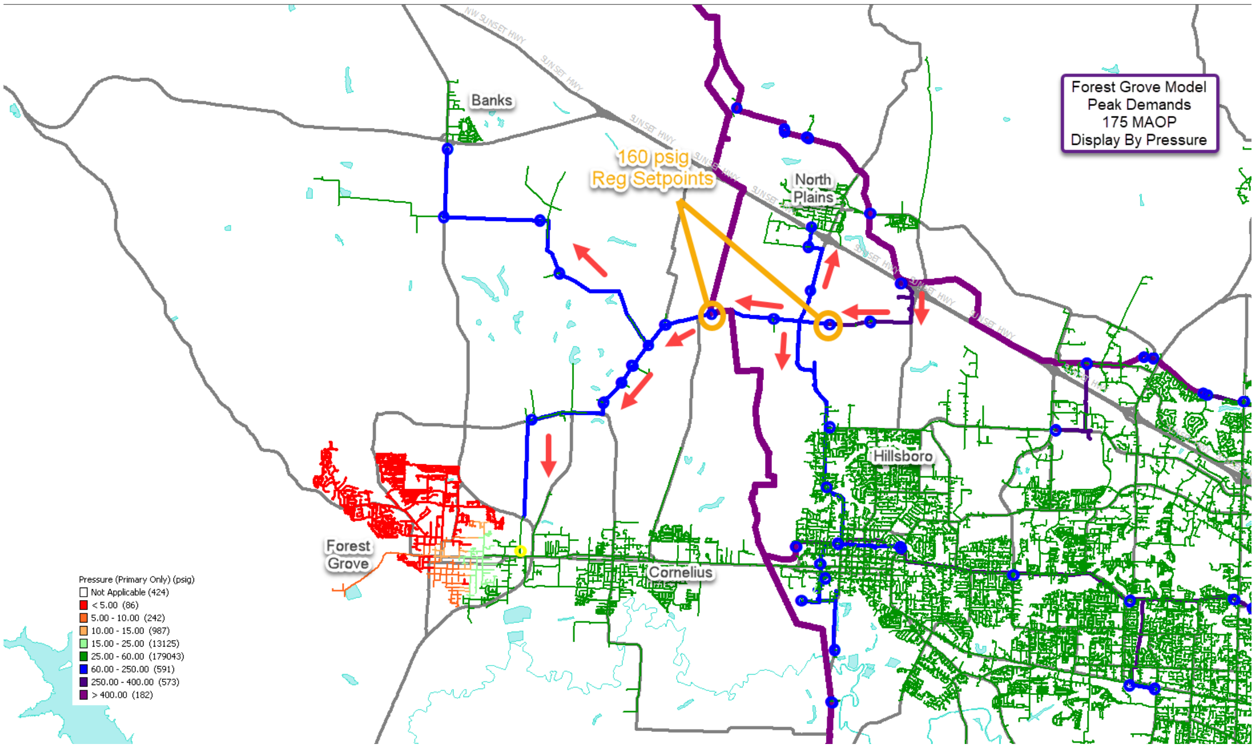
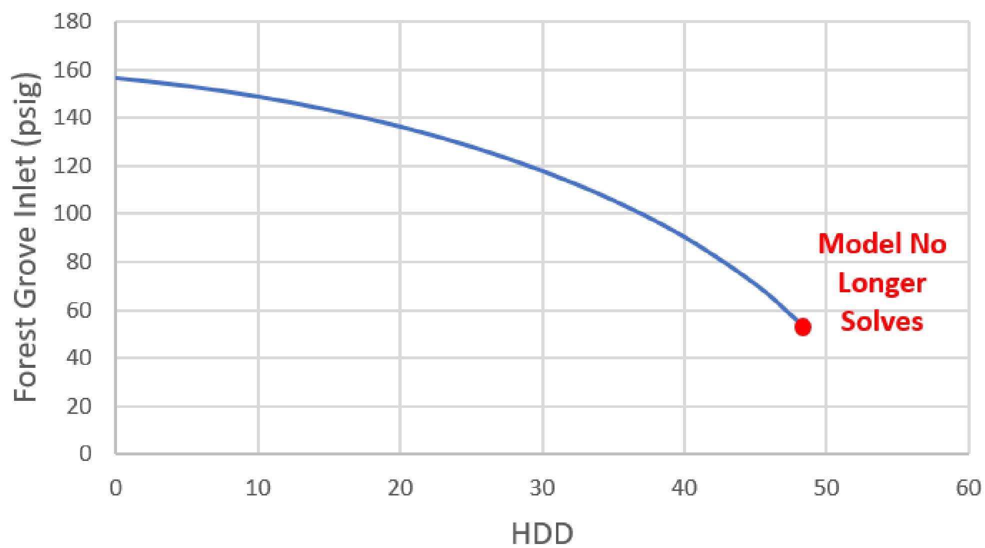


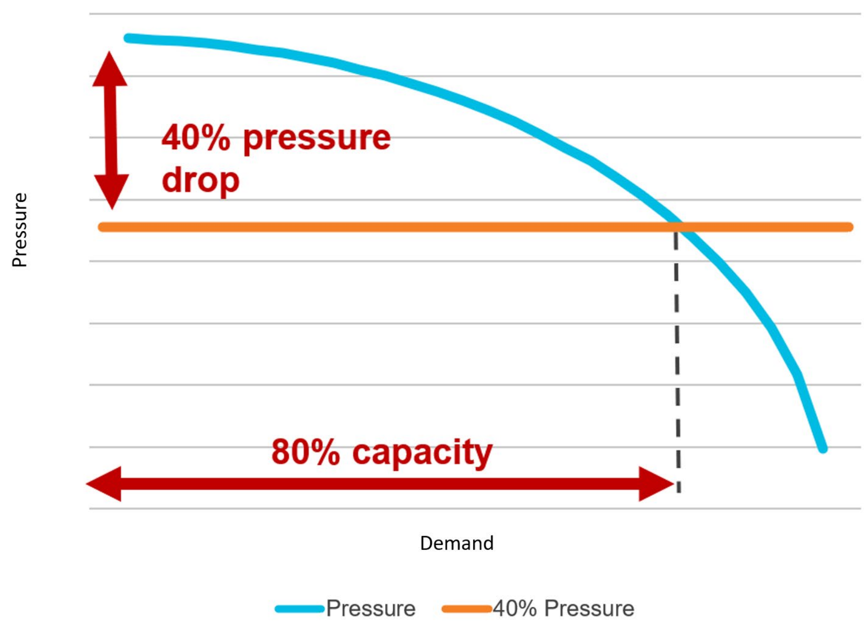
Figure 8.19 shows Synergi Gas™ results for the Forest Grove district regulator inlet pressures against various Heating Degree Days (HDDs). As the weather gets colder, the Forest Grove district regulator inlet pressure decreases. The graph illustrates that the relationship between pressure and capacity is nonlinear. The nonlinear relationship means that as demands are added in Forest Grove, the system becomes more sensitive to pressure loss. The graph terminates at 49 HDD. At 49 HDD, the model does not solve because of insufficient inlet pressure to the Forest Grove district regulator. Regulators require adequate inlet pressure to operate properly and deliver gas to downstream customers, which is typically 25 psig higher than the outlet pressure.

Figure 8.19: Forest Grove District Regulator Inlet Pressure Over Various Temperatures



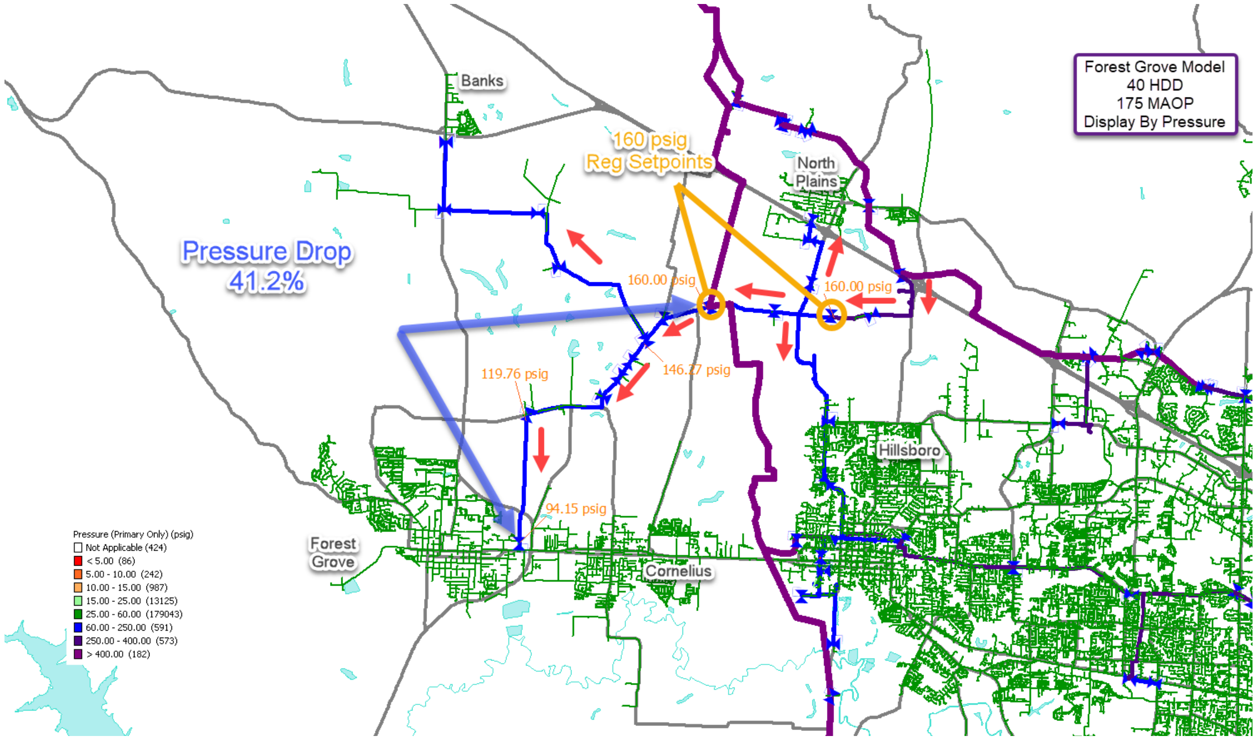
As mentioned in earlier in this Chapter, NW Natural's high pressure reinforcement criteria include addressing pressure drops that exceed 40% from the source to the end of the system. A system with a pressure reduction of 40% equates to an 80% level of capacity utilization. Small increases in demand from weather or growth can lead to outages when pipelines operate above 80% capacity. As shown in Figure 8.20, increases in demand from colder weather or growth increases the probability of outages when pipelines operate above 80% capacity as pipeline pressure decreases rapidly.

Figure 8.20: Pressure Drop Vs Demand



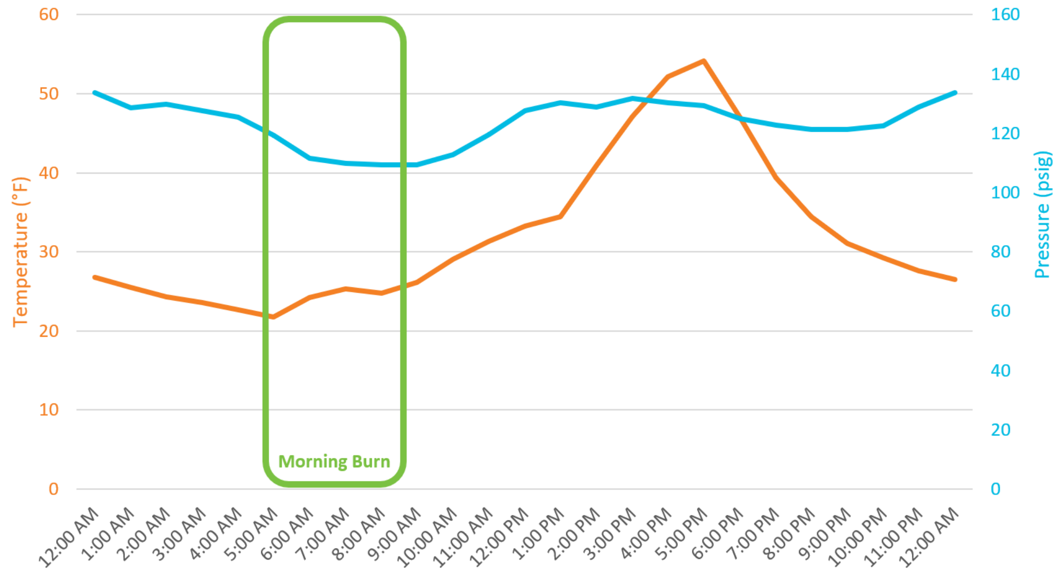
As displayed in Figure 8.21, the model results indicate that an average temperate of 25°F would cause the pressures on the Forest Grove Feeder to drop by over 40%. This area experiences a cold event with an average daily temperature less than 25°F about once every 3 years. The last cold event occurred in January of 2017.

Figure 8.21: 40% Pressure Drop for the Existing System



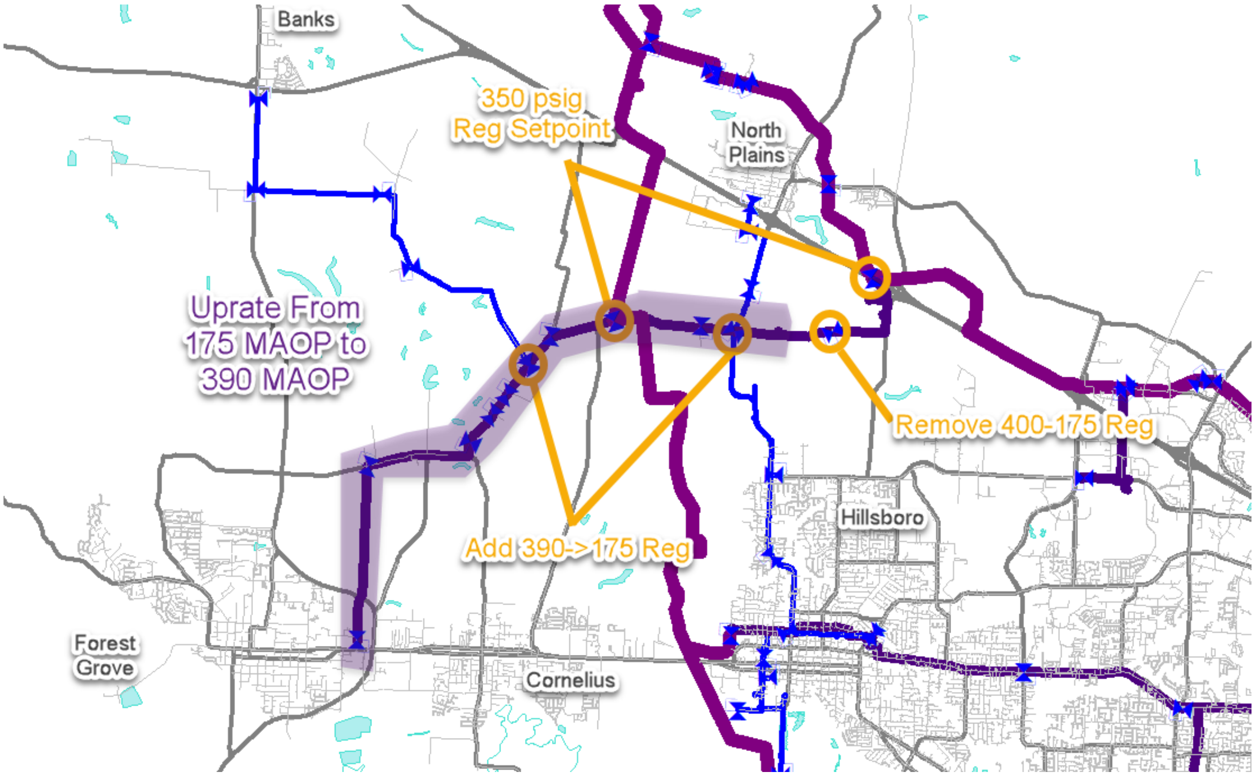
NW Natural began collecting EPPR pressure data in November 2020. During the sample period, the highest pressure drop occurred on February 23, 2022. Data retrieved from the EPPR revealed that the Forest Grove district regulator inlet pressure fell below 109 psig while the district regulators feeding the Forest Grove Feeder were set to 160 psig. Although the pressure drop was not greater than 40%, the pressure reads were within 1% of the modeled value of 110 psig. The EPPR case temperature during this day revealed that Forest Grove average daily temperature was 32°F. Figure 8.22 shows the recorded pressures and temperatures during the February 23, 2022, event. One area highlighted in Figure 8.22 is the morning burn. The morning burn is defined as the peak usage hour when businesses open, and where gas use increases as customers cook, adjust thermostats, and use hot water as they prepare for the day.

Figure 8.22: EPPR Data - February 23, 2022



The high pressure main on the Forest Grove Feeder was originally tested to allow a pressure uprate to an MAOP higher than the current 175 MAOP. As a general rule, the easiest and least expensive way to increase the capacity of a pipeline is to increase its operating pressure. Uprating a portion of the Forest Grove Feeder to an MAOP of 390 psig increases the capacity of this pipeline to deliver gas reliably to Forest Grove. The 175 MAOP laterals to Banks, North Plains, and Hillsboro do not have capacity constraints and would remain at their current 175 MAOP. Two new 390 to 175 district regulators must be installed to isolate these laterals from the newly uprated feeder. An existing 400 to 175 district regulator would be removed. All other district regulators and service regulators along the newly uprated line would be certified to operate at the new MAOP. Figure 8.23 shows the modifications required for the high-pressure system to uprate the pipeline.

Figure 8.23: Proposed System Reinforcement



As depicted in Figure 8.24, under peak conditions, the inlet pressure at the Forest Grove district regulator would be 303 psig with the Forest Grove Feeder Uprate in place. The corresponding pressure drop across the high-pressure system is 13.4% (based on upstream regulator setpoint of 350 psig), which is below the 40% pressure drop criterion to identify weak high-pressure systems. The model results show that pressure on the Forest Grove low-pressure system would be above 5 psig with the uprated pipeline. With the reinforcement in place, the Forest Grove Feeder would have adequate capacity to serve demands in the area.

Figure 8.24: Uprated System Peak Model

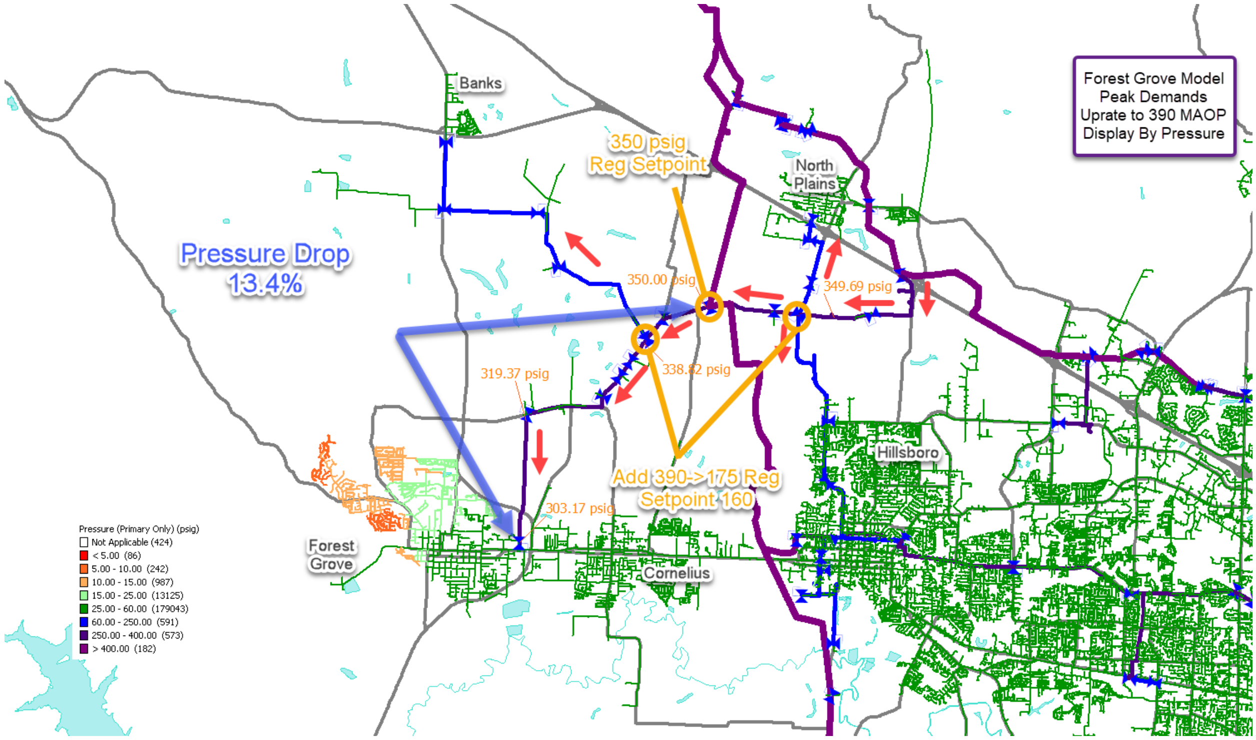
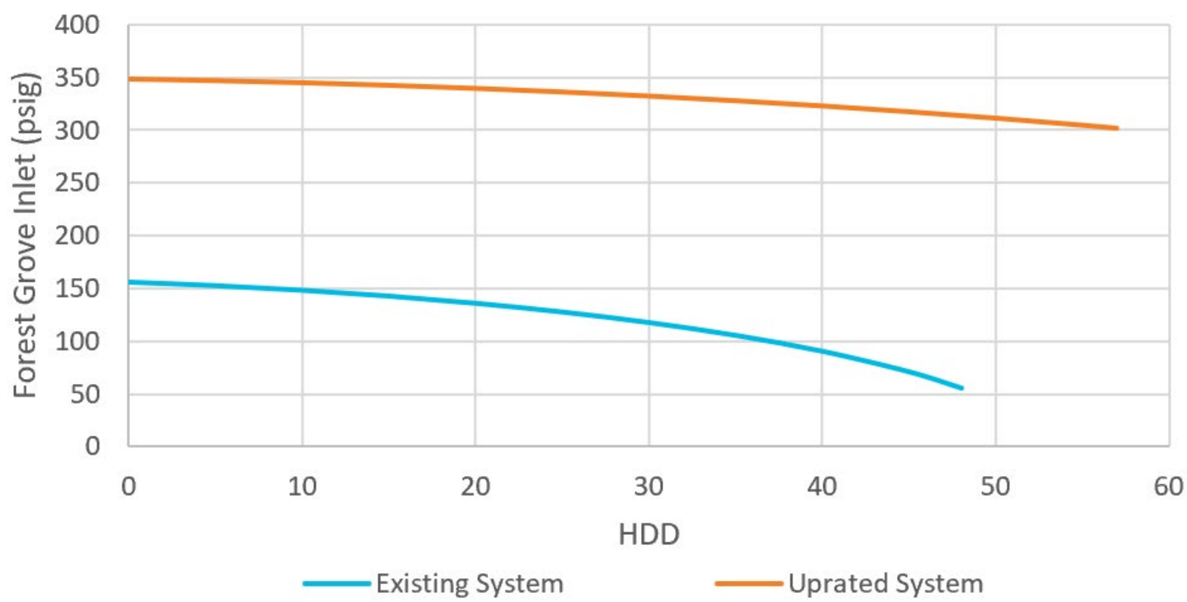


Figure 8.25 shows the pressures "before" and "after" the improvement. The "before" curve is the existing system applying current peak demands with interruptible customers disabled. The existing system curve shown in blue stops at 49 HDD because we do not have adequate inlet pressure at the Forest Grove district regulator for the model to solve. The "after" curve is the model results of the uprated system using existing demands with interruptible customers disabled. The difference between the curves captures the pressure benefits from the uprate.

Figure 8.25: Pressure Improvement



8.5.4 Uprate Scope

The items below would have to be completed in order to safely operate the Forest Grove Feeder at 390 MAOP:

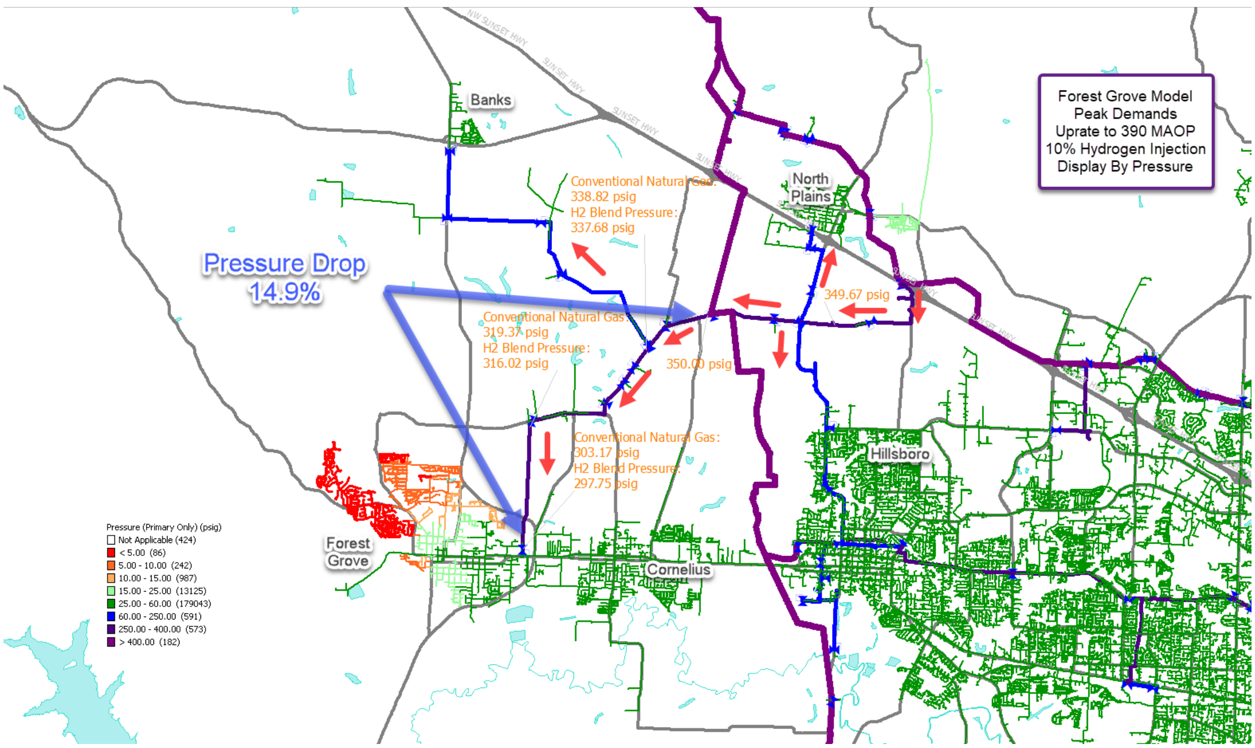
- Uprate approximately 6.3 miles of high-pressure main from an MAOP of 175 to an MAOP of 390
- Potentially uprate/replace 12 service regulator inlets
- Potentially uprate/replace 4 district regulator inlets
- Abandon 1 district regulator
- Install 2 district regulators

8.5.5 Hydrogen Compatibility

NW Natural is seeking opportunities for blending hydrogen with natural gas to lower carbon emissions. Hydrogen blended with conventional natural gas lowers the BTU values of the gas on a pipeline system. Lower BTU value gas requires higher volumes to serve the same demand because each volumetric unit of gas contains a smaller amount of energy. The higher volume of gas required to serve the same demand increases velocities in the pipeline, resulting in increased frictional losses and higher pressure drops compared to gas with higher BTU values.

Because the pressure loss across a pipeline would be higher for hydrogen blends, the existing system could not receive a hydrogen blend without further worsening the inlet pressure of the Forest Grove district regulator. Synergi Gas™ was used to model the implications of introducing hydrogen blends into the Forest Grove Feeder after uprating the pipeline from an MAOP of 175 to an MAOP of 390. The model results compare the pressures at the inlet of the Forest Grove Feeder for conventional natural gas with a gas blend that includes 10% hydrogen by volume. Model results show that flowing conventional natural gas during a peak event would cause the inlet pressure at the Forest Grove district regulator to be 303 psig. Comparatively, with hydrogen blended gas, the pressure at the inlet of the Forest Grove district regulator would be 298 psig. If a hydrogen blend were introduced onto the Forest Grove Feeder, the proposed uprate of the system would satisfy existing and future peak demands on the Forest Grove Feeder. Figure 8.26 shows the Synergi Gas™ model results for the 10% by volume hydrogen model run.

Figure 8.26: Uprated System Peak Model with 10% Hydrogen Blend



8.5.6 Project Alternatives

In addition to the tradition pipeline solution, NW Natural considered targeted interruptible schedule agreements by estimating the technically potential load savings from large firm industrial loads in the affected area switching to interruptible service. Even with all firm industrial loads curtailed in the model, Synergi Gas™ results demonstrate that the 175 MAOP system will continue to experience a greater than 40% pressure drop during peak hourly conditions indicating that there is insufficient technical potential available.

NW Natural also considered a satellite LNG Facility. The estimated cost to site LNG facility to serve affected area was estimated to cost significantly higher than pipeline uprate. Capital costs alone were estimated to be over $15 million dollars. Thus, this alternative was not considered further.

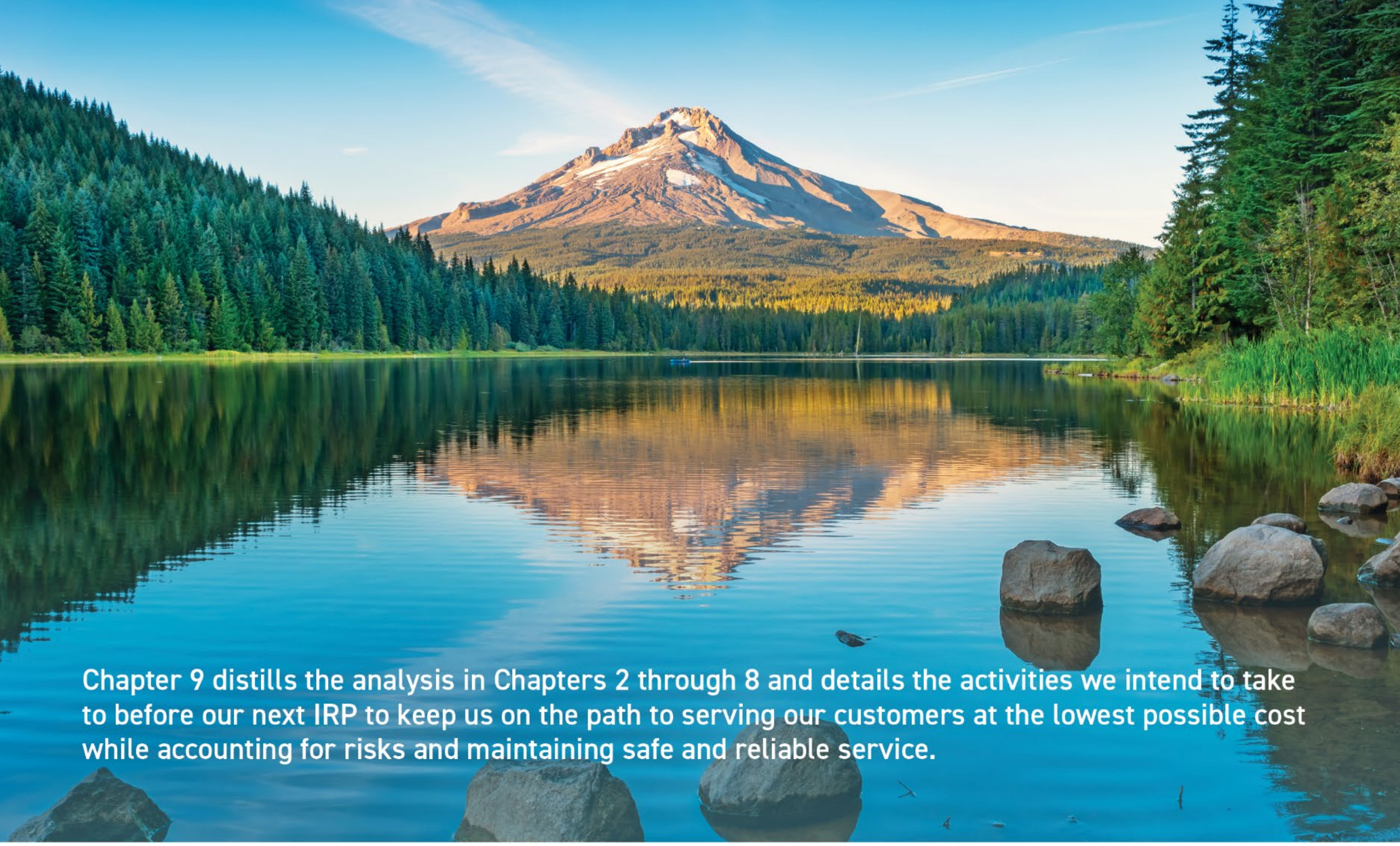
Lastly, NW Natural also considered geographically targeted RNG/Synthetic Methane but the site was not conducive to a cost-effective RNG interconnection project. RNG supplies typically originate from landfills, digesters, wastewater facilities, farms, and other waste management operations and thus one of these RNG-producing facilities would have to be in the area of need.

The Forest Grove Feeder Uprate shown in Table 8.4 is the sole project which will have an action item for which NW Natural is requesting acknowledgement by the Public Utility Commission of Oregon. Following NW Natural's final investment decision, this project will be implemented between 2024 and 2025.

Estimated costs for this project are stated in 2022 dollars and do not include construction overhead. A project's estimated cost may change over time, as it moves from a conceptual design to its final engineering specification. Additionally, both updated cost estimates and the actual cost of a project when constructed may differ from preliminary cost estimates due to actual inflation (cost escalation) differing from projected inflation, i.e., differences due to changes in the real price of a project between the preliminary cost estimate to a refined cost estimate to actual cost.

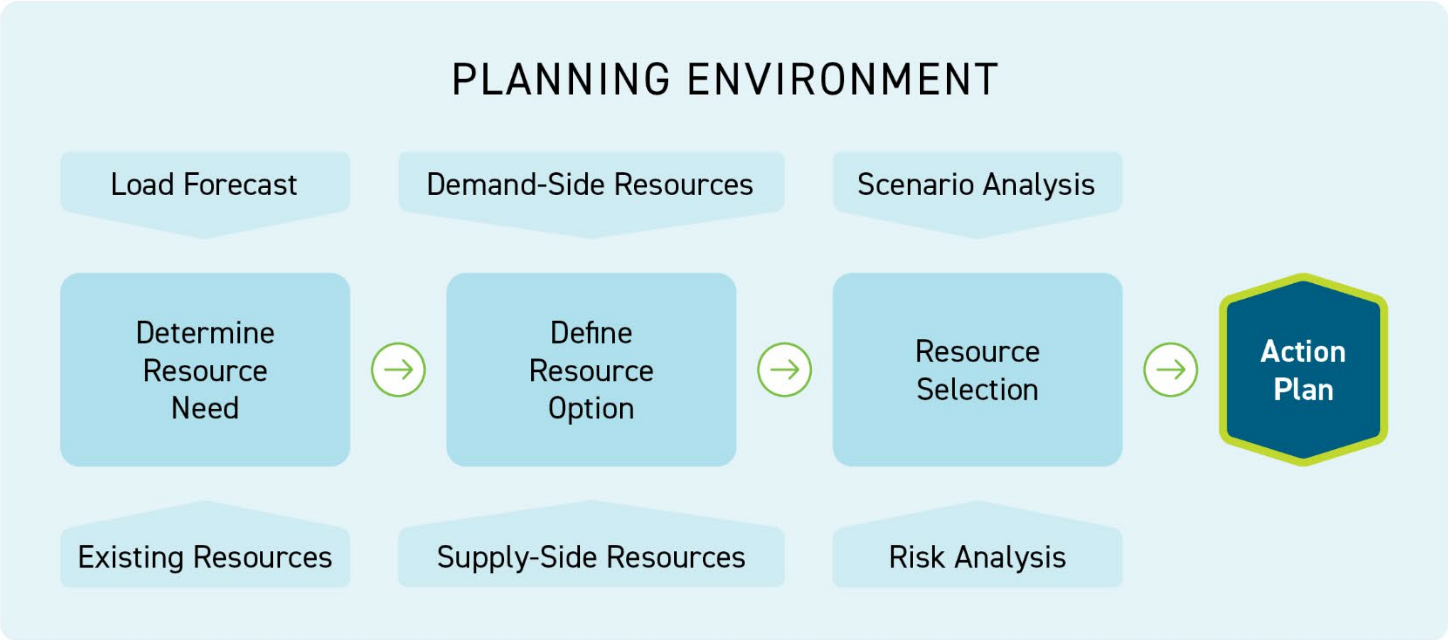
Table 8.4: Distribution System Project

Project	Schedule	Estimated Cost (Millions of $2021)	Estimated PVRR (Millions of $2021)
Forest Grove Feeder Uprate	2025	$3.0 - $6.2	$3.0 -$7.0



Chapter 9 distills the analysis in Chapters 2 through 8 and details the activities we intend to take to before our next IRP to keep us on the path to serving our customers at the lowest possible cost while accounting for risks and maintaining safe and reliable service.

9 Action Plan



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9.1 Action Plan

The Action Plan turns the results of the IRP analysis into discrete near-term activities that represent the best combination of least cost and least risk over the IRP planning horizon. The action items in this Action Plan are robust in regard to a wide range of potential future outcomes and therefore all represent low regret ways to move forward in the current environment.

Capacity Resource Action Items:

1. Acquire 20,000 Dth/day of deliverability from either recalling Mist, a city gate deal, or a combination of both for the 2023-24 gas year. Based upon updated load forecast in upcoming IRP updates recall Mist capacity as required for the 2024-25 and 2025-26 gas years.
2. Replace the Cold Box at the Portland liquified natural gas (LNG) facility for a targeted in-service date of 2026 at an estimated cost of $7.5 to $15 million.
3. Scope a residential and small commercial demand response program to supplement our large commercial and industrial programs and file by 2024.

Oregon Emissions Compliance Action Items:

4. Working through Energy Trust of Oregon, acquire 5.7 – 7.8 million therms of first year savings in 2023 and 6.7 – 8.9 million therms of first year savings in 2024, or the amount identified by the Energy Trust board.
5. In Oregon, to achieve SB 98 targets, seek to acquire 3.5 million Dths of renewable natural gas (RNG) in 2024 and 4.2 million Dths of RNG in 2025, representing 5% and 6% of normal weather sales load in 2024 and 2025.
6. Work with Energy Trust of Oregon, the Alliance of Western Energy Consumers and other stakeholders to develop energy efficiency programs for transportation schedule customers by 2024.
    - While this item is a part of our compliance strategy, NW Natural is not asking for acknowledgment from the OPUC of this item as we are already pursuing this action.
7. In Oregon, purchase Community Climate Investments representing any additional Climate Protection Plan (CPP) compliance needs for years 2022 and 2023 in Q4 2023 and for year 2024 in Q4 2024 based upon actual emissions to ensure compliance with the 2022-2024 compliance period.

Distribution System Action Item:

8. In Oregon, uprate the Forest Grove Feeder (also known as the McKay Creek Feeder) to be in service for the 2025 gas year at an estimated cost of $3.0 to $7.0 million.

Washington Emissions Compliance Action Items:

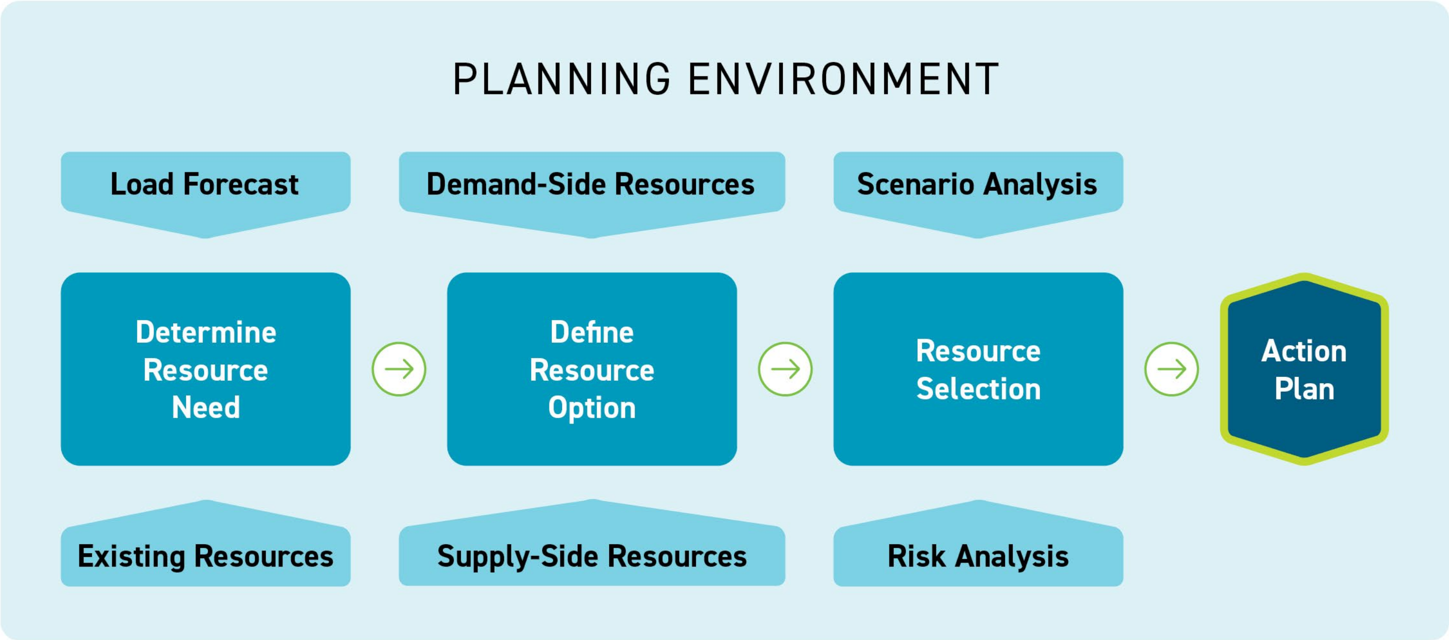
9. In Washington, acquire carbon offsets compliant with the Climate Commitment Act’s Cap-and-Invest program for 5% of expected weather emissions in year 2023 and 2024. Seek to acquire additional offsets representing 3% of expected weather emissions allowed for CCA compliance

on tribal lands, and if they can be acquired for a lower price than the program allowance price floor for years 2023 and 2024, acquire these offsets.

10. In Washington, to support HB 1257, seek to acquire 600,000 Dths of renewable natural gas (RNG) in 2024 and 800,000 Dths of RNG in 2025, representing 6% and 8% of normal weather compliance gas in 2024 and 2025.
11. In Washington, purchase emissions allowances equal to emissions at an estimate of the 95th percentile of need for annual compliance net of voluntary RNG, carbon offsets, and freely allocated but not consigned allowances.
12. Working through Energy Trust of Oregon, acquire 275,000-370,000 therms of first year savings in 2023 and 276,000-310,000 therms of first year savings in 2024, or the amount approved through WUTC Biennial Energy Efficiency Plan.
13. Work with Energy Trust of Oregon, the Alliance of Western Energy Consumers and other stakeholders to develop energy efficiency programs for transportation and industrial sales schedule customers by 2024.

Public involvement and input are essential to the development of our IRP. This chapter discusses how NW Natural involved the public through stakeholder workshops, meetings for the public, and other means of communication.

10 Public Participation



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10.1 Public Participation

Public involvement and input are essential to the IRP development. In accordance with guidelines from both Oregon and Washington and to encourage an open and transparent process, the public is encouraged to attend IRP workshops and meetings, and to submit comments during public comment periods.

In the current state, the public can find information about the IRP and associated activities on the NW Natural website site, under the About Us > Resource Planning Page. This page includes multiple drop-down menus which house a description of the IRP process, current IRP working groups and how to contact the IRP team, current and previous IRPs, and a letter from the CEO. As indicated on the website, members of the public, including community-based organizations and advocacy groups, can contact the IRP team and request to be included in the IRP distribution list by contacting IRP@nwnatural.com. All meetings are open to all members of the public and any member of the public can request to be added to the distribution list. The IRP distribution list is utilized to announce IRP related activities including Technical Working Groups (TWGs), and to provide invitations to virtual meetings. For the 2022 IRP Meeting for the Public, NW Natural additionally utilized a registration link through the website, whilst also providing an announcement via the distribution list. The Meeting for the Public is described in more detail in Section 10.3.

NW Natural is invested in increasing effective participation in its IRP process and will continue to seek out and implement process improvements. As noted in Chapter 2 as well as later in this chapter (see Section 10.4), the IRP process was the impetus for the creation of NW Natural's inaugural Community and Equity Advisory Group (CEAG). Feedback provided thus far on participation activities in the 2022 IRP has been recorded (see Appendix J) and NW Natural looks forward to working with stakeholders on applying such feedback in its next IRP process.

10.2 Technical Working Groups

The Technical Working Group (TWG) is an integral part of developing NW Natural's resource plans. During this planning cycle, NW Natural worked with representatives from Oregon Public Utility Commission (OPUC) of Oregon Staff; Washington Utilities and Transportation Commission (WUTC) Staff; Citizens' Utility Board of Oregon; Energy Trust of Oregon; Alliance of Western Energy Consumers (AWEC); Washington's Office of the Attorney General; Northwest Gas Association; Northwest Energy Coalition; Green Energy Institute at Lewis & Clark Law School; Enbridge Pipeline; Fortis BC; Avista; Cascade Natural Gas; Puget Sound Energy; and other stakeholders.

NW Natural held seven TWG meetings and one meeting for the public as part of its 2022 IRP process. Prior to the 2022 IRP TWG series, NW Natural held two supplemental TWGs pursuant to Oregon Public Utility Commission Order No. 21-013 in Docket LC-71. Due to COVID-19, all meetings were held virtually. NW Natural saw an increase in the number and diversity of participants utilizing virtual platforms. Below is a brief summary of each meeting.

Supplemental TWG No. 1, Load Considerations – September 29, 2021
Held virtually via Microsoft Teams. NW Natural reviewed modeling tools used within load forecasting and discussed with stakeholders the potential implications to modeling and forecasting from recent policies enacted in Oregon and Washington. Stakeholders were asked to provide feedback to NW Natural regarding key demand-side inputs needed for end-use load forecasting.

Supplemental TWG No. 2, Emission Considerations – December 9, 2021
Held virtually via Microsoft Teams. NW Natural used the first portion of this supplemental TWG to allow stakeholders that opportunity to ask questions related to NW Natural's presentation through UM 2178, Natural Gas Fact Finding Per EO 20-04.

During the second half to the TWG, NW Natural presented the modeling challenges and considerations created by emissions compliance policies in both Oregon and Washington. TWG participants discussed challenges and potential solutions utilizing the tools available. Feedback was requested from stakeholders on additional thoughts to modeling challenges.

TWG No. 1, Planning Environment and Environmental Policy – January 14, 2022
Held virtually via Microsoft Teams. During the first half of TWG No. 1, NW Natural provided an introduction to NW Natural. During this introduction, the IRP team reviewed, at a high-level, gas purchases, customer types and rate schedules, emissions context, system capacity resources, and distribution system planning options. This portion of the TWG also included NW Natural's view on the scope and role of the IRP, the regulatory basis for IRP process, IRP timelines, least cost-least risk considerations, and the interplay of the parts within the planning environment which culminate in the Action Plan. The IRP team additionally provided updates on actions since the 2018 IRP and 2018 IRP Update, and new challenges for the 2022 IRP.

The second portion of the TWG was dedicated to the Planning Environment and Scenario Development. The IRP team reviewed changes in the policy landscape which impact the IRP in either or both Oregon and Washington. The team discussed with stakeholders the challenges associated with new policies and the compliance mechanisms associated with each. Lastly, the IRP team reviewed the development of scenarios and types of analysis within such scenarios. Scenario analysis used in the 2018 IRP was reviewed and draft scenarios for the 2022 IRP were presented. TWG attendees discussed draft scenarios and provided initial feedback during the presentation. Stakeholders were provided further time to provide feedback on scenarios with feedback requested back to the IRP team by February 4, 2022.

TWG No. 2, Load Forecasting – February 11, 2022
Held virtually via Microsoft Teams. NW Natural discussed the goals, purpose, and framework within which load forecasts are developed, including the differences in the 2022 IRP compared to previous years. The TWG focused on understanding several concepts about load forecasting including (1) when

forecasting there is a trade-off between model parsimony and accuracy/precision (2) historical trends establish our reference case, which is a key starting point for understanding how structural changes to customer growth and stock turnover of end-use equipment impact overall demand (3) the importance for peak planning in IRPs and the trade-off of between costs for reliable service and the risks of resource constraints during an extreme cold event and (4) load uncertainty and an overview of stakeholder feedback on draft scenarios as well as a preview of the draft load forecasts within such scenarios.

Each part of load forecast modeling was reviewed with detailed discussion related to each section including the differences between the types of load forecasts; residential and commercial customer count and use per customer (UPC), and industrial, large commercial, and compressed natural gas (CNG). This discussion included accounting for impacts from energy efficiency and total sales and transportation loads. NW Natural also reviewed the reference case for the expected weather load forecast and the design weather load forecast (inclusive of a cold event and peak day load forecast).

Lastly, NW Natural gave an overview of stakeholder feedback on draft scenarios presented in TWG No. 1 as well as a preview of the draft load forecasts within such scenarios.

TWG No. 3, Supply-Side Resources – March 28, 2022
Held virtually via Microsoft Teams. The first portion of this TWG was dedicated to reviewing feedback received from stakeholders on the 2022 IRP scenarios and NW Natural's stochastic modeling to account for uncertainty in load scenarios. The remainder of the TWG focused on supply-side resources.

During the presentation on supply-side resources, the IRP team discussed the differences and overlap between gas supply capacity and distribution capacity resources; existing supply-side resources and an overview of conventional market fundamentals; Portland LNG; and RNG and hydrogen resources. The team went into a detailed discussion of Portland LNG's contribution to serving current load and its requirements to serve including an overview of the required Cold Box to continue operations at Portland LNG, and an overview of alternatives to the Cold Box to maintain reliable service for current peak day operations.

Lastly, ICF reviewed and discussed the availability of RNG and hydrogen resources at a national level. The IRP expanded upon this review with a discussion of the policy environment and markets for RNG and hydrogen, as well as current NW Natural projects. The IRP team also briefly reviewed NW Natural's methodology for evaluating the incremental cost of RNG resources.

TWG No. 4, Avoided Costs and Demand-Side Resources– April 13, 2022
Held virtually via Microsoft Teams. The first portion of the TWG focused on understanding several concepts about Avoided Costs. The IRP team reviewed what avoided costs are; principles of and standard industry approaches to avoided costs; applications of avoided costs in cost-effectiveness

evaluations, as well as the components of avoided costs and their associated resource option application; energy and environmental related avoided costs including CPP and CCA compliance costs and calculating GHG price components; Risk Reduction Value and commodity price risk reduction costs; and infrastructure and capacity avoided costs including their relation to peak load and peak savings. NW Natural also shared avoided cost results by end-use for both OR and WA.

The second portion of the TWG focused on OR And WA Conservation Potential Assessments (CPAs) and emerging technologies. Energy Trust of Oregon (ETO) presented a section on OR CPA for Sales Customers, including forecast results. Applied Energy Group (AEG) presented a section on WA CPA for Transport Customers, including draft conservation potential results. The IRP team reviewed the WA CPA for sales load completed by AEG in 2021 and presented results for CPA for WA Transport Customers also conducted by AEG in 2021. GTI gave a presentation on thermal (gas) heat pumps and the status of new technologies coming to the market for residential and/or commercial customers. Finally, NEEA spoke to market transformation and the partnerships between various organization which can accelerate the adoption of emerging technology.

TWG No. 5, Distribution System Planning– April 25, 2022

Held virtually via Microsoft Teams. The IRP team reviewed distribution system planning (DSP) processes, modeling, and standards as they are applied within the IRP process. This includes the deployment of both “pipeline” and “non-pipeline” solutions. The Technical Working Group focused on (1) peak hour demand including that the design of system is based on peak hour customer demand and how weather is a major driver, and (2) non-pipeline solutions and the criteria they must meet in order to be an alternative distribution system resource, and (3) distribution system planning objectives.

During the discussion of DSP objectives, NW Natural reviewed meeting peak hour requirements, addressing localized system needs, and choosing the cost-effective alternative while accounting for risk. Points of consideration included that NW Natural’s DSP is in a transition from a “just-in-time” planning process to a forward-looking planning process and that this transition is assisted by the improvements in system modeling through the Customer Management Module (CMM) project. Tools for system modeling and planning such as SCADA, and Synergi™, as well as reinforcement standards were also reviewed in detail.

Lastly, NW Natural discussed alternative analysis, the Geographically Targeted Energy Efficiency (GeoTEE) pilot, and the proposed Forest Grove Feeder system reinforcement project based upon principles and modeling as discussed.

TWG No. 6, Low Carbon Gas Evaluation Methodology and Emissions Compliance Mechanisms – June 1, 2022

Held virtually via Microsoft Teams. The first portion of the TWG focused on low carbon gas, (i.e., RNG) evaluation methodology, beginning with a review of IRP related activities and policies since filing the

2018 IRP update, as well as the evolution of NW Natural's evaluation methodology and key terminology related to low carbon/ renewable resources. The IRP team then reviewed and discussed:

- Project types of low-GHG resources including the differences between bundled and unbundled purchases
- Application of avoided costs, utilizing examples to illustrate the various types of costs avoided such as Transport, Compliance, Infrastructure, and Capacity
- How the cost of RNG is evaluated against conventional gas and the calculations used
- An in depth look at the components within the cost calculations and evaluation methodology
- Accounting for risk and uncertainty, including the tools and calculations utilized; NW Natural accounts for two main types of risk in its RNG methodology - Market and Policy

The second portion of the TWG was dedicated to reviewing PLEXOS®, the system resource planning model. The IRP team discussed how the model incorporates new policies including emissions compliance, as well as previously accounted for inputs such as weather and climate change, and the social cost of carbon. The IRP team then led stakeholders through modeling examples and a demonstration of NW Natural's complex model within the modeling software.

TWG No. 7, Portfolio Results and Actions – September 8, 2022
Held virtually via Microsoft Teams. During the first portion of the TWG, NW Natural reviewed which topics were covered in the previous six TWGs as they apply to the IRP process. NW Natural spoke to the risk analysis and discussed scenario vs simulation analysis including the importance of each in determining resource decisions. The team also discussed feedback from stakeholders on the draft IRP and provided scenario results for both Oregon and Washington. Scenario analysis was broken into three categories: Capacity Planning, Energy Planning, and Emissions Planning. In discussing the scenarios and results, NW Natural responded to some of the stakeholder feedback from the draft IRP and how the team is applying the feedback to the final IRP including clarifying its use of the terms "reference case" and "business-as-usual case" and where assumptions were adjusted.

The second portion focused on the Monte Carlo simulations- inputs and outputs, and the Action Plan. During this time, stakeholders and NW Natural held a robust discussion regarding the Monte Carlo draws and reviewed each action item individually with time allowed for open questions and discussion. NW Natural additionally held an open Q & A with the remaining time left in the workshop. Stakeholders provided thoughtful feedback throughout the TWG, of which NW Natural has considered.

Appendix G contains the (virtual) attendance lists for each TWG meeting.

10.3 IRP Draft Release and Meeting for the Public

The public is made aware of the IRP draft release through announcements on the NW Natural website and via a bill insert sent to all NW Natural customers. The Company additionally invited customers to participate in the resource planning process by hosting a Meeting for the Public on the evening of July 18, 2022. A bill insert notice, sent to all customers beginning on May 24, 2022, informed customers about the IRP process, draft release, welcomed customers to submit feedback, and invited customers to attend the Meeting for the Public. Appendix H contains a copy of the bill insert notice that was sent out to all customers.

Meeting for the Public

Held virtually via Zoom during evening hours on July 18, 2022. NW Natural customers were notified and invited to a Meeting for the Public workshop via a bill insert notice as well as a posting on the Resource Planning page of NW Natural's website. For this meeting, NW Natural utilized a registration link which contained a field for questions and comments with the intent to understand the type of discussion participants were interested in.

During this workshop, NW Natural provided an overview of the company; described the IRP process and addressed how people can get involved and/or learn more; answered such questions as: How much gas will our customers use? How much energy can we save through conservation? Where will NW Natural get its gas supply?; and presented the draft Action Plan. Attendees were especially interested in understanding the modeling scenarios, how disparate utilities (i.e., a gas utility and a water utility) may or may not coordinate on resource planning and distribution projects, understanding RNG and Hydrogen, and energy conservation relative to commercial and industrial growth in the region.

10.4 Community and Equity Advisory Group

The Company's IRP process was the driving force behind the formation of NW Natural's inaugural Community and Equity Advisory Group (CEAG). NW Natural recognized particular communities and customer groups have historically not been included or engaged in the resource planning process. The Company additionally recognized that many issues related to resource planning intersect with other areas of operations and community needs. Thus, the CEAG has been formed to advise the Company on various programs and processes, including, but not limited to, the resource planning process. Members of the CEAG are recruited from community-based organizations representing historically underrepresented voices in the energy planning environment. Member organizations are compensated for participation in the CEAG. NW Natural held a grounding meeting with member organizations and a Diversity, Equity, Inclusion, and Belonging (DEIB) facilitator on June 30, 2022, and will be holding its first CEAG meeting with all members at the end of September 2022.

Though the timing of the 2022 IRP and standing up the inaugural CEAG did not fully align, NW Natural expects the CEAG will assist with increasing and improving upon current public participation in its future IRPs.

Appendices

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Appendix A: IRP Requirements and Updates

A.1 NW Natural's 2022 IRP - Oregon Compliance

NW Natural's 2022 IRP - Oregon Compliance			
Citation	Requirement	NW Natural Compliance	Chapter
Order No. 07-047			
Guideline 1(a)	All resources must be evaluated on a consistent and comparable basis.	NW Natural uses a site-specific cost of service model to estimate the PVRR of NW Natural owned resources. Existing non-NW Natural owned resources use their current tariff rates and future resource costs are developed using estimates from the owner of those facilities. Additionally, new to the 2018 IRP, NW Natural developed a methodology for a consistent and comparable basis for evaluating renewable resources. This methodology has been updated and is included as an appendix to this IRP. NW Natural uses avoided costs to evaluate the cost effectiveness of Demand-side resources.	4, 5, 6, 7, 8
	Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	Chapters Five and Six focus on supply-side and compliance resources, and demand-side resources, respectively. The supply-side options considered in Chapter Six range from existing and proposed interstate pipeline capacity from multiple providers and NW Natural's Mist underground storage to various types of renewable natural gas, and imported LNG, and includes satellite LNG facilities sited at various locations within NW Natural's service territory. For those resources evaluated as being sufficiently viable to be included in resource portfolio optimization, NW Natural clearly defines each resource's in-service date before which the respective resource is unavailable for selection as part of a resource portfolio. Because NW Natural identified unserved demand occurring in all areas of its service	2, 3, 5, 6, and 7

		territory within the planning horizon in the absence of supply-side resource acquisition, the Company considered a variety of supply-side options to meet local, regional, and system-wide demand. These options included satellite LNG, on- and off-system renewable resources, NW Natural pipeline enhancements, and interstate pipeline expansions. The in-service dates of prospective resources range from short-term, such as Mist recall supplies to longer-term resources such as new interstate pipelines. NW Natural also performed analyses varying the in-service dates of different resources. NW Natural's analysis considers all prospective supply-side resources to be available, as of assumed in-service dates, throughout the remainder of the planning horizon. Meeting compliance obligations in both Oregon and Washington over the planning horizon is a major focus for this IRP. Compliance obligations and resources are discussed in Chapter Three and Six, respectively. NW Natural has additionally considered technologies which are not currently available but have been identified for continued monitoring and future assessment.	
	Consistent assumptions and methods should be used for evaluation of all resources.	NW Natural uses a site-specific cost of service model to estimate the PVRR of NW Natural owned resources. Existing non-NW Natural owned resources use their current tariff rates and future resources costs are developed using estimates from the owner of those facilities. NW Natural uses avoided costs to evaluate the cost effectiveness of Demand-side resources (energy efficiency and demand response) and supply-side resources (most notably the low carbon gas evaluation methodology). Compliance resources are also evaluated on a PVRR basis.	7

	The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	NW Natural uses a real after-tax discount rate of 3.4 percent in this IRP, which it derives using the currently authorized values associated with its cost of capital in Oregon. The Company incorporates a 2.86 percent annual rate of inflation, which it estimated using methods with which the Commission is familiar. Note that a real after-tax discount rate of 3.83 percent was used by ETO and AEG in their DSM savings potential analyses included Chapter Five. As discussed in Chapter Four of this IRP, ETO and AEG's energy savings forecasts need to be completed prior to NW Natural's resource optimization analysis. Therefore, NW Natural provided the 3.83 percent discount rate to ETO and AEG in 2021 and updated the discount rate to 3.4 percent in May 2022 and used it in resource optimization to reflect of the influence of the recent dynamic economic environment.	5, 6, 7, and Appendix A
Guideline 1(b)	Risk and Uncertainty must be considered.		
1.b.2 (note that 1.b.1 applies to electric utilities)	At a minimum, utilities should address the following sources of risk and uncertainty: Natural gas utilities: demand (peak, swing, and base load), commodity supply and price, transportation availability and price, and cost to comply with any regulation of greenhouse gas emissions.	Risk and uncertainty are intrinsic characteristics in long-term planning and NW Natural performed a risk analysis including both a stochastic analysis and a wide range of sensitivities to evaluate the impact of risk and uncertainty. More specifically, NW Natural analyzed demand uncertainty (peak, swing, and baseload) by using deterministic load forecasts. The Company analyzed weather uncertainty, gas price uncertainty, cost of compliance uncertainty, load, and resource-costs uncertainty in its stochastic analysis. Due to the degree of uncertainty of loads, policy, costs, and resources, for this IRP rather than developing a base case, NW Natural uses the range of cases, stochastic simulation, and risk analysis	2, 3, 4, 5, 6, and 7

		to inform this IRP. Finally, NW Natural discusses the impacts of complying with recently passed GHG emissions regulation and the uncertainty associated with the levels of the cost of compliance and potential emissions reduction alternatives. Chapter Seven contains the discussion of the Company's risk analysis, assumptions, and results.	
	Utilities should identify in their plans any additional sources of risk and uncertainty.	In addition to the uncertainties mentioned above, NW Natural has also modeled different sources of renewable resources. Not only does this take carbon compliance into consideration, but also tests the robustness of the plan given different renewable resources with different costs and different carbon attributes.	6, 7
Guideline 1(c)	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers. The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	The primary goal of this IRP is the selection of a portfolio of resources with the best combination of expected costs and risks over the planning horizon. In this IRP, the portfolio selected depends upon the prospective development of a number of renewable natural gas projects. The analysis considers all costs that could reasonably be included in rates over the long-term, which extends beyond the planning horizon and the life of the resource. The robustness of the expected costs was evaluated in the stochastic risk analysis found in Chapter Seven.	7

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	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	NW Natural uses PVRR as the key cost metric in this IRP and includes analysis of current and estimated future costs of both long- and short-lived resources.	7
	To address risk, the plan should include, at a minimum:		
1.c.1	Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	NW Natural assesses both the variability of costs and the severity of bad outcomes in the risk analysis which includes both a stochastic and sensitivity analysis in Chapter Seven.	7
1.c.2	Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	NW Natural provides retail customers with a bundled gas product including gas storage by aggregating load and acquiring gas supplies through wholesale market physical purchases that may be hedged using physical storage or financial transactions. The following goals guide the physical or financial hedging of gas prices: 1) reliability; 2) lowest reasonable cost; 3) rate stability; 4) cost recovery; and 5) environmental stewardship.	Appendix E
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	NW Natural uses a probabilistic peak planning standard to accurately capture risk in its resource selection. Further, the Company augments its deterministic least cost portfolio optimization with a rigorous risk analysis, and its underlying	1, 3, 4, 6, and 7

		forecasts of weather and gas price variables with stochastic elements. NW Natural considered not only the strictly economic data in its assessment of resource options, but also the likelihood of alternative resources being available, analysis of demand and price forecasting, and the reliability benefits associated with certain resources. NW Natural uses this same process to balance costs and risks for compliance resources.	
Guideline 1(d)	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	This IRP includes compliance plans to meet Oregon's Climate Protection Plan and other policies that promote GHG emissions reductions. The Company's underlying gas price forecast provided by an outside consultant includes the cost of compliance with most known environmental regulations. The Company includes an emissions forecast associated with the considered resource portfolios, and explicitly models the outcomes of disparate policy futures including deep decarbonization of the natural gas system and an outright moratorium on new natural gas customer growth. As always, NW Natural works closely with Energy Trust of Oregon to acquire all cost-effective energy savings available for customers and continues to work to fully value the system benefits of demand-side resources.	2, 4, 5, 6, and 7

Guideline 2(a)	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.	NW Natural provided the public considerable opportunities for participating in the development of the Company's 2022 IRP. The Company held seven Technical Working Group (TWG) meetings, and one meeting for the public. The Company website includes a section on how one can become involved in NW Natural's IRP process and includes the dates and associated presentations for all 2022 IRP meetings, the draft 2022 IRP (which will be replaced with the final 2022 IRP upon filing), and previous IRPs. Additionally, new to the 2022 IRP process, NW Natural utilized virtual platforms to host IRP related meetings, creating a more accessible and inclusive environment for the public and stakeholders. Beginning with TWG No. 3, NW Natural recorded the TWGs and additionally posted these recordings to its website. NW Natural further notified customers of the 2022 IRP process in a June 2022 bill insert, which invited the submission of comments and announced the July 18, 2022, meeting for the public. Chapter Ten discusses the technical working groups and the meeting for the public.	10
Guideline 2(b)	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through	As evidenced by materials included in the plan, NW Natural has put forth all relevant non-confidential information necessary to produce a comprehensive plan.	

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	any other mechanism approved by the Commission.		
Guideline 2(c)	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	NW Natural submitted on July 29, after conducting six TWG meetings, an initial draft plan in both Oregon and Washington and posted this plan on the Company website. Further, NW Natural held a Meeting for the Public on July 18, 2022, in which the Company also described the process in which the public can review and comment upon the draft. Finally, the action plan contained within the draft plan was discussed at a TWG meeting held on August 23, 2022.	10
Guideline 3(a)	The utility must file an IRP within two years of its previous IRP acknowledgement order.	NW Natural's 2018 IRP was acknowledged by the Commission on March 4, 2019; see Order No. 19-073 in Docket No. LC 71. NW Natural was granted Temporary Exemption from OAR 860-027-0400(3) with the purpose of changing the filing date of its upcoming Integrated Resource Plan (IRP) from March 4, 2021, to July 2022; see Order 21-013 in Docket No. LC 71. NW Natural was granted an additional Temporary Exemption from OAR 860-027-0400(3) with the purpose of changing the filing date of its upcoming Integrated Resource Plan (IRP) from July 2022 to September 2022; see Order No. 22-288 in Docket No. LC 71.	
Guideline 3(b)	The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	NW Natural will comply with this guideline.	
Guideline 3(c)	Commission Staff and parties should complete their comments and	NW Natural looks forward to working with Commission Staff and interested parties in a review of this plan.	

	recommendations within six months of IRP filing.		
Guideline 3(d)	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.	NW Natural is prepared for this process.	
Guideline 3(e)	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	NW Natural is prepared to receive direction from the Commission regarding analysis required in its next IRP.	
Guideline 3(f)	Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must	NW Natural plans to file an annual report as required.	

	summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.		
Guideline 3(g)	Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that: 1) Describes what actions the utility has taken to implement the plan; 2-Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and 3-Justifies any deviations from the acknowledged action plan.	NW Natural acknowledges this guideline.	
Guideline 4	At a minimum the plan must include the following elements:		
Guideline 4(a)	An explanation of how the utility met each of the	This appendix is intended to comply with this guideline by providing an itemized response to each of the substantive and procedural requirements.	

	substantive and procedural requirements.		
Guideline 4(b)	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions	The IRP looked at high and low customer growth and also analyzes scenarios associated with both high and low demand growth. Due to the degree of uncertainty of loads, policy, costs, and resources, for this IRP rather than developing a base case, NW Natural uses the range of cases, stochastic simulation, and risk analysis to inform its action plan until the next IRP. Chapter Seven provides the stochastic load risk analysis results.	3, 7
Guideline 4(c)	For electric utilities …	Not applicable to NW Natural’s gas utility operations.	
Guideline 4(d)	For natural gas utilities, a determination of the peaking, swing and baseload gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and baseload), transportation and storage needed to bridge the gap between expected loads and resources.	New to this IRP, NW Natural utilized the PLEXOS® optimization model as discussed with Staff and stakeholders throughout the 2022 IRP TWG meetings. NW Natural analyzes on an integrated basis gas supply, transportation, and storage, along with demand-side resources to reliably meet peak, swing, and base-load system requirements. For this IRP, NW Natural utilizes a 90% probability coldest winter planning standard augmented with a historic seven-day cold weather event, which includes the probabilistically established planning standard day, against which to evaluate the cost and risk trade-offs of various supply- and demand-side resources available to PLEXOS®. NW Natural's integrated resource planning reflects the Company’s evaluation and selection of a planning standard which provides reliability for customers. Resulting resource portfolios provide the best combinations of expected costs and associated risks and uncertainties for the utility and its customers.	7, Appendix B, F, and G

Guideline 4(e)	Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology.	NW Natural determined the best resource mix by studying supply-side options currently used such as pipeline transportation contracts, and gas supply and renewable natural gas contracts; as well as alternative options such as additional capacity or infrastructure enhancements. The Company also considered future developments such as pipeline enhancements, renewable natural gas projects, power-to-gas (a suite of technologies that use electrolysis in an electrolyzer to separate water molecules into oxygen and hydrogen), and other compliance resources. Chapter Six discusses the various supply-side and compliance resource options and their costs. NW Natural compiled demand-side resource options with assistance from the ETO as well as AEG, and these options are identified in Chapter Five. Further, Chapter Two discusses various efficient end use equipment.	2, 5,6
Guideline 4(f)	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	NW Natural uses a planning standard that uses statistics and Monte Carlo simulation of the demand drivers to set a standard that the company's resource capacity can serve the highest firm sales demand day going into each future winter with 99% certainty. PLEXOS® is used to determine least-cost, least-risk portfolio and a scenario and stochastic risk analysis is completed to stress test the portfolio. The Synergi Gas™ software package also provides the Company the opportunity to evaluate performance of the distribution system under a variety of conditions, with the analysis typically focused on meeting peak day customer demands while maintaining system stability. Chapter Eight discusses the approach the Company uses to provide reliable service at the distribution system planning level.	3, 6, 7, 8

Guideline 4(g)	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered.	Chapter Seven describes alternative resource mix scenarios and forward-looking sensitivities involving commodity availability, commodity cost, transportation cost, and/or load forecast inputs evaluated in the IRP. The Company also included expected GHG policy compliance costs in its price forecasts and analyzed sensitivities related to compliance costs. Further, NW Natural factored compliance costs explicitly into the determination of the Company's avoided cost, which in turn factored into the identification of cost-effective demand-side resources and on-system resources such as renewable natural gas.	2, 4, 5, 6 and 7
Guideline 4(h)	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations — system-wide or delivered to a specific portion of the system.	As described above and in more detail in the Plan, NW Natural designed numerous alternate resource mix scenarios, where each scenario allows for changes to the supply-side, demand-side, and compliance resources available for selection. Chapter Seven and associated appendices document the resource portfolio options evaluated in this IRP.	7
Guideline 4(i)	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties.	Chapter Seven discusses the results of the stochastic risk analysis and tests the robustness of the expected resource choice over a wide slate of future environments that represent uncertainty of natural gas prices, weather, policy, and resource costs.	7
Guideline 4(j)	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Chapter Seven discusses the results of the stochastic risk analysis and tests the robustness of the expected resource choice over a wide slate of future environments that	7

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		represent uncertainty of natural gas prices, weather, and resource costs.	
Guideline 4(k)	Analysis of the uncertainties associated with each portfolio evaluated.	Chapter Seven discusses the results of the stochastic risk analysis and tests the robustness of the expected resource choice over a wide slate of future environments that represent uncertainty of natural gas prices, weather, and resource costs.	7
Guideline 4(l)	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.	Chapter Seven discusses the results of the stochastic risk analysis and selection of the resource portfolio.	7
Guideline 4(m)	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation.	NW Natural does not believe resource strategy is inconsistent with state or federal energy policies that were established upon filing this IRP. Potential barriers to implementation may relate to the ultimate availability and timing of certain incremental resources selected for the Company's selected portfolio due to facility siting/permitting challenges, market viability, and others. Chapters Two, Six, and Seven discuss such potential barriers.	2, 6, and 7
Guideline 4(n)	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	Chapter One presents NW Natural's multiyear action plan, which identifies the short-term actions the Company intends to pursue within the next two to four years.	1

Guideline 5	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	Chapter 6 discusses pipeline transmission line costs and potential future expansions.	6
Guideline 6(a)	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	As discussed in Chapter Five, NW Natural worked with ETO and AEG to analyze the potential energy savings that could be cost-effectively procured within the Company's service territory over the next 30 years. The studies determined the achievable potential by analyzing customer demographics together with energy efficiency measure data. The results were then evaluated with supply-side resources using PLEXOS®. A deployment scenario was applied to the total potential. NW Natural and ETO review these assumptions annually when ETO plans its program budget for the subsequent calendar year.	5
Guideline 6(b)	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility	NW Natural's Schedule 301, Public Purposes Funding Surcharge, contains a special condition requiring NW Natural to work with ETO every year to determine if the funding level is appropriate to meet the subsequent year's	1, 9

	should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	therm savings targets. NW Natural has included in its action plan, item 4, identifying specific annual savings targets.	
Guideline 6(c)	To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: 1) determine the amount of conservation resources in the best cost/ risk portfolio without regard to any limits on funding of conservation programs; and 2) identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	See response to Guideline 6(b)	
Guideline 7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	NW Natural offers interruptible rates which account for approximately 22 percent of the Company's throughput. This allows NW Natural to reduce system stress during periods of unusually high demand. NW Natural engaged the Brattle Group to assess additional DR potential and opportunities of technology-enabled voluntary DR programs for peak load shaving. NW Natural is proposing a residential and small commercial DR pilot as part of its Action Plan in this IRP.	

Guideline 8	See Amended Guideline 8 through **ORDER NO. 08-339**		
Guideline 8 (a)	BASE CASE AND OTHER COMPLIANCE SCENARIOS: The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. The utility also should develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Each compliance scenario should include a time profile of CO_2 compliance requirements. The utility should identify whether the basis of those requirements, or "costs," would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms such as allowance or credit trading or a safety valve). The analysis should recognize significant and important upstream	NW Natural explicitly incorporates expected regulatory compliance costs in its analyses. Due to the degree of uncertainty of loads, policy, costs, and resources, for this IRP rather than developing a base case, NW Natural uses the range of cases, stochastic simulation, and risk analysis to inform its action plan until the next IRP. Within the scenarios analyzed, NW Natural believes Scenario 1- Balanced Decarbonization reflects the most likely near-term regulatory compliance future.	2, 4, 7

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	emissions that would likely have a significant impact on its resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.		
Guideline 8 (b)	TESTING ALTERNATIVE PORTFOLIOS AGAINST THE COMPLIANCE SCENARIOS: The utility should estimate, under each of the compliance scenarios, the present value of revenue requirement (PVRR) costs and risk measures, over at least 20 years, for a set of reasonable alternative portfolios from which the preferred portfolio is selected. The utility should incorporate end-effect considerations in the analyses to allow for comparisons of portfolios containing resources with economic or physical lives that extend beyond the planning period. The utility should also modify projected lifetimes as necessary to be consistent with	Chapter Seven discusses the results of the stochastic risk analysis and tests the robustness of the expected resource choice over a wide slate of future environments that represent uncertainty of policy and compliance costs.	7

	the compliance scenario under analysis. In addition, the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection.		
Guideline 8 (c)	TRIGGER POINT ANALYSIS. The utility should identify at least one CO_2 compliance “turning point” scenario which, if anticipated now, would lead to, or "trigger" the selection of a portfolio of resources that is substantially different from the preferred portfolio. The utility should develop a substitute portfolio appropriate for this trigger-point scenario and compare the substitute portfolio's expected cost and risk performance to that of the preferred portfolio - under the base case and each of the above CO_2 compliance scenarios. The utility should provide its assessment of whether a CO_2 regulatory future that is equally or more	NW Natural evaluated numerous scenarios including aggressive load reductions. NW Natural’s preferred portfolio is based upon a risk-adjusted approach rather than selecting a base case for this reason.	7

	stringent than the identified trigger point will be mandated.		
Guideline 8 (d)	OREGON COMPLIANCE PORTFOLIO: If none of the above portfolios is consistent with Oregon energy policies (including state goals for reducing greenhouse gas emissions) as those policies are applied to the utility, the utility should construct the best cost/risk portfolio that achieves that consistency, present its cost and risk parameters, and compare it to those of the preferred and alternative portfolios.	NW Natural's preferred portfolio is consistent with OR energy policies.	7
Guideline 9	Direct Access Loads.	Not applicable to NW Natural's gas utility operations.	
Guideline 10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.	This plan studies the supply-side needs for NW Natural's complete service territory which includes customers in Oregon and Washington.	
Guideline 11	Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet	NW Natural analyzes on an integrated basis gas supply, transportation, and storage, along with demand-side resources to reliably meet peak, swing, and base-load system requirements. For this IRP, NW Natural utilizes a 90% probability coldest winter planning standard	3, 7

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	peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility’s chosen portfolio achieves its stated reliability, cost and risk objectives.	augmented with a historic seven-day cold weather event, which includes the probabilistically established planning standard day, against which to evaluate the cost and risk trade-offs of various supply- and demand-side resources available to PLEXOS®. NW Natural's integrated resource planning reflects the Company’s evaluation and selection of a planning standard which provides reliability for customers. Resulting resource portfolios provide the best combinations of expected costs and associated risks and uncertainties for the utility and its customers.	
Guideline 12	Distributed Generation. Electric utilities should…	Not applicable to NW Natural’s gas utility operations.	
Guideline 13(a)	Resource Acquisition. An electric utility should…	Not applicable to NW Natural’s gas utility operations.	
Guideline 13(b)	Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.	Appendix E describes NW Natural’s Gas Acquisition Plan (GAP) detailing the Company’s strategies and practices for acquiring gas supplies. The Company's Gas Acquisition Plan is centered on the following goals: 1) Reliability, 2) Diversity, 3) Price Stability, and 4) Cost Recovery.	Appendix E
Order No. 19-073, LC 71 - Staff Recommendation No. 1	Staff recommends that the Company provide a narrative in the next IRP to explain the factors that led to the Company's choice for the blending and transitioning years from the SME panel forecast to the econometric forecast, as well as supporting statistical analysis.	NW Natural has provided a narrative in Chapter Three on the factors leading to the Company’s choice for the blending and transitioning years from the SME panel forecast to the econometric forecast. Supporting statistical analysis can be found in Appendix B.	3, Appendix B

Order No. 19-073, LC 71- Staff Recommendation No. 2	Staff recommends the establishment of a consistent standard relating to the year in which the Company blends and fully transitions from the SME panel to the econometric forecast. The standard should stay the same from one IRP to the next unless the Company provides statistical and narrative evidence it has found a substantial improvement over the current method.	As a standard, the fourth year of the customer count forecast is "blended". NW Natural has provided a narrative in Chapter Three on the blending and transitioning years from the SME panel forecast to the econometric forecast. Supporting statistical analysis can be found in Appendix B.	3, Appendix B
Order No. 19-073, LC 71- Staff Recommendation No. 3	A common tool used within load forecasting to track the usage of market segments is tracking customers with the NAICS or SICS database. Staff recommends that NW Natural pursue the creation of such a tool for the next IRP.	With this IRP the Company has moved to an improved end use load forecasting model which we believe is more helpful in developing a load forecast.	
Order No. 19-073, LC 71- Staff Recommendation No. 4	Staff recommends the Company work with Staff and stakeholders through technical working groups to address Staff's concerns regarding model evaluation and specification testing for the 2020 IRP.	Prior to filing the 2022 IRP, NW Natural held two supplemental and seven Technical Working Groups in which the Company worked with Staff and stakeholders regarding model evaluation and specification testing.	
Order No. 19-073, LC 71- Staff	Prior to the 2020 IRP, Staff recommends NW Natural	On September 21, 2021, NW Natural held a supplemental Technical Working Group on the topic of Planning Standard	

Recommendation No. 5	coordinate a TWG focused on the Company's method of implementing probabilistic methodology for the capacity planning standard and peak hour standard for distribution system planning. NWN should share the relevant modeling inputs, outputs, and workpapers with stakeholders at least one week in advance of the TWG.	during which the Company discussed its method of implementing probabilistic methodology for the capacity planning standard and peak hour standard for distribution system planning.	
Order No. 19-073, LC 71- Staff Recommendation No. 6	Work with staff to review any proposed end use load profiles that deviate from those used by other independent regional organizations as part of UM 1893 and in their next IRP filing. The review may potentially involve third parties and additional supporting research.	NW Natural participated in stakeholder workshops held in docket UM 1893 and hosted a supplemental avoided cost workshop on October 8, 2021.	
Order No. 19-073, LC 71- Staff Recommendation No. 7	Staff recommends acknowledgement of NWN's Action Item number 9: Working through Energy Trust, NW Natural will acquire therm savings of 5.2 million therms in 2019 and 5.4 million therms in 2020, or the amount identified and approved by the Energy Trust board.	NA. See Update on Action Items in Section A.4.1	

Order No. 19-073, LC 71- Staff Recommendation No. 8	Staff recommends NWN continue to include Staff and stakeholders in the planning and implementation of the targeted DSM pilot with the Commission in 2019.	NW Natural included Staff and stakeholders in the planning and implementation of the targeted DSM pilot (GeoTEE). NW Natural discussed GeoTEE and presented preliminary results during TWG No. 5 on April 25, 2022.	
Order No. 19-073, LC 71- Staff Recommendation No. 9	Staff recommends NWN hire a third party to perform a Demand Response Potential Study in its service territory. This analysis should include an independent review of NWN's analysis of their interruptible rates as a DR option.	NW Natural engaged Brattle Group to perform a Demand Response Potential Study. Please see Chapter 8 for additional information.	8
Order No. 19-073, LC 71- Staff Recommendation No. 10	For significant maintenance projects and studies that could result in significant capital investments to facilitate future use of the resource, Staff recommends the Company consider including these projects in future Action Plans.	The Company has considered including such projects in future Action Plans.	
Order No. 19-073, LC 71- Staff Recommendation No. 11	For any state that continues not to have a carbon policy by the next IRP, include an additional carbon price path in the stochastic analysis that is near or equal to zero.	NA. Washington and Oregon established carbon policies of which NW Natural plans to comply.	1, 2
Order No. 19-073, LC 71- Staff	Based on evidence made available by NWN since Staff's final comments, Staff	NA. See Update on Action Items in Section A.4.1	

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Recommendation No. 12	recommends acknowledgement of the following distribution projects: - The Hood River project; - The South Oregon City project; - The Kuebler project; - The Sandy Feeder project; and the - Happy Valley project.		
Order No. 19-073, LC 71- Staff Recommendation No. 13	NW Natural should continue to monitor the area of concern in North Eugene and report back in a future IRP or IRP update if there is a violation of distribution system planning standards.	NW Natural continues to monitor the North Eugene system with an Electronic Portable Pressure Recorder (EPPR) and has not recorded any pressure violations. Additionally, NW Natural created a Eugene Model utilizing CMM customer data forecasts. The Eugene model does not exhibit the low pressures that were found in legacy models and the CMM pressure forecasts resemble the data that has been capture in the field via EPPR. If a violation of DSP standards is found, the Company will report back in a future IRP or IRP update.	
Order No. 19-073, LC 71- Staff Recommendation No. 14	Staff recommends that NW Natural Re-file Appendix H to address the concerns identified by Staff in Final Comments and further elaborated in the Staff Report.	NW Natural refiled Appendix H with the Commission on January 10, 2020, in docket No. LC 71.	
Order No. 19-073, LC 71- Staff Recommendation No. 15	(a) As part of an RNG investigation, Staff recommends NWN provide modeling inputs, outputs, and other relevant workpapers to parties in the investigation docket at least 30 days before signing any RNG contract or initiating any RNG project. (b)	Docket no. UM 2030 was started in 2019 and completed October 2020. The RNG evaluation methodology was amended and approved and is now being used to evaluate RNG resources.	

	Staff recommends acknowledging a revised action item for RNG: "NW Natural will participate in an investigation into the use of the Company's proposed methodology to evaluate renewable natural gas (RNG) cost-effectiveness. Until the investigation is complete, NW Natural will procure RNG deemed cost-effective through the methodology in revised Appendix H, up to a 4.5 million therm annual limit on total delivery, for up to ten years (up to 45 million therms in total). The investigation will review the appropriate process for procuring cost-effective RNG resources that do not align with the timeline of acknowledgement in an IRP as well as review the 4.5 million therm annual limit on cost-effective RNG procurement. If NW Natural seeks to procure additional cost-effective RNG before the conclusion of the investigation, it will seek acknowledgment in an IRP update. If the investigation		

	results in the 4.5 million therm annual limit being adjusted or eliminated, or in other changes, the Commission may direct NW Natural to file an update to reflect its findings."		
Order No. 21-013, LC 71	Grant an exemption for Northwest Natural Gas Company from OAR 860-027-0400(3) allowing a 16 month extension (July 29, 2022) to the Company's March 2021 IRP Filing deadline. And, direct NW Natural to launch its 2022 IRP Technical Working Group meetings upon DEQ's filing of draft CPP rules so as to begin the IRP stakeholder input process on this element and explore any associated work.	NW Natural began its 2022 IRP process, after DEQ's filing of draft CPP rules, with two supplemental Technical Working Groups, Load Considerations held on September 29, 2021, and Emissions Considerations held on December 9, 2021. A central focus of these TWGs was CPP draft rule implications on the IRP and associated work.	10
Order No. 21-274, LC 71 Recommendation No. 1	In response to Staff's question regarding hydrogen, NWN reports that the uprated pipeline will be able to accommodate hydrogen-blended gas without fears of hydrogen leakage. NWN will provide a detailed write up regarding hydrogen blending in its 2022 IRP.	NW Natural discusses hydrogen blending in Chapter 8.	8

Order No. 21-274, LC 71 Recommendation No. 2	Staff finds that a stakeholder process to discuss resiliency in Oregon's natural gas supply could lead to valuable information, including an agreed-upon definition of resiliency and any appropriate credit for the resiliency value of local RNG projects capable of providing supply during a pipeline outage. Staff will consider whether to facilitate the beginning of such a process at an appropriate time. Additionally, Staff expects that NWN will engage Staff and stakeholders on discussions of this issue as part of the development process of the next IRP.	NW Natural discussed the issue of resiliency with Staff and stakeholder during its IRP development process. NW Natural is supportive of the OPUC beginning a process to investigate regional resource adequacy across the natural gas and electric systems, but not as a part of any single utility's IRP.	6, 10
Order No. 21-274, LC 71 Recommendation No. 3	Staff suggests that the Company take steps to address this Staff Recommendation before the next IRP is filed. A stakeholder workshop in Docket No. LC 71 to discuss the Company's monthly factors and end use categories would be adequate.	NW Natural held a workshop on avoided costs on October 8, 2021.	
Order No. 21-274, LC 71	Acknowledge in part and decline to acknowledge in part	NW Natural participated in stakeholder workshops held in docket UM 1893 and hosted a workshop on October 8,	

Recommendation No. 4	NW Natural's third update to its 2018 Integrated Resource Plan. Decline to acknowledge NWN's distribution capacity and risk reduction avoided costs for purposes of its use in NWN's next avoided cost filing, and direct NW Natural to include the updated avoided cost data in its next avoided cost filing, with a supporting explanation for use of the data.	2021, with Staff, members from the Northwest Power and Conservation Council and additional stakeholders to review the methodology and values for the distribution capacity and risk reduction avoided costs filed in the 2018 IRP Update #3.	

A.2 NW Natural's 2022 IRP - Washington Compliance

NW Natural's 2022 IRP - Washington Compliance		
Rule	Requirement	Plan Citation
WAC 480-90-238(4)	Work plan filed no later than 12 months before next IRP due date.	NW Natural filed its original work plan on August 23, 2019. The Company filed three revisions to the work plan on August 23, 2019, March 3, 2020, and February 11, 2021.
WAC 480-90-238(4)	Work plan outlines content of IRP.	The work plan filed on March 3, 2020, outlined the content of the 2022 IRP.
WAC 480-90-238(4)	Work plan outlines method for assessing potential resources (see LRC analysis below).	The work plan file on February 11, 2021, outlines the methodology used in developing the 2022 IRP. NW Natural developed and integrated demand forecasts, weather patterns, natural gas price forecasts, and demand- and supply-side resources into gas supply and planning optimization software. The modeling results guided NW Natural toward the lowest reasonable cost resource portfolio.
WAC 480-90-238(5)	Work plan outlines timing and extent of public participation.	The work plan filed on February 11, 2021, states three supplemental working group meetings and six technical working group meetings, beginning on May 5, 2021, with the final technical working group meeting scheduled for April 14, 2022. Due to delays in various rulemakings in Oregon and Washington, NW Natural worked with Staff and stakeholders to adjust the timing of its technical working groups in order to align with such impactful processes and policies. Supplemental technical working groups began June 1, 2021, with the final technical working group held on August 23, 2022. All IRP related workshops were announced via the NW Natural website with schedule updates provided through the technical working groups, distribution list announcements, and website updates. Lastly, customers were notified of this IRP's process through a May 2022 bill insert, a facsimile of which is included in 0. This bill

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		insert welcomed public comments and invited customers to a public meeting, which occurred on July 18, 2022.
WAC 480-90-238(4)	Integrated resource plan submitted within two years of previous plan.	NW Natural filed its 2018 IRP on August 24, 2018. See Docket No. UG-170911. NW Natural was granted an exemption from WAC 80-90-238(4) on February 6, 2020. See Docket No. UG-190711, Order 01. This exemption was extended through Order 03, in Docket No. UG-190711.
WAC 480-90-238(5)	Commission issues notice of public hearing after company files plan for review.	Pending.
WAC 480-90-238(5)	Commission holds public hearing.	Pending.
WAC 480-90-238(2)(a)	Plan describes mix of natural gas supply.	Chapter Six outlines currently held and available supply-side resource options including existing and proposed interstate pipeline capacity from multiple providers, NW Natural's Mist underground storage, offtakes, imported LNG, and satellite LNG facilities. NW Natural has also provided a commentary of renewable supply-side options such as RNG and Hydrogen blending.
WAC 480-90-238(2)(a)	Plan describes conservation supply.	Chapter Five documents how NW Natural determined the achievable potential of demand-side management (DSM) within its service territory through 2050. Chapter Four presents Avoided Costs.

WAC 480-90-238(2)(a)	Plan addresses supply in terms of current and future needs of utility and ratepayers.	NW Natural analyzed current demand and examined uncertainty regarding future demand (peak, swing, and baseload) by using deterministic load forecasts. NW Natural develops a range of customer needs through scenarios and stochastic simulation, through a risk analysis to inform its action plan until the next IRP. The Company analyzed weather uncertainty, gas price uncertainty, cost of compliance uncertainty, load, and resource-costs uncertainty in its stochastic analysis. Finally, NW Natural discusses the impacts of complying with recently passed GHG emissions regulation and the uncertainty associated with the levels of the cost of compliance and potential emissions reduction alternatives.
WAC 480-90-238(2)(a) &(b)	Plan uses lowest reasonable cost (LRC) analysis to select mix of resources.	NW Natural considered the strictly economic data assessed by the PLEXOS® model; the likely availability of certain resources such as imported or satellite LNG; scenario analysis of demand and gas prices; and the results of an extensive risk analysis to various factors to ensure consideration of resource uncertainties and costs of risks when developing the plan. After considering all these factors, the Company selected a near-term preferred portfolio given the various futures and identified resources consistent with that portfolio for that specific future acquisition.
WAC 480-90-238(2)(b)	LRC analysis considers resource costs.	Chapter Seven identifies the costs of supply-side resource portfolios for each of multiple possible futures. A fundamental task associated with this is the estimation of the revenue requirements associated with discrete supply-side resources, including commodity prices. Chapter Seven discusses the results of the stochastic risk analysis and tests the robustness of the expected resource choice over a wide slate of future environments that represent uncertainty of natural gas prices, weather, policy, and resource costs.

WAC 480-90-238(2)(b)	LRC analysis considers market-volatility risks.	NW Natural developed several different risk analyses through a range of scenarios and stochastic simulation to examine risks associated with uncertainty regarding natural gas prices and price volatility, as well as availability of renewable natural gas and other compliance resources. These sensitivities evaluated higher levels of avoided costs, different natural gas price paths over the planning horizon, and the effects of alternative futures involving LNG exports on natural gas prices. NW Natural used the results of these sensitivities to inform its resource acquisition plan.
WAC 480-90-238(2)(b)	LRC analysis considers demand side uncertainties.	Chapters Four, Five, and Seven discuss DSM's effect on the supply-side resource mix. Chapter Eight discusses demand-side resources within the context of Distribution System Planning.
WAC 480-90-238(2)(b)	LRC analysis considers resource effect on system operation.	Chapter Seven discusses the multiple scenarios studied in this plan.
WAC 480-90-238(2)(b)	LRC analysis considers risks imposed on ratepayers.	The primary goal of this IRP is the selection of a portfolio of resources which comply with state and federal environmental regulations and have the best combination of expected costs and risks over the planning horizon. In this IRP, the portfolio selected depends upon the prospective development of a number of renewable natural gas projects. The analysis considers all costs that could reasonably be included in rates over the long-term, which extends beyond the planning horizon and the life of the resource. NW Natural performed a risk analysis including both a stochastic analysis and a wide range of sensitivities to evaluate the impact of risk and uncertainty. The Company analyzed weather uncertainty, gas price uncertainty, cost of compliance uncertainty, load, and resource-costs uncertainty in its stochastic analysis. Finally, NW Natural discusses the impacts of complying with recently passed GHG

		emissions regulation and the uncertainty associated with the levels of the cost of compliance and potential emissions reduction alternatives. Chapter Seven contains the discussion of the Company's risk analysis, assumptions, and results.
WAC 480-90-238(2)(b)	LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government.	NW Natural discusses new and developing state and federal policies in Chapter Two. NW Natural explicitly incorporates expected regulatory compliance costs in its analyses. Due to the degree of uncertainty of loads, policy, costs, and resources, for this IRP rather than developing a base case, NW Natural uses the range of cases, stochastic simulation, and risk analysis to inform its action plan until the next IRP. This IRP includes compliance plans to meet Washington's Climate Commitment Act and other policies that promote GHG emissions reductions. The Company's underlying gas price forecast provided by an outside consultant includes the cost of compliance with most known environmental regulations. The Company includes an emissions forecast associated with the considered resource portfolios, and explicitly models the outcomes of disparate policy futures including deep decarbonization of the natural gas system and an outright moratorium on new natural gas customer growth. Chapter Seven describes alternative resource mix scenarios and forward-looking sensitivities involving commodity availability, commodity cost, transportation cost, and/or load forecast inputs evaluated in the IRP. The Company also included expected GHG policy compliance costs in its price forecasts and analyzed sensitivities related to compliance costs. Further, NW Natural factored compliance

		costs explicitly into the determination of the Company's avoided cost, which in turn factored into the identification of cost-effective demand-side resources and on-system resources such as renewable natural gas.
WAC 480-90-238(2)(b)	LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	As stated above, NW Natural explicitly incorporates expected regulatory compliance costs in its analyses. The Company's underlying gas price forecast provided by an outside consultant includes the cost of compliance with most known environmental regulations. The Company includes an emissions forecast associated with the considered resource portfolios, and explicitly models the outcomes of disparate policy futures including deep decarbonization of the natural gas system and an outright moratorium on new natural gas customer growth. Chapter Seven describes alternative resource mix scenarios and forward-looking sensitivities involving commodity availability, commodity cost, transportation cost, and/or load forecast inputs evaluated in the IRP. The Company also included expected GHG policy compliance costs in its price forecasts and analyzed sensitivities related to compliance costs.
WAC 480-90-238(2)(b)	LRC analysis considers need for security of supply.	Chapter Six and Appendix E discuss supply and common gas purchasing practices, respectively. The primary objective of the Gas Acquisition Plan (GAP) is to ensure gas supplies are sufficient to meet firm customer demand. To meet this objective, NW Natural's primary goal is reliability, followed by lowest reasonable cost, rate stability, and cost recovery all while reducing the carbon content of the energy we deliver.
WAC 480-90-238(2)(c)	Plan defines conservation as any reduction in natural gas consumption that results from increases in the efficiency of energy use or distribution.	The Plan defines energy reductions from DSM programs in the Company's service territory as the reduction of gas consumption resulting from the installation of a cost-effective conservation measure.

WAC 480-90-238(3)(a)	Plan includes a range of forecasts of future demand.	This Plan evaluates a range of forecasts including high and low customer growth. The Company explicitly models the outcomes of disparate policy futures including deep decarbonization of the natural gas system and an outright moratorium on new natural gas customer growth.
WAC 480-90-238(3)(a)	Plan develops forecasts using methods that examine the effect of economic forces on the consumption of natural gas.	NW Natural analyzed a range of alternative resource portfolios through risk analysis that accounts for high and low customer growth and a range of load forecasts through scenario and simulation work.
WAC 480-90-238(3)(a)	Plan develops forecasts using methods that address changes in the number, type and efficiency of natural gas end-uses.	NW Natural analyzed a range of alternative resource portfolios through risk analysis that accounts for high and low customer growth and a range of load forecasts through scenario and simulation work. The range of loads may be thought of as resulting from changes in the number, type, and efficiency of natural gas end uses. Additionally, in its risk analysis, the plan evaluates the impact from various avoided costs as well as new gas end-use technologies.
WAC 480-90-238(3)(b)	Plan includes an assessment of commercially available conservation, including load management.	Chapter Five provides a discussion of conservation and demand-side resources. With respect to demand-side load management, NW Natural foresees continuing to shave peak load requirements when and where necessary by curtailing interruptible customers and is exploring other avenues of DSM.
WAC 480-90-238(3)(b)	Plan includes an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	Chapter Five details how NW Natural delivers energy efficiency programs that offer customers incentives for implementing cost effective demand-side management measures. Additionally, NW Natural, in partnership with Energy Trust of Oregon, has been testing an Accelerated/Enhanced Geographically Targeted DSM pilot since September 2019 (i.e., GeoTEE). New to this IRP, AEG

		evaluated the DSM potential for transportation customers and a summary of the analysis is provided in Chapter Five.
WAC 480-90-238(3)(c)	Plan includes an assessment of conventional and commercially available nonconventional gas supplies.	NW Natural determined the best resource mix by studying supply-side options currently used, such as pipeline transportation contracts and gas supply and renewable natural gas contracts; as well as alternative options such as additional capacity or infrastructure enhancements. The Company also considered future developments such as pipeline enhancements, renewable natural gas projects, power-to-gas (a suite of technologies that use electrolysis in an electrolyzer to separate water molecules into oxygen and hydrogen), and other compliance resources. Chapter Six discusses the various supply-side and compliance resource options and their costs.
WAC 480-90-238(3)(d)	Plan includes an assessment of opportunities for using company-owned or contracted storage.	NW Natural assessed its Mist underground storage, Jackson Prairie underground storage, imported LNG, as well as satellite LNG facilities located at various locations within the Company's service territory as resource options.
WAC 480-90-238(3)(e)	Plan includes an assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources.	Chapter Six discusses NW Natural's assessment of pipeline capability, reliability, and additional pipeline resources.
WAC 480-90-238(3)(f)	Plan includes a comparative evaluation of the cost of natural gas purchasing strategies, storage options, delivery resources, and improvements in conservation using a consistent method to calculate cost-effectiveness.	NW Natural determined the best resource mix by studying supply-side options currently used such as pipeline transportation contracts, and gas supply and renewable natural gas contracts; as well as alternative options such as additional capacity or infrastructure enhancements. The Company also considered future developments such as pipeline enhancements, renewable natural gas projects, power-to-gas (a suite of technologies that use electrolysis in an electrolyzer to separate water molecules into oxygen and hydrogen), and other compliance resources. Chapter Six discusses the various supply-

		side and compliance resource options and their costs. NW Natural compiled demand-side resource options with assistance from the ETO as well as AEG, and these options are identified in Chapter Five. Further, Chapter Two discusses various efficient end use equipment. Utilizing PLEXOS®, the Company determined the least cost resource mix through linear programing optimization as well as performed various sensitivities in its risk analysis, which is discussed in Chapter Seven.
WAC 480-90-238(3)(g)	Plan includes at least a 10-year long-range planning horizon.	The long-range plans NW Natural discusses in this IRP span more than a 10-year planning horizon, with plans out to 2050.
WAC 480-90-238(3)(g)	Demand forecasts and resource evaluations are integrated into the long-range plan for resource acquisition.	This IRP integrates demand forecasts with the cost, risk, and capabilities of alternative resource portfolios into a long-term plan for resource acquisition.
WAC 480-90-238(3)(h)	Plan includes a two-year action plan that implements the long-range plan.	The Action Plan in this IRP details NW Natural's actions related to supply-side, compliance, and demand-side resource acquisition over the next two to four years of the planning horizon.
WAC 480-90-238(3)(i)	Plan includes a progress report on the implementation of the previously filed plan.	Chapters Five, Six, and Eight discuss progress on both the demand- and supply-side activities since the last previously filed plan. Appendix A, Section A.4 discusses progress on Action Items and other key updates since the last previously filed plan.
WAC 480-90-238(5)	Plan includes description of consultation with commission staff. (Description not required).	WUTC Commission Staff was a party to the Technical Working Groups. NW Natural documents public participation in Chapter Ten and Appendix H.
WAC 480-90-238(5)	Plan includes a description of completion of work plan. (Description not required)	The Multi-Year Action Plan in Chapter One and the Technical Working Groups outlined in Chapter Ten serve to document NW Natural's successful completion of the work plan.
2018 IRP Acknowledgement Letter and	The Company should pursue all conservation measures made cost	NW Natural is pursuing all conservation measures considered to be cost effective.

Attachment, Docket UG-170911, Recommendation No. 1	effective by the projected rise in the Company's avoided cost.	
2018 IRP Acknowledgement Letter and Attachment, Docket UG-170911, Recommendation No. 2	The Company must continuously monitor the usage pattern of the interstate pipeline to determine whether the assumptions in the Plan continue to hold true.	The Company continuously monitors the usage pattern of the interstate pipeline and routinely reevaluates assumptions in the plan. Interstate pipelines are discussed in Chapter 6 and Appendix E.
2018 IRP Acknowledgement Letter and Attachment, Docket UG-170911, Recommendation No. 3	The Company should monitor the conditions that affect the zonal configuration of NW Pipeline's system.	The Company collaborates with NW Pipeline to ensure that assumptions around gas deliveries from Williams are valid and gas deliveries are able to reach citygates as modeled in this IRP.
2018 IRP Acknowledgement Letter and Attachment, Docket UG-170911, Recommendation No. 4	[Capacity Planning Standard] We encourage the Company to pursue refinements and verification of this methodology in future IRP cycles, including further analysis of how many years of historical data is appropriate to use in its modeling.	On September 21, 2021, NW Natural held a supplemental Technical Working Group on the topic of Planning Standard during which the Company discussed its method of implementing probabilistic methodology for the capacity planning standard and peak hour standard for distribution system planning.

2018 IRP Acknowledgement Letter and Attachment, Docket UG-170911, Recommendation No. 5	NW Natural should include a sensitivity that does not include a price on carbon for comparison of both emissions and price.	Washington and Oregon established carbon policies of which NW Natural plans to comply.

A.3 Update on Action Items from the 2018 IRP Update #3

Action Description	Update on Action Item
Complete North Coast Uprate Reinforcement Project	The project began in early 2022 for planning, design and assessing permit requirements. It is anticipated construction will be performed in multiple phases beginning in late 2022 or early 2023. Project planned for completion by October 31, 2024.
Complete Replacement of the Cold Box at NW Natural Newport LNG facility	This project is in the initiation phase and will schedule information will remain preliminary until an EPC contractor is selected and begins work. The preliminary schedule estimates design will continue through late 2023. Procurement would begin for long-lead items in mid-2023 with construction following in the second half of 2024. The project is anticipated to be complete and placed into service in Fall 2025.

A.4 Updates from the 2018 IRP

A.4.1 Updates on the 2018 Action Plan

Joint Multiyear Action Plan	
Supply Resource Investments	Update On Action Item
1) Recall 10,000 Dth/day of Mist storage capacity for the 2020-21 gas year. Recall 35,000 Dth/day of Mist storage capacity for the 2021-22 gas year.	Updated load projections resulted in no Mist Recall being required for the 2020-21 gas year. Lower cost Citygate deliveries of 5,000Dth/Day were deployed for the 2021-22 gas year
2) NW Natural will participate in an investigation into the use of the Company's proposed methodology to evaluate renewable natural gas (RNG) cost-effectiveness. Until the investigation is complete, NW Natural will procure RNG deemed cost-effective through the methodology in revised Appendix H, up to a 4.5 million therm annual limit on total delivery, for up to ten years (up to 45 million therms in total). The investigation will review the appropriate process for procuring cost-effective RNG resources that do not align with the timeline of acknowledgement in an IRP as well as review the 4.5 million therm annual limit on cost-effective RNG procurement. If NW Natural seeks to procure additional cost-effective RNG before the conclusion of the investigation, it will seek acknowledgment in an IRP update. If the investigation results in the 4.5 million therm annual limit being adjusted or eliminated, or in other changes, the Commission may direct NW Natural to file an update to reflect its findings.	Docket no. UM 2030 was started in 2019 and completed October 2020. The RNG evaluation methodology was amended and approved and is now being used to evaluate RNG resources.
Oregon-Only Action Plan	
Distribution System Planning Projects	Update On Action Item
3) Proceed with the Hood River Reinforcement project to be in service for the 2019 heating season and at a preliminary estimated cost ranging from $3.5 million to $7 million.	Construction started and the project was placed into service in September 2020 and included in rates.

4) Proceed with the Happy Valley Reinforcement project to be in service for the 2019 heating season and at a preliminary estimated cost ranging from $3 million to $5 million.	Construction started and the project was placed into service in March, 2020 and included in rates.
5) Proceed with the Sandy Feeder Reinforcement project to be in service for the 2020 heating season and at a preliminary estimated cost ranging from $15 million to $21 million.	Construction started and the project was placed into service in October, 2020 and included in rates.
6) Proceed with the South Oregon City Reinforcement project to be in service for the 2020 heating season and at a preliminary estimated cost ranging from $4 million to $6 million.	Construction started and the project was placed into service in April, 2020 and included in rates.
7) Proceed with the Kuebler Road Reinforcement project to be in service for either the 2020 or 2021 heating season and at a preliminary estimated cost ranging from $14 million to $20 million.	Construction for the project began in June, 2022 and is approximately 75% complete. The project is expected to be placed into service in October 2022.
Demand-side Resources	Update On Action Item
9) Working through Energy Trust, NW Natural will acquire therm savings of 5.2 million therms in 2019 and 5.4 million therms in 2020, or the amount identified and approved by the Energy Trust board.	Energy Trust acquired 97% of the 2019 goal on behalf of NW Natural customers. Energy Trust acquired 114% of the 2020 goal on behalf of NW Natural customers.
Washington-Only Action Item	
10) Working through Energy Trust, NW Natural will acquire therm savings of 368,000 therms in 2019 and 375,000 therms in 2020, or the amount identified and approved by the Energy Trust board.	Energy Trust acquired 101% of the 2019 goal on behalf of NW Natural customers. Energy trust acquired 94% of the 2020 goal on behalf of NW Natural customers.

Appendix B: Resource Needs

B.1 Customer Count Forecast Technical Details

Oregon's Office of Economic Analysis (OEA) was the data source of the exogenous variables used in the four econometric customer forecasting models as specified in Equations from (1) to (4) in the 2022 IRP. As OEA forecasts U.S. housing starts and Oregon's nonfarm employment 10 years ahead, NW Natural used Population Research Center (PRC) at Portland State University (PSU)'s long-term forecast of Oregon's population to project U.S. housing starts[1] and Oregon's nonfarm employment beyond 2030, respectively.

Residential:

$$\Delta OR\ customer\ rate_t = \alpha + b_1 \frac{(\Delta OR\ starts_t + \Delta OR\ starts_{t-1})}{2} \quad (1)$$

$$\Delta WA\ customer\ rate_t = \alpha + b_1 \frac{(\Delta \ln (US\ starts_t) + \Delta \ln (US\ starts_{t-1}))}{2} \quad (2)$$

Commercial:

$$\Delta OR\ customer\ rate_t = \alpha + b_1 \frac{(\Delta \ln (OR\ pop_t) + \Delta \ln (OR\ pop_{t-1}) + \Delta \ln (OR\ pop_{t-2}))}{3} \quad (3)$$

$$\Delta WA\ customer\ rate_t = \alpha + b_1 \frac{(\Delta \ln (OR\ emp_t) + \Delta \ln (OR\ emp_{t-1}) + \Delta \ln (OR\ emp_{t-2}))}{3} \quad (4)$$

The dependent and independent variables used in the equations are defined in Table B.1 while the estimated parameters of the equations are reported in Table B.2.

[1] NW Natural projected U.S. housing starts by first using PRC at PSU's forecast of Oregon's population and the 1991–2021 average historical relationship between the annual average rates of growth of U.S. and Oregon's population to project U.S. population beyond 2027. The Company then used the average annual rate of change in projected U.S. population growth to project U.S. housing starts.

Table B.1: Dependent and Independent Variables used in Equations (1) – (4)

Equation	Dependent Variable	Independent variable
(1) OR Residential	OR Residential Customer Growth	Change in housing stock (OR housing Starts)
(2) WA Residential	WA Residential Customer Growth	Change in housing stock (US housing Starts)
(3) OR Commercial	OR Commercial Customer Growth	Population growth (OR population)
(4) WA Commercial	WA Commercial Customer Growth	Local economic activity (Total employment growth in OR)

Table B.2: Parameter Estimates for Equations (1) – (4)

Equation #	α	β_1
1- OR Residential	-158	405**
2- WA Residential	37	1768**
3- OR Commercial	29	64625*
4- WA Commercial	158**	1.3*
† Note that significance levels are indicated by asterisks: *p<0.1, **p<0.05, and ***p<0.01.		

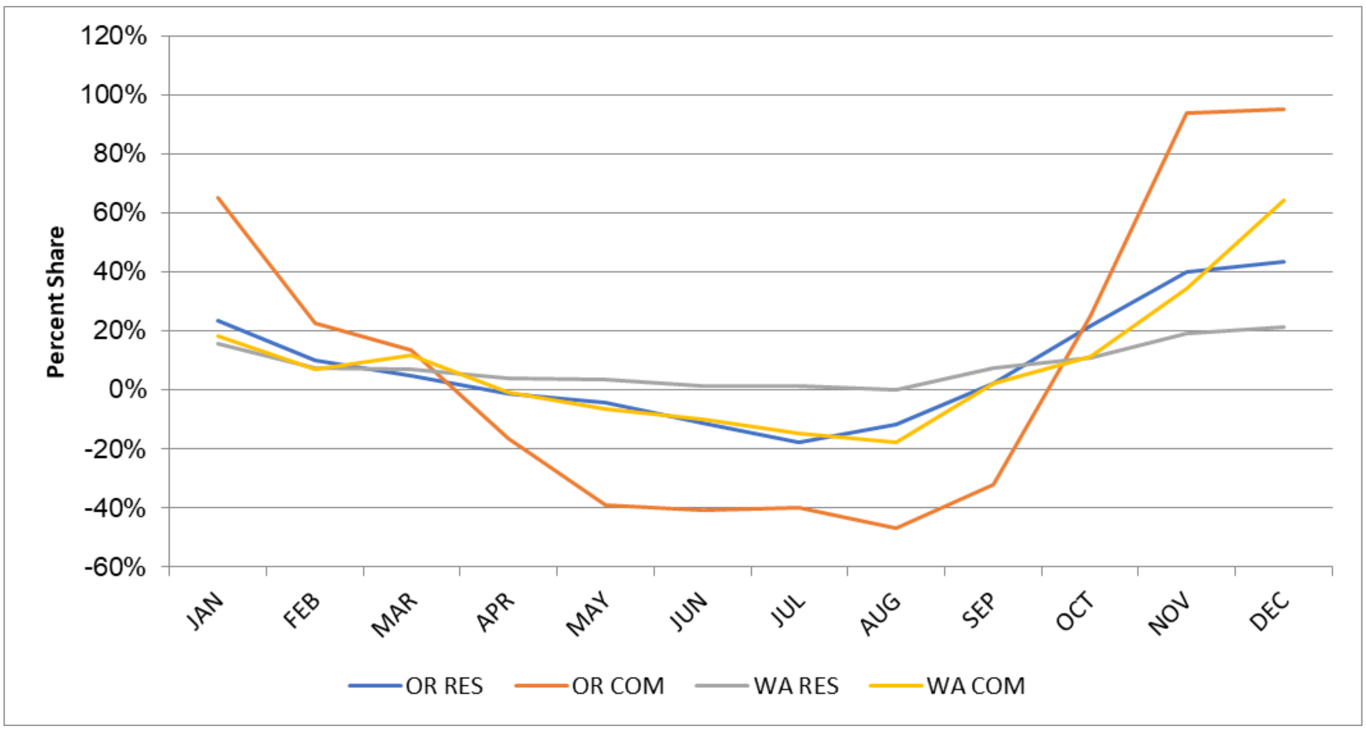
B.1.1 Allocations

As shown in Table 3.2 Customer Count Series, for purposes of planning associated with the 2022 IRP, NW Natural has 10 load centers: eight in Oregon and two in Washington. The analysis of alternative approaches to forecasting customers described above results in four customer forecasts, each at the state-level: Oregon residential, Oregon commercial, Washington residential, and Washington commercial. As NW Natural has a need to forecast customers not only at the system or state-levels, but also at a more granular distribution level, the Company uses allocation methods to transform the four state-level forecasts into load center forecasts. Additionally, the customer forecasts at the state-level are for year-end and peak load forecasts require monthly forecasts of customers and NW Natural uses allocation methods to transform year-end customer values into monthly values. Methods used for allocations are described below.

Allocation to Months

Figure B.1 shows the estimated monthly share of calendar year-over-year change in customers represented by each calendar month. Note that monthly share values for Oregon and Washington residential customers and for Washington commercial customers are similar, while those for Oregon Commercial are more extreme.

Figure B.1: Monthly Shares of Calendar Year-over-Year Change in Customers



Allocation to Load Centers

NW Natural allocates month-over-month changes from state-level by month to load center by month on the basis of the contribution of each load center within the state to the increase in state-level customers over the September 2008 through December 2019 timeframe. These allocations are made separately for each of the four customer forecasts; i.e., Oregon residential, Oregon commercial, Washington residential, and Washington commercial.

Table B.3 shows the average annual rates of customer change by load center and state for residential customers and commercial customers over the 2022-2050 planning horizon. Note that NW Natural has provided service to Coos Bay for only two decades and there may be a relatively greater potential for customer change through conversions from other fuels in this load center than in other parts of the Company's service area.

Table B.3: Average Annual Customer Reference Case Change Rates – 2022-2050

Load Center		Residential	Commercial
OREGON			
Albany		0.70%	0.60%
Astoria		1.20%	0.40%
Coos Bay		4.70%	4.20%
Columbia River Gorge – OR		1.50%	0.80%
Eugene		1.20%	0.90%
Lincoln City		1.00%	-0.10%
Portland		1.00%	0.80%
Salem		1.00%	1.10%
Total Oregon		**1.00%**	**0.80%**
WASHINGTON			
Columbia River Gorge – WA		1.70%	0.30%
Vancouver		2.60%	1.90%
Total Washington		**2.60%**	**1.80%**

Allocation to Components of Customer Change

NW Natural models separate usage profiles for existing customers, new construction customer additions, and conversion customer additions. Customer losses are accounted for by a declining existing customer count through time.

NW Natural used the "components" forecasts at state-level and projected customer loss rates based on the SME forecast for 2021-2024 and the new construction rate forecast for 2025 forward to allocate month-end customer levels at the load center level to these components. This was done by state and separately for residential and commercial customers. As the SME panel forecast includes the component detail, these allocations are for 2025 and subsequent years.

B.2 Climate Change Adjusted Weather Forecasts Technical Details

Incorporating data from five different climate models from the Intergovernmental Panel on Climate Change (IPCC), NW Natural has developed a climate change adjusted weather forecast out until 2050. We have selected several representative load centers for the NW Natural service territory, as seen in table.

Table B.4: Climate Change Adjusted Cumulative Annual HDD (base 58°F) Forecasts by Location

Year	Albany	Astoria	Coos Bay	Dallas	Eugene	Lincoln City	Portland	Salem	Vancouver
2022	2488	2574	2039	2797	2551	2407	2077	2443	2528
2023	2403	2444	1892	2752	2452	2237	2030	2337	2483
2024	2494	2611	2014	2815	2542	2411	2091	2455	2579
2025	2302	2440	1884	2502	2337	2245	1897	2228	2343
2026	2421	2515	1973	2719	2477	2324	2044	2374	2501
2027	2681	2801	2296	2988	2726	2630	2303	2632	2729
2028	2397	2501	2027	2639	2439	2355	1974	2323	2437
2029	2372	2500	1978	2686	2421	2336	2046	2338	2464
2030	2405	2513	2002	2671	2448	2332	2033	2360	2472
2031	2624	2789	2259	2952	2663	2595	2254	2581	2698
2032	2542	2678	2167	2832	2587	2502	2135	2500	2618
2033	2252	2396	1856	2501	2309	2218	1872	2203	2297
2034	2465	2563	2129	2703	2551	2455	2049	2401	2473
2035	2207	2242	1780	2442	2316	2088	1814	2150	2243
2036	2181	2324	1762	2412	2236	2135	1831	2127	2234
2037	2266	2326	1828	2559	2333	2175	1903	2207	2321
2038	2047	2146	1585	2304	2097	1980	1691	1987	2106
2039	2075	2130	1577	2292	2097	1952	1703	2020	2129
2040	2280	2356	1849	2572	2339	2154	1912	2220	2350
2041	2361	2483	1944	2566	2395	2326	2004	2275	2415
2042	2246	2388	1791	2512	2273	2211	1879	2180	2302
2043	2223	2226	1666	2446	2233	2061	1795	2131	2254
2044	2210	2264	1733	2483	2249	2110	1841	2123	2273
2045	2119	2263	1660	2453	2156	2075	1809	2047	2210
2046	2187	2341	1737	2453	2193	2159	1861	2126	2297
2047	2174	2273	1753	2522	2232	2112	1866	2137	2298
2048	2281	2328	1807	2528	2300	2151	1899	2188	2316
2049	2277	2365	1883	2490	2317	2262	1903	2217	2331
2050	2239	2319	1748	2482	2284	2115	1852	2210	2312

B.3 Residential and Small Commercial Use per Customer Model Technical Details

In the process of modelling resource needs, we calculate the Use Per Customer (UPC). As detailed in the IRP, use per customer demand is a function of Temperature (T) as follows:

$$\underline{Use\ Per\ Customers\ (UPC)}$$

$$= Y_1 + b_1 * (T) \qquad if\ :\ T \geq K^*$$

$$= Y_2 + b_2 * (T) \qquad if\ :\ T < K^*$$

This formula is used in conjunction with the following table to estimate the UPC for different classes at different temperatures experienced by the system.

Table B.5: UPC Model Coefficients

State	Load Center	Class	Sub-class	k0	k1	y1	b1	b2	y2
OR	ALB	C1	com_exist	55	65	6.669179	-0.06265	-0.55237	34.88348
OR	AST	C1	com_exist	50	61	3.808998	0	-0.43536	28.33427
OR	COOS	C1	com_exist	53	63	4.247724	0	-0.75662	49.61732
OR	DALO	C1	com_exist	55	64	6.312669	-0.04816	-0.51628	33.47306
WA	DALW	C1	com_exist	55	64	6.312669	-0.04816	-0.51628	33.47306
OR	EUG	C1	com_exist	52	64	9.264012	-0.08986	-0.66883	41.67186
OR	LC	C1	com_exist	52	60	5.314521	0	-0.50649	32.63146
OR	POR	C1	com_exist	50	64	8.348593	-0.07674	-0.69673	43.95235
OR	SAL	C1	com_exist	54	64	6.269305	-0.05467	-0.66637	41.07671
WA	VAN	C1	com_exist	50	64	8.754356	-0.08192	-0.64224	40.70289
OR	ALB	R1	res_exist	52	68	1.233887	-0.01193	-0.14742	9.162369
OR	AST	R1	res_exist	50	60	2.208741	-0.02694	-0.15716	9.543513
OR	COOS	R1	res_exist	55	63	0.37091	0	-0.15725	9.658525
OR	DALO	R1	res_exist	50	64	1.322217	-0.0121	-0.10839	7.129867
WA	DALW	R1	res_exist	50	64	1.322217	-0.0121	-0.10839	7.129867
OR	EUG	R1	res_exist	51	67	1.064213	-0.00879	-0.13879	8.674684
OR	LC	R1	res_exist	53	60	2.737316	-0.03725	-0.15457	9.122087
OR	POR	R1	res_exist	50	65	1.798423	-0.01901	-0.1616	10.24808
OR	SAL	R1	res_exist	52	68	1.060155	-0.0087	-0.1594	9.927056
WA	VAN	R1	res_exist	50	66	1.687177	-0.0162	-0.16209	10.23714
OR		C1	com_nc	55	67	4.634968	0	-0.89078	63.75738
OR		C1	com_conv	55	67	3.197445	0	-0.59551	40.3124
WA		C1	com_nc	50	65	3.737502	0	-0.59568	43.12067
WA		C1	com_conv	50	65	3.937895	0	-1.03514	56.96523
OR		R1	res_sfnc	50	67	1.874433	-0.02113	-0.12682	8.2212
OR		R1	res_mfnc	50	67	0.414328	-0.00475	-0.04175	2.370682
OR		R1	res_conv	50	67	0.877146	-0.00973	-0.10727	7.004857
WA		R1	res_conv	53	68	0.265548	0	-0.12328	7.740597
WA		R1	res_sfnc	53	68	0.25363	0	-0.13705	8.493505
WA		R1	res_mfnc	53	68	0.156704	0	-0.04737	2.869121

B.4 Industrial, Large Commercial and Compressed Natural Gas (CNG) Load Forecast Model Technical Details

Using the below equation, Industrial and Large Commercial load is forecasted for our model. D(log) is the first difference logged value. Results from this model are shared in Table B.7.

Industrial Load Estimation Equation

$$\Delta LOG(NW\ Natural\ Industrial\ Demand) = \alpha + \beta * \Delta LOG(Industrial\ Production)$$

Table B.6: Industrial Load Forecast Parameters[2]

Variable	Coefficient	Standard Error
α	-0.016634	0.009474
ΔLOG(Industrial Production)	0.703172	0.216706

[2] Source: OEA.

B.5 Peak Day Forecast Modelling

Table B.7: Model Coefficients – Daily System Load

Driver	Units	Coefficients	Standard Error
Temperature	Hourly Average (°F)	15,852.05	6,749.16
Previous Day Temperature	Hourly Average (°F)	-8,615.11	318.22
+ Temperature Interaction		138.14	6.83
Solar Radiation	Daily Sum (watts/m^2)	-12.72	2.38
+ Temperature Interaction		0.15	0.05
Wind Speed	Hourly Average (mph)	5,341.27	662.89
+ Temperature Interaction		-44.84	15.43
Snow Depth	Daily Measure (inches)	-24,821.04	5,350.68
+ Temperature Interaction		636.52	174.26
Customer Count	N/A	2.67	0.47
+ Temperature Interaction		-0.05	0.01
Friday Indicator	N/A	-35,274.63	7,015.24
+ Temperature Interaction		576.74	154.4
Saturday Indicator	N/A	-52,131.89	7,665.59
+ Temperature Interaction		708.4	172.08
Sunday Indicator	N/A	-44,956.72	6,960.35
+ Temperature Interaction		677.02	156.96
Holiday Indicator	N/A	-26,295.56	3,353.69
Annual Time Trend	Years after 2008	-16,419.67	4,454.15
+ Temperature Interaction		381.99	100.01
Bull Run Creek Temperature	Daily Measure (°F)	-1,539.93	128.64
COVID-19 Indicator		-69,350.23	19140.87
+ Temperature Interaction		1,526.86	429.7813
Constant		-504,550.50	299,508.80

Appendix C: Avoided Costs

NW Natural®

C.1 Levelized Avoided Costs by State and End Use

Table C.1: Avoided Cost Summary by State, Year, and Policy

Year	Real (2021$)							
	Infrastructure Costs				Commodity Costs		nental Compliance Costs	
	Supply ($/Dth/Day)	Washington Distribution ($/Dth/Hour)	Oregon Distribution ($/Dth/Hour)	System Distribution ($/Dth/Hour)	Gas and Transport Costs ($/Dth)	Hedge Value ($/Dth)	Oregon Carbon Policy Scenarios: Base Case	Washington Carbon Price:
2022	$0.089	$0.776	$0.469	$0.504	$5.189	$0.149	$5.733	$5.209
2023	$0.089	$0.776	$0.469	$0.504	$4.056	$0.363	$5.786	$5.311
2024	$0.089	$0.776	$0.469	$0.504	$3.149	$0.520	$5.839	$5.412
2025	$0.089	$0.776	$0.469	$0.504	$3.340	$0.605	$5.892	$5.514
2026	$0.089	$0.776	$0.469	$0.504	$3.104	$0.659	$5.946	$5.602
2027	$0.089	$0.776	$0.469	$0.504	$3.105	$0.765	$5.999	$5.691
2028	$0.089	$0.776	$0.469	$0.504	$3.189	$0.727	$6.052	$5.780
2029	$0.089	$0.776	$0.469	$0.504	$3.260	$0.798	$6.105	$5.869
2030	$0.089	$0.776	$0.469	$0.504	$3.234	$0.816	$6.158	$5.957
2031	$0.089	$0.776	$0.469	$0.504	$3.269	$0.810	$6.211	$6.033
2032	$0.089	$0.776	$0.469	$0.504	$3.314	$0.908	$6.264	$6.109
2033	$0.089	$0.776	$0.469	$0.504	$3.375	$0.899	$7.884	$6.185
2034	$0.089	$0.776	$0.469	$0.504	$3.390	$0.967	$7.601	$6.261
2035	$0.089	$0.776	$0.469	$0.504	$3.312	$1.039	$7.308	$6.338
2036	$0.089	$0.776	$0.469	$0.504	$3.330	$1.036	$12.751	$6.439
2037	$0.089	$0.776	$0.469	$0.504	$3.408	$0.953	$12.308	$6.540
2038	$0.089	$0.776	$0.469	$0.504	$3.405	$1.062	$11.874	$6.642
2039	$0.089	$0.776	$0.469	$0.504	$3.411	$1.043	$11.414	$6.743
2040	$0.089	$0.776	$0.469	$0.504	$3.491	$1.106	$10.836	$6.845
2041	$0.089	$0.776	$0.469	$0.504	$3.467	$1.103	$10.350	$6.921
2042	$0.089	$0.776	$0.469	$0.504	$3.604	$1.119	$9.887	$6.997
2043	$0.089	$0.776	$0.469	$0.504	$3.728	$1.120	$9.336	$7.073
2044	$0.089	$0.776	$0.469	$0.504	$3.761	$1.143	$8.871	$7.149
2045	$0.089	$0.776	$0.469	$0.504	$3.836	$1.154	$8.283	$7.225
2046	$0.089	$0.776	$0.469	$0.504	$3.838	$1.264	$7.706	$7.326
2047	$0.089	$0.776	$0.469	$0.504	$3.927	$1.208	$7.262	$7.428
2048	$0.089	$0.776	$0.469	$0.504	$4.019	$1.273	$6.824	$7.529
2049	$0.089	$0.776	$0.469	$0.504	$4.048	$1.248	$6.336	$7.630
2050	$0.089	$0.776	$0.469	$0.504	$4.113	$1.282	$5.832	$7.732
Levelized	**$0.089**	**$0.776**	**$0.469**	**$0.504**	**$3.554**	**$0.862**	**$7.608**	**$6.263**

Figure C.1: Oregon 30-year Levelized Avoided Costs by End Use

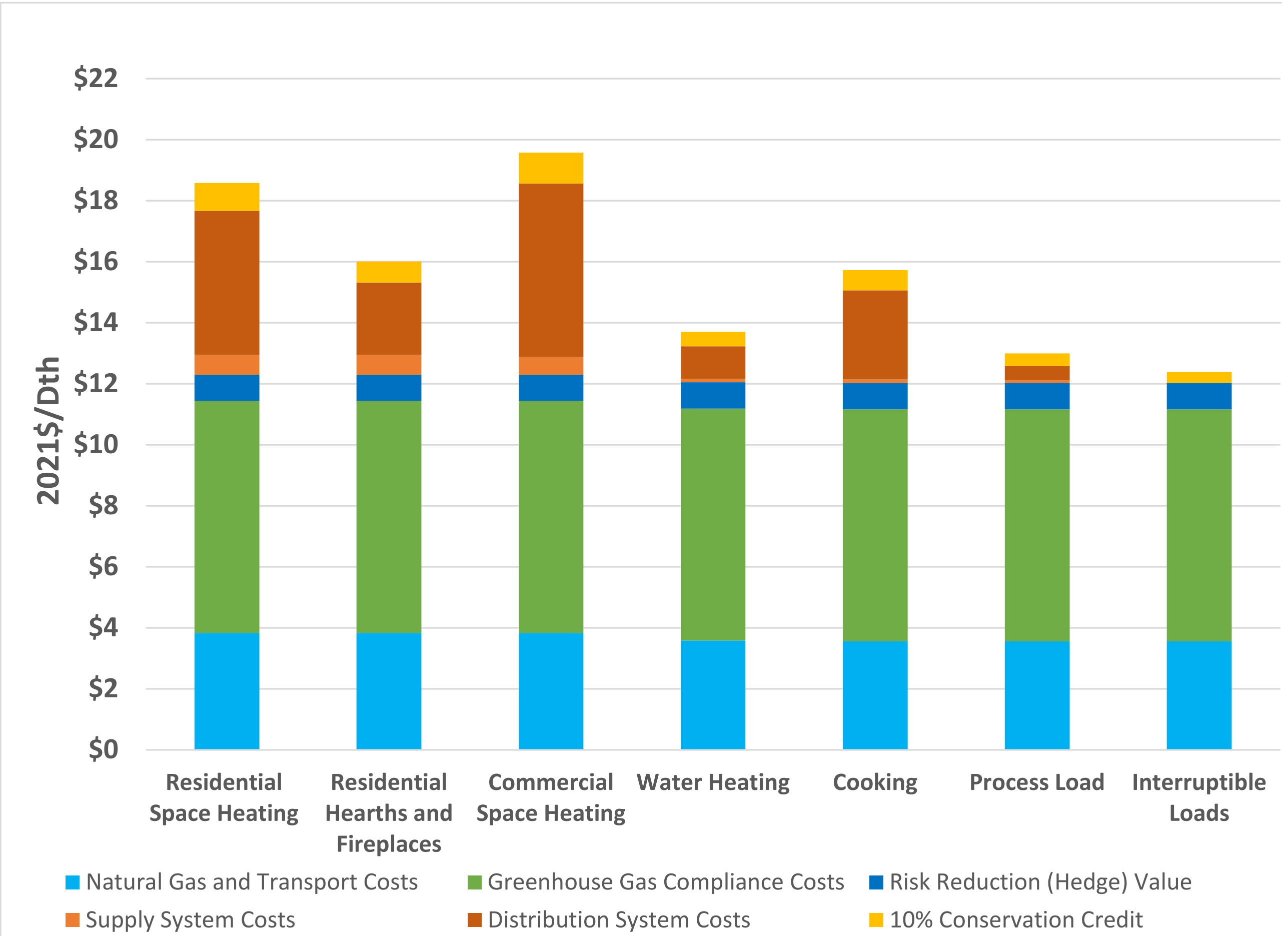


Figure C.2: Washington 30-year Levelized Avoided Costs by End Use

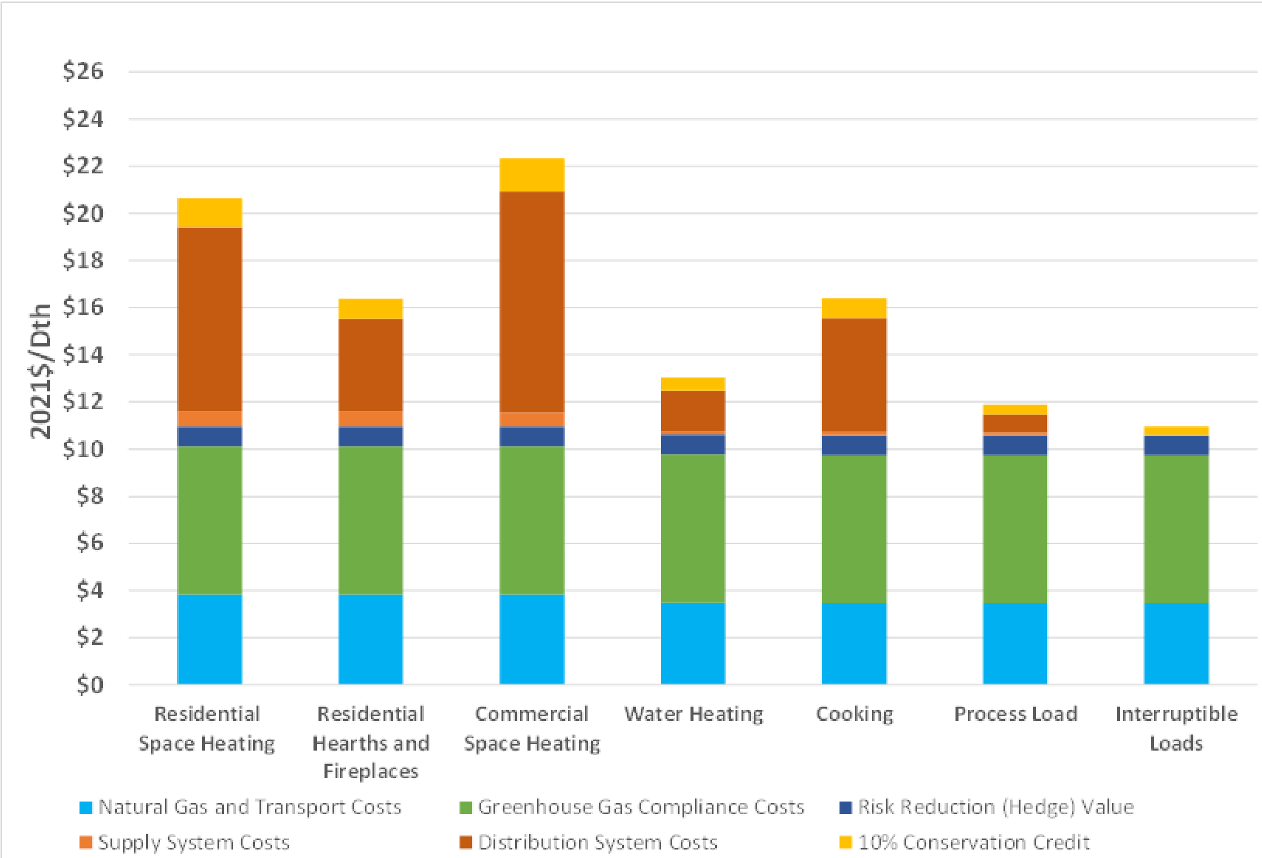


Table C.2: Avoided Cost by Year and End Use

	Oregon Total Avoided Costs by End Use (2021$)							Washington Total Avoided Costs by End Use (2021$)						
	Residential Space Heating	Residential Hearths and Fireplaces	Commercial Space Heating	Water Heating	Cooking	Process Load	Interruptible Load	Residential Space Heating	Residential Hearths and Fireplaces	Commercial Space Heating	Water Heating	Cooking	Process Load	Interruptible Load
2022	$17.41	$14.83	$18.40	$12.88	$14.93	$12.20	$11.59	$20.29	$16.02	$21.98	$13.12	$16.52	$12.02	$11.07
2023	$16.73	$14.15	$17.72	$11.94	$13.95	$11.22	$10.61	$19.66	$15.39	$21.35	$12.23	$15.59	$11.09	$10.13
2024	$16.12	$13.54	$17.11	$11.15	$13.17	$10.44	$9.82	$19.10	$14.83	$20.79	$11.49	$14.85	$10.35	$9.40
2025	$16.37	$13.79	$17.36	$11.49	$13.52	$10.78	$10.17	$19.40	$15.13	$21.09	$11.89	$15.25	$10.74	$9.79
2026	$16.25	$13.67	$17.24	$11.34	$13.36	$10.63	$10.02	$19.31	$15.04	$21.01	$11.77	$15.13	$10.63	$9.68
2027	$16.43	$13.85	$17.42	$11.50	$13.52	$10.79	$10.18	$19.52	$15.26	$21.22	$11.96	$15.32	$10.82	$9.87
2028	$16.57	$14.00	$17.57	$11.61	$13.63	$10.90	$10.29	$19.71	$15.44	$21.40	$12.11	$15.47	$10.97	$10.01
2029	$16.75	$14.17	$17.74	$11.82	$13.83	$11.10	$10.49	$19.92	$15.65	$21.61	$12.35	$15.71	$11.20	$10.25
2030	$16.78	$14.21	$17.78	$11.85	$13.88	$11.15	$10.53	$19.99	$15.72	$21.68	$12.42	$15.78	$11.28	$10.33
2031	$16.87	$14.29	$17.86	$11.94	$13.96	$11.23	$10.62	$20.10	$15.83	$21.79	$12.53	$15.89	$11.39	$10.44
2032	$17.06	$14.48	$18.05	$12.14	$14.16	$11.43	$10.82	$20.31	$16.04	$22.00	$12.75	$16.12	$11.61	$10.66
2033	$18.73	$16.15	$19.72	$13.82	$15.84	$13.11	$12.49	$20.43	$16.16	$22.13	$12.89	$16.25	$11.75	$10.80
2034	$18.51	$15.93	$19.50	$13.62	$15.64	$12.91	$12.30	$20.57	$16.30	$22.26	$13.05	$16.41	$11.91	$10.96
2035	$18.20	$15.62	$19.19	$13.31	$15.33	$12.60	$11.99	$20.63	$16.37	$22.33	$13.11	$16.47	$11.97	$11.02
2036	$23.70	$21.12	$24.69	$18.77	$20.79	$18.06	$17.45	$20.79	$16.52	$22.48	$13.23	$16.59	$12.09	$11.14
2037	$23.21	$20.63	$24.20	$18.33	$20.35	$17.62	$17.01	$20.85	$16.58	$22.54	$13.33	$16.70	$12.19	$11.24
2038	$22.87	$20.30	$23.87	$18.00	$20.02	$17.29	$16.68	$21.05	$16.78	$22.74	$13.53	$16.90	$12.40	$11.45
2039	$22.43	$19.85	$23.42	$17.53	$19.55	$16.82	$16.21	$21.17	$16.90	$22.86	$13.63	$16.99	$12.49	$11.54
2040	$21.97	$19.39	$22.96	$17.10	$19.13	$16.40	$15.78	$21.38	$17.11	$23.07	$13.87	$17.24	$12.74	$11.79
2041	$21.49	$18.92	$22.49	$16.59	$18.61	$15.88	$15.27	$21.47	$17.20	$23.16	$13.93	$17.29	$12.79	$11.84
2042	$21.19	$18.61	$22.18	$16.29	$18.31	$15.58	$14.97	$21.71	$17.44	$23.40	$14.17	$17.53	$13.03	$12.08
2043	$20.74	$18.16	$21.73	$15.87	$17.90	$15.17	$14.56	$21.88	$17.61	$23.57	$14.38	$17.75	$13.25	$12.29
2044	$20.37	$17.79	$21.36	$15.47	$17.49	$14.76	$14.15	$22.05	$17.78	$23.74	$14.52	$17.88	$13.38	$12.43
2045	$19.83	$17.25	$20.82	$14.97	$17.00	$14.27	$13.66	$22.18	$17.91	$23.87	$14.68	$18.05	$13.55	$12.60
2046	$19.41	$16.83	$20.40	$14.51	$16.54	$13.80	$13.19	$22.43	$18.16	$24.12	$14.90	$18.27	$13.76	$12.81
2047	$19.00	$16.42	$19.99	$14.11	$16.13	$13.40	$12.79	$22.57	$18.30	$24.26	$15.04	$18.41	$13.91	$12.96
2048	$18.70	$16.12	$19.69	$13.83	$15.86	$13.13	$12.52	$22.81	$18.54	$24.50	$15.30	$18.68	$14.17	$13.22
2049	$18.23	$15.65	$19.22	$13.35	$15.38	$12.65	$12.04	$22.93	$18.66	$24.62	$15.42	$18.79	$14.28	$13.33
2050	$17.94	$15.36	$18.93	$12.96	$14.98	$12.25	$11.64	$23.25	$18.98	$24.94	$15.63	$18.99	$14.49	$13.54
Levelized	**$18.58**	**$16.00**	**$19.57**	**$13.70**	**$15.72**	**$12.99**	**$12.38**	**$20.64**	**$16.37**	**$22.33**	**$13.12**	**$16.49**	**$11.98**	**$11.03**

C.2 Avoided Costs by IRP and State

Figure C.3: Oregon Levelized Costs by IRP

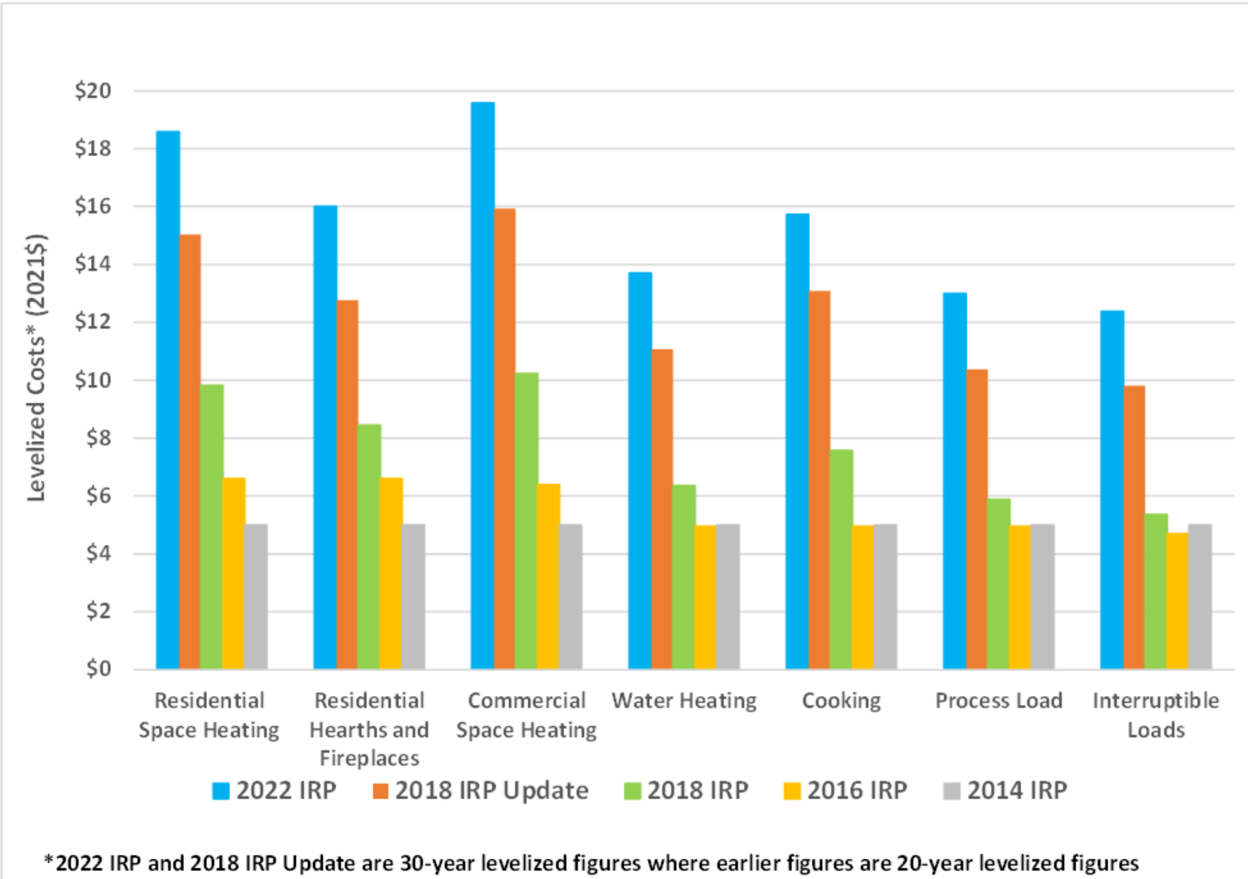


Figure C.4: Washington Levelized Costs by IRP

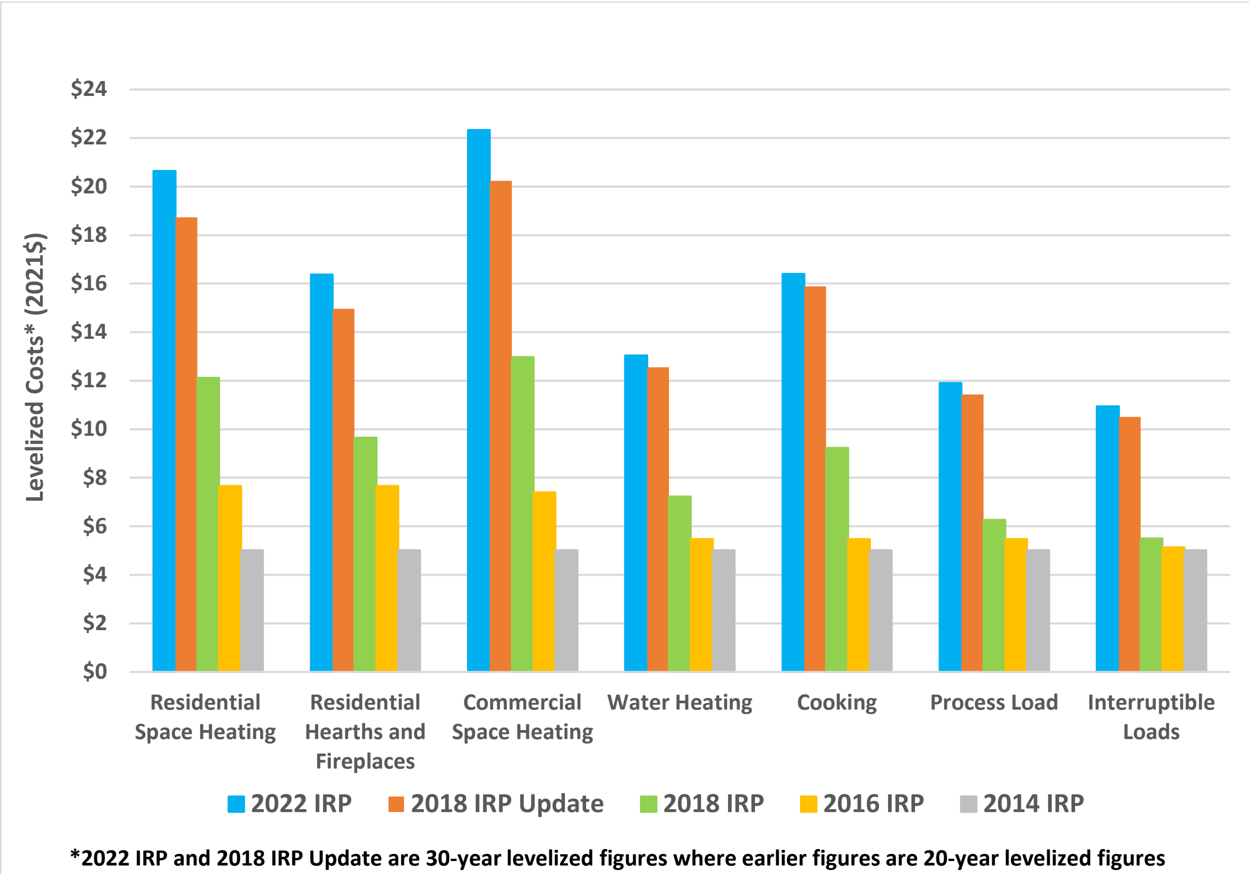


Figure C.5: Oregon Change in Levelized Costs: 2022 IRP vs 2018 IRP Update

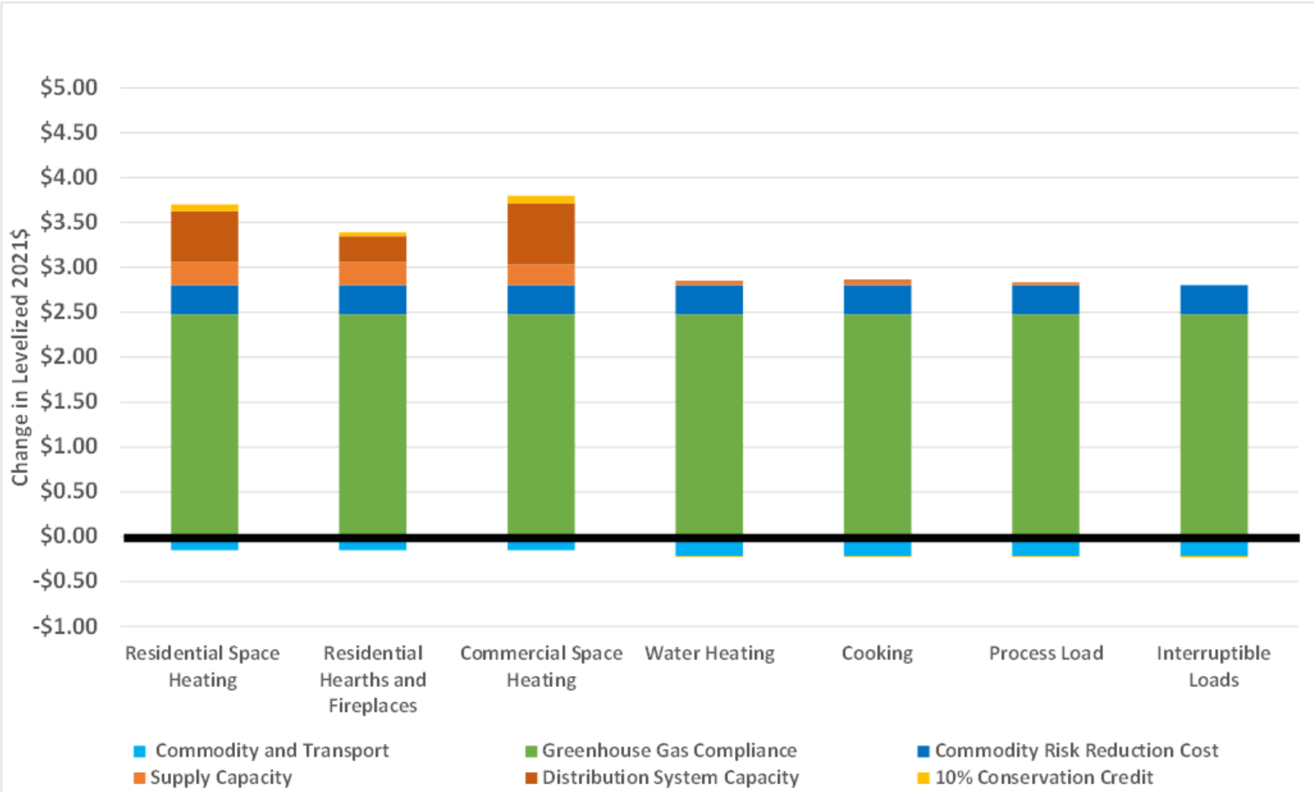
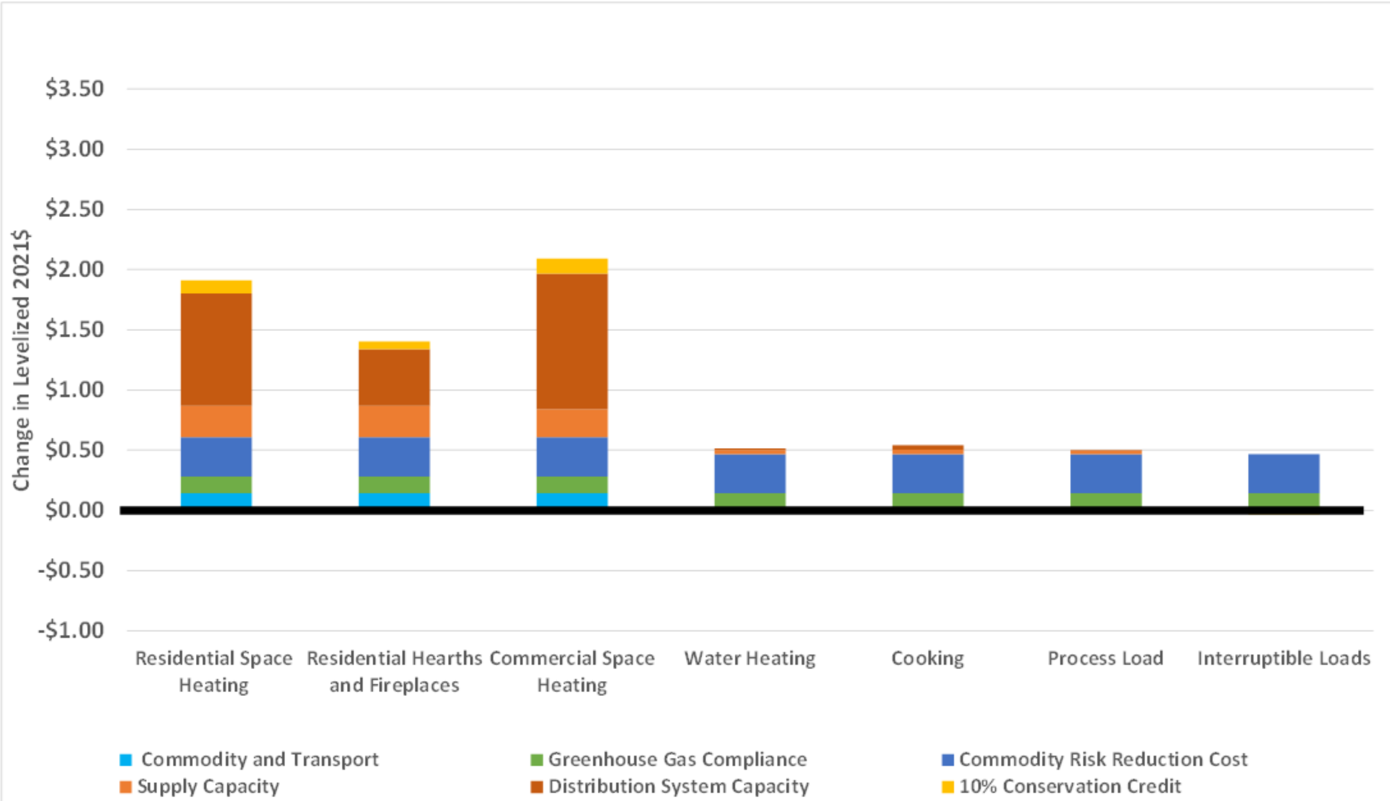


Figure C.6: Washington Change in Levelized Costs: 2022 IRP vs 2018 IRP Update



C.3 Total Avoided Costs by End Use and Year

Figure C.7: Oregon Total Avoided Costs by End Use and Year

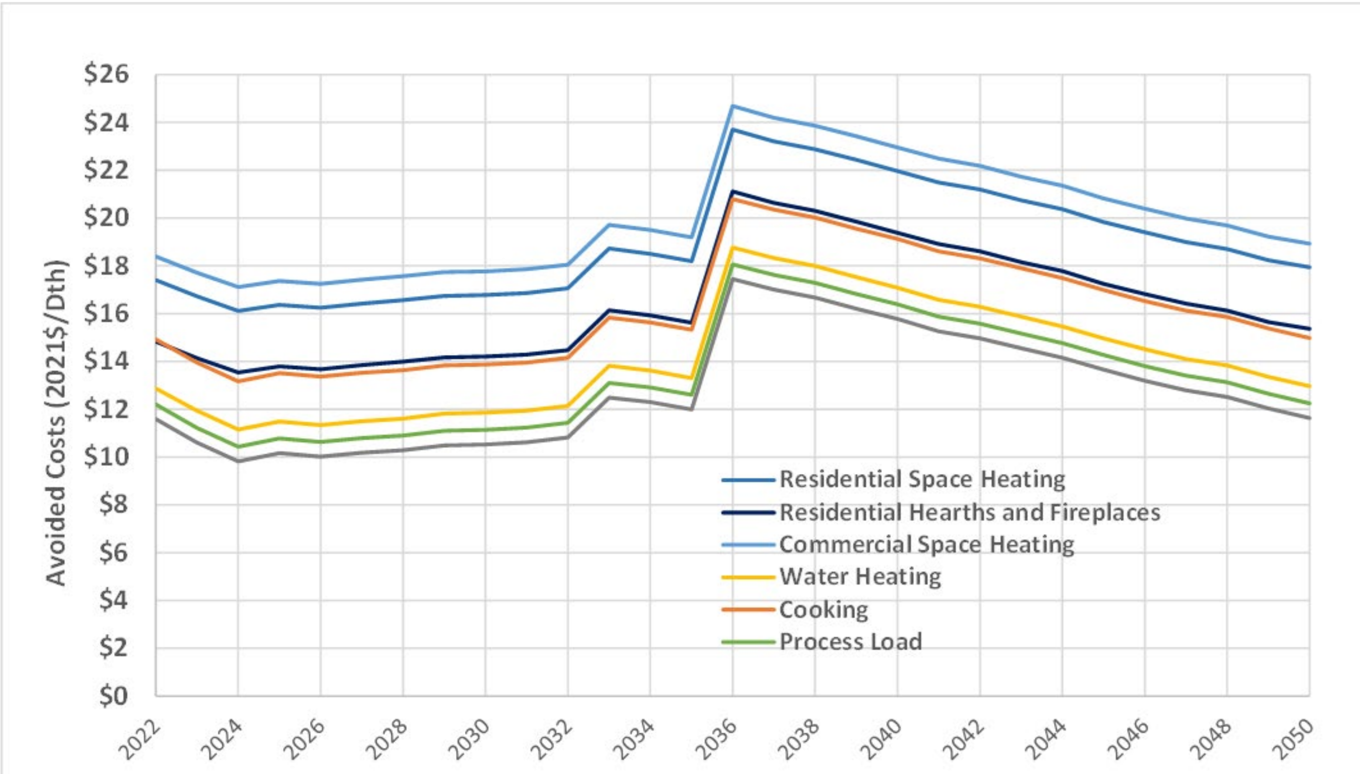


Figure C.8: Washington Total Avoided Costs by End Use and Year

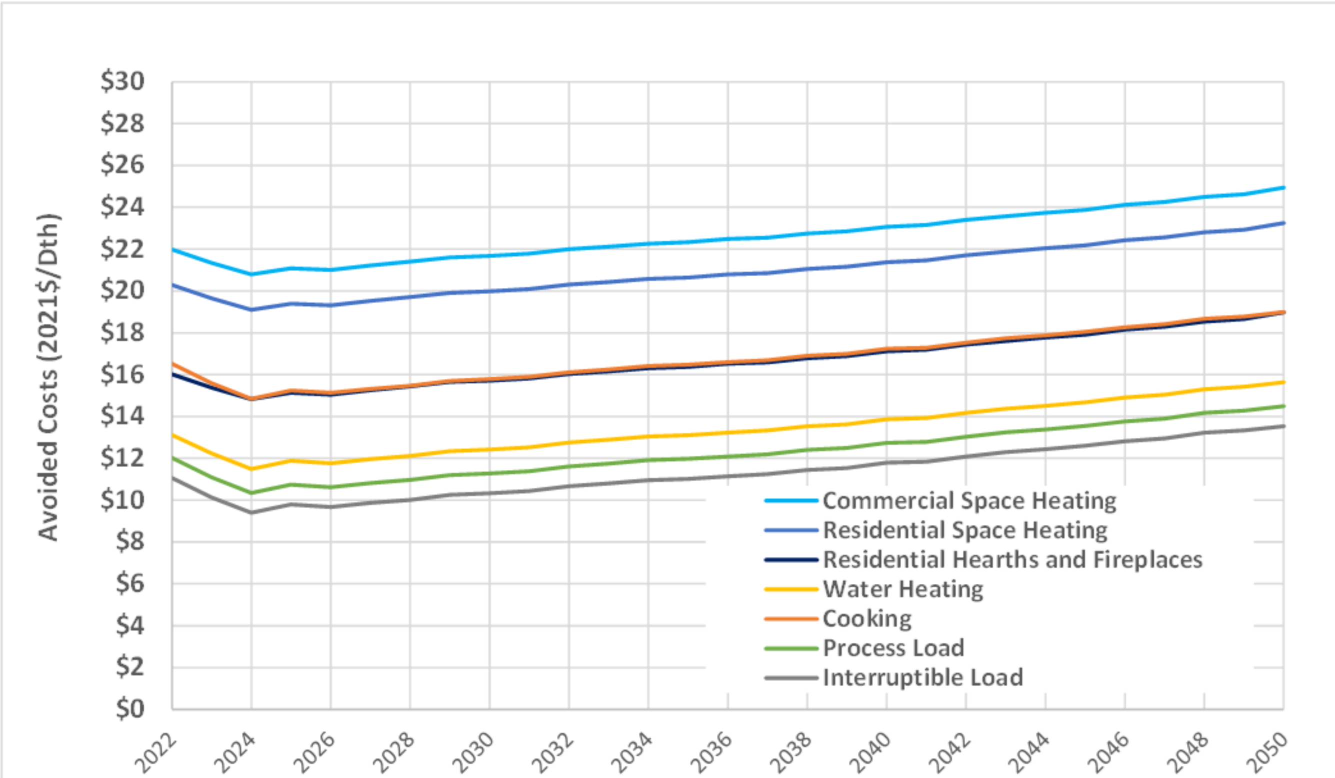


Figure C.9: Residential Space Heating Avoided Cost Breakdown – Oregon

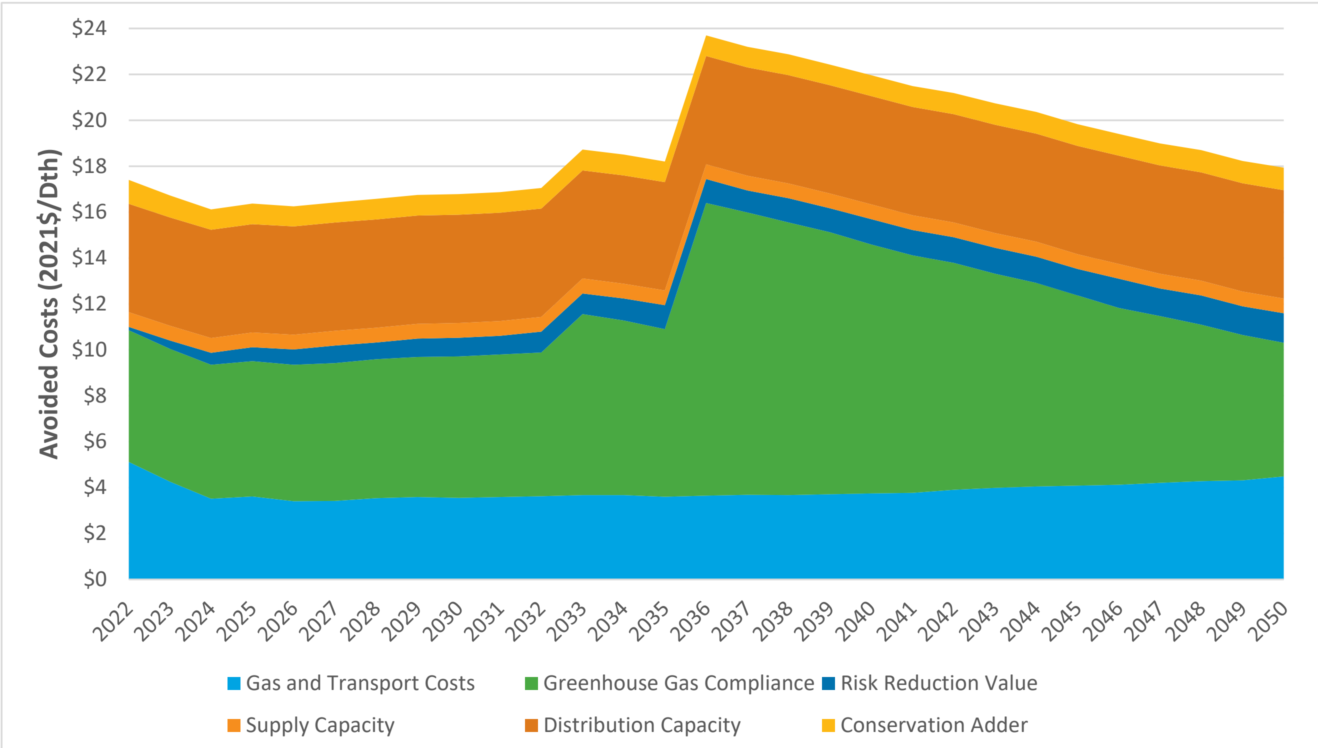
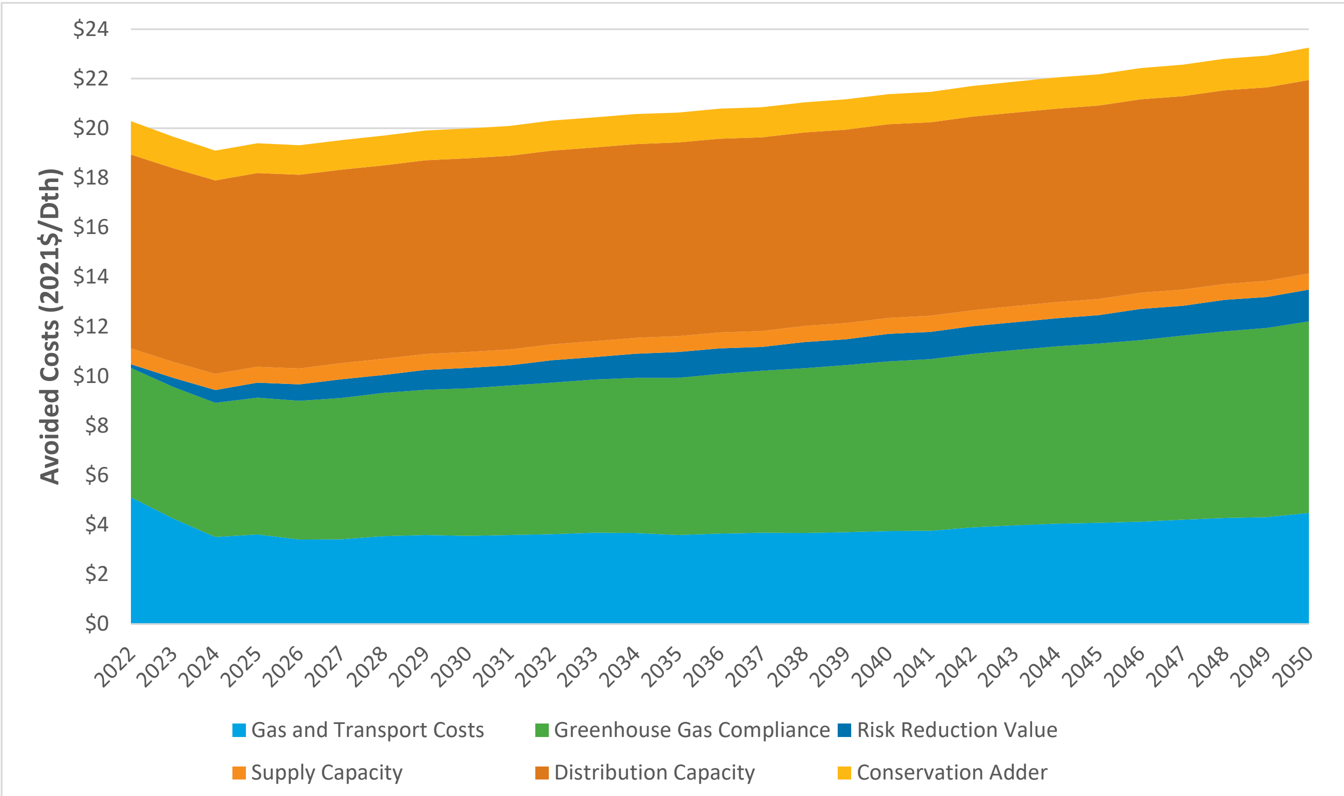


Figure C.10: Residential Space Heating Avoided Cost Breakdown– Washington



Appendix D: Demand-Side Resources

D.1 Deployment Summary[3]

See following pages

Table D.1: Oregon Deployment Summary 2022-2031

Gross Savings (Therms)		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
New Buildings (Includes MF)	Com-New	359,446	311,166	299,823	295,903	298,584	293,030	306,078	320,806	332,610	345,016
	NEEA-MartetTX	122,242	367,872	385,638	385,638	385,638	378,826	372,135	365,561	359,104	352,761
Existing Buildings (No MF)	Com-ROB	221,743	320,669	333,054	347,365	348,776	367,482	383,907	398,060	410,154	420,707
	Com-SEM	285,575	418,683	444,633	479,044	485,792	482,760	511,022	524,242	519,899	497,621
	Com-RET	1,252,113	1,706,450	1,804,364	1,794,076	1,719,743	1,615,804	1,472,899	1,386,060	1,177,535	951,104
Industrial	Ind-RET	1,218,366	1,422,372	1,527,633	1,754,348	1,756,483	1,560,709	1,415,177	1,183,336	916,988	665,824
	Ind-SEM	27,988	30,000	30,000	30,000	30,000	29,622	29,345	29,069	28,792	28,404
	Ind-ROB	54,910	64,936	69,741	80,091	80,189	81,257	81,752	82,212	82,686	83,163
Residential New	Res-ManufNH	1,590	3,394	3,394	3,394	3,394	3,340	3,280	3,215	3,147	3,076
	Res-NewHomes	255,034	247,674	145,991	145,991	145,991	186,669	234,560	288,258	358,029	426,311
	Res-MarketTx	820,903	870,834	1,261,157	1,261,156	1,261,157	1,246,781	1,236,441	1,219,839	1,201,150	1,179,261
Residential Existing	Res-Tstat	574,496	705,768	1,013,410	1,064,081	1,117,285	1,057,379	1,004,745	880,335	711,649	534,480
	Res-TstatOpt	40,390	3,527	4,341	4,341	4,341	24,462	42,551	58,467	72,064	83,194
	Res-WaterHeat	37,539	32,986	41,232	41,232	41,232	78,543	124,096	178,502	241,961	312,936
	Res-Shell	186,605	464,534	444,344	411,719	434,444	475,058	525,361	558,933	569,174	552,569
	Res-Heat-ROB	257,703	317,791	376,317	376,317	376,317	430,711	487,492	546,150	658,470	729,087
Multi-family Existing	MF-RET	48,845	65,329	68,060	68,775	66,396	53,386	44,556	33,898	23,782	15,649
	MF-ROB	87,791	126,957	131,860	137,526	138,084	142,490	145,887	135,532	138,790	140,288
Other	Large-Project Adder	-	-	250,190	250,190	250,190	250,190	250,190	250,190	250,190	250,190
	Com-Cooking	269,935	269,229	274,888	273,136	280,248	288,500	304,584	298,608	329,099	339,447
	Total	**6,123,213**	**7,750,168**	**8,910,070**	**9,204,324**	**9,224,283**	**9,046,998**	**8,976,058**	**8,741,271**	**8,385,273**	**7,911,087**

[3] Provided by the Energy Trust of Oregon

Table D.2: Oregon Deployment Summary 2032-2041

Gross Savings (Therms)		2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	Total
New Buildings (Includes MF)	Com-New	356,429	368,124	378,712	389,431	397,989	411,209	418,551	427,635	436,882	446,892	7,194,314
	NEEA-MartetTX	346,530	340,409	334,396	328,489	322,687	316,987	311,388	305,888	300,485	295,177	6,677,850
Existing Buildings (No MF)	Com-ROB	427,461	423,704	424,381	417,961	314,368	313,100	321,174	324,487	280,479	229,951	7,028,983
	Com-SEM	459,479	409,603	353,234	295,580	240,877	191,911	150,099	115,649	75,851	-	6,941,554
	Com-RET	736,533	553,203	364,862	93,825	61,697	45,676	47,463	47,971	47,020	44,623	16,923,018
Industrial	Ind-RET	459,807	306,262	200,905	131,482	32,547	13,632	14,298	14,551	14,350	13,637	14,622,706
	Ind-SEM	27,961	27,343	26,791	26,220	25,668	25,021	24,453	23,612	23,612	23,124	547,028
	Ind-ROB	83,663	83,979	84,527	85,048	85,665	85,978	86,593	87,235	71,564	52,964	1,568,151
Residential New	Res-ManufNH	3,101	3,028	2,955	2,929	2,855	2,829	2,755	2,729	2,656	2,582	59,640
	Res-NewHomes	466,792	501,887	575,577	651,840	702,185	744,127	810,597	872,941	929,569	988,534	9,678,559
	Res-MarketTx	1,080,834	984,912	969,147	953,242	902,688	851,020	834,420	817,960	801,362	791,860	20,546,124
Residential Existing	Res-Tstat	377,392	254,040	165,202	67,683	-	-	-	-	-	-	9,527,945
	Res-TstatOpt	91,706	105,028	117,817	130,024	141,596	39,690	-	-	-	-	963,537
	Res-WaterHeat	390,302	471,231	552,111	629,201	699,413	760,905	813,239	857,110	893,851	924,975	8,122,597
	Res-Shell	510,309	448,373	375,770	301,802	232,598	174,699	128,272	92,517	65,851	31,639	6,984,574
	Res-Heat-ROB	795,126	860,256	923,720	984,821	1,042,959	1,097,649	1,148,532	1,195,384	1,238,102	1,276,696	15,119,602
Multi-family Existing	MF-RET	9,830	3,454	-	-	-	-	-	-	-	-	501,960
	MF-ROB	141,173	143,040	136,555	136,869	131,023	130,050	128,637	129,697	141,977	86,404	2,630,630
Other	Large-Project Adder	250,190	250,190	250,190	250,190	250,190	250,190	250,190	250,190	250,190	250,190	4,503,423
	Com-Cooking	365,716	351,959	379,521	387,447	413,574	391,257	417,357	423,554	450,636	425,190	6,933,882
	Total	**7,380,334**	**6,890,025**	**6,616,373**	**6,264,086**	**6,000,579**	**5,845,930**	**5,908,019**	**5,989,110**	**6,024,436**	**5,884,439**	**147,076,076**

Table D.3: Oregon Deployment Summary 2041-2050

Gross Savings (Therms)		2042	2043	2044	2045	2046	2047	2048	2049	2050	Total
New Buildings (Includes MF)	Com-New	453,346	456,341	462,099	466,565	470,927	477,998	482,517	486,536	490,536	11,441,179
	NEEA-MartetTX	289,963	284,841	279,810	274,867	270,012	265,243	260,557	255,955	251,434	9,110,532
Existing Buildings (No MF)	Com-ROB	233,847	211,126	246,036	241,161	267,003	223,846	255,330	253,444	278,312	9,239,088
	Com-SEM	-	-	-	-	-	-	-	-	-	6,941,554
	Com-RET	40,999	36,447	31,445	26,398	21,636	17,373	13,714	10,676	8,220	17,129,926
Industrial	Ind-RET	12,573	11,222	9,724	8,166	6,715	5,409	4,286	3,336	2,577	14,686,714
	Ind-SEM	-	-	-	-	-	-	-	-	-	547,028
	Ind-ROB	33,794	11,452	12,233	12,953	13,704	14,437	15,160	15,786	16,429	1,714,100
Residential New	Res-ManufNH	2,514	2,490	2,423	2,356	2,294	2,272	2,210	2,149	2,092	80,441
	Res-NewHomes	996,269	1,003,108	1,008,698	1,022,373	1,038,722	1,053,814	1,067,282	1,089,063	1,112,612	19,070,499
	Res-MarketTx	776,415	761,099	745,654	736,813	722,441	708,190	693,819	685,593	672,220	27,048,368
Residential Existing	Res-Tstat	-	-	-	-	-	-	-	-	-	9,527,945
	Res-TstatOpt	-	-	-	-	-	-	-	-	-	963,537
	Res-WaterHeat	895,528	870,346	851,982	820,999	805,125	734,146	510,433	489,622	511,518	14,612,296
	Res-Shell	-	-	-	-	-	-	-	-	-	6,984,574
	Res-Heat-ROB	1,311,264	1,341,983	1,365,778	1,388,218	1,408,805	1,536,035	1,555,628	1,571,729	1,592,070	28,191,111
Multi-family Existing	MF-RET	-	-	-	-	-	-	-	-	-	501,960
	MF-ROB	77,704	49,887	56,307	55,737	58,611	33,319	37,867	34,034	37,747	3,071,843
Other	Large-Project Adder	250,190	250,190	250,190	250,190	250,190	250,190	250,190	250,190	250,190	6,755,134
	Com-Cooking	263,108	237,452	212,814	99,473	120,885	64,519	86,132	40,722	49,509	8,108,496
	Total	**5,637,513**	**5,527,985**	**5,535,192**	**5,406,270**	**5,457,072**	**5,386,789**	**5,235,125**	**5,188,835**	**5,275,467**	**195,726,325**

D.2 Measure Levels[4]

See following pages

Table D.4: Oregon 20-Year Cumulative Potential (Commercial)

Sector	Measure Name	Measure Type	End Use	20-year Cumulative Technical Potential (therms)	20-year Cumulative Achievable Potential (therms)	20-year Cumulative Cost-Effective Potential (therms)	% of Total Sector C/E Potential	Average Levelized Cost ($/therm)
Commercial	Com - SEM GAS SPHT	Retrofit	Behavioral	8,166,534	6,941,554	6,941,554	13%	$1.05
Commercial	Com - Zero Net Energy	New Construction	Other	5,363,675	4,559,124	-	0%	$7.87
Commercial	Com - Gas Fryer	Replace on Burnout	Cooking	5,334,679	4,534,477	4,534,477	8%	$0.37
Commercial	Com - Gas Absorption HPWH GAS WHT	Replace on Burnout	Water Heating	4,438,716	3,772,909	3,772,909	7%	$0.08
Commercial	Com - Demand Controlled Ventilation GAS SPHT	Retrofit	Ventilation	4,421,679	3,758,427	3,758,427	7%	$0.15
Commercial	Com - NC Package (10% Better than Code)	New Construction	Other	4,393,399	3,734,389	3,277,208	6%	$1.23
Commercial	Com - Condensing Boiler GAS SPHT	Replace on Burnout	Heating	4,372,284	3,716,441	3,716,441	7%	$0.44
Commercial	Com - EMS GAS SPHT	Retrofit	Behavioral	3,218,829	2,736,005	2,736,005	5%	$1.00
Commercial	Com - Condensing Gas RTU GAS SPHT	Replace on Burnout	Heating	2,438,840	2,073,014	2,073,014	4%	$0.74
Commercial	Com - Refrig - Retrofit Doors to Open Display Cases GAS SPHT	Retrofit	Refrigeration	2,326,388	2,210,068	2,210,068	4%	$0.69
Commercial	Com - Gas RTU Advanced Tier 1 Package Upgrade GAS SPHT	Retrofit	Heating	2,137,330	1,816,730	1,816,730	3%	$1.03
Commercial	Com - WiFi Connected Thermostat GAS SPHT	Retrofit	Heating	2,124,080	1,805,468	1,805,468	3%	$0.88
Commercial	Com - Pipe Insulation DHW GAS WHT	Retrofit	Water Heating	1,995,338	1,696,038	1,696,038	3%	$0.36
Commercial	Com - Gas Absorption HPWH GAS WHT - NEW only	New Construction	Water Heating	1,754,052	1,490,944	1,490,944	3%	$0.07
Commercial	Com - Automatic Conveyor Broiler Gas	Replace on Burnout	Cooking	1,716,965	1,459,420	1,459,420	3%	-$0.18
Commercial	Com - Roof Insulation R0 Base GAS SPHT, Z1	Retrofit	Weatherization	1,535,486	921,292	921,292	2%	$0.19
Commercial	Com - Pipe Insulation Space Heating Boiler	Retrofit	Heating	1,468,966	1,248,621	1,248,621	2%	$0.28
Commercial	Com - Condensing Boiler GAS SPHT - NEW only	New Construction	Heating	1,334,287	1,134,144	1,134,144	2%	$0.65
Commercial	Com - Gas Combination Oven	Replace on Burnout	Cooking	1,259,948	1,070,956	1,070,956	2%	$0.00
Commercial	Com - Gas Fryer - NEW Only	New Construction	Cooking	1,198,603	1,018,812	1,018,812	2%	$0.37
Commercial	Com - Efficient Windows GAS SPHT - NEW only	New Construction	Weatherization	1,108,481	665,088	299,328	1%	$2.09
Commercial	Com - Gas Fired Heat Pump GAS SPHT	Replace on Burnout	Heating	1,013,909	963,214	963,214	2%	$0.94
Commercial	Com - WiFi Connected Thermostat GAS SPHT - NEW only	New Construction	Heating	914,956	869,209	854,457	2%	$0.85
Commercial	Com - Gas Griddle	Replace on Burnout	Cooking	883,149	750,676	750,676	1%	$1.04
Commercial	Com - VFD Kitchen Vent Hood GAS SPHT	Retrofit	Heating	878,859	747,030	747,030	1%	$1.24
Commercial	Com - Efficient Windows GAS SPHT	Retrofit	Weatherization	683,398	410,039	-	0%	$16.33
Commercial	Com - Condensing Gas Furnace GAS SPHT	Replace on Burnout	Heating	612,406	520,545	520,545	1%	$0.84
Commercial	Com - Gas Fired Heat Pump GAS SPHT - NEW only	New Construction	Heating	567,365	538,997	538,997	1%	$0.89
Commercial	Com - DHW Circulator Pumps/Controls GAS WHT	Retrofit	Water Heating	554,569	526,841	526,841	1%	$0.30
Commercial	Com - Gas Convection Oven	Replace on Burnout	Cooking	393,598	334,558	334,558	1%	$0.41
Commercial	Com - Automatic Conveyor Broiler Gas - NEW Only	New Construction	Cooking	382,986	325,538	325,538	1%	-$0.18
Commercial	Com - Hot Water Temperature Reset GAS SPHT	Retrofit	Heating	333,108	283,142	283,142	1%	$0.26
Commercial	Com - Thin Triple Pane Windows GAS SPHT - NEW only	New Construction	Weatherization	332,852	199,711	-	0%	$16.62

[4] Provided by the Energy Trust of Oregon

Table D.4- Continued: Oregon 20-Year Cumulative Potential (Commercial)

Sector	Measure Name	Measure Type	End Use	20-year Cumulative Technical Potential (therms)	20-year Cumulative Achievable Potential (therms)	20-year Cumulative Cost-Effective Potential (therms)	% of Total Sector C/E Potential	Average Levelized Cost ($/therm)
Commercial	Com - Gas Combination Oven - NEW Only	New Construction	Cooking	248,411	211,150	211,150	0%	$0.00
Commercial	Com - Thin Triple Pane Windows GAS SPHT	Retrofit	Weatherization	216,469	129,881	-	0%	$16.38
Commercial	Com - Gas Griddle - NEW Only	New Construction	Cooking	191,529	162,800	162,800	0%	$1.03
Commercial	Com - VFD Kitchen Vent Hood GAS SPHT - NEW Only	New Construction	Heating	188,413	160,151	160,151	0%	$1.24
Commercial	Com - PreRinse Spray Valve GAS WHT	Retrofit	Water Heating	184,751	157,039	157,039	0%	-$3.07
Commercial	Com - Wall Insulation GAS SPHT, Z1	Retrofit	Weatherization	180,468	108,281	-	0%	$0.54
Commercial	Com - Roof Insulation R5 Base GAS SPHT, Z1	Retrofit	Weatherization	180,161	108,097	108,097	0%	$1.38
Commercial	Com - Gas Steamer	Replace on Burnout	Cooking	141,034	119,879	119,879	0%	-$2.43
Commercial	Com - Modulating Burner GAS SPHT	Retrofit	Heating	108,283	92,041	92,041	0%	$0.47
Commercial	Com - Gas Convection Oven - NEW Only	New Construction	Cooking	79,743	67,782	67,782	0%	$0.41
Commercial	Com - Pool Heaters Indoor	Replace on Burnout	Water Heating	67,056	56,997	56,997	0%	$0.40
Commercial	Com - Eff. Gas Clothes Washer	Replace on Burnout	Appliance	65,730	62,443	62,443	0%	$0.79
Commercial	Com - Condensing Gas Storage Water Heater GAS WHT - NEW only	New Construction	Water Heating	54,311	46,164	46,164	0%	$0.01
Commercial	Com - Steam Trap Maintenance GAS SPHT	Retrofit	Heating	44,478	37,806	37,806	0%	$0.18
Commercial	Com - Pool Heaters Outdoor	Replace on Burnout	Water Heating	41,159	34,985	34,985	0%	$0.38
Commercial	Com - Gas Steamer - NEW Only	New Construction	Cooking	29,313	24,916	24,916	0%	-$2.43
Commercial	Com - Roof Insulation R0 Base GAS SPHT, Z2	Retrofit	Weatherization	23,430	14,058	14,058	0%	$0.13
Commercial	Com - Condensing Gas Instantaneous Water Heater GAS WHT - NEW only	New Construction	Water Heating	15,549	13,217	13,217	0%	$0.01
Commercial	Com - Eff. Gas Clothes Washer - NEW Only	New Construction	Appliance	10,831	10,289	10,289	0%	$0.79
Commercial	Com - Wall Insulation GAS SPHT, Z2	Retrofit	Weatherization	3,255	1,953	-	0%	$0.30
Commercial	Com - Roof Insulation R5 Base GAS SPHT, Z2	Retrofit	Weatherization	3,033	1,820	1,820	0%	$0.83

Table D.5: Oregon 20-Year Cumulative Potential (Industrial)

Sector	Measure Name	Measure Type	End Use	20-year Cumulative Technical Potential (therms)	20-year Cumulative Achievable Potential (therms)	20-year Cumulative Cost-Effective Potential (therms)	% of Total Sector C/E Potential	Average Levelized Cost ($/therm)
Industrial	Ind - Custom Boiler	Retrofit	Process Heating	3,342,520	2,841,142	2,841,142	16%	$0.22
Industrial	Ind - Custom Primary Process (Gas)	Retrofit	Process Heating	2,760,206	2,346,175	2,346,175	13%	$0.24
Industrial	Ind - Boiler Heat Recovery	Retrofit	HVAC	2,164,508	1,839,832	1,839,832	10%	$0.01
Industrial	Ind - Ceiling/Roof Insulation	Retrofit	Weatherization	1,707,045	1,450,988	1,450,988	8%	$0.05
Industrial	Ind - Wall Insulation (Gas)	Retrofit	Process Heating	1,673,435	1,422,420	1,422,420	8%	$0.05
Industrial	Ind - Gas-fired HP Water Heater	Replace on Burnout	Water Heating	1,130,192	960,663	960,663	5%	$0.22
Industrial	Ind - Radiant Heating (Gas)	Replace on Burnout	Process Heating	1,012,643	860,747	860,747	5%	$0.27
Industrial	Ind - Steam Trap Maintenance	Retrofit	Process Heating	1,008,196	856,967	856,967	5%	$0.02
Industrial	Ind - Custom HVAC (Gas)	Retrofit	HVAC	866,822	736,799	736,799	4%	$0.44
Industrial	Ind - Boiler Load Control	Retrofit	Process Heating	792,879	673,948	673,948	4%	$0.00
Industrial	Ind - Water Heating	Replace on Burnout	Process Heating	750,093	637,579	637,579	4%	$0.49
Industrial	Ind - Advanced Wall Insulation	Retrofit	Weatherization	655,713	557,356	557,356	3%	$1.41
Industrial	Ind - Custom O&M	Retrofit	Process Heating	643,562	547,028	547,028	3%	$0.03
Industrial	Ind - SEM (Gas)	Retrofit	Process Heating	643,562	547,028	547,028	3%	$0.24
Industrial	Ind - Steam Pipe Insulation	Retrofit	Process Heating	605,919	515,031	515,031	3%	$0.05
Industrial	Ind - Process Insulation	Retrofit	Process Heating	353,441	300,425	300,425	2%	$0.16
Industrial	Ind - Greenhouse - Under Bench Heating	Retrofit	Process Heating	326,801	277,781	277,781	2%	$0.17
Industrial	Ind - Custom Secondary Process (Gas)	Retrofit	Process Heating	297,442	252,826	252,826	1%	$0.47
Industrial	Ind - Greenhouse - Thermal Curtain	Retrofit	Process Heating	173,208	147,227	147,227	1%	$0.32
Industrial	Ind - Greenhouse - IR Poly Film	Retrofit	Process Heating	171,604	145,863	145,863	1%	$0.12
Industrial	Ind - Greenhouse - Controller	Retrofit	Process Heating	82,411	70,050	70,050	0%	$0.11
Industrial	Ind - Condensing Greenhouse Boiler	Replace on Burnout	Process Heating	73,750	62,688	62,688	0%	$0.74
Industrial	Ind - Greenhouse - Condensing Unit Heater	Retrofit	Process Heating	54,747	46,535	46,535	0%	$0.22

Table D.6: Oregon 20-Year Cumulative Potential (Residential)

Sector	Measure Name	Measure Type	End Use	20-year Cumulative Technical Potential (therms)	20-year Cumulative Achievable Potential (therms)	20-year Cumulative Cost-Effective Potential (therms)	% of Total Sector C/E Potential	Average Levelized Cost ($/therm)
Residential	Res - Window Replacement Tier 2 (U ≤ 0.27) GAS SPHT	Replace on Burnout	Weatherization	35,250,116	21,150,070	21,150,070	13%	$0.14
Residential	Res - Gas Absorption Heat Pump Water Heater GAS WHT	Replace on Burnout	Water Heating	28,338,580	24,087,793	24,087,793	15%	$0.26
Residential	Res - Window Tier 3 GAS SPHT	Replace on Burnout	Weatherization	24,805,637	14,883,382	14,883,382	9%	$0.17
Residential	Res - Market Transformation NH GAS SPHT DHW - Gas Only - NEW only	New Construction	Weatherization	22,261,413	22,261,413	22,261,413	14%	$0.41
Residential	Res - Smart Tstat - Gas FAF GAS SPHT	Retrofit	Heating	11,428,475	9,714,203	9,714,203	6%	$0.58
Residential	Res - AFUE 90 to 95 Furnace GAS SPHT	Replace on Burnout	Heating	11,145,676	9,473,825	9,473,825	6%	$0.74
Residential	Res - Thin Triple Pane Windows GAS SPHT	Replace on Burnout	Weatherization	10,803,940	6,482,364	6,482,364	4%	$0.74
Residential	Res - Path 4 Advanced Whole Home GAS SPHT DHW - Gas Only - NEW only	New Construction	Heating	9,822,459	8,349,090	8,349,090	5%	$2.76
Residential	Res - Path 2 MECH + DHW GAS WHT Space Heat - Gas Only - NEW only	New Construction	Water Heating	8,274,243	7,033,107	7,033,107	4%	$2.99
Residential	Res - Path 3 MECH + DHW GAS WHT Space Heat - Gas Only - NEW only	New Construction	Water Heating	7,798,140	6,628,419	6,628,419	4%	$2.55
Residential	Res - Gas Fireplace - 70-74 FE GAS SPHT	Replace on Burnout	Heating	4,344,120	3,692,502	3,692,502	2%	$0.00
Residential	Res - AFUE 96+ Furnace GAS SPHT	Replace on Burnout	Heating	3,950,339	3,357,788	3,357,788	2%	$1.85
Residential	Res - Wall insulation GAS SPHT, Z1	Retrofit	Weatherization	3,588,872	2,153,323	2,153,323	1%	$1.93
Residential	Res - Wall insulation R-30 GAS SPHT, Z1	Retrofit	Weatherization	3,306,873	1,984,124	-	0%	$3.58
Residential	Res - Floor insulation GAS SPHT, Z1	Retrofit	Weatherization	3,044,577	1,826,746	1,826,746	1%	$2.28
Residential	Res - AFUE 90 to 95 Furnace GAS SPHT - NEW only	New Construction	Heating	2,852,699	2,424,794	2,424,794	2%	$0.74
Residential	Res - Attic insulation (R13-R18 starting condition) GAS SPHT, Z1- RET	Retrofit	Weatherization	2,755,127	1,653,076	1,653,076	1%	$1.45
Residential	Res - Path 5 Emerging Super Efficient Whole Home GAS SPHT DHW - Gas Only - NEW only	New Construction	Heating	2,189,545	1,861,113	1,861,113	1%	$10.22
Residential	Res - Gas Fired HP (>100% Eff) GAS SPHT	Replace on Burnout	Heating	2,164,390	1,839,732	-	0%	$9.56
Residential	Res - Attic insulation (R0-R11 starting condition) GAS SPHT, Z1- RET	Retrofit	Weatherization	2,065,894	1,239,537	1,239,537	1%	$0.79
Residential	Res - Market Transformation NH GAS SPHT DHW - Elec Only - NEW only	New Construction	Weatherization	2,038,472	2,038,472	2,038,472	1%	$0.46
Residential	Res - Multifamily Commercial Size Condensing Tank Water Heater GAS WHT - NEW only	New Construction	Water Heating	1,279,576	1,087,639	1,087,639	1%	$0.08
Residential	Res - Tankless Gas Hot Water Heater GAS WHT - NEW only	New Construction	Water Heating	1,267,253	1,077,165	-	0%	$2.21
Residential	Res - Multifamily Commercial Size Condensing Tank Water Heater GAS WHT	Replace on Burnout	Water Heating	1,237,874	1,052,193	1,052,193	1%	$0.08
Residential	Res - Tankless Gas Hot Water Heater GAS WHT	Replace on Burnout	Water Heating	1,225,953	1,042,060	-	0%	$2.55
Residential	Res - Tstat Optimization GAS SPHT	Retrofit	Heating	1,133,573	963,537	963,537	1%	$0.26
Residential	Res - Gas Fireplace - 75+ FE GAS SPHT	Replace on Burnout	Heating	1,071,263	910,574	910,574	1%	$0.00
Residential	Res - Attic insulation R-60 GAS SPHT, Z1	Retrofit	Weatherization	1,039,136	623,482	-	0%	$9.49
Residential	Res - Elec Hi-eff Clotheswasher GAS WHT	Replace on Burnout	Water Heating	952,284	809,442	809,442	1%	-$4.91
Residential	Res - AFUE 96+ Furnace GAS SPHT - NEW only	New Construction	Heating	801,747	681,485	453,402	0%	$1.52
Residential	Res - Path 4 Advanced Whole Home GAS SPHT DHW - Elec Only - NEW only	New Construction	Heating	738,329	627,579	627,579	0%	$3.83
Residential	Res - Gas Fired HP (>100% Eff) GAS SPHT - NEW only	New Construction	Heating	711,018	604,365	-	0%	$11.16

Table D.6- Continued: Oregon 20-Year Cumulative Potential (Residential)

Sector	Measure Name	Measure Type	End Use	20-year Cumulative Technical Potential (therms)	20-year Cumulative Achievable Potential (therms)	20-year Cumulative Cost-Effective Potential (therms)	% of Total Sector C/E Potential	Average Levelized Cost ($/therm)
Residential	Res - Path 2 MECH + DHW ER WHT Space Heat - Gas Only - NEW only	New Construction	Water Heating	520,608	442,517	442,517	0%	$6.25
Residential	Res - Path 3 MECH + DHW ER WHT Space Heat - Gas Only - NEW only	New Construction	Water Heating	506,535	430,555	430,555	0%	$4.79
Residential	Res - Condensing Furnaces (MF) GAS SPHT	Replace on Burnout	Heating	416,886	354,353	354,353	0%	$0.38
Residential	Res - Cellular Shades GAS SPHT	Retrofit	Weatherization	380,644	323,547	-	0%	$9.56
Residential	Res - Hot Water Condensing Boiler for Space Heat (MF) GAS SPHT	Replace on Burnout	Heating	350,327	297,778	297,778	0%	$0.30
Residential	Res - Path 2 MECH + DHW GAS WHT Space Heat - Avg. Elec Mixed Market - NEW only	New Construction	Water Heating	326,329	277,379	277,379	0%	$6.35
Residential	Res - Path 3 MECH + DHW GAS WHT Space Heat - Avg. Elec Mixed Market - NEW only	New Construction	Water Heating	292,541	248,660	248,660	0%	$7.48
Residential	Res - Market Transformation NH AVG ELEC SPHT DHW - Gas Only - NEW only	New Construction	Weatherization	275,210	275,210	-	0%	$3.59
Residential	Res - Path 4 Advanced Whole Home AVG ELEC SPHT DHW - Gas Only - NEW only	New Construction	Heating	273,691	232,637	232,637	0%	$9.34
Residential	Res - Multifamily Pipe Insulation GAS WHT	Retrofit	Water Heating	176,614	150,122	150,122	0%	$0.29
Residential	Res - Path 5 Emerging Super Efficient Whole Home GAS SPHT DHW - Elec Only - NEW only	New Construction	Heating	162,711	138,304	138,304	0%	$14.33
Residential	Res - Gas Fireplace - Ignition System GAS SPHT	Replace on Burnout	Heating	151,827	129,053	129,053	0%	$0.99
Residential	Res - Thermostatic Radiator Valves	Retrofit	Water Heating	140,362	119,308	119,308	0%	$0.33
Residential	Res - Hot Water Condensing Boiler for Space Heat (MF) GAS SPHT - NEW only	New Construction	Heating	128,677	109,375	109,375	0%	$0.20
Residential	Res - Elec Hi-eff Clotheswasher MF GAS WHT - NEW only	New Construction	Water Heating	122,842	104,415	104,415	0%	-$3.32
Residential	Res - Elec Hi-eff Clotheswasher MF GAS WHT	Replace on Burnout	Water Heating	118,838	101,013	101,013	0%	-$3.32
Residential	Res - 0.70+ EF Gas Storage Water Heater GAS WHT - NEW only	New Construction	Water Heating	114,854	97,626	97,626	0%	$0.49
Residential	Res - 0.70+ EF Gas Storage Water Heater GAS WHT	Replace on Burnout	Water Heating	111,111	94,445	94,445	0%	$0.49
Residential	Res - Steam trap replacement GAS SPHT- ROB	Replace on Burnout	Heating	103,696	88,142	88,142	0%	$0.18
Residential	Res - Condensing Furnaces (MF) GAS SPHT - NEW only	New Construction	Heating	103,627	88,083	88,083	0%	$0.38
Residential	Res - New MH - Energy Star GAS SPHT, Z1 - NEW only	New Construction	Weatherization	73,085	62,122	62,122	0%	$1.08
Residential	Res - Energy Star Gas Clothes Dryer	Replace on Burnout	Appliance	66,677	63,343	63,343	0%	$1.05
Residential	Res - Path 5 Emerging Super Efficient Whole Home AVG ELEC SPHT DHW - Gas Only - NEW only	New Construction	Heating	62,778	53,361	53,361	0%	$33.60
Residential	Res - Wall insulation R-30 GAS SPHT, Z2	Retrofit	Weatherization	51,284	30,770	-	0%	$2.33
Residential	Res - Duct Sealing MH GAS SPHT	Retrofit	Weatherization	43,926	37,337	37,337	0%	$0.97
Residential	Res - Wall insulation GAS SPHT, Z2	Retrofit	Weatherization	39,737	23,842	23,842	0%	$1.76
Residential	Res - Window Replacement Tier 2 (U ≤ 0.27) GAS SPHT - NEW only	New Construction	Weatherization	39,078	23,447	23,447	0%	$0.14
Residential	Res - Elec Hi-eff Clotheswasher GAS WHT - NEW only	New Construction	Water Heating	36,062	30,653	30,653	0%	-$4.91
Residential	Res - Floor insulation GAS SPHT, Z2	Retrofit	Weatherization	33,682	20,209	20,209	0%	$2.08
Residential	Res - Attic insulation (R13-R18 starting condition) GAS SPHT, Z2- RET	Retrofit	Weatherization	29,970	17,982	17,982	0%	$1.34
Residential	Res - Window Tier 3 GAS SPHT - NEW only	New Construction	Weatherization	27,499	16,500	16,500	0%	$0.17
Residential	Res - Attic insulation (R0-R11 starting condition) GAS SPHT, Z2- RET	Retrofit	Weatherization	20,868	12,521	12,521	0%	$0.79

Table D.6- Continued: Oregon 20-Year Cumulative Potential (Residential)

Sector	Measure Name	Measure Type	End Use	20-year Cumulative Technical Potential (therms)	20-year Cumulative Achievable Potential (therms)	20-year Cumulative Cost-Effective Potential (therms)	% of Total Sector C/E Potential	Average Levelized Cost ($/therm)
Residential	Res - Wall insulation MF GAS SPHT, Z1	Retrofit	Weatherization	17,029	10,217	10,217	0%	$1.93
Residential	Res - Attic insulation R-60 GAS SPHT, Z2	Retrofit	Weatherization	16,115	9,669	-	0%	$6.18
Residential	Res - Ceiling insulation - side by side R49 GAS SPHT, Z1	Retrofit	Weatherization	14,955	8,973	8,973	0%	$0.92
Residential	Res - Ceiling insulation - stacked R49 GAS SPHT	Retrofit	Weatherization	13,175	7,905	7,905	0%	$0.82
Residential	Res - Floor insulation - 2-4 & side by side GAS SPHT, Z1	Retrofit	Weatherization	12,675	7,605	7,605	0%	$2.15
Residential	Res - Dmd Ctrl Recirc. GAS WHT	Retrofit	Water Heating	2,026	1,722	1,722	0%	$1.06
Residential	Res - Showerhead, 1.5 GPM GAS WHT - NEW only	New Construction	Water Heating	1,977	1,681	1,681	0%	-$0.11
Residential	Res - Energy Star Gas Clothes Dryer - NEW only	New Construction	Appliance	1,620	1,539	1,539	0%	$1.05
Residential	Res - Bathroom Faucet Aerators, 0.5 gpm GAS WHT - NEW only	New Construction	Water Heating	1,612	1,371	1,371	0%	-$0.18
Residential	Res - New MH - Energy Star GAS SPHT, Z2 - NEW only	New Construction	Weatherization	738	627	627	0%	$1.08
Residential	Res - Kitchen Faucet Aerators, 1.0 gpm GAS WHT - NEW only	New Construction	Water Heating	662	563	563	0%	-$0.15
Residential	Res - Wall insulation MF GAS SPHT, Z2	Retrofit	Weatherization	189	113	113	0%	$1.74
Residential	Res - Ceiling insulation - side by side R49 GAS SPHT, Z2	Retrofit	Weatherization	151	91	91	0%	$0.92
Residential	Res - Floor insulation - 2-4 & side by side GAS SPHT, Z2	Retrofit	Weatherization	140	84	84	0%	$1.98

D.3 AEG Oregon Transport Memorandum

The following pages are provided by Applied Energy Group (AEG)

MEMORANDUM

To: Matthew Doyle, Laney Ralph, Haixiao Huang, Melissa Martin – NW Natural

From: Eli Morris, Neil Grigsby, Ken Walter, Stephanie Chen - AEG

Date: August 16, 2022

Re: NW Natural Oregon 2022 Transportation Customer Potential Study

Background

With the passing of Executive Order 20-04 in March 2020, statewide greenhouse gas emissions from large stationary sources, transportation fuel, and other liquid and gaseous fuels will be limited by new goals from the Oregon Department of Environmental Quality (DEQ). The resulting Climate Protection Program (CPP) formalizes emission reduction requirements for Oregon's natural gas utilities, including the responsibility for on-site emission of natural gas transportation customers.[1] NW Natural's transportation customers have not historically paid into the public purpose charge and thus are currently not eligible to participate in natural gas energy efficiency programs administered by the Energy Trust of Oregon. NW Natural engaged Applied Energy Group (AEG) to assess the potential that exists with Oregon transportation customers and inform what energy efficiency programs for transportation customers could look like in the future.

The Washington Conservation Potential Assessment (CPA) that AEG completed for NW Natural in 2021 provided a starting point to assess the potential for energy efficiency to reduce greenhouse gas (GHG) emissions at transportation customer sites.[2] As discussed in the "Key Data Sources" section below, AEG was able to use many of the same data sources from the Washington CPA, updated as appropriate to capture Oregon transportation customer characteristics, to efficiently complete this study.

The remainder of this memo presents high-level study results for the reference case, followed by an overview of AEG's methodology, identification of key data sources, and considerations and recommendations as NW Natural considers new program options to reach these customers.

Methodology

AEG began the analysis by characterizing NW Natural's Oregon transportation customers' energy consumption in the base year of the study (2021) using NW Natural customer and sales data. This characterization resulted in energy use distribution by sector, segment and end use. Using NW Natural load forecasts and measure

[1] Transportation customers are non-residential natural gas consumers, typically large industrial users, who purchase natural gas from an alternate supplier, but use NW Natural's distribution system to deliver the fuel to their sites.

[2] The 2021 Washington Conservation Potential Study is available at the following URL:
https://apiproxy.utc.wa.gov/cases/GetDocument?docID=3&year=2021&docketNumber=210773

characterizations from the 2021 Washington CPA, AEG then developed a baseline energy projection over the 30-year study period. Oregon transportation customer equipment specifications were informed by NW Natural's equipment database and vetted with NW Natural Field Technicians. The Northwest Power and Conservation Council (NWPCC) 2021 Power Plan ramp rates informed measure adoption throughout the forecast and were the basis in analyzing the three scenarios provided in this study.

Results Summary

A summary of the identified energy efficiency potential at Oregon transportation customer sites is presented in Table 1. AEG notes the following considerations in reviewing these results:

- The potential presented in this memo represents expected levels using average assumptions across customers and equipment. However, because a small number of customers represent a majority of transportation customer consumption (the top 10% of the largest Oregon transportation customers make up roughly 76% of NW Natural Oregon transportation load), actual energy efficiency impacts may vary widely depending on whether these large customers choose to participate in potential programs and customer specific characteristics. As such, these results should be viewed as planning assumptions that are likely to differ in practice.
- The study relied on the best available data from NW Natural and secondary sources, which did not include on-site assessments of transportation customer equipment efficiency or practices. Information on typical characteristics by market segment (i.e., business or industry type) were used to estimate current conditions and remaining opportunities for these customers.
- AEG modeled three achievable potential scenarios to test the effects of slower and faster adoption of energy efficiency measures. The results shown in Table 1 are for the "reference case," with results for the two alternate scenarios presented later in this memo.
- AEG estimated achievable economic potential from both the Total Resource Cost (TRC) and Utility Cost Test (UCT) perspective. While AEG does not take a position on which test is more appropriate for assessing the cost-effectiveness of transportation customer potential, the difference in estimated potential using the two tests is small.
- Energy Trust of Oregon staff have experience designing and implementing programs for natural gas industrial sales customers in Oregon. Although the characteristics of a transportation customer may differ from a large sales customer, Energy Trust of Oregon's industrial sales energy efficiency measures are comparable to the measures evaluated in this study. As such, AEG and NW Natural staff reviewed draft and final study results with Energy Trust of Oregon staff to gather feedback on key findings. After reviewing the results, staff from the three organizations agreed that the findings were reasonable, given the considerations described above.

Table 1. Summary Potential Results – Reference Case

Scenario	2022	2023	2024	2026	2031	2040	2050
Baseline Load Projection Absent Future Savings (mTherms)	357,025	357,418	355,616	350,191	340,047	323,605	304,190
Cumulative Savings (mTherms)							
TRC Achievable Economic Potential	1,531	2,883	4,155	6,721	13,424	18,166	17,481
UCT Achievable Economic Potential	1,537	2,894	4,170	6,746	13,480	18,287	17,655

Achievable Technical Potential	1,844	3,448	4,929	7,867	15,346	20,220	19,392
Technical Potential	2,291	4,298	6,158	9,842	19,167	25,882	25,622
Cumulative Savings (% of Baseline)							
TRC Achievable Economic Potential	0.43%	0.81%	1.17%	1.92%	3.95%	5.61%	5.75%
UCT Achievable Economic Potential	0.43%	0.81%	1.17%	1.93%	3.96%	5.65%	5.80%
Achievable Technical Potential	0.52%	0.96%	1.39%	2.25%	4.51%	6.25%	6.37%
Technical Potential	0.64%	1.20%	1.73%	2.81%	5.64%	8.00%	8.42%

Key Data Sources

AEG used NW Natural's 2021 Washington Conservation Potential Assessment (CPA) as the foundation for this assessment. While Washington transportation customers were excluded from the 2021 Washington CPA because they do not fund NW Natural's Washington conservation programs, the assessment did include a scenario to estimate energy efficiency potential for Washington transportation customers. Key updates from Washington CPA assumptions included:

- Input and market characterization data for this analysis was specific to NW Natural's Oregon transportation customers, including baseline sales and forecasts, industry designations, and equipment saturations from NW Natural's tracking database. The Washington model generally formed the basis for measure cost assumptions and savings percentage estimates.
- AEG was also able to work with NW Natural transportation customer account managers and field technicians to learn more about these customers' existing energy-using equipment, including recent upgrades and planned replacements. NW Natural Account Representatives provided insights on how many transportation customers are using strategic energy management (SEM) and control systems and reported that many high consumption customers likely have dedicated engineering staff for these systems.
- NW Natural conducted a thorough review of equipment data in NW Natural's account management database to ensure that boilers used for process loads were classified correctly and not misidentified as space heating load. AEG then benchmarked the distribution of end use loads with data from the US Energy Information Administration's Commercial Building and Manufacturing Energy Consumption Surveys (CBECS and MECS) and discussed notable differences with NW Natural to ensure that they reflected known aspects of those customers accurately. For example, if a particular manufacturing sector showed a greater proportion of space heating load than expected compared to MECS data, NW Natural could confirm that sector for their Oregon transportation customers was dominated by a facility with significant conditioned space and whose product line did not require as much natural gas use.
- The assessment leveraged the Washington CPA measure list, updated to reflect NW Natural feedback on measures applicable to this specific set of customers. NW Natural account managers reported that multiple transportation customers have expressed insulating several areas of their process equipment and lines, some of which were identified as measures with high potential within this assessment.

Where data gaps existed in NW Natural data, AEG relied on national and regional data sources for assumptions in the potential model.

Table 2 summarizes key data sources used and how they informed the study.

Table 2. Key Data Source Summary

Data Source	Used for
NW Natural Utility Data	Load segmentation by industry/building type, presence of equipment, end use load distribution, comparison baseline forecast, economics inputs, scenario development
Northwest Power and Conservation Council's 2021 Power Plan	Technical Achievable ramp rate library and study methodology
NEEA's 2019 and 2014 Commercial Building Stock Assessment (CBSA)	Benchmark equipment saturations, normalized end use and equipment intensity (therms per sq.ft)
US Energy Information Administration (EIA) 2014 Manufacturing Energy Consumption Survey (MECS) and 2012 Commercial Building Energy Consumption Survey (CBECS)	Estimated equipment use per unit, end use distribution of natural gas use by business/industry type, benchmarking equipment presence (saturation)
EIA's 2020 Annual Energy Outlook	Reference baseline purchase assumptions, equipment lifetimes and costs

Potential Scenarios Analyzed

At NW Natural's request, AEG developed three potential scenarios based on different assumptions regarding the rate at which potential could be acquired. These scenarios are intended to capture a range of potential measure adoption for this segment of customers who have not previously participated in natural gas energy efficiency programs:

- The **Reference Case** started with standard ramp rate assumptions from the Northwest Power and Conservation Council's (Council's) 2021 Power Plan, mapped to natural gas measures,[3] then moved these ramp rates to the next most aggressive ramp rate for all measures except strategic energy management, which was already on the highest ramp rate.
- The **Low Case** used standard ramp rate assumptions from the Northwest Power and Conservation Council's (Council's) 2021 Power Plan, mapped to natural gas measures without adjustment.
- The **High Case** moved all measures except strategic energy management to the most aggressive Council ramp rate.

Potential Results

Reference Case

Figure 1 presents the cumulative reference case potential from 2022 through 2051 by type. As shown, based on the ramp rates used, a majority of the potential is assumed to be acquired over 10 years, and almost all over 20 years. Only a small amount of potential remains for acquisition from 2042-2051, primarily for equipment that was not assumed to be upgraded during the first 20 years of the forecast period.

[3] The Council's Power Plan only covers electric measures. To adapt these ramp rates for this natural gas assessment, AEG mapped gas measures to the same or similar electric measure.

Figure 1. Reference Case Cumulative Potential

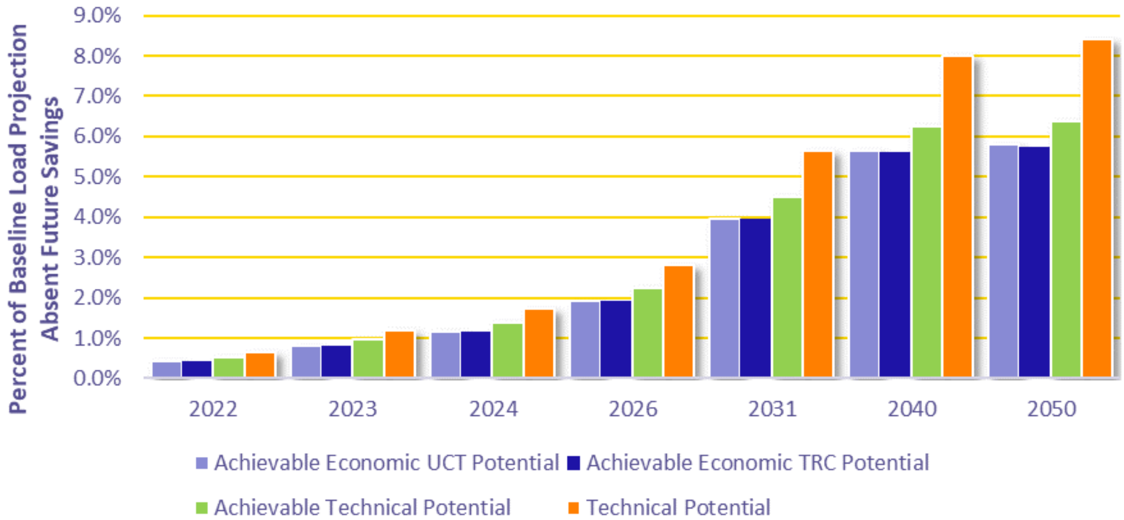


Figure 2 and

Figure 3 present the cumulative reference case potential in 2042 by market segment and end use, respectively. As shown, based on the composition of NW Natural's Oregon transportation customers, paper manufacturing is the segment with the largest identified potential, followed by chemicals, stone/clay/glass, and primary metals. The process (75%) and space heating (23%) end uses account for nearly all of the identified achievable economic potential.

Figure 2. Reference Case Cumulative TRC Achievable Economic Potential by Market Segment, 2042

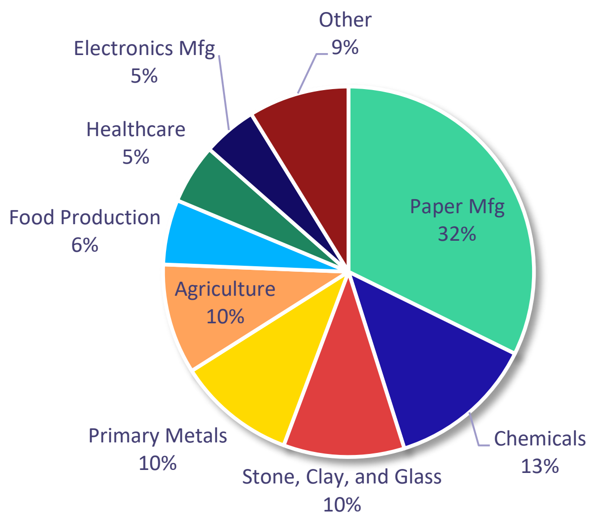
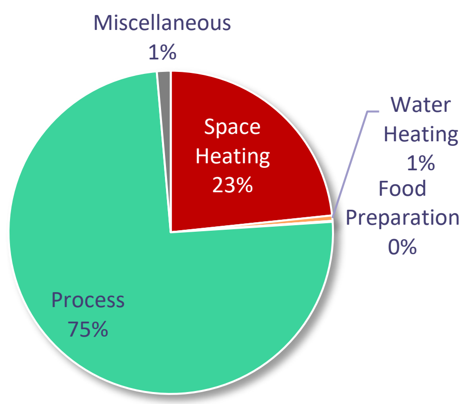


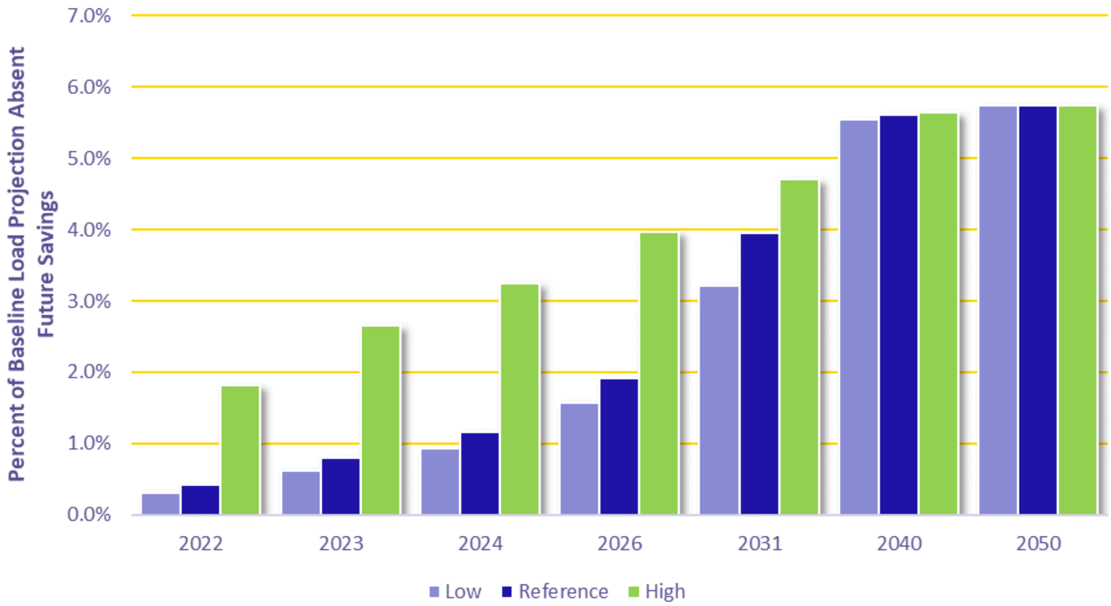
Figure 3. Reference Case Cumulative TRC Achievable Economic Potential by End Use, 2042



Low and High Cases

A comparison of cumulative potential as a percent of baseline sales across cases is provided in Figure 4. Because ramp rates were the only assumptions changed across scenarios, the total long-term potential and composition of savings by market segment does not vary significantly across scenarios. What does vary is the assumed timing of acquisition, with the high case representing significantly faster savings acquisition as shown.

Figure 4. Cumulative TRC Achievable Economic Potential by Case



Considerations and Recommendations

This assessment was a first step in identifying and realizing natural gas energy efficiency (and associated greenhouse gas emissions reductions) within NW Natural's transportation customer base. While program design is outside the scope of this assessment, AEG notes the following items for NW Natural as it determines the best way to achieve these savings:

- Many of the inputs into the analysis are averages across market segments based on the best available data sources and may not reflect the available potential at any individual site. **To address this, AEG recommends that NW Natural consider sponsoring audits of specific transportation customer sites to better understand current equipment and practices to refine estimates of available potential for these customers.**
- Because a small number of customers account for a large amount of transportation customer consumption, whether these customers choose to participate in future programs will significantly affect the amount of savings that NW Natural is able to achieve. This uncertainty could increase or decrease acquisition levels relative to the potential identified in this assessment. **As NW Natural considers new program designs for transportation customers, AEG recommends targeted outreach to the largest customers to understand their likelihood of participating in future programs, including to what extent and on what timeline.**
- In performing this assessment, AEG heard from NW Natural account managers and Energy Trust of Oregon staff that strategic energy management (SEM) programs tend to be popular with commercial and industrial customers when there are robust utility incentives that do not require capital investments. **As it considers new programs for transportation customers, AEG recommends NW Natural consider offering incentives for SEM as an option that could see rapid uptake and participation.**
- NW Natural's Oregon transportation customers do not currently pay the Public Purpose Charge (PPC) and are not eligible to participate in programs funded by the PPC. **In considering new program offerings for these customers, NW Natural should carefully consider the appropriate cost recovery mechanism to fund transportation customer programs.**
- Traditional natural gas energy efficiency programs incentivize customers to reduce energy consumption and assess cost-effectiveness based on the costs avoided by the utility in not having to supply that energy (along with additional benefit streams, depending on the prevailing cost-effectiveness test in the jurisdiction). In the case of transportation customers, the traditional energy efficiency tests may not apply, as the commodity cost is not incurred by the utility. Moreover, NW Natural's focus with new programs for these customers is reducing greenhouse gas emissions. As such, **AEG recommends NW Natural consider energy efficiency program designs that incentivize customers based on avoided greenhouse gas emissions (rather than energy savings) and align cost-effectiveness tests with the value of these greenhouse gas emissions reductions to NW Natural's system.**
- Utilities typically select energy efficiency program implementors through a Request for Proposals (RFP) process, which allows a utility to compare vendor qualifications, applicable experience, delivery cost, and other factors across multiple proposals. For a utility without a recent history of implementing energy efficiency programs directly, a Request for Qualifications (RFQ) can be an effective tool to "pre-qualify" firms to receive the RFP. This RFQ-to-RFP process allows a utility to narrow the pool of RFP recipients to

the most qualified firms and to narrow the scope of the RFP, as much of the necessary information will have already been collected through the RFQ. **AEG recommends NW Natural issue an RFQ to identify firms qualified to deliver new energy efficiency programs to transportation customers, and use the results of this RFQ process to develop an RFP, as necessary, to send to qualified firms.**

- Utilities are increasingly including performance-based incentives in contracts with implementation contractors. This payment structure ties compensation to performance targets or milestones throughout the duration of the contract. This is typically accomplished through one of two mechanisms:
    - Holdback: A percentage of funds, commonly 10% of the contract value, is held back from payment until the targets are met.
    - Fixed and variable components: A percentage of the contract value is fixed and the remaining contract amount is tied to performance. For example, 5% of contract value for startup/mobilization costs, 15% for program management, and 80% for variable activity. The vendor would receive a $ per unit delivered up to 80% of contract value, tying a larger portion of their revenue to their performance.

AEG recommends NW Natural use one of these mechanisms to tie program costs to vendor performance. NW Natural could use the RFQ process described above to gather information on vendors' preferred incentive-based mechanism and build this compensation structure into its RFP.

Appendix E: Supply-Side Resources

E.1 Gas Purchasing Common Practices

NW Natural also utilizes financial derivative hedges (mainly swaps) to manage cost risks. The physical baseload supply contracts mentioned in Chapter 6, which are priced at a variable index price, can be fixed using financial swaps. This is done for a large portion of our portfolio to lock in prices and decrease the volatility of costs in our gas supply portfolio for customers.

In addition to the long-term supply planning done in this IRP, NW Natural prepares a Gas Acquisition Plan (GAP) each year. The GAP is reviewed and approved by NW Natural's Gas Acquisition Strategy and Policies (GASP) Committee, but such plans are always subject to change based on market conditions. The primary objective of the Gas Acquisition Plan (GAP) is to ensure gas supplies are sufficient to meet firm customer demand. To meet this objective, our primary goal is reliability, followed by lowest reasonable cost, rate stability, and cost recovery all while reducing the carbon content of the energy we deliver. The focus of the GAP is on the upcoming gas contracting year (November through October); however, this focus extends several years into the future for multi-year hedging considerations. Longer-term resource planning is the focus of the IRP and is not covered in the GAP, except of course to assure consistency in the transition from near-term to longer-term planning decisions.

E.2 Pipeline Charges

There are three primary costs components associated with pipeline contracts, one that is a fixed charge and two variable components. Table E.1 outlines these three components.

Table E.1: Three Cost Components for Pipeline Charges

Component	Description
Demand Charge	This is a fix cost associated with holding the capacity rights to ship gas on a pipeline. Often specified in $/Dth/day, this price multiplied by the capacity amount held by the shipper and 365 would provide the annual payment to the interstate pipeline regardless of how much gas is shipped over the course of that year. Also known as a reservation charge.
Variable Charge	This a variable charge associated with how much gas is scheduled on the pipeline each day. Some pipelines have postage-stamp variable charges that are independent of the receipt and delivery points, whereas other pipelines charge based not only the amount of gas scheduled but the distance that it is scheduled.
Fuel Charge	This is a secondary indirect variable charge that takes a percentage of the natural gas that is shipped on the pipeline.

E.3 Gas Supply Contracts

Table E.2: NW Natural Firm Off-System Gas Supply Contracts for the 2021/2022 Tracker Year

Supply Location	Duration	Baseload Qty (Dth/day)	Swing Qty (Dth/day)	Contract Termination Date
British Columbia:				
MacQuarie Energy Canada Ltd.	Nov-Jan	5,000		1/31/2022
TD Energy Trading Inc	Nov-Feb	5,000		2/28/2022
Direct Energy Marketing Limited	Nov-Mar	5,000		3/31/2022
IGI Resources	Nov-Mar	5,000		3/31/2022
J. Aron & Company	Nov-Mar	11,000		3/31/2022
MacQuarie Energy Canada Ltd.	Nov-Mar	10,000		3/31/2022
Powerex Corp	Nov-Mar	6,000		3/31/2022
TD Energy Trading Inc	Nov-Mar	11,000		3/31/2022
Canadian Natural Resources	Nov-Oct	10,000		10/31/2022
ConocoPhillips Canada Marketing	Nov-Oct	3,000		10/31/2022
TD Energy Trading Inc	Nov-Oct	5,000		10/31/2022
Powerex Corp	Apr-May	5,000		5/31/2022
ConocoPhillips Canada Marketing	Apr	10,000		4/30/2022
J. Aron & Company	Apr	2,000		4/30/2022
MacQuarie Energy Canada Ltd.	Apr	5,000		4/30/2022
J. Aron & Company	Oct	5,000		10/31/2022
Alberta:				
ConocoPhillips Canada Marketing	Nov-Jan	5,000		1/31/2022
Direct Energy Marketing Limited	Nov-Jan	5,000		1/31/2022
PetroChina International (Canada) Trading	Nov-Jan	10,000		1/31/2022
J. Aron & Company	Nov-Feb	5,000		2/28/2022
Castleton Commodities	Nov-Mar	5,000		3/31/2022
ConocoPhillips Canada Marketing	Nov-Mar	5,000		3/31/2022
EDF Trading North America, LLC	Nov-Mar	5,000		3/31/2022
Powerex Corp	Nov-Mar	5,000		3/31/2022
Suncor Energy Marketing Inc	Nov-Mar	15,000		3/31/2022
BP Canada Energy Group	Nov-Oct	10,000		10/31/2022
Shell North America (Canada) Inc	Nov-Oct	5,000		10/31/2022
J. Aron & Company	Dec-Feb	5,000		2/28/2022
J. Aron & Company	Dec-Jan	5,000		1/31/2022
Powerex Corp	Dec-Jan	5,000		1/31/2022
Castleton Commodities	Apr-Jun	3,000		6/30/2022
Castleton Commodities	Apr-May	5,000		5/31/2022
Direct Energy Marketing Limited	Apr-May	5,000		5/31/2022
J. Aron & Company	Apr-May	5,000		5/31/2022
Direct Energy Marketing Limited	Feb-Mar	5,000		3/31/2022
Suncor Energy Marketing Inc	Apr	11,000		4/30/2022
ConocoPhillips Canada Marketing	Apr	6,000		4/30/2022
Powerex Corp	Feb	5,000		2/8/2022
J. Aron & Company	Mar	3,000		3/31/2022
BP Canada Energy Group	Oct	5,000		10/31/2022
Castleton Commodities	Oct	13,000		10/31/2022
IGI Resources	Oct	5,000		10/31/2022
Suncor Energy Marketing Inc	Oct	5,000		10/31/2022
Shell North America (Canada) Inc	Oct	5,000		10/31/2022

Table E.2 - Continued: NW Natural Firm Off-System Gas Supply Contracts for the 2021/2022 Tracker Year

Supply Location	Duration	Baseload Qty (Dth/day)	Swing Qty (Dth/day)	Contract Termination Date
Rockies:				
CIMA Energy LTD	Nov-Mar	5,000		3/31/2022
ConocoPhillips Company	Nov-Mar	16,000		3/31/2022
Koch Energy Services, Inc	Nov-Mar	10,000		3/31/2022
MacQuarie Energy, LLC	Nov-Mar	5,000		3/31/2022
XTO Energy Inc	Nov-Mar	5,000		3/31/2022
Citadel Energy Marketing, LLC	Nov-Oct	15,000		10/31/2022
ConocoPhillips Company	Nov-Oct	5,000		10/31/2022
MacQuarie Energy, LLC	Nov-Oct	4,000		10/31/2022
Spotlight Energy, LLC	Nov-Oct	5,000		10/31/2022
CIMA Energy LTD	Dec-Jan	10,000		1/31/2022
Citadel Energy Marketing, LLC	Dec-Jan	5,000		1/31/2022
MacQuarie Energy, LLC	Dec-Jan	5,000		1/31/2022
CIMA Energy LTD	Dec-Feb	5,000		2/28/2022
ConocoPhillips Company	Dec-Feb	5,000		2/28/2022
IGI Resources, Inc	Dec-Feb	15,000		2/28/2022
ConocoPhillips Company	Feb	5,000		2/28/2022
MacQuarie Energy, LLC	Mar	7,000		3/31/2022
MacQuarie Energy, LLC	Apr	6,000		4/30/2022
ConocoPhillips Company	Nov-Mar		10,000	3/31/2022
ConocoPhillips Company	Apr-Oct		10,000	10/31/2022

Month	Baseload Qty (Dth/day)	Baseload+Swing (Dth/day)
Nov-21	221,000	231,000
Dec-21	281,000	291,000
Jan-22	281,000	291,000
Feb-22	241,000	251,000
Mar-22	201,000	211,000
Apr-22	125,000	135,000
May-22	85,000	95,000
Jun-22	65,000	75,000
Jul-22	62,000	72,000
Aug-22	62,000	72,000
Sep-22	62,000	72,000
Oct-22	100,000	110,000

Notes:

† Contract quantities represent deliveries into upstream pipelines. Accordingly, quantities delivered into NW Natural's system are slightly less due to upstream pipeline fuel consumption.

‡ Nov-Mar "Swing" contracts represent physical call options at NWN's discretion, while the Apr-Oct "Swing" contracts represent physical put options at the supplier's discretion.

Table E.3: NW Natural Firm Transportation Capacity for the 2021/2022 Tracker Year

See next page for Table

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
Northwest Pipeline:		
Sales Conversion (#100005)	214,889	10/31/2031
1993 Expansion (#100058)	35,155	9/30/2044
1995 Expansion (#100138)	102,000	10/31/2030
Occidental cap. acq. (#139153)	1,046	10/31/2030
Occidental cap. acq. (#139154)	4,000	10/31/2030
International Paper cap. acq. (#138065)	4,147	10/31/2030
March Point cap. acq. (#136455)	12,000	12/31/2046
Total NWP Capacity	373,237	
less recallable release to -		
Portland General Electric	(30,000)	10/31/2022
Net NWP Capacity	343,237	
TransCanada - GTN:		
Sales Conversion (#00180)	3,616	10/31/2030
1993 Expansion (#00164)	46,549	10/31/2030
1995 Rationalization (#11030)	56,000	10/31/2030
Total GTN Capacity	106,165	
TransCanada - Foothills:		
1993 Expansion	47,727	10/31/2022
1995 Rationalization	57,417	10/31/2022
Engage Capacity Acquisition	3,708	10/31/2022
2004 Capacity Acquisition	48,669	10/31/2025
Total Foothills Capacity	157,521	
less release to -		
Shell Energy North America (Canada) Inc	(48,669)	10/31/2025
Net Foothills Capacity	108,852	
TransCanada - NOVA:		
1993 Expansion	48,135	10/31/2025
1995 Rationalization	57,909	10/31/2025
Engage Capacity Acquisition	3,739	10/31/2025
2004 Capacity Acquisition	49,138	10/31/2025
Total NOVA Capacity	158,921	
less release to -		
Shell Energy North America (Canada) Inc	(49,138)	10/31/2025
Net NOVA Capacity	109,783	
T-South		
Capacity (through Tenaska)	19,000	3/31/2026
Capacity (through FortisBC)	47,391	10/31/2025
2021 Expansion	25,511	10/31/2061
Total T-South Capacity	91,902	

Notes:

† All of the above agreements continue year-to-year after termination at NW Natural's sole option except for PGE, which requires mutual agreement to continue, and the T-South contracts with Tenaska and Fortis, which have no renewal rights.

‡ The T-South contract with FortisBC is for 47,391 Dth from 11/1/2020 through 10/31/2023, and then is reduced to 28,435 Dth from 11/1/2023 through 10/31/2025.

♠ The numbers shown for the 1993 Expansion contracts on GTN and Foothills are for the winter season (Oct-Mar) only. Both contracts decline during the summer season (Apr-Sep) to approximately 30,000 Dth/day.

♦ Segmented capacity has not been included in this table.

♣ T-South capacity includes the new T-South Expansion contract awarded in 2017, which begins November 1, 2021.

• The 2004 Capacity Acquisition on NOVA and Foothills totaling about 49,000 Dth/day has been released to a third party through 10/31/2025. The revenues related to this arrangement are being credited back to customers as outlined in Schedule P.

Table E.4: NW Natural Firm Storage Resources for the 2021/2022 Tracker Year

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)	Termination Date
Jackson Prairie:			
SGS-2F	46,030	1,120,288	10/31/2025
TF-2 (primary firm portion)	23,038	839,046	10/31/2025
TF-2 (primary firm portion)	9,467	281,242	10/31/2025
TF-1	13,525	n/a	10/31/2031
Firm On-System Storage Plants:			
Mist (reserved for core)	305,000	12,258,591	n/a
Portland LNG Plant	130,800	499,656	n/a
Newport LNG Plant	64,500	967,500	n/a
Total On-System Storage	500,300	13,725,747	
Total Firm Storage Resource	546,330	14,846,035	

Notes:

† The SGS-2F and TF-2 contracts have a unilateral annual evergreen provision (continuation at NW Natural's sole option), while the TF-1 contract requires mutual consent with Northwest Pipeline to continue after the indicated termination date.

‡ The TF-2 contracts also contain additional "subordinated" firm service of 9,586 Dth/day on the first agreement listed above and 3,939 Dth/day on the second agreement. The subordinated service is NOT included in NW Natural's peak day planning.

♠ On-system storage peak deliverability is based on design criteria, for example, Mist is at least 50% full.

♦ Mist numbers pertain to the portion reserved for core utility service per the Company's Integrated Resource Plan. Additional capacity and deliverability at Mist have been contracted under varying terms to Interstate storage customers.

♣ The Dth numbers for Mist, Newport LNG and Portland LNG are approximate in that they are converted from Mcf volumes, and so depend on the heat content of the stored gas. The current heat content used for Mist is 1060 Btu/cf. The current heat content used for Newport is 1075 Btu/cf and Portland LNG is 1090 Btu/cf.

● Newport LNG tank de-rated to 90% of the tank capacity pending CO2 removal project.

♠♠ Due to an Engineering analysis of the Portland LNG tank, liquifaction will be limited to 76% of the tank's capacity.

♦♦ NW Natural has no supply-basin storage contract for the coming year.

Table E.5: NW Natural Other Resources: Recall Agreements, City Deliveries and Mist Production for the 2021/2022 Tracker Year

Type	Max. Daily Rate (Dth/day)	Max. Availability (days)	Termination Date
Recall Agreements:			
PGE	30,000	30	10/31/2022
International Paper	8,000	40	Upon 1-year notice
Georgia Pacific-Halsey mill	1,000	15	Upon 1-year notice
Total Recall Resource	39,000		
Citygate Deliveries:			
Citygate Delivery	5,000	5	2/28/2022
On-System Supplies:			
Renewable Natural Gas	≈2,000	n/a	Varying Terms
Mist Production	≈1,000	n/a	Life of the wells
Total On System Supplies	3,000		
Notes:			
† There are a variety of terms and conditions surrounding the recall rights under each of the above agreements, but they all include delivery of the gas to NW Natural's system.			
‡ Citygate deal has been negotiated for 5 days peaking at 5,000 dth/day.			
♠ Mist production is currently flowing at roughly the figure shown above. Flows vary as new wells are added and older wells deplete. NW Natural's obligation is to buy gas from existing wells through the life of those wells.			
♦ Assumes three Renewable Natural Gas (RNG) projects are online this winter.			

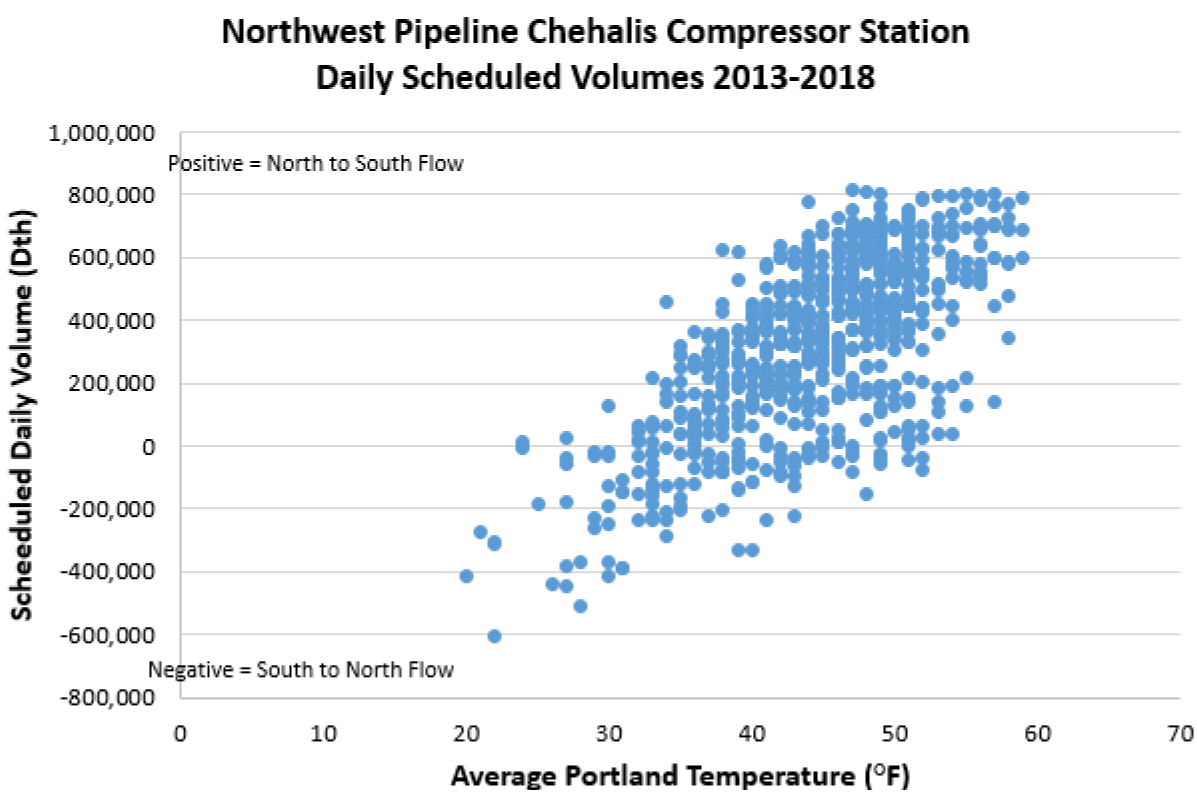
Table E.6: NW Natural Peak Day Resource Summary for the 2021/2022 Tracker Year

Resource Type	Max. Daily Rate (Dth/day)
Net Deliverability over Upstream Pipeline Capacity	343,237
Off-System Storage (Jackson Prairie only)	46,030
On-System Storage (Mist, Portland LNG and Newport LNG)	500,300
Recallable Capacity and Supply Agreements	39,000
Citygate Deliveries	5,000
On-System Supplies	3,000
Segmented Capacity (not primary firm)	60,700
Total Peak Day Resources	997,267
Notes:	
† Per 2018 IRP Update #3, Segmented Capacity currently is included as a firm resource through 2021-2025 gas years. Afterwards reliance reduces to 30,000 dth/day into the future.	

E.4 Chehalis Compressor Analysis

In the 2016 IRP, an analysis of NWP flow data along the I-5 corridor over the prior five winters showed that as the weather gets colder, the predominant flow direction is south to north through the main constraint point at NWP's Chehalis compressor station. Hence, gas flowing south from Sumas on segmented capacity should have greater pipeline reliability as design day conditions are approached. This analysis is shown in Figure E.1 below.

Figure E.1: Implied Reliability of Segmented Capacity



Experience over the past several winters continues to support our use of segmented capacity during cold weather events.

Table E.7 (Jackson Prairie Related Transportation Agreements) shows the configuration of agreements that transport gas from Jackson Prairie on NWP's system.

Table E.7: Jackson Prairie Related Transportation Agreements

Service Type	Primary Firm Rate (Dth/day)	Subordinate Firm Rate (Dth/day)
TF-1	13,525	-
TF-2	23,038	9,586
TF-2	9,467	3,939
Total	46,030	13,525

E.4 Compliance Resource Additional Detail

Table E.8: California LCFS CI Scores

Facility Location	Feedstock	Current Certified CI	Facility Location	Feedstock	Current Certified CI
California	Wastewater Sludge (030)	76.98	California	Landfill Gas (025)	120.04
California	Dairy Manure (026)	-758.46	California	Landfill Gas (025)	109.81
California	Dairy Manure (026)	-750.81	California	Wastewater Sludge (030)	109.01
California	Landfill Gas (025)	74.7	California	Other Organic Waste (029)	0.28
California	Dairy Manure (026)	-562.5	California	Landfill Gas (025)	158.25
Washington	Landfill Gas (025)	44.18	California	Landfill Gas (025)	138.90
California	Dairy Manure (026)	-431.65	California	Landfill Gas (025)	136.44
California	Dairy Manure (026)	-420.69	California	Landfill Gas (025)	136.31
California	Dairy Manure (026)	-418.9	California	Landfill Gas (025)	131.51
California	Dairy Manure (026)	-417.35	California	Landfill Gas (025)	131.39
California	Dairy Manure (026)	-417.27	California	Landfill Gas (025)	129.09
California	Dairy Manure (026)	-417.26	California	Landfill Gas (025)	109.68
California	Dairy Manure (026)	-417.24	California	Landfill Gas (025)	99.48
California	Dairy Manure (026)	-414.26	California	Landfill Gas (025)	99.48
Washington	Landfill Gas (025)	41.09	California	Landfill Gas (025)	99.48
California	Dairy Manure (026)	-406.28	California	Landfill Gas (025)	96.41
California	Dairy Manure (026)	-405.57	California	Landfill Gas (025)	76.71
California	Dairy Manure (026)	-405.41	California	Landfill Gas (025)	73.14
California	Dairy Manure (026)	-392.44	California	Waste Beverage	69.82
California	Swine Manure (044)	-390.47	California	Landfill Gas (025)	65.77
California	Dairy Manure (026)	-389.66	California	Landfill Gas	62.30
California	Dairy Manure (026)	-388.91	Washington	Landfill Gas (025)	53.11
California	Dairy Manure (026)	-388.29	Washington	Landfill Gas (025)	50.02
California	Dairy Manure (026)	-385.4	California	Landfill Gas	44.07
California	Dairy Manure (026)	-382.11	Washington	Landfill Gas - CNG	42.78
California	Swine Manure (044)	-374.14	California	Landfill Gas	41.46
California	Dairy Manure (026)	-366.91	California	Landfill Gas	37.39
California	Dairy Manure (026)	-356.29	Washington	Landfill Gas (025)	37.19
California	Swine Manure (044)	-354.78	California	Landfill Gas	32.28
California	Dairy Manure (026)	-353.38	California	Landfill Gas	31.98
California	Dairy Manure (026)	-349.17	Washington	Landfill Gas - CNG	30.90
California	Swine Manure (044)	-338.45	California	Landfill Gas - CNG	30.50
California	Wastewater Sludge (030)	30.31	California	Waste Wine	22.06
California	Dairy Manure (026)	-293.72	California	Landfill Gas	13.29
California	Dairy Manure (026)	-287.07	California	Landfill Gas	10.71
Washington	Landfill Gas (025)	28.24	California	Landfill Gas	10.32
California	Dairy Manure (026)	-259.22	California	Landfill Gas	9.97
California	Dairy Manure (026)	-255.83	California	Landfill Gas	7.74
California	Dairy Manure (026)	-254.95	California	Landfill Gas	7.39
California	Dairy Manure (026)	-251.36	California	Sugarbeets	7.18
California	Dairy Manure (026)	-249.43	California	Landfill Gas	-5.28
California	Dairy Manure (026)	-241	California	Landfill Gas	-12.65
California	Dairy Manure (026)	-239.31	California	Dairy Manure (026)	-108.43
California	Dairy Manure (026)	-220.45	Oregon	Dairy Manure (026)	-188.78
California	Dairy Manure (026)	-216.05	California	Dairy Manure (026)	-192.49
California	Dairy Manure (026)	-210.67	California	Other Organic Waste (029)	-233.49
California	Dairy Manure (026)	-204.81	California	Dairy Manure (026)	-323.10
California	Urban Landscaping Waste (028)	2.51	California	Dairy Manure (026)	-352.89
California	Wastewater Sludge (030)	19.28	California	Dairy Manure (026)	-355.35
California	Landfill Gas (025)	18.96	California	Dairy Manure (026)	-368.04
California	Dairy Manure (026)	-179.71	California	Dairy Manure (026)	-374.10
California	Dairy Manure (026)	-169.35	California	Dairy Manure (026)	-377.83
California	Landfill Gas (025)	15.87	California	Dairy Manure (026)	-525.14
California	Landfill Gas (025)	129.09	California	Dairy Manure (026)	-558.62
California	Dairy Manure (026)	-126.52	California	Dairy Manure (026)	-592.68
California	Landfill Gas (025)	125.44	California	Dairy Manure (026)	-630.72

E.5 Storage Plant Asset Management Programs

NW Natural's three on-system storage plants are crucial elements of our resource portfolio, providing approximately half of the gas required on the design peak day. Due to their age and the need to maintain these resources, NW Natural has developed asset management programs for each plant[5] that consists of 10-year plans typically informed by outside consultant studies and inclusive of projects being evaluated in this IRP.

The selection criteria for the projects in each plant's plan includes the following:

- High priority due to failing condition
- Equipment no longer supported by manufacturer
- Cyber-security considerations
- Regulatory compliance
- Safety compliance
- Facility reliability
- End-of-life replacement

End-of-life replacement

The term end-of-life as used here may have several determinants, such as functional degradation, failure risks, or regulatory requirements. End-of-life indicators include:

- Severe corrosion within a component or system, due to atmospheric, galvanic corrosion, or minor issues with insulation over time
- Mechanical wear effects any of the rotating equipment onsite
- Fatigue caused by cycling in materials particularly in systems with significant temperature changes
- Technology that has become unsupported and at risk for failure without the ability to support a repair

All required projects going forward will be constructed to contemporaneous seismic standards. This usually requires replacement of an original foundation with foundation systems designed to accommodate ground liquefaction.

Project execution dates may vary from those identified below due to:

- New information obtained on the facility/component condition, resulting in a change to the urgency of the project
- An opportunity to improve execution efficiency
- The need to prevent and/or reduce interruptions to facility distribution system operations
- Permitting requirements
- Loss of resources redirected to issues which require near term resolutions
- Internal and any required external approval processes

[5] Mist was initially bult in the late 1980's, Newport LNG was built in the mid-1970's, and Portland LNG was bult in the late 1960's.

The following sections provide details on the key projects for each plant.

E.5.1 Mist Asset Management Program

Mist Gas Storage Facility

Planning Document
2022 – 10 year plan
Date updated: Sept 20, 2022

Contents

Scope

This plan is for the Mist Gas Storage facility. Capital construction projects included in this plan are based upon projects identified in the EN Engineering Facility Assessment Study (June 2016) of the Mist Gas Storage Facility.

End-of-life may include and have several determinants, such as functional degradation, failure risks, or regulatory requirements. End-of-life indicators include:

- Severe corrosion within a component or system due to atmospheric, galvanic corrosion, or minor issues with insulation over time;
- Mechanical wear effects of any of the rotating equipment onsite;
- Fatigue caused by cycling in materials, particularly in systems with significant temperature changes; and
- The technology used in many of these systems that has become unsupported and at risk for failure without the ability to support a repair.

All required projects going forward will be constructed to contemporaneous seismic standards. This usually requires replacement of an original foundation with foundation systems designed to accommodate updated standards and ground liquefaction issues.

Project execution dates may be required to vary in the future from those identified due to:

- New information obtained on the facility/component condition, resulting in a change to the urgency of the project;
- An opportunity to improve execution efficiency;
- The need to prevent and/or reduce interruptions to facility distribution system operations;
- Permitting;
- Loss of resources redirected to issues which require near term resolutions; and/or
- The IRP process.

Estimated or actual costs specified in this document do not include construction overhead (COH).

Selection Criteria

Each project is included in the plan for one or more of the following reasons:

- Replacement of equipment is at end-of-life;
- Refurbishment or preventative maintenance to extend the asset's useful life;
- Compliance with environmental or safety regulations or concerns; and/or
- Identified within the Reliability Program

Section One – 1 to 3 years (2022 to 2024)

Mist 2022

Compressor Replacement Study

- Scope, schedule, budget
- Create action plan to replace turbines and conduct 20% engineering per study results
- Begin permitting investigation
- Cost in 2022: $500,000 (+100%/-50%)
- 100% Utility asset

GC500 RT21 Power Turbine Compressor Overhaul 2022

- Overhaul GC500 RT21 power turbine. End of life 4th stage blades
- Replace end of life diaphragm
- Cost in 2022: $810,000 (+100%/-50%)
- 100% Utility asset

GC500 RBB-6 Centrifugal Compressor Overhaul 2022

- Replace end of life dry gas seals
- Replace end of life bearings
- Cost in 2022: $800,000 (+100%/-50%)
- 100% Utility asset
-

GC600 RF-20 Centrifugal Compressor Overhaul 2022

- Replace end of life dry gas seals
- Replace end of life bearings
- Cost in 2022: $800,000 (+100%/-50%)
- 100% Utility asset

Fire Suppression and Detection Upgrades, Year 1

- Replace end of life gas and fire detection equipment
- Replace end of life fire suppression water piping
- Engineer and upgrade fire pond pump system
- Cost in 2022: $750,000 (+100%/-50%)
- 100% Utility asset

GC300 and GC400 Cooler Replacement

- Replace end of life Gas Cooler

- Upsize Gas Cooler capacity to improve compressor efficiency
- Cost in 2022: $900,000 (+100%/-50%)
- 100% Utility asset

GC300 and GC400 Heavy Piston Upgrade

- Replace obsolete light pistons to heavy pistons to allow operation at 100% torque
- Replace power heads
- Replace power liners
- Replace end of life bearings on the GC400
- Cost in 2022: $450,000 (+100%/-50%)
- 100% Utility asset

Electrical System Upgrades Phase 1, Year 1

- New 1000 kVA Transformer, replace primary switchgear, construct new PDC, refeed circuits from Transformer to MCC-1A.
- End of Life or inadequate for new systems.
- Cost in 2022: $1,500,000 total (+100%/-50%)
- 100% Utility asset

Electrical System Upgrades Phase 2, Year 1

- Upgrade Mechanical MCC, upgrade south MCC, refeed circuit to Bruer, add disconnects to 100/200 and 300/400 buildings, refeed Miller Station.
- Begin permitting investigation
- End of Life or inadequate for new systems.
- Project planning to start in Q4 2022
- Cost in 2022: $125,000 (out of $2,500,000 total from 2022-2024) (+100%/-50%)
- 100% Utility asset

Wastewater Containment, Year 1

- Replace existing single-walled oil and water waste tanks at plant with fully contained dual-wall systems. Increase water storage capacity for produced water.
- Required to meet SPCC requirements
- Project planning to start in Q4 2022, and project completion in Q3 2023.
- Cost in 2022: $100,000 (out of $600,000 from 2022 to 2023) (+100%/-50%)
- 100% Utility asset

Pipeline Upgrades, Year 1

- EN Engineering modeled the Mist wellhead to Miller Station pipelines, identified bottlenecks, and provided solution to improve system flow, reducing horsepower requirements.
- Replace 10" & 8" single line section at Al's View Lot with 12" line
- Add Automated Valves and controls for Twin 16's
- Retire Bruer South Loop from CC#6 (~13,000 ft)
- Replace Bruer & Flora 12" pipe to 20" turbine headers w/ 16" @ Miller
- Improve flow paths from Flora Pools (separate from Meyer)
- Add a separate pipeline from Myer to Miller Station
- Add interconnect between NMF & SMF to back generator fuel gas line

- Based on recommendations contained in the EN Engineering Facility Assessment study.
- Begin permitting investigation
- Project planning to start in Q2 2022, and project completion in Q2 2024
- Cost in 2022: $250,000 (out of $5,000,000 from 2022 to 2024) (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Meyer)

Well Rework

- Fifty-one (51) underground storage wells within the Mist storage fields have been identified to be reworked over an 8-year time period, in accordance with the Pipeline and Hazardous Materials Safety Administration (PHMSA) adopted new safety regulations.
- In order to complete the mandated preventative and mitigative measures for the 51 wells at the Mist facility within the 8-year guideline, NWN must complete an average of 6 to 7 wells per year, or as the risk assessment mandates.
- Cost in 2022: $5,500,000 (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer).

Fiber Line Upgrades

- Upgrade fiber lines for S. Wells (Busch, Reichhold, Al's, & Schlicker) & Meyer.
- Based on recommendations contained in the EN Engineering Facility Assessment study – existing lines are not sufficient for amount of data transferred.
- Project planning to start in Q3 2022, and project completion is Q4 2023.
- Planned and executed Q2 2022
- Cost in 2022: $500,000 (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer).

Mist 2023

Electrical System Upgrades Phase 2, Year 2

- Upgrade Mechanical MCC, upgrade south MCC, refeed circuit to Bruer, add disconnects to 100/200 and 300/400 buildings, refeed Miller Station.
- Begin EFSC amendment
- Complete detail design
- Execution completed by Q3 2024
- Cost in 2023: $250,000 (out of $2,500,000 total from 2022-2024) (+100%/-50%)
- 100% Utility asset

Wastewater Containment, Year 2

- Replace existing single-walled oil and water waste tanks at plant with fully contained dual-wall systems. Increase water storage capacity for produced water.
- Required to meet SPCC requirements
- Project planning to start in Q4 2022, and project completion in Q4 2023.
- Cost in 2023: $500,000 (out of $600,000 from 2022 to 2023) (+100%/-50%)
- 100% Utility asset

Pipeline Upgrades, Year 2

- EN Engineering modeled the Mist wellhead to Miller Station pipelines, identified bottlenecks, and provided solution to improve system flow, reducing horsepower requirements.
- Replace 10" & 8" single line section at Al's View Lot with 12" line (high vels)
- Add Automated Valves and controls for Twin 16's
- Retire Bruer South Loop from CC#6 (~13,000 ft)
- Replace Bruer & Flora 12" pipe to 20" turbine headers w/ 16" @ Miller
- Improve flow paths from Flora Pools (separate from Meyer)
- Add a separate pipeline from Myer to Miller Station
- Add interconnect between NMF & SMF to back generator fuel gas line
- Based on recommendations contained in the EN Engineering Facility Assessment study.
- Complete EFSC amendment
- Project planning to start in Q2 2022, and project completion in Q2 2024
- Cost in 2023: $250,000 (out of $5,000,000 from 2022 to 2024) (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Meyer)

Well Rework

- Fifty-one (51) underground storage wells within the Mist storage fields have been identified to be reworked over an 8-year time period, in accordance with the Pipeline and Hazardous Materials Safety Administration (PHMSA) adopted new safety regulations.
- In order to complete the mandated preventative and mitigative measures for the 51 wells at the Mist facility within the 8-year guideline, NWN must complete an average of 6 to 7 wells per year, or as the risk assessment mandates.
- Cost in 2023: $5,500,000. (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Upgrade Gas Separation at Wellheads, Year 1

- Construction activities will be scheduled to follow the Well Rework Program
- Replace and refurbish topside mechanical equipment at the fifty-one (51) underground storage wells over an 8-year period
- NWN must complete an average of 6 to 7 wells per year
- Cost in 2023: $1,500,000. (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Miller Station Gathering Line Separator Refurbishment

- Restore five (5) existing separators dump system
- Replace corroded pipe
- Clean per separator OEM recommendation
- Cost in 2023: $750,000 total (+100%/-50%)
- 100% Utility asset

Upgrade Miller Station Building

- Construct tenant improvements for Miller station
- Address remodel of old control room, kitchen, and other workspaces
- Evaluate site drainage around building

- Evaluate electrical and IT wiring
- Cost in 2022: $1,500,000 (out of a total of $1,750,000) (+100%/-50%)
- Complete construction in 2022.
- This is a facilities project
-

Instrument and Controls Upgrade Phase 3, Year 1

- Replace moisture analyzers (3 total, @ Miller N. & S. Feeders + Meyer).
- Upgrade flow transmitters (qty = 12, annubar to multivariable transmitters).
- Upgrade pressure transmitters (qty = 10).
- Replace 3 chromatographs.
- Additional Minor Instrumentation Upgrades (switches, connectors, etc...).
- Current systems will be at end of life.
- Project planning to start in Q1 2023, and project completion is Q4 2023.
- Cost in 2023: $100,000 (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Mist 2024

Compressor Replacement - Phase 1 (2024 IRP), Year 1

- Complete replacement of GC-500 turbine compressor by end of 2028.
- Add Phase I to the 2024 IRP
- Develop action plan and conduct 30% engineering per study results from project 201983 (Compressor Evaluation Study)
- Cost in 2024: $250,000 (out of a total cost of $28,000,000 from 2024 – 2028). (+100%/-50%)
- 100% Utility asset (pending study recommendation)

Electrical System Upgrades Phase 2, Year 2

- Upgrade Mechanical MCC, upgrade south MCC, refeed circuit to Bruer, Add disconnects to 100/200 and 300/400 buildings, refeed Miller Station.
- Complete EFSC amendment
- Begin Construction
- Execution completed by Q3 2024
- Cost in 2024: $2,000,000 (out of $2,500,000 total from 2022-2024) (+100%/-50%)
- 100% Utility asset

Pipeline Upgrades, Year 3

- EN Engineering modeled the Mist wellhead to Miller Station pipelines, identified bottlenecks, and provided solution to improve system flow, reducing horsepower requirements.
- Replace 10" & 8" single line section at Al's View Lot with 12" line (high vels)
- Add Automated Valves and controls for Twin 16's
- Retire Bruer South Loop from CC#6 (~13,000 ft)
- Replace Bruer & Flora 12" pipe to 20" turbine headers w/ 16" @ Miller
- Improve flow paths from Flora Pools (separate from Meyer)
- Add a separate pipeline from Myer to Miller Station

- Add interconnect between NMF & SMF to back generator fuel gas line
- Based on recommendations contained in the EN Engineering Facility Assessment study.
- Complete construction
- Project planning to start in Q2 2022, and project completion in Q2 2024
- Cost in 2024: $3,500,000 (out of $5,000,000 from 2022 to 2024) (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Meyer)

AI's Dehydration System Removal

- Decommission and remove the AI's dehydration system.
- Dehy study by EN Eng concluded this system is no longer needed.
- Project planning to start in Q1 2024, Completion will be Q4 2024.
- Cost in 2024: $800,000 (+100%/-50%)
- 100% Utility asset

Instrument and Controls Upgrade, Phase 3, Year 2

- Replace moisture analyzers (3 total, @ Miller N. & S. Feeders + Meyer).
- Upgrade flow transmitters (qty = 12, annubar to multivariable transmitters).
- Upgrade pressure transmitters (qty = 10).
- Replace 3 chromatographs.
- Additional Minor Instrumentation Upgrades (switches, connectors, etc...).
- Current systems will be at end of life.
- Project planning to start in Q1 2023, and project completion is Q4 2023.
- Cost in 2024: $1,000,000 (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Well Rework

- Fifty-one (51) underground storage wells within the Mist storage fields have been identified to be reworked over an 8-year time period, in accordance with the Pipeline and Hazardous Materials Safety Administration (PHMSA) adopted new safety regulations.
- In order to complete the mandated preventative and mitigative measures for the 51 wells at the Mist facility within the 8-year guideline, NWN must complete an average of 6 to 7 wells per year, or as the risk assessment mandates.
- Cost in 2023: $5,500,000. (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Upgrade Gas Separation at Wellheads

- Construction activities will be scheduled to follow the Well Rework Program
- Replace and refurbish topside mechanical equipment at the fifty-one (51) underground storage wells over an 8-year period
- NWN must complete an average of 6 to 7 wells per year
- Cost in 2023: $1,500,000. (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Upgrade Gas Conditioning at Wellheads, Year 2

- Replace Methanol tanks and injection system at 8 wellhead locations
- End of Life or inadequate for new systems.

- Cost in 2024: $3,000,000 (+100%/-50%)

Section Two – 4 to 7 years (2025 to 2028)

Mist 2025

Compressor Replacement - Phase 1 (2024 IRP), Year 2

- Complete Replacement 500 turbine compressor by end of 2028
- Begin EFSC process & engineering and for Phase I.
- Begin EFSC amendment process in 2025 & finish in 2026 (300-day process).
- Cost in 2025: $750,000 (out of a total cost of $28,000,000 for Phase I). (+100%/-50%)
- 100% Utility asset (pending study recommendation)

Small Dehydration System Replacement (2024 IRP), Year 1

- Replace small dehydration system.
- In 2016, the study to determine the path forward was included in the 2016 IRP.
- Project planning to start in Q2 2025 with RFP developed and sent to EPC contractors. Execution to commence in Q2, 2026 and completion in Q4 2026.
- Cost in 2025: $2,000,000 (out of a total cost of $10,500,000) (+100%/-50%)
- Mix of Utility and Gas Storage assets.

Well Rework

- Fifty-one (51) underground storage wells within the Mist storage fields have been identified to be reworked over an 8-year time period, in accordance with the Pipeline and Hazardous Materials Safety Administration (PHMSA) adopted new safety regulations.
- In order to complete the mandated preventative and mitigative measures for the 51 wells at the Mist facility within the 8-year guideline, NWN must complete an average of 6 to 7 wells per year, or as the risk assessment mandates.
- Cost in 2023: $5,500,000. (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Upgrade Gas Separation at Wellheads, Year 3

- Construction activities will be scheduled to follow the Well Rework Program
- Replace and refurbish topside mechanical equipment at the fifty-one (51) underground storage wells over an 8-year period
- NWN must complete an average of 6 to 7 wells per year
- Cost in 2023: $1,500,000. (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Mist 2026

Compressor Replacement - Phase 1 (2024 IRP), Year 3

- Continue EFSC permitting, engineering, design and permitting per study results from project to replace the GC-500
- Cost in 2026: $2,500,000 (out of a total cost of $28,000,000 from 2024 - 2028). (+100%/-50%)
- 100% Utility asset (pending 2019/20 study recommendation)

Compressor Replacement - Phase 2 (2026 IRP), Year 1

- Complete replacement of 600 turbine by 2030.
- Add Phase II to the 2026 IRP
- Develop action plan and conduct 30% engineering per study results from project 201983 (Compressor Evaluation Study)
- Cost in 2026: $250,000 (out of a total cost of $28,000,000 from 2026 – 2030). (+100%/-50%)
- 100% Utility asset (pending study recommendation)

Small Dehydration System Replacement (2024 IRP), Year 2

- Replace small dehydration system.
- In 2016, the study to determine the path forward was included in the 2016 IRP.
- Project planning to start in Q2 2025 with RFP developed and sent to EPC contractors. Execution to commence in Q2, 2026 and completion in Q4 2026. Cost in 2026: $8,500,000 (out of a total

Well Rework

- Fifty-one (51) underground storage wells within the Mist storage fields have been identified to be reworked over an 8-year time period, in accordance with the Pipeline and Hazardous Materials Safety Administration (PHMSA) adopted new safety regulations.
- In order to complete the mandated preventative and mitigative measures for the 51 wells at the Mist facility within the 8-year guideline, NWN must complete an average of 6 to 7 wells per year, or as the risk assessment mandates.
- Cost in 2023: $5,500,000. (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Upgrade Gas Separation at Wellheads, Year 4

- Construction activities will be scheduled to follow the Well Rework Program
- Replace and refurbish topside mechanical equipment at the fifty-one (51) underground storage wells over an 8-year period
- NWN must complete an average of 6 to 7 wells per year
- Cost in 2023: $1,500,000. (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Mist 2027

Compressor Replacement - Phase 1 (2024 IRP), Year 4

- Complete engineering, design and permitting per study results from project to replace the GC-500
- Long-lead procurement.

- Cost in 2027: $4,500,000 (out of a total cost of $28,000,000 from 2024 - 2028). (+100%/-50%)
- 100% Utility asset (pending 2019/20 study recommendation)

Compressor Replacement - Phase 2 (2026 IRP), Year 2
- Complete Replacement 600 turbine compressor by end of 2030
- Begin EFSC process & engineering and for Phase II.
- Begin EFSC amendment process in 2027 & finish in 2028 (300-day process).
- Cost in 2027: $750,000 (out of a total cost of $28,000,000 for Phase I). (+100%/-50%)
- 100% Utility asset (pending study recommendation)

Well Rework
- Fifty-one (51) underground storage wells within the Mist storage fields have been identified to be reworked over an 8-year time period, in accordance with the Pipeline and Hazardous Materials Safety Administration (PHMSA) adopted new safety regulations.
- In order to complete the mandated preventative and mitigative measures for the 51 wells at the Mist facility within the 8-year guideline, NWN must complete an average of 6 to 7 wells per year, or as the risk assessment mandates.
- Cost in 2023: $5,500,000. (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Upgrade Gas Separation at Wellheads, Year 5
- Construction activities will be scheduled to follow the Well Rework Program
- Replace and refurbish topside mechanical equipment at the fifty-one (51) underground storage wells over an 8-year period
- NWN must complete an average of 6 to 7 wells per year
- Cost in 2023: $1,500,000. (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Mist 2028

Compressor Replacement - Phase 1 (2024 IRP), Year 5
- Complete installation for the project to replace the GC-500
- Cost in 2028: $20,000,000 (out of a total cost of $28,000,000 from 2024 - 2028). (+100%/-50%)
- 100% Utility asset

Compressor Replacement - Phase 2 (2026 IRP), Year 3
- Continue EFSC permitting, engineering, design and permitting per study results from project to replace the GC-600
- Cost in 2028: $2,500,000 (out of a total cost of $28,000,000 from 2026 - 2030). (+100%/-50%)
- 100% Utility asset (pending 2019/20 study recommendation)

Lube Oil Piping Upgrades

- Replace existing single-walled lube oil piping at plant with fully contained dual-wall systems.
- Required to meet future SPCC requirements
- Project planning and execution in 2026.
- Cost in 2028: $500,000 (+100%/-50%)
- 100% Utility asset

Well Rework

- Fifty-one (51) underground storage wells within the Mist storage fields have been identified to be reworked over an 8-year time period, in accordance with the Pipeline and Hazardous Materials Safety Administration (PHMSA) adopted new safety regulations.
- In order to complete the mandated preventative and mitigative measures for the 51 wells at the Mist facility within the 8-year guideline, NWN must complete an average of 6 to 7 wells per year, or as the risk assessment mandates.
- Cost in 2023: $5,500,000. (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Upgrade Gas Separation at Wellheads, Year 6

- Construction activities will be scheduled to follow the Well Rework Program
- Replace and refurbish topside mechanical equipment at the fifty-one (51) underground storage wells over an 8-year period
- NWN must complete an average of 6 to 7 wells per year
- Cost in 2023: $1,500,000. (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Section Three – 7 to 10 years (2029 to 2032)

Mist 2029

Compressor Replacement - Phase 2 (2026 IRP), Year 4

- Complete engineering, design and permitting per study results from project to replace the GC-600
- Long-lead procurement.
- Cost in 2029: $4,500,000 (out of a total cost of $28,000,000 from 2026 - 2030). (+100%/-50%)
- 100% Utility asset (pending 2019/20 study recommendation)

Well Rework

- Fifty-one (51) underground storage wells within the Mist storage fields have been identified to be reworked over an 8-year time period, in accordance with the Pipeline and Hazardous Materials Safety Administration (PHMSA) adopted new safety regulations.
- In order to complete the mandated preventative and mitigative measures for the 51 wells at the Mist facility within the 8-year guideline, NWN must complete an average of 6 to 7 wells per year, or as the risk assessment mandates.

- Cost in 2023: $5,500,000. (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Upgrade Gas Separation at Wellheads, Year 7

- Construction activities will be scheduled to follow the Well Rework Program
- Replace and refurbish topside mechanical equipment at the fifty-one (51) underground storage wells over an 8-year period
- NWN must complete an average of 6 to 7 wells per year
- Cost in 2023: $1,500,000. (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Mist 2030

Compressor Replacement - Phase 2 (2026 IRP), Year 5

- Complete installation of new GC-600.
- Cost in 2030: $20,000,000 (out of a total cost of $28,000,000 from 2026 - 2030) (+100%/-50%)
- Mix of Utility and Gas Storage assets

Well Rework

- Fifty-one (51) underground storage wells within the Mist storage fields have been identified to be reworked over an 8-year time period, in accordance with the Pipeline and Hazardous Materials Safety Administration (PHMSA) adopted new safety regulations.
- In order to complete the mandated preventative and mitigative measures for the 51 wells at the Mist facility within the 8-year guideline, NWN must complete an average of 6 to 7 wells per year, or as the risk assessment mandates.
- Cost in 2023: $5,500,000. (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Upgrade Gas Separation at Wellheads, Year 8

- Construction activities will be scheduled to follow the Well Rework Program
- Replace and refurbish topside mechanical equipment at the fifty-one (51) underground storage wells over an 8-year period
- NWN must complete an average of 6 to 7 wells per year
- Cost in 2023: $1,500,000. (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Mist 2031

Well Rework

- Fifty-one (51) underground storage wells within the Mist storage fields have been identified to be reworked over an 8-year time period, in accordance with the Pipeline and Hazardous Materials Safety Administration (PHMSA) adopted new safety regulations.

- In order to complete the mandated preventative and mitigative measures for the 51 wells at the Mist facility within the 8-year guideline, NWN must complete an average of 6 to 7 wells per year, or as the risk assessment mandates.
- Cost in 2023: $5,500,000. (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Mist 2032

Well Rework

- Fifty-one (51) underground storage wells within the Mist storage fields have been identified to be reworked over an 8-year time period, in accordance with the Pipeline and Hazardous Materials Safety Administration (PHMSA) adopted new safety regulations.
- In order to complete the mandated preventative and mitigative measures for the 51 wells at the Mist facility within the 8-year guideline, NWN must complete an average of 6 to 7 wells per year, or as the risk assessment mandates.
- Cost in 2023: $5,500,000. (+100%/-50%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer)

Section Four – Projects Completed in 2021

Mist 2021

300-400 Compressor Controls Upgrade

- Modernize the control systems of the 300 and 400 compressors at Miller Station in order to obtain more useful life out of aging equipment and increase the utilization of these compressors to reduce the load on the turbine compressors in order to lower the maintenance requirements on the turbine compressors and reduce Miller station fuel consumption.
- Cost in 2021: $2,280,000 out of $3,000,000 (+100%/-50%)
- 100% Utility asset

Electrical System Upgrades (Planning)

- Review System Grounding, Power Quality, & Arc Flash Studies, New MCC for Electrical Room, new transmission feed to miller station, MCC Breaker Upgrades, MCC upgrade for mech bldg, & New 750 kVA Transformer.
- End of Life or inadequate for new systems.
- Project planning to start in Q3 2020, and project completion is 2021.
- Cost in 2021: $50,000 out of $125,000 (+100%/-50%)
- This will be dependent upon the results of the compressor study.
- 100% Utility asset

Well Rework

- Fifty-one (51) underground storage wells within the Mist storage fields have been identified to be reworked over an 8-year time period, in accordance with the Pipeline and Hazardous Materials Safety Administration (PHMSA) adopted new safety regulations.

- In order to complete the mandated preventative and mitigative measures for the 51 wells at the Mist facility within the 8-year guideline, NWN must complete an average of 6 to 7 wells per year, or as the risk assessment mandates.
- Cost in 2021: $3,000,000 (+50%/-25%)
- Mix of Utility and Gas Storage assets (due to Busch, Reichhold, & Meyer).

Upgrade Mist Air Compressor System PH II

- Replace existing air compressors which are both end of life and below the capacity of the plant. Sizing is dependent on new compressor size and power availability.
- Requires upgrade facility power to enable larger unit. Moving from two 25 Hp to 60 Hp motors.
- Planning 2021, execution 2021.
- Cost in 2021: $700,000. (+50%/-25%)

Small Dehy Thermal Oxidizer Refurbishment

- Replace existing end of life glycol pumps
- Replace inadequately sized reboiler/TO actuators
- Insulate Flue to temperature control improvement
- Small TO controls update
- Planning 2021, execution 2021.
- Cost in 2021: $500,000. (+100%/-50%)

Mist Corrosion Abatement – Phase 4

- This project will utilize In-Line Inspection (ILI) tools to evaluate the existing conditions and validate the integrity of the following pipelines:
  - 8” Flora ILI Loop – from Miller Station to Flora and back to Miller Station;
  - 8” Bruer ILI – from Miller Station to Bruer Pool (IW22d-10); and
  - 12” Bruer P64.04 ILI – from Miller Station to Storage Well 13b-11-65.
- Project planning to started in 2020, and project completion anticipated in Q3 2021.
- Total forecasted costs: $2,638,520 in 2021. (+100%/-50%)
- 100% Utility asset.

Upgrade Miller Station Building (Planning)

- Prepare design of tenant improvements for Miller station
- Address remodel of old control room, kitchen, and other workspaces
- Evaluate site drainage around building
- Evaluate electrical and IT wiring
- Cost in 2021: $250,000 (out of a total cost of $1,750,000) (+100%/-50%)
- Complete construction in 2022.

E.5.2 Newport LNG Asset Management Program

Newport LNG

Planning Document
2022 – 10 year plan
Date updated: 9/20/2022

Contents

Scope

This 10 year plan is for large capital projects at the Newport LNG Facility.

Each project relates to work within the plant boundaries. Typically, these projects are intended to support liquefaction, vaporization or storage of LNG. The vast majority of these projects are mechanical, usually replacing piping or rotating equipment at end of life.

All projects required going forward are being constructed to current seismic standards. This usually requires replacement of original foundation with foundation systems designed to contend with soil liquefaction of the area.

Note: Project execution dates may vary from the proposed plan due to:

- new information obtained on the facility/component condition resulting in a change to the urgency of the project;
- an opportunity to improve execution efficiency;
- the need to prevent and/or reduce interruptions to facility distribution system operations;
- permitting; or
- The IRP Process

Selection Criteria

Each project is selected because one or more of the following reasons:

- End of life
- Technology Refresh
- Maintenance
- Environmental and safety compliance
- Substantially extend life of equipment

Section One 1-3 years – (2022 through 2024)

General Budget Note:
Total project budget for all years is identified in each respective summary below. For specific year by year spend see the table at the end of this document.

2022

Pretreatment Regeneration Optimization (2020 through 2022)
Project will fundamentally change the pretreatment system design altering the way mol sieve vessels are regenerated. This changes the system from a closed loop to an open loop regeneration system. Over time the resulting system should reduce the amount of water and CO2 remaining in the process stream. As a result, this would improve overall reliability of the plant which currently must shut down due to related issues.

- Additional heat exchangers for new process streams which will be separated
- Modification of piping system, additional, valves and instrumentation
- Control system to be reconfigured

- Add new blower to facilitate partially recycling the regeneration gas.
- $4.85M (all years)

Cold Box Replacement - 2021 IRP Update (2022 through 2025)
(Design)

- Owners engineer to develop RFP
- EPC biding effort for overall scope
- Select Engineer and construction contractor
- Start detailed engineering
- $17.6M includes contingency

T-1 Tank Improvements (2022 through 2023)
This project will replace or modify tank appurtenances to meet current operation requirements.

- Hire design firm with LNG tank expertise to review tank and provide detail designs for improvement where required.
- Review tie-off points for access to top of tank. If necessary, weld reinforcing pads to dome with tie off railing.
- Review valves on tank to determine replacement needs. Replace if needed and add natural gas vacuum make up in lieu of current fresh air make up.
- Verify if pearlite insulation requires replacement at upper portion of tank. Execute replacement if required.
- $1.5 M +100% - 50%

T-1 Tank Foundation Heating System Replacement (2021 through 2022)
Extend life of equipment

- Tank foundation heating elements may be nearing end of life based on discrepancy in the temperature indicators.
- Install new heating elements
- Install new temperature control system regulating voltage in heat trace
- $1.5M +50% -20%

High Voltage Switchgear (2021 through 2023)
Safety

- This project was determined to be required as the result of an arc flash study which identified the hazard presented by the incoming switchgear.
- Incoming switchgear is no longer sized correctly for current plant load.
- Project will replace the equipment in kind
- $1M +50% -20%

Mixed Refrigerant Manifold Replacement (2022 through 2023)

- Perform detail design of manifold replacement
- Order long lead valves.
- $500 +100% - 50%

2023

Mixed Refrigerant Manifold Replacement (2022 through 2023)

- Replace isolation and control valves at mixing manifold within process building
- Remove existing manifold
- Re-use compressor and separation vessels
- Install new piping and equipment/piping supports
- $500 +100% - 50%

Cold Box Replacement - 2021 IRP Update (2022 through 2025)
(Cont. Engineering and Early Purchase)

- Continued Engineering
- Procure thermal oxidizer
- Procure and install mol sieve media
- Procure cold box
- $17.6M includes contingency (total cost estimate, see table for annual spend)

LNG Tank Painting O&M
Project Summary:

- Construct scaffolding for access around the entire tank to the top of the shell.
- Construct containment system encircling the tank to capture blast media.
- Abrasive blast entire tank. Stripping all existing coatings and creating surface profile for new coating system.
- Apply three part coating system, zinc base, epoxy mid-coat and polyurethane topcoat.
- Removal of all blast media, containment, and disposal.
- Estimated at $1.25M to $2M

2024

Cold Box Replacement - 2021 IRP Update (2022 through 2025)
(Preliminary construction)

- Install thermal oxidizer
- Review finalized construction budget with EPC contractor
- Begin civil work
- Order remainder of equipment and materials
- $17.6M includes contingency (total cost estimate, see table for annual spend)

Seismic Mitigation Study

- This project would develop an approach for improving the seismic capacity of the soil surrounding the LNG tank.
- Review breadth of overall scope.
- The project outcome would provide an approach and budget for larger construction effort.
- $500k   +100% - 50%

Section Two 4 to 6 years – (2025 through 2027)

2025

Cold Box Replacement - 2021 IRP Update (2022 through 2025)
(Construction and commissioning)

- Complete onsite construction
- Demolition of existing Cold Box and Cryax
- Commissioning of system
- Training
- $17.6M includes contingency (total cost estimate, see table for annual spend)

C1 and C2 Compressor Overhauls
Extend life of equipment

- Disassemble, inspect, and overhaul compressors C1 and C2.
- $1M +100% - 50%

2026

No projects planned

2027

Control System Technology Refresh

- PLC (Programmable Logic Controller) systems are not designed to last indefinitely. This project will study and replace equipment which has become unsupported or otherwise at end of life.
- $400k +100% - 50%

Section Three 7 to 10 years – (2028 through 2031)

2028

C-3 Compressor Hot Section Overhaul

- Compressor C-3 to be disassembled and overhauled to ensure reliable service for another 10 years. 30,000 hour major overhaul.
- $1.5M +100% - 50%

2029-2030

No projects planned

2031

Molecular Sieve Replacement Project
Extend life of equipment

- Molecular sieve media has an anticipated life of 10 years. This project will replace the media in the five vessels in the pre-treatment system.
- $1M +100% - 50%

Fire and Gas System Study and refresh
Technology Upgrade

- Review the plant's overall fire prevention and safety mechanisms.

- Perform Fire Engineer study.
- Make changes based on study findings. May include changes to placement and quantity of gas detectors or fire eyes.
- Replace computer control systems for fire and gas monitoring to ensure life of equipment extends another 10 years.
- $500k +100% - 50%

2032

No projects planned

Section Four – Projects Completed in 2021

Turbine Replacement

End of life

- The solar turbine, which powers the C-3 compressor, was overhauled.
- The core components, gas producer and power turbine were replaced with a refurbished section provided by solar.
- The turbines life expectancy has been significantly extended as a result of this work, anticipating 7-10 years or 30,000 hours of runtime.
- $500k

E.5.3 Portland LNG Asset Management Program

Portland LNG

Planning Document
2022 – 10-year plan
Date updated: September 20, 2022

Contents

Scope

This 10 year plan is for capital projects at the Portland LNG Facility.

Each project relates to work within the plant boundaries. Typically, these projects are intended to support liquefaction, vaporization or storage of LNG. The vast majority of these projects are mechanical, usually replacing piping or rotating equipment at end of life.

Note: Project execution dates may vary from the proposed plan due to:

- new information obtained on the facility/component condition resulting in a change to the urgency of the project;
- an opportunity to improve execution efficiency;
- the need to prevent and/or reduce interruptions to facility distribution system operations;
- permitting; and
- The IRP Process.

Selection Criteria

Each project is selected because one or more of the following reasons:

- End of life
- Preventative maintenance
- Environmental and safety compliance
- Substantially extend Life of equipment

Assumptions

This 10 year plan was developed with the assumption that the liquefaction system will be replaced. This eliminates some projects which would otherwise reach end of life in in the 5-to-10-year time frame.

All Estimates **exclude** COH

Section One – 1 to 3 years (2022 to 2024)

2022

Valve Replacement (year 1/2)

- Many of PLNG's valves are original to the plant and are either leaking, have a failed or failing actuator, or are no longer supported by any vendor for repair services.
- SHA worked with the operations team to identify valves and actuators to be replaced. SHA documented the valves in their facility assessment report.
- Additional air leaks on valves and valve actuators were identified by Harder Mechanical as part of a plant compressed air audit and added to the list.
- Total project cost is estimated to be $1.5M -50%/+100% based on the SHA estimates over two years.
- Per the Facility Assessment Report, the valves and associated equipment to be replaced in this project span the Tier 3, Tier 2, and Tier 1 designations.

Purchase and Install New Boil off C4 Compressors (Year 1 of 2)

End of Life

- A new boil off gas compressor will be purchased as the lead working compressor for the site.
- SHA identified a new oil filled screw compressor as the best option for NW Natural.
- SHA created a purchase spec in 2021 and NW Natural used it to go to bid in 2022.
- The project is scheduled to be complete in 2023.
- $2.5M -50%/+100% over two years.
- Per the facility assessment report this is a Tier 3 project.

Cold Box replacement study

End of Life

- Sanborn and Head completed the cold box FEED study in 2021.
- If the IRP project is acknowledged, design and construction would start in 2023 and complete in 2025.
- SHA estimates for the cold box replacement are between $5.2M and $11.2M -50%/+100%.
- This assessment was sperate and in parallel with the Facility Assessment Report and did not receive a Tier designation. However, if the cold box does not move forward the Facility Assessment Report recommends several Tier 3 items that need to be executed at the plant.

15 Year Plan/Facility Assessment Report

- Sanborn and Head performed a Facility Assessment of the PLNG plant, investigating what equipment would be required to keep the plant running safely and operationally efficient over the next 10-15 years.

- The results of the Facility Assessment Report are compiled in this 10-year plan for the projects that are ~ $1M or more. Smaller dollar items are not in this report.
- The 15-year plan was completed in January of 2022.
- Sanborn and Head provided a Tiered ranking system to assess various plant project. The Tiers are outlined below,

    - Tier 3 – Potential safety issues, Items which are considered to have a high potential to disrupt plant operation or impact plant reliability/operability/capacity within the next 5 years, HAZOP recommendations to resolve high risk scenarios.
    - Tier 2 - Items which are considered to have the potential to disrupt plant operation or impact plant reliability/operability within the next 10 years, Items which are considered to have the potential to cause the plant to operate at reduced capacity for more than one week within the next 10 years, HAZOP recommendations to resolve medium risk scenarios.
    - Tier 3 - Items which are not considered to have the potential to disrupt plant operation or impact plant reliability/operability within the 15-year lifetime of the plant, Items which are considered to have the potential to cause the plant to operate at reduced capacity for up to one week, HAZOP recommendations to resolve low risk scenarios.

2023

Valve Replacement (Year 2/2)

- Many of PLNG's valves are original to the plant and are either leaking, have a failed or failing actuator, or are no longer supported by any vendor for repair services.
- SHA worked with the operations team to identify valves and actuators to be replaced. SHA documented the valves in their facility assessment report.
- Additional air leaks on valves and valve actuators were identified by Harder Mechanical as part of a plant compressed air audit and added to the list.
- Total project cost is estimated to be $1.5M -50%/+100% based on the SHA estimates over two years.
- Per the Facility Assessment Report the valves and associated equipment to be replaced in this project span the Tier 3, Tier 2, and Tier 1 designations.

Pre-treatment improvements

- This line item was previously dedicated to replacing the mole sieve media.
- SHA pretreatment improvements recommend the following scope
    - Pretreatment I&C controls upgrade

        - E4 relief valve sizing evaluation
        - Removal of sulfur Blimp.
        - Replace mole sieve drier Media
        - Replace mole sieve CO2 media
        - Review the integrity of the mole sieve vessels
    - Total cost is $800k -50%/+100%.
    - This is a Tier 3 Project per the Facility Assessment Report.

Purchase and Install New Boil off C4 Compressor (Year 2 of 2)
End of Life
- A new boil off gas compressor will be purchased as the lead working compressor for the site.
- SHA identified a new oil filled screw compressor as the best option for NW Natural.
- SHA created a purchase spec in 2021 and NW Natural used it to go to bid in 2022.
- The project is scheduled to be complete in 2023.
- $2.5M -50%/+100% over two years.
- Per the facility assessment report this is a Tier 3 project.

Cold Box Replacement (Year 1/3)
- If the IRP project is acknowledged
- Purchase equipment
- Perform Design
- Obtain permits
- Identify a contractor
- SHA estimates for the cold box replacement are between $5.2M and $11.2M -50%/+100%.
- This assessment was sperate and in parallel with the Facility Assessment Report and did not receive a Tier designation. However, if the cold box does not move forward the Facility Assessment Report recommends several Tier 3 items that need to be executed at the plant.

2024
Cold Box Replacement (Year 2/3)
- Continue construction.

- SHA estimates for the cold box replacement are between $5.2M and $11.2M.

H-5 Vaporizer Top Works and Bottom Works Upgrades
- Replace bottom works per SHA 15-year plan. $1.5M -50%/+100%.
- Replace top works per SHA 15-year plan. $1M -50%/+100%.
- This was categorized as a Tier 3 Item per the Facility Assessment Report.

Section Two – 4 to 6 years (2025 to 2027)

2025

Cold Box Replacement (Year 3/3)
- Complete construction and commission the equipment.
- SHA estimates for the cold box replacement are between $5.2M and $11.2M.

PLNG pump out skid modernization and replacement
- o Refurbish P1 Pump
- o Inspect and repair foundation and heating elements
- o Install Pressure transmitters
- o Replace cool down valves and main LNG product valves
- o Project cost $450k -50%/+100%.
- o This is considered a Tier 3 item per the Facility Assessment Report.

H-7 Vaporizer Top Works Upgrade
- Replace top works per SHA 15-year plan. $1M -50%/+100%.
- This is considered a Tier 3 item per the Facility Assessment Report.

2nd New Boil Off Gas (BOG) compressor, C5 (year 1 / 2)
- Spec and design one new BOG compressor to replace both C2 and C3 compressors.
- Total Project $2.5M over two years. -50%/+100%.

2026

2nd New BOG compressor C5 (year 2 / 2)

- Purchase and construction of new BOG.
- Total Project $2.5M over two years. -50%/+100%.
- This is considered a Tier 2 item per the Facility Assessment Report.

2027

New C-1 Turbo Expander Oil Skid

- Replace the existing oil skid with new Atlas Copco designed oil skid
- $1.65M -50%/+100%.
- This is considered a Tier 2 item per the Facility Assessment Report

Section Three – 7 to 10 years (2028 to 2031)

2028

Fire and Gas System Update

- Perform engineering review of fire and gas detection systems.
- Implement changes to system to update to current technology and eliminate out of date equipment.
- Would bring older equipment up to date with new liquefaction plant.
- $500k -50%/+100%.
- A replacement of this system was not identified in the Facility Assessment Report but relocating the gas sensors was mentioned. This project was identified before the Facility Assessment Report and Identified by our plant operations team as equipment that needs to be replaced.

2029

MCC/HMI Replacement

- Replace MCC per the SHA 15-year report
- Upgrade the plant HMI system per SHA 15-year report
- Total project cost $700k -50%/+100%.
- This is considered a Tier 1 item per the Facility Assessment Report

Section Four – Projects Completed in 2021

New Plant Air compressors and Air receiver tanks were installed in 2021.

C2 Boil Off Compressors rebuild
End of Life

- Portland LNG has two boil off compressors which are original to the plant and at the end of the reliable life (C2 and C3).
- This project rebuilds each compressor by NEAC, the original equipment manufacturer. The exception is the actual compressor body casting and the pedestal that it sits on. The casting needs to be shipped to Texas to analyze its integrity for both units.
- $520k +/-30%

PLC Replacement
Technology Upgrade

- Portland LNG operates with a programmable logic controller (PLC) 5, which is out of date, no longer supported and not maintainable. The PLC is fully utilized which leaves little to no room for additional devices which can be added to the Portland LNG facility.
- Replacement with Modern PLC.
- Rerun fiber to existing field panels. Upgrade field panels with new fiber module.
- Retrofit the Existing MCC room to a new IT server room. Migrate PLC's, IT, network, and security IT equipment to the new server room
- 2.29 million +/- 30%

Cold Box replacement study
End of Life

- Sanborn and Head will be conducting a replacement study on the PLNG cold box.
- The study will look at the cost, procurement, and schedule to replace the cold box. The intent is to have a study package by July of 2021 that can be reviewed with the IRP team. If the IRP team approves the project, design and construction would start in 2022 and complete in 2025.
- Study only $300,000 +/- 20%.

Sanborn Head Study - Facility Assessment Report

Please find this study at the end of the document.

Sanborn Head Study- Portland LNG Cold Box

Please find this study at the end of the document.

Appendix F: Simulation Inputs to PLEXOS®

F.1 Gas Price Simulation

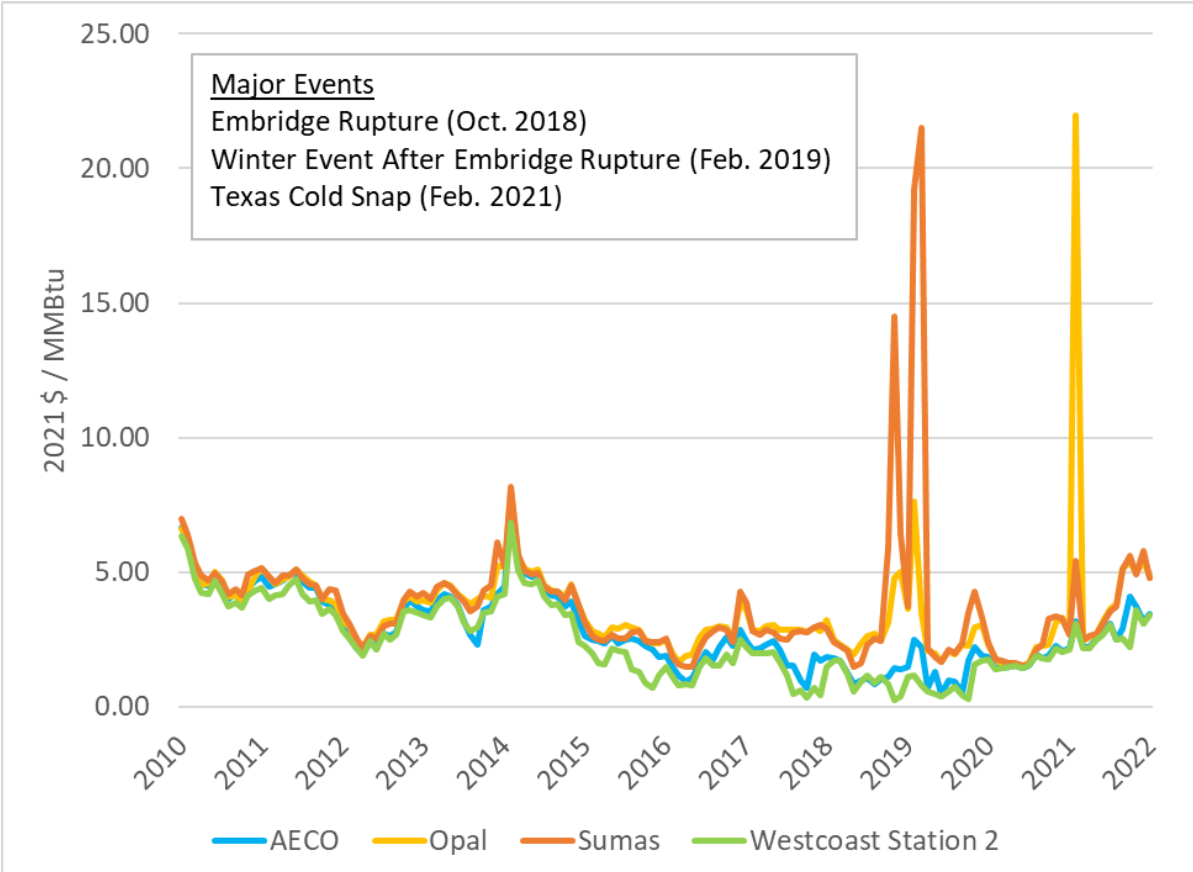
The Monte Carlo gas price simulation produces 500 gas price paths (i.e., stochastic draws) for gas prices hubs across the U.S. and Canada based on historical price shocks. This IRP focuses on the four gas hubs where NW Natural purchases gas for customers (AECO, Sumas, Opal and Westcoast Station 2). These simulations are used in NW Natural's risk assessment.

For gas prices at different locations there are two important correlations which must be considered when simulating stochastic draws:

1) Correlation across time – For example, gas prices today are likely to be correlated with previous gas prices both year-over-year and from month-to-month. These monthly fluctuations in gas prices reflect the continuous shifts in natural gas supply, natural gas storage, and natural gas demand.
2) Correlation across basins or hubs – Interstate pipeline capacity limits the amount of gas able to be transported or "shipped" from one region. In addition to localized supply and demand, these shipping charges create different but highly correlated prices across different basins.

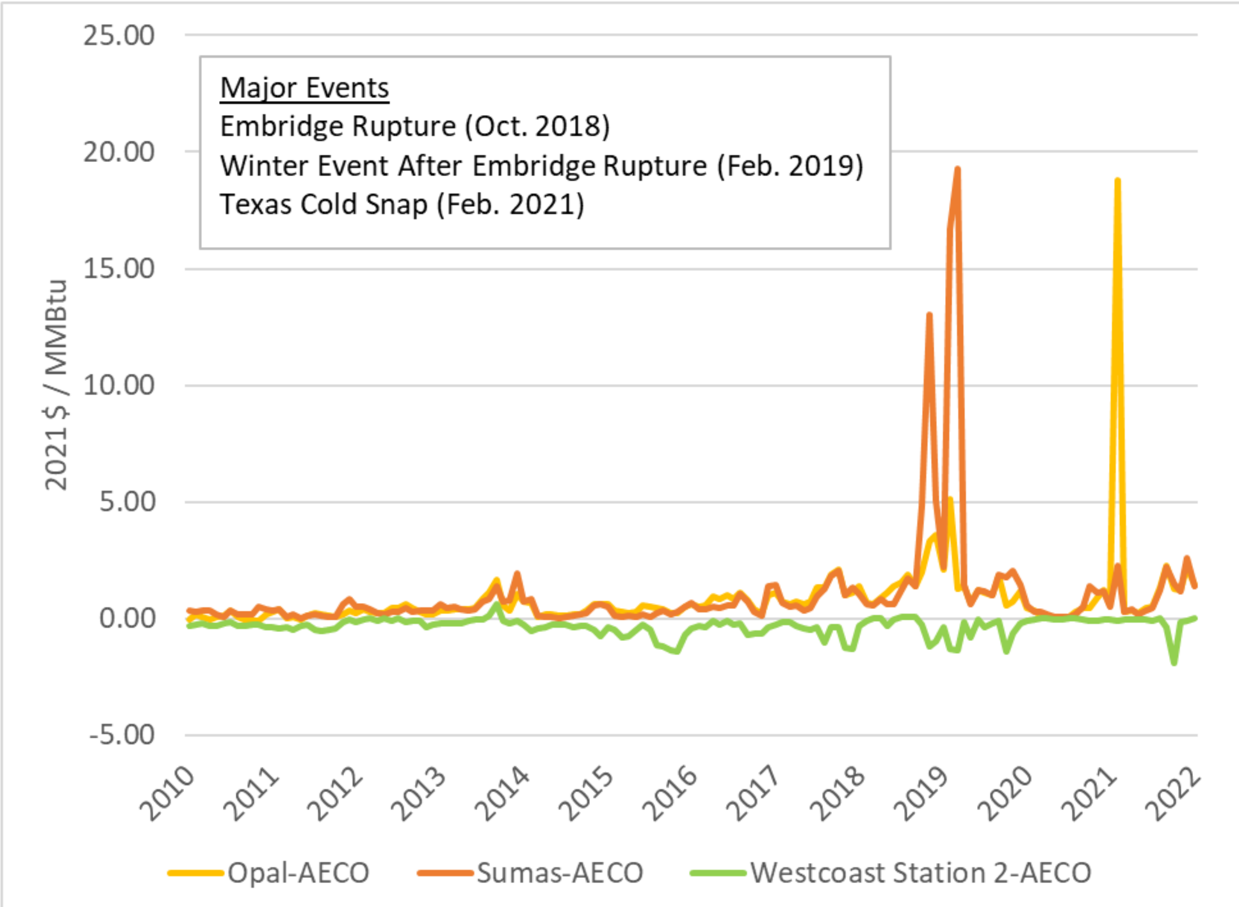
The Monte Carlo process used for this IRP uses historical gas prices to account for these two correlations within the simulation. Figure F.1 shows historical monthly gas prices for the four hubs and illustrates the correlations across time and the four supply basins.

Figure F.1: Historical Gas Prices



The difference between one location and a major gas hub is often referred to as the price basis. Figure F.2 shows the historical monthly basis between the other three gas hubs and AECO (i.e., hub price minus AECO gas prices).

Figure F.2: Historical AECO Basis



The Monte Carlo simulation is coded using RStudio software and uses historical and forecasted monthly gas prices from the *IHS: North American Natural Gas Long-term Outlook – February 2022*.[6] In general, the simulation process first simulates annual gas prices for 500 draws for each basin based on historical annual prices shocks (i.e., changes from one year to the next). After an annual price simulation is complete for each hub, a secondary stochastic process is completed to apply monthly shapes to each hub as well. The simulation is tied to the IHS forecast such that the median annual price of the 500 simulation is equal to the annual IHS price forecast in each year of the forecast for each basin. The more detailed technical steps of the simulation are outlined below in two phases.

[6] The methodology to create simulated gas prices has been improved since the 2018 IRP. In the 2018 IRP the simulation included a reversion factor to tie back to the IHS forecast. The large price spikes at Sumas and Opal in the following years caused issues with this approach as the simulated prices were highly dependent on the strength of the reversion month-over-month. By simulating at the annual level first and at the monthly level second, this new methodology better captures the relationship between annual and monthly prices.

Phase 1: Simulate annual gas prices for each gas hub over the planning horizon

Step 1: Calculate an average historical and forecasted annual price from monthly prices for each hub.

Step 2: Calculate basis to AECO for each hub (i.e., hub price minus AECO gas prices).

Step 3: Use "auto.arima" package to define an ARIMA model for annual AECO prices and calculate residuals from the model based on historical training set.

Step 4: For each year in the planning horizon the AECO price ($AECO_t$) is equal to the previous annual price ($AECO_{t-1}$) plus a randomly selected residual from the ARIMA model (ε_y).

NOTE: A coding loop runs steps 5-7 to generate a value for each year, before looping over these steps again for the following year.

Step 5: For each of the other hubs and each year in the planning horizon apply the annual basis from the same year as the stochastic residual selected.

$$AECO_t = AECO_{t-1} + \varepsilon_y$$

$$Opal_t = AECO_t + \left(Opal_y - AECO_y\right)$$

$$Sumas_t = AECO_t + \left(Sumas_y - AECO_y\right)$$

$$WestCoastSt2_t = AECO_t + \left(WestCoastSt_y - AECO_y\right)$$

$$where:$$

$$t = forecast\ year$$

$$y = stocastic\ historical\ year\ selected$$

Step 6: Adjust gas price levels by adding a factor equal to the IHS forecast price minus median price of the draws. This creates the tie between the simulation and IHS forecast.

Step 7: Adjust any prices that exceed the lower bound parameter.

$$if: Hub_t < lb$$

$$then: Hub_t = Hub_{t-1} - \xi * (Hub_{t-1} - lb)$$

$$where:$$

$$lb = lower\ bound; [set\ to\ \$0.75]$$

$$\{\xi \in \mathbb{R} \mid 0 < \xi < 1\}; [set\ to\ 0.5]$$

Phase 2: Simulate monthly gas prices for each gas hub over the planning horizon

Step 1: Calculate historical monthly shape by dividing the monthly prices by the annual price

Step 2: For each forecast year and draw, randomly select a historical year and apply that monthly shape to the stochastically forecasted annual price.

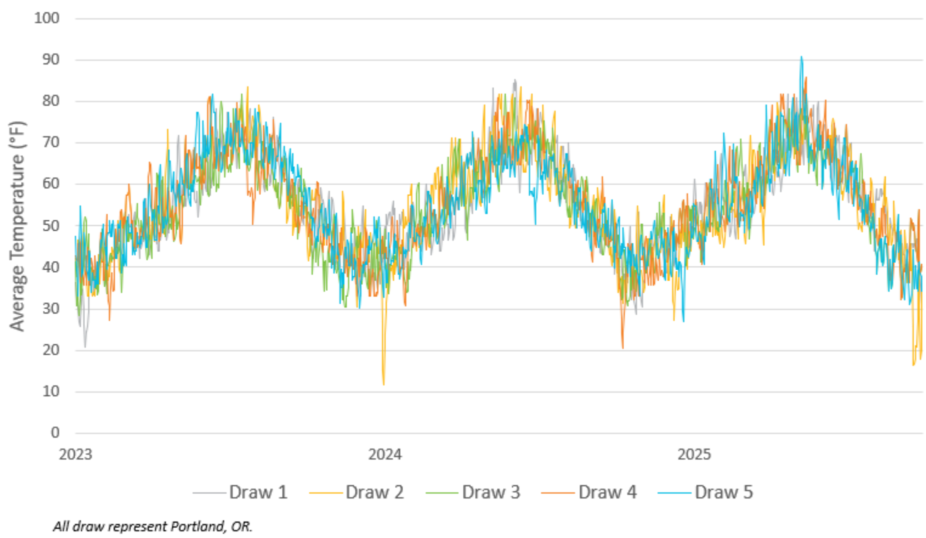
Additional technical notes:

- Historical and forecasted years in the simulation are defined as gas years (November-October).
- The monthly Sumas price is constrained to be greater than or equal to the minimum of AECO and WestCoastStation2.
- Even through daily prices can dip close to zero (even negative on occasion), the lower bound for monthly is set to $0.75. For reference, the minimum monthly price in the historical data is $0.79 at AECO in August 2018.
- All prices are simulated as real 2021 $/MMBtu.
- The training set for the “auto.arima” uses data back to 2005.
- The stochastic shocks are pulled from post data back to 2010 (i.e., post shale gale when horizontal drilling became widespread drastically lowering prices and reduced year over year volatility.

F.2 Daily Temperature Weather Simulation

The process outlined here creates a simulation for daily temperatures inclusive of climate change trends, which is used in combination with heating and non-heating usage coefficients for sub-classes of customers. A separate simulation of yearly peak day conditions, inclusive additional demand drivers, is done for developing the peak day forecast and is separate from the simulation discussed here, which is an input to produce stochastic demand, which in turn is an input to PLEXOS® (see Chapter 3, for details).

Figure F.3: Weather Simulation Draw Example



The daily temperature simulation produces a daily temperature for each location and draw that preserves the two important correlations:

1. Correlation across locations – when it is cold in Eugene it is likely cold in Portland, but the relationship between any two locations is not deterministic and can vary[7]
2. Correlation with climate change trends in overall temperatures – Even though year-over-year cumulative HDDs is random the over trend of HDD is decreasing over the planning horizon

Phase 1: Correlation across locations

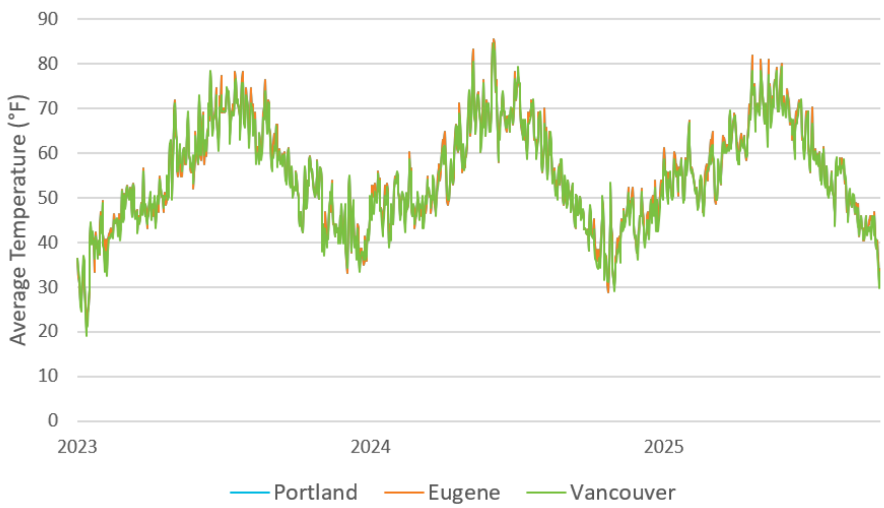
Step 1: Randomly pair a historical year to each forecast month and each draw

Step 2: For each location assign the historical weather for each location based on the randomly selected historical year and matching historical and forecast month

This ensures that data a single historical month is applied across all locations.

[7] In January of 2013 temperatures in Eugene plummeted to historic lows, while temperatures across the rest of the service territory were much milder in comparison.

Figure F.4: Weather Simulation Example by Location



All locations are represented as draw 1.

Phase 2: Correlation with climate change trends

For each location do:

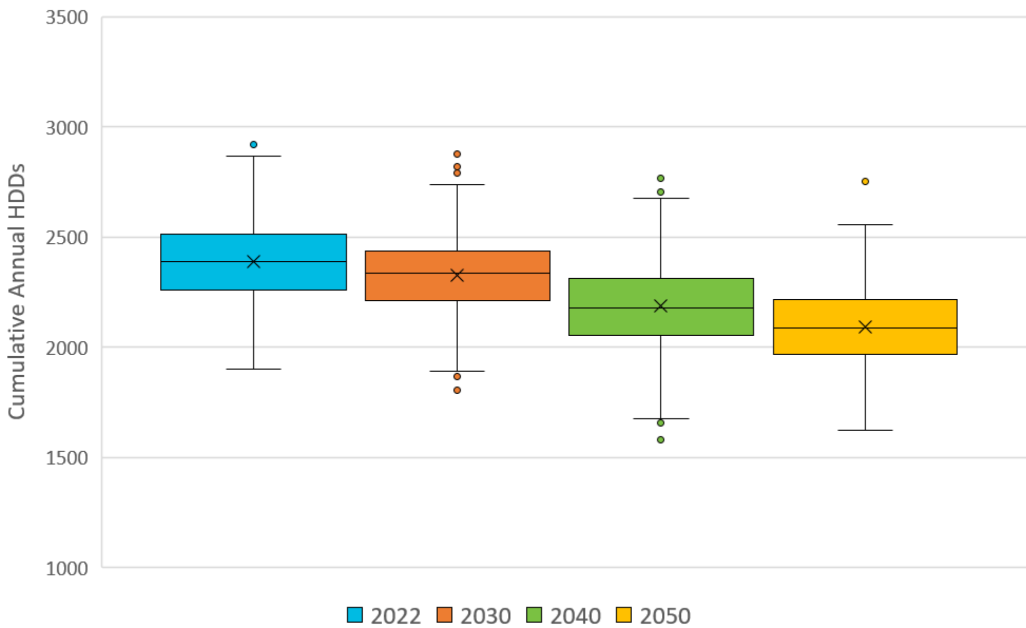
Step 1: For each draw calculate the cumulative HDD for a gas year

Step 2: Calculate the difference between the average cumulative HDD across all draws for a single gas year and the reference case HDD target for that location

Step 3: Adjust all temperatures by this difference divided by 365

Step 4: loop Steps 1 – 3 until the average cumulative gas year HDDs across all draws equal the base case climate change adjusted cumulative HDDs

Figure F.5: Climate Change Trends Across Planning Horizon



All locations are Portland, OR.

F.3 Fixed Resource Cost Simulation

There is uncertainty with the fixed costs associated with capacity resources that the PLEXOS® model can select from. This uncertainty may be caused by unforeseen complications in construction or spikes in sector specific labor or material costs. Cost uncertainty with large capital projects often skews right, therefore the simulation uses a log-normal distribution where the natural log of the high-estimate represents the 95th percentile of the log-normal distribution. The reference case resource cost is the 50th percentile of the log-normal distribution. The sector specific labor and material costs are likely to be correlated across the different capacity resource options. To account for this correlation a 60% correlation factor is applied to shocks in the resource costs.

Figure F.6 shows the range of capacity costs from the simulation for the capacity resources over the planning horizon.

Figure F.7 shows the range of capacity costs for the Portland LNG Cold Box and the two-alternative evaluated through the PLEXOS® model. These figures display capacity costs ($/Dth/Day) for an apples-to-apples comparison based on daily deliverability.

Figure F.6: Capacity Resources Fixed Cost Simulation (500 Draws)

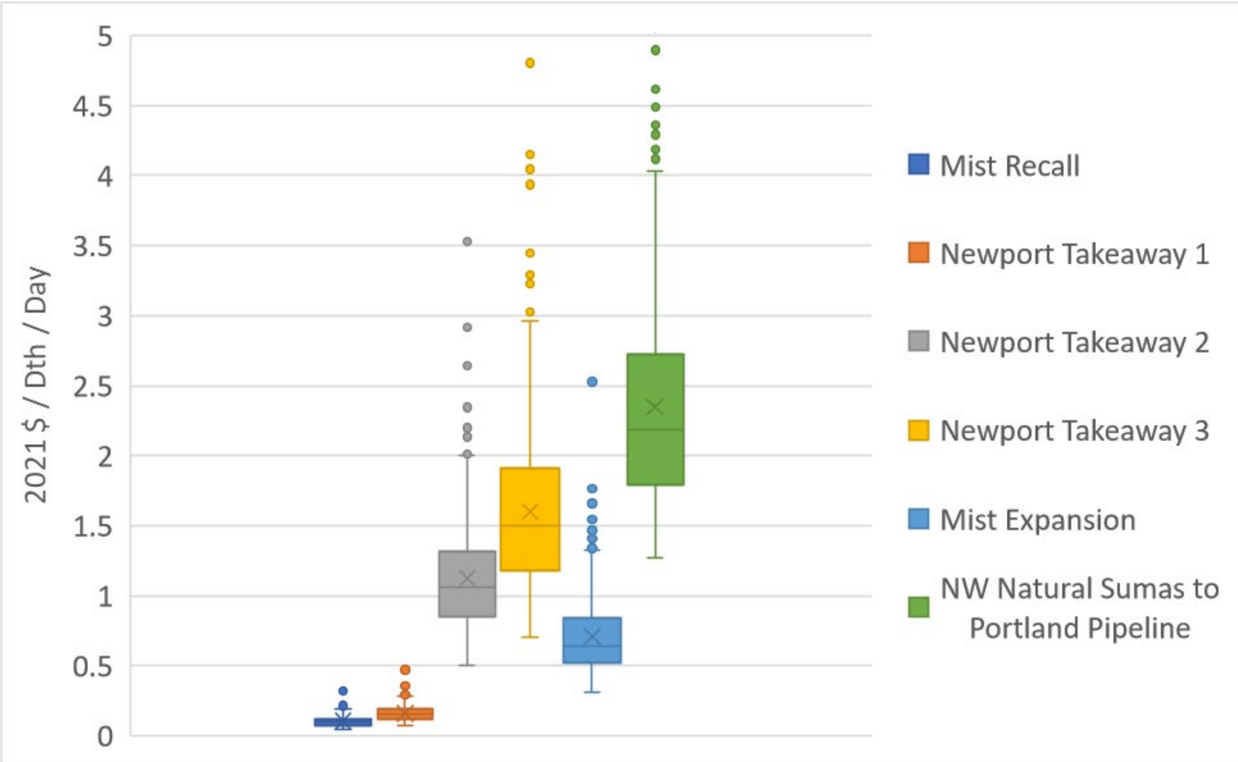
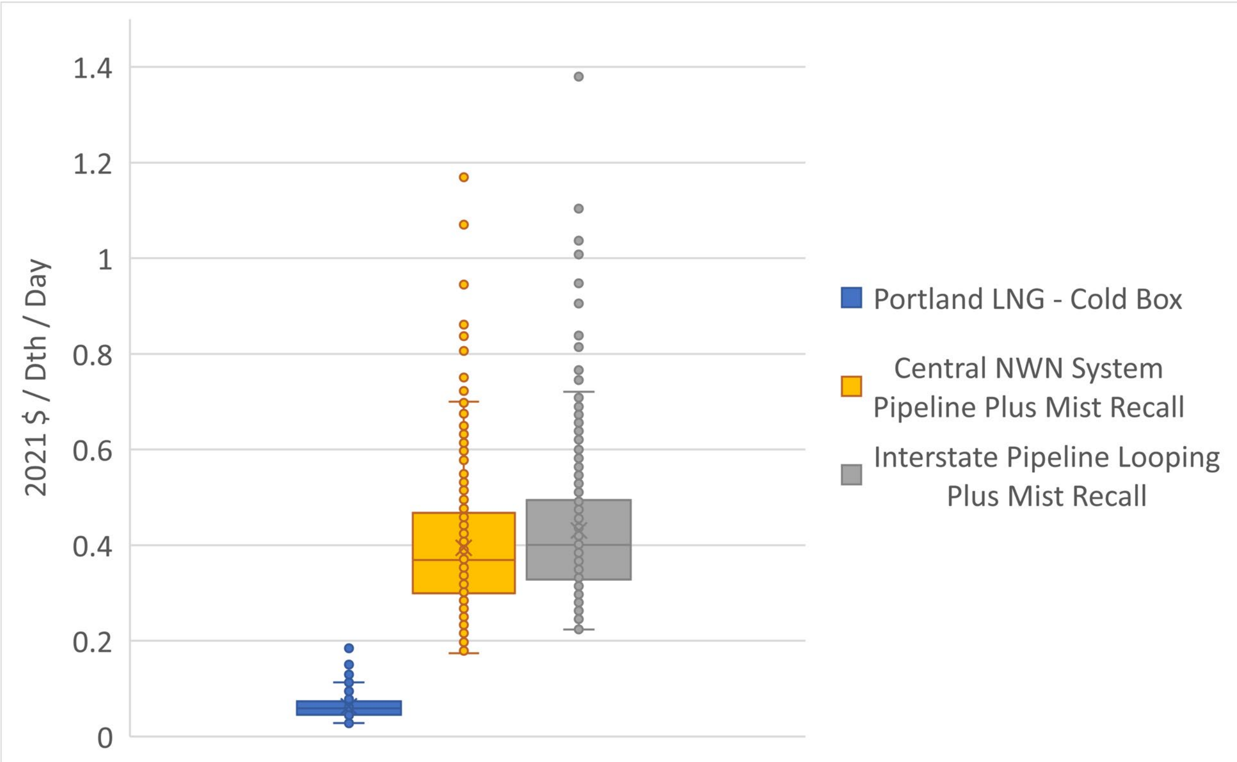


Figure F.7: Portland Cold Box and Cold Box Alternatives



Appendix G: Portfolio Selection

NW Natural®

Figure G.1: Peak Day Demand by Scenario

Gas Year	Reference	Scenario 1- Balanced Decarbonization	Scenario 2- Carbon Neutral	Scenario 3- Dual-Fuel Heating	Scenario 4- New Gas Customer Moratorium	Scenario 5- Aggressive Building Electrification	Scenario 6- Full Building Electrification	Scenario 7- RNG and H2 Policy Support	Scenario 8- Limited RNG	Scenario 9- Supply-Focused Decarbonization
	Dth/day	Dth/day	Dth/day	Dth/day	Dth/day	Dth/day	Dth/day	Dth/day	Dth/day	Dth/day
2022-23	1,008,708	1,008,709	1,008,708	1,008,709	1,008,709	1,008,708	1,008,708	1,008,709	1,008,709	1,008,709
2023-24	1,018,191	1,010,720	1,008,013	1,010,720	1,010,720	1,017,804	984,991	1,010,720	1,010,720	1,010,714
2024-25	1,027,864	1,011,574	1,006,556	1,012,252	997,832	997,645	946,244	1,011,574	1,011,516	1,012,239
2025-26	1,038,545	1,012,970	1,006,030	1,015,004	985,146	978,203	908,252	1,012,970	1,012,857	1,014,983
2026-27	1,051,101	1,015,329	1,006,869	1,019,437	974,156	960,909	872,203	1,015,406	1,015,237	1,019,407
2027-28	1,060,815	1,014,358	1,004,614	1,021,126	960,585	941,520	834,291	1,014,510	1,014,287	1,021,098
2028-29	1,072,524	1,014,039	1,003,294	1,024,060	948,233	923,767	797,818	1,014,263	1,013,988	1,024,034
2029-30	1,081,316	1,010,367	998,738	1,024,172	933,842	903,812	759,531	1,010,653	1,010,337	1,024,147
2030-31	1,091,507	1,008,086	995,008	1,025,592	921,272	885,219	722,445	1,008,433	1,008,076	1,025,569
2031-32	1,102,273	1,005,792	990,518	1,026,869	909,993	867,586	686,172	1,006,199	1,005,802	1,026,846
2032-33	1,112,746	1,002,488	984,453	1,026,990	899,077	849,890	649,798	1,002,953	1,002,516	1,026,969
2033-34	1,121,629	999,298	978,003	1,027,140	888,343	831,527	612,948	999,820	999,345	1,027,121
2034-35	1,130,124	996,014	970,749	1,027,118	877,960	812,964	575,985	996,592	996,079	1,027,100
2035-36	1,140,104	993,029	962,939	1,027,307	869,125	795,768	540,003	993,663	993,112	1,027,290
2036-37	1,149,011	988,199	952,918	1,025,480	859,615	777,792	503,429	988,886	988,299	1,025,464
2037-38	1,156,416	982,951	942,161	1,023,110	849,848	759,251	466,541	983,690	983,068	1,023,096
2038-39	1,166,190	980,021	933,473	1,023,077	842,105	742,399	430,653	980,813	980,156	1,023,064
2039-40	1,173,967	975,624	923,133	1,021,413	833,321	724,441	394,125	976,466	975,775	1,021,401
2040-41	1,181,592	971,286	913,072	1,019,739	824,426	706,140	357,375	972,176	971,453	1,019,728
2041-42	1,189,893	970,393	906,729	1,021,633	817,036	688,401	320,934	971,331	970,575	1,021,624
2042-43	1,199,026	969,442	900,301	1,023,430	810,195	671,121	284,660	970,428	969,641	1,023,422
2043-44	1,206,813	967,386	892,785	1,024,001	802,698	653,213	248,122	968,418	967,600	1,023,994
2044-45	1,214,623	964,282	884,447	1,023,445	794,900	635,105	211,456	965,358	964,510	1,023,439
2045-46	1,223,090	961,832	876,719	1,023,534	787,787	617,503	174,960	962,952	962,075	1,023,530
2046-47	1,229,438	957,698	867,516	1,021,775	779,530	598,871	138,202	958,859	957,954	1,021,772
2047-48	1,237,217	955,135	859,813	1,021,647	772,750	581,096	135,986	956,338	955,405	1,021,644
2048-49	1,245,282	951,368	851,080	1,020,236	765,689	563,274	133,710	952,612	951,651	1,020,235
2049-50	1,252,729	947,341	842,042	1,018,346	758,596	545,291	131,398	948,626	947,638	1,018,346

Figure G.2: Mist Recall by Scenario

Fiscal Year	Reference	Scenario 1- Balanced Decarbonization	Scenario 2- Carbon Neutral	Scenario 3- Dual-Fuel Heating	Scenario 4- New Gas Customer Moratorium	Scenario 5- Aggressive Building Electrification	Scenario 6- Full Building Electrification	Scenario 7- RNG and H2 Policy Support	Scenario 8- Limited RNG	Scenario 9- Supply-Focused Decarbonization
	Dth/day	Dth/day	Dth/day	Dth/day	Dth/day	Dth/day	Dth/day	Dth/day	Dth/day	Dth/day
2023	27,409	19,898	17,410	19,898	19,898	27,022	-	19,898	19,898	19,892
2024	37,142	20,757	17,410	21,439	19,898	27,022	-	20,757	20,757	21,426
2025	113,138	53,761	40,168	32,713	30,532	27,022	18,494	73,136	73,136	71,302
2026	113,138	53,761	40,168	32,713	30,532	27,022	18,494	73,136	73,136	71,302
2027	131,321	84,753	75,946	91,415	30,532	27,022	18,494	84,753	84,753	91,378
2028	143,096	84,753	75,946	94,375	30,532	27,022	18,494	84,753	84,753	94,331
2029	151,936	84,753	75,946	94,495	30,532	27,022	18,494	84,753	84,753	94,444
2030	162,184	84,753	75,946	95,931	30,532	27,022	18,494	84,753	84,753	95,875
2031	173,011	84,753	75,946	97,222	30,532	27,022	18,494	84,753	84,753	97,159
2032	183,544	84,753	75,946	97,351	30,532	27,022	18,494	84,753	84,753	97,282
2033	192,478	84,753	75,946	97,509	30,532	27,022	18,494	84,753	84,753	97,435
2034	201,017	84,753	75,946	97,509	30,532	27,022	18,494	84,753	84,753	97,435
2035	201,017	84,753	75,946	97,686	30,532	27,022	18,494	84,753	84,753	97,605
2036	203,803	84,753	75,946	97,686	30,532	27,022	18,494	84,753	84,753	97,605
2037	203,803	84,753	75,946	97,686	30,532	27,022	18,494	84,753	84,753	97,605
2038	203,803	84,753	75,946	97,686	30,532	27,022	18,494	84,753	84,753	97,605
2039	203,803	84,753	75,946	97,686	30,532	27,022	18,494	84,753	84,753	97,605
2040	203,803	84,753	75,946	97,686	30,532	27,022	18,494	84,753	84,753	97,605
2041	203,803	84,753	75,946	97,686	30,532	27,022	18,494	84,753	84,753	97,605
2042	203,803	84,753	75,946	97,686	30,532	27,022	18,494	84,753	84,753	97,605
2043	203,803	84,753	75,946	97,686	30,532	27,022	18,494	84,753	84,753	97,605
2044	203,803	84,753	75,946	97,686	30,532	27,022	18,494	84,753	84,753	97,605
2045	203,803	84,753	75,946	97,686	30,532	27,022	18,494	84,753	84,753	97,605
2046	203,803	84,753	75,946	97,686	30,532	27,022	18,494	84,753	84,753	97,605
2047	203,803	84,753	75,946	97,686	30,532	27,022	18,494	84,753	84,753	97,605
2048	203,803	84,753	75,946	97,686	30,532	27,022	18,494	84,753	84,753	97,605
2049	203,803	84,753	75,946	97,686	30,532	27,022	18,494	84,753	84,753	97,605
2050	203,803	84,753	75,946	97,686	30,532	27,022	18,494	84,753	84,753	97,605

Figure G.3: Oregon Compliance Option: CCIs by Scenario

Fiscal Year	Reference	Scenario 1- Balanced Decarbonization	Scenario 2- Carbon Neutral	Scenario 3- Dual-Fuel Heating	Scenario 4- New Gas Customer Moratorium	Scenario 5- Aggressive Building Electrification	Scenario 6- Full Building Electrification	Scenario 7- RNG and H2 Policy Support	Scenario 8- Limited RNG	Scenario 9- Supply-Focused Decarbonization
	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu
2022	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0
2024	1,003	372	0	0	372	0	0	0	372	372
2025	2,827	1,592	0	902	1,264	0	0	1,728	1,728	1,794
2026	6,481	4,386	9	3,360	3,403	206	0	4,823	4,823	4,941
2027	10,126	7,165	1,618	5,565	5,553	1,266	0	0	7,830	8,029
2028	12,383	9,326	3,225	7,330	7,360	2,123	0	3,892	11,339	10,382
2029	16,109	12,040	4,809	9,234	9,449	3,176	0	6,721	13,538	13,348
2030	20,524	15,399	6,427	11,851	12,222	4,876	0	10,102	16,299	16,950
2031	23,354	15,885	8,022	11,019	11,613	6,210	0	13,417	10,231	19,906
2032	7,611	19,868	10,183	14,347	15,083	8,115	0	17,369	14,175	12,574
2033	10,312	5,524	11,187	15,912	14,581	9,104	0	10,491	16,870	8,797
2034	14,665	8,354	12,764	10,660	10,341	10,636	0	12,310	20,199	12,364
2035	15,190	11,785	14,410	13,521	13,418	12,241	0	15,723	7,835	16,003
2036	3,946	13,662	6,628	9,621	10,043	10,924	0	5,768	5,768	5,435
2037	6,414	15,187	9,522	10,625	11,375	11,101	0	7,297	7,297	7,140
2038	9,400	5,423	7,604	7,942	7,423	8,199	0	9,377	9,377	9,382
2039	12,358	7,562	11,046	9,604	9,373	8,872	0	11,498	11,498	11,649
2040	15,841	10,155	9,169	11,534	11,782	8,386	0	11,242	14,100	14,377
2041	2,012	5,158	4,995	4,717	4,468	6,874	0	4,621	3,193	3,006
2042	4,952	7,493	8,642	6,555	6,556	7,545	0	6,942	5,513	5,422
2043	7,886	9,833	12,347	8,258	8,627	8,285	0	9,278	7,850	7,845
2044	7,916	5,151	4,712	6,034	6,062	4,332	0	8,161	9,590	7,203
2045	1,637	2,455	381	3,147	2,750	4,822	0	0	0	2,391
2046	4,572	4,843	4,151	5,068	4,938	5,629	0	0	2,375	4,823
2047	7,501	7,230	7,922	7,006	7,135	6,445	0	0	4,748	7,251
2048	0	0	0	0	0	0	0	0	4,950	0
2049	0	0	0	0	0	0	0	0	6,964	0
2050	0	0	0	0	0	0	0	0	0	0

Figure G.4: Oregon Compliance Option: RNG Tranche 1 by Scenario

Fiscal Year	Reference	Scenario 1- Balanced Decarbonization	Scenario 2- Carbon Neutral	Scenario 3- Dual-Fuel Heating	Scenario 4- New Gas Customer Moratorium	Scenario 5- Aggressive Building Electrification	Scenario 6- Full Building Electrification	Scenario 7- RNG and H2 Policy Support	Scenario 8- Limited RNG	Scenario 9- Supply-Focused Decarbonization
	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu
2022	1,800	1,797	1,796	1,797	1,797	1,802	1,802	5,388	1,797	1,797
2023	4,188	4,137	4,078	4,107	4,137	4,166	3,911	5,388	2,424	4,137
2024	4,200	4,149	4,089	4,119	4,149	4,178	3,921	5,403	4,149	4,149
2025	5,493	5,373	5,267	5,297	5,337	5,361	4,844	5,388	5,388	5,387
2026	6,257	6,034	5,908	5,907	5,912	5,889	5,181	6,088	6,088	6,084
2027	7,032	6,686	6,544	6,468	6,466	6,389	5,467	14,606	6,776	6,775
2028	9,845	8,570	7,795	7,944	8,009	7,733	5,741	14,943	7,032	8,772
2029	9,818	8,547	7,773	7,922	7,988	7,711	5,725	14,902	7,013	8,749
2030	9,818	8,547	7,773	7,922	7,988	7,711	5,725	14,902	7,013	8,749
2031	11,396	11,396	7,773	11,396	11,396	7,711	5,725	14,902	7,013	8,937
2032	11,427	11,427	7,795	11,427	11,427	7,733	5,741	14,943	7,032	8,961
2033	11,396	11,396	7,773	11,396	11,396	7,711	5,725	14,902	7,013	8,937
2034	11,396	11,396	7,773	11,396	11,396	7,711	5,725	14,902	7,013	8,937
2035	11,396	11,396	7,773	11,396	11,396	7,711	5,725	14,902	7,013	8,937
2036	11,427	11,427	7,795	11,427	11,427	7,733	5,741	14,943	7,032	8,961
2037	11,396	11,396	7,773	11,396	11,396	7,711	5,725	14,902	7,013	8,937
2038	11,396	11,396	7,773	11,396	11,396	7,711	5,725	14,902	7,013	8,937
2039	11,396	11,396	7,773	11,396	11,396	7,711	5,725	14,902	7,013	8,937
2040	11,427	11,427	7,795	11,427	11,427	7,733	5,741	14,943	7,032	8,961
2041	11,396	11,396	7,773	11,396	11,396	7,711	5,725	14,902	7,013	8,937
2042	11,396	11,396	7,773	11,396	11,396	7,711	5,725	14,902	7,013	8,937
2043	11,396	11,396	7,773	11,396	11,396	7,711	5,725	14,902	7,013	8,937
2044	11,427	11,427	7,795	11,427	11,427	7,733	5,741	14,943	7,032	8,961
2045	11,396	11,396	7,773	11,396	11,396	7,711	5,725	14,902	7,013	8,937
2046	11,396	11,396	7,773	11,396	11,396	7,711	5,725	14,902	7,013	8,937
2047	11,396	11,396	7,773	11,396	11,396	7,711	5,725	14,902	7,013	8,937
2048	11,427	11,427	7,795	11,427	11,427	7,733	5,741	14,943	7,032	8,961
2049	11,396	11,396	7,773	11,396	11,396	7,711	5,725	14,902	7,013	8,937
2050	11,396	11,396	7,773	11,396	11,396	7,711	5,725	14,902	7,013	8,937

Figure G.5: Oregon Compliance Option: RNG Tranche 2 by Scenario

Fiscal Year	Reference	Scenario 1-Balanced Decarbonization	Scenario 2-Carbon Neutral	Scenario 3-Dual-Fuel Heating	Scenario 4-New Gas Customer Moratorium	Scenario 5-Aggressive Building Electrification	Scenario 6-Full Building Electrification	Scenario 7-RNG and H2 Policy Support	Scenario 8-Limited RNG	Scenario 9-Supply-Focused Decarbonization
	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu
2022	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	463	0
2029	0	0	0	0	0	0	0	0	468	0
2030	0	0	0	0	0	0	0	0	468	0
2031	0	0	0	0	0	0	0	0	468	0
2032	0	0	0	0	0	0	0	0	470	0
2033	0	0	0	0	0	0	0	0	468	0
2034	0	0	0	0	0	0	0	0	468	0
2035	0	0	0	0	0	0	0	0	468	0
2036	0	0	0	0	0	0	0	0	470	0
2037	0	0	0	0	0	0	0	0	468	0
2038	0	0	0	0	0	0	0	0	468	0
2039	0	0	0	0	0	0	0	0	468	0
2040	0	0	0	0	0	0	0	0	470	0
2041	0	0	0	0	0	0	0	0	468	0
2042	0	0	0	0	0	0	0	0	468	0
2043	0	0	0	0	0	0	0	0	468	0
2044	0	0	0	0	0	0	0	0	470	0
2045	0	0	0	0	0	0	0	0	468	0
2046	0	0	0	0	0	0	0	0	468	0
2047	0	0	0	0	0	0	0	0	468	0
2048	0	0	0	0	0	0	0	0	470	0
2049	0	0	0	0	0	0	0	0	468	0
2050	0	0	0	0	0	0	0	0	468	0

Figure G.6: Oregon Compliance Option: Hydrogen by Scenario

Fiscal Year	Reference	Scenario 1- Balanced Decarbonization	Scenario 2- Carbon Neutral	Scenario 3- Dual-Fuel Heating	Scenario 4- New Gas Customer Moratorium	Scenario 5- Aggressive Building Electrification	Scenario 6- Full Building Electrification	Scenario 7- RNG and H2 Policy Support	Scenario 8- Limited RNG	Scenario 9- Supply-Focused Decarbonization
	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu
2022	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	151	0	604	0
2030	0	0	597	0	0	0	279	0	1,224	0
2031	0	0	1,181	0	0	385	354	0	10,606	448
2032	20,831	0	1,793	0	0	783	409	0	10,635	12,024
2033	21,873	17,040	2,289	511	2,829	1,074	408	9,564	10,606	18,714
2034	21,873	17,560	2,809	8,531	10,057	1,374	408	11,074	10,606	18,714
2035	21,873	17,560	3,322	8,531	10,057	1,649	408	11,074	10,606	18,714
2036	21,933	17,608	13,822	14,632	15,820	4,028	409	23,731	10,635	32,219
2037	21,873	17,560	13,784	14,592	15,777	4,017	408	23,666	10,606	32,131
2038	21,873	17,560	19,122	14,592	15,777	7,573	408	23,666	10,606	32,131
2039	21,873	17,560	19,122	14,592	15,777	7,573	408	23,666	10,606	32,131
2040	21,933	17,608	24,994	14,632	15,820	9,161	409	26,588	10,635	32,219
2041	21,873	17,560	32,160	14,592	15,777	9,136	408	26,515	10,606	32,131
2042	21,873	17,560	32,160	14,592	15,777	9,136	408	26,515	10,606	32,131
2043	21,873	17,560	32,160	14,592	15,777	9,136	408	26,515	10,606	32,131
2044	21,933	17,608	32,248	14,632	15,820	9,161	409	26,588	10,635	32,219
2045	21,873	17,560	32,160	14,592	15,777	9,136	408	26,515	10,606	32,131
2046	21,873	17,560	32,160	14,592	15,777	9,136	408	26,515	10,606	32,131
2047	21,873	17,560	32,160	14,592	15,777	9,136	408	26,515	10,606	32,131
2048	21,933	17,608	32,248	14,632	15,820	9,161	409	26,588	10,635	32,219
2049	21,873	17,560	32,160	14,592	15,777	9,136	408	26,515	10,606	32,131
2050	21,873	17,560	32,160	14,592	15,777	9,136	408	26,515	10,606	32,131

Figure G.7: Oregon Compliance Option: Synthetic Methane by Scenario

Fiscal Year	Reference	Scenario 1- Balanced Decarbonization	Scenario 2- Carbon Neutral	Scenario 3- Dual-Fuel Heating	Scenario 4- New Gas Customer Moratorium	Scenario 5- Aggressive Building Electrification	Scenario 6- Full Building Electrification	Scenario 7- RNG and H2 Policy Support	Scenario 8- Limited RNG	Scenario 9- Supply-Focused Decarbonization
	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu
2022	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0	0
2035	3,833	0	0	0	0	0	0	0	15,777	0
2036	18,709	804	0	0	0	0	0	0	20,537	0
2037	18,658	802	0	0	0	0	0	0	20,481	0
2038	18,658	12,665	0	4,300	5,862	0	0	0	20,481	0
2039	18,658	12,665	0	4,300	5,862	0	0	0	20,481	0
2040	18,709	12,700	0	4,311	5,878	0	0	0	20,537	0
2041	34,884	19,423	0	12,471	14,761	1,853	0	8,358	33,117	13,199
2042	34,884	19,423	0	12,471	14,761	1,915	0	8,358	33,117	13,199
2043	34,884	19,423	0	12,471	14,761	1,915	0	8,358	33,117	13,199
2044	38,393	26,915	11,764	16,750	19,862	6,956	0	12,255	34,220	16,714
2045	47,014	31,415	19,419	20,787	24,815	6,937	0	22,249	45,579	23,391
2046	47,014	31,415	19,419	20,787	24,815	6,937	0	24,624	45,579	23,391
2047	47,014	31,415	19,419	20,787	24,815	6,937	0	26,997	45,579	23,391
2048	58,048	41,518	31,551	30,103	34,605	14,484	0	29,830	48,274	33,541
2049	60,387	43,492	34,971	31,790	36,464	15,057	0	31,776	48,142	35,510
2050	63,315	46,014	38,798	34,109	38,864	15,910	0	34,139	57,470	37,915

Figure G.8: Washington Compliance Option: Purchase Allowances by Scenario

Fiscal Year	Reference	Scenario 1- Balanced Decarbonization	Scenario 2- Carbon Neutral	Scenario 3- Dual-Fuel Heating	Scenario 4- New Gas Customer Moratorium	Scenario 5- Aggressive Building Electrification	Scenario 6- Full Building Electrification	Scenario 7- RNG and H2 Policy Support	Scenario 8- Limited RNG	Scenario 9- Supply-Focused Decarbonization
	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu
2022	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0
2025	1,435	1,124	0	1,019	1,104	1,102	99	0	1,564	1,132
2026	2,736	2,401	0	2,273	2,268	2,159	1,339	2,166	2,456	2,459
2027	580	300	0	191	176	62	0	0	354	357
2028	3,577	3,020	0	2,758	2,741	2,537	839	1,706	3,194	3,138
2029	4,004	3,298	0	2,929	2,931	2,606	1,360	2,609	3,410	3,445
2030	4,360	3,532	0	3,087	3,096	2,705	1,325	2,920	3,645	3,702
2031	1,738	1,111	0	775	781	469	0	539	1,190	1,240
2032	4,521	3,455	0	2,876	2,892	2,362	162	2,988	3,562	3,671
2033	4,509	3,334	1,053	2,685	2,720	2,129	367	2,932	3,439	3,571
2034	4,552	3,275	1,430	2,567	2,607	1,945	56	2,941	3,376	3,531
2035	1,855	938	0	431	458	0	0	644	1,007	1,124
2036	4,684	3,217	1,093	2,402	2,444	1,582	0	3,026	3,312	3,511
2037	4,658	3,110	2,020	2,245	2,300	1,421	0	2,979	3,202	3,419
2038	4,686	3,050	2,295	2,128	2,202	1,255	0	2,984	3,141	3,374
2039	1,919	774	377	125	193	0	0	745	836	1,003
2040	4,785	2,981	2,898	1,935	2,057	460	0	382	3,069	3,330
2041	4,747	2,886	3,140	1,795	1,932	780	0	352	2,971	3,242
2042	3,875	1,989	925	936	1,065	624	0	379	2,929	1,062
2043	1,196	0	0	0	0	0	0	0	730	0
2044	4,237	2,063	874	148	361	0	0	0	2,964	0
2045	4,331	2,186	2,037	907	1,055	0	0	0	2,912	1,170
2046	4,476	2,239	2,411	866	1,045	0	0	0	2,899	1,233
2047	1,721	163	720	0	0	0	0	0	733	0
2048	4,814	2,390	3,209	35	397	0	0	0	2,911	439
2049	0	0	0	43	4	0	0	0	2,855	0
2050	0	0	0	0	0	0	0	0	0	0

Figure G.9: Washington Compliance Option: Offsets by Scenario

Fiscal Year	Reference	Scenario 1- Balanced Decarbonization	Scenario 2- Carbon Neutral	Scenario 3- Dual-Fuel Heating	Scenario 4- New Gas Customer Moratorium	Scenario 5- Aggressive Building Electrification	Scenario 6- Full Building Electrification	Scenario 7- RNG and H2 Policy Support	Scenario 8- Limited RNG	Scenario 9- Supply-Focused Decarbonization
	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu
2022	0	0	0	0	0	0	0	0	0	0
2023	937	887	0	885	892	898	800	508	1,101	885
2024	1,663	1,549	0	1,509	1,554	1,566	1,146	1,170	1,764	1,547
2025	800	899	0	916	873	847	1,182	1,663	475	909
2026	0	0	154	0	0	0	0	0	0	0
2027	2,614	2,437	322	2,347	2,346	2,274	1,369	1,857	2,465	2,473
2028	0	0	543	0	0	0	582	608	0	0
2029	0	0	649	0	0	0	0	0	0	0
2030	0	0	810	0	0	0	0	0	0	-
2031	2,676	2,355	968	2,177	2,185	2,040	1,000	2,386	2,386	2,419
2032	0	0	1,176	0	0	0	557	0	0	0
2033	0	0	223	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0	0
2035	2,736	2,282	1,587	2,026	2,042	1,766	0	2,311	2,311	2,371
2036	0	0	698	0	0	49	0	0	0	0
2037	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0
2039	2,791	2,214	2,195	1,872	1,913	1,092	0	2,242	2,242	2,322
2040	0	0	0	0	0	506	0	0	0	0
2041	0	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0	0
2043	2,846	2,057	1,293	927	1,062	517	0	445	2,195	1,143
2044	0	112	831	825	741	420	0	556	0	1,146
2045	0	0	0	0	0	281	0	571	0	0
2046	0	0	0	0	0	172	0	623	0	0
2047	2,898	2,126	2,067	823	1,033	63	0	672	2,151	1,292
2048	0	0	0	806	667	0	0	769	0	963
2049	0	0	0	0	0	0	0	0	0	0
2050	0	0	0	0	0	0	0	0	0	0

Figure G.10: Washington Compliance Option: RNG Tranche 1 by Scenario

Fiscal Year	Reference	Scenario 1- Balanced Decarbonization	Scenario 2- Carbon Neutral	Scenario 3- Dual-Fuel Heating	Scenario 4- New Gas Customer Moratorium	Scenario 5- Aggressive Building Electrification	Scenario 6- Full Building Electrification	Scenario 7- RNG and H2 Policy Support	Scenario 8- Limited RNG	Scenario 9- Supply-Focused Decarbonization
	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu
2022	258	258	258	258	258	258	258	1,249	258	258
2023	893	871	653	861	866	875	807	1,249	656	872
2024	896	873	655	863	868	877	809	1,252	658	875
2025	893	871	866	861	866	875	807	1,249	873	872
2026	992	952	950	937	936	940	848	1,249	959	959
2027	1,091	1,032	1,032	1,005	1,003	1,002	882	2,006	965	1,043
2028	1,298	1,190	1,121	1,130	1,130	1,066	916	2,012	968	1,211
2029	1,295	1,187	1,194	1,127	1,127	1,063	913	2,006	965	1,207
2030	1,295	1,187	1,194	1,127	1,127	1,063	913	2,006	965	1,207
2031	1,295	1,187	1,194	1,127	1,127	1,063	913	2,006	965	1,207
2032	1,298	1,190	1,197	1,130	1,130	1,066	916	2,012	968	1,211
2033	1,295	1,187	1,194	1,127	1,127	1,063	913	2,006	965	1,207
2034	1,295	1,187	1,194	1,127	1,127	1,063	913	2,006	965	1,207
2035	1,295	1,187	1,194	1,127	1,127	1,063	913	2,006	965	1,207
2036	1,298	1,190	1,197	1,130	1,130	1,066	916	2,012	968	1,211
2037	1,295	1,187	1,194	1,127	1,127	1,063	913	2,006	965	1,207
2038	1,295	1,187	1,194	1,127	1,127	1,063	913	2,006	965	1,207
2039	1,295	1,187	1,194	1,127	1,127	1,063	913	2,006	965	1,207
2040	1,298	1,190	1,197	1,130	1,130	1,066	916	2,012	968	1,211
2041	1,295	1,187	1,194	1,127	1,127	1,063	913	2,006	965	1,207
2042	1,295	1,187	1,194	1,127	1,127	1,063	913	2,006	965	1,207
2043	1,295	1,187	1,194	1,127	1,127	1,063	913	2,006	965	1,207
2044	1,298	1,190	1,197	1,130	1,130	1,066	916	2,012	968	1,211
2045	1,295	1,187	1,194	1,127	1,127	1,063	913	2,006	965	1,207
2046	1,295	1,187	1,194	1,127	1,127	1,063	913	2,006	965	1,207
2047	1,295	1,187	1,194	1,127	1,127	1,063	913	2,006	965	1,207
2048	1,298	1,190	1,197	1,130	1,130	1,066	916	2,012	968	1,211
2049	1,295	1,187	1,194	1,127	1,127	1,063	913	2,006	965	1,207
2050	1,295	1,187	1,194	1,127	1,127	1,063	913	2,006	965	1,207

Figure G.11: Washington Compliance Option: RNG Tranche 2 by Scenario

Fiscal Year	Reference	Scenario 1- Balanced Decarbonization	Scenario 2- Carbon Neutral	Scenario 3- Dual-Fuel Heating	Scenario 4- New Gas Customer Moratorium	Scenario 5- Aggressive Building Electrification	Scenario 6- Full Building Electrification	Scenario 7- RNG and H2 Policy Support	Scenario 8- Limited RNG	Scenario 9- Supply-Focused Decarbonization
	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu
2022	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0	0
2041	0	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0	0
2049	0	0	0	0	0	0	0	0	0	0
2050	0	0	0	0	0	0	0	0	0	0

Figure G.12: Washington Compliance Option: Hydrogen by Scenario

Fiscal Year	Reference	Scenario 1- Balanced Decarbonization	Scenario 2- Carbon Neutral	Scenario 3- Dual-Fuel Heating	Scenario 4- New Gas Customer Moratorium	Scenario 5- Aggressive Building Electrification	Scenario 6- Full Building Electrification	Scenario 7- RNG and H2 Policy Support	Scenario 8- Limited RNG	Scenario 9- Supply-Focused Decarbonization
	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu
2022	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	78	0
2028	0	0	0	0	0	0	0	0	165	0
2029	0	0	0	0	0	50	18	0	239	0
2030	104	75	79	56	57	101	32	0	316	80
2031	209	148	156	110	113	147	40	0	390	159
2032	322	226	238	168	170	195	44	0	469	243
2033	424	290	306	208	216	230	44	0	535	314
2034	533	361	378	255	264	265	44	0	606	391
2035	644	432	450	301	312	298	44	0	678	469
2036	765	509	527	354	364	332	44	0	757	554
2037	869	570	586	387	402	352	44	0	817	622
2038	983	636	649	421	443	374	44	0	884	696
2039	1,099	700	711	448	482	392	44	0	950	768
2040	1,227	775	781	487	527	413	44	2,669	1,026	851
2041	1,333	832	832	510	557	419	44	2,662	1,065	914
2042	2,340	1,757	3,407	1,320	1,385	433	44	2,662	1,065	3,137
2043	2,340	1,757	3,407	1,320	1,385	433	44	2,662	1,065	3,137
2044	2,377	1,762	3,416	1,323	1,389	456	44	2,669	1,068	3,272
2045	2,373	1,757	3,407	1,320	1,385	454	44	2,662	1,065	3,263
2046	2,384	1,757	3,407	1,320	1,385	454	44	2,662	1,065	3,263
2047	2,395	1,757	3,407	1,320	1,385	454	44	2,662	1,065	3,263
2048	2,421	1,762	3,416	1,323	1,389	456	44	2,669	1,068	3,272
2049	2,417	1,757	3,407	1,320	1,385	454	44	2,662	1,065	3,263
2050	2,427	1,757	3,407	1,320	1,385	454	44	2,662	1,065	3,263

Figure G.13: Washington Compliance Options: Synthetic Methane by Scenario

Fiscal Year	Reference	Scenario 1-Balanced Decarbonization	Scenario 2-Carbon Neutral	Scenario 3-Dual-Fuel Heating	Scenario 4-New Gas Customer Moratorium	Scenario 5-Aggressive Building Electrification	Scenario 6-Full Building Electrification	Scenario 7-RNG and H2 Policy Support	Scenario 8-Limited RNG	Scenario 9-Supply-Focused Decarbonization
	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu	BBtu
2022	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0	0
2041	0	0	0	0	0	0	0	0	18	0
2042	0	0	0	0	0	0	0	0	88	0
2043	0	0	0	0	0	0	0	0	158	0
2044	0	0	0	0	0	0	0	0	237	0
2045	0	0	0	0	0	0	0	0	296	0
2046	0	0	0	0	0	0	0	0	362	0
2047	0	0	0	0	0	0	0	0	427	0
2048	0	0	0	0	0	0	0	0	503	0
2049	4,894	2,397	3,552	753	1,017	0	0	775	558	1,415
2050	5,028	2,447	3,935	753	1,017	0	0	811	3,449	1,459

Appendix H: Technical Working Group Attendance

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Appendix I: Meeting for the Public Bill Insert Notice

NW NATURAL'S 2022 INTEGRATED RESOURCE PLAN (IRP)

The IRP is NW Natural's long-term plan to serve customers and answer questions, such as: How much gas will our customers use? How much energy can we save through conservation? Where will NW Natural get its gas supply?

Please join us for a discussion of these and other topics to help develop the IRP:

DATE: Monday, July 18, 2022

TIME: 6 p.m. to 8 p.m.

ONLINE OR BY PHONE: See meeting information at nwnatural.com/IRP

You can also mail any questions or comments about the plan to:

NW Natural
Attn: Integrated Resource Plan
250 SW Taylor Street
Portland, OR 97204

A copy of the draft 2022 Integrated Resource Plan will be available on our website in early July, at **nwnatural.com/IRP**.

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At NW Natural, we have a responsibility to reliably and affordably meet our customers' current and future energy needs. Every few years, Integrated Resource Planning (IRP) develops a plan that best meets customers' forecasted long-term energy requirements with the goal of minimizing the combination of costs and risks for NW Natural customers. This robust planning process evaluates many factors, including but not limited to:

- Environmental policy
- Customer growth
- Consumption trends
- Demand-side resources, such as energy efficiency and demand response
- Supply-side resources, such as renewable natural gas and storage options

The NW Natural IRP is developed through a process open to the public and informed by feedback and a formal review by a diverse set of interested parties. For more information, please visit **nwnatural.com/IRP**.

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Appendix J: Draft Comments

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J.1 Draft Comments

NW Natural invited and received comments/questions on its Draft IRP from a number of stakeholders. As several of the comments/questions were similar and often related to the same topic, NW Natural has created the table below which summarizes the comments received by topic and NW Natural's response. NW Natural appreciates the feedback and engagement in its 2022 IRP process.

Topic	Summary of Draft Combined Comments	Response from NW Natural
General	We received comments asking for more explanation of the distinction between Reference Case and Base Case, and the purpose that each case is serving in the analysis.	NW Natural has now included a Reference Case in the Glossary and has also provided a section in Chapter 2 that discusses what is meant by Reference Case as well as a discussion about why NW Natural not including a base case in this IRP. More specifically, a reference case is a projection of demand based on historical trends embedded in customer additions, customer losses, and customer usage profile throughout the year across residential, commercial, and industrial sectors. This is the comparative case that allows one to gain but for understanding. Additionally, due to the degree of uncertainty of loads, policy, costs, and resources, for this IRP rather than developing a base case, NW Natural uses the range of cases, stochastic simulation, and risk analysis to inform its action plan for the next couple of years until the next IRP. For purposes of this IRP, the action plan is the selected portfolio.

Topic	**Summary of Draft Combined Comments**	**Response from NW Natural**
General	NW Natural received a few comments, noting typos, missing words, or unclear sentences. Additionally, there were numerous requests for additional discussion and information.	NW Natural appreciates these comments and has made corrections based on this feedback. Additionally, NW Natural has tried to include additional information about key topics such as RNG and Hydrogen within the body of the IRP to provide clarity. Lastly, NW Natural has added more materials and information in the appendices in support of key topics and underlying assumptions.
General	NW Natural received a comment regarding PLEXOS® and suggesting more discussion about it especially with it being new to this IRP and a cause for one of the requested waivers allowing a delay.	NW Natural has updated the Executive Summary to add more about what is new to this IRP or what has changed and PLEXOS® is discussed as the first item. NW Natural also expanded its discussion about the core algorithms of the PLEXOS modelling software and the computational hurdles of completing the complex IRP modeling.
General	NW Natural received comments requesting more information be included regarding the inputs contained in each of the portfolios shown in Chapter 7.	NW Natural has expanded its description and information relating to each of the portfolios in Chapter 7 and included additional information within its Appendices. As the previous chapters build to this portfolio evaluation and selection chapter, additional information has also been added throughout the IRP and the reader may find additional information in other relevant chapters. Further, NW Natural will be providing workpapers that should also contain the requested information in more detail.
General	NW Natural received some comments asking for information like that provided in the UM2178 workshop. More specifically,	NW Natural now includes the estimated bill impacts. Please see Chapter 7 for more information.

Topic	Summary of Draft Combined Comments	Response from NW Natural
	requesting information about potential residential ratepayer impacts.	
General	NW Natural received comments asking about how it compares resources.	NW Natural compares resources using the least cost, least risk framework. It does so by calculating the PVRR for different resources and using risk analysis to evaluate resulting portfolios to inform the action plan.
Gas Price Forecast	NW Natural received some comments about its gas price forecast. More specifically, comments were asking about more details relative to our gas price forecast as well as concerns about the volatility of gas prices and how that is factored into the analysis.	NW Natural has added some additional information about its gas price forecast and in Chapter 2, now includes a chart that shows both the history and forecast range for the weighted average cost of gas. Additionally, as part of its risk analysis, NW Natural includes a detail discussion about the price simulation of conventional natural gas as one of the stochastic variables.
Environmental Policy	NW Natural received several comments asking about the recently passed Inflation Reduction Act and its impact on the IRP.	The IRP process is complex and highly technical. By its nature, to develop portfolios, forecasts must be locked down at some point in time during the process. This is one of the reasons that the IRP is redone on a biannual cadence, recognizing the changing environment. The IRA was passed after NW Natural released its draft IRP and within approximately a month from its filing date. We have referred to it in several places within the IRP but did not specifically include it in the modeling. However, due to the scenario analyses that NW Natural performed, several of areas that will likely be impacted by the IRA have indeed been included. By means of example, one of the scenarios anticipated

Topic	Summary of Draft Combined Comments	Response from NW Natural
		a production tax credit for hydrogen. NW Natural will continue to monitor the environment for impacts from the IRA and other policies and use these to inform its planning processes.
Environmental Policy	NW Natural received comments on SB 98 and, how we are thinking about SB 98 and does the CPP require gas to be on-system?	NW Natural has expanded its compliance discussion of SB 98 and the CPP within the results as well as in Chapter 6 where we discuss resources. SB 98 and the CPP allow for “book and claim” reporting and tracking of RNG. The Greenhouse Gas Reporting program does not require the physical delivery of specific RNG molecules to end-users on NW Natural’s distribution system.
Environmental Policy	NW Natural was asked various questions about the CPP and how it would apply. Some of the questions asked about the use of non-local RNG, the use of CCIs, and costs for compliance resources	NW Natural has expanded its compliance discussion and now includes several charts that identify costs for RNG, hydrogen, and CCIs. Please refer to Chapter 6 for additional information.
Emerging Technologies	NW Natural received multiple comments relating to Gas Heat Pumps. A number of the comments were asking about what the adoption rates were and the source of these adoption rates.	The adoption curve for gas heat pumps was based on information from GTI, NEEA and SMEs. Based on feedback from stakeholders, NW Natural has scaled back its adoption curve assumptions. Please refer to end use forecasting in Chapter 3 for more information. Additionally, please refer to the workpapers for additional information.
Load Forecast	NW Natural received several comments related to both its customer forecast and its subsequent load forecast. Many of the comments were related to gas bans, code changes, a presumption of the cost	There is a high degree of uncertainty relative to NW Natural’s load forecast in this IRP. For this reason, NW Natural is using a reference case for comparative purposes as well as scenario analysis to understand the implications of various load forecasts

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Topic	Summary of Draft Combined Comments	Response from NW Natural
	effectiveness of electrification and environmental policies promoting electrification.	and how that might impact our Action Plan. Additionally, as was mentioned before, the IRP is not a policy making document, but it does take potential futures into consideration including a high electrification scenario. However, no municipality has currently passed a "gas ban" in Oregon. As NW Natural has commented before, NW Natural strongly disagrees that mandating customers to defect from the gas system is a CPP compliance pathway for Oregon gas utilities. The CPP requires gas utilities to meet GHG emissions targets and does not require them to stop serving customers. NW Natural does not know the full cost to serve that customer on the electric system inclusive of the incremental generation, transmission, distribution cost, which are in addition to the incremental equipment and installation costs for customers to switch to an all-electric home. As such NW Natural is not able to validate that electrification would be is a least cost, least risk option for customers that have chosen gas end-use equipment. That said, NW Natural did include several scenarios with varying degrees of electrification. See chapter 7 for scenario details. As is the objective with our scenario and other risk analyses, these are used to inform a low regret and robust action items in our action plan.
Load Forecast	NW Natural received comments asking for more information relating to Washington customers and load forecasts.	NW Natural appreciates the feedback as it relates to Washington and agrees. Additional information has been provided for Clark and Skamania counties and

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Topic	Summary of Draft Combined Comments	Response from NW Natural
		has noted that both counties are also included in the Portland MSA.
Load Forecast	NW Natural received several comments about how weather and more specifically climate change was included into its load forecast. Several questions asked for more clarity relative to the role of climate change in determining both the Design Peak Weather and the Design Winter Weather.	NW Natural discussed the role of weather in Chapter 3. As discussed, NW Natural incorporated five selected IPCC climate models for each of its load centers. As the design winter weather is an adjustment to the expected weather forecast for the winter months, by extension it too incorporates climate change trends. The impacts of climate change on cold snaps such as is modeled with the Design Peak Weather is still uncertain and unclear in both frequency and magnitude. NW Natural will continue to test this relationship.
Load Forecast	As was mentioned in previous comments, NW received comments to examine additional scenarios that captured aggressive reductions in gas demand.	NW Natural, in fact, did include scenarios that captured aggressive reductions in gas demand, including full building electrification, which all but eliminates installations of any new natural gas equipment in residential and small commercial buildings. In future IRPs, NW Natural will evaluate any additional scenarios that are relevant and informative, but policies requiring customers to remove their working natural gas equipment before needing replacement is outside the scope of being informative as a scenario to help inform the action plan.
Demand Side Management	NW Natural received several comments relative to Hybrid Heating. More specifically, questions related to adoption	NW Natural does consider hybrid heating to reduce gas use whilst allowing gas customers the ability to use their gas furnace as back up during periods of cold weather. Please see Chapter 3's end use section

Topic	Summary of Draft Combined Comments	Response from NW Natural
	rates and the use of gas public purpose funds to promote hybrid systems.	for a discussion of the anticipated adoption rates. At the time of this writing, NW Natural is not planning to use gas public purpose funds for fuel switching nor is it aware that this is possible. The IRP is not a policy document and the question of using gas public purpose funds for fuel switching is a policy question and not discussed in the IRP.
Demand Side Management	NW Natural received several comments relative to energy efficiency and its value as a compliance resource. It was proposed that NW Natural show energy efficiency graphically in comparison to other compliance resources.	NW Natural strongly agrees with the value of energy efficiency both as a decarbonization tool as well as an affordability measure. NW Natural appreciates the suggestion and adding energy efficiency and other load reductions to the compliance graphs. See Chapter 7 for details.
Demand Side Management	NW Natural received a few comments relative to avoided costs. More specifically, the comments were asking for clarification relative if the CPP caused avoided costs to increase or decrease from the prior IRP.	NW Natural has adjusted its language to clarify that the CPP has caused Avoided Costs related to GHG compliance costs to increase and thus increasing the amount of cost-effective energy efficiency. NW Natural also notes that GHG compliance costs have also increased significantly for Washington as well as HB 1257 requires the use of the Social Cost of Carbon for resource planning, which is used for Washington's avoided GHG compliance costs.
Demand Side Management	NW Natural received comments relative to DSM potential methodology. More specifically, the comments related to the methodology that AEG used and if it was like the ETO's methodology. There were also comments with suggestions for making the table clearer.	Methodology descriptions for the resource assessment process has been included for both ETO and AEG. Please refer to Chapter 5, appendix D, and WUTC Docket 210773 for more information. Additionally, labels for both tables and graphs have been updated.

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Topic	Summary of Draft Combined Comments	Response from NW Natural
Demand Side Management	NW Natural received several comments about the forecasted amount of energy efficiency savings by the ETO and how those savings are going to be achieved. More specifically, the comments requested more specificity relative to the program offerings and made mention of increases in the projected energy efficiency forecast. Additionally, the comments asked for more explanation for savings associated with emerging technologies.	As discussed in Chapters 4 and 5, avoided costs for both Oregon and Washington have materially increased since the last IRP and in turn increased the amount of cost-effective energy efficiency. Please see Chapter 4 for the specifics on the avoided costs. Additionally, the Energy Trust of Oregon has provided the deployment summary in Appendix D. Energy Trust also explained that they apply risk adjustment factors to emerging technologies based on market, technical and data risk. Lastly, NW Natural works with the Energy Trust of Oregon to ensure that consistent with methodology in Chapter 5, Energy Trust has sufficient funding to acquire the forecasted therm savings, or the amount identified and approved by the Energy Trust board.
Supply Side Resources	NW Natural received some comments about its one of its demand response programs and more specifically about its Industrial Recall options and how often it is used. There was also a comment about the emissions associated with this option.	NW Natural has utilized the industrial recall options twice over the past five years. These are options are near the top of our resource stack, meaning they are the on of the last resources to be dispatched in order to meet peak capacity requirements and should be expected to rarely be utilized. The counterparties involved with these recall agreements mays switch to alternative fuels, such as diesel, or decide to shut down if their gas supplies are recalled. Therefore, net emissions to society from NW Natural evoking an industrial recall agreement could either increase or decrease, but the magnitude of the impact to net emissions is de minimis due to the rarity of exercising these options.

Topic	Summary of Draft Combined Comments	Response from NW Natural
Supply Side Resources	NW Natural received several comments about the Portland LNG facility and more specifically the replacement of the Cold Box.	NW Natural has updated the section relating to Portland LNG Cold Box replacement and provided additional information. Please see Chapter 6 and the associated appendices for additional information.
Renewables	NW Natural received a few comments and questions relative to RNG. More specifically, the comments requested more information, clarifications, and support for the expected availability and costs of RNG along with comments about the competitiveness of the market and this impact on our assumptions.	Knowing that there is a lot of interest in RNG (and hydrogen) NW Natural has expanded its discussion in Chapter 6 on RNG and specifically addresses concerns about RNG supply. NW Natural's assumptions are informed by third party analysis as well as our own experience through our RFP process. Chapter 6 also includes information on costs. As is recognized, the RNG market is quite dynamic and as the market matures, additional information will become available. NW Natural uses both scenario analysis and stochastic analysis to better understand risks associated with RNG and this in turn is used to information the action plan. Please see Chapter 6 for more information on RNG and please see Chapter 7 for more information on the risk analysis.
Renewables	As mentioned above, NW Natural received several comments asking about carbon intensities of RNG and Hydrogen and how the reporting of carbon intensities between both SB 98 and the CPP compare.	NW Natural has expanded the discussion on carbon intensities in both Chapter 6 as well as in the Appendices. By means of example, Chapter 6 now includes a table for all the carbon intensities for registered projects in the Oregon Clean Fuels Program. NW Natural also discusses carbon intensity reporting. Carbon intensity reporting is required for SB 98 compliance, and it is expected that Washington will also have a reporting requirement. Thus, while the CPP treats RNG acquisitions as zero

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Topic	Summary of Draft Combined Comments	Response from NW Natural
		anthropogenic carbon dioxide (i.e., CI score = 0) meeting compliance obligations at this time, the CI information will be available through different reporting vehicles.
Renewables	NW Natural received many comments on Hydrogen and Power to Gas. These comments were regarding the various colors/types of Hydrogen, clarification on what Power to Gas is and similar to questions regarding RNG, questions about availability and costs. NW Natural will respond to these comments by first focusing on the Hydrogen questions and then addressing P2G.	Similar to NW Natural's response to RNG, we have expanded our discussion of Hydrogen and now include a chart that explains the different types of Hydrogen (often described as the different colors of Hydrogen). Chapter 6 also now contains information about costs, availability, and carbon intensity. NW Natural also addresses the pressure related properties that limit Hydrogen as a resource for our Forest Grove Uprate project. Similar to RNG, the Hydrogen market is very dynamic. By means of example, NW Natural notes that in our recent RFP process, hydrogen resources have been identified that are cost competitive with RNG. The Inflation Reduction Act (IRA) enables a hydrogen production tax credit that is predicted to continue to make hydrogen and synthetic methane more cost-effective resources in the next two decades. As with RNG, NW Natural uses both scenario analysis and stochastic analysis to better understand risks associated with Hydrogen and this in turn is used to information the action plan. Please see Chapter 6 for more information on RNG and please see Chapter 7 for more information on the risk analysis.
Renewables	As was mentioned above, as a subset of comments received on Hydrogen, NW	Like the comments above, noting the interest from the comments, NW Natural has expanded its

Topic	Summary of Draft Combined Comments	Response from NW Natural
	Natural received several comments on Power to Gas (P2G). More specifically, what is P2G, what is its role and storage potential and timeline on providing service.	discussion of P2G in Chapter 6. This includes a definition of P2G. Relative to the role of P2G, it will be viewed as a low-carbon resource just like any other resources. The one nuance is that it may make sense to serve large customers with 100% hydrogen from dedicated hydrogen production projects alongside distribution blending to increase decarbonization efficiencies and decrease costs. Relative to the storage potential, Mist appears to have the geology to support more storage development. Hydrogen and synthetic methane can be used to fill these reservoirs and store low-carbon energy for months or years at a time. This energy can be distributed through either the gas or electric grids when it is needed, such as during times of low water/wind/solar resources to thermal generation plants, or to homes and businesses during low temperature winter peak conditions. Lastly, P2G projects are currently in the early planning and development stages.
Compliance Planning	NW Natural has received multiple comments related to compliance with OR and WA legislation. More specifically, the questions were asking how NW Natural plans on complying with these new regulations especially in the medium and long term. NW Natural was also encouraged to include of a discussion relative to how it was thinking of	There is a lot of uncertainty in the future relative to loads, costs, resources, and future policy. For this reason, NW Natural rather than identifying a base case or even a preferred portfolio, NW Natural has identified the compliance actions that it will be taking before the next IRP is filed. NW Natural will comply will all Oregon and Washington laws and will also use a least cost, least risk framework for evaluating its compliance resources.

Topic	Summary of Draft Combined Comments	Response from NW Natural
	compliance and specifically a comment was offered to include more information regarding GHG compliance costs.	NW Natural appreciates the comment about adding more information to the discussion relative to GHG costs. To this end, in addition to GHG compliance costs included in avoided costs in Chapter 4, it has also added substantially to the section about both RNG and Hydrogen in Chapter 6. Additionally, NW Natural has added some additional discussion to Chapter 7 which discusses both the portfolio results of the different scenarios as well as the risk analysis used to inform the action.
Compliance Planning	NW Natural received some comments relative to using unbundled RTCs to meet CPP compliance obligations. There were concerns that this may not be correct or that our interpretation and the rules around using RTCs may become more stringent in future years.	NW Natural is confident in its interpretation of the CPP Compliance obligations, and we continue to keep in close communication with the DEQ to plan properly for our ratepayers.
Portfolio Results	NW Natural received comments regarding the portfolio results and the impacts on customers.	NW Natural has updated the IRP to include a section on Customer Bill Impacts. Please see Chapter 7 for more information.
Portfolio Results	NW Natural received a number of comments and questions relative to the sawtooth shape of the results and with offset and purchase allowance amounts were alternating every few years.	NW Natural has updated these charts for the final submission, please see Chapter 7 for details about the flexibility of compliance instruments within a compliance period.
Portfolio Results	NW Natural was asked about results and the need for capacity resources. More specifically, NW Natural was asked to	NW Natural has revised the portfolio results in Chapter 7. For NW Natural cost estimates and resources quantities needed to serve its Peak Day

Topic	Summary of Draft Combined Comments	Response from NW Natural
	quantify the amount of investment needed to serve peak.	please refer to Chapters 3 and 6. Lastly, NW Natural includes detailed information on its portfolio analysis in the appendix.
Risk Analysis/Scenario Analysis	As noted above, NW Natural received many comments regarding electrification. More specifically, electrification was seen to potentially reduce load and thus, needed to be considered to inform the action plan.	As was noted above, NW Natural did evaluate several scenarios with varying levels of electrification. The results of these portfolios were used to inform our action plan. As the policy and market landscape continues to evolve, NW Natural will continue to monitor policy, codes and standards, and trends in customer additions and losses. The IRP is updated and refiled approximately every two years to update the data, assumptions, and models to reflect changes through time.
Risk Analysis/Scenario Analysis	NW Natural received a question about the scenarios that were evaluated. More specifically, NW Natural was asked about why other scenarios were not included.	The company works together with stakeholders during the Technical Working Groups to identify what scenarios to include in the IRP and must limit the scope to a manageable number of scenarios to be able to complete the IRP.
Distribution System Planning	NW Natural received comments relative to non-pipeline alternatives as distribution system planning solutions. More specifically, there were comments to include more discussion about the non-pipeline solutions explored, costs of these alternatives and the implications of electrification.	NW Natural does evaluate nonpipelined solutions for distribution system planning and has included this discussion in Chapter 8. NW Natural uses the same framework for distribution system planning as it does for system planning – least cost least risk. As such, alternative non-pipeline solutions may provide an opportunity to reduce costs and risks. In order to be able to evaluation non-pipeline solutions the Company needs to be able estimate the cost, quantity and reliability of any distribution system a option included non-pipeline options. The primary

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Topic	Summary of Draft Combined Comments	Response from NW Natural
		objective of our current GeoTEE pilot program is to develop as supply curve so that it may be included as a solution on an equal basis as our pipeline solutions. It is also one of the reasons that we are proposing a GeoDR pilot as well.
Distribution System Planning	NW Natural received comments about using electrification to "prune" the gas system or as a non-pipeline solution for distribution system planning.	As stated above, as a fuel of choice, customers can leave the gas system today. When they chose to stay, NW Natural has an obligation to serve and to serve with the fuel and end use equipment selected by the customer. Additionally, NW Natural is not privy to the cost and emissions shift that would take place on the electric side, it is not able to do a complete analysis of least cost – least risk.
Distribution System Planning	NW Natural received several comments requesting clarification about the Forest Grove project and more specifically about the need for the project.	NW Natural has rewritten our Distribution System Planning section to clarify. Please see Chapter 8. More specifically though, the uprates to the Forest Grove Feeder are necessary to serve existing communities. It is needed to serve an existing pressure issue.
Distribution System Planning	NW Natural received several comments about future distribution system planning needs and more specifically if there are additional sections that may need reinforcements.	As discussed in more detail in Chapter 8, NW Natural is completing an improvement to its distribution system planning process and tools. This improvement should provide more granularity and insights into our distribution system planning. As discussed in the Chapter 8, normally NW Natural provides a 10-year system reinforcement plan with the IRP. However; since the Company is in transition with a significant improvement to distribution system planning NW Natural will provide this 10-

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Topic	Summary of Draft Combined Comments	Response from NW Natural
		year plan via an IRP update once these improvements are complete.
Public Engagement	NW Natural received several comments and suggestions about how the company is engaging the public in the IRP process.	With this IRP, NW Natural posted its presentations and to the extent available also posted video of its technical working groups. NW Natural will continue this practice moving forward. We have recently launched a Community and Equity Advisory Group and we hope to integrate these valuable comments into our IRP process. There is still more that can be done, and we value the input of our communities in improving the IRP process and serving our stakeholders better.
Data/Assumption/Workpaper	NW Natural received many comments with regard to data, assumptions and workpapers. More specifically, comments requested that excel files be provided with intact formulas, workpapers be provided with assumptions identified, the data behind some of the charts and graphs be provided and so on.	An IRP is quite complex and includes many models some run in excel but many models must use more complex statistical and optimization software. It is NW Natural's objective to provide comprehensive and user-friendly workpapers to be as transparent as possible. Due to the extent and complexity of the workpapers as discussed at the last TWG, it may take some time to pull all the workpapers together in a format and organization that is most helpful and transparent for stakeholders.

Appendix K: Low Emissions Gas Resource Evaluation Methodology

K.1 Terminology

Renewable Natural Gas (RNG): Per ORS 757.392, means any of the following products processed to meet pipeline quality standards or transportation fuel grade requirements:

(a)Biogas that is upgraded to meet natural gas pipeline quality standards such that it may blend with, or substitute for, geologic natural gas;

(b)Hydrogen gas derived from renewable energy sources; or

(c)Methane gas derived from any combination of: (A)Biogas; (B)Hydrogen gas or carbon oxides derived from renewable energy sources; or (C)Waste carbon dioxide.

While a more comprehensive description of RNG resources would be "low carbon gas" the term RNG will be used interchangeable with low carbon gas in this methodology.

RNG Portfolio: A collection of RNG resources that is optimized to maximize delivery of RTCs to NW Natural customers under SB 98 while minimizing the % of annual revenue requirement required to fund the RTC procurement. This portfolio is overseen by the Renewable Resources Committee and maintained by the Renewable Resources team. This portfolio may be broadened from time to time to include RNG resources designed to support other programs and policies, such as a voluntary "green" tariff for customers. This policy will be updated as those new programs and policies are developed.

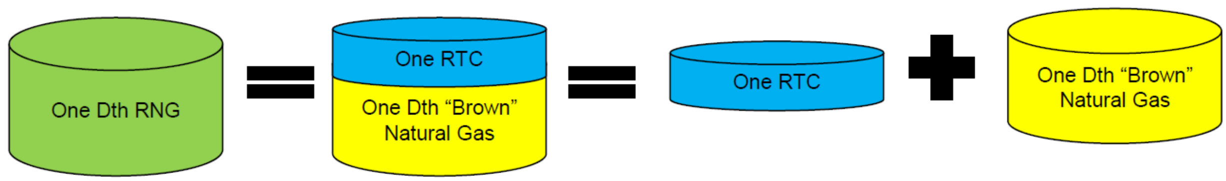
RNG Resource Pipeline: A list of all RNG resources known to the Renewable Resources team that could become part of NW Natural's portfolio of RNG. This pipeline includes information gathered during origination activities including issuance of RFPs for RNG resources.

Acquisition: In this policy, any RNG or RTC procurement contract, investment in RNG project development, or acquisition of an RNG project is referred to collectively as an "acquisition" of an RNG resource.

Offtake: an RNG resource that is purely a contract for the purchase of RTCs or bundled RNG (environmental attributes plus "brown gas.") An offtake requires no capital investment and is a pure pass-through cost that, per the final OPUC rules related to SB 98, is to be recovered via the Purchased Gas Adjustment.

Development Project: An RNG resource that requires some amount of capital investment and legal agreements associated with ownership of assets.

Brown gas: When RNG is purchased as a bundled commodity it can be separated into RTCs and "brown" gas. Once the RTC is separated from the underlying gas, the brown gas does not carry any environmental benefits. It can be separately accounted for distinct from the transactions associated with the RTCs. In most cases the brown gas will be sold locally to a buyer able to take delivery of physical gas near the point of RNG production. The costs or revenues associated with transacting any brown gas related to an RNG transaction are taken into account when determining a resource's total incremental cost.



Renewable Thermal Certificate (RTC): The unique environmental attributes from the production, transportation, and use of one dekatherm of RNG.

Senate Bill 98 (SB 98)/ OAR 860-150: A bill passed by the Oregon Legislature and signed into law in 2019. [8] The law establishes targets for Oregon's natural gas utilities to procure renewable natural gas for its sales customers and recover costs prudently incurred to meet those targets. The rules to implement SB 98 are Division 150 of Chapter 860 of Oregon's Administrative Rules (OAR 860-150), which were ordered into rule by the Oregon Public Utility Commission (OPUC).[9]

Cost of Service model: An Excel-based financial model that calculates the overall cost to customers of an RNG or RTC resource, considering the utility costs of debt and equity if any capital investments are required, utility tax burden, anticipated cost recovery activity and timing, and other relevant and salient aspects of a procurement, project development, or investment (collectively "Transaction").

Incremental Cost Workbook: An Excel-based model that evaluates the value of RNG resources for NW Natural customers. It calculates the incremental cost of RNG based upon "all-in costs," where the difference in the cost of service of an RNG resource and the costs avoided from not needing to procure an equivalent amount of conventional natural gas is the incremental cost. Using the most recent methodology approved by the OPUC to calculate incremental costs[10] and the direction of OAR 860-150, this model produces a levelized incremental cost, that is risk-adjusted to reflect the overall incremental cost of a resource. The model yields the cost of delivering the RTC and brown gas, bundled together, to NW Natural customers. Thus, when evaluating RNG resources, this policy stipulates the incremental cost of an RNG resource is the incremental cost of delivering that RNG as a bundled resource, inclusive of the underlying gas. When a transaction is for RTCs only, the model attributes a brown gas purchase to the deal in order to compare deals on an apples-to-apples basis.

Incremental Cost: The levelized incremental cost of projects contributing to NW Natural's RNG portfolio over the remaining expected life of the project. This metric is the expected incremental cost of an RNG resource to NW Natural customers and is not risk-adjusted. The incremental cost of each resource in the RNG portfolio is included in the annual RNG compliance report detailed in OAR 860-

[8] https://olis.leg.state.or.us/liz/2019R1/Measures/Overview/SB98
[9] See OPUC Order No. 20-227 and https://secure.sos.state.or.us/oard/viewSingleRule.action?ruleVrsnRsn=271677
[10] See OPUC Order No. 20-403 at https://apps.puc.state.or.us/orders/2020ords/20-403.pdf

150-0600, where the summation of the total incremental cost of each resource in the portfolio is the total incremental revenue requirement of the RNG portfolio.

FYRALIC (First Year Risk-Adjusted Levelized Incremental Cost): The levelized risk-adjusted incremental cost as calculated as an output of the Incremental Cost model for the first year a prospective project is expected to deliver RTCs to NW Natural customers. This cost, in levelized $/Dth over the expected life of the project, is deemed to be the incremental cost of RNG for evaluation of prospective RNG resources based upon the OAR 860-150-0200 and the calculation methodology approved by the OPUC in Order No. 20-403.

RNG Acquisition Target: A year by year target of RNG for delivery to NW Natural customers based upon complying with OR SB 98, Oregon Department of Environmental Quality's (ODEQ's) Climate Protection Program (CPP), WA HB 1257, and Washington's Cap-and-Invest program under the Climate Commitment Act (CCA).

K.2 Purpose and Overview

As part of its 2018 Integrated Resource Plan (IRP), NW Natural proposed a methodology to evaluate prospective low emissions gas resources based upon risk-adjusted "all-in" costs. While there are low emissions gas resources that are not renewable natural gas (RNG), this appendix will colloquially refer to low emissions gas as RNG. This methodology went through a regulatory investigative process and resulted in an order by the OPUC (Order 20-403) approving the methodology that represents the majority of updated methodology included in this appendix.

This appendix updates the methodology approved in OPUC Order No. 20-043 to account for developments from SB 98 rulemaking in Oregon and the establishment of Oregon DEQ's Climate Protection Program. The purpose of this methodology calculating the levelized incremental cost of each resource in NW Natural's RNG portfolio for the compliance reports detailed in OAR 860-150-0200 and 0600 and to calculate the risk-adjusted levelized incremental cost to compare *prospective* RNG resources using the stochastic Monte Carlo simulation analysis in the 2022 IRP. This methodology is an application of numerous resource planning and rate-making concepts and accounting, including:

- Comparing resources on a fair and consistent basis
- Least cost/least risk planning standard
- Incremental costs
- Avoided costs
- Cost of service
- Levelized costs
- Accounting for risk/risk-adjustment

The methodology is also developed to be able to be flexible enough to appropriate assess all potential RNG resource types, of which there are many. While there are many sub-types, Table K.2 shows the types of resources that allow NW Natural to obtain the renewable thermal credits that prove RNG ownership for its customers:

Table K.1: Low Emissions (RNG) Resource Types

	RTC Acquired	Attach physical gas to obtain bundled RNG for Incrmental Cost	Sale of "Brown" gas	Avoided Commodity Costs	Avoided Capacity Costs
Unbundled Environmental Attribute (RTC) Purchase	✓	✓			
Bundled RNG Delivered to NW Natural's System	✓			✓	
Bundled RNG with Brown Gas Sales	✓	✓	✓	✓*	
On-System Bundled RNG	✓		✓	✓	✓

In addition to being able to account for different resource types the evaluation methodology needs to take into account the RNG acquisition process which the evaluation methodology folds into accounts for market conditions for RNG projects. As a practical matter, we will need to make decisions at the pace that the RNG market dictates, which is usually faster than IRP acknowledgement allows. The Incremental Cost Workbook that implements this methodology was developed taking into account RNG market conditions, which requires the ability to make frequent updates to the terms of prospective RNG resources while maintaining the ability to compare all prospective resources on equal footing.

K.3 Evaluation Methodology

The RNG Incremental Cost Workbook that is included in the workpapers to NW Natural's 2022 IRP implements the following calculations of risk-adjusted levelized incremental "all-in" cost:

Annual all-in cost of RNG (R) =

Cost of methane (M) + Emissions compliance costs (E) – Avoided infrastructure costs (I)

Or: $$R_T = M_T + E_T - I_T$$

Where:

$$M_T = X_T + \sum_{t=1}^{365} [P_{T,t} + Y_{T,t}^{RNG}] Q_{T,t}$$

$$E_T = \sum_{t=1}^{365} N^{RNG} G_T Q_{T,t}$$

$$I_T = S_T A_T + DH_T$$

Substituting leaves the annual all-in cost of RNG as:

$$R_T = X_T - S_T A_T - DH_T + \sum_{t=1}^{365} [P_{T,t} + Y_{T,t}^{RNG} + N^{RNG} G_T] Q_{T,t}$$

Where the annual all-in cost of the conventional natural gas alternative (C) is:

$$C_T = \sum_{t=1}^{365} [V_{T,t} + Y_{T,t}^{CONV} + N^{CONV} G_T] Q_{T,t}$$

The levelized incremental cost (IC) for each prospective resource is used for evaluation where IC is:

$$IC = \sum_{T=k}^{T=k+z} \frac{R_T - C_T}{[1+d]^T}$$

This is risk-adjusted to account for uncertainty where the metric used for evaluating prospective projects is the first-year risk-adjusted levelized incremental cost (FYRALIC):

$$FYRALIC = 0.75 * \text{deterministic } LIC + 0.25 * \text{95th Percentile Stochastic } LIC$$

Table K.2: Project Evaluation Component Descriptions

Term	Units	Description	Source	Project Specific?	Input or Output of IC Workbook?	Treated as Uncertain?
R	\$/Year	Annual all-in cost of prospective renewable natural gas (RNG) project	Output of RNG evaluation process	Yes	Output	Yes
C	\$/Year	Annual all-in cost of conventional natural gas alternative	Output of RNG evaluation process	Yes	Output	Yes
M	\$/Year	Annual costs of natural gas and the associated facilities and operations to access it	Output of RNG evaluation process	Yes	Output	Yes
E	\$/Year	Annual greenhouse gas emissions compliance costs	Output of RNG evaluation process	Yes	Output	Yes
I	\$/Year	Annual infrastructure costs avoided with on-system supply	Output of RNG evaluation process	Yes	Output	Yes
Q	Dth	Expected or contracted daily quantity of RNG supplied by project	Project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
P	\$/Dth	Contracted or expected volumetric price of RNG	Project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
T	Year	Year relative to current year, where the current year T = 0, next year T = 1, etc.	Project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
k	Year	When the RNG purhcase starts in # of years in the future; k = RNG start year - current year	Project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
z	Years	Duration of RNG purchase in years	Project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
t	Days	Day number in year ***T*** from 1 to 365	N/A	No	Input	No
V	\$/Dth	Price of conventional gas that would be displaced by RNG project	Marginal price of conventional gas dispatched in PLEXOS in run without RNG project	Yes	Input	Yes
Y	\$/Dth	Variable transport costs to deliver gas to NWN's system	*For off-system RNG* - based upon geographic location of project; *For conventional gas* - determined from marginal gas dispatched in PLEXOS	Yes	Input	No
X	\$/Year	Annual revenue requirement of capital costs to access resource	Engineering project evaluation or RNG supplier counterparty	Yes	Input	If no contractual obligation
N	TonsCO_2e /Dth	Greenhouse gas intensity of natural gas being considered	From actual project certification if available, from California Air & Resources Board by biogas type if no certification has been completed	Yes	Input	No
G	\$ /TonCO_2e	Volumetric Greenhouse gas emissions compliance costs/price	Expected greenhouse gas compliance costs from the most recently acknowledged IRP	No	Input	Yes
S	\$/Dth	System supply capacity cost to serve one Dth of peak DAY load	Based upon marginal supply capacity resource cost by year as determined from PLEXOS modeling in most recent IRP	No	Input	Yes
A	Dth	Minimum natural gas supplied on a peak DAY by project	Project evaluation or contractual obligation from RNG supplier counterparty	Yes	Input	If no contractual obligation
D	\$/Dth	Distribution system capacity cost to serve one DTH of peak HOUR load	Distribution system cost to serve peak hour load from avoided costs in most recently acknowledged IRP	No	Input	No
H	Dth	Minimum natural gas supplied on a peak HOUR by project	Project evaluation or contractual obligation from RNG supplier counterparty	Yes	Input	If no contractual obligation
d	% rate	Discount Rate	Discount rate from most recently acknowledged IRP	No	Input	No

Table K.3: Input Update Frequency

Inputs and Forecasts	Frequency of Update	Additional Explanation
Resource Under Evaluation	Most Current Estimate	For example, if an RNG project requires any capital costs, the most current estimate of those costs will be run through the cost-of-service model and used for the evaluation.
Gas Prices (Deterministic and Stochastic)	Twice a year	Stochastic gas prices are updated once a year using the Monte Carlo process detailed in the most recent IRP and the most recent gas price forecast from a third-party consultant
Peak Day & Annual Load Forecast	Once a year	These forecasts are updated spring/summer to include data from the most recent heating season.
GHG Compliance Cost Expectations (Deterministic and Stochastic)	Once a year	The GHG compliance cost assumptions will be updated each year after the legislation sessions in each state or when legislation is signed into law.
Design, Normal, and Stochastic Weather	Each IRP	Resources are planned based on design weather, but are evaluated on cost using normal and stochastic weather.
Gas Supply Capacity Costs (Deterministic and Stochastic)	Each IRP	For the 2018 IRP base case this included the cost of a pipeline uprate, a local pipeline expansion, and representative.
Distribution System Capacity Costs	Each IRP	NW Natural will calculate and present the avoided distribution avoided costs through the IRP process.

K.4 Incremental Cost Workbook

The last version of this methodology filed by NW Natural was completed prior to acquisition of NW Natural's first RNG resource to deliver RNG to its customers. NW Natural has now began acquiring RNG for its customers. Consequently, the description of how NW Natural *planned* to evaluate RNG resources for its customers has been replaced with the tools NW Natural is actually to evaluate and acquire RNG. The RNG evaluation methodology described in this document is now implemented in the Company's RNG Incremental Cost Workbook, which is provided as a workpaper to the 2022 IRP. Each prospective project has its own incremental cost workbook that calculates FYRALIC and can be updated at any time so that resources can be compared on equal footing and the LIC of existing projects can be calculated for portfolio management and compliance reporting.

K.5 Evaluation Methodology as Part of Acquisition Process

NW Natural's Renewable Resources team continually collects information about the RNG market and specific opportunities for the procurement of RNG. This information is collected through research and communication with RNG project developers, marketers, investment funds, feedstock owners, and others involved in the RNG market. Additionally, the Renewable Resources team will issue RFPs for new RNG resources at least once per year. Prospective resources are analyzed for their eligibility to be used for compliance with the policies under which NW Natural is a covered party (OR-SB 98, OR-CPP, WA-HB 1257, and WA-CCA). Resources deemed eligible are incorporated into the full list of RNG resources assessed for feasibility (the RNG Resource Pipeline).

The RNG Resource Pipeline is updated continually as new information is collected on potential RNG resources. Once the Renewable Resources team has sufficient information about a resource, it conducts an initial feasibility assessment. Inputs to this activity typically include the financial information shared by the counterparty as well as the team's own analysis of the gas production, equipment costs, and other relevant information. The Renewable Resources team uses the Cost-of-Service model and the Incremental Cost model to determine whether the RNG Resource could potentially yield a First Year Risk-Adjusted Levelized Incremental Cost (FYRALIC) that would be competitive with other RNG resources in the RNG Pipeline. If relevant, the Renewable Resources team works with Gas Supply to estimate the impact of any sale of brown gas or any requirements to transport the commodity associated with the RNG resource. The feasibility assessment produces an estimated FYRALIC in the form of $/Dth of delivered RNG.

The FYRALIC reflects the Renewable Resources team's current assessment of risks of the RNG resource. These risks are quantified as risk inputs in the Incremental Cost Workbook. As new information is gathered about the resource throughout its evaluation, these risk inputs may be updated.

If this initial feasibility assessment yields an estimated FYRALIC at or below the current known average incremental cost of delivered RNG in the RNG Resource Pipeline, the prospective resource will move forward to a diligence phase and a potential recommendation for acquisition.

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FACILITY ASSESSMENT REPORT
PORTLAND LNG FACILITY
Portland, OR

Prepared for NW Natural Gas Company
File No. 4661.05_REPORT-001

February 15, 2022
Revision 1

FACILITY ASSESSMENT REPORT

REVISION LOG

REVISION NUMBER	NOTES
REVISION A	DRAFT - Issued for NWN Review
REVISION 0	INCORPORATE NWN COMMENTS
REVISION 1	REVISED BOC INSTALLATION DATES

TABLE OF CONTENTS

REFERENCES

[REF 1] 4461.04_HAZOP-001: Hazard and Operability (HAZOP) Report – Portland LNG Facility

[REF 2] 4661.04_FEED-001 Cold Box Replacement FEED

[REF 3] 4661.04_EVAL-002 Pretreatment System Evaluation

[REF 4] 4661.07_EVAL-001 LNG Pump and Vaporizer Inlet Cooldown Evaluation

[REF 5] 4661.06-001 HCV-98 Replacement Recommendation Memo

[REF 6] 4661.04_EVAL-001 Cold Box Nitrogen Supply Evaluation

1.0 EXECUTIVE SUMMARY

NW Natural Gas Company (NWN) owns and operates the Portland Liquefied Natural Gas (LNG) facility (Facility) located in Portland, OR, providing an available supplemental gas sendout capacity of up to 60 MMSCFD to the NWN gas distribution system. The facility includes a liquefaction train, rated at 2.15 MMSCFD (approximately 26,000 gpd), which is used during non-heating seasons to liquefy gas for storage and vaporization. The Portland facility is a peak shaving facility, designed to supplement the NWN natural gas distribution system during the coldest design day.

To assist with development of capital budgets for continued operation and maintenance of the Facility, NWN has contracted with Sanborn, Head and Associates, Inc. (Sanborn Head) to perform an assessment of the current condition of the Facility based on observed equipment conditions, facility operating history, equipment maintenance practices, and industry operating experience. Additionally, Sanborn Head has conducted a Hazard and Operability study (HAZOP) of the existing critical plant processes and systems to identify potential risks to reliability and/or safety.

This report provides an assessment of the current condition of the Facility and recommendations for equipment upgrades where deemed appropriate. Priority is given to those components which pose the greatest risk to system process safety and reliability, as determined by a tiered ranking system which considers the likelihood of equipment failure as well as the potential impact of equipment failure on facility availability. Priority is also given to components and/or operating scenarios whose mis-operation or failure could lead to process safety risks (as determined by the HAZOP). The objective of this assessment is to assist in the identification of those areas where NWN should invest capital, considering risk and potential business impact to NWN as a whole.

It is expected that NWN will use the information presented in this report to develop their capital investment plan for the Portland facility for the next 15 years.

2.0 SUMMARY OF RECOMMENDATIONS AND SPENDING PLANS

As a result of the assessments performed at the Facility, the following recommendations are provided with the goal of maximizing Facility reliability over the next 15 years. Note that additional recommendations are included in subsequent sections. The recommendations listed below are considered most critical to long term facility reliability.

1. Complete HAZOP recommendations to resolve high-risk scenarios. Reference the latest revision of [REF 1] documents.
2. Perform a refurbishment of LNG sendout pump P-1 as described in section 4.4.1.
3. Upgrade valves and instrumentation in the LNG sendout pump area as described in sections 4.4.1, 4.4.2 and 4.4.3 to improve LNG sendout reliability and performance. Note that cost savings and efficiency would likely be gained by performing these upgrades as a single project.
4. Implement solutions described in LNG Pump and Vaporizer Inlet Cooldown Evaluation to enhance LNG sendout operations. Reference the latest revision of [REF 4] documents.
5. Perform a top-works and bottom-works upgrade of vaporizer H-5, including control valve upgrades/additions as described in section 4.5.1.
6. Perform a top-works upgrade of vaporizer H-7, including control valve upgrades/additions as described in section 4.5.3.
7. Perform one of the options for recommended pretreatment system upgrades described in the Pretreatment System Evaluation. Reference the latest revision of [REF 3] documents.
8. Install a third BOG compressor package and/or replace the two existing compressors as described in section 4.6.1.
9. Replace the existing cold box as described in the Cold Box Replacement FEED. Reference the latest revision of [REF 2] documents.
10. Replace plant inlet/outlet ESD valve HCV-98. Reference the latest revision of [REF 2] documents.

The tables on the subsequent page provide summaries of the recommended 15-year capital spending plans for each of the following scenarios:

- **Scenario 1 – Table 2.1**: Cold Box is replaced; Pretreatment System is not replaced.
- **Scenario 2 – Table 2.2:** Cold Box and Pretreatment System are replaced.
- **Scenario 3 – Table 2.3:** Cold Box and Pretreatment System <u>are not</u> replaced.

Refer to the tables provided in the appendices for additional description and costs associated with the individual projects/recommendations for each system.

Table 2.1
Summary of Recommended Spending Plan for Scenario 1
(Cold Box is Replaced, Pretreatment System is Not Replaced)

System or Equipment	2022 (Y1)	2023 (Y2)	2024 (Y3)	2025 (Y4)	2026 (Y5)	2027 (Y6)	2028 (Y7)	2029 (Y8)	2030 (Y9)	2031 (Y10)	2032 (Y11)	2033 (Y12)	2034 (Y13)	2035 (Y14)	2036 (Y15)
General	$125.0K			$75.0K			$75.0K		$150.0K	$175.0K	$100.0K	$100.0K	$175.0K	$150.0K	$100.0K
Plant Control System	$175.0K	$50.0K	$50.0K	$50.0K	$50.0K	$50.0K	$50.0K	$250.0K	$50.0K	$50.0K	$50.0K	$50.0K	$50.0K	$50.0K	$50.0K
Storage Tank T-1	$60.0K				$50.0K			$600.0K			$60.0K				
HCV-70	$5.0K			$97.5K											
LNG Sendout	TBD			$627.0K						$50.0K					
Vaporizer H-5	$55.0K		$2,555.0K												
Vaporizer H-6	$27.5K														
Vaporizer H-7	$55.0K			$1,055.0K											
BOG Compressors	$2,700.0K			$500.0K	$2,000.0K										
HCV-98	$35.0K														
Pretreatment System		$2,202.5K													
Turbo Expander C-1	$205.0K				$75.0K	$1,650.0K									
Exchangers	$47.0K					$22.0K		$60.0K		$105.0K					
W-G System	$35.0K					$20.0K									
Oil Heater H-8						$8.0K									
Plant Inlet	$5.0K														
ESD System	$125.0K					$2.0K									
Gas Chromatography									$55.0K						
Security system									$25.0K						
Motor Control Center								$500.0K							
Totals	$3,654.5K	$2,252.5K	$2,605.0K	$2,404.5K	$2,175.0K	$1,752.0K	$125.0K	$1,410.0K	$280.0K	$380.0K	$210.0K	$150.0K	$225.0K	$200.0K	$150.0K

Table 2.2
Summary of Recommended Spending Plan for Scenario 2
(Cold Box and Pretreatment System are Replaced)

System or Equipment	2022 (Y1)	2023 (Y2)	2024 (Y3)	2025 (Y4)	2026 (Y5)	2027 (Y6)	2028 (Y7)	2029 (Y8)	2030 (Y9)	2031 (Y10)	2032 (Y11)	2033 (Y12)	2034 (Y13)	2035 (Y14)	2036 (Y15)
General	$125.0K			$75.0K			$75.0K	$50.0K	$100.0K	$175.0K	$100.0K	$100.0K	$225.0K	$100.0K	$100.0K
Plant Control System	$175.0K	$50.0K	$50.0K	$50.0K	$50.0K	$50.0K	$50.0K	$250.0K	$50.0K	$50.0K	$50.0K	$50.0K	$50.0K	$50.0K	$50.0K
Storage Tank T-1	$60.0K				$50.0K			$600.0K			$60.0K				
HCV-70	$5.0K		$97.5K												
LNG Sendout	TBD		$627.0K							$50.0K					
Vaporizer H-5	$55.0K	$2,555.0K													
Vaporizer H-6	$27.5K														
Vaporizer H-7	$55.0K		$1,055.0K												
BOG Compressors	$2,700.0K		$500.0K	$2,000.0K											
HCV-98	$35.0K														
Pretreatment System		$92.5K													
Turbo Expander C-1	$205.0K				$75.0K		$1,650.0K								
Exchangers	$47.0K				$42.0K			$60.0K		$105.0K					
W-G System	$35.0K														
Plant Inlet	$5.0K														
ESD System	$125.0K				$2.0K										
Gas Chromatography									$55.0K						
Security System									$25.0K						
Motor Control Center								$500.0K							
Totals	$3,654.5K	$2,697.5K	$2,329.5K	$2,125.0K	$219.0K	$50.0K	$1,775.0K	$1,460.0K	$230.0K	$380.0K	$210.0K	$150.0K	$275.0K	$150.0K	$150.0K

Table 2.3
Summary of Recommended Spending Plan for Scenario 3
(Cold Box and Pretreatment System are Not Replaced)

System or Equipment	2022 (Y1)	2023 (Y2)	2024 (Y3)	2025 (Y4)	2026 (Y5)	2027 (Y6)	2028 (Y7)	2029 (Y8)	2030 (Y9)	2031 (Y10)	2032 (Y11)	2033 (Y12)	2034 (Y13)	2035 (Y14)	2036 (Y15)
General	$125.0K			$75.0K			$75.0K		$150.0K	$175.0K	$100.0K	$100.0K	$175.0K	$150.0K	$100.0K
Plant Control System	$175.0K	$50.0K	$50.0K	$50.0K	$50.0K	$50.0K	$50.0K	$250.0K	$50.0K	$50.0K	$50.0K	$50.0K	$50.0K	$50.0K	$50.0K
Storage Tank T-1	$60.0K				$50.0K			$600.0K			$60.0K				
HCV-70	$5.0K			$97.5K											
LNG Sendout	TBD			$627.0K						$50.0K					
Vaporizer H-5	$55.0K		$2,555.0K												
Vaporizer H-6	$27.5K														
Vaporizer H-7	$55.0K			$1,055.0K											
BOG Compressors	$2,700.0K			$500.0K	$2,000.0K										
HCV-98	$35.0K														
Pretreatment System		$2,202.5K													
Turbo Expander C-1	$205.0K				$75.0K	$1,650.0K									
Exchangers	$347.0K					$22.0K		$60.0K		$105.0K					
Cold Box	$850.0K														
W-G System	$35.0K					$20.0K									
Oil Heater H-8						$8.0K									
Plant Inlet	$5.0K														
ESD System	$125.0K					$2.0K									
Gas Chromatography									$55.0K						
Security system									$25.0K						
Motor Control Center								$500.0K							
Totals	$4,804.5K	$2,252.5K	$2,605.0K	$2,404.5K	$2,175.0K	$1,752.0K	$125.0K	$1,410.0K	$280.0K	$380.0K	$210.0K	$150.0K	$225.0K	$200.0K	$150.0K

3.0 ASSESSMENT METHODOLOGY

3.1 Site Visits

Sanborn Head personnel Evan Ciscell and Jeff Chamberlin visited the Facility on April 7 and 8, 2021 to perform a visual observation of plant equipment conditions, review available plant documentation and interview plant personnel to acquire verbal feedback on known operational and maintenance history. Sanborn Head personnel Evan Ciscell and Chris Finnegan also visited the site on May 25-27, 2021 to conduct a HAZOP and gather additional information related to the assessment. NWN personnel participating in these meetings and plant walkdowns included Ryan Weber, Dale Throm, Jason Gardiner, and Frances Aberin.

The objective of the Facility visits was to assess whether plant equipment, in its current condition and age, can support operation at the Facility's design basis capacity with focus on sendout or liquefaction, as applicable. Additionally, equipment and systems were evaluated to identify upgrades or modifications necessary to allow the facilities to continue to operate reliably when required for the foreseeable future (defined as 15 years).

3.2 Facility Design Basis

Based on information received from NWN personnel, the Facility is assumed to have the capacity to vaporize 60,000 Dth over a 24-hour gas day to meet design day requirements. Therefore 60,000 Dth/day is assumed as the design basis capacity for the Facility for LNG vaporization operations. The design basis for liquefaction operations is 2.15 MMSCFD based on the original design of the liquefaction system.

3.3 Tier Ranking for Recommended Capital Expenditures

In order to prioritize recommendations for the purpose of developing the spending plan, each recommendation which will require capital spending was placed into one of three Tier categories. To assign the Tier categories, the likelihood of component failure as well as its potential to impact plant performance and/or reliability was qualitatively assessed based on historical performance, industry experience, and observations of the equipment condition during site walk-downs. The criteria for each Tier are given below.

Tier Category	Criteria
3	• Potential safety issues. • Items which are considered to have a high potential to disrupt plant operation or impact plant reliability/operability/capacity within the next 5 years. • HAZOP recommendations to resolve high risk scenarios.
2	• Items which are considered to have the potential to disrupt plant operation or impact plant reliability/operability within the next 10 years. • Items which are considered to have the potential to cause the plant to operate at reduced capacity for more than one week within the next 10 years. • HAZOP recommendations to resolve medium risk scenarios.
1	• Items which are not considered to have the potential to disrupt plant operation or impact plant reliability/operability within the 15-year lifetime of the plant. • Items which are considered to have the potential to cause the plant to operate at reduced capacity for up to one week. • HAZOP recommendations to resolve low risk scenarios.

Note that for purposes of this report – 'plant operation' will refer to either vaporization operation or liquefaction operation, as applicable.

3.4 Recommended Capital Spending Plans

Based upon the Tier rankings, as well as Sanborn Head's experience with similar facilities, recommendations for equipment upgrades and/or replacements were made and prioritized over the 15-year lifetime of the plant. In general, it is recommended that Tier 3 items be addressed within the next 5 years, Tier 2 items be addressed within the next 5-10 years, and Tier 1 items, considered lower priorities, be addressed as funding and schedule allow over the next 15 years.

NWN is currently evaluating separate potential projects to replace the existing cold box and the existing pretreatment system. NWN personnel requested that Sanborn Head develop three separate 15-year recommended capital spending plans, each of which should consider one of the following scenarios:

- Scenario 1: Cold box is replaced; pretreatment system is not replaced.
- Scenario 2: Cold box and pretreatment system are replaced.
- Scenario 3: Cold box and pretreatment system are not replaced.

Tables summarizing the 15-year recommended capital spending plan for each of the scenarios listed above are provided in Appendices B (Scenario 1), C (Scenario 2) and D (Scenario 3). Costs are rough order of magnitude estimates. A table summarizing other recommendations provided in this report which would be expected to be implemented or completed by NWN personnel with little to no capital spending required, including preventive maintenance (PM) items, is provided in Appendix E.

4.0 FACILITY ASSESSMENT

4.1 Facility Description

The Portland LNG facility is located at 7900 NW St. Helens Road along the eastern shore of the Willamette River in Portland, OR. It was constructed in 1968 by Chicago Bridge and Iron Company, and includes a 0.6 BCF flat-bottomed, double-walled, single containment LNG storage tank. Two installed boiloff compressor systems provide pressure control for the tank. Boiloff gas is injected into the NWN 57 psig natural gas distribution system.

The tank has a set of two external multi-stage vertical lift LNG sendout pumps, located within the LNG storage impoundment area. Each pump is designed for 100% sendout capacity. The Facility includes three submerged combustion vaporizers, two of which are rated for 30MMSCFD and the third rated for 60MMSCFD. Interconnecting piping between the LNG sendout pumps and the vaporizers allow for either pump to supply any of the installed vaporizers. The vaporization sendout is injected into the NWN 450 psig natural gas distribution system.

The Facility includes a natural gas-expander type liquefaction system which utilizes a compressor-loaded high speed turbo expander to produce refrigeration and a cold box exchanger to utilize this refrigeration for the liquefaction of natural gas. The liquefaction system is designed for 2.15 MMSCFD. During liquefaction, regeneration tail gas from the feed gas pretreatment system flows to both the NWN 85 psig and 57 psig distribution systems.

Appendix A provides a high-level process flow diagram of the Facility's processes.

4.2 Facility Operating History

The Facility was placed into service in 1968 and has remained in service since that time. However, aging equipment and changes to certain process conditions have impacted capacity, reliability, and operability. In particular, increased CO2 levels in the feed gas have led to reliability issues in liquefaction operations. The demand for vaporization to support the distribution system is primarily weather dependent. The Facility was called upon to vaporize in 2020 however reliability issues associated with aging equipment prevented the Facility from vaporizing.

Facility instrumentation and control systems have been upgraded, but equipment upgrades have generally been limited and the majority of process equipment is original to the Facility. The subsequent sections describe the issues encountered for particular systems/equipment.

4.3 LNG Tank and Supporting Systems

4.3.1 Storage Tank T-1

LNG Storage tank T-1 is a 0.6 BCF flat-bottomed, field-erected storage tank with a design pressure of 2.0 psig. NWN personnel reported no known issues with the tank. There have been no known thermal cycles of the tank since it was placed into service.

NWN is not aware of any structural deterioration of the tank piles/foundation/ exterior construction. Tank elevation surveys are performed annually and have shown no unusual differences in the elevations of the bolts around the base of the tank between 2007 and 2020. NWN personnel were not able to confirm the date of the last thermographic scan of the tank. However, visual inspections have not identified any frosting or indication of insulation degradation. NWN personnel were also unable to confirm whether any third-party tank corrosion inspections have been performed on the tank.

NWN personnel noted that currently, the tank level is maintained at no greater than 69'-1" (approximately 76% of maximum design level) as a result of a recent, third-party evaluation of the tank that considered the original tank construction relative to current local seismic codes and regulations. This assessment does not evaluate the analysis presented in the third-party report, and recommendations assume that NWN will continue to operate at this reduced level in the future.

Based on density profile information provided by NWN, the properties of the current liquid inventory of T-1 are within range of those outlined in the tank design basis. Based on gas chromatograph data collected during LNG vaporization, the liquid within the tank has a heating value of approximately 1080 BTU/SCF. Density profiles are performed periodically using the Enraf level gauge to monitor for liquid stratification and/or weathering of the LNG stored in the tank, and no issues were reported by NWN personnel. It was noted by NWN that although the density profiles are generally performed each year, there is currently no formal PM scheduled for this activity.

Generally, NWN has reported no increase in boiloff gas generation during liquefaction, vaporization or holding mode operations, and reported no issues with maintaining tank pressures within the normal operating pressure of approximately 1.1 psig. This suggests that the existing tank insulation system has not degraded from the original tank construction.

Based on discussions with NWN personnel, observations during the site visits and the results of the HAZOP, it is recommended that NWN:

1. Contract with a third-party firm to perform a comprehensive inspection and assessment of tank T-1 to include corrosion evaluation and thermographic scan of the tank. This should be performed every 10 years. Sanborn Head can provide recommendations for firms to perform this task. This is considered a Tier 3 item. The cost for this inspection is expected to be on the order of $60,000.
2. Plan for repainting the tank (including full sandblast, prep and coat) once during the next 15 years. It is unknown when the tank was last repainted. Note it is possible that the results of the tank inspection will determine the existing paint coatings to be sufficient for the remaining life of the Facility. This is considered a Tier 1 item. If required, the cost to repaint the tank is expected to be on the order of $600,000.

3. Create an annual PM task to perform an LNG density profile of the tank.
4. Consider changing the tank high level alarm setpoint in the plant control system to reflect the current procedural level limits.

4.3.2 Tank T-1 Relief Valves and Vacuum Breakers

Storage tank T-1 includes a 6" pilot-operated relief valve, SV-434, a 6" relief valve, SV-435, and a 12" vacuum breaker. NWN personnel did not note any known issues with the relief valves or vacuum breaker. Annual testing and calibration are performed on the relief valves. No testing or calibration is currently performed on the vacuum breaker.

During the HAZOP workshop, it was noted that the existing 6" isolation valve for the Enraf level gauge, if closed, would isolate the tank from SV-434 and SV-435. Additionally, the isolation valves to the SV-434 pilot, if closed, could prevent operation of the relief valve. NWN personnel indicated that these valves are car-sealed open, however plant drawings do not show the car-seals. Reference section 4.12.1 for a general recommendation to formalize the Facility's car-seal program and documentation.

Based on discussions with NWN personnel and our observations during the site visits, it is recommended that NWN should:

1. Establish a scheduled PM procedure to perform annual testing and calibration of the vacuum breaker.

4.3.3 Level and Temperature Instrumentation

Tank T-1 is equipped with three independent level instruments:

- Enraf level gauge: The Enraf is a servo-style level indicator that also provides the ability to perform density profiles of the liquid in the tank. NWN personnel reported occasional issues with the instrument, believed to be due to freezing/binding in the instrument stand-pipe at the top of the tank, however generally the Enraf has operated reliably. This device is not calibrated as part of a scheduled PM procedure.
- Shands and Jurs level gage LT-1: LT-1 is a float actuated, tape driven level indicator. NWN personnel indicated that this device was recently repaired and has operated reliably since the repair. LT-1 level indication generally matches the Enraf level gauge to within less than one foot. Based on our experience, Sanborn Head believes the tape level gauge to be near the end of its useful life.
- Differential pressure transmitter LT-T1: LT-T1 monitors the differential pressure between the LNG withdrawal connection at the bottom of the tank, and the tank vapor space. NWN indicates that while the level indication from this transmitter generally follows the indications of the other tank instruments, the level measurement does not match the Enraf or LT-1. Based on a review of the PLC ladder logic, the current scaling for LT-1 assumes a liquid specific gravity to be 0.42. As the actual liquid specific gravity is

approximately 0.455 (based on density profile data), NWN could consider updating the PLC scaling for a more accurate level indication.

Temperature measurement devices for storage tank T-1 consist of temperature sensing elements located at 10' elevation intervals on the tank wall, as well as the Enraf level gauge. NWN personnel have indicated that multiple tank temperature sensing elements appear to be sending incorrect values to the plant control system. It is likely not possible to replace the temperature sensing elements with LNG in the tank, but NWN could consider investigating the field wiring to the plant control system in order to rule out a potential cause of inaccurate signals.

Based on discussions with NWN personnel and our observations during the site visits, it is recommended that NWN should:

1. Plan for the replacement of the existing LT-1 tape level gauge with a new Enraf level instrument (or equivalent) within the next 5-10 years. This is considered a Tier 2 item. The cost of this upgrade is expected to be on the order of $50,000.
2. For each tank level measurement device, a calibration procedure should be developed, and an annually scheduled PM procedure should be established.
3. Implement an independent tank high-high level cutoff to shut down the liquefier. Reference NFPA 59A-2001, 7.1.1.3 and HAZOP recommendation 113. This is considered a Tier 3 item.

4.3.4 Ice Cover at Storage Tank Withdrawal Line

The withdrawal line on storage tank T-1 is connected to the tank by a bellows located upstream of ESD valve HCV-70. The bellows is directly connected to the tank, with no upstream isolation valve. The bellows is susceptible to falling ice, snow or other debris from the top of the tank.

Based on discussions with NWN personnel and our observations during the site visits, it is recommended that NWN should:

1. Construct a protective cover or similar device over the bellows and HCV-70 to protect from potential damage due to falling ice or snow. Because a failure of the bellows would prevent vaporization operations as well as create a major hazard, this is considered a Tier 3 item. The total cost to construct this cover is expected to be on the order of $15,000.
2. Perform regular visual inspections of the bellows. Consider performing non-destructive testing in conjunction with a tank inspection.

4.3.5 Storage Tank Withdrawal Line ESD Valve HCV-70

Solenoid-controlled swing check valve HCV-70 serves as the emergency shutdown valve for the LNG storage tank withdrawal line. If an ESD occurs, a solenoid holding the lever controlling position of the internal swing check valve is de-energized. This action releases the lever, causing the swing check valve to seat, blocking LNG flow from the storage tank to pumps P-1 and P-2. The design of the valve allows for any liquid trapped between HCV-70 and downstream isolation valves to bleed back into the storage tank as it warms.

This valve has previously been observed by NWN personnel to become covered with ice, causing failure of the valve to close upon an ESD event. The buildup of ice may be a result of the insulation installed around the shaft which connects to the actuating lever. Buildup of ice on the valve actuator lever may be the result of pipe insulation installed on the valve actuator shaft creating a "thermal bridging effect", whereby the insulation prevents the covered section of the shaft from absorbing ambient heat, causing the actuator lever to become too cold and accumulate frost.

The following information was discussed with the Emerson representative regarding this valve:

- No "off the shelf" solution exists to provide freeze protection for this valve or actuator.
- This style of valve body is no longer manufactured or serviced.
- Replacement parts are available for the actuator. An Emerson field service technician could rebuild the actuator to extend its service life.
- The manufacturer of the valve discontinued use of the existing style of actuator in 1995 and switched to a Kinetrol vane actuator.
- A Kinetrol vane actuator cannot be retrofit onto the existing valve without modification. An Emerson representative could perform an evaluation to determine whether this is feasible.

Because only a single shutoff valve is installed between HCV-70 and the storage tank, the removal of HCV-70 for replacement is not recommended with LNG in the tank. Although a failure in the open position would not prevent plant operation, HCV-70 is an ESD device which could create a potential hazard if not operating correctly. As a longer-term solution, NWN could consider adding an additional ESD valve downstream of HCV-70. Alternatively, NWN could consider configuring TCV-66 and TCV-67 (LNG pump suction valves) to close upon an ESD, augmenting the shutoff function of HCV-70.

Based on the information above, it is recommended that NWN should:

1. Remove the insulation around the shaft connected to the actuating lever, rework the insulation as required, and seal the opening in the insulation jacket. This is considered a Tier 3 item. The total cost of this work is expected to be on the order of $5,000.
2. Perform periodic inspections of this valve to confirm freedom of movement whenever the valve is open. The inspection frequency will depend upon observed icing conditions. Perform mechanical clearing of ice buildup as required.
3. Consider installing an additional ESD valve downstream of HCV-70. This is considered a Tier 3 item. The total cost to install this valve is expected to be on the order of $82,500.

4.4 LNG Sendout Pumps

4.4.1 LNG Pumps P-1 and P-2

The Facility includes two 250 HP cryogenic, multi-staged, vertical lift pumps, P-1 and P-2. The pumps were manufactured by Bingham and are now supported by Sulzer. The pumps are original to the plant and are approximately 50 years old. According to documentation received from Sulzer, Pump P-2 was last refurbished in 2014. This refurbishment consisted of a basic repair with replacement of wear parts and no replacement of any major components. Sulzer was not able to locate any documentation for any previous repairs or refurbishments on P-1. NWN personnel are also unaware of any work ever having been performed on P-1.

NWN personnel have stated that motor winding megger tests and basic maintenance including cleaning and lubrication are performed on the pumps annually.

Based on information and a quotation provided to Sanborn Head by Sulzer in October 2020, a refurbishment frequency of 15 years for the pumps is recommended. Pumps in this service typically fail due to foreign particulates and debris migrating through the system. During the next refurbishment, Sulzer recommends comparing "as-found" dimensions for items such as ring and bearing clearances to OEM specifications to aid in evaluating the appropriate mean time between refurbishments.

The original plant operation manual includes a procedure for pump cooldown, which states that the cooldown duration should be approximately three hours. When performing this procedure, NWN personnel have observed the actual cooldown duration to be much shorter. Per the procedure, pump cooldown valves HCV-68A and HCV-69A are left open even after pump inlet valves TCV-66 and TCV-67 are opened, where normally cooldown valves will be shut after opening of the main pump suction valves and starting the pumps to reduce heat leak to the pump suction. It was confirmed that .375 bore orifices are installed in the pump cooldown lines for both pumps. As a result of discussions with NWN, Sanborn Head was contracted to perform a separate evaluation focused on LNG pump and vaporizer LNG inlet header cooldown. Reference the latest revision of [REF 4] documents.

The LNG pumps do not currently have detection devices installed to monitor for pump vibration or low flow. Differential pressure switches DPS-64 and DPS-65 shut the pumps down on low differential pressure to protect against cavitation, but there is currently no device installed for high discharge pressure detection.

Heating elements are installed around the pump barrels to prevent frost heave in the pump foundations. Temperature sensing elements are installed in the foundations and connected to controllers located at the base of each pump. NWN personnel are unsure whether the pump foundation heating systems are currently functional.

Based on the information above, it is recommended that NWN should:

1. Refurbish P-1 in the next 1-2 years and refurbish P-2 in the next 10 years. Rewind motor if testing indicates a need. The refurbishment of P-1 is considered a Tier 3 item and the refurbishment of P-2 is considered a Tier 2 item. The total cost of a pump refurbishment is expected to be on the order of $50,000 based on a budgetary quotation received from Sulzer. The total cost to rewind a motor is expected to be on the order of $10,000. If testing indicates that a motor rewind may possibly be required within the next 10 years, it is recommended that this be performed proactively while the associated pump is out of service for refurbishment.
2. Pump motors should be inspected, tested, and serviced in accordance with NFPA 70B as a part of a scheduled PM procedure. While recommendations for frequency of motor inspections and insulation resistance testing varies, given the importance of these pumps, a frequency of 2-3 years is suggested.
3. Consider pre-planning for the rewinding of the motors to potentially decrease turnaround time in the event of a motor failure.
4. Consider installing pressure transmitters at the discharge of each pump to allow high and low discharge pressure alarms which would shut down the associated pump in the event of deadheading, cavitation, etc. This is considered a Tier 3 item. The total cost to install these transmitters is expected to be on the order of $22,000. Efficiency would likely be gained by performing this installation in conjunction with the upgrades described in sections 4.4.2 and 4.4.3.
5. The pump foundation heating systems should be tested, and any inoperative components should be replaced. This is considered a Tier 3 item. The cost to perform repairs will depend on which (if any) components require replacement.
6. Implement modifications to meet manufacturer requirements and recommendations per latest revision of [REF 4] documents.

4.4.2 Recycle Valves PCV-62 and PCV-63 and Controllers

Based on a pump curve provided by Bingham Pump Co., a minimum flow of 264 GPM per pump is required to allow adequate cooling of LNG Pumps P-1 and P-2. This is accomplished with pneumatically operated control valves PCV-62 AND PCV-63 in the pump discharge recirculation lines. The positions of these valves are modulated based upon pump discharge pressure to maintain the minimum required flow through each pump.

- The two Foxboro local pneumatic pressure controllers which operate PCV-62 and PCV-63 are original to the plant. These controllers are not serviceable by NWN personnel and service technicians who understand how to adjust the vintage mechanical technology are not readily available.
- The recycle valves PCV-62 and PCV-62 are also original to the plant, performance is unknown due to vintage controls, and do not include position feedback.

It is recommended that NWN consider replacement of the recycle controller and valves within the next 2 years as they are important to LNG pump minimum flow protection and to vaporizer line cooldown control. This is considered a Tier 3 item.

For additional information and costs of replacement options, reference the latest revision of [REF 4] documents. Efficiency would likely be gained by performing this replacement in conjunction with the pressure transmitter addition described in section 4.4.1 and the control valve upgrade described in section 4.4.3.

4.4.3 LNG Pump Control Valves

The LNG Pump configuration includes the following valves:

- Pump inlet control valves TCV-66 and TCV-67.
- Pump barrel cooldown valves HCV-68A and HCV-69A.
- Sendout line cooldown valves HCV-58 and HCV-60.
- Sendout line automated isolation valves HCV-59 and HCV-61.

These valves include pneumatic actuators which appear to be original to the plant. TCV-66 and TCV-67 are pneumatically operated manual valves which are controlled locally rather than from the plant control system. They are equipped with mechanical limit switches intended to provide position indication to the control room. It was noted that several of the limit switches fail to actuate due to gaps between the arms and targets. To properly support operations and control, valve indication in the control room is valuable information.

Based on the information above, it is recommended that NWN should:

1. Consider installing new actuators for TCV-66 and TCV-67. This would include integrating control of these valves into the plant control system. The total cost for this upgrade is expected to be on the order of $55,000.
2. Consider replacing the actuators, including limit switches and solenoid valves for each of the HCV valves listed above. For valves not currently equipped with limit switches, this would involve adding inputs to the plant control system to allow the position of each valve to be displayed in the control room. The total cost for this upgrade is expected to be on the order of $165,000.

These upgrades are considered Tier 3 items. Efficiency would likely be gained by performing these upgrades in conjunction with the pressure transmitter installation described in section 4.4.1 and the PCV upgrade described in section 4.4.2.

4.4.4 RV-405

Pressure relief valve RV-405 is installed on the LNG header piping between Pumps P-1/P-2 and the vaporizers. It is located approximately 1 foot above the grating on a walkway above the LNG pump containment area. It was noted that the relief valve is installed a short distance from the piping header, which could potentially lead to ice buildup around the spring side of the relief.

To reduce the likelihood of ice buildup causing a failure of relief valve RV-405 to lift and/or reseat, it is recommended that NWN should:

1. Consider reconfiguring the piping to allow increased distance between the LNG header pipe and RV-405. This is considered a Tier 3 item. The total cost for this work is expected to be on the order of $10,000.

4.4.5 LNG Header to Vaporizers

As part of the normal startup of LNG vaporization, Facility operating procedures require a controlled cooldown of the 6" LNG piping header between the LNG pumps and the vaporizers. The line is currently cooled by opening HCV-58 and HCV-60 pump discharge isolation bypass valves and controlling the cooldown flow using one of the downstream vaporizer LNG inlet flow control valves. Operations personnel questioned whether the configuration provides adequate cooldown control due to a recent rapid cooldown event. The event caused at least one pipe support block to shift off its base plate which resulted in the LNG piping header falling off its supports. In response, NWN contracted piping inspection, pipe stress analysis, and pipe support replacement project to confirm the piping system and pipe support systems were acceptable for operation.

As a result of discussions with NWN, Sanborn Head was contracted to perform a separate evaluation focused on LNG pump and vaporizer LNG inlet header cooldown. Reference the latest revision of [REF 4] documents for findings and solutions, both short-term to support the 2021-2022 heating season and long-term to better serve the life of the facility. Selected cooldown improvement solutions are considered Tier 3 items.

4.4.6 Piping and Insulation

The piping header between the LNG pumps and the vaporizers is not currently insulated. This was questioned from two points of view:

- LNG line cooldown due to length and configuration of piping to vaporizers.
- Personal safety due to potential ice patches on driveway and walkways below frosted line.

Reference the latest revision of [REF 4] documents for findings and recommendations in regard the vaporizer inlet header insulation.

4.5 LNG Vaporization Equipment

4.5.1 Vaporizer H-5

Submerged combustion LNG vaporizer H-5 is rated for 60MMSCFD. Based on the available documentation, the unit was manufactured by T-Thermal and installed in 1970. It is currently supported by Linde. The unit is installed in a concrete water bath and located inside a dedicated building which also houses the associated combustion air blower. It is not known to NWN personnel when the vaporizer top-works (burners, instrumentation) were last refurbished. Based on a nameplate located on the tube bundle inlet, the bottom-works (tube bundle, weir, downcomer) were last refurbished in 1990.

NWN personnel indicated that upon a previous burner failure in Vaporizer H-5, cold gas was passed into the NG outlet piping of the vaporizer. NWN personnel became aware of the issue only when ice was observed on the outside of the pipe. The pipe is painted carbon steel and the paint is currently peeling, likely due to thermal expansion. There are two temperature elements installed in the NG outlet piping, one of which is likely used for burner control. The second is connected to a temperature switch which appears to be configured to provide a low discharge temperature alarm to the plant control system. It is unknown why this alarm was not activated during the incident described above. TAG confirmed the plant control system logic is configured to alarm on low outlet temperature.

LNG inlet shutoff valve HCV-5 has a solenoid operator which is controlled from the plant control system. LNG inlet flow control valve FCV-5 is also controlled by the plant control system via an I-to-P located near the H-6 building. The plant control system logic should be configured to close FCV-5 followed by HCV-5 upon detection of a low-low discharge temperature. Additionally, a separate low-temperature shutoff valve is required on the vaporizer NG outlet piping per NFPA 59A.

The pneumatic circuit for FCV-5 includes an accumulator tank which is fed through a solenoid valve. The solenoid valve is currently bypassed with hard piping and its intended function in this configuration is unclear. The FCV-5 actuator includes a Fisher 377 trip valve. According to information received from an Emerson representative, the trip valve was originally configured to cause FCV-5 to fail closed when the pneumatic supply pressure fell below 64 PSI. Based on a walkdown of the pneumatic controls and review of the PLC ladder logic, it is likely that with the solenoid bypassed – low temperature interlocks and shutdown of LNG flow to the vaporizer would be blocked – it is possible this is the cause of the low temperature condition described above.

It was observed that no position indication sensors are installed on either FCV- 5 or HCV-5.

Vaporizer HCV-5 includes a combustibles analyzer on the exhaust stack. According to information received from Linde, the control system for a vaporizer equipped with an updated top-works design would alarm upon detection of high combustibles and shut off LNG flow upon detection of high-high combustibles. This functionality could potentially detect a tube leak; however, Linde still recommends pressure testing the tubing bundle prior to each vaporization season. Pressure testing is not currently performed, and it is unclear whether the combustibles analyzer is functioning or whether the plant control system will cause a shutdown upon detection of high combustibles.

Based on recommendations from Linde, the H-5 vaporizer requires combustion system upgrades/replacement with top-works improvements every 15 years and bottom-works every 30 years. As the previous bottom-works upgrade appears to have been performed in 1990 and it is not known by NWN personnel when a top-works upgrade was last performed, it is recommended that NWN pursue these within the next 2-3 years. This is considered a Tier 3 item. Budgetary pricing provided by Linde indicates that the cost of a top-works upgrade will be on the order of $1MM and the cost of a bottom-works upgrade will be on the order of $1.5MM.

In conjunction with the top-works upgrade, it is recommended that NWN should:

1. Install a dedicated low-temperature shutoff valve on the NG outlet piping. Reference HAZOP recommendation 131. This is considered a Tier 3 item. The total cost to install this valve is expected to be on the order of $55,000.
2. Review the pneumatic circuit and valve lineup for FCV-5. Verify whether the existing configuration ensures all protective shutdowns are in service.
3. Confirm why a low-temperature alarm at the NG outlet of H-5 did not display on the control room HMI during the burner failure incident described above.
4. Consider implementing a high-flow alarm on inlet flow meter FT-5.
5. Consider adding a water bath low-temperature alarm/permissive to ensure minimum bath temperature before admitting LNG to the vaporizer.
6. Consider adding a water bath high-temperature alarm.
7. Confirm whether the exhaust stack combustibles analyzer is functional and what, if any, associated interlocks are included in the plant control system logic.
8. Consider upgrading FCV-5 with a modern digital/pneumatic positioner. At a minimum, it is recommended that a position indication sensor be added to allow monitoring of valve position from the control room. This is considered a Tier 3 item. The total cost to upgrade the positioner is expected to be on the order of $27,500.
9. Consider replacing the HCV-5 actuator, including solenoid valves and limit switches. At a minimum, it is recommended that limit switches be added to allow monitoring of valve position from the control room. This is considered a Tier 3 item. The total cost to replace the actuator is expected to be on the order of $27,500.

Short-term, it is recommended that NWN should:

10. Contract with a Fisher service technician to calibrate/function test FCV-5 and identify whether valve replacement or rebuild is required.
11. Add an annual PM to perform functional checks of protective interlocks at the start of each vaporization season, likely in conjunction with system calibrations.
12. Perform visual inspection and pressure testing of the tube bundle at the start of each vaporization season.
13. Consider maintaining out of service vaporizers in hot-standby on pilot in order to reduce time required to start.

4.5.2 Vaporizer H-6

Submerged combustion LNG Vaporizer H-6 is rated for 30MMSCFD. The unit was originally manufactured by Ryan Industries and is currently supported by Linde. The unit was refurbished by Linde in 2017, including the top-works (burners, instrumentation, and control system) and bottom-works (tube bundle, weir, downcomer). The updated control system includes a standalone Allen-Bradley PLC with local HMI, located adjacent to the unit. The screens on this HMI are also available in the control room HMI. The unit is installed in a concrete water bath and located inside a building which also houses Vaporizer H-7 and the associated combustion air blowers.

NWN personnel have reported that to their knowledge, Vaporizer H-6 has not operated reliably since the top works/controls upgrade. During the last attempt to operate the unit, the burners failed to light – this was believed by NWN to be due to an interlock in the control system. A representative from Linde is scheduled to visit the Facility in October 2021 to perform tuning on all three vaporizers and Linde indicated that they planned to address the control system issues on Vaporizer H-6 at that time.

Based on recommendations from Linde, the H-6 vaporizer will require combustion system upgrades/replacement with top-works improvements every 15 years and bottom-works every 30 years. As the top-works and bottom-works were recently upgraded, it is not anticipated that this will be required in the next 15 years.

It is recommended that NWN should:

1. Work with Linde to resolve any control system issues which currently prevent the unit from operating.
2. Consider upgrading FCV-6 with a modern digital/pneumatic positioner. At a minimum, it is recommended that a position indication sensor be added to allow monitoring of valve position from the control room. Short-term, contract with a Fisher service technician to calibrate/function test FCV-6 and identify whether valve replacement or rebuild is required. This is considered a Tier 3 item. The total cost to upgrade the positioner is expected to be on the order of $27,500.
3. Add an annual PM to perform functional checks of protective interlocks at the start of each vaporization season, likely in conjunction with system calibrations.
4. Perform visual inspection and pressure testing of the tube bundle at the start of each vaporization season.
5. Consider maintaining out of service vaporizers in hot-standby on pilot in order to reduce time required to start.
6. Consider implementing a high flow alarm on inlet flow meter FT-6.

4.5.3 Vaporizer H-7

Submerged combustion LNG Vaporizer H-7 is rated for 30MMSCFD. The unit was originally manufactured by Ryan Industries and is currently supported by Linde. It is installed in a concrete water bath and located inside a building which also houses Vaporizer H-6 and the associated combustion air blowers. It is not known to NWN personnel when the vaporizer top-works (burners, instrumentation) were last refurbished. Based on a nameplate located on the tube bundle inlet, the bottom-works (tube bundle, weir, downcomer) were last refurbished in 2001.

According to Linde, NWN intended to perform a top-works refurbishment/controls upgrade on this unit after a H-6, but this was never completed. NWN personnel report reliability issues with the unit's instrumentation and controls, such as a level switch failure which caused the water bath to overflow. It was observed that no position indication sensors are installed on either FCV- 7 or HCV-7. It was also noted that the plant control system does not currently include a high temperature alarm for the H-7 water bath. Additionally, the unit does not currently have a combustibles analyzer installed on the exhaust stack and a separate low-temperature shutoff valve is required on the vaporizer NG outlet piping per NFPA 59A.

Based on recommendations from Linde, the H-7 vaporizer will require combustion system upgrades/replacement with top-works improvements every 15 years and bottom-works every 30 years. As it is not known by NWN personnel when a top-works upgrade was last performed, it is recommended that NWN pursue this within the next 3-5 years. This is considered a Tier 3 item. ROM budgetary pricing provided by Linde indicates that the cost of a top-works upgrade will be on the order of $1MM.

In conjunction with the top-works upgrade, it is recommended that NWN should:

1. Install a dedicated low temperature shutoff valve on the NG outlet piping. This is considered a Tier 3 item. Reference HAZOP recommendation 133. The total cost to install this valve is expected to be on the order of $55,000.
2. Consider adding a high temperature alarm and/or interlock to shut down H-7 on high outlet temperature, consistent with the other vaporizers. Reference HAZOP recommendations 129 and 140. This is considered a Tier 3 item and could be completed by NWN's controls integrator in conjunction with other HAZOP recommendations.
3. Consider implementing a high flow alarm on inlet flow meter FT-7.
4. Consider adding a low bath temperature alarm/permissive to ensure minimum bath temperature before admitting LNG to the vaporizer.
5. Consider adding a water bath high-temperature alarm.
6. Consider adding a high temperature alarm and/or interlock to shutdown H-7 on high temperature, consistent with the other vaporizers. Reference
7. Install an exhaust stack combustibles analyzer and add associated alarms/interlocks to the plant control system logic. Note that this would likely be included in a top-works upgrade.
8. Consider upgrading FCV-7 with a modern digital/pneumatic positioner. At a minimum, it is recommended that a position indication sensor be added to allow monitoring of valve position from the control room. This is considered a Tier 3 item. The total cost to upgrade the positioner is expected to be on the order of $27,500.
9. Consider replacing the HCV-7 actuator, including solenoid valves and limit switches. At a minimum, it is recommended that limit switches be added to allow monitoring of valve position from the control room. This is considered a Tier 3 item. The total cost to replace the actuator is expected to be on the order of $27,500.
10. Consider adding an additional valve on the NG outlet for DBB isolation without requiring H-7 to be isolated.

Short-term, it is recommended that NWN should:

11. Contract with a Fisher service technician to calibrate/function test FCV-7 and identify whether valve replacement or rebuild is required.
12. Add an annual PM to perform functional checks of protective interlocks at the start of each vaporization season, likely in conjunction with system calibrations.
13. Perform visual inspection and pressure testing of the tube bundle at the start of each vaporization season.
14. Consider maintaining out of service vaporizers in hot-standby on pilot in order to reduce time required to start.

4.6 LNG Tank Boiloff Systems

4.6.1 BOG Compressors C-2 and C-3

The BOG Compressors are water-cooled, V-belt driven, reciprocating compressors with single-stage, double-acting cylinders. Compressor C-2 is original to the plant and has a nameplate discharge pressure of 51 psig. Compressor C-3 was installed in 1986 and has a nameplate discharge pressure of 40.3 psig. The compressors discharge to the 57# underground pipeline through heat exchanger E-6 and oil separator S-7, and when liquefying, through the CO2 adsorber regeneration system. Both compressors currently operate at discharge pressures which exceed their nameplate values. Per a Harris Group memo, dated January 31, 2020, "NEAC Compressor Service USA, the owner of the original compressor patents from Pennsylvania Process Compressors, has indicated that we can safely operate both compressors up to a maximum discharge pressure of 80.8 psia (66.1 psig)". During liquefaction, there are times when the C-2 and C-3 discharge pressure relief valves lift as the operating pressure to overcome the distribution and system pressures approaches the relief valve setpoint. For this reason, NWN may want to consider increasing the compressor discharge relief valve setpoints to ~65 psig. However, in order to do so, a detailed review of the design and pressure testing records for the downstream piping and systems should be performed. If documentation is unavailable, the downstream piping should be pressure tested to the higher MAOP before any relief valve changes are performed. Additionally, instrumentation may need to be replaced to meet the higher MAOP.

A 6" manual discretional vent valve was recently installed in the boiloff compressor suction header downstream of E-10 ambient boiloff heater. The manual valve is installed to allow for operations to control tank pressure by venting warm LNG vapor to atmosphere in the event boiloff compressors are not available for operation such as power outage, maintenance, or other. When utilized, operations will need to be mindful not to exceed the capacity of the E-10 ambient preheater using this valve so the discharged vapor is warm and rises for good mixing with air. Any cold vapor will hug the ground for some time and could cause a safety issue inside or outside the facility. It is recommended to consider the addition of a new temperature gauge or indicating transmitter at the outlet of E-10, upstream of the new discretionary vent, and to update the holding system and boiloff compressor operation procedures for the use of the new discretionary vent valve and the required process and safety monitoring during its use.

Additionally, the boiloff piping insulation was observed to be deteriorating in many areas, which could allow moisture intrusion and lead to ice buildup under the insulation causing further damage.

NWN has recently completed a refurbishment of the compressors and is currently in the process of evaluating options for their replacement and/or the addition of a third compressor. The following options are being considered:

1. Installation of an oil-free rotary screw gas compressor, which would serve as a third compressor.
2. Replacement of the existing compressors with two skid-packaged Neuman & Esser belt driven, single stage, non-lubricated, single throw, horizontal reciprocating compressors, each with a water-cooled cylinder.
3. Replacement of the existing compressors with two skid-packaged Neuman & Esser belt-driven, single stage, non-lubricated, single throw, v-type reciprocating compressors, each with two water-cooled cylinders.

Traditionally, oil-free reciprocating compressors, similar to those at the PLNG facility, have been a common selection for boiloff compressors in LNG plants. However, today, oil free and flooded screw compressors are alternative options. Oil flooded screw compressors have been a common modern selection due to their turndown capability for tank pressure control and low maintenance requirements. Turndown capability is valuable to tank pressure control as it allows for the tank to be controlled at a stable pressure, minimizing the additional boiloff caused from cycling the tank pressure with on-off operation of a reciprocating compressor, which is the current standard operating practice at PLNG. The following table provides a comparison summary for the three technologies:

Flooded Screw Compressors vs. Oil-Free Reciprocating vs. Oil-Free Screw Compressors			
	Oil-Free Reciprocating	Oil-Free Screw	Oil Flooded Screw
Operating Efficiency and Turndown	Most efficient at 100% loaded. Limited unloading ability reduces efficiency due to start-stop operation. Turndown solutions available include: VFD to ~50% capacity and suction valve unloaders for up to 4 steps of rough turndown. Requires recycle valve to minimize start-stop of compressor	Less efficient at 100% than recip. VFD provides turndown to ~30-50% of rated capacity. Allowable turndown depends on the adequacy of the bearing lubrication at low speed and the compressor discharge temperature. Requires recycle valve to minimize start-stop of compressor	Less efficient at 100% than recip. Most efficient for year-round boiloff handling operation due to its capability to turndown to ~10% of rated capacity in small increments using its suction slide valve and, if sized correctly, typically eliminating the need for start-stop operation common to recip.
Maintenance	Higher wear and tear and lower reliability (i.e. more maintenance time) due to start-stop operation, higher vibration, and more moving parts.	More wear and tear and less reliability (i.e. more maintenance time) than a flooded screw compressor due to lack of lubrication and start-stop operation. A spare screw assembly is highly recommended.	Lowest maintenance requirements due to the small number of wearing and moving parts. Minimal start/stop of unit typically required. A spare screw assembly recommended.
Oil Contamination	None	None	Standard bulk oil-gas separator included with compressor package is typically sufficient for discharge to gas distribution. As boiloff is used for regen gas to the CO2 molecular sieve beds at PLNG, it is important to specify additional oil removal capability to ~1 ppb which typically includes a coalescing filter separator and, if required, an activated carbon bed as a final filter. However, if the pretreatment system is replaced as per pretreatment evaluation 4661.04-EVAL-02, then compressed boiloff gas will no longer be required for regen gas and the standard compressor skid bulk oil removal offering may be sufficient.

Flooded Screw Compressors vs. Oil-Free Reciprocating vs. Oil-Free Screw Compressors			
	Oil-Free Reciprocating	Oil-Free Screw	Oil Flooded Screw
Pressures	Highest pressure ratio	Lowest pressure ratio but does have a unit to meet	Pressure ratios (~8:1)
Skid size	Largest footprint	Smaller footprint than recip but larger than oil flooded screw	Smallest footprint
Pulsation	Inherent with design, Pulsation dampeners required	Smooth flow, typically no pulsation dampeners required	Smooth flow, typically no pulsation dampeners required
Noise	Highest decibel levels	Higher frequency but lower decibel level than recip	Higher frequency but lower decibel level than recip
Budget Installed Cost (incl. engineering)	$2,760,000	$2,020,000	$2,470,000

Based on the comparison above, it is recommended that NWN consider an oil flooded screw compressor package for the new 3rd compressor and/or replacement units. Prior to making a decision, NWN could consider performing an evaluation to identify the minimum and maximum capacity requirements for boiloff based upon all modes of facility operation. This will assist in understanding turndown needs of the compressor package which assists in identifying the best compressor type solution for the application.

Based on the information above and the results of the HAZOP, it is recommended that NWN should:

1. Consider the following for the existing boiloff compressors and/or include in the design of new boiloff compressors:
    a. Implement a low suction pressure trip to preclude damage to both compressors during a common low suction pressure event. Reference HAZOP recommendation 65. This is considered a Tier 3 item and could be completed by NWN's controls integrator in conjunction with other HAZOP recommendations.
    b. Implement a low tank pressure shutdown that is active in Manual Mode operation. Reference HAZOP recommendation 67. This will involve modifications to the existing compressor control wiring. This is considered a Tier 3 item. The cost of these modifications is expected to be on the order of $15,000.
    c. Add a high discharge temperature alarm. Reference HAZOP recommendation 71. This is considered a Tier 3 item and could be completed by NWN's controls integrator in conjunction with other HAZOP recommendations.
    d. Add a low suction temperature alarm which provides an alarm prior to the trip setpoint. Reference HAZOP recommendation 72. This is

considered a Tier 3 item and could be completed by NWN's controls integrator in conjunction with other HAZOP recommendations.

   e. Implement a high vibration trip on C-2. Reference HAZOP recommendation 73. The total cost to add a vibration sensor and implement the associated control logic is expected to be on the order of $5,000 to $20,000, depending upon whether a vibration switch or accelerometer-based instrument is used.

2. Consider removing PCV-18 and installing blind flanges at the connections as this valve was intended for an operating mode that is no longer used at PLNG. Reference HAZOP recommendation 68. This is considered a Tier 3 item. The cost to remove this valve is expected to be on the order of $5,000.
3. Consider a boiloff handling system evaluation to support the decision to replace or add additional capacity. The cost of this evaluation is expected to be on the order of $50,000 and would likely include the following:
   a. Develop a design basis for the boiloff compressor system including minimum and maximum capacity and discharge pressure conditions considering all facility operating modes.
   b. Based upon the design basis, identify the most suitable compressor capacity and redundancy configuration, i.e 2 x 100% vs. 3 x 50%, considering available turndown of evaluated compressor technology types, including recip, oil flooded screw, and if preferred oil-free screw.
   c. Develop installed capital and estimated annual operating costs for each compressor type and its redundancy configuration that best suits the application.
   d. Develop a boiloff compressor skid specification and project scope of work for the selected compressor type.
4. Install a new 3rd boiloff compressor and/or replace the existing boiloff compressors as per the results of the above evaluation. This is considered to be Tier 3 for one compressor and Tier 2 for 2nd and/or 3rd compressor. The associated costs, including engineering and commissioning, are expected to be on the order of $2MM to $3MM per compressor.
5. Install a temperature gauge or indicating transmitter at the outlet of E-10 ambient boiloff preheater and update the holding system and boiloff compressor operation procedures for the use of the new discretionary vent valve. This is considered a Tier 3 item. The cost to install a temperature transmitter is expected to be on the order of $5,000.
6. Car seal closed the 2" isolation valve for the tank makeup regulator which currently has the capability to provide pressurized natural gas from upstream E-6 aftercooler to upstream E-13/E-10 boiloff preheaters without overpressure protection. Reference HAZOP recommendation 69.
7. Consider replacing boiloff system insulation within the next 5 years. This is considered a Tier 3 item. The associated cost is expected to be on the order of $100,000.

4.6.2 Heat Exchangers E-6, E-10 and E-13

Cold natural gas vapor flows from storage tank to the boiloff system. When in liquefaction mode, this gas is pre-heated via the cold box pass C, upstream of compressors C-2 and C-3. When in holding mode, gas vapor is preheated via shell-and tube heat exchanger E-13 and/or ambient heater E-10.

E-13 transfers compressor heat of compression from the C-2/C-3 discharge to preheat the boiloff gas supply to the C-2/C-3 suction. E-10 is an ambient fin-tube exchanger that provides additional pre-heating of the boiloff gas. Installed valves allow either heat exchanger to be bypassed, although the normal system lineup has both heat exchangers in service. NWN reported no known issues with the condition or operation of E-13 and E-10.

Additional boiloff gas cooling is provided by shell-and-tube heat exchanger E-6, which uses water-glycol to cool C-2/C-3 discharge gas flow, prior to the 57# pipeline. NWN reported no known issues with the condition or operation of E-6, and there are no recommendations for E-6.

The HAZOP identified that the existing boiloff gas system does not include high-temperature interlocks to protect the 57# system from failure of the E-6 aftercooler to provide cooling. The HAZOP also identified a section of piping and pressure regulation that, as shown on PID drawing P-004, bypasses the boiloff gas pre-heaters, compressors, and aftercoolers. NWN could not confirm the purpose of this piping flow path and pressure regulator.

Based on the information above, it is recommended that NWN should:

1. Consider implementing new control logic to shutdown C-2/C-3 upon high-high outlet temperature from E-6. Reference HAZOP recommendation 70. This is considered a Tier 3 item and could be completed by NWN's controls integrator in conjunction with other HAZOP recommendations.
2. Consider budgeting for the replacement of E-6 withing the next 5 to 10 years. This is considered a Tier 2 item. The cost of this replacement is expected to be on the order of $20,000.
3. Consider budgeting for the replacement of E-10 withing the next 5 to 10 years. This is considered a Tier 2 item. The cost of this replacement is expected to be on the order of $40,000.
4. Consider budgeting for the replacement of E-13 withing the next 10 to 15 years. This is considered a Tier 2 item. The cost of this replacement is expected to be on the order of $105,000.

4.6.3 Oil Separator S-7

Oil separator S-7 is designed to remove all liquid particles 10 microns and larger as well as 99% of liquid particles 3 microns and larger from the boiloff gas compressor discharge, prior to the 57# pipeline. NWN noted no known issues with S-7, and there were no HAZOP recommendations associated with the separator.

4.6.4 BOG Compressor Valves

The unloader valves on each compressor are suspected by NWN personnel to be leaking instrument air into the gas stream with the potential to result in a combustible gas mixture in the downstream piping. As the instrument air system operates at 100 psig and the compressor discharge operates at 40-60 psig, it is possible the unloaders could leak instrument air into the gas piping if there is a path to do so via failed seals, o-rings, etc. However, it is considered to be low risk if the valves are maintained. Based on the information above, it is recommended that NWN should:

1. Repair any faulty valve components, O-rings, etc. at the earliest opportunity as this is considered Tier 3. The cost to perform these repairs is expected to be on the order of $1000 to $10,000.

NWN has also shared concern that if the plant loses instrument air, the unloader valves will not function, preventing use of the boiloff compressors. Due to this concern, NWN requested consideration to use natural gas for power gas instead of instrument air. Sanborn Head is of the opinion that air should continue to be utilized for the following reasons:

- The new instrument air supply system includes 2 x 100% air compressors reducing the risk of instrument air loss.
- In the event that the instrument air system is taken down for maintenance, NWN could utilize temporary nitrogen supply to maintain the boiloff compressors in service during the IAS maintenance outage.
  - Note: If the cold box replacement project is to proceed, a nitrogen supply system will be installed and can be designed to provide backup to the instrument air supply in addition to the cold box purge supply requirements. Reference the latest revision of [REF 2] documents for more information.
- Changing the design to potentially increase emissions is inconsistent with evolving regulatory requirements that continue to stress minimization of the release of methane to the atmosphere.
- As the unloaders were designed for instrument air, it is recommended that instrument air continue to be used unless NWN obtains approval from the compressor component supplier to utilize natural gas instead of air.
  - Note: If the compressor component supplier does approve natural gas use instead of air, NWN should request a gas quality specification from the vendor as it is expected that a natural gas dryer may be required to remove any water from the gas which could affect the function of the unloader valves.

4.6.5 BOG Flow Transmitter

A flow transmitter is currently installed on the plant sendout to the 57# line which measures LNG tank boiloff flow during holding and vaporization mode. However, no flow transmitter exists to measure boiloff gas flowrate during liquefaction mode since the 57# line also receives flow from the cold box and the dehydration bed regeneration tail gas system. During liquefaction, the boiloff flowrate value is currently calculated from other flows and pressures.

Based on the information above, it is recommended that NWN should:

1. Install a Coriolis flow meter on the discharge of the boiloff compressors, prior to the split to the CO2 adsorber regen gas supply and the direct line

to the 57# distribution system. This is considered a Tier 1 item. The total cost to install this flow meter is expected to be on the order of $50,000.

4.7 LNG Liquefaction – Feed Gas and Pretreatment Systems

4.7.1 Plant Inlet/Outlet ESD Valve HCV-98

Reference the latest revision of [REF 5] documents for a complete description of the HCV-98 ESD valve, comparison of replacement options, and recommendations for its replacement. The following two installation options are considered:

1. Relocate the ESD valve and install a new ball valve with pneumatic actuator assembly, in a position closer to the orifice meter (streetside), allowing the new valve to be installed with its stem in the vertical position and the actuator mounted on top of the valve, in parallel with the piping. The total cost associated with this option is expected to be on the order of $70,000.
2. Install the new valve in the same location as that of the existing HCV-98 valve, with the new valve stem in the horizontal position, facing the control building and the actuator mounted on the same side, parallel with the piping. The spring return cylinder would be located closer to the orifice meter side of the valve. The total cost associated with this option is expected to be on the order of $35,000.

NWN personnel have indicated that between the two options listed above, Option 1 is preferred. Therefore, this option and corresponding budget installed cost is included within the 15-year recommended capital spending plan summary tables provided in Appendices B, C and D of this report. The replacement of this valve is considered a Tier 3 item.

4.7.2 Pretreatment System

Reference the latest revision of [REF 3] documents for a description and current condition of pretreatment system components, performance and improvement evaluation, and identified upgrade options. The following two options are presented and considered to be Tier 3:

- Replace the existing pretreatment system in its entirety as per upgrade option 5.1 described within the pretreatment evaluation report to improve performance, safety, and availability. This option is assumed to be completed as a separate capital project within the 15-year recommended capital spending plan summary table provided in Appendix C of this report.
- Reuse existing systems and execute the following options described within the pretreatment evaluation report that will improve the safety and availability but will have no impact on performance. This option assumes the pretreatment system is not replaced (option 5.1 above) and the following corresponding budget installed costs are considered within the 15-year recommended capital spending plan summary table provided in Appendix B of this report.
  - Option 5.5: Switching Valve Replacement. The total cost of this replacement is expected to be on the order of $1,300,000.

- Option 5.6: Pretreatment Instrument & Control Upgrades. The total cost of these upgrades is expected to be on the order of $310,000
- Option 5.7: E-4 Relief Valve Sizing Evaluation and Replacement as Required. The total cost of this replacement is expected to be on the order of $2000 to $10,000.
- Option 5.8: Remove Sulfur Blimp V-1. The total cost of this removal is expected to be on the order of $210,000.
- Option 5.9: Replace Molecular Sieve in Drier Vessels. The total cost of this replacement is expected to be on the order of $140,000
- Option 5.10: Replace Molecular Sieve in CO2 Adsorbers Vessels. The total cost of this replacement is expected to be on the order of $140,000.

The following HAZOP recommendations are considered Tier 3 items which NWN should consider ***if the existing pretreatment system is not replaced in its entirety.*** Reference the 15-year recommended capital spending plan summary table provided in Appendix B.

1. Review the normal NWN NG distribution configuration and valve lineups to ensure the mixer station relief valve is not isolated from plant outlet piping. Reference HAZOP recommendation 6.
2. Consider adding a high-high level alarm and shutdown of the liquefier on high S-1 level. Reference HAZOP recommendation 23. This will require the installation of a level switch in S-1. The total cost to install this level switch is expected to be on the order of $27,500.
3. Consider adding a pressurization bypass around N2-1, and a pressure rate-of -rise alarm and/or trip of liquefaction. Reference HAZOP recommendation 31. The total cost to install this bypass is expected to be on the order of $15,000.
4. Consider implementing a high temperature interlock to shutdown LSD. This may require the addition of an automated shutoff valve downstream of FIT-13 or downstream of S-5. Reference HAZOP recommendation 97. The total cost to install this valve is expected to be on the order of $50,000.

The following HAZOP recommendations are considered Tier 3 items and could be completed by NWN's controls integrator in conjunction with other HAZOP recommendations ***if the existing pretreatment system is not replaced in its entirety.*** Reference the 15-year recommended capital spending plan summary table provided in Appendix B.

5. Consider implementing an interlock to prevent a switch from heating mode if the temperature setpoint is not reached.
6. Consider adding a high temperature alarm on the E-4 cooler outlet. Reference HAZOP recommendation 18. Also consider adding a high-high temperature trip on cooler outlet temperature. Reference HAZOP recommendation 19.
7. Consider adding a high temperature alarm and high-high temperature trip of the liquefier based on TE-21-1. Reference HAZOP recommendation 21.

8. Consider adding an interlock to prevent switching dryer bed online until low temperature reached, to ensure sufficient cool down. Reference HAZOP recommendation 22.
9. Consider adding a high temperature alarm/ high-high temperature shutdown of FCV-5 based on TE-21-60. Reference HAZOP recommendation 86.

4.8 LNG Liquefaction – Expander-Compressor and Supporting Systems

4.8.1 Turbo Expander C-1

The Facility uses an open-loop natural gas expander cycle to liquefy the feed gas. Turbo expander C-1 provides refrigeration to the main liquefaction heat exchanger by expanding dry natural gas from across an expander wheel at approximately 450 psig to approximately 50 psig low pressure. Heat is transferred from the liquefaction stream to the refrigeration stream. The refrigeration gas then is compressed by C-1, cooled, and injected into the NWN 85# distribution pipeline. C-1 operates at approximately 42,000 rpm, and is skid mounted with all associated instrumentation and a forced lubrication system.

NWN has considered in previous evaluations the replacement of the existing turbo expander but has elected to maintain the existing unit and integrate it with a new cold box. Therefore, replacement of the turbo expander is not considered in this assessment. It was noted that NWN has a spare rotating assembly for the turbo expander. Atlas Copco also recommended that NWN should consider procurement of a spare set of nozzle parts in order to minimize down time in the event of damage.

To avoid bearing damage, it is critical that the turbo expander reaches zero RPM before the associated lube oil system is shut down. NWN personnel indicated that zero RPM verification is currently accomplished by listening for movement of the rotating assembly at the turbo expander. Atlas Copco indicated that the existing speed sensor installed in the turbo expander is not accurate below approximately 1000 to 3000 RPM and is not suitable for zero speed confirmation. Atlas Copco provided budgetary pricing for replacing the existing speed sensor with a newer more sensitive model which would improve low speed detection down to approximately 300 RPM.

Based on recommendations received from Atlas Copco, NWN should:

1. Consider procurement of a spare nozzle set for the turbo expander. This is considered a Tier 2 item. Atlas Copco provided budgetary pricing of $75,000 for the spare nozzle set.
2. Consider replacing the existing turbo expander speed sensor. This is considered a Tier 3 item. Atlas Copco provided budgetary pricing of $3,500 for the new speed sensing hardware. The total cost of this replacement is expected to be on the order of $10,000.

The HAZOP workshop identified several potential enhancements to the turbo expander process controls and interlocks to improve the process safety, given that the existing unit is to remain in service. The following HAZOP recommendations are considered Tier 3 items and could be completed by NWN's controls integrator in conjunction with other HAZOP recommendations:

1. Implement a high-pressure alarm at PT-33 to alert the operator of a high-pressure condition at the C-1 discharge.
2. Implement differential pressure monitoring across strainer A and a high-differential pressure alarm using existing transmitters PT-24 and PT-130.
3. Implement a high temperature alarm at the C-1 inlet to alert the operator of a higher than normal operating temperature.

Additional HAZOP recommendations associated with the existing expander control valves and the existing lube-oil system are described in sections 4.8.2 and 4.8.3 below.

4.8.2 Valves Located at Turbo Expander

Turbo expander C-1 flow control and shutdown is performed by multiple pneumatically-operated valves, controlled from the plant control system. Based on observed conditions and discussions with NWN personnel, the existing valves are believed to be original to the plant and may be nearing end-of life. NWN personnel have noted that several of the control valves and manual valves located at the turbo expander do not seal completely.

Turbo expander NG inlet valve PCV-24 is a linear actuated valve which utilizes an original Fisher linear pneumatic actuator with a solenoid operated pneumatic positioner. This valve has been observed to leak gas. In one instance following operation of the turbo expander, PCV-24 became frozen and failed to fully close upon receiving a close command from the plant control system. The result was damaged turbo expander bearings due to continued rotation of the turbine after full shutdown of the bearing lube oil system. PCV-24 was observed to have a natural gas purge line installed to the valve operator gearcase. It is unknown why this purge is necessary.

It was noted that NWN has no information on SV-423 and it is not known whether this valve has sufficient capacity for a fail-closed case of HCV-33.

Based on the information above, it is recommended that NWN should:

1. Consider performing an evaluation of the sizing criteria for SV-423 and verifying whether the existing valve meets this criteria.
2. Consider replacing valves PCV-24, HCV-74 and HCV-74E with modern valves such as those manufactured by Fisher. It is also recommended that NWN consider replacing the actuator on FCV-22. All new valves/actuators should be equipped with position feedback devices or limit switches. These are considered Tier 3 items. The total cost of these replacements is expected to be on the order of:
    - PCV-24 - $40,000
    - HCV-74 - $125,000
    - HCV-74E - $20,000
    - FCV-22 (actuator only) - $10,000

4.8.3 Turbo Expander Lube Oil System

The turbo expander is equipped with a lube oil system which is original to the plant and consists of two 15 gpm oil pumps in a lead-lag configuration, a water-cooled oil cooler, duplex 10-micron filters, an oil reservoir with heater, a bladder type coast down accumulator and a float operated multi-port drainer.

The following items were noted regarding the lube oil system:

- The valves and instrumentation on lube oil system are not tagged on the P&I drawings or in the field.
- Handles have been removed from multiple lube oil system valves.
- The field piping does is inconsistent with the P&I drawing - the F3-F4 filter assembly has a 4-way valve which opens/closes the inlet/outlet of the filters. It is not possible to isolate both sets of filters – the P&I drawing is incorrect.
- Relief valves for the lube oil system are not currently tested because the relief valves are flanged and must be removed to test.

NWN personnel discussed a recent incident where PCV-24 became frozen open causing an unintended supply of natural gas from the cold box to the turbo expander. Under the assumption that the turbo expander was not rotating, operations shut down the lube oil system which resulted in damage to the turbo expander bearings. The operating procedure was subsequently revised to include verification of zero RPM at the turbo expander before the lube oil system can be shut down. An attempt was made to add an interlock to the plant control system to prevent this incident from recurring, but this was not possible with the current lube oil system "hand-off-auto" switch configuration. The "off" position of the switch is hard-wired, meaning no interlock in the control logic can fully prevent an inadvertent shutdown of the pumps while the turbo expander is rotating.

Based on the information above and the fact that the turbo expander lube oil system is critical to liquefaction operation, it is recommended that NWN should:

1. Consider the complete replacement of the lube oil system. This is considered a Tier 2 item. Atlas Copco provided a budgetary price of $600,000 for a new lube oil skid. Total installation cost for the new skid is expected to be on the order of $1,650,000.
2. Establish a scheduled PM procedure for testing of lube oil system relief valves.
3. Create and add tags to the P&I drawings as well as the devices in the field.
4. Replace any valves which are missing handles (or replace handles) and car-seal open as required.
5. Consider re-wiring/reprogramming the lube oil system "hand-off-auto" switch as two PLC inputs, "hand" and "auto", with the lack of either input representing the "off" position in the PLC. In conjunction with the speed sensor replacement described in section 4.8.1 above, this would allow a zero-speed confirmation interlock to be incorporated into the plant control system which would prevent the lube oil system from shutting down until the turbo expander reaches zero RPM.

4.8.4 Seal Gas System

The seal gas system is original to the plant and is designed to provide natural gas to the turbo expander in order to seal the shaft and prevent process gas from escaping to the atmosphere. Natural gas is supplied to the system from filter F-1 and passes through heat exchanger SGH-1 to be warmed before being supplied to the turbo expander shaft seals. It is then returned to the 57# pipeline after being cooled using water-glycol in shell and tube heat exchanger E-15. NWN personnel have reported no known issues with the seal gas system. However, the following is recommended:

- Seal gas system be evaluated by Atlas Copco and replaced as required in conjunction with the lube oil system replacement described in the section above.
- NWN review the turbo expander procedure and consult Atlas Copco to ensure that proper guidance is provided for maintaining operation of the seal gas system until temperatures at the cold box/in the process are above the temperature specified by Atlas Copco to protect the bearings of the turbo expander.

4.9 LNG Liquefaction – Heat Exchangers and Vessels

4.9.1 Cold Box

NWN is currently pursuing the full replacement of the cold box as well as associated valves and piping. Reference the latest revision of [REF 2] documents for details related to the existing cold box and the planned replacement.

HAZOP recommendations related to the cold box have been included within the cold box replacement scope of work identified within the FEED report.

If the existing cold box is not replaced, it is recommended that NWN should:

1. Convert the existing cold box natural gas purge to a nitrogen purge to reduce fugitive methane emissions, improve safety, and enable detection of leaks within the cold box heat exchangers. This will require the addition of a fixed nitrogen supply. As per the nitrogen supply evaluation [REF 6] conducted as part of the cold box replacement FEED study, a bulk nitrogen storage and vaporization system is recommended to be installed as the nitrogen supply source. This is considered a Tier 3 item. Total cost is expected to be on the order of $310,000.
2. Replace heat exchanger E-14 due to issues identified in [REF 2] documents. This is considered a Tier 3 item. Total cost of the replacement is expected to be on the order of $300,000.
3. Replace control valves associated with the cold box as described in [REF 2] documents. This is considered a Tier 3 item. Total cost to replace the valves is expected to be on the order of $350,000.

A 15-year recommended capital spending plan summary table which considers the scenario in which NWN elects to replace neither the cold box nor the pretreatment system is provided in Appendix D.

The following HAZOP recommendations are considered Tier 3 items which NWN should consider ***if the existing cold box is not replaced*** in order to lessen the likelihood of exceeding design parameters, contamination or plugging of liquefaction or refrigeration flow paths within the Cold Box. The total cost to implement these recommendations is expected to be on the order of $190,000.

1. Integration of high-high moisture alarm and liquefier trip to prevent carryover of moisture into the new Cold Box upon Dehydration (Dehy) system breakthrough.
2. Installation of a new CO2 analyzer with high-high CO2 ppm alarm and liquefier trip to prevent carryover of CO2 into the new Cold Box upon CO2 adsorber system breakthrough.
3. Implementation of low and high temperature monitoring, alarms, and liquefier shutdowns for process transients that could lead to exceedance of design temperatures in the Cold Box streams, including:
    a. High and high-high temperature at E-4 outlet/cooler inlet (TE-21-32).
    b. High-high temperature at the Dehy outlet (TE-21-21).
    c. Low temperature at flash gas outlet from Cold Box (TE-21-40/43).
    d. High temperature at the liquefier outlet (TE-21-32)
    e. High differential temperature/rate-of-change across Cold Box passes.
4. Implementation of high-high flow alarm and liquefier shutdown (FIT-16).
5. Implementation of liquefier shutdown on high-high tank level or high-high tank pressure at storage tank T-1.
6. Integration of differential pressure indication for all Cold Box passes.
7. Implementation of E-14 low and low-low outlet gas temperature alarm and interlock to mitigate the risk of high liquid (heavy hydrocarbons) flow to E-14 that could result in cold gas to the carbon steel outlet piping feeding the 85# distribution system if the LCV(s) feeding E-14 were to fail open. Consider E-14 pressure rating and/or overpressure protection in implementation design. Refer to the E-14 evaluation in section 4.2 within this report.

4.9.2 Recommendations for Operational Improvement of Liquefaction

It was noted that ice blockage has occurred at the LNG inlet to T-1 due to freezing of contaminants when not liquefying. This requires shutdown/warmup with helium used to purge. This is more than likely the result of exceeding the capacity of the CO2 adsorbers. As operations runs the cold box outlet LNG temperature warmer than design to mitigate/slow down the CO2 plugging of the cold box passes, the higher than design CO2 content in the LNG is more than likely flowing downstream to the tank. When expanded across FCV-16 (J-T valve), the liquid temperature drops and more than likely causes some CO2 solids to be dropped out. Once the system is shut down and the LNG in the piping vaporizes to the tank, it is possible that more CO2 solids drop out during this process and as it is at the tank inlet, the temperature remains cold enough to maintain the CO2 as a solid. NWN should consider replacing the pretreatment system or modifying its operations to stay within the design capacity of the system. Refer to the pretreatment evaluation report, document # 4661.04-EVAL-02 and Section 4.7.2 above, for more information.

4.10 Hot Oil System

4.10.1 Oil Heater H-8

Gas-fired oil heater H-8 was manufactured by Exotherm and installed in 2016. It is used to heat Therminol for use in CO2 adsorber regen shell and tube heat exchanger E-100 and dehy regen shell and tube heat exchanger E-101. The oil heater includes a standalone PLC control system and is currently supported and serviced by Exotherm. This includes safety interlock and combustion checks, performed on an annual basis. The unit is located within a containment curb in the northern corner of the Facility. It was noted that the containment curb around the oil heater has several holes which would prevent the curb from effectively containing a leak or spill.

Flow transmitter FT-H01 is used to measure the flow of Therminol into oil heater H-8. NWN personnel have been unable to zero out this flow transmitter. It was noted that the sensing lines come out of the top of the orifice flanges. This configuration can potentially lead to gasses becoming trapped in the sensing lines. For liquid measurement, it is preferable to have lines come from the bottom of flanges and slope up from the transmitter to the process in order to allow any gasses to escape the sensing lines thereby avoiding vapor traps.

Based on the information above, it is recommended that NWN should:

1. Consider repairing the containment curb around oil heater H-8. This is considered a Tier 2 item. The cost of this repair is expected to be on the order of $5,000.
2. Consider relocating flow transmitter FT-H01 to a point below the orifice flanges. Sensing lines should be reconfigured to come from the bottom of the flanges and slope upward from the transmitter to the process. This is considered a Tier 2 item. The cost of this relocation is expected to be on the order of $3,000.

Please note that if a pretreatment system replacement were to occur, the hot oil heating system would require replacement and the above corrections should be considered in the new system design. Refer to the pretreatment evaluation report, document # 4661.04-EVAL-02, for more information.

4.11 Water-Glycol System

4.11.1 Pumps P-5, P-6, P-8 and P-9

The main LNG cooling system consists of approximately 800 gallons of water-glycol mixture circulated by either pump P-5 or pump P-6 through five liquefaction heat exchangers and a fan coil heat exchanger. The secondary cooling system consists of approximately 100 gallons of water-glycol mixture circulated by either pump P-8 or P-9 through the boiloff compressor jackets, boiloff compressor aftercoolers and a fan coil heat exchanger. The system was designed to use a 50/50 water-glycol mixture but currently utilizes only 40% propylene glycol. NWN personnel have noted gas leakage into the water-glycol system. A tube leak in one or more of the heat exchangers is suspected to be the source of this leakage. Additionally, corrosion components and fine magnetic material have been observed in the water-glycol mixture.

During liquefaction, C-2, C-3 and E-6 are switched over to pumps P-5/P-6 and the E-11 circuit. Pumps P-8/P-9 feed E-4 exclusively. It is not known to NWN personnel why the system is configured this way. It was also noted that the pumps are not run during the off-season and the Facility does not keep spare pumps on hand for the replacement of either P-5/P-6 or P-8/P-9.

NWN personnel noted that during a previous incident during which the cleanup skid was running but the water-glycol pumps were not, the temperature of a heat exchanger increased enough to cause paint peeling but no alarm was activated in the plant control system.

Based on the information above, it is recommended that NWN should:

1. Consider procuring and keeping on hand spare pumps for the replacement of P-5/P-6 and P-8/P-9. The cost to procure these spares is expected to be on the order of $20,000.
2. Consider adding an interlock to shut down the liquefier upon a loss of P-5/P-6. Reference HAZOP recommendation 161. This is considered a Tier 3 item and could be completed by NWN’s controls integrator in conjunction with other HAZOP recommendations.
3. Consider periodically running the water-glycol pumps during the off-season.
4. Consider adding periodic checks of air vents with CGI to the regular operator rounds or establish as a scheduled PM procedure in order to detect accumulation of gas in the water-glycol system.
5. Consider adding a gas detector at the water-glycol expansion tank vent to detect the presence of gas in the system. This is considered a Tier 3 item. The cost to install a detector is expected to be on the order of $15,000.
6. Consider establishing an annual PM procedure for lab analysis of the water-glycol mixture.
7. Consider updating the controls for P-5/P-6 and P-7/P-8 to improve the detection of and automatic response to a pump failure.

4.11.2 Coolers E-11 and F-2

Essex fin-fan exchanger E-11 provides cooling for the main LNG water-glycol cooling system. It was noted that the cooling fans for this exchanger are controlled locally by temperature switches rather than by the plant control system. There are two cooling fans on the E-11 cooler – liquefaction at reduced capacity may still be possible on loss of one cooling fan.

Cooling box fan F-2 provides cooling for the secondary water-glycol cooling system. During liquefaction, C-2, C-3 and E-6 are switched over to pumps P-5/P-6 and the E-11 cooling circuit. Pumps P-8/P-9 feed E-4 exclusively utilizing the F-2 cooler. It is not known to NWN personnel why the system is configured this way. F-2 represents a single point failure during liquefaction in this configuration.

Based on the information above, it is recommended that NWN should:

1. Consider installing temperature transmitters on the inlet and outlet of E-11 and integrating the control of the cooling fans into the plant control system. This is considered a Tier 2 item. The cost to perform this upgrade is expected to be on the order of $22,000.
2. Consider stocking spare parts for F-2 and E-11 to minimize liquefaction down time on cooling fan failure. Cost is Tier 2 and estimated to be ~$20,000.

4.12 Balance of Plant and General Recommendations

4.12.1 Car-Seal Program

It was noted that no formal car-seal program exists for the Facility. The HAZOP workshop identified multiple valves which were noted on the P&I drawings as CSO or CSC, but it was unknown to NWN personnel whether the corresponding car-seals are in place. The HAZOP workshop also identified valves which should be car-sealed and currently are not.

It is recommended that NWN should:

1. Develop a formal car-seal program which would identify all existing and required car-seals, including those in front of relief valves. P&I drawings should be updated to reflect all CSO/CSC valves.

4.12.2 Relief Valve Discharge Piping

It was noted that the discharge piping for multiple relief valves is installed at head-level or otherwise in a vicinity where personnel could potentially be present. This represents a potential safety hazard.

It is recommended that NWN should:

1. Consider conducting a survey to identify any relief valves for which the configuration of the discharge piping represents a potential safety hazard.
2. Consider modifying the relief valve discharge piping for any valves identified in the survey described above in order to avoid releases at head level, etc. This is considered a Tier 3 item. The cost to perform these modifications will depend on the quantity of valves identified in the survey as well as the configurations of existing piping and modifications required.

4.12.3 Plant Inlet Traffic Bollards

It was noted that the vicinity of the plant inlet piping is lacking adequate barriers, bollards, etc. to provide protection against vehicle/equipment impacts.

It is recommended that NWN should:

1. Install additional traffic bollards to protect piping and equipment in the vicinity of the plant inlet. This is considered a Tier 3 item. The total cost for this installation is expected to be on the order of $5,000.

4.12.4 Gas Chromatograph

A single ABB Model NGC 8206 gas chromatograph (GC) currently provides gas composition analysis for multiple process streams throughout the Facility. A second ABB GC is installed in the Chromatograph building, adjacent to the functioning GC. The second unit is powered but is currently disconnected from the sampling system. Each unit has three-stream analysis capabilities.

The operating GC analyzes different groups of process stream samples based upon operator manual selections. Manual valving is currently used to allow operators to select which Facility processes are analyzed by the working chromatograph.

NWN operators have expressed a desire to automate selection of the process streams being analyzed using automated valving controlled by the plant control system, switching streams at programmed intervals. The operators also suggested that the second, non-functioning GC should be reconnected to the sample system to analyze more process streams simultaneously, thereby requiring less time for the analysis of all streams.

It is recommended that the additional, offline GC be reconnected to the sampling system to take advantage of its availability as well as to reduce the amount of time required for completion of gas composition analysis. Automation of the sampling system would provide some optimization of the gas analysis process, along with added convenience/operational improvement. Therefore, although not considered a high priority it is recommended that automation of the sampling system be further evaluated. This is considered a Tier 1 item. The cost to bring the second GC online and automate the sampling system is expected to be on the order of $55,000.

4.12.5 Instrument Air System

The instrument air system provides clean, dry compressed air for the operation of pneumatically operated valves as well as the purging of electrical enclosures. It was recently replaced in its entirety and there are no known issues or concerns with the system. It is currently supported and serviced by Rogers Machinery Company, Inc. in accordance with the manufacturer's maintenance manual. NWN noted no known issues with the instrument air system, and there were no HAZOP recommendations associated with the system.

4.12.6 Pipe Insulation and Corrosion Inspections

NWN personnel indicated that an internal NWN corrosion engineer and technicians perform periodic inspections of the cathodic protection systems for underground pipes into and out of the Facility. No regular inspections of piping within the Facility are performed.

It was noted that piping insulation was damaged or missing in multiple locations in the Facility. It is assumed that the insulation in a given area would be replaced as a part of a major project/equipment replacement in that area (i.e., the cold box replacement). However, other repairs are likely to be required over the 15-year life of the plant.

It is recommended that NWN should:

1. Perform corrosion inspections every 3 years, including a spot inspection under insulation. The cost for each inspection is expected to be on the order of $75,000. This includes the following:
    a. $40,000 for inspection;
    b. $10,000 to repair affected insulation;
    c. $25,000 to recoat piping as needed.
2. Budget for miscellaneous insulation repairs over the 15-year life of the Facility. This is considered a Tier 1 item. This is expected to involve two insulation repair projects over the 15-year life of the Facility, the cost for each of which is expected to be on the order of $50,000.
3. Consider the installation of site glasses/ports to facilitate corrosion inspections. However, it should be noted that on cryogenic lines this can potentially induce moisture into the insulation which can lead to premature failure of the insulation.

4.12.7 Fire and Gas Detection and Protection Systems

Fire and Gas detection for the Facility is provided by a Det-ronics Eagle Quantum system, with its main control panel located in the control building. Gas detectors and IR sensors are installed in various locations throughout the Facility. It was noted that several of the gas detectors are located at ground level, which may not be ideal for the detection of gas.

It is recommended that NWN should:

1. Consider reviewing the existing gas detector locations to optimize gas detection coverage and update the current fire protection evaluation as applicable.

4.12.8 ESD System

Emergency shutdown (ESD) pushbutton stations are installed at various locations in the Facility and initiate a plant shutdown when activated. The ESD system is “hardwired” and does not rely on control system logic to accomplish a plant shutdown. When the ESD system is activated, LNG sendout, vaporization, BOG compression, pretreatment and liquefaction systems are stopped, and the associated equipment is shut down. Additionally, storage tank withdrawal line ESD valve HCV-70 and plant inlet/outlet ESD valve HCV-98 close upon activation of the ESD system. It was noted that no ESD valves are currently installed to isolate the 57# or 85# systems upon activation of the ESD system.

An ESD pushbutton was observed to be installed on a handrail support at the base of the access platform for HCV-70. This location would potentially require an operator to approach a leak in order to activate the ESD pushbutton. It was also noted that the ESD pushbuttons in the H-5 and H-6/H-7 vaporizer buildings are located just inside the doorways. NWN personnel have indicated that these pushbuttons are easily confused with light switches in the current locations.

Based on the information above, it is recommended that NWN should:

1. Consider installing valves to isolate the 57# and 85# systems upon activation of the ESD system. This is considered a Tier 3 item. The total cost to install these valves is expected to be on the order of $120,000.
2. Consider relocating the pushbutton near HCV-70 to a point along the exit path leading up out of the LNG containment area such as at the base of the stairs. This is considered a Tier 3 item. The total cost for this relocation is expected to be on the order of $5,000.
3. Consider relocating the pushbuttons inside the doors of the H-5 and H-6/H-7 buildings. This is considered a Tier 2 item. The total cost for this relocation is expected to be on the order of $2,000.
4. Consider the addition of guards on these pushbuttons to prevent accidental activation.

4.12.9 Motor Control Center Expansion

The original plant Motor Control Center (MCC) was replaced within the last several years with new MCC-1 and MCC-2. There are a limited number of spare buckets/spaces available in the existing MCCs to support integration of additional equipment. The MCCs are located within the main control room portion of the existing control building. NWN personnel indicated a desire to segregate /separate the MCCs from the main operator work area and would consider options to install a wall or partition to separate the MCC.

To segregate the MCC equipment from the operator work area as well as to allow the addition of additional MCC sections, NWN could consider a project involving the following:

1. Install a wall and door within the control building to effectively create a separate MCC room. This would likely involve relocating the existing exterior door located on the northeast corner of the control building.
2. Install a new lineup of MCC sections against the new wall, facing the existing MCC.
3. Replace the existing service panel with a new switchboard which would include a circuit breaker to feed the new MCC sections. Additionally, an automatic transfer switch could be incorporated into this new switchboard to replace the existing manual transfer switch for generator G-2.

It was noted that although desirable to segregate the MCC equipment, code required working clearances to all electrical equipment are maintained with the current configuration. This is therefore considered a Tier 1 item as it is not considered a safety issue but rather an opportunity for operational improvement. The cost of the project will depend on the scope, including ampacity of the new MCC, number of sections to be added, etc., but it is expected that the total cost would likely be on the order of $500,000.

4.12.10 Standby Power System

The existing standby power systems at the Facility consist of:

- Generator G-1, a 150 KW natural gas-fueled generator which supplies power to critical loads on MCC-2 (lighting, instrument air compressors, fire alarm system, etc.). An automatic transfer switch in MCC-2 starts G2 on loss of utility power.
- Generator G-2, a 750 KW diesel-fueled generator which can supply power to all Facility electrical loads, specifically the boiloff and vaporization equipment that are considered critical functions of the LNG Facility. A manual transfer switch allows for manual switchover from utility power to generator power when required.
- UPS, an uninterruptible power supply provides battery-backed continuous power to critical control system loads.

Although not considered a high priority, NWN personnel have indicated that automatic startup and transfer of generator G-2 would be desirable. In order to determine whether this is feasible, a load study should be completed to confirm whether generator G-2 is sized adequately to provide power to all connected loads expected to run simultaneously, which is a requirement of the National Electrical Code for automatic transfer equipment. Assuming G-2 is sized adequately, the replacement of the existing manual transfer switch with an automatic transfer switch could be accomplished as a part of the MCC expansion project discussed in the section above.

Other than operational issues associated with manual startup and switching, NWN noted no known issues with the standby power system. There are no additional recommendations for the system other than continuation of factory service/PM.

4.12.11 Security System

The security system at the Facility consists of cameras installed at various locations throughout the site. Monitors for the cameras are located in the control building. NWN personnel reported no known issues with the security system.

It is recommended that NWN should:

1. Budget for an upgrade to cameras and controls/monitoring equipment during the 15-year life of the Facility due to obsolescence/software upgrades. This is considered a Tier 1 item. The cost of the upgrade is expected to be on the order of $25,000.

4.12.12 Plant Control System

An Allen Bradley ControlLogix PLC-based system provides monitoring and control for the plant systems, including the pretreatment, liquefaction equipment, boiloff, vaporization and plant auxiliary systems. A PC-based HMI system is networked to the PLC system to provide operator interface to the plant equipment. NWN has a current project to reconfigure the PLC system, upgrading existing processors and relocating the processors and HMI network servers and equipment to a separate room. This project is expected to be completed in 2021. It is anticipated that an additional HMI hardware/software upgrade will be required within the next 15 years

In addition to automatic control, data acquisition/storage and monitoring functions, the plant control system provides certain protective interlocks for process equipment. However, based on discussions with NWN and TAG personnel, there are multiple interlocks which are not currently in place, and should be integrated into the system. Refer to the sections above and the HAZOP report and for recommendations on specific interlocks which should be implemented.

Typical documentation for a plant control system would include a control narrative, alarm setpoint list, alarm cause/effect matrix and interlock list. It was noted that these documents do not exist for the PLNG Facility. Additionally, the TAG representative interviewed during Sanborn Head's site visit indicated that the control system logic is generally disorganized, due in part to piecemeal modifications by various parties over the life of the facility. This disorganization was also noted by Sanborn Head during our review of the control system logic performed in support of the HAZOP.

Based on the information above, it is recommended that NWN should:

1. Consider budgeting for an HMI hardware/software upgrade to be performed within the next 15 years. This is considered a Tier 1 item. The cost of this upgrade is expected to be on the order of $200,000.
2. Consider creating documentation for the plant control system, including a control narrative, alarm setpoint list, alarm cause/effect matrix and interlock list. This is considered a Tier 3 item. The cost to create this documentation is expected to be on the order of $100,000.
3. Consider implementing control system logic modifications in response to the HAZOP actions. It is recommended that items identified as high priority in the HAZOP report should be implemented in 2022. This is considered a Tier 3 item. The cost for NWN's controls integrator to perform these modifications to the control system logic is expected to be on the order of $75,000.
4. Consider budgeting $50,000 per year for future updates to control system logic.

5.0 APPENDICES

APPENDIX A: Facility Process Flow Diagram

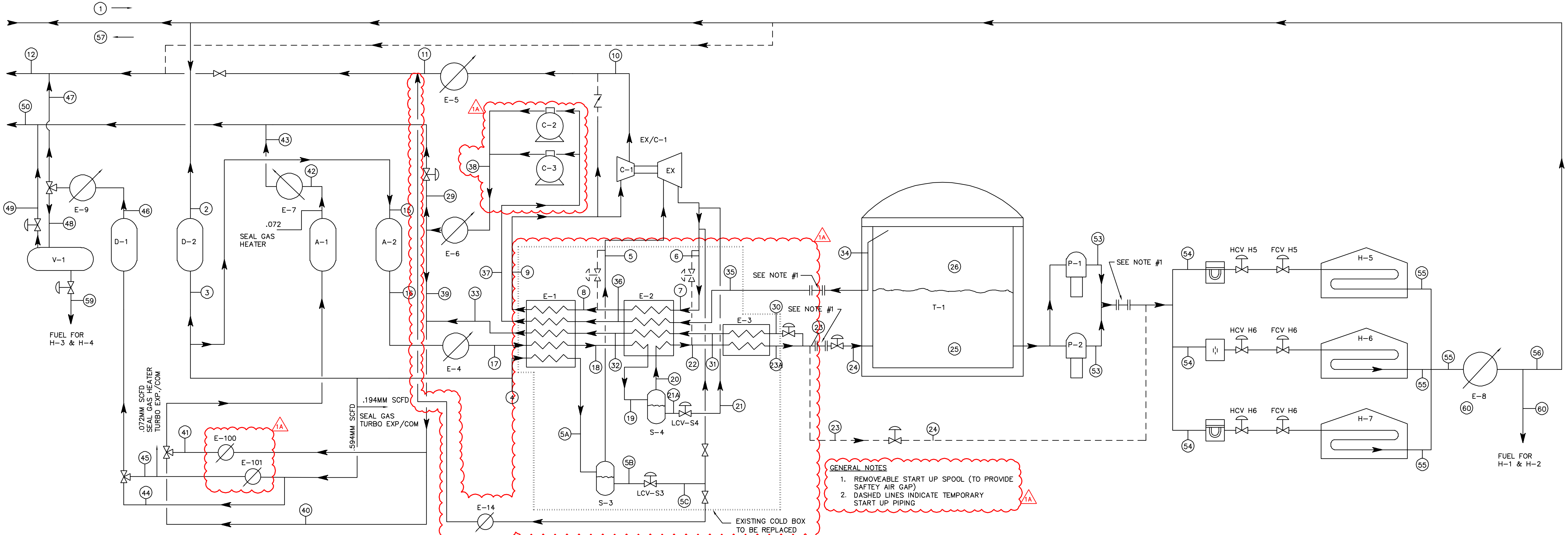
APPENDIX B: Recommended 15-Year Capital Spending Plan for Scenario 1 (Cold Box is Replaced, Pretreatment System is Not Replaced)

APPENDIX C: Recommended 15-Year Capital Spending Plan for Scenario 2 (Cold Box and Pretreatment System are Replaced)

APPENDIX D: Recommended 15-Year Capital Spending Plan for Scenario 3 (Cold Box and Pretreatment System are Not Replaced)

APPENDIX E: Summary of PM Recommendations

Appendix A: Facility Process Flow Diagram



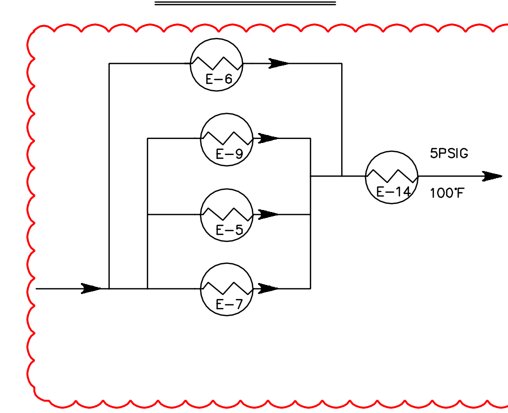
NORMAL LIQUEFACTION THRU THE EXPANDER

	FLOW MOL HR	FLOW MMSCFD	PRES PSIA	TEMP °F	MW	COMPOSITION, MOL% N_2	CH_4	C_2H_6	C_3H_8	$C_4H_{10}^+$	CO_2	PRES.PSIA MAX	PRES.PSIA MIN	FLOW MMSCFD MAX	FLOW MMSCFD MIN
1	2147	1958	465	+60	17.38	1.10	92.24	4.88	0.91	0.47	0.40				
2	2147	1958	462	+60											
3	2147	1958	455	+70											
4	1618	14.75	453	+70											
5	1618	14.75	450	−50											
6	1618	14.75	68	−166											
7	1622	14.80	67	−166	17.43	1.10	92.07	4.94	0.95	0.54	0.40				
8	1622	14.80	65	−92											
9	1622	14.80	63	65											
10	1622	14.80	118	180											
11	1622	14.80	105	90											
12	1651	15.06	100	90	--	1.56	92.68	4.02	0.73	0.37	0.64				
13															
14	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
15	464	4.23	455	70	17.38	1.10	92.24	4.88	0.91	0.47	0.40				
16	462	4.21	450	70	17.25	1.10	92.62	4.90	0.91	0.47	--				
17	462	4.21	445	70											
18	462	4.21	443	−55											
19	462	4.21	442	−80											
20	456	4.16	442	−80	17.08	1.11	93.22	4.68	0.75	0.24					
21	6	.05	65	−150±	30.49	0.12	46.61	21.28	13.86	18.13					
22	456	4.16	440	−145	17.08	1.11	93.22	4.68	0.75	0.24					
23	325.4	2.97	438	−215											
24	325.4	2.97	16+	−257											
25	236	2.15	16	−257	17.32	0.17	98.28	6.26	0.99	0.33					
26	--	--	16	−257	16.48	3.90	96.09	0.01	--	--					
27	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
28	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
29	0.0	0.00	62	110	16.48	3.90	96.09	0.01	--	--	--	--	--	2.65	--
30	130	1.19	64	−225	17.08	1.11	93.22	4.68	0.75	0.24	--				

	FLOW MOL HR	FLOW MMSCFD	PRES PSIA	TEMP °F	MW	COMPOSITION, MOL% N_2	CH_4	C_2H_6	C_3H_8	$C_4H_{10}^+$	CO_2	PRES.PSIA MAX	PRES.PSIA MIN	FLOW MMSCFD MAX	FLOW MMSCFD MIN
31	130	1.19	63	−155	17.08	1.11	93.22	4.68	0.75	0.24	--				
32	130	1.19	63	−92											
33	130	1.19	62	65											
34	89.3	.82	16	−200	16.48	3.90	96.09	0.01	--	--					
35	89.3	.82	15.37	−190											
36	89.3	.82	15.25	−92											
37	89.3	.82	14.74	60											
38	89.3	.82	65	240											
39	89.3	.82	62	110											
40	149	136	60	90	16.48	2.19	94.35	2.85	0.46	0.15				2.01	
41	71	0.65	59	550										2.01	
42	234	2.14	55	70/550	16.74	2.17	93.44	2.82	0.46	0.15	0.96			2.03	
43	234	2.14	51	110										2.03	
44	12	.11	105	90	17.43	1.10	92.07	4.94	0.95	0.54	0.40			.33	
45	24	.22	104	550										.33	
46	36	.33	104	90/550										.33	
47	28	.26	102	110										.33	
48	8	.07	102	110										.33	
49	5	.04	51	90		219	94.35	2.85	0.46	0.15	--				
50	234	2.14	51	90		1.52	92.59	4.18	0.78	0.36	0.57				
51	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
52	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
53		60.0	600	−255		0.17	92.28	6.26	1.32	1.32	1.32				
54		60.0	585	−255											
55		60.0	555	+60											
56		60.0	550	+60											
57		60.0	550	60											
58	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
59	3	.03	20	90	--	--	--	--	--	--	--	--	--	--	--
60	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

EXISTING DATA TABLE. REFER TO COLD BOX SPECIFICATION FOR NEW COLD BOX PERFORMANCE.

WATER FLOW



FOR USE AS REFERENCE FOR COLD BOX FEED PROJECT, FEED PHASE ONLY. SANBORN HEAD REVISED THIS DRAWING ONLY WHERE INDICATED BY THE REV CLOUD AND REV TRIANGLE TO REFLECT EXISTING FACILITY CONDITIONS AS OBSERVED EITHER FROM ORIGINAL P&ID DRAWINGS AND/OR EXISTING FIELD CONDITIONS. ALL OTHER INFORMATION WAS PROVIDED BY NORTHWEST NATURAL AND HAS NOT BEEN ALTERED BY SANBORN HEAD.

SANBORN HEAD

ECO	DR.	APP.	REVISIONS	DATE	MF
1A	JDH		UPDATED PER AS-IS CONDITIONS	5/27/21	
B	SPT		REMOVED BOIL-OFF MAKE-UP TABLE	9/29/17	
	KKD		ADDED H5 H6 AND H7	2/12/06	

P-100

NORTHWEST NATURAL GAS COMPANY
ENGINEERING DEPARTMENT

PROCESS FLOW DIAGRAM

PORTLAND, OREGON

CHK. DATE	PLAT	DR. MRA DATE
APP. DATE	W.M. NO.	SCALE NONE
APP. DATE	DWG. NO.	2/17

Appendix B: Recommended 15-Year Capital Spending Plan for Scenario 1
(Cold Box is Replaced, Pretreatment System is Not Replaced)

Prepared by: Sanborn Head & Associates
February 15, 2022 - Rev. 1

NW Natural

Recommended 15-Year Capital Spending Plan for Scenario 1
(Cold Box is Replaced, Pretreatment System is Not Replaced)

			Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9	Y10	Y11	Y12	Y13	Y14	Y15	
System or Equipment	**Description of Project**	**Reference Section in Assessment Report**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**Line total**
Tier 3 Items																		
Balance of Plant (General)	Survey and possibly modify relief valve discharge piping	4.12.2	TBD															$ -
Balance of Plant (General)	Perform piping corrosion inspection	4.12.6	$ 75,000			$ 75,000			$ 75,000			$ 75,000			$ 75,000			$ 375,000
Plant Control System	Update logic per HAZOP recommendations	4.12.12	$ 75,000															$ 75,000
Plant Control System	Control system documentation	4.12.12	$ 100,000															$ 100,000
Plant Control System	Control logic updates	4.12.12		$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 700,000
Storage Tank T-1	Perform corrosion/thermographic inspection	4.3.1	$ 60,000										$ 60,000					$ 120,000
HCV-70	Install ice cover over HCV-70 area	4.3.4				$ 15,000												$ 15,000
HCV-70	Prevent ice buildup on HCV-70	4.3.5	$ 5,000															$ 5,000
HCV-70	Install additional ESD valve downstream of HCV-70 if needed	4.3.5				$ 82,500												$ 82,500
LNG Sendout Pump P-1	Refurbish pump	4.4.1				$ 50,000												$ 50,000
LNG Sendout Pumps	Inspect and repair foundation heating systems	4.4.1	TBD															$ -
LNG Sendout Pumps	Install pressure transmitters at pump discharges	4.4.1				$ 22,000												$ 22,000
LNG Sendout Pumps	Replace recycle valves and pneumatic controllers	4.4.2				$ 165,000												$ 165,000
TCV-66, 67	Upgrade actuators	4.4.3				$ 55,000												$ 55,000
HCV-68A, 69A, 58, 59, 60, 61	Upgrade actuators	4.4.3				$ 165,000												$ 165,000
RV-405	Reconfigure piping	4.4.4				$ 10,000												$ 10,000
LNG Pump/Vaporizer	Piping cooldown upgrades	4.4.5				$ 160,000												$ 160,000
Vaporizer H-5	Top-works upgrade	4.5.1			$ 1,000,000													$ 1,000,000
Vaporizer H-5	Bottom-works upgrade	4.5.1			$ 1,500,000													$ 1,500,000
Vaporizer H-5	Install low temp shutoff valve - HAZOP 131	4.5.1			$ 55,000													$ 55,000
FCV-5	Replace positioner	4.5.1	$ 27,500															$ 27,500
HCV-5	Replace actuator, solenoids and limit switches	4.5.1	$ 27,500															$ 27,500
FCV-6	Replace positioner	4.5.2	$ 27,500															$ 27,500
Vaporizer H-7	Top-works upgrade	4.5.3				$ 1,000,000												$ 1,000,000
Vaporizer H-7	Install low temp shutoff valve - HAZOP 133	4.5.3				$ 55,000												$ 55,000
FCV-7	Replace positioner	4.5.3	$ 27,500															$ 27,500
HCV-7	Replace actuator, solenoids and limit switches	4.5.3	$ 27,500															$ 27,500
BO Compressors C-2, C-3	Low tank pressure shutdown in manual mode - HAZOP 67	4.6.1	$ 15,000															$ 15,000
BO Compressors C-2, C-3	Repair unloaders faulty valve components, o-ring, etc	4.6.1	$ 10,000															$ 10,000
BO Compressor C-2	Add high vibration trip - HAZOP 73	4.6.1	$ 20,000															$ 20,000
PCV-18	Remove PCV-18	4.6.1	$ 5,000															$ 5,000
BO Compressors	Boiloff handling system evaluation and specification	4.6.1	$ 50,000															$ 50,000
BO Compressors	Design/Bid new BOC	4.6.1	$ 500,000															$ 500,000
BO Compressors	Purchase and Install new BOC	4.6.1	$ 2,000,000															$ 2,000,000
BO Compressors	Replace BO insulation	4.6.1	$ 100,000															$ 100,000
T-1 discretionary vent	Install TIT at E-10 outlet/update procedures	4.6.1	$ 5,000															$ 5,000
HCV-98	Replace valve (leave in current location)	4.7.1	$ 35,000															$ 35,000
Pretreatment System	Install S-1 high level switch to shut down liquefier - HAZOP 23	4.7.2		$ 27,500														$ 27,500
Pretreatment System	Install pressurization bypass around N2-1 - HAZOP 31	4.7.2		$ 15,000														$ 15,000
Pretreatment System	Install valve to shutdown LSD on high temp - HAZOP 97	4.7.2		$ 50,000														$ 50,000
Pretreatment System	Switching valve skid replacement	4.7.2		$ 1,300,000														$ 1,300,000
Pretreatment System	I & C upgrades	4.7.2		$ 310,000														$ 310,000
Pretreatment System	Relief valve sizing evaluation and possible replacement	4.7.2		$ 10,000														$ 10,000
Pretreatment System	Remove sulfur blimp V-1	4.7.2		$ 210,000														$ 210,000
Pretreatment System	Replace molecular sieve in dryer vessels	4.7.2		$ 140,000														$ 140,000
Pretreatment System	Replace molecular sieve in CO2 adsorber vessels	4.7.2		$ 140,000														$ 140,000
Turbo Expander C-1	Upgrade speed sensor, interlock with lube oil system - HAZOP 61 & 106	4.8.1	$ 10,000															$ 10,000
Turbo Expander C-1	Replace PCV-24	4.8.1	$ 40,000															$ 40,000
Turbo Expander C-1	Replace HCV-74	4.8.1	$ 125,000															$ 125,000
Turbo Expander C-1	Replace HCV-74E	4.8.1	$ 20,000															$ 20,000
Turbo Expander C-1	Replace FCV-22 actuator	4.8.1	$ 10,000															$ 10,000
E-14	Install low-temp shutdown valve on E-14 outlet to 85# sys - HAZOP 35	4.9.1	$ 42,000															$ 42,000
W-G System	Add gas detector at expansion tank vent	4.11.1	$ 15,000															$ 15,000
W-G System	Procure spare pumps	4.11.1	$ 20,000															$ 20,000
Plant Inlet	Install bollards at plant inlet area	4.12.3	$ 5,000															$ 5,000
ESD System	Add ESD valves for isolation of 57# and 85# systems	4.12.8	$ 120,000															$ 120,000
ESD System	Relocate pushbutton near HCV-70	4.12.8	$ 5,000															$ 5,000

Prepared by: Sanborn Head & Associates
February 15, 2022 - Rev. 1

NW Natural

Recommended 15-Year Capital Spending Plan for Scenario 1
(Cold Box is Replaced, Pretreatment System is Not Replaced)

System or Equipment	Description of Project	Reference Section in Assessment Report	Y1 2022	Y2 2023	Y3 2024	Y4 2025	Y5 2026	Y6 2027	Y7 2028	Y8 2029	Y9 2030	Y10 2031	Y11 2032	Y12 2033	Y13 2034	Y14 2035	Y15 2036	Line total
Tier 2 Items																		
Storage Tank T-1	Replace tape level gauge	4.3.3					$ 50,000											$ 50,000
LNG Sendout Pump P-2	Refurbish pump	4.4.1										$ 50,000						$ 50,000
Turbo Expander C-1	Procure spare nozzle set	4.8.1					$ 75,000											$ 75,000
Turbo Expander C-1	Replace lube oil system	4.8.3						$ 1,650,000										$ 1,650,000
Oil Heater H-8	Repair curb	4.10.1						$ 5,000										$ 5,000
Oil Heater H-8	Relocate FT-H01	4.10.1						$ 3,000										$ 3,000
E-6	Replace E-6	4.6.2								$ 20,000								$ 20,000
E-10	Replace E-10	4.6.2								$ 40,000								$ 40,000
E-13	Replace E-13	4.6.2										$ 105,000						$ 105,000
E-11	Install temp transmitters on inlet and outlet of E-11	4.11.2						$ 22,000										$ 22,000
ESD System	Relocate pushbuttons in vaporizer buildings	4.12.8						$ 2,000										$ 2,000
E-11/F-2 W/G Coolers	Stock cooling fan spare parts	4.11.2						$ 20,000										$ 20,000
BO Compresors	Design/Bid replacement BOC	4.6.1				$ 500,000												$ 500,000
BO Compresors	Purchase and Install replacement BOC	4.6.1					$ 2,000,000											$ 2,000,000
Tier 1 Items																		
Balance of Plant (General)	Misc. small projects										$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 700,000
Balance of Plant (General)	Misc. insulation repairs	4.12.6									$ 50,000					$ 50,000		$ 100,000
Storage Tank T-1	Paint tank	4.3.1								$ 600,000								$ 600,000
Gas Chromatography	Bring second GC online, automate valve switching	4.12.4									$ 55,000							$ 55,000
Plant Control System	HMI upgrade	4.12.12								$ 200,000								$ 200,000
Security system	Ugrade cameras and monitoring equipment	4.12.11									$ 25,000							$ 25,000
Motor Control Center	Install MCC sections, separate MCC room from operator area	4.12.9								$ 500,000								$ 500,000
BOG Flow Transmitter	Install FT to measure BOG from Liquefaction	4.6.5	$ 50,000															
Totals			$ 3,654,500	$ 2,252,500	$ 2,605,000	$ 2,404,500	$ 2,175,000	$ 1,752,000	$ 125,000	$ 1,410,000	$ 280,000	$ 380,000	$ 210,000	$ 150,000	$ 225,000	$ 200,000	$ 150,000	$ 17,973,500

Appendix C: Recommended 15-Year Capital Spending Plan for Scenario 2
(Cold Box and Pretreatment System are Replaced)

Prepared by: Sanborn Head & Associates
February 15, 2022 - Rev. 1

NW Natural

Recommended 15-Year Capital Spending Plan for Scenario 2
(Cold Box and Pretreatment System are Replaced)

			Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9	Y10	Y11	Y12	Y13	Y14	Y15	
System or Equipment	**Description of Project**	**Reference Section in Assessment Report**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**Line total**
Tier 3 Items																		
Balance of Plant (General)	Survey and possibly modify relief valve discharge piping	4.12.2	TBD															$ -
Balance of Plant (General)	Perform piping corrosion inspection	4.12.6	$ 75,000			$ 75,000			$ 75,000			$ 75,000			$ 75,000			$ 375,000
Plant Control System	Update logic per HAZOP recommendations	4.12.12	$ 75,000															$ 75,000
Plant Control System	Control system documentation	4.12.12	$ 100,000															$ 100,000
Plant Control System	Control logic updates	4.12.12		$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 700,000
Storage Tank T-1	Perform corrosion/thermographic inspection	4.3.1	$ 60,000										$ 60,000					$ 120,000
HCV-70	Install ice cover over HCV-70 area	4.3.4			$ 15,000													$ 15,000
HCV-70	Prevent ice buildup on HCV-70	4.3.5	$ 5,000															$ 5,000
HCV-70	Install additional ESD valve downstream of HCV-70 if needed	4.3.5			$ 82,500													$ 82,500
LNG Sendout Pump P-1	Refurbish pump	4.4.1			$ 50,000													$ 50,000
LNG Sendout Pumps	Inspect and repair foundation heating systems	4.4.1	TBD															$ -
LNG Sendout Pumps	Install pressure transmitters at pump discharges	4.4.1			$ 22,000													$ 22,000
LNG Sendout Pumps	Replace recycle valves and pneumatic controllers	4.4.2			$ 165,000													$ 165,000
TCV-66, 67	Upgrade actuators	4.4.3			$ 55,000													$ 55,000
HCV-68A, 69A, 58, 59, 60, 61	Upgrade actuators	4.4.3			$ 165,000													$ 165,000
RV-405	Reconfigure piping	4.4.4			$ 10,000													$ 10,000
LNG Pump/Vaporizer	Piping cooldown upgrades	4.4.5			$ 160,000													$ 160,000
Vaporizer H-5	Top-works upgrade	4.5.1		$ 1,000,000														$ 1,000,000
Vaporizer H-5	Bottom-works upgrade	4.5.1		$ 1,500,000														$ 1,500,000
Vaporizer H-5	Install low temp shutoff valve - HAZOP 131	4.5.1		$ 55,000														$ 55,000
FCV-5	Replace positioner	4.5.1	$ 27,500															$ 27,500
HCV-5	Replace actuator, solenoids and limit switches	4.5.1	$ 27,500															$ 27,500
FCV-6	Replace positioner	4.5.2	$ 27,500															$ 27,500
Vaporizer H-7	Top-works upgrade	4.5.3			$ 1,000,000													$ 1,000,000
Vaporizer H-7	Install low temp shutoff valve - HAZOP 133	4.5.3			$ 55,000													$ 55,000
FCV-7	Replace positioner	4.5.3	$ 27,500															$ 27,500
HCV-7	Replace actuator, solenoids and limit switches	4.5.3	$ 27,500															$ 27,500
BO Compressors C-2, C-3	Low tank pressure shutdown in manual mode - HAZOP 67	4.6.1	$ 15,000															$ 15,000
BO Compressors C-2, C-3	Repair unloaders faulty valve components, o-ring, etc	4.6.1	$ 10,000															$ 10,000
BO Compressor C-2	Add high vibration trip - HAZOP 73	4.6.1	$ 20,000															$ 20,000
PCV-18	Remove PCV-18	4.6.1	$ 5,000															$ 5,000
BO Compressors	Boiloff handling system evaluation and specification	4.6.1	$ 50,000															$ 50,000
BO Compressors	Design/Bid new BOC	4.6.1	$ 500,000															$ 500,000
BO Compressors	Purchase and Install new BOC	4.6.1	$ 2,000,000															$ 2,000,000
BO Compressors	Relace BO insulation	4.6.1	$ 100,000															$ 100,000
T-1 discretionary vent	Install TIT at E-10 outlet/update procedures	4.6.1	$ 5,000															$ 5,000
HCV-98	Replace valve (leave in current location)	4.7.1	$ 35,000															$ 35,000
Pretreatment System	Install S-1 high level switch to shut down liquefier - HAZOP 23	4.7.2		$ 27,500														$ 27,500
Pretreatment System	Install pressurization bypass around N2-1 - HAZOP 31	4.7.2		$ 15,000														$ 15,000
Pretreatment System	Install valve to shutdown LSD on high temp - HAZOP 97	4.7.2		$ 50,000														$ 50,000
Turbo Expander C-1	Upgrade speed sensor, interlock with lube oil system - HAZOP 61 & 106	4.8.1	$ 10,000															$ 10,000
Turbo Expander C-1	Replace PCV-24	4.8.1	$ 40,000															$ 40,000
Turbo Expander C-1	Replace HCV-74	4.8.1	$ 125,000															$ 125,000
Turbo Expander C-1	Replace HCV-74E	4.8.1	$ 20,000															$ 20,000
Turbo Expander C-1	Replace FCV-22 actuator	4.8.1	$ 10,000															$ 10,000
E-14	Install low-temp shutdown valve on E-14 outlet to 85# sys - HAZOP 35	4.9.1	$ 42,000															$ 42,000
W-G System	Add gas detector at expansion tank vent	4.11.1	$ 15,000															$ 15,000
W-G System	Procure spare pumps	4.11.1	$ 20,000															$ 20,000
Plant Inlet	Install bollards at plant inlet area	4.12.3	$ 5,000															$ 5,000
ESD System	Add ESD valves for isolation of 57# and 85# systems	4.12.8	$ 120,000															$ 120,000
ESD System	Relocate pushbutton near HCV-70	4.12.8	$ 5,000															$ 5,000

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Recommended 15-Year Capital Spending Plan for Scenario 2
(Cold Box and Pretreatment System are Replaced)

System or Equipment	Description of Project	Reference Section in Assessment Report	Y1 2022	Y2 2023	Y3 2024	Y4 2025	Y5 2026	Y6 2027	Y7 2028	Y8 2029	Y9 2030	Y10 2031	Y11 2032	Y12 2033	Y13 2034	Y14 2035	Y15 2036	Line total
Tier 2 Items																		
Storage Tank T-1	Replace tape level gauge	4.3.3					$ 50,000											$ 50,000
LNG Sendout Pump P-2	Refurbish pump	4.4.1										$ 50,000						$ 50,000
Turbo Expander C-1	Procure spare nozzle set	4.8.1					$ 75,000											$ 75,000
Turbo Expander C-1	Replace lube oil system	4.8.3							$ 1,650,000									$ 1,650,000
E-6	Replace E-6	4.6.2								$ 20,000								$ 20,000
E-10	Replace E-10	4.6.2								$ 40,000								$ 40,000
E-13	Replace E-13	4.6.2										$ 105,000						$ 105,000
E-11	Install temp transmitters on inlet and outlet of E-11	4.11.2					$ 22,000											$ 22,000
ESD System	Relocate pushbuttons in vaporizer buildings	4.12.8					$ 2,000											$ 2,000
E-11/F-2 W/G Coolers	Stock cooling fan spare parts	4.11.2					$ 20,000											$ 20,000
BO Compresors	Design/Bid replacement BOC	4.6.1			$ 500,000													$ 500,000
BO Compresors	Purchase and Install replacement BOC	4.6.1				$ 2,000,000												$ 2,000,000
Tier 1 Items																		
Balance of Plant (General)	Misc. small projects										$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 700,000
Balance of Plant (General)	Misc. insulation repairs	4.12.6								$ 50,000					$ 50,000			$ 100,000
Storage Tank T-1	Paint tank	4.3.1								$ 600,000								$ 600,000
Gas Chromatography	Bring second GC online, automate valve switching	4.12.4									$ 55,000							$ 55,000
Plant Control System	HMI upgrade	4.12.12								$ 200,000								$ 200,000
Security system	Ugrade cameras and monitoring equipment	4.12.11									$ 25,000							$ 25,000
Motor Control Center	Install MCC sections, separate MCC room from operator area	4.12.9								$ 500,000								$ 500,000
BOG Flow Transmitter	Install FT to measure BOG from Liquefaction	4.6.5	$ 50,000															
Totals			$ 3,654,500	$ 2,697,500	$ 2,329,500	$ 2,125,000	$ 219,000	$ 50,000	$ 1,775,000	$ 1,460,000	$ 230,000	$ 380,000	$ 210,000	$ 150,000	$ 275,000	$ 150,000	$ 150,000	$ 15,855,500

Appendix D: Recommended 15-Year Capital Spending Plan for Scenario 3 (Cold Box and Pretreatment System are Not Replaced)

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February 15, 2022 - Rev. 1

NW Natural

Recommended 15-Year Capital Spending Plan for Scenario 3
(Cold Box and Pretreatment System are Not Replaced)

			Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9	Y10	Y11	Y12	Y13	Y14	Y15	
System or Equipment	Description of Project	Reference Section in Assessment Report	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Line total
Tier 3 Items																		
Balance of Plant (General)	Survey and possibly modify relief valve discharge piping	4.12.2	TBD															$ -
Balance of Plant (General)	Perform piping corrosion inspection	4.12.6	$ 75,000			$ 75,000			$ 75,000			$ 75,000			$ 75,000			$ 375,000
Plant Control System	Update logic per HAZOP recommendations	4.12.12	$ 75,000															$ 75,000
Plant Control System	Control system documentation	4.12.12	$ 100,000															$ 100,000
Plant Control System	Control logic updates	4.12.12		$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 700,000
Storage Tank T-1	Perform corrosion/thermographic inspection	4.3.1	$ 60,000										$ 60,000					$ 120,000
HCV-70	Install ice cover over HCV-70 area	4.3.4				$ 15,000												$ 15,000
HCV-70	Prevent ice buildup on HCV-70	4.3.5	$ 5,000															$ 5,000
HCV-70	Install additional ESD valve downstream of HCV-70 if needed	4.3.5				$ 82,500												$ 82,500
LNG Sendout Pump P-1	Refurbish pump	4.4.1				$ 50,000												$ 50,000
LNG Sendout Pumps	Inspect and repair foundation heating systems	4.4.1	TBD															$ -
LNG Sendout Pumps	Install pressure transmitters at pump discharges	4.4.1				$ 22,000												$ 22,000
LNG Sendout Pumps	Replace recycle valves and pneumatic controllers	4.4.2				$ 165,000												$ 165,000
TCV-66, 67	Upgrade actuators	4.4.3				$ 55,000												$ 55,000
HCV-68A, 69A, 58, 59, 60, 61	Upgrade actuators	4.4.3				$ 165,000												$ 165,000
RV-405	Reconfigure piping	4.4.4				$ 10,000												$ 10,000
LNG Pump/Vaporizer	Piping cooldown upgrades	4.4.5				$ 160,000												$ 160,000
Vaporizer H-5	Top-works upgrade	4.5.1			$ 1,000,000													$ 1,000,000
Vaporizer H-5	Bottom-works upgrade	4.5.1			$ 1,500,000													$ 1,500,000
Vaporizer H-5	Install low temp shutoff valve - HAZOP 131	4.5.1			$ 55,000													$ 55,000
FCV-5	Replace positioner	4.5.1	$ 27,500															$ 27,500
HCV-5	Replace actuator, solenoids and limit switches	4.5.1	$ 27,500															$ 27,500
FCV-6	Replace positioner	4.5.2	$ 27,500															$ 27,500
Vaporizer H-7	Top-works upgrade	4.5.3				$ 1,000,000												$ 1,000,000
Vaporizer H-7	Install low temp shutoff valve - HAZOP 133	4.5.3				$ 55,000												$ 55,000
FCV-7	Replace positioner	4.5.3	$ 27,500															$ 27,500
HCV-7	Replace actuator, solenoids and limit switches	4.5.3	$ 27,500															$ 27,500
BO Compressors C-2, C-3	Low tank pressure shutdown in manual mode - HAZOP 67	4.6.1	$ 15,000															$ 15,000
BO Compressors C-2, C-3	Repair unloaders faulty valve components, o-ring, etc	4.6.1	$ 10,000															$ 10,000
BO Compressor C-2	Add high vibration trip - HAZOP 73	4.6.1	$ 20,000															$ 20,000
PCV-18	Remove PCV-18	4.6.1	$ 5,000															$ 5,000
BO Compressors	Boiloff handling system evaluation and specification	4.6.1	$ 50,000															$ 50,000
BO Compressors	Design/Bid new BOC	4.6.1	$ 500,000															$ 500,000
BO Compressors	Purchase and Install new BOC	4.6.1	$ 2,000,000															$ 2,000,000
BO Compressors	Replace BO insulation	4.6.1	$ 100,000															$ 100,000
T-1 discretionary vent	Install TIT at E-10 outlet/update procedures	4.6.1	$ 5,000															$ 5,000
HCV-98	Replace valve (leave in current location)	4.7.1	$ 35,000															$ 35,000
Pretreatment System	Install S-1 high level switch to shut down liquefier - HAZOP 23	4.7.2		$ 27,500														$ 27,500
Pretreatment System	Install pressurization bypass around N2-1 - HAZOP 31	4.7.2		$ 15,000														$ 15,000
Pretreatment System	Install valve to shutdown LSD on high temp - HAZOP 97	4.7.2		$ 50,000														$ 50,000
Pretreatment System	Switching valve skid replacement	4.7.2		$ 1,300,000														$ 1,300,000
Pretreatment System	I & C upgrades	4.7.2		$ 310,000														$ 310,000
Pretreatment System	Relief valve sizing evaluation and possible replacement	4.7.2		$ 10,000														$ 10,000
Pretreatment System	Remove sulfur blimp V-1	4.7.2		$ 210,000														$ 210,000
Pretreatment System	Replace molecular sieve in dryer vessels	4.7.2		$ 140,000														$ 140,000
Pretreatment System	Replace molecular sieve in CO2 adsorber vessels	4.7.2		$ 140,000														$ 140,000
Turbo Expander C-1	Upgrade speed sensor, interlock with lube oil system - HAZOP 61 & 106	4.8.1	$ 10,000															$ 10,000
Turbo Expander C-1	Replace PCV-24	4.8.1	$ 40,000															$ 40,000
Turbo Expander C-1	Replace HCV-74	4.8.1	$ 125,000															$ 125,000
Turbo Expander C-1	Replace HCV-74E	4.8.1	$ 20,000															$ 20,000
Turbo Expander C-1	Replace FCV-22 actuator	4.8.1	$ 10,000															$ 10,000
E-14	Install low-temp shutdown valve on E-14 outlet to 85# sys - HAZOP 35	4.9.1	$ 42,000															$ 42,000
E-14	Replace E-14	4.9.1	$ 300,000															$ 300,000
Cold Box	Convert cold box purge to nitrogen	4.9.1	$ 310,000															$ 310,000
Cold Box	Replace cold box control valves	4.9.1	$ 350,000															$ 350,000
Cold Box	Implement HAZOP recommendations for cold box	4.9.1	$ 190,000															$ 190,000
W-G System	Add gas detector at expansion tank vent	4.11.1	$ 15,000															$ 15,000
W-G System	Procure spare pumps	4.11.1	$ 20,000															$ 20,000
Plant Inlet	Install bollards at plant inlet area	4.12.3	$ 5,000															$ 5,000
ESD System	Add ESD valves for isolation of 57# and 85# systems	4.12.8	$ 120,000															$ 120,000
ESD System	Relocate pushbutton near HCV-70	4.12.8	$ 5,000															$ 5,000

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Recommended 15-Year Capital Spending Plan for Scenario 3
(Cold Box and Pretreatment System are Not Replaced)

			Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9	Y10	Y11	Y12	Y13	Y14	Y15	
System or Equipment	**Description of Project**	**Reference Section in Assessment Report**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**Line total**
Tier 2 Items																		
Storage Tank T-1	Replace tape level gauge	4.3.3					$ 50,000											$ 50,000
LNG Sendout Pump P-2	Refurbish pump	4.4.1										$ 50,000						$ 50,000
Turbo Expander C-1	Procure spare nozzle set	4.8.1					$ 75,000											$ 75,000
Turbo Expander C-1	Replace lube oil system	4.8.3						$ 1,650,000										$ 1,650,000
Oil Heater H-8	Repair curb	4.10.1						$ 5,000										$ 5,000
Oil Heater H-8	Relocate FT-H01	4.10.1						$ 3,000										$ 3,000
E-6	Replace E-6	4.6.2								$ 20,000								$ 20,000
E-10	Replace E-10	4.6.2								$ 40,000								$ 40,000
E-13	Replace E-13	4.6.2										$ 105,000						$ 105,000
E-11	Install temp transmitters on inlet and outlet of E-11	4.11.2						$ 22,000										$ 22,000
ESD System	Relocate pushbuttons in vaporizer buildings	4.12.8						$ 2,000										$ 2,000
E-11/F-2 W/G Coolers	Stock cooling fan spare parts	4.11.2						$ 20,000										$ 20,000
BO Compresors	Design/Bid replacement BOC	4.6.1				$ 500,000												$ 500,000
BO Compresors	Purchase and Install replacement BOC	4.6.1					$ 2,000,000											$ 2,000,000
Tier 1 Items																		
Balance of Plant (General)	Misc. small projects										$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 700,000
Balance of Plant (General)	Misc. insulation repairs	4.12.6									$ 50,000					$ 50,000		$ 100,000
Storage Tank T-1	Paint tank	4.3.1								$ 600,000								$ 600,000
Gas Chromatography	Bring second GC online, automate valve switching	4.12.4									$ 55,000							$ 55,000
Plant Control System	HMI upgrade	4.12.12								$ 200,000								$ 200,000
Security system	Ugrade cameras and monitoring equipment	4.12.11									$ 25,000							$ 25,000
Motor Control Center	Install MCC sections, separate MCC room from operator area	4.12.9								$ 500,000								$ 500,000
BOG Flow Transmitter	Install FT to measure BOG from Liquefaction	4.6.5	$ 50,000															
Totals			$ 4,804,500	$ 2,252,500	$ 2,605,000	$ 2,404,500	$ 2,175,000	$ 1,752,000	$ 125,000	$ 1,410,000	$ 280,000	$ 380,000	$ 210,000	$ 150,000	$ 225,000	$ 200,000	$ 150,000	$ 19,123,500

Appendix E: Summary of PM Recommendations

Summary of PM Recommendations

System or Equipment	Recommended Actions	Reference Section in Assessment Report
General	Develop a formal car-seal program and update P&I drawings accordingly.	4.12.1
Storage Tank T-1	Perform annual LNG density profile.	4.3.1
Storage Tank T-1	Establish a scheduled PM procedure to test and calibrate vacuum breakers.	4.3.2
Storage Tank T-1	Establish a scheduled PM procedure to test and calibrate storage tank level instrumentation	4.3.3
Storage Tank T-1	Perform regular visual inspections of the bellows located on the withdrawal line upstream of HCV-70.	4.3.4
HCV-70	Perform regular visual inspections to check for ice buildup. Confirm freedom of movement of the valve/actuator. Clear any ice buildup as required.	4.3.5
LNG Sendout Pumps	Establish a scheduled PM procedure to inspect, test and service the P-1 and P-2 motors in accordance with NFPA 70B.	4.4.1
Vaporizer H-5	Investigate the pneumatic circuit for FCV-5 and remove any unnecessary/unused components. Contract with a Fisher service technician to calibrate/function test FCV-5.	4.5.1
Vaporizer H-5	Establish an annual PM procedure to perform functional checks of protective interlocks at the start of each vaporization season, likely in conjunction with system calibrations.	4.5.1
Vaporizer H-5	Perform visual inspection and pressure testing of the tube bundle at the start of each vaporization season.	4.5.1
Vaporizer H-6	Establish an annual PM procedure to perform functional checks of protective interlocks at the start of each vaporization season, likely in conjunction with system calibrations.	4.5.2
Vaporizer H-6	Perform visual inspection and pressure testing of the tube bundle at the start of each vaporization season.	4.5.2
Vaporizer H-7	Contract with a Fisher service technician to calibrate/function test FCV-7.	4.5.3
Vaporizer H-7	Establish an annual PM procedure to perform functional checks of protective interlocks at the start of each vaporization season, likely in conjunction with system calibrations.	4.5.3
Vaporizer H-7	Perform visual inspection and pressure testing of the tube bundle at the start of each vaporization season.	4.5.3
Turbo Expander Lube Oil System	Establish a scheduled PM procedure to test lube oil system relief valves.	4.8.3
W-G System	Establish a scheduled PM procedure to periodically run the W-G pumps in the off season.	4.11.1
W-G System	Consider adding periodic checks of air vents with CGI to the regular operator rounds or establish as a scheduled PM procedure in order to detect accumulation of gas in the water-glycol system	4.11.1
W-G System	Establish an annual PM procedure for lab analysis of the water-glycol mixture.	4.11.1

SANBORN HEAD

Building Trust. Engineering Success.

COLD BOX REPLACEMENT FEED REPORT

PORTLAND LNG FACILITY

Portland, OR

Prepared for Northwest Natural Gas Company
Sanborn Head Project Number: 4661.04

Document #: FEED-001

November 23, 2021
Revision 2

COLD BOX REPLACEMENT FEED REPORT

REVISION LOG

REVISION	REVISION DATE	REVISION NOTES
A	6/4/2021	Draft issuance to NWN for review and comment.
1	7/9/2021	Issued to NWN.
2	11/23/2021	Issued to NWN. Content added to Section 1.

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APPENDICES

Appendix A	Geotechnical Investigation, GeoEngineers
Appendix B	Design Wind Speed Report, CPP Wind
Appendix C	Nitrogen Source and Supply Evaluation
Appendix D	Design Basis
Appendix E1	Cold Box Specification
Appendix E2	Pre-treatment UOP Adsorbent Bed Design Datasheets
Appendix E3	Mercury Guard UOP Adsorbent Bed Design Datasheet
Appendix E4	Equipment/Component Replacement List
Appendix F	Permit Matrix

REFERENCES

[REF 1] 4461.04_HAZOP-001_R0A: Hazard and Operability (HAZOP) Report – Portland LNG Facility, Revision 0

[REF 2] 4661.04_PISET-001_R0A: Preliminary Design Drawings Set, PFD and P&IDs, Sanborn Head Revision A, Varying Sheet Revisions, Prepared 6/4/2021

[REF 3] 4661.04_GASET-001_R0B: Preliminary Design Drawing Set, Overall Site Plan and Cold Box General Arrangements, Revision B, Prepared 7/6/2021

1.0 EXECUTIVE SUMMARY

Northwest Natural Gas Company (NWN) has retained Sanborn, Head and Associates, Inc. (Sanborn Head) to perform a front end engineering (FEED) study to replace the existing Cold Box at the Portland Oregon LNG Facility (Facility).

The Cold Box is proposed for replacement to improve safety and reliability based upon the following considerations:

- Safety – The Cold Box is purged with natural gas and constantly bleeds, creating an atmosphere around the Cold Box that consistently registers at least 0.5% gas concentration (10% LEL). The new Cold Box will be purged with nitrogen, an inert gas which improves the area safety and offers opportunity for leak detection within the Cold Box.

- Fouling of the Cold Box Heat Exchanger Passes – Process modelling identified poor performance as a result of temperature imbalance between the Cold Box heat exchanger passes. This may be due to loss of heat transfer due to a coating of contaminants within the heat exchanger passes or leaks between passes. Due to the repeated plugging of the heat exchanger passes given the recent history of the feed gas composition exceeding the design capacity of the upstream pretreatment system, contaminant coating may be permanent and it is possible leaks have developed due to the added stress on the walls. Refer to section 4.2 Process Model Results for additional information.

- Age – The existing Cold Box heat exchanger design is outdated. Modern heat exchangers, when operated per manufacturer requirements, are less prone to failure than the older designs. Should one of the heat exchangers fail, repair may not be possible depending upon the severity of the failure causing significant downtime for the liquefier since new heat exchangers have a lead time of at least 1 year without including specification and installation. As identified above, it is possible the heat exchangers already have pass to pass leaks which leads to the belief the equipment has reached the end of its useful life and failure may be imminent.

- Temperature Rating – The existing Cold Box heat exchanger maximum temperature rating is 100 °F. This limits liquefaction operation to days when the ambient temperature does not exceed 75-80 °F based upon the current configuration of the E-4 feed cooler and the F-2 water/glycol cooling supply loop. Based on local historical TMY2 ambient temperature data, liquefaction operation may be limited to 90% of the liquefaction season from April 1 through October 1 and as low as 77% of the time in August. The new Cold Box will be rated for 150 °F, mitigating the ambient temperature limit concerns.

Supporting this FEED study, in large part, are the appended preliminary design documents which may serve as the basis for execution of detailed design to procure and install a new Cold Box.

To reduce the risk of plugging, fouling, and poor performance persisting after the installation of the new Cold Box, upgrades or replacement of the existing pre-treatment system are highly recommended to reduce the CO2 content in the gas to the cold box heat exchangers. While the pretreatment system is discussed in Section 4 of this study, refer to document *4661.04_EVAL-02* for a detailed evaluation of the existing pretreatment system and recommendations for improving its performance. It is recommended any improvements to the pretreatment system be executed before or in parallel with the replacement of the Cold Box. Note, if improvements to the pretreatment system are made prior to or in parallel with the Cold Box replacement project, the Cold Box specification should be updated prior to the release for proposal for any pre-treatment system modifications which improve the quality of the inlet gas over that which is specified.

To support the new Cold Box, a new bulk nitrogen storage system is required to provide continuous purging of the Cold Box. A mercury guard filter is also recommended for protection of the aluminum heat exchangers and piping within the Cold Box. To ensure the required heavy ends vaporization is provided at E-14, the heat exchanger either requires replacement or vendor consultation to confirm performance and addition of overpressure protection. Lastly, a Hazard and Operability workshop performed on the Cold Box liquefaction flow paths yielded recommendations to enhance process and personnel safety.

Costs to demolish the existing Cold Box, then to install and integrate the new major components with exception of the pre-treatment and any E-14 heavy ends vaporizer improvements were estimated to an AACE Class 4 cost estimate accuracy. The total estimated project cost is $7.49 million with a low range of $5.24 million to a high range of $11.24 million. Refer to the section on Opinion of Probable Construction Cost (OPCC) for additional information.

The total project duration is estimated at 18 months from the start of Cold Box procurement to end of commissioning. The engineering phase is proposed to occur within the first 12 months in parallel with the Cold Box procurement and shipment. After the Cold Box is delivered on site, 6 months are proposed for construction and commissioning.

1.1 The FEED Process

Evaluations were executed to develop a Design Basis to support preliminary engineering and design of the Cold Box and its integration into the Facility's mechanical, electrical, and controls systems including:

- Geotechnical investigation
- Wind Study
- Nitrogen source and supply evaluation
- Hazard and Operability Study (HAZOP) based on existing conditions
- Pre-treatment evaluation

The FEED study was advanced with preliminary design tasks including the development of:

- Process model

- Written Cold Box specification
- Preliminary design documents:
    - Process Flow Diagram (PFD)
    - Process and Instrumentation Diagram (P&ID)
    - General arrangement drawings of the physical plant

Using the documents above, budget estimates for the Cold Box and new equipment to integrate the new Cold Box were solicited from multiple vendors. The result of the findings is summarized in an Opinion of Probable Construction Cost (OPCC). Furthermore, a schedule was developed based on NWN requirements and the availability of the Cold Box Vendors.

Refer to the appendices for more details on the evaluations discussed above. The results of the evaluations, where prudent, are summarized in the body of this report.

2.0 PRELIMINARY INVESTIGATIONS

2.1 General Data Gathering

Information supporting this FEED was gathered by Sanborn Head from NWN as summarized below:

- Formal information requests
- Weekly review meetings
- A data gathering site visit performed by Sanborn Head from 4/6/2021 to 4/8/2021
    - A metrological 3D scan of the Cold Box area piping was performed
    - This site visit was executed alongside a separate effort by Sanborn Head to perform a Facility Assessment
- Two HAZOP studies were facilitated by Sanborn Head
    - 5/4/2021 to 5/6/2021 for systems directly effected by the Cold Box replacement
    - 5/25/2021 to 5/27/2021 for the balance of systems to support the separate Facility Assessment effort

2.2 Geotechnical Investigation

2.2.1 *Overview*

A geotechnical investigation was performed by GeoEngineers, Inc. (GeoEngineers) of Portland, OR, to determine soil conditions in the vicinity of the proposed locations of the new Cold Box and new bulk nitrogen storage system. GeoEngineers then performed preliminary foundation design and provided cost estimates for the foundations to support the new Cold Box and bulk nitrogen storage system.

2.2.2 *Seismic Design Parameters*

Based on GeoEngineers' findings, the existing site soils may be subject to liquefaction during a seismic event and therefore, the recommended site classification is Site Class F. Refer to Appendix A for the seismic design parameters recommended by GeoEngineers. It is important to note, the fundamental period of vibration is assumed less than 0.5 seconds for any new structures designed to the proposed seismic design parameters. If the fundamental period of vibration is greater than 0.5 seconds for any new structure, a site specific seismic response analysis will be required. The cost of a site specific seismic response analysis is estimated at $30k ± and may require additional time in permitting for approval by the Authority Having Jurisdiction (AHJ).

A site specific seismic response analysis can be performed even if the fundamental period of vibration for any new structure is less than 0.5 seconds and the analysis often leads to less conservative seismic design parameters. However, the cost of the analysis is typically not recouped in the design and construction cost of the structures, so the conservative code specified seismic design parameters are typically used.

2.2.3 *Foundation Recommendations*

After review of subsurface conditions, structural loads and geometry, and consideration of seismic hazards, micropiles are recommended to support both the new Cold Box and the bulk nitrogen storage system.

Micropiles can be socketed into the underlying basalt bedrock to provide greater resistance to uplift compared to conventional driven piles that would refuse at or near top of bedrock. In addition, micropiles can be easily battered in order to resist lateral loads/movement due to liquefaction/lateral spread during and following a seismic event. Considerations to the precise locations of underground utilities will be required prior to installation. Once installed, the micropiles can be tied together in a concrete mat foundation.

Based on structural loads and geometry, 6 micropiles per foundation may be required. Preliminary review of the geotechnical data and preliminary calculations estimate a required bond length into the basalt of 10 feet, and a total micropile length of 75 feet. Refer to the OPCC for estimated costs. **Refer to Appendix A** for the Geotechnical investigation.

2.3 Design Wind Speed Report

DOT 49 CFR 193.2067 (b)(2)(i) requires structures at an LNG facility be designed for a 150-mph sustained (183 mph 3-second gust) wind speed unless a lower velocity is justified by adequate supportive data. 49 CFR 193.2067 (b)(2)(ii) provides a methodology for operators to develop a site-specific wind speed based on statistical analysis of historical meteorological data at the site. CPP Wind of Windsor, Colorado was retained to prepare a site specific wind speed report to quantify and document a lower design wind speed, if applicable, and in accordance with 49 CFR 193.2067 (b)(2)(ii).

CPP concluded a design 3-second gust wind speed of 124 mph could be used for structural design and analysis for this Facility (assuming Exposure Category C at a height of 33 feet). Therefore, structural provisions and associated construction costs may be reduced due to the reduced design wind speed. **Refer to Appendix B** for the Design Wind Speed Report.

2.4 Nitrogen Source and Supply Evaluation

The existing Cold Box utilizes natural gas for purging to reduce infiltration of moist air into the Cold Box and therefore, minimize ice formation. Nitrogen purge gas will be utilized for the new Cold Box to reduce fugitive methane emissions, improve safety, and enable detection of leaks within the Cold Box. The estimated purge demand for the new Cold Box is up to 130 gallons per day of liquid nitrogen, or 7 SCFM gaseous nitrogen. To account for other nitrogen uses at the Facility such as purging equipment into and out of service, a total design flow rate of approximately 230 GPD liquid nitrogen (13 SCFM gaseous nitrogen) was assumed. Multiple nitrogen storage volumes and systems were evaluated for feasibility and cost.

NWN has elected to pursue an owner purchased/owned bulk nitrogen storage system. To meet the design flow rate, a 6,000 gallon bulk storage tank will satisfy the design demand for approximately 18 days with a 30% volume contingency remaining until empty. A remote telemetry system will be provided by the nitrogen supplier to automate planning and execution of deliveries. In comparison to a leased bulk storage system, an owner purchased system will enable NWN to optimize nitrogen supply and delivery contract costs. **Refer to Appendix C** for the complete evaluation.

Since the completion of the evaluation, the changes listed below have been made which increase the cost over that described in the evaluation in **Appendix C**. It is worth noting, since all bulk storage options will require these features, the cost of each bulk storage option relative to the other remains similar:

- Foundation costs have increased due to the recommendation of a foundation built with micropiles in lieu of a simple mat foundation.
- Cost of nitrogen distribution piping was added.
- Contingencies to estimated costs were added.

2.5 HAZOP

Sanborn Head facilitated a Hazard and Operability (HAZOP) workshop, with participation by NWN and Sanborn Head personnel, to evaluate the existing Cold Box and liquefaction flow paths. The HAZOP is a systematic process to identify potential process deviations and their causes, to evaluate the consequences of these deviations, to identify existing safeguards, and to provide recommendations to either eliminate the hazards or to lessen the risk. For this FEED study, the HAZOP intended to identify potential enhancements to the Cold Box design to improve process or personnel safety. The HAZOP team also evaluated existing Facility systems beyond the Cold Box, and [REF 1] documents the results of the workshop. Specific to the Cold Box FEED, the HAZOP recommends:

1. Incorporation of enhanced instrumentation and control strategies as part of the Cold Box replacement project to lessen the likelihood of exceeding design parameters, contamination or plugging of liquefaction or refrigeration flow paths within the Cold Box. Enhancements include:

    a. Integration of high-high moisture alarm and liquefier trip to prevent carryover of moisture into the new Cold Box upon Dehydration (Dehy) system breakthrough.

b. Installation of a new CO2 analyzer with high-high CO2 ppm alarm and liquefier trip to prevent carryover of CO2 into the new Cold Box upon CO2 adsorber system breakthrough.

c. Implementation of low and high temperature monitoring, alarms, and liquefier shutdowns for process transients that could lead to exceedance of design temperatures in the Cold Box streams, including:

    i. High and high-high temperature at E-4 outlet/cooler inlet (TE-21-32).

    ii. High-high temperature at the Dehy outlet (TE-21-21).

    iii. Low temperature at flash gas outlet from Cold Box (TE-21-40/43).

    iv. High temperature at the liquefier outlet (TE-21-32)

    v. High differential temperature/rate-of-change across Cold Box passes.

d. Implementation of high-high flow alarm and liquefier shutdown (FIT-16).

e. Implementation of liquefier shutdown on high-high tank level or high-high tank pressure at storage tank T-1.

f. Integration of differential pressure indication for all Cold Box passes.

g. Implementation of E-14 low and low-low outlet gas temperature alarm and interlock to mitigate the risk of high liquid (heavy hydrocarbons) flow to E-14 that could result in cold gas to the carbon steel outlet piping feeding the 85# distribution system if the LCV(s) feeding E-14 were to fail open. Consider E-14 pressure rating and/or overpressure protection in implementation design. Refer to the E-14 evaluation in section 4.2 within this report.

2. Specification of a 150°F design temperature for the Cold Box inlet, to increase design margin from normal feed gas inlet temperatures.

3. Where applicable, specification of double-block-and-bleed isolation valves and inclusion of adequate purge and vent connections, to improve safety during maintenance activities.

4. Where new automated control valves are included, specification of position feedback to the control system, with valve position deviation alarms to alert operators of potential valve malfunctions.

5. Consideration of hard-piped connections to allow for maintenance de-rime when necessary (the current practice is to use temporary hoses for this maintenance).

The recommendations listed have been considered and incorporated into the FEED and OPCC.

The HAZOP team identified several recommendations for process improvements and protective interlocks associated with the upstream natural gas pre-treatment system operation, downstream heavy ends vaporization system, and the existing Facility Emergency Shutdown (ESD) components and operation. These recommendations are not directly associated with the Cold Box FEED and are not included in the OPCC. Refer to the Process Model and Pre-Treatment Evaluation sections of this FEED Report and [REF 1] for additional information.

3.0 DESIGN BASIS

A Design Basis was developed to document the Facility's site information, ambient design conditions, feed gas conditions and compositions, existing systems and equipment, and to serve as the basis for development of design criteria for the new Cold Box. **Refer to Appendix D** for the Design Basis.

4.0 PROCESS MODEL

4.1 Process Model Description

A process model was developed using ProMax® process simulation software to simulate the original Cold Box and pre-treatment system design, identify current liquefaction system performance based upon current operating data, and identify the new Cold Box design operating conditions based upon the design basis feed gas and tail gas conditions and existing turboexpander performance, including identification of the minimum required performance of the pretreatment systems. The following is a summary of work performed with the process model:

1. Process model developed based upon the original system design.

2. Reviewed plant operating data from the Fall 2020 liquefaction run and calibrated the process model to identify the performance of the existing turboexpander and Cold Box.

3. Utilizing the identified performance of the existing turboexpander, new Cold Box design models were generated using the feed and tail gas conditions identified within the design basis, using the rating case gas composition. Two additional models were developed using the off-design gas composition cases (rich and lean) to identify the Cold Box design conditions for these cases with possible reduction of LNG production capacity.

4. A CO_2 sensitivity evaluation was completed for the rating and off-design case models to identify the maximum CO_2 concentration for the expander inlet stream that was expected not to produce CO_2 solids at the expander outlet, resulting in plugging of the Cold Box passes. The resulting maximum CO_2 concentration that was suitable for all cases was identified.

5. The resulting process stream data and performance for all cases was included within the Cold Box specification, transmitted to Cold Box vendors in a request for proposal to serve as a basis for their preliminary design and budget quotation.

6. Current installed heavy ends vaporizer, E-14, was evaluated per the requirements of the rating and off-design case models to identify any capacity limitations.

For process model results as they pertain to the Cold Box for design and off-design cases, **refer to Appendix E1**, **Cold Box Specification**.

4.2 Process Model Results

Calibration of the original model to 2020 operating data identified a temperature imbalance of the existing system, causing the outlet gas temperatures from E-2 to E-1 to vary by 30°F-50°F between passes whereas the temperatures would be expected to be within 5°F of each other. The temperature imbalance may be due to loss of heat transfer due to a coating of contaminants within the heat exchanger passes or leaks between passes. Contaminant coating is more than likely the cause given the recent history of the gas composition exceeding the design capacity of the upstream pretreatment system and plugging of the Cold Box passes. However, it is possible there are leaks between passes exasperating the heat transfer issue given the age of the equipment and the continued plugging issues causing added stress on the pass walls. Although additional testing could be identified to better define the source of the issue, a Cold Box heat exchanger replacement is considered to be the best path given the age of the equipment and the safety improvement a new nitrogen purged Cold Box would bring to the facility.

The new Cold Box design models identified it is possible to achieve the 2.15 MMSCFD original rated LNG capacity for the rating case and the off-design cases using the existing turboexpander performance defined in the calibrated models, pending vendor confirmation of heat exchanger performance.

The CO_2 sensitivity evaluation identified a maximum CO_2 concentration of 0.4 mol% at the expander inlet for the rating and off design cases that is not expected to produced CO_2 solids at the expander outlet, assuming the expander inlet temperature is operated at -50°F to -60°F as is currently operated. This matched the original design gas composition of the liquefier so was a reasonable finding. However, it is important to note the following:

- For the off-design lean case, the expander inlet is required to be run at a minimum temperature of -50°F or warmer to prevent the expander outlet from running too cold and having the potential to produce CO_2 solids. To support operation in this case, the new installation requires either temperature control of the expander inlet temperature or removal of additional CO_2 from the expander inlet gas. Adding temperature control to the expander inlet will require additional controls, added operation complexity, added heat exchanger cost, and will reduce system efficiency (an expander inlet temperature control solution is not included in the OPCC). Removal of CO_2 at the dehydrators will require a full replacement of the dehydrators but will provide the best efficiency and similar controls as the existing facility.

- The expander design operating outlet temperature is within 10°F of the expected CO2 solids formation for a 0.4 mol% maximum CO2 concentration, resulting in cold box vendors more than likely taking exception to performance guarantees due to low safety margin unless the CO2 is removed. Removal of CO_2 at the dehydrators will require a full replacement of the dehydrators but will allow liquefaction vendors to provide performance guarantees on their offering without exception to CO2 content.

E-14 evaluation identified the rated duty of the heat exchanger is sufficient. However, the following potential issues were identified:

- E-14 is designed for cold vapor at the inlet in lieu of the actual operating conditions consisting of cryogenic liquid or 2-phase flow. Due to this, it is possible, the heat exchanger will not sufficiently vaporize and warm the liquid as required. It is recommended the heat exchanger vendor be consulted on the actual expected operating conditions to confirm performance. Cost for replacement of E-14 was estimated and included in the OPCC as a contingency within the Cold Box Systems Integration line item cost.

- E-14 has a pressure rating of 150 psig. This is sufficient for the normal operating pressure. However, as per the HAZOP findings, the heat exchanger has the potential to be exposed to 450 psig and currently has no overpressure protection. This can be solved by heat exchanger replacement with pressure rating of 550 psig, consistent with upstream system pressure rating, or by adding overpressure protection.

5.0 PRETREATMENT EVALUATION SUMMARY

UOP, a known and proven Molecular Sieve supplier, was consulted on the best available performance of the existing pretreatment systems and available upgrades based upon the design inlet conditions for the pretreatment system identified within the new Cold Box design models for the rating case, requiring a maximum of 0.4 mol% CO2 at the outlet of the dehydrators and 50 ppm CO2 at the outlet of the CO2 adsorbers. **Refer to Appendix E2** for the resulting UOP design data sheets. The following summarizes the options presented within the designs.

- Dehydrators
  - Existing 2-Bed System – Capable of removing water and mercaptans only
  - Add third Bed to Existing System – No added benefit due to bed size
  - Replace dehydrators and CO2 adsorbers with new 3-Bed System - Capable of removing water, mercaptans, and 1 mol% CO2 to 50 ppm or less – Existing CO2 adsorbers can be eliminated
- CO2 Adsorbers
  - Existing 2-Bed System – Capable of removing 0.6 mol% CO2 to 50 ppm or less
  - Add third Bed to Existing System – Capable of removing 1 mol% CO2 to 50 ppm or less

To provide the best available performance of the new Cold Box, it is recommended to replace the existing 4-bed pretreatment system with a new 3-bed pretreatment system. This recommendation is based on:

- Results from a CO_2 sensitivity analysis
- Feedback from Cold Box vendors
- The above preliminary UOP design data

The new 3-bed pretreatment system should be designed for a minimum of 1 mol% CO2 feed gas concentration to remove mercaptans, water, and CO_2 in one system. In contrast to the existing system, the regen gas would be sourced from the expander system tail gas stream since the regen gas flow is greater for the new 3-bed system. This would eliminate the need for using the LNG slip stream flow through cold box exchanger pass B as the regen gas source. In addition to new adsorber vessels and valve skid, the new 3-bed system would require a new hot oil heating system, a regen gas cooler, tail gas separator and a regen gas booster compressor to provide the pressure required to overcome the pressure drop of the regen flow path. Added benefits of the new regen gas flow source are the following:

- Allows for the LNG slip stream used for subcooling at the cold box lower end (via Pass B) to be flashed to a pressure ~10 psi lower than current conditions since the flow will go directly to the 57 psig system instead of through the adsorber regen gas flow path, providing added refrigeration.
- LNG slip stream flow via Pass B no longer needs to be set to maintain regen flow but only to be set to provide the refrigeration required for the cold box performance, providing added system efficiency.

Please refer to the Pretreatment Evaluation under separate cover (document # *4661.04_EVAL-02)* for a summary of the options, advantage, disadvantages, and budget costs. Costs to update the pretreatment system are not included within the Cold Box Replacement OPCC. However, it is recommended that any pretreatment system modifications required for Cold Box performance be performed either before or in parallel with the Cold Box replacement. Please note that if pretreatment modifications are conducted before or in parallel with the Cold Box replacement, the Cold Box performance specification should be updated to account for the pretreatment system change prior to release for proposal.

6.0 SPECIFICATIONS

A procurement specification was developed for the Cold Box to support the solicitation of budget estimates from vendors. List specifications are provided for all other equipment to enable development of cost estimates for the OPCC.

6.1 Cold Box Procurement Specification

Refer to Appendix E1 for the Cold Box procurement specification. The Cold Box specification shall be updated for any pre-treatment system modifications which improve the quality of the inlet gas over that which is specified.

6.2 Pre-Treatment UOP Datasheets

Refer to Appendix E2 for the pre-treatment UOP Adsorbent Bed Design Datasheets for the options identified in section 5.0.

6.3 Mercury Guard UOP Datasheets

Refer to Appendix E3 for the Mercury Guard UOP Adsorbent Bed Design Datasheet - (Vessel shall be designed for 550 PSIG @ 150°F)

6.4 Valves, Piping, and Instrumentation

Refer to Appendix E4 for valves, filters, piping, and instrumentation list specifications.

6.5 Bulk Nitrogen Storage System

The bulk nitrogen storage system is specified in Table 6.5.1 below. **Refer to Appendix C** for additional information.

Table 6.5.1: Bulk Nitrogen Storage System Specification

System/Parameter	Specification
General	
Area Classification	Class I, Division 1 and Division 2, Group D.
Loading Station	Loading station shall be extended from bulk storage equipment and accessible outside of primary LNG equipment secured fence line. Loading station shall have controlled access.
Mechanical [Note 1]	
Bulk Storage Tank, General	Self-supporting, double wall, vacuum and perlite insulated, vertical tank with 6,000 gallon liquid product volume capacity, 86” outside diameter and 383” height including support legs, 70,000 lbs full.
Inner Vessel	ASME VIII Division 1, SA240 304 stainless steel inner vessel with design temperature -320°F to 120°F and 250 MAWP.
Outer Vessel	A36 carbon steel outer vessel painted per manufacturer and final color by NWN, vacuum test port.
Vaporizers	Quantity 2 x 100% ambient vaporizers, aluminum fin, each 23”L x 23”W x 152” H, 300 lbs dry.
Design Flow Rate	0 - 200 gallons per day liquid nitrogen (0 - 13 SCFM N_2 gas)
Civil	
Foundation	Foundation to support vaporizers, bulk storage tank, piping, and controls. Additional foundations shall be provided to support loading station and pipe rack to/from loading station.
Electrical and I/C	
Level, Pressure, Temperature Monitoring and Control	As required for system monitoring and control via plant PLC and HMI.
Telemetry System	As specified by contracted liquid N2 supplier to remotely monitor tank fill level and automate deliveries.
Power	As required by the N2 supplier telemetry system.

Notes:

1. Design flow rate and equipment size to be verified during detailed design per Cold Box vendor specification and planned auxiliary use by NWN. Refer to Appendix C for alternative size options for varying rates of design flow.

7.0 PRELIMINARY DESIGN

7.1 Preliminary Design Drawings

Preliminary PFD, P&ID and general arrangement drawings were drafted to document existing conditions, demolition, and new piping and equipment. Refer to documents *PISET-001* [REF 3] and *GASET-001* [REF 2].

7.2 Preliminary Controls Integration Strategy

The overall strategy for the integration of new controls is to maintain the existing Facility controls architecture. As specified, the new Cold Box shall be provided with its own remote I/O enclosure and all sensing lines and instrument wiring within the vendor scope shall be routed to the panel by the vendor. The vendor will provide an Allen Bradley series 1794 Flex I/O rack, including redundant EtherNet/IP media adaptor, power supplies, terminal bases and I/O modules as required to accommodate all instrumentation and control devices within the Vendor's scope of supply. The control system provided by the vendor will match the existing systems used at the Facility.

Changes to instrumentation and controls required by the installation of the new Cold Box are outlined below:

- **Temperature Elements:** The existing Cold Box contains QTY 37 temperature elements, and the new Cold Box may contain as few as 26 and is a result of reduction in heat exchanger cores. Refer to the preliminary design drawings for the existing and new proposed temperature element tags, quantities, and locations. Temperature elements within the Cold Box will be provided by the Cold Box Vendor and others outside of the Cold Box shell will be provided by others.

- **Pressure Transmitters:** As identified in the HAZOP, it may be beneficial to monitor for fouling of the heat exchanger by providing additional sensing lines and differential pressure transmitters for each nozzle set of the new Cold Box. These differential pressure transmitters are included in the equipment list and OPCC but are not shown on the Design Documents.

- **CO_2 Monitoring**: Improvement in monitoring CO_2 content of the liquefaction stream may be made with the addition of a CO_2 analyzer. Its output could be integrated into alarms for operator notification and shutdown during liquefaction. The existing CO_2 monitoring is performed by a gas chromatograph, resulting in long process lag time and poor ability to respond to process transients.

- **Level Transmitters and Level Control Valves:** The quantity of liquid level transmitters and liquid level control valves is likely to be reduced from QTY 3 to QTY 2 based on the reduction in separator quantity within the new Cold Box. The liquid level control valves, installed outside of the Cold Box, will be provided new by the Cold Box Vendor based on the age of the existing.

- **Gas and Flame Detection Systems:** At least one gas detector will be added to the outlet of the Cold Box nitrogen purge gas stream to detect natural gas leaks from inside the Cold Box. Other existing gas detection and flame detection devices will be relocated or adjusted to maximize coverage based on the new Cold Box configuration. Any new gas or flame detection equipment will be integrated into the Facility's Fire and Gas Detection system.

In-kind replacements to the instrumentation and controls (I/C) are required due to piping spool removal, redesign, and replacement to enable installation of the new Cold Box. **Refer to the Equipment List in Appendix E4** for equipment designated as reused or replaced. Noteworthy replacements of I/C equipment are summarized below:

- **Flow Meters:** QTY 2 Coriolis flow meters may be replaced in kind based on the manufacturer's recommendation to have a remote transmitter head to enable reliable operation on a cryogenic line. Installation of new meters is expected to be more reliable and cost-effective than reconfiguration of the existing meters, based on feedback from the manufacturer.

Refer to the Cold Box specification and P&ID series demo and new construction drawings for additional information specific to instruments and controls modifications.

7.3 Permitting Matrix

Permitting requirements were researched to help determine construction schedule and permitting costs. NWN personnel experienced in the permitting process for LNG assets were contacted to assist in development of the matrix with the balance of research aided by internet research and publicly available documents. **Refer to Appendix F** for the Permit Matrix, the results of which are incorporated into the Proposed Project Schedule and OPCC. It is recommended to continue to evaluate the permitting requirements upon determination of final scope, schedule, and project construction phasing.

8.0 OPINION OF PROBABLE CONSTRUCTION COST

An OPCC was developed to a Class 4 accuracy as defined by the Association for the Advancement of Cost Engineers (AACE). An AACE Class 4 accuracy provides an estimate which is -15% to -30% on the low side and +20% to +50% on the high side. For this project, the extremes of the low and high ranges are provided in the context of the estimated value to show the entire project value range. The summary of the OPCC is in Table OPCC-1.

Table OPCC-1: AACE Class IV Cost Estimate for NWN Cold Box Replacement

Column	1	2	3
Line	**Description and Breakdown**	**% of Total Project Cost**	**Estimated Installed Cost with Contingency**
1	**Equipment**	**58%**	***$ 4,310,000***
2	2.15 MMSCFD Cold Box	48%	$ 3,560,000
3	Bulk Nitrogen Storage System & Integration	7%	$ 540,000
4	Mercury Guard Equipment & Integration	3%	$ 210,000
5	**Cold Box Systems Integration**	**18%**	***$ 1,330,000***
6	Cold Box Integration, Valves, Equipment, IC	18%	$ 1,330,000
7	**Civil/Structural**	**5%**	***$ 390,000***
8	Cold Box Foundation Incl. Demo of Mat with Piles	3%	$ 190,000
9	Nitrogen Storage System Foundation	2%	$ 140,000
10	Mercury Guard Foundation	1%	$ 60,000
11	**Engineering, Design & Construction Management**	**18%**	***$ 1,340,000***
12	Cold Box Integration Engineering	8%	$ 600,000
13	Cold Box CM	8%	$ 590,000
14	Nitrogen System Engineering	1%	$ 80,000
15	Nitrogen System CM	1%	$ 70,000
16	**Permitting**	**2%**	***$ 120,000***
17	Permitting	2%	$ 120,000
18		**Grand Total**	**$ 7,490,000**
19		**AACE Class IV Low Range (-30%)**	**$ 5,243,000**
20		**AACE Class IV High Range (+50%)**	**$ 11,235,000**

Table OPCC-2 summarizes the entire project value range as the future value assuming a period of two years at an annual inflation rate of 9.0%. The annual inflation rate was estimated as the average of labor (11%) and materials (7%) from Engineering News Record historical market data from the past two years.

Table OPCC-2: AACE Class IV Cost Estimate for NWN Cold Box Replacement Assuming Simple Annual Inflation of 9.0% for 2 Years		
18B	**Grand Total**	**$ 8,838,200**
19B	**AACE Class IV Low Range (-30%)**	**$ 6,186,740**
20B	**AACE Class IV High Range (+50%)**	**$ 13,257,300**

Estimates were based upon the following assumptions:

1. Asbestos abatement not required.
2. Other than contaminated soils, other hazardous material removal is excluded as no other has been identified.
3. Other than known below grade utilities or foundations, no other underground obstructions, i.e. boulders, ledge, unknown foundations will hinder civil construction.
4. Site is accessible to cranes, lifts, and hoists for demolition and construction of existing/new equipment removal/placement.
5. Site is reasonably accessible for Cold Box and bulk nitrogen storage tank delivery trucks to limit pick/place count.
6. NWN Overhead to support the project during all phases is not included.

Budgetary quotations received from the following vendors for the **Cold Box**:

1. CHART
2. Air Liquide
3. Cosmodyne
4. Linde

The Cold Box Vendor budgetary quotations ranged from $1 million to $2.5 million and lead times of 44 to 56 weeks after receipt of order. Higher vendor engineering costs are typical of all vendor budget quotations due to the combination of small liquefaction capacity and open loop natural gas expansion cycle of the existing Cold box. Cold Boxes of this cycle type and size were phased out in the late 70's in favor of other cycles due to the availability of the required flow takeaway from lower pressure distribution systems.

9.0 PROJECT SCOPE OF WORK

The anticipated work required to complete execution of the Cold Box replacement includes, but is not limited to, the scope of work outlined below. The scope of work summarizes engineering, procurement, construction, and commissioning phases of the project.

1. Cold Box Procurement

The Cold Box procurement specification can be included in a request for proposal to obtain best and final offer (BAFO) proposals from vendors (Note, the Cold Box specification shall be updated prior to release for proposal for any pre-treatment system modifications which improve the quality of the inlet gas over that which is specified). Sanborn Head considers each of the four vendors who provided budgetary pricing in support of the FEED to be qualified to engineer and furnish the new Cold Box. Once final proposals are received, it is recommended that NWN utilize their Owner's Engineer or detailed engineering firm to provide a technical evaluation of the submitted proposals to be utilized in the vendor selection process.

2. Detailed Design Engineering and Specification

Engineering shall be performed in cooperation with a selected Cold Box vendor to finalize the new Cold Box design. The integration design engineering may be completed in parallel with procurement of the Cold Box. Below is a high level summary of detailed design engineering and specification tasks as they relate to major equipment, minor equipment, and Cold Box integration:

- 2.1. Procurement Specification and Technical Reviews/Support
  - 2.1.1. Cold Box (Technical Reviews/support only)
  - 2.1.2. Mercury Guard
  - 2.1.3. E-14 Heavy Ends Vaporizer (Replace if required for system performance)
  - 2.1.4. New CO2 Analyzer
  - 2.1.5. Bulk Nitrogen Storage and Supply System
  - 2.1.6. Instrumentation, Control Valve & Specialty Components
- 2.2. Update Process Flow and Piping & Instrument Diagrams to include
  - 2.2.1. Vendor Requirements
  - 2.2.2. HAZOP Results
- 2.3. Major Equipment and Component Integration Design
  - 2.3.1. Demolition Plans and Procedures
  - 2.3.2. Determination of Fundamental Period of Vibration for Major Structures (by Equipment Vendors)
  - 2.3.3. Civil Site Plan & Foundation Design
  - 2.3.4. Piping and Pipe Support Design, including Pipe Stress Analysis

2.3.5. Pipe Coating and Insulation Specifications

2.3.6. Electrical and Controls

2.3.7. Purging plans, in/out of service

2.3.8. Crane/lift plans for Cold Box removal and installation

2.3.9. Commissioning Plans

2.3.10. Update to the existing Facility Fire Study

2.3.11. Civil, Mechanical, and Electrical Installation Specifications

2.3.12. HAZOP closeout documentation

2.4. Permitting Documentation to include at a minimum:

2.4.1. Erosion and Sediment Control Plan

2.5. Management of Change

2.5.1. Update operating procedures

2.5.2. Update training procedures

2.5.3. Update Facility documentation

3. Procurement

Major long lead equipment in addition to the Cold Box shall be procured in parallel with Detailed Design and Engineering. Major and minor equipment are summarized below:

3.1. Major Equipment

3.1.1. Mercury Guard

3.1.2. E-14 Heavy Ends Vaporizer (as required)

3.1.3. Bulk Nitrogen Storage and Supply System

3.2. Minor Equipment

3.2.1. Piping and associated hangars and supports

3.2.2. Access ladders, platforms

3.2.3. Insulation

3.2.4. Valves and Mechanical Components

3.2.5. Instrumentation and Controls

4. Demolition and Disposal

Major tasks for demolition of existing equipment are outlined below. Note, demolition of connected equipment may require reuse and shall be determined in the detailed design phase:

4.1. Purge out of Service and Physically Isolate Mechanically and Electrically

4.2. Demo Existing Cold Box

4.2.1. Cold Box

4.2.2. Perlite Insulation

4.2.3. Cold Box Foundation

4.3. Demo Connected Equipment

4.3.1. Piping Insulation

4.3.2. Piping

4.3.3. Valves

4.3.4. Instrumentation and Controls

4.4. Disposal of Demolished Equipment and Materials

4.4.1. Scrap Equipment, Metal, and Piping (Note: NWN to perform testing to confirm no asbestos or lead abatement will be required within the scope of work.)

4.4.2. Contaminated Soils

4.4.3. Cold Box Perlite

5. Construction

Construction will involve the following disciplines and corresponding equipment:

5.1. Civil

5.1.1. New Cold box foundation

5.1.2. New Bulk Nitrogen Storage System foundation

5.1.3. New Mercury Guard foundation

5.2. Structural

5.2.1. New Piping Supports

5.2.2. New Access Ladders and Platforms

5.2.2.1. On New Cold Box

5.2.2.2. To restore existing pipe rack access

5.3. Mechanical

5.3.1. New Cold Box

5.3.2. New Piping and valves for Cold Box Integration

5.3.2.1. Non-destructive testing

5.3.3. Piping insulation

5.3.4. Cold Box insulation

5.4. Electrical

5.4.1. Power supply to the Bulk Nitrogen Storage System

5.4.2. Power supply to new controls

5.5. Controls and Instrumentation

5.5.1. Updates to control networks and remote I/O

5.5.2. Development of new PLC control software and HMI displays

6. Commissioning

New, reused, and replaced equipment shall be commissioned to ensure the safety in all modes of operation. The following lists major equipment which may require individual vendor commissioning plans that are incorporated into the overall commissioning plan:

6.1. Cold Box

6.2. Bulk Nitrogen Storage System

6.3. Mercury Guard

6.4. Controls and instrumentation for all the above.

10.0 PROPOSED PROJECT SCHEDULE

Table 10.0.1 provides the estimated overall project execution schedule based upon the budget proposals received from the equipment vendors.

Table 10.0.1: Proposed Project Schedule

	Engineer & Procure						**Liquefier Out of Service**						
Months	**2**	**4**	**6**	**8**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**
Cold Box Procure/Ship													
Engineering													
Long Lead Procure/Ship													
Construction Bid/Permits													
Construction - Demolition													
Construction - Civil													
Construction - Mech													
Construction - Elec													
Commissioning													
Project Closeout													

General Notes:

A. It is recommended this schedule be utilized for project planning purposes. For example, NWN shall release the detailed engineering contract and cold box purchase order approximately one year prior to the desired construction start date.

APPENDIX A

Geotechnical Investigation, GeoEngineers

Preliminary Geotechnical Engineering Evaluation

NW Natural Cold Box FEED Preliminary Design
Portland LNG Facility
Portland, Oregon

for
Sanborn Head & Associates

June 30, 2021

GeoEngineers
Earth Science + Technology

Preliminary Geotechnical Engineering Evaluation

NW Natural Cold Box FEED Preliminary Design
Portland LNG Facility
Portland, Oregon

for
Sanborn Head & Associates

June 30, 2021

GeoEngineers

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File No. 6024-210-03

June 30, 2021

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1.0 INTRODUCTION

GeoEngineers, Inc. (GeoEngineers), is pleased to submit this preliminary geotechnical engineering evaluation report for the proposed construction of a new Cold Box FEED and Bulk Nitrogen Storage at the NW Natural Portland LNG Facility located at 7900 St. Helens Road in Portland, Oregon. The Portland LNG Facility is located on the west bank of the Willamette River south of the St. Johns Bridge. The location of the site is shown in the Vicinity Map, Figure 1.

The project includes the proposed construction of a Cold Box structure at the location of the existing Cold Box. The new Cold Box structure is anticipated to be approximately 11 feet in length, 11 feet in width, and 30 to 60 feet in height. The project also includes the construction of a new Bulk Nitrogen Storage system. The liquid nitrogen tank proposed as part of the Bulk Nitrogen Storage system is anticipated to be approximately 7 feet in diameter and 30 feet in height. The general locations of both the Cold Box structure and the Bulk Nitrogen Storage system are shown in the Site Plan, Figure 2. Specific project plans have not been developed yet.

2.0 SCOPE OF SERVICES

The purpose of our services was to evaluate soil and groundwater conditions within the project area in order to provide this preliminary geotechnical engineering evaluation report. It is our understanding that further design of the proposed Cold Box FEED and Bulk Nitrogen Storage will continue during a subsequent Detailed Design phase for the project. Our specific scope of services is detailed in our January 19, 2021, proposal to you, but in general included providing general project management; reviewing relevant and available geotechnical resources; exploring subsurface soil and groundwater conditions; collecting representative soil samples; completing geotechnical and environmental laboratory testing; performing geotechnical analyses; and preparing this preliminary geotechnical evaluation report, including preliminary geotechnical parameters for design and preliminary foundation recommendations.

3.0 SITE CONDITIONS

3.1. Surface Conditions

The site is located within the NW Natural Portland LNG Facility, which includes a large natural gas storage tank and associated piping, equipment, and buildings related to the storage and distribution of natural gas. The site topography within the proposed improvement area is essentially flat and at about Elevation 40 feet North American Vertical Datum 88 (NAVD 88). A Site Plan is provided as Figure 2.

3.2. Site Geology

The geology of the site is mapped by Oregon Department of Geology and Mineral Industries (DOGAMI) Open File Report O-90-2, Earthquake Hazard Geology Maps of the Portland Metropolitan Area, Oregon (Madin 1990) as underlain by approximately 60 feet of unconsolidated alluvium comprised of intercalated clay, silt, sand and gravel from the Willamette and Columbia Rivers. These are underlain by older alluvial deposits, including Troutdale siltstones, sandstones and conglomerates, as well as poorly indurated clays and silts. Madin (1990) shows the older alluvial deposits extending to depths of approximately 80 to 150 feet below ground surface (bgs) where they overlie basement rocks of the Columbia River Basalt Group (CRBG) and possibly older volcanic rocks.

Our borings suggest that the site geology largely conforms to the published mapping but that the site is mantled by man-made fill and that the depth to CRBG bedrock is less than that suggested by Madin (1990).

3.3. Subsurface Conditions

We completed field explorations for this study between April 22 and 29, 2021. Our explorations included two drilled borings (B-1-21 and B-2-21) to depths ranging between 60 and 70 feet bgs. Boring B-1-21 was advanced in the general vicinity of the new Cold Box structure and boring B-2-21 was advanced in the general vicinity of the Bulk Nitrogen Storage system. The locations of B-1-21 and B-2-21 are shown in Figure 2. A summary of our exploration methods as well as the boring logs can be found in Appendix A. Laboratory test results are also provided in the exploration logs and described in Appendix A.

In addition to the field exploration performed specifically for this project, GeoEngineers has performed previous geotechnical engineering work at the Portland LNG Facility for other components at the facility, including the advancement of drilled borings. Borings B-1-15 and B-1-17 through B-3-17 were advanced at the project site previously and these boring locations are also shown in Figure 2. The previous work performed for the liquification facility is documented in *Preliminary Geotechnical Engineering Evaluation, NW Natural LNG Liquification Facility, Portland, Oregon* (GeoEngineers 2017).

Based on subsurface conditions encountered in borings B-1-21 and B-2-21, as well as review of the soil borings advanced at the project site previously, the subsurface can be divided into three general soil/rock layers. In general, subsurface conditions consist of a variable mantling of fill to depths of approximately 15 to 20 feet bgs over silt and fine sand and gravel alluvium to a depth of approximately 55 to 65 feet bgs, below which hard basalt bedrock was encountered to terminal depth. The following paragraphs describe these layers in more detail.

3.3.1. Fill Material

Asphalt concrete (AC) pavement or crushed aggregate was encountered at the ground surface. Beneath the surface materials, a mixture of silt and sand interpreted as fill placed during the development of the site was encountered. The fill consisted of loose fine to medium sand with varying amounts of silt and medium stiff silt with estimated low plasticity.

The fill soils typically displayed field indications of petroleum products, including visible sheen and petrochemical odors. Composite samples of soil were collected during drilling for waste profiling purposes. Results of environmental testing show that compounds related to petroleum were detected in the samples submitted. However, waste profiling indicated that the fill material sampled met the criteria for non-hazardous waste disposal. A summary of results of environmental testing of the composite samples are provided in Appendix B.

3.3.2. Willamette River Alluvium

Below the fill material, Holocene alluvial sediments of the Willamette River were encountered. The alluvial deposits extended from approximately 20 feet to 65 feet bgs in boring B-1-21 and from approximately 15 feet to 55 feet bgs in boring B-2-21. The Willamette River Alluvium generally consisted of very soft to medium stiff silt overlying very loose to medium dense silty sand. In addition, very dense poorly graded gravel and sand alluvium was encountered in boring B-1-21 below a depth of approximately 55 feet bgs and just above the basalt bedrock. No indication of petrochemicals was observed during drilling in the alluvial soils.

3.3.3. Columbia River Basalt Group (CRBG)

Basalt of the CRBG was encountered at approximately 65 feet bgs in boring B-1-21 and 55 feet bgs in boring B-2-21. Borings drilled previously at the project site encountered the basalt bedrock at similar depths ranging from approximately 48 to 69 feet bgs. Drilling rate and standard penetration testing (SPT) blow counts from the samples driven in the CRBG suggests that the upper zones of the CRBG consists of hard, slightly weathered to fresh basalt rock.

3.4. Groundwater

Groundwater was encountered at a depth of approximately 17 feet bgs in boring B-1-21, but was not observed in boring B-2-21 due to the method of drilling. In addition, groundwater was encountered at a depth of approximately 24 feet bgs in previous borings advanced at the project site. Groundwater conditions at the site are expected to vary seasonally due to rainfall events, river level, and other factors not observed in our explorations.

4.0 CONCLUSIONS

Based on our explorations, testing and analyses, it is our opinion that the site is suitable for the proposed project from a geotechnical standpoint, provided a suitable foundation solution is selected that meets the project requirements. We offer the following conclusions regarding geotechnical design at the site.

- Fill and alluvial soil present at the project site are liquefiable during the design earthquake. Liquefaction induced settlement up to 16 inches and lateral spreading up to 3 feet should be anticipated.
- The near surface site soils are contaminated and are not suitable for reuse as structural fill. Waste profiling indicated that the material sampled met the criteria for non-hazardous waste disposal. Material generated during site excavation should be removed from the site and properly disposed at an approved landfill. A summary of results of environmental testing are provided in Appendix B.
- Groundwater was encountered at approximately 17 feet bgs (approximately Elevation 23 feet NAVD 88). Groundwater may be encountered at shallower depths during extended periods of wet weather and during periods of high river levels.
- The selected foundation system consisting of micropiles should be designed to support structural loads, limit settlement to acceptable levels, mitigate for liquefaction induced settlement and associated lateral spreading, minimize disposal of contaminated soils and be approved by environmental regulatory agencies.

5.0 SEISMIC DESIGN PARAMETERS

Parameters provided in Table 1 are based on subsurface conditions encountered during our exploration program, as well as subsurface conditions encountered in borings drilled previously. Based on the presence of potentially liquefiable soils (see discussion in Section 6.0), Site Class F was selected for preliminary seismic design for the project. However, if the fundamental period of each of the proposed structures for the project will be less than 0.5 seconds, exceptions documented in Section 20.3.1 of the 2016 *Minimum Design Loads for Buildings and Other Structures* (American Society of Civil Engineers [ASCE] 7-16) can be used to approximate recommended seismic design parameters for the project. In determining seismic design parameters with this exception, Site Class D was selected for the project, as allowed by ASCE 7-16 for structures with a period less than 0.5 seconds. Therefore, the seismic design parameters presented in Table 1 are based on Site Class D. It is recommended that the fundamental period of the proposed structures be determined during subsequent design phases for the project to validate the use of exceptions in Section 20.3.1 of ASCE 7-16.

Parameters provided in Table 1 are based on the procedure outlined in the 2018 International Building Code (IBC), which references the ASCE 7-16. Per ASCE 7-16 Section 11.4.8, a ground motion hazard analysis or site-specific response analysis is required to determine the ground motions for structures on Site Class D sites with S_1 greater than or equal to 0.2g. As stated previously, the site is assumed to be classified as Site Class D and has a recommended S_1 value of 0.409g; therefore, the provision of 11.4.8 applies. Alternatively, the parameters listed in Table 1 below may be used to determine the design ground motions if Exception 2 of Section 11.4.8 of ASCE 7-16 is used. Using this exception, the seismic response coefficient (C_s) is determined by Equation (Eq.) (12.8-2) for values of $T \leq 1.5T_S$, and taken as equal to 1.5 times the value computed in accordance with either Eq. (12.8-3) for $T_L \geq T > 1.5T_s$ or Eq. (12.8-4) for $T > T_L$, where T represents the fundamental period of the structure and T_S=0.757 sec. If requested, we can complete a site-specific seismic response analysis, which might provide somewhat reduced seismic demands from the parameters in Table 1 and the requirements for using Exception 2 of Section 11.4.8 in ASCE 7-16. The reduced values will likely not be significant enough to warrant the additional cost of further evaluation if designing to 2018 IBC. For preliminary design purposes, we recommend seismic design be performed using the values presented in Table 1.

TABLE 1. MAPPED 2018 IBC SEISMIC DESIGN PARAMETERS

Parameter	Recommended Value[1,2,3]
Site Class	F
Mapped Spectral Response Acceleration at Short Period (S_S)	0.894 g
Mapped Spectral Response Acceleration at 1 Second Period (S_1)	0.409 g
Site Modified Peak Ground Acceleration (PGA_M), (based on Site Class D)	0.484 g
Site Amplification Factor at 0.2 second period (F_a), (based on Site Class D)	1.142
Site Amplification Factor at 1.0 second period (F_v), (based on Site Class D)	1.891
Design Spectral Acceleration at 0.2 second period (S_{DS}), (based on Site Class D)	0.681 g
Design Spectral Acceleration at 1.0 second period (S_{D1}), (based on Site Class D)	0.516 g

Notes:

[1] Parameters developed based on Latitude 45.5783951° and Longitude -122.7610446° using the ATC Hazards online tool.

[2] These values are only valid if the structural engineer utilizes Exception 2 of Section 11.4.8 (ASCE 7-16). tool.

[3] Ground surface spectral acceleration values for Site Class D are only valid if the structural engineer utilizes exceptions in Section 20.3.1 (ASCE 7-16) and the fundamental period of structure is less than 0.5 seconds.

6.0 SEISMIC HAZARDS

The following sections present a discussion of seismic hazards consisting of liquefaction, post-liquefaction settlement, lateral spreading, and other seismic hazards.

6.1. Liquefaction

Liquefaction is a phenomenon caused by a rapid increase in pore water pressure that reduces the effective stress between soil particles to near zero. The excessive buildup of pore water pressure results in the sudden loss of shear strength in a soil. Granular soil, which relies on interparticle friction for strength, is susceptible to liquefaction until the excess pore pressures can dissipate. Sand boils and flows observed at the ground surface after an earthquake are the result of excess pore pressures dissipating upwards, carrying soil particles with the draining water. In general, loose, saturated sand soil with low silt and clay contents is the most susceptible to liquefaction. Low plasticity, silty sand may be moderately susceptible to liquefaction under relatively higher levels of ground shaking.

We evaluated the liquefaction potential of the site using the Simplified Procedure (Youd et al. 2001). The Simplified Procedure is based on comparing the cyclic resistance ratio (CRR) of a soil layer (the cyclic shear stress required to cause liquefaction) to the cyclic stress ratio (CSR) induced by an earthquake. The factor of safety against liquefaction is determined by dividing the CSR by the CRR. Liquefaction hazards, including settlement and related effects, can occur when the factor of safety against liquefaction is less than 1.0. Based on results of the liquefaction analysis using the 2018 IBC design seismic event (2 percent chance of exceedance in 50 years, or 2,475-year event), the alluvial deposits underlying the site are potentially liquefiable. Based on subsurface conditions encountered in B-1-21 and B-2-21, the alluvial deposits are present to a depth of approximately 55 feet bgs.

6.2. Post-Liquefaction Settlement

Post-liquefaction settlement was estimated for the alluvial deposits present at the project site using methods developed by Ishihara and Yoshimine (1992). The post-liquefaction analysis resulted in estimated post-liquefaction settlement values ranging from 9 to 16 inches. Differential settlement of up to half the total settlement is estimated within a 50-foot distance. A summary of results of the post-liquefaction settlement analysis is presented in Table 2.

TABLE 2. POST-LIQUEFACTION SETTLEMENT ESTIMATE

Boring Location	Estimated Settlement[1,2] (inches)
B-1-21	9 to 14
B-2-21	12 to 16

Notes:

[1] Based on methods developed by Ishihara and Yoshimine (1992).

[2] Differential settlement estimated to be up to half the total settlement values estimated.

6.3. Lateral Spreading

Lateral spread occurs when large blocks of ground are displaced down gentle slopes or toward stream channels as a result of liquefaction of subsurface soil during an earthquake. Based on the presence of liquefiable soil at the project site, as well as an open slope face along the west bank of the Willamette River located at the eastern limit of the site, lateral spread is considered a seismic hazard at the project site. The top of slope for the west bank of the Willamette River is located approximately 750 to 800 feet from the proposed locations of the new Cold Box structure and Bulk Nitrogen Storage. Methods developed by Youd et al. (2002) were used to estimate lateral spread in the general vicinity of the proposed locations of the new Cold Box and Bulk Nitrogen Storage. The analysis resulted in an estimated 1 to 3 feet of lateral spread within the general vicinity of the proposed structures during a design seismic event.

6.4. Other Seismic Hazards

Tectonic deformations result from fault displacements or regional uplift and subsidence during an earthquake. Because there are no known faults crossing the project site, fault displacements are not anticipated. Regional uplift and subsidence are generally associated with ruptures along subduction zones. Given the site is located approximately 65 miles from the Cascadia Subduction Zone, minimal uplift and subsidence are estimated for the project site.

7.0 FOUNDATION RECOMMENDATIONS

7.1. General

Due to the presence of liquefiable soil at the site, it is our opinion that deep foundations be used to support the proposed structures. Various deep foundation options were considered that may be applicable for the proposed structures based on soil conditions, environmental contamination, size and layout of proposed structures, vibration considerations, and access limitations. General prerequisites considered in selecting a recommended deep foundation option are as follows:

- Deep foundation installation does not create an avenue for contaminant transfer to deeper alluvial soil deposits.
- Due to the relative cost of disposal of contaminated soil, deep foundation installation generates no or limited spoils.
- Due to access limitations, especially at the proposed location of the new Cold Box structure, deep foundation installation can be achieved using smaller equipment.
- Based on the assumed dimensions of the proposed structures, relatively large overturning moments during seismic loading are anticipated which will result in large uplift demands on the foundation system. Therefore, the foundation system will likely need to be socketed into the basalt bedrock to resist uplift loading.
- As discussed previously, post-liquefaction settlement and lateral spread are seismic hazards present at the project site. Therefore, the foundation system will need to resist loading due to vertical and lateral soil movement.

Based on review of the general prerequisites listed above, as well as consideration of other foundation design requirements, micropiles are the recommended foundation system for preliminary design of the new Cold Box and Bulk Nitrogen Storage structures. Additional discussion and preliminary analyses for the recommended micropiles is provided in the following sections.

7.2. Micropiles

Micropiles are high capacity, small diameter (typically 5 to 10 inches in diameter) drilled and grouted piles. Micropiles are installed by drilling a steel-cased boring into soil or rock. Cuttings are removed with circulating drilling fluid, typically water or air. Reinforcement generally consists of high-strength steel pipe casing with one or more large steel reinforcing bars installed with centralizers down the center of the bore hole. Common casing diameters are equal to 5½, 7, and 9⅝ inches, with 7-inch-diameter casing being the most popular. Following reinforcing steel insertion, a sand-cement grout is placed (either via gravity or under pressure) through a tremie into the bored hole. The bored hole is filled from the bottom up while the casing is either withdrawn or left in place. Based on subsurface conditions and seismic hazards present at the project site, it is assumed for preliminary design that steel casing would be drilled to the top of basalt bedrock, an uncased rock socket would be drilled into the basalt bedrock, and one or more large steel reinforcing bars would be installed from the bottom of the rock socket up to the pile cap. A general detail of a typical micropile is provided in Figure 3.

Additional considerations for the micropiles for use in preliminary design are summarized as follows:

- Based on anticipated uplift loading, it is assumed a rock socket for each micropile will be required.
- Based on anticipated lateral loading due to soil movement, it is assumed that a larger casing (7- or 9⅝-inch-diameter) will be required to provide adequate lateral pile capacity.
- Lateral loading due to soil movement may require some of the micropiles to be battered.

The following subsections summarize general design parameters for axial and lateral analysis of micropiles for preliminary design.

7.2.1. Axial Resistance

Structural loads for static and seismic loading have not been determined for preliminary design of the proposed Cold Box and Bulk Nitrogen Storage structures. It is our understanding that structural loads and load cases will be determined as part of the detailed design phase for the project. However, preliminary geotechnical design parameters for axial resistance of micropiles were estimated for use in determining the relative size and quantity of micropiles required for the proposed structures. We recommend that axial resistance for the proposed micropiles be determined using methods presented in the Federal Highway Administration (FHWA) *Micropile Design and Construction Reference Manual* (FHWA 2005). Because the alluvial deposits are susceptible to liquefaction, axial resistance of the micopiles should only be considered within the rock socket in the basalt bedrock. Axial resistance can be determined using the equation (from FHWA, 2005) presented below:

$$P = \frac{\alpha_{bond}}{FS} \times \pi \times D_b \times L_b$$

where:

P = allowable axial load

α_{bond} = bond strength (Table 5-3 of FHWA 2005) = 200 to 600 pounds per square inch for basalt

FS = factor of safety = 2

D_b = diameter of bond zone (rock socket)

L_b = length of bond zone (rock socket)

Based on general recommended bond strength values in basalt as well as typical rock socket diameters, an allowable axial (compression and uplift) capacity of the bond zone equal to 15 to 40 kips per foot of rock socket can be assumed for preliminary design. The length of rock socket should be determined using the equation above for axial loads, but should also checked for lateral resistance (see discussion below). Based on the depth to basalt bedrock, the proposed micropiles are estimated to be approximately 70 to 75 feet in length.

In addition, as design for the project progresses and the size, quantity, and layout of the micropiles are determined based on structural loads, the geotechnical and structural capacity of the micropiles should also be checked using downdrag loads due to liquefaction and post-liquefaction settlement.

7.2.2. Lateral Resistance

The required lateral resistance of the micropile foundation system (pile group) should be evaluated during the detailed design phase of the project once structure dimensions and loads have been determined. It is recommended that lateral analyses methods such as those presented in *Guidelines on Foundation Loading and Deformation Due to Liquefaction Induced Lateral Spreading* (CALTRANS 2012) for the unrestrained ground displacement design case be used to evaluate the lateral resistance of the micropile foundation system for each proposed structure. Analyses results of lateral resistance should be used to validate the size, length, quantity, and layout of proposed micropiles.

8.0 LIMITATIONS

We have prepared this report for the exclusive use of Sanborn Head & Associates, NW Natural, and their authorized agents and/or regulatory agencies for the proposed NW Natural Cold Box FEED Preliminary Design Project at the Portland LNG Facility in Portland, Oregon. This report is not intended for use by others, and the information contained herein is not applicable to other sites. No other party may rely on the product of our services unless we agree in advance and in writing to such reliance.

Within the limitations of scope, schedule, and budget, our services have been executed in accordance with generally accepted practices in the area at the time this report was prepared. No warranty or other conditions, express or implied, should be understood.

Please refer to Appendix C titled “Report Limitations and Guidelines for Use” for additional information pertaining to use of this report.

9.0 REFERENCES

American Society of Civil Engineers (ASCE). 2017. Minimum Design Loads and Associated Criteria for Buildings and Other Structures.

California Department of Transportation (CALTRANS). 2012. Guidelines on Foundation Loading and Deformation Due to Liquefaction Induced Lateral Spreading. January 2012.

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FIGURES

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Feet

Notes:

1. The locations of all features shown are approximate.
2. This drawing is for information purposes. It is intended to assist in showing features discussed in an attached document. GeoEngineers, Inc. cannot guarantee the accuracy and content of electronic files. The master file is stored by GeoEngineers, Inc. and will serve as the official record of this communication.

Data Source: ESRI

Projection: NAD 1983 UTM Zone 10N

Vicinity Map

NW Natural – Cold Box FEED – Portland LNG Facility
Portland, Oregon

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Figure 1

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Legend

- Boring Number and Approximate Location (GeoEngineers, 2021)
- Previous Boring Number and Approximate Location (GeoEngineers, 2017)
- Previous Boring Number and Approximate Location (GeoEngineers, 2015)
- Proposed Site Location

Notes:
1. The locations of all features shown are approximate.
2. This drawing is for information purposes. It is intended to assist in showing features discussed in an attached document. GeoEngineers, Inc. cannot guarantee the accuracy and content of electronic files. The master file is stored by GeoEngineers, Inc. and will serve as the official record of this communication.

Data Source: 2020 image from Multnomah County GIS Server.

Projection: NAD 1983 StatePlane Oregon North FIPS 3601 Feet

Site Plan

NW Natural – Cold Box FEED – Portland LNG Facility
Portland, Oregon

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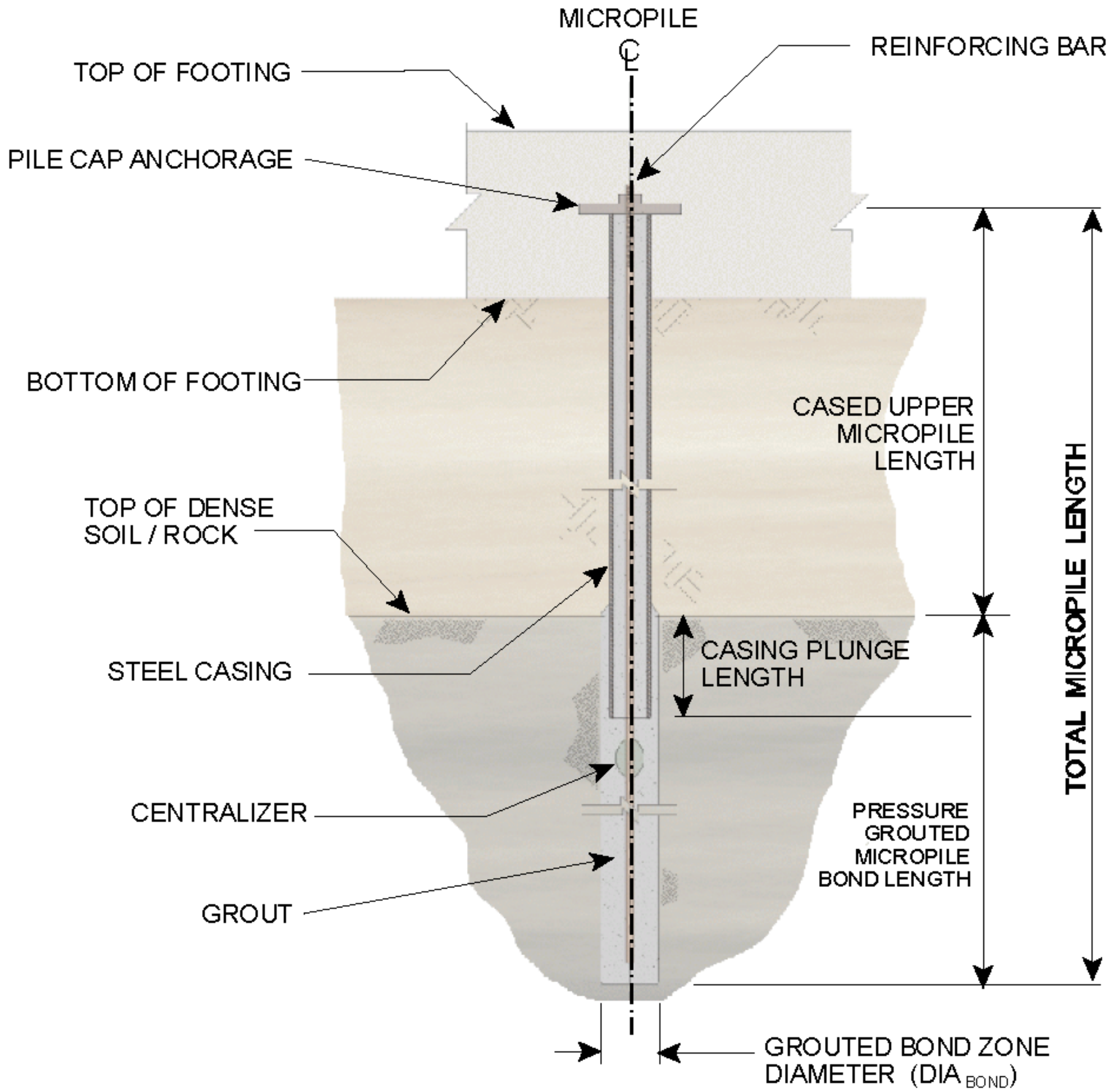
Figure 2



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1. The locations of all features shown are approximate.
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Data Source: Micropile Design and Construction, Reference Manual (FHWA, 2005)

Projection: WGS 1984 Web Mercator Auxiliary Sphere

Micropile Typical Detail

NW Natural – Cold Box FEED – Portland LNG Facility
Portland, Oregon

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Figure 3

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APPENDICES

Appendix A
Field Explorations and Geotechnical Laboratory Testing

APPENDIX A
FIELD EXPLORATIONS AND GEOTECHNICAL LABORATORY TESTING

Field Explorations

Soil and groundwater conditions at the proposed NW Natural Cold Box FEED Preliminary Design project were explored between April 22 and 29, 2021, by completing a total of two borings (B-1-21 and B-2-21) at the approximate locations shown in the Site Plan, Figure 2. The borings were advanced using hollow-stem auger and mud-rotary techniques to depths of 60 to 70 feet below ground surface (bgs) using a truck-mounted drill rig owned and operated by Western States Soil Conservation of Aurora, Oregon. In accordance with environmental requirements for the project, the borings were drilled using hollow-stem auger methods through potentially contaminated fills, and mud-rotary methods thereafter, with an "environmental seal" at the elevation where mud-rotary methods began. The borings were backfilled using NW Natural's preferred backfill methods consisting of a mixture of Wyoming sodium bentonite and Organoclay.

The drilling was continuously monitored by an engineering geologist from our office who maintained a detailed log of subsurface explorations, visually classified the soil encountered and obtained representative soil samples from the borings. Representative soil samples were obtained from each boring at approximate 5- to 10-foot-depth intervals using a 1-inch, inside-diameter, standard split spoon sampler. The sampler was driven into the soil using a hydraulic-drive 140-pound hammer, free-falling 30 inches on each blow. The number of blows required to drive the sampler each of three, 6-inch increments of penetration were recorded in the field. The sum of the blow counts for the last two, 6-inch increments of penetration is reported on the boring logs as the ASTM International (ASTM) Standard Practices Test Method D 1556 Standard Penetration Test (SPT) N-value.

Recovered soil samples were visually classified in the field in general accordance with ASTM D 2488 and the classification chart listed in Key to Exploration Logs, Figure A-1. Logs of the borings are presented in Figures A-2 and A-3. The logs are based on interpretation of the field and laboratory data and indicate the depth at which subsurface materials or their characteristics change, although these changes might actually be gradual.

Geotechnical Laboratory Testing

Soil samples obtained from the explorations were visually classified in the field and in our laboratory using the Unified Soil Classification System (USCS) and ASTM classification methods. ASTM Test Method D 2488 was used to visually classify the soil samples, while ASTM D 2487 was used to classify the soils based on laboratory tests results. Moisture contents, Atterberg limits, and percent fines (silt- and clay-size particles passing the No. 200 sieve) were completed. Results of laboratory testing are presented on the exploration logs at the respective sample depths. The Atterberg limits results are also included in Figure A-4.

SOIL CLASSIFICATION CHART

MAJOR DIVISIONS			SYMBOLS GRAPH	SYMBOLS LETTER	TYPICAL DESCRIPTIONS
COARSE GRAINED SOILS MORE THAN 50% RETAINED ON NO. 200 SIEVE	GRAVEL AND GRAVELLY SOILS MORE THAN 50% OF COARSE FRACTION RETAINED ON NO. 4 SIEVE	CLEAN GRAVELS (LITTLE OR NO FINES)		GW	WELL-GRADED GRAVELS, GRAVEL - SAND MIXTURES
				GP	POORLY-GRADED GRAVELS, GRAVEL - SAND MIXTURES
		GRAVELS WITH FINES (APPRECIABLE AMOUNT OF FINES)		GM	SILTY GRAVELS, GRAVEL - SAND - SILT MIXTURES
				GC	CLAYEY GRAVELS, GRAVEL - SAND - CLAY MIXTURES
	SAND AND SANDY SOILS MORE THAN 50% OF COARSE FRACTION PASSING ON NO. 4 SIEVE	CLEAN SANDS (LITTLE OR NO FINES)		SW	WELL-GRADED SANDS, GRAVELLY SANDS
				SP	POORLY-GRADED SANDS, GRAVELLY SAND
		SANDS WITH FINES (APPRECIABLE AMOUNT OF FINES)		SM	SILTY SANDS, SAND - SILT MIXTURES
				SC	CLAYEY SANDS, SAND - CLAY MIXTURES
FINE GRAINED SOILS MORE THAN 50% PASSING NO. 200 SIEVE	SILTS AND CLAYS	LIQUID LIMIT LESS THAN 50		ML	INORGANIC SILTS, ROCK FLOUR, CLAYEY SILTS WITH SLIGHT PLASTICITY
				CL	INORGANIC CLAYS OF LOW TO MEDIUM PLASTICITY, GRAVELLY CLAYS, SANDY CLAYS, SILTY CLAYS, LEAN CLAYS
				OL	ORGANIC SILTS AND ORGANIC SILTY CLAYS OF LOW PLASTICITY
	SILTS AND CLAYS	LIQUID LIMIT GREATER THAN 50		MH	INORGANIC SILTS, MICACEOUS OR DIATOMACEOUS SILTY SOILS
				CH	INORGANIC CLAYS OF HIGH PLASTICITY
				OH	ORGANIC CLAYS AND SILTS OF MEDIUM TO HIGH PLASTICITY
HIGHLY ORGANIC SOILS				PT	PEAT, HUMUS, SWAMP SOILS WITH HIGH ORGANIC CONTENTS

NOTE: Multiple symbols are used to indicate borderline or dual soil classifications

Sampler Symbol Descriptions

- 2.4-inch I.D. split barrel
- Standard Penetration Test (SPT)
- Shelby tube
- Piston
- Direct-Push
- Bulk or grab
- Continuous Coring

Blowcount is recorded for driven samplers as the number of blows required to advance sampler 12 inches (or distance noted). See exploration log for hammer weight and drop.

"P" indicates sampler pushed using the weight of the drill rig.

"WOH" indicates sampler pushed using the weight of the hammer.

ADDITIONAL MATERIAL SYMBOLS

SYMBOLS GRAPH	SYMBOLS LETTER	TYPICAL DESCRIPTIONS
	AC	Asphalt Concrete
	CC	Cement Concrete
	CR	Crushed Rock/ Quarry Spalls
	SOD	Sod/Forest Duff
	TS	Topsoil

Groundwater Contact

Measured groundwater level in exploration, well, or piezometer

Measured free product in well or piezometer

Graphic Log Contact

Distinct contact between soil strata

Approximate contact between soil strata

Material Description Contact

Contact between geologic units

Contact between soil of the same geologic unit

Laboratory / Field Tests

%F	Percent fines
%G	Percent gravel
AL	Atterberg limits
CA	Chemical analysis
CP	Laboratory compaction test
CS	Consolidation test
DD	Dry density
DS	Direct shear
HA	Hydrometer analysis
MC	Moisture content
MD	Moisture content and dry density
Mohs	Mohs hardness scale
OC	Organic content
PM	Permeability or hydraulic conductivity
PI	Plasticity index
PL	Point load test
PP	Pocket penetrometer
SA	Sieve analysis
TX	Triaxial compression
UC	Unconfined compression
VS	Vane shear

Sheen Classification

NS	No Visible Sheen
SS	Slight Sheen
MS	Moderate Sheen
HS	Heavy Sheen

NOTE: The reader must refer to the discussion in the report text and the logs of explorations for a proper understanding of subsurface conditions. Descriptions on the logs apply only at the specific exploration locations and at the time the explorations were made; they are not warranted to be representative of subsurface conditions at other locations or times.

Key to Exploration Logs

GeoEngineers

Figure A-1

Drilled	Start	End	Total Depth (ft)	70	Logged By	JLL	Driller	Western States Soil Conservation, Inc.	Drilling Method	Hollow-stem Auger/Mud-Rotary
	4/22/2021	4/23/2021			Checked By	BJH				

Surface Elevation (ft) / Vertical Datum	39 / NAVD88	Hammer Data	Autohammer 140 (lbs) / 30 (in) Drop	Drilling Equipment	CME-75 truck
Latitude / Longitude	45.578425 / -122.760852	System / Datum	Decimal Degrees / WGS84	See "Remarks" section for groundwater observed	

Notes:

Elevation (feet)	Depth (feet)	FIELD DATA: Interval	Recovered (in)	Blows/foot	Collected Sample	Sample Name / Testing	Graphic Log	Group Classification	MATERIAL DESCRIPTION	Moisture Content (%)	Fines Content (%)	REMARKS
	0							AC	4-inch-thick asphalt concrete pavement			
								GM	8-inch-thick aggregate base			
								SM	Black silty medium to coarse sand, occasional rounded to angular gravel (loose, moist) (fill)			Strong petroleum odor
35								ML	Gray silt with fine sand, occasional gravel to cobble-sized basalt fragments, trace wood fragments and organic matter (very soft, moist)			
	5	☒	16	1		1						Strong odor
30								SP-SM	Black poorly-graded fine sand with silt (loose, wet)			Groundwater observed at approximately 9 feet below ground surface during drilling
	10	☒	14	8		2						
25												
	15											Heavy tar-like sheen at 17 feet Static water level at 17 feet
20												
	20	☒	16	7		3		ML	Gray silt, low plasticity, micaceous, homogeneous (medium stiff, moist) (alluvium)			No odor
15												
	25											
10												
	30	☒	16	8		4						No odor
								SM	Dark gray silty fine sand, micaceous (loose, wet)			
5												
	35											

Note: See Figure A-1 for explanation of symbols.
Coordinates Data Source: Horizontal approximated based on . Vertical approximated based on .

Log of Boring B-1-21

GeoEngineers

Project: NW Natural Cold Box FEED - Portland LNG Facility
Project Location: Portland, Oregon
Project Number: 6024-210-03

Figure A-2
Sheet 1 of 2

Elevation (feet)	Depth (feet)	FIELD DATA: Interval	FIELD DATA: Recovered (in)	FIELD DATA: Blows/foot	FIELD DATA: Collected Sample	FIELD DATA: Sample Name / Testing	Graphic Log	Group Classification	MATERIAL DESCRIPTION	Moisture Content (%)	Fines Content (%)	REMARKS
	35											
0												
	40		16	10		5 / %F			Becomes gray-brown, homogeneous	35	14	
-5												
	45											
-10												
	50		14	11		6			Becomes brown, medium dense			
-15												
	55							GP-GM	Dark gray poorly-graded basalt gravel with sand and silt, rounded to subangular, medium to coarse sand (very dense, wet)			
-20												
	60		10	50		7 / %F				8	7	
-25												
	65							BSLT	Black basalt, trace red-brown staining, hard, fresh to slightly weathered (Columbia River Basalt)			Drill action becomes slow, smooth drilling
-30												
	70		TR	50/0"		8						

Log of Boring B-1-21 (continued)

GeoEngineers

Project: NW Natural Cold Box FEED - Portland LNG Facility
Project Location: Portland, Oregon
Project Number: 6024-210-03

Figure A-2
Sheet 2 of 2

Drilled	Start 4/29/2021	End 4/29/2021	Total Depth (ft)	60	Logged By JLL	Checked By BJH	Driller	Western States Soil Conservation, Inc.	Drilling Method	Hollow-stem Auger/Mud-Rotary

Surface Elevation (ft) Vertical Datum	40 NAVD88	Hammer Data	Autohammer 140 (lbs) / 30 (in) Drop	Drilling Equipment	CME-75 truck
Latitude Longitude	45.57867 -122.761603	System Datum	Decimal Degrees WGS84	See "Remarks" section for groundwater observed	

Notes:

Elevation (feet)	Depth (feet)	FIELD DATA: Interval	Recovered (in)	Blows/foot	Collected Sample	Sample Name / Testing	Graphic Log	Group Classification	MATERIAL DESCRIPTION	Moisture Content (%)	Fines Content (%)	REMARKS
	0							GP	12-inch-thick gravel pavement			
								GM	Dark gray silty gravel, occasional cobble-sized concrete fragments (dense, moist) (fill)			
35	5		18	7		1		ML	Light brown silt, trace to occasional gravel, low plasticity (medium stiff, moist)			Faint odor
30	10		16	4		2			Becomes dark gray wilt with fine sand (soft, moist)			Faint sheen; faint petroleum odor
25	15		16	4		3 AL		ML	Dark gray silt, trace fine sand (soft, moist) (alluvium)	43		AL (LL = 36; PI = 5)
20	20		16	1		4 %F			Becomes yellow-brown fine sandy silt, non-plastic (very soft, wet)	45	73	No odor
15	25							SM	Yellow-brown silty fine sand (loose, wet)			
10	30		14	10		5 %F				40	43	No odor
5	35											

Note: See Figure A-1 for explanation of symbols.
Coordinates Data Source: Horizontal approximated based on . Vertical approximated based on .

Log of Boring B-2-21

GeoEngineers

Project: NW Natural Cold Box FEED - Portland LNG Facility
Project Location: Portland, Oregon
Project Number: 6024-210-03

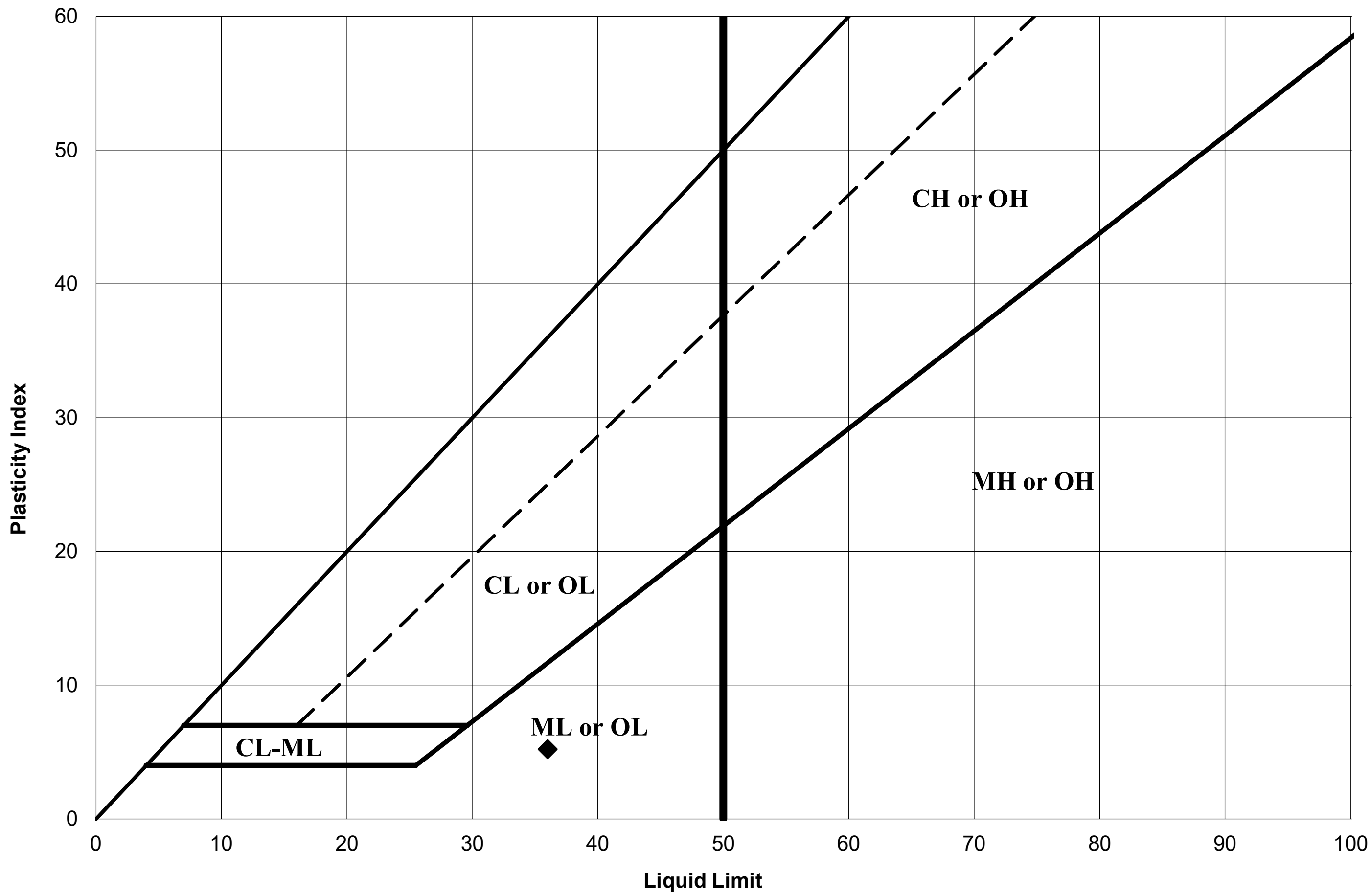
Elevation (feet)	Depth (feet)	Interval	Recovered (in)	Blows/foot	Collected Sample	Sample Name / Testing	Graphic Log	Group Classification	MATERIAL DESCRIPTION	Moisture Content (%)	Fines Content (%)	REMARKS
	35											
0	40		10	4		6			Becomes very loose to loose			No odor
-5	45											
									Becomes brown, micaceous, homogeneous (dense, wet)			
-10	50		16	36		7						
-15	55							BSLT	Black basalt, trace red-brown staining, hard, fresh to slightly weathered (Columbia River Basalt)			
-20	60		TR	50/0"		8						

Log of Boring B-2-21 (continued)

GeoEngineers

Project: NW Natural Cold Box FEED - Portland LNG Facility
Project Location: Portland, Oregon
Project Number: 6024-210-03

Project:	NW Natural Cold Box FEED		
Project No.	6024-210-03	**Date:**	05/05/21
Boring/TP No.	B-2-21	**Tested By:**	JL
Sample No./Depth:	3 at 15ft	**Checked By:**	BH
USCS Classification:	ML	**PA/PM:**	GAL



Moisture Content, %	Liquid Limit	Plastic Limit	Plasticity Index	USCS	Description
43	36	31	5	**ML**	**Dark gray SILT**

GEOENGINEERS

4000 Kruse Way Place, Lake Oswego, OR 97035

Atterberg Limits ASTM D 4318-05

Figure A-4

APPENDIX B
Environmental Soil Test Results

ANALYTICAL REPORT

May 20, 2021

GeoEngineers- Portland, OR

Sample Delivery Group:	L1346726
Samples Received:	05/01/2021
Project Number:	6024-210-03
Description:	NW Natural Cold Box FEED
Site:	PORTLAND GAOCO
Report To:	Cris Watkins 4000 Kruse Way Place Bldg. 3, Suite 200 Lake Oswego, OR 97035

Entire Report Reviewed By:

Brian Ford
Project Manager

Pace Analytical National
12065 Lebanon Rd Mount Juliet, TN 37122 615-758-5858 800-767-5859 www.pacenational.com

TABLE OF CONTENTS

	Collected by	Collected date/time	Received date/time
B-1-21 L1346726-01 Solid	John Lawer	04/23/21 16:15	05/01/21 10:00

Method	Batch	Dilution	Preparation date/time	Analysis date/time	Analyst	Location
Total Solids by Method 2540 G-2011	WG1664798	1	05/06/21 09:15	05/06/21 09:23	JWW	Mt. Juliet, TN
Wet Chemistry by Method 9012B	WG1666002	1	05/07/21 02:51	05/07/21 19:29	JER	Mt. Juliet, TN
Mercury by Method 7471B	WG1666113	1	05/07/21 08:30	05/07/21 10:37	ABL	Mt. Juliet, TN
Metals (ICPMS) by Method 6020B	WG1664520	5	05/05/21 10:53	05/05/21 15:25	LD	Mt. Juliet, TN
Volatile Organic Compounds (GC) by Method NWTPHGX	WG1665369	1460	04/23/21 16:15	05/06/21 18:22	BMB	Mt. Juliet, TN
Volatile Organic Compounds (GC/MS) by Method 8260D	WG1664671	117	04/23/21 16:15	05/05/21 18:06	BMB	Mt. Juliet, TN
Semi-Volatile Organic Compounds (GC) by Method NWTPHDX-NO SGT	WG1664922	20	05/06/21 09:40	05/07/21 01:40	DMG	Mt. Juliet, TN
Semi Volatile Organic Compounds (GC/MS) by Method 8270E-SIM	WG1664932	1	05/06/21 00:40	05/06/21 22:27	AAT	Mt. Juliet, TN
Semi Volatile Organic Compounds (GC/MS) by Method 8270E-SIM	WG1664932	20	05/06/21 00:40	05/10/21 14:08	AAT	Mt. Juliet, TN

	Collected by	Collected date/time	Received date/time
B-2-21 L1346726-02 Solid	John Lawer	04/29/21 15:00	05/01/21 10:00

Method	Batch	Dilution	Preparation date/time	Analysis date/time	Analyst	Location
Total Solids by Method 2540 G-2011	WG1664798	1	05/06/21 09:15	05/06/21 09:23	JWW	Mt. Juliet, TN
Wet Chemistry by Method 9012B	WG1668189	1	05/11/21 15:12	05/11/21 17:09	KEG	Mt. Juliet, TN
Mercury by Method 7471B	WG1666113	1	05/07/21 08:30	05/07/21 10:39	ABL	Mt. Juliet, TN
Metals (ICPMS) by Method 6020B	WG1664520	5	05/05/21 10:53	05/05/21 15:28	LD	Mt. Juliet, TN
Volatile Organic Compounds (GC) by Method NWTPHGX	WG1667212	33	04/29/21 15:00	05/10/21 12:47	BMB	Mt. Juliet, TN
Volatile Organic Compounds (GC/MS) by Method 8260D	WG1665450	52.8	04/29/21 15:00	05/06/21 23:36	BMB	Mt. Juliet, TN
Semi-Volatile Organic Compounds (GC) by Method NWTPHDX-NO SGT	WG1666451	5	05/07/21 22:47	05/08/21 23:52	CAG	Mt. Juliet, TN
Semi Volatile Organic Compounds (GC/MS) by Method 8270E-SIM	WG1669305	1	05/13/21 08:57	05/13/21 21:44	AAT	Mt. Juliet, TN
Semi Volatile Organic Compounds (GC/MS) by Method 8270E-SIM	WG1669305	10	05/13/21 08:57	05/14/21 07:53	AAT	Mt. Juliet, TN

All sample aliquots were received at the correct temperature, in the proper containers, with the appropriate preservatives, and within method specified holding times, unless qualified or notated within the report. Where applicable, all MDL (LOD) and RDL (LOQ) values reported for environmental samples have been corrected for the dilution factor used in the analysis. All Method and Batch Quality Control are within established criteria except where addressed in this case narrative, a non-conformance form or properly qualified within the sample results. By my digital signature below, I affirm to the best of my knowledge, all problems/anomalies observed by the laboratory as having the potential to affect the quality of the data have been identified by the laboratory, and no information or data have been knowingly withheld that would affect the quality of the data.

Brian Ford

Brian Ford
Project Manager

Cp Tc Ss Cn Sr Qc Gl Al Sc

Total Solids by Method 2540 G-2011

Analyte	Result %	Qualifier	Dilution	Analysis date / time	Batch
Total Solids	80.6		1	05/06/2021 09:23	WG1664798

Wet Chemistry by Method 9012B

Analyte	Result (dry) mg/kg	Qualifier	RDL (dry) mg/kg	Dilution	Analysis date / time	Batch
Cyanide	0.607		0.310	1	05/07/2021 19:29	WG1666002

Mercury by Method 7471B

Analyte	Result (dry) mg/kg	Qualifier	RDL (dry) mg/kg	Dilution	Analysis date / time	Batch
Mercury	0.0946		0.0496	1	05/07/2021 10:37	WG1666113

Metals (ICPMS) by Method 6020B

Analyte	Result (dry) mg/kg	Qualifier	RDL (dry) mg/kg	Dilution	Analysis date / time	Batch
Arsenic	10.2		1.24	5	05/05/2021 15:25	WG1664520
Barium	170		3.10	5	05/05/2021 15:25	WG1664520
Cadmium	ND		1.24	5	05/05/2021 15:25	WG1664520
Chromium	19.3		6.20	5	05/05/2021 15:25	WG1664520
Lead	14.8		2.48	5	05/05/2021 15:25	WG1664520
Selenium	ND		3.10	5	05/05/2021 15:25	WG1664520
Silver	ND		0.620	5	05/05/2021 15:25	WG1664520

Volatile Organic Compounds (GC) by Method NWTPHGX

Analyte	Result (dry) mg/kg	Qualifier	RDL (dry) mg/kg	Dilution	Analysis date / time	Batch
Gasoline Range Organics-NWTPH	316		205	1460	05/06/2021 18:22	WG1665369
(S) a,a,a-Trifluorotoluene(FID)	*98.4*		*77.0-120*		*05/06/2021 18:22*	WG1665369

Volatile Organic Compounds (GC/MS) by Method 8260D

Analyte	Result (dry) mg/kg	Qualifier	RDL (dry) mg/kg	Dilution	Analysis date / time	Batch
Acetone	ND		8.22	117	05/05/2021 18:06	WG1664671
Acrylonitrile	ND		2.05	117	05/05/2021 18:06	WG1664671
Benzene	0.308		0.164	117	05/05/2021 18:06	WG1664671
Bromobenzene	ND		2.05	117	05/05/2021 18:06	WG1664671
Bromodichloromethane	ND		0.412	117	05/05/2021 18:06	WG1664671
Bromoform	ND		4.12	117	05/05/2021 18:06	WG1664671
Bromomethane	ND		2.05	117	05/05/2021 18:06	WG1664671
n-Butylbenzene	ND		2.05	117	05/05/2021 18:06	WG1664671
sec-Butylbenzene	ND		2.05	117	05/05/2021 18:06	WG1664671
tert-Butylbenzene	ND		0.822	117	05/05/2021 18:06	WG1664671
Carbon tetrachloride	ND		0.822	117	05/05/2021 18:06	WG1664671
Chlorobenzene	ND		0.412	117	05/05/2021 18:06	WG1664671
Chlorodibromomethane	ND		0.412	117	05/05/2021 18:06	WG1664671
Chloroethane	ND		0.822	117	05/05/2021 18:06	WG1664671
Chloroform	ND		0.412	117	05/05/2021 18:06	WG1664671
Chloromethane	ND		2.05	117	05/05/2021 18:06	WG1664671
2-Chlorotoluene	ND		0.412	117	05/05/2021 18:06	WG1664671
4-Chlorotoluene	ND		0.822	117	05/05/2021 18:06	WG1664671
1,2-Dibromo-3-Chloropropane	ND		4.12	117	05/05/2021 18:06	WG1664671
1,2-Dibromoethane	ND		0.412	117	05/05/2021 18:06	WG1664671
Dibromomethane	ND		0.822	117	05/05/2021 18:06	WG1664671

Volatile Organic Compounds (GC/MS) by Method 8260D

Analyte	Result (dry) mg/kg	Qualifier	RDL (dry) mg/kg	Dilution	Analysis date / time	Batch
1,2-Dichlorobenzene	ND		0.822	117	05/05/2021 18:06	WG1664671
1,3-Dichlorobenzene	ND		0.822	117	05/05/2021 18:06	WG1664671
1,4-Dichlorobenzene	ND		0.822	117	05/05/2021 18:06	WG1664671
Dichlorodifluoromethane	ND		0.412	117	05/05/2021 18:06	WG1664671
1,1-Dichloroethane	ND		0.412	117	05/05/2021 18:06	WG1664671
1,2-Dichloroethane	ND		0.412	117	05/05/2021 18:06	WG1664671
1,1-Dichloroethene	ND		0.412	117	05/05/2021 18:06	WG1664671
cis-1,2-Dichloroethene	ND		0.412	117	05/05/2021 18:06	WG1664671
trans-1,2-Dichloroethene	ND		0.822	117	05/05/2021 18:06	WG1664671
1,2-Dichloropropane	ND		0.822	117	05/05/2021 18:06	WG1664671
1,1-Dichloropropene	ND		0.412	117	05/05/2021 18:06	WG1664671
1,3-Dichloropropane	ND		0.822	117	05/05/2021 18:06	WG1664671
cis-1,3-Dichloropropene	ND		0.412	117	05/05/2021 18:06	WG1664671
trans-1,3-Dichloropropene	ND		0.822	117	05/05/2021 18:06	WG1664671
2,2-Dichloropropane	ND		0.412	117	05/05/2021 18:06	WG1664671
Di-isopropyl ether	ND		0.164	117	05/05/2021 18:06	WG1664671
Ethylbenzene	ND		0.412	117	05/05/2021 18:06	WG1664671
Hexachloro-1,3-butadiene	ND		4.12	117	05/05/2021 18:06	WG1664671
Isopropylbenzene	ND		0.412	117	05/05/2021 18:06	WG1664671
p-Isopropyltoluene	0.896		0.822	117	05/05/2021 18:06	WG1664671
2-Butanone (MEK)	ND		16.4	117	05/05/2021 18:06	WG1664671
Methylene Chloride	ND		4.12	117	05/05/2021 18:06	WG1664671
4-Methyl-2-pentanone (MIBK)	ND		4.12	117	05/05/2021 18:06	WG1664671
Methyl tert-butyl ether	ND		0.164	117	05/05/2021 18:06	WG1664671
Naphthalene	10.5		2.05	117	05/05/2021 18:06	WG1664671
n-Propylbenzene	ND		0.822	117	05/05/2021 18:06	WG1664671
Styrene	ND		2.05	117	05/05/2021 18:06	WG1664671
1,1,1,2-Tetrachloroethane	ND		0.412	117	05/05/2021 18:06	WG1664671
1,1,2,2-Tetrachloroethane	ND		0.412	117	05/05/2021 18:06	WG1664671
1,1,2-Trichlorotrifluoroethane	ND		0.412	117	05/05/2021 18:06	WG1664671
Tetrachloroethene	ND		0.412	117	05/05/2021 18:06	WG1664671
Toluene	ND		0.822	117	05/05/2021 18:06	WG1664671
1,2,3-Trichlorobenzene	ND		2.05	117	05/05/2021 18:06	WG1664671
1,2,4-Trichlorobenzene	ND		2.05	117	05/05/2021 18:06	WG1664671
1,1,1-Trichloroethane	ND		0.412	117	05/05/2021 18:06	WG1664671
1,1,2-Trichloroethane	ND		0.412	117	05/05/2021 18:06	WG1664671
Trichloroethene	ND		0.164	117	05/05/2021 18:06	WG1664671
Trichlorofluoromethane	ND		0.412	117	05/05/2021 18:06	WG1664671
1,2,3-Trichloropropane	ND		2.05	117	05/05/2021 18:06	WG1664671
1,2,4-Trimethylbenzene	1.57		0.822	117	05/05/2021 18:06	WG1664671
1,2,3-Trimethylbenzene	ND		0.822	117	05/05/2021 18:06	WG1664671
1,3,5-Trimethylbenzene	ND		0.822	117	05/05/2021 18:06	WG1664671
Vinyl chloride	ND		0.412	117	05/05/2021 18:06	WG1664671
Xylenes, Total	ND		1.07	117	05/05/2021 18:06	WG1664671
(S) Toluene-d8	*104*		*75.0-131*		*05/05/2021 18:06*	WG1664671
(S) 4-Bromofluorobenzene	*102*		*67.0-138*		*05/05/2021 18:06*	WG1664671
(S) 1,2-Dichloroethane-d4	*103*		*70.0-130*		*05/05/2021 18:06*	WG1664671

Semi-Volatile Organic Compounds (GC) by Method NWTPHDX-NO SGT

Analyte	Result (dry) mg/kg	Qualifier	RDL (dry) mg/kg	Dilution	Analysis date / time	Batch
Diesel Range Organics (DRO)	110		99.3	20	05/07/2021 01:40	WG1664922
Residual Range Organics (RRO)	ND		248	20	05/07/2021 01:40	WG1664922
(S) o-Terphenyl	*86.9*	J7	*18.0-148*		*05/07/2021 01:40*	WG1664922

1 Cp
2 Tc
3 Ss
4 Cn
5 Sr
6 Qc
7 Gl
8 Al
9 Sc

Semi Volatile Organic Compounds (GC/MS) by Method 8270E-SIM

Analyte	Result (dry) mg/kg	Qualifier	RDL (dry) mg/kg	Dilution	Analysis date / time	Batch
Anthracene	1.96	J4	0.00745	1	05/06/2021 22:27	WG1664932
Acenaphthene	3.00	J4	0.00745	1	05/06/2021 22:27	WG1664932
Acenaphthylene	0.655	J4	0.00745	1	05/06/2021 22:27	WG1664932
Benzo(a)anthracene	2.33	J4	0.00745	1	05/06/2021 22:27	WG1664932
Benzo(a)pyrene	2.32	J4	0.00745	1	05/06/2021 22:27	WG1664932
Benzo(b)fluoranthene	2.11	J4	0.00745	1	05/06/2021 22:27	WG1664932
Benzo(g,h,i)perylene	2.00	J4	0.00745	1	05/06/2021 22:27	WG1664932
Benzo(k)fluoranthene	0.777	J4	0.00745	1	05/06/2021 22:27	WG1664932
Chrysene	2.69	J4	0.00745	1	05/06/2021 22:27	WG1664932
Dibenz(a,h)anthracene	0.195	J4	0.00745	1	05/06/2021 22:27	WG1664932
Fluoranthene	8.25	J4	0.149	20	05/10/2021 14:08	WG1664932
Fluorene	2.71	J4	0.00745	1	05/06/2021 22:27	WG1664932
Indeno(1,2,3-cd)pyrene	1.75	J4	0.00745	1	05/06/2021 22:27	WG1664932
Naphthalene	2.66	J4	0.0248	1	05/06/2021 22:27	WG1664932
Phenanthrene	10.9	J4	0.149	20	05/10/2021 14:08	WG1664932
Pyrene	8.93	J4	0.149	20	05/10/2021 14:08	WG1664932
1-Methylnaphthalene	1.96	J4	0.0248	1	05/06/2021 22:27	WG1664932
2-Methylnaphthalene	2.59	J4	0.0248	1	05/06/2021 22:27	WG1664932
2-Chloronaphthalene	ND	J4	0.0248	1	05/06/2021 22:27	WG1664932
(S) Nitrobenzene-d5	*89.6*		*14.0-149*		*05/06/2021 22:27*	WG1664932
(S) Nitrobenzene-d5	*44.8*	J7	*14.0-149*		*05/10/2021 14:08*	WG1664932
(S) 2-Fluorobiphenyl	*78.8*	J7	*34.0-125*		*05/10/2021 14:08*	WG1664932
(S) 2-Fluorobiphenyl	*68.8*		*34.0-125*		*05/06/2021 22:27*	WG1664932
(S) p-Terphenyl-d14	*99.0*	J7	*23.0-120*		*05/10/2021 14:08*	WG1664932
(S) p-Terphenyl-d14	*91.0*		*23.0-120*		*05/06/2021 22:27*	WG1664932

Sample Narrative:

L1346726-01 WG1664932: Duplicate Analysis performed due to QC failure. Results confirm; reporting in hold data

Total Solids by Method 2540 G-2011

Analyte	Result %	Qualifier	Dilution	Analysis date / time	Batch
Total Solids	78.6		1	05/06/2021 09:23	WG1664798

Wet Chemistry by Method 9012B

Analyte	Result (dry) mg/kg	Qualifier	RDL (dry) mg/kg	Dilution	Analysis date / time	Batch
Cyanide	1.25		0.318	1	05/11/2021 17:09	WG1668189

Mercury by Method 7471B

Analyte	Result (dry) mg/kg	Qualifier	RDL (dry) mg/kg	Dilution	Analysis date / time	Batch
Mercury	ND		0.0509	1	05/07/2021 10:39	WG1666113

Metals (ICPMS) by Method 6020B

Analyte	Result (dry) mg/kg	Qualifier	RDL (dry) mg/kg	Dilution	Analysis date / time	Batch
Arsenic	9.63		1.27	5	05/05/2021 15:28	WG1664520
Barium	142		3.18	5	05/05/2021 15:28	WG1664520
Cadmium	ND		1.27	5	05/05/2021 15:28	WG1664520
Chromium	25.0		6.36	5	05/05/2021 15:28	WG1664520
Lead	25.6		2.55	5	05/05/2021 15:28	WG1664520
Selenium	ND		3.18	5	05/05/2021 15:28	WG1664520
Silver	ND		0.636	5	05/05/2021 15:28	WG1664520

Volatile Organic Compounds (GC) by Method NWTPHGX

Analyte	Result (dry) mg/kg	Qualifier	RDL (dry) mg/kg	Dilution	Analysis date / time	Batch
Gasoline Range Organics-NWTPH	14.6		4.88	33	05/10/2021 12:47	WG1667212
(S) a,a,a-Trifluorotoluene(FID)	*97.9*		*77.0-120*		*05/10/2021 12:47*	WG1667212

Volatile Organic Compounds (GC/MS) by Method 8260D

Analyte	Result (dry) mg/kg	Qualifier	RDL (dry) mg/kg	Dilution	Analysis date / time	Batch
Acetone	ND	J4	3.90	52.8	05/06/2021 23:36	WG1665450
Acrylonitrile	ND		0.976	52.8	05/06/2021 23:36	WG1665450
Benzene	ND		0.0781	52.8	05/06/2021 23:36	WG1665450
Bromobenzene	ND		0.976	52.8	05/06/2021 23:36	WG1665450
Bromodichloromethane	ND		0.195	52.8	05/06/2021 23:36	WG1665450
Bromoform	ND		1.95	52.8	05/06/2021 23:36	WG1665450
Bromomethane	ND		0.976	52.8	05/06/2021 23:36	WG1665450
n-Butylbenzene	ND		0.976	52.8	05/06/2021 23:36	WG1665450
sec-Butylbenzene	ND		0.976	52.8	05/06/2021 23:36	WG1665450
tert-Butylbenzene	ND		0.390	52.8	05/06/2021 23:36	WG1665450
Carbon tetrachloride	ND	C3	0.390	52.8	05/06/2021 23:36	WG1665450
Chlorobenzene	ND		0.195	52.8	05/06/2021 23:36	WG1665450
Chlorodibromomethane	ND		0.195	52.8	05/06/2021 23:36	WG1665450
Chloroethane	ND		0.390	52.8	05/06/2021 23:36	WG1665450
Chloroform	ND		0.195	52.8	05/06/2021 23:36	WG1665450
Chloromethane	ND		0.976	52.8	05/06/2021 23:36	WG1665450
2-Chlorotoluene	ND		0.195	52.8	05/06/2021 23:36	WG1665450
4-Chlorotoluene	ND		0.390	52.8	05/06/2021 23:36	WG1665450
1,2-Dibromo-3-Chloropropane	ND		1.95	52.8	05/06/2021 23:36	WG1665450
1,2-Dibromoethane	ND		0.195	52.8	05/06/2021 23:36	WG1665450
Dibromomethane	ND		0.390	52.8	05/06/2021 23:36	WG1665450

Volatile Organic Compounds (GC/MS) by Method 8260D

Analyte	Result (dry) mg/kg	Qualifier	RDL (dry) mg/kg	Dilution	Analysis date / time	Batch
1,2-Dichlorobenzene	ND		0.390	52.8	05/06/2021 23:36	WG1665450
1,3-Dichlorobenzene	ND		0.390	52.8	05/06/2021 23:36	WG1665450
1,4-Dichlorobenzene	ND		0.390	52.8	05/06/2021 23:36	WG1665450
Dichlorodifluoromethane	ND		0.195	52.8	05/06/2021 23:36	WG1665450
1,1-Dichloroethane	ND		0.195	52.8	05/06/2021 23:36	WG1665450
1,2-Dichloroethane	ND		0.195	52.8	05/06/2021 23:36	WG1665450
1,1-Dichloroethene	ND		0.195	52.8	05/06/2021 23:36	WG1665450
cis-1,2-Dichloroethene	ND		0.195	52.8	05/06/2021 23:36	WG1665450
trans-1,2-Dichloroethene	ND		0.390	52.8	05/06/2021 23:36	WG1665450
1,2-Dichloropropane	ND		0.390	52.8	05/06/2021 23:36	WG1665450
1,1-Dichloropropene	ND	C3	0.195	52.8	05/06/2021 23:36	WG1665450
1,3-Dichloropropane	ND		0.390	52.8	05/06/2021 23:36	WG1665450
cis-1,3-Dichloropropene	ND		0.195	52.8	05/06/2021 23:36	WG1665450
trans-1,3-Dichloropropene	ND		0.390	52.8	05/06/2021 23:36	WG1665450
2,2-Dichloropropane	ND		0.195	52.8	05/06/2021 23:36	WG1665450
Di-isopropyl ether	ND		0.0781	52.8	05/06/2021 23:36	WG1665450
Ethylbenzene	0.402		0.195	52.8	05/06/2021 23:36	WG1665450
Hexachloro-1,3-butadiene	ND	C3	1.95	52.8	05/06/2021 23:36	WG1665450
Isopropylbenzene	ND		0.195	52.8	05/06/2021 23:36	WG1665450
p-Isopropyltoluene	ND		0.390	52.8	05/06/2021 23:36	WG1665450
2-Butanone (MEK)	ND		7.81	52.8	05/06/2021 23:36	WG1665450
Methylene Chloride	ND		1.95	52.8	05/06/2021 23:36	WG1665450
4-Methyl-2-pentanone (MIBK)	ND		1.95	52.8	05/06/2021 23:36	WG1665450
Methyl tert-butyl ether	ND		0.0781	52.8	05/06/2021 23:36	WG1665450
Naphthalene	87.7		0.976	52.8	05/06/2021 23:36	WG1665450
n-Propylbenzene	ND		0.390	52.8	05/06/2021 23:36	WG1665450
Styrene	ND		0.976	52.8	05/06/2021 23:36	WG1665450
1,1,1,2-Tetrachloroethane	ND		0.195	52.8	05/06/2021 23:36	WG1665450
1,1,2,2-Tetrachloroethane	ND		0.195	52.8	05/06/2021 23:36	WG1665450
1,1,2-Trichlorotrifluoroethane	ND		0.195	52.8	05/06/2021 23:36	WG1665450
Tetrachloroethene	ND		0.195	52.8	05/06/2021 23:36	WG1665450
Toluene	ND		0.390	52.8	05/06/2021 23:36	WG1665450
1,2,3-Trichlorobenzene	ND	C3	0.976	52.8	05/06/2021 23:36	WG1665450
1,2,4-Trichlorobenzene	ND	C3	0.976	52.8	05/06/2021 23:36	WG1665450
1,1,1-Trichloroethane	ND		0.195	52.8	05/06/2021 23:36	WG1665450
1,1,2-Trichloroethane	ND		0.195	52.8	05/06/2021 23:36	WG1665450
Trichloroethene	ND		0.0781	52.8	05/06/2021 23:36	WG1665450
Trichlorofluoromethane	ND	C3	0.195	52.8	05/06/2021 23:36	WG1665450
1,2,3-Trichloropropane	ND		0.976	52.8	05/06/2021 23:36	WG1665450
1,2,4-Trimethylbenzene	1.77		0.390	52.8	05/06/2021 23:36	WG1665450
1,2,3-Trimethylbenzene	0.532		0.390	52.8	05/06/2021 23:36	WG1665450
1,3,5-Trimethylbenzene	0.670		0.390	52.8	05/06/2021 23:36	WG1665450
Vinyl chloride	ND		0.195	52.8	05/06/2021 23:36	WG1665450
Xylenes, Total	0.982		0.507	52.8	05/06/2021 23:36	WG1665450
(S) Toluene-d8	*105*		*75.0-131*		*05/06/2021 23:36*	WG1665450
(S) 4-Bromofluorobenzene	*95.4*		*67.0-138*		*05/06/2021 23:36*	WG1665450
(S) 1,2-Dichloroethane-d4	*100*		*70.0-130*		*05/06/2021 23:36*	WG1665450

Sample Narrative:

L1346726-02 WG1665450: Targets too high to run lower.

Semi-Volatile Organic Compounds (GC) by Method NWTPHDX-NO SGT

Analyte	Result (dry) mg/kg	Qualifier	RDL (dry) mg/kg	Dilution	Analysis date / time	Batch
Diesel Range Organics (DRO)	369		25.5	5	05/08/2021 23:52	WG1666451
Residual Range Organics (RRO)	199		63.6	5	05/08/2021 23:52	WG1666451

1 Cp
2 Tc
3 Ss
4 Cn
5 Sr
6 Qc
7 Gl
8 Al
9 Sc

Semi-Volatile Organic Compounds (GC) by Method NWTPHDX-NO SGT

Analyte	Result (dry) mg/kg	Qualifier	RDL (dry) mg/kg	Dilution	Analysis date / time	Batch
(S) o-Terphenyl	*119*		*18.0-148*		*05/08/2021 23:52*	WG1666451

Semi Volatile Organic Compounds (GC/MS) by Method 8270E-SIM

Analyte	Result (dry) mg/kg	Qualifier	RDL (dry) mg/kg	Dilution	Analysis date / time	Batch
Anthracene	0.680		0.00764	1	05/13/2021 21:44	WG1669305
Acenaphthene	0.535		0.00764	1	05/13/2021 21:44	WG1669305
Acenaphthylene	0.356		0.00764	1	05/13/2021 21:44	WG1669305
Benzo(a)anthracene	0.927		0.00764	1	05/13/2021 21:44	WG1669305
Benzo(a)pyrene	0.844		0.00764	1	05/13/2021 21:44	WG1669305
Benzo(b)fluoranthene	0.720		0.00764	1	05/13/2021 21:44	WG1669305
Benzo(g,h,i)perylene	0.648		0.00764	1	05/13/2021 21:44	WG1669305
Benzo(k)fluoranthene	0.255		0.00764	1	05/13/2021 21:44	WG1669305
Chrysene	1.09		0.00764	1	05/13/2021 21:44	WG1669305
Dibenz(a,h)anthracene	0.0817		0.00764	1	05/13/2021 21:44	WG1669305
Fluoranthene	2.19		0.00764	1	05/13/2021 21:44	WG1669305
Fluorene	0.750		0.00764	1	05/13/2021 21:44	WG1669305
Indeno(1,2,3-cd)pyrene	0.573		0.00764	1	05/13/2021 21:44	WG1669305
Naphthalene	7.76		0.255	10	05/14/2021 07:53	WG1669305
Phenanthrene	4.21		0.00764	1	05/13/2021 21:44	WG1669305
Pyrene	2.74		0.00764	1	05/13/2021 21:44	WG1669305
1-Methylnaphthalene	1.26		0.0255	1	05/13/2021 21:44	WG1669305
2-Methylnaphthalene	1.63		0.0255	1	05/13/2021 21:44	WG1669305
2-Chloronaphthalene	ND		0.0255	1	05/13/2021 21:44	WG1669305
(S) Nitrobenzene-d5	*76.1*		*14.0-149*		*05/14/2021 07:53*	WG1669305
(S) Nitrobenzene-d5	*79.7*		*14.0-149*		*05/13/2021 21:44*	WG1669305
(S) 2-Fluorobiphenyl	*78.3*		*34.0-125*		*05/13/2021 21:44*	WG1669305
(S) 2-Fluorobiphenyl	*69.2*		*34.0-125*		*05/14/2021 07:53*	WG1669305
(S) p-Terphenyl-d14	*79.6*		*23.0-120*		*05/13/2021 21:44*	WG1669305
(S) p-Terphenyl-d14	*79.9*		*23.0-120*		*05/14/2021 07:53*	WG1669305

QUALITY CONTROL SUMMARY

L1346726-01,02

Method Blank (MB)

(MB) R3652014-1 05/06/21 09:23

Analyte	MB Result %	MB Qualifier	MB MDL %	MB RDL %
Total Solids	0.00100			

L1346714-10 Original Sample (OS) • Duplicate (DUP)

(OS) L1346714-10 05/06/21 09:23 • (DUP) R3652014-3 05/06/21 09:23

Analyte	Original Result %	DUP Result %	Dilution	DUP RPD %	DUP Qualifier	DUP RPD Limits %
Total Solids	99.6	99.7	1	0.0619		10

Laboratory Control Sample (LCS)

(LCS) R3652014-2 05/06/21 09:23

Analyte	Spike Amount %	LCS Result %	LCS Rec. %	Rec. Limits %	LCS Qualifier
Total Solids	50.0	50.0	100	85.0-115	

1 Cp
2 Tc
3 Ss
4 Cn
5 Sr
6 Qc
7 Gl
8 Al
9 Sc

Method Blank (MB)

(MB) R3651876-1 05/07/21 16:48

Analyte	MB Result mg/kg	MB Qualifier	MB MDL mg/kg	MB RDL mg/kg
Cyanide	U		0.0733	0.250

L1345756-01 Original Sample (OS) • Duplicate (DUP)

(OS) L1345756-01 05/07/21 16:53 • (DUP) R3651876-3 05/07/21 16:54

Analyte	Original Result mg/kg	DUP Result mg/kg	Dilution	DUP RPD %	DUP Qualifier	DUP RPD Limits %
Cyanide	ND	ND	1	0.000		20

L1346277-01 Original Sample (OS) • Duplicate (DUP)

(OS) L1346277-01 05/07/21 19:58 • (DUP) R3651876-8 05/07/21 19:59

Analyte	Original Result (dry)	DUP Result (dry)	Dilution	DUP RPD %	DUP Qualifier	DUP RPD Limits %
Cyanide	6.47	7.14	5	9.82		20

Laboratory Control Sample (LCS)

(LCS) R3651876-2 05/07/21 16:49

Analyte	Spike Amount mg/kg	LCS Result mg/kg	LCS Rec. %	Rec. Limits %	LCS Qualifier
Cyanide	2.50	2.49	99.6	85.0-115	

L1345962-01 Original Sample (OS) • Matrix Spike (MS) • Matrix Spike Duplicate (MSD)

(OS) L1345962-01 05/07/21 16:56 • (MS) R3651876-4 05/07/21 16:58 • (MSD) R3651876-5 05/07/21 17:01

Analyte	Spike Amount (dry) mg/kg	Original Result (dry) mg/kg	MS Result (dry) mg/kg	MSD Result (dry) mg/kg	MS Rec. %	MSD Rec. %	Dilution	Rec. Limits %	MS Qualifier	MSD Qualifier	RPD %	RPD Limits %
Cyanide	12.8	3.00	8.38	8.09	42.2	39.9	1	75.0-125	J6	J6	3.52	20

L1347392-02 Original Sample (OS) • Matrix Spike (MS) • Matrix Spike Duplicate (MSD)

(OS) L1347392-02 05/07/21 19:30 • (MS) R3651876-6 05/07/21 19:31 • (MSD) R3651876-7 05/07/21 19:32

Analyte	Spike Amount (dry)	Original Result (dry)	MS Result (dry)	MSD Result (dry)	MS Rec.	MSD Rec.	Dilution	Rec. Limits	MS Qualifier	MSD Qualifier	RPD	RPD Limits
	mg/kg				%	%		%			%	%
Cyanide	1.67	ND	1.87	1.88	91.3	91.7	1	75.0-125			0.355	20

QUALITY CONTROL SUMMARY

Method Blank (MB)

(MB) R3653114-1 05/11/21 16:47

Analyte	MB Result mg/kg	MB Qualifier	MB MDL mg/kg	MB RDL mg/kg
Cyanide	U		0.0733	0.250

L1346726-02 Original Sample (OS) • Duplicate (DUP)

(OS) L1346726-02 05/11/21 17:09 • (DUP) R3653114-5 05/11/21 17:55

Analyte	Original Result (dry) mg/kg	DUP Result (dry) mg/kg	Dilution	DUP RPD %	DUP Qualifier	DUP RPD Limits %
Cyanide	1.25	1.30	1	3.48		20

L1347741-02 Original Sample (OS) • Duplicate (DUP)

(OS) L1347741-02 05/11/21 18:02 • (DUP) R3653114-8 05/11/21 18:03

Analyte	Original Result mg/kg	DUP Result mg/kg	Dilution	DUP RPD %	DUP Qualifier	DUP RPD Limits %
Cyanide	ND	ND	1	0.000		20

Laboratory Control Sample (LCS)

(LCS) R3653114-2 05/11/21 16:48

Analyte	Spike Amount mg/kg	LCS Result mg/kg	LCS Rec. %	Rec. Limits %	LCS Qualifier
Cyanide	2.50	2.34	93.7	85.0-115	

L1346199-01 Original Sample (OS) • Matrix Spike (MS) • Matrix Spike Duplicate (MSD)

(OS) L1346199-01 05/11/21 16:56 • (MS) R3653114-3 05/11/21 16:57 • (MSD) R3653114-4 05/11/21 17:00

Analyte	Spike Amount mg/kg	Original Result mg/kg	MS Result mg/kg	MSD Result mg/kg	MS Rec. %	MSD Rec. %	Dilution	Rec. Limits %	MS Qualifier	MSD Qualifier	RPD %	RPD Limits %
Cyanide	1.67	ND	1.44	1.33	86.1	79.8	1	75.0-125			7.71	20

L1346853-01 Original Sample (OS) • Matrix Spike (MS) • Matrix Spike Duplicate (MSD)

(OS) L1346853-01 05/11/21 17:57 • (MS) R3653114-6 05/11/21 17:58 • (MSD) R3653114-7 05/11/21 17:59

Analyte	Spike Amount mg/kg	Original Result mg/kg	MS Result mg/kg	MSD Result mg/kg	MS Rec. %	MSD Rec. %	Dilution	Rec. Limits %	MS Qualifier	MSD Qualifier	RPD %	RPD Limits %
Cyanide	1.67	ND	1.22	1.14	67.8	63.0	1	75.0-125	J6	J6	6.81	20

Method Blank (MB)

(MB) R3651682-1 05/07/21 10:24

Analyte	MB Result mg/kg	MB Qualifier	MB MDL mg/kg	MB RDL mg/kg
Mercury	U		0.0180	0.0400

Laboratory Control Sample (LCS)

(LCS) R3651682-2 05/07/21 10:27

Analyte	Spike Amount mg/kg	LCS Result mg/kg	LCS Rec. %	Rec. Limits %	LCS Qualifier
Mercury	0.500	0.559	112	80.0-120	

L1348255-01 Original Sample (OS) • Matrix Spike (MS) • Matrix Spike Duplicate (MSD)

(OS) L1348255-01 05/07/21 10:29 • (MS) R3651682-3 05/07/21 10:32 • (MSD) R3651682-4 05/07/21 10:34

Analyte	Spike Amount (dry) mg/kg	Original Result (dry) mg/kg	MS Result (dry) mg/kg	MSD Result (dry) mg/kg	MS Rec. %	MSD Rec. %	Dilution	Rec. Limits %	MS Qualifier	MSD Qualifier	RPD %	RPD Limits %
Mercury	0.742	0.0630	0.941	0.986	118	124	1	75.0-125			4.59	20

1 Cp
2 Tc
3 Ss
4 Cn
5 Sr
6 Qc
7 Gl
8 Al
9 Sc

Method Blank (MB)

(MB) R3650818-1 05/05/21 15:00

Analyte	MB Result mg/kg	MB Qualifier	MB MDL mg/kg	MB RDL mg/kg
Arsenic	U		0.100	1.00
Barium	U		0.152	2.50
Cadmium	U		0.0855	1.00
Chromium	U		0.297	5.00
Lead	0.231	J	0.0990	2.00
Selenium	U		0.180	2.50
Silver	U		0.0865	0.500

Laboratory Control Sample (LCS)

(LCS) R3650818-2 05/05/21 15:03

Analyte	Spike Amount mg/kg	LCS Result mg/kg	LCS Rec. %	Rec. Limits %	LCS Qualifier
Arsenic	100	95.2	95.2	80.0-120	
Barium	100	95.8	95.8	80.0-120	
Cadmium	100	101	101	80.0-120	
Chromium	100	97.5	97.5	80.0-120	
Lead	100	101	101	80.0-120	
Selenium	100	99.5	99.5	80.0-120	
Silver	20.0	20.1	101	80.0-120	

L1347459-01 Original Sample (OS) • Matrix Spike (MS) • Matrix Spike Duplicate (MSD)

(OS) L1347459-01 05/05/21 15:06 • (MS) R3650818-5 05/05/21 15:16 • (MSD) R3650818-6 05/05/21 15:19

Analyte	Spike Amount (dry) mg/kg	Original Result (dry) mg/kg	MS Result (dry) mg/kg	MSD Result (dry) mg/kg	MS Rec. %	MSD Rec. %	Dilution	Rec. Limits %	MS Qualifier	MSD Qualifier	RPD %	RPD Limits %
Arsenic	105	12.0	113	107	96.2	90.2	5	75.0-125			5.75	20
Barium	105	68.3	178	168	104	94.9	5	75.0-125			5.50	20
Cadmium	105	1.42	112	105	105	98.4	5	75.0-125			6.48	20
Chromium	105	298	379	270	77.2	0.000	5	75.0-125		J3 J6	33.5	20
Lead	105	40.5	159	149	113	103	5	75.0-125			6.87	20
Selenium	105	ND	111	103	105	97.5	5	75.0-125			7.28	20
Silver	21.1	ND	22.1	20.7	105	98.3	5	75.0-125			6.63	20

Method Blank (MB)

(MB) R3651200-2 05/06/21 12:00

Analyte	MB Result mg/kg	MB Qualifier	MB MDL mg/kg	MB RDL mg/kg
Gasoline Range Organics-NWTPH	U		0.0339	0.100
(S) a,a,a-Trifluorotoluene(FID)	*97.9*			*77.0-120*

Laboratory Control Sample (LCS)

(LCS) R3651200-1 05/06/21 11:16

Analyte	Spike Amount mg/kg	LCS Result mg/kg	LCS Rec. %	Rec. Limits %	LCS Qualifier
Gasoline Range Organics-NWTPH	5.50	5.09	92.5	71.0-124	
(S) a,a,a-Trifluorotoluene(FID)			*107*	*77.0-120*	

Method Blank (MB)

(MB) R3652571-2 05/10/21 02:50

Analyte	MB Result mg/kg	MB Qualifier	MB MDL mg/kg	MB RDL mg/kg
Gasoline Range Organics-NWTPH	U		0.0339	0.100
(S) a,a,a-Trifluorotoluene(FID)	*95.4*			*77.0-120*

Laboratory Control Sample (LCS)

(LCS) R3652571-1 05/10/21 02:06

Analyte	Spike Amount mg/kg	LCS Result mg/kg	LCS Rec. %	Rec. Limits %	LCS Qualifier
Gasoline Range Organics-NWTPH	5.50	5.23	95.1	71.0-124	
(S) a,a,a-Trifluorotoluene(FID)			*112*	*77.0-120*	

1 Cp
2 Tc
3 Ss
4 Cn
5 Sr
6 Qc
7 Gl
8 Al
9 Sc

Method Blank (MB)

(MB) R3650868-3 05/05/21 13:34

Analyte	MB Result mg/kg	MB Qualifier	MB MDL mg/kg	MB RDL mg/kg
Acetone	U		0.0365	0.0500
Acrylonitrile	U		0.00361	0.0125
Benzene	U		0.000467	0.00100
Bromobenzene	U		0.000900	0.0125
Bromodichloromethane	U		0.000725	0.00250
Bromoform	U		0.00117	0.0250
Bromomethane	U		0.00197	0.0125
n-Butylbenzene	U		0.00525	0.0125
sec-Butylbenzene	U		0.00288	0.0125
tert-Butylbenzene	U		0.00195	0.00500
Carbon tetrachloride	U		0.000898	0.00500
Chlorobenzene	U		0.000210	0.00250
Chlorodibromomethane	U		0.000612	0.00250
Chloroethane	U		0.00170	0.00500
Chloroform	U		0.00103	0.00250
Chloromethane	U		0.00435	0.0125
2-Chlorotoluene	U		0.000865	0.00250
4-Chlorotoluene	U		0.000450	0.00500
1,2-Dibromo-3-Chloropropane	U		0.00390	0.0250
1,2-Dibromoethane	U		0.000648	0.00250
Dibromomethane	U		0.000750	0.00500
1,2-Dichlorobenzene	U		0.000425	0.00500
1,3-Dichlorobenzene	U		0.000600	0.00500
1,4-Dichlorobenzene	U		0.000700	0.00500
Dichlorodifluoromethane	U		0.00161	0.00250
1,1-Dichloroethane	U		0.000491	0.00250
1,2-Dichloroethane	U		0.000649	0.00250
1,1-Dichloroethene	U		0.000606	0.00250
cis-1,2-Dichloroethene	U		0.000734	0.00250
trans-1,2-Dichloroethene	U		0.00104	0.00500
1,2-Dichloropropane	U		0.00142	0.00500
1,1-Dichloropropene	U		0.000809	0.00250
1,3-Dichloropropane	U		0.000501	0.00500
cis-1,3-Dichloropropene	U		0.000757	0.00250
trans-1,3-Dichloropropene	U		0.00114	0.00500
2,2-Dichloropropane	U		0.00138	0.00250
Di-isopropyl ether	U		0.000410	0.00100
Ethylbenzene	U		0.000737	0.00250
Hexachloro-1,3-butadiene	U		0.00600	0.0250
Isopropylbenzene	U		0.000425	0.00250

Cp Tc Ss Cn Sr Qc Gl Al Sc

Method Blank (MB)

(MB) R3650868-3 05/05/21 13:34

Analyte	MB Result mg/kg	MB Qualifier	MB MDL mg/kg	MB RDL mg/kg
p-Isopropyltoluene	U		0.00255	0.00500
2-Butanone (MEK)	0.0948	J	0.0635	0.100
Methylene Chloride	U		0.00664	0.0250
4-Methyl-2-pentanone (MIBK)	U		0.00228	0.0250
Methyl tert-butyl ether	U		0.000350	0.00100
Naphthalene	U		0.00488	0.0125
n-Propylbenzene	U		0.000950	0.00500
Styrene	U		0.000229	0.0125
1,1,1,2-Tetrachloroethane	U		0.000948	0.00250
1,1,2,2-Tetrachloroethane	U		0.000695	0.00250
Tetrachloroethene	U		0.000896	0.00250
Toluene	U		0.00130	0.00500
1,1,2-Trichlorotrifluoroethane	U		0.000754	0.00250
1,2,3-Trichlorobenzene	U		0.00733	0.0125
1,2,4-Trichlorobenzene	U		0.00440	0.0125
1,1,1-Trichloroethane	U		0.000923	0.00250
1,1,2-Trichloroethane	U		0.000597	0.00250
Trichloroethene	U		0.000584	0.00100
Trichlorofluoromethane	U		0.000827	0.00250
1,2,3-Trichloropropane	U		0.00162	0.0125
1,2,3-Trimethylbenzene	U		0.00158	0.00500
1,2,4-Trimethylbenzene	U		0.00158	0.00500
1,3,5-Trimethylbenzene	U		0.00200	0.00500
Vinyl chloride	U		0.00116	0.00250
Xylenes, Total	U		0.000880	0.00650
(S) Toluene-d8	*99.6*			*75.0-131*
(S) 4-Bromofluorobenzene	*101*			*67.0-138*
(S) 1,2-Dichloroethane-d4	*101*			*70.0-130*

Laboratory Control Sample (LCS) • Laboratory Control Sample Duplicate (LCSD)

(LCS) R3650868-1 05/05/21 12:18 • (LCSD) R3650868-2 05/05/21 12:37

Analyte	Spike Amount mg/kg	LCS Result mg/kg	LCSD Result mg/kg	LCS Rec. %	LCSD Rec. %	Rec. Limits %	LCS Qualifier	LCSD Qualifier	RPD %	RPD Limits %
Acetone	0.625	0.649	0.664	104	106	10.0-160			2.28	31
Acrylonitrile	0.625	0.645	0.649	103	104	45.0-153			0.618	22
Benzene	0.125	0.133	0.133	106	106	70.0-123			0.000	20
Bromobenzene	0.125	0.127	0.131	102	105	73.0-121			3.10	20
Bromodichloromethane	0.125	0.122	0.123	97.6	98.4	73.0-121			0.816	20

Laboratory Control Sample (LCS) • Laboratory Control Sample Duplicate (LCSD)

(LCS) R3650868-1 05/05/21 12:18 • (LCSD) R3650868-2 05/05/21 12:37

Analyte	Spike Amount mg/kg	LCS Result mg/kg	LCSD Result mg/kg	LCS Rec. %	LCSD Rec. %	Rec. Limits %	LCS Qualifier	LCSD Qualifier	RPD %	RPD Limits %
Bromoform	0.125	0.131	0.136	105	109	64.0-132			3.75	20
Bromomethane	0.125	0.138	0.137	110	110	56.0-147			0.727	20
n-Butylbenzene	0.125	0.126	0.125	101	100	68.0-135			0.797	20
sec-Butylbenzene	0.125	0.129	0.127	103	102	74.0-130			1.56	20
tert-Butylbenzene	0.125	0.128	0.125	102	100	75.0-127			2.37	20
Carbon tetrachloride	0.125	0.134	0.136	107	109	66.0-128			1.48	20
Chlorobenzene	0.125	0.121	0.124	96.8	99.2	76.0-128			2.45	20
Chlorodibromomethane	0.125	0.131	0.134	105	107	74.0-127			2.26	20
Chloroethane	0.125	0.123	0.121	98.4	96.8	61.0-134			1.64	20
Chloroform	0.125	0.124	0.126	99.2	101	72.0-123			1.60	20
Chloromethane	0.125	0.121	0.129	96.8	103	51.0-138			6.40	20
2-Chlorotoluene	0.125	0.128	0.132	102	106	75.0-124			3.08	20
4-Chlorotoluene	0.125	0.116	0.122	92.8	97.6	75.0-124			5.04	20
1,2-Dibromo-3-Chloropropane	0.125	0.128	0.132	102	106	59.0-130			3.08	20
1,2-Dibromoethane	0.125	0.129	0.134	103	107	74.0-128			3.80	20
Dibromomethane	0.125	0.138	0.136	110	109	75.0-122			1.46	20
1,2-Dichlorobenzene	0.125	0.125	0.134	100	107	76.0-124			6.95	20
1,3-Dichlorobenzene	0.125	0.125	0.127	100	102	76.0-125			1.59	20
1,4-Dichlorobenzene	0.125	0.121	0.123	96.8	98.4	77.0-121			1.64	20
Dichlorodifluoromethane	0.125	0.137	0.143	110	114	43.0-156			4.29	20
1,1-Dichloroethane	0.125	0.131	0.130	105	104	70.0-127			0.766	20
1,2-Dichloroethane	0.125	0.122	0.126	97.6	101	65.0-131			3.23	20
1,1-Dichloroethene	0.125	0.131	0.128	105	102	65.0-131			2.32	20
cis-1,2-Dichloroethene	0.125	0.131	0.133	105	106	73.0-125			1.52	20
trans-1,2-Dichloroethene	0.125	0.132	0.127	106	102	71.0-125			3.86	20
1,2-Dichloropropane	0.125	0.130	0.129	104	103	74.0-125			0.772	20
1,1-Dichloropropene	0.125	0.126	0.123	101	98.4	73.0-125			2.41	20
1,3-Dichloropropane	0.125	0.131	0.133	105	106	80.0-125			1.52	20
cis-1,3-Dichloropropene	0.125	0.129	0.131	103	105	76.0-127			1.54	20
trans-1,3-Dichloropropene	0.125	0.130	0.133	104	106	73.0-127			2.28	20
2,2-Dichloropropane	0.125	0.152	0.152	122	122	59.0-135			0.000	20
Di-isopropyl ether	0.125	0.129	0.134	103	107	60.0-136			3.80	20
Ethylbenzene	0.125	0.123	0.128	98.4	102	74.0-126			3.98	20
Hexachloro-1,3-butadiene	0.125	0.140	0.145	112	116	57.0-150			3.51	20
Isopropylbenzene	0.125	0.123	0.127	98.4	102	72.0-127			3.20	20
p-Isopropyltoluene	0.125	0.126	0.128	101	102	72.0-133			1.57	20
2-Butanone (MEK)	0.625	0.721	0.728	115	116	30.0-160			0.966	24
Methylene Chloride	0.125	0.123	0.121	98.4	96.8	68.0-123			1.64	20
4-Methyl-2-pentanone (MIBK)	0.625	0.658	0.685	105	110	56.0-143			4.02	20
Methyl tert-butyl ether	0.125	0.130	0.149	104	119	66.0-132			13.6	20

Laboratory Control Sample (LCS) • Laboratory Control Sample Duplicate (LCSD)

(LCS) R3650868-1 05/05/21 12:18 • (LCSD) R3650868-2 05/05/21 12:37

Analyte	Spike Amount mg/kg	LCS Result mg/kg	LCSD Result mg/kg	LCS Rec. %	LCSD Rec. %	Rec. Limits %	LCS Qualifier	LCSD Qualifier	RPD %	RPD Limits %
Naphthalene	0.125	0.126	0.133	101	106	59.0-130			5.41	20
n-Propylbenzene	0.125	0.119	0.123	95.2	98.4	74.0-126			3.31	20
Styrene	0.125	0.123	0.127	98.4	102	72.0-127			3.20	20
1,1,1,2-Tetrachloroethane	0.125	0.130	0.136	104	109	74.0-129			4.51	20
1,1,2,2-Tetrachloroethane	0.125	0.126	0.130	101	104	68.0-128			3.12	20
Tetrachloroethene	0.125	0.126	0.129	101	103	70.0-136			2.35	20
Toluene	0.125	0.126	0.129	101	103	75.0-121			2.35	20
1,1,2-Trichlorotrifluoroethane	0.125	0.144	0.143	115	114	61.0-139			0.697	20
1,2,3-Trichlorobenzene	0.125	0.123	0.128	98.4	102	59.0-139			3.98	20
1,2,4-Trichlorobenzene	0.125	0.132	0.132	106	106	62.0-137			0.000	20
1,1,1-Trichloroethane	0.125	0.125	0.129	100	103	69.0-126			3.15	20
1,1,2-Trichloroethane	0.125	0.122	0.127	97.6	102	78.0-123			4.02	20
Trichloroethene	0.125	0.124	0.124	99.2	99.2	76.0-126			0.000	20
Trichlorofluoromethane	0.125	0.136	0.137	109	110	61.0-142			0.733	20
1,2,3-Trichloropropane	0.125	0.129	0.130	103	104	67.0-129			0.772	20
1,2,3-Trimethylbenzene	0.125	0.121	0.127	96.8	102	74.0-124			4.84	20
1,2,4-Trimethylbenzene	0.125	0.123	0.126	98.4	101	70.0-126			2.41	20
1,3,5-Trimethylbenzene	0.125	0.125	0.129	100	103	73.0-127			3.15	20
Vinyl chloride	0.125	0.131	0.127	105	102	63.0-134			3.10	20
Xylenes, Total	0.375	0.368	0.385	98.1	103	72.0-127			4.52	20
(S) Toluene-d8				*99.7*	*101*	*75.0-131*				
(S) 4-Bromofluorobenzene				*99.4*	*101*	*67.0-138*				
(S) 1,2-Dichloroethane-d4				*106*	*105*	*70.0-130*				

Method Blank (MB)

(MB) R3651527-3 05/06/21 21:22

Analyte	MB Result mg/kg	MB Qualifier	MB MDL mg/kg	MB RDL mg/kg
Acetone	U		0.0365	0.0500
Acrylonitrile	U		0.00361	0.0125
Benzene	U		0.000467	0.00100
Bromobenzene	U		0.000900	0.0125
Bromodichloromethane	U		0.000725	0.00250
Bromoform	U		0.00117	0.0250
Bromomethane	U		0.00197	0.0125
n-Butylbenzene	U		0.00525	0.0125
sec-Butylbenzene	U		0.00288	0.0125
tert-Butylbenzene	U		0.00195	0.00500
Carbon tetrachloride	U		0.000898	0.00500
Chlorobenzene	U		0.000210	0.00250
Chlorodibromomethane	U		0.000612	0.00250
Chloroethane	U		0.00170	0.00500
Chloroform	U		0.00103	0.00250
Chloromethane	U		0.00435	0.0125
2-Chlorotoluene	U		0.000865	0.00250
4-Chlorotoluene	U		0.000450	0.00500
1,2-Dibromo-3-Chloropropane	U		0.00390	0.0250
1,2-Dibromoethane	U		0.000648	0.00250
Dibromomethane	U		0.000750	0.00500
1,2-Dichlorobenzene	U		0.000425	0.00500
1,3-Dichlorobenzene	U		0.000600	0.00500
1,4-Dichlorobenzene	U		0.000700	0.00500
Dichlorodifluoromethane	U		0.00161	0.00250
1,1-Dichloroethane	U		0.000491	0.00250
1,2-Dichloroethane	U		0.000649	0.00250
1,1-Dichloroethene	U		0.000606	0.00250
cis-1,2-Dichloroethene	U		0.000734	0.00250
trans-1,2-Dichloroethene	U		0.00104	0.00500
1,2-Dichloropropane	U		0.00142	0.00500
1,1-Dichloropropene	U		0.000809	0.00250
1,3-Dichloropropane	U		0.000501	0.00500
cis-1,3-Dichloropropene	U		0.000757	0.00250
trans-1,3-Dichloropropene	U		0.00114	0.00500
2,2-Dichloropropane	U		0.00138	0.00250
Di-isopropyl ether	U		0.000410	0.00100
Ethylbenzene	U		0.000737	0.00250
Hexachloro-1,3-butadiene	U		0.00600	0.0250
Isopropylbenzene	U		0.000425	0.00250

Method Blank (MB)

(MB) R3651527-3 05/06/21 21:22

Analyte	MB Result mg/kg	MB Qualifier	MB MDL mg/kg	MB RDL mg/kg
p-Isopropyltoluene	U		0.00255	0.00500
2-Butanone (MEK)	U		0.0635	0.100
Methylene Chloride	U		0.00664	0.0250
4-Methyl-2-pentanone (MIBK)	U		0.00228	0.0250
Methyl tert-butyl ether	U		0.000350	0.00100
Naphthalene	U		0.00488	0.0125
n-Propylbenzene	U		0.000950	0.00500
Styrene	U		0.000229	0.0125
1,1,1,2-Tetrachloroethane	U		0.000948	0.00250
1,1,2,2-Tetrachloroethane	U		0.000695	0.00250
Tetrachloroethene	U		0.000896	0.00250
Toluene	U		0.00130	0.00500
1,1,2-Trichlorotrifluoroethane	U		0.000754	0.00250
1,2,3-Trichlorobenzene	U		0.00733	0.0125
1,2,4-Trichlorobenzene	U		0.00440	0.0125
1,1,1-Trichloroethane	U		0.000923	0.00250
1,1,2-Trichloroethane	U		0.000597	0.00250
Trichloroethene	U		0.000584	0.00100
Trichlorofluoromethane	U		0.000827	0.00250
1,2,3-Trichloropropane	U		0.00162	0.0125
1,2,3-Trimethylbenzene	U		0.00158	0.00500
1,2,4-Trimethylbenzene	U		0.00158	0.00500
1,3,5-Trimethylbenzene	U		0.00200	0.00500
Vinyl chloride	U		0.00116	0.00250
Xylenes, Total	U		0.000880	0.00650
(S) Toluene-d8	*107*			*75.0-131*
(S) 4-Bromofluorobenzene	*94.3*			*67.0-138*
(S) 1,2-Dichloroethane-d4	*84.3*			*70.0-130*

Laboratory Control Sample (LCS) • Laboratory Control Sample Duplicate (LCSD)

(LCS) R3651527-1 05/06/21 20:06 • (LCSD) R3651527-2 05/06/21 20:25

Analyte	Spike Amount mg/kg	LCS Result mg/kg	LCSD Result mg/kg	LCS Rec. %	LCSD Rec. %	Rec. Limits %	LCS Qualifier	LCSD Qualifier	RPD %	RPD Limits %
Acetone	0.625	1.02	1.13	163	181	10.0-160	J4	J4	10.2	31
Acrylonitrile	0.625	0.854	0.869	137	139	45.0-153			1.74	22
Benzene	0.125	0.110	0.106	88.0	84.8	70.0-123			3.70	20
Bromobenzene	0.125	0.120	0.111	96.0	88.8	73.0-121			7.79	20
Bromodichloromethane	0.125	0.115	0.114	92.0	91.2	73.0-121			0.873	20

Laboratory Control Sample (LCS) • Laboratory Control Sample Duplicate (LCSD)

(LCS) R3651527-1 05/06/21 20:06 • (LCSD) R3651527-2 05/06/21 20:25

Analyte	Spike Amount mg/kg	LCS Result mg/kg	LCSD Result mg/kg	LCS Rec. %	LCSD Rec. %	Rec. Limits %	LCS Qualifier	LCSD Qualifier	RPD %	RPD Limits %
Bromoform	0.125	0.118	0.114	94.4	91.2	64.0-132			3.45	20
Bromomethane	0.125	0.107	0.0907	85.6	72.6	56.0-147			16.5	20
n-Butylbenzene	0.125	0.114	0.113	91.2	90.4	68.0-135			0.881	20
sec-Butylbenzene	0.125	0.119	0.106	95.2	84.8	74.0-130			11.6	20
tert-Butylbenzene	0.125	0.116	0.101	92.8	80.8	75.0-127			13.8	20
Carbon tetrachloride	0.125	0.0939	0.0883	75.1	70.6	66.0-128			6.15	20
Chlorobenzene	0.125	0.115	0.109	92.0	87.2	76.0-128			5.36	20
Chlorodibromomethane	0.125	0.125	0.115	100	92.0	74.0-127			8.33	20
Chloroethane	0.125	0.0997	0.0882	79.8	70.6	61.0-134			12.2	20
Chloroform	0.125	0.108	0.105	86.4	84.0	72.0-123			2.82	20
Chloromethane	0.125	0.107	0.0940	85.6	75.2	51.0-138			12.9	20
2-Chlorotoluene	0.125	0.119	0.112	95.2	89.6	75.0-124			6.06	20
4-Chlorotoluene	0.125	0.129	0.117	103	93.6	75.0-124			9.76	20
1,2-Dibromo-3-Chloropropane	0.125	0.123	0.145	98.4	116	59.0-130			16.4	20
1,2-Dibromoethane	0.125	0.118	0.119	94.4	95.2	74.0-128			0.844	20
Dibromomethane	0.125	0.123	0.116	98.4	92.8	75.0-122			5.86	20
1,2-Dichlorobenzene	0.125	0.117	0.117	93.6	93.6	76.0-124			0.000	20
1,3-Dichlorobenzene	0.125	0.118	0.115	94.4	92.0	76.0-125			2.58	20
1,4-Dichlorobenzene	0.125	0.118	0.118	94.4	94.4	77.0-121			0.000	20
Dichlorodifluoromethane	0.125	0.117	0.108	93.6	86.4	43.0-156			8.00	20
1,1-Dichloroethane	0.125	0.114	0.110	91.2	88.0	70.0-127			3.57	20
1,2-Dichloroethane	0.125	0.116	0.112	92.8	89.6	65.0-131			3.51	20
1,1-Dichloroethene	0.125	0.100	0.0928	80.0	74.2	65.0-131			7.47	20
cis-1,2-Dichloroethene	0.125	0.113	0.103	90.4	82.4	73.0-125			9.26	20
trans-1,2-Dichloroethene	0.125	0.101	0.0961	80.8	76.9	71.0-125			4.97	20
1,2-Dichloropropane	0.125	0.125	0.115	100	92.0	74.0-125			8.33	20
1,1-Dichloropropene	0.125	0.0992	0.0967	79.4	77.4	73.0-125			2.55	20
1,3-Dichloropropane	0.125	0.124	0.119	99.2	95.2	80.0-125			4.12	20
cis-1,3-Dichloropropene	0.125	0.105	0.101	84.0	80.8	76.0-127			3.88	20
trans-1,3-Dichloropropene	0.125	0.117	0.112	93.6	89.6	73.0-127			4.37	20
2,2-Dichloropropane	0.125	0.107	0.0892	85.6	71.4	59.0-135			18.1	20
Di-isopropyl ether	0.125	0.124	0.112	99.2	89.6	60.0-136			10.2	20
Ethylbenzene	0.125	0.110	0.104	88.0	83.2	74.0-126			5.61	20
Hexachloro-1,3-butadiene	0.125	0.0991	0.0980	79.3	78.4	57.0-150			1.12	20
Isopropylbenzene	0.125	0.108	0.101	86.4	80.8	72.0-127			6.70	20
p-Isopropyltoluene	0.125	0.109	0.102	87.2	81.6	72.0-133			6.64	20
2-Butanone (MEK)	0.625	0.862	0.801	138	128	30.0-160			7.34	24
Methylene Chloride	0.125	0.114	0.105	91.2	84.0	68.0-123			8.22	20
4-Methyl-2-pentanone (MIBK)	0.625	0.740	0.738	118	118	56.0-143			0.271	20
Methyl tert-butyl ether	0.125	0.133	0.119	106	95.2	66.0-132			11.1	20

1 Cp
2 Tc
3 Ss
4 Cn
5 Sr
6 Qc
7 Gl
8 Al
9 Sc

Laboratory Control Sample (LCS) • Laboratory Control Sample Duplicate (LCSD)

(LCS) R3651527-1 05/06/21 20:06 • (LCSD) R3651527-2 05/06/21 20:25

Analyte	Spike Amount mg/kg	LCS Result mg/kg	LCSD Result mg/kg	LCS Rec. %	LCSD Rec. %	Rec. Limits %	LCS Qualifier	LCSD Qualifier	RPD %	RPD Limits %
Naphthalene	0.125	0.114	0.131	91.2	105	59.0-130			13.9	20
n-Propylbenzene	0.125	0.128	0.116	102	92.8	74.0-126			9.84	20
Styrene	0.125	0.119	0.110	95.2	88.0	72.0-127			7.86	20
1,1,1,2-Tetrachloroethane	0.125	0.107	0.0993	85.6	79.4	74.0-129			7.46	20
1,1,2,2-Tetrachloroethane	0.125	0.133	0.125	106	100	68.0-128			6.20	20
Tetrachloroethene	0.125	0.110	0.107	88.0	85.6	70.0-136			2.76	20
Toluene	0.125	0.116	0.108	92.8	86.4	75.0-121			7.14	20
1,1,2-Trichlorotrifluoroethane	0.125	0.108	0.0928	86.4	74.2	61.0-139			15.1	20
1,2,3-Trichlorobenzene	0.125	0.0976	0.108	78.1	86.4	59.0-139			10.1	20
1,2,4-Trichlorobenzene	0.125	0.0989	0.117	79.1	93.6	62.0-137			16.8	20
1,1,1-Trichloroethane	0.125	0.106	0.0899	84.8	71.9	69.0-126			16.4	20
1,1,2-Trichloroethane	0.125	0.124	0.115	99.2	92.0	78.0-123			7.53	20
Trichloroethene	0.125	0.108	0.105	86.4	84.0	76.0-126			2.82	20
Trichlorofluoromethane	0.125	0.0954	0.0822	76.3	65.8	61.0-142			14.9	20
1,2,3-Trichloropropane	0.125	0.134	0.127	107	102	67.0-129			5.36	20
1,2,3-Trimethylbenzene	0.125	0.116	0.110	92.8	88.0	74.0-124			5.31	20
1,2,4-Trimethylbenzene	0.125	0.116	0.110	92.8	88.0	70.0-126			5.31	20
1,3,5-Trimethylbenzene	0.125	0.109	0.0995	87.2	79.6	73.0-127			9.11	20
Vinyl chloride	0.125	0.101	0.0909	80.8	72.7	63.0-134			10.5	20
Xylenes, Total	0.375	0.341	0.330	90.9	88.0	72.0-127			3.28	20
(S) Toluene-d8				*102*	*101*	*75.0-131*				
(S) 4-Bromofluorobenzene				*95.5*	*96.4*	*67.0-138*				
(S) 1,2-Dichloroethane-d4				*104*	*106*	*70.0-130*				

Method Blank (MB)

(MB) R3651572-1 05/06/21 22:50

Analyte	MB Result mg/kg	MB Qualifier	MB MDL mg/kg	MB RDL mg/kg
Diesel Range Organics (DRO)	U		1.33	4.00
Residual Range Organics (RRO)	U		3.33	10.0
(S) o-Terphenyl	*76.0*			*18.0-148*

Laboratory Control Sample (LCS)

(LCS) R3651572-2 05/06/21 23:03

Analyte	Spike Amount mg/kg	LCS Result mg/kg	LCS Rec. %	Rec. Limits %	LCS Qualifier
Diesel Range Organics (DRO)	50.0	48.8	97.6	50.0-150	
(S) o-Terphenyl			*65.0*	*18.0-148*	

L1346403-04 Original Sample (OS) • Matrix Spike (MS) • Matrix Spike Duplicate (MSD)

(OS) L1346403-04 05/07/21 00:08 • (MS) R3651572-3 05/07/21 00:21 • (MSD) R3651572-4 05/07/21 00:34

Analyte	Spike Amount (dry) mg/kg	Original Result (dry)	MS Result (dry)	MSD Result (dry)	MS Rec. %	MSD Rec. %	Dilution	Rec. Limits %	MS Qualifier	MSD Qualifier	RPD %	RPD Limits %
Diesel Range Organics (DRO)	48.5	7.01	51.1	50.8	82.2	81.1	1	50.0-150			0.651	20
(S) o-Terphenyl					*47.4*	*46.2*		*18.0-148*				

1 Cp
2 Tc
3 Ss
4 Cn
5 Sr
6 Qc
7 Gl
8 Al
9 Sc

Method Blank (MB)

(MB) R3652070-1 05/08/21 21:46

Analyte	MB Result mg/kg	MB Qualifier	MB MDL mg/kg	MB RDL mg/kg
Diesel Range Organics (DRO)	U		1.33	4.00
Residual Range Organics (RRO)	U		3.33	10.0
(S) o-Terphenyl	*76.1*			*18.0-148*

Laboratory Control Sample (LCS)

(LCS) R3652070-2 05/08/21 21:58

Analyte	Spike Amount mg/kg	LCS Result mg/kg	LCS Rec. %	Rec. Limits %	LCS Qualifier
Diesel Range Organics (DRO)	50.0	44.1	88.2	50.0-150	
(S) o-Terphenyl			*83.3*	*18.0-148*	

Method Blank (MB)

(MB) R3652500-2 05/06/21 18:31

Analyte	MB Result mg/kg	MB Qualifier	MB MDL mg/kg	MB RDL mg/kg
Anthracene	U		0.00230	0.00600
Acenaphthene	U		0.00209	0.00600
Acenaphthylene	U		0.00216	0.00600
Benzo(a)anthracene	U		0.00173	0.00600
Benzo(a)pyrene	U		0.00179	0.00600
Benzo(b)fluoranthene	U		0.00153	0.00600
Benzo(g,h,i)perylene	U		0.00177	0.00600
Benzo(k)fluoranthene	U		0.00215	0.00600
Chrysene	U		0.00232	0.00600
Dibenz(a,h)anthracene	U		0.00172	0.00600
Fluoranthene	U		0.00227	0.00600
Fluorene	U		0.00205	0.00600
Indeno(1,2,3-cd)pyrene	U		0.00181	0.00600
Naphthalene	U		0.00408	0.0200
Phenanthrene	U		0.00231	0.00600
Pyrene	U		0.00200	0.00600
1-Methylnaphthalene	U		0.00449	0.0200
2-Methylnaphthalene	U		0.00427	0.0200
2-Chloronaphthalene	U		0.00466	0.0200
(S) Nitrobenzene-d5	*52.6*			*14.0-149*
(S) 2-Fluorobiphenyl	*71.2*			*34.0-125*
(S) p-Terphenyl-d14	*93.3*			*23.0-120*

Laboratory Control Sample (LCS)

(LCS) R3652500-1 05/06/21 18:11

Analyte	Spike Amount mg/kg	LCS Result mg/kg	LCS Rec. %	Rec. Limits %	LCS Qualifier
Anthracene	0.0800	U	0.000	50.0-126	J4
Acenaphthene	0.0800	U	0.000	50.0-120	J4
Acenaphthylene	0.0800	U	0.000	50.0-120	J4
Benzo(a)anthracene	0.0800	U	0.000	45.0-120	J4
Benzo(a)pyrene	0.0800	U	0.000	42.0-120	J4
Benzo(b)fluoranthene	0.0800	U	0.000	42.0-121	J4
Benzo(g,h,i)perylene	0.0800	U	0.000	45.0-125	J4
Benzo(k)fluoranthene	0.0800	U	0.000	49.0-125	J4
Chrysene	0.0800	U	0.000	49.0-122	J4
Dibenz(a,h)anthracene	0.0800	U	0.000	47.0-125	J4
Fluoranthene	0.0800	U	0.000	49.0-129	J4

Laboratory Control Sample (LCS)

(LCS) R3652500-1 05/06/21 18:11

Analyte	Spike Amount mg/kg	LCS Result mg/kg	LCS Rec. %	Rec. Limits %	LCS Qualifier
Fluorene	0.0800	U	0.000	49.0-120	J4
Indeno(1,2,3-cd)pyrene	0.0800	U	0.000	46.0-125	J4
Naphthalene	0.0800	0.000469	0.586	50.0-120	J4
Phenanthrene	0.0800	U	0.000	47.0-120	J4
Pyrene	0.0800	U	0.000	43.0-123	J4
1-Methylnaphthalene	0.0800	0.0000500	0.0625	51.0-121	J4
2-Methylnaphthalene	0.0800	0.000194	0.242	50.0-120	J4
2-Chloronaphthalene	0.0800	0.0000361	0.0451	50.0-120	J4
(S) Nitrobenzene-d5			*51.6*	*14.0-149*	
(S) 2-Fluorobiphenyl			*71.9*	*34.0-125*	
(S) p-Terphenyl-d14			*95.1*	*23.0-120*	

Method Blank (MB)

(MB) R3654354-2 05/13/21 17:08

Analyte	MB Result mg/kg	MB Qualifier	MB MDL mg/kg	MB RDL mg/kg
Anthracene	U		0.00230	0.00600
Acenaphthene	U		0.00209	0.00600
Acenaphthylene	U		0.00216	0.00600
Benzo(a)anthracene	U		0.00173	0.00600
Benzo(a)pyrene	U		0.00179	0.00600
Benzo(b)fluoranthene	U		0.00153	0.00600
Benzo(g,h,i)perylene	U		0.00177	0.00600
Benzo(k)fluoranthene	U		0.00215	0.00600
Chrysene	U		0.00232	0.00600
Dibenz(a,h)anthracene	U		0.00172	0.00600
Fluoranthene	U		0.00227	0.00600
Fluorene	U		0.00205	0.00600
Indeno(1,2,3-cd)pyrene	U		0.00181	0.00600
Naphthalene	U		0.00408	0.0200
Phenanthrene	U		0.00231	0.00600
Pyrene	U		0.00200	0.00600
1-Methylnaphthalene	U		0.00449	0.0200
2-Methylnaphthalene	U		0.00427	0.0200
2-Chloronaphthalene	U		0.00466	0.0200
(S) Nitrobenzene-d5	*73.0*			*14.0-149*
(S) 2-Fluorobiphenyl	*81.2*			*34.0-125*
(S) p-Terphenyl-d14	*84.5*			*23.0-120*

Laboratory Control Sample (LCS)

(LCS) R3654354-1 05/13/21 16:48

Analyte	Spike Amount mg/kg	LCS Result mg/kg	LCS Rec. %	Rec. Limits %	LCS Qualifier
Anthracene	0.0800	0.0676	84.5	50.0-126	
Acenaphthene	0.0800	0.0691	86.4	50.0-120	
Acenaphthylene	0.0800	0.0706	88.3	50.0-120	
Benzo(a)anthracene	0.0800	0.0634	79.3	45.0-120	
Benzo(a)pyrene	0.0800	0.0489	61.1	42.0-120	
Benzo(b)fluoranthene	0.0800	0.0624	78.0	42.0-121	
Benzo(g,h,i)perylene	0.0800	0.0577	72.1	45.0-125	
Benzo(k)fluoranthene	0.0800	0.0619	77.4	49.0-125	
Chrysene	0.0800	0.0679	84.9	49.0-122	
Dibenz(a,h)anthracene	0.0800	0.0581	72.6	47.0-125	
Fluoranthene	0.0800	0.0735	91.9	49.0-129	

Laboratory Control Sample (LCS)

(LCS) R3654354-1 05/13/21 16:48

Analyte	Spike Amount mg/kg	LCS Result mg/kg	LCS Rec. %	Rec. Limits %	LCS Qualifier
Fluorene	0.0800	0.0733	91.6	49.0-120	
Indeno(1,2,3-cd)pyrene	0.0800	0.0565	70.6	46.0-125	
Naphthalene	0.0800	0.0681	85.1	50.0-120	
Phenanthrene	0.0800	0.0724	90.5	47.0-120	
Pyrene	0.0800	0.0680	85.0	43.0-123	
1-Methylnaphthalene	0.0800	0.0662	82.8	51.0-121	
2-Methylnaphthalene	0.0800	0.0636	79.5	50.0-120	
2-Chloronaphthalene	0.0800	0.0732	91.5	50.0-120	
(S) Nitrobenzene-d5			*81.1*	*14.0-149*	
(S) 2-Fluorobiphenyl			*86.9*	*34.0-125*	
(S) p-Terphenyl-d14			*85.1*	*23.0-120*	

L1349384-04 Original Sample (OS) • Matrix Spike (MS) • Matrix Spike Duplicate (MSD)

(OS) L1349384-04 05/13/21 17:28 • (MS) R3654354-3 05/13/21 17:47 • (MSD) R3654354-4 05/13/21 18:07

Analyte	Spike Amount mg/kg	Original Result mg/kg	MS Result mg/kg	MSD Result mg/kg	MS Rec. %	MSD Rec. %	Dilution	Rec. Limits %	MS Qualifier	MSD Qualifier	RPD %	RPD Limits %
Anthracene	0.0780	ND	0.0627	0.0651	80.4	83.5	1	10.0-145			3.76	30
Acenaphthene	0.0780	ND	0.0638	0.0648	81.8	83.1	1	14.0-127			1.56	27
Acenaphthylene	0.0780	ND	0.0644	0.0660	82.6	84.6	1	21.0-124			2.45	25
Benzo(a)anthracene	0.0780	ND	0.0589	0.0607	75.5	77.8	1	10.0-139			3.01	30
Benzo(a)pyrene	0.0780	ND	0.0545	0.0565	69.9	72.4	1	10.0-141			3.60	31
Benzo(b)fluoranthene	0.0780	ND	0.0578	0.0599	74.1	76.8	1	10.0-140			3.57	36
Benzo(g,h,i)perylene	0.0780	ND	0.0533	0.0545	68.3	69.9	1	10.0-140			2.23	33
Benzo(k)fluoranthene	0.0780	ND	0.0573	0.0582	73.5	74.6	1	10.0-137			1.56	31
Chrysene	0.0780	ND	0.0625	0.0650	80.1	83.3	1	10.0-145			3.92	30
Dibenz(a,h)anthracene	0.0780	ND	0.0542	0.0558	69.5	71.5	1	10.0-132			2.91	31
Fluoranthene	0.0780	ND	0.0696	0.0718	89.2	92.1	1	10.0-153			3.11	33
Fluorene	0.0780	ND	0.0672	0.0692	86.2	88.7	1	11.0-130			2.93	29
Indeno(1,2,3-cd)pyrene	0.0780	ND	0.0519	0.0541	66.5	69.4	1	10.0-137			4.15	32
Naphthalene	0.0780	ND	0.0753	0.0716	86.7	81.9	1	10.0-135			5.04	27
Phenanthrene	0.0780	ND	0.0676	0.0709	86.7	90.9	1	10.0-144			4.77	31
Pyrene	0.0780	ND	0.0619	0.0643	79.4	82.4	1	10.0-148			3.80	35
1-Methylnaphthalene	0.0780	ND	0.0644	0.0644	82.6	82.6	1	10.0-142			0.000	28
2-Methylnaphthalene	0.0780	ND	0.0648	0.0646	83.1	82.8	1	10.0-137			0.309	28
2-Chloronaphthalene	0.0780	ND	0.0678	0.0692	86.9	88.7	1	29.0-120			2.04	24
(S) Nitrobenzene-d5					*75.6*	*95.8*		*14.0-149*				
(S) 2-Fluorobiphenyl					*85.0*	*86.1*		*34.0-125*				
(S) p-Terphenyl-d14					*80.2*	*84.3*		*23.0-120*				

Guide to Reading and Understanding Your Laboratory Report

The information below is designed to better explain the various terms used in your report of analytical results from the Laboratory. This is not intended as a comprehensive explanation, and if you have additional questions please contact your project representative.

Results Disclaimer - Information that may be provided by the customer, and contained within this report, include Permit Limits, Project Name, Sample ID, Sample Matrix, Sample Preservation, Field Blanks, Field Spikes, Field Duplicates, On-Site Data, Sampling Collection Dates/Times, and Sampling Location. Results relate to the accuracy of this information provided, and as the samples are received.

Abbreviations and Definitions

(dry)	Results are reported based on the dry weight of the sample. [this will only be present on a dry report basis for soils].
MDL	Method Detection Limit.
ND	Not detected at the Reporting Limit (or MDL where applicable).
RDL	Reported Detection Limit.
RDL (dry)	Reported Detection Limit.
Rec.	Recovery.
RPD	Relative Percent Difference.
SDG	Sample Delivery Group.
(S)	Surrogate (Surrogate Standard) - Analytes added to every blank, sample, Laboratory Control Sample/Duplicate and Matrix Spike/Duplicate; used to evaluate analytical efficiency by measuring recovery. Surrogates are not expected to be detected in all environmental media.
U	Not detected at the Reporting Limit (or MDL where applicable).
Analyte	The name of the particular compound or analysis performed. Some Analyses and Methods will have multiple analytes reported.
Dilution	If the sample matrix contains an interfering material, the sample preparation volume or weight values differ from the standard, or if concentrations of analytes in the sample are higher than the highest limit of concentration that the laboratory can accurately report, the sample may be diluted for analysis. If a value different than 1 is used in this field, the result reported has already been corrected for this factor.
Limits	These are the target % recovery ranges or % difference value that the laboratory has historically determined as normal for the method and analyte being reported. Successful QC Sample analysis will target all analytes recovered or duplicated within these ranges.
Original Sample	The non-spiked sample in the prep batch used to determine the Relative Percent Difference (RPD) from a quality control sample. The Original Sample may not be included within the reported SDG.
Qualifier	This column provides a letter and/or number designation that corresponds to additional information concerning the result reported. If a Qualifier is present, a definition per Qualifier is provided within the Glossary and Definitions page and potentially a discussion of possible implications of the Qualifier in the Case Narrative if applicable.
Result	The actual analytical final result (corrected for any sample specific characteristics) reported for your sample. If there was no measurable result returned for a specific analyte, the result in this column may state “ND” (Not Detected) or “BDL” (Below Detectable Levels). The information in the results column should always be accompanied by either an MDL (Method Detection Limit) or RDL (Reporting Detection Limit) that defines the lowest value that the laboratory could detect or report for this analyte.
Uncertainty (Radiochemistry)	Confidence level of 2 sigma.
Case Narrative (Cn)	A brief discussion about the included sample results, including a discussion of any non-conformances to protocol observed either at sample receipt by the laboratory from the field or during the analytical process. If present, there will be a section in the Case Narrative to discuss the meaning of any data qualifiers used in the report.
Quality Control Summary (Qc)	This section of the report includes the results of the laboratory quality control analyses required by procedure or analytical methods to assist in evaluating the validity of the results reported for your samples. These analyses are not being performed on your samples typically, but on laboratory generated material.
Sample Chain of Custody (Sc)	This is the document created in the field when your samples were initially collected. This is used to verify the time and date of collection, the person collecting the samples, and the analyses that the laboratory is requested to perform. This chain of custody also documents all persons (excluding commercial shippers) that have had control or possession of the samples from the time of collection until delivery to the laboratory for analysis.
Sample Results (Sr)	This section of your report will provide the results of all testing performed on your samples. These results are provided by sample ID and are separated by the analyses performed on each sample. The header line of each analysis section for each sample will provide the name and method number for the analysis reported.
Sample Summary (Ss)	This section of the Analytical Report defines the specific analyses performed for each sample ID, including the dates and times of preparation and/or analysis.

Qualifier	Description
C3	The reported concentration is an estimate. The continuing calibration standard associated with this data responded low. Method sensitivity check is acceptable.
J	The identification of the analyte is acceptable; the reported value is an estimate.
J3	The associated batch QC was outside the established quality control range for precision.
J4	The associated batch QC was outside the established quality control range for accuracy.
J6	The sample matrix interfered with the ability to make any accurate determination; spike value is low.
J7	Surrogate recovery cannot be used for control limit evaluation due to dilution.

1 Cp
2 Tc
3 Ss
4 Cn
5 Sr
6 Qc
7 Gl
8 Al
9 Sc

Pace Analytical National 12065 Lebanon Rd Mount Juliet, TN 37122

Alabama	40660	Nebraska	NE-OS-15-05
Alaska	17-026	Nevada	TN000032021-1
Arizona	AZ0612	New Hampshire	2975
Arkansas	88-0469	New Jersey–NELAP	TN002
California	2932	New Mexico [1]	TN00003
Colorado	TN00003	New York	11742
Connecticut	PH-0197	North Carolina	Env375
Florida	E87487	North Carolina [1]	DW21704
Georgia	NELAP	North Carolina [3]	41
Georgia [1]	923	North Dakota	R-140
Idaho	TN00003	Ohio–VAP	CL0069
Illinois	200008	Oklahoma	9915
Indiana	C-TN-01	Oregon	TN200002
Iowa	364	Pennsylvania	68-02979
Kansas	E-10277	Rhode Island	LAO00356
Kentucky [1 6]	KY90010	South Carolina	84004002
Kentucky [2]	16	South Dakota	n/a
Louisiana	AI30792	Tennessee [1 4]	2006
Louisiana	LA018	Texas	T104704245-20-18
Maine	TN00003	Texas [5]	LAB0152
Maryland	324	Utah	TN000032021-11
Massachusetts	M-TN003	Vermont	VT2006
Michigan	9958	Virginia	110033
Minnesota	047-999-395	Washington	C847
Mississippi	TN00003	West Virginia	233
Missouri	340	Wisconsin	998093910
Montana	CERT0086	Wyoming	A2LA
A2LA – ISO 17025	1461.01	AIHA-LAP,LLC EMLAP	100789
A2LA – ISO 17025 [5]	1461.02	DOD	1461.01
Canada	1461.01	USDA	P330-15-00234
EPA–Crypto	TN00003		

[1] Drinking Water [2] Underground Storage Tanks [3] Aquatic Toxicity [4] Chemical/Microbiological [5] Mold [6] Wastewater n/a Accreditation not applicable

* Not all certifications held by the laboratory are applicable to the results reported in the attached report.

* Accreditation is only applicable to the test methods specified on each scope of accreditation held by Pace Analytical.

APPENDIX C
Report Limitations and Guidelines for Use

APPENDIX C
REPORT LIMITATIONS AND GUIDELINES FOR USE[1]

This appendix provides information to help you manage your risks with respect to the use of this report.

Read These Provisions Closely

It is important to recognize that the geoscience practices (geotechnical engineering, geology and environmental science) rely on professional judgment and opinion to a greater extent than other engineering and natural science disciplines, where more precise and/or readily observable data may exist. To help clients better understand how this difference pertains to our services, GeoEngineers includes the following explanatory "limitations" provisions in its reports. Please confer with GeoEngineers if you need to know more how these "Report Limitations and Guidelines for Use" apply to your project or site.

Geotechnical Services Are Performed for Specific Purposes, Persons and Projects

This report has been prepared for Sanborn Head & Associates, NW Natural, and their agents for the Project specifically identified in the report. The information contained herein is not applicable to other sites or projects.

GeoEngineers structures its services to meet the specific needs of its clients. No party other than the party to whom this report is addressed may rely on the product of our services unless we agree to such reliance in advance and in writing. Within the limitations of the agreed scope of services for the Project, and its schedule and budget, our services have been executed in accordance with our Agreement with Sanborn Head & Associates dated January 19, 2021, and generally accepted geotechnical practices in this area at the time this report was prepared. We do not authorize, and will not be responsible for, the use of this report for any purposes or projects other than those identified in the report.

A Geotechnical Engineering or Geologic Report is Based on a Unique Set of Project-Specific Factors

This report has been prepared for the proposed NW Natural Cold Box FEED Preliminary Design Project at the Portland LNG Facility in Portland, Oregon. GeoEngineers considered a number of unique, project-specific factors when establishing the scope of services for this project and report. Unless GeoEngineers specifically indicates otherwise, it is important not to rely on this report if it was:

- not prepared for you,
- not prepared for your project,
- not prepared for the specific site explored, or
- completed before important project changes were made.

For example, changes that can affect the applicability of this report include those that affect:

- the function of the proposed structure;

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[1] Developed based on material provided by GBA, Geoprofessional Business Association; www.geoprofessional.org.

- elevation, configuration, location, orientation or weight of the proposed structure;
- composition of the design team; or
- project ownership.

If changes occur after the date of this report, GeoEngineers cannot be responsible for any consequences of such changes in relation to this report unless we have been given the opportunity to review our interpretations and recommendations. Based on that review, we can provide written modifications or confirmation, as appropriate.

Environmental Concerns Are Not Covered

Unless environmental services were specifically included in our scope of services, this report does not provide any environmental findings, conclusions, or recommendations, including but not limited to, the likelihood of encountering underground storage tanks or regulated contaminants.

Subsurface Conditions Can Change

This geotechnical or geologic report is based on conditions that existed at the time the study was performed. The findings and conclusions of this report may be affected by the passage of time, by man-made events such as construction on or adjacent to the site, new information or technology that becomes available subsequent to the report date, or by natural events such as floods, earthquakes, slope instability or groundwater fluctuations. If more than a few months have passed since issuance of our report or work product, or if any of the described events may have occurred, please contact GeoEngineers before applying this report for its intended purpose so that we may evaluate whether changed conditions affect the continued reliability or applicability of our conclusions and recommendations.

Geotechnical and Geologic Findings Are Professional Opinions

Our interpretations of subsurface conditions are based on field observations from widely spaced sampling locations in the vicinity the site. Site exploration identifies the specific subsurface conditions only at those points where subsurface tests are conducted, or samples are taken. GeoEngineers reviewed field and laboratory data and then applied its professional judgment to render an informed opinion about subsurface conditions at other locations. Actual subsurface conditions may differ, sometimes significantly, from the opinions presented in this report. Our report, conclusions and interpretations are not a warranty of the actual subsurface conditions.

Geotechnical Engineering Report Recommendations Are Not Final

We have developed the following recommendations based on data gathered from subsurface investigation(s). These investigations sample just a small percentage of a site to create a snapshot of the subsurface conditions elsewhere on the site. Such sampling on its own cannot provide a complete and accurate view of subsurface conditions for the entire site. Therefore, the recommendations included in this report are preliminary and should not be considered final. GeoEngineers' recommendations can be finalized only by observing actual subsurface conditions revealed during construction. GeoEngineers cannot assume responsibility or liability for the recommendations in this report if we do not perform construction observation.

We recommend that you allow sufficient monitoring, testing and consultation during construction by GeoEngineers to confirm that the conditions encountered are consistent with those indicated by the explorations, to provide recommendations for design changes if the conditions revealed during the work differ from those anticipated, and to evaluate whether earthwork activities are completed in accordance with our recommendations. Retaining GeoEngineers for construction observation for this project is the most effective means of managing the risks associated with unanticipated conditions. If another party performs field observation and confirms our expectations, the other party must take full responsibility for both the observations and recommendations. Please note, however, that another party would lack our project-specific knowledge and resources.

A Geotechnical Engineering or Geologic Report Could Be Subject to Misinterpretation

Misinterpretation of this report by members of the design team or by contractors can result in costly problems. GeoEngineers can help reduce the risks of misinterpretation by conferring with appropriate members of the design team after submitting the report, reviewing pertinent elements of the design team's plans and specifications, participating in pre-bid and preconstruction conferences, and providing construction observation.

Do Not Redraw the Exploration Logs

Geotechnical engineers and geologists prepare final boring and testing logs based upon their interpretation of field logs and laboratory data. The logs included in a geotechnical engineering or geologic report should never be redrawn for inclusion in architectural or other design drawings. Photographic or electronic reproduction is acceptable, but separating logs from the report can create a risk of misinterpretation.

Give Contractors a Complete Report and Guidance

To help reduce the risk of problems associated with unanticipated subsurface conditions, GeoEngineers recommends giving contractors the complete geotechnical engineering or geologic report, including these "Report Limitations and Guidelines for Use." When providing the report, you should preface it with a clearly written letter of transmittal that:

- advises contractors that the report was not prepared for purposes of bid development and that its accuracy is limited; and
- encourages contractors to confer with GeoEngineers and/or to conduct additional study to obtain the specific types of information they need or prefer.

Contractors Are Responsible for Site Safety on Their Own Construction Projects

Our geotechnical recommendations are not intended to direct the contractor's procedures, methods, schedule or management of the work site. The contractor is solely responsible for job site safety and for managing construction operations to minimize risks to on-site personnel and adjacent properties.

Biological Pollutants

GeoEngineers' Scope of Work specifically excludes the investigation, detection, prevention or assessment of the presence of Biological Pollutants. Accordingly, this report does not include any interpretations, recommendations, findings or conclusions regarding the detecting, assessing, preventing or abating of Biological Pollutants, and no conclusions or inferences should be drawn regarding Biological Pollutants as they may relate to this project. The term "Biological Pollutants" includes, but is not limited to, molds, fungi, spores, bacteria and viruses, and/or any of their byproducts.

A Client that desires these specialized services is advised to obtain them from a consultant who offers services in this specialized field.

GeoEngineers

APPENDIX B

Design Wind Speed Report, CPP Wind

DESIGN WIND SPEED REPORT

CPP PROJECT 15211
15 APRIL 2021

PORTLAND LNG FACILITY
Portland, Oregon

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EXECUTIVE SUMMARY

CPP conducted a site-specific wind climate assessment for the Portland LNG Facility to provide suitable, accurate design-level wind speeds for structural analysis and design.

In accordance with the requirements of 49 CFR 193.2067 paragraph (b)(2)(ii) *Wind Forces*, this probabilistic wind assessment utilizes the most critical combination of wind velocity and duration based on reliable wind data from multiple locations near the project site. This wind assessment determined the wind data to be adequate and the probabilistic method to be reliable. A storm-type separation analysis and tornado study are included in this wind assessment.

This analysis satisfies the requirements of 49 CFR 193.2067 paragraph (b)(2)(ii) for design of an LNG facility. The CPP recommended 10,000-year mean recurrence interval (MRI) design wind speed should be used in place of the wind speed of 49 CFR 193.2067 paragraph (b)(2)(i) that assumes a sustained wind velocity of no less than 150 mph. While the definition of “sustained” 150 mph wind is not specifically defined in 49 CFR, the meteorological meaning for a sustained wind is a period of 1-minute. A 150-mph sustained wind in an open country environment is equivalent to a 183-mph 3-second peak gust. The site-specific 10,000-year design wind speed (3 second gust wind speed, 33 feet, Exposure Category C) is to be used per the requirements of The American Society of Civil Engineers (ASCE) *Minimum Design Loads for Buildings and Other Structures* (ASCE 7).

Based on this analysis, a design wind speed for a 10,000-year MRI (0.5 percent probability of exceedance in 50 years) was determined to be 124 mph (3 second gust wind speed, 33 feet, Exposure Category C) and applicable for the structural design of the Portland LNG project. This is a strength-level wind speed to be used as such in the ASCE 7-16 load combinations. The recommended design wind speed and the extreme wind speed analysis methods used in this study comply with the code requirements of ASCE 7.

In order to calculate the required wind loading on any structure, the design equations and provisions of ASCE 7-16 (the national US standard) should be followed. Chapter 2 of the ASCE 7-16 standard provides load combinations to be evaluated with the wind loads represented as *W*. It is the responsibility of the structural engineer to choose and apply the combinations correctly. The Portland LNG site-specific wind loading parameters include:

ASCE 7-16 design parameters	Portland LNG
***$\hat{U}_{10,000}$* (3-second gust, mph), basic wind speed**	124
***K_e*, ground elevation factor**	1.0
***K_d*, wind directionality factor**	0.85
***K_{zt}*, topographic factor**	1.0
***K_z*, velocity pressure exposure coefficient**	Exposure Category C Table 26.10-1 by height, ASCE 7-16
ASCE 7-16 Load combinations	Chapter 2 of ASCE 7-16

INTRODUCTION

This report summarizes the local extreme wind climate analysis for the Portland LNG Facility located in Portland, Oregon (Figure 1). Historical weather data were used to determine the site-specific 10,000-year MRI design wind speed. A site-specific analysis was then performed to account for the effects of far-field upwind terrain using published and accepted analytical procedures. This information was then used to determine site-specific design wind speeds that can then be used in the determination of appropriate wind loads (per ASCE 7-16) for the structures at the facility. The provided data are based on a CPP analysis of design-level wind speeds varying by direction, analysis of meteorological data, and the application of engineering judgment based on the authors' experience. CPP has performed similar analysis for thousands of buildings/structures worldwide for over 35 years. All data analysis was performed in accordance with the American Society of Civil Engineers (ASCE) Standard 7-16 (2017).

Figure 1. Portland LNG site location.

SITE-SPECIFIC CLIMATE ANALYSIS

CODE BASIS

Maps of basic wind speed for the United States are provided by The American Society of Civil Engineers (ASCE 7) to be used in the calculation of design wind loads. The design equations and provisions of ASCE 7 (the national US standard) are the basis for wind loading in most US design standards. As such, the methodology of the basis for determining design wind speeds has been published (and accepted by experts in the field of wind engineering) and can be followed per the requirements of ASCE 7.

The 49 CFR 193.2067 code references the older ASCE 7-05 (2006) design standard. If ASCE 7-05 is to be used for design, then the design speeds should also be checked against the current ASCE 7-16 design methods as this could impact other structures in the facility. The design wind speed MRI corresponds to a strength design wind load and should be applied accordingly per the requirements of Chapter 2 in ASCE 7, which was changed from the 7-05 to 7-10 versions.

Our analysis considers and complies with all versions of ASCE 7, although we recommend using the current and best guidance for wind loading as outlined in ASCE 7-16, which has been adopted by the local building regulations within the City of Portland and State of Oregon (2019 OSSC).

ASCE 7 REQUIREMENTS

The American Society of Civil Engineers *Minimum Design Loads and Associated Criteria for Buildings and Other Structures* (ASCE 7-16) should be considered in the calculation of design wind loads. ASCE 7-16 acknowledges that their wind speeds are not site-specific and provides criteria for determining wind speed at specific sites. Section 26.5.2 of ASCE 7-16 requires that if the authority having jurisdiction is to adjust the basic wind speed, it must be *"based on meteorological information and an estimate of the basic wind speed obtained in accordance with the provisions of Section 26.5.3."* Section 26.5.3 of ASCE 7-16, "Estimation of Basic Wind Speeds from Regional Climatic Data" provides instructions for determining design wind speeds in these regions:

> *In areas outside hurricane-prone regions, regional climatic data shall only be used in lieu of the basic wind speeds given in Fig. 26.5-1 and 26.5-2 when (1) approved extreme-value statistical-analysis procedures have been employed in reducing the data; and (2) the length of record, sampling error, averaging time, anemometer height, data quality, and terrain exposure of the anemometer have been taken into account. Reduction in basic wind speed below that of Fig. 26.5-1 and 26.5-2 shall be permitted.*

In the course of our study, we fulfilled both conditions (1) and (2). We have used approved procedures described by Palutikof et al. (1999), including the same extreme value statistical procedures that were used to develop the ASCE 7-16 wind speed maps. Key staff at CPP were involved in the peer review of these wind maps, so we are familiar with their derivation.

APPROVED EXTREME-VALUE STATISTICAL ANALYSIS

Historical peak gust and mean speeds at weather stations close to the site location were evaluated (Figure 2). Hourly surface observations were obtained from the National Centers for Environmental Information (NCEI). The raw data files of hourly and sub-hourly mean wind speeds and gusts from NCEI allow CPP to perform quality control and normalization of the data as required by ASCE 7. Peak gust data from both thunderstorm and non-thunderstorm winds were analyzed separately in keeping with the widely accepted storm-type separation principle which was used for the ASCE 7-16 wind maps.

Annual peak gusts and peak wind gusts from independent storms were evaluated. The Method of Independent Storms (MIS) (Palutikof et al. 1999) was used to produce an independent data set for the extreme value analysis. This method yields lower uncertainty than using the single worst peak gust per year. MIS considers all storms above a certain threshold (generally three or more storms per year), therefore including significantly more storms over a given record.

The annual and independent storm gust wind speeds were fit to a Gumbel (Type I) extreme value distribution. This is the same kind of analysis used to determine the design wind speeds in the ASCE 7-16 wind map for non-hurricane locations.

The peak wind gust data was fit to the Gumbel (Type I) extreme value distribution using a Weighted Least Squares (WLS) method. This is an alternative fitting strategy to account for the error associated with each point being greatest for the largest extremes. There are other methods of fitting the data, including a linear-least-squares fit, the Maximum Likelihood Estimates (MLE), and the Method of Moments (MoM). The predictions from these three methods typically varies by under 5%.

BASIC DESIGN WIND SPEED, *V*

For the Portland LNG Facility, wind speeds for structural design are influenced by non-thunderstorm winds and potentially tornadoes. CPP utilized existing historical peak gust data measured at regional meteorological stations to determine a 10,000-year recurrence wind speed (0.5 percent probability of exceedance in 50 years) at the project site. In accordance with the requirements of 49 CFR 193.2067 paragraph (b)(2)(ii) *Wind Forces*, this probabilistic wind assessment utilizes the most critical combination of wind velocity and duration based on reliable wind data from multiple locations near the project site. This wind assessment determined the wind data to be adequate and the probabilistic methods to be reliable.

Historic peak gust records from the airports closest to the site (Figure 2) were used in the analysis of local design wind speeds. The method of independent storms (MIS; Palutikof 1999) was used as the method of producing an independent data set for the extreme value analysis. This method yields lower uncertainty than using the single worst peak gust per year. MIS considers all storms above a certain threshold (generally three or more storms per year), therefore including more storms over a given record. The independent storm wind speeds were fit to a Gumbel (Type I) extreme value distribution. The prediction of wind speed versus return period resulting from this distribution was adjusted by the number of storms per year, i.e. the predicted return period is equal to the return period based on the variate from the Type I fit divided by the average number of storms per year considered.

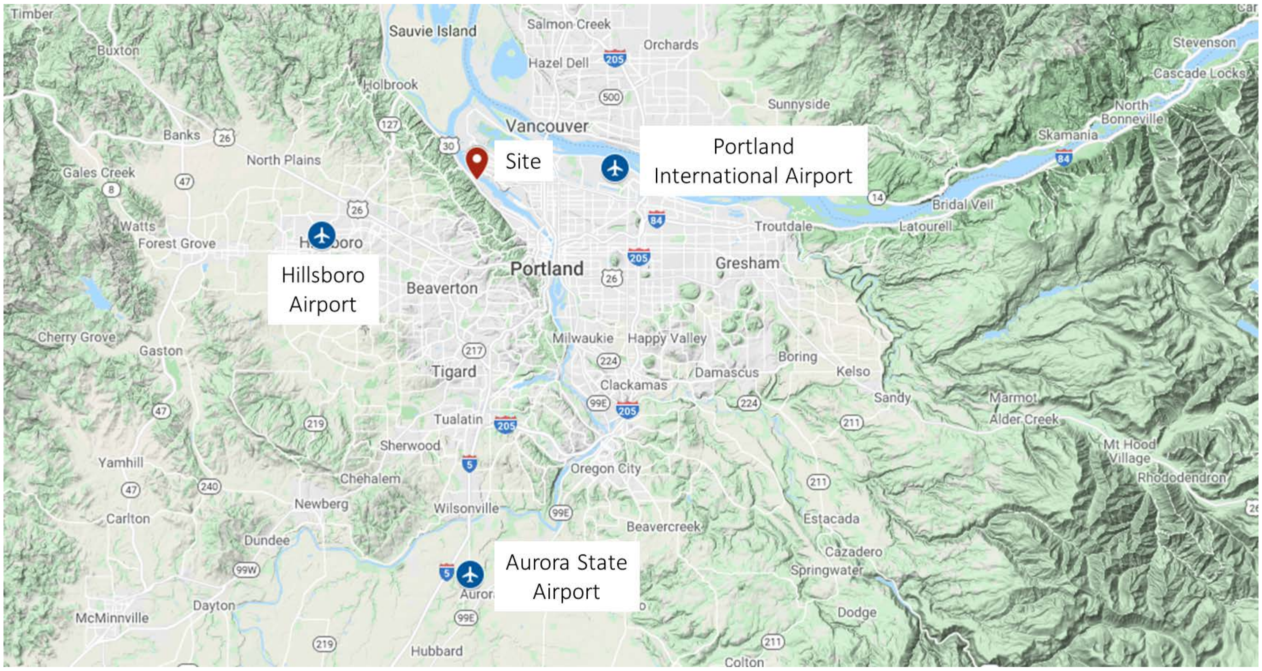

Figure 2. Project location and surrounding meteorological stations.

Storm separation has also been performed for this study, since it is well known that different storm types will produce different extreme wind probability distributions, in keeping with the widely accepted storm-type separation principle which was used for the most recent wind maps in ASCE 7. The hourly TD3505 data records were used to isolate peak gusts due to thunderstorms from the present weather observations for the storm separation analysis.

These results indicate that non-thunderstorm winds are more severe compared to the other storm-type events at the required 10,000-year MRI for design at this project location. From our research, it was found that this region often experiences powerful midlatitude or extratropical cyclones (ETCs). These low-pressure weather systems regularly produce intense storms moving in off the Pacific Ocean that routinely impact the Pacific Northwest coast. While the cool waters of the Pacific prevent tropical cyclones from reaching the shores of the Pacific Northwest, ETCs often develop in this region.

Analysis of tornadic winds in the region was performed using the data and procedures presented in NUREG/CR-4461, Rev. 2. The methods for both point and finite-sized structures were used for estimating the tornado strike and conditional probabilities that a maximum wind speed would exceed. Tornado characteristics estimated for the 2° latitude and longitude boxes were used as they are considered the most reliable. Return period estimates for a tornado striking a site with a 2000-ft width are presented below in Figure 3 with reference to the Enhanced Fujita Scale (EF) wind speed intervals. The tornado evaluation for the LNG site indicates that tornado wind speeds for structural design are lower than the gust speeds at the required design return period of 10,000 years.

Figure 3 shows the variation of wind speed with return period without directional influence for the wind storm types described above. Return period is plotted on a logarithmic scale to permit examination of wind speed over a wide range of return periods. Peak gust wind speeds were fit to a Gumbel (Type I) distribution. Tornado wind speeds were also predicted as a function of return period.

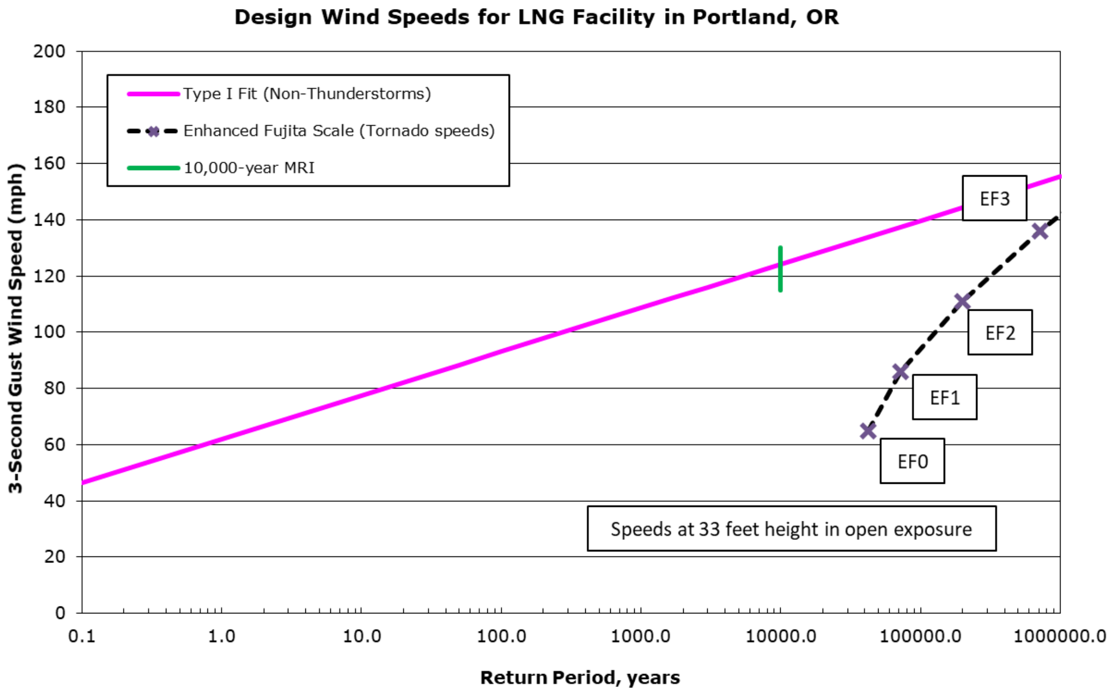

Figure 3. Wind speed risk for the Portland LNG Facility.

Since the extrapolation of data to a 10,000-year return period introduces some error, other propagated fit types were evaluated to examine the range of predicted design wind speeds. These results are shown in Figure 4. This plot shows the raw historic data, several methods of fitting a line through the data, as well as 95% confidence limits. The fitting methods used were method of moments ('MOM'), maximum likelihood estimate ('MaxLE'), Matlab robust fitting algorithm ('Robust'), linear, and weighted least squares ('WLS'). The scatter between methods at 10,000 years are relatively small.

Uncertainty is addressed in two different ways. The uncertainty in the measured data is expressed as 95% confidence limits that the measured data represents the true distribution. This is achieved through a Monte Carlo routine where thousands of storms are randomly generated from the WLS parent distribution. The results are shown bracketing the measured data by the red lines spreading away from the primary fit. There is a 5% probability that a data point will lie outside these red lines if the assumed parent distribution is true. Uncertainty in extrapolating the WLS fit from the measured data is expressed through the light blue 95% confidence lines bracketing the predictions at large return periods. This is also accomplished by a Monte Carlo routine in which the same number of storms (as was measured) is randomly selected from the Type I distribution and refitted. This is repeated thousands of times to produce the confidence limits.

The 95% confidence limits indicate a maximum wind speed of about 121 mph for a 10,000-year mean recurrence interval. This non-thunderstorm upper limit falls below 124 mph, which shows that our recommended design speed covers the expected range of uncertainty.

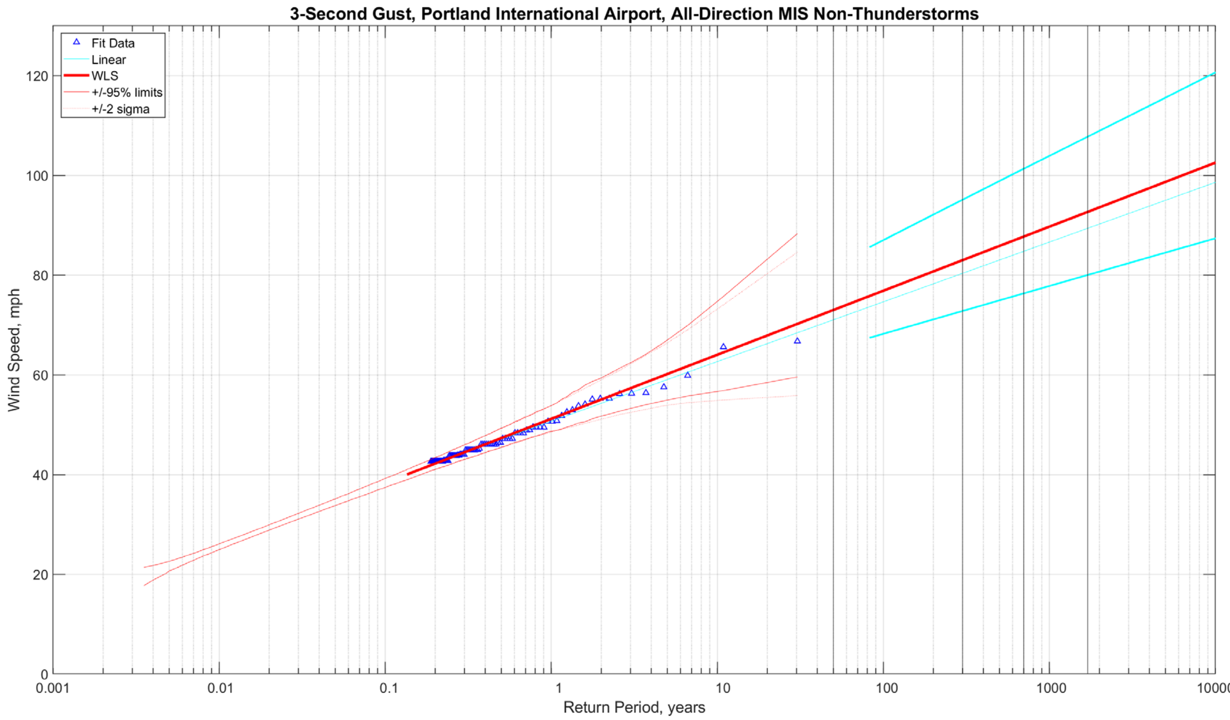

Figure 4. Range of predicted wind speeds for the Portland LNG Facility.

Based on the site-specific data, CPP has developed an extreme wind climate model with the following design speed for the Portland LNG Facility.

10,000-year mean return interval – 124 mph (3-second gust, 33 feet, Exposure category C)

EXPOSURE CATEGORY ANALYSIS, K_Z

To determine the exposure requirements at the project location, a site-specific analysis was performed using the guidelines of ASCE 7-16 and an ESDU Internal Boundary Layer model (ESDU 1993). Several parameters affect the determination of wind speed in the neutrally stable atmospheric boundary layer: geographic location and the reference wind speed, the height above the ground, surface roughness changes upwind and at the site, and the surrounding topography. All of these parameters were included in the analysis to determine the appropriate exposures at the project site. This analysis used aerial and satellite imagery to identify roughness heights and fetch lengths.

ASCE 7-16 requires that a structure be designed for each wind direction considered using an exposure category that is "based on ground surface roughness that is determined from natural topography, vegetation, and constructed facilities" (ASCE 7-16, Section 26.7). ASCE 7-16 also states "an intermediate exposure between the preceding categories is permitted in a transition zone, provided that it is determined by a rational analysis method defined in the recognized literature." ESDU is referenced in ASCE 49-12 and ASCE 7-16.

The approximate surface roughness and fetch length (the measured distance representative of the selected terrain surface roughness) values were determined to account for the effects due to local variations in surface roughness as a function of wind azimuth. These changes in roughness upwind of the site, modeled using the

ESDU Internal Boundary Layer analysis, are included in the resulting velocity pressure exposure coefficients (K_z) (reference height of 33 feet). These factors are applicable for each of their respective wind direction quadrants.

Directional K_z values, height above ground level	N	E	S	W
ASCE7 *Kz*, 33 feet	0.80	0.80	0.70	0.70
ASCE7 Exposure Category	B-C	B-C	B	B
ASCE7 Site Exposure Category	Exposure Category C applies to the project site			

ASCE 7 LOAD COMBINATIONS

The wind load coefficients of ASCE 7-16 will be multiplied by a reference velocity pressure based on the site-specific design parameters outlined above as determined for the LNG facility. In addition, Chapter 2 of the ASCE 7-16 standard provides load combinations to be evaluated with the wind load represented as *W*:

- From 2.3.2, for Strength Design (LRFD): 1.0*W*
- From 2.4.1, for Allowable Stress Design (ASD): 0.6*W*

Wind speeds in ASCE 7-16 are provided for each Risk Category that are directly applicable for determining pressures for strength design. For traditional allowable stress design, the applicable load factors (such as 0.6 in ASCE 7-16) specified by the appropriate code or standard can be applied. It is the responsibility of the structural engineer to choose and apply the combinations correctly.

The 7-05 standard load combinations with the wind load represented as *W* are:

- From 2.3.2, for Strength Design (LRFD): 1.6*W*
- From 2.4.1, for Allowable Stress Design (ASD): 1.0*W*

In ASCE 7-05, Strength Design (LRFD) includes a factor of safety in its load combinations (1.6*W*). The purpose of this load factor is to factor up design wind loads to a higher recurrence interval since the ASCE 7-05 wind maps were developed and based on nominal 50-year mean recurrence intervals.

Therefore, to be able to properly utilize the load combinations specified in section 2.3 and 2.4 of ASCE 7-05 the 10,000-year design wind speed, 124 mph, must be reduced by a factor of $\sqrt{1.6}$ or the design wind pressure must be reduced by a factor of 1.6, so that when the ASCE load combinations are utilized the structure design is performed according to a 10,000-year MRI and not an MRI that is significantly higher than the required 10,000-year design point.

SUMMARY

The analysis presented above provides the appropriate design wind speeds as a function of return period for structural design of the Portland LNG Facility located in Portland, Oregon.

Based on the data presented above, CPP has developed and recommends the following design wind speeds for the Newport Facility; consistent with the requirements of 49 CFR 193.2067 (b)(2)(ii) for a 10,000-year mean recurrence interval (0.5 percent probability of exceedance in 50 years):

Design Wind Speed – 124 mph (3-second gust, 33 feet, Exposure Category C)

This is a strength-level wind speed to be used as such in the ASCE 7-16 load combinations. The design wind speed and the extreme wind speed analysis methods used in this study comply with the code requirements. The recommendations are based on identical extreme value statistical analyses that provided the basis for the ASCE 7 wind maps over the past two decades (Peterka and Shahid 1998).

Our analysis and recommendations are based on extensive experience performing wind climate studies throughout the world to determine design wind speeds as a function of return period. CPP has been involved in wind engineering for more than 35 years including the use of boundary-layer wind tunnels for defining wind loads on structures (thousands of buildings and structures evaluated worldwide). CPP personnel have extensive experience in recommending design wind speeds and analyzing field meteorological data measured for this specific purpose.

Additional equations and discussion can be found in the listed references below. The techniques described throughout this report are commonly used and accepted analysis methods used by the wind engineering community as the basis for determining wind speeds for design of buildings and other structures. These techniques have been reviewed by the ASCE Task Committee on Wind Loads and were also used to develop the wind maps in ASCE 7.

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ASCE 7-10 (2010), "Minimum Design Loads for Buildings and Other Structures," Standard ANSI/ASCE 7-10, American Society of Civil Engineers and American National Standards Institute, New York.

ASCE 7-16 (2017), "Minimum Design Loads and Associated Criteria for Buildings and Other Structures," Standard ASCE/SEI 7-16, American Society of Civil Engineers and Structural Engineering Institute, Virginia.

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APPENDIX C

Nitrogen Source and Supply Evaluation

SANBORN HEAD

Building Trust. Engineering Success.

NITROGEN SUPPLY EVALUATION

PORTLAND LNG FACILITY

Portland, OR

Prepared for Northwest Natural Gas Company
Sanborn Head Project Number: 4661.04

Document #: EVAL-001

April 23, 2021
Revision A

NITROGEN SUPPLY EVALUATION

REVISION LOG

REVISION	REVISION DATE	REVISION NOTES
A	4/23/2021	Issued for NWN review and comment.

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1.0 EXECUTIVE SUMMARY

The purpose of this evaluation was to consider multiple options for supplying nitrogen (N_2) to the new cold box at the Northwest Natural (NWN) Portland LNG Facility. A daily total demand of 300 gallons per day of liquid N_2 was assumed as the basis for design. The effects of reducing demand was investigated. The following N_2 sources were evaluated.

1. Bulk N_2 Storage Tank, Equipment and N_2 Provided by Airgas
2. Bulk N_2 Storage Tank, Equipment Provided by NWN and N_2 Provided by Airgas
3. N_2 Gas Generation System
4. High Pressure N_2 Gas Cylinders
5. Liquid N_2 Dewars

In summary, Options 1, 2, and 3 are viable. Options 4 and 5 are not recommended based on the demand and recurrence of refills required for the small containers. Airgas offers 7 or 10 year contracts and therefore, a period of just 7 years was selected as a basis for the cost estimates. The summary of costs are shown in Table 1.0.1 for a range of N_2 demand.

Table 1.0.1: Estimated Cost of Ownership After 7 Years

Option 1: Bulk N_2 (Airgas)	(300 GPD N_2)	(200 GPD N_2)	(100 GPD N_2)
Capital Cost	$ 30,000	$ 30,000	$ 25,000
Monthly Cost	$ 5,800	$ 4,600	$ 3,100
Estimated Cost after 7 Years	**$ 517,200**	**$ 416,400**	**$ 285,400**
Option 2: Bulk N_2 (NWN Owned)	(300 GPD N_2)	(200 GPD N_2)	(100 GPD N_2)
Capital Cost	$ 524,200	$ 434,100	$ 283,600
Monthly Cost[Note 1]	$ 1,400	$ 1,100	$ 690
Estimated Cost after 7 Years	**$ 641,800**	**$ 526,500**	**$ 341,560**
Option 3: N_2 Generation (Atlas Copco)	(300 GPD N_2)	(200 GPD N_2)	(100 GPD N_2)
Capital Cost[Note 2]	$ 301,200	$ 301,200	$ 301,200
Monthly Cost	$ 1,400	$ 1,350	$ 1,300
Estimated Cost after 7 Years	**$ 418,800**	**$ 414,600**	**$ 410,400**

General Notes:

a. Costs do not include facility distribution piping. It is assumed facility distribution piping costs are the same between Options 1, 2, & 3.
b. Density of 6.7 lb/gallon Liquid N_2
c. Maintenance costs are not included, although considered minimal and will primarily include instrumentation maintenance and tank coatings.

Notes:

1. Assumes the same bulk delivery fees as Option 1.
2. Assumes installation of 10' x 15' heated enclosure with foundation & power. Capital equipment cost for entire range of gas demand utilizes the same equipment and is sized for 300 GPD N_2.

The capital costs are broken out in Table 1.0.2 for only the 300 gpd demand for all options to provide insight into the assumptions made for equipment, installation, and engineering/supervision.

Table 1.0.2: Estimated Capital Cost Breakout for 300 GPD N_2 Demand			
Description	**Option 1: Bulk N_2 (by Airgas)**	**Option 2: Bulk N_2 (by NWN)**	**Option 3: N_2 Generator (Atlas Copco)**
Equipment	$ -	$ 390,400	$ 80,300
Installation	$ 30,000	$ 78,100	$ 172,300
Engineering/Construction Supervision	$ -	$ 55,700	$ 48,600
Total	**$ 30,000**	**$ 524,200**	**$ 301,200**

Additionally, advantages and disadvantages of Options 1, 2, and 3 are listed in Table 1.0.3.

Table 1.0.3: Advantages and Disadvantages of the Viable Options	
Option 1: Bulk N_2 System (Provided by Airgas)	
Advantage	**Disadvantage**
Simple system	Additional risk from additional cryogenic fluids on site
Fixed price	Installation of foundation
No external building and associated support equipment required	Dependent on AirGas
Minimal power requirement	-
Capital cost expenditure is primarily spread over 7 years due to AirGas contract.	-
Low cancellation costs (prorate of installation fee, only) & Airgas takes their equipment back	-
Minimal to no maintenance required by NWN staff	-
Higher purity N_2 supply (99.995 is lowest quality N_2 provided by Airgas)	-
Redundant vaporizers.	-
Option 2: Bulk N_2 System (Provided by NWN)	
Advantage	**Disadvantage**
All in Option 1 unless otherwise stated	All in Option 1 unless otherwise stated
Ability to shop for best liquid nitrogen price	Responsible for calling in deliveries
-	Responsible for maintenance and operation
-	Installation cost for entire system is expended at installation
N_2 Generation System	
Advantage	**Disadvantage**
NWN would own the system.	May require additional enclosure
NWN would own the nitrogen supply.	Enclosure would require heat, lighting, and gas detection depending on location
Additional enclosure could be provided for other uses.	More complex system with wearing components, fluids, and media. Potential for oil carryover if oil removal systems are not maintained/performing properly.
May utilize existing compressed air system as backup compressed air supply to the N_2 generation system if existing instrument air compressors have available capacity.	Potential for lower purity N_2 (vendor commits to 99.000% purity output).
	No redundancy unless multiple compressor sets or N_2 generation towers are purchased

2.0 EVALUATION ASSUMPTIONS

Table 2.0.1 summarizes the N_2 demand assumptions for this evaluation.

Table 2.0.1: Estimated N2 Demand		
Equipment	**Demand**	
-	*gpd (liquid N_2)*	*SCFM N_2 Gas*
Cold Box Continuous Purge[Note 1]	130 - 200	7 - 13
Maintenance, Average Continuous Use[Note 2]	100	6
Grand Total	**230 - 300**	**7 - 19**

Notes:
1. Estimated minimum liquid N_2 demand per Cosmodyne is 130 gpd. Observed liquid N_2 demand for cold box purge is up to 200 gpd.
2. Assumed. This requirement may be reduced pending actual maintenance use.

Other assumptions made for this evaluation are as follows:

1. A minimum of 99.0 % purity N_2 gas is required at each end use, based upon specification included in previous liquefaction vendor quotations.

3.0 OPT 1: BULK N_2 PROVIDED BY AIRGAS

3.1 Contact

Airgas was contacted to investigate all options considered in this evaluation and ultimately, recommended a liquid N_2 storage tank based on their experience and the estimated demand. The contact to Airgas Bulk Gas Specialist is:

Jim Graber
Bulk Gases Specialist – N OR & SW WA
Airgas USA, LLC – Nor Pac Region
Cell: (503)703-3722
jim.graber@airgas.com

3.2 Summary of Info Received

The system configuration recommendation from Airgas consisted of information received during telephone calls and emails. The basic specification information received is outlined below:

1. 1 x 11,000 gallon tank with capacity for 1.2 MMSCF N_2 gas
2. 2 x 100% Ambient Vaporizers
3. 1 x Telemetry System
4. Pressure Control & Manifolds
5. Installation

11,000 Gallon Tank: Airgas would own the above ground assets while NWN would pay a monthly fee for the equipment. There are options for 7 or 10 year contracts with some pricing advantage to a longer contract of about $150± per month. If NWN terminates the contract early, NWN is responsible to pay the balance of the installation costs, pro-rated.

Installation costs should be assumed $20,000± and are included in the monthly fee. NWN would be required to provide piping up to the Airgas system and Airgas would perform the final connection. The fee for the equipment is approximately $1,600/month and the cost of delivered gas would be approximately $0.45/100 SCF N_2 Gas.

3,000 Gallon Tank: If N_2 demand is reduced to 100 gpd liquid, a 3,000 gallon tank would satisfy the Facility. A smaller tank would reduce the monthly fee but increase the delivered cost of liquid N_2, over the 11,000 gallon tank option. Assuming installation costs are similar, the fee for the equipment is approximately $900/month and the cost of delivered gas would be approximately $0.58/100 SCF N_2 Gas.

General: N_2 deliveries are limited to a maximum of 600,000 SCF. Airgas' proposed scope of supply includes level instrumentation and a telemetry system which is monitored remotely by Airgas to ensure N_2 deliveries are schedule as required to maintain the storage tank at least 20%-30% full. Any maintenance required to the bulk N_2 storage system would be provided by Airgas, including unscheduled maintenance due to equipment failures. Airgas communicated the majority of Airgas customers lease the bulk N_2 system equipment.

4.0 OPT 2: BULK N_2 PROVIDED BY NWN

4.1 General Summary

Equipment costs were developed for a bulk nitrogen system provided by NWN based on Sanborn Head's previous experience with owner installed bulk nitrogen storage systems. All equipment costs were assumed the same for each N_2 demand with exception of tank costs. Tank costs were scaled to arrive at two tank sizes to match Airgas offerings: 11,000 gallons and 3,000 gallons for the 300 gpd and 100 gpd N_2 demands, respectively. A mid-range tank size of 7,000 gallons was assumed to develop the capital equipment costs to support the 200 gpd N_2 demand.

Airgas typically provides 3-year supply contracts and would include an Airgas supplied telemetry (as required) to automatically schedule deliveries. The telemetry unit would be approximately $50 per month on top of any other contract charges. Airgas cited minimal delivery and supply contract pricing advantage over Option 1. Therefore, Option 2 assumes the same delivery and supply costs as Option 1.

5.0 OPT 3: N_2 GENERATION SYSTEM

5.1 Contact

Atlas Copco was solicited to provide budgetary information for a 31 SCFM nitrogen generation system. The primary contact used at Atlas Copco was:

Jeff Boutwell
Sales Engineer
Atlas Copco Compressors LLC
75 Rio Vista Street
Billerica, MA 01862
Phone: 401-439-4676 - Mobile: 401-439-4676
E-mail: Jeff.Boutwell@us.atlascopco.com

5.2 Summary of Info Received

A rotary screw compressor with minimum base load capacity of 31 SCFM and a nitrogen generation tower was proposed. The molecular sieve media within the tower is designed to last between 15 and 20 years. This is accomplished by ensuring the compressed air is as clean as possible before it enters the tower. Therefore, three stages of filtration are provided between the air compressor and the mole sieve.

The molecular sieve material is only worn or fouled when other contaminates such as oil are able to pass into the molecular sieve. Thus, the importance of maintenance is high. It was reported the cost of the mol sieve material is 40% of the generator, or $21,000 not including installation or markup. This mol sieve replacement cost could be considered as a contingency when comparing the cost of this system to other solutions.

All equipment can be provided loose from Atlas Copco but can also be provided within a skidded enclosure. A quotation was requested from Atlas Copco, but as of this writing, has not been received. For more information on costs of the loose equipment, refer to Appendix A.

6.0 OPT 4: HIGH PRESSURE N_2 GAS CYLINDERS

6.1 Contact

One Airgas store in the Portland area was contacted to inquire about the largest size of high pressure gas N_2 cylinders. The contact used was:

Airgas Store
3632 N.E. Columbia Blvd.
Portland, OR 97211
(503) 288-2527

6.2 Summary of Info Received

The largest gas cylinder available is a 300 CF cylinder weighing approximately 200 pounds when full. The cylinder is approximately 5' high and 9" in diameter. These cylinders have a compressed N_2 gas volume of 300 ft^3 when full. Pickup and delivery of 6-packs of these cylinders can be provided by Airgas.

6.3 Evaluation

Based on the estimated N_2 demand, the use of gas cylinders is not practical and was not investigated further.

7.0 OPT 5: LIQUID N_2 DEWARS

7.1 Contact

One Airgas store in the Portland area was contacted to inquire about the largest size of liquid nitrogen dewars. The contact used was:

Airgas Store
3632 N.E. Columbia Blvd.
Portland, OR 97211
(503) 288-2527

7.2 Summary of Info Received

Dewar size available from Airgas in the Portland area range from 1 liter (smallest) to 180 liters (largest). 180 liters is equivalent to 48 gallons of liquid N_2. Pickup and delivery of 6-packs of these cylinders can be provided by Airgas.

7.3 Evaluation

Based on the estimated N_2 demand, the dewars would require frequent refilling/replacement and would not provide the Facility with sufficient supply contingency. For example, at 300 gpd demand and assuming the dewars would be delivered in 6-packs, one 6-pack would satisfy demand for only approximately one day. Alternatively, fulfilling the cold box purge requirement of 100 - 200 gpd during liquefaction operation would consume a 6-pack every 2-3 days during liquefaction operation.

The costs for utilizing dewars were not investigated further.

APPENDIX A

Atlas Copco Nitrogen Generator Budgetary Quotation

Sanborn Head & Associates, Inc.

Jonathon Hillman

Quote no 2182491
03/17/2021

Contact: Jonathon Hillman
Company: Sanborn Head & Associates, Inc.
Address: 20 Foundry Street
Concord NH 03301
Phone: +1 413-834-2338
Email:

Dear Jonathon Hillman

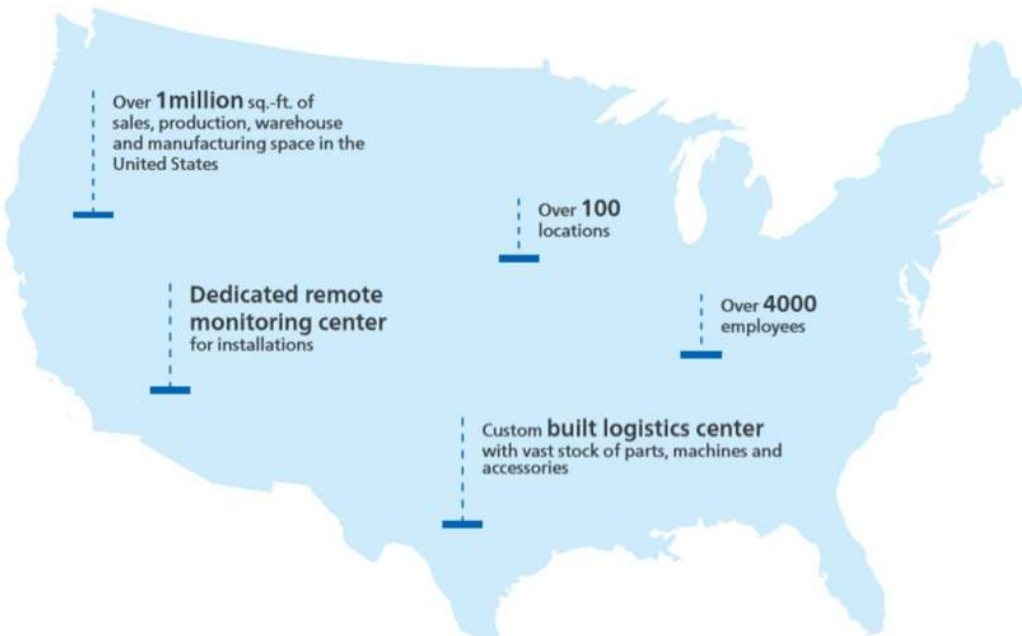
Thank you for your recent enquiry. Further to our discussions, please find enclosed our quotation as per your requirements.

We trust the enclosed information is of interest and look forward to hearing back with your comments. If you require any further information on this or any of our products or services, please do not hesitate to contact me.

Best Regards,

Jeff Boutwell
Sales Engineer
Mobile: +1 401-439-4676
jeffery.boutwell@atlascopco.com

The Atlas Copco Group in the **United States**



Proud to be 1st

- ★ Air compressor manufacturer to be awarded ISO 8573-1 CLASS 0 certification.
- ★ Air compressor manufacturer to launch integrated Variable Speed Drive (VSD) compressors.
- ★ Air compressor manufacturer to launch full feature compressors with integrated dryers.
- ★ Air compressor manufacturer to launch an electronic control and monitoring system.
- ★ The only air compressor manufacturer to have been listed in the world's Top 100 Sustainable companies on five separate occasions.

Contents

Price Summary

Product Number	Description	Qty	Unit Value (USD)	Total Price (USD)
8102317701	NGP40+ % CSA Model: NGP40+ Purity Indicator: Percentage Probe (95%-99.9%) Nitrogen Flow Rate:32 cfm @ 99% purity 100 psi Nitrogen Purity: 99% Nitrogen PDP Sensor Supply Voltage: 115-230 V Weight: 1506 lbs. Electrical Approval: CSA-UL Footprint: 55.1"L x 33.1"W x 79.3"H	1	51,146.40	51,146.40
8153171015	GA18VSD+ FF API 460V 60 Oil Injected Screw Compressor - Air Cooled -Capacity: 131.0 CFM @ 102 PSI -Motor: 25HP, Permanent Magnet IE5 Motor and Yaskawa Drive - Voltage: 460V/3ph/60Hz -179 PSI Maximum Operating Pressure -Advanced Microprocessor Control: Elektronikon Touch -Long Life RDX (Roto Duty Extend) Synthetic Oil -Full Feature Model: Integrated refrigerant dryer -Footprint: 49"L x 31"W x 63"H	1	23,667.60	23,667.60
8102297838	High efficiency coalescing filter UD45+ (NPT 1)	1	465.00	465.00
8102296897	QDT 45 Carbon tower NPT-THREAD	1	1,745.40	1,745.40
8102264044	PDP50+ (NPT 1)	1	271.20	271.20
1280567301	240 Gallon 200Psi rated vertical air & Nitrogen receivers	2	1,212.00	2,424.00
1280585377	Gauge & Safety relief valve for receivers	2	80.40	160.80
8102044040	EWD 50 Zero air loss drain	1	212.40	212.40
8102264028	Final Filter PDP35+ (NPT)	1	246.60	246.60
	Grand Total (excl VAT) USD			**80,339.40**

Payment & delivery conditions

Quote valid to:	04/16/2021
Commissioning:	Not included unless otherwise noted
Installation:	Not included unless otherwise noted
Warranty:	See Standard Conditions of Sale
Payment terms:	30 days net
Delivery time:	12-18 weeks ARO
Incoterms & location:	EXW - Rock Hill

Delivery Terms Equipment will be delivered in our standard packaging unless otherwise stated (off-loading and positioning to be done by others). Optional items may impact delivery. Delivery time can be confirmed upon acceptance of your order/final instructions to proceed.

GA 18-37 VSD$^+$ PLUS PRODUCT DESCRIPTION

ATLAS COPCO COMPRESSORS

Overview

The revolutionary new GA 18-37 VSD+ is packed with innovative features that increase its efficiency, cuts its energy consumption, lowers its noise levels, and reduces its operating costs. On top of that, it meets or even exceeds all currently applicable efficiency standards. With its innovative vertical design, Atlas Copco's GA 18-37 VSD+ brings a game-changing revolution in the compressor industry. It offers Variable Speed Drive+ as standard, a compact motor and footprint thanks to its in-house design and iPM (interior Permanent Magnet) technology. The GA 18-37 VSD+ **reduces energy consumption** by **50%** on average, with uptimes assured even in the harshest operational conditions. The GA 18-37 VSD+ is the air compressor of the future, designed in-house by Atlas Copco. It will set a new standard for years to come, positioning Atlas Copco as a leader in the compressed air industry. As standard, these units are designed to operate in 46°C/115°F ambient conditions and are available as Full Feature that includes an integrated dryer.

The GA 18-37 air compressors are available in 25hp, 30 hp, 35hp, 40hp and 50hp variants with flows ranging from 31.2 to 246.4 cfm.

These compressors are constructed with the following major components:

- State of the art compression element
- The patented, oil cooled, IP66 (NEMA4X) motor exceeds all IEEE and NEMA Premium efficiency standards
- Elektronikon® Touch graphic controller
- High efficiency aftercooler
- Innovative cooling fan
- Moisture separator
- Inlet air filter
- **Full Feature** includes an integrated refrigerated air dryer using environmentally friendly R410a refrigerant.

GA 18 VSD PLUS 175FF

ATLAS COPCO COMPRESSORS

Model: GA18VSD+ 175 AFF

	58 psi	102 psi	138 psi	181 psi	Unit
Inlet conditions					
1. Barometric pressure	14.5	14.5	14.5	14.5	psi(g)
2. Ambient air temperature	68	68	68	68	°F
3. Relative humidity	0	0	0	0	%

Performance [(1)]					
1. Operating pressure	80	102	138	181	psi(g)
2. Capacity delivered @ min rpm	31.8	31.2	35.8	48.5	cfm
3. Capacity delivered @ max rpm	134.0	131.0	112.4	91.2	cfm
4. Package power input @ min rpm	5.9	7.6	10.1	15.0	kW
5. Package power input @ max rpm	20.9	24.7	23.5	24.1	kW
6. Sound level [(2)]	67	67	67	67	dB(A)
7. Minimum ambient temperature	34	34	34	34	°F
8. Maximum ambient temperature	115	115	115	115	°F

Cooling data		
1. Cooling air flow	2,755	cfm
2. Cooling air flow (dryer)	889	cfm
3. Discharge air temperature (ambient + °F)	9	°F

Electrical data		
1. Motor	25	hp
2. Motor type	Synchronous Interior Permanent Magnet	
3. Enclosure	IP66	
4. Efficiency	94.8	%
5. Bearing	Anti-friction	
6. Insulation	F w/ B rise	
7. Starter type	Soft Start	

Physical data		
1. Dimensions (L x W x H)	49.7x30.7x62.6	inches
2. Shipping weight	1277	Lbs.
3. Air discharge size	1	inches NPT
4. Condensate drain size	6	mm.
5. Oil sump capacity	3.7	gallons

1. Performance (free air delivery) measured according to ISO1217.

2. Operating Sound Level: Operating sound levels for machines equipped with recommended standard motors and enclosures are guaranteed ±3 dB(A) when measured in free field conditions at a distance of 1 meter according to CAGI PNEUROP Test Code.

UD+ Coalescing Filters

Filtration

This revolution in filters utilizes our Nautilus technology to combine the traditional 2 stages of coalescing filters into a single stage filter.

The exciting part of this combination filter is the performance.

This single filter has a 40% lower pressure drop than the traditional 2 filters in series set-up and it does this without compromising on performance.

Independent testing according to ISO 12500-1:2007 and ISO 8573-2:2007 show that the new UD+ Filter provides the same quality air class by achieving 0.0009 ppm oil levels.

Capacities

The UD PLUS range of cast filters can handle flow rates up to 1165 cfm @ 100 psi and are available with threaded connections ranging from 3/8” to 3”.

Product Highlights

1. Superb cost savings

- 40% lower pressure drops
- Single filter installation costs
- Low energy consumption
- Large effective filtration areas
- Low resistance to the air flow

2. Optimal filtration

- Exceptional flow path through housing and cartridge
- Limited system operating costs
- Considerable reduction of air turbulence and pressure drop

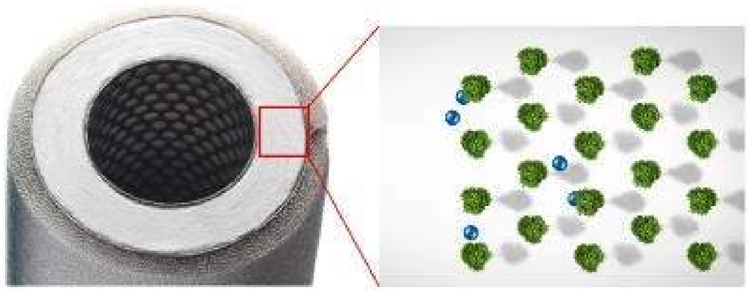
3. Reliable filtration

- High performance stainless steel filter cores ensure reliable performance of the elements
- Internal ribs to protect the element from damage and route oil droplets
- Automatic drain designed for ultimate performance

4. Operational ease

- Small footprint
- Sight glass provides for easy monitoring
- Push on element
- Audible alarms for unseeled housings

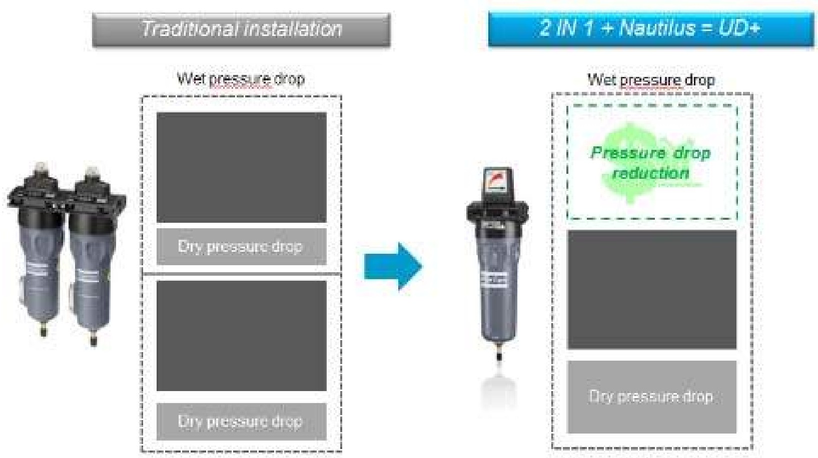
Nautilus Filter Technology

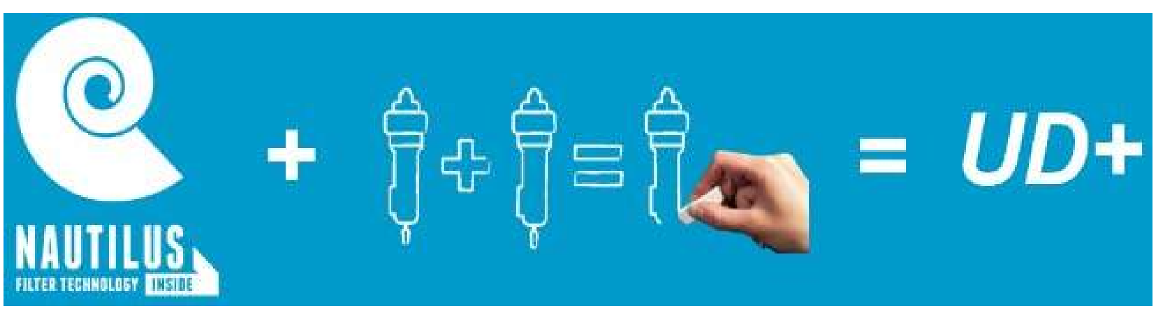


After years of research and development, Atlas Copco has created the UD+. By utilizing a large number of open layers of wrapped glass fiber media Atlas Copco have been able to reduce the pressure drop of the standard coalescing filter while maintaining oil removal performance. This reduction has allowed for the combination of 2 filter stages into one which has created a coalescing filter with an unrivaled wet pressure drop.

Low Pressure Drop

Before the UD+, (2) filters were needed to meet the 0.01 micron oil removal requirements of most applications. The 40% lower pressure drops that the UD+ has over this (2) filter configuration means reducing the energy costs of your compressed air system





NGP+ N2 Generator (8-100)

PSA Nitrogen Generator

Product Description

On-site industrial gas generators offer a more sustainable and cost-efficient solution than gas delivered in cylinders or bulk liquid supply, which require transport, handling and resulting administration. The NGP+ nitrogen generator simply plugs into an existing compressed air installation and offers an independent, reliable and flexible supply of nitrogen.
The new NGP+ sets new standards in efficiency with Air-to-Nitrogen ratios from:

1,8 (95% N2)
5,5 (99,999% N2)

On-site vs. liquid or bottled

- Your own independent supply of industrial gas
Non-stop availability: 24 hours a day, 7 days a week
- Significant economies of scale and lower operational costs: no rental charges, transport expenses and bulk user evaporation losses
- No safety hazards when handling high-pressure cylinders
- Easy integration within existing compressed air installations

The ultimate energy Saver

In addition to a standby mode which stops the generator when there is no demand, the NGP+ utilizes a unique purge control algorithm that can extend cycle times at low nitrogen demand. This reduces air consumption at low nitrogen flow rates and cooler inlet temperatures resulting

Exceptional Convenience

- Low installation and running cost – highly efficient technology.
- No additional costs such as order processing, refills and delivery charges.
- Virtually service free.
- Quick pay back – often less than a year compared to bulk N2.

Ready to use

- Plug-and-play
- No specialist installation
- Fully automated and monitored including oxygen sensor and flow meter as standard

High Flow capacity

The wide product range and nitrogen flows up to 6050 cfm makes the NGP series ideal for applications such as food processing, pharmaceutical, metal industry, oil & gas, marine, packaging and many more.

Self Regulating

System includes a minimum pressure valve with by-pass nozzle for fast start-up and when running automatically regulates to the requested nitrogen pressure and purity. This simplifies the process and makes it extremely easy to change purity. It also allows for off-spec nitrogen flushing

Highest Quality CMS

The Carbon molecular sieve used in the NGP+ has been selected for maximum performance. It has been packed to a high density and kept compact by spring loading.

Controls

By properly monitoring your nitrogen/oxygen system you can not only decrease downtime but also save energy and reduce maintenance. With an extensive array of sensors including inlet air monitoring the NGP+ in able to provide complete control and system optimization.

Extensive list standard sensors and components

- Inlet temperature
- Inlet pressure
- Inlet dewpoint
- Digital display
- Thermal mass flow meter
- Zirconium Oxygen sensor
- Outlet pressure regulator
- SmartLink remote monitoring

Remote control and connectivity functions
The controller can be started and stopped locally, via a wired remote switch. With the SmartLink Smart boxes that are supplied standard with every unit, systems can be monitored online and are available to receive alarm messages through mobile phones. Generator data through Modbus, Profibus is also optional.

QDT 45 - Oil Vapor Removal Filter - Technical Data Sheet

Reference conditions

1. Compressed air effective inlet pressure	100	psi(g)
2. Ambient air temperature	68	°F
3. Compressed air inlet temperature	95	°F
4. Oil concentration upstream of the filter (vapors)	0.35	ppm
5. Pressure dewpoint of inlet air	39	°F

Limitations for operations

1. Maximum compressed air effective inlet pressure	232	psi(g)
2. Minimum compressed air effective inlet pressure	15	psi(g)
3. Maximum ambient air temperature	122	°F
4. Minimum ambient air temperature	14	°F
5. Maximum compressed air inlet temperature	151	°F
6. Minimum compressed air inlet temperature	34	°F

Performance data (1)

1. Nominal flow at filter inlet (2)	95	cfm
2. Initial pressure drop over filter when dry	5	psi(g)
3. Maximum oil carry over (1)	0.003	ppm
4. Quality class of air at outlet of filter (3)	- - 1	

Design data

1. Number of filter elements		1	
2. Dimension of inlet and outlet connections		1	NPT
3. Net weight		33	lb
4. Shipping dimensions:	Length	9	in
	Width	7	in
	Height	28	in

(1) At reference conditions
(2) Referenced to an absolute pressure of 14.5 psi and a temperature of 60°F
(3) According to ISO 8573-1 (ed. 2010) in a typical installation
(4) High upstream concentrations of oil result in lower element lifetime and high downstream concentration of vapor

QDT Activated Carbon Tower

Filtration

In applications such as pharmaceutical, food and beverage and electronics, where air purity is critical, there is often a requirement to remove residual oil vapors and odors from the compressed air supply. Atlas Copco has developed a filter which can provide this level of clean air, known as the QDT.

This activated carbon filter is able to remove both vapors and odors down to 0.003 ppm, which is class 1 clean air according to ISO 8573-1.

Range

The QDT activated carbon towers are available for flow rates of 45 to 655 scfm, based on standard operating conditions.

Working Principle

Using two kinds of activated carbon the QDT removes oil vapour and odors through a process of adsorption. Unlike coalescing filters, which do not collect vapors, the QDT maintains a steady pressure drop of 5psi or less throughout its lifetime.

Maintenance Cost

As a direct result of being sized for real site conditions, the life of the QDT elements will be at least 4,000 hours and up to 6,000 hours. Ultimately this means not only better performance, but much cheaper maintenance costs too.

Ultimate Performance

Unlike other carbon based filters, the QDT is sized for real life. There are many look alike products which have a similar performance rating but for inlet temperatures of just 68°F. The QDT is designed and sized for an inlet temperatures of 95°F, meaning it will actually delivery the performance expected continuously, all year round.

Easy to use

The QDT filters can be either floor or wall mounted and can be banked together to accommodate larger flows. Additionally, the units can be fitted with a maintenance indicator, ensuring the consumables are changed before they become saturated and downstream processes contaminated.

EWD – Zero Air Loss Drain

Condensate Drain

Atlas Copco's range of EWD electronically controlled condensate drains is synonymous with safe, dependable and economical condensate management.

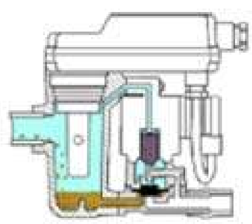
The intelligent drain function monitors condensate build-up with liquid level sensors and evacuates the condensate only when necessary, thereby avoiding compressed air waste and providing for considerable energy savings.

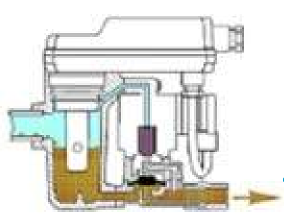
The EWD drain device offers security and confidence, enabling you to solve all condensate discharge problems even in heavily contaminated systems.

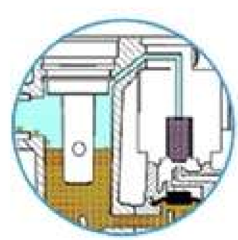
How is an EWD better than a timer operated drain?

Atlas Copco's EWD range is superior to timer operated drains in several key ways. First, Atlas Copco's EWDs have wide passage ways and timer operated drains have narrow ones; narrow passage ways increase the likelihood that the unit will become blocked, thereby not allowing the unit to drain properly. Second, timer operated drains are inferior in their design and often result in drains becoming stuck open, which wastes air and decreases overall efficiency. Lastly, timer controlled drains open at constant intervals and each time they open, an average of 25cfm of compressed air is wasted, which can become very expensive; Atlas Copco's EWDs wastes absolutely no compressed air.

The EWD Process







1. Condensate enters the drain and collects in the sump.
2. The diaphragm valve is closed due to the solenoid valve allowing pressure compensation through the pilot supply line. The pressurized space above the diaphragm is larger than that below it, ensuring and absolutely leak-proof seal.
3. Once the condensate level reaches the upper limit the solenoid valve is engaged, closing the pilot supply line.
   The pressure on top of the diaphragm is allowed to escape and the diaphragm lifts off the valve seat.
4. Then the pressurized condensate forces its way into the discharge pipe.
5. As the condensate drains away, the level probe monitors the speed at which the level drops, calculating exactly when to shut the diaphragm so that no air escapes.
6. If a problem develops, such as a blocked outlet or faulty diaphragm, the drain switches to "fault mode". Both the flashing alarm light and the volt free contact are activated and the drain switches to a "timer" mode until the problem is resolved.

Model: EWD 50 (A)

Limitations for operations		**EWD 50 (A)**	
1. Minimum working pressure		11.6	psi(g)
2. Maximum working pressure		232	psi(g)
3. Minimum allowable inlet temperature		34	°F
4. Maximum allowable inlet temperature		140	°F
5. Suitable for oil free condensate		Yes	

Reference conditions A		
1. Relative air humidity	90	%
2. Ambient air temperature	104	°F
Performance data (1) (*for reference conditions A*)		
1. Maximum compressor capacity		
- without integrated dryer	106	cfm
- with integrated dryer	70	cfm
2. Maximum refrigeration dryer capacity	212	cfm
3. Maximum filter capacity	1059	cfm

Reference conditions B		
1. Relative air humidity	70	%
2. Ambient air temperature	95	°F
Performance data (1) (*for reference conditions B*)		
1. Maximum compressor capacity		
- without integrated dryer	138	cfm
- with integrated dryer	91	cfm
2. Maximum refrigeration dryer capacity	275	cfm
3. Maximum filter capacity	1377	cfm

Design data			
1. Dimension of compressed air connections:	Inlet	½	G/NPT
	Outlet	¼	G/NPT
2. Net weight		1.5	lb
3. Power consumption		2	W
4. Dimensions: Length		6.7	in
Width		2.8	in
Height		4.5	in
5. Shipping dimensions: Length		7.1	in
Width		5.1	in
Height		3.5	in
6. Shipping weight		2.2	lb

(1) At reference conditions
(2) Referred to an absolute pressure of 1 bar and 20°C
(3) According to ISO 8573-2 in a typical installation

Atlas Copco PLUS Filters		**DD+35**	**DDp+35**	**PD+35**	**PDp+35**	**QD+35**	
Reference conditions							
Compressed air effective inlet pressure		102	102	102	102	102	psi(g)
Ambient air temperature		68	68	68	68	68	°F
Compressed air inlet temperature		68	68	68	68	68	°F
Principle Data							
Compressed air inlet pressure	Max	232	232	232	232	232	psi(g)
	Min	15	15	15	15	15	
Compressed air inlet temperature	Max	151	151	151	151	95	°F
	Min	34	34	34	34	34	
Ambient temperature	Max	149	149	149	149	95	°F
	Min	34	34	34	34	34	
Recommended pressure drop	Max	5	5	5	5	-	psi
Specific data *(At reference conditions)*							
Rated Flow		74	74	74	74	74	cfm
Pressure drop element - DRY		0.9	0.9	1.1	1.1	1.9	psi
Pressure drop element - WET							
Challenge/inlet oil concentration (ppm) =	0.1	-	-	2.4	-	-	psi
Challenge/inlet oil concentration (ppm) =	3	2.2	-	2.7	-	-	psi
Challenge/inlet oil concentration (ppm) =	10	2.2	-	2.8	-	-	psi
Challenge/inlet oil concentration (ppm) =	40	2.4	-	2.9	-	-	psi
Pressure drop filter + element - DRY		1.2	1.2	1.4	1.4	2.0	psi
Pressure drop filter + element - WET							
Challenge/inlet oil concentration (ppm) =	0.1	-	-	2.8	-	-	psi
Challenge/inlet oil concentration (ppm) =	3	2.5	-	3.0	-	-	psi
Challenge/inlet oil concentration (ppm) =	10	2.6	-	3.1	-	-	psi
Challenge/inlet oil concentration (ppm) =	40	2.8	-	3.3	-	-	psi
Oil carry-over (PD+ - DD+ Aerosol / QD+ Vapor)							
Challenge/inlet oil concentration (ppm) =	0.01	-	-	-	-	0.003	ppm
Challenge/inlet oil concentration (ppm) =	0.1	-	-	< 0.001	-	-	ppm
Challenge/inlet oil concentration (ppm) =	3	0.02	-	0.002	-	-	ppm
Challenge/inlet oil concentration (ppm) =	10	0.07	-	0.008	-	-	ppm
Challenge/inlet oil concentration (ppm) =	40	0.28	-	0.03	-	-	ppm
Micron Rating		**1.0**	**1.0**	**0.01**	**0.01**	**n/a**	
Count efficiency	MPPS	MPPS=0.1µm - 99.92		MPPS=0.06µm - 99.98		-	%
	1 µm	99.998	99.998	> 99.999	> 99.999	-	%
	0.01 µm	99.94	99.94	99.995	99.995	-	%
ISO 8573-1:2010 Class		**2:-:2**	**2:-:-**	**1:-:2**	**1:-:-**	**1:-:1**	
NOTE		Testing per ISO-12500-1, ISO-12500-1. QD+ performance is after DD+/PD+ filters					
Design data							
Number of filter elements							
Dimension of inlet and outlet connections		1-Jan	1-Jan	1-Jan	1-Jan	1-Jan	
Net weight		1/2	1/2	1/2	1/2	1/2	G/NPT
Shipping weight		2.9	2.6	2.9	2.9	2.4	lb
Shipping dimensions:	Length	3.1	3.1	3.1	3.1	2.9	lb
	Width	16	16	16	16	16	in
	Height	4	4	4	4	4	in

Correction Factors

Working pressure (psig)	14.5	29	43.5	58	72.5	87
Correction factor	0.38	0.53	0.65	0.75	0.83	0.92
Working pressure (psig)	101.5	116	145	174	203	232
Correction factor	1	1.06	1.2	1.31	1.41	1.5

Atlas Copco PLUS Filters		DD+50	DDp+50	PD+50	PDp+50	QD+50	
Reference conditions							
Compressed air effective inlet pressure		102	102	102	102	102	psi(g)
Ambient air temperature		68	68	68	68	68	°F
Compressed air inlet temperature		68	68	68	68	68	°F
Principle Data							
Compressed air inlet pressure	Max	232	232	232	232	232	psi(g)
	Min	15	15	15	15	15	
Compressed air inlet temperature	Max	151	151	151	151	95	°F
	Min	34	34	34	34	34	
Ambient temperature	Max	149	149	149	149	95	°F
	Min	34	34	34	34	34	
Recommended pressure drop	Max	5	5	5	5	-	psi
Specific data *(At reference conditions)*							
Rated Flow		106	106	106	106	106	cfm
Pressure drop element - DRY		0.9	0.9	1.1	1.1	1.9	psi
Pressure drop element - WET							
Challenge/inlet oil concentration (ppm) =	0.1	-	-	2.4	-	-	psi
Challenge/inlet oil concentration (ppm) =	3	2.2	-	2.7	-	-	psi
Challenge/inlet oil concentration (ppm) =	10	2.2	-	2.8	-	-	psi
Challenge/inlet oil concentration (ppm) =	40	2.4	-	2.9	-	-	psi
Pressure drop filter + element - DRY		1.2	1.2	1.4	1.4	2.0	psi
Pressure drop filter + element - WET							
Challenge/inlet oil concentration (ppm) =	0.1	-	-	2.8	-	-	psi
Challenge/inlet oil concentration (ppm) =	3	2.5	-	3.0	-	-	psi
Challenge/inlet oil concentration (ppm) =	10	2.6	-	3.1	-	-	psi
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Oil carry-over (PD+ - DD+ Aerosol / QD+ Vapor)							
Challenge/inlet oil concentration (ppm) =	0.01	-	-	-	-	0.003	ppm
Challenge/inlet oil concentration (ppm) =	0.1	-	-	< 0.001	-	-	ppm
Challenge/inlet oil concentration (ppm) =	3	0.02	-	0.002	-	-	ppm
Challenge/inlet oil concentration (ppm) =	10	0.07	-	0.008	-	-	ppm
Challenge/inlet oil concentration (ppm) =	40	0.28	-	0.03	-	-	ppm
Micron Rating		**1.0**	**1.0**	**0.01**	**0.01**	**n/a**	
Count efficiency	MPPS	MPPS=0.1µm - 99.92		MPPS=0.06µm - 99.98		-	%
	1 µm	99.998	99.998	> 99.999	> 99.999	-	%
	0.01 µm	99.94	99.94	99.995	99.995	-	%
ISO 8573-1:2010 Class		**2:-:2**	**2:-:-**	**1:-:2**	**1:-:-**	**1:-:1**	
NOTE	Testing per ISO-12500-1, ISO-12500-1. QD+ performance is after DD+/PD+ filters						
Design data							
Number of filter elements							
Dimension of inlet and outlet connections		1-Jan	1-Jan	1-Jan	1-Jan	1-Jan	
Net weight		3/4 or 1	3/4 or 1	3/4 or 1	3/4 or 1	3/4 or 1	G/NPT
Shipping weight		4.2	4.0	4.2	4.2	4.2	lb
Shipping dimensions:	Length	4.6	4.6	4.6	4.6	4.4	lb
	Width	17	17	17	17	17	in
	Height	6	6	6	6	6	in

Correction Factors

Working pressure (psig)	14.5	29	43.5	58	72.5	87
Correction factor	0.38	0.53	0.65	0.75	0.83	0.92
Working pressure (psig)	101.5	116	145	174	203	232
Correction factor	1	1.06	1.2	1.31	1.41	1.5


Atlas Copco
Should you consider buying a new compressor?
What You Save On The Purchase Price Today, Can Result In Significant Costs Incurred Tomorrow.
GA15VSD+ FF

An air compressor is a long-term investment, so a smart buying decision starts with asking the right questions. You need to find out - up front - what costs you will really incur over the life of your investment.

Here's some information you'll want to gather.

1 Why do you need a new compressor?

That's the most important question to ask because sometimes you really don't need a new compressor. Maybe you need a better control system so your compressors work together more efficiently. Maybe you need an air receiver or some piping changes. Ask an Atlas Copco sales engineer to look over your air system carefully. There's no charge to help you identify exactly what you might need.

2 What is the compressor capacity, in cubic feet per minute, delivered, per brake horsepower, at the pressure required?

This is the measure of compressor efficiency. Remember, energy- not equipment- is your biggest single cost component of compressed air! You need to know how much air you get at the pressure you need, and how much energy it takes to get there.

3 Find out if a Variable Speed Drive compressor can benefit your air system.

VSD compressors continuously adjust compressed air output to match production line demand. In many applications, VSD significantly reduces energy consumption. But not all VSD compressors are the same. Only a system designed and manufactured as VSD from the ground up can provide optimal performance in all situations.

4 Get an estimate of all life-cycle costs, including energy and maintenance.

Of course the first cost component is the equipment invoice, but the much more significant cost for an air compressor is the energy it uses - month after month, for its entire operating life. Compressors that use less sophisticated technology consume more energy. Maintenance costs should be examined carefully, too, since some compressors are designed for maintenance twice as frequently as others!

5 Does your air compressor company have a Customer Satisfaction Program?

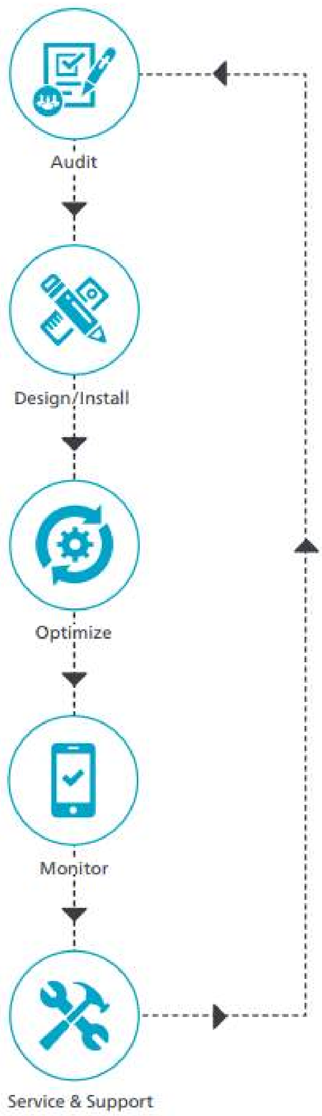
At Atlas Copco, we believe that Customer Satisfaction is the measure of how well we provide air system solutions. That's why we regularly seek feedback from customers on how they feel about the products and service we provide. Satisfied customers keep Atlas Copco a leading global air compressor manufacturer.

When you need a new compressor, remember to consider the **Big Picture...** it can save you **Big Money!**
To learn more, give Atlas Copco a call.

Atlas Copco Compressors LLC
300 Technology Center Dr. #550
Phone: +18038175774
www.atlascopco.com/airusa

Atlas Copco – The Connected Efficiency Journey

Our promise to you is we do more. And together with you, we are more! No other company offers more technologies to produce and manage air, but we don't try to be a total solutions provider and we're not a 'one-stop-shop'. Instead, we innovate in the focused areas where we are confident we can provide a complete solution that has the lowest cost of ownership, maximizing efficiency and, most importantly, offer a complete service package that is second to none.



Audit

Every air journey starts here. Our trained audit teams use ultrasonic leak detection and precision flow measurement equipment, and the non-intrusive audit system can be scaled for any operation. We learn exactly where you are now and prove what you can save. It's the backbone of our promise and what we stand behind before asking you to invest. Anybody who claims a saving based purely on product performance and not on your unique circumstances is just guessing—we like to deal solely in facts. We can help you determine if a compressor upgrade qualifies for rebates from your local electrical utility company.

Design & Install

We apply creative thinking and advanced software to design integrated air production and distribution systems. At our custom design facility in Houston, Texas, we can custom fit our products to meet your specific needs. Our designs emphasize today's efficiency with future expansion that's ready when you are. Our unrivaled experience means we know what creates a great installation, and our local team will support you. We can do a computer-designed turnkey installation of your entire system, including equipment, air treatment, and state-of-the-art piping throughout your facility, no matter the size.

Optimize

This is the biggest advancement in compressed air over the last decade. Control systems leveraged by the Internet of Things mean you no longer need to be with your machine to make it perform. Optimizer 4.0, our simple and sophisticated user interface, ensures that you're always in the know, in control and in charge of your savings. No matter how many compressors, dryers, blowers or pumps you have, you're like the conductor of the orchestra—and you make it play in perfect tune.

Monitor

Just about all Atlas Copco equipment comes with remote monitoring and diagnostic capability. Our team keeps an eye on your system and contacts you if a need arises. Most importantly, we monitor your demand and suggest savings to make you an energy efficiency rock star! You can be away from the office or take that hard-earned vacation with complete peace of mind because we've got your back. However, if you want to watch your product while away, all you need is a smartphone.

Service & Support

Help is always close at hand. Atlas Copco has over 4,000 employees across the U.S., so one of our factory trained technicians is never far away. We can dispatch them at a moment's notice and GPS technology lets you know where they are. Plus our centralized technical support team is as close as your phone. All of us work together to provide a service solution that fits your needs—whether it's doing your own maintenance or us taking full responsibility for keeping your system running.

Standard Conditions of Sale

GENERAL – Unless otherwise expressly agreed in writing by a duly authorized representative of Atlas Copco these terms and conditions supersede all other communications and agreements and notwithstanding any conflicting or different terms and conditions in any order or acceptance of Purchaser, all sales and shipments shall exclusively be governed by these terms and conditions. When used herein "affiliates" shall mean Atlas Copco AB and its wholly-owned subsidiaries. Section headings are for purposes of convenience only. "Products" as used herein shall include products, parts and accessories furnished Purchaser by Atlas Copco. Orders shall be subject to acceptance at Atlas Copco Compressors LLC's principal corporate offices in Rock Hill, South Carolina.

DELIVERY – Unless otherwise agreed in writing, Products manufactured, assembled or warehoused in the continental United States are delivered F.O.B. shipping point, and Products shipped from outside the continental United States are delivered F.O.B. point of entry. Where the scheduled delivery of Products is delayed by Purchaser or by reason of any of the contingencies referred to in Section 5. Atlas Copco may deliver such Products by moving it to storage for the account of and at the risk of Purchaser. Shipping dates are approximate and are based upon prompt receipt of all necessary information and approvals from Purchaser. Atlas Copco reserves the right to make delivery installments.

SECURITY AND RISK OF LOSS - Upon request from Atlas Copco, Purchaser agrees to execute a security agreement covering the Products sold or other assets and to perform all acts which may be necessary to perfect and assure a security position of Atlas Copco. Notwithstanding any agreement with respect to delivery terms or payment of transportation charges, the risk of loss or damage shall pass to Purchaser and delivery shall be deemed to be complete upon delivery to a private or common carrier or upon moving into storage, whichever occurs first, at the point of shipment for Products assembled, manufactured or warehoused in the continental United States or at the point of entry for Products shipped from outside the continental United States.

PAYMENT – If Purchaser fails to pay any invoice when due, Atlas Copco may defer deliveries under this or any other contract with Purchaser, except upon receipt of satisfactory security for or cash in payment of any such invoice.

A service charge of the lesser of 1% per month or the highest rate permitted by applicable law shall be charged on all overdue accounts. Failure on the part of Purchaser to pay invoices when due shall, at the option of Atlas Copco, constitute a default in addition to all other remedies Atlas Copco may have under these conditions of sale or applicable law. If, in the judgment of Atlas Copco, the financial condition of Purchaser at any time prior to delivery does not justify the terms of payment specified. Atlas Copco may require payment in advance or cancel any outstanding order, whereupon Atlas Copco shall be entitled to receive reasonable cancellation charges. If delivery is delayed by Purchaser, payment shall become due on the date Atlas Copco is prepared to make delivery. Should manufacture be delayed by Purchaser, pro rata payments shall become due if and to the extent required at Atlas Copco by its contracts with the manufacturer. All installment deliveries shall be separately invoiced and paid for without regard to subsequent deliveries. Delays in delivery or non-conformities in any installment shall not relieve Purchaser of its obligations to accept any pay for remaining installments.

FORCE MAJEURE – Atlas Copco shall not be liable for loss, damage, detention, or delay, nor be deemed to be in default from causes beyond its reasonable control or from fire, strike or other concerted action of workmen, act or omission of any governmental authority or of Purchaser, compliance with import or export regulations, insurrection or riot, embargo, delays or shortages in transportation, or inability to obtain necessary engineering talent, labor, materials, or manufacturing facilities from usual sources. In the event of delay due to any such cause, the date of delivery will be postponed by such length of time as may be reasonably necessary to compensate for the delay.

NEW PRODUCT WARRANTY – Atlas Copco warrants to the Purchaser that all stationary compressors, portable compressors, compressed air dyers, Atlas Copco-designed compressor parts and other Products manufactured by Atlas Copco and affiliates shall be free of defects in design, material and workmanship for a period of fifteen (15) months from date of shipment to Purchaser, or twelve (12) months from date of initial start-up, whichever occurs first, except as set forth below or in the New Products Warranty attached hereto.

Should any failure to conform with this warranty appear prior to or after shipment of the Product to Purchaser during the specified periods under normal and proper use and provided the Product has been properly stored, installed, handled and maintained by the Purchaser, Atlas Copco shall, if given prompt notice by Purchaser, repair or replace, the non-conforming Product or authorize repair or replacement by the Purchaser at Atlas Copco's expense.

Replaced Products become the property of Atlas Copco.

Atlas Copco warrants Products or parts thereof repaired or replaced pursuant to the above warranty under normal and proper use, storage, handling, installation, and maintenance, against defects in design, workmanship and material for a period of thirty (30) days from date of start-up of such repaired or replaced Products or parts thereof or the expiration of the original Product warranty, whichever is longer.

When the nature of the defect is such that it is appropriate in the judgment of Atlas Copco to do so, repairs will be made at the site of the Product. Repair or replacement under applicable warranty shall be made at no charge for replacement parts, F.O.B. Atlas Copco Warehouse, warranty labor, serviceman transportation and living costs, when work is performed during normal working hours (8 a.m. to 4:30 p.m. Monday through Friday, exclusive of holidays). Labor performed at other times will be billed at the overtime rate then prevailing for services of Atlas Copco personnel.

The Atlas Copco warranty does not extend to Products not manufactured by Atlas Copco or affiliates. As to such Products, Purchaser shall be entitled to proceed only upon the terms of that particular manufacturer's warranty. The Atlas Copco warranty does not apply to defects in material provided by Purchaser or to design stipulated by Purchaser.

Used Products, Products not manufactured by Atlas Copco or affiliates and Products excluded from the above warranties are sold AS IS with no representation or warranty, and ALL WARRANTTIES OF QUALITY, WRITTEN, ORAL, OR IMPLIED, other than may be expressly agreed to by Atlas Copco in writing, INCLUDING WITHOUT LIMITATION WARRANTIES OF MERCHANTIABILITY OR FITNESS, ARE HEREBY DISCLAIMED.

Any services performed by Atlas Copco in connection with the sale, installation, servicing or repair of a Product are warranted to be performed in a workmanlike manner. If any nonconformity with this warranty appears within 45 days after the services are performed, the exclusive obligation of Atlas Copco shall be to re-perform the services the services in a conforming manner.

THE FOREGOING WARRANTIES ARE EXCLUSIVE AND IN LIEU OF ALL OTHER WARRANTIES OF QUALITY, WRITTEN, ORAL OR IMPLIED, AND ALL OTHER WARRANTIES, INCLUDING WITHOUT LIMITATION ANY WARRANTY OF MERCHANTABILITY OR FITNESS ARE HEREBY DISCLAIMED. Correction of nonconformities as provided above shall be Purchaser's exclusive remedy and shall constitute fulfillment of all liabilities of Atlas Copco (including any liability for direct, indirect, special, incidental or consequential damage) whether in warranty, strict liability, contract, tort, negligence, or otherwise with respect to the quality of or any defect in Products or associated services delivered or performed hereunder.

LIMITATION OF LIABILITY – IN NO EVENT SHALL ATLAS COPCO BE LIABLE FOR SPECIAL, INDIRECT, INCIDENTAL OR CONSEQUENTIAL DAMAGES, however arising, whether in warranty, strict liability, contract, tort, negligence or otherwise, including but not limited to loss of profits or revenue, loss of total or partial use of the Products or facilities or services, downtime cost, or claims of the Purchaser for such or other damages whether on account of Products furnished hereunder or delays in delivery thereof or services performed upon or with respect to such Products. Atlas Copco's liability on any claim whether in warranty, strict liability, contract, tort, negligence or otherwise for any loss or damage arising out of, connected with, or resulting from this contract or the performance or breach thereof, or from the design, manufacture, sale, delivery, resale, repair, replacement, installation, technical direction of installation, inspection, servicing, operation or use of any Product covered by or furnished under this contract shall in no case (except as provided in the section entitled "Patent Indemnity") exceed the purchase price allocable to the Product or Part thereof which gives rise to the claim.

All causes of action against Atlas Copco arising out of or relating to this contract or the performance hereof shall expire unless brought within on year of time of accrual thereof.

PRICES – Prices to the Purchaser shall be the Atlas Copco list price in effect at time of order. Atlas Copco may, upon thirty (30) days prior written notice to Purchaser, change prices, or other terms of sale affecting the Products, by issuing new price schedules, bulletins or other notices.

This contract applies to new Products only. Purchases of used equipment shall be on terms to be agreed upon at time of sale to Purchaser.

This price does not include any Federal, state or local property, license, privilege, sales, service use, excise, value added, gross receipts, or other like taxes which may now or hereafter by applicable to, measured by or imposed upon or with respect to this transaction, the property, its purchase, sale, replacement, value, or use, or any services performed in connection therewith. Purchaser agrees to pay or reimburse Atlas Copco, its subcontractors or suppliers any such taxes, which Atlas Copco, its subcontractors or suppliers are required to pay or collect or which are required to be withheld by Purchaser.

The price shall also be subject to adjustment in accordance with the published Price Adjustment Clauses, which price adjustment information shall supersede the terms of this Section 8, where inconsistent herewith.

INFORMATION FURNISHED PURCHASER – Any design, manufacturing drawings or other information or materials submitted to the Purchaser and not intended for dissemination by Purchaser remain the exclusive property of Atlas Copco and may not, without its consent, be copied or communicated to a third party.

PATENT INDEMNITY – For purposes only of this Section 10, where used, the designation "Atlas Copco" shall be deemed to mean Atlas Copco North America Inc. and its subsidiaries.

Atlas Copco shall at its own expense defend any suits or proceedings brought against purchaser insofar as based on an allegation that Products furnished hereunder constitute an infringement of any claim of any patent of the United States of America, other than a claim covering a process performed by said Products or a product produced by said Product, provided that such Products are manufactured by Atlas Copco, are not supplied according to Purchaser's detailed design, are used as sold by Atlas Copco. Purchaser shall have made all payments then due hereunder, and Atlas Copco is notified promptly in writing and given authority, information and assistance for the defense of said suite or proceeding; and Atlas Copco shall pay all damages and costs awarded in any suit or proceeding so defended, provided that his indemnity shall not extend to any infringement based upon the combination of said Products or any portion thereof with other Products or things not furnished hereunder unless Atlas Copco is a contributory infringer. Atlas Copco shall not be responsible for any settlement of such suit or proceeding made without its written consent. If in any suit or proceeding defended hereunder any Product is held to constitute infringement, and its use is enjoined, Atlas Copco shall, at its option and its own expense, either replace said Products with non-infringing Products; or modify them so that they become non-infringing; or remove them and refund the purchase price and the transportation costs thereof. THE FOREGOING STATES THE ENTIRE LIABILITY OF ATLAS COPCO AND AFFILIATES WITH RESPECT TO PATENT INFRINGEMENT.

To the extent that said Products or any portion thereof are supplied according to Purchaser's detailed design or instructions, or modified by Purchaser, or combined by Purchaser with equipment or things not furnished hereunder, except to the extent that Atlas Copco is a contributory infringer, or are used by Purchaser to perform a process, or produce a product, and by reason of said design, instructions, modification, combination, performance or production, a suit or proceeding is brought against Atlas Copco, Purchaser agrees to indemnify Atlas Copco in the manner and to the extent Atlas Copco indemnities Purchaser in this Section 10 insofar as the terms hereof are appropriate.

ASSIGNMENT – Any assignment of this contract or any rights hereunder, without prior written consent of Atlas Copco by a duly authorized representative thereof shall be void.

TERMINATION – Any order or contract may be cancelled by Purchaser only upon payment of reasonable charges (including an allowance for profit) based upon costs and expenses incurred, and commitments made by Atlas Copco.

PARTIAL INVALIDITY – If any provision herein or portion thereof shall for any reason be held invalid or unenforceable, such invalidity or enforceability shall not affect any other provision or portion thereof, but these conditions shall be construed as if such invalid or unenforceable provision or portion thereof had never been contained therein.

REMEDIES – The remedies expressly provided for in these conditions shall be in addition to any other remedies, which Atlas Copco may have under the Uniform Commercial Code or other applicable law.

SMARTLINK: The equipment may include a data monitoring service called SMARTLINK. The data received by Atlas Copco may be used by Atlas Copco and certain third party distributors and contractors for the purpose of increasing overall customer service. Atlas Copco will use commercially reasonable efforts to ensure that Purchaser's data is kept confidential. Purchaser acknowledges that the use of the SMARTLINK is provided "as is", that use of the service is entirely at Purchaser's risk, and that Atlas Copco may discontinue the SMARTLINK service at any time. Purchaser may request discontinuance of the SMARTLINK service at any time.

NOTE: Sale of the equipment or services described or referred to herein at the price indicated is expressly conditioned upon the terms and conditions set forth on the front and back of this page. Any confirmatory action by the Purchaser hereunder, or any acceptance of such equipment of services, shall constitute assent to said terms and conditions. Any additional or different terms or conditions set forth in the Purchaser's order or other communications are objected to by Seller and shall not be effective or binding unless assented to in writing by an authorized representative of Seller.

PAYMENT TERMS

Unless expressly agreed to in writing on a specific contract or order, our standard payment terms are:

For orders under $100,000 the payment terms shall be **Net 30 days** from date of shipment.

For orders over $100,000 or with lead times greater than six months the following terms shall apply:

1. Domestic Shipments

A. 30% of order value 30 Days from date of customer's purchase order.
B. 30% of order value after passage of 1/3 of the time from date of customer's order to the originally scheduled shipment date.
C. 30% of order value after passage of 2/3 of the time from date of customer's order to the originally scheduled shipment date.
D. 10% of order value, net 30 days from date of shipment.

In those cases where progress payments are required, all work on the order will cease if payment is not received in accordance with the payment schedule.

2. Export Shipments

All export shipments are subject to purchaser arranging for an irrevocable letter of credit in favor of Atlas Copco Compressors LLC, from a recognized American bank.

Should the order fall in a category that requires progress payments, the letter of credit shall be arranged to release payment in accordance with the agreed payment schedule.

3. Payment Retention

Payment retention will not be allowed. An irrevocable bank letter of credit will be furnished at Atlas Copco's expense in lieu of retention.

4. Credit Approval

All terms are subject to credit approval by Atlas Copco Compressors LLC.

CANCELLATION SCHEDULE

Definitions:
Standard Stocked Equipment - equipment as shown in the current catalog and available for shipment from the US Distribution Center.
Standard Non-Stocked Equipment - equipment as shown in the current catalog but not currently stocked at the US Distribution Center.
Engineered Equipment - equipment requiring customized features not shown in the current catalog.

Orders for Standard Stocked Equipment
* 20% of equipment price

Orders for Standard Non-Stocked Equipment
A) Prior to release for manufacturing:
* 20% of equipment price

B) After production has started:
* 40% of equipment price

C) After production has been completed:
* 60% of equipment price

Orders for Engineered Equipment
A) Prior to release for manufacturing:
* 20% of the purchase price

B) After production has started
* 40% of the base compressor price
* 40% of optional equipment of purchased materials will be charged

C) After production has completed
* 60% of the base compressor price
* 100% of optional equipment

APPENDIX D

Design Basis

SANBORN HEAD

Building Trust. Engineering Success.

DESIGN BASIS FOR COLD BOX FEED

PORTLAND LNG FACILITY

Portland, OR

Prepared for Northwest Natural Gas Company
Sanborn Head Project Number: 4661.04

Document #: DESB-001

July 09, 2021
Revision 3

DESIGN BASIS FOR COLD BOX FEED

REVISION LOG

REVISION	REVISION DATE	REVISION NOTES
A	3/9/2021	Issued for NWN review and comment.
1	4/23/2021	Issued for FEED Study.
2	6/3/2021	Issued for FEED Report.
3	7/9/2021	Issued for FEED Report.

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REFERENCES

[REF 1] NWN PLNG Liquefaction Replacement Report 20201030, REV 1, SH Project Number 4661.02

[REF 2] PDX LNG OP MANUAL 1967.pdf (*if specified, page number indicates page # of pdf file)*

[REF 3] RV0824 Gasco PID Updates Full Package.pdf *(if specified, page number indicates page #of pdf file, or where specified, sheet name)*

[REF 4] Response received from Ryan Weber to Information Request dated March 9, 2021. (*if provided, additional reference notes specifies file type, meeting minutes, or email used for reference)*

[REF 5] Design Wind Speed Report, March 31, 2021, Portland LNG Facility Portland OR. *CPP Wind Engineering & Air Quality Consultants*. CPP Project 15211.

[REF 6] Information received during and after Sanborn Head site visit week of 4/5/2021.

[REF 7] Assumptions for Rating Case of new Cold Box Specification (Sanborn Head Document: SPEC-COLD BOX, latest revision)

[REF 8] Preliminary Geotechnical Evaluation, June 30, 2021, Portland LNG Facility Portland OR. *GeoEngineers, Inc.* GeoEngineers File No. 6024-210-03.

1.0 DESIGN BASIS SUMMARY

This design basis summarizes parameters describing the site conditions, equipment specifications, and process stream constituents specific to the NWN owned LNG peak shaving facility (Facility) located in Portland Oregon, Multnomah County. The purpose of this design basis is to develop a basis to perform a front-end engineering and design study (FEED) for an in-kind Cold Box replacement. The existing pretreatment, expander-compressor, and other liquefier controls and equipment in service are not intended for replacement.

Additionally, the capabilities of the existing pre-treatment system are documented for purposes of investigating modifications to improve the removal of CO2 from the incoming gas.

The parameters defined herein will serve as the basis for the FEED. **Refer to Table 5.1.1 for the rated liquefaction rate of the Cold Box during operation.** Refer to [REF 7] for additional design conditions for individual gas and liquid connections to and from the Cold Box.

2.0 CODES & STANDARDS

Codes and standards incorporated by reference into the standards listed below shall also apply. Unless otherwise noted, the most recent edition of the referenced and standards shall apply.

Table 2.0.1: Codes and Standards

Code	Title	Incorporated
49 CFR Part 193	Liquefied Natural Gas Facilities: Federal Safety Standards (Latest Edition)	Federal
PHMSA FAQ's	Pipeline and Hazardous Materials Safety Administration, Frequently Asked Questions (July 25, 2017)	Federal
AGA Purging Principles and Practices	American Gas Association, Purging Principles and Practices (4th Edition)	49 CFR Part 193
NFPA 59A	National Fire Protection Association, Standard for production, Storage, and Handling of Liquefied Natural Gas, (2001 & 2006 Editions)	49 CFR Part 193
ASME B31.3	American Society of Mechanical Engineers, Process Piping, ASME Code for Pressure Piping (Latest Edition)	NFPA 59A
ASME BPVC, Sect. VIII, Division 1	Rules for Construction of Pressure Vessels (2007 Edition)	49 CFR Part 193
2019 Oregon Structural Specialty Code[1]	Based on the 2018 International Building Code	State
2019 Oregon Mechanical Specialty Code[1]	Based on the 2018 International Mechanical Code and International Fuel Gas Code	State
2017 Oregon Electrical Specialty Code[1]	Based on the 2017 Edition of NFPA 70, National Electrical Code, with Oregon Amendments, including Oregon amendments to the 2017 NEC	State
ASCE 7-16	Design Loads, American Society of Civil Engineers	2019 Oregon Specialty Structural Code

Notes:

1. Refer to the following link for the Oregon Specialty Codes: https://www.oregon.gov/bcd/codes-stand/Pages/adopted-codes.aspx

3.0 SITE INFORMATION AND AMBIENT DESIGN CONDITIONS

Table 3.0.1: Ambient Conditions

Condition	Value	Reference
Location		
Project Location	Portland, OR Multnomah County	N/A
Elevation	25 feet	Google Earth
Latitude	45°34'43.03"N (45.57862)	
Longitude	122°45'37.65"W (122.7605)	
Atmospheric Pressure	14.7 PSIA (average)	Assumed
Temperature		
Rating Case, Ambient Temperature	60°F DB	Assumed

Table 3.0.1: Ambient Conditions		
Condition	**Value**	**Reference**
Min/Max Ambient Temperatures	25 °F DB / 91.2 °F DB	ASHRAE 2017 Fundamentals[Note 1]
Hottest Month	August	
Design Cooling Temperature	91.2 °F DB / 67.5 °F MCWB	
Coolest Month	December	
Relative Humidity	0%-100%	Assumed
Precipitation & Flooding		
Average Annual Precipitation	36.3 inches	ASHRAE 2017 Fundamentals[Note 1]
Maximum 1 Hour Rainfall, 100-year	1.5 inch/hour	2019 Oregon Specialty Structural Code, §1611.1
Design Snow Load	25 lb/ft^2	2019 Oregon Specialty Structural Code[Note 3]
Flood Zone Definition[Note 4]	No Definition	Not within "FEMA 500 Year Flood Area"
Ground Water Level	To be determined from Geotech Study	
Wind		
$\hat{U}_{10,000}$ (3-Second Gust, mph), Basic Wind Speed	124	[REF 5]
K_E, Ground Elevation Factor	1.0	[REF 5]
K_d, Wind Directionality Factor	0.85	[REF 5]
K_{ZT}, Topographic Factor	1.0	[REF 5]
K_Z, Velocity Pressure Exposure Coefficient	Exposure Category C, Table 26.10-1 by height, ASCE 7-16	[REF 5]
ASCE 7-16 Load Combinations (Wind only)	Chapter 2 of ASCE 7-16	[REF 5]
Design Wind Speed (Summary)[Note 2]	124 MPH (3-second, 33 feet, Exposure Category C)	[REF 5]

Seismic [Notes 5, 6, 7]		
Site Classification	F	[REF 8]
Mapped Spectral Response Acceleration at Short Period (S_s)	0.894 g	[REF 8]
Mapped Spectral Response Acceleration at 1 Second Period Period (S_1)	0.409 g	[REF 8]
Site Modified Peak Ground Acceleration (PGA_M)	0.484 g [Note 8]	[REF 8]
Site Amplification Factor at 0.2 second period (F_a)	1.142 [Note 8]	[REF 8]
Site Amplification Factor at 1.0 second period (F_v)	1.891 [Note 8]	[REF 8]
Design Spectral Acceleration at 0.2 second period (S_{DS})	0.681 g [Note 8]	[REF 8]
Design Spectral Acceleration at 1.0 second period (S_{D1})	0.516 g [Note 8]	[REF 8]

Noise		
Equipment Noise	85 dBA@ 3 ft (outside)	Assumed

Notes:

1. Site data from Portland International Airport and based on 99.6 percentile for design min temperature and 0.04 percentile for design maximum temperature.
2. Gust wind speed calculated in accordance with DOT 49 CFR 193.2067 per [REF 5].
3. 20 lb/ft^2 minimum as required by Portland.gov and includes 5 lb/ft^2 rain-on-snow surcharge as required per 2019 Oregon Specialty Structural Code §1608.2.5.
4. As determined from: https://www.portlandoregon.gov/bes/article/215594
5. Parameters developed based on Latitude 45.5783951° and Longitude -122.7610446° using the ATC Hazards online tool.

Table 3.0.1: Ambient Conditions		
Condition	**Value**	**Reference**

6. These values are only valid if the structural engineer utilizes Exception 2 of Section 11.4.8 (ASCE 7-16).
7. Ground surface spectral acceleration values for Site Class D are only valid if the structural engineer utilizes exceptions in Section 20.3.1 (ASCE 7-16) and the fundamental period of structure is less than 0.5 seconds.
8. Based on Site Class D.

4.0 FACILITY FEED GAS CONDITIONS AND COMPOSITIONS

4.1 Facility Feed Gas Connections and Conditions

Table 4.1.1: Facility Feed Gas Connections and Conditions		
Condition	**Value**	**Reference**
Facility Inlet		
Inlet Pressure, Rating Case	410 PSIG	Assumed[NOTE 1]
Inlet Pressure Range	385 PSIG – 450 PSIG	Operating Data Range
Inlet Temperature, Rating Case	60 °F	[REF 1], Page 36
Inlet Temperature, Range	50°F – 70°F	Assumed
Inlet, System MAOP (Pipeline)	450 PSIG MAOP	[REF 3], P-001
Inlet, System MAOP (Plant)	550 PSIG MAOP	[REF 1], Page 36
57# Distribution System		
Outlet Pressure, Rating Case	40 PSIG	Operating Data[Note 2]
Outlet Pressure Range	30 PSIG – 57 PSIG	[REF 4], DB Markup
Outlet Temperature, Range	40°F to 120°F	[REF 1], Page 37
Outlet, System MAOP	57 PSIG MAOP	[REF 3], P-001
85# Distribution System		
Outlet Pressure, Rating Case	75 PSIG	Assumption[NOTE 3]
Outlet Pressure Range	70 to 85 PSIG	[REF 1], Page 37
Outlet Temperature, Range	40°F to 120°F	[REF 1], Page 37
Outlet, System MAOP	450 PSIG MAOP	[REF 4], DB Markup

General Notes:

A. The System will be designed to run at the Rating Case and shall be capable of running continuously throughout the ranges specified with potential performance impacts.

Notes:

1. 450 PSIG per [REF 1, Page 36]. Assumption made to conservatively increase energy requirement for liquefaction.
2. 57 PIG per [REF 1, Page 29]. Assumption based upon common operating conditions.
3. 85 PSIG per [REF 1, Page 37] and is a suitable operating condition during times other than liquefaction. Assumption made for rating case to obtain rated liquefaction rate per process model output.

4.2 Facility Feed Gas Composition

The feed gas to the Facility its constituents are summarized in Table 4.2.1. The System shall run optimally at the **Rating Case** and shall be capable of running continuously at **Off Design Lean Feed** and **Off Design Rich Feed** cases with some loss in efficiency.

Table 4.2.1: Facility Feed Gas Composition

Component	Original[4]	Rating Case[5]	Off Design Lean Feed	Off Design Rich Feed	Unit
Methane	92.24	93.63	96.67	89.10	Mol %
Ethane	4.88	4.5	1.32	7.62	Mol %
Propane	0.91	0.35	0.19	1.38	Mol %
Iso-Butane	0.47[NOTE 6]	0.05	0.007	0.274	Mol %
n-Butane	NA	0.045	0.006	0.298	Mol %
Iso-Pentane	NA	0.010	0.001	0.041	Mol %
n-Pentane	NA	0.008	0	0.029	Mol %
C6+	NA	0.005	0.001	0.028	Mol %
Nitrogen	1.10	0.55	0.72	0.16	Mol %
C02[1]	0.40	0.85[NOTE 1]	1.08	1.08	Mol %
Oxygen[2]	NA	NA	NA	NA	ppm
Water	7[NOTE 3]	7	7	7	lbs/MMSCF
Mercaptans[Note 7]	Unknown	1	1	1	lbs/MMSCF
H2S	Unknown	0.25	0.25	0.25	Grains/100CF
Total Sulfur	3.1[NOTE 3]	20	20	20	Grains/100CF

General Notes:

A. ND = Non Detect, NA = Not Analyzed.

Notes:

1. The pretreatment system is existing. The maximum allowed mol% of C02 will be limited by the capability of the existing pretreatment system to meet the specified liquefaction performance.
2. Oxygen in regen gas is anticipated at 10 ppm or less.
3. From [REF 2], Page 5.
4. Source = Drawing P-100, Process Flow Diagram, Revision B dated 9/29/17, unless otherwise noted.
5. Utilized as design basis in [REF 1] which was previously developed for the liquefier replacement studies by CH4 and Sanborn Head.
6. Butane value is assumed to be C4+ since original PFD includes only C_4H_{10} and no other heavier hydrocarbon components.
7. Odorant used is Chevron Phillips Chemical Company LP, Scentinel S-20.

5.0 EXISTING SYSTEMS AND EQUIPEMENT

5.1 Liquefaction System – Existing Cold Box

Table 5.1.1: Existing Cold Box		
Condition	**Value**	**Reference**
General		
System Type	Natural Gas Expansion Cycle	-
Quantity of Liquefaction Trains	One	-
Design, E1, Pass A	650 PSIG @ (-)150 °F to 100°F	[REF 4], Nameplate Photo
Design, E1, Passes B, C, D, E	550 PSIG @ (-)150 °F to 100°F	[REF 4], Nameplate Photo
Design, E2, Pass A	650 PSIG @ (-)150 °F to 100°F	[REF 4], Nameplate Photo
Design, E2, Passes B, C, D	550 PSIG @ (-)150 °F to 100°F	[REF 4], Nameplate Photo
Design, E3, Pass A	650 PSIG @ (-)275 °F to 100°F	[REF 4], Nameplate Photo
Design, E3, Pass B	550 PSIG @ (-)275 °F to 100°F	[REF 4], Nameplate Photo
Design, S2	550 PSIG @ (-)260°F	[REF 4], Nameplate Photo
Design, S3	550 PSIG @ (-)260°F	[REF 4], Nameplate Photo
Design, S4	550 PSIG @ (-)260°F	[REF 4], Nameplate Photo
Insulation	Perlite	[REF 2], Page 22
Enclosure Purge Gas Pressure	2 inches water column	[REF 2], Page 22
Enclosure Material	Coated Carbon Steel	Observed
Heat Exchanger Material	Brazed Aluminum Plate	[REF 2], Page 4
Separator Material	Aluminum	[REF 2], Page 22
Piping Material	Aluminum	[REF 2], Page 22
E1: Quantity of Cores	4	[REF 2], Page 10
E2: Quantity of Cores	3	[REF 2], Page 10
E3: Quantity of Cores	1	[REF 2], Page 10
Liquefaction Ratings, "Normal Liquefaction" Mode		
Purpose	Use of compressor-loaded high speed turbo expander to produce refrigeration gas for use in the cold box.	[REF 2], Page 4
Net Liquefaction Rate, Rating Case	2.15 MMSCFD	[REF 2], Page 5
"Holding" Mode		
Purpose	To maintain tank pressure within its design limits during periods of plant shutdown. No gas is removed from the pipeline during this mode, thus, the pre-treatment system is not operational. In this mode, the boiloff compressors remain on to maintain the tank pressure within design limits. Boiloff gas bypasses the cold box in this mode and is preheated by E-10 and E-13 in lieu of the cold box exchangers.	[REF 3], P-004 & Observation
Net Liquefaction Rate	No liquefaction	Observed
Design Inlet and Outlet Conditions		
For design inlet and outlet conditions, refer to the P-100, Process Flow Diagram, of [REF 2]. Inlet and outlet flow, pressure, and temperature conditions will be further developed when preparing the cold box specification. For inlet and outlet conditions of the expander and compressor, refer to the associated table in this Design Basis.		

5.2 Liquefaction System – Turbo Expander (EX-C-1)

Table 5.2.1: Turbo Expander (EX-C-1)		
Condition	**Value**	**Reference**
General		
Make	Rotoflow Corporation, LA	[REF 2], Page 9
Sub-Systems	Oil Lubrication and Seal Gas (Natural Gas)	[REF 2], Page 9
QTY Compressor Stages/Arrangement[1]	1	[REF 3], P-006
QTY Expander Stages/Arrangement[1]	1	[REF 3], P-006
Expander Inlet Nozzle/Shutoff Valve	FIC 22 / PCV 24	[REF 4], DB Markup
Normal Rotational Speed	40,000 RPM	[REF 4], DB Markup
Alarm Rotational Speed	42,000 RPM	[REF 4], DB Markup
Shutdown Rotational Speed	44,000 RPM	[REF 4], DB Markup
Expander Design Conditions		
Expander Flow	28,216 lbs/hr	[REF 4], Data Sheet
Expander Inlet/Outlet Pressure	450 PSIA / 68 PSIA	[REF 3], P-100
Expander Inlet/Outlet Temperature	-50°F / -166°F	[REF 3], P-100
Compressor Design Conditions		
Compressor Flow	28,216 lbs/hr	[REF 4], Data Sheet
Compressor Inlet/Outlet Pressure	63 PSIA / 118 PSIA	[REF 3], P-100
Compressor Inlet/Outlet Temperature	65 °F / 180 °F	[REF 3], P-100
Notes: 1. Compressor/expander is on single shaft.		

5.3 Pretreatment – Dehydrators (D-1, D-2)

Table 5.3.1: Dehydrators (D-1, D-2)		
Condition	**Value**	**Reference**
General		
Quantity Units	2	[REF 3], P-100
Pretreatment Type	Two-Bed, batch Type Mol Sieve using Linde Type 13X Mol Sieves in each Bed	[REF 2], Page 41
Purpose[1]	Removal of water and sulfur[1]	[REF 2], Page 41
General Duty Cycle (Absorb/Regen)	12 Hours/12 Hours	[REF 2], Page 41
Mercury Guard	none	-
Design Inlet Conditions		
Design feed gas flow rate	22.1 MMSCFD NG at Design Composition	[REF 2], Page 5
Design feed gas inlet temperature	60°F	[REF 3], P-100
Design feed gas inlet pressure	424.7 PSIA (410 PSIG)	[REF 7], Stream 2
Design Water Content at Inlet	7 lbs / MMSCF	[REF 2], Page 5
Design Sulfur Content at Inlet	3.1 grains / 100 SCF	[REF 2], Page 5
Design CO2 Content at Inlet	None specified	[Note 1]
Design Constituent Removal		

Table 5.3.1: Dehydrators (D-1, D-2)		
Condition	**Value**	**Reference**
Design Water Content at Outlet	1 ppm	[REF 2], Page 5
Design Sulfur Content at Outlet	1/10 grain per 100 SCF	[REF 2], Page 5
Design CO2 Content at Outlet	None specified	[Note 1]
Design Regeneration Heating and Cooling Cycles		
Depressurization time prior to Regen	30 minutes	[REF 2], Page 43
Regen heating time	6 hours	[REF 6]
Regen heating inlet temperature	550 °F	[REF 3], P-100
Regen heating gas flow rate	15 MSCFH (controlled)	[REF 6]
Regen heating normal operating pressure	103.7 PSIA (89.0 PSIG)	[REF 7], Stream 45
Regen cooling time	6 hours	[REF 6]
Regen cooling inlet temperature	90 °F	[REF 3], P-100
Regen cooling gas flow rate	15 MSCFH (controlled)	[REF 6]
Regen cooling normal operating pressure	103.7 PSIA (89.0 PSIG)	[REF 7], Stream 45
Re-pressurization	5 minutes	[REF 2], Page 43
General Notes: 1. Dehydrator capabilities and media will be reviewed with goal of enhancing capabilities to partially remove $C0_2$.		

5.4 Pretreatment – Adsorbers (A-1, A-2)

Table 5.4.1: Adsorbers (A-1, A-2)		
Condition	**Value**	**Reference**
General		
Quantity Units	2	[REF 3], P-100
Pretreatment Type	Two-Bed using 9,000 lbs of LNG-5 (8x12 pellets)	[REF 6]
Purpose[1]	Removal of CO_2	[REF 2], Page 43
General Duty Cycle (Absorb/Regen)	3 Hours/3 Hours	[REF 6]
Mercury Guard	none	-
Design Inlet Conditions		
Design feed gas flow rate	5.5 MMSCFD at Design Composition	[REF 2], Page 5
Design feed gas inlet temperature	64.9°F	[REF 7], Stream 15
Design feed gas inlet pressure	417.7 PSIA (403 PSIG)	[REF 7], Stream 15
Design Constituent Removal		
Design CO_2 Concentration at Inlet	0.4 mol%	[REF 2], Page 5
Design CO_2 Concentration at Outlet	100 ppm $C0_2$	[REF 2], Page 5
Design Regeneration Heating and Cooling Cycles		
Depressurization time prior to Regen	6 minutes	[REF 2], Page 45
Regen heating time	80.2 minutes	[REF 6]
Regen heating inlet temperature	550 °F	[REF 3], P-100

Table 5.4.1: Adsorbers (A-1, A-2)		
Condition	**Value**	**Reference**
Regen heating gas flow rate	60 MSCFH	[REF 6]
Regen heating normal operating pressure	60 PSIA (45.3 PSIG)	[REF 7], Stream 41
Regen cooling time	1.66 hours	[REF 6]
Regen cooling inlet temperature	70 °F	[REF 3], P-100
Regen cooling gas flow rate	60 MSCFH	[REF 6]
Regen cooling normal operating pressure	60 PSIA (45.3 PSIG)	[REF 7], Stream 41
Re-pressurization	2 minutes	[REF 2], Page 45
General Notes: 1. Adsorber capabilities and media will be reviewed with goal of enhancing capabilities to remove $C0_2$ beyond current 0.4 mol% capability.		

5.5 LNG Storage Tank

Table 5.5.1: LNG Storage Tank		
Condition	**Value**	**Reference**
LNG Tank		
LNG Tank Normal Operating Pressure (Vapor Space), Rating Case	0.5 PSIG	[REF 1], Page 36
LNG Tank Normal Operating Pressure Range (Vapor Space)	0.5-1.5 PSIG	[REF 1], Page 36
LNG Tank MAOP	2 PSIG	[REF 1], Page 36
LNG Tank Normal Operating Temperature	-257 °F	[REF 3], P-100
LNG Tank Capacity	175,000 BBLS, (0.6 BCF)	[REF 1], Page 36
LNG Tank (Inner) Dimensions	118’-0” Ø x 95’-11” H	CBI DWG 1A, Rev 3, 6/26/1969
Maximum Tank Liquid Level	90’-11”	[REF 1], Page 36
Fill Nozzle Liquid Level	3‘ – 9 ¾”	[REF 1], Page 36
LNG Tank Boiloff Rate, Maximum, Rating Case	0.35 MMSCFD	[REF 2], Page 6
LNG Tank NER	0.058% of tank contents/day	Calculated per above

5.6 Boiloff Compressors (C-2, C-3)

Table 5.6.1: Boiloff Compressors (C-2, C-3)		
Condition	**Value**	**Reference**
Gas Flow, Rating Case (each)	35 MSCFH	[REF 4], DB Markup
Redundancy	2	[REF 4], DB Markup
Suction Temperature, Rating Case	60 °F	[REF 3], P-100
Suction Temperature, Range	(-)10 °F → 70 °F	[REF 4], DB Markup
Suction Pressure, Rating Case	14.6 psia	[REF 4], C3 Perform Sheet
Suction Pressure, Range	1.08 → 1.15 PSIG	-
Discharge Temperature, Rating Case	240 °F	[REF 3], P-100
Discharge Pressure, Rating Case	65.6 PSIA	[REF 4], C3 Perform Sheet

5.7 Water Glycol Gas Cooler, (E-4)

Table 5.7.1: Water Glycol Gas Cooler (E-4)		
Condition	**Value**	**Reference**
Gas Outlet Temperature at Ambient Temperature Rating Case	70°F	Assumed

6.0 AVAILABLE UTILITIES

Table 6.0.1: Available Utilities		
Condition	**Value**	**Reference**
Instrument Air Operating Pressure, Rating Case	100 PSIG	[REF 4], PID P-014
Instrument Air Maximum Dew Point	Desiccant Dryer → (-) 20°F	Assumption
Electrical Power	480/277 VAC, 3-phase, 60 Hz 208/120 VAC, 3-phase, 60 Hz	[REF 1]

APPENDIX E1

Cold Box Specification

EQUIPMENT SPECIFICATION

Tag	Description
COLD BOX	**Cold Box and Accessory Equipment**

Refer to the Table of Contents for additional information.

Project Data

Prepared for:	Northwest Natural Gas Company (NWN)
Facility:	LNG Facility
Location:	Portland, OR
Sanborn Head File:	4661.04

Revision Log

Rev	Date	By	Notes
A	4/22/2021	JDH	Issued for budgetary quotation and preliminary design.
B	6/04/2021	JDH	Issued for FEED Study
1	7/9/2021	JDH	Issued for FEED Study

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ATTACHMENTS

Attachment #	Description
1	NWN PAINTING SPECIFICATION, ENGINEERING STANDARD 50-002
2	TURBO EXPANDER (C-1) DATA SHEET

1.0 INTRODUCTION

A new cold box system (Cold Box) shall be provided to replace an existing cold box system for Northwest Natural Gas Company (Owner) LNG Facility located at 7900 NW St Helens Road, Portland Oregon (Facility).

Refer to the PFD and P&ID drawings in document *PISET-001* and the general arrangement drawings in document *GASET-001*. The P&ID shall be the controlling drawing for the existing external cold box piping. The demo (D-) series general arrangement drawings shall be referenced to locate the new Cold Box and its process nozzles. The process nozzles shall be located in proximity to the corresponding tie points as shown on the D-series general arrangement drawings, or as required, to reduce length of process piping spools where possible. The existing turbo-expander shall be utilized at its installed location. The mechanical (M-) series are conceptual only.

2.0 COLD BOX GENERAL SPECIFICATION

Table 2.0.1: Cold Box General Specification

System/Parameter	Specification
General	
System Type	Natural Gas Expansion Cycle
Quantity of Liquefaction Trains	One
General Performance	
Liquefaction Ratings, "Normal Liquefaction" Mode	
Description	Use of the high-speed turbo expander-compressor to utilize dry natural gas as refrigerant for production of liquefied natural gas in the Cold Box.
Net Liquefaction Rate, Rating Case	2.15 MM SCFD

3.0 COLD BOX PERFORMANCE SPECIFICATION

The Cold Box shall produce 2.15 MMSCFD net LNG in the tank considering an LNG tank pressure of 15.2 psia using the Rating Case natural gas feed, expander natural gas feed, and the existing Atlas Copco turbo expander. Refer to Table 3.0.3 and Figure 3.0.1.

The Rating Case (as detailed in Table 3.0.3) is the required performance with some flexibility available for Vendor design per Table 3.0.1.

Table 3.0.1: Summary of Firm and Variable Process Streams

PFD Str #	Stream Description	Pressure	Temperature	Flow	Gas Composition
4	Warm expander gas	Firm	Firm	Firm	Firm
5	Expander Inlet	Firm	Variable	Firm	Firm

Table 3.0.1: Summary of Firm and Variable Process Streams

PFD Str #	Stream Description	Pressure	Temperature	Flow	Gas Composition
6	Expander Outlet	Firm	Variable	Firm	Firm
7	Expander Outlet/HHC Mix	Firm	Variable	Firm	Variable
9	Compressor Suction	Firm	Firm	Firm	Variable
10	Compressor Discharge	Firm	Variable	Firm	Variable
17	Clean Gas Feed	Firm	Firm	Up to 4 MMSCFD	Firm
23A	LNG	Firm	Variable	Variable	Variable
30	Cold LNG Flash Gas	Firm	Variable	Variable	Variable
33	Warm LNG Flash Gas	Firm	Firm	Variable	Variable
34/35	Cold Boiloff Gas	Firm	Firm	0.1 to 0.5 MMSCFD	Variable
37	Warm Boiloff Gas	Firm	Firm	0.1 to 0.5 MMSCFD	Variable

General Note:

A. The existing turbo expander (C-1) data sheet is included in Attachment 2 to support the Vendor design. Any change in flow, pressure, and temperature at the existing turbo expander from the rating and off-design cases presented in Tables 3.0.3, 3.0.4, and 3.0.5 shall be provided within the Vendor's offering to allow Sanborn Head to verify performance with Atlas Copco.

The system shall be capable of running continuously at the following alternate conditions with some loss in efficiency:

- Off Design Lean Feed Case (Refer to Table 3.0.4)
- Off Design Rich Feed Case (Refer to Table 3.0.5)
- System Normal Operating Pressure and Temperature Ranges

Table 3.0.2: Summary of Normal Operating Pressure and Temperature Ranges

PFD Stream #	Stream Description	Pressure Range (Rating Value)	Temperature Range (Rating Value)
17	Clean feed gas	370 – 430 psig (393 psig)	50°F – 100°F (70 °F)
4	Warm expander gas	375 – 440 psig (401 psig)	50°F – 75°F (65 °F)

Table 3.0.2: Summary of Normal Operating Pressure and Temperature Ranges			
PFD Stream #	**Stream Description**	**Pressure Range (Rating Value)**	**Temperature Range (Rating Value)**
10	Turboexpander compressor discharge	70 – 90 psig (83 psig)	--
33	Warm LNG flash gas outlet	40 – 65 psig (48 psig)	--
26	LNG Tank Pressure	15.2 – 16.2 psia (15.2 psia)	--

The new Cold Box shall include the following:

- Heat Exchanger(s) required to meet performance.
- Heavy ends separator with level control capability, designed to remove the heavy hydrocarbons to a concentration that will not cause hydrocarbon solids plating or plugging of the heat exchanger passes during normal operation. Instrumentation and control valve by vendor, PLC control by others.
- Expander inlet separator with inlet gas temperature control and level control capability to remove any liquids prior to the expander. Instrumentation and control valves by vendor, PLC control by others.
- Temperature elements at all heat exchanger inlets and outlets.
- Nitrogen purge gas system with gas detection to alarm operations of a leak within the box.
- Transmitters to measure differential pressure across all heat exchanger passes except the boiloff pass.

Refer to the full process flow diagram in document *PISET-001* with corresponding stream numbers. Figure 3.0.1 is provided for convenience, showing the immediate process streams around the cold box.

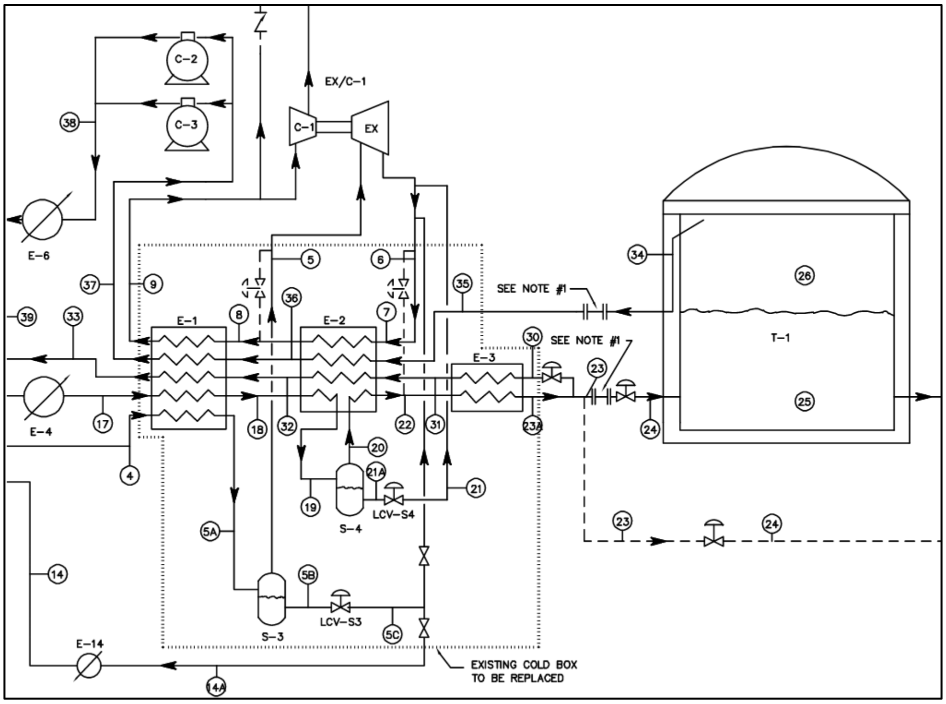


Figure 3.0.1: PFD of Cold Box (Refer to Document *PISET-001* for Additional Information)

The following tables describe the Cold Box performance for all three cases; Rating, Rich, and Lean.

Table 3.0.3: Cold Box Performance Specification (Rating Case)

	PFD Stream Number →		4	5	6	7	9	10	17	21A	23A	30	33	34/35	37
Mole Fraction	Methane		94.064	94.064	94.064	94.062	94.062	94.062	94.435	36.736	94.456	94.456	94.456	97.160	97.160
	Ethane		4.5208	4.5208	4.5208	4.5213	4.5213	4.5213	4.5387	21.5398	4.5323	4.5323	4.5323	0.0100	0.0100
	Ethylene		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	Propane		0.3516	0.3516	0.3516	0.3519	0.3519	0.3519	0.3530	9.5504	0.3496	0.3496	0.3496	0.0000	0.0000
	Isobutane		0.0502	0.0502	0.0502	0.0504	0.0504	0.0504	0.0504	5.1286	0.0485	0.0485	0.0485	0.0000	0.0000
	n-Butane		0.0452	0.0452	0.0452	0.0454	0.0454	0.0454	0.0454	7.2797	0.0427	0.0427	0.0427	0.0000	0.0000
	Isopentane		0.0100	0.0100	0.0100	0.0102	0.0102	0.0102	0.0101	5.1715	0.0082	0.0082	0.0082	0.0000	0.0000
	n-Pentane		0.0080	0.0080	0.0080	0.0082	0.0082	0.0082	0.0081	5.2617	0.0061	0.0061	0.0061	0.0000	0.0000
	Hexane		0.0050	0.0050	0.0050	0.0053	0.0053	0.0053	0.0050	9.2945	0.0016	0.0016	0.0016	0.0000	0.0000
	Nitrogen		0.5525	0.5525	0.5525	0.5525	0.5525	0.5525	0.5547	0.0379	0.5549	0.5549	0.5549	2.8303	2.8303
	Carbon Dioxide		0.3928	0.3928	0.3928	0.3928	0.3928	0.3928	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	Water		0	0	0	0	0	0	0	0	0	0	0	0	0
Fluid Properties	Temperature	°F	65	-60	-172.5	-172.5	65	148.6	70	-80	-217	-219	65	-190	65
	Pressure	psig	401	399	49.0	49.0	47.0	83.4	393.0	391.0	389.0	51.3	48.3	0.3	0.1
	Mass Flow	lb/h	26214.4	26214.4	26214.4	26215.9	26215.9	26215.9	6986.0	6.1	6979.9	2149.8	2149.8	768.9	768.9
	Std Vapor Volumetric Flow	MMSCFD	14.04	14.04	14.04	14.04	14.04	14.04	3.77	0.00	3.76	1.16	1.16	0.43	0.43
	Mole Fraction Vapor	%	100.00	100.00	97.43	97.43	100.00	100.00	100.00	0.00	0.00	1.43	100.00	100.00	100.00
	Molecular Weight	lb/lbmol	17.01	17.01	17.01	17.01	17.01	17.01	16.90	39.34	16.89	16.89	16.89	16.38	16.38
	Mass Density	lb/ft^3	1.35	2.00	0.38	0.38	0.19	0.26	1.30	35.86	25.48	14.56	0.19	0.09	0.04
	Mass Cp	Btu/(lb*°F)	0.5621	0.6063	0.5102	0.5102	0.5170	0.5491	0.5647	0.5432	0.8354	0.8429	0.5205	0.4898	0.5152
	Dynamic Viscosity	cP	0.0114	0.0094	--	--	0.0109	0.0124	0.0114	0.1833	0.0857	--	0.0109	0.0060	0.0111
	Thermal Conductivity	Btu/(h*ft*°F)	0.0199	0.0158	--	--	0.0186	0.0224	0.0201	0.0756	0.0890	--	0.0186	0.0090	0.0188

Table 3.0.4: Cold Box Performance Specification (Off Design Lean Case)

	PFD Stream Number →		4	5	6	7	9	10	17	21A	23A	30	33	34/35	37
Mole Fraction	Methane		97.348	97.348	97.348	97.348	97.348	97.348	97.730	--	97.730	97.730	97.730	96.410	96.410
	Ethane		1.3293	1.3293	1.3293	1.3293	1.3293	1.3293	1.3345	--	1.3345	1.3345	1.3345	0.0029	0.0029
	Ethylene		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	--	0.0000	0.0000	0.0000	0.0000	0.0000
	Propane		0.1913	0.1913	0.1913	0.1913	0.1913	0.1913	0.1921	--	0.1921	0.1921	0.1921	0.0000	0.0000
	Isobutane		0.0070	0.0070	0.0070	0.0070	0.0070	0.0070	0.0071	--	0.0071	0.0071	0.0071	0.0000	0.0000
	n-Butane		0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0061	--	0.0061	0.0061	0.0061	0.0000	0.0000
	Isopentane		0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	--	0.0010	0.0010	0.0010	0.0000	0.0000
	n-Pentane		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	--	0.0000	0.0000	0.0000	0.0000	0.0000
	Hexane		0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	--	0.0010	0.0010	0.0010	0.0000	0.0000
	Nitrogen		0.7250	0.7250	0.7250	0.7250	0.7250	0.7250	0.7279	--	0.7279	0.7279	0.7279	3.5875	3.5875
	Carbon Dioxide		0.3915	0.3915	0.3915	0.3915	0.3915	0.3915	0.0000	--	0.0000	0.0000	0.0000	0.0000	0.0000
	Water		0	0	0	0	0	0	0	--	0	0	0	0	0
Fluid Properties	Temperature	°F	65	-50	-178.1	-178.1	42	130.8	70	-80	-217	-221	42	-190	42
	Pressure	psig	401	399	49.0	49.0	47.0	86.7	393.0	391.0	389.0	51.3	48.3	0.3	0.1
	Mass Flow	lb/h	25413.7	25413.7	25413.7	25413.7	25413.7	25413.7	7254.3	0.0	7254.3	3482.0	3482.0	639.6	639.6
	Std Vapor Volumetric Flow	MMSCFD	14.04	14.04	14.04	14.04	14.04	14.04	4.03	0.00	4.03	1.94	1.94	0.35	0.35
	Mole Fraction Vapor	%	100.00	100.00	99.68	99.68	100.00	100.00	100.00	--	0.00	2.08	100.00	100.00	100.00
	Molecular Weight	lb/lbmol	16.49	16.49	16.49	16.49	16.49	16.49	16.38	--	16.38	16.38	16.38	16.47	16.47
	Mass Density	lb/ft^3	1.30	1.83	0.37	0.37	0.19	0.27	1.25	--	24.79	11.91	0.19	0.09	0.05
	Mass Cp	Btu/(lb*°F)	0.5667	0.5972	0.5141	0.5141	0.5174	0.5481	0.5695	--	0.8668	0.8704	0.5209	0.4867	0.5057
	Dynamic Viscosity	cP	0.0115	0.0096	--	--	0.0106	0.0122	0.0115	--	0.0789	--	0.0106	0.0060	0.0108
	Thermal Conductivity	Btu/(h*ft*°F)	0.0202	0.0163	--	--	0.0179	0.0218	0.0204	--	0.0877	--	0.0180	0.0090	0.0178

Table 3.0.5: Cold Box Performance Specification (Off Design Rich Case)

	PFD Stream Number →		4	5	6	7	9	10	17	21A	23A	30	33	34/35	37
Mole Fraction	Methane		89.701	90.725	90.725	89.089	89.089	89.089	90.064	38.669	92.422	92.422	92.422	99.128	99.128
	Ethane		7.6714	7.3650	7.3650	7.9475	7.9475	7.9475	7.7024	30.6883	6.6477	6.6477	6.6477	0.0155	0.0155
	Ethylene		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	Propane		1.3893	1.0809	1.0809	1.5800	1.5800	1.5800	1.3949	17.2875	0.6657	0.6657	0.6657	0.0000	0.0000
	Isobutane		0.2758	0.1358	0.1358	0.3347	0.3347	0.3347	0.2770	5.1833	0.0518	0.0518	0.0518	0.0000	0.0000
	n-Butane		0.3000	0.1183	0.1183	0.3678	0.3678	0.3678	0.3012	5.9553	0.0418	0.0418	0.0418	0.0000	0.0000
	Isopentane		0.0413	0.0065	0.0065	0.0517	0.0517	0.0517	0.0414	0.9104	0.0016	0.0016	0.0016	0.0000	0.0000
	n-Pentane		0.0292	0.0037	0.0037	0.0366	0.0366	0.0366	0.0293	0.6484	0.0009	0.0009	0.0009	0.0000	0.0000
	Hexane		0.0282	0.0006	0.0006	0.0356	0.0356	0.0356	0.0283	0.6424	0.0001	0.0001	0.0001	0.0000	0.0000
	Nitrogen		0.1611	0.1637	0.1637	0.1593	0.1593	0.1593	0.1617	0.0153	0.1684	0.1684	0.1684	0.8560	0.8560
	Carbon Dioxide		0.4023	0.4006	0.4006	0.3975	0.3975	0.3975	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	Water		0	0	0	0	0	0	0	0	0	0	0	0	0
Fluid Properties	Temperature	°F	65	-60	-158.8	-155.6	65	144.2	70	-80	-215	-217	65	-190	65
	Pressure	psig	401	399	49.0	49.0	47.0	83.1	393.0	391.0	389.0	51.3	48.3	0.3	0.1
	Mass Flow	lb/h	27658.3	26698.6	26698.6	28242.3	28242.3	28242.3	7685.1	590.0	7095.1	2100.1	2100.1	781.2	781.2
	Std Vapor Volumetric Flow	MMSCFD	14.04	13.80	13.80	14.21	14.21	14.21	3.92	0.17	3.75	1.11	1.11	0.44	0.44
	Mole Fraction Vapor	%	100.00	100.00	95.28	93.22	100.00	100.00	100.00	0.00	0.00	1.38	100.00	100.00	100.00
	Molecular Weight	lb/lbmol	17.94	17.62	17.62	18.10	18.10	18.10	17.84	31.21	17.22	17.22	17.22	16.15	16.15
	Mass Density	lb/ft^3	1.44	2.11	0.39	0.40	0.20	0.28	1.38	31.52	25.81	14.96	0.19	0.09	0.04
	Mass Cp	Btu/(lb*°F)	0.5559	0.6098	0.5047	0.5043	0.5061	0.5386	0.5582	0.6152	0.8205	0.8275	0.5173	0.4983	0.5246
	Dynamic Viscosity	cP	0.0113	0.0093	--	--	0.0108	0.0121	0.0113	0.1200	0.0890	--	0.0108	0.0059	0.0110
	Thermal Conductivity	Btu/(h*ft*°F)	0.0195	0.0156	--	--	0.0181	0.0216	0.0197	0.0734	0.0892	--	0.0184	0.0090	0.0189

4.0 COLD BOX MECHANICAL SPECIFICATION

Table 4.0.1: Cold Box Mechanical Specification

System/Parameter			**Specification**			
Mechanical Specifications (Plant Process Piping / Cold Box Nozzles)						
Process Stream	**Flow Direction**	**Conne-ction Size**	**Tie Point***	**PFD Stream Number***	**Pressure Rating**	**New Cold Box Nozzle Type**
Compressor Inlet	Outlet	10”	TP-01A	9	550 psig	300# RFWN
Expander Outlet	Inlet	10“	TP-18	7	550 psig	BW
Warm Boiloff Gas	Outlet	6“	TP-02	37	550 psig	300# RFWN
Cold Boiloff Gas	Inlet	6”	TP-03	34/35	550 psig	BW
Warm LNG Flash Gas	Outlet	4”	TP-06	33	550 psig	300# RFWN
Cold LNG Flash Gas	Inlet	2 ½”	TP-09/12	30	550 psig	BW
Warm Expander Gas	Inlet	6”	TP-07	4	550 psig	300# RFWN
Expander Inlet	Outlet	2 ½”	TP-13	5	550 psig	300# RFWN
LNG	Outlet	2 ½”	TP-09/12	23A	550 psig	BW
Clean Gas Feed	Inlet	3”	TP-16	17	550 psig	300# RFWN
*Refer to *PISET-001* and *GASET-001* for locations of Tie Points and refer to the Performance Specification for Stream Number correlation.						

Mechanical Specifications (Cold Box Internal Piping, Separators, and Heat Exchangers)	
Pressure and Temperature Ratings	
Design Pressure	Vendor to Provide, 550 PSIG minimum
Design Temperature	-275 °F to 150 °F
Materials	
Heat Exchanger Material	Aluminum
Separator Material	Vendor to Provide
Piping Material	Vendor to Provide
Piping Support Material	Vendor to Provide
Valves	
Vent and Drain Valves	Goddard, Ladish, or equal (Vendor to Provide).
Control Valves	Fisher or approved equivalent, with Fisher DVC6200 digital positioner and position feedback
General Heat Exchanger Configuration	
Heat Exchanger Configuration General Notes:	1. Configuration shall be specified by the Vendor to achieve the specified minimum performance requirements and per vendor design. 2. Heat exchanger designs shall consider pressure balance during all possible modes of operation, including pressure and temperature differentials experienced during startup cold down and shutdown warmup.
General Separator Configuration	
Separator Configuration General Notes:	1. Configuration shall be specified by the Vendor to achieve the minimum performance requirements as per vendor design.
General Cold Box Notes:	

Table 4.0.1: Cold Box Mechanical Specification	
System/Parameter	**Specification**
1. All low point piping and equipment within the cold box shall pitch down out of the cold box to the drain location. Each drain shall have a socket weld cryogenic gate valve with threaded one end nipple and pipe cap. Refer to *GASET-001* for proposed drain location. 2. Any high points within the Cold Box shall have a high point vent. Connected piping shall be considered a high point vent if it is the highest point in the system and can be vented via vent valve by others Each vent shall have a socket weld cryogenic gate valve with threaded one end nipple and pipe cap.	
Quality Assurance and Quality Control	
Non Destructive Testing	100% required for heat exchangers and piping
Pressure Test (Pneumatic)	1.25 x MAOP per 49 CFR 193
Pressure Test (Hydro)	1.5 x MAOP per 49 CFR 193 – If hydro testing is utilized, specify procedure to fully drain and dry piping and heat exchangers for cryogenic operation
Mechanical Specifications (Cold Box Shell/Skin)	
Dimensions and Ratings	
Shell Design Pressure	Vendor to Provide. Shell shall be gas tight.
Purge Gas/Purity	Nitrogen / Vendor to Provide Purity Required
Purge Gas Supply Pressure	Vendor to Provide Required at N2 Regulator/flow setter inlet
Purge Gas Flow and Duration for Commissioning	Vendor to Provide
Purge Gas Flow Rate while Operating	Vendor to Provide
Cold Box Shell Dimensions	Vendor to Provide (not to exceed footprint of existing Cold Box as shown on the drawings (132" W x 236" L), height as required)
Purge Gas Inlet/Outlet Connection Sizes	Vendor to Provide
Manway Size(s) and Location(s)	Vendor to Provide
Inspection Ports	Vendor to Provide
Materials	
Insulation	Perlite
Shell	Carbon steel prepared by dry abrasive blast cleaning to SSPC-SP 6 per NWN Paint Specification Engineering Standard 50-002, refer to Attachment 1.
Shell Coating	Paint system by vendor. Finish coat shall match Haze Gray color, per NWN Paint Specification Engineering Standard 50-002, refer to Attachment 1.
Penetration Seals	Vendor to provide. Penetrations to/from the Cold Box shell shall allow for expansion and contraction of penetrating piping while maintaining the assembly gas tight.
Access Port Seals	Vendor to provide
Internal Structural Support	Vendor to provide
General	

Table 4.0.1: Cold Box Mechanical Specification	
System/Parameter	**Specification**
Purge Gas	Arrangement of purge gas inlet connection(s) shall effectively purge all sections of the cold box. The purge gas outlet connection shall be located so all sections of the cold box are effectively purged.
Piping Connection Labels	Permanently affixed to cold box shell at each connection location and visible from ground level.
Piping Penetrations	All penetrations through the cold box shell wall shall be sealed water and gas tight and shall allow for expansion and contraction.
Controls Wiring Penetrations	All controls wiring penetrations wall shall be sealed water and gas tight and shall allow for expansion and contraction of the shell.
Mechanical Specifications (External Piping Supports)	
Coating	Hot Dipped Galvanized per ASTM A123 per NWN Paint Specification Engineering Standard 50-002, refer to Attachment 1.
Mechanical Specifications (Overall)	
Dimensions and Ratings	
Overall Dimensions for Shipping/Freight	Vendor to provide, for each piece, as required.
Overall Weight, Shipping	Vendor to provide
Overall Weight, Operating	Vendor to provide
Structural Civil Specifications (Overall)	
General	
Ladders/Platforms/Railings Around Top of Cold Box	Vendor to provide
Lifting Lugs	Vendor to provide
Pipe Supports	Vendor to provide quantity ten (10) T or H-style supports at preliminary locations identified on Sheet M-0103-01 within attached GA drawing set *GASET-001*. Each support shall be assumed to carry 500 lb loads. Final design support quantity, location, and loads to be provided 4-6 weeks after receipt of vendor general arrangement approval drawing.
Foundation Design	By others.
Anchorage Design	By others.

5.0 COLD BOX INSTRUMENTATION AND CONTROLS SPECIFICATION

The Vendor shall provide sensors, instrumentation, and piping/tubing, as required to ensure proper operation and monitoring of the Cold Box including but not limited to, pressure transmitters, separator level transmitters, temperature sensors, and control valves within scope.

Table 5.0.1: Instrumentation and Controls Specification	
System/Parameter	**Specification**
General	
Area Classification	Class I, Division 1 and Division 2, Group D
Instrumentation	
Temperature Sensors	Dual Element Thermocouple or RTD
Level (Differential Pressure) Transmitters	Foxboro IGP10 Series. Electronic version and output signal: Intelligent; Digital HART and 4-20mA. 316L SS process connections and diaphragm, silicone fill fluid, ½ NPT conduit connections (both sides), aluminum housing, FM approval for installation in Class I, Division 1 and Division 2, Group D areas. Each transmitter shall be supplied with a 5-valve manifold, Anderson Greenwood M6TA Series. Transmitters and manifolds to be shipped loose for field installation.
Gas Detectors	• A gas detector shall be installed on purge gas outlet to notify operations of a leak within the box. • If a point detector is utilized, Vendor to include Det-Tronics PointWatch Eclipse Gas Detector, part #007168-012 • If in-line gas detector utilized, Vendor to provide proposed manufacturer and model number.
Cold Box I/O	
General Electrical Requirements	Vendor shall provide one Remote I/O Enclosure to be located on the outside of the shell of the Cold Box. Conduit and wiring from all cold box interior and exterior instrumentation shall be installed to the Remote I/O Enclosure by the Vendor. All conduit installed outside the shell of the cold box shall be threaded rigid galvanized steel. The Remote I/O Enclosure shall contain all hardware necessary to interface between the instrumentation and control devices within the Vendor's scope of supply and the existing site control system. All electrical installation shall be suitable for the Class I Division 2 Group D area classification, shall be in accordance with the 2017 Oregon Electrical Specialty Code, and built, listed and labelled in accordance with UL508A.
Existing Site Control System	Allen Bradly ControlLogix PLC with dual L85E controllers. Remote I/O racks located throughout the site are Allen Bradly series 1794 Flex I/O which communicate to the controllers via EtherNet/IP.
Vendor Supplied I/O Enclosure Requirements	Stainless steel, NEMA type 4X, built in accordance with UL 508A. The enclosure shall contain an Allen Bradley series 1794 Flex I/O rack, including redundant EtherNet/IP media adaptor, power supplies, terminal bases and I/O modules as required to accommodate all instrumentation and control devices within the Vendor's scope of supply.

6.0 COLD BOX VENDOR ENGINEERING DELIVERABLES

Table 6.0.1: Cold Box Vendor Services	
System/Parameter	**Specification**
Vendor Engineering Deliverables	Vendor shall provide the following documents, at a minimum, to support the vendor performance requirements/guarantee. Additionally, the documents shall support the integration design (by others) of the new Cold Box into the existing facility systems: 1. PFD 2. P&ID within Cold Box battery limits (design integration P&ID by others) 3. Cold Box general arrangement drawings with dimensioned nozzle locations, nozzle sizes, and allowable nozzle loads (design integration general arrangement drawings will be by others) 4. Simulations / heat and material balances 5. Foundation load analysis 6. Control Loop Diagrams 7. I/O List, Control panel/junction box general arrangement drawing, wiring diagrams, and other standard documentation required to communicate cold box installation and control requirements. 8. Equipment, Instrument, and Control Valve Datasheets 9. Utility Requirements (control power, nitrogen, etc) 10. Standard Cold Box IOM 11. QA/QC documentation 12. Process Performance Guarantee
Engineering Peer Review of Documents	Vendor shall provide engineering services to review the facility documents updated by others showing the integration of the new Cold Box including: 1. Operating procedures 2. Cause-effect/interlock matrix 3. Alarm list 4. Control's narrative/sequence of operations
Commissioning Support	A T&M field services rate sheet shall be provided for Commissioning support offered on a T&M basis.

7.0 CODES & STANDARDS

Table 7.0.1: Codes and Standards		
Code	**Title**	**Incorporated**
49 CFR Part 193	Liquefied Natural Gas Facilities: Federal Safety Standards (Latest Edition)	Federal
PHMSA FAQ's	Pipeline and Hazardous Materials Safety Administration, Frequently Asked Questions (July 25, 2017)	Federal
AGA Purging Principles and Practices	American Gas Association, Purging Principles and Practices (4th Edition)	49 CFR Part 193
NFPA 59A	National Fire Protection Association, Standard for production, Storage, and Handling of Liquefied Natural Gas, (2001 & 2006 Editions)	49 CFR Part 193

Table 7.0.1: Codes and Standards		
Code	**Title**	**Incorporated**
ASME B31.3	American Society of Mechanical Engineers, Process Piping, ASME Code for Pressure Piping (Latest Edition)	NFPA 59A
ASME BPVC, Sect. VIII, Division 1	Rules for Construction of Pressure Vessels (2007 Edition)	49 CFR Part 193
2019 Oregon Structural Specialty Code[1]	Based on the 2018 International Building Code	State
2019 Oregon Mechanical Specialty Code[1]	Based on the 2018 International Mechanical Code and International Fuel Gas Code	State
2017 Oregon Electrical Specialty Code[1]	Based on the 2017 Edition of NFPA 70, National Electrical Code, with Oregon Amendments, including Oregon amendments to the 2017 NEC	State
UL 508A	Standard for Construction of Industrial Control Panels	-
ASCE 7-16	Design Loads, American Society of Civil Engineers	2019 Oregon Specialty Structural Code
General Notes: 1. Refer to the following link for the Oregon Specialty Codes: https://www.oregon.gov/bcd/codes-stand/Pages/adopted-codes.aspx		

8.0 SITE INFORMATION AND AMBIENT DESIGN CONDITIONS

Table 8.0.1: Ambient Conditions		
Condition	**Value**	**Reference**
Location		
Project Location	Portland, OR Multnomah County	N/A
Elevation	25 feet	Google Earth
Latitude	45°34'43.03"N (45.57862)	
Longitude	122°45'37.65"W (122.7605)	
Atmospheric Pressure	14.7 PSIA (average)	Assumed
Temperature		
Min/Max Design Ambient Temperatures	25 °F DB / 91.2 °F DB	ASHRAE 2017 Fundamentals[Note 1]
Hottest Month	August	
Design Cooling Temperature	91.2 °F DB / 67.5 °F MCWB	
Coolest Month	December	
Relative Humidity	0%-100%	Assumed
Precipitation & Flooding		
Average Annual Precipitation	36.3 inches	ASHRAE 2017 Fundamentals[Note 1]
Maximum 1 Hour Rainfall, 100-year	1.5 inch/hour	2019 Oregon Specialty Structural Code, §1611.1
Design Snow Load	25 lb/ft^2	2019 Oregon Specialty Structural Code[Note 3]

Table 8.0.1: Ambient Conditions

Condition	Value	Reference
Flood Zone Definition [Note 4]	No Definition	Not within "FEMA 500 Year Flood Area"
Wind		
$\hat{U}_{10,000}$ (3-Second Gust, mph), Basic Wind Speed	124	[Note 2]
K_E, Ground Elevation Factor	1.0	[Note 2]
K_d, Wind Directionality Factor	0.85	[Note 2]
K_{ZT}, Topographic Factor	1.0	[Note 2]
K_Z, Velocity Pressure Exposure Coefficient	Exposure Category C, Table 26.10-1 by height, ASCE 7-16	[Note 2]
ASCE 7-16 Load Combinations (Wind only)	Chapter 2 of ASCE 7-16	[Note 2]
Design Wind Speed (Summary)	124 MPH (3-second, 33 feet, Exposure Category C)	[Note 2]

Seismic [Notes 5, 6, 7]		
Site Classification	F	[REF 8]
Mapped Spectral Response Acceleration at Short Period (S_s)	0.894 g	[REF 8]
Mapped Spectral Response Acceleration at 1 Second Period Period (S_1)	0.409 g	[REF 8]
Site Modified Peak Ground Acceleration (PGA_M)	0.484 g [Note 8]	[REF 8]
Site Amplification Factor at 0.2 second period (F_a)	1.142 [Note 8]	[REF 8]
Site Amplification Factor at 1.0 second period (F_v)	1.891 [Note 8]	[REF 8]
Design Spectral Acceleration at 0.2 second period (S_{DS})	0.681 g [Note 8]	[REF 8]
Design Spectral Acceleration at 1.0 second period (S_{D1})	0.516 g [Note 8]	[REF 8]

Noise		
Equipment Noise	85 dBA@ 3 ft (outside)	Assumed

Notes:

1. Site data from Portland International Airport and based on 99.6 percentile for design min temperature and 0.04 percentile for design maximum temperature.
2. Gust wind speed calculated in accordance with DOT 49 CFR 193.2067 per Design Wind Speed Report, March 31, 2021, Portland LNG Facility Portland OR. *CPP Wind Engineering & Air Quality Consultants*. CPP Project 15211.
3. 20 lb/ft^2 minimum as required by Portland.gov and includes 5 lb/ft^2 rain-on-snow surcharge as required per 2019 Oregon Specialty Structural Code §1608.2.5.
4. As determined from: https://www.portlandoregon.gov/bes/article/215594
5. Parameters developed based on Latitude 45.5783951° and Longitude -122.7610446° using the ATC Hazards online tool.
6. These values are only valid if the structural engineer utilizes Exception 2 of Section 11.4.8 (ASCE 7-16).
7. Ground surface spectral acceleration values for Site Class D are only valid if the structural engineer utilizes exceptions in Section 20.3.1 (ASCE 7-16) and the fundamental period of structure is less than 0.5 seconds.
8. Based on Site Class D.

COLD BOX SPECIFICATION ATTACHMENT 1:

PAINTING SPECIFICATION, ENGINEERING STANDARD 50-002

NW Natural

Section:	Class 50 – LNG Piping Systems		
Subject:	Material Coatings for Atmospheric Corrosion Control		
Revision:	01	Effective Date:	11/28/17
Approved:	Maggie Emery	Reviewed:	Mike McKenzie

1. Purpose

This standard identifies the approved coatings for exposed or above ground pipe within LNG facilities that are approved for purchase and use in NW Natural's pipeline system.

Combinations of approved coatings designed for site specific conditions may be utilized and shall be approved by the Engineering Manager.

2. Specifications

2.1 Performance Specifications

The coatings for exposed or above ground pipe and gas supply facilities shall have the following features, when applicable:

1. Protection from atmospheric corrosion
2. Resistance to UV exposure
3. Water based for ease of clean up, or manufacturer applied coating
4. Application over zinc-electroplated material

2.2 Material Specifications

The coatings shall meet typical industry standards for adhesion, corrosion weathering, and abrasion resistance.

2.3 Approved Manufacturer(s)

The following coatings are approved for use on exposed or above ground pipe and gas supply facilities as specified in Section 2.4.

2.3.1 Sherwin-Williams - COROTHANE® I MIO-ZINC (B65A14 & B69D210)

2.3.2 Sherwin-Williams - COROTHANE® I-IRONOX® B (B65A11)

2.3.3 Sherwin-Williams - SHER-CRYL™ HPA High Performance Acrylic Gloss Coating (B66-300 Gloss & B66-350 Semi-Gloss)

2.3.4 PPG – Hi-Temp 1027 for specific high-temperature insulated applications

NW Natural

2.4 Usage Specification

Coatings shall be applied per the manufacturer recommendations.

2.4.1 Surface Preparation

Surface preparation shall be dry abrasive blast cleaning to SSPC-SP 6, “Commercial Blast” (ISO-Sa 2) with a 1 to 2 mils profile.

When abrasive blast cleaning is not an option, the following methods are acceptable:

1. SSPC-SP 15 “ Commercial Grade Power Tool Cleaning”, with a minimum 25 µm (1.0 mil) profile
2. SSPC-SP 12, “ Surface Preparation by Water-jetting Prior to Recoating” to meet the visual definition of WJ-3, “ Thorough Cleaning.” Use potable water;
3. SSPC-SP3, “ Power Tool Cleaning” (ISO-St 3) or SSPC-SP 2, “ Hand Tool Cleaning” (ISO-St 2)

2.4.2 The following assets shall be coated with approved coatings to the specified dry film thickness (DFT).

1. Process Piping, Design Temperature -20°F to 250°F – Field or Shop Application
    a. (1) Primer Coat: COROTHANE® I MIO-ZINC (3.0-4.0 mils DFT)
    b. (1) Intermediate Coat: COROTHANE® I-IRONOX (3.0-5.0 mils DFT)
    c. (1) Top Coat: SHER-CRYL™ HPA, Color: Haze Gray (2.5-4.0 mils DFT)
2. Process Piping, Design Temperature 250°F to 1000°F, Insulated – Field or Shop Application
    a. (1) Primer Coat: PPG Hi-Temp 1027 (5.0 to 6.0 mils) DFT
    b. (1) Top Coat: PPG Hi-Temp 1027 (5.0 to 6.0 mils) DFT
3. Process Piping, Design Temperature 250°F to 400°F, Non-Insulated – Field or Shop Application
    a. (1) Primer Coat: PPG Hi-Temp 1027 (5.0 to 6.0 mils) DFT
    b. (1) Top Coat: PPG Hi-Temp 500 VS (2.0 to 2.5 mils) DFT
4. Structural Steel
    a. Hot dip galvanized per ASTM A123

3. Shipping and Packaging Instructions

NW Natural

Standard shipping and packaging are acceptable.

4. Receiving Inspection Requirements

Standard receiving inspection is acceptable.

5. References

Sherwin Williams Data Sheet 5.01	COROTHANE® I MIO-ZINC PRIMER
Sherwin Williams Data Sheet 5.07	COROTHANE® I IRONOX® B
Sherwin Williams Data Sheet 1.26	SHER-CRYL™ HPA
PPG Hi-Temp 1027 Product Data Sheet	PPG HI-TEMP 1027
PPG Hi-Temp 500 VS Product Data Sheet	PPG HI-TEMP 500 VS
ASTM A123	HOT DIP GALVANIZING

6. Revision History

Ref 01	11/28/17	Added sections on coatings above 250 F and for galvanizing. Updated references.
Rev 00	12/21/16	New Standard (12/21/16)

COLD BOX SPECIFICATION ATTACHMENT 2:

EXISTING TURBO EXPANDER (C-1) DATA SHEET

MAFI-TRENCH CORPORATION
MACHINE CHARACTERISTICS

CUSTOMER							JOB NUMBER
NORTHWEST NATURAL GAS							368
PREPARED BY: C. BECHTEL			DATE: 09-18-86				TYPE/SIZE:
APPROVED BY: J. LILLARD			DATE: 09-18-86				EC2.5

GAS COMP. MOL %						
OPER. COND. STAGE	DESIGN EXP.	DESIGN COMP.				
N_2	1.10	1.10				
CO_2	0.40	0.40				
H_2						
C_1	92.24	92.24				
C_2	4.88	4.88				
C_3	0.91	0.91				
iC_4	0.47	0.47				
nC_4						
iC_5						
nC_5						
C_6						
C_7						
FLOW RATE						
Lbs/hr.	28216	28216				
GAS PHYSICAL CHARACTERISTIC						
MW	17.423	17.423				
PROCESS GAS CONDITIONS						
P in PSIA	440	63.7				
T in °F	-50	65				
P out PSIA	68.7	113				
T out °F	-164.3	158.1				
Wt.% Liq.	7.7%	0				
MACHINE CHARACTERISTICS						
RPM	40,000					
Eff. %	83%	75%				
HP	572	547				
WT.% LIQ.	7.7%	0				
FLANGE SIZE AND VELOCITY RAT						
INLET	4"(43)300#	10"(72)150#				
OUTLET	8"(56)300#	10"(48)150#				
BEARING HORSE POWER LOSS						
	25 HP, 1.5"0					

O-MANUAL.368 BL9

INSTALLATION

FUNCTION	PROCEDURE	SPECIFICATION DWG. OR ILLUS.
SET UP:	PLACE UNIT ON PEDESTAL (CUSTOMER PROVIDED) DO NOT REMOVE PROTECTIVE COVERS FROM ALL FLANGES UNTIL READY TO CONNECT PLANT PIPING. REMOVE DESICCANT BAGS FROM EXPANDER DISCHARGE IF PRESENT.	SEE EXPANDER-COMPRESSOR OUTLINE DIMENSIONS.
PIPE AND LINE CONNECTIONS:	SHUTDOWN VALVE, MUST BE SIZED TO CLOSE IN 1/2 SECOND.	INSTALL, CONNECT SOLENOID AND CHECK OPERATION.
	COMPRESSOR INLET - INSTALL INLET SCREEN. EXPANDER INLET - CONFIRM INLET SCREEN INSTALLED. (MAXIMUM PRESSURE DROP ACROSS SCREENS 20 PSI).	INSURE APEX IS UPSTREAM. PROVIDE GAUGES TO MONITOR PRESSURE DROP.
	SEAL GAS SUPPLY TO PANEL REGULATOR, SEE PAGE 7.	BLOW DOWN LINES TO ENSURE CLEAN, DRY COMPATIBLE GAS.
ACTUATOR:	MOUNT ACTUATOR PER ACTUATOR SET-UP PROCEDURE (SEE PAGE 23)	BLOW DOWN SUPPLY AND SIGNAL LINES BEFORE HOOKUP.
	CHECK ACTUATOR TRAVEL.	SEE PAGE 7.
OIL RESERVOIR:	FLUSH LUBE OIL RESERVOIR BY BYPASSING THE JOURNAL BEARING HOUSING DIRECTLY TO THE RESERVOIR. CHECK AND CLEAN FILTERS UNTIL CYCLED OIL IS CLEAN. REPEAT AS LONG AS NECESSARY.	SEE PAGE 7. <u>DO NOT USE DETERGENT OIL.</u>
	CHECK LUBE OIL LEVEL. NOTE: PRESSURIZED SYSTEMS MUST BE SHUT DOWN AND DEPRESSURIZED BEFORE FILLING, UNLESS A SPECIAL PUMP IS PROVIDED.	

UNIT SPECIFICATIONS

JOB NO.: 368 CUSTOMER: NORTHWEST NATURAL GAS DATE: JANUARY, 1986

BEARING LUBRICATION	TYPE	VISCOSITY	POUR POINT	
LUBE OIL SPECIFICATIONS	TURBINE OIL NON-FOAM NON-DET.	150 - 175 SSU @ 100° F	-40° F	

LUBE OIL SYSTEM	NORMAL	ALARM	SHUTDOWN	REFERENCE
LUBE OIL DIFFERENTIAL PRESSURE TO BEARINGS	150 PSID	110 PSID	90 PSID	ABOVE RESERVOIR PRESSURE
BEARING THRUST DIFFERENTIAL	50 PSID	150 PSID	200 PSID	
OIL TEMPERATURE TO UNIT	110° F		130° F	
MAXIMUM BEARING TEMPERATURE (RTD)		180° F	200° F	
MAXIMUM DRAIN TEMPERATURE		165° F	180° F	
LOW BEARING TEMPERATURE			60° F COLDSTART	PREVENTS START

SEAL GAS	NORMAL	ALARM	SHUTDOWN	REFERENCE
DIFFERENTIAL PRESSURE	50 PSID		20 PSID	ABOVE WHEEL PRESSURE
FLOW (CUSTOMER SUPPLY TO UNIT)	135 SCFM			MOL WT OF SEAL GAS = 17.4

UNIT	NORMAL	ALARM	SHUTDOWN	REFERENCE
SPEED	40,000 RPM	42,000 RPM	44,000 RPM	
ACTUATOR ROD TRAVEL STOP TO STOP	1.250 IN			
VIBRATION	0.5 MILS	0.8 MILS	1.5 MILS	

APPENDIX E2

Pre-treatment UOP Adsorbent Bed Design Datasheets

UOP A Honeywell Company

New Pretreatment System to Replace Existing Driers and CO_2 Adsorbers

UOP Design Summary Sheet

Customer / End User:	NWN Portland	Date:	7/2/2021
Location:		Design Number:	NWN Peakshaver, 3-vessel, 2 hr ads
Engineering Contractor:	Sanborn Head & Associates	Unit Description:	
Location:		UOP SFDC Treating Unit ID:	
Version Design Tool:	1.3.72	UOP SFDC Case Nr:	
		Vessel Tag Nr:	

Process Description:

3-bed unit operated in 1 bed in adsorption and two beds in series cool and heat regeneration

Adsorbent Bed Design

Number of Adsorbent Vessels:	3	Adsorbent Bed Height:	16.57 ft	Vessel Tag Number:	
Adsorbent Bed Diameter:	6 ft	Bed Height with Inerts:	17.8 ft	Insulation:	Internal Castable Insulation

ADSORBENT	Quantity Per Bed kg	Total Quantity kg
LNG-V 8 x 12 beads	8505.0	25515.0
Total	8505.0	25515.0

INERTS	Height of Layer ft	Quantity Per ft3	Total Quantity ft3
3/4" Inert Balls	0.49	14	42
1/8" Inert Balls	0.25	7	21
1/4" Inert Balls	0.25	7	21
1/2" Inert Balls	0.25	7	21

Process Design

		Adsorption	Depressurization	Heating	Cooling	Repressurization	Standby
Adsorption Time	hours	2.0		1.9	1.9		0.1
Flow Direction		Down	Down	Up	Down	Down	
Type of Cycle		Open		Open	Open		
Pressure Drop	psi	<2		<2	<1		

Process Conditions

		Feed	Product	Regeneration (Heating)	Regeneration (Cooling)
Phase		GAS		GAS	GAS
Total Molar Flow	MMSCFD(60F	19.0	12.8	6.0	6.0
Total Mass Flow	lb/hr	35827.7		11062.2	11062.2
Molar Flow / Bed	MMSCFD(60F	19.0		6.0	6.0
Temperature	F	65.0		550.0	70.0
Pressure	psia	417.70		74.70	74.70
Molecular Weight		17.17		16.79	16.79
Composition:		mol%		mol%	mol%
Nitrogen		0.549		1.0001	1.0001
Methane		93.4575		94.9847	94.9847
Ethane		4.5117		3.6502	3.6502
Propane		0.3494		0.28	0.28
i-Butane		0.0499		0.039	0.039
n-Butane		0.0449		0.034	0.034
i-Pentane		0.01		0.006	0.006
n-Pentane		0.008		0.005	0.005
n-Hexane		0.005		0.001	0.001
Contaminants:					
CO2	ppm mol	10000	<50		
H2O	ppm mol	147	<1		

Add sulfur and mercaptan to contaminants list for removal for further design

Notes

Note 1: Adsorption time is the minimum expected adsorption time after 3 years of operation and with 1 bed(s)in adsorption.

Note 2: Standby time includes time for valve switching, de- and re-pressurization (max. 3.5 bar /min; Flow direction: DOWN) and standby time.

Note 3: Support system: Support grating with ceramic balls.

Note 4: Single phase flow is mandatory for good operation of the sorption unit.

Note 5: Internal vessel diameter is 6.0 ft

UOP A Honeywell Company

Available Performance of Existing CO_2 Adsorbers

UOP Design Summary Sheet

Customer / End User:	NWN Portland		Date:	5/13/2021
Location:			Design Number:	Sanborn Head, NWN Peakshaver, 2-vessel
Engineering Contractor:	Sanborn Head & Associates		Unit Description:	
Location:			UOP SFDC Treating Unit ID:	
Version Design Tool:		3.67	UOP SFDC Case Nr:	
			Vessel Tag Nr:	

Process Description:
2-bed unit operated in 1 bed in adsorption and 1 bed in regeneration

Adsorbent Bed Design

Number of Adsorbent Vessels:	2	Adsorbent Bed Height:	9.68 ft	Vessel Tag Number:	
Adsorbent Bed Diameter:	3.83 ft	Bed Height with Inerts:	10.91 ft	Insulation:	Internal Castable Insulation

ADSORBENT	Quantity Per Bed kg	Total Quantity kg
LNG-V 8 x 12 beads	2025.0	4050.0
Total	2025.0	4050.0

INERTS	Height of Layer ft	Quantity Per ft3	Total Quantity ft3
3/4" Inert Balls	0.49	6	11
1/8" Inert Balls	0.25	3	6
1/4" Inert Balls	0.25	3	6
1/2" Inert Balls	0.25	3	6

Process Design

		Adsorption	Depressurization	Heating	Cooling	Repressurization	Standby
Adsorption Time	hours	3.5		1.9	1.5		0.1
Flow Direction		Down	Down	Up	Up	Down	
Type of Cycle		Open		Open	Open		
Pressure Drop	psi	<1		<1	<1		

Process Conditions

		Feed	Product	Regeneration (Heating)	Regeneration (Cooling)
Phase		GAS		GAS	GAS
Total Molar Flow	MMSCFD(60F	4.0		1.4	1.4
Total Mass Flow	lb/hr	7495.0		2654.9	2654.9
Molar Flow / Bed	MMSCFD(60F	4.0		1.4	1.4
Temperature	F	65.0		550.0	70.0
Pressure	psia	417.70		74.70	74.70
Molecular Weight		17.06		16.79	16.79
Composition:		mol%		mol%	mol%
Nitrogen		0.5513		1.0001	1.0001
Methane		93.849		94.9847	94.9847
Ethane		4.5306		3.6502	3.6502
Propane		0.3508		0.28	0.28
i-Butane		0.0501		0.039	0.039
n-Butane		0.0451		0.034	0.034
i-Pentane		0.01		0.006	0.006
n-Pentane		0.008		0.005	0.005
n-Hexane		0.005		0.001	0.001
H2O		0		0	0
Contaminants:					
CO2	ppm mol	6000	<50		

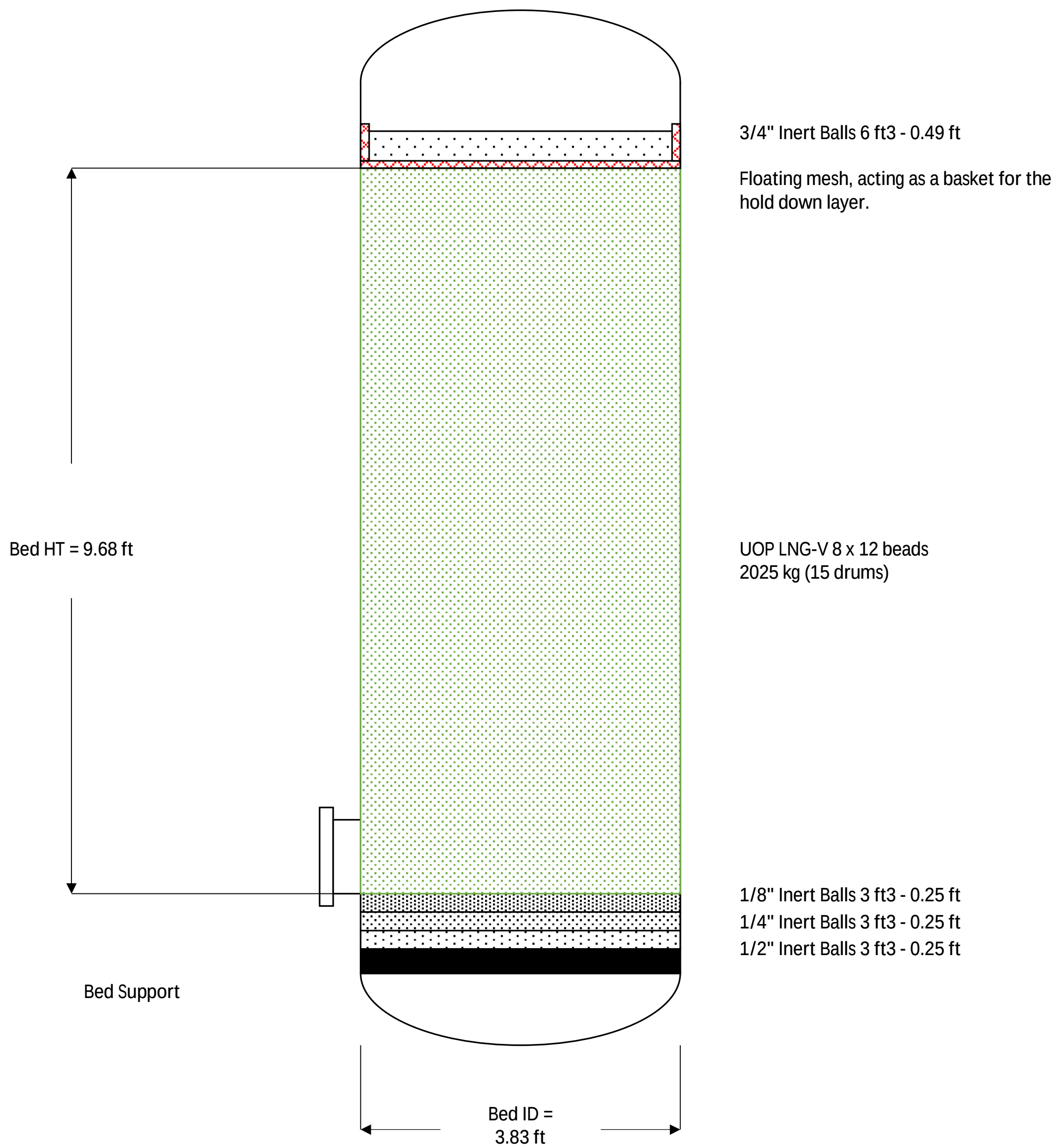
Notes

Note 1: Adsorption time is the minimum expected adsorption time after 3 years of operation and with 1 bed(s)in adsorption.
Note 2: Standby time includes time for valve switching, de- and re-pressurization (max. 3.5 bar /min; Flow direction: DOWN) and standby time.
Note 3: Support system: Support grating with ceramic balls.
Note 4: Single phase flow is mandatory for good operation of the sorption unit.

UOP A Honeywell Company

UOP Design Summary Sheet

Customer / End User:	NWN Portland	Date:	5/13/2021
Location:		Design Number:	Sanborn Head, NWN Peakshaver, 2-vessel
Engineering Contractor:	Sanborn Head & Associates	Unit Description:	
Location:		UOP SFDC Treating Unit ID:	
Version Design Tool:	3.67	UOP SFDC Case Nr:	
		Vessel Tag Nr:	



Notes

For the top floating screen, install a 20 US mesh stainless steel screen (screen diameter 5.15 ft, wire diameter 0.51 mm, sieve opening 0.85 mm) on top of the UOP Sorbent. This screen should be folded upwards along the vessel wall. If laid in sections, these sections should overlap 100-150 mm and be wired together with stainless steel wire and two rows of stitches.

UOP A Honeywell Company

Available Performance when Adding 3rd Bed to Existing CO_2 Adsorbers

UOP Design Summary Sheet

Customer / End User:	NWN Portland	Date:	5/13/2021
Location:		Design Number:	Sanborn Head, NWN Peakshaver, 3-vessel
Engineering Contractor:	Sanborn Head & Associates	Unit Description:	
Location:		UOP SFDC Treating Unit ID:	
Version Design Tool:	3.67	UOP SFDC Case Nr:	
		Vessel Tag Nr:	

Process Description:
3-bed unit operated in 1 bed in adsorption and two beds in series cool and heat regeneration

Adsorbent Bed Design

Number of Adsorbent Vessels:	3	Adsorbent Bed Height:	9.68 ft	Vessel Tag Number:	
Adsorbent Bed Diameter:	3.83 ft	Bed Height with Inerts:	10.91 ft	Insulation:	Internal Castable Insulation

ADSORBENT	Quantity Per Bed kg	Total Quantity kg
LNG-V 8 x 12 beads	2025.0	6075.0
Total	2025.0	6075.0

INERTS	Height of Layer ft	Quantity Per ft3	Total Quantity ft3
3/4" Inert Balls	0.49	6	17
1/8" Inert Balls	0.25	3	9
1/4" Inert Balls	0.25	3	9
1/2" Inert Balls	0.25	3	9

Process Design

		Adsorption	Depressurization	Heating	Cooling	Repressurization	Standby
Adsorption Time	hours	2.4		2.0	2.0		0.4
Flow Direction		Down	Down	Up	Down	Down	
Type of Cycle		Open		Open	Open		
Pressure Drop	psi	<1		<1	<1		

Process Conditions

		Feed	Product	Regeneration (Heating)	Regeneration (Cooling)
Phase		GAS		GAS	GAS
Total Molar Flow	MMSCFD(60F	4.0		1.4	1.4
Total Mass Flow	lb/hr	7542.6		2654.9	2654.9
Molar Flow / Bed	MMSCFD(60F	4.0		1.4	1.4
Temperature	F	65.0		550.0	70.0
Pressure	psia	417.70		74.70	74.70
Molecular Weight		17.17		16.79	16.79
Composition:		mol%		mol%	mol%
Nitrogen		0.5491		1.0001	1.0001
Methane		93.4714		94.9847	94.9847
Ethane		4.5123		3.6502	3.6502
Propane		0.3494		0.28	0.28
i-Butane		0.0499		0.039	0.039
n-Butane		0.0449		0.034	0.034
i-Pentane		0.01		0.006	0.006
n-Pentane		0.008		0.005	0.005
n-Hexane		0.005		0.001	0.001
H2O		0		0	0
Contaminants:					
CO2	ppm mol	10000	<50		

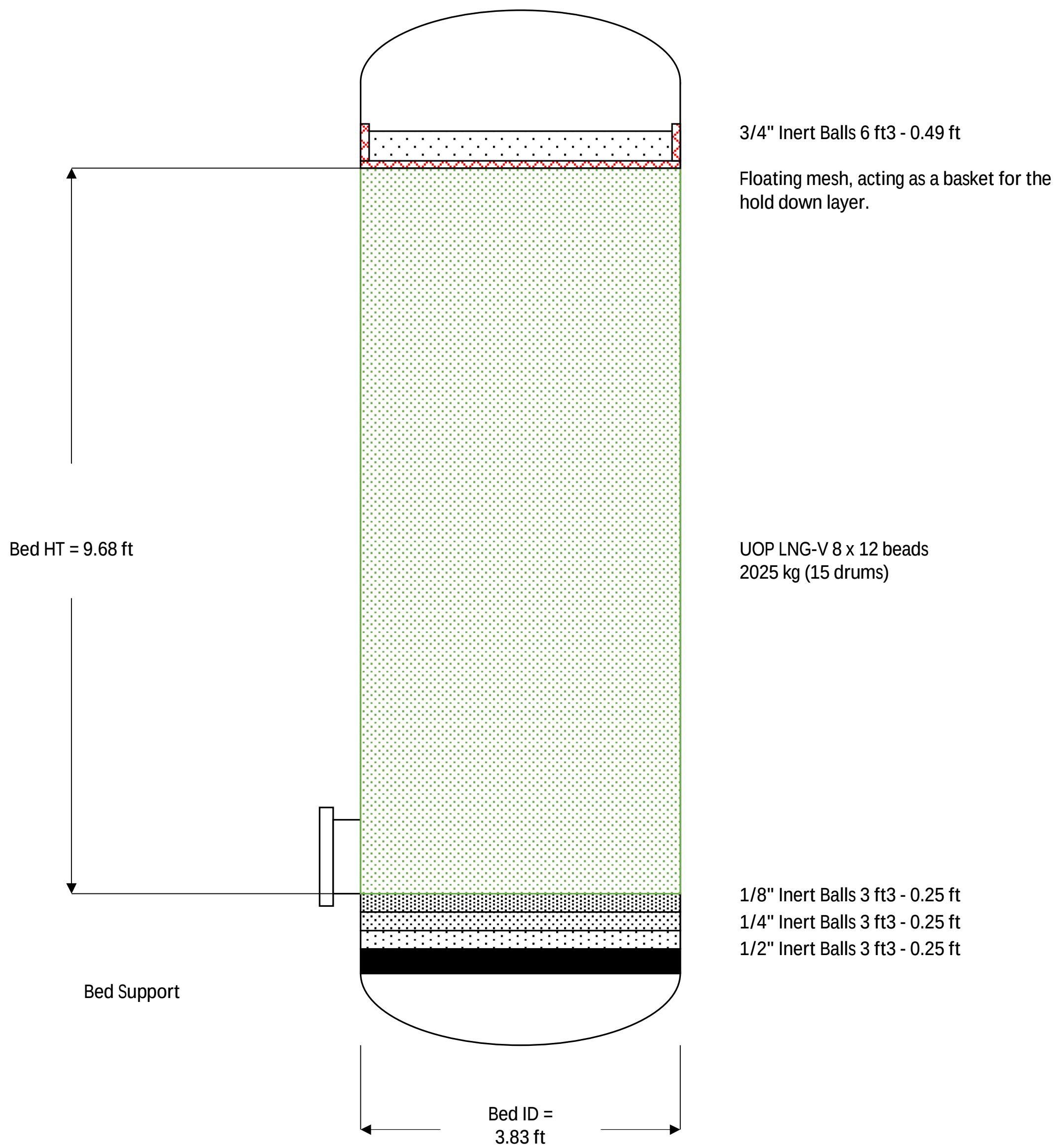
Notes

Note 1: Adsorption time is the minimum expected adsorption time after 3 years of operation and with 1 bed(s)in adsorption.
Note 2: Standby time includes time for valve switching, de- and re-pressurization (max. 3.5 bar /min; Flow direction: DOWN) and standby time.
Note 3: Support system: Support grating with ceramic balls.
Note 4: Single phase flow is mandatory for good operation of the sorption unit.

UOP A Honeywell Company

UOP Design Summary Sheet

Customer / End User:	NWN Portland	Date:	5/13/2021
Location:		Design Number:	Sanborn Head, NWN Peakshaver, 3-vessel
Engineering Contractor:	Sanborn Head & Associates	Unit Description:	
Location:		UOP SFDC Treating Unit ID:	
Version Design Tool:	3.67	UOP SFDC Case Nr:	
		Vessel Tag Nr:	



Notes

For the top floating screen, install a 20 US mesh stainless steel screen (screen diameter 5.15 ft, wire diameter 0.51 mm, sieve opening 0.85 mm) on top of the UOP Sorbent. This screen should be folded upwards along the vessel wall. If laid in sections, these sections should overlap 100-150 mm and be wired together with stainless steel wire and two rows of stitches.

APPENDIX E3

Mercury Guard UOP Adsorbent Bed Design Datasheet

UOP A Honeywell Company

UOP Design Summary Sheet

Customer / End User:	NWN Portland	Date:	5/19/2021
Location:		Design Number:	Sanborn Head, NWN MRU
Engineering Contractor:	Sanborn Head & Associates	Unit Description:	Mercury Removal Unit
Location:		UOP SFDC Treating Unit ID:	
Version Design Tool:	3.67	UOP SFDC Case Nr:	
		Vessel Tag Nr:	

Process Description:
Single-bed unit operated in one bed in adsorption.

Adsorbent Bed Design

Number of Adsorbent Vessels:	1	Adsorbent Bed Height:	6.56 ft	Vessel Tag Number:	
Adsorbent Bed Diameter:	4 ft	Bed Height with Inerts:	7.79 ft	Insulation:	External Insulation

ADSORBENT	Quantity Per Bed kg	Total Quantity kg
GB-562S 5 x 8 beads	1920.0	1920.0
Total	1920.0	1920.0

INERTS	Height of Layer ft	Quantity Per ft3	Total Quantity ft3
3/4" Inert Balls	0.49	6	6
1/8" Inert Balls	0.25	3	3
1/4" Inert Balls	0.25	3	3
1/2" Inert Balls	0.25	3	3
3/4" Inert Balls		8	8

Process Design

		Adsorption	Depressurization	Heating	Cooling	Repressurization	Standby
Adsorption Time		>10 Years					
Flow Direction		Down					
Type of Cycle		Open					
Pressure Drop	psi	< 1.19					

Process Conditions

		Feed	Product	Regeneration (Heating)	Regeneration (Cooling)
Phase		GAS			
Total Molar Flow	MMSCFD(60F	19.0			
Total Mass Flow	lb/hr	35827.6			
Molar Flow / Bed	MMSCFD(60F	19			
Temperature	F	60			
Pressure	psia	417.7			
Molecular Weight		17.17			
Composition:		mol%		mol%	mol%
Nitrogen		0.549			
CO2		0.9999			
Methane		93.4576			
Ethane		4.5117			
Propane		0.3494			
i-Butane		0.0499			
n-Butane		0.0449			
i-Pentane		0.01			
n-Pentane		0.008			
n-Hexane		0.005			
H2O		0.0147			
Contaminants:					
Mercury	µg/Nm3	15.33	<10 ng/Nm3		
	ppbw	20			

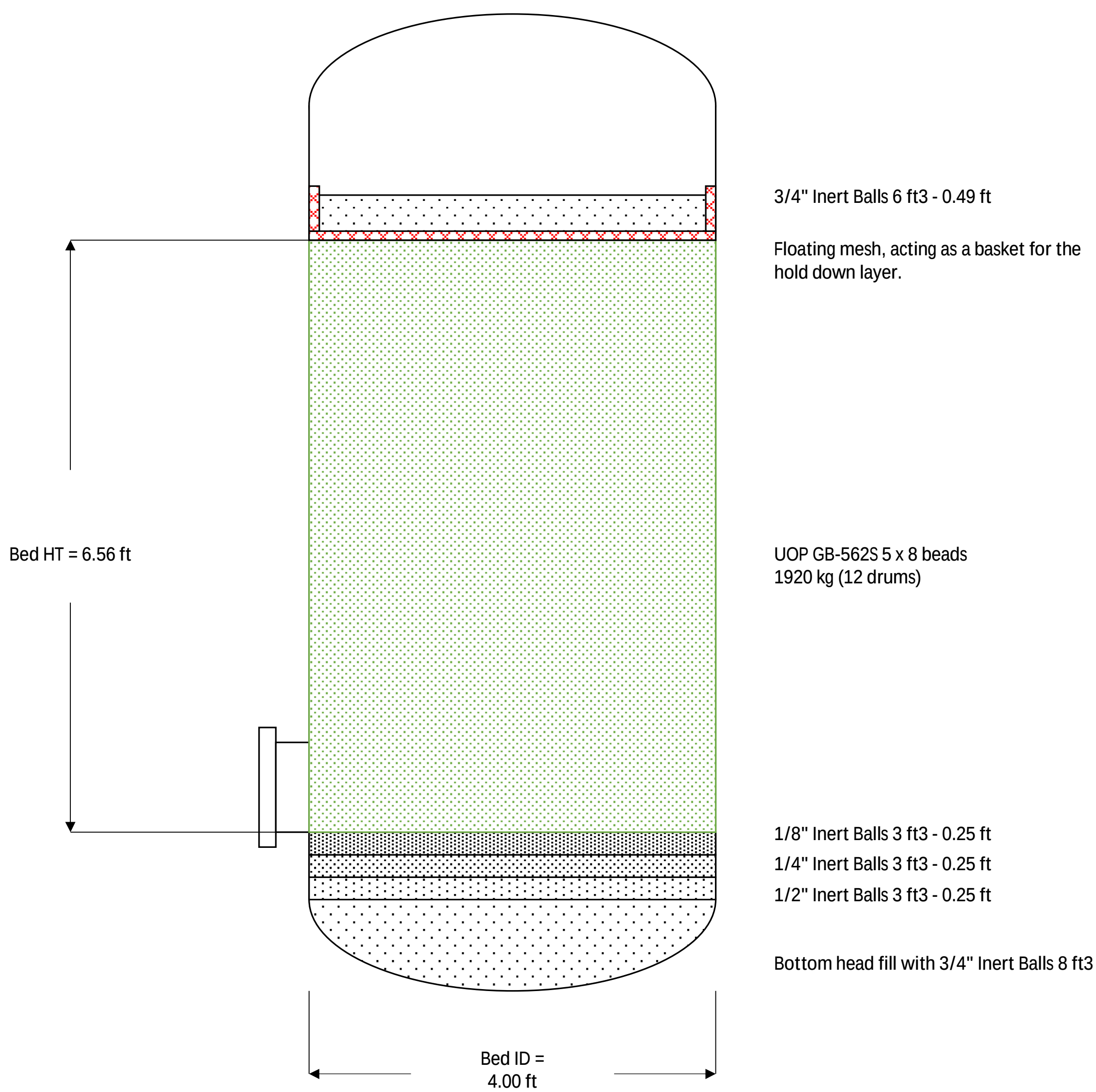
Notes

Note 1: Adsorption time is the minimum expected adsorption time with 1 bed(s).
Note 2: Single phase flow is mandatory for good operation of the sorption unit.
Note 3: Support system: Bottom head filled with ceramic balls
Note 4: Pressure drop is per vessel.

UOP A Honeywell Company

UOP Design Summary Sheet

Customer / End User:	NWN Portland	Date:	5/19/2021
Location:		Design Number:	Sanborn Head, NWN MRU
Engineering Contractor:	Sanborn Head & Associates	Unit Description:	Mercury Removal Unit
Location:		UOP SFDC Treating Unit ID:	
Version Design Tool:	3.67	UOP SFDC Case Nr:	
		Vessel Tag Nr:	



Notes

For the top floating screen, install a 20 US mesh stainless steel screen (screen diameter 5.31 ft, wire diameter 0.51 mm, sieve opening 0.85 mm) on top of the UOP Sorbent. This screen should be folded upwards along the vessel wall. If laid in sections, these sections should overlap 100-150 mm and be wired together with stainless steel wire and two rows of stitches.

APPENDIX E4

Equipment/Component Replacement List

Equipment/Component Replacement List

Table ER-1: Equipment/Component Replacement List

Line	Tag	Basic Description	Description	Normal Operating Temp (°F)	Normal Working Fluid/Gas	Line Identification	Shown on P&ID	Tie Point Basis	Proposed Action
1	PCV-24	Control Valve	4" Expander Inlet Pressure Control plug valve. On/off control with actuator and limit switches.	-60	Natural Gas	6"-A8-N9	P-006	TP-13	Replace
2	HCV-74E	Control Valve	1" Expander Bypass Globe Valve, with On/off control with actuator and limit switches.	-60	Natural Gas	1"	P-006	TP-13/18	Replace
3	LCV-42	Control Valve	2" S-4 Level Control Valve, with modulating actuator/positioner.	-80	Heavy Hydrocarbons	2"-A8-N35	P-007	NA	Replace
4	LCV-S3	Control Valve	1/2" S-3 Level Control Valve, with modulating actuator/positioner.	-70	Heavy Hydrocarbons	1/2"	P-007	NA	Replace
5	FCV-16	Control Valve	1 1/2" LNG J-T Globe Valve, with modulating actuator/positioner.	-220	Liquid Natural Gas	1 1/2"-A8-N39	P-008	None	Replace
6	FCV-20	Control Valve	1 1/2" LNG Flash Gas Globe valve with modulating actuator/positioner.	-220	Liquid Natural Gas	1 1/2"-A8-N10	P-007	TP-09/12 (12 route)	Replace
7	HCV-74	Control Valve	10" C-1 Compressor Suction HCV with open/close actuator and limit switches	65	Natural Gas	10"-B4-N15	P-006	TP 01A	Replace
8	HCV-98	Control Valve	8" Emergency Shutdown Ball Valve with on/off control with actuator and limit switches.	60	Natural Gas	10"-B4-N1	P-002	NA	Replace under alternate project scope.
9	FCV-13	Control Valve	3" Control Ball Valve, with on/off control with actuator and limit switches.	60	Natural Gas	4"-B4-N50	P-004	TP-06	Replace
10									
11									
12									
13	N71-23	Gate Valve	6" Isolation Gate Valve	-190	Natural Gas	6"-A8-N71	P-007	TP 03	Replace
14	N44-14	Gate Valve	4" Isolation Gate Valve	65	Natural Gas	4"-B4-N44	P-007	TP 06	Replace
15	No Tag GV	Gate Valve	6" Isolation Gate Valve with extended stem	65	Natural Gas	6"-B4-N4	P-007	TP-07	Replace
16	N11-22	Gate Valve	10" Isolation Valve with extended stem	-170	Natural Gas	10"-A8-N11	P-007, P-006	TP-18	Replace
17	New GV	Gate Valve	8" Isolation Gate Valves for new Mercury Guard, QTY 3	65	Natural Gas	8"-B4-N19	P-002	New	Replace
18	N45-17	Ball Valve	3" isolation ball valve	65	Natural Gas	3"-B4-N50	P-004	TP-06	Replace
19	No Tag BV	Ball Valve	4" isolation ball valve	65	Natural Gas	4"-B4-N50	P-004	TP-06	Replace
20	No Tag BV	Ball Valve	4" isolation ball valve	65	Natural Gas	4"-B4-N45	P-004	TP-06	Replace
21	No Tag BV	Ball Valve	4" isolation ball valve	65	Natural Gas	4"-B4-N50	P-006	TP-01C	Replace
22	N19-13	Ball Valve	4" isolation ball valve	65	Natural Gas	4"-B4-N83	P-006	TP-01C	Replace
23									
24									
25									
26	RD-XX	Safety Valve	6" Rupture Disc, SP 200 PSIG	65	Natural Gas	10"-B4-N15	P-006	TP 01A	Replace
27	SV-424	Safety Valve	3/4" x 1" Safety Valve, Set at 550 PSIG	65	Natural Gas	4"-B4-N44	P-007	TP 06	Replace
28	SV-401	Safety Valve	3/4" x 1 1/2" Safety Valve, Set at 550 PSIG	65	Natural Gas	1 1/2"-A8-N10	P-007	TP-09/12 (12 route)	Replace
29	New RV	Safety Valve	New RV for Mercury Guard	65	Natural Gas	8"-B4-N19	P-002	New	Replace
30									
31									
32									
33	None	Small Valve	3/4" drain/bleed/vent valve	-170	Natural Gas	6"-A8-N71	P-007	TP 03	Replace
34	N44-14A	Small Valve	1/2" Bleed valve	65	Natural Gas	4"-B4-N44	P-007	TP 06	Replace
35	None	Small Valve	Block and Bleed Assembly for SV-424: 3/4" isolation ball valve, 1/4" bleed plug valve, small dia piping	65	Natural Gas	4"-B4-N44	P-007	TP 06	Replace
36	None	Small Valve	1/2" drain/bleed/vent gate valve	-220	Liquid Natural Gas	1 1/2"-A8-N39	P-007	TP-09/12 (09 route)	Replace
37	None	Small Valve	3/4" drain/bleed/vent gate valve	-220	Natural Gas	1 1/2"-A8-N10	P-007	TP-09/12 (12 route)	Replace
38	None	Small Valve	Block and Bleed Assembly for SV-401: 3/4" Block gate valve, 1/4" Bleed valve, small dia piping	-220	Liquid Natural Gas	1 1/2"-A8-N10	P-007	TP-09/12 (12 route)	Replace
39	SD-1, SD-2	Small Valve	SD-1, SD-2, Separator Diversion valves for drain flow from S-3	-60	Heavy Hydrocarbons	3/4" to E-14	P-007	TP-33/TP-18	Replace
40	S4-1, S4-2	Small Valve	SD-3, SD-4. Separator Diversion valves for drain flow from S-4	-80	Heavy Hydrocarbons	3/4" to E-14	P-007	TP-33/TP-18	Replace

Equipment/Component Replacement List

Table ER-1: Equipment/Component Replacement List

41									
42									
43									
44	None	Small Tubing	Spool/isolation valves for S-4 liquid out	-170	Heavy Hydrocarbons	2"-A8-N35	P-007	NA	Replace
45	None	Small Tubing	Spool/isolation valves for S-3 liquid out	-170	Heavy Hydrocarbons	3/4", 1/2", 1"	P-007	NA	Replace
46	None	Spool	Spool	65	Natural Gas	10"-B4-N15	P-007, P-006	TP 01A	Replace
47	None	Spool	Spool	65	Natural Gas	8"-B4-N16	P-006	TP 01B	Replace
48	None	Spool	Spool	65	Natural Gas	4"-B4-N83	P-006	TP 01C	Replace
49	None	Spool	Spool	65	Natural Gas	6"-A10-N75	P-007, P-004	TP 02	Replace
50	None	Spool	Spool	-170	Natural Gas	6"-A8-N71	P-007	TP 03	Replace
51	None	Spool	Spool	65	Natural Gas	4"-B4-N44	P-007	TP 06	Replace
52	None	Spool	Spool	65	Natural Gas	6"-B4-N4	P-007	TP-07	Replace
53	None	Spool	Spool	-220	Liquid Natural Gas	1 1/2"-A8-N39	P-007	TP-09/12 (09 route)	Replace
54	None	Spool	Spool	-220	Liquid Natural Gas	1 1/2"-A8-N10	P-007	TP-09/12 (12 route)	Replace
55	None	Spool	Spool	-60	Natural Gas	6"-A8-N9	P-007	TP-13	Replace
56	None	Spool	Spool	65	Natural Gas	4"-B4-N29	P-007	TP-16	Replace
57	None	Spool	Spool	-170	Natural Gas	10"-A8-N11	P-007, P-006	TP-18	Replace
58	None	Spool	Spool	65	Natural Gas	4"-B4-N50	P-004	TP-06	Replace
59	None	Spool	Spool	65	Natural Gas	3"-B4-N86	P-004	TP-06	Replace
60	None	Spool	Spool	65	Natural Gas	4"-B4-N45	P-004	TP-06	Replace
61	None	Spool	Spool, New for Mercury Guard Installation	60	Natural Gas	8"-B4-N16	P-002	NA	Replace
62	BEL-01	Spool	10" Bellows	-170	Natural Gas	10"-A8-N11	P-007, P-006	TP-18	Reuse
63	None	Spool	Spool	65	Natural Gas	4"-B4-N59	P-006	TP-01C±	Replace
64									
65									
66									
67	TE-XX	I/C	Temperature Element	65	Natural Gas	6"-A10-N75	P-007, P-004	TP 02	Replace
68	TE-e	I/C	Temperature Element	-170	Natural Gas	6"-A8-N71	P-007	TP 03	Replace
69	TE-C	I/C	Temperature Element	-220	Liquid Natural Gas	1 1/2"-A8-N39	P-007	TP-09/12 (09 route)	Replace
70	TE-D	I/C	Temperature Element	-220	Natural Gas	1 1/2"-A8-N10	P-007	TP-09/12 (12 route)	Replace
71	TE-25	I/C	Temperature Element	-60	Natural Gas	6"-A8-N9	P-007	TP-13	Replace
72	TE-B	I/C	Temperature Element	-60	Natural Gas	6"-A8-N9	P-007	TP-13	Replace
73	FT-20	I/C	I/P Transducer for FCV-20	NA	NA	1 1/2"-A8-N10	P-007	TP-09/12 (12 route)	Reuse
74	FIT-20	I/C	Coriolis Flow Meter & Indicating Transmitter	-220	NA	1 1/2"-A8-N10	P-007	TP-09/12 (12 route)	Replace
75	PT-14	I/C	Pressure Transmitter	65	Natural Gas	10"-B4-N15	P-006	TP 01A	Reuse
76	FIT-16	I/C	Coriolis Flow Meter & Indicating Transmitter	-220	Natural Gas	1 1/2"-A8-N39	P-007	TP-09/12 (09 route)	Replace
77	New	I/C	Cold Box Differential Pressure Transmitters, QTY 6	-220	Natural Gas/Liquid Natural Gas	Various	Various	Multiple	Replace
78	New	I/C	C02 Analyzer with Pressure and Temp Stream Specs Listed	NA	Natural Gas	NA	NA	New	Replace
79									
80									
81									
82	LCV-S2	NA	S-2 Level Control Valve	NA	NA	1/2"	P-007	NA	Remove Only
83	None	NA	Spool/isolation valves for S-2 liquid out piping	NA	NA	3/4", 1/2"	P-007	NA	Remove Only
84	TCV-27	NA	Liquefaction Boiloff Mode Temperature Control Valve	NA	NA	2"-A8-N52	P-007	NA	Remove Only
85	Spool	NA	Liquefaction Boiloff Mode Refrigerant Outlet (FCV removed previously)	NA	NA	6"-A8-N55	P-007	NA	Remove Only
86	None	Small Tubing	3/4" Tubing to E-14 Heavy Ends Vaporizer	-60	Heavy Hydrocarbons	3/4"	P-007	NA	Remove Only
87	None	Small Valve	1/2" drain/bleed/vent valve	-60	Natural Gas	6"-A8-N9	P-007	TP-13	Remove Only
88	N35-24	Small Valve	2" Block Valve in S-4 Drain Outlet		Heavy Hydrocarbons	2"-A8-N35	P-007	TP-33/TP-18	Remove Only
89	TABLE END								

APPENDIX F

Permit Matrix

Permitting Matrix

Table PM-1: Permitting Matrix for NWN Cold Box Replacement, Portland OR

Item #	Permit of Approval	Regulatory Agency	Required [Note 1]	Estimated Approval Timeframe	Comments
1	Commercial Mechanical Permit	City of Portland	YES	4-6 Weeks [Note 2]	Project is mechanical in nature and will reuqire a mechanical permit for the work.
2	Commercial Electrical	City of Portland	YES	N/A [Note 2]	Covered under Commercial Mechanical.
3	Erosion and Sediment Control Plan	City of Portland	YES	3-4 Months	10 cubic yard soil removal threshold. Soil removal required for foundation demolition and installation will exceed the threshold.
4	Erosion and Sediment Control Plan	State of Oregon	No	N/A	1 acre soil removal threshold
5	EFSC Certificate	Oregon DOE	No	N/A	Currently grandfathered out of this requirement. Trigger including but not limited to: Liquefaction capacity increase.
6	Commercial Alteration - Tenant Improvement Building Permits & Inspections (Level 3) - Building Permit, Life Safety, Water, Errosion Control	City of Portland	No	3-4 Months	Only required if triggered during Commercial Mechanical Permitting process. Triggers inlcuding but not limited to: Increase in building footprint or addition of new structure under Commercial Code.
7	Building	City of Portland	No	N/A	Covered under Commercial Mechanical if required.
8	Temporary Construction Easements	City of Portland	No	N/A	There is adequate space, this is not required.
9	Air Permit	Environmental Protection Agency	No	N/A	No additional air emissions.
10	NPDES Stormwater	City of Portland	No	N/A	Per Norwest Engineering.
11	Flood Plain Development Permit Application for Non Residence	City of Portland	No	N/A	Site is not in a current flood zone.
12	Demolition	City of Portland	No	N/A	Portland only requires permit for residential demolition.
13	401 Water Quality Certification	State of Oregon	No	N/A	Per Norwest Engineering.

General Notes:

A. Information obtained from publicly available information, Northwest Natural Gas Company, and Norwest Engineering.

Notes:

1. Applicability based on Cold Box replacement scope only and information gathered from sources as indicated in Note A. Refer to comments for basis.
2. Based on the requirement for an Erosion and Sediment Control Plan, the approval time frame for all required permits may extend to 3-4 months if submitted as one application. Note, only one permit may be in construction at any one time (Per City of Porland Oregon).

CERTIFICATE OF SERVICE

I hereby certify that on October 21, 2022, I have served by electronic mail NW NATURAL'S ERRATA TO ITS INTEGRATED RESOURCE PLAN upon all parties of record for docket LC 79.

LC 79

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DATED October 21, 2022, Troutdale, Oregon.

/s/ Erica Lee-Pella
Erica Lee-Pella
Rates & Regulatory Affairs, NW Natural