NW Natural

2018 Integrated Resource Plan

LC-71

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Draft for Public Comment

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NW NATURAL 2018 INTEGRATED RESOURCE PLAN

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CHAPTER 1

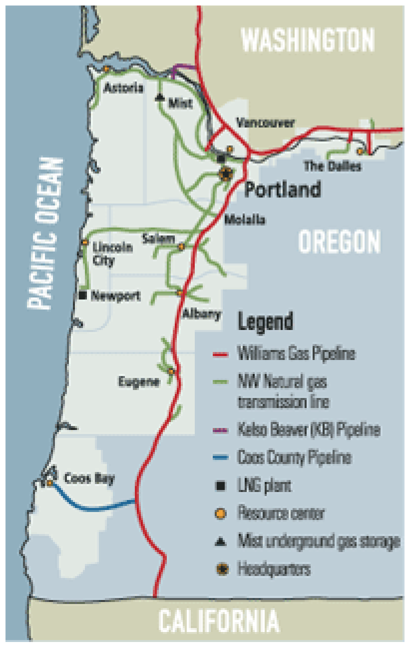
EXECUTIVE SUMMARY

1. OVERVIEW

1.1. ABOUT NW NATURAL

NW Natural Gas Company (NW Natural) is a 159-year-old natural gas local distribution and storage company headquartered in Portland, Oregon. NW Natural serves approximately 2.5 million people in Oregon and Washington via over 740,000 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 percent of NW Natural's customers reside in Oregon, with the other 11 percent in the state of Washington. Residential customers account for roughly 90 percent of our customer accounts.

Figure 1.1: NW Natural's Service Territory



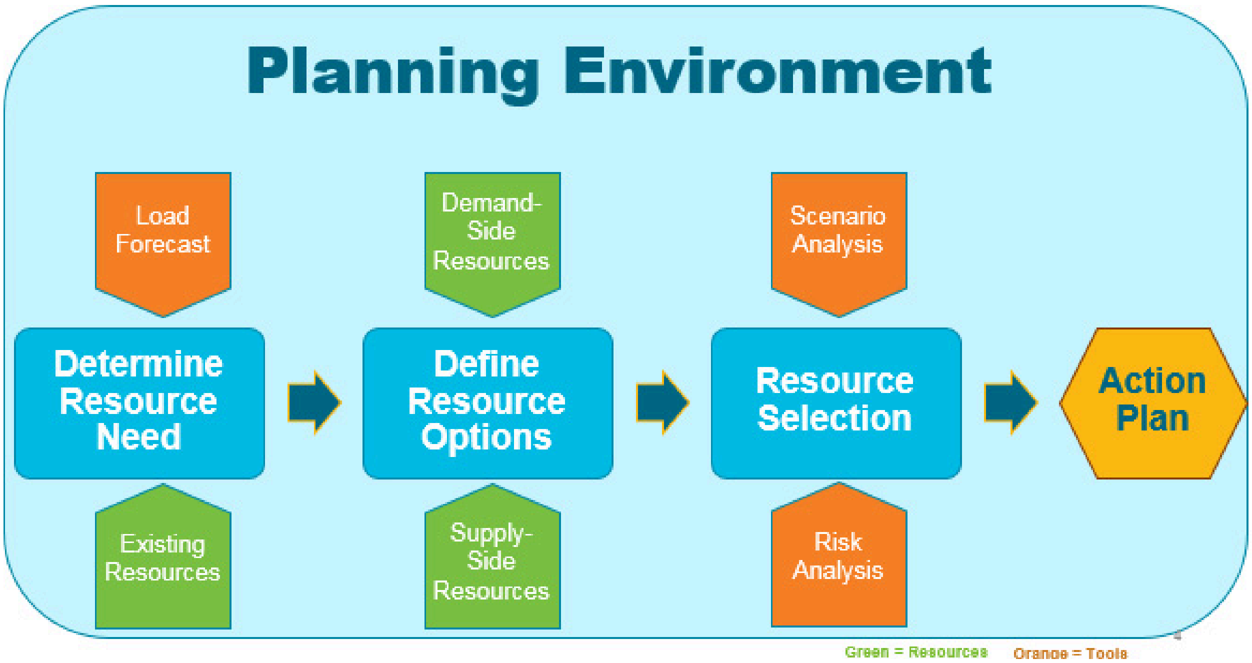
1.2. IRP PLANNING PROCESS

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 long-term resource plan (an Integrated Resource Plan, or IRP) with a 20-year planning horizon on approximately two-year cycles.

The IRP is the result of a rigorous analytical process that follows three broad steps: 1) forecasting our customers' future natural gas needs; 2) determining the 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 serve their natural gas needs (supply-side resources); and 3) identifying the portfolio of resources with the best combination of cost and risk for our customers (see Figure 1.2).

NW Natural conducts this process to ensure that we have adequate gas supply to meet customer needs (system capacity planning), and to ensure that we can distribute the gas we bring onto our system so that each of our customers can be served reliably (distribution system planning).

Figure 1.2: Integrated Resource Planning Process



2. PLANNING ENVIRONMENT

2.1. ECONOMIC OUTLOOK

Most areas within NW Natural's service territory have recovered to their pre-recession economic positions. Slower, yet continued, economic growth is expected moving forward. Manufacturing and construction activity generally lagged the economic recovery in Oregon and Washington, and have not recovered their pre-recession peaks in Oregon. Both are expected to maintain slow growth moving forward (Figure 1.3). Following a rapid upswing in housing construction, market forces and a wave of policy interventions will likely continue to slow growth from its pace over the 2010-2016 recovery[1]. Overall, NW Natural forecasts customers to grow at an expected annual rate of 1.5% (Figure 1.4).

[1] Housing policies such as construction taxes and inclusionary zoning are expected to dampen multifamily deliveries in the near and medium term in the Portland metro area.

Figure 1.3: Oregon Employment vs. Pre-recession peak

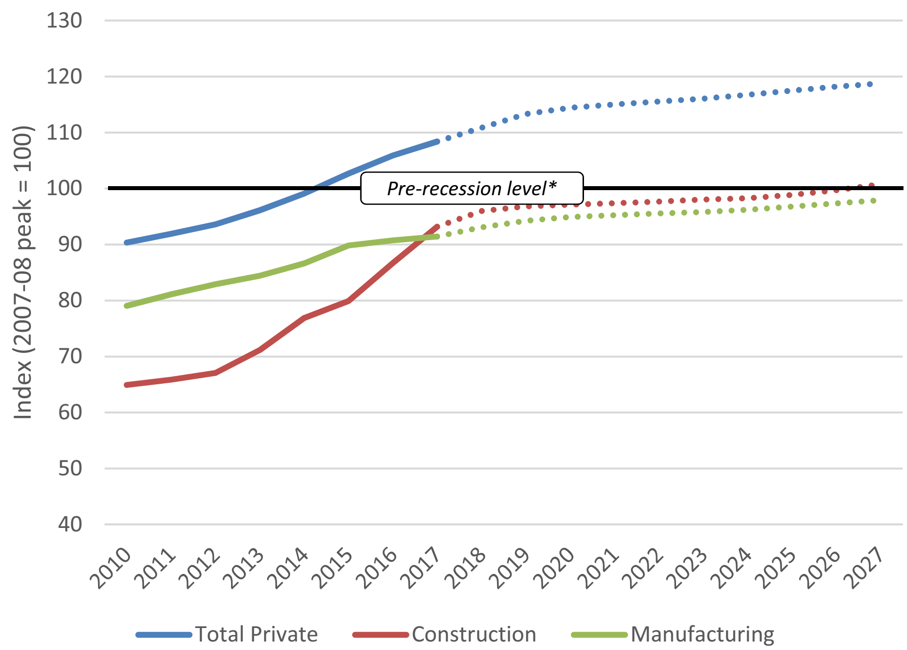
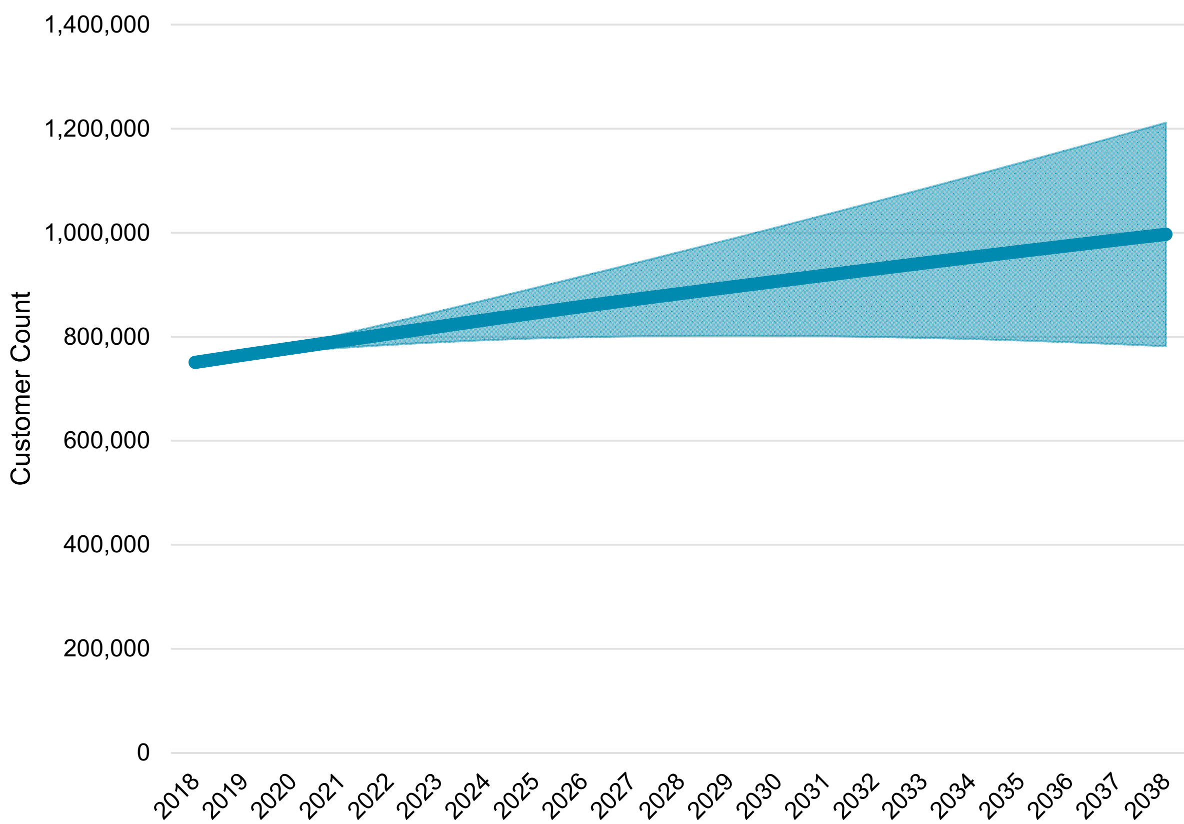


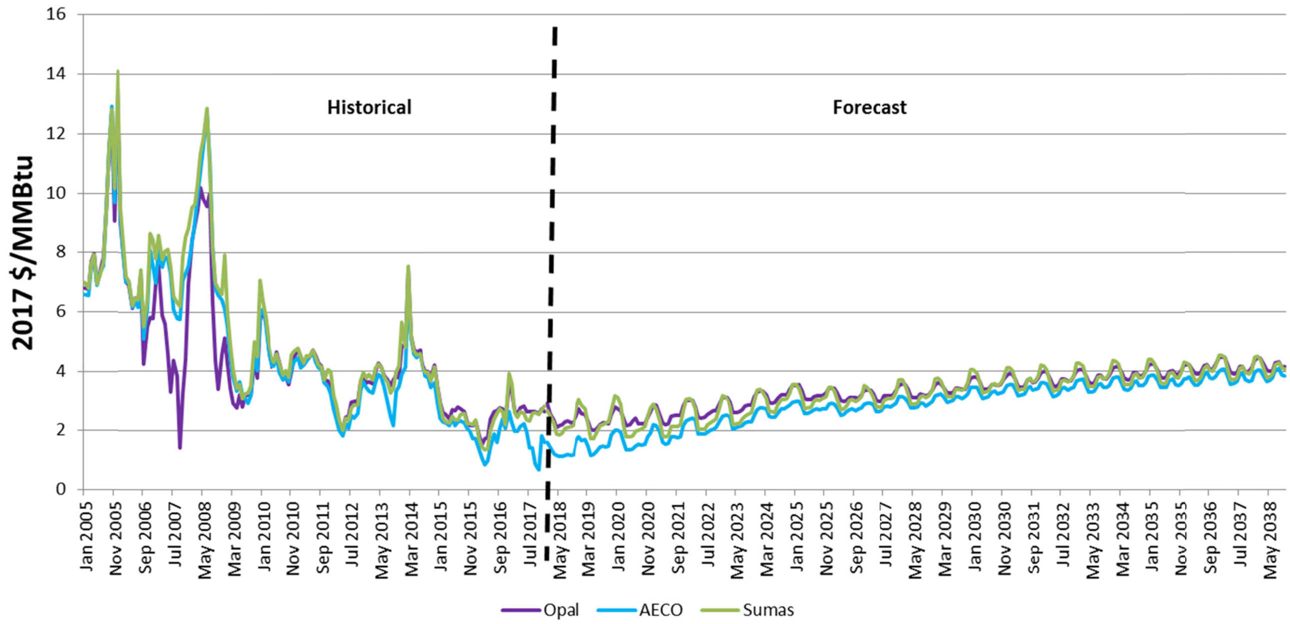
Figure 1.4: Customer growth forecast range



2.2. GAS PRICES

Gas prices impact planning and are a major source of uncertainty. Typically, NW Natural purchases natural gas from three areas: the Rockies (using the Opal trading hub), British Columbia (Station 2 and Sumas/Huntingdon), and Alberta (AECO). NW Natural expects future gas prices will be influenced by numerous factors, including economic conditions, demand, increasing use of natural gas to fuel power generation, potential national or regional carbon policies, weather, and traditional and new supplies (e.g. from gas produced using more efficient extraction technologies). The Company reviews several price forecasts and has developed a base case gas price forecast shown below. As can be seen in the forecast below, prices are expected to increase gradually from their current low of approximately \$2-\$3/Dth to approximately \$4/Dth over the planning horizon (Figure 1.5).

Figure 1.5: Natural Gas Prices Expected to Increase Slowly



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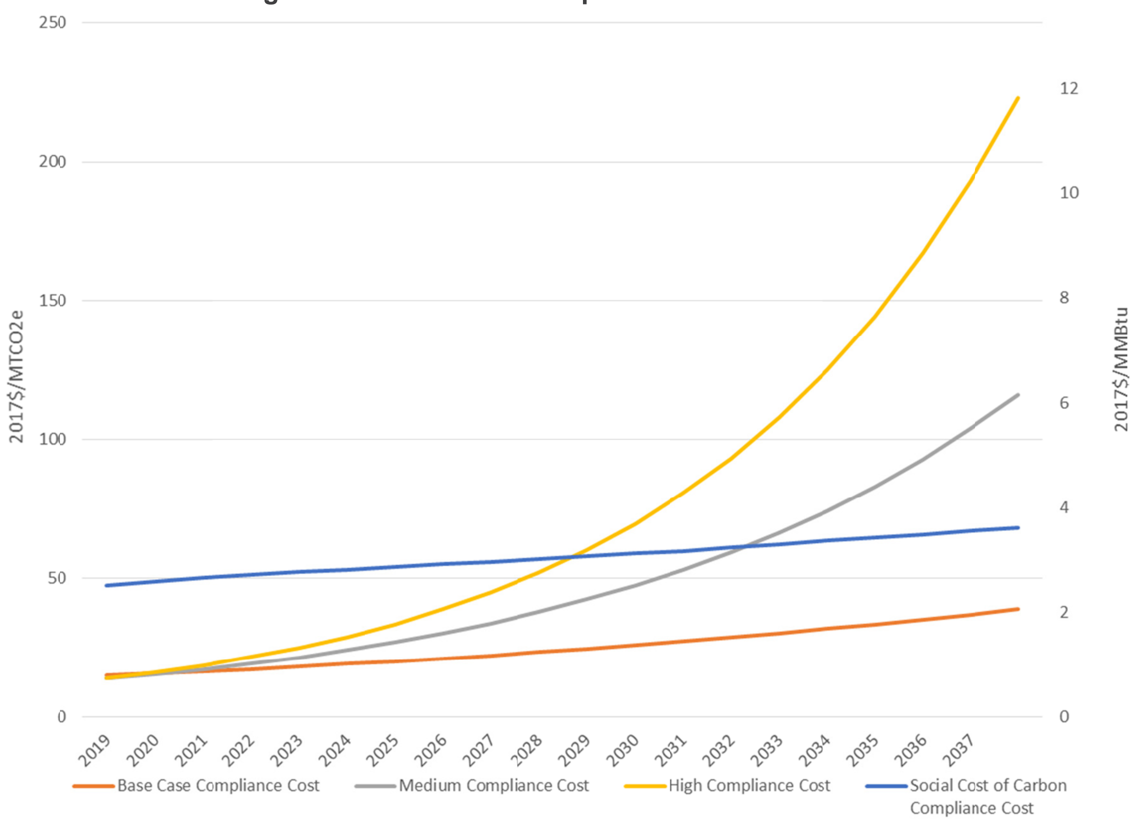
2.3. ENVIRONMENTAL POLICY

While future policy measures designed to reduce greenhouse gas (GHG) emissions remains highly uncertain in both Oregon and Washington, there is a growing likelihood that both states will implement incremental GHG reduction policies that will impact NW Natural customers over the IRP planning horizon. The timing, level, and customer impact of these policies represent the biggest source of uncertainty faced in this IRP and we have taken new steps to consider the implications of these policies.

A wide range of emissions compliance policies, represented in terms of carbon prices, are considered (Figure 1.6). The social cost of carbon price forecast is from EPA's mid-price of the social cost of carbon based on a 2% discount rate. Three ramping price paths are chosen based on cap-and-trade allowance price forecasts. Low, medium, and high cases are taken from the California Energy Commission's forecast of the cap-and-trade allowance prices in the market administered under the California Air and Resource Board.

In addition to carbon pricing, this IRP analyzes low carbon gas supply options, such as renewable natural gas and power-to-gas, to show the timeframe in which these resources may be cost-effective.

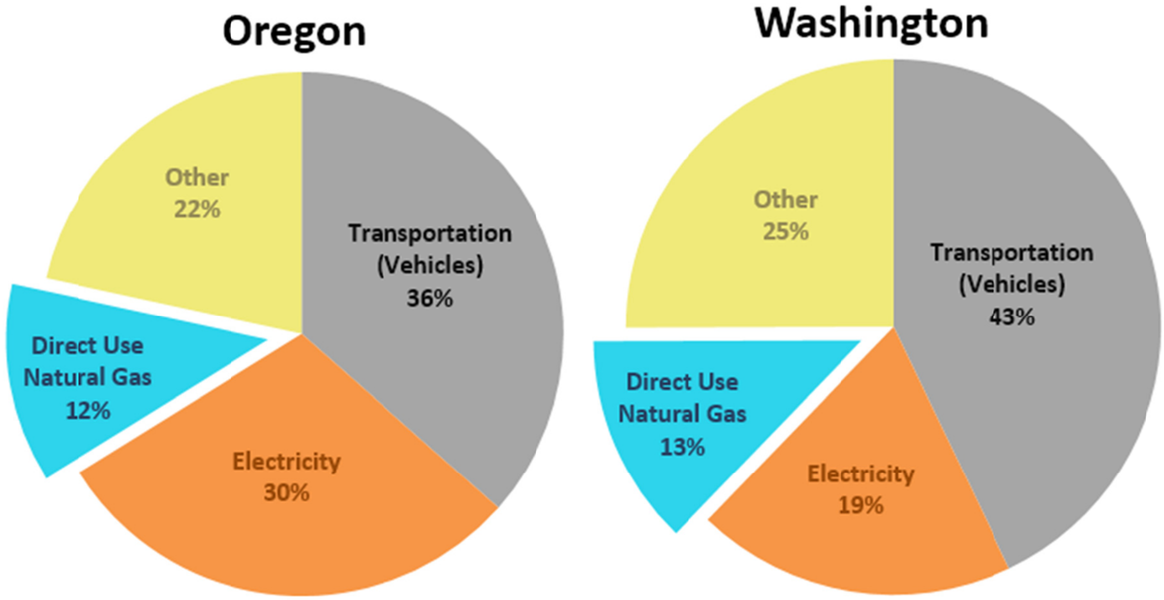
Figure 1.6: Emissions Compliance Cost Sensitivities



Given the focus on carbon pricing and carbon intensity, it is important to understand the contribution of the direct use of natural gas[2] — and NW Natural's customers specifically — to society's overall GHG emissions. The direct use of natural gas represented roughly 12% of Oregon's GHG emissions in 2015 (see Figure 1.7).[3] This was approximately a third of transportation sector emissions and well less than half of the emissions from electricity use in the state. Based on reported data to Washington State, the direct use of gas accounted for 13%, with less than half of one percent attributed to NW Natural's Washington customers.

[2] The direct use of natural gas is defined as gas that is used on-site by a residential, commercial, or industrial customer for their energy needs, and therefore includes all gas that is not used for electric generation.
[3] https://www.oregon.gov/deq/aq/programs/Pages/GHG-Inventory.aspx

Figure 1.7: Current State-Level Emissions Profile



Sources of data: latest year from the GHG emissions inventories published by the Oregon Department of Environmental Quality (2015) and Washington Department of Ecology (2012)

3. SUPPLY PLANNING

3.1. SYSTEM CAPACITY PLANNING

Load

On an annual basis, the Company's sales load consists predominantly of space heating (Figure 1.8). During peak conditions, sales load and total throughput are driven by space heat. Because of the needs for space heating, NW Natural's loads have very high peaks compared to average daily loads. Peak capacity needs are expected to grow 0.92% annually while annual sales load is expected to grow 0.6% annually (Figure 1.9).

Figure 1.8: NW Natural Monthly Sales Load by End Use

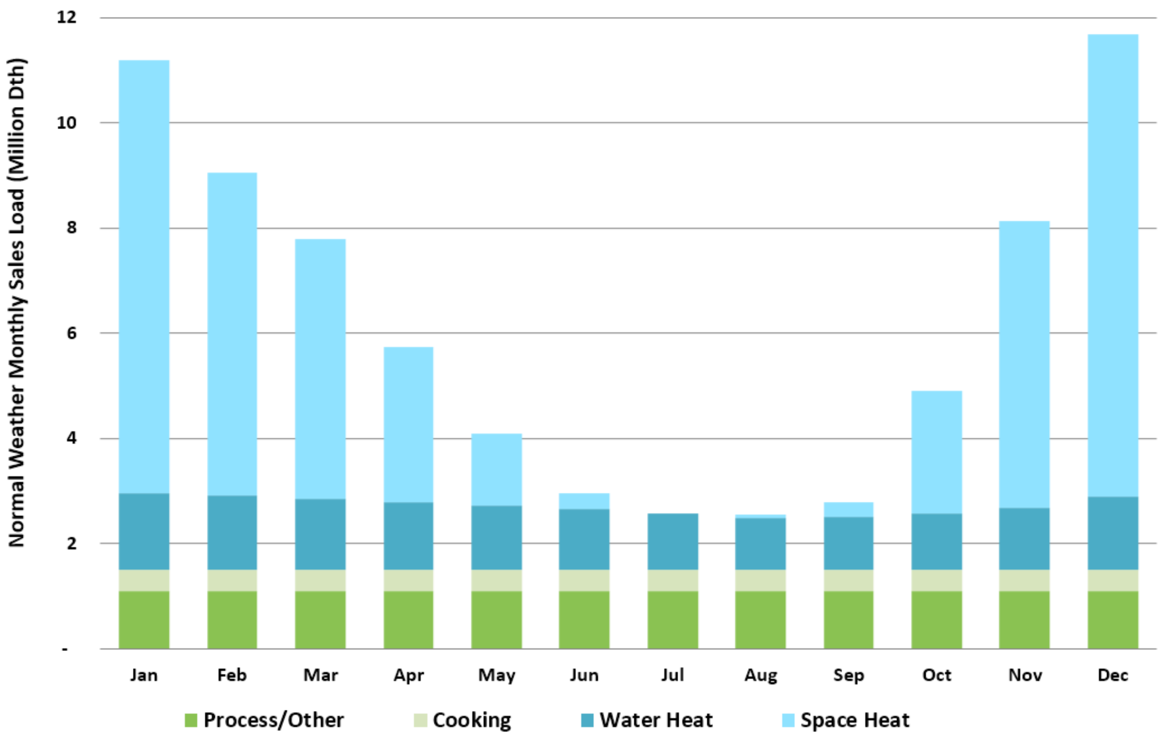
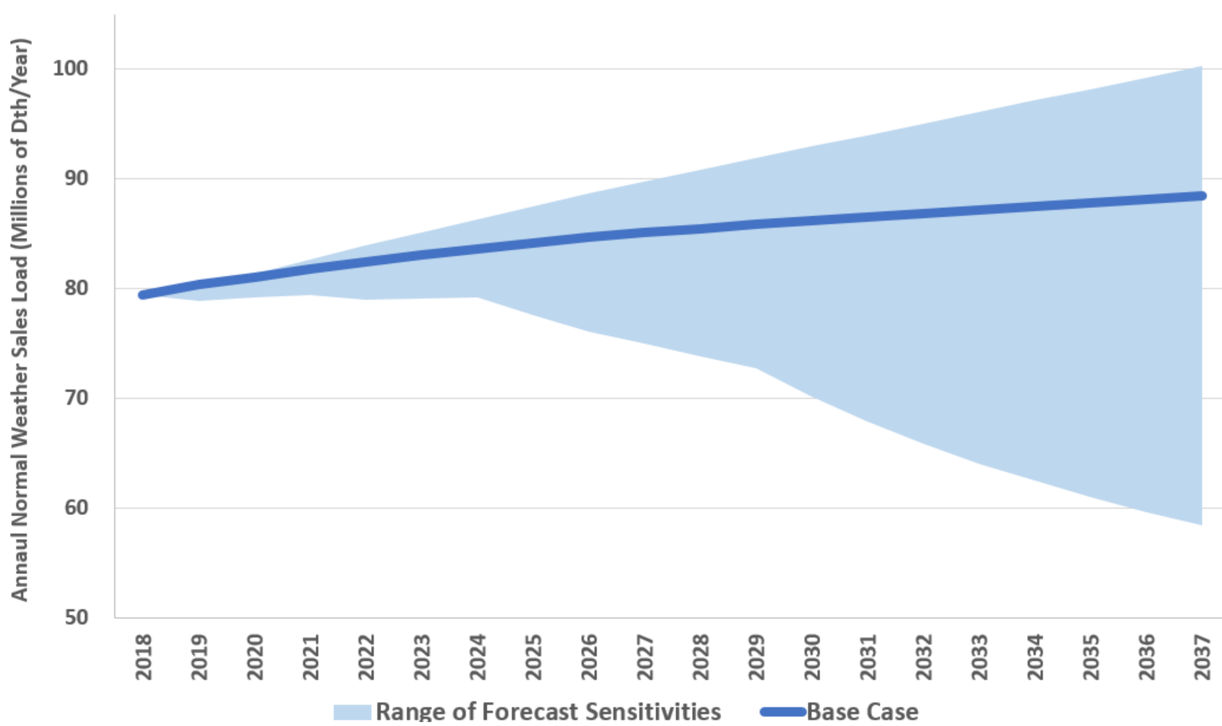


Figure 1.9: Annual load forecast range

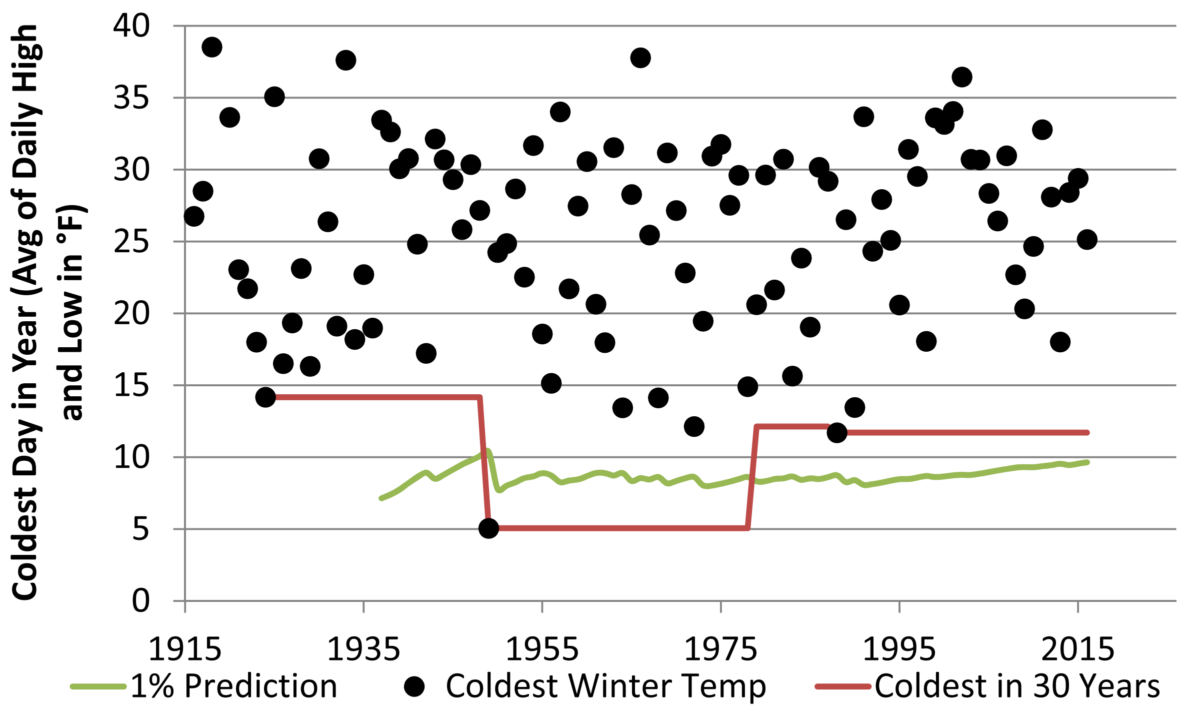


Capacity Planning Standard

As discussed in more detail in Chapter Three, a material change in NW Natural's 2018 IRP is an update to the capacity planning standard methodology. The capacity planning standard is used to quantify firm resource requirements for customers. NW Natural based its capacity planning standard in the 2014 IRP on the coldest system-wide average temperature in the last 30 years. This was improved upon in the 2016 IRP where the capacity planning standard became the highest firm sales requirement day in 30 years based on more variables in addition to temperature.

The 2018 IRP moves NW Natural to a risk-based capacity planning standard where the Company plans to meet the highest demand day in any given year with 99 percent certainty. This risk-based methodology creates more stability in capacity planning over a long-term horizon. Figure 1.10 illustrates that, using temperature as an example, a coldest-in-30 year standard results in material swings in the capacity planning standard while a risk-based approach is more consistent.

Figure 1.10: Relative stability of a risk-based planning standard

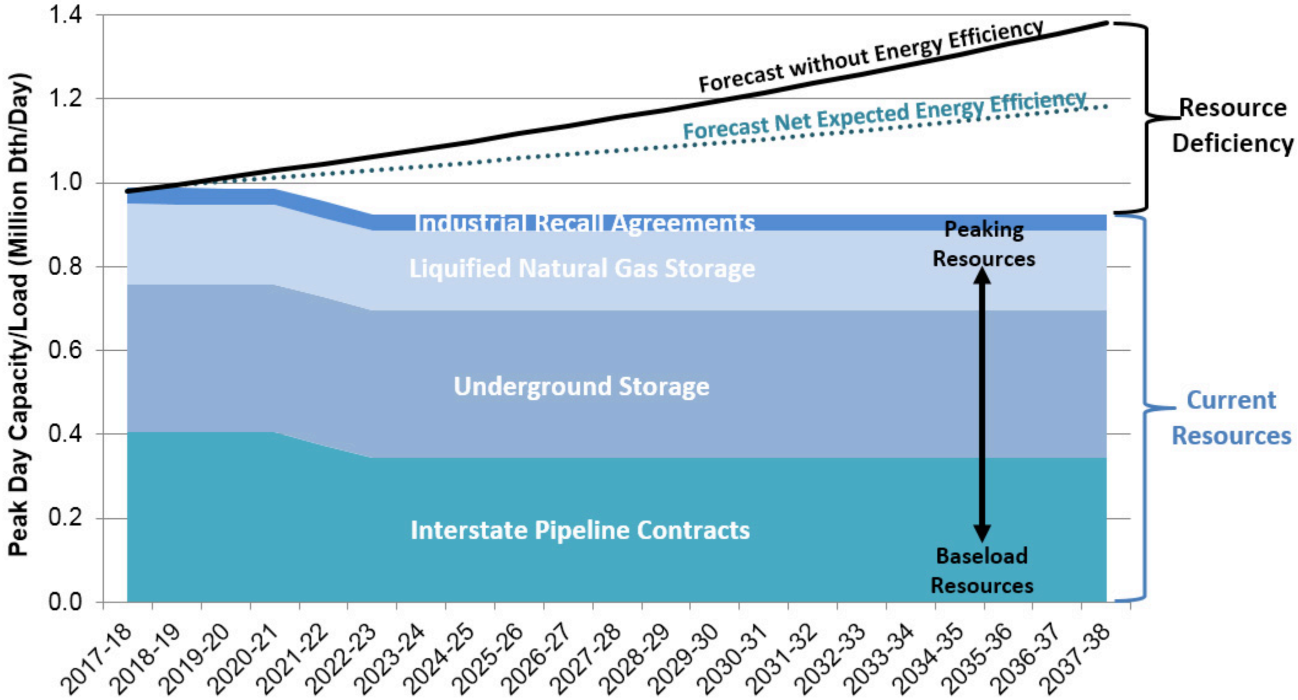


NW Natural used a Monte Carlo simulation of the highest demand day in each year of the planning horizon, based on historical data, to estimate the 99th percentile of requirements. It was also assumed that supply resources are always available (i.e. no forced outages). This new approach will not only increase stability for planning purposes, but by incorporating new data every year it will reflect any underlying trends in extreme weather. The new capacity planning standard is consistent with NW Natural's 2016 IRP peak day demand level, which is estimated as equivalent to a 99.2 percent certainty of serving the highest firm sales demand day.

Resource Deficiency

As can be seen in Figure 1.11 NW Natural has a resource deficiency of 250,000 Dth/day in 2038 after accounting for energy efficiency savings. This resource deficiency is due to load growth, changes in peak day demand, and changes in the near-term resource stack while being partially offset by an increase in demand-side resources.

Figure 1.11: Load-resource balance



3.2. RESOURCE OPTIONS

There are two ways to meet our customers' needs: (1) reduce their demand; or (2) reliably serve their demand, and our process is to determine the appropriate combination of the two approaches to serve our customers reliably and at a low cost.

Avoided Costs

NW Natural continues to improve its avoided cost methodology and drivers as discussed in more detail in Chapter Four. In particular, as seen in Table 1.1, the avoided costs in 2018 provide more granularity into avoided costs associated with specific end use equipment.

Table 1.1: Application of avoided costs to resource options

Costs Avoided		Demand-Side Resources			Supply-Side Resources		
		Energy Efficiency	Demand Response: Interruptible Schedules	Demand Response: Other DR	Low-Carbon Gas Supply: On-System Resources	Low-Carbon Gas Supply: 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	√			?	?	

Demand-side resources

NW Natural partners with Energy Trust to administer its residential and commercial energy efficiency programs in both Oregon and Washington. Energy Trust provides the 20-year demand-side resource forecast that the Company incorporates into its load forecasts. The current forecast shows cumulative energy efficiency savings of 16 million Dth (Figure 1.12) which represents a 15 percent decrease in expected annual load in 2038 (Figure 1.13).

Figure 1.12: Expected Cumulative Incented Energy Efficiency Savings via Energy Trust

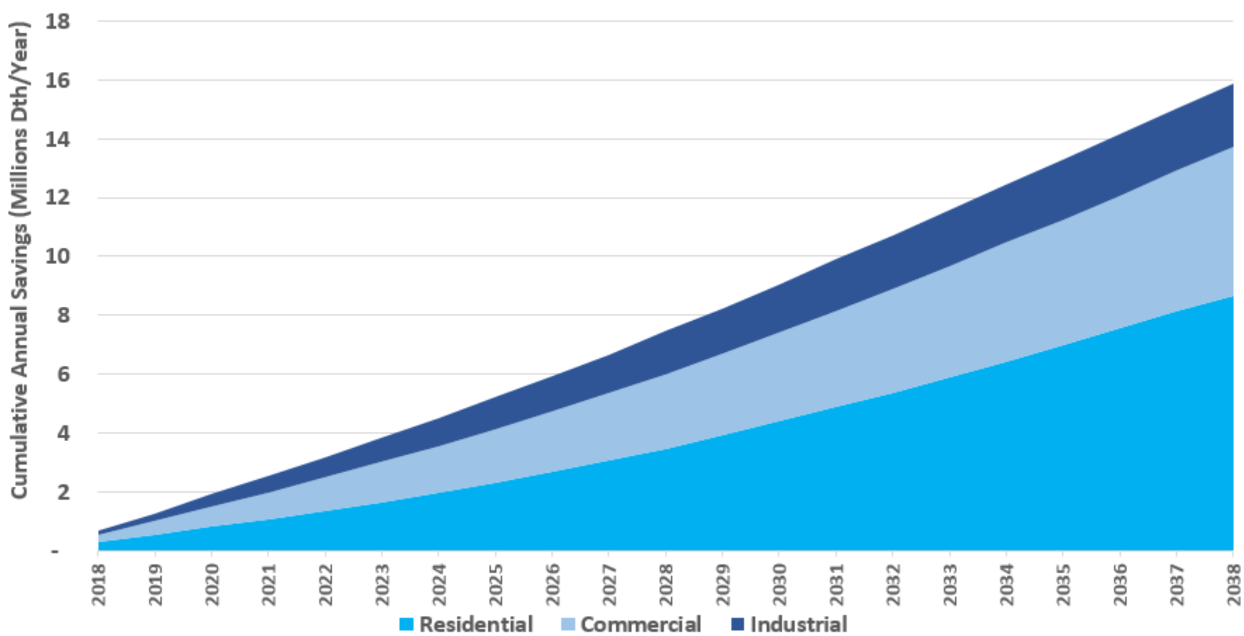
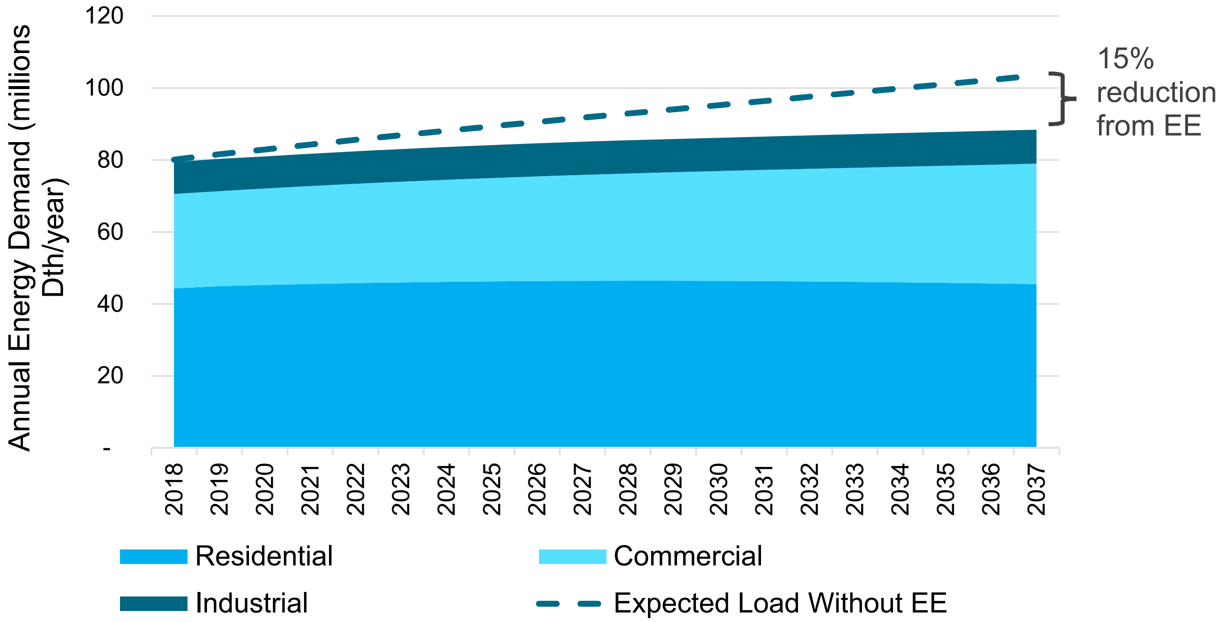


Figure 1.13: Annual sales forecast with and without EE



Supply-side resources

New to this IRP is the inclusion of various types of renewable natural gas (RNG) and other decarbonizing supply resources alongside traditional options such as pipeline and on-system storage (Table 1.2). RNG's environmental benefits, combined with emissions policies, have generated considerable growth in the RNG industry and increased the availability of RNG since the 2016 IRP[4].

Table 1.2: Resource options considered

Resource	Description
Mist Recall	Transferring Mist storage from interstate storage customers utility customers
North Mist II and III	Completing new storage wells and building takeaway pipeline capacity to serve utility customers
Local Pipeline Expansions	A pipeline expansion specifically for NW Natural needs
Regional Pipeline Expansions	Regional pipeline expansions for multiple shippers
Central Coast Feeder 1-3	Three projects which can incrementally increase from Newport LNG
RNG 1-5	Representative renewable natural gas projects from landfills, waste water treatment plants, or dairy farms
Power-to-Gas	A power-to-gas facility at Mist to produce hydrogen which is blended into natural gas

[4] http://www.rngcoalition.com/news/2018/6/28/increased-focus-on-renewable-natural-gas-at-world-gas-conference-2018

There are various sources of RNG including wastewater treatment plants, landfills, and dairy farms (Chapter Six discusses these potential resources in more detail). Depending on the feedstock, the environmental benefits of RNG can be substantial, and in some cases provide a net negative impact to carbon emissions and result in a net negative carbon compliance cost (Figure 1.14). For example, by 2037, with carbon compliance costs associated with conventional gas expected to be slightly over $2 per MMBtu, dairy RNG could have as much as an $8 per MMBtu benefit toward compliance costs. After valuing the on-system benefits and the emissions compliance benefit of dairy RNG, the all-in cost for on-system dairy in 2037 is projected to be slightly over $2 per MMBtu. Figure 1.15 shows a side-by-side comparison of expected all-in costs of conventional gas and the all-in costs of on-system RNG options (RNG 1-5 are representative projects considered for resource planning).

Figure 1.14: Expected Compliance Costs by Resource Type

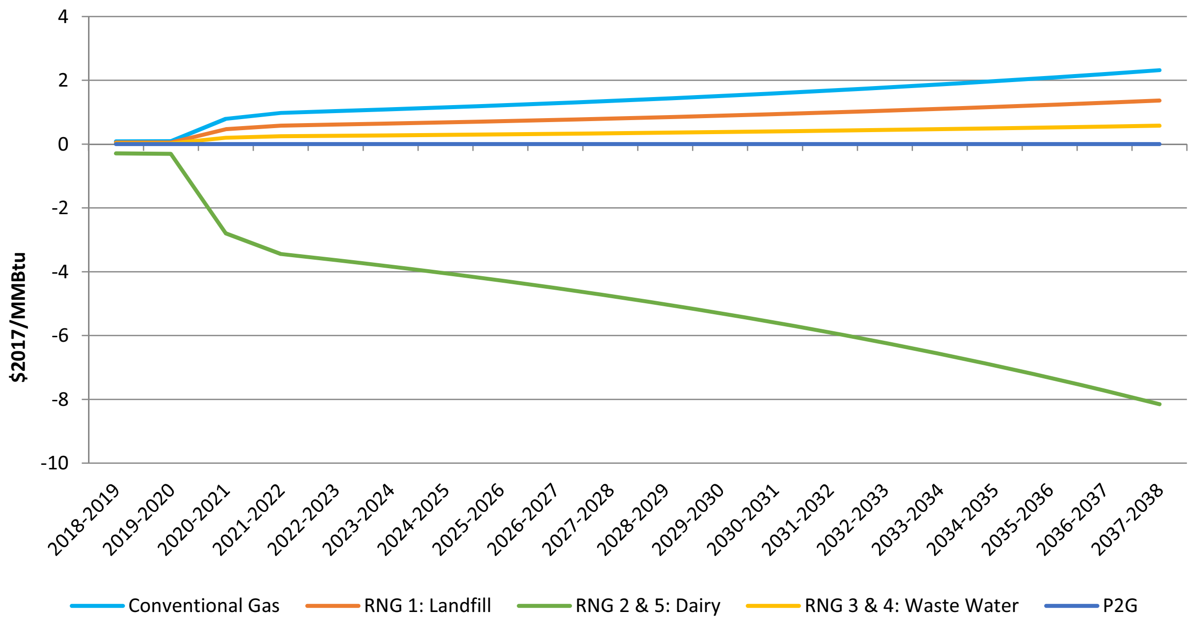
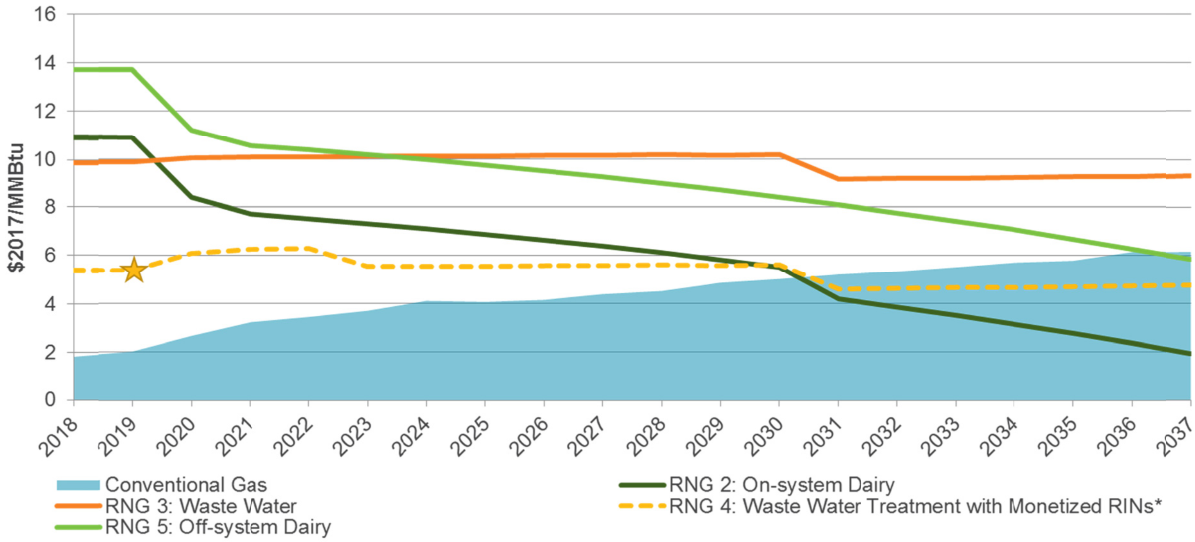


Figure 1.15: All-in Cost of Conventional Gas vs. Various RNG Sources



3.3. RESOURCE SELECTION

In order to choose a resource portfolio with the best combination of cost and risk, supply resource decisions are informed through a two-step process. First, a deterministic portfolio selection produces a least-cost portfolio of resources over the planning horizon given the Company's expectation of the future. Second, a risk assessment is performed that tests alternative possible futures by varying the input assumptions, shown in Table 1.3, through sensitivity analysis and stochastic analysis.

Table 1.3: IRP Key uncertainties evaluated in risk analysis

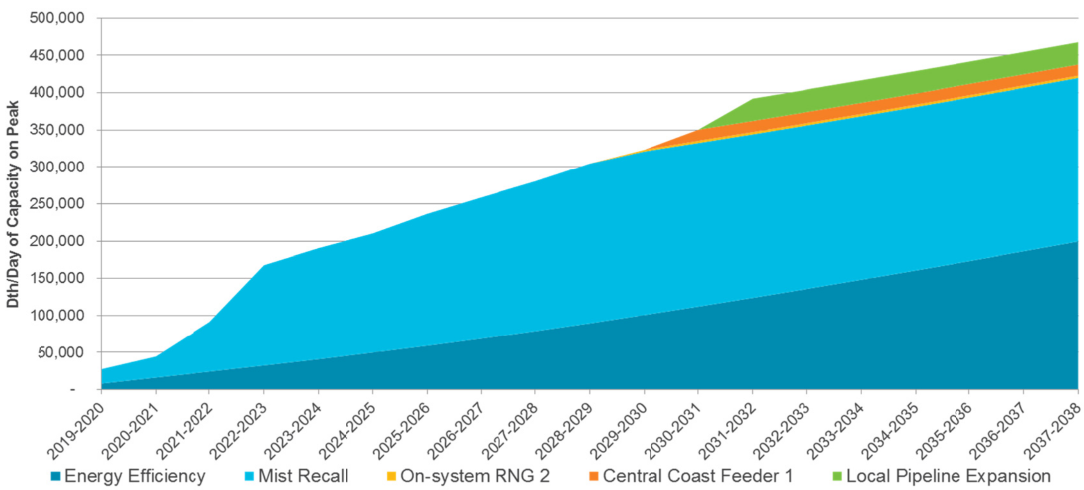
IRP Risk Analyses		
	Stochastic Analysis	Sensitivity Analysis
Environmental Policy	✓	✓
Commodity Price	✓	
Economic Growth		✓
Supply Infrastructure		✓
Resource Costs	✓	✓
Technological Change		✓
Weather	✓	

Base Case Portfolio

The base case presents NW Natural's expected load requirements, as well as its expected planning environment. More specifically, it includes its expected gas price forecast, its expected cost of compliance, and likely available future resources and technologies. The base case portfolio results drive the Company's Action Plan and is additionally informed by the risk analysis discussed below and in detail in Chapter seven.

The base case results show a preferred portfolio relies on demand-side resources and Mist Recall in the short and medium-term but still requires additional resources over the long term. Figure 1.16 shows the least-cost portfolio resource acquisitions over the planning horizon.

Figure 1.16: Base Case Portfolio Resources

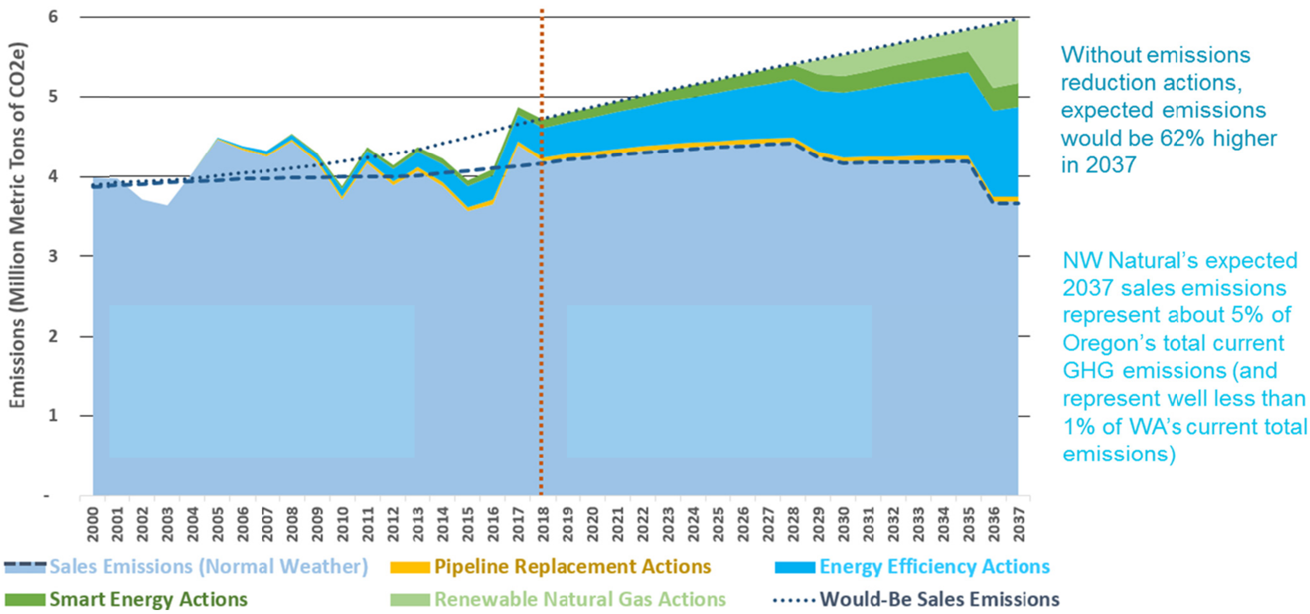


The principal learnings from the base case include:

1) In the short term, after energy efficiency, Mist Recall is selected as the least cost resource
2) Central Coast Feeder 1 (a phase of the project formerly known as a phase of the Christiansen Compressor), and some pipeline capacity are identified as least cost resources in the long term
3) On-system RNG is selected as a least cost capacity resource
4) Off-system RNG is selected to replace conventional gas beginning in 2036

As a new addition in the 2018 IRP, NW Natural is including a forecast of emissions over the planning horizon. The base case results show that NW Natural customers can significantly reduce their expected emissions with emissions reduction contributions from energy efficiency, voluntary customer offsets, and renewable natural gas (Figure 1.17).

Figure 1.17: Base case emissions forecast



Sensitivity analysis

The sensitivity analysis changes various assumptions in the planning environment and examines how deviations from the Company's base case assumptions can impact our resource planning and future emissions. NW Natural created three groups of sensitivities in this IRP: supply infrastructure, economic growth, and environmental policy (Table 1.4).

Table 1.4: Sensitivities in the 2018 IRP

Supply Infrastructure Sensitivities	1. Base Case – No New Regional Pipeline 2. New Regional Pipeline in 2025 – Fully Subscribed 3. New Regional Pipeline in 2025 – Excess Capacity
Economic Growth Sensitivities	4. High Customer Growth 5. Low Customer Growth
Environmental Policy Sensitivities	6. Social Cost of Carbon Used in Resource Planning 7. Natural Gas Deep Decarbonization 8. Compressed Natural Gas in Medium- and Heavy-Duty Transportation 9. New Direct Use Gas Customer Moratorium in 2025

The supply infrastructure sensitivities use the base case demand assumptions test our portfolio against two possible regional infrastructure scenarios. For the regional pipeline options, NW Natural modeled a proxy pipeline to help demonstrate how the Company would analyze a future regional pipeline decision. The economic growth sensitivities use a statistical range to analyze portfolios with higher or lower customer growth.

Sensitivities are also created to test how demand, resource selection, and emissions vary under different environmental policies. The four environmental policy sensitivities include:

- Social Cost of Carbon in Resource Planning uses a social cost of carbon as the carbon price incorporated into resource planning
- Deep Decarbonization assumes the most aggressive adoption of high efficiency end use equipment and building shell improvements aimed to effectively reduce carbon emissions from NW Natural while still providing all energy services demanded by our customers.
- CNG Adoption in Medium and Heavy-Duty Transportation considers where the societal carbon reduction from displacing diesel adds roughly five million therms to the Company's annual load each year over the next twenty years.
- New Direct Use gas Customer Moratorium in 2025 models an extreme policy scenario that would ban any new natural gas customers from new construction or conversions starting in 2025.

Emissions forecast by sensitivity

As was mentioned above, new to the 2018 IRP, is NW Natural's forecast of emissions for the base case and each of the sensitivities. Figure 1.18 compares the annual emissions forecasts of the base case and each of the environmental policy sensitivities. As discussed earlier, both the social cost of carbon and the deep decarbonization sensitivities incorporate policies that incentivize renewable gas resources and energy efficiency measures, causing the emissions forecast to decrease early and trend downward over 20 years. By 2037 the emissions in the social cost of carbon sensitivity drops by almost a third of 2017 levels, and by almost two-thirds of 2017 levels in the deep decarbonization sensitivity, while still providing the same energy services.

Figure 1.18: Base Case vs. Environmental Policy Sensitivities Emissions Forecast

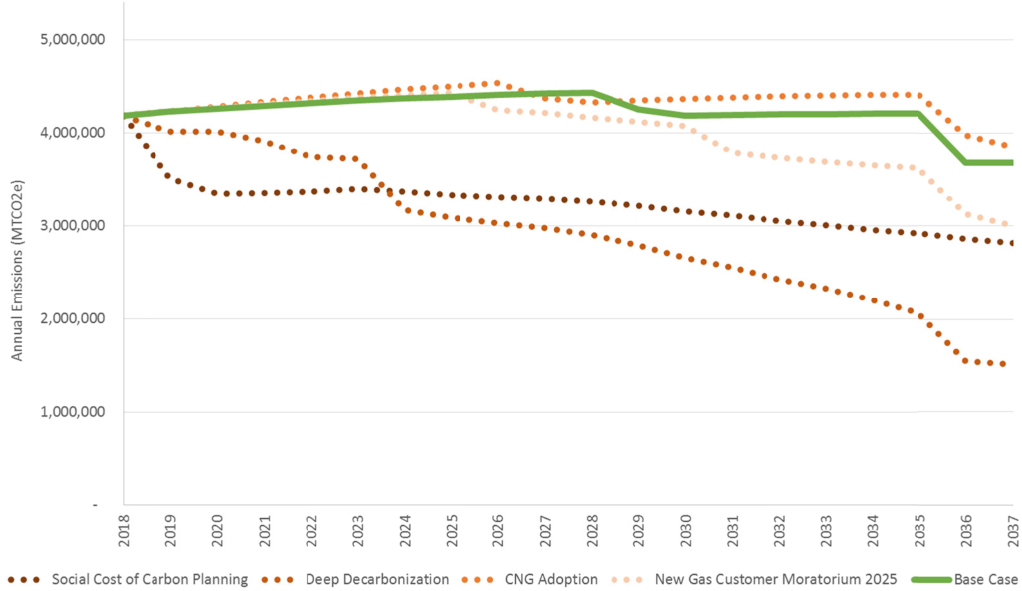


Figure 1.19 shows the contribution of various activities toward emission reduction in 2037. In each sensitivity renewable natural gas and energy efficiency drive significant reductions in total emissions.

Figure 1.19: NW Natural 2037 Emissions Projection and Would-be Emissions without Emissions Reduction Activity by Sensitivity

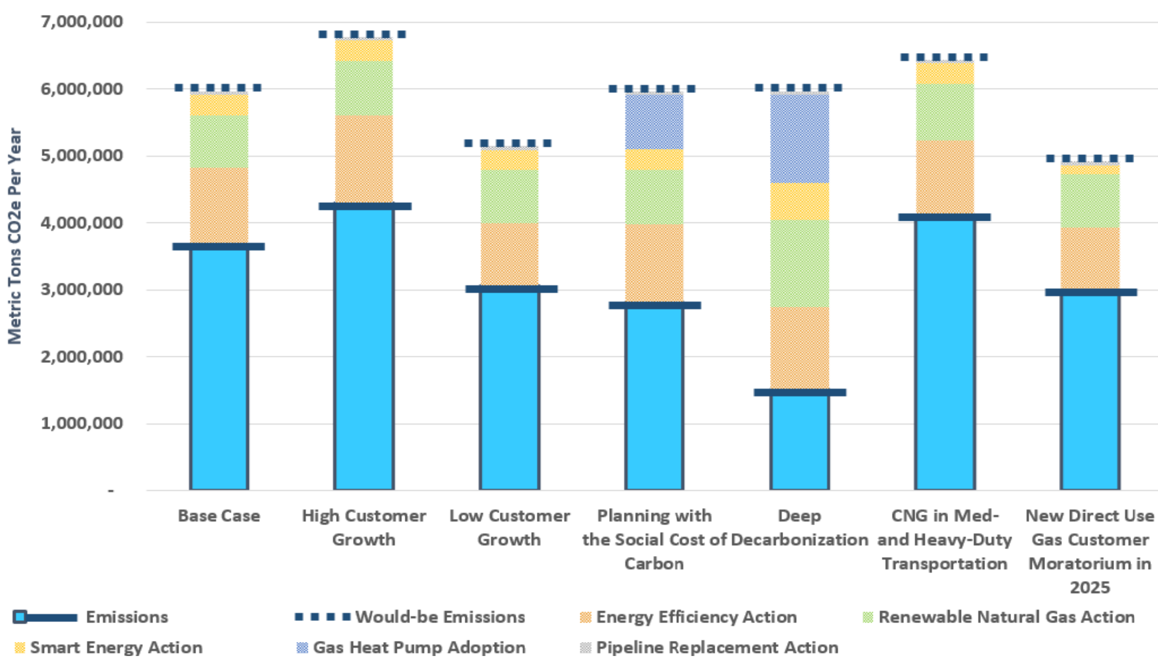
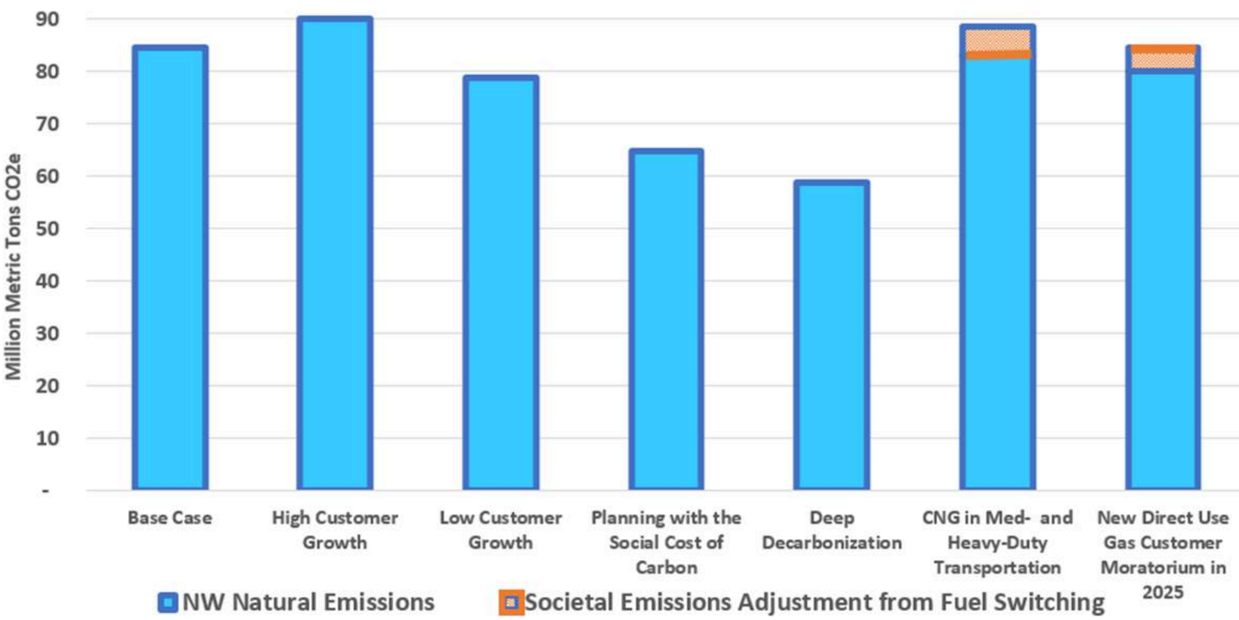


Figure 1.20 compares the cumulative emissions across sensitivities for the whole 20-year planning horizon. The CNG adoption and the direct use moratorium sensitivities change in the energy services provided by NW Natural, but the demand for these services is equal across all

the environmental policy and base case sensitivities. In the CNG adoption sensitivity, CNG is assumed to replace diesel fuel typically used for medium- and heavy-duty fleets. CNG is less carbon intensive than diesel per vehicle mile traveled, thus societal emissions are less than the base case even though emissions from NW Natural have increased.[5] The direct use moratorium sensitivity assumes that the energy services previously provided by NW Natural would be served through 250% efficient electric appliances. Using a forecasted 2037 carbon intensity for electric utilities in the Pacific Northwest, overall societal emissions increase in this sensitivity.[6]

Figure 1.20: NW Natural Cumulative Emissions 2018-2037



Stochastic analysis

After resource portfolios are deterministically created to meet the forecasted energy and capacity needs for each of the supply infrastructure sensitivities, stochastic analysis is completed on each of these same portfolios through two separate Monte Carlo simulations. The result of the stochastic analysis for a single sensitivity is a net present value of revenue requirement (NPVRR) distribution which is representative of the potential future costs under a wide range of assumptions. The distributions of the portfolios can then be compared to identify which portfolio represents the best combination of cost and risk for customers. Inputs into the stochastic analysis are discussed in more detail in Chapter Seven and include the following inputs: weather, commodity prices, carbon prices, and supply resources option costs.

The stochastic analysis also reveals how the uncertainty in carbon policy affects resource decisions. Figure 1.21 shows the volumes of off-system RNG that is chosen in the stochastic

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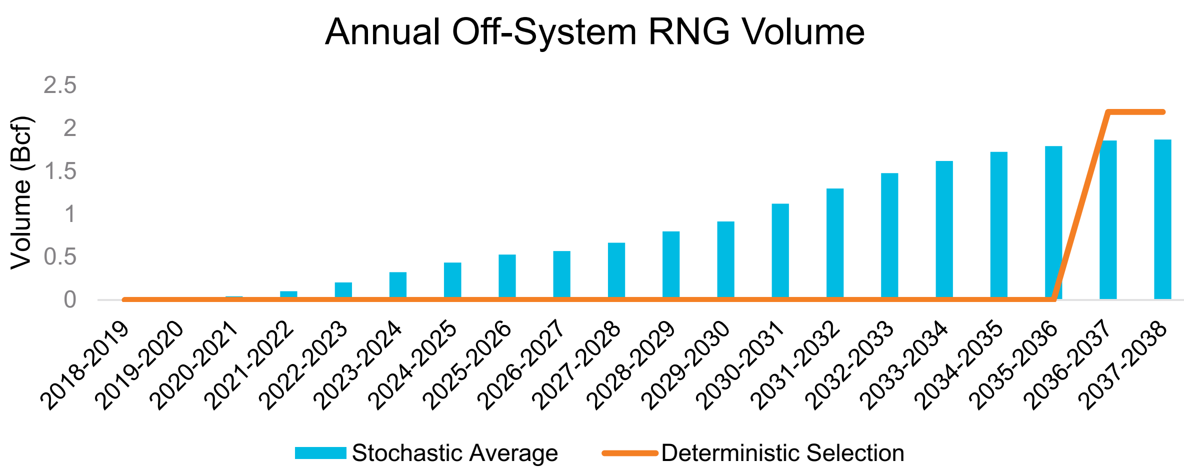
[5] For this calculation CNG vehicles emit 17% less emissions per mile travels and travel an average distance traveled of 21,000 miles per year.
[6] The carbon intensity forecast for 2037 for Pacific Northwest electric utilities comes from the Northwest Power and Conservation Council's figures for marginal carbon intensity.

analysis (blue bars) compared to the deterministic optimization (orange line). Because off-system RNG acts only as a replacement for conventional gas (it does not contribute to capacity needs), it is chosen based on its all-in price (commodity plus carbon price adder) relative to conventional gas. While the deterministic case shows off-system RNG being acquired very late in the planning horizon, the stochastic analysis shows that this resource may be cost effective much earlier. Because the stochastic analysis uses a fixed capacity resource portfolio, we have not performed a similar analysis for on-system RNG resources. However, the conclusion is likely to be the same. It will be important for NW Natural to take a deeper look at RNG resources because they may be cost-effective in the near future.

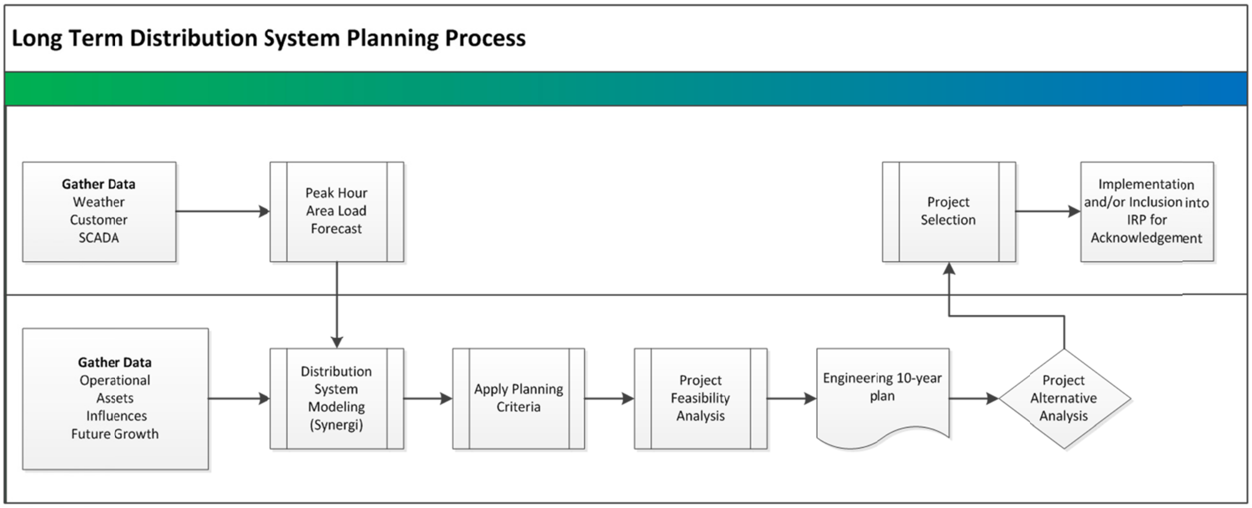
Figure 1.21: Annual Off-System RNG



4. DISTRIBUTION SYSTEM PLANNING

In addition to supply resource planning, the IRP identifies distribution system capacity needs and determines cost-effective solutions. The process for distribution system planning is similar to gas supply planning but uses a peak hour demand instead of a peak day and planning is performed within specific geographic locations inside of NW Natural's service territory. This planning process requires determining potential distribution system constraints, analyzing alternative potential solutions, and assessing the costs of viable alternatives. Figure 1.22 below is an illustration of this process. Whereas the location of system growth has minimal effect on supply planning, distribution planning is highly dependent on the location of additional load. Over the short term (1-3 years) the Company has insight into where growth will occur on the distribution system, but the longer term is much more uncertain. Because of the locational uncertainty the distribution system planning is limited to a 10-year horizon.

Figure 1.22: Distribution System Planning Process



Distribution system issues are identified either by system modeling or by live pressure readings during cold events. Distribution system modeling uses Synergi Gas™ network modeling software to model the Company's network of mains (pipes) and services. Synergi™ allows graphical analysis and interpretation by system planners. A Synergi™ model contains detailed information regarding a specific portion of NW Natural's system. This information includes pipe size, length, roughness, and configuration; customer loads; source gas pressures and flow rates; regulator settings and characteristics; and more. Using a peak hour model to forecast the demand in a given area, Synergi™ allows planners to visualize any system constraints and analyze the impact of various solutions.

Once NW Natural identifies a distribution system issue, the Company considers multiple traditional pipeline solutions to address the issue. These solutions may include constructing pipelines of differing size, operating pressures, and routes; performing pressure uprates to increase capacity of existing pipelines; and installing equipment such as district regulators or compressors. These pipeline solutions are compared against non-pipeline alternatives which include supply-side resources (such as satellite LNG storage) and demand-side resources (such as additional interruptible customers).

The projects shown in Table 1.5 are those which have action items for which NW Natural is requesting acknowledgement by the Public Utility Commission of Oregon. These projects are discussed in detail in Chapter Eight.

Table 1.5: Distribution System Planning Projects

Project	Schedule	Estimated Cost (Millions of $2017)
Hood River Reinforcement	2019	$3.5 - $7.1
Happy Valley Reinforcement	2019	$2.9 - $4.7
Sandy Feeder Reinforcement	2020	$15.2 - $21.1
North Eugene Reinforcement	2020	$5.3 - $10.6
South Oregon City Reinforcement	2020	$4.1 - $6.2
Kuebler Road Reinforcement	2020 - 2021	$14.1 - $19.7
Total		**$45.1 - $69.4**

5. ACTION PLAN

This action plan sets forth the key resource additions and changes, studies, and ongoing monitoring activities. For this IRP, NW Natural separated the action plan into three parts. The first action plan is the joint plan, which includes proposed activities applicable to both Oregon and Washington. The second part of the action plan includes only those activities specific to Oregon and the third part includes only those activities specific to Washington.

5.1. JOINT MULTIYEAR ACTION PLAN

Supply Resource investments

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.
2) Use the methodology detailed in Appendix H to evaluate renewable natural gas resources against conventional sources based upon “all-in costs,” where all-in costs are defined as:

    All-in costs = Net Present Value ([cost for delivered gas] + [net GHG emissions intensity*Cost of GHG Emissions Compliance] – [avoided supply capacity costs] – [avoided distribution capacity costs])

5.2. OREGON-ONLY ACTION PLAN

Distribution System Planning Projects

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.
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.
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.

6) Proceed with the North Eugene Reinforcement project to be in service for the 2020 heating season and at a preliminary estimated cost ranging from $5 million to $11 million.
7) 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.
8) 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.

Demand-side resources

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.

5.3. WASHINGTON-ONLY ACTION PLAN

Demand-side resources

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.

CHAPTER 2

PLANNING ENVIRONMENT

KEY TAKEAWAYS

Key findings in this chapter include the following:

- Most of the areas within NW Natural's service territory have recovered to their pre-recession economic positions. Slower, continued growth is expected moving forward.
- Gas commodity prices are at historic lows and are expected to stay low but gradually rise over the planning horizon to approximately $4/Dth
- The direct use of natural gas in 2015 accounted for 12% of total GHG emissions in Oregon, with roughly 8% attributed to NW Natural customer use. The direct use of gas accounted for 13% in Washington, with 0.5%% attributed to NW Natural customers.
- Where natural gas service is readily available, the majority of homes and businesses use natural gas for their space and water heating needs and space heating makes up more than 80% of the total energy needs of homes and businesses in the Pacific Northwest during the peak hour of extreme cold weather events.
- This IRP, for the first time, presents a greenhouse gas (GHG) emissions forecast for the company as these emissions are a factor of growing importance in resource planning.
- While the policy instrument to price carbon remains uncertain in both Oregon and Washington, there is a growing likelihood of state policy changes that will implement a price on carbon that impacts the company.
- The company has taken new steps to model carbon emissions as well as low carbon gas supply options – such as renewable natural gas – to show if and when these newly available resources may be selected as least cost and least risk resource options within the IRP.

1. OVERVIEW

When putting together the Integrated Resource Plan (IRP), it is important to understand the planning environment and how it can impact the plan now and in the future. Reviewing the planning environment helps to identify future risks and opportunities and other potential impacts to the plan. When evaluating the planning environment the company considers:

- Economic and demographic factors
- The commodity price environment

- Environmental policy environment
- Game changers and new technology
- We take these factors into consideration for our load forecast, potential future resources, and the risk analysis. These factors are discussed in more detail below.

2. ECONOMIC AND DEMOGRAPHIC FACTORS

Economic and demographic factors are important underlying drivers of load growth. Not only can they influence customer growth but they can also influence existing customer usage especially on the industrial side. NW Natural considers the economic and demographic factors discussed below.

2.1. U.S. ECONOMIC AND DEMOGRAPHIC OUTLOOK

As NW Natural prepares its 2018 IRP, the US economy has entered its ninth year of expansion, the second longest in history. Despite tightening labor markets, slowly accelerating inflation, and transient volatility in financial markets, year-over-year growth of real output has climbed steadily from a low point in early 2016[1] and the national unemployment rate is beneath its pre-recession level.[2] A key driver of this late stage boost to growth has been federal policy – an unusually timed fiscal expansion in the form of an expanded federal spending plan passed in early February 2018, and the sweeping reforms of the Tax Cuts and Jobs Act, which took force in January 2018. At the Federal Reserve Bank Federal Open Market Committee (FOMC) meeting in March 2018, the median expectation for real GDP growth remained above 2% through at least 2020, with longer term figures just below that rate. Fed staff notes the clear influence of combined federal tax cuts and budget expansion in their medium run projections, though the "unprecedented" timing of the policies (at or near the top of business cycle) would likely be a limit on their impacts.[3]

At this time, risks to growth at the national level are roughly balanced. In the near and middle term, the principal downside risk to the national economy is higher than expected inflation as the effects of federal policy unfold and capacity utilization inches towards its maximum, which could prompt a more aggressive monetary tightening path at the Fed and "harder" landing at the end of the current cycle. Other material risks are largely geopolitical in nature, including increasingly retaliatory barriers to trade between the U.S. and its trading partners.

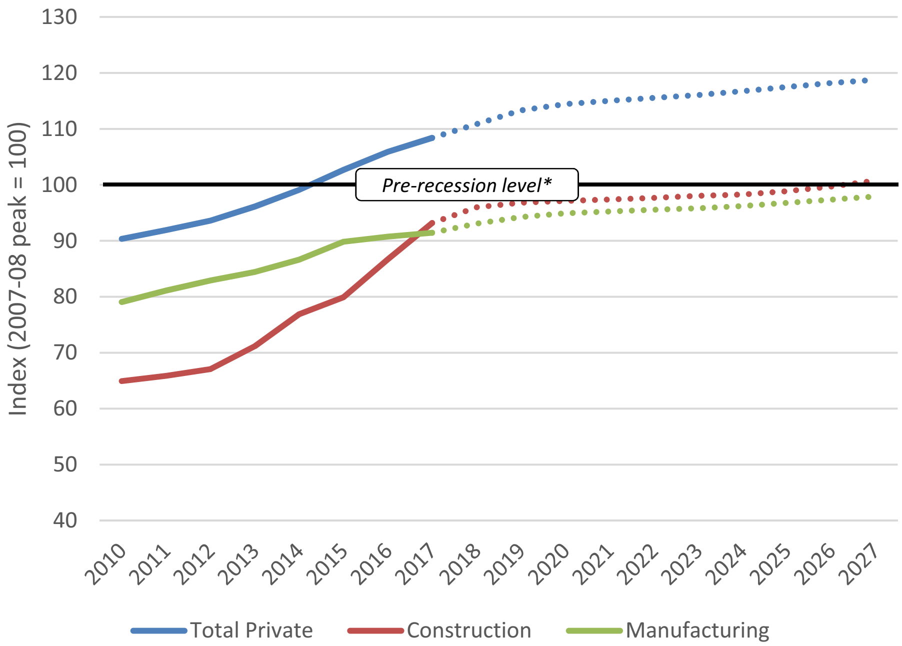
2.2. OREGON ECONOMIC AND DEMOGRAPHIC OUTLOOK

Despite mixed signals in the most recently available data,[4] the Oregon economy appears healthy and set for continued growth (Figure 2.1). Private sector employment has consistently

[1] U.S. Bureau of Economic Analysis; retrieved April 17th, 2018
[2] U.S. Bureau of Labor Statistics; retrieved April 17th, 2018
[3] Minutes of the Federal Open Market Committee March 20-21, 2018; retrieved April 17th, 2018
[4] Private sector employment growth and total output in Oregon peaked in 2015, but remain at positive levels expected at late-cycle conditions. Having grown at a rapid pace since late 2010, Oregon housing starts leveled off in mid-2016. See US Bureau of Labor Statistics Current Employment Survey, US Bureau of Economic Analysis Regional Economic Accounts, and Oregon Office of Economic Analysis Economic and Revenue Forecasts, respectively, for detailed information

grown at a higher than 2% rate since 2013, substantially faster than the state's working-age population. Associated wage gains have outperformed the national average as regional businesses compete for a shrinking pool of available applicants.[5] Consumer facing service industries (e.g., health care, leisure and hospitality) and professional services have led the recovery and expansion, construction and the goods-producing industries have steadily, albeit slowly and incompletely, regained losses from the 2008-09 recession.

Figure 2.1: Oregon Employment vs. Pre-recession peak; Forecasts



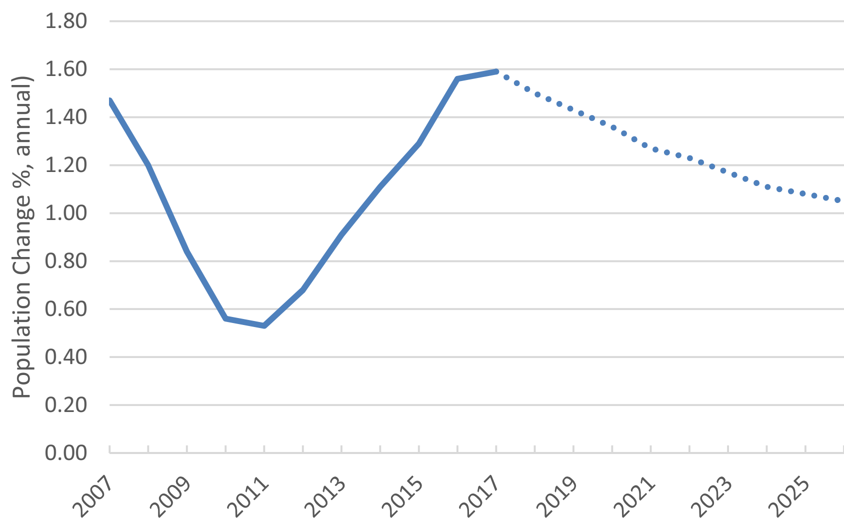
The latest available state-level employment forecast from the state's Office of Economic Analysis (OEA) follows the essential story of national expectations: OEA projects continued strong job growth in the 2% per year range while the regional and national economies transition from a crest of rapid expansion to more typical long-run patterns through the early 2020's. Notably, OEA expects that activity will be largely propelled by the same service industries that have led Oregon's economy through the recovery; manufacturing employment will not recover to its pre-recession (2007) level by the end of its 2027 horizon, and construction employment is projected to inch back to its peak only in the final year of the forecast, nearly two decades after the recession began.

State level demographic trends similarly suggest the approach the end to an era of remarkable growth. Oregon never lost population during the depths of the recession. However, the inbound flows of migrants to the state that drive the majority of population change briefly slowed to the lowest rates in recent history, before rising again as the state packed on an additional 325,000

[5] Oregon Employment Department, "A Lack of Applicants in a Growing Economy", May 2017, retrieved April 17, 2018; Oregon Office of Economic Analysis, Oregon Economic and Revenue Forecast, March 2018, retrieved April 17 2018

residents between 2010 and 2017. These gains, like new employment, were mostly absorbed by metro areas in NW Natural's service territory and the central and southern parts of the state.[6] OEA's demographic forecast pegs 2017-2018 as a peak in terms of both net migration and overall population growth, though the wave is expected to only slowly recede over the next decade (Figure 2.2).

Figure 2.2: Oregon Population Growth, 2007 – 2017; Forecast

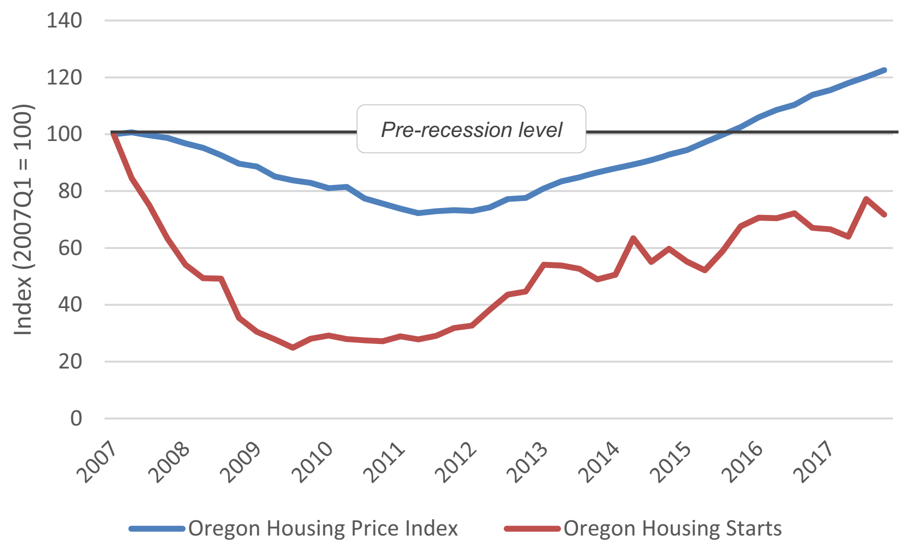


Rapid population growth, a solid job market, and unevenly rising income levels have been the defining characteristics of Oregon's recovery and expansion. The combination of these factors has produced a conspicuous housing affordability issue in much of the state, augmented by a deep structural rout of housing markets during the recession. The supply/demand mismatch has been particularly acute in the multifamily submarket (largely within NW Natural's urban territory); a delayed but sizeable development response in the Portland region has eased rent growth and will likely clear the worst of the near-term disequilibrium there, but an equally sizeable surge of housing policy presents a potential headwind to continued supply growth.

Despite strong market price signals that are expected to continue in the near term for the single family market, other factors such as rising labor and land costs have begun to soften the building recovery, and construction is not expected to return to its mid-2000's pace in much of the state (Figure 2.3). Single family housing prices in metro areas increased at double-digit rates over much of 2014-2017 period, and have only slightly tapered into single digit growth in 2017.

[6] Oregon Employment Department, June 2 2017, retrieved April 18, 2018

Figure 2.3: Oregon Housing Prices and Housing Starts vs. Pre-Recession Peak



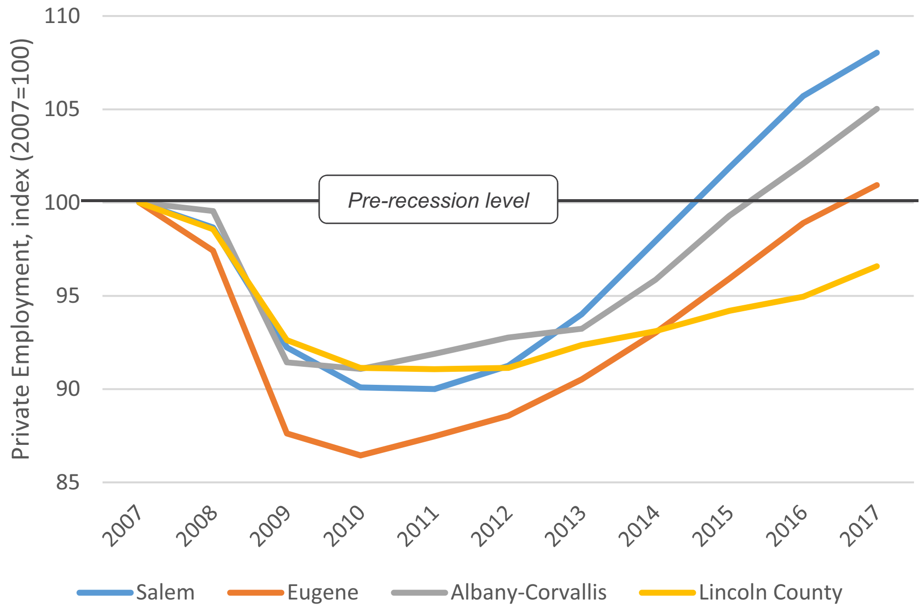
2.3. NW NATURAL SYSTEM AREA ECONOMIC AND DEMOGRAPHIC OUTLOOK

As noted, Oregon's economic dynamics are concentrated in and driven by areas that largely comprise NW Natural's service territory. The five Oregon counties in the Portland metropolitan area attracted 58% of the new residents and captured 62% of the new jobs added in Oregon since 2010.[7] Combined with Clark County, Washington, the Portland MSA grew significantly faster than either state in terms of population or employment.

Other population centers within NW Natural's territory have had more mixed experiences in terms of economic recovery (Figure 2.4). While the Salem area labor market roughly kept pace with Portland, growth in areas further south and west have generally lagged, recovering pre-recession levels later and with less momentum heading in to 2018.

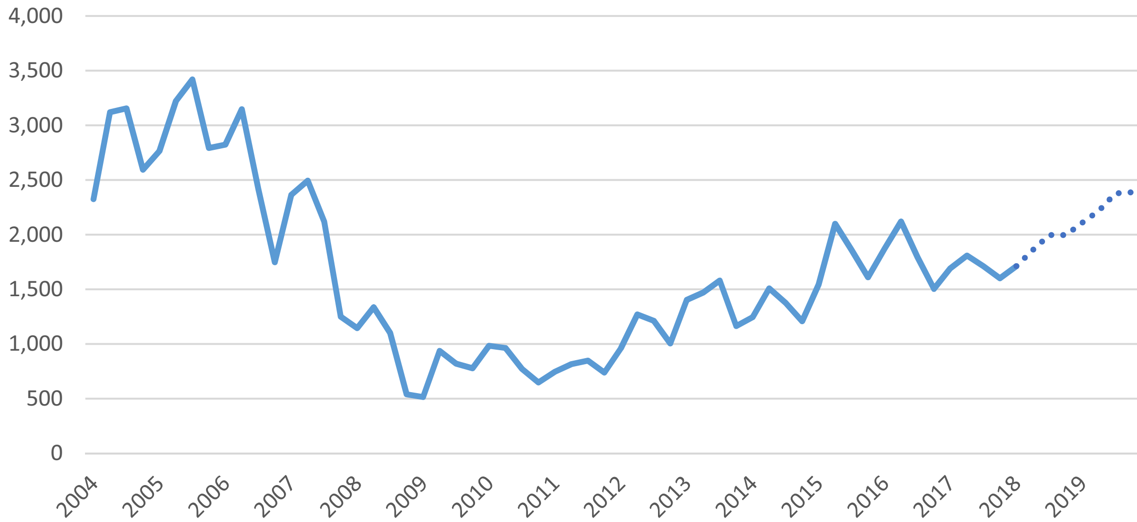
[7] U.S. Census Bureau population estimates from April 2010 to July 1st, 2017; US Bureau of Labor Statistics Current Employment Survey annual estimates from 2010 to 2017

Figure 2.4: Private Employment vs. Pre-recession Peak, Select Areas



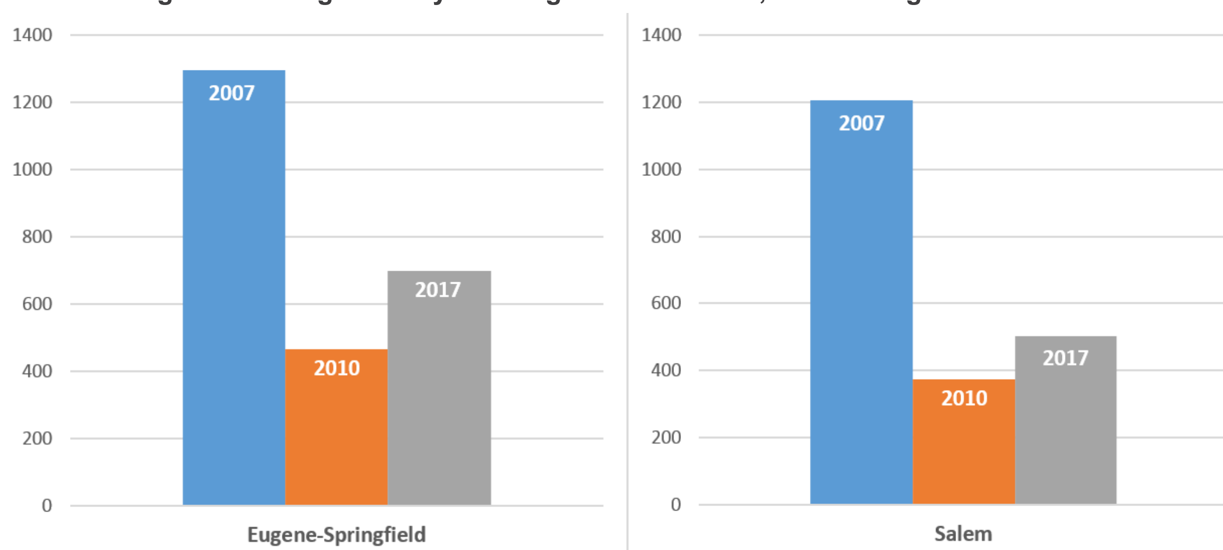
Following a prolonged period of inadequate housing supply growth, cost of living and housing affordability remain center stage for the urban areas of the region, reaching beyond the Portland area into the Willamette Valley and beyond. These factors have already had material impacts on real estate, construction, and development markets, most notably a multifamily building boom in Portland, rapidly tightening single family home markets, and concerted policy interventions in cities within the service area (Figure 2.5).To varying degrees, normal market forces combined with housing policies such as construction taxes and inclusionary zoning are expected to dampen multifamily deliveries in the near and medium term in the Portland metro area, but single family construction is expected to continue its recovery to regain a pace not seen since 2007. The share of households owning a home (as opposed to renting) climbed back to majority status by 2015 after a brief period of rental dominance, and is expected to increase over the next decade. Clark County, Washington stands out in terms of single family growth; whereas the county once captured slightly more than one quarter of single family construction activity in the 7-county metro area, it now captures slightly more than one third.

Figure 2.5: Single Family Housing Starts, Portland-Vancouver-Hillsboro MSA[8]



Single family building remains remarkably muted elsewhere in the territory relative to pre-recession levels. In the Eugene-Springfield region, for example and as shown in Figure 2.6, construction levels still hover at just over half that of 2007; in Salem, the figure is materially lower. Population growth in these two areas has returned to pre-recession rates, once again illustrating the continuing pressure on the existing building stock in places far outside of Portland market.

Figure 2.6: Single Family Building Permits Issued, Select Oregon Metro Areas



[8] Source: Northwest Economic Research Center, March 2018 Forecast

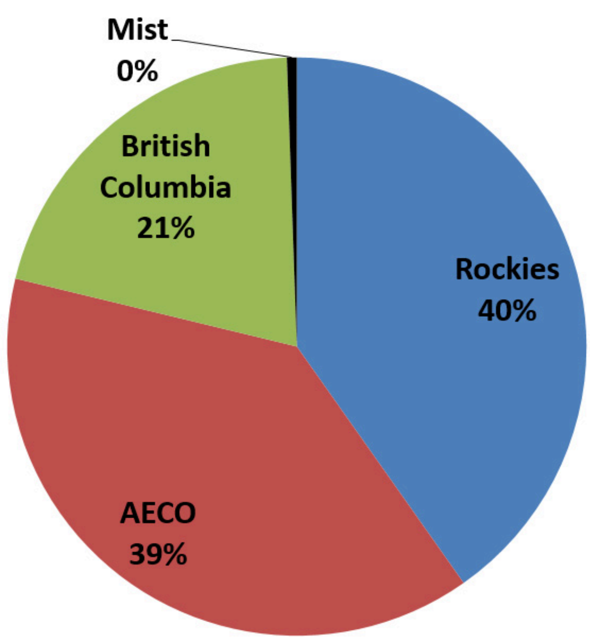
3. NATURAL GAS PRICES

NW Natural uses planning horizon forecasts of natural gas prices by trading hub in developing the Company's IRP. These forecasts include monthly price forecasts for Henry Hub, Rockies (using the Opal trading hub), British Columbia (Station 2 and Sumas/Huntingdon), and Alberta (AECO). Like many commodities, volatility in natural gas prices makes forecasting prices highly uncertain. NW Natural expects future gas prices will be influenced by numerous factors, including economic conditions, demand, increasing use of natural gas to fuel power generation, potential national or regional carbon policies,[9] weather, and new and traditional supplies—such as gas produced using more efficient extraction technologies. The Company reviews several price forecasts and has developed a base case gas price forecast as well as additional price outlooks to represent reasonable ranges of future prices for the trading hubs from which the Company purchases gas supplies.

3.1. NATURAL GAS SUPPLY BASINS

The Company's upstream pipeline contracts enable it to purchase roughly 40% of its supplies from Rockies and Alberta along with 20% from British Columbia (Figure 2.7). Lower liquidity in British Columbia has prompted the Company to baseload more of its supplies from this region. The Company will continue to favor spot purchases from Alberta due to generally lower prices and very strong liquidity.

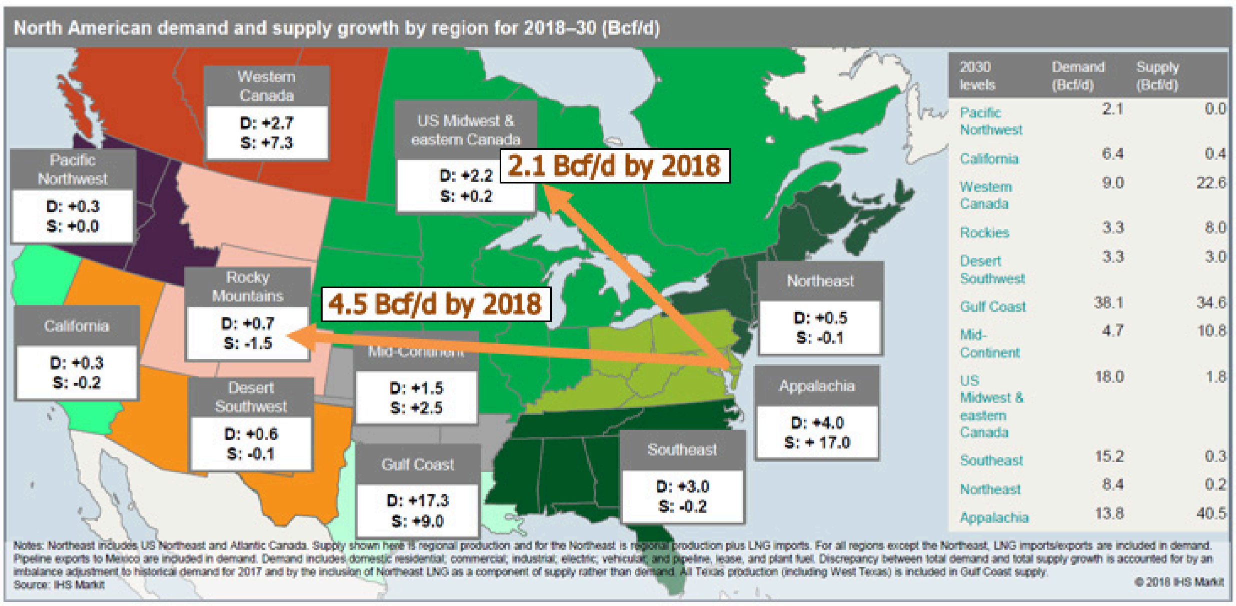
Figure 2.7: Diversity of purchased gas in 2017



[9] Energy policies and environmental considerations regarding policies related to emissions of greenhouse gases and specifically to emissions of carbon dioxide produced by combustion of fossil fuels will be discussed in more detail later on in this chapter.

A bearish factor for British Columbia, Rockies and Alberta has been the growing U.S. Northeast production. Supply in Appalachia is expected to increase significantly, while demand in the Northwest creeps slightly higher than supplies (Figure 2.8). This will have the effect of pushing gas Westward into areas NW Natural purchases gas (Figure 2.8). Appalachia's limits are currently constrained by infrastructure which is constricting outflow to other regions. In 2018 it is forecasted that an additional 4.5 Bcf/d will be flowing to the West South-Central region while 2.1 Bcf/d flow to Eastern Canada.[10] Additional supply options in these regions could put downward pressure on Western Canadian gas prices. These factors are highly susceptible to pipeline construction and regulatory factors.

Figure 2.8: Demand and Supply Growth by Region



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As will be discussed in Chapter 6 in more detail, the Company changes its purchase patterns to acquire the lowest-priced gas while assuring supply reliability. Transportation costs and fuel losses are factored into resource choices. Regional prices could shift again with future Canadian LNG exports, growing exports to Mexico, new pipelines and other factors.

3.2. HISTORIC CONDITIONS

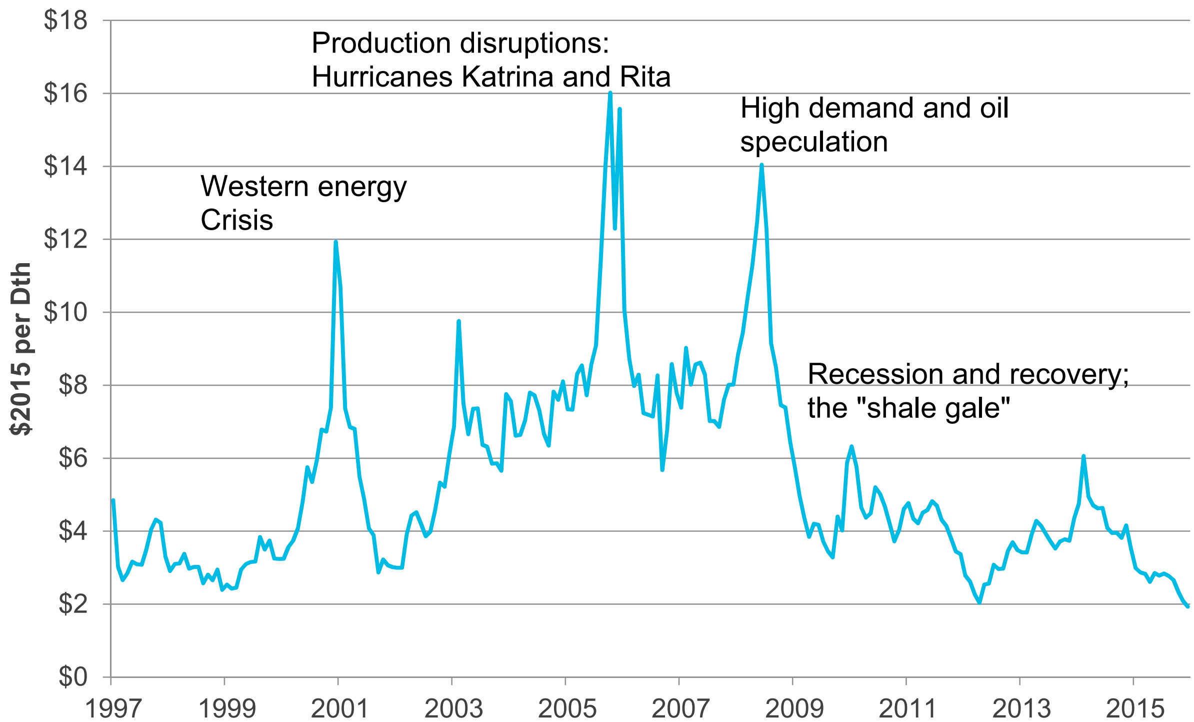
Over the past 50 years, natural gas has gone through a series of shortages and oversupply; many of these events have caused policy shifts including deregulation. Deregulation lead to the rise of financial derivative markets and the establishment of a national benchmark price at the Henry Hub trading point in Erath, Louisiana, as well as a shift from longer term contracts to spot

[10] Source: IHS "Natural Gas Watch: Shale Gas Reloaded; The search for a new balance in North American natural gas markets through 2025" July 2016.

trading. Once U.S. natural gas became a freely traded commodity, lower prices created new demand and the market has attempted to balance itself through competition, increased efficiencies, technological improvements, and the discovery of more natural gas.[11]

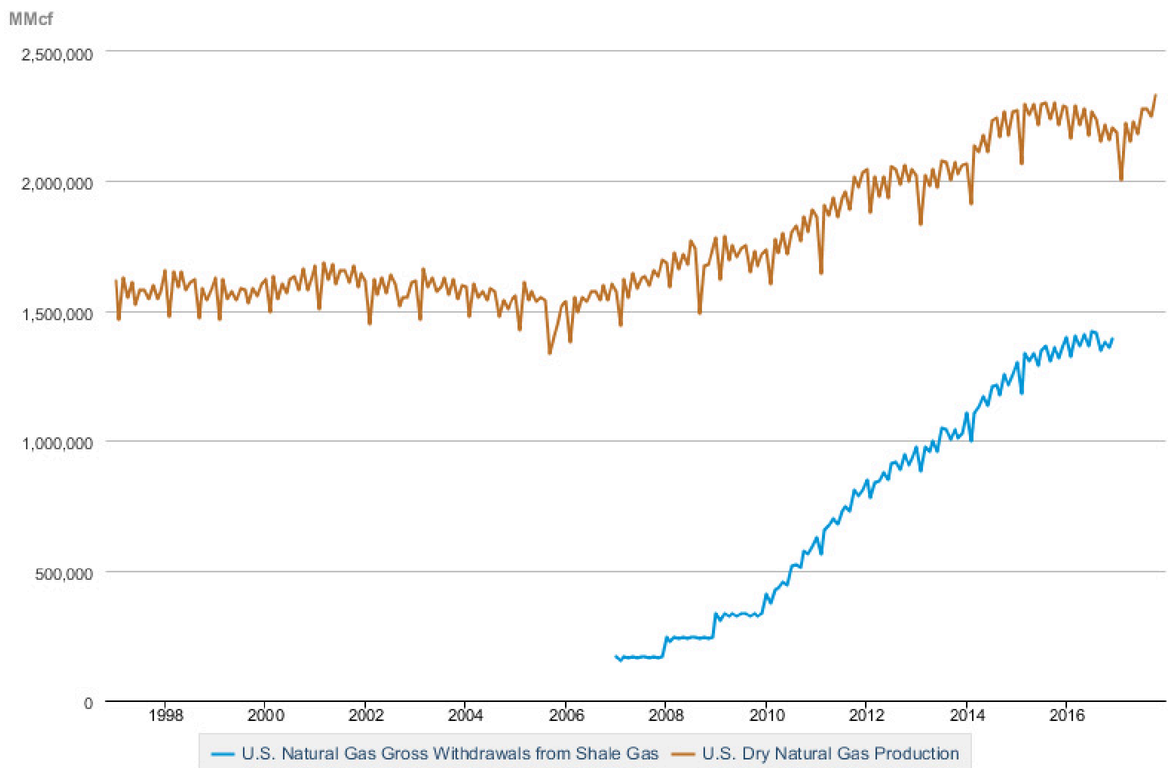
As can be seen in Figure 2.9, throughout the 2000s, the turmoil of hurricanes, the collapse of Enron and fallout for other trading companies, and other factors led to gas prices spiking, in October, 2005.[12] At the time (prior to the shale gale), nearly 38.7% of gas production came from the gulf which increased the impact of hurricane season.[13] In 2008, a global economic recession reduced demand. Concurrently, the advent of horizontal drilling into shale formations, especially in the Northeast U.S., unleashed a surge of production (Figure 2.10). The oversupply pushed down prices.

Figure 2.9: Henry Hub Natural Gas Spot Prices



[11] Goldman Sachs, Time for LNG to Grow Up and Face Off Against Coal, March 5, 2015.
[12] Source: EIA "Henry Hub Natural Gas Spot Price" https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm, February 7, 2018
[13] https://www.dallasfed.org/~/media/documents/research/houston/2005/hb0508.pdf

Figure 2.10: Shale gas production increases dramatically since 2007



Source : U.S. Energy Information Administration

3.3. CURRENT MARKET CONDITIONS

Events during the past year have impacted supply and demand balances in the current markets. The winter of 2016-2017 was harsh in Oregon, producing eight winter events and, according to the Oregonian, "the metro area's winter lacked only the Four Horsemen of the Apocalypse and a swarm of locusts."[14] The winter of 2017-2018 experienced a mild December mixed with a very cold January in the eastern half of the continent, which created highly volatile gas prices and an accelerated depletion of storage inventories.[15]

Natural gas production continues to grow in United States (Figure 2.11). Wells drilled in the Marcellus and Utica basins (Appalachia) are producing 5-10% more efficiently than forecasted, a substantial increase. With new technologies, well drilling times are dramatically reducing. Since 2013 many basins have seen drilling times reduced by 30-40% allowing for more cost-effective drilling. While Rockies gas has generally been declining, some basins in the Rockies such as the Denver-Julesburg (DJ) have been rapidly expanding which works to stabilize the Rockies market. The allure of the DJ basin is that the basin is relatively shallow, making drilling more cost effective.[16] Gas production from the Montney region which is a prolific supply basin

[14] Source: The Oregonian "Oregon's winter of 2016-17 won't soon be forgotten." February 25, 2017 http://www.oregonlive.com/weather/index.ssf/2017/02/oregons_winter_of_2016-17_wont.html
[15] Source: RBC Capital Markets, "Gas Storage Report" January 25, 2018
[16] Source: Platts. LDC Conference, October 2017.

that spans northern British Columbia and Alberta, Canada (illustrated in Figure 2.12) has also been expanding rapidly. The Montney, is very important because it is one of our main supply points. We access this supply from both our AECO and Westcoast (T-South) pipeline capacity. In figure 2.12, Montney represents the majority of the blue swath that makes up Canadian production.

Figure 2.11: North American Gas Production by Region

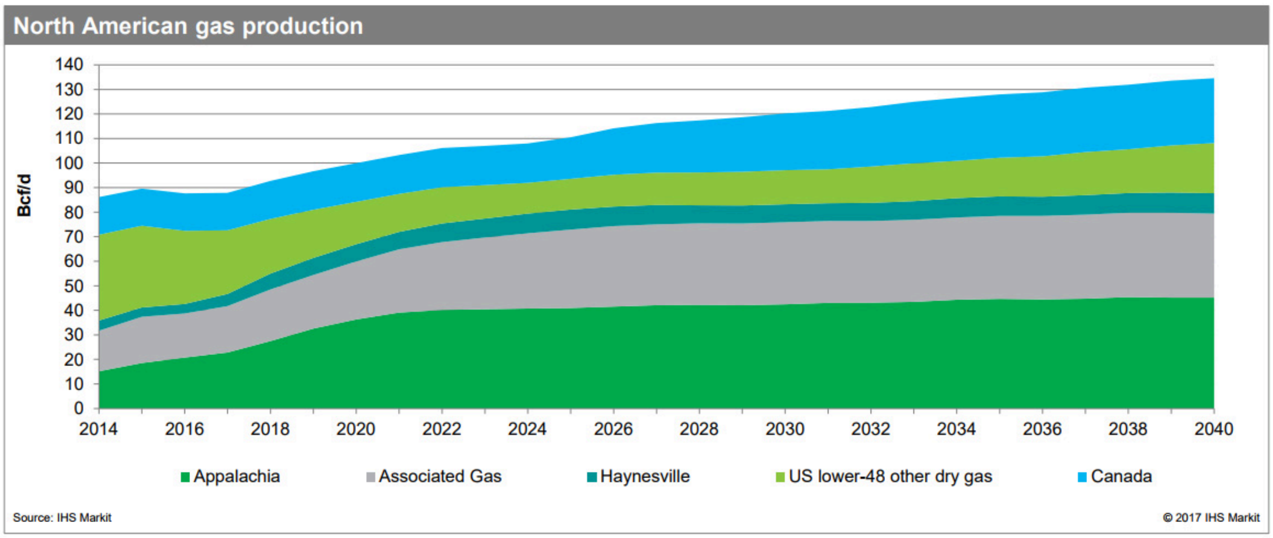


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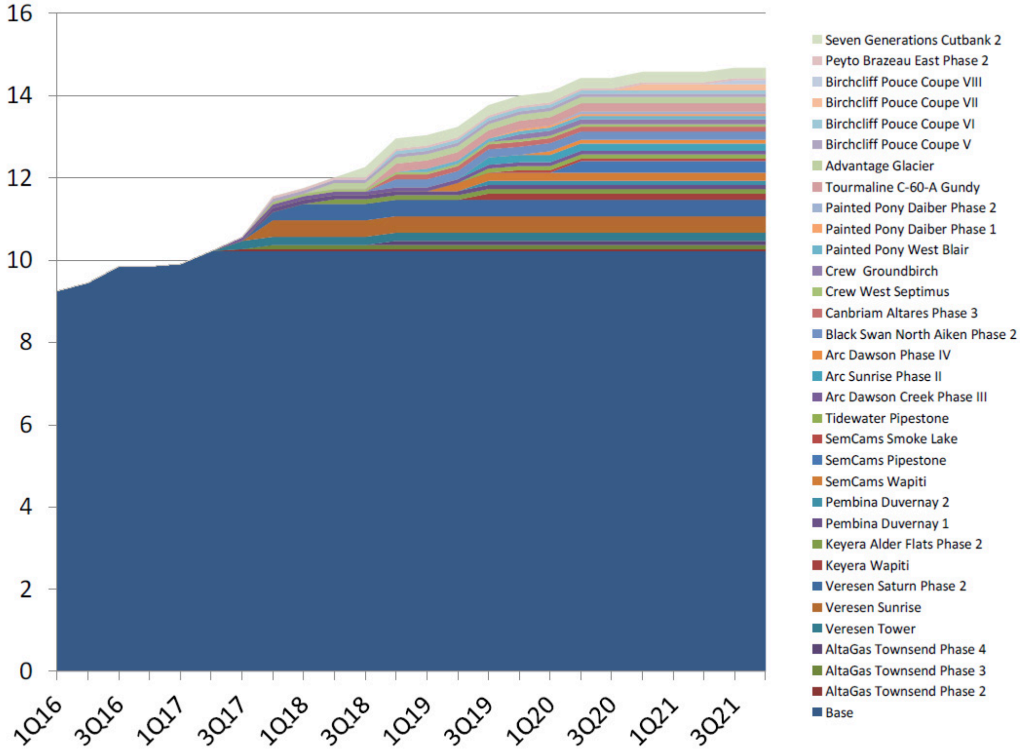
Figure 2.12: Montney Expansion Production



Source: BMO Capital Markets Research "2018 Year Ahead: Looking for Goldilocks" 1/11/2018

Associated gas[17] is also expected to continue to grow, however this production is very sensitive to the crude oil market as associated gas is obtained from crude wells. Lower oil prices have the potential to stall drilling and reduce the supply of associated gas. Because a large amount of gas production is associative, an inverse relationship develops as higher oil prices drive more drilling, which means a more abundant supply of associated natural gas and thus cheaper gas prices. Low oil prices usually result in less drilling, less associated gas, and higher gas prices.

The increase in natural gas production is currently being balanced by an increase in natural gas demand, including exports. The abundance of natural gas and low prices has made investing in liquefied natural gas (LNG) exports much more attractive as well as exports to Mexico via pipelines. The most significant LNG export facility in the U.S. is the Sabine Pass LNG station, located in Louisiana, exporting ~2 Bcf/d by the end of 2017.[18]

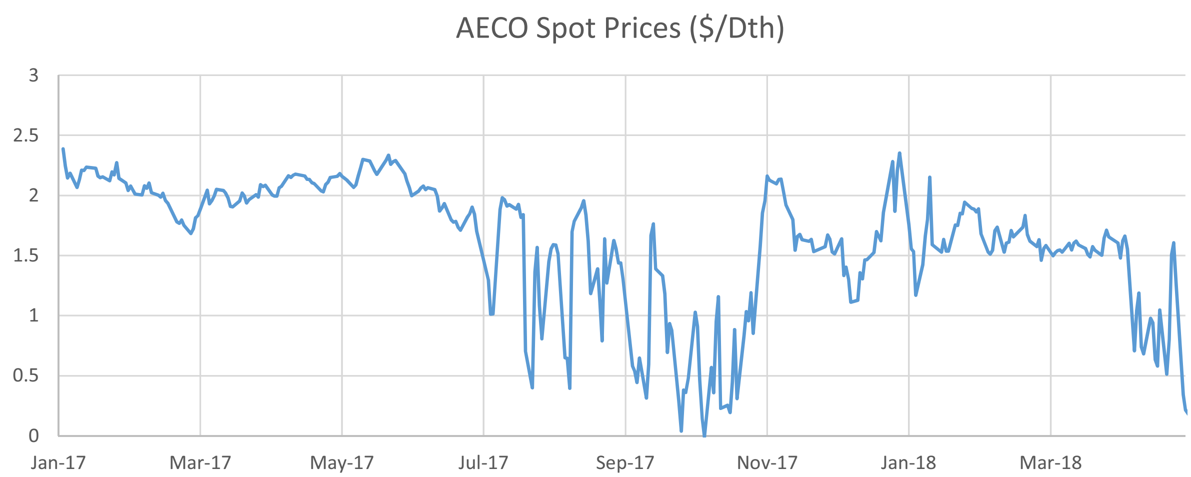
In the Pacific Northwest, the Woodfibre LNG facility has reached the final investment decision (FID); it has been the only Pacific NW LNG facility to do so.[19] The cancellation of LNG projects such as the Pacific NW LNG, coupled with copious amounts of natural gas being produced in

[17] Associated gas is gas obtained as a by-product of drilling for oil and other liquids.
[18] Source: SNL "As US exports more natural gas, New England continues to rely on LNG from abroad" https://platform.mi.spglobal.com/web/client?auth=inherit#news/article?id=43058729&KeyProductLinkType=14
[19] Source: CBC News "Woodfibre LNG project confident it will move forward despite Pacific Northwest setback" - http://www.cbc.ca/news/canada/british-columbia/woodfibre-lng-project-confident-it-will-move-forward-despite-pacific-northwest-setback-1.4224156

the Eastern U.S. have put a lot of negative price pressure on Western Canadian gas, particularly the Montney basin where the majority of our natural gas is purchased. With strong competition from the East, and faltering prospects for LNG exports in the West, prices have been low and are forecast to remain that way in the PNW.[20]

Market trends in Alberta have resulted in extremely low prices in autumn of 2017 and again in spring of 2018. Pipeline maintenance projects stranded gas which traded for as low as $0.00/Dth in Alberta (Figure 2.13). These trends are expected to continue until at least 2020 when new pipelines are completed, such as the Alliance expansion, the Westcoast expansion, and the restoration of capacity on Empress and McNeil on the TCPL NOVA system.[21]

Figure 2.13: Historical AECO Spot Prices



Source: Morningstar Historical Data

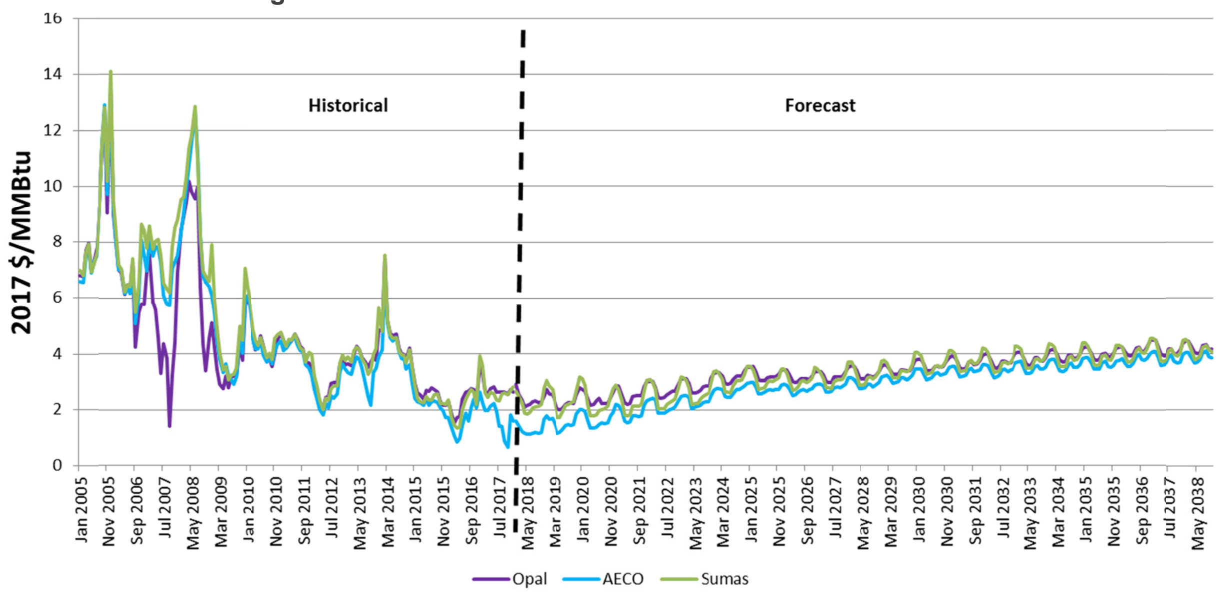
[20] Source: IHS “Western Canada Regional Analysis” December 2017
[21] Source: Conversations with IHS Market, April 2018

3.4. FORECAST OF NATURAL GAS PRICES

NW Natural's 2018 IRP natural gas price forecast is of monthly prices developed by a third-party provider (IHS) based on market fundamentals. NW Natural includes the price forecast in the Company's SENDOUT® resource planning modeling software, which is used for analyzing and developing the optimal plan for purchasing and transporting natural gas to the Company's customers.

Additionally, future natural gas prices impact avoided cost calculations and thereby the level of predicted Energy Trust demand-side management energy-efficiency (DSM/EE) savings. Figure 2.14 displays the historical spot prices for 2005–2017 and the 2018 IRP expected price forecast. As can be seen in the forecast below, prices are expected to increase gradually from their current low of about $2-$3/Dth to approximately $4/Dth over the planning horizon.

Figure 2.14: Historical and Forecasted Natural Gas Prices



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3.5. POTENTIAL GAME CHANGERS

A number of factors are currently being considered which depend on factors that are either difficult or impossible to predict. Changing government policy, investment decisions in capital projects, and shifting energy sources are items which may impact price.

Particularly the following factors pose risk for prices going forward:

- Canadian government changes – the current government in Alberta is currently supporting the conversion of coal power plants to natural gas by the implantation of carbon taxes.[22] Should the government change direction we could see a slowdown in switching away from coal.

- American government changes –the following risk factors may impact natural gas prices:
  - NAFTA changes may occur, which could potentially affect the prices of imports of Canadian gas[23]
  - Steel tariffs may inhibit the construction of pipelines as well as LNG facilities[24]
- Capital Projects
  - The Jordan Cove export facility in BC could increase demand from basins NW Natural purchases gas
  - Methanol projects currently being investigated in the Pacific Northwest could affect regional demand
- Shifting Power Energy Supplies – Increases or decreases to power generation sources would directly impact natural gas demand.
  - The addition of renewable power capacity on the electric grid
  - Incentives for renewables could be extended, making investment in renewable energy more attractive
  - Changes in coal power facility retirements could impact natural gas demand

3.6. CONCLUSIONS

Gas prices are currently at historic lows and are forecasted to increase over time. The current price risks mainly focus around infrastructure. If drilling for oil slows, associated gas production will decrease, decreasing supply. If exports and export capacity increases, demand will also increase. Oil prices, government policies, capital investments and other factors pose risk to natural gas prices.

4. ENVIRONMENTAL POLICY

While environmental policy at the federal level is very difficult to predict, policy changes to add a price on carbon in Oregon and Washington appears nearly inevitable during the company's planning horizon. Because of this policy development, the company for the first time is including in the IRP a detailed emissions forecast. This chapter also explores various carbon reduction policies that may be placed on the company and the various strategies the company might use to address these GHG reduction requirements. Because the company believes there is a climate imperative to take action and because we see these policy changes on the horizon, NW Natural has developed a Low Carbon Pathway as part of the company's strategic planning

[22] Source: IHS. "Alberta's future power system comes into focus", June 1, 2018 This content is extracted from IHS Global Gas service and was developed as part of an ongoing subscription service. No part of this content was developed for or is meant to reflect a specific endorsement of a policy or regulatory outcome. The use of this content was approved in advance by IHS. Any further use or redistribution of this content is strictly prohibited without written permission by IHS. Copyright 2018, all rights reserved.

[23] Source: SNL, "'We'd like to keep it going': Energy leaders lobby against scrapping NAFTA" 3/15/2018 https://platform.mi.spglobal.com/web/client?auth=inherit#news/article?id=43889629&KeyProductLinkType=6

[24] Source: SNL, "Steel tariffs may disrupt future US crude, LNG exports" 6/5/2018 https://platform.mi.spglobal.com/web/client?auth=inherit#news/article?id=44814990&KeyProductLinkType=6

effort. This chapter explores actions outlined within the company's low carbon pathway that includes efforts to reduce the carbon intensity of our product, to reduce our customers' carbon footprint, and to find ways to replace higher carbon fuels – like diesel in heavy duty vehicles.

4.1. OREGON AND WASHINGTON GREENHOUSE GAS EMISSIONS

According to the Oregon Department of Environmental Quality's Greenhouse Gas Inventory (figure 2.15), direct use of natural gas represented roughly 12% of Oregon's GHG emissions in 2015.[25] This was approximately a third of transportation sector emissions and less than half of the emissions from electricity use in the state. Based on reported data to Washington State, the direct use of gas accounted for 13%, with 0.5% attributed to NW Natural's Washington customers.

Figure 2.15: Oregon and Washington Greenhouse Gas Emissions[26]

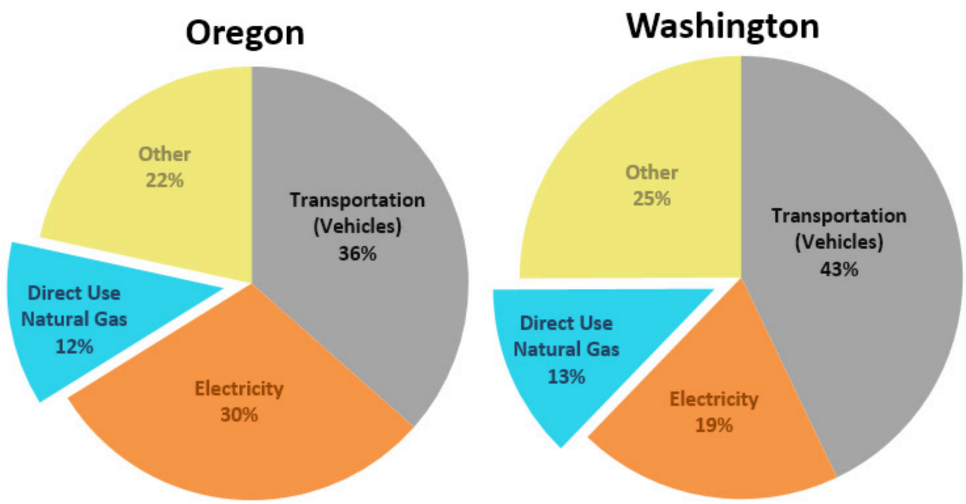


Figure 2.16, shows a breakdown of the 12% of emission that come from direct use of natural gas in Oregon. Each column independently shows how the 12% is divided by end use, customer type, and by gas supplier. When considering emissions from end uses, almost half of the emissions from direct use of natural gas, 5.7% of the state's total, come from process/other load. Space heating accounts for the other major component of direct use emissions, but only accounts for 4.7% of the state's total emissions. Emissions from cooking and water heating combined account for roughly 2% of the state's total emissions.

[25] https://www.oregon.gov/deq/aq/programs/Pages/GHG-Inventory.aspx
[26] Pie sizes represent GHG emissions (in CO_2 equivalent) of the state and the region. Source of data: latest year from the GHG emissions inventories published by Oregon (2015), and the Washington Department of Ecology (2012).

Figure 2.16: 2015 Oregon Greenhouse Gas Emissions

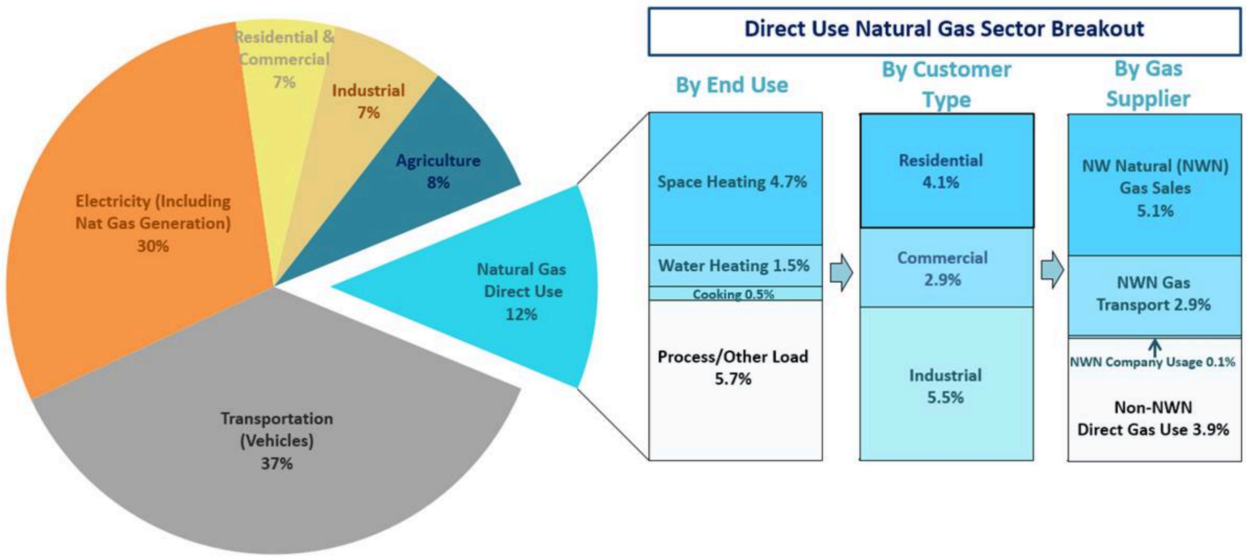


Table 2.1 further breaks out natural gas emissions by NW Natural's share and customer sector, as a percentage of Oregon's total 2015 emissions. Nearly all emissions reported by NW Natural are due to customer direct use. Only 0.1% of Oregon's emissions came from company operations or from methane emissions that escaped from NW Natural's infrastructure network.[27]

Table 2.1: Direct Use of Natural Gas Share of Total 2015 Oregon GHG Emissions

Customer Sector	NW Natural	Oregon Total
Residential	2.6%	4.1%
Commercial Sales	1.7%	2.8%
Commercial Transport	0.1%	
Industrial Sales	0.8%	5.5%
Industrial Transport	2.8%	
Company Usage and Fugitive Methane	0.1%	N/A[28]

As the largest natural gas LDC in the Oregon, NW Natural's throughput comprises a majority of the direct use emissions (Figure 2.7): 5.1% of Oregon's GHG emissions came from gas purchased by NW Natural and delivered to its sales customers; and 2.9% came from gas independently purchased by large users, but transported through NW Natural's pipeline network (customers on NW Natural's transportation schedules). Industrial emissions represent the

[27] Methane emissions have a higher emission impact in CO_2 equivalent terms than natural gas that is combusted. NW Natural has one of the tightest distribution systems in the United States because it has replaced all higher emitting bare steel and cast iron pipe that was once part of its system.
[28] We do not have access to data regarding operational or fugitive system methane emissions of Avista or Cascade Natural Gas

largest share of the state's emissions that come from the direct use of natural gas (5.5% of the state's total in 2015, 3.6% from NW Natural industrial customers). Industrial customers on transport schedules make up 46% of these emissions.

4.2. EMISSIONS, WEATHER AND ANNUAL VARIATIONS

To align with Oregon's GHG inventory, the emissions shown in Table 2.1 are NW Natural's actual emissions in 2015. These will vary from year to year, based on weather.[29] Overall emissions will be higher in years with colder than average heating seasons and lower in years with milder than average heating seasons. Even with this variation, overall emissions in any one year will typically be within 10% of the emissions during a normal weather year.

Consequently, swings in emissions from year to year or relative to a base year (which itself may not be a year with normal weather emissions) may not be due to trends that will persist through time, but rather annual deviations due to weather. That's why it's often more useful to present "weather normalized" figures[30] when using historical data, as emissions forecasts are based upon expectations of normal weather.[31]

4.3. FULL-SOURCE EMISSIONS ACCOUNTING

Neither Oregon nor Washington GHG inventories discussed above incorporate life-cycle accounting, which means these inventories include emissions at the end use and do not include any carbon impacts along the value chain. As a result, this omits emissions from the energy sector associated with coal mining, natural gas production, solar panel and wind turbine manufacturing and so forth.

Specific to natural gas, the only non-combustion emissions included in Oregon's GHG inventory come from an estimate of the carbon dioxide equivalent (CO_2e) of methane[32] emitted from natural gas infrastructure located in Oregon. In fact, these emissions represent a small portion of total value chain methane emissions, given that the Pacific Northwest is not a natural gas production region, and that the largest source associated methane emissions occur upstream of the local infrastructure from out-of-state production and processing.[33]

However, even though NW Natural is not required to report upstream methane emissions to the environmental regulators in its service territory[34] or to the EPA, we recognizes that without natural gas production the company could not deliver the fuel that its customers use to heat their homes, businesses, and water and fuel industry in its service territory.

[29] Annual reported emissions from electricity and heating oil are also dependent upon weather
[30] Which represent expected emissions for a year with normal weather
[31] Note that weather normalization processes can incorporate climate change.
[32] Methane (chemical formula CH4) is the main constituent of natural gas.
[33] The gas used in the Pacific Northwest is primarily produced in the American Rockies, British Columbia or Alberta, and these methane emissions are typically reported in those states or provinces.
[34] The Oregon Department of Environmental Quality (ODEQ) and the Washington Department of Ecology

Furthermore, given that methane is a more potent greenhouse gas than carbon dioxide,[35] methane emissions from the natural gas value chain are important to consider when evaluating the contribution of natural gas use to societal GHG emissions.

The EPA estimates that natural gas life cycle methane emissions represent 1.44% of total natural gas use with the breakdown by sector in the direct use of natural gas value chain shown in Table 2.2.

Table 2.2: EPA Estimates of Methane Emissions from the Natural Gas Value Chain 1990-2014

Industry Sector	Emission Rate[36]
Production & Gathering	0.55%
Processing	0.18%
Transmission & Storage	0.44%
Distribution	0.26%
Life Cycle Total Fugitive Emissions	1.44%

These national averages indicate the largest source of methane emissions from the natural gas value chain is the production and gathering sector, followed by the transmission and storage sector. The distribution sector, to which NW Natural belongs, represents a relatively small share of the natural gas value chain's methane emissions.

4.4. NW NATURAL SYSTEM EMISSIONS

Distribution system's emission rates are even smaller for NW Natural given that the company has taken action to reduce the methane emissions on our distribution system by (among other things) replacing all cast iron and bare steel pipes in our distribution network. Because of this work, NW Natural has among the tightest systems in the country. Per our reports to the EPA, methane emissions from NW Natural's system are less than half that of national average at only 0.10% of throughput.[37] This results in the methane emissions from the natural gas value chain representing 1.28% of all gas used by NW Natural customers, which represents an increase in the carbon intensity of the product we deliver by 1.73 lbs per therm (an increase of 15% per therm relative to combustion alone).

Additionally, some natural gas is used (combusted) by compressors and other equipment to deliver it from its location of production to the end use customer. For NW Natural, this usage

[35] This is based upon 100-year global warming potential (GWP), where the EPA estimates that methane has a GWP 86 times that of carbon dioxide if a 20-year GWP is used. See https://www.epa.gov/ghgemissions/understanding-global-warming-potentials
[36] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014. Note that the 1990-2015 update from April 2017 revises the overall emissions down from 1.44% to 1.21%.
[37] Based upon on our 2015 reporting to the EPA through Subpart W. These reduced emissions relative to the national average represent an annual savings of 69,000 metric tons of CO_2e emitted.

represents 2.6% of the gas it purchases, which adds another 0.35 lbs per therm of CO_2e to the carbon intensity of our delivered product.

The total impact of emissions and consumption along the value chain is the lifecycle GHG intensity of the conventional natural gas. These factors, applied to the natural gas NW Natural delivers to its customers, result in an additional 13.8 lbs CO_2e per therm, which is about 18% higher than end-use combustion alone.

4.5. POLICY CONTEXT

The election of President Trump in 2016 marked a significant shift in federal environmental policy. The new administration rolled back executive orders empowering the EPA to regulate GHG emissions, challenged ambitious state vehicle emissions standards, and withdrew from the Paris Climate Agreement, a global accord designed to strengthen the global response to the threat of climate change.

Many communities responded in force.[38] In the Pacific Northwest, where these conversations had been going on for some time, action has intensified at the state and local level. This section includes a summary of the key policy initiatives at the state and local level that could impact natural gas usage and sourcing. It's important to note that policy conversations shift quickly so this summary is based on the latest current information and is likely to change.

4.6. STATE CLIMATE POLICY

Carbon pricing is a key policy objective in Oregon and Washington, though the states are approaching it in different ways. Each state is committed to a serious conversation about carbon pricing in the next 12 months, and NW Natural fully expects to see a carbon price in the company's planning horizon.

Oregon

In the 2018 Short Legislative Session the Clean Energy Jobs Bill (SB 1070) proposed a cap and invest program designed to price carbon and drive emission reductions. Under this proposal, utilities would have been consigned allowances based on a historic baseline and revenue from allowance sales was to be divvied up among a variety of programs including Energy-Intensive-Trade-Exposed (EITE) companies, low-income communities, clean energy projects, and others.

The bill did not pass during the short session but conversations are already beginning for the 2019 session. Issues at the center of the debate were allowance allocation, offset provision, timing, and revenue distribution and it is unclear how the 2019 proposal will borrow or diverge from SB 1070. NW Natural is committed to being present and productive during future discussions.

[38] A coalition of more than 2,700 CEOs, mayors, governors, college presidents, and other leaders, representing more than 130 million Americans and $6.2 trillion of the U.S. economy, have signed the We Are Still In declaration, demonstrating their commitment the Paris Agreement. www.wearestillin.com/we-are-still-declaration

Washington

Washington State also held a short session in 2018, with a slightly different debate but a similar outcome to Oregon. SB 6203 would have imposed a \$12/MTCO$_2$e on the sale or use of fossil fuels beginning in 2019, increasing each year by \$1.80/MTCO$_2$e until it reached \$30/MTCO$_2$e . This was a top priority for Governor Jay Inslee but ultimately did not make it through the legislative process. In March 2018, the Thurston County Superior Court ruled that parts of the Clean Air Rule are invalid. The judge ruled that the state lacked authority to require emissions reductions on gasoline and natural-gas distributors that do not burn fuels themselves.

After the legislature failed to adopt a bill, a coalition of environmental, tribal and social justice groups began work on creating a ballot initiative for November 2018 that would place a fee on GHG emissions.

4.7. STATE RENEWABLE NATURAL GAS POLICY

Oregon

Renewable Natural Gas (RNG) is attracting attention in Oregon as a source of low-carbon transportation fuel and as a way to decarbonize the natural gas pipeline. In 2017, SB 334 passed the legislature, requiring the Oregon Department of Energy (ODOE) to study the technical potential of RNG in the state. The agency is creating an inventory of feedstocks in Oregon; a detailed review of the biogas and RNG supply chain from the original location to the end user; and identifying barriers and policy alternatives to support RNG development. The ODOE task force is currently underway and is expected to deliver its report to the legislature in September.

Washington

In the 2018 short session, Washington followed Oregon and passed HB 2586, requiring the Washington Utility and Transportation Commission (UTC) to recommend to the legislature whether to adopt an RNG procurement standard. The legislation also requires the development of a voluntary gas quality standard, in consultation with utilities, offers tax breaks for RNG conditioning and compression equipment, and a tax break for the land occupied by a digester.

4.8. STATE POLICY ON AIR QUALITY AND VEHICLES THAT OPERATE ON CNG OR RNG

The transportation sector is the largest contributor to carbon emissions in both Oregon and Washington, and it continues to grow. As the state ramps up its conversations on cap and trade, NW Natural will pay close attention to how a price on carbon will impact the heavy duty sector, since compressed natural gas (CNG) and RNG can be used in heavy duty vehicles to displace diesel emissions.

Beyond cap and trade, NW Natural expects conversations regarding diesel emissions and air pollution to be a focus of state and local initiatives. Indeed, the state is expected to receive several million dollars through the VW settlement and DEQ will be responsible for administering the program. In the legislature, there is little agreement on where and how this money should be spent, with the only consensus being that school busses should be modernized to reduce air pollution around schools.

Regardless of what happens with the VW settlement dollars, smaller regions are moving forward to get a better sense of the diesel pollution problem. In early May 2018, the EPA awarded the Oregon DEQ $466,276 to research better ways to monitor diesel exhaust to help protect Portland's most vulnerable citizens. To conduct this research, DEQ is partnering with local colleges, community groups and government agencies. Portland State University and Reed College will lead the research, with Neighbors for Clean Air, Multnomah County, and the City of Portland actively participating in the two-year study.

Because CNG engines provide the cleanest and most cost effective solution for heavy duty vehicles, NW Natural expects natural gas to be deployed to both decarbonize and clean up the transportation sector.[39] The company will continue to partner with the NW Alliance for Clean Transportation, Neighbors for Clean Air, local jurisdictions, and researchers to better understand the data and how emerging natural gas vehicle technology might solve some of the air quality and GHG issues.

4.9. LOCAL CLIMATE ACTION

Across Oregon, communities large and small are actively working to decrease GHG emissions as they see efforts stalled at the federal level. Climate Action Plans are proliferating; communities are interested in partnering with their utilities to better understand their energy mix and how they might reduce GHG emissions associated with electricity and natural gas usage.

NW Natural is interested in working with communities to find areas of partnership. Many communities are interested in upgrading their wastewater treatment plants, purchasing offsets to reduce emissions from their natural gas usage, transitioning city-owned fleets to RNG or CNG, and/or incenting energy efficient buildings and homes.

NW Natural is working with the City of Portland's Bureau of Environmental Services Columbia Boulevard Waste Water Treatment Plant to capture RNG and inject it on to the pipeline for use in the heavy duty transportation sector. This public-private cooperative effort is expected to cut 21,000 $MTCO_2e$ per year, add $3 million in annual revenue to the city's coffers, and replace enough diesel to power 154 garbage trucks each year. This project will be the first in Oregon to inject RNG into natural gas system and is an example of a new local source of natural gas that has economic, environmental, and public health benefits.

[39] CNG accounts for a 20% reduction in carbon emissions compared to diesel; RNG is an 80%+ reduction in carbon emissions. Both RNG and CNG account for a 90% reduction in air pollution; Zero PM2.5 and close to zero NOx – both air pollutants responsible for increased asthma and heart disease.

The Metropolitan Wastewater Management Commission (MWMC), which operates the WWTP for Eugene and Springfield, has also approved the plan to move forward to connect the plant to the NW Natural pipeline.

These are just a few examples of how NW Natural envisions partnering with the communities it serves. Providing an equitable low carbon natural gas option for interested communities is a crucial way for Oregon to lead on energy and climate policy.

4.10. IRP CARBON COMPLIANCE COSTS

Policy legislation surrounding carbon reduction is evolving in Oregon and Washington. The Company expects to contribute to this evolution and offer any insights in order for policies to effectively reduce carbon emissions. We incorporate this expectation into our resources planning because we expect to have compliance obligations arising in the near future. However, specific policy outcomes are extremely hard to predict prior to legislation actually passing. Oregon's cap-and-trade bill has several unknowns regarding obligated parties and allowance allocation. It is likely that the details of the carbon tax in Washington will change. Additionally the interaction of policy across states, that is, any linkage between Oregon and Washington carbon markets or even a link to California's market, is uncertain. The uncertainty of these policies makes it difficult to incorporate specific policies and subsequently their forecasted policy outcomes into the Company' forecasting models.

What we do know is that any policy that aims to reduce GHG emissions will increase the price of any fuel that emits GHG emissions. An effective policy will have prices adjust based on a fuel's GHG intensity and apply a price adder, denominated in dollars per metric ton of CO_2 equivalent ($/MT$CO_2$e), adjusted for the amount of emissions released during a specific process (e.g., burning natural gas). In other words, fuels with a higher carbon intensity will have a relatively higher price adder, low carbon intensity fuels will have a relatively smaller price adder, and no price adder for fuels with a zero carbon intensity.

As a proxy for the various emission policies that could unfold in Oregon and Washington, the Company uses a $/MT$CO_2$e price path as the expected greenhouse gas (GHG) emissions compliance cost, also referred as a carbon price, for short, throughout this IRP.[40]

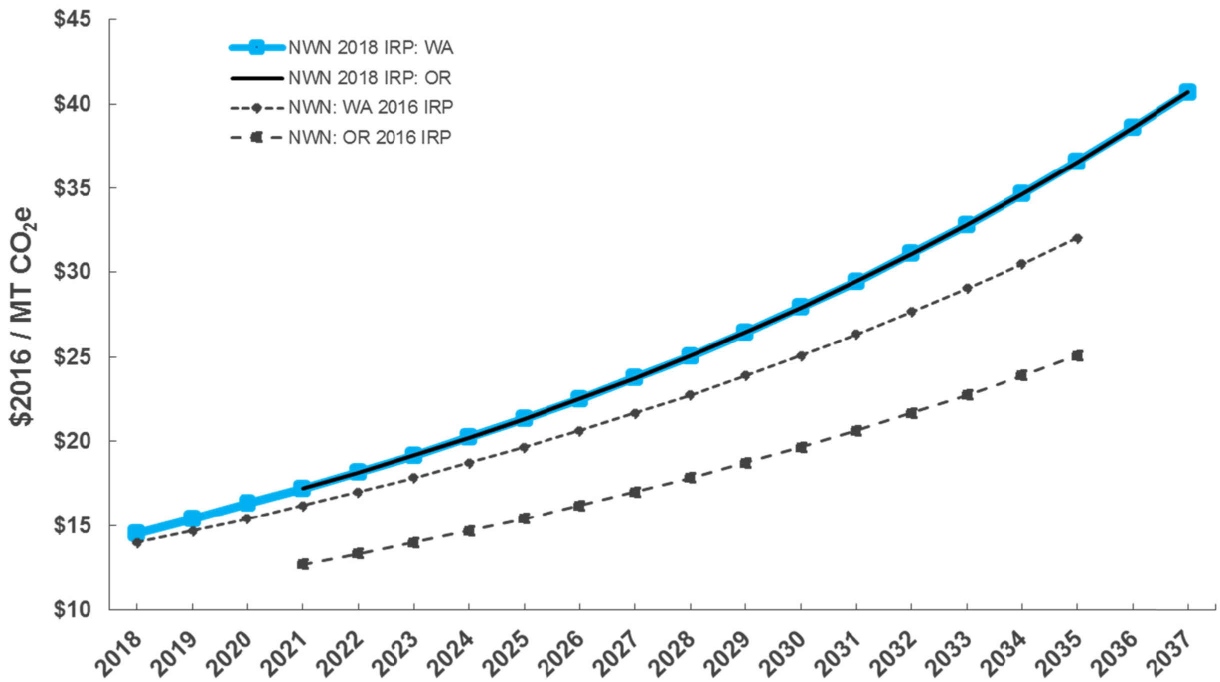
Figure 2.16 shows the price path for the carbon price used over the planning horizon as compared to the carbon price assumed in the 2016 IRP. At the start of building the assumptions for the IRP, legislation seemed more likely to pass earlier in Washington than Oregon. Thus

[40] The Company uses the California Energy Commission's low prices (high consumption scenario) for allowance prices in the California's cap-and-trade program to inform the base case carbon price forecast.

carbon price starts earlier in Washington then in Oregon starting a little less than \$15/ $MTCO_2e$ and ramping to just over \$40/ $MTCO_2e$ in 2036.[41]

It is possible that carbon prices could differ between states, however; we model them to be the same once a policy starts in Oregon. Having the same carbon prices in both states implicitly assumes the markets are linked together. This is different than the assumed carbon prices used in the 2016 IRP, which differed by state and were slightly lower. Additionally, the 2018 IRP incorporates these carbon prices into our resource optimization for the first time, as the Company is now evaluating resources with different carbon intensities. Similar to the 2016 IRP the carbon prices are still included into the avoided costs.

Figure 2.17: Expected Greenhouse Gas (GHG) Emissions Compliance Cost



Although Figure 2.17 shows the Company's expected carbon price, the outcomes of specific policies can greatly impact the carbon price and the uncertainty surrounding these prices is very large. A carbon price via a tax based on the social cost of carbon will start really high, but will be relatively flat over time. A cap-and-trade with a declining cap could allow a relatively lower carbon price at the start, but ramp up the carbon price each year. Under cap-and-trade the slope of the carbon price path is highly dependent on the declining emissions cap dictated by policy.

Figure 2.18 shows three alternative carbon price paths in addition to the expected carbon price which are used in the risk analysis discussed in Chapter 7. The social cost of carbon price path

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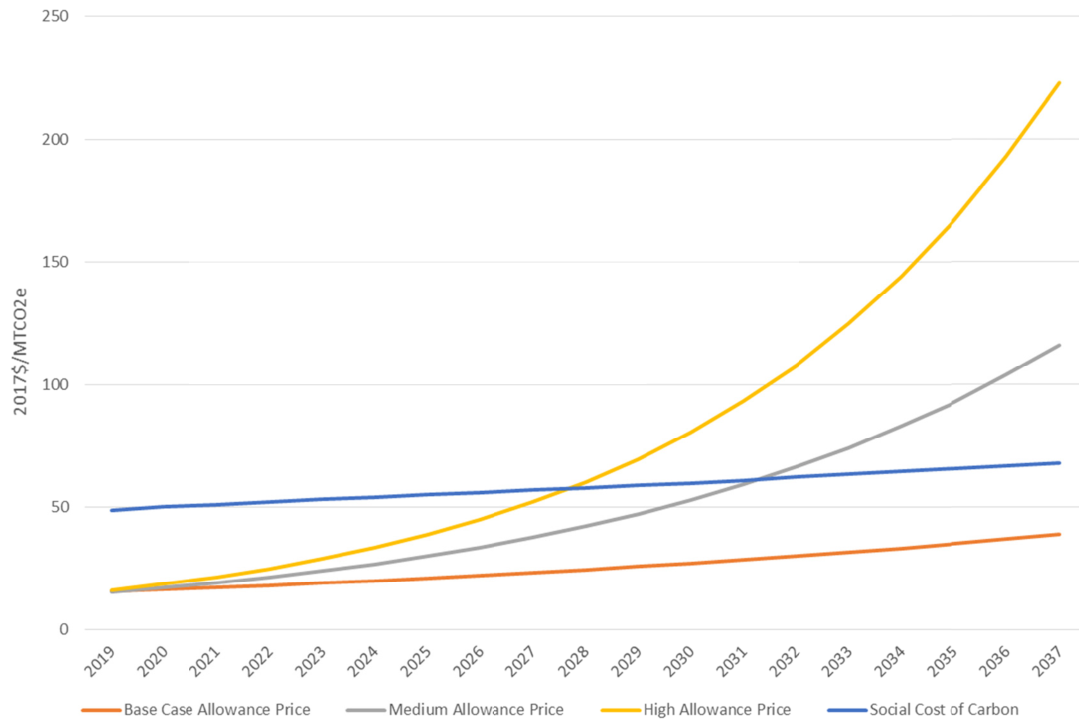
[41] A system weighted carbon price is calculate for the first three years (i.e., 90% Oregon and 10% Washington) and applied to all gas prices.

starts at \$48/ $MTCO_2e$ and gradually rises to \$68/ $MTCO_2e$ by 2037.[42] The other paths all start at \$14/ $MTCO_2e$ but ramp at different rates with the high price exceeding \$200/ $MTCO_2e$ by 2037.[43] This high end range of uncertainty reflects an asymmetric risk in regards to policy and the possible carbon prices that could materialize. Different policy outcomes can significantly change the carbon price with a lot of upside price risk for the Company and customers.

Figure 2.18: Alternative Emission Compliance Costs



4.11. OUR LOW CARBON PATHWAY

While the emissions associated with the direct use of natural gas are modest, there are important reductions our system can contribute to an effective and affordable regional climate strategy. We believe that achieving these reductions is in the interests of our customers and society as a whole.

Accordingly, in the yearlong effort to develop NW Natural's 2016 Strategic Plan, we challenged ourselves to think pragmatically and creatively about what NW Natural can do to cost-effectively reduce emissions and help our region meet its climate goals. We analyzed the costs and feasibility of a wide variety of options to reduce the emissions footprint of the direct use of

[42] The social cost of carbon price forecast is pulled from EPA's-mid price of the social cost of carbon based on a 2% discount rate.
[43] The three ramping price paths are allowance price forecasts for the cap-and-trade market administered under the California Air and Resource Board. Low, medium and high forecasts are produced by the California Energy Commission through 2030. Each forecast was continued through 2037 for this IRP by applying an annual average growth rate.

natural gas in our service territory over the next 20 years. Our work on the low carbon pathway also is designed to build momentum for further reductions as part of deep decarbonization going forward. This major analytical effort results in the company setting a carbon savings goal that is aggressive yet feasible.

Our Goal: Carbon Savings

Our goal is to facilitate a 30% carbon savings from 2015 emissions levels[44] associated with current and newly acquired customers by 2035.

This carbon goal is intended to effectively prepare NW Natural for a low-carbon future. Embedding this effort into a strategic planning process provided the company a road map with key challenges and opportunities anticipated in the near term, while also defining areas that will need special emphasis or resources, above and beyond business as usual.

This multiyear effort will define a pathway to emissions savings through cutting-edge innovations that are on the horizon, alongside near-term solutions that can lower the carbon intensity of our product while affordably meeting the energy needs and preferences of the communities we serve. This plan relies on use of our extensive and modern pipeline system, which already serves hundreds of thousands of homes and businesses, in new ways to drive down emissions. We intend to partner with customers, regulators, environmental groups and advocates to pursue innovations and cutting-edge technologies.

Why a goal

NW Natural's Carbon Goal has been developed in recognition that carbon policy is under development that will require the company to drive reductions over time. We believe the goal will provide a head start to the benefit of our customers to effectively plan for a carbon-constrained future. In fact, we believe that taking voluntary action now in areas with burgeoning reduction opportunities is a prudent strategy to prepare the company and its customers for future statewide carbon compliance obligations we believe are likely in both Oregon and Washington.

Emissions-reduction activities in NW Natural's carbon goal

After casting a wide net for emission reduction activities and evaluating these opportunities, the viable savings options for the direct use of natural gas sector fall into three broad categories:

- **Our Product** Reducing the carbon intensity of the natural gas delivered to our customers

[44] During planning, we determined to use 2015 as our baseline rather than some earlier date that would have allowed us to count earlier actions and successes in driving down emissions. The purpose of the goal was to look forward at what we expect to be measured against in the years to come.

- **Our Customers' Use** Working with customers to reduce or offset their natural gas usage
- **Transportation** Converting higher carbon intensity fuels to natural gas

Table 2.3 shows these three categories of reductions and shows the more specific measures in each category used to construct the company's carbon reductions goal.

Table 2.3: Description of the categories of emissions reductions with NW Natural's Low Carbon Pathway

OUR PRODUCT	OUR CUSTOMERS	TRANSPORTATION
REDUCE CARBON INTENSITY	REDUCE AND OFFSET CONSUMPTION	REPLACE MORE CARBON INTENSIVE FUELS
NW NATURAL OPERATIONS UPSTREAM METHANE REDUCTION RENEWABLE NATURAL GAS POWER TO GAS (hydrogen pathway)	ENERGY EFFICIENCY SMART ENERGY (voluntary offsets) GAS + RENEWABLE HYBRID EQUIPMENT (solar thermal)	CNG AND RNG SERVE TRASH TRUCKS AND RETURN-TO-BASE FLEETS
achievable savings 5 ↔ 20% low to high potential	achievable savings 15 ↔ 30% low to high potential	achievable savings 1 ↔ 5% low to high potential

Current efforts

The company is engaged in activities that result in lowering GHG emissions. The largest reduction opportunity and the least expensive of the opportunities is our work – in partnership with the Energy Trust – to help our customers reduce their energy use. The company plans for energy efficiency resources are discussed in great detail within section X of this documents. The other program that results in lowering GHG emissions is the Smart Energy program discussed below.

Smart Energy

Recognizing some of our customers wanted to do more to reduce their carbon footprint, in 2007 NW Natural began offering the Smart Energy program. Under the tag line, "Use Less, Offset the Rest," the program allows customers to reduce their usage as much as possible and then to voluntarily offset the GHG emissions associated with the rest of their gas use. (Smart Energy was made available to Washington customers in 2010.)

Under the program, customers can either sign up under a fixed rate program for $5.50/per month, based on average usage, or can sign up to offset 100 percent of their emissions based on their actual use. As of today[45], we have over 42,000 customers enrolled in Smart Energy; just over 7% of Oregon residential customers have enrolled. The money collected through Smart Energy™ customer charges are invested in local renewable energy projects — generally regional biogas projects — that will generate carbon offsets.

In its effort to provide high quality carbon offsets, the Company has partnered with The Climate Trust, a nationally recognized leader in the carbon market. The Climate Trust identifies projects and contracts for offsets, then verifies, and retires each Smart Energy™ offset. Through the Trust, the program has funded over 731,000 short tons of CO_2 offsets, equal to the annual greenhouse gas emissions of over 142,000 passenger vehicles.

The offset projects from Smart Energy consist of eleven projects within the region – five in Oregon, three in Washington, two in Idaho and one in northern California. Ten of these projects are on dairy farms capturing methane from cow manure and turning it into biogas. The eleventh uses wastewater from a potato processing plan to create biogas.

The Smart Energy program provides clear carbon benefits to the voluntary participants of the program who have offsets retired on their behalf. The program also has broader benefits that accrue to customers who are non-participants. First, the program provides real and measurable greenhouse gas benefits. While these offset benefits will be retired by The Climate Trust for the participants, the environmental benefits of these actions accrue to all. Second, the program allows all NW Natural customers an opportunity to learn about their “carbon footprint” and the specific steps they can take to reduce it. As our state and country move toward carbon regulation, it will become more important that all customers make the connection between their energy use and their carbon impacts. Third, the Smart Energy program will provide an opportunity for the State of Oregon, Public Utility Commission, and NW Natural to develop and hone policy tools that will be critical in the upcoming regulation of greenhouse gases. Finally, it can be argued that customers appreciate having options whether or not they participate in these options. The existence of the program, and its availability to all customers, is of value for all and thus justifies spreading some costs to all NW Natural customers.

Voluntary Methane Reductions

NW Natural’s efforts to maintain a modern pipeline system significantly reduce the potential for methane emissions throughout the system. The full replacement of all leak prone pipe material (cast iron by 2000 and uncoated steel by 2015) contributes to a low emitting system. To continue to drive down emissions NW Natural joined the Environmental Protection Agency’s Methane Challenge under the Natural Gas Star program in 2016. Participants in this challenge adopt best practices above and beyond compliance to further reduce the methane emissions associated with system operations.

[45] As of April 30, 2018

As part of the challenge the company has focused on reducing emissions associated with routine maintenance. Pipeline blow-downs are events in which a portion of pipeline is isolated and emptied of natural gas for repairs, replacements and construction. Industry standard practice was to allow natural gas to vent directly to atmosphere. As a participant in the Methane Challenge, NW Natural has formalized less emitting best practices into standard operating procedures for blow downs including pressure reduction via line drawdown, hot tapping (redirecting gas when possible to reduce the area being vented) and for the remaining gas when appropriate the use of a portable flare. The combustion of methane reduces the greenhouse gas impacts as compared to direct release.

New Efforts

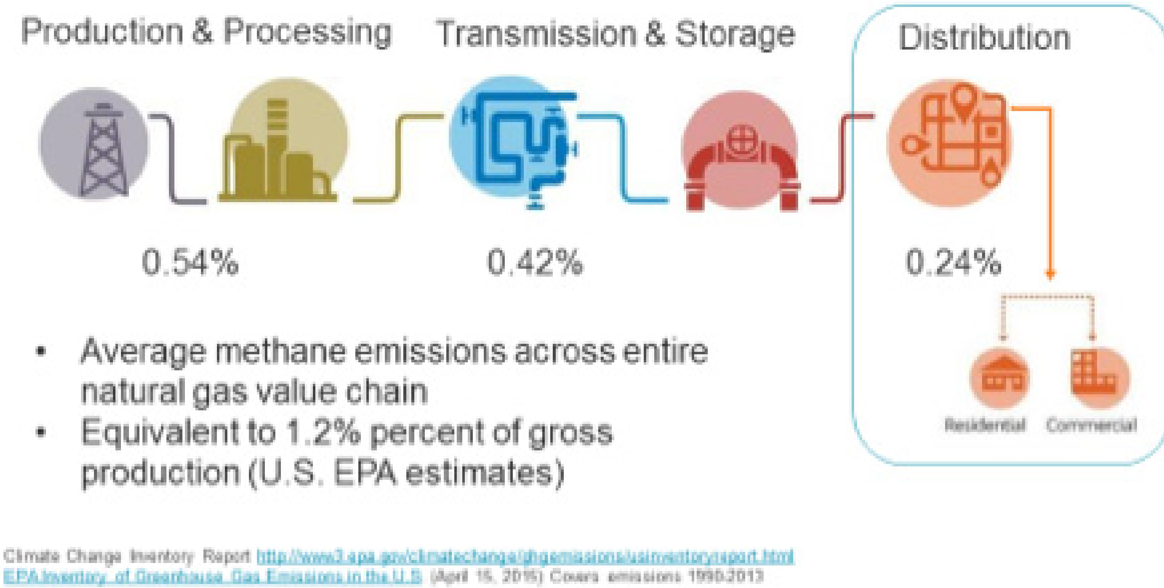
NW Natural is exploring new areas that will drive down emissions. The most significant of these is the purchase of renewable natural gas (RNG). RNG is handled as part of the IRP's resource acquisition section in chapter six. The company's work to explore methods to further reduce upstream methane emissions is discussed below.

Reducing upstream methane

The primary constituent of Natural Gas, methane (CH4) is a short-term high impact greenhouse gas. In relative terms the direct emissions of methane into the atmosphere have an intensity of 28-34x that of carbon dioxide[46]. This higher impact makes it a priority for emission reduction in the entire natural gas value. As shown in figure 2.19, the natural gas value chain includes production, processing, transmission, storage and distribution. At every stage along the value chain there are opportunities to reduce emissions. As a distribution company, NW Natural has taken measures to reduce emissions as outlined above through system integrity replacement and participation in the methane challenge. However, the greatest opportunity to pursue reduction in the value chain is found in the production sector. The Company is currently working on a pathway to manage our supply chain with greater transparency and detail about the production of the natural gas that we purchase for our customers.

[46] Using the USEPA 100 year greenhouse gas intensity in CO_2e

Figure 2.19: Supply Chain Emissions



Our customers and other stakeholders want to know more about where and how the natural gas we deliver to their homes and businesses is produced. With the increased domestic production associated about horizontal drilling and hydraulic fracturing public interest is high, and call for greater disclosure of environmental impacts is happening in the regions where we operate. NW Natural has been engaged for more than five years with partners including the Environmental Defense Fund (EDF) and the Natural Resources Defense Council (NRDC), to increase transparency about wellhead practices as well as identifying ways we can participate in encouraging best practices. More recently NW Natural has been an active member of the Natural Gas Supply Collaborative, a group of natural gas buyers in North America who are urging production transparency in all facets of natural gas production. In addition to methane intensity this group is also working to drive transparency around water, land and community impacts of gas production.

Methane associated with natural gas production is a frequent topic of inquiry in public forums from both policy makers and customers. Methane released directly into the atmosphere from the pipeline system and the facilities involved in its production and transport is termed fugitive emissions. In both the United States and Canada natural gas producers report on these emissions through mandatory annual greenhouse gas reporting programs. This information is public data, released each year via environmental regulators in both countries. NW Natural purchases gas primarily from British Columbia, Alberta and the United States Rocky Mountains.

There is significant regional variance in emission intensity. This is due to both geology and environmental regulations applied to producers. However, national average emissions are consistently used by policy makers when including emissions upstream of combustion. As policy makers are developing carbon reduction goals with the full lifecycle in mind there is value in a more granular look at regional variance for a more complete picture and to better measure the impacts of stringent production regulation in yielding fewer emissions.

In the 2016 IRP NW Natural introduced the idea of developing a pilot through which The Company would incent producers to adopt production best practices as outlined in our earlier work with Natural Resources Defense Council. For example, incenting a producer with high bleed pneumatic devices to replace the equipment with low and no bleed. After working with producers, it was discovered that industry is taking action toward best practices in advance of regulation. Through the American Petroleum Institute's Environmental Partnerships more than a quarter of natural gas producers have committed to adoption of comprehensive emission and impact reducing practices. Additionally the Gas Technology Institute and the Center for Methane Innovation are working to increase the efficacy of leak detection to speed detection. These trends indicated that a direct pilot was not necessary to drive action. However, with more information about the supply chain, it is now possible to differentiate between those companies and production regions that are making accelerated improvements over those who lag behind.

To better reflect regional and company variance in emissions the company has used data science to pull together and make the information made available by government agencies (in both Canada and the United States) at the facility level consumable. We are now working to determine how the emission intensity of various locations and companies could influence the decisions we make about natural gas supply purchases.

5. NEW TECHNOLOGIES

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

The three largest initiatives represent a long-term, energy savings resource capable of delivering over 280 million therms annually to the Northwest region, at a weighted average total resource cost (TRC) of $0.28/Therm. Below is an overview of the five technologies outlined in the 2014-2019 Natural Gas Business Plan[47] as well as their expected long-term saving potential.

5.1. EFFICIENT GAS WATER HEATERS

The Natural Gas Collaborative has a goal to transform the residential gas water heating market; making gas-fired heat pump water heaters the standard in gas water heating appliances (Figure 2.20). The Natural Gas Business Plan indicates a significant market for this product in the Northwest (1.7 million customers) and a high long-term savings potential (over 100 million annual therms in the Northwest during a 20-year period). 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;

[47] https://neea.org/img/documents/neea-2015-2019-natural-gas-market-transformation-business-plan.pdf

ultimately influencing federal manufacturing standards for gas water heaters. Broad commercialization is estimated 2020-2025.

Figure 2.20: SMTI High Efficiency Heat Pump Water Heater[48]

5.2. COMBINATION SPACE AND WATER HEATING SYSTEMS (COMBI SYSTEMS)

Gas-fired heat pump technologies can be applied in a combination approach, providing both space and water heating at greater efficiency than standalone high-efficiency gas furnaces and water heaters. Combi systems (an example is shown below in figure 2.21) have an estimated potential savings of over 163 million therms in the Northwest during a 20-year period. The Collaborative is working with manufacturers to develop a combination space and water heat pump system for use in both new construction and retrofit applications. Eventually, NEEA plans to develop this approach into new energy code proposals as an allowable compliance approach for new construction. Broad commercialization is estimated 2020-2025.

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[48] Source Northwest Energy Efficiency Alliance (NEEA) presentation - April 25th 2018 at NW Natural 2018 IRP Technical Working Group

Figure 2.21: Combination Space and Water Heating SMTI Heat Pump[49]

5.3. HEARTH PRODUCTS

The hearth products initiative is two-pronged. The first strategy intends to eliminate standing pilot lights in gas hearth products. This has the potential to save the region 25 million therms over a 20-year period. The second strategy aims to influence the development of a low-capacity hearth – with approximately half the gas input as a typical hearth, with the same aesthetic flame presence. NEEA is working to achieve this second strategy by influencing manufacturer product development. This second strategy has the potential to save the region roughly 1 million therms over a 20-year period.

5.4. CONDENSING ROOFTOP UNITS

Condensing rooftop units are packaged, weatherized, commercial natural gas indirect air heating systems that may or may not include ventilation and/or air conditioning, mounted externally to a building, that capture heat from the products of combustion (flue gases) to achieve a minimum thermal efficiency (TE) or annual fuel utilization efficiency (AFUE) of 90%. Capturing heat from the products of combustion causes the water vapor component to condense, and since the units are typically mounted on building rooftops, the units are referred to as condensing rooftop units, or condensing RTUs. Condensing RTUs have been in the market since 2014, but only small manufacturers offer products and sales are very low: estimated at less than 1% of the total RTU market. Lack of sales and investment are due to low natural gas prices, the absence of regulatory drivers, lack of market pressure to expand product lines and lack of awareness throughout the supply chain. NEEA's goal is to transform the market such that Northwest commercial building owners and manager install condensing RTUs as standard practice and ultimately, a federal requirement of at least 90% efficiency for commercial warm air furnaces. This effort has the potential to save between 20-60 million therms during a 20-year period.

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[49] Source Northwest Energy Efficiency Alliance (NEEA) presentation - April 25th 2018 at NW Natural 2018 IRP Technical Working Group

5.5. EFFICIENT GAS DRYERS

The Efficient Gas Dryers program focuses on ENERGY STAR-qualified gas dryers while continuing to scan for emerging dryer technologies such as modulating valve or heat recovery. ENERGY STAR® gas dryers have been in the market since 2015, but initial lab test results indicated a wide range of performance quality and more specifically, room for improvement in their auto termination technologies. The Efficient Gas Dryers Program will engage efficiency partners to create market leverage, influence the reliability of performance of ENERGY STAR-qualified dryers, and influence the improvement of federal test protocol and efficiency standards. These efforts have the potential to save the region more than two million therms over a 20-year period.

5.6. OTHER PORTFOLIO ACTIVITIES

The Collaborative also recognizes the necessity of other activities to advance the portfolio, such as scanning for new technologies and codes and standards work, and includes these activities as separate tasks. For additional detail, please refer to NEEA's Natural Gas Business Plan.

6. CONCLUSIONS AND KEY FINDINGS

- Most of the areas within NW Natural's service territory have recovered to their pre-recession economic positions. Slower, continued growth is expected moving forward.
- Manufacturing and Construction activity generally lagged the economic recovery in Oregon and Washington, and have not recovered their pre-recession peaks in Oregon. Both are expected to maintain very slow growth moving forward
- Following a rapid upswing in housing construction, market forces and a wave of policy intervention will likely continue to slow growth from its pace over the 2010-2016 recovery
- Gas commodity prices are at historic lows and are expected to stay low but gradual rise over the planning horizon to just under $6/Dth
- The direct use of natural gas in 2015 accounted for 12% of total GHG emissions in Oregon, with roughly 8% attributed to NW Natural customer use. The direct use of gas accounted for 13% in Washington, with 0.5%% attributed to NW Natural customers.
- Where natural gas service is readily available in NW Natural's service territory, the majority of homes and businesses use natural gas for their space and water heating needs and space heating makes up more than 80% of the total energy needs of homes and businesses in the Pacific Northwest during the peak hour of extreme cold weather events.
- Forecasted compliance costs associated with GHG emissions are set based on expected compliance obligations, which have been estimated using the expected compliance cost curve generated in California. The load forecast and a range of forecasted compliance costs are used to develop the company's resource plan and various sensitivities for the plan's base case.

- While the policy instrument to price carbon remains uncertain in both Oregon and Washington, there is a growing likelihood of state policy changes that will implement a price on carbon that impacts the company.
- As part of this IRP, the company has taken new steps to model carbon emissions as well as low carbon gas supply options – such as renewable natural gas – to show if and when these newly available resources may be selected as least cost and least risk resource options within the IRP
- Given likely policy changes on climate and the desires of our customers, the company has developed a carbon savings goal of 30% by 2035, based on a 2015 baseline.

CHAPTER 3

LOAD FORECAST

KEY TAKEAWAYS

Key findings in this chapter include the following:

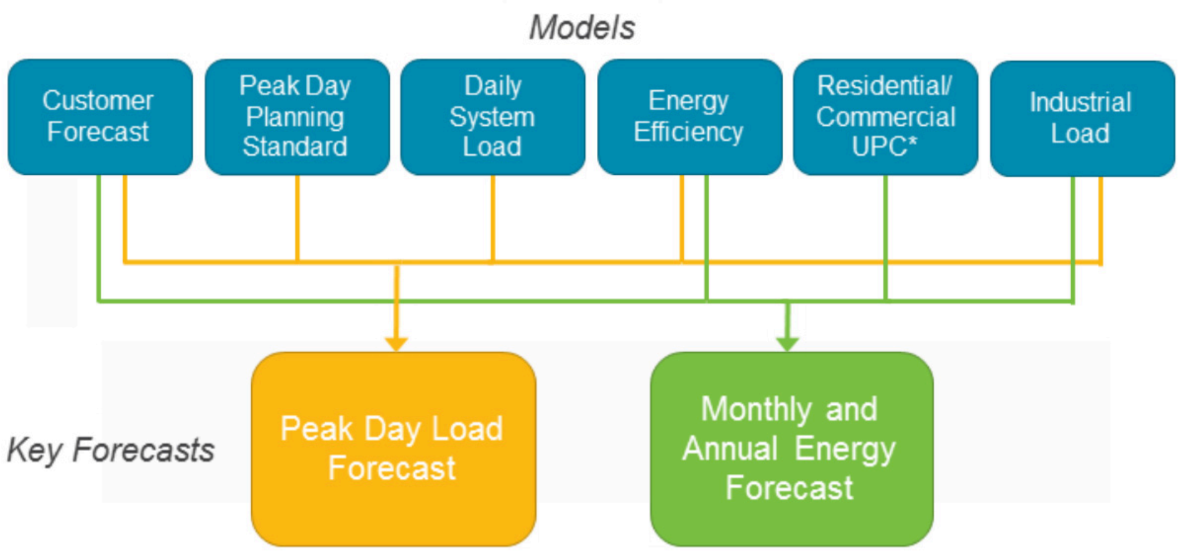
- Customer forecasts
  - Compared four alternative approaches to forecasting
  - Average annual growth rates for 2018–2038 planning horizon are 1.5% for residential customers and 1.4% for commercial customers
  - Average annual growth rates are similar to those in the 2016 IRP in total and for residential customers, and somewhat higher for commercial customers
  - Average annual growth rates versus 2016 IRP for 2017–2035 are somewhat lower for Oregon and somewhat higher for Washington
  - Average annual rate of growth is higher in Washington than in Oregon
- Annual use per customer
  - Annual use per customer is forecast to decline at an average annual rate of -1.3% for residential customers and -0.2% for commercial customers
- Annual load
  - Total residential load is forecasted to peak in 2028 before beginning to decline
  - Total commercial load is forecasted to grow at an average annual rate of 1.3%
  - Total industrial load is forecasted to grow at an average annual rate of 0.1%
  - Total sales load is forecasted to grow at an average annual rate of 0.6%
- Peak day planning standard
  - The capacity planning standard has been updated to use a risk-based methodology where NW Natural will plan to serve the highest firm sales demand day in any year with 99 percent certainty
- Peak day forecast
  - Average annual growth for peak demand is 0.92% over the next twenty years
  - Average annual growth in peak is somewhat lower compared to the 2016 IRP

1. INTRODUCTION

This chapter discusses NW Natural's load requirements, including customer forecasts, annual energy use per customer forecasts, annual load forecasts, the peak day planning standard, and peak day load forecasts. It discusses the methods and models the Company uses, how these are developed, and the resulting forecasts.

NW Natural's load forecasts serve as the foundation of many related IRP analyses, and are comprised of multiple pieces. The Company's daily system flow model combines with customer, energy efficiency and industrial load forecasts to produce the peak day load forecast (defined by the peak day planning standard, see Section 7). Annual use-per-customer models, combined with these same constituent forecasts, drive the Company's monthly and annual energy forecast (see Figure 3.1).

Figure 3.1: Demand Forecast Process[1]



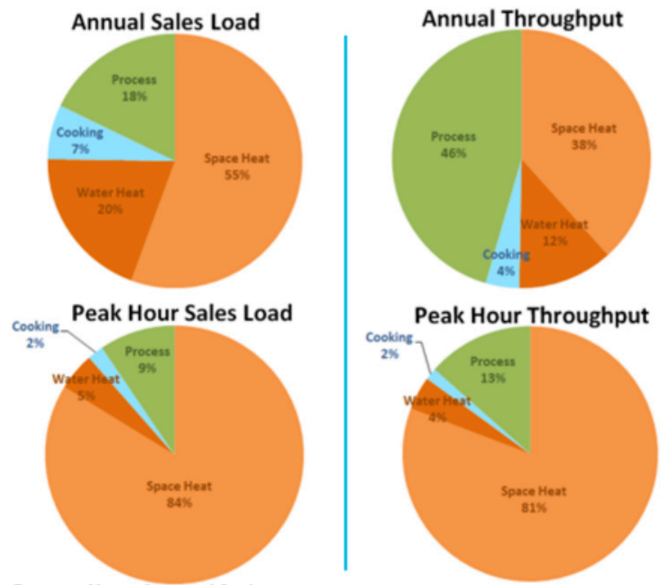
A brief examination of NW Natural's load provides context for this composite process. The Company serves two types of load: "sales" (the load of customers for whom NW Natural acquires and transports natural gas) and "transportation" (the load of customers that procure their own commodity, which is transported via NW Natural's system). These two types of customers are further divided into "firm" and "interruptible" service types. Interruptible customers—almost exclusively large industrial customers and large commercial customers—elect to receive lower priority gas service than firm customers, and pay a reduced rate. All residential customers, and most commercial customers, receive firm sales service.

On an annual basis, the Company's sales load is strongly dominated by space and water heating (Figure 3.2). These end uses represent about half of total annual throughput (sales plus transportation) as well, though the load of transportation customers tends to be driven by

[1] The acronym UPC in Figure 3.1 refers to use per customer, and is discussed later in this chapter.

industrial processes. During peak conditions, both sales and throughput are driven by space heat.

Figure 3.2: NW Natural Load by End Use



The dynamic nature of NW Natural's load necessitates essentially two parallel planning purposes—one set of decisions regarding gas supply purchases and storage injections and withdrawals in order to meet demand throughout the year, and another process for determining adequate system capacity in order to meet peak demand under extreme conditions. In short, the Company's load is characterized by fairly stable base load and large space heating driven peaks. Figures 3.3 and 3.4 illustrate this pattern with two different views of load over the course of an average year and load at peak temperatures relative to load on milder days.

Figure 3.3: NW Natural Sales Load by Month

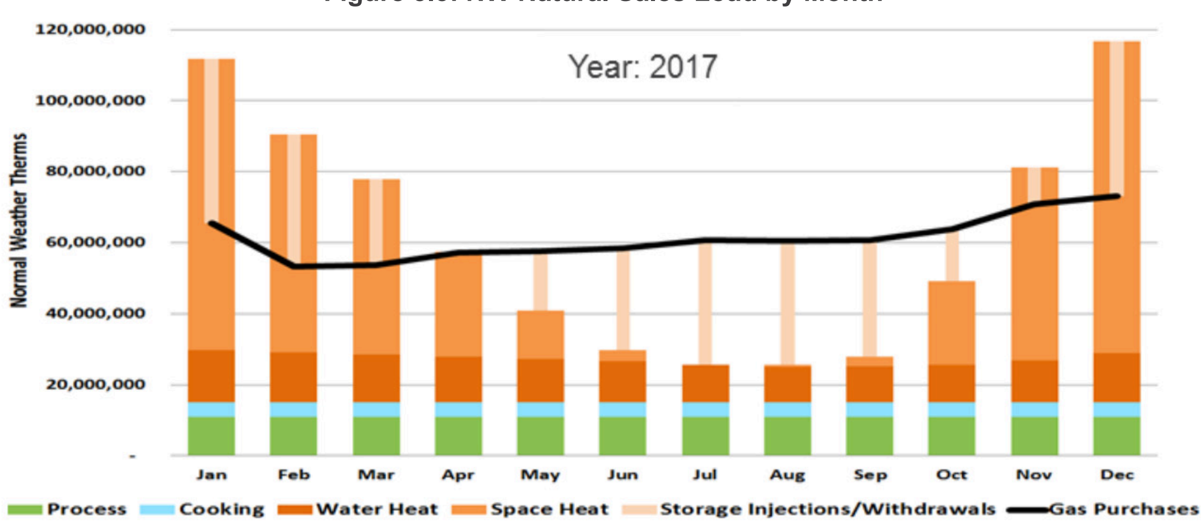
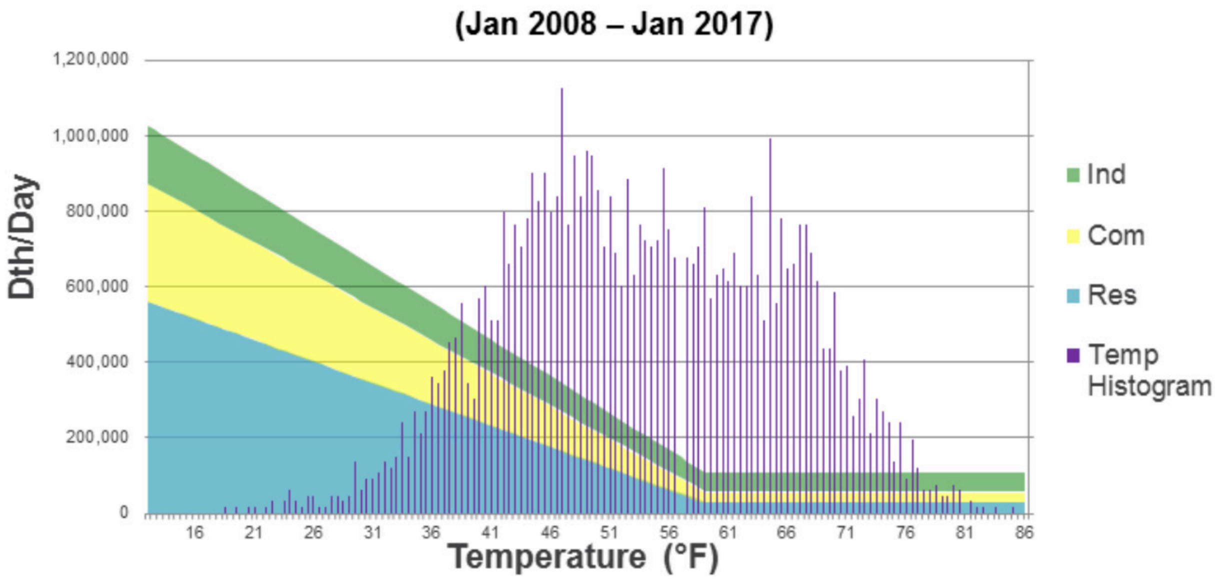


Figure 3.3 summarizes the distinct annual load shape of NW Natural's system. In the coldest months, space heating needs more than double system load relative to the base load of cooking

and industrial processes. While the system's load shape across months is instructive for understanding annual operations and gas commodity procurement, the Company must also plan for extreme conditions on days within those months (and further, during hours within cold days). Figure 3.4 summarizes the relationship between load and daily temperature.[2]

Figure 3.4: Daily System Firm Sales Load by Temperature



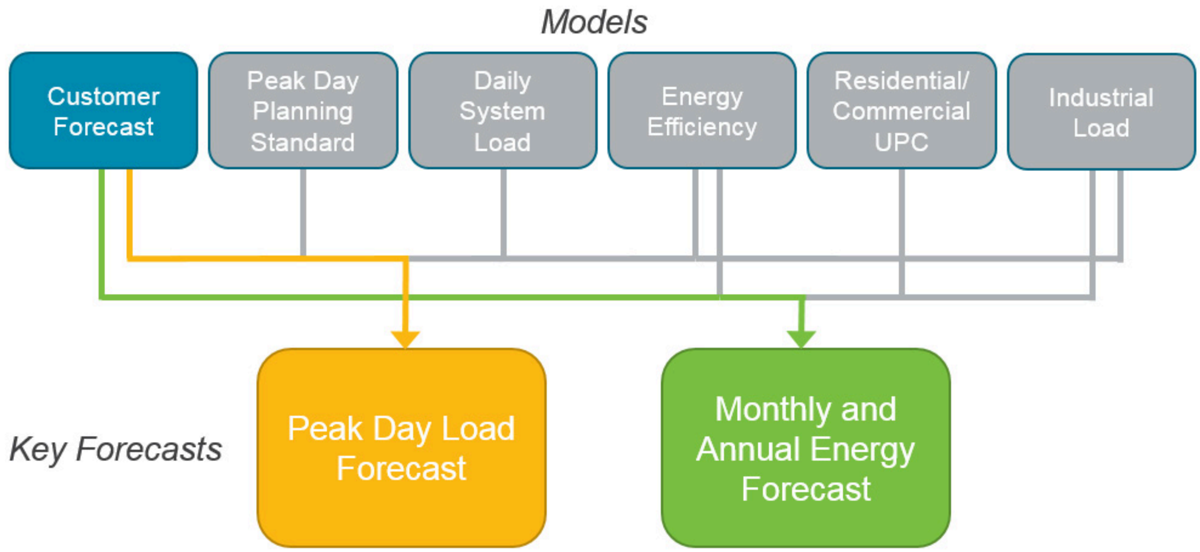
Note that at the far left tail of the distribution of daily temperatures experienced in the last decade, firm sales load would be expected to more than quintuple the base load experienced on milder temperature days. Thus, while average days make up the bulk of days for NW Natural's system, infrastructure requirements are defined by extreme, if relatively less common, conditions.

2. CUSTOMER FORECAST

The customer forecast is the starting point of the Company's load forecasting and is a key input into both the peak load forecast and the annual energy forecast; see Figure 3.5. Customer growth is a primary driver for additional demand both annually and on peak, for which, NW Natural must plan its resources.

[2] Load is driven by weather variables other than temperature, and these are discussed later in this chapter.

Figure 3.5: Demand Forecast Process



NW Natural develops separate forecasts for residential and commercial customers for each state, as each differs not only in average use on an annual basis, but also in load factor; i.e., residential customers have a lower load factor (are "more peaky") than do commercial customers.

NW Natural does not forecast the number of industrial customers due to the extreme range of usage levels by these customers.

2.1. ECONOMETRIC CUSTOMER FORECASTS

NW Natural used some of the same steps in its approach for developing and evaluating econometric models used to forecast customers in the 2018 IRP that the Company used in the 2016 IRP. These include such things as the use of annual data, ensuring stationarity of dependent variables, and evaluating multiple explanatory variables and their transformations. Forecast models used annual data for two primary reasons. A considerably longer history is available for customer data at an annual frequency than such data at a monthly frequency. Additionally, 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 moving averages, leads/lags, and combinations of each. 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.

NW Natural performed the preceding activities using historical data through 2016. The Company evaluated models using alternative explanatory variables, from those not previously eliminated, for each type of customer forecast using the ARIMA structure selected for that forecast by comparing metrics associated with the errors of out-of-sample forecasts. Out-of-sample forecasts used data through 2011 to fit each model, with each model used to subsequently forecast values for 2012 – 2016. Additionally, the Company used forecasts of explanatory variables that were available in 2012 for these out-of-sample forecasts in 2012–2016. This means NW Natural incorporated the accuracy of the explanatory variable's forecast in addition to the accuracy of the econometric model in selecting explanatory variables for use in a model for each customer forecast.

NW Natural used three criteria to evaluate these alternative out-of-sample forecasts: mean absolute percentage error (MAPE), average error, and root mean squared error (RMSE). The Company applied the three criteria to the forecast errors for 2014–2016.[3] Forecast errors for 2012 and 2013 were not included in evaluating alternative econometric forecasts as forecast values for the first two years of the forecast period are from forecasts prepared by an internal Subject Matter Expert (SME) Panel. NW Natural discusses the SME Panel forecasts below. These evaluations resulted in the selection of an econometric model with a specific ARIMA structure and incorporating a specific explanatory variable for each customer forecast.

2.2. ALTERNATIVE APPROACHES TO ECONOMETRIC CUSTOMER FORECASTS

NW Natural analyzed four alternative approaches to forecasting customers for the 2018 IRP. NW Natural has, in recent IRPs, forecast customers at the state level. Staff of the Public Utility Commission of Oregon, in Final Comments regarding the Company's 2016 IRP, "…recommended that the Company continue to explore the use of load center-specific data [to forecast customers by load center]."[4] NW Natural evaluated forecasting customers by load center using load center-specific data for use in the 2018 IRP.

The Company also evaluated forecasting year-end values of customers directly versus forecasting components of customer change, which are sequentially added to year-end values for the prior year to obtain year-end forecasts of customer levels. The Company used this latter "components" approach in recent IRPs, where the components are customer additions due to new construction and customer additions due to conversion from other fuel types, as well as so-called customer "losses."[5] NW Natural refers to the approach in which levels of customers are

[3] Where the forecast available in 2012 for an explanatory variable did not include a value necessary to produce a 2016 forecast value, NW Natural evaluated alternative forecasts by applying the criteria to errors for those years that could be forecast; i.e., to 2014–2015.
[4] See; e.g., page 4 of Appendix A in Order No. 17-059 in Docket No. LC 64.
[5] Customer losses are an accounting reconciliation, calculated as the difference between period-over-period net change in customers and the sum of new construction customer additions and conversion customer additions.

directly forecast as the “levels” approach and the approach in which components of customer change are forecast as the “components” approach.

NW Natural developed customer forecasts by state as well as for each of Oregon’s[6] eight load centers.[7] For each of these 10 geographies, the Company developed out-of-sample customer forecasts using the “levels” approach and customer forecasts using the “components” approach. For the “components” approach at the load center level, only new construction customer additions were forecast, as values of customer conversions at the load center level are volatile on a year-to-year basis. The Company forecast customer conversions at the state level.

NW Natural estimated customer losses[8] at the state level for both “component” approaches, using averages of historical values for 2011–2016 for residential and commercial customers separately. Table 3.1 shows the four approaches to customer forecasts NW Natural analyzed for use in the 2018 IRP.

Table 3.1: Alternative Forecast Approaches Analyzed

	Load Center-level	State-level
“Components” Approach	OR only	OR & WA
“Levels” Approach	OR only	OR & WA

NW Natural used the results of customer forecasts for geographies that include most (Portland load center) or all (Oregon) of the Company’s Oregon customers to select from alternative ARIMA structures and potential explanatory variables to use in the individual Oregon load center forecasts. NW Natural made these selections using the same general approach described above. After selecting a specific ARIMA structure and a specific explanatory variable for each customer forecast, NW Natural developed out-of-sample forecasts for each Oregon load center, using both the components approach and the levels approach.

A primary objective of integrated resource planning is identifying any future resource deficit. As resource adequacy is, for NW Natural, assessed at the system level, it is the accuracy of customer forecasts at the system level that is most important. To evaluate the relative accuracy of the four alternative approaches to customer forecasts for the 2018 IRP, the Company aggregated all customer forecasts for each of the four approaches to system level forecasts of residential plus firm sales commercial customers.

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6 NW Natural has two Washington load centers: Columbia River Gorge – Washington and Vancouver. As the Vancouver load center represents approximately 97 percent of the Company’s residential plus commercial customers in Washington, little value is likely to be realized by preparing customer forecasts for the Company’s two Washington load centers individually. See also the discussion of customer forecast allocations later in this chapter.

7 These are, in the 2018 IRP, Albany, Astoria, Columbia River Gorge–Oregon, Coos Bay, Eugene, Lincoln City, Portland, and Salem.

8 NW Natural defines customer “losses” as the year-over-year net change in customers less the sum of customer additions from new construction and conversion. Investigation has shown that the vast majority of these customers in a given year return as active customers in subsequent years.

Table 3.2 compares the accuracy of the four approaches using the three criteria discussed above. The approach of forecasting customer levels directly by state is more accurate[9] by each of these three criteria than are the other three approaches. Therefore, NW Natural used this approach to the Company's econometric customer forecasts in the 2018 IRP.

Table 3.2: Forecast Accuracy of Alternative Forecast Approaches

Forecast Approach	MAPE	Average Error	RMSE
Levels – State	0.29%	2,067	2,405
Components – State	0.66%	4,643	4,654
Components – Load Center[10]	0.76%	5,395	5,419
Levels – Load Center[11]	1.15%	8,152	8,307

Please see Appendix C for descriptions of each econometric model used to forecast residential and firm sales commercial customers, using the "levels" approach at the state-level.

Exogenous Variables used in Econometric Customer Forecast Models

Table 3.3 shows the exogenous variable used in each of the four econometric customer forecasting models. The source of the forecast of the exogenous variable used in each of the four customer forecast econometric model used in the 2018 IRP was Oregon's Office of Economic Analysis (OEA). As OEA forecasts U.S. housing starts and Oregon's nonfarm employment 10 years ahead, NW Natural used OEA's forecast of Oregon's population to project, respectively, U.S. housing starts[12] and Oregon's nonfarm employment through 2042.

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)

2.3. SUBJECT MATTER EXPERT PANEL FORECASTS

NW Natural's customer forecasts in the 2018 IRP are blends of two different types of forecasts: those developed using econometric methods and those developed using a panel of internal subject matter experts (SME panel). The SME panel is composed of employees from multiple work groups, including Business Analytics, Customer Acquisition, Integrated Resource

[9] Note that a smaller value for any one of the three criteria indicates a more accurate forecast.
[10] NW Natural forecast new construction customer additions by Oregon load center, and conversions and losses at the state-level.
[11] NW Natural forecast customer levels by Oregon load center. Washington customer forecasts were at the state-level.
[12] NW Natural projected U.S. housing starts by first using OEA's forecast of Oregon's population and the 1991–2016 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.

Planning, Major Account Services, Marketing, and Strategic Planning. The panel meets on a quarterly basis to update its previous forecast and prepares a budgetary forecast in the fourth quarter. The panel uses both quantitative information, such as the number of Oregon housing starts forecasted by Oregon's Office of Economic Analysis (OEA), and qualitative information, including a "pipeline" measure of likely multifamily new construction housing customer additions, as well as information gathered directly from the trade ally community to develop annual forecasts of residential and commercial customers for a five-year timeframe.

NW Natural believes the accuracy of customer forecasts developed by the SME panel has improved in recent years, in part by developing better methods for forecasting residential new construction customer additions.

Timing of transition between types of customer forecasts

Timing requirements of the IRP process are such that NW Natural finalized customer forecasts in the 2018 IRP before 2017 data was available. Therefore, the first forecast year is 2017. NW Natural assessed blending the two types of forecasts at alternative near-term timeframes for the 2018 IRP. The Company compared the accuracy of out-of-sample econometric forecasts with those of past SME Panel forecasts, aggregating forecasts of residential and commercial customers as of year-end for each type of forecast to the system level. The comparison used econometric forecasts for three different out-of-sample timeframes, using models developed using actual data through 2011, 2012, and 2013 to forecast, respectively, years 2012–2016, 2013–2016, and 2014–2016. The SME Panel forecasts used were those prepared in October of 2012, 2013, and 2014; matching the econometric forecasts in terms of actual data used for each of the three different timeframes. For each of the three different forecast timeframes, the aggregated SME Panel forecasts were more accurate for both the first and second forecast years than were the aggregated econometric forecasts. Therefore, NW Natural compared the errors of the two types of forecasts blended in the third year with the errors of those blended in the fourth year.[13]

The comparison used as the measure of errors the mean absolute percentage error (MAPE) for the three out-of-sample forecasts for each of the third and fourth[14] forecast years for each of the two types of forecasts (see Table 3.4).

[13] To limit the number of potential comparisons, the two types of forecasts in either forecast year 3 or 4 are equally weighted.
[14] Note that only the out-of-sample forecasts for 2012-2016 and 2013-2016 have a fourth forecast year; therefore, the MAPE values for the fourth forecast year use errors from two out-of-sample forecasts, while those for the third forecast year use errors from all three out-of-sample forecasts.

Table 3.4: MAPE Values for Three Sets of Forecasts using Alternative Blend Years

	FORECAST TYPE		FORECAST BLENDED IN YEAR	
Forecast Year	**SME Panel**	**Econometric**	**3**	**4**
1	0.07%	0.13%		
2	0.19%	0.26%		
3	0.33%	0.30%	0.31%	0.33%
4	0.27%	0.26%	0.26%	0.26%
Average of 3 & 4	0.30%	0.28%	0.28%	0.29%

Blending the two types of forecasts in either forecast year 3 or forecast year 4 resulted in very similar levels of accuracy, as measured by MAPE values, for forecast years 3 and 4 individually and for the average of the two. As the SME panel's forecasting process has improved in recent years, the Company blends the two types of customer forecasts used in the 2018 IRP in the fourth year, with the SME panel forecast receiving a one-third weight and the econometric forecast a two-thirds weight. Customer forecasts for years prior to the fourth forecast year are those produced by the SME panel, while forecasts for years after the fourth forecast year use econometric methods.

Method of blending SME panel customer forecasts with econometric customer forecasts

NW Natural used the weightings above to average the 2020 growth in SME panel customer forecast with the 2020 growth in the econometric customer forecast and added this value to the 2019 SME panel customer forecast. For years 2021 forward, the Company added the growth in the econometric customer forecast to the value of the customer forecast for the prior year. It did this to derive each of the Oregon residential, Washington residential, Oregon commercial, and Washington commercial customer forecasts.

2.4. RESIDENTIAL AND FIRM SALES COMMERCIAL CUSTOMER FORECASTS

Figure 3.6 compares the forecast of system residential plus commercial customers used in the 2018 IRP with that of the 2016 IRP, while Figures 3.7 and 3.8 are the comparisons for Oregon and Washington, respectively.

Figure 3.6: System Residential plus Commercial Customers

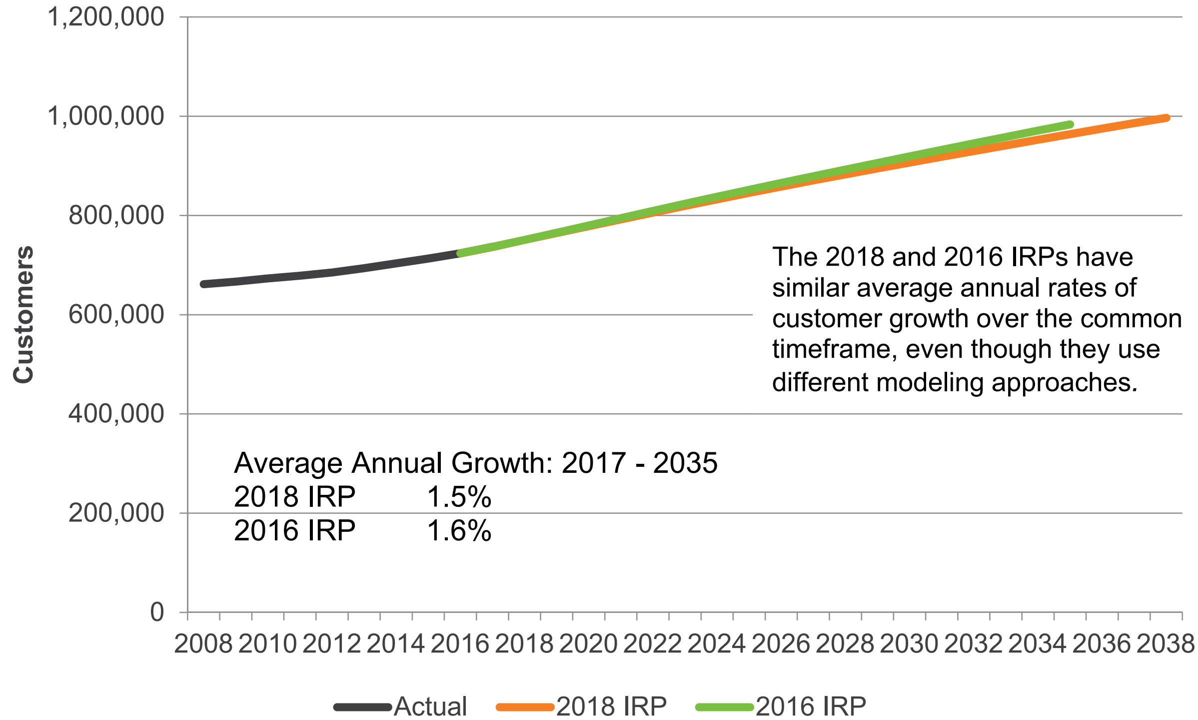


Figure 3.7: Oregon Residential plus Commercial Customers

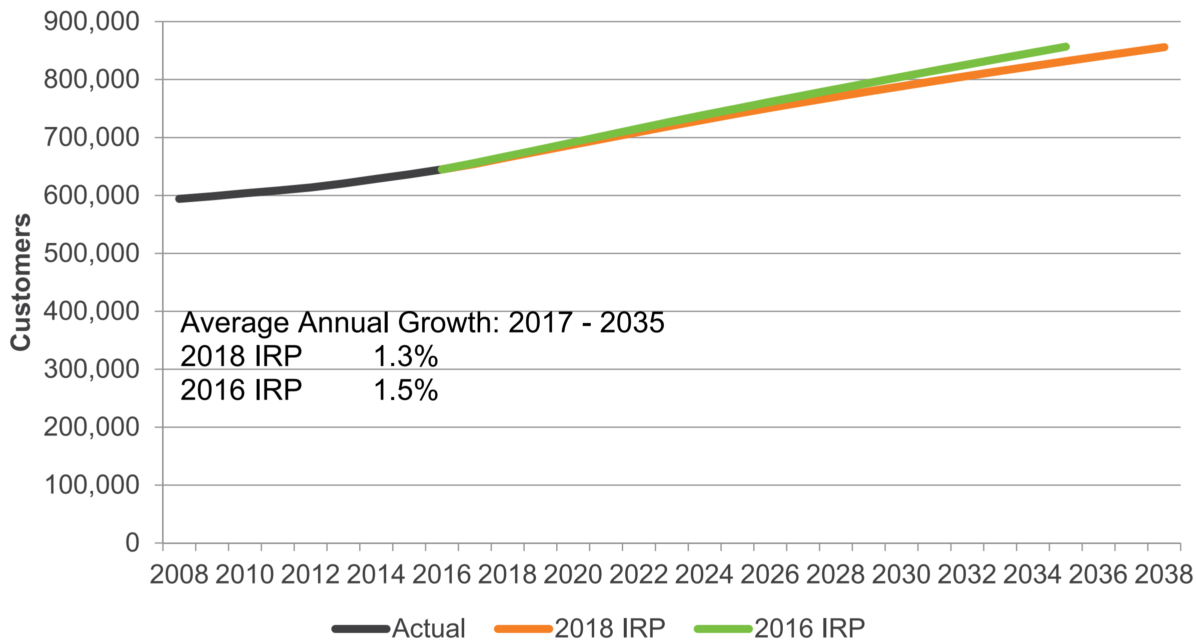


Figure 3.8: Washington Residential plus Commercial Customers

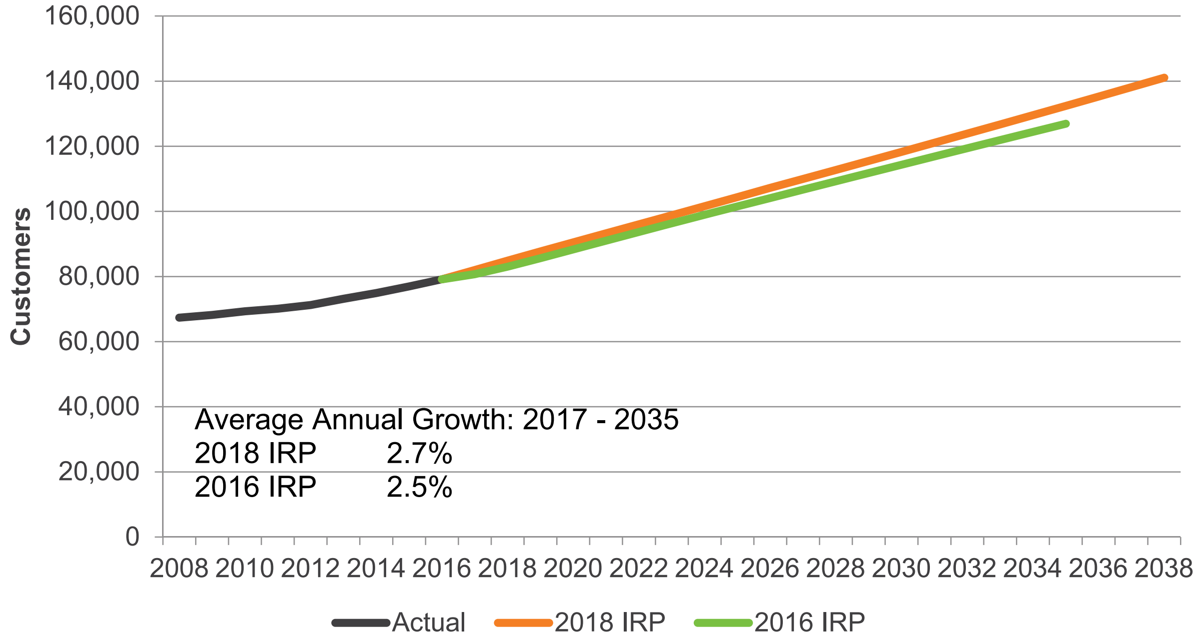


Figure 3.9 compares the forecast of system residential customers used in the 2018 IRP with that of the 2016 IRP, while Figure 3.10 is the comparison of system commercial customers.

Figure 3.9: System Residential Customers

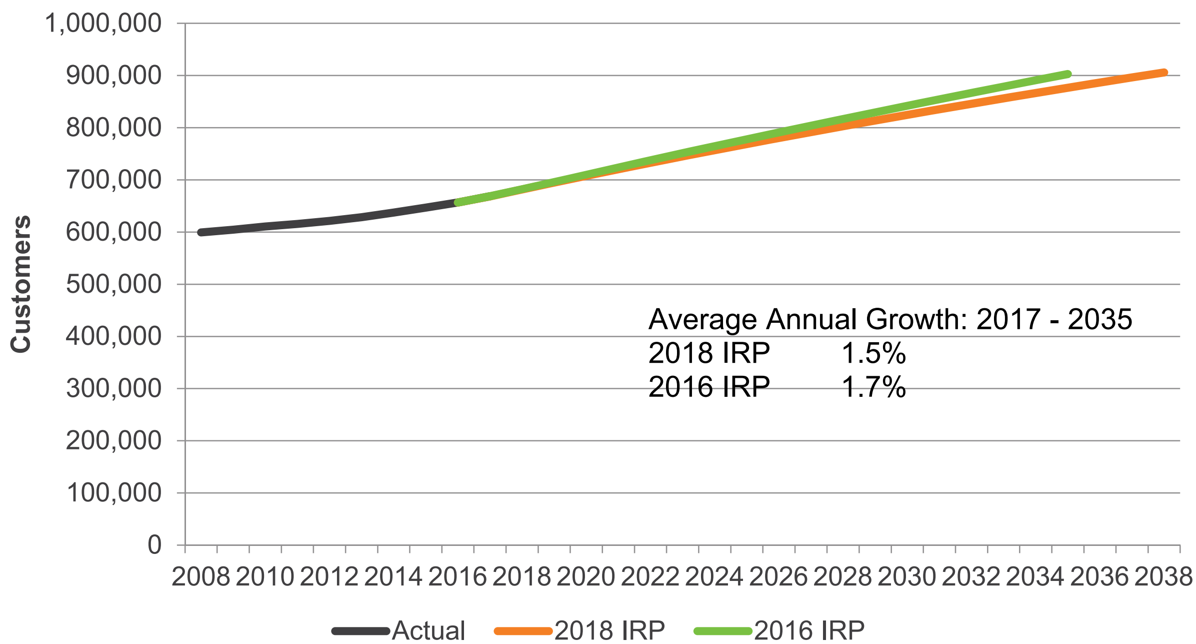
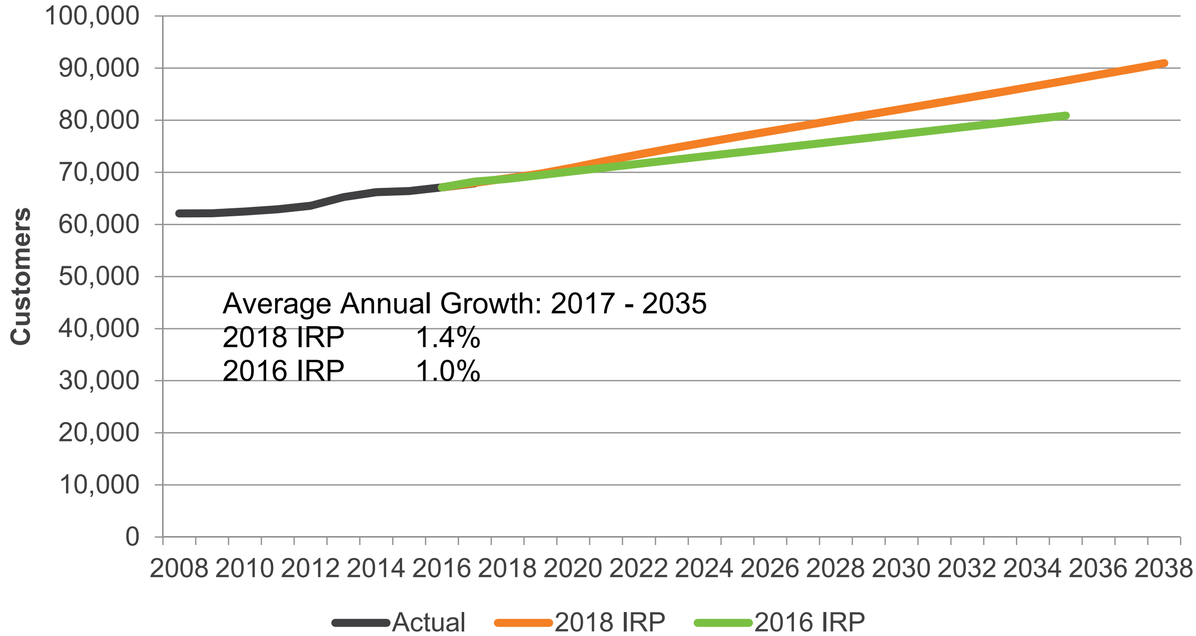


Figure 3.10: System Commercial Customers



High and Low Customer Growth Cases

NW Natural developed two alternative sensitivities to the Base Case customer forecasts discussed above. Figure 3.11 compares, for residential plus firm sales commercial customers, the Base Case with these two alternative customer growth sensitivities. The High and Low Cases use high and low SME panel customer forecasts, which transition to econometric forecasts in 2020 as described above. NW Natural used 90 percent confidence intervals around each Base Case customer forecast to derive the High and Low Case econometric customer forecasts.

Figure 3.11: System Residential plus Commercial Customers: Base Case High Case, and Low Case

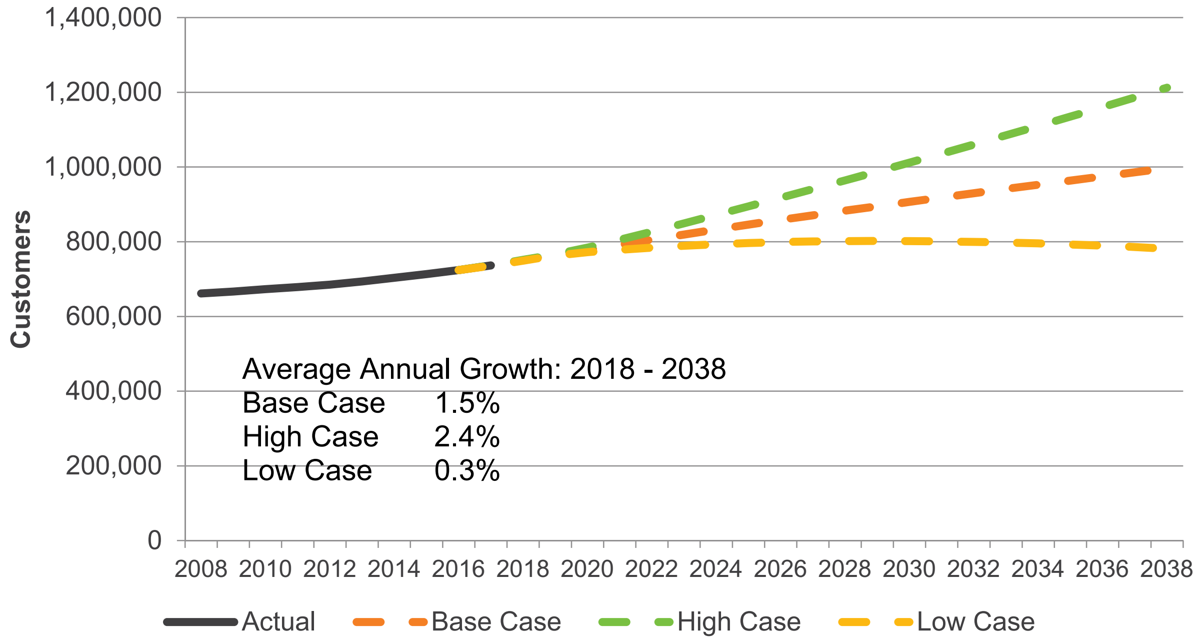


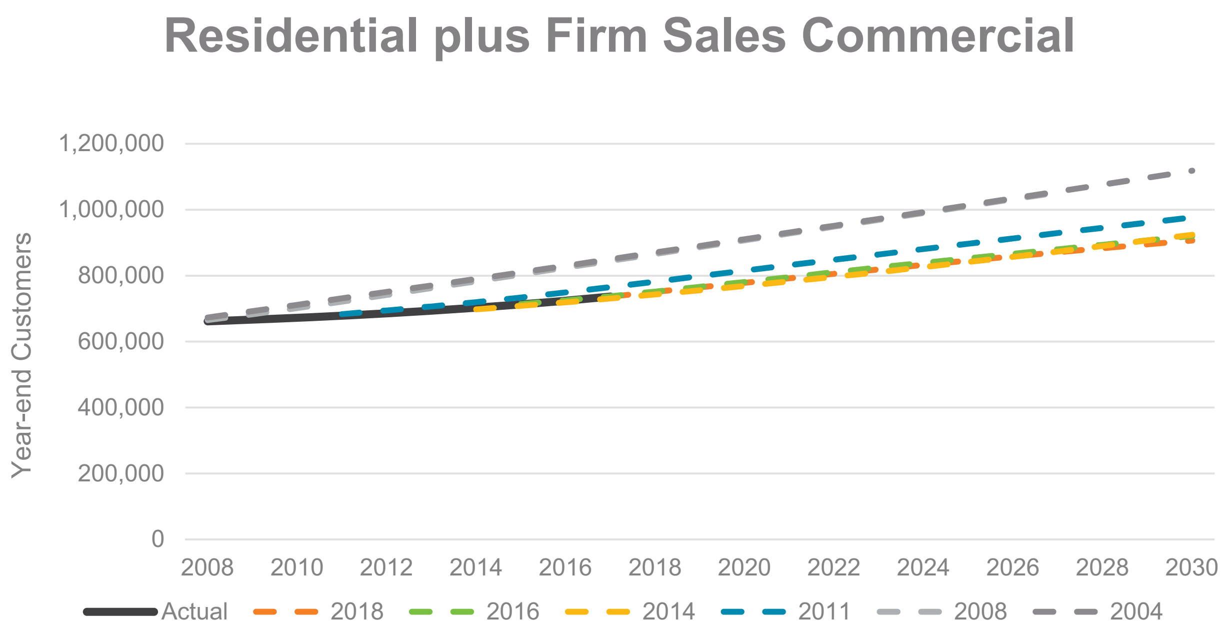
Table 3.5 has average annual rates of growth in the customer forecasts for each of the Base, High, and Low Cases.

Table 3.5: Average Annual Customer Growth Rates 2018–2038

		SYS	OR	WA
Base Case				
	Res + Com	1.5%	1.3%	2.6%
	Res	1.5%	1.3%	2.7%
	Com	1.4%	1.3%	2.1%
High Case				
	Res + Com	2.4%	2.2%	3.8%
	Res	2.5%	2.3%	3.9%
	Com	1.6%	1.5%	2.3%
Low Case				
	Res + Com	0.3%	0.2%	1.1%
	Res	0.2%	0.1%	1.0%
	Com	1.2%	1.1%	2.0%

Figure 3.12 shows that the forecast of System Residential plus Firm Sales Commercial customers in the 2018 IRP is similar not only to the 2016 IRP's forecast, but also to the 2014 IRP's. Customer forecasts in the 2004 and 2008 IRPs were materially higher. The 2011 IRP customer forecast, while developed post-recession, was also higher than the customer forecast in any of the 2014, 2016, or 2016 IRPs.

Figure 3.12: Customer forecasts in the 2018 and prior IRPs



Comparison of 2018 IRP Customer Forecasts with 2016 IRP Customer Forecasts

Table 3.6 summarizes the primary differences between customer forecasts in the 2018 IRP and the 2016 IRP.

Table 3.6: Primary Customer Forecasting Differences between the 2018 and 2016 IRPs

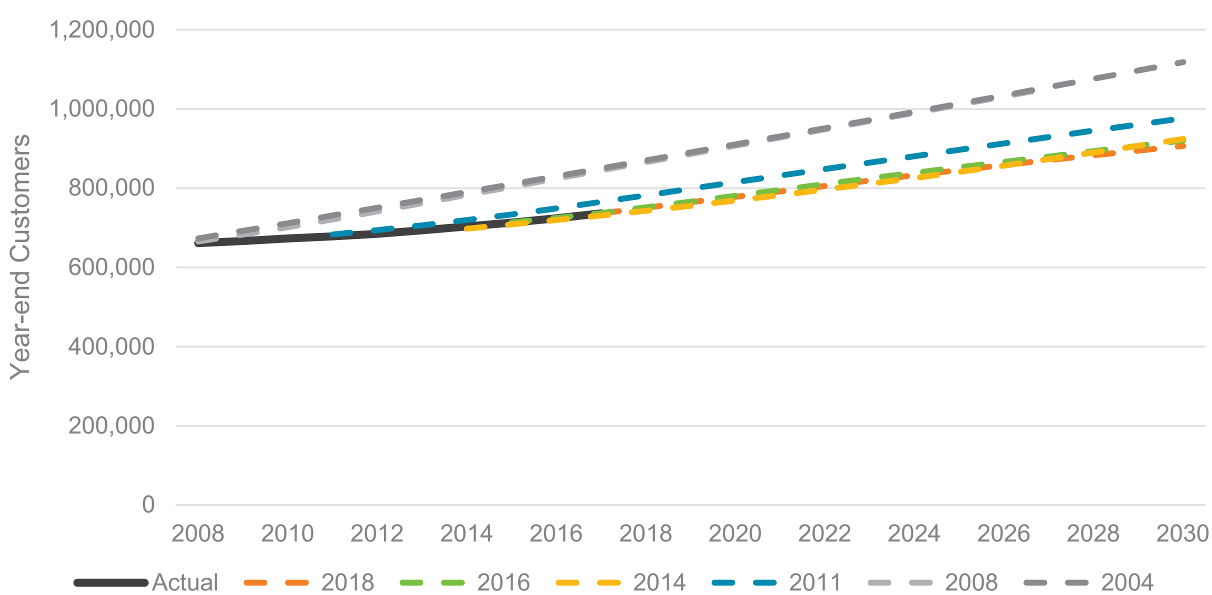
	2018 IRP	**2016 IRP**
Econometric modeling approach	Levels	Components
Primary assessment tool	Out-of-sample forecast errors	In-sample forecast errors ("fit")
Econometric model (forecasted state(s))	Exogenous variable (Source[15])	
Residential customers (OR; WA)	U.S. Housing Starts (OEA)	-
Residential New Construction (OR; WA)	-	Oregon Housing Starts (OEA)
Residential Conversions (OR; WA)	-	Time Trend
Commercial customers (OR)	OR Population (OEA)	-
Commercial customers (WA)	OR Nonfarm Employment (OEA)	-

[15] Regarding the source of forecasts of exogenous variables, "OEA" refers to Oregon's Office of Economic Analysis and "W&P" refers to Woods & Poole.

Commercial New Construction (OR; WA)	-	Portland MSA nonfarm/non-manufacturing employment (W&P)
Commercial Conversions (OR; WA)	-	Time trend
Other components of customer change		
Customer Losses (Residential; Commercial)	-	5-year historical average rate
Year of SME Panel and Econometric Forecast blending	Year 4	Year 3

While NW Natural made numerous changes in how the Company prepared customer forecasts in the 2018 IRP, forecast results—the aggregate forecast of residential and firm sales commercial customers on a system basis—in the 2018 IRP is similar to that in the 2016 IRP. Figure 3.13 compares aggregate customer forecasts in the 2004, 2008, 2011, 2014, 2016, and 2018 IRPs. See also the charts above comparing the 2018 IRP forecast of residential customers and the 2018 IRP forecast of commercial customers with the respective forecasts in the 2016 IRP.

Figure 3.13: System Residential plus Commercial Customers in the 2018 and Prior IRPs



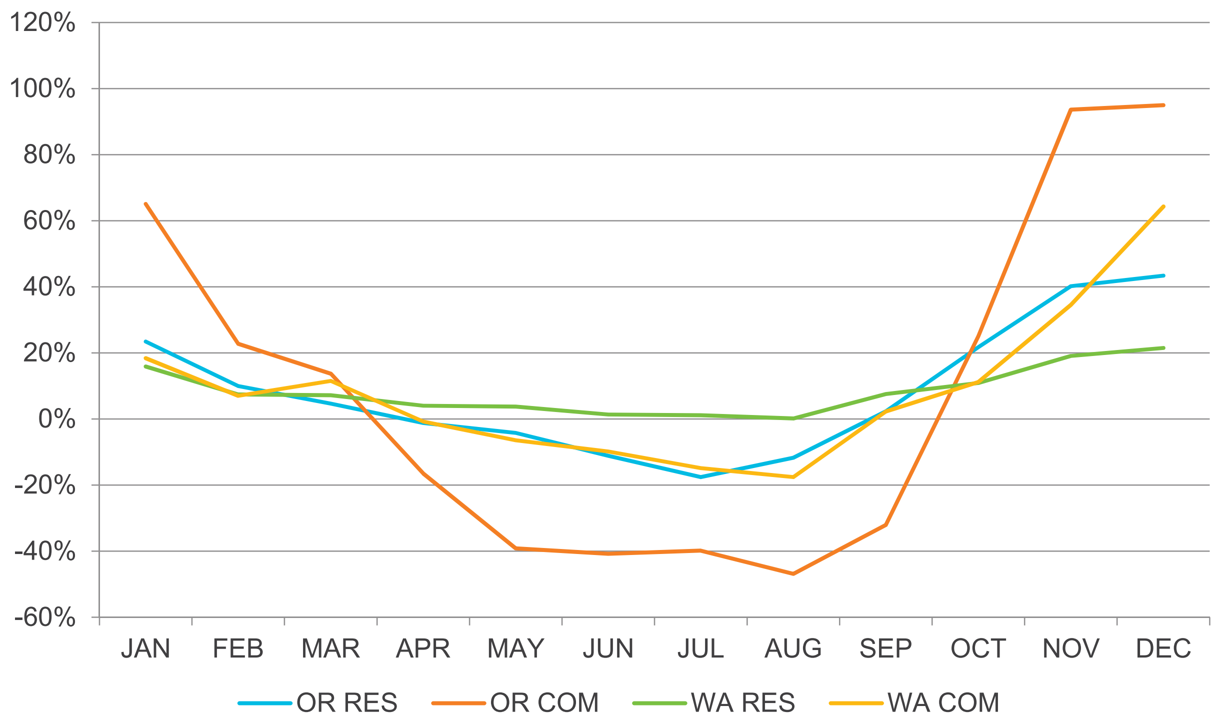
2.5. ALLOCATIONS

NW Natural has, for purposes of planning associated with the 2018 IRP, 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 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

NW Natural discusses the statistical models used to allocate annual (year-end) customer forecasts to monthly customer forecasts in Appendix C. It is the shoulder months of March – May and September that had the most variability over this historical timeframe. Figure 3.14 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 3.14: 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 2009 through August 2017 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 3.7 shows the average annual rates of customer growth by load center and state for residential customers and commercial customers over the 2018–2038 planning horizon. Note that NW Natural has provided service to Coos Bay for less than two decades and there may be a relatively greater potential for customer growth through conversions from other fuels in this load center than in other parts of the Company's service area.

Table 3.7: Average Annual Customer Growth Rates – Base Case

Load Center	Residential	Commercial
OREGON		
Albany	0.9%	0.9%
Astoria	1.5%	0.5%
Coos Bay	3.9%	4.4%
Columbia River Gorge – OR	1.7%	1.2%
Eugene	1.4%	1.4%
Lincoln City	1.2%	0.0%
Portland	1.3%	1.4%
Salem	1.2%	1.3%
Total Oregon	**1.3%**	**1.3%**
WASHINGTON		
Columbia River Gorge – WA	1.9%	0.6%
Vancouver	2.7%	2.2%
Total Washington	**2.7%**	**2.1%**

Allocation to Components of Customer Change

NW Natural, using the SENDOUT software application, models customers as existing, new construction customer additions, conversion customer additions, and customer losses. This is done as different categories have different usage levels; e.g., new construction customer additions tend to have less use on average than do existing customers. NW Natural used the "components" forecasts at state-level and projected customer loss rates based on the average of loss rates over 2012–2016 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 2020 and subsequent years.

2.6. CUSTOMER FORECAST SUMMARY

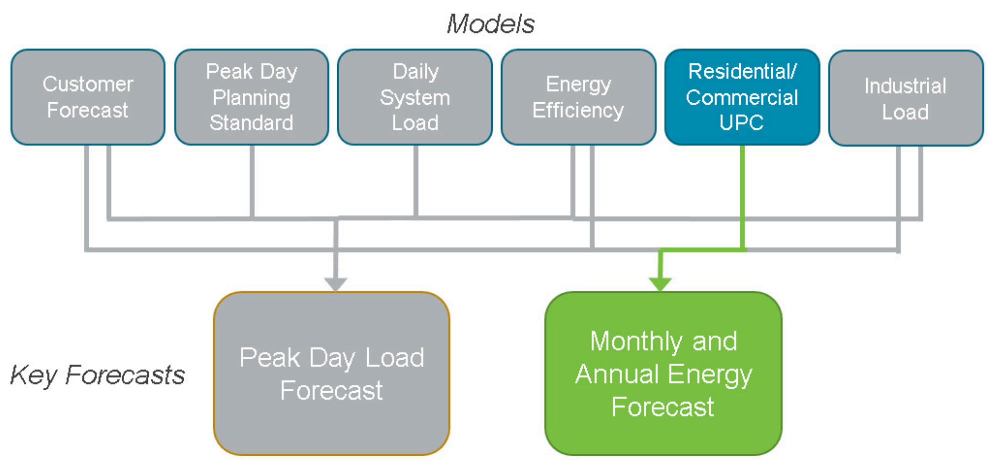
NW Natural investigated changes suggested by stakeholders regarding the 2016 IRP. To evaluate the four alternative approaches to forecasting customers considered, the Company used multiple criteria applied to the errors of out-of-sample forecasts. As a result of these evaluations, NW Natural selected the approach that proved to be most accurate in out-of-sample forecasts, and forecasts customers in the 2018 IRP at the state level and directly forecasts the number of customers, as opposed to the approach used in the 2016 IRP of individually forecasting the components of customer change at the state level.

The average annual rate of aggregate customer growth in the 2018 IRP is very similar to that in the 2016 IRP over the common timeframe of 2017–2035; with an average annual rate of 1.5 percent in the 2018 IRP versus the 1.6 percent rate in the 2016 IRP.

3. RESIDENTIAL AND COMMERCIAL USAGE

Total annual demand for residential and commercial customers is forecasted by multiplying the customer count and annual use per customer (see Figure 3.15). Annual weather-normalized usage per customer (UPC) is forecasted for residential and commercial customer classes using billing data, temperature history, and energy efficiency savings projections. Prior to the 2016 IRP residential and commercial coefficients along with the industrial demand were used directly to estimate the highest firm sales demand day requirements. In the 2016 IRP the Company transitioned from using the UPC coefficients to using a daily system model to estimate the peak day demand needs. In this IRP and the 2016 IRP, UPC has a smaller role in determining system resource needs but is still necessary to forecast total energy demand.

Figure 3.15: Demand Forecast Process – Annual Use per Customer



UPC is forecasted at the state and component level. The components are:

1) Residential existing customers (current customer base)
2) Residential conversion customers (existing building stock fuel switching)
3) Residential new construction (newly build single and multifamily housing)
4) Commercial existing customers (current customer base)
5) Commercial conversion customers (existing building stock fuel switching)
6) Commercial new construction (newly constructed commercial buildings)

Figures 3.16 and 3.17 show the forecasted first year (before DSM) estimates of usage per customers for residential and commercial customer classes, respectively. While residential, existing customer, and conversion customer usage has declined slightly over several IRPs, residential new construction has seen a 21 percent reduction in estimated annual usage since the 2013 IRP. In contrast to residential customers, commercial customer usage today appears to be similar or higher than in previous IRPs.

Figure 3.16: First year residential annual usage per customer

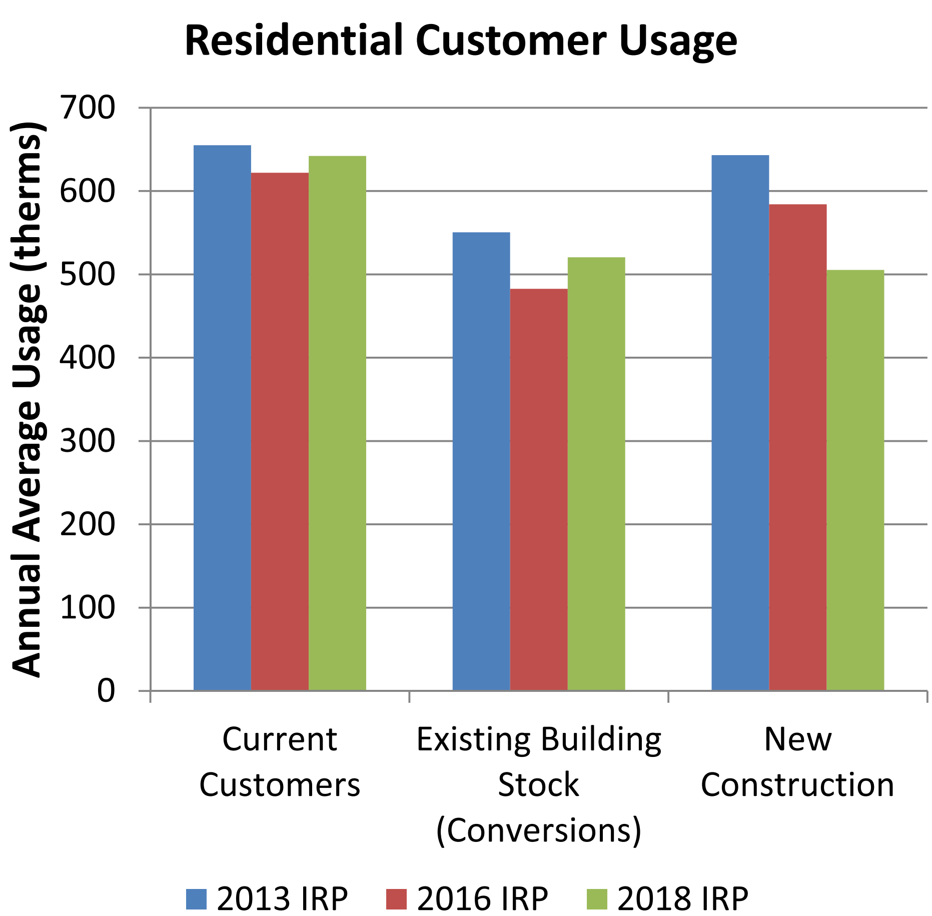
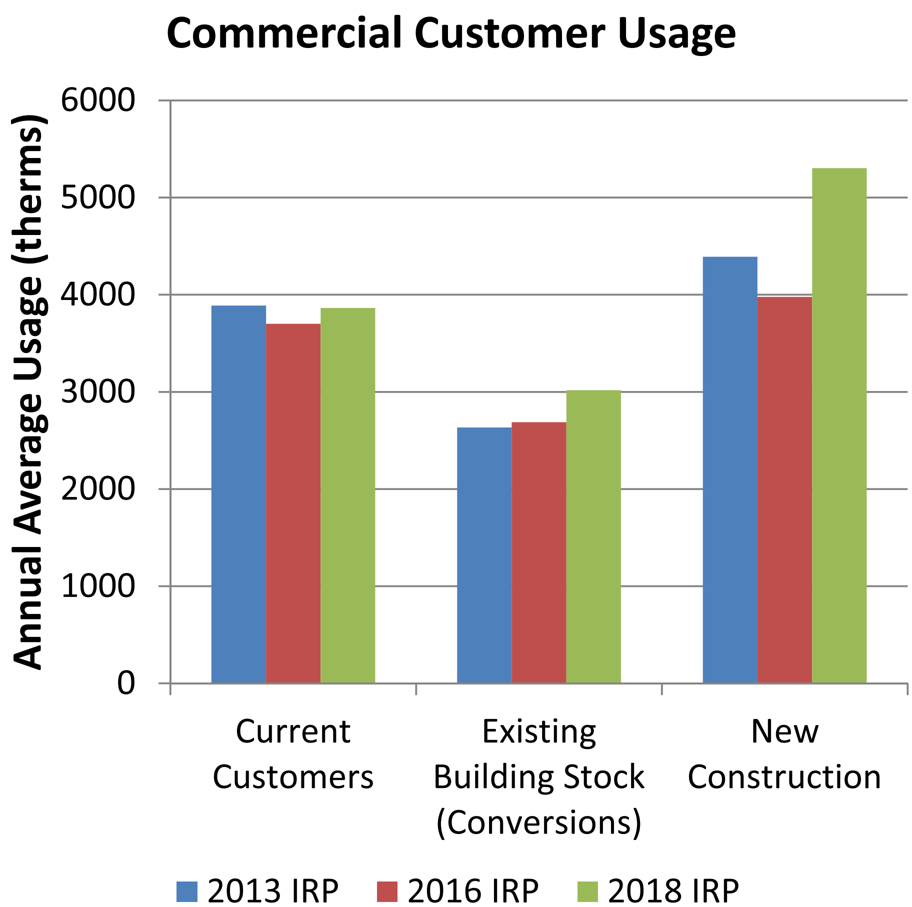


Figure 3.17: First year commercial annual usage per customer



Incentivized Cost-Effective Energy Efficiency

NW Natural applied the forecasted annual energy savings by adjusting the annual usage coefficients such that the reductions match the projected base load and heat load savings from the Energy Trust forecast. See Chapter 5 for discussion and the forecast of incentivized energy efficiency.

Non-incentivized Annual Use per Customer Trend

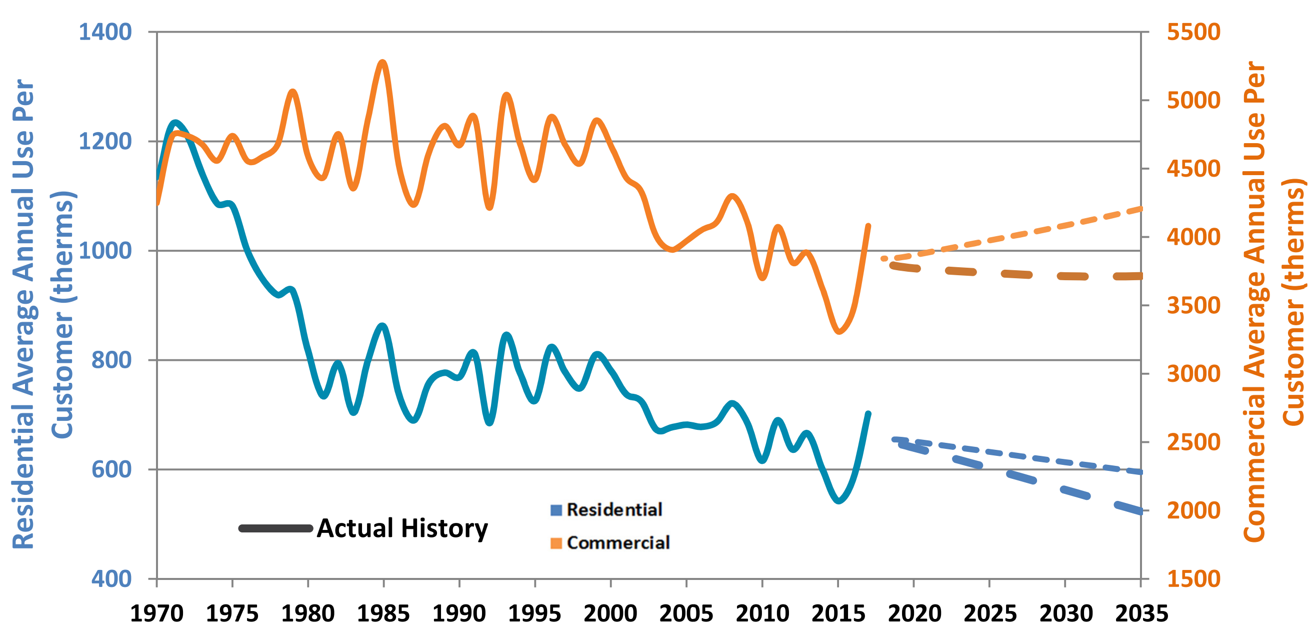
In addition to incentivized energy efficiency, annual energy usage can also decline for various other reasons. For instance an old appliance may be replaced with a new standard efficiency appliance which is more efficient than the old appliance but not as efficient as what might be acquired with incentives. Another reason NW Natural may see changes in energy usage is due to changes in customers' end uses. Tracking a large sample of NW Natural customers over time might show that they add additional gas equipment, switch some equipment to a different fuel type, or become a noncustomer due to demolition of an old house or a full conversion to electricity. These and similar changes will result in changes in average annual use per customer over time.

To estimate the non-incentivized trend requires that NW Natural use a sample of customers who have not participated in Energy Trust programs over a period of time. Billing data dating to 2009 and NW Natural customer participation information from Energy Trust dating from 2004 through 2016 were combined resulting in a data period ranging from 2009–2016. A time variable was added to the regression for both base load and heat load.

Annual Use per Customer Trend

Figure 3.18 shows NW Natural's forecast of average annual use per customer for Residential and Commercial customers before and after incentivized DSM savings. Residential average annual use per customer declines at an average annual rate of -1.28 percent per year while commercial average annual use per customer is declining at an average annual rate of -0.15 percent per year.

Figure 3.18: Trend in Use per Customer with and Without DSM



Combining the customer forecast and annual use per customer forecast results in annual load forecasts for residential and commercial customers (Figures 3.19 and 3.20, respectively). Due to large declines in residential UPC over the planning horizon, the annual residential demand peaks in 2028 before beginning to decline. Commercial total demand increases throughout the planning horizon (1.33 percent annual growth rate) driven by higher usage in new construction.

Figure 3.19: Residential Annual Demand Forecast

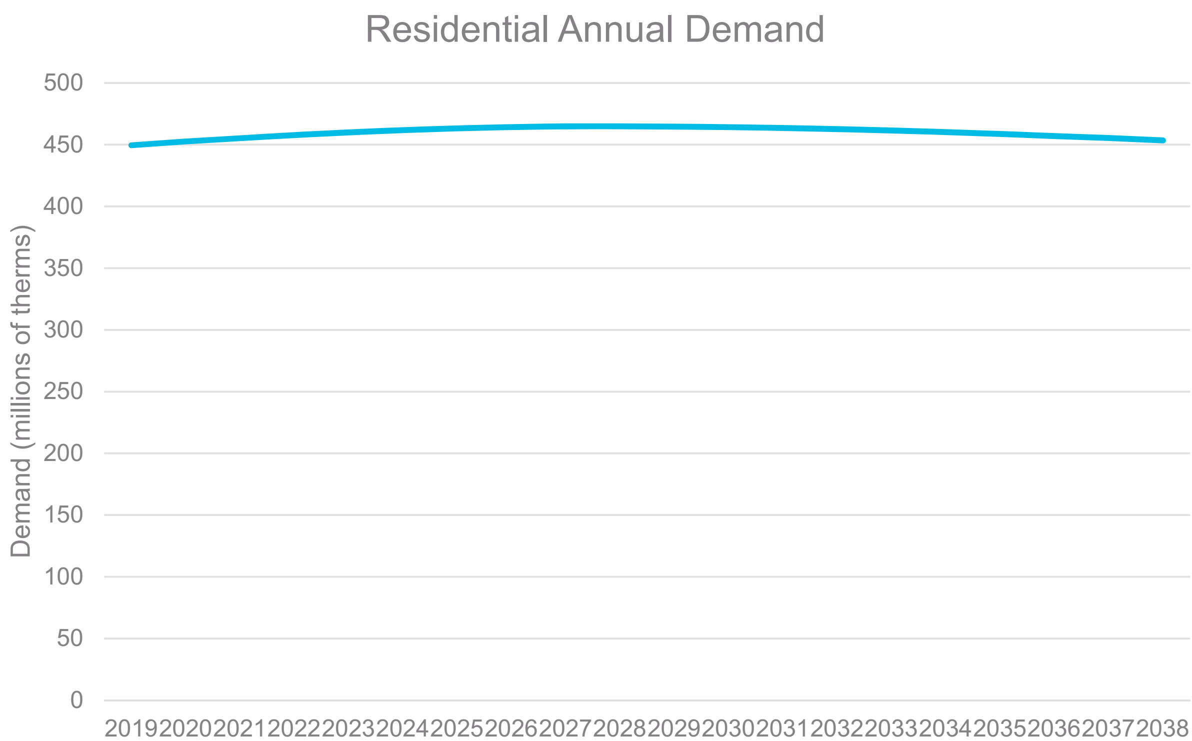
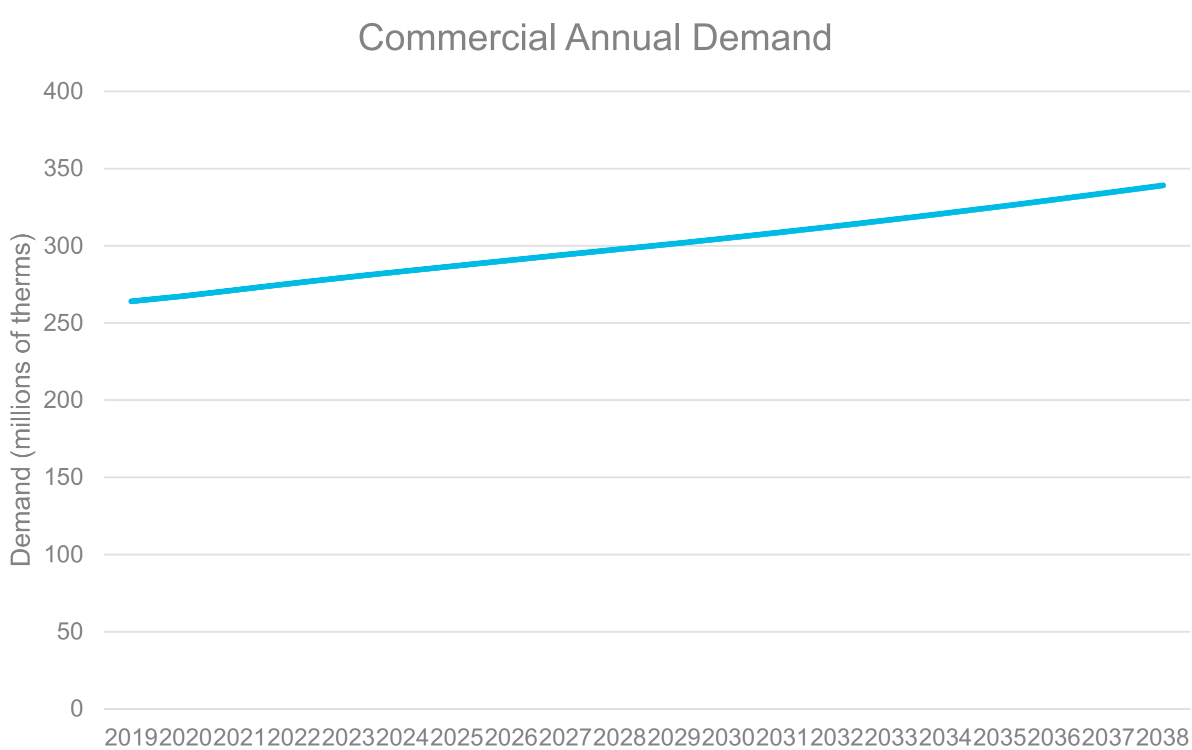


Figure 3.20: Commercial Annual Demand Forecast

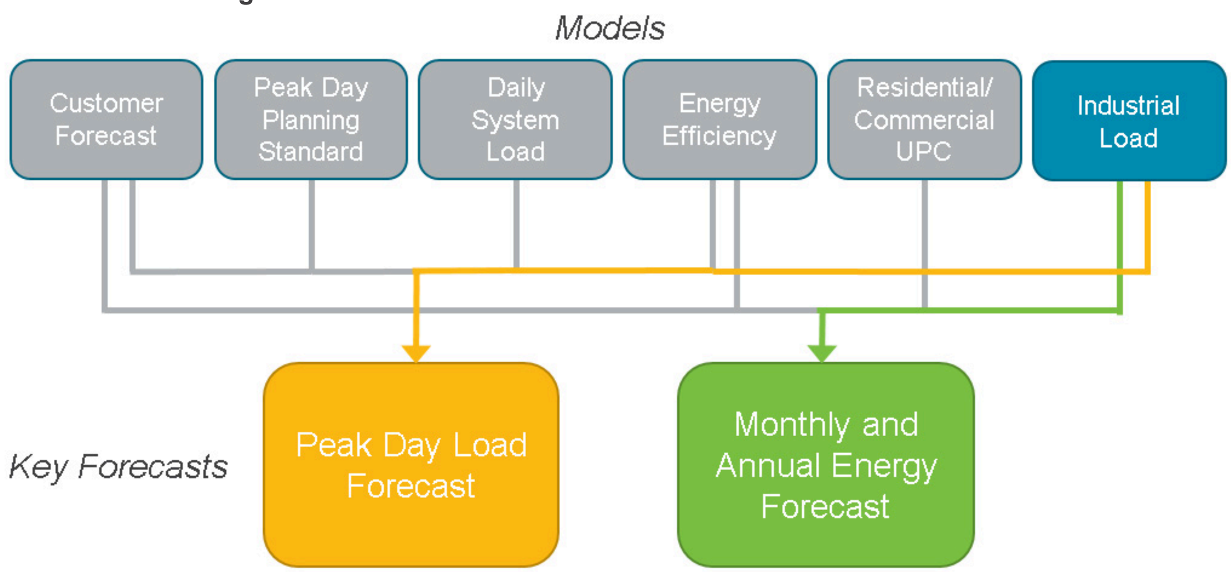


4. INDUSTRIAL AND EMERGING MARKET LOAD

4.1. INDUSTRIAL

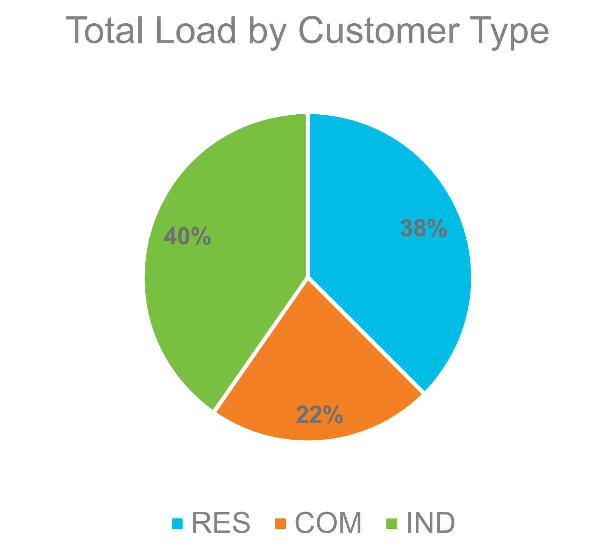
As noted earlier, NW Natural does not forecast Industrial load by forecasting use per customer and multiplying by forecasted customers due to the extreme differences in usage levels by these customers. Instead, the Company directly forecasts the annual load of industrial customers (see Figure 3.21). NW Natural's industrial load can be separated into four classes of service: firm sales, firm transportation, interruptible sales, and interruptible transportation. The only class of service not used in some way for resource modeling in the 2018 IRP is interruptible transportation.[16] Figure 3.22 shows the proportions of NW Natural's 2017 load by customer type for all classes of service as well as for firm sales only.[17]

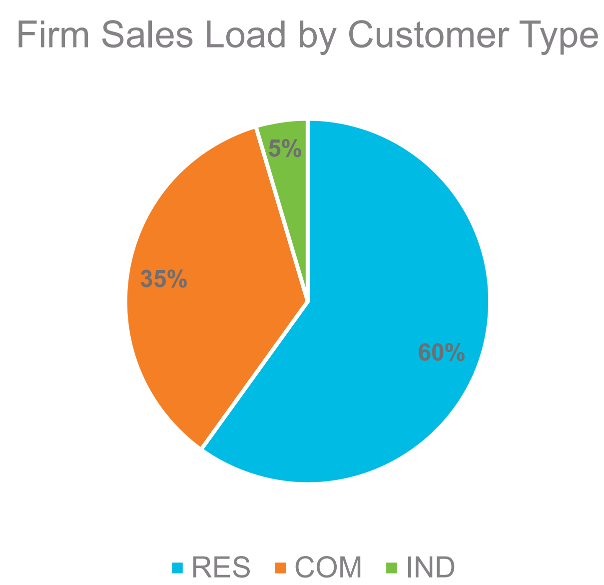
Figure 3.21: Demand Forecast Process – Annual Industrial Load



[16] Interruptible sales load is a component of the firm plus interruptible sales load that drives certain aspects of resource optimization, such as natural gas commodity requirements.
[17] Source: NW Natural's 2017 Form 10-K filing.

Figure 3.22: 2017 Total and Firm Sales Loads by Customer Type





NW Natural's firm sales load drives supply resource requirements and the Company's on-system resource requirements, including storage. The total of firm sales and firm transportation drives some on-system resource requirements, including requirements for the Company's distribution system.

Econometric forecasts

NW Natural used methods to develop an econometric forecast of industrial load similar to those used to develop econometric models used to forecast residential and commercial customers, including ARIMA structure and exogenous variable selection. Forecasting approaches involving separately forecasting loads for each industrial class of service were generally unsuccessful.

Therefore, NW Natural forecast total industrial load and allocated to individual classes of service (as well as to month and load center, as was done for residential and commercial customers). See Appendix C for information related to the econometric models used to forecast industrial load.

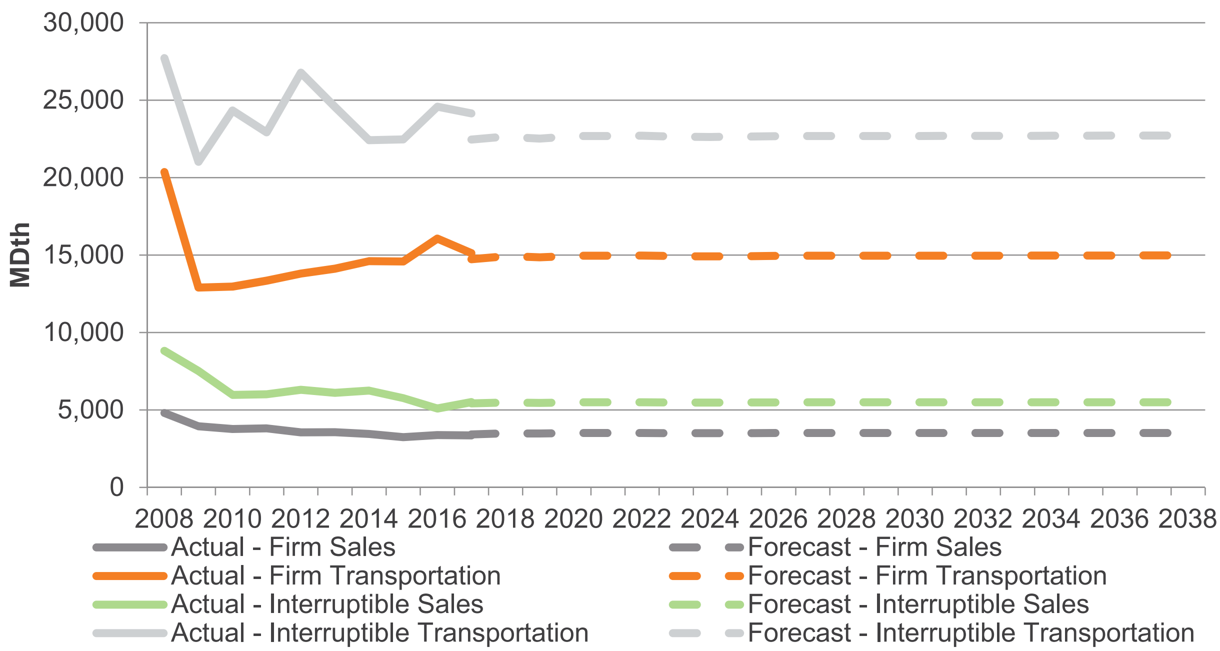
SME panel forecasts

Similar to the SME panel forecast NW Natural uses as a component of its customer forecasts for the 2018 IRP, the Company uses a SME panel forecast of industrial load to blend with the econometric forecast discussed above. NW Natural uses the SME panel forecast for 2017 and 2018, 2019 is an equally-weighted blend of the two forecasts, and 2020 forward is the econometric forecast.

Allocations

NW Natural uses the composition of the SME panel forecast, which is by class of service, to allocate the total industrial load to the four classes of service. Figure 3.23 shows the annual industrial load by class of service.

Figure 3.23: System Industrial Load by Class of Service – Base Case

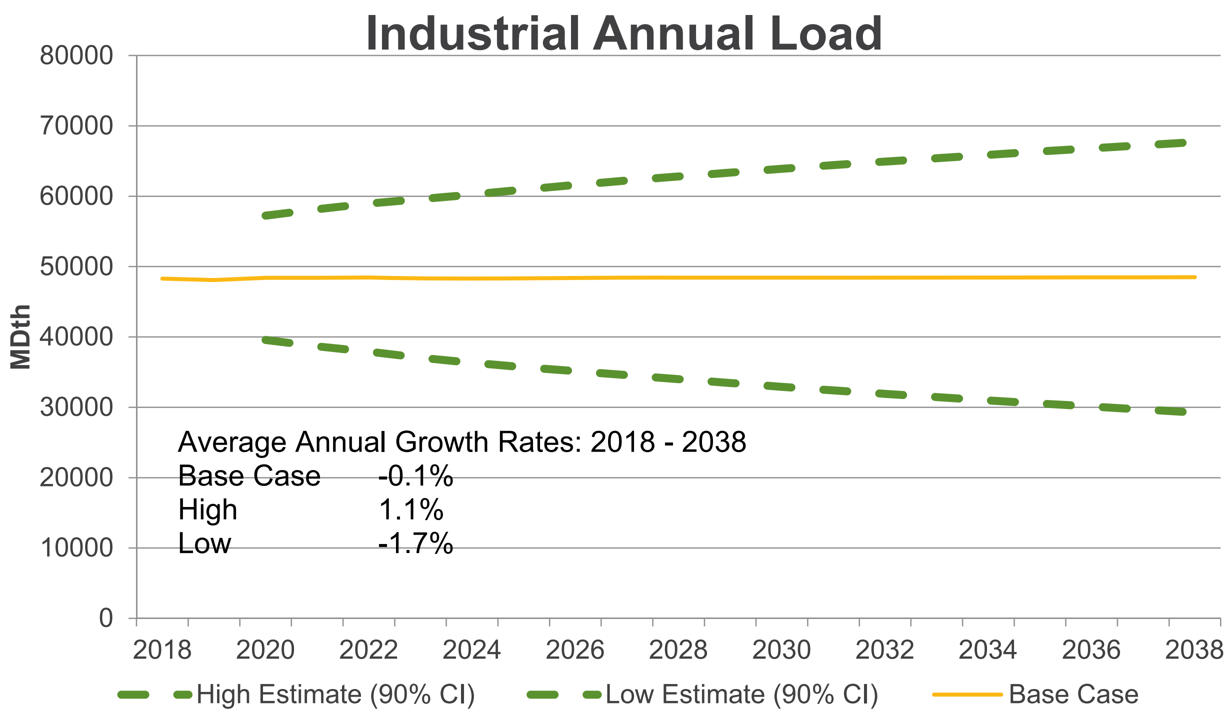


NW Natural uses detail included within the SME panel forecast of industrial load to allocate the industrial load forecasts by service classes from annual to monthly and from system totals to load centers.

High and low sensitivities

NW Natural uses the 90 percent confidence interval of the econometric forecast to derive high and low industrial load forecast sensitivities. These are then allocated in the same way the Base Case forecast is allocated. Figure 3.24 shows the Base Case as well as the high and low industrial load forecasts.

Figure 3.24: System Industrial Load: Base Case, High and Low Sensitivities



4.2. COMPRESSED NATURAL GAS SERVICE

The 2018 IRP load forecast includes a load forecast associated with NW Natural's Compressed Natural Gas (CNG) service, which the Company considers to be an emerging market. NW Natural's Business Development team developed the CNG load forecast based on fundamental analysis from the perspective of the CNG service customer. While the CNG load grows relatively more quickly that other loads, it starts from a small base; e.g., CNG firm sales load was about 0.2 percent of system firm sales load in 2017. The CNG load represents 0.6 percent of system firm sales load in 2038 and 1.3 percent of system firm sales plus firm transportation.

Figure 3.25 shows the CNG firm sales load and the firm sales load other than CNG. Figure 3.26 shows the firm sales and firm transportation load for CNG and the firm sales and firm transportation other than CNG.

Figure 3.25: Firm Sales Load: for CNG and for all other System

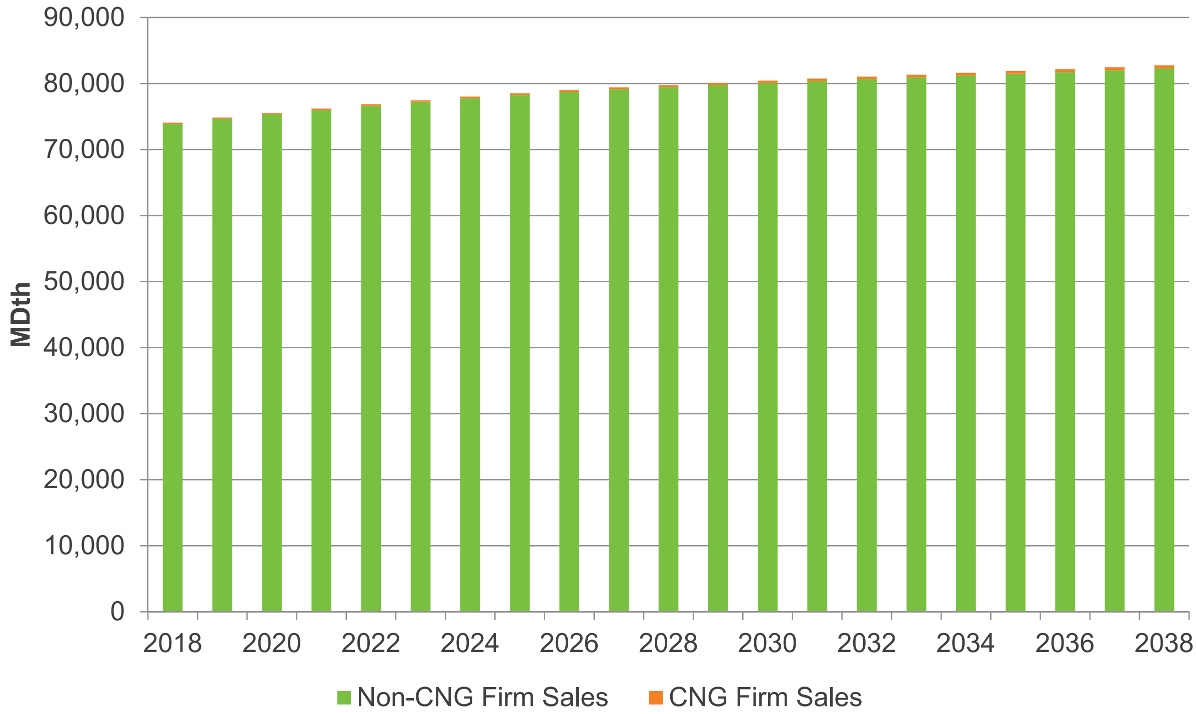
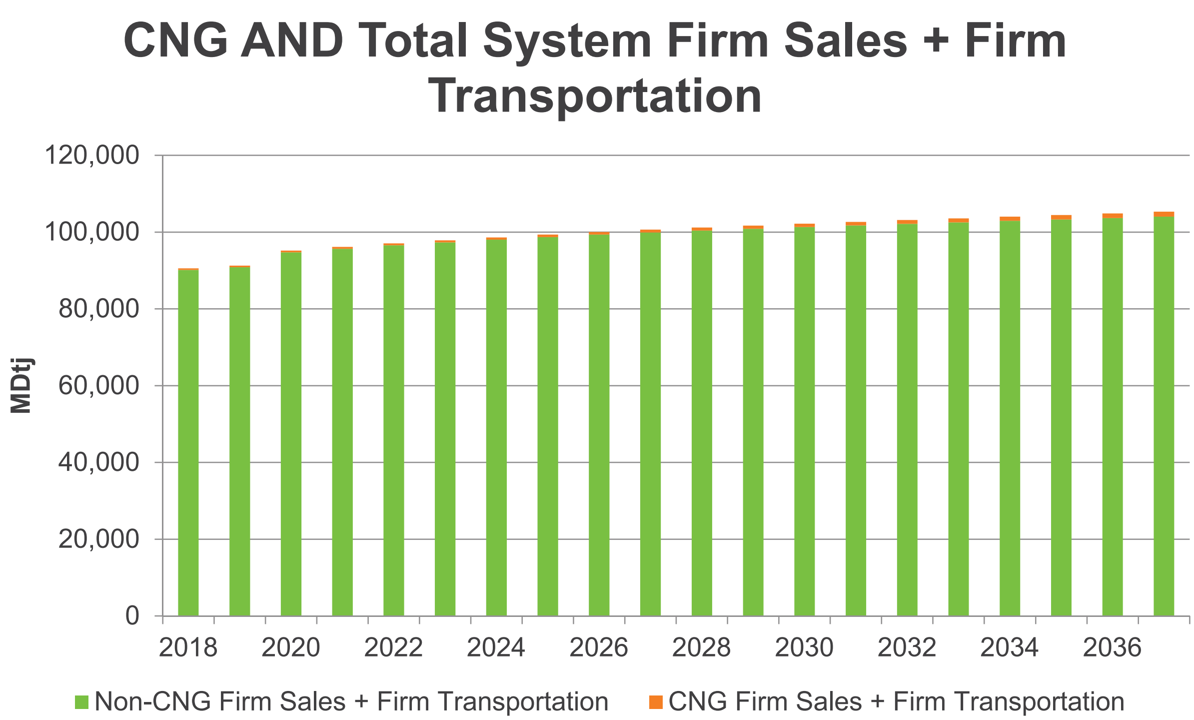


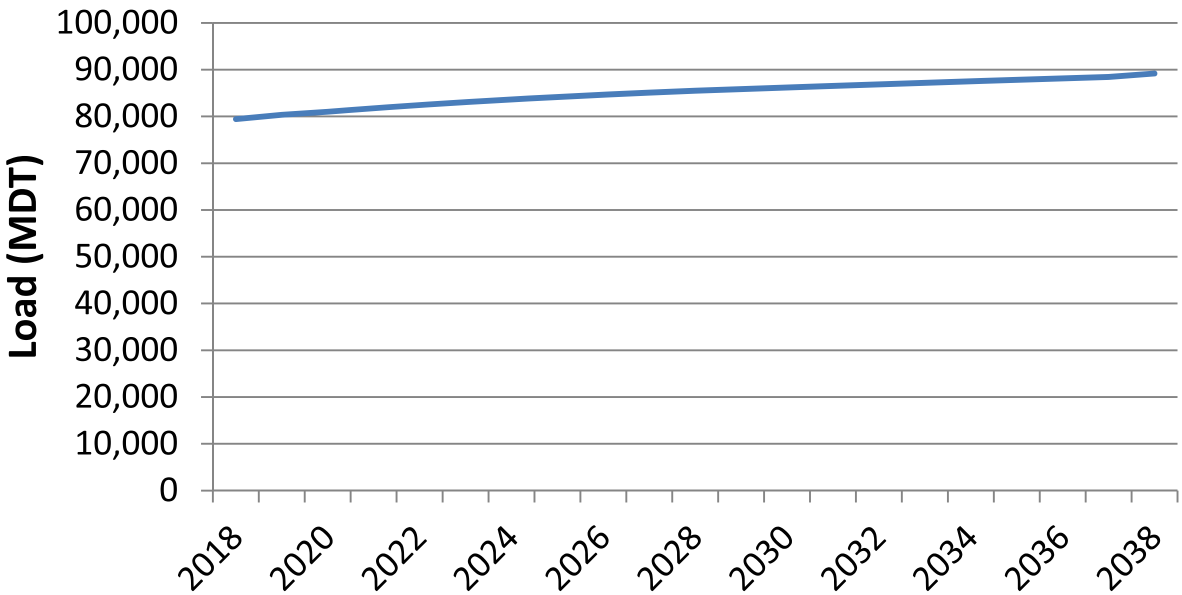
Figure 3.26: Firm Sales plus Firm Transportation Load – for CNG and for all other System



5. TOTAL ANNUAL LOAD FORECAST

Combining the customer forecasts, the annual use per customer forecasts, and the industrial/emerging market forecasts provides the total expected annual sales demand forecast (Figure 3.27). Over the planning horizon the expected annual growth rate is 0.6 percent.

Figure 3.27: Total annual firm sales demand forecast

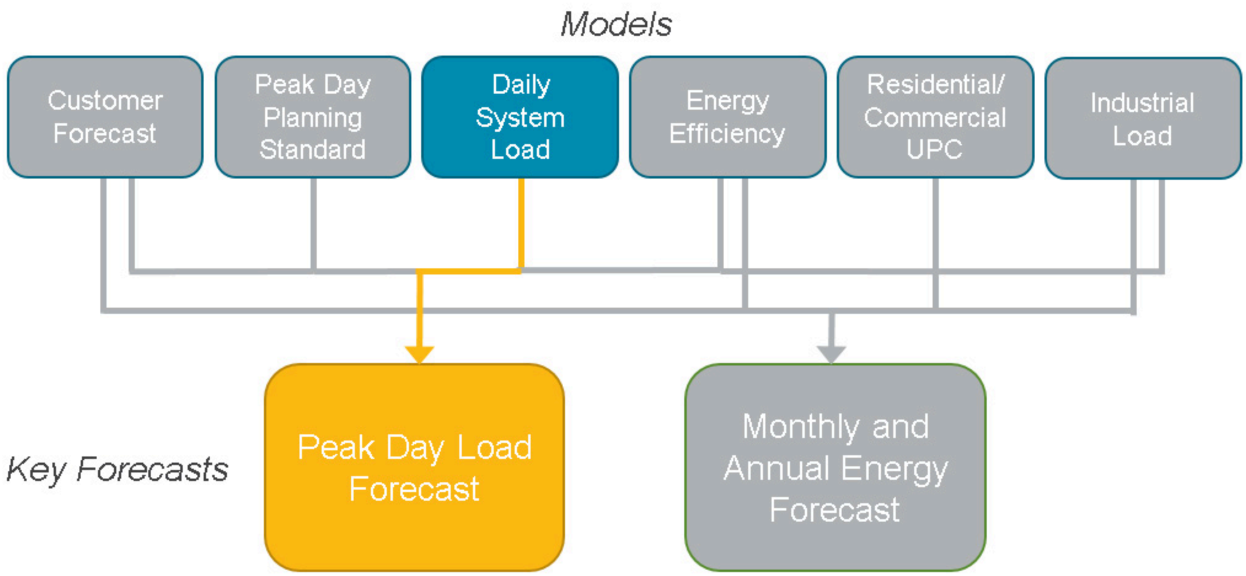


6. DAILY SYSTEM LOAD MODEL

The daily system load model is an econometric model used to measure the relationship between daily firm sales load and the drivers of daily load, for example temperature (see Figure 3.28). Using historical data of each daily driver, the model statistically estimates coefficients, which represent the ceteris paribus relationship between each daily driver and daily firm sales load.[18] These coefficients are subsequently used as an input into the peak day planning standard, discussed in the next section. The purpose of the daily system load model for resource planning is to predict daily firm sales during peak demand conditions created from a combination of daily demand drivers.

[18] The daily system load model focuses on daily firm sales as the Company 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.

Figure 3.28: Demand Forecast Process – Daily System Load



6.1. DAILY DEMAND DRIVERS

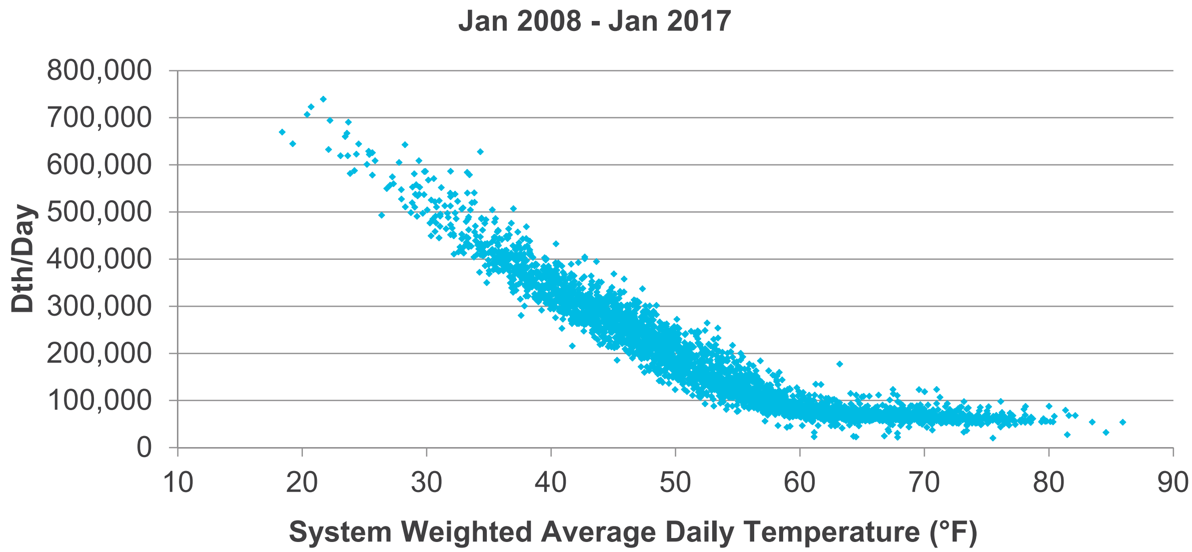
The daily system load models includes 12 drivers: temperature, lagged temperature, solar radiation, wind speed, snow depth, customer count, day of the week indicator variables, a holiday indicator variable, a time trend and water heater water inlet temperature.

During peak conditions roughly 84 percent of the Company'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 a very cold and windy winter weekday when temperature drops and gas demand for space heating spikes.

Figure 3.29 shows a scatter plot of temperature and a daily firm sales load. This figure illustrates a negative linear relationship exists between daily load and temperature. There is a structural break in this relationship at 59°F as space heating equipment (e.g., furnaces) kick on at temperatures less than 59°F. In order to capture this relationship the daily system load model is split piecewise into two models; average daily temperature less than 59°F and average daily temperature greater than 59°F.[19] The coefficients from the less than 59°F model are used as inputs into the peak day planning standard.

[19] Daily temperatures are calculated as system-weighted daily averages from hourly weather data. See Section 6.3 for more details.

Figure 3.29: Daily Firm Sales Load and Temperature



In addition to temperature, the Company includes a daily lagged temperature variable into the model. The necessity of including a lagged temperature value 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 the Company's gate stations and at the Company's on-system storage locations. Additionally, data is collected for interruptible sales and transportation customers who have higher frequency meters that record their daily off-take. 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 and, therefore, present in the data.[20] Including a lagged temperature variable helps capture this lagged data response to changes in weather.

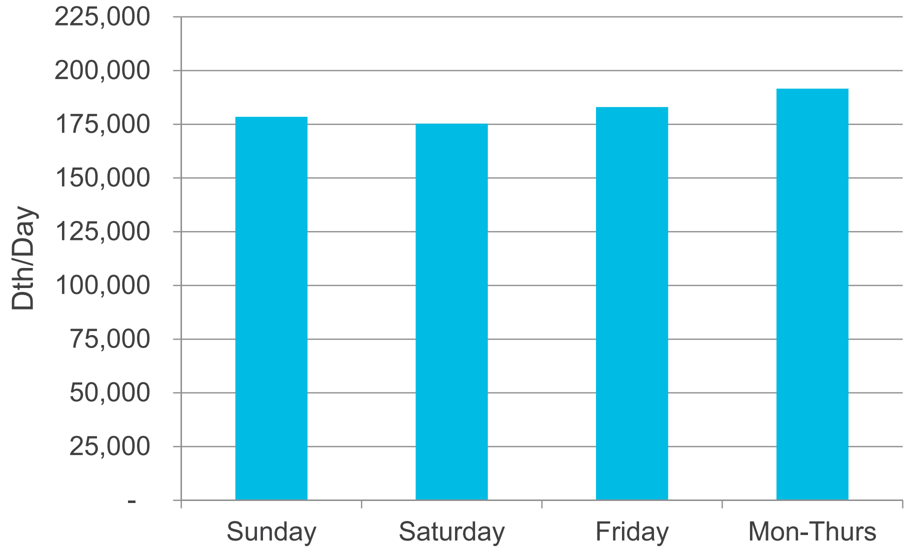
Wind and solar radiation have positive and negative impacts on daily load, respectively. High winds cool building structures, which in turn require additional gas to maintain space heating. Conversely, days with higher solar radiation heat buildings and reduce heating demand.

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 down for the weekend. Daily load on Friday also shows a significant decrease in daily load relative to Monday through Thursday.[21] Figure 3.30 shows daily average use for Monday-Thursday, Friday, Saturday and Sunday. To capture this effect

[20] 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.
[21] 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.

the model includes Friday, Saturday, and Sunday indicator, or dummy, variables.[22] A similar effect is captured by a holiday indicator variable.[23]

Figure 3.30: Average Firm Sales Daily Use by Weekday



Snow depth and water heater inlet temperature are two new drivers used in the 2018 IRP daily system load model. Snow depth is a proxy for business closures and the effect is similar to a weekend or holiday. Since snow depth is often correlated with cold weather, this effect is less intuitive, but after controlling for other weather drivers additional snow depth causes more schools and businesses shut down, and has a statistically significant negative impact on load.[24] The Company uses Bull Run River water temperature as a proxy for water heater inlet temperature.[25] Colder inlet water temperature requires additional heat to warm, thus has a negative effect on load.

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 the Company's daily load. Counter to customer growth, through energy efficiency efforts and changes in customer profiles,[26] use per customer is declining. In order to account for this change over time the model includes a time trend.

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[22] Throughout this section weekday refers to a Monday through Thursday.
[23] 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.
[24] The Company initially tried to attain data on school closures, but could not find sufficient data.
[25] Portland is the Company's largest load center with data on surface water temperature readily available through the U.S. Geological Survey (USGS).
[26] For example, the addition of higher efficiency new construction homes.

6.2. INTERACTION EFFECTS

New to the 2018 IRP daily system load model, the Company incorporates interaction effects between variables, primarily temperature and other independent variables. The purpose of including interaction effect starts with recognizing that a single driver alone fails to sufficiently explain changes daily load primarily used for space heating. For example, daily load on a warm summer day with no wind will not be very different from daily load on a windy summer day. However, the impact of wind greatly increases as temperatures decrease. Table 3.8 shows the different impacts of a few of the dependent variables at 25°F and 45°F.

Table 3.8: Impact of a One Unit Change in the Driver

Driver	Temp 25°F	Temp 45°F
Previous Day Temperature (°F)	-6,986 (232)	-3,788 (136)
Wind Speed (mph)	5,865 (421)	3,578 (246)
Solar Radiation (watts/m2/day)	-15 (1)	-7 (<1)
Saturday Indicator	-37,689 (3848)	-18,178 (1235)

Note: standard error shown in parentheses.

As Table 3.8 shows, the magnitude of the impact for each driver increases as temperatures decrease. It is important to note that the magnitude of the impact across drivers should not be compared as the units for each driver are completely different.

6.3. DAILY SYSTEM LOAD MODEL DATA

The Company uses nine years of historical gas day firm sales flow data from January 2008 through January 2017. NW Natural does not collect daily data for firm sales customers. However, data is collected from over thirty gate stations, three on-system storage facilities, and daily off-take from all interruptible sales and transportation customers. Daily firm sales for the system are calculated as:

Firm Sales = On-System Flow – Interruptible Sales Customers Use – Transportation Customers Use ± Storage

Storage injections, which typically occur in the summer and shoulder months are subtracted and withdrawals are added to the total.

Hourly weather data is collected from 11 different airports within the service area and are system weighted by load area shares to get aggregated system-level measurements. Hourly averages for the gas day (7 a.m. – 7 a.m. PST) are used for daily temperature (°F) and wind speed (mph). Daily solar radiation is calculated as the sum of hourly solar radiation (watts/m2) within a gas day. Snow depth (inches) and the Bull Run River temperature (°F) are daily measurements.

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

$$System\ Firm\ Sales_t = \alpha + \sum_{\mathrm{i}=1}^{22} \beta_{it} Driver_{it} + \epsilon_t$$

Where α is a constant, βi are the estimated coefficients, t is a daily index and ε is a random error. Full results are listed in Table C.7 in Appendix C.

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 with the exception of 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.

An additional interaction is included between wind speed, temperature and the time trend. The interaction between temperature and wind is changing over time and requires an additional time interaction. This is intuitive, as building shells become tighter within the housing stock over time.27

[27] The housing stock is becoming tighter overtime, either through insulating or adding new windows to old structures or through the addition of tighter new construction buildings.

6.4. CHANGES FROM THE 2016 IRP DAILY SYSTEM LOAD MODEL

The 2018 IRP daily system load model specification has been modified from the daily system load model constructed in the 2016 IRP. Table 3.9 gives a brief summary of the changes in specification between IRPs.

Table 3.9: Change in Daily System Load Model from 2016 IRP to 2018 IRP

	2016 IRP	2018 IRP
Dependent Variable	Daily Use Per Customer (UPC)	System Load - Total Daily Flow (Dth)
Added / Dropped Drivers		Added -Snow Depth -Water Heater Inlet Water Temp Dropped -Precipitation
Interaction Terms	No Interactions	Temperature Interaction: -Previous Day Temp -Wind Speed -Solar Radiation -Friday, Saturday, Sunday, Holiday Indicators -Time Trend Temperature and Time Trend Interaction: -Wind Speed
Data	Only Cold Days Temperature < 38° Observations: 295	All Heating Days Temperature < 59° Observations: 2170

The 2016 IRP model predicted use per customer (daily system firm sales divided by the number of customers) as a function of the daily drivers or right-hand-side variables. For the 2018 IRP the Company now models daily system firm sales as the dependent variable and include the number of customers as a right-hand-side variable. Snow depth and water heater inlet water temperature are two new drivers that have been added to the model and help decrease some of the unexplained variation. Precipitation has been dropped from the model due to statistically insignificant impact on load.

Interaction effects between temperature and the other driver variables and the interaction between temperature, wind, and the time trend are also new this IRP. As mentioned in Section 6.2 these interaction terms capture the non-linear effect of the driver variables across different temperature ranges. To address this issue, the 2016 IRP modelled three different temperature ranges and focused on coefficients of the coldest range, daily average temperatures less than 38°F, to apply to the planning standard. This approach created a tradeoff in choosing the appropriate temperature cutoff for the coldest range. A colder cutoff temperature would better reflect how drivers (e.g., wind) impacts peak load demand, but inherently exclude observations used in the coldest range regression. By including the interaction between temperature and the other driver variables, the model can take advantage of more data from the full range of heating days (i.e., daily average temperatures less than 59°F) to inform the estimated coefficients.

These changes to the 2018 IRP daily system load model are relatively minor improvements compared the improvements made between the 2014 to 2016 IRP, but these changes do improve the Company's load forecast on peak. To evaluate the change in specification, the Company uses an out-of-sample prediction for days with temperature less than 30°F during the 2016-2017 heating season. Table 3.10 compares both specifications ability to predict the coldest days during the 2016–2017 heating season, when those observations are excluded from the regression.

Table 3.10: Methodology Change Evaluation

Error			**Bias**		
	2016 (%)	**2018 (%)**		**2016 (%)**	**2018 (%)**
Average Abs Error	5.95%	3.13%	Average Bias	5.21%	0.69%
Min Abs Error	0.56%	0.17%	Max Over Forecast	12.24%	8.89%
Max Abs Error	12.24%	8.89%	Max Under Forecast	-4.78 %	-6.90%

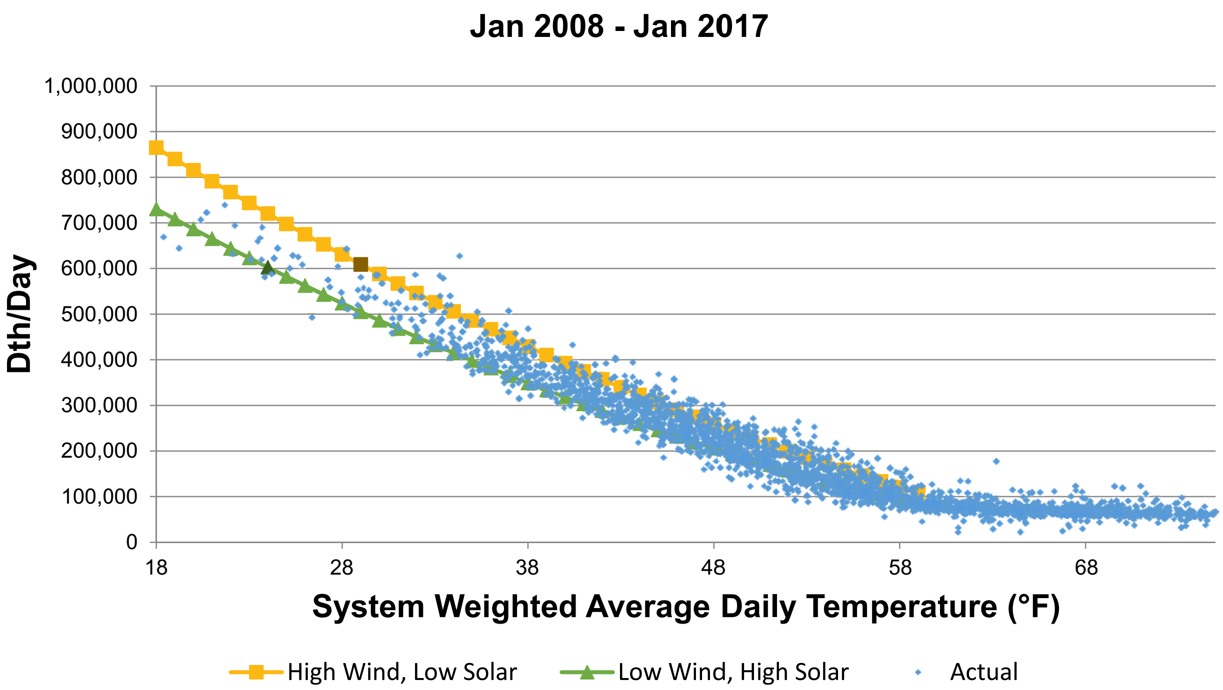
*Negative bias indicates an under forecast, Positive bias indicates an over forecast.

The 2018 specification performs slightly better, both on the average absolute value of errors, which indicates how far off is the forecast and the average bias, which indicates if the model is under or over forecasting at the coldest temperatures.

6.5. DAILY SYSTEM LOAD MODEL PREDICTED VALUES

Using the estimated coefficients (shown in Table C.7 in Appendix C) the daily system load model can predict the daily system load under different weather conditions. Figure 3.31 shows a scatter plot for weekday load across a range of temperatures. The lines show the predict values for (1) a high wind, low solar day; (2) a low wind, high solar day.

Figure 3.31: Daily Firm Sales Weekday Load and Predicted Load by Temperature



The two predicted lines (yellow and green) show how load is dependent on a combination of factors. For example, a load requirement of 600,000 dekatherms can be caused by very cold weather, but with low wind and high solar (dark green triangle). Alternatively, 600,000 dekatherms can be caused by slightly warmer weather, but is a lot windier with less solar radiation (dark yellow square). The take-away from this graph is that a combination of all these drivers causes daily load to peak. The Company has develop a new planning standard to statistically measure a peak load requirement to account for the diverse impacts of these drivers on load within the service area.

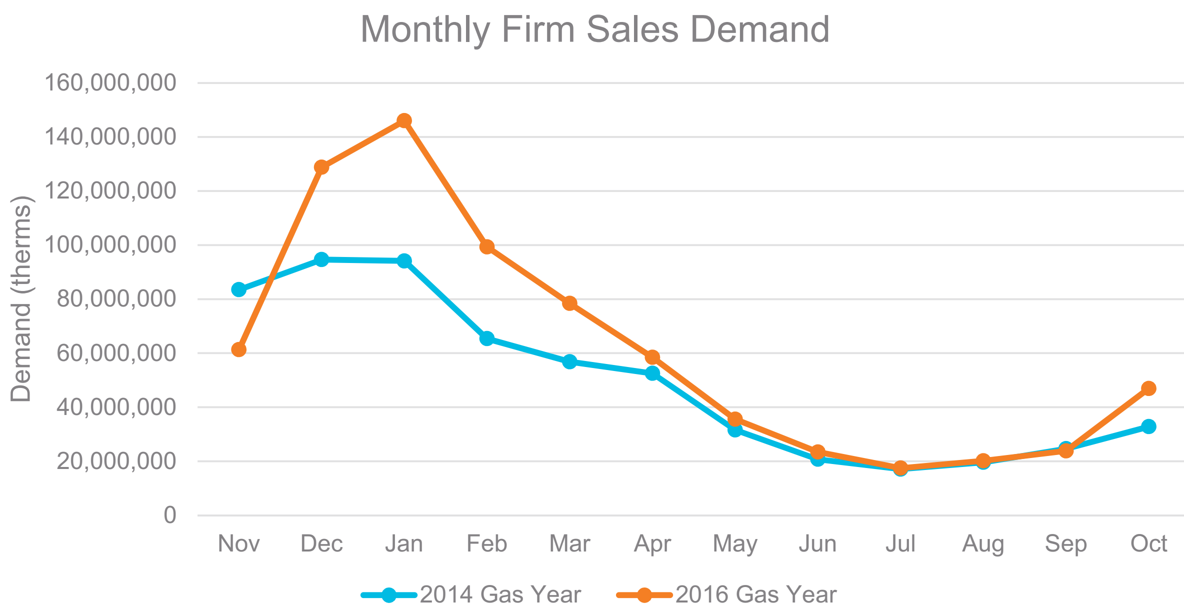
7. PLANNING STANDARD

Developing a planning standard is important for selecting the right mix of resources to cost-effectively serve customers and ensure that customers, many of whom use natural gas for heating their homes, can reliably receive service under cold weather conditions.
Supply resources are chosen to cost-effectively meet the needs for total sales demand in a year (energy) and a maximum firm sales demand (capacity). The planning standard defines how NW Natural addresses these two needs.

7.1. ENERGY PLANNING STANDARD

Energy is the total volume and seasonal pattern of gas delivered throughout a full year. Figure 3.32 shows natural gas usage is highly seasonal and very weather-dependent due to the needs for space heating in cold months.

Figure 3.32: Seasonality and Annual Variability in Natural Gas Demand



For the energy planning standard, the Company selects the actual weather taken from the approximate 10th percentile of historical winter average temperatures and the actual weather from the 50th percentile historical summer average temperatures.

The 10th percentile of winter average temperature is chosen instead of the 50th percentile in order to have an adequate volume of on- and off-system seasonal storage for the heating season. NW Natural relies heavily on seasonal storage resources to serve winter sales demand. Seasonal storage allows the Company to use excess non-heating season pipeline capacity to fill the storage resources with generally lower priced gas which will be delivered during the heating season. NW Natural does not need to contract for as much firm pipeline capacity to serve winter demand which keeps the utilization of the pipeline high and total costs for customer lower. However, storage resources have a fixed volume that can be delivered and each storage resource has a deliverability profile which changes depending on how full the resource is when withdrawing gas.28 For this reason NW Natural uses a colder than average winter to plan resource acquisition.

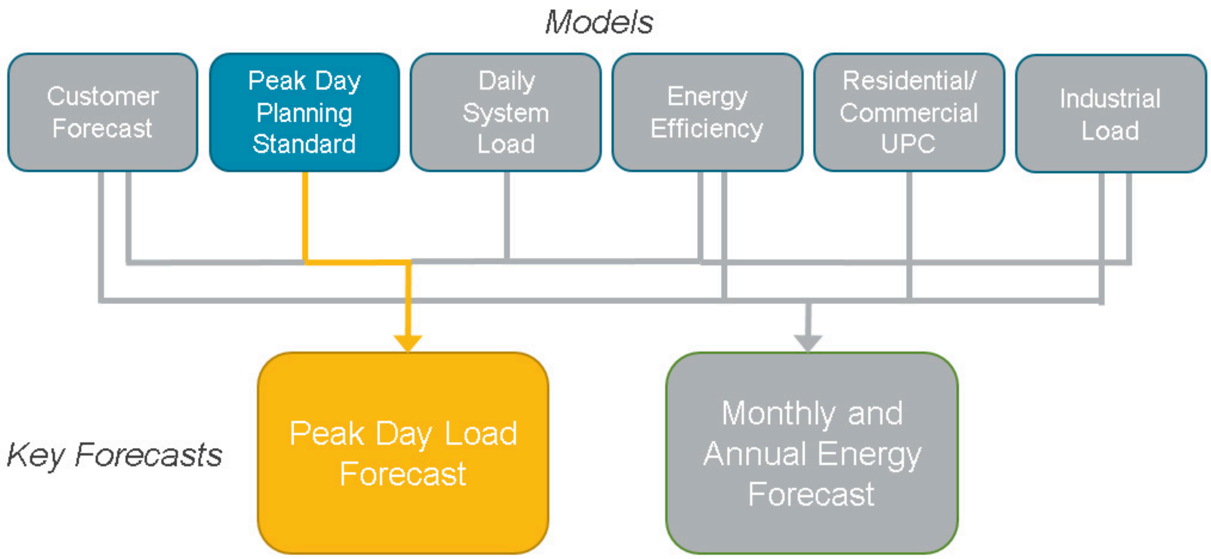
7.2. CAPACITY PLANNING STANDARD

Capacity is the daily maximum volume of gas that the system can deliver to customers. For several IRPs the Company has incrementally updated its methodology for planning capacity needs. Those changes have been focused on improving the accuracy of demand forecasts under various weather conditions and those accuracy improvements continue in this IRP (see Section 6.4). In addition to demand forecast accuracy improvements the Company is changing

[28] For example, the Jackson Prairie underground storage facility's maximum daily deliverability declines by 2 percent for each 1 percent of available total storage capacity under 60 percent of maximum storage capacity.

how a peak planning day is defined. Previous IRPs used a standard based on reviewing a rolling 30 years of history and selecting the actual conditions which would produce the highest estimated daily demand. For this IRP NW Natural has moved to a statistical approach where it plans to serve the highest firm sales demand day in each gas year with 99 percent certainty (see Figure 3.33).

Figure 3.33: Demand Forecast Process – Peak Day Planning Standard

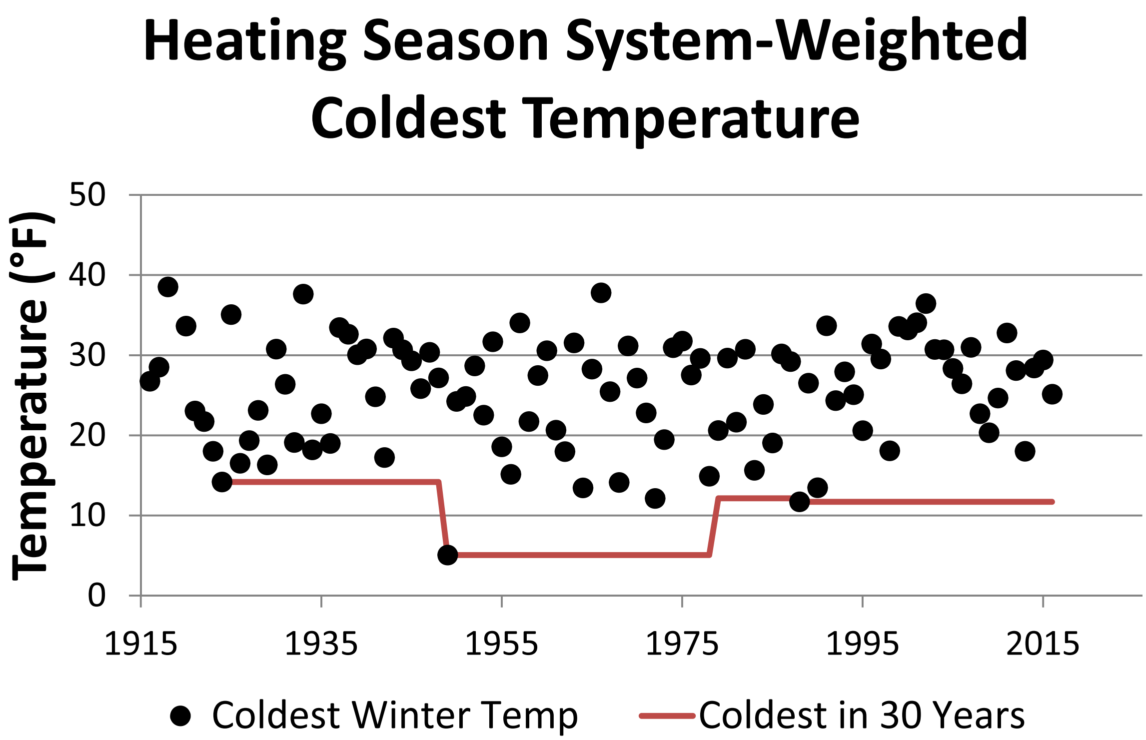


In reviewing the capacity planning standard the Company identified two related issues with the definition of a peak day which needed to be addressed.

1) The peak day could change dramatically if the system experiences a more extreme weather event than anything in the previous 30 years or if 30 years pass without experiencing a weather event as extreme.
2) The most extreme weather event in the previous 30 years is not equivalent to a weather event with a 1-in-30 probability of occurring.

While the Company's capacity planning standard considers many weather and non-weather variables, the temperature variable will be used to illustrate the issues. The first issue is apparent when looking at a long history of weather events. Figure 3.34 shows the lowest observed system-weighted average daily temperature for each gas year over a 100 year period. If the Company capacity planning standard was only based on temperature, the red line would represent the temperature value selected in a rolling 1-in-30 year capacity planning standard. In 1949 the planning temperature value would have dropped from approximately 14°F to 5°F. This would have translated into a massive need for more system capacity. Subsequent to the 5°F day in 1949, 30 years pass without experiencing a day as with the same or lower temperature. In 1979 the temperature standard would have moved from 5°F to 12°F. At that point in time the Company would have had a large excess of capacity and would likely need to plan to drop a significant amount of resources. This instability in planning is not good for customers or the Company.

Figure 3.34: Changes in the coldest-in-30 year temperature

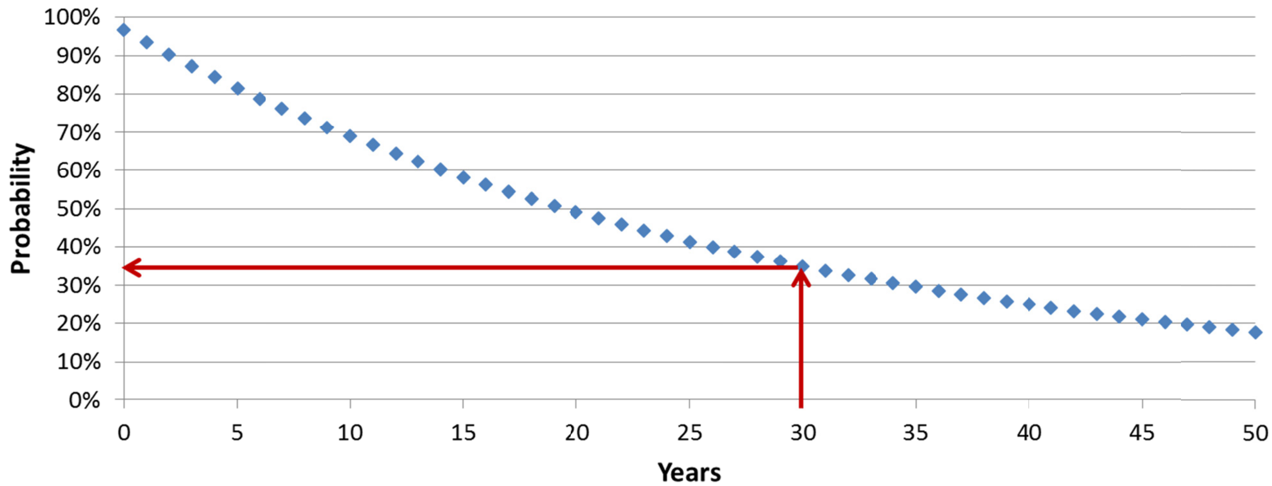


A second problem arises when using a capacity planning standard based on looking at the "coldest-in-X years." It is preferable to think about capacity planning in terms of the probability that the capacity is insufficient to serve load. Without modeling the historical weather it is not possible to know the expected probability of a certain event happening. In other words, the coldest observed temperature in the last 30 years is not equivalent to saying that the observed temperature had a 1-in-30 probability of occurring.

As an example, consider we know the distribution of coldest temperatures and that it is independent of other factors and we calculate the temperature at the 3.3333rd percentile to be 15°F. We can say that there is a 3.3333 percent probability (1-in-30) that a newly observed temperature will be 15°F or lower. If we continuously draw temperatures from this distribution and observe if they are either above or below 15°F, then we can model the time before observing a single temperature that is at or below 15°F as a negative binomial distribution or NB(r,p) where r=1 for the number of times a single temperature is below 15°F and p=0.9666 for the probability that the temperature is above 15°F. The expected time before observing a temperature at or below 15°F is calculated as $p/(1-p)$ = 29. In other words we would expect that we would observe 29 temperatures above 15°F before a single observation at or below 15°F. However, this is the expected, or average, time and we should expect significant variability in the actual time between events. This can be seen in Figure 3.35, where the horizontal axis value is the number of years between events and the vertical axis is the probability that at least X years pass before observing a value less than or equal to 15°F. Figure

3.30 shows that there is approximately a 35 percent probability that at least 30 observation pass before we have a temperature at least as low as 15°F.

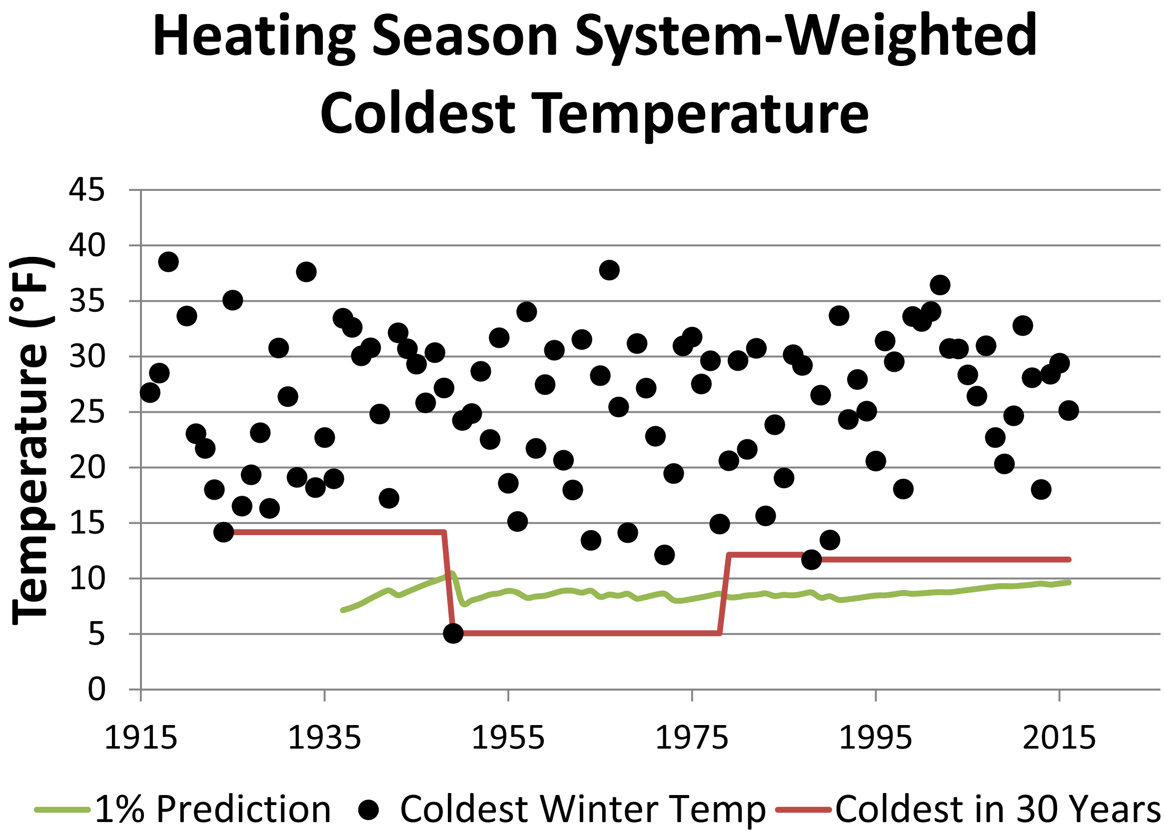
Figure 3.35: Probability of at least X years between 1-in-30 events



This statistical example shows that if planning is restricted to selecting extreme values within a certain timeframe, the actual risk of the selection cannot be ascertained. The coldest temperature in a 30 year period may in fact have a relatively high likelihood of being met or exceeded and NW Natural's customers will incur more risk than they would like.
In order to resolve the issues noted above the Company has created a new capacity planning standard methodology which creates a distribution of the highest demand day in a gas year. Based on this distribution the Company will plan to meet the highest firm sales demand in a given year with 99 percent certainty.

Figure 3.36 shows an example of how this change in methodology will produce a capacity planning standard which is relatively immune to large shifts
The distribution of the highest firm sales demand day in a year is created through a Monte Carlo simulation of the driver variables from the Company's daily firm sales demand forecast model. As an additional consideration the simulation considers the forecast error inherent in the daily forecast model.

Figure 3.36: Relative stability of a risk-based planning standard



In order to meet the highest firm sales demand day in a given year with 99 percent certainty, NW Natural must hold the resources capable of meeting the standard. Because the Company uses the assumption that supply resources are always available, the capacity planning standard is equivalent to the 99th percentile of the highest firm sales demand day in a year. If the Company assumed that supply resources were not always available then the capacity planning standard would be greater than the 99th percentile of highest firm sales demand in a given year because additional resources would be required to account for less than 100 percent availability of supply resources.

A Monte Carlo simulation of the highest firm sales demand day for each heating season produces a distribution of potential highest firm sales demand and is used to estimate the 99th percentile. Each draw of the simulation selects from a distribution of each of the variables used in the daily system model as described above. After the variables are entered into the daily system model the final demand is selected from the distribution around the expected demand based on the model forecast error.

Table 3.11: Variables used in highest heating season demand day

Item Number	Variable	Description
1	Lowest heating season temperature	The system-weighted lowest average daily temperature for the heating season. The distribution is based on 100 years of history.
2	Previous day temperature differential	The difference between (1) and the previous day temperature. Modeled as a function of (1) using a 100 year history.
3	Wind speed	System-weighted average daily wind speed. Modeled as a function of temperature using a 35 year history.
4	Solar radiation	System-weighted average daily solar radiation. Modeled as a function of temperature and month.
5	Water heater inlet temperature	Modeled as a normal distribution around a monthly mean.
6	Snow depth	Modeled as a function of temperature and the probability of non-zero snow depth.
7	Month	Discrete probability of the month containing the (1) based on 100 year history.
8	Day of week	Discrete probability of the day of the week (M-Th/Fri/Sat/Sun)
9	Customer count	Distribution taken from econometric model (see above)
10	Daily forecast error	Error distribution of daily firm sales load from econometric model (see above)

8. PEAK DAY LOAD FORECAST

The peak day load forecast incorporates the customer forecast, the industrial load forecast, energy efficiency forecast, the daily system load model and the peak day planning standard. The combination of these models results in a 20 year forecast of the daily resource requirement needed to meet demand on a peak day (see Figure 3.37).29

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

Figure 3.37 Demand Forecast Process – Peak Day Load Forecast

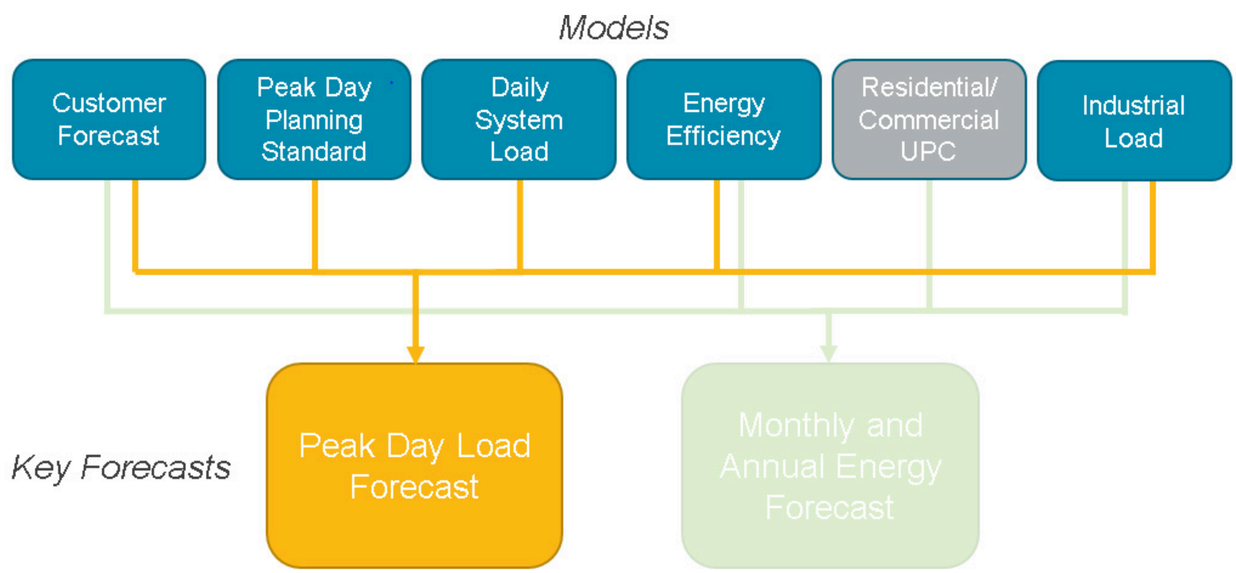
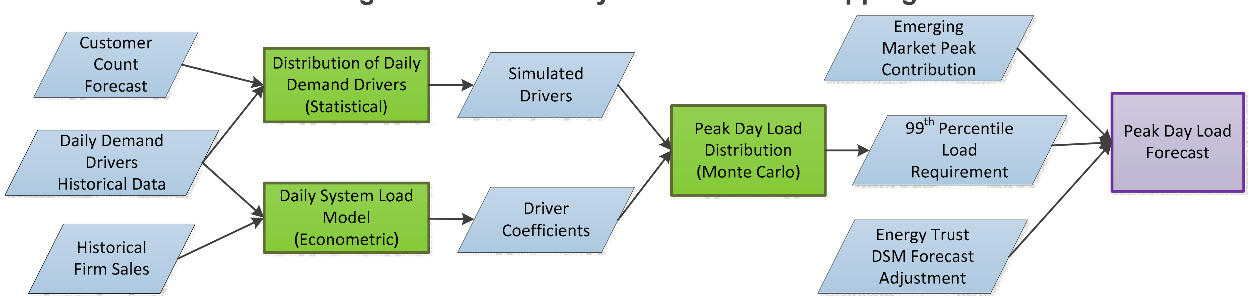


Figure 3.38 lays out the process to forecasting a peak day load requirement over the planning horizon.

Figure 3.38: Peak Day Load Forecast Mapping

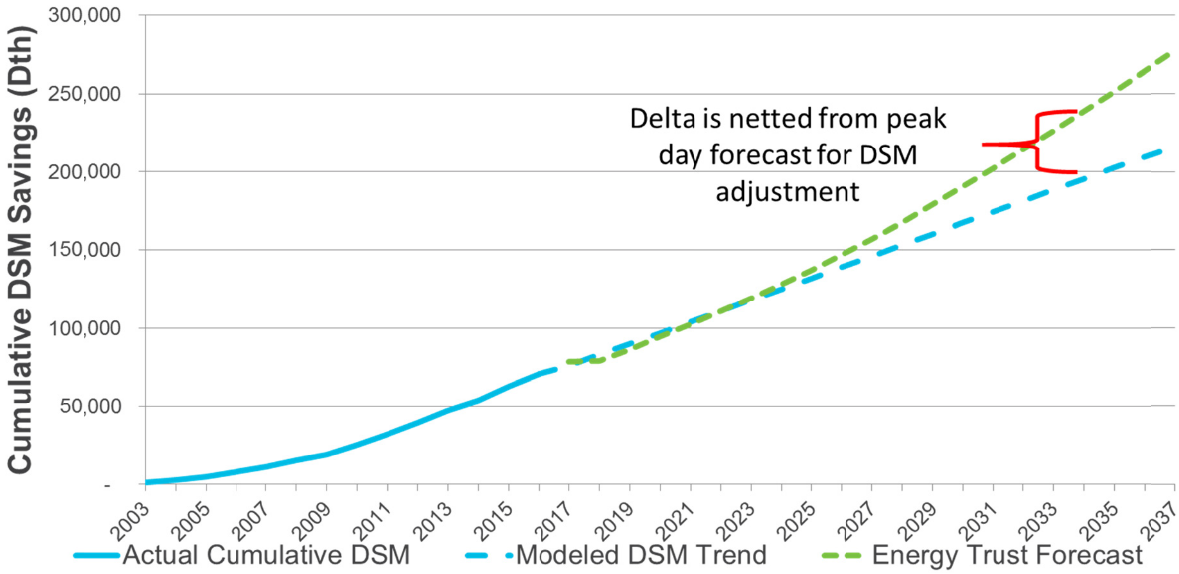


There are two adjustments to the 99th percentile load requirement before the peak day load forecast is finalized. Both adjustments are necessary due to a divergence from the historical data and trends modeled through the rest of the process. First, an adjustment is made for the additional demand on peak from emerging markets. Currently this consists of the Company's expected firm sales demand from growth in the CNG sector. Expected demand growth from CNG is small30 and the firm sales share of that growth is even less. Additionally, CNG load is modeled as flat (i.e., does not vary with weather) and therefore, has a minuscule impact to the peak day load forecast.31

[30] Refer to section 4.2 of this chapter.
[31] In the base case CNG comprises 0.07 percent of peak load by 2037.

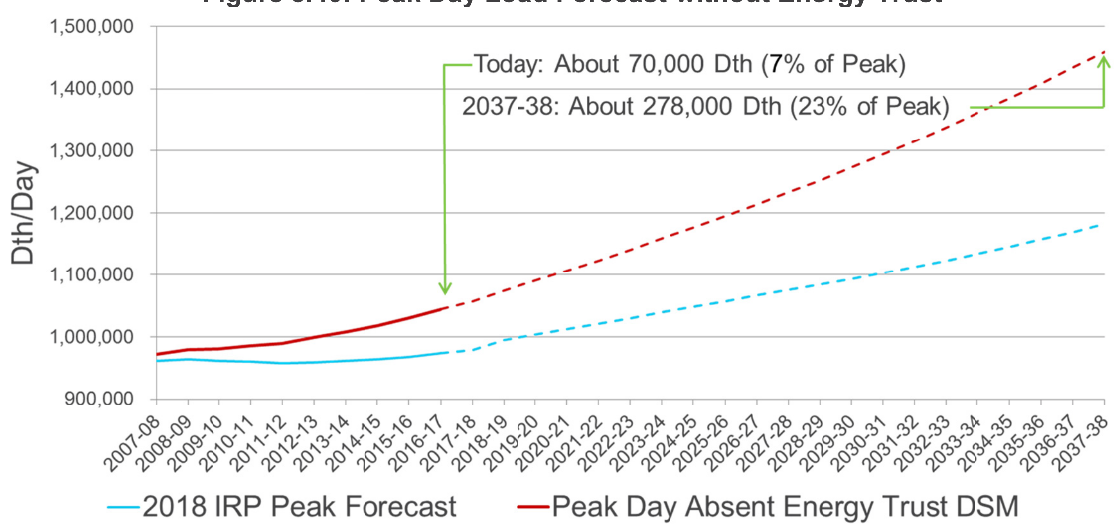
The 99th percentile load requirement includes a time trend capturing trends in the data, part of which is driven by past DSM. The second adjustment incorporates Energy Trust's DSM forecast of energy savings and the delta between the existing trend and Energy Trust's forecast. Figure 3.39 shows this delta. Please see Chapter 4 for a detailed discussion on demand-side resources.

Figure 3.39: DSM Peak Day Savings Trend and Forecast



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 space heating. Figure 3.40 shows the peak day forecast absent any DSM programs.

Figure 3.40: Peak Day Load Forecast without Energy Trust



By 2037, DSM programs will reduced peak day load by about 278,000 Dth or 23 percent or peak load. This roughly the capacity equivalent of two Gasco LNG facilities.

Compared to the 2016 IRP peak day forecast has decreased by 3 percent by 2035 as shown in Figure 3.41.

Figure 3.41: Peak Day Comparison 2016 IRP to 2018 IRP

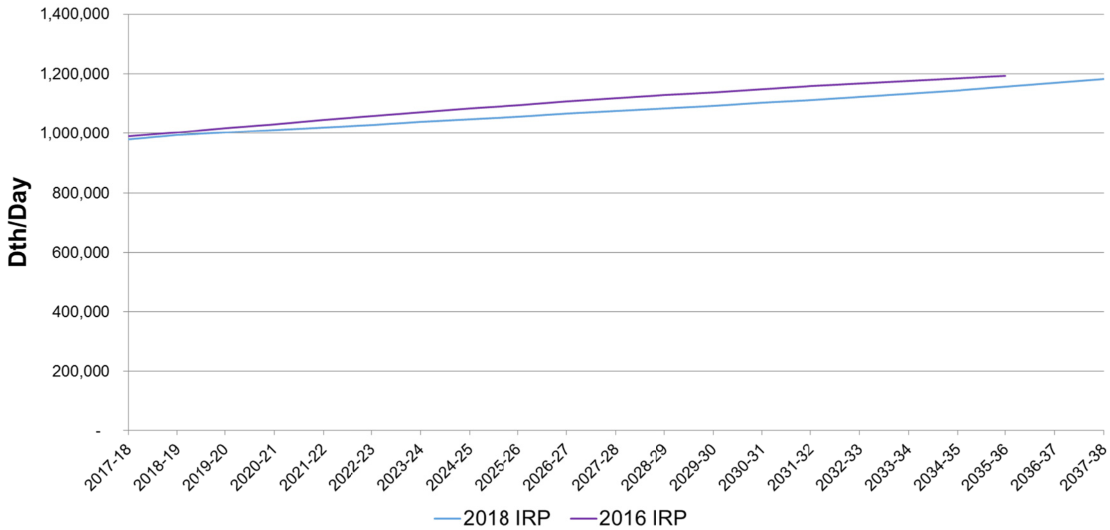
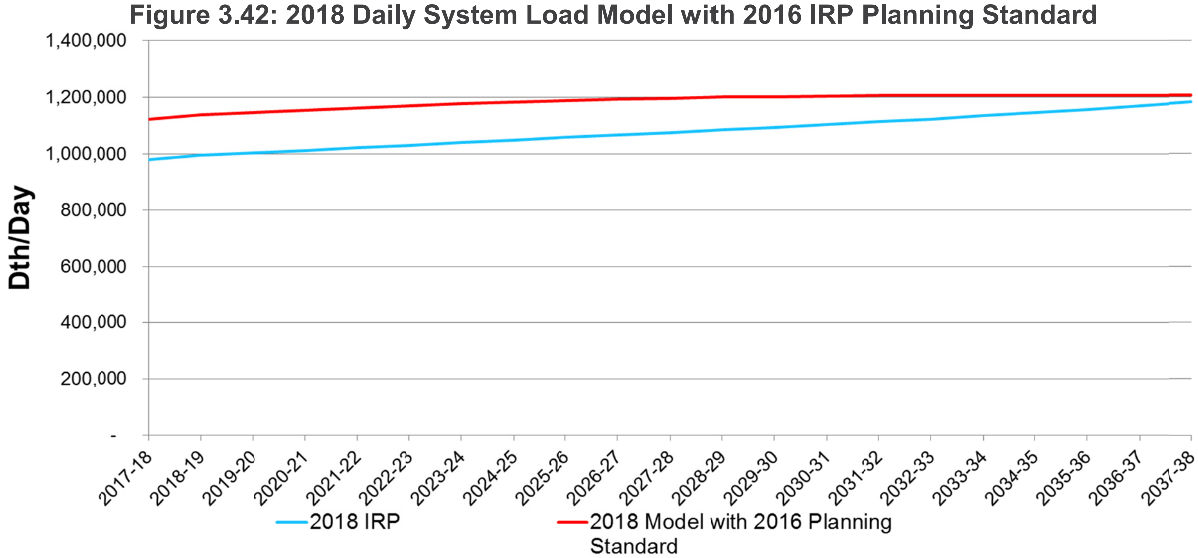


Figure 3.42 compares the 2018 IRP forecast with what the forecast would have been using the 2016 IRP planning standard with the 2018 daily system load model.

Figure 3.42: 2018 Daily System Load Model with 2016 IRP Planning Standard



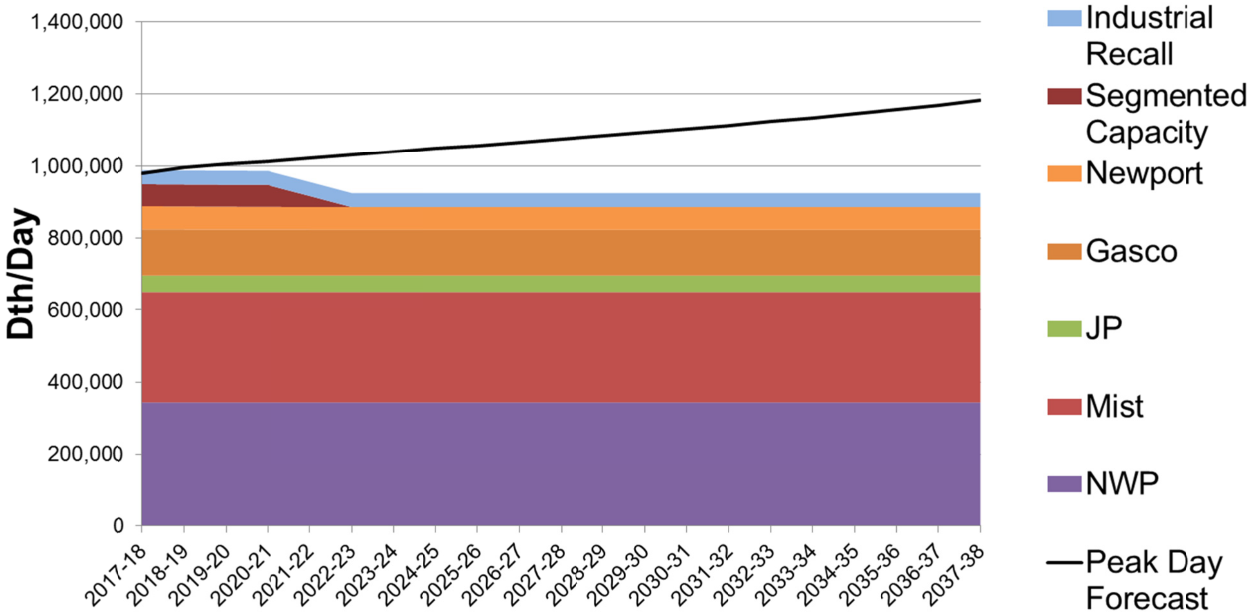
Using the 2016 IRP planning standard produces a forecast equivalent to the 99.7 percentile of the 2018 peak load distribution in the first year of the planning horizon. This suggests that the weather on the February 3, 1989 was an extreme weather event.

Summary

The peak day forecast and the annual energy forecast are the culmination of six separate models, shown by Figure 3.1 at the beginning of this chapter. Both forecasts are important in the Company's integrated resources planning, but the peak day forecast is the real crux of acquiring resources (both demand-side and supply-side) in order to deliver gas to all of

NW Natural's firm sales customers under peak conditions. Figure 3.43 shows the peak day forecast over-laid the Company's current supply resources.

Figure 3.43: Supply Resource Stack and Peak Day Forecast



Integrated resource planning takes a holistic analysis to plan for the least cost and least risk resources. Fundamentally, the IRP seeks to identify and remediate and shortfall between NW Natural's current resource stack and the peak day forecast as a necessary condition for resource planning.32 The menu of potential resources are discussed in Chapters 5 and 6 and the selected portfolios are discussed in Chapter 7.

[32] Having adequate resources to meet peak day requirements is a necessary, but not sufficient condition as the total deliverability from supply resources may exceed the peak day forecast. The necessity to exceed the peak day forecast may result from a resource: (1) being needed to meet total energy requirements; (2) becoming cost effective based on commodity costs; (3) provides a location specific benefit; or (4) is a "lumpy" resource that when needed can only be taken in capacity increments greater than the capacity need.

CHAPTER 4

AVOIDED COSTS

KEY TAKEAWAYS

- NW Natural calculates five (and uses 6) separate avoided cost components that are estimated and presented separately rather than aggregated and provided as a total avoided cost figure
- The separate components of avoided cost are applied to each demand- and supply-side resource option considered in the 2018 IRP based upon the costs those resources actually avoid
- A more detailed estimate of distribution system costs avoided with peak hour gas energy savings or supply has been made to further the work NW Natural has done in previous IRPs to fully value the infrastructure costs avoided via energy savings or energy supply during peak periods
- For energy efficiency measures, avoided costs have been calculated for 3 new end uses to add to the 4 end uses from the 2016 IRP
- Avoided cost estimates for most end uses for energy efficiency have increased since the 2016 IRP, due primarily to higher expected emissions compliance costs and the more detailed distribution system infrastructure methodology new to the 2018 IRP
- Avoided costs are being applied to low carbon gas supply resources (renewable natural gas and power-to-gas) for the first time as part of the more robust analysis conducted relative to those resources in the 2018 IRP

1. OVERVIEW

As part of the IRP process, NW Natural calculates a 20-year forecast of avoided costs. 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 was not demanded, due to efforts such as energy efficiency (EE), 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 manner that is expected to be the most cost-effective to meet customer needs is implemented. Practically, the avoided cost forecast is a key component of the cost-effectiveness test that is conducted by Energy Trust of Oregon (Energy Trust) to determine the DSM savings projection detailed in Chapter 5.

Chapter 4 details the methodology used to calculate each component of NW Natural's avoided costs. It also describes how the methodology has evolved with a focus on better accounting for how energy savings on peak help avoid or delay investments in supply capacity as well as distribution system capacity resources. The methodology used by NW Natural to calculate its avoided cost forecast has seen continued improvement since the 2014 IRP, and the Company is working with Energy Trust in order to make additional improvements implementable within the broader distribution planning and IRP processes. For the 2018 IRP, three key methodological improvements were made to NW Natural's avoided costs:

- A more detailed estimate of avoided distribution system infrastructure costs has been made via new calculations of (i) the cost of serving additional peak hour load and (ii) the contribution of different end uses to the peak hour load that NW Natural plans its distribution system infrastructure to serve
- The avoided costs of three additional end uses – (i) residential hearths and fireplaces, (ii) domestic water heating, and (iii) cooking[1] have been disaggregated and added to the four end uses from the 2016 IRP (residential space heating, commercial space heating, base load, and interruptible load) for energy efficiency cost-effectiveness evaluations
- Avoided costs have been applied to 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

This chapter also presents the avoided costs results for the demand side and supply side resources to which the concept is applied. NW Natural continues to work to improve it 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.

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 avoided costs components' values depending vary by end use or supply resource and indicates that the natural gas purchase and transport costs avoided and distribution system infrastructure costs avoided have seen methodological changes from the 2016 IRP[2]:

[1] Residential hearths and fireplaces were assigned the residential space heating end use avoided costs and domestic water heating and cooking were assigned the base load avoided costs in the 2016 IRP

[2] Note that while many of the components are estimated using the same methodology as the 2016 IRP, they have updated assumptions that results in the values being different in the 2018 IRP

Table 4.1 Avoided Costs Components and Application Summary

Components		Calculation Characteristics		Resource Option Application					
				Demand-Side Resources			Supply-Side Resources		
					Demand Response		Low-Carbon Gas Supply		
		Varies by Load or Supply Shape?	Methodology Change from 2016 IRP?	Energy Efficiency	Interruptible Schedules	Other DR	On-System Resources	Off-System Resources	Recall Agreements
Commodity Related Avoided Costs	Natural Gas Purchase and Transport Costs	Yes	Yes	√			√	√	
	Greenhouse Gas Compliance Costs	No	No	√			√	√	
	Commodity Price Risk Reduction Value	No	No	√			√	√	
Infrastructure Related Avoided Costs	Supply Capacity Costs	Yes	No	√	√	√	√		√
	Distribution System Costs	Yes	Yes	√	√	√	√		
Unquantified Conservation Costs	10% Northwest Power & Conservation Council Credit	Yes	No	√			?	?	

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.[3] For example, it is irrelevant from a GHG emissions compliance cost perspective whether the emissions occur during a peak period or any other time of the year.

Gas and Transport Costs:

This component represents the cost of the natural gas commodity itself. The main driver of these costs is the base case natural gas price forecast detailed in Chapter Two, 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,[4] where that unit may be from an expected daily spot purchase 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 SENDOUT® optimization model and is aggregated to the monthly level. In previous IRPs avoided commodity and transport costs varied through time but were constant across end uses, whereas in this IRP each end use has its own estimate based upon 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 D.

[3] 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
[4] Which by cost minimization protocols is the most expensive unit of gas purchased that day

Greenhouse Gas Emissions Compliance Costs:

NW Natural explicitly includes environmental incremental policy compliance costs in its portfolio modeling assumptions (in addition to the current policies embedded in the gas price forecasts provided by a third party consultant): a base case expectation, medium and high sensitivities, and the Social Cost of Carbon (SCC), outlined in detail in Chapter 2. Each potential compliance cost path generates a different avoided cost scenario, and is specific to each state in NW Natural's territory.

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

While the "cost to achieve natural gas price certainty" is a more accurate representation of this component of avoided costs, the name has been kept for convention and recognition from the Oregon PUC process that led to its inclusion in the 2016 IRP.[5] 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 energy efficiency, 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 the 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 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.[6] Practically, when the hedge value of DSM is added to the gas and transport costs it represents the fixed price of gas that could be obtained through financial hedging instruments and replaces the spot price forecast as the price of gas for evaluating demand-side resources. The same hedge value is applied in both states and to all end uses, and is the least significant component of avoided costs. In the current natural gas market, dynamics are such that long-term hedges can be procured at a price that is lower than forecasted spot prices over the hedge period. However, when market forces lead to a calculated hedge value that is negative a value of zero is assigned.

2.2. 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. In order to estimate infrastructure costs avoided for any resource there are two pieces that need to be calculated:

[5] See OPUC docket No. UM 1622.
[6] Inclusive of the costs of assessing and managing counterparty risk of financial hedging.

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 Energy Trust programs come from large industrial customers, though many of these customers elect to be on interruptible schedules.[7] These customers are interrupted during peak events and do not contribute to peak load or the infrastructure designed to serve it as a result. Therefore, savings acquired for interruptible customers avoid commodity related 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 the savings they provide on 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 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, but 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.

Supply Capacity Costs:

NW Natural's methodology for estimating supply capacity costs has not changed since the last IRP, though it has been applied to the new end uses considered for energy efficiency and the on-system supply resources discussed in Chapter Six.

Estimating the incremental infrastructure costs of serving peak day load:

Given the longstanding process of coordination between NW Natural and Energy Trust (see Figure 4.2 for a visual depiction of this coordination) the DSM savings projection provided by Energy Trust is 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 in order to assign a cost for the supply

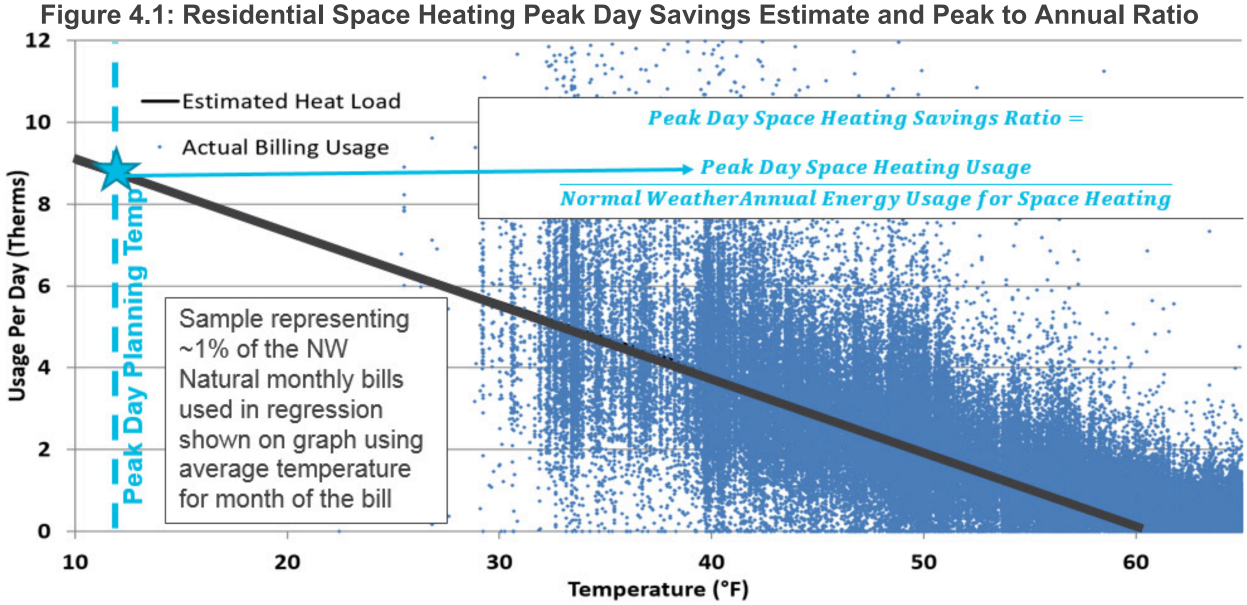
[7] Note that interruptible customers pay a lower rate than firm customers, with the difference in rate being the estimated infrastructure costs that are saved by interrupting customers during peak events

capacity costs being avoided. While 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 Seven.[8] For supply-side resources, the supply capacity costs avoided are determined within the resource planning optimization.

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 customers who use natural gas to heat their homes.[9] While there is much variation in usage due to differences in customer equipment efficiency, behavior, and home type, size, and relative shell efficiency, the average NW Natural residential customers' 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), on average residential customers 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 Energy Trust's annual savings estimated from 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.

8 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.

9 Note that if a thermostat is set to a fixed temperature and the efficiency of the customers' 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

Similarly, the peak day to annual usage ratios were calculated for all the end uses considered. These ratios are shown in Table 4.2.

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)	**0.0176**	NW Natural Regressions
Commercial Space Heating	**0.0157**	NW Natural Regressions
Water Heating	**0.0033**	NW Natural Regressions and NEAA Water Heater Study
Cooking	**0.0036**	Analysis of ODOE RECS data
Process Load	**0.0027**	Annual/365

Distribution Capacity Costs:

The same general process undertaken for supply resource capacity costs avoided is also completed with regard to 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.

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

This state-specific calculation relies upon historical information about the costs to reinforce the distribution system and It is based upon an average of the revenue requirement of projects that were completed over the previous five years to reinforce the distribution system. Note that these costs do not include the costs associated with installing new services or meters, operation and maintenance costs, or any costs associated commodity purchases or our supply capacity resouces, they represent only the revenue requirement of the deprication 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 Eight. 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 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 is new to the 2018 IRP.

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 a the 7am hour on the peak day, this is done by estimating the share of peak day savings/supply that will occur during the 7am hour of a peak day 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 (7am) 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 sytem hourly flow regressions and the Electric Power Research Institute (EPRI) residential peak space heating load shape) that were averaged to calculatre the hourly to daily peak hour factor for residential space heating. Using NW Natural's hourly load forecasting methodology described in Chapter Eight, 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 percent.[10] 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 0.102 percent 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 are 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	0.00102	NWN System Hourly Flows & EPRI Load Shape
Hearths and Fireplaces	0.00051	EPRI Load Shape
Commercial Space Heating	0.00123	NWN System Hourly Flows & EPRI Load Shapes
Water Heating	0.00026	NWN System Hourly Flows & Ecotope water heating study and
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.

2.3. UNQUANTIFIED CONSERVATION AVOIDED COSTS

Ten Percent Northwest Power and Conservation Council Conservation Credit:

Since a number of the components of avoided costs vary by state, year and end use, even though the 10 percent conservation credit is applied to consistently it results in a different number across these factors.This adder is applied to all but the hedge value of DSM and the expected emmissions compliance cost components.

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

3. DEMAND-SIDE APPLICATIONS OF AVOIDED COSTS

3.1. SUMMARY

Figure 4.1 details how avoided costs and demand-side management (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 Energy Trust. Note that estimating the infrastructure (capacity) costs that can be avoided with energy conservation complicates the general process of obtaining the DSM savings projections from Energy Trust. This complexity arises because in the process the DSM savings projection has to be made before supply-side resource choice modeling, meaning that assumptions about what supply-side capacity resources will be chosen from the resource choice optimization need to be made before that process has begun in order to complete the cost-effectiveness test and complete the IRP process. The work done by Energy Trust is the primary subject of Chapter Five.

Figure 4.1: IRP DSM Process, Current and Aspirational

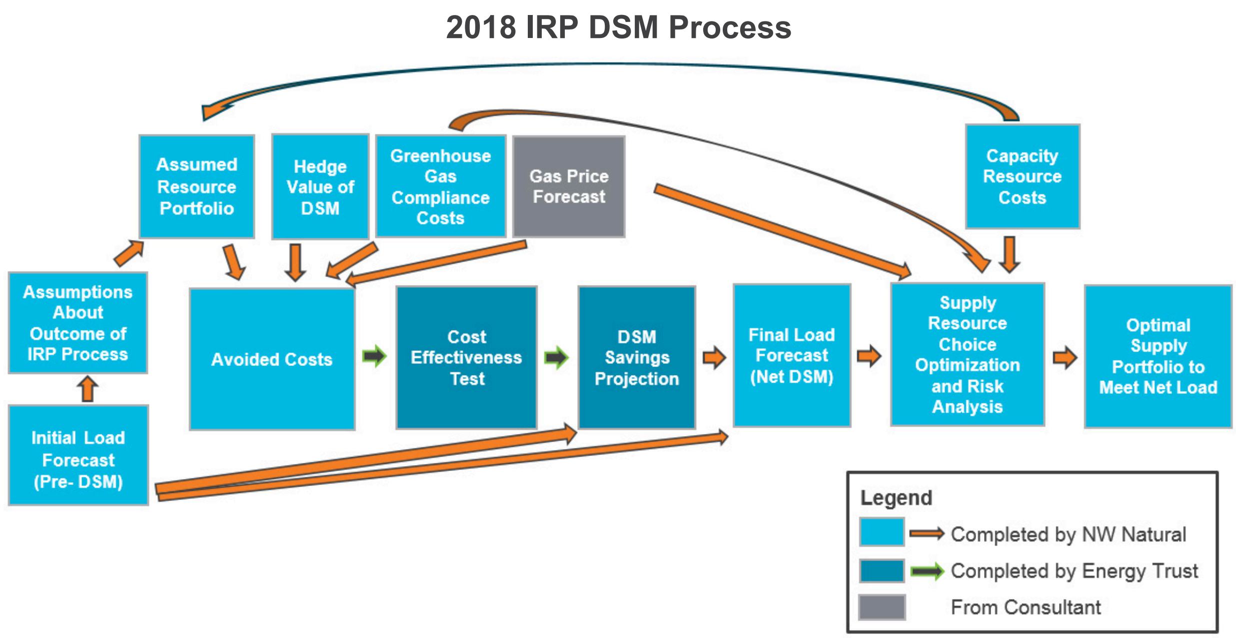


Table 4.4, and Figures 4.2 (Oregon) and 4.3 (Washington) summarize the breakdown of avoided costs by state and across end uses and notes how the figures have changed since the 2016 IRP. Note that seven streams of avoided costs were provided by NW Natural to Energy Trust for each state for their cost-effectiveness evaluation process. The figures are presented in levelized terms to provide a more succinct summary of the results, though this disguises how the avoided cost figures change through time, which is an important consideration, given that different DSM measures have very different expected lives. This detail is provided in Appendix D.

Table 4.4: Avoided Cost Summary Results by End Use and State

20 Year Levelized Avoided Costs (2017$/Dth)								
		Commodity Related Costs Avoided			Infrastructure Related Costs Avoided (Capacity Deferral)		Conservation Adder	Total Avoided Costs
		Natural Gas and Transport Costs	Greenhouse Gas Compliance Costs	Commodity Risk Reduction Costs (Hedge Value)	Supply Resources	Distribution System Resources	10% Power Council Credit	
Oregon	Residential Space Heating	$3.49*			$1.37	$2.27***	$0.56	$8.92***
	Residential Hearths and	$3.49*			$1.37	$1.14**	$0.44	$7.68***
	Commercial Space Heating	$3.49*			$1.23	$2.74***	$0.60	$9.28***
	Water Heating	$3.31	$1.23**	$0	$0.26	$0.58**	$0.39	$5.77***
	Cooking	$3.29			$0.28	$1.58***	$0.49	$6.87***
	Process Load	$3.29			$0.21	$0.25*	$0.35	$5.34**
	Interruptible Loads	$3.29			X	X	$0.33	$4.87*
Washington	Residential Space Heating	$3.49*			$1.33	$4.09***	$0.73*	$10.99***
	Residential Hearths and	$3.49*			$1.33	$2.06***	$0.53	$8.76***
	Commercial Space Heating	$3.49*			$1.19	$4.93***	$0.82*	$11.78***
	Water Heating	$3.31	$1.36*	$0	$0.25	$1.04**	$0.43	$6.41***
	Cooking	$3.29			$0.27	$2.85***	$0.61*	$8.38***
	Process Load	$3.29			$0.21	$0.46*	$0.37	$5.68**
	Interruptible Loads	$3.29			X	X	$0.33	$4.99*

Stars notate change from 2016 IRP where no star = change less than $0.15/Dth, * = increase between $0.15 and $0.50/Dth, ** = increase between $0.50 and $1/Dth; *** = increase > $1/Dth

Figure 4.2: Oregon 20-year Levelized Avoided Costs by End Use

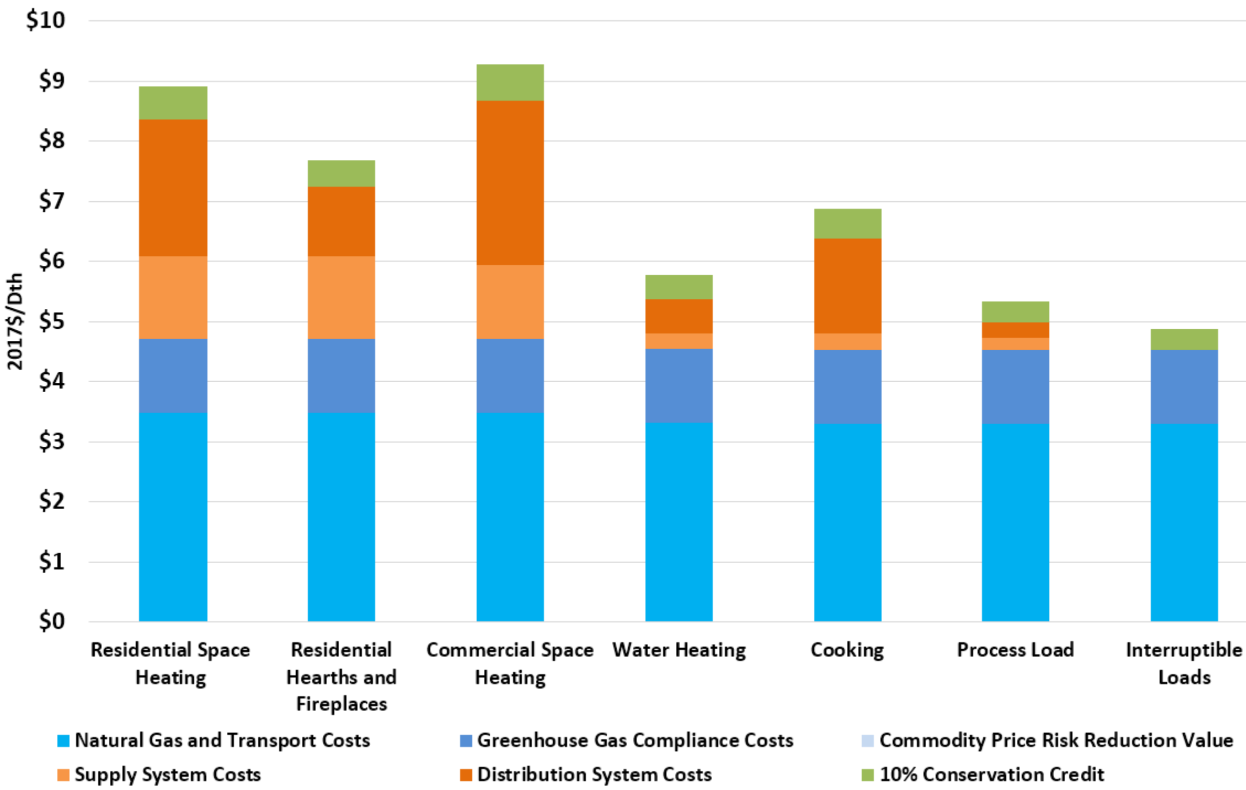
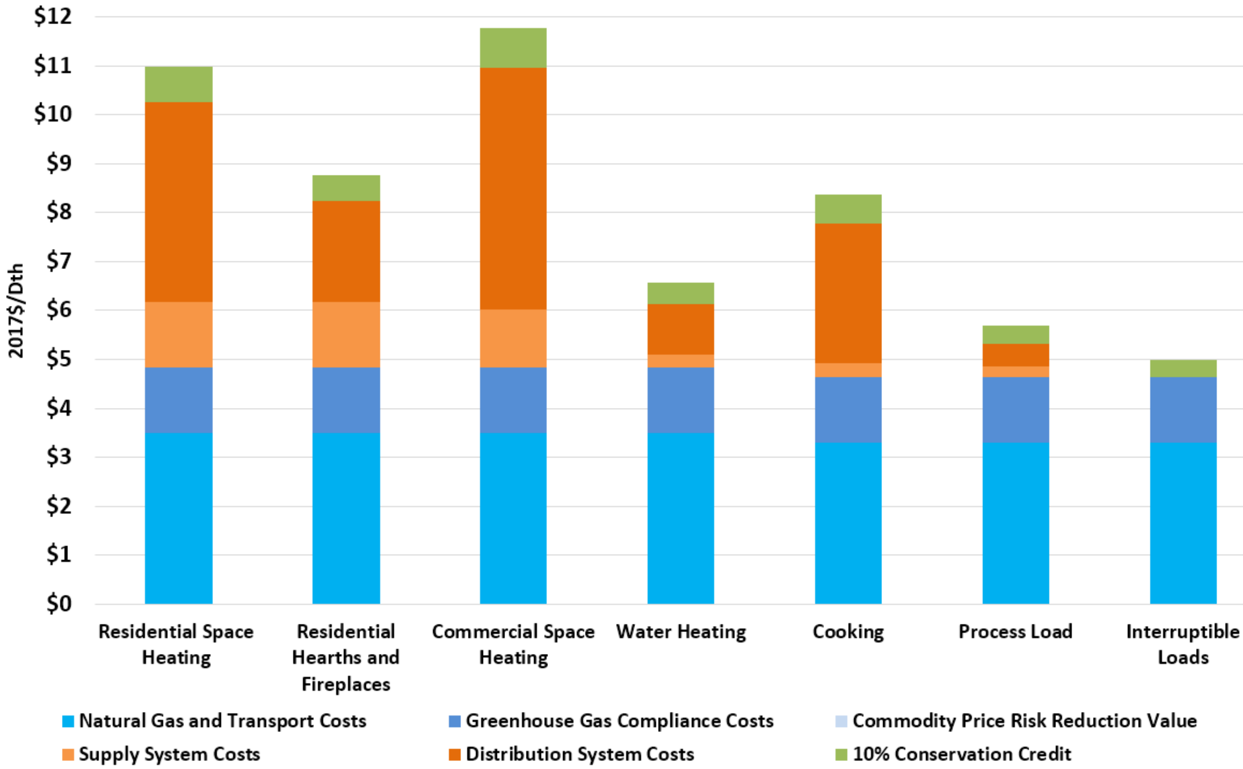


Figure 4.3: Washington 20-year Levelized Avoided Costs by End Use



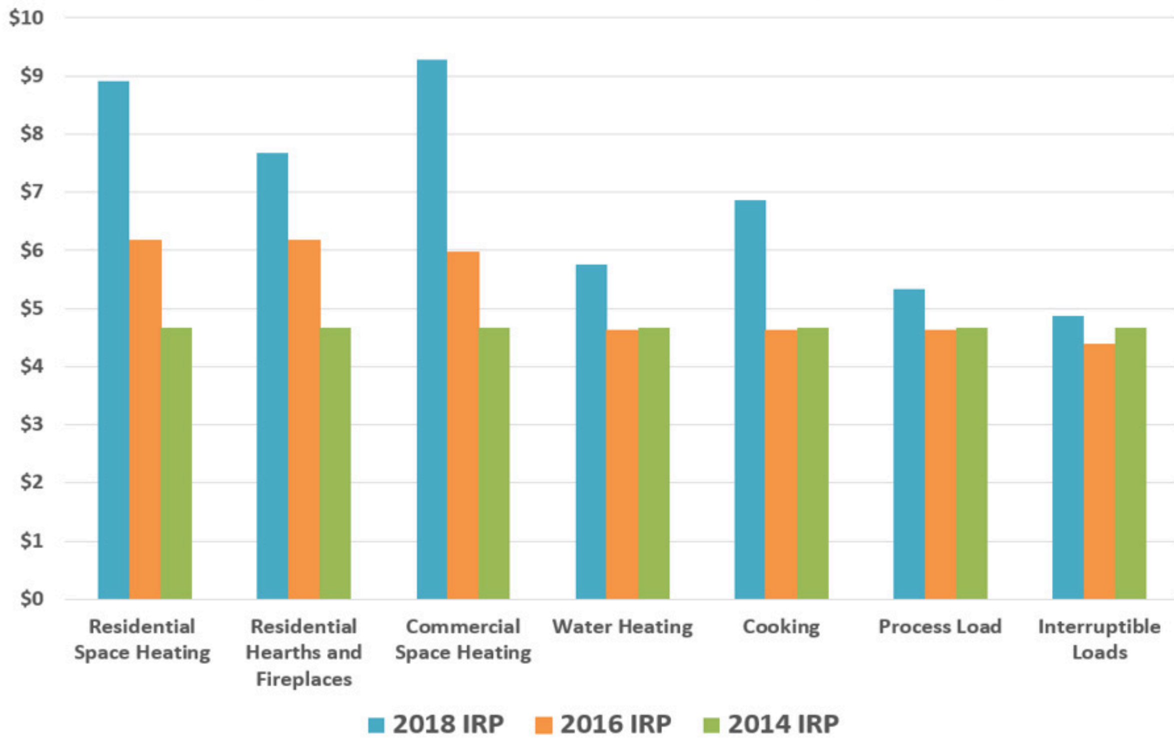
The summary results provide the following key takeaways:

1) Continued improvements to NW Natural's methodology in calculating avoided costs have more accurately captured the capacity value of DSM measures, particularly those related to the natural gas distribution system.
2) These improvements have raised avoided cost estimates significantly relative to those in the 2016 IRP, which were themselves higher than previous IRPs.
3) Avoided costs vary widely by end use, driven by the difference in capacity costs (both supply and distribution) avoided. This is an important feature enhanced by further disaggregating end use types relative to the 2016 IRP.
4) Washington distribution system avoided costs are generally higher than Oregon avoided costs, due largely to the differences in distribution capacity costs across the states and a higher expectation of emissions compliance costs. Relative to Oregon, Washington avoided costs are more than 20 percent higher for residential space heating, 25 percent higher for commercial space heating, and 11 percent higher for water heating.
5) Including environmental policy compliance costs are now included in all load scenarios – base case as well as each sensitivity analyzed.

3.2. AVOIDED COSTS RESULTS THROUGH TIME

Figure 4.4 shows avoided costs for Oregon for the different end uses evaluated in the 2018 IRP, the avoided costs from the 2016 IRP, and those used in 2014 (which were constant across end uses). Improvements to the Company's methodology for calculating peak savings from DSM are visible in the marked increase in estimated avoided costs for space heating measures. End uses formerly considered "base load" in prior IRPs – water heating and cooking – have been analyzed individually in this IRP and thus exhibit some additional peak-related savings.

Figure 4.4: Avoided Costs Through Time: 2018, 2016, and 2014 IRPs- Oregon Example[11]

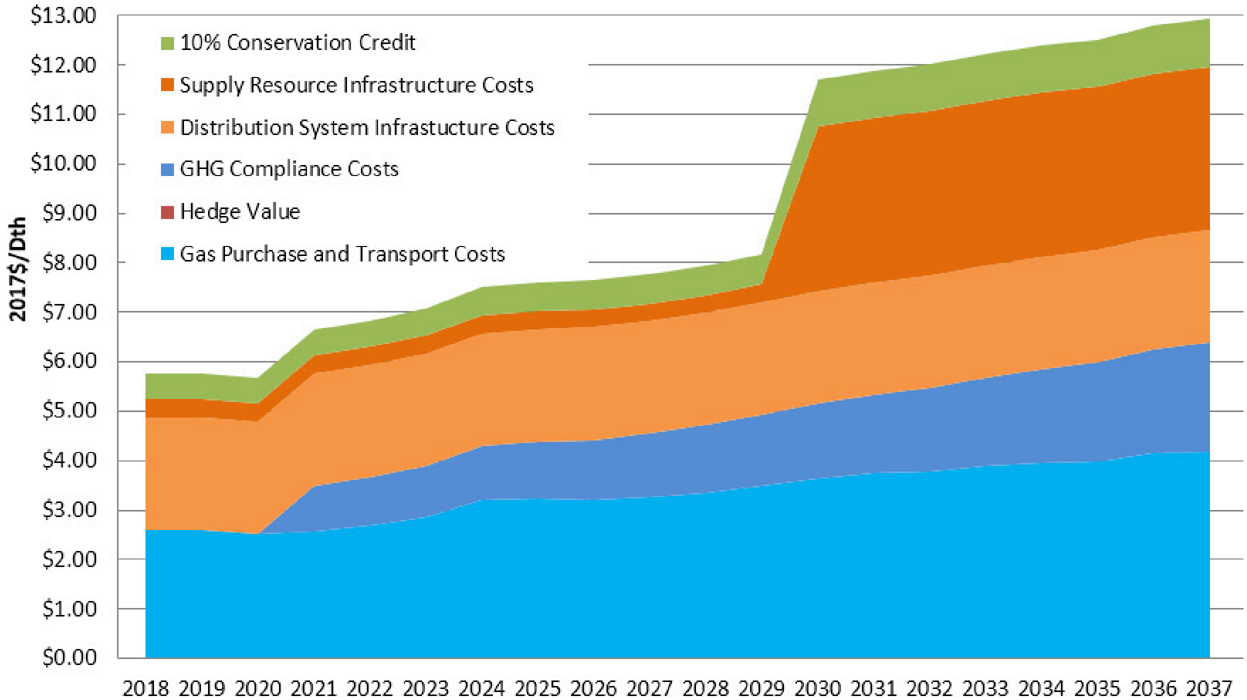


3.3. AVOIDED COST COMPONENT BREAKDOWN THROUGH TIME

In addition to the total avoided costs per end use (by state) through time and the component breakdown in levelized terms, how the different components vary through time is also important. Figure 4.5 uses Oregon residential space heat as an example to show this variation[12]. Much of the incline in the later years of the planning horizon is due to supply capacity costs increasing sharply as Mist storage recall would be exhausted.

[11] Please refer to Appendix D for Washington system estimates
[12] Please refer to Appendix D for Washington system values, and those for other end uses

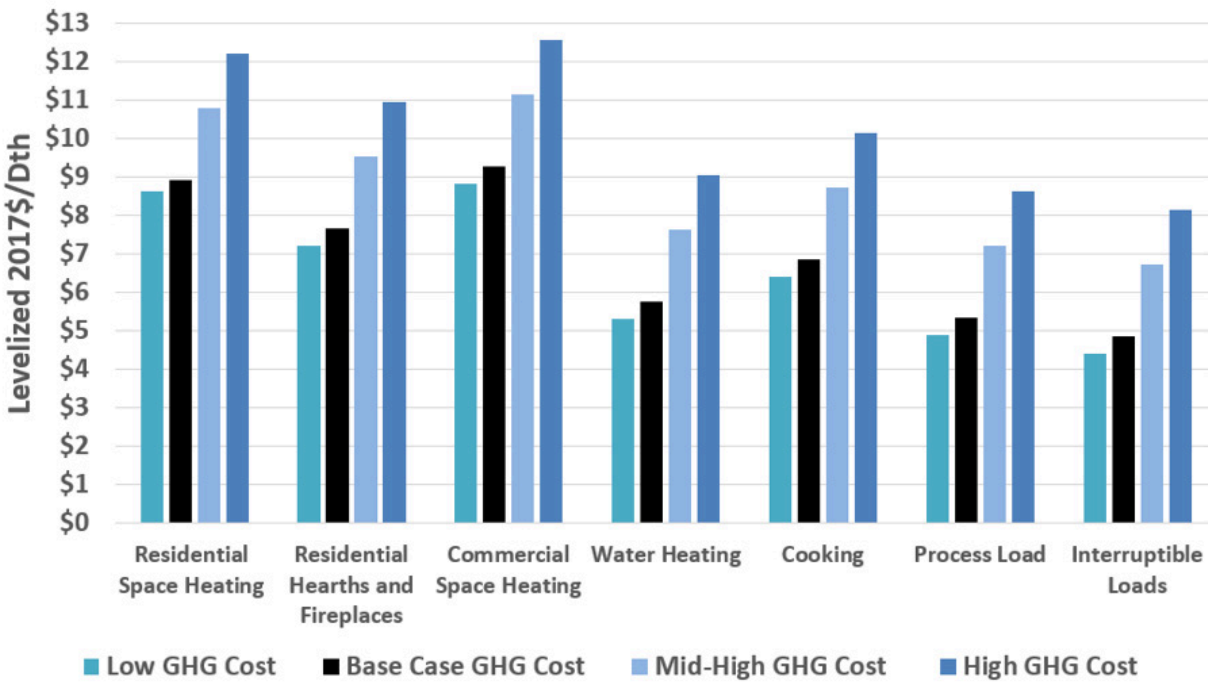
Figure 4.5: Avoided Cost Component Breakdown through Time Example- Oregon Residential Space Heat



3.4. AVOIDED COST BY INCREMENTAL STATE CARBON POLICY SCENARIO

As is detailed in Chapters Two, Six, and Seven, potential GHG emissions compliance costs are a key uncertainty in this IRP. Potential emissions compliance costs are consequently and important component of avoided costs. Figure 4.5 shows how avoided costs change using the different emissions compliance costs sensitivities detailed in Chapter 2 (see Figure 2.18) to show how much expected compliance costs could impact the costs avoided through energy efficiency.

Figure 4.5: Avoided Costs by Incremental State Carbon Policy Scenarios-Oregon Example



4. SUPPLY-SIDE APPLICATIONS OF AVOIDED COSTS

PLACEHOLDER FOR FINAL IRP

5. KEY FINDINGS

- NW Natural calculates five (and uses 6) separate avoided cost components that are estimated and presented separately rather than aggregated and provided as a total avoided cost figure
- The separate components of avoided cost are applied to each demand- and supply-side resource option considered in the 2018 IRP based upon the costs those resources actually avoid

- A more detailed estimate of distribution system costs avoided with peak hour gas energy savings or supply has been made to further the work NW Natural has done in previous IRPs to fully value the infrastructure costs avoided via energy savings or energy supply during peak periods
- For energy efficiency measures, avoided costs have been calculated for 3 new end uses to add to the 4 end uses from the 2016 IRP
- Avoided cost estimates for most end uses for energy efficiency have increased since the 2016 IRP, due primarily to higher expected emissions compliance costs and the more detailed distribution system infrastructure methodology new to the 2018 IRP
- Avoided costs are being applied to low carbon gas supply resources (renewable natural gas and power-to-gas) for the first time as part of the more robust analysis conducted relative to those resources in the 2018 IRP

CHAPTER 5

DEMAND-SIDE RESOURCES

KEY TAKEAWAYS

Key findings in this chapter include the following:

- Oregon savings potential identified in the resource assessment model increased by 91 percent. The final deployed savings projection of 138.95 million therms is 59% higher than the 2016 IRP savings projection.
- Washington savings potential identified in the resource assessment model increased by 129%. The final deployed savings projection of 11.27 million therms is 75% higher than the 2016 IRP savings projection.
- Based on stakeholder meeting feedback, Energy Trust incorporated a ‘megaproject adder’ to its forecast and adopted Northwest Power and Conservation Council 20-year deployment rate assumptions in order to address a pattern of under forecasting savings from large, unforeseen projects in past IRPs.
- Energy Trust made significant updates to its resource assessment modeling tool, including the addition of new measures and refreshed measure-level assumptions.
- New, more valuable Avoided Costs were responsible for a 27% increase in cost effective savings potential.
- Since 2010, NW Natural has treated over 1,900 homes in Oregon and saved over 440,000 therms through its Oregon Low-income Energy Efficiency Program.
- Since 2010, NW Natural has treated over 80 homes in Washington and saved over 31,000 therms through its Washington Low-Income Energy Efficiency Program.
- Improvements to these programs have been made and NW Natural continues to seek ways to increase the number of homes treated per year.

1. ENERGY TRUST BACKGROUND

As the administrator for NW Natural energy efficiency programs, the Energy Trust provides the following information (shown in maroon text)

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.[1]

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[2] identified that cost-effective industrial saving 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 savings incentives, 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.[3] 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.[4]

2. ENERGY TRUST FORECAST OVERVIEW AND HIGH-LEVEL RESULTS

[1] See Order No. 02-634 in Docket No. UG 143.
[2] See Docket No. LC 45.
[3] See Order No. 4 in Docket UG-080546.
[4] 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.

Energy Trust developed a 20-year DSM resource forecast for NW Natural 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 2018 IRP results show that NW Natural can save 31.9 million therms[5] in Oregon and Southwest Washington in the next five years from 2018 to 2022 and over 150.2 million therms by 2037.[6] These results represent a 24% and 60% increase respectively in cost-effective DSM potential over the prior IRP in 2016. The three main drivers of this increased potential are:

1) *Increased Value of Avoided Costs:* NW Natural developed new avoided costs utilized in this forecast, which are much more valuable than the previous IRP, leading to more measures passing the cost effectiveness test.
2) *Measure additions and updates:* Energy Trust added ten new emerging technologies to the model and updated measure level assumption for several of the existing measures
3) *Updates to final savings projection methodology:* Based on stakeholder meeting feedback, Energy Trust incorporated a 'megaproject adder' to its forecast and adopted deployment rates that calibrate to Northwest Power and Conservation Council 20-year deployment rate assumptions from their 7th Power Plan.

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.

[5] 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 and Washington combined unless otherwise explicitly noted. Energy Trust publicly reports its Oregon savings and goals in "net" savings, which are adjusted for market effects including free ridership and spillover. Free ridership refers to a customer's participating in the program when the program information or incentive did not influence the customer's efficiency decision. Spillover refers to the savings from customers that proceed with an energy-efficiency action because Energy Trust is present in the market and influenced them, but they did not participate directly in an Energy Trust program. In Washington savings are reported as "gross" savings as directed by Washington Utilities and Transportation Commission (WUTC). Gross savings are not adjusted for market effects and most accurately reflect the reductions NW Natural will see on their system.

[6] Includes over 1.1 million therms of market transformation savings resulting from code changes driven by Energy Trust's New Buildings Program. Also includes 3.6 million therms from a mega-project adder incorporated into the savings forecast.

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

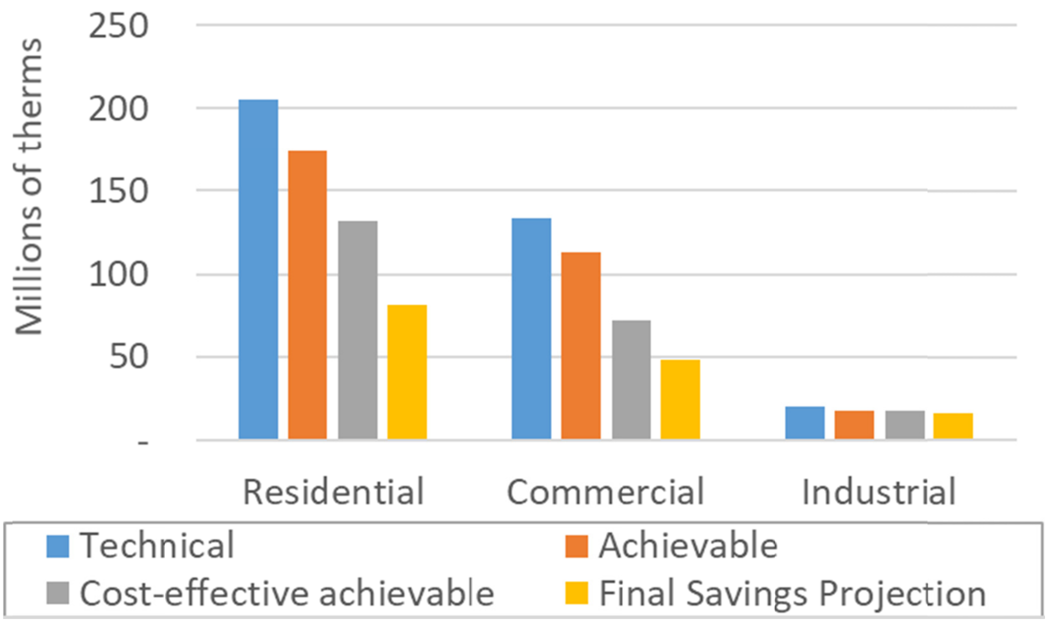
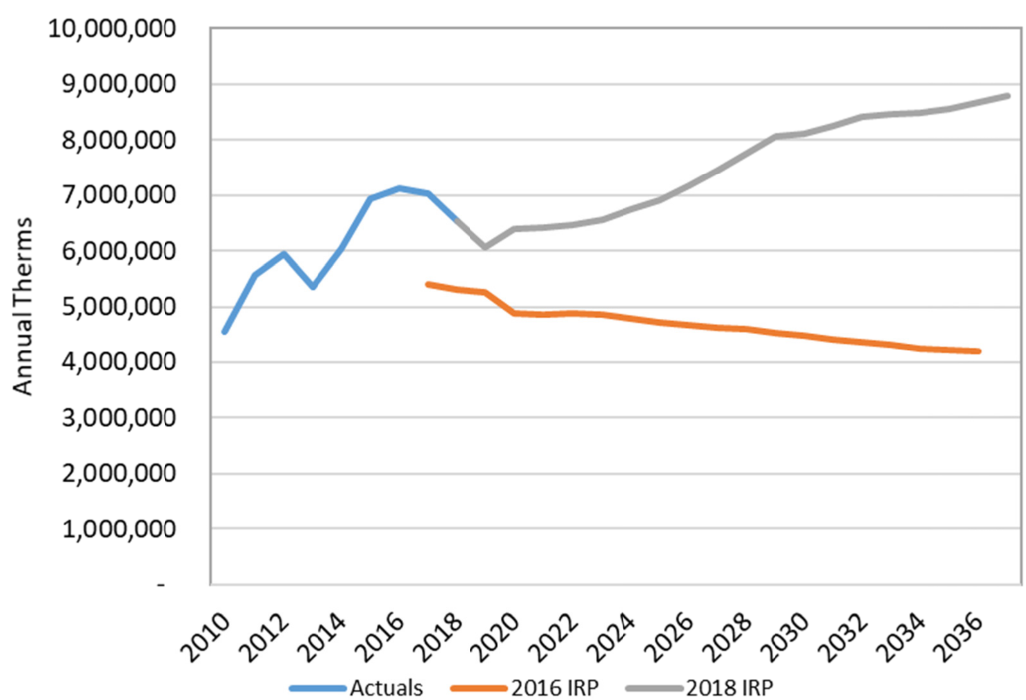


Figure 5.2 links actual historic savings going back to 2010 to the new savings projection for the 2018 IRP. It also compares the 2018 IRP forecast to the 2016 IRP forecast.

Figure 5.2: Annual Savings Projection Comparison for 2016 and 2018 IRPs, with Actual savings since 2010



3. IMPROVEMENTS TO ENERGY TRUST'S SAVINGS PROJECTION METHODOLOGY

Energy Trust hosted a stakeholder meeting in September 2017 to get feedback on Energy Trust's forecast process. Attendees included utilities, OPUC staff, and other regional stakeholders like the Northwest Gas Association. Some of the most significant themes that emerged from this process include:

- Energy Trust annual savings achievements have been consistently exceeding IRP targets.
- Utilities and stakeholders are interested in receiving a forecast based on more than just "firm" resources achieved through program activity.
- Utilities are interested in the best projection Energy Trust can provide. Achievements should fluctuate on both sides of the forecast over time.
- Forecast has been missing some estimation of future resources that Energy Trust cannot currently identify.
    - New large single loads that utilities have difficulty forecasting and associated large efficiency 'mega-projects'.
    - Emerging Technology of the future that has not yet been developed to the point where Energy Trust includes it in its model.
- Short-term forecasts are most important to utilities and the OPUC in the following order. 1-2 years, 3-5 years, 6-10 years, and 11-20 years.

As a result of this feedback, Energy Trust made several changes to improve its IRP forecasts. Incremental improvements made to the NW Natural forecast include:

- Inclusion of additional behavioral savings and near net-zero homes and buildings
- Increased coordination with program managers and a move to think about forecast in three time periods
    - 1-2 years (short term) - Rely on programs and align with savings goals from most recent budget
    - 3-5 years (midterm) - Programs and planning work together to extend program trends based on market intelligence
    - 6-20 years (long term) - Planning forecasts long-term acquisition rate
- Addition of forecast "megaproject adder" to account for large unidentified projects. These have previously not been forecast as loads or opportunities and have resulted in significant forecasting error. The addition is based on past large project savings averages.
- Adoption of deployment rates that calibrate to Northwest Power and Conservation Council's 20-year total deployments
    - Acquisition rates for cost-effective achievable retrofit potential approach 100% at the end of 20-year period in Oregon, where Energy Trust has had a

sustained active presence. In Washington, acquisition rates for cost-effective achievable potential approach 85% due to fewer years in the market with less established networks.

- Assumes that by the end of 20-year period acquisition rates for replace on burnout and new construction measures will approach 100% acquisition in Oregon and 85% in Washington, regardless of whether the savings come through programs, market transformation, or code adoption.

4. 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 demand-side efficiency 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, costs and market penetration assumptions. These measures are scaled up to NW Natural's service territory based on a set of applicability assumptions for each measure adjusted with NW Natural inputs, such as customer and load forecasts, among others. The product of all these factors results in the total 20-year DSM potential available for acquisition to serve NW Natural's customers and associated demand.

In the intervening years since NW Natural's 2016 IRP, Energy Trust has made a number of updates and improvements to the RA model, which contributed to the increase in energy efficiency potential identified in this DSM forecast:

- *Refreshed measure level assumptions* – Measure inputs for measures spanning all three 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 and saturation rates. The most significant measure update was for residential new home construction. Energy Trust's go-to-market energy performance score (EPS) pathways were incorporated into the model for this study and represent a significantly different approach from the previously used measure, resulting in additional savings potential.
- *Addition of new measures* – New measures include cooking equipment for restaurants, industrial measures, smart thermostats, and a suite of additional emerging technology measures, all of which contributed additional cost-effective potential.
- *Updated measure density and saturation rates* that identify the remaining opportunities for installation from third party research and survey work: The Residential Building Stock Assessment (RBSA) and Commercial Building Stock Assessment (CBSA), large-scale research efforts undertaken by the Northwest Energy Efficiency Alliance (NEEA)--serve as the primary resources for developing residential and commercial measure densities

and saturation factors. These factors characterize the existing building stock and identify the number of possible locations for certain DSM measures to be installed. Since these studies have not been updated since the last IRP, Energy Trust updated certain key measures using internal data on historical program performance. Energy Trust also updated saturation rates based on NW Natural-specific data.

Table 5.1 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.

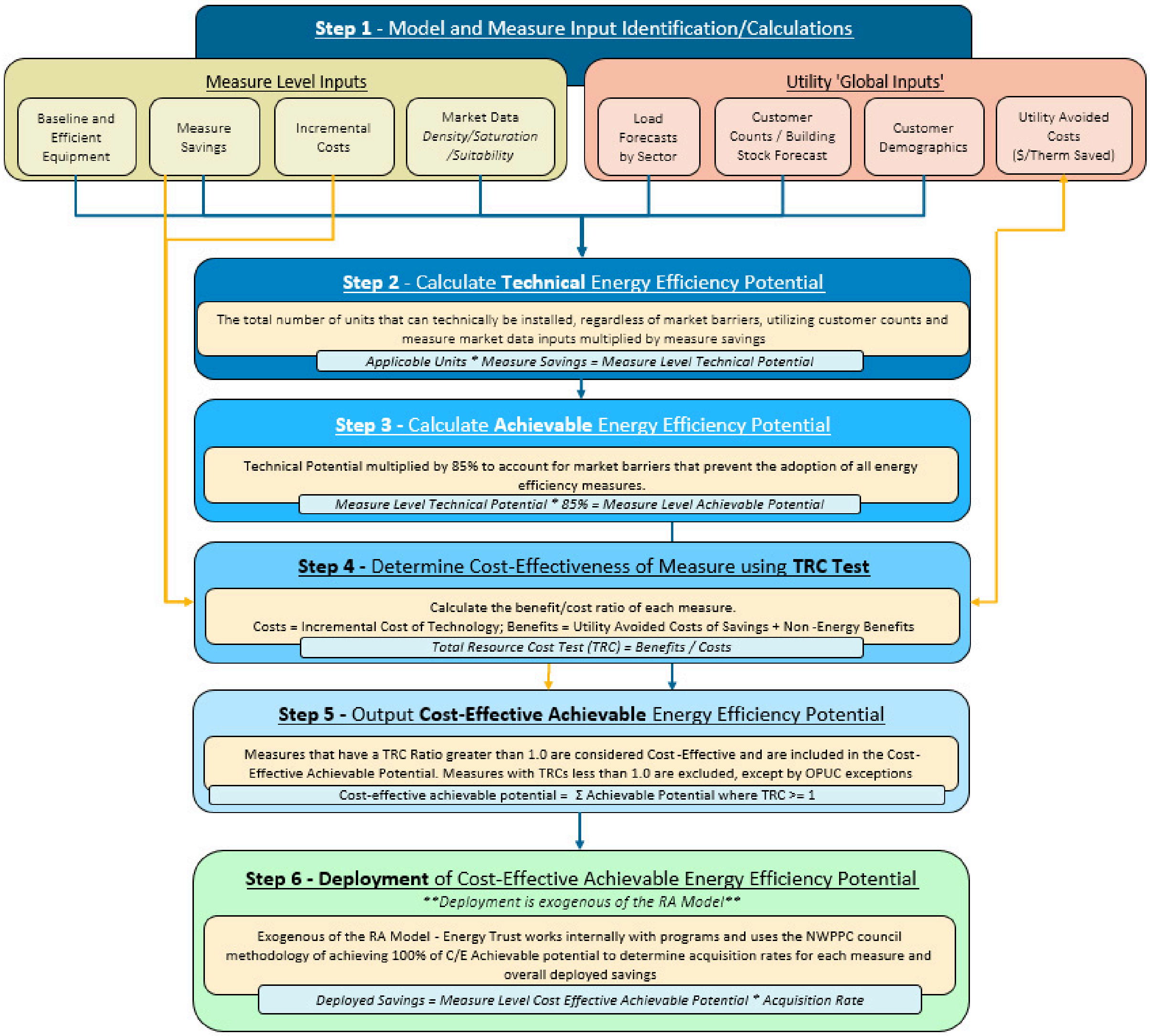
Table 5.1: Three categories of savings potential identified by the RA Model

Not technically feasible	Technical Potential		
Not technically feasible	Market barriers	Achievable Potential 85% of Technical	
Not technically feasible	Market barriers	Not cost effective	Cost-Effective Potential

5. 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 5.3. 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 20 year forecast. The actual deployment of these savings (the acquisition percentage of the total potential each year – Step 6 of Figure 5.3) 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 5.3.

Figure 5.3: 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 a 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.[7] Simultaneous to this effort, Energy

[7] 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 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.

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[8], 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 95% EF Furnace replacing an 80% EF baseline furnace).
  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.

Appendix D contains tables of the measures studied for each customer class and a summary of the economic assessment for each.

- *Utility Global Inputs:*

  The RA Model requires several utility level inputs to create the DSM forecast. These inputs include:

[8] 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).

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.
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 by 15 percent, to account for market barriers that prevent total adoption of all cost-effective measures. Defining the achievable potential as 85 percent of the technical potential is the generally accepted method employed by many industry experts, including the Northwest Power and Conservation Council (NWPCC) and National Renewable Energy Lab (NREL).

Achievable Potential =	Technical Potential * 85%

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 an efficiency 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.[9] The net present-value of these benefits is calculated based on the measure's expected lifespan using the Company's discount rate.[10]

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.

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 or allowance for the use of the Utility Cost Test is granted by the WUTC.

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

[9] See Chapter Four for a discussion of NW Natural's avoided cost.
[10] NW Natural's real after-tax annual discount rates used in the 2018 IRP are 4.91 percent for Oregon and 5.64 percent for Washington.

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 (85% of technical potential) 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 and is therefore offered by Energy Trust programs.[11]

Step 6: Deployment of Cost-Effective Achievable Energy Efficiency Potential
After determining the cumulative 20-year 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. 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 'megaproject adder', savings that account for large unidentified projects that consistently appear in Energy Trust's historic 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 Table 5.2.

Table 5.2: 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>

6. 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.

[11] The cost-effective override was not applied due to measures being cost-effective using blended avoided costs because NW Natural's 2018 IRP avoided costs are higher than the blended avoided costs currently in use.

6.1. FORECASTED SAVINGS POTENTIAL BY TYPE

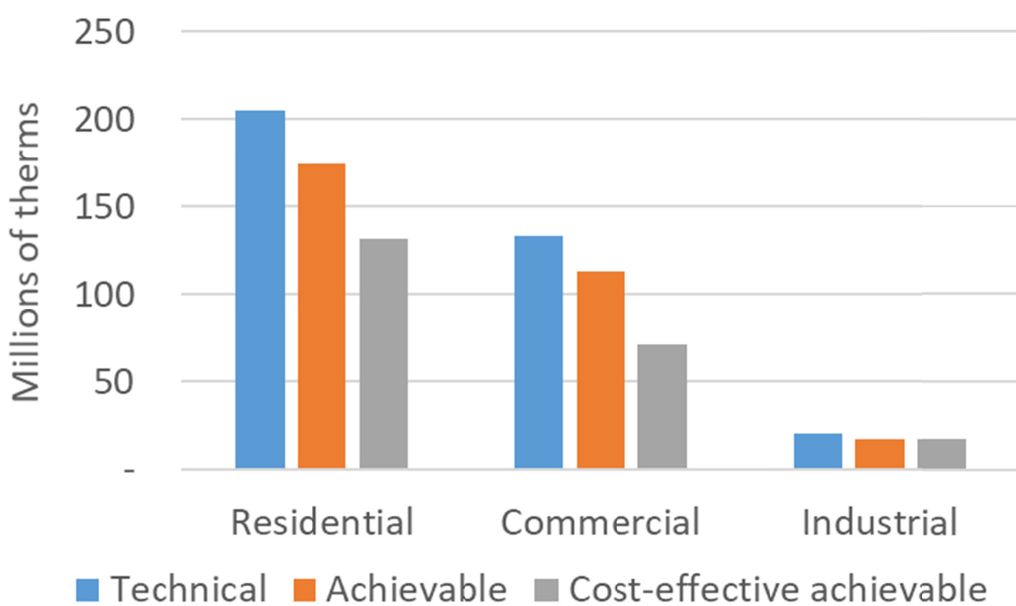
Table 5.3 summarizes the technical, achievable, and cost-effective potential for NW Natural's system in Oregon and Southwest Washington by market sector. These savings represent the total 20-year cumulative savings potential identified in the RA Model by the three types identified in Table 5.1. Modeled 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 5.3: Summary of Cumulative Modeled Savings Potential - 2018–2037

Sector	Technical Potential (Therms)	Achievable Potential (Therms)	Cost-effective achievable Potential (Therms)
Residential	205,002,056	174,251,748	131,558,409
Commercial	133,029,052	113,074,695	71,576,229
Industrial	20,560,996	17,476,846	17,362,638
Total	358,592,104	304,803,289	220,497,276

Figure 5.4 shows cumulative forecasted savings potential across the three sectors Energy Trust serves, as well as the type of potential identified in NW Natural's service territory.

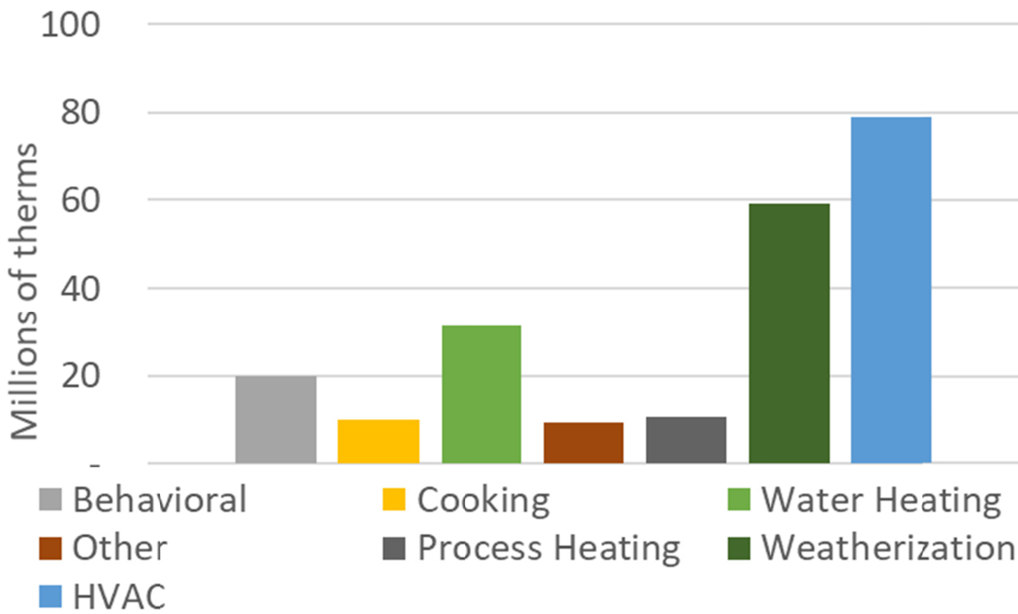
Figure 5.4: Summary of Cumulative Modeled Savings Potential - 2018–2037 - by Sector and type of Potential



These results show that for the Residential and Commercial Sectors, approximately 64 and 54 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, nearly all of the achievable potential identified is also found to be cost effective.

Figure 5.5 below provides a breakdown of NW Natural's 20-year cost-effective DSM savings potential by end use.

Figure 5.5: 20-year Cumulative Cost-Effective Potential by End Use



The HVAC and weatherization end uses top the list and represent all measures that save space heat. Water heating includes water heating equipment from all sectors, as well as showerheads and aerators. 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 includes greenhouse upgrades for the industrial program and a new emerging technology measure for path to net zero buildings.

Figure 5.6 below shows the amount of emerging technology savings within each category of DSM potential, highlighting the contributions of commercially available and emerging technology DSM. This graph shows that while over 77 million therms of the DSM technical potential consists of emerging technology, once the cost-effectiveness screen is applied, over 23 million, or 30% of that potential remains. For commercially available measures, of the 280 million therms of technical potential, over 197 million, or 70% of the potential remains. 11% of the total cost effective potential identified in the model is from emerging technology measures.

Figure 5.6: Cumulative 20-year potential by savings type, detailing the contributions of commercially available and emerging technology

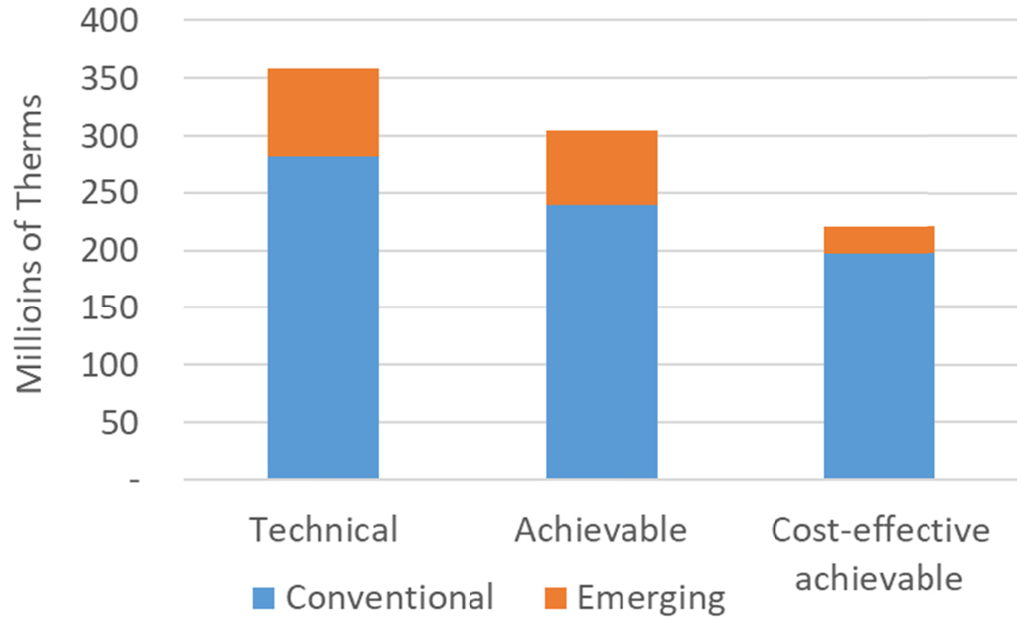


Table 5.4 shows the savings potential in the resource assessment model that was added by employing the cost-effectiveness override option in the model. The cost-effectiveness override option forces non-cost-effective potential into the cost-effective potential results and is used when a measure meets one of the following two criteria. Reason two detailed below was not used in this IRP as the 2018 IRP avoided costs are higher than the blended avoided costs currently in use by Energy Trust programs.

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 5.4: Cumulative Cost-Effective Potential (2018-2037) due to use of Cost-effectiveness override

Sector	Yes CE Override	No CE Override	Difference
Residential	115.80	107.42	8.37
Commercial	62.79	62.79	-
Industrial	16.53	16.53	-
Total DSM:	195.12	186.74	8.37

In this IRP 4% 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 included 0.67-0.69 Efficiency factor (EF) gas storage water heaters and attic, floor, and wall insulation. All these savings come from the Residential Sector.

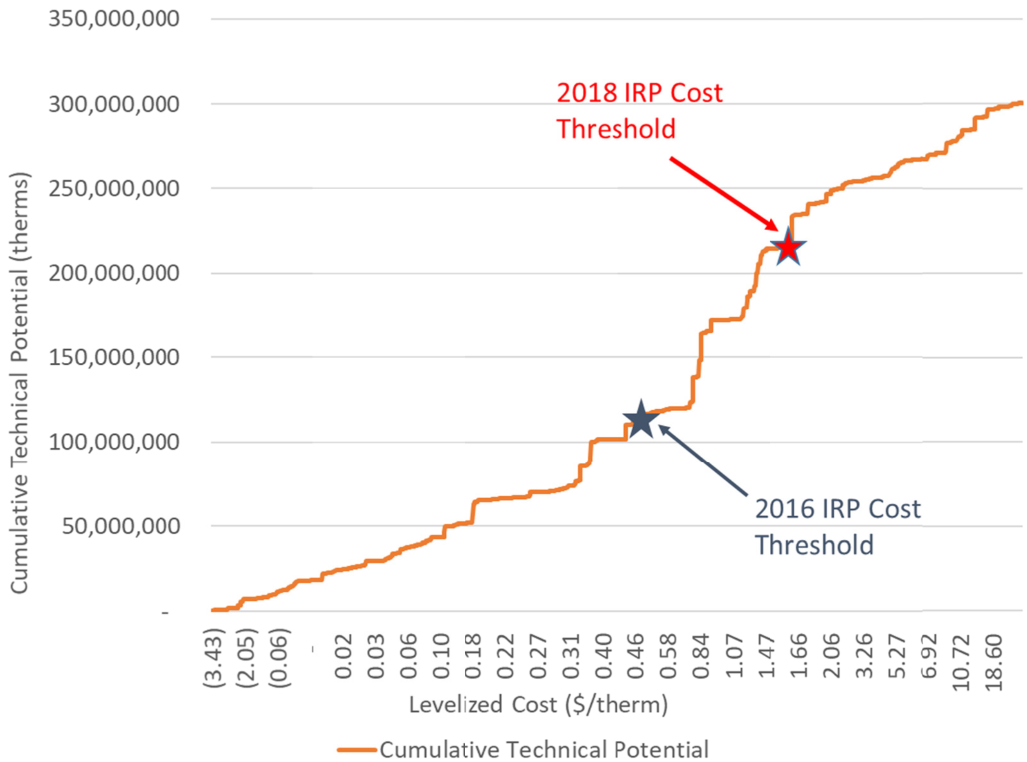
6.2. SUPPLY CURVE AND LEVELIZED COSTS

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 and Washington State discount rates of 4.91 percent and 5.64 percent, respectively. The annualized measure cost is then divided by the annual energy savings, in therms.

Figure 5.7 shows the supply curve developed for this IRP that can be used for comparing demand-side and supply-side resources. The two cost thresholds shown as stars on the supply curve line represent the approximate levelized cost cutoff that corresponds with the amount of cost-effective DSM potential identified by the RA Model in the 2018 and 2016 IRPs, as determined by the TRC, when ordering all measures based on their levelized cost.

Figure 5.7: 20-year Gas Supply Curve showing the approximate levelized cost cutoffs from the 2016 IRP and the current 2018 IRPs12



The tables in Appendix D depict the 20-year cumulative achievable and cost-effective achievable potential forecast per measure grouped by sector. The tables also include the weighted average levelized cost for the savings of each measure.

6.3. 2018 MODEL RESULTS COMPARED TO 2016

Table 5.5 below shows the total modeled potential for DSM in this IRP compared to the prior IRP in 2016. The increased potential is primarily found in the residential sector and is primarily driven by new measures like smart thermostats and New Home construction packages that better reflect the delivery of the New Homes program at Energy Trust. The New Homes potential identified by the model represents the amount of potential from making every new home in the forecast constructed 10-50% above the current energy code. This modeled savings amount is mitigated by the amount of savings potential selected for deployment as shown in the final savings projection beginning on page 5.17. 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. For example, the New Homes program currently brings in about 35-40 % of the total new homes construction market. Assumptions based on historical program performance are considered when generating the final annual savings projection. The final

[12] Measures with negative levelized costs have a high proportion of non-energy benefits, which outweigh the incremental total resource cost of the measures.

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 5.5: Total 2018 IRP Cost-Effective Modeled Potential compared to 2016 IRP modeled potential by Sector

	Total Cost Effective Potential 2016 IRP (Millions of therms)	Total Cost Effective Potential 2018 IRP (Millions of therms)
Residential	39.2	131.56
Commercial	56.1	71.58
Industrial	17.66	17.36
All DSM	112.97	220.5

Table 5.6 builds off Table 5.5 and details the key factors that drove the change in cost-effective potential for DSM in this IRP compared to the prior IRP in 2016. Note that potential from measures with OPUC exceptions and the use of the cost-effectiveness override is negative 13 percent. This means the cost-effectiveness override application in the model had a smaller impact on cost effective potential than the previous 2016 IRP.

Table 5.6: Key Changes in Model that Increased Potential from 2016 IRP to 2018 IRP

Change Component	Change in DSM Savings (Millions of Therms) from 2016 to 2018 IRPs	% of Total
Measure Exceptions	(14.10)	-13%
Emerging Technology	11.13	11%
RES Smart T-Stats	15.27	13%
Change in Avoided Costs	28.58	27%
Change in Model Assumptions	64.43	61%
Total Change from 2016 to 2018 IRP	105.31	99%

6.4. FINAL SAVINGS PROJECTION

The results of the final savings projection show that Energy Trust can save 31.9 million therms across NW Natural's system in Oregon and Southwest Washington in the next five years from 2018 to 2022 and over 150.2 million therms by 2037

The final savings projection of 150.2 million therms by 2037 in NW Natural's service territory in Oregon and SW Washington, which is decremented from NW Natural's load forecast, contains a reduction to the full cost-effective potential shown in Table 5.6. 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 5.7 depicts savings projections for NW Natural's multistate system. Note that while industrial DSM potential was identified in modeled potential for Washington, Energy Trust programs do not currently deliver industrial programs in Washington except where customers in commercial rate classes have industrial end uses. Thus, Washington potential for the industrial rate class is not included in the following savings projections. The 'Other' sector referenced in the savings projections include the megaproject adder and Commercial New Buildings market transformation savings, which were forecasted outside of that Sector's standard savings.

Table 5.7: 20-Year Cumulative Savings Potential by type, including final savings projection

	Technical	Achievable	Cost-effective	Energy Trust Savings Projection
Residential	205.00	174.26	131.56	81.13
Commercial	133.03	113.07	71.58	47.98
Industrial	20.56	17.47	17.36	16.40
Other	0	0	0	4.71
All DSM	358.60	304.80	220.50	150.22

Figure 5.8 shows the annual savings projection by Sector. The initial drop in savings from 2018 to 2019 is primarily due to the expiration of approximately half a million therms being claimed by the Residential New Homes program from past building code changes (otherwise known as market transformation savings).

Figure 5.8: 20-Year Annual Savings Projection by Sector

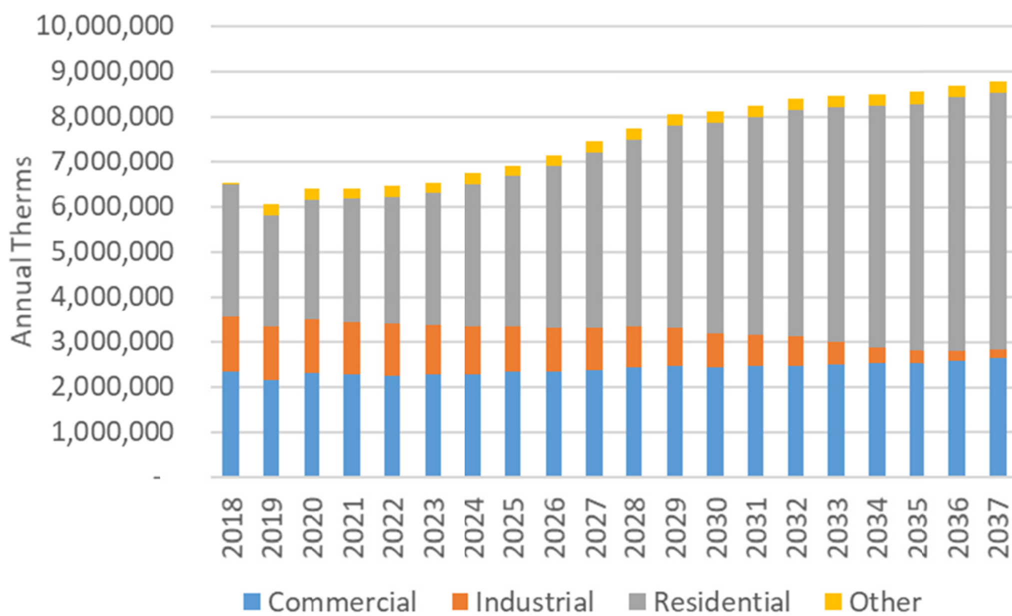
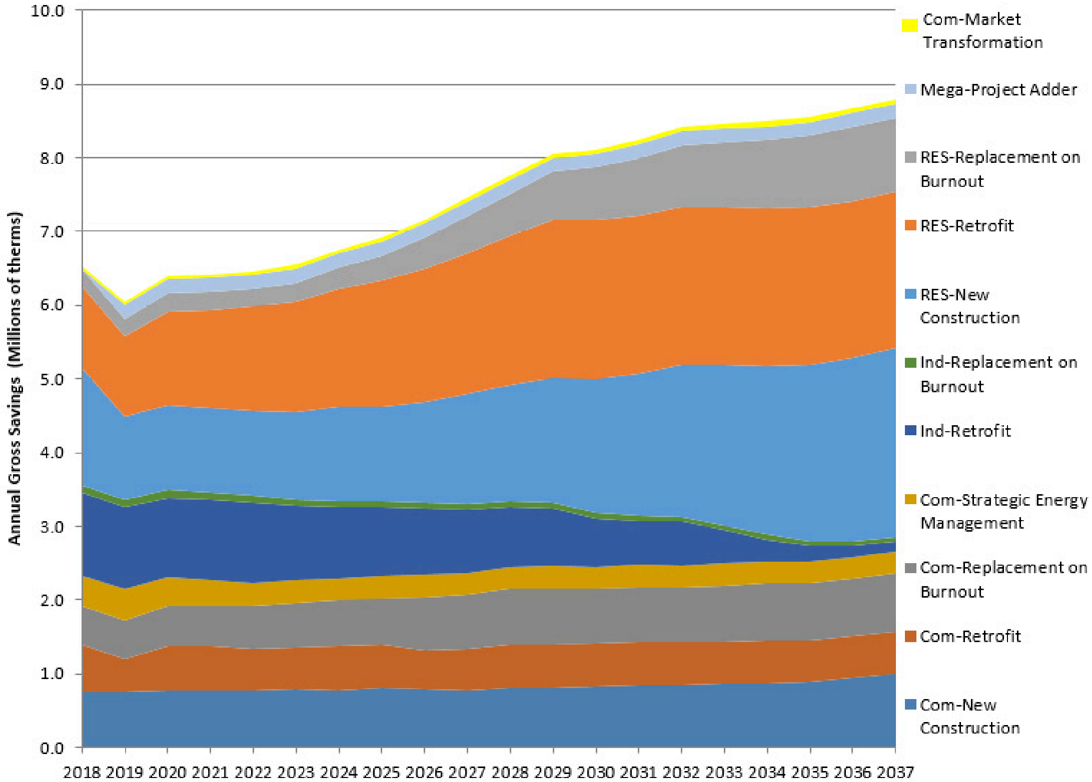


Figure 5.9 shows the annual savings projection by Sector-Measure Type. This view provides greater detail into the types of savings being forecasted and their relative contribution through time.

Figure 5.9: Annual Savings Projection by Sector-Measure Type



6.5. PEAK SAVINGS DEPLOYMENT

Figures 5.10 and 5.11 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 5.10: NW Natural's Annual Peak-Day Savings Projection by Sector

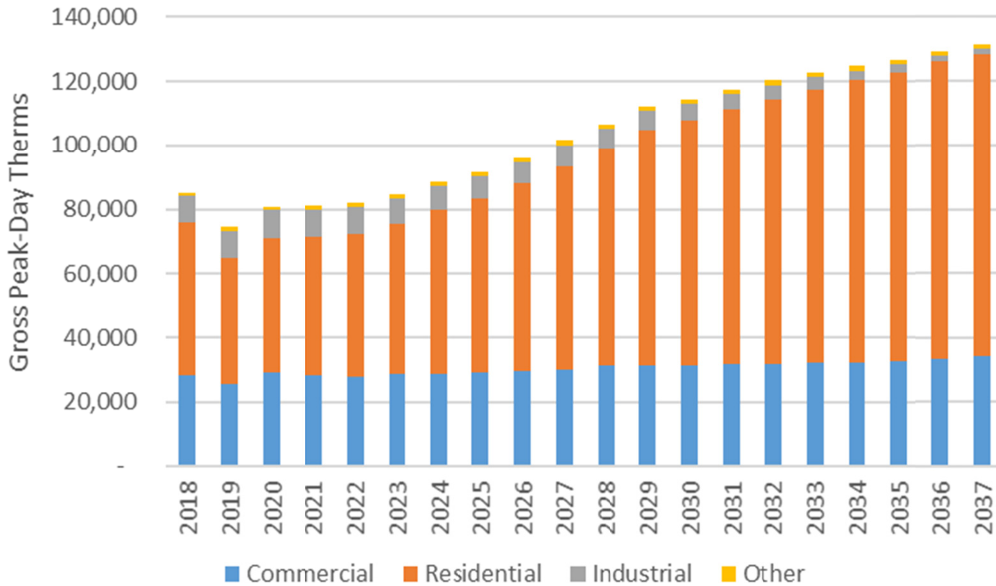
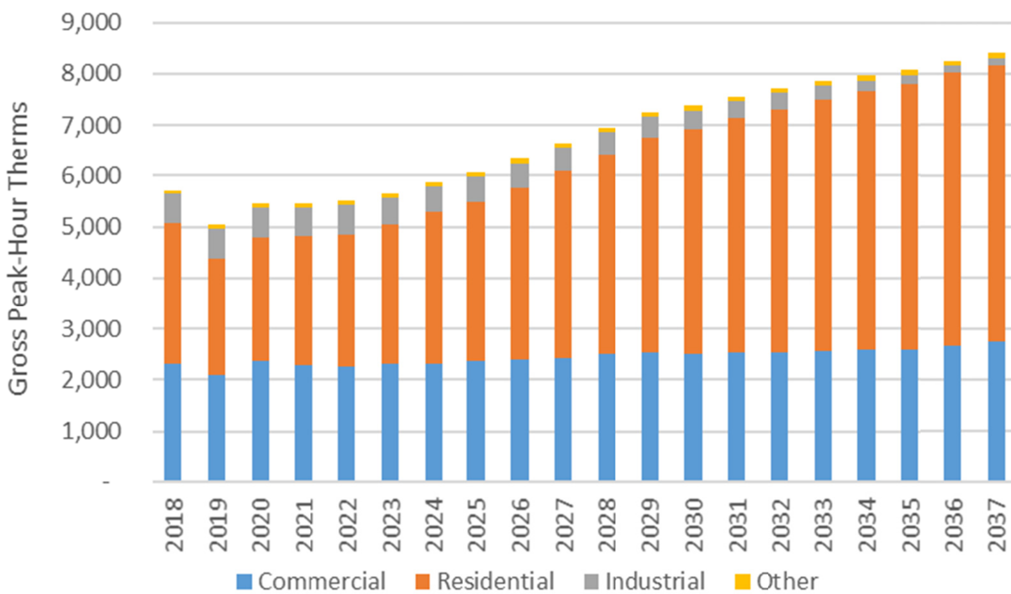


Figure 5.11: NW Natural's Annual Peak-Hour Savings Projection by Sector



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 2,072,420 therms or 1.4% of the 150.2 million therm savings projection. The total peak-hour savings over the 20-year savings projection is 135,136 therms or 0.09% of the 150.2 million therm savings projection.

7. ENERGY EFFICIENCY SENSITIVITIES

7.1. NW NATURAL SCENARIO RUNS OVERVIEW

Energy Trust worked with NW Natural to develop four scenarios to test based on high and low runs of two separate drivers: carbon policy and deployment ramp rates. Scenarios 1 and 2 are based upon changes to avoided costs under different carbon policy pricing scenarios, which were provided to Energy Trust by NW Natural. Scenarios 3 and 4 were based on changing deployment ramp rates, both an accelerated and a decelerated case:

- Scenario 1: Base Case Ramp Rates / Low CO2 Carbon Policy Adder Avoided Costs
- Scenario 2: Base Case Ramp Rates / High CO2 Carbon Policy Adder Avoided Costs
- Scenario 3: Low Ramp Rates / Reference Case Avoided Costs
- Scenario 4: High Ramp Rates / Reference Case Avoided Costs

7.2. CARBON POLICY SCENARIOS

NW Natural provided Energy Trust with several scenarios for different levels of carbon policy: expected, low, social, and high carbon policy scenarios. Energy Trust's base case forecast utilized the expected carbon policy carbon scenario, while Scenario 1 utilized the low carbon policy adder and the Scenario 2 utilized the high policy adder. The deployment ramp rates in both of these scenarios were unchanged from the base case.

The Scenario Results section below details the results of all the scenarios collectively. Overall, Scenario 1 (Low Carbon Policy) resulted in minimal reductions of potential savings, cumulatively saving 99% of the base case. Scenario 2 (High Carbon Policy) increased the savings potential about 5% cumulatively over the forecast timeframe. The High Carbon Policy adder yields more potential because the higher carbon adder results in some measures becoming cost effective earlier in the 20-year period. Overall, the carbon policy adder of the avoided cost buildup are only a portion of the total avoided costs and have relatively little impact on the overall cumulative energy savings potential, which is especially true for the Low Carbon Policy scenario.

7.3. DEPLOYMENT SCENARIOS

Energy Trust provided two additional scenarios which accelerated and decelerated the deployment ramp rates of the available energy efficiency potential. In these two scenarios, avoided costs remained unchanged and utilized the base case avoided costs and expected carbon policy scenario. For the accelerated deployment scenario (Scenario 4), Energy Trust accelerated the base case deployment ramp rates by 5 years and decelerated the ramp rates by 5 years in the low ramp scenario (Scenario 3). These scenarios are meant to represent what may be seen on NW Natural's system if savings are achieved faster or slower than what the base case, which could be for a wide array of reasons and could be considered 'uncertainty bounds'.

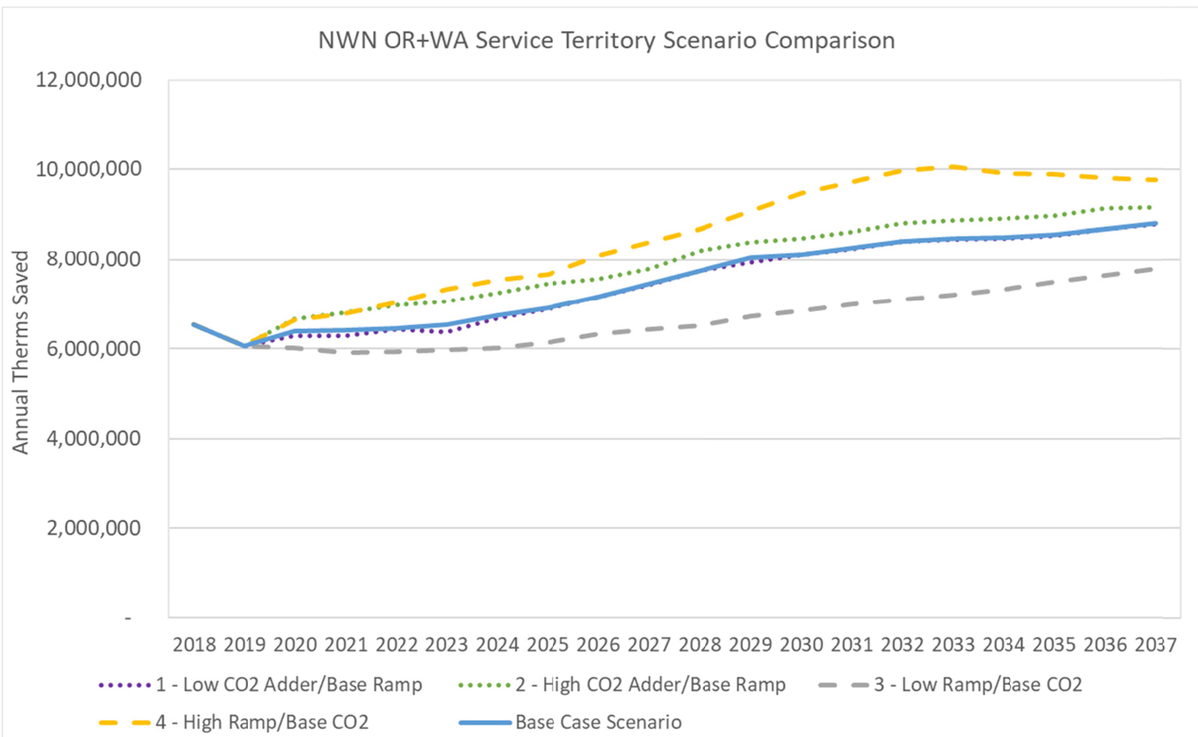
7.4. SCENARIO RESULTS

Table 5.8 and Figure 5.12 detail the results of scenario runs performed by Energy Trust.

Table 5.8: Cumulative Potential by Sensitivity

Scenario Run	20-year Cumulative Potential (MM Therms – OR & WA)	Variance from Base Case (Cumulative)
Base Case Scenario	150.22	100%
Scenario 1: Low CO2 Adder/Base Ramp	149.43	99%
Scenario 2: High CO2 Adder/Base Ramp	157.64	105%
Scenario 3: Low Ramp/Base CO2	133.03	89%
Scenario 4: High Ramp/Base CO2	168.37	112%

Figure 5.12: Annual Therms Save by Sensitivity



8. LOW-INCOME ENERGY EFFICIENCY PROGRAMS

8.1. OREGON LOW-INCOME ENERGY EFFICIENCY PROGRAM (OLIEE)

Since 2002, a portion of public purpose funding collected by NW Natural has been provided for its Oregon Low-Income Energy Efficiency (OLIEE) program through a surcharge to Oregon Residential and Commercial customers' energy bills.[13] OLIEE funding attempts to provide

[13] See Order No. 02-634 in Docket No. UG-143.

equitable access to energy efficiency programs by being used to improve the efficiency of NW Natural's low-income customers' homes through the installation of high-efficiency equipment and weatherization measures. The program is delivered by 10 Community Action Agencies (Agencies) within NW Natural's Oregon service territory.

In 2015, after a number of years of statewide underperformance within low income programs, representatives from Community Action Partnership of Oregon (CAPO), Public Utility Commission of Oregon Staff, Oregon Citizens' Utility Board (CUB), Avista Utilities, Cascade Natural Gas, and NW Natural came together to discuss root causes. As a result of these discussions, NW Natural filed tariff changes and the revised program became effective on March 1, 2016. The changes were designed to decouple the local utility program from the federal programs and funding in order to release the agencies from the process and prioritization constraints that make it especially difficult and expensive to weatherize gas homes.

The changes improved program performance such that NW Natural filed tariff changes in 2017 to ensure stable funding and program controls to serve approximately 300 homes per year.

Table 5.9 shows the number of homes treated and therms saved in OLIEE per year.

Table 5.9: Homes Treated Through OLIEE Program

Program Year	Homes Treated	Therms Saved (Estimated)
2016-2017	260	59,232
2015-2016	231	52,817
2014–2015	198	45,876
2013–2014	201	46,756
2012–2013	151	36,995
2011–2012	541	92,708[14]
2010–2011	339	108,141

8.2. WASHINGTON LOW-INCOME ENERGY EFFICIENCY PROGRAM (WA – LIEE)

On Oct. 1, 2009, NW Natural launched a revised low-income program identified as WA-LIEE (Washington Low-Income Energy Efficiency). Modeled after Oregon's OLIEE program, the WA-LIEE program reimburses the two administering Agencies for installing weatherization measures that are cost-effective when analyzed in aggregate.

The agencies rely on a number of funding sources and leverage each within a typical home. This structure ties the WA-LIEE program to external factors such as state and federal funding.

[14] Therms saved per unit were significantly reduced in 2011-12 due to the extent of multifamily units weatherized that year (approximately 50 percent).

The Company has worked with its energy efficiency advisory group (EEAG) over the past few years to strengthen the program and enable the agencies to be successful. Since 2015 the Company has:

- Removed the stipulation requiring a customer's dwelling be built before 1991 to allow weatherization services in newer housing stock.
- Provided Program funding up to $11,000 for the 2016 program year for customer outreach.
- Increased the maximum rebate amount per home to the greater of $5,000 or the average total installed cost of measures as reported by the Agencies for the prior program year which allows for increased funding and reimbursement as job costs/materials increase. The WA-LIEE contribution was also increased from 90 to 100 percent of job costs.
- Recognized an increase in average savings per home by covering more upgrades per home.

As part of the Company's efforts to adaptively manage the program and address comments to the Company's 2016 IRP, NW Natural staff have focused on finding ways to support the agencies. Since 2016 the Company has:

- Provided robust outreach to each agency, including phone calls, email notes, in-person meeting at each agency and attended a customer site audit to understand their programs, their challenges and to offer ongoing support.
- Engaged with The Energy Project and WA Department of Commerce to discuss ways to remove barriers identified by agencies and to identify opportunities for improvement.
- Reduced one barrier, funding, by working with the EEAG to increase the contribution towards Health, Safety and Repairs to $1,000.
- Worked with Clark County Weatherization staff to identify pilot opportunities to reach additional eligible customers.

NW Natural is monitoring the program and continues to seek and support changes that will increase the number of homes treated per year. Table 5.10 shows the number of homes treated and therms saved in WALIEE per year.

Table 5.10: Homes Treated Through WALIEE

Year	Homes Treated	Therms Saved (Estimated)
2017	13	6,132
2016	16	6,048
2015	9	3,213
2014	10	3,050
2013	20	7,026
2012	8	2,538
2011	11	3,575

CHAPTER 6

SUPPLY-SIDE RESOURCES

KEY TAKEAWAYS

Key findings in this chapter include the following:

- New to this IRP is the inclusion of various types of renewable natural gas (RNG) and other decarbonizing supply resources alongside traditional options such as pipeline and on-system storage.
- Depending on the feedstock, the environmental benefits of RNG can be substantial, and in some cases provide a net negative impact to carbon emissions and result in a net negative carbon compliance cost.
- RNG could be an attractive supply resource due to its net positive environmental benefits, including a reduced carbon dioxide (CO_2)-equivalent emissions profile relative to conventional natural gas.
- Supply resource options considered to fill the Company's capacity deficit include interstate pipelines expansions, on-system storage, and renewable natural gas resources.
- Updated analysis and experience have shown that segmented capacity is a reliable winter resource, which will be maintained in the portfolio until Northwest Pipeline dynamics change and erode its reliability. Such changes are not expected to occur until at least 2021, but the situation will be closely monitored.

1. OVERVIEW

This chapter discusses the gas supply resources the Company currently uses to meet existing Firm customer supply requirements, recent changes in that portfolio, and the supply-side alternatives that could be used to meet the forecasted growth in gas requirements as described in chapter three. Supply-side resources include not only the gas itself, but also the pipeline capacity required to transport the gas, the Company's gas storage options, and the major system enhancements necessary to distribute the gas.[1] This chapter describes these resources without judgment as to the long-term resources that will be chosen, which is performed through the linear programming analysis presented in chapter seven. 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

[1] Most of the planning for getting supplies distributed within NW Natural's service territory to customers is covered in chapter eight Distribution System Planning

"cutting room floor." Other sections in this chapter will examine risk elements associated with certain supply resources, as well as a discussion of gas price hedging and other means to mitigate supply risks.

The gas supply planning process focuses on securing and dispatching gas supply resources to ensure reliable service to the Company's sales customers. The amount of gas needed is greatly influenced by customer behavior. Several factors can affect customer behavior and cause hourly, daily, seasonal, and annual variations in the amount of gas required. Much of this variation is due to changes in the weather. However, changes in business conditions, efficiency measures, changing technology, and the price of natural gas service relative to other fuel alternatives also influence customer gas use. These behavioral factors are accounted for in the Company's gas requirements forecast and are discussed in more detail in chapter three.

1.1. SUPPLY RESOURCE TYPES

The ability to plan for customer requirement variations while maintaining reliability of service is best accomplished by having a variety of supply resources available. The Company's current supply portfolio includes natural gas supplies contracted on a term basis or purchased on the spot (daily) market, which are transported on the interstate pipeline system, as well as storage resources, which are gas supplies purchased during off-peak periods and stored for use in either underground formations or in above-ground tanks as liquefied natural gas (LNG)[2]. Both can be used as peaking resources during periods of high demand.

Another resource in the Company's portfolio is a variation on storage. It consists of optional supply agreements with industrial customers, operators of gas-fired electric generation plants and gas suppliers. These "recall agreements" allow the Company to obtain gas supplies controlled by these parties for a limited number of days during the heating season. The alternate fuel tanks of the end-users could be thought of as the storage medium. In the event of a recall, these end-users decide whether to shut down or switch to alternative fuel as they see fit.

For a variety of reasons, these recall agreements most closely resemble the Company's LNG supplies. First, there is a strict limitation on the number of days in which the recall option is made available to the Company during the heating season. Second, the delivery point is at the citygate[3] or within the Company's service territory, mirroring that of the Company's storage resources. And finally, like LNG, this is a relatively expensive resource on a pure cent per therm basis because prospective suppliers of this service expect it to be called upon during the harshest weather, when alternate fuel costs are highest and resupply is uncertain, and so they

[2] Liquefied natural gas (LNG) is natural gas in its liquid form. When natural gas is cooled to -258° Fahrenheit (-161° Celsius), it becomes a clear, colorless, odorless liquid. LNG is neither corrosive nor toxic. Natural gas is primarily methane with low concentrations of other hydrocarbons, water, carbon dioxide, nitrogen, oxygen and sulfur. Most of these other elements are removed during the liquefaction process. The remaining natural gas is primarily methane with only small amounts of other hydrocarbons. LNG weighs less than half the weight of water, so it will float if spilled on water, and then vaporize as it warms above -258°.

[3] A "gate station" is a location where the Company's distribution system is physically connected to the upstream delivering pipeline (usually Northwest Pipeline). Operations such as metering, pressure regulation and odorization occur at gate stations. The Company has over 40 gate stations and they are collectively referred to as the "citygate."

must include the possible cost of plant shutdowns and product loss. Most customers are simply unwilling to even consider providing such a service on a negotiated basis, and others may be too small to be of interest to the Company. However, because recall agreements can be cost-effective when looking at overall costs, the Company continues to pursue such resources where feasible.

1.2. SATISFYING CUSTOMER REQUIREMENTS

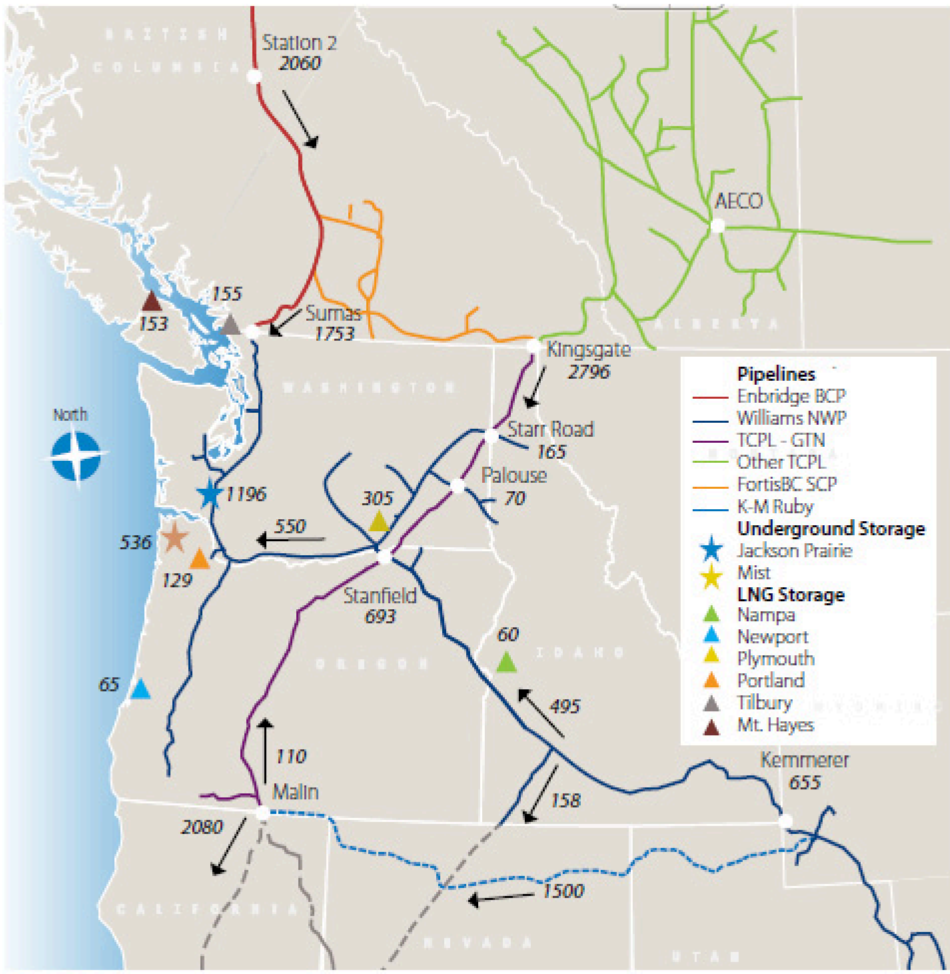
NW Natural expects its gas supply requirements to increase as its firm customer population grows. The characteristics of this load increase are a critical component of the resource selection process. For example, water heater demand is relatively constant throughout the year. Additional water heater load could be met most efficiently and economically by a resource that has relatively constant deliverability year-round—a baseload resource. The growth in space heating requirements tends to be highly seasonal in nature. This type of load growth is best met with a combination of baseload and peaking resources (as can be seen in Figure 3.3 in Chapter three). Peaking resources are designed to deliver large volumes of gas for a short duration, such as during cold weather episodes.

Given these complexities, the Company has assembled a portfolio of supplies to meet the projected needs of its Firm customers. At the same time, this portfolio is flexible enough to enable the Company to negotiate better opportunities as they arise. Existing contracts have staggered terms of greater than one year to very short-term arrangements of 30 days or less. This variety gives the Company the security of longer-term agreements, but still allows the Company to seek more economic transactions in the shorter term.

2. CURRENT RESOURCES

A map showing the existing natural gas pipeline and storage infrastructure in the Pacific Northwest is shown in Figure 6.1, which may be helpful as a reference as each component of NW Natural's supply portfolio is described in the following sections. The capacities in the map are shown in thousands of Dths per day (MDth/day). As discussed in section 4.4 of this chapter, the heat content of the gas currently flowing through the Northwest Pipeline system is slightly elevated compared with history, so current capacities are slightly higher than shown in the map.

Figure 6.1: Pacific Northwest Infrastructure and Capacities (in MDth/day)



Source: Northwest Gas Association, 2017 Gas Outlook

2.1. GAS SUPPLY CONTRACTS

The Company has a portfolio of term supply contracts for each year, as presented and reviewed in the annual Purchased Gas Adjustment (PGA) proceedings in Oregon and Washington. The most recently approved portfolio of term contract – for the 2017-2018 PGA period – is included in in Appendix F, Table F.1. 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” means one party has an option to deliver or receive (as applicable) all, some or none of the indicated volumes at its sole discretion.

In addition to term contracts, the Company buys a large portion of its 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. The Company maintains a diversified array of suppliers from which it can buy gas on a spot or term basis.

2.2. PIPELINE TRANSPORTATION CONTRACTS

The Company holds firm transportation contracts for capacity on the interstate pipeline system of Northwest Pipeline Corporation (NWP), over which all of the Company's supplies must flow except for the small amount of natural gas that is locally produced either in the Mist field (less than two percent of annual purchases) or from biogas (zero for now).

For gas sourced in the US Rockies, transportation over NWP is all that is needed to bring the supplies to the Company's territory.

For gas sourced in British Columbia, some of the purchases are made directly into the NWP system at the international border at a point that is called Sumas on the US side and Huntingdon on the Canadian side. Extending northward from the international border is the Westcoast Energy pipeline system, which is now owned by Enbridge and referred to as such in Figure 6.1. Purchases in northern British Columbia are made at a trading hub called Station 2, and accordingly those supplies first require transportation by Enbridge before reaching the Huntingdon/Sumas 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 (also referred to as NOVA Inventory Transfer or NIT). Two transportation pathways exist for AECO supplies to reach NWP's system and then NW Natural:

1) Through three pipeline systems that are all units of TransCanada Pipelines Limited (TCPL), starting in Alberta with NOVA Gas Transmission Limited (NGTL or NOVA), then the Foothills pipeline in southeastern British Columbia, and then at the international border, at the Kingsgate point in northern Idaho, into Gas Transmission Northwest (GTN), which extends southward and connects to NWP at Starr Road, in eastern Washington (near Spokane) and at Stanfield, in northeastern Oregon.
2) Same initial path through NOVA and Foothills, but then into the Southern Crossing Pipeline (SCP) owned by FortisBC Energy Inc. (Fortis), which arranges for the further delivery of the gas into NWP at Huntingdon/Sumas.

The Company has released a small portion of its NWP capacity to one customer but has retained certain heating season recall rights. Details of the current portfolio of pipeline transportation contracts are provided in Appendix F, Table F.2.

Since the implementation of the Federal Energy Regulatory Commission's (FERC) Order 636 in 1993, capacity rights on US interstate pipelines have been commoditized; i.e., capacity can be bought and sold like other commodities. These releases and acquisitions 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 also can occur on the Canadian pipelines. In general, Canadian pipeline transactions are consistent with most of the NAESB standards.

As mentioned above, virtually all of the natural gas used by the Company and its customers has to be transported at one time of the year or another over the NWP system, which is fully subscribed in the areas served by the Company. Usage among NWP capacity holders tends to peak in roughly a 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 the Company 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, the Company will continue to monitor and utilize the capacity release mechanism whenever appropriate, but primarily this will mean continuing to use its asset management agreement (AMA) with a third party to find value-added transactions that benefit customers.

2.3. STORAGE RESOURCES

The Company relies on four existing storage facilities in or near its market area to augment the supplies transported from British Columbia, Alberta and the Rockies. These consist of underground storage at Mist and Jackson Prairie, along with LNG plants located in Portland (also referred to as Gasco) and Newport, Oregon. The Company owns and operates Mist, Gasco, and Newport LNG, all of which reside within the Company's service territory. Hence, gas typically is placed into storage at these facilities during off-peak periods, and when needed during peak periods, these supplies do not require further transportation on the NWP system.

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

Table 6.1 shows the maximum capabilities of these four firm storage resources, while Table 6.2 shows the configuration of agreements that transport the gas from Jackson Prairie on NWP's system.

Table 6.1: Firm Storage Resources as of November 2017[4]

Facility	Maximum Daily Rate (Dth/day)	Maximum Seasonal Capacity (Dth)
Mist (reserved for Core)	305,000	11,382,120*
Newport LNG[5]	65,280 *	761,600 *
Portland LNG[6]	131,880 *	371,902 *
Jackson Prairie	46,030	1,120,288

Table 6.2: 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

The Company's utility customers currently receive underground storage service at Mist through the Miller Station central control and compressor facility using four depleted production reservoirs (Bruer, Flora, Al's Pool and a portion of Reichhold), collectively referred to as Mist storage. The Mist storage deliverability and seasonal capacity shown in Table 6.1 represent the portion of the present facilities reserved for utility service. Mist began storage operations in 1989 and currently has a maximum total daily deliverability of 515 million cubic feet[7] per day (MMcf/day) and a total working gas capacity of 16 billion cubic feet (Bcf) in the above mentioned reservoirs plus three newer reservoirs (Schlicker, Busch and Meyer). 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 changed recently and results in some adjustments that will be discussed in detail in a subsequent section.

[4] 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 June 2018 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.

[5] Newport LNG tank maximum capacity currently de-rated pending results of the CO_2 removal project, and the available capacity also takes into account a minimum tank level needed for normal operations.

[6] Portland LNG maximum capacity currently de-rated pending results of an ongoing engineering analysis, and the available capacity also takes into account a minimum tank level needed for normal operations.

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

Capacity in excess of core needs is made available for the nonutility 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. The IRP models the recallable portion of Mist as an incremental resource.

The Company also contracts on occasion for storage service in the supply basins, most typically in Alberta due to its relative abundance of merchant storage facilities. These contracts are not modeled in the IRP because they would double-count the same upstream pipeline capacity used for the Company's normal gas purchases. That is, any gas placed in supply-basin storage will use the same pipeline capacity for delivery to the Company's service territory as would normal winter purchases. Accordingly, a decision to contract for supply-basin storage is based on the differentials between winter and summer gas purchase prices versus the cost of the storage service, which change constantly. As with other commodity contracts, financial hedges, etc., the process to review supply-basin storage agreements is part of the annual PGA filing rather than the IRP. At present the Company has no supply-basin storage contracts.

2.4. OTHER SUPPLY RESOURCES

The prior sections discussed the two most prevalent types of supply-side resources: 1) gas purchased by the Company in the supply basins and transported using the Company's pipeline contracts to its service territory; and 2) storage facilities, both underground and LNG. There are four other types of supply-side resources that the Company may be using now and/or in the future – Recallable Supply Agreements, Citygate Deliveries, Mist Production, and On-System Renewable Natural Gas (RNG). These are described as follows.

1) *Recallable Supply Agreements:* While not to be confused with Mist Recall, in a sense this is a variation on storage. These are third-party agreements that allow the Company to utilize gas supplies delivered to end users in the Company's service territory for a limited number of days during the heating season. These supplies otherwise would be consumed by those end users, but instead, they turn to their own alternatives for energy supplies and/or scale back operations as they so choose. The Company has three longstanding recall arrangements as summarized in Table 6.3 below.

Table 6.3: Recallable Supply Agreements as of November 2017

Counterparty	Max. Daily Rate (Dth/day)	Max. Annual Recall (Days)
Company X	30,000	30
Company Y	8,000	40
Company Z	1,000	15
Total	39,000	

All of the above agreements are long past their original termination dates, but provide for year-to-year continuation if mutually acceptable with the counterparty. The first agreement above utilizes NWP capacity that NW Natural previously released to Company X, and should this recallable supply agreement terminate, the 30,000 Dth/day of NWP capacity would return to NW Natural. In contrast, the other two agreements utilize NW Pipeline capacity held by those two companies.

The pricing of the recallable supplies reflects the peaking nature of the service. That is, the incremental price of any recalled supplies is tied to the counterparty's alternative fuel costs (diesel or propane) and so would not be economic to dispatch unless weather conditions were extremely cold.

1) *Citygate Deliveries:* As the name implies, these are contracts for gas supplies delivered directly to the Company's service territory by the supplier utilizing their own NWP transportation service. Such deliveries could be arranged as baseload supplies, or on a swing basis, i.e., delivered or not each day at the option of the Company. The Company has utilized citygate agreements on occasion in the past when cost effective. These usually take the form of swing arrangements that allows up to five days' usage during the December through February time period. If deliveries are utilized, the commodity price for the delivered volumes is index-based and expected to be extremely high. For example, the Company evaluated its options to fill a small resource gap identified in this IRP for the 2018-2019 winter heating season, and decided that a Citygate delivery contract was the best alternative. The details of this evaluation will be included in the Company's 2018 PGA filing.
2) *Mist Production:* This is the native gas still being produced from reservoirs in the Mist field about 60 miles northwest of Portland. Production of the local gas allows for the eventual conversion of those underground reservoirs to storage use, and in the meantime, the local gas is being purchased at a competitive price. As previously mentioned the flow rate is small and total Mist production amounts to less than 2 percent of the Company's annual gas purchases
3) *On-System RNG:* While we currently do not purchase any RNG to serve our customers, RNG will soon flow through our system. It is likely that the first RNG on our system will see its environmental attributes monetized by other parties, and the RNG (stripped of its environmental attributes) will be purchased by the Company at a price that is competitive with traditional supplies. Of course this still will constitute a supply resource for the Company in meeting customer requirements, albeit a small one (far less than 1 percent of the Company purchases) for at least the next few years. A much more detailed discussion of RNG can be found in section seven of this chapter.

3. RISK ELEMENTS

3.1. OVERVIEW

An implicit assumption of most prior IRPs has been that supply-side resources function perfectly, i.e., to their design capacities, when and as needed to meet Firm customer requirements. More recently, the topic of resource reliability has been explored by the Company. For example, as customer loads approach the peak day design, the weather conditions are by definition extreme, and so it is not unreasonable to assess some likelihood of resource outages arising from such extreme conditions. The purpose of this section is to make explicit some significant supply-side risk elements that have been part of the Company's implicit assumptions within past resource plans.

3.2. CURTAILMENT OF FIRM PIPELINE SERVICE

The risk element that highlighted the need for this section was the realization that certain firm resources do not need to experience physical outages for the service to be curtailed. The specific resource in question was NWP's Rate Schedule TF-2 transportation service.

What is TF-2 service? During the deregulation of the gas industry in the late 1980s, the merchant function of the interstate pipelines was unbundled and firm sales services were converted to firm transportation services. For NWP, this is their Rate Schedule TF-1. Later, in the early 1990s, storage services also became subject to unbundling, that is, separating the service at the storage facility itself from the pipeline transportation service that had been included (bundled) within the storage service rate schedule. While the unbundled pipeline transportation service was considered a firm service, using the same TF-1 rate structure did not seem appropriate since the transportation service associated with a storage facility would not be available year-round, but only when gas was available for withdrawal or vaporization from that storage facility. Thus was born Rate Schedule TF-2 out of a NWP rate case settlement about 20 years ago. In this region, that unbundling applied to Jackson Prairie and Plymouth.[8]

Plymouth is an LNG plant located in eastern Washington across the Columbia River from Umatilla, Oregon. It is owned by NWP, which has operated it since the 1970s. Service at Plymouth is contracted by NWP to a small number of parties that previously included NW Natural.

The subordinate or secondary nature of portions of the TF-2 firm transportation service had been in place for those 20 years without incident (the terms "subordinate" and "secondary" are used synonymously by NWP to denote priorities that are below that of TF-1 "primary" firm transportation service). Then came Dec. 6, 2013. On that morning, as a cold weather event was enveloping the region, the Company scheduled ("nominated") its Plymouth storage service (Rate Schedule LS-1) and related TF-2 transportation service for flow the following gas day. NWP initially confirmed those nominations, but then informed the Company later that same day that the TF-2 service would have to be curtailed due to its secondary nature and a lack of available transportation capacity between the Plymouth plant and the Company's system. That is, there was no available capacity through the Columbia River Gorge section of NWP's pipeline system.

The curtailment of this TF-2 service led to numerous discussions with NWP. NWP stated that it performed an historical analysis of NW Natural's Plymouth TF-2 service examining NWP's highest peak day of demand in the I-5 corridor for each of the last 14 years. NWP's analysis indicated that NW Natural's Plymouth TF-2 service would have been reliable in 12 of those prior

[8] For further details see NWP's FERC Docket No. RP93-5-011.

14 years. Of course none of these prior 14 years experienced weather conditions comparable to the Company's design weather peak day.

NW Natural concluded that it could no longer count on its 60,100 Dth/day of Plymouth TF-2 service as a firm resource during design cold weather events. It might flow, or it might be curtailed due to its secondary nature—there is no way to know in advance as it depends on the actions of other NWP TF-1 transportation service holders. Accordingly, the Company removed Plymouth TF-2 deliveries from its firm resource stack in the 2014 IRP because they were less reliable than previously believed.[9]

Plymouth effectively became a supply area storage facility for the Company. That is, like the Alberta storage contracts previously discussed, the decision to contract for storage service at Plymouth would need to be based on its cost-effectiveness in offsetting other supply area purchases.

Supply-basin storage agreements have in the past pertained to underground storage, in which the withdrawals generally need to be spread to some extent throughout the entire winter but the service charges can be relatively low. In contrast, Plymouth's LS-1 service could be utilized in a concentrated manner on a small number of (presumably) very highest priced winter days. But because Plymouth is an LNG facility, those LS-1 charges are substantially higher on a per unit basis than underground storage. In recent years, except for the cold weather event in early February 2014, there were no occasions in which gas from Plymouth was a relative bargain compared to spot gas prices. Accordingly, the Company terminated its LS-1 and related TF-2 agreements with NWP, which took effect on Oct. 31, 2015.

In those same December 2013 discussions with NWP, the question also arose as to the reliability of the portion of the Company's TF-2 firm transportation service agreements from Jackson Prairie that were labeled as subordinate. As shown in Table 6-2, this amounts to 13,525 Dth/day.

Since Jackson Prairie is north of the Company's service territory, its TF-2 service flows in the same path as gas from British Columbia (the Sumas receipt point), not from the east through the already-constrained Columbia River Gorge section as with Plymouth. The Company learned that this pathway from Jackson Prairie appears reliable for now. For example, NWP confirmed that the pathway from Jackson Prairie has never been constrained in all the years since the execution of these particular TF-2 service agreements in 1989. However, the subordinate nature of any service does mean it has a lower priority than primary firm service and so has a greater likelihood of curtailment.

Over the long term, it did not appear prudent to rely on this type of capacity because eventually the loads on the NWP system being served from Sumas will grow and reduce the reliability of

[9] It should be noted that this evaluation occurred prior to the March 31, 2014 explosion at the Plymouth plant that crippled its service capabilities for about two years.

any transportation that is less than TF-1 primary firm service. Subsequent negotiations with NWP yielded a discounted TF-1 service from Jackson Prairie to provide 13,525 Dth/day of additional firm transportation service, as detailed in the Company's 2014 IRP Update filing made in May 2015. This agreement has a primary term until October 31, 2031,[10] with a standard annual bi-lateral evergreen provision thereafter. Hence, the Company believes this issue has been resolved and can model the entire Jackson Prairie storage contract as a firm resource for the full IRP planning period.

3.3. RELIANCE ON "SEGMENTED" CAPACITY AS A RESOURCE

The removal of Plymouth in 2014 created an immediate deficiency in NW Natural's resource stack. To deal with that deficiency, at least for the short term, the Company decided to rely in part on another NWP transportation resource that, like secondary and subordinate TF-2 capacity, also has a scheduling priority that is below TF-1 primary firm service, namely segmented TF-1 capacity. To explain segmented capacity, it probably is helpful to start by describing three attributes of NWP's pipeline system operations.

First, NWP's pipeline system receives gas supplies from the north (British Columbia gas delivered via WEI), from the south (U.S. Rockies directly into NWP), and in the rough middle of the system (Alberta gas delivered via GTN). This means that when buying and scheduling gas purchases, the apparent flow of the gas on paper may not match the actual physical flow of the gas. This is due to the interplay of offsetting gas movements and is generally referred to as "displacement." This is what gave rise to the "postage stamp" rate design that traditionally has been used on NWP. A postage stamp can transport an envelope across town or across the country for the same rate. It is an apt analogy for NWP, where the same rate applies whether the gas is being shipped 100 miles or 1,000 miles.

Second, the usage of a NWP transportation agreement is not strictly limited to the receipt and delivery points listed in those contracts. The contractual points establish the "primary" firm characteristics of the service, but other receipt and/or delivery points could be used as well. In those cases, some aspect of the transportation service will not be primary firm, i.e., it will be secondary firm. Just as described above in the TF-2 discussion, the relative reliability of secondary TF-1 service depends on the constraints in that secondary pathway that is being used. This is no different from other pipeline systems in the U.S., but because of NWP's postage stamp rate design, the customer ("shipper") does not pay any additional charges if the new pathway is longer than the original pathway.

Third, there is the process of segmentation itself. A pipeline contract is used to transport gas from points where gas is received into the NWP system (receipt points) to points when gas is delivered to an interconnecting party such as an Local Distribution Company (LDC), another pipeline or a direct connect customer (delivery points). In the illustration below (Figure 6.2), "A" is a circle and denotes the primary receipt point, while "D" is a diamond and indicates the

[10] Previously October 31, 2023, but recently extended another eight years as part of a 2017 negotiation with Northwest Pipeline that included other contract extensions.

primary delivery point. Between the primary receipt and primary delivery points in a contract (between A and D), there could be numerous other receipt or delivery points (illustrated in Figure 6.2 as delivery point "B" and receipt point "C"). These in-between points could be used on a secondary basis as mentioned in the preceding paragraph. That is, gas could be transported from A to B or from C to D.

If a shipper only wants to use the "segment" from A to B, then the remainder of its capacity goes unutilized while the shipper pays the same postage stamp rate for the shorter movement.

Could the shipper release the segment from C to D while still using the segment from A to B? Yes, that is the essence of capacity segmentation and release. The "releasing" shipper pays the exact same postage stamp rate for the movement from A to B, so NWP is kept whole. Any payment that a "replacement" shipper is willing to make for the segment from C to D goes to the releasing shipper, except for the variable costs of transportation service that reimburse NWP for the incremental usage of the pipeline.

Figure 6.2: Capacity Segmentation Illustration

From this basic concept of capacity segmentation and release, two important features follow.

First, the releasing shipper, who retained the segment from A to B, could still use that segment to move gas from A to D. The delivery point is said to have been "flexed" from B to D. This is now secondary firm transportation because the gas is being moved outside of its new primary pathway (A to B). The reliability of service has been compromised, but the extent depends on the pathway being used. Similarly, the replacement shipper also is not restricted to just to the C to D segment, but on a secondary basis could move gas from A to D, i.e., "flex" the receipt point from C to A. Most importantly, there are no additional demand charges to either shipper from these longer movements due to the postage stamp design.

Second, there is nothing that precludes the releasing shipper and the replacement shipper from being the same party. A shipper could leverage its original capacity and hold multiple segments, with no additional costs except for the variable charges applicable to the actual delivered gas volumes. The number of segments that can be created is a function of the receipt and delivery points that lay in-between the points in the original contract. The downside is that the segments would be secondary firm if used outside their new pathways. Again, the extent to which that is a detriment depends on the competition for capacity in the applicable pathways.

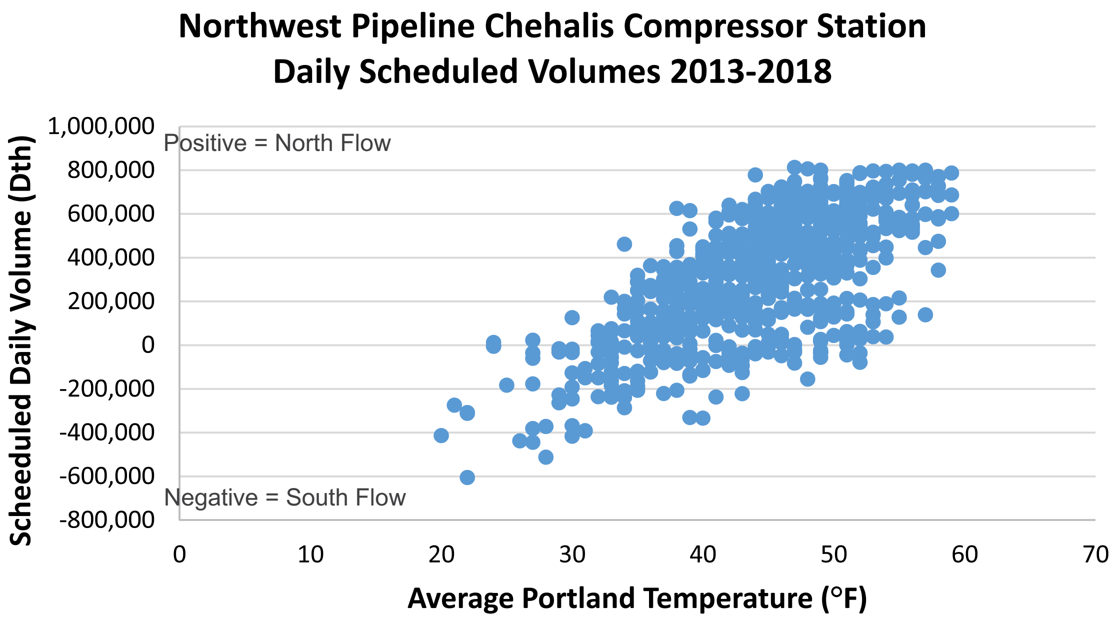
For many years now, NW Natural has performed such capacity segmentations and releases (to itself and others), then flexed the receipt and delivery points to create useful, albeit secondary, firm transportation on the NWP system. The creation of Interstate Storage service was particularly helpful because it led to the development of Molalla and Deer Island gate stations as delivery points on NWP's system, where before they only had been receipt points. Indeed, all of the useful capacity segmentations performed by NW Natural tend to relate back to Molalla and Deer Island as the key points for segmentation.

Because of its secondary nature, the Company had refrained from including segmented capacity in its past IRP analyses. The Plymouth situation, however, and the related discussion pertaining to Jackson Prairie, caused a reassessment of this approach in the 2014 IRP. As with the subordinate TF-2 capacity from Jackson Prairie, NW Natural has created segmented TF-1 capacity that flows from the north (Sumas) in a path that has not experienced any constraints, even during the coldest weather events in recent years. For that reason, segmented capacity was modeled for the first time in the 2014 IRP.

Since there are no demand costs and (aside from Sumas commodity costs) very low variable charges associated with segmented capacity, its selection in our IRP analysis is assured. The Company had 43,800 Dth/day of such segmented capacity in its 2014 analysis. Another 16,900 Dth/day of segmented capacity subsequently was created, and this entire amount of 60,700 Dth/day was included in the 2016 IRP. This amount remains in the current planning.

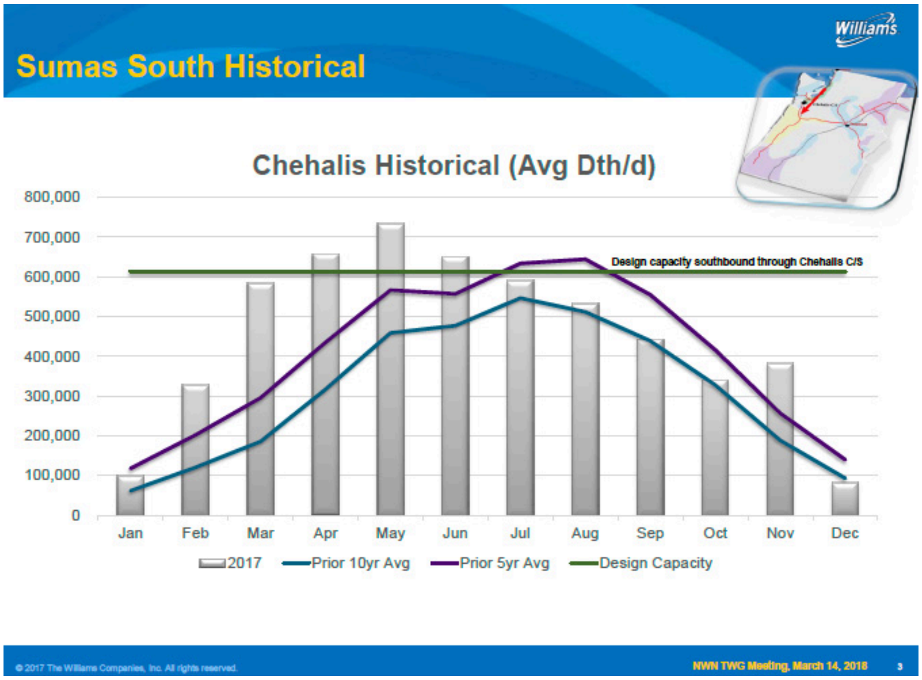
In the 2016 IRP, an analysis of NWP flow data in the I-5 corridor over the prior five winters showed that as the weather gets colder, the predominant flow direction is south to north through the main constraint point at NWP's Chehalis compressor station. Hence, gas flowing south from Sumas on segmented capacity should have greater pipeline reliability as design day conditions are approached. This analysis has been updated to reflect the last three winters and is shown in Figure 6.3 below.

Figure 6.3: Implied Reliability of Segmented Capacity



Another view of the Chehalis constraint was presented by NWP during a 2018 IRP Technical Working Group meeting, as shown in Figure 6.4 below. This chart shows historical monthly average flows southbound through Chehalis. The volumes clearly decrease during the winter months such that they are considerably below the constraint level, i.e., the design capacity. This supports the Company's conclusion that reliance on segmented capacity, even though it is not a firm resource, is reasonable under current operating conditions on the NWP system.

Figure 6.4: Chehalis South Flows on a Monthly Basis



Additionally, the Company now has some experience in using segmented capacity and the results have been very encouraging. Specifically, for the last two winters, all or some of the segmented capacity was used on 87 days during the period of December 1, 2016 - May 3, 2017, and on 79 days during December 1, 2017- April 30, 2018. Of those 166 days, there was only one occurrence in which the full volume was not delivered, and that was due to an issue with the gas supplier, not the pipeline transportation itself.

Looking forward, new load developments between Sumas and the Company's service territory might undermine the reliability of this service, especially if not accompanied by an equivalent capacity expansion of NWP's system and upstream infrastructure to get more gas supplies to Sumas. So, the key question now about segmented capacity is: "How many years should we assume segmented capacity would be available on a reasonably reliable basis?"

In the 2014 and 2016 IRPs, the assumption was that it would take five years before load changes in the I-5 corridor between the Canadian border and Oregon might totally erode the reliability of this service. We now believe that by 2021, regional coal plant retirements will have started to take place, while very large industrial loads (e.g., methanol production) could conceivably be starting service. Accordingly, this segmented capacity is assumed to be fully available until November 2021, then partially phase out during the 2021-2022 winter and completely phase out by the 2022-2023 winter. Of course this assumption is subject to constant monitoring and reevaluation as necessary.

3.4. IMPACT OF OPERATIONAL FLOW ORDERS

Interstate pipelines have a variety of methods to ensure they can deliver on their firm commitments. The first is the use of their line pressure and storage volumes to balance deliveries with receipts of gas. When pressures start sagging and storage volumes run low, an "entitlement" event may be declared. In that event, shippers must not use more (take delivery) of more than a specified volume of gas in a day, which in turn is based on the volume that the shipper has received from its suppliers. If the shipper takes delivery of more gas than it is entitled to use, penalty charges can be applied by the pipeline on that shipper, which are intentionally onerous to motivate compliance with the entitlement order.

Sometimes entitlements are not sufficient to correct imbalances on the NWP system. Displacement (which is sometimes necessary to provide firm deliveries) has saved money for shippers over the years by eliminating the construction of certain facilities that might have been considered duplicative. However, it also greatly complicates the operation of the NWP system because it anticipates certain shippers acting in certain ways; basically, projections as to how shippers will use their contracts. If the shippers do not "follow the script," imbalances can build quickly on the NWP system. NWP's use of line pressure, storage and entitlement orders helps to manage such situations, but those do not necessarily provide all the signals necessary to totally correct/reverse the build-up of such imbalances. In that event, NWP will turn to the issuance of operational flow orders (OFOs).

OFOs are another tool provided for in NWP's tariffs. Through OFOs, NWP can dictate to shippers how they utilize their contracts in order to bring balance to the pipeline system. For example, an OFO may dictate that a shipper in the Pacific Northwest reduce its purchases of Rockies gas and/or increase its purchases of Sumas gas in order to relieve the capacity bottleneck that exists in the Columbia River Gorge section of NWP. Because of the potential financial repercussions on the shippers, NWP cannot impose OFOs without first exhausting other remedies. This is exactly what exposed the tenuous nature of the secondary TF-2 service from Plymouth in December 2013; by its tariff, NWP could not impose OFOs on TF-1 shippers to ensure that secondary TF-2 service would flow.

Besides the effects it has on transportation service, a related impact of OFOs is that it creates its own commodity price distortions. For example, if Rockies commodity prices are below Sumas, then shippers are motivated to buy more Rockies gas. If this causes an imbalance that can only be cured through an OFO, then the demand for gas at Sumas will necessarily increase while the demand for gas in the Rockies will diminish. The price spreads between Sumas and Rockies that originally caused the lop-sided purchasing decisions are very likely then to become even larger. While NWP is not imposing a direct financial penalty on shippers by initiating the OFO, there is an indirect penalty/cost because of this impact on commodity prices.

The simple cure for OFOs is to build more pipeline infrastructure in a way that relieves the current bottlenecks. That cost is relatively easy to estimate. What is difficult to estimate is the benefit from the resulting mitigation or elimination of OFOs. For this IRP, the working assumption is that OFOs are rare and cannot be expected to coincide with design day conditions, and hence do not need to be considered in the analysis.

3.5. MDDO RESTRICTIONS AT GATE STATIONS

As previously mentioned, a gate station is a location at which the Company is physically connected to the upstream pipeline network. There are over 40 major gate stations in the Company's system, and they are sometimes collectively referred to as the "citygate." With some minor exceptions, all of the gate stations directly connect the Company to NWP. The exceptions are the gate stations that connect to the Kelso-Beaver Pipeline and the Coos County Pipeline. However, since the Company's service on those pipelines is itself dependent on their connections to NWP, it is a distinction without a difference. Accordingly, NWP's operating rules, processes and procedures for deliveries at gate stations are of fundamental importance.

Each transportation contract between the Company and NWP specifies certain receipt and delivery points. The delivery points are usually gate stations, though they also could include off-system storage facilities like Jackson Prairie. The quantity that NWP is obligated to transport each day under a contract is called the Contract Demand (CD). The amount that NWP is obligated to deliver at a gate station—assuming the Company has secured the necessary gas supplies—is referred to as the Maximum Daily Delivery Obligation (MDDO).

Over the years, the Company could add MDDOs by increasing its contracted CD with NWP. The advent of Mist storage, and Mist recalls, as a primary resource for meeting load growth, has changed that dynamic. Now the Company can save money with Mist by avoiding subscriptions to new CD, but that also means that MDDOs are not increasing.

The issue is that as customer growth continues, some existing gate stations require more capacity, and the building of entirely new gate stations may be an effective way to serve the growth. The Company has paid NWP for the new or expanded gate stations, but without receiving any additional MDDOs. That is, the Company has paid for new capacity but did not acquire any firm rights from NWP to use that capacity. Meanwhile, as service from Mist has grown, it has displaced the need for MDDOs at certain existing gate stations. These displaced MDDOs can be used at the new/expanded gate stations, but that may only be the case when Mist is in full withdrawal mode. So while Mist provides tremendous flexibility in serving customer needs, it has significantly complicated the process of gate station planning.

These gate stations reside at the intersection of our upstream analysis (using SENDOUT®) and our distribution system planning (using Synergi). The upstream analysis relies on the CD under each contract because that is the effective limitation on supplies that can be procured at the receipt points into NWP. But for distribution planning, there are two logical choices: use the MDDOs as the gate station limit, or use the actual physical capacity of each gate station. In many cases they are the same number, but over the years, a gap has been growing and will continue to grow as long as Mist recalls are the most cost-effective resource to meet load growth.

If the Company uses MDDOs to reflect the firm delivery limit from NWP, then the analysis would indicate the need for new CD subscriptions from NWP. If the actual physical capacities are used, the requirement shrinks dramatically, but the Company runs the risk that at some point a new customer on NWP's system will subscribe to new CD with the intent of moving gas to one of these gate stations, thus reducing the reliability of the Company's deliveries there. In effect, this is another case where the Company is relying on a less-than-firm service because it creates savings for customers (avoids more costly CD subscriptions) while the risks of losing that service are believed to be minimal for most gate stations for the foreseeable future.

For the 2016 IRP, after studying the alternatives and consulting with NWP, it became clear that a third approach was appropriate. Rather than modeling either the physical capacity or the MDDOs at each individual gate station, certain gate stations could be grouped together and treated conjunctively if they fell within the same "zone." Zones typically are delineated by NWP's compressor stations. In effect, as long as the physical capacity at a gate station is not exceeded, there is no specific MDDO limit at that gate station as long as the total MDDOs within the zone are not exceeded. Even more importantly, unused MDDOs in a zone can be, in essence, redeployed for use in zones lying upstream on NWP's system.

This concept is extremely important for cold weather and design day planning. During cold weather, the Company's on-system storage plants (Mist, Gasco, and Newport LNG) likely would be in withdrawal/vaporization mode at or near their maximum capabilities. Large storage withdrawals into a load center can act to reduce gas receipts from NWP at gate stations serving the same load center. The unused MDDOs from those gate stations then can be assumed for modeling purposes to be available for use at other gate stations. For example, reductions at Portland-area gate stations related to Mist and Gasco withdrawals result in more MDDOs available for Clark County gate stations.

Using this modeling approach, the 2016 IRP showed that there were ample MDDOs to serve customers, and that continues to be the case in this IRP.

4. CHANGES IN THE EXISTING RESOURCE PORTFOLIO

Since the 2016 IRP, there have been four changes to the existing supply-side resource portfolio, as described below.

4.1. NORTHWEST PIPELINE CONTRACT EXTENSIONS

Starting in February 2017, negotiations between NW Natural and Northwest Pipeline (NWP) led to the signing of a memorandum of understanding (MOU) in August 2017 in which it was agreed that various transportation contracts would be extended in term, along with NWP providing operational improvements at several interconnection points with NW Natural. All of the extended NWP contracts had been assumed to persist throughout the planning horizon in prior IRPs. A contract of particular interest to NW Natural was the discounted TF-1 service from Jackson Prairie. As mentioned in section 3.2 of this chapter, this contract firmed up the reliability of 13,525 Dth/day of Jackson Prairie storage service, but its term ended in 2023 and its discounted nature gave no assurance that it would be renewed by NWP. But as part of the MOU, the termination date of that contract was extended from 2023 to 2031.

4.2. T-SOUTH CONTRACT EXTENSION

T-South refers to the pipeline transmission system in British Columbia between Compressor Station 2 (“Station 2”) in northern BC and Huntingdon/Sumas (“Sumas”) at the international border. T-South is part of the Westcoast Energy system, which is owned by Enbridge (after its recent acquisition of Spectra). The T-South system is fully subscribed, but NW Natural has been able to acquire some T-South service over time from existing capacity holders at market prices. As mentioned in Chapter 3, Section 4.4 of the 2016 IRP, there are both economic considerations to holding T-South capacity (i.e., the price spread between Station 2 and Sumas), as well as reliability considerations given the relative liquidity of supply at Station 2 versus Sumas.

NW Natural had an opportunity in 2017 to extend the term of its existing acquisition of 19,000 Dth/day of T-South capacity from October 31, 2018 to October 31, 2021. The subsequent analysis showed that there were customer benefits to the extension, which was executed in September 2017.

4.3. T-SOUTH EXPANSION PROJECT PARTICIPATION

As reported in the Company’s 2016 IRP Update filing of August 9, 2017, a T-South expansion project is in progress. It is shown in the following Figure 6.5 as “T-South Looping” on the Enbridge system in central BC.

Figure 6.5: Infrastructure Projects Proposed to Serve the Region

Source: NWGA 2017 Gas Outlook, Figure C6

Station 2 provides an alternative to Sumas for purchases of gas in BC, but as mentioned above, T-South capacity currently is fully subscribed on an annual basis. Winter-only (November-March) T-South service had been available until an Enbridge open season during December 2016/January 2017 claimed the last remaining 160 million cubic feet per day (MMcfd) of such service. NW Natural participated in this Winter-Only open season, but its bids of 7 and 11 year terms were not awarded. The winners in that open season bid contract terms exceeding 40 years.

Due to this interest in T-South service, Enbridge decided to hold an open season in the spring of 2017 for an expansion of year-round T-South service of up to 190 MMcfd. NW Natural also participated in this expansion open season. In June 2017, Enbridge awarded to NW Natural a contract quantity of 672.90 thousand cubic meters per day (103m3/day), or roughly 25,000 Dth/day, of year-round T-South capacity for a 40 year term that commences with the in-service date of the T-South expansion project. This start date is anticipated to be November 1, 2020. It should be noted that NW Natural successfully bid a 40 year contract for capacity during the T-South expansion open season.

Except for Mist production gas, and until on-system renewable natural gas is available, deliveries from NWP are the sole source of gas into NW Natural's system. NWP's tariff specifies a minimum heat content of 985 Btu/cf with no maximum limit.

Our three on-system storage facilities were designed and permitted in volumetric units, which then are converted to energy units for IRP and PGA purposes. Heat content is the conversion factor, expressed in Btu/cf, and it has been relatively stable over the years; that is, until a few years ago.

As oil and gas supplies grew, a glut of natural gas liquids (NGLs) developed in the supply basins. NGLs include ethane, propane, butane, and some heavier hydrocarbons. With falling commodity prices, the incentive to process NGLs out of the gas stream has shrunk. In particular, the profit margins for separating ethane are such that a noticeable amount of ethane is being left in the natural gas stream. Noticeable meaning that the heat content on NWP's system has moved from a range around 1020 Btu/cf to a range closer to 1090 Btu/cf.

For the LNG plants, heat content increases also reflect the further effect of "weathering" that occurs to the inventory. The LNG is at -258° F, and since the double-walled tanks are not perfect insulators, a small amount of LNG will warm enough to turn back to gas. Technically this LNG is boiling as it turns from liquid phase to gaseous. This "boil-off" gas is not lost but just flows into the distribution system, taking the heat with it and keeping the rest of the LNG at -258° F. Methane is the first component of the LNG to boil-off, which then raises the proportion of ethane in the remaining LNG, again raising its overall heat content.

The higher Btu value of the gas flowing over NWP's system could reverse itself at any time, but probably not until profit margins improve on ethane removal. Accordingly, as was done in the 2016 IRP, the Company has reassessed the heat content used for the storage plant volumetric conversions and concluded that small changes are appropriate.

Because these changes are relatively small (less than 5,000 Dth/day in aggregate for the two LNG plants), rather than try to forecast how their heat contents might vary in the future, NW Natural will retain the current values over the IRP planning horizon and reassess them in two years, i.e., as the next IRP is being prepared.

As for Mist, there is no immediate adjustment to deliverability because Core requirements and Mist recalls have always been specified on an energy basis. However, the heat-content adjustment does imply a slight increase in the amount of Mist recall that would be available in future years. Again, this change is relatively small (less than 5,000 Dth/day) and will be revisited in each subsequent IRP.

5. METHANOL PLANT CAPACITY SHARING

As mentioned in the 2016 IRP (chapter 3, section 7.8), the developer of a methanol project presented a resource option to NW Natural that was an intriguing variation of industrial recall. The arrangement involves a year-round NWP capacity release from NW Natural to the developer, coupled with a limited recall right. However, unlike other recall arrangements, the recall right in this case only extends to a certain portion of the released capacity. Because a portion is not recallable, the Company would need to advance its next resource acquisition to cover the shortfall, presumably Mist Recall given the time frame.

Because this arrangement would not involve any kind of permanent NWP capacity release, it would result in no difference in the Company's resource portfolio by the end of the IRP planning period. Instead, it could be viewed as an optimization of resources within the IRP period. The developer and NW Natural continue to explore such an arrangement that, if beneficial for customers, could be put in place when the project is ready to move ahead.

6. NW NATURAL'S STORAGE PLANT PROJECTS

NW Natural's three on-system storage plants are crucial elements of the Company's resource portfolio, providing approximately half of the gas required on the design peak day. But with Mist initially built in the late1980s, Newport LNG in the mid-1970s, and Portland LNG in the late 1960s, these facilities also are experiencing increased maintenance needs due to their age. Accordingly, the Company has developed asset management programs for each plant that consists of a mix of preventative maintenance, repair and replacement projects. These projects may involve outside consultant studies as well as analysis of alternatives.

The following sections provide details on the largest key projects for each plant. A complete list of all projects is in Appendix F: Supply Side Resources.

6.1. MIST ASSET MANAGEMENT PROJECTS

This section discusses NW Natural's plan for capital projects at the Mist 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.

Large Dehydrator

The large dehydration system at Miller Station at Mist has reached end-of-life and is not functioning as designed; the OPUC acknowledged a 2016 IRP action item for repairing or replacing the large dehydrator system.[11] A third party engineering evaluation of the system concluded that the existing dehydrator system should be replaced, and an in-depth economic and alternatives analysis is currently underway.

Compression at Miller Station Study

Mist was originally built with 80,000 Dth/day of maximum deliverability in 1989, which grew to 190,000 Dth/day by 2000. The core portion of Mist has now grown to 305,000 Dth/day, and future Mist recalls of course will increase that amount until it equals all of the existing Mist deliverability. Two reciprocating compressors (the "recips") were part of the original facility design in the 1980s, and two large turbine compressors (the "turbines") were added in the late 1990s and early 2000s, respectively. The recips are inefficiently sized now for the flow conditions and operations at Mist. The result is overuse of the turbines, which causes additional maintenance cost due to excessive use and deformations. NW Natural will conduct a study to

[11] See NW Natural 2016 IRP, Chapter 3 for a detailed discussion.

determine the best solutions for compressor operations at Miller Station. The study is to be completed in 2019, and if necessary, the first phase of compressor replacement could start as early as 2020. It is estimated the study would have a total cost of $600,000.

6.2. PORTLAND LNG PLANT PROJECTS

The Portland LNG plant (also referred to as "Gasco") was constructed by Chicago Bridge and Iron and commissioned in 1969. As a resource specifically used for peak shaving, NW Natural requires high availability and reliability from Gasco. The facility and its major process components were designed for a nominal 25- to 30-year life, and it is now almost 50 years old.

Several mechanical and operational issues have been identified within the facility, and an in-depth engineering, economic, and alternatives analysis is underway. Contingent on the results of this analysis, the Company will identify and move forward with the best combination of solutions to address the issues. Two potentially significant issues—the facility's liquefaction system and cold box heat exchangers—are described below.

The Company retained an engineering consultant to study the existing liquefaction and pretreatment systems. This study is still in progress, and along with internal analysis by the Company, will identify which refurbishment and/or replacement options are best for the plant. The consultant's liquefaction study is expected to run through 2018 at a total cost of $850,000. Contingent on the results of this study and internal analysis, NW Natural will proceed with refurbishment or replacement of the liquefaction and associated system.

The other significant issue identified at Portland LNG is that the facility's cold box heat exchangers—original to the plant —no longer function reliably. The cold box was not designed to process current pipeline deliveries with their higher concentration of NGLs (as mentioned in section 4.4), which condense in unintended parts of the heat exchanger. This causes the production rate to decrease, fouls the liquid separation system, and periodically requires a complete shutdown and blow down to clear the system, leading to downtime in the liquefaction process. Contingent on the results of the internal evaluation of the facility, NW Natural may have to replace the pretreatment system with a modern system designed to process current gas streams, and replace the cold box, associated appurtenances and instrumentation, boil off compressors, and glycol system heat exchangers. It is estimated that these replacements could have a total cost of roughly $40 million.

6.3. NEWPORT LNG PLANT PROJECTS

The Newport LNG plant was constructed by Chicago Bridge and Iron and commissioned in 1977. As a resource specifically used for peak shaving, NW Natural requires the same high availability and reliability from the Newport plant as it does for Gasco. The Newport facility and its major process components were designed for a nominal 25- to 30-year life, and it is now over 40 years old.

For this IRP, there are no new major capital projects at the Newport LNG plant to describe in this section, but a listing of other projects is provided in Appendix F.

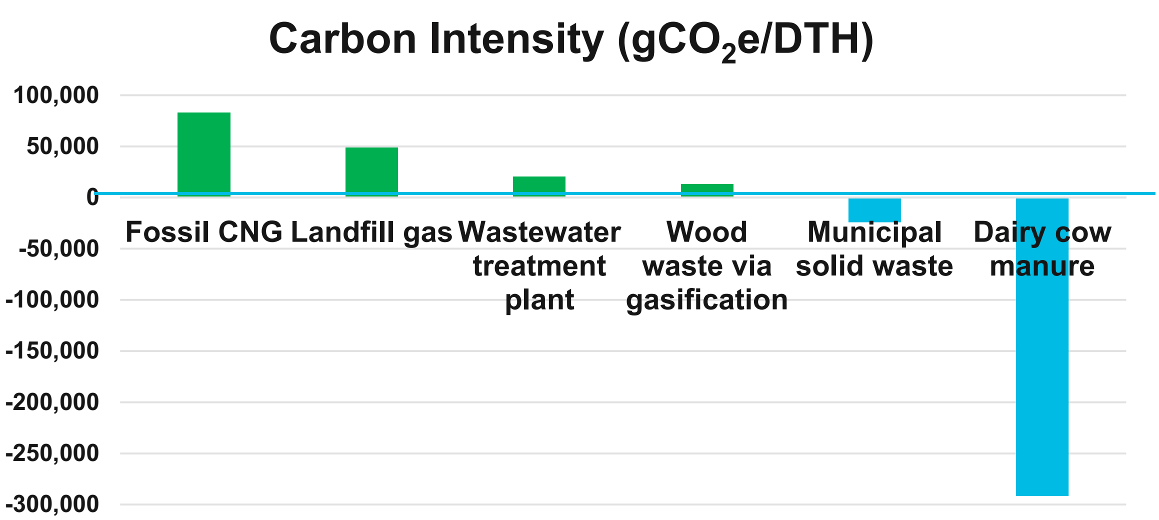
7. RENEWABLE NATURAL GAS

7.1. OVERVIEW

Renewable natural gas (RNG) is methane that has been captured and collected from an existing source (e.g., wastewater treatment plants or dairy manures), processed and compressed to meet existing gas pipeline standards, and injected into a gas pipeline system for delivery to end-use customers. While RNG has been discussed at a high level in the past[12], this marks the first time that it has been fully analyzed as a potential resource in a Company IRP and compared to conventional resources.

RNG can be an attractive resource due to its net positive environmental benefits, including a reduced carbon dioxide (CO_2)-equivalent emissions profile relative to conventional natural gas. Much of this benefit is due to the fact that most RNG resources would be emitting methane into the atmosphere absent the gas collection and processing activities inherent in RNG production, so the environmental benefits include the reduction of methane venting directly into the atmosphere. Methane is a potent greenhouse gas, and thus valuation of reduced methane is typically embedded within most policies designed to reduce atmospheric CO_2. Depending on the RNG feedstock, these reduced methane benefits can be substantial, in some cases providing a net negative impact on overall CO_2-equivalent emissions (see Figure 6.6). This means that for those cases, each unit of RNG used reduces the absolute CO_2-equivalent emissions in the atmosphere.

Figure 6.6: Carbon Intensity of Selected RNG Resources



Source: California Air Resources Board (Jaffe 2016). Note these numbers consider the resource compressed into CNG, so they reflect the efficiency losses inherent in compression (compression efficiency is assumed to be the same across all presented RNG resources)

[12] See, e.g., the Company's 2016 IRP, pages 3.39-3.40.

Due to the fact that we consider future costs of emitting carbon dioxide within our avoided cost analyses (see chapter four), resources that offer a reduced-carbon product for delivery to customers are of keen interest to the Company. In future years, when new policies or regulations are anticipated to be in place that more highly value carbon reductions, resources such as RNG may become more cost-effective for customers than other more traditional sources of natural gas. For this reason, and due to the growth and maturation of the renewable natural gas (RNG) industry and increased availability of RNG since the 2016 IRP, the Company considers a variety of potential RNG resources in this IRP.

Since 2016, the Company has also made significant progress in working with RNG projects that wish to interconnect with our system. Work to interconnect the first on-system RNG project will begin in 2018. Located at the City of Portland's Columbia Boulevard Wastewater Treatment Plant, this plant will produce RNG that NW Natural will buy (stripped of its environmental attributes) for delivery to customers. The very lucrative environmental attributes will be separated from the RNG and sold by the City via a third party into several existing credit markets. These credit markets are driving considerable investment interest in RNG projects, and are critical to the early-stage growth of the nascent RNG industry. However, they are linked to state and federal policies that are not guaranteed to exist in the future, and thus the economics of RNG projects in the future are very difficult to predict and potentially highly variable. To understand how RNG resources, inclusive of their environmental attributes, might look in the future for our own customers, NW Natural has engaged in outreach to current RNG producers and project developers, as well as third party credit marketers and those affiliated with the existing supportive policies. For purposes of this IRP, the Company has made its best estimates of the impact of these credits on RNG project economics in the future.

Five different RNG scenarios were evaluated during portfolio modeling in this IRP, as described below. These scenarios are not inclusive of all of the RNG resources available today, but represent the types of resources that are most ready for near-term delivery based on the Company's understanding of the regional RNG market. NW Natural continues to track existing federal and state-level policies that impact the development and growth of the RNG market, and is engaged in the important work the Oregon Department of Energy is conducting to evaluate the full technical potential for RNG within Oregon, as authorized by the 2017 Oregon Senate Bill 334[13]. The market realities of RNG are constantly changing, in part due to the above-mentioned federal and state policies, and the Company will continually evaluate a variety of RNG resources and track their evolving cost characteristics.

7.2. PURCHASE RNG FROM EXISTING RNG PROJECT (SCENARIO ONE)

There are currently 111 operational or in-development RNG projects in the United States[14]. The first scenario considers a purchase of 100,000 Dth/year from one of these existing operational projects, located at a landfill. This scenario reflects our knowledge of the existing premium paid for RNG by parties that are subject to compliance requirements under federal and state policies.

[13] See full text of Oregon Senate Bill 334 here: https://olis.leg.state.or.us/liz/2017R1/Downloads/MeasureDocument/SB334.
[14] Data per the Coalition for Renewable Natural Gas: http://www.rngcoalition.com/rng-production-facilities/

These policies include the federal Renewable Fuel Standard, the California Low-Carbon Fuel Standard, and the Oregon Clean Fuels Program. At current trading prices, the credit premium on landfill gas that accesses both the federal and the California trading programs can command a premium of $32.48 above the underlying commodity cost of gas. In this scenario we assume we must compete with that existing credit market price to acquire the gas for delivery to our customers, and that we have to pay to transport that gas to our distribution system. We also assume that we enter into a short-term contract for the gas, which generally requires a higher price than longer-term contracts for RNG production. This scenario was designed to reflect the cost of RNG procured for immediate delivery to our customers today from existing RNG producers.

7.3. PURCHASE RNG VIA A FUTURE LONG-TERM CONTRACT FROM AN EXISTING ON-SYSTEM PROJECT (SCENARIO TWO)

The afore-mentioned policies that grant significant credit value in the market for RNG right now could see their long-term impact on RNG prices decrease over time, depending on how annual credit targets are developed. Due to the uncertainty facing RNG project developers in the medium- to long-term, contracts for RNG to be executed after the period during which market-based credits are expected to be highly lucrative are of interest to reduce long-term risk of the RNG projects. Further, we find project developers may benefit from showing potential financing partners that their project has a long-term revenue stream available well after these credits expire. In some cases RNG project developers are interested in selling a portion of their gas into the shorter-term credit market while selling another portion of their gas to other parties via long-term fixed price contracts, thereby reducing their risk exposure.

For this scenario, we model a contract for delivery of 100,000 Dth/year of RNG in years 2023-2033 from a regional dairy located near our pipeline infrastructure. It is assumed that the RNG project developer would fully monetize the available credits in years 2018-2022, and be interested in then entering into a contract for guaranteed revenues from the sale of RNG from 2023-2033. This reflects recent conversations we have had with RNG project developers working to secure financing for their projects.

There are two main reasons this scenario becomes a cost-effective resource for our customers in the future. First, the RNG is assumed to be derived from the anaerobic digestion of dairy manure, which, as seen in Figure 6.6, has a net negative carbon intensity. This, again, is due to the fact that RNG production at a dairy will capture methane that had previously escaped into the atmosphere and use it for productive purposes, thus both displacing fossil gas as well as avoiding significant methane emissions. In future years, when we anticipate that the cost of compliance associated with the emissions of carbon dioxide rise, the substantial emissions reductions available through dairy-based RNG make the resource cost-effective for customers.

Additionally, this RNG is assumed to be purchased from a project located at a dairy that is located very near our existing pipeline infrastructure. Thus, by purchasing the 100,000 Dth/year from this nearby resource, we avoid the need to transport that same amount of gas from far-away basins while also reinforcing our distribution system capacity in the area near this supply source. This makes the resource further cost-effective for customers.

Notable in this scenario is that this is the cost of acquiring RNG from a project developed by a third party that is driven by the presence and economics of the transportation fuel credit markets. The long-term contract is available to us at a discount to what would be assumed to be the revenues associated with credit acquisition as a sort of long-term hedge; if we developed the entire dairy project ourselves, we would not need to compete with the transportation fuel credit markets.

7.4. DEVELOP RNG PRODUCTION AT EXISTING WASTEWATER TREATMENT PLANT (SCENARIO THREE)

Due to the high value of credits associated with selling RNG into the transportation fuels market, we consider in Scenario Three whether developing our own RNG for delivery to our customers could mitigate the need to compete against the highly lucrative credit markets. This project assumes 100,000 Dth/year are produced from a RNG plant developed at an existing wastewater treatment plant that already has in-place anaerobic digestion. Our assumptions were informed by data collected from and conversations with several existing regional wastewater treatment plants that have recently undergone RNG project development and/or have commissioned engineering consultations to consider such development. The costs associated with Scenario Three are derived by examining investment in RNG as a utility investment; thus, the costs of operating the project are analyzed through our utility cost-of-service model.

Scenario Three assumes that the RNG produced onsite is delivered to our customers as soon as it is available, and that no monetization of the value of RNG in the transportation fuels market occurs. In this scenario we invest in gas conditioning and cleanup, gas compression, and the cost to interconnect the system to our pipeline. We also pay the wastewater treatment plant for their raw biogas coming out of their anaerobic digestion process. In addition to the upfront capital costs, we also incur annual expenses for the operation and maintenance of the equipment in which we invest.

Scenario Three also assumes that the RNG production occurs at a wastewater treatment plant located near our existing infrastructure. As with Scenario Two, this assumption yields an economic benefit within the scenario in the form of avoided transportation of gas from out-of-state resources and reinforcement of our distribution system in the area near this supply source.

7.5. DEVELOP RNG PRODUCTION AT EXISTING WASTEWATER TREATMENT PLANT; MONETIZE MARKET CREDITS (SCENARIO FOUR)

This scenario is physically exactly the same as Scenario Three. We consider the same 100,000 Dth/year RNG development at the same wastewater treatment plant, with the same costs assumed for development and operation of the plant, examined through a cost-of-service model. What distinguishes Scenario Four from Scenario Three is that instead of developing the project for immediate delivery to our customers, this scenario assumes that the RNG is sold into the transportation fuel credit markets in Year 1-5, with delivery to our customers for direct use beginning in Year 6. This approach allows for a greater revenue stream in the early years of the project, which thus reduces the overall levelized cost of delivered gas throughout the entire project's lifespan.

The purpose of structuring Scenario Four in this way is to examine whether early-year monetization of the transportation fuel credits could be significant enough to reduce the overall cost of delivering RNG to our customers in the medium and long term. We find that the impact of the monetization of these credits is significant, reducing the overall cost of delivery of RNG to our customers by about 36% when compared to a scenario that does not immediately monetize the transportation credits.

7.6. PURCHASE RNG VIA A FUTURE LONG-TERM CONTRACT FROM AN EXISTING OFF-SYSTEM PROJECT (SCENARIO FIVE)

Scenario Five is similar to Scenario Two, in that the 100,000 Dth/year RNG is purchased for delivery 2023-2033 from an existing project at a dairy. This allows the project developer to fully monetize the transportation fuel credits in the years prior to contracted delivery for our customers. Scenario Five differs from Scenario Two in that Scenario Five considers this contractual arrangement only with dairies that are located off our system. In this way, these resources are not capacity resources, and the overall economics of this scenario do not reflect the additional economic benefit of selecting resources that are on our system and allow us to avoid transportation of gas from out of state. In fact, some of these dairies considered in Scenario Five are out of state. We see especially large concentrations of potentially available RNG in Idaho. This scenario does, however, reflect the substantial carbon benefit seen by utilizing RNG from dairy manure resources.

7.7. RNG AS A FUTURE RESOURCE

The development of markets around credits produced when using RNG in CNG vehicles has stimulated an increased understanding of the carbon intensities of different RNG resources, and a better understanding of how RNG compares to conventional natural gas resources. We will continue to track this important analysis, and hone our own internal analysis of how the carbon intensities of these resources impact their value to customers in future years where we anticipate higher costs associated with carbon emissions. The economic drive to invest in RNG projects has yielded an increase in interest among potential RNG project developers in interconnecting with our system. We anticipate the growth of the RNG industry to continue in the coming years, reflecting the tightening emissions reduction goals embedded in the California and Oregon state-level clean fuels programs that provide the lucrative credits for RNG production. We also look forward to the findings of the Oregon Department of Energy's forthcoming report on RNG to the legislature, and will continue to work with current and potential RNG producers to better understand this growing market.

NW Natural also will continue to track in detail costs associated with RNG production. We believe there may be RNG resources developed in the near term that could provide cost-effective resources for our customers. In order to be able to better analyze whether these resources are indeed the most cost-effective resources available as they are developed, NW Natural is proposing an Action Item in this IRP that establishes a methodology for evaluating and valuing such resources. This Action Item is fully detailed in Appendix H, and we believe provides NW Natural with a pathway toward better evaluating how specific projects compare to other cost-effective options to serve our customers.

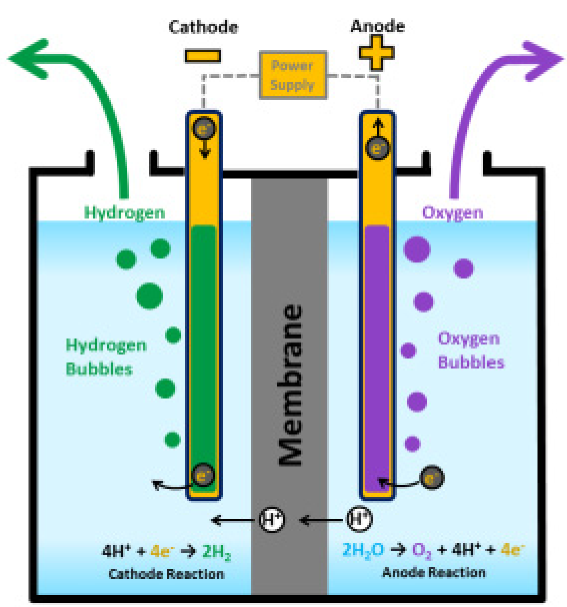
8. POWER-TO-GAS (P2G)

8.1. OVERVIEW

Power-to-gas (P2G) 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[15]. A discussion of P2G as a potential resource option is new to the Company's IRP process.

Figure 6.7 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 6.7: 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%. The company is reviewing research

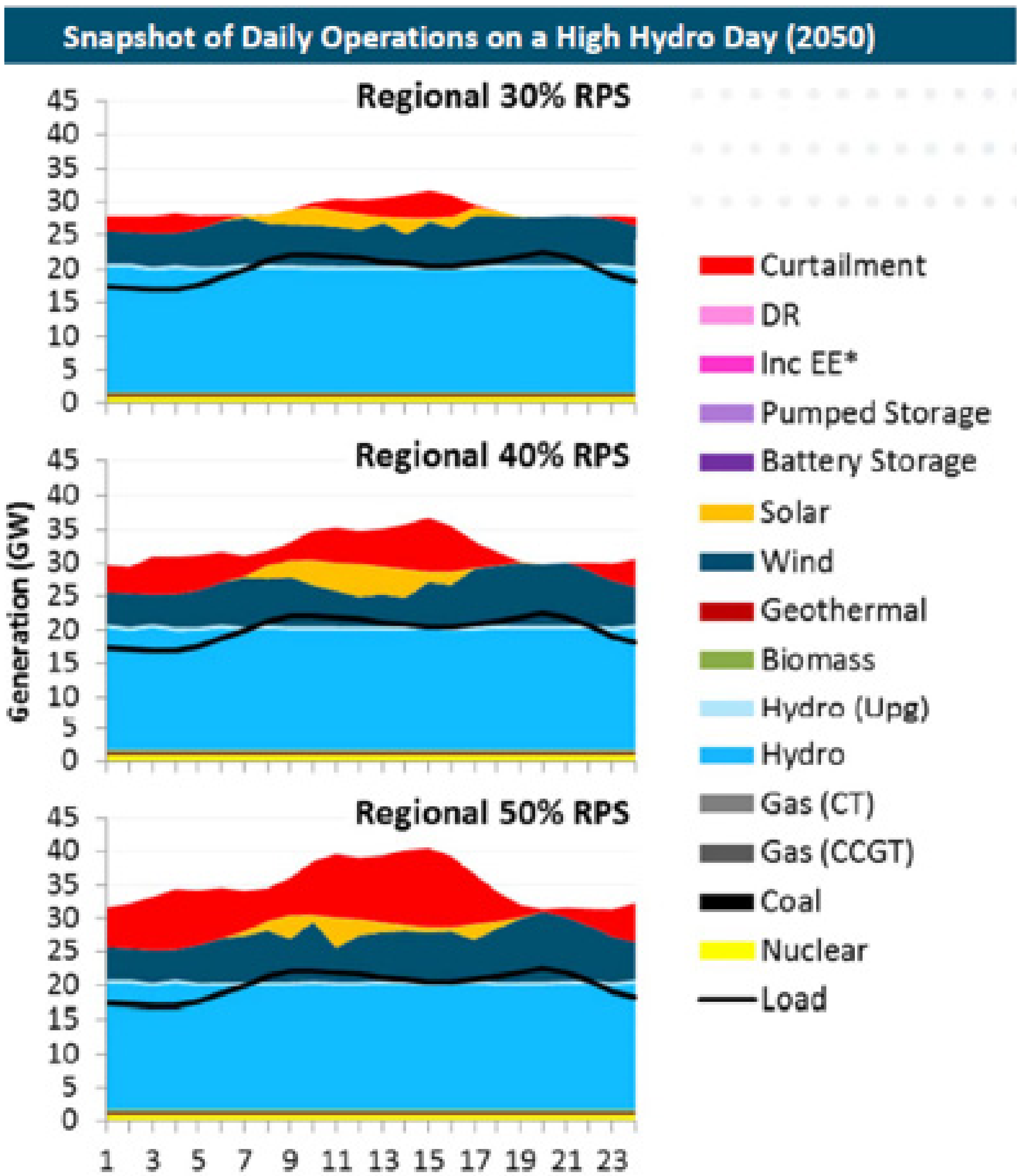
[15] See, e.g., the HyDeploy project: https://hydeploy.co.uk/

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.

8.2. 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.

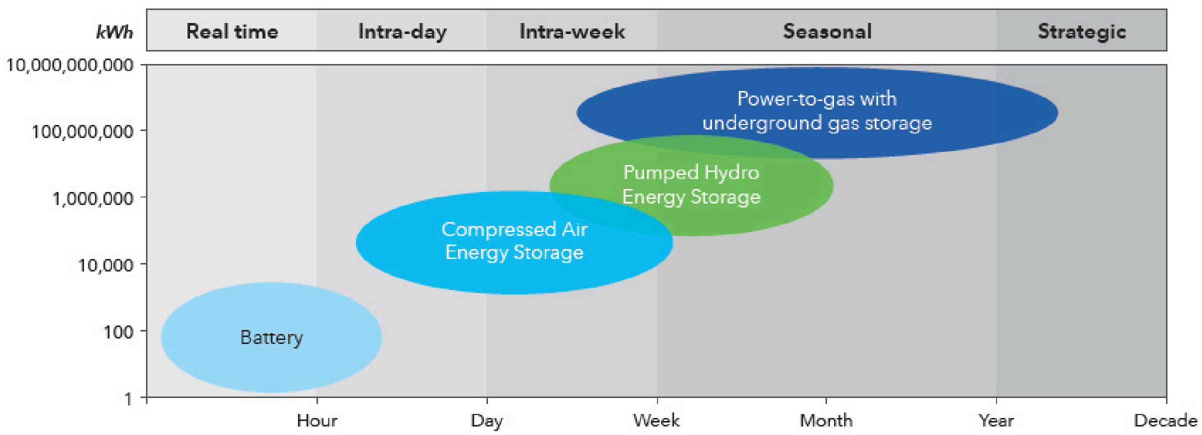
Figure 6.8: Expected curtailed power in future high-renewable electricity scenarios



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

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, 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.[16] 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: http://www.europeanpowertogas.com/media/files/European%20Power%20to%20Gas_White%20Paper.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.

[16] 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.

8.3. 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 advances 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 manner in which it will be operated.

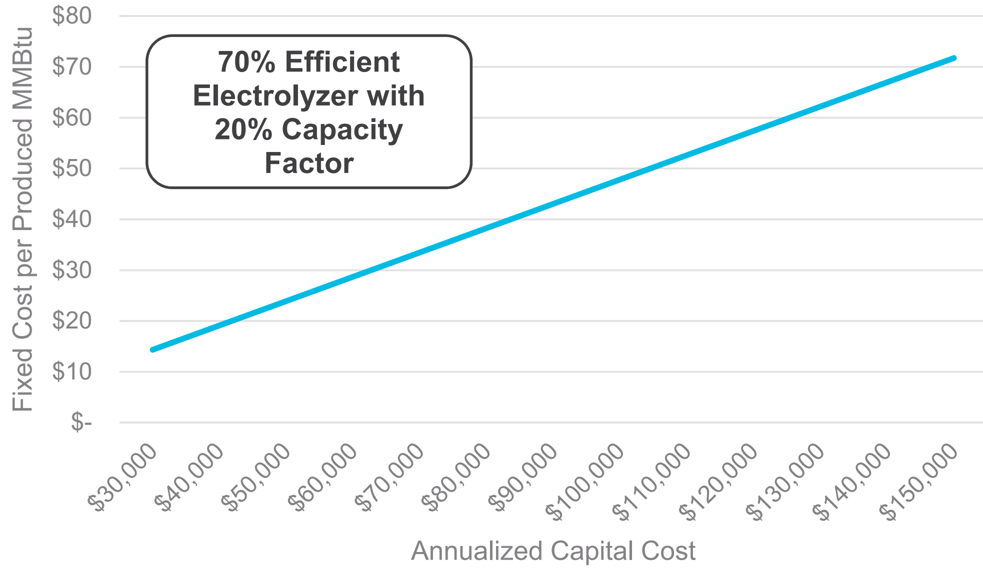
Today most P2G projects are located in Europe, where P2G has been identified as a critical component of a low-carbon future. In the U.S., several demonstration projects exist, and several projects are being designed in Canada.

8.4. 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 - its utilization factor. Additionally, the functional and emissions attributes of the various P2G technologies influence its relative cost effectiveness for a regional natural gas system.

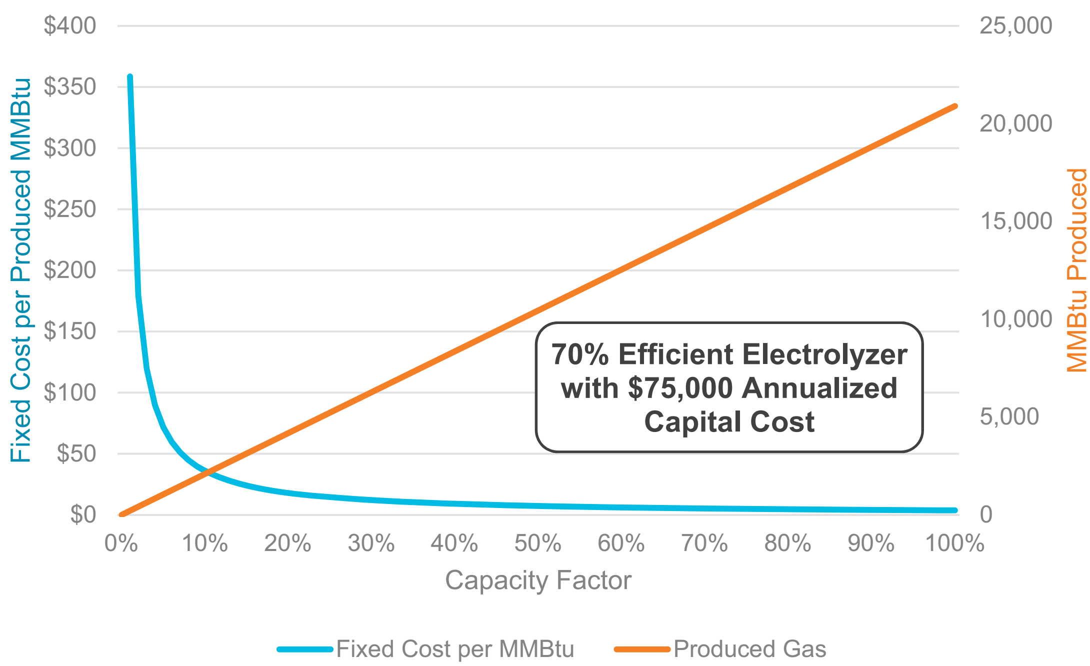
A 2018 report commissioned by NW Natural found recent commercial-scale electrolyzer projects with construction costs between $500 and $1000 per kW of capability, a range consistent with other recent industry estimates. As with most emerging technologies, these costs are expected to decline through time. 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, Figures 6.10 and 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



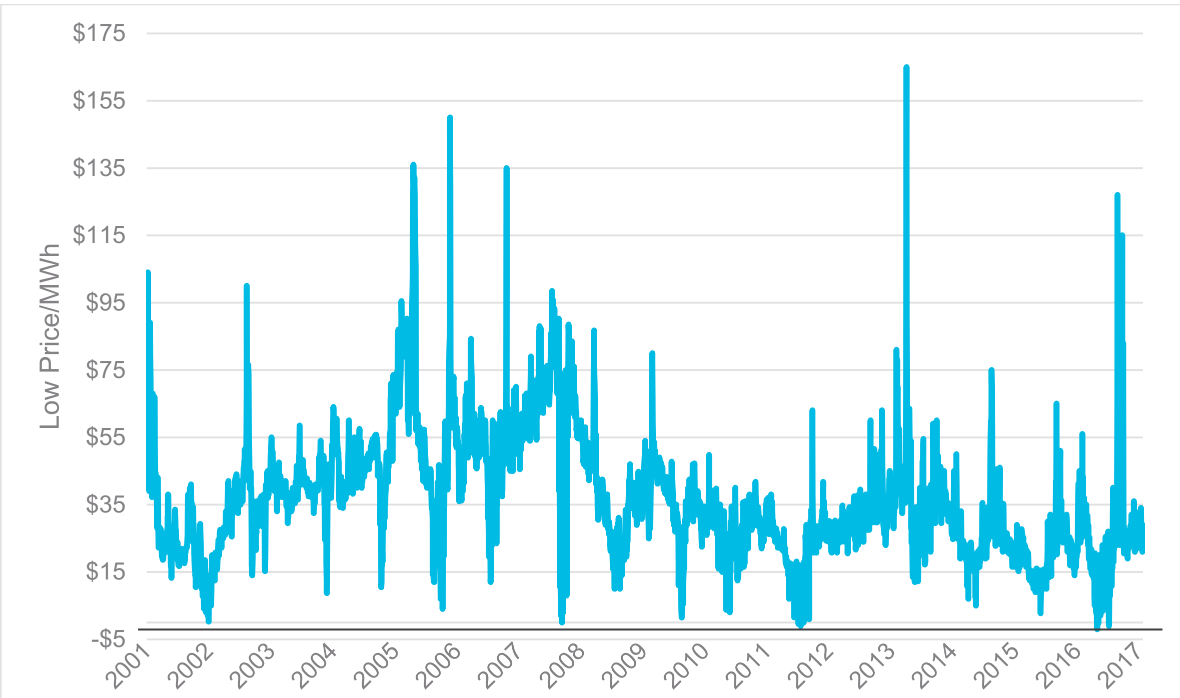
And below, Figure 6.11 illustrates the cost impact of capacity factor on a 70 percent efficient 1 MW electrolyzer with a $75,000 annualized capital cost. If the facility is operated at capacity for an entire year, the capital (fixed) cost per MMBtu of produced gas would be $3.59. If the facility were 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 US and elsewhere, but several methanation facilities are in use in the US 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 its 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.

8.5. POWER-TO-GAS AS A DIRECT-USE NATURAL GAS SUPPLY RESOURCE

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.

For portfolio analysis in the 2018 IRP, NW Natural models electrolyzer technology with construction capital costs declining over the planning horizon, and utilization factor modestly rising as policy-compliant renewable resources increase as a share of electricity generation. Electricity "feedstock" prices are assumed to be zero but limited in availability, which constrains the assumed capacity factor of the modeled resource. However, the company will continue to investigate the economics of purchasing low-cost (but not free) electricity for use in P2G production – the cost-effectiveness threshold in this regards depends on expected pipeline gas prices and transport costs, rather than a requirement that electricity be absolutely free. To capture the value of on-system P2G to NW Natural's distribution system, avoided costs described in chapter four are applied to the modeled resource.

9. FUTURE RESOURCE ALTERNATIVES

Beyond the existing gas supply resources mentioned previously, and the discussion of RNG and P2G immediately above, the Company 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. These options will be evaluated in chapter seven using SENDOUT®.[17] Also, satellite storage is described and evaluated in chapter eight as a distribution system alternative.

9.1. INTERSTATE CAPACITY ADDITIONS

The Company holds existing contract demand (CD) and gate station capacity on: 1) NWP's mainline serving the Company's 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) NWP's Grants Pass Lateral (GPL) serving the Company's 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)

[17] Demand-Side Management is also considered a resource but is covered in a separate chapter.

areas. Therefore, consideration of incremental NWP capacity, separately on the mainline and on the GPL, is a starting point for the Company's assessment of incremental interstate pipeline capacity in this IRP.

Since the Company 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 the Company to reconfigure or add to its 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 the Company'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. However, neither that type of risk management nor the broader regional benefits of new pipeline infrastructure are part of the analysis in this IRP.

In this IRP, the Company has evaluated the potential acquisition of interstate pipeline capacity via the following potential projects (see Figure 6.5 for a map of each of these projects):

- **Local Expansion Projects:**
    - **NWP Sumas Expansion:** This is incremental NWP capacity from Sumas that is designed to serve only NW Natural's load growth needs. Accordingly, it would have a relatively small scale and so could be expected to have a relatively high unit cost. On the other hand, it would offer the best fit to the Company's resource timing.
- **Regional Expansion Projects:**
    - **NWP Sumas Express:** This is capacity from Sumas on a NWP project that would bundle NW Natural's subscription with other regional requests from parties such as power generators and large petrochemical projects. The scale of this project is larger than the Local Project mentioned above, resulting in a more favorable unit cost, but with timelines necessarily aligned with the needs of the project's anchor customers, whoever they might be.

- **Pacific Connector:** The Pacific Connector Pipeline project is tied to the development of the Jordan Cove LNG export terminal in Coos Bay, Oregon. This pipeline starts near Malin, Oregon and would cross NWP's Grants Pass Lateral (GPL) in the vicinity of Roseburg, Oregon. Service from NWP would be needed to move the gas from Roseburg northward on the GPL to the Company's service territory, starting with the Eugene area. For this IRP, references to "Pacific Connector" refer to the bundled pipeline service from Malin to the Company's citygate.
- **Trail West:** A potential pipeline starting at GTN's system near Madras, Oregon, and connecting NWP's Grants Pass Lateral near Molalla, Oregon. Since portions of the Company's distribution system are not connected to Molalla, incremental pipeline capacity would be needed to transport gas northbound to certain load centers.

The Company would acquire capacity on GTN and/or other applicable upstream pipelines in conjunction with some of the above alternatives in order to secure its gas supplies at liquid trading points.

The acquisition of incremental pipeline capacity spans a wide range of lead times. It would be dependent on the length and success of the pipeline's open season process, regulatory permitting times, and the time required to construct the required facilities, which could include restrictive periods due to environmental considerations.

9.2. STORAGE ADDITIONS

This section describes the various gas storage resource alternatives available to the Company, including any related pipeline infrastructure improvements that would be necessary to bring the gas supplies to a market center in the Company's system.

9.2.1. MIST RECALL

In addition to the existing Mist storage capacity currently reserved for the core market (see Table 6.1), the Company 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 the Company's utility customers as those third-party firm storage agreements expire.

Mist is ideally located in the Company'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 incremental load requirements in the Portland area, which is traditionally the area where the majority of the Company's firm load growth lies. Mist gas may also be directly delivered to loads westward along the Columbia River from St. Helens to Astoria, and southward to the Salem and Albany areas. However, Mist recall is not suitable to serve load growth in the Eugene area. This is because Eugene is not physically connected to Mist through the

Company's distribution system, nor is Eugene's location on the NWP system such that Mist could have an impact via displacement of NWP deliveries to the Portland area (as is the case for non-connected Company load centers located in Washington).

There are three practical considerations that apply to Mist Recall:

1) Recall decisions are made roughly a year prior to the capacity's transition to the utility portfolio. On or about May 1, the Company wants to start filling any recalled capacity so as to have the maximum inventory in place by the start of the heating season. Working backwards from May 1, ISS customers need time to empty their inventory accounts if their capacity is going to be recalled by the Company. And the more prior notice they get, the more value they find in ISS service. So the Company informs an ISS customer in the months before the prior heating season if their contract will not be renewed. Accordingly, the Company has established the prior summer as the time at which it makes its recall decisions. This timeline is depicted in Figure 6.13 below.

Figure 6.13: 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 and so, in turn, the customer 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.

9.2.2. MIST EXPANSION

NW Natural is currently engaged in a project called the North Mist Expansion Project that combines a new underground storage reservoir, a new compression station, and a new transmission pipeline to serve Portland General Electric (PGE) at Port Westward. 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 being 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 gas from a new Mist storage reservoir to the Company's load centers.

NW Natural identifies two prospective Mist expansion projects for core customer use in this IRP as "North Mist II" and "North Mist III." Each project involves 50 MMcf/day (rounded to 50,000 Dth/day) of maximum delivery capacity coupled with a maximum storage capacity of 1.0 billion cubic feet (1 Bcf, or 1 million Dth),18 and each involves two new compressor stations19 and associated appurtenances. These storage and deliverability capabilities would be exclusively for utility use. Should a third party want to subscribe to a North Mist II/North Mist III expansion, total deliverability and storage capacity might be increased to match those additional subscribed amounts.

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.

The prospective North Mist II and North Mist III projects differ by their takeaway pipelines. The North Mist II project involves increasing the capacity of existing pipelines from Mist southbound to NW Natural's existing interconnection with NWP at the Molalla gate station and onto NWP's Grants Pass Lateral (GPL). NW Natural would contract with NWP for transport to NW Natural's load centers as appropriate. The North Mist III project involves expanding the capacity and sharing the new 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 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 considers the investment cost of a North Mist II and North Mist III expansion to be equivalent, with an estimated range of $76 to $111 million for either in $2017. The Company's experience developing the North Mist project for PGE informs the range of estimated cost. The least cost alternative based on estimated investment and O&M costs is North Mist III, although the two alternatives are very similar in levelized cost per therm.

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 the Company's load centers in Washington; specifically, the concern involves the potential violation of the Company'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.

[18] As each of the two projects involves developing a separate storage reservoir and separate takeaway capability, NW Natural could develop both, with a combined 100 MMcf/day maximum delivery capacity and a total of 2.0 Bcf of storage capacity.

[19] For each project, one compressor station would be in the storage field and a second would relate to the takeaway pipeline.

9.2.3. NEWPORT TAKEAWAY IMPROVEMENTS

As previously mentioned, the daily deliverability of the Newport LNG plant is modeled at 60 MMcf/day (adjusted slightly upward in the near term for higher heat content) due to pipeline infrastructure limitations. However, the Newport plant has all the equipment and permitting necessary to vaporize and deliver up to 100 MMcf/day. To reach this 100 MMcf/day capability, infrastructure additions would be needed on the Newport to Salem pipeline (Central Coast feeder) and other related pipelines to deliver an incremental 40 MMcf/day. In past IRPs this was modeled in a single increment referred to as the Christensen Compressor project. A closer look in this IRP reveals that it could be broken into three phases, each delivering a portion of the 40 MMcf/day but at very different costs. These three phases have been identified as:

1) *Central Coast Feeder 1:* CCF1 would increase the maximum pressure rating of 40 miles of the Central Coast Feeder, adding 15 MMcf/day at an estimated cost of roughly $5-7 million (roughly $0.08/Dth).
2) *Central Coast Feeder 2:* CCF2 would add a new compressor station near Lincoln City, Oregon, adding 13 MMcf/day at an estimated cost of roughly $25-25 million (roughly $0.49/Dth).
3) *Central Coast Feeder 3:* CCF3 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 at an estimated cost of roughly $41-54 million (roughly $1.20/Dth).

These three improvement projects would have to be undertaken in the above order, but as can be seen by their estimated costs, they naturally would occur in that order in any case.

9.2.4. OTHER REGIONAL STORAGE

Jackson Prairie is the only other storage facility adjacent to the Company's service territory, but it is fully contracted and no new expansions are contemplated by its owners at this time. All other regional storage facilities would require, at a minimum, the acquisition of additional pipeline capacity on NWP's system. The area with readily available storage capacity—Alberta—would require the acquisition of additional pipeline capacity on three additional pipelines upstream of NWP. Accordingly, the acquisition of storage capacity in the supply basins is only relevant if the acquisition of the necessary upstream pipeline capacity is itself cost-effective.

9.3. LONGER TERM CITYGATE DELIVERIES

As previously mentioned in this chapter (section 2.4), citygate deliveries have been contracted in the past because they were cost-effective for satisfying peak resource requirements. However, those contracts were available only for near-term periods, perhaps only the immediate heating season. This makes it difficult to model citygate deliveries as an IRP resource. However, the Company will continue to explore obtaining bids for multi-winter citygate delivery service so that it can be modeled in the IRP. And citygate deliveries will continue to be subject to evaluation for optimizing shorter-term resource decisions that are reviewed through the annual PGA process.

9.4. ALTERNATIVES NOT YET DEFINED ENOUGH FOR EVALUATION

The Company identified several other potential gas supply resources that could influence the design of its future gas resource portfolio. However, at this time, these potential resources are not yet sufficiently well-defined commercially and/or technically to warrant inclusion in the SENDOUT® model analysis or even a preliminary economic screening for this IRP.

Incremental Interruptible Load: The Company's peak day plans presume that all interruptible sales are curtailed. One question is whether more firm customers could and should be enticed to migrate to interruptible schedules to ease the Company's design peak requirements. This appears to be a matter of rate design. The Company did propose a rate design change in its 2012 Oregon general rate case that would have altered the way in which interruptible service was made available. That concept did not gain traction, but the Company would be willing to pursue other proposals at a future time.

Additional Industrial Recall Agreements: As previously mentioned, the Company has three long-time recall arrangements with large industrial/generation end-users, two of which bring their own NWP capacity into the portfolio. The Company has had no success finding additional large end-users willing to enter into similar agreements. The Company will continue asking but has no expectation that voluntary curtailment, which is what this amounts to, will garner any interest without an extreme financial commitment. This concept also is explored as a potential alternative in the evaluation of distribution system reinforcements.

NWP Storage Redelivery Proposal on a Stand-alone Basis: NWP has proposed a firm storage redelivery pipeline service that has been modeled in conjunction with the North Mist II and the North Mist III pipeline take-away alternates. That led to a question - could that service be useful on a stand-alone basis, e.g., to transport existing supplies or gas arising from Mist Recall? However, there appears to be no scenario in which such supplies require NWP transportation service because either (a) load growth in the Portland-area load center consumes all of the Mist gas supplies before they can reach NWP's system, or (b) there is not enough load growth to require additional Mist Recall.

LNG Imports: It has been about 10 years since LNG import terminals were proposed for Oregon. In theory, the Pacific Northwest could be a market for some of the LNG currently exported from Alaska, or potentially exported in the future from British Columbia. However, there are no import projects being contemplated and this alternative remains purely conceptual at this time.

Coal-bed Methane: Periodically over the years, interest had been expressed by third parties in the development of coal-bed methane (CBM) reserves known to exist in Coos County, Oregon. CBM can be totally interchangeable with "normal" pipeline gas, and the location of the CBM at the extreme end of its service territory makes this resource particularly intriguing to the Company. However, the "shale gale" and its resulting reduction in natural gas prices, among other reasons, stifled previous efforts to bring this resource to market. At present, a new party (Coos Bay Energy LLC) has once again started a CBM development program and the Company is monitoring their efforts, but it would be pre-mature to include CBM as a supply resource.

Southern Crossing Expansion: FortisBC has proposed a reinforcement project for the Southern Crossing Pipeline that would permit more flow of Alberta gas to Sumas (as previously shown in Figure 6.5). However, this project also would require an expansion of NWP from Sumas to be useful to NW Natural, and so does not need to be modeled since it essentially is replicated by the current inclusion of the NWP Sumas expansion projects.

LNG/CNG Mobile Fleet: The Company possesses one LNG and a variety of CNG trailers that are used to support localized operations, both during planned outages as well as cold weather events. However, the capacity of these trailers is extremely small. The largest is the LNG trailer, with a useful capacity of about 900 Dth, but its deployment requires considerable effort compared to CNG. The largest CNG trailers each hold about 100 Dth. These are valuable resources but suited only to serve very small and viable problem areas in the distribution system.

Adsorbed Natural Gas: This technology has been under development for over 10 years and offers the possibility of storing much higher volumes of natural gas at much lower pressures than is now accomplished using CNG. That is why if this technology does achieve a breakthrough, it most likely would start with the natural gas vehicle market as an alternative to traditional CNG tanks. However, while intriguing, there are no timelines or cost estimates that can be modeled yet.

System Leakage Reductions: A topic of interest the last few years has been methane leakage from natural gas infrastructure, sometimes referred to as fugitive gas emissions. The main focus has been on methane as a contributor to greenhouse gas emissions, but a secondary question has been whether this also imposes a current cost on consumers for the wasted volumes. While this may be a general industry concern, NW Natural is in the forefront of leakage reduction due to its past and ongoing efforts to replace older pipelines that are the most susceptible to leakage, and it currently ranks among the very best gas utilities in terms of the lowest ratio of leaks per mile of pipe.[20] Accordingly, as a potential supply resource, the reduction of gas leakage is already being fully addressed.

Expansion of Local Production: The Mist underground storage field sits on many reservoirs in which native gas is slowly being produced—or not produced at all—due to its low heat content. The reason for this is the high nitrogen content of the native gas. Efforts to increase production

[20] NW Natural was tied for best in the nation in 2016 according to this S&P Global article from 8/11/2017: https://platform.mi.spglobal.com/web/client?auth=inherit#news/article?id=41618017&KeyProductLinkType=2

levels would require the removal of some of this nitrogen, for example, by employing a nitrogen rejection unit (NRU) in the field. Ultimately, this decision is under the purview of the third party that possesses the local production rights. If the economics were favorable, that third party would proceed with the NRU or other means to increase the production and sale of their gas. The fact that it is not being pursued at this time is a reflection of the relatively low current market price of natural gas.

Physically Connect the Oregon and Washington Systems: Rather than moving Mist gas solely by displacement to locations in Washington, why not physically connect the Company's pipeline system in the Portland area with its pipeline system in Clark County? While this would quickly remove a major limitation to serving Clark County, the movement of its own gas across state lines would jeopardize the Company's Hinshaw status, i.e., its exemption from FERC jurisdiction under the Natural Gas Act of 1938.

NW Natural will continue to monitor these options and include them as future resource options should something happen that would make these options more attractive in the future.

10. GAS SUPPLY PORTFOLIO ACQUISITION STRATEGY

10.1. OVERVIEW

This section provides the Company's strategies for acquiring gas supplies as described in the Company's Gas Acquisition Plan (GAP) for 2018-2019. The GAP is reviewed and approved by the Company's Gas Acquisition Strategy and Policies (GASP) Committee, but such plans are always subject to change based on market conditions. The primary objective of these gas acquisition plans is to ensure that supplies are sufficient to meet expected firm customer load requirements under design year conditions at a reasonable cost. Under other than design year conditions, the Company also expects to serve interruptible sales customers. The focus of the GAP is on the forthcoming gas contracting year which runs from November through the following October, which also coincides with the upcoming PGA "tracker" year. This focus extends several years into the future for multi-year hedging considerations. Longer-term resource planning is the focus of the IRP and hence are not covered in the GAP, except of course to assure consistency in the transition from near-term to longer-term planning decisions.

The remainder of this section provides excerpts from the current GAP, and as mentioned above, its primary focus is on the 2018-2019 "tracker" year.

10.2. PLAN GOALS

Reliability: The first priority of the company's gas acquisition plan (GAP) is to ensure a gas resource portfolio that is sufficient to satisfy core customer requirements under design year weather conditions as defined in the Integrated Resource Plan (IRP). Compromising reliability is not acceptable. As a part of the reliability goals, the Company maintains a diversity of physical supplies from Alberta, British Columbia and the Rockies.

Lowest Reasonable Cost: Gas supplies will be acquired at the lowest reasonable cost for customers – that is, at the best mix of cost and risk. The company takes a diversified portfolio approach with gas purchases paced during the contracting season. The company also optimizes its gas supply resource assets using a third party marketer as well as its own staff to lower costs with minimal risk to stakeholders.

Price Stability: Customers are sensitive to price volatility in addition to prices. Consequently, the company uses a mix of physical assets (storage and gas reserves), fixed-price supply purchases, and financial instruments (derivatives) to hedge price variability.

Cost Recovery: With the exception of approved gas reserve purchases, NW Natural does not earn a return for acquiring and selling gas commodity supplies, yet the sale of these supplies typically produces the largest item in the company's total revenue stream. Risks associated with the payment and recovery of gas acquisition costs need to be minimized, such as strong credit policies and counterparty oversight for financial hedging.

Environmental Stewardship: NW Natural's Strategic Plan includes "environmental stewardship" as one of the Company's five core values. NW Natural's gas acquisition staff will support the Company's efforts in this regard as may be deemed appropriate.

10.3. RELATIONSHIP TO THE INTEGRATED RESOURCE PLAN

The IRP contains the company's long-range analysis of loads and resources spanning a 20-year horizon. It is prepared approximately every two years and involves considerable regulatory and public input.

Because the IRP focuses on long-term decisions, it does not include many of the details that are provided in the GAP. Nevertheless, there is consistency between the GAP and the IRP to ensure that long-range decisions are reflected in current decisions, and vice versa.
Hedging strategies are being refined as the result of current dockets at the Oregon and Washington state utility commissions.[21] These proceedings are expected to improve the overall hedging strategies over time.

10.4. STRATEGIES

The GASP Committee forms gas acquisition strategies based on the market outlook and on load projections. These strategies include:

Price Hedges – Utilize financial derivative hedges and fixed-price supplies including gas reserves to manage cost risks. In previous years, 75% of expected sales volumes were hedged financially or physically with these tools when also including volumes held in storage. However, gas purchased for storage injection is purchased on the spot market, i.e., not price hedged, so to clarify that distinction, storage volumes are no longer included when discussing the

[21] UM1720 in Oregon, UG-132019 in Washington.

company's price hedge target. In this way, price hedges continue to reflect that unhedged purchases comprise approximately half of the total purchases for the tracker period. The remaining half consists of gas purchased at spot prices for injections into storage or load. Further, the company is transitioning away from a single static hedge target. To accomplish this, our initial price hedge target will be approximately half of our annual sales requirement for the coming tracker year, but that target could be adjusted up or down during the ensuing months as determined by changing market conditions.

Market Area Storage – Market Area Storage refers to three storage facilities exist which are directly connected to the company's distribution system: Mist (the portion reserved for core utility customers), Newport LNG, and Portland LNG. Additionally, the company's storage contract at the Jackson Prairie facility near Chehalis, Washington is also included. "Market area" has the important distinction that these storage facilities displace the need for year-round upstream pipeline capacity; accordingly, their economics are driven primarily by the avoided cost of such pipeline capacity rather than winter/summer price spreads. (Note: While Jackson Prairie is not directly connected to NW Natural's system, its withdrawals are transported using heavily discounted primary firm service on Northwest Pipeline that is not available to other off-system storage facilities, hence it is considered to be in this category. For this same reason, Plymouth LNG was dropped from consideration in 2015 when it was determined that its heavily discounted Northwest Pipeline transportation was not a primary firm service.) Market area storage comprises approximately of 17% of annual sales, and as mentioned above, the price of gas injected into storage is not previously hedged. It also should be mentioned that market area storage can be critical to the operation of certain portions of the company's distribution system, so that its dispatch may be required for operational reasons too.

Supply Basin Storage – "Supply basin" refers to Alberta, British Columbia and the Rockies, where storage can act as an alternative source of supply. Supply basin storage uses the same upstream pipeline capacity as our other supply basin purchases, so as long as winter supply availability is not at issue, it is the winter/summer price spreads that drive the decision as to whether or not to subscribe to such services. The economic analysis of supply basin storage, as well as the placing of a cap of 15% of annual requirements on such volumes, is described in guidelines previously established by GASP. The company has one supply basin storage agreement in place that is set to expire at the end of the 2017-18 winter, and based on the current market, it is conceivable that no new upstream storage deals will be made for 2018-19 winter. If we do contract additional upstream storage, we will incorporate this into the hedging strategy.

Supply Basin Diversity – Maximize supplies from the regions that afford the lowest prices. Gas from Station 2 in northern British Columbia typically has the lowest cost in the Company's supply region. Alberta is typically the next lowest. Sumas and Rockies are often higher priced and purchased to a greater extent in the winter to meet increased demand. Keys to price shifts include production levels (especially in the Eastern US from surging, high efficiency shale gas plays), new pipelines, power generation, regional demand as low energy prices spur an industrial renaissance, growing exports (both LNG and via pipeline to Mexico), and weather.

Additionally, maintaining a diversity of supply basins allows us to maintain a higher level of reliability. For example, greater diversity lessens the overall impact of pipeline outages or adverse weather conditions (well freeze-offs) that may affect an individual supply basin.

Storage Injections – Fill storage at a pace that might present opportunities to purchase gas at times that best benefit core customers.

Sumas Liquidity – Due to its relative lack of trading liquidity, continue to base load virtually all purchases from British Columbia (Huntingdon/Sumas) during the winter season when spot supply deliveries might be unreliable and prices more volatile. Substitute Station 2 for Huntingdon/Sumas purchases to the extent that Westcoast T-South capacity can be obtained at a reasonable cost. Additionally, substitute Alberta gas flowing via Southern Crossing when it may be obtained for a reasonable cost.

11. SUPPLY RESOURCE DISPATCHING

The Company utilizes SENDOUT® to perform its dispatch modeling each fall. Based on expected conditions, this modeling provides guidance as to dispatching from various pipeline supplies and storage facilities. These economic dispatch volumes also flow into the Company's PGA filing.

Perhaps more importantly, SENDOUT® is used to dispatch supplies to meet design day conditions as defined through the IRP process. This leads to the creation of guidelines representing the optimal inventory levels on each day for each storage resource, under the premise that the remainder of the heating season will match design conditions. These guidelines provide insights for operational personnel as they make daily dispatch decisions throughout the heating season.

12. SUPPLY DIVERSITY AND RISK MITIGATION PRACTICES

12.1. BACKGROUND

The Company's upstream pipeline contracts enable it to purchase roughly one-third of its supplies from each of the major supply regions in the area: British Columbia, Alberta and the US Rockies. Lower liquidity in British Columbia has prompted the Company to baseload more of its supplies from this region, i.e., rely less on that region for spot purchases. The Company currently favors spot purchases from Alberta due to generally lower prices.

However, the overall mix of British Columbia, Alberta and Rockies gas purchases can change from year to year in reaction to changing market dynamics. Recent examples include:

Marcellus and Utica Shale: Shale gas was well known but considered unconventional and uneconomic up until about 10 years ago. Its emergence and abundance at economic prices directly transformed gas markets in the eastern US and Canada, with ripples extending across the continent. Combined with slow economic growth, shale gas displaced some of the demand for Rockies and Western Canadian supplies with resulting bearish impacts on prices.

Growth of Exports: The first large-scale shipment of LNG from the Gulf of Mexico occurred in February 2016, with subsequent shipments occurring about once a week in 2016, increasing to once every day or two in 2017 and currently. Meanwhile, the export of natural gas via pipeline to Mexico has grown to have a larger influence on U.S. markets, amounting to roughly double the volume of gas compared to LNG exports.[22] As this gas flows out of the US from Texas and the southern tier of states, it creates a pull on supplies that appears to be having a bullish impact on Rockies prices.
Coal Plant Retirements: As a result of federal air quality mandates, aging coal plant inefficiencies, and low natural gas prices, coal's share of US power generation has dropped from a peak of around 50% in the early 2000s to about 30% today and further reductions are expected over time. The Pacific Northwest will see its share of this phenomenon with Boardman, both units at Centralia, and the Colstrip 1 and 2 units all expected to retire between 2020 and 2025. These coal plant retirements are being replaced by a mix of renewables and gas-fired generation, creating upward pressure on natural gas prices to some extent.

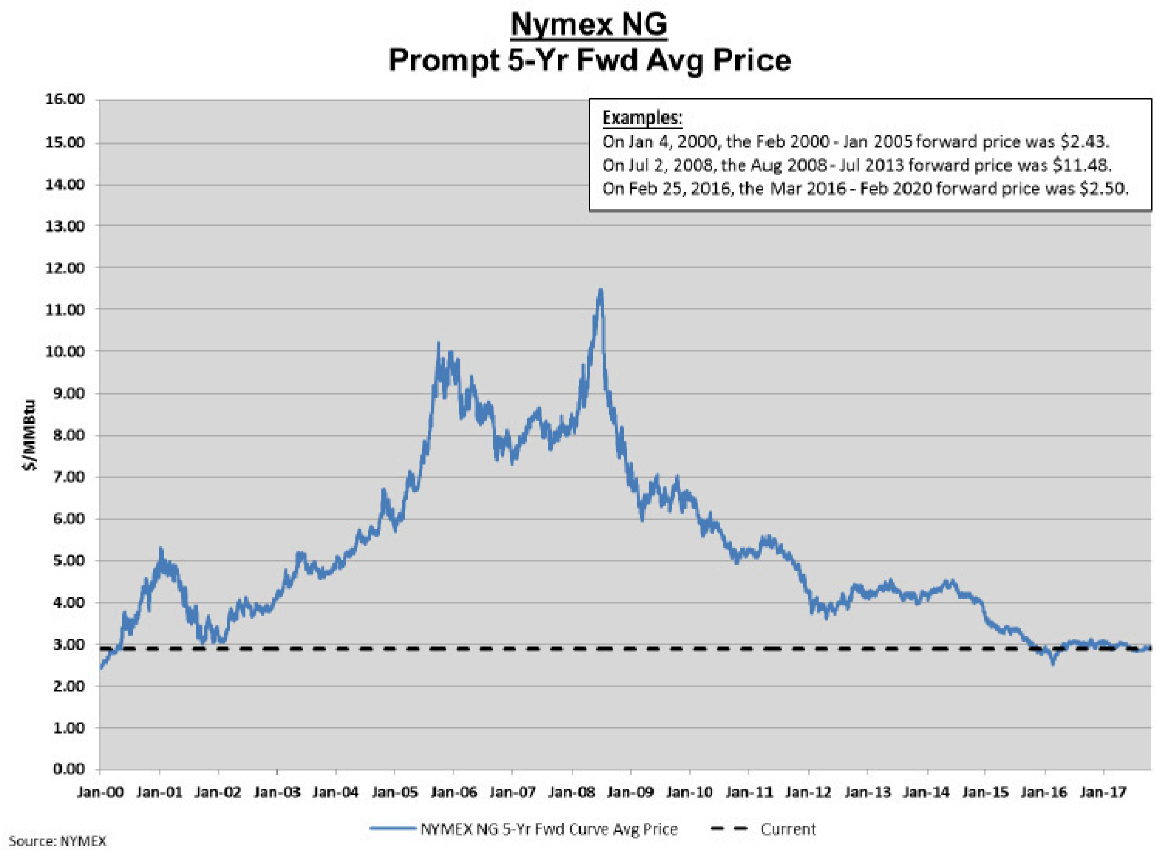
Ruby Pipeline: The Ruby Pipeline commenced service in mid-2011 from Wyoming to the California/Oregon border, providing another outlet for Rockies gas. However, Ruby is not fully contracted and its open capacity could serve as further impetus for the Jordan Cove/Pacific Connector project.

NGLs: Prices for natural gas liquids (NGLs) such as propane and butane have tended to track oil prices more closely than natural gas. As a result, drilling activity generally has shifted to regions where the natural gas is "wetter" (has more NGLs) and market access is available. This then led to a glut of NGLs and the higher heat content on the NWP system that was discussed earlier.

Overall, the growth of gas supplies (the "shale gale") and the lingering effects of the country's economic recession have resulted in a dramatic reduction of gas prices, with the Company's gas rates now lower than they were 15 years ago. Future price expectations also are currently at historically low levels (see Figure 6.14).

[22] Energy Information Administration - https://www.eia.gov/dnav/ng/ng_move_expc_s1_m.htm

Figure 6.14: Rolling 5-Year Forward Price since 2000



Source: BP presentation to the Western Energy Institute Energy Management Forum, 11/2/2017

As the tight nationwide balance between supply and demand of the early 2000s transitioned to the current era of plentiful supplies, the Company's physical gas contracting practices have evolved to place more reliance on the spot market during cold weather or other extreme load periods. In the past, spot gas would have been less than 10 percent of total purchases during the heating season. But in recent years, spot gas constitutes over one-third of the Company's total purchases during the year (including for storage injection) and about the same proportion for purchases made specifically during the heating season.

Physical gas contracting strategies for 2018-2019 that are consistent with strategies of recent years include:

- Maintaining a diversity of physical supplies from Alberta, British Columbia and U.S. Rockies.
- Buying supplies at trading points with high "liquidity" in order to access the most competitively priced and reliable supplies.
- Continuing to shift the source of physical supplies to the lowest-cost source region.
- Evaluating the cost-effectiveness of "citygate" deliveries, including as a potential backstop to continued reliance on segmented capacity.

Figures 6.15 and 6.16 provide graphical representations of the Company's physical gas supply resources and diversity during 2017.

Figure 6.15: Gas Supply Diversity by Contract Length for Calendar Year 2017

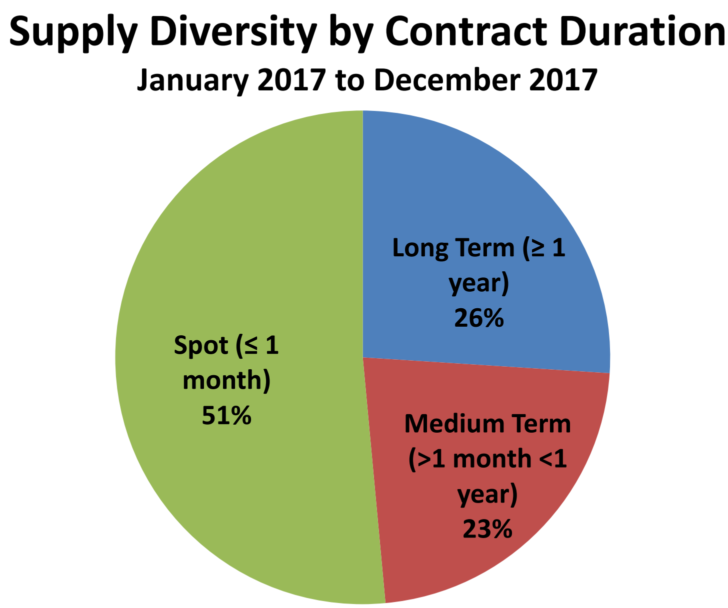
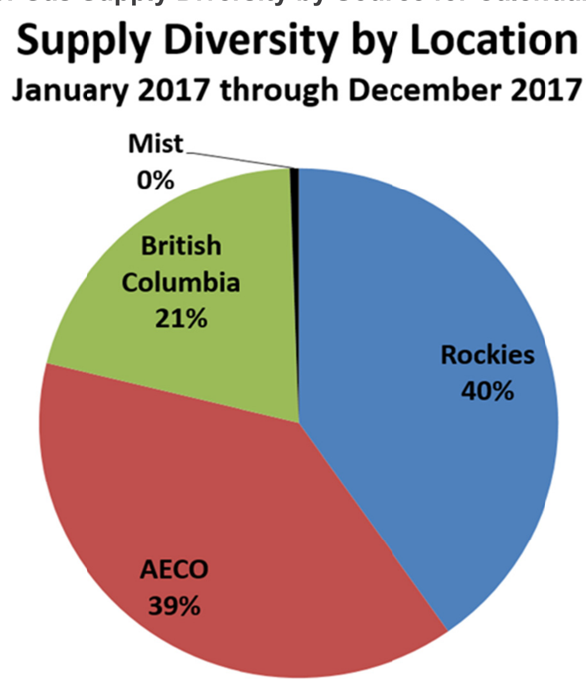


Figure 6.16: Gas Supply Diversity by Source for Calendar Year 2017



As supply contracts expire, new opportunities to re-contract supplies under different arrangements will be examined.

12.2. PHYSICAL AND FINANCIAL HEDGING

The Company provides its retail sales customers with a gas service that bundles together the gas commodity, upstream pipeline transportation, off-system contracted gas storage, and on-system gas storage owned and controlled by the Company. To accomplish this, the Company aggregates load and acquires gas supplies for its core retail customers through wholesale market physical purchases that may be hedged using physical storage or financial transactions. The goals described in section 10.2 of this chapter guide the physical and financial hedging of gas supplies.

The use of selected financial derivative products provides the Company with the ability to employ prudent risk management strategies within designated parameters for natural gas commodity prices. Authorized derivative instruments are defined within the Company's Gas Supply Risk Management Policies (GSRMP), and they are used in accordance with the hedging strategies and plans approved in the GAP. All wholesale gas transactions must be within the limits set forth by those policies and relate to the Company's utility requirements. This is intended to prevent speculative risk.

The GASP Committee maintains oversight for the development and enforcement of the GSRMP. Within those policies, the Derivatives Policy establishes governance and controls for financial derivative instruments related to natural gas commodity prices including financial commodity hedge transactions.

While hedging strategies have evolved over the years, these basic principles have been maintained:

- Portfolio diversity
- Attention to long-term price fundamentals
- Flexibility to seize new opportunities

12.3. HEDGING TARGETS

A major focus for the GASP Committee is the establishment, review and approval of annual hedging targets for the gas supply portfolio. Hedging in this context falls into the following general categories:

- Pre-authorized financial derivative instruments (up to five years with approved counterparties)
- Longer-term structures
- Fixed price gas purchase agreements
- Gas injected into storage

Hedging targets, that is, the percentage of the portfolio to be hedged and in what manner, are developed for the upcoming PGA "tracker" year as well as future years based on the Company's view of long-term price fundamentals.

In past years, the Company targeted 75% of expected PGA year sales requirements for hedging via all methods, i.e., the sum of financial derivatives, fixed price physical supply contracts, gas reserves and storage. That was within the range recommended by a consultant (Aether Advisors) study that was including in the 2014 IRP.

Recently, to improve on this process, the Company modified its overall hedging approach to be increasingly risk responsive. An initial target of 50% price hedges was set for the 2018-19 tracker year. This 50% includes financial derivatives, fixed price physical purchases, and gas reserves. When combined with storage volumes, which currently equate to 17% of expected annual sales, this initial hedge target is lower than for previous PGA years. But as part of the new risk-responsive approach, hedging targets are expected to adjust up or down over time as new market information is analyzed. Further discussions on hedging are expected to occur during the annual PGA process.

12.4. MODELING OF GAS ACQUISITION COSTS

As done in its prior IRPs, the Company has not included the commodity costs of any specific gas acquisition or hedging arrangement in its modeling. For example, it has not embedded the expected price of gas from its existing gas reserves purchase agreement, nor the hedge prices from its multi-year financial hedges. Doing so would be problematic and unhelpful.

One of the building blocks of the IRP analysis is a price forecast applicable to commodity gas purchases at various trading hubs in the region (AECO, Sumas, et al.). This permits a complete evaluation and comparison of different demand-side measures and supply-side resources. Embedding any current financial swap or other agreement within that forecast would likely improperly skew the results because those prices are available only with those particular transactions, which are not unlimited in volume. If the Company were to use past transactional prices as a proxy for the marginal cost of gas, the model would not produce a realistic analysis of the options currently available for purchasing gas. Moreover, the existence of past financial transactions does not necessarily have an effect on the location at which the Company will purchase physical gas in the future because the Company can always choose to apply the proceeds from financial transactions to whatever purchases it does makes, and it will strive to make those purchases at the lowest cost locations. This approach has been approved in the past.

13. RECENT ACTION STEPS

The Executive Summary of the Company's 2016 IRP had a Multiyear Action Plan with two items related to supply-side resources.[23] Those items, along with the actions actually undertaken by the Company, are as follows:

1) Plan to recall 30,000 Dth/day of Mist storage capacity from the interstate storage account effective May 2019 to serve the core customer needs, subject to a review based on an update of the annual load forecast in the summer of 2018.

23 See 2016 IRP, page 1.18.

This item was modified prior to acknowledgement to read:

> Plan to recall 15,000 Dth/day of Mist storage capacity from the interstate storage account effective May 2018 to serve core customer needs, subject to a review based on an update of the annual load forecast in the summer of 2017. Plan to recall 15,000 Dth/day of Mist storage capacity from the interstate storage account effective May 2019 to serve core customer needs, subject to a review based on an update of the annual load forecast in the summer of 2018.[24]

Regarding the modified action item above, the Company updated its load forecast in the summer of 2017 using its prior methodology and determined that a Mist Recall effective May 2018 was not warranted. This was reported in the Company's 2016 IRP Update filed in August 2017. Based on the updated load forecast in this IRP, the Company currently intends to recall 20,000 Dth/day effective May 2019 to serve core customer needs.

2) Replace or repair, depending on relative cost-effectiveness, the large dehydrator at Mist's Miller Station. Replacement is currently estimated to cost between $6 million and $7 million based on estimates obtained from a third-party engineering consulting firm engaged by NW Natural. NW Natural will evaluate alternatives associate with the Al's Pool and Miller Station small dehydrator systems at Mist to determine if and when additional actions are warranted.

As mentioned in section 6.1 of this chapter, a third party engineering evaluation of the system concluded that the existing dehydrator system should be replaced, and an in-depth economic and alternatives analysis is currently underway.

14. RECAP AND KEY FINDINGS

- Based on its forecast methodology in 2017 (the same as used in the 2016 IRP), the Company did not recall any Mist deliverability effective May 2018.
- Based on the forecast methodology in this IRP, the Company identified a small resource gap of less than 10,000 Dth/day for the 2018-2019 design peak day. The Company has filled this gap with a citygate delivery contract. Further details will be provided in the Company's summer 2018 PGA filing.
- Based on the forecast methodology in this IRP, the Company currently intends to recall 20,000 Dth/day of Mist deliverability effective May 2019 to meet the 2019-2020 design peak day.
- Updated analysis and experience have shown segmented capacity to be a reliable winter resource for the Company. Due to its minimal cost, segmented capacity will be maintained in the portfolio until system dynamics change on the NWP system such that additional demand for gas from Sumas erodes its reliability. At the moment, those changes are not expected to occur until at least 2021, but the situation will be closely monitored.

[24] OPUC Order 17-059 issued 2/21/2017, Appendix A, page 14.

- Contracting for Westcoast T-South capacity is a means to lower the Company's reliance on the Sumas trading point. From a portfolio diversification standpoint, this is desirable considering both liquidity of supply and price volatility at Sumas. To that end, the Company has extended an existing arrangement for 19,000 Dth/day of T-South capacity, and more significantly, has contracted for approximately 25,000 Dth/day of new T-South capacity through a Westcoast expansion project that is expected to commence service in November 2020. This new contract will be for a 40-year term.
- The Company negotiated extensions for many of its NWP contracts in 2017, with the key being the extension to 2031 of a transportation contract that assures firm delivery of gas withdrawn from the Jackson Prairie storage facility.
- The glut of NGLs in the region, and resulting higher heat content of gas delivered to the Company's system, continues to support a slightly higher assessment of the capabilities of the Company's storage facilities. However, this effect is small and should phase out over time as NGL extraction economics improve. It will be reevaluated in each IRP.
- It is expected that RNG from the Portland wastewater treatment plant on Columbia Boulevard will enter the Company's system starting in early 2019. While initially a very small resource, more RNG projects are possible.
- The company's three on-system storage plants—Mist, Newport LNG, and Portland LNG—each play a crucial role in the resource portfolio but they are aging, so an asset management program has been developed for each plant to assure their operations continue to be efficient and cost-effective for customers.

CHAPTER 7

PORTFOLIO SELECTION

KEY TAKEAWAYS

Key findings in this chapter include the following:

- Base Case Sensitivities
  - In the expected demand portfolio assuming no new regional pipeline, Mist Recall, On-system Dairy RNG, Central Coast Feeder 1 and Local Sumas expansion are selected as least cost resources
  - If a new regional pipeline does come online with excess capacity, that regional pipeline is selected instead of the Local Sumas expansion, which also could affect the timing of the other additions
  - Without expected emissions reduction actions over the planning horizon, NW Natural's annual emissions expectations would be 62 percent higher on an annual basis in 2037
  - Since 2000, the GHG emissions of the average NW Natural residential customer have declined by 19 percent, and they are expected to decline an additional 42 percent by 2037, primarily due to planned emissions reduction action
- Risk Analysis (Stochastic)
  - The availability of a regional pipeline creates a least cost and least risk portfolio
  - Accounting for the uncertainty of commodity prices and environmental policy leads to earlier acquisition of RNG
- Risk Analysis (Sensitivities)
  - The biggest resource acquisition difference across sensitivities is the expected pace of Mist Recall and Renewable Natural Gas (RNG) acquisition
  - Expected emissions vary greatly by assumed environmental policy regimes due to differences in energy efficiency work, RNG acquisition, power-to-gas development, end-use equipment adoption, and varying customer enrollment in NWN's Smart Energy program
  - Drastic emissions reductions (65 percent or more relative to current levels) are possible on an annual basis by 2037 while still serving the same energy needs

1. SUPPLY RESOURCE PLANNING OVERVIEW

Long term system supply planning is a complex process that guides the Company in acquiring the appropriate mix of resources with the best combination of cost and risk to meet both (1) capacity requirements, being able to deliver gas on a peak day, and (2) energy requirements, being able to serve customers year round. The available supply resources offer different capacity and energy services at various costs. For example, NW Natural's Newport LNG facility provides roughly 63,000 Dth/day of capacity, but could only provide about 10 days of energy before being completely emptied. On the other hand, upstream pipeline capacity provides 365 days of both capacity and energy, some of which is needed during the summer to fill the Company's storage facilities.

In order to choose resources in a least cost manner, while still meeting capacity and energy requirements, NW Natural uses the optimization software, SENDOUT®.[1] The software implements a linear program (LP) algorithm to find a deterministic least cost solution optimizing the entire gas supply portfolio, including supply, transportation, storage assets and renewable gas resources.[2] The objective function of the LP engine seeks to minimize total system costs associated with meeting daily load subject to capacity constraints and constitutes the Company's Supply Resource Planning Model.

The Supply Resource Planning Model acts as a tool to guide the Company's resource decisions; it is not the final answer. The deterministic model makes resource decisions based on perfect knowledge of the 20-year planning horizon, including weather, load, future resource availability, and supply prices. For example, a decision made in year five may have been informed by an event occurring in year ten. In reality, events further out in time have more uncertainty than near term events, but the deterministic run views all years with certainty. Thus, supply resource decisions are informed through a two-step process.

> *Step 1:* Deterministic Portfolio Selection – Use a deterministic optimization to select adequate resources to meet planning standard criteria for energy and capacity for every year in the planning horizon for expected demand sensitivities.
>
> *Step 2:* Risk Assessment – Test alternative possible futures by varying input assumptions through both a (1) stochastic analysis and (2) a sensitivity analysis.

The deterministic portfolio selection produces the least cost portfolio of resources over the planning horizon given the Company's expectation of the future. The risk assessment provides a risk planning analysis given uncertainty around environmental policy, commodity prices, economic growth, supply infrastructure, resource costs, technological change and weather. Through this process the Company chooses the least cost; least risk supply resource portfolio in the near term to include in this IRP action plan.

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1 ABB (ASEA Brown Boveri) is a Swedish-Swiss multinational corporation headquartered in Zürich, Switzerland, operating mainly in robotics and the power and automation technology areas. It does business as the ABB Group. SENDOUT is a product belonging to ABB.

2 Renewable gas resources include on-system RNG and on-system power-to-gas options.

2. SUPPLY RESOURCE PLANNING MODEL – SENDOUT©

Five primary components are integrated within the SENDOUT® resource planning model.

1) Load forecast and demand-side management (Chapters Three, Four, and Five)
2) Design weather pattern (Chapter Three)
3) Natural gas price forecast inclusive of expected carbon price (Chapter Two)
4) Current supply resources (Chapter Six)
5) Potential future resources (Chapters Six)

Load Forecast and Demand-side Management

The Company incorporates the customer forecast, annual use per customer coefficients, industrial and emerging market demand, and estimated peak day firm sales load (adjusted for Energy Trust's forecast of DSM) into the supply resource planning model. Additionally, a high-cost penalty is attached to unserved firm demand such that the resource model attempts to serve all firm demand using the resource options available to it. For interruptible loads, the penalty is set sufficiently low that the model does not serve this category during peak events, but high enough that the model chooses to serve it otherwise.

Design Weather Pattern

The Company has developed a statistically based design weather pattern which is colder than 90 percent of the winters that the service area has experienced in 30 years. This weather pattern is used for each year in the model.

Natural Gas Price Forecast Inclusive of Expected Carbon Price

A cost is associated with each unit of natural gas supply sourced in the resource model. These costs can drive planning to focus on certain low-cost sources. Substantial differences between summer and winter prices could, therefore, influence the decision between a pipeline resource and a storage resource. Long-term price differentials between supply basins may drive pipeline resource decisions to steer toward the lower priced basins.

The Company uses the price forecasts described in chapter two as inputs to the optimization model inclusive of the expected GHG emissions compliance costs or carbon price, also described in chapter two. The carbon price is translated to a price adder in dollars per Dth and is applied consistently to prices across basins.[3] This carbon price adder is also consistently applied to low carbon supply resources, which are new the 2018 IRP.[4] The total commodity price plus the expected carbon price adder are then input into SENDOUT®.

[3] The conversion factor is based on the U.S. Energy Information Administration's carbon dioxide emissions coefficient of 117 lbs. of CO_2 per MMBtu (0.05307 metric tonnes per MMBtu).
[4] The carbon prices adder is source specific based on assumed carbon intensities discussed later in this chapter.

Current Supply Resources

NW Natural discusses existing supply resources in Chapter Six. Existing resources include interstate pipeline capacity (Northwest Pipeline), on-system storage (Mist, Newport LNG, and Portland LNG), off-system storage (Jackson Prairie), and a number of industrial recall agreements.

Potential Future Resources

The gas requirements for the system over the planning horizon are met by both current and future supply resources. Future supply resources, discussed in detail in chapter Six, fall into three basic categories:

a) Interstate pipeline capacity additions (traditional)
b) Storage takeaway upgrade or additions (traditional)
c) Renewable gas resources (modeled as options for the first time)

The supply resource planning model incorporates future supply resources options to be selected to meet peak demand based on least cost and risk. Table 7.1 gives a summary description of the traditional resource options considered for selection and a range of the capacity costs associated with each resource.

Table 7.1: Modeled Future Supply Resources

Capacity Resources	Description	Cost ($/Dth/day)
Mist Recall	Transferring Mist storage from interstate customers to Core Utility	0.05 - 0.11
North Mist II	Completing new storage wells and building southbound takeaway pipeline capacity from Mist	0.38 - 0.54
North Mist III	Completing new storage wells and building northbound takeaway pipeline capacity from Mist	0.35 - 0.50
Local Pipeline Expansions	Williams completes an expansion specifically for NW Natural	1.10 - 1.70
Regional Pipeline Expansions	Regional NWP, Trail West and Pacific Connector expansions for multiple shippers	0.50 - 1.20
Central Coast Feeder 1-3	Three projects have been identified that can increase this takeaway capacity from Newport LNG	0.08 - 1.20

New to this IRP, on-system renewable gas resources are evaluated on par with the other supply resources. Similarly, off-system renewable gas resources are evaluated on par with purchasing conventional natural gas at a supply basin. This evaluation of renewable gas resources required careful consideration, given the incorporation of our expected carbon price.

If all supply resource options provide only conventional natural gas to the system, carbon intensity would be equal across all gas procured and including an expected carbon price would not impact resource planning. However, renewable gas resources have lower carbon intensities than conventional gas. Additionally, renewable gas resources have heterogeneous carbon intensities depending on their source. This can provide more or less incentive to procure a resource based on the relative carbon intensity (given a positive carbon price). Table 7.2 summarizes both the on-system and off-system renewable gas resources evaluated in this IRP. More detailed descriptions can be found in Chapter Six.

Table 7.2: Modeled Types of RNG

Resources	Description	Commodity Cost ($/Dth)	Estimated Percent CO_2e Reduction Compared to Conventional Gas
RNG 1 : Landfill Gas*	Purchase RNG at market value inclusive of the environmental attributes and have delivered along NWP	30.25	41%
RNG 2 : On-system Dairy Gas	Contract with on-system dairy farmers to purchase their dairy digester biogas	14.00	452%
RNG 3 : Waste Water	Develop an RNG facility at a wastewater treatment plant to clean and capture methane	12.65	75%
RNG 4 : Waste Water with Monetized RINs	Develop an RNG facility at a wastewater treatment plant to clean and capture methane, but monetize transportation fuel credits in years 1-5 to offset some costs	8.10	75%
RNG 5 : Off-system Dairy*	Contract with off-system dairy farmers to purchase their dairy digester biogas.	14.00	452%
Power-to-Gas	Build a power to gas facility at Mist to blend in produced hydrogen into natural gas	67.52-20.26	100%

*RNG 1 & 5 are not capacity resources and cannot be used to meet peak demand.
Power-to-Gas cost is assumed to be declining over time.

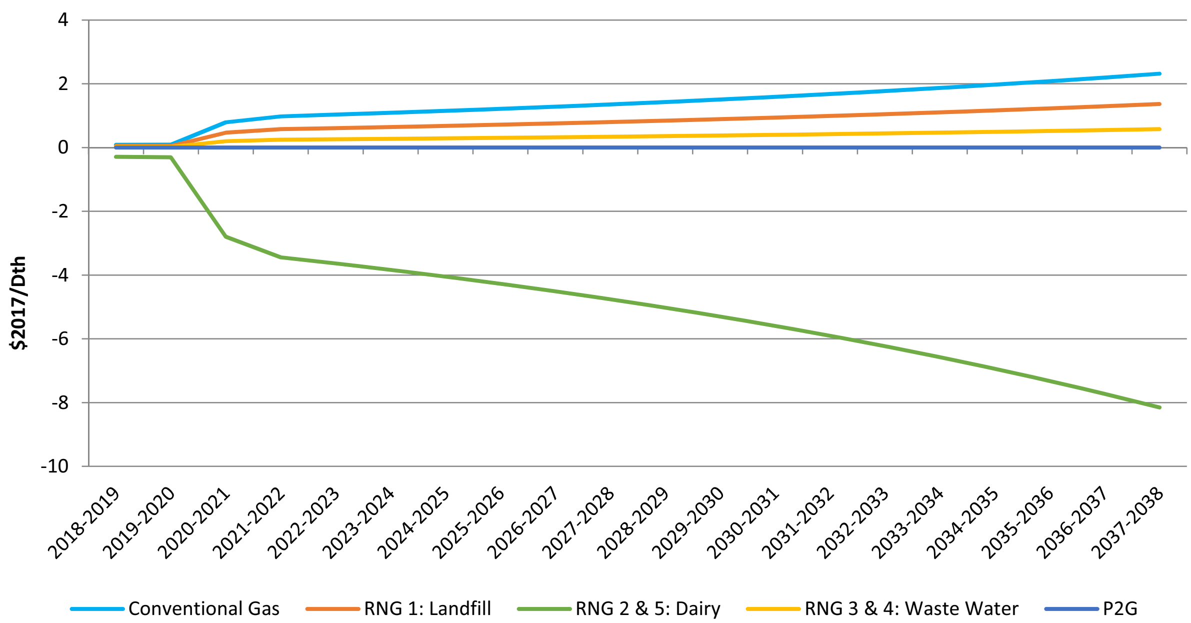
3. VALUING THE BENEFITS OF RENEWABLE GAS RESOURCES

On-system renewable resources provide three major benefits that may make them a cost-effective option relative to other capacity resources; (1) emissions compliance benefits, (2) avoided marginal capacity costs; and (3) avoided system reinforcement costs. Off-system renewable gas resources only avoid compliance costs and cannot be considered for capacity benefits as the Company still needs upstream pipeline capacity to bring the gas to our system. These benefits are evaluated and considered within the supply resource planning model to compare resources on an all-in cost basis.

Emissions compliance benefits

Figure 7.1 shows the expected carbon price translated to dollars per MMBtu by resource type. Dairy RNG, due to a negative carbon intensity, actually provides a benefit (i.e., negative cost). Other RNG sources still have positive carbon intensities, but the compliance costs are less than conventional natural gas. Power-to-gas has a zero compliance cost as long as the input electricity is carbon free. By 2037, compliance costs associated with conventional gas are expected to be slightly above $2 per Dth, but dairy RNG could have as much as an $8 per Dth benefit toward compliance.

Figure 7.1: Expected Compliance Costs by Resource Type



Avoided supply capacity costs

On-system resources are injected directly on NW Natural's distribution system. Having on-system resources adds additional capacity services (Dth/day) and energy services required to meet peak and annual demand. Therefore, the cost of the next best alternative resource is avoided by having an on-system system resource. This value is incorporated by SENDOUT through its cost-minimizing optimization. For example, if on-system RNG contributes 3,000 Dth/day every day of the year this could avoid the need to subscribe to 3,000 Dth/day of pipeline capacity and thus the associated pipeline transmission costs.[5]

[5] The expected reservation charge for a NW Natural specific expansion on NW Pipeline is $1.10/Dth/Day.

Avoided distribution capacity costs

As already stated, on-system supply injects gas directly into the Company's distribution system. This additional gas increases the pressure to the pipeline network, which in turn supports the physical delivery of gas. Low pressures occur within the system when demand spikes and gas flow increases. Bottlenecks within the system can result in low pressure, which could ultimately lead to customer outages. Typically, the solutions to relieve these bottlenecks would require a system reinforcement project (e.g. looping a pipeline or adding a tie to a stronger adjacent section of the system). The development of an on-system supply resource in the right location could delay or avoid the reinforcement project.

As described in Chapter Four, the estimated distribution system costs avoided are based upon the expected amount of gas the RNG resource is expected to supply during a peak hour to support the distribution system and the estimated cost to supply incremental peak hour load. Resources that supply more gas during a peak hour avoid more distribution system costs. This methodology is consistent with how energy efficiency avoided costs are valued.

4. DETERMINISTIC PORTFOLIO SELECTION RESULTS

Regional pipeline expansions are driven by demand growth for natural gas over the entire Pacific Northwest region. Although demand growth from the Company's service territory does influence a regional pipeline expansion, the decision to offer an open season for a regional expansion of an interstate pipeline are beyond the Company's control. In order to plan our resources accordingly we model three possible infrastructure futures given our expected demand assumptions.

1) Base Case - No new regional interstate pipeline over the planning horizon
2) Regional pipeline project in 2025 – expected to be fully subscribed
3) Regional pipeline project in 2025 – expected to have excess capacity

Currently, there is no regional expansion planned for the region. Therefore, the first sensitivity represents a business as usual sensitivity for resource planning. The second and third sensitivities are hypothetical futures to demonstrate how the Company would evaluate a decision to subscribe to capacity if an open season for a regional pipeline is announced.

The first step to making supply resource decisions the Company uses the supply resource planning model to run deterministic resource optimization for each of the three supply infrastructure sensitivities. Table 7.3 lays out the foundational assumptions for these sensitivities.

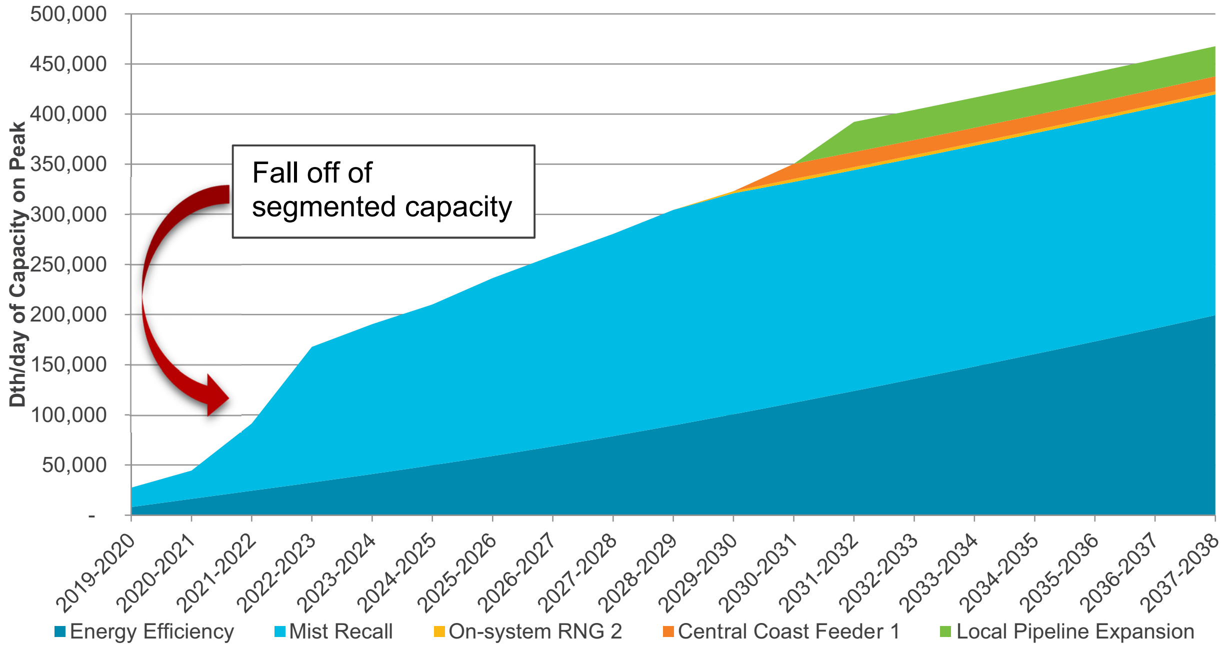
Table 7.3: Supply Infrastructure Sensitivities

<table>
<tr><th colspan="2"></th><th colspan="3">Supply Infrastructure Sensitivities</th></tr>
<tr><th colspan="2"></th><th>1</th><th>2</th><th>3</th></tr>
<tr><th colspan="2"></th><th>Base Case - No New Regional Pipeline</th><th>New Regional Pipeline in 2025 - Fully Subscribed</th><th>New Regional Pipeline in 2025 - Excess Capacity</th></tr>
<tr><td rowspan="5">Demand-Side</td><td>Customer Growth</td><td colspan="3">Expected (Statistical Trend Continuation)</td></tr>
<tr><td>Space Heat Equipment</td><td colspan="3" rowspan="3">Expected (Trend Continuation Plus Adjustment for Energy Trust Energy Efficiency Savings Projection)</td></tr>
<tr><td>Water Heating Equipment</td></tr>
<tr><td>Industrial Load Efficiency</td></tr>
<tr><td>Building Shell Improvement</td><td colspan="3">Shell Related Savings in Energy Trust Energy</td></tr>
<tr><td rowspan="3">Supply-Side</td><td>Regional Interstate Pipeline Expansion</td><td>No new regional interstate pipeline in Planning Horizon</td><td>Regional Pipeline Project in 2025 - Fully Subscribed</td><td>Regional Pipeline Project in 2025 - Excess Capacity</td></tr>
<tr><td>Renewable Natural Gas</td><td colspan="3" rowspan="3">Base Case Assumptions</td></tr>
<tr><td>Power-to-Gas Hydrogen</td></tr>
<tr><td colspan="2">Carbon Pricing</td></tr>
</table>

4.1. NO NEW REGIONAL INTERSTATE PIPELINE OVER THE PLANNING HORIZON

The Base Case assumes that there is no regional pipeline expansion over the planning horizon. Figure 7.2 shows the incremental supply resource daily capacity additions needed to meet our capacity and energy requirements over the planning horizon.

Figure 7.2: Base Case - No New Regional Portfolio



The Company has shown these incremental resource graphs in prior IRPs, however, new to the 2018 IRP, in presentation only, we show energy efficiency as a supply resource and its forecasted impact on peak day load. The sharp two year ramp in Mist Recall starting in 2021-2022 is due to the fall off of segmented capacity, which the Company currently relies on as a firm resource, but does not consider it firm beyond 2022-2023.[6] Mist Recall is the most cost effective supply resource and is recalled until it is exhausted in 2029-2030 gas year.

After Mist Recall is exhausted the model chooses on-system RNG as the next cost effective resource, however, on-system dairy RNG is limited in capacity to 3,000 Dth/day.[7] It should be noted that in the deterministic optimization off-system dairy RNG becomes cost effective in the 2036-2037 gas year relative to conventional gas and the model chooses maximum allowed capacity (6,000 Dth/day). Figure 7.2 does not show off-system RNG as it does not add capacity needed to meet peak demand, i.e., without additional interstate pipeline service, the off-system RNG simply would displace an equivalent quantity of conventional gas supplies from the resource portfolio rather than add to that portfolio.

The first stage of the Central Coast Feeder upgrade is also chosen as a cost effective resource in 2030-2031, which allows an additional 15,000 Dth/day takeaway from the Newport LNG plant to serve areas in Salem and Albany. A local pipeline expansion (i.e., NW Natural specific) of 30,000 Dth/day is selected in the 2031-2032 gas year. The local expansion is modeled as a single point in time expansion, which forces the model to appropriately size the resources for the remainder of the planning horizon.

[6] See Chapter Six for more details about segmented capacity.
[7] Capacity limitations for RNG are based on estimated availability for each RNG source. Actual technical potential is currently being study by the Oregon Department of Energy and will better inform the Company's expectation of potential capacity limitations.

In the Base Case the representative on-system dairy gas is chosen as a cost effective resource starting in the 2029-2030 gas year. Once this renewable resource is cost-effective the resource choice optimization model chooses the maximum amount that is included in the model for consideration (i.e., 3,000 Dth/day). The representative off-system RNG is chosen as a least cost resource starting in 2036 and the model selects the maximum capacity (i.e., 6,000 Dth/day). As a result the Company acquires 9,000 Dth/day of dairy gas by 2037 as a part of the least cost portfolio for the Base Case. This results in an expected 3.7 percent of all total sales load in 2037 being RNG, but due to the negative carbon intensity of dairy RNG the resultant reduction in emissions is 16.8 percent. This equates to a reduction of 787,999 $MTCO_2e$, in 2037, though it represents a cumulative savings of 3,301,058 $MTCO_2e$ over the 20-year planning horizon (though savings start in 2029).

The reason on-system dairy gas is cost-effective once Mist Recall is exhausted is based on the all-in cost comparison between gas resources. The purchasing cost for conventional gas includes the expected commodity price, variable transportation costs[8] and the expected GHG emissions compliance costs. The expected all-in cost of conventional gas in real terms by 2037 is about $6 per Dth. After valuing the on-system benefits and the emissions compliance benefit of dairy RNG the all-in cost for on-system dairy in 2037 is a little over $2 per Dth. Figure 7.3 shows a side-by-side comparison of expected all-in costs of conventional gas (modelled from the AECO supply basin) and the all-in costs of on-system RNG.

[8] Transportation costs include a fuel charge (variables costs associated with the extra gas used by the interstate pipelines to transport gas across their system. For example, a 1 percent fuel charge requires purchasing 101 MMBtus at the receipt point in order to have 100 MMBtus delivered) and the variable rate portion of pipeline tariffs.

Figure 7.3: Comparison of Conventional Gas vs. On System Dairy RNG All-In Costs

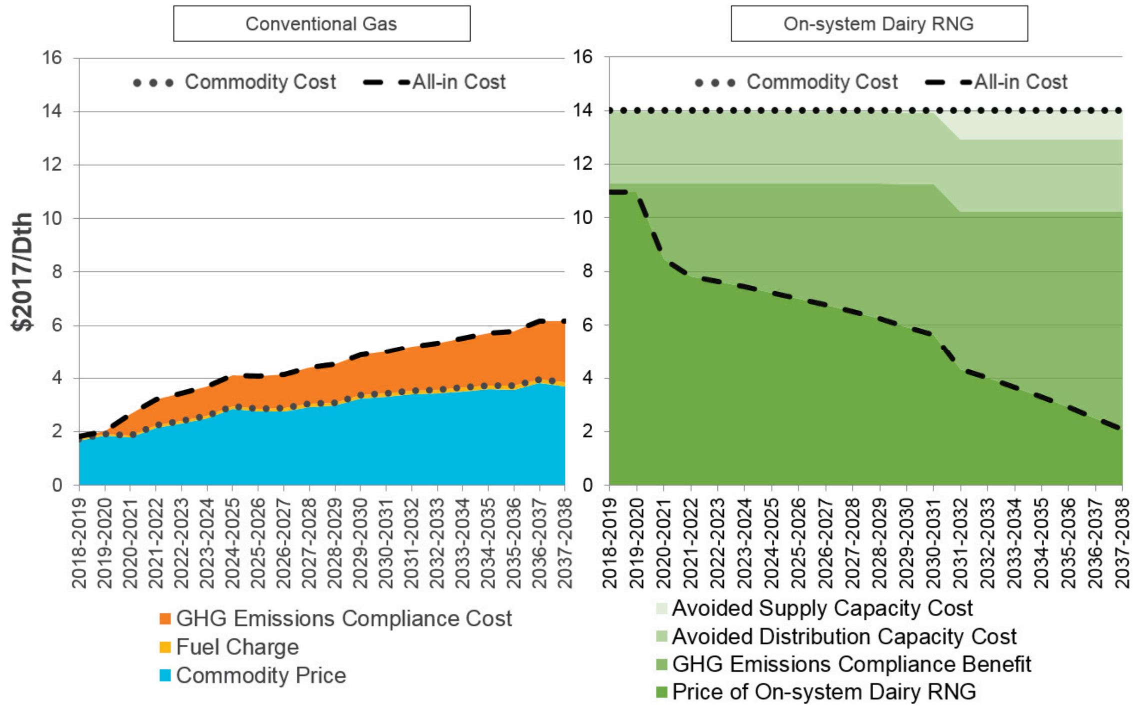
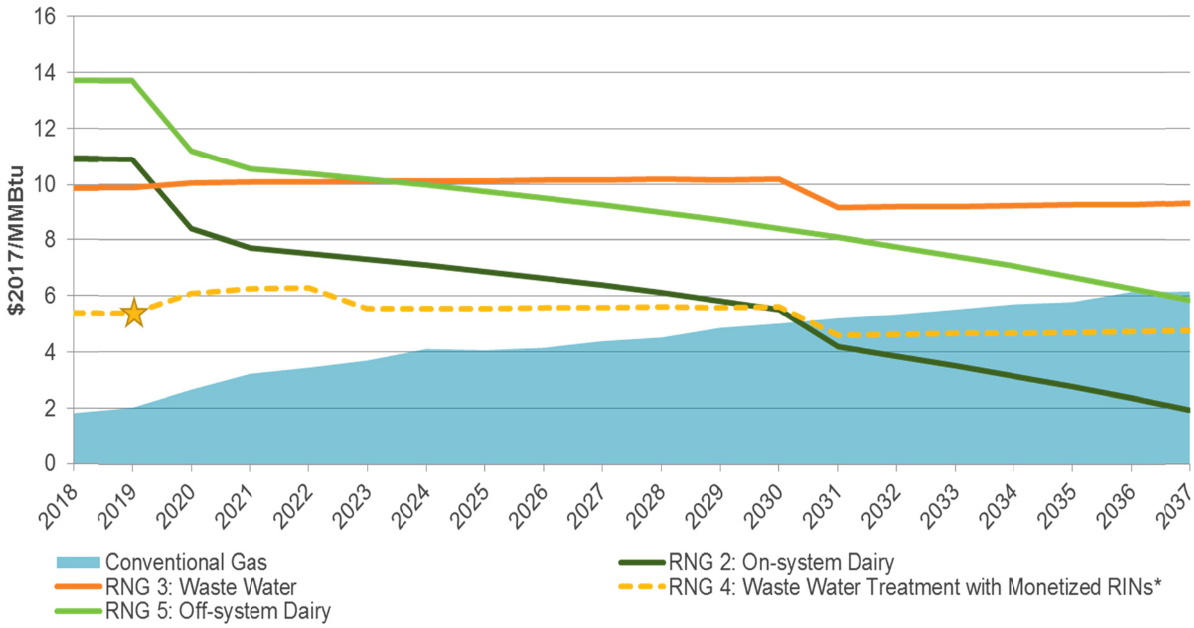


Figure 7.4 shows the expected all-in costs for each of the renewable gas resources compared to the expected all-in cost of conventional gas.[9] The yellow star in Figure 7.4 indicates a single decision point where the resource can be acquired. Potential RNG opportunities may be similar in nature and face a "now or never" decision.[10] The cost-effectiveness of this decision is dependent on the present value costs and benefits over the planning horizon (e.g., weighing the future benefits against the up-front costs). The supply resource planning model performs this NPV analysis through optimization.

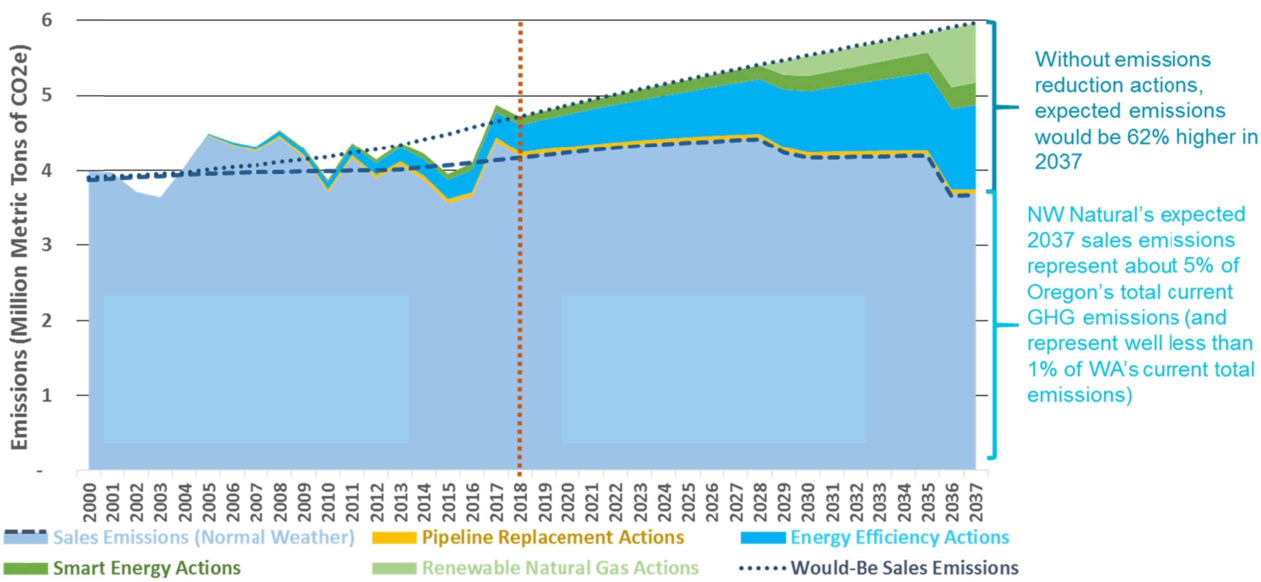
[9] This expected cost of gas is modelled from the expected cost of AECO gas prices. The average cost across the Company's supply basins is slightly higher.
[10] Sources of RNG do have alternative outlets besides selling gas to NW Natural. An RNG opportunity available today will not be available in the future if the RNG provide contracts with an alternative buyer.

Figure 7.4: Comparison of Conventional Gas vs. Various RNG Sources



In addition to acquiring renewable gas resources, the Company has taken and is expected to take other cost-effective activities to reduce emissions. Figure 7.5 shows NW Natural's expected reported emissions under the Base Case,11 the impact of past and expected emissions reduction activities, and what emissions would have been and could be without these activities.

Figure 7.5: NW Natural Base Case Emissions Forecast

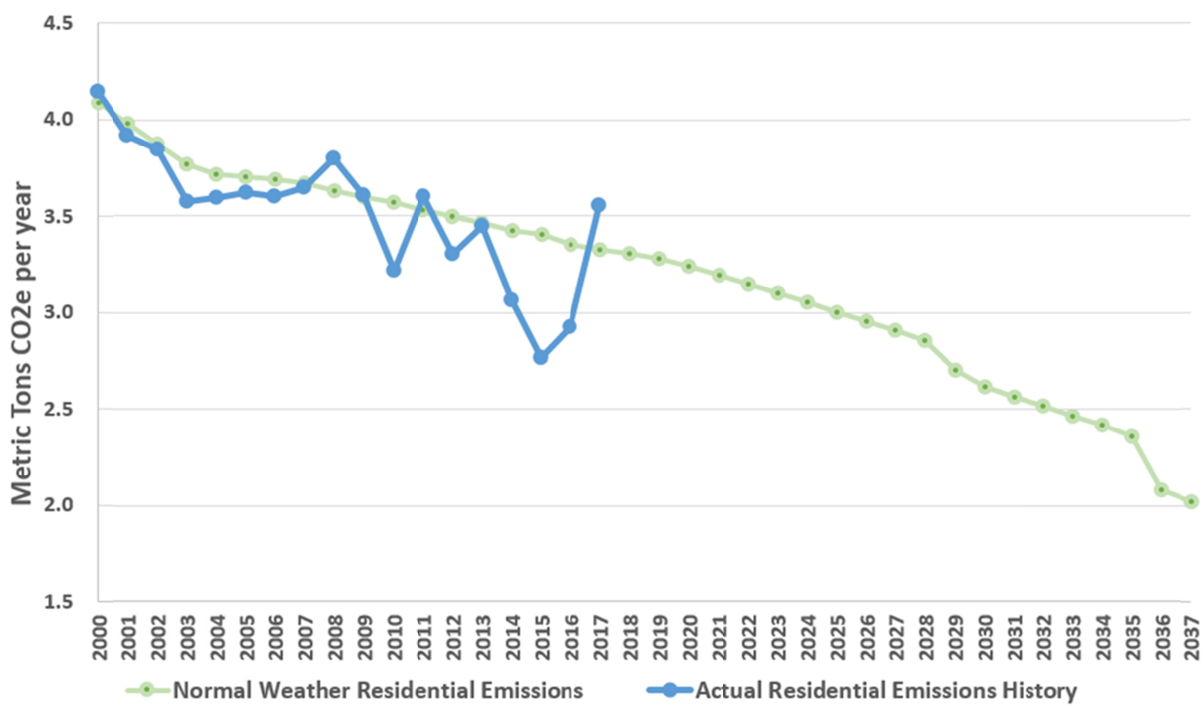


[11] The emissions forecast is based on normal weather.

As Figure 7.5 details, NW Natural's sales customers' expected reported emissions would be 62 percent higher in 2037 if not for past and expected cost-effective activities to reduce GHG emissions. In terms of impact, by 2037 the cumulative impact from energy efficiency through Energy Trust of Oregon and NEEA is expected to result in emissions savings equivalent to 31 percent of expected 2037 emissions. Additionally, the Company expects to save 21 percent of 2037 emissions through renewable natural gas, roughly 2 percent from its previous pipeline replacement action, and 8 percent from voluntary customer action through NW Natural's self-funded Smart Energy program offering.

Note that the total sales emissions shown in Figure 7.5 represent the combined impact of numerous trends which generally fall within three broad categories: (1) number of customers, (2) energy use per customer, and (3) emissions intensity of the gas sold to customers by NW Natural. On a per customer basis emissions have declined over the past twenty years due to increasing efficiency in natural gas use that has overcome the increase in the penetration of natural gas end use appliances by NW Natural's average residential and commercial customer. With the help of energy efficiency and decreasing the carbon intensity of our product through RNG resources emissions reductions, per customer are expected to continue to decrease for the next twenty years. Figure 7.6 shows the annual emissions of the average NW Natural residential customer and shows emissions have fallen 19 percent since 2000 and are expected to decline another 42 percent from their current levels by 2037, so that emissions per customer are expected to be less than half of what they were in 2000 by the year 2037.

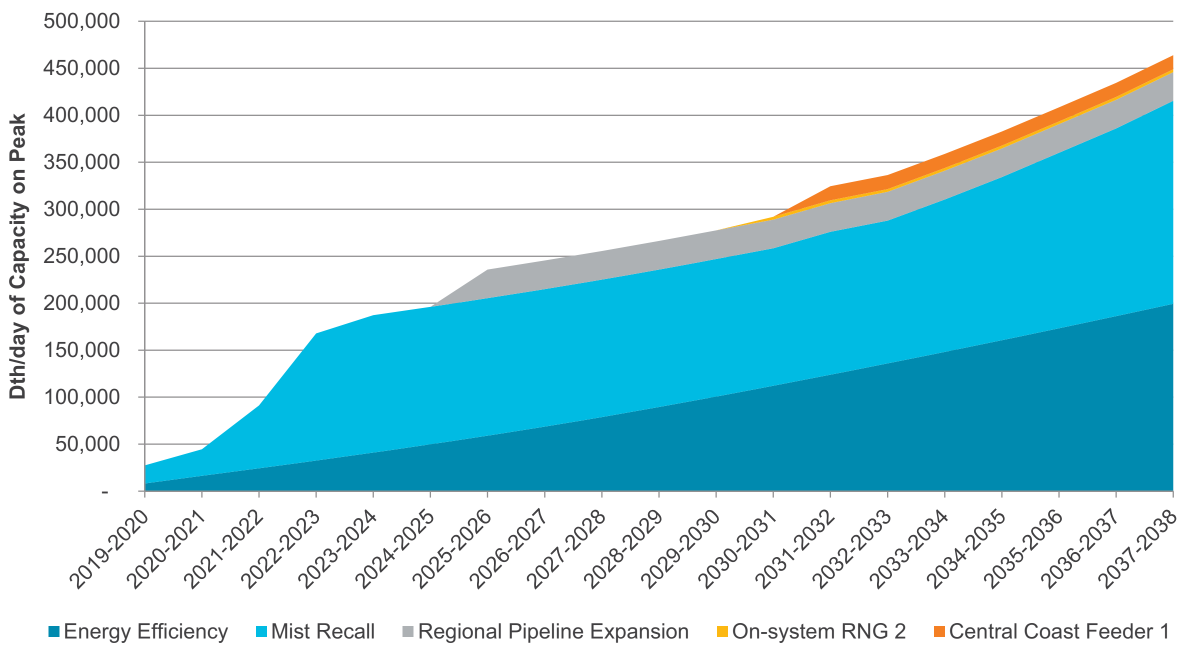
Figure 7.6: Average Residential GHG Emissions per Year



4.2. SENSITIVITY 2: FULLY-SUBSCRIBED REGIONAL PIPELINE PROJECT IN 2025

Through the supply resource planning model we introduce a regional pipeline option for the 2025-2026 gas year and only available to start in that year. If the pipeline is expected to be fully subscribed then NW Natural will have a single opportunity to obtain rights to capacity through an open season. Figure 7.7 shows the least cost portfolio selection for this sensitivity.

Figure 7.7: Sensitivity 2 – Regional Pipeline Fully Subscribed in 2025

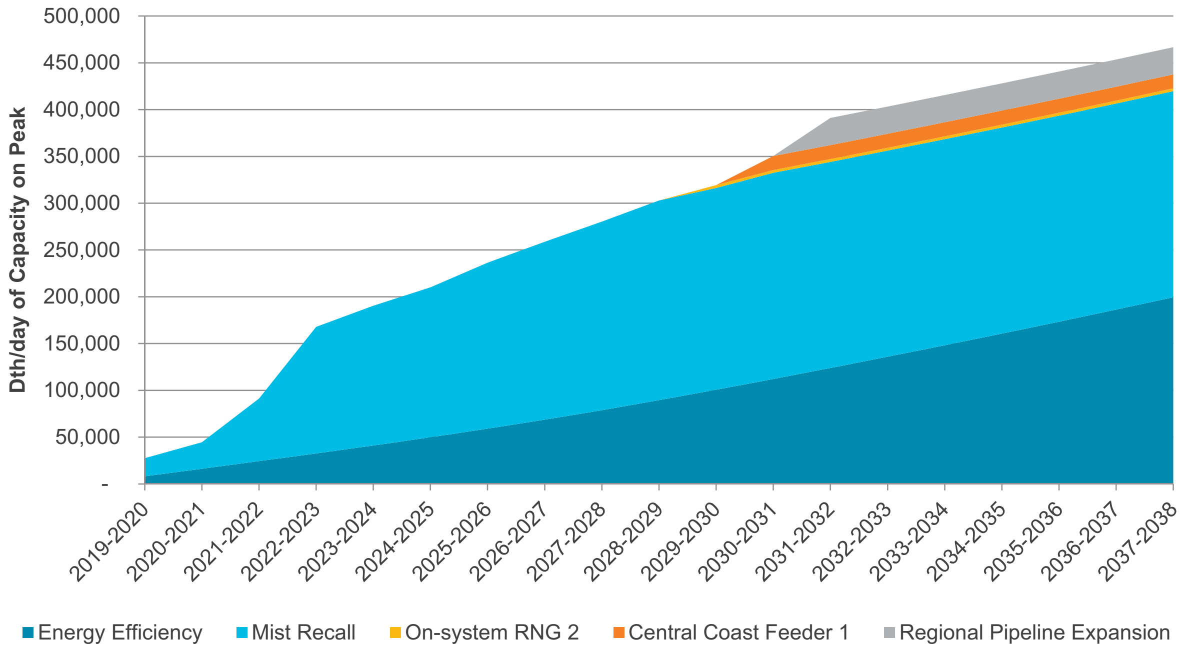


Here we see that if a regional pipeline expansion occurred in 2025 it would be cost effective for NW Natural to subscribe roughly 30,000 Dth/day of capacity. The fact that the model chooses to subscribe capacity in 2025-2026 intuitively suggests that this portfolio selection has lower present value cost than forgoing the open season opportunity and choosing another more expensive supply resource when it is needed later in the planning horizon. By getting pipeline capacity the model takes advantage of the available supply from the pipeline and delays having to recall Mist storage.

4.3. REGIONAL PIPELINE PROJECT IN 2025 – EXCESS CAPACITY

If a regional pipeline is built and available starting in 2025-2026, but has excess capacity over the planning horizon, NW Natural can subscribe to the pipeline as needed. Figure 7.8 show the incremental resources chosen for this sensitivity.

Figure 7.8: Sensitivity 3 –Regional Pipeline Excess Capacity in 2025



It is cost effect to subscribe to 30,000 Dth/day of the excess regional pipeline capacity in 2031-2032. This is identical to the no regional pipeline over the planning horizon sensitivity except that the lower cost regional expansion capacity is chosen instead of the higher cost local expansion. For this sensitivity, the contract choice was modeled as obtaining a single contract (i.e., 30,000 Dth/day), but the Company could further reduce the present value of the portfolio if smaller staggered contracts are available and can be added as needed.

4.4. DETERMINISTIC PORTFOLIO SELECTION SUMMARY

The deterministic portfolio results are best summarized by the following points:

- The near term portfolio selections, which inform the Company's action plan, are identical across the supply infrastructure sensitivities
- Cost-effective energy efficiency is expected to reduce peak loads by a significant amount over the planning horizon, greatly reducing the amount of supply capacity resources expected to be acquired
- Mist Recall continues to be a least cost asset for customers to be able deliver gas onto the system during a peak event
- Some of the representative renewable natural gas resources modeled show as least-cost resources over the planning horizon
- NW Natural would utilize the supply resource planning model to help inform a decision to subscribe to capacity during an open season
- Given our expected costs, it would be cost-effective for NW Natural to subscribe capacity to a regional pipeline

- The timing of this subscription would depend on our expectation of how much excess capacity is likely to be available on the pipeline in the future.
- Without expected emissions reduction actions over the planning horizon, NW Natural's annual emissions expectations would be 62 percent higher on an annual basis in 2037
- Since 2000, the GHG emissions of the average NW Natural residential customer have declined by 19 percent, and they are expected to decline an additional 42 percent by 2037, primarily due to planned emissions reduction action

5. RISK ANALYSIS OVERVIEW

While the deterministic portfolio selection gives us the least cost portfolio, the risk analysis evaluates areas of uncertainty to test the robustness of the Base Case assumptions. In the risk analysis we aim to answer the following questions. Given uncertainty:

1) What is possible range and distribution of the costs for the selected portfolio?
2) How often could the least cost portfolio not be a least cost option?
3) How does the least cost portfolio selection change due to fundamental changes in the planning environment?

The risk analysis is divided into two sections; the stochastic analysis (to help answer questions 1 and 2); and the sensitivity analysis (to help answer question 3). Table 7.4 provides a summary of the key uncertainties evaluated under each part the risk analysis.

Table 7.4: IRP Key Uncertainties Evaluated in Risk Analysis

IRP Risk Analyses		
	Stochastic Analysis	Sensitivity Analysis
Environmental Policy	✓	✓
Commodity Price	✓	
Economic Growth		✓
Supply Infrastructure		✓
Resource Costs	✓	✓
Technological Change		✓
Weather	✓	

6. STOCHASTIC ANALYSIS

After resource portfolios are deterministically created to meet the energy and capacity needs for each of the supply infrastructure sensitivities, stochastic analysis is completed on each of these same portfolios through two separate Monte Carlo simulations. The result of the stochastic analysis for a single sensitivity is a PVRR distribution which is representative of the potential future costs under a wide range of assumptions. The distributions of the portfolios can then be compared to identify which portfolio represents the best combination of cost and risk for customers.

6.1. SIMULATION 1: VARIABLE COSTS AND WEATHER AS STOCHASTIC INPUTS

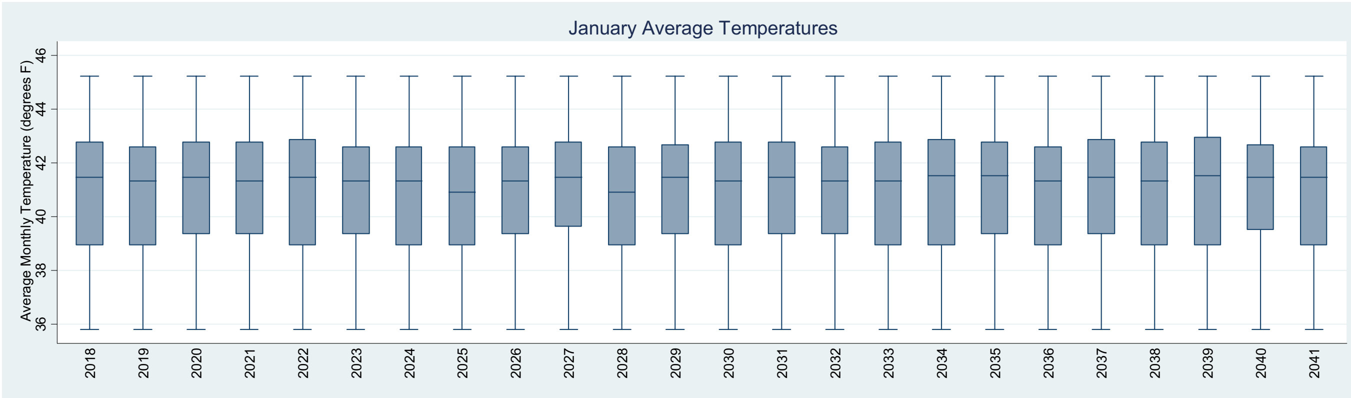
Weather, commodity prices, and carbon prices are simulated and then the resource portfolio is dispatched optimally for each simulation draw for each day of the planning horizon. Each of 500 simulation draws generates daily load center weather, monthly basin prices, and annual carbon prices by randomly drawing from defined distributions so that each resulting draw (or “future”) is different than the deterministic future but in a way that is consistent with the best approximation of the uncertainty of each component. The same 500 futures are used for each resource portfolio so that the PVRR for each portfolio can be compared for each simulated future/draw/future environment. Note that after the simulation is run a complete cost minimizing optimization is run for each future for each portfolio to determine the PVRR of the variable costs for the portfolio.

Stochastic Input #1: Weather

The weather data is drawn from a 30 year history of daily temperature data. For each month in a draw a year is chosen and the actual daily temperatures across all load centers are used in order to maintain temperature correlations. To exemplify the variation in weather across draws of the simulation, Figure 7.9 shows boxplots of the average monthly temperature for January (though like prices the simulation actually generated daily temperature values) in the Central Portland load center by year in the planning horizon.

NW Natural’s service territory weather and commodity prices are not highly correlated, even in winter months, because the weather-price relationship is driven primarily by North American weather as a whole. Since weather in the Portland area is not strongly correlated with weather continent-wide, weather in NW Natural’s service territory is not strongly correlated with natural gas prices at the relevant trading hubs.

Figure 7.9: Variable Cost Stochastic Input #1- Weather
(Central Portland Load Center January Example)



Stochastic Input #2: Commodity Prices

Monthly commodity prices for each supply basin are modelled as the previous period price adjusted by a reversion parameter and a basin specific shock. The reversion parameter brings the price closer to our expected prices but asymmetrically to create a lower-bound correction. Coincident shocks for each basin are pulled from a distribution of residuals created from ARIMA models fitted on each basin's historical prices.[12] This ensures that basin prices are correlated both month-to-month and across supply basins, which create realistic commodity price paths for any single draw, see Figure 7.10. This process creates a credible distribution of price paths for this stochastic analysis that are correlated across basins, but also correlated from month to month, see Figure 7.11.

[12] Next period prices are modelled as the previous period price adjusted by a reversion parameter (ρ) back to our expected prices ($AECO_t^E$) plus a basin specific shock (ϵ_t): $AECO_t = (1-\rho)AECO_{t-1} + \rho AECO_t^E + \epsilon_t$. The shock ($\epsilon_t$) is pulled from a distribution of residuals from arima models fitted on historical prices for each basin. Shocks are pulled coincidently across basins. The reversion parameter used is small, but asymmetric to create a lower-bound correction. The reversion parameter is even stronger if price go negative.

Figure 7.10: Commodity Price Correlation across Basins within a Single Draw

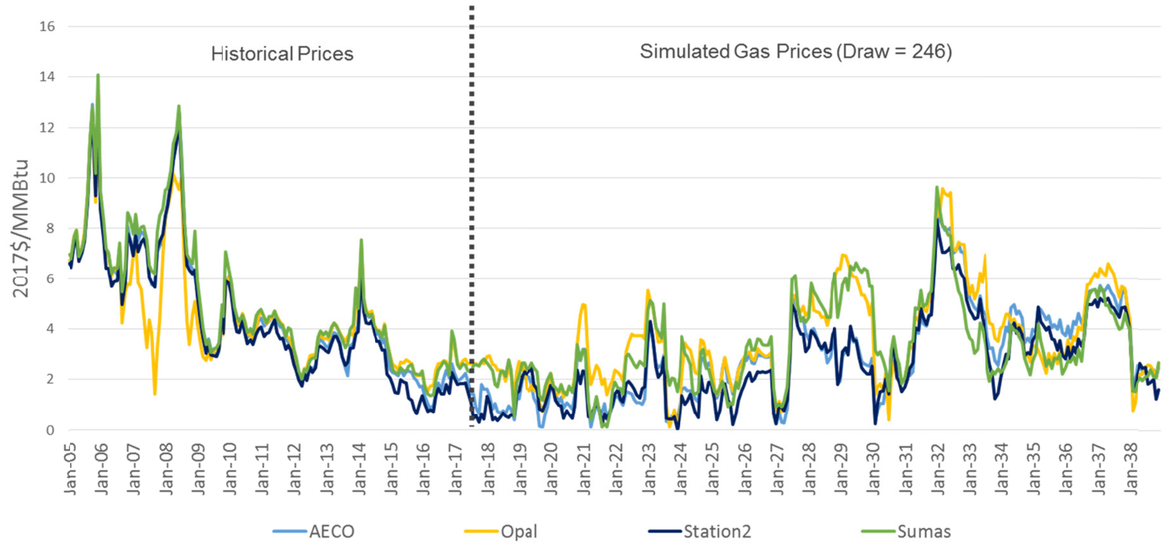
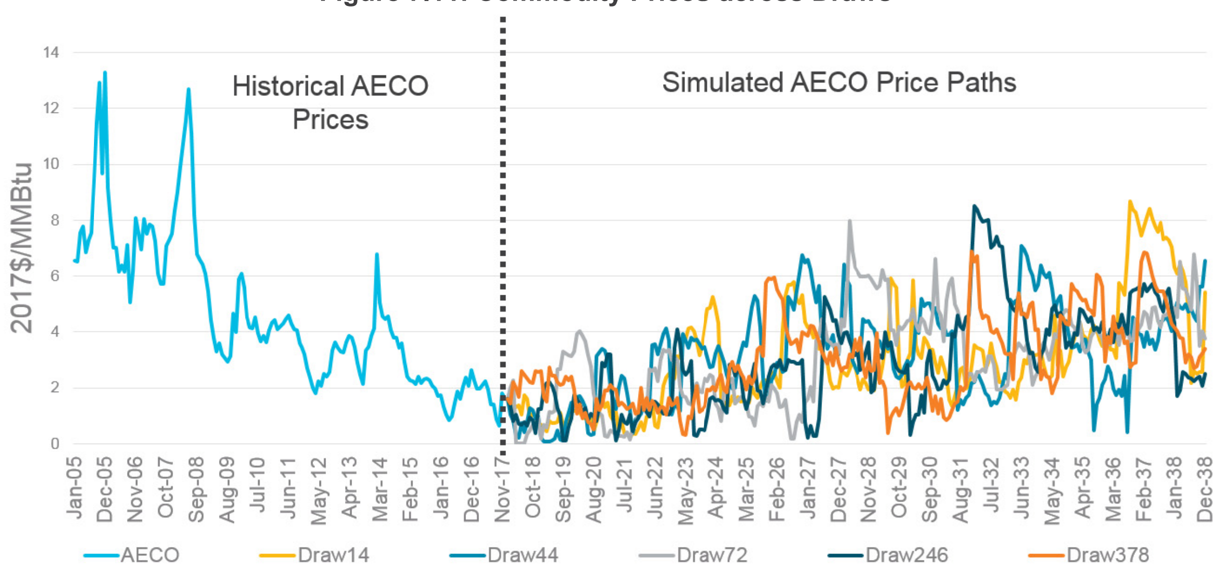
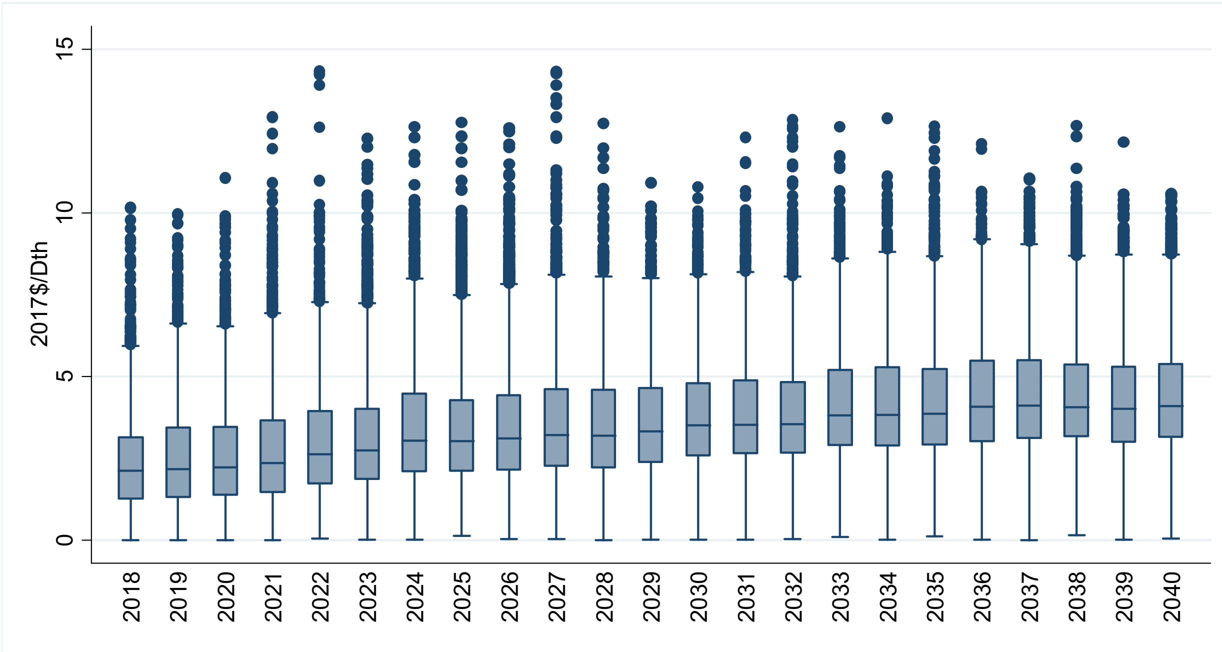


Figure 7.11: Commodity Prices across Draws



The Monte Carlo simulation uses 500 different gas prices draws generate from this process. The distribution of the gas prices for all basins is shown by the box-plot graph in Figure 7.12.

Figure 7.12: Distribution of Gas Prices

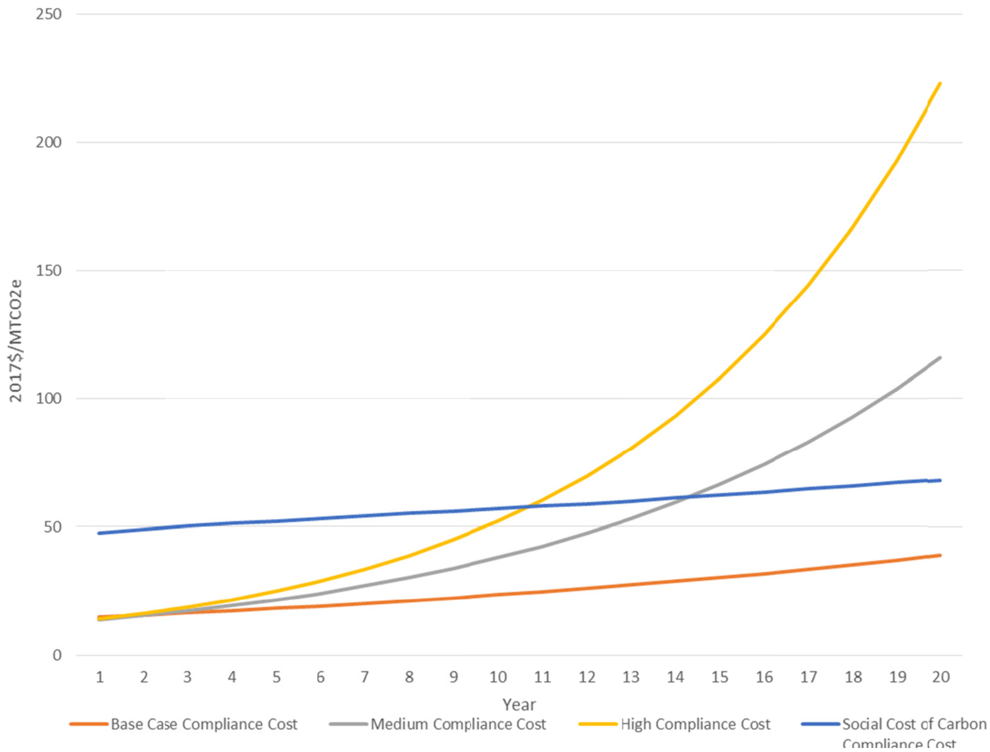


Stochastic Input #3: Carbon Prices

The Company also models a distribution of potential carbon prices based on four potential carbon price paths shown by Figure 7.13.[13] Forecasting both the type of policy and timing of the policy is very difficult and uncertain. In order to model this for the stochastic analysis the simulation creates 500 draws from these possible paths.

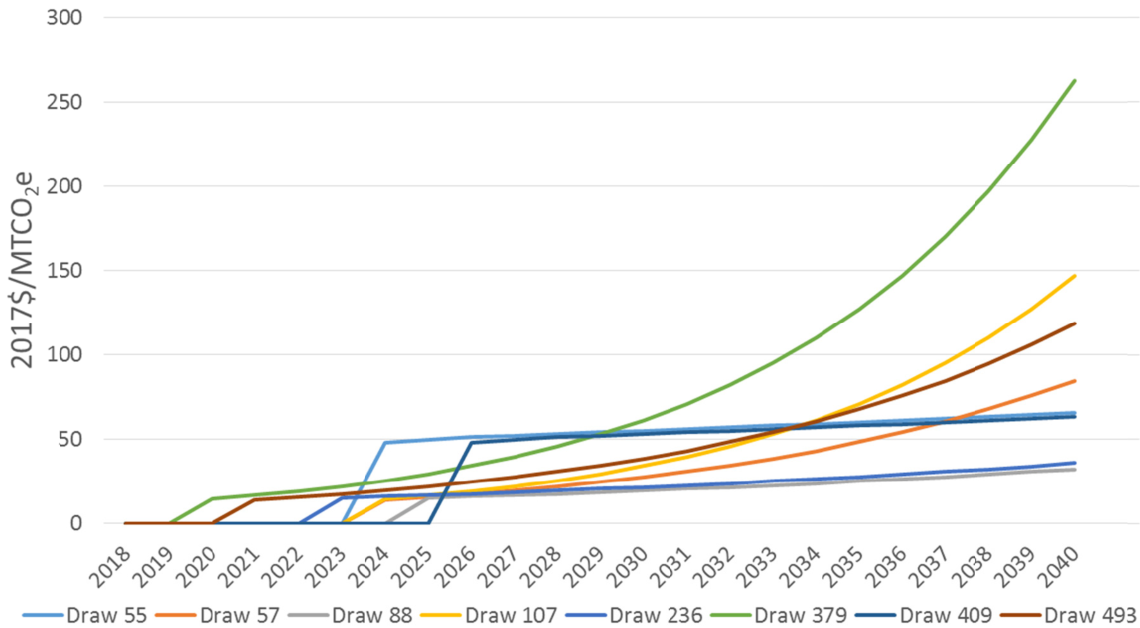
[13] The social cost of carbon price forecast is pulled from EPA's-mid price of the social cost of carbon based on a 2 percent discount rate. The three ramping price paths are allowance price forecasts for the cap-and-trade market administered under the California Air and Resource Board. Low, medium and high forecasts are produced by the California Energy Commission through 2030. The low price path is used for the Company's base case assumptions.

Figure 7.13: Potential Carbon Price Paths



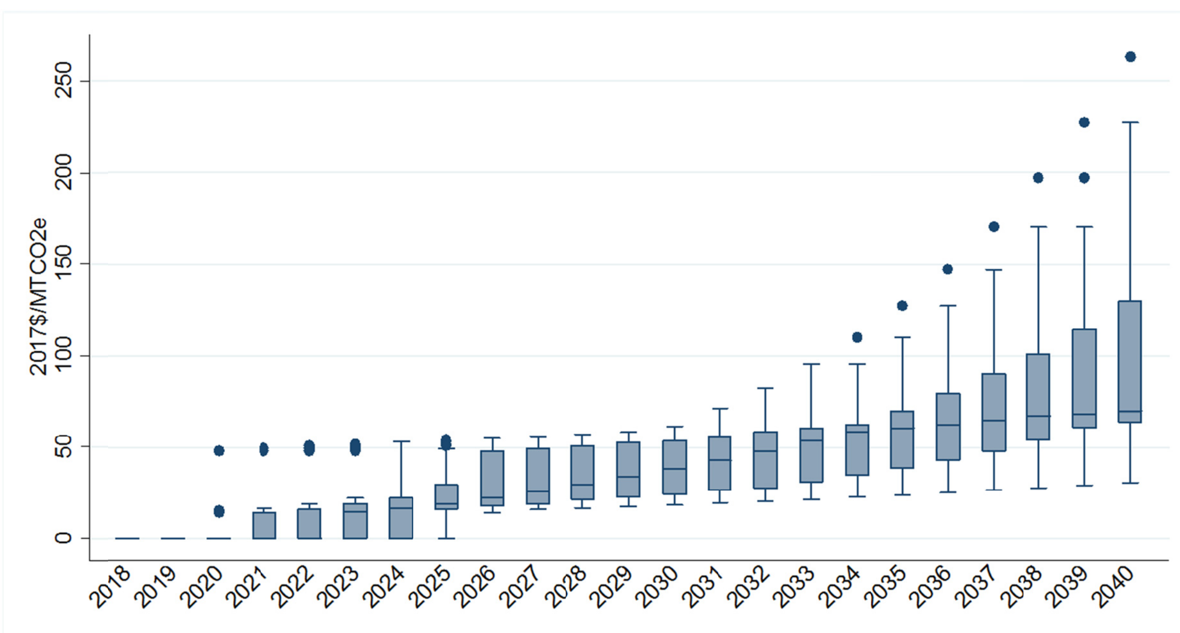
Each path as an equal probability of occurring. The policy must start by January of 2026, but has an equal probability of starting each year leading up to 2026. Once a policy starts it begins on the trajectory path starting as year 1 cost levels. Figure 7.14 shows an example how the timing and policy can vary across draws used in the Monte Carlo simulation.

Figure 7.14: GHG Compliance Cost across Draws



By varying both the type of policy and the timing of when the policy starts a distribution of possible carbon prices is created for the stochastic analysis. This distribution is summarized by the box plot diagram in Figure 7.15.

Figure 7.15: Distribution of Carbon Prices



6.2. SIMULATION 2: FIXED COSTS WITH SUPPLY RESOURCE OPTION COSTS AS THE STOCHASTIC INPUT

Stochastic Input #4: Supply Resource Option Costs

Uncertainty in the costs of the supply resource options considered is simulated separately from Simulation 1.[14] Supply resource costs are typically represented in a dollars per Dth of daily capacity[15] and are fixed costs since they are either reservation charge payments paid monthly regardless of the utilization of the contracted capacity or they represent the levelized revenue requirements of owned resources. Resource costs are a large driver of the difference in PVRR across portfolios and the assumptions about prospective resource costs could impact the position of a given resource as the expected least-cost option to meet customer needs. For example, if there were two resource options—one with an expected cost of $0.50/Dth of Daily Capacity and the other with an expected cost of $0.55/Dth of Daily Capacity, with both sourcing gas at the same trading hub so that the expected variable costs associated with either option are equal. Yet, both options have different levels of relative cost risk (so that it is possible with a reasonable degree of certainty that the $0.50/Dth of Daily Capacity option could turn out to be $0.75/Dth of Daily Capacity but highly unlikely the $0.55/Dth of Daily Capacity option could turn out to be above 0.65/Dth of Daily Capacity) it may make sense to choose the option that is not expected to be the least-cost option to mitigate the higher risk associated with the option that is lowest cost in the expected case.

Figure 7.16 shows the results of the simulation of 500 cost outcomes for a sample of the supply resource options considered.

The regional pipeline costs and their distribution (low and high estimates) are defined from a cost study by a third party consultant[16] and information provided by the interstate pipeline companies then combined into one resource notated as the "Regional Interstate Pipeline." Mist Recall costs and distribution characteristics are defined by current Mist accounts and the potential cost of service impact of the Mist Asset Management program. Central Coast Feeder project costs and distributions have been estimated by NW Natural engineers. North Mist project costs for core customers are defined by NW Natural's experience developing the North Mist Expansion Project for use by Portland General Electric. As is typical with large construction projects, each resource option is more likely to experience cost overruns of a given magnitude than they are to experience a savings relative to the current projected cost of the same magnitude (i.e., upside risk is greater than downside risk/benefit for all options). Note, however, that while the risk is asymmetric for all of the resource options, the asymmetry is not equivalent across resources.

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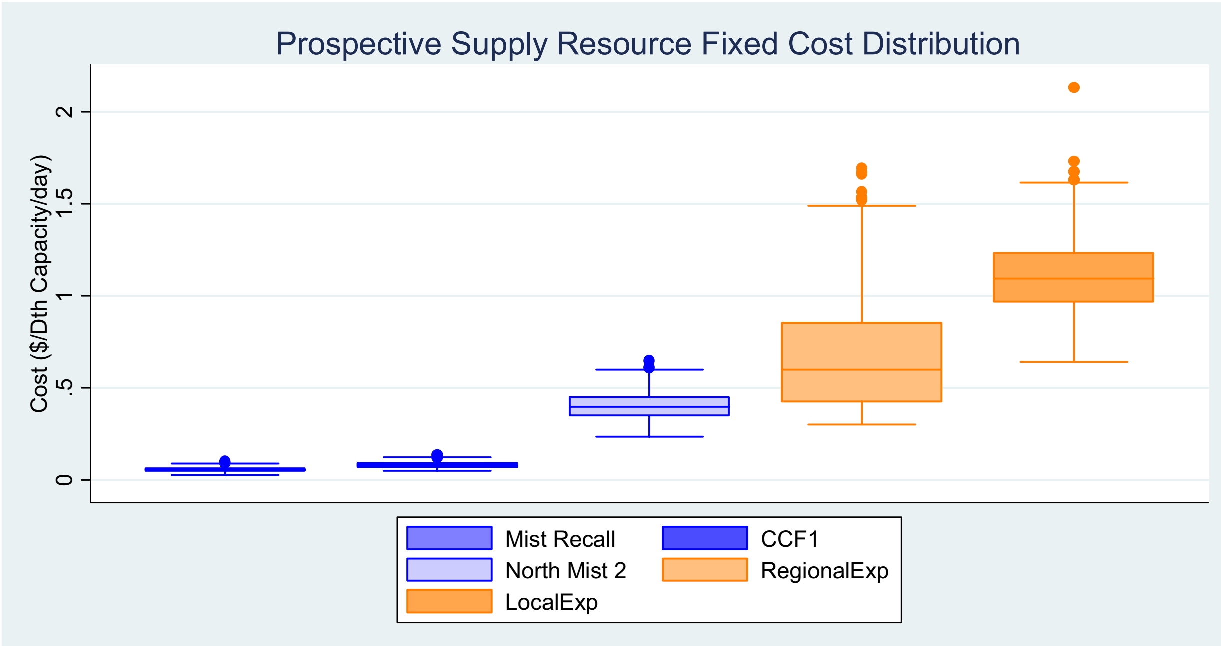
[14] Note that this implies that resource cost variation, which is related to permitting and construction cost uncertainty, is not correlated with variation in weather or natural gas prices. Given this independence, separating resource cost uncertainty into a separate simulation provides the exact same results one would obtain by combining fixed and variable cost uncertainty into one simulation within SENDOUT® but would result in 100 times the modeling run time.

[15] Meaning, for example, if a resource cost is $0.50/Dth of daily capacity and 10,000 Dth/day are contracted the annual payment for the resource in a non-leap year is $0.50* 10,000 *365 = $1.825 million and is the same in all non-leap years.

[16] See Confidential Appendix 7 in NW Natural's 2014 IRP for this report from Willbros Group, Inc.

Figure 7.16: Fixed Cost Stochastic Input- Supply Resource Costs (2017$)



While keeping in mind that supply resource option costs do not represent all of the difference in cost between portfolios for any given future (as the variable cost component that is estimated in Simulation 1 and its subsequent optimizations must be considered as well to estimate total portfolio PVRR), Mist Recall is the least cost and lowest risk option available to customers. Additionally, the Central Coast Feeder 1 project is lower cost than each of the other options other than Mist Recall for the fixed cost component and there is no overlap in the fixed cost outcomes. There is, however, considerable overlap in the fixed-cost estimate ranges of North Mist with that of the prospective regional interstate pipeline projects, making a choice between these options more inherently risky. Note, however, that NW Natural does not face a choice between these resource options in this IRP and is unlikely to face a decision on these resource in the next IRP.

6.3. COMBINING SIMULATIONS 1 AND 2

After both simulations are complete every possible combination of outcomes from the two simulations is paired to determine the net present value of costs of each of the supply infrastructure sensitivities under the resulting 250,000 prospective future environments.

Before proceeding, it is important to note that it is not appropriate to compare the PVRR of the portfolios for the infrastructure sensitivities detailed in this chapter and conclude that one portfolio shows as the best combination of cost and risk for NW Natural’s customers, as the only interstate pipeline option NW Natural has control over is the Local Sumas Expansion project, which is a NW Natural specific expansion. If a regional interstate pipeline project shows as the least-cost alternative it does not mean the Company can plan on subscribing to that pipeline because it may not be built and available for subscription and the timing may not align with the modeled sensitivity.

The difference in costs across portfolios and across draws for any given future are driven primarily by four factors: (1) the difference in fixed costs of the resource options being considered; (2) price basin differentials and the supply basins/trading hubs associated with the different resource options; (3) the difference between storage and pipeline resources as they relate to seasonal price spreads and the ability to purchase gas at the cheapest available basin for storage resources whereas pipeline resources are typically tied to purchasing gas at a particular supply basin; and (4) the difference in carbon prices.

7. RESULTS

The portfolios representing the infrastructure sensitivities are compared in two ways. First, their distributions are compared against each other at the 50th, 95th, and 99th percentiles. The 50th percentile (or median) is the expected cost of the portfolio. However, it is possible that the lowest expected cost portfolio might have a higher risk. Using the 95th and 99th percentile we can see how severe a bad outcome may be for each of the portfolios. Second, we can examine the portfolio performance under the same draw conditions. Looking at the NPVRR for each draw we can see how often we would expect one portfolio to outperform another.

Figure 7.17 shows the distribution NPVRR outcomes for the 250,000 draws using the No Regional Pipeline portfolio. The red bars show the location of the median (left), 95th percentile (middle), and 99th percentile (right) of the distribution. Table 7.4 compares these values across the infrastructure sensitivities. For all measurements we can see that having a regional pipeline available is lower cost and lower risk as the NPVRR at each of the relevant percentiles are lower than in the No Regional Pipeline sensitivity.

Table 7.5 shows the results when we compare two portfolios under the same draw conditions. In contrast to the distributional comparison where subscribing to a regional pipeline in 2025 was always lower expected cost and lower risk, this comparison shows that there is significant overlap in that 33 percent of draws it would be lower cost to not subscribe to a regional interstate pipeline. In other words, if we were to decide today to subscribe to regional interstate pipeline in 2025, there is a 67 percent chance that the NPVRR over the next 20 years would be lower than if we chose to forgo the regional interstate pipeline.

Figure 7.17: Example Histogram Resulting from Stochastic Analysis of a Single Portfolio

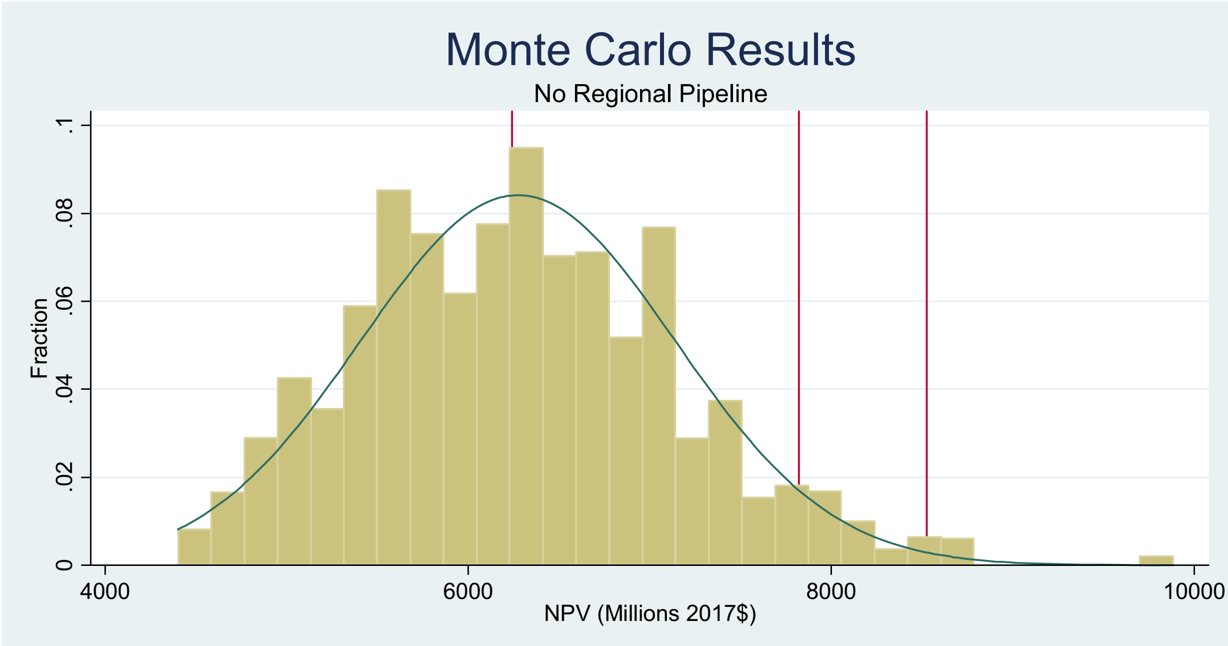


Table 7.4: Comparison of the Distribution of Infrastructure Sensitivity Portfolios

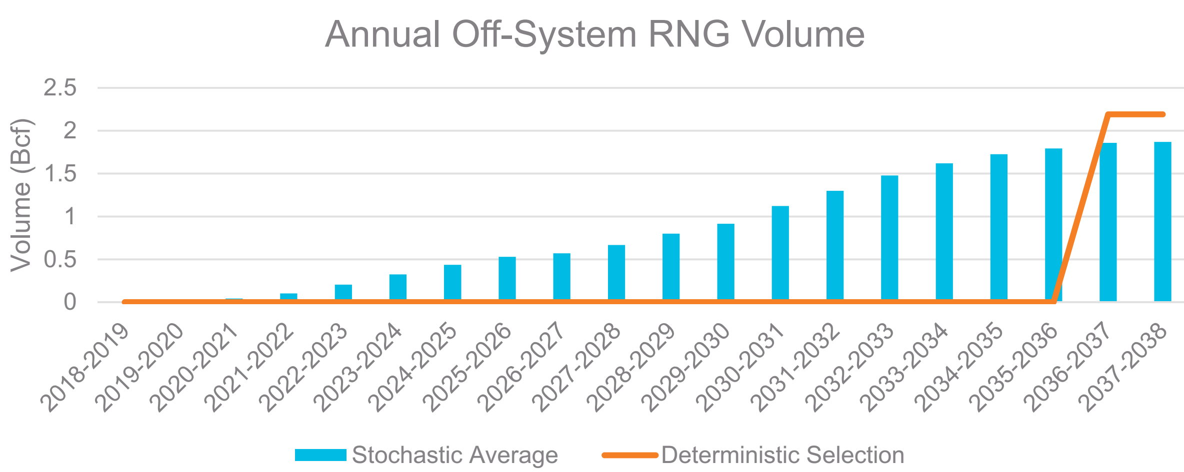
Portfolio Cost Distribution NPVRR (millions of dollars)			
	No Regional Pipeline	Regional Pipeline (Fully Subscribed)	Regional Pipeline (Excess Capacity)
Median	6,242	6,233	6,226
95th percentile	7,822	7,815	7,803
99th percentile	8,525	8,516	8,515

Table 7.5: Draw by Draw Portfolio Comparison

Portfolio	Lower Cost Draws (#)	Lower Cost Draws (%)
No Regional Pipeline	82,542	33%
Regional Pipeline (Excess Capacity)	167,458	67%

In addition to evaluating total portfolio cost, the stochastic analysis allows us to better evaluate RNG options. Figure 7.18 shows the volumes of off-system RNG that is chosen in the stochastic analysis (blue bars) compared to the deterministic optimization (orange line). Because off-system RNG acts only as a replacement for conventional gas (it does not contribute to capacity needs) it is chosen based on its all-in price (commodity plus carbon price adder) relative to conventional gas. While the deterministic case shows off-system RNG being acquired very late in the planning horizon, the stochastic analysis shows that this resource may be cost effective much earlier. Because the stochastic analysis uses a fixed capacity resource portfolio we have not performed a similar analysis for on-system RNG resources. However, the conclusion is likely to be the same. It will be important for NW Natural to take a deeper look at RNG resources because they may be cost-effective in the near future.

Figure 7.18: Annual Off-System RNG



8. SENSITIVITIES ANALYSIS

The sensitivities analysis changes various assumptions in the planning environment and examines how deviations from the Company's expected base assumptions can impact our resource planning. In addition to the three supply infrastructure sensitivities we look at two economic growth sensitivities and four environmental policy sensitivities. Each of these sensitivities represent six different possible futures that diverge from the Company's expectations, but are designed to highlight the impacts of specific areas of uncertainty. The future that comes to fruition is likely to combine aspects of each sensitivity. Table 7.6 lays out the key assumptions used to build each sensitivity. It is important to note that each of these sensitivities describe "what-if" environments that are beyond NW Natural's control, and therefore one cannot choose among the resulting portfolios. They are meant to inform what the resulting loads, resource portfolios and emissions trajectories might look like if the assumptions in the portfolio came to bear.

The rest of this section summarizes each sensitivity as compared to the Base Case. Note that the annual load forecast, peak day forecast, and emissions forecast does not change across the supply infrastructure sensitivities.

Table 7.6: Sensitivities and Key Assumptions

		Supply Infrastructure Sensitivities			Economic Growth Sensitivities		Environmental Policy Sensitivities			
		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**
		Base Case - No New Regional Pipeline	**New Regional Pipeline in 2025 - Fully Subscribed**	**New Regional Pipeline in 2025 - Excess Capacity**	**High Customer Growth**	**Low Customer Growth**	**Use Social Cost of Carbon in Resource Planning**	**Deep Decarbonization**	**CNG Adoption in Medium- and Heavy-Duty Transportation**	**New Direct Use Gas Customer Moratorium in 2025**
Demand-Side Assumptions	**Customer Growth**	Expected (Statistical Trend Continuation)			High 90% Confidence Interval	Low 90% Confidence Interval	Expected (Statistical Trend Continuation)		Expected Res and High Comm and Ind CNG	No new direct use customers allowed after 2025
	Space Heat Equipment						Newly installed units 25% Natural Gas Powered Heat Pumps in 2025 and 50% in 2030	Newly installed units 50% Natural Gas Powered Heat Pumps in 2025 and 100% GHP in 2030	Trend Continuation Plus EE Savings Projection	Trend Continuation Plus EE Savings Projection for Existing Customers
	Water Heating Equipment	Expected (Trend Continuation Plus Adjustment for Energy Trust Energy Efficiency Savings Projection)			Expected (Trend Continuation Plus Adjustment for Energy Trust Energy Efficiency Savings Projection)		New units 25% Nat Gas Heat Pump WH in 2025 and 50% GHPWH in 2030	New units 50% Nat Gas Heat Pump WH in 2025 and 100% GHPWH in 2030	Trend Continuation Plus Adjustment for Energy Trust Energy Efficiency Savings Projection	
	Industrial Load Efficiency						25% Increase in Industrial Efficiency	50% Increase in Industrial Use Efficiency	Trend Continuation	
	Building Shell Improvement	Shell Related Savings in Energy Trust Energy Efficiency Savings Projection			Shell Related Savings in Energy Trust Energy Efficiency Savings Projection		High CO2 Price Sensitivity Energy Efficiency Savings	Aggressive Shell Savings	Shell Related Savings in Energy Trust Energy Efficiency Savings Projection	
Supply-Side Assumptions	**Regional Interstate Pipeline Expansion**	No new regional interstate pipeline in Planning Horizon	Regional Pipeline Project in 2025 - Fully Subscribed	Regional Pipeline Project in 2025 - Excess Capacity	No new regional interstate pipeline in Planning Horizon		No new regional interstate pipeline in Planning Horizon			
	Renewable Natural Gas						Base Case Assumptions	Policy, Market, and Costs Attractive for Direct Use RNG	Continuation of Federal Transportation RNG Policy	Base Case Assumptions
	Power-to-Gas Hydrogen	Base Case Assumptions			Base Case Assumptions			Policy, Market, and Costs Attractive for PtG	Base Case Assumptions	
	Carbon Pricing						Social Cost of Carbon	High Sensitivity		

8.1. SENSITIVITY DESCRIPTION AND ASSUMPTIONS

Supply Infrastructure Sensitivities

These three sensitivities all use our expected demand load forecast, energy efficiency savings projection, and resource costs, and only vary by the supply-side resource options available and they are described in detail above. Note that only the Base Case represents portfolio options that are expected to be fully within NW Natural's control (i.e., NW Natural cannot control larger regional pipeline expansions, which is driven by demand from multiple shippers)..

Economic Growth Sensitivities
Sensitivities 4 and 5: High Customer Growth & Low Customer Growth

Two economic growth sensitivities use all base case assumptions except the customer growth forecast, which is primarily driven by expected economic activity (see Chapter Three). The high and low customer growth sensitivities use the 90th percent confidence intervals around the Base Case econometric customer forecast detailed in Chapter Three. These sensitivities assume the same resource costs as the Base Case, and like the Base Case there is not a new regional pipeline expansion/project assumed available to contract capacity on over the planning horizon.

Environmental Policy Sensitivities

As is described in Chapter 2, the largest source of uncertainty in this IRP is prospective is NW Natural's potential compliance obligations under different environmental policies in Oregon and Washington. These sensitivities are meant to show how different types of prospective environmental policies that have been discussed in our service territory might impact NW Natural's resource planning and our expected resultant emissions profiles through time. They are meant to represent a wide slate of potential policy environments, though are chosen with the idea of being able to somewhat isolate certain policy impacts. Neither the key assumptions in these sensitivities nor the results should not be viewed as advocacy for any type of policy nor an assessment of the likelihood of any particular policy, which NW Natural does not view as within the scope of resource planning in its IRPs.

Sensitivity 6: Using the Social Cost of Carbon in Resource Planning
This sensitivity uses the Social Cost of Carbon (SCC)[17] as the expected GHG emissions compliance cost in each year of the planning horizon in resource planning decisions. Note that this does not necessarily mean that a tax is imposed at the SCC (though this could be the case), but resources are planned such that the SCC is internalized into the cost for each resource based on the carbon intensity of the resource. This provides an effective subsidy to lower emitting resources simply for resource planning. This policy has been discussed in numerous contexts. Colorado has mandated the use of SCC in utility resource planning and a

[17] The U.S. Environmental Protection Agency's SCC estimate from January 2017 using a 3 percent discount rate is used, see https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html. See Figure 7.13.

number of states are considering similar policies. The Washington UTC has also suggested utilities in Washington state use the SCC in resource planning in comments on recent IRPs in Washington.

This sensitivity assumes that higher all-in gas prices will incentivize faster adoption of more efficient end use equipment. Sensitivity 6 uses the Base Case customer growth forecast but uses the stock replacement end-use load forecasting technique described in Chapter 3 to forecast annual and peak day loads (rather than the econometric methods that are used for the Base Case). This sensitivity assumes that starting in the year 2025 25 percent of the space and water heating appliances our customers (and expected customers) install in a given year will be natural gas powered heat pumps and starting in 2030 50 percent of newly installed natural gas space and water heating units will be natural gas powered heat pumps.[18] Additionally, this sensitivity assumes energy efficiency uptake through Energy Trust of Oregon based upon the high emissions compliance avoided cost sensitivity case presented in Chapter Five and a 25 percent increase in industrial energy use efficiency. This sensitivity assumes the same resource costs as the Base Case, and like the Base Case assumes there is not a new regional pipeline expansion/project available to contract capacity on over the planning horizon.

Sensitivity 7: Direct Use Natural Gas Deep Decarbonization

The deep decarbonization sensitivity incorporates several assumptions about environmental policy aimed at – or that results in – the direct use of natural gas decarbonizing while still serving the energy service requirements seen in the Base Case. This sensitivity includes a number of assumptions that would make lower carbon sources of methane more attractive and incent technological or market change that result in the installation of natural gas powered heat pumps as the primary equipment used to serve our customers' space and water heating needs by the end of the planning horizon.

Specifically, the GHG emissions compliance cost used in this sensitivity starts lower than the social cost of carbon, but escalates above it over the planning horizon.[19] This sensitivity uses the Base Case customer growth forecast, but uses end use load forecasting with the assumption that by 2025 half of the space and water heating equipment our customers install in a given year will be natural gas powered heat pumps and by 2030 all of our customers' newly installed space and water heating equipment will be natural gas powered heat pump technology. Sensitivity 7 also assumes an aggressive 50 percent increase in industrial direct use efficiency. Also, due to a combination of policy and market conditions the price of renewable natural gas and power-to-gas are assumed to be lower than in the Base Case.[20] Additionally, this sensitivity uses the most aggressive sensitivity for energy efficiency provided by Energy Trust of Oregon for this IRP (the high ramp rate sensitivity) described in Chapter Five. Like the

[18] Note that newly installed natural gas units is the summation of two things, units that are replaced on burnout and units installed in newly constructed structures (and is not the percentage of all units that exists). Newly installed units does not refer to any newly installed units beyond the expected units in NW Natural's base case customer growth and usage forecasts.
[19] See Figure 7.13.
[20] RNG costs are assumed to decrease by 15 percent. Power-to-gas cost decrease more steeply, starting at $64.84 per MMBtu in 2018 to $6.75 per MMBtu by 2038.

Base Case, this sensitivity assumes there is not a new regional pipeline expansion/project available to contract capacity on over the planning horizon.

Sensitivity 8: CNG Adoption in Medium and Heavy-Duty Transportation
The transportation sector is the largest contributor to emissions in both Oregon and Washington. Consequently, policy discussions often focus on this sector as a key place to seek emissions reduction. While electrification is usually the application considered in the light-duty transportation sector, policies that incent the use of compressed natural gas in the medium and heavy-duty vehicle sectors to displace higher emitting diesel have been implemented in many jurisdictions and further policy boosting CNG in this sector. These policies may be something we see in our service territory in the near future. Policies incenting CNG use also cite drastic reductions in smog and particulates, fleet resiliency and increased safety as benefits along with reduced GHG emissions relative to diesel use.

Sensitivity 8 assumes that by the end of the planning horizon (2037) one-quarter of the medium and heavy duty trucks in our service territory run on CNG. This means that there are 22,000 medium- and heavy-duty trucks running on CNG in 2037. This is the only deviation in assumptions from the Base Case for Sensitivity 8. An optimistic CNG growth outlook would incrementally add roughly five million therms to the Company's annual load each year over the next twenty years.

Sensitivity 9: New Direct Use Natural Gas Customer Moratorium Starting in 2025
Some policy discussions have suggested more blunt policy tools, like bans on all use of fossil fuels or code changes that would mandate electric equipment be installed for the energy needs that are currently primarily being served by the direct use of natural gas (e.g., residential and commercial space and water heating). To show the impact of an approach along these lines, Sensitivity 9 models the impact of a moratorium in NW Natural's service territory on new direct use natural gas customer hookups starting in 2025.

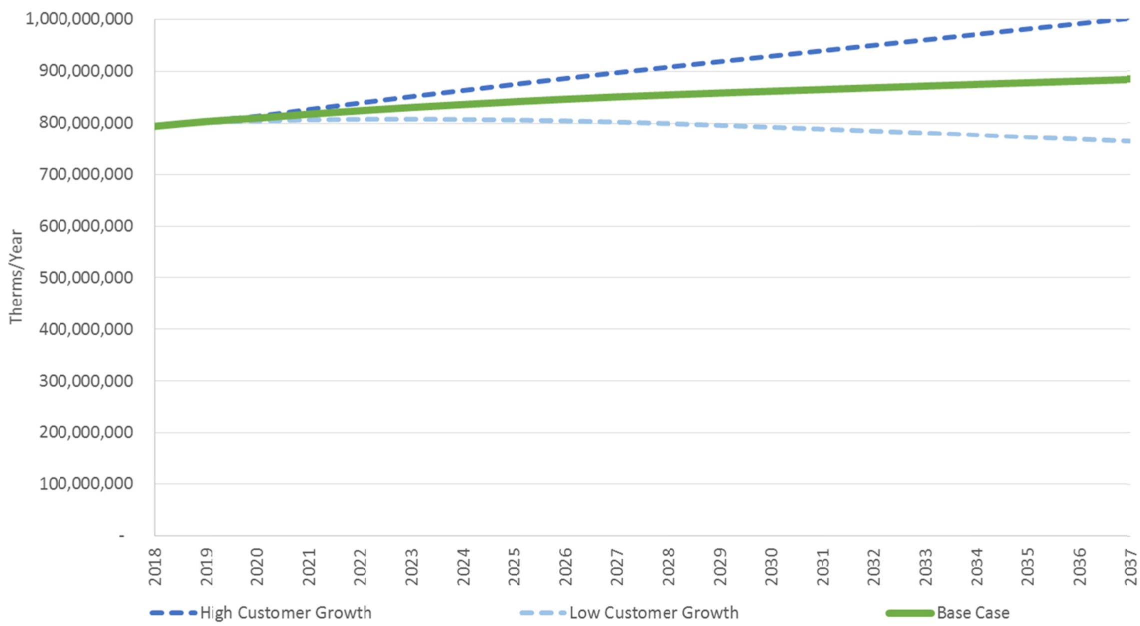
Specifically, this sensitivity assumes NW Natural does not add any new customers starting in 2025 and that the historical rate of customer losses due to building structure demolition and fuel switching away from natural gas continues over the planning horizon. This sensitivity includes a much lower expectation of energy efficiency over the IRP planning horizon. The reason for this is that even though new construction additions in any given year represent about 1 percent of NW Natural's total customer base at the end of a year, new construction represents a disproportionate share of the potential energy efficiency given that it is much easier to save energy when a structure is being built than to retrofit an existing structure. All other assumptions are the same as the Base Case.

8.2. ANNUAL LOAD FORECAST BY SENSITIVITY

All of the load forecasts in the IRP are the result of combining the impacts of the change in number of customers and the impact of changes in the amount of gas those customers use (i.e. use per customers).

The annual load of the economic growth sensitivities are intuitive and straight forward. The result of the high customer growth sensitivity forecasts a 1.2 percent average annual growth rate. The results of the low customer growth sensitivity is that annual load decreases at an average annual rate of -0.2 percent average annual growth rate as a decreasing trend in use per customer more than offsets a small gain in customer growth. Figure 7.19 presents the load forecasts of the economic growth sensitivities relative to the Base Case.

Figure 7.19: Economic Sensitivities Annual Load Comparison

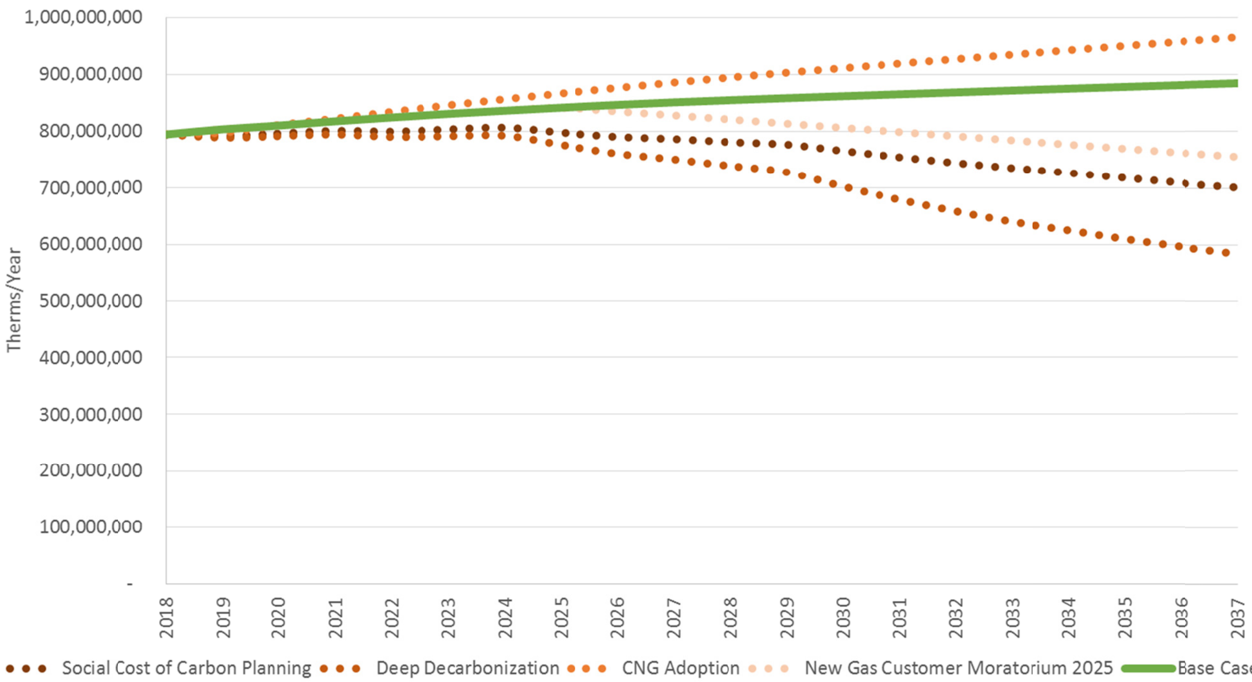


The resulting load forecasts for the four environmental policy sensitivities are presented in Figure 7.20. For Sensitivities 5 and 6 the resulting decline in use per customer is drastic enough that it overpowers the impact from customer growth and expected annual loads decline over time, with the more aggressive efficiency assumptions used in the Deep Decarbonization (Sensitivity 6) the impact is more pronounced than in the SCC in resource planning sensitivity (Sensitivity 5). There is an important distinction between the Company's "load" and the "energy services" the Company provides, as it is possible to provide the same energy services with less load through more efficient end use equipment. Despite declining annual loads in these sensitivities, the same energy services are still being provided by NW Natural as in the Base Case, it is just being done more efficiently.

Alternatively, the third and fourth environmental policy sensitivities do impact the energy services provided by the Company. The CNG adoption in medium- and heavy-duty transportation sensitivity adds load that the Company must serve (shown by the top orange line in Figure 7.20). This additional load replaces the energy service that would otherwise be served by alternative fuels (typically diesel). With this high adoption trajectory CNG would compose of roughly 10 percent of the Company's forecast annual sales load by 2037.

The last environmental policy sensitivity, a moratorium on new direct use natural gas customers starting in 2025 shows a decline in annual load. Under this policy the energy services expected to be provided for new construction and conversion customers are no longer being provided by the Company. This expected demand must be served by alternative fuels.

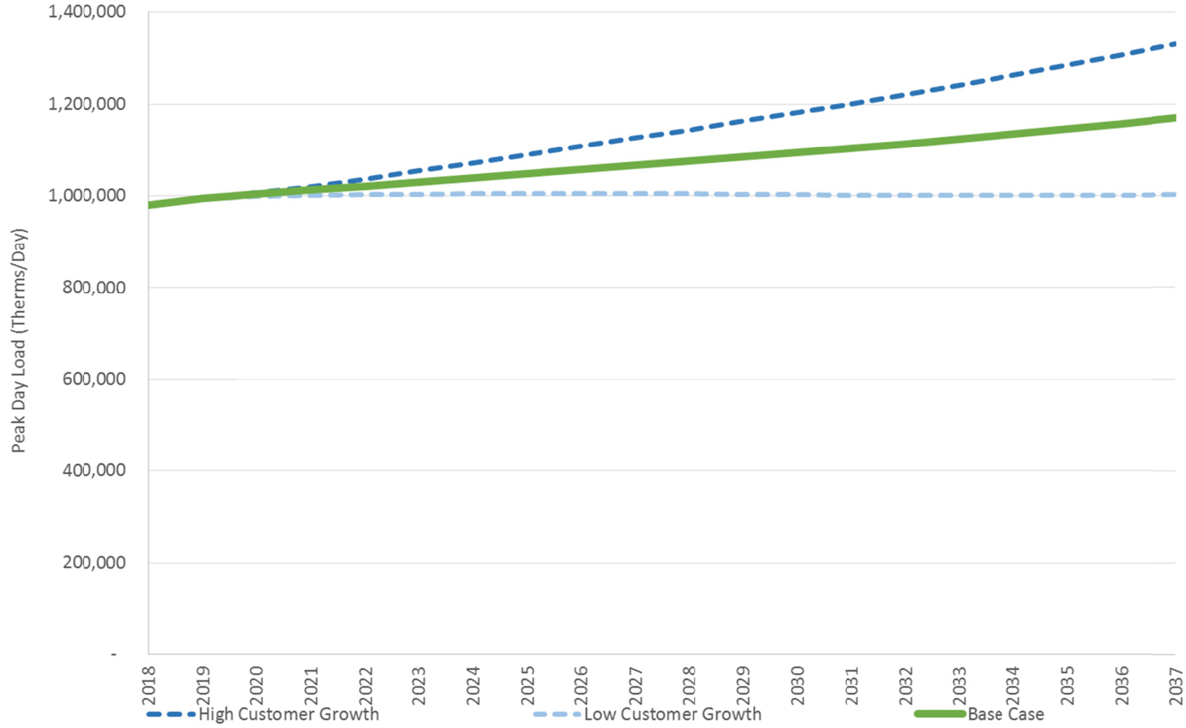
Figure 7.20: Environmental Policy - Annual Load Forecasts



8.3. PEAK LOAD FORECAST BY SENSITIVITY

Figures 7.21 and 7.22 show the resulting peak day load forecasts for the economic growth and environmental policy sensitivities, respectively, as compared to the Base Case. The peak for the high customer growth sensitivity has a 1.6 percent average annual growth rate, while the peak for the low customer growth sensitivity is effectively flat (0.1 percent average annual growth rate).

Figure 7.21: Economic Growth Sensitivities – Peak Day Forecast



Despite a decrease in the annual load forecast for Sensitivities 4 and 5, the analysis shows an increase in the peak day forecast (Figure 7.22). This is partially due to the way air source heat pump equipment works, regardless of the fuel used to power it. As temperature decreases the efficiency of air source heat pumps (including gas powered heat pumps and heat pump water heaters) also declines as the equipment has to work harder to pull heat out of the air.[21] Even though gas powered heat pumps result in a decrease in expected use on a per customer basis at all times, the load reduction in percentage terms is much lower on peak than usage reduction for the year as a whole. As a result the peak forecast for these two sensitivities the decline in peak use per customer is not sufficient to overcome the increase in the number of customers, such that the peak load forecasts are still increasing.

The peak day forecast for each of the environmental policy sensitivities is less than the Base Case, with the exception of the CNG adoption sensitivity. The additional CNG is non-seasonal load (i.e. “flat” load) and if brought on as firm sales (as shown) adds only a small percentage to the peak day forecast, roughly 2% by 2037.[22] If all the additional CNG load elects to be on

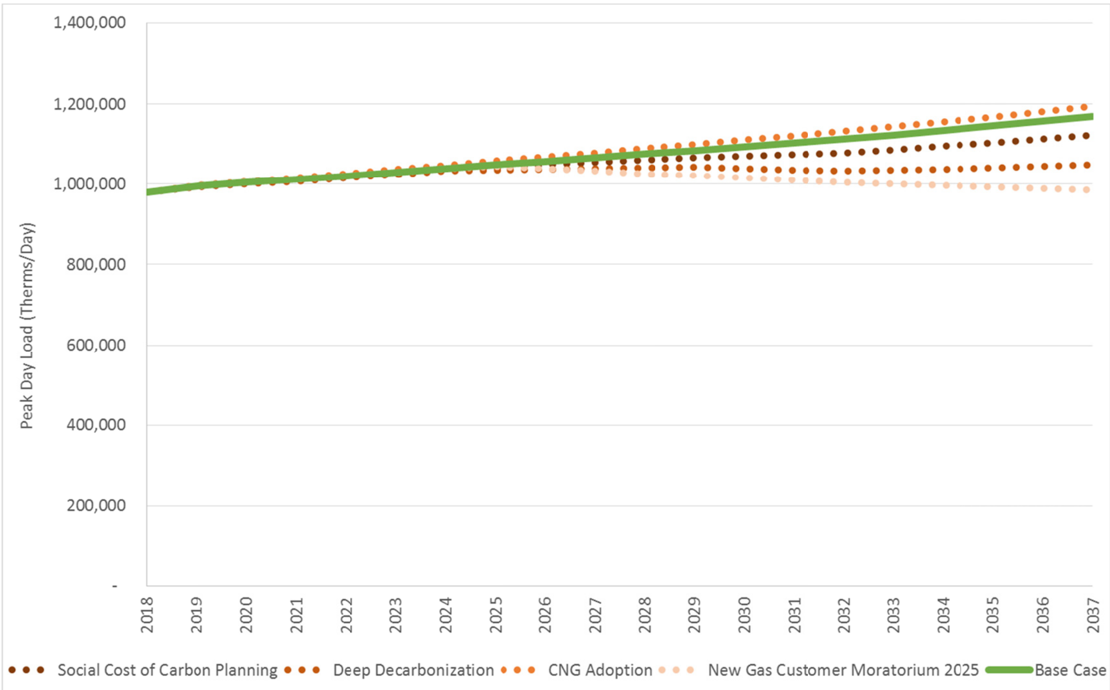
[21] The assumed annual efficiency of natural gas powered heat pumps for space heating is 140 percent from 2025 to 2030 and 150 percent afterwards, whereas peak efficiency is assumed to be 120 percent efficient. The assumed annual efficiency of gas heat pumps is assumed to be 130 percent efficient from 2025 to 2030 and 145 percent efficient afterwards and 110 percent efficient on peak from 2025 to 2030 and 120 percent efficient after 2030.

[22] The CNG adoption in medium- and heavy-duty transportation sensitivity includes the new incremental CNG load as firm sales to show the potential impact on societal GHG emissions. Modelling CNG adoption as firm sales is a bookend load requirement from a resource planning perspective. It is likely that the majority of new CNG load would elect to be on transportation schedules, and therefore would not be considered when planning for peak day capacity needs.

transportation schedules then the peak day forecast would not be any different than the Base Case.

The peak for Sensitivity 9 is exactly equal to the Base Case until 2025 when the moratorium of new direct use gas customers begins. After 2025 the peak slightly decreases over time as the Company slowly loses existing customers.

Figure 7.22: Environmental Sensitivities – Peak Day Load



8.4. RESOURCE PORTFOLIO CHOICE BY SENSITIVITY

Each of the sensitivities have varying assumptions that change either the energy services provided by NW Natural (i.e. how many homes and business we supply the source for heating or hot water) or the cost effectiveness of the different supply resources available (via either changes in the expected costs of the resources themselves and/or the expected costs of emissions compliance) relative to the Base Case. Table 7.7 summarizes how each sensitivity diverges from the Base Case for these two key dynamics.

Table 7.7: Summary Comparison of Deviations from Base Case Assumptions by Sensitivity

<table>
<tr><th></th><th></th><th>Change in Energy Services Provided by NW Natural</th><th>Change in Cost Effectiveness of Resources</th></tr>
<tr><td rowspan="2">Driven by Economic Factors</td><td>High Customer Growth (4)</td><td>✓</td><td></td></tr>
<tr><td>Low Customer Growth (5)</td><td>✓</td><td></td></tr>
<tr><td rowspan="4">Driven by Policy</td><td>Use Social Cost of Carbon in Resource Planning (6)</td><td></td><td>✓</td></tr>
<tr><td>Deep Decarbonization (7)</td><td></td><td>✓</td></tr>
<tr><td>CNG Adoption in Medium- and Heavy-Duty Transportation (8)</td><td>✓</td><td></td></tr>
<tr><td>New Direct Use Gas Customer Moratorium in 2025 (9)</td><td>✓</td><td></td></tr>
</table>

Given the relevant loads of the sensitivities shown above as well as the resource option costs detailed in Table 7.2 a least cost portfolio is optimized using SENDOUT, just as is completed with the Base Case assumptions in the determine the Base Case portfolio results..

The capacity resources that contribute to peak day demand selected for each portfolio are shown in Table 7.8. Note that the optimization includes the choice of both capacity resources as well as energy resource (i.e., sources of gas supply) and that Table 7.8 does not show gas supply resources included in the portfolio that do not contribute to peak day supply resource capacity.

Table 7.8: Peak Day Load and Incremental Supply by Sensitivity

		Supply Infrastructure Sensitivities			Economic Growth Sensitivities		Environmental Policy Sensitivities			
		No New Regional Pipeline	New Regional Pipeline in 2025- Fully Subscribed	New Regional Pipeline in 2025- Excess Capacity	High Customer Growth	Low Customer Growth	Use Social Cost of Carbon in Resource Planning	Deep Decarbonization	CNG Adoption in Medium- and Heavy-Duty Transportation	New Direct Use Gas Customer Moratorium in 2025
Peak Load 2037-2038 Gas Year (Dth/Day)		1,181,833	1,181,833	1,181,833	1,355,499	1,003,112	1,134,772	1,055,316	1,209,482	982,655
Incremental Resource Capacity Contribution to Peak		Resource Timing								
Resource	Dth/Day									
Exhaust Mist Recall	220,300	2029	2037	2029	2037	-	-	-	2037	-
Pipeline	Varied by Sensitivity →	Local	Regional	Regional	Local	-	-	-	Local	-
		30,000	30,000	30,000	100,000	-	-	-	40,000	-
		2031	2025	2031	2024	-	-	-	2029	-
Central Coast Feeder 1	15,000	2030	2031	2030	2031	-	2034	-	2028	-
Mist Expansion (II & III)	100,000	-	-	-	2033	-	-	-	-	-
RNG 2 : On-System Dairy	3,000	2029	2030	2029	2029	2029	2019	2021	2027	2031
RNG 3: On-System Waste Water	5,000	-	-	-	-	-	-	2034	-	-
RNG 4: On-System Waste Water with Monatized RIN Values	1,500	-	-	-	2019	-	2019	2019	2019	-
P2G: Power-to-Gas (No Methanation)	21,900	-	-	-	-	-	-	2036	-	-

8.5. EMISSIONS FORECAST BY SENSITIVITY

As stated prior, the timing of the acquisition of renewable gas resources is a critical component of the Company's annual emissions forecast and the cumulative emissions over the planning horizon. Table 7.9 summarizes the timing for renewable gas resources (both on- and off-system) and emissions reductions through renewable gas resources procurement for each sensitivity.[23] Similar to renewable resources for electric utilities, by lowering the carbon intensity of the gas flowing through the system the Company can decouple emissions from load.

The economic growth sensitivities are similar to the Base Case. In the high sensitivity it is cost effective to procure the RNG 4 option (waste water treatment with monetized RIN values), which must be acquired in 2019. Although the RNG 4 option is a relatively very small amount (1,500 Dth/day), it is acquired early on and has a sizable impact on the cumulative emission savings over the planning horizon. The same RNG resources are acquired in the low customer growth sensitivity as the Base Case resulting in a higher share of sales load from renewables, 4.2 percent in 2037.

The environmental policy sensitivities are more complex and differ widely from the Base Case. On- and off-system dairy RNG along with RNG from on-system waste water treatment with monetized RIN values are all cost effective immediately when resource planning with the social cost of carbon sensitivity (4). The social cost of carbon starts much higher relative to the Base Case impacting the cost effectiveness of less carbon intensive gas. The annual emissions saving is a small increase from the Base Case annual saving in 2037, but since all three sources are selected straightaway the cumulative impact over the planning horizon is drastically larger.

There is a similar impact in the deep decarbonization sensitivity although the time of resource selection varies overtime with the selection of RNG 3 in 2034 and power-to-gas in 2036. The addition of these two resources, particularly power-to-gas, drastically increases the share to sales load from renewable resources. This increase in share is largely driven by the policy assumptions that lower the costs and encourage the developments of renewable gas resources. The CNG adoption in medium- and heavy-duty transportation sensitivity selects four RNG options within the planning horizon. These RNG options are being modelled as flat supply, that is, RNG can deliver the same amount of gas each day of the year.[24] CNG load is also flat, that is, demands are roughly the same about each day of the year. RNG's flat supply better serves the additional CNG flat demand in this sensitivity, where the alternative supply options are either more expensive pipeline capacity (which is also flat) or non-flat storage supply options.

The new direct use gas customer moratorium in 2025 only selects the two dairy RNG options and selects them later in the planning horizon. Because less RNG resources are chosen and

[23] Note that the Company does other actions to reduce emissions. Table 7.9 only shows the emissions reductions associated with renewable gas resource procurement.
[24] RNG is currently being modelled as flat, which is similar to pipeline capacity, but there may be non-flat supply components for RNG. The Company is still studying RNG and how supply profile of RNG will deliver gas onto the system.

chosen late in the planning horizon, the cumulative reduction from renewable gas resources is considerably smaller relative to the other environmental policy sensitivities.

Table 7.9: Timing of RNG Resources and Emissions Reductions by Sensitivity

		Supply Infrastructure Sensitivities			Economic Growth Sensitivities		Environmental Policy Sensitivities			
		Base Case- No New Regional Pipeline	New Regional Pipeline in 2025- Fully Subscribed	New Regional Pipeline in 2025- Excess Capacity	High Customer Growth	Low Customer Growth	Use Social Cost of Carbon in Resource Planning	Deep Decarbonization	CNG Adoption in Medium- and Heavy-Duty Transportation	New Direct Use Gas Customer Moratorium in 2025
First Year Renewable Resource Option Chosen	RNG1- Off-System Landfill	-	-	-	-	-	-	-	-	-
	RNG2- On-System Dairy	2029	2030	2029	2030	2029	2019	2021	2027	2031
	RNG3- On-System WWTP	-	-	-	-	-	-	2034	2037	-
	RNG4- On-System WWTP w/ RIN sales	-	-	-	2019	-	2019	2019	2019	-
	RNG5- Off-System Dairy	2036	2036	2036	2036	2036	2019	2023	2036	2036
	P2G- Power to Gas Hydrogen	-	-	-	-	-	-	2036	-	-
Share of Sales Load in Renewables in 2037		3.7%	3.7%	3.7%	3.8%	4.2%	5.3%	21.0%	5.1%	4.4%
Share of Sales Emissions Reduced in 2037		16.8%	16.8%	16.8%	15.2%	18.9%	21.1%	38.7%	15.9%	20.1%
Metric Tons CO2e Reduced in 2037		787,999	787,999	787,999	809,791	787,999	809,791	1,306,650	846,635	787,999
Metric Tons CO2e Reduced Over 20 Year Horizon		3,301,058	3,101,547	3,301,058	3,479,989	3,328,308	15,221,541	13,216,113	4,238,085	2,802,975

Figure 7.23 compares the annual emissions forecast for Base Case (green) and the economic growth sensitivities (blue). Driven by customer growth, emissions are expected to gradually increase until 2029. The first drop in emissions is driven by procuring on-system dairy RNG. The

second drop in 2036 is driven by procuring off-system dairy RNG. Both the high and low customer growth sensitivities follow similar paths, but shifted due to high and low gas demand.

Figure 7.23: Economic Sensitivity vs. Base Case Emissions Forecast

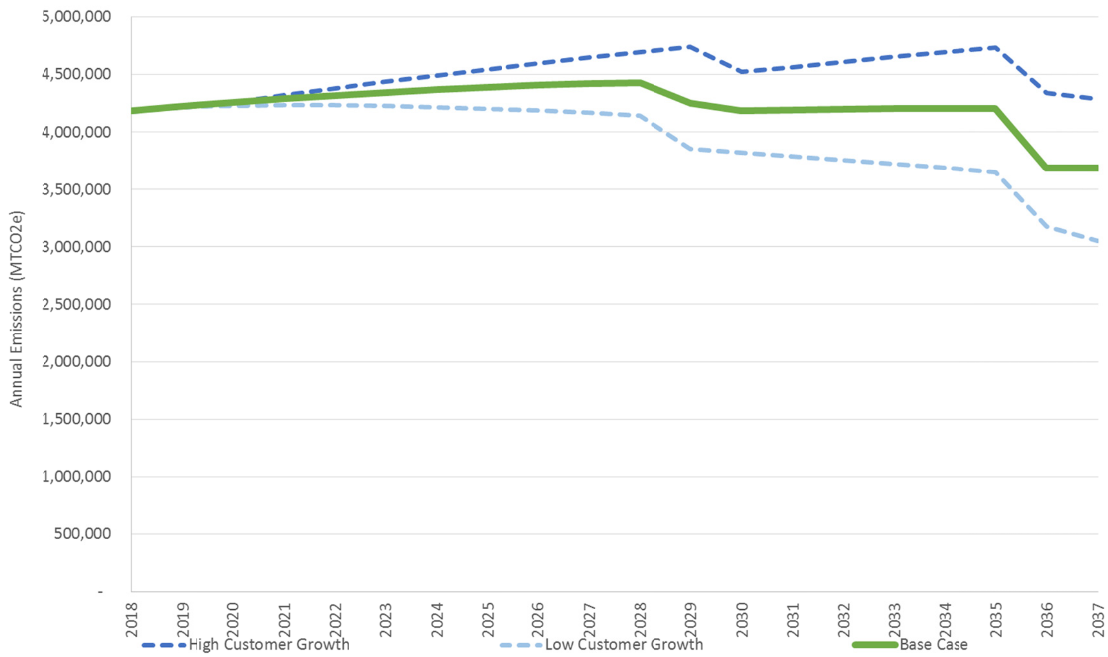


Figure 7.24 compares the annual emissions forecasts of the Base Case and each of the environmental policy sensitivities. As discussed earlier, both the social cost of carbon and the deep decarbonization sensitivities incorporate policies that incentivize renewable gas resources and energy efficiency measure causing the emissions forecast to decrease early and trend downward over 20 years. By 2037 the emissions in the social cost of carbon sensitivity drops by almost a third of 2017 levels and almost two-thirds of 2017 levels in the deep decarbonization sensitivity while still serving the same energy services.

The CNG adoption sensitivity adds load to the system. Thus emissions actually increase from the Company's perspective, relative to the Base Case. The new gas customer moratorium in 2025 sensitivity starts declining emission later, losing some of the cumulative benefits of reducing emissions early, and does not achieve the same level of reduction in 2037, relative to Sensitivities 4 and 5.

Figure 7.24: Base Case vs. Environmental Policy Sensitivities Emissions Forecast

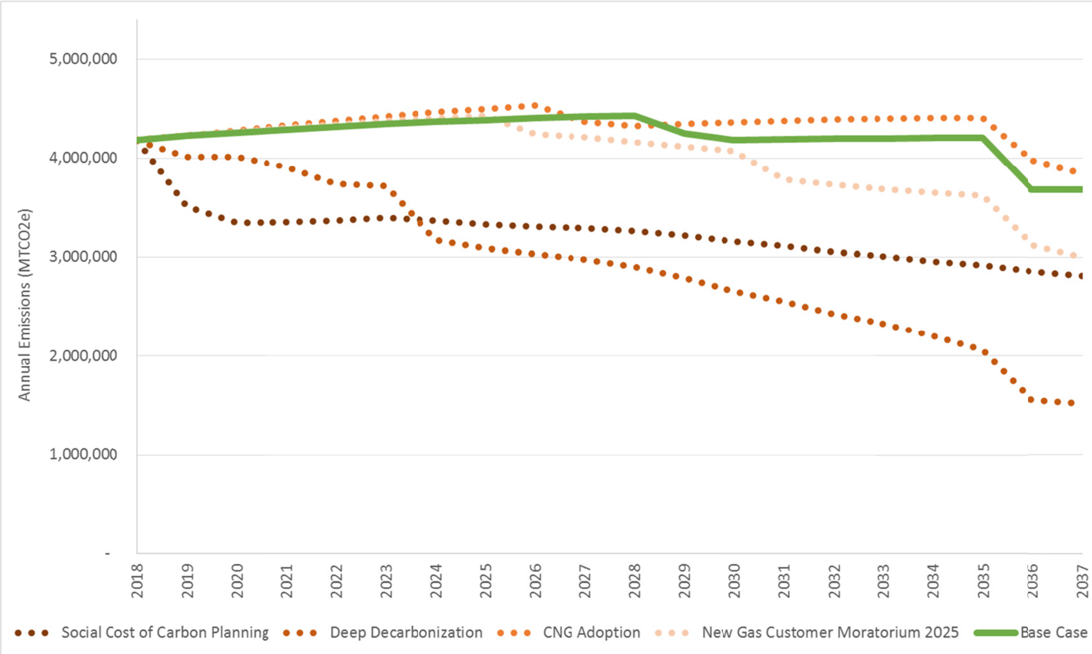
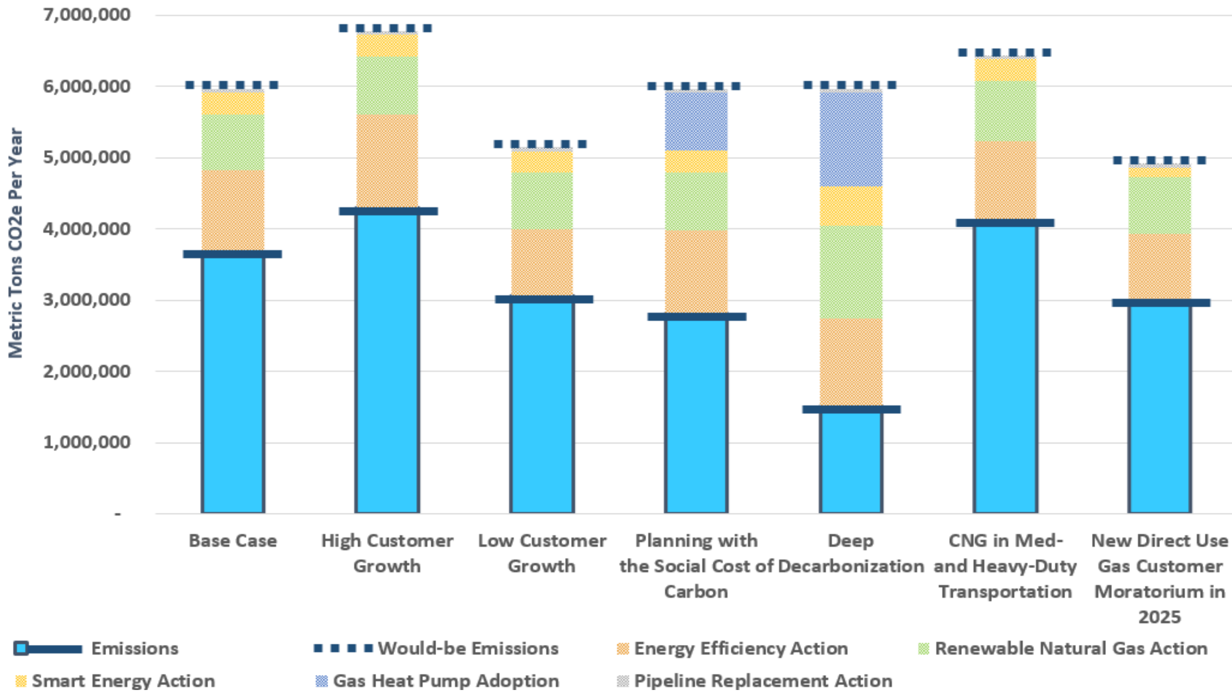


Figure 7.25 summarizes the contribution for each activity toward emission reduction by sensitivity in 2037. Figure 7.25 is akin to Figure 7.5 for the Base Case, but singling out the last year of the planning horizon to compare across sensitivities. Sensitivities 4 and 5 break out an additional activity attributed to the adoption of gas heat pump adoption.

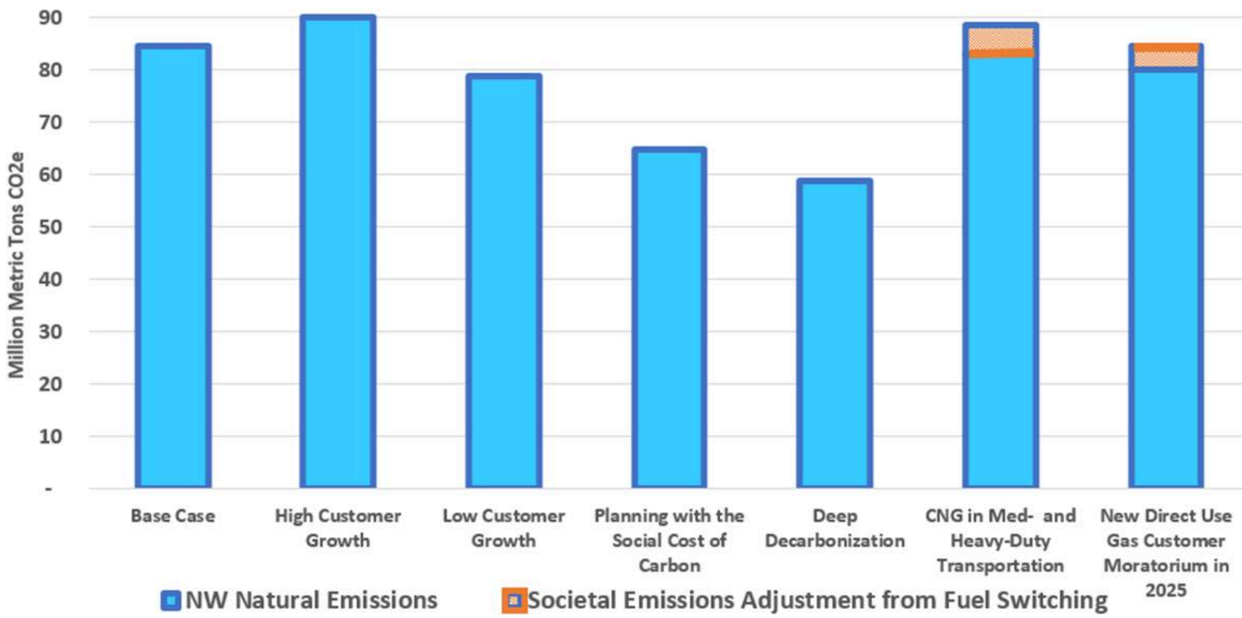
Figure 7.25: NW Natural 2037 Emissions Projection and Would-be Emissions without Emissions Reduction Activity by Sensitivity



As Figure 7.25 shows only a single year, Figure 7.26 compares the cumulative emissions across sensitivities for the whole 20 year planning horizon. Remember Sensitivities 8 and 9 change in the energy services provided by NW Natural, but the demand for these services is equal across all the environmental policy and base case sensitivities. These energy services are otherwise presumed to be serve by another fuel. This means there is a difference between the Company's emissions and the emissions experienced by society, which are represented by the orange line in Figure 7.26. In the CNG adoption sensitivity, CNG is presumed to replace diesel fuel typically used for medium- and heavy-duty fleets. CNG is less carbon intensive than diesel per vehicle mile traveled, thus societal emissions are less than the Base Case even though emissions from NW Natural have increased.[25]

[25] For this calculation CNG vehicles emit 17 percent less emissions per mile travels and travel an average distance traveled of 21,000 miles per year.

Figure 7.26: NW Natural Cumulative Emissions 2018-2037



The last sensitivity (9) assumes that the energy services that would have been provided by NW Natural in the absence a moratorium are now served through electric appliances. Annual electricity generation in the Pacific Northwest is not carbon free. Using a forecasted 2037 carbon intensity of electric utilities in the Pacific Northwest and assuming load is replaced with 250 percent electricity end use efficiency, the societal emissions are more than the Company's emissions.[26] Table 7.10 summarizes by sensitivity the 2037 annual emissions, the contribution of each activity discussed, the 2037 annual emissions saved, the percent of Oregon's 2016 GHG emissions saved in 2037 and the cumulative emissions save over twenty year.

The sensitivities analysis highlights the various impacts and effectiveness of potential environmental policies aimed at reducing GHG emissions. It is unlikely that a single policy approach, as designed by the analysis, will occur and aspects of each sensitivities will certainly intertwine. This analysis takes a rigorous analytical approach to the impacts of specific policy outcomes, ceteris paribus (all else held equal).

[26] The carbon intensity forecast for 2037 for Pacific Northwest electric utilities comes from the Northwest Power and Conservation Council's figures for marginal carbon intensity.

Table 7.10: Emissions Forecast Detail by Sensitivity

		Supply Infrastructure Sensitivities			Economic Growth Sensitivities		Environmental Policy Sensitivities			
		No New Regional Pipeline	New Regional Pipeline in 2025- Fully Subscribed	New Regional Pipeline in 2025- Excess Capacity	High Customer Growth	Low Customer Growth	Use Social Cost of Carbon in Resource Planning	Deep Decarbonization	CNG Adoption in Medium- and Heavy-Duty Transportation	New Direct Use Gas Customer Moratorium in 2025
NWN 2037 GHG Emissions Projection (Million Metric Tons CO2e)		3.7	3.7	3.7	4.3	3.1	2.8	1.5	4.0	3.0
Share NW Natural Emissions Would Be Higher in 2037 Absent Action From:	Energy Efficiency	31%	31%	31%	31%	31%	42%	81%	28%	31%
	Natural Gas Heat Pump Adoption	0%	0%	0%	0%	0%	29%	86%	0%	0%
	Renewable Natural Gas	21%	21%	21%	19%	26%	29%	86%	21%	26%
	Smart Energy	8%	8%	8%	7%	10%	11%	37%	7%	5%
	All Actions*	62%	62%	62%	59%	70%	114%	298%	58%	66%
NWN GHG Annual Emissions Saved in 2037 (Million Metric Tons CO2e)		2.3	2.3	2.3	2.5	2.1	3.2	4.4	2.3	1.9
Share of Total Oregon 2016 GHG Emissions Saved in 2037		3.7%	3.7%	3.7%	4.0%	3.4%	5.2%	7.1%	3.7%	3.1%
Cumulative NWN GHG Emissions Saved Over 20 Year Horizon (Million Metric Tons CO2e)		22.7	22.7	22.7	24.2	21.4	42.5	48.4	23.6	19.6

9. PORTFOLIO SELECTION CONCLUSION

The purpose of the deterministic portfolio selections and the risk analysis (both the stochastic analysis and sensitivities analysis) are to inform supply resources decisions that appropriately balance cost and risk for customers. The results of this chapter are the primary justification for the system capacity resources (both supply-side and demand-side) and the related action items included in the action plan. When we look at the totality of the results of this chapter suggest the following:

1) Currently, no regional pipeline has been announced. NW Natural believes the earliest a regional pipeline could come online is in 2025, which is beyond the timeframe for the necessary action items. Therefore, the system capacity resources procured are identical across supply infrastructure sensitivities. In other words, the system capacity resources included in the action items for this IRP would be the same regardless of whether or not a regional pipeline were to come online at some point in the future beyond 2025.
2) Energy efficiency procured by the Energy Trust is the least cost least and least risk system capacity resource to meet peak demand. Above and beyond the available energy efficiency, Mist Recall is the least cost and least risk resource to meet peak day load.
3) The results of the risk analysis, both the stochastic and sensitivity analysis, suggest that RNG will be a cost-effective resource in the near future. After adjusting for risk or potential environmental policy RNG is likely to be cost-effective much earlier in the planning horizon. The representative RNG project evaluated in the IRP are hypothetical, however, NW Natural can utilized this resource optimization framework to evaluate specific projects as RNG opportunities arise. The specifics for evaluating RNG opportunities are detailed in Appendix H, but will be kept confidential.

CHAPTER 8

DISTRIBUTION SYSTEM PLANNING

KEY TAKEAWAYS

Key findings in this chapter include the following:

- NW Natural uses a 10-year planning horizon for distribution system planning
- Modeling software is utilized to identify or validate system issues
- NW Natural designs its distribution system to peak hour load requirements
- Standard criteria are applied to identify system issues and to initiate reinforcement projects
- Alternatives analyses are performed
- NW Natural plans to complete six larger distribution system projects over the next four years

1. INTRODUCTION

This chapter discusses NW Natural's distribution system planning and includes an overview, features of the current system, engineering and computer modeling methods, and the criteria NW Natural use to establish project priorities.

This chapter also describes new distribution system projects, each of which addresses an area of identified weakness within the distribution system; and includes Key Findings associated with distribution system planning.

2. EXISTING DISTRIBUTION SYSTEM

NW Natural's gas distribution system consists of approximately 14 thousand miles of transmission and distribution mains, of which approximately 87 percent are in Oregon with the remaining 13 percent in Washington.[1] The Company removed its last known bare steel pipe in 2015.

NW Natural's Oregon service area includes 39 gate stations[2] and approximately 990 district regulator stations. The Company's Washington service area includes 15 gate stations and approximately 75 district regulator stations.

NW Natural owns and operates two liquefied natural gas (LNG) storage plants and the Mist underground storage facility, which are discussed in Chapter 6.

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1 Source: 2017 FERC Form 2 Oregon Supplement for year ending December 31, 2017.
2 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.

3. DISTRIBUTION SYSTEM PLANNING

NW Natural's distribution system planning process ensures that the Company:

- 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; and
- Addresses distribution system needs related to localized customer or demand growth.

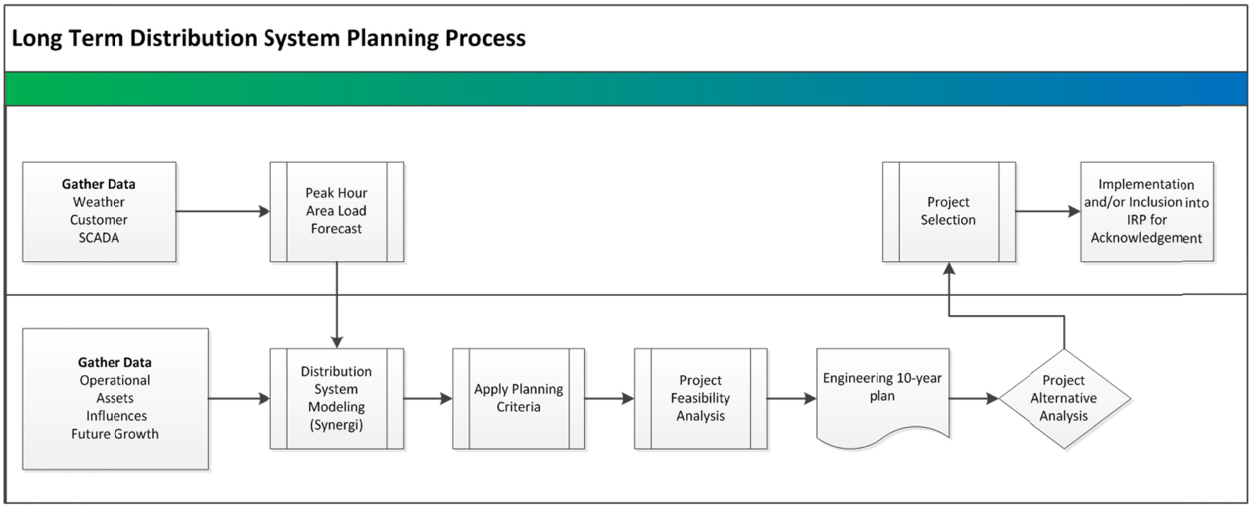
The goals of distribution system planning are the design of a distribution system meeting firm service customers' current natural gas needs under peak hour conditions[3] and to plan for reinforcement in order to serve future firm service requirements. Distribution system planning identifies operational problems and areas within the distribution system requiring reinforcement due to existing requirements and/or future requirements based on growth indicators. NW Natural, by knowing where and under what conditions pressure problems may (or do) occur, can incorporate necessary reinforcement projects into annual budgets and distribution project planning, thereby avoiding costly reactive and potentially emergency solutions.

The Company's Engineering Department—collaborating with the Construction and Marketing departments and incorporating input from external economic development and planning agencies—plans the expansion, reinforcement, and replacement of NW Natural's distribution system facilities. This planning process requires forecasting customer peak hour demand, determining potential distribution system constraints, analyzing alternative potential solutions, and assessing the costs of viable alternatives. This planning is ongoing and integrates the requirements associated with customer growth into the Company's construction forecasts.

NW Natural's Engineering Department annually reviews and updates a forward looking 10-year plan for larger projects. This 10 year plan provides budgetary forecasts and company-wide vision and prioritization to the distribution system planning process. NW Natural selects projects from the 10 year plan for inclusion in the IRP based on estimated cost, system needs, supply implications, as well as timing considerations related to the IRP.

[3] 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 which includes an hour in which use is maximal. The Company discussed its peak hour standard with stakeholders in the fifth Technical Working Group meeting (see slides 74 – 85). See also the discussion of use of peak day load forecasts in Chapter 3.

Figure 8.1: Distribution System Planning Process



For projects that will be completed within one to three years, NW Natural's distribution system engineers complete a project planning process that documents system modeling and modeling results, selects an initial route where a new pipeline facility is indicated, provides an associated high-level cost estimate, and includes an analysis of alternatives, which the Company discusses in Section 3.4 below. Normally, these projects may be included in the IRP action plan. Figure 8.1 shows the distribution system planning process in a flow chart diagram.

Projects that are forecasted to be completed within a four- to seven-year timeframe include a project description, preliminary modeling documentation, a preliminary schedule, and a high-level cost estimate. A project to be completed in the fourth year is likely to be an action item in the current IRP, while a project targeted for completion in years five through seven may be an action item in future IRP's.

Projects to be completed in the eight- to 10-year timeframe include preliminary modeling documentation and a high level cost estimate. Project planning associated with issues having this timeframe for resolution is at the conceptual level only and discussion of such projects are not typically included in an IRP unless very significant investments are indicated.

3.1. PLANNING TOOLS

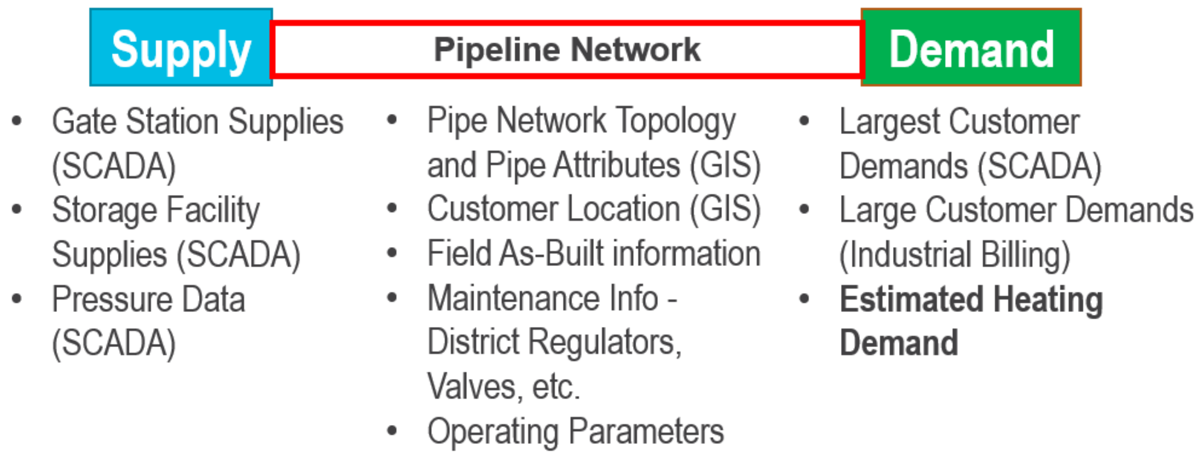
System modeling

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 delivery of natural gas from supplies, through the Company's pipeline networks, to customers' locations.

NW Natural uses Synergi Gas™ network modeling software to model the Company's network of mains (pipes) and services. A Synergi™ model helps predict capacity constraints and associated system performance in alternative scenarios differing in assumed weather (and

related conditions) and future loads resulting from alternative assumptions regarding load growth. Synergi™ allows graphical analysis and interpretation by system planners.
As is shown in Figure 8.2, a Synergi™ 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 gate flows and pressures.

Figure 8.2: Data Used in Synergi™ Models



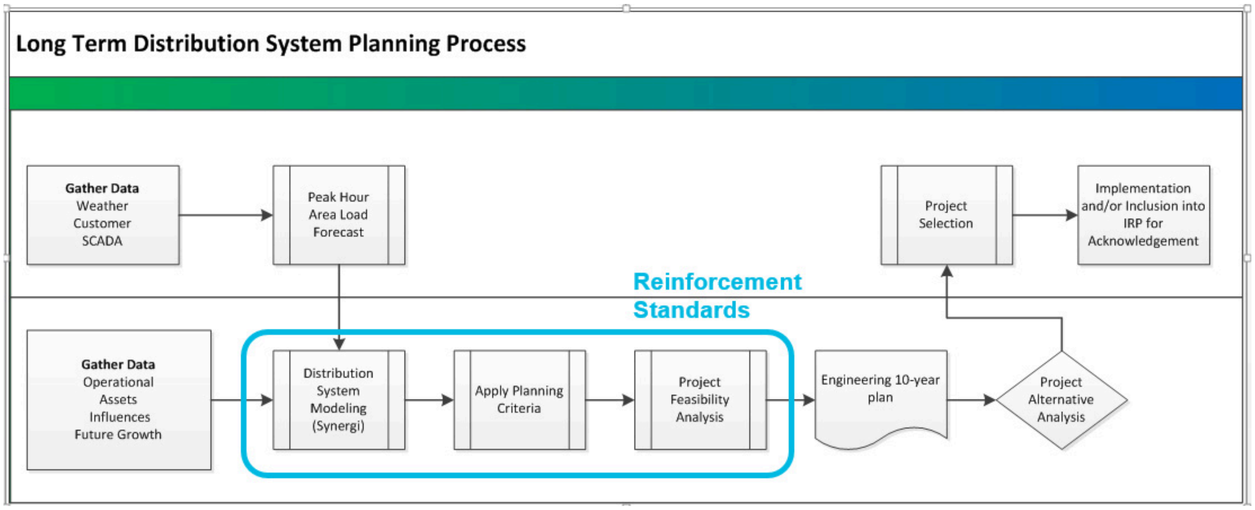
Synergi™ uses mathematical flow equations and an iterative calculation method to evaluate whether the modeled system is balanced. A Synergi™ model shows flows and pressures at every point in the modeled system and, when balanced, the relationship between flows and whether pressures at all points in the 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. NW Natural will occasionally run a field data collection process called a Cold Weather Survey to collect system pressures during cold weather conditions. The Company uses these pressures to validate Synergi™ modeled results. 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; i.e., Synergi™ models are a representation of the actual system. These models are a static snapshot of expected system conditions under the provided data.

Synergi™ simulation capability allows the Company 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, and much more.

System reinforcement standards

As shown in Figure 8.3, system reinforcement standards are a required component of the distribution system planning process. The standards are based on multiple criteria that indicate conditions representing a pipeline nearing peak capacity, a regulator about to fail, customers not being served with adequate pressure or volume, etc. The system reinforcement standards represent trigger points which indicate systems under stress and in need of imminent attention to reliably serve customers.

Figure 8.3: Distribution System Planning Process – Reinforcement Standards



Transmission and high pressure distribution systems (systems operating at greater than 60 psig) have different characteristics than other components of NW Natural's distribution system, and design parameters associated with peak hour load requirements differ as well. System reinforcement parameters for these systems include:

- Experience at least a 30 percent pressure drop over the facility indicates an investigation will be initiated
- Experience or model a 40 percent pressure drop indicates reinforcing the facility experiencing the drop is critical, as a 40 percent pressure drop equates to an 80 percent level of capacity utilization
- For pipelines that feed other high pressure systems, consider minimum inlet pressure requirements for proper regulator function in addition to total pressure drop
- 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
- Firm service customer delivery requirements (flow or pressure)
- Identified in the IRP associated with supply requirements or needs.

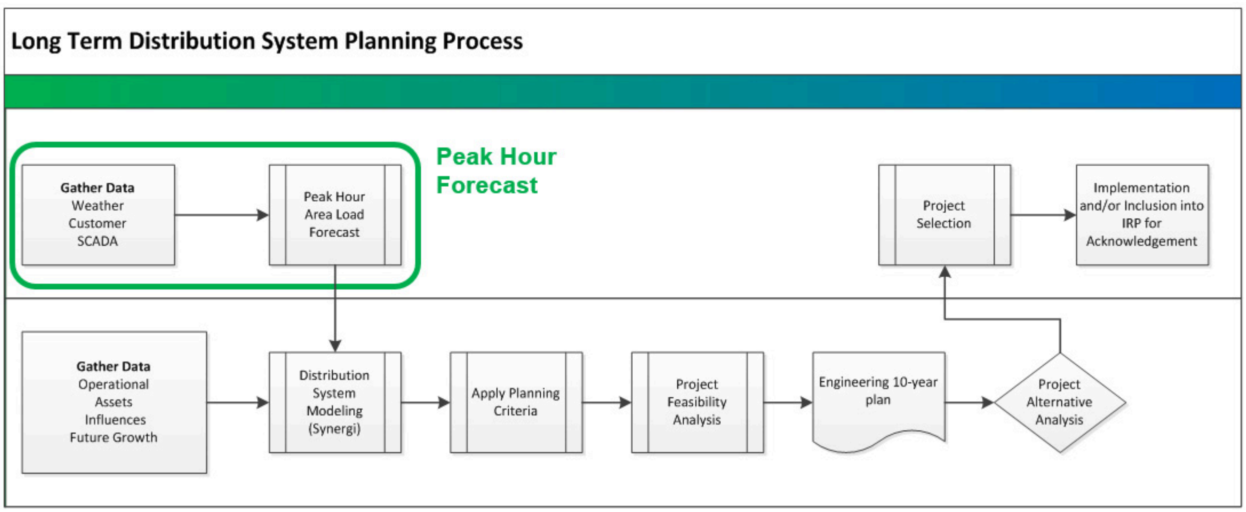
The system reinforcement parameters associated with peak hour load requirements for distribution systems that are not high pressure (systems operating at 60 psig or less) are:

- Experience a minimum distribution pressure of 15 psig[4] Indicates an investigation will be initiated
- Experience or model minimum distribution pressure of 10 psig indicates reinforcement is critical
- 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
- Firm service customer delivery requirements (flow or pressure)

Peak hour load forecast

As can be seen in Figure 8.4, determining peak hour load/demand is a critical part of distribution system planning as it establishes the minimum criterion for meeting customer needs. The peak hour load forecast is the goal which must be met by the capacity of the piping network.

Figure 8.4: Distribution System Planning Process – Peak Hour



Peak hour load forecasting is discussed in Section 4 below. These forecasts are made at either the load center level or the aggregation of multiple load centers.

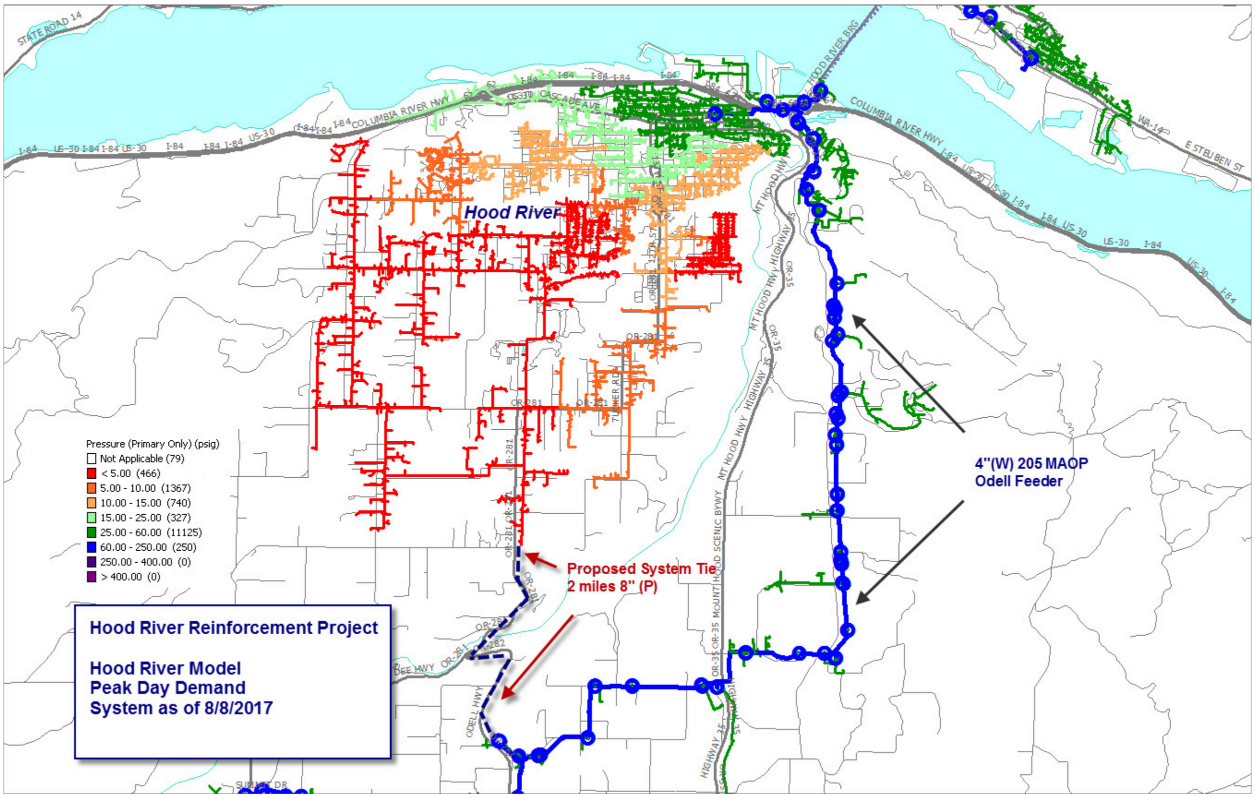
3.2. IDENTIFICATION OF DISTRIBUTION SYSTEM ISSUES

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 8.5, an area of the Class B distribution system[5] 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 a number of

[4] Pounds per square inch gauge: a standard measure of pressure within a pipeline facility.
[5] Class B systems are those operating at 60 psig or less.

customer outages occurred in the Hood River Area under non-peak conditions. The low pressure areas below 10 psig are indicated in orange and red colors, while more satisfactory pressure areas 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, and is served by a single gate station on Northwest Pipeline (NWP) and is not connected to other parts of NW Natural's distribution system.

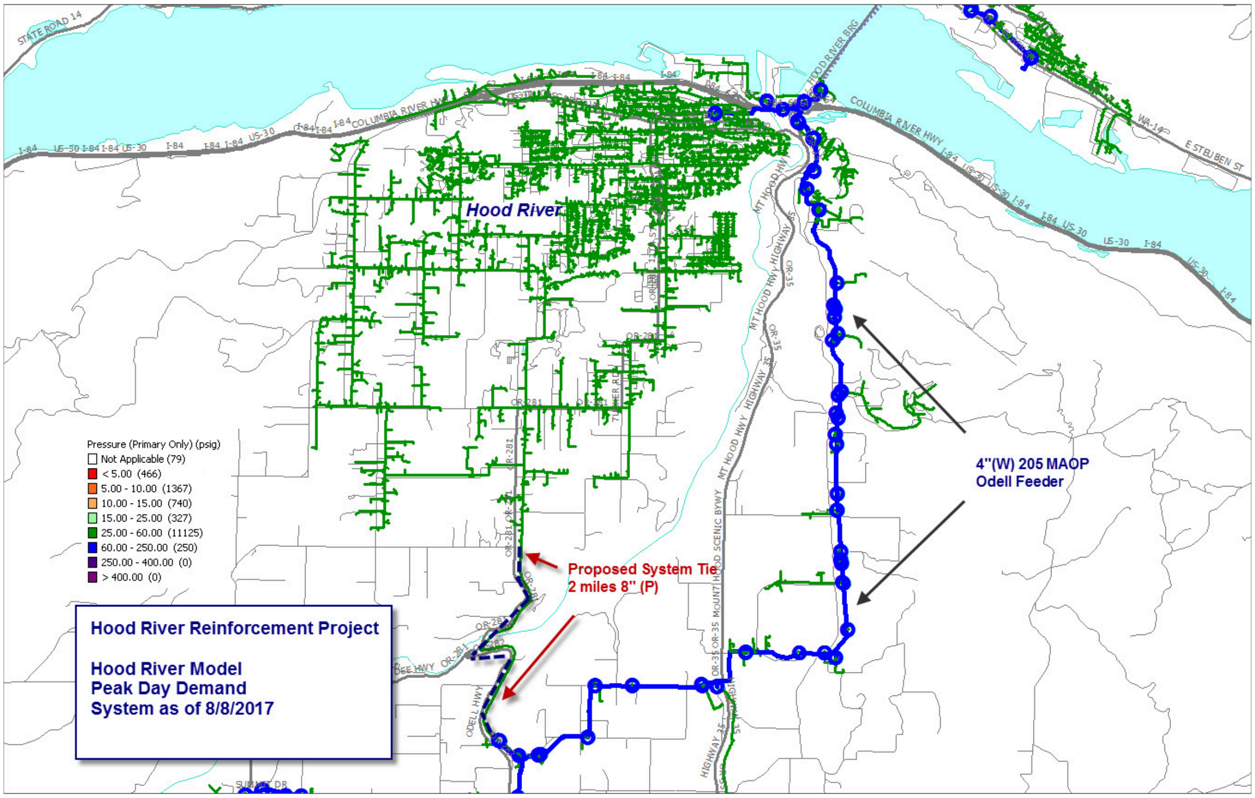
Figure 8.5: Illustration of Hood River Area Pressure Issues



3.3. ISSUE ASSESSMENT AND PROJECT IDENTIFICATION

Once NW Natural identifies a distribution system issue, the Company considers multiple traditional pipeline solutions to address the issue. These solutions may include constructing pipelines of differing size, operating pressures, and routes; performing pressure uprates to increase capacity of existing pipelines; and installing equipment such as district regulators or compressors. As in most problem solving activities the goal is to identify the most efficient, least cost, least risk solution to solve the existing problem. Solutions are validated with models to verify effectiveness (note the red areas in Figure 8.5 are green in Figure 8.6).

Figure 8.6: Illustration of Hood River Area Pressure Issues and Resolution



After a system issue has been identified and a traditional pipeline solution has been selected, NW Natural estimates the cost of the solution. A project is identified and is placed in the Company's 10 year planning process to be prioritized with other projects. If the estimated cost of the proposed solution is greater than $1 million dollars the project is tentatively identified for inclusion in an IRP and an alternatives analysis is performed and documented.

3.4. ALTERNATIVES ANALYSIS

NW Natural uses alternatives analysis to compare the estimated costs and capability of non-pipeline alternatives to those of the proposed pipeline solution. Non-pipeline alternatives typically assessed include augmenting the capacity of the existing pipeline with a local peaking asset in lieu of additional new pipeline capacity, the use of demand-side management means for reducing the local demand on peak, or some other alternative.

Alternative Supply-side Peaking Capability

NW Natural considers alternative characteristics for a pipeline solution to the identified issue as a first step in developing supply-side solutions to an identified distribution system issue. These alternative characteristics include the path a pipeline solution might take and related issues, the size of the pipe, the material used in the pipe, and the probable methods—or combinations of methods—of pipeline construction.

There are only a few viable supply-side solutions to meet natural gas peaking needs other than installation of an appropriately designed and constructed pipeline solution and each includes some sort of local natural gas storage capability. 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 examines satellite LNG facilities in the alternatives analysis process and other peaking assets may be considered if appropriate.

NW Natural does not discuss use of the Company's CNG mobile fleet as an alternative for the distribution system issues discussed in this chapter as, at a total capacity of 100 Dth for CNG,[6] they do not have the capacity to adequately address larger system issues. The CNG trailer would provide sufficient gas to meet the required shortfall for the issue in the Hood River distribution system for less than 90 minutes. While 90 minutes is a period longer than a peak hour, the CNG trailer does not represent an adequate alternative for most system reinforcement issues.

NW Natural does not discuss use of the Company's LNG trailer and vaporizer as an alternative for distribution system issues. Although the trailer itself can store 900 Dth, the vaporizer can only vaporize and deliver at a rate of 30 Dth/hour. This delivery rate makes mobile LNG unsuitable as an alternative for most system reinforcement issues.

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 have a very high cost per therm delivered.

Alternative Demand-side Solutions

Demand-side management comes in many forms. NW Natural currently has many large interruptible customers who can be curtailed upon formal notice from the Company. This is one form of demand-side management. Another demand-side approach is to contractually arrange for voluntary service curtailment by larger firm service customers within the area impacted. NW Natural begins the assessment of this alternative by examining historical loads of current larger non-residential firm service customers in the area of impact for the proposed pipeline solution. If the estimated peak hour usage by these customers is potentially of sufficient volume to materially defer (or eliminate) the need to implement a supply-side solution, NW Natural would then conduct additional analysis regarding whether customer-specific geographically

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[6] See Chapter 6.

focused interruptibility agreements[7] 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.

4. FORECASTING PEAK HOUR LOAD

Much as NW Natural's peak day load forecast informs the Company's supply resource planning, 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 geographic areas of NW Natural's service territory. The Company included peak hour load forecasts in its 2016 IRP process[8] and has redefined its peak planning standard for both peak day and peak hour forecasts in the 2018 IRP. NW Natural monitors, updates, and works to improve the Company'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.

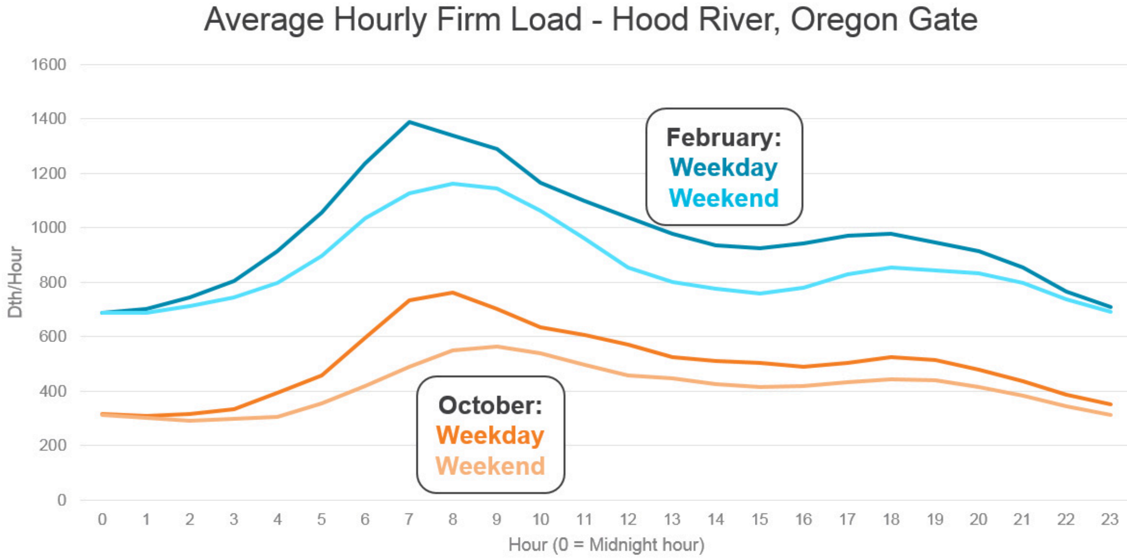
4.1. ESTIMATING PEAK HOUR LOAD

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 statistical relationship 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.

One of the primary differences between peak hour and peak day models is the presence of time-of-day effects. The intra-day 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 8.7). The morning peak is typically lower and later on weekend days.

[7] NW Natural also refers to such agreements as "localized interruptibility agreements."
[8] See Chapter 3 and Appendix C in NW Natural's 2016 IRP.

Figure 8.7: Hood River Area Intra-day Load Shapes

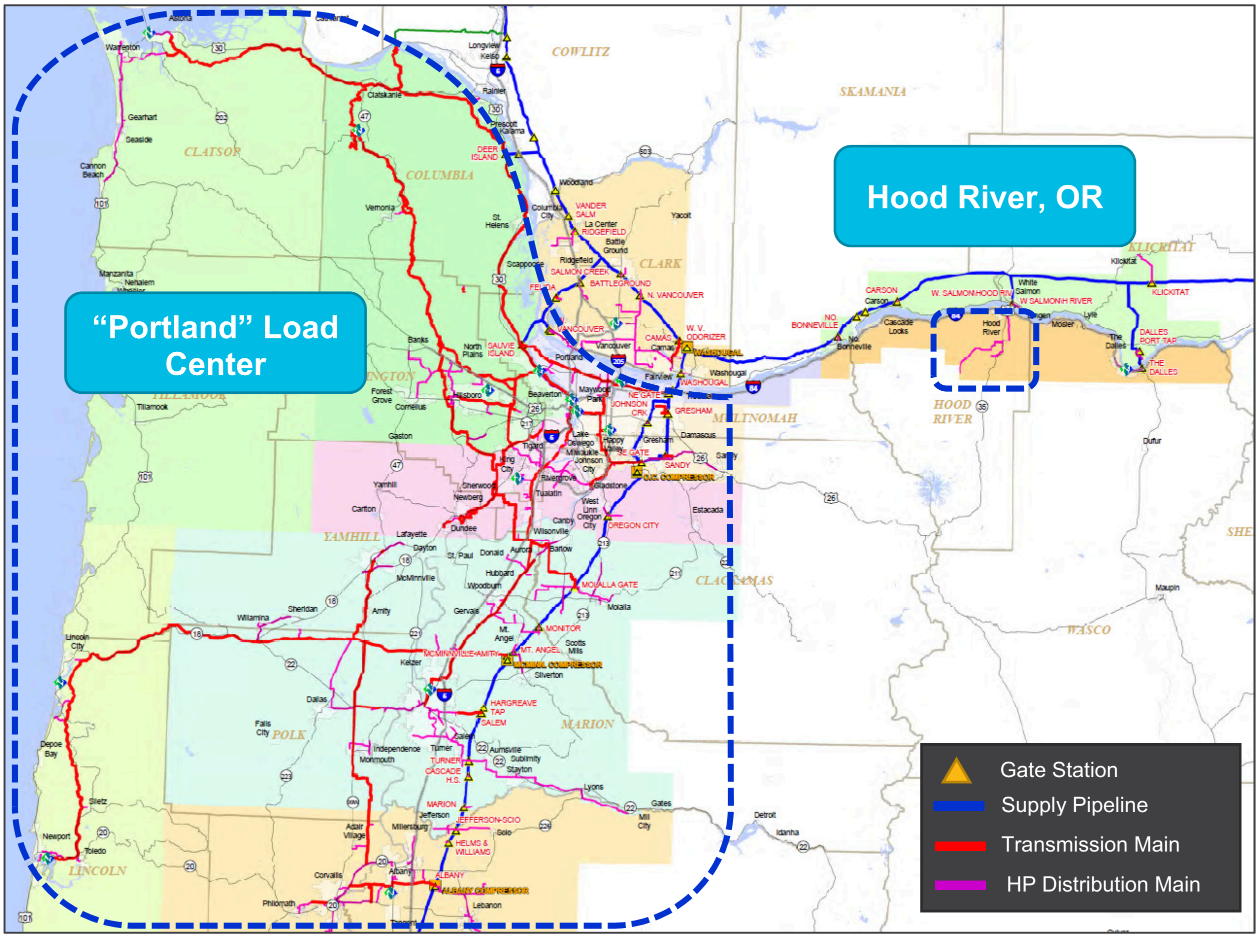


Temperature alters hourly effects, as it does the effects of weather variables.[9] When temperatures stay cold on average throughout the day—on dark, wintry days in February, for example—the intraday load shape is less pronounced than one during the shoulder season, when midday high temperatures diverge 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 needs to be met in any given instant, the time dimension granularity is constrained to hourly due to data limitations.[10] The geographic granularity of peak hour modeling is constrained by the availability of data. For example, the area served downstream of the Hood River, Oregon gate station (Figure 8.8) 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.

[9] For a full discussion of load forecasting variables and their interactions, please see Chapter 3 - Load Forecast.
[10] 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.

Figure 8.8: Hood River, OR 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 and its 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.

4.2. 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 the Company's peak day planning standard,[11] an area's peak hour is defined by the firm resource needed to have a 99 percent chance to be able to meet 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.

5. DISTRIBUTION SYSTEM PROJECTS – 2018 IRP ACTION ITEMS

The projects described below and shown in Table 8.2 are those which will have action items for which NW Natural is requesting acknowledgement by the Public Utility Commission of Oregon. Following the Company's final investment decision, these projects will be implemented between 2019 and 2021.

Estimated costs for these projects are stated in $2017. 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 estimate to actual cost.

[11] See Chapter 3 for a detailed discussion of NW Natural's peak day planning standard.

Table 8.2: Distribution System Planning Projects

Project	Schedule	Estimated Cost (Millions of $2017)	Estimated PVRR (Millions of $2017)
Hood River Reinforcement	2019	$3.5–$7.1	$3.6–$7.2
Happy Valley Reinforcement	2019	$2.9–$4.7	$3.0–$4.8
Sandy Feeder Reinforcement	2020	$15.2–$21.1	$14.3–$19.7
North Eugene Reinforcement	2020	$5.3–$10.6	$5.0–$9.9
South Oregon City Reinforcement	2020	$4.1–$6.2	$3.9–$5.8
Kuebler Road Reinforcement	2020–2021	$14.1– $19.7	$13.2–$18.4
Total		$45.1–$69.4	$43.0–$65.8

NW Natural discusses the identified need for each project below and includes the estimated investment cost and the estimated present value of revenue requirements (PVRR).12

5.1. HOOD RIVER REINFORCEMENT

The Hood River Reinforcement project is designed to improve distribution system pressures and reliability for firm service customers in the Hood River area of the Columbia River Gorge – Oregon load center. Hood River has experienced significant growth and its existing gas system configuration is unable to supply customer needs on very cold days. Firm service customers experienced outages in January, 2017 under non-peak conditions. Modeling indicates customer outages on a peak hour will occur absent implementation of a remediating solution (see Figure 8.10).

The Hood River Reinforcement project takes advantage of the capacity of the existing 4-inch high pressure pipeline serving Odell to provide an alternate supply into the south end of Hood River (see Figure 8.11). The project is approximately 2 miles of pipeline and includes a bridge crossing and a district regulator. The pipeline will either be 4-inch high pressure steel or 8-inch poly distribution main.

[12] Estimated investment cost and estimated PVRR values are stated in 2017 dollars.

Figure 8.9: Existing Hood River System under peak hour demand

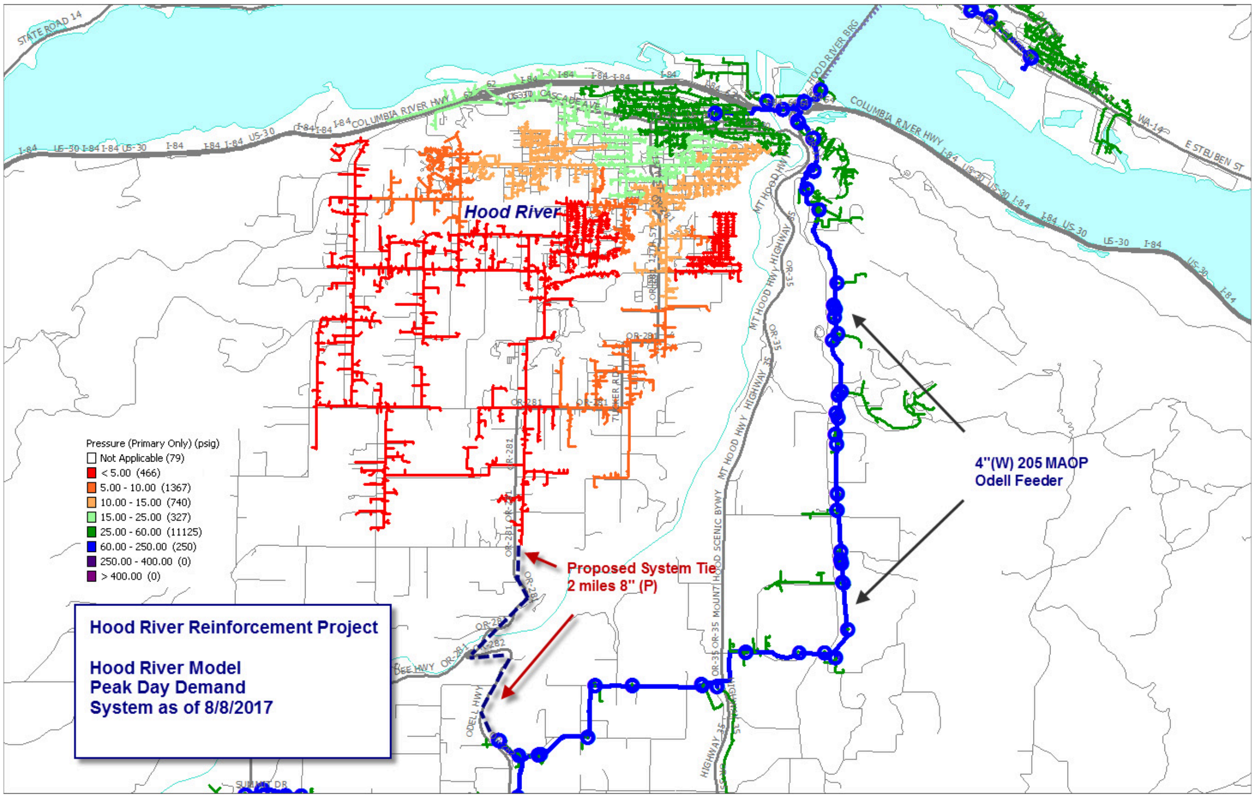
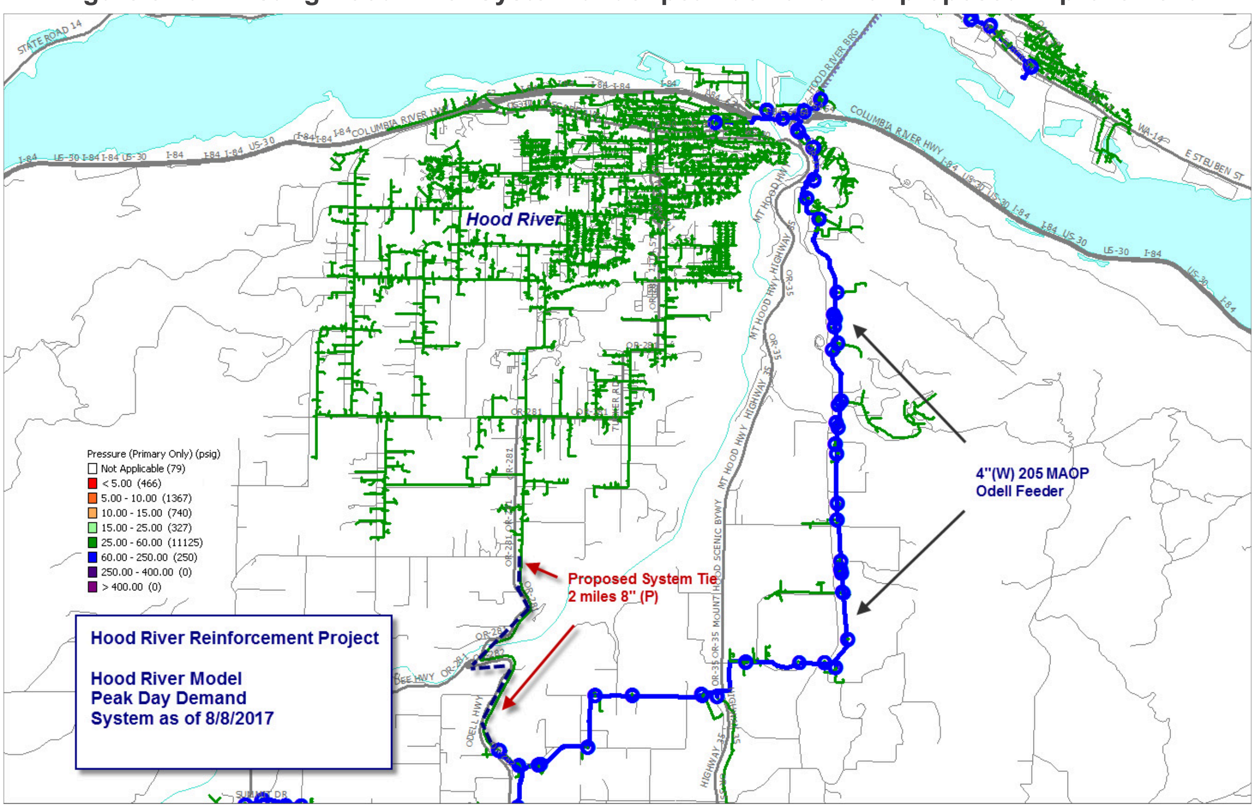


Figure 8.10: Existing Hood River System under peak demand with proposed improvement



As the issue with the distribution system is an existing condition, construction is planned for 2019. The cost of this project is estimated at $3.5 million to $7.1 million, with an associated $3.6 to $7.2 million range in estimated PVRR. NW Natural analyzed the placement of a satellite LNG facility in 2019 as an alternative which would defer pipeline construction. As the range of estimated PVRR is $10.1 to $19.0 million, this potential solution is more costly than constructing the new pipeline facility.

5.2. HAPPY VALLEY REINFORCEMENT

The Happy Valley Reinforcement project is designed to support distribution system pressures for firm service customers in the Happy Valley area of the Portland load center. Happy Valley has experienced significant customer growth since the late 1990's and is one of the weaker areas in NW Natural's distribution system. Observed pressures were well below NW Natural's 10 psig distribution system standard in January, 2017 under non-peak conditions. Modeling indicates that very low pressures and potential outages will occur under peak conditions (as shown in Figure 8.12).

The Happy Valley Reinforcement project (shown in Figure 8.13) extends approximately 1.2 miles of 6-inch wrapped steel high pressure pipeline from Highway 212 to Sunnyside Road and installs a new district regulator. Modeling indicates significant improvements in system pressures which will help accommodating confirmed near-term firm growth in this area of Happy Valley.

Figure 8.11: Existing Happy Valley System under peak demand

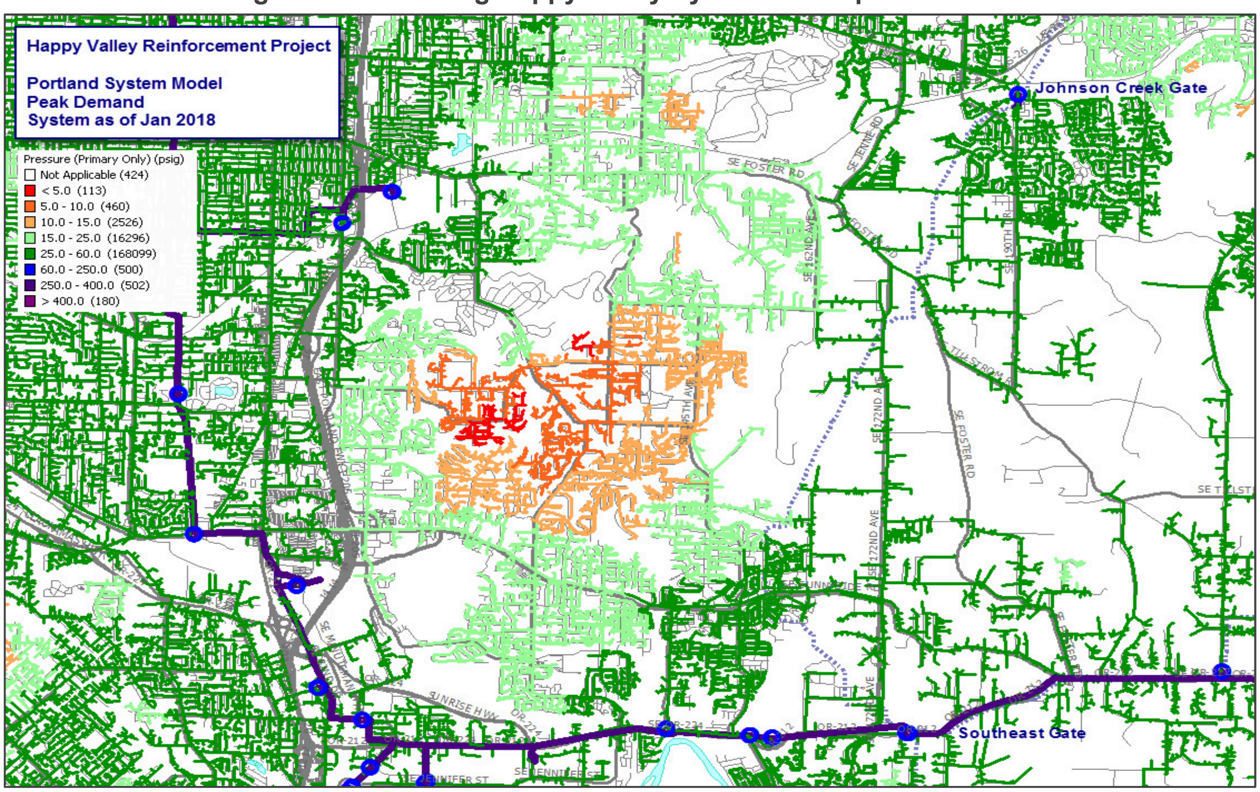
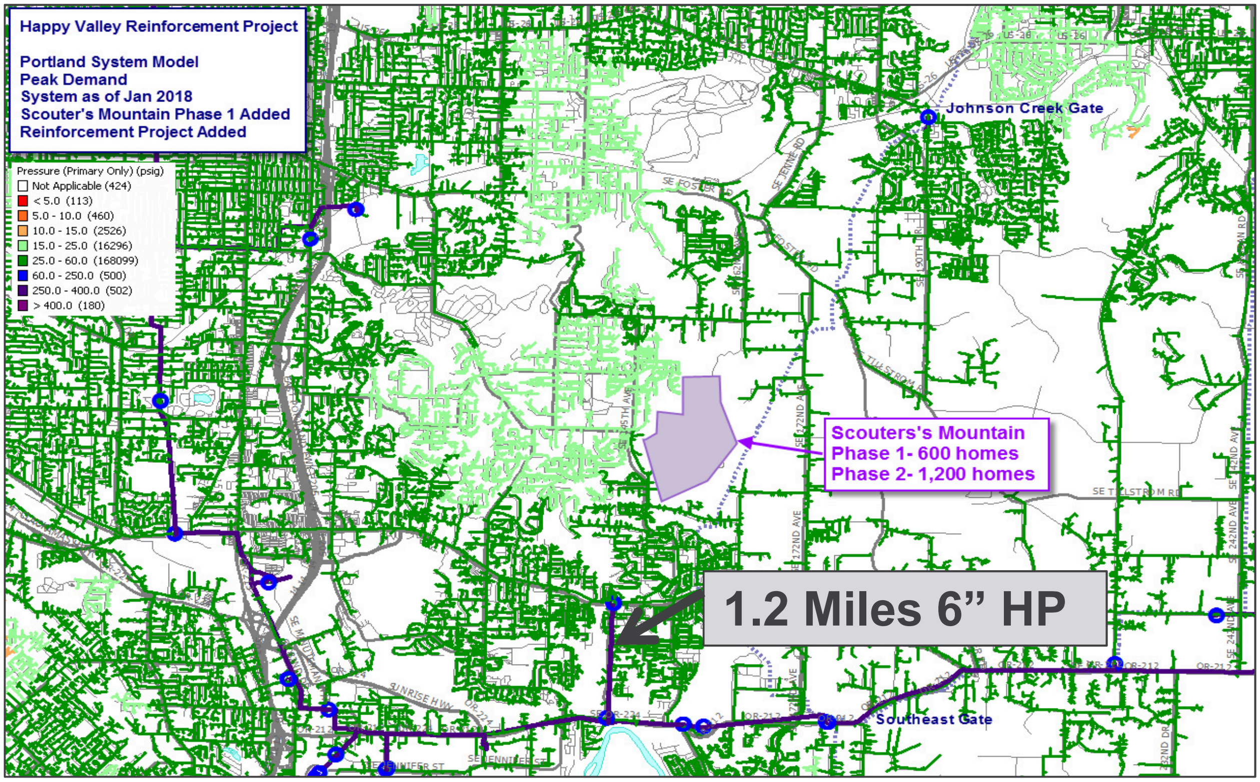


Figure 8.12: Existing Happy Valley System under peak demand with proposed improvement



As the issue with the distribution system in the Happy Valley area is an existing condition, construction is planned for 2019. The cost of this project is estimated at $2.9 million to $4.7 million, with an associated $3.0 to $4.8 million range in estimated PVRR. NW Natural analyzed the placement of a satellite LNG facility as an alternative which would defer pipeline construction. As the range of estimated PVRR is $17.3 to $32.4 million, this potential solution is more costly than constructing the new pipeline facility.

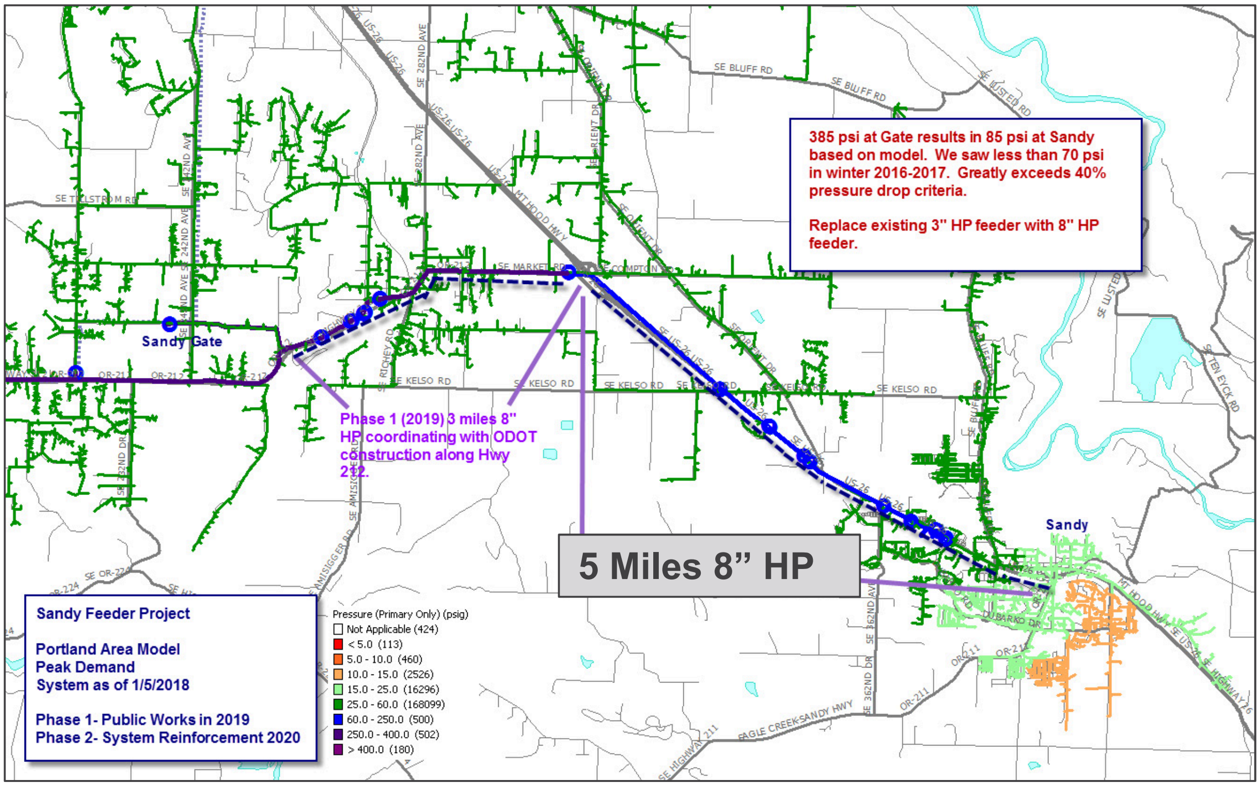
5.3. SANDY FEEDER REINFORCEMENT

The Sandy Feeder Reinforcement project replaces a portion[13] of the pipeline that is the primary feed for Sandy, Oregon and adjacent areas. NW Natural installed the existing 3-inch high pressure pipeline in 1965 and it currently experiences extreme pressure drops under cold weather conditions. NW Natural observed pressure drops exceeding 80 percent during non-peak conditions in January, 2017. This level of pressure drop jeopardizes the Company's ability to reliably serve customers in the Sandy area. Modeling indicates that many firm service customers will experience outages under peak conditions. Systemic growth in the Sandy area has resulted in peak hour customer requirements that currently exceed the capacity of the existing pipeline.

[13] The portion of the Sandy Feeder that is not replaced under the reinforcement project is being replaced earlier. This is due to the Oregon Department of Transportation's requirement related to its road construction project. This public works replacement project is mandated.

As shown in Figure 8.9, the project14 consists of approximately five miles of 8-inch wrapped steel high pressure pipeline and a new district regulator station at the end of the pipeline.

Figure 8.13: Sandy Feeder Reinforcement Project



As the issue with the distribution system in the Sandy area of the Portland load center is an existing condition, construction is planned for 2020. The cost of this project is estimated at $15.2 to $21.1 million, with an associated $14.3 to $19.7 million range of estimated PVRR. NW Natural analyzed the placement of a satellite LNG facility as an alternative which would defer pipeline construction. The range of estimated PVRR for this potential solution is $15.8 to $29.7 million. While the low values in the two estimated PVRR ranges are similar, the high values are not and reflect the greater cost risk of the satellite LNG alternative. Due to the cost risk of the satellite LNG alternative, the pipeline solution represents the best combination of cost and risk.

5.4. NORTH EUGENE REINFORCEMENT

The North Eugene Reinforcement project addresses existing low distribution system pressures due to significant residential growth along River Road north of Eugene, Oregon (see Figure 8.[14]). Observed pressures were well below the 10 psig distribution system standard in January, 2017. Modeling indicates that the demand of existing firm service customers under peak

[14] The Sandy Feeder Reinforcement project is identified as Phase 2 in Figure 8.13. Phase 1 in Figure 8.13 refers to the Sandy Feeder public works project, which involves a 2019 relocation mandated by road construction.

conditions exceeds the capacity of the local distribution system. The North Eugene Reinforcement project installs approximately 2 miles of 6-inch wrapped steel high pressure pipeline and 1 mile of 6-inch Class B pipeline from Highway 99 to River Road. This pipeline delivers gas to River Road from the north and west and greatly improves system pressures on peak (see Figure 8.15).

Figure 8.14: Existing North Eugene System under peak demand

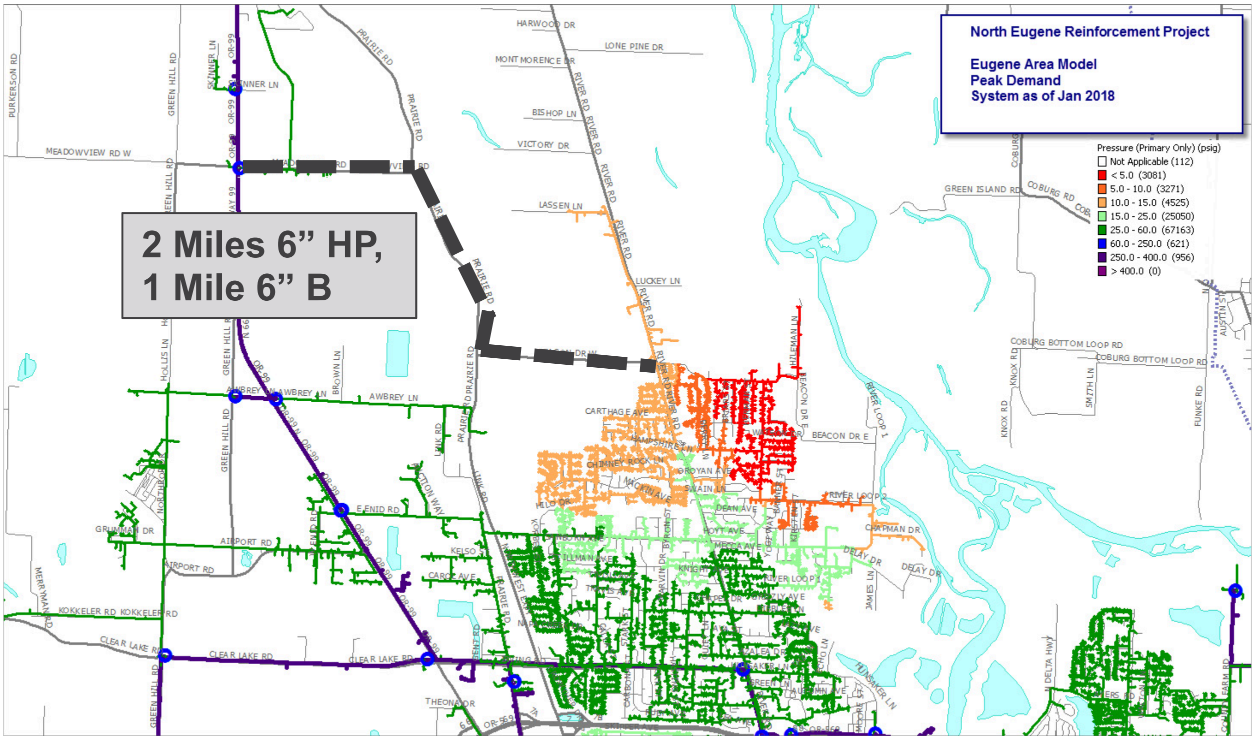
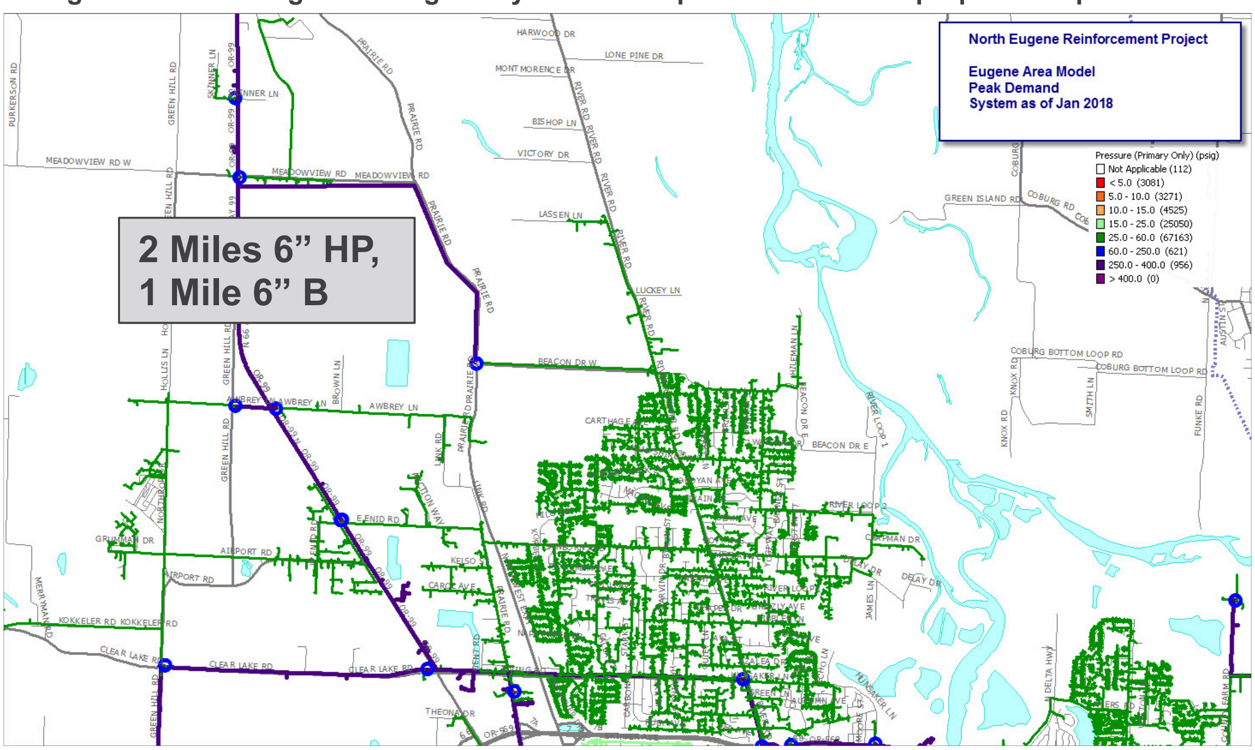


Figure 8.15: Existing North Eugene System under peak demand with proposed improvement



As this issue with the distribution system in the Eugene load center is an existing condition, construction is planned for 2020. The cost of this project is estimated at $5.3 million to

$10.6 million, with an associated $5.0 to $9.9 million range in estimated PVRR. NW Natural analyzed the placement of a satellite LNG facility as an alternative which would defer pipeline construction. As the range of estimated PVRR is $14.7 to $27.5 million, this potential solution is more costly than constructing the new pipeline facility.

5.5. SOUTH OREGON CITY REINFORCEMENT

The South Oregon City Reinforcement project is designed to support distribution system pressures for firm service customers in the Oregon City area of the Portland load center. The south Oregon City area has historically been a weak area in NW Natural's distribution system and the increased load associated with firm service customer growth has exceeded the capacity of the existing distribution system (see Figure 8.16). NW Natural has observed distribution pressures well below the 10 psig standard under non-peak conditions in this area of Oregon City. The South Oregon City Reinforcement project installs approximately 1.5 miles of 6-inch wrapped steel high pressure pipeline (see Figure 8.17).

Figure 8.16: Existing South Oregon City System under peak demand

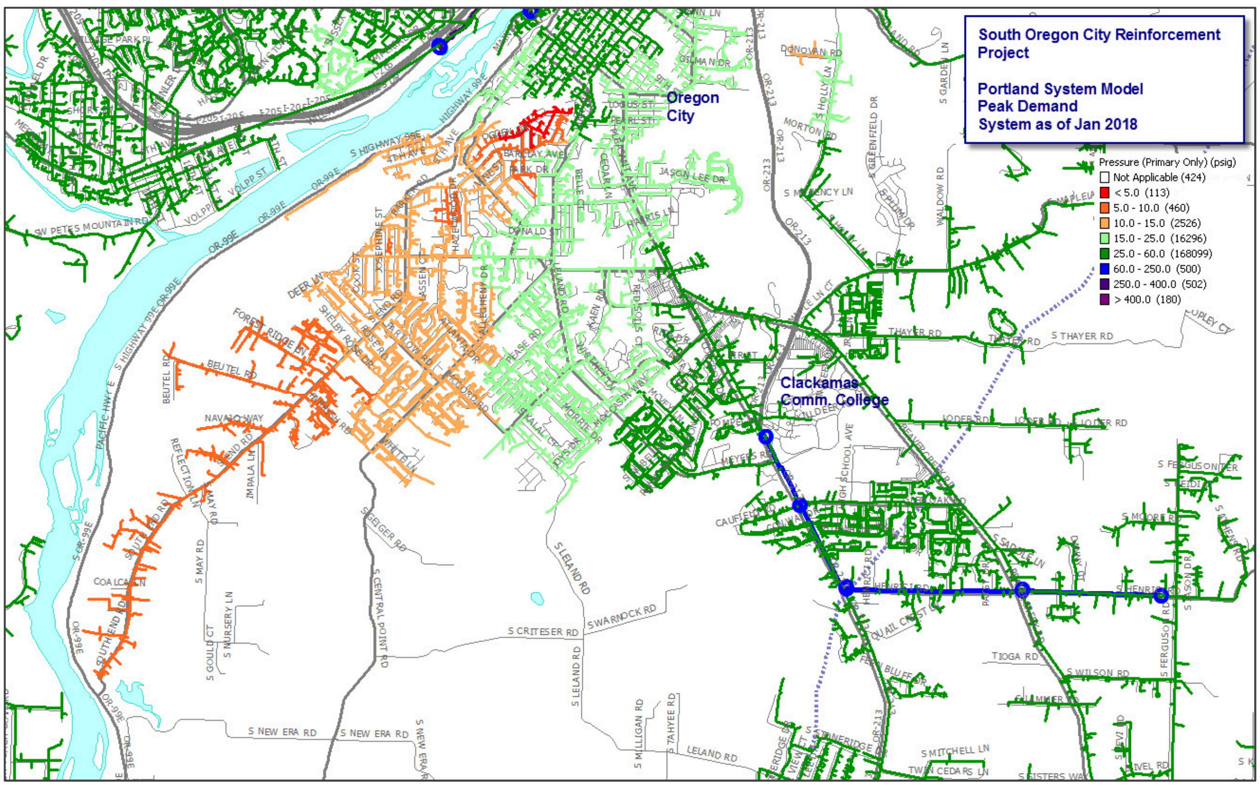
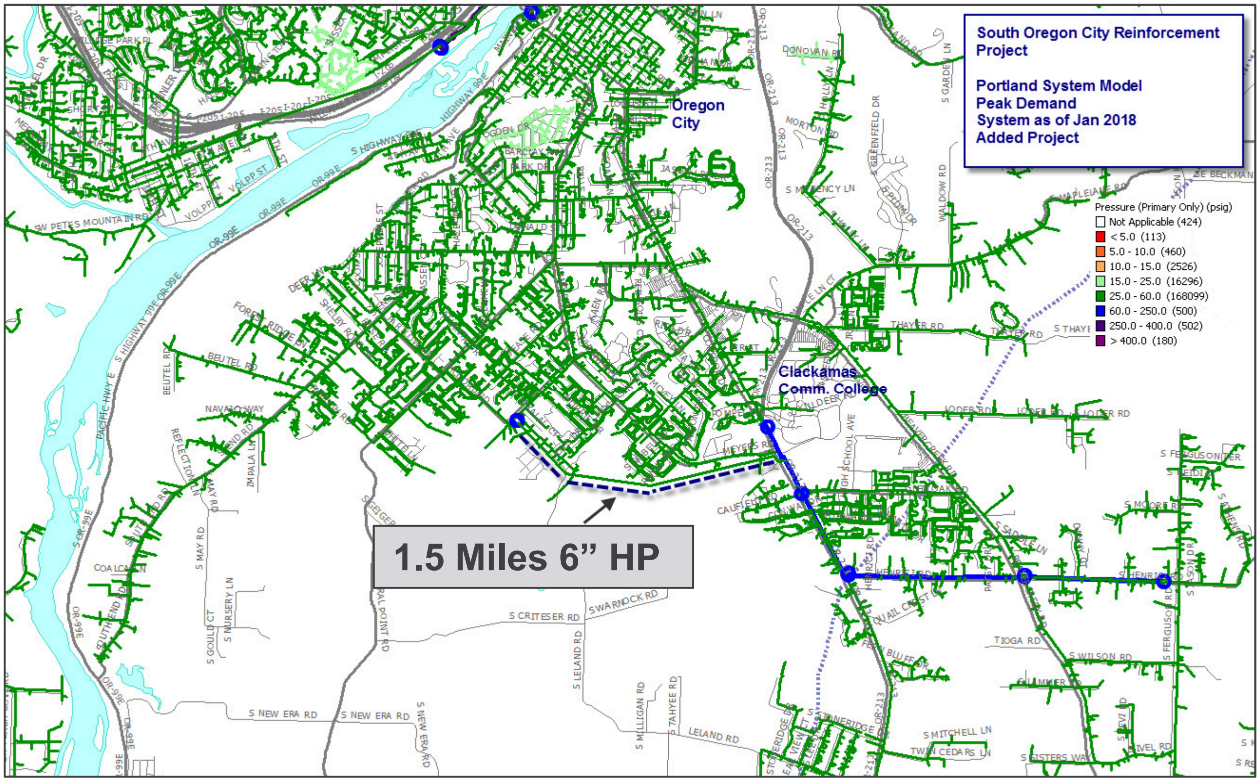


Figure 8.17: Existing South Oregon City System under peak demand with proposed improvement

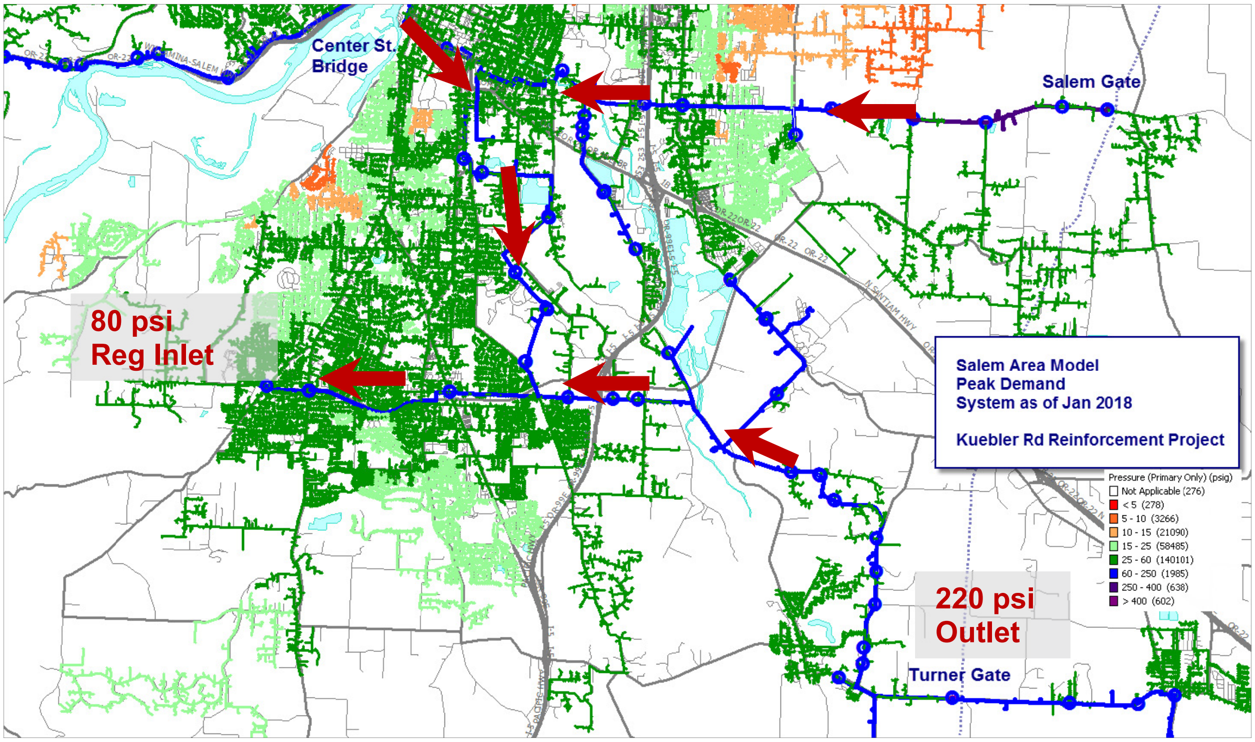


As the issue with the distribution system in the South Oregon City area of the Portland load center is an existing condition, construction is planned for 2020. The cost of this project is estimated at $4.1 million to $6.2 million, with an associated $3.9 to $5.8 million range in estimated PVRR. NW Natural analyzed the placement of a satellite LNG facility as an alternative which would defer pipeline construction. As the range of estimated PVRR is $14.7 to $27.5 million, this potential solution is more costly than constructing the new pipeline facility.

5.6. KUEBLER ROAD REINFORCEMENT

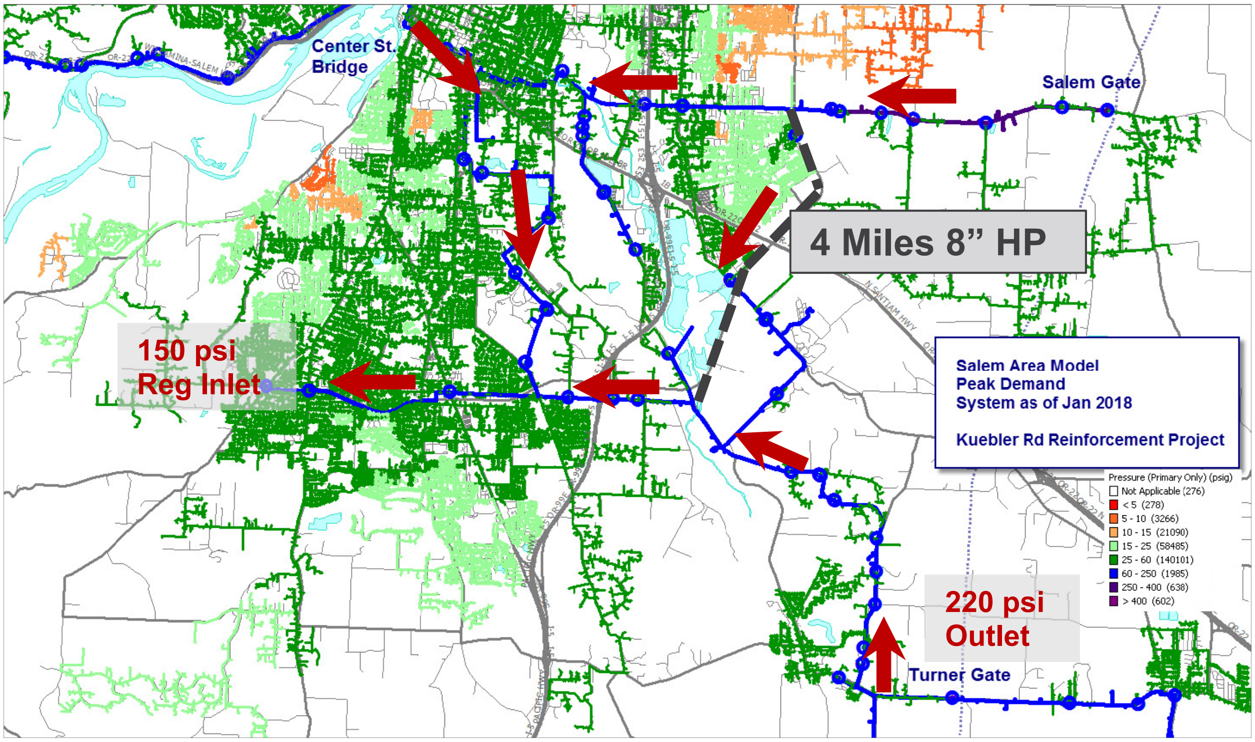
The Kuebler Road Reinforcement project is designed to support high pressure distribution system pressures for firm service customers in the South Salem area. As shown in Figure 8.18, the 225 MAOP system in Salem is fed by three different sources: Turner Gate in the south and Salem Gate and Center Street Bridge regulators in the north. The north and south portions of this system are connected by a single 6-inch pipe which does not have adequate capacity under cold weather conditions. Growth to the south and west has increased demand on the Turner Gate and the high pressure distribution system to the point where pressure drop criteria are exceeded and regulator inlet pressures are in jeopardy. A pressure of 80 psig was experienced in January, 2017 under non-peak at the southwest end of the 225 MAOP system. This equates to a pressure drop of over 60 percent and exceeds NW Natural’s standard.

Figure 8.18: Existing Kuebler Road System under peak demand



The Kuebler Road Project installs approximately 4 miles of 8-inch high pressure pipeline to create a high pressure loop in the Salem 225 MAOP system (see Figure 8.19). This pipeline allows Salem Gate and the Center Street Bridge regulators to contribute significantly more supply to the southern end of the system and reduce demand from Turner Gate. The project restores pressures at the southwest end of the system to reasonable conditions. This project also has the benefit of eliminating planned improvements at Turner Gate, which were estimated to cost $2 million.

Figure 8.19: Existing Kuebler Road System under peak demand with proposed improvement



The issue with the high pressure distribution system in the Kuebler Road area of South Salem is an existing condition and construction is planned for completion in 2021 or earlier. The cost of this project is estimated at $14.1 million to $19.7 million, with an associated $13.2 to $18.4 million range in estimated PVRR. NW Natural analyzed the placement of a satellite LNG facility as an alternative which would defer pipeline construction. As the range of estimated PVRR is $14.6 to $27.3 million, this potential solution is more costly than constructing the new pipeline facility.

5.7. ALTERNATIVES TO PROJECTS

NW Natural assessed a satellite LNG facility as a supply-side alternative to each pipeline project, with the facility sized to address the same issue addressed by each project described above. The Company views the permitting process for satellite LNG facilities in particular as one likely to present considerable challenges. Table 8.3 compares the range of estimated PVRR for each project above with the estimated cost of the satellite LNG alternative.

Table 8.3: PVRR Ranges of Project and Satellite LNG Alternative (Millions of $2017)

Reinforcement Project	Year	PIPELINE PROJECT Low PVRR Estimate	PIPELINE PROJECT High PVRR Estimate	SATELLITE LNG ALTERNATIVE Low PVRR Estimate	SATELLITE LNG ALTERNATIVE High PVRR Estimate
Hood River	2019	$3.6	$7.2	$10.1	$19.0
Happy Valley	2019	$3.0	$4.8	$17.3	$32.4
Sandy Feeder	2020	$14.3	$19.7	$15.8	$29.7
North Eugene	2020	$5.0	$9.9	$14.7	$27.5
South Oregon City	2020	$3.9	$5.8	$14.7	$27.5
Kuebler Road	2020–2021	$13.2	$18.4	$14.6	$27.3

NW Natural also assessed the feasibility for a demand-side alternative to address the same issue addressed by each project described above. This alternative is the use of customer-specific geographically focused defined interruptibility agreements (localized interruptibility agreements) discussed above. Table 8.4 includes information regarding this demand-side alternative for each project above.

Table 8.4: Potential Customer-specific Localized Interruptibility Agreements Project Alternatives

Reinforcement Project	Potential Customers	Estimated Potential Peak Hour Therm Reduction	Required Peak Hour Therm Reduction	Assessment of Feasibility
Hood River	9	713	670	No
Happy Valley	8	1,432	3,300	No
Sandy Feeder	7	278	2,060	No
North Eugene	1	61	725	No
South Oregon City	5	402	1,100	No
Kuebler Road	15	440	2,000	No

6. DISTRIBUTION SYSTEM PROJECT UPDATES

The 2016 IRP included several distribution system projects as action items and NW Natural provides brief updates of these below.

Southeast Eugene Reinforcement Project

The sole 2016 IRP action item related to NW Natural's distribution system in Oregon was the SE Eugene reinforcement project which included an estimated cost of $4 to $6 million with completion expected in 2018. The Public Utility Commission of Oregon adopted Staff's recommendation regarding this project, where Staff's conclusion was that the Commission should acknowledge this action item.[15]

NW Natural based distribution system projects' cost estimates in the 2016 IRP on historic cost per mile construction costs and has recently received bids for this project's construction. The Company has updated its estimated cost to a range of $9 to $10 million based on information in the received bids. The Company updated its alternatives analysis using the revised cost estimate and concluded the project remained the least cost - least risk solution to the identified issue. The project is expected to be completed in 2018.

Clark County Projects

The 2016 IRP included an action item related to future construction of several distribution system projects in Clark County, including an estimated cost of $21 million over the next three years. These projects included the Camas Reinforcement, Washougal Extension, 119th Street to Salmon Creek, and Vancouver Core Phase 2.

NW Natural completed the Camas Reinforcement project and the 119th Street to Salmon Creek project in 2017, with actual costs of $6.3 million and $5.1 million, respectively.

NW Natural has reviewed contractor bids and awarded the contract to construct the Washougal Reinforcement project.[16] The project is expected to be completed in 2018, and NW Natural has revised the estimated cost to a range of $5.9 to $6.5 million.

The estimated cost of the Vancouver Core Phase 2 project, after more detailed analysis, is estimated to cost less than $1 million, with completion planned for 2019.

7. KEY FINDINGS

For distribution system planning, NW Natural

- Uses a 10-year planning horizon
- Uses modeling software to identify or validate system issues
- Designs to peak hour
- Applies standard criteria to identify system issues and to initiate reinforcement projects
- Performs alternatives analyses looking at both demand-side and supply-side alternatives
- Includes six Oregon projects in the 2018 IRP Action Plan

[15] See Order No. 17-059 in Docket No. LC 64, the Oregon proceeding associated with NW Natural's 2016 IRP.
[16] NW Natural also refers to this project as the Washougal Reinforcement project.

CHAPTER 9

PUBLIC PARTICIPATION

1. TECHNICAL WORKING GROUP

The Technical Working Group (TWG) is an integral part of developing NW Natural's resource plans. During this planning cycle, the Company worked with representatives from Citizens' Utility Board of Oregon; Energy Trust of Oregon; Alliance of Western Energy Consumers (Formerly known as Northwest Industrial Gas Users); Northwest Pipeline Corporation; Public Utility Commission of Oregon staff; Washington Utilities and Transportation Commission staff; Northwest Gas Association; Washington's Office of the Attorney General, Williams Pipeline; Transcanada – GTN; Avista; Northwest Energy Efficiency Alliance (NEEA); Fortis B.C.; Cascade Natural Gas; Northwest Energy Coalition; and other stakeholders.

NW Natural scheduled eight TWG meetings and one Open House as part of its 2018 IRP process. Below is a brief summary of each meeting.

- TWG No. 1 – held on December 20, 2017

NW Natural reviewed the 2016 IRP Action Plan, 2018 process and schedule, current planning environment including economic and demographic data, gas prices, and environmental policies.

- TWG No. 2 – held on February 28, 2018

NW Natural reviewed the customer growth forecast, daily demand drivers, planning standard, peak day forecast, annual usage forecast, industrial forecast, and CNG forecast.

- TWG No. 3 – held on March 14, 2018

NW Natural reviewed the supply resource overview, future Mist Storage opportunities, avoided cost, RNG, and power–to-gas. Williams Pipeline and GTN provided updates and Energy Trust of Oregon reviewed their demand side resource forecast.

- TWG No. 4 – held on April 25, 2018

NW Natural reviewed Newport LNG takeaway enhancements, upstream methane emissions, an environmental update, portfolio selection modeling, expected demand portfolios, and the expected demand emissions forecast. NEEA provided an overview of the Natural Gas Collaborative and new gas technologies.

- TWG No. 5 – held on May 22, 2018

NW Natural reviewed CNG in the transportation sector, portfolio risk analysis, distribution system planning, and distribution projects.

- TWG No. 6 – held on June 27, 2018

- NW Natural reviewed the 2018 IRP Action Plan and the 2018 IRP Draft.

Appendix I contains the sign-in sheets for each TWG meeting.

The company began the TWG series with an Open House on October 16, 2017 to review the modeling tools to be used for analysis and to provide an overview of our system. In addition to these meetings, TWG participants were invited to an additional meeting allowing a repeat of the Load Forecast held on May 28, 2018.

2. PUBLIC PARTICIPATION

NW Natural has invited customers to participate in the resource planning process by hosting a public meeting on the evening of July 17, 2018. A bill insert sent to all customers in June 2018 informed customers about the IRP process, welcomed customers to submit comments, and invited customers to attend the public meeting.

APPENDIX A

GLOSSARY

AECO	Alberta Energy Company
AGA	American Gas Association
AMA	
ARIMA	Autoregressive integrated moving average
Achievable Potential	
Bcf	A billion cubic feet
Base Case	
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.
CHP	Combined Heat & Power
CIS	Customer Information System
CNG	Compressed Natural Gas
CO^2	Carbon Dioxide
CO^2e	Carbon Dioxide Equivalent
CPI	Consumer Price Index
CUB	Oregon Citizens' Utility Board
Capacity	
City gate	
Class B (pipeline system)	A pipeline system operating at 60 psig or less
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 excess electrical energy, if any, being transmitted into the local power supply company's lines.
Cost effective	
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 his take of gas depending on the severity of the shortfall between gas supply and demand and the customer's position in the hierarchy.
DR	Demand Response
DSM	Demand-side Management
Dth	Dekatherm (or Decatherm)
Distribution/Distribution System	
EE	Energy Efficiency
EFRC	Energy Frontier Research Center
EIA	US Energy Information Administration
EPA	Environmental Protection Agency
ERU	Emission Reduction Unit
ETO	Energy Trust of Oregon
Energy (Resource, Load, Forecast)	
Entitlement	
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	
Gasco	Portland LNG Plant
GIS	Geographical information system
GHG	Greenhouse gas

HDD	Heating degree day
Hedging	Any method of minimizing the risk of price change.
Henry Hub	Natural gas referencing price point
Incremental	
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.
Interstate	
Jackson Prairie	
LDC	Local Distribution Company
LNG	Liquified Natural Gas
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)
Load	
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
Mcf/day	A thousand cubic feet per day
MDDO	
MDT	A thousand dekatherms
MMcf/day	
MMDT	A million dekatherms

MSA	Metropolitan Statistical Area(s) 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)	
Moving Average	
NEAA	
NGL	
NWIGU/	Northwest Industrial Gas Users
NWGA	Northwest Gas Association
NWPCC	Northwest Power Council
NWPL	Northwest Pipeline
NPVRR (also PVRR)	Net present value revenue requirement
Normal Distribution	
Normal Weather	
ODOE	Oregon Department of Energy
OEA	State of Oregon's Office of Economic Analysis
OFO	
OLIEE	Oregon Low Income Energy Efficiency
OPUC	Public Utility Commission of Oregon
PGA	Purchased Gas Adjustment
P2G	Power-to-gas
PVRR (also NPVRR)	Present Value of Revenue Requirement
Peak (Day, Hour)	
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.
PSIG	Pounds per Square Inch Gauge

REC	Renewable energy certificate
RIN	Renewable identification number
RMSE	Root mean squared error
RNG	Renewable natural gas
Recall	
Rockies	
SCADA (system)	Supervisory Control and Data Acquisition
SME Panel	A panel composed of subject matter experts
Segmented Capacity	
SENDOUT	Optimization modeling software used by NW Natural
Station 2	
Stochastic	
Sumas/Huntingdon	
Synergi™	
T-DSM	Targeted-Demand-side Management
TF-1	
TF-2	
Technical Potential	
Therm	Unit of measurement 1 Therm = 29.3 KWh
Total Resource Cost (test)	
Transmission, natural gas	
Transportation (Sales, 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
Utility Cost Test (UCT)	
WACOG	Weighted Average Cost of Gas
WAIEE	

W & P	Woods & Poole forecasting service
WUTC	Washington Utilities & Transportation Commission

Glossary - to be completed for Final Filing

APPENDIX B

IRP REQUIREMENTS

NW Natural's 2018 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 has developed a methodology for a consistent and comparable basis for evaluating renewable resources.	7
	All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	NW Natural attempted to include all known supply- and demand-side resource options in its evaluation. Supply-side options studied include not only the source of gas, but also the pipeline capacity required to transport the gas, the Company's gas storage options, the system enhancements necessary to distribute the gas and recall agreements. The demand-side study looked at all the potential energy savings available within the Company's service territory.	4, 5, 6, 7, and 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- 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, imported LNG, and includes satellite LNG facilities sited at various locations within the Company's service territory. For those resources evaluated as being sufficiently viable to be included in resource portfolio optimization, the Company clearly defines each resource's in-service date before which the respective resource is unavailable for selection as part of a resource portfolio. Because the Company identified unserved demand occurring in all areas of its service territory within the 20-year planning horizon in the absence of supply-side resource acquisition, it 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. The Company 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 20-year planning horizon. The Company has also considered technologies which are not currently available but have been identified for continued monitoring and future assessment.	5,6, and 7
	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. Additionally new to the 2018 IRP, NW Natural has developed a methodology for a consistent and comparable basis for evaluating renewable resources.	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 4.905 percent in this IRP, which it derives using the currently authorized values associated with its cost of capital in Oregon. The Company incorporates a 1.96 percent annual rate of inflation, which it estimated using methods with which the Commission is familiar.	5, 6, and 7
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, including forecasts characterized as traditional Base Case and low and high load growth scenarios. The Company analyzed weather uncertainty, gas price uncertainty, cost of compliance uncertainty, and resource costs uncertainty in its stochastic analysis. Finally, new to this IRP discusses the impacts of complying with prospective greenhouse gas 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.	2, 3, 4, 5, 6, and 7
	Utilities should identify in their plans any additional sources of risk and uncertainty.	New to this IRP and in addition to the uncertainties mentioned above, the Company has also modeled different sources of renewable resources. Not only does this take carbon compliance into consideration but 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 a 20 year planning horizon. In this IRP that portfolio selected depends upon the prospective development of a number of interstate pipeline 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

	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:		
	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
	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) price stability, and 4) cost recovery. Chapter six discusses hedging.	6
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	New to this IRP, 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 sensitivity and risk analysis, and its underlying 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.	1,3,4, 6, and 7

Guideline 1(d)	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	NW Natural expects state-level carbon policy within the IRP time frame. The Company's underlying gas price forecast provided by our outside consultant includes the cost of compliance with most known environmental regulations. In addition, the Company included as a proxy for future state regulation incremental compliance costs based on several potential policies in the region. New to this IRP, 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. The Company proposes, as an action item, a methodology for valuing renewable natural gas contracts. As always, NW Natural works closely with Energy Trust 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 2018 IRP. The Company held seven Technical Working Group (TWG) meetings, and one public meeting. NW Natural notified customers of the 2018 IRP process in a June 2018 bill insert, which invited the submission of comments and announced the July 17, 2018 public meeting. Chapter nine discusses the technical working groups and the public meeting.	9

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 any other mechanism approved by the Commission.	As evidenced by materials included in the plan, NW Natural has put forth all relevant non-confidential information necessary to produce a comprehensive Plan.	
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 XX, 2018**, after conducting five TWG meetings, an initial draft plan in both Oregon and Washington. The action plan contained within the draft plan was discussed at a technical working group meeting held on June 27, 2018.	9
Guideline 3(a)	The utility must file an IRP for within two years of its previous IRP acknowledgement order.	The Commission acknowledged NW Natural's 2016 IRP on February 21, 2017; see Order No. 17-059 in Docket No. LC 64.	
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 recommendations within six months of IRP filing.	The Company looks forward to working with Staff and interested parties in their review of this plan.	
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.	The Company 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 summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	The Company plans to file an annual report as required.	
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.	The Company 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 substantive and procedural requirements.	This appendix is intended to comply with this guideline by providing an itemized response to each of the 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 Base Case demand forecast uses NW Natural's projected customer growth and projected prices. The IRP also analyzes scenarios associated with both high and low demand growth. 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 base-load 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 base-load), transportation and storage needed to bridge the gap between expected loads and resources.	Using the SENDOUT® optimization model, NW Natural determined the peaking, swing, and baseload gas supply and associated transportation and storage for each year of the 20-year planning horizon. Please see Chapter seven and its appendix for information regarding individual scenarios and sensitivities used in the Company's optimization modeling and the required timing of specific resources in each case.	7
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, gas supply contracts, and physical and financial hedging; as well as alternative options such as additional capacity or infrastructure enhancements. The Company also considered future developments such as pipeline enhancements, on-system renewable natural gas and on-system power-to-gas. Chapter six discusses the various supply side options and their costs. The Company compiled demand-side resource options with assistance from the Energy Trust of Oregon, and these options are identified in Chapter five.	5,6

Guideline 4(f)	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	Chapter six discusses NW Natural's Gas Supply Risk Management Policies, modeling tools, and cost/risk considerations that form the basis for planning and maintaining reliable gas service. For example, the Company's Gas Supply Department uses SENDOUT© to perform its dispatch modeling from various pipeline supplies and storage facilities. The objective is to ensure reliable service during the heating season on an aggregate, system-wide basis as well as achieve the maximum economic benefit from seasonal price differences and varying gas delivery terms. The SynerGEE® 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 growing 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.	6, 7 and 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 the 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 carbon policy compliance costs in it price forecasts and analyzed sensitivities related to compliance costs. Further, The Company 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 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 represent uncertainty of natural gas prices, weather and resource costs.	7
Guideline 4(k)	Analysis of the uncertainties associated with each portfolio evaluated.	Chapters six and seven discuss the uncertainties associated with the availability and cost of resources.	6 and 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 its preferred portfolio is inconsistent with state or federal energy policies. Potential barriers to implementation may relate to the ultimate availability and timing of certain incremental resources selected for the Company's preferred portfolio due to facility siting / permitting challenges, market viability, and others. Chapters six, two, 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 multi-year action plan, which identifies the short-term actions the Company intends to pursue within the next two to four years.	1
Guideline 5	Transmission	Not applicable to NW Natural's gas utility operations	
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 Energy Trust of Oregon to analyze the potential energy savings that could be cost-effectively procured within the Company's service territory over the next 20 years. The study determined the achievable potential by analyzing customer demographics together with energy efficiency measure data. The results were then evaluated with supply-side resources using SENDOUT®. A deployment scenario was applied to the total potential. The Company and Energy Trust review these assumptions each year when Energy Trust 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 should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	Appendix five provides annual therm savings targets for NW Natural's Oregon and Washington service areas. These targets are disaggregated to specific customer segment and program type. NW Natural's Schedule 301, Public Purposes Funding Surcharge, contains a special condition requiring NW Natural to work with Energy Trust every year to determine if the funding level is appropriate to meet the subsequent year's therm savings targets. At the time of this review, the Company and Energy Trust evaluate the applicable IRP annual target and consider unforeseen influences that may either increase or reduce the subsequent year's target. NW Natural then files an updated tariff which proposes Schedule 301 adjustments in order to sufficiently fund the subsequent year's target, including a buffer fund for unexpected expenses.	Appendix 5
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.	Not applicable.	
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 27 percent of the Company's throughput. This allows the Company to reduce system stress during periods of unusually high demand.	

Guideline 8	Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for CO_2, NO_x, SO_2, and Hg emissions. Utilities should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from \$0 - \$40 (1990\$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for NO_x, SO_2, and Hg, if applicable.	NW Natural explicitly incorporates expected regulatory compliance costs in its analyses, including Base Case portfolio results and sensitivities to a range of potential policy futures.	2, 4, 6, 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 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.	NW Natural analyzes on an integrated basis gas supply, transportation, and storage, along with demand-side resources; to reliably meet peak, swing, and baseload system requirements. For this IRP, the Company 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 SENDOUT®. 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.	3 and 7
Guideline 12	Distributed Generation	Not applicable to NW Natural’s gas utility operations.	
Guideline 13(a)	Resource Acquisition	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.	Chapter six describes NW Natural's Gas Acquisition Plan 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.	6
Order No. 11-196 , UM 1286	For natural gas utilities, each IRP preparation process and final published IRP will address both planning to meet normal annual expected demand (as defined by the LOC - both base-load and swing) by day and planning to meet annual peak demand by day. The planning will include gas supply and associated transportation along with expected use of storage.	NW Natural views its plan to meet normal annual expected demand as being wholly encompassed within the Company's plan to meet demand in a year with design weather. As the plan addresses demand on an annual basis predicated on design weather, which includes a peak day, resource decisions within the plan fully reflect the Company's ability to meet demand under normal conditions on an annual basis.	

NW Natural's 2018 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 25, 2017. The Company filed three additional revisions to the work plan on October 16, 2017, January 18, 2018, and June 8, 2018.
WAC 480-90-238(4)	Work plan outlines content of IRP.	The work plan filed on August 25, 2017 outlined the content of the 2018 IRP.
WAC 480-90-238(4)	Work plan outlines method for assessing potential resources. (See LRC analysis below)	The work plan filed on August 25, 2017, provided the methodology used in developing the 2018 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 the Company toward the least cost resource portfolio.
WAC 480-90-238(5)	Work plan outlines timing and extent of public participation.	The work plan filed on August 25, 2017, states seven technical working group meetings were scheduled: December 6, 2017; January 24, 2018; February 14, 2018; March 14, 2018, April 11, 2018, May 9, 2018, and June 27, 2018. The work plan was revised on October 16, 2017 to change five of the meeting dates due to conflicts with stakeholder schedules. On January 18, 2018 the work plan was updated to reflect the cancellation of the January 31 technical working group as well as revised agenda topics for the February 28 and March 14 Technical Working Group meetings to cover the January 31 agenda topics. The work plan was revised on June 8, 2018 to add a technical working group meeting on August 2. Additionally, NW Natural held a review session on May 24, 2018. Lastly, customers were notified of this IRP's process through a June 2018 bill insert, a facsimile of which is included in Appendix Nine. This bill insert welcomed public comments and invited customers to a public meeting, which occurred on July 17, 2018.
WAC 480-90-238(4)	Integrated resource plan submitted within two years of previous plan.	NW Natural filed its 2016 IRP on August 26, 2016. *See* Docket No. UG-151776.
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 options including existing and proposed interstate pipeline capacity from multiple providers, the Company's Mist underground storage, imported LNG and Satellite LNG facilities. The Company has also provided a commentary of other alternative supply side option such as biogas.
WAC 480-90-238(2)(a)	Plan describes conservation supply.	Chapter Five documents how NW Natural determined the achievable potential of DSM within its service territory over the next 20 years.
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 using a set of deterministic load forecasts, including the traditional low and high load growth scenarios. The Company projected annual customer counts by customer sub-class and prepared customer forecasts for three scenarios; including low growth, the Company's Base Case, and high growth. NW Natural then statistically estimated gas usage equations for each customer subclass (or market segment). The Company derived design year (including peak day) projections using multiple regression models, and separating base load from temperature-sensitive load. Next, the Company integrated design weather and forecasted customers with gas usage equations to derive firm service design day peak demand requirements for each 20-year forecast scenario.
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 SENDOUT® 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 alternative 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.

WAC 480-90-238(2)(b)	LRC analysis considers market-volatility risks.	NW Natural developed several different risk analyses in addition to the Base Case in part to examine risks associated with uncertainty regarding natural gas prices and price volatility. These sensitivities evaluated higher levels of avoided costs, different natural gas prices price paths over the planning horizon, and the effects of alternative futures involving LNG exports on natural gas prices. The Company 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 discusses DSM's effect on the supply-side resource mix. Additionally, the Company analyzed both high and low avoided cost scenarios.
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.	NW Natural developed several risk analyses including which resources and their acquisition timing prevent unserved demand from firm service customers. In addition to sensitivities analyzing the impact of alternative natural gas price paths, NW Natural performed various risk analyses including a risk analysis of construction costs for both new interstate pipelines as well as future underground storage. NW Natural also evaluated the impact of various environmental policies. Please see Chapter Seven for the risk analysis.

WAC 480-90-238(2)(b)	LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government.	NW Natural's 2018 IRP considers adoption of regulation reflecting the potential and likely state or federal policies with respect to GHG emissions. The Company models a GHG emissions compliance cost (referred to as a carbon price) and applies this carbon price adder consistently to gas commodities costs base on the carbon intensity of the gas commodity. For conventional gas, this equates to a carbon price adder is added onto forecasts the Company obtained from a third-party vendor. For renewable gas sources, this carbon adder, which can be negative for some sources, is added to the commodity cost of renewable gas source. The expected carbon price is model as proxy for various regulation outcomes reflecting Washington or regional policies with respect to GHG emissions and is not modeled for any specific policy outcome. The expected carbon price model in the 2018 IRP starts at a level of $14.86 per MTCO2e in Washington and $0 per MTCO2e in Oregon. Oregon is modeled to start a policy in 2021 at which point the carbon price is equal to the carbon price in Washington which increases annually to $44.03 per MTCO2e in 2037 (dollar values in $2017). The Company discusses new and developing state and federal policies in Chapter Two Planning Environment
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's Base Case natural gas price forecast in the 2018 IRP and adds an incremental carbon price as a proxy for GHG emissions compliance cost associated with regulation reflecting Washington or regional policies. This carbon price is first applied to natural gas and renewable gas sources delivered by NW Natural in 2017 at a level of $14.86 per MTCO2e and increases annually to $44.03 per MTCO2e in 2037 (dollar values in $2017). Additionally, NW Natural's 2018 IRP includes a risk analyses that incorporates a range of potential carbon prices including a social cost of carbon starting at $47.42 per MTCO2e in 2018.
WAC 480-90-238(2)(b)	LRC analysis considers need for security of supply.	The Plan identifies in Chapter Six that the Company's first priority is to ensure it has a gas resource portfolio sufficient to satisfy core customer requirements. The second priority is to achieve sufficient resources at the lowest cost to customers.

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 the amount of gas needed to serve the Company's firm service customers, including under future circumstances different from those of the Base Case.
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 alternative resource portfolios under changes from the Base Case load forecast due to high and low customer growth and, using the resource optimization capabilities of SENDOUT®, compared these with the portfolios produced under the Base Case load forecast.
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.	The Plan examines the impact of higher and lower loads than those in the Base Case load forecast, which 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.	The achievable potential study performed to determine the potential of demand-side management programs that should be included in NW Natural's preferred portfolio began with a study of all known commercially available conservation measures, including those not currently in the market place. Chapter Five provides an overview of new measures as well as interesting findings. With respect to demand-side load management, the Company foresees continuing to shave peak load requirements when and where necessary by curtailing interruptible customers.
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 the Energy Trust is proposing doing an Accelerated/Enhanced Geographically Targeted DSM pilot.

WAC 480-90-238(3)(c)	Plan includes an assessment of conventional and commercially available nonconventional gas supplies.	In Chapter six, NW Natural determined the best resource mix by studying supply-side options currently used, such as pipeline transportation contracts, gas supply contracts, storage, and physical and financial hedging, as well as future alternatives such as additional capacity or infrastructure enhancements. In the 2018 IRP, NW Natural also includes renewable resources such as renewable natural gas and potentially hydrogen or methanated hydrogen.
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 discuss 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, gas supply contracts, and physical and financial hedging; as well as alternative options such as additional capacity or infrastructure enhancements. New to the 2018 IRP, The Company also developed a methodology to compare the cost of renewable resources with conventional gas resources. The Company also considered future developments such as imported/exported LNG and pipeline enhancements. SENDOUT® determined the least cost resource mix through linear programing optimization as well as performed various sensitivities in its risk analysis, which the Plan discusses 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 a 20-year planning horizon.
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- 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 and Six, and Eight discuss progress on both the demand and supply side activities 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 Group. NW Natural documents public participation in Appendix Nine.
WAC 480-90-238(5)	Plan includes a description of completion of work plan. (Description not required)	The Key Takeaways at the beginning of most chapters and the Multi-Year Action Plan in Chapter One serve to document NW Natural's successful completion of the Plan.

APPENDIX C

LOAD FORECAST

Appendix C documents econometric and other quantitative models NW Natural used in developing load forecasts for the 2018 IRP. See Chapter 3 for discussions regarding different aspects of the load forecast.

1. ECONOMETRIC MODELS FOR CUSTOMER FORECASTS

Following are descriptions of each econometric model used to forecast residential and firm sales customers, using the "levels" approach at the state-level. Each of the four econometric models involve differencing variables and include a time trend. Only the Washington commercial model includes any autoregressive (AR) or moving average (MA) parameters.

1.1 RESIDENTIAL CUSTOMER FORECASTS - OREGON

The econometric model used to forecast Oregon residential customers is of the form ARIMA(0,2,0).

$$\Delta^2 ORRES_t = \alpha_1 \times \Delta YEAR_t + \alpha_2 \times \Delta\left(\frac{USHOUS_t + USHOUS_{t-1} + USHOUS_{t-2}}{3}\right) + \varepsilon_t$$

Where:

$ORRES_t$ is the number of Oregon residential customers at year-end in year t

$YEAR_t$ is an integer value representing year t

$USHOUS_t$ is the number of U.S. housing starts in year t (in millions)[1]

ε_t represents the error in year t

Coefficients and p-values associated with the econometric model used for Oregon residential customers are in Table C.1.

Table C.1: Model Coefficients – Oregon Residential

Coefficient	Value	p-value
α_1	-204.359	0.593
α_2	7,821.800	0.004

1.2 RESIDENTIAL CUSTOMER FORECASTS - WASHINGTON

The econometric model used to forecast Washington residential customers is of the form ARIMA(0,2,0).

[1] Oregon's Office of Economic Analysis (OEA) forecasts Oregon housing starts as a function of two exogenous variables, one of which is U.S. housing starts. See documentation of econometric models used by OEA at http://www.oregon.gov/das/OEA/Documents/economic_methodology_dec2010.pdf (accessed April 27, 2018).

$$\Delta^2 WARES_t = \alpha_1 \times \Delta YEAR_t + \alpha_2 \times \Delta\left(\frac{USHOUS_t + USHOUS_{t-1} + USHOUS_{t-2}}{3}\right) + \varepsilon_t$$

Where:

$WARES_t$ is the number of Washington residential customers at year-end in year t

$YEAR_t$ is an integer value representing year t

$USHOUS_t$ is the number of U.S. housing starts in year t (in millions)

ε_t represents the error in year t

Coefficients and p-values associated with the econometric model used for Washington residential customers are in Table C.2.

Table C.2: Model Coefficients – Washington Residential

Coefficient	Value	p-value
α_1	2.508	0.975
α_2	1548.200	0.006

1.3 COMMERCIAL CUSTOMER FORECASTS - OREGON

The econometric model used to forecast Oregon commercial customers is of the form ARIMA(0,1,0).

$$\Delta ORCOM_t = \alpha_1 \times \Delta YEAR_t + \alpha_2 \times \Delta\left(\frac{ORPOP_t + ORPOP_{t-1} + ORPOP_{t-2}}{3}\right) + \varepsilon_t$$

Where:

$ORCOM_t$ is the number of Oregon commercial customers at year-end in year t

$YEAR_t$ is an integer value representing year t

$ORPOP_t$ is Oregon's population in year t (in millions)

ε_t represents the error in year t

Coefficients and p-values associated with the econometric model used for Oregon commercial customers are in Table C.3.

Table C.3: Model Coefficients – Oregon Commercial

Coefficient	Value	p-value
α_1	-106.667	0.822
α_2	222.116	0.037

1.4 COMMERCIAL CUSTOMER FORECASTS - WASHINGTON

The econometric model used to forecast Washington commercial customers is of the form ARIMA(2,1,0).

$$\Delta WACOM_t = \alpha_1 \times \Delta WACOM_{t-1} + \alpha_2 \times \Delta WACOM_{t-2} + \alpha_3 \times \Delta YEAR_t + \alpha_4 \times \Delta\left(\frac{ORNFEMP_t + ORNFEMP_{t-1} + ORNFEMP_{t-2}}{3}\right) + \varepsilon_t$$

Where:

$WACOM_t$ is the number of Washington commercial customers at year-end in year t

$YEAR_t$ is an integer value representing year t

$ORNFEMP_t$ is Oregon's nonfarm employment in year t (in thousands)

ε_t represents the error in year t

Coefficients and p-values associated with the econometric model used for Washington commercial customers are in Table C.4.

Table C.4: Model Coefficients – Washington Commercial

Coefficient	Value	p-value
α_1	0.263	0.229
α_2	-0.413	0.096
α_3	157.299	<0.0001
α_4	1.303	0.028

1.5 EXOGENOUS VARIABLES

The source of the forecast of the exogenous variable used in each of the four customer forecast econometric model used in the 2018 IRP was Oregon's Office of Economic Analysis (OEA). As OEA forecasts U.S. housing starts and Oregon's nonfarm employment 10 years ahead, NW Natural used OEA's forecast of Oregon's population to project, respectively, U.S. housing starts[2] and Oregon's nonfarm employment through 2042.

[2] NW Natural projected U.S. housing starts by first using OEA's forecast of Oregon's population and the 1991–2016 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.

1.6 ECONOMETRIC MODELS FOR ALLOCATING ANNUAL CUSTOMER FORECASTS TO MONTHS

NW Natural discusses the econometric model used to forecast the monthly allocation values for Oregon residential customers as an example of the four models. This model is of the form ARIMA(1,0,0). This model used four dummy variables to account for extreme values in two pairs of months: October and November of 2009 and November and December of 2012. Table C.5 has the coefficient value and p-value associated with each independent variable used.

$$\begin{aligned}\mathrm{ORPCT}_m = \alpha_1 \times \mathrm{ORPCT}_{m-1} + \alpha_2 \times \mathrm{INDOCT2009} + \alpha_3 \times \mathrm{INDNOV2009} \\ + \alpha_4 \times \mathrm{INDNOV2012} + \alpha_5 \times \mathrm{INDDEC2012} + \boldsymbol{MONTH} \times \boldsymbol{b} + \varepsilon_t\end{aligned}$$

Where:

ORPCT_{m-1} is the proportion of annual growth attributable to the prior month

INDOCT2009, INDNOV2009, INDNOV2012, and INDDEC2012 represent dummy variables for months with extreme values

MONTH_m is 12 x 1 column vector populated by binary indicators for each of the calendar year's 12 months

ε_m is the error in month m.

Coefficients and p-values associated with the econometric model used for allocating Oregon residential customers from year-end annual values to monthly values are in Table C.5.

Table C.5: Model Coefficients – Monthly Allocation – Oregon Residential

Explanatory Variable	Coefficient Value	p-value
$ORPCT_{m-1}$	0.510	<.0001
INDOCT2009	-2.671	<.0001
INDNOV2009	2.793	<.0001
INDNOV2012	0.625	<.0001
INDDEC2012	-0.470	<.0001
JAN	0.234	<.0001
FEB	0.100	.0005
MAR	0.042	0.0983
APR	-0.012	0.6650
MAY	-0.042	0.1381
JUN	-0.111	0.0002
JUL	-0.176	<.0001
AUG	-0.117	<.0001
SEP	0.023	0.4072
OCT	0.218	<.0001
NOV	0.402	<.0001
DEC	0.434	<.0001

NW Natural normalized the coefficients in Table C.5 such that the sum of the normalized coefficients equaled 100 percent.

2. USE PER CUSTOMER ECONOMETRIC MODELS

The econometric models for residential and commercial UPC use monthly average UPC and monthly average HDD along with an indicator variable for summer months:

$$UPC_t = \beta_1 \times HDD_t + \alpha_1 + a_2 \times Summer + \varepsilon_t$$

Where:

UPC_t is the historical monthly average UPC

HDD_t is the historical monthly system-weighted average HDD (using base 59 for residential and 58 for commercial)

Summer is an indicator variable for summer months (July, August, and September)

ε_t is the error in month t

3. ECONOMETRIC MODELS FOR ANNUAL INDUSTRIAL LOAD

The econometric model used to forecast industrial load in the 2018 IRP is of the form ARIMA(1,1,0). Table C.6 has the coefficient value and p-value associated with each independent variable used.

$$\Delta INDLOAD_t = \alpha_1 \times \Delta INDLOAD_{t-1} + \alpha_2 \times \Delta YEAR_t + \alpha_3 \times \Delta OREMPS3_t + \varepsilon_t$$

Where:

$INDLOAD_t$ is the system industrial load in year t

YEARt is an integer value representing year t

OREMPS3t is the aggregate employment in Oregon's Computer and Electronics, Metal and Machinery, and Wood Products industries (in thousands)

ε_t is the error in year t.

Table C.6: Model Coefficients – System Industrial Load

Coefficient	Value	p-value
α_1	-0.88.065	0.870
α_2	-0.449	0.046
α_3	369.054	0.004

4. DAILY SYSTEM LOAD MODEL RESULTS

Table C.7 presents the coefficients and standard errors for the daily system load model. Given the interaction effects between temperature and other drivers the coefficients should not be interpreted in isolation.[3]

Table C.7: Model Coefficients – Daily System Load

Regressor	Units	Coefficient	Standard Error	p-value
Previous Day Temperature	Hourly Average (°F)	-10,983.1	403.0	0.000
+Temperature Interaction		159.9	7.6	0.000
Wind Speed	Hourly Average (mph)	8,723.0	866.5	0.000
+Temperature Interaction		-140.3	19.4	0.000
+Time Interaction		2.9	1.1	0.008
Solar Radiation	Daily Sum (watts/m2)	-24.2	2.1	0.000
+Temperature Interaction		0.4	0.0	0.000
Snow Depth	Daily Measure (inches)	-36,611.2	7,433.9	0.000
+Temperature Interaction		951.1	256.5	0.000
Customer Count	N/A	1.5	0.1	0.000
+Temperature Interaction		0.0	0.0	0.000
Friday Dummy	N/A	-49,594.1	9,439.0	0.000
+Temperature Interaction		875.0	191.6	0.000
Saturday Dummy	N/A	-62,078.1	7,637.6	0.000
+Temperature Interaction		975.6	154.7	0.000
Sunday Dummy	N/A	-57,384.7	7,802.7	0.000
+Temperature Interaction		954.8	160.2	0.000
Holiday Dummy	N/A	-63,975.6	18,812.7	0.001
+Temperature Interaction		1,013.6	386.7	0.009
Annual Time Trend	Years after 2008	-11,598.6	1,499.5	0.000
+Temperature Interaction		240.7	25.6	0.000
Bull Run Creek Temperature	Daily Measure (°F)	-2,033.4	185.2	0.000
Constant		260,837.4	79,151.4	0.001

3 In isolation each coefficient represents the impact of a one unit change in the variable evaluated at a daily average temperature of 0°F, which does not occur at a system-weighted level for NW Natural's service territory.

APPENDIX D

AVOIDED COSTS

1. LEVELIZED AVOIDED COSTS BY STATE AND END USE

Table D.1: Avoided Cost Summary by State, Year, and Policy

Year	Real (2017$)												
	Capital			Commodity		Carbon Sensitivities							
	Supply ($/Dth/Day)	Washington Distribution ($/Dth/Hour)	Oregon Distribution ($/Dth/Hour)	Gas and Transport Costs ($/Dth)	Hedge Value ($/Dth)*	Oregon Reference Carbon Policy ($/Dth)- Expectation	Oregon Carbon Policy Scenario: Low ($/Dth)	Oregon Carbon Policy Scenario: Mid ($/Dth)- Social Cost of	Oregon Carbon Policy Scenario: High ($/Dth)	Washington Reference Carbon Policy ($/Dth)- Expectation	Washington Carbon Policy Scenario: Low ($/Dth)	Washington Carbon Policy Scenario: Mid ($/Dth)- Social Cost of	Washington Carbon Policy Scenario: High ($/Dth)
2018	$0.057	$0.413	$0.254	$2.611	-$0.005	$0.000	$0.000	$2.569	$3.866	$0.789	$0.704	$2.569	$3.866
2019	$0.057	$0.413	$0.254	$2.608	-$0.310	$0.000	$0.000	$2.647	$3.944	$0.837	$0.729	$2.647	$3.944
2020	$0.057	$0.413	$0.254	$2.520	-$0.245	$0.000	$0.000	$2.724	$4.022	$0.886	$0.755	$2.724	$4.022
2021	$0.057	$0.413	$0.254	$2.558	-$0.260	$0.936	$0.000	$2.776	$4.100	$0.936	$0.782	$2.776	$4.100
2022	$0.057	$0.413	$0.254	$2.671	-$0.338	$0.988	$0.000	$2.828	$4.177	$0.988	$0.809	$2.828	$4.177
2023	$0.057	$0.413	$0.254	$2.850	-$0.553	$1.043	$0.000	$2.880	$4.255	$1.043	$0.838	$2.880	$4.255
2024	$0.057	$0.413	$0.254	$3.190	-$0.935	$1.100	$0.000	$2.932	$4.333	$1.100	$0.867	$2.932	$4.333
2025	$0.057	$0.488	$0.254	$3.228	-$1.001	$1.161	$0.915	$2.984	$4.411	$1.161	$0.915	$2.984	$4.411
2026	$0.057	$0.488	$0.254	$3.196	-$0.967	$1.225	$0.966	$3.036	$4.476	$1.225	$0.966	$3.036	$4.476
2027	$0.057	$0.488	$0.254	$3.246	-$1.047	$1.293	$1.019	$3.088	$4.541	$1.293	$1.019	$3.088	$4.541
2028	$0.057	$0.488	$0.254	$3.349	-$1.164	$1.365	$1.076	$3.140	$4.606	$1.365	$1.076	$3.140	$4.606
2029	$0.057	$0.488	$0.254	$3.496	-$1.388	$1.440	$1.135	$3.191	$4.670	$1.440	$1.135	$3.191	$4.670
2030	$0.518	$0.488	$0.254	$3.645	-$1.544	$1.520	$1.198	$3.243	$4.735	$1.520	$1.198	$3.243	$4.735
2031	$0.518	$0.488	$0.254	$3.735	-$1.659	$1.604	$1.264	$3.308	$4.800	$1.604	$1.264	$3.308	$4.800
2032	$0.518	$0.488	$0.254	$3.785	-$1.679	$1.693	$1.334	$3.373	$4.865	$1.693	$1.334	$3.373	$4.865
2033	$0.518	$0.488	$0.254	$3.892	-$1.798	$1.786	$1.408	$3.438	$4.930	$1.786	$1.408	$3.438	$4.930
2034	$0.518	$0.488	$0.254	$3.950	-$1.880	$1.885	$1.486	$3.503	$4.995	$1.885	$1.486	$3.503	$4.995
2035	$0.514	$0.488	$0.254	$3.988	-$1.926	$1.989	$1.568	$3.568	$5.060	$1.989	$1.568	$3.568	$5.060
2036	$0.514	$0.488	$0.254	$4.139	-$2.084	$2.099	$1.655	$3.633	$5.137	$2.099	$1.655	$3.633	$5.137
2037	$0.514	$0.488	$0.254	$4.174	-$2.131	$2.215	$1.746	$3.697	$5.215	$2.215	$1.746	$3.697	$5.215
2038	$0.514	$0.488	$0.254	$4.251	-$2.243	$2.338	$1.843	$3.762	$5.293	$2.338	$1.843	$3.762	$5.293
Levelized	**$0.193**	**$0.453**	**$0.254**	**$3.201**	**-$0.974**	**$1.106**	**$0.677**	**$3.043**	**$4.453**	**$1.284**	**$1.033**	**$3.043**	**$4.453**

Figure D.1: Oregon 20-year Levelized Avoided Costs by End Use

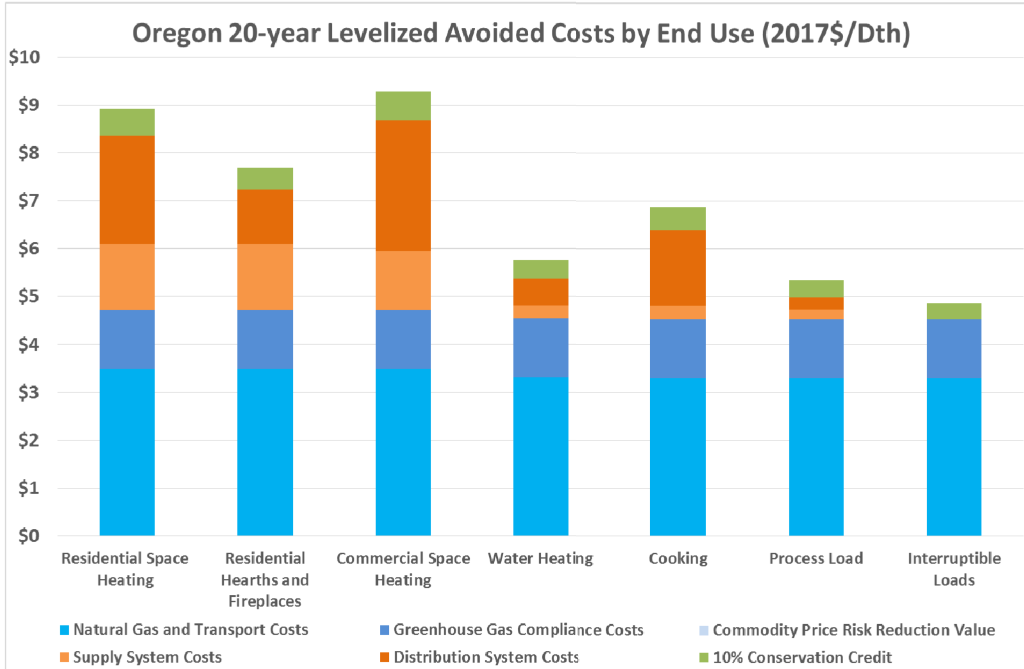


Figure D.2: Washington 20-year Levelized Avoided Costs by End Use

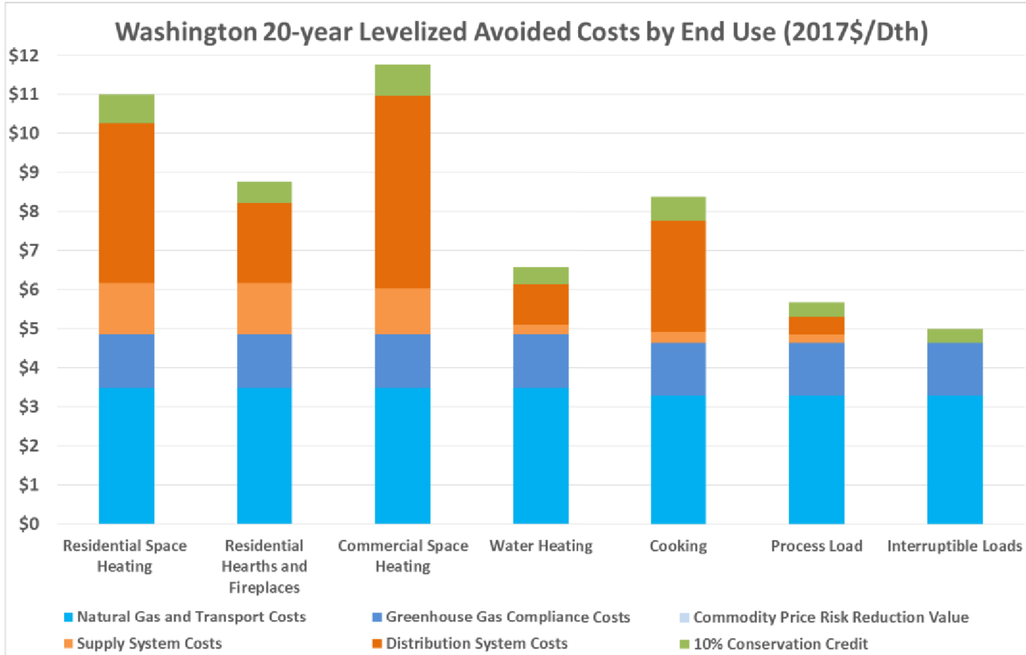


Table D.2: Avoided Cost by Year and End Use

	Oregon End Use Total Avoided Costs (2017$)						Washington End Use Avoided Costs (2017$)					
	Residential Space Heating	Residential Hearths and Fireplaces	Commercial Space Heating	Water Heating	Cooking	Process Load	Residential Space Heating	Residential Hearths and Fireplaces	Commercial Space Heating	Water Heating	Cooking	Process Load
2018	$5.73	$4.49	$6.21	$3.58	$4.69	$3.21	$8.09	$6.07	$8.89	$4.76	$6.57	$4.17
2019	$5.73	$4.49	$6.20	$3.57	$4.69	$3.21	$8.13	$6.12	$8.93	$4.81	$6.62	$4.22
2020	$5.63	$4.39	$6.11	$3.48	$4.59	$3.11	$8.09	$6.07	$8.88	$4.76	$6.57	$4.17
2021	$6.61	$5.37	$7.09	$4.45	$5.57	$4.09	$8.18	$6.16	$8.98	$4.85	$6.66	$4.26
2022	$6.79	$5.55	$7.26	$4.63	$5.74	$4.26	$8.35	$6.34	$9.15	$5.03	$6.84	$4.44
2023	$7.04	$5.80	$7.51	$4.88	$5.99	$4.51	$8.61	$6.59	$9.40	$5.28	$7.09	$4.69
2024	$7.47	$6.23	$7.94	$5.31	$6.43	$4.95	$9.04	$7.02	$9.83	$5.71	$7.52	$5.12
2025	$7.57	$6.33	$8.05	$5.42	$6.53	$5.05	$9.87	$7.49	$10.82	$6.00	$8.14	$5.31
2026	$7.60	$6.36	$8.08	$5.45	$6.56	$5.08	$9.90	$7.52	$10.85	$6.03	$8.17	$5.33
2027	$7.72	$6.48	$8.20	$5.57	$6.68	$5.20	$10.02	$7.64	$10.97	$6.15	$8.29	$5.46
2028	$7.91	$6.67	$8.38	$5.75	$6.87	$5.38	$10.21	$7.83	$11.16	$6.34	$8.47	$5.64
2029	$8.15	$6.91	$8.62	$5.99	$7.10	$5.62	$10.45	$8.06	$11.39	$6.58	$8.71	$5.88
2030	$11.36	$10.12	$11.51	$6.79	$7.95	$6.33	$13.66	$11.27	$14.28	$7.38	$9.55	$6.58
2031	$11.54	$10.30	$11.69	$6.97	$8.13	$6.51	$13.84	$11.46	$14.47	$7.56	$9.74	$6.77
2032	$11.68	$10.44	$11.84	$7.12	$8.27	$6.65	$13.98	$11.60	$14.61	$7.70	$9.88	$6.91
2033	$11.89	$10.65	$12.05	$7.33	$8.48	$6.86	$14.19	$11.81	$14.82	$7.91	$10.09	$7.12
2034	$12.06	$10.82	$12.21	$7.49	$8.65	$7.03	$14.36	$11.97	$14.98	$8.08	$10.25	$7.28
2035	$12.18	$10.94	$12.33	$7.63	$8.79	$7.17	$14.48	$12.09	$15.11	$8.22	$10.39	$7.43
2036	$12.45	$11.21	$12.61	$7.91	$9.06	$7.45	$14.75	$12.37	$15.38	$8.49	$10.67	$7.70
2037	$12.61	$11.37	$12.76	$8.06	$9.22	$7.60	$14.91	$12.52	$15.54	$8.65	$10.83	$7.86
2038	$12.81	$11.57	$12.97	$8.27	$9.43	$7.81	$15.11	$12.73	$15.74	$8.85	$11.03	$8.06
Levelized	**$8.71**	**$7.47**	**$9.08**	**$5.74**	**$6.86**	**$5.34**	**$10.76**	**$8.52**	**$11.54**	**$6.33**	**$8.34**	**$5.64**

2. AVOIDED COSTS BY IRP AND STATE

Figure D.3: Oregon 20-year Levelized Costs by IRP

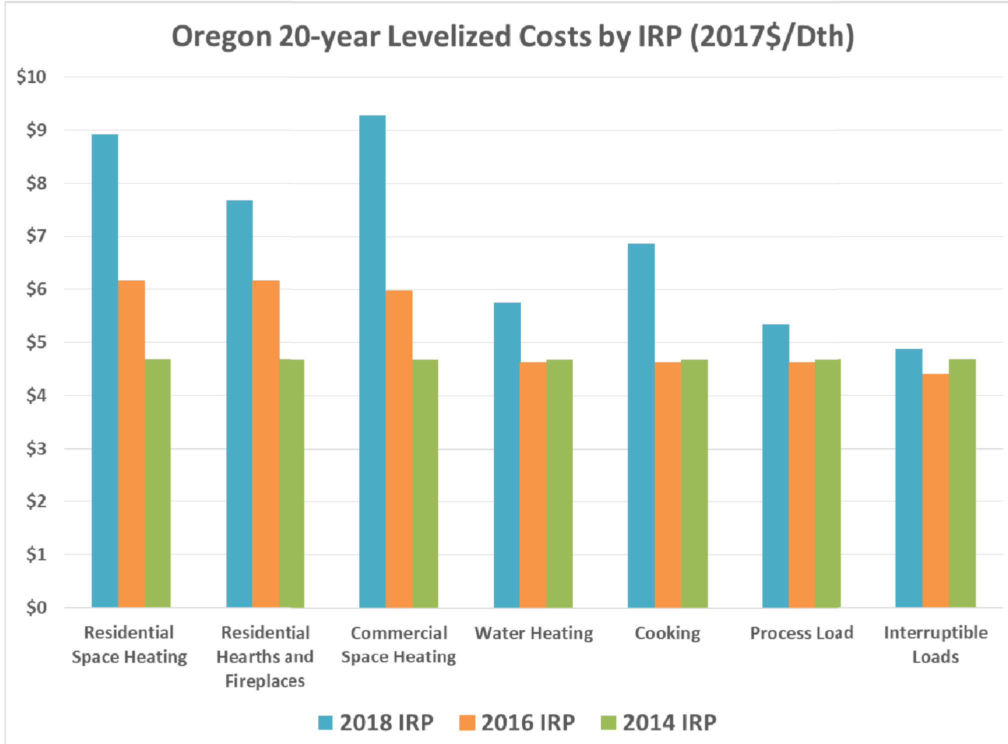
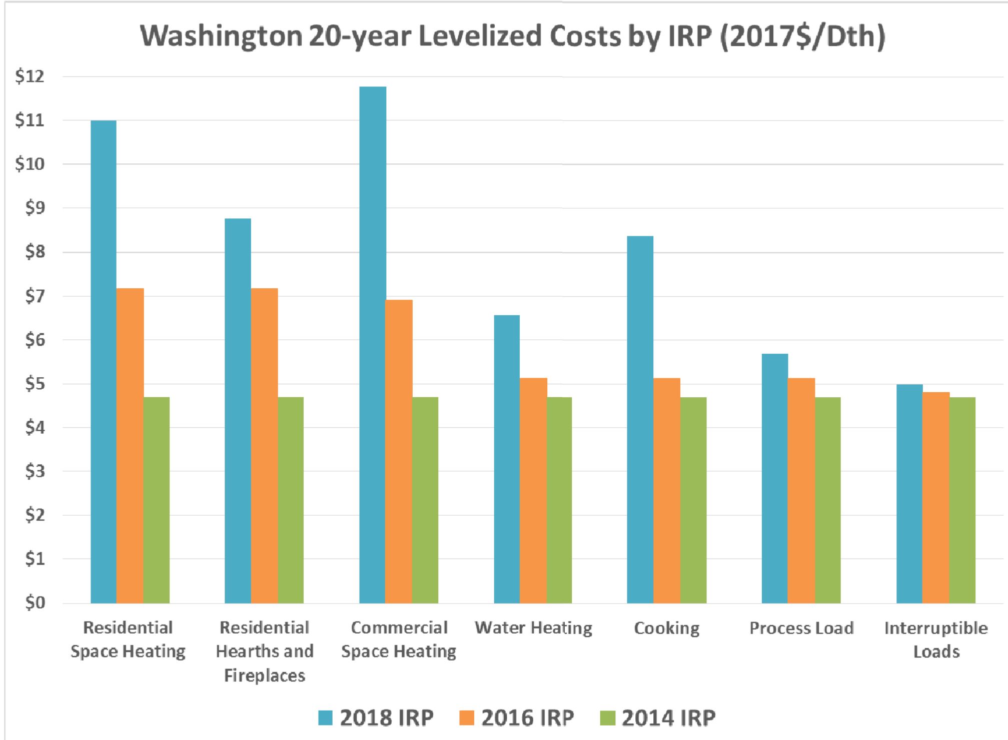


Figure D.4: Washington 20-year Levelized Costs by IRP



3. LEVELIZED AVOIDED COSTS BY STATE AND GHG COST SCENARIO

Figure D.5: Oregon 20-Year Avoided Costs by GHG Compliance Cost Scenario

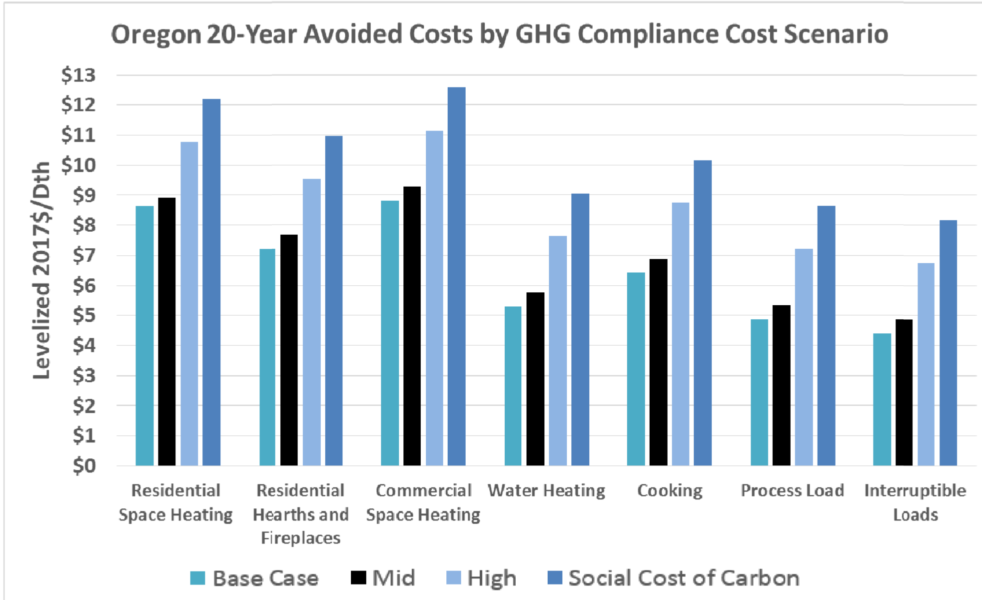
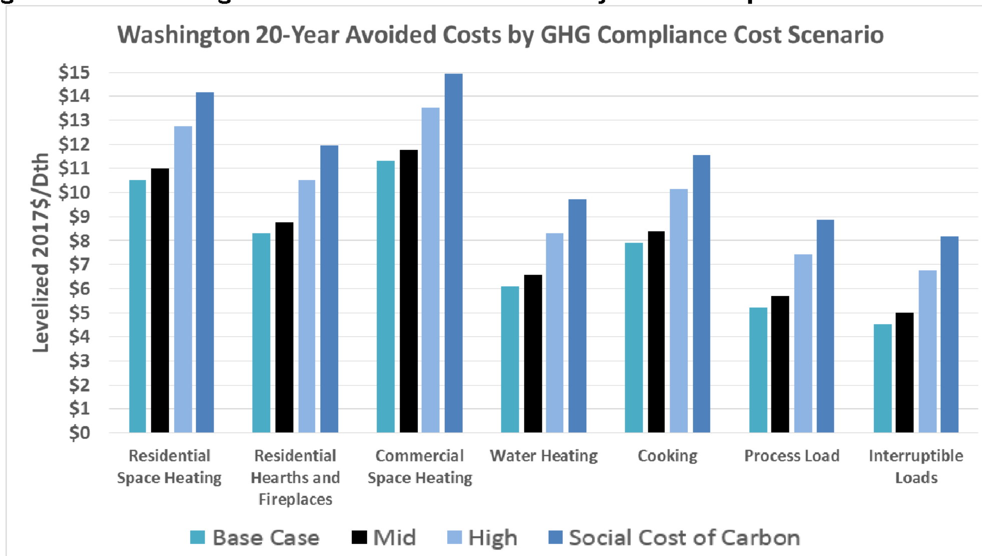


Figure D.6: Washington 20-Year Avoided Costs by GHG Compliance Cost Scenario



APPENDIX E

DEMAND-SIDE RESOURCES

1. OREGON SPECIFIC GRAPHS

Figure E.1: 20-year Savings Potential for Oregon by Sector and Potential Type.

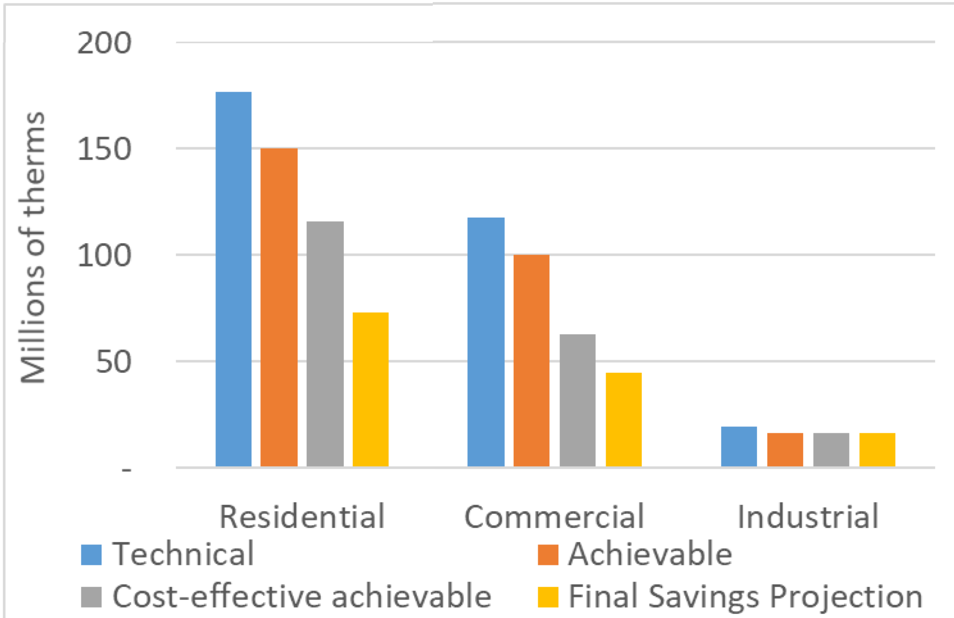


Figure E.2: Annual Savings History and IRP Savings Projection Comparison for Oregon

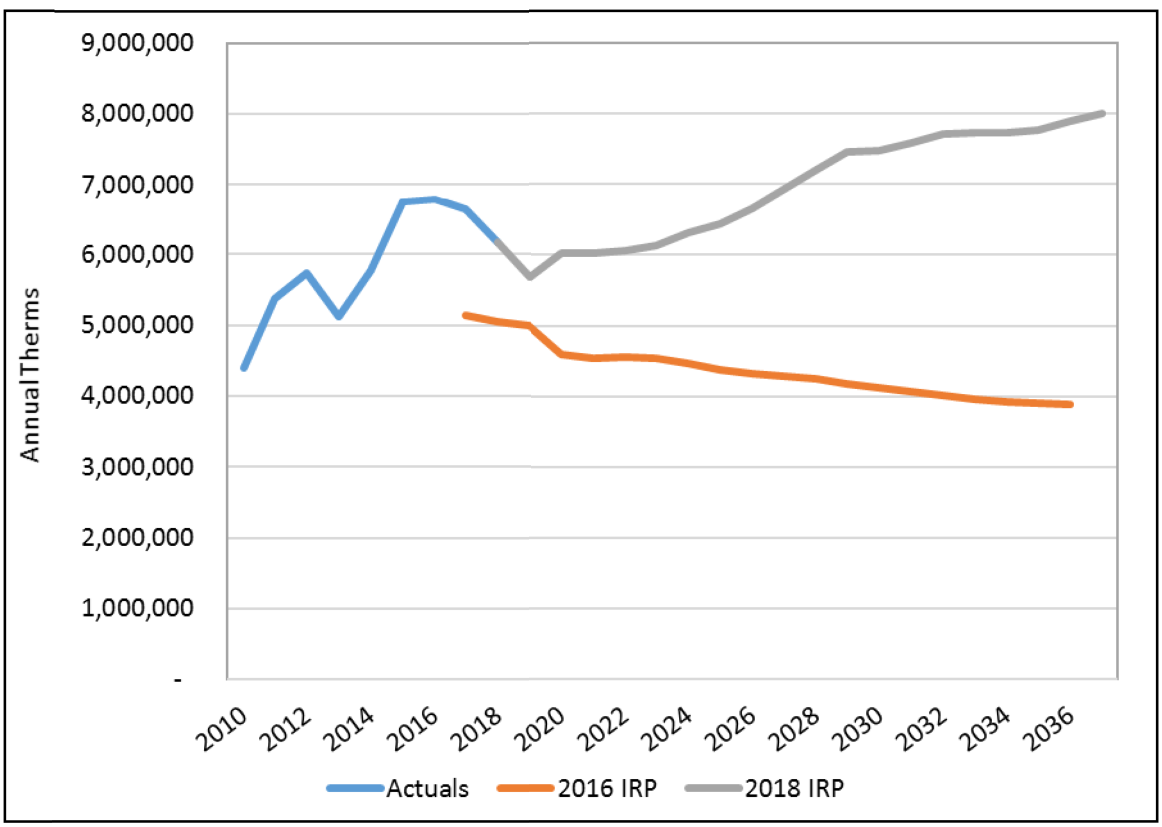


Table E.1: Summary of Cumulative Modeled Savings Potential - 2018–2037 for Oregon

	Technical Potential (Therms)	Achievable Potential (Therms)	Cost-effective achievable Potential (Therms)
Residential	176,924,084	150,385,472	115,796,692
Commercial	117,601,754	99,961,491	62,789,802
Industrial	19,581,139	16,643,968	16,529,760
Efficiency Total	314,106,978	266,990,931	195,116,254

Figure E.3: Summary of Cumulative Modeled Savings Potential for Oregon - 2018–2037 - by Sector and type of Potential

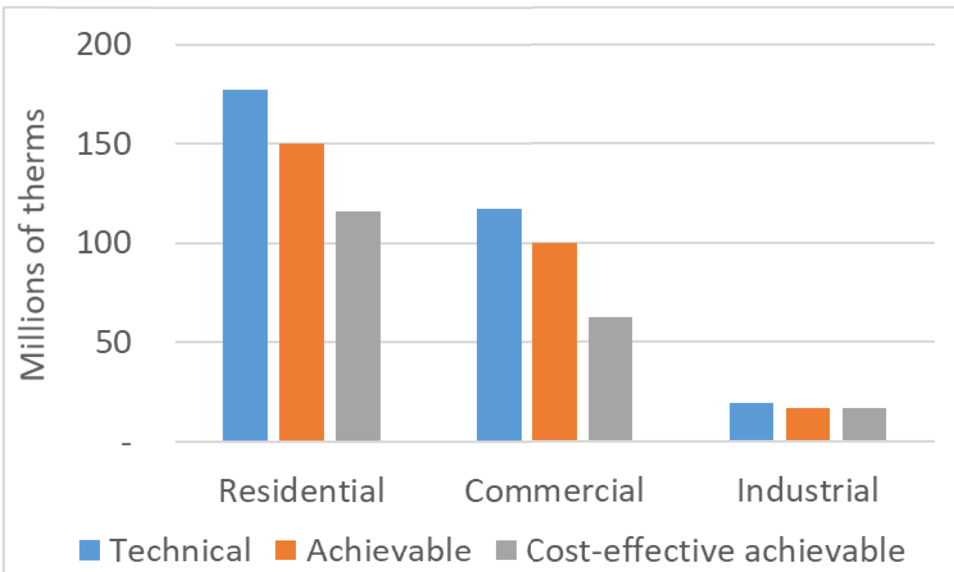


Figure E.4: 20-year Cumulative Cost-Effective Potential for Oregon by End Use

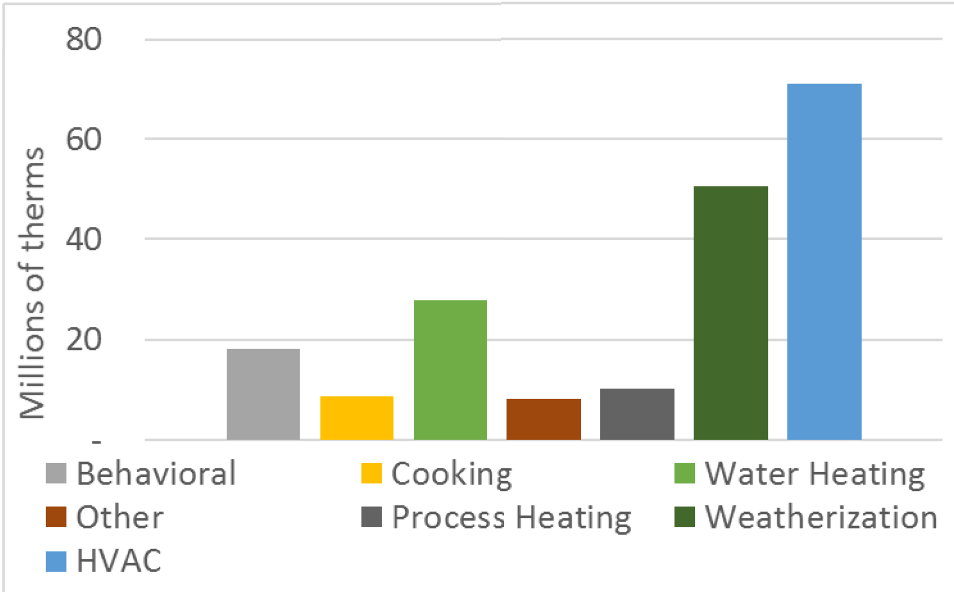


Figure E.5: Cumulative 20-year potential for Oregon by savings type, detailing the contributions of commercially available and emerging technology.

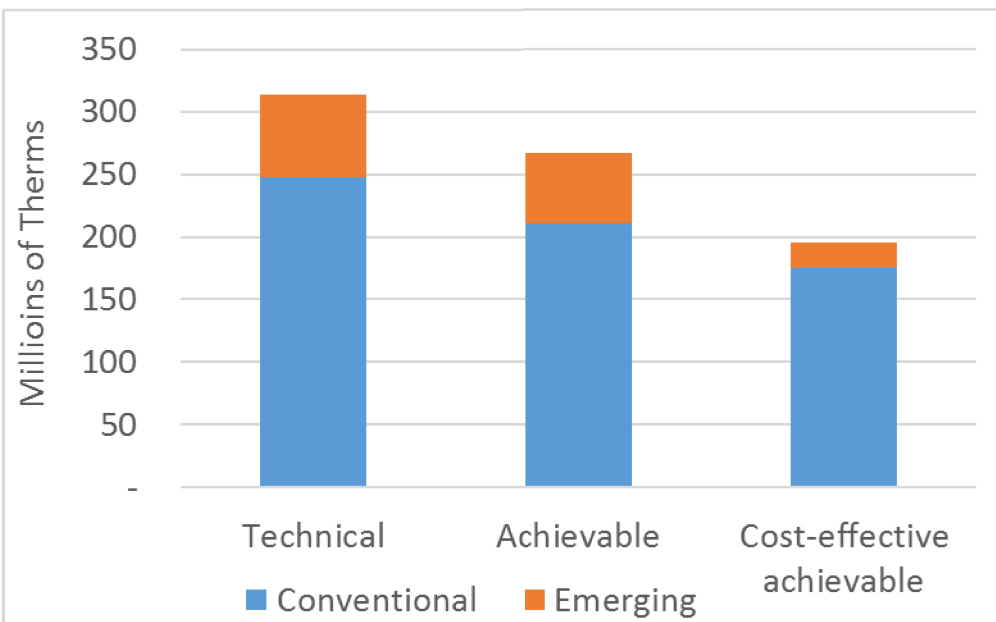


Table E.2: Cumulative Cost-Effective Potential for Oregon (2018-2037) due to use of Cost-effectiveness override

Sector	Yes CE Override	No CE Override	Difference
Residential	115.80	107.42	8.37
Commercial	62.79	62.79	-
Industrial	16.53	16.53	-
Total DSM:	195.12	186.74	8.37

Figure E.6: 20-year Gas Supply Curve for Oregon showing the approximate levelized cost cutoffs from the 2016 IRP and the current 2018 IRPs.

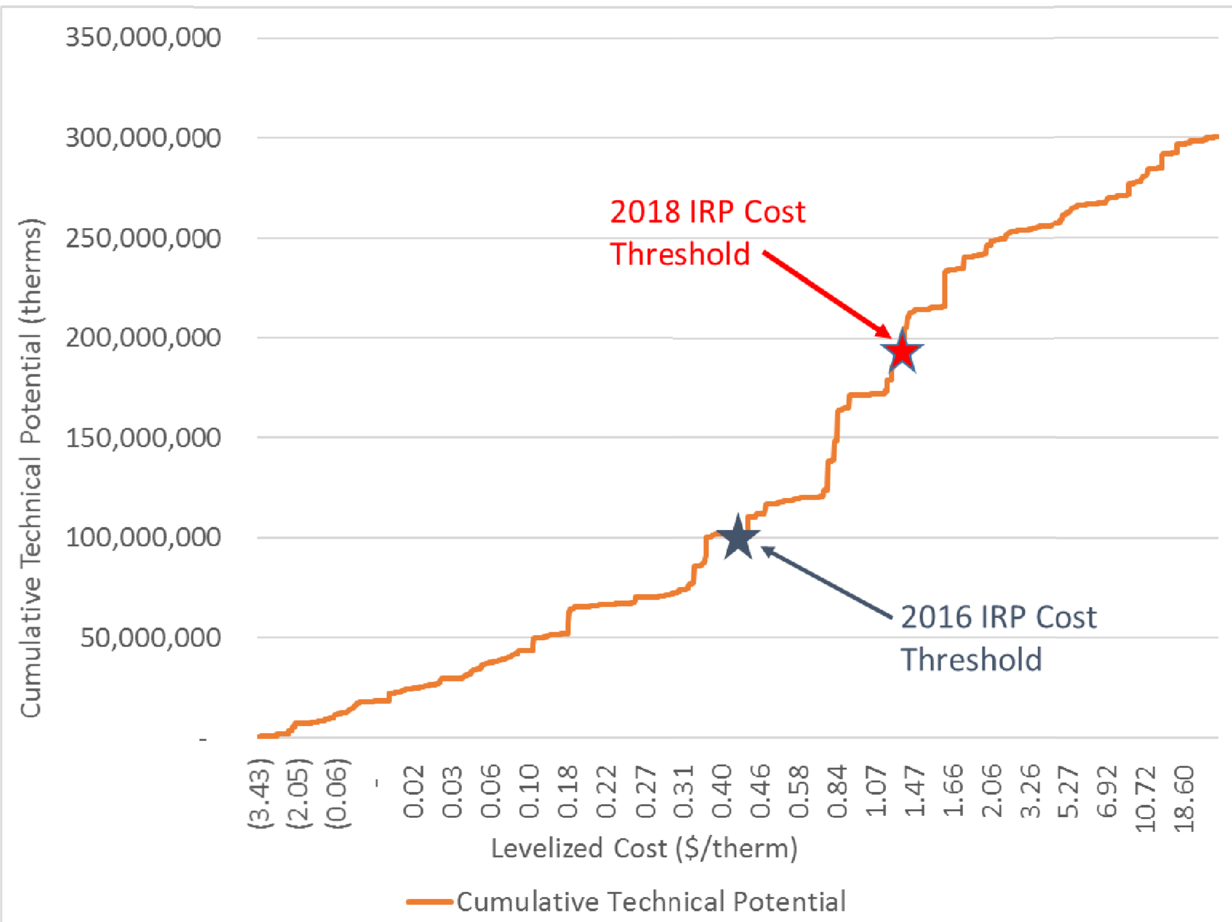


Table E.3: Total 2018 IRP Cost-Effective Modeled Potential for Oregon compared to 2016 IRP modeled potential by Sector

	Total Potential 2016 IRP (Millions of therms)	Total Potential 2018 IRP (Millions of therms)
Residential	33.53	115.8
Commercial	51.23	62.79
Industrial	17.14	16.53
All DSM	101.9	195.12

Table E.3: Key Changes in Model that Increased Potential for Oregon from 2016 IRP to 2018 IRP

Change Component	Change in DSM Savings (Millions of Therms) from 2016 to 2018	% of Total
Measure Exceptions	(7.00)	-8%
Emerging Technology	9.02	10%
RES Smart T-Stats	13.81	15%
Change in Avoided Costs	26.10	29%
Change in Model Assumptions	49.63	54%
Total Change from 2016 to 2018 IRP	91.57	100%

Table E.4: 20-Year Cumulative Savings Potential for Oregon by type, including final savings projection

	Technical	Achievable	Cost-effective	Energy Trust Savings Projection
Residential	176.92	150.39	115.8	72.83
Commercial	117.6	99.96	62.79	45.01
Industrial	19.58	16.64	16.53	16.40
Other	0	0	0	4.71
All DSM	314.11	266.99	195.12	138.95

Figure E.7: 20-Year Annual Savings Projection for Oregon by Sector

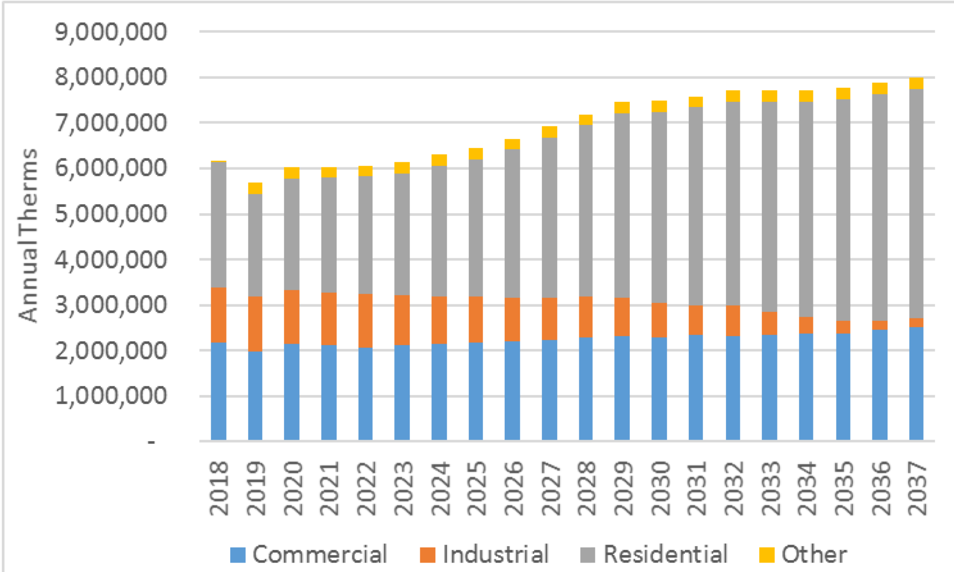


Figure E.8: Annual Savings Projection for Oregon by Sector-Measure Type

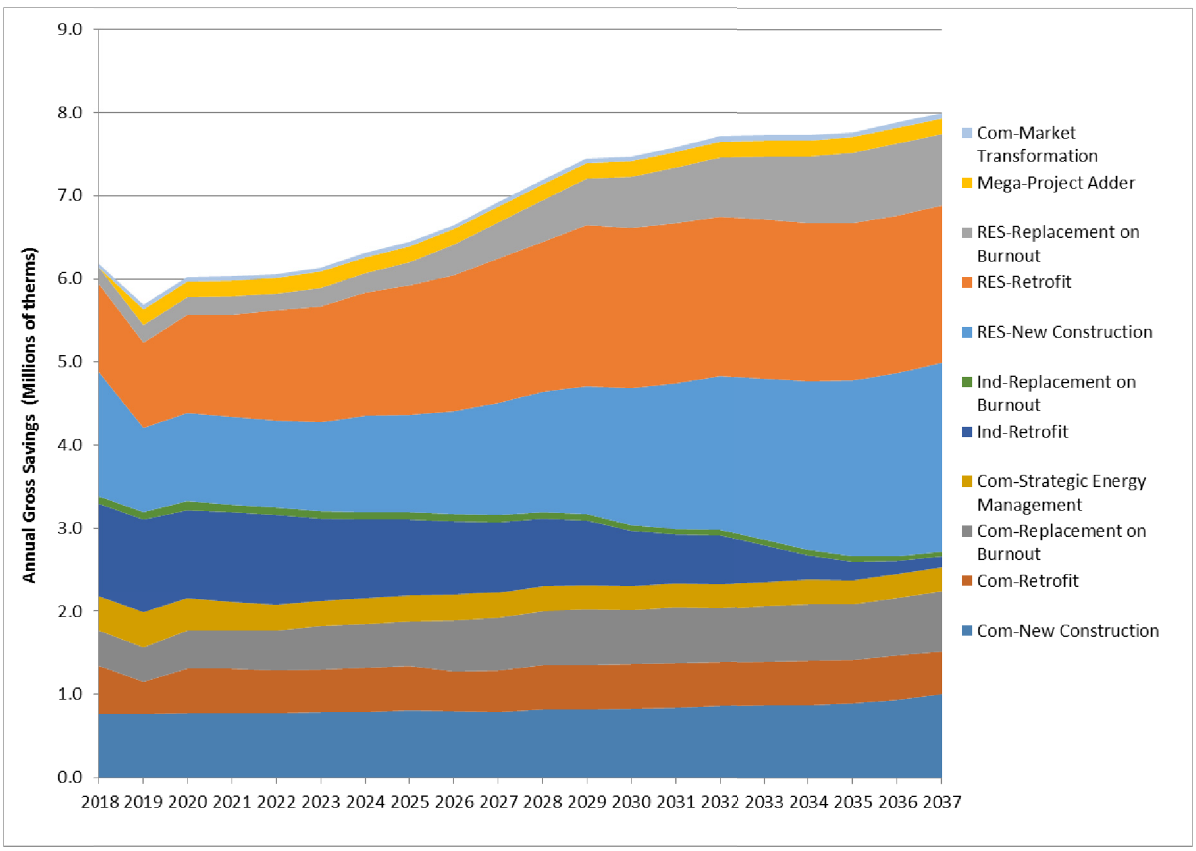


Figure E.9: NW Natural's Annual Peak-Day Savings Projection for Oregon by Sector

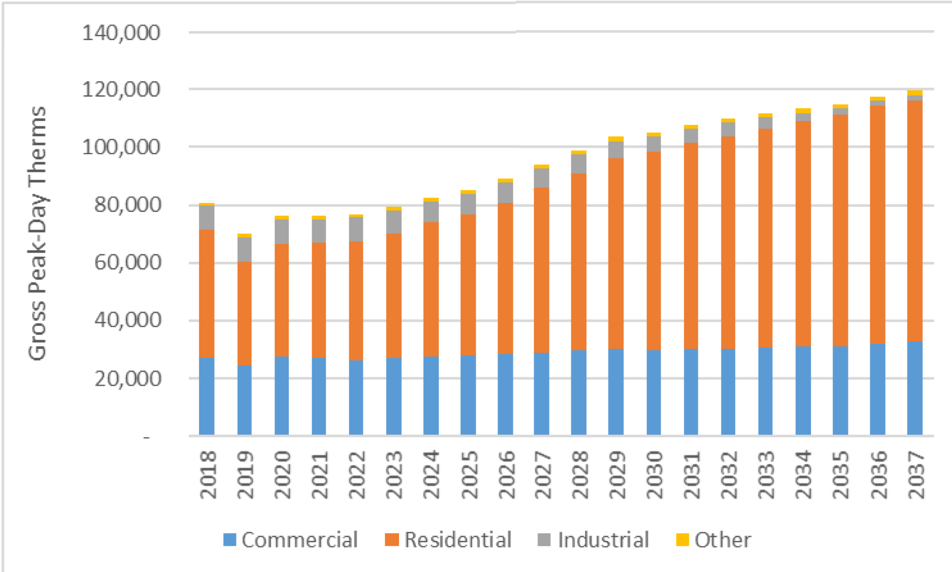
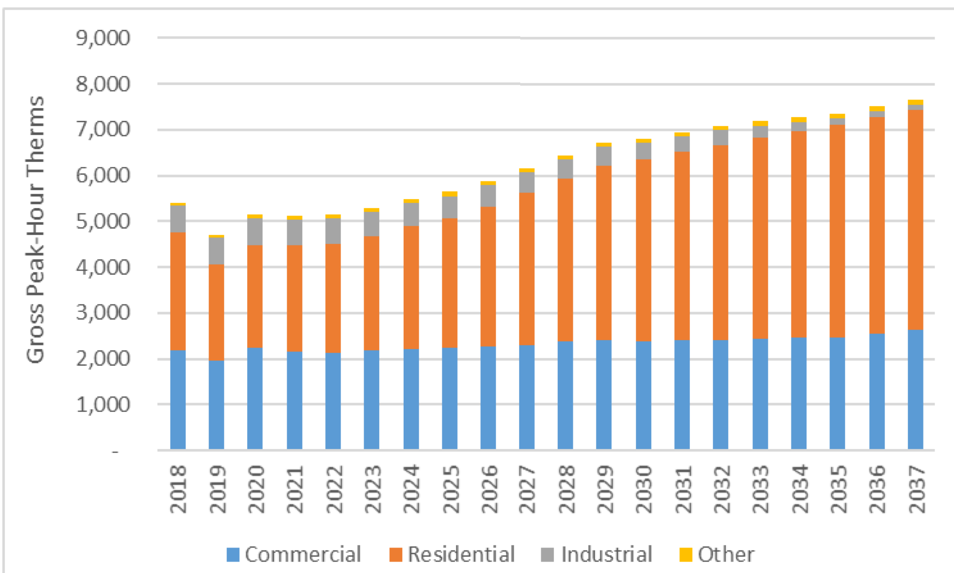


Figure E.10: NW Natural's Annual Peak-Hour Savings Projection for Oregon by Sector



2. WASHINGTON SPECIFIC GRAPHS

Figure E.11: 20-year Savings Potential for Washington by Sector and Potential Type.

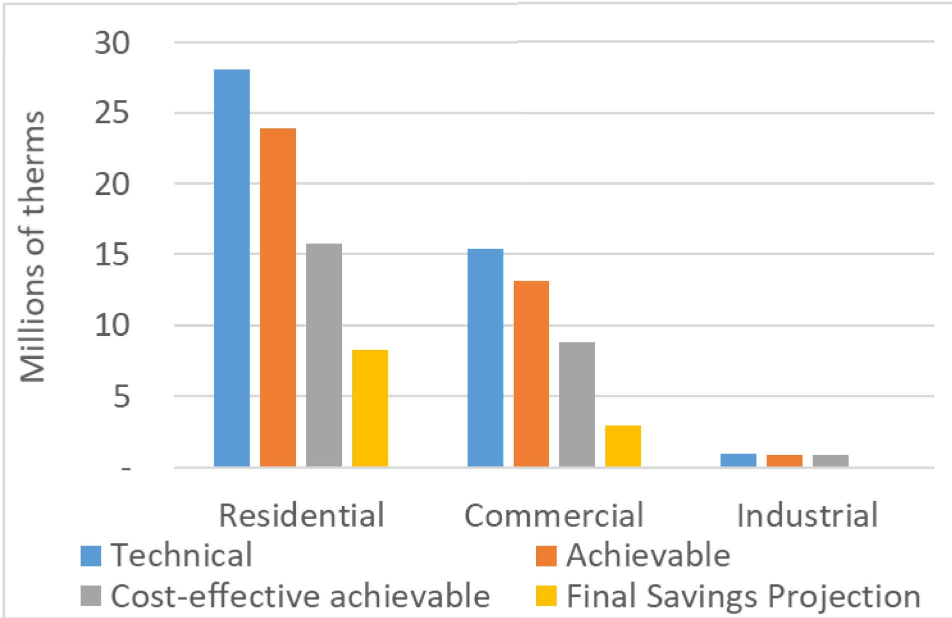


Figure E.12: Annual Savings Projection Comparison for Washington for 2016 and 2018 IRPs, with Actual savings since 2010

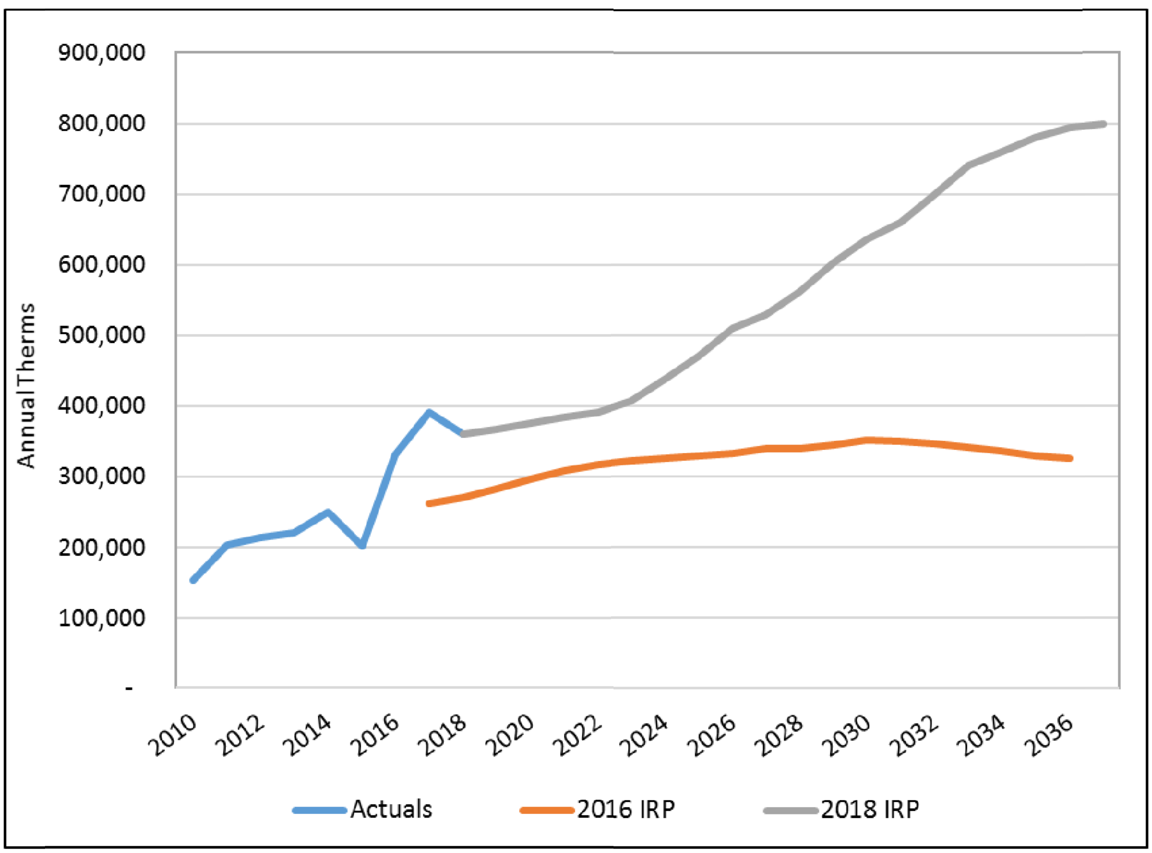


Table E.5: Summary of Cumulative Modeled Savings Potential for Washington - 2018–2037

	Technical Potential (Therms)	Achievable Potential (Therms)	Cost-effective achievable Potential (Therms)
Residential	28,077,972	23,866,276	15,761,717
Commercial	15,427,298	13,113,203	8,786,427
Industrial	979,856	832,878	832,878
Efficiency Total	44,485,126	37,812,357	25,381,021

Figure E.13: Summary of Cumulative Modeled Savings Potential for Washington - 2018–2037 - by Sector and type of Potential

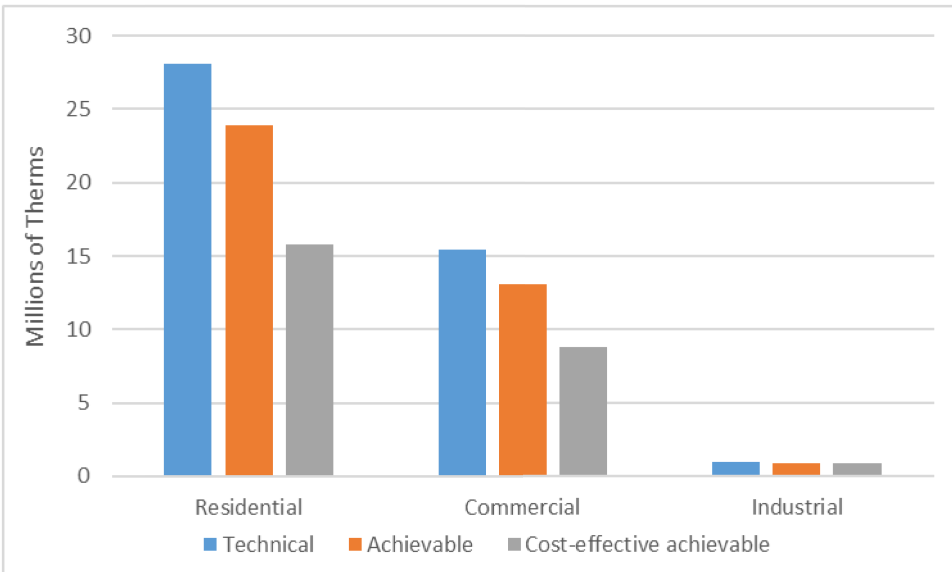


Figure E.14: 20-year Cumulative Cost-Effective Potential for Washington by End Use

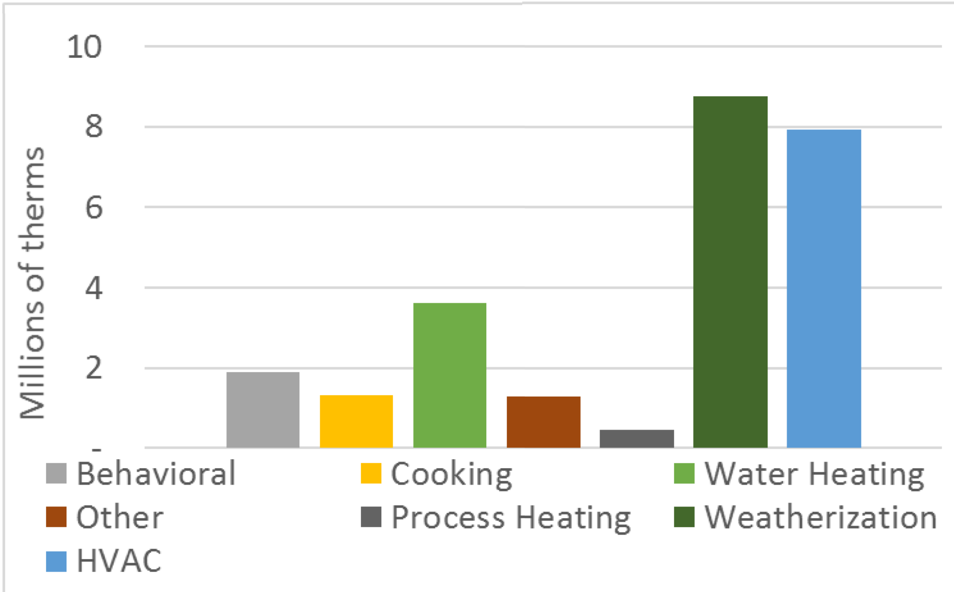


Figure E.15: Cumulative 20-year potential by savings type for Washington, detailing the contributions of commercially available and emerging technology.

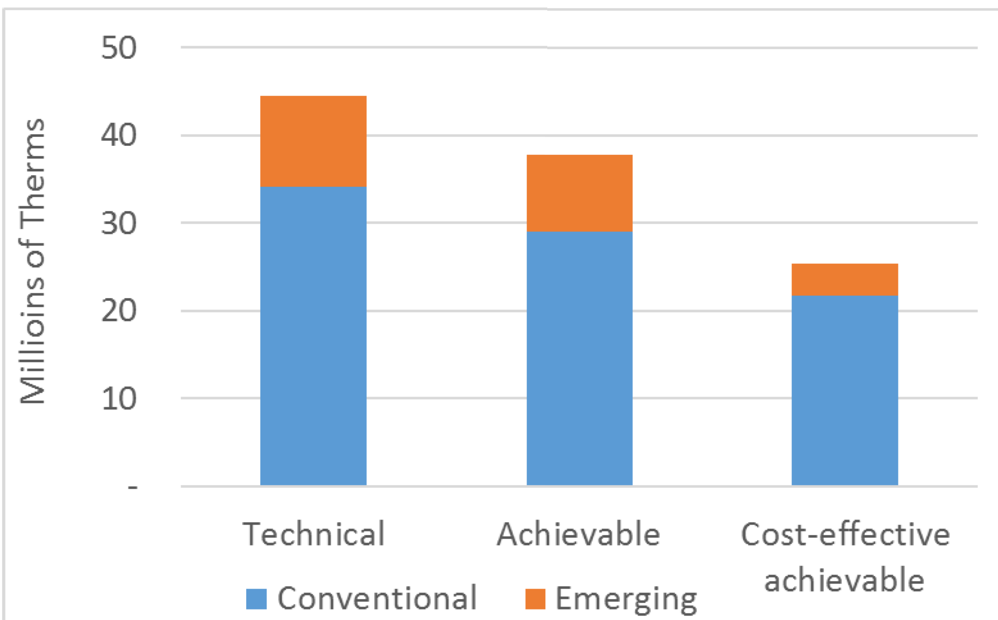


Table E.6: Cumulative Cost-Effective Potential for Washington (2018-2037) due to use of Cost-effectiveness override

Sector	Yes CE Override	No CE Override	Difference
Residential	15.76	15.32	0.44
Commercial	8.79	8.79	-
Industrial	0.83	0.83	-
Total DSM:	25.38	24.94	0.44

Figure E.16: 20-year Gas Supply Curve for Washington showing the approximate levelized cost cutoffs from the 2016 IRP and the current 2018 IRPs.

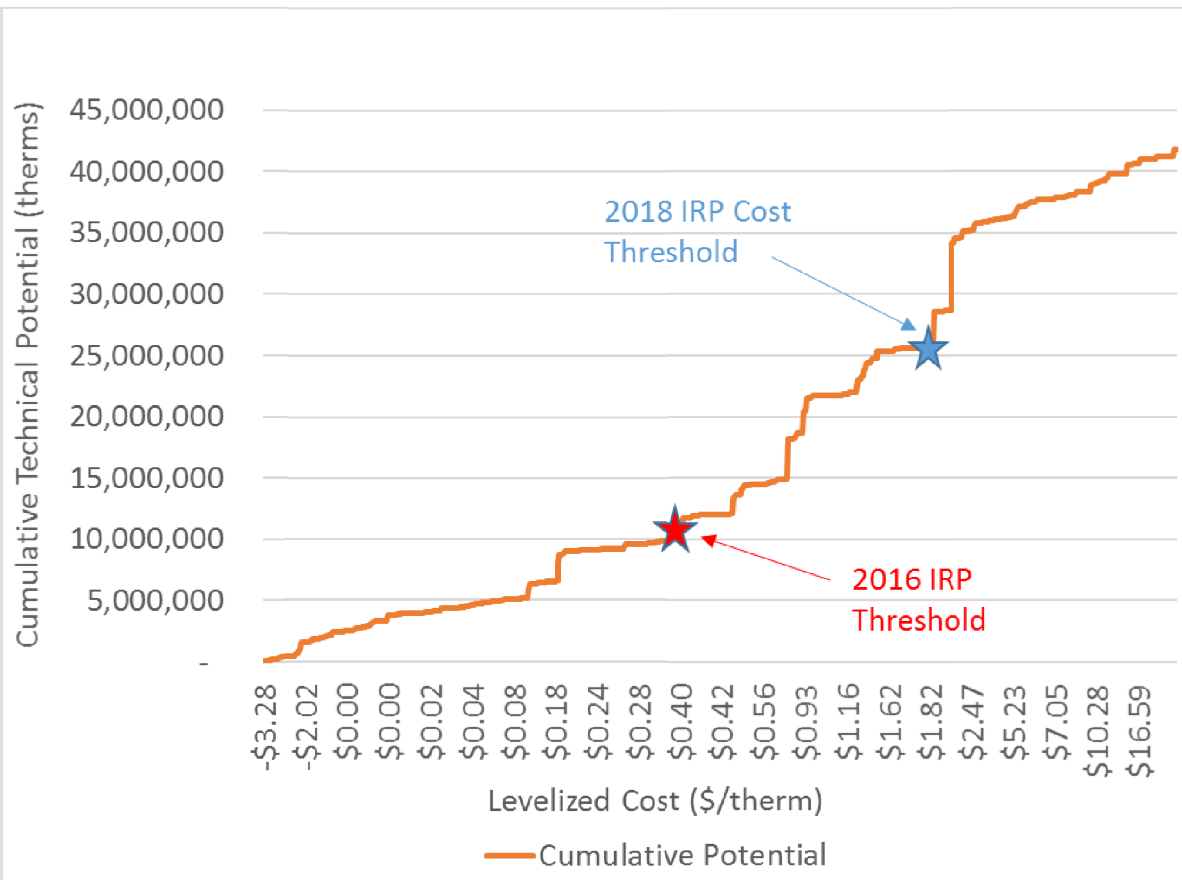


Table E.7: Total 2018 IRP Cost-Effective Modeled Potential for Washington compared to 2016 IRP modeled potential by Sector

	Total Potential 2016 IRP (Millions of therms)	Total Potential 2018 IRP (Millions of therms)
Residential	5.67	15.76
Commercial	4.87	8.79
Industrial	0.52	0.83
All DSM	11.07	25.38

Table E.8: Key Changes in Model that Increased Potential for Washington from 2016 IRP to 2018 IRP

Change Component	Change in DSM Savings (Millions of Therms) from 2016 to 2018	% of Total
Measure Exceptions	(7.10)	-47%
Emerging Technology	2.10	14%
RES Smart T-Stats	1.46	10%
Change in Avoided Costs	2.48	16%
Change in Model Assumptions	16.26	107%
Total Change from 2016 to 2018 IRP	**15.20**	**100%**

Table E.9: 20-Year Cumulative Savings Potential for Washington by type, including final savings projection

	Technical	Achievable	Cost-effective	Energy Trust Savings Projection
Residential	28.08	23.87	15.76	8.31
Commercial	15.43	13.11	8.79	2.96
Industrial	0.98	0.83	0.83	0
All DSM	44.49	37.81	25.38	11.27

Figure E.17: 20-Year Annual Savings Projection for Washington by Sector

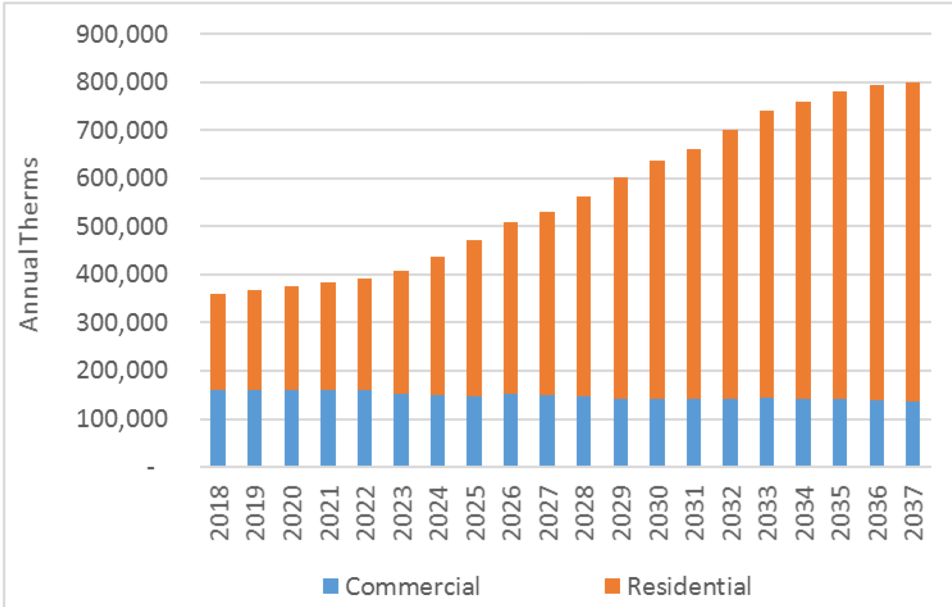


Figure E.18: Washington Annual Savings Projection for Washington by Sector-Measure Type

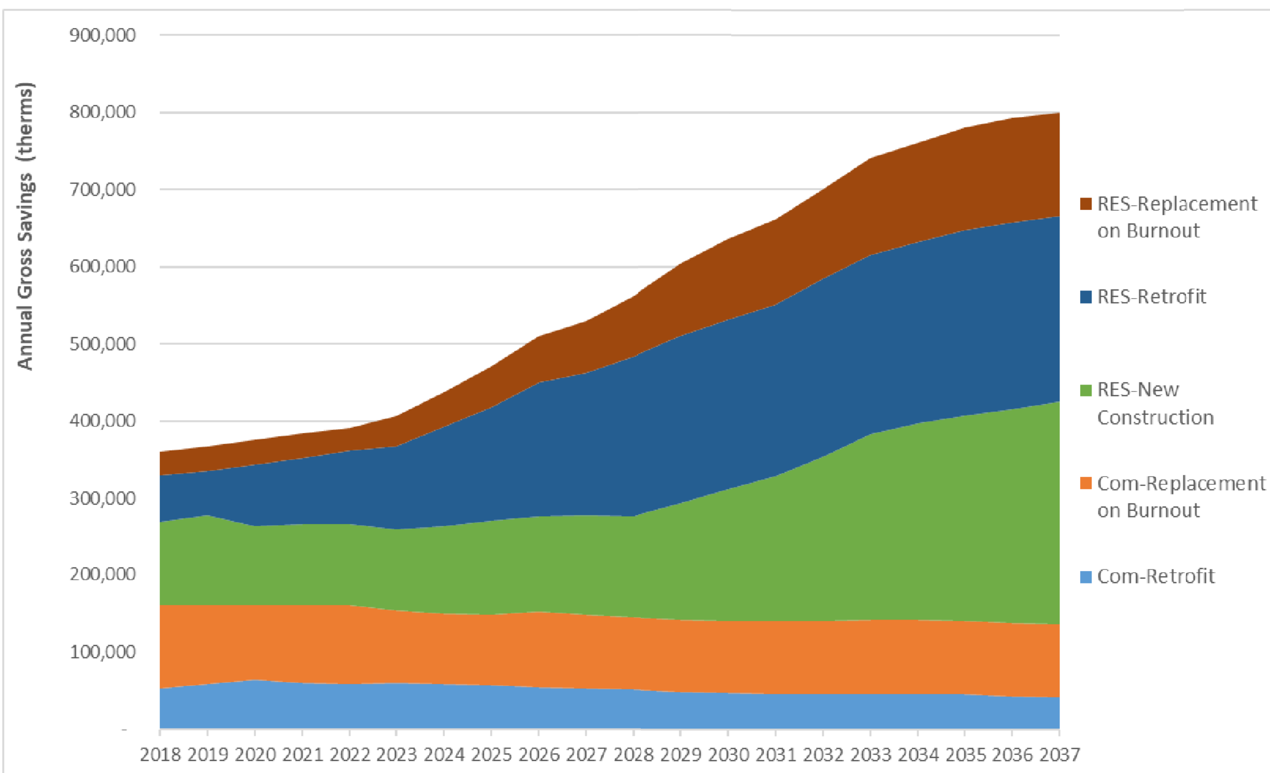


Figure E.19: NW Natural's Annual Peak-Day Savings for Washington Projection by Sector

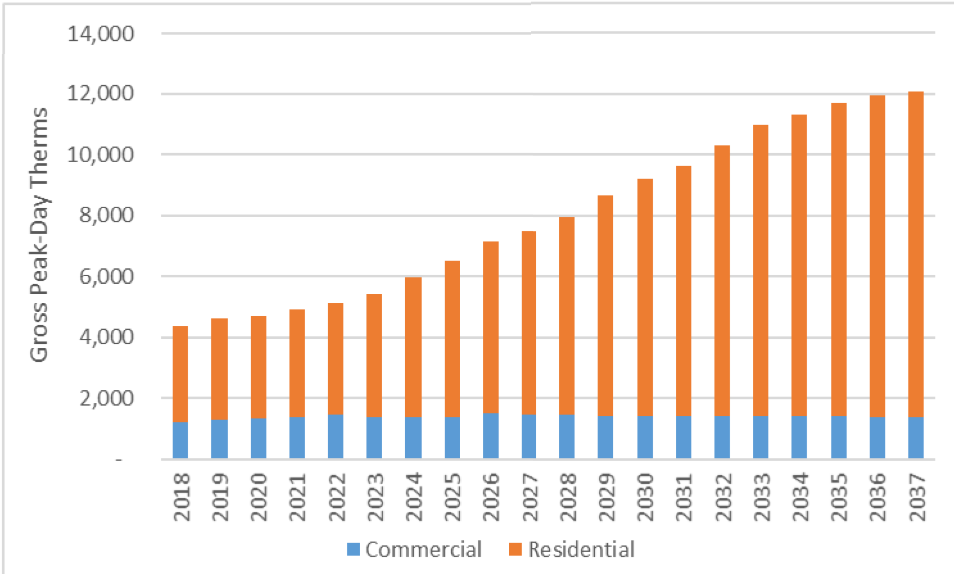
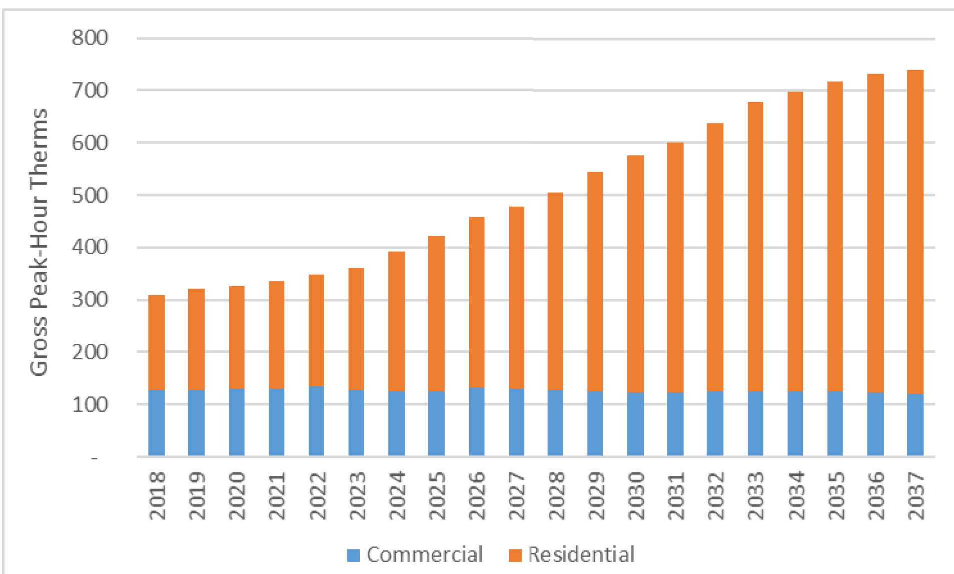


Figure E.20: NW Natural's Annual Peak-Hour Savings for Washington Projection by Sector



3. DEPLOYMENT SUMMARY

Table E.10: Oregon Deployment Summary 2018-2027

Oregon 20-Year Cost-Effective DSM Savings Projection

Sector	Type	End Use	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Commercial	New Construction	Cooling	-	-	-	-	-	-	9,146	8,919	8,725	8,633
		Heating	490,944	348,116	412,043	407,032	405,160	373,740	365,888	358,304	353,061	349,333
		Other	-	212,236	248,112	248,230	246,189	302,084	294,683	327,937	321,008	317,736
		Water Heating	220,763	160,842	80,947	84,593	87,956	80,807	78,486	77,233	75,443	74,106
		Weatherization	41,419	31,617	30,971	32,184	32,707	29,082	28,853	28,959	28,383	27,930
		Behavioral	-	-	-	-	-	-	-	-	-	-
		Appliance	1,016	753	127	161	187	168	160	160	155	150
	Retrofit	Heating	350,807	255,007	348,338	338,898	326,003	324,725	335,894	334,580	299,945	312,093
		Ventilation	62,849	36,284	48,699	47,375	45,446	45,263	46,815	46,627	41,796	43,478
		Water Heating	1,473	848	1,134	19,547	19,096	20,452	28,637	28,539	25,597	26,643
		Weatherization	164,302	97,130	130,303	126,698	121,482	120,933	125,021	124,460	111,512	115,946
	Replacement on Burnout	Cooking	129,905	122,497	149,538	142,749	141,493	139,576	138,086	136,047	133,923	132,425
		Heating	142,720	139,275	147,041	147,339	170,385	201,221	208,736	219,912	300,743	319,540
		Water Heating	155,694	155,335	167,255	169,702	168,403	173,521	179,275	183,909	187,681	191,551
	Strategic Energy Management	Behavioral	411,787	424,140	381,726	343,553	309,198	307,934	306,677	305,427	304,183	302,944
Industrial	Retrofit	HVAC	243,121	242,843	230,955	234,756	234,312	215,482	207,324	199,350	191,376	183,402
		Other	101,583	101,505	96,536	98,125	97,940	90,069	86,659	83,326	79,993	76,660
		Process Heating	779,113	778,055	739,966	752,146	754,092	693,490	667,233	645,055	619,253	593,451
	Replacement on Burnout	HVAC	21,943	21,967	25,258	22,182	21,356	20,226	19,517	19,274	18,703	17,877
		Water Heating	66,802	68,193	86,150	71,654	71,164	68,055	67,050	68,368	67,906	66,039
Residential	New Construction	Behavioral	42,059	28,852	29,763	29,583	29,425	23,708	12,006	12,633	13,483	14,506
		Heating	1,704	1,168	1,253	1,247	1,240	227,240	730,644	716,968	765,590	836,869
		Water Heating	493,745	338,670	350,060	347,887	346,005	278,796	141,184	148,555	158,561	170,582
		Weatherization	949,016	648,814	679,480	673,620	669,439	539,599	273,293	287,528	306,845	330,156
	Retrofit	Behavioral	66,027	61,205	69,351	69,293	71,016	70,817	70,619	70,421	70,224	70,027
		Water Heating	201,667	186,941	213,976	213,798	219,113	218,500	217,888	217,278	216,670	216,063
		Heating	139,167	172,978	215,003	267,237	332,162	406,700	496,288	574,499	653,454	761,828
		Weatherization	650,279	602,793	683,017	682,448	699,414	697,644	696,500	694,550	692,605	690,666
	Replacement on Burnout	Appliance	3,971	3,758	3,595	3,375	3,040	3,336	3,437	4,049	5,086	5,982
		Heating	69,218	66,552	64,209	61,391	56,074	62,374	65,229	78,046	99,553	118,967
		Water Heating	74,171	68,465	63,199	58,337	51,157	54,678	55,060	63,531	78,192	90,222
		Weatherization	52,837	72,053	82,937	96,733	92,024	105,404	112,902	137,818	179,208	217,959
Other	Mega-Project Adder	Other	-	189,723	189,723	189,723	189,723	189,723	189,723	189,723	189,723	189,723
	New Buildings Market Transformation	Other	46,550	47,129	48,034	49,056	50,048	50,670	51,643	52,742	53,808	54,832
	Commercial	**Total:**	**2,173,679**	**1,984,077**	**2,146,235**	**2,108,062**	**2,073,707**	**2,119,505**	**2,146,358**	**2,181,012**	**2,192,154**	**2,222,509**
	Industrial	**Total:**	**1,212,562**	**1,212,562**	**1,178,864**	**1,178,864**	**1,178,864**	**1,087,322**	**1,047,783**	**1,015,372**	**977,230**	**937,428**
	Residential	**Total:**	**2,743,860**	**2,252,250**	**2,455,841**	**2,504,950**	**2,570,109**	**2,688,795**	**2,875,050**	**3,005,876**	**3,239,470**	**3,523,825**
	Other	**Total:**	**46,550**	**236,852**	**237,757**	**238,779**	**239,771**	**240,393**	**241,366**	**242,465**	**243,531**	**244,555**
	Energy Efficiency	**Total:**	**6,176,651**	**5,685,742**	**6,018,697**	**6,030,655**	**6,062,451**	**6,136,016**	**6,310,556**	**6,444,726**	**6,652,386**	**6,928,317**

Table E.10: Oregon Deployment Summary 2028-2037

Oregon 20-Year Cost-Effective DSM Savings Projection

Sector	Type	End Use	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Commercial	New Construction	Cooling	8,591	8,635	8,661	8,789	8,884	9,012	9,106	10,958	11,778	12,476	**132,312**
		Heating	346,582	348,058	349,717	354,415	358,928	363,592	368,277	373,008	401,060	425,332	**7,552,592**
		Other	349,569	351,053	352,447	366,427	370,785	375,622	380,216	385,020	403,616	427,620	**6,280,591**
		Water Heating	73,224	73,133	73,244	73,513	73,748	74,054	74,252	74,471	79,375	83,418	**1,773,610**
		Weatherization	37,427	37,603	37,772	38,261	41,110	41,633	42,046	42,638	45,715	48,470	**724,780**
		Behavioral	-	-	301	297	292	288	283	277	290	298	**2,325**
		Appliance	146	145	145	142	140	138	136	133	139	143	**4,443**
	Retrofit	Heating	330,717	329,426	328,733	327,452	326,176	324,906	323,641	322,382	321,128	319,880	**6,480,732**
		Ventilation	46,068	45,884	45,700	45,517	45,335	45,154	44,974	44,794	44,616	44,438	**917,112**
		Water Heating	28,247	28,150	40,203	40,082	39,961	39,841	39,721	39,602	39,483	39,364	**546,619**
		Weatherization	122,795	122,246	121,699	121,156	120,615	120,077	119,542	119,010	118,481	117,954	**2,441,362**
	Replacement on Burnout	Cooking	131,353	131,187	123,102	124,826	119,280	122,040	124,994	121,677	125,621	129,641	**2,619,959**
		Heating	329,287	340,284	329,014	341,773	333,353	346,487	359,389	352,962	366,474	379,852	**5,475,786**
		Water Heating	195,184	199,423	190,696	196,004	189,261	194,872	200,355	195,180	201,197	207,084	**3,701,583**
	Strategic Energy Management	Behavioral	301,712	300,485	299,263	298,048	296,838	295,634	294,435	293,242	292,054	290,872	**6,360,152**
Industrial	Retrofit	HVAC	175,425	167,452	143,530	127,582	127,582	95,687	63,791	47,843	33,490	28,706	**3,194,008**
		Other	73,326	69,993	59,994	53,328	53,328	39,996	26,664	19,998	13,999	11,999	**1,335,017**
		Process Heating	567,641	541,840	464,434	412,830	412,830	309,623	206,415	154,811	108,368	92,887	**10,293,534**
	Replacement on Burnout	HVAC	16,519	15,608	14,759	13,955	13,199	12,485	11,812	11,177	10,578	10,014	**338,409**
		Water Heating	61,812	59,703	57,738	55,845	54,036	52,299	50,635	49,038	47,507	46,038	**1,236,033**
Residential	New Construction	Behavioral	15,509	16,535	17,757	18,853	19,902	20,916	21,895	22,832	23,731	24,596	**438,544**
		Heating	894,722	953,986	1,017,535	1,080,204	1,140,384	1,198,442	1,254,548	1,308,289	1,359,803	1,409,265	**14,901,103**
		Water Heating	182,385	194,451	207,376	220,191	232,427	244,280	255,710	266,657	277,149	287,256	**5,141,927**
		Weatherization	352,962	376,314	401,339	426,060	449,800	472,697	494,838	516,047	536,372	555,888	**9,940,106**
	Retrofit	Behavioral	69,831	69,635	70,755	70,557	70,359	70,162	69,966	69,770	69,575	69,380	**1,388,987**
		Water Heating	215,458	214,855	214,253	213,653	213,055	212,458	211,863	211,270	210,679	210,089	**4,249,527**
		Heating	833,397	848,990	846,612	844,242	841,878	839,521	837,170	834,826	832,489	830,158	**12,408,598**
		Weatherization	688,732	799,302	797,064	794,832	792,607	790,387	788,174	785,968	783,767	781,572	**14,592,321**
	Replacement on Burnout	Appliance	6,767	7,460	8,082	8,630	9,106	9,521	9,880	10,189	10,453	10,064	**129,779**
		Heating	136,590	152,639	167,348	180,668	192,660	203,431	213,065	221,634	229,218	222,328	**2,661,194**
		Water Heating	99,938	107,626	113,539	117,906	120,929	122,790	123,649	123,649	122,917	114,576	**1,824,532**
		Weatherization	255,010	290,827	326,062	360,182	392,742	424,051	454,021	482,657	510,011	505,378	**5,150,815**
Other	Mega-Project Adder	Other	189,723	189,723	189,723	189,723	189,723	189,723	189,723	189,723	189,723	189,723	**3,604,745**
	New Buildings Market Transformation	Other	55,830	56,804	57,755	58,694	59,625	60,563	61,506	62,466	63,441	64,432	**1,105,624**
	Commercial	**Total:**	**2,300,903**	**2,315,710**	**2,300,699**	**2,336,703**	**2,324,705**	**2,353,350**	**2,381,368**	**2,375,354**	**2,451,027**	**2,526,841**	**45,013,956**
	Industrial	**Total:**	**894,724**	**854,595**	**740,454**	**663,541**	**660,975**	**510,089**	**359,317**	**282,868**	**213,942**	**189,644**	**16,397,001**
	Residential	**Total:**	**3,751,302**	**4,032,620**	**4,187,723**	**4,335,978**	**4,475,849**	**4,608,658**	**4,734,779**	**4,853,787**	**4,966,162**	**5,020,549**	**72,827,433**
	Other	**Total:**	**245,554**	**246,528**	**247,478**	**248,417**	**249,349**	**250,286**	**251,230**	**252,189**	**253,164**	**254,156**	**4,710,369**
	Energy Efficiency	**Total:**	**7,192,482**	**7,449,452**	**7,476,355**	**7,584,638**	**7,710,878**	**7,722,382**	**7,726,694**	**7,764,197**	**7,884,296**	**7,991,190**	**138,948,759**

Table E.11: Washington Deployment Summary 2018-2027

Washington 20-Year Cost-Effective DSM Savings Projection

Sector	Type	End Use	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Commercial	Retrofit	Heating	31,081	34,619	36,850	33,680	33,273	33,071	31,568	30,822	30,018	29,221
		Ventilation	4,211	4,690	4,992	4,562	4,506	4,478	4,274	4,164	4,055	3,947
		Water Heating	5,089	5,651	7,027	7,538	7,430	9,620	9,172	8,926	8,683	8,442
		Weatherization	12,334	13,727	14,600	13,334	13,161	13,071	12,467	12,139	11,813	11,491
	Replacement on Burnout	Cooking	72,996	66,414	60,965	57,185	51,727	45,575	43,102	40,830	38,309	36,072
		Heating	13,174	13,593	14,023	21,636	28,421	27,037	27,778	30,147	38,663	39,229
		Water Heating	21,114	21,306	21,543	22,064	21,483	20,234	20,449	20,576	20,283	19,973
Residential	New Construction	Behavioral	5,520	5,901	5,205	5,335	5,334	5,344	5,767	6,160	6,282	6,470
		Heating	-	-	-	-	-	-	-	-	-	-
		Water Heating	51	49	566	591	578	610	614	703	722	702
		Weatherization	104,348	111,551	97,979	100,413	100,426	100,584	108,585	115,950	118,250	121,810
	Retrofit	Behavioral	2,644	2,390	3,397	3,476	3,604	3,905	4,270	4,824	5,754	6,197
		Water Heating	15,707	14,199	20,181	20,648	21,408	23,196	25,365	28,654	34,181	36,811
		Weatherization	26,394	23,861	33,912	34,697	35,974	38,978	49,226	55,609	66,337	71,441
		Heating	14,368	17,816	22,092	27,394	33,969	41,462	50,439	58,206	65,999	71,113
	Replacement on Burnout	Appliance	729	668	641	564	549	706	792	924	1,044	1,153
		Heating	9,051	8,354	8,135	7,246	7,080	9,156	10,338	12,133	13,788	15,312
		Water Heating	11,545	10,125	9,592	8,173	7,544	9,286	10,000	11,209	12,174	12,923
		Weatherization	9,523	12,548	13,602	14,939	15,244	20,342	23,599	28,386	33,008	37,473
	Commercial	**Total:**	**160,000**	**160,000**	**160,000**	**160,000**	**160,000**	**153,085**	**148,811**	**147,604**	**151,825**	**148,375**
	Residential	**Total:**	**199,880**	**207,462**	**215,302**	**223,476**	**231,709**	**253,568**	**288,995**	**322,757**	**357,539**	**381,404**
	Energy Efficiency	**Total:**	**359,880**	**367,462**	**375,302**	**383,476**	**391,709**	**406,653**	**437,806**	**470,361**	**509,364**	**529,779**

Table E.12: Washington Deployment Summary 2028-2037

Washington 20-Year Cost-Effective DSM Savings Projection

Sector	Type	End Use	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Commercial	Retrofit	Heating	28,429	26,969	25,521	25,421	25,321	25,222	25,123	25,025	23,615	22,869	**577,719**
		Ventilation	3,840	3,642	3,446	3,432	3,418	3,405	3,391	3,377	3,187	3,086	**78,104**
		Water Heating	8,203	7,772	7,346	7,309	7,271	7,234	7,198	7,161	6,750	6,530	**150,351**
		Weatherization	11,171	10,589	10,012	9,966	9,919	9,873	9,826	9,781	9,223	8,925	**227,422**
	Replacement on Burnout	Cooking	34,612	33,559	33,384	32,718	32,513	32,908	32,526	31,996	31,815	31,545	**840,752**
		Heating	39,379	39,852	40,934	41,346	42,269	43,227	43,592	43,441	43,354	43,275	**674,372**
		Water Heating	19,850	19,859	20,222	20,216	20,437	20,808	20,778	20,544	20,397	20,225	**412,360**
Residential	New Construction	Behavioral	3,220	3,696	4,225	4,652	5,246	5,929	6,288	6,566	6,845	7,128	**111,112**
		Heating	66,725	76,613	86,954	95,768	107,958	122,070	129,410	135,148	140,883	146,716	**1,108,245**
		Water Heating	375	403	486	497	596	626	706	733	759	786	**11,152**
		Weatherization	60,607	69,589	78,982	86,987	98,060	110,878	117,545	122,757	127,967	133,265	**2,086,533**
	Retrofit	Behavioral	7,014	7,537	7,886	8,031	8,553	8,692	8,828	9,150	9,281	9,227	**124,661**
		Water Heating	41,661	44,773	45,622	46,459	49,484	50,285	51,075	52,934	53,696	53,379	**729,718**
		Weatherization	80,853	86,893	88,540	90,164	96,034	97,589	99,122	102,731	104,209	103,594	**1,386,156**
		Heating	76,841	78,035	77,575	77,117	76,662	76,210	75,760	75,313	74,869	74,427	**1,165,666**
	Replacement on Burnout	Appliance	1,352	1,586	1,767	1,850	1,930	2,092	2,125	2,199	2,231	2,189	**27,090**
		Heating	18,030	21,210	23,630	24,738	25,776	27,882	28,240	29,113	29,423	28,717	**357,349**
		Water Heating	14,523	16,279	17,238	17,136	16,949	17,385	16,690	16,297	15,591	14,393	**265,052**
		Weatherization	45,150	54,391	62,145	66,706	71,210	78,906	81,807	86,291	89,173	88,954	**933,396**
	Commercial	**Total:**	**145,484**	**142,243**	**140,866**	**140,407**	**141,148**	**142,677**	**142,435**	**141,326**	**138,340**	**136,455**	**2,961,080**
	Residential	**Total:**	**416,350**	**461,006**	**495,048**	**520,105**	**558,458**	**598,544**	**617,596**	**639,230**	**654,927**	**662,774**	**8,306,129**
	Energy Efficiency	**Total:**	**561,834**	**603,249**	**635,914**	**660,512**	**699,606**	**741,221**	**760,031**	**780,555**	**793,267**	**799,229**	**11,267,209**

4. MEASURE LEVELS

Table E.13: 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 - Energy Recovery Ventilator - Gas Heating	Retrofit	Heating	20,895,233	17,760,948	-	0%	$13.10
Commercial	Com - SEM	Retrofit	Behavioral	18,680,900	15,878,765	15,878,765	25%	$0.70
Commercial	Com - ZNE	New Construction	Other	11,423,238	9,709,752	6,828,548	11%	$3.80
Commercial	Com - DDC HVAC Controls	New Construction	Heating	9,265,416	7,875,604	7,855,208	13%	$1.42
Commercial	Com - DOAS/HRV - GAS SH	Replacement On Burnout	Heating	5,550,977	4,718,331	3,058,027	5%	$0.35
Commercial	Com - DHW Condensing Tankless	Replacement On Burnout	Water Heating	5,526,342	4,697,391	4,697,391	7%	$0.32
Commercial	Com - Demand Control Ventilation	Retrofit	Heating	5,366,884	4,561,851	4,561,851	7%	$0.03
Commercial	Com - HVAC System Commissioning	New Construction	Cooling	4,093,931	3,479,841	145,672	0%	$5.87
Commercial	Com - AC Heat Recovery, HW	Retrofit	Water Heating	3,127,941	2,658,750	385,032	1%	$3.69
Commercial	Com - Gas Fryer	Replacement On Burnout	Cooking	2,895,894	2,461,510	2,461,510	4%	$0.24
Commercial	Com - Windows Upgrade (New)	New Construction	Weatherization	2,690,824	2,287,200	714,281	1%	$1.27
Commercial	Com - Gas Combi Oven	Replacement On Burnout	Cooking	2,476,323	2,104,875	2,104,875	3%	-$0.09
Commercial	Com - Highly Insulated Windows (RET)	Retrofit	Weatherization	2,095,516	1,781,188	-	0%	$4.19
Commercial	Com - Gas Griddle	Replacement On Burnout	Cooking	2,012,746	1,710,834	1,710,834	3%	$0.39
Commercial	Com - Hot Water Condensing Boiler	Replacement On Burnout	Heating	1,857,180	1,578,603	1,578,603	3%	$0.20
Commercial	Com - Gas Steamer	Replacement On Burnout	Cooking	1,696,942	1,442,401	1,442,401	2%	-$0.50
Commercial	Com - Windows Upgrade (RET)	Retrofit	Weatherization	1,626,782	1,382,765	-	0%	$4.63
Commercial	Com - Roof Insulation	Retrofit	Weatherization	1,598,383	1,358,626	1,358,626	2%	$0.16
Commercial	Com - Steam Trap Maintenance	Retrofit	Heating	1,589,202	1,350,822	1,350,822	2%	$0.40
Commercial	Com - Cond Furnace	Replacement On Burnout	Heating	1,496,723	1,272,215	1,272,215	2%	$0.00
Commercial	Com - Highly Insulated Windows (NEW)	New Construction	Weatherization	1,463,969	1,244,374	-	0%	$4.15
Commercial	Com - NEW Showerhead 1.5GPM GAS DHW	New Construction	Water Heating	1,415,466	1,203,146	1,203,146	2%	-$2.80
Commercial	Com - RET Showerhead 1.75GPM GAS DHW	Retrofit	Water Heating	1,370,769	1,165,153	-	0%	$0.00
Commercial	Com - Gas Conv. Oven	Replacement On Burnout	Cooking	1,343,948	1,142,356	949,522	2%	$0.47
Commercial	Com - Wall Insulation	Retrofit	Weatherization	1,177,008	1,000,457	1,000,457	2%	$0.52
Commercial	Com - Advanced Ventilation Controls	Retrofit	Ventilation	1,062,481	903,109	888,759	1%	$8.62
Commercial	Com - Gas-fired HP HW	Replacement On Burnout	Water Heating	638,159	542,435	-	0%	$8.67
Commercial	Com - VIP, R-35 wall (NEW)	New Construction	Weatherization	561,263	477,074	-	0%	$6.75
Commercial	Com - VIP, R-35 wall (RET-R-11)	Retrofit	Weatherization	512,829	435,905	-	0%	$15.39
Commercial	Com - DHW Circulation Pump	Retrofit	Water Heating	450,193	382,664	382,664	1%	$1.66
Commercial	Com - Hot Water Temperature Reset	Retrofit	Heating	354,402	301,242	301,242	0%	$0.06
Commercial	Com - Gas-fired HP, Heating	Replacement On Burnout	Heating	302,332	256,982	251,173	0%	$1.07
Commercial	Com - Steam Balance	Retrofit	Heating	287,212	244,130	179,971	0%	$0.94
Commercial	Com - VIP, R-35 wall (RET-no insl'n)	Retrofit	Weatherization	219,068	186,207	-	0%	$14.07
Commercial	Com - Secondary Windows Glazing	Retrofit	Weatherization	206,794	175,775	-	0%	$0.00
Commercial	Com - Modulating Burner - School	Replacement On Burnout	Heating	143,574	122,038	122,038	0%	$0.38
Commercial	Com - Modulating Burner - Office	Replacement On Burnout	Heating	64,127	54,508	54,508	0%	$0.38
Commercial	Com - RET Showerhead 1.5GPM GAS DHW	Retrofit	Water Heating	23,044	19,588	19,588	0%	-$2.72
Commercial	Com - Modulating Burner - Retail	Replacement On Burnout	Heating	12,312	10,465	10,465	0%	$0.38
Commercial	Com - Modulating Burner - Other	Replacement On Burnout	Heating	11,033	9,378	9,378	0%	$0.38
Commercial	Com - Modulating Burner - Other Health	Replacement On Burnout	Heating	5,999	5,099	5,099	0%	$0.38
Commercial	Com - VFD Venthood	Retrofit	Heating	4,368	3,713	3,713	0%	$0.90
Commercial	Com - High Efficiency Unit Heater	Replacement On Burnout	Heating	2,589	2,200	2,200	0%	$0.40
Commercial	Com - Modulating Burner - Lodging	Replacement On Burnout	Heating	1,149	977	977	0%	$0.38
Commercial	Com - Modulating Burner - Grocery	Replacement On Burnout	Heating	288	245	245	0%	$0.38

Table E.14: 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 - Burner upgrades	Retrofit	Process Heating	2,940,988	2,499,839	2,499,839	15%	$0.07
Industrial	Ind - Boiler Tune-up	Retrofit	Process Heating	2,602,581	2,212,194	2,212,194	13%	$0.03
Industrial	Ind - Roof Insulation- R0-R30	Retrofit	HVAC	1,829,626	1,555,182	1,555,182	9%	$0.06
Industrial	Ind - Wall Insulation- R0- R11	Retrofit	HVAC	1,793,602	1,524,562	1,524,562	9%	$0.06
Industrial	Ind - Steam Balance	Retrofit	Process Heating	1,658,447	1,409,680	1,409,680	9%	$0.34
Industrial	Ind - HW Condensing Boiler	Replacement On Burnout	Water Heating	1,291,262	1,097,573	1,097,573	7%	$0.23
Industrial	Ind - Boiler Heat Recovery	Retrofit	Process Heating	1,095,326	931,027	931,027	6%	$0.04
Industrial	Ind - Steam Trap Maintenance	Retrofit	Process Heating	1,075,898	914,513	914,513	6%	$0.02
Industrial	Ind - Process Boiler Insulation	Retrofit	Process Heating	836,383	710,925	710,925	4%	$0.02
Industrial	Ind - Boiler Load Control	Retrofit	Process Heating	728,611	619,319	619,319	4%	$0.02
Industrial	Ind - Vent Damper Control	Retrofit	Process Heating	670,995	570,346	570,346	3%	$0.01
Industrial	Ind - Greenhouse Upgrade - Condensing Unit Heater	Retrofit	Other	604,941	514,200	514,200	3%	$0.03
Industrial	Ind - Steam line pipe insulation	Retrofit	Process Heating	532,835	452,910	452,910	3%	$0.01
Industrial	Ind - Greenhouse Upgrade - Under Bench Heating	Retrofit	Other	524,768	446,053	446,053	3%	$0.29
Industrial	Ind - High Efficiency Unit Heater	Replacement On Burnout	HVAC	429,261	364,872	364,872	2%	$0.03
Industrial	Ind - Greenhouse Upgrade - IR Poly Film	Retrofit	Other	282,189	239,860	239,860	1%	$0.01
Industrial	Ind - Wall Insulation- VIP, R0-R35	Retrofit	HVAC	263,550	224,017	109,809	1%	$1.58
Industrial	Ind - Gas-fired HP Water Heater	Replacement On Burnout	Water Heating	263,313	223,816	223,816	1%	$0.27
Industrial	Ind - Greenhouse Upgrade - Thermal Curtain	Retrofit	Other	156,566	133,081	133,081	1%	$0.06

Table E.15: 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 4 Advanced Whole Home Gas Heat Gas DHW	New Construction	Heating	23,639,956	20,093,963	11,245,663	10%	$1.48
Residential	Res - Smart Tstat - Gas FAF	Retrofit	Heating	16,159,309	13,735,412	13,735,412	12%	$0.89
Residential	Res - Path 1 ORIECC-Shell Gas Heat Gas DHW	New Construction	Weatherization	15,393,657	13,084,609	13,084,609	11%	$0.79
Residential	Res - Window Replacement Tier 2 (U ≤ 0.27), Gas SPHT	Replacement On Burnout	Weatherization	12,037,296	10,231,702	10,231,702	9%	$0.18
Residential	Res - Path 2 MECH + DHW Gas Heat Gas DHW	New Construction	Water Heating	9,678,382	8,226,625	-	0%	$0.37
Residential	Res - Attic insulation in WA (R0-R18 starting condition)	Retrofit	Weatherization	9,349,058	7,946,699	-	0%	$0.84
Residential	Res - 0.70+ EF Gas Storage Water Heater	Replacement On Burnout	Water Heating	9,055,426	7,697,112	7,697,112	7%	$0.43
Residential	Res - Path 5 Emerging Super Efficient Whole Home Gas Heat Gas DHW	New Construction	Heating	8,960,715	7,616,607	6,966,071	6%	$1.40
Residential	Res - Path 3 MECH + DHW 2 Gas Heat Ele DHW	New Construction	Water Heating	7,158,846	6,085,019	6,085,019	5%	$1.06
Residential	Res - Window Replacement Tier 1 (U =0.28 -> 0.30), Gas SPHT	Replacement On Burnout	Weatherization	6,690,637	5,687,042	5,687,042	5%	$0.12
Residential	Res - Path 4 Advanced Whole Home Gas Heat Ele DHW	New Construction	Heating	6,409,280	5,447,888	3,963,646	3%	$1.67
Residential	Res - Insulating Window Attachments (Gas SH) Z1	Retrofit	Weatherization	5,606,348	4,765,395	-	0%	$9.44
Residential	Res - Wall insulation GAS SPHT HZ1	Retrofit	Weatherization	5,084,068	4,321,458	4,321,458	4%	$1.41
Residential	Res - Attic insulation GAS SPHT (R13-R18 starting condition) HZ1	Retrofit	Weatherization	5,025,911	4,272,024	4,272,024	4%	$1.13
Residential	Res - AFUE 90 to 95 Furnace, Z1 - SF	Replacement On Burnout	Heating	4,960,833	4,216,708	4,216,708	4%	$0.47
Residential	Res - Floor insulation GAS SPHT HZ1	Retrofit	Weatherization	4,667,193	3,967,114	3,967,114	3%	$2.02
Residential	Res - Gas Fireplace - 70-74 FE	Replacement On Burnout	Heating	4,063,811	3,454,240	3,454,240	3%	$0.00
Residential	Res - Attic insulation GAS SPHT (R0-R12 starting condition) HZ1	Retrofit	Weatherization	3,055,204	2,596,923	2,596,923	2%	$0.73
Residential	Res - Duct Sealing, Gas SH, Z1	Retrofit	Weatherization	2,976,393	2,529,934	2,529,934	2%	$1.26
Residential	Res - Bathroom Faucet Aerators, 1.0 gpm- Gas	Retrofit	Water Heating	1,890,000	1,606,500	1,606,500	1%	-$2.32
Residential	Res - Behavior Savings (RET)	Retrofit	Behavioral	1,844,409	1,567,747	1,567,747	1%	$1.43
Residential	Res - Showerhead, 1.50 GPM - Gas	Retrofit	Water Heating	1,817,939	1,545,248	1,545,248	1%	-$2.05
Residential	Res - Kitchen Faucet Aerators, 1.5 gpm- Gas	Retrofit	Water Heating	1,658,157	1,409,433	1,409,433	1%	-$2.33
Residential	Res - Gas Fireplace - Ignition System	Replacement On Burnout	Heating	1,148,021	975,818	975,818	1%	$0.19
Residential	Res - Wx insulation (wall), RET, ET, Gas SH, Z1	Retrofit	Weatherization	1,144,355	972,702	-	0%	$32.97
Residential	Res - Gas Fireplace - 75+ FE	Replacement On Burnout	Heating	932,937	792,997	792,997	1%	$0.30
Residential	Res - Path 3 MECH + DHW 2 Ele Heat Gas DHW	New Construction	Water Heating	696,798	592,279	592,279	1%	$1.54
Residential	Res - Behavior Savings (NEW)	New Construction	Behavioral	671,432	570,717	570,717	0%	$1.43
Residential	Res - Elec Hi-eff Clothes Washer - Gas DHW	Replacement On Burnout	Appliance	581,630	494,386	494,386	0%	-$3.43
Residential	Res - Path 5 Emerging Super Efficient Whole Home Gas Heat Ele DHW	New Construction	Heating	577,955	491,262	263,834	0%	$4.15
Residential	Res - AFUE 98/96 Furnace, Z1 - SF	Replacement On Burnout	Heating	563,470	478,949	-	0%	$1.57
Residential	Res - Knee wall insulation - GAS SPHT	Retrofit	Weatherization	401,761	341,497	-	0%	$1.84
Residential	Res - Window Replacement (U<.20), Gas SF	Replacement On Burnout	Weatherization	379,692	322,739	322,739	0%	$0.03
Residential	Res - Tankless Gas Hot Water Heater (NEW)	New Construction	Water Heating	353,593	300,554	300,554	0%	$0.34
Residential	Res - Rim joist insulation - GAS SPHT	Retrofit	Weatherization	341,582	290,345	-	0%	$1.84
Residential	Res - Showerwand, 1.50 GPM - Gas	Retrofit	Water Heating	267,338	227,237	227,237	0%	-$1.84
Residential	Res - New MH - Eco Gas Z1	Replacement On Burnout	Weatherization	216,888	184,355	147,564	0%	$1.16
Residential	Res - Showerhead, 1.50 GPM - Gas (NEW MF Only)	New Construction	Water Heating	153,703	130,648	130,648	0%	-$1.65
Residential	Res - AFUE 90 to 95 Furnace, Z1	Replacement On Burnout	Heating	152,183	129,356	129,356	0%	$0.59
Residential	Res - Wx insulation (wall), NEW, ET, Gas SH, Z1	New Construction	Weatherization	145,398	123,588	-	0%	$29.96
Residential	Res - New Multifamily 1.5GPM GAS DHW	New Construction	Water Heating	118,036	100,330	100,330	0%	-$1.65

Table E.15 – 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 - New Multifamily 1.75GPM GAS DHW	New Construction	Water Heating	87,523	74,395	74,395	0%	-$1.58
Residential	Res - Insulating Window Attachments (Gas SH) Z2	Retrofit	Weatherization	66,071	56,160	-	0%	$8.09
Residential	Res - Dmd Ctrl Recirc.	Retrofit	Water Heating	57,348	48,746	48,746	0%	$0.71
Residential	Res - Wall insulation GAS SPHT HZ2	Retrofit	Weatherization	56,292	47,848	47,848	0%	$1.29
Residential	Res - Attic insulation GAS SPHT (R13-R18 starting condition) HZ2	Retrofit	Weatherization	54,672	46,471	46,471	0%	$1.05
Residential	Res - Floor insulation GAS SPHT HZ2	Retrofit	Weatherization	51,633	43,888	43,888	0%	$1.84
Residential	Res - Wx insulation (ceiling), RET, ET, Gas SH, Z1	Retrofit	Weatherization	50,427	42,863	-	0%	$8.90
Residential	Res - AFUE 90 to 95 Furnace, Z2 - SF	Replacement On Burnout	Heating	50,109	42,593	42,593	0%	$0.47
Residential	Res - Ceiling insulation - side by side GAS SPHT R49	Retrofit	Weatherization	42,264	35,925	35,925	0%	$0.44
Residential	Res - AFUE 98/96 Furnace, Z1	Replacement On Burnout	Heating	38,799	32,979	-	0%	$1.51
Residential	Res - Behavior Competitions	Retrofit	Behavioral	34,916	29,678	29,678	0%	$2.95
Residential	Res - Attic insulation GAS SPHT (R0-R12 starting condition) HZ2	Retrofit	Weatherization	33,947	28,855	28,855	0%	$0.67
Residential	Res - Floor insulation - 2-4 & side by side GAS SPHT	Retrofit	Weatherization	31,165	26,490	26,490	0%	$1.94
Residential	Res - Duct Sealing, Gas SH, Z2	Retrofit	Weatherization	30,065	25,555	25,555	0%	$1.26
Residential	Res - Elec Hi-eff Dishwasher - Gas DHW - SF	Replacement On Burnout	Appliance	28,524	24,246	-	0%	$9.62
Residential	Res - Path 4 Advanced Whole Home Ele Heat Gas DHW	New Construction	Heating	26,461	22,492	22,492	0%	$58.59
Residential	Res - Flat-roof insulation R5 or less to R20 GAS SPHT - Zone 1	Retrofit	Weatherization	22,438	19,072	19,072	0%	$0.60
Residential	Res - Path 5 Emerging Super Efficient Whole Home Ele Heat Gas DHW	New Construction	Heating	21,763	18,498	10,957	0%	$11.18
Residential	Res - Ceiling insulation - stacked GAS SPHT R49	Retrofit	Weatherization	21,132	17,962	17,962	0%	$1.08
Residential	Res - Wall insulation - 2-4 & side by side GAS SPHT	Retrofit	Weatherization	18,138	15,417	15,417	0%	$1.44
Residential	Res - Showerhead, 1.50 GPM - Gas (NEW Only)	New Construction	Water Heating	15,102	12,837	12,837	0%	-$2.04
Residential	Res - Wx insulation (wall), RET, ET, Gas SH, Z2	Retrofit	Weatherization	12,661	10,762	-	0%	$30.10
Residential	Res - Behavior Competitions (NEW only)	New Construction	Behavioral	6,461	5,492	3,970	0%	$2.67
Residential	Res - New MH - HPMH Gas Z1	Replacement On Burnout	Weatherization	5,779	4,912	-	0%	$22.01
Residential	Res - AFUE 98/96 Furnace, Z2 - SF	Replacement On Burnout	Heating	5,692	4,838	-	0%	$1.57
Residential	Res - Window Replacement (U<.20), Gas MF	Replacement On Burnout	Weatherization	4,231	3,596	3,596	0%	$0.03
Residential	Res - Wx insulation (ceiling), NEW, ET, Gas SH, Z1	New Construction	Weatherization	3,428	2,914	-	0%	$9.66
Residential	Res - 0.67/0.70 EF Gas Storage Water Heater for Multi-Family Centralized Hot Water System	Replacement On Burnout	Water Heating	3,308	2,812	-	0%	$28.99
Residential	Res - New MH - Eco Gas Z2	Replacement On Burnout	Weatherization	3,170	2,694	2,694	0%	$0.80
Residential	Res - HRV, Gas SH, Z1	New Construction	Heating	3,053	2,595	1,485	0%	$0.87
Residential	Res - Hot Water Condensing Boiler for Space Heat (MF)	Replacement On Burnout	Heating	1,926	1,637	1,637	0%	$0.22
Residential	Res - AFUE 90 to 95 Furnace, Z2	Replacement On Burnout	Heating	1,537	1,307	1,307	0%	$0.59
Residential	Res - Wx insulation (wall), NEW, ET, Gas SH, Z2	New Construction	Weatherization	1,470	1,249	-	0%	$29.94
Residential	Res - Wx insulation (ceiling), RET, ET, Gas SH, Z2	Retrofit	Weatherization	553	470	-	0%	$8.20
Residential	Res - Window Replacement (U<.20), Gas MH	Replacement On Burnout	Weatherization	547	465	465	0%	$0.03
Residential	Res - Rim joist insulation -2-4 & side by side GAS SPHT	Retrofit	Weatherization	454	386	-	0%	$1.84
Residential	Res - AFUE 98/96 Furnace, Z2	Replacement On Burnout	Heating	392	333	-	0%	$1.51
Residential	Res - Elec Hi-eff Dishwasher - Gas DHW	Replacement On Burnout	Appliance	370	315	-	0%	$14.47
Residential	Res - Flat-roof insulation R5 or less to R20 GAS SPHT - Zone 2	Retrofit	Weatherization	335	285	285	0%	$0.41
Residential	Res - Knee wall insulation -2-4 & side by side GAS SPHT	Retrofit	Weatherization	206	175	-	0%	$1.84
Residential	Res - New MH - HPMH Gas Z2	Replacement On Burnout	Weatherization	67	57	-	0%	$19.04
Residential	Res - Wx insulation (ceiling), NEW, ET, Gas SH, Z2	New Construction	Weatherization	35	30	-	0%	$9.58
Residential	Res - HRV, Gas SH, Z2	New Construction	Heating	22	18	10	0%	$1.25

Table E.16: Washington 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 - ZNE	New Construction	Other	2,142,679	1,821,277	1,259,260	14%	$4.04
Commercial	Com - Energy Recovery Ventilator - Gas Heating	Retrofit	Heating	2,100,413	1,785,351	-	0%	$13.79
Commercial	Com - SEM	Retrofit	Behavioral	1,834,103	1,558,988	1,558,988	18%	$0.66
Commercial	Com - DDC HVAC Controls	New Construction	Heating	1,655,962	1,407,568	1,405,637	16%	$1.47
Commercial	Com - DOAS/HRV - GAS SH	Replacement On Burnout	Heating	784,312	666,665	480,857	5%	$0.34
Commercial	Com - HVAC System Commissioning	New Construction	Cooling	739,658	628,709	47,944	1%	$5.84
Commercial	Com - DHW Condensing Tankless	Replacement On Burnout	Water Heating	734,250	624,113	624,113	7%	$0.34
Commercial	Com - Demand Control Ventilation	Retrofit	Heating	545,964	464,069	464,069	5%	$0.03
Commercial	Com - Windows Upgrade (New)	New Construction	Weatherization	530,421	450,857	237,089	3%	$1.31
Commercial	Com - Gas Fryer	Replacement On Burnout	Cooking	434,574	369,388	369,388	4%	$0.25
Commercial	Com - Gas Combi Oven	Replacement On Burnout	Cooking	371,351	315,648	315,648	4%	-$0.08
Commercial	Com - Gas Griddle	Replacement On Burnout	Cooking	301,656	256,408	256,408	3%	$0.40
Commercial	Com - Hot Water Condensing Boiler	Replacement On Burnout	Heating	293,705	249,649	249,649	3%	$0.22
Commercial	Com - AC Heat Recovery, HW	Retrofit	Water Heating	292,562	248,678	45,558	1%	$3.67
Commercial	Com - Highly Insulated Windows (NEW)	New Construction	Weatherization	262,370	223,014	6,524	0%	$4.43
Commercial	Com - Gas Steamer	Replacement On Burnout	Cooking	251,163	213,488	213,488	2%	-$0.49
Commercial	Com - Highly Insulated Windows (RET)	Retrofit	Weatherization	217,643	184,997	-	0%	$4.56
Commercial	Com - Cond Furnace	Replacement On Burnout	Heating	204,779	174,062	174,062	2%	$0.00
Commercial	Com - Gas Conv. Oven	Replacement On Burnout	Cooking	202,520	172,142	172,142	2%	$0.49
Commercial	Com - NEW Showerhead 1.5GPM GAS DHW	New Construction	Water Heating	198,004	168,304	168,304	2%	-$2.80
Commercial	Com - Roof Insulation	Retrofit	Weatherization	178,542	151,760	151,760	2%	$0.17
Commercial	Com - Windows Upgrade (RET)	Retrofit	Weatherization	168,960	143,616	-	0%	$5.03
Commercial	Com - Steam Trap Maintenance	Retrofit	Heating	153,594	130,555	130,555	1%	$0.41
Commercial	Com - Wall Insulation	Retrofit	Weatherization	121,449	103,231	103,231	1%	$0.56
Commercial	Com - RET Showerhead 1.75GPM GAS DHW	Retrofit	Water Heating	118,502	100,727	100,727	1%	-$2.82
Commercial	Com - Advanced Ventilation Controls	Retrofit	Ventilation	104,938	89,197	88,166	1%	$8.91
Commercial	Com - VIP, R-35 wall (NEW)	New Construction	Weatherization	104,065	88,455	-	0%	$7.27
Commercial	Com - Gas-fired HP HW	Replacement On Burnout	Water Heating	87,120	74,052	-	0%	$8.75
Commercial	Com - VIP, R-35 wall (RET-R-11)	Retrofit	Weatherization	52,916	44,979	-	0%	$16.59
Commercial	Com - Gas-fired HP, Heating	Replacement On Burnout	Heating	47,454	40,336	40,336	0%	$1.16
Commercial	Com - DHW Circulation Pump	Retrofit	Water Heating	47,382	40,274	40,274	0%	$1.72
Commercial	Com - Hot Water Temperature Reset	Retrofit	Heating	39,781	33,814	33,814	0%	$0.06
Commercial	Com - Steam Balance	Retrofit	Heating	32,292	27,449	24,523	0%	$0.94
Commercial	Com - VIP, R-35 wall (RET-no insl'n)	Retrofit	Weatherization	22,604	19,214	-	0%	$15.17
Commercial	Com - Secondary Windows Glazing	Retrofit	Weatherization	21,478	18,256	-	0%	$68.04
Commercial	Com - Modulating Burner - School	Replacement On Burnout	Heating	18,888	16,055	16,055	0%	$0.40
Commercial	Com - Modulating Burner - Office	Replacement On Burnout	Heating	5,407	4,596	4,596	0%	$0.40
Commercial	Com - Modulating Burner - Retail	Replacement On Burnout	Heating	1,333	1,133	1,133	0%	$0.40
Commercial	Com - Modulating Burner - Other	Replacement On Burnout	Heating	882	749	749	0%	$0.40
Commercial	Com - Modulating Burner - Other Health	Replacement On Burnout	Heating	679	577	577	0%	$0.40
Commercial	Com - VFD Venthood	Retrofit	Heating	532	452	452	0%	$0.94
Commercial	Com - High Efficiency Unit Heater	Replacement On Burnout	Heating	282	240	240	0%	$0.42
Commercial	Com - Modulating Burner - Lodging	Replacement On Burnout	Heating	88	75	75	0%	$0.40
Commercial	Com - Modulating Burner - Grocery	Replacement On Burnout	Heating	41	35	35	0%	$0.40

Table E.17: Washington 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 - Burner upgrades	Retrofit	Process Heating	130,319	110,771	110,771	13%	$0.07
Industrial	Ind - Roof Insulation- R0-R30	Retrofit	HVAC	124,385	105,728	105,728	13%	$0.06
Industrial	Ind - Wall Insulation- R0- R11	Retrofit	HVAC	121,936	103,646	103,646	12%	$0.06
Industrial	Ind - Boiler Tune-up	Retrofit	Process Heating	115,324	98,025	98,025	12%	$0.03
Industrial	Ind - HW Condensing Boiler	Replacement On Burnout	Water Heating	80,751	68,638	68,638	8%	$0.26
Industrial	Ind - Steam Balance	Retrofit	Process Heating	77,326	65,727	65,727	8%	$0.29
Industrial	Ind - Boiler Heat Recovery	Retrofit	Process Heating	48,535	41,255	41,255	5%	$0.04
Industrial	Ind - Steam Trap Maintenance	Retrofit	Process Heating	47,674	40,523	40,523	5%	$0.02
Industrial	Ind - Process Boiler Insulation	Retrofit	Process Heating	36,829	31,305	31,305	4%	$0.02
Industrial	Ind - High Efficiency Unit Heater	Replacement On Burnout	HVAC	36,329	30,880	30,880	4%	$0.03
Industrial	Ind - Boiler Load Control	Retrofit	Process Heating	32,286	27,443	27,443	3%	$0.02
Industrial	Ind - Vent Damper Control	Retrofit	Process Heating	29,733	25,273	25,273	3%	$0.01
Industrial	Ind - Steam line pipe insulation	Retrofit	Process Heating	23,463	19,943	19,943	2%	$0.01
Industrial	Ind - Wall Insulation- VIP, R0-R35	Retrofit	HVAC	17,917	15,230	15,230	2%	$1.71
Industrial	Ind - Greenhouse Upgrade - Condensing Unit Heater	Retrofit	Other	16,360	13,906	13,906	2%	$0.03
Industrial	Ind - Gas-fired HP Water Heater	Replacement On Burnout	Water Heating	14,630	12,436	12,436	1%	$0.28
Industrial	Ind - Greenhouse Upgrade - Under Bench Heating	Retrofit	Other	14,192	12,063	12,063	1%	$0.30
Industrial	Ind - Greenhouse Upgrade - IR Poly Film	Retrofit	Other	7,632	6,487	6,487	1%	$0.01
Industrial	Ind - Greenhouse Upgrade - Thermal Curtain	Retrofit	Other	4,234	3,599	3,599	0%	$0.06

Table E.18: Washington 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 4 Advanced Whole Home Gas Heat Gas DHW	New Construction	Heating	6,604,236	5,613,601	-	0%	$2.09
Residential	Res - Path 1 ORIECC-Shell Gas Heat Gas DHW	New Construction	Weatherization	3,603,089	3,062,626	3,062,626	19%	$0.71
Residential	Res - Path 5 Emerging Super Efficient Whole Home Gas Heat Gas DHW	New Construction	Heating	3,156,032	2,682,627	1,692,586	11%	$1.89
Residential	Res - Window Replacement Tier 2 (U ≤ 0.27), Gas SPHT	Replacement On Burnout	Weatherization	2,315,052	1,967,794	1,967,794	12%	$0.20
Residential	Res - Smart Tstat - Gas FAF	Retrofit	Heating	1,714,243	1,457,106	1,457,106	9%	$0.92
Residential	Res - 0.70+ EF Gas Storage Water Heater	Replacement On Burnout	Water Heating	1,408,912	1,197,575	1,197,575	8%	$0.45
Residential	Res - Window Replacement Tier 1 (U =0.28 -> 0.30), Gas SPHT	Replacement On Burnout	Weatherization	1,283,139	1,090,669	1,090,669	7%	$0.13
Residential	Res - Attic insulation in WA (R0-R18 starting condition)	Retrofit	Weatherization	1,031,646	876,899	876,899	6%	$0.93
Residential	Res - AFUE 90 to 95 Furnace, Z1 - SF	Replacement On Burnout	Heating	882,879	750,447	750,447	5%	$0.50
Residential	Res - Showerhead, 1.50 GPM - Gas	Retrofit	Water Heating	646,836	549,811	549,811	3%	-$2.05
Residential	Res - Insulating Window Attachments (Gas SH) Z1	Retrofit	Weatherization	606,735	515,725	-	0%	$9.88
Residential	Res - Wall insulation GAS SPHT HZ1	Retrofit	Weatherization	562,414	478,052	478,052	3%	$1.56
Residential	Res - Attic insulation GAS SPHT (R13-R18 starting condition) HZ1	Retrofit	Weatherization	554,597	471,407	-	0%	$1.24
Residential	Res - Floor insulation GAS SPHT HZ1	Retrofit	Weatherization	516,487	439,014	439,014	3%	$2.22
Residential	Res - Gas Fireplace - 70-74 FE	Replacement On Burnout	Heating	463,856	394,277	394,277	3%	$0.00
Residential	Res - Attic insulation GAS SPHT (R0-R12 starting condition) HZ1	Retrofit	Weatherization	337,134	286,564	-	0%	$0.81
Residential	Res - Duct Sealing, Gas SH, Z1	Retrofit	Weatherization	326,955	277,911	277,911	2%	$1.34
Residential	Res - Bathroom Faucet Aerators, 1.0 gpm- Gas	Retrofit	Water Heating	266,847	226,820	226,820	1%	-$2.32
Residential	Res - Kitchen Faucet Aerators, 1.5 gpm- Gas	Retrofit	Water Heating	234,175	199,049	199,049	1%	-$2.33
Residential	Res - Behavior Savings (RET)	Retrofit	Behavioral	211,440	179,724	179,724	1%	$1.43
Residential	Res - Behavior Savings (NEW)	New Construction	Behavioral	191,319	162,621	162,621	1%	$1.43
Residential	Res - Tankless Gas Hot Water Heater (NEW)	New Construction	Water Heating	169,188	143,810	143,810	1%	$0.36
Residential	Res - Gas Fireplace - Ignition System	Replacement On Burnout	Heating	131,039	111,383	111,383	1%	$0.21
Residential	Res - Elec Hi-eff Clothes Washer - Gas DHW	Replacement On Burnout	Appliance	121,413	103,201	103,201	1%	-$3.28
Residential	Res - Wx insulation (wall), RET, ET, Gas SH, Z1	Retrofit	Weatherization	107,985	91,787	-	0%	$30.70
Residential	Res - Gas Fireplace - 75+ FE	Replacement On Burnout	Heating	106,488	90,515	90,515	1%	$0.31
Residential	Res - Showerwand, 1.50 GPM - Gas	Retrofit	Water Heating	95,129	80,859	80,859	1%	-$1.83
Residential	Res - Showerhead, 1.50 GPM - Gas (NEW MF Only)	New Construction	Water Heating	73,093	62,129	62,129	0%	-$1.64
Residential	Res - Window Replacement (U<.20), Gas SF	Replacement On Burnout	Weatherization	69,310	58,913	58,913	0%	$0.03
Residential	Res - AFUE 98/96 Furnace, Z1 - SF	Replacement On Burnout	Heating	66,258	56,319	-	0%	$1.68
Residential	Res - New Multifamily 1.5GPM GAS DHW	New Construction	Water Heating	56,131	47,712	47,712	0%	-$1.64
Residential	Res - Knee wall insulation - GAS SPHT	Retrofit	Weatherization	44,084	37,471	-	0%	$2.03
Residential	Res - New Multifamily 1.75GPM GAS DHW	New Construction	Water Heating	41,621	35,378	35,378	0%	-$1.57
Residential	Res - Rim joist insulation - GAS SPHT	Retrofit	Weatherization	37,409	31,798	-	0%	$2.03
Residential	Res - Dmd Ctrl Recirc.	Retrofit	Water Heating	12,989	11,040	11,040	0%	$0.72
Residential	Res - Showerhead, 1.50 GPM - Gas (NEW Only)	New Construction	Water Heating	7,557	6,424	6,424	0%	-$2.03
Residential	Res - Elec Hi-eff Dishwasher - Gas DHW - SF	Replacement On Burnout	Appliance	5,917	5,029	-	0%	$10.16
Residential	Res - Behavior Competitions	Retrofit	Behavioral	5,659	4,810	4,810	0%	$3.02
Residential	Res - Wx insulation (ceiling), RET, ET, Gas SH, Z1	Retrofit	Weatherization	4,741	4,030	-	0%	$9.09
Residential	Res - Behavior Competitions (NEW only)	New Construction	Behavioral	2,925	2,486	1,774	0%	$2.67
Residential	Res - 0.67/0.70 EF Gas Storage Water Heater for Multi-Family Centralized Hot Water System	Replacement On Burnout	Water Heating	927	788	788	0%	$30.61
Residential	Res - Elec Hi-eff Dishwasher - Gas DHW	Replacement On Burnout	Appliance	88	75	-	0%	$15.30

APPENDIX F

SUPPLY-SIDE RESOURCES

Current Resource Details

Table F.1

Firm Off-System Gas Supply Contracts
for the 2017/2018 Tracker Year

Supply Location	Duration	Baseload Quantity (Dth/day)	Swing Quantity (Dth/day)	Contract Termination Date
British Columbia:				
ConocoPhillips (Canada)	Nov-Mar	5,000		3/31/2018
J. Aron	Nov-Mar	5,000		3/31/2018
J. Aron	Nov-Mar	5,000		3/31/2018
ConocoPhillips Canada	Nov-Mar	5,000		3/31/2018
BP Canada Energy Group ULC	Nov-Mar	10,000		3/31/2018
TD Energy Trading, Inc.	Nov-Oct	5,000		10/31/2018
BP Canada Energy Group ULC	Nov-Oct	5,000		10/31/2018
Alberta:				
ConocoPhillips (Canada)	Nov-Mar	5,000		3/31/2018
TD Energy	Nov-Mar	5,000		3/31/2018
J. Aron	Nov-Mar	5,000		3/31/2018
Enstor Energy Services	Nov-Mar	5,000		3/31/2018
Powerex	Nov-Oct	5,000		10/31/2018
Suncor Energy	Nov-Mar	5,000		3/31/2018
Enstor Energy LLC	Nov-Oct	5,000		10/31/2018
Shell Energy North America (Canada)	Nov-Oct	5,000		10/31/2018
Shell Energy North America (Canada)	Nov-Mar	5,000		3/31/2018
Macquarie Energy Canada	Nov-Mar	5,000		3/31/2018
Shell Energy North America (Canada)	Nov-Mar	5,000		3/31/2018
TD Energy Trading, Inc.	Nov-Mar	5,000		3/31/2018
Macquarie Energy Canada	Nov-Mar	5,000		3/31/2018
Rockies:				
Anadarko Energy Services	Nov-Mar	5,000		3/31/2018
Citadel Energy Marketing	Nov-Oct	5,000		10/31/2018
Citadel Energy Marketing	Nov-Oct	5,000		10/31/2018
MacQuarie Energy	Nov-Mar	5,000		3/31/2018
Ultra Resources	Nov-Mar	10,000		3/31/2018
J. Aron	Nov-Mar		10,000	3/31/2018
J. Aron	Apr-Oct		10,000	10/31/2018
Ultra Resources	Nov-Oct	5,000		10/31/2018
MacQuarie Energy, LLC	Nov-Oct	5,000		10/31/2018
IGI Resources	Nov-Oct	5,000		10/31/2018
ConocoPhillips Company	Nov-Oct	5,000		10/31/2018
Concord Energy, LLC	Nov-Mar	5,000		3/31/2018
Anadarko Energy Services Company	Nov-Mar	5,000		3/31/2018
ConocoPhillips Company	Nov-Mar	5,000		3/31/2018
MacQuarie Energy, LLC	Nov-Mar	5,000		3/31/2018
ConocoPhillips Company	Nov-Mar	5,000		3/31/2018
Total, November-March		180,000	10,000	
Total, April-October		55,000	10,000	

Notes:

1. Contract quantities represent deliveries into upstream pipelines. Accordingly, quantities delivered into NW Natural's system are slightly less due to upstream pipeline fuel consumption.
2. 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 F.2

Firm Transportation Capacity
for the 2017/2018 Tracker Year

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	10/31/2025
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)	10/31/2018
Net NWP Capacity	343,237	
TransCanada - GTN:		
Sales Conversion	3,616	10/31/2023
1993 Expansion	46,549	10/31/2023
1995 Rationalization	56,000	10/31/2021
Total GTN Capacity	106,165	
TransCanada - Foothills:		
1993 Expansion	47,727	10/31/2018
1995 Rationalization	57,417	10/31/2018
Engage Capacity Acquisition	3,708	10/31/2018
2004 Capacity Acquisition	48,669	10/31/2018
Total Foothills Capacity	157,521	
TransCanada - NOVA:		
1993 Expansion	48,135	10/31/2020
1995 Rationalization	57,909	10/31/2020
Engage Capacity Acquisition	3,739	10/31/2020
2004 Capacity Acquisition	49,138	10/31/2020
Total NOVA Capacity	158,921	
T-South Capacity (through Tenaska)	19,000	10/31/2018
Southern Crossing Pipeline	48,000	10/31/2020

Notes:

1. 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 contract, which is through a 2-year contract with Tenaska.
2. The Southern Crossing contract is denominated in volumetric units, hence the Dth units shown are an approximation.
3. 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.
4. Segmented capacity has not been included in this table.
5. T-South capacity does not include the new T-South Expansion contract of approximately 25,000 Dth/day, which will begin no earlier than November 1, 2020.
6. Termination dates have been updated to reflect the Memorandum of Understanding with Northwest Pipeline dated August 29, 2017.

NW NATURAL'S STORAGE PLANT PROJECTS

NW Natural's three on-system storage plants are crucial elements of the Company's resource portfolio, providing approximately half of the gas required on the design peak day. But with Mist initially built in the late1980s, Newport LNG in the mid-1970s, and Portland LNG in the late 1960s, these facilities also are showing their age. Accordingly, the Company has developed asset management programs for each plant that consists of a mix of preventative maintenance, repair and replacement projects. These projects may involve outside consultant studies as well as analysis of alternatives.

The selection criteria for the projects in each plant's plan included 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

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; 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 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 and/or
- Internal and any required external approval processes.

The following sections provide details on the key projects for each plant.

MIST ASSET MANAGEMENT PROJECTS

This section discusses NW Natural's plan for capital projects at the Mist 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. Each project in this category will be executed in accordance with NW Natural's Project Management Organization processes and managed through a project stage gate process.

New Control Building

- A new control room was needed to house the new control system and data center.
- Completed in September 2017
- $1.7 million[1]

Instrument and Control Upgrade (Phase 1)

- Replace the control system with a new modern control system and install new data center, upgrade remote input / output connections to Ethernet / Fiber Optic.
- Existing PLC controller no longer supported after July 2017. Network segmentation included in the project will improve cyber-security for the facility.
- Project planning started in Q4 2016, and project completion is Q3 2018.
- Estimated cost $1.1 million (out of a total cost of $3.2 million)

Large Dehydration System

- Repair or replace existing Large Dehydration system, which has reached end-of-life and is not functioning as originally designed, depending on the results of engineering, economic and alternatives analyses.
- The 2016 IRP included an action item for repairing or replacing the large dehydrator system, which was acknowledged by OPUC.
- Project planning start was Q4 2016, and a third party engineering study was completed in December 2017,
- An economic and alternatives analysis is now underway.
- Expected costs are dependent on the results of the analysis.

Fiber Network (Phase 1)

- Install a fiber network for the control system from Miller Station to the Bruer and Flora wells, as the existing radio communication system has become unreliable.
- Project planning started in Q1 2017, EFSC approval anticipated in 2018, and project completion in Q3 2019.
- Estimated cost $300,000 (out of a total cost of $1.050 million)

Standby Generator

- Install a new natural gas powered backup generator capable of powering the entire plant should utility power not be available.
- Included in EN Engineering Facility Assessment. Existing standby generator is undersized.
- Project planning started in Q1 2018, and project completion in Q4 2018.
- Estimated cost $850,000

Corrosion Abatement (Phase 1)

- This project will perform In-line inspections on the twin 16 inch lines between Miller Station and Busch manifold.
- Lines have not been pigged previously.
- Project planning started in Q2 2017, and project completion will be Q3 2018.

[1] Estimated or actual costs related to Mist projects do not include construction overhead (COH).

- Estimated cost $700,000 (out of a total cost of $1 million; note that $300,000 was spent in 2017)

Corrosion Abatement (Phase 2)

- This project will perform In-line inspections on the 8 inch line between Schlicker well and Busch manifold and the 12 inch line between Reichhold well and Busch manifold.
- Lines have not been pigged previously.
- Project planning started in Q4 2017, and project completion in Q3 2018.
- Estimated cost $750,000

Fiber Network (Phase 2)

- Installation of a fiber network for the control system from Miller Station to the Bruer and Flora wells.
- Existing radio communication system has become unreliable.
- Project planning started in Q1 2017, EFSC approval in 2018, and project completion in Q3 2019.
- Estimated cost $750,000 (out of a total estimated cost of $1.05 million)

Corrosion Abatement (Phase 3)

- This project will perform In-line inspections on the two 8 inch lines between Al's View and Busch manifold and the two 6 inch lines between Al's View and Al's wells.
- Lines have not been pigged previously.
- Project planning to start in Q1 2019, and project completion in Q3 2019.
- Estimated cost $1.5 million

Compressor Study

- Conduct a study to determine the best solutions for compressor operations and replacement at Miller Station.
- The existing reciprocating compressors are not properly sized for the flow conditions at Mist and are not suited for peak operation. The result is overuse of the turbine compressors which causes additional maintenance cost due to excessive use and deformations.
- Study to be completed in 2019. First phase of compressor replacement will take place in 2020 and 2021.
- $600,000 in 2019

Instrument and Controls Upgrade (Phase 2)

- Upgrade flow computers at Miller Station and the I/W wells. This involves replacing 37 total systems.
- Current systems are at end-of-life
- Planning and Execution phases will both be in 2019
- Estimated cost $200,000 (out of a total estimated cost of $1.1 million)

PORTLAND LNG PLANT PROJECTS

This section discusses NW Natural's plan for capital projects at the Portland LNG plant (this facility also is referred to as "Gasco"). The Portland LNG projects are typically performed within the facility boundaries. They encompass the replacement of mechanical process equipment used for the liquefaction, vaporization or storage of LNG.

Fire and Gas System
Added additional gas and fire sensors throughout the facility in 2017. This was based on the result of a third party study.

- Installed a high resolution articulated camera on top of the tank to monitor the relief stacks.
- Installed new relief stacks, which direct venting upward instead of horizontal.
- $360,000[2]

Replace Piping Insulation
Removed deteriorated insulation and replaced on part of the liquefaction piping system in 2017.

- $326,000

Replace H-6 Vaporizer
Replaced H-6 vaporizer and associated control system in 2017.

- $2.8 million

Replace Mole Sieve
Replaced pretreatment system mole sieve in 2017.

- $105,000

Process Instrumentation
Installed two gas chromatographs and combination CO_2 moisture analyzer in 2017.

- $220,000

Cold Box Cleaning
Dust has settled in sections of the cold box causing periodic plugging which requires system shutdowns.

- Purge and clean cold box internal aluminum heat exchangers in 2018.
- The cold box will be purged with gas to push particulate out of the system.
- Estimated cost $150,000

Note that the cold box is the core of the liquefaction process at Portland LNG and critical to the entire plant.

Tank Impoundment
Design and construct a liner to be installed in T-1 impoundment area in 2018. This liner will separate contaminated ground water from comingling with rain water. This will reduce total contaminated ground water in the impoundment, enabling the discharge of clean water into the Willamette River.

- Estimated cost $5.5 million

Liquefaction System Study
Retained a consulting engineering company to study the existing LNG plant's liquefaction and pretreatment systems. The study will clarify what replacement and refurbishment options are suitable for the facility.

- Estimated cost $850,000
- Results of this study may lead to other capital projects in ensuing years such as:
    - Replace H-7 Vaporizer Controls (estimated cost $2 million)
    - Replace Liquefaction and Associated System (very roughly estimated cost $40 million)

[2] Estimated or actual costs related to Portland LNG projects do not include construction overhead (COH).

- Tank Seismic Study (estimated cost $300,000)
- Cyber Security and Control Building (estimated cost $5 million)

NEWPORT LNG PLANT PROJECTS

This section discusses NW Natural's plan for capital projects at the Newport LNG facility. The Newport LNG projects are typically performed within the facility boundaries. They encompass the replacement of mechanical process equipment used for the liquefaction, vaporization or storage of LNG.

H-1 Vaporizer Replacement

- Replaced H-1 vaporizer and control system in 2017
- $3.1 million[3]

Control System Modernization

- Replaced plant control system in 2017
- Upgrade cyber security and network, $2.9 million

Turbine Modernization

- Replaced control system on compressor C-3, installed new fire and gas systems for compressor C-3, and installed dry seal system in 2017
- $2 million

Pretreatment System

- Installed molecular sieve dehydration and CO2 removal system in 2017
- $11.7 million

Control Building

- Constructed new blast resistant control building in 2017
- $2.8 million

Glycol Piping

- Related action item in 2014 IRP acknowledged by OPUC.
- Replace underground PVC piping in process building with above ground steel construction in 2018.
- This project is included in the Newport reliability program.
- The original PVC piping was at risk of failure if a minor seismic event occurred.
- Estimated cost $1.44 million

Replace E-3 Heat Exchanger

- Replace existing mixed refrigerant heat exchanger to provide adequate cooling for C-3 turbine in 2018.
- Equipment is at the end of its operating life and no longer meets performance requirements.
- Requires additional electrical equipment to accommodate 2 additional fans associated with the new heat exchanger.
- Install new foundation system to meet seismic requirements.
- Replace existing end-of-life annubar meter with new flow meter.
- Estimated cost $1.836 million

[3] Estimated or actual costs related to Newport LNG projects do not include construction overhead (COH).

Replace E-5 Heat Exchanger

- Replace existing fin fan glycol heat exchanger in 2018.
- The existing heat exchanger no longer meets demand and is at its end-of-life.
- E-5 is a critical piece of equipment required for safe operation of the plant and to support liquefaction and holding mode boil-off compression.
- Install new foundation system to meet seismic requirements.
- Estimated cost $1.618 million

C-1 Compressor Motor Replacement

- Performance of existing motor has deteriorated over the last liquefaction season and it is now running above nameplate amperage. Therefore this motor has been determined to be at end-of-life and will be replaced in 2018.
- Estimated cost $300,000

Replace Standby Generator

- Related action item in 2014 IRP acknowledged by OPUC.
- The existing standby generator is at the end of its useful life.
- This project will replace the diesel generator with a low emission natural gas generator in 2018.
- Estimated cost $1.4 million

Cold Box Cleaning

Perform purging and cleaning of cold box internal aluminum heat exchangers. These exchangers are constructed of narrow channels for maximum heat transfer, and these can easily become plugged over time.

- A specialty engineering firm will be hired to determine the type of solvents to use as well as methods for cleaning. A third party company will then perform the cleaning process in 2018.
- Estimated cost $280,000

T-1 Ground Improvement Seismic Design

A study completed in 2017 determined improvements to the ground surrounding the tank are required to ensure integrity of the tank impoundment during a seismic event.

- Project will include a preliminary concept in 2019.
- Includes detail design of proposed solution and cost estimate.
- Estimated cost $350,000

Replace Cold Box

The Cold Box heat exchangers are original to the plant and no longer function reliably. The cold box was not designed to process current pipeline gas constituents. Increasing butane, ethane and propane concentrations condense in unintended parts of the heat exchanger. This causes the production rate to decrease, fouls the liquid separation system, and periodically requires a complete shutdown and blow down to clear system. This leads to downtime in the liquefaction process.

- This project will also update the cryogenic system to comply with existing codes.
- Update plant designs, process models and other critical drawings plant-wide in 2019 to ensure they are current at the end of the cold box installation.
- Estimated cost $4.8 million

Replace H-2 Vaporizer Controls

The H-2 vaporizer's existing control system is obsolete and no longer supported by manufacturer.

- Replace the control system in 2019, bringing this equipment into compliance with current burner management standards, and up to date with the design of the H-1 control system installed in 2017.
- Estimated cost $2 million

T-1 Tank Roof Access Platform

Tank appurtenances on the roof of the tank are not accessible. Given the age of the tank it is necessary to ensure all tank appurtenances can be safely and readily reached for annual inspections.

- To be performed in 2019.
- Estimated cost $500,000

APPENDIX G

PORTFOLIO SELECTION

Figure G.1: High Customer Growth

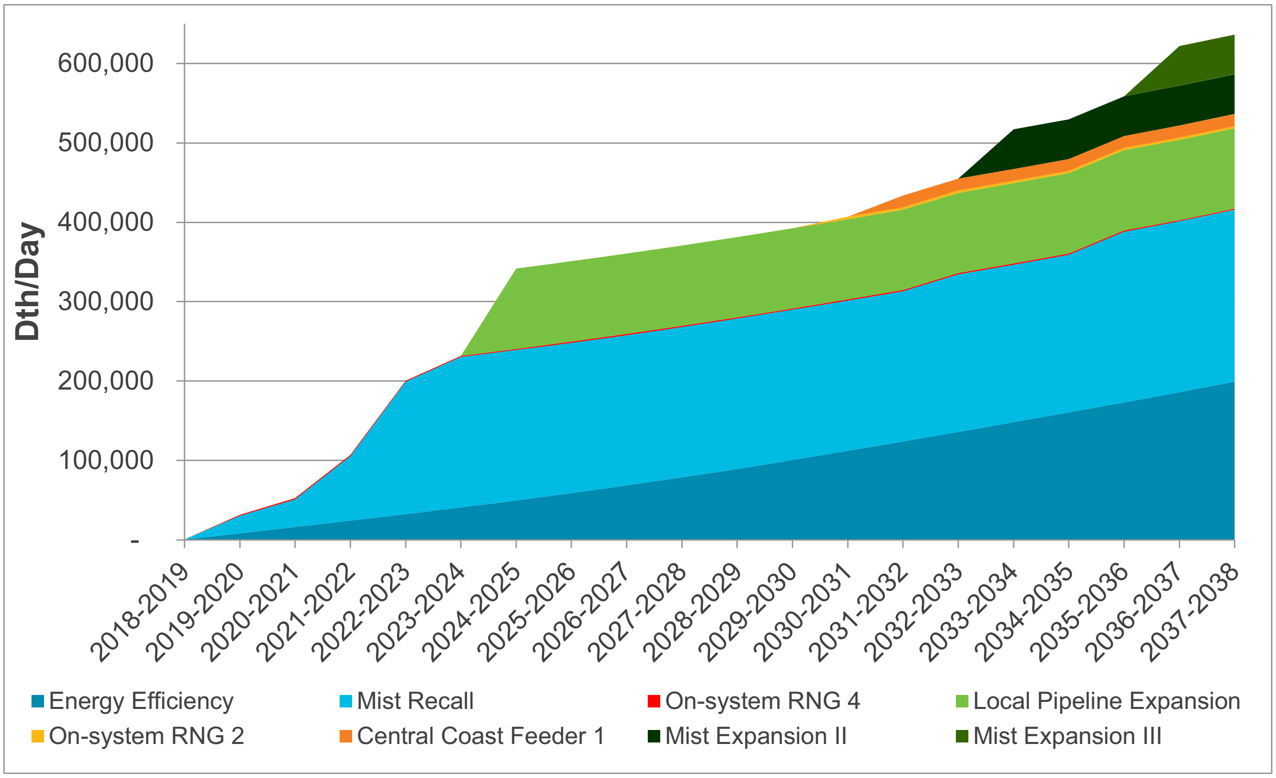


Figure G.2 Low Customer Growth

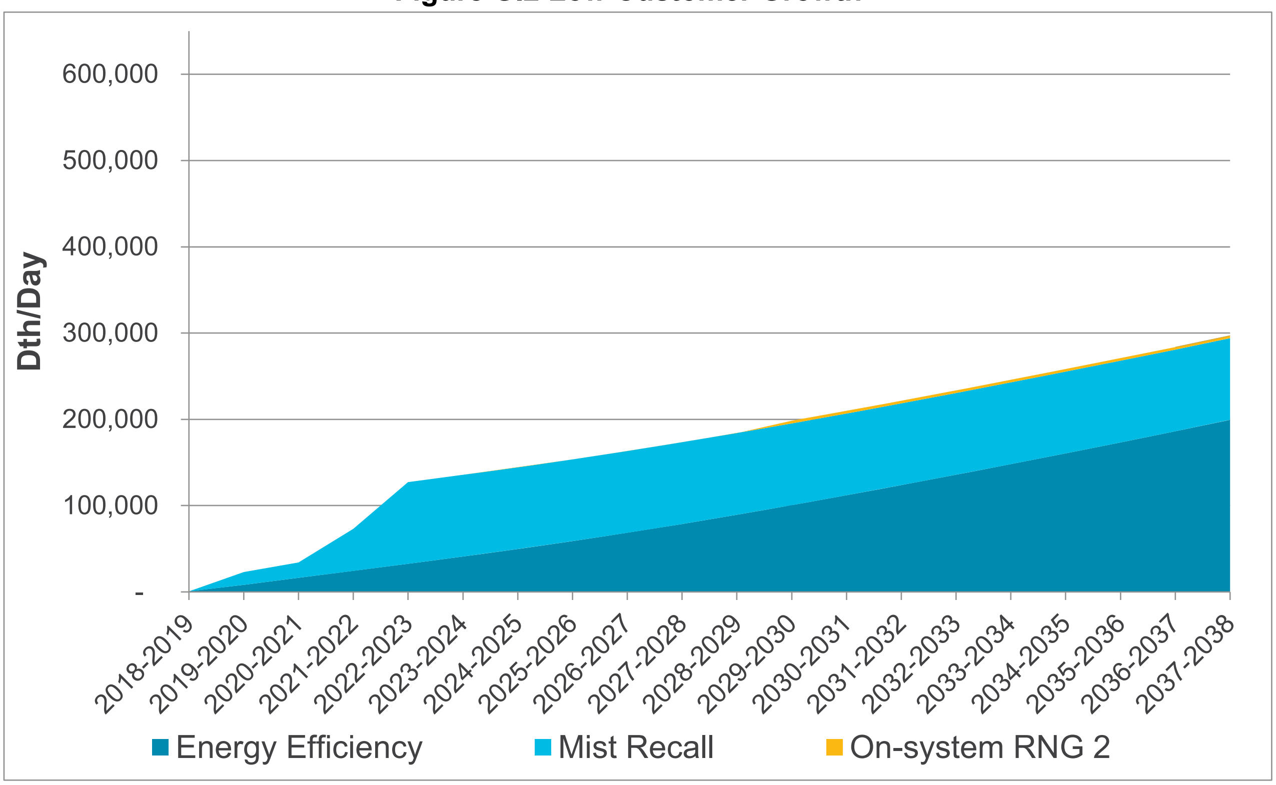


Figure G.3: Use Social Cost of Carbon in Resource Planning

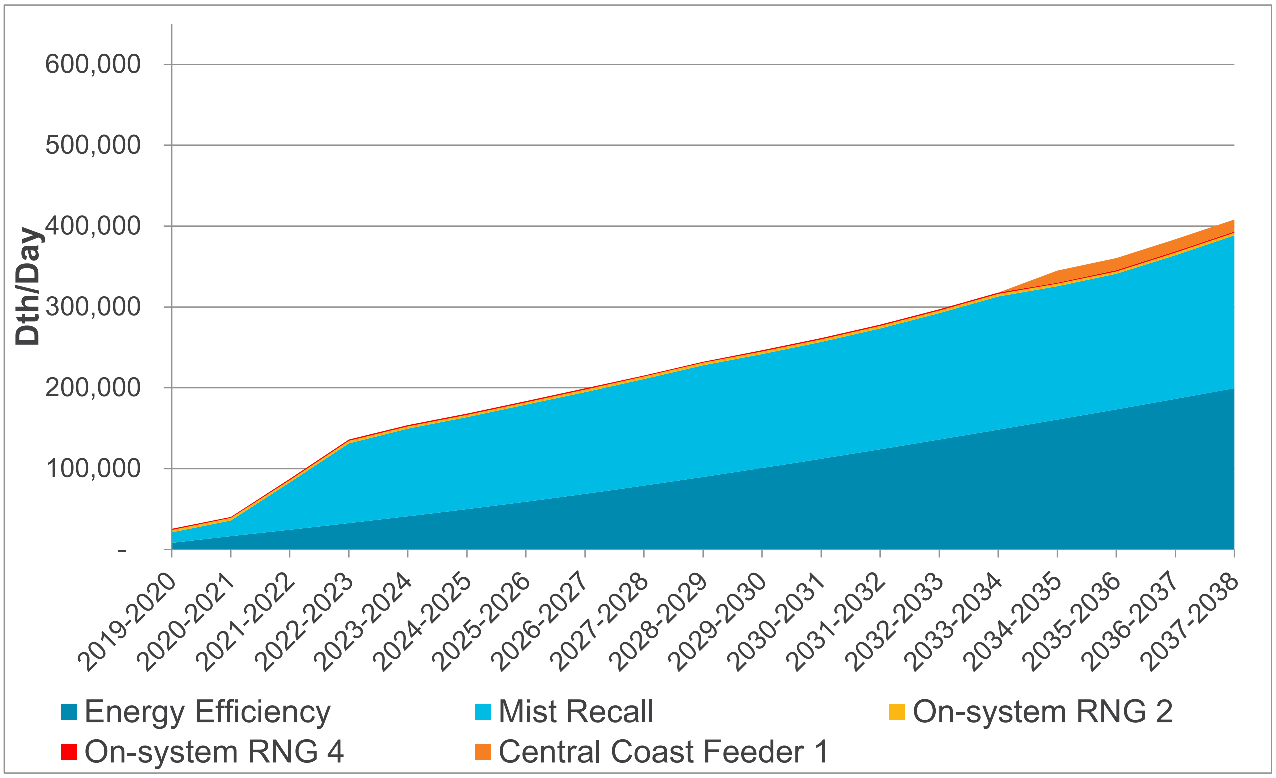


Figure G.4: Deep Decarbonization

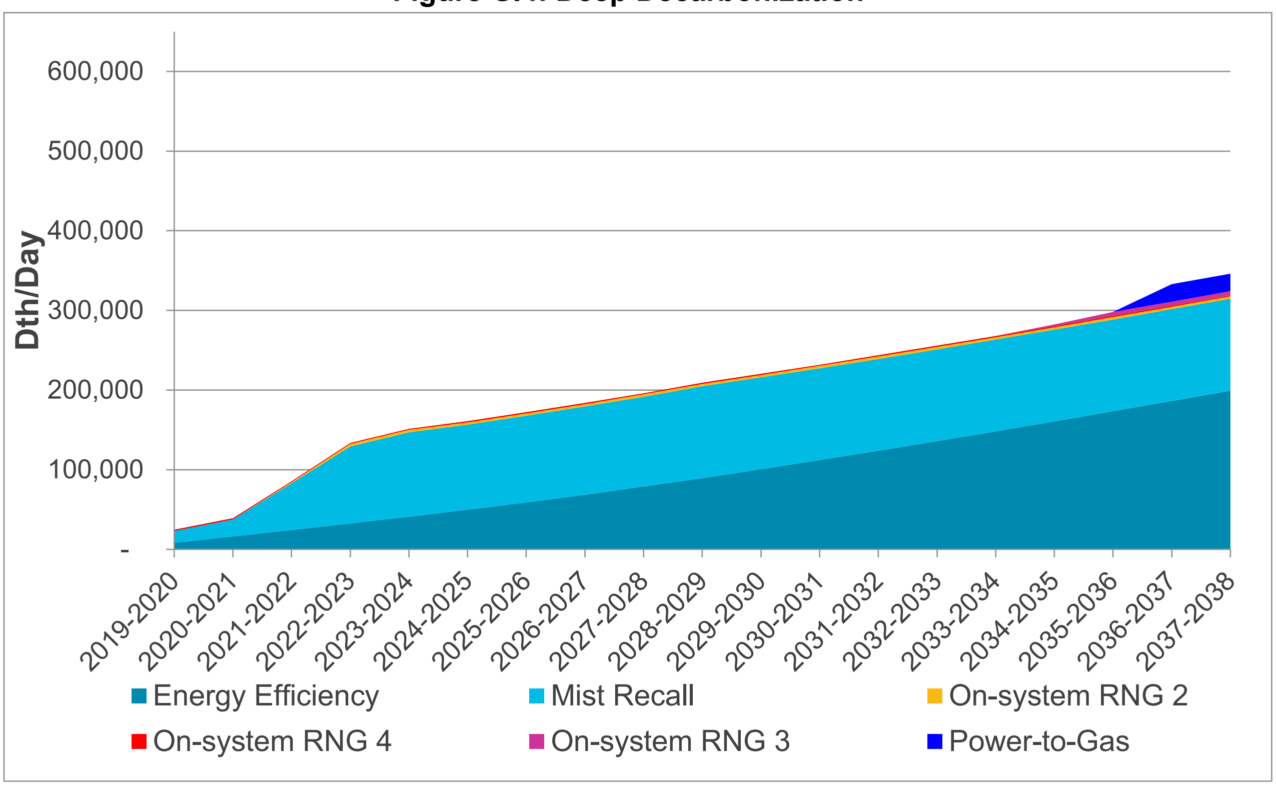


Figure G.5 CNG Adoption in Medium- and Heavy Duty Transportation

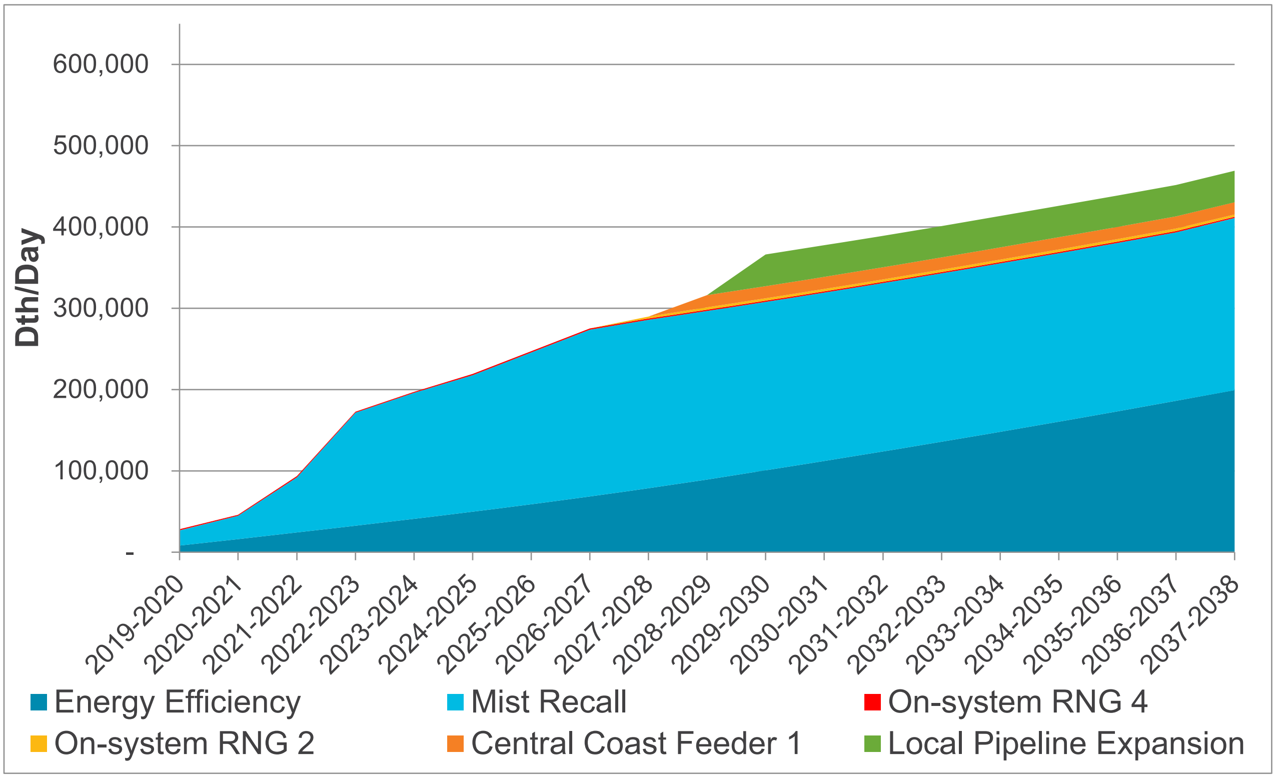
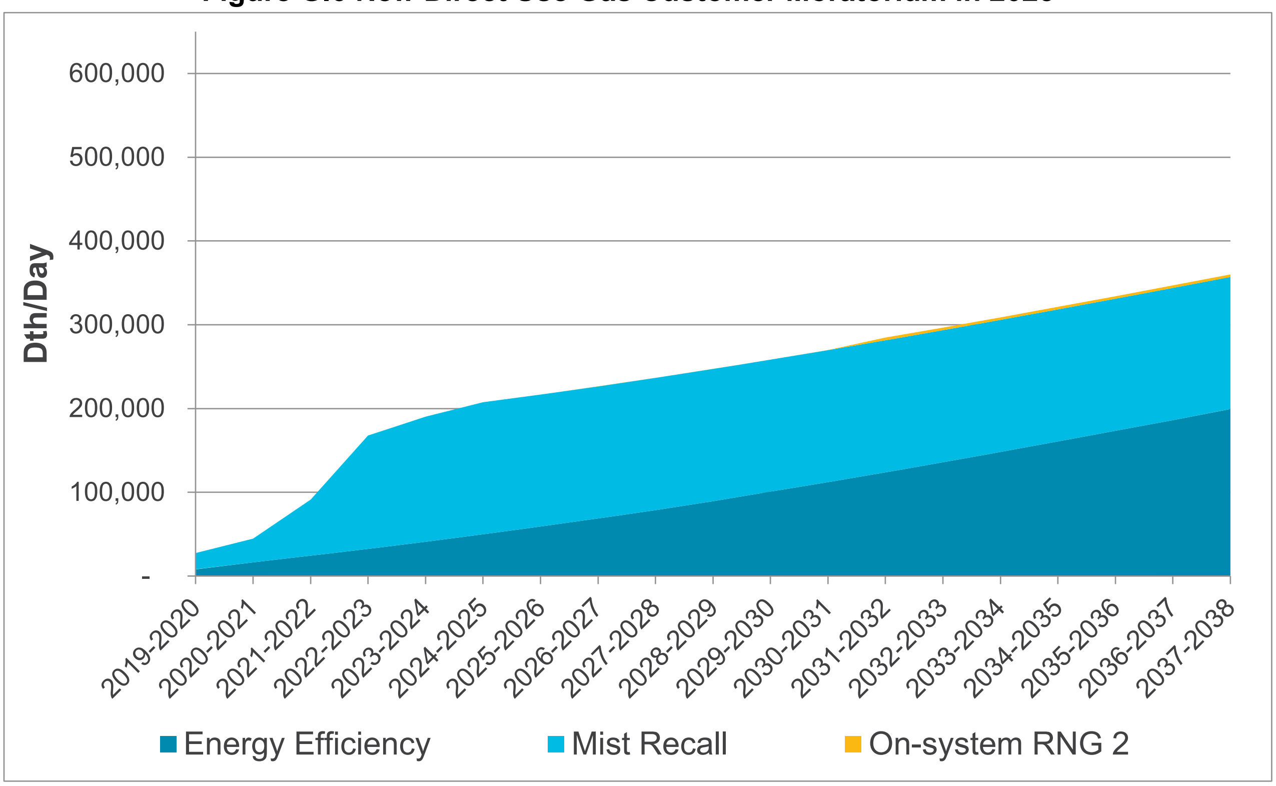


Figure G.6 New Direct Use Gas Customer Moratorium in 2025



PLACEHOLDER FOR CONFIDENTIAL APPENDIX H TO BE FILED SEPARATELY FROM THIS DRAFT

RENEWABLE GAS SUPPLY RESOURCE EVALUATION METHODOLOGY

APPENDIX I

TECHNICAL WORKING GROUP SIGN-IN SHEETS

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* ~~These~~ Attended via Webex

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Michael Lerch	NW Natural	michael.lerch@nwnatural.org
Kyle Frankiewich	WUTC	
Andrew Rector	WUTC	
Michael Breish	NW Energy	
Tom Pardee	Avista	
Dan Kirshner	NWGA	
Tamy Linver	NWN	
Ryan Bracken	"	
Dave Lenar	"	
Steve Storm	"	
Mike Parvuszkiewicz	"	
Carole Barron	"	

* Attended via phone/WebEx link

NW NATURAL 2018 INTEGRATED RESOURCE PLAN (IRP)
27-Jun-18

NAME	COMPANY	EMAIL
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Steve Storm	NWN	
Mike Paruszkiewicz	NWN	
Ryan Bracken	NWN	
Dave Lenar	NWN	
Matt Doyle	NWN	
* Andrew Rector	WUTCC	
* Ed Finklea	AWEC	
* Ken Ross	Fortis B.C.	
* Corey Dahl	WA Attorney General's Office	

* Participated via WebEx & Teleconference

APPENDIX J

MEETING FOR THE PUBLIC BILL INSERT

NW NATURAL'S 2018 INTEGRATED RESOURCE PLAN (IRP)

The IRP being developed this year answers questions like: How much gas will our customers use? How much energy can we save through conservation? Where will NW Natural get its gas supply?

We invite you to join us for a discussion of these and other topics to help us develop the IRP:

DATE: Tuesday, July 17, 2018

TIME: 6 p.m. to 8 p.m.

PLACE: One Pacific Square, 4th Floor Hospitality Room Center
220 NW Second Avenue, Portland, Oregon (accessible by MAX)

NW Natural®

05/18

YOU MAY ALSO MAIL ANY QUESTIONS OR COMMENTS ABOUT THE PLAN TO:

NW Natural
Attn: Integrated Resource Plan
220 NW Second Avenue
Portland, OR 97209

A copy of the draft 2018 Integrated Resource Plan will be available on our website by June 22, 2018.
Go to **nwnatural.com.** Click on the About Us link, then click on Rates and Regulations, then click on Regulatory Activities. Toward the bottom half of the page is a link for the Integrated Resource Plan.