2014

Integrated Resource Plan

LC-60

and UG-131473

NW Natural®

Forward Looking Statement

This planning document contains forward-looking statements. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events and other statements that are other than statements of historical facts. NW Natural's expectations, beliefs and projections are expressed in good faith and are believed to have a reasonable basis. However, each such forward-looking statement involves uncertainties that could cause the actual results to differ materially from those projected in such forward-looking statements.

All subsequent forward-looking statements, whether written or oral and whether made by or on behalf of NW Natural also are expressly qualified by these cautionary statements. Any forward-looking statement speaks only as of the date on which such statement is made. New factors emerge from time to time and it is not possible for NW Natural to predict all such factors, nor can it assess the impact of each factor or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

The forecasts and projections included in this document have been developed for the purposes of integrated resource planning and should not be used for investment decisions. Disclosure of this information or use of the information for investment purposes could constitute a violation of federal securities laws.

NW Natural®

CHAPTER 1 – EXECUTIVE SUMMARY

CHAPTER 2 – GAS REQUIREMENTS FORECAST

CHAPTER 3 – SUPPLY-SIDE RESOURCES

CHAPTER 4 – DEMAND-SIDE RESOURCES

CHAPTER 5 – ENERGY POLICIES AND ENVIRONMENTAL CONSIDERATIONS

CHAPTER 6 – DISTRIBUTION SYSTEM PLANNING

CHAPTER 7 – LINEAR PROGRAMMING AND RISK ANALYSIS

CHAPTER 8 – AVOIDED COST DETERMINATION

CHAPTER 9 – PUBLIC PARTICIPATION

APPENDIX 1 – REGULATORY COMPLIANCE

APPENDIX 2 – GAS REQUIREMENTS FORECAST

APPENDIX 3 – SUPPLY SIDE RESOURCES

APPENDIX 4 – DEMAND-SIDE RESOURCES

THERE IS NO APPENDIX 5

APPENDIX 6 – DISTRIBUTION SYSTEM PLANNING

APPENDIX 7 – LINEAR PROGRAMMING AND THE COMPANY'S RESOURCE CHOICES

APPENDIX 8 – AVOIDED COSTS

APPENDIX 9 – PUBLIC PARTICIPATION

Chapter 1: Executive Summary

I. Introduction and Background

1. Introduction

This Executive Summary provides an overview of the key findings in NW Natural's 2014 Integrated Resource Plan (IRP) and includes the Company's multi-year action plan. NW Natural develops a long-term resource plan with a 20-year planning horizon on approximately two year cycles, with this IRP covering the 2014-2033 timeframe. The primary goals of the IRP are to 1) identify customers' future gas needs (i.e., forecast load), 2) determine the options available to meet those needs (i.e., identify supply-side and distribution resource options), and 3) identify the portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers through rigorous analysis of both costs and risks.

2. Description of NW Natural

NW Natural is a 155 year-old natural gas local distribution and storage company headquartered in Portland, Oregon, serving almost 700,000 customers in Oregon and Washington. 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 60% of NW Natural's customers reside in the Portland area, with another 10% in the state of Washington. Residential customers comprise roughly 90% of the customer base.

Figure 1.1 – NW Natural's Service Territory

3. Regulatory Guidelines

The Oregon requirements for Integrated Resource Planning as set forth in the Oregon Administrative Rule (OAR) 860-027-400 and the Washington requirements as set forth in Washington Administrative Code (WAC) 480-90-238 can be broadly summarized in the following seven actions:

1) Examine a range of demand forecasts;
2) Examine all feasible means of meeting demand;
3) Treat supply-side and demand-side resources (DSM) consistently;
4) Describe the Company's long-term plan for meeting expected load growth;
5) Describe the Company's plan for resource acquisitions between planning cycles;
6) Take uncertainties in planning into account; and
7) Involve the public in the planning process.

II. Principal Conclusions

1. There are immediate as well as future needs under design day peak demand conditions for additional gas supply resources. This is due to (A) load growth; (B) changes to NW Natural's firm peak resource portfolio; and (C) a decreased opportunity for deploying cost-effective energy efficiency. Additionally, improved and more granular modeling has identified the need for distribution system upgrades in Vancouver/Clark County as soon as is feasible and in the Salem area by 2019.

2. There is a high degree of uncertainty regarding proposed regional gas projects (such as methanol/feedstock plants, Jordan Cove LNG, and Oregon LNG) and the prospective interstate pipelines needed to serve them (Cross-Cascades, Pacific Connector, and Washington Expansion). This uncertainty surrounding regional projects beyond NW Natural's control makes it difficult to select a specific long-term gas supply resource portfolio since the optimal set of resource additions depends on which scenario unfolds.

3. The best way to manage the uncertainty regarding prospective interstate pipeline projects is to keep open NW Natural's options to participate as future shippers on Cross-Cascades or the Pacific Connector by using the unique flexibility of NW Natural's Mist storage facility using Mist Recall. This strategy provides a cost effective bridge to a longer-term solution, which likely includes a North Mist Expansion project and subscribing to one of the as-of-yet unbuilt interstate pipelines or pipeline expansions.

4. Investments are required to NW Natural's infrastructure to ensure gas can be reliably transported to NW Natural's customers during peak weather events. The necessary projects are: (A) finishing the refurbishment project at the Newport LNG facility; (B) upgrading the city gate and distribution system in Clark County, WA; and (C) permitting and constructing the South Salem Feeder.

5. Recent events and the high degree of uncertainty accompanying this planning cycle highlight the need to manage the risks facing NW Natural's customers, particularly (A) the risk of assuming 100% reliability of all resources in the Company's firm resource stack; and (B) gas price volatility and the upside risk of natural gas prices over the planning horizon.

6. Analysis of prospective regulation associated with carbon dioxide emissions, which is new in this IRP, shows that such regulation is unlikely to impact resource choices or the action plan in this IRP.

III. Discussion of Principal Conclusions

1. There are immediate as well as future needs under design day peak demand conditions for additional gas supply resources. This is due to (A) load growth; (B) changes to NW Natural's firm peak resource portfolio; and (C) a decreased opportunity for deploying cost-effective energy efficiency. Additionally, improved and more granular modeling has identified the need for distribution system upgrades in Vancouver/Clark County as soon as is feasible and in the Salem area by 2019.

A. Load Growth

NW Natural's load forecast is driven primarily by residential and commercial customer growth. This growth is a function of the health of the local economy and housing market, as well as the relative attractiveness of natural gas versus alternate heating fuels (electricity, oil, etc.) to spur home fuel conversions. As the U.S. continues recovering from the great recession, so do the economies in NW Natural's service territory—as can be seen by the 1.3% customer growth rate experienced in 2013. This is particularly true for NW Natural's Washington service territory, where Clark County is projected to be the third-fastest growing county in the Pacific Northwest.[1] This results in an average annual Firm Sales customer growth rate over the planning horizon of 1.9% in the Company's Base Case load forecast, which is slightly higher than the 1.65% rate forecast in the most recently acknowledged IRP in Washington and 1.84% in the most recently acknowledged Oregon IRP.[2]

The average annual Firm Sales customer growth rates over the planning horizon for Oregon and Washington are 1.6% and 3.8%, respectively. Additionally, NW Natural's Base Case load forecast, net of the energy savings resulting from demand-side management (DSM) energy efficiency programs implemented by the Energy Trust of Oregon (ETO), projects a 1.3% average annual rate of growth in Firm Sales annual load and a 1.3% average annual rate of growth in its Firm Sales design day[3] peak demand over the 20-year planning horizon. The latter rate represents an increase in the growth rate of approximately 0.4% from the average annual rate in the Company's most recently filed IRP, its 2013 Washington IRP. This increase is due to a combination of stronger customer growth and reduced DSM. In addition to being discussed below, DSM is also discussed in detail in Chapter Four - Demand Side Resources.

B. Changes to the Company's Current Firm Resource Stack

One of the most significant changes in this IRP over previous IRPs is a removal of resources from the firm resource stack that NW Natural previously assumed could be reliably called upon to meet design day peak demand and their partial replacement with interim resources as a bridge to a long-term solution. The changes are:[4]

---

1 Woods & Poole forecast Clark County to have the third-highest rate of population growth of all 119 counties in Idaho, Oregon, and Washington over the period 2010 through 2040. Woods & Poole is a commercial provider of economic and demographic forecasts.

2 UG-120417, NW Natural's Washington2013 Integrated Resource Plan and LC 51, NW Natural's Oregon 2011 Modified Integrated Resource Plan.

3 NW Natural uses the terms "peak day" and "design day" interchangeably in this IRP unless otherwise stated.

4 In August, 2014, shortly before filing this IRP NW Natural signed a contract to add citygate delivery service of 20,000 DT/day for the winter of 2014/15 to ensure reliable service to customers for the upcoming winter

1. Removal of the Plymouth LNG facility's deliverability starting immediately
2. Removal of a portion of the Jackson Prairie storage facility's deliverability starting in 2018[5]
3. Addition of segmented capacity on Northwest Pipeline in 2014 for a 5-year period

These decisions are discussed in more detail in Chapter Three - Supply Side Resources. However, as a high-level summary, NW Natural has transportation contracts with Northwest Pipeline (NWP) to move gas from both the Plymouth and Jackson Prairie storage facilities that have been included in the Company's firm resource stack for decades. During the December cold spell last winter, NWP curtailed the Company's service from Plymouth, showing that the Company's service from the facility through the Columbia River Gorge is less reliable than NW Natural previously believed. Subsequently, NWP confirmed to NW Natural that its capacity from Plymouth and Jackson Prairie, while labeled as firm capacity, is "secondary firm" and is subject to curtailment. As a result, NW Natural removed the Plymouth facility from its firm resource stack starting this upcoming winter and for its modeling removes a portion of Jackson Prairie from the firm set of resources starting in 2018.[6]

Removing Plymouth from the firm resource stack created an immediate resource shortfall that is being partially filled in the near-term with a resource known as "segmented capacity." Chapter Three discusses segmented capacity in detail, but as a practical matter, at very low cost, it allows NW Natural to move additional gas supplies from the Sumas trading hub to the Company's service territory by utilizing the Company's existing contracts. Segmented capacity is considered reliable in the interim since it relies on the much less constrained path from Sumas, but it is also technically secondary firm (or subordinate) capacity on NWP—just like the pipeline capacity from Plymouth LNG and a portion of the capacity from Jackson Prairie. Consequently, segmented capacity cannot be counted upon as a permanent solution to the current resource deficiency as the path along the I-5 corridor becomes more constrained. To ensure future reliability, the Company models a two year phase out of the segmented capacity on NWP from the Company's firm peak resource stack beginning in 2017.

C. DSM Cost-Effectiveness

On a system wide basis, the Company's overall forecast of 20-year demand-side management (DSM) energy savings is down slightly from the projection in NW Natural's most recently filed IRP (the Washington 2013 IRP) due to a decrease in the cost-effectiveness of DSM measures.[7] There are three primary reasons the cost-effectiveness of DSM programs decreased relative to prior IRPs:

1. Lower forecasted gas prices than previous IRPs led to lower avoided costs

---

[5] NW Natural may ultimately decide to keep this portion of Jackson Prairie for economic and balancing reasons.

[6] While the pathway from Jackson Prairie to NW Natural's service territory has never been constrained since its inception in 1989, a curtailment is possible in the future. Complicating matters, there was an explosion on March 31, 2014 at the Plymouth LNG facility that damaged certain liquefaction process equipment and one of Plymouth's two storage tanks. Even if NW Natural wanted to fill its storage account for the coming winter, there is little or no opportunity to do so.

[7] This is true even when including the technical potential of the non-cost effective measures offered in Oregon under the exceptions granted in Order No. 94-590 in Docket No .UM 551. *See* Docket No. UM 1622.

2. Programs are providing less energy savings than expected
3. DSM program costs are proving higher than expected

To mitigate the impact of these decreases in cost-effectiveness, the Public Utility Commission of Oregon is temporally allowing a limited exception to the cost effective standard. Note, however, that while cost-effectiveness has decreased overall, due to a higher rate of customer growth in NW Natural's Washington service area, the overall savings potential in Washington have increased substantially. The figures on page 4.3 detail the cost-effectiveness supply curves for both Oregon and Washington.

D. Improved Modeling and Resource Deficiencies in Vancouver/Clark County and the Salem Area
As Chapter Seven discusses in more detail, NW Natural improved its system modeling in this IRP in several ways. In addition to modeling down to the load center, the resource modeling now incorporates the physical capacity limitations on both NWP's gate stations as well as the Company's pipeline capacity for moving gas from the gate station into the load center. The modeling enhancements combined with an updated customer growth forecast of NW Natural's Clark County service territory have highlighted an immediate resource deficiency in both the supply and the distribution system in the Vancouver load center, and a projected deficiency in the Salem/Albany area beginning in 2019. These are illustrated in Figures 1.2 and 1.3 respectively (following).

Figure 1.2 – Clark County Design Day Peak Demand and Physical Delivery Constraints

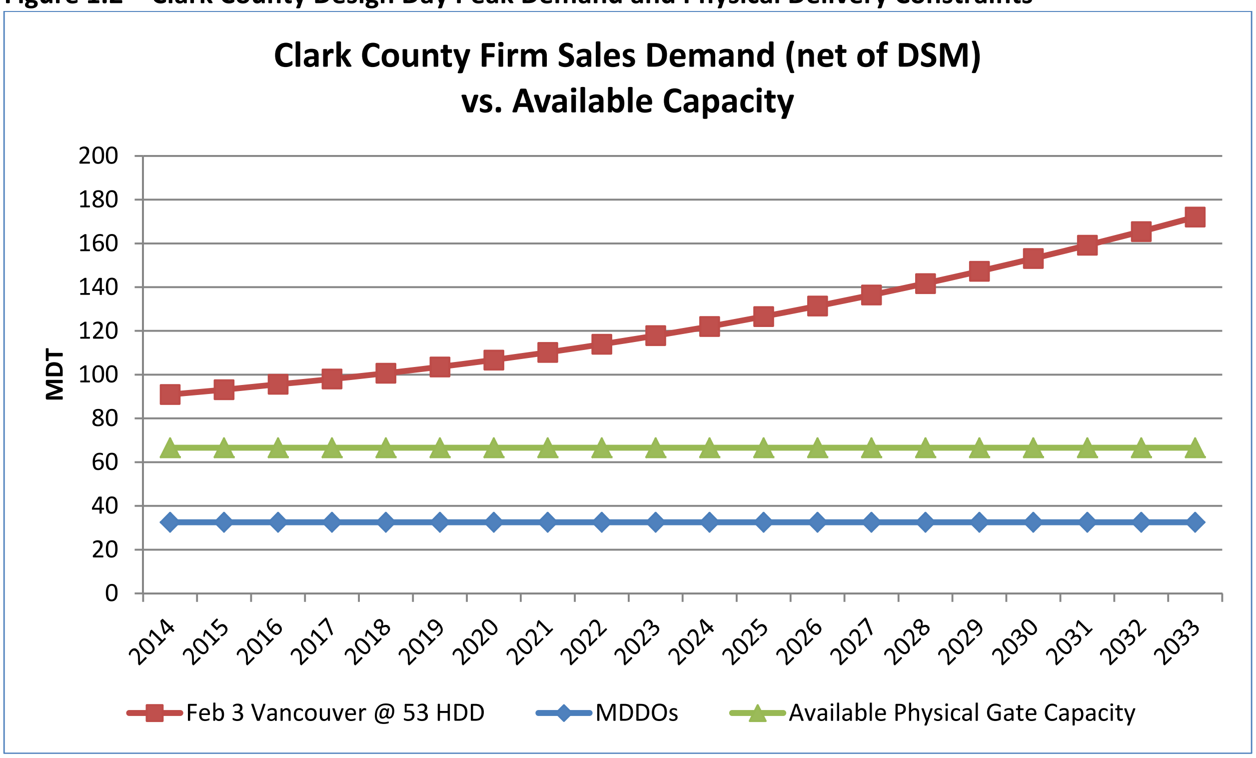
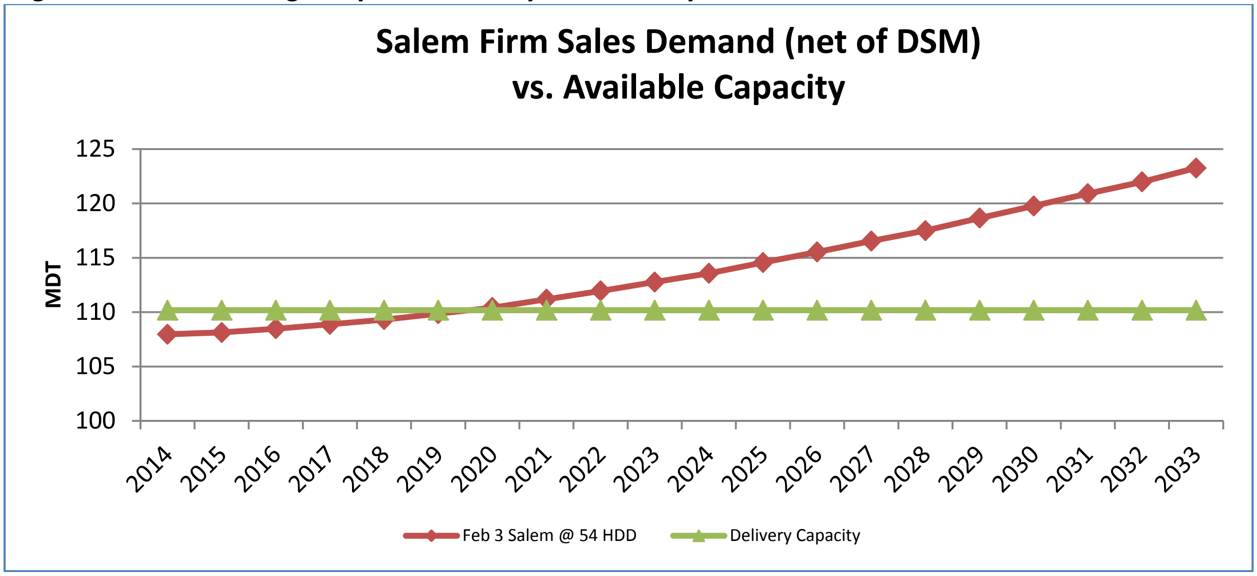


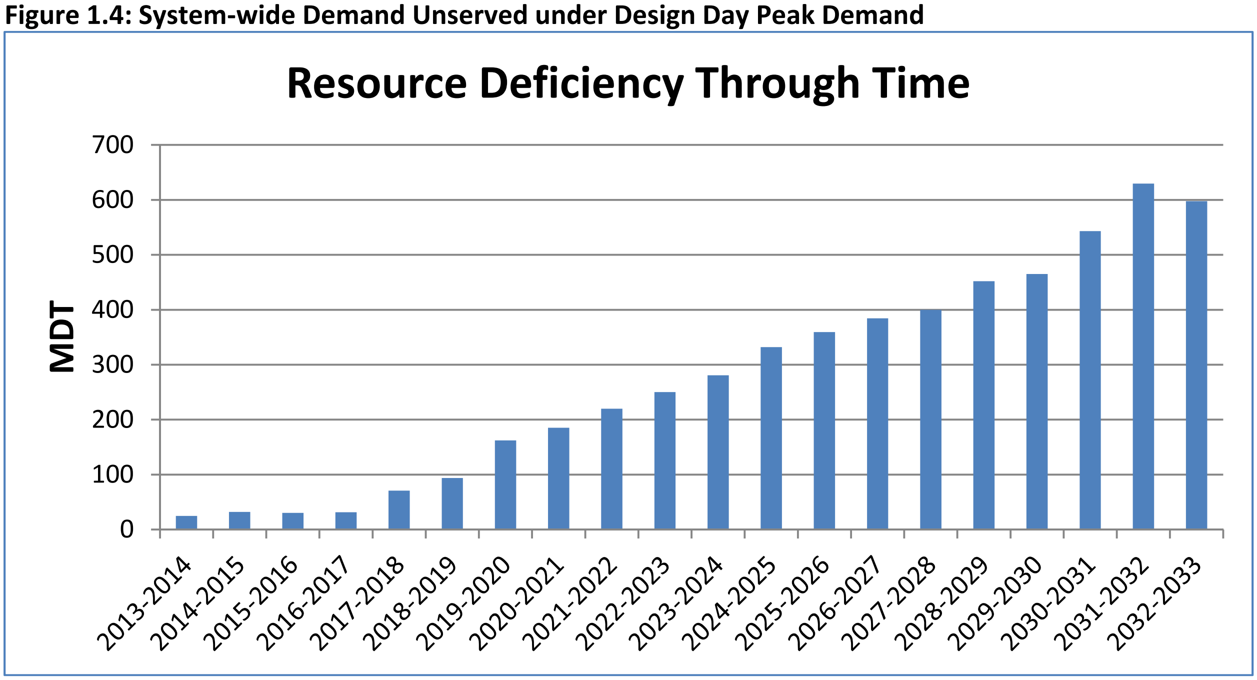
Figure 1.3 - Salem Design Day Load and Physical Delivery Constraints



E. Total Impact and the Need for Additional Resources

Combining the impacts discussed above allows NW Natural to determine its resource position—how resource deficient/sufficient the Company is over the planning horizon—in order to establish the level of resource acquisitions necessary to reliably serve customers. Figure 1.4 (following) shows the amount of unserved demand that would be expected on NW Natural's system during a design day peak demand event through time if no additional resources were added.

Figure 1.4: System-wide Demand Unserved under Design Day Peak Demand



2. ***There is a high degree of uncertainty regarding proposed regional gas projects (such as methanol/feedstock plants, Jordan Cove LNG, and Oregon LNG) and the prospective interstate pipelines needed to serve them (Cross-Cascades, Pacific Connector, and Washington Expansion). This uncertainty surrounding regional projects beyond NW Natural's control makes it difficult to select a specific long-term gas supply resource portfolio since the optimal set of resource additions depends on which scenario unfolds.***

The next step in determining the appropriate resource portfolio is to identify the supply options available to meet the deficiency detailed above and in Chapters Two and Four. The options and costs of the supply-side resources considered in this IRP are discussed in detail in Chapter Three- Supply Side Resources, but a high level description of the most plausible choices analyzed are found in Table 1.1 below:

Table 1.1 Potential and Plausible Supply Side Resources

	Resource	**Description**	**Abbrev**
Beyond NWN Control	Cross-Cascades	New Interstate Pipeline project connecting GTN's mainline north of Madras, Oregon to the gate station at Molalla. Gas coming off of Cross-Cascades could be taken directly into NW Natural's system or transported over NWP via an NMAX service.	CC
	Washington Expansion	Expansion of NWP's Interstate Pipeline in the I-5 corridor from Sumas south associated with the proposed Oregon LNG export facility.	WEX
	Sumas Expansion (Regional)	Similar to the Washington Expansion but a smaller expansion that is sized assuming there is no Oregon LNG Project.	SE(R)
	Pacific Connector	New Interstate pipeline associated with the proposed Jordan Cove LNG export facility from Turquoise Flats (near Malin, Oregon) to the Jordan Cove facility near Coos Bay. This option includes the ability to move gas north on NWP's Grants Pass Lateral to the Company's load centers.	PCGP
Choice of NWN	Mist Recall	Additional to the existing Mist storage capacity currently reserved for the core market, the Company has capacity contracted to third parties in the interstate/intrastate storage market that can be recalled for service to the Company's utility customers as agreements expire.	MR
	North Mist	Development of one or more new reservoirs, compression station, and pipeline facilities located to the north of the existing Mist storage facilities complex.	NM
	Sumas Expansion (Local)	A local Sumas expansion that is similar to a regional expansion, but is initiated at the request of NW Natural and so sized and timed specifically for the Company's needs.	SE(L)
	Christenson Compressor	A compressor located between Newport and Salem to increase the takeaway capacity of Newport LNG.	CCP
	All others	All others – such as Satellite LNG in Clark County or Salem and other resources (see Chapters Three and Seven)	OTHER

When NW Natural began evaluating the supply-side resource options available to meet its projected resource deficiency, it became apparent that including all of the options in Table 1.1 as possibilities available to be selected by the optimization in the typical manner of analysis in an IRP made little sense. This is because the prospects of a majority of the interstate pipeline options are interdependent and it is highly unlikely all of them will go forward. Furthermore, NW Natural does not have control over whether most of the prospective interstate pipeline options will get built (as detailed in Table 1.1 above). Consequently, some of the options in the table will develop into real options for the Company and others will not, and this is largely independent of any decision-- or set of decisions-- made by NW Natural. Therefore, to an extent not typical in past IRPs, the least cost resource portfolio is largely contingent upon which future develops. In this case, hypothetical examples are helpful in illustrating this contingent future dilemma; how it impacts the supply resources available to NW Natural; and ultimately how it could force NW Natural into a sub-optimal firm resource stack if the Company does not pursue a "wait and see" strategy at this time:

<u>Hypothetical Example 1:</u>
While it is possible that either the Washington Expansion (WEX) *or* the Pacific Connector (PC) could be built, it is unlikely both would. However, including all prospective projects in the choice set of supply side resources for portfolio choice is typical in IRPs. Assume NW Natural took the classical approach to IRP modeling and included both projects in the choice set of resources and optimization showed subscribing to capacity on the Pacific Connector as customers' least cost option. Subsequently, the Company made arrangements to subscribe as shippers to PC, while foregoing the opportunity to contract capacity on the Washington Expansion. However, if PC ended up not being built—an outcome beyond NW Natural's control—at a date too late for the Company to secure capacity on WEX, NW Natural would have had to resort to potentially more costly options for its customers. Clearly, in this case it would not have been in NW Natural's best interest to construct an inflexible plan dependent upon the Pacific Connector, even though it was theoretically the least cost option.

<u>Hypothetical Example 2:</u>
Assume NW Natural asked NWP to build a local expansion from Sumas to its service territory to satisfy its needs because the other interstate pipeline options were uncertain to be built and beyond the Company's control. However, after this decision was made the Jordan Cove LNG facility subsequently went forward and the Pacific Connector was built. In this case it may have been that PC would have been lowest cost option to serve customers, rendering the decision to move forward with the local Sumas Expansion a bad choice in hindsight.[8]

Given the current climate of uncertainty about what supply side resources will actually be available in the future to meet customer needs, NW Natural determined it best to analyze this risk with five different scenarios that represent the futures that have a tangible possibility of coming to fruition given today's information. The Company analyzed each scenario to determine the scenario-specific portfolio of resources that represents the least cost option for that possible future. This analysis is presented in detail in Chapter Seven- Linear Programming and Risk Analysis and a description of each scenario is provided in Table 1.2 below.

[8] Note that if NW Natural requested NWP to construct a Sumas South Expansion on its behalf it would require the Company to be locked in to that capacity for a significant amount of time.

Table 1.2: Plausible Future Scenarios

Scenario	Label	Scenario Description
A: No LNG Exports	A1	No LNG Exports and No Regional Projects
	A2	No LNG Exports and all Regional Pipeline options available (in 2020)
	A3	No LNG Exports and only Sumas Expansion (Regional) pipeline option available in 2020 (Cross-Cascades is not an option)
B: LNG Exports	B1	Exports from Oregon LNG in 2020 (with all Regional pipeline options)
	B2	Exports from Jordan Cove in 2020 (with all Regional pipeline options)

As is explained by the hypothetical examples above, it is not plausible to assume that all of the resources shown in Table 1.1 above are available in each scenario described in Table 1.2. Hence, Table 1.3 shows the resources that are available for selection in the optimization by scenario:

Table 1.3: Resources Available for Selection by Scenario

Resources Available	Abbrev	Scenario				
		A1	A2	A3	B1	B2
Cross-Cascades	CC		X		X	X
Pacific Connector	PCGP					X
Washington Expansion	WEX				X	
Sumas Expansion Regional	SE(R)		X	X		X
Sumas Expansion Local	SE(L)	X	X	X	X	X
Mist Recall	MR	X	X	X	X	X
North Mist	NM	X	X	X	X	X
Christenson Compressor	CCP	X	X	X	X	X
All others	OTHER	X	X	X	X	X

In summary, NW Natural believes there is currently too much uncertainty regarding prospective pipelines projects to determine the long-term resource portfolio that represents the best mix of costs and risks. Furthermore, more clarity on prospective projects is expected in the two to five year timeframe to alleviate much of this uncertainty. Given this information, it is not surprising that the analysis performed by the Company and presented in detail in Chapter Seven shows the best course of action is to use flexible resources to reliably meet customers' needs in the near-term while maintaining optionality to participate in prospective interstate pipeline projects. This allows the Company to continue to analyze future supply-side resource projects as time passes and more information becomes available.

3. The best way to manage the uncertainty regarding prospective interstate pipeline projects is to keep open NW Natural's options to participate as future shippers on Cross-Cascades or the Pacific Connector by using the unique flexibility of NW Natural's Mist storage facility (i.e. Mist Recall). This strategy provides a cost effective bridge to a longer-term solution, which likely includes a North Mist Expansion project and subscribing to one of the as-of-yet unbuilt interstate pipelines or pipeline expansions.

As can be seen in Chapter Seven, each plausible future (i.e. scenario) described above was analyzed to determine the least cost portfolio under the relevant conditions for that future using the Company's cost minimizing SENDOUT® optimization model. Many of the resources chosen are selected regardless of which interstate pipeline projects get built. Specifically, the resources chosen to be added to NW Natural's firm resource stack in the near-term (between now and 2020) are identical across all scenarios, though the resources added to the portfolio in 2020 and thereafter vary depending upon which future unfolds. Detailed results of this portfolio analysis are found in Chapter Seven, with a summary below.

<u>Resource Additions before 2020</u>
Resource additions before 2020 are robust across all scenarios, with the following supply resources selected in every scenario:

1) Segmented Capacity on NWP (2014-2018)
2) Incremental Mist Recall (2015 and thereafter)

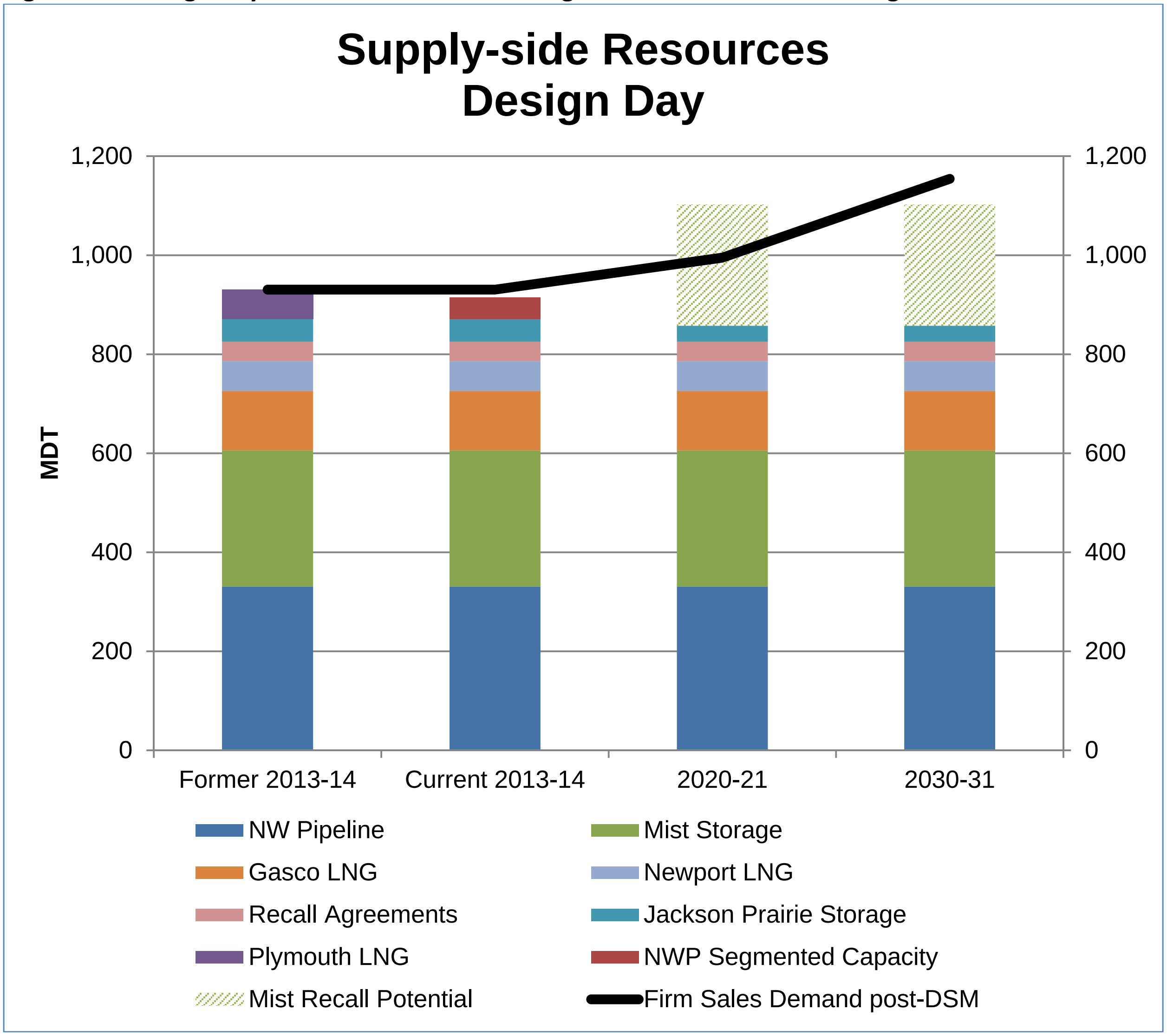
As discussed above, on a system-wide basis replacing Plymouth LNG with segmented capacity still leaves NW Natural slightly resource deficient for the upcoming winter from a peak demand planning perspective. This shortfall during cold weather events is exacerbated over time if new resources are not added to the Company's portfolio (see Figure 1.4 above) due to load growth and the removal of a portion of Jackson Prairie storage from the firm resource stack in 2018 and the interim segmented capacity being phased out starting in 2017.

Therefore, the main near term resource addition (up until at least 2020) in every scenario that is chosen as the least cost option to meet expected shortfalls is Mist Recall. Mist Recall is the linchpin of the Company's strategy to keep its options open while the prospective interstate pipeline projects play out and is described in detail in Chapter Three. The Mist storage facility is a flexible resource for NW Natural's customers in that recall capacity can be added in smaller increments,[9] allowing the Company to address resource shortfalls as they arrive along with updated information about load growth, DSM, and most importantly prospective interstate pipeline projects. As can be seen in Chapter Seven, the amount of Mist Recall chosen as the best combination of cost and risk for NW Natural customers is not on the same timeline in every scenario. That being said, in each prospective future the entire 245 MDT/day of Mist Recall available is expected to be added to the portfolio by the end of the planning horizon. Even with Mist Recall exhausted, the resources currently available to meet extreme cold weather events are not sufficient at the end of the 20 year plan, as is shown in Figure 1.5 (following).

---

9 As opposed to say, signing a precedence agreement for a long-term obligation to a significant amount of interstate pipeline capacity on an uncertain pipeline project.

Figure 1.5 - Design Day Peak Demand with Existing Resource Portfolio Including Mist Recall



<u>Resource Additions 2020 and Later</u>

Table 1.4 that follows details the resources selected to meet expected shortfalls later in the planning horizon. Along with the discounted expected total system costs under each scenario (i.e., Net Present Value of Revenue Requirements, or NPVRR), the table also shows the resources that were selected as part of the portfolio. Additionally, the year in which resource would be added to the firm resource stack—to be called upon to meet peak demand should that future happen—is noted.

Table 1.4 – Summary of Resource Additions that Vary by Scenario

Scenario	Resources Selected	Total NPVRR ($Billion)
A1: No Regional Project	North Mist Expansion (2020) Sumas Expansion (Local) (2025)	**$6.663**
A2: All Pipeline Options available (no LNG Exports)	Cross-Cascades (2020) North Mist Expansion (2030)	**$6.607**
A3: Sumas Expansion (Regional) (no LNG Exports; no Cross-Cascades)	North Mist Expansion (2020) Sumas Expansion (Local) (2025)	**$6.663**
B1: Oregon LNG (with Washington Expansion)	Cross-Cascades (2020) North Mist Expansion (2030)	**$6.636**
B2: Jordan Cove LNG (with Pacific Connector)	Pacific Connector (2020) North Mist Expansion (2030)	**$6.709**

The following conclusions can be drawn from these results, the details of which are discussed in Chapter Seven:

1) In addition to Mist Recall a North Mist Expansion is needed within the planning horizon under every scenario, and potentially as soon as 2020 under certain conditions.
2) Additional pipeline capacity is needed under every scenario in addition to Mist Recall and North Mist Expansion. Which particular pipeline option is the least cost option depends upon the future that unfolds.
3) The amount and timing of Mist Recall, North Mist, and interstate pipeline capacity added to the portfolio varies across scenarios.
4) Subscribing to the Washington Expansion or a regional Sumas Expansion is not chosen in any scenario.
5) The least cost future is the no LNG with a Cross-Cascades pipeline scenario; the highest cost future is with Jordan Cove LNG and the associated Pacific Connector.

An important new finding in this IRP is that a North Mist expansion project is part of the portfolio regardless of the future that comes to fruition. This indicates that no matter the future that plays out, a North Mist expansion is part of the preferred portfolio.

North Mist is the label NW Natural uses for a prospective project expanding the storage and delivery capacity of the Mist Storage facility. The Company modeled North Mist expansion as a unique, standalone project in this IRP, with the working concept of the project involving a collection of facilities that are not physically interconnected with NW Natural's existing storage and transmission facilities.[10] Since North Mist is a developing concept there are some remaining uncertainties regarding this project's cost. For one, NW Natural does not fully control the costs of the project since other parties may be

10 There may be alternative configurations of the project which integrate the North Mist facilities with NW Natural's existing facilities that are lower cost than the standalone option modeled in this IRP. Further investigation of this option is necessary.

involved, with the project's cost declining from the perspective of core customers, if one or more third parties participates in the expansion. Specifically, costs are reduced for NW Natural customers if the new takeaway pipeline is upsized due to third party participation.

Chapter Three discusses the North Mist expansion to one or more new reservoirs and the new pipeline necessary to connect the project to the Company's system. At the end of this chapter an action item to conduct additional analysis regarding North Mist, and in particular upsizing the takeaway capacity of the project to further evaluate the project's feasibility, is included.

In addition, NW Natural expects that it will be a shipper for additional capacity on an as of yet undetermined interstate pipeline given that in all scenarios the North Mist project is accompanied by an interstate pipeline option. The Cross-Cascades pipeline shows as the lowest cost interstate pipeline option at the current time, though subscribing to the pipeline is dependent upon the pipeline existing. Furthermore, if the Jordan Cove LNG project goes forward and the Pacific Connector is built, subscribing to PC is the least cost alternative. Consequently, at the current time NW Natural finds it is best to preserve the optionality to be shippers on the Cross-Cascades or Pacific Connector pipelines, with participation potentially including discussions with project sponsors.

If neither the Cross-Cascades nor the Pacific Connector pipelines are developed, the Company's fallback plan for acquiring additional interstate pipeline capacity is a Sumas Expansion (Local) of NWP built at the request of NW Natural. While more expensive, this project can be timed and sized more closely to the Company's needs. This project would not be needed until 2025 at the earliest. Consequently, no action is needed at this time. In the meantime, the Company will continue to explore other potentially lower cost alternatives.

There is one other post-2020 resource chosen in every scenario: the Christensen Compressor Project (CCP). It is selected to be added to the Company's resources in every scenario in 2025 and provides additional local peaking gas supply by adding additional rated capacity from the Newport LNG facility to the Salem and Albany load centers to meet anticipated shortfalls. Note that this project is not needed for more than 10 years, and is, therefore, not found in the Action Plan at the end of this Chapter.

Testing the Robustness of the Results with Risk Sensitivities

The results shown in Table 1.4 and discussed above are dependent upon assumptions about load growth, gas prices, carbon regulation, and reliability. To assess the robustness of these results, the Company tested the least cost portfolio across a number of assumption sensitivities. This risk analysis is discussed in detail in Chapter Seven, but Table 1.5 (following) sets forth a high level summary of the risks evaluated:

Table 1.5 Risk Sensitivity Results

Sensitivity	Risk Category	Impact on Assumptions	Impact on Near-term Resource Acquisitions
High Customer Growth	Demand	2.1% avg annual growth	Increased Mist Recall
Low Customer Growth	Demand	1.4% avg annual growth	Decreased Mist Recall
High Gas Prices	Demand	3% DSM increase	None
Low Gas Prices	Demand	1% DSM decrease	None
Medium Emerging Markets	Demand	Higher demand	None
High Emerging Markets	Demand	Higher demand	None
Carbon Regulation – High Price	Demand	Lower growth	None
Carbon Regulation –Medium Price	Demand	Lower growth	None
LNG Export Projects	Resource Options		None
Pipeline Construction Costs	Resource Costs	Higher/Lower pipeline tariffs	None
Reliability of Existing Resources	Loss of Load		None

In most cases, the risks identified by the Company do not alter the near-term resource acquisition plan (i.e., the Action Plan). Furthermore, in the cases where the near-term resource acquisition plan is impacted, the only change is the amount of Mist Recall that is acquired by the Company in the years before 2020. Given the adaptability of Mist Recall, this is not a troubling result as NW Natural can add Mist Recall in increments that make sense for its customers. In summary, this risk analysis shows that the Company's strategy of using Mist Recall to meet resource shortfalls until 2020 is robust across all plausible futures.

To sum up, if one thinks in terms of a preferred portfolio, NW Natural's preferred portfolio could be described as relying on Mist Recall in the short-term and, pending updated analysis in future IRPs, a North Mist expansion in concert with the lowest cost available new interstate pipeline option in the long-term.

4. Investments are required to NW Natural's infrastructure to ensure gas can be reliably transported to NW Natural's customers during peak weather events. The necessary projects are: (A) finishing the refurbishment project at the Newport LNG facility; (B) upgrading the city gate and distribution system in Clark County, WA; and (C) permitting and constructing the South Salem Feeder.

The following infrastructure projects are selected under each scenario along an identical or similar timeframe:[11]

[11] Note that the Mid-Willamette Valley Feeder (MWVF) is not included in this list since it is nearly complete and the IRP is a planning document focused on future resource decisions. The MWVF is included in the Company's firm resource stack for all of its modeling in this IRP. The Newport LNG refurbishment is included in this list since the project is in the early stages and most expenditures have not been made.

1) Continue with the refurbishment project of the Newport LNG facility (2014)
2) Upgrade city gates and the distribution system in Clark County, WA (beginning in 2014)
3) Begin permitting (2015) and constructing (In service 2019) the South Salem Feeder

The continuation of the recently commenced Newport LNG refurbishment project is necessary to prolong the life of the Newport facility so that it can continue to be included in the firm resource stack and serve NW Natural customers into the future. The ongoing project is discussed in more detail in Chapter Three and is included in the Action Plan below.

As is detailed in Figure 1.2 above, NWP gate stations serving Vancouver/Clark County are insufficient to serve current design day peak demand at the local level. As the Company's analysis confirms, NW Natural needs to address this issue immediately in order to ensure no outages occur in the event of severely cold weather.

This infrastructure improvement entails a number of city-gate and distribution system upgrades, with the projects detailed in Chapter Six – Distribution System. Until these projects are complete NW Natural plans to temporarily use LNG and CNG trailers to supplement interstate pipeline deliveries to the Vancouver load center under cold weather conditions to avoid curtailing firm service customers.

Lastly, the Salem area has experienced low pressure during recent cold weather events and, as is shown in Figure 1.3 above, beginning in 2019 the projected peak day demand of the Salem area is expected to outstrip the available capacity into the Salem area. Consequently, regardless of the scenario being considered, the South Salem Feeder is selected in 2019 to add capacity from the Mid-Willamette Valley Feeder into the Salem area to address this shortfall. This project is also detailed in Chapter Six.

Note that these projects are near-term projects that can be found in the Action Plan at the end of this chapter.

5. Recent events and the high degree of uncertainty accompanying this planning cycle highlight the need to manage the risks facing NW Natural's customers, particularly (A) the risk of assuming 100 % reliability of all resources in the Company's firm resource stack; and (B) gas price volatility and the upside risk of natural gas prices over the planning horizon.

As a general rule of thumb, the more uncertain the future, the greater the need for diversification. The current climate of atypically high uncertainty due to prospective export LNG and interstate pipelines reinforces NW Natural's need for a diverse and appropriately hedged portfolio of gas supply resources, and has spurred the Company to think about sources of risk that have been under-analyzed.

A. Risk of Assuming 100 % Reliability of Resources in Firm Resource Stack
NW Natural introduced the concept of performing a reliability risk analysis as part of the IRP process in an earlier IRP. NW Natural's recent experiences with the Plymouth LNG facility have underscored the need to question the typical assumption in IRPs that the resources considered firm in the resource stack will be 100% reliable in meeting load during extreme weather events. Not only did NW Natural's pipeline transportation service from the Plymouth LNG facility get curtailed this past winter, but an explosion damaged the facility itself at the end of March, 2014. The first event unexpectedly led the Company to remove the facility from its firm resource stack on little notice, and the second event reinforced the potential reliability risks of its resources notwithstanding their years of prior service. NW

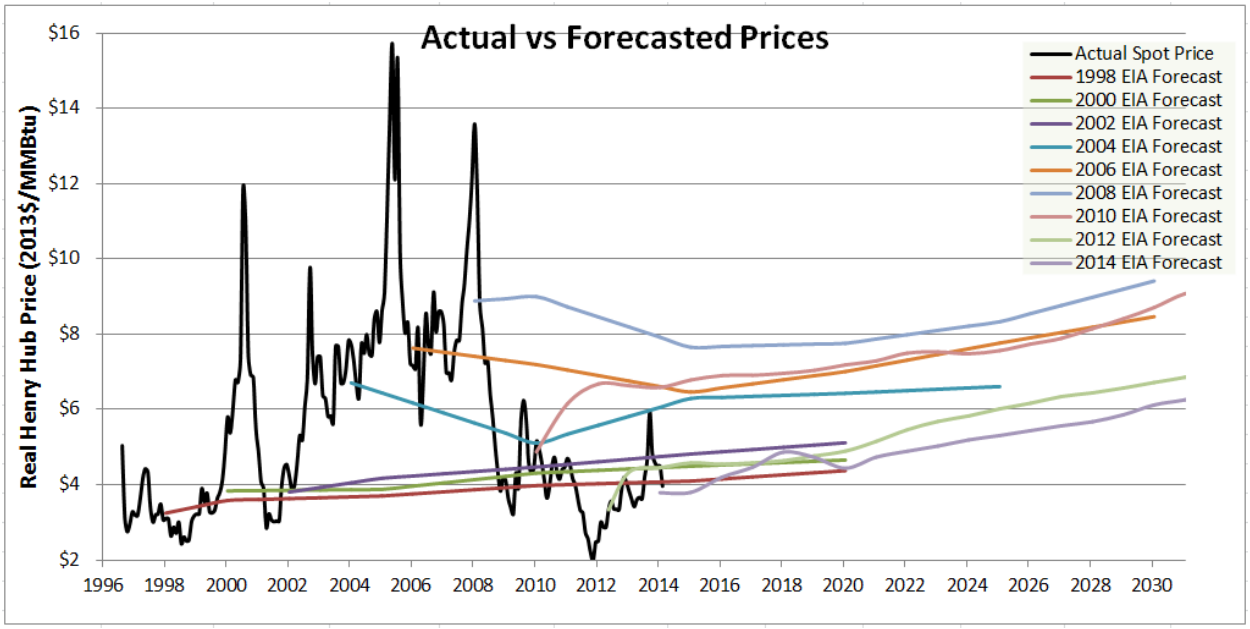
Natural believes a plan based on assuming all resources are available 100% of the time is an insufficient plan and does not adequately address the risk of a resource failure. The challenge is to estimate the probability of the failure occurring coincident with a peak (or near peak) event. The Company is currently gathering documentation supporting this concept and hopes to incorporate this analysis in the next IRP.

In addition to this expected alteration to the planning standard NW Natural will use to determine peak resource needs, NW Natural is also reviewing specific areas of risk to its firm resource stack. One risk the Company has identified is the reliance upon un-contracted gate station capacity exceeding the Company's contracted Maximum Daily Delivered Obligation (MDDO) with NWP. This issue is discussed in in more detail in Chapter Three.

B. Long-term Natural Gas Price Volatility and the Upside Risk of Gas Prices

Figure 1.6 below shows past EIA price forecasts for natural gas prices on two-year time intervals in comparison to actual prices in real terms. The current forecast for prices going forward is also included:

Figure 1.6 Comparing Past and Present Forecasts to Actual Prices



This graph highlights the following:

1) Actual prices are more volatile than forecasted prices and price events can be short or long term
2) Price run ups relative to previous forecasts are more extreme than relative price lows
3) Forecasted prices are usually too high when prices are high and too low when prices are low, i.e., they are overly influenced by then-existing market conditions
4) Gas prices are currently lower than the average price over the last 20 years

That gas prices are more volatile than forecasted should not be surprising given the methods used in forecasting. Long term forecasts given in yearly intervals are not meant to show short term price events that last for days, weeks, months, or even one or two years. Furthermore, prices generally rise higher above previous forecasts than they fall below them. That commodity prices, particularly those in the extractive sector like natural gas, are best characterized by a distribution skewed toward the high end is well documented.[12] Moreover, that price forecasts put too much weight on current prices, particularly during either high or low price periods, is expected given that most forecasts are developed using time series techniques that heavily weight the most recent data. Lastly, the Figure 1.6 points out that relative to historical prices, current prices are on the low end in real terms. For example, it is much more plausible that gas prices could rise $3/Dth than fall $3/Dth.

Figure 1.6 is also useful in detailing how a hedging program that layers in hedges over long periods of time (roughly 10 years or longer) is particularly effective in reducing customer exposure to rate shock and providing protection against prolonged periods of high prices. Longer term hedges in concert with short- and mid-term hedges reduce customer exposer to longer term price events that programs without long term hedges cannot. For example, a 10-year hedge executed in 1999 would have been very effective in reducing rate swings during the 2000-2008 time frame that saw high and volatile prices over a period much longer than the typical 3-year time frame of short- and mid-term hedging programs.

That being said, evaluating the balance of reduced exposure to gas prices with possible higher average costs (i.e. hedging in high prices) is exacerbated when evaluating hedges that will have an impact on rates for long periods of time. For example, the hypothetical long term hedge executed in 1999 just discussed would not have only reduced customer exposure to a long term price event, but would likely have resulted in lower, and probably much lower, rates for customers on average over the duration of the hedge. Correspondingly, a long-term hedge executed in 2008, when expectations of long term gas prices were much higher, would have reduced customer exposure to long term price events, but likely would have done so with a net cost to customers.

Since it is beneficial to reduce price volatility for customers and since prices are below the historical average, the Company contracted with an independent third party consultant to evaluate the environment for additional long-term hedges using fundamental analysis. The consultant's study drew the following conclusions:

1) Long-term hedging should be evaluated on a broader set of criteria than short-term hedging, focusing on locking-in supply costs at a known and attractive level
2) The range in gas prices over the coming ten to twenty years will be wider and start at a higher level than recent years due to the following:
    a. Producer economics support a long-term price floor of $4/Dth
    b. Global demand for LNG and increased demand for power production and transportation is likely to support higher gas prices in the Pacific Northwest
    c. Regulatory uncertainty for both coal and natural gas has the potential to impact prices on the high end
3) Current gas forecasts do not seem to properly account for all aspects of (2).
4) Given (1) and (2), a reasonable band for long-term hedges in the 10+- year timeframe is up to 25-35 % of expected gas needs
5) Given the illiquid market for long-term physical and financial hedges, purchasing proven reserves on behalf of customers is the best option for long-term hedging

In addition to the conclusions reached by the consultant, it is NW Natural's belief that (1) natural gas is beginning to substitute for oil in chemical industries and the transportation sector, and that (2) the

[12] Statistical analysis most often shows that natural gas prices are best represented by a lognormal distribution.

divergence between North American gas prices and global oil prices is likely to support substitution towards natural gas and a narrowing of the price spread over time.

Since long term hedges are an effective part of a hedging program to reduce exposure to commodity price volatility, and analysis supports that prices are more likely to rise than remain at current levels or fall in the future, NW Natural will further evaluate the merits and possibility of additional long-term hedges. The Company has set a target of price-protecting up to 25% of expected annual gas requirements over the 20-year planning horizon. The Company's approved (and currently under consideration for approval) long-term hedge amounts to roughly 15% of load requirements over the next couple of years, then they gradually declines and average roughly 10% of requirements over the next 10 years. Consequently, the Company expects to execute additional long-term hedges in line with the recommendations of its consultant. Hedging is discussed in more detail in Chapter Three and an action item related to long-term hedging is included at the end of this Chapter.

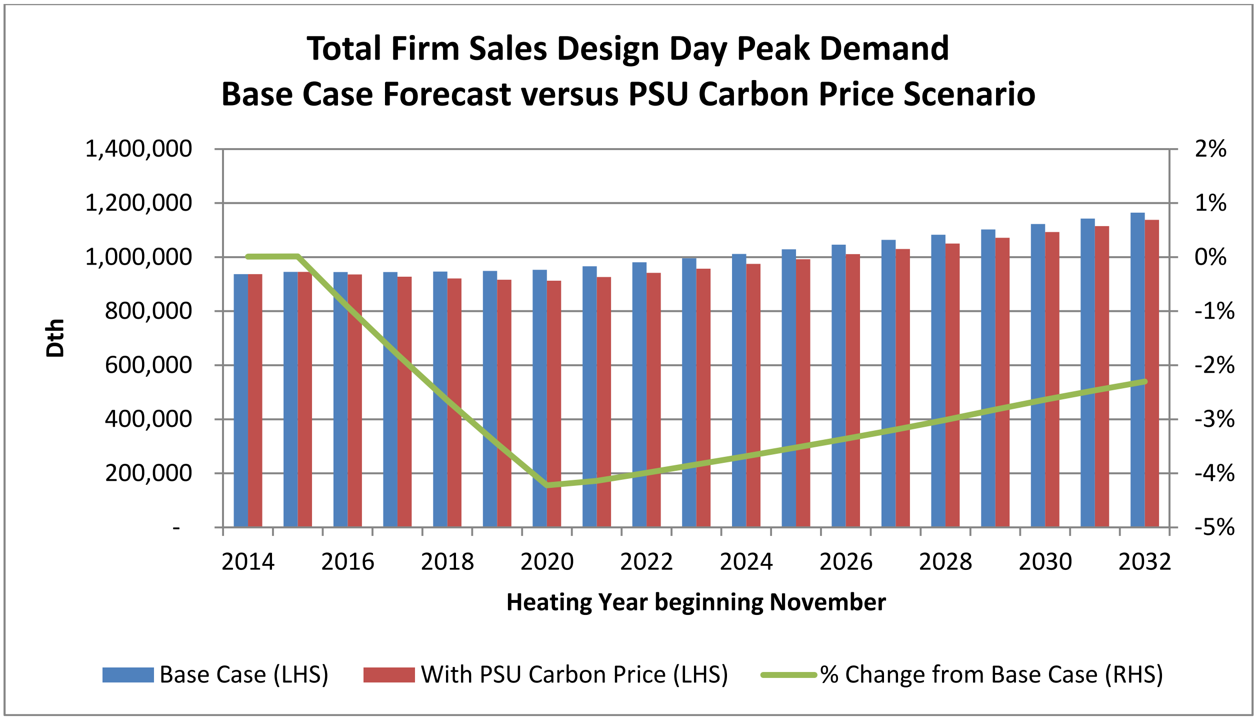
6. Analysis of prospective regulation associated with carbon dioxide emissions, which is new in this IRP, shows that such regulation is unlikely to impact resource choices or the action plan in this IRP.

Chapter Five includes a detailed description and analysis of the carbon dioxide (CO_2) sensitivities included in this IRP and used to inform the Company's planning. NW Natural's 2014 IRP's base set of assumptions incorporates a carbon dioxide emission (carbon) price. The Company uses IHS CERA's North American Natural Gas price forecast,[13] which incorporates a carbon price beginning in 2021 at \$8.78 per metric ton of CO_2 equivalent ($MTCO_2e$) and increases annually to \$15.01 per $MTCO_2e$ in 2032 (both prices in \$2013). Additionally, the Company analyzes two additional scenarios using a medium and a high price for carbon.

As can be seen below in Figure 1.5, even in the high carbon price scenario, there is a relatively small reduction in total Firm Sales on a Design Day.

13 Source: IHS Inc. This content is extracted from IHS Energy North America Natural 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 ~~a~~ without written permission by IHS. Copyright 2013, all rights reserved."

Figure 1.5 – Total Firm Sales Design Day Peak Demand: Base Case Load Forecast and PSU Carbon Price Scenario



Furthermore, NW Natural analyzes two additional scenarios with higher carbon prices than that in the Base Case price forecast (i.e. higher than the carbon price embedded in the IHS CERA natural gas price forecast used in the Base Case assumptions). The higher of these two, which NW Natural refers to as the PSU Carbon Price[14] scenario, assumes implementation of a carbon tax in 2016 (versus 2021 in the Base Case forecast). The 2016 price is $9.45 per metric ton of CO_2 equivalent ($MTCO_2e$)[15] and increases to $41.96 per $MTCO_2e$ in 2032.

NW Natural bases its “medium” carbon price on an *ex ante* forecast of carbon prices associated with California’s Assembly Bill 32. NW Natural discusses modeling alternative carbon prices in Chapter Two and in greater detail in Chapter Five.

IV. Public Involvement

NW Natural’s Technical Working Group (TWG) brings together professionals representing a variety of entities that have an interest in the Company’s planning. This group includes representatives from Washington Utilities and Transportation Commission Staff, Public Utility Commission of Oregon Staff, Citizens’ Utility Board of Oregon (CUB), Northwest Industrial Gas Users (NWIGU), Northwest Power and

[14] NW Natural bases carbon prices in the PSU Carbon Price scenario on those described in “Carbon Tax and Shift: How to make it work for Oregon’s Economy” prepared by the Northwest Economic Research Center (NERC) in 2013. NERC is associated with Portland State University (PSU) and Jenny H. Liu and Jeff Renfro of NERC authored the report

[15] NW Natural performs its 2014 IRP modeling in real terms and generally expresses dollar amounts in terms of 2013 dollars ($2013).

Conservation Council (NWPCC), Washington Public Counsel, Northwest Energy Coalition, and Williams Pipeline. The Company held Technical Working Group meetings in 2013 on August 22nd and October 2nd, and in 2014 on January 23rd, March 7th, April 3rd, and July 11th. NW Natural included a bill insert with December 2013 bills sent to both Oregon and Washington customers, notifying them of the draft plan and soliciting public comments and a public meeting was held on April 15, 2014.

Multi-Year Action Plan

Note that new to this IRP and in an effort to be as transparent as possible, NW Natural is including cost estimates for proposed projects in Section 2.1 of the action plan below. As is always the case with cost estimates, it is possible that actual costs could come in above or below those estimated before project commencement or completion.

1. Load Forecasting

   1.1 Continue to refine growth projections for the Clark County load center.

   1.2 Create a demand forecast scenario based upon the assumed construction of NIW's methanol plants.

2. Resource Additions and Changes

   2.1 Acquire resources in the near-term consistent with meeting the Base Case firm sales load forecast.

      a. Recall 30,000 Dth/day of Mist storage capacity from the interstate storage account effective May 2015 to serve the core customer needs reflected in the Base Case load forecast.

      b. Complete Clark County distribution projects to address Vancouver load center needs – estimated timing of projects is over the next five years with an estimated total capital cost of $25 million.

      c. Proceed with the Newport refurbishment project and continue investigating Portland Gasco refurbishment alternatives. Estimated timing of Newport refurbishment is over next three years at an estimated cost of $25 million.

      d. Construct the South Salem Feeder to serve load growth in the Salem area – estimated timing is to begin permitting in 2015 with an in-service date in 2019; estimated cost of $25 million.

   2.2 Additional actions related to changes to resource stack:

      a. Given that segmented capacity is an interim solution, continue working with NWP to investigate options regarding both the Plymouth and Jackson Prairie storage facilities.

b. Explore alternatives with NWP for increasing contracted MDDO capacity at Vancouver gates, including but not limited to, TF-1 contract extensions and/or subscription for additional CD capacity at some future date.

c. Provide termination notice to NWP on the Company's existing Plymouth LS-1 and TF-2 service agreements by October 31, 2014 (effective November 1, 2015), unless NWP offers a viable economic alternative solution before that notice cut-off date.

2.3 Analyses to be performed for future pipelines and alternative resources:

a. Complete analysis regarding North Mist: refine cost estimates; quantify the value of the project's optionality created by upsizing the associated takeaway pipeline near-term versus at some future date(s); and research applicability of the Company's Hinshaw Exemption. NW Natural will submit this analysis for the Commission's review by May 2015.

b. Preserve the optionality of participating in both the Cross-Cascades and Pacific Connector interstate pipelines by working with the Project Sponsors and exploring what preserving this optionality requires. Timing is contingent on other parties. Updates will be provided at the annual updates.

c. Conduct cost risk analysis on acquiring capacity on the proposed Pacific Connector pipeline to ensure that the Company has fully analyzed its options should the project move forward. These analyses will be included in the next IRP.

3. Demand-Side Resources and Environmental Considerations

3.1 Explore assessing a premium value to account for any natural gas price volatility hedging value associated with DSM energy savings

3.2 Follow Oregon Docket No. UM 1622 and revise annual DSM targets as needed in accordance with any changes to the program resulting from Energy Trust requested investigation into the exceptions to the cost effectiveness guidelines.

3.3 Monitor the implications of EPA regulation 111(d) on future coal plant retirements and the consequential impact of natural gas supply prices.

4. Hedging

4.1 Increase the Company's long-term hedged position of gas requirements from the current level of approximately 10% up to 25% consistent with the recommendation of the Company's consultant. NW Natural will propose specific long-term hedging parameters for Commission and stakeholder review prior to June 30, 2015.

5. Ongoing Activities and Noteworthy items that might be included in future IRPs

5.1 Continue monitoring the data and sources used for the customer growth forecast.

5.2 Continue monitoring pipeline projects that have been identified in this IRP and that are associated with LNG export facilities.

5.3 Continue reviewing national and regional supply and price forecasts and their sensitivity to environmental regulation, LNG exports, and other factors.

5.4 Continue exploring the load implications from the emerging growth markets of power generation, industrial, and transportation.

5.5 Continue updating and refining resource cost estimates included in modeling and options considered such as satellite CNG/LNG.

5.6 Continue acquiring cost effective therm savings through energy efficiency programs administered by Energy Trust of Oregon.

5.7 Continue monitoring GHG legislation.

5.8 Continue developing more statistically sophisticated approaches for probabilistically measuring reliability risk management. Explore other modeling tools for potentially supplementing SENDOUT®. Develop a database that allows the Company to more effectively analyze reliability risk.

Chapter 2: Gas Requirements Forecast

NW Natural®

I. OVERVIEW OF LOAD FORECAST METHODOLOGY

The load forecast is the starting point for developing NW Natural's IRP. It represents the future daily gas supply requirements around which the Company develops its resource plan. An accurate gauge of future demand is essential to ensure acquisition of sufficient resources in an optimal manner. Residential and commercial space heating comprise the bulk of demand on NW Natural's system, and thus total requirements are naturally weather dependent. Therefore, it is important to design the load forecast around an atypically severe winter, one that is much colder than normal and augmented by a very cold coincident design ("peak") day event. In this way, NW Natural ensures the development of a resource plan that is capable of reliably serving customers under a variety of circumstances, including extremely cold weather. The load forecast is also used for estimating the total amount of energy savings available in the Company's service territory through energy efficiency programs administered by Energy Trust of Oregon (ETO).

NW Natural provides resource adequacy—upstream pipeline capacity, storage capacity, and the gas commodity itself—for its Firm Sales customers. While Firm Transportation customers provide for their own upstream resource needs, the Company provides distribution services for these customers. NW Natural considers the load requirements of Interruptible Sales customers only with respect to commodity requirements for non-peak deliverability, as the Company does not plan for upstream pipeline or storage capacity to serve these customers during peak or near-peak conditions. NW Natural's 2014 IRP does not consider the loads of Interruptible Transportation customers.

Consistent with NW Natural's most recent action plans,[1, 2] NW Natural bases its load forecast on 12 load centers that more closely match system demands and flows than the load center configurations used in prior IRPs. The 12 load centers are: Albany, Astoria, Coos Bay, Eugene, Newport/Lincoln City, three Portland metropolitan area load centers (West, Central, and East), Salem, The Dalles (Oregon), The Dalles (Washington), and Vancouver. Individual load centers differ by usage patterns, weather, rates of customer growth, and resource availability. These 12 load centers also define the separate points of demand, along with supply and distribution system connections, as modeled in SENDOUT®, the Company's resource planning and modeling software package.

---

1 NW Natural's 2011 Modified Oregon IRP, docketed as No. LC 51, included as action items 1.4: "Review the demand forecast methodology for accuracy"; 1.5 "Investigate data collection requirements to analyze demand forecast error regionally"; and 1.6 "Consider expanding forecasting methods to include environmental scanning, deliberative polling, neural networks, or other that may have value."

2 Action Item 1.2 on page 1.19 of NW Natural's 2013 Washington IRP, docketed as UG-120417, included that the Company would "[r]efine the load forecast zones to better match individual load centers from a transmission and pipeline delivery standpoint."

There are seven primary steps involved in preparing NW Natural's load forecast:

1. Customer forecast: 20-year estimates of future customer counts by load center and customer category on a monthly basis;
2. Load model: statistical modeling of load by load center and customer category using heating degree days (HDD) as the explanatory variable;
3. Natural gas price forecast: monthly price forecast by supply basin or pricing hub;
4. Design weather development: design weather pattern with average summer temperatures and a winter colder than 90 percent of winters in the past 30 years plus a seven-day cold event based on an historical occurrence, including a 53 HDD system coincident peak;
5. Load forecast: combining the load model with the customer forecast and design weather, also integrating demand-side resource options;
6. Load scenarios: development of other potential, but less likely, load growth patterns and the associated load forecast; and
7. Forecast accuracy analysis: measurement of forecast performance using the load model coefficients to predict load requirements and compare the results to actual loads.

Appendix Two contains the detailed customer and Post DSM demand forecasts.

II. CUSTOMER FORECAST[3, 4]

The customer forecast is the starting point for the load forecasting process. NW Natural relies on internal business intelligence and information from external sources such as Oregon's Office of Economic Analysis (OEA) to forecast the number of customers on a monthly basis over the 20-year planning horizon. Table 2.1 lists the categories of customers that NW Natural forecasts and Table 2.2 lists the Company's load centers and actual Residential and Commercial Firm Sales customer counts as of December 2013.

NW Natural forecasts numbers of customers for each combination of load center and customer category for a total of 96 discrete customer forecasts. The New Construction and Conversion categories reflect customer growth as new customers are added. NW Natural forecasts the number of customers in the Existing categories as declining at a constant rate over time as customer losses occur from the initial level. The forecast methodology involves blending near- and long-term economic outlooks. The information sources and methods NW Natural uses to produce estimates depend on the customer category, and these are described in detail in their respective sections below.

---

[3] Customers in this context refer to Firm Sales customers or to Firm Sales and Firm Transport customers. NW Natural includes Firm Transport customers where relevant; i.e., with respect to the Company's capabilities vis-à-vis delivery of gas over its facilities from a city gate to a Firm Transport customer.

[4] NW Natural forecasts the load of Industrial Firm Sales customers directly in this IRP, and not by forecasting the number of customers and multiplying by the monthly forecast of use per customer. The process of forecasting these loads is described later in this chapter.

Table 2.1 – Forecasted Customer Categories

Residential Existing Multi-family

Residential Existing Single-family

Residential New Construction Multi-family

Residential New Construction Single-family

Residential Conversion

Commercial Existing

Commercial New Construction

Commercial Conversion

Table 2.2 – NW Natural Load Centers[5]

Load Center	Customers	% of System
Albany	40,192	5.8%
Astoria	12,583	1.8%
Coos Bay	1,444	0.2%
The Dalles (OR)	5,626	0.8%
Eugene	39,310	5.7%
Lincoln City/Newport	10,525	1.5%
Portland Central	190,188	27.4%
Portland East	99,588	14.4%
Portland West	132,144	19.0%
Salem	89,379	12.9%
The Dalles (WA)	1,925	0.3%
Vancouver	73,186	10.3%
Total System	693,892	100.0%

Economic activity within NW Natural's service area continues to improve over levels observed in recent IRPs. The Company's 2013 Washington IRP included that:

> "According to the November 2012 OEA forecast, housing starts in Oregon dropped by 41.7% in 2008 and 40.8% in 2009 during the most recent recession. Starts were static at a positive 0.3% in 2010, and even though they improved by 6% year-over-years [*sic*] in 2011, they remained 37% below the number of starts recorded in 2007. The Company's customer growth rates have

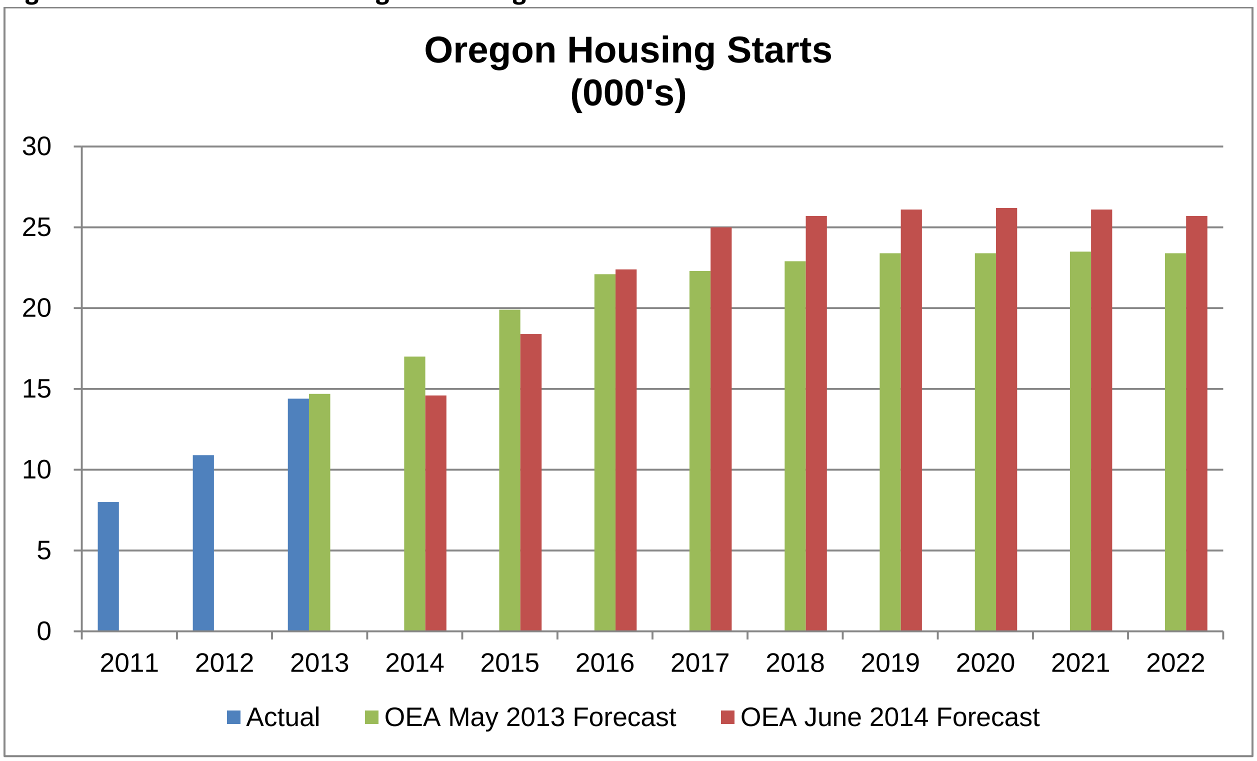
[5] December 2013 numbers of customers in Table 2.2 are actual values. Numbers of customers for 2013 appearing elsewhere in this chapter are forecast values. The first year of the forecast period in this IRP begins November 2013.

dropped accordingly. In 2006, the customer growth rate was over 3%. In 2011, growth had slowed to less than 1%."[6]

OEA's most recent forecast[7] of Oregon housing starts, released May 28, 2014 and shown in Figure 2.1, provides some cause for optimism, with the accompanying narrative noting that:

> "Housing starts today in Oregon total nearly 14,000 at an annualized rate, which represents growth of about 80 percent from the recessionary lows of 2009 and 2010. A level of about 21,000 is the long-run average for the state prior to the housing bubble, and the forecast calls for strong growth in the coming few years with starts reaching 18,400 in 2015 and 22,400 in 2016. Over the extended horizon, starts are expected to average a little more than 23,000 per year to meet demand for a larger population and also, partially, to catch-up for the underbuilding that has occurred in recent years. As of today, new home construction is cumulatively about one year behind the stable growth levels of prior decades even after accounting for the overbuilding during the boom."[8]

Figure 2.1 OEA Forecast of Oregon Housing Starts



---

[6] NW Natural's 2013 Washington IRP at page 2.3.

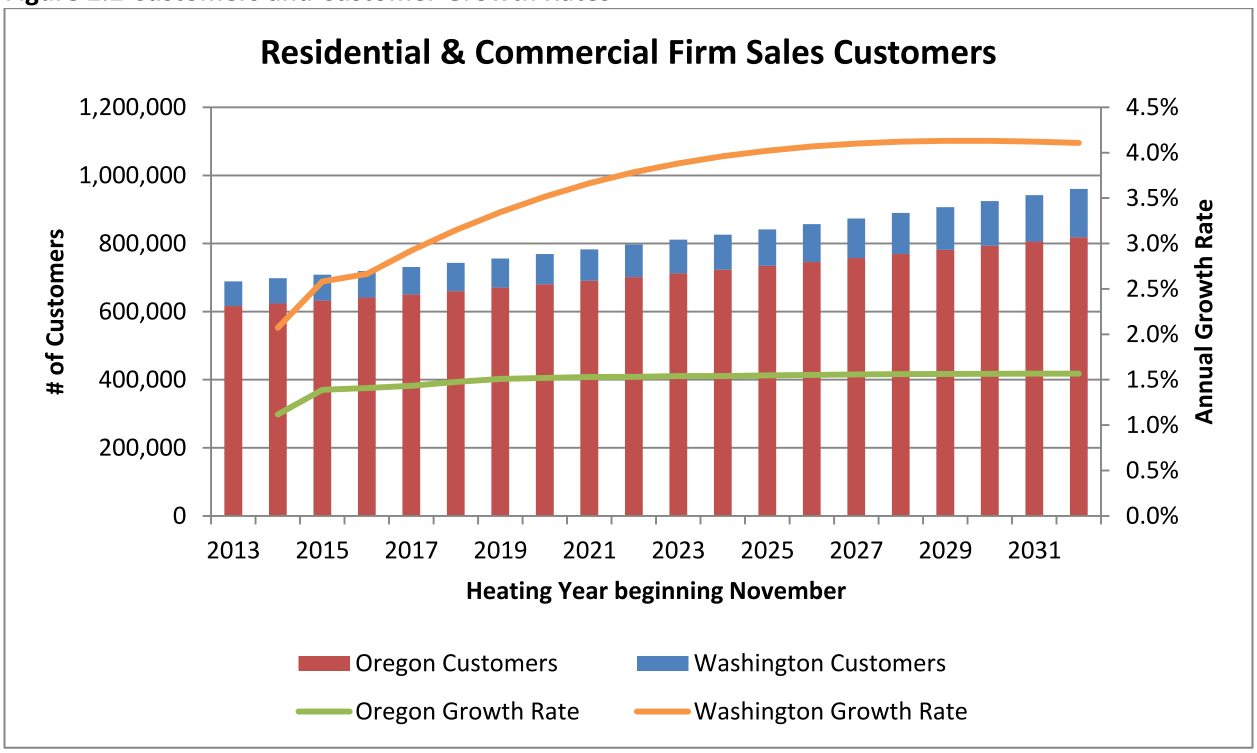
[7] See Table A.4 of Appendix A of the June 2014 forecast at http://www.oregon.gov/DAS/OEA/docs/economic/appendixa.pdf (accessed August 5, 2014).

[8] See page 14 of the June 2014 forecast at http://www.oregon.gov/DAS/OEA/docs/economic/forecast0614.pdf (accessed August 5, 2014).

Annual rates of customer growth on a system basis in this IRP range from 1.4 percent early in the planning period to 1.9 percent in later years. The customer forecast reflects an average annual rate of customer growth over the next 19 years of 1.9 percent on a system basis, with Oregon at 1.6 percent and Washington at 3.8 percent. NW Natural's forecasts use county-level demographic and economic forecasts provided by Woods & Poole Economics, Inc.[9] in several ways, as discussed below. Woods & Poole projects Clark County, Washington to have the third highest average annual rate of population growth[10] over the period 2010 through 2040 of the 119 counties in the states of Idaho, Oregon, and Washington.[11]

Figure 2.2 illustrates by state the total forecasted level of Residential and Commercial Firm Sales customers as well as the annual rates of customer growth.

Figure 2.2 Customers and Customer Growth Rates



9 Woods & Poole is a commercial provider of economic and demographic forecasts. NW Natural uses Woods & Poole forecasts at the county level, aggregating county-level data for applicable load centers.

10 The two counties having a higher average annual rate of population growth are adjacent counties in eastern Idaho with a combined 2010 population of approximately 50 thousand; i.e., Woods & Poole project Clark County Washington to be the fastest growing metropolitan county in the three states.

11 Washington's higher rates of customer growth are due in part to NW Natural having a lower level of market penetration in the Company's Washington service area as compared with its Oregon service area, and also to a large number of new housing developments being built in the greater Vancouver area.

NW Natural's 2014 IRP customer forecast varies considerably from some previous IRPs. Figures 2.3, 2.4, and 2.5 compare the 2014 IRP customer forecasts with those of the 2004, 2008, 2011 Modified, and 2013 Washington IRPs. The 2014 IRP customer forecasts are very similar, however, to those in the Company's 2013 Washington IRP and are essentially indistinguishable for the total and Residential customer forecasts. The forecast of Commercial Firm Sales customers is higher than in the 2013 Washington IRP due to continued employment growth forecasted for the latter years of the planning horizon.

Figure 2.3 - Residential Customer Forecasts

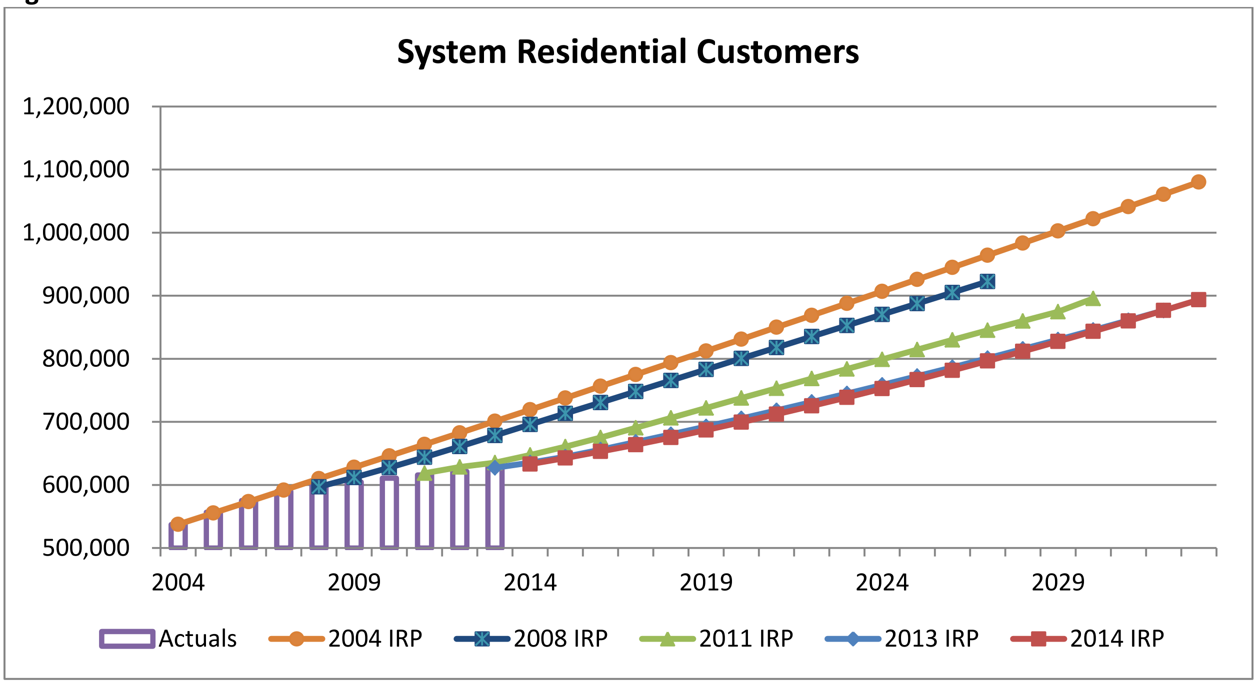


Figure 2.4 – Commercial Customer Forecasts

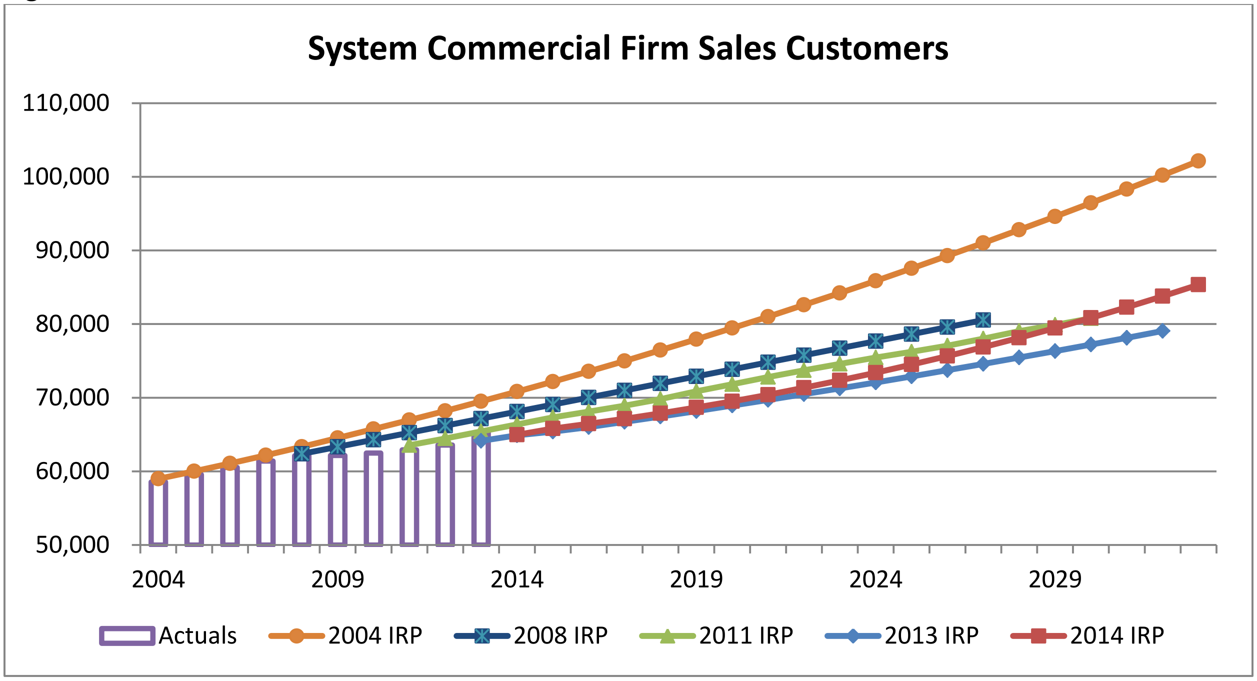
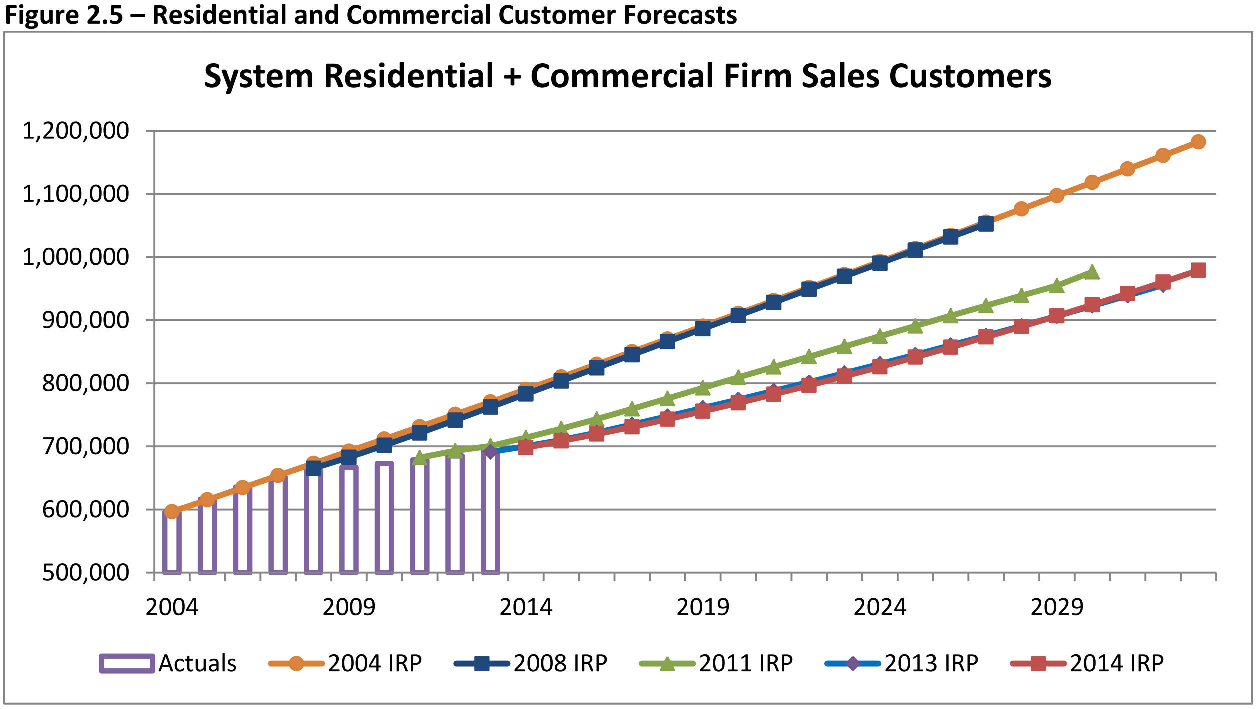


Figure 2.5 – Residential and Commercial Customer Forecasts



A. Residential Customer Forecast

NW Natural forecasts customer growth in the residential sector individually for three of the categories in Table 2.1:

1. New Construction Single-family
2. New Construction Multi-family
3. Conversions

The load forecast adds all new Residential customers to the customer base in one of these categories. NW Natural reflects attrition of Residential customers over time with reductions in the Residential Existing customer category. The annual rate of Residential customer attrition is constant over time, but varies between Oregon and Washington.

For Oregon residential new construction, NW Natural bases the Company's econometric forecast of Oregon Residential new construction customers on the OEA's May 2013 forecast of housing starts for both New Construction Single-family and New Construction Multi-family. The May 2013 OEA forecast of housing starts is tied to the April 2013 IHS Global Insight baseline U.S. national forecast of housing starts. The econometric forecast of Oregon New Construction Multi-family includes a Housing Affordability Index as an additional explanatory variable. NW Natural calculates the Housing Affordability Index as the ratio of mean household income[12] to the housing price index forecast by OEA.

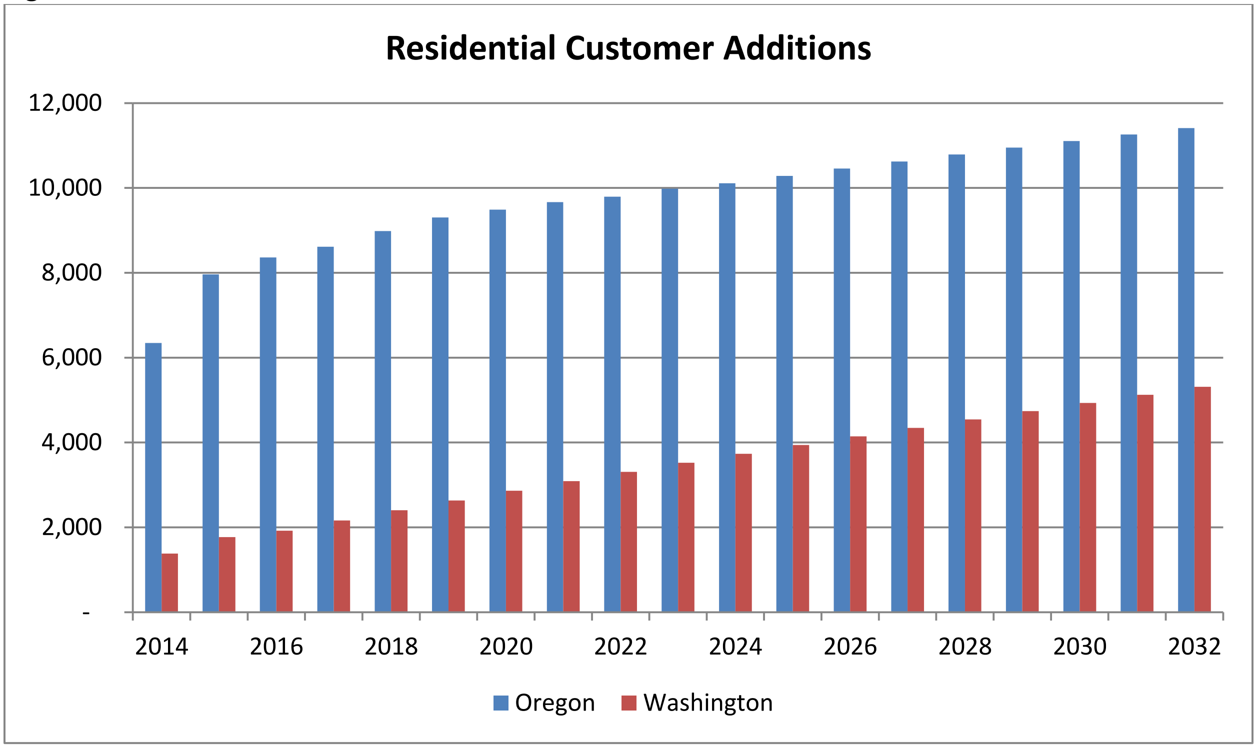
For Oregon residential conversions, NW Natural uses an internal subject matter expert (SME) panel for forecasting the first two years and develops econometric forecasts for the second year forward. Forecasts for the second year are an average of the two approaches. The panel experts analyze and incorporate into the residential conversion customer forecast information from internal and external sources, including trends, employment information, economic indices, real estate information, inventories information, building activity, permitting activity, technology, incentives, internal programs, and judgment. NW Natural's econometric forecast of Oregon Residential conversions uses the total number of households as the explanatory variable, with data provided by Woods & Poole.

NW Natural develops the econometric forecast of Washington Residential new construction customers using total households as the explanatory variable, with data provided by Woods & Poole and specifically for those Washington geographies in the Company's Washington service area. The Company holds forecast values of Washington residential conversions for the third year and forward at the level of the SME panel's second year forecast, as the econometric forecast lacks sufficient explanatory power.

Figure 2.6 shows the annual net addition of Residential customers by state over the 2014-2032 timeframe.

[12] NW Natural uses data provided by Woods & Poole, Inc. for mean household Income.

Figure 2.6 - Residential Customer Additions



B. Commercial Firm Sales Customer Forecast

NW Natural forecasts customer growth in the commercial sector separately for two of the categories in Table 2.1:

1. New Construction
2. Conversions

All new Commercial Firm Sales customers are added to the customer base in one of these categories. Analogous with the approach NW Natural uses for Residential customers, attrition of Commercial customers over time is reflected by a constant rate of reduction over time. The Commercial customer attrition rate varies between Oregon and Washington.

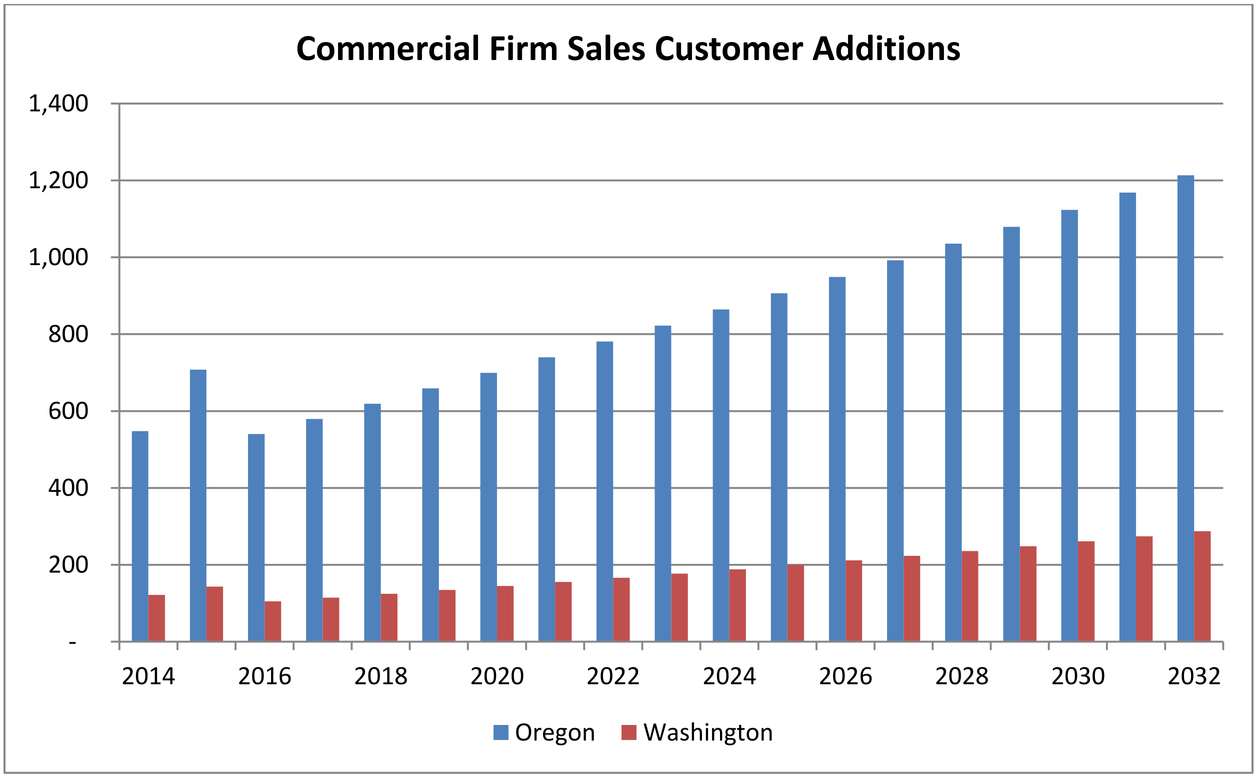
NW Natural uses the SME panel to forecast the first two years and develops econometric forecasts for the second year forward. Forecasts for the second year are an average of the two approaches.
NW Natural develops the econometric forecast of Oregon commercial new construction using non-manufacturing employment as the explanatory variable[13] and develops the econometric forecast of Washington commercial new construction using total employment as the explanatory variable, with data provided by Woods & Poole.

[13] The Oregon forecasts of non-manufacturing employment are from Woods & Poole.

NW Natural holds forecast values of both Oregon and Washington commercial conversions for the third year and forward at the level of the SME panel's second year forecast, as the econometric forecasts lack sufficient explanatory power.

Figure 2.7 shows the annual net addition of Commercial customers by state over the 2014 – 2032 timeframe.

Figure 2.7 - Commercial Customer Additions



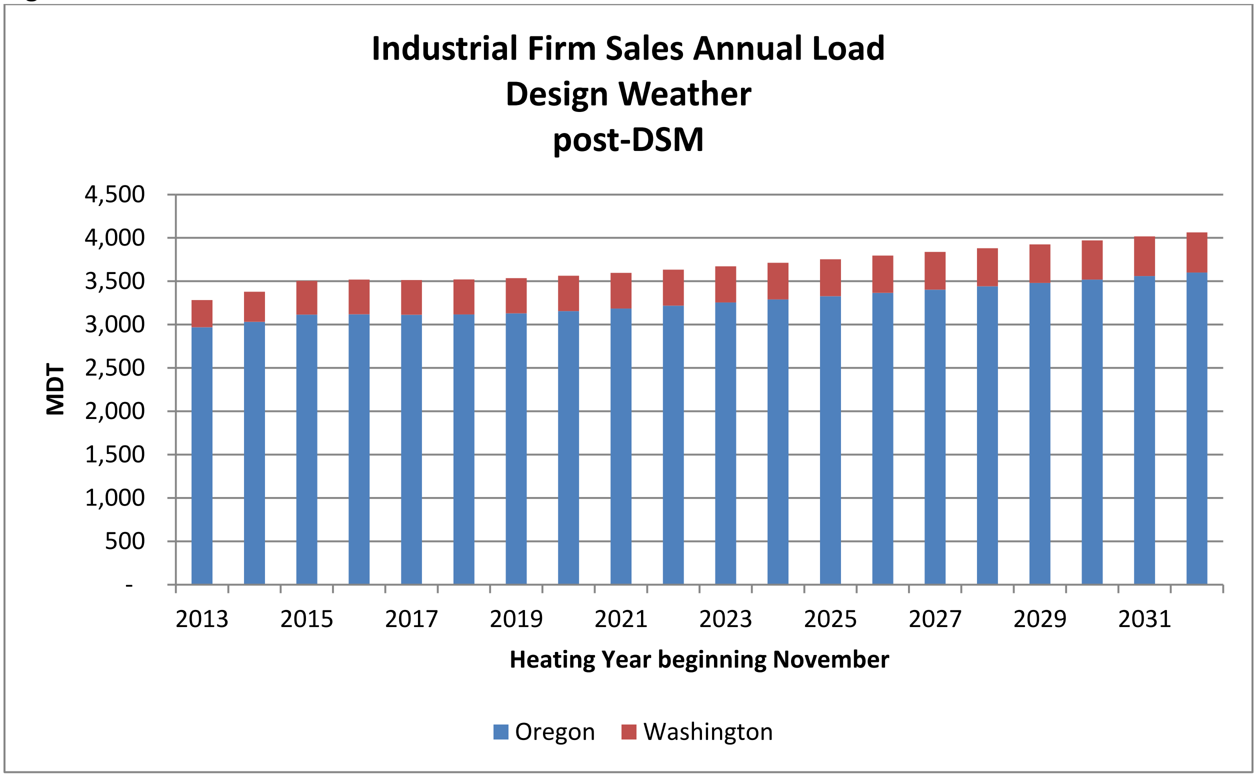
C. Industrial Load Forecast

Rather than separately develop a forecast of Industrial customers and estimates of use per Industrial customer, analogous with the approach NW Natural uses for Residential and Commercial customers, the Company forecasts the total load of Industrial customers directly due to the wide range in actual natural gas use by these customers. NW Natural uses internal information obtained from account managers and customer insights for developing the Company's near-term forecast of both Oregon and Washington Industrial loads. The Company develops econometric forecasts for long-term Industrial load using manufacturing employment augmented with a two percent annual rate of growth[14] in labor productivity to proxy manufacturing output. This follows from the intuition that gas use by Industrial customers varies more with levels of output than with levels of employees.

[14] The annual average rate of growth in U.S. labor productivity over the period 1988 through 2013 was 3.2 percent per U.S. Bureau of Labor statistics accessed February 15, 2014 at http://data.bls.gov/ .

NW Natural develops a forecast of Industrial load in total, and allocates this to Industrial Firm Sales, Industrial Interruptible Sales, and Industrial Firm Transportation based on actual 2012 loads. Figure 2.8 depicts the post-DSM[15] Industrial Firm Sales load. Please see Chapter Four for discussion of DSM.

Figure 2.8 – Industrial Firm Sales Load



Industrial Sales customers, both Firm and Interruptible, continue to recover from the negative growth that dominated during the 2007 – 2009 recession and immediately thereafter. The economic downturn caused plants and factories to cut back on shifts, and these customers consumed less natural gas across the region during the recession. NW Natural anticipates that, as economic expansion continues and natural gas maintains its competitive price advantage over competing fuels, the load of Industrial Firm Sales customers will continue to increase.

D. Alternative Load Growth Scenarios

NW Natural believes the Base Case load forecast using design weather represents the most likely severe weather outcome from a perspective of prudent resource planning. The Company also evaluated resource planning under scenarios having alternative load levels. Some scenarios provide alternative load projections based on changes to assumptions underlying the Base Case customer forecast. Scenarios also serve to provide limits to the Base Case load forecast by establishing a floor and a ceiling on expected load. NW Natural developed two alternative load scenarios with respect to load growth:

15 Post-DSM (for post- demand-side management) refers to the reduction in gross load after decrements forecast as a result of implementation of demand-side management programs by ETO. All loads referenced in this chapter refer to post-DSM loads. Please refer to Chapter Four.

1. Low Load Growth: lower Residential/Commercial customer growth and lower Industrial load growth due to slower than expected service area economic and population growth; and
2. High Load Growth: higher Residential/Commercial customer growth and higher Industrial load growth resulting from higher than expected service area economic and population growth.

NW Natural uses monthly values for the Residential and Commercial customer categories in Table 2.1 that differ from those in the Base Case customer forecast for developing the High and Low Load Growth scenarios.[16] NW Natural uses somewhat different approaches to these scenarios at the state level. The Company implements the Oregon portion of the High and Low Load Growth scenarios by starting with the annual rates of Oregon's population[17] growth over the 20-year period 1993 through 2012. NW Natural derives a High Growth (Low Growth) scenario factor by adding (subtracting) one standard deviation of the arithmetic mean of the annual rates of population growth over this period to (one plus) the geometric mean of population growth over the same period, and dividing this result by (one plus) the geometric mean of population growth. This yields a High Growth factor of 100.81 percent and a Low Growth factor of 99.19 percent, with both values expressed on an annual basis and rounded here to four decimal places. NW Natural applies the equivalent monthly factors, compounded monthly over the planning horizon, to the Base Case forecast's monthly values for the customer and load categories[18] listed in Table 2.2 on a load center basis for each Oregon load center.

NW Natural uses methods for developing the Washington portion of the High and Low Load Growth scenario similar to those used for Oregon, but bases adjustments to the Base Case forecast's customer and load categories' monthly values on Low, Medium, and High population forecasts for Clark County obtained from Washington's Office of Financial Management.[19] NW Natural divided (one plus) the geometric mean annual rate of population growth for the High Growth (Low Growth) forecast by (one plus) the geometric mean annual rate of population growth for the Medium forecast. This yields a High Growth factor of 100.77 percent and a Low Growth factor of 99.14 percent, with both expressed on an annual basis and rounded here to four decimal places. Analogous with the approach the Company uses for Oregon load centers, NW Natural applied the equivalent monthly rates, compounded monthly over the planning horizon, to the Base Case forecast's monthly values for the customer categories listed in Table 2.2 on a load center basis for both Washington load centers.

---

16 The translation from customers to loads uses the same Residential and Commercial use per customer values for the High and Low Load Growth scenarios as the Base Case load forecast.

17 Northwest Natural obtained historical Oregon population data from Table 1 of the Portland State University Population Research Center's April 19, 2013 "2012 Annual Population Report;" accessed February 13, 2014 at http://www.pdx.edu/prc/annual-oregon-population-report .

18 These take the form of $Scenario\ Category\ Value\ = Base\ Case\ Category\ Value\ \times\ Factor^{m-1}$, where *m* is the month's index value and ranges from 1 for November, 2013 to (20 years X 12 months =) 240 for October, 2033. Note that the one month lag reflected in the *m*-1 exponent is necessary to ensure identical values across the Base Case forecast and Low and Low Growth scenarios for November 2013. An exception to this method is with respect to the existing categories, for which NW Natural uses the same *rates* of decline for the High Load Growth and Low Load Growth scenarios as it uses in the Base Case forecast.

19 Accessed February 14, 2014 at http://www.ofm.wa.gov/pop/gma/projections12/projections12.asp .

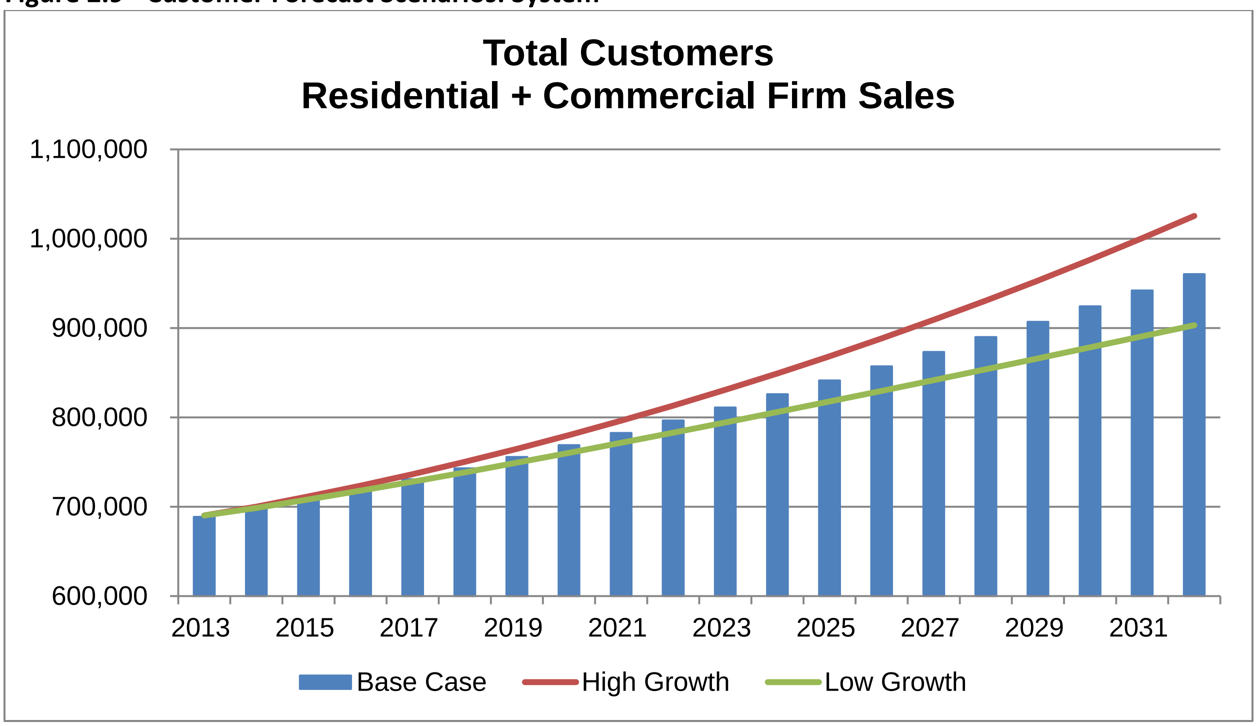
NW Natural considers using factors derived either statistically (for Oregon) or from actual alternative forecasts (for Washington) of population to represent reasonable methods for establishing High and Low Load Growth forecasts. While there may be considerable correlation between different explanatory variables, intuition suggests most are correlated with population over timeframes similar to that of the planning horizon.

Table 2.3[20] shows the average annual rates of customer growth for the Base Case customer forecast and the High and Low Growth scenarios. Figure 2.9 depicts the total number of NW Natural's Residential and Commercial Firm Sales customers for each of the Base Case forecast, the High Load Growth scenario, and the Low Load Growth scenario. Figures 2.10 and 2.11 present the information at the state level.

Table 2.3 - Average Annual Rates of Customer Growth 2014 – 2032

	Residential			Commercial			Company Total		
	Base	High	Low	Base	High	Low	Base	High	Low
Oregon	1.6%	1.8%	1.3%	1.4%	2.1%	0.4%	1.6%	1.8%	1.2%
Washington	3.9%	4.1%	3.2%	2.6%	3.3%	1.6%	3.8%	4.1%	3.1%
NW Natural	1.9%	2.1%	1.5%	1.5%	2.2%	0.5%	1.9%	2.1%	1.4%

Figure 2.9 - Customer Forecast Scenarios: System



[20] Note that, as displayed, the rates in Table 2.3 are rounded to three decimal places.

Figure 2.10 - Customer Forecast Scenarios: Oregon

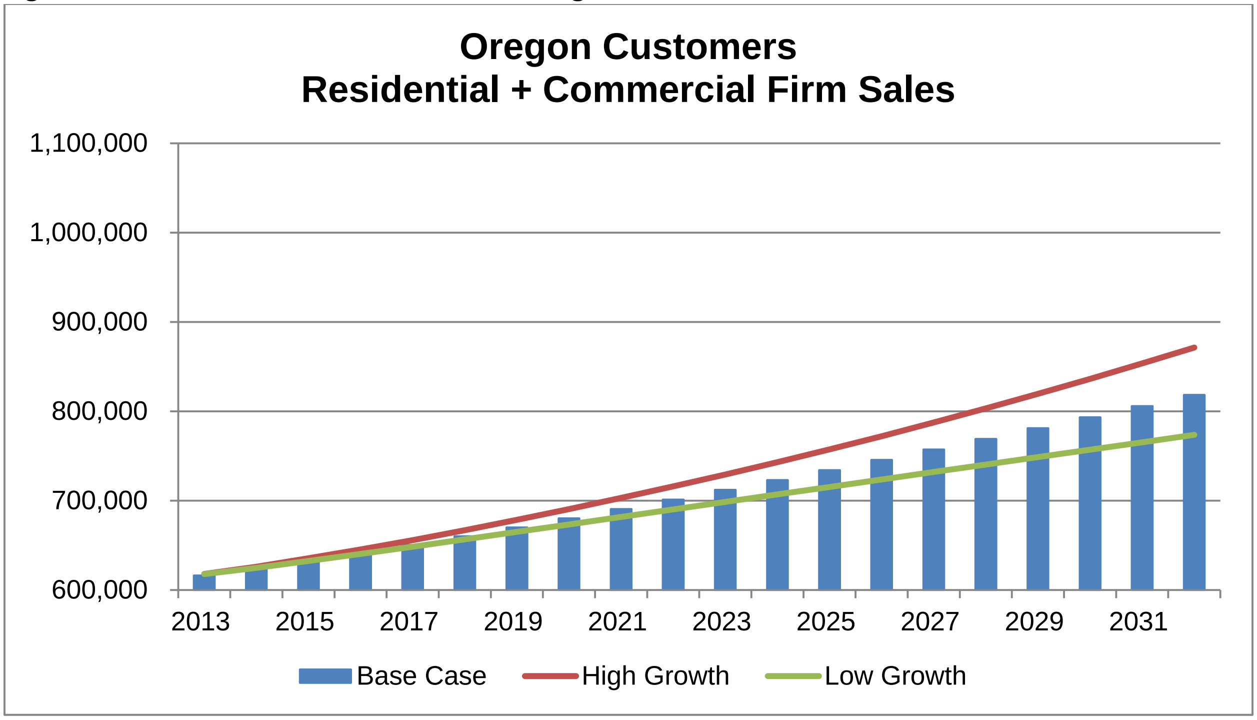
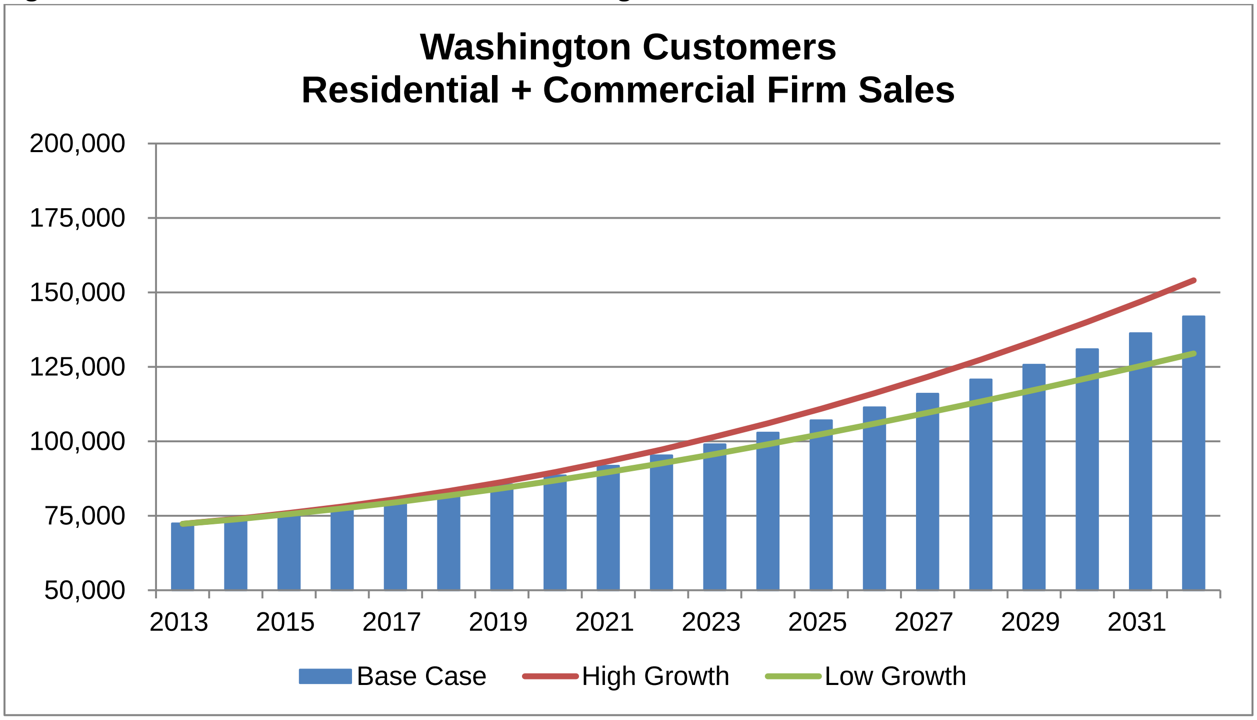


Figure 2.11 - Customer Forecast Scenarios: Washington



III. LOAD FORECAST MODEL

The next step in the load forecasting process is modeling the relationship between HDD and the demand for natural gas on a per customer basis. NW Natural collects billing cycle data by category and load center and matches this data with regional temperature data. While temperature data is available on a daily basis, customer usage by region and customer category is not. The Company derives detailed customer usage data from billing cycle information, which is collected throughout each month on a rolling basis. NW Natural uses usage data from the 48-month period in 2008 through 2011 for developing estimates of use per customer. Temperature data is compiled to match the billing cycles. A typical month has 22 billing cycles—one for each business day. A mid-month cycle contains aggregated customer usage data from the first half of the current month and the second half of the previous month. A cycle at the beginning of a month collects usage data primarily from the previous month, while an end-of-month cycle includes data from that month only.

The next step is fitting a statistical load forecast model to the data set. Not only are there variations in climate and weather between load centers, but each load center's customer base may have unique usage characteristics. As an example, coastal areas may have large numbers of vacation homes and seasonal businesses whose energy use varies more with weekends and holiday periods than is the case for NW Natural's system as a whole. Differences in usage patterns and levels of use between load centers may be related to the average size and age of the dwellings or businesses and the average efficiencies of the equipment and appliances in use within the load center. Numerous other variables may potentially have causal relationships with average use per customer, including degree of cloud cover, wind direction and velocity, day of the week, etc. A commonly held view is that the presence of wind in particular influences average use per customer for a given level of HDD. NW Natural develops a load forecast model for each combination of customer category and load center.

NW Natural separates daily use into two components: base load and heat load. The Company assumes the base load component is constant for each day throughout the year and independent of ambient temperatures. Base load represents natural gas uses such as water heating and cooking. Heat load represents natural gas demand for space heating. For the heat load component of the load forecast, NW Natural uses regression analysis to model daily use per customer as a function of daily HDD. Daily HDD measures the extent to which the daily mean temperature (the simple average of the high and low temperatures for the day) falls below a reference temperature, which in this analysis is 65° F.

Equation 2.1 Daily Use per Customer

$$U = U_B + U_H$$

$$where$$

$$U = daily\ use\ per\ customer$$

$$U_B = \ daily\ base\ load\ use\ per\ customer$$

$$U_H = daily\ heat\ load\ use\ per\ customer$$

A. Base Load

The first step in deriving the load model involves estimating the base load component. This is done by performing a linear regression with average daily use per customer as a function of HDD using customer usage data from the months of July, August, and September. While there may be some heating load during cooler summer days, the value of the y-intercept (average use per customer when HDD are zero) provides the estimated base load factor.

Equation 2.2 Base Load Model

$$U = c + r \times x$$

$$where\ U = daily\ average\ use\ per\ customer\ in\ summer\ months$$

$$x = HDD\ per\ day$$

$$r = heat\ factor$$

$$c = intercept$$

$$setting\ x = 0$$

$$U_B = c = daily\ base\ load\ per\ customer$$

B. Heat Load

For the non-summer months, NW Natural subtracts the base load value from the average daily use per customer data to estimate use representing heat load. The Company models heat load as a non-linear function of HDD for Residential and Commercial customers. The functional form of the heat load model is sometimes referred to as a double log model of demand. At relatively low HDD values, a curve representing the functional relationship is relatively flat. As temperature becomes colder and HDD values increase, heat load increases and at an increasing rate; i.e., the curve becomes steeper.

Following natural log transformations, NW Natural derives the heat load by performing a linear regression on the transformed variables. The Company limits the rate of change in the heat response to increasing HDD (the "steepness of the curve")[21] by restricting the maximum natural log value of HDD to log(45).

Equation 2.3 Heat Load Regression

$$\ln\left(\frac{W}{HDD}\right) = d + r_h \times x_1$$

$$where$$

$$W = \ daily\ average\ use\ per\ customer, decremented\ for\ base\ load$$

---

21 See the following discussion of design day peak demand.

$$x_1 = \ln(HDD)$$

$$r_h = heat\ rate$$

$$d = intercept$$

NW Natural transforms the fitted function from the double log form by exponentiation of both sides, resulting in the relationship between HDD and the heat load component of use per customer.

Equation 2.4 Heat Load

$$U_H = (HDD) \times e^{[d + r_h \times \ln(\mathrm{Min}(45, HDD))\,]}$$

$$where$$

$$U_H = daily\ average\ heat\ load\ per\ customer$$

Equation 2.5 Computation of Use per Customer

$$S = B + H \times HDD$$

$$where$$

$$S = average\ use\ per\ customer\ per\ day$$

$$B = U_B = average\ base\ use\ per\ customer\ per\ day$$

$$H = \frac{U_H}{HDD} = heat\ rate$$

NW Natural does not model Industrial load as a function of daily HDD values, instead applying seasonal factors to annual load forecasts.

C. Implementation

To implement NW Natural's load model in SENDOUT®, the daily use per customer equation must be transformed into a piecewise linear function of HDD. The Company does this by fitting two segments to the use per customer function.

D. Design Day Peak Demand

The slope of the non-linear load curve increases as HDD values increase, as described above. Historically, some natural gas local distribution companies have seen usage begin to flatten at very low temperatures (high HDD values). In an article titled "Bend-Over," authors John Little and Jeffrey Rosenbloom[22] found that the "bend-over" effect does exist, and their analysis showed the effect starting at a temperature of 20° F. In other words, Little and Rosenbloom found that customers did not continue to increase consumption of natural gas at the same rate as temperatures drop when it is very cold. However, the reasons for this are not clear. One hypothesis is that in very cold weather most heating appliances are running at maximum capacity and cannot consume additional gas even if temperatures continue to drop. NW Natural has very few data points to analyze this phenomenon since its service area has a relatively mild climate. The few existing data points do seem to indicate that a shift occurs in the load curve. Therefore, in application, the load forecast model includes a "bending" of the curve beginning at an HDD value of 45 (20° F.), reflecting Equation 2.4 above.

E. Use per Customer and Price Elasticity

NW Natural believes the delivered price of natural gas affects the level of customer demand. If the price the customer pays for gas increases, economic theory suggests customer use at any given HDD value is expected—all else being equal—to decline (and vice versa). NW Natural included a price variable in the load forecasting models of some prior IRPs to capture the customer use response to a change in delivered price, which response is known as the price elasticity of demand. For the 2014 IRP, the Company includes a price elasticity effect only for its High Gas Price sensitivity case. The reason for omitting a price elasticity parameter is that the forecast of natural gas prices and therefore of delivered prices is essentially flat in real terms.

The American Gas Association (AGA) released a study on natural gas use and price elasticity in 2007.[23] The study analyzed residential use per customer (UPC) trends from 50 natural gas local distribution companies (LDCs) from across the country. The authors found that weather normalized use per customer in the residential sector had been declining since 1980 at an annual rate of about one percent. In the more recent portion of this timeframe, from 2000 to 2006, the annual rate of decline accelerated to 2.2 percent. The driving force thought to be behind the decline in use per customer was the consistent increase of natural gas prices. NW Natural experienced a similar rate of decline in use per customer during that timeframe. The AGA study reported a long-run price elasticity value of -0.12 for the residential sector in the Pacific region. NW Natural's Oregon decoupling mechanism, prior to changes made in compliance with Orders in Docket No. UG 221, used price elasticity values of -0.172 for Residential customers and -0.11 for Commercial customers in determining decoupling adjustments.

NW Natural did not explicitly incorporate impacts on the Base Case load forecast in response to price changes after examining the IHS CERA forecast of natural gas prices, which NW Natural concludes are reasonably characterized as being "flat" over the planning horizon.[24]

F. Use per Customer Dynamics

NW Natural incorporates a trend component into the annual load forecast under expected weather for Residential and Commercial Firm Sales customers. This is in addition to a load decrement for the DSM

---

22 "Bend-Over", John Little and Jeffrey Rosenbloom; Fortnightly; April 1994.

23 "An Economic Analysis of Consumer Response to Natural Gas Prices," Frederick Joutz and Robert Trost, March 2007.

24 See Figure 2.17, which shows the IHS CERA forecast of Henry Hub spot prices, as well as the associated text.

energy savings discussed in Chapter Four.[25] The average annual rate of change in average use per customer for Residential and Commercial Firm Sales customers is shown in Table 2.4 (following).

Table 2.4 – Average Annual Rate of Change in Average Annual Use per Firm Sales Customer with Expected Weather: Heating Years 2013 – 2014 through 2032 – 2033

	OR	WA
Residential	-0.5%	-0.1%
Commercial	-0.5%	-0.6%

IV. WEATHER

Climate[26] plays a primary role in the load forecast, particularly under the assumption in the traditional planning standard of 100 percent resource availability. The HDD explanatory variable in the heat load model (Equation 2.4) is a key driver of daily load,[27, 28] and specifically of design day peak demand. NW Natural analyzed historical temperature data within its service area and designed an annual HDD pattern ("design weather") resulting in loads which significantly stress the Company's system on both annual load and design day peak demand bases. NW Natural repeats the design weather pattern in each year of the design weather load forecast so that the appropriate resources can be developed to reliably serve firm sales customers should a severe winter or a very cold period of days occur in any year.

NW Natural collects and analyzes temperature data obtained from the National Oceanic and Atmospheric Administration (NOAA) representing the twelve load center regions of the Company's service area. NW Natural derives the design weather pattern from a data set with 30 years (1983 – 2012) of historical daily temperature observations. The Company transforms the daily average temperatures (T) used for each load center to a 65° F.-based HDD value by a simple conversion: HDD = max(0,65-T). The design weather year is composed of two statistically derived portions. The non-heating season (the months of April through October, or "Summer") portion of the design weather year uses daily summer temperatures for a year at the 50th percentile of years in the 30-year summer weather history, which is 1993. The heating season (the months of November through March, or "winter") portion of the design weather year uses daily temperatures for a year at the 90th percentile of years in the 30-year winter weather history, which is 1992.[29]

---

25 See also Chapter Seven for discussion regarding the integration of DSM within the SENDOUT® optimization modeling.

26 NW Natural uses climate in this context in the sense of "average weather over some extended period of time."

27 Note the discussion above regarding factors in addition to HDD that may relate to average use per customer; e.g., wind.

28 Other regional gas utilities also consider HDD to be a primary driver of average use per customer. See; e.g., Appendix H of Puget Sound Energy's 2013 IRP, pages H-4 through H-5 (accessed February 22, 2014 at http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppH.pdf) and page 17 of Cascade Natural Gas' 2011 IRP (accessed February 22, 2014 at http://www.cngc.com/docs/regulatory/2011_irp_may.pdf?sfvrsn=0).

29 NW Natural's 2013 Washington IRP used temperatures at the 85th percentile for the complete heating year (summer and winter) from a 20-year weather history.

NW Natural incorporates temperatures from the seven-day historical period January 31 through February 6, 1989 to model an unusually cold multi-day weather event. The Company uses the actual system weighted 53 HDD from February 3, 1989, as the design ("peak") day for planning purposes. The system weighted 53 HDD experienced on that date corresponds to a system weighted average daily temperature of 12° F. Temperatures on the three days preceding and three days following the February 3, 1989 design day were also colder than average and NW Natural superimposes these six days' actual HDD values on the design weather to incorporate a seven-day cold event within the 2014 IRP's design weather.[30]

Figure 2.12 – Comparison of Design Heating Season Weather with Normal Weather

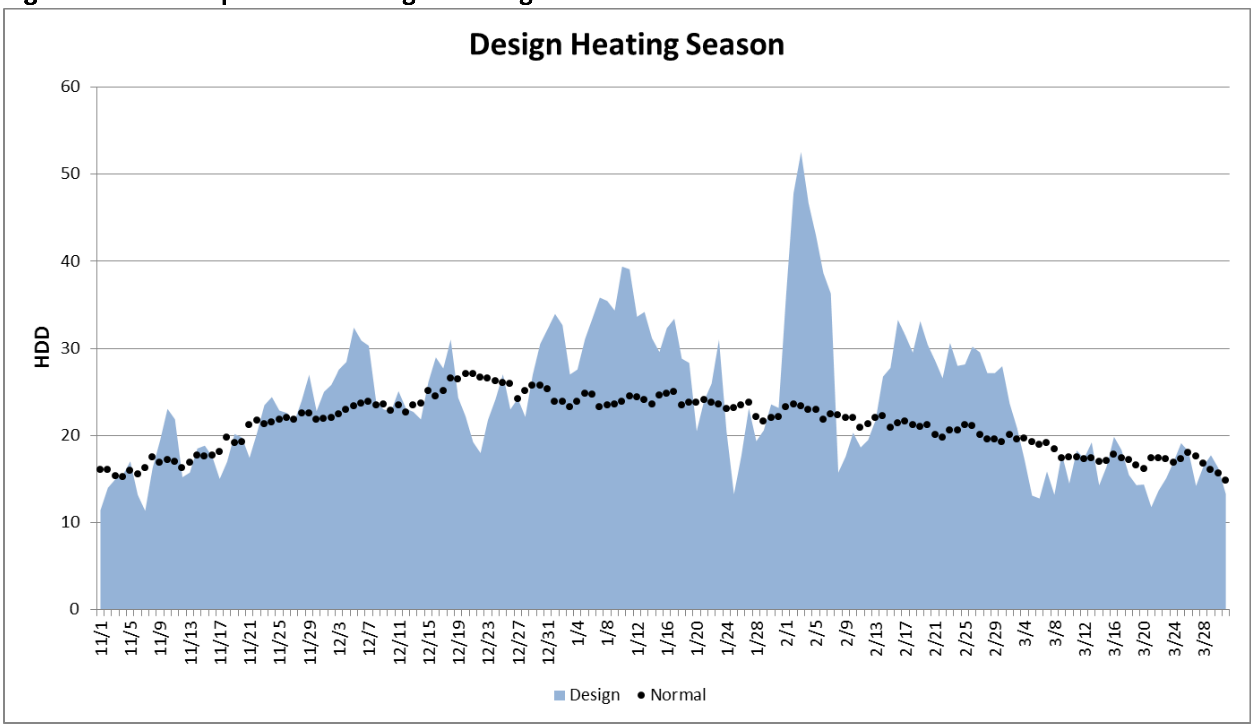
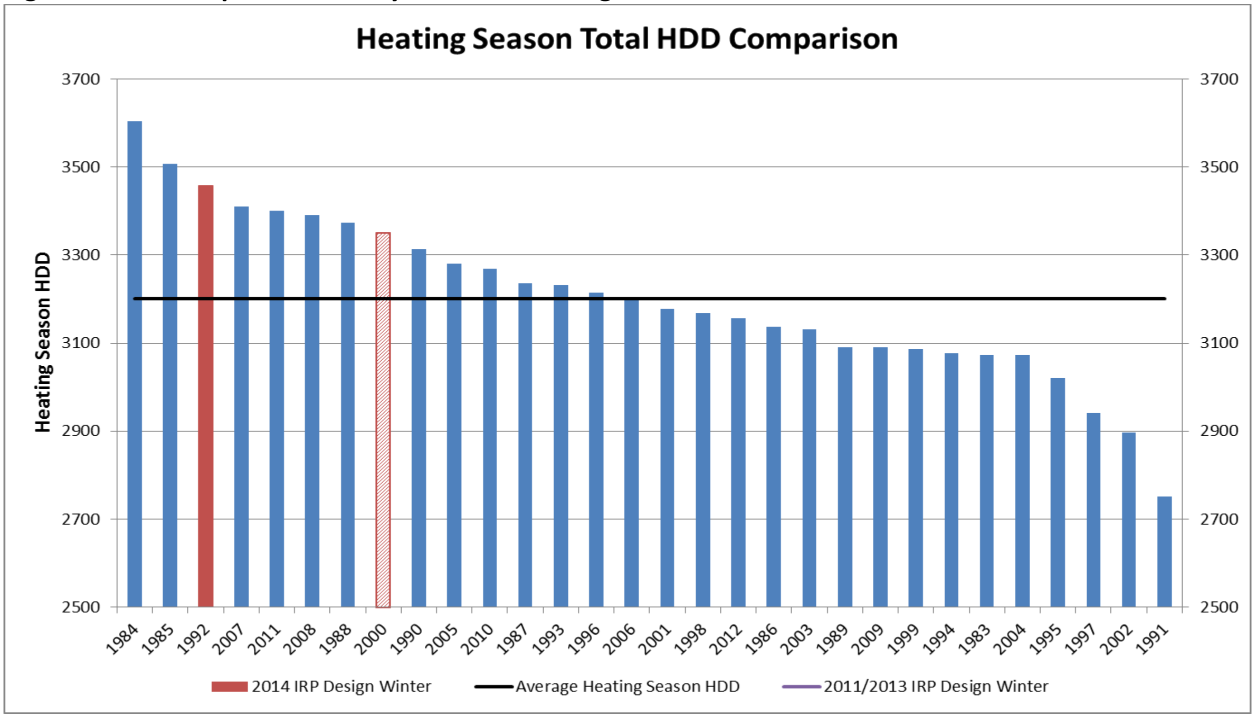


Figure 2.12 compares the heating season design weather with normal (or expected) weather on a daily basis. Figures 2.13 and 2.14 compare NW Natural's 2014 IRP heating season design weather with weather in other heating seasons over the past 30 years, with values in the former figure sorted by total heating season HDD and values in the latter figure presenting the HDD value for each heating season in chronological order. Table 2.5 compares summer and winter design weather for the 2013 Washington and 2014 IRPs, showing that the total HDD values for the design weather year are comparable for the two IRPs, and that the 2014 IRP places relatively more emphasis on the design winter. Figure 2.15 compares the design heating season weather in the 2011 Modified, 2013 Washington, and 2014 IRPs on a daily basis, with the associated footnote describing the representation of this information in Figure 2.15.

[30] NW Natural used a three day peak event in the 2013 Washington IRP.

Figure 2.13 – Comparison of 30-year Total Heating Season HDD[31]



31 The bar colored "light red" represents the heating season beginning in 2000, which NW Natural used for the "design winter" in the Company's 2011 Modified Oregon IRP and 2013 Washington IRP.

Figure 2.14 – 30-Year Comparison of Total Heating Season HDD

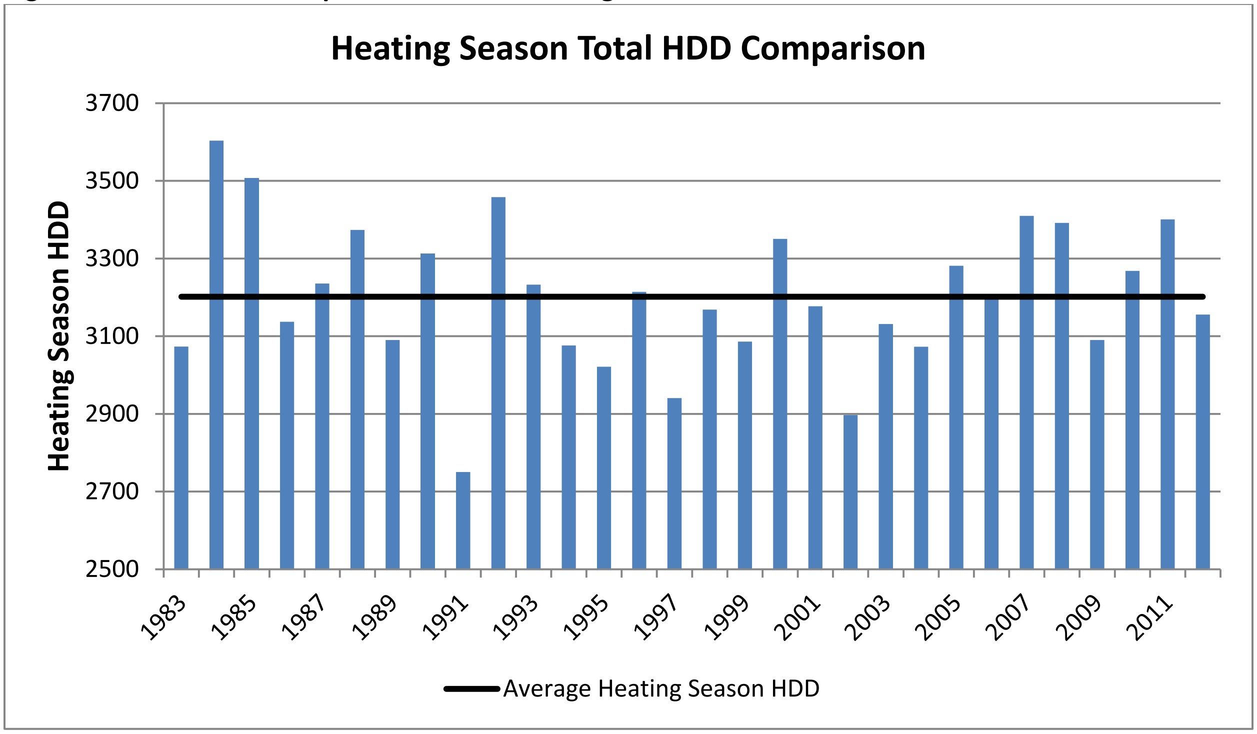
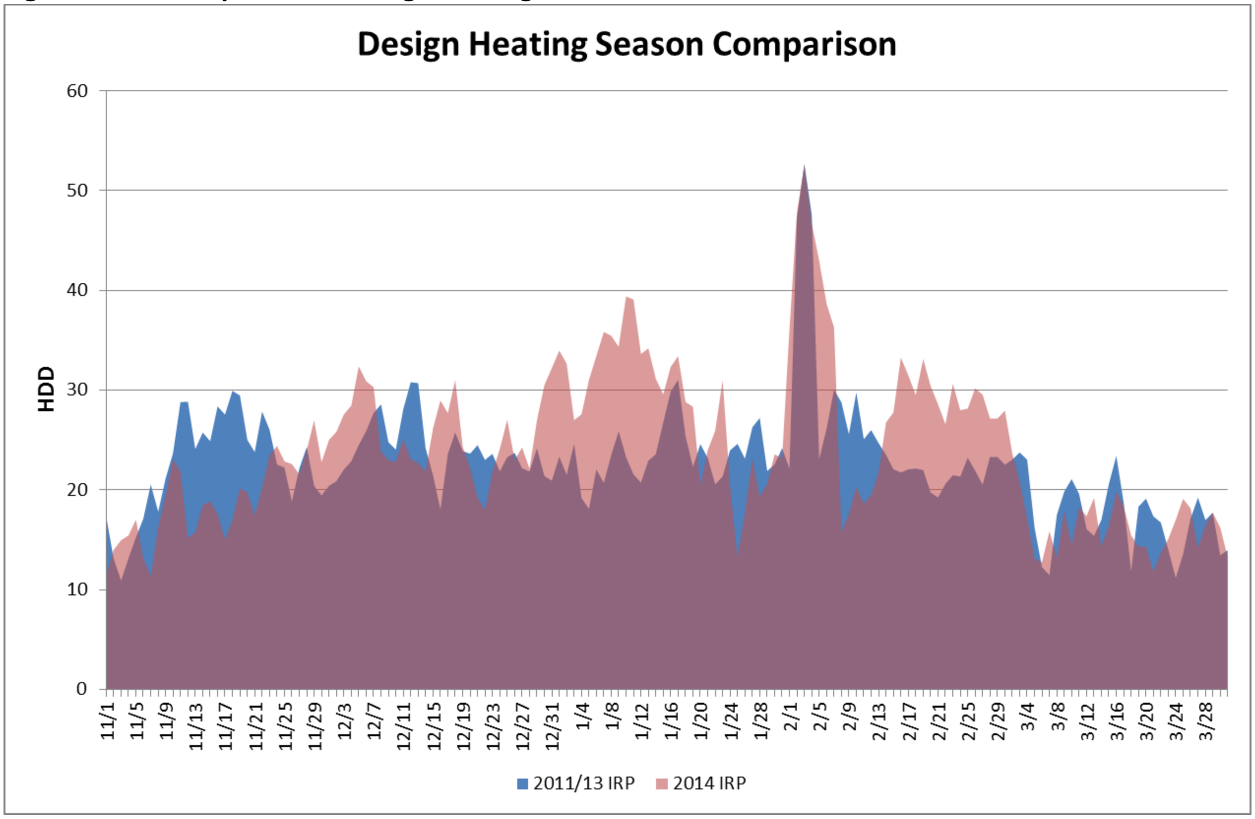


Table 2.5 – Weather by Season for 2013 Washington and 2014 IRPs

	Design Summer	Design Winter	Design Year
2014 IRP	1,129	3,624	4,753
2013 IRP	1,314	3,444	4,758
Difference	(185)	180	(5)

Figure 2.15 – Comparison of Design Heating Season Weather for Different IRPs[32]



NW Natural believes the design weather the Company uses in the 2014 IRP provides a robust test for system resources. The non-heating season design weather is modeled as being "average" in temperature. The heating season weather has a relatively cold January and February when compared with average daily temperatures over the past 30 years. February includes a seven-day cold event centered on the system-weighted 53 HDD day NW Natural uses as the Company's design day and experienced on February 3, 1989. Chapter Seven discusses how the change in design weather affects resource selection.[33]

32 As shown by the legend in this chart, the "blue" area indicates the HDD values of the 2011 and 2013 IRPs' design weather and the "pink" area that of the 2014 IRP. The "maroon" color indicates the intersection of the two design weather series; i.e., when the 2014 IRP design weather is *colder* (higher HDD level) than the 2011 and 2013 IRPs' design weather, "maroon" represents the level of the warmer (lower HDD value) 2011 and 2013 IRPs' design weather. Conversely, when the 2014 IRP design weather is *warmer* (lower HDD level) than the 2011 and 2013 IRPs' design weather, "maroon" represents the level of the warmer (lower HDD value) 2014 IRP design weather. Alternatively stated, if—for a given day—the two colors are "pink" (higher HDD) and "maroon" (lower HDD), the latter represents the HDD level for the 2011 and 2013 IRPs and if the two colors are "blue" (higher HDD) and "maroon" (lower HDD), the latter represents the HDD level for the 2014 IRP.

33 NW Natural used the design weather used in the 2013 Washington IRP and the 2013 Oregon IRP Update in place of the design weather used in this IRP to assess the impact of the change in design weather. See the discussion in Chapter Seven.

V. GAS PRICE FORECAST

NW Natural uses a 20-year natural gas price forecast by supply basin as part of the IRP process. The forecast includes a monthly price outlook for Henry Hub, Rockies (Opal), British Columbia (Sumas), Alberta (Alberta Energy Co., or AECO) and Malin. Like many commodities, volatility in natural gas prices at historic levels makes forecasting spot prices highly uncertain. NW Natural expects future gas prices will be influenced by numerous factors; including economic conditions, demand, power generation, potential national or regional carbon policies,[34, 35] weather, and new and traditional supplies—such as gas produced using more efficient extraction technologies. The Company reviews several public and proprietary price forecasts and has developed a Base Case gas price forecast as well as high and low price outlooks to represent reasonable ranges of future prices for the basins from which the Company purchases gas supplies.

NW Natural also used natural gas price forecasts, developed by IHS CERA at the Company's request, in scenarios in which different combinations of regional pipelines and/or LNG export facilities come into fruition. See Chapter Seven for a description of these scenarios.

A. Price Volatility

The combination of lower demand and increased supplies has resulted in low gas prices over the last several years relative to the several prior years. Improved drilling technologies have tremendously increased the potential supply of "unconventional" gas from shale deposits throughout North America. The slower than expected recovery from the 2007 – 2009 recession continues to suppress growth in demand for natural gas. Henry Hub spot prices dipped below $4 per dekatherm (Dth) in 2009, while Rockies and Canadian spot prices dropped below $3 per Dth. Henry Hub spot prices were under $2 per Dth in April 2009. According to IHS CERA Chairman Daniel Yergin, "As recently as 2007 it was widely thought that natural gas was in tight supply and the U.S. was going to become a growing importer of gas. But this outlook has been turned on its head by the shale gale.[36]

Figure 2.16 displays the history of monthly natural gas prices since 1997. Monthly average spot prices at Henry Hub, the reference pricing point for the North American natural gas market, exceeded $12 per Dth as recently as June 2008. Hurricanes Katrina and Rita drove prices over $13 per Dth in late 2005. The Western energy crisis in 2000 – 2001 spiked prices over $8 per Dth. Price declines since 2008 have allowed NW Natural to reduce Washington residential rates by 24 percent in late 2009, by 2 percent in 2010, by 2.5 percent in 2011, and by about 9 percent in 2012. The Company reduced Oregon residential rates by approximately 20 percent in late 2009.

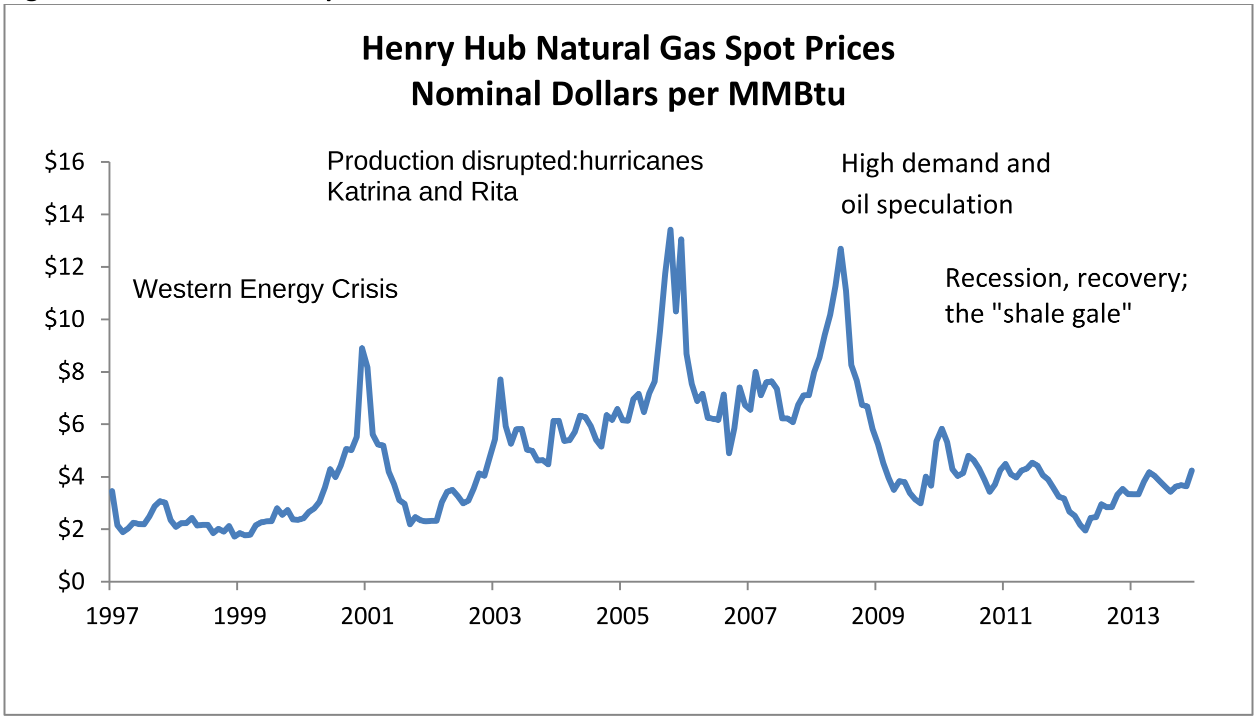
---

[34] See Chapter Five as well as the discussion in this chapter regarding policies related to emissions of greenhouse gases and specifically to emissions of carbon dioxide produced by combustion of fossil fuels. NW Natural is unable to quantify the impact on natural gas prices of new national or regional environmental policies until details of such policies are known.

[35] The Base Case natural gas price forecast includes a carbon price beginning in 2021. See Chapter Five for a discussion of alternative carbon prices.

[36] The IHS CERA press release of March 10, 2010; accessed April 21, 2013 at http://press.ihs.com/press-release/energy-power/ihs-cera-shale-gas-can-be-game-changer-north-americas-energy-future .

Figure 2.16 - Natural Gas Spot Price



B. Price Forecast

The forecast of natural gas prices impacts the least cost planning modeling and avoided cost calculations. NW Natural also uses the forecast as a basis for developing the High and Low Gas Price scenarios' load forecasts. NW Natural includes the price forecast in the Company's SENDOUT® resource planning modeling software, and the level of future natural gas prices may impact future resource decisions. NW Natural uses SENDOUT® for analyzing and developing the optimal plan[37] for purchasing and transporting natural gas to the Company's customers. Gas supply cost is the dominant component of avoided cost calculations, and the price forecast can play a significant role in estimating costs and determining the resource portfolio(s) with the best mix of cost and risk.

NW Natural's price forecast, which the Company derives from a proprietary forecast developed by third party provider IHS CERA Inc.,[38] offers a long-term look at the natural gas market. Figure 2.17 displays the price forecast used in this IRP as well as the following additional natural gas price forecasts:

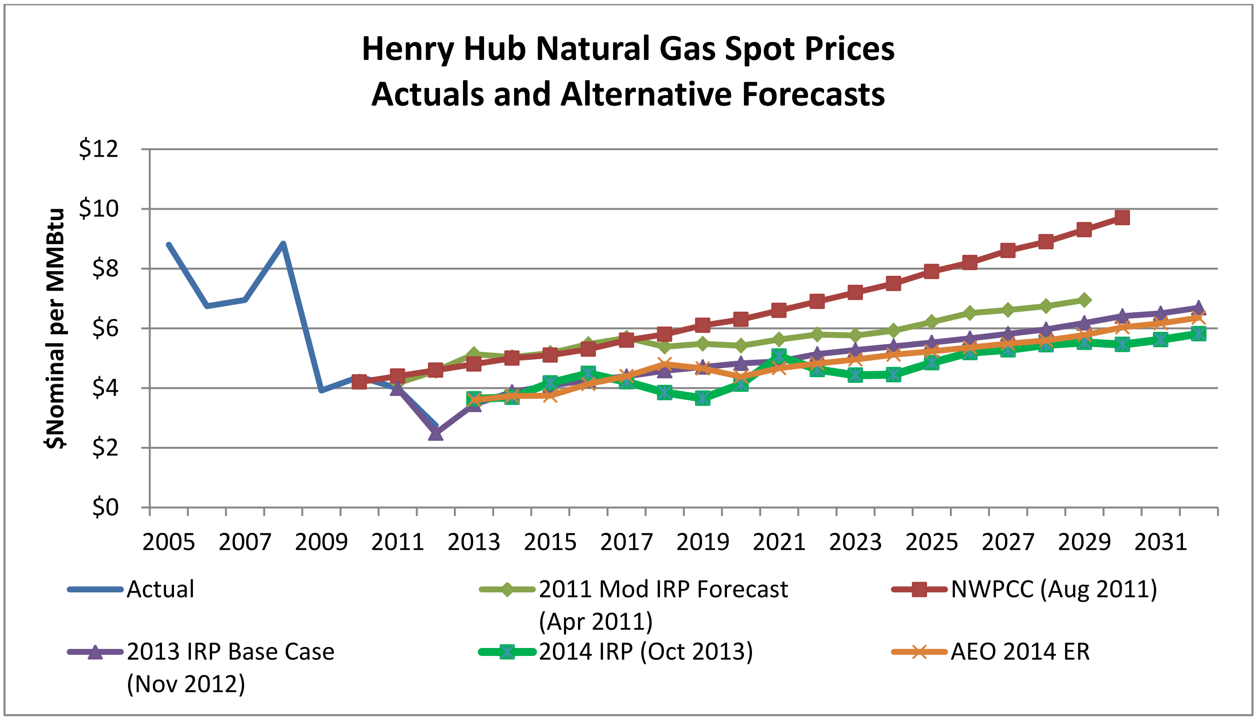
---

[37] NW Natural intends that an "optimal plan" is understood in this context to be a part of the larger resource solution that provides the "best mix of cost and risk" in conforming to the Public Utility Commission of Oregon's IRP Guideline 1c. By "optimal," NW Natural means "best and most effective;" with this definition appearing in the online Merriam-Webster at http://www.merriam-webster.com/dictionary/optimal (accessed August 5, 2014).

[38] Source: IHS Inc. This content is extracted from IHS Energy North America Natural 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 2013, all rights reserved.

1. Northwest Power and Conservation Council (NWPCC; August 2011)
2. Modified 2011 IRP Forecast (April 2011)
3. 2013 Washington IRP (October 2012)
4. 2014 IRP (October 2013)
5. U.S Energy Information Administration (EIA; December 2013)

Figure 2.17 – Natural Gas Price Forecasts



VI. EMERGING MARKETS

NW Natural expects the historic decline in gas prices resulting from the use of transformational shale recovery methods to result in increased uses of natural gas over time in three or more areas. The primary markets are likely to be electric power generation, industrial processes and feedstock,[39] and transportation. The transportation market may include local fleets and passenger vehicles, long-haul trucking, marine, and even railroad applications. The emerging transportation markets will require support by both liquefied natural gas (LNG) and compressed natural gas (CNG) facilities. An additional market that may emerge due to lower gas prices is distributed generation, where smaller, local facilities powered by natural gas provide a portion of electricity requirements.

[39] The online version of The Oregonian reported on January 22, 2014 that two methanol plants costing $1 billion each are being planned for the Pacific Northwest. Accessed February 19, 2014 at http://www.oregonlive.com/business/index.ssf/2014/01/backers_say_twin_1_billion_met.html .

NW Natural developed three scenarios[40] for emerging market growth, and included the lowest projected emerging market load in the Base Case load forecast. The Company selected the Low Emerging Market scenario for use in the Base Case load forecast to reflect the high degree of uncertainty surrounding these markets. As emerging natural gas markets develop over the coming years, NW Natural can, if warranted, incorporate higher load levels into the Base Case load forecast of future IRPs, still leaving adequate time to respond by adding resources required to serve these markets' firm service load requirements.

NW Natural included the Medium and High Emerging Market scenarios in models specific to those scenarios. Emerging market load growth in the High scenario is quite dramatic, including load requirements associated with potential feedstock needs, power generation, and long-haul trucking conversions.[41] The High Emerging Market scenario has annual load for emerging markets by the end of the planning horizon equivalent to NW Natural's current load. On the same basis, the medium case would be about 13 percent of current load, and the low case NW Natural includes in the Base Case load forecast is about eight percent of current load.[42] The following figures show projected loads for each scenario by market segment. Figure 2.21 compares the three scenarios' loads.

[40] NW Natural develops the Company's resource requirements generally using only Firm Sales service loads, but includes Firm Transportation customers for distribution system requirements. The Company recognizes that the Firm Sales or Firm Transportation portions of these emerging markets loads are, as discussed in a Technical Working Group meeting, relatively small relative to their total sizes.

[41] NW Natural describes the analysis of the Emerging Market scenarios in Chapter Seven.

[42] These are comparisons of the total Emerging Market annual load under the respective scenario for heating year 2032 – 2033 with the forecast 2013 – 2014 Firm service annual load.

Figure 2.18 – Low Emerging Market Scenario by Segment

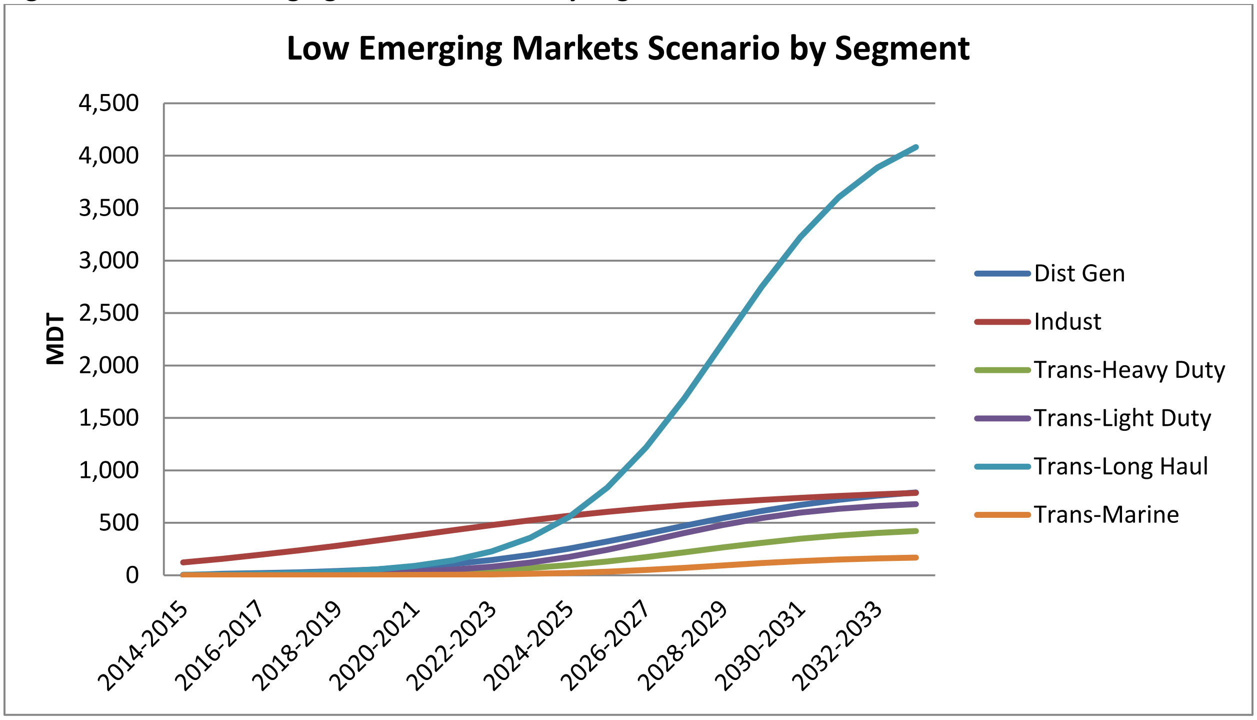


Figure 2.19 – Medium Emerging Market Scenario by Segment

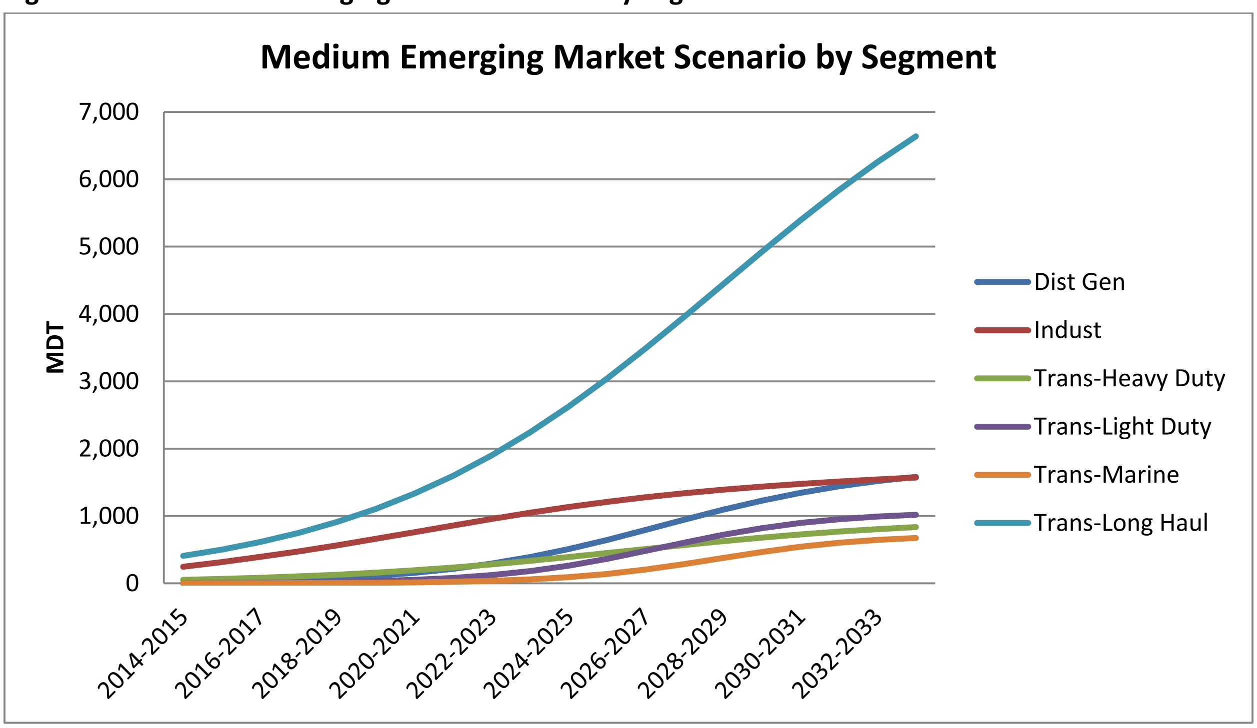


Figure 2.20 – High Emerging Market Scenario by Segment

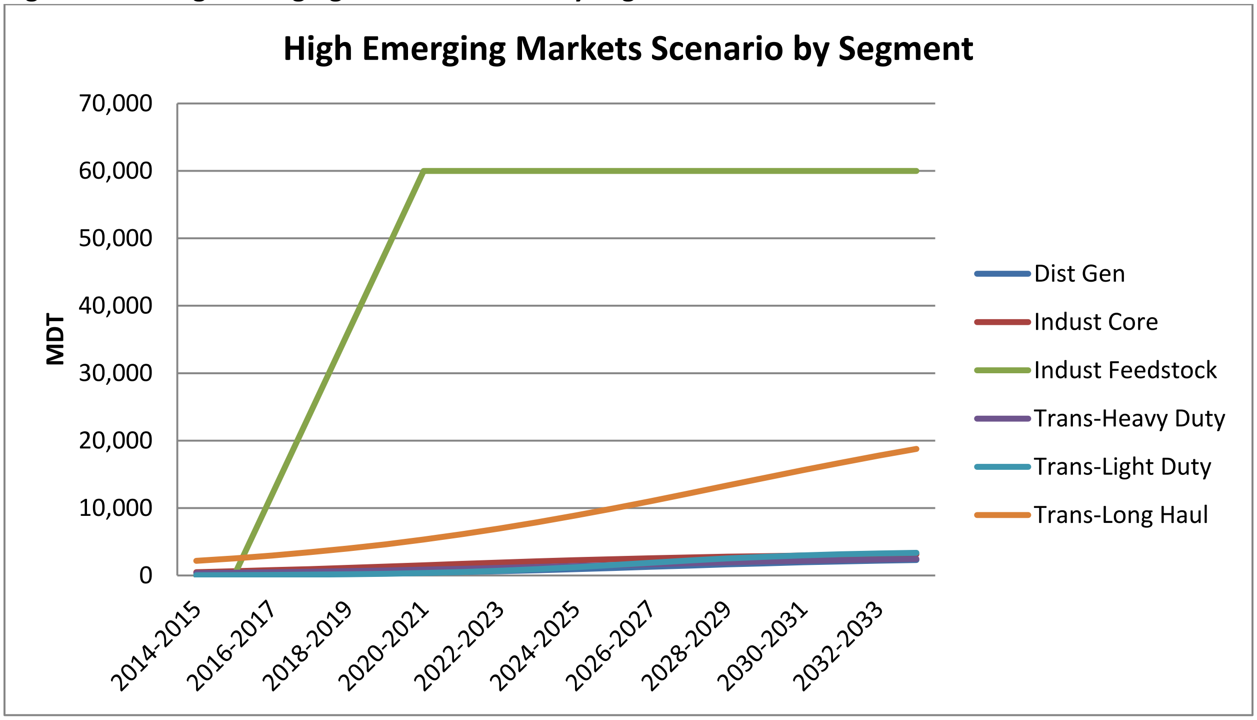
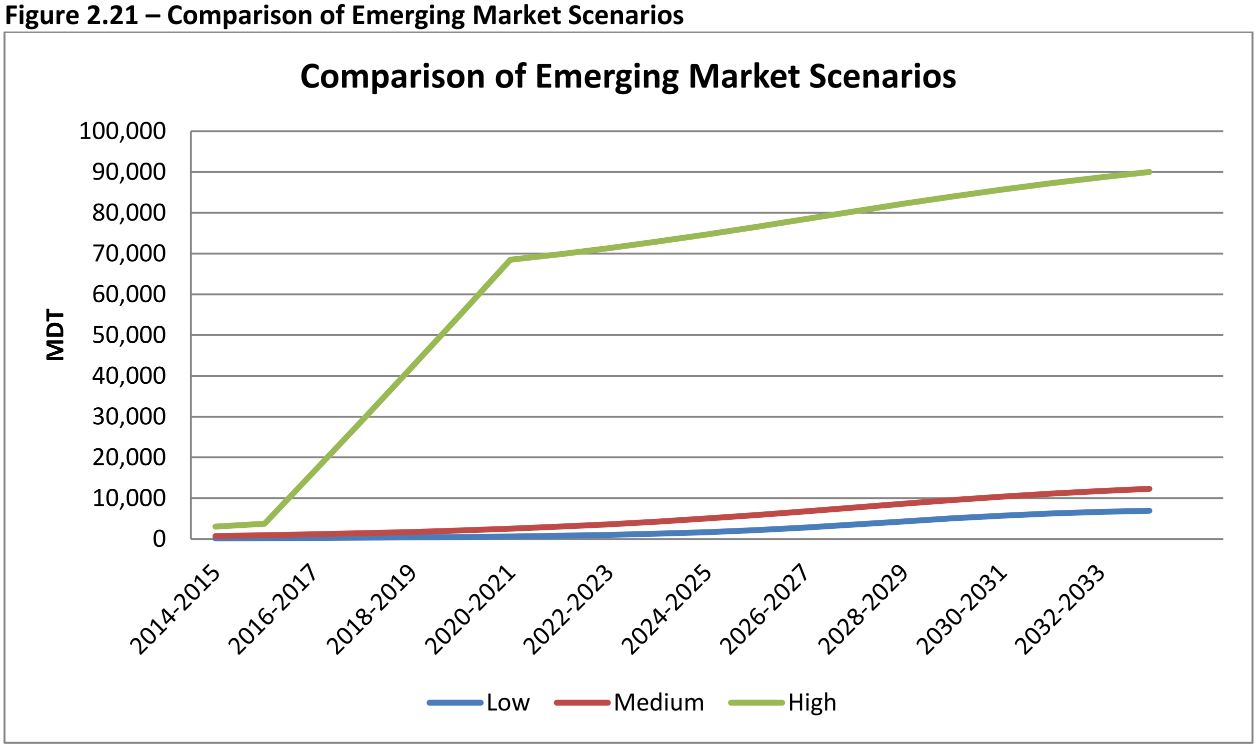


Figure 2.21 – Comparison of Emerging Market Scenarios



VII. RESULTS

NW Natural incorporates the primary components of the load forecast—customer forecast, use per customer model, and weather pattern—into a daily load forecast for each combination of load center and customer category.

The Company decrements forecasts of gross load requirements for the levels of DSM energy savings forecast by ETO. Chapters Four and Seven provide background on how ETO estimated the DSM savings and how NW Natural integrated these into the Firm Sales and Firm Sales plus Firm Transport load forecasts.

Additionally, NW Natural decrements the gross loads by an additional 50 percent of the DSM amounts estimated by ETO. This represents a perceived declining average use per customer trend understood to be incremental to ETO's DSM forecast. The end results are daily post-DSM load forecasts of gas requirements around which NW Natural develops the Company's resource plan.

A. Base Case Forecast

NW Natural's Base Case design weather load forecast[43] provides the best estimate of future firm service load requirements for a colder-than-average winter, with a multiday cold event that includes a very cold design (peak) day.

Figure 2.22 shows the composition of the post-DSM design day peak demand for Firm Sales customers by load center for the first year in the planning horizon, while Figure 2.23 shows the same information for the last year in the planning horizon. Figure 2.24 shows the composition of growth in Firm Sales post-DSM design day peak demand over the planning horizon, with the increase in Vancouver approximately 30 percent of NW Natural's increase.

The design day peak demand for firm service customers over the planning period have average annual growth rates of 1.0 percent for Oregon, 3.4 percent for Washington, and 1.3 percent for NW Natural; all on post-DSM bases and as shown in Table 2.6. Design day peak demand for each of these over the planning horizon is shown in Figure 2.25. As previously discussed, the higher rate of growth in Washington is primarily due to a higher projected rate of customer growth for the Vancouver load center. Figure 2.26 shows the annual rates of growth in design day peak demand over the planning horizon.

As noted in the Overview section above, Firm Transportation customers provide for their own upstream resource adequacy needs. Therefore NW Natural does not incorporate the gas supply needs of these customers into its supply resource planning. The Company does provide firm distribution services for these customers however, so their needs must be considered in distribution system planning.
Figure 2.27 shows the total of Firm Sales and Firm Transportation design day peak demand over the planning horizon.

---

[43] Firm Sales load values in this section include the portion of Emerging Markets load that NW Natural anticipates will be Firm Sales, as opposed to Interruptible or Firm Transport.

Figure 2.22 – Firm Sales Design Day Peak Demand Composition by Load Center: 2013 – 2014

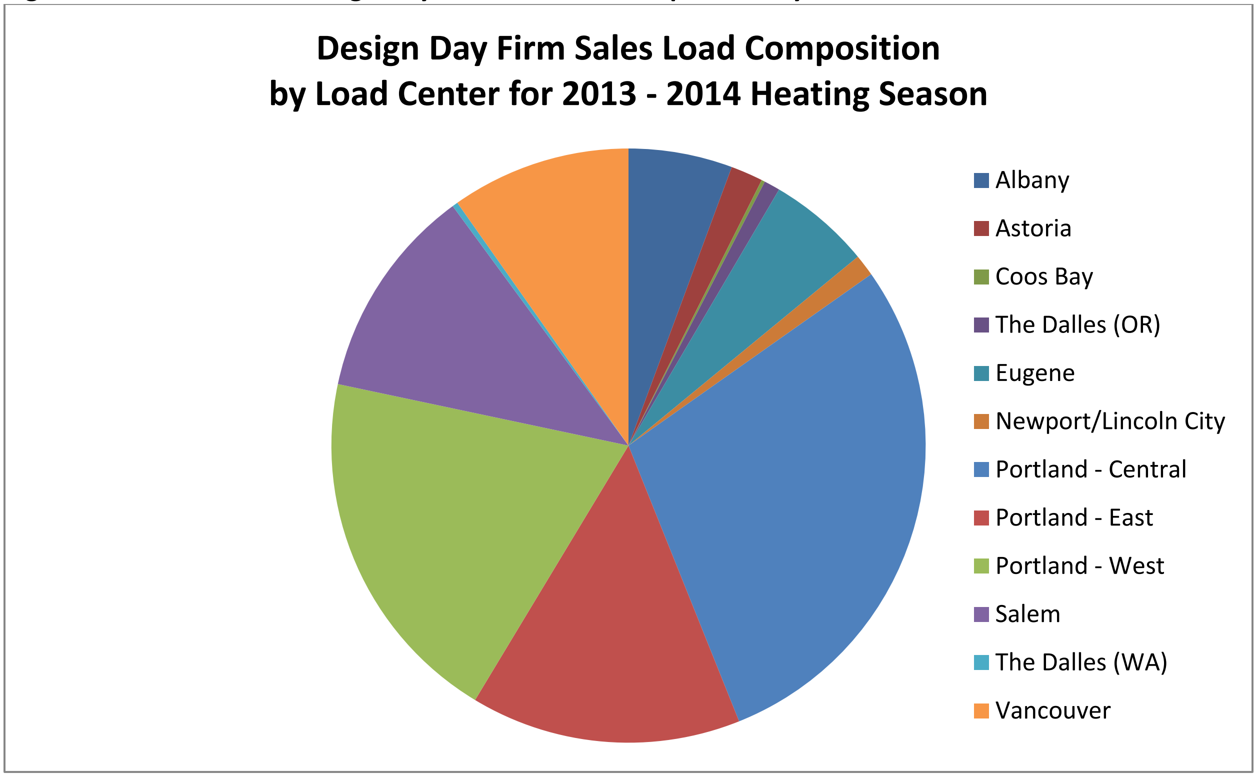


Figure 2.23 – Firm Sales Design Day Peak Demand Composition by Load Center: 2032 – 2033

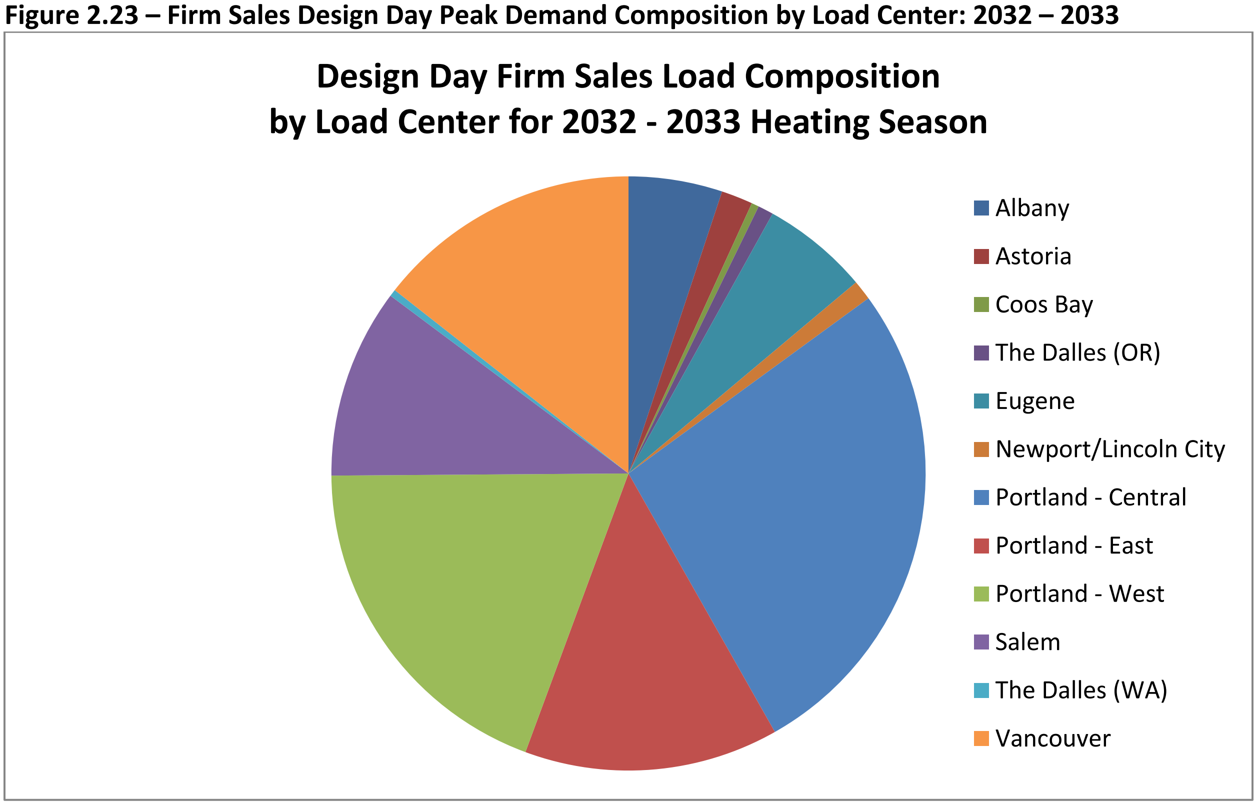


Figure 2.24 – Composition of Growth in Firm Sales Design Day Peak Demand over Planning Horizon

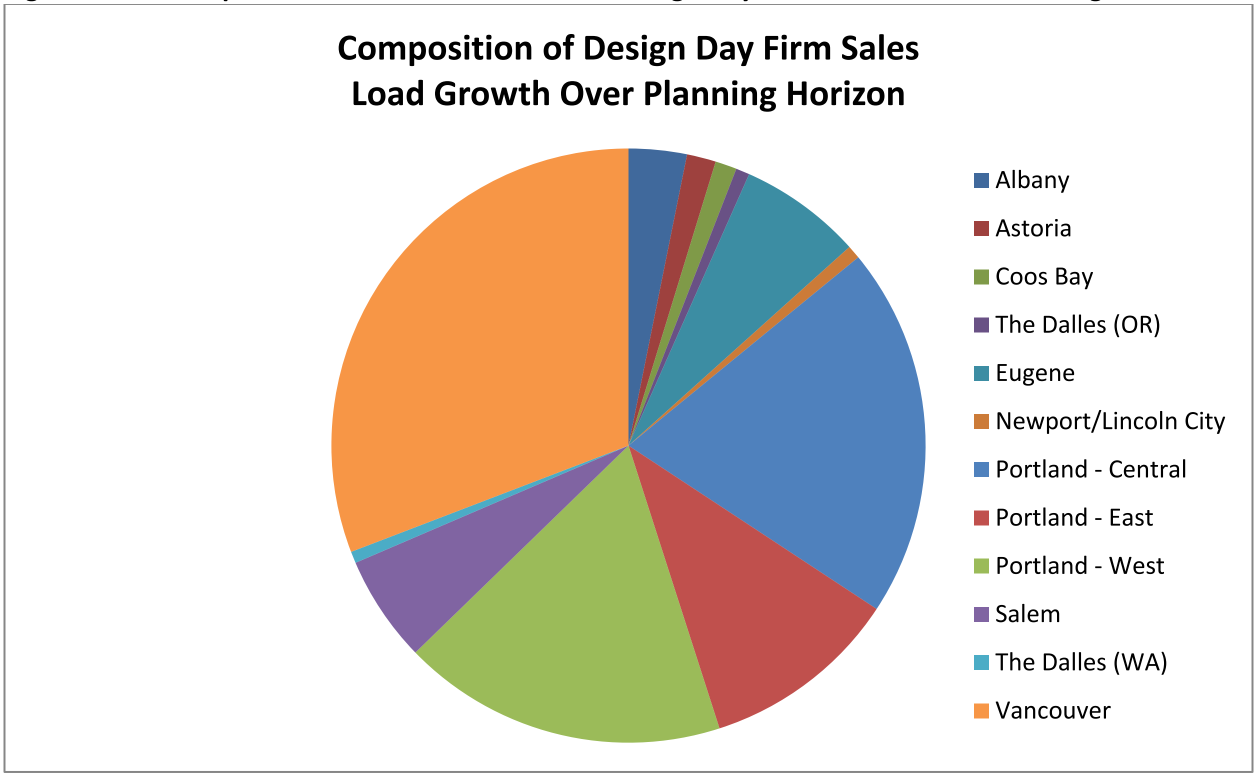


Figure 2.25 – Firm Sales Design Day Peak Demand

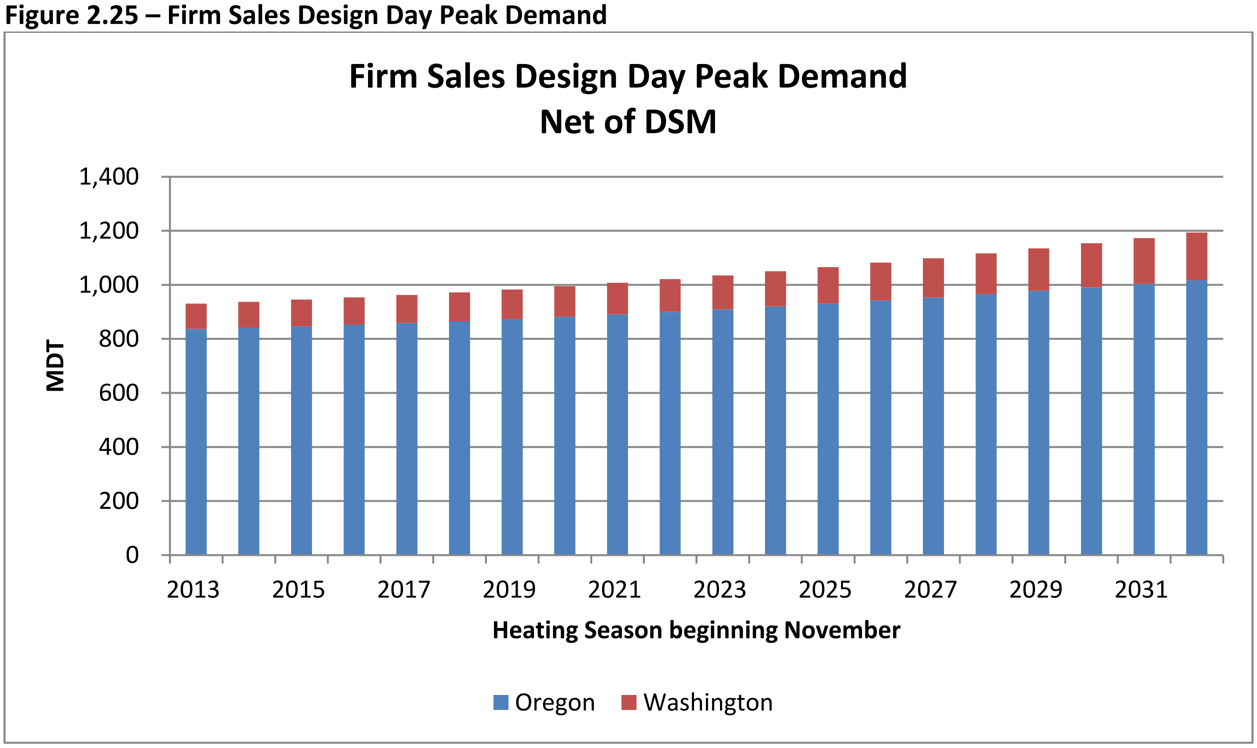


Figure 2.26 – Annual Growth Rates in Firm Sales Design Day Peak Demand

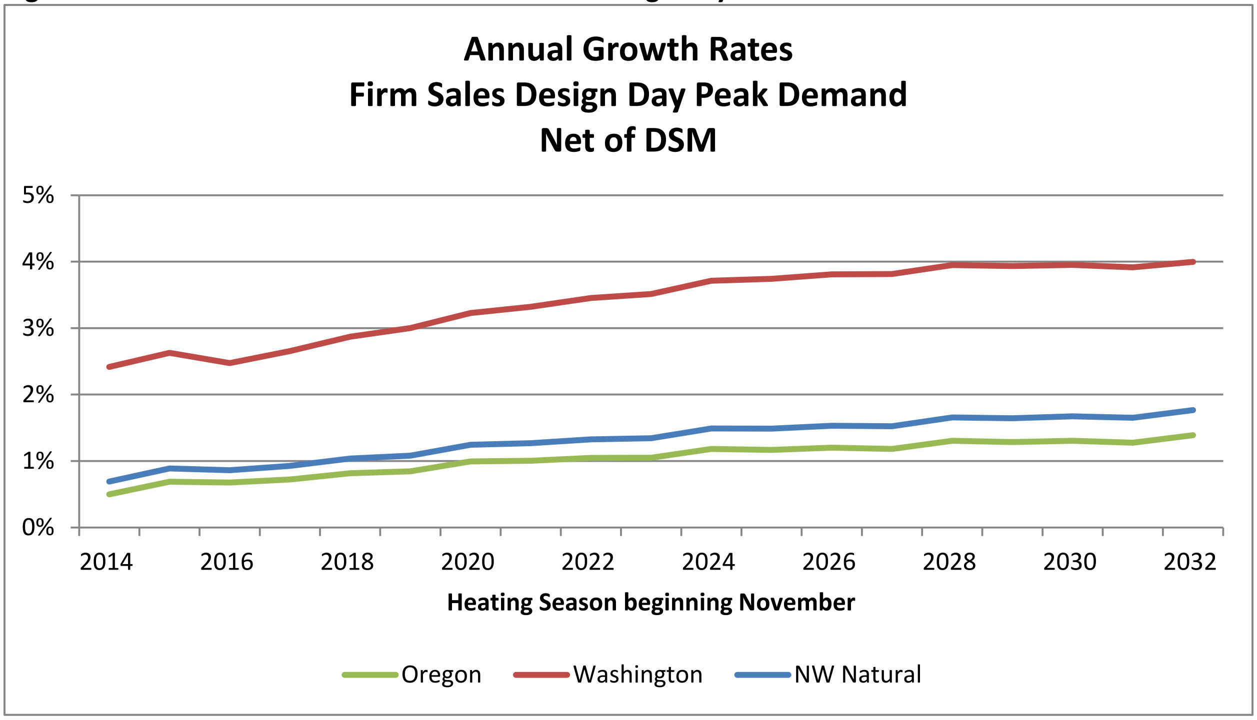


Figure 2.27– Firm Sales and Firm Transportation Design Day Peak Demand

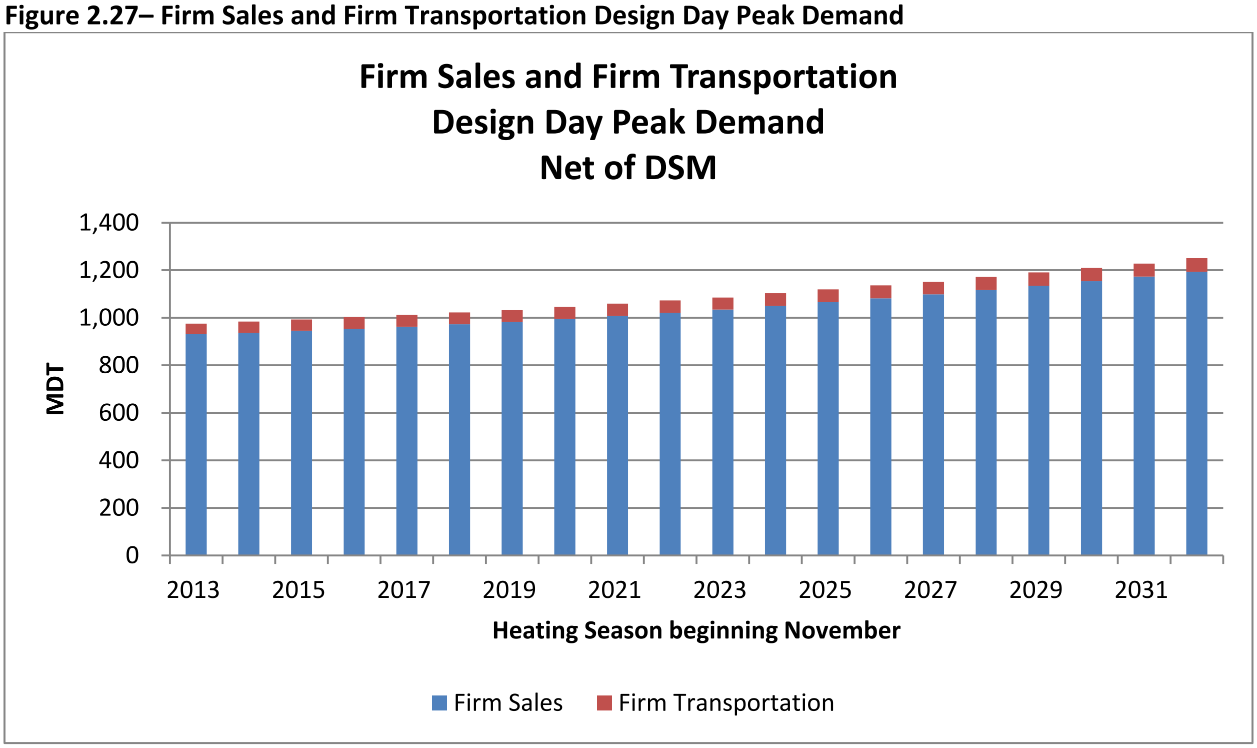


Figure 2.28 shows the Base Case forecast's Firm Sales design day peak demand net of DSM by load center. Figure 2.29 shows the Base Case forecast's Firm Sales annual load net of DSM by load center. Figure 2.30 shows the Base Case forecast's Firm Sales annual load net of DSM by state. See Chapter Four for discussion of the DSM forecast.

Figure 2.28 – Base Case Forecast Firm Sales Design Day Peak Demand

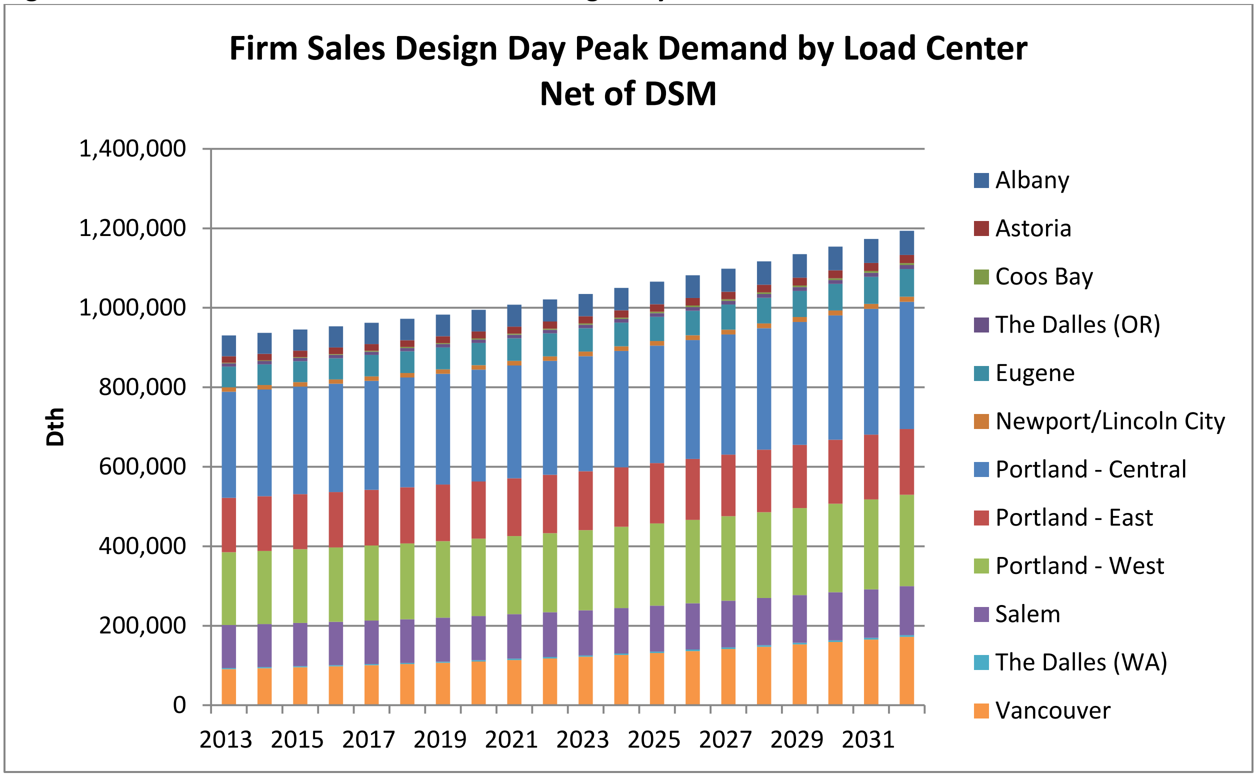


Figure 2.29 - Base Case Forecast Firm Sales Annual Load

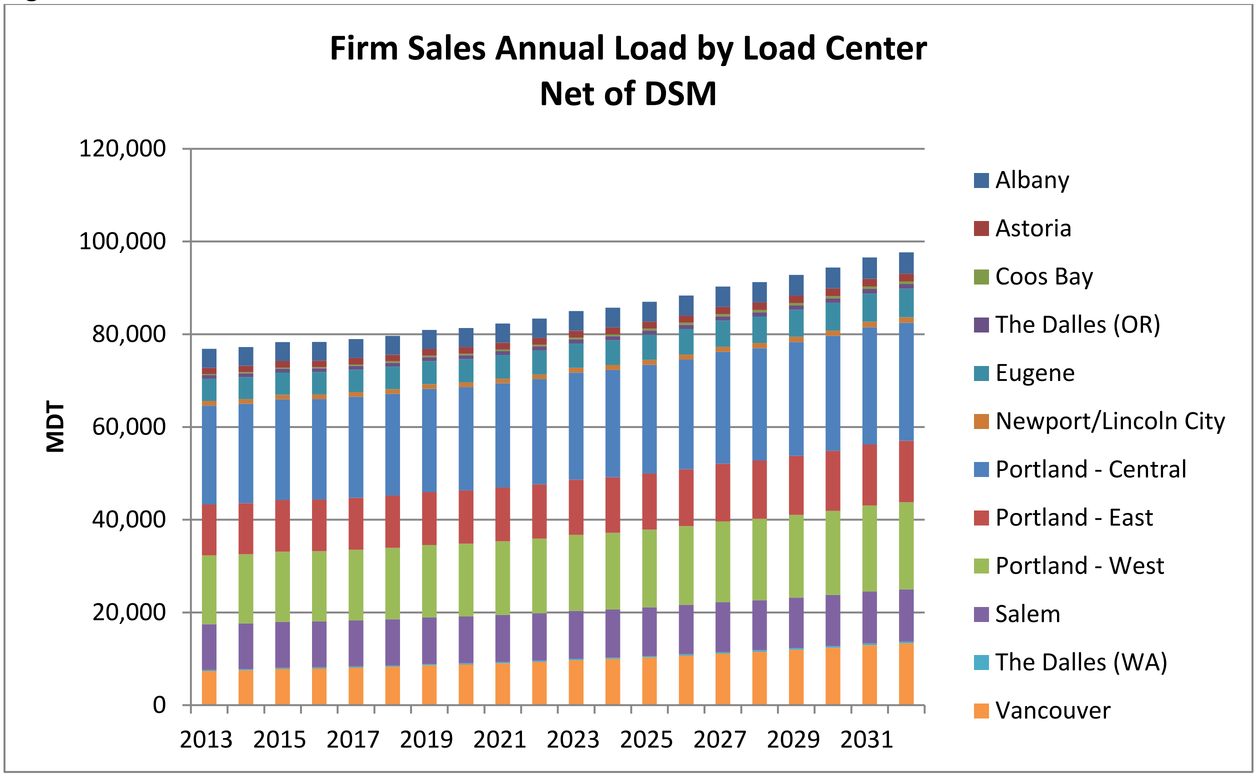
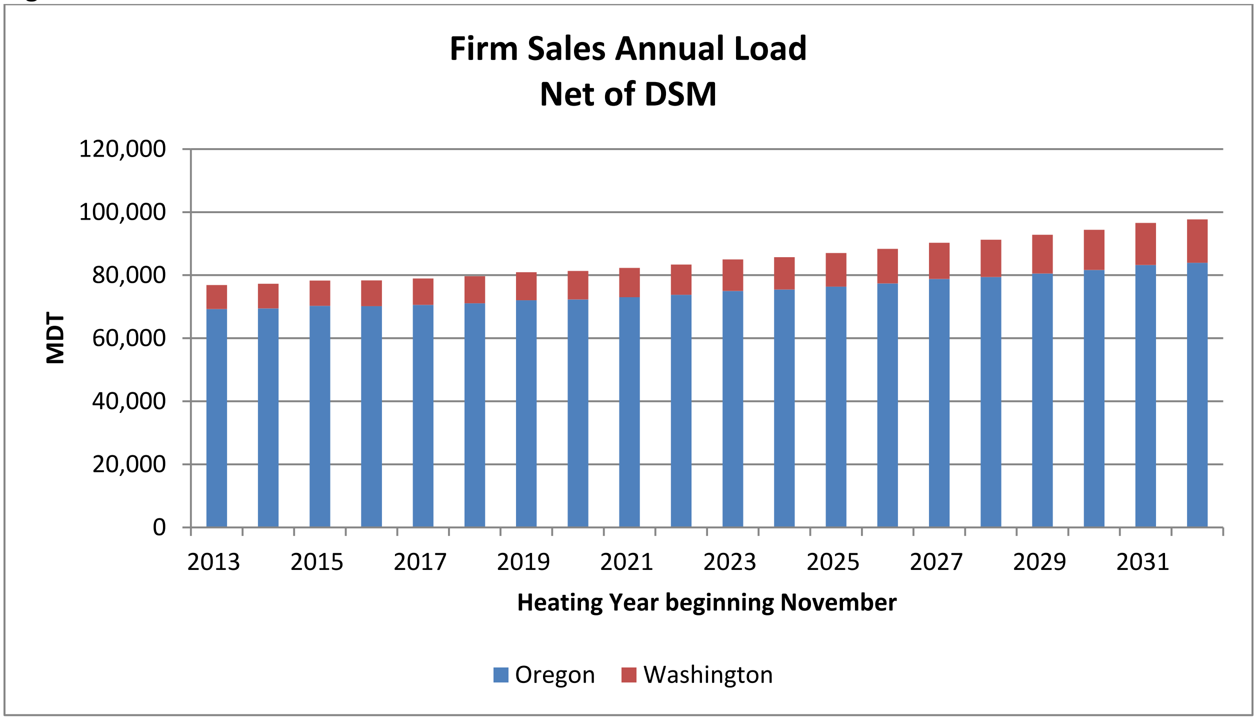


Figure 2.30 – Firm Sales Annual Load



B. Alternative Growth Scenarios

Table 2.6 compares the Firm service design day peak demand average annual growth rates for the Base Case forecast and the High Load Growth and Low Load Growth scenarios described above.[44] The underlying Firm service design day peak demand includes the portion of the Low Emerging Markets scenario NW Natural projects as Firm Sales or Firm Transport. The following figures compare Firm Sales customers for the same three scenarios over the planning horizon.

Table 2.6 – Average Annual Growth Rates of Firm Service Design Day Peak Demand

	Base	High	Low
Oregon	1.0%	1.5%	0.6%
Washington	3.4%	3.9%	2.8%
NW Natural	1.3%	1.8%	0.9%

[44] See the discussion of methods used for deriving the High and Low Load Growth scenarios in this chapter's Section II D.

Figure 2.31 – NW Natural Residential and Commercial Firm Sales Customers

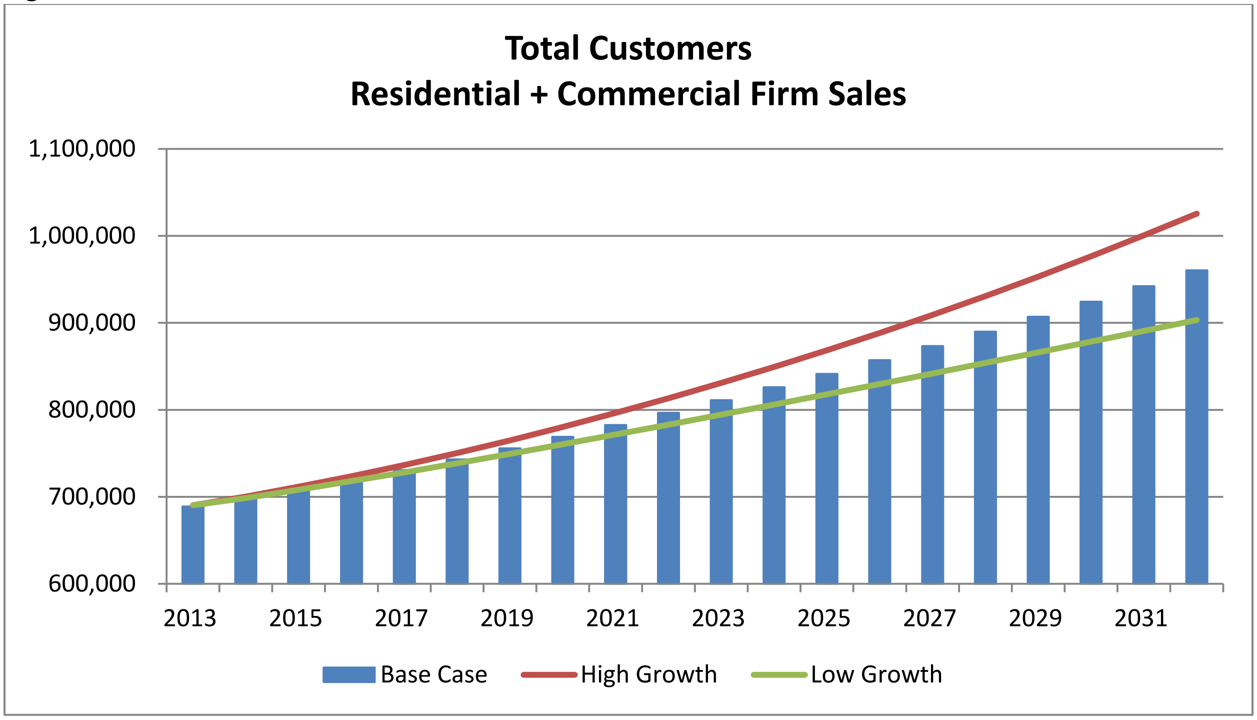


Figure 2.32 – Oregon Residential and Commercial Firm Sales Customers

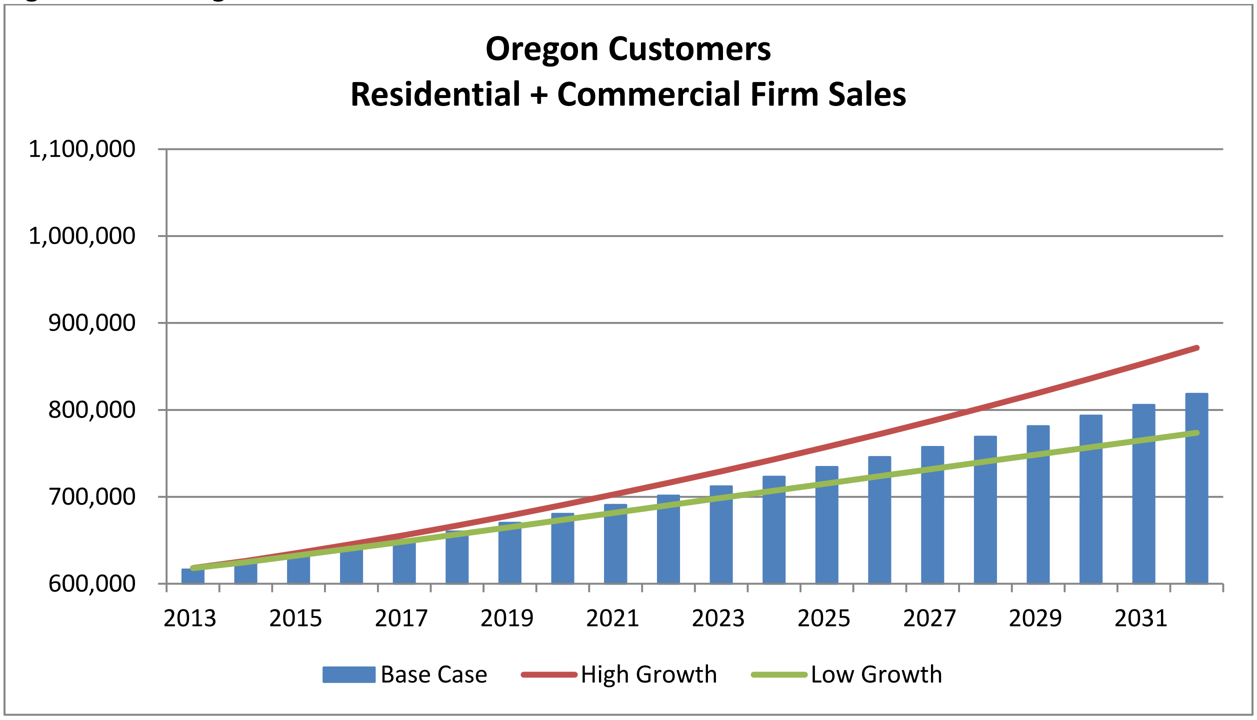


Figure 2.33 – Washington Residential and Commercial Firm Sales Customers

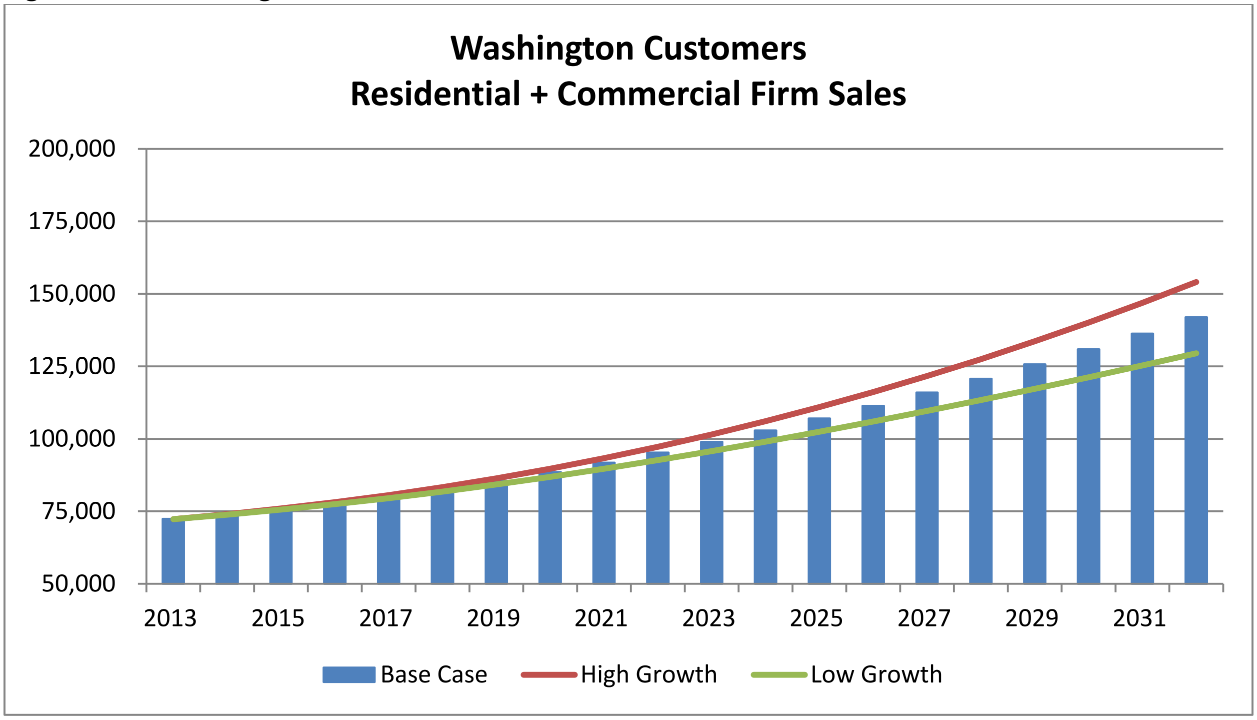


Figure 2.34 shows Firm service (Firm Sales and Firm Transportation) design day peak demand net of DSM for the Base Case forecast and alternative scenarios. The Base Case forecast includes the Low Emerging Markets scenario, while the Medium and High Emerging Markets scenarios include the Base Case forecast's design day peak demand for core customers. Note that levels of Firm service design day peak demand do not materially change between the Base Case forecast and the Medium Emerging Market scenarios due to the relatively small portion of Firm service design day peak demand represented by the Low and Medium Emerging Market scenarios. The High Emerging Markets scenario includes the design day peak demand of an Industrial Feedstock customer with Firm Transportation service.

Figure 2.35 shows Firm service design day peak demand net of DSM for the Base Case forecast and alternative scenarios in Figure 2.34. The High Emerging Markets includes annual load from an Industrial Feedstock customer as Firm Transportation, corresponding with the High Emerging Markets design day peak demand. See also Figures 2.18 – 2.21.

Figure 2.34 – Firm Service Design Day Peak Demand by Scenario

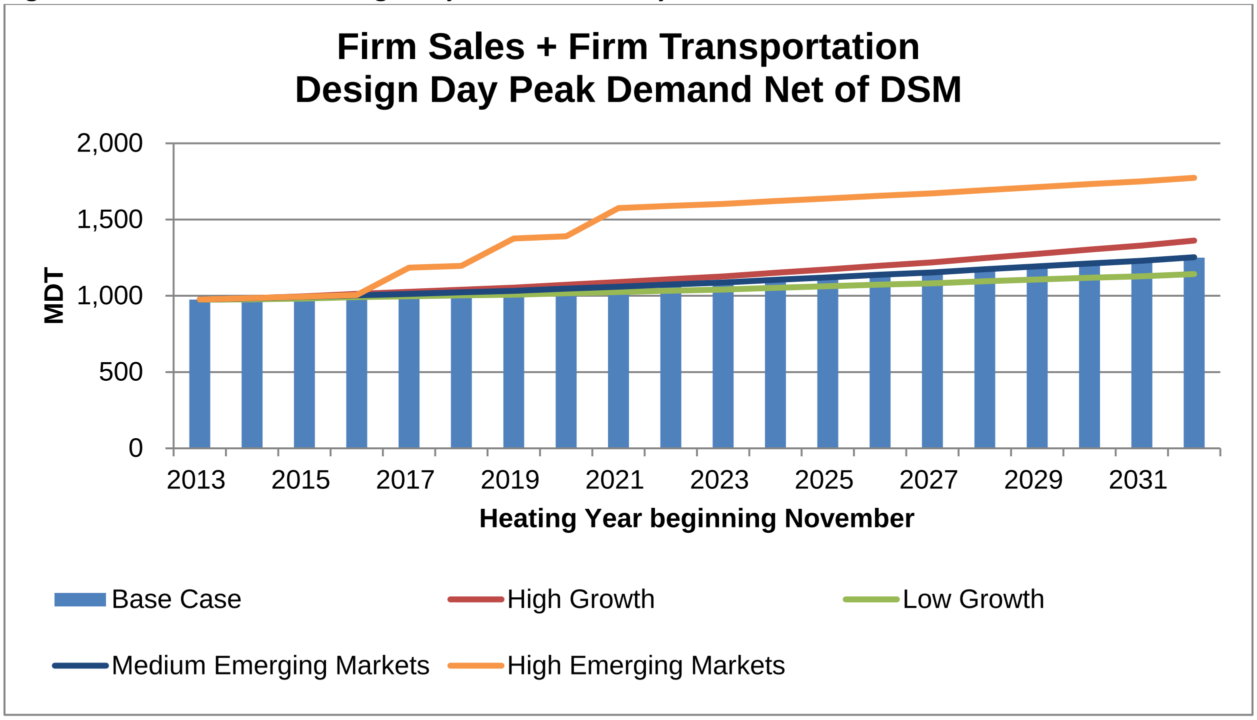
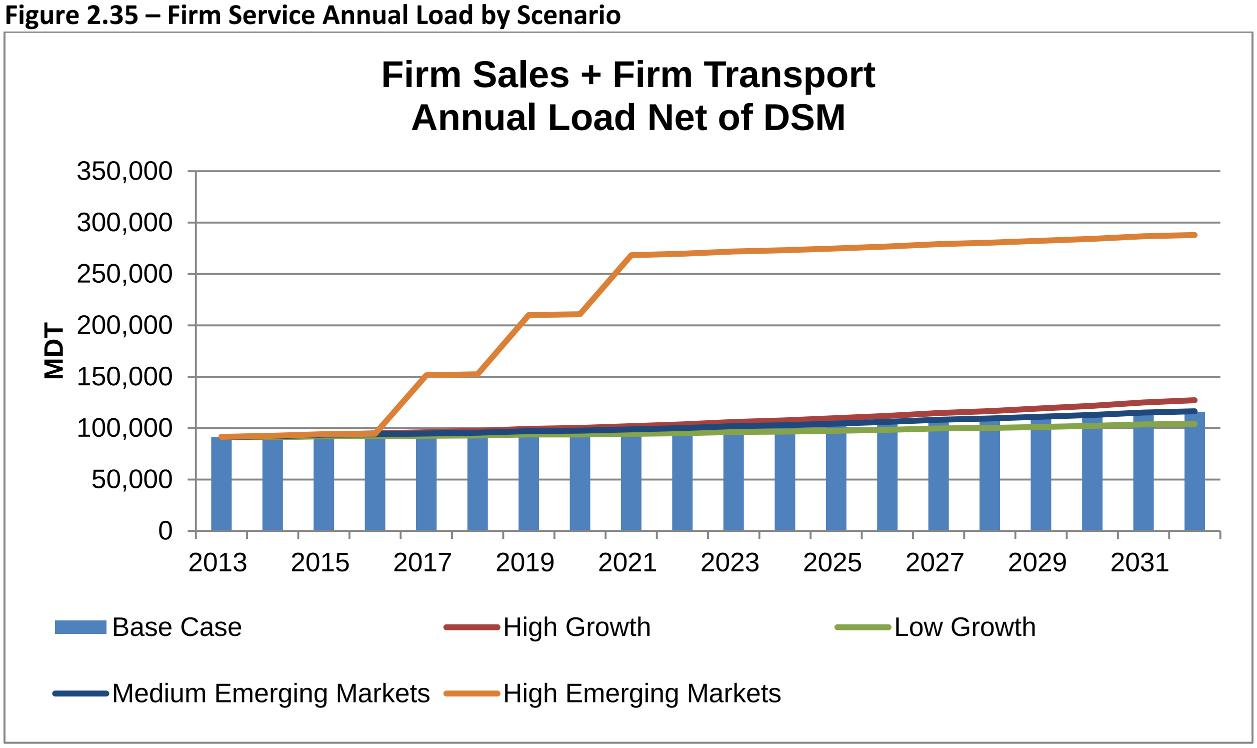


Figure 2.35 – Firm Service Annual Load by Scenario



C. Alternative Carbon Scenario

NW Natural's Base Case gas price forecast includes a carbon price implemented in 2021 at $8.78 per metric ton of carbon dioxide equivalent ($MTCO_2e$) and increasing to $15.01 per $MTCO_2e$ in 2032 (both prices in $2013). Stakeholders participating in the Company's Technical Working Group meetings requested an analysis of a carbon tax implemented earlier and at a materially higher rate than that in the Base Case forecast. NW Natural bases the carbon prices in this scenario on those described in "Carbon Tax and Shift: How to make it work for Oregon's Economy" prepared by the Northwest Economic Research Center[45] (NERC) in 2013. The Company refers to this scenario as the PSU Carbon Price scenario. NW Natural considers the earliest possible implementation to be January 1, 2016 and uses the same nominal dollar value at implementation as in the NERC report. Figure 2.36 shows the carbon price in the PSU Carbon Price scenario as well as the difference between it and the carbon price embedded within the Base Case forecast (with both in nominal dollars per $MTCO_2e$). Figure 2.37 shows both in 2013 dollars per therm.[46] Table 2.7 shows the average annual carbon tax paid by Residential and Commercial customers in the year of implementation and in the last year of the planning horizon for the carbon price embedded in the Base Case forecast and the PSU Carbon Price.

Table 2.7 – Average Annual Amounts of Carbon Tax per Customer: Base Case Forecast and PSU Carbon Price

	Average Annual Therm Use per Customer[47]	2021 Base Case	2032 Base Case	2016 PSU	2032 PSU
Residential	636	$28.64	$48.98	$31.89	$141.60
Commercial	3,845	$173.15	$296.12	$192.82	$856.06

45 NERC is associated with Portland State University's College of Urban and Public Affairs. Jenny H. Liu and Jeff Renfro of NERC authored the report.

46 NW Natural's least cost resource optimization analysis using the SENDOUT® software package uses costs expressed in real terms. The Company assumes a 1.9 percent annual rate of inflation for 2014 through the end of the planning period.

47 The indicated average annual use per customer values are those from NW Natural's October 15, 2013 Schedule 190 tariff filing.

Figure 2.36 – PSU Carbon Price per $MTCO_2e$

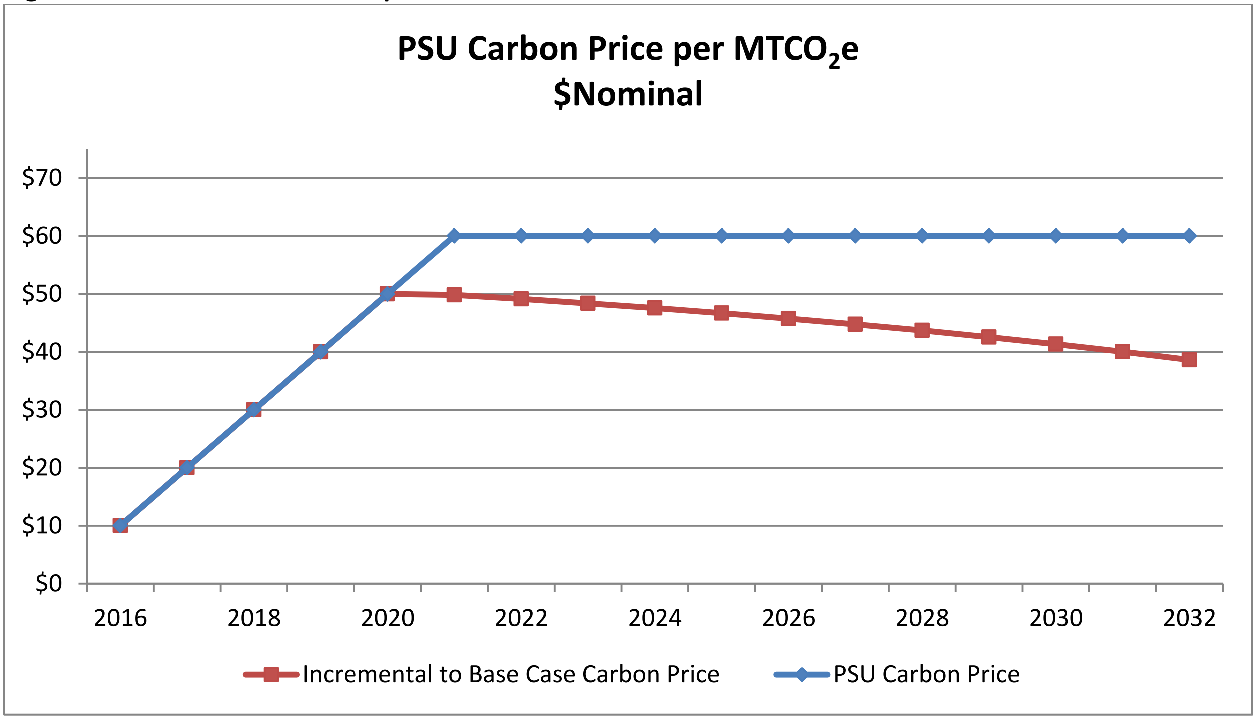
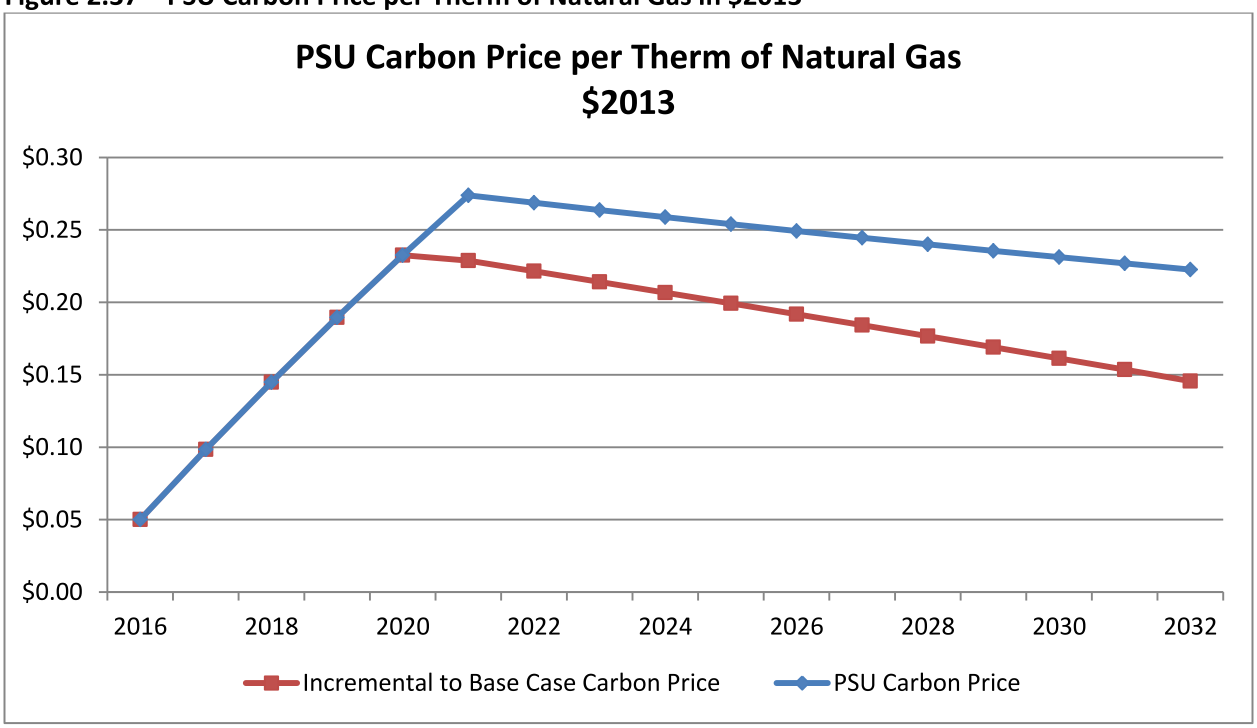
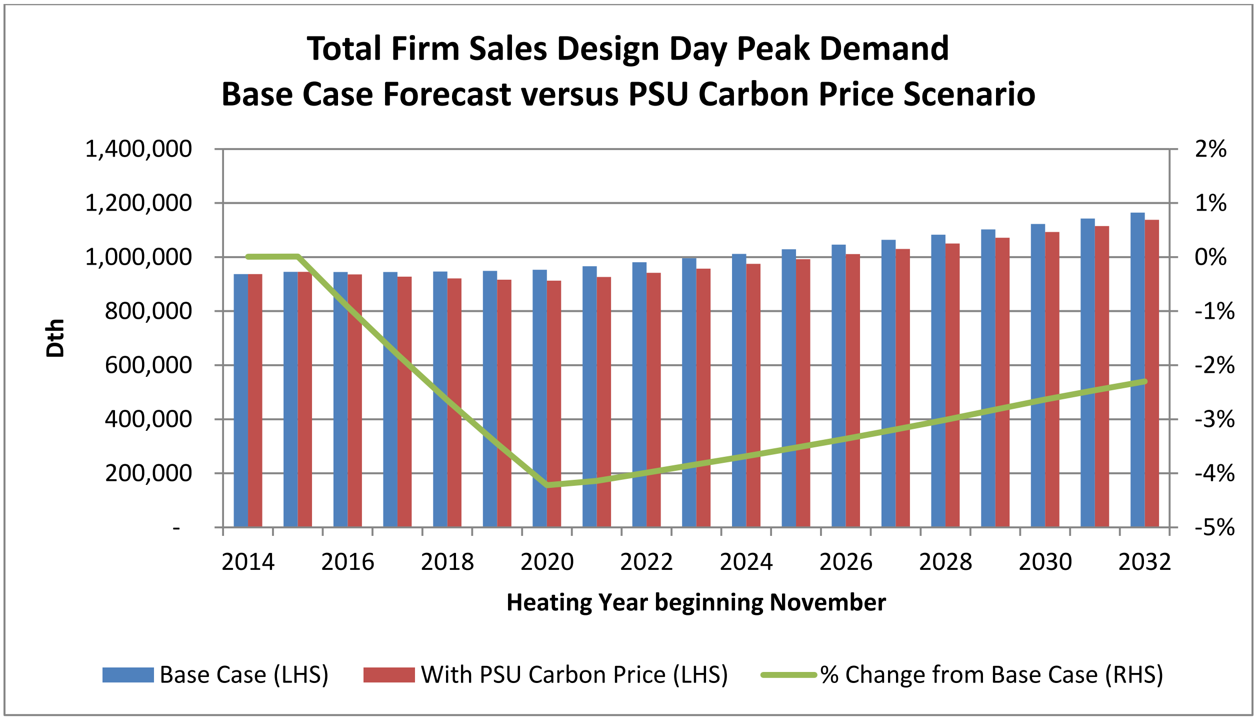


Figure 2.37 – PSU Carbon Price per Therm of Natural Gas in $2013



NW Natural describes the analysis of the impact this scenario has on design day peak demand and annual load in Chapter Five. A primary result is that there are relatively small declines in total Firm Sales design day peak demand and annual load. Figure 2.38 shows the Firm Sales design day peak demand for the Base Case forecast and in the PSU Carbon Price scenario as well as the percent change from the Base Case forecast. NW Natural discusses the impact of the carbon price scenarios on resource planning in Chapter Seven.

Figure 2.38 – Total Firm Sales Design Day Peak Demand: Base Case Forecast and PSU Carbon Price Scenario



VIII. FORECAST ACCURACY AND PEAK DAY ANALYSIS

NW Natural monitors the accuracy of its load forecast model by comparing forecast loads for two relatively recent cold weather events with actual loads. The Company records actual daily gas requirements in aggregate form. NW Natural measures the overall quantity of gas required to meet demand on a daily basis along with the daily temperature; however, the daily demand data is not differentiated by individual region and category. In order to measure forecast accuracy on a daily system-wide basis, NW Natural combines the load forecast model parameters with the actual customer mix, and temperatures from the timeframe to calculate predicted demand. NW Natural compares the results with the actual daily "sendout," or amount of gas the Company delivered to customers to meet demand for each of the days.

Two recent cold weather days are December 8, 2013, and February 6, 2014. Table 2.8 (following) summarizes for each date the HDD and weather conditions; number of customers; and actual load and the predicted load based on the models used in this IRP.

Table 2.8 – Comparison of Predicted and Actual Cold Weather Loads[48]

Date[49]	Actual Firm Demand (MDT)	Forecast Firm Demand (MDT)	Error (MDT & %)	Residential & Commercial FS[50] Customers	System HDD	Ave. Wind Speed at PDX	General Weather Conditions
Sunday 12/8/2013	692	844	-152 -22%	691,682	46.6	4	No measurable precipitation
Thursday 2/6/2014	745	768	-23 -3%	696,091	42.3	22	Snow

February 6, 2014 established NW Natural's single-day record for delivered gas. While both days were atypically cold, Table 2.8 highlights some differences between the two: February 6, 2014 was a Thursday, not a weekend day, and was a relatively windy day. A higher load may have resulted had December 8 been a weekday and one with more adverse weather.

48 Both actual and predicted loads are those for Firm Sales plus Firm Transport.

49 The HDD data correspond with calendar dates while gas volumes are over the 24 hours of the Gas Day, which begins at 7:00 a.m. Pacific Time.

50 The number of Commercial customers includes only those with Firm Sales service. Customer values for each date results from interpolation of the respective current and prior month's values.

IX. KEY FINDINGS

- Relatively slow regional economic growth will continue, with a positive outlook regarding Oregon housing starts.
- Firm Sales customer growth averages 1.9% annually in the Base Case forecast, with Oregon's rate averaging 1.6% and Washington's rate averaging 3.8%.
- Alternative Firm Sales customer growth scenarios have average annual rates of 2.1% in the High Load Growth scenario and 1.4% in the Low Load Growth scenario.
- Henry Hub natural gas spot prices in real terms will be essentially "flat" over the planning horizon.
- Emerging Markets' load requirements grow slowly early in the planning horizon in the Low scenario NW Natural incorporates into the Company's Base Case forecast.
- Firm Sales design day peak demand grows at annual rates over the planning horizon of 1.0% in Oregon; 3.4% in Washington; and 1.3% for NW Natural.
- Increases in Firm Sales design day peak demand over the planning horizon are concentrated in a small number of load centers, with Vancouver accounting for over 30% of the growth and the three Portland load centers for almost 50%.
- Expected near-term Emerging Market load growth involving Firm Service requirements will be at a pace allowing for updated analyses of required resources in future IRPs. Emergence of one or more Industrial Firm Service "feedstock" customers is difficult to predict and would likely require additional and potentially out-of-cycle resource planning.
- The impact on design day peak demand and annual loads of a carbon tax that is materially higher and implemented earlier than that in the Base Case forecast is relatively small.

Chapter 3: Supply-Side Resources

NW Natural®

I. 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 Two. 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, in response to Technical Working Group feedback, potential resources are discussed in this chapter that are ultimately deemed too speculative to include in the portfolio choice analysis in Chapter Seven, with explanations for why they ended up on the "cutting room floor." 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 Two.

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 recallable supply agreements with industrial customers, operators of gas-fired electric generation plants, and gas

---

1. Note that the Mid-Willamette Valley Feeder (MWVF) has not been included in the descriptions found in this chapter since it is nearly complete and the IRP is a planning document focused on future resource decisions. The MWVF is included in the Company's firm resource stack for all of its modeling in this IRP..

2. Liquefied natural gas (LNG) is natural gas in its liquid form. When natural gas is cooled to minus 258 degrees Fahrenheit (-161 degrees 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. During the liquefaction process, most of these other elements are removed. 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, then vaporize as it warms above -258 degrees.

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. It is up to the end-users for these gas supplies to either shut down or switch to those alternative fuels. For a variety of reasons, these recall agreements most closely resemble the Company's LNG supplies. First, there is the strict limitation on days recall is available during the heating season. Second, the delivery to or within the Company's service territory mirrors that of the Company's LNG plants and related contracts. 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 re-supply is uncertain, and so they 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.

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. Peaking resources are designed to deliver large volumes of gas for a short duration, such as during cold weather episodes.

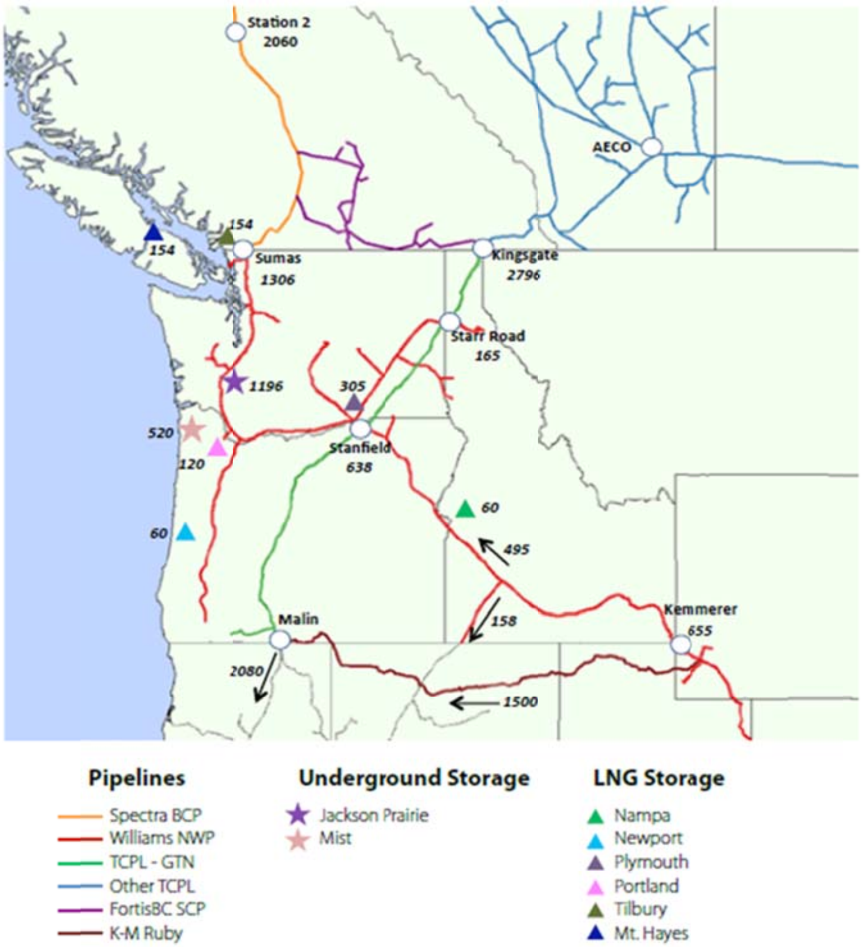
The possible effects of price elasticity on gas requirements have been discussed in prior IRPs. Chapter Two discusses price elasticity in the context of NW Natural's load forecasting. Basic economic theory holds that when the price of a good or service increases, then all else being equal, demand for that good or service should decrease. For natural gas, this could arise from structural changes, such as the installation of higher efficiency appliances and insulating materials. Or, it could result from behavioral changes, such as turning down thermostat settings and dressing warmer. The structural changes should persist under most conditions, but the behavioral changes easily could be reversed. For example, a customer may lower the setting of his/her thermostat in response to higher prices, but during an extreme cold weather episode, raise that thermostat setting rather than risk frozen pipes or endure uncomfortable conditions. This may be a temporary move having a negligible impact on annual requirements, but—when aggregated over many customers—could have a meaningful impact on design day requirements.

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.

II. CURRENT RESOURCES

A map showing all of the current natural gas pipeline and storage infrastructure in the Pacific Northwest is shown in Figure 3.1, which may be helpful as a reference as each component of NW Natural's supply portfolio is described in the following sections.

Figure 3.1 – Pacific Northwest Infrastructure and Capacities (in MDth/day)



Source: NWGA 2014 Gas Outlook

A. Gas Supply Contracts

The Company's portfolio of supply contracts for the 2013-2014 heating season is indicated in Table 3.1. The contracts with recent expiration dates have been either renegotiated or are in the process of being replaced for the next heating season, as discussed in the Company's Purchased Gas Adjustment (PGA) filing that is currently in progress (a preliminary update of this table for the 2014-2015 heating season can be found in NW Natural's August 1, 2014 PGA filing documents).[3] The term "Baseload Quantity" refers to a contract with a daily delivery obligation, while the label "Swing Supply" means one party has an option to take all, some or none of the indicated volumes at its discretion.

B. Current Pipeline Transportation Contracts

The Company holds firm transportation contracts for capacity on the Northwest Pipeline Corporation (NWP) interstate pipeline system, over which all of the Company's supplies must flow except for the small amount of local gas produced in the Mist field (currently less than 2% of annual requirements). For its purchases in Alberta and British Columbia, NW Natural also holds transportation contracts on the pipeline systems upstream of NWP, namely Gas Transmission Northwest (GTN, a unit of TransCanada Pipelines Limited), TransCanada's system in southeastern British Columbia (known as Foothills), TransCanada's Alberta system (known as NGTL or Nova), Westcoast Energy Inc. (WEI, a division of Spectra Energy) and the Southern Crossing Pipeline (SCP) owned by FortisBC Inc. (formerly known as Terasen and before that BC Gas). 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 transportation contracts are provided in Table 3.2.

Since the implementation of FERC Order 636 in 1993, capacity rights on U.S. interstate pipelines have been commoditized; *i.e.*, capacity can be bought and sold like other commodities. These 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. Unlike the WEI and TransCanada pipeline systems, the NWP system remains 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.

[3] See OPUC Docket No. UG 278.

Table 3.1[4] - Firm Off-System Gas Supply Contracts for the 2013-2014 Tracker Year

Supply Location	Duration	Baseload Quantity (Dth/day)	Swing Supply (Dth/day)	Contract Termination Date
British Columbia (Station 2):				
Conoco Phillips	Nov-Oct	5,000		10/31/2014
Macquarie Energy	Nov-Mar	5,000		3/31/2014
J. Aron & Company	Nov-Mar	5,000		3/31/2014
Shell Energy North America	Nov-Oct	5,000		10/31/2014
Powerex	Nov-Mar	5,000		3/31/2014
Suncor Energy Marketing	Nov-Mar	5,000		3/31/2014
EDF Trading North America	Nov-Mar	5,000		3/31/2014
Iberdrola Energy Services	Nov-Mar	5,000		3/31/2014
J. Aron & Company	Nov-Mar	5,000		3/31/2014
Alberta:				
Macquarie Energy	Nov-Mar	5,000		3/31/2014
JP Morgan	Nov-Oct	10,000		10/31/2014
Shell Energy North America (Canada)	Nov-Mar	5,000		3/31/2014
Powerex	Nov-Mar	5,000		3/31/2014
Shell Energy North America (Canada)	Nov-Mar	5,000		3/31/2014
Husky Energy Marketing	Nov-Mar	10,000		3/31/2014
J. Aron & Company	Nov-Mar		10,000	3/31/2014
J. Aron & Company	Apr-Oct		10,000	10/31/2014
Suncor Energy Marketing	Nov-Mar	5,000		3/31/2014
Rockies:				
Shell Energy North America (US)	Nov-Oct	5,000		10/31/2014
Conoco Phillips	Nov-Oct	5,000		10/31/2014
Ultra Resources	Nov-Mar	5,000		3/31/2014
Conoco Phillips	Nov-Mar	5,000		3/31/2014
IGI Resources	Nov-Oct	10,000		10/31/2014
Macquarie Energy	Nov-Oct	5,000		10/31/2014
Ultra Resources	Nov-Oct	10,000		10/31/2014
Iberdrola Energy Services	Nov-Oct	5,000		10/31/2014
Macquarie Energy	Nov-Oct	5,000		10/31/2014
Anadarko Energy Services	Nov-Mar	5,000		3/31/2014
Shell Energy North America (US)	Nov-Mar	5,000		3/31/2014
Chevron Natural Gas	Nov-Mar	5,000		3/31/2014
Enserco Energy	Nov-Mar	5,000		3/31/2014
ONEOK Energy Services	Nov-Mar		10,000	3/31/2014
Trademark Merchant Energy	Nov-Mar		10,000	3/31/2014
Total Off-System Firm Contract Supply		165,000	40,000	

Table 3.2[5] - Firm Transportation Capacity as of November 2014

4 Notes to Table 3.1:

a. Contract quantities represent deliveries into upstream pipelines. Accordingly, quantities delivered into the Company's system are slightly less due to upstream pipeline fuel consumption.
b. Nov-Mar "Swing" contracts represent physical call options at the Company's discretion, while the Apr-Oct "Swing" contracts represent physical put options at the supplier's discretion.

Pipeline and Contract	Contract Demand (CD) (Dth/day)	Termination Date
NWP (TF-1 Service):		
Sales Conversion	214,889	9/30/2018
1993 Expansion	35,155	9/30/2044
1995 Expansion	102,000	11/30/2016
Occidental Cap. Acquisition	1,046	3/31/2016
Occidental Cap. Acquisition	4,000	3/31/2025
International Paper Cap. Acquisition	4,147	11/30/2016
Total NWP Capacity	361,237	
less recallable release to -		
Portland General Electric (PGE)	(30,000)	10/31/2016
Net NWP Capacity	331,237	
GTN:		
Sales Conversion	3,616	10/31/2023
1993 Expansion	46,549	10/31/2023
1995 Rationalization	56,000	10/31/2016
Total GTN Capacity	106,165	
Foothills:		
1993 Expansion	47,727	10/31/2015
1995 Rationalization	57,417	10/31/2015
Engage Capacity Acquisition	3,708	10/31/2015
2004 Capacity Acquisition	48,669	10/31/2016
Total Foothills Capacity	157,521	
NGTL:		
1993 Expansion	48,135	10/31/2015
1995 Rationalization	57,909	10/31/2015
Engage Capacity Acquisition	3,739	10/31/2015
2004 Capacity Acquisition	49,138	10/31/2015
Total NGTL Capacity	158,921	
WEI T-South Capacity	58,000	10/31/2014
Southern Crossing Pipeline (SCP)	48,000	10/31/2020

[5] Notes to Table 3.2:

a. For existing contracts, the SENDOUT® model uses the pipeline rates currently paid by NW Natural, i.e., there are no assumptions regarding future rate increases or decreases for existing pipeline capacity.
b. The WEI and SCP contracts are denominated in volumetric units. Accordingly, the above energy units are approximations. More importantly, the WEI contract is scheduled to expire on 10/31/2014 and, as discussed later in this chapter, renewal is **not** currently expected.
c. The contract demands shown for the 1993 Expansion contracts on GTN and Foothills are for the winter season (October-March) only. Both decline during the summer season (April-September) to approximately 30,000 Dth/day.

C. Current Storage Resources

For decades, the Company has relied on five 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), Newport, and Plymouth in Washington State. 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.

By contrast, others operate and own the Jackson Prairie and Plymouth facilities, which have been in service since the 1970s at locations outside the Company's service territory. The Company currently has firm storage service agreements at both of these facilities along with associated NWP capacity to move those stored supplies to the Company's service territory when needed. Jackson Prairie is located north of the Company's territory near Centralia, Washington. Plymouth is located east of the Columbia River Gorge, roughly 25 miles south of the Tri-Cities area. Table 3.3 shows the maximum capabilities of these firm storage resources for the coming winter, with Plymouth included for reference purposes but the numbers stricken for reasons that will be discussed later in this chapter.

Table 3.3 – Firm Storage Resources as of November 2014

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Capacity (Dth)
Jackson Prairie	46,030	1,120,288
Plymouth LNG	~~60,100~~	~~478,900~~
Mist (reserved for core)	275,000	9,976,780
Gasco LNG	120,000	600,000
Newport LNG	60,000	900,000

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 3.3 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 520,000 Dth/day and a total working gas capacity of about 16 million Dths in the above mentioned reservoirs plus three newer reservoirs (Schlicker, Busch and Meyer). Capacity in excess of core needs is made available for the non-utility storage business and AMA activities. As core needs grow, existing storage capacity may be recalled and transferred for use by core utility customers, which NW Natural refers to as Mist Recall. 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. The 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. Accordingly, 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 three such supply-basin storage contracts, all in Alberta, with maximum seasonal capacities in the following amounts:

TransCanada Gas Storage Partnership	947,817 Dth
AECO Gas Storage Partnership (Niska)	1,895,817 Dth
J. Aron & Company	1,153,000 Dth

A significant change from prior IRPs is the Company's reconsideration of its Plymouth LNG contract. The table below relates the Company's existing storage service agreements at Jackson Prairie and Plymouth under NWP's Rate Schedules SGS-2F and LS-1, respectively; to the associated transportation service agreements provided under NWP's Rate Schedule TF-2 (the implications of "Primary" versus "Subordinate" or "Secondary" service will be covered later in this chapter):

Table 3.4 – NWP Storage Agreements and Related TF-2 Transportation Service

Facility	Max. Daily Rate (Dth/day)	Portion of TF-2 that is Primary Firm Service (Dth/day)	Portion of TF-2 that is Subordinate or Secondary Firm Service (Dth/day)
Jackson Prairie:			
SGS-2F	46,030		
TF-2	32,624	23,038	9,586
TF-2	13,406	9,467	3,939
Total TF-2	46,030	32,505	13,525
Plymouth LNG:			
LS-1	60,100		
TF-2	60,100	0	60,100

D. Other Current Supply Resources

The Company uses three other types of supply-side resource in its current portfolio – Recall Agreements, Citygate Deliveries and Mist Production – which can be described as follows.

i. Recall Agreements: Not to be confused with Mist recall, but in a sense 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 currently has three such recall arrangements, as summarized in Table 3.5 below.

Table 3.5[6] - Recallable Supply Arrangements as of November 2014

Counterparty	Max. Daily Rate (Dth/day)	Max. Annual Recall (days)	Termination Date
PGE	30,000	30	10/31/2016
International Paper	8,000	40	10/31/2015
Georgia-Pacific - Halsey	1,000	15	upon 1 year notice
Total Recall Resource	39,000		

All of the above agreements provide for continuation after the termination date if mutually acceptable. The Georgia-Pacific deal is already in its annual evergreen period. The PGE deal utilizes NWP capacity that the Company releases on a recallable basis and correlates to customer release volumes shown in Table 3.2. Should this arrangement terminate, the released NWP capacity would revert back to the Company. In contrast, the International Paper and Georgia Pacific deals utilize NWP capacity held by those companies.

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

ii. 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 currently has one Citygate agreement in place for the coming winter, a swing arrangement 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. This is the Company's first Citygate Delivery agreement since 2004, reflecting the need to find stopgap resources for the 2014-2015 winter to replace peak day supplies that would have been counted upon from the Plymouth LNG plant.

iii. 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 two% of the Company's annual gas purchases.

---

6 For each listed recall resource, the SENDOUT® model includes the cost the Company is currently paying for the service.

III. RISK ELEMENTS

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.[7] 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 equipment or pipeline outages arising from such harsh conditions. The purpose of this section is to make explicit some significant supply-side risk elements, other than the potential for physical equipment/pipeline outages, that also have been part of the Company's implicit assumptions within past resource plans.

A. 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 is 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. In this region, that unbundling applied to Jackson Prairie and Plymouth. 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/vaporization from that storage facility. Thus was born Rate Schedule TF-2 out of a NWP rate case settlement about twenty years ago.[8]

The subordinate or secondary nature of portions of the TF-2 firm transportation service had been in place for those twenty 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 December 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.

---

7 See Chapter 5 of NW Natural's 2013 Integrated Resource Plan as filed on March 28, 2013, in WUTC Docket No. UG-120417.

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

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 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 this IRP because they are less reliable than previously believed.

The primary case for maintaining the Plymouth LS-1 storage service is that Plymouth gas could be transported using the Company's TF-1 service agreements with NWP, thereby offsetting other gas purchases that it might have made. As with storage service in the supply basins, the differences between summer and winter gas prices may be more than sufficient to offset the costs of the LS-1 service.

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 LS-1 service could be utilized in a concentrated manner on a small number of the very highest priced winter days. If spot gas prices spike high enough on those days, then the savings from using LS-1 gas might be more than enough to offset the costs of subscribing to the LS-1 service. Because Plymouth is an LNG facility, those LS-1 charges are substantial on a per unit basis (currently over $3/Dth), but during the cold weather event experienced in early February 2014, there were many days in which gas from Plymouth was a relative bargain compared to spot gas prices.

NW Natural has until October 31 of the current year to decide whether to terminate its Plymouth LS-1 and/or TF-2 service agreements. Pending any offer of a viable alternative solution from NWP, NW Natural will terminate these service agreements, as the existing agreements do not provide "all-weather" firm capabilities on which the Company can rely.

Interestingly, NWN learned that Puget Sound Energy (PSE) recently reached its own conclusion regarding its Plymouth TF-2 service, i.e., that it was no longer reliable enough to include in their firm resource stack, but might have enough arbitrage value to be retained. [9]

In those same December 2013 discussions with NWP, the question also arose as to the reliability of portions of the Company's TF-2 firm transportation service agreements from Jackson Prairie that are labeled as subordinate. As shown in Table 3-4, this amounts to 13,525 Dth/day. Since Jackson Prairie is

[9] *See* PSE's May 2013 IRP, pages 6-17 through 6-18, at http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_Chap6.pdf .

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. 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 does 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 any transportation that is less than TF-1 primary firm service. However, given the slow load growth in the region, it seems reasonable to expect that this Jackson Prairie subordinate TF-2 capacity will remain useful for at least the next five years. Five years is based primarily on the regional coal plant shutdowns that are scheduled to start in 2020, which should result in the addition and utilization of new power generation, some of which likely will be gas-fired and located in the I-5 corridor between Sumas and NW Natural's service territory. For that reason, the subordinate TF-2 service from Jackson Prairie has been retained in the first five years of the IRP analysis. As might be expected, one action item will be to watch for any developments between Jackson Prairie and the Company's service territory that might undermine the reliability of this service and alter the five year assumption.

B. Reliance on "Segmented" Capacity as a Resource

The removal of Plymouth created an immediate deficiency in NW Natural's resource stack. To deal with this deficiency, at least for the short term, the Company intends 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—segmented TF-1 capacity. To explain segmented capacity, it is probably 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 LDC, another pipeline or a direct connect customer (delivery points). In the illustration below (Figure 3.2), "A" is a circle and denotes the primary receipt point, while "D" is a diamond and indicates the 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 3.2 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 3.2 – 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 as a delivery point on NWP's system, where before it had been only a receipt point. Indeed, all of the useful capacity segmentations performed by NW Natural tend to relate back to Molalla as the key point 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. 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 has been modeled for the first time in this IRP. And as with the Jackson Prairie subordinate TF-2 capacity, this segmented capacity has been modeled as being available for the next five years.

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 seems assured. The Company currently has 43,800 Dth/day of such segmented capacity, and will evaluate if more can be created. And of course one action item will be to watch for any developments between Sumas and the Company's service territory that might undermine the reliability of this service and alter the five year assumption.

C. 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. This is because of NWP's reliance on displacement to provide certain firm deliveries. Displacement 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. In future IRPs, the Company will attempt to analyze and estimate an OFO-reduction benefit.

D. MDDO Restrictions at Gate Stations

A "gate station" is a location at which the Company is physically connected to the upstream pipeline network. Gate stations include billing quality metering and pressure regulation equipment, and usually (but not always) include other devices such as odorizers and telemetry. Two particular gate stations - Deer Island and Molalla - also include compressors for redelivery of gas back to NWP. There are over major 40 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).

Prior to the deregulation of the late 1980s, NWP had a single firm sales contract with the Company that had more MDDOs than it had CD. This reflected the rolling nature of cold weather events, in which peak requirements could ebb and flow across the Company's service territory. In essence, the CD represented the coincident peak requirements of the Company, while the MDDOs represented the non-coincident peaks of the individual gate stations. This flexibility had, and continues to have, great value to any LDC whose gate stations are dispersed over a relatively wide geographic area because it avoids the costs associated with additional and potentially duplicative CD subscriptions.

After deregulation, when NWP was expanding its system in the 1990s, the new transportation contracts had a strict one-to-one relationship between CD and MDDOs. There was to be no additional flexibility, and that remains the practice to date.

Over the years, the Company could add MDDOs only 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 SynerGEE®). 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.

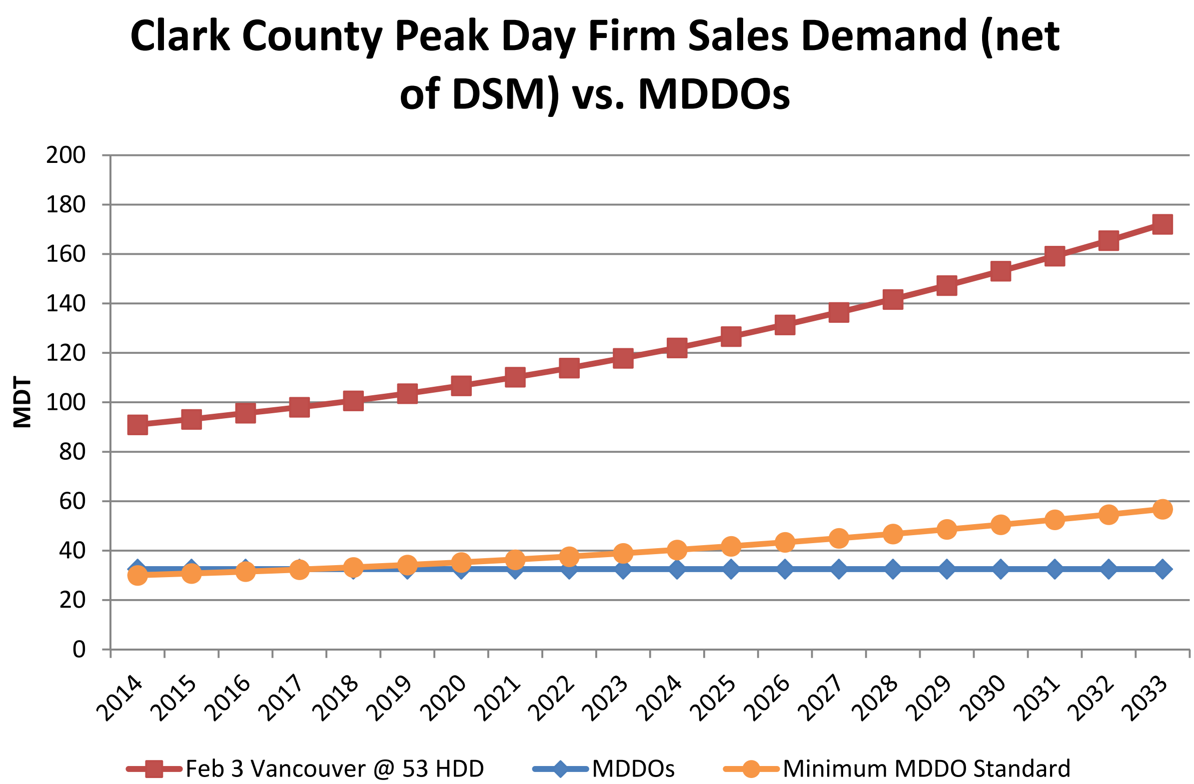
The most obvious example of this gap, and the reason why this is coming up for the first time in an IRP, is the Company's system serving Clark County, Washington. There are six gate stations feeding the Company's distribution system there. Three gate stations – Van Der Salm (serving La Center), Salmon Creek and Felida - were built under facility agreements with NWP in which the Company paid for the work but received no new MDDOs, while other gates (such as North Vancouver) have had their capacity expanded in the same manner.

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) and the risks of losing that service are believed to be *de minimus* for most gate stations for the foreseeable future.

While the Company will study the alternatives and determine what standards are needed regarding MDDOs and gate station planning, the modeling in this IRP will assume a minimum MDDO standard of 33% of forecasted design day demand. This standard would apply to those service areas that are served solely from NWP gate stations (i.e. Clark County, The Dalles (OR and WA), and Eugene). Currently, the MDDOs for Clark County gates are nearing this minimum standard are with load growth is projected to be below the standard beginning in 2018 (Figure 3.3). The Company is currently evaluating options to increase MDDOs in the area.

Figure 3.3 Clark County MDDOs



IV. CHANGES IN THE EXISTING RESOURCE PORTFOLIO

There are five changes to the existing supply-side resource portfolio as described below, of which the first four have already been discussed at length in preceding sections of this chapter.

A. Plymouth LNG Storage

The Company has removed Plymouth deliveries of 60,100 Dth/day for its firm resource stack effective immediately. While a decision to terminate the related NWP contracts does not need to occur prior to

October 31, 2014, and NW Natural will continue to pursue its dialogue with NWP to see if there are any workable alternatives, Plymouth service is not sufficiently firm to include in the Company's peak day resource stack due to last winter's experience (which occurred prior to the plant accident).

B. Jackson Prairie Underground Storage

All service from Jackson Prairie is currently retained in the Company's firm resource stack. However, the 13,525 Dth/day portion of the TF-2 service that is contractually identified as subordinate firm service is assumed to degrade in reliability five years hence and so is phased out of the resource portfolio. The five year assumption will be reevaluated each year to determine whether it can be lengthened or should be shortened.

C. Segmented Capacity

The Company will rely on 43,800 Dth/day of segmented capacity moving outside its primary path to deliver volumes from Sumas when needed. As with the subordinate TF-2 service from Jackson Prairie, the planning assumption is that this segmented capacity will need to be phased out over time.

D. Citygate Deliveries

The Company has added 20,000 Dth/day of peak day service as a stopgap resource for the coming winter. A third party has bundled together supplies sourced from Sumas along with their own transportation service on NWP to deliver gas on a limited basis to NW Natural's service territory. This agreement is only in place during the December 2014-February 2015 period and is discussed in more detail in the Company's current PGA filing. Whether this resource could and should be re-contracted for future winters will be evaluated after the winter season.

E. T-South Contract Expiration

As shown in Table 3.2, the WEI T-South contract will expire on October 31, 2014, unless the Company takes action to renew it. However, it was determined that it was cost effective to allow that contract to expire. While commodity purchase costs will go up because more gas will be purchased at Sumas rather than Station 2, the reduction in pipeline demand charges will be more than enough to produce net cost savings for customers. Such an analysis has been included in the Company's current PGA filing. It is expected that a reevaluation will be performed each year to determine if there are economic or other reasons, such as concerns over supply liquidity at Sumas, to contract once again for T-South service.

V. NW NATURAL'S LNG PLANT PROJECTS

As mentioned above, NW Natural owns and operates two LNG peak shaving facilities. The first is in Newport, Oregon which consists of a 1,000,000 Dth capacity storage tank, liquefaction facilities capable of processing about 5,500 Dth/day, and vaporization capacity of up to 100,000 Dth/day ("Newport"). This facility was constructed by Chicago Bridge and Iron and commissioned in 1977. Because the Company's pipeline system limits Newport to serving the central coast and Salem market areas, the full 100,000 Dth/day vaporization rate is not achievable. Instead, 60,000 Dth/day is the effective limit on vaporization at Newport. But as in past IRPs, one part of this IRP's analysis is a consideration of pipeline take-away improvements, increasing access to other market areas, which would allow utilization of Newport's full vaporization capacity.

The Company's other LNG plant is in Portland, Oregon and consists of a 600,000 Dth capacity storage tank, liquefaction facilities capable of processing about 2,150 Dth/day, and vaporization capacity of 120,000 Dth/day ("Gasco"). This facility was also constructed by Chicago Bridge and Iron and commissioned in 1969.

The facilities and major process components of these LNG plants were designed for a nominal 25 to 30 year life. Newport and Gasco are now 37 and 45 years old, respectively. NW Natural is beginning a major refurbishment for Newport and considering a major refurbishment for Gasco. For Newport, this includes addressing issues with the liquefaction process including removal of carbon dioxide (CO_2) from the incoming natural gas stream, which has been very gradually collecting in the tank and settling on its floor in solid form (commonly known as dry ice). The dry ice issue at Newport is severe enough that, to avoid weight issues on the floor of the storage tank, the Company has reduced the maximum quantity of LNG to be stored there from 1,000,000 Dth down to 900,000 Dth. Fortunately, so far this issue has not affected the daily vaporization rate and the reliance on Newport within the Company's peak day resource stack.

As resources specifically used for peak shaving, NW Natural requires high availability, reliability and productivity from the LNG plants. NW Natural has evaluated the options for making modifications to the Newport LNG facility that will enhance reliability, reduce maintenance cost and extend the operational life expectancy an additional 25-30 years. Refurbishment of the Newport facility has begun because this is the least-cost alternative (see Appendix 3 for further details). As for Gasco, the company plans on contracting with the same engineering company to perform a similar study and will perform an alternatives analysis once that study is completed. So, while not technically a change to the existing resource stack, the project at Newport allows for the cost-effective retention of an existing resource.

VI. FUTURE RESOURCE ALTERNATIVES

Beyond the existing gas supply resources mentioned previously, the Company considers additional gas supply resource options including Mist recall, further Mist expansion, the acquisition of new interstate pipeline capacity, satellite LNG and CNG storage, and various extensions/expansions of its own pipeline system. The primary alternatives are described in more detail below. These options will be evaluated in Chapter Seven using SENDOUT®.

A. Interstate Capacity Additions

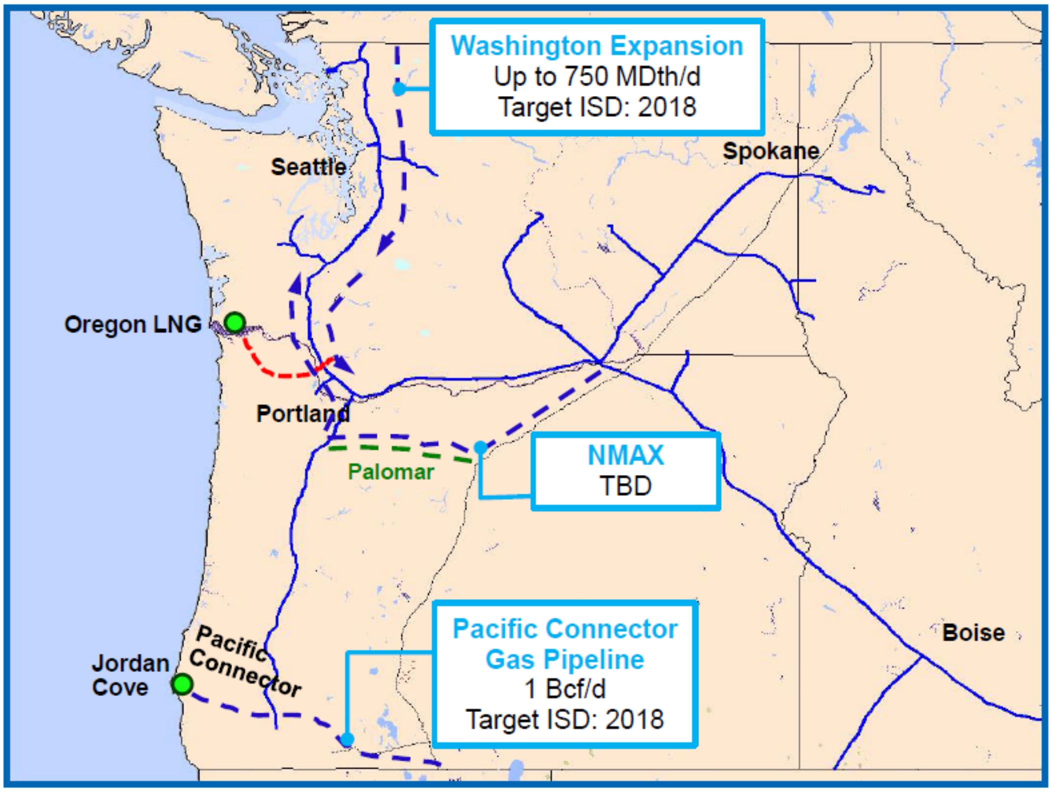
The Company holds existing contract demand (CD) and gate station capacity on: 1) NWP's mainline serving the Company's service areas from Portland to the north coast of Oregon, Clark County in Washington, and various small communities located along or near the Columbia River in both Oregon and Washington, 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. 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.

In response to its reliance solely on NWP for delivery of interstate gas supplies, NW Natural partnered with TransCanada Corporation to form Palomar Gas Transmission LLC (Palomar). Palomar proposed to develop, build, and operate a pipeline connecting GTN's mainline north of Madras, Oregon, to the Company at Molalla. On December 11, 2008, Palomar filed an application for a certificate to build and operate the pipeline with the Federal Energy Regulatory Commission (FERC). On March 23, 2011, Palomar withdrew its original pipeline application with FERC, while stating its expectation of re-filing at a later date. Information for a new Cross-Cascades pipeline project in collaboration with NWP, called Palomar/Blue Bridge, was presented in February 2011 at a public workshop jointly sponsored by the Public Utility Commission of Oregon and the Washington Utility and Transportation Commission. The information presented included new estimates for pipeline rates and service dates.

More recently, in November 2012, NWP announced the reformulation of Palomar/Blue Bridge into a new Cross-Cascades project called the Northwest Market Area Expansion (NMAX). Concurrently, NWP solicited interest in an expansion south from the U.S./Canadian border at Sumas to serve the proposed Oregon LNG export terminal in Warrenton, Oregon. This is the "Washington Expansion" project. As depicted in Figure 3.3, both of these projects could serve the Company's service territory. Of course both projects would be subject to approval by the FERC as well as numerous other Federal and State agencies, and because of these permitting processes, neither could be expected to be in service prior to 2018. NWP filed an application for a certificate of public convenience and necessity for the Washington Expansion Project in June 2013, but since Oregon LNG was the only specified customer, it is difficult to ascertain how deep into the permitting process this application will proceed. However, it is possible that the Washington Expansion project could proceed with sufficient customer interest aside from the Oregon LNG project. Accordingly, modeling of the Washington Expansion in this IRP has been examined both with and without the associated impact of the Oregon LNG project, as described in more detail in Chapter Seven.

Figure 3.4 - Potential Regional Pipeline Expansion Projects



Source: Williams Northwest Pipeline, August 2014

For the purposes of this IRP, it is assumed that the Cross-Cascades project could be in service as early as 2020, which in turn assumes an open season is initiated and indicates sufficient support to re-initiate FERC permitting work.

From the Company's perspective, the region will need to add more gas infrastructure over the next 5-7 years to serve growth in regional natural gas demand, primarily from the power generation and industrial sectors[10]. The primary benefit from meeting this growth from development of a Cross-Cascades pipeline would be to improve the gas system resiliency and enhance reliability by having greater resource diversity. This is particularly important given the accelerating convergence and interdependency of the electric and gas systems. A second regional benefit is that it would mitigate the Sumas price risk from potential 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.

10 There is broad regional support for this perspective, for example, in the Northwest Gas Association's 2014 Gas Outlook, page 4: "Additional capacity is likely to be required within the forecast horizon to serve new demand for natural gas, particularly on a peak (design) day."

For purposes of this IRP, the Company has focused on the costs and benefits to its customers and not attempted to quantify the broader regional benefit. The Willamette Valley, including the Portland/Vancouver metro area, is served solely by NWP. Adding a second interstate pipeline delivery corridor would assure both the security of gas supply as well as reliable gas service well into the future for core customers.[11]

In this IRP, the Company has evaluated the potential acquisition of interstate pipeline capacity in several forms:

1) NWP Sumas Expansion (Local Project) – this is incremental NWP capacity from Sumas that is designed to serve only NW Natural's needs and so can be timed to meet the Company's load growth projections.

2) NWP Sumas Expansion (Regional Project) – this is capacity on NWP's Washington Expansion regional pipeline project, which necessarily follows the timelines required by that project's anchor customers, whoever they might be.

3) Oregon LNG/Washington Expansion - a variation of a Sumas Expansion that is tied to the development/timelines of the Oregon LNG export terminal in Warrenton, Oregon.

4) 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 GPL in the vicinity of Roseburg, Oregon. Service from NWP would be needed to move the gas from Roseburg northward to the Company's service territory. For this IRP, references to "Pacific Connector" refer to the bundled pipeline service from Malin to the Company's citygate.

5) Cross-Cascades - a pipeline starting at GTN's system near Madras, Oregon, and connecting to both NW Natural's high pressure distribution system and NWP's Grants Pass Lateral near Molalla, Oregon. From Molalla, gas could move readily through NW Natural's system to major portions of the Portland, Salem and other load centers. However, incremental pipeline capacity would be required to transport gas other load centers, the significant one being the east side of Portland. To access that particular load, two options were considered:
    a. The Company could construct a high pressure transmission facility from the Molalla area to this portion of its Portland load centers (Eastside Loop);
    b. NWP has proposed an NMAX service that would bundle Cross-Cascades capacity with northbound Grant's Pass Lateral capacity.[12]

---

[11] To ensure the matching of resources to requirements, NW Natural has modeled a turn back of up to 55,000 Dth/day of existing NWP capacity from Stanfield to the Company's service territory with acquisition of capacity on Cross-Cascades.

[12] NW Natural established Cross-Cascades with NMAX as the lower cost of the two Cross-Cascades alternatives by comparing estimated rates provided by NWP for bundled service on Cross-Cascades and NMAX with the

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. For example, since there are no gas trading activities at Madras, Oregon, consideration of either Cross-Cascades alternative necessarily includes upstream pipeline subscriptions to access the Malin and/or AECO trading hubs.

The model also includes capacity of 12,000 Dth/day of NWP capacity from the Rockies to Portland that was acquired in a 2008 agreement with the March Point Cogeneration Company. This vintage-priced capacity will become part of the Company's portfolio effective January 1, 2017.

The acquisition of incremental pipeline capacity spans a wide range of lead times. It is 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. Only the NWP Sumas Expansion (Local Project) option is considered flexible and simple enough to be available as early as November 2015. For all other interstate pipeline options mentioned above, November 2020 has been modeled as the very earliest that any of them could be in service.

B. Storage Additions

1. Mist Recall

In addition to the existing Mist storage capacity currently reserved for the core market (see Table 3.3); the Company has four reservoirs (a portion of Reichhold and all of Schlicker, Busch and Meyer) that also have been developed for storage services. They currently serve the interstate/intrastate storage market, but could be recalled for service to the Company's utility customers as those third party 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 area. However, Mist recall may not be suitable to serve load growth in more remote areas such as the southern end of the Company's service territory; e.g., Eugene.

2. North Mist

NW Natural developed a proposal combining an expansion of Mist storage and a new transmission facility to meet the needs of a prospective third party customer. The Company originally premised its analysis associated with this proposal on the results of prior IRPs, in which the available Mist

---

sum of estimated rates for Cross-Cascades (to Molalla) provided by the project's sponsors and the revenue requirement associated with an Eastside Loop (see Chapter Seven).

Recall capacity was sufficient for utility growth requirements throughout the respective planning horizons of those prior IRPs. However, the loss of the Plymouth LNG facility and the planned phase-out of segmented TF-1 capacity from Sumas and subordinate TF-2 capacity from Jackson Prairie make it clear this IRP must consider alternatives involving expansion of Mist for core customer use beyond the existing limits of Mist Recall capacity.

The storage reservoirs currently in service at Mist and storage incorporated into the proposal to the prospective third party do not collectively exhaust Mist storage potential; there are many existing Mist *production reservoirs* that theoretically NW Natural could develop into additional storage resources. The primary impediment in doing so is not geological, but the challenges associated with developing new pipeline takeaway capacity meeting the Company's specific service territory requirements.

NW Natural refers to a prospective Mist expansion project for core customer use in this IRP as "North Mist."[13] North Mist consists of 100,000 Dth/day of maximum delivery capacity coupled with a maximum storage capacity of 2.0 billion cubic feet (Bcf; which is approximately 2,000,000 Dth) and includes a new compressor station and associated appurtenances. These capabilities would be exclusively for utility use, so should a third party subscribe to the North Mist expansion, total deliverability and storage capacity would increase to match those additional subscribed amounts.

The design of the 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. With exhaustion of all available Mist Recall capacity, the existing takeaway pipelines from Mist[14] will be at their maximum capacities and incapable of transporting additional gas during the heating season.

NW Natural developed a Mist expansion resource alternative on a unique, standalone basis; i.e., the project concept to date involves new facilities not physically interconnected with NW Natural's existing Mist storage and transmission facilities. Takeaway from the new storage involves transporting gas on a new NW Natural high pressure transmission facility north to the Kelso-Beaver Pipeline (KB Pipeline); from there to NWP's system; and contracting with NWP for transport back to NW Natural's system. The analysis assumes NWP is willing to offer a storage-related transportation service on a firm basis and at a cost reflective of similar offerings that have occurred in the recent past.

NW Natural's core customers may benefit by realizing economies of scale if a new takeaway pipeline is larger than one sized to accommodate core customers only, which requires one or more

13 NW Natural has previously used the name "Emerald Expansion" to describe a more generic version of the next Mist expansion project.

14 NW Natural refers to the existing northbound pipeline as the North Mist Pipeline; while the South Mist Pipeline coupled with the South Mist Pipeline Extension comprise the exiting southbound takeaway pipeline capacity.

additional participants to subscribe to the North Mist expansion. This alternative assumes—for the new pipeline only—utility participation for the benefit of core customers is required prior to when the storage capacity is needed for core customers.[15] The resource portfolio analysis discussed in Chapters One and Seven included the alternative with third party participation.

A preliminary evaluation estimated the cost of the project at $73.5 million with third party participation.[16] The costs of a North Mist project of course have some uncertainty. With third party subscription to capacity on the takeaway pipeline, core customer costs are less than if they had to pay the full cost of the pipeline. However, achieving this is not currently within NW Natural's control.

Much of the timing and value of North Mist involves addressing the need for additional MDDOs for the Clark County load center; see the discussion above regarding this issue. NW Natural has not yet had sufficient time to determine whether this potential resource is achievable without the Company violating its Federal Energy Regulatory Commission (FERC) Hinshaw exemption. The Company is also working with NWP to determine if there are other viable alternatives to address the Clark County MDDO situation.

3. Clark County Large-scale LNG Plant

NW Natural developed cost estimates for a Gasco-sized LNG facility in Clark County based partially on experiences with the Newport refurbishment costs. The estimated construction costs for the liquefaction, storage, and vaporization facility is $100 million. The Company would also need to construct new high pressure transmission facilities reaching from the LNG storage into the Clark County distribution system. This cost is estimated to be an additional $100 million.

C. High Pressure Transmission

Supply-side infrastructure additions accompany the need to increase resources to meet load growth, regardless of whether supplies come from on-system sources such as Mist, Newport, Gasco or satellite LNG storage, or from off-system sources such as the Company's numerous gate station interconnections with NWP or a new Cross-Cascades pipeline. The Company's Engineering Department plans for these additions.

Three on-system projects directly associated with potential supply-side resources are described below. Further discussion of smaller on-system pipeline projects is provided in Chapter Six.

1. Christenson Compressor Project

As previously mentioned, the daily deliverability of the Newport LNG plant is modeled at 60,000 Dth/day due to pipeline infrastructure limitations, but the Newport plant has all the equipment and

---

15 This assumes expansion for a third party occurs prior to the time storage is expanded for core customers.

16 There may be alternative configurations integrating North Mist with NW Natural's existing infrastructure that have lower costs than the standalone option analyzed in this IRP. More investigation is necessary to determine this.

permitting necessary to vaporize and deliver up to 100,000 Dth/day. To reach this 100,000 Dth/day capability, infrastructure additions would be needed on the Newport to Salem pipeline (Central Coast feeder) to deliver an incremental 40,000 Dth/day. This project would consist of installing a 2,000 horsepower compressor at Christenson on the Central Coast Feeder and is estimated to cost $30 million.

2. Eastside Loop

As already described, one potential supply resource is a new Cross-Cascades pipeline connecting to NW Natural's system in the vicinity of Molalla, Oregon. Molalla is a key point because it connects with NWP and is the current terminus of the Company's South Mist Pipeline Extension (SMPE), a 24-inch high pressure pipeline serving the south and west portions of the Portland load area from both NWP and Mist storage. If a Cross-Cascades pipeline also connects to the Company's system in this area, additional infrastructure would assure access to load on the eastside of the Portland metro area. For the purpose of this IRP, $70 million has been assumed as a rough estimate of the cost of a new high pressure transmission facility connecting a Cross-Cascades pipeline to NW Natural's distribution system on the eastside of the Portland load centers.

3. The South Willamette Valley Feeder (SWVF)

The South Willamette Valley Feeder Project increases the Company's ability to move gas between the Albany and Eugene load centers, with the primary result of creating pipeline capacity to deliver gas from NW Natural's Newport LNG facility to the Eugene load center. The high level cost estimate for this project is approximately $58 million.

D. Satellite LNG Storage

Some gas utilities rely on satellite LNG tanks to meet a portion of their peaking requirements. The term "satellite" is commonly used because the facility is scaled down and has no liquefaction capability of its own. Instead, its usefulness revolves around the availability of another (no doubt larger) facility with the ability to supply the LNG to fill its tank(s). LNG facilities in this context are peaking resources because they provide only a few days of deliverability, and should not be confused with the much larger facilities contemplated as LNG export or import terminals.

The concept is that a small tank serving a remote area would be filled with LNG as winter approaches, and the site manned during cold weather episodes when vaporization is required. Since there is no on-site liquefaction process, the facility is fairly simple in design and operation. Where peaking demands are sharpest, the addition of satellite LNG could defer significant pipeline infrastructure investments.

Satellite LNG is well established in this country but generally confined to the Northeast, as indicated by this excerpt from a 2003 report issued by the U.S. Energy Information Administration:

> Of the 96 LNG storage facilities connected to the pipeline grid, roughly 57 have liquefaction capacity. Most of the remaining 39 storage facilities are located in the Northeast…where many facilities are close enough to the Distrigas import facility to receive LNG by truck. Massachusetts alone accounts for 14 satellite facilities, or roughly

40 percent of all satellite facilities in the United States. In New Jersey, which contains the second highest number of satellites, there are 5 facilities.[17]

The Company's interest in this concept was tempered in the past by concerns over obtaining siting and zoning approvals in our service territory. However, successful examples of satellite LNG do exist in the Pacific Northwest, including a facility that Puget Sound Energy built near Gig Harbor, Washington, as well as one built by Intermountain Gas on its Idaho Falls Lateral.

NW Natural evaluated satellite LNG in Willamette Valley locations near Salem and Eugene. The Company has modeled these resources as having the equivalent of 90,000 Dth of storage capacity and a maximum deliverability of 30,000 Dth/day for three days. The Company believes these are reasonable assumptions based on industry research of comparable facilities.

NW Natural examined the economic feasibility of meeting the design day shortfall in the Company's Clark County load center using satellite LNG facilities. The Company based the cost of infrastructure on an estimate prepared by JenMar Concepts and assumed the use of two acre sites with a single 50,000 gallon storage capability and vaporization capability that depletes the on-site supply in approximately three days. A three-day resource capability is a reasonable match with the Company's design peak criteria.

A total of 21 separate sites would be necessary to meet the projected 2015 shortfall in the Clark County load center. The number of sites grows to 80 by 2033, with both the Clark County load center shortage and the number of satellite LNG storage sites shown in Figure 3.5.

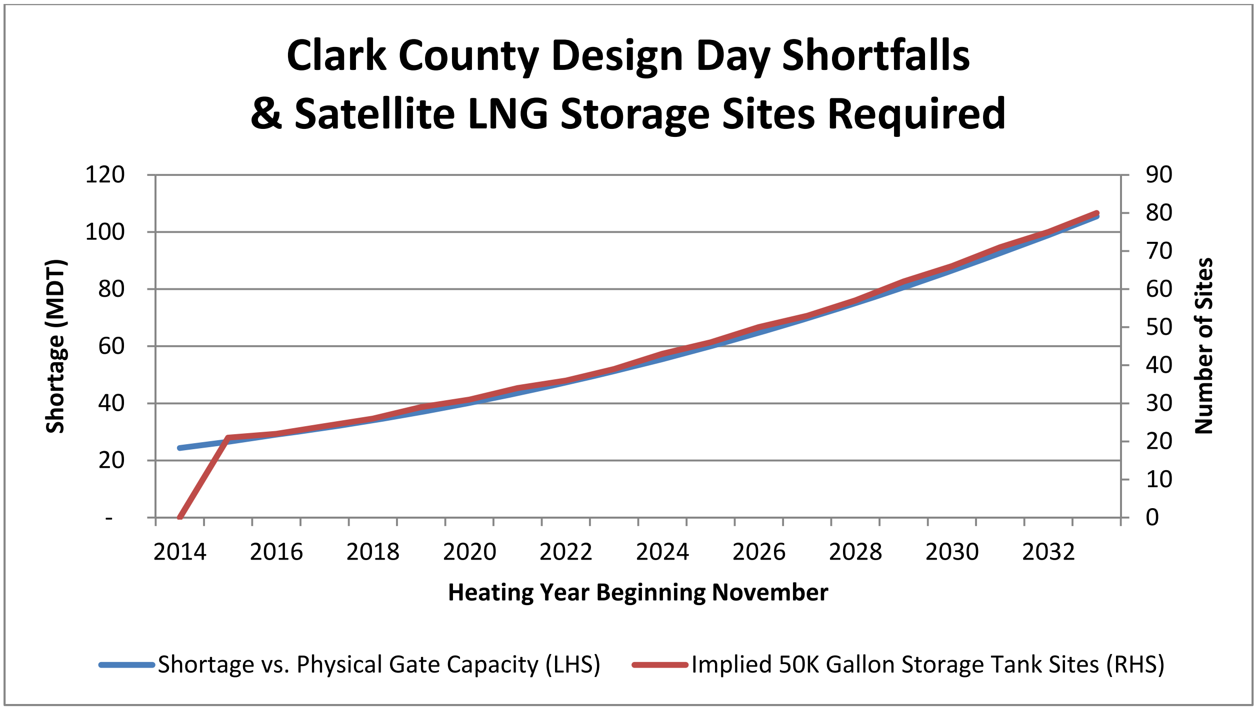
The present value of revenue requirements (PVRR) over the 20-year planning horizon using satellite LNG storage located in Clark County to meet the project shortfall under design weather conditions[18] is estimated at $292 million. The amount reflects estimated revenue requirements associated with land and on-site infrastructure only; it does not include any incremental revenue requirements for loading LNG at NW Natural's Gasco LNG facility located in Portland, transporting the LNG to the storage sites located within Clark County, nor staffing the satellite sites during vaporization operations.

---

17 *See* http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2003/lng/lng2003.pdf .

18 Each storage site is sized such that shortages associated with approximately three days of design weather are met. See the description of NW Natural's design weather cold event in Chapter Two.

Figure 3.5 – Clark County Satellite LNG



E. Satellite CNG Storage

NW Natural's IRP Technical Advisory Group also requested that the Company examine the use of satellite compressed natural gas (CNG) facilities. These have some of the same issues in terms of addressing supply needs as do satellite LNG facilities. In particular, the issue of scaling is much larger since CNG physically contains much less natural gas than an equivalent volume of LNG.[19] So while satellite CNG facilities may be cost-effective under some circumstances, such as serving a small community approaching existing pipeline capacity under design day conditions, such facilities are unable to effectively address NW Natural's near-term issues.

F. Jackson Prairie

The most recent expansion of Jackson Prairie storage was completed in 2012 and NW Natural is not aware of any further expansion potential at the facility. The Company has pursued the idea of contacting for service from an existing capacity holder at Jackson Prairie. Besides the cost of the service itself, another consideration is the reliability of the pipeline transportation service between Jackson Prairie and the Company's service territory. Preliminary responses have not been economically

---

[19] One cubic foot of LNG is equivalent to about 640 cubic feet of natural gas at standard conditions. One cubic foot of CNG is equivalent to about 240 cubic feet of natural gas at standard conditions (assuming it has been compressed to 3,600 psig).

attractive, but the Company will continue to explore this opportunity.

G. Alternatives considered but 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.

1. 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 when it makes it next general rate case filing,

2. Additional Industrial Recall Agreements. As previously mentioned, the Company has three existing recall arrangements with large industrial/generation end-users, but so far has had no success finding additional large end-users willing to enter into such 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.

To illustrate the limitations of recall agreements as a resource, the shortfall (in the absence of additional resources) for NW Natural's Clark County load center is about 24,000 Dth if a design peak day occurs during the 2014-2015 heating season. This shortfall grows to about 105,000 Dth by the end of the planning horizon (2033-2034 heating season) if nothing is done. The maximum daily volumes under contract for all of the Company's current large commercial and industrial customers in Clark County total to approximately 3,600 Dth. Therefore, even if every single large commercial and industrial customer in Clark County agreed to a recall arrangement, it would only satisfy 15% of the current shortfall situation and less than 4% of the long-term requirement.

3. 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 different North Mist pipeline take-away alternates. A question arose as to whether that service should be evaluated 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 (2) if there is not enough load growth then it means there is no need for additional Mist Recall.

4. PGE Recall Agreement modifications. Since the Company's resource requirements are driven first and foremost by design peak day considerations, the Company has approached PGE to see if its 30,000 Dth/day recall arrangement could be modified in some way to provide additional peak day supplies, perhaps in exchange for reducing the maximum number of recall days. PGE is willing to consider modifications to the existing agreement, but at this time there is nothing of substance that can be evaluated.

5. Floating LNG Storage. An idea that came out of a TWG meeting was to use LNG stored in a vessel that would be anchored in the Columbia River to supply the Clark County load center, which would avoid siting one or more LNG storage facilities on land. However, this also would require the construction of additional pipeline infrastructure since the areas poised for load growth in Clark County are diverse and some are located further away from the Columbia River. Needless to say, there also would be considerable research necessary to ascertain the feasibility of anchoring an LNG vessel in the Columbia River for an extended period. This alternative remains at the conceptual phase right now.

6. LNG Imports. It seems only recently that several LNG import terminals were proposed for Oregon and NW Natural was including them in its IRP analysis. However, with the proliferation of gas supplies in North America resulting from the development of shale resources, no import proposals currently exist and none are likely for the foreseeable future. It was suggested at a TWG meeting that LNG imports from Alaska be evaluated as a resource option. This suggestion also proposed carbon emissions from PGE's Port Westward Power Plant be shipped to Alaska for sequestration and thus offset some of the costs of importing LNG. There are currently no proposals to ship carbon emissions to Alaska either. This alternative remains at the conceptual phase right now.

7. Biogas. This refers to methane produced from biomass sources including wastewater treatment plants, animal manure, landfills, woody biomass, or crop residuals. If biogas is purified to the standards of the pipeline industry, it is commonly referred to as biomethane or renewable gas (RG). The American Gas Foundation (AGF) recently conducted a study regarding the technical potential for producing RG, which predicts that RG could meet 4 to 10% of natural gas use in the United States.[20]

While the supply is currently very small, the production of RG has the potential to provide a wide range of benefits far beyond further diversification of the Company's gas purchase portfolio. For example:

- RG can reduce greenhouse gas emissions and produce other related carbon benefits;
- Projects to generate RG could be built adjacent to existing pipelines in a manner so as to provide system reinforcement;
- Electricity from biogas can offset other forms of thermal generation; and
- RG could result in local economic investments and job creation.

[20] "The Potential for Renewable Gas: Biogas Derived from Biomass Feedstocks and Upgraded to Pipeline Quality." AGF, September 2011. Total natural gas use refers to total demand in 2010 of 24 trillion cubic feet, which includes gas used for electric generation.

An analysis completed for the Oregon Department of Energy reviewed the use of biogas from several of the state's waste water treatment plants (WWTPs).[21] Among the findings of this report was that the RG from several of the plants may be worth more as a vehicle fuel rather than for heating or to make electricity.

To prepare itself for the potential of RG, the Company has developed gas quality standards and sampling criteria for any proposed RG facilities desiring to interconnect with and deliver gas into the Company's distribution system. One such interconnection agreement has been signed to date, but the proposed pricing for the RG (more than twice the current cost of gas delivered to the Company's system) suggested that the Company will not be the buyer for this or other RG supplies unless gas price volatility, technological advancements, or regulatory changes speed the adoption of this particular source of natural gas. For example, it would take the imposition of a carbon tax in the range of $100 per ton of CO_2 emissions to close the current gap, assuming RG would be exempt from that tax.[22]

Another possibility is that the renewable value of the RG will be severable and separately marketable, a concept known in the electric sector as Renewable Energy Certificates or "green tags." This might allow the Company to purchase the RG at a price that is competitive to other delivered gas supplies, while allowing the RG developer to achieve the required economics.

8. Coal-bed Methane. Periodically over the years, interest had been expressed by third parties in the development of coal-bed methane reserves found in Coos County. The location of the gas at the extreme end of its service territory made this resource particularly intriguing to the Company. Some third parties did drill test wells to better ascertain the extent of these reserves, including as recently as five years ago.[23] However, the "shale gale" and its resulting reduction in natural gas prices, among other reasons, have stifled any recent interest in this potential resource.

9. Southern Crossing Expansion. FortisBC has proposed a reinforcement project for the Southern Crossing Pipeline that would permit more flow of Alberta gas to Sumas. This would also require an expansion of NWP from Sumas, and so does not need to be modeled since it essentially is replicated by the current inclusion of the NWP Sumas Expansion (Regional Project).

---

21 "Bioenergy Optimization Assessment of Wastewater Treatment Plants", Tetra Tech Inc. for the Oregon Department of Energy, March 20, 2012.

22 Natural gas emits approximately 53 kg of CO_2 per Dth (source: "Carbon Dioxide Emissions for Stationary Combustion" posted by EIA at http://www.eia.gov/oiaf/1605/coefficients.html#tbl1). Calculation is then $100/ton times 53 kg/Dth divided by 907 kg/ton = $5.84/Dth, which when added to the estimated $4.71/Dth cost of gas delivered to the Company's system in calendar 2012, would be at the low end of the $10-$12/Dth range at which RG is expected to be priced per discussions with RG developers.

23 See http://library.state.or.us/repository/2011/201109010951034/index.pdf .

10. 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. See also the preceding discussion of satellite LNG as a potential solution to design weather shortages in NW Natural's Clark County load center.

11. Adsorbed Natural Gas (ANG). This technology has been under development for over ten years and offers the possibility of storing much higher volumes of natural gas at much lower pressures than is now accomplished using CNG[24]. However, while intriguing, there are no timelines or cost estimates that can be modeled yet.

12. System Leakage Reductions. A topic of interest the last few years has been methane leakage for 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.[25] 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 number one among gas utilities with the lowest ratio of leaks per mile of pipe.[26] Accordingly, as a potential supply resource, the reduction of gas leakage is already being fully addressed.

13. 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 Btu content. The reason for this is the high nitrogen content of the native gas. Efforts to increase production 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 current relatively low market price of natural gas.

14. Physically Connect the Oregon and Washington Systems. Rather than moving Mist gas

---

[24] See, for example, http://www.gl-nobledenton.com/en/consulting/asset_integrity/879.php .

[25] For example, see the article "EPA's 'fugitive methane' data under fire again" in the *Gas Daily* dated November 6, 2013.

[26] For details see the article "Northeast LDCS, led by Con Edison, rank highest in leaks per mile of pipeline" from SNL dated March 25, 2014.

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.

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.

VII. GAS SUPPLY PORTFOLIO ACQUISITION STRATEGY

A. Overview

This section provides the Company's strategies for acquiring gas supplies as described in the Company's Gas Acquisition Plan (GAP) for 2014-2015. 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 for up to two additional contracting years for multi-year hedging considerations. Longer-term resources plans and hedging targets are 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 focus is on the 2014-15 "tracker" year along with the subsequent two years for hedging considerations.

B. Plan Goals

1. **<u>Reliability</u>**
   The first priority of the Company's 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 IRP. Compromising reliability is not acceptable.
2. **<u>Lowest Reasonable Cost</u>**
   Gas supplies will be acquired at the lowest reasonable cost for customers – that is, 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 in order to lower costs with minimal risk to stakeholders.
3. **<u>Price Stability</u>**
   Customers are sensitive to price volatility in addition to prices. Consequently, the Company uses physical assets (e.g. storage) and financial instruments (e.g. derivatives and fixed price purchases) to hedge price variability.

4. **Cost Recovery**
   With the exception of the previously approved gas reserves purchase, NW Natural does not earn a return for acquiring and selling gas commodity supplies, yet the cost of these supplies typically amounts to 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. On the financial hedging side, this means strong credit policies and counterparty oversight. On the legal side, this mandates scrupulous compliance to standards of conduct. Since regulatory disallowances could be devastating, maintaining trust and credibility with state regulatory bodies is imperative.

5. **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.

C. 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 with respect to resource requirements, 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.

D. Strategies

The GASP Committee forms gas acquisition strategies based on the market outlook and on load projections. The following is a summary of strategies:

- Utilize financial derivative hedges, storage (both market-area and supply-basin), and fixed-price supplies including gas reserves and local production to manage cost risks. For the 2014-15 year, about 75% of expected sales volumes will be hedged with these tools. Hedges reflect the assembly of a diverse portfolio and also allows for unhedged purchases to comprise about half of the total purchases for the period, i.e., the 25% of annual expected sales volumes intentionally left unhedged plus all of the gas volumes purchased for injection into storage.
- Financial derivative hedges will comprise 36% to 42% of requirements. The upper end of this range is based on no changes to current storage volumes. The lower end of this range reflects the potential cost-effective acquisition of additional supply-basin storage, thereby offsetting (lowering) financial hedges by the equivalent volume.
- Maximize supplies from the regions that afford the lowest prices. Gas from the U.S. Rocky Mountain region (Rockies) was once our lowest-cost supply. Alberta gas is now the lowest. Keys to price shifts include production levels (especially in the Eastern U.S. from surging shale gas plays), power generation and weather.
- Fill storage at a pace that might present opportunities to purchase gas at times that best benefit core customers.
- Maintain a diversity of physical supplies from Alberta, British Columbia and Rockies.
- Due to its relative lack of trading liquidity, increase baseload purchases from British Columbia during the winter season when spot supply deliveries might be unreliable and prices more volatile.

VIII. SUPPLY-SIDE 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 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.

IX. SUPPLY DIVERISTY AND RISK MITIGATION PRACTICES

A. 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 U.S. 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 will continue to favor spot purchases from Alberta and the Rockies due to generally lower prices. However, the overall mix of British Columbia, Alberta and Rockies gas purchases changes from year-to-year in reaction to changing market dynamics. Recent examples include -

- Marcellus and Utica Shale: The emergence of unconventional gas supplies in the eastern U.S., combined with slow economic growth, has displaced some of the demand for Rockies and Western Canadian supplies. At the moment, the most bearish impacts have been felt in Alberta, but the recent moves by the Rockies Express Pipeline (REX) to become bi-directional means that Rockies gas also feels the impact.[27]
- Ruby: The Ruby Pipeline commenced service in mid-2011 from Wyoming to the California/Oregon border, providing another outlet for Rockies gas. However, only 72% of Ruby's capacity is currently contracted and those contracts begin expiring in 2021.[28] This situation 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.

---

27 "East-to-West Gas Flows Begin on Rockies Express Pipeline", June 19, 2014, http://www.fellonmccord.com/tag/rex/

28 http://online.wsj.com/news/articles/SB10001424052702304626304579505662881343266

Until about five years ago, the tight nationwide balance between supply and demand resulted in lower confidence in spot markets during cold weather or other extreme load periods. Reflecting that concern, the Company's previous contracting practice was to select a minimal summer load, including storage injections, as an amount suitable for year-round baseload (take-or-pay) supply contracting. It would then fill up most of its remaining pipeline capacity with winter term (November-March) supply contracts. Some of these November to March contracts would be baseload (take-or-pay) in nature, while others would provide optionality on purchases to avoid over-contracting in the event of a mild winter. In general, spot purchases had been less than 10% of total purchases during the heating season.

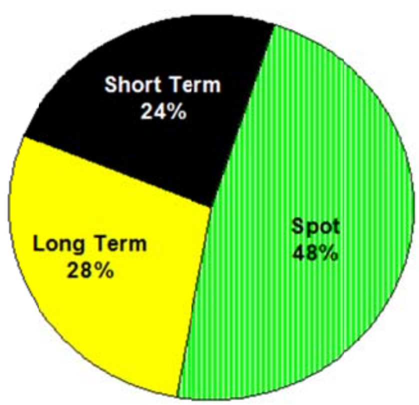
More recently, though, with the surge in supplies represented by shale gas, the Company has decreased its reliance on term contracts and allowed spot purchases to be much higher.

Physical gas contracting strategies for 2014-2015 that are consistent with strategies of recent years include:

- Maintain a diversity of physical supplies from Alberta, British Columbia and U.S. Rockies.
- Buy supplies at trading points with high "liquidity" in order to access the most competitively priced and reliable supplies.
- Continue to shift the source of physical supplies to the lowest-cost source region. In recent years, Rockies gas offered the best prices as production increased due to anticipation of REX and the Ruby Pipeline. Since those pipelines became fully operational, Rockies term prices have risen higher than Alberta prices. British Columbia gas typically has been priced higher than Rockies and Alberta.

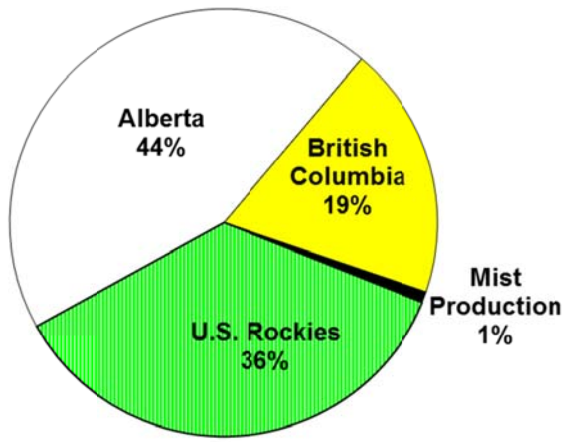
Figures 3.6 and 3.7 provide graphical representations of the Company's physical gas supply resources and diversity during 2013.

FIGURE 3.6 – Gas Supply Diversity by Contract Length for Calendar Year 2013



[Note: as used in Figure 3.6, Long Term means one year or longer, Medium Term is greater than a month but less than a year, and Short Term is up to a month.]

Figure 3.7 – Gas Supply Diversity by Source for Calendar Year 2013



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

B. 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. As previously described in Section VII.B of this chapter, four goals guide the physical and financial hedging of gas supplies: Reliability, Lowest Reasonable Cost, Price Stability and Cost Recovery.

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. The objective is to use derivative products to structure hedging strategies as defined by the Company's Gas Supply Risk Management Policies (GSRMP). 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 Company's Gas Acquisition Strategy and Policies (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

C. 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:

- Financial Derivative Instruments, i.e., Swaps and Options
- Fixed Price Gas Purchase Agreements
- Natural Gas Reserve Acquisitions
- 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. The growth of shale gas and the country's economic recession resulted in a dramatic reduction of gas prices, with the Company's cost of gas now equivalent to levels not seen in 10 years.[29] So a prime example of this process was evaluating whether these lower prices should be locked-in for a long-term period, and if so, for what portion of the portfolio, and under what type of structure that would be secure for a long-term period. One result of course was the 2011 gas reserves purchase agreement with Encana Oil & Gas (USA) Inc. (Encana), which will be discussed in detail in a subsequent section.

Questions regarding the development of hedging targets led to an action plan item in the last IRP, and to that end, the Company commissioned Aether Advisors LLC ("Aether") to perform an independent review of its hedging program. Aether issued its first report to the Company in January 2014, which is included in Appendix Three. Key findings of that report were:

- It is important that utilities have an integrated hedging program over a broad time horizon.
- Long-term hedging provides long-term rate stability and reliable supply for customers.
- NW Natural's hedging program is effective at managing gas supply costs for customers.
- There are compelling reasons for NW Natural to consider additional long-term hedging.

The January 2014 Aether report also pointed to the need for consolidation in the GSRMP regarding targets for financial derivatives and natural gas reserves, which had been treated separately, and better clarity around the hedge targets moving out in time. For example, gas injected into storage is treated as a hedge going into the PGA year, but Aether pointed out that it really is a short-term hedge since the gas is purchased at market prices in the months just prior to the start of the PGA year. Accordingly, longer-term hedge targets should reflect the exclusion of gas purchased for storage.

Aether had specific recommendations for establishing hedging targets and stress-testing the results. They entail a probabilistic approach to the customers' tolerance for rate increases. Aether also differentiated between time periods with the following understanding:

---

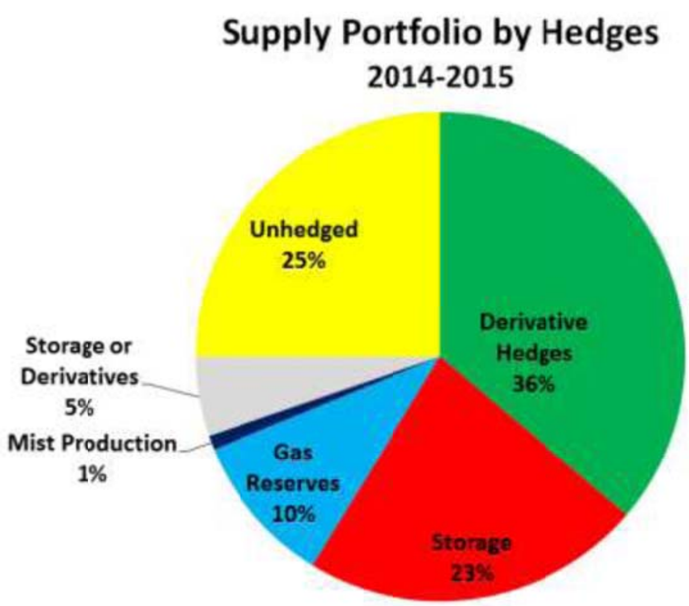
29 https://www.nwnatural.com/uploadedFiles/OR_WACOG(1).pdf

- Short-Term means the current and upcoming PGA period, so storage can be considered a tool for hedging.
- Medium-Term goes through the next three PGA periods because that is the limit under which conventional financial hedges can be secured per the limits specified in the Company's GSRMP.
- Long-Term accordingly refers to the time period beyond the next three PGA periods, conceivably out 20 years or more when a transaction like a gas reserves purchase is under consideration.

D. Current Percent Hedged

The Company's main hedging target has been to hedge a total of 75% of its expected requirements going into each PGA year. That would leave 25% to be purchased at unhedged prices during the PGA year. Gas purchased for storage injection (about 20-25% of total requirements), while considered a type of hedging for the upcoming PGA year, also consists of unhedged purchases made during the spring/summer months. Accordingly, about half of the Company's total purchases each year are hedged through financial derivatives, fixed price contracts or gas reserves, while the other half of the purchases are made at short-term or spot market prices (see Figure 3.8). Further targets have been developed, such as for winter versus summer months, as described in the GAP for each year.

FIGURE 3.8 – Gas Supply Portfolio Hedge Targets for 2014-2015



D. Long-Term Hedging Strategies and Plans

Aether completed a second report in July 2014 (also included in Appendix Three) that focused on Long-Term hedging. Long-Term in this context refers to periods extending beyond the next three PGA "tracker" years. The reason for this focus is that the fundamentals of gas production and demand patterns across the country appear to favor the locking-in of gas prices now for longer-term periods. In addition, special consideration is given to periods beyond the next three years because conventional financial derivative hedging currently is limited to five years under the Company's GSRMP due to credit risks. That is, anything beyond five years requires additional precautions or deal structures that ensure against counterparty default. Moreover, the Company currently has no counterparties approved for financial transactions beyond a three-year period, hence the focus on Long-Term as anything extending beyond the next three PGA years.

On the supply side, U.S. gas production currently is robust, hitting new records with some regularity.[30] It is unlikely that production technology will stagnate, and is actually likely it could improve over time. The only significant production impediment that might appear on the horizon would be new (or more stringently enforced existing) regulations that place certain developable lands out-of-bounds, or more likely, that add significantly to the cost of production and so eliminate certain areas from development due to declining economics.

But on the demand side, the Company's view continues to be that the country is at an inflection point. Power generation will lead the way, spurred by both coal plant retirements and renewable energy mandates that will push the need for more gas-fired electric generation to replace retired units and support the grid. LNG exports will add to the demand for natural gas, with the first terminal expected to begin operation in 2015.[31] Then there is the expected industrial renaissance, with cheap U.S. natural gas fueling a surge in the petrochemical industry.[32] An example is the announcement in April 2014 that a multinational group is evaluating three sites in the Pacific Northwest for the construction of plants that will convert natural gas to methanol for shipment to China.[33] And of course there are other possibilities for accelerated natural gas demand growth, for example, as a transportation fuel for ships, trains, trucks and automobiles.

While there can never be any guarantees, this appears to be a prime time for locking in long-term gas prices for a larger portion of the portfolio. Whether or not this results in a portfolio that beats the market will not be known for many years and is not the point in any case, because now is the time to increase the Company's "insurance policy" against the price volatility that the above factors can be reasonably expected to create in the market.

---

30 For example, see http://www.forbes.com/sites/williampentland/2014/06/01/natural-gas-production-reached-record-high-in-march/ .

31 http://www.platts.com/latest-news/shipping/houston/cheniere-selling-short--mid-term-lng-supply-from-21048249

32 For example, http://www.wallstreetdaily.com/2014/04/02/shale-gas/ .

33 http://www.thenewstribune.com/2014/04/23/3163248/multinational-group-proposes-18.html

Of course deciding that it is timely to enter into long-term hedging is only the first step. The second step is deciding the volume to hedge. The July 2014 Aether report recommends a long-term hedging range of up to 35% of expected annual requirements[34] Aether also recommends the hedge percentage decline over time due to factors such as market liquidity, load forecast uncertainties and the size of the financial commitments involved in these types of transactions. To that end, the Company currently has adopted the guideline that no more than 25% of expected annual requirements would be price protected through Long-Term hedges.

The final step in Long-Term hedging is deciding on the appropriate transaction. Financial derivatives would be considered as long as additional "insurance" (such as a credit facility) is included in the evaluation to protect against counterparty default. Ownership of the gas, such as through a gas reserves acquisition, eliminates that particular source of risk but potentially introduces other risks that similarly must be accounted for in the evaluation. Gas reserve ownership does have an additional benefit in that the natural decline over time that is associated with production wells fits very well with the concept of a hedging strategy that declines in percentage over time.

This will be a continuing topic of discussion between the Company and stakeholders as the Company takes steps to act on its market view.

It is worth noting that NW Natural is not the only regional utility looking for such long-term price certainty. For example:

- PacifiCorp issued a Request for Proposal (RFP) in May 2012 seeking proposals for fixed-price physical supply and/or financial hedges for terms of 4 to 10 years.[35]
- Indiana Gas Co., a subsidiary of Vectren Energy, entered into a 10-year fixed price contract in March 2013.[36]
- The state of Virginia enacted legislation in April 2014 to allow the state's natural gas utilities, including Washington Gas and Virginia Natural Gas, to pursue long-term contracts and investments for up to 25% of their annual firm sales demand.[37]

E. Joint Venture for Gas Reserves

In April 2011, the Company entered into agreements with Encana under which the Company and Encana agreed to participate in a joint venture to develop gas reserves located in the Jonah Field, located in the Green River Basin in Sublette County, Wyoming.[38] Under these agreements, the Company pays a

---

34 Aether Advisors report dated July 2014, page 68.

35 *See* http://www.pacificorp.com/sup/rfps/2012NatGasRFP.html , "2012 Natural Gas RFP Main Document (MS Word file)," page 1.

36 SNL Financial, "Vectren subsidiary enters 10-year fixed price contract with natural gas supplier," July 31, 2013.

37 See http://biz.yahoo.com/e/140429/gas10-q.html for a portion of the Form 10-Q for AGL Resources issued April 29, 2014 (AGL is the parent of Virginia Natural Gas).

38 On April 28, 2011, the OPUC issued an order finding the Company's actions prudent in entering into a joint venture with Encana to develop gas reserves on behalf of its Oregon customers. *See* Docket No. UM 1520,

portion of the costs of drilling in the Jonah field, and in return receives rights to the production of gas from certain sections of the field. Under the agreement, the Company has Encana market the gas for the Company, applying the proceeds from the sale by Encana as an offset to the Company's own gas purchase costs.

This venture provides Oregon utility sales customers with long-term supplies at stable pricing over about a 30-year period. [By prior agreement, NW Natural does not include this joint venture in rates for its Washington customers but instead maintains two separate portfolios for Oregon and Washington for PGA purposes, as contemplated in the WUTC's Order No. 5 in Docket No. UG-111233.]

During the first 10 years of the agreement, the Company projected the volume of gas under the Encana transaction to be approximately 8-10% of the Company's average annual requirements for its utility operations, with a peak of about 15% in the years during the height of the drilling program. It expected its investment to result in the eventual total availability of about 93 billion cubic feet (Bcf) of gas, assuming the development of the contemplated 102 wells, at a highly competitive price as compared to equivalent gas supply purchase alternatives over the same term.

Recently though, on March 31, 2014, Encana announced the sale of its interest in the Jonah field to an affiliate of TPG Capital (Jonah Energy LLC), with a transition to be completed by year-end 2014. The Jonah field is overwhelmingly "dry" gas and this sale is part of a strategic move by Encana to refocus on "wet", i.e., liquids-rich gas plays. [39]

Effective March 7, 2014, the Company and Encana mutually agreed to terminate the obligation to drill and fund carry wells under the Carry and Earning Agreement after completing 72 of the planned 102 wells. The remaining wells can still be drilled under the Joint Operating Agreement with no obligation to "carry" a portion of Encana's capital, which significantly reduces the projected capital costs to develop these additional wells.

Projected volume from the 72 wells developed under the Carry and Earning Agreement totals 66.9 Bcf. If the 30 additional wells are developed under the Joint Operating Agreement, the additional volumes are projected to total 24.4 Bcf. The development of the 30 additional wells is currently under discussion between the Company and Oregon regulatory staff. Of course this discussion ties in closely with the Company's view towards the fundamentals of long-term hedging in the current market environment as described in the preceding section.

F. Modeling of Gas Acquisition Costs

As done in its prior IRPs, the Company has not specifically modeled the commodity cost of any particular gas acquisition option. For example, it has not embedded the expected price of gas under the joint

---

Order No. 11-176.

[39] http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/encana-sells-wyoming-gas-assets-for-18-billion/article17735435/

venture with Encana, or the new proposed development with Jonah Energy LLC, as an available price in its models. 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 the Encana gas reserves price or any other current agreement within that forecast would likely skew the results improperly because those prices are available under just the particular transactions, which have limited volumes. If the Company were to use the price from the Encana or Jonah Energy 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 the these gas reserve transactions does not have an effect on the location at which the Company will purchase gas because the Company can always choose to apply the proceeds from the 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.[40]

Although the gas reserves acquisition does not alter the resource options modeled in this IRP, it is possible that this could change in future IRPs. For instance, unexpected supply constraints in the Rockies could lead to the Company relying on the physical receipt of the gas reserve supplies rather than just the financial proceeds. In that unlikely case, the NWP capacity available to the Company in the Rockies would need to be split between the gas reserves and gas purchased under other supply contracts.

X. RECENT ACTION STEPS

The Company's most recent IRP was the 2013 Washington IRP filed in March 2013 with the WUTC and acknowledged in December 2013 (letter dated December, 16, 2013 in WUTC docket UG-120417). Its list of six action items regarding supply-side resources, along with the actions actually undertaken by the Company, is as follows:

I. Acquire resources in the near-term consistent with the Base Case Resources. Specifically, recall Mist storage capacity from the interstate storage account to serve the core customer needs reflected in the base case forecast.

Most recently the Company recalled 10,000 Dth/day of deliverability at its Mist storage field in 2009, another 10,000 Dth/day in 2011, and 15,000 Dth/day in 2012, along with related annual storage capacity. Recall decisions are made during the summer for an effective date of May 1st of the following

[40] For example, in David Danner's (then WUTC Executive Director and Secretary) letter to NW Natural dated January 13, 2012, the WUTC acknowledged the Company's previous IRP filed in Docket No. UG-100245 and confirmed that NW Natural's approach to limiting the inclusion of the Encana transaction in its analyses was appropriate.

year. During summer 2013, the analysis indicated no need for additional resources. With this current IRP, reflecting the events experienced during the winter of 2013/2014 as previously described, have led to the decision this summer to recall 30,000 Dth/day of Mist deliverability effective May 1, 2015.

II. Support development of a regional cross-Cascades pipeline from a reliability risk management standpoint and to diversify the current resource portfolio. Negotiate and sign an acceptable Precedent Agreement with the cross-Cascades pipeline sponsors for Commission review and approval. Proceed with participation in the project as a shipper depending on the results of the open season.

Efforts to move forward on a Precedent Agreement were put on hold while this current IRP is in progress. At present, the timing for a new open season has not yet been announced by the project sponsors.

III. Update and refine resource cost estimates.

This current IRP represents the latest update of cost estimates and resource evaluations.

IV. Monitor west coast LNG export project development and their potential impact on local natural gas prices.

The Company contracted with Black & Veatch (B&V) to perform a regional analysis including the impact of LNG exports from British Columbia. That study was completed in July 2013 and can be found in Appendix Three. Regarding LNG exports from British Columbia, B&V concluded that:

- LNG exports in British Columbia will reduce traditional Western Canadian supplies that flow south to Sumas and then into the Pacific Northwest market.
- Without additional infrastructure development by 2020, gas markets west of the Cascade Mountain range in Oregon and Washington (“West of Cascades”) will be constrained for 166 days under normal weather conditions.
- Incremental pipeline capacity into the West of Cascades region will help mitigate increases to Sumas basis pricing.

More recently, the probability of LNG exports from the proposed Jordan Cove facility was sufficient to spur the modeling of a resource alternative utilizing a portion of the associated Pacific Connector pipeline.

NW Natural also contracted earlier this year with IHS CERA to analyze the price impact of the two LNG export terminal projects proposed in Oregon. That analysis is described in Chapter 7 and the IHS CERA report itself is provided in Appendix 7.

V. Investigate Newport LNG and Portland “Gasco” LNG refurbishment alternatives and if material address in a future IRP.

For Newport, a variety of refurbishment alternatives including a "do-nothing" scenario were considered and the decision made to proceed with a major refurbishment project, details of which can be found in Appendix Three. Options for the Gasco refurbishment continue to be evaluated.

VI. Develop gas supply parameters for use in evaluating potential additional gas reserves acquisitions and address in a future IRP.

The January 2014 Aether study was the first step in this effort, which continued with a July 2014 report that focused on long-term hedging. Through its recommendations, the Company developed a long-term hedging target of no more than 25% of annual requirements for its portfolio over the 20-year planning horizon.

XI. RECAP AND KEY FINDINGS

- Due to the loss of the Plymouth LNG resource, the Company will recall 30,000 Dth/day of Mist deliverability effective May 1, 2015, and will use a combination of other resources to fill the gap for the coming winter.

- The Company needs to plan for the eventual phase-out of certain resources whose peak day reliability is expected to degrade over time, specifically:
    - 43,800 Dth/day of Sumas supply utilizingTF-1 segmented capacity, and
    - 13,525 Dth/day of Jackson Prairie service delivered using subordinate TF-2 capacity.

- The Company should continue to work with NWP to evaluate and refine the reliability considerations regarding subordinate and segmented firm transportation service.
    - Unless progress is made, the current expectation is that the Company will officially terminate its Plymouth LS-1 and TF-2 agreements with NWP at the next opportunity.

- It is now possible that all Mist Recall will be utilized within the planning horizon of the IRP, necessitating the evaluation of potential expansion capacity that was previously thought unnecessary for utility use (the North Mist expansion). The Company should conduct additional analysis regarding North Mist, particularly regarding the costs and benefits of upsizing the overall expansion project if additional parties are interested in taking storage service.

- A portfolio approach is desirable because it dampens volatility and assures more stable pricing for customers.
    - The January 2014 Aether report independently confirmed that the Company has an effective hedging program.

- Additional Long-Term pricing arrangements appear to be appropriate as part of a diversified portfolio.
    - With the approved Encana gas reserves agreement and the contemplated Jonah Energy transaction, the Company currently has about a 15% Long-Term hedge position over the

next few years, with an average of roughly 10% over the next 10 years due to the natural decline of the well production.

- The July 2014 Aether reports recommends up to a 35% Long-Term hedged position, but to be conservative, the Company currently has adopted a guideline to have no more than 25% of its expected annual purchase requirements in the form of Long-Term hedges.
- Financial derivative contracts are limited by credit quality considerations to no more than five years in duration under the GSRMP, but under current financial conditions, three years is a more realistic maximum contract length.
- The addition of new long-term hedge transactions would be made on a case-by-case basis only after careful analysis and review of the costs and benefits of the contemplated transaction(s).

- Development of gate station planning standards will assume greater importance over time as the gap grows between MDDOs and physical gate capacities, especially for gate stations serving the Clark County load center.

- Refurbishment of the 37-year old Newport LNG Plant should proceed, including resolution of the dry ice issue that has de-rated the plant's total storage capacity.

- The perceived likelihood of an LNG export terminal at Jordan Cove is now sufficient to warrant evaluation of the resource option presented by construction of the Pacific Connector pipeline.

- Contracting for T-South capacity should be re-evaluated each year due to the potential for changing price spreads between Station 2 and Sumas and other relevant considerations such as supply liquidity.

- There are a variety of resources that are too speculative for inclusion in this analysis, but that determination should be revisited in future IRPs.

Chapter 4: Demand-Side Management

NW Natural®

I. OVERVIEW

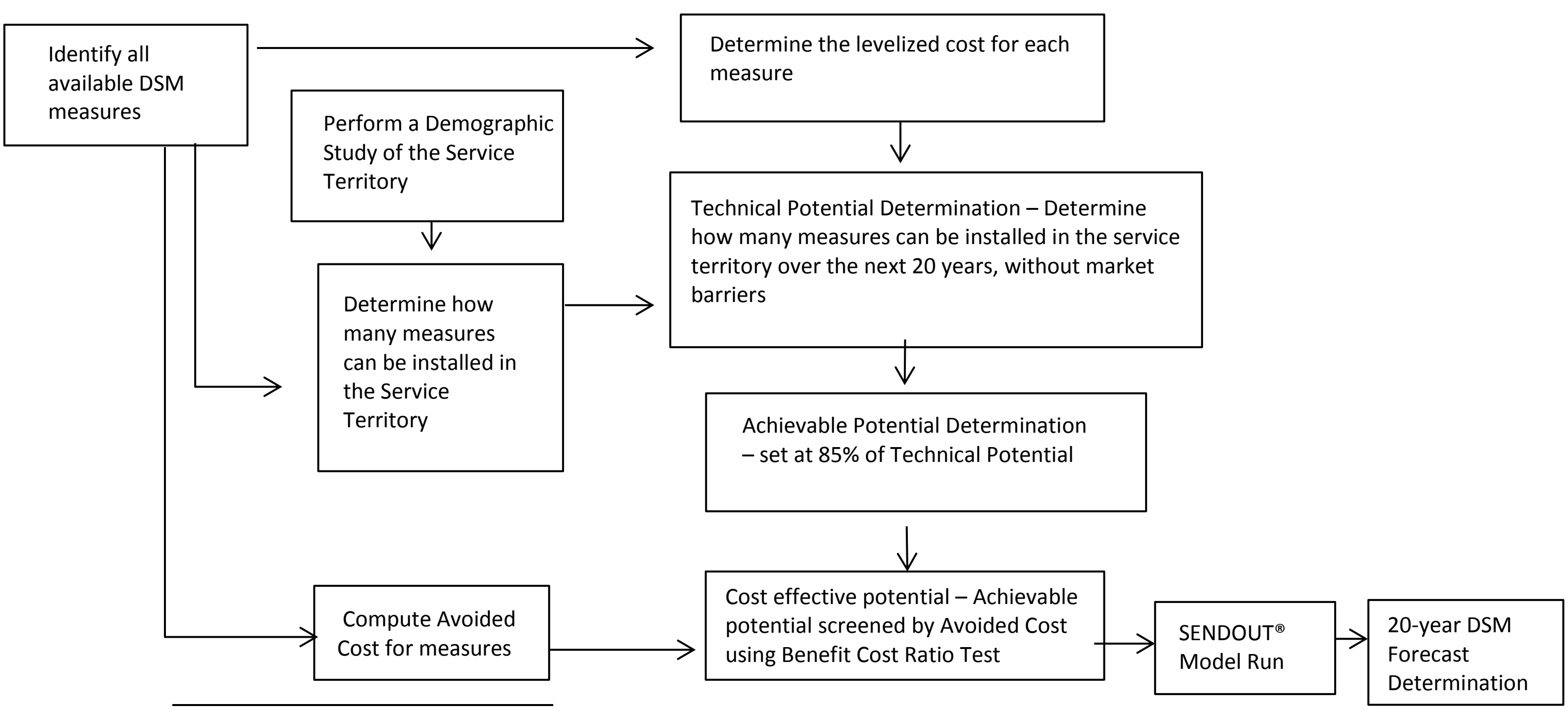
NW Natural worked with Energy Trust of Oregon (Energy Trust) to forecast the 20-year demand-side management (DSM) potential for the Company's service territory. Energy Trust is a non-profit organization that was initially established to provide energy efficiency services and a renewable energy program to Oregon investor-owned electric utility customers. Since its inception, Energy Trust has grown from serving only electric customers to serving 70 percent of Oregon's electric customers and most of Oregon's natural gas customers. As of October 1, 2009, Energy Trust also serves NW Natural's Washington customers.

The Company leaned heavily on Energy Trust's expertise in the development of the 20-year demand-side management (DSM) forecast. The forecast of cost effective therm savings was generated for the Company's service territory and was then included in SENDOUT® as a reduction to demand for each load center. The results show that the Company can save 20.5 million therms by 2018 and over 47.7 million therms by 2033 in its Oregon service territory[1] and 1.1 million therms by 2018 and 3.6 million by 2033 in Washington.

II. METHODOLOGY FOR DETERMINING THE COST EFFECTIVE DSM POTENTIAL

The DSM assessment began by determining the technical potential, which in this context refers to the complete penetration of all cost-effective DSM measures within the NW Natural's service territory. Figure 4.1 below provides an overview of this initial process followed by a more in-depth discussion of each step.

Figure 4.1 - 20-Year DSM Forecast Determination Methodology



[1] Includes 35 million cost effective therms of potential and 12.6 million therms of market transformation savings over

A. 20-Year DSM Forecast

1) Identify all available DSM measures

Energy Trust compiled a list of all commercially available measures for single family and multi-family residential, commercial, and industrial applications installed in new or existing structures. Since the Company's 2013 Washington IRP, no significant measures have been added to the gas energy conservation measure portfolio.

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

2) Determine the levelized cost for each measure

Once the list of measures was compiled, Energy Trust determined a levelized cost for each measure. The levelized cost is the present value of the total cost of the measure over its economic life converted to equal annual payments. The levelized cost calculation starts with the incremental capital cost of a given measure. The total cost is amortized over an estimated measure lifetime using the Company's discount rate of 4.58 percent.[2] The annual net measure cost is then divided by the annual net energy savings therms. This formula produces the levelized cost estimate in dollars per therm saved, as illustrated in the following formula:

$$LevelizedCost = \frac{Net\ Annual\ Cost(\$)}{Net\ Annual\ Savings}$$

Levelized costs can be graphically depicted to demonstrate the total potential of therms that could be saved at various costs for all commercially available conservation measures. Figures 4.2 and 4.3 below show a resource supply curve that can be used for comparing demand-side and supply-side resources.

[2] The 4.58 percent discount rate is NW Natural's Oregon real after-tax weighted average cost of capital (and assumes a 1.9 percent annual inflation rate).

Figure 4.2 – NW Natural's Oregon Service Territory Gas Supply Curve

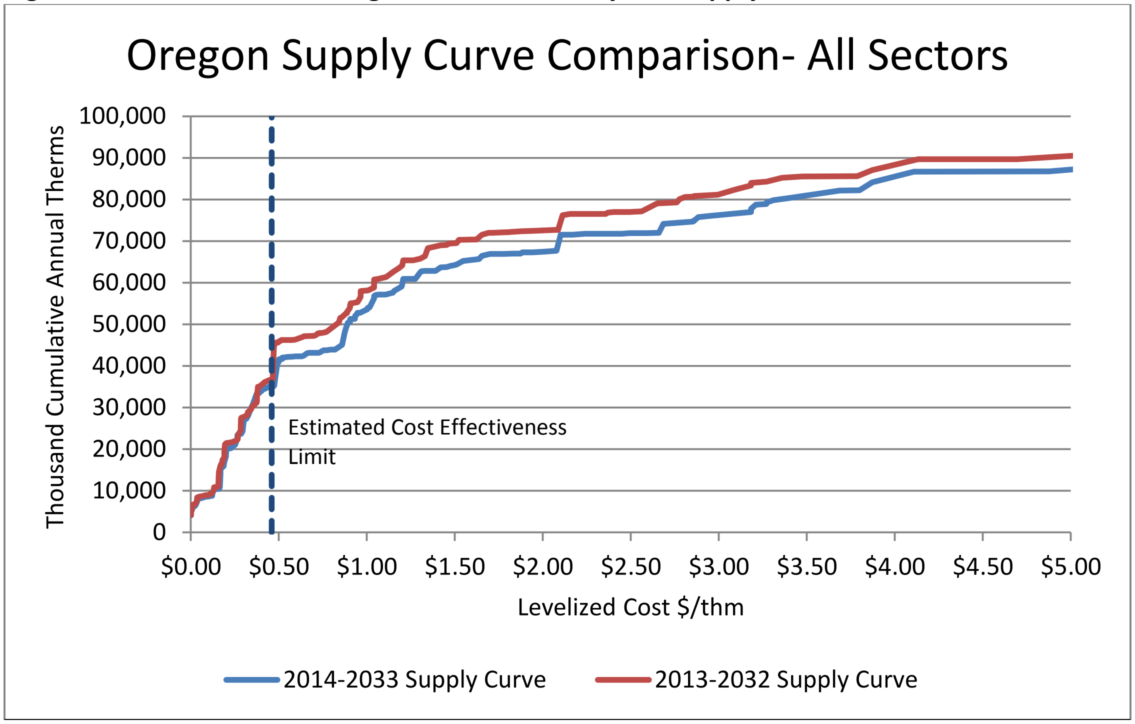


Figure 4.3 – NW Natural's Washington Service Territory Gas Supply Curve

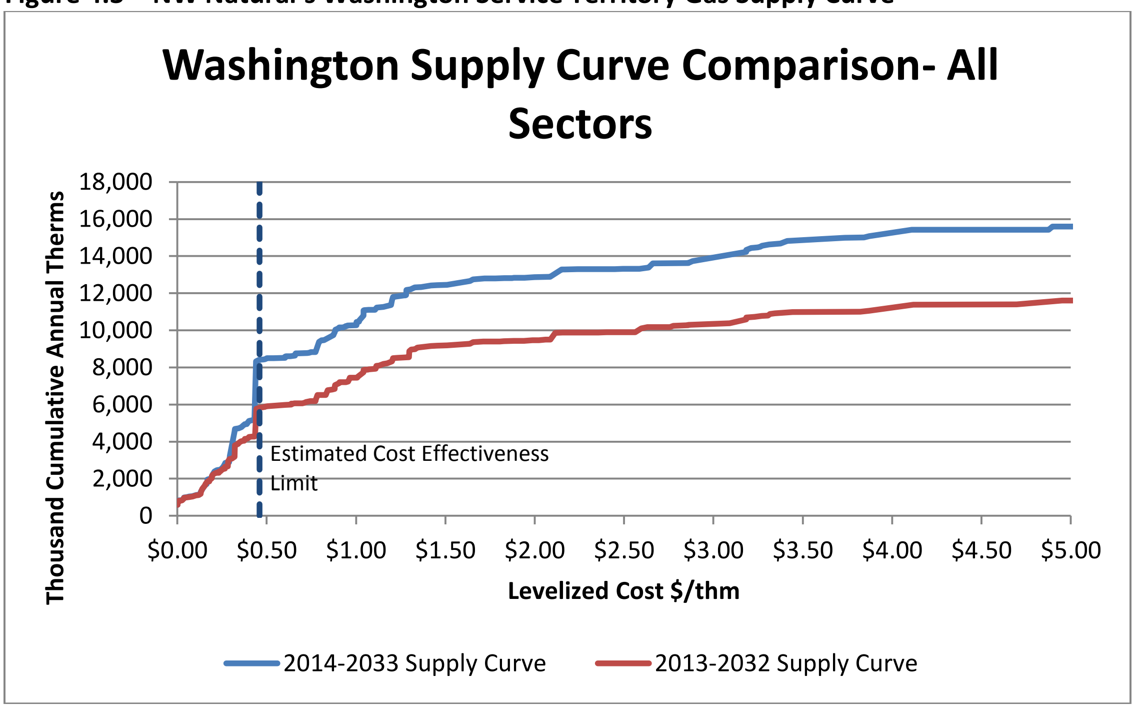


Figure 4.3 shows a bigger potential for DSM in this IRP than the prior IRP. This is largely due to a 24% increase in the customer forecast for the Clark county area. Other refinements affecting this include updated modeling assumptions such as more accurate percentages of single-family verses manufactured homes in Washington.

3) Demographic Study
At the same time steps 1 through 2 above were being completed, Energy Trust was also performing a demographic study. Using NW Natural's customer load forecasts discussed in Chapter Two, Energy Trust applied its knowledge of existing stock conditions and building codes to the Company's customer forecast.

NW Natural serves over 690,000 residential, commercial, and industrial customers in Oregon and Washington, including interruptible customers. Table 4.1 shows total customer counts, overall consumption, and average use for NW Natural's Firm Sales customers.

Table 4.1 – FY 2013 Customer Statistics Sector – All Customers

Sector	Average Number of Customers	Actual Sales (therms)	Average Use Per Customer
Residential	625,017	404,781,021	648
Commercial	64,426	246,436,035	3,825
Industrial Firm	566	34,543,127	61,030
Industrial Interruptible	143	59,521,836	416,237
Total	690,152	745,282,019	1,080

Table 4.2 below shows the same Customer Statistics for NW Natural's Oregon service territory.

Table 4.2 – FY 2013 Customer Statistics Sector - Oregon

Sector	Average Number of Customers	Actual Sales (therms)	Average Use Per Customer
Residential	558,775	359,367,889	643
Commercial	58,456	226,177,414	3,869
Industrial Firm	529	31,367,824	59,353
Industrial Interruptible	137	57,729,225	422,925
Total	617,896	674,642,351	1,092

Table 4.3 below shows the same Customer Statistics for NW Natural's Washington service territory.

Table 4.3 - FY 2011 Customer Statistics Sector - Washington

Sector	Average Number of Customers	Actual Sales (therms)	Average Use Per Customer
Residential	66,242	45,413,133	686
Commercial	5,971	20,258,621	3,393
Industrial Firm	38	3,175,304	84,675
Industrial Interruptible	7	1,792,611	275,786
Total	72,256	70,639,668	978

Interruptible customers are included since the Company provides energy efficiency programs for these customers. Conversely, Transportation customers are not included, as the Company does not have energy efficiency programs for these customers.

4) Combining knowledge of all available DSM measures with existing stock data results in a determination of how many measures can be installed in the service territory.

5 & 6)Technical and Achievable Potential Determination

The technical potential determination is the total therms saved from all cost-effective measures that could be installed in NW Natural's service territory. The technical potential assumes 100 percent adoption, which is not realistic.

The technical potential is reduced by 15 percent to account for market barriers that prevent total adoption of all cost effective measures. This adjusted total is referred to as the *achievable potential*. Defining the achievable potential as 85 percent of the technical potential is the generally accepted method employed by many industry experts including Northwest Power and Conservation Council (NWPCC) and National Renewable Energy Lab (NREL). The overall potential is also decreased due to constraints on the ability to launch programs as recognized in the deployment scenario.

7) Compute avoided cost for each DSM measure.

Energy Trust also assessed the net present value of the costs that would be avoided by installing each measure. The assessment considered the period of the energy savings, or rather the lifetime of the measure and the seasonal value of the energy savings. Savings that occur during the winter season are more valuable than savings that occur during the summer season because gas commodity prices are higher during the space heating season. The net present value of savings represents the potential benefit of the measure.

8The Cost Effective Potential
To determine the cost effective potential, Energy Trust screened the achievable DSM measures using the Total Resource Cost (TRC) test.
This test was used to evaluate the total benefits attributable to the measure divided by the sum of all related costs. A TRC test value equal to or greater than one means the value of benefits equal or exceed the costs, and the program is therefore cost-effective. 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) The value of gas energy saved, as determined by the therms saved multiplied by the Company's avoided cost, plus 10% for non-quantified energy benefits.[3] The total avoided cost for a measure depends upon that measure's life and seasonality.
b) Non-energy benefits as quantified by a reasonable and practical method.

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, and state and federal tax credits.

Tables 4.4 and 4.5 summarize the technical, achievable, and cost-effective potential for each customer class in Oregon and Washington, respectively.

Table 4.4 - Summary of Resource Potential - NW Natural's OR Service Territory 2014 – 2033

Oregon	Technical Potential (Therms)	Achievable Potential (Therms)	Cost Effective Achievable Potential (Therms)	Cost Effective Achievable Potential + Excepted Measures Potential (Therms)*
RES	55,111,443	46,844,727	11,581,766	21,767,985
COM	32,200,993	27,370,844	14,981,139	14,981,139
IND	16,899,951	14,364,958	8,500,595	8,500,595
Efficiency Total	**104,212,386**	**88,580,528**	**35,063,500**	**45,249,719**

**The OPUC is currently considering exceptions to cost effectiveness criteria for several residential measures*

3 *See* Chapter Eight for a discussion of NW Natural's avoided cost.

Table 4.5 - Summary of Resource Potential - NW Natural's WA Service Territory 2014 – 2033

Washington	Technical Potential (therms)	Total Achievable (therms)	Cost Effective Achievable + Excepted Measures* (therms)
RES	12,586,997	10,698,947	6,655,622
COM	4,574,032	3,887,927	2,058,009
IND	1,368,373	1,163,117	736,108
Efficiency Total	**18,529,402**	**15,749,992**	**9,449,739**

* Cost effective achievable potential as measured by the TRC, plus additional cost-effective residential weatherization potential as measured by the Utility Cost Test (UCT)

Figures 4.4 and 4.5 below depict the 20-year DSM forecast and the average levelized cost for the savings acquired for each customer class in Oregon and Washington, respectively.

Figure 4.4 – Achievable Potential in Oregon through 2033

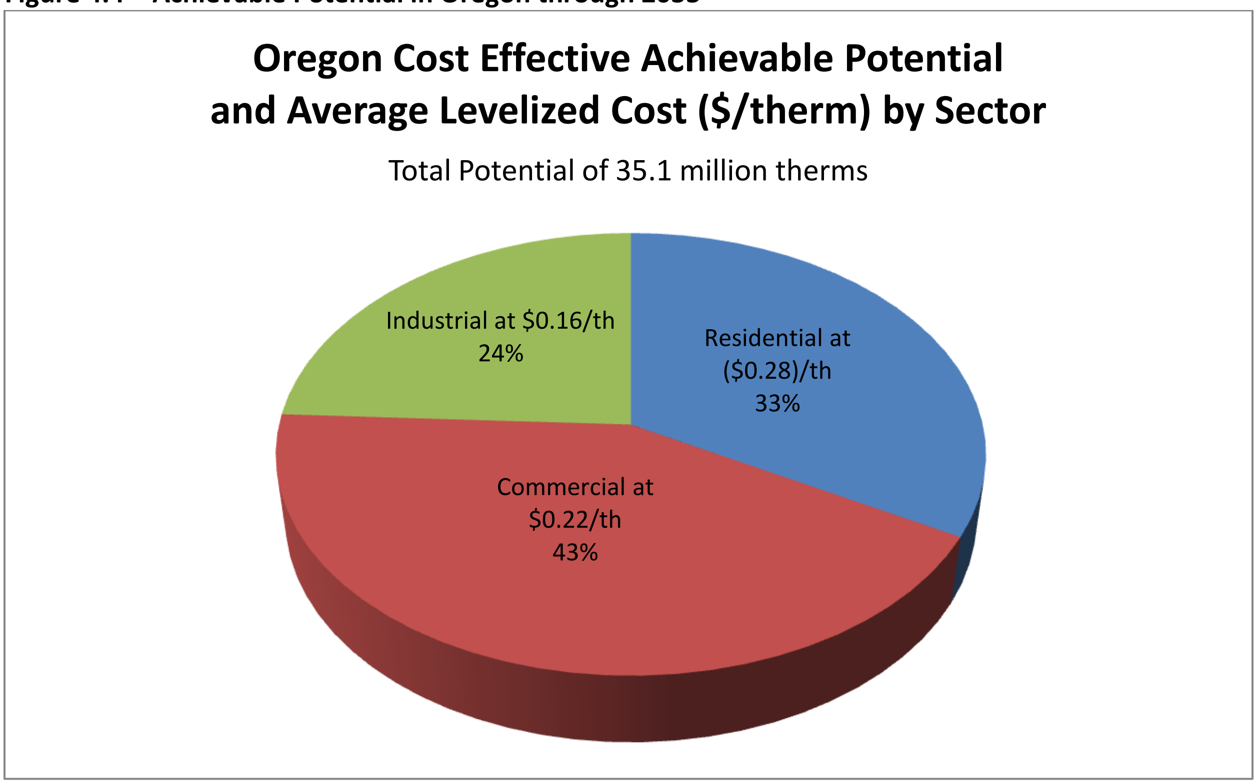
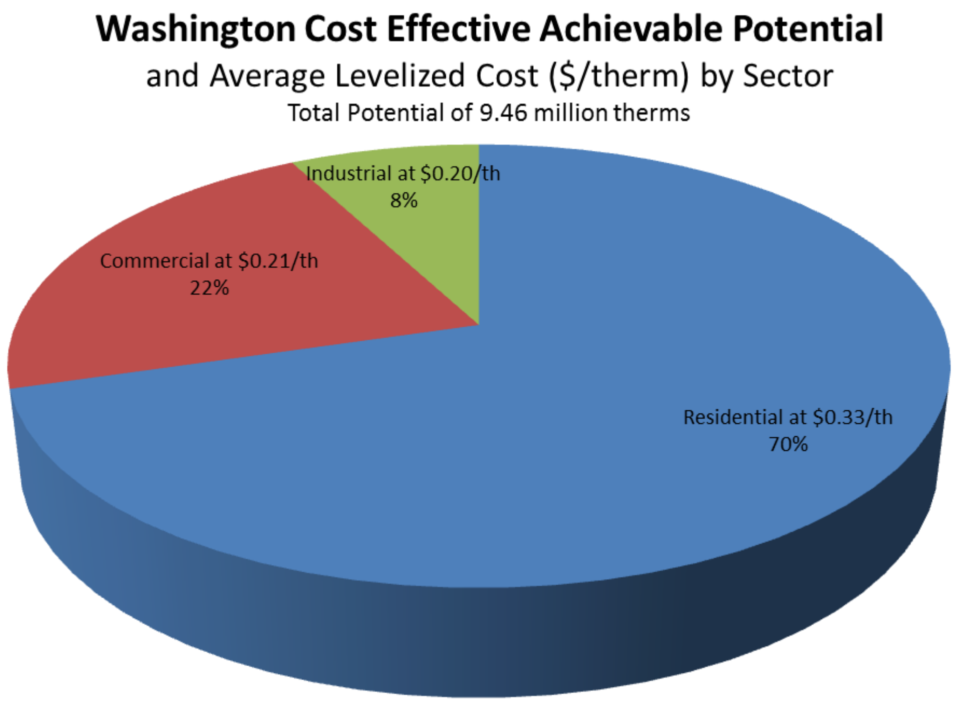


Figure 4.5 – Achievable Potential in Washington through 2033



Tables 4.6 and 4.7 below show the average levelized cost per therm by customer class for both the Oregon and Washington portfolios, respectively.

Table 4.6 – Average Levelized Costs per Therm Per Customer Class - Oregon

Oregon	Average Levelized Cost	Cost Effective Achievable Potential
Residential at ($0.28)/Th	$ (0.28)	11,581,766
Commercial at $0.22/Th	$0.22	14,981,139
Industrial at $0.16/Th	$ 0.16	8,500,595

Table 4.7 – Average Levelized Costs per Therm Per Customer Class – Washington

	Average Levelized Cost	Cost Effective Achievable Potential*
Residential at $0.33/th	$ 0.33	6,655,622
Commercial at $0.21/th	$ 0.21	2,058,009
Industrial at $0.20/th	$ 0.20	736,108

* Cost effective achievable potential as measured by the TRC, plus additional cost-effective residential weatherization potential as measured by the Utility Cost Test (UCT)

Tables 4.8 through 4.13 below provide a breakdown of the therm savings and levelized cost per therm on a customer class basis by state.

Oregon

Table 4.8 - Oregon Residential Sector Gas Achievable Potential Savings for 2014-2033

Screened by TRC Measure Category	Thousand Therm	$/Therm, Levelized
New Appliance	227	($0.03)
New Construction	2,381	$0.35
New DHW	0	$0.00
Replace Equipment	723	$0.03
Replace Appliance	531	($0.04)
Replace DHW	3,432	($1.52)
Weatherize Retrofit	4,288	$0.25
Total	**11,582**	**($0.28)**

Table 4.9 - Oregon Commercial Sector Gas Achievable Potential Savings for 2014-2033

Screened by TRC Measure Category	Thousand Therms	$/Therm, Levelized
New Construction	568	$0.10
New Cooking	378	$0.20
Replace Equipment	2,683	$0.22
Replace Shell	3,095	$0.23
Replace Cooking	1,237	$0.30
Retrofit Equipment	4,233	$0.22
Retrofit Shell	2,787	$0.21
Total	**14,981**	**$0.22**

Table 4.10 - Oregon Industrial Sector Gas Achievable Potential Savings for 2014-2033

Screened by TRC Measure Category	Thousand Therms	$/Therm, Levelized
Replacement DHW	3	($11.36)
Replacement Process Boiler	1,111	$0.17
Replacement Space Heat	600	$0.36
Retrofit DHW	1,265	$0.14
Retrofit Process Boiler	3,067	$0.06
Retrofit Weatherization	2,457	$0.26
Total	**8,501**	**$0.16**

WASHINGTON

Table 4.11 - Washington Residential Sector Gas Achievable Potential Savings for 2014-2033

Screened by BCR Measure Category	Thousand Therm	$/Therm, Levelized
New Appliance	77	$ 0.01
New Construction	5,091	$ 0.45
New DHW	27	$ 0.91
Replace Equipment	76	$ 0.03
Replace Appliance	42	$ 0.00
Replace DHW	568	$ (1.11)
Weatherize Retrofit	775	$ 0.68
Total	**6,656**	**$ 0.33**

Table 4.12 - Washington Commercial Sector Gas Achievable Potential Savings for 2014-2033

Screened by TRC Measure Category	Thousand Therms	$/Therm, Levelized
New Construction	263	$0.16
New Cooking	123	$0.19
Replace Equipment	401	$0.21
Replace Shell	354	$0.23
Replace Cooking	214	$0.30
Retrofit Equipment	432	$0.19
Retrofit Shell	270	$0.20
Total	**2,058**	**$0.21**

Table 4.13 - Washington Industrial Sector Gas Achievable Potential Savings for 2014-2033

Screened by TRC Measure Category	Thousand Therms	$/Therm, Levelized
Replacement DHW	49	$0.01
Replacement Process Boiler	22	$0.03
Replacement Space Heat	72	$0.36
Retrofit DHW	191	$0.16
Retrofit Process Boiler	255	$0.12
Retrofit Weatherization	148	$0.39
Total	**736**	**$0.20**

After determining the 20-year cost effective achievable potential, Energy Trust develops a deployment scenario based on past deployment experience and knowledge of the developing market. A deployment scenario is an educated guess of future adoption rates for new technologies and installed measures represented within the cost effective potential study plus, in Oregon, forecasted market transformation savings. It tries to provide a more short-term, annualized perspective on 20-year savings potential.

The final reported cost effective deployment is slightly different for Washington and Oregon. The Oregon savings forecast includes therms saved by known changes to future building codes and equipment standards where Energy Trust played a role in advancing the adoption of these codes and standards. Since energy consumption is reduced when building and equipment codes are adopted, it is appropriate to decrement the Company's load forecast accordingly and allow the program to assume some of the savings since Energy Trust's work in transforming the market influenced the changes in code. This is not done for the Washington cost effective achievable potential since the Washington Utilities and Transportation Commission (WUTC) has not acknowledged that this is an appropriate practice. Further, Energy Trust is not actively engaged in the codes process in Washington.

Similarly, Oregon's therm savings targets are adjusted for spillover effect. Spillover occurs when a person not applying for program incentives reduces his/her energy use or installs energy efficient measures because the program has raised his/her awareness of energy efficiency. Numbers are further adjusted for free ridership, which refers to a customer's participating in the program when the program information or incentive did not influence the customer's efficiency decision. Again, these adjustments are not made for the Washington cost effective achievable potential as the state historically has not supported the application of these adjustments.

Figures 4.6 and 4.7 depict the deployment scenarios for Oregon and Washington, respectively.

Figure 4.6 – Oregon Deployment Scenario

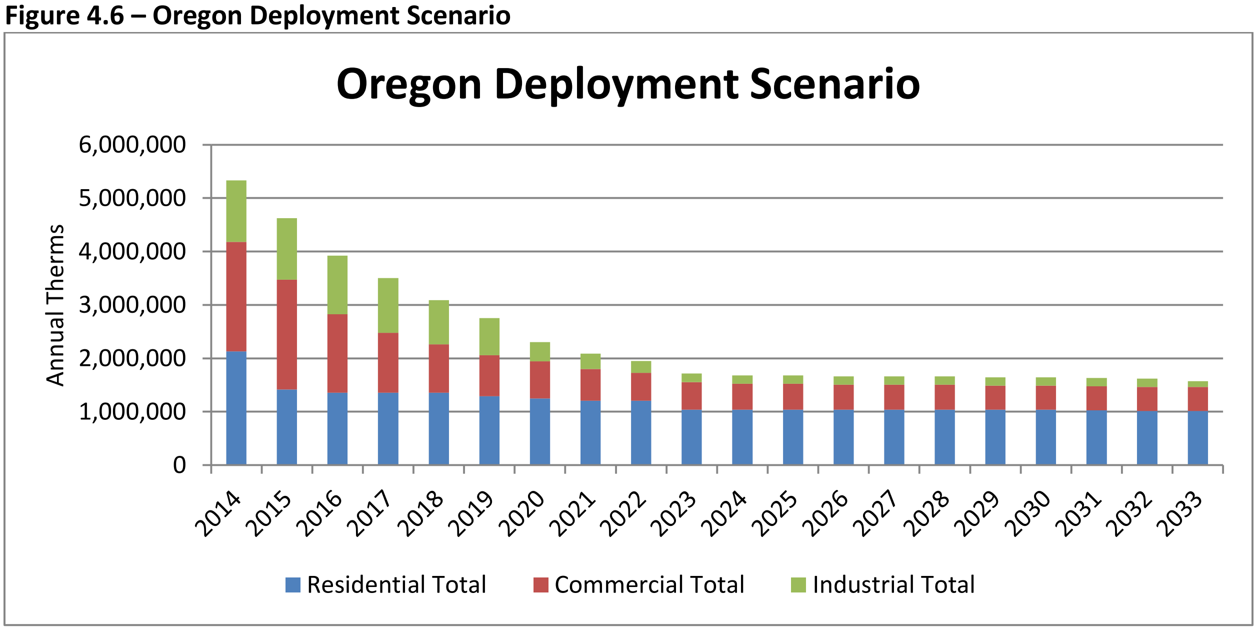
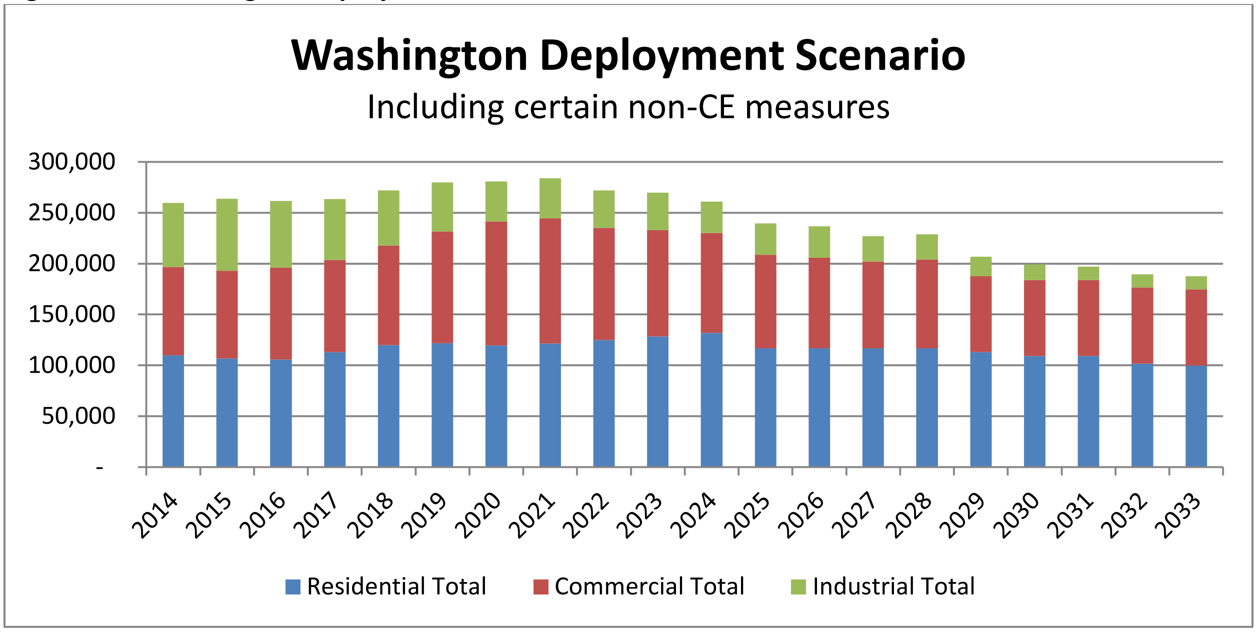


Figure 4.7 – Washington Deployment Scenario



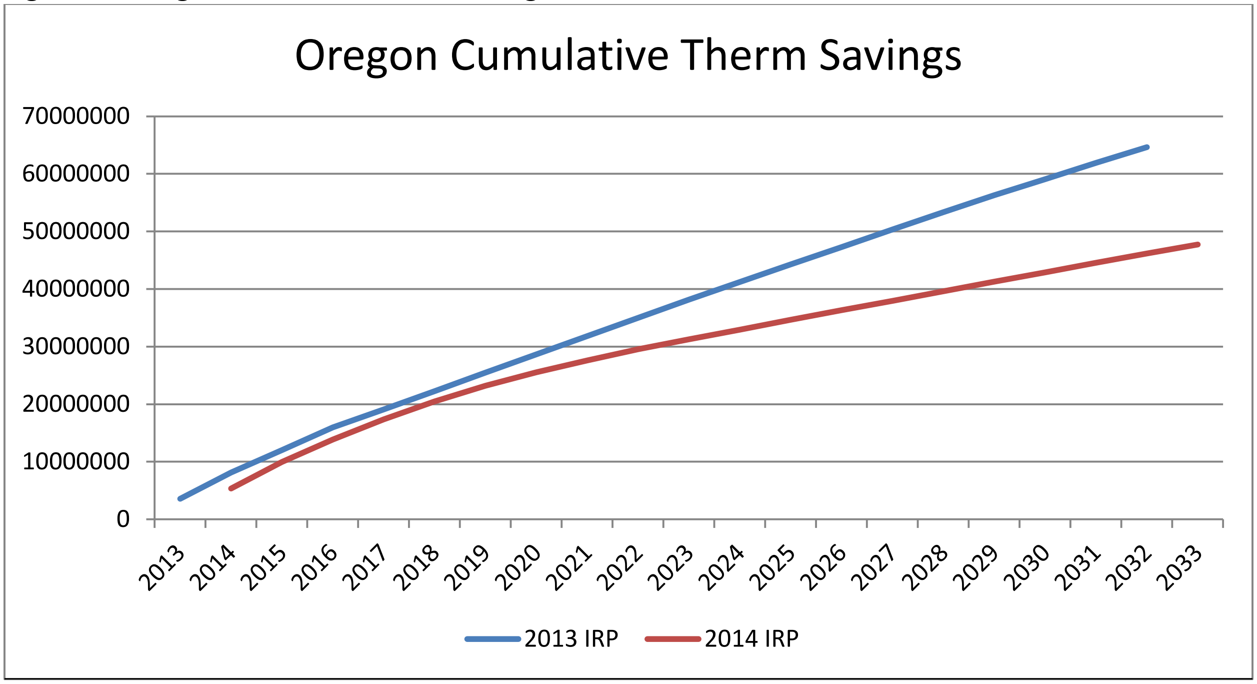
B. Evaluation of Achievable Potential in SENDOUT®

The deployment scenario was evaluated in the SENDOUT® model to determine the optimal resource portfolio potential. During this process, the achievable potential DSM savings were allocated among the demand regions and adjusted for weather.

Measures are assigned designations of “must take” or “discretionary.” As the titles suggest, with all sensitivities, the SENDOUT® model must choose all DSM labeled “must take.” New construction measures and replacement programs are “must take” to avoid what is referred to as “a lost opportunity,” which occurs when new construction is built or replacement appliances are installed without consideration for efficiency. The less efficient building or appliance will not likely be replaced or retrofitted during its useful life, resulting in a lost savings opportunity for this timeframe. Retrofit measures, on the other hand, are labeled discretionary. The SENDOUT® model may choose the adoption of these measures to the degree they are the least cost option as compared with all other supply-side resources.

Figures 4.8 and 4.9 below graphically demonstrate the savings potential in Oregon and Washington, respectively, over the next 20 years.

Figure 4.8 Oregon Cumulative Therm Savings



The overall savings potential of the portfolio of measures offered in Oregon is down slightly from the Company's last IRP for the following reasons:

- A decrease in residential customer growth
- A decrease in the industrial customer load forecasts
- Reduced natural gas prices resulting in a lower avoided cost
- Reduced gas savings due to lower market transformation savings forecasts for efficient gas furnaces, new homes and commercial building code changes

Figure 4.9 - Washington Cumulative Therm Savings

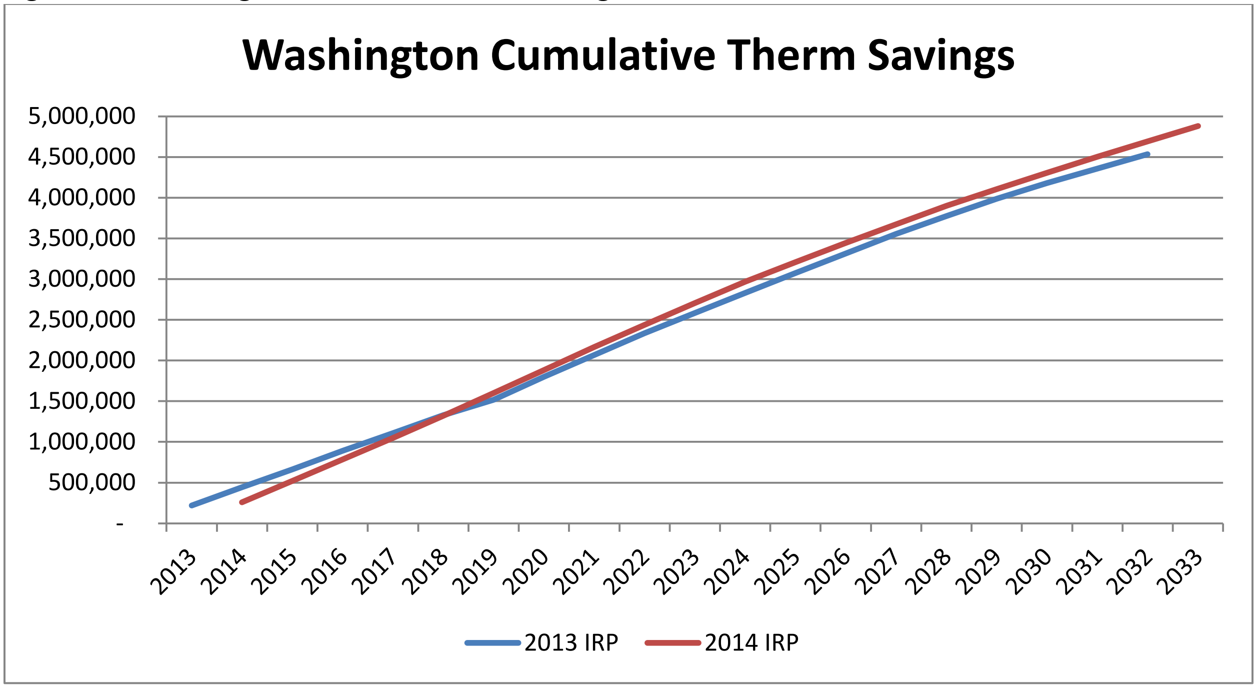


Figure 4.9 shows the cumulative 20-year deployed savings compared to the 2013 Washington IRP. The cost effective achievable savings potential for Washington is higher than it was in the Company's last IRP for the following reasons:

- Substantially higher Residential customer and load forecasts
- Revised assumptions for single family verses manufactured home split
- Increased Commercial and Industrial load forecasts

The 2013 Washington IRP 20-year cumulative deployment also included residential savings for a 2020 code change. Because those savings were not reflected in NW Natural's load forecast in 2013, the savings adjustment was included in the savings deployment. For this IRP, the residential code change savings were included in the load forecast, not reflected in the 20-year savings deployment. This approach better reflects how savings from market code advances are accounted for in Washington.

III. PROGRAM FUNDING AND DELIVERY

A. Oregon

1. Residential, Commercial, and Industrial Programs

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 administrative responsibility of the energy efficiency programs to a third party.[4]

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, independently-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[5] identified that cost effective industrial saving were available, the Company worked with Energy Trust to launch an Industrial DSM program. This program is available to Industrial Firm Sales and Industrial Interruptible Sales 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. As noted above, NW Natural foresees 51.3 million therms of its 20-year demand coming from demand-side management measures.

Since the onset of the "shale gale"—the greatly increased availability of natural gas through advanced extraction technologies—the price for natural gas has declined, which results in a reduced avoided cost. A lower avoided cost means that fewer energy efficiency measures are cost effective. The measures that are no longer cost effective are ceiling, wall, and floor insulation, the 0.67 EF gas tank water heater, residential air sealing, and the new homes packages. Energy Trust was concerned that removing these measures from the gas portfolio would result negatively in lost savings opportunities, and filed a request with the Public Utility Commission of Oregon for approval to offer non-cost effective measures in accordance with the exceptions to the cost effectiveness standard provided in OPUC Order No. 94-590. In Order No. 13-256, the Commission provided a limited waiver and required Energy Trust to submit a report on July 1, 2014 analyzing the costs and benefits of these measures. Parties are currently engaged in discussions about the Energy Trust's report. At this time, it is unclear what conclusions the Commission will draw as a result of this docket. If the Energy Trust is allowed an ongoing exception to the non-cost effective measures, the technical potential as presented herein will be revised upward as stated below in Table 4.14.

---

4 *See* Order No. 02-634 in Docket No. UG 143.

5 *See* Docket No. LC 45.

Table 4.14 – Comparison Total Potential with and without Cost Effective Measures

	Technical Potential (therms)	Total Achievable (therms)	Cost Effective Achievable (therms)	Cost Effective Achievable + Excepted Measures (therms)
RES	67,698,440	57,543,674	14,088,401	28,423,607
COM	36,775,025	31,258,771	17,039,148	17,039,148
IND	18,268,324	15,528,075	9,236,703	9,236,703
Efficiency Total	**122,741,789**	**104,330,520**	**40,364,252**	**54,699,458**

The difference in potential savings is not significant enough to remove or replace other resources in the Base Case resource portfolio, but NW Natural will track Docket No. UM 1622 and will include in its next Annual IRP Update a discussion of the impact that the conclusion of the UM 1622 proceeding will have on its energy efficiency acquisition targets.

2. Oregon Low Income Energy Efficiency Program (OLIEE)[6]

Since October 2002, NW Natural has collected public purpose funding for its Oregon Low Income Energy Efficiency (OLIEE) program through a 0.25 percent surcharge to Oregon Residential and Commercial customers' energy bills.[7] OLIEE funding is 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 ten Community Action Agencies (Agencies) within NW Natural's Oregon service territory.

When the public purpose charge was implemented, NW Natural estimated the Agencies would weatherize approximately 700 to 800 more homes than they were able to serve previously. However, the program has not come close to meeting that target. As a result, program funding began to accrue.

In response to the growing OLIEE balance and the lack of OLIEE market penetration, NW Natural collaborated with the Agencies, Community Action Partnership of Oregon (CAPO), Public Utility Commission of Oregon Staff and the Citizens' Utility Board (CUB) to revise the program and liberalize its funding for qualifying homes. The OLIEE program was redesigned from paying prescriptive amounts for the installation of specific measures, to paying for all energy efficiency measures deemed cost-effective when analyzed in aggregate. The OLIEE pilot's new "whole house" perspective was adopted in conjunction with a series of annually escalating agency targets. This re-design made OLIEE more comparable to the state legislated low income program offered to customers with electrically heated homes.

6 OLIEE program parameters are outlined in Schedule 320 and funding for the program is collected per Schedule 301.

7 *See* Order No. 02-634 in Docket No. UG-143.

This approach was successfully piloted for three years, in large part because of the influx of American Recovery and Reinvestment Funds to the Agencies during this timeframe. NW Natural filed a comprehensive pilot review on May 31, 2010 which included a third party impact study. While the realized savings were less than those reported, Agencies have been able to treat more homes and as a result, have spent down the reserve of OLIEE funds. On October 1, 2010, the Company's Oregon Tariff Schedule 320 was revised to allow the pilot program to be the Company's ongoing offering.

In a continued effort to ensure that funds collected for low income programs were getting to applicable customers, the program was revised again on November 27, 2013, to remove the requirement that other sources of federal or state dollars be applied to each project; to allow nonfunctioning furnaces to be replaced without demonstrating that the new furnace would result in reduced energy savings;[8] and to increase the per home incentive cap from $4,000 to $5,000. These changes were made in an effort to remove the barriers preventing Agencies from delivering services to qualifying customers. NW Natural is interested in whether these changes will over time help increase the number of homes treated per year. Table 4.15 below shows the number of homes treated and therms saved in OLIEE per year.

Table 4.15 – Homes Treated through OLIEE Program

Program Year	Homes Treated	Therms Saved (Estimated)
2012-13	151	36,995
2011-12	541	92,708[9]
2010-11	339	108,141

B. Washington

1. <u>Residential and Commercial Programs</u>

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.[10] 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.[11]

---

8 No energy is used in furnaces that don't function. Therefore a newer, more cost-effective model will not result in reduced savings since the replacement will allow the customer to heat space that previously wasn't being conditioned.

9 Therms saved per unit were significantly reduced in 2011-12 due to the extent of multi-family units weatherized that year (approximately 50%)

10 *See* Order No. 4 in Docket UG-080546.

11 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.

While the program is relatively new, it has successfully achieved its annual targets since its inception. Targets are based on IRP savings goals. Program results for 2013 were presented to the WUTC and EEAG in the 2013 Annual Report filed April 23, 2014.

The Company's program portfolio has consistently delivered savings cost effectively, having a total resource cost of one or greater. With lower gas prices and, consequently, lower avoided costs, other natural gas utilities in the region have struggled to keep their programs cost effective. The WUTC opened docket No. UG-121207 to investigate methods for evaluating the cost effectiveness of natural gas energy efficiency therm savings. NW Natural participated in this docket and expressed a willingness to reconsider aspects of traditional methodologies. The Commission issued a Policy Statement in October 2013 which states a preference for the use of a balanced TRC on a portfolio level, and in lieu of that, the Utility Cost Test (UCT). NW Natural and Energy Trust have considered the Commission's Policy Statement; Energy Trust performed analysis on how the application of the TRC verses the UCT would impact the program. The Company met with its EEAG on April 25. 2014, and proposed using the UCT as the primary cost effectiveness screening tool for the 2015 program year. Since no party objected to the proposal, the Company will revise its tariff and Energy Efficiency Plan to reflect this change, which will both comply with the Policy Statement and allow the Company to offer a sound program.

2. <u>Washington Low Income Energy Efficiency Program (WA-LIEE)</u>

On October 1, 2009, NW Natural launched a revised low income program identified as WA-LIEE (Washington Low Income Energy Efficiency). Modeled after its Oregon OLIEE pilot, the WA-LIEE program reimburses the two administering Agencies for installing weatherization measures that are cost-effective when analyzed in aggregate. Reimbursements are capped at the lesser of 90 percent of the job cost or $3,500. The program has to date had modest success in treating homes for applicable customers. The Company is working to enhance its communications on the availability of the program. Table 4.16 below shows the number of homes treated and therms saved in WALIEE per year.

Table 4.16 – Homes treated through WALIEE

Year	Homes Treated	Therms Saved (Estimated)
2013	20	7026
2012	8	2538
2011	11	3575

IV. LOAD MANAGEMENT AND DEMAND RESPONSE

Demand response reduces system load requirements during cold snaps or other times when the system is stressed. Many of NW Natural's customers can choose to receive service on an Interruptible rate schedule. Approximately 30 percent of the Company's annual throughput is for Interruptible Sales or Interruptible Transportation service. Both customer groups are required to have a back-up heating system and large volume customers gravitate towards Interruptible service because of the low distribution charges. If unique circumstances occur, such as a system disruption or a high demand event, the Company may call on Interruptible service customers to curtail their load. When an Interruptible customer fails to reduce usage during a curtailment event, that customer is billed penalty charges in accordance with the tariff.

V. CONCLUSION

NW Natural recognizes the enduring value customers receive as a result of investments in energy efficiency. The Company intends to achieve the therm savings targets identified in this study and recognizes the current timeframe is one in which gas prices have declined and policy makers are considering the implications of lower avoided costs on the cost effective analysis of DSM.

Chapter 5: Energy Policies and Environmental Considerations

NW Natural®

I. OVERVIEW

The Company meets all minimum local, state and federal environmental requirements that regulate practices of a local distribution company (LDC) and when appropriate voluntarily exceeds such requirements. Environmental stewardship is a core value that guides the services offered to NW Natural customers, in addition to the Company's administrative operations and field work. Indeed, NW Natural is very proud of its work in this area and is a model for other LDCs around the country.

The Company promotes sustainability across all internal operation functions. Actions in this area include: a fleet idling reduction initiative to reduce emissions and increase efficiency; concerted waste reduction in all offices and service centers, including a composting program; incentivizing commute alternatives, including free public transit passes, decreased parking rates for car pools and a bike program; environmental and energy aware facility remodels and retrofits; and creation of an employee Green Team. For more information on the Company's sustainability program, please see the Company's Annual Community and Sustainability Report[1].

On the customer side, the Company works with Energy Trust of Oregon to capture all cost effective conservation to help customers reduce their gas usage, lower their bills and to reduce their carbon footprint. As a complementary measure to encouraging the efficient use of natural gas, the Company offers the Smart Energy program to those customers interested in offsetting the greenhouse gas (GHG) footprint associated with natural gas. NW Natural was the first stand-alone gas company to offer an offset product when it began offering the product in 2007. Since its inception, the program has enrolled 22,827 customers and offset 300,624 tons of CO_2e.

Policies surrounding GHG emissions could have a substantive impact on NW Natural for two main reasons. First, local, state and federal governments are rapidly moving toward policies that drive down GHG emissions. Concurrently, new technologies like hydraulic fracturing have unlocked gas from shale and existing conventional supplies, providing the U.S. with natural gas sufficient for approximately 100 years at current rates of consumption.[2] NW Natural therefore expects to see a focus on policies that will drive the use of natural gas into sectors where the fuel can both save customers money and drive down net GHG emissions (i.e., by using natural gas to replace higher carbon-intensity fuels such as oil used to heat homes and fuel factories, and gasoline and diesel used in the transportation sector). Secondly, because methane is a potent GHG, and because a future price on CO_2 (carbon) emissions is likely, it is crucial that the Company continues to reduce methane emissions and explore other ways to mitigate GHG emissions to the greatest extent possible.

The first part of this chapter provides an overview of policies targeting greenhouse gas emissions. The second part provides NW Natural's analysis of the impact on the Company's resource plan of a carbon price on combustible fuels, including natural gas.

---

[1] This report can be found on NW Natural's website at https://www.nwnatural.com/Content/CommunityReport/2013/

A. Criteria Pollutants, Greenhouse Gases and Carbon Equivalency

1. Criteria pollutants

Emissions from natural gas combustion include nitrogen oxides (NOx), carbon monoxide (CO), carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), volatile organic compounds (VOCs), trace amounts of sulfur dioxide (SO_2), and particulate matter (PM). Combustion of natural gas emits lower quantities of greenhouse gases and criteria pollutants per unit of energy produced when compared with other fossil fuels because natural gas is more easily fully combusted, and in part because natural gas contains fewer impurities than any other fossil fuel.[3] Because emissions of criteria pollutants are low and largely regulated by the efficiency of the appliance, this chapter focuses on greenhouse gas emissions from natural gas combustion.

2. Greenhouse gases and carbon dioxide equivalencies

As Table 5.1 (following) illustrates, the carbon content of natural gas is relatively low compared to other fuel types, on a CO_2/Btu basis.

Table 5.1 – Carbon Dioxide Emissions Coefficients

	Pounds CO_2 per Million Btu
For homes and businesses	
Propane	139.0
Home Heating and Diesel Fuel	161.3
Coal (All types)	210.2
Natural Gas	117.0
Gasoline	157.2

Typically, nearly all of the fuel carbon (99.9 percent) in natural gas is converted to CO_2 during the combustion process. However, CO_2, CH_4, and N_2O are emitted in small quantities during combustion; these are greenhouse gases that have internationally-accepted carbon dioxide equivalencies. Table 5.2 (following), using data from the U.S. Environmental Protection Agency (EPA) and the Intergovernmental Panel on Climate Change (IPCC), illustrates carbon equivalencies for each greenhouse gas.[4]

3 See at http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/natural_gas_1998_issues_trends/pdf/chapter2.pdf .

4 http://www.epa.gov/climateleadership/documents/emission-factors.pdf .

Table 5.2 – Carbon Equivalencies of Greenhouse Gas Emissions

Greenhouse Gas	Chemical Formula	Carbon Equivalency (CO_2e)
Carbon Dioxide	CO_2	1
Methane	CH_4	21 – 25
Nitrous oxide	N_2O	298
Hydrofluerocarbons	HFCs	150 – 11,700
Sulphur hexafluoride	SF_6	23,900
Perfluorocarbons	CFs	6,500 – 8,700

II. STATE, REGIONAL, AND FEDERAL ENERGY POLICIES

A. State

1. Oregon Energy Policy

Policies in Oregon are evolving to clarify the future role of natural gas. The Governor's 10-Year Energy Action Plan[5] (published in December 2012) sets out a high level vision for the use of natural gas in the state over the next decade. The 2013 legislative session provided additional policy direction with passage of Senate Bill (SB) 844, which provides incentives for natural gas utilities to implement projects that reduce GHG emissions. SB 844 provides an opportunity for NW Natural and other gas utilities in Oregon to survey ways they might voluntarily contribute to the state meeting its carbon reduction goals.

Though rulemaking to implement SB 844 is not yet finalized, the Company is beginning to explore options for projects that concentrate on using natural gas to displace higher carbon fuels (such as oil), using gas as efficiently as possible (where standard efficiency programs leave off), and finding ways to best use renewable natural gas to reduce GHG emissions. These possible projects may lead the way in helping Oregon develop a new and evolving vision for the use of abundant natural gas and, over time, integrating renewable natural gas into this system.

Additionally, NW Natural is monitoring a study underway that analyzes the effects of a carbon tax with the results due back to the legislature in time for the 2015 session.

2. Washington Energy Policy

Washington passed legislation establishing a Climate Workgroup that was charged with developing recommendations and submitting them to the legislature. NW Natural is monitoring this ongoing policy work. The workgroup was not able to reach agreement, but issued a report with competing recommendations that includes:

- A binding cap on carbon emissions that focuses on larger emission sectors such as transportation, buildings and electricity;
- Measures to reduce the State's use of electricity generated by coal-powered facilities in other states;
- An energy smart building program to include promotion of new financing, incentives and support systems;

[5] See, e.g., at http://www.oregon.gov/energy/pages/ten_year/ten_year_energy_plan.aspx (accessed April 28, 2014).

- Finance dedicated and sustained funding for the State's research institutions, utilities and businesses to develop, demonstrate and deploy new renewable energy and energy-efficiency technologies;
- Work towards modernizing the State's transportation of goods and people by promoting clean cars, and accelerating the use of cleaner fuels, and also improving how it plans and funds its transportation system to incorporate climate change considerations and to better connect land use and transportation plans.

B. Regional Energy Policy

On a regional level, the governors of Oregon, Washington, California, and the Premier of British Columbia have signed a climate change agreement known as the Pacific Coast Collaborative,[6] in which these governments agree to lead national and international policy on climate change with specific actions to:

- Account for the costs of carbon pollution in each jurisdiction.
- Harmonize 2050 targets for greenhouse gas reductions and develop mid-term targets needed to support long-term reduction goals.
- Affirm the need to inform policy with findings from climate science.
- Cooperate with national and sub-national governments around the world to press for an international agreement on climate change in 2015.
- Enlist support for research on ocean acidification and take action to combat it.

C. Federal Energy Policy

Federal policy on pricing carbon is largely stalled and NW Natural does not expect movement in the near future. The Obama administration is instead using regulatory channels to mitigate greenhouse gas emissions. In early June, 2014, the EPA published a draft of Section 111(d), a state-based program for existing electricity generating sources. It establishes guidelines and the states then must design programs that follow the guidelines to achieve specified reductions. DEQ is the lead agency and is tasked with writing the plan for Oregon, but it is working closely with the Public Utility Commission of Oregon and the Oregon Department of Energy to determine Oregon's path forward. DEQ is currently working to understand what the rule means and how it will apply to Oregon. These agencies will be generating comments and questions to submit to EPA by the October 2014 comment deadline.

Oregon is required to reduce GHG emissions from power plants by 48 percent by 2030. Oregon is currently among the most efficient states when it comes to electricity generation and it should be noted that EPA is considering generation within each state's borders. As such, coal emissions generated as a result of energy imports from Utah, Wyoming and Montana do not count towards Oregon's emission inventory.

Because the rule is still in draft form, the state's compliance path is ambiguous and will likely remain unclear until the rule is finalized. It seems clear at this early phase of development that these

---

6 See at http://www.pacificcoastcollaborative.org/Documents/Pacific%20Coast%20Climate%20Action%20Plan.pdf (accessed April 30, 2014).

regulations will impact Portland General Electric (PGE) and PacifiCorp, and therefore may have a tangential impact on NW Natural. For instance, depending on where and how PGE and PacifiCorp replace their coal resources, Oregon's natural gas pipeline capacity could be impacted. Or, if electricity prices increase, direct use of natural gas could be more attractive. Additionally, it's possible that a national movement towards natural gas electricity generation could impact national natural gas prices.

Ultimately, it's too early to know in what ways and to what degree this nascent regulation will impact NW Natural. As the discussions move forward nationally and in Oregon, NW Natural will pay close attention and engage in the process where appropriate and applicable.

It is worthwhile noting that the shale gas revolution has focused the attention of state and federal policy makers on the environmental impacts of natural gas production. Additionally, there is an increased focus on methane emissions from the natural gas supply chain—from production through distribution—to ensure that using natural gas to displace more carbon-intensive fuels has a net benefit with respect to GHG emissions. Though upstream emissions from production are not within the Company's business, NW Natural is participating in multiple national studies to get at these very important questions. Based on administration numbers, 31 percent of methane emissions come from production, 15 percent from processing, 34 percent from transmission and storage, and 20 percent from distribution. According to the most recent EPA inventory of GHG emissions - released in April, 2014 - only 0.24 percent of produced natural gas is emitted from the delivery system.

By far the biggest driver of this number is the modernization of pipeline—replacing older pipe made of cast iron and bare steel with more modern coated steel and poly pipe. With the support of the PUC, the Company has compressed its schedule for pipeline modernization. The Company completed its cast iron replacement in 2000 and has less than ten miles of bare steel remaining. This is scheduled for replacement before the end of 2015.

Because the majority of emissions come from upstream of the LDC, the Company is looking for ways to partner and/or drive emissions reductions upstream. For example, a large blow down of a 20-inch pipe was planned by the Company's transmission partner. The transmission company could lower the pressure on its pipe from 650 psi to 350 psi but not any lower. However, NW Natural's gas control group was able to help bring the pressure down to 100 psi. This simple coordination across companies saved enough gas to serve the daily needs of 10,000 homes, not to mention avoiding significant methane emissions that would have otherwise been emitted into the atmosphere.

As a local distribution company (LDC), the Company believes it has a critical role in understanding upstream production practices, sharing information with stakeholders regarding these practices and, where possible, influencing a move towards best practices all along the gas value chain. It is also the Company's belief that NW Natural customers expect it to drive best management practices in its own business and all the way through the value chain. NW Natural's early efforts to explore possible gas certification based on production practices is one such effort to lead the way on impacting upstream practices. The Company currently is partnering with the Natural Resources Defense Council (NRDC) on this effort to develop and then potentially test a pilot to certify natural gas that meets a standard of best practices. Besides this work, the Company is engaging with producers and others to better define current practices from its gas producers and sharing this information with stakeholders. This effort to improve transparency is a critical first step towards influencing practices upstream. If successful, the Company would bring any effort to pilot a certification program to the Commission for review.

III. ANALYSIS OF CARBON PRICES

A. Base Case Forecast

NW Natural's analysis of potential future CO_2 emissions (carbon) prices concludes that a carbon tax[7] of up to $60 per metric ton of carbon dioxide equivalent ($MTCO_2e$) will have minimal impact on the Company's resource portfolio planning over the planning horizon given what is known today. The primary impact is to delay acquisition of certain resources. Sensitivities involving Firm Sales load requirements from Emerging Markets show minimal impact for the Medium or High Emerging Markets scenarios as compared with the Low Emerging Markets scenario embedded in the Base Case forecast.

NW Natural's Base Case forecast includes a price on carbon as the natural gas price forecast embedded in the Base Case forecast includes, on a supply basin spot price basis, a price associated with the carbon content of natural gas. NW Natural believes this forecast represents the most likely regulatory compliance future[8] associated with CO_2 emissions.[9] Additionally, the forecast carbon price represents a

---

[7] NW Natural has identified research concluding the most reliable and efficient way to achieve given climate-change objectives is the use of direct taxation or regulatory policies which create a market price for CO_2 and other greenhouse gas emissions. See; e.g., page 145 of "Effect of U.S. Tax Policy on Greenhouse Gas Emissions;" William D. Nordhaus, et al.; National Academy of Science; 2013 (accessed May 2, 2014 at http://www.infrastructureusa.org/wp-content/uploads/2013/07/18299.pdf). A citation in this chapter to a non-Company source which includes any conclusions, opinions, or policy prescriptions is not *prima facie* indication of NW Natural's concurrence with any such conclusions, opinions, or policy prescriptions.

[8] NW Natural notes that the current regulatory compliance regime for CO_2 emissions has no carbon price and that implementation of a regulatory compliance regime applicable to CO_2 emissions resulting from NW Natural customers' combustion of natural gas delivered by the Company with a positive carbon price within the planning horizon of this IRP is uncertain.

[9] The effect of any future "cap and trade" regulatory apparatus on CO_2 emissions, including those implemented as a jurisdictional response to any new EPA regulations associated with Section 111(d) of the 1963 Federal Clean Air Act, as subsequently amended, is reasonably illustrated as a first approach with the modeling results of a carbon tax.

proxy[10, 11] for potential regulatory compliance futures related to emissions of greenhouse gases (GHG) other than CO_2; including methane, nitrous oxides, sulfur oxides, and mercury.[12, 13]

NW Natural considers, for purposes of IRP scenario development and analysis, a carbon price as a Pigovian tax[14] on the carbon content of combustible fuels implemented on a national or broad regional basis and similar in implementation to that currently in effect in British Columbia, Canada; i.e., a "…broad-based tax that applies to the purchase or use of fuels, such as gasoline, diesel, natural gas, heating oil, propane and coal, and the use of combustibles, such as peat and tires, when used to produce heat or energy."[15] NW Natural assumes "upstream" measurement and taxation, with the cost of purchased gas therefore including the carbon price.[16] In other words, the carbon tax is paid by the purchaser, and NW Natural pays the carbon tax simultaneous with payment for the natural gas the

---

10 As discussed above, combustion of natural gas produces carbon dioxide (CO_2) and nitrous oxides (N_2O). Leakage of natural gas into the atmosphere—which may occur during production, storage, or transportation of natural gas, as well as a result of incomplete natural gas combustion—releases methane (CH_4). Emissions of sulfur dioxide (SO_2) and mercury compounds from combustion of natural gas are negligible according to the U.S. Environmental Protection Agency (EPA). See; e.g., http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html (accessed April 28, 2014).

11 See; e.g., Annex 6.1 at A-384 of EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011 (2013) at http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Annexes.pdf (accessed April 30, 2014). The global warming potential (GWP) of greenhouse gases other than CO_2 can be expressed in terms of CO_2 equivalence for specified timeframes. See also Chapter Eight of the Intergovernmental Planning on Climate Change's (IPCC) Fifth Assessment Report (2013) at http://www.climatechange2013.org/images/report/WG1AR5_Chapter08_FINAL.pdf (accessed April 30, 2014).

12 The third party-provided natural gas price forecast the Company uses in its 2014 IRP includes a carbon price forecast and does not include any price forecasts associated with other greenhouse gases.

13 See the preceding discussion regarding CO_2 equivalencies for other greenhouse gases.

14 A Pigovian tax is a tax applied to a market activity which generates a negative externality (a cost to one or more third parties). For a market activity having a negative externality, the activity's social cost is greater than its private cost. In such a case, the market outcome is not efficient and may lead to over-consumption of the product. See; e.g., the definition at http://en.wikipedia.org/wiki/Pigovian_tax (accessed May 1, 2014); "Arthur Cecil Pigou," *The Concise Encyclopedia of Economics.* 2008. Library of Economics and Liberty. 14; accessed March 14, 2014 at http://www.econlib.org/library/Enc/bios/Pigou.html ; "A Carbon Fee [Tax] That America Could Live With" [*sic*] by N. Gregory Mankiw, appearing September 1, 2013 on page BU4 of the printed New York edition of *The New York Times* (accessed May 2, 2014 at http://www.nytimes.com/2013/09/01/business/a-carbon-tax-that-america-could-live-with.html?smid=pl-share&_r=1&); and "Smart Taxes: An Open Invitation to Join the Pigou Club" by N. Gregory Mankiw at pages 14 – 23 of the Eastern Economic Journal, 2009, 35 (accessed May 2, 2014 at http://scholar.harvard.edu/files/mankiw/files/smart_taxes.pdf).

15 See; e.g., the Tax Bulletin issued in revised form by the British Columbia Ministry of Finance in June, 2013 at http://www.sbr.gov.bc.ca/documents_library/bulletins/mft-ct_005.pdf (accessed February 13, 2014).

16 NW Natural does not assume any impact on the price of natural gas *per se* as a result of a carbon price, as any such impact is presumably incorporated within the associated gas price forecasts embedded in the Base Case forecast. The Company cannot at this time specify with certainty the direction of change in the price of natural gas *per se* resulting from imposition of a carbon price.

Company purchases for delivery to its customers. NW Natural also assumes for modeling purposes the amount of tax paid is incorporated within the annually filed purchased gas adjustment (PGA) mechanisms and "flows through" on a per therm basis to both firm sales and interruptible sales ratepayers in a manner similar to other costs associated with purchased natural gas.

IHS CERA's natural gas price forecast,[17] which NW Natural uses as the Company's primary forecast of natural gas prices, incorporates a carbon price[18] beginning in 2021 at a level of $8.78 per metric ton of carbon dioxide equivalent ($MTCO_2e$) and increasing annually to $15.01 per $MTCO_2e$ in 2032 (both prices in $2013).[19] These dollar values per $MTCO_2e$ equate to $0.05 and $0.08 per therm,[20] respectively (both values in $2013 and rounded to two decimal places). Figures 5.1 and 5.2 (following) illustrate the levels and timing of the carbon price in NW Natural's Base Case forecast, with the two figures showing the same carbon price(s) expressed in two different quantities.

---

17 Source: IHS Inc. This content is extracted from IHS Energy North America Natural 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 ~~a~~ without written permission by IHS. Copyright (2013), all rights reserved.

18 NW Natural understands the forecasted natural gas prices inclusive of a carbon tax to therefore incorporate the effect of the carbon price on the underlying price of natural gas.

19 NW Natural's 2014 IRP assumes an annual rate of inflation over the planning horizon, as measured by the GDP deflator, of 1.9 percent.

20 This conversion from a carbon price per $MTCO_2e$ to a carbon price per therm of natural gas is based on 1.0 MMBtu equaling 10 therms of natural gas and approximately 0.0053 $MTCO_2e$ per therm of natural gas. See the EPA website, accessed February 13, 2014, at http://www.epa.gov/cleanenergy/energy-resources/refs.html .

Figure 5.1 – Base Case Forecast Carbon Price per $MTCO_2e$

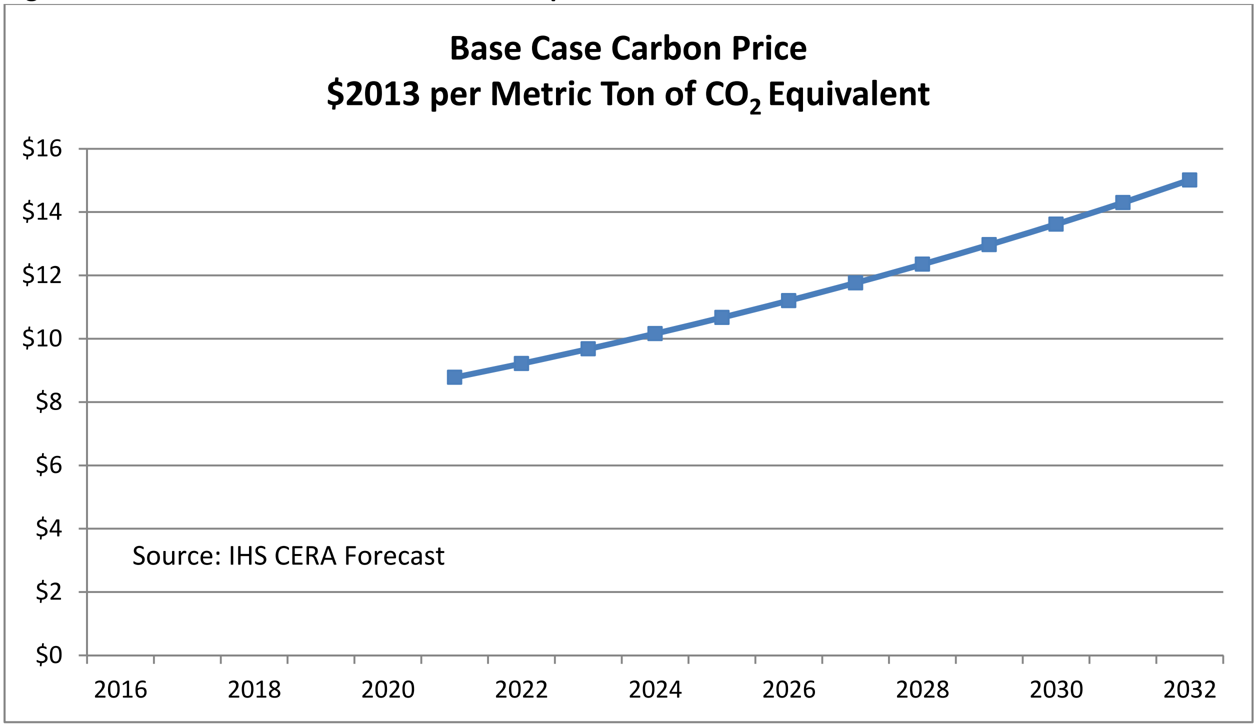
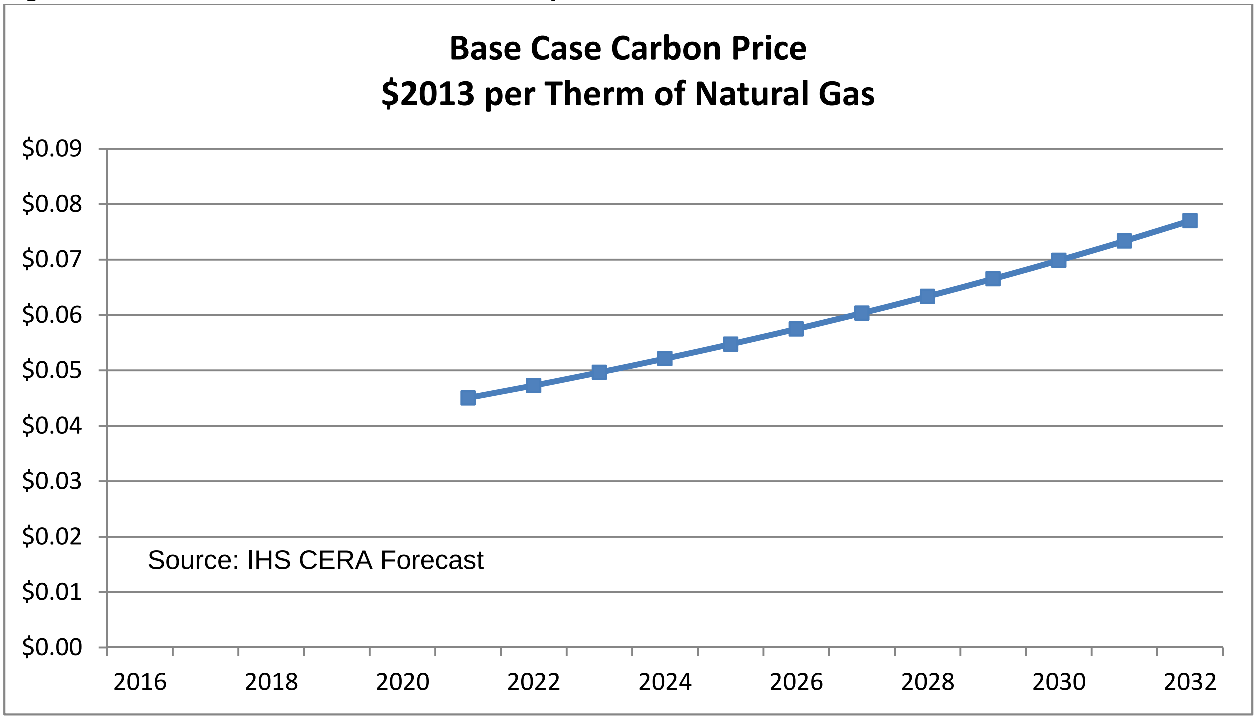


Figure 5.2 – Base Case Forecast Carbon Price per Therm of Natural Gas



One implication of a carbon price embedded within the natural gas price forecast is the de facto inclusion of the impact of fuel substitution resulting from the higher effective cost of combusting a fossil fuel—including potential increases in demand for natural gas, such as by electricity generators—on future natural gas prices. The EPA proposed the Clean Power Plan to cut carbon emissions from existing power plants on June 2, 2014. NW Natural's understanding of EPA's proposed rule based on a preliminary review is that it estimates a maximum impact "…attributable to policy-induced changes in overall power sector demand" on projected average Henry Hub (spot) natural gas real prices of 12.5 percent in 2020.[21] This maximum estimate is not dissimilar in magnitude to the projected *minimum* carbon tax in NW Natural's Base Case natural gas price forecast of between four and five cents per therm expressed as a percentage of the underlying natural gas price. See Figure 5.2 and, in Chapter Two, Figure 2.17.[22]

B. Alternative Carbon Price Scenarios

NW Natural complies with the Public Utility Commission of Oregon's IRP Guideline 8[23] in part by including the effect of a carbon price in the Company's Base Case forecast as discussed above. NW Natural also considered two additional carbon prices, assessing the differential resource requirements as compared with those of the Base Case forecast. Incorporating feedback from participants in its Technical Working Group (TWG) meetings and a November 22, 2013 workshop on IRP scenarios, the Company examined the impact of two carbon price paths that are generally higher and are implemented earlier than the carbon price in the Base Case forecast. Notwithstanding that NW Natural considers the Base Case forecast's carbon price to represent the "most likely regulatory compliance future for carbon dioxide,"[24] the Company describes the two alternative carbon price paths as a Medium carbon price and a High carbon price (and the Base Case forecast's carbon price as a Low carbon price).

The Medium carbon price sensitivity uses carbon prices based on the "$20 in 2020" path of carbon prices estimated by the Economic and Allocation Advisory Committee (EAAC)[25] of California's

---

21 See Table 3-19 on page 3-38 of EPA's "Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants;" dated June 2014 (accessed August 4, 2014 at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf).

22 Figure 2.17 shows Henry Hub spot prices in nominal terms. IHS/CERA's forecast of 2020 Henry Hub spot prices is an average $3.82 ($2012). A carbon tax equivalent to approximately $0.50 per MMBtu ($2013, see Figure 5.3) is 14.7 percent of a $3.89 per MMBtu price ($2013) equivalent result of applying NW Natural's assumed 1.9 percent annual rate of inflation, less the $0.50 per MMBtu tax.

23 See page 1 of Appendix C to the Public Utility Commission of Oregon's Order No. 08-339 in Docket No. UM 1302.

24 Ibid.

25 See; e.g., Exhibit 5 of the October 20, 2009 memorandum from Cal/EPA and the EAAC Policy Team to EAAC members regarding estimated allowance values at http://www.climatechange.ca.gov/eaac/documents/state_reports/Allowance_Prices--Memo_from_State_Staff.pdf (accessed April 30, 2014) and pages 31 – 32 of the EAAC's March 2010 "Allocating Emissions Allowances Under a California Cap-and-Trade Program" at http://www.climatechange.ca.gov/eaac/documents/eaac_reports/2010-03-22_EAAC_Allocation_Report_Final.pdf (accessed April 30, 2014).

Environmental Protection Agency and its Air Resource Board, which is associated with that state's Global Warming Solutions Act of 2006. This legislation is also known as Assembly Bill 32 (AB 32). NW Natural uses nominal prices estimated by the EAAC, with an initial (nominal) price of $12.54 per MT$CO_2$e and increasing at an annual rate of six percent. NW Natural models this carbon price path as beginning in 2016,[26] with the six percent annual increase occurring throughout the remainder of the planning horizon. The Medium carbon price scenario reaches a nominal $20 per MT$CO_2$e in 2024. NW Natural refers to the Medium carbon price sensitivity as the "California AB 32" (or "AB 32") carbon price.

NW Natural also analyzes the impact of a carbon tax implemented in 2016 at $10 per MT$CO_2$e and increasing by $10 annually to a maximum of $60 in 2021 (both values in nominal terms). This High carbon price sensitivity has a carbon price path based on that included in the March 1, 2013 "Carbon Tax and Shift: How to make it work for Oregon's economy" report delivered to the Oregon legislature.[27] NW Natural refers to the High carbon price sensitivity as the "PSU" carbon price. Figure 5.3 shows the Base Case forecast's carbon price path and the carbon price path in each alternative carbon price in real dollars per therm.[28]

---

26 NW Natural's November 22, 2013 workshop on IRP scenarios resulted in a consensus identification of 2016 as the estimated earliest possible effective beginning date for a carbon price applicable in either Oregon or Washington.

27 Authors of the report are Jenny Liu and Jeff Renfro of the Northwest Economic Research Center (NERC), which is associated with Portland State University's College of Urban and Public Affairs. See the report at http://www.pdx.edu/nerc/sites/www.pdx.edu.nerc/files/carbontax2013.pdf (accessed April 30, 2014). NW Natural understands the carbon prices in the report to be per MTCO_2e and to be stated in nominal terms.

28 NW Natural performs its 2014 IRP modeling in real terms and expresses dollar amounts in $2013.

Figure 5.3 – Carbon Price Scenarios in $2013 per Therm

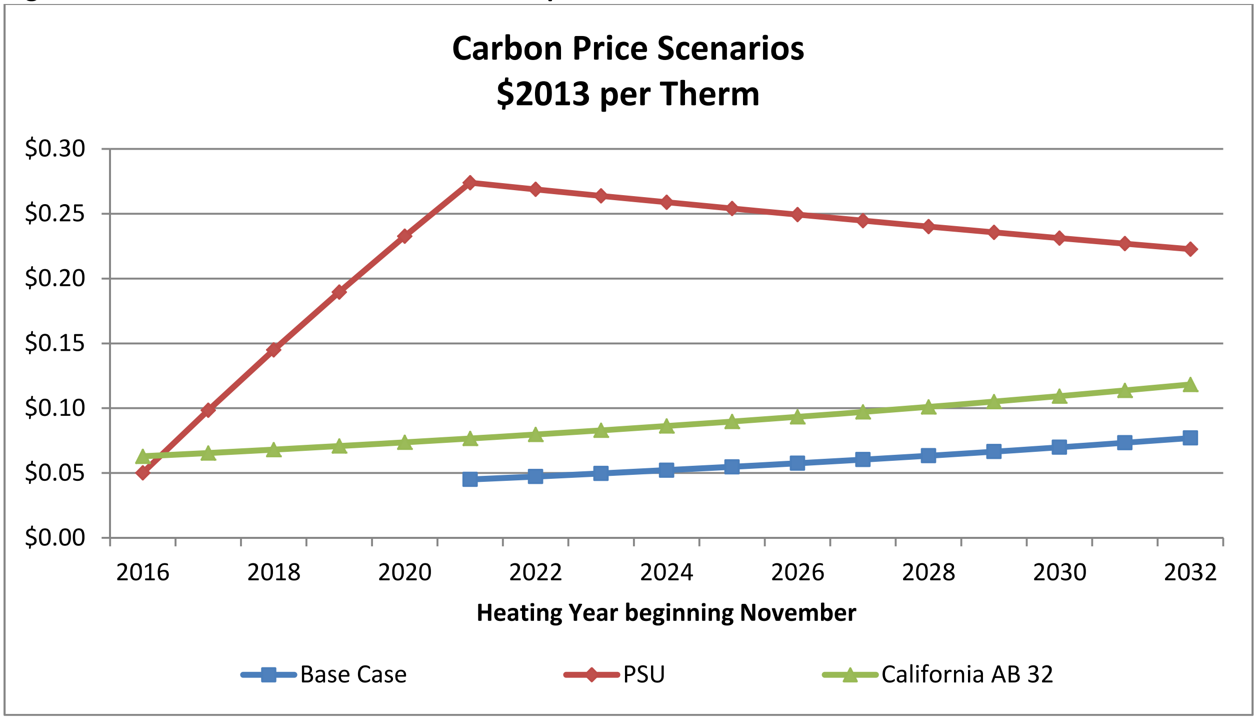
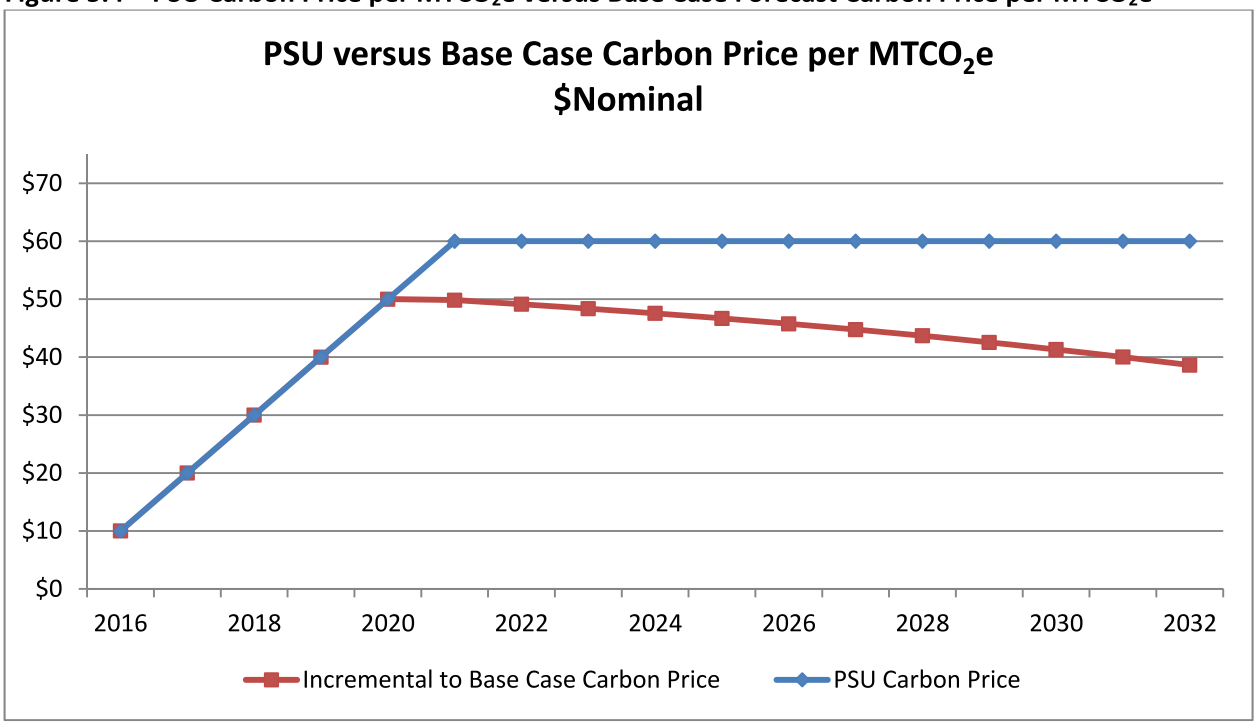


Table 5.4 shows the estimated average annual carbon tax paid by Residential and Commercial customers in the year of implementation and in the last year of the planning horizon under the Base Case forecast and PSU carbon prices. Figure 5.4 shows the nominal price per MTCO2e for the PSU carbon price as well as the difference between this price path and that of the Base Case forecast and Figure 5.5 shows the price in $2013 per therm and the difference from the Base Case forecast.

Table 5.3 – Average Annual Amounts of Carbon Tax per Customer: Base Case Forecast and PSU Carbon Price

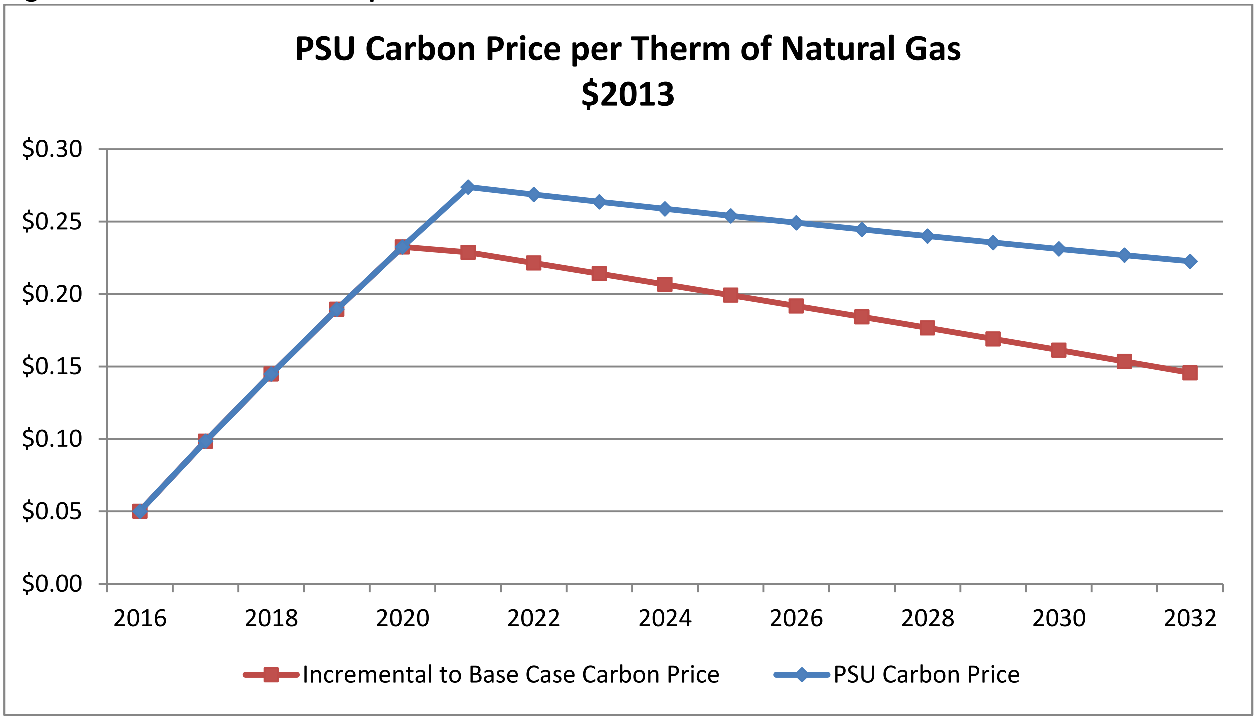
	Average Annual Therm Use per Customer[29]	2021 Base Case	2032 Base Case	2016 PSU	2032 PSU
Oregon					
Residential	636	$28.64	$48.98	$31.89	$141.60
Commercial	3,845	$173.15	$296.12	$192.82	$856.06
Washington					
Residential	664	$29.90	$51.14	$33.30	$147.83
Commercial	3,710	$167.07	$285.72	$186.05	$826.01

Figure 5.4 – PSU Carbon Price per $MTCO_2e$ versus Base Case Forecast Carbon Price per $MTCO_2e$



[29] The Oregon annual average use per customer values are those in NW Natural's October 15, 2013 Oregon Schedule 190 tariff filing. The Washington annual average use per customer values are those in NW Natural's 2013 – 2014 PGA filing.

Figure 5.5 – PSU Carbon Price per Therm of Natural Gas in $2013



C. Analysis

NW Natural's analysis of the two carbon price scenarios decomposes changes from the Base Case forecast in design day peak demand and annual load into two components. The first is a very conservative "own price elastic[30] response" that the Company views as encompassing all incremental demand-side management reduction in natural gas usage resulting from implementation of a carbon price at the respective levels, as well as reduction in usage levels for all other reasons related to the standalone change in the price of delivered natural gas. While NW Natural considers implementing a carbon tax on combustible fuels will result in increased effective prices paid for most—if not all—goods and services, this approach is conservative by virtue of not including any substitution effects.[31, 32] For

---

30 "Own" price elasticity is the commonly referenced price elasticity; i.e., relating the change in volume of a good or service to a change in price of that same good or service. This differs from "cross price elasticity," which relates the change in volume to the change in the price of some other good or service; i.e., cross price elasticity may be thought of as a measure of the "substitutability" of the first good or service for the second. Hereafter in this chapter, "own" is omitted when referring to "own price elasticity." See also the following footnote.

31 An example of a substitution effect is any change in natural gas volumes as a result of changes in the *relative* effective prices of alternative heating fuels and technologies following imposition of a carbon price. While increased deployment of DSM programs can be considered alternative resources, NW Natural takes the position that the measures of (own) price elasticities the Company uses in the analysis incorporate this specific type of substitution; i.e., "substitution" by using less natural gas.

32 The Base Case natural gas price forecast includes, as previously discussed, a carbon tax. Therefore the Base Case natural gas price forecast includes the impact on natural gas prices as a result of this carbon tax. In other

this component of change, it is as if NW Natural's price of delivered natural gas—which includes the carbon tax—is the only price that increases.[33]

The second component of change is to shift, at the 2016 contemplated year of imposition of a carbon tax in the PSU Carbon Price scenario, from the design day peak demand and annual load values in the Low Emerging Markets Case, which levels are embedded into the Base Case forecast, to those in the High Emerging Markets scenario discussed in Chapter Two. This component might be thought of as including some very limited substitution effects.[34] The difference between the Base Case forecast ("Low") level and the PSU carbon price ("High") level of Emerging Markets Firm Sales as shown in Figure 5.6 is approximately four thousand dekatherms in terms of design day peak demand in the heating year beginning November 2032. This compares with NW Natural's total Firm Sales design day peak demand in the same heating year of approximately 1.2 million dekatherms. In other words, the impact of the High (or Medium) Emerging Markets Firm Sales design day peak demand level and that embedded in the Base Case forecast is very small relative to the level of total—which includes core—Firm Sales.

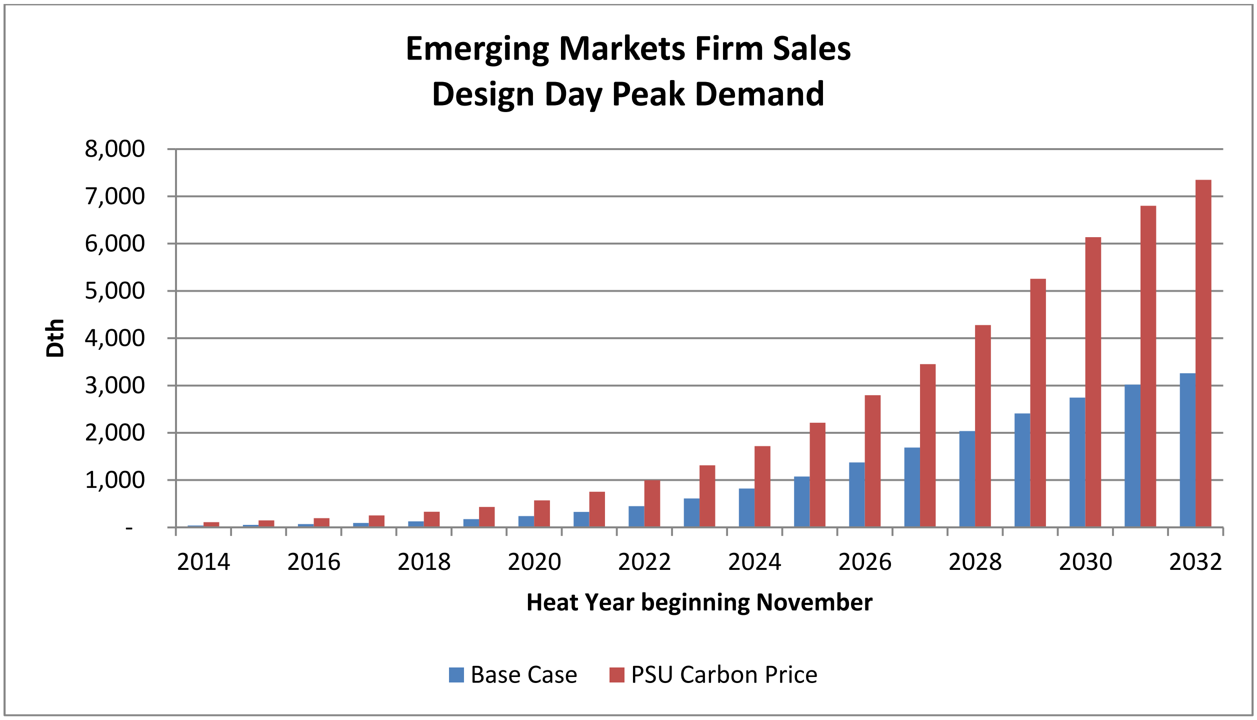
---

words, the impact of fuel substitution on natural gas prices, including substitution of natural gas from more carbon intensive technologies by electricity generators, as a result of a carbon tax is incorporated in the Base Case natural gas price forecast.

33 NW Natural notes that this perspective also does not consider any income effects and that the current British Columbia carbon tax is "revenue neutral" (and therefore "income neutral" in a collective sense). See; e.g., page 5 of "Carbon Tax and Shift: How to make it work for Oregon's Economy;" Jenny H. Liu and Jeff Renfro; 2013.

34 In that existing organizations involved in these Emerging Markets may currently be using a fuel or technology alternative to natural gas and use more natural gas (or become new users) after imposition of a carbon price.

Figure 5.6 – Emerging Markets Firm Sales: Base Case Forecast and PSU Carbon Price Design Day Peak Demand



NW Natural validates the increase in Firm Sales Emerging Market design day peak demand by analyzing the impact of NW Natural's estimated effects of the PSU Carbon Price scenario's carbon tax on the delivered prices of electricity[35] in the Company's service area as well as on the prices of transportation fuels. The real delivered price of electricity represents the estimated electricity prices of a "composite" electric utility composed of Portland General Electric (PGE), Eugene Water & Electric Board (EWEB), and Clark County PUD. NW Natural weights the 2012 average prices of these utilities, obtained from the federal Energy Information Administration (EIA),[36] at 80 percent for PGE and 10 percent for each of the two other utilities, reflecting a rough approximation of respective overlaps in service areas, with EWEB serving as a proxy for other Oregon public power utilities with which NW Natural's service area overlaps.

NW Natural models its delivered prices and those of the electric utilities without incorporating any price increases associated with accommodating growing loads over the planning horizon.[37] NW Natural develops the carbon intensity of delivered electricity using information obtained from the Oregon

---

[35] This delivered price of electricity or natural gas is understood to include the relevant levels of carbon tax.

[36] See EIA's *Electric Sales, Revenue and Average Price* report's Tables 6, 7, and 8, for Residential, Commercial, and Industrial electricity rates, respectively, at http://www.eia.gov/electricity/sales_revenue_price/ (accessed March 13, 2014).

[37] Note that the impacts on natural gas prices of changes in electricity load and of changes in the composition of generating technologies are already incorporated in the Base Case natural gas price forecast.

Department of Energy for PGE[38] and from Clark County PUD's and EWEB's websites.[39] Electricity prices in this scenario increase in 2021 not only as a result of the carbon tax increasing by $10 over the level of 2020, but also as the result of an increase in PGE rates as modeled by NW Natural. PGE's modeled electricity prices, representing 80 percent of the Composite Electric Utility's rates, increase approximately nine percent in 2021 as a result of both complying with Oregon's Renewable Portfolio Standard (RPS) and ceasing coal-fired generation at the Boardman facility ("Boardman")—with each occurring in 2020. In reality, PGE's prices will not increase in one year (2021) between 2012 and 2021 (inclusive), but in more than one year as the utility incorporates new generation facilities for meeting Oregon's RPS into rate base over this timeframe. NW Natural's, PGE's, and Clark County PUD's delivered prices increase over the timeframe due to the increasing carbon tax in this scenario.[40, 41] The modeled prices of EWEB's delivered electricity do not materially increase in real terms due to the very low portion of 2012 electricity supply generated using combustible fuels containing carbon.[42]

NW Natural, in lieu of providing a comprehensive description of this modeling, lists certain additional assumptions below:

- PGE's 2014 loads by customer class are from information supplied in Oregon Docket No. UE 262
- The level of PGE's existing energy from renewable sources is from PGE's draft 2013 IRP
- NW Natural bases incremental revenue requirements on the levelized cost information in EIA's 2013 Annual Energy Outlook (2013 AEO)[43] associated with facilities assumed to begin production in 2018 for the following generic generation technologies: natural gas-fueled combined cycle combustion turbines (CCCT) and wind
- The revenue requirement for Boardman's *incremental* depreciation (and decommissioning cost) is an annualized value based on information in PGE's Advice No. 11-07 in Oregon Docket No. UE 230
- Boardman's fixed Operations and Maintenance (O&M) expense and variable O&M expense per megawatt hour (MWh), including fuel, is from the EIA source cited above for generic generation technologies and represents the associated revenue requirements

---

38 See at http://www.oregon.gov/energy/pages/oregons_electric_power_mix.aspx (accessed March 13, 2014).

39 See EWEB's website at http://www.eweb.org/resources/portfolio (accessed March 13, 2014) and Clark County PUD's at http://www.clarkpublicutilities.com/index.cfm/aboutus/ourpowersupply/fuelmix/ (accessed March 19, 2014). NW Natural adjusted Clark County PUD's supply mix by increasing the amount from the River Road natural gas-fired combined cycle combustion turbine (CCCT) to 37 percent based on information on page 3 of the utility's 2012 IRP at http://www.clarkpublicutilities.com/index.cfm/linkservid/3CFE4A49-FAC3-4B07-911D1B5090FBB58C/showMeta/0/ (accessed March 13, 2014) and reducing the hydro component by an offsetting amount.

40 For NW Natural, these increases are due to the increasing *increment* of the PSU carbon price over the levels of the carbon price in the Base Case forecast through 2020. After 2020, this increment declines (in real terms).

41 PGE prices also increase as result of deploying generation facilities to meet Oregon's 2020 RPS standard and replacing the output from the Boardman coal plant, as discussed above.

42 The percent of EWEB's electricity generated by either natural gas or coal in 2012 is, per the previously cited website, 1.38 percent.

43 See EIA's "Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013;" accessed May 6, 2014 at http://www.eia.gov/forecasts/aeo/er/pdf/electricity_generation.pdf .

- NW Natural bases its estimate of Boardman's energy output available to PGE on information in PGE's draft 2013 IRP
- NW Natural adjusts all costs where necessary to be expressed in real 2013 dollars and therefore comparable to other dollar values used in the Company's analyses
- PGE is the only electric utility of the four included in the analysis changing the composition of generation technologies over the planning horizon and does so only in 2020

Table 5.4 (following) shows NW Natural's "generation math" estimates for PGE.

Table 5.4 — Estimated Changes in PGE Generation Sources (millions of kWh)

2014 load[44]	19,240
Implied 2020 Oregon RPS requirement[45]	3,848
Less: existing renewables[46]	2,155
Equals: RPS deficit (filled with Wind[47])	1,693
Boardman generation[48]	2,724
Less: RPS deficit filled with Wind	1,693
Equals: remaining generation deficit (filled with CCCT)	1, 031

Figure 5.7 shows delivered electricity prices for each electric utility as well as for the Composite Electric Utility by customer class, including prices for both 2013 and 2021 for PGE, Clark County PUD, and the Composite Electric Utility. The carbon content of electricity delivered by EWEB is sufficiently low that an impact on delivered price under a carbon price at this level is indiscernible.

44 From Oregon Docket No. UE 262.

45 This analysis does not assume any losses in transmission and distribution.

46 See page 102 of PGE's draft 2013 IRP.

47 This analysis does not incorporate any requirements for incremental reserves.

48 NW Natural derived this value from information on page 22 of PGE's draft 2013 IRP.

Figure 5.7 – Prices of Delivered Electricity for Regional Electric Utilities

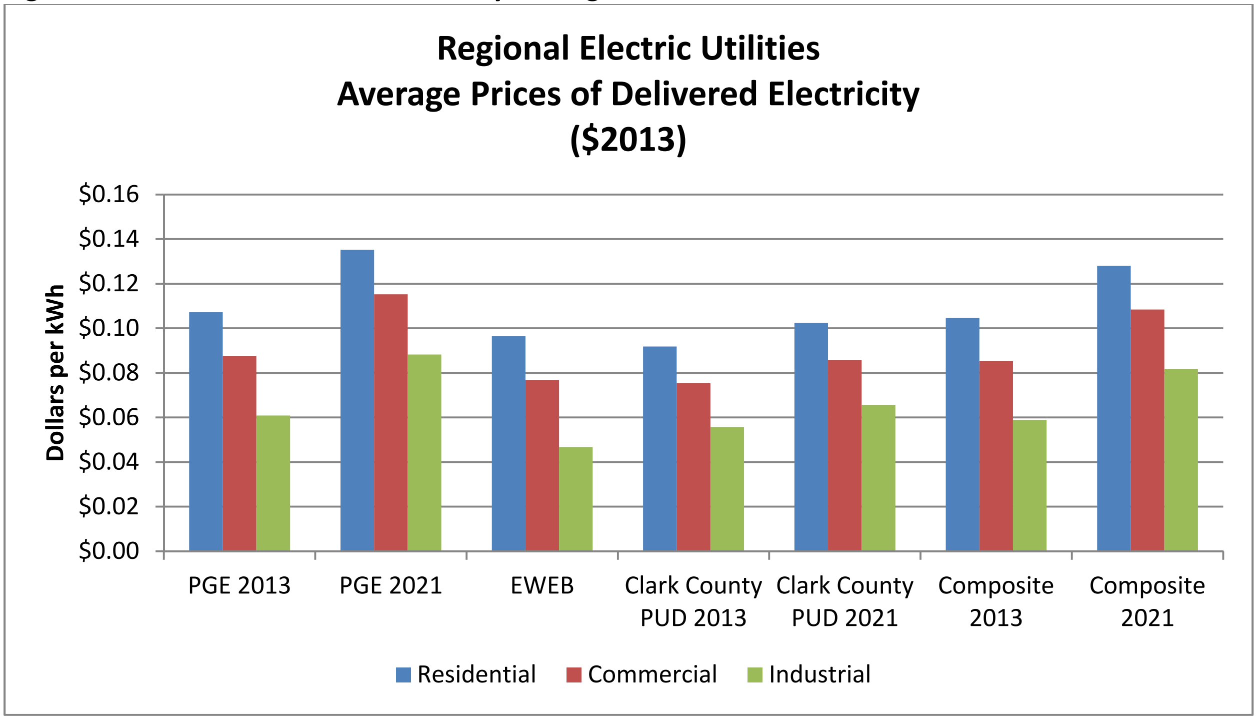
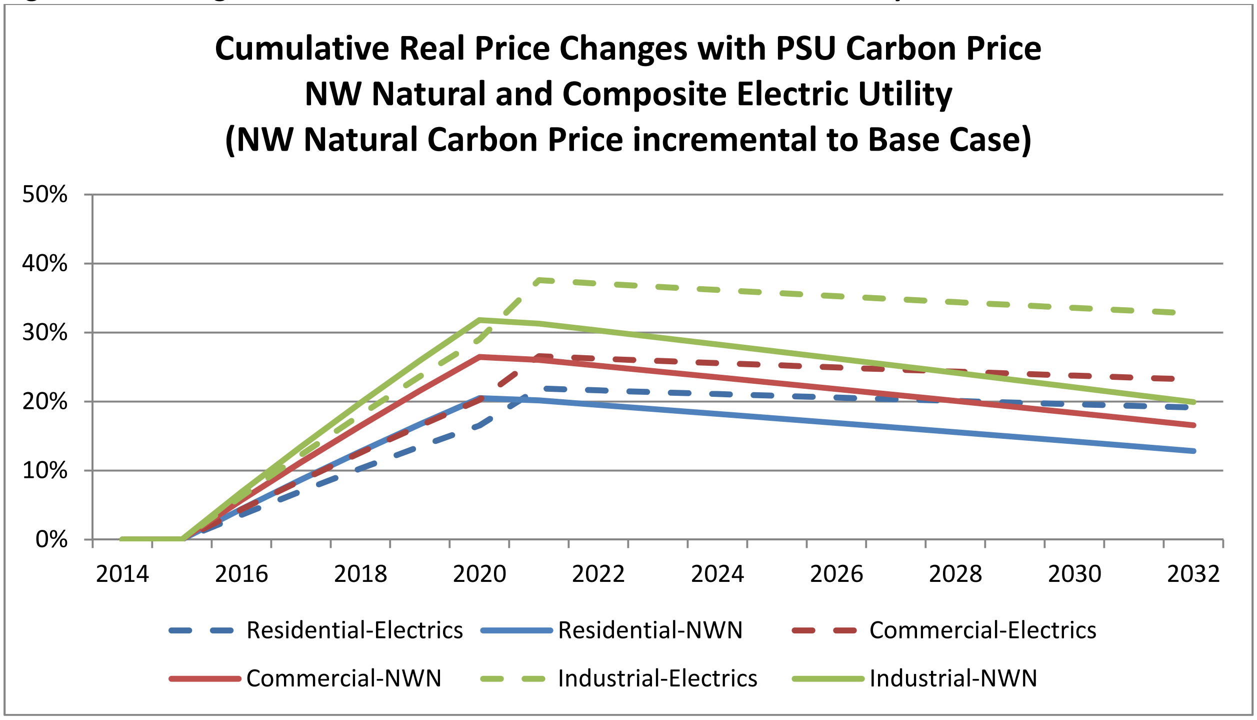


Figure 5.8 depicts changes in NW Natural's price of delivered natural gas and the Composite Electric Utility's price of delivered electricity over the planning horizon for Residential, Commercial, and Industrial customers. [49]

[49] The service territory of NW Natural also overlaps with that of PacifiCorp, To the extent that electricity delivered by PacifiCorp in these overlapping service territories has a greater carbon intensity than that of the Composite Electric Utility, the analysis is conservative in that PacifiCorp's rates would presumably increase by more than those of PGE. In other words, including PacifiCorp would likely increase the rates of the Composite Electric Utility by more than is reflected in this analysis.

Figure 5.8 – Changes in Real Prices of Delivered Natural Gas and Electricity with PSU Carbon Price

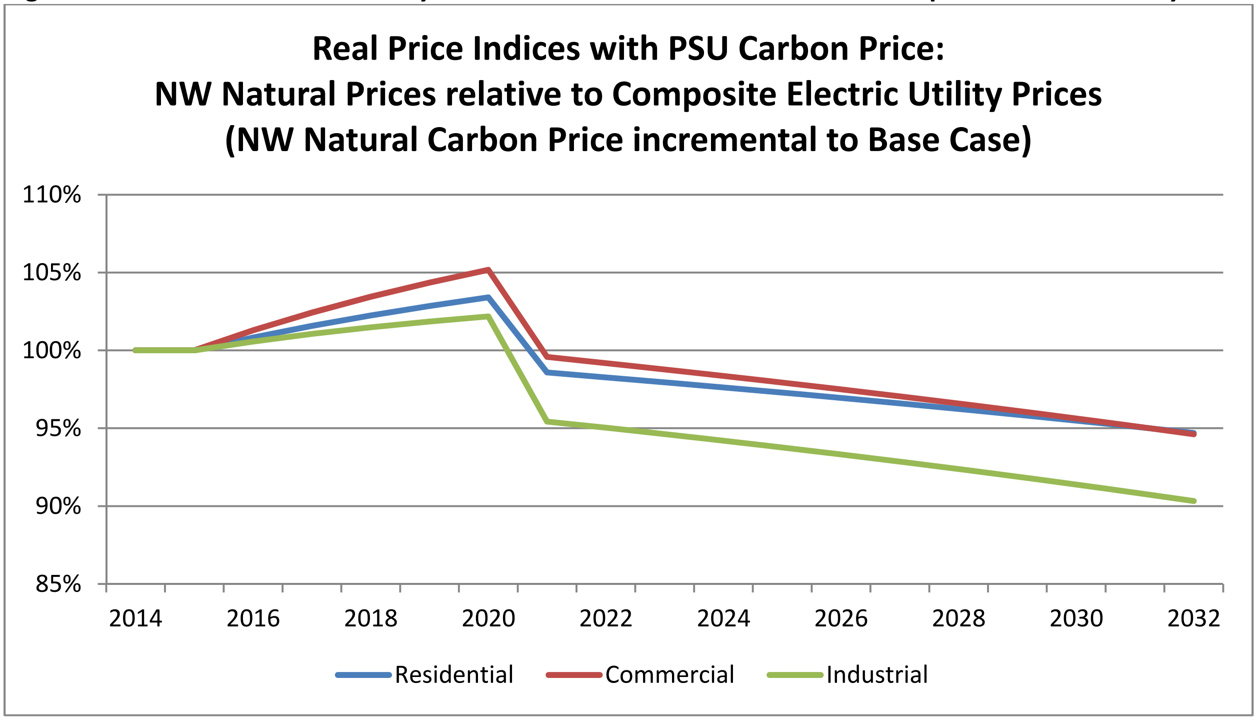


NW Natural's real delivered prices of natural gas increases more quickly in the PSU Carbon Price scenario than do the Composite Electric Utility's prices of delivered electricity from the 2016 year of carbon tax implementation in this scenario through 2020. NW Natural's real delivered prices of natural gas decline relative to the real delivered electricity prices of the Composite Electric Utility after 2020 for each customer category. This is primarily due to the carbon price embedded in the Base Case forecast increasing in real terms over the period 2021 through 2032, while the PSU Carbon Price is flat in nominal terms and declining in real terms over this period.[50] Additionally, and as can be seen in Figure 5.8, NW Natural's real prices of delivered natural gas are lower than the real delivered prices of the Composite Electric Utility relative to 2012 prices in all periods after 2020; i.e., for 2021 through the end of the planning horizon, NW Natural's real delivered prices of natural gas have cumulative increases less than the cumulative increases in the real delivered price of the Composite Electric Utility's electricity. Figure 5.9 shows this more directly; i.e., NW Natural's real prices increase more than those of the Composite Electric Utility prior to 2021 (above 100 percent/positive slope), less in the period after 2020 (negative slope), and also less on a cumulative basis after 2020 (below 100 percent). As mentioned above, PGE's effective delivered real prices will obviously not increase in 2021 and not any prior year in the planning horizon. A more incremental approach to modeling PGE's delivered prices might result in lines in Figure 5.9 that decline (or at least do not increase) every year throughout the planning horizon.

---

[50] Recall the discussion in Section III of Chapter Two regarding NW Natural's delivered prices being essentially flat in real terms over the planning horizon, with the delivered prices including the carbon price embedded in the Base Case forecast. NW Natural assumes the delivered price of the electric utilities incorporated within the Composite Electric Utility—other than the adjustments for PGE discussed above—to be flat in real terms prior to the impact of the PSU carbon price.

Figure 5.9 – Indices of Real Price by Customer Class: NW Natural versus Composite Electric Utility



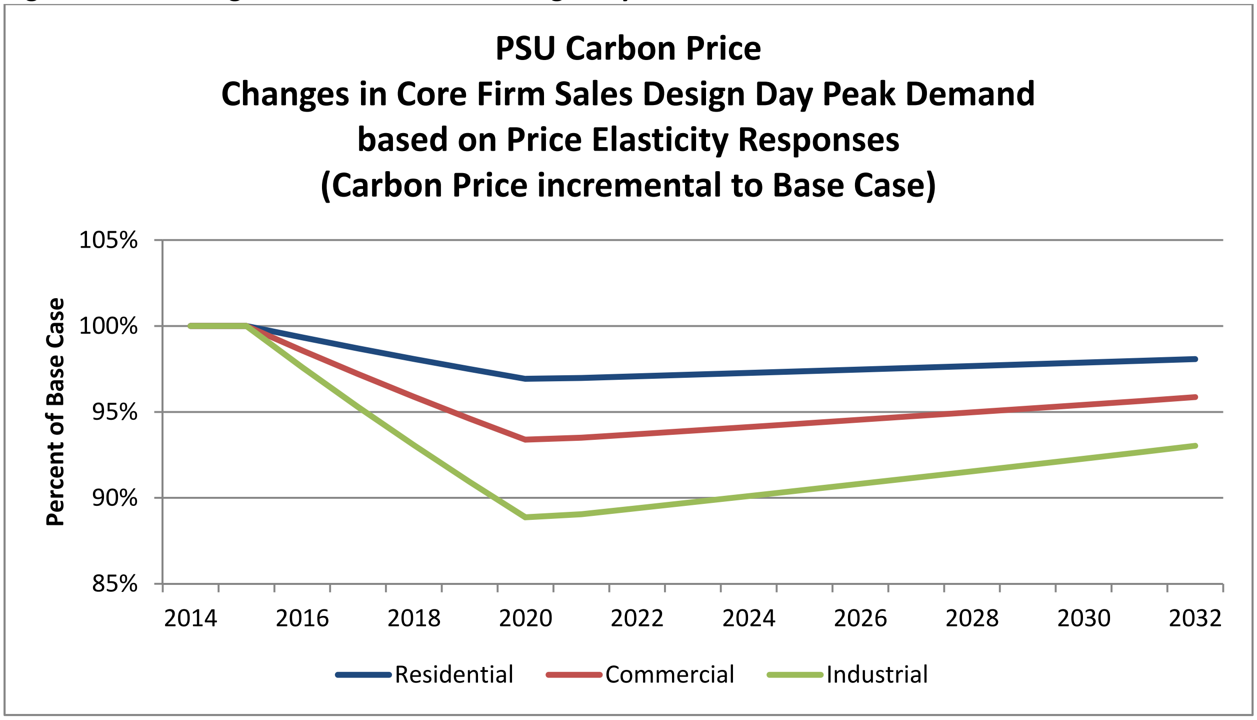
NW Natural models changes in its Firm Sales annual load and design day peak demand resulting from imposition of a carbon tax higher (and earlier) than that in the Base Case forecast by reflecting a price elasticity response to the changing real delivered price due to the PSU carbon price.[51] As NW Natural's Base Case natural gas commodity price forecast used for scenario development and therefore the Company's real delivered price of natural gas does not increase over the planning horizon in the Base Case forecast, the effective change in the real delivered price of natural gas in this scenario is the annual difference between the PSU carbon price and the carbon price embedded in the Base Case delivered natural gas price. NW Natural uses price elasticity of demand parameters of -0.15, -0.25, and -0.35 for, respectively, Residential, Commercial, and Industrial customers.[52, 53] This has the impacts shown in Figure 5.10 on core Firm Sales[54] design day peak demand.

---

51 More precisely, to the positive differential between the PSU carbon price and the carbon price embedded in NW Natural's Base Case forecast. See also the preceding footnote.

52 The values for price elasticity of demand for Residential and Commercial customers are those used by EIA in the agency's National Energy Modeling System (NEMS). See page 32 of EIA's "Assumptions to AEO2013" for Residential natural gas and page 45 for Commercial natural gas at http://www.eia.gov/forecasts/aeo/assumptions/ (accessed May 15, 2014). Note that EIA uses a -0.30 (Residential) and a -0.25 (Commercial; for all major end uses other than refrigeration) price elasticity of demand for *electricity* in the NEMS. This implies the percent reduction as a result of price elasticity in Residential electricity use per customer for a given percentage increase in effective delivered price exceeds the percentage reduction as a result of price elasticity in Residential natural gas use per customer for that same given percentage increase in effective delivered price.

Figure 5.10 – Changes in Core Firm Sales Design Day Peak Demand Due to PSU Carbon Price



A price on the carbon content in combustible fuels impacts more than the delivered prices of natural gas and electricity, as noted above. Figure 5.11 shows relative price changes for motor fuels and alternatives over the planning horizon with implementation of the PSU carbon price and Figure 5.12 shows relative price changes for distillate fuel oil, delivered electricity, and delivered natural gas for Industrial customers with implementation of the PSU carbon price.

---

[53] The value of price elasticity of demand NW Natural uses for Industrial customers is one the Company estimates on an *ad hoc* basis.

[54] Core Firm Sales design day peak demand does not include the Firm Sales design day peak demand associated with Emerging Markets.

Figure 5.11 –Price Changes of Transportation Fuels with PSU Carbon Price

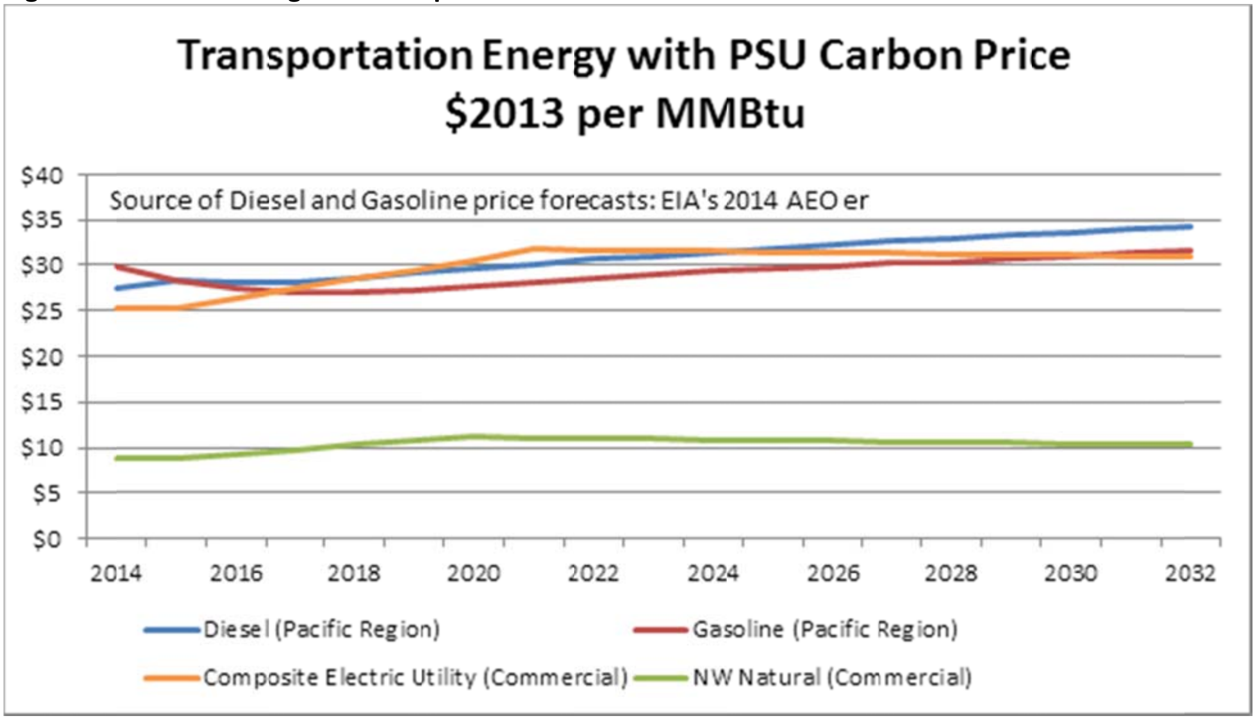
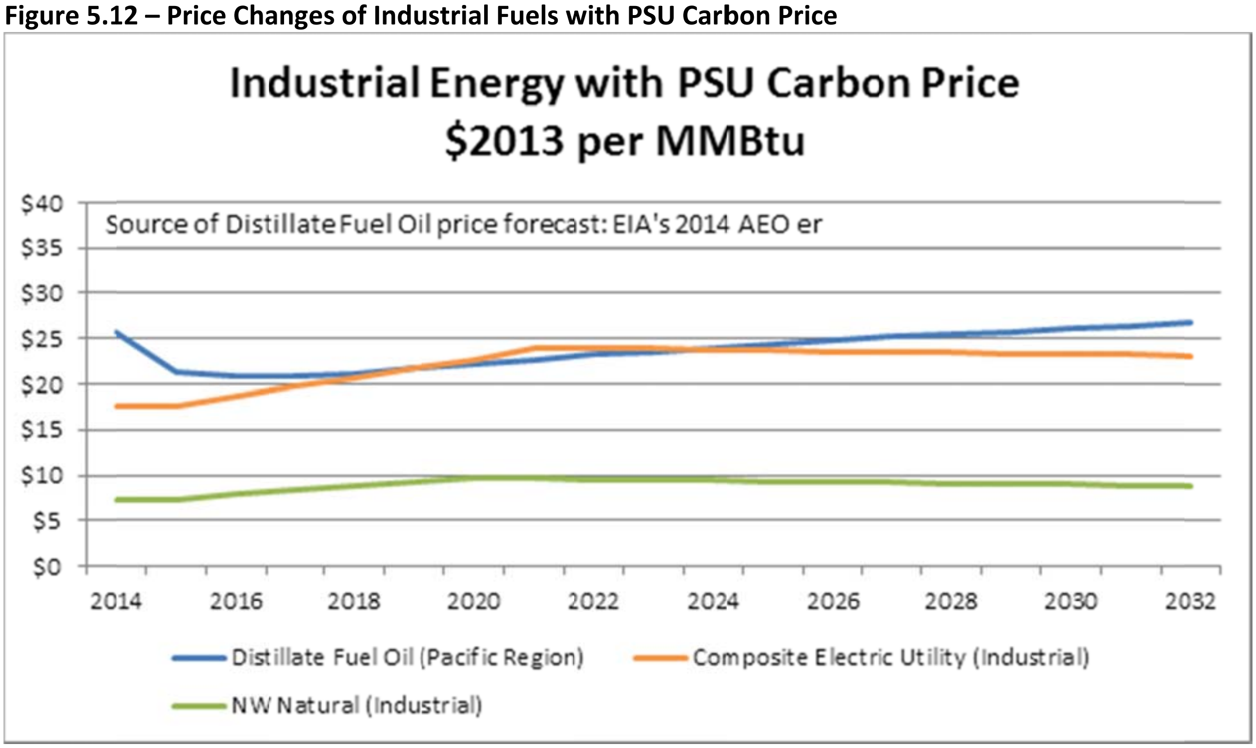
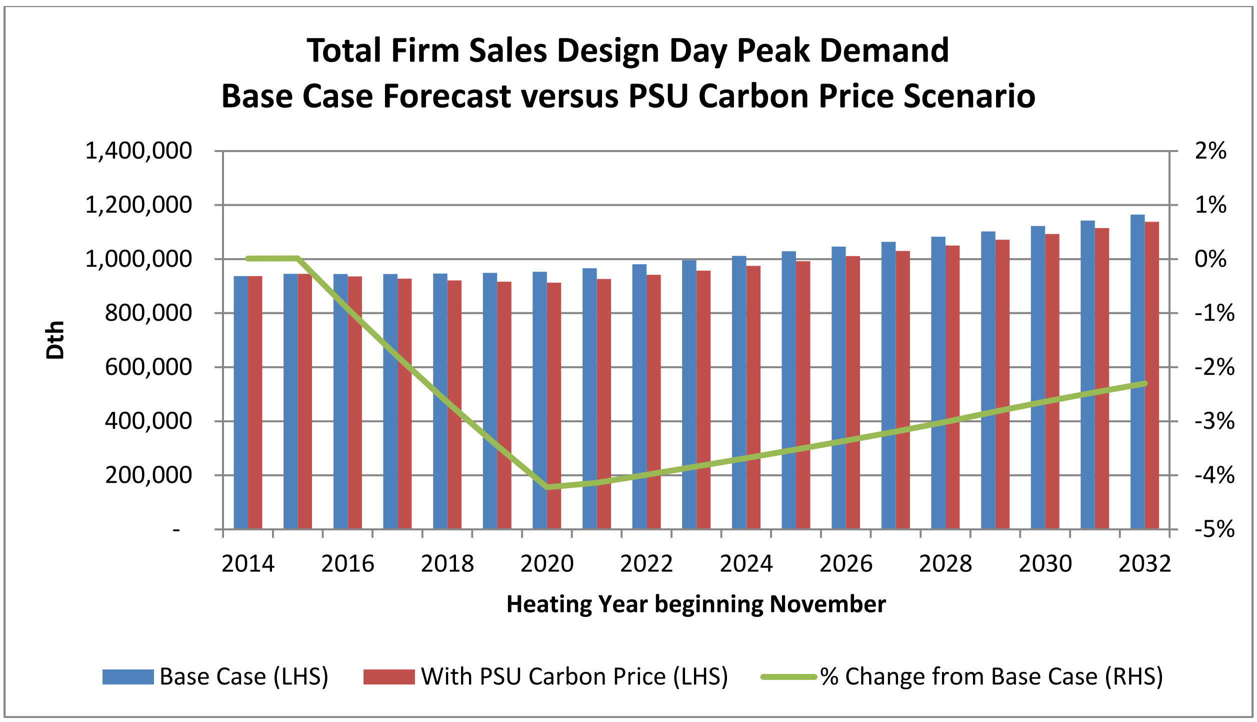


Figure 5.12 – Price Changes of Industrial Fuels with PSU Carbon Price



As a result of the expected market dynamics associated with projections of NW Natural's delivered prices of natural gas, the delivered prices of electricity within the Company's service area, the prices of conventional transportation fuels, and the prices of certain industrial fuels in the PSU Carbon Price scenario, the Company increases the total Firm Sales design day peak demand and annual loads by the differences between those in the Low Emerging Markets scenario—the respective levels of which are embedded in the Base Case forecast—and those in the Medium Emerging Markets scenario.[55] Figure 5.13 shows the total Firm Sales design day peak demand in the Base Case and in the PSU Carbon Price scenario, as well as the percent change in design day peak demand in the PSU Carbon Price scenario versus the Base Case forecast. As the diurnal natural gas load shape of Industrial customers is understood to be flatter than those of Residential and Commercial customers, and Industrial customers have the largest relative decline in usage in this scenario,[56] the declines in design day peak demand from the Base Case to the PSU Carbon Price scenario shown in Figure 5.12 are likely overstated.

Figure 5.13 – Total Firm Sales Design Day Peak Demand: Base Case Forecast[57] and PSU Carbon Price Scenario



55 See also Section VI of Chapter Two.

56 Note that the (absolute value of) price elasticity for Industrial customers exceeds that of Residential and Commercial customers and that the relative increase in the delivered price of natural gas for Industrial customers is, as shown in Figure 5.8, greater than that for Residential and Commercial customers.

57 The parenthetical "LHS" associated with the two left-most entries in the legend refers to the left hand scale; i.e., total firm sales design day peak demand is measured in Dth.

IV. RESULTS

NW Natural incorporated the PSU Carbon Price scenario's load parameters into its SENDOUT® resource optimization analysis. The primary impacts on resource planning are delayed timeframes for implementing the South Salem Feeder and Christenson Compressor projects.[58] As the impacts on resource planning of the PSU Carbon Price scenario are modest, NW Natural did not complete a SENDOUT® optimization of the AB 32 Carbon Price scenario.

V. KEY FINDINGS

- NW Natural's Base Case forecast of natural gas prices includes a carbon price implemented in 2021 and increased annually through the remaining planning horizon.
- The PSU Carbon Price scenario analyzes an alternative carbon tax implemented in 2016 at $10 per $MTCO_2e$ and increased by $10 annually to $60 in 2021, which is materially higher and implemented earlier than the carbon tax in the Base Case forecast.
- The level of carbon tax in the PSU Carbon Price scenario will increase the delivered prices of natural gas, electricity, industrial and transportation fuels, and many other goods and services.
- Firm Sales design day peak demand and annual loads decline modestly in the PSU Carbon Price scenario as compared with the Base Case forecast.
- The primary resource planning outcome in the PSU Carbon Price scenario is to delay implementation of two resource projects.

---

[58] See the related discussion in Chapter Seven.

Chapter 6: Distribution System Planning

NW Natural®

I. Background

NW Natural includes a high-level presentation of its distribution system planning with the objectives of both increasing transparency and capturing projects that may be viewed as significant for delivery of gas within the Company's distribution service area. Securing adequate natural gas supplies and ensuring sufficient pipeline transportation capacity become secondary issues if the distribution system is inadequate for delivering gas to where it is needed.

II. Scope

NW Natural has benefitted from the Public Utility Commission of Oregon's clarifying its expectation with respect to being kept informed about anticipated major utility investments[1] as well as from the Company's most recent rate case.[2] This IRP discusses only those distribution projects meeting one or both of the following criteria:

> High-pressure ("HP") transmission projects required to move gas supplies to the Company's discrete load centers (as opposed to moving gas within a load center); or
>
> Major system reinforcement or system expansion projects with an estimated construction cost exceeding $10 million.

NW Natural proposed similar criteria in the Company's 2013 Washington IRP[3] as well as in its 2013 update of its 2011 Oregon IRP.[4] NW Natural discusses those major distribution system enhancements meeting one or both criteria in this chapter. The Company also lists smaller projects having projected costs totaling between $5 and $10 million dollars in Appendix Six. Supply-side infrastructure additions are those projects associated with the need to increase resources for meeting load growth, which the Company discusses in Chapter Three.

III. Nomenclature

NW Natural uses the term "distribution system" in this IRP when referring to all Company-owned pipe downstream from a city gate. NW Natural's distribution system includes both high-pressure pipelines as well as pipelines at lower distribution pressures. While "transmission systems" are considered to be those interstate pipeline systems that bring gas supply to the city gate (as discussed in Chapter Three), federal pipeline safety regulations classify the Company's mains as either distribution or transmission. To avoid confusion, NW Natural refers to projects meeting either criterion set forth above as HP transmission/distribution projects.

---

[1] Order No. 12-493 in Docket No. UE 246 at 33.

[2] Order No 12-437, in Docket No. UG 221, footnote 44 at 17.

[3] See page 7.1.

[4] See page 22.

IV. Overview

The goal of distribution planning is the design of a distribution system meeting firm customers' current natural gas needs under specific cold weather conditions and planning for expansion to serve future firm requirements. Distribution system planning identifies potential planning or operational problems and areas of the distribution system requiring reinforcement. By knowing where and under what conditions pressure problems may (or do) occur, the Company can incorporate necessary reinforcements into annual budget and distribution project planning, thereby avoiding costly reactive and potentially emergency solutions.

The Company's Engineering Department—collaborating closely with the Construction and Marketing departments, and using input from economic development and planning agencies—plans the expansion, reinforcement, and replacement of distribution system facilities. This planning is ongoing and integrates new requirements associated with customer growth into the Company's construction forecasts.

NW Natural uses computer simulation modeling to assist with validating the need for and timing of specific system expansion, reinforcement, or replacement projects. Projects indicated by this modeling as being required in the near-term (within one to two years) are highly likely to be built in order to meet specified customer delivery requirements. Projects indicated as being required in the mid-term (three to five years) may potentially be deferred as a result of adjustments to the level of forecasted growth and the geographic location of new customers. Estimates associated with projects identified by modeling as required for the long-term (five years and beyond) tend to be general projections based on the expected economic development of the geographic region, gas supply resource acquisitions, and customer use dynamics, and NW Natural adjusts these estimates over time with updates to estimated future requirements.

NW Natural's distribution system planning ensures that the Company:

- ✓ Operates and maintains its distribution system in a safe and reliable manner;
- ✓ Performs timely maintenance and makes necessary reliability improvements;
- ✓ Complies with all state and federal laws and regulations;
- ✓ Operates a distribution system that meets hourly peak demands as well as day-to-day demands;
- ✓ Plans for future needs in a timely fashion;
- ✓ Addresses distribution system needs related to localized customer or demand growth; and
- ✓ Plans and develops a distribution system that is sufficiently flexible to adapt to conditions in the future that differ from those forecast at the time of planning, such as the uncertain demand from Emerging Markets.

This planning process[5] requires forecasting local growth in design day peak demand, determining potential distribution system constraints, analyzing potential solutions, and assessing the costs of each potential solution.

---

[5] While some of the listed items represent activities involving primarily operations and maintenance expenditures, such as those associated with *operating* a distribution system, these activities are related to system planning in the context provided for the proposed scoping criteria discussed above, if not for resource planning *per se*.

V. Existing Distribution System

NW Natural's gas distribution system consists of approximately 13 thousand miles of distribution mains, of which approximately 87 percent is in Oregon with the remaining 13 percent in Washington. The Company's Oregon service area includes 42 gate stations[6] and 987 district regulator stations. The Washington service area includes 15 gate stations and 73 district regulator stations.

NW Natural can also dispatch two large compressed natural gas (CNG) trailers each rated at 1,000 therm capacity, a liquefied natural gas (LNG) trailer rated at 8,500 therms capacity, and assorted small CNG trailers rated below 100 therms for short-term and localized use to support cold weather operations or while conducting pipeline maintenance procedures.

VI. Distribution System Planning Methodology

A. Overview

Two primary factors determine the required level of incremental infrastructure investment: load growth and reliability issues. Load growth requires system expansion both to accommodate new demand as well as peak system performance. System reinforcements relate to reliability and this term refers to either upgrades or additions that increase system capacity, reliability, or safety. Other factors NW Natural considers include pipeline safety regulations, which may drive the need to replace assets based on the location and condition of pipelines and relocations of pipelines in order to accommodate public works projects.

The planning process requires, in addition to meeting load associated with local demand growth, determining potential distribution system constraints and reliability issues, analyzing potential solutions, and assessing the costs associated with each solution considered.

The planning process begins with an evaluation of the system's current performance and then considers load growth and system constraints, both now and in the future. Assumptions regarding customer load growth draws from the IRP load forecasts[7] and from discussions with local area management regarding main and service requests, major account representatives, developers, local trade allies, and field personnel. NW Natural integrates this information with the system performance assessment for both the short- and long-terms, which results in a long-term planning and strategic outlook that assists in identifying the best options for addressing system needs.

B. Computer Modeling

NW Natural uses SynerGEE® software, which is in wide use throughout the industry, to model the Company's network of mains and services and to perform network demand studies. The SynerGEE® model helps predict capacity constraints and associated system performance in alternative scenarios differing in assumed temperatures (HDD) and future loads resulting from alternative assumptions regarding load growth. SynerGEE® allows graphical analysis and interpretation by system planners.

---

6 Gate station values for both Oregon and Washington include all upstream pipeline interconnections, including farm taps.

7 This IRP discusses load forecasts in Chapter Two.

The SynerGEE® model contains detailed information on NW Natural's system, such as pipe size, length, pipe roughness, and configuration; customer loads; source gas flow rates and pressures; internal regulator settings and characteristics; and more. The model utilizes 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 distribution; and from the Supervisory Control and Data Acquisition (SCADA) system for large customer loads, system pressures, gate flows and pressures, value status; and key regulator pressure settings.

The SynerGEE® model uses mathematical flow equations and an iterative calculation method to evaluate whether the modeled system is balanced. A SynerGEE® 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 SynerGEE® model has pressure and flow results closely corresponding with those of the observed actual (physical) system.

NW Natural compares the results of a SynerGEE® model to actual observed conditions in order to validate the model. Model validation is very important for creating a SynerGEE® model that accurately reflects the Company's system.

A validated SynerGEE® model can be used to simulate the distribution system's performance under a variety of conditions. The focus of this analysis is typically on meeting growing peak day customer demands while maintaining system stability. NW Natural uses the SynerGEE® model to project gas requirements at discrete delivery nodes based on observed flow rates during recent cold weather episodes. Flow rates are then calibrated to match design peak weather conditions and to reflect the effects of customer growth.

SynerGEE® simulation capability allows the Company to efficiently evaluate distribution system performance in terms of stability, reliability, and safety under conditions ranging from peak-day delivery requirements to both planned and unplanned temporary service interruptions. SynerGEE® modeling allows NW Natural to evaluate various scenarios designed to stress-test the system's response to alternative demand forecasts and/or system constraints

Distribution system improvements take multiple forms. NW Natural can loop a pipeline, which means constructing a new pipe near an existing pipeline that is currently or will soon be at design capacity. The Company can upsize or uprate pipelines. Upsizing replaces an existing pipeline with a larger diameter pipe, while uprating a pipeline increases its maximum allowable operating pressure (MAOP). The Company can also install compressor stations to boost a pipeline's operating pressure closer to its MAOP, thereby increasing overall gas flow rates. Each alternative solution has—under any given scenario—unique costs, benefits, timing implications, and risk.

NW Natural assesses alternative means for meeting system expansion and reinforcement needs using multiple criteria. The Company evaluates proposed solutions and solution sets with regard to cost and deferral of future costs, safety, system reliability, system stability, timing vis-à-vis that of other projects, system utilization improvement, and the ability to meet future gas delivery requirements. The "best" proposed solution is the least cost, safest, and most reliable solution for ratepayers.[8] As any one alternative solution may not be the "best" with respect to each criterion, determining the optimal solution[9] from the available alternatives involves qualitative assessment of the relevant characteristics of each alternative solution.

Depending on a specific project's requirements, SynerGEE® modeling may be augmented by or occasionally replaced with modeling conducted using Excel spreadsheets. Analyzing multiple scenarios on a relatively simple system may be completed more quickly using an Excel spreadsheet than when using SynerGEE®. NW Natural validates Excel spreadsheet models using the same process used for a SynerGEE® model, so modeling using either method provides similar results.

C. Demand

Core system demand typically has a morning peaking period between 7 a.m. and 8 a.m. The peak hour demand for these customers can be as much as 50 percent greater than the hourly average of the diurnal demand. Due to the importance of responding to *hourly* peaking in the distribution system, NW Natural typically plans for distribution system capacity requirements based on peak hour demand.

Actual system demand for various times and weather conditions are typically captured from real time[10] SCADA information, which is available every day. NW Natural assumes for modeling purposes that smaller gates for which SCADA information is not available have fixed outlet pressures, and the Company adjusts downstream loads for these locations as is appropriate for the specified weather conditions.

D. Modeling Scenarios

SynerGEE® has a variety of features for evaluating results and identifying potential solutions to correct a pressure problem. NW Natural can make model changes to determine how the system would perform with a variety of enhancements, such as increased regulator pressure, pipe looping, additional supply source, etc. The Company enters such changes and then rebalances the model. A typical output is a color-coded map showing system pressure levels, examples of which are shown in Figures 6.1 and 6.2 (following). NW Natural can quickly consider a variety of potential solutions for low-pressure areas and determine the short- and long-term effectiveness of each. Once identified, the Company can evaluate each potential solution's cost[11] as part of the process for determining the best alternative.

---

8 NW Natural intends that a solution that is the least cost, safest, and most reliable of alternative solutions is understood to be a solution consistent with the Public Utility Commission of Oregon's goal that "…utility resource plans should identify resources that provide the best mix of cost and risk," as stated on page 1 of Order No. 07-002 in Docket No. UM 1056 and elaborated on in other sections of this Order, including in footnote 3; on pages 5 through 8; and in Guideline 1c on pages 1 and 2 of Appendix A (including footnote 1 "…[w]e sometimes refer to this portfolio as the "best cost/risk portfolio." ").

9 NW Natural intends that an "optimal solution" is understood in this context to be a solution that provides the "best mix of cost and risk" in conforming to the Public Utility Commission of Oregon's IRP Guideline 1c. By "optimal," NW Natural means "best and most effective;" with this definition appearing in the online Merriam-Webster at http://www.merriam-webster.com/dictionary/optimal (accessed August 5, 2014).

10 SCADA data is transmitted every two minutes.

11 SynerGEE® does not incorporate cost considerations. The process of determining a potential solution's cost effectiveness appropriately incorporates analysis reflecting the Public Utility Commission of Oregon's IRP

As a general matter, the practical industry standard for computing design capacity of a new pipeline is based on a maximum 20 percent pressure drop. A pressure drop exceeding 20 percent indicates there may be insufficient capacity on the Company's system to accommodate all of its firm demand requirements. A pressure drop of 40 percent from the source pressure (a district regulator or gate) to the delivery point causes significantly greater concern.[12] In addition to looking at the pressure drops on the pipeline from source pressure to delivery pressure, NW Natural evaluates the inlet pressure of a district regulator relative to the delivered outlet pressure. The differential between the inlet and outlet pressures at a district regulator determines its maximum deliverable flow. While there are many factors used to assess the health of a system, limiting pipeline pressure drops to no more than 40 percent from the planned pressure is often thought of as an industry standard and NW Natural uses this as a general guideline. NW Natural believes that, as a general matter,[13] limiting pressure drops to no more than 40 percent allows the Company to provide reliable service to firm customers.

NW Natural models various scenarios, stress-testing how the system will respond to varying demand forecasts and system constraints. The Company can analyze alternative solutions for meeting delivery capacity requirements and addressing reliability issues based on modeling results.

Guideline 1c; i.e., "[t]he 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." Emphasis added; see Order No. 07-002 in Docket No. UM 1056, Appendix A page 2 of 7.

12 A 40 percent pressure drop through a pipe uses 80 percent of the pipe's available capacity: if pressure has dropped by 40 percent and load then increases by 25 percent, the increase in load would cause pressure at the end of the pipe to be zero.

13 There are specific exceptions to this general guideline.

Figure 6.1 – Distribution System Pressures: Existing System

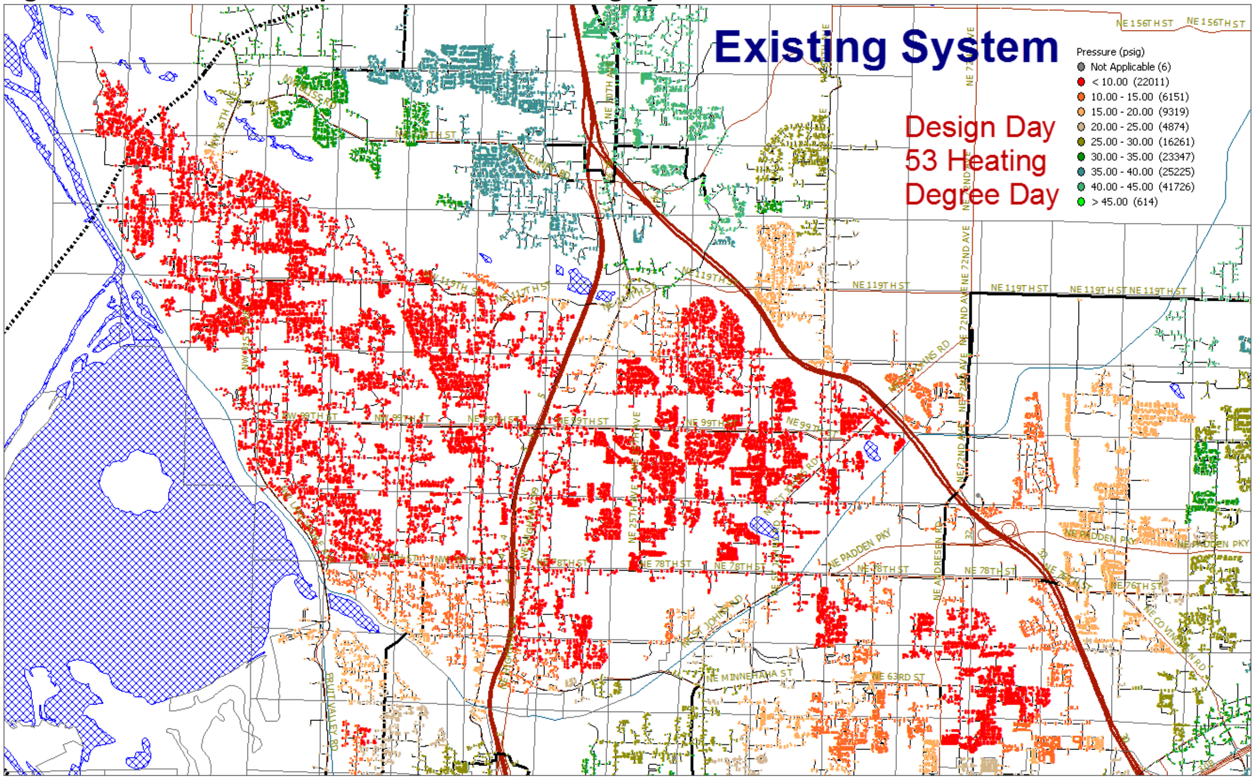
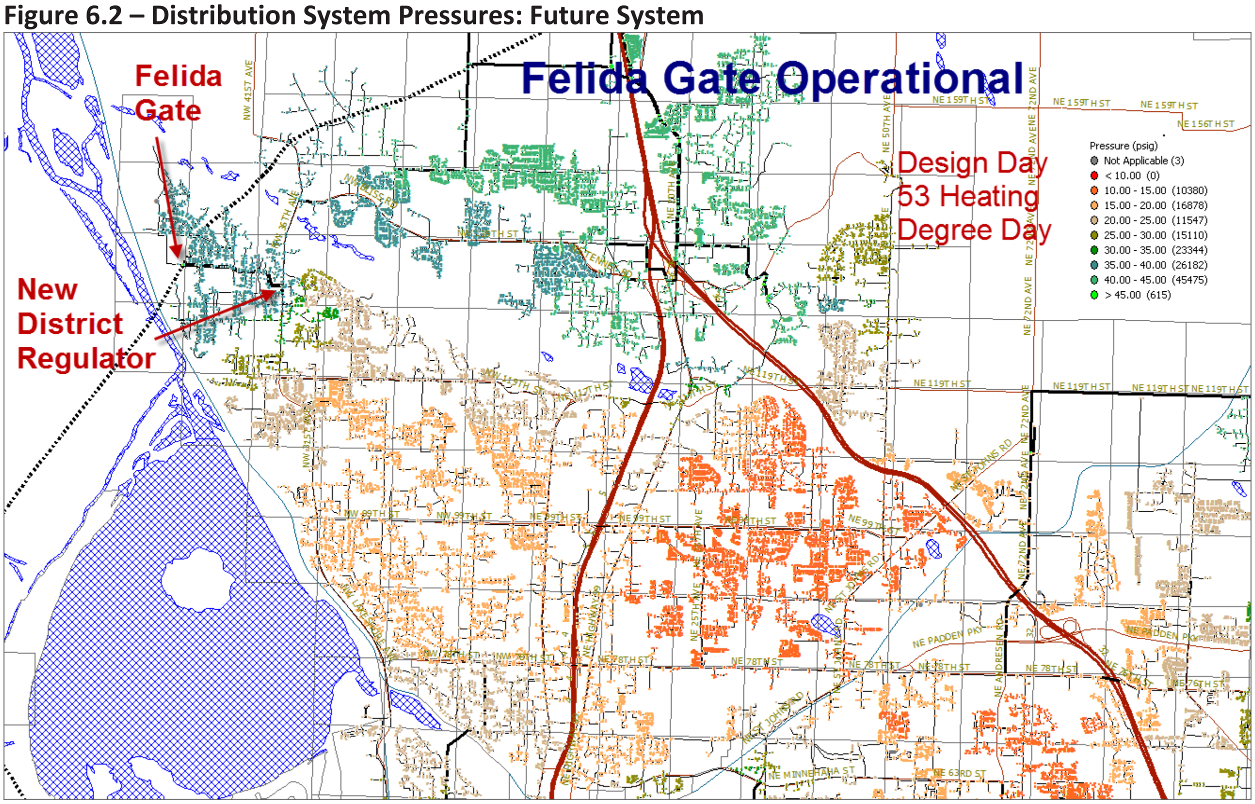


Figure 6.2 – Distribution System Pressures: Future System



E. Planning Results

NW Natural develops both short- and long-term infrastructure plans based on load growth projections, system integrity issues,[14] and other system-impacting issues. These plans consist of proposed projects the Company includes in its capital planning process. NW Natural reviews these plans annually, and the scope and needs of each project may evolve over time as new information becomes available. Actual solutions implemented may be different from those planned due to conditions that differ from those forecast. The Company integrates annual plans into the budgeting process, which also includes planning for other types of distribution capital expenditures and infrastructure upgrades.

VII. Significant Potential HP Transmission/Distribution System Planning Projects

There are currently three potential projects (all sited in Oregon) meeting the criteria specified at the beginning of this chapter and not included in Chapter Three. These are presented in alphabetical order and with no implied relative importance. These projects represent high level potential future resources with preliminary cost estimates and were included in the SENDOUT® modeling. As is always the case with cost estimates, it is possible that actual costs could come in above or below those estimated before project commencement or completion.

NW Natural's analysis indicates a need for more gas supply capacity in some of the Company's Willamette Valley load centers. NW Natural has identified each project listed below as a potential option for increasing the amount of gas flowing to one or more of the Company's Willamette Valley load centers.

Aurora Compressor

This project involves installing a 2,000 horsepower compressor at Aurora to increase the flow rate by approximately 50 percent. This project will increase Mist supply to the Salem load center. NW Natural is investigating this project and preliminary estimates indicate the project cost could be between $5 and $10 million.

Newberg to Central Coast Feeder

Similar in some ways to the Aurora Compressor project listed above, this project would allow additional gas supplies to flow from Mist to the Salem and Albany load centers. The project consists of approximately 25 miles of 16-inch pipeline connecting the Central Coast Feeder to NW Natural's system near Newberg. As with the other projects described here, this project is still in the conceptual phase and the high level cost estimate is approximately $54 million.

South Salem Feeder

The South Salem Feeder project is also one of the options being considered that would allow more gas to flow to the Salem load center. This project would consist of installing a 12 inch pipeline from the Mid-

[14] System integrity issues include those associated with the stability, reliability, and safety of NW Natural's system.

Willamette Valley Feeder to the South Salem feeder system. This project's cost estimate is approximately $25 million.

Prior to NW Natural deciding to proceed with the Aurora Compressor project or the Newberg to Central Coast Feeder project, the Company will perform additional analysis and refine cost estimates and estimated revenue requirements. NW Natural includes planning construction of the South Salem Feeder project in the 2014 IRP Action Plan.[15]

VIII. Other Distribution System Projects

As previously mentioned, the Vancouver load center requires additional system infrastructure investments and NW Natural is planning five potential projects that appear to meet (or nearly meet) the listing criteria for a smaller project (one costing between $5 and $10 million). These projects can be found in Appendix Six and each is in the process of being more thoroughly analyzed. However, they are presented here as NW Natural intends to implement one or more of these projects in the near- and medium-term depending on the outcome of the additional analysis.

IX. Key Findings

- NW Natural identified three projects that meet the criteria for inclusion in the IRP set forth above.
- The South Salem Feeder is a resource option that provides additional distribution system support to the Salem load center and is included in NW Natural's Action Plan.
- NW Natural identified five smaller projects that address resource needs in the Vancouver load center. These projects are listed in Appendix Six.

---

15 See Section V of Chapter One.

Chapter 7: Linear Programming and Risk Analysis

I. SYSTEM PLANNING OVERVIEW

NW Natural employs the optimization method of linear programming to integrate the significant planning components, and to generate and evaluate long-term resource plans. Linear programming (LP) is a mathematical optimization technique which solves the "general problem of allocating limited resources among competing activities in the best possible way."[1] For the IRP, the Company's LP model examines all reasonable means for acquiring demand-side and/or supply-side resources to meet growing customer load and determines the series of resource decisions through time which results in a least cost plan. The LP 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 10. LP modeling also allows for various combinations of resources, called portfolios, to be evaluated under assorted load scenarios and ranked according to cost.

The Company holds a license with Ventyx, an ABB company, for its gas supply planning and optimization software product SENDOUT®. This application is designed to optimize the entire gas supply portfolio, including supply, transportation, storage assets, and conservation programs. The general optimization problem is a minimum-cost capacitated network flow problem. The objective function of the LP engine within SENDOUT® seeks to minimize system costs associated with meeting daily load subject to pipeline capacity constraints. The resource mix optimization module sizes resources to meet load based on the associated fixed and variable costs of the resource. The Monte Carlo module provides risk planning analysis around hundreds of weather and price simulations. This allows portfolios to be evaluated from a probabilistic standpoint.

A. Resource Planning Model Integration

Six primary components are integrated within the SENDOUT® resource planning model.

1. Load forecast (Chapter Two)
2. Temperature pattern (Chapter Two)
3. Natural gas price forecast (Chapter Two)
4. Demand-side management resources (Chapter Four)
5. Current supply-side resources (Chapter Three)
6. Potential future resources (Chapters Three and Six)

1. Load Forecast

The Company uses demand usage factors to incorporate the demand forecast into the resource planning model. The usage factors include the number of customers by region and category, as well as the customer and region-specific base and heat load factors. The usage factors are used in combination with temperature data to generate an overall gas requirement for each of the demand centers. The methodology for the derivation of the demand usage factors is presented in Chapter Two. Additionally, a high cost penalty is attached to unserved firm demand so 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 cold weather periods, but high enough that the model chooses to serve it otherwise.

---

[1] Hillier, Fredrick S. and Lieberman, Gerald L, Introduction To Operations Research 6th Edition, McGraw-Hill, Inc., 1995, 25.

2. Temperature Pattern

The Company has developed a statistically based weather pattern, referred to as design weather and outlined in Chapter Two, which was designed to be colder than 90 percent of the winters that the service area has experienced in 30 years. In addition, the annual temperature pattern was augmented with the very cold seven day peak event from February 1989. The thirty-year data set of temperatures has been included in the resource model to provide a basis for the weather portion of the Portfolio Risk Analysis.

In this IRP, NW Natural developed modeling and resource planning around the design weather as explained above. Should capacity become constrained in a service area for any reason, including a weather event that exceeds the Company's planning standard, the Company can balance the system by curtailing service. The guidelines for curtailment are established in Rules 13 and 14 in the Oregon Tariff and Rules 15 and 16 in the Company's Washington Tariff. These rules establish a priority for curtailment. Customers on interruptible schedules are curtailed first, followed by non-essential human needs firm sales industrial and commercial customers. The last to be curtailed are firm residential and essential human needs customers. It is not uncommon during the heating season for the Company to call a curtailment event for a portion of its interruptible sales and/or transportation customers. These customers pay lower distribution charges and they generally provide services in a sector that requires them to have a back-up energy source, or gives them the flexibility to scale back or shut down operations for short periods. Violations of curtailment orders are subject to penalty charges and other remedies as allowed under the Company's approved tariffs.

3. Natural Gas 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 and can also allow the model to take advantage of seasonal variability. For instance, one low-cost strategy might involve purchasing gas during the summer months when prices are lower and holding the supply in a storage facility until needed to meet high winter load. Substantial differences between summer and winter prices could, therefore, influence storage resource decisions as well as supply purchase decisions. Long-term price differentials between supply basins may also drive pipeline resource decisions to steer toward the lower priced basins. The Company used the various price forecasts described in Chapter Two to evaluate supply options and costs. Gas price also has a strong influence on the expected overall cost to meet customer load across the planning horizon, since gas commodity costs are typically the largest cost component of any LDC IRP.

4. Demand-side management resources

As discussed in Chapter Four, the Company worked with Energy Trust of Oregon (Energy Trust) to generate a twenty-year demand side management (DSM) forecast which estimates the cost and amount of therm savings that can be procured by providing incentives to customers for implementing energy efficiency measures. The energy savings and cost forecast were integrated into the SENDOUT® resource planning model so that DSM may offset supply-side resources through time. The savings were deducted from the load forecast with the remaining load served by supply-side resources.

Energy Trust provided the DSM forecast on an annual and state-wide basis. In order to implement the forecast into the resource model, the energy savings were allocated among the Company's load regions on a monthly basis.

5. Current supply-side resources

NW Natural discusses existing supply-side resources in Chapter Three.

6. Future supply-side resources

The gas requirements for each load center are met by supply-side resources. The Company's future supply-side resources are incorporated into the SENDOUT® resource planning model. These resources fall into four basic categories:

1. Commodity Supply
2. Interstate Pipeline
3. High Pressure Transmission
4. Storage

Table 7.1 lists a number of the future resources that are available in the resource planning model. For additional and further descriptions of these resources, refer to Chapters Three and Six and Appendix Seven. Interstate pipelines are modeled at either their current tariff rate or an estimated rate for new projects. High pressure transmission projects are modeled at their estimated annual revenue requirements. "End effects" also are considered, that is, the analysis actually was performed over a period longer than the 20-year IRP planning horizon to ensure that resource choices made in the later years were not effected simply because cost streams were cut off after year 20. Figures 7.1 and 7.2 display model diagrams for pipeline and supply resources, and Figure 7.3 is a model diagram for Storage and other service area resources.

Table 7.1 - Future Resource and Portfolio Options

	Resource	Description	Abbrev
Beyond NWN Control	Cross-Cascades	New Interstate Pipeline project connecting GTN's mainline north of Madras, Oregon to the gate station at Molalla. Gas coming off of Cross-Cascades could be taken directly into NW Naturals system or transported over NWP via an NMAX service.	CC
Beyond NWN Control	Washington Expansion	Expansion of NWP's Interstate Pipeline in the I-5 corridor from Sumas south associated with the proposed Oregon LNG export facility.	WEX
Beyond NWN Control	Sumas Expansion Regional	Similar to the Washington Expansion but a smaller expansion that is sized assuming there is no Oregon LNG Project.	SE(R)
Beyond NWN Control	Pacific Connector	New Interstate pipeline associated with the proposed Jordan Cove LNG export facility from Turquoise Flats (Near Malin, Oregon) to the Jordan Cove Facility near Coos Bay. This option includes the ability to move gas north on NWP's Grants Pass Lateral to the Company's load centers.	PCGP
Choice of NWN[2]	Mist Recall	Additional to the existing Mist storage capacity currently reserved for the core market, the Company has capacity contracted to third parties in the interstate/intrastate storage market that can be recalled for service to the Company's utility customers as agreements expire.	MR
Choice of NWN[2]	North Mist	Development of a new set of reservoirs, compression station and pipeline facilities located to the north of the existing Mist storage facilities complex.	NM
Choice of NWN[2]	Sumas Expansion Local	A local Sumas expansion that is similar to a regional expansion, but is initiated at the request of NW Natural and sized specifically for the Company's needs.	SE(L)
Choice of NWN[2]	Christenson Compressor	A compressor located between Newport and Salem to increase the takeaway capacity of Newport LNG.	CCP
Choice of NWN[2]	All others	All others – includes Satellite LNG in Clark County and other resources (see Chapters Three and Seven).	OTHER

Abbreviation	Portfolio
PCGP/NM	Pacific Connector with North Mist
NM/SE(L)	North Mist with Sumas Expansion (Local Project)
CC/TB/NM	Cross-Cascades with NWP vintage capacity turnback and North Mist
CCLNG/NM	Clark County LNG with North Mist

[2] Note that NW Natural controls the timing of the in-service date of the resources options under its control, but the in-service times for the projects out of the control of the Company must be assumed (see Table 7.1).

Figure 7.1 – Pipeline and Supply Model Diagram

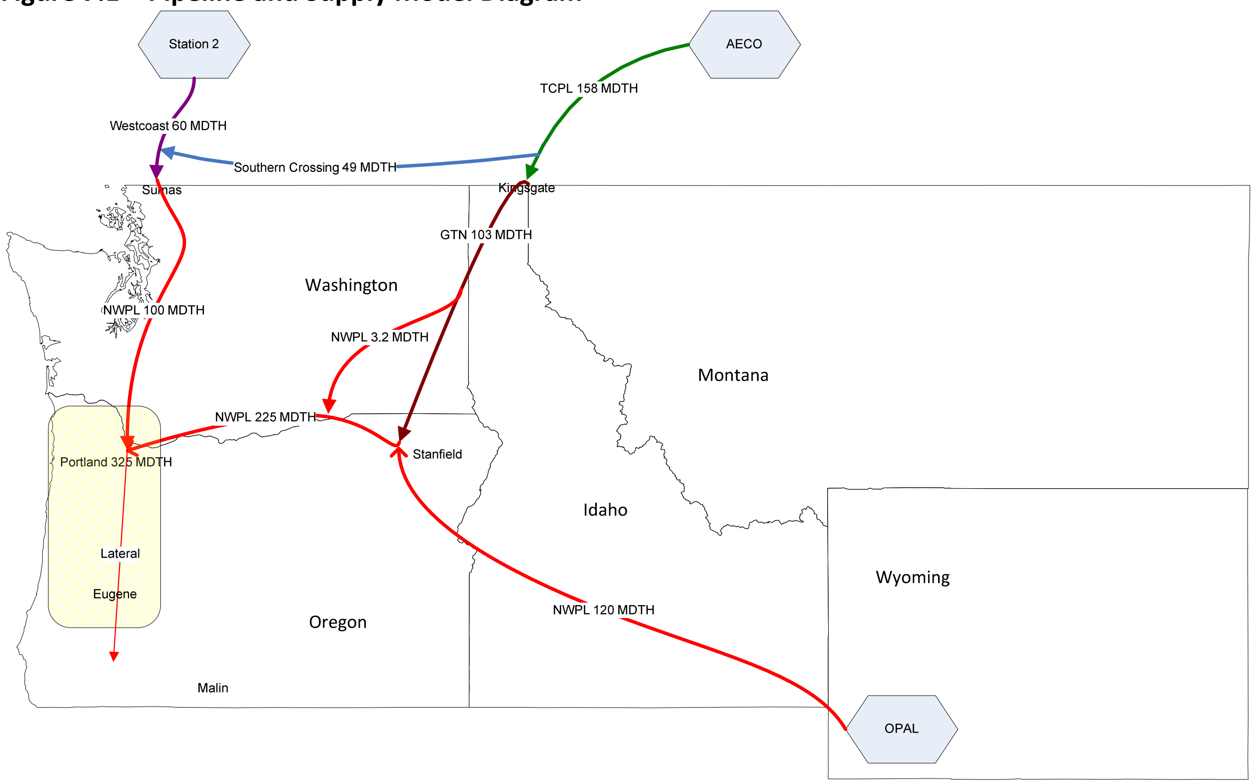
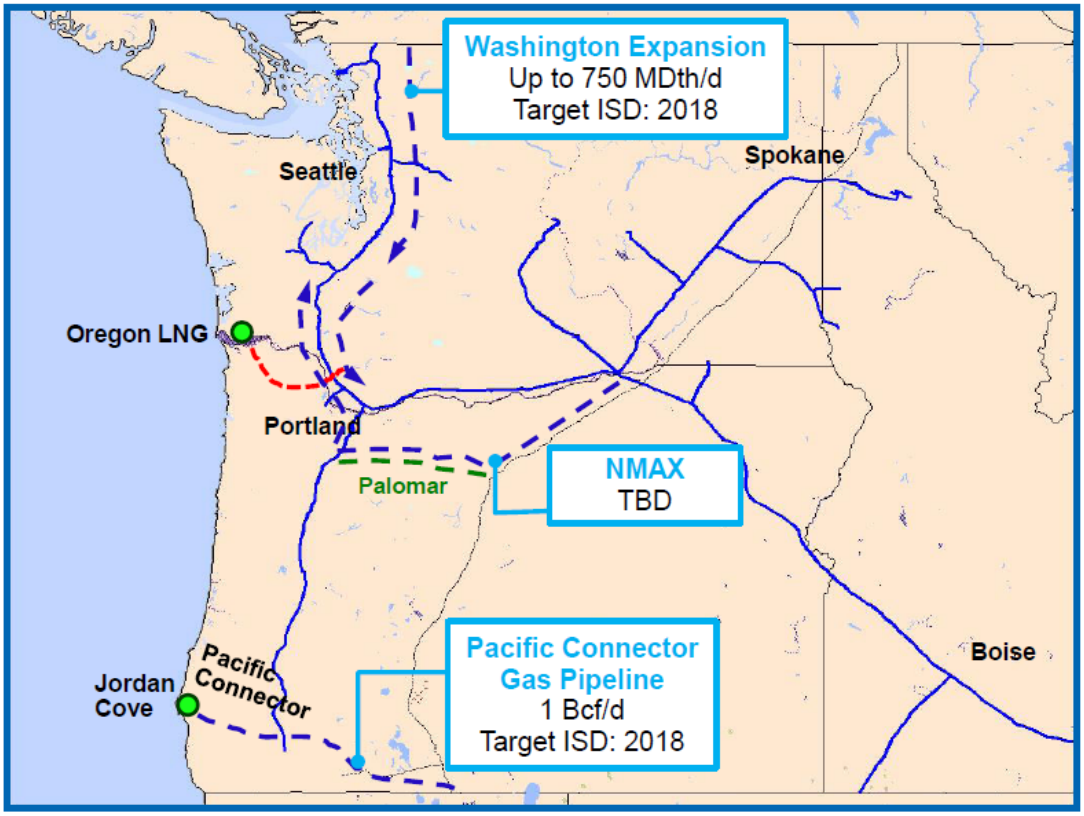
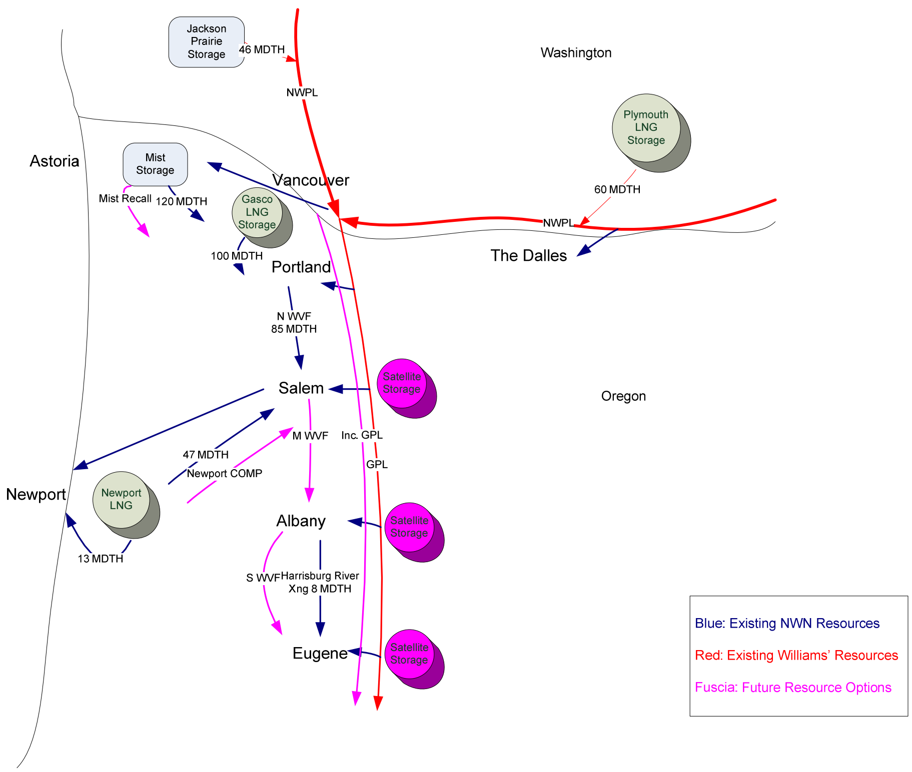


Figure 7.2 – Pipeline and Supply Model Diagram with Proposed Pipeline Projects



Source: Williams Northwest Pipeline, August 2014

Figure 7.3 – Storage & Service Area Resources Model Diagram



B. System Modeling

SENDOUT® uses a network diagram that represents the pipelines both inside and outside NW Natural's system which deliver gas to the Company's customers (Appendix 7A.1). Included in this model are all relevant pipeline capacities, fixed and variable costs, and seasonal or other time-sensitive capacity constraints. Ideally this model will sufficiently reflect the real operating parameters of the Company's system. As part of the IRP process this model is constantly refined to better reflect reality.

The system model in this IRP has been improved in several ways from those used in prior IRPs. The previous Portland load center has been split into three distinct areas (West, Central, and East) based on an analysis of gas flows on NW Natural's distribution system. The model also now incorporates the physical capacity limitations of NWP's gate stations as well as the Company's pipeline capacity extending from gate stations into the load centers. This level of granularity allows NW Natural to find weak points within the supply and delivery systems. In particular, this addition has revealed that during cold weather—even at temperatures well above design day—NW Natural faces challenges in serving the load within the Company's Clark County service territory (Figure 7.4). It has also shown that the Salem service area will need additional capacity beginning in 2019 (Figure 7.5).

Figure 7.4 – Clark County Design Day Load and Physical Delivery Constraints

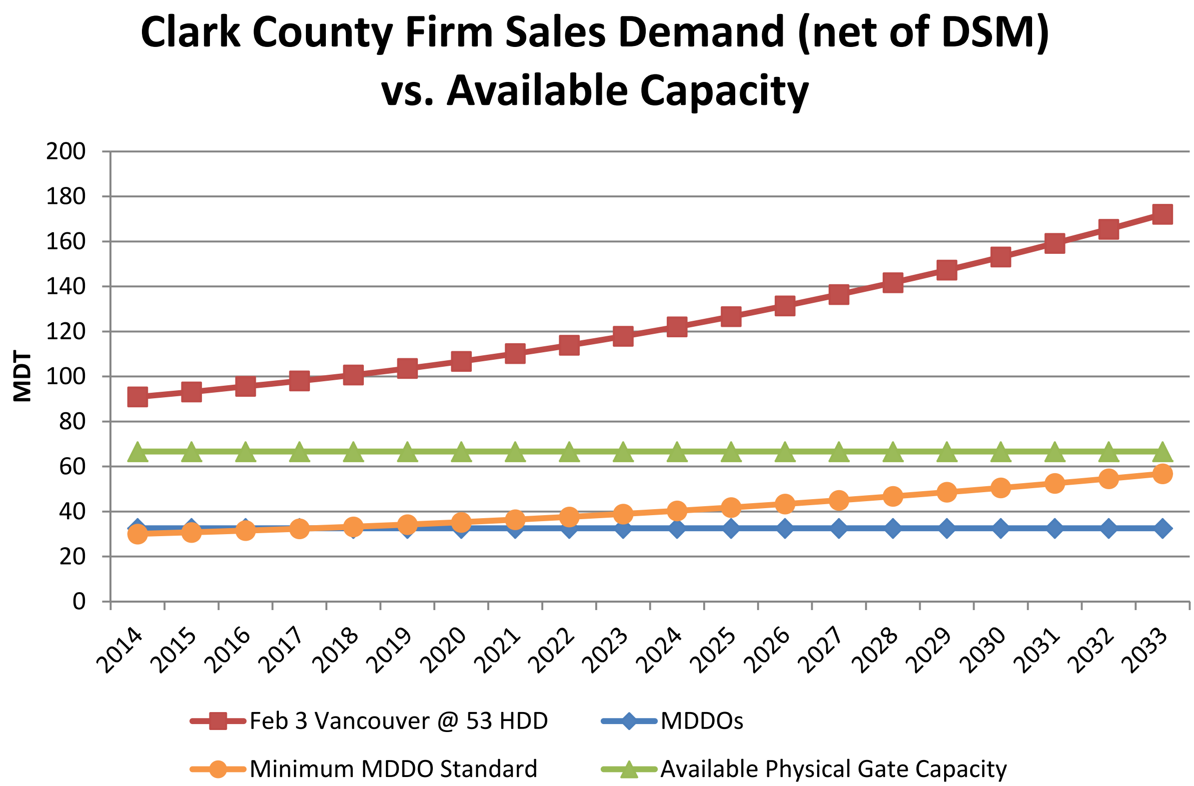
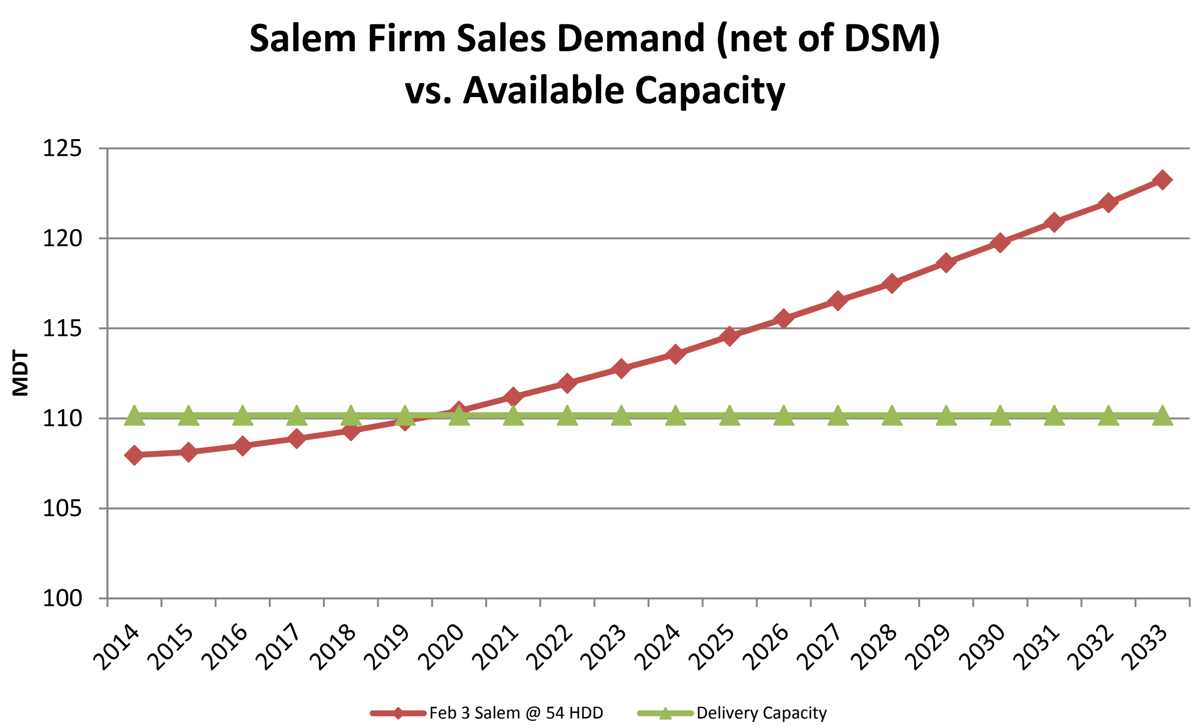


Figure 7.5 – Salem Design Day Load and Physical Delivery Constraints



II. RESOURCE PLANNING MODEL RESULTS

The process of running SENDOUT® includes three basic steps. First, a set of model inputs must be entered into the application. These include the previously discussed load parameters, weather patterns, price forecast, demand-side management factors, and current resources. Next, the set of future resource options with individual decision factors (timing, capacity, cost, etc.) are configured within the model. The application is then run and the output collected. The output results include the timeframe and size of the resource decisions, served and unserved load, and the supply, transport, storage and DSM costs. Total costs are tabulated and the net present value of revenue requirements (NPVRR) is calculated. For all scenarios NW Natural uses the traditional planning standard (i.e., design weather and 100 percent resource availability).

A. With Existing Supply Resources

The Company's existing resource base is unable to meet expected peak day demand over the planning horizon (Figure 7.6). This is in part due to the removal of Plymouth LNG as well as a portion of Jackson Prairie. Figure 7.7 shows that Mist Recall alone is unable to meet the expected demands within the planning horizon. Without any additional supply additions, Mist Recall would be fully utilized by 2024.

Figure 7.6 – System Resource Deficiency on Design Day

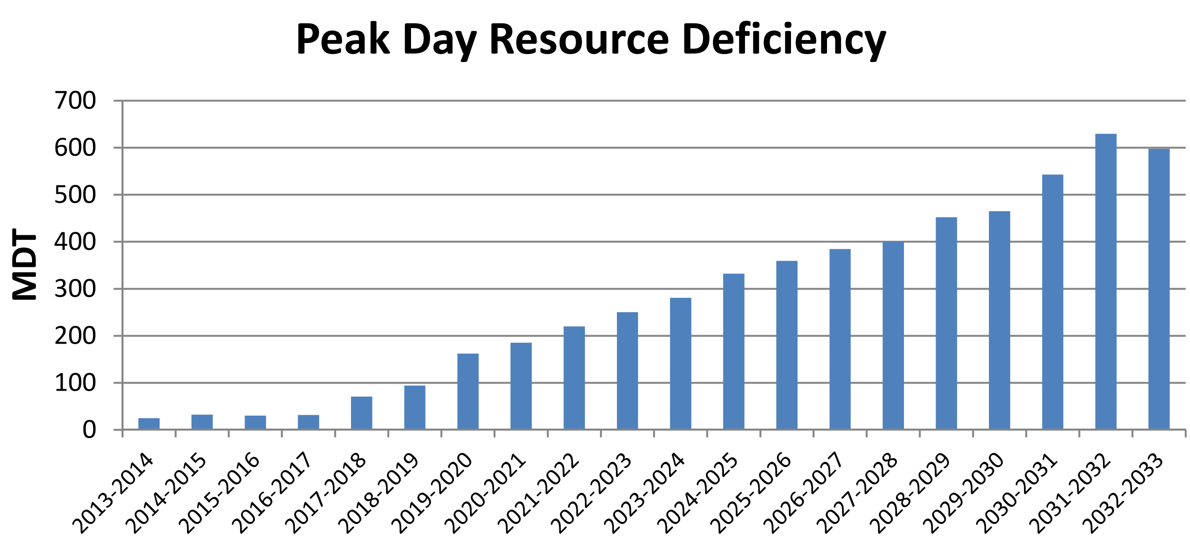
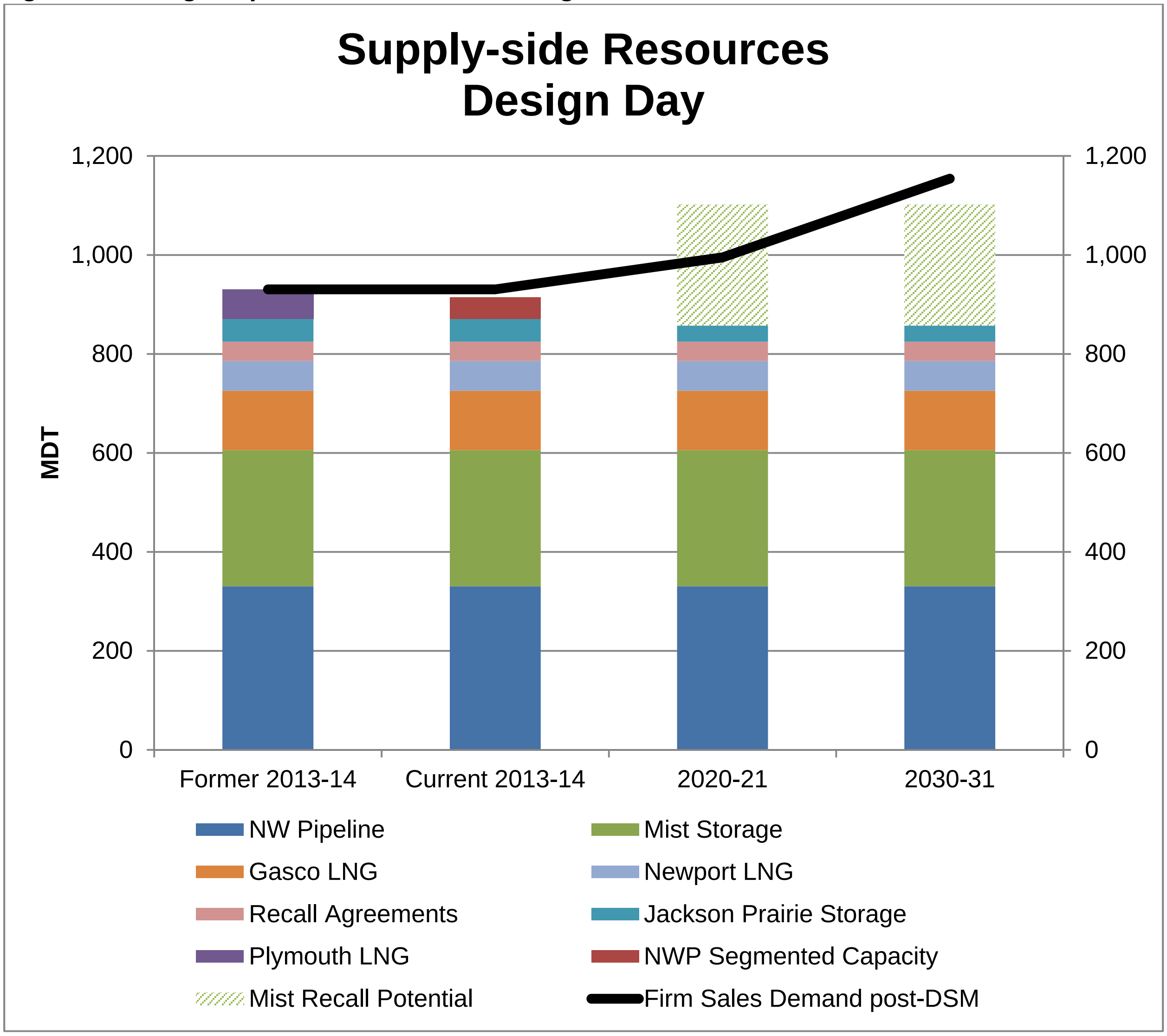


Figure 7.7 –Design Day Peak Demand with Existing Resource Portfolio



B. Planning Results with Expected Load

A number of currently proposed projects in the Northwest could impact NW Natural's decisions about acquiring resources. This section explores those scenarios and compares the resulting resource portfolios (Table 7.2 below contains scenario labels and descriptions and Table 7.3 below contains the abbreviatios and scenario assumptions). Each scenario has a separate set of available resource options as well as a distinct gas price forecast (Table 7.4). The scenarios are described below.

<u>Scenario A: No LNG exports</u>

Description: Neither Jordan Cove nor Oregon LNG export facilities are built. In order to serve growing regional load it is possible that Cross-Cascades with NMAX and/or Sumas Expansion (Regional Project) could be built.

Scenario A1: No regional pipeline projects

Description: Neither CC nor SE(R) are built. NW Natural's options include contracting for smaller expansions on a Sumas Expansion (Local Project) or invest in on-system storage resources (North Mist or Clark County LNG). These are alternatives considered within NW Natural's control.

Scenario A2: All regional pipeline options are available

Description: CC and/or SE(R) is built to support growing regional demand. NW Natural may choose to contract on either the CC or SE(R) regional pipeline. NW Natural's options also include contracting for smaller expansions on a Sumas Expansion (Local Project) or invest in on-system storage resources (North Mist or Clark County LNG).

Scenario A3: Sumas Expansion (Regional Project) is built

Description: Only SE(R) is built to support growing regional demand; CC does not proceed. NW Natural may choose to contract on this regional pipeline in addition to the options of contracting for smaller expansions on a Sumas Expansion (Local Project) or investing in on-system storage resources (North Mist or Clark County LNG).

Scenario B: LNG Exports

Description: Either Jordan Cove or Oregon LNG export facilities are built. In addition to the pipeline developed to transport LNG exports, in order to serve growing in-region load it is also possible that Cross-Cascades and/or Sumas Expansion (Regional Project) could be built.

Scenario B1: Oregon LNG is built

Description: WEX is built to support LNG exports. Jordan Cove and the Pacific Connector are not built. In order to support other regional demand growth Cross-Cascades could be built. NW Natural's options also include contracting for smaller expansions on a Sumas Expansion (Local Project) or invest in on-system storage resources (North Mist or Clark County LNG).

Scenario B2: Jordan Cove is built

Description: Pacific Connector is built to support LNG exports. Oregon LNG and WEX are not built. In order to support other regional demand growth, Cross-Cascades or a Sumas Expansion (Regional Project) could be built. NW Natural's options also include contracting for smaller expansions on a Sumas Expansion (Local Project) or invest in on-system storage resources (North Mist or Clark County LNG).

Table 7.2 – Scenario Labels and Descriptons

Scenario	Label	Scenario Description
A: No LNG Exports	A1	No LNG Exports and No Regional Projects
	A2	No LNG Exports and all Regional Pipeline options available (in 2020)
	A3	No LNG Exports and only Sumas Expansion (Regional) pipeline option available in 2020 (Cross-Cascades is not an option)
B: LNG Exports	B1	Exports from Oregon LNG in 2020 (with all Regional pipeline options)
	B2	Exports from Jordan Cove in 2020 (with all Regional pipeline options)

Table 7.3 – Scenario Assumptions Matrix

Resources Available	Abbrev	Scenario A1	Scenario A2	Scenario A3	Scenario B	Scenario C
Cross-Cascades	CC		X		X	X
Pacific Connector	PCGP					X
Washington Expansion	WEX				X	
Sumas Expansion Regional	SE(R)		X	X		X
Sumas Expansion Local	SE(L)	X	X	X	X	X
Mist Recall	MR	X	X	X	X	X
North Mist	NM	X	X	X	X	X
Christenson Compressor	CCP	X	X	X	X	X
All others	OTHER	X	X	X	X	X

Table 7.4 – Supply-side Resource Costs

	Resource Fixed Incremental Costs per Dth					Total Fixed Cost ($ per Dth/day)	Increment Dth/day	Annual Cost ($000)	Commodity Hub
	Main Pipe	Nmax	AECO to Madras	Malin to Madras	Ruby				
Cross-Cascades (Malin)	$ 0.41	$ 0.12		$ 0.14		$ 0.67	110,000	$ 26,901	Malin (if no JC)
Cross-Cascades (AECO)	$ 0.41	$ 0.12	$ 0.55			$ 1.08	110,000	$ 43,362	AECO (if JC)
Cross-Cascades (Opal)	$ 0.41	$ 0.12		$ 0.14	$0.75	$ 1.42	110,000	$ 57,013	Opal (if JC)
	Main Pipe	T-South							
WEX	$ 0.56	$ 0.47				$ 1.03	110,000	$ 41,355	Station 2
Sumas Expansion (Local)	$ 0.88	$ 0.47				$ 1.35	50,000	$ 24,638	Station 2
Sumas Expansion (Regional)	$ 0.46	$ 0.47				$ 0.93	110,000	$ 37,340	Station 2
	Main Pipe	Ruby	AECO to Malin						
PCGP	$ 0.40	$ 0.75				$ 1.15	52,000	$ 21,827	Opal
PCGP	$ 0.40		$ 0.69			$ 1.09	52,000	$ 20,688	AECO
	Liqufaction/ Storage	Transmission							
Clark County LNG	$ 0.30	$ 0.25				$ 0.55	120,000	$ 24,090	Lowest Cost
	Storage w/Takeaway	NWP							
North Mist	$ 0.24	$ 0.10				$ 0.34	50,000	$ 6,198	Lowest Cost

Portfolio Results

Certain distribution and supply projects are selected in every portfolio. These include Mist Recall, South Salem Feeder, Christenson Compressor Project, and Clark County gate/takeaway improvements. In the first several years of the plan the same amount of Mist Recall is taken in all portfolios. Beginning in 2020 varying levels of Mist Recall are taken in each portfolio due to the types of other resources available (see below). For example, if capacity is acquired on an interstate pipeline then additional Mist Recall is pushed further into the planning horizon. However, if a storage resource is acquired (i.e., North Mist Expansion) then additional Mist Recall is taken sooner.

Shorter Term Acquisitions

The following projects are selected under each scenario at the same point in time to address specific system deficiencies :

1) Mist Recall (beginning in 2015)
2) Clark County gate/distribution system upgrades (beginning in 2014)
3) South Salem Feeder (2019)
4) Christenson Compressor Project (2025)

Mist Recall

As discussed in Chapter Three, the Company made significant changes to its firm resource stack (removal of Plymouth LNG and some TF-2 capacity from Jackson Prarie, and the addition of segmented capacity). These changes result in a net decrease in firm resources. In order to address the immeadiate needs, Mist Recall is taken in every portfolio beginning in 2015. Through 2020 the level of Mist Recall taken is the same for each portfolio in order to replace resources which are being phased out and to serve increased load growth in the Portland Metro area (including Clark County)(see Table 7.5 below). After 2020 the amounts of Mist Recall taken each year depends heavily on the type and size of additional resources that are acquired. For example, Mist Recall is acquired at a slower pace if additional pipeline capacity is added in 2020 compared to the addition of another storage resource.

Table 7.5 – Timing and Cumulative Volume of Mist Recall

Year	Mist Recall (Incremental Dth/day)	Mist Recall (Cumulative Dth/day)
2015	30,000	30,000
2016	0	30,000
2017	50,000	80,000
2018	25,000	105,000

Clark County Gate/Distribution System

As shown in Figure 7.5 above, NWP gate stations serving Vancouver/Clark County are insufficient to serve current (2014) design day peak demand. NW Natural will need to address this issue in order to ensure no outages occur in the event of severely cold weather. NW Natural needs to address this deficiency with a number of city-gate and distribution system upgrades (see Chapter Six). Until these projects are completed NW Natural plans to continue using LNG and CNG trailers to supplement interstate pipeline deliveries to the Clark County load center under cold weather conditions to minimize the likelihood and degree of firm customer curtailment.

South Salem Feeder

The Salem area has experienced low pressure during recent cold weather events and, as is shown in Figure 7.5 above, beginning in 2019 the projected peak day demand in the Salem area is expected to outstrip the available capacity into the Salem area. The South Salem Feeder allows gas from the

Newport LNG facility to reach the Salem load center under cold weather conditions. The only other alternative to serving this demand in the Salem area is improved takeaway and/or new takeaway from the Grants Pass Lateral combined with new pipeline capacity to the Salem gate stations.

Christenson Compressor Project

The Christenson Compressor Project (CCP) is selected in each scenario in 2025. The CCP provides additional peaking gas supply from Newport LNG to Salem and Albany via the Mid-Willamette Valley Feeder. Due to the design of the pipeline system, output from the Newport LNG facility, while rated at 100 MDT/day, can only deliver 60 MDT/day of output. The CCP project would allow the system to handle the full capacity from the Newport LNG facility, providing an additional 40 MDT/day of peaking supplies to the Salem and Albany load centers.

Longer Term Acquisitions

It is highly uncertain which resources the Company will rely on past 2020. There is a large degree of uncertainty regarding proposed regional gas demand projects (such as methanol/feedstock plants, Jordan Cove LNG, and Oregon LNG) and the prospective interstate pipelines needed to serve them (Cross-Cascades, Pacific Connector, and Washington Expansion). This uncertainty surrounding regional projects outside of NW Natural's control makes it difficult to develop a portfolio of specific long-term resources, as the least cost portfolio depends on which scenario unfolds.

The portfolio NPVRR results are shown in Table 7.6 below and detailed results for each portfolio are found in Appendix 7. The results show that in every future scenario, the North Mist Expansion is a component of the lowest cost portfolio. In scenarios A1 and A3 North Mist Expansion is the primary long-term resource acquired due to its lower cost as compared to the Clark County LNG facility and a Sumas Expansion (Regional Project). In scenario A2 Cross-Cascades is chosen as the main long-term resource at a capacity of 110 MDT/day combined with a turnback of 55 MDT/day of vintage NWP capacity through the Gorge, resulting in a net increase in pipeline capacity of 55 MDT/day. In order to serve additional load growth later in the planning horizon, North Mist is selected in 2030.

Table 7.6 – Cost of Alternative Resource Portfolios in Alternative Scenarios

Scenario A1				
	Supply NPVRR ($000)	Transportation NPVRR ($000)	Storage NPVRR ($000)	Total NPVRR ($000)
NM/SE(L)	4,762,240	1,390,824	436,331	6,663,006
CCLNG/NM	4,778,362	1,240,607	606,488	6,699,067

Scenario A2				
	Supply NPVRR ($000)	Transportation NPVRR ($000)	Storage NPVRR ($000)	Total NPVRR ($000)
CC/TB/NM	4,778,185	1,367,457	387,497	6,606,748
NM/SE(L)	4,747,500	1,389,954	436,631	6,647,694
CCLNG/NM	4,761,515	1,240,074	606,525	6,681,723
SE(R)	4,731,370	1,533,256	356,508	6,694,743

Scenario A3				
	Supply NPVRR ($000)	Transportation NPVRR ($000)	Storage NPVRR ($000)	Total NPVRR ($000)
NM/SE(L)	4,762,240	1,390,824	436,331	6,663,006
CCLNG/NM	4,778,362	1,240,607	606,488	6,699,067
SE(R)	4,741,258	1,536,201	356,498	6,707,566

Scenario B1				
	Supply NPVRR ($000)	Transportation NPVRR ($000)	Storage NPVRR ($000)	Total NPVRR ($000)
CC/TB/NM	4,709,493	1,465,471	387,318	6,635,891
NM/SE(L)	4,648,617	1,487,237	436,604	6,646,067
CCLNG/NM	4,672,254	1,339,365	606,883	6,692,112
WEX	4,842,551	1,565,400	358,283	6,839,843

Scenario B2				
	Supply NPVRR ($000)	Transportation NPVRR ($000)	Storage NPVRR ($000)	Total NPVRR ($000)
PCGP/NM	4,854,781	1,389,441	391,066	6,708,897
NM/SE(L)	4,876,372	1,391,765	434,956	6,776,703
CC/TB/NM	4,850,835	1,485,642	386,736	6,796,823
SE(R)	4,843,121	1,535,410	356,584	6,808,724
CCLNG/NM	4,902,162	1,240,778	606,639	6,823,189

Figure 7.8 shows the potential range of portfolio costs for each future. It is clear that with any LNG exports from Oregon, total portfolio costs increase. These cost increases are driven by increased commodity costs either directly or indirectly by the need to acquire upstream capacity in order to mitigate the risk of price spikes at relatively illiquid market hubs.

Figure 7.8 – Ranges of Net Present Value of Revenue Requirements for Certain Scenarios

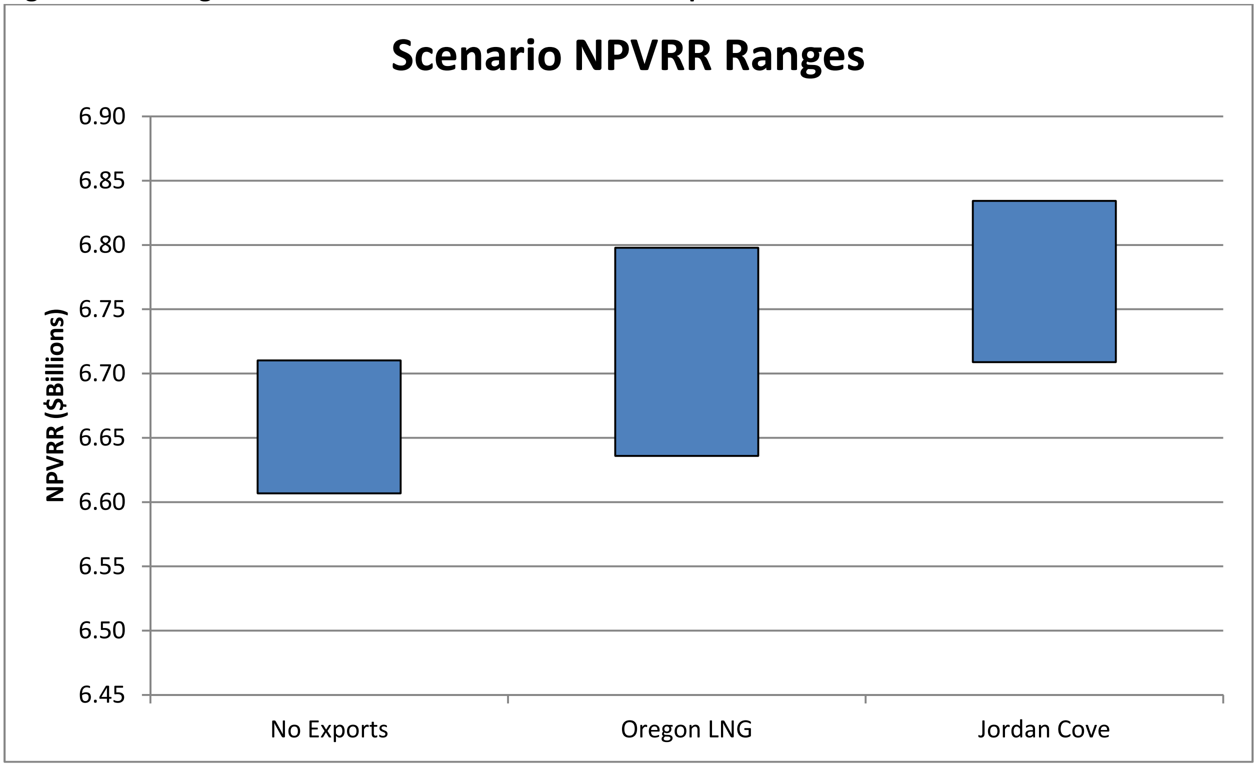
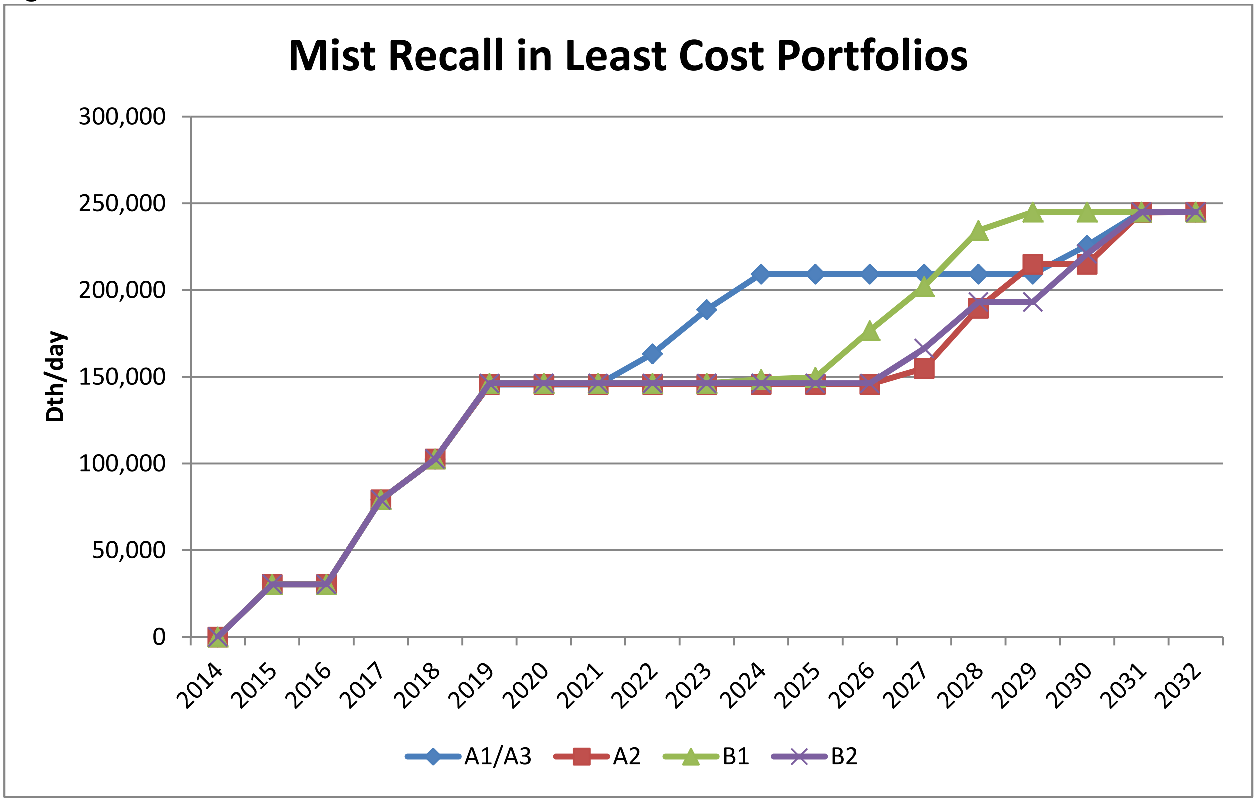


Table 7.7 – Summary of Resource Additions by Scenario for Least Cost Resource Portfolios

Scenario	Resources Selected in Least Cost Portfolios		Total NPVRR ($Billion)
	Distribution Resources	Supply Resources	
A1: No Regional Project (no LNG Exports)	Clark County Improvements (2014) South Salem Feeder (2019)	Segmented Capacity (2014-2019) Mist Recall (2015) North Mist Expansion (2024) Christenson Compressor (2025) Sumas Expansion (Local) (2030)	**$6.663**
A2: All Regional Options (no LNG Exports)	Clark County Improvements (2014) South Salem Feeder (2019)	Segmented Capacity (2014-2019) Mist Recall (2015) Cross-Cascades (2020) Christenson Compressor (2025) North Mist Expansion (2030)	**$6.607**
A3: Washington Expansion (no LNG Exports)	Clark County Improvements (2014) South Salem Feeder (2019)	Segmented Capacity (2014-2019) Mist Recall (2015) North Mist Expansion (2024) Christenson Compressor (2025) Sumas Expansion (Local) (2030)	**$6.663**
B1: Oregon LNG	Clark County Improvements (2014) South Salem Feeder (2019)	Segmented Capacity (2014-2019) Mist Recall (2015) Cross-Cascades (2020) Christenson Compressor (2025) North Mist Expansion (2030)	**$6.636**
B2: Jordan Cove	Clark County Improvements (2014) South Salem Feeder (2019)	Segmented Capacity (2014-2019) Mist Recall (2015) Pacific Connector (2020) Christenson Compressor (2025) North Mist Expansion (2030)	**$6.709**

Figure 7.9 – Mist Recall Volumes in Least Cost Portfolios for Alternative Scenarios



NW Natural draws the following conclusions from these results:

1) <u>A North Mist Expansion is needed within the planning horizon under every scenario, and potentially as soon as 2020 under certain conditions.</u>

   An important finding in this IRP is that a North Mist expansion project is part of the portfolio regardless of the future that comes to fruition. This indicates that no matter the future that plays out a North Mist expansion is part of a least cost portfolio. As discussed in Chapter Three, a more detailed analysis is still required for this resource. As modeled here, North Mist is not connected with current Mist storage or transmission facilities. It's initial concept was as a separate standalone set of facilities. This results in North Mist capacity being acquired before all Mist Recall is taken in order to satisfy the MDDO requirement in Clark County by using the new north bound takeaway route. However, there could be other configurations which integrate North Mist facilities with the existing Mist storage facilities or other ways to address the MDDO issue which would not require the Company to use North Mist storage capacity before all Mist Recall capacity is taken. It is important to note that even if the Company addresses these issues, North Mist would still be part of the resource portfolio after all of Mist Recall is acquired. Additionally, in order to preserve the North Mist option as modeled here, NW Natural would require that the planned pipeline extending north from the reseviors be upsized when it is constructed.[3] NW Natural will conduct additional analysis regarding the option of upsizing the takeaway capacity of the project and any alternative pathways. It is not anticipated that a decision on the size of the pipeline will have to made until the end of 2015.

2) <u>Additional pipeline capacity is needed under every scenario. Which particular pipeline option is the least cost option depends upon the future that unfolds.</u>

   NW Natural expects that it will be a shipper for additional capacity on an as of yet undetermined interstate pipeline given that an interstate pipeline option is selected as part of the least cost portfolio in all scenarios. The Cross-Cascades pipeline with commodity supplies from Malin, bundled in as part of NWP's NMAX service for delivery to NW Natural load centers, is the lowest cost interstate pipeline potential option not dependent on export LNG. Its viability, however, is dependent on sufficient regional subscription to economically justify the pipeline's construction. Alternatively, if the Jordan Cove LNG project goes forward and the Pacific Connector is built, subscribing to PCGP is the least cost alternative. Consequently, NW Natural's best course of action is to preserve the optionality to be a shipper on the Cross-Cascades or Pacific Connector pipeline.

   If neither Cross-Cascades nor Pacific Connector pipelines are developed, then the Company's fallback (or default) plan for additional interstate pipeline is a Sumas Expansion (Local) which would follow a North Mist project. While more expensive than regional pipeline options in other scenarios, the SE(L) can be somewhat timed and sized more closely to the Company's needs. This capacity would not be needed until 2025 at the earliest. Consequently, no action is necessary at this time. In the meantime, the Company will continue to explore lower cost alternatives. As always, these options, as well as any new alternatives, will be evaluated again in the next IRP.

3) <u>The value of flexibility from Mist Recall is demonstrated by the varying amounts and timing of North Mist and interstate pipeline capacity added to the portfolios.</u>

   In contrast to the many pipeline options where NW Natural must add capacity in large blocks, Mist Recall's flexibility allows the Company to respond to changes in resource needs by adding in small blocks of capacity. Figure 7.9 above shows the cumulative Mist Recall additions over time for the least cost portfolio in each scenario.

4) <u>Subscribing to the Washington Expansion or a regional Sumas Expansion is not chosen in any scenario.</u>

   In each scenario modeled, neither the Washington Expansion nor Sumas Expansion (Regional) were selected as part of a least cost portfolio. In the Oregon LNG scenario there are two portfolios which would have a lower expected NPVRR – CC/TB/NM and NM/SE(L). The WEX and

[3] See Chapter Three for a discussion of optionality associated with North Mist.

SE(R) are both higher cost than Cross-Cascades on a per unit basis when all upstream and downstream requirements are considered (Table 7.7 above). North Mist is also lower cost and would delay the need for additional interstate capacity by a number of years, giving NW Natural time to evaluate any new pipeline option which becomes available.

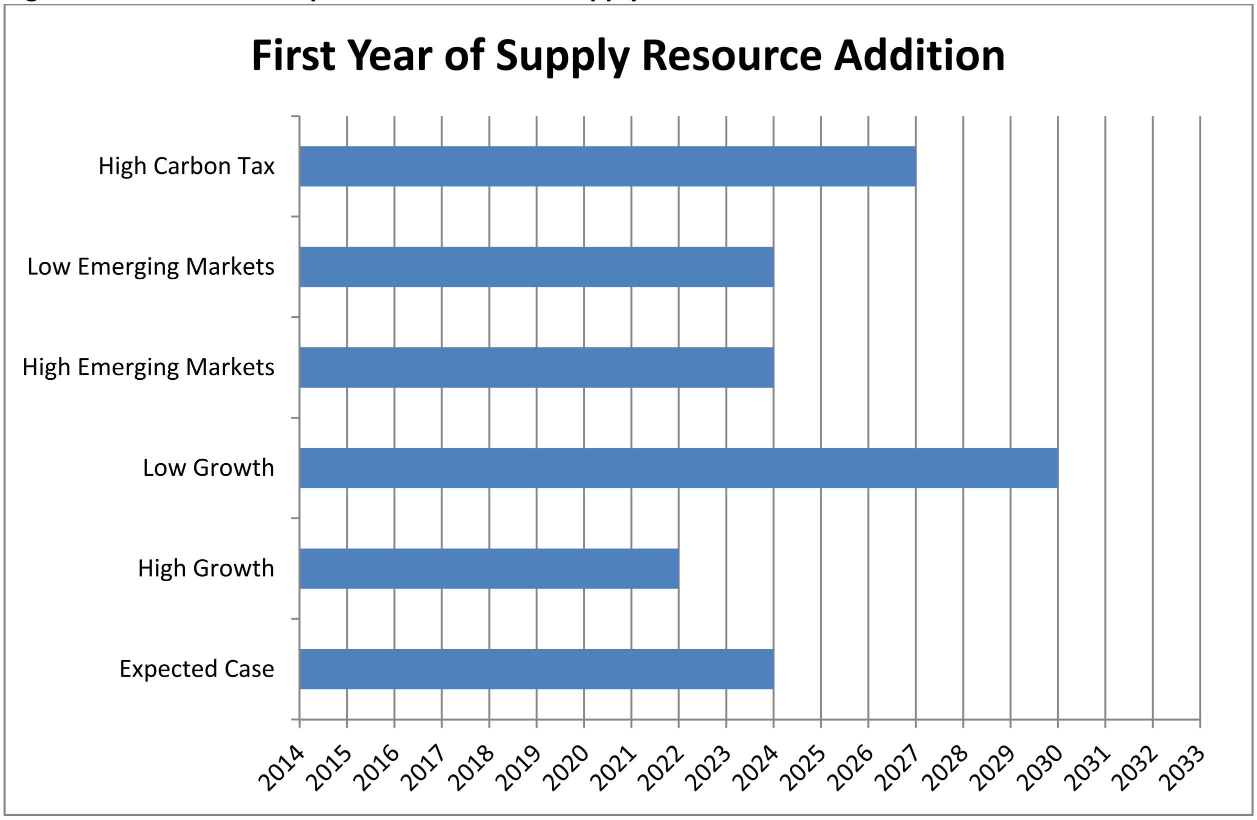
5) The least cost scenario is no LNG with a Cross-Cascades pipeline; the highest cost scenario is Jordan Cove LNG with Pacific Connector.

   The future which provides NW Natural customers with the lowest expected costs is one in which there are no LNG exports and Cross-Cascades is available. In this scenario gas prices are low at the production basins and stable at market hubs, meaning that the Company is able to purchase gas at good prices without necessarily subscribing to all the upstream capacity. Alternatively, the highest cost future is one with LNG exports out of Jordan Cove. In this scenario not only are gas prices higher, but the Company would also subscribe to pipeline capacity upstream of market hubs to avoid price spikes at those hubs during the heating season.

C. Additional Model Runs

In addition to looking at the expected case assumptions, NW Natural analyzed a number of demand scenarios. These include high/low customer growth, high/low emerging market loads, and a carbon dioxide emissions tax. Figure 7.10 below shows the first year in which a supply resource (other than Mist Recall and without consideration of an MDDO standard) is added for each of the five scenarios as compared to the expected case. With the exception of the low growth scenario, all scenarios are seen adding a supply resource within three years of the expected case. The low growth scenario first adds a new supply resource in 2030.

Figure 7.10 – Scenario Impact on First Year of Supply-side Resource Addition



D. Reliability

1. Design Weather (Previous Planning Standard)

As part of the Company's risk planning, the design weather has been updated from earlier IRPs to reflect a colder winter period. Modeling results (Appendix 7) show no material changes to the portfolio.

2. Resource Reliability (Probabilistic Planning)

In the 2013 WA IRP and 2011 OR IRP Update the Company began to explore the idea of probabilistic resource planning—planning for less than 100 percent resource availability. What is presented here is an example of an approach the Company is considering using in future IRPs to further evaluate the risk inherent in a portfolio and has no bearing on the Companys current resource acquisition plan.

<u>Methodology</u>

The analysis begins by creating the probability distribution of the incidence of HDD = x (or >= x) and a storage resource outage occurring within a winter period (November - February) (Figures 7.11 and 7.12). A 30-year weather history is used to compute the HDD probabilities. It is assumed that each storage resource has an outage occurrence of one time in five years.[4] Using SENDOUT®, every combination of

---

[4] Based on internal expert knowledge. In the future, this parameter should be computed from historical observations.

year, HDD, and storage resource outage is simulated. For each HDD in each planning year, the unserved demand given a certain resource outage (assuming all other resources are at full deliverability) is found.

Figure 7.11 – 30-Year Cumulative Distribution Function for Winter Temperatures

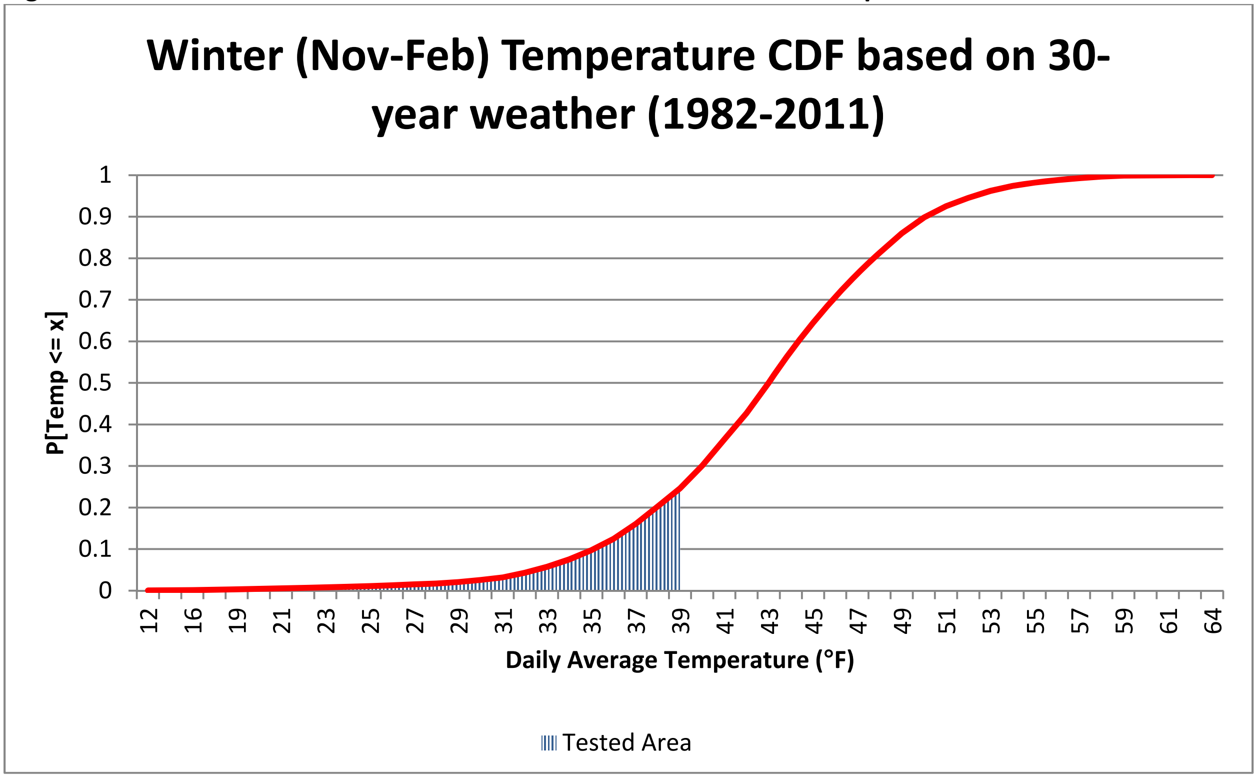
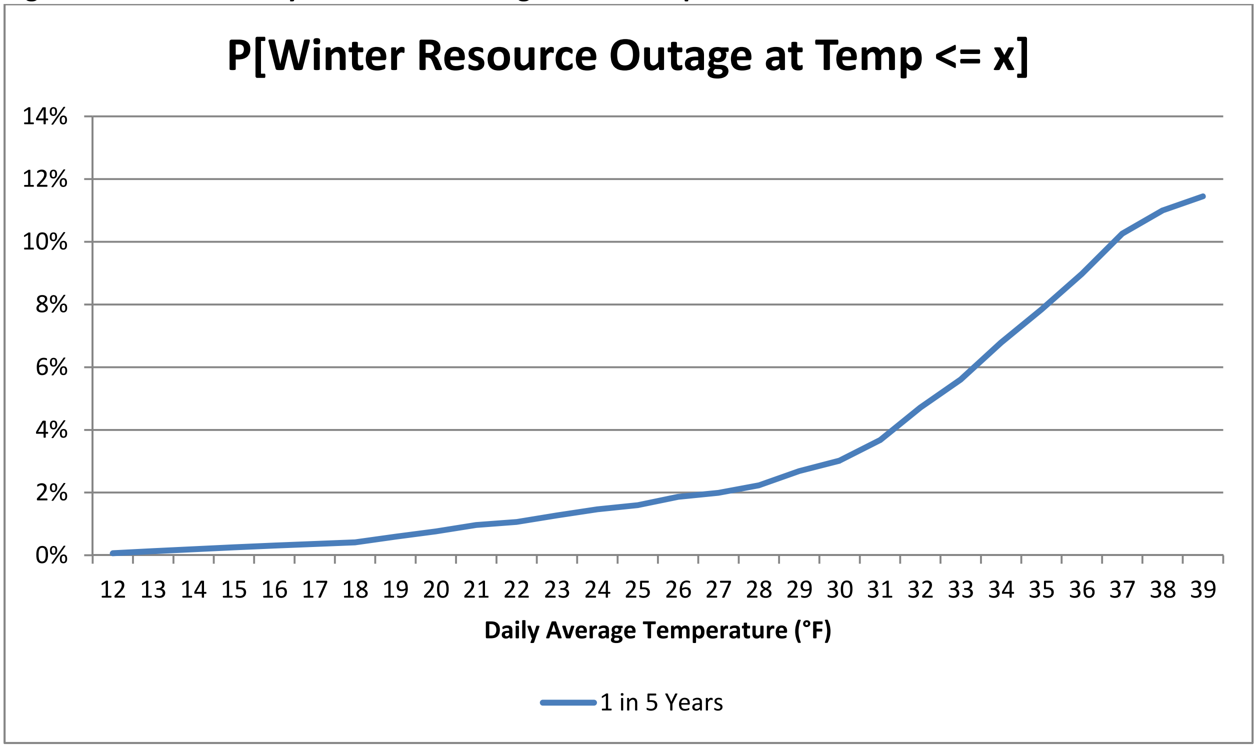


Figure 7.12 – Probability of Resource Outage Given Temperature



<u>Example Results</u>
Figure 7.13 shows, for the 2017 heating season, the unserved demand over a range of HDD when the Gasco LNG facility is not operating along with the expected joint probability of the HDD and outage occurring within the heating season. Figure 7.14 shows, for each year of the planning horizon, the expected (probability-weighted) unserved demand. Note that the drops in expected unserved demand in 2018 and 2025 are due, respectively, to the addition of interstate pipeline capacity and increased Newport LNG output.

Figure 7.13 – Unserved Demand and Temperature for GASCO Resource Outage Example

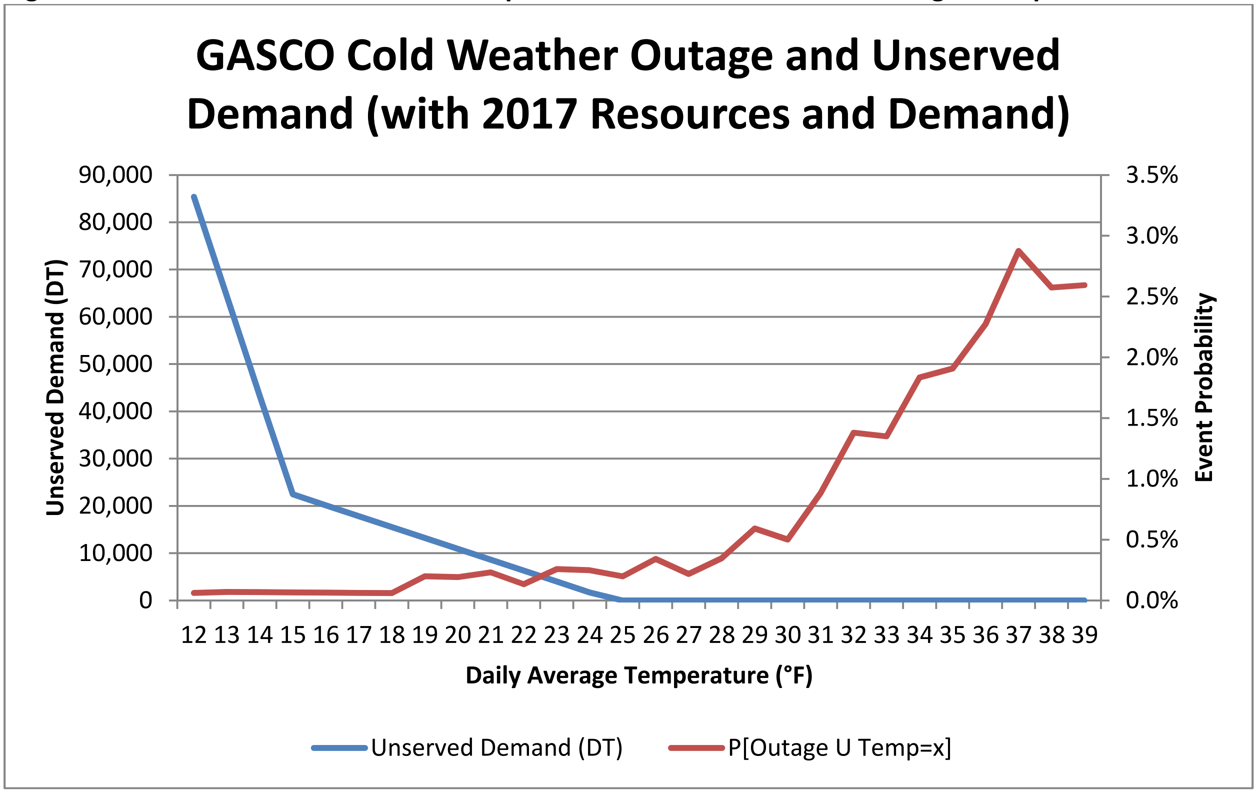


Figure 7.14 – Expected Annual Unserved Demand for GASCO Resource Outage Example

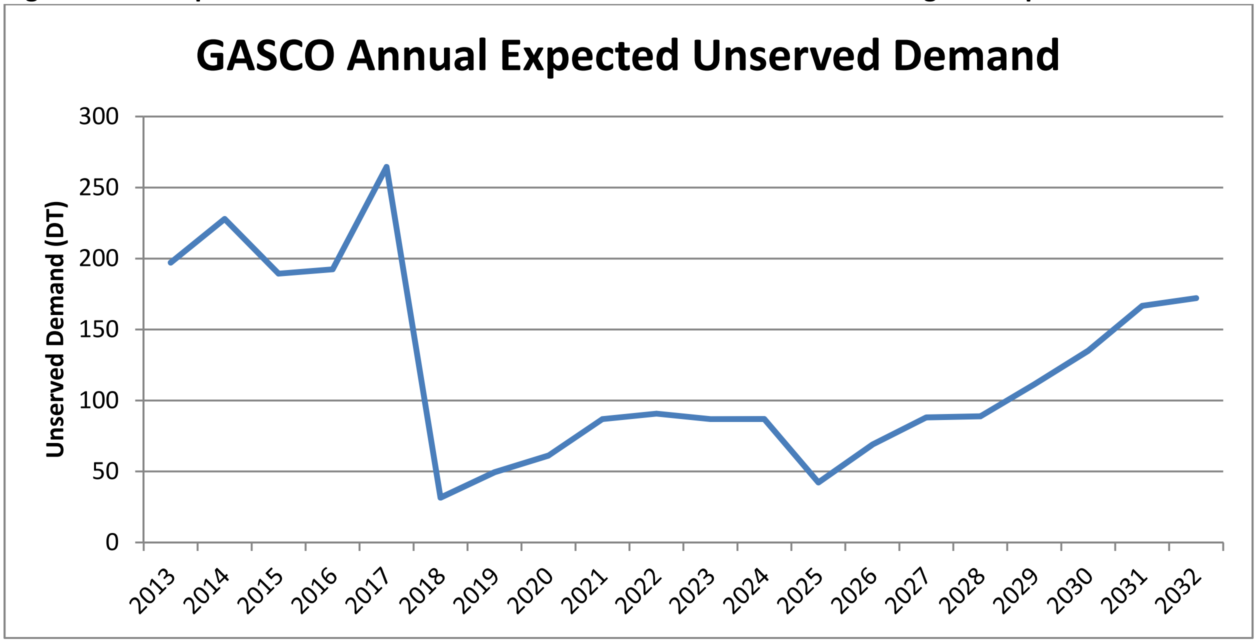
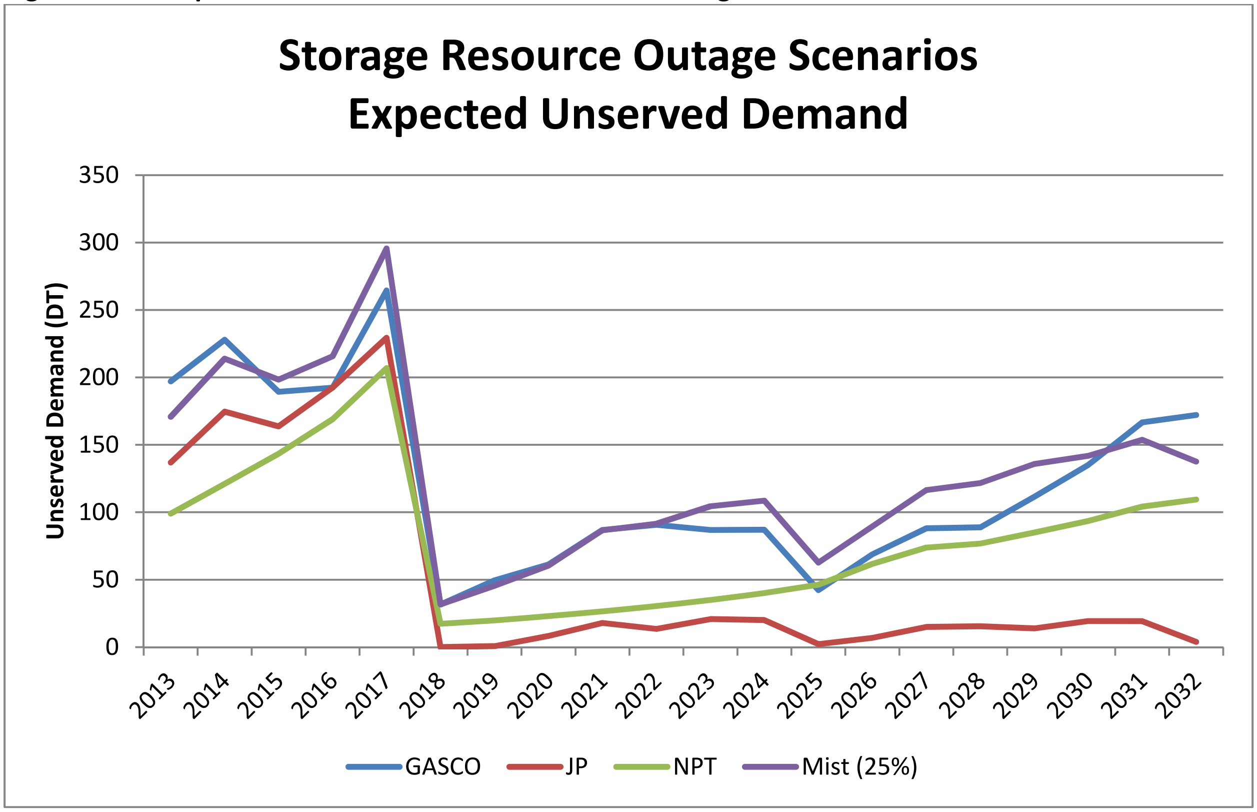


Figure 7.15 compares the expected unserved demand over the planning horizon when outages are considered for each of four storage resources. Using this comparative approach, the Company could evaluate the relative reliability of each storage facility and plan appropriately.

Figure 7.15 – Expected Annual Unserved Demand for Storage Resources



III. Portfolio Risks

NW Natural addresses portfolio and scenario risk in a number of ways. Each portfolio is constructed around a weather pattern that represents the 90th percentile of winter weather conditions with an extreme weather event superimposed (see Chapter Two for details). Using this design weather pattern allows the Company to select the resources which limit the risk of loss of load during cold weather. At the scenario level the largest risks are 1) gas price volatility and 2) new pipeline tariff uncertainty. Gas price volatility is addressed by using distinct gas price scenarios developed by IHS CERA.[5] Basin prices have historically been highly correlated. However, there is a significant risk that an LNG export facility could cause the price at one or more basins to diverge from other basins.

NW Natural contracted with Willbros to evaluate the construction cost risk associated with three possible future pipelines (Cross-Cascades, Washington Expansion, and Pacific Connector).[6] From these cost estimates the Company constructed the range of tariff rates which it could expect to pay if it were to contract on one of these pipelines. Table 7.8 below shows the low, expected, and high NPVRR values associated with low, mid-range, and high construction costs for prospective interstate pipelines.

---

5 See IHS CERA report, Appendix 7.

6 See Willbros report, Appendix 7.

Table 7.8 – Scenario NPVRR Values with Alternative Levels of Interstate Pipeline Construction Costs

Portfolio	Scenario A1		
	Low	**Mid**	**High**
NM/SE(L)		6,663,006	
CCLNG/NM		6,699,067	

Portfolio	Scenario A2		
	Low	**Mid**	**High**
CC/TB/NM	6,559,434	6,606,748	6,662,934
NM/SE(L)		6,647,694	
CCLNG/NM		6,681,723	
SE(R)	6,679,957	6,694,743	6,721,357

Portfolio	Scenario A3		
	Low	**Mid**	**High**
NM/SE(L)		6,663,006	
CCLNG/NM		6,699,067	
SE(R)	6,692,780	6,707,566	6,734,180

Portfolio	Scenario B1		
	Low	**Mid**	**High**
CC/TB/NM	6,588,577	6,635,891	6,692,077
NM/SE(L)		6,646,067	
CCLNG/NM		6,692,112	
WEX	6,825,058	6,839,843	6,866,458

Portfolio	Scenario B2		
	Low	**Mid**	**High**
PCGP/NM	6,701,907	6,708,897	6,722,876
NM/SE(L)		6,776,703	
CC/TB/NM	6,749,508	6,796,823	6,853,009
SE(R)	6,793,938	6,808,724	6,835,338
CCLNG/NM		6,823,189	

IV. Key Findings

- The Clark County area needs additional gate and distribution capacity in the short-term to provide reliable service as well as additional supply to serve long-term growth.
- The Salem area requires additional peak supply within the planning horizon.
- Increasing the Central Coast Feeder capacity by installing a compressor at Christenson is needed.
- A North Mist Expansion is needed within the planning horizon under every scenario, and potentially as soon as 2020 under certain conditions.
- Mist Recall can serve some, but not all, future supply needs . Additional pipeline capacity is needed under every scenario. Which particular pipeline option is the least cost option depends upon the future that unfolds.
- The value of flexibility from Mist Recall is demonstrated by the varying amounts and timing of North Mist and interstate pipeline capacity added to the portfolios.
- Subscribing to the Washington Expansion or a regional Sumas Expansion is not chosen in any scenario.
- The least cost scenario is no LNG with a Cross-Cascades pipeline; the highest cost scenario is Jordan Cove LNG with Pacific Connector.

Chapter 8: Avoided Cost Determination

NW Natural®

I. OVERVIEW

As part of the IRP process, NW Natural calculates a 20-year forecast of avoided costs. In this case, the avoided cost is an estimated cost to serve the next unit of demand with a supply side resource option at a point in time. This incremental cost to serve represents the cost that could be avoided through energy conservation. Therefore, the avoided cost forecast can be used as a guideline for comparing energy conservation with the cost of acquiring and transporting natural gas to meet demand. In addition, this IRP evaluates the impact that a range of environmental externalities, including CO_2 emission prices, would have on the avoided costs in terms of cost adders and supply costs. This analysis results in an expected avoided cost case based on the base case

II. COSTS INCLUDED IN AVOIDED COST

The Company's cost is comprised of the following costs:

- The long term gas price forecast compiled from a consultant's gas price forecast;
- A price for carbon included in the gas price forecast.[1]
- Gas storage carrying costs for inventory;
- Upstream variable transmission costs;
- Peak related on-system transmission costs; and
- A 10 percent adder for unidentified environmental benefits, as recommended by the Northwest Power and Conservation Council ("NWPCC").

During this process, the Company was asked to include a value in its avoided cost for risk mitigation, or rather, a hedge value. While the Oregon Commission determined in Order No. 94-590 that "the effect of conservation in reducing uncertainty in meeting load growth is included in the ten percent cost and no separate adjustment is necessary" (page 9), in its next IRP, the Company plans to investigate whether it should assign a value to the risk mitigation provided to customers through DSM and if so, what that value should be. An action item to this extent is included in this plan.

III. Methodology

The SENDOUT® resource planning model was used to generate the avoided costs. SENDOUT® contains a marginal cost report which lists the daily incremental cost to serve the next unit of demand for each demand region. The DSM functionality was turned off so energy conservation was not an option for the model; demand was served with supply side resources only. The model determines the lowest cost method for serving the next unit of demand and computes a marginal cost. This computed marginal cost includes 1) the long term gas price forecast compiled from a consultant's gas price forecast; 2) Gas storage carrying costs for inventory; 3) Upstream variable transmission costs; and 4) Peak related on-system transmission costs.

As discussed in previous chapters, it is uncertain yet which supply side resource portfolio will materialize and yet a base case needs to be created to calculate the avoided cost. Thus, using the base case demand parameters as inputs, including the design weather pattern, and base case customer and gas price forecasts, in addition to existing supply side resources, the Company's resource portfolio for purposes of the avoided cost calculation include Mist Storage Recall, Newport Refurbishment, Cross-Cascades with

---

[1] The Henry Hub spot price of natural gas IHS CERA forecasts has an embedded projected carbon cost see Chapter Five for more information.

NMAX, South Salem Feeder, and Christenson Compressor. To the extent that a resource portfolio emerges as more than likely, the Company will recalculate the avoided costs and attendant DSM.

IV. Results

Table 8.1 lists the numerical results for costs in $/DT. Further details around avoided costs are included in Appendix 8.

Table 8.1 - Avoided Cost and Environmental Externality Adder

Year	Avoided Cost (Nominal $/DT) Base Case	With 10% Conservation Base Case
2013-14	3.92	4.32
2014-15	4.02	4.42
2015-16	4.83	5.32
2016-17	4.02	4.42
2017-18	3.50	3.85
2018-19	3.59	3.95
2019-20	4.14	4.55
2020-21	4.81	5.29
2021-22	4.52	4.97
2022-23	4.25	4.67
2023-24	4.55	5.01
2024-25	4.91	5.40
2025-26	5.37	5.91
2026-27	5.72	6.30
2027-28	5.62	6.18
2028-29	5.56	6.11
2029-30	5.57	6.13
2030-31	5.71	6.28
2031-32	5.83	6.41
2032-33	6.16	6.78

Figure 8.1 charts the avoided costs resulting from the Base Case. The blue bars represent the avoided cost expressed in $/DT.

Figure 8.1 - Base Case Avoided Costs

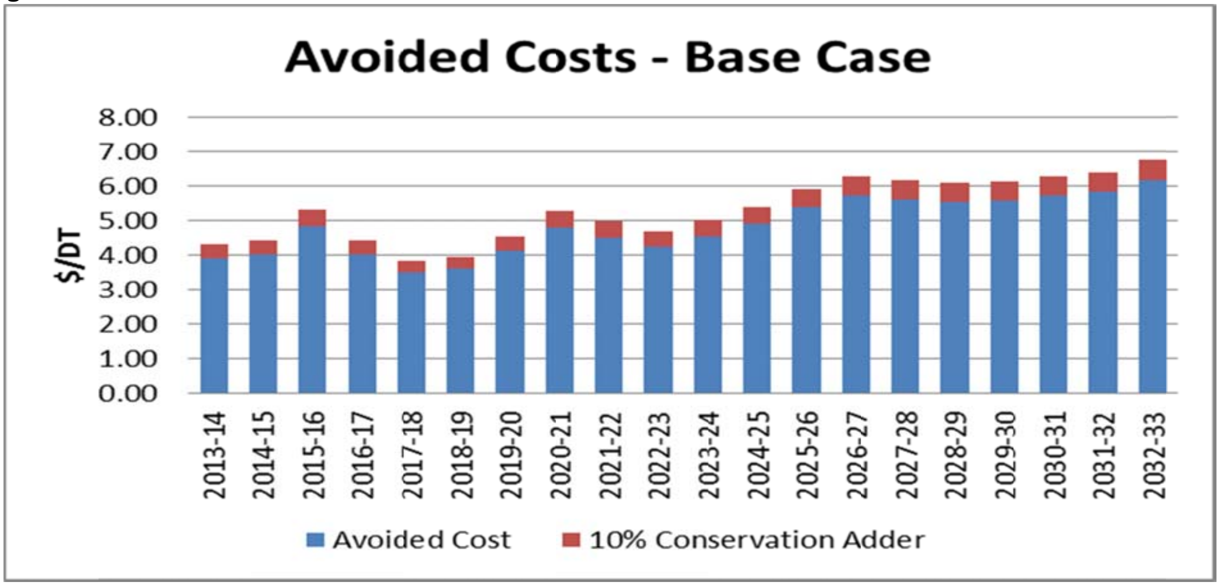
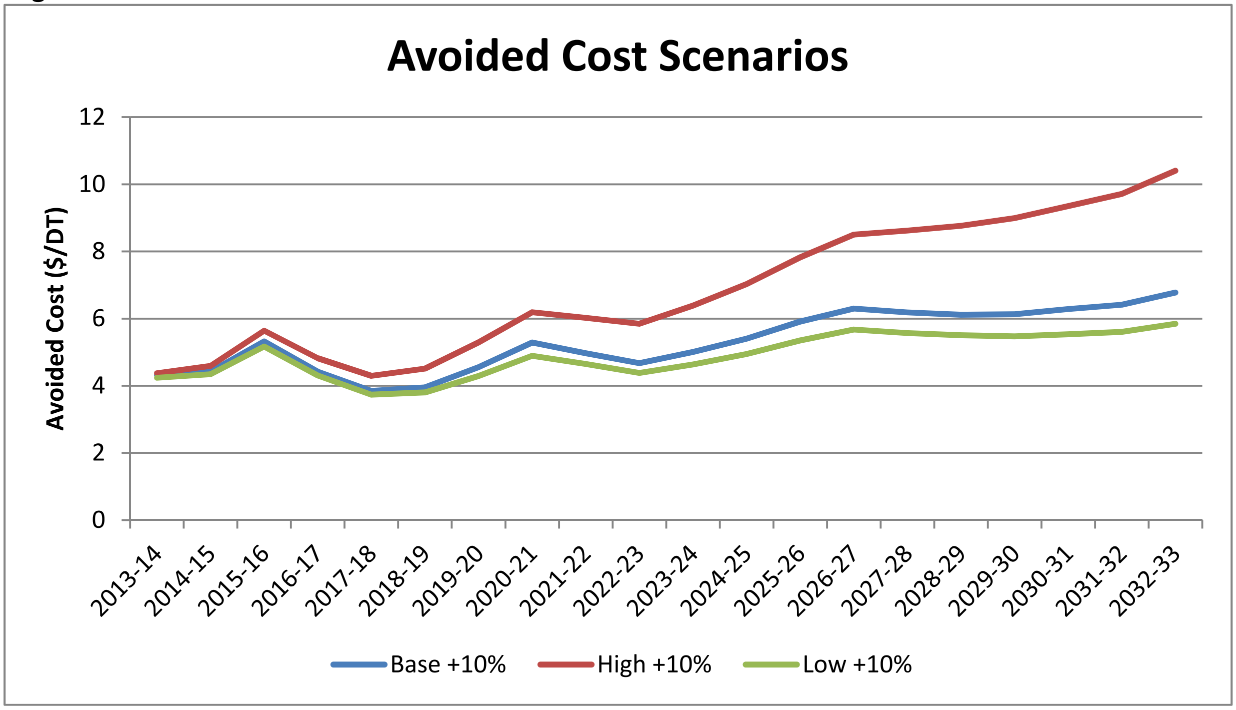


Figure 8.2 below displays the high, low, and Base Case cost scenarios with all costs rolled up—the avoided costs along with the 10 percent conservation adder.

Figure 8.2 – Avoided Cost Scenarios



V. Key Findings

Avoided costs were calculated for the expected demand and gas price and included a carbon dioxide emissions cost as well. The range in avoided cost impacted by carbon could affect the amount of cost effective DSM that is achievable in future years.

Chapter 9: Public Participation

NW Natural®

I. 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 the Citizen's Utility Board, Energy Trust of Oregon; Northwest Energy Coalition Council, Northwest Power and Conservation Council; Northwest Industrial Gas Users; Northwest Pipeline Corporation; the Public Utility Commission of Oregon Staff; the Washington Utilities & Transportation Commission Staff; and the Northwest Gas Association.

NW Natural hosted six TWG meetings and one scenario building workshop as part of its 2014 IRP process. Below is a brief summary of each meeting.

- <u>TWG No.1 held on August 22, 2013</u>
  NW Natural reviewed a recap from most recent 2013 NW Natural Washington IRP and 2013 Oregon IRP Update, projected major issues/updates for 2014 IRP, the Gas Supply Outlook and Price Forecast, and our preliminary forecast results

- <u>TWG No. 2 held on October 2, 2013</u>
  NW Natural reviewed the revised load forecast, discussed scenarios, and discussed the criteria to be used to determine what Distribution System Planning projects should be included in the IRP.

- <u>Scenario Workshop – November 22, 2013</u>
  NW Natural held a half-day scenario workshop as opposed to a technical working group to try to identify those scenarios that were most meaningful to the technical working group.

- <u>TWG No. 3 scheduled on December 10th</u>
  This TWG was cancelled due to weather.

- <u>TWG No.4 held on January 23, 2014</u>
  NW Natural invited Energy Trust of Oregon to discuss the demand side management forecast and then the Company presented its emerging price forecast, discussed changes to the resource stack, reviewed preliminary base case findings and discussed the scenarios and sensitivities it would be running.

- <u>TWG No. 5 held on March 7, 2014</u>
  NW Natural presented an overview of both the SENDOUT® and the SynerGEE® models, explained the potential constraints of modeling, discussed modeling results and then provided a summary of its draft IRP that was sent to parties on February 28, 2014.

- <u>TWG No.6 held on April 3, 2014</u>
  NW Natural discussed the possible regional pipelines and LNG export terminals; provided an overview of its risk analysis and carbon pricing analysis; and discussed its hedging practices and plans to refurbish its Newport LNG facility.

- <u>TWG No. 7 held on July 11' 2014</u>
  NW Natural discussed its risk analysis, its analysis of additional supply-side alternatives, and reviewed its T-South renewal decision.

Appendix 9 contains the sign in sheets for each TWG meeting

II. PUBLIC PARTICIPATION

NW Natural invited customers to participate in the resource planning process by hosting a public meeting on the evening of April 15, 2014. A bill insert sent to all customers in December 2013 billings informed customers about the IRP process, welcomed customers to submit comments, and invited customers to attend the public meeting. Two customers submitted comments. Copies of those comments are included in Appendix 9.

Appendix 1: Regulatory Compliance

NW Natural's 2014 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.		
	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, including some specifically requested by stakeholders. 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, and the system enhancements necessary to distribute the gas. The demand-side study looked at all the potential energy savings available within the Company's service territory.	3,4, and 7
	Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling	Chapters Three and Four focus on supply- and demand-side resources, respectively. The supply-side options considered in Chapter Three range from existing and proposed interstate pipeline capacity from multiple providers and NW Natural's Mist underground storage to 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, NW Natural pipeline enhancements, and interstate pipeline expansions. The in-service dates of prospective resources range from short-term, such as Mist Recall supplies available in Fall 2014, to longer-term resources such as new interstate pipelines, which have been modeled using 2020 in-service dates. 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 such as biogas, which is not currently available but has been identified for continued monitoring and future assessment.	3,4, and 7
	Consistent assumptions and methods should be used for evaluation of all resources.	NW Natural evaluated all resources, both supply- and demand-side, on a consistent basis in the SENDOUT® model, which programmatically and objectively applied common assumptions, approaches and methodology to each supply-side resource option. This specifically included consideration of end effects for prospective on-system resources. Chapter Seven includes specific descriptions of the resource evaluation methodology.	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 4.58 percent in this IRP, which it derives using the currently authorized values associated with its cost of capital in Oregon. The Company incorporates a 1.9 percent annual rate of inflation, which it estimated using methods with which the Commission is familiar.	7
Guideline 1(b)	Risk and Uncertainty must be considered.		

NW Natural's 2014 IRP - Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
1.b.2	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 wide range of sensitivities and scenarios 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 first projected annual customer counts by customer sub-class and prepared three scenarios of customer growth, including a Base Case and low and high load growth scenarios. The Company statistically estimated gas usage equations for each customer subclass (or market segment). NW Natural derived design year (including peak day) projections using multiple regression analysis, separating baseload use and temperature-sensitive use. The Company integrated design weather conditions, projected prices, and customer forecasts with gas usage equations to derive firm gas requirements for the Base Case forecast and each scenario. Additionally, NW Natural used a Base Case plus high and low gas price forecasts and developed high and low customer growth forecasts as well. Stemming from the Company's understanding that natural gas is at an inflection point, with a future evolving that differs from the past, NW Natural's planning includes three different load forecasts for emerging markets. NW Natural discusses risk and uncertainty associated with commodity supply, prices, and availability of transportation capacity in Chapter Seven, which also discusses the results of sensitivity analysis involving price simulations for future supply basin-specific and North American supply restrictions. NW Natural also contracted with outside consultants to evaluate the supply basin price differential risk that might arise with an LNG Export facility coming on line as well as to assess the construction risk of certain potential future resource options. Finally, this IRP discusses the impacts of complying with prospective greenhouse gas emissions regulation and the risk and uncertainty associated with these in Chapters Four and Five. Chapter Four contains the Company's evaluation of cost effective demand-side management based on an avoided cost that included an emission adder (a carbon price). The higher avoided cost resulted in a higher level of achievable demand-side resource potential than would result absent inclusion of an emission adder. Chapter Eight includes high and low sensitivities of NW Natural's avoided cost.	2, 3, 4, 5, 7, 8
	Utilities should identify in their plans any additional sources of risk and uncertainty.	Additional sources of risk have been evaluated by the Company. Specifically, the Company identifies the risk of assuming 100 percent reliability for the supply-side resources in the Company's firm resource stack during an extreme weather event. Additionally, NW Natural is evaluating the risk of relying upon un-contracted gate station capacity exceeding the Company's contracted Maximum Daily Delivered Obligation (MDDO) with Northwest Pipeline.	3, 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 numer of interstate pipeline projects. The analysis considers all costs that could reasonably be included in rates over the long term, which extends beyong the planning horizon and the life of the resource.	7

NW Natural's 2014 IRP - Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
	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.	3,6,7
	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 scenario and sensitivity analyses discussed 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 Three discusses hedging in detail.	3
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	This IRP uses a 90th percentile design weather standard augmented by an historic seven-day peak event to evaluate the cost and risk trade-offs of various supply- and demand-side resources. This planning standard reflects the Company's assessment that costs associated with using a higher planning standard are not justified in comparison with the risk of weather occurring that is colder. Further analysis of how the Company's resource choices appropriately balance cost and risk are in Chapter Seven. In short, NW Natural considered not only the strictly economic data the Company assessed using SENDOUT®, but also the likelihood of certain resources such as satellite LNG being available, analysis of demand and price forecasting, and the non-economic but significant reliability benefits offered by certain resources.	1,7

NW Natural's 2014 IRP - Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
Guideline 1(d)	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	Policy appears to be trending toward carbon constraints. To this end, the Company's gas price forecast includes a carbon price beginning in 2021 at a level of $8.74 per metric ton of CO2 equivalent (MTCO2e) and increasing annually to $15.70 per MTCO2e in 2033 (both prices in $2013). NW Natural considers the carbon price forecast in scenario development as a carbon tax on the carbon content of combustible fuels implemented on a national (or broad regional) basis and similar in its implementation to that currently in effect in British Columbia, Canada. It is still unknown the extent of the impact from the Environmental Protection Agency's Regulation 111(d) this too is being taken into consideration and monitored as the electric utilities make their plans known. Climate change regulation may also require more DSM or through taxation cause more DSM to be cost effective. New and developing state and federal policies are discussed in Chapters Four and Five.	2,3,4,5,and 8
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 2014 IRP. The Company held six Technical Working Group (TWG) meetings, one workshop, and one public meeting. NW Natural notified customers of the 2014 IRP process in an December 2013 bill insert, which invited the submission of written or electronic comments and announced the April 15 public meeting. Chapter Nine discusses the technical working groups and the public meeting. Beyond these forums, the Company has been answering parties' informal data requests.	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 February 28, 2014, after conducting three TWG meetings, an initial draft plan in both Oregon and Washington. The draft plan was discussed at a technical working group meeting held on March 7, 2014.	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 2011 Modified IRP on May 9, 2012; see Order No. 12-161 in Docket No. LC 51. NW Natural requested a four month extension of the 2014 filing date on April 22, 2014. The Commission granted the Company's request in Order No. 14-179 on May 28, 2014 in the Company's 2014 IRP Docket No. LC 60, with a filing date of August 29, 2014.	
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.	

NW Natural's 2014 IRP - Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
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:		

NW Natural's 2014 IRP - Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
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. However, the IRP also analyzes scenarios associated with both high and low demand growth. The Company additionally considers three scenarios that address demand generated from emerging markets and scenarios using various prices that could impact load. Chapters Two and Five discuss these scenarios. Chapter Seven provides the load scenario and risk analysis results. Chapter Two details the assumptions for this analysis. With respect to stochastic load risk analysis, a primary source of load risk stems from futures NW Natural views as having binary outcomes; e.g., an LNG export facility is developed at a specific location by a specific time or it is not. As a result, NW Natural's discrete scenario analysis affords a better understanding of resource planning impacts given futures having what may be viewed as random outcomes.	2, 5 and 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 the appendix to Chapter Seven 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

NW Natural's 2014 IRP - Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
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. Chapter Three 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 Four and Appendix Four. Chapter Seven and its appendices also set forth the major cost assumptions.	3,4, and 7
Guideline 4(f)	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	Explanation: Chapter Three 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 Six discusses the approach the Company uses to provide reliable service at the Distribution System Planning Level.	3 and 6
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 identified the gas price forecasts, which represent key assumptions. The Company also included a cost of carbon in its Base Case price forecast and analyzed sensitivities related to the price of carbon. Further, The Company identified specific environmental compliance costs that were factored into the determination of the Company's avoided cost, which in turn factored into the identification of cost-effective demand-side resources. The assumptions for the various scenarios included in Chapter Seven may be found in its associated Appendices.	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

NW Natural's 2014 IRP - Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
Guideline 4(i)	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties.	NW Natural developed price, load, and carbon dioxide emissions tax sensitivity cases in addition to the alternative scenarios mentioned in 4(h) above. The price sensitivity cases differ from the alternate scenarios in that they do not provide for a new resource mix decision (i.e., composition of the resource portfolio is held constant). Instead, the purpose of these sensitivities is to stress test the resource portfolio to changes in the Base Case gas price forecast. In the load sensitivity cases, standard deviations of variables associated with load levels were used to generate high and low demand forecasts. In the carbon dioxide emissions tax sensitivity cases, changes in the forecasted demand are driven by price elasticities and increased cost of delivered natural gas with varying levels of tax. Taking the high and low forecasts and forecasts under increased carbon emissions taxes, a candidate portfolio was evaluated which tested the timing of the first resource acquisition other than Mist Recall.	
Guideline 4(j)	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Chapters One and Seven describe the resource options evaluated and discuss uncertainties associated with resource availability, construction lead time, and cost (e.g., LNG storage). These chapters also discuss the evaluation results.	1, 7
Guideline 4(k)	Analysis of the uncertainties associated with each portfolio evaluated.	Chapters One and Seven discuss the analyses and results of the uncertainties associated with each portfolio.	1,7
Guideline 4(l)	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.	NW Natural evaluated cost/risk tradeoffs for each portfolio of resources in five different futures. Chapters One and Seven describe the Company's portfolio analysis.	1,7
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 (e.g., satellite LNG, imported LNG) due to facility siting / permitting challenges, market viability, and others. Chapters Three and Seven discuss such potential barriers. Additionally, all implications of the EPA's draft carbon pollution standards under Sections 111(b) and 111(d) are not well understood at this time.	5
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	

NW Natural's 2014 IRP - Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
Guideline 6(a)	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	As discussed in Chapter Four, 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.	4 and 8
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 Four 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.	4
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 40 percent of the Company's throughput. This allows the Company to reduce system stress during periods of unusually high demand.	

NW Natural's 2014 IRP - Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
Guideline 8	Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for CO2, NOx, SO2, and Hg emissions. Utilities should analyze the range of potential CO2 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 NOx, SO2, and Hg, if applicable.	Unlike electric utilities, environmental cost issues rarely impact a gas utility's supply-side resource choices. At present, the only supply-side implication of environmental externalities in the Company's direct gas distribution system is that some methods of natural gas storage require combustion of the gas. Upstream gas system infrastructure (pipelines and gathering systems) do produce some CO_2 emissions from compressors used to pressurize and move gas throughout the system. However, the Company incorporates a carbon price into its gas price forecast beginning in 2021 at a level of $8.78 per metric ton of CO2 equivalent (MTCO2e) and increasing annually to $15.01 per MTCO2e in 2032 (both prices in $2013). NW Natural considers the carbon price forecast in scenario development as a carbon tax on the carbon content of combustible fuels implemented on a national (or broad regional) basis and similar in its implementation to that currently in effect in British Columbia, Canada.	5
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 an 90% probability coldest winter planning standard augmented with an historic seven-day cold weather event, which includes the design 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.	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 Three 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.	3

NW Natural's 2014 IRP - Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
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 2014 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 work plan on August 12, 2013 and filed a supplement to the workplan on September 12, 2013.
WAC 480-90-238(4)	Work plan outlines content of IRP.	The work plan filed on August 12, 2013, outlined the content of the 2014 IRP.
WAC 480-90-238(4)	Work plan outlines method for assessing potential resources. (See LRC analysis below)	The work plan filed on August 12, 2013, provided the methodology used in developing the 2014 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 12, 2013, states four technical working group meetings were scheduled: August 22, 2013; October 2, 2013; December 10, 2013; and January 23, 2014. However, six technical working groups were held on August 22, 2013; October 2, 2013; January 23, 2014; March 7, 2014; April 3, 2014; and July 11, 2014. Additionally NW Natural held a scenario workshop on November 22, 2013. Lastly, customers were notified of this IRP's process through a December 2013 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 April 15, 2014.
WAC 480-90-238(4)	Integrated resource plan submitted within two years of previous plan.	NW Natural filed its 2013 IRP on March 30, 2013. *See* Docket No. UG-120417.
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)	Chapter Three outlines currently held and potential supply-side resource options, including existing and proposed interstate pipeline capacity from multiple providers; the Company's Mist underground storage; and imported LNG and	Chapter Three 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 Four documents how NW Natural determined the achievable potential of DSM within its service territory over the next 20 years. NW Natural then screened the achievable potential with supply-side resource option using the SENDOUT® resource optimization software.
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
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 and identified resources consistent with that portfolio for future acquisition.

NW Natural's 2014 IRP - Washington Compliance

Rule	Requirement	Plan Citation
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 eleven different risk analyses in addition to the Base Case and five resource portfolio alternatives used 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.	Chapter Four 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.	Chapter Seven addresses the various risk analysis performed by NW Natural, the most important of which is 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 engaged a consult anting firm to forecast the impact on gas prices at the various supply basins and price hubs resulting from prospective LNG exports from alternative locations, with these supplied by alternative basins and interstate pipelines. Similarly, based on a risk analysis of interstate pipeline construction costs commissioned from a different consulting firm, the Company examined the risk to ratepayers from higher construction costs manifested through increased interstate pipeline rates. The Company considered reliability risks as well.
WAC 480-90-238(2)(b)	LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government.	Policy appears to be trending toward carbon constraints. To this end, NW Natural's Base Case gas price forecast includes a carbon price beginning in 2021 at a level of $8.78 per metric ton of CO_2 equivalent ($MTCO_2e$) and increasing annually to $15.01 per $MTCO_2e$ in 2032 (both prices in $2013). NW Natural considers the carbon price forecast in scenario development as a carbon tax on the carbon content of combustible fuels implemented on a national (or broad regional) basis and similar in its implementation to that currently in effect in British Columbia, Canada. The final form of the Environmental Protection Agency's draft Regulation 111(d) is unknown, and the Company considers the potential impact on natural gas prices as the impact of evolving electric utilities' plans becomes more certain. New regulation associated with climate change may also result in the acquisition of more DSM or—through taxation—result in more DSM being cost effective. Chapters Four and Five discuss new and developing state and federal policies.
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 gas price forecast includes a carbon price beginning in 2021 at a level of $8.78 per metric ton of CO2 equivalent (MTCO2e) and increasing annually to $15.01 per MTCO2e in 2032 (both prices in $2013). NW Natural considers the carbon price forecast in scenario development as a carbon tax on the carbon content of combustible fuels implemented on a national (or broad regional) basis and similar in its implementation to that currently in effect in British Columbia, Canada. Please see the discussion of the Company's analysis in Chapter Five.

NW Natural's 2014 IRP - Washington Compliance

Rule	Requirement	Plan Citation
WAC 480-90-238(2)(b)	LRC analysis considers need for security of supply.	The Plan states in Chapter Three 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. The Company is also including a reliability analysis and will continue to refine this analysis.
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. These include not only cases of high and low load growth, but also the impact of alternative carbon prices.
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 natural gas prices as well as alternative carbon prices and, using the resource optimization capabilities of SENDOUT®, compared these with the portfolios produced under the Base Case load forecast. As discussed above, the Company also engaged an outside consultant to develop multiple scenarios of the impact on gas prices at supply basins and pricing hubs used by the Company resulting from LNG exports. Additionally, NW Natural used the results of an outside consultant engaged by the Company to analyze the impact of higher interstate pipeline tariffs on prospective resource portfolios resulting from cost overruns in constructing new or materially augmenting existing interstate pipelines.
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. NW Natural includes more specific analysis of the impact on resource requirements of alternative futures involving higher loads than in the Base Case load forecast in the industrial and transportation sectors.
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 Four 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 Four details how NW Natural delivers energy efficiency programs that offer customers incentives for implementing cost effective demand-side management measures. Appendix Four contains the Company's Schedule G, Energy Efficiency Services and Programs—Residential and Commercial. Appendix Four also includes the Company's Energy Efficiency Plan, which discusses the policies and parameters governing the Washington programs.
WAC 480-90-238(3)(c)	Plan includes an assessment of conventional and commercially available nonconventional gas supplies.	NW Natural determined the best resource mix by studying supply-side options currently used, such as pipeline transportation contracts, gas supply contracts, storage, and physical and financial hedging, as well as future alternatives such as additional capacity or infrastructure enhancements. Potential future developments such as imported LNG, biogas, and pipeline enhancements were also considered.
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, imported LNG, as well as Satellite LNG facilities located at various locations within the Company's service territory as resource options.

NW Natural's 2014 IRP - Washington Compliance

Rule	Requirement	Plan Citation
WAC 480-90-238(3)(e)	Plan includes an assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources.	A primary conclusion of this Plan is that, with the loss of firm Plymouth LNG resources, the long term uncertainty of Jackson Prairie Firm Resources, greater visibility into specific load center needs, NW Natural should seek cost-effective resource options in addition to using Mist Recall. Chapters Three and Seven discuss additional pipeline options evaluated by the Company.
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. 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, 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 planning horizon. Additionally, the Action Plan discusses ongoing reviews or other actions to be accomplished by the Company, including those specific to load forecasting, resource portfolio optimization (SENDOUT® modeling), Avoided Cost determination, and Public Involvement.
WAC 480-90-238(3)(i)	Plan includes a progress report on the implementation of the previously filed plan.	Chapter Three contains a progress report on each item 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 Findings at the end of each chapter and the Multi-Year Action Plan in Chapter One serve to document NW Natural's successful completion of the Plan.

Appendix 2: Gas Requirements Forecast

NW Natural®

Appendix 2.1 Customer Forecast – Base Case: Residential + Commercial Firm Sales

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland-Central	Portland-East	Portland-West	Salem	Vancouver	System
2013	39,812	12,480	1,448	5,551	1,896	39,176	10,161	189,794	97,271	131,858	88,860	70,519	688,827
2014	40,108	12,703	1,566	5,643	1,919	39,809	10,293	192,302	98,402	133,339	89,702	72,128	697,913
2015	40,461	12,952	1,696	5,750	1,946	40,563	10,443	195,099	99,720	135,144	90,701	74,012	708,486
2016	40,815	13,210	1,819	5,854	1,975	41,249	10,610	197,793	101,106	137,156	91,812	76,008	719,406
2017	41,177	13,473	1,947	5,960	2,007	41,973	10,782	200,566	102,533	139,238	92,960	78,253	730,871
2018	41,553	13,743	2,080	6,070	2,044	42,744	10,961	203,440	104,022	141,430	94,164	80,743	742,994
2019	41,939	14,019	2,218	6,183	2,084	43,559	11,146	206,400	105,564	143,719	95,416	83,472	755,718
2020	42,329	14,298	2,360	6,297	2,128	44,409	11,334	209,419	107,137	146,064	96,697	86,437	768,908
2021	42,723	14,580	2,505	6,412	2,176	45,293	11,525	212,494	108,741	148,464	98,004	89,634	782,551
2022	43,118	14,862	2,654	6,528	2,228	46,209	11,719	215,614	110,367	150,908	99,332	93,057	796,595
2023	43,518	15,146	2,807	6,645	2,284	47,161	11,915	218,787	112,025	153,414	100,689	96,701	811,091
2024	43,920	15,430	2,963	6,763	2,344	48,147	12,113	222,001	113,706	155,966	102,065	100,562	825,981
2025	44,325	15,716	3,123	6,882	2,409	49,171	12,313	225,263	115,418	158,580	103,469	104,637	841,305
2026	44,734	16,002	3,285	7,002	2,477	50,233	12,516	228,572	117,159	161,257	104,898	108,923	857,059
2027	45,146	16,288	3,452	7,123	2,550	51,333	12,721	231,926	118,931	163,995	106,354	113,419	873,237
2028	45,562	16,575	3,621	7,245	2,627	52,470	12,929	235,323	120,732	166,796	107,834	118,121	889,835
2029	45,980	16,862	3,794	7,367	2,708	53,645	13,138	238,762	122,561	169,658	109,340	123,027	906,844
2030	46,402	17,149	3,970	7,490	2,794	54,858	13,350	242,242	124,419	172,582	110,869	128,135	924,260
2031	46,825	17,434	4,149	7,613	2,884	56,108	13,563	245,761	126,306	175,568	112,423	133,442	942,078
2032	47,251	17,719	4,331	7,737	2,979	57,397	13,778	249,318	128,220	178,616	113,999	138,947	960,295

Appendix 2.2 Customer Forecast – Base Case: Residential

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013	35,757	10,803	1,098	4,438	1,679	33,934	8,903	173,017	88,783	121,140	80,209	64,844	624,604
2014	36,015	10,998	1,175	4,510	1,697	34,484	9,036	175,402	89,852	122,515	80,949	66,329	632,962
2015	36,325	11,215	1,260	4,593	1,720	35,144	9,187	178,050	91,097	124,195	81,832	68,075	642,691
2016	36,650	11,449	1,341	4,679	1,744	35,755	9,359	180,620	92,428	126,120	82,858	69,969	652,973
2017	36,980	11,688	1,427	4,767	1,773	36,399	9,535	183,262	93,794	128,105	83,916	72,104	663,751
2018	37,321	11,934	1,518	4,857	1,805	37,086	9,717	185,995	95,217	130,191	85,024	74,474	675,138
2019	37,670	12,185	1,613	4,950	1,840	37,813	9,905	188,805	96,686	132,363	86,174	77,073	687,076
2020	38,021	12,437	1,711	5,044	1,879	38,570	10,095	191,663	98,181	134,581	87,348	79,898	699,430
2021	38,373	12,692	1,814	5,138	1,922	39,357	10,287	194,568	99,700	136,844	88,544	82,945	712,185
2022	38,724	12,948	1,919	5,232	1,968	40,170	10,481	197,507	101,235	139,139	89,756	86,208	725,289
2023	39,078	13,205	2,028	5,328	2,018	41,015	10,678	200,489	102,796	141,486	90,992	89,681	738,793
2024	39,431	13,462	2,141	5,423	2,072	41,890	10,876	203,500	104,372	143,868	92,243	93,360	752,638
2025	39,785	13,721	2,257	5,520	2,129	42,798	11,075	206,548	105,972	146,300	93,516	97,242	766,863
2026	40,141	13,980	2,376	5,617	2,190	43,738	11,277	209,631	107,595	148,783	94,811	101,324	781,464
2027	40,499	14,241	2,498	5,714	2,255	44,711	11,480	212,746	109,241	151,316	96,128	105,604	796,435
2028	40,858	14,502	2,624	5,813	2,325	45,717	11,686	215,893	110,908	153,899	97,466	110,078	811,768
2029	41,217	14,763	2,754	5,912	2,398	46,756	11,892	219,068	112,597	156,531	98,825	114,745	827,458
2030	41,578	15,025	2,886	6,011	2,475	47,827	12,101	222,271	114,306	159,211	100,205	119,600	843,496
2031	41,939	15,288	3,022	6,112	2,556	48,930	12,311	225,499	116,035	161,941	101,605	124,642	859,879
2032	42,300	15,550	3,161	6,212	2,641	50,067	12,522	228,752	117,784	164,719	103,025	129,869	876,602

Appendix 2.3 Customer Forecast – Base Case: Commercial Firm Sales

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013	4,056	1,677	350	1,112	217	5,242	1,265	16,778	8,488	10,718	8,652	5,676	64,229
2014	4,093	1,705	391	1,134	221	5,325	1,270	16,900	8,549	10,824	8,753	5,799	64,964
2015	4,136	1,737	436	1,157	226	5,419	1,276	17,049	8,624	10,949	8,868	5,938	65,815
2016	4,165	1,760	478	1,175	230	5,494	1,279	17,172	8,679	11,036	8,954	6,039	66,461
2017	4,197	1,785	520	1,193	234	5,574	1,282	17,304	8,739	11,133	9,044	6,149	67,155
2018	4,232	1,809	563	1,212	239	5,657	1,286	17,445	8,805	11,239	9,140	6,269	67,898
2019	4,269	1,835	605	1,232	244	5,746	1,291	17,595	8,878	11,356	9,242	6,399	68,692
2020	4,308	1,861	648	1,253	249	5,839	1,296	17,756	8,956	11,483	9,348	6,539	69,536
2021	4,350	1,887	692	1,274	254	5,936	1,302	17,926	9,041	11,620	9,460	6,689	70,431
2022	4,394	1,914	735	1,295	260	6,038	1,309	18,107	9,132	11,768	9,576	6,849	71,378
2023	4,441	1,941	778	1,317	266	6,145	1,316	18,298	9,229	11,927	9,697	7,020	72,377
2024	4,489	1,968	822	1,340	273	6,257	1,324	18,501	9,334	12,098	9,823	7,202	73,429
2025	4,540	1,995	866	1,362	280	6,373	1,332	18,715	9,445	12,280	9,953	7,395	74,536
2026	4,593	2,022	910	1,385	287	6,495	1,340	18,941	9,564	12,474	10,087	7,599	75,696
2027	4,648	2,048	953	1,408	294	6,621	1,350	19,180	9,690	12,679	10,225	7,815	76,911
2028	4,704	2,074	997	1,432	302	6,753	1,359	19,430	9,823	12,897	10,368	8,042	78,182
2029	4,763	2,099	1,041	1,455	311	6,889	1,369	19,694	9,965	13,128	10,514	8,282	79,510
2030	4,824	2,123	1,084	1,479	319	7,031	1,379	19,971	10,114	13,371	10,664	8,535	80,894
2031	4,887	2,147	1,127	1,502	329	7,178	1,390	20,262	10,271	13,628	10,818	8,799	82,337
2032	4,951	2,169	1,171	1,525	338	7,330	1,401	20,566	10,437	13,897	10,974	9,077	83,838

Appendix 2.4 Customer Forecast – High Growth: Residential + Commercial Firm Sales

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013	39,811	12,478	1,444	5,549	1,896	97,270	10,168	189,866	97,270	131,852	88,855	70,414	746,873
2014	40,146	12,719	1,568	5,653	1,921	98,493	10,319	192,649	98,493	133,451	89,785	72,055	757,250
2015	40,545	12,990	1,703	5,771	1,950	99,928	10,492	195,780	99,928	135,406	90,890	74,017	769,400
2016	40,957	13,276	1,836	5,891	1,983	101,462	10,687	198,870	101,462	137,617	92,137	76,143	782,321
2017	41,382	13,571	1,975	6,013	2,019	103,066	10,889	202,096	103,066	139,937	93,442	78,548	796,004
2018	41,830	13,879	2,121	6,142	2,060	104,763	11,103	205,486	104,763	142,413	94,830	81,245	810,636
2019	42,298	14,199	2,275	6,276	2,106	106,548	11,326	209,028	106,548	145,036	96,294	84,236	826,171
2020	42,780	14,527	2,435	6,413	2,157	108,398	11,557	212,698	108,398	147,767	97,815	87,524	842,469
2021	43,275	14,863	2,602	6,555	2,212	110,313	11,795	216,492	110,313	150,604	99,393	91,112	859,530
2022	43,781	15,206	2,775	6,699	2,273	112,287	12,039	220,402	112,287	153,539	101,021	94,999	877,309
2023	44,301	15,557	2,955	6,847	2,339	114,331	12,291	224,439	114,331	156,592	102,710	99,186	895,880
2024	44,832	15,913	3,142	6,998	2,411	116,436	12,549	228,591	116,436	159,750	104,450	103,676	915,184
2025	45,378	16,277	3,335	7,154	2,488	118,610	12,814	232,868	118,610	163,030	106,250	108,470	935,285
2026	45,938	16,648	3,535	7,312	2,572	120,856	13,086	237,271	120,856	166,436	108,111	113,572	956,193
2027	46,512	17,026	3,742	7,475	2,661	123,174	13,365	241,799	123,174	169,968	110,033	118,986	977,915
2028	47,100	17,410	3,956	7,640	2,757	125,564	13,652	246,454	125,564	173,631	112,016	124,715	1,000,459
2029	47,702	17,800	4,176	7,810	2,859	128,028	13,946	251,234	128,028	177,425	114,062	130,763	1,023,833
2030	48,317	18,196	4,404	7,982	2,968	130,565	14,246	256,142	130,565	181,353	116,169	137,134	1,048,043
2031	48,946	18,598	4,639	8,158	3,084	133,178	14,554	261,176	133,178	185,418	118,340	143,830	1,073,099
2032	49,589	19,005	4,881	8,338	3,207	135,866	14,869	266,339	135,866	189,622	120,575	150,857	1,099,015

Appendix 2.5 Customer Forecast – High Growth: Residential

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013	35,757	10,804	1,098	4,439	1,679	33,934	8,903	173,018	88,784	121,141	80,209	64,735	624,500
2014	36,021	11,002	1,176	4,511	1,698	34,495	9,039	175,452	89,875	122,544	80,965	66,207	632,985
2015	36,345	11,226	1,264	4,597	1,721	35,178	9,195	178,201	91,167	124,286	81,884	67,983	643,048
2016	36,691	11,474	1,349	4,688	1,747	35,824	9,376	180,925	92,573	126,315	82,968	69,959	653,889
2017	37,049	11,730	1,441	4,782	1,777	36,516	9,565	183,776	94,043	128,445	84,107	72,201	665,433
2018	37,427	11,997	1,539	4,881	1,812	37,266	9,764	186,776	95,600	130,720	85,321	74,725	677,827
2019	37,821	12,275	1,643	4,984	1,850	38,071	9,971	189,914	97,237	133,128	86,603	77,530	691,028
2020	38,226	12,560	1,753	5,090	1,893	38,923	10,186	193,163	98,930	135,630	87,935	80,618	704,906
2021	38,640	12,853	1,868	5,198	1,941	39,821	10,406	196,521	100,680	138,226	89,315	83,993	719,462
2022	39,061	13,151	1,989	5,309	1,994	40,764	10,633	199,978	102,480	140,903	90,739	87,653	734,652
2023	39,494	13,456	2,115	5,422	2,051	41,758	10,866	203,543	104,340	143,684	92,215	91,598	750,543
2024	39,934	13,767	2,247	5,537	2,114	42,802	11,104	207,206	106,252	146,554	93,734	95,831	767,082
2025	40,386	14,084	2,385	5,656	2,181	43,900	11,349	210,975	108,223	149,530	95,306	100,352	784,326
2026	40,847	14,408	2,529	5,777	2,254	45,052	11,600	214,849	110,255	152,614	96,931	105,166	802,282
2027	41,319	14,738	2,679	5,901	2,333	46,261	11,857	218,828	112,348	155,808	98,609	110,274	820,955
2028	41,802	15,075	2,835	6,028	2,417	47,527	12,121	222,912	114,503	159,113	100,341	115,680	840,353
2029	42,295	15,417	2,997	6,158	2,507	48,851	12,391	227,100	116,718	162,530	102,128	121,387	860,480
2030	42,798	15,767	3,166	6,291	2,603	50,235	12,667	231,392	118,996	166,062	103,969	127,396	881,341
2031	43,311	16,122	3,341	6,427	2,705	51,679	12,950	235,786	121,335	169,710	105,866	133,713	902,944
2032	43,834	16,483	3,522	6,565	2,814	53,184	13,239	240,284	123,737	173,476	107,818	140,340	925,298

Appendix 2.6 Customer Forecast – High Growth: Commercial Firm Sales

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013	4,054	1,674	346	1,111	217	5,237	1,265	16,776	8,487	10,712	8,645	5,679	64,201
2014	4,124	1,718	391	1,141	223	5,364	1,280	17,036	8,618	10,907	8,819	5,848	65,470
2015	4,201	1,763	440	1,174	230	5,501	1,297	17,321	8,761	11,119	9,006	6,034	66,847
2016	4,266	1,802	487	1,203	236	5,625	1,310	17,589	8,890	11,302	9,169	6,184	68,062
2017	4,333	1,841	534	1,231	242	5,751	1,324	17,865	9,022	11,492	9,335	6,346	69,317
2018	4,403	1,882	582	1,261	249	5,884	1,339	18,153	9,163	11,693	9,509	6,520	70,639
2019	4,477	1,924	632	1,292	256	6,023	1,355	18,455	9,311	11,908	9,691	6,707	72,030
2020	4,554	1,967	682	1,324	263	6,169	1,371	18,771	9,468	12,136	9,881	6,906	73,492
2021	4,635	2,010	734	1,356	271	6,321	1,388	19,101	9,633	12,379	10,078	7,119	75,027
2022	4,719	2,055	786	1,390	279	6,481	1,406	19,447	9,807	12,636	10,283	7,346	76,637
2023	4,807	2,101	840	1,425	288	6,648	1,425	19,809	9,991	12,908	10,495	7,588	78,325
2024	4,898	2,147	894	1,461	297	6,823	1,445	20,187	10,184	13,196	10,716	7,845	80,092
2025	4,993	2,194	950	1,498	307	7,005	1,465	20,582	10,387	13,500	10,944	8,117	81,942
2026	5,091	2,241	1,006	1,535	318	7,195	1,486	20,996	10,601	13,822	11,180	8,406	83,877
2027	5,193	2,288	1,063	1,573	329	7,394	1,508	21,429	10,825	14,161	11,424	8,712	85,898
2028	5,298	2,335	1,120	1,612	340	7,600	1,531	21,881	11,062	14,518	11,675	9,035	88,009
2029	5,407	2,383	1,179	1,651	352	7,816	1,555	22,354	11,309	14,895	11,934	9,377	90,212
2030	5,520	2,430	1,238	1,691	365	8,040	1,579	22,848	11,570	15,291	12,200	9,737	92,509
2031	5,636	2,476	1,298	1,732	379	8,273	1,604	23,365	11,843	15,708	12,474	10,117	94,904
2032	5,755	2,522	1,358	1,773	393	8,516	1,630	23,904	12,129	16,146	12,756	10,518	97,400

Appendix 2.7 Customer Forecast – Low Growth: Residential + Commercial Firm Sales

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013	39,804	12,475	1,444	5,547	1,895	39,163	10,166	189,767	97,257	131,835	88,841	70,404	688,599
2014	40,059	12,680	1,558	5,629	1,916	39,740	10,290	192,078	98,291	133,195	89,592	71,902	696,930
2015	40,361	12,905	1,680	5,722	1,940	40,420	10,431	194,615	99,482	134,835	90,474	73,653	706,519
2016	40,659	13,135	1,795	5,812	1,966	41,023	10,585	197,000	100,715	136,646	91,449	75,498	716,282
2017	40,954	13,364	1,911	5,900	1,994	41,647	10,740	199,403	101,957	138,478	92,432	77,535	726,316
2018	41,254	13,596	2,031	5,991	2,026	42,302	10,898	201,846	103,229	140,375	93,446	79,767	736,760
2019	41,556	13,828	2,152	6,082	2,060	42,984	11,059	204,316	104,523	142,320	94,481	82,185	747,545
2020	41,855	14,057	2,275	6,172	2,098	43,685	11,219	206,784	105,816	144,275	95,518	84,780	758,534
2021	42,148	14,284	2,399	6,261	2,138	44,403	11,378	209,248	107,108	146,238	96,557	87,542	769,704
2022	42,435	14,507	2,524	6,350	2,182	45,133	11,535	211,696	108,391	148,196	97,589	90,465	781,004
2023	42,718	14,726	2,650	6,437	2,228	45,882	11,692	214,136	109,674	150,168	98,624	93,535	792,471
2024	42,995	14,941	2,777	6,523	2,277	46,646	11,847	216,556	110,948	152,138	99,651	96,747	804,046
2025	43,268	15,152	2,905	6,608	2,328	47,427	12,001	218,963	112,220	154,119	100,679	100,090	815,759
2026	43,536	15,359	3,033	6,692	2,383	48,225	12,153	221,355	113,489	156,110	101,705	103,560	827,600
2027	43,800	15,562	3,161	6,775	2,440	49,039	12,304	223,730	114,755	158,111	102,729	107,153	839,559
2028	44,059	15,761	3,291	6,857	2,499	49,868	12,453	226,086	116,017	160,121	103,750	110,859	851,622
2029	44,313	15,955	3,420	6,937	2,562	50,713	12,601	228,423	117,273	162,139	104,769	114,674	863,779
2030	44,562	16,144	3,550	7,016	2,627	51,572	12,747	230,739	118,525	164,164	105,783	118,593	876,022
2031	44,806	16,328	3,679	7,094	2,694	52,444	12,891	233,032	119,771	166,196	106,793	122,607	888,337
2032	45,044	16,508	3,809	7,170	2,764	53,331	13,034	235,302	121,011	168,233	107,798	126,715	900,719

Appendix 2.8 Customer Forecast – Low Growth: Residential

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013	35,756	10,803	1,098	4,438	1,679	33,933	8,903	173,015	88,782	121,139	80,208	64,733	624,487
2014	36,008	10,994	1,174	4,508	1,697	34,473	9,033	175,347	89,828	122,483	80,930	66,156	632,630
2015	36,304	11,202	1,255	4,588	1,718	35,107	9,178	177,886	91,021	124,096	81,776	67,821	641,952
2016	36,607	11,423	1,333	4,669	1,742	35,681	9,340	180,293	92,271	125,911	82,740	69,616	651,627
2017	36,906	11,644	1,413	4,750	1,768	36,275	9,503	182,715	93,529	127,744	83,712	71,597	661,556
2018	37,209	11,867	1,496	4,832	1,798	36,897	9,668	185,170	94,811	129,633	84,710	73,766	671,855
2019	37,512	12,090	1,581	4,915	1,829	37,543	9,835	187,643	96,110	131,562	85,725	76,112	682,456
2020	37,808	12,310	1,668	4,996	1,864	38,204	10,000	190,107	97,404	133,492	86,739	78,627	693,220
2021	38,098	12,527	1,758	5,076	1,902	38,879	10,165	192,558	98,691	135,422	87,751	81,303	704,128
2022	38,380	12,740	1,848	5,155	1,942	39,564	10,327	194,985	99,964	137,338	88,753	84,130	715,126
2023	38,656	12,951	1,940	5,232	1,984	40,263	10,488	197,396	101,231	139,260	89,754	87,098	726,254
2024	38,925	13,157	2,034	5,309	2,030	40,975	10,646	199,779	102,484	141,171	90,745	90,199	737,452
2025	39,187	13,359	2,128	5,384	2,077	41,701	10,803	202,140	103,730	143,084	91,733	93,425	748,753
2026	39,444	13,558	2,224	5,458	2,127	42,441	10,958	204,477	104,968	145,000	92,718	96,770	760,145
2027	39,695	13,754	2,321	5,531	2,180	43,194	11,111	206,789	106,197	146,917	93,698	100,229	771,617
2028	39,940	13,945	2,420	5,603	2,235	43,959	11,263	209,075	107,417	148,834	94,674	103,794	783,160
2029	40,179	14,133	2,519	5,674	2,292	44,737	11,412	211,332	108,627	150,751	95,645	107,461	794,763
2030	40,412	14,317	2,619	5,744	2,352	45,526	11,560	213,559	109,826	152,667	96,610	111,223	806,414
2031	40,639	14,497	2,720	5,813	2,414	46,327	11,705	215,754	111,014	154,581	97,569	115,074	818,106
2032	40,859	14,673	2,821	5,881	2,479	47,138	11,848	217,918	112,190	156,492	98,522	119,011	829,832

Appendix 2.9 Customer Forecast – Low Growth: Commercial Firm Sales

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013	4,048	1,672	346	1,109	216	5,229	1,263	16,752	8,475	10,697	8,633	5,671	64,112
2014	4,051	1,687	384	1,121	219	5,268	1,257	16,731	8,463	10,711	8,661	5,746	64,299
2015	4,057	1,703	425	1,134	222	5,313	1,253	16,729	8,461	10,739	8,698	5,832	64,566
2016	4,052	1,712	462	1,142	224	5,342	1,245	16,707	8,444	10,735	8,709	5,881	64,655
2017	4,048	1,720	499	1,150	226	5,372	1,237	16,688	8,428	10,734	8,720	5,938	64,760
2018	4,045	1,729	535	1,158	228	5,405	1,230	16,676	8,418	10,742	8,736	6,002	64,905
2019	4,045	1,738	571	1,167	231	5,441	1,224	16,673	8,412	10,758	8,755	6,073	65,089
2020	4,046	1,747	606	1,176	234	5,481	1,218	16,678	8,412	10,783	8,779	6,153	65,314
2021	4,050	1,757	641	1,185	237	5,524	1,213	16,690	8,417	10,816	8,806	6,239	65,576
2022	4,055	1,766	676	1,195	240	5,570	1,208	16,711	8,428	10,858	8,836	6,335	65,878
2023	4,062	1,775	710	1,204	244	5,619	1,204	16,740	8,443	10,908	8,870	6,437	66,217
2024	4,071	1,784	743	1,214	247	5,671	1,201	16,778	8,464	10,967	8,906	6,548	66,594
2025	4,081	1,793	776	1,224	251	5,726	1,198	16,823	8,490	11,035	8,945	6,665	67,006
2026	4,092	1,801	808	1,234	255	5,784	1,195	16,877	8,521	11,110	8,987	6,790	67,455
2027	4,105	1,809	840	1,244	260	5,845	1,192	16,940	8,558	11,194	9,031	6,925	67,942
2028	4,119	1,816	871	1,253	264	5,909	1,190	17,011	8,600	11,287	9,076	7,064	68,462
2029	4,134	1,822	901	1,263	269	5,976	1,189	17,091	8,647	11,388	9,124	7,213	69,017
2030	4,150	1,827	931	1,272	275	6,045	1,187	17,180	8,699	11,498	9,174	7,370	69,608
2031	4,167	1,831	960	1,281	280	6,118	1,186	17,278	8,757	11,615	9,225	7,533	70,230
2032	4,185	1,834	988	1,289	286	6,193	1,185	17,384	8,821	11,742	9,277	7,704	70,887

Appendix 2.10 Annual Load Forecast (post-DSM) – Base Case: Firm Sales (MMDT)

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013-2014	4,057.30	1,382.84	211.28	829.51	238.69	4,755.23	996.61	21,350.05	10,968.95	14,830.14	9,855.10	7,380.33	76,856.03
2014-2015	4,050.50	1,387.94	224.49	827.49	240.84	4,753.64	993.76	21,439.84	11,010.94	14,913.48	9,853.65	7,554.85	77,251.42
2015-2016	4,075.31	1,402.65	239.16	833.68	245.82	4,786.83	996.70	21,706.09	11,148.81	15,134.58	9,926.06	7,799.69	78,295.38
2016-2017	4,052.33	1,403.76	253.15	829.04	246.91	4,796.62	992.46	21,681.52	11,137.69	15,143.24	9,894.45	7,924.30	78,355.49
2017-2018	4,060.57	1,413.43	269.02	831.80	250.37	4,837.22	994.27	21,805.01	11,202.58	15,253.84	9,923.94	8,109.62	78,951.67
2018-2019	4,073.79	1,424.98	285.39	835.94	254.33	4,886.31	997.66	21,950.57	11,280.53	15,385.92	9,965.49	8,316.82	79,657.72
2019-2020	4,116.18	1,444.88	303.59	847.63	261.09	4,965.80	1,006.51	22,249.20	11,437.93	15,628.14	10,068.67	8,596.11	80,925.72
2020-2021	4,112.89	1,452.54	319.45	847.76	263.78	5,006.60	1,008.83	22,497.86	11,469.35	15,704.88	10,079.19	8,788.31	81,352.43
2021-2022	4,138.03	1,468.37	337.15	855.26	269.30	5,076.53	1,016.71	22,712.25	11,577.61	15,887.35	10,148.54	9,052.50	82,325.23
2022-2023	4,166.70	1,485.65	355.34	863.77	275.43	5,152.68	1,026.34	22,725.58	11,694.38	16,084.14	10,225.28	9,338.56	83,380.52
2023-2024	4,224.82	1,511.57	375.73	879.96	284.70	5,259.56	1,042.08	23,083.48	11,891.61	16,392.43	10,362.74	9,704.68	85,013.37
2024-2025	4,235.33	1,524.70	393.15	883.90	289.71	5,323.77	1,051.62	23,192.38	11,955.31	16,522.94	10,401.22	9,975.92	85,749.97
2025-2026	4,273.88	1,546.00	412.72	895.33	297.95	5,417.42	1,067.15	23,452.48	12,096.54	16,761.16	10,497.19	10,327.66	87,045.47
2026-2027	4,314.79	1,568.21	432.66	907.58	307.02	5,516.09	1,084.36	23,725.58	12,244.92	17,011.81	10,598.02	10,700.64	88,411.68
2027-2028	4,383.60	1,598.38	454.95	927.48	319.84	5,645.02	1,106.96	24,153.71	12,473.66	17,374.54	10,756.92	11,162.11	90,357.17
2028-2029	4,401.87	1,614.52	473.44	934.46	328.46	5,726.64	1,122.00	24,303.53	12,562.39	17,548.52	10,811.78	11,509.43	91,337.05
2029-2030	4,447.63	1,638.38	494.26	949.13	341.06	5,838.24	1,141.49	24,605.69	12,731.80	17,834.66	10,924.40	11,945.50	92,892.23
2030-2031	4,493.07	1,661.09	514.88	963.30	354.10	5,952.34	1,159.68	24,912.58	12,906.00	18,130.02	11,038.26	12,400.09	94,485.40
2031-2032	4,564.99	1,689.99	537.64	983.96	370.51	6,096.67	1,180.68	25,375.06	13,162.13	18,541.03	11,209.11	12,950.84	96,662.63
2032-2033	4,582.70	1,702.35	555.34	989.60	381.14	6,188.14	1,191.71	25,541.69	13,268.98	18,749.02	11,269.45	13,362.73	97,782.83

Appendix 2.11 Annual Load Forecast (post-DSM) – Base Case: Residential (MMDT)

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013-2014	2,430.34	746.40	62.58	288.26	140.76	2,181.19	483.69	13,331.31	6,843.74	9,342.31	5,509.95	4,832.28	46,192.80
2014-2015	2,430.03	753.27	65.97	289.72	142.11	2,197.71	485.14	13,428.12	6,881.14	9,386.00	5,520.33	4,938.47	46,518.01
2015-2016	2,453.11	766.96	70.08	295.22	145.20	2,235.95	490.75	13,647.37	6,986.61	9,530.03	5,581.78	5,095.92	47,298.98
2016-2017	2,444.49	772.80	73.34	295.40	145.87	2,250.46	492.06	13,684.55	7,002.78	9,556.48	5,583.42	5,204.05	47,505.70
2017-2018	2,451.98	782.74	77.13	298.33	148.21	2,278.36	495.74	13,813.08	7,065.88	9,648.03	5,618.49	5,362.97	48,040.94
2018-2019	2,460.37	793.13	81.14	301.45	150.86	2,309.04	499.73	13,948.12	7,133.24	9,747.44	5,657.05	5,539.24	48,620.81
2019-2020	2,485.76	808.00	85.77	307.53	155.27	2,354.44	506.32	14,180.73	7,250.91	9,917.06	5,731.36	5,769.10	49,552.24
2020-2021	2,479.66	814.98	89.74	308.15	157.03	2,377.84	508.56	14,236.51	7,278.48	9,964.66	5,743.33	5,935.04	49,893.97
2021-2022	2,489.99	826.19	94.30	311.62	160.56	2,415.18	513.25	14,387.02	7,354.50	10,079.39	5,789.56	6,153.70	50,575.26
2022-2023	2,500.73	837.61	99.03	315.16	164.41	2,454.50	518.13	14,541.16	7,432.61	10,198.09	5,837.76	6,387.72	51,286.90
2023-2024	2,529.16	853.81	104.49	321.81	170.20	2,509.56	525.78	14,798.64	7,563.54	10,390.18	5,923.43	6,679.89	52,370.49
2024-2025	2,525.06	861.46	109.06	322.68	173.12	2,540.71	528.79	14,868.43	7,599.16	10,452.95	5,943.50	6,900.38	52,825.29
2025-2026	2,537.44	873.48	114.32	326.51	177.97	2,586.56	534.26	15,035.24	7,684.76	10,585.72	5,998.43	7,179.35	53,634.02
2026-2027	2,549.97	885.56	119.73	330.39	183.14	2,634.26	539.81	15,204.02	7,771.90	10,722.18	6,054.75	7,473.04	54,468.76
2027-2028	2,579.32	902.23	125.92	337.36	190.44	2,697.64	547.92	15,474.07	7,911.17	10,931.99	6,147.16	7,831.69	55,676.92
2028-2029	2,575.40	909.85	131.01	338.28	194.51	2,735.26	551.18	15,546.95	7,950.69	11,006.11	6,171.52	8,103.11	56,213.87
2029-2030	2,588.29	922.05	136.88	342.28	200.71	2,788.55	556.98	15,720.82	8,042.24	11,153.54	6,231.92	8,439.26	57,123.51
2030-2031	2,601.28	934.27	142.90	346.33	207.26	2,843.71	562.86	15,896.20	8,135.23	11,304.63	6,293.65	8,789.31	58,057.62
2031-2032	2,631.51	951.33	149.83	353.62	216.19	2,915.75	571.41	16,177.60	8,282.83	11,533.11	6,393.00	9,212.58	59,388.76
2032-2033	2,627.78	958.84	155.42	354.56	221.43	2,959.90	574.90	16,252.36	8,325.92	11,618.49	6,421.59	9,530.40	60,001.60

Appendix 2.12 : Annual Load Forecasts (post-DSM) – Base Case: Commercial Firm Sales (MMDT)

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013-2014	1,479.28	621.00	133.59	453.01	92.91	2,193.95	477.09	7,425.57	3,761.97	4,760.03	3,735.40	2,238.68	27,372.47
2014-2015	1,474.14	617.79	145.86	451.68	94.02	2,199.35	472.19	7,387.85	3,747.30	4,760.90	3,715.94	2,272.11	27,339.14
2015-2016	1,478.37	617.34	159.10	453.99	95.94	2,217.00	469.21	7,398.19	3,756.74	4,792.17	3,716.57	2,316.39	27,471.00
2016-2017	1,465.32	612.06	170.36	449.25	96.10	2,215.01	463.55	7,334.27	3,725.90	4,766.35	3,682.33	2,323.81	27,304.30
2017-2018	1,465.50	611.16	182.61	449.19	97.21	2,229.40	460.94	7,330.82	3,726.37	4,781.64	3,675.89	2,348.31	27,359.06
2018-2019	1,469.00	611.38	195.06	449.97	98.50	2,248.20	459.24	7,340.55	3,734.20	4,807.67	3,675.84	2,376.48	27,466.08
2019-2020	1,483.78	615.07	208.60	454.91	100.75	2,281.25	459.92	7,403.15	3,769.58	4,870.57	3,699.28	2,422.13	27,768.99
2020-2021	1,483.12	613.85	220.32	453.17	101.54	2,295.61	457.67	7,389.48	3,766.80	4,885.58	3,689.01	2,443.25	27,799.41
2021-2022	1,493.35	615.90	233.12	455.47	103.31	2,323.86	457.67	7,427.71	3,791.08	4,936.84	3,701.44	2,482.67	28,022.42
2022-2023	1,505.35	618.30	246.00	458.11	105.24	2,354.77	458.08	7,474.19	3,820.20	4,995.73	3,717.07	2,527.19	28,280.23
2023-2024	1,527.56	623.54	260.08	464.64	108.21	2,398.96	460.45	7,570.06	3,875.27	5,089.96	3,753.61	2,592.03	28,724.37
2024-2025	1,533.16	623.42	271.77	463.97	109.59	2,422.82	459.69	7,586.96	3,890.56	5,133.40	3,754.73	2,631.57	28,881.64
2025-2026	1,548.88	626.04	284.64	467.13	112.03	2,459.96	460.86	7,653.52	3,931.94	5,212.38	3,776.59	2,691.55	29,225.52
2026-2027	1,565.80	628.68	297.49	470.43	114.64	2,499.26	462.27	7,727.24	3,977.63	5,298.38	3,800.44	2,756.65	29,598.89
2027-2028	1,593.17	634.03	311.72	477.68	118.40	2,552.58	465.61	7,852.35	4,050.45	5,421.88	3,845.29	2,843.75	30,166.93
2028-2029	1,602.72	633.62	322.99	477.22	120.41	2,583.86	465.66	7,895.39	4,081.61	5,491.06	3,853.07	2,902.33	30,429.93
2029-2030	1,622.79	635.92	335.65	480.71	123.59	2,629.40	467.65	7,990.80	4,140.39	5,598.38	3,882.02	2,983.55	30,890.85
2030-2031	1,643.82	638.00	348.22	484.21	126.96	2,677.01	469.81	8,093.66	4,203.66	5,712.98	3,912.43	3,070.34	31,381.10
2031-2032	1,675.70	642.69	362.38	491.76	131.62	2,739.62	473.90	8,250.82	4,295.77	5,868.04	3,964.14	3,181.66	32,078.10
2032-2033	1,688.56	641.34	373.02	491.13	134.33	2,778.51	474.57	8,322.58	4,344.07	5,964.65	3,977.36	3,260.66	32,450.78

Appendix 2.13 Annual Load Forecast (post-DSM) – Base Case: Industrial Firm Sales (MMDT)

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013-2014	146.80	14.74	15.07	88.14	5.01	379.23	34.98	592.20	362.70	726.06	609.01	308.91	3,282.86
2014-2015	144.68	15.59	12.57	85.88	4.68	354.97	34.87	622.06	381.51	763.39	615.98	343.40	3,379.58
2015-2016	141.56	16.57	9.83	84.14	4.64	331.67	34.59	657.99	404.05	808.03	625.74	386.13	3,504.95
2016-2017	139.50	16.55	9.24	83.92	4.86	328.21	34.06	659.28	407.10	814.74	626.02	394.71	3,518.19
2017-2018	139.08	16.43	8.97	83.56	4.82	325.53	33.81	655.92	407.70	816.77	625.89	395.91	3,514.40
2018-2019	139.06	16.36	8.72	83.45	4.79	323.79	33.65	654.46	409.46	821.14	627.54	397.67	3,520.09
2019-2020	139.43	16.33	8.50	83.57	4.77	322.97	33.60	654.85	412.41	827.85	631.02	400.01	3,535.33
2020-2021	140.38	16.37	8.31	84.04	4.76	323.45	33.67	657.93	417.05	837.99	637.07	403.08	3,564.10
2021-2022	141.50	16.42	8.13	84.59	4.74	324.29	33.77	661.74	422.19	849.17	643.89	406.23	3,596.67
2022-2023	142.77	16.49	7.95	85.24	4.73	325.46	33.91	666.27	427.83	861.35	651.46	409.62	3,633.07
2023-2024	144.16	16.57	7.78	85.96	4.72	326.87	34.07	671.33	433.86	874.35	659.60	413.17	3,672.44
2024-2025	145.58	16.65	7.60	86.68	4.71	328.30	34.23	676.47	439.99	887.57	667.87	417.22	3,712.87
2025-2026	147.01	16.73	7.42	87.42	4.71	329.74	34.39	681.66	446.21	900.98	676.26	421.35	3,753.86
2026-2027	148.46	16.81	7.23	88.16	4.70	331.18	34.56	686.91	452.52	914.60	684.76	425.61	3,795.51
2027-2028	149.93	16.89	7.04	88.92	4.70	332.62	34.72	692.22	458.92	928.41	693.39	430.35	3,838.12
2028-2029	151.42	16.98	6.84	89.68	4.70	334.07	34.89	697.56	465.41	942.41	702.12	435.31	3,881.36
2029-2030	152.92	17.06	6.64	90.44	4.70	335.52	35.05	702.98	471.99	956.63	710.98	440.75	3,925.66
2030-2031	154.45	17.14	6.44	91.22	4.71	336.98	35.22	708.45	478.67	971.06	719.96	446.56	3,970.86
2031-2032	155.99	17.22	6.23	92.01	4.71	338.44	35.38	713.96	485.44	985.68	729.05	452.54	4,016.65
2032-2033	157.58	17.31	6.02	92.82	4.72	339.96	35.56	719.65	492.39	1,000.69	738.41	458.64	4,063.72

Appendix 2.14 Annual Load Forecast (post-DSM) – Base Case: Emerging Markets Firm Sales (MMDT)

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013-2014	0.89	0.70	0.05	0.11	0.01	0.86	0.85	0.96	0.53	1.74	0.74	0.46	7.90
2014-2015	1.65	1.29	0.09	0.21	0.03	1.60	1.57	1.81	1.00	3.19	1.40	0.87	14.70
2015-2016	2.28	1.78	0.14	0.32	0.05	2.21	2.14	2.54	1.41	4.36	1.97	1.25	20.45
2016-2017	3.02	2.35	0.21	0.48	0.08	2.94	2.79	3.42	1.92	5.67	2.68	1.74	27.29
2017-2018	4.01	3.10	0.32	0.72	0.12	3.93	3.77	5.19	2.63	7.39	3.67	2.43	37.28
2018-2019	5.37	4.11	0.48	1.07	0.19	5.29	5.03	7.43	3.62	9.66	5.06	3.43	50.73
2019-2020	7.21	5.48	0.72	1.61	0.29	7.14	6.68	10.47	5.03	12.66	7.01	4.87	69.15
2020-2021	9.73	7.34	1.08	2.41	0.45	9.69	8.94	14.94	7.03	16.64	9.77	6.94	94.95
2021-2022	13.19	9.86	1.60	3.58	0.69	13.20	12.02	21.39	9.84	21.96	13.65	9.89	130.88
2022-2023	17.85	13.25	2.35	5.26	1.05	17.95	16.22	30.64	13.74	28.96	19.00	14.03	180.31
2023-2024	23.93	17.66	3.38	7.56	1.57	24.16	21.78	43.45	18.94	37.93	26.11	19.59	246.07
2024-2025	31.54	23.18	4.72	10.57	2.29	31.95	28.91	60.53	25.59	49.02	35.13	26.74	330.17
2025-2026	40.54	29.75	6.35	14.27	3.25	41.16	37.64	82.06	33.64	62.08	45.92	35.41	432.06
2026-2027	50.56	37.16	8.21	18.60	4.54	51.39	47.72	107.40	42.87	76.66	58.05	45.34	548.52
2027-2028	61.17	45.23	10.28	23.52	6.31	62.18	58.70	135.07	53.11	92.25	71.07	56.32	675.20
2028-2029	72.34	54.07	12.60	29.29	8.84	73.45	70.28	163.64	64.69	108.95	85.06	68.68	811.89
2029-2030	83.63	63.36	15.08	35.69	12.06	84.76	81.81	191.10	77.17	126.12	99.48	81.94	952.20
2030-2031	93.52	71.68	17.31	41.54	15.18	94.63	91.79	214.27	88.45	141.35	112.22	93.87	1,075.81
2031-2032	101.79	78.74	19.21	46.58	17.99	102.86	99.98	232.69	98.09	154.21	122.92	104.06	1,179.12
2032-2033	108.78	84.86	20.88	51.10	20.65	109.77	106.68	247.10	106.59	165.20	132.10	113.02	1,266.72

Appendix 2.15 Annual Load Forecast (post-DSM) – Base Case: Firm Transportation (MMDT)

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013-2014	1,690.29	2.93	0.05	22.81	0.01	2,384.87	2.59	2,701.55	1,103.43	5,362.83	363.56	732.31	14,367.23
2014-2015	1,701.58	4.30	0.09	22.72	0.01	2,379.43	4.45	2,871.10	1,166.27	5,487.78	375.89	781.83	14,795.47
2015-2016	1,699.28	5.37	0.13	22.72	0.02	2,373.63	6.00	3,068.01	1,240.86	5,630.23	389.38	841.69	15,277.31
2016-2017	1,702.86	6.43	0.17	23.11	0.03	2,375.53	7.80	3,119.40	1,267.07	5,679.23	396.42	859.56	15,437.61
2017-2018	1,723.17	7.71	0.22	23.44	0.04	2,377.79	10.22	3,149.33	1,284.74	5,715.90	403.02	867.94	15,563.51
2018-2019	1,744.09	9.25	0.28	23.82	0.06	2,380.37	13.44	3,181.89	1,302.87	5,753.78	409.99	876.56	15,696.41
2019-2020	1,765.56	11.10	0.36	24.24	0.08	2,383.32	17.82	3,218.13	1,321.44	5,792.87	417.32	885.41	15,837.64
2020-2021	1,787.76	13.31	0.47	24.71	0.10	2,386.73	23.91	3,260.21	1,340.57	5,833.44	425.14	894.71	15,991.06
2021-2022	1,810.74	15.97	0.60	25.25	0.14	2,390.68	32.48	3,310.86	1,360.27	5,875.62	433.49	904.32	16,160.42
2022-2023	1,834.58	19.15	0.77	25.88	0.18	2,395.27	44.62	3,374.18	1,380.61	5,919.58	442.47	914.33	16,351.63
2023-2024	1,859.32	22.88	0.98	26.59	0.24	2,400.53	61.57	3,455.07	1,401.60	5,965.40	452.11	924.76	16,571.04
2024-2025	1,884.97	27.14	1.22	27.39	0.31	2,406.45	84.73	3,559.16	1,423.26	6,013.08	462.40	935.71	16,825.81
2025-2026	1,911.41	31.85	1.49	28.26	0.38	2,412.93	115.00	3,690.35	1,445.53	6,062.40	473.24	947.04	17,119.89
2026-2027	1,938.37	36.80	1.78	29.18	0.46	2,419.70	152.00	3,847.88	1,468.23	6,112.82	484.42	958.56	17,450.20
2027-2028	1,965.44	41.67	2.07	30.09	0.55	2,426.38	193.17	4,022.54	1,491.13	6,163.58	495.61	970.17	17,802.42
2028-2029	1,992.24	46.19	2.34	30.96	0.62	2,432.63	234.55	4,199.43	1,514.01	6,213.93	506.50	981.68	18,155.10
2029-2030	2,018.66	50.21	2.58	31.76	0.69	2,438.27	272.16	4,363.28	1,536.80	6,263.62	516.95	992.89	18,487.87
2030-2031	2,044.46	53.56	2.78	32.47	0.75	2,443.09	303.00	4,502.61	1,559.35	6,312.18	526.79	1,003.81	18,784.85
2031-2032	2,069.62	56.27	2.94	33.09	0.79	2,447.12	326.39	4,614.59	1,581.67	6,359.64	536.02	1,014.32	19,042.47
2032-2033	2,094.13	58.28	3.06	33.62	0.83	2,450.31	342.45	4,699.90	1,603.74	6,405.95	544.60	1,024.55	19,261.42

Appendix 2.16 Annual Load Forecast (post-DSM) – Base Case: Firm Sales + Firm Transportation (MDT)

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013-2014	5,747.60	1,385.77	211.32	852.32	238.69	7,140.10	999.20	24,051.61	12,072.38	20,192.97	10,218.66	8,112.64	91,223.26
2014-2015	5,752.08	1,392.24	224.59	850.21	240.86	7,133.07	998.21	24,310.94	12,177.22	20,401.26	10,229.54	8,336.68	92,046.89
2015-2016	5,774.59	1,408.02	239.29	856.40	245.85	7,160.46	1,002.70	24,774.10	12,389.67	20,764.81	10,315.44	8,641.38	93,572.70
2016-2017	5,755.19	1,410.19	253.32	852.15	246.94	7,172.16	1,000.27	24,800.92	12,404.76	20,822.47	10,290.87	8,783.86	93,793.10
2017-2018	5,783.74	1,421.14	269.24	855.25	250.41	7,215.01	1,004.49	24,954.34	12,487.32	20,969.73	10,326.96	8,977.56	94,515.18
2018-2019	5,817.88	1,434.23	285.67	859.76	254.39	7,266.69	1,011.10	25,132.46	12,583.40	21,139.70	10,375.47	9,193.38	95,354.13
2019-2020	5,881.73	1,455.97	303.95	871.86	261.16	7,349.12	1,024.33	25,467.33	12,759.37	21,421.00	10,485.99	9,481.53	96,763.36
2020-2021	5,900.66	1,465.85	319.91	872.47	263.88	7,393.32	1,032.74	25,559.07	12,809.92	21,538.32	10,504.33	9,683.02	97,343.49
2021-2022	5,948.76	1,484.35	337.75	880.51	269.44	7,467.22	1,049.19	25,808.72	12,937.88	21,762.97	10,582.04	9,956.82	98,485.64
2022-2023	6,001.28	1,504.80	356.11	889.65	275.61	7,547.95	1,070.95	26,086.43	13,074.99	22,003.72	10,667.75	10,252.89	99,732.15
2023-2024	6,084.14	1,534.45	376.70	906.56	284.94	7,660.09	1,103.65	26,538.55	13,293.21	22,357.83	10,814.85	10,629.45	101,584.42
2024-2025	6,120.30	1,551.84	394.37	911.29	290.02	7,730.22	1,136.35	26,751.54	13,378.57	22,536.01	10,863.62	10,911.63	102,575.78
2025-2026	6,185.29	1,577.85	414.21	923.60	298.34	7,830.34	1,182.15	27,142.83	13,542.07	22,823.55	10,970.43	11,274.70	104,165.35
2026-2027	6,253.16	1,605.01	434.44	936.76	307.49	7,935.79	1,236.37	27,573.46	13,713.15	23,124.63	11,082.44	11,659.21	105,861.88
2027-2028	6,349.04	1,640.05	457.03	957.57	320.39	8,071.40	1,300.13	28,176.26	13,964.79	23,538.12	11,252.53	12,132.29	108,159.59
2028-2029	6,394.12	1,660.71	475.78	965.43	329.08	8,159.27	1,356.56	28,502.96	14,076.40	23,762.46	11,318.28	12,491.10	109,492.15
2029-2030	6,466.29	1,688.59	496.84	980.89	341.75	8,276.50	1,413.65	28,968.97	14,268.59	24,098.28	11,441.35	12,938.39	111,380.10
2030-2031	6,537.53	1,714.65	517.66	995.77	354.85	8,395.43	1,462.68	29,415.19	14,465.35	24,442.20	11,565.05	13,403.89	113,270.25
2031-2032	6,634.60	1,746.26	540.59	1,017.05	371.31	8,543.79	1,507.07	29,989.65	14,743.80	24,900.68	11,745.13	13,965.17	115,705.10
2032-2033	6,676.83	1,760.64	558.40	1,023.22	381.96	8,638.44	1,534.15	30,241.59	14,872.72	25,154.97	11,814.06	14,387.28	117,044.25

Appendix 2.17 Annual Load Forecast (post-DSM) – Base Case: Interruptible (MDT)

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013-2014	860.71	56.99	191.86	185.82	0.17	943.52	18.76	754.88	528.51	680.96	1,514.77	154.81	5,891.77
2014-2015	853.96	60.04	173.30	180.95	0.20	886.34	19.73	767.66	529.80	691.25	1,522.43	160.17	5,845.82
2015-2016	842.20	63.38	151.97	176.98	0.25	831.17	20.34	783.55	531.67	703.77	1,533.21	166.84	5,805.33
2016-2017	832.81	64.24	146.20	176.49	0.28	823.91	21.15	783.05	530.34	705.90	1,530.42	168.43	5,783.21
2017-2018	831.67	64.85	143.87	175.87	0.30	818.72	22.26	780.81	529.32	707.15	1,528.43	168.83	5,772.07
2018-2019	832.92	65.76	141.82	175.77	0.32	815.96	23.60	780.17	529.06	709.86	1,529.69	169.43	5,774.37
2019-2020	836.64	66.99	140.04	176.19	0.36	815.64	25.17	781.04	529.49	713.95	1,534.06	170.26	5,789.81
2020-2021	843.65	68.59	138.58	177.33	0.41	818.62	27.01	783.81	530.65	719.63	1,542.55	171.42	5,822.26
2021-2022	851.94	70.50	137.26	178.81	0.49	822.82	29.12	787.67	532.42	726.34	1,552.82	172.95	5,863.13
2022-2023	861.52	72.77	136.08	180.64	0.60	828.25	31.54	792.65	534.79	734.06	1,564.83	175.02	5,912.78
2023-2024	872.23	75.41	135.03	182.83	0.76	834.76	34.28	798.66	537.71	742.66	1,578.29	177.65	5,970.28
2024-2025	883.56	78.38	134.06	185.27	0.95	841.82	37.32	805.50	541.17	751.99	1,592.66	180.92	6,033.58
2025-2026	895.37	81.61	133.15	187.91	1.18	849.31	40.61	812.98	545.01	761.86	1,607.71	184.63	6,101.33
2026-2027	907.42	84.93	132.25	190.64	1.42	856.96	43.95	820.74	549.04	771.94	1,623.15	188.56	6,171.02
2027-2028	919.35	88.10	131.30	193.33	1.65	864.41	47.13	828.25	552.93	781.76	1,638.54	192.40	6,239.16
2028-2029	930.88	90.92	130.23	195.85	1.85	871.37	49.97	835.11	556.45	790.95	1,653.51	195.87	6,302.96
2029-2030	941.97	93.35	129.03	198.17	2.01	877.76	52.41	841.22	559.51	799.42	1,668.02	198.91	6,361.78
2030-2031	952.50	95.32	127.69	200.27	2.14	883.50	54.38	846.46	562.06	807.03	1,681.95	201.43	6,414.73
2031-2032	962.57	96.89	126.22	202.19	2.22	888.67	55.96	850.95	564.17	813.90	1,695.38	203.48	6,462.59
2032-2033	972.35	98.08	124.64	203.96	2.28	893.42	57.11	854.79	565.88	820.04	1,708.54	205.08	6,506.19

Appendix 2.18 Annual Load Forecast (post-DSM) – Base Case: Emerging Markets (Low Case) (MDT)

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013-2014	5.41	4.35	0.15	0.36	0.03	5.16	5.47	5.52	2.95	11.16	4.14	2.34	47.04
2014-2015	9.07	7.28	0.28	0.68	0.06	8.68	9.10	9.34	5.01	18.57	7.05	4.04	79.17
2015-2016	11.95	9.57	0.40	0.96	0.10	11.45	11.93	12.39	6.67	24.34	9.37	5.43	104.56
2016-2017	15.07	12.04	0.55	1.32	0.14	14.46	14.95	15.75	8.51	30.50	11.95	7.00	132.26
2017-2018	18.91	15.06	0.77	1.81	0.21	18.18	18.61	19.96	10.83	37.94	15.21	9.04	166.53
2018-2019	23.65	18.76	1.07	2.52	0.32	22.80	23.05	25.27	13.79	46.96	19.35	11.69	209.23
2019-2020	29.50	23.29	1.51	3.51	0.48	28.52	28.40	31.98	17.57	57.84	24.63	15.16	262.41
2020-2021	36.80	28.90	2.14	4.93	0.72	35.70	34.91	40.56	22.46	71.06	31.45	19.76	329.39
2021-2022	45.96	35.87	3.03	6.93	1.08	44.76	42.89	51.61	28.81	87.24	40.30	25.88	414.38
2022-2023	57.43	44.54	4.27	9.71	1.60	56.17	52.63	65.76	37.04	106.97	51.74	33.97	521.85
2023-2024	71.50	55.10	5.93	13.42	2.33	70.22	64.33	83.46	47.44	130.64	66.14	44.35	654.86
2024-2025	88.27	67.64	8.03	18.15	3.31	87.02	78.05	104.88	60.16	158.36	83.67	57.19	814.73
2025-2026	107.40	81.95	10.54	23.83	4.58	106.21	93.56	129.58	74.98	189.65	103.97	72.27	998.52
2026-2027	127.97	97.42	13.35	30.25	6.19	126.85	110.18	156.34	91.31	223.15	126.06	88.95	1,198.03
2027-2028	148.83	113.31	16.33	37.21	8.27	147.75	127.10	183.65	108.44	257.14	148.75	106.46	1,403.24
2028-2029	169.33	129.29	19.46	44.79	11.08	168.21	143.85	210.74	126.26	290.68	171.49	124.71	1,609.90
2029-2030	188.74	144.81	22.62	52.71	14.53	187.51	159.88	236.63	144.11	322.61	193.44	143.00	1,810.59
2030-2031	205.27	158.23	25.38	59.74	17.83	203.90	173.66	258.73	159.71	350.01	212.26	158.97	1,983.69
2031-2032	218.81	169.36	27.68	65.68	20.77	217.28	185.05	276.82	172.75	372.64	227.73	172.28	2,126.84

Appendix 2.19 Design Day Load Forecast (post-DSM) – Base Case: Firm Sales (MDT)

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland-Central	Portland-East	Portland - West	Salem	Vancouver	System
2013-2014	52.58	16.30	1.74	8.11	2.84	51.86	10.98	267.20	136.86	183.18	107.96	90.93	930.55
2014-2015	52.73	16.43	1.88	8.15	2.89	52.19	11.00	268.66	137.51	184.25	108.12	93.15	936.98
2015-2016	52.98	16.59	2.02	8.20	2.94	52.64	11.05	270.56	138.44	185.77	108.48	95.63	945.30
2016-2017	53.21	16.76	2.16	8.26	2.98	53.20	11.09	272.32	139.34	187.22	108.88	98.02	953.45
2017-2018	53.48	16.94	2.31	8.33	3.03	53.80	11.15	274.23	140.30	188.76	109.31	100.66	962.29
2018-2019	53.79	17.13	2.46	8.41	3.08	54.47	11.22	276.36	141.39	190.51	109.86	103.58	972.27
2019-2020	54.12	17.34	2.61	8.48	3.14	55.17	11.30	278.60	142.54	192.33	110.41	106.72	982.77
2020-2021	54.52	17.55	2.77	8.59	3.20	56.01	11.39	281.15	143.89	194.53	111.19	110.20	995.00
2021-2022	54.94	17.78	2.93	8.69	3.27	56.87	11.48	283.78	145.27	196.76	111.95	113.90	1,007.62
2022-2023	55.38	18.00	3.09	8.80	3.35	57.78	11.58	286.53	146.72	199.11	112.77	117.87	1,020.98
2023-2024	55.83	18.24	3.26	8.90	3.43	58.69	11.69	289.34	148.20	201.48	113.57	122.04	1,034.68
2024-2025	56.34	18.48	3.43	9.03	3.52	59.75	11.81	292.45	149.87	204.23	114.57	126.61	1,050.09
2025-2026	56.85	18.73	3.60	9.15	3.62	60.81	11.94	295.58	151.55	206.98	115.53	131.39	1,065.71
2026-2027	57.39	18.97	3.77	9.28	3.72	61.91	12.06	298.81	153.30	209.85	116.54	136.43	1,082.03
2027-2028	57.92	19.22	3.94	9.40	3.83	63.02	12.20	302.06	155.05	212.73	117.49	141.66	1,098.52
2028-2029	58.51	19.48	4.12	9.54	3.95	64.26	12.33	305.59	157.00	215.98	118.65	147.29	1,116.69
2029-2030	59.09	19.73	4.30	9.67	4.08	65.50	12.48	309.13	158.96	219.24	119.76	153.11	1,135.05
2030-2031	59.69	19.98	4.47	9.81	4.22	66.78	12.62	312.78	160.99	222.62	120.90	159.18	1,154.03
2031-2032	60.27	20.22	4.65	9.93	4.36	68.06	12.76	316.42	163.00	225.99	121.98	165.44	1,173.07
2032-2033	60.90	20.46	4.83	10.07	4.51	69.47	12.90	320.36	165.23	229.75	123.25	172.07	1,193.80

Appendix 2.20 Design Day Load Forecast (post-DSM) – Base Case: Residential (MDT)

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland-Central	Portland-East	Portland-West	Salem	Vancouver	System
2013-2014	34.34	9.88	0.59	3.43	1.83	27.02	6.58	178.92	91.82	125.32	67.81	65.48	613.02
2014-2015	34.43	9.99	0.63	3.45	1.85	27.27	6.62	180.55	92.48	126.11	68.04	66.96	618.39
2015-2016	34.63	10.14	0.66	3.49	1.88	27.63	6.69	182.62	93.43	127.39	68.50	68.69	625.74
2016-2017	34.80	10.29	0.70	3.52	1.90	27.98	6.75	184.54	94.37	128.71	68.97	70.66	633.19
2017-2018	34.99	10.43	0.74	3.56	1.94	28.35	6.81	186.53	95.34	130.08	69.47	72.87	641.11
2018-2019	35.18	10.59	0.77	3.60	1.97	28.76	6.88	188.61	96.36	131.57	70.01	75.33	649.63
2019-2020	35.39	10.75	0.82	3.64	2.01	29.19	6.95	190.77	97.43	133.14	70.59	78.01	658.69
2020-2021	35.59	10.91	0.86	3.68	2.06	29.65	7.03	192.98	98.53	134.76	71.20	80.86	668.10
2021-2022	35.81	11.07	0.90	3.73	2.10	30.13	7.10	195.24	99.66	136.43	71.82	83.94	677.94
2022-2023	36.02	11.24	0.95	3.77	2.15	30.63	7.18	197.54	100.81	138.14	72.47	87.22	688.13
2023-2024	36.24	11.40	0.99	3.82	2.21	31.17	7.26	199.93	102.00	139.92	73.14	90.72	698.81
2024-2025	36.47	11.57	1.04	3.86	2.27	31.72	7.34	202.34	103.21	141.75	73.84	94.42	709.84
2025-2026	36.69	11.74	1.09	3.91	2.33	32.30	7.43	204.79	104.45	143.62	74.55	98.33	721.24
2026-2027	36.92	11.91	1.15	3.96	2.40	32.90	7.51	207.26	105.70	145.55	75.29	102.44	732.99
2027-2028	37.15	12.08	1.20	4.00	2.47	33.52	7.59	209.77	106.98	147.52	76.03	106.75	745.08
2028-2029	37.38	12.26	1.26	4.05	2.55	34.17	7.68	212.29	108.27	149.54	76.80	111.25	757.50
2029-2030	37.61	12.43	1.31	4.10	2.63	34.83	7.77	214.84	109.59	151.61	77.58	115.95	770.26
2030-2031	37.84	12.60	1.37	4.15	2.72	35.53	7.85	217.42	110.92	153.73	78.37	120.84	783.35
2031-2032	38.08	12.77	1.43	4.20	2.81	36.24	7.94	220.01	112.28	155.90	79.19	125.92	796.77
2032-2033	38.31	12.95	1.49	4.25	2.91	36.98	8.03	222.63	113.65	158.13	80.02	131.18	810.52

Appendix 2.21 Design Day Load Forecast (post-DSM) – Base Case: Commercial Firm Sales (MDT)

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland-Central	Portland-East	Portland-West	Salem	Vancouver	System
2013-2014	17.64	6.39	1.10	4.41	1.00	23.45	4.34	86.09	43.61	55.14	38.26	24.26	305.68
2014-2015	17.70	6.40	1.21	4.44	1.01	23.61	4.32	85.70	43.46	55.16	38.08	24.76	305.85
2015-2016	17.78	6.42	1.32	4.47	1.03	23.80	4.30	85.41	43.37	55.25	37.93	25.32	306.39
2016-2017	17.81	6.43	1.43	4.49	1.05	23.98	4.28	85.18	43.27	55.27	37.79	25.69	306.64
2017-2018	17.89	6.46	1.54	4.52	1.06	24.21	4.27	85.11	43.26	55.41	37.72	26.10	307.55
2018-2019	18.01	6.50	1.65	4.55	1.08	24.49	4.27	85.17	43.32	55.66	37.72	26.56	308.96
2019-2020	18.15	6.54	1.77	4.60	1.10	24.79	4.27	85.32	43.44	56.00	37.75	27.07	310.79
2020-2021	18.31	6.59	1.88	4.64	1.12	25.13	4.28	85.56	43.61	56.41	37.82	27.62	312.97
2021-2022	18.50	6.64	1.99	4.70	1.14	25.49	4.29	85.90	43.83	56.91	37.93	28.22	315.54
2022-2023	18.71	6.70	2.11	4.76	1.16	25.88	4.31	86.32	44.10	57.49	38.06	28.88	318.47
2023-2024	18.94	6.76	2.23	4.82	1.19	26.29	4.32	86.80	44.41	58.13	38.22	29.59	321.69
2024-2025	19.18	6.81	2.34	4.88	1.22	26.72	4.34	87.36	44.77	58.85	38.40	30.36	325.23
2025-2026	19.44	6.87	2.46	4.94	1.25	27.17	4.37	87.98	45.17	59.64	38.59	31.19	329.07
2026-2027	19.71	6.93	2.57	5.01	1.28	27.64	4.39	88.69	45.62	60.50	38.81	32.08	333.22
2027-2028	20.00	6.99	2.69	5.07	1.31	28.14	4.42	89.46	46.11	61.43	39.04	33.02	337.68
2028-2029	20.30	7.04	2.80	5.14	1.35	28.65	4.45	90.31	46.64	62.44	39.28	34.02	342.43
2029-2030	20.62	7.10	2.92	5.21	1.39	29.19	4.48	91.24	47.22	63.53	39.55	35.09	347.52
2030-2031	20.95	7.15	3.03	5.28	1.43	29.75	4.51	92.25	47.85	64.69	39.82	36.22	352.93
2031-2032	21.29	7.20	3.15	5.34	1.47	30.33	4.54	93.34	48.53	65.93	40.11	37.42	358.65
2032-2033	21.64	7.25	3.26	5.41	1.51	30.93	4.58	94.52	49.26	67.25	40.42	38.68	364.70

Appendix 2.22 Design Day Load Forecast (post-DSM) – Base Case: Industrial Firm Sales (MDT)

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland-Central	Portland-East	Portland-West	Salem	Vancouver	System
2013-2014	0.60	0.03	0.05	0.28	0.01	1.39	0.06	2.19	1.43	2.71	1.88	1.19	11.82
2014-2015	0.59	0.03	0.04	0.26	0.02	1.31	0.06	2.40	1.56	2.97	2.00	1.43	12.70
2015-2016	0.57	0.03	0.03	0.25	0.03	1.20	0.06	2.52	1.64	3.12	2.04	1.61	13.11
2016-2017	0.59	0.03	0.03	0.25	0.03	1.23	0.06	2.59	1.70	3.24	2.11	1.67	13.55
2017-2018	0.59	0.03	0.03	0.25	0.03	1.22	0.06	2.58	1.70	3.24	2.11	1.67	13.53
2018-2019	0.59	0.03	0.03	0.25	0.03	1.22	0.06	2.57	1.71	3.26	2.12	1.68	13.55
2019-2020	0.57	0.03	0.03	0.24	0.03	1.17	0.06	2.48	1.66	3.17	2.05	1.63	13.13
2020-2021	0.59	0.03	0.03	0.25	0.03	1.21	0.06	2.58	1.74	3.32	2.14	1.70	13.70
2021-2022	0.59	0.03	0.03	0.25	0.03	1.22	0.06	2.60	1.75	3.36	2.16	1.72	13.81
2022-2023	0.60	0.03	0.03	0.26	0.03	1.22	0.06	2.61	1.78	3.41	2.19	1.73	13.94
2023-2024	0.58	0.03	0.03	0.25	0.03	1.18	0.06	2.54	1.74	3.34	2.14	1.68	13.59
2024-2025	0.61	0.03	0.03	0.26	0.03	1.23	0.06	2.65	1.82	3.50	2.24	1.76	14.22
2025-2026	0.62	0.03	0.03	0.26	0.03	1.23	0.06	2.66	1.85	3.55	2.26	1.77	14.37
2026-2027	0.62	0.03	0.03	0.26	0.03	1.24	0.06	2.68	1.87	3.61	2.29	1.79	14.52
2027-2028	0.61	0.03	0.03	0.26	0.03	1.20	0.06	2.61	1.83	3.53	2.24	1.74	14.16
2028-2029	0.63	0.03	0.03	0.27	0.03	1.24	0.06	2.72	1.92	3.71	2.35	1.83	14.82
2029-2030	0.64	0.03	0.02	0.27	0.03	1.25	0.06	2.74	1.95	3.76	2.37	1.85	14.98
2030-2031	0.64	0.03	0.02	0.27	0.03	1.25	0.06	2.76	1.97	3.82	2.40	1.87	15.14
2031-2032	0.63	0.03	0.02	0.26	0.03	1.21	0.06	2.68	1.93	3.74	2.35	1.83	14.77
2032-2033	0.66	0.03	0.02	0.28	0.03	1.26	0.06	2.80	2.03	3.93	2.46	1.92	15.47

Appendix 2.23 Design Day Load Forecast (post-DSM) – Base Case: Firm Transportation (MDT)

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland-Central	Portland-East	Portland-West	Salem	Vancouver	System
2013-2014	5.36	0.01	0.00	0.07	0.00	8.34	0.01	8.31	3.50	15.88	1.11	2.29	44.87
2014-2015	5.41	0.01	0.00	0.07	0.00	8.33	0.01	9.15	3.82	16.49	1.20	2.58	47.07
2015-2016	5.28	0.01	0.00	0.07	0.00	8.03	0.01	9.65	4.00	16.50	1.25	2.77	47.57
2016-2017	5.53	0.01	0.00	0.07	0.00	8.33	0.02	10.07	4.20	17.20	1.31	2.89	49.62
2017-2018	5.59	0.02	0.00	0.07	0.00	8.33	0.02	10.15	4.25	17.31	1.33	2.92	49.98
2018-2019	5.65	0.02	0.00	0.07	0.00	8.34	0.03	10.23	4.30	17.42	1.35	2.95	50.35
2019-2020	5.51	0.03	0.00	0.07	0.00	8.06	0.03	9.95	4.21	16.93	1.33	2.88	49.00
2020-2021	5.77	0.03	0.00	0.07	0.00	8.36	0.04	10.39	4.42	17.66	1.40	3.01	51.14
2021-2022	5.84	0.04	0.00	0.07	0.00	8.37	0.05	10.47	4.48	17.78	1.42	3.04	51.56
2022-2023	5.91	0.05	0.00	0.08	0.00	8.38	0.06	10.56	4.54	17.91	1.45	3.07	52.00
2023-2024	5.78	0.06	0.00	0.08	0.00	8.10	0.07	10.28	4.44	17.43	1.43	3.00	50.67
2024-2025	6.06	0.07	0.00	0.08	0.00	8.41	0.08	10.74	4.66	18.19	1.50	3.14	52.94
2025-2026	6.13	0.08	0.00	0.08	0.00	8.42	0.10	10.84	4.73	18.33	1.54	3.18	53.44
2026-2027	6.21	0.09	0.00	0.08	0.00	8.44	0.12	10.93	4.80	18.48	1.57	3.22	53.96
2027-2028	6.08	0.11	0.01	0.08	0.00	8.17	0.13	10.65	4.70	18.00	1.55	3.14	52.63
2028-2029	6.37	0.12	0.01	0.09	0.00	8.48	0.15	11.13	4.93	18.78	1.63	3.29	54.99
2029-2030	6.45	0.13	0.01	0.09	0.00	8.49	0.16	11.22	5.00	18.93	1.67	3.33	55.49
2030-2031	6.53	0.14	0.01	0.09	0.00	8.51	0.17	11.32	5.07	19.08	1.69	3.37	55.97
2031-2032	6.38	0.15	0.01	0.09	0.00	8.23	0.18	11.02	4.96	18.57	1.67	3.29	54.55
2032-2033	6.67	0.15	0.01	0.10	0.00	8.53	0.19	11.50	5.20	19.36	1.75	3.44	56.89

Appendix 2.24 Design Day Load Forecast (post-DSM) – Base Case: Firm Sales + Firm Transportation (MDT)

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland-Central	Portland-East	Portland-West	Salem	Vancouver	System
2013-2014	57.93	16.30	1.74	8.18	2.84	60.21	10.99	275.51	140.36	199.06	109.07	93.22	975.42
2014-2015	58.14	16.43	1.88	8.22	2.89	60.53	11.01	277.81	141.33	200.74	109.33	95.73	984.05
2015-2016	58.26	16.60	2.02	8.27	2.94	60.68	11.06	280.21	142.45	202.27	109.72	98.39	992.86
2016-2017	58.74	16.77	2.16	8.33	2.98	61.53	11.11	282.39	143.53	204.42	110.19	100.92	1003.07
2017-2018	59.06	16.95	2.31	8.40	3.03	62.13	11.17	284.38	144.55	206.06	110.64	103.58	1012.27
2018-2019	59.43	17.15	2.46	8.48	3.08	62.81	11.25	286.59	145.70	207.93	111.21	106.53	1022.62
2019-2020	59.63	17.36	2.61	8.55	3.14	63.23	11.33	288.55	146.75	209.27	111.74	109.60	1031.77
2020-2021	60.30	17.58	2.77	8.66	3.20	64.37	11.43	291.54	148.31	212.19	112.58	113.21	1046.14
2021-2022	60.78	17.81	2.93	8.76	3.27	65.24	11.53	294.25	149.75	214.54	113.37	116.94	1059.18
2022-2023	61.29	18.05	3.10	8.87	3.35	66.15	11.64	297.09	151.26	217.02	114.21	120.94	1072.98
2023-2024	61.60	18.30	3.26	8.98	3.43	66.80	11.76	299.63	152.64	218.91	114.99	125.05	1085.35
2024-2025	62.40	18.55	3.43	9.11	3.52	68.15	11.90	303.20	154.54	222.41	116.07	129.76	1103.04
2025-2026	62.99	18.81	3.60	9.23	3.62	69.23	12.04	306.42	156.28	225.31	117.07	134.57	1119.16
2026-2027	63.60	19.07	3.77	9.36	3.72	70.35	12.18	309.75	158.10	228.33	118.10	139.64	1135.99
2027-2028	64.00	19.33	3.95	9.48	3.83	71.19	12.33	312.71	159.75	230.73	119.04	144.81	1151.15
2028-2029	64.88	19.60	4.12	9.63	3.95	72.74	12.48	316.71	161.94	234.76	120.28	150.58	1171.68
2029-2030	65.54	19.86	4.30	9.76	4.08	73.99	12.64	320.36	163.97	238.17	121.43	156.44	1190.54
2030-2031	66.21	20.12	4.48	9.90	4.22	75.29	12.79	324.09	166.06	241.69	122.60	162.55	1210.00
2031-2032	66.65	20.37	4.66	10.02	4.36	76.29	12.94	327.44	167.97	244.55	123.65	168.72	1227.62
2032-2033	67.58	20.61	4.84	10.17	4.51	78.00	13.09	331.86	170.43	249.10	125.00	175.51	1250.69

Appendix 2.25 Design Day Load Forecast (post-DSM) – Base Case: Emerging Markets Firm Sales (Low Case) (MDT)

Year	Albany	Astoria	Coos Bay	Dalles, OR	Dalles, WA	Eugene	Newport	Portland-Central	Portland-East	Portland-West	Salem	Vancouver	System
2013-2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.02
2014-2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.04
2015-2016	0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.01	0.01	0.00	0.05
2016-2017	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.01	0.01	0.00	0.07
2017-2018	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.09
2018-2019	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.02	0.01	0.03	0.01	0.01	0.13
2019-2020	0.02	0.01	0.00	0.00	0.00	0.02	0.02	0.02	0.01	0.03	0.02	0.01	0.17
2020-2021	0.02	0.02	0.00	0.01	0.00	0.02	0.02	0.03	0.02	0.04	0.02	0.02	0.23
2021-2022	0.03	0.03	0.00	0.01	0.00	0.03	0.03	0.04	0.03	0.06	0.03	0.03	0.32
2022-2023	0.05	0.03	0.01	0.01	0.00	0.05	0.04	0.06	0.04	0.07	0.05	0.04	0.44
2023-2024	0.06	0.05	0.01	0.02	0.00	0.06	0.05	0.08	0.05	0.10	0.07	0.05	0.59
2024-2025	0.08	0.06	0.01	0.03	0.01	0.08	0.06	0.11	0.07	0.13	0.09	0.07	0.79
2025-2026	0.11	0.08	0.02	0.04	0.01	0.11	0.08	0.14	0.09	0.16	0.12	0.09	1.03
2026-2027	0.13	0.10	0.02	0.05	0.01	0.13	0.10	0.18	0.11	0.20	0.15	0.12	1.31
2027-2028	0.16	0.12	0.03	0.06	0.02	0.16	0.12	0.22	0.14	0.24	0.19	0.15	1.61
2028-2029	0.19	0.14	0.03	0.08	0.02	0.19	0.14	0.27	0.17	0.29	0.22	0.18	1.93
2029-2030	0.22	0.17	0.04	0.09	0.03	0.23	0.17	0.31	0.20	0.34	0.26	0.22	2.29
2030-2031	0.25	0.19	0.05	0.11	0.04	0.25	0.19	0.35	0.24	0.38	0.30	0.25	2.61
2031-2032	0.27	0.21	0.05	0.12	0.05	0.28	0.21	0.39	0.26	0.41	0.33	0.28	2.87
2032-2033	0.29	0.23	0.06	0.14	0.05	0.30	0.22	0.41	0.29	0.45	0.36	0.30	3.10

Appendix 3: Supply-Side Resources

NW Natural®

Newport LNG Refurbishment Analysis

Newport LNG Background

NW Natural owns and operates an LNG peak shaving facility located in Newport, Oregon which consists of a 1,000,000 Dth capacity storage tank; liquefaction facilities capable of processing approximately 5,500 Dth/day; and vaporization capacity of up to 100,000 Dth/day ("Newport"). Chicago Bridge and Iron constructed the facility, which was commissioned in 1977.

Newport's facilities and major process components were designed for a nominal 25- to 30-year life. Newport is now 37 years old and NW Natural is considering a major refurbishment of the plant. The planned refurbishment addresses issues with the liquefaction process; including removal of carbon dioxide (CO_2) from the incoming natural gas stream, which has been gradually collecting in the tank over the course of the facility's life and settling on its floor in solid form (commonly known as dry ice). Newport's dry ice issue is sufficiently severe that, to avoid issues associated with excess weight on the floor of the storage tank, the Company has reduced the maximum quantity of LNG to be stored from 1,000,000 Dth to 900,000 Dth. Fortunately, this issue has not as yet affected the daily vaporization rate and NW Natural's reliance on Newport as a component of the Company's peak day resource stack.

The breakdown of estimated refurbishment costs are shown in Table 1 below:

Table 1 Newport Refurbishment Estimated Costs

Components	Investment ($2013)	Levelized Annual Revenue Requirement ($2013)
Structures & Improvements	8,042,222	734,294
Gas Holders	947,222	93,259
Liquefaction Equipment	8,913,243	837,041
Vaporizing Equipment	4,425,056	431,267
Compressor Equipment	305,556	120,447
LNG Refueling Facilities	775,867	71,363
Total Newport LNG Project	23,409,165	2,287,671

Alternatives

NW Natural is considering two high level options associated with Newport: 1) spend approximately $23 million to extend the facility's life (Option 1); or 2) keep the facility operational until the Company acquires an alternative supply source (Option 2). NW Natural identified two alternatives within Option 2 to replace Newport's 60,000 Dth/day of firm peaking supplies:

A. Contract with NWP for additional pipeline capacity from Sumas south to city gates on NWP's Grants Pass Lateral

B. Construct a 25 mile high pressure transmission facility between Newburg and the Central Coast Feeder coupled with additional Mist Recall

Alternative A has a very high cost for pipeline capacity (estimated at twice the current NWP tariff rate, with the *annual* cost for 60,000 Dth/day of capacity estimated at $19.3 million) and requires gate and distribution system upgrades at additional costs. Alternative B is much lower cost, with construction costs for 25 miles of a 16-inch high pressure pipeline estimated at $54 million (see below). While this is significantly higher than the cost to refurbish Newport, the estimated total annual operating costs of a pipeline facility ($0.2 million) are significantly lower than those for an LNG facility ($2.0 million). The new pipeline would have an estimated capacity of 77,000 Dth/day.

NW Natural used SENDOUT® to determine whether the Company should refurbish Newport or pursue Option 2's Alternative B. Table 2 shows the net present value of revenue requirement (NPVRR) of a 20-year resource plan associated with each of the two courses of action.

Table 2 - NPVRR Comparison

Scenario	Supply NPVRR ($000)	Transportation NPVRR ($000)	Storage NPVRR ($000)	Total NPVRR ($000)
With Newport Refurbishment	4,762,240	1,390,824	436,331	6,663,006
Without Refurbishment (Alternative B)	4,737,118	1,454,366	426,245	6,691,339

Table 2 shows that a 20-year portfolio including Newport after the $23 million refurbishment project has a NPVRR savings of approximately $28 million versus the next best option.

Project Assumptions
Newberg to Christensen Bridle
16" W HP 1-059-006 to 2-095-023

25 miles total	Miles				
Easy construction	21.4	$	1,900,000	$	40,720,095
Moderate construction	1.1	$	2,400,000	$	2,636,364
Difficult construction	0.6	$	3,000,000	$	1,931,818
Very difficult construction	2.0	$	4,000,000	$	7,981,818
EFSC Permit				$	1,000,000
	25.2			$	54,270,095

5280 = 1 mile

4200	1-059-006	Hwy 99 - Newburg
6336	1-060-004	Hwy 99
3400	1-061-002	Hwy 99
2600	1-061-000	Hwy 99
3200	2-061-001	Hwy 99 - SPRR
3300	2-062-002	Hwy 99
3800	2-063-003	Hwy 99
3100	2-064-004	Hwy 99 - RR Spur
3100	2-065-004	Hwy 99
6864		Hwy 99 - river x2
8448		Hwy 99 to Dayton Bypass - river x2
6623		Hwy 18 to Hwy 221 - Dayton - river
2000		SE 3rd St (221) to Ferry - river
8976		Ferry St to Hwy 233
12632		Amity Dayton Hwy 233
19536		Amity Dayton Hwy 233 - river x2
5280	2-083-022	Hwy 233
2800	2-084-022	Hwy 99
5200	2-086-022	Hwy 99
5400	2-088-022	Hwy 99 - river x2
5280	2-090-023	Hwy 99
7920		Hwy 99 - river
2900	2-095-023	Hwy 99
132895	feet	
25.17	miles	

1 year for design and route selection before we can start the EFSC process
EFSC - 2 year siting process after route is selected - 16" + pipe and 5 miles +
Permitting - ODOT, Multiple County permits, DSL/Corp
Threatened and Endangered Species study, Habitat study - biologist, Archy study

Considerations:
Night work - assume 30% increase in cost
ODOT crossings - assume 50% increase in cost for the crossing
RR crossings - assume 50% increase in cost for the crossing
Costs include current COH rates
Archy
Ground conditions
Permitting

Aether Report is Confidential

- Subject to General Protective Order No. 14-142 in Oregon
- Subject to WAC 480-07-160 in Washington

Black & Veatch Report is Confidential

- Subject to General Protective Order No. 14-142 in Oregon
- Subject to WAC 480-07-160 in Washington

Appendix 4: Demand-Side Resources

NW Natural®

Oregon Cost Effective DSM Savings Deployment

Program	Deployment		2014	2015	2016	2017
Resid New			446,820	119,042	119,042	119,042
	New Construction	RES	441,355	119,042	119,042	119,042
	New DHW	RES	5,465	-	-	-
Existing Residential			1,142,777	672,907	615,118	615,118
	Retrofit	RES	903,296	465,145	407,356	407,356
	Replace DHW	RES	203,307	171,588	171,588	171,588
	Replace equipment	RES	36,174	36,174	36,174	36,174
	Appliances, new & replace	RES	37,886	37,886	37,886	37,886
	Solar Water heat - Residential	RES	-	-	-	-
Commercial Existing			2,003,621	2,011,278	1,422,657	1,071,650
	Replace Equip	COM	134,147	134,147	134,147	134,147
	Replace Shell	COM	154,742	154,742	154,742	154,742
	Retrofit Wx	COM	648,702	651,742	418,056	278,704
	Retrofit Equip	COM	985,284	989,902	634,966	423,311
	Cooking Appliances	COM	80,746	80,746	80,746	80,746
Commercial New			28,415	28,415	28,415	28,415
	New Constr	COM	28,415	28,415	28,415	28,415
Industrial			1,151,420	1,151,420	1,093,820	1,026,941
	Retrofit	IND	726,383	726,383	689,723	647,156
	Replacement	IND	425,037	425,037	404,098	379,785
	RES Market Transformation	RES	502,996	585,749	585,749	585,749
	COM Market Transformation	COM	17,552	17,552	17,552	17,552
Residential Total		**RES**	**2,130,479**	**1,415,585**	**1,357,795**	**1,357,795**
Commercial Total		**COM**	**2,049,588**	**2,057,245**	**1,468,624**	**1,117,616**
Industrial Total		**IND**	**1,151,420**	**1,151,420**	**1,093,820**	**1,026,941**
Efficiency Total			**5,331,487**	**4,624,249**	**3,920,239**	**3,502,353**

Oregon Cost Effective DSM Savings Deployment

Program	Deployment		2018	2019	2020	2021
Resid New			119,042	119,042	119,042	119,042
	New Construction	RES	119,042	119,042	119,042	119,042
	New DHW	RES	-	-	-	-
Existing Residential			615,118	550,799	507,919	465,040
	Retrofit	RES	407,356	343,036	300,157	257,277
	Replace DHW	RES	171,588	171,588	171,588	171,588
	Replace equipment	RES	36,174	36,174	36,174	36,174
	Appliances, new & replace	RES	37,886	37,886	37,886	37,886
	Solar Water heat - Residential	RES	-	-	-	-
Commercial Existing			861,045	720,642	650,441	545,139
	Replace Equip	COM	134,147	134,147	134,147	134,147
	Replace Shell	COM	154,742	154,742	154,742	154,742
	Retrofit Wx	COM	195,093	139,352	111,482	69,676
	Retrofit Equip	COM	296,318	211,655	169,324	105,828
	Cooking Appliances	COM	80,746	80,746	80,746	80,746
Commercial New			28,415	28,415	28,415	28,415
	New Constr	COM	28,415	28,415	28,415	28,415
Industrial			826,304	692,546	358,151	291,272
	Retrofit	IND	519,457	434,324	221,492	178,926
	Replacement	IND	306,847	258,222	136,659	112,346
	RES Market Transformation	RES	585,749	585,749	585,749	585,749
	COM Market Transformation	COM	17,552	17,552	17,552	17,552
Residential Total		**RES**	**1,357,795**	**1,293,476**	**1,250,596**	**1,207,717**
Commercial Total		**COM**	**907,012**	**766,609**	**696,407**	**591,105**
Industrial Total		**IND**	**826,304**	**692,546**	**358,151**	**291,272**
Efficiency Total			**3,091,111**	**2,752,631**	**2,305,155**	**2,090,094**

Oregon Cost Effective DSM Savings Deployment

Program	Deployment		2022	2023	2024	2025
Resid New			119,042	119,042	119,042	119,042
	New Construction	RES	119,042	119,042	119,042	119,042
	New DHW	RES	-	-	-	-
Existing Residential			465,040	293,521	293,521	293,521
	Retrofit	RES	257,277	85,759	85,759	85,759
	Replace DHW	RES	171,588	171,588	171,588	171,588
	Replace equipment	RES	36,174	36,174	36,174	36,174
	Appliances, new & replace	RES	37,886	37,886	37,886	37,886
	Solar Water heat - Residential	RES	-	-	-	-
Commercial Existing			474,937	474,937	439,836	439,836
	Replace Equip	COM	134,147	134,147	134,147	134,147
	Replace Shell	COM	154,742	154,742	154,742	154,742
	Retrofit Wx	COM	41,806	41,806	27,870	27,870
	Retrofit Equip	COM	63,497	63,497	42,331	42,331
	Cooking Appliances	COM	80,746	80,746	80,746	80,746
Commercial New			28,415	28,415	28,415	28,415
	New Constr	COM	28,415	28,415	28,415	28,415
Industrial			224,393	157,514	157,514	157,514
	Retrofit	IND	136,359	93,793	93,793	93,793
	Replacement	IND	88,034	63,721	63,721	63,721
	RES Market Transformation	RES	585,749	585,749	585,749	585,749
	COM Market Transformation	COM	17,552	17,552	17,552	17,552
Residential Total		**RES**	**1,207,717**	**1,036,199**	**1,036,199**	**1,036,199**
Commercial Total		**COM**	**520,904**	**520,904**	**485,803**	**485,803**
Industrial Total		**IND**	**224,393**	**157,514**	**157,514**	**157,514**
Efficiency Total			**1,953,013**	**1,714,616**	**1,679,515**	**1,679,515**

Oregon Cost Effective DSM Savings Deployment

Program	Deployment		2026	2027	2028	2029
Resid New			119,042	119,042	119,042	119,042
	New Construction	RES	119,042	119,042	119,042	119,042
	New DHW	RES	-	-	-	-
Existing Residential			293,521	293,521	293,521	293,521
	Retrofit	RES	85,759	85,759	85,759	85,759
	Replace DHW	RES	171,588	171,588	171,588	171,588
	Replace equipment	RES	36,174	36,174	36,174	36,174
	Appliances, new & replace	RES	37,886	37,886	37,886	37,886
	Solar Water heat - Residential	RES	-	-	-	-
Commercial Existing			422,286	422,286	422,286	404,736
	Replace Equip	COM	134,147	134,147	134,147	134,147
	Replace Shell	COM	154,742	154,742	154,742	154,742
	Retrofit Wx	COM	20,903	20,903	20,903	13,935
	Retrofit Equip	COM	31,748	31,748	31,748	21,166
	Cooking Appliances	COM	80,746	80,746	80,746	80,746
Commercial New			28,415	28,415	28,415	28,415
	New Constr	COM	28,415	28,415	28,415	28,415
Industrial			157,514	157,514	157,514	157,514
	Retrofit	IND	93,793	93,793	93,793	93,793
	Replacement	IND	63,721	63,721	63,721	63,721
	RES Market Transformation	RES	585,749	585,749	585,749	585,749
	COM Market Transformation	COM	17,552	17,552	17,552	17,552
Residential Total		**RES**	**1,036,199**	**1,036,199**	**1,036,199**	**1,036,199**
Commercial Total		**COM**	**468,253**	**468,253**	**468,253**	**450,702**
Industrial Total		**IND**	**157,514**	**157,514**	**157,514**	**157,514**
Efficiency Total			**1,661,965**	**1,661,965**	**1,661,965**	**1,644,415**

Oregon Cost Effective DSM Savings Deployment

Program	Deployment		2030	2031	2032	2033
Resid New			119,042	119,042	119,042	119,042
	New Construction	RES	119,042	119,042	119,042	119,042
	New DHW	RES	-	-	-	-
Existing Residential			293,521	282,802	272,082	272,082
	Retrofit	RES	85,759	75,039	64,319	64,319
	Replace DHW	RES	171,588	171,588	171,588	171,588
	Replace equipment	RES	36,174	36,174	36,174	36,174
	Appliances, new & replace	RES	37,886	37,886	37,886	37,886
	Solar Water heat - Residential	RES	-	-	-	-
Commercial Existing			404,736	404,736	404,736	404,736
	Replace Equip	COM	134,147	134,147	134,147	134,147
	Replace Shell	COM	154,742	154,742	154,742	154,742
	Retrofit Wx	COM	13,935	13,935	13,935	13,935
	Retrofit Equip	COM	21,166	21,166	21,166	21,166
	Cooking Appliances	COM	80,746	80,746	80,746	80,746
Commercial New			28,415	28,415	28,415	28,415
	New Constr	COM	28,415	28,415	28,415	28,415
Industrial			157,514	157,514	157,514	107,354
	Retrofit	IND	93,793	93,793	93,793	61,868
	Replacement	IND	63,721	63,721	63,721	45,486
	RES Market Transformation	RES	585,749	585,749	585,749	585,749
	COM Market Transformation	COM	17,552	17,552	17,552	17,552
Residential Total		**RES**	**1,036,199**	**1,025,479**	**1,014,759**	**1,014,759**
Commercial Total		**COM**	**450,702**	**450,702**	**450,702**	**450,702**
Industrial Total		**IND**	**157,514**	**157,514**	**157,514**	**107,354**
Efficiency Total			**1,644,415**	**1,633,695**	**1,622,975**	**1,572,816**

Oregon Cost Effective DSM Savings Deployment

Program	Deployment		Total
Resid New			2,708,617
	New Construction	RES	2,703,152
	New DHW	RES	5,465
Existing Residential			8,824,973
	Retrofit	RES	4,638,006
	Replace DHW	RES	3,463,479
	Replace equipment	RES	723,488
	Appliances, new & replace	RES	757,725
	Solar Water heat - Residential	RES	-
Commercial Existing			14,406,557
	Replace Equip	COM	2,682,935
	Replace Shell	COM	3,094,848
	Retrofit Wx	COM	2,784,541
	Retrofit Equip	COM	4,229,317
	Cooking Appliances	COM	1,614,916
Commercial New			568,292
	New Constr	COM	568,292
Industrial			8,498,757
	Retrofit	IND	5,279,998
	Replacement	IND	3,218,759
	RES Market Transformation	RES	-
	COM Market Transformation	COM	-
Residential Total		**RES**	**23,923,542**
Commercial Total		**COM**	**15,325,889**
Industrial Total		**IND**	**8,498,757**
Efficiency Total			**47,748,187**

Washington Cost Effectiveness DSM By Year

Program	Deployment		2014	2015	2016	2017	2018	2019
Resid New			37,107	38,387	40,946	46,064	51,182	51,182
	New Construction	RES	36,910	38,183	40,728	45,819	50,910	50,910
	New DHW	RES	197	204	218	245	272	272
Existing Residential			71,066	66,604	63,113	65,005	66,614	68,223
	Retrofit	RES	56,871	52,409	48,918	48,918	48,918	48,918
	Replace DHW	RES	12,525	12,525	12,525	14,196	15,615	17,035
	Replace equipment	RES	1,670	1,670	1,670	1,892	2,081	2,271
	Appliances, new & replace	RES	1,672	1,693	1,736	1,962	2,167	2,286
	Solar Water heat - Residential	RES	-	-	-	-	-	-
Commercial Existing			77,575	77,042	80,929	81,202	88,500	100,129
	Replace Equip	COM	14,048	14,048	14,248	14,349	14,449	14,850
	Replace Shell	COM	12,380	12,380	12,557	12,646	12,734	13,088
	Retrofit Wx	COM	15,124	14,919	16,203	16,203	18,904	22,954
	Retrofit Equip	COM	24,216	23,888	25,944	25,944	30,268	36,754
	Cooking Appliances	COM	11,807	11,807	11,976	12,060	12,145	12,482
Commercial New			9,209	9,209	9,341	9,406	9,472	9,735
	New Constr	COM	9,209	9,209	9,341	9,406	9,472	9,735
Industrial			63,216	70,749	65,606	59,846	54,050	48,254
	Retrofit	IND	57,168	64,630	59,380	53,442	47,504	41,566
	Replacement	IND	6,048	6,119	6,226	6,404	6,546	6,689
Residential Total		**RES**	109,845	106,684	105,795	113,032	119,963	121,691
Commercial Total		**COM**	86,784	86,251	90,269	90,608	97,972	109,864
Industrial Total		**IND**	63,216	70,749	65,606	59,846	54,050	48,254
Efficiency Total			**259,845**	**263,684**	**261,670**	**263,486**	**271,985**	**279,810**

Washington Cost Effectiveness DSM By Year

Program	Deployment		2020	2021	2022	2023	2024	2025
Resid New			51,182	51,182	51,182	51,182	51,182	51,182
	New Construction	RES	50,910	50,910	50,910	50,910	50,910	50,910
	New DHW	RES	272	272	272	272	272	272
Existing Residential			66,069	67,677	70,895	74,113	77,330	62,278
	Retrofit	RES	45,155	45,155	45,155	45,155	45,155	30,103
	Replace DHW	RES	18,454	19,874	22,713	25,552	28,391	28,391
	Replace equipment	RES	2,460	2,649	3,027	3,406	3,784	3,784
	Appliances, new & replace	RES	2,405	2,524	2,762	3,000	3,238	3,238
	Solar Water heat - Residential	RES	-	-	-	-	-	-
Commercial Existing			111,758	112,851	99,894	93,962	87,484	81,005
	Replace Equip	COM	15,252	15,653	16,055	16,456	16,657	16,857
	Replace Shell	COM	13,442	13,795	14,149	14,503	14,680	14,856
	Retrofit Wx	COM	27,005	27,005	21,604	18,904	16,203	13,503
	Retrofit Equip	COM	43,240	43,240	34,592	30,268	25,944	21,620
	Cooking Appliances	COM	12,819	13,157	13,494	13,832	14,000	14,169
Commercial New			9,998	10,261	10,525	10,788	10,919	11,051
	New Constr	COM	9,998	10,261	10,525	10,788	10,919	11,051
Industrial			39,490	39,561	36,663	36,734	30,867	30,867
	Retrofit	IND	32,659	32,659	29,690	29,690	23,752	23,752
	Replacement	IND	6,831	6,902	6,973	7,044	7,116	7,116
Residential Total		**RES**	119,656	121,384	124,839	128,295	131,751	116,699
Commercial Total		**COM**	121,757	123,112	110,419	104,750	98,403	92,056
Industrial Total		**IND**	39,490	39,561	36,663	36,734	30,867	30,867
Efficiency Total			**280,902**	**284,057**	**271,921**	**269,779**	**261,021**	**239,622**

Washington Cost Effectiveness DSM By Year

Program	Deployment		2026	2027	2028	2029	2030	2031
Resid New			51,182	51,182	51,182	51,182	51,182	51,182
	New Construction	RES	50,910	50,910	50,910	50,910	50,910	50,910
	New DHW	RES	272	272	272	272	272	272
Existing Residential			62,278	62,278	62,278	58,516	54,753	54,753
	Retrofit	RES	30,103	30,103	30,103	26,340	22,577	22,577
	Replace DHW	RES	28,391	28,391	28,391	28,391	28,391	28,391
	Replace equipment	RES	3,784	3,784	3,784	3,784	3,784	3,784
	Appliances, new & replace	RES	3,238	3,238	3,238	3,238	3,238	3,238
	Solar Water heat - Residential	RES	-	-	-	-	-	-
Commercial Existing			77,258	72,965	74,330	61,647	61,647	61,647
	Replace Equip	COM	18,061	19,065	19,566	20,068	20,068	20,068
	Replace Shell	COM	15,918	16,802	17,244	17,686	17,686	17,686
	Retrofit Wx	COM	10,802	8,102	8,102	2,701	2,701	2,701
	Retrofit Equip	COM	17,296	12,972	12,972	4,324	4,324	4,324
	Cooking Appliances	COM	15,181	16,024	16,446	16,868	16,868	16,868
Commercial New			11,840	12,498	12,827	13,156	13,156	13,156
	New Constr	COM	11,840	12,498	12,827	13,156	13,156	13,156
Industrial			30,867	24,929	24,929	18,991	15,429	13,054
	Retrofit	IND	23,752	17,814	17,814	11,876	8,313	5,938
	Replacement	IND	7,116	7,116	7,116	7,116	7,116	7,116
Residential Total		**RES**	116,699	116,699	116,699	112,936	109,173	109,173
Commercial Total		**COM**	89,098	85,462	87,157	74,802	74,802	74,802
Industrial Total		**IND**	30,867	24,929	24,929	18,991	15,429	13,054
Efficiency Total			**236,665**	**227,091**	**228,785**	**206,730**	**199,404**	**197,029**

Washington Cost Effectiveness DSM By Year

Program	Deployment		2032	2033	Total
Resid New			51,182	51,182	981,420
	New Construction	RES	50,910	50,910	976,204
	New DHW	RES	272	272	5,216
Existing Residential			47,227	45,345	1,266,416
	Retrofit	RES	15,052	13,170	750,854
	Replace DHW	RES	28,391	28,391	454,925
	Replace equipment	RES	3,784	3,784	60,637
	Appliances, new & replace	RES	3,238	3,238	54,591
	Solar Water heat - Residential	RES	-	-	-
Commercial Existing			61,647	61,647	1,625,115
	Replace Equip	COM	20,068	20,068	339,954
	Replace Shell	COM	17,686	17,686	299,604
	Retrofit Wx	COM	2,701	2,701	269,038
	Retrofit Equip	COM	4,324	4,324	430,780
	Cooking Appliances	COM	16,868	16,868	285,739
Commercial New			13,156	13,156	222,858
	New Constr	COM	13,156	13,156	222,858
Industrial			13,054	13,054	730,211
	Retrofit	IND	5,938	5,938	593,273
	Replacement	IND	7,116	7,116	136,938
Residential Total		**RES**	101,647	99,766	2,302,426
Commercial Total		**COM**	74,802	74,802	1,847,973
Industrial Total		**IND**	13,054	13,054	730,211
Efficiency Total			**189,503**	**187,622**	**4,880,610**

Table 1: Detailed Measure Table, Residential Sector Gas Savings and 2033 Technical Potential

Measure Description	Program	Average Lifetime	Total Incremental Cost	Total O&M Impact ($)	Gas Savings Therms	Level Cost, $/th	BCR
Low Flow Showerhead	Replace GasDHW	15	5,017,092	-76,338,930	4,595,320	(1.52)	100.00
Gas 2.20 MEF Washer	New Appl	14	5,190,204	-9,453,613	128,148	(0.54)	100.00
Gas 2.20 MEF Washer	ReplaceAppl	14	24,478,732	-44,586,389	470,078	(0.47)	100.00
Gas ETO Dishwasher	New Appl	12	2,455,221	-4,312,164	37,091	(0.36)	100.00
Gas ETO Dishwasher	ReplaceAppl	12	6,746,419	-11,848,896	79,270	(0.35)	100.00
Gas 2.46 MEF Washer	ReplaceAppl	14	50,218,806	-49,911,388	601,290	0.01	1.54
Gas 2.46 MEF Washer	New Appl	14	23,149,230	-23,007,520	330,703	0.01	1.48
Gas Hearth	Replace GasDHW	20	399,587	0	940,204	0.03	14.22
Windows, replacement (U=.30)	Retro Gas	45	5,709,751	0	2,001,021	0.17	3.18
Windows, replacement (U=.25)	Retro Gas	45	18,534,907	0	3,581,169	0.30	1.76
NW Energy Star BOP Ducts Inside	New Gas	35	67,450,486	0	4,300,725	0.34	1.53
AFUE 92 to condensing combo hydrocoil, Z A	New GasEquip	25	721,004	0	124,974	0.42	1.20
NW Energy Star BOP Equip Upg	New Gas	25	182,101,870	0	10,194,543	0.47	1.07
Wx insulation (ceiling, floor), Z A	Retro Gas	45	654,458	0	63,671	0.60	0.88
Near Net Zero	New Gas	45	3,890,410	0	298,521	0.72	0.73
MH Duct Sealing, Z A	Retro Gas	20	12,341	0	1,303	0.77	0.64
NW Energy Star BOP Env Upg	New Gas	35	66,786,092	0	1,754,021	0.86	0.61
HRV, Z A	Retro Gas	18	27,176,373	10,912,096	3,786,199	0.87	0.56
Wx SF Ceiling Insulation, Zone A	Retro Gas	45	20,900,342	0	1,373,015	0.88	0.60
Energy Star 0.67 EF	New GasDHW	12	1,274,295	0	160,582	0.91	0.50
Energy Star 0.67 EF	Replace GasDHW	12	6,795,851	0	856,388	0.91	0.50
MF Corridor Ventilation	Retro Gas	15	12,237,575	0	1,191,758	1.00	0.48
MF Corridor Ventilation	New Gas	15	3,655,822	0	356,023	1.00	0.48
Energy Star 0.67 EF after 2015	New GasDHW	12	9,342,796	0	1,023,868	1.04	0.43
Energy Star 0.67 EF after 2015	Replace GasDHW	12	25,636,879	0	2,809,521	1.04	0.43
Tankless Gas	New GasDHW	15	1,133,138	0	103,285	1.07	0.43
Tankless Gas after 2015	New GasDHW	15	11,984,588	0	974,844	1.20	0.39
AFUE 95 Furnace, Z A	Replace GasEquip	25	25,694,178	2,856,554	1,712,945	1.21	0.42
Wx SF Wall Insulation, Zone A	Retro Gas	45	27,242,365	0	1,111,488	1.42	0.37
Condensing Tankless	New GasDHW	15	1,165,514	0	78,250	1.45	0.32

Table 1: Detailed Measure Table, Residential Sector Gas Savings and 2033 Technical Potential

Measure Description	Program	Average Lifetime	Total Incremental Cost	Total O&M Impact ($)	Gas Savings Therms	Level Cost, $/th	BCR
Wx SF Duct Sealing, Z A	Retro Gas	20	4,889,123	0	264,277	1.51	0.33
Condensing Tankless Gas after 2015	New GasDHW	15	13,201,123	0	786,850	1.64	0.28
Wx SF Floor Insulation, Zone A	Retro Gas	45	30,511,448	0	1,067,901	1.65	0.32
Wx Air Sealing, Z A	Retro Gas	20	6,538,581	0	283,339	1.88	0.26
Windows, retrofit (U=.25)	Retro Gas	45	179,614,486	0	4,939,702	2.11	0.25
Windows, retrofit (U=.30)	Retro Gas	45	125,893,446	0	2,717,802	2.68	0.20
Solar DHW (50 gal) - gas backup	New GasDHW	20	5,973,423	0	170,511	2.86	0.16
Solar DHW - gas	Replace GasDHW	20	6,668,942	0	190,363	2.86	0.16
Solar DHW - Gas after 2015	New GasDHW	20	62,666,199	0	1,606,457	3.18	0.14
Solar DHW - gas afer 2015	Replace GasDHW	20	41,985,410	0	1,076,291	3.18	0.14
Condensing Tankless	Replace GasDHW	15	16,009,206	0	477,698	3.27	0.14
Tankless Gas	Replace GasDHW	15	23,878,705	0	704,346	3.31	0.14
HRV, E*	New Gas	18	17,462,118	0	444,322	3.41	0.14
OPower/Behavior Savings	Behavior	1	23,696,042	0	2,191,052	3.69	0.13
Condensing Tankless after 2015	Replace GasDHW	15	90,699,372	0	2,287,202	3.87	0.12
Tankless Gas after 2015	Replace GasDHW	15	145,176,951	0	3,450,109	4.11	0.11

Table 2: Detailed Measure Table, Commercial Sector Gas Savings and 2033 Technical Potential

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Gas Impacts (therms)	Levelized Cost, $/th	BCR
Estar Commercial Clothes Washer	Install high performance commercial clot	Replace	Water Heat	10	632,888	-3,965,739	17,751	(5.75)	6.68
Estar Commercial Clothes Washer	Install high performance commercial clot	New	Water Heat	10	41,691	-208,049	3,780	(3.13)	5.63
EStar Steam Cooker	Replace with EStar in place of convention	Replace	Cooking	10	118,988	-298,037	15,212	(1.54)	2.94
EStar Steam Cooker	Install EStar in place of conventional	New	Cooking	10	45,666	-114,383	5,907	(1.52)	2.94
Efficient Estar Dishwasher	Retrofit with EStar in place of convention	Retrofit	Water Heat	12	621,775	-3,065,317	286,323	(0.29)	11.00
Efficient Estar Dishwasher	Install EStar in place of conventional	New	Water Heat	12	533,112	-2,628,214	245,494	(0.29)	11.00
DHW Wrap	Insulate the surface of the storage water	Retrofit	Water Heat	7	24,096	0	148,101	0.03	15.65
Estar Convection Oven	Replace with EStar in place of convention	Replace	Cooking	12	120,261	0	205,661	0.07	6.74
Roof Insulation - Attic R0-30	Roof Insulation - Attic R0-30. Application	Retrofit	Heating	45	704,248	0	299,217	0.08	6.35
HW Boiler Tune	Tune up in accordance with Minneapolis	Retrofit	Heating	5	11,331	0	25,250	0.10	4.39
EStar Fryer	Install EStar in place of conventional	New	Cooking	8	224,904	0	324,348	0.11	4.12
Roof Insulation - Rigid R0-11	Roof Insulation - Rigid R0-11-not includin	Replace	Heating	45	3,197,440	0	796,919	0.12	4.30
Hot Water Temperature Reset	Controller automatically resets the delive	Retrofit	Heating	10	1,311,834	0	1,295,974	0.13	3.50
DHW Shower Heads	Install low flow shower heads (2.0 gallons	Retrofit	Water Heat	8	110,881	0	107,770	0.16	2.77
Wall Insulation - Blown R11	Wall Insulation - Blown R11. Application:	Retrofit	Heating	45	7,633,602	0	2,161,164	0.17	3.14
Roof Insulation - Rigid R0-22	Roof Insulation - Rigid R0-22-- not includi	Replace	Heating	45	5,522,851	0	904,581	0.19	2.82
DHW Condensing Tankless (repl)	Costs and savings are incremental over a	Replace	Water Heat	15	4,132,796	0	2,091,159	0.20	2.33
Steam Balance	Single-pipe steam systems are notorious	Retrofit	Heating	15	1,118,764	0	533,341	0.20	2.36
Heat Reclaim	Large Grocery - Heat recovery to space he	New	Refrigeration	18	1,905,609	0	202,983	0.21	2.26
Wall Insulation - Spray On for Metal Buildings	Wall Insulation - Spray On for Metal Build	Retrofit	Heating	45	664,845	0	174,898	0.23	2.31
Heat Reclaim	Large Grocery - Heat recovery to space he	Replace	Refrigeration	18	6,960,787	0	696,132	0.23	2.04
DCV	Applicable to single zone packaged syster	Retrofit	Heating	10	10,849,663	0	1,147,807	0.24	1.93
Estar Convection Oven	Install EStar in place of conventional	New	Cooking	12	193,794	0	90,697	0.24	1.85
Windows - Add Low E to Vinyl Tint	Windows - Add Low E to Vinyl Tint. Appl	Replace	Heating	20	3,700,578	0	345,991	0.25	2.01
Roof Insulation - Rigid R11-22	Roof Insulation - Rigid R11-22 2" rigid add	Replace	Heating	45	10,535,790	0	1,521,296	0.26	1.99
Roof Insulation - Blanket R0-19	Roof Insulation - Blanket R0-19. Applicati	Retrofit	Heating	45	1,022,517	0	216,938	0.27	1.97
Ducts	Duct retrofit of both insulation and air se	Retrofit	Heating	15	3,570,229	0	369,454	0.28	1.75
Roof Insulation - Blanket R0-30	Roof Insulation - Blanket R0-30. Applicati	Retrofit	Heating	45	1,150,332	0	227,607	0.29	1.83
DHW Condensing Tank (new)	Costs and savings are incremental over a	New	Water Heat	15	1,254,283	0	427,594	0.31	1.47
EStar Fryer	Replace with EStar in place of convention	Replace	Cooking	8	2,035,814	0	977,099	0.33	1.37
Windows - Add Low E and Argon to Vinyl Tint	Windows - Add Low E and Argon to Vinyl	Replace	Heating	20	5,787,370	0	477,972	0.34	1.43
Roof Insulation - Attic 11-30	Roof Insulation - Attic 11-30. Application	Retrofit	Heating	45	4,276,789	0	516,752	0.36	1.45
DestratificationFan	Destrat fan reduces heat load	Retrofit	Heating	12	4,710,772	0	1,429,389	0.38	1.25
Hot Food Holding Cabinet	Install EStar in place of conventional	New	Cooking	8	427,318	0	168,501	0.40	1.13
Hot Food Holding Cabinet	Install EStar in place of conventional	Replace	Cooking	8	1,318,467	0	509,364	0.40	1.10
Vent Damper	Install vent damper downstream of the d	Retrofit	Heating	12	527,661	0	145,430	0.41	1.14
DHW Condensing Tank (repl)	Costs and savings are incremental over a	Replace	Water Heat	15	3,343,081	0	775,523	0.45	1.04
EStar Griddle	Install EStar in place of conventional	New	Cooking	12	247,871	0	60,466	0.47	0.96
DHW Condensing Tankless (new)	Costs and savings are incremental over a	New	Water Heat	15	1,550,575	0	329,878	0.47	0.98
Windows - Tinted AL Code to Class 40	Windows - Tinted AL Code to Class 40. A	Replace	Heating	20	2,715,155	0	94,529	0.48	1.02
EStar Griddle	Replace with EStar in place of convention	Replace	Cooking	12	559,021	0	123,796	0.52	0.87
Combo Hieff Boiler (repl)	Replace existing boiler with unit meeting	Replace	Heating	20	2,717,311	0	432,869	0.52	0.95
DHW Hieff Boiler (new)	Replace existing boiler with unit meeting	New	Water Heat	20	991,556	0	155,904	0.54	0.88
Ozone Laundry Treatment	Ozone treatment allows use of cold wate	Retrofit	Water Heat	10	522,136	-79,481	103,869	0.55	0.84

Table 2: Detailed Measure Table, Commercial Sector Gas Savings and 2033 Technical Potential

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Gas Impacts (therms)	Levelized Cost, $/th	BCR
Combo Hieff Boiler (new)	Replace existing boiler with unit meeting	New	Heating	20	543,015	0	77,330	0.58	0.82
Windows - Tinted AL Code to Class 40	Windows - Tinted AL Code to Class 40. A	New	Heating	20	1,380,325	0	52,899	0.61	0.77
SPC Hieff Boiler Replace	Install near condensing boiler. Assumed	Replace	Heating	20	1,393,123	0	177,469	0.64	0.77
DHW Cond Boiler (new)	Replace with boiler using condensing or p	New	Water Heat	20	3,020,743	0	345,700	0.75	0.64
Cond Furnace (new)	Condensing / pulse package or residentia	New	Heating	18	2,207,879	0	244,463	0.79	0.59
Roof Insulation - Roofcut 0-22	Roof Insulation - Roofcut 0-22. Applicatio	Replace	Heating	45	13,999	0	612	0.82	0.64
Power burner	Replace standard burner with a power bu	Retrofit	Heating	12	11,341,475	0	1,500,550	0.86	0.55
SPC Cond Boiler Replace	Install condensing boiler. Assumed seaso	Replace	Heating	20	5,163,173	0	476,365	0.89	0.56
DHW Hieff Boiler (repl)	Replace existing boiler with unit meeting	Replace	Water Heat	20	2,153,614	0	201,218	0.91	0.54
DHW Pipe Ins	Add 1" insulation to pipes used for steam	New	Water Heat	15	273,107	0	28,970	0.92	0.50
DHW Faucets	Add aerators to existing faucets to reduce	Retrofit	Water Heat	8	42,915	0	7,185	0.93	0.48
Combo Cond Boiler (repl)	Replace with boiler using condensing or p	Replace	Heating	20	10,809,835	0	959,841	0.93	0.53
Roof Insulation - Rigid R11-33	Roof Insulation - Rigid R11-33: add 4' of in	Replace	Heating	45	15,803,686	0	471,723	0.94	0.56
DHW Faucets	Add aerators to existing faucets to reduce	New	Water Heat	8	29,160	0	4,747	0.96	0.46
DHW Recirc Controls	Install electronic controller to hot water b	Retrofit	Water Heat	10	1,037,556	0	134,689	1.01	0.44
Combo Cond Boiler (new)	Replace with boiler using condensing or p	New	Heating	20	2,108,539	0	171,470	1.02	0.47
Windows - Tinted AL Code to Class 36	Windows - Tinted AL Code to Class 36. Ap	Replace	Heating	20	6,787,888	0	164,287	1.03	0.48
SPC Cond Boiler (new)	Install condensing boiler. Assumed seaso	New	Heating	20	10,110,661	0	722,436	1.15	0.41
DDC HVAC controls	Control set up and algorithm. This assum	New	Heating	5	15,214,418	0	1,631,757	1.17	0.37
Rooftop Condensing Burner	Install condensing burner	New	Heating	10	9,319,654	0	452,326	1.22	0.38
Windows - Tinted AL Code to Class 36	Windows - Tinted AL Code to Class 36. Ap	New	Heating	20	3,450,813	0	85,042	1.30	0.36
Windows - Add Argon to Vinyl Lowe	Windows - Add Argon to Vinyl Lowe. Ap	Replace	Heating	20	8,371,374	0	541,552	1.31	0.38
Waste Water Heat Exchanger	Install HX on waste water	Retrofit	Water Heat	15	326,461	0	22,057	1.39	0.33
DHW Cond Boiler (repl)	Replace with boiler using condensing or p	Replace	Water Heat	20	7,749,501	0	446,179	1.48	0.33
Waste Water Heat Exchanger	Install HX on waste water	New	Water Heat	15	1,330,214	0	88,491	1.49	0.31
Cond Unit Heater from Nat draft (replace)	Install condensing power draft units (90%	Replace	Heating	18	19,790,009	0	1,127,941	1.55	0.32
Steam Trap Maintenance	Set up a in-house steam trap maintenanc	Retrofit	Heating	10	1,631,765	6,204,289	602,130	1.70	0.27
Roof Insulation - Blanket R11-41	Roof Insulation - Blanket R11-41. Applica	Retrofit	Heating	45	2,875,830	0	88,909	1.83	0.29
Computerized Water Heater Control	Install intelligent controls on the hot wat	Retrofit	Water Heat	15	1,215,680	0	61,477	1.88	0.25
Roof Insulation - Blanket R11-30	Roof Insulation - Blanket R11-30. Applica	Retrofit	Heating	45	2,556,293	0	74,091	1.94	0.27
Windows - Non-Tinted AL Code to Class 40	Windows - Non-Tinted AL Code to Class 4	New	Heating	20	3,754,705	0	158,261	2.01	0.23
Windows - Non-Tinted AL Code to Class 40	Windows - Non-Tinted AL Code to Class 4	Replace	Heating	20	8,677,211	0	346,081	2.08	0.24
Computerized Water Heater Control	Install intelligent controls on the hot wat	New	Water Heat	15	608,456	0	23,390	2.57	0.18
Cond Furnace (repl)	Condensing / pulse package or residentia	Replace	Heating	18	24,968,506	0	766,079	2.85	0.17
Warm Up Control	This measure is designed to implement a	Retrofit	Heating	10	10,291,472	0	451,937	2.95	0.16
Windows - Non-Tinted AL Code to Class 36	Windows - Non-Tinted AL Code to Class 3	New	Heating	20	9,386,762	0	240,611	3.27	0.14
Windows - Non-Tinted AL Code to Class 36	Windows - Non-Tinted AL Code to Class 3	Replace	Heating	20	21,693,027	0	529,363	3.38	0.15
Windows - Non-Tinted AL Code to Class 45	Windows - Non-Tinted AL Code to Class 4	Replace	Heating	20	5,770,345	0	126,307	3.80	0.13
HVAC System Commissioning	HVAC system commissioning. Includes te	New	Heating	7	54,159,762	0	1,028,925	4.73	0.09
Solar Hot Water	Install solar water heaters on large use fa	Retrofit	Water Heat	15	10,763,023	609,762	130,385	8.25	0.06
Solar Hot Water	Install solar water heaters on large use fa	New	Water Heat	15	5,360,772	303,706	49,393	11.27	0.04
Cond Unit Heater from power draft (replace)	Install condensing power draft units (90%	Replace	Heating	18	710,150,161	0	751,960	83.23	0.01
Windows - Tinted AL Code to Class 45	Windows - Tinted AL Code to Class 45. Ap	Replace	Heating	20	634,966,091	0	17,741	144.10	0.00

Table 3: Detailed Measure Table, Industrial Sector Gas Savings and 2033 Technical Potential

Conservation Measure	Potential Savings (th/yr)	Annual O&M Cost	Levelized Cost ($/th)	Initial Cost, k$	BCR
Chiller heat recovery (Electronics)	52,153	0	$ 1.28	682	0.36
Combo Cond Boiler (repl)	787,962	0	$ 0.66	6,390	0.71
Combo Cond Boiler (retro)	0	0	$ 1.78	0	na
Combo Hieff Boiler (repl)	403,590	0	$ 0.36	1,779	1.31
Combo Hieff Boiler (retro)	0	0	$ 1.87	0	na
Cond Furnace (repl)	805,744	0	$ 2.88	23,784	0.16
Cond Unit Heater from Nat draft (replace)	0	0	$ 1.11	0	na
Cond Unit Heater from power draft (replace)	283,297	0	$ 2.24	7,301	0.21
Heat Recovery to HW	1,495,534	-201,045	$ 0.17	4,640	1.56
DHW Cond Boiler (repl)	429,730	0	$ 0.16	863	2.87
DHW Cond Boiler (retro)	0	0	$ 0.51	0	na
DHW Condensing Tank (repl)	350,323	0	$ 0.03	96	17.15
DHW Condensing Tank (retro)	0	0	$ 0.12	0	na
DHW Hieff Boiler (repl)	220,105	0	$ 0.05	138	9.17
DHW Hieff Boiler (retro)	0	0	$ 0.40	0	na
DHW Pipe Ins	48,914	0	$ 0.02	10	22.32
DHW Std. Boiler (retro)	7,247	0	$ 0.24	21	1.95
DHW Wrap	21,740	0	$ 0.00	0	100.00
Ducts	1,272,546	0	$ 3.21	41,835	0.14
Hi Eff Unit Heater (replace)	765,666	0	$ 0.36	3,137	1.31
Hi Eff Unit Heater (retro)	0	0	$ 2.17	0	na
HiEff Clothes Washer (retro)	3,696	-44,923	$ (11.36)	30	1.92
HiEff Clothes Washer (repl)	3,696	-44,923	$ (11.36)	30	1.92
Hot Water Temperature Reset	1,723,480	0	$ 0.20	2,652	2.19
HW Boiler Tune	947,904	0	$ 0.19	758	2.34
Power burner	1,397,211	0	$ 1.20	14,654	0.37
Process Boiler Controls	164,214	0	$ 0.00	3	289.79
Process Boiler Insulation	1,015,140	1,242	$ 0.01	81	59.68
Process Boiler Load Control	507,570	0	$ 0.00	10	251.15
Process Boiler Maintenance	253,785	132	$ 0.00	0	100.00

Table 3: Detailed Measure Table, Industrial Sector Gas Savings and 2033 Technical Potential

Conservation Measure	Potential Savings (th/yr)	Annual O&M Cost	Levelized Cost ($/th)	Initial Cost, k$	BCR
Process Boiler Steam Trap Maintenance	824,801	29,963	$ 0.04	0	100.00
Process Boiler Water Treatment	126,893	0	$ 0.00	1	538.17
Roof Insulation - Blanket R0-19	409,806	0	$ 0.36	2,238	1.34
Roof Insulation - Blanket R0-30	429,961	0	$ 0.39	2,518	1.25
Roof Insulation - Blanket R11-30	149,292	0	$ 2.66	5,968	0.18
Roof Insulation - Blanket R11-41	179,150	0	$ 2.49	6,714	0.20
Roof Insulation - Rigid R11-22 repl	421,362	0	$ 0.94	5,968	0.52
Roof Insulation - Rigid R11-33 repl	207,814	0	$ 2.87	8,952	0.17
Solar Hot Water	45,561	0	$ 4.88	2,723	0.10
SPC Cond Boiler Replace	446,267	0	$ 1.15	6,307	0.41
SPC Cond Boiler Retro	0	0	$ 2.45	0	na
SPC Hieff Boiler Replace	258,031	0	$ 0.74	2,337	0.64
SPC Hieff Boiler Retro	0	0	$ 2.59	0	na
Steam Balance (Wood Prod)	59,943	0	$ 0.39	239	1.18
Steam Trap Maint (Wood Prod)	74,097	0	$ 0.67	381	0.66
Upgrade Process Heat	211,525	-137,608	$ 1.05	2,143	0.48
Vent Damper	858,336	-137,608	$ 0.50	3,715	0.92
Wall Insulation - Blown R11	275,256	0	$ 0.26	1,089	1.85
Wall Insulation - Spray On for Metal Buildings	302,217	0	$ 0.29	1,331	1.66
Waste Water Heat Exchanger	59,581	0	$ 0.73	531	0.65
Ozone Treated Laundry	0	0	$ 0.19	0	na

Appendix 6: Distribution System Planning

Appendix 6.1 - Washington Distribution System Projects

Washington Distribution System Projects within Next Five Years					
Name	Location	Description	Purpose	Estimated Cost	Anticipated Construction
119th Street	NE 119th St. in Vancouver from NE 111th Avenue to NE 72nd Avenue	Approximately 1.5 miles of 8-inch wrapped steel Class D High-Pressure Main	Reinforce distribution system in this area north of Vancouver	$5.4 million	2014
Camas Reinforcement	NW Pacific Rim Blvd to Sierra St in Camas	Approximately 2.4 miles of 12-inch wrapped steel Class D High-Pressure Main	Reinforce High-Pressure distribution system serving Camas area	$4.6million	2015
Washougal Extension	20th Street to 39th Street in Washougal	Approximately 1.2 miles of 6-inch wrapped steel Class D High-Pressure Main	Reinforce distribution system serving this part of Washougal	$4.5 million	2015
119th Street to Salmon Creek	NE 119th St. in Vancouver to Salmon Creek Road	Approximately 2.4 miles of 8-inch wrapped steel Class D High-Pressure Main	Reinforce distribution system in this area north of Vancouver	$6.1 million	2017
Vancouver Core Replacement	East Access Road to Reserve	Approximately 1.8 miles of 12-inch wrapped steel Class D High-Pressure Main	Reinforce the High-Pressure distribution system serving South Vancouver. Eliminates a reduction in pressure due to pipe size.	$4.3 million	2017

Appendix 7: Linear Programming and Risk Analysis

NW Natural®

Figure 7A.1 – System Diagram

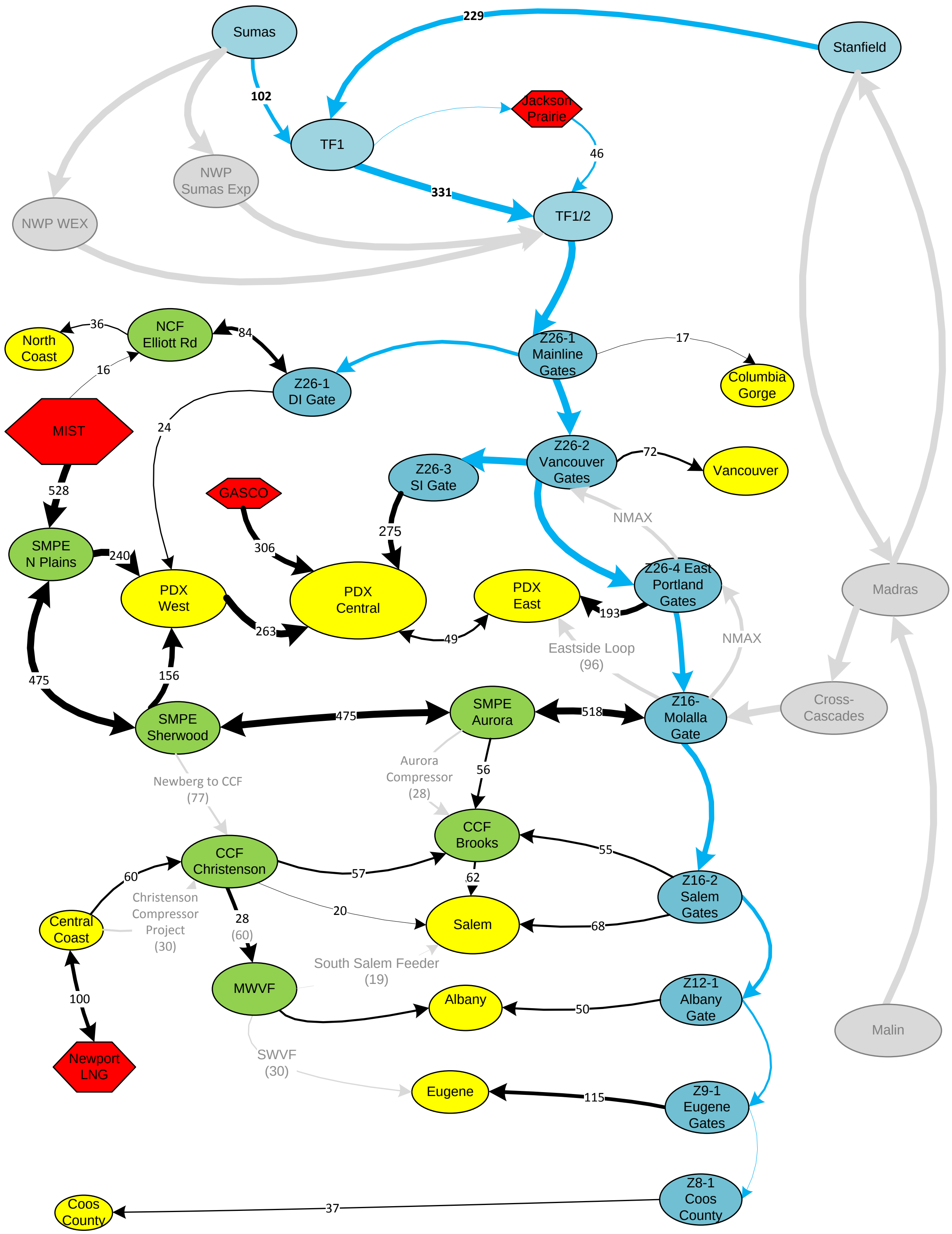


Table 7A.1 – Resource Options

Resource	Size (Range)	Rate or Annual Revenue Requirement ($/DT/day) ($2013)	Date Available
Interstate Pipeline			
Incremental/Decremental CD on TransCanada NOVA/BC/GTN system (TCPL & GTN)	(-127 – 969 MDT)	Current tariff rates	Nov-15
Incremental T-South	(0-500 MDT)	Current tariff rate	Nov-15
GTN Malin to/from Madras/Stanfield	(0 – 450 MDT)	Current tariff rates	Nov-20
CD on cross-Cascades	(0/110 – 450 MDT)	0.41 – 0.73	Nov-20
NMAX	(0-450 MDT)	0.12	Nov-20
CD on NWP's Washington Expansion (WEX) Project	(0 – 500 MDT)	0.56	Nov-20
Sumas Expansion (Regional)	(0 – 500 MDT)	0.46	Nov-20
Sumas Expansion (Local)	(0 – 500 MDT)	0.88	Nov-15
Pacific Connector Gas Pipeline	(0 – 52 MDT)	0.40	Nov-20
High Pressure Transmission			
Christenson Compressor Project (CCP)	40 MDT	$3.1 million	Nov-18
South Willamette Valley Feeder (SWVF)	30 MDT	$6.2 million	Nov-18
Eastside Loop (ESL)	96 MDT	$7.5 million	Nov-20
Aurora Compressor Project (ACP)	28 MDT	$1.6 million	Nov-18
Newberg to Central Coast Feeder (NCCF)	77 MDT	$5.8 million	Nov-18
South Salem Feeder (SSF)	19 MDT	$2.2 million	Nov-18
Storage			
Mist Recall	(0 – 245 MDT)	0.10	Nov-14
North Mist (plus associated takeaway)	(0 – 100 MDT)	0.34	Nov-20
LNG Storage projects	Variable	Variable	Nov-20

A1: NM/SE(L)	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	NPVRR - 4.58%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0458
DEMAND (DT)																					
Forecast Firm Sales Demand (net DSM)	76,856,029	77,251,424	78,295,384	78,355,486	78,951,673	79,657,724	80,925,719	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Served Firm Sales Demand	76,779,274	77,166,099	78,295,384	78,355,486	78,951,673	79,655,191	80,922,155	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Unserved Firm Sales Demand	76,755	85,325	0	0	0	2,534	3,564	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Firm Sales Demand (net DSM)	930,549	936,976	945,296	953,453	962,290	972,270	982,777	995,009	1,007,630	1,021,003	1,034,718	1,050,150	1,065,798	1,082,157	1,098,681	1,116,901	1,135,300	1,154,306	1,173,372	1,194,115	
Peak Day Firm Sales Demand Unserved	26,927	32,133	-	-	-	85	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000) $2013																					
Supply Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Supply Variable Costs	306,068	318,930	370,383	314,301	282,777	274,117	313,729	347,529	352,968	319,129	343,564	364,689	389,328	426,198	419,126	414,167	415,071	424,806	432,758	446,334	
Total Supply Costs	306,068	318,930	370,383	314,301	282,777	274,117	313,729	347,529	352,968	319,129	343,564	364,689	389,328	426,198	419,126	414,167	415,071	424,806	432,758	446,334	**4,762,240**
Transport Fixed Costs	88,000	88,000	94,379	95,897	96,417	86,565	88,883	89,404	89,678	89,972	90,274	90,620	118,947	119,321	119,701	120,126	120,559	121,010	121,466	123,595	
Transport Variable Costs	3,472	3,436	3,181	3,407	3,725	3,109	3,046	3,030	3,263	3,257	3,315	3,325	3,322	3,425	3,499	3,541	3,613	3,680	3,746	3,759	
Total Transport Cost	91,473	91,436	97,561	99,304	100,141	89,674	91,929	92,433	92,940	93,229	93,589	93,945	122,269	122,746	123,200	123,667	124,172	124,690	125,212	127,354	**1,390,824**
Storage Fixed Cost	22,445	23,585	23,956	25,176	26,360	27,721	32,510	34,598	35,043	35,899	36,722	36,973	36,973	36,973	36,973	36,973	37,388	39,492	42,628	43,708	
Storage Variable Cost	66	225	110	110	284	266	271	128	268	277	288	301	92	243	288	339	377	425	425	424	
Total Storage Cost	22,511	23,810	24,066	25,286	26,644	27,986	32,780	34,725	35,311	36,175	37,010	37,274	37,065	37,216	37,261	37,312	37,765	39,917	43,054	44,133	**436,331**
DSM Annual Utility Cost		12,079	11,635	7,160	6,562	6,033	5,425	5,398	4,999	4,795	4,031	3,968	3,865	3,831	3,808	3,812	3,719	3,688	3,639	3,552	**73,609**
Total Costs	420,051	446,255	503,644	446,052	416,124	397,810	443,864	480,086	486,219	453,328	478,195	499,877	552,527	589,991	583,394	578,958	580,727	593,101	604,664	621,372	**6,663,006**
Key Resource Decisions (Cumulative Dth/day)																					
Mist Recall	-	-	30,292	30,292	79,099	102,536	145,466	145,466	145,466	163,262	188,766	209,220	209,220	209,220	209,220	209,220	209,220	225,803	245,000	245,000	
WEX/SE(R)/SE(L)	-	-	-	-	-	-	-	-	-	-	-	-	50,000	50,000	50,000	50,000	50,000	50,000	50,000	51,549	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Pacific Connector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
North Mist	-	-	-	-	-	-	-	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	100,000	100,000	
CCLNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South Salem Feeder	-	-	-	-	-	-	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	
Christenson Compressor	-	-	-	-	-	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Clark County	-	-	31,145	31,145	33,871	34,444	36,477	43,738	47,555	51,653	55,860	60,679	65,605	70,801	76,092	81,997	87,995	94,251	100,578	107,522	

A1: CCLNG/NM	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	NPVRR - 4.58%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0458
DEMAND (DT)																					
Forecast Firm Sales Demand (net DSM)	76,856,029	77,251,424	78,295,384	78,355,486	78,951,673	79,657,724	80,925,719	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Served Firm Sales Demand	0	0	265	0	275	276	268	0	0	287	281	295	299	303	296	0	315	320	12,452	22,200	
Unserved Firm Sales Demand	0	0	613	635	637	640	622	0	0	669	655	688	698	708	693	0	0	749	35,480	70,967	
Peak Day Firm Sales Demand (net DSM)	930,549	936,976	945,296	953,453	962,290	972,270	982,777	995,009	1,007,630	1,021,003	1,034,718	1,050,150	1,065,798	1,082,157	1,098,681	1,116,901	1,135,300	1,154,306	1,173,372	1,194,115	
Peak Day Firm Sales Demand Unserved	26,928	32,134	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000) $2013																					
Supply Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Supply Variable Costs	306,068	320,894	371,770	316,207	285,031	274,183	311,726	344,422	353,035	320,166	344,064	366,339	398,781	431,546	427,718	418,241	418,043	423,286	427,260	440,809	
Total Supply Costs	306,068	320,894	371,770	316,207	285,031	274,183	311,726	344,422	353,035	320,166	344,064	366,339	398,781	431,546	427,718	418,241	418,043	423,286	427,260	440,809	**4,778,362**
Transport Fixed Costs	88,000	78,102	84,481	85,999	86,519	86,763	89,170	89,497	89,497	89,497	89,498	89,499	92,649	92,649	92,651	92,656	92,658	92,662	92,664	92,734	
Transport Variable Costs	3,472	2,899	2,708	2,870	3,119	3,109	3,028	3,004	3,253	3,262	3,315	3,334	3,392	3,448	3,544	3,557	3,618	3,648	3,684	3,691	
Total Transport Cost	91,472	81,002	87,190	88,869	89,638	89,872	92,198	92,501	92,750	92,759	92,813	92,833	96,041	96,097	96,195	96,213	96,275	96,310	96,348	96,425	**1,240,607**
Storage Fixed Cost	22,445	23,585	23,956	25,176	26,362	27,741	44,617	52,621	52,621	52,621	53,142	53,628	54,451	55,377	64,186	68,362	68,791	69,002	69,002	69,002	
Storage Variable Cost	66	225	110	110	284	266	338	81	254	379	387	408	435	443	390	467	505	522	504	503	
Total Storage Cost	22,511	23,810	24,066	25,286	26,646	28,007	44,955	52,702	52,875	53,000	53,529	54,036	54,887	55,820	64,576	68,828	69,297	69,524	69,506	69,505	**606,488**
DSM Annual Utility Cost		12,079	11,635	7,160	6,562	6,033	5,425	5,398	4,999	4,795	4,031	3,968	3,865	3,831	3,808	3,812	3,719	3,688	3,639	3,552	**73,609**
Total Costs	420,051	437,784	494,660	437,522	407,877	398,095	454,304	495,023	503,659	470,719	494,437	517,176	553,573	587,294	592,297	587,094	587,334	592,808	596,754	610,292	**6,699,067**
Key Resource Decisions (Cumulative Dth/day)																					
Mist Recall	-	-	30,292	30,292	79,099	102,621	146,248	146,248	146,248	146,248	146,248	167,095	176,297	204,732	227,816	227,816	227,816	245,000	245,000	245,000	
WEX/SE(R)/SE(L)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Pacific Connector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
North Mist	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100,000	100,000	100,000	100,000	100,000	
CCLNG	-	-	-	-	-	-	-	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	
South Salem Feeder	-	-	-	-	-	-	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	
Christenson Compressor	-	-	-	-	-	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Clark County	-	-	31,145	31,145	33,871	36,893	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	

A2: CC/TB/NM	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	NPVRR - 4.58%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0458
DEMAND (DT)																					
Forecast Firm Sales Demand (net DSM)	76,856,029	77,251,424	78,295,384	78,355,486	78,951,673	79,657,724	80,925,719	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Served Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Unserved Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Firm Sales Demand (net DSM)	930,549	936,976	945,296	953,453	962,290	972,270	982,777	995,009	1,007,630	1,021,003	1,034,718	1,050,150	1,065,798	1,082,157	1,098,681	1,116,901	1,135,300	1,154,306	1,173,372	1,194,115	
Peak Day Firm Sales Demand Unserved	26,927	26,732	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000) $2013																					
Supply Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Supply Variable Costs	306,068	318,930	370,383	314,302	282,783	274,134	307,841	338,483	356,786	320,052	342,204	365,756	393,015	432,007	426,037	420,100	420,915	429,539	439,436	455,237	
Total Supply Costs	306,068	318,930	370,383	314,302	282,783	274,134	307,841	338,483	356,786	320,052	342,204	365,756	393,015	432,007	426,037	420,100	420,915	429,539	439,436	455,237	4,778,185
Transport Fixed Costs	88,001	88,001	94,380	95,897	96,417	86,763	89,171	99,912	100,186	100,482	100,785	101,131	104,654	105,027	105,408	105,834	106,267	106,719	107,175	107,746	
Transport Variable Costs	3,472	3,436	3,181	3,407	3,725	3,109	2,994	2,862	3,149	3,113	3,145	3,175	3,202	3,303	3,418	3,452	3,555	3,624	3,703	3,718	
Total Transport Cost	91,473	91,437	97,561	99,304	100,142	89,872	92,165	102,774	103,335	103,594	103,929	104,306	107,856	108,330	108,826	109,286	109,822	110,343	110,878	111,464	1,367,457
Storage Fixed Cost	22,445	23,585	23,956	25,176	26,362	27,726	28,254	28,254	28,254	28,254	28,254	28,254	28,254	28,485	29,466	30,524	35,097	37,930	41,164	42,569	
Storage Variable Cost	66	225	110	110	284	266	185	71	102	259	164	174	147	325	385	393	410	402	425	428	
Total Storage Cost	22,511	23,810	24,066	25,286	26,646	27,992	28,438	28,325	28,356	28,513	28,417	28,428	28,401	28,811	29,851	30,917	35,507	38,332	41,589	42,997	387,497
DSM Annual Utility Cost		12,079	11,635	7,160	6,562	6,033	5,425	5,398	4,999	4,795	4,031	3,968	3,865	3,831	3,808	3,812	3,719	3,688	3,639	3,552	73,609
Total Costs	420,051	446,255	503,645	446,052	416,133	398,032	433,870	474,980	493,476	456,954	478,582	502,458	533,137	572,979	568,521	564,115	569,963	581,902	595,542	613,250	6,606,748
Key Resource Decisions (Cumulative Dth/day)																					
Mist Recall	-	-	30,291	30,291	79,098	102,620	145,651	145,651	145,651	145,651	145,651	145,651	145,651	145,651	154,918	189,597	214,922	214,922	244,711	245,000	
WEX/SE(R)/SE(L)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	-	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	
Pacific Connector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
North Mist	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50,000	50,000	100,000	
CCLNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South Salem Feeder	-	-	-	-	-	-	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	
Christenson Compressor	-	-	-	-	-	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Clark County	-	-	31,145	31,145	33,871	36,893	40,041	43,738	47,555	51,653	55,860	60,679	65,605	70,801	76,092	81,997	87,995	94,251	100,578	107,522	

A2: NM/SE(L)	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	NPVRR - 4.58%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0458
DEMAND (DT)																					
Forecast Firm Sales Demand (net DSM)	76,856,029	77,251,424	78,295,384	78,355,486	78,951,673	79,657,724	80,925,719	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Served Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Unserved Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Firm Sales Demand (net DSM)	930,549	936,976	945,296	953,453	962,290	972,270	982,777	995,009	1,007,630	1,021,003	1,034,718	1,050,150	1,065,798	1,082,157	1,098,681	1,116,901	1,135,300	1,154,306	1,173,372	1,194,115	
Peak Day Firm Sales Demand Unserved	26,927	32,133	-	-	-	-	1,123	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000) $2013																					
Supply Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Supply Variable Costs	306,068	318,930	370,383	314,301	282,777	274,117	313,729	345,261	350,190	317,014	341,490	362,741	387,305	424,151	417,739	412,261	413,104	422,883	430,693	445,419	
Total Supply Costs	306,068	318,930	370,383	314,301	282,777	274,117	313,729	345,261	350,190	317,014	341,490	362,741	387,305	424,151	417,739	412,261	413,104	422,883	430,693	445,419	4,747,500
Transport Fixed Costs	88,000	88,000	94,379	95,897	96,417	86,565	88,883	89,404	89,678	89,972	90,274	90,620	118,947	119,321	119,702	120,127	120,559	121,010	121,466	122,826	
Transport Variable Costs	3,472	3,436	3,181	3,407	3,725	3,109	3,046	2,918	3,159	3,163	3,220	3,227	3,214	3,307	3,431	3,475	3,596	3,681	3,747	3,759	
Total Transport Cost	91,473	91,436	97,561	99,304	100,141	89,674	91,929	92,322	92,837	93,135	93,495	93,847	122,160	122,629	123,134	123,602	124,154	124,691	125,213	126,585	1,389,954
Storage Fixed Cost	22,445	23,585	23,956	25,176	26,360	27,721	32,510	34,598	35,043	35,898	36,722	36,973	36,973	36,973	36,973	36,973	37,569	39,581	42,833	44,012	
Storage Variable Cost	66	225	110	110	284	266	271	126	270	278	289	302	61	222	283	326	349	425	427	424	
Total Storage Cost	22,511	23,810	24,066	25,286	26,644	27,986	32,780	34,724	35,313	36,177	37,011	37,275	37,034	37,195	37,256	37,299	37,918	40,006	43,259	44,436	436,631
DSM Annual Utility Cost		12,079	11,635	7,160	6,562	6,033	5,425	5,398	4,999	4,795	4,031	3,968	3,865	3,831	3,808	3,812	3,719	3,688	3,639	3,552	73,609
Total Costs	420,051	446,255	503,644	446,052	416,124	397,810	443,864	477,705	483,339	451,120	476,027	497,832	550,364	587,805	581,936	576,973	578,896	591,268	602,804	619,992	6,647,694
Key Resource Decisions (Cumulative Dth/day)																					
Mist Recall	-	-	30,292	30,292	79,099	102,536	145,466	145,466	145,466	163,262	188,766	209,220	209,220	209,220	209,220	209,220	209,220	233,061	245,000	245,000	
WEX/SE(R)/SE(L)	-	-	-	-	-	-	-	-	-	-	-	-	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Pacific Connector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
North Mist	-	-	-	-	-	-	-	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	100,000	100,000	
CCLNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South Salem Feeder	-	-	-	-	-	-	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	
Christenson Compressor	-	-	-	-	-	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Clark County	-	-	31,145	31,145	33,871	34,444	36,477	43,738	47,555	51,653	55,860	60,679	65,605	70,801	76,092	81,997	87,995	94,251	100,578	107,522	

A2: CCLNG/NM	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	NPVRR - 4.58%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0458
DEMAND (DT)																					
Forecast Firm Sales Demand (net DSM)	76,856,029	77,251,424	78,295,384	78,355,486	78,951,673	79,657,724	80,925,719	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Served Firm Sales Demand	8,073	7,621	2,338	2,411	2,403	2,402	2,323	0	0	2,458	2,394	2,502	2,525	2,548	2,482	0	2,618	2,642	173,358	205,411	
Unserved Firm Sales Demand	0	0	36	0	37	37	36	0	0	37	36	37	37	38	36	0	0	0	1,576	4,514	
Peak Day Firm Sales Demand (net DSM)	930,549	936,976	945,296	953,453	962,290	972,270	982,777	995,009	1,007,630	1,021,003	1,034,718	1,050,150	1,065,798	1,082,157	1,098,681	1,116,901	1,135,300	1,154,306	1,173,372	1,194,115	
Peak Day Firm Sales Demand Unserved	26,928	32,134	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000) $2013																					
Supply Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Supply Variable Costs	306,068	320,894	371,770	316,207	285,031	274,183	311,647	342,545	349,994	317,986	341,910	364,513	396,649	429,220	425,495	415,421	415,761	420,686	424,701	439,179	
Total Supply Costs	306,068	320,894	371,770	316,207	285,031	274,183	311,647	342,545	349,994	317,986	341,910	364,513	396,649	429,220	425,495	415,421	415,761	420,686	424,701	439,179	**4,761,515**
Transport Fixed Costs	88,000	78,102	84,481	85,999	86,519	86,763	89,170	89,497	89,497	89,497	89,498	89,499	92,649	92,649	92,651	92,656	92,658	92,662	92,664	92,734	
Transport Variable Costs	3,472	2,899	2,708	2,870	3,119	3,109	3,027	2,897	3,142	3,166	3,220	3,232	3,278	3,347	3,494	3,500	3,600	3,646	3,682	3,689	
Total Transport Cost	91,472	81,002	87,190	88,869	89,638	89,872	92,197	92,394	92,639	92,663	92,718	92,732	95,927	95,996	96,145	96,157	96,257	96,308	96,346	96,423	**1,240,074**
Storage Fixed Cost	22,445	23,585	23,956	25,176	26,362	27,741	44,617	52,621	52,621	52,621	53,142	53,674	54,477	55,378	64,186	68,362	68,791	69,002	69,002	69,002	
Storage Variable Cost	66	225	110	110	284	266	335	77	253	381	389	409	422	441	405	452	510	523	505	505	
Total Storage Cost	22,511	23,810	24,066	25,286	26,646	28,007	44,952	52,698	52,874	53,002	53,531	54,084	54,899	55,819	64,590	68,814	69,301	69,525	69,507	69,507	**606,525**
DSM Annual Utility Cost		12,079	11,635	7,160	6,562	6,033	5,425	5,398	4,999	4,795	4,031	3,968	3,865	3,831	3,808	3,812	3,719	3,688	3,639	3,552	**73,609**
Total Costs	420,051	437,784	494,660	437,522	407,877	398,095	454,222	493,035	500,506	468,446	492,190	515,296	551,340	584,866	590,038	584,203	585,039	590,206	594,194	608,661	**6,681,723**
Key Resource Decisions (Cumulative Dth/day)																					
Mist Recall	-	-	30,292	30,292	79,099	102,621	146,248	146,248	146,248	146,248	146,248	167,077	178,174	204,834	227,816	227,816	227,816	245,000	245,000	245,000	
WEX/SE(R)/SE(L)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Pacific Connector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
North Mist	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100,000	100,000	100,000	100,000	100,000	
CCLNG	-	-	-	-	-	-	-	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	
South Salem Feeder	-	-	-	-	-	-	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	
Christenson Compressor	-	-	-	-	-	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Clark County	-	-	31,145	31,145	33,871	36,893	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	

A2: SE(R)	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	NPVRR - 4.58%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0458
DEMAND (DT)																					
Forecast Firm Sales Demand (net DSM)	76,856,029	77,251,424	78,295,384	78,355,486	78,951,673	79,657,724	80,925,719	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Served Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Unserved Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Firm Sales Demand (net DSM)	930,549	936,976	945,296	953,453	962,290	972,270	982,777	995,009	1,007,630	1,021,003	1,034,718	1,050,150	1,065,798	1,082,157	1,098,681	1,116,901	1,135,300	1,154,306	1,173,372	1,194,115	
Peak Day Firm Sales Demand Unserved	32,274	26,732	-	-	-	85	1,123	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000) $2013																					
Supply Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Supply Variable Costs	306,068	320,894	371,769	313,981	287,189	270,918	306,968	329,301	356,471	313,981	337,009	360,612	386,432	423,128	418,860	413,187	412,907	420,753	431,256	443,913	
Total Supply Costs	306,068	320,894	371,769	313,981	287,189	270,918	306,968	329,301	356,471	313,981	337,009	360,612	386,432	423,128	418,860	413,187	412,907	420,753	431,256	443,913	**4,731,370**
Transport Fixed Costs	88,000	78,103	84,482	85,999	86,519	86,565	88,883	126,709	126,983	127,279	127,581	127,929	131,431	131,804	132,184	132,610	133,043	133,495	133,951	134,452	
Transport Variable Costs	3,472	2,899	2,708	2,846	3,139	3,074	2,988	3,573	3,881	3,884	4,107	3,822	4,051	4,139	4,308	4,340	4,489	4,640	4,762	4,827	
Total Transport Cost	91,473	81,002	87,190	88,845	89,658	89,639	91,871	130,282	130,864	131,163	131,689	131,751	135,482	135,942	136,492	136,950	137,532	138,134	138,712	139,279	**1,533,256**
Storage Fixed Cost	22,445	23,585	23,956	24,081	25,824	26,884	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,144	27,690	28,400	29,500	29,924	
Storage Variable Cost	66	225	110	108	282	149	48	68	104	235	181	159	80	228	292	321	348	381	387	392	
Total Storage Cost	22,511	23,810	24,066	24,189	26,106	27,033	27,048	27,068	27,104	27,236	27,181	27,159	27,080	27,228	27,293	27,465	28,038	28,781	29,887	30,316	**356,508**
DSM Annual Utility Cost		12,079	11,635	7,160	6,562	6,033	5,425	5,398	4,999	4,795	4,031	3,968	3,865	3,831	3,808	3,812	3,719	3,688	3,639	3,552	**73,609**
Total Costs	420,051	437,785	494,660	434,175	409,515	393,623	431,313	492,050	519,439	477,175	499,910	523,490	552,858	590,129	586,452	581,414	582,197	591,357	603,494	617,059	**6,694,743**
Key Resource Decisions (Cumulative Dth/day)																					
Mist Recall	-	-	30,292	30,292	35,299	102,536	112,014	112,014	112,014	112,014	112,014	112,014	112,014	112,014	112,014	112,014	117,754	136,782	155,866	190,486	
WEX/SE(R)/SE(L)	-	-	-	-	-	-	-	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Pacific Connector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
North Mist	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
CCLNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South Salem Feeder	-	-	-	-	-	-	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	
Christenson Compressor	-	-	-	-	-	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Clark County	-	-	31,145	31,145	33,871	34,444	36,477	43,738	47,555	51,653	55,860	60,679	65,605	70,801	76,092	81,997	87,995	94,251	100,578	107,522	

A3: NM/SE(L)	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	NPVRR - 4.58%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0458
DEMAND (DT)																					
Forecast Firm Sales Demand (net DSM)	76,856,029	77,251,424	78,295,384	78,355,486	78,951,673	79,657,724	80,925,719	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Served Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Unserved Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Firm Sales Demand (net DSM)	930,549	936,976	945,296	953,453	962,290	972,270	982,777	995,009	1,007,630	1,021,003	1,034,718	1,050,150	1,065,798	1,082,157	1,098,681	1,116,901	1,135,300	1,154,306	1,173,372	1,194,115	
Peak Day Firm Sales Demand Unserved	26,927	32,133	-	-	-	85	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000) $2013																					
Supply Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Supply Variable Costs	306,068	318,930	370,383	314,301	282,777	274,117	313,729	347,529	352,968	319,129	343,564	364,689	389,328	426,198	419,126	414,167	415,071	424,806	432,758	446,334	
Total Supply Costs	306,068	318,930	370,383	314,301	282,777	274,117	313,729	347,529	352,968	319,129	343,564	364,689	389,328	426,198	419,126	414,167	415,071	424,806	432,758	446,334	**4,762,240**
Transport Fixed Costs	88,000	88,000	94,379	95,897	96,417	86,565	88,883	89,404	89,678	89,972	90,274	90,620	118,947	119,321	119,701	120,126	120,559	121,010	121,466	123,595	
Transport Variable Costs	3,472	3,436	3,181	3,407	3,725	3,109	3,046	3,030	3,263	3,257	3,315	3,325	3,322	3,425	3,499	3,541	3,613	3,680	3,746	3,759	
Total Transport Cost	91,473	91,436	97,561	99,304	100,141	89,674	91,929	92,433	92,940	93,229	93,589	93,945	122,269	122,746	123,200	123,667	124,172	124,690	125,212	127,354	**1,390,824**
Storage Fixed Cost	22,445	23,585	23,956	25,176	26,360	27,721	32,510	34,598	35,043	35,899	36,722	36,973	36,973	36,973	36,973	36,973	37,388	39,492	42,628	43,708	
Storage Variable Cost	66	225	110	110	284	266	271	128	268	277	288	301	92	243	288	339	377	425	425	424	
Total Storage Cost	22,511	23,810	24,066	25,286	26,644	27,986	32,780	34,725	35,311	36,175	37,010	37,274	37,065	37,216	37,261	37,312	37,765	39,917	43,054	44,133	**436,331**
DSM Annual Utility Cost		12,079	11,635	7,160	6,562	6,033	5,425	5,398	4,999	4,795	4,031	3,968	3,865	3,831	3,808	3,812	3,719	3,688	3,639	3,552	**73,609**
Total Costs	420,051	446,255	503,644	446,052	416,124	397,810	443,864	480,086	486,219	453,328	478,195	499,877	552,527	589,991	583,394	578,958	580,727	593,101	604,664	621,372	**6,663,006**
Key Resource Decisions (Cumulative Dth/day)																					
Mist Recall	-	-	30,292	30,292	79,099	102,536	145,466	145,466	145,466	163,262	188,766	209,220	209,220	209,220	209,220	209,220	209,220	225,803	245,000	245,000	
WEX/SE(R)/SE(L)	-	-	-	-	-	-	-	-	-	-	-	-	50,000	50,000	50,000	50,000	50,000	50,000	50,000	51,549	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Pacific Connector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
North Mist	-	-	-	-	-	-	-	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	100,000	100,000	
CCLNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South Salem Feeder	-	-	-	-	-	-	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	
Christenson Compressor	-	-	-	-	-	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Clark County	-	-	31,145	31,145	33,871	34,444	36,477	43,738	47,555	51,653	55,860	60,679	65,605	70,801	76,092	81,997	87,995	94,251	100,578	107,522	

A3: CCLNG/NM	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	NPVRR - 4.58%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0458
DEMAND (DT)																					
Forecast Firm Sales Demand (net DSM)	76,856,029	77,251,424	78,295,384	78,355,486	78,951,673	79,657,724	80,925,719	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Served Firm Sales Demand	0	0	265	0	275	276	268	0	0	287	281	295	299	303	296	0	315	320	12,452	22,200	
Unserved Firm Sales Demand	0	0	613	635	637	640	622	0	0	669	655	688	698	708	693	0	0	749	35,480	70,967	
Peak Day Firm Sales Demand (net DSM)	930,549	936,976	945,296	953,453	962,290	972,270	982,777	995,009	1,007,630	1,021,003	1,034,718	1,050,150	1,065,798	1,082,157	1,098,681	1,116,901	1,135,300	1,154,306	1,173,372	1,194,115	
Peak Day Firm Sales Demand Unserved	26,928	32,134	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000) $2013																					
Supply Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Supply Variable Costs	306,068	320,894	371,770	316,207	285,031	274,183	311,726	344,422	353,035	320,166	344,064	366,339	398,781	431,546	427,718	418,241	418,043	423,286	427,260	440,809	
Total Supply Costs	306,068	320,894	371,770	316,207	285,031	274,183	311,726	344,422	353,035	320,166	344,064	366,339	398,781	431,546	427,718	418,241	418,043	423,286	427,260	440,809	**4,778,362**
Transport Fixed Costs	88,000	78,102	84,481	85,999	86,519	86,763	89,170	89,497	89,497	89,497	89,498	89,499	92,649	92,649	92,651	92,656	92,658	92,662	92,664	92,734	
Transport Variable Costs	3,472	2,899	2,708	2,870	3,119	3,109	3,028	3,004	3,253	3,262	3,315	3,334	3,392	3,448	3,544	3,557	3,618	3,648	3,684	3,691	
Total Transport Cost	91,472	81,002	87,190	88,869	89,638	89,872	92,198	92,501	92,750	92,759	92,813	92,833	96,041	96,097	96,195	96,213	96,275	96,310	96,348	96,425	**1,240,607**
Storage Fixed Cost	22,445	23,585	23,956	25,176	26,362	27,741	44,617	52,621	52,621	52,621	53,142	53,628	54,451	55,377	64,186	68,362	68,791	69,002	69,002	69,002	
Storage Variable Cost	66	225	110	110	284	266	338	81	254	379	387	408	435	443	390	467	505	522	504	503	
Total Storage Cost	22,511	23,810	24,066	25,286	26,646	28,007	44,955	52,702	52,875	53,000	53,529	54,036	54,887	55,820	64,576	68,828	69,297	69,524	69,506	69,505	**606,488**
DSM Annual Utility Cost		12,079	11,635	7,160	6,562	6,033	5,425	5,398	4,999	4,795	4,031	3,968	3,865	3,831	3,808	3,812	3,719	3,688	3,639	3,552	**73,609**
Total Costs	420,051	437,784	494,660	437,522	407,877	398,095	454,304	495,023	503,659	470,719	494,437	517,176	553,573	587,294	592,297	587,094	587,334	592,808	596,754	610,292	**6,699,067**
Key Resource Decisions (Cumulative Dth/day)																					
Mist Recall	-	-	30,292	30,292	79,099	102,621	146,248	146,248	146,248	146,248	146,248	167,095	176,297	204,732	227,816	227,816	227,816	245,000	245,000	245,000	
WEX/SE(R)/SE(L)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Pacific Connector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
North Mist	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100,000	100,000	100,000	100,000	100,000	
CCLNG	-	-	-	-	-	-	-	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	
South Salem Feeder	-	-	-	-	-	-	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	
Christenson Compressor	-	-	-	-	-	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Clark County	-	-	31,145	31,145	33,871	36,893	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	

A3: SE(R)	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	NPVRR - 4.58%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0458
DEMAND (DT)																					
Forecast Firm Sales Demand (net DSM)	76,856,029	77,251,424	78,295,384	78,355,486	78,951,673	79,657,724	80,925,719	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Served Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Unserved Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Firm Sales Demand (net DSM)	930,549	936,976	945,296	953,453	962,290	972,270	982,777	995,009	1,007,630	1,021,003	1,034,718	1,050,150	1,065,798	1,082,157	1,098,681	1,116,901	1,135,300	1,154,306	1,173,372	1,194,115	
Peak Day Firm Sales Demand Unserved	32,274	26,732	-	-	-	85	1,123	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000) $2013																					
Supply Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Supply Variable Costs	306,068	320,894	371,769	313,981	287,208	270,931	306,968	330,748	356,947	316,146	337,787	362,427	388,222	424,727	420,772	414,675	413,648	421,585	431,792	445,571	
Total Supply Costs	306,068	320,894	371,769	313,981	287,208	270,931	306,968	330,748	356,947	316,146	337,787	362,427	388,222	424,727	420,772	414,675	413,648	421,585	431,792	445,571	**4,741,258**
Transport Fixed Costs	88,000	78,103	84,482	85,999	86,519	86,565	88,883	126,709	126,983	127,279	127,581	127,929	131,431	131,804	132,184	132,611	133,043	133,495	133,951	134,452	
Transport Variable Costs	3,472	2,899	2,708	2,846	3,139	3,074	2,988	4,095	4,703	4,589	4,583	4,099	4,245	4,363	4,468	4,589	4,875	4,972	5,115	5,042	
Total Transport Cost	91,473	81,002	87,190	88,845	89,658	89,639	91,871	130,804	131,686	131,867	132,164	132,027	135,676	136,166	136,652	137,199	137,918	138,466	139,066	139,494	**1,536,201**
Storage Fixed Cost	22,445	23,585	23,956	24,081	25,824	26,884	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,144	27,690	28,400	29,500	29,924	
Storage Variable Cost	66	225	110	108	283	149	48	67	87	259	153	158	77	229	292	321	348	381	392	398	
Total Storage Cost	22,511	23,810	24,066	24,189	26,107	27,033	27,048	27,068	27,088	27,259	27,153	27,158	27,077	27,230	27,292	27,465	28,039	28,781	29,892	30,322	**356,498**
DSM Annual Utility Cost		12,079	11,635	7,160	6,562	6,033	5,425	5,398	4,999	4,795	4,031	3,968	3,865	3,831	3,808	3,812	3,719	3,688	3,639	3,552	**73,609**
Total Costs	420,051	437,785	494,660	434,175	409,536	393,636	431,313	494,018	520,720	480,067	501,135	525,580	554,840	591,954	588,523	583,151	583,324	592,521	604,389	618,939	**6,707,566**
Key Resource Decisions (Cumulative Dth/day)																					
Mist Recall	-	-	30,292	30,292	35,299	102,536	112,014	112,014	112,014	112,014	112,014	112,014	112,014	112,014	112,014	112,014	117,754	136,782	155,866	190,486	
WEX/SE(R)/SE(L)	-	-	-	-	-	-	-	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Pacific Connector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
North Mist	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
CCLNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South Salem Feeder	-	-	-	-	-	-	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	
Christenson Compressor	-	-	-	-	-	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Clark County	-	-	31,145	31,145	33,871	34,444	36,477	43,738	47,555	51,653	55,860	60,679	65,605	70,801	76,092	81,997	87,995	94,251	100,578	107,522	

B1: CC/TB/NM	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	NPVRR - 4.58%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0458
DEMAND (DT)																					
Forecast Firm Sales Demand (net DSM)	76,856,029	77,251,424	78,295,384	78,355,486	78,951,673	79,657,724	80,925,719	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Served Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Unserved Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Firm Sales Demand (net DSM)	930,549	936,976	945,296	953,453	962,290	972,270	982,777	995,009	1,007,630	1,021,003	1,034,718	1,050,150	1,065,798	1,082,157	1,098,681	1,116,901	1,135,300	1,154,306	1,173,372	1,194,115	
Peak Day Firm Sales Demand Unserved	26,927	26,732	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000) $2013																					
Supply Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Supply Variable Costs	306,068	318,930	370,383	314,331	286,240	283,147	301,788	342,881	375,634	348,370	354,909	332,943	352,844	379,961	392,876	404,608	403,711	412,868	435,018	452,361	
Total Supply Costs	306,068	318,930	370,383	314,331	286,240	283,147	301,788	342,881	375,634	348,370	354,909	332,943	352,844	379,961	392,876	404,608	403,711	412,868	435,018	452,361	**4,709,493**
Transport Fixed Costs	88,001	88,001	94,380	95,897	96,417	96,751	99,158	110,049	110,323	110,618	110,920	111,268	114,770	115,144	115,525	115,951	116,384	116,836	117,292	117,863	
Transport Variable Costs	3,472	3,436	3,181	3,408	3,914	3,966	3,949	3,412	4,172	3,838	4,206	4,103	4,100	4,206	4,283	4,320	4,377	4,439	4,516	4,465	
Total Transport Cost	91,473	91,437	97,561	99,305	100,331	100,717	103,107	113,461	114,495	114,456	115,125	115,371	118,870	119,349	119,808	120,271	120,761	121,275	121,808	122,328	**1,465,471**
Storage Fixed Cost	22,445	23,585	23,956	25,176	26,362	27,741	28,276	28,276	28,276	28,276	28,276	28,276	28,276	28,556	29,528	30,568	35,141	37,928	40,672	41,848	
Storage Variable Cost	66	225	110	110	291	259	279	75	208	57	212	284	158	335	369	403	398	410	425	425	
Total Storage Cost	22,511	23,810	24,066	25,286	26,653	28,001	28,555	28,351	28,484	28,333	28,488	28,560	28,434	28,891	29,897	30,971	35,539	38,338	41,098	42,273	**387,318**
DSM Annual Utility Cost		12,079	11,635	7,160	6,562	6,033	5,425	5,398	4,999	4,795	4,031	3,968	3,865	3,831	3,808	3,812	3,719	3,688	3,639	3,552	**73,609**
Total Costs	420,051	446,255	503,645	446,082	419,786	417,898	438,875	490,091	523,612	495,954	502,553	480,842	504,013	532,032	546,389	559,662	563,730	576,169	601,563	620,514	**6,635,891**
Key Resource Decisions (Cumulative Dth/day)																					
Mist Recall	-	-	30,291	30,291	79,098	102,620	146,245	146,245	146,245	146,245	146,245	146,245	146,245	146,245	157,437	190,830	216,083	216,083	244,049	245,000	
WEX/SE(R)/SE(L)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	-	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	
Pacific Connector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
North Mist	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50,000	50,000	100,000	
CCLNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South Salem Feeder	-	-	-	-	-	-	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	
Christenson Compressor	-	-	-	-	-	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Clark County	-	-	31,145	31,145	33,871	36,893	40,041	43,738	47,555	51,653	55,860	60,679	65,605	70,801	76,092	81,997	87,995	94,251	100,578	107,522	

B1: NM/SE(L)	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	NPVRR - 4.58%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0458
DEMAND (DT)																					
Forecast Firm Sales Demand (net DSM)	76,856,029	77,251,424	78,295,384	78,355,486	78,951,673	79,657,724	80,925,719	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Served Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Unserved Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Firm Sales Demand (net DSM)	930,549	936,976	945,296	953,453	962,290	972,270	982,777	995,009	1,007,630	1,021,003	1,034,718	1,050,150	1,065,798	1,082,157	1,098,681	1,116,901	1,135,300	1,154,306	1,173,372	1,194,115	
Peak Day Firm Sales Demand Unserved	26,927	32,133	-	-	-	85	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000) $2013																					
Supply Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Supply Variable Costs	306,068	318,930	370,383	314,330	286,234	283,409	305,961	369,476	349,470	359,457	335,557	318,070	340,804	357,071	374,519	391,919	399,393	399,186	426,999	444,903	
Total Supply Costs	306,068	318,930	370,383	314,330	286,234	283,409	305,961	369,476	349,470	359,457	335,557	318,070	340,804	357,071	374,519	391,919	399,393	399,186	426,999	444,903	4,648,617
Transport Fixed Costs	88,000	88,000	94,379	95,897	96,417	96,517	98,834	99,355	99,629	99,923	100,225	100,572	128,899	129,273	129,654	130,078	130,511	130,962	131,418	134,093	
Transport Variable Costs	3,472	3,436	3,181	3,408	3,914	3,966	3,978	3,705	4,077	4,029	4,167	4,094	4,181	4,207	4,289	4,351	4,478	4,447	4,486	4,425	
Total Transport Cost	91,473	91,436	97,561	99,304	100,331	100,483	102,812	103,061	103,706	103,952	104,393	104,666	133,079	133,480	133,942	134,429	134,989	135,409	135,904	138,518	1,487,237
Storage Fixed Cost	22,445	23,585	23,956	25,176	26,360	27,820	32,658	34,746	35,128	35,957	36,742	36,973	36,973	36,973	36,973	36,973	37,480	39,644	42,434	43,341	
Storage Variable Cost	66	225	110	110	291	259	281	103	270	274	285	198	199	233	284	331	402	425	425	425	
Total Storage Cost	22,511	23,810	24,066	25,286	26,651	28,079	32,939	34,849	35,398	36,231	37,027	37,171	37,172	37,206	37,257	37,304	37,883	40,069	42,859	43,766	436,604
DSM Annual Utility Cost		12,079	11,635	7,160	6,562	6,033	5,425	5,398	4,999	4,795	4,031	3,968	3,865	3,831	3,808	3,812	3,719	3,688	3,639	3,552	73,609
Total Costs	420,051	446,255	503,644	446,081	419,778	418,004	447,137	512,783	493,574	504,435	481,008	463,875	514,920	531,588	549,525	567,464	575,984	578,353	609,402	630,739	6,646,067
Key Resource Decisions (Cumulative Dth/day)																					
Mist Recall	-	-	30,292	30,292	79,099	102,536	149,434	149,434	149,434	164,747	190,379	209,220	209,220	209,220	209,220	209,220	209,220	229,511	245,000	245,000	
WEX/SE(R)/SE(L)	-	-	-	-	-	-	-	-	-	-	-	-	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Pacific Connector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
North Mist	-	-	-	-	-	-	-	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	100,000	100,000	
CCLNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South Salem Feeder	-	-	-	-	-	-	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	
Christenson Compressor	-	-	-	-	-	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Clark County	-	-	31,145	31,145	33,871	34,444	36,477	43,738	47,555	51,653	55,860	60,679	65,605	70,801	76,092	81,997	87,995	94,251	100,578	107,522	

B1: CCLNG/NM	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	NPVRR - 4.58%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0458
DEMAND (DT)																					
Forecast Firm Sales Demand (net DSM)	76,856,029	77,251,424	78,295,384	78,355,486	78,951,673	79,657,724	80,925,719	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Served Firm Sales Demand	0	0	613	635	637	640	622	0	660	669	655	688	698	708	693	0	739	1,284	40,425	70,967	
Unserved Firm Sales Demand	541	2,926	2,989	3,090	3,088	3,095	3,002	0	3,167	3,201	3,127	3,276	3,314	3,353	3,276	0	3,473	9,851	209,851	228,698	
Peak Day Firm Sales Demand (net DSM)	930,549	936,976	945,296	953,453	962,290	972,270	982,777	995,009	1,007,630	1,021,003	1,034,718	1,050,150	1,065,798	1,082,157	1,098,681	1,116,901	1,135,300	1,154,306	1,173,372	1,194,115	
Peak Day Firm Sales Demand Unserved	26,928	32,134	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000) $2013																					
Supply Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Supply Variable Costs	306,068	320,894	371,770	316,236	288,981	283,212	304,398	363,589	351,861	357,145	336,549	324,459	347,489	368,594	387,919	398,406	398,716	402,442	422,152	439,468	
Total Supply Costs	306,068	320,894	371,770	316,236	288,981	283,212	304,398	363,589	351,861	357,145	336,549	324,459	347,489	368,594	387,919	398,406	398,716	402,442	422,152	439,468	4,672,254
Transport Fixed Costs	88,000	78,102	84,481	85,999	86,519	96,996	99,404	99,731	99,731	99,731	99,732	99,733	102,882	102,883	102,885	102,889	102,891	102,896	102,898	102,968	
Transport Variable Costs	3,472	2,899	2,708	2,870	3,187	3,986	3,984	3,633	4,119	3,983	4,196	4,163	4,212	4,274	4,378	4,389	4,464	4,469	4,518	4,383	
Total Transport Cost	91,472	81,002	87,190	88,869	89,706	100,982	103,388	103,364	103,850	103,714	103,928	103,896	107,095	107,157	107,263	107,279	107,355	107,364	107,416	107,351	1,339,365
Storage Fixed Cost	22,445	23,585	23,956	25,176	26,362	27,775	44,667	52,670	52,670	52,670	53,244	53,644	54,459	55,422	64,238	68,414	68,809	69,002	69,002	69,002	
Storage Variable Cost	66	225	110	110	287	261	386	86	335	251	421	430	448	441	408	429	525	531	503	510	
Total Storage Cost	22,511	23,810	24,066	25,286	26,649	28,036	45,053	52,756	53,006	52,922	53,664	54,074	54,907	55,863	64,646	68,843	69,334	69,533	69,505	69,512	606,883
DSM Annual Utility Cost		12,079	11,635	7,160	6,562	6,033	5,425	5,398	4,999	4,795	4,031	3,968	3,865	3,831	3,808	3,812	3,719	3,688	3,639	3,552	73,609
Total Costs	420,051	437,784	494,660	437,551	411,898	418,263	458,264	525,107	513,716	518,576	498,173	486,398	513,356	535,444	563,635	578,340	579,123	583,027	602,712	619,882	6,692,112
Key Resource Decisions (Cumulative Dth/day)																					
Mist Recall	-	-	30,292	30,292	79,099	102,621	147,583	147,583	147,583	147,583	147,583	170,502	175,268	205,559	229,213	229,213	229,213	245,000	245,000	245,000	
WEX/SE(R)/SE(L)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Pacific Connector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
North Mist	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100,000	100,000	100,000	100,000	100,000	
CCLNG	-	-	-	-	-	-	-	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	
South Salem Feeder	-	-	-	-	-	-	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	
Christenson Compressor	-	-	-	-	-	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Clark County	-	-	31,145	31,145	33,871	36,893	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	

B1: WEX	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	NPVRR - 4.58%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0458
DEMAND (DT)																					
Forecast Firm Sales Demand (net DSM)	76,856,029	77,251,424	78,295,384	78,355,486	78,951,673	79,657,724	80,925,719	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Served Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Unserved Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Firm Sales Demand (net DSM)	930,549	936,976	945,296	953,453	962,290	972,270	982,777	995,009	1,007,630	1,021,003	1,034,718	1,050,150	1,065,798	1,082,157	1,098,681	1,116,901	1,135,300	1,154,306	1,173,372	1,194,115	
Peak Day Firm Sales Demand Unserved	32,274	26,732	-	-	-	85	1,123	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000) $2013																					
Supply Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Supply Variable Costs	306,068	320,894	371,769	314,318	291,028	287,449	329,019	362,084	356,758	354,808	352,786	340,895	363,183	386,913	403,237	412,460	419,840	430,094	451,581	471,085	
Total Supply Costs	306,068	320,894	371,769	314,318	291,028	287,449	329,019	362,084	356,758	354,808	352,786	340,895	363,183	386,913	403,237	412,460	419,840	430,094	451,581	471,085	4,800,320
Transport Fixed Costs	88,000	78,103	84,482	85,999	86,519	86,572	88,889	130,723	130,996	131,292	131,593	131,943	135,445	135,817	136,199	136,625	137,058	137,509	137,966	138,466	
Transport Variable Costs	3,472	2,899	2,708	2,849	3,206	3,116	3,135	3,840	4,360	4,280	4,464	4,394	4,410	4,552	4,640	4,709	4,838	4,924	5,039	4,826	
Total Transport Cost	91,473	81,002	87,190	88,849	89,726	89,688	92,025	134,563	135,356	135,571	136,057	136,337	139,854	140,369	140,839	141,334	141,896	142,433	143,004	143,292	1,565,641
Storage Fixed Cost	22,445	23,585	23,956	24,081	25,824	26,884	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,144	27,690	28,400	29,500	29,924	
Storage Variable Cost	66	225	110	106	294	139	218	66	224	41	286	114	156	244	286	318	378	405	441	437	
Total Storage Cost	22,511	23,810	24,066	24,187	26,117	27,023	27,218	27,067	27,224	27,041	27,287	27,114	27,157	27,245	27,286	27,462	28,068	28,806	29,941	30,361	356,749
DSM Annual Utility Cost		12,079	11,635	7,160	6,562	6,033	5,425	5,398	4,999	4,795	4,031	3,968	3,865	3,831	3,808	3,812	3,719	3,688	3,639	3,552	73,609
Total Costs	420,051	437,785	494,660	434,514	413,433	410,192	453,687	529,112	524,338	522,216	520,161	508,314	534,059	558,358	575,170	585,068	593,523	605,021	628,166	648,290	6,796,319
Key Resource Decisions (Cumulative Dth/day)																					
Mist Recall	-	-	30,292	30,292	35,299	102,536	112,014	112,014	112,014	112,014	112,014	112,014	112,014	112,014	112,014	112,014	117,754	136,782	155,866	190,486	
WEX/SE(R)/SE(L)	-	-	-	-	-	-	-	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Pacific Connector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
North Mist	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
CCLNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South Salem Feeder	-	-	-	-	-	-	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	
Christenson Compressor	-	-	-	-	-	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Clark County	-	-	31,145	31,145	33,871	34,444	36,477	43,738	47,555	51,653	55,860	60,679	65,605	70,801	76,092	81,997	87,995	94,251	100,578	107,522	

B2: PC/NM	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	NPVRR - 4.58%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0458
DEMAND (DT)																					
Forecast Firm Sales Demand (net DSM)	76,856,029	77,251,424	78,295,384	78,355,486	78,951,673	79,657,724	80,925,719	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Served Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Unserved Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Firm Sales Demand (net DSM)	930,549	936,976	945,296	953,453	962,290	972,270	982,777	995,009	1,007,630	1,021,003	1,034,718	1,050,150	1,065,798	1,082,157	1,098,681	1,116,901	1,135,300	1,154,306	1,173,372	1,194,115	
Peak Day Firm Sales Demand Unserved	26,928	26,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000) $2013																					
Supply Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Supply Variable Costs	306,068	318,930	370,383	314,331	286,654	301,748	353,548	362,184	337,812	369,716	364,056	347,011	371,663	395,074	410,066	421,610	424,520	431,269	455,785	472,939	
Total Supply Costs	306,068	318,930	370,383	314,331	286,654	301,748	353,548	362,184	337,812	369,716	364,056	347,011	371,663	395,074	410,066	421,610	424,520	431,269	455,785	472,939	4,854,781
Transport Fixed Costs	88,000	88,000	94,379	95,897	96,417	86,763	89,170	102,998	103,306	103,637	103,978	104,367	107,914	108,334	108,763	109,241	109,674	110,125	110,582	111,153	
Transport Variable Costs	3,472	3,436	3,181	3,408	3,915	3,114	3,060	2,645	2,786	2,731	2,937	2,894	2,950	3,009	3,092	3,139	3,203	3,264	3,317	3,304	
Total Transport Cost	91,473	91,436	97,561	99,305	100,332	89,877	92,230	105,643	106,092	106,368	106,915	107,261	110,863	111,343	111,856	112,380	112,878	113,389	113,899	114,457	1,389,441
Storage Fixed Cost	22,445	23,585	23,956	25,176	26,362	27,741	28,276	28,276	28,276	28,276	28,276	28,276	28,276	28,777	29,694	34,286	37,068	38,411	41,280	42,445	
Storage Variable Cost	66	225	110	110	296	256	187	69	272	34	272	185	229	324	366	352	392	424	420	425	
Total Storage Cost	22,511	23,810	24,066	25,286	26,658	27,997	28,462	28,345	28,548	28,310	28,548	28,461	28,505	29,102	30,060	34,639	37,460	38,835	41,700	42,870	391,066
DSM Annual Utility Cost		12,079	11,635	7,160	6,562	6,033	5,425	5,398	4,999	4,795	4,031	3,968	3,865	3,831	3,808	3,812	3,719	3,688	3,639	3,552	73,609
Total Costs	420,051	446,255	503,644	446,082	420,206	425,655	479,666	501,571	477,451	509,189	503,549	486,701	514,896	539,349	555,789	572,440	578,576	587,182	615,024	633,818	6,708,897
Key Resource Decisions (Cumulative Dth/day)																					
Mist Recall	-	-	30,291	30,291	79,098	102,620	146,245	146,245	146,245	146,245	146,245	146,245	146,245	146,245	166,302	193,155	193,155	220,887	245,000	245,000	
WEX/SE(R)/SE(L)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Pacific Connector	-	-	-	-	-	-	-	52,000	52,000	52,000	52,000	52,000	52,000	52,000	52,000	52,000	52,000	52,000	52,000	52,000	
North Mist	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50,000	50,000	100,000	100,000	
CCLNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South Salem Feeder	-	-	-	-	-	-	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	
Christenson Compressor	-	-	-	-	-	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Clark County	-	-	31,145	31,145	33,871	36,893	40,041	43,738	47,555	51,653	55,860	60,679	65,605	70,801	76,092	81,997	87,995	94,251	100,578	107,522	

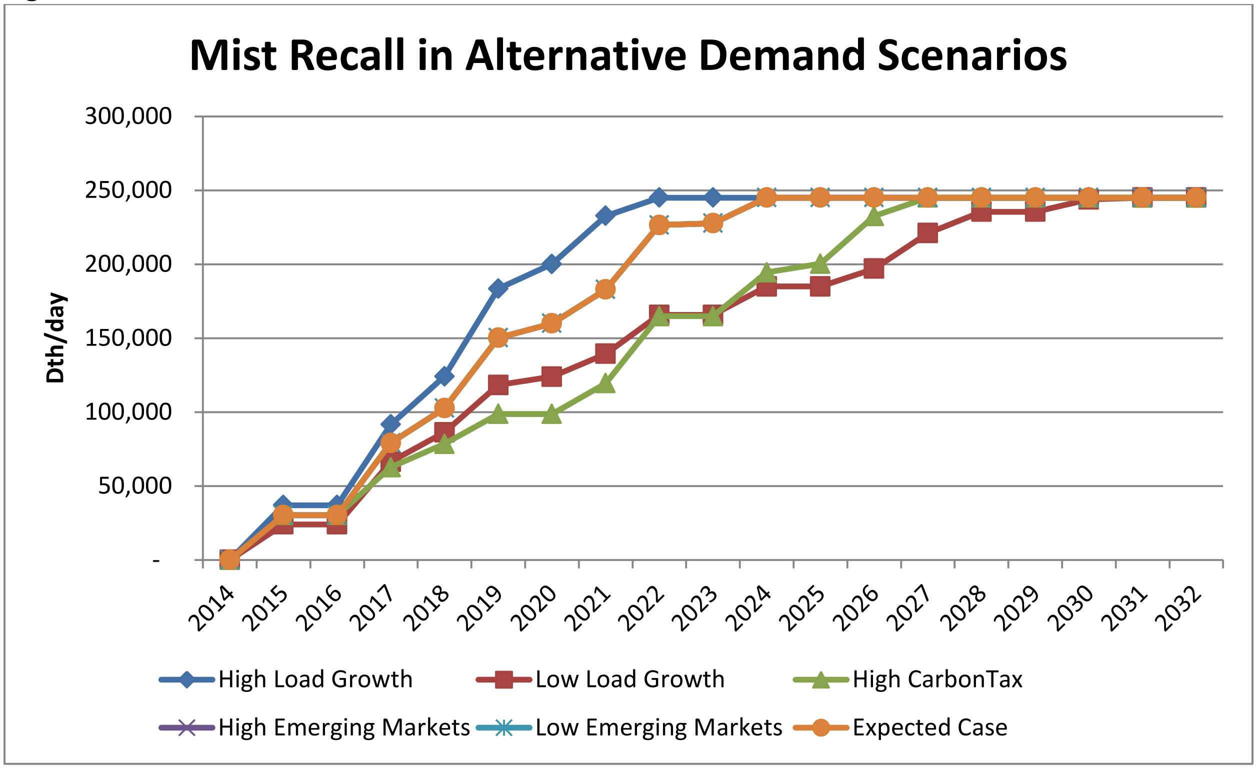
B2: NM/SE(L)	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	NPVRR - 4.58%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0458
DEMAND (DT)																					
Forecast Firm Sales Demand (net DSM)	76,856,029	77,251,424	78,295,384	78,355,486	78,951,673	79,657,724	80,925,719	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Served Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Unserved Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Firm Sales Demand (net DSM)	930,549	936,976	945,296	953,453	962,290	972,270	982,777	995,009	1,007,630	1,021,003	1,034,718	1,050,150	1,065,798	1,082,157	1,098,681	1,116,901	1,135,300	1,154,306	1,173,372	1,194,115	
Peak Day Firm Sales Demand Unserved	26,927	32,133	-	-	-	85	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000) $2013																					
Supply Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Supply Variable Costs	306,068	318,930	370,383	314,330	286,648	301,675	359,631	368,835	342,761	386,694	362,668	350,299	372,202	392,421	406,821	419,181	425,150	431,647	454,847	473,623	
Total Supply Costs	306,068	318,930	370,383	314,330	286,648	301,675	359,631	368,835	342,761	386,694	362,668	350,299	372,202	392,421	406,821	419,181	425,150	431,647	454,847	473,623	4,876,372
Transport Fixed Costs	88,000	88,000	94,379	95,897	96,417	86,565	88,883	89,404	89,678	89,972	90,273	90,620	118,944	119,318	119,700	120,126	120,559	121,010	121,466	125,182	
Transport Variable Costs	3,472	3,436	3,181	3,408	3,915	3,114	3,114	3,139	3,225	3,250	3,325	3,306	3,372	3,425	3,495	3,533	3,619	3,677	3,729	3,737	
Total Transport Cost	91,473	91,436	97,561	99,304	100,331	89,679	91,997	92,543	92,903	93,222	93,598	93,927	122,317	122,743	123,195	123,659	124,178	124,687	125,195	128,919	1,391,765
Storage Fixed Cost	22,445	23,585	23,956	25,176	26,360	27,721	32,510	34,598	35,157	35,897	36,694	36,973	36,973	36,973	36,973	36,973	37,582	39,588	41,150	41,505	
Storage Variable Cost	66	225	110	110	295	256	257	137	274	267	286	218	233	266	287	321	395	408	419	425	
Total Storage Cost	22,511	23,810	24,066	25,286	26,656	27,976	32,766	34,734	35,431	36,164	36,981	37,191	37,206	37,239	37,260	37,294	37,977	39,996	41,568	41,930	434,956
DSM Annual Utility Cost		12,079	11,635	7,160	6,562	6,033	5,425	5,398	4,999	4,795	4,031	3,968	3,865	3,831	3,808	3,812	3,719	3,688	3,639	3,552	73,609
Total Costs	420,051	446,255	503,644	446,081	420,197	425,363	489,820	501,511	476,094	520,875	497,279	485,385	535,588	556,234	571,084	583,945	591,024	600,017	625,250	648,024	6,776,703
Key Resource Decisions (Cumulative Dth/day)																					
Mist Recall	-	-	30,292	30,292	79,099	102,536	145,466	145,466	145,466	167,833	186,474	209,221	209,221	209,221	209,221	209,221	209,221	233,588	245,000	245,000	
WEX/SE(R)/SE(L)	-	-	-	-	-	-	-	-	-	-	-	-	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Pacific Connector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
North Mist	-	-	-	-	-	-	-	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	100,000	100,000	
CCLNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South Salem Feeder	-	-	-	-	-	-	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	
Christenson Compressor	-	-	-	-	-	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Clark County	-	-	31,145	31,145	33,871	34,444	36,477	43,738	47,555	51,653	55,860	60,679	65,605	70,801	76,092	81,997	87,995	94,251	100,578	107,522	

B2: CC/TB/NM	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	NPVRR - 4.58%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0458
DEMAND (DT)																					
Forecast Firm Sales Demand (net DSM)	76,856,029	77,251,424	78,295,384	78,355,486	78,951,673	79,657,724	80,925,719	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Served Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Unserved Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Firm Sales Demand (net DSM)	930,549	936,976	945,296	953,453	962,290	972,270	982,777	995,009	1,007,630	1,021,003	1,034,718	1,050,150	1,065,798	1,082,157	1,098,681	1,116,901	1,135,300	1,154,306	1,173,372	1,194,115	
Peak Day Firm Sales Demand Unserved	26,927	26,732	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000) $2013																					
Supply Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Supply Variable Costs	306,068	318,930	370,383	314,331	286,654	301,748	353,520	361,794	337,647	369,349	363,684	346,875	370,799	393,084	410,071	421,537	423,617	431,180	454,654	472,191	
Total Supply Costs	306,068	318,930	370,383	314,331	286,654	301,748	353,520	361,794	337,647	369,349	363,684	346,875	370,799	393,084	410,071	421,537	423,617	431,180	454,654	472,191	4,850,835
Transport Fixed Costs	88,001	88,001	94,380	95,897	96,417	86,763	89,171	115,516	115,790	116,085	116,387	116,734	120,519	120,893	121,274	121,700	122,133	122,585	123,041	123,612	
Transport Variable Costs	3,472	3,436	3,181	3,408	3,915	3,114	3,060	3,214	3,370	3,317	3,526	3,478	3,538	3,577	3,684	3,729	3,795	3,857	3,900	3,880	
Total Transport Cost	91,473	91,437	97,561	99,305	100,332	89,878	92,231	118,730	119,160	119,402	119,914	120,213	124,057	124,470	124,958	125,429	125,928	126,442	126,941	127,492	1,485,642
Storage Fixed Cost	22,445	23,585	23,956	25,176	26,362	27,741	28,276	28,276	28,276	28,276	28,276	28,276	28,276	28,502	29,483	30,544	35,118	37,944	40,249	41,201	
Storage Variable Cost	66	225	110	110	296	256	186	64	271	34	271	184	224	322	366	396	402	423	416	419	
Total Storage Cost	22,511	23,810	24,066	25,286	26,658	27,997	28,461	28,340	28,547	28,310	28,547	28,459	28,500	28,824	29,849	30,940	35,520	38,367	40,665	41,619	386,736
DSM Annual Utility Cost		12,079	11,635	7,160	6,562	6,033	5,425	5,398	4,999	4,795	4,031	3,968	3,865	3,831	3,808	3,812	3,719	3,688	3,639	3,552	73,609
Total Costs	420,051	446,255	503,645	446,082	420,206	425,655	479,637	514,262	490,354	521,856	516,176	499,515	527,221	550,209	568,685	581,719	588,785	599,678	625,899	644,855	6,796,823
Key Resource Decisions (Cumulative Dth/day)																					
Mist Recall	-	-	30,291	30,291	79,098	102,620	146,245	146,245	146,245	146,245	146,245	146,245	146,245	146,245	155,300	190,080	215,472	215,472	245,000	245,000	
WEX/SE(R)/SE(L)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	-	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	
Pacific Connector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
North Mist	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50,000	50,000	100,000	
CCLNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South Salem Feeder	-	-	-	-	-	-	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	
Christenson Compressor	-	-	-	-	-	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Clark County	-	-	31,145	31,145	33,871	36,893	40,041	43,738	47,555	51,653	55,860	60,679	65,605	70,801	76,092	81,997	87,995	94,251	100,578	107,522	

B2: SE(R)	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	NPVRR - 4.58%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0458
DEMAND (DT)																					
Forecast Firm Sales Demand (net DSM)	76,856,029	77,251,424	78,295,384	78,355,486	78,951,673	79,657,724	80,925,719	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Served Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Unserved Firm Sales Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Firm Sales Demand (net DSM)	930,549	936,976	945,296	953,453	962,290	972,270	982,777	995,009	1,007,630	1,021,003	1,034,718	1,050,150	1,065,798	1,082,157	1,098,681	1,116,901	1,135,300	1,154,306	1,173,372	1,194,115	
Peak Day Firm Sales Demand Unserved	32,274	26,732	-	-	-	85	1,123	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000) $2013																					
Supply Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Supply Variable Costs	306,068	320,894	371,769	314,318	291,342	297,772	341,683	353,012	350,843	355,858	376,244	344,307	368,060	388,930	409,488	417,232	426,547	430,111	457,281	475,793	
Total Supply Costs	306,068	320,894	371,769	314,318	291,342	297,772	341,683	353,012	350,843	355,858	376,244	344,307	368,060	388,930	409,488	417,232	426,547	430,111	457,281	475,793	**4,843,121**
Transport Fixed Costs	88,000	78,103	84,482	85,999	86,519	86,565	88,883	126,707	126,981	127,276	127,578	127,928	131,430	131,803	132,184	132,610	133,043	133,494	133,951	134,451	
Transport Variable Costs	3,472	2,899	2,708	2,849	3,206	3,071	2,943	4,146	4,289	4,092	4,456	4,278	4,435	4,423	4,528	4,559	4,683	4,713	4,893	4,811	
Total Transport Cost	91,473	81,002	87,190	88,849	89,725	89,636	91,825	130,854	131,270	131,368	132,035	132,206	135,865	136,226	136,712	137,169	137,726	138,208	138,844	139,262	**1,535,410**
Storage Fixed Cost	22,445	23,585	23,956	24,081	25,824	26,884	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,144	27,690	28,400	29,500	29,924	
Storage Variable Cost	66	225	110	106	294	109	32	103	216	61	286	93	154	232	296	306	388	394	440	414	
Total Storage Cost	22,511	23,810	24,066	24,187	26,117	26,993	27,032	27,104	27,217	27,061	27,287	27,093	27,154	27,232	27,296	27,450	28,078	28,794	29,940	30,338	**356,584**
DSM Annual Utility Cost		12,079	11,635	7,160	6,562	6,033	5,425	5,398	4,999	4,795	4,031	3,968	3,865	3,831	3,808	3,812	3,719	3,688	3,639	3,552	**73,609**
Total Costs	420,051	437,785	494,660	434,514	413,747	420,434	465,966	516,367	514,329	519,082	539,597	507,575	534,944	556,219	577,304	585,663	596,069	600,801	629,704	648,946	**6,808,724**
Key Resource Decisions (Cumulative Dth/day)																					
Mist Recall	-	-	30,292	30,292	35,299	102,536	112,014	112,014	112,014	112,014	112,014	112,014	112,014	112,014	112,014	112,014	117,754	136,782	155,866	190,486	
WEX/SE(R)/SE(L)	-	-	-	-	-	-	-	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Pacific Connector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
North Mist	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
CCLNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South Salem Feeder	-	-	-	-	-	-	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	
Christenson Compressor	-	-	-	-	-	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Clark County	-	-	31,145	31,145	33,871	34,444	36,477	43,738	47,555	51,653	55,860	60,679	65,605	70,801	76,092	81,997	87,995	94,251	100,578	107,522	

B2: CCLNG/NM	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	NPVRR - 4.58%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0458
DEMAND (DT)																					
Forecast Firm Sales Demand (net DSM)	76,856,029	77,251,424	78,295,384	78,355,486	78,951,673	79,657,724	80,925,719	81,352,430	82,325,225	83,380,516	85,013,373	85,749,969	87,045,466	88,411,683	90,357,171	91,337,053	92,892,233	94,485,396	96,662,630	97,782,834	
Served Firm Sales Demand	0	0	613	635	637	640	622	0	660	669	655	688	698	708	693	0	0	749	40,425	70,967	
Unserved Firm Sales Demand	541	2,926	2,989	3,090	3,088	3,095	3,002	0	3,167	3,201	3,127	3,276	3,314	3,353	3,276	0	3,473	3,514	165,481	228,698	
Peak Day Firm Sales Demand (net DSM)	930,549	936,976	945,296	953,453	962,290	972,270	982,777	995,009	1,007,630	1,021,003	1,034,718	1,050,150	1,065,798	1,082,157	1,098,681	1,116,901	1,135,300	1,154,306	1,173,372	1,194,115	
Peak Day Firm Sales Demand Unserved	26,928	32,134	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
COST ($000) $2013																					
Supply Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Supply Variable Costs	306,068	320,894	371,770	316,236	289,433	301,748	357,366	363,791	345,823	383,820	364,167	353,769	382,746	403,242	419,348	425,298	427,973	430,781	452,065	471,181	
Total Supply Costs	306,068	320,894	371,770	316,236	289,433	301,748	357,366	363,791	345,823	383,820	364,167	353,769	382,746	403,242	419,348	425,298	427,973	430,781	452,065	471,181	**4,902,162**
Transport Fixed Costs	88,000	78,102	84,481	85,999	86,519	86,763	89,170	89,497	89,497	89,497	89,497	89,499	92,649	92,649	92,651	92,654	92,657	92,662	92,664	92,734	
Transport Variable Costs	3,472	2,899	2,708	2,870	3,188	3,114	3,094	3,100	3,250	3,229	3,331	3,334	3,402	3,447	3,549	3,554	3,617	3,646	3,685	3,688	
Total Transport Cost	91,472	81,002	87,190	88,869	89,707	89,877	92,264	92,597	92,747	92,726	92,828	92,833	96,050	96,096	96,200	96,208	96,274	96,308	96,349	96,422	**1,240,778**
Storage Fixed Cost	22,445	23,585	23,956	25,176	26,362	27,741	44,617	52,621	52,621	52,621	53,253	53,616	54,486	55,410	64,186	68,362	68,791	69,002	69,002	69,002	
Storage Variable Cost	66	225	110	110	294	256	327	95	382	243	403	418	427	447	424	502	508	513	504	507	
Total Storage Cost	22,511	23,810	24,066	25,286	26,656	27,997	44,944	52,716	53,002	52,864	53,656	54,034	54,913	55,857	64,610	68,864	69,299	69,515	69,506	69,509	**606,639**
DSM Annual Utility Cost		12,079	11,635	7,160	6,562	6,033	5,425	5,398	4,999	4,795	4,031	3,968	3,865	3,831	3,808	3,812	3,719	3,688	3,639	3,552	**73,609**
Total Costs	420,051	437,784	494,660	437,551	412,358	425,655	500,000	514,502	496,571	534,205	514,683	504,605	537,574	559,026	583,966	594,181	597,266	600,292	621,559	640,664	**6,823,189**
Key Resource Decisions (Cumulative Dth/day)																					
Mist Recall	-	-	30,292	30,292	79,099	102,621	146,248	146,248	146,248	146,248	146,248	171,531	173,682	207,407	227,816	227,816	227,816	245,000	245,000	245,000	
WEX/SE(R)/SE(L)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Cross-Cascades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Pacific Connector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
North Mist	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100,000	100,000	100,000	100,000	100,000	
CCLNG	-	-	-	-	-	-	-	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	
South Salem Feeder	-	-	-	-	-	-	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000	
Christenson Compressor	-	-	-	-	-	-	-	-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Clark County	-	-	31,145	31,145	33,871	36,893	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	40,041	

Figure 7A.2 – Mist Recall in Alternative Demand Scenarios



IHS CERA Report is Confidential

- Subject to General Protective Order No. 14-142 in Oregon
- Subject to WAC 480-07-160 in Washington

Willbros Report is Confidential

- Subject to General Protective Order No. 14-142 in Oregon
- Subject to WAC 480-07-160 in Washington

Appendix 8: Avoided Costs

NW Natural®

		ALB	AST	COOS	DALO	DALW	EUG	NPT	PDX_C	PDX_E	PDX_W	SAL	VAN	System
2013-14	Annual	3.99	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.57	3.97	3.63
2013-14	Nov	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49
2013-14	Dec	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75
2013-14	Jan	3.96	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.78
2013-14	Feb	8.65	3.77	3.77	3.77	3.77	3.77	3.78	3.77	3.77	3.77	3.89	8.65	4.60
2013-14	Mar	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53
2013-14	Apr	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50
2013-14	May	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47
2013-14	Jun	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49
2013-14	Jul	3.48	3.48	3.48	3.48	3.48	3.48	3.48	3.48	3.48	3.48	3.48	3.48	3.48
2013-14	Aug	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49
2013-14	Sep	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49
2013-14	Oct	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52

		ALB	AST	COOS	DALO	DALW	EUG	NPT	PDX_C	PDX_E	PDX_W	SAL	VAN	System
2014-15	Annual	4.30	3.86	3.86	3.86	3.86	3.86	3.87	3.86	3.86	3.86	3.87	4.42	3.95
2014-15	Nov	3.65	3.65	3.65	3.65	3.65	3.65	3.65	3.65	3.65	3.65	3.65	3.65	3.65
2014-15	Dec	3.87	3.87	3.87	3.87	3.87	3.87	3.87	3.87	3.87	3.87	3.87	3.87	3.87
2014-15	Jan	4.08	3.88	3.89	3.88	3.88	3.89	3.89	3.89	3.88	3.89	3.89	3.88	3.90
2014-15	Feb	9.14	4.14	4.14	4.14	4.14	4.14	4.16	4.14	4.14	4.14	4.16	10.87	5.12
2014-15	Mar	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77
2014-15	Apr	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76
2014-15	May	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76
2014-15	Jun	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78
2014-15	Jul	3.81	3.81	3.81	3.81	3.81	3.81	3.81	3.81	3.81	3.81	3.81	3.81	3.81
2014-15	Aug	3.87	3.87	3.87	3.87	3.87	3.87	3.87	3.87	3.87	3.87	3.87	3.87	3.87
2014-15	Sep	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99
2014-15	Oct	4.08	4.08	4.08	4.08	4.08	4.08	4.08	4.08	4.08	4.08	4.08	4.08	4.08

		ALB	AST	COOS	DALO	DALW	EUG	NPT	PDX_C	PDX_E	PDX_W	SAL	VAN	System
2015-16	Annual	4.62	4.62	4.62	4.62	4.62	4.62	4.62	4.62	4.62	4.62	4.62	4.76	4.63
2015-16	Nov	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46
2015-16	Dec	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15
2015-16	Jan	5.18	5.18	5.18	5.18	5.18	5.18	5.18	5.18	5.18	5.18	5.18	5.18	5.18
2015-16	Feb	6.80	6.80	6.80	6.80	6.80	6.80	6.80	6.80	6.80	6.80	6.80	8.53	6.94
2015-16	Mar	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88
2015-16	Apr	4.57	4.57	4.57	4.57	4.57	4.57	4.57	4.57	4.57	4.57	4.57	4.57	4.57
2015-16	May	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30
2015-16	Jun	4.21	4.21	4.21	4.21	4.21	4.21	4.21	4.21	4.21	4.21	4.21	4.21	4.21
2015-16	Jul	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25
2015-16	Aug	3.91	3.91	3.91	3.91	3.91	3.91	3.91	3.91	3.91	3.91	3.91	3.91	3.91
2015-16	Sep	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83
2015-16	Oct	3.86	3.86	3.86	3.86	3.86	3.86	3.86	3.86	3.86	3.86	3.86	3.86	3.86

		ALB	AST	COOS	DALO	DALW	EUG	NPT	PDX_C	PDX_E	PDX_W	SAL	VAN	System
2016-17	Annual	3.98	3.98	3.98	3.98	3.98	3.98	3.98	3.98	3.98	3.98	3.98	4.14	3.99
2016-17	Nov	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94
2016-17	Dec	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07
2016-17	Jan	4.11	4.08	4.08	4.08	4.08	4.08	4.08	4.08	4.08	4.08	4.08	4.08	4.08
2016-17	Feb	4.38	4.38	4.38	4.38	4.38	4.38	4.41	4.38	4.38	4.38	4.41	6.27	4.54
2016-17	Mar	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94
2016-17	Apr	3.86	3.86	3.86	3.86	3.86	3.86	3.86	3.86	3.86	3.86	3.86	3.86	3.86
2016-17	May	3.88	3.88	3.88	3.88	3.88	3.88	3.88	3.88	3.88	3.88	3.88	3.88	3.88
2016-17	Jun	3.89	3.89	3.89	3.89	3.89	3.89	3.89	3.89	3.89	3.89	3.89	3.89	3.89
2016-17	Jul	3.90	3.90	3.90	3.90	3.90	3.90	3.90	3.90	3.90	3.90	3.90	3.90	3.90
2016-17	Aug	3.92	3.92	3.92	3.92	3.92	3.92	3.92	3.92	3.92	3.92	3.92	3.92	3.92
2016-17	Sep	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93
2016-17	Oct	3.95	3.95	3.95	3.95	3.95	3.95	3.95	3.95	3.95	3.95	3.95	3.95	3.95
		ALB	**AST**	**COOS**	**DALO**	**DALW**	**EUG**	**NPT**	**PDX_C**	**PDX_E**	**PDX_W**	**SAL**	**VAN**	**System**
2017-18	Annual	3.84	3.84	3.84	3.86	3.84	3.84	3.84	3.84	3.84	3.84	3.84	4.01	3.86
2017-18	Nov	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09
2017-18	Dec	4.17	4.17	4.17	4.17	4.17	4.17	4.17	4.17	4.17	4.17	4.17	4.17	4.17
2017-18	Jan	4.21	4.19	4.19	4.19	4.19	4.19	4.19	4.19	4.19	4.19	4.19	4.19	4.19
2017-18	Feb	6.25	6.24	6.24	6.43	6.24	6.24	6.28	6.24	6.24	6.24	6.28	8.25	6.43
2017-18	Mar	3.88	3.88	3.88	3.88	3.88	3.88	3.88	3.88	3.88	3.88	3.88	3.88	3.88
2017-18	Apr	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58
2017-18	May	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44
2017-18	Jun	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29
2017-18	Jul	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28
2017-18	Aug	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29
2017-18	Sep	3.31	3.31	3.31	3.31	3.31	3.31	3.31	3.31	3.31	3.31	3.31	3.31	3.31
2017-18	Oct	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32
		ALB	**AST**	**COOS**	**DALO**	**DALW**	**EUG**	**NPT**	**PDX_C**	**PDX_E**	**PDX_W**	**SAL**	**VAN**	**System**
2018-19	Annual	3.33	3.33	3.33	3.35	3.33	3.33	3.34	3.33	3.33	3.33	3.35	3.35	3.34
2018-19	Nov	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43
2018-19	Dec	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46
2018-19	Jan	3.49	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47
2018-19	Feb	3.55	3.52	3.52	3.73	3.52	3.52	3.57	3.52	3.52	3.52	3.78	3.73	3.59
2018-19	Mar	3.35	3.35	3.35	3.35	3.35	3.35	3.35	3.35	3.35	3.35	3.35	3.35	3.35
2018-19	Apr	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25
2018-19	May	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21
2018-19	Jun	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21
2018-19	Jul	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24
2018-19	Aug	3.26	3.26	3.26	3.26	3.26	3.26	3.26	3.26	3.26	3.26	3.26	3.26	3.26
2018-19	Sep	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29
2018-19	Oct	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28

		ALB	AST	COOS	DALO	DALW	EUG	NPT	PDX_C	PDX_E	PDX_W	SAL	VAN	System
2019-20	Annual	3.76	3.76	3.76	3.78	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.78	3.76
2019-20	Nov	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57
2019-20	Dec	3.69	3.69	3.69	3.69	3.69	3.69	3.69	3.69	3.69	3.69	3.69	3.69	3.69
2019-20	Jan	3.76	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.74
2019-20	Feb	3.87	3.84	3.84	4.03	3.84	3.84	3.89	3.84	3.84	3.84	3.89	4.03	3.88
2019-20	Mar	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76	3.76
2019-20	Apr	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72
2019-20	May	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72
2019-20	Jun	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75
2019-20	Jul	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78
2019-20	Aug	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83
2019-20	Sep	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83
2019-20	Oct	3.89	3.89	3.89	3.89	3.89	3.89	3.89	3.89	3.89	3.89	3.89	3.89	3.89
		ALB	**AST**	**COOS**	**DALO**	**DALW**	**EUG**	**NPT**	**PDX_C**	**PDX_E**	**PDX_W**	**SAL**	**VAN**	**System**
2020-21	Annual	4.69	4.69	4.57	4.70	4.69	4.69	4.69	4.69	4.69	4.69	4.69	4.88	4.70
2020-21	Nov	4.10	4.10	3.97	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.09
2020-21	Dec	4.19	4.19	4.00	4.19	4.19	4.19	4.19	4.19	4.19	4.19	4.19	4.19	4.17
2020-21	Jan	4.56	4.55	4.10	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.51
2020-21	Feb	4.79	4.78	4.21	4.96	4.78	4.78	4.80	4.78	4.78	4.78	4.80	7.11	4.95
2020-21	Mar	4.54	4.54	4.41	4.54	4.54	4.54	4.54	4.54	4.54	4.54	4.54	4.54	4.53
2020-21	Apr	4.66	4.66	4.66	4.66	4.66	4.66	4.66	4.66	4.66	4.66	4.66	4.66	4.66
2020-21	May	4.73	4.73	4.71	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.72
2020-21	Jun	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80
2020-21	Jul	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89
2020-21	Aug	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.96
2020-21	Sep	5.03	5.03	5.03	5.03	5.03	5.03	5.03	5.03	5.03	5.03	5.03	5.03	5.03
2020-21	Oct	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05
		ALB	**AST**	**COOS**	**DALO**	**DALW**	**EUG**	**NPT**	**PDX_C**	**PDX_E**	**PDX_W**	**SAL**	**VAN**	**System**
2021-22	Annual	4.47	4.47	4.36	4.48	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.48	4.46
2021-22	Nov	5.04	5.04	4.90	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.03
2021-22	Dec	5.06	5.06	4.95	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.05
2021-22	Jan	5.06	5.06	4.75	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.04
2021-22	Feb	5.09	5.09	4.67	5.27	5.09	5.09	5.11	5.09	5.09	5.09	5.11	5.27	5.09
2021-22	Mar	4.46	4.46	4.44	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46
2021-22	Apr	4.12	4.12	4.11	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12
2021-22	May	4.07	4.07	4.02	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.06
2021-22	Jun	4.08	4.08	4.01	4.08	4.08	4.08	4.08	4.08	4.08	4.08	4.08	4.08	4.07
2021-22	Jul	4.09	4.09	4.02	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.08
2021-22	Aug	4.11	4.11	4.05	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.10
2021-22	Sep	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18
2021-22	Oct	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23

		ALB	AST	COOS	DALO	DALW	EUG	NPT	PDX_C	PDX_E	PDX_W	SAL	VAN	System
2022-23	Annual	4.45	4.44	4.15	4.46	4.44	4.44	4.45	4.44	4.44	4.44	4.45	4.46	4.42
2022-23	Nov	4.54	4.54	4.43	4.54	4.54	4.54	4.54	4.54	4.54	4.54	4.54	4.54	4.53
2022-23	Dec	4.56	4.56	4.40	4.56	4.56	4.56	4.56	4.56	4.56	4.56	4.56	4.56	4.54
2022-23	Jan	4.59	4.55	4.33	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.54
2022-23	Feb	7.09	7.09	4.28	7.26	7.09	7.09	7.13	7.09	7.09	7.09	7.13	7.26	6.89
2022-23	Mar	4.20	4.20	4.17	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20
2022-23	Apr	4.07	4.07	4.06	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07
2022-23	May	3.99	3.99	3.94	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.98
2022-23	Jun	4.00	4.00	3.92	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	3.99
2022-23	Jul	4.01	4.01	3.96	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01
2022-23	Aug	4.03	4.03	4.02	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03
2022-23	Sep	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12
2022-23	Oct	4.19	4.19	4.19	4.19	4.19	4.19	4.19	4.19	4.19	4.19	4.19	4.19	4.19
		ALB	AST	COOS	DALO	DALW	EUG	NPT	PDX_C	PDX_E	PDX_W	SAL	VAN	System
2023-24	Annual	4.44	4.43	4.15	4.46	4.43	4.43	4.44	4.43	4.43	4.43	4.44	4.65	4.43
2023-24	Nov	4.26	4.26	4.13	4.26	4.26	4.26	4.26	4.26	4.26	4.26	4.26	4.26	4.25
2023-24	Dec	4.40	4.40	4.24	4.40	4.40	4.40	4.40	4.40	4.40	4.40	4.40	4.40	4.38
2023-24	Jan	4.45	4.41	4.29	4.41	4.41	4.41	4.41	4.41	4.41	4.41	4.41	4.41	4.41
2023-24	Feb	7.10	7.08	4.29	7.42	7.08	7.08	7.12	7.08	7.08	7.08	7.12	9.69	7.10
2023-24	Mar	4.33	4.33	4.31	4.33	4.33	4.33	4.33	4.33	4.33	4.33	4.33	4.33	4.33
2023-24	Apr	4.10	4.10	4.09	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10
2023-24	May	4.04	4.04	4.00	4.04	4.04	4.04	4.04	4.04	4.04	4.04	4.04	4.04	4.04
2023-24	Jun	4.04	4.04	3.99	4.04	4.04	4.04	4.04	4.04	4.04	4.04	4.04	4.04	4.04
2023-24	Jul	4.06	4.06	4.00	4.06	4.06	4.06	4.06	4.06	4.06	4.06	4.06	4.06	4.05
2023-24	Aug	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09
2023-24	Sep	4.16	4.16	4.16	4.16	4.16	4.16	4.16	4.16	4.16	4.16	4.16	4.16	4.16
2023-24	Oct	4.21	4.21	4.21	4.21	4.21	4.21	4.21	4.21	4.21	4.21	4.21	4.21	4.21
		ALB	AST	COOS	DALO	DALW	EUG	NPT	PDX_C	PDX_E	PDX_W	SAL	VAN	System
2024-25	Annual	4.87	4.86	4.57	4.89	4.86	4.86	4.87	4.86	4.86	4.86	4.87	4.88	4.85
2024-25	Nov	4.56	4.56	4.50	4.56	4.56	4.56	4.56	4.56	4.56	4.56	4.56	4.56	4.55
2024-25	Dec	4.66	4.66	4.53	4.66	4.66	4.66	4.66	4.66	4.66	4.66	4.66	4.66	4.65
2024-25	Jan	4.75	4.70	4.58	4.70	4.70	4.70	4.70	4.70	4.70	4.70	4.70	4.70	4.70
2024-25	Feb	7.68	7.63	4.66	7.96	7.63	7.63	7.71	7.63	7.63	7.63	7.71	7.79	7.44
2024-25	Mar	4.72	4.72	4.70	4.72	4.72	4.72	4.72	4.72	4.72	4.72	4.72	4.72	4.72
2024-25	Apr	4.55	4.55	4.54	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55
2024-25	May	4.53	4.53	4.47	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.52
2024-25	Jun	4.55	4.55	4.47	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.54
2024-25	Jul	4.56	4.56	4.50	4.56	4.56	4.56	4.56	4.56	4.56	4.56	4.56	4.56	4.56
2024-25	Aug	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60
2024-25	Sep	4.64	4.64	4.64	4.64	4.64	4.64	4.64	4.64	4.64	4.64	4.64	4.64	4.64
2024-25	Oct	4.69	4.69	4.69	4.69	4.69	4.69	4.69	4.69	4.69	4.69	4.69	4.69	4.69

		ALB	AST	COOS	DALO	DALW	EUG	NPT	PDX_C	PDX_E	PDX_W	SAL	VAN	System
2025-26	Annual	5.01	5.00	4.96	5.04	5.00	5.00	5.01	5.00	5.00	5.00	5.01	5.25	5.03
2025-26	Nov	4.99	4.99	4.93	4.99	4.99	4.99	4.99	4.99	4.99	4.99	4.99	4.99	4.99
2025-26	Dec	5.10	5.10	5.00	5.10	5.10	5.10	5.10	5.10	5.10	5.10	5.10	5.10	5.09
2025-26	Jan	5.20	5.16	5.11	5.16	5.16	5.16	5.16	5.16	5.16	5.16	5.16	5.16	5.16
2025-26	Feb	5.27	5.24	5.12	5.69	5.24	5.24	5.30	5.24	5.24	5.24	5.30	8.21	5.53
2025-26	Mar	5.14	5.14	5.13	5.14	5.14	5.14	5.14	5.14	5.14	5.14	5.14	5.14	5.14
2025-26	Apr	4.90	4.90	4.87	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.89
2025-26	May	4.87	4.87	4.82	4.87	4.87	4.87	4.87	4.87	4.87	4.87	4.87	4.87	4.87
2025-26	Jun	4.88	4.88	4.79	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.87
2025-26	Jul	4.90	4.90	4.86	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.89
2025-26	Aug	4.92	4.92	4.92	4.92	4.92	4.92	4.92	4.92	4.92	4.92	4.92	4.92	4.92
2025-26	Sep	4.97	4.97	4.97	4.97	4.97	4.97	4.97	4.97	4.97	4.97	4.97	4.97	4.97
2025-26	Oct	4.98	4.98	4.98	4.98	4.98	4.98	4.98	4.98	4.98	4.98	4.98	4.98	4.98
		ALB	**AST**	**COOS**	**DALO**	**DALW**	**EUG**	**NPT**	**PDX_C**	**PDX_E**	**PDX_W**	**SAL**	**VAN**	**System**
2026-27	Annual	5.19	5.18	5.12	5.46	5.44	5.18	5.19	5.18	5.18	5.18	5.19	5.20	5.23
2026-27	Nov	5.26	5.26	5.24	5.26	5.26	5.26	5.26	5.26	5.26	5.26	5.26	5.26	5.26
2026-27	Dec	5.37	5.37	5.25	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.36
2026-27	Jan	5.45	5.41	5.30	5.41	5.41	5.41	5.41	5.41	5.41	5.41	5.41	5.41	5.40
2026-27	Feb	5.63	5.60	5.33	8.84	8.71	5.60	5.65	5.60	5.60	5.60	5.65	5.74	6.13
2026-27	Mar	5.31	5.31	5.29	5.31	5.31	5.31	5.31	5.31	5.31	5.31	5.31	5.31	5.31
2026-27	Apr	5.06	5.06	5.04	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.05
2026-27	May	4.98	4.98	4.95	4.98	4.98	4.98	4.98	4.98	4.98	4.98	4.98	4.98	4.98
2026-27	Jun	4.99	4.99	4.91	4.99	4.99	4.99	4.99	4.99	4.99	4.99	4.99	4.99	4.99
2026-27	Jul	5.01	5.01	4.92	5.01	5.01	5.01	5.01	5.01	5.01	5.01	5.01	5.01	5.00
2026-27	Aug	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04
2026-27	Sep	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08	5.08
2026-27	Oct	5.11	5.11	5.11	5.11	5.11	5.11	5.11	5.11	5.11	5.11	5.11	5.11	5.11
		ALB	**AST**	**COOS**	**DALO**	**DALW**	**EUG**	**NPT**	**PDX_C**	**PDX_E**	**PDX_W**	**SAL**	**VAN**	**System**
2027-28	Annual	5.61	5.61	5.28	5.88	5.87	5.61	5.61	5.61	5.61	5.61	5.61	5.87	5.65
2027-28	Nov	5.29	5.29	5.26	5.29	5.29	5.29	5.29	5.29	5.29	5.29	5.29	5.29	5.29
2027-28	Dec	5.45	5.45	5.31	5.45	5.45	5.45	5.45	5.45	5.45	5.45	5.45	5.45	5.44
2027-28	Jan	5.58	5.53	5.41	5.53	5.53	5.53	5.53	5.53	5.53	5.53	5.53	5.53	5.52
2027-28	Feb	8.73	8.70	5.44	11.98	11.85	8.70	8.75	8.70	8.70	8.70	8.75	11.85	9.24
2027-28	Mar	5.43	5.43	5.40	5.43	5.43	5.43	5.43	5.43	5.43	5.43	5.43	5.43	5.42
2027-28	Apr	5.22	5.22	5.19	5.22	5.22	5.22	5.22	5.22	5.22	5.22	5.22	5.22	5.21
2027-28	May	5.20	5.20	5.13	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20
2027-28	Jun	5.22	5.22	5.11	5.22	5.22	5.22	5.22	5.22	5.22	5.22	5.22	5.22	5.21
2027-28	Jul	5.24	5.24	5.12	5.24	5.24	5.24	5.24	5.24	5.24	5.24	5.24	5.24	5.23
2027-28	Aug	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28
2027-28	Sep	5.35	5.35	5.35	5.35	5.35	5.35	5.35	5.35	5.35	5.35	5.35	5.35	5.35
2027-28	Oct	5.36	5.36	5.36	5.36	5.36	5.36	5.36	5.36	5.36	5.36	5.36	5.36	5.36

		ALB	AST	COOS	DALO	DALW	EUG	NPT	PDX_C	PDX_E	PDX_W	SAL	VAN	System
2028-29	Annual	5.79	5.78	5.44	5.80	6.06	5.78	5.78	5.78	5.78	5.78	5.78	5.79	5.78
2028-29	Nov	5.63	5.63	5.58	5.63	5.63	5.63	5.63	5.63	5.63	5.63	5.63	5.63	5.62
2028-29	Dec	5.78	5.78	5.65	5.78	5.78	5.78	5.78	5.78	5.78	5.78	5.78	5.78	5.77
2028-29	Jan	5.87	5.82	5.69	5.82	5.82	5.82	5.82	5.82	5.82	5.82	5.82	5.82	5.81
2028-29	Feb	9.32	9.29	5.77	9.54	12.71	9.29	9.35	9.29	9.29	9.29	9.35	9.42	9.33
2028-29	Mar	5.67	5.67	5.66	5.67	5.67	5.67	5.67	5.67	5.67	5.67	5.67	5.67	5.66
2028-29	Apr	5.39	5.39	5.36	5.39	5.39	5.39	5.39	5.39	5.39	5.39	5.39	5.39	5.39
2028-29	May	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25
2028-29	Jun	5.26	5.26	5.17	5.26	5.26	5.26	5.26	5.26	5.26	5.26	5.26	5.26	5.25
2028-29	Jul	5.28	5.28	5.14	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.27
2028-29	Aug	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30
2028-29	Sep	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33
2028-29	Oct	5.37	5.37	5.34	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.36

		ALB	AST	COOS	DALO	DALW	EUG	NPT	PDX_C	PDX_E	PDX_W	SAL	VAN	System
2029-30	Annual	5.72	5.71	5.34	5.73	5.72	5.71	5.72	5.71	5.71	5.71	5.72	6.01	5.71
2029-30	Nov	5.66	5.66	5.62	5.66	5.66	5.66	5.66	5.66	5.66	5.66	5.66	5.66	5.65
2029-30	Dec	5.91	5.91	5.78	5.91	5.91	5.91	5.91	5.91	5.91	5.91	5.91	5.91	5.90
2029-30	Jan	5.97	5.92	5.56	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.90
2029-30	Feb	9.39	9.36	5.67	9.60	9.48	9.36	9.42	9.36	9.36	9.36	9.42	12.95	9.39
2029-30	Mar	5.54	5.54	5.48	5.54	5.54	5.54	5.54	5.54	5.54	5.54	5.54	5.54	5.54
2029-30	Apr	5.27	5.27	5.22	5.27	5.27	5.27	5.27	5.27	5.27	5.27	5.27	5.27	5.27
2029-30	May	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07
2029-30	Jun	5.09	5.09	5.03	5.09	5.09	5.09	5.09	5.09	5.09	5.09	5.09	5.09	5.08
2029-30	Jul	5.11	5.11	5.10	5.11	5.11	5.11	5.11	5.11	5.11	5.11	5.11	5.11	5.11
2029-30	Aug	5.13	5.13	5.12	5.13	5.13	5.13	5.13	5.13	5.13	5.13	5.13	5.13	5.13
2029-30	Sep	5.22	5.22	5.22	5.22	5.22	5.22	5.22	5.22	5.22	5.22	5.22	5.22	5.22
2029-30	Oct	5.27	5.27	5.27	5.27	5.27	5.27	5.27	5.27	5.27	5.27	5.27	5.27	5.27

		ALB	AST	COOS	DALO	DALW	EUG	NPT	PDX_C	PDX_E	PDX_W	SAL	VAN	System
2030-31	Annual	5.51	5.50	5.43	5.82	5.81	5.50	5.51	5.50	5.50	5.50	5.51	5.81	5.57
2030-31	Nov	5.54	5.54	5.49	5.54	5.54	5.54	5.54	5.54	5.54	5.54	5.54	5.54	5.54
2030-31	Dec	5.75	5.75	5.61	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.73
2030-31	Jan	5.85	5.79	5.66	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79
2030-31	Feb	5.94	5.91	5.69	9.79	9.67	5.91	5.97	5.91	5.91	5.91	5.97	9.67	6.85
2030-31	Mar	5.53	5.53	5.45	5.53	5.53	5.53	5.53	5.53	5.53	5.53	5.53	5.53	5.53
2030-31	Apr	5.33	5.33	5.27	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.32
2030-31	May	5.28	5.28	5.24	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28
2030-31	Jun	5.31	5.31	5.24	5.31	5.31	5.31	5.31	5.31	5.31	5.31	5.31	5.31	5.30
2030-31	Jul	5.33	5.33	5.30	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.32
2030-31	Aug	5.35	5.35	5.32	5.35	5.35	5.35	5.35	5.35	5.35	5.35	5.35	5.35	5.35
2030-31	Sep	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40
2030-31	Oct	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48

		ALB	AST	COOS	DALO	DALW	EUG	NPT	PDX_C	PDX_E	PDX_W	SAL	VAN	System
2031-32	Annual	5.73	5.72	5.67	5.74	6.04	5.72	5.73	5.72	5.72	5.72	5.73	6.04	5.77
2031-32	Nov	5.80	5.80	5.76	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80
2031-32	Dec	6.10	6.10	5.95	6.10	6.10	6.10	6.10	6.10	6.10	6.10	6.10	6.10	6.08
2031-32	Jan	6.21	6.15	6.01	6.15	6.15	6.15	6.15	6.15	6.15	6.15	6.15	6.15	6.15
2031-32	Feb	6.19	6.12	6.05	6.36	9.94	6.12	6.22	6.15	6.15	6.15	6.22	9.94	6.80
2031-32	Mar	5.83	5.83	5.77	5.83	5.83	5.83	5.83	5.83	5.83	5.83	5.83	5.83	5.83
2031-32	Apr	5.56	5.56	5.51	5.56	5.56	5.56	5.56	5.56	5.56	5.56	5.56	5.56	5.56
2031-32	May	5.44	5.44	5.44	5.44	5.44	5.44	5.44	5.44	5.44	5.44	5.44	5.44	5.44
2031-32	Jun	5.46	5.46	5.44	5.46	5.46	5.46	5.46	5.46	5.46	5.46	5.46	5.46	5.46
2031-32	Jul	5.49	5.49	5.43	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.48
2031-32	Aug	5.51	5.51	5.47	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.50
2031-32	Sep	5.56	5.56	5.56	5.56	5.56	5.56	5.56	5.56	5.56	5.56	5.56	5.56	5.56
2031-32	Oct	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60
		ALB	**AST**	**COOS**	**DALO**	**DALW**	**EUG**	**NPT**	**PDX_C**	**PDX_E**	**PDX_W**	**SAL**	**VAN**	**System**
2032-33	Annual	6.03	6.02	5.95	6.37	6.36	6.36	6.03	6.02	6.02	6.02	6.03	6.03	6.10
2032-33	Nov	6.03	6.03	5.98	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.02
2032-33	Dec	6.42	6.42	6.28	6.42	6.42	6.42	6.42	6.42	6.42	6.42	6.42	6.42	6.41
2032-33	Jan	6.55	6.46	6.33	6.46	6.46	6.46	6.46	6.46	6.46	6.46	6.46	6.46	6.46
2032-33	Feb	6.55	6.48	6.41	10.74	10.62	10.62	6.58	6.51	6.51	6.51	6.58	6.57	7.56
2032-33	Mar	6.02	6.02	5.97	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.01
2032-33	Apr	5.81	5.81	5.72	5.81	5.81	5.81	5.81	5.81	5.81	5.81	5.81	5.81	5.80
2032-33	May	5.76	5.76	5.66	5.76	5.76	5.76	5.76	5.76	5.76	5.76	5.76	5.76	5.75
2032-33	Jun	5.77	5.77	5.66	5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.76
2032-33	Jul	5.81	5.81	5.74	5.81	5.81	5.81	5.81	5.81	5.81	5.81	5.81	5.81	5.80
2032-33	Aug	5.83	5.83	5.79	5.83	5.83	5.83	5.83	5.83	5.83	5.83	5.83	5.83	5.83
2032-33	Sep	5.89	5.89	5.89	5.89	5.89	5.89	5.89	5.89	5.89	5.89	5.89	5.89	5.89
2032-33	Oct	5.95	5.95	5.95	5.95	5.95	5.95	5.95	5.95	5.95	5.95	5.95	5.95	5.95

Appendix 9: Public Participation

NW Natural®

NW Natural –2014 Integrated Resource Plan (IRP)
August 22, 2013

NAME - please print	Company	Email
Catriona McCracken	CUB	Catriona@oregoncub.org
Ben Hemson	NW Gas Assoc.	BHemson@NWGA.org
Nadine Hanhan	CUB	Nadine@oregoncub.org
Dave Lenar	NWN	DPL@nwnatural.com
Steve Storm	NWN	steve.storm@nwnatural.com
Mark Thompson	Forefront Economics	mark@forecon.com
Nancy Lange	NWN	nancy.lange@nwnatural.com
Teresa Hagins	Northwest Pipeline	Teresa.L.Hagins@williams.com
David Nightingale	WUTC	dnightin@utc.wa.gov
Jaime McGovern		
Ted Light	ETO	ted.light@energytrust.org
Elaine Prause	Energy Trust	elaine.prause@energytrust.org

On Phone:
Steve Simmons NWPPC
Mark Sellers-Vaughn Cascade Nat'l Gas.

NW Natural –2014 Integrated Resource Plan (IRP)
October 2, 2013

NAME - please print	Company	Email
Teresa Hagins	williams-northwest Pipeline	Teresa.L.Hagins@williams.com.
Kelly Irvine	Avista	Kelly.Irvine@avistacorp.com
Nadine Hanhan	CUB	Nadine@oregoncub.org
Catriona McCracken	CUB	Catriona@oregoncub.org
Bob Jenks	CUB	bob@oregoncub.org
Ben Hemson	NWGA	BHemson@NWGA.org
Dan Kirschner	NWGA	dkirschner@nwga.org
Linda Chang	NW Natural	linda.chang@nwnatural.com
Glenn Carlson	NW NATURAL	gcc@nwnatural.com
Chris McGuire	WUTC	cmcguire@utc.wa.gov
Brad Cebulko	WUTC	bcebulko@utc.wa.gov
Jorge Ordonez	OPUC	Jorge.Ordonez@state.or.us.
Ed Finklea	NWIGU	efinklea@nwigu.org
Wendy Gerlitz	NWEC	wendy@nwenergy.org
Randy Friedman	NWN	randy.friedman@nwnatural.com
On phone:		
Lisa Gorsuch, OPUC		
David Nightingale, WUTC		

NW Natural –2014 Integrated Resource Plan (IRP) Scenario Workshop
November 22, 2013

NAME - please print	Company	Email
Tami S. Linver	NW Nat'l	TSL@nwnatural.com
Keith White	NW Natural	jkw@nwnatural.com
Steve Storm	NW Natural	steve.storm@nwnatural.com
Dave Lenw	NW Natural	DPL@nwnatural.com
STEVE NELSON	NW NATURAL	sen@nwnatural.com
Nancy Lange	NW Natural	nll@nwnatural.com
Catriona McCracken	~~CUB~~ CUB	Catriona@oregoncub.org
Jason Jones	DOJ	jason.w.jones@state.or.us
Ryan Bracken	OPUC	ryan.bracken@state.or.us
Brad Cebulko	WUTC	bcebulko@utc.wa.gov.
Chris McGuire	WUTC	cmcguire@utc.wa.gov
Ted Light	Energy Trust	ted.light@energytrust.org
ADAM SHICK	ENERGY TRUST	adam.shick@energytrust.org
Nadine Hanhan	CUB	Nadine@oregoncub.org
SOMMER TEMPLET	CUB	Sommer@oregoncub.org
Ed Finklea	NWIGU	efinklea@nwigu.org
Bill Edmonds	NWN	wre@nwnatural.com
Mark Thompson	ForeFront Economics	mark@forecon.com
Dan Kirschner	NW Gas Assoc.	dkirschner@nwga.org

NW Natural –2014 Integrated Resource Plan (IRP) Scenario Workshop
January 23, 2014

NAME - please print	Company	Email
Steve Storm	NW Natural	steve.storm@nwnatural.com
Dave Lenar	NWN	dple@nwnatural.com
Jennifer Gross	NWN	jas@nwnatural.c
Ryan Bracken	~~NWN~~ OPUC Staff	ryan.bracken@state.or.us
Jorge Ordonez	OPUC Staff	jorge.ordonez@state.or.us
LISA GORSUCH (503)378-3778	OREGON PUC STAFF	lisa.gorsuch@state.or.us
Ted Light	ETO	ted.light@energytrust.org
Adam Shick	ETO	adam.shick@energytrust.org
Elaine Prause	ETO	elaine.prause@energytrust.org
Tommy Brooks	CABLE HUSTON/NWIGU	tbrooks@cablehuston.com
Nadine Hanhan	CUB	Nadine@oregoncub.org
Teresa Hagins	Northwest Pipeline	Teresa.L.Hagins@williams.com
Mark Thompson	Forefront Economics	mark@forecon.com
Ben Hemson	NW GAS ASSOC.	BHemson@NWGA.org
Brad Cebulko	WUTC	bcebulko@utc.wa.gov
Chris McGuire	WUTC	cmcguire@utc.wa.gov
GARY BAUER	NWN	
Jon Huddleston	NWN	jon.huddleston@nwnatural.com
STEVE NELSON	NWN	sen@nwnatural.com
Glenn Carlson	NWN	gcc@nwnatural
Bill Edmonds	NWN	wke
Joshua Skov	consultant	joshua.skov@gmail.com
[illegible]	NW Natural	
Randy Friedman	NWN	randy.friedman@nwnatural.com
Keith White	NWN	jkw@nwnatural.com

NW Natural –2014 Integrated Resource Plan (IRP) Scenario Workshop
March 7, 2014

NAME - please print	Company	Email
Nadine Hanhan	CUB	Nadine@oregoncub.org
Kelly Fukai	Avista	Kelly.Fukai@avistacorp.com
Teresa Hagins	Williams - NWP	Teresa.L.Hagins@williams.com
Jon Huddleston	NWN	jon.huddleston@nwnatural.com
Nancy Lange	NWN	nancy.lange@nwnatural.com
Brad Cebulko	WUTC	bcebulko@utc.wa.gov
Glenn Carlson	NWN	gcc@nwnatural.com
Ed Finklea	NWIGU	efinklea@nwigu.org
STEVE NELSON	NWNATURAL	sen@nwnatural.com
Sommer Templet	CUB	sommer@oregoncub.org
STEVE HARPER	AVISTA	steve.harper@avistacorp.com
LISA GORSUCH	OREGON PUC STAFF	lisa.gorsuch@state.or.us
Jennifer Gross	NWN	jag@nwnatural.com
Devin Gilbert	NWN	Devin.Gilbert@nwnatural.com
Tammy S. Linver	NWN	tsl@nwnatural.com
Dave Lang	NWN	DPL@nwnatural.com
Steve Storm	NWN	steve.storm@nwnatural.com
Ryan Bracken	OPUC	ryan.bracken@state.or.us
Aster Adams	OPUC	aster.adams@state.or.us
Keith White	NWN	jkw@nwnatural.com

NW Natural –2014 Integrated Resource Plan (IRP) TWG
April 3, 2014

NAME - please print	Company	Email
Kelly Fukai	Avista	kelly.fukai@avistacorp.com
Dave Lenon	NWN	dxl@nwnatural.com
Devin Gilbert	NWN	drg@nwnatural.com
Sara Althoff	CUB	sarah.k.althoff@gmail.com
Teresa Hagins	Williams - NWP	Teresa.L.Hagins@williams.com
Jon Huddleston	NWN	jon.huddleston@nwnatural.com
Sommer Templet	CUB	sommer@oregoncub.org
Mark Thompson	NWN	mrt@nwnatural.com
Ed Finklea	NWIGU	efinklea@nwigu.org
Nadine Hanhan	CUB	Nadine@oregoncub.org
Barbara Summers	NWN	barbara.summers@nwnatural.com
Randy Friedman	NWN	randy.friedman@nwnatural.com
Ryan Bracken	OPUC	ryan.bracken@state.or.us
Brad Cebulko	WUTC	bcebulko@utc.wa.gov
LISA GORSUCH	OPUC	lisa.gorsuch@state.or.us
Elaine Prause	ETO	elaine.prause@energytrust.org

NW Natural
2014 IRP Technical Working Group Meeting
July 11, 2014

NAME - please print	Company	Email
Jason Jones	DOJ	jason.w.jones@state.or.us
LISA GORSUCH	OPUC	lisa.gorsuch@state.or.us
Teresa Hagins	Northwest Pipeline	Teresa.L.Hagins@williams.com
Nadine Hanhan	CUB	Nadine@oregoncub.org
Ed Finklea	NWIGU	efinklea@nwigu.org
Randy Friedman	NWN	randy.friedman@nwnatural.com
Andrew Speer	NWN	Andrew.Speer@nwnatural.com
Steve Storm	NWN	Steve.Storm@nwnatural.com
Dave Lener	NWN	dpl@nwnatural.com
Ron Gullberg	Willbros	Ron.Gullberg@willbros.com
Ben Hemson	NW Gas Assoc.	BHemson@NWGA.org
[illegible]	NWN	[illegible]@nwnatural.com
Keith White	NWN	jkw@nwnatural.com
On Phone:		
Brad Cebulko - WUTC Staff		
Erik Colville - OPUC Staff		
Lynn Dahlberg - Williams		

NW Natural –2014 Integrated Resource Plan (IRP) Public Meeting
April 15, 2014 – 6 p.m. – Hospitality Center

NAME - please print	Company	Email
JOHN DUNZER	COLUMBIA BIOENERGY	JOHNDUNZER@MSN.COM
BILL STALLMAN	PUBLIC ADVOCATE CNG	stallmanbill@yahoo.com
Randy Friedman	NWN	randy.friedman@nwnatural.com
Dave Lear	NWN	dpl@nwnatural.com
Steve Stearns	NWN	steve.stearns@nwnatural.com

NW NATURAL'S 2014 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: April 15, 2014
Time: 6 p.m. to 7 p.m.
Place: One Pacific Square, 4th Floor Hospitality Room Center
220 NW Second Avenue, Portland, Oregon
(accessible by MAX)

Unable to Attend?

We can email a PowerPoint presentation to you.
Send your email request to IRPlan@nwnatural.com.

NW Natural®
We grew up here.

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 2014 Integrated Resource Plan will be available on our website after March 3, 2014. Go to **nwnatural.com**. Click on the *About Us* link, then click on *Rates and Regulations*, then click on *Regulatory Affairs*. Toward the bottom half of the page is a link for the *Integrated Resource Plan*.

Notes... TO: NW Natural
From Esther D. Lewis
2730 NE 77th Pl. 97213

I have several younger friends who live in rentals. I think you should push landlords to insulate and add stormwindows to their properties - not to mention more efficient heating systems — Many of them should be ashamed of their properties.
But what kind of push it will take I have not yet figured out - That's your professional JOB — Good Luck!

April 28, 2014

NW Natural
220 NW Second Avenue
Portland, Oregon 97209
Attn :Integrated Resource Plan

Dear Gas Co.

I live in Seaside and am one of your customers. Just like you are I am interested in an ample supply at a reasonable cost of natural gas for my household hot water, space heating and gas generated electricity. Hopefully someday gas will power my vehicles. Thank you for your invitation to your 2014 IRP meeting on April 15th.

In reading your plan, I see that there are supply problems. There is ample gas thanks to fracking but not enough pipelines to get it to us in a reliable manner. Many Oregonians are fighting expansion of fossil fuel pipelines like your proposed Cross Cascades project and I don't believe you should put all our eggs in this basket. The WEX project may also never see the light of day.

You state that you are looking for the next least costly way to achieve increased natural gas supplies to Oregon. Also in terms of desirability it should be DOMESTIC NON FRACKED gas to eliminate other objections. Before you laugh, you should open up the box of imported LNG. Yes I said the bad word of LNG but hear me out. First I am talking imported LNG from the Kenai Penisula of Alaska. Anchorage does not have an adequate future supply of natural gas and they are planning the construction of a "bullet line" from north of Fairbanks to Anchorage. In order to make economic sense they need a large customer which could be Oregon. They have an existing LNG facility that is mothballed. They say they will supply gas at the Henry Hub price.

The balance of such a project is contained in the attached project description which involves the sequestration of green house gases from Port Westward so that Oregon can meet its 2020 goals which are highly supported by the Oregon public and are now not obtainable per the State. This project will work and it will be economical and it would solve our supply problem. I have had the feasibility studied by Northwest Federal Labs at the tri-cities. Note Port Westward is in Columbia County which is open to this type of development not Clatsop County.

Second is the need for more storage. Out here on the North Coast we are putting together a mitigation plan for the Cascadia Earthquake and Tsunami. Since the State says that we will be without electrical power for 6 months we are supporting a distributed power generation facility to be located in our area. There is no reason that the NorthCoast shouldn't have a co-located LNG storage facility like the one Northwest has in Newport.

Please call me John Dunzer 503 738-6885 johndunzer@msn.com

May 1, 2013

To: Lisa Schwartz and Bill Drumheller, OR Dept of Energy
Margie Hoffmann, Governor's Energy Policy Advisor
Susan Ackerman, Chair OR Public Utilities Commission
Gary Josephson, Pacific Northwest National Laboratory

From: John Dunzer CEO Columbia Bioenergy LLC

Subject:
PLAN TO ECONOMICALLY MEET OREGON GREENHOUSE GAS GOALS THROUGH CO2 CAPTURE AT PGE'S PORT WESTWARD POWER PLANTS AND SEQUESTRATION/GAS FIELD ENHANCEMENT AT KENAI ALASKA

The State of Oregon has adopted greenhouse gas reduction goals for 2020, 2035 and 2050. These goals are tied to reducing Oregon's CO2 emissions a percentage (2020-10%, 2035-40%, 2050-75%) below1990 levels. Oregon has grown in population since 1990 and will continue to grow as will its CO2 emissions unless changes are made. The Oregon 10 year energy action plan has adopted a strategy of dealing with stopping CO2 growth through a program of energy conservation and increased energy efficiency. To meet actual CO2 reduction to and below 1990 levels other major actions must be taken.

Despite significant hydropower resources, Oregon's electricity production is a major source of CO2 emissions generating in-state over 8 million tons of CO2 per year. The Oregon Public Utilities Commission (OPUC) prepares a report every two years identifying the utilities' plan for reducing CO2 to meet state goals. The most recent OPUC report (GHG Reduction Goal Rate Impact Report) was issued just 6 months ago on November 1, 2012.

The utilities plan to eliminate the use of coal to generate electrical power for instate usage by 2020. Replacement power will come from wind power and new natural gas power plants. Electrical rate increases to pay for these changes are projected to be upwards of 30%. The report is silent on how further CO2 reductions required to meet 2035 and 2050 state goals could be achieved.

Recently Oregon commissioned a report which dealt with the costs of a wide variety of CO2 reduction actions. One of the four sectors considered was electrical power generation. 26 mitigation actions were considered of which 17 were using renewable fuels, 4 were advanced fossil fuel designs, 2 were nuclear, and the remaining 3 were modifications to the electrical grid. The use of renewable fuels like wind as planned by the utilities as replacements for coal elimination scored poorly on the cost-effectiveness scale. This lack of cost effectiveness as well as the reduction by Oregon of financial incentives for wind projects requires additional analysis of the planning of utility CO2 reduction strategies.

The technology of CO2 capture from industrial plant emissions has been in use for over 60 years. As the atmospheric impacts of CO2 emissions (global warming) have been better understood in the last few years, a major research area has evolved to identify the potential for CO2 capture and storage (CCS) from high emitting stationary sources such as fossil fueled power plants. Five years ago, The Northwest Power & Conservation Council studied the use of CCS and found that under specific conditions it is economically feasible. This plan suggests that these specific conditions can be created by modifying the following existing equipment:

- the PGE natural gas fired power plants at Port Westward
- the presently underused Kenai Alaska natural gas facilities
- a conventionally sized CO2 tanker

This will allow Oregon to meet many of its CO2 reduction goals without the major rate increases that are presently projected.

The proposed system hinges on a CCS systems approach entitled "Cryogenic CO2 Capture Using Cold Energy from LNG". Figure 1, from the French firm GDF SUEZ, illustrates the principle of this technology.

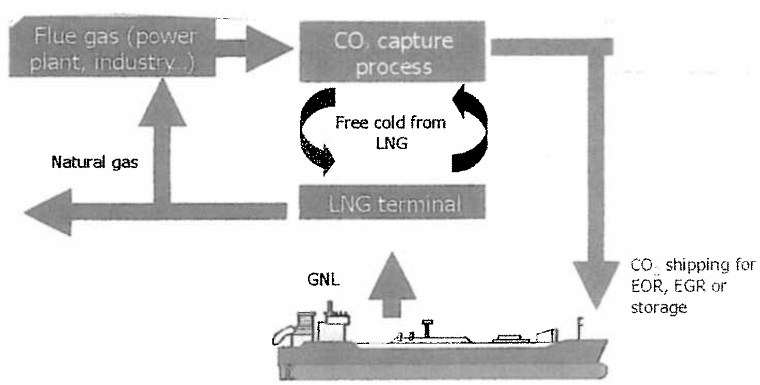
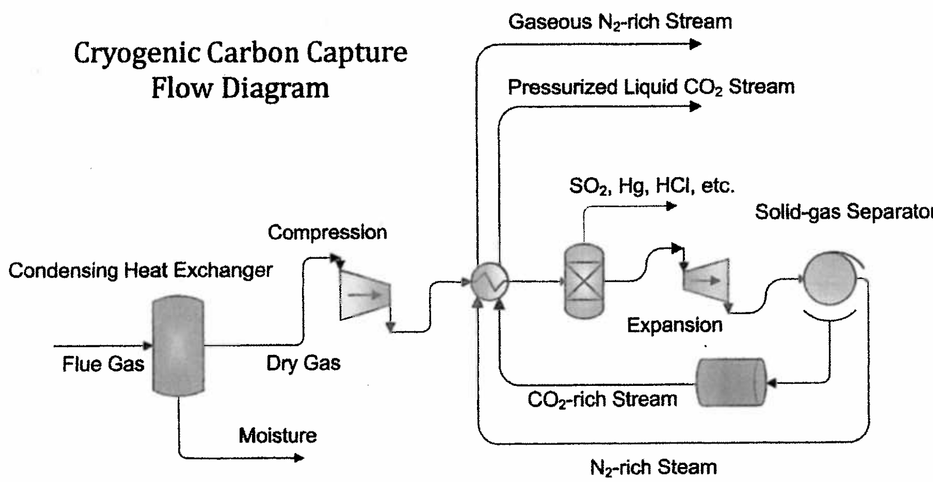


Figure 1 : The principle of the CO_2 capture using cold from LNG

This technology uses the cold energy released during LNG re-gasification process to freeze out and then liquefy the CO2 from power plant flue gases. The Canadian agency, Climate Change and Emissions Management, has selected the cryogenic capture technology of a US firm, Sustainable Energy Solutions for funding. Figure 2 illustrates The fundamentals of Cryogenic Capture Technology.

Cryogenic Carbon Capture (CCC) is a patent pending process developed by Dr. Larry Baxter at Brigham Young University. It is designed to separate a nearly pure stream of CO_2 from power plant flue gas. The CCC process is applied post combustion and is suitable for retrofitting existing power plants..



Process Description

The Cryogenic Carbon Capture (CCC) process dries and cools a flue gas stream, modestly compresses it, and cools it to slightly above the frost point of CO_2. The gas is then expanded, further cooling the stream and precipitating solid CO_2. The solid CO2 is separated from the flue gas and the pure CO_2 stream is pressurized. The cooled CO_2 and N_2 streams are then used in a heat exchanger to cool incoming flue gas. The final result is the CO_2 in a liquid phase and a gaseous nitrogen stream.

Figure 2 : Cryogenic Carbon Capture

To further improve the energy requirements of this capture technology and reduce its costs (now projected at $33 per ton of CO2) it is proposed that a hybrid process be utilized. The hybrid process would use as a first step a membrane to initially concentrate CO2 in the flue emissions to 40% which will maximizes the efficiency of the cryogenic capture process ($25 per ton of CO2).

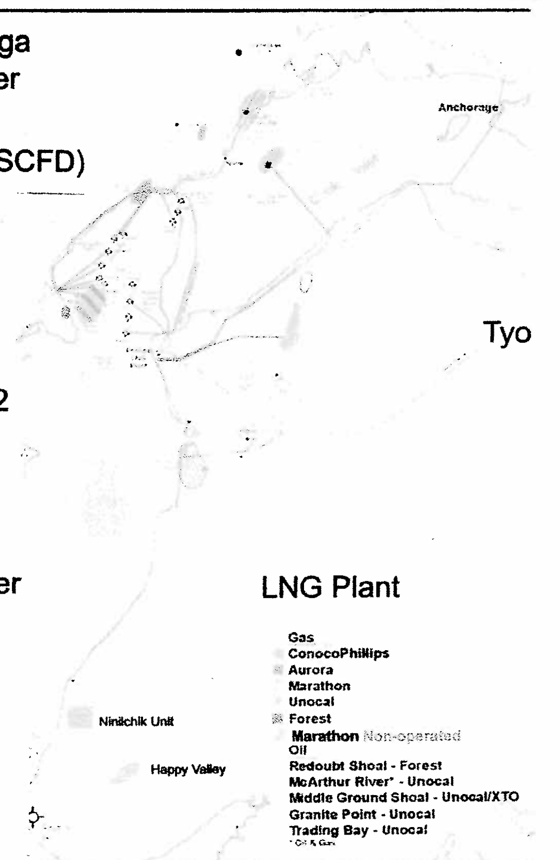
It would be desirable to store the captured CO2 near the Port Westward power plants. Historically the most cost effective CO2 storage method is its use to enhance fossil fuel production. Oregon (Mist is used for natural gas storage) and Washington have no fossil fuel reservoirs to enhance with CO2 injection. The Kenai gas field in the Cook inlet near Anchorage Alaska, a short sea voyage from Port Westward is such a reservoir. Figure 3 is a brief description of this field. The field is used to supplement winter energy supplies for the local area but the bulk of its capability has been mothballed because its Asian customers have switched after 41 years to suppliers capable of larger deliveries. Alaskans worry that the availability of their natural gas will be crippled because of field flooding and lack of investment incentive on the part of oil company owners.

Kenai LNG Plant - 1969
- 70% COP, 30% Marathon
- 1.3 million tons per year capacity (~240 MMSCFD)
- Currently a 1-ship operation
- Export license ends March 2011

North Cook Inlet Unit (NCIU) – 1969
- 100 % COP
- Produced from Tyonek Platform (16 wells, 12 producing), 40 mile pipeline to LNG plant
- 50-60 MMSCFD gross production

Beluga River Unit (BRU) – 1968
- 33% COP (Chevron, Municipal Light & Power 33%)
- Onshore operation (19 wells, 12 producing)
- 100 – 120 mmscfd gross production

Customers
- LNG – Tokyo Electric and Tokyo Gas
- Local sales primarily to Enstar and Chugach



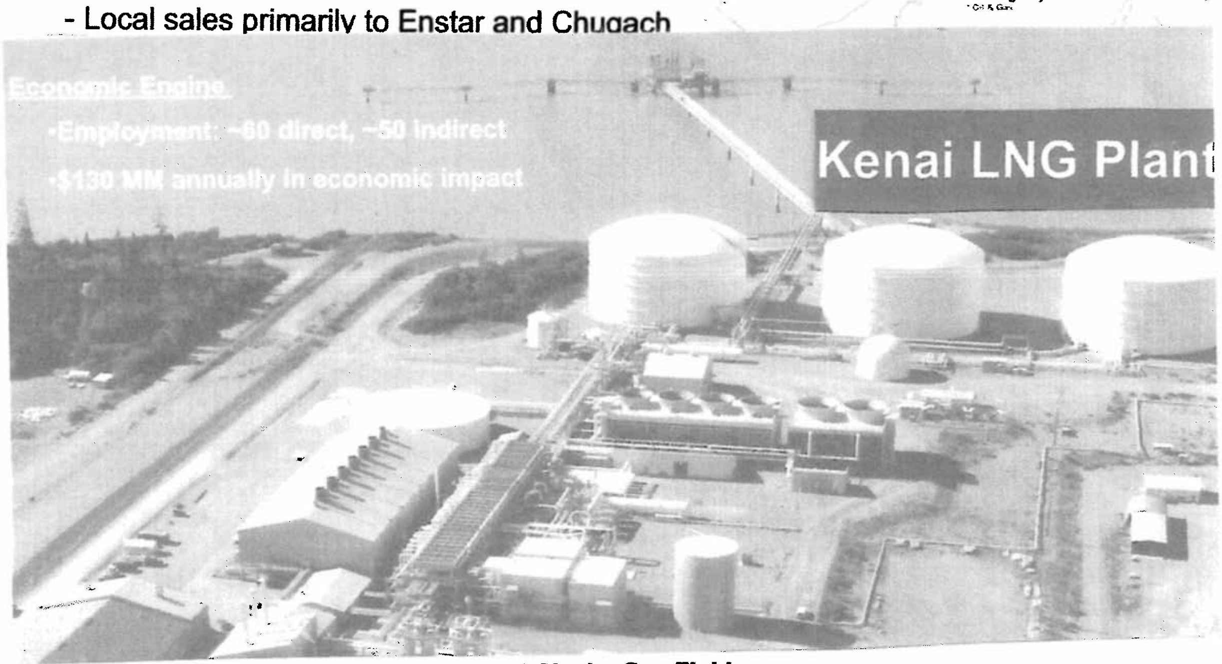


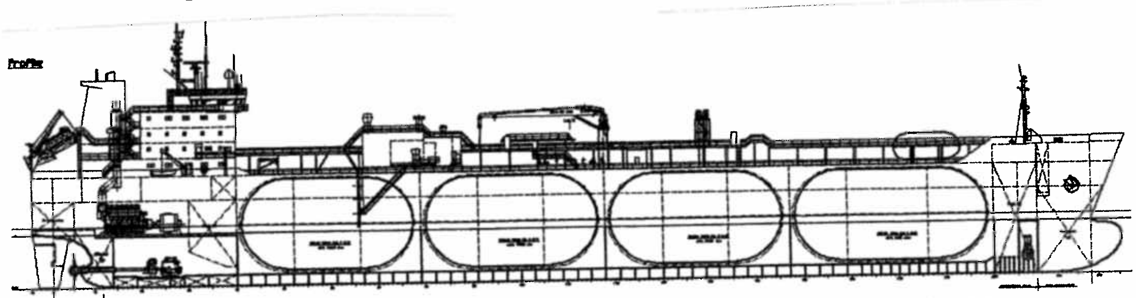
Figure 3 : Kenai Alaska Gas Field

Oregon now has available a significant amount of natural gas primarily as a result of the use of fracking technology in Rocky Mountain shale fields. It is expected that investment in new pipelines will be required from these areas and these projects as well as fracking face major public opposition. The Port Westward power plants are major consumers of natural gas and are supplied from pipelines under the Columbia River. Recently, concern has been raised about the vulnerability of these natural gas pipelines due to a Cascadia 9.0 earthquake forecasted to occur during the next 50 years. The direct shipment of natural gas to Port Westward by ship from the existing unused LNG terminal at Kenai would be a very desirable solution to earthquake resilience.

Piped in domestic fracked natural gas is now an economical supply for Oregon. Natural gas shipped from Alaska will also be competitively priced because of the following factors:

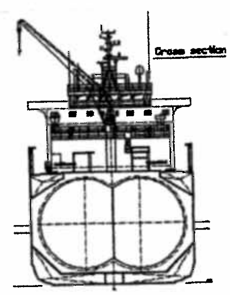
- cost of production will be low because the entire production system (wells, distribution lines and LNG plant) has been fully amortized.
- The free cold energy extracted from the LNG can be utilized for carbon capture reducing capture costs well below the projected $25 per ton of CO_2.
- Ship refueling facilities(new ships will run on LNG not oil) could be established at Port Westward which would use this supply.
- No need to rebuild the supply pipeline for earthquake potential

One of the key elements is the cost of sea transportation. It is proposed that the tanker that was previously discussed for transporting the CO_2 to Alaska for sequestration be modified to also ship LNG on its return voyage. CO_2 tankers have cryogenic tanks capable of being easily modified to carry LNG or CO_2. This joint ship usage would cut transportation costs for CO_2 and LNG in half. A standard sized 30,000 cu mt CO_2 vessel making one round trip a week would provide the capacity to achieve these goals. Figure 4 is a pictorial of such a ship.



lbp = 175.2 m
b = 27.6 m
d = 8.8 m
speed = 17.5 kn

Figure 4 : 30,000 cu.mt. CO2/LNG Tanker



The Oregon Public Utilities Commission has permitted Northwest Natural Gas to use Oregon customer charges to pay for its investment in Wyoming gas fracking facilities. It would not be a stretch for PGE to invest in the purchase of an interest in the Alaskan gas field and the dedicated vessel and the modifications necessary to execute this plan. Oregon electric companies and consumers have a long history of funding environmental improvements as described by Figure 5.

Choose the Blue Sky option that's right for you.

	Additional cost	Monthly renewable energy commitment	Source	*Environmental benefits
Block	$1.95 for each 100-kilowatt-hour block of wind energy	Flexible: You can purchase as many blocks as you want	Block purchase supports 100% wind from the Western region. Participation may also help fund new community-based renewable energy projects that can support other certified resources such as solar, geothermal, low-impact hydro, wave or tidal action or low emissions biomass	It's like not driving a car nearly 1,518 miles when you buy one block per month for a year
Usage	This option costs an additional $0.0105 per kwh – about $8-10 per month for a typical Oregon customer	100% of your energy use	Blend of 100% Pacific Northwest renewable resources from Oregon, Washington and Idaho.** In 2013, the resource mix is likely to include wind (70%) and biomass (30%)	It's like not driving a car for each year you are enrolled
Habitat	Same as the Usage option, PLUS $2.50 donation to restore and preserve habitats for native fish including salmon in Oregon through the nonprofit called The Freshwater Trust.	100% of your energy use	Blend of 100% Pacific Northwest renewable resources from Oregon, Washington and Idaho.** In 2013, the resource mix is likely to include wind (70%) and biomass (30%)	It's like not driving a car for each year you are enrolled Plus habitat restoration and preservation

New, lower costs for Usage and Habitat options.

For more information, visit **pacificpower.net/bluesky** or call **1-800-769-3717.**

When you enroll, Pacific Power purchases renewable energy certificates from newly developed renewable energy facilities on your behalf. This helps renewable energy facilities and allows you to green your own electricity use. For every unit of renewable electricity generated, an equivalent amount of renewable energy certificates are produced. The purchase also helps build a market for renewable electricity and may have other local and global environmental benefits. For more information about RECs, please visit pacificpower.net/bluesky or green-e.org.

Energy CERTIFIED

Figure 5 : Consumer Funding Program

August 14, 2013

Oregon Senator Ron Wyden, Chair Senate Energy and Natural Resources Committee

Alaska Senator Lisa Murkowski, Ranking Republican Senate Energy and Natural Resources Committee

Subject: A Program You Could Support

Attachment : PLAN TO MEET OREGON GREENHOUSE GAS GOALS THROUGH CO2 CAPTURE AT PGE'S PORT WESTWARD POWER PLANTS AND SEQUESTRATION AT KENAI ALASKA -MAY 2013

In a July 28th article in the Oregonian it was mentioned that during an August 2012 joint trip to Alaska, Senator Wyden assured Senator Murkowski that "his opposition to LNG gas export terminals in the Northwest didn't extend to a longstanding facility in Alaska. I have just returned from visiting the Anchorage home office of ConocoPhillips Alaska Inc. This is the firm who owns the now idled LNG export facility on the Kenai Peninsula. The Cook Inlet gas field which supplied the export gas is now running short of gas endangering the amount needed for providing a local supply for Southwestern Alaska. Natural gas supplies from Northern Alaska do not have market access. From an Alaskan viewpoint it is necessary to find an economical solution that will bring northern Alaskan gas to the Anchorage area. The proposed bullet natural gas pipeline project or an off-shoot of a larger gas pipeline can be economical if demand is increased by opening the shuttered fertilizer plant as well as using the Kenai LNG plant for export.

The gas exported from Alaska should go to Port Westward on the Columbia River in Oregon for use in their three gas fired generating stations. Gas for these PGE electrical plants presently comes from an existing gas pipeline from Canada. The Pacific Northwest National Labs has determined that it is feasible to load a modified LNG tanker with liquefied greenhouse gases captured from power plant emissions. By back loading the tanker, transportation costs become reasonable making the cost of the natural gas delivered to Port Westward competitive to PGE existing pipeline gas costs. The back loaded greenhouse gas will be shipped to Alaska to be sequestered in the Kenai Gas Field and will also result in enhanced future gas recovery from this field. Much of the injection wells and piping systems already exist for greenhouse gas sequestration at Kenai.

So what we have for Alaskans is a medium sized LNG/CO2 tanker making once a week round trip sailings between Port Westward Oregon and Kenai Alaska. The bullet gas line to Anchorage becomes economically feasible assuring Alaskans an adequate supply of natural gas as well as good jobs at the existing Fertilizer Plant and LNG facility. The Alaskan Dept of Geology has already confirmed that there is existing storage capability at the Cook Inlet Fields to handle greenhouse gas sequestration for the Oregon power plants as well as from the an operating Fertilizer Plant and LNG facility. This is a whole new job area for Alaska and it is totally green.

So what we have for Oregonians is a way for them to meet the greenhouse gas reductions goals established by their legislators in an economical manner. The cost of gas used for electrical generation in Oregon will not go up. The cost of capture to allow greenhouse gas reduction can easily be absorbed by a voluntary consumer program much like the existing "blue skies program" which is used to subsidize wind and solar energy. Sequestration using this plan will be the least expensive method of Oregon greenhouse gas reduction. In addition, the cryogenic energy from the LNG at Port Westward can be used to inexpensively produce the industrial gases (O_2,N_2,Argon,H_2) that are needed by Oregon's semiconductor manufacturers. Use of the cryogenic energy from the import of LNG can also economically produce high quality recycled rubber from old tires. These industries are presently used by China and Japan at their LNG receiving stations and will generate at least a hundred new green jobs for Oregonians. There will be no need now for new 36 inch gas pipelines to be built across sensitive environmental areas. Port Westward could then economically provide LNG as a fuel for use by Columbia River shipping. Ships are now converting to LNG to eliminate the emissions created by the use of bunker oil but the Columbia River has no refueling capability. A conventionally sized LNG/CO_2 tanker will eliminate the need for additional coast guard resources and not require Columbia River dredging. Small tanker size means that any danger predicted from ignition of LNG would be insignificant and this would mean that their passage up the Columbia will have no impact on other river users.

The United States must find a better way to utilize this wonderful opportunity that increased supplies of domestic natural gas have provided. Don't ship it overseas. Most of the investment has been made to enable us to create a better life for all of our citizens. The technology and most of the necessary facilities already exist for this type of project. The project is environmentally attractive to even the most strident environmentalist. There is no Wall Street Banker or Texas Oil Man seeking to rape and pillage our future for the sake of an extra buck. Just Oregonians and Alaskans and Democrats and Republicans getting something worthwhile done for a better future.

Trying to make a difference,

John Dunzer
Appointed by Governor Kitzhaber as an Oregon Change Agent
johndunzer@msn.com
(503)738-6885

Cc: Bill Drumheller Oregon Dept of Energy
Gov Kitzhaber Oregon
Gov Parnell Alaska
Dave Robertson, VP PGE
Craig Vaughn ConocoPhillips Alaska