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March 3, 2014

VIA ELECTRONIC FILING

Steven King, Secretary and Executive Director
WASHINGTON UTILITIES & TRANSPORTATION COMMISSION
1300 S Evergreen Park Drive, SW
Post Office Box 47250
Olympia, Washington 98504-7250

Re: UG-131473 – Draft 2014Integrated Resource Plan

Dear Mr. Danner:

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), hereby files its Draft 2014 Integrated Resource Plan (IRP) in Docket No. UG-131473.

Please contact me at (503) 226-4211, extension 3590, if you have any questions.

Sincerely,

NW NATURAL

/s/ Jennifer Gross

Jennifer Gross
Rates & Regulatory Affairs

enclosures

DRAFT

2014

Integrated Resource Plan

LC-XX

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®

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Chapter 1: Executive Summary

NW Natural®

I. Introduction and Background

A. Introduction
This Executive Summary provides an overview of NW Natural's key findings in its 2014 Integrated Resource Plan (IRP) and includes a multi-year action plan. NW Natural develops a long-term resource plan every two years. The IRP defines the mix of natural gas supply- and demand-side measures designated to meet expected future demand and reliability requirements at the lowest reasonable cost to the utility and its ratepayers.

B. Description of NW Natural
NW Natural is a 155 year old natural gas local distribution and storage company headquartered in Portland, Oregon, serving almost 695,000 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 percent of customers reside in the Portland area, with another 10 percent in the state of Washington. Residential customers comprise roughly 90 percent of the customer base.

C. 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 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

A. Natural Gas Demand
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 a result of the housing market crash, the great recession, and the subsequent slow recovery, NW Natural's annual customer growth had fallen to 1 percent or less in recent years. However, as the country slowly recovers from the great recession, so do the economies in NW Natural's service territory as can be seen by the 1.3 percent customer growth rate for 2013.[1] This is particularly true for NW Natural's Washington service territory, where Clark County is projected to be the third-

[1] The 2013 annual customer growth rates for Oregon and Washington were 1.1 percent and 2.7 percent, respectively.

fastest growing county in the Pacific Northwest.[2] This has resulted in an average annual Firm Sales customer growth rate of 1.9 percent in the Company's Base Case, which is slightly higher than 1.65 percent rate forecast in the previously filed IRP. The average annual Firm Sales customer growth rates over the planning horizon for Oregon and Washington are 1.8 percent and 3.8 percent, respectively.

As mentioned in previous IRPs, the Company believes that the introduction and proliferation of relatively low-cost production from shale gas has been a transformational event for the industry. The "shale gale" has resulted in forecasts that reflect low gas prices relative to a decade ago that can be sustained, on average, over a long-term period. Thus, while there may be lags between the supply growth and demand response, this demand stimulus can already be seen with the recent announcement of two $1 billion methanol plants planned in or adjacent to the Company's service area. To account for this anticipated demand, the Company has created three Emerging Market scenarios (Low, Medium, and High). NW Natural includes the Emerging Market Low growth estimate in its Base Case and the Medium and High Emerging Markets sensitivity cases to ensure the resource plan has sufficient adaptability to respond to this potentially higher rate of load growth.

NW Natural's Base Case, which incorporates the Low Emerging Markets scenario and is net of the energy savings resulting from demand-side management (DSM) energy efficiency programs implemented by the Energy Trust of Oregon (ETO), includes a 1.3 percent average annual rate of growth in Firm Sales annual load and a 1.3 percent 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 of less than 0.4 percent from the average annual rate in the Company's most recently filed Integrated Resource Plan (IRP), its 2013 Washington IRP. The former rate—1.3 percent average annual rate of growth in Firm Sales annual load—is the same as the rate in the 2013 Washington IRP.[4]

B. DSM Cost-Effectiveness

Low gas prices, while an obvious benefit for customers, result in lower avoided costs, which in turn result in fewer energy efficiency measures being cost effective. To mitigate this impact in Oregon, the Public Utility Commission is allowing a limited exception to the cost effective standard. Additionally, due to a higher rate of customer growth in NW Natural's Washington service area, the overall savings potential in Washington has increased substantially. Nevertheless, the Company's overall forecast of 20-year demand-side management energy savings is down slightly from that in the most recently filed (2013) Washington IRP.

C. Changes to the Resource Stack

One of the most significant changes in this IRP over previous IRPs is the recent change to NW Natural's resource stack. NW Natural has Rate Schedule TF- 2 transportation contracts with Northwest Pipeline (NWP) to move gas from both the Plymouth and Jackson Prairie storage facilities. On December 6, 2013, NWP curtailed the Company's Plymouth TF-2 service, which showed the TF-2 transportation

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2 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.

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

4 NW Natural's 2013 Washington IRP included an average annual growth rate in Firm Sales annual load of 1.27 percent and an average annual growth rate in Firm Sales design day peak demand of 0.92 percent.

service on NWP's system through the Columbia River Gorge to not be as reliable as previously believed. Subsequently, NWP confirmed that this service is "secondary" and would have been reliable on the coldest days in 12 of the prior 14 years, leading the Company to conclude that the Plymouth TF-2 curtailment in December 2013 was not an aberration or one-time occurrence. This outcome resulted in NW Natural inquiries regarding the reliability of its TF-2 service from Jackson Prairie. While the pathway from Jackson Prairie to NW Natural's service territory has not been constrained since the inception of this particular service in 1989, a NWP curtailment of secondary TF-2 capacity is possible in the future.

This situation creates an immediate resource deficiency that NW Natural is currently addressing. To allow for more time to investigate alternative solutions, the Company is relying on an interim solution known as segmented capacity to supplement accelerated Mist Recall. Chapter Three discusses this in detail, but as a practical matter, segmented capacity allows NW Natural to move additional gas supplies from Sumas, but in a secondary or subordinate capacity on NWP, that cannot be counted upon as a permanent solution to the current resource deficiency.

This recent experience led to NW Natural's reviewing other areas of risk. One risk the Company has identified is the reliance upon un-contracted gate station capacity above the Company's contracted Maximum Daily Delivered Obligation (MDDO) with NWP. NW Natural is questioning the appropriate relationship between MDDO and design day peak demand and is currently conducting analysis on this issue.

D. Immediate Plan to Address Vancouver/Clark County

Consistent with NW Natural's 2013 Washington IRP action plan and as will be discussed in more detail in Chapter Seven, the Company improved its system modeling in this IRP in several ways. The resource modeling now incorporates the physical capacity limitations on both NWP's gate stations as well as the Company's pipeline capacity 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 resource deficiencies, in both supply and distribution systems, in the Vancouver load center.

E. Reliability Risk Analysis

Placeholder for probabilistic reliability risk analysis.

F. Base Case Resource Plan

NW Natural's Base Case resource plan has four summary objectives:

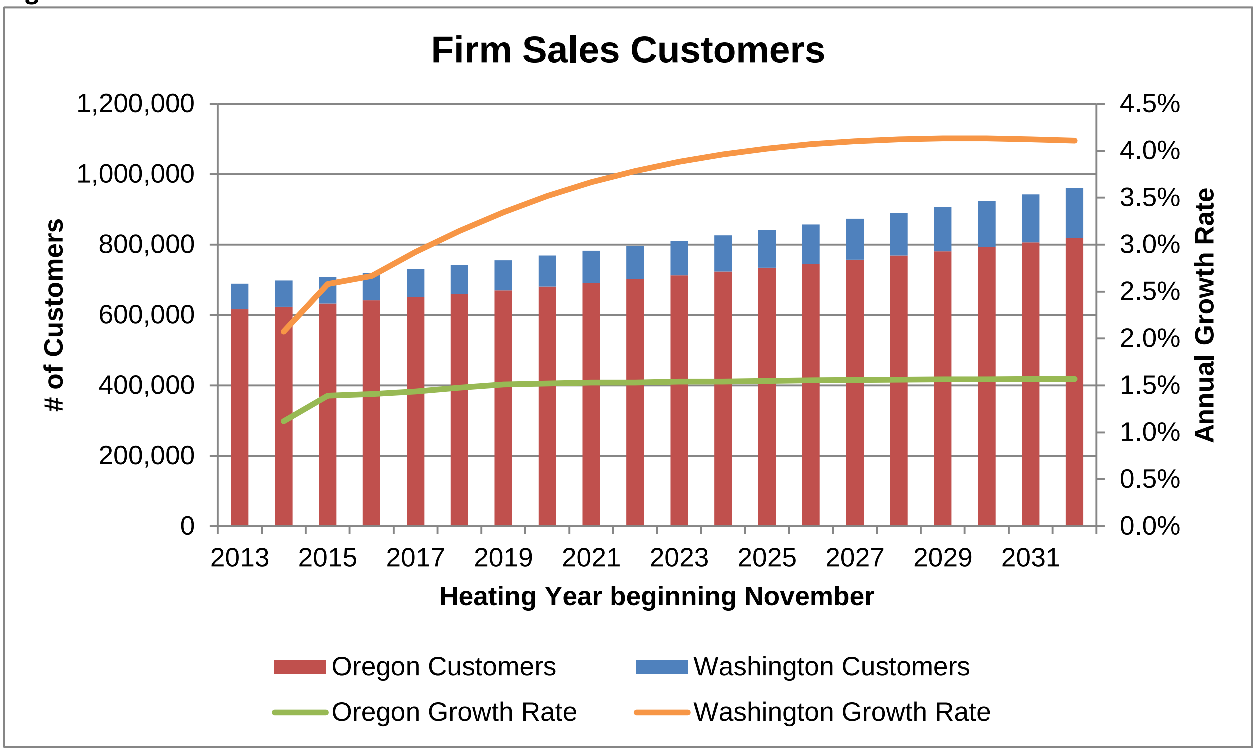
1. The plan must address the Company's most urgent reliability priorities such as Vancouver; replacement of Plymouth with a firm resource; and a long-term solution to replace segmented capacity.
2. The plan needs to be flexible and robust in order to handle demand uncertainty due to a forecasted sustained low natural gas prices stimulating innovation; uncertainty around carbon legislation and its implications; and uncertainty of the implications of announced new feedstock facilities such as the methanol plants recently announced by Northwest Innovation Works (NIW).
3. The Company's plan must address ours and the region's need for additional regional pipeline capacity within the 2020 timeframe.
4. The plan must address any distribution system deficiencies identified over the planning horizon and identify any major infrastructure resource addition.

III. Demand Forecasts

A. Customer Forecast

As mentioned above, NW Natural's load forecast is primarily a function of Residential and Commercial customer growth. Figure 1.1 below shows the forecast of customers by state and the associated annual growth rates.

Figure 1.1



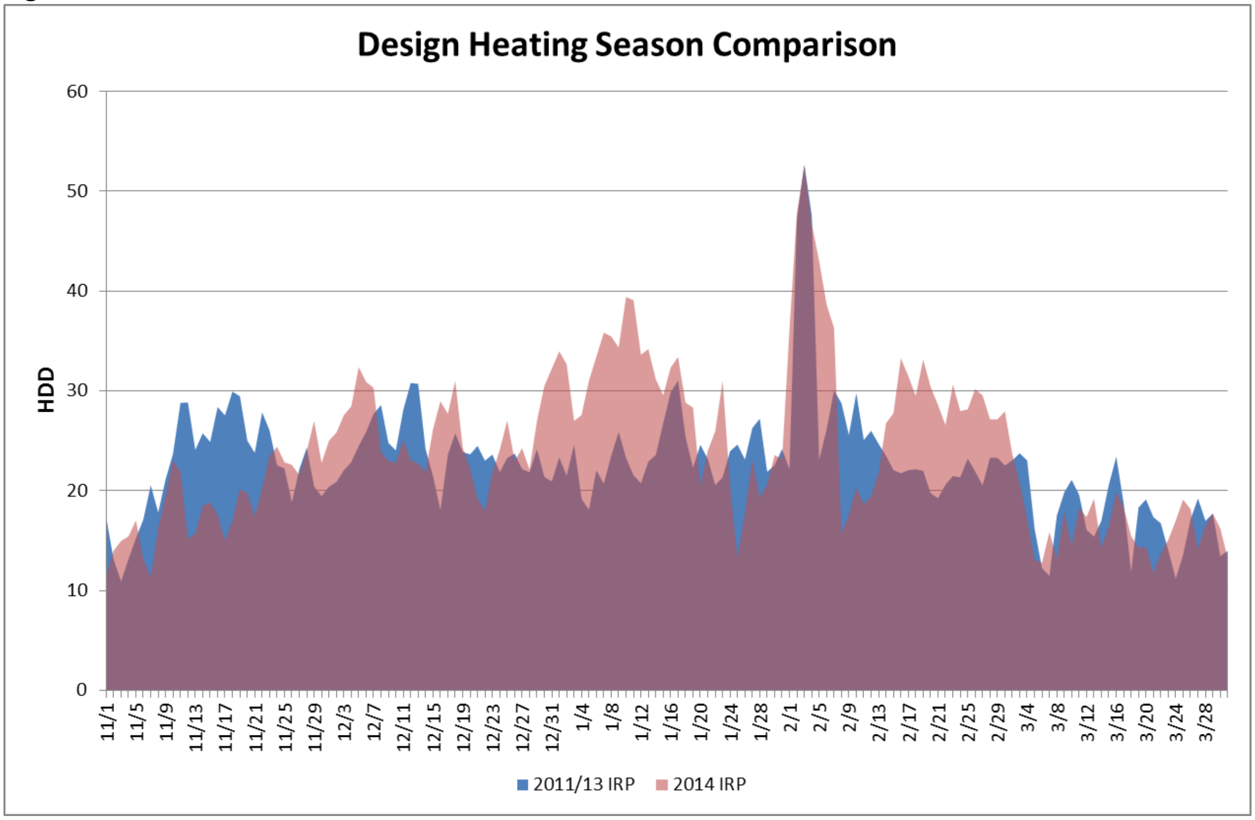
As can be seen from Figure 1.1 above, Washington's average annual growth rate over the planning horizon of 3.8 percent is substantially higher than Oregon's 1.6 percent. This is partially a function of NW Natural's smaller customer base in Washington, with customer additions appearing proportionally greater, and partially a result of a healthy growth forecast for Clark County. The Company will continue monitoring Clark County's growth as it recovers from the great recession.

B. Weather

While NW Natural's 2014 IRP retains the same 53 HDD design day standard of previous IRPs, the Company extends the duration of the cold event to include the three days preceding and the three days following the peak day event. This provides not only a more robust testing of NW Natural's system, but the Company believes it to be more reflective of actual cold weather events as they move through the Company's service area.

As discussed in Chapter Two, NW Natural develops its design weather using 30 years of data (1983 – 2012) and calculates a non-winter portion equating to a 50th percentile year and a winter heating season portion equating to a 90th percentile year. Figure 1.2 below overlays the 2014 IRP's design weather on that of prior IRPs.

Figure 1.2



C. Natural Gas Price Forecast

Another key step in the Company's load forecasting process is reviewing natural gas price forecasts. Figure 1.3 below shows the Company's price forecast[5] relative to previous IRPs as well as compared to two forecasts from external public sources—EIA and NWPCC. As can be seen, prices are expected to gradually increase over time in nominal terms[6] and more-or-less reflect limited change after accounting for projected inflation.

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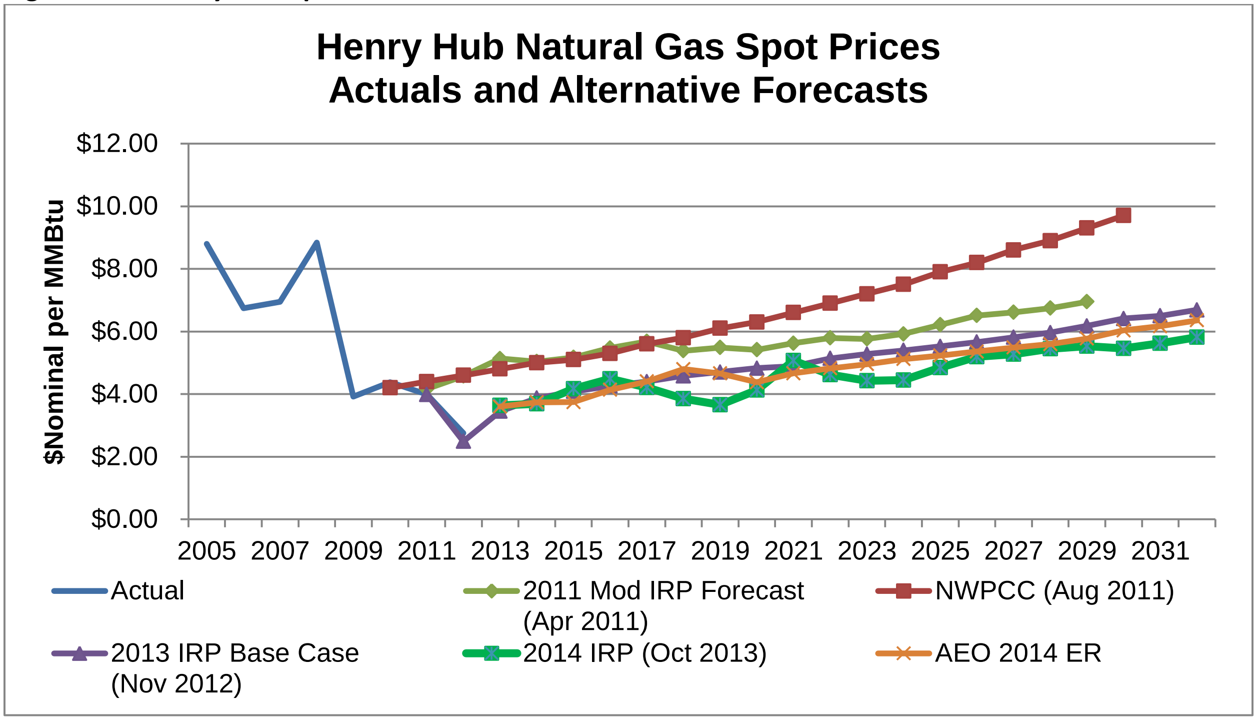
[5] Source: IHS Inc. This content is extracted from IHS Energy North America Natural Gas service and was developed as part of an ongoing subscription service. No part of this content was developed for or is meant to reflect a specific endorsement of a policy or regulatory outcome. The use of this content 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.

[6] At NW Natural's 1.9 percent assumed annual rate of inflation over this IRP's planning horizon, natural gas at \$4.00 per MMBtu in 2013 is the same real price as gas at a nominal price of \$5.72 in 2032.

Figure 1.3 – Henry Hub Spot Prices



D. Load Forecast

After considering customer forecasts, natural gas price forecasts, projected changes in average use per customer, and ETO's forecast of DSM energy efficiency savings (discussed later on in this chapter), NW Natural's Firm Sales design day peak demand forecast reflects an average annual growth rate of 1.3 percent. Figure 1.4 below shows the Firm Sales design day peak demand net of DSM on an annual basis over the planning horizon for both Oregon and Washington and Figure 1.5 shows the Firm Sales annual load net of DSM for both Oregon and Washington.

Figure 1.4 – Firm Sales Design Day Peak Demand Net of DSM

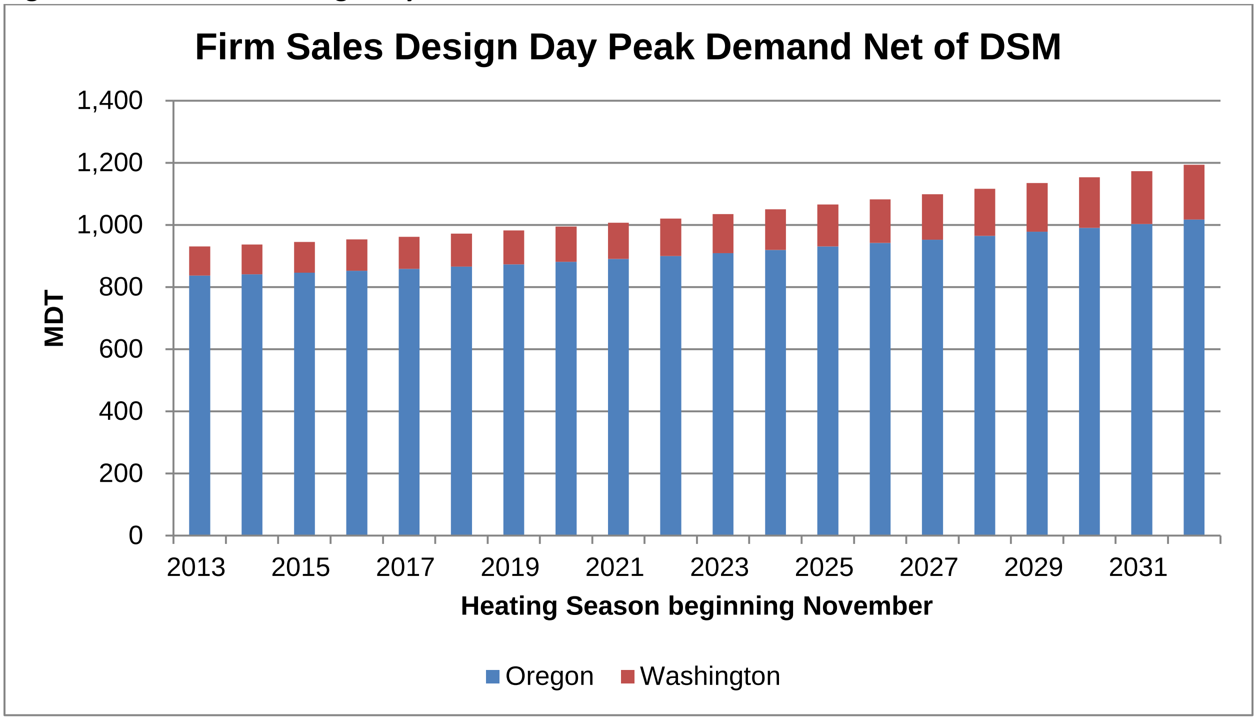
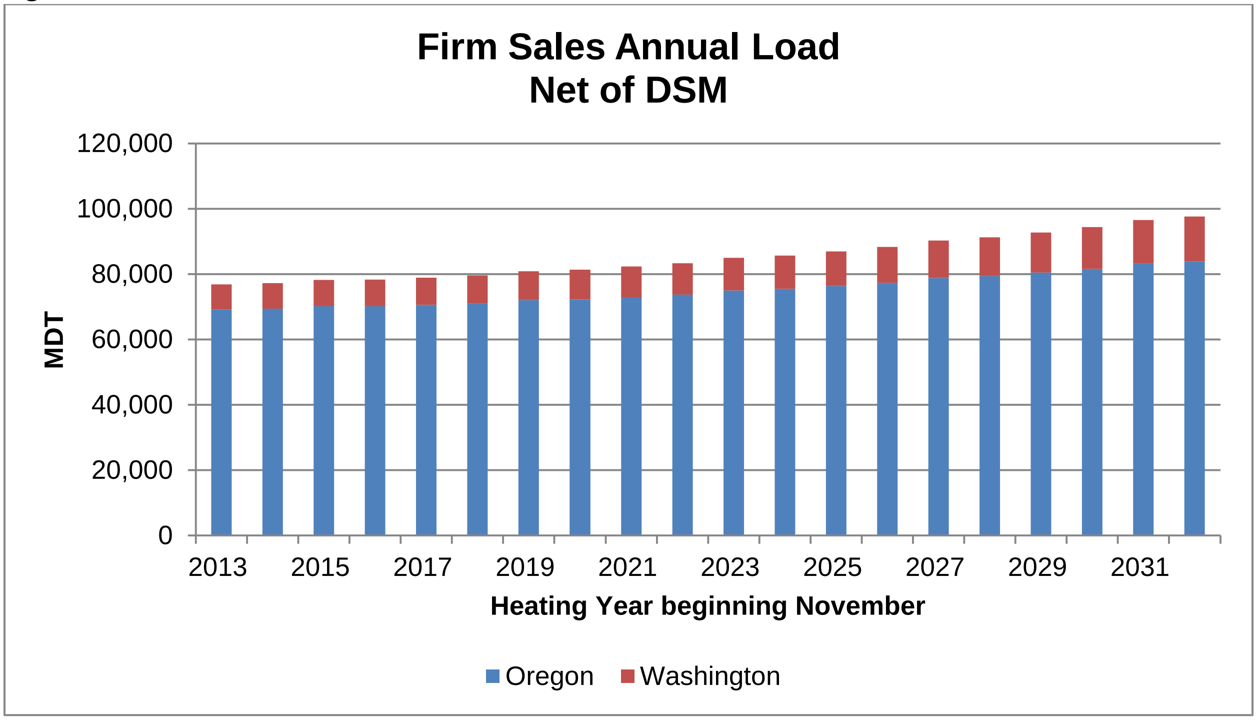


Figure 1.5 – Firm Sales Annual Load Net of DSM



NW Natural forecasts Firm Transportation loads in this IRP. Firm Transportation customers provide for their own upstream resource adequacy needs and the Company therefore does not incorporate the gas supply needs of these customers into its supply resource planning. However, the Company does provide firm distribution services for these customers, so these loads must be incorporated into NW Natural's distribution system planning. The design day peak demand net of DSM and the annual load net of DSM, respectively, for both Firm Sales and Firm Transportation customers over the planning horizon is shown later in this chapter.

E. Design Day Peak Demand and Annual Load Sensitivity Cases

NW Natural considers the four following demand forecast sensitivity cases in this IRP:

- Low Load Growth
- High Load Growth
- Medium Emerging Markets
- High Emerging Markets[7]

The two load growth sensitivity cases consider traditional demand drivers and produce average annual rates of Firm Sales customer growth of 1.4 percent and 2.1 percent for the Low and High Load Growth cases, respectively. Firm Sales design day peak demand grows at an average annual rate of 0.9 percent in the Low Load Growth case and 1.8 percent in the High Load Growth case.

The two Emerging Markets sensitivity cases examine the potential local impact from growth in new markets driven primarily by lower gas prices resulting from low cost production, but these are also potentially impacted by future carbon legislation. NW Natural anticipates emerging markets will include three sectors—distributed generation, new industrial loads such as plants using natural gas as feedstock, and transportation. The Emerging Markets cases have a more significant impact on annual energy requirements than on design day peak demand due to the relatively high load factors and/or counter-cyclical usage patterns associated with these sectors. As one example and based on typical driving patterns, NW Natural expects gas consumed in the transportation sector to be higher during the summer months than in the winter months.

Figures 1.6 and 1.7 below show the forecasted impacts on design day peak demand and on annual energy requirements associated with these sensitivity cases.[8]

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[7] NOTE FOR DRAFT: While our High Emerging Markets case includes a projection of the load of a feedstock plant such as the recent announcement of the two methanol plants by Northwest Innovation Works, NW Natural is still uncertain how much load it would serve and what type of service it would provide. For the DRAFT, this load is assumed to be firm transportation.

[8] See footnote 7.

Figure 1.6– Firm Service Design Day Peak Demand Forecast

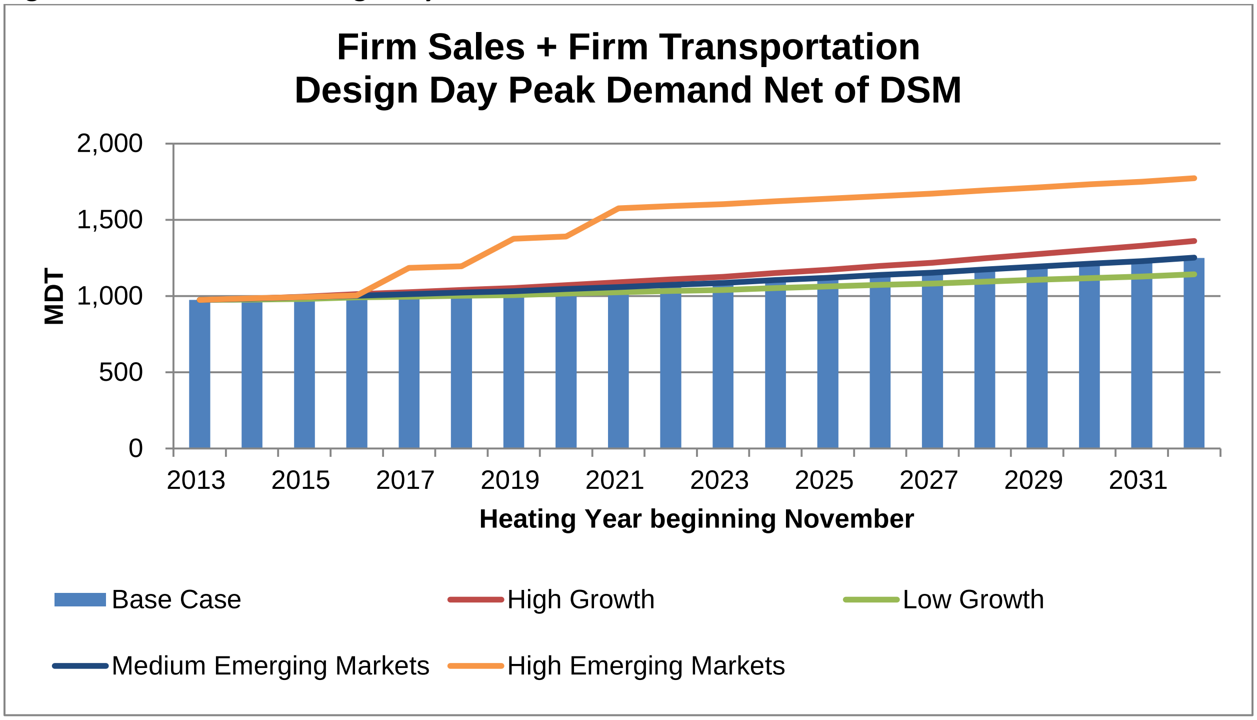
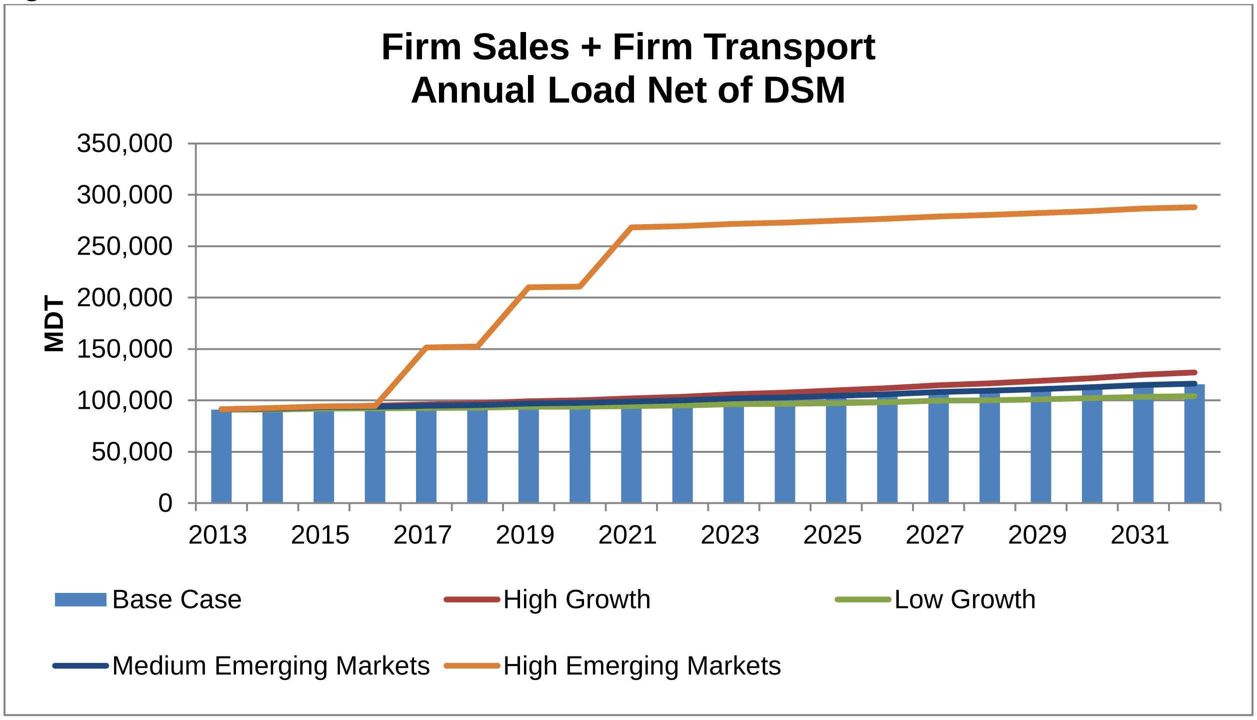


Figure 1.7 – Firm Service Annual Load Forecast



F. Carbon Sensitivity Cases

NW Natural's 2014 IRP Base Case incorporates a carbon price. The Company uses IHS CERA's North American Natural Gas price forecast[9], which incorporates a carbon price beginning in 2021 at $8.74 per metric ton of CO_2 equivalent ($MTCO_2e$) and increases annually to $15.70 per $MTCO_2e$ in 2033 (both prices in $2013). Additionally, the Company analyzes two additional scenarios using a medium and a high price for carbon.

PLACEHOLDER FOR ADDITIONAL CARBON INFORMATION WHEN AVAILABLE

IV. Supply-Side Resources

A. Resource Alternatives

With Plymouth no longer in the resource stack, the long-term availability of secondary capacity from Jackson Prairie uncertain, and improved visibility into system constraints, NW Natural examines a variety of resource options in this IRP. The Company essentially has six types of resource supply alternatives to consider, with the sixth being a combination of any of the five options noted. While NW Natural considered many more options, after initial investigation and analysis, the Company reduced this list to those potential alternatives considered for meeting future demand growth and addressing system reliability. Table 1.1 below lists the future supply-side resources NW Natural modeled:

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[9] 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."

Table 1.1 Alternative Resource Options

Resource Supply Options	Constraint Addressed	Options
Supply Basins	Not enough gas supply	Station Two (BC) Opal (Rockies) AECO (Alberta) Sumas (BC) Malin (Rockies)
Regional Interstate Pipelines	Not enough capacity	Cross-Cascades (CC with N-Max or Eastside Loop) NWP – Washington Expansion (WEX) NWP – Sumas Expansion Additional CD on GTN Additional CD on TransCan (TCPL)
Storage	Not enough supply Not enough capacity More cost effective resource even if enough supply/capacity	Mist Recall Satellite LNG
Supply-side High Pressure Transmission Pipelines (Non-Interstate)	Brings additional supply to load centers from storage or elsewhere	South Willamette Valley Feeder (SWVF) Eastside Loop (ESL)Christenson Compressor Project (CCP)
Distribution System Planning Projects	Not enough capacity behind the city gate	Vancouver distribution projects Aurora Compressor Project (ACP) Newberg to Central Coast Feeder (NCCF) South Salem Feeder (SSF)

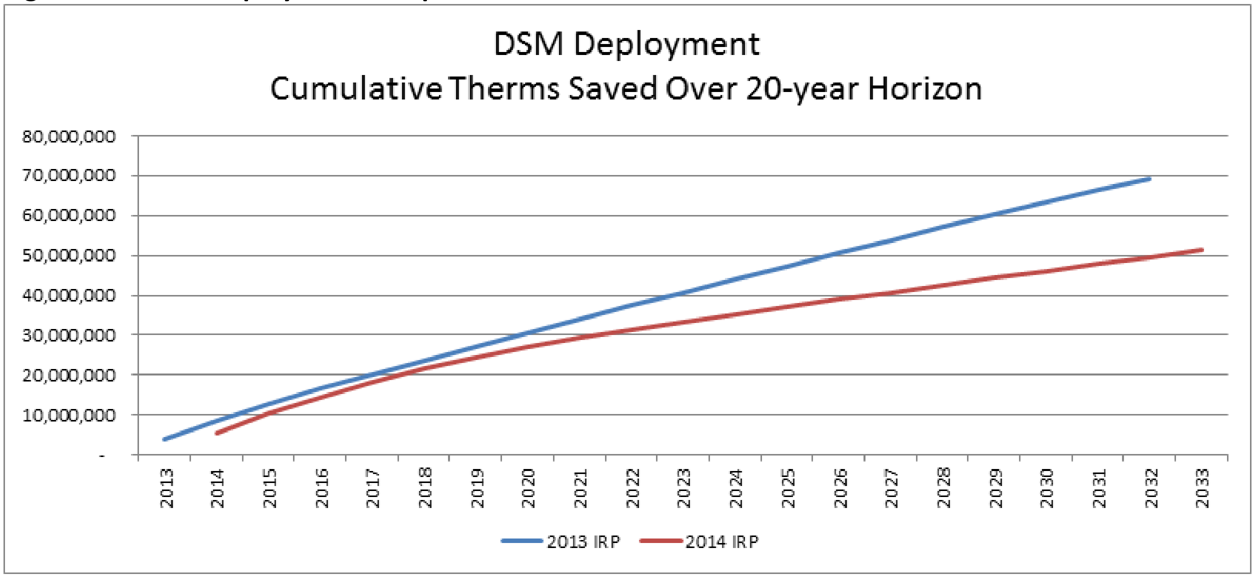
NW Natural discusses each of these options, as well as other alternatives considered but not modeled in either Chapter Three (Supply Side Resources) and Six (Distribution System Planning).

B. Demand-Side Resources

The combined DSM savings potential for the 2014 IRP is slightly lower than in the most recently filed (2013) Washington IRP. The reduced potential is due primarily to lower avoided costs as a result of lower gas prices, but is materially offset by higher forecasted growth in Washington than was in the 2013 Washington IRP.

Figure 1.8 below illustrates the difference in the forecasted DSM cumulative therm savings potential deployment presented in the Company's 2013 Washington IRP verses the deployment schedule identified in this plan.

Figure 1.8– DSM Deployment Comparison of 2013 and 2014 in 2011 Modified IRP and 2013 IRPs

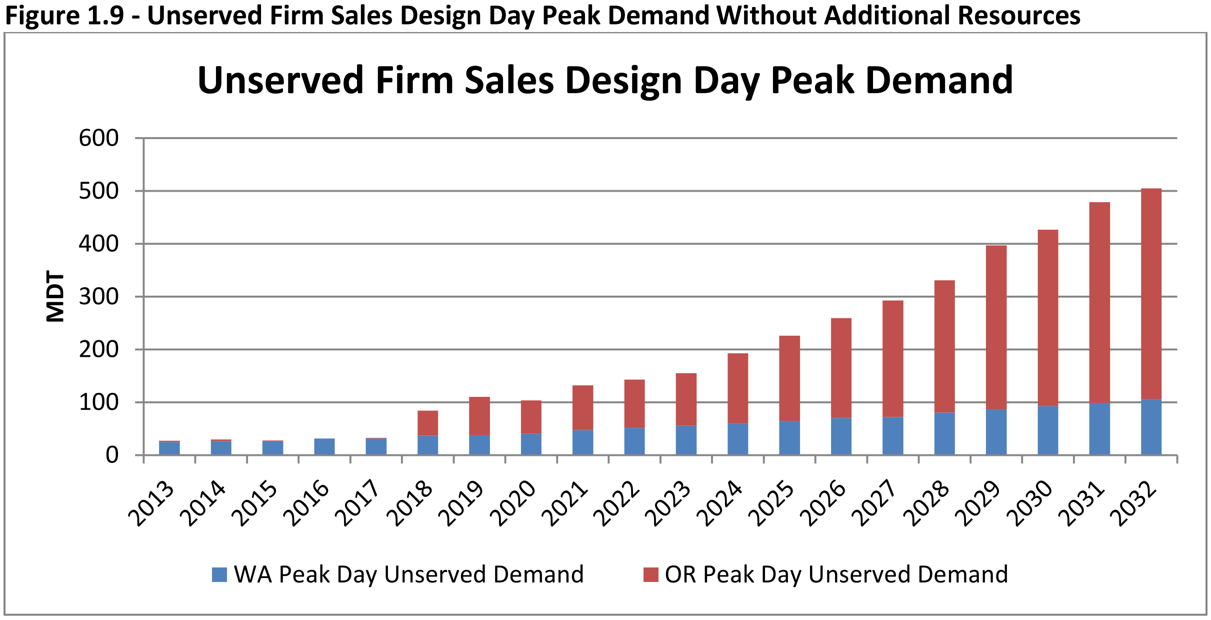


V. Resource Portfolio Analysis

A. Base Case

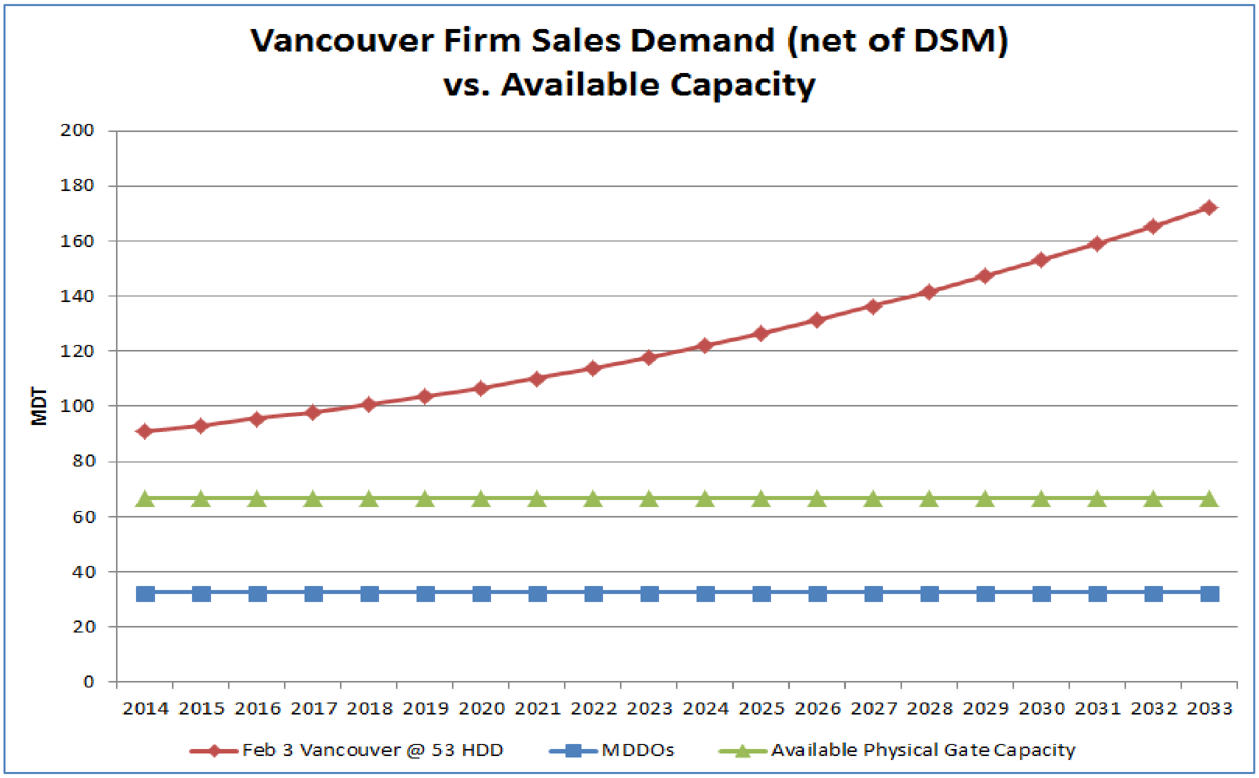
NW Natural's Base Case portfolio analysis has traditionally assumed 100 percent resource availability (i.e., no resource outages). Referring to this as a traditional planning standard approach, the Company's Base Case identifies the near-term need for additional gate capacity and distribution system infrastructure in the Vancouver load center and, to a lesser degree, the Salem load center, and further identifies that over the planning horizon there are resource deficiencies that cannot be solved with additional Mist Recall alone. This is due in part to the change in status of previously assumed firm storage resources (secondary TF-2 service from Plymouth and Jackson Prairie) which in total amount to 65 MDT/day or approximately 7 percent of current forecasted design day demand. Figure 1.9 shows the design day unserved load in the absence of additional (new) resources on an annual basis.

Figure 1.9 - Unserved Firm Sales Design Day Peak Demand Without Additional Resources



As mentioned above, NW Natural's Base Case identifies an existing resource deficiency in Vancouver. Figure 1.10 below illustrates the existing Vancouver resource deficiency.

Figure 1.10 – Design Day Peak Demand and Physical Delivery Constraints



While a significant risk of customer outages in the Vancouver area exists until improvements can be made, NW Natural plans to continue using LNG and CNG trailers to supplement interstate pipeline deliveries to the Vancouver load center under cold weather conditions.

B. Reliability Risk Analysis

Placeholder - To Be Completed

C. Base Case Resource Plan

NW Natural's Base Case resource plan must address these four key objectives:

1. **The plan must address NW Natural's most urgent reliability priorities:**

	Reliability Priority	Plan
1	Address need for capacity in Vancouver	✓ Use CNG/LNG trailers in short term ✓ Increase gate capacity ✓ Better align MDDO's with Contract Demand (CD) by securing additional CD ✓ Increase distribution system infrastructure and takeaway capabilities
2	Address loss of Plymouth as a firm resource	✓ In the near term replace with Mist Recall and Segmented Capacity
3	Find a long term solution to replace segmented capacity	✓ In the long term replace with least cost interstate pipeline capacity currently identified as Cross-Cascades (this assumes no long term solution with NWP can be found) or if Cross-Cascades does not proceed, replace with next least cost option available

2. **The plan must be flexible and robust in order to handle uncertainty associated with future demand:**

	Uncertainty	Plan
1	Natural gas is at an inflection point. Demand for emerging markets such as transportation is still developing	✓ For medium case of emerging markets use additional Mist Recall supplemented by Cross-Cascades or if Cross-Cascades is not available, the next least cost interstate pipeline capacity option. Because Cross Cascades has low cost expandability for flexibility to meet potential future increased demands above the base case.
2	Demand from utility size customers such as the recently announced methanol plant	✓ Be prepared to participate in regional pipeline projects ○ WEX further along in permitting, but is currently tied to Oregon LNG export ○ Enter into a precedent agreement with Cross-Cascades sponsors
3	Implications of any carbon legislation	✓ TBD PENDING OUTCOME OF CARBON SCENARIOS

3. **The plan must address NW Natural's need for additional pipeline capacity beginning in the 2020 timeframe:**

	Obtain Pipeline Capacity	Plan
1	Proceed with least cost option – Cross Cascades	✓ The Company should support Cross-Cascades by entering into a precedent agreement with the Cross-Cascades project sponsors which would enable an open season and determine the project's economic viability ✓ Support initiation of the critical path FERC permitting process by the project sponsors, contingent upon the results of the open season
2	Develop a contingency plan to Cross Cascades	✓ Take a minimum amount of Sumas Expansion in the near term and leverage Mist Recall to the maximum extent

4. The plan must address any distribution system deficiencies identified over the planning horizon and identify any major infrastructure resource addition.

	Resource Addition	Plan
1	South Salem area	✓ Build South Salem Feeder to be able to meet need in 2019 timeframe
2	South Salem and Albany areas	✓ Install additional compression along the central coast feeder to improve Newport LNG takeaway capacity in the 2025 timeframe

NW Natural believes the Base Case Resource Plan Additions set forth below in Table 1.2 combined with the Company's action plan achieves these objectives in the least cost manner.

Table 1.2 – Base Case Resource Plan Supply Additions[10,11]

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10 The NWP Capacity is actually a turn back of capacity through the Columbia River Gorge no longer needed due to having additional capacity from Cross-Cascades.

11 For a complete list of all resource additions, please see Chapter Seven.

Cumulative Supply Additions (Reductions) (MDT/day)								
	2015	2016	2017	2018	2019	2020	2025	2030
Mist Recall	30	30	35	35	35	35	75	138
Cross-Cascades capacity				110	110	110	110	110
Segmented capacity	44	44	44	0	0	0	0	0
Plymouth LNG	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)
Jackson Prairie				(14)	(14)	(14)	(14)	(14)
NWP capacity				(8)	(8)	(8)	(8)	(8)
Net Supply Change	14	14	19	63	63	63	103	166

D. Cross-Cascades

As mentioned above, Cross-Cascades is one of three interstate pipeline options NW Natural analyzed and modeled using the SENDOUT® software package. The Company explored other interstate options, but eliminated these without further analysis for a variety of reasons. A list of alternatives NW Natural considered can be found near the end of Chapter Three. Of the remaining interstate options (NWP Washington Expansion and NWP Sumas Expansion), the Washington Expansion project is the other regional pipeline proposal and this project will require shippers in addition to NW Natural in order to be viable. Absent one or more additional shippers, it is unlikely that any of the regional projects would proceed.

Additionally, as it relates to development of a new Cross-Cascades pipeline, there are three distinct steps in the process that will afford the Public Utility Commission of Oregon and the Washington Utilities and Transportation Commission opportunity for review. This IRP submission represents the first opportunity for review, allowing the Commissions to review the Company's supporting analysis and intended action plan. The second opportunity for review follows the Company's signing a Precedent Agreement (PA) with the Cross-Cascades project sponsors. This agreement will require the Commissions' approvals as an affiliated interest transaction. The third opportunity is after the results of the project's open season are known. The Company would not be financially obligated to the full project costs on behalf of its customers unless the results are consistent with the assumptions used in the 2014 IRP analysis and the PA review.

VI. Public Involvement

The Technical Working Group (TWG) brings together professionals representing a variety of entities having an interest in the Company's IRP process. NW Natural reached out to a wide audience including representatives from Washington Utilities and Transportation Commission Staff, Oregon Public Utility Commission Staff, Citizens' Utility Board of Oregon (CUB), Northwest Industrial Gas Users (NWIGU), Northwest Power and Conservation Council (NWPCC), Washington Public Counsel, Northwest Energy Coalition, and Williams Pipeline. The Company held Technical Working Group meetings on August 22 and October 2, 2013 and January 23, 2014[12]. NW Natural included a bill insert with December 2013 bills

[12] NOTE FOR DRAFT – will update with additional meetings for final.

sent to both Oregon and Washington customers, notifying them of the draft plan and soliciting public comments.

VII. Multi-Year Action Plan

1. Load Forecasting

   1.1 Continue refining growth projections for the Vancouver load center.

   1.2 Continue refining the demand forecast related to the NIW's methanol plants

2. Resource Additions

   2.1 Acquire resources in the near-term consistent with the Base Case Resources.

      a. Recall Mist storage capacity from the interstate storage account to serve the core customer needs reflected in the Base Case load forecast

      b. Plan to build the South Salem Feeder to serve load growth in the Salem area

   2.2 Continue working with NWP to investigate options regarding both the Plymouth and Jackson Prairie storage facilities.

   2.3 Support development of a regional Cross-Cascades pipeline. Negotiate and sign an acceptable Precedent Agreement with the Cross-Cascades pipeline sponsors for the Commissions' review and approval. Proceed with participating in the project as a shipper contingent upon the results of the open season.

   2.4 Continue to analyze the relationship between design day peak demand and contracted MDDOs. In particular, this plan should identify options including whether NW Natural must acquire additional CD.

   2.5 Proceed with the Newport refurbishment project and continue investigating Portland Gasco refurbishment alternatives.

3. Demand-Side Resources and Environmental Considerations

   3.1 Explore additional energy efficiency opportunities beyond the scope of previous assessments to identify any new and potentially cost-effective delivery approaches or savings areas.

   3.2 Explore demand-side potential from a peak capacity management perspective.

   3.3 Explore assessing a premium value to account for any hedging value associated with DSM energy savings

3.4 The Company will track Oregon Docket No. UM 1622 and will revise its annual DSM targets in accordance with any changes to the program resulting from this investigation of Energy Trust requested exceptions to the cost effectiveness guidelines.

3.5 The Company will work with WUTC Staff, its EEAG and other LDCs to bring its program into compliance with the Policy Statement issued in UG-121207. The Company will revise its tariff and EE Plan accordingly.

4. Ongoing Activities

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

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

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

4.4 Continue updating and refining resource cost estimates included in modeling.

4.5 Continue acquiring the cost effective therm savings targets included in Appendix 4 through existing energy efficiency programs administered by Energy Trust of Oregon.

4.6 Continue monitoring Carbon and GHG legislation.

4.7 Continue developing more statistically sophisticated approaches for probabilistically measuring reliability risk management. Explore other modeling tools for potentially supplementing SENDOUT®.

4.8 Continue investigating studies addressing the cost of unserved demand, with a focus on differentiating the cost based on the size of curtailment and relative impact on different customer priority levels.

Chapter 2: Gas Requirements Forecast

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 the 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 adequacy 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.

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[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.

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%

The economic strength 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 in 2011, they remained 37% below the number of starts recorded in 2007. The Company's customer growth rates have dropped

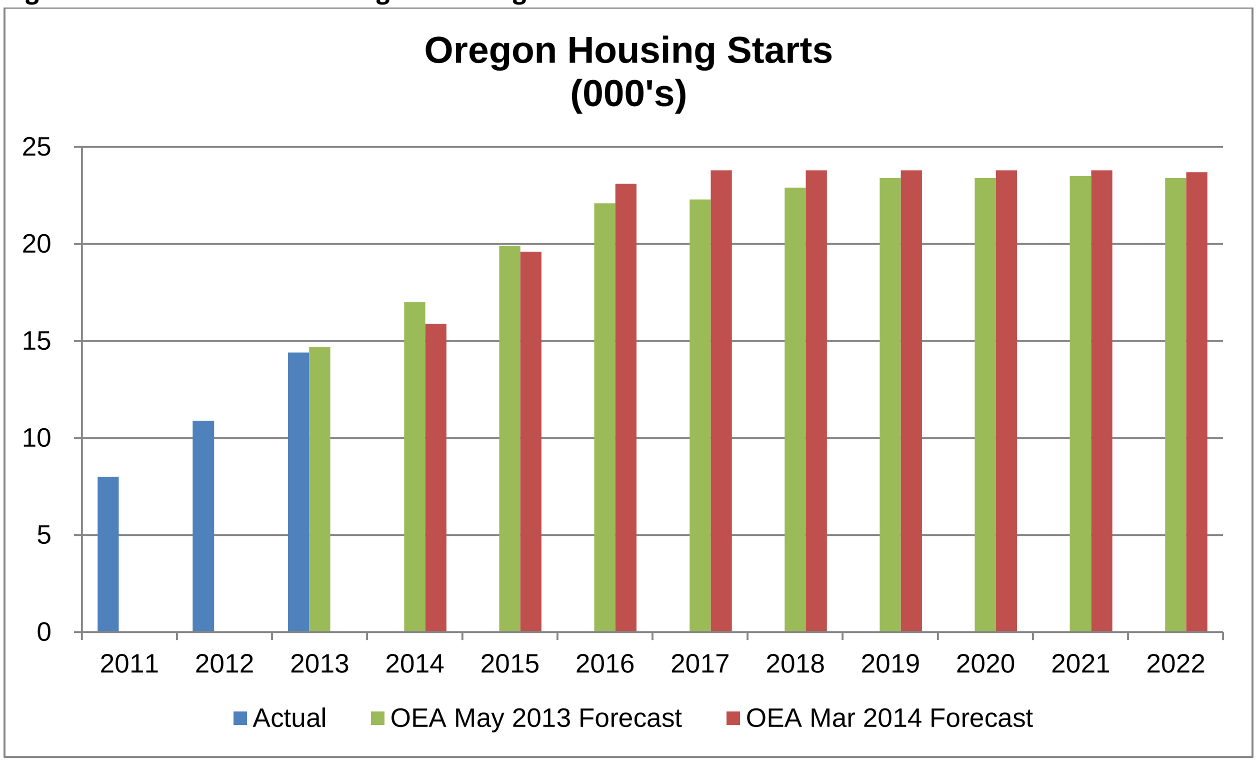
5 December 2013 numbers of customers in Table 2.2 are actual values. Numbers of customers for 2013 appearing elsewhere in this chapter are forecast values. The first year of the forecast period in this IRP begins November 2013.

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 February 12, 2014 and shown in Figure 2.1, provides some cause for optimism, with the accompanying narrative noting that:

"Housing starts today in Oregon total just more than 14,000 at an annualized rate, which represents growth of over 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 15,900 in 2014 and 19,600 in 2015. Over the extended horizon, starts are expected to average a little more than 23,000 per year to meet the load requirements of a larger population and also, partially, to catch-up for the underbuilding that has occurred in recent years."[8]

Figure 2.1 OEA Forecast of Oregon Housing Starts



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

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

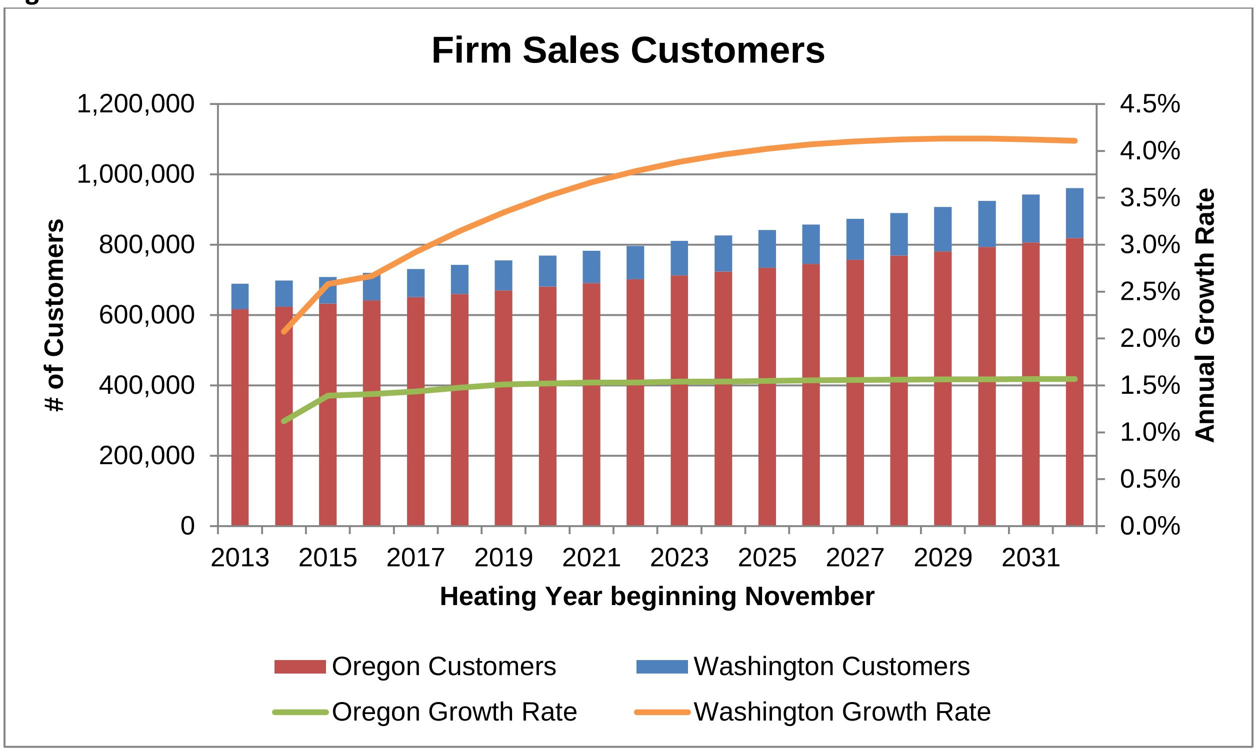
7 Accessed February 13, 2014 at http://www.oregon.gov/DAS/OEA/docs/economic/appendixa.pdf . See Table A.4.

8 Accessed February 12, 2014 at http://www.oregon.gov/DAS/OEA/docs/economic/oregon.pdf .

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 the level of customers by state and in total as well as the annual rates of customer growth by state.

Figure 2.2 Customers and Customer Growth Rates



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. At the same time, the 2014 IRP customer forecasts are very similar to those in the Company's 2013 Washington IRP and essentially indistinguishable for the total and Residential

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 a lower level of market penetration than that for NW Natural's Oregon service area and also to a large number of new housing developments being built in the greater Vancouver area.

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

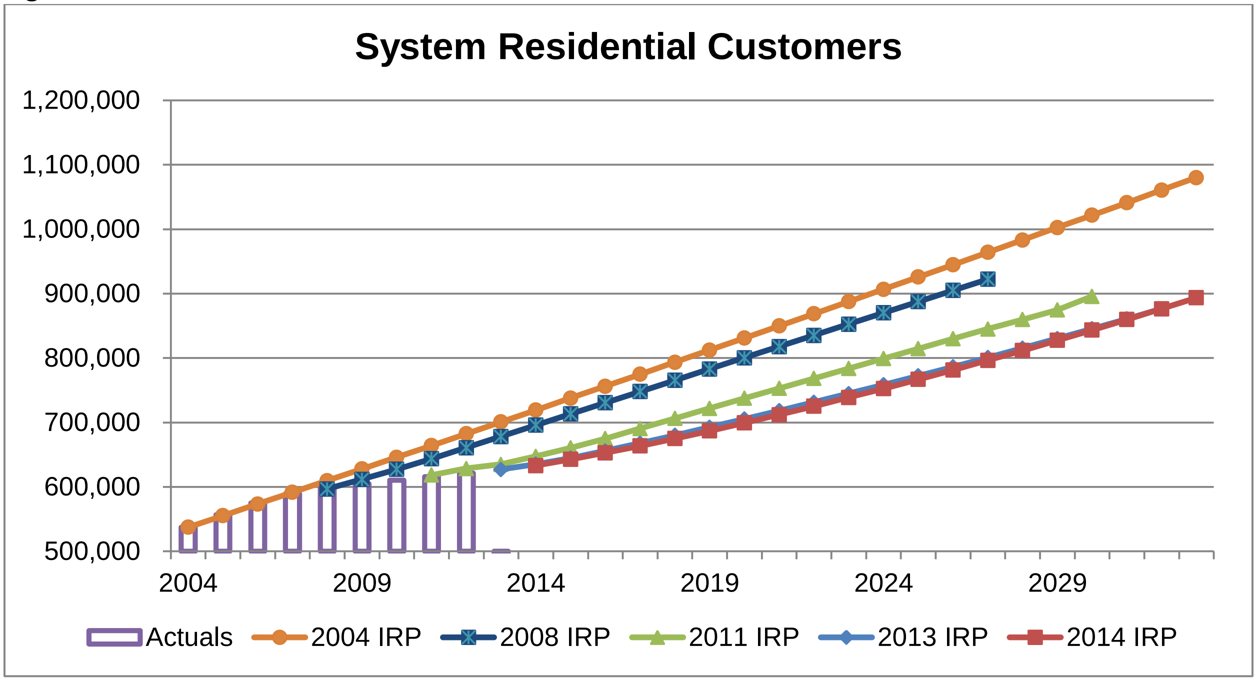


Figure 2.4 – Commercial Customer Forecasts

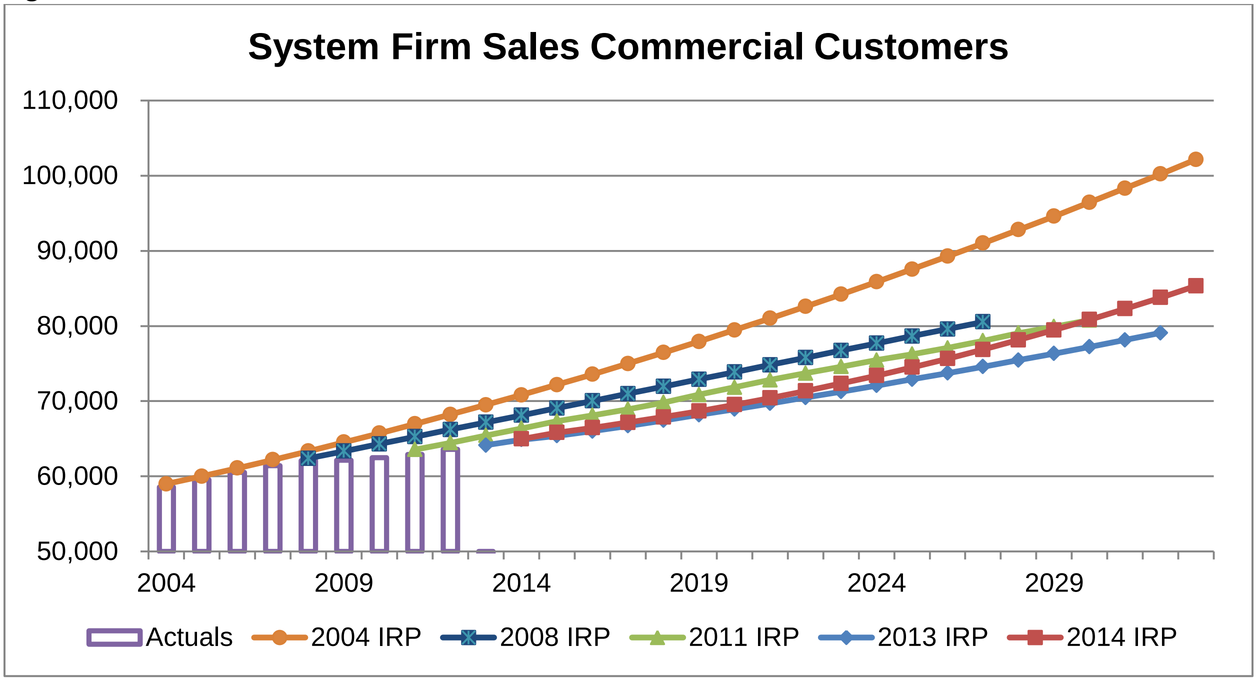
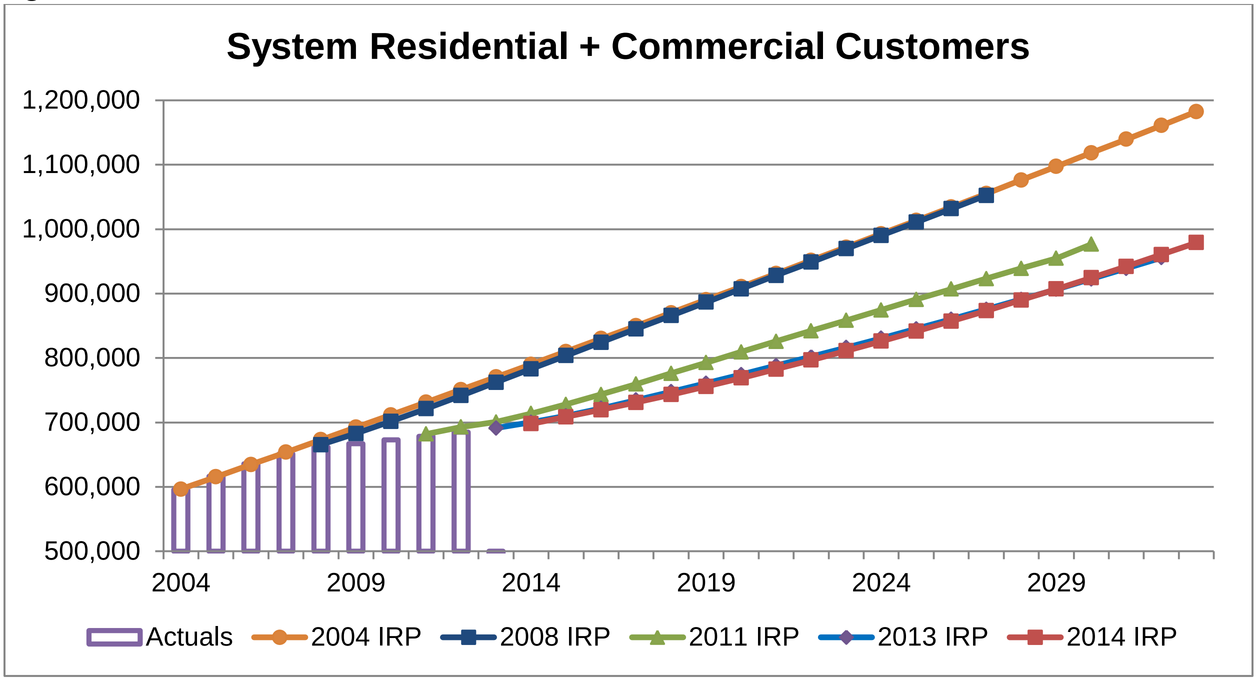


Figure 2.5 – Residential and Commercial Customer Forecasts



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.

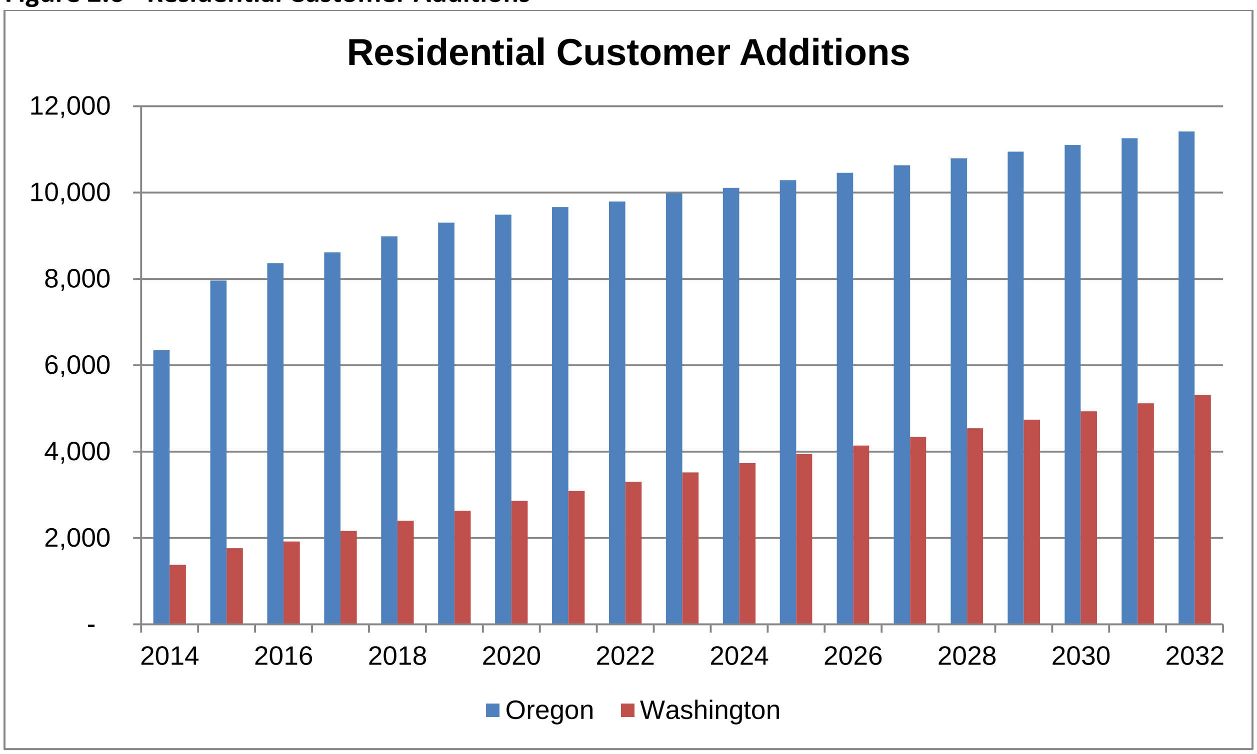
[12] NW Natural uses data provided by Woods & Poole, Inc. for mean household Income.

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. These 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.

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

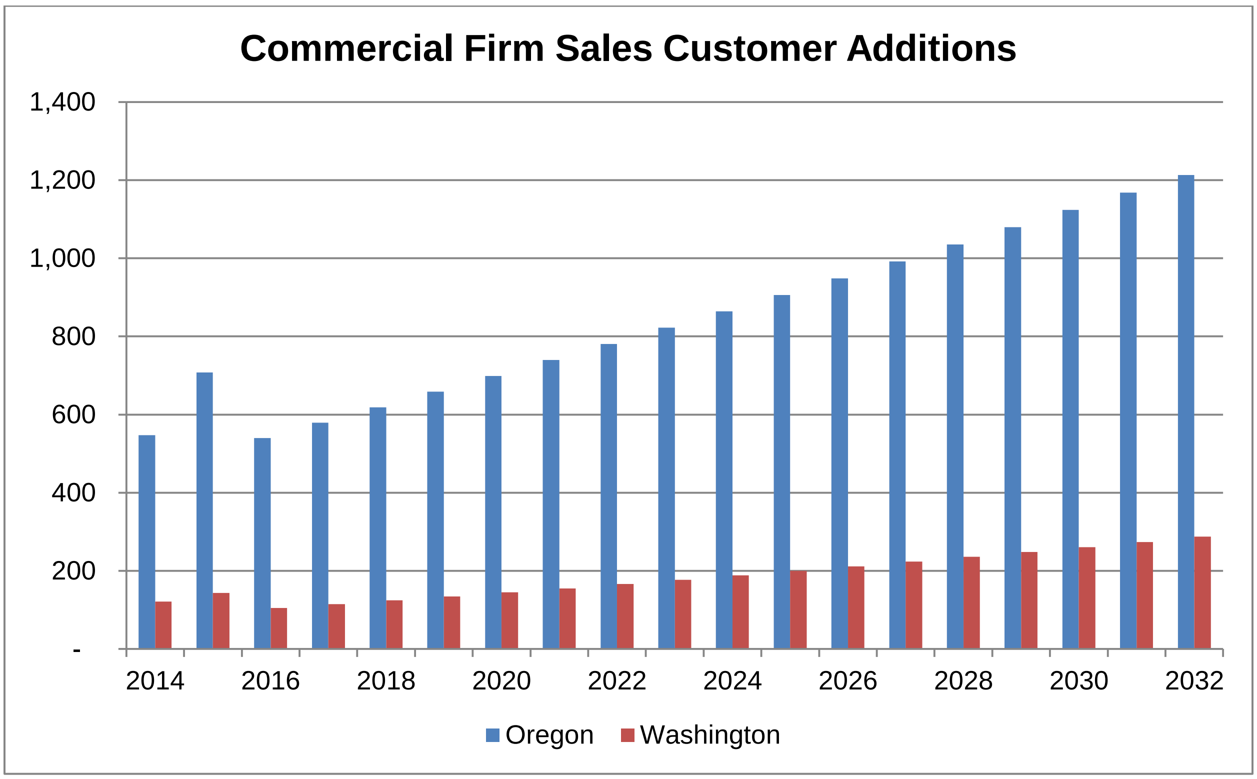
All new Commercial Firm Sales customers are added to the customer base in one of these categories. Analogous with the approach NW Natural uses for Residential customers, attrition of Commercial customers over time is reflected by a constant rate of reduction over time. The Commercial customer attrition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

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



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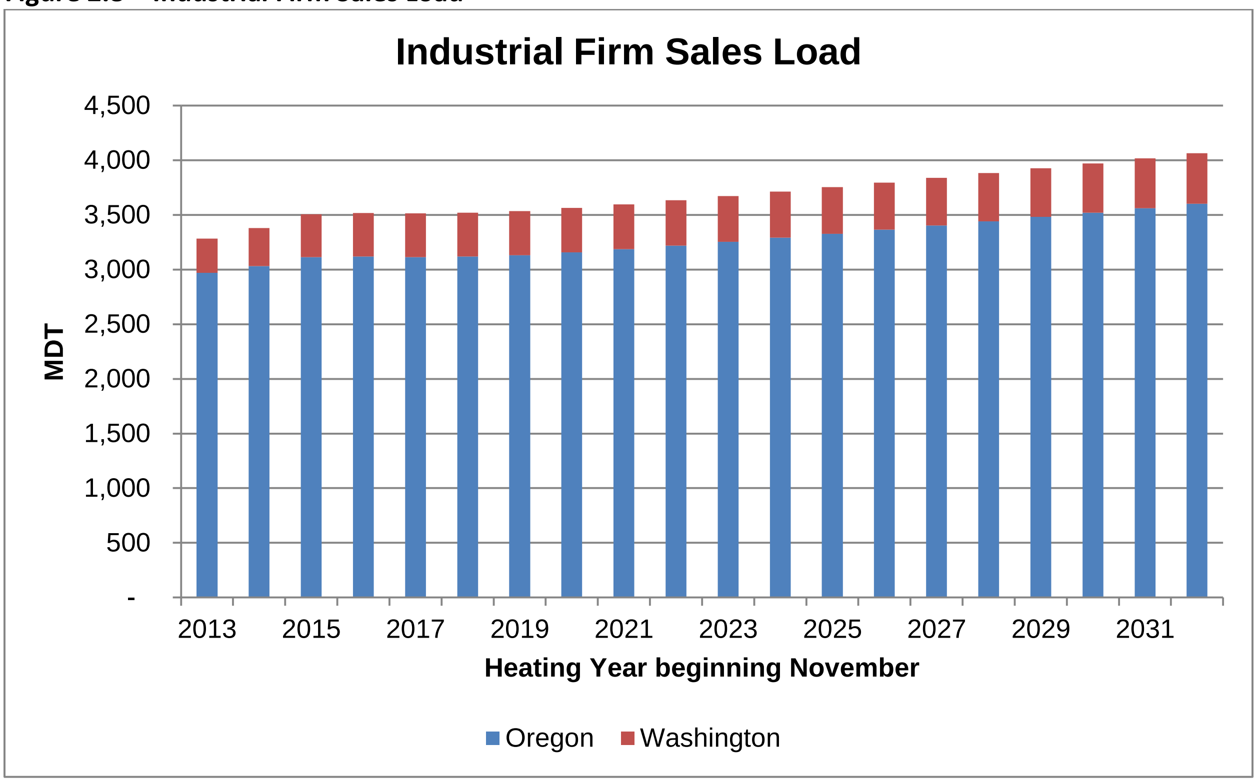
13 The Oregon forecasts of non-manufacturing employment are from Woods & Poole.

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.

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



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[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/ .

[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 the ETO. All loads referenced in this chapter refer to post-DSM loads. Please refer to Chapter Four.

Industrial Sales customers, both Firm and Interruptible, have recently begun 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 has evaluated resource planning under scenarios having alternative potential outcomes with respect to levels of load. 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 forecast by establishing a floor and a ceiling on expected load. NW Natural developed two alternative load scenarios with respect to load growth:

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 lower 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 for developing the High and Low Load Growth scenarios. 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[16] 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 monthly values for the customer and load categories[17] listed in Table 2.2 on a load center basis for each Oregon load center.

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[16] 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 .

[17] 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 is necessary to ensure identical values across the Base Case 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.

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 customer and load categories' monthly values on Low, Medium, and High population forecasts for Clark County obtained from Washington's Office of Financial Management.[18] 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 monthly values for the customer categories listed in Table 2.2 on a load center basis for both Washington load centers.

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 those in the planning horizon.

Table 2.3[19] shows the average annual rates of customer growth for the Base Case 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, 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			State 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%

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

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

Figure 2.9 - Customer Forecast Scenarios: System

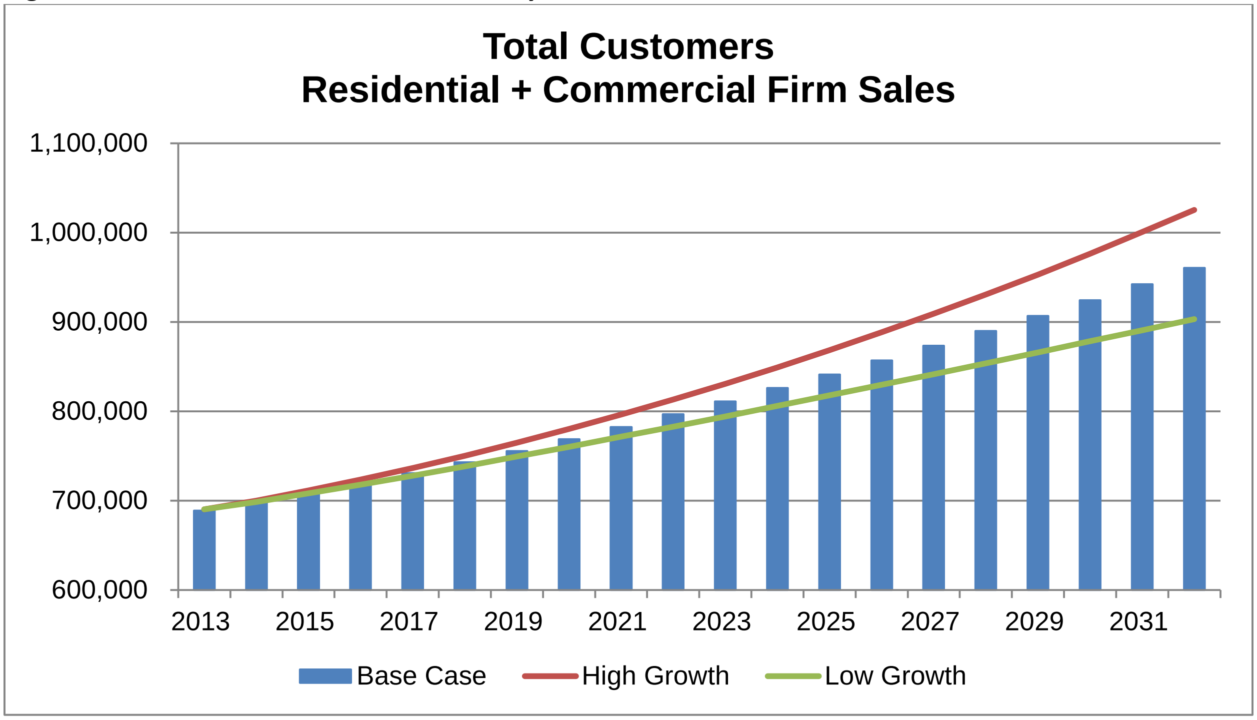


Figure 2.10 - Customer Forecast Scenarios: Oregon

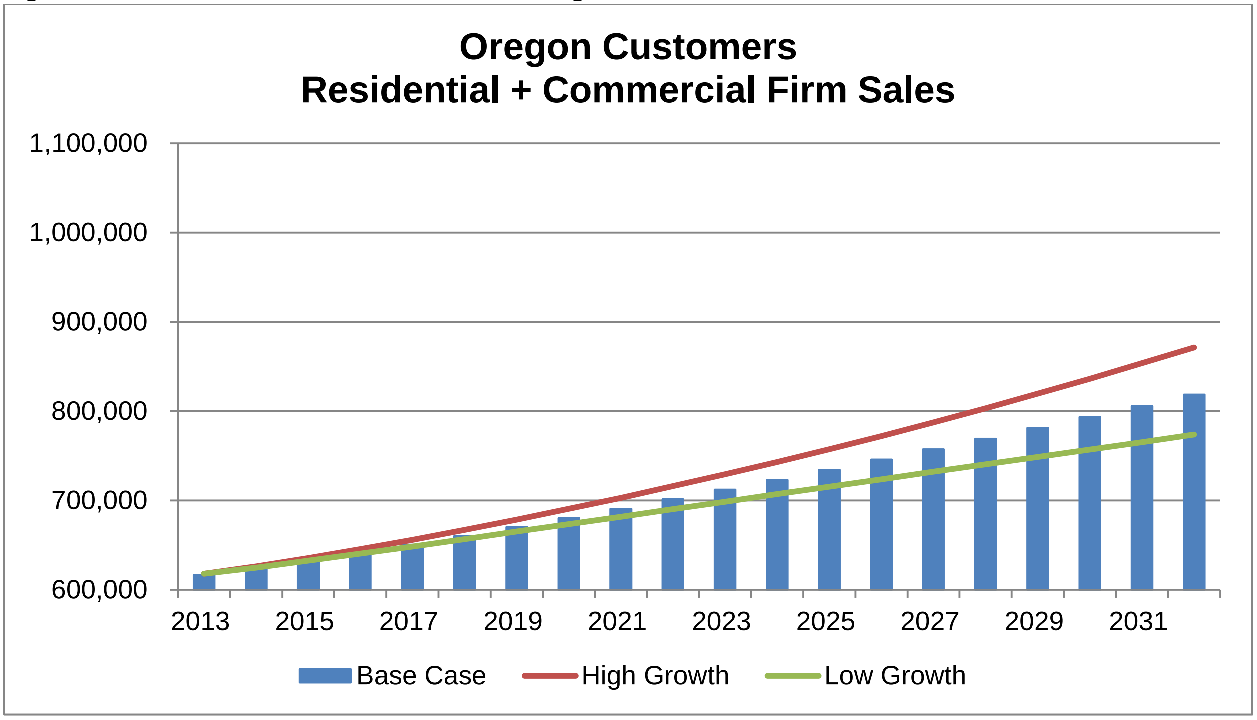
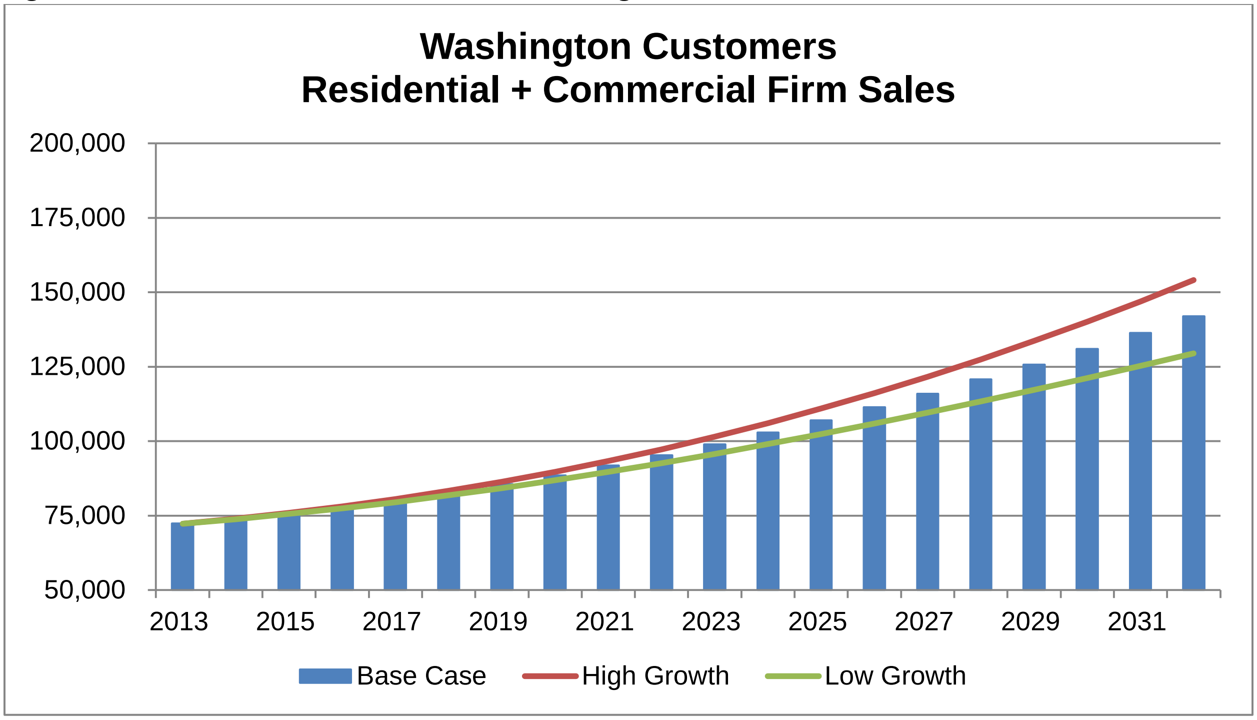


Figure 2.11 - Customer Forecast Scenarios: Washington



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. There are numerous other variables which may potentially have causal relationships to average use per customer, including degree of cloud cover, wind direction and velocity, day of the week, etc.[20] 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

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

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

$$x = HDD\ per\ day$$

$$r = heat\ factor$$

$$c = intercept$$

$$setting\ x = 0$$

[20] NW Natural will investigate the feasibility of including additional explanatory variables into the Company's use per customer modeling for the 2016 IRP.

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

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 log value of HDD to log(45).

Equation 2.3 Heat Load Regression

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

$$where$$

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

$$x_1 = \ \ln(HDD)$$

$$r_h = heat\ rate$$

$$d = intercept$$

NW Natural transforms the fitted function from the double log form by exponentiating 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

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

[21] See the following discussion of design day peak demand.

$where$

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

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

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

NW Natural does not model Industrial load as a linear 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.

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

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 (LDC) 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]

IV. WEATHER

Climate[25] 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,[26, 27] 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

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

24 See Figure 2.5, which shows the IHS CERA forecast of Henry Hub spot prices and also the related text.

25 NW Natural uses climate in this context as meaning "average weather over some extended period of time."

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

27 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).

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 Winter temperatures for a year at the 90th percentile of years in the 30-year Winter weather history, which is 1992.[28]

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 day 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 include a seven-day cold event.[29]

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 other heating season weather over the last 30 years, with the former figure sorted by total heating season HDD and the latter figure presenting the heating season HDD values chronologically. Table 2.4 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.

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28 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.

29 The Company used a three day peak event in the 2013 Washington IRP.

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

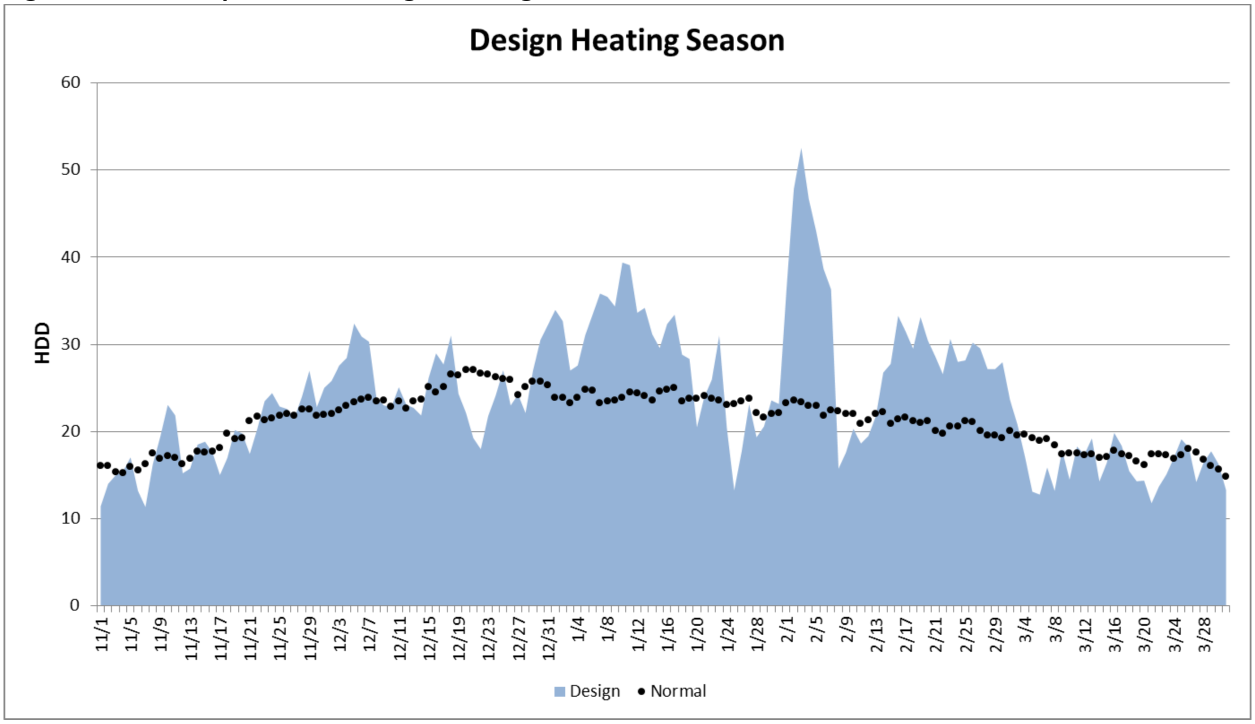


Figure 2.13 – Comparison of 30-year Total Heating Season HDD

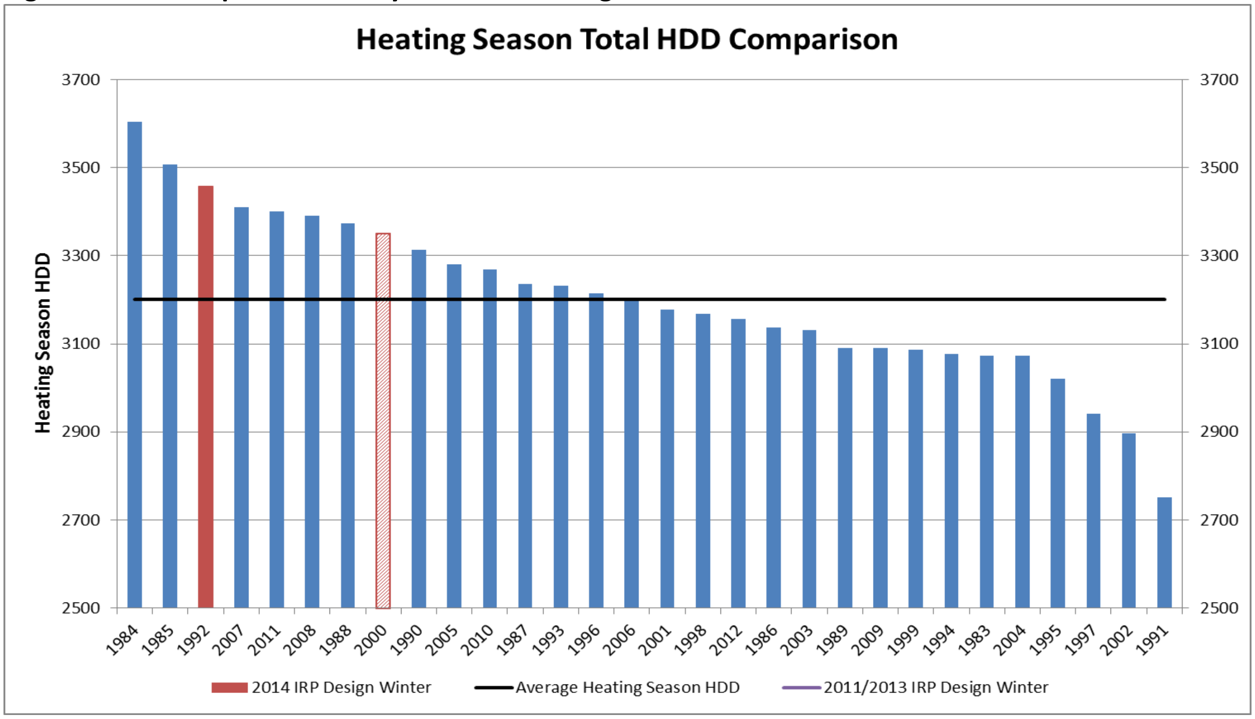


Figure 2.14 – 30-Year Comparison of Total Heating Season HDD

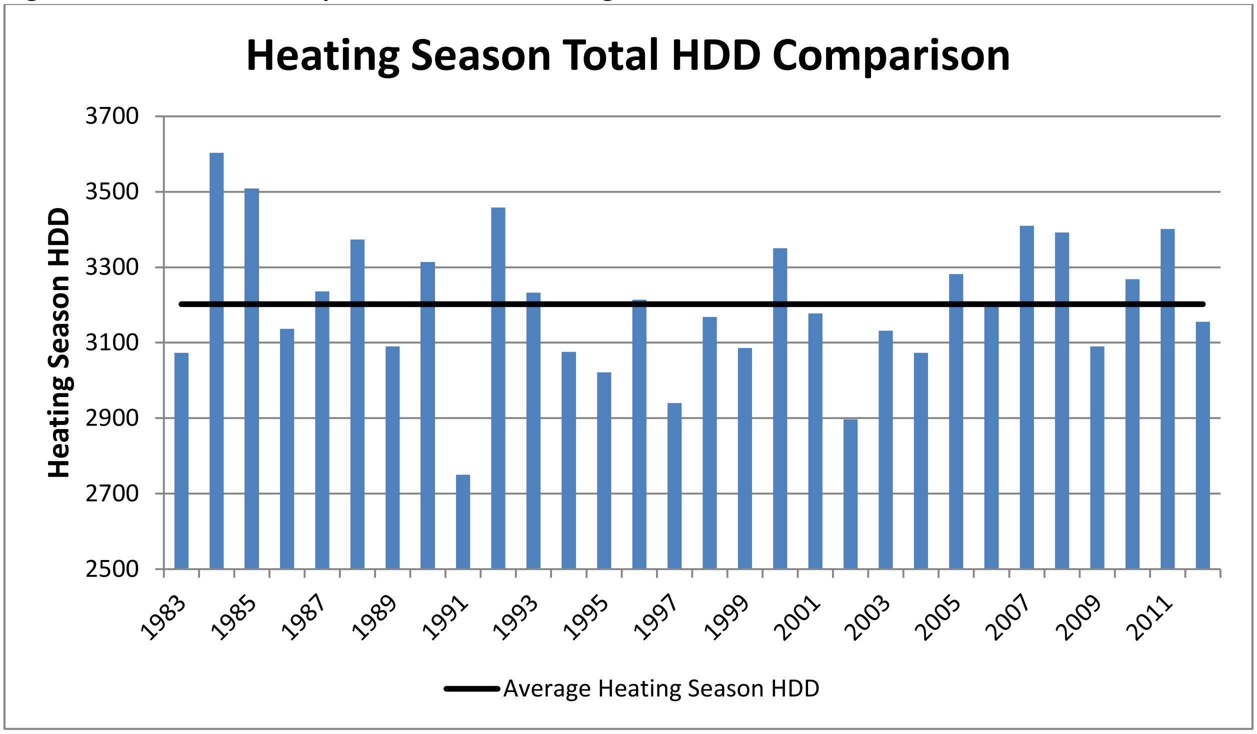
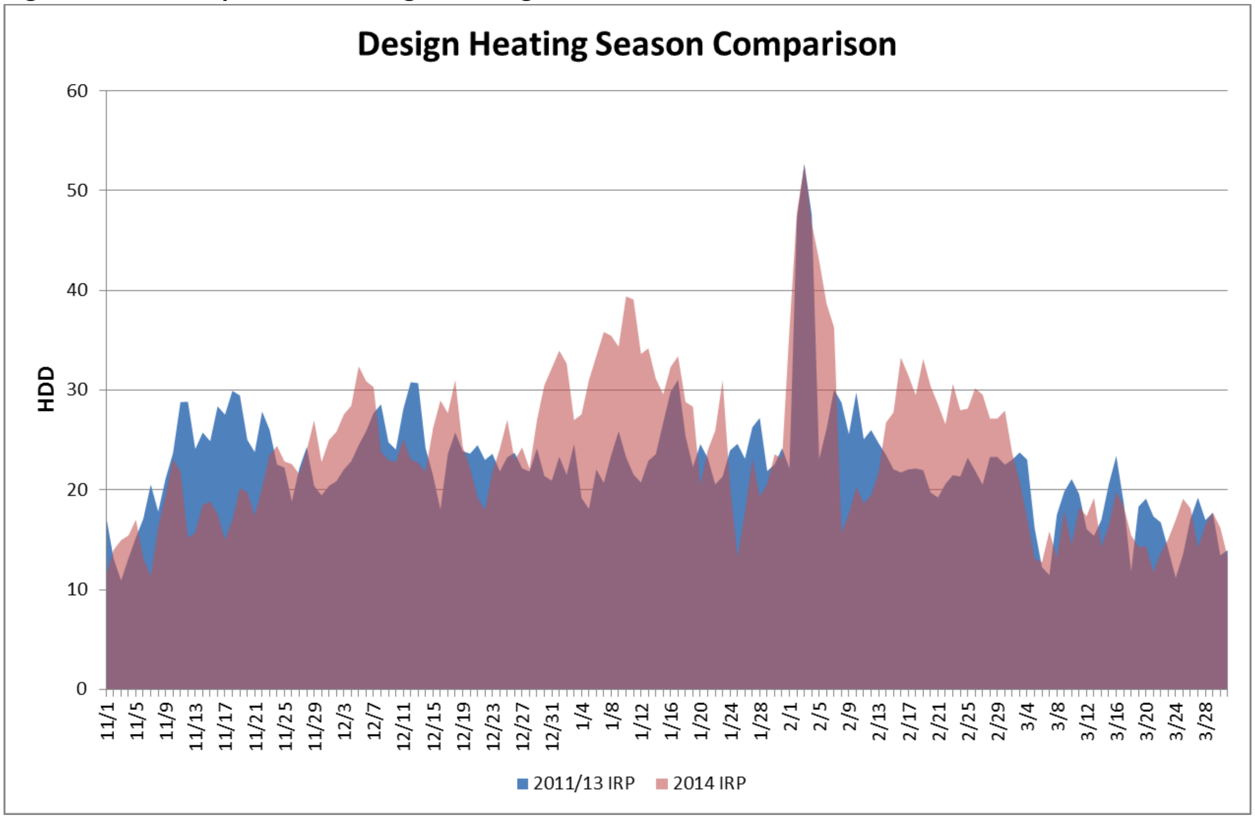


Table 2.4 – Weather by Season for 2013 Washington and 2014 IRPs

	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



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.

V. GAS PRICE FORECAST

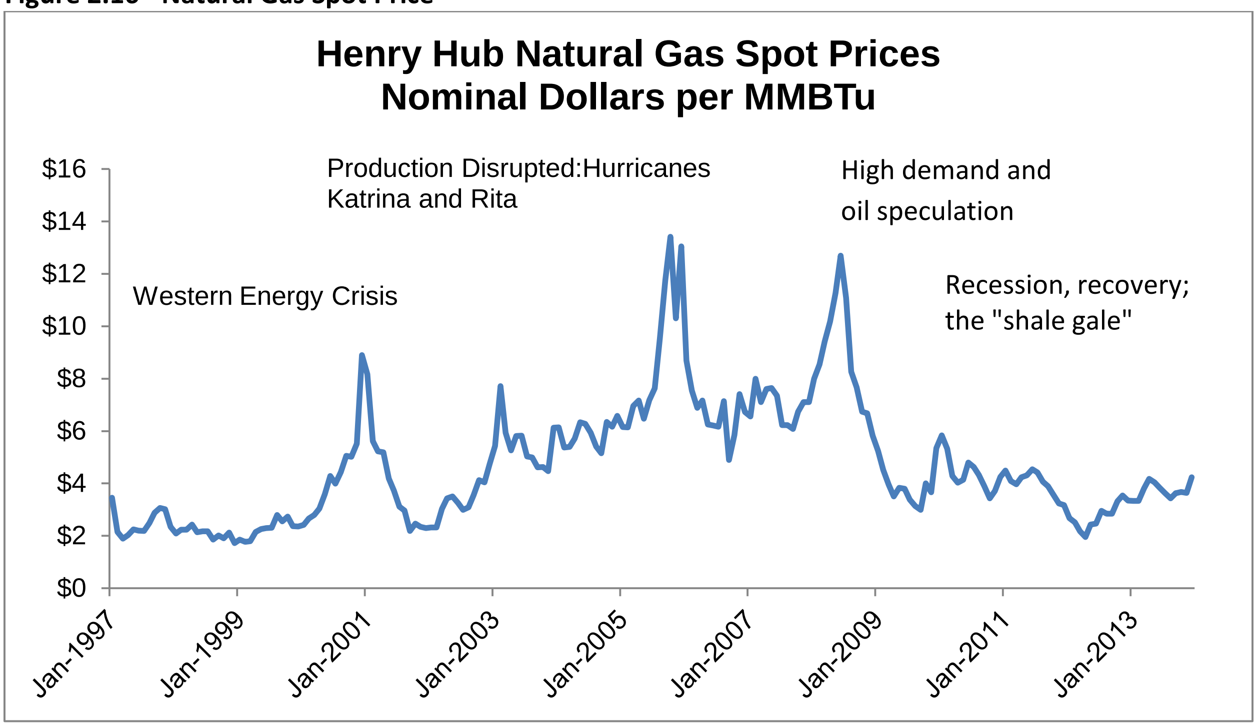
NW Natural uses a 20-year natural gas price forecast by supply basin as part of the IRP process. The forecast includes a monthly price outlook for Henry Hub, Rockies (Opal), British Columbia (Sumas), Alberta (AECO) and Malin. Like many commodities, the historic volatility in natural gas prices makes 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, weather, and new and traditional supplies—including gas produced using more efficient extraction technologies. The Company reviews several public and proprietary price forecastsand 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.

A. Price Volatility

The combination of lower demand and increased supplies has resulted in low gas prices over the past four 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 natural gas demand. 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”.

Figure 2.16 displays the history of natural gas prices since 1997. 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.

Figure 2.16 - Natural Gas Spot Price



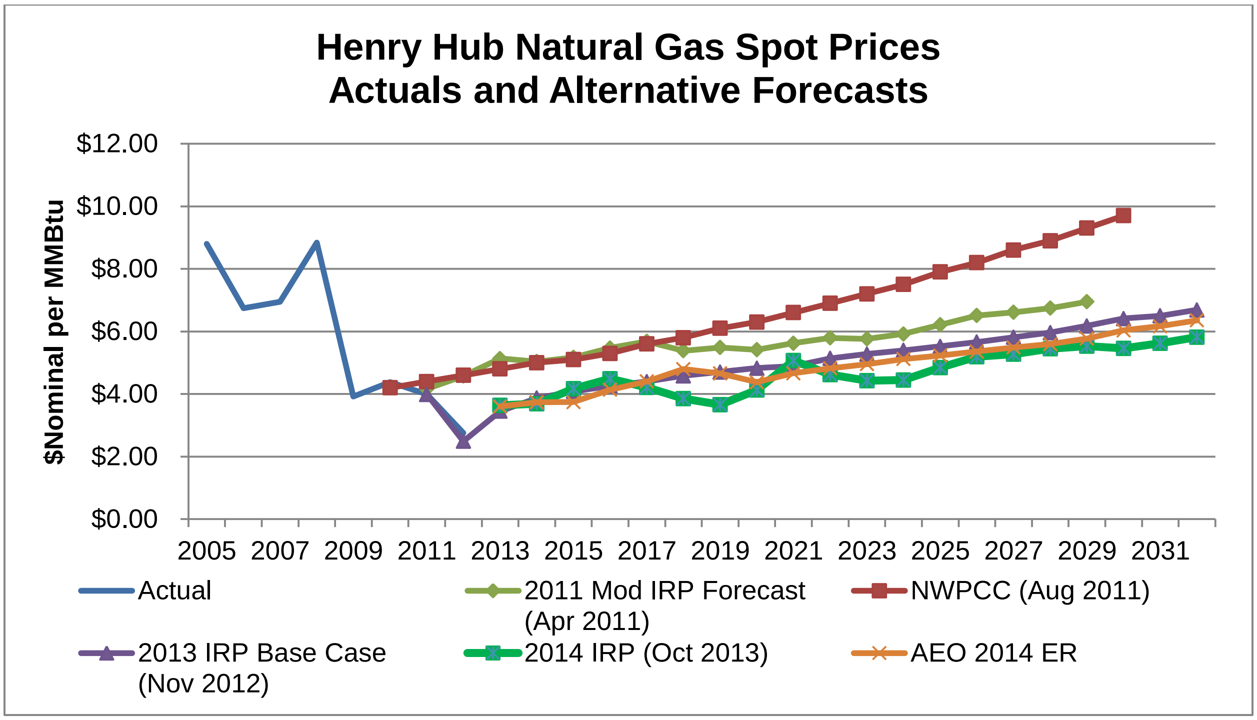
B. Price Forecast

The forecast of natural gas prices impacts the least cost planning modeling and avoided cost calculations. NW Natural also uses the forecast 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 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.

NW Natural's price forecast, which the Company derives from a proprietary forecast developed by third party provider IHS CERA Inc.,[30] 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:

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

30 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.

primary markets are likely to be electric power generation, industrial processes and feedstock,[31] 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 (i.e., where smaller, local facilities powered by natural gas provide a portion of electric requirements).

NW Natural developed three scenarios 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 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. 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 resource modeling is about eight percent of current load.[32] The following figures show projected loads for each scenario by market segment. Figure 2.21 compares the three scenarios' loads.

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[31] 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 .

[32] 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

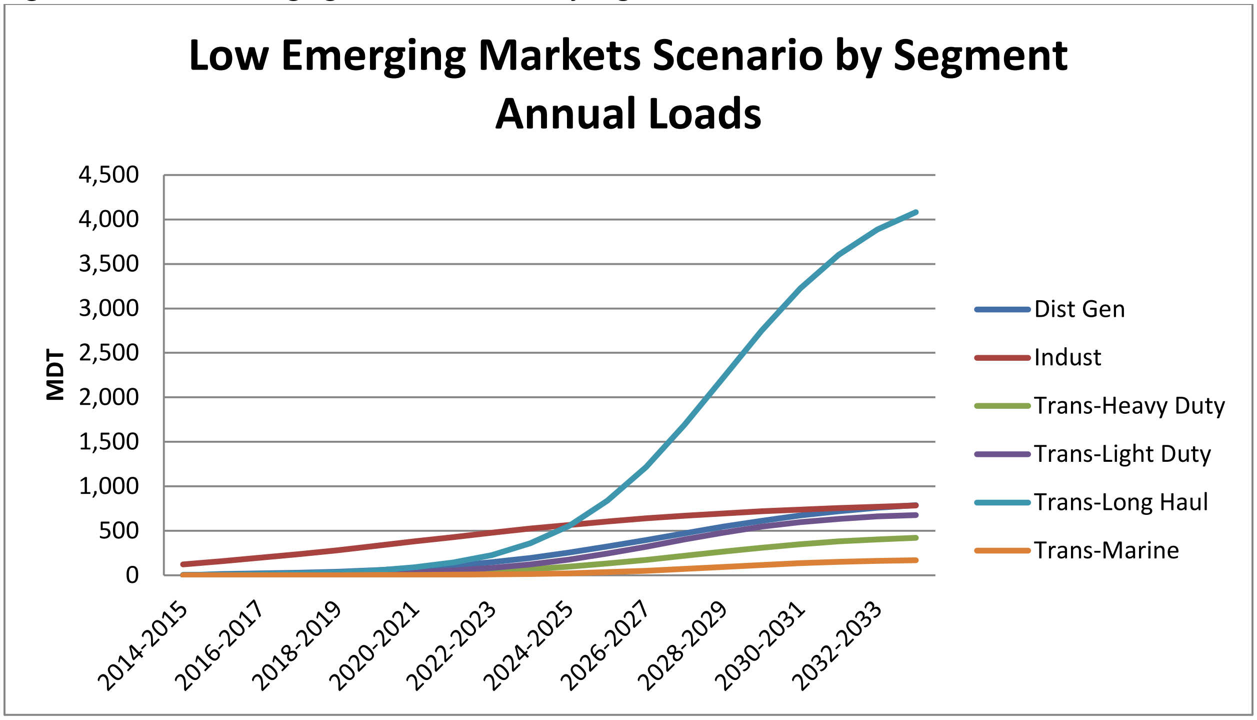


Figure 2.19 – Medium Emerging Market Scenario by Segment

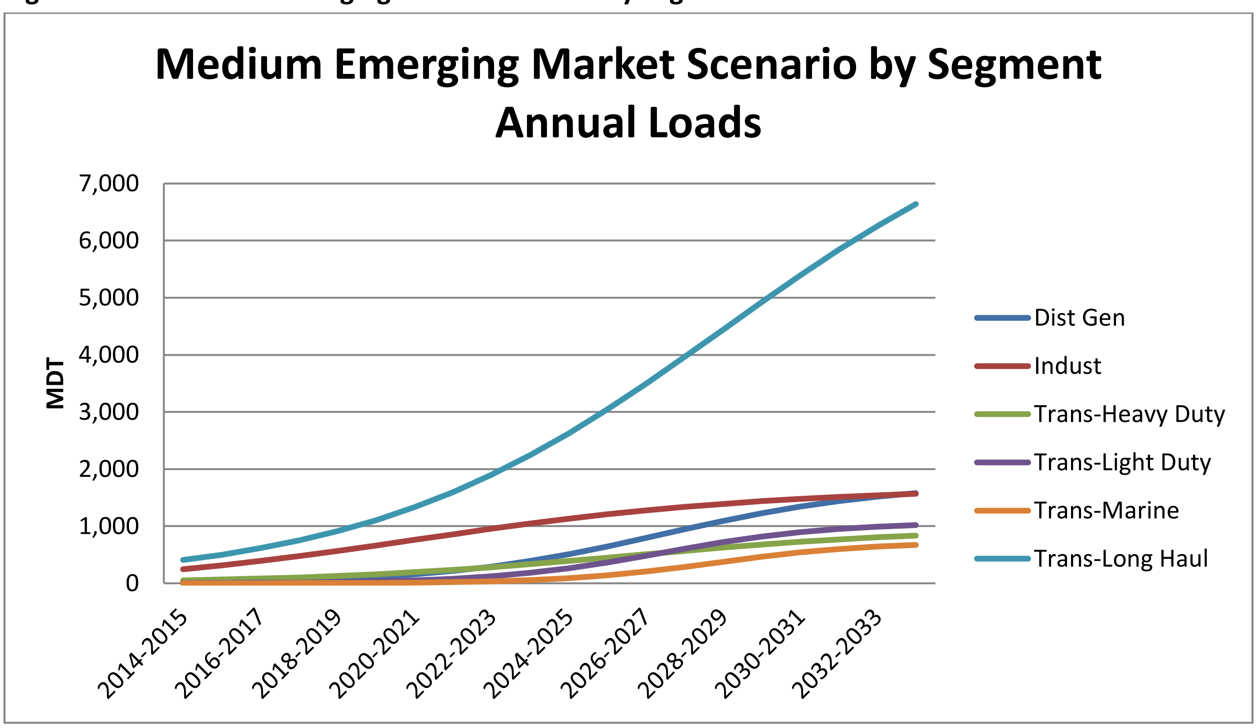


Figure 2.20 – High Emerging Market Scenario by Segment

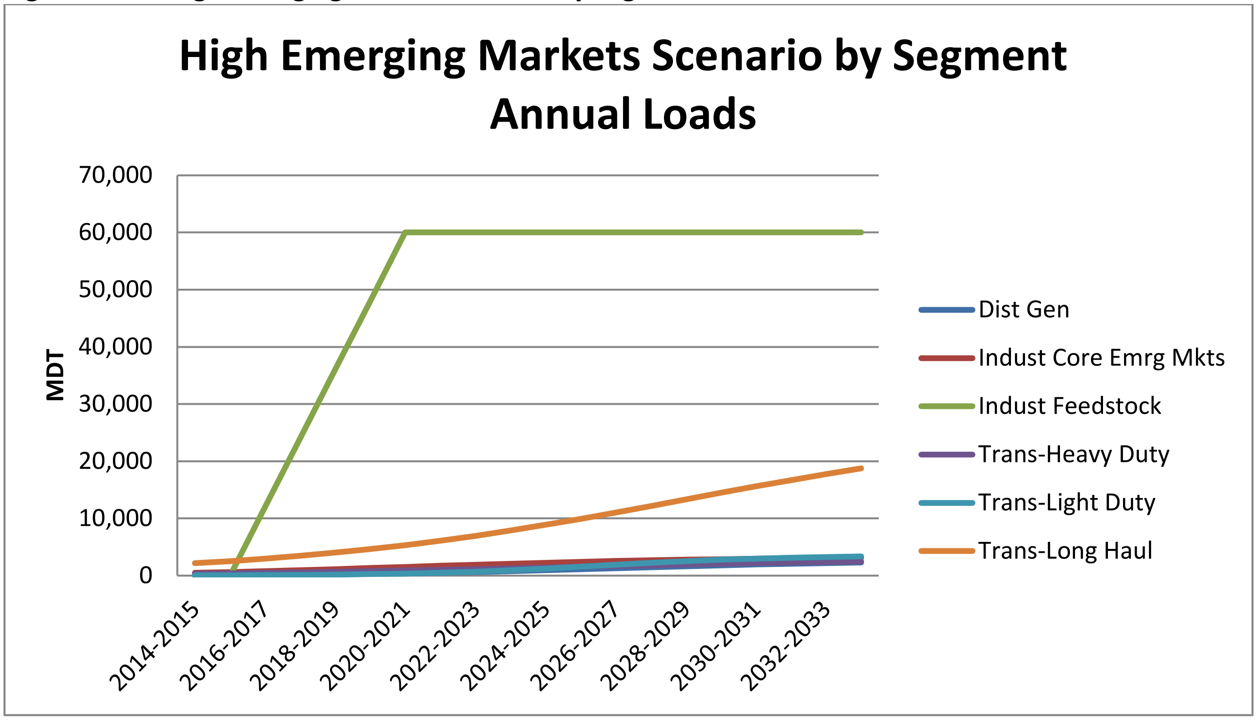
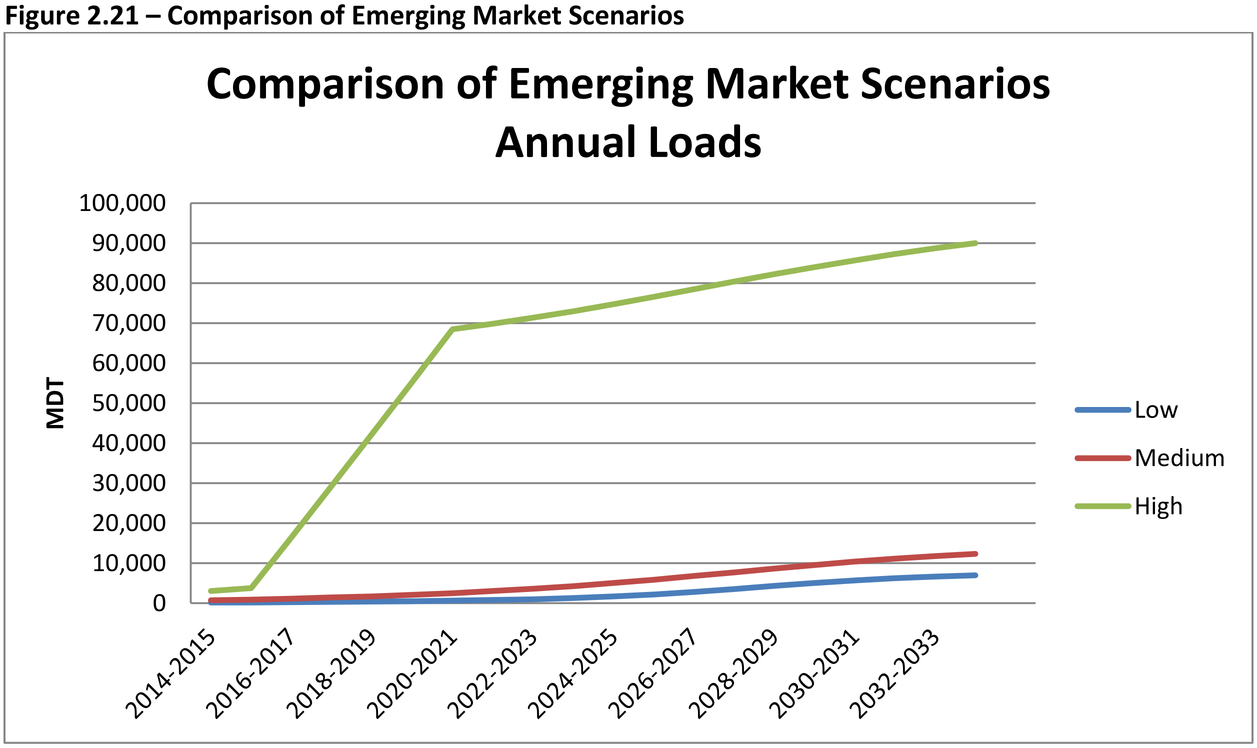


Figure 2.21 – Comparison of Emerging Market Scenarios



VII. RESULTS

NW Natural combines the primary components of the load forecast—customer forecast, use per customer model, and weather pattern—to generate 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 the 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

NW Natural's Base Case design weather load forecast[33] provides the best estimate of future firm service load requirements for a colder than average winter with a multiday cold event including 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 2.5. 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, as Firm Transportation customers provide for their own upstream resource adequacy needs, 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.

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33 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

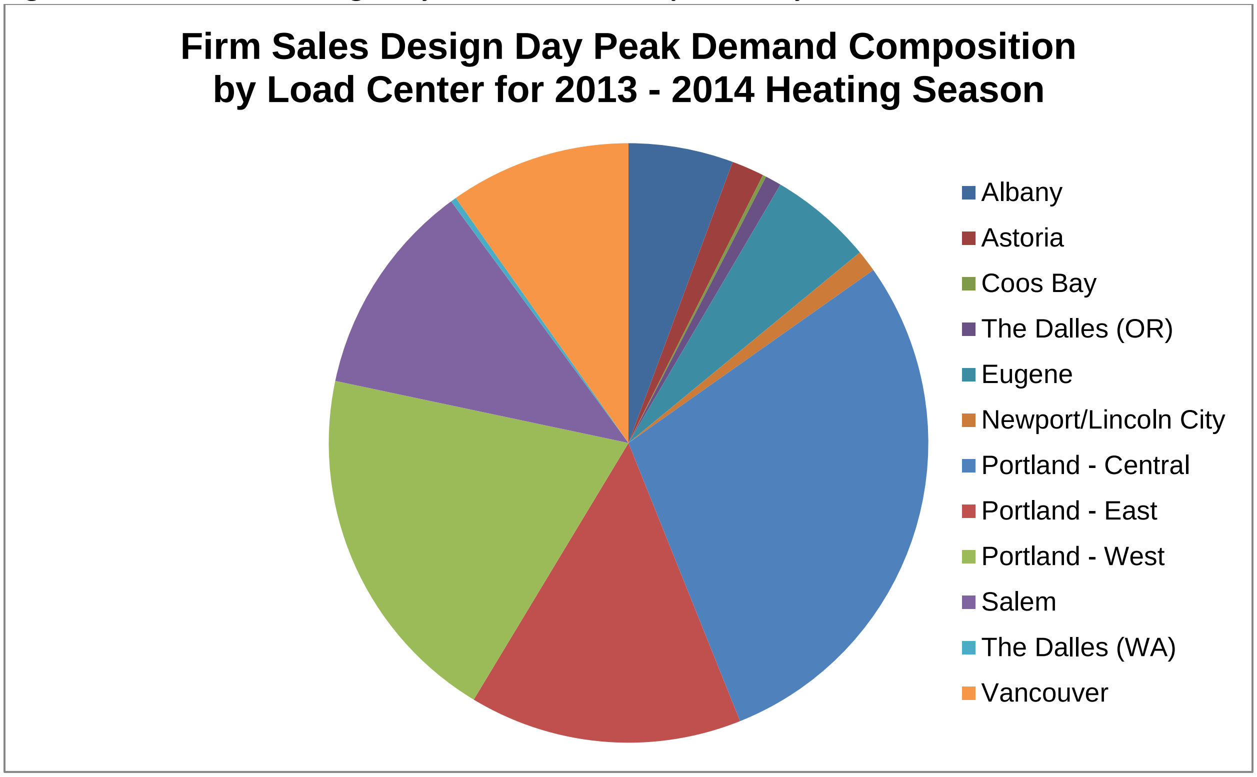


Figure 2.23 – Firm Sales Design Day Peak Demand Composition by Load Center: 2032 - 2033

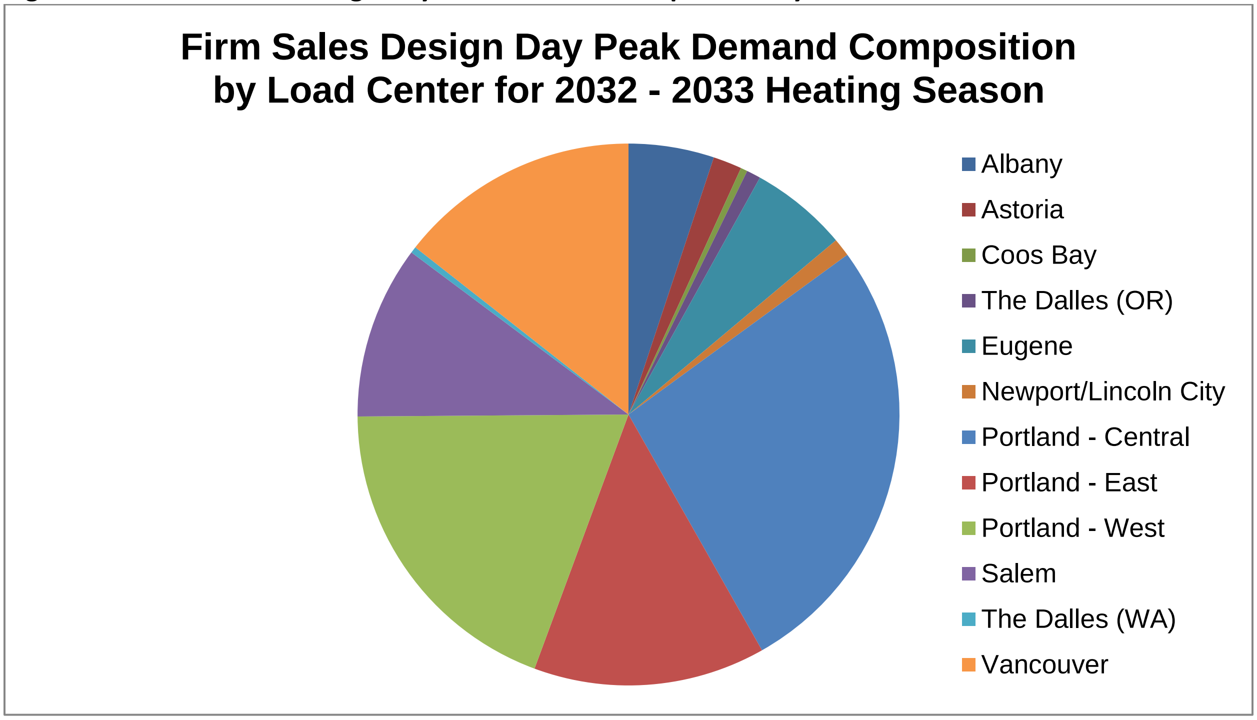


Figure 2.24 – Composition of Growth in Firm Sales Design Day Peak Demand over Planning Horizon

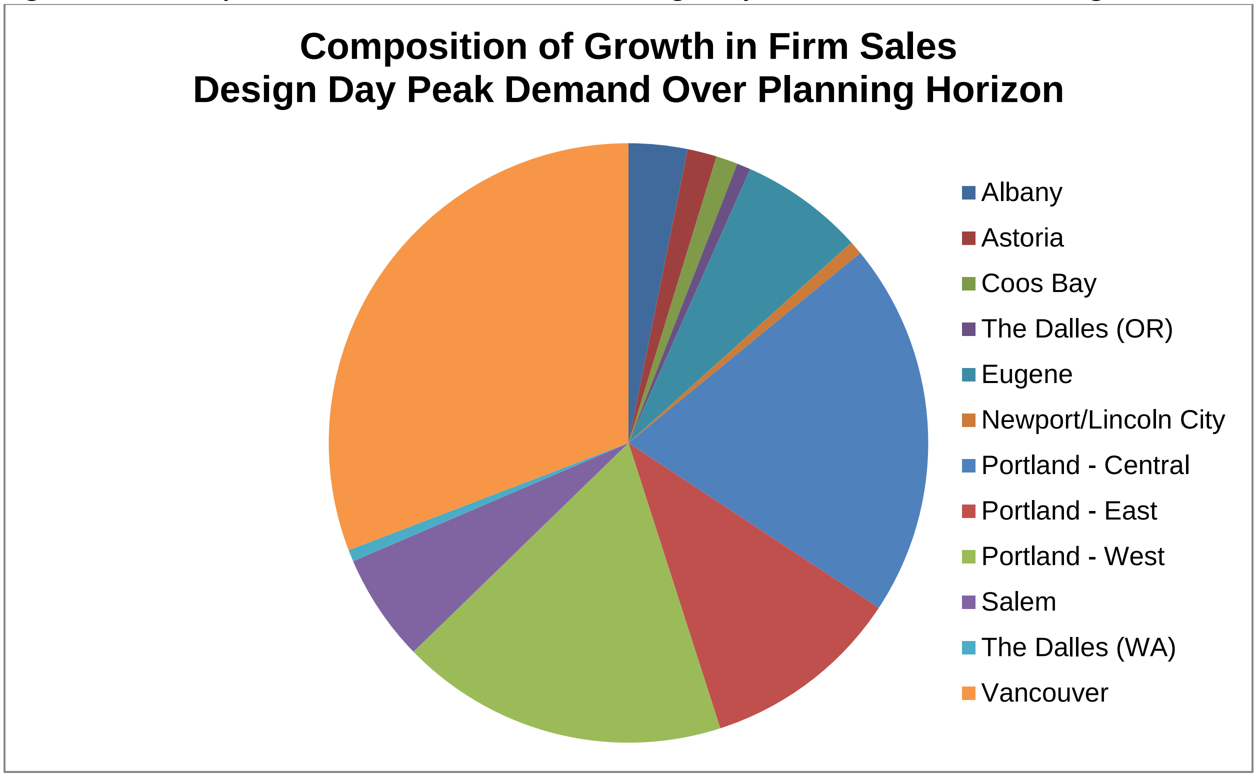


Figure 2.25 – Firm Sales Design Day Peak Demand

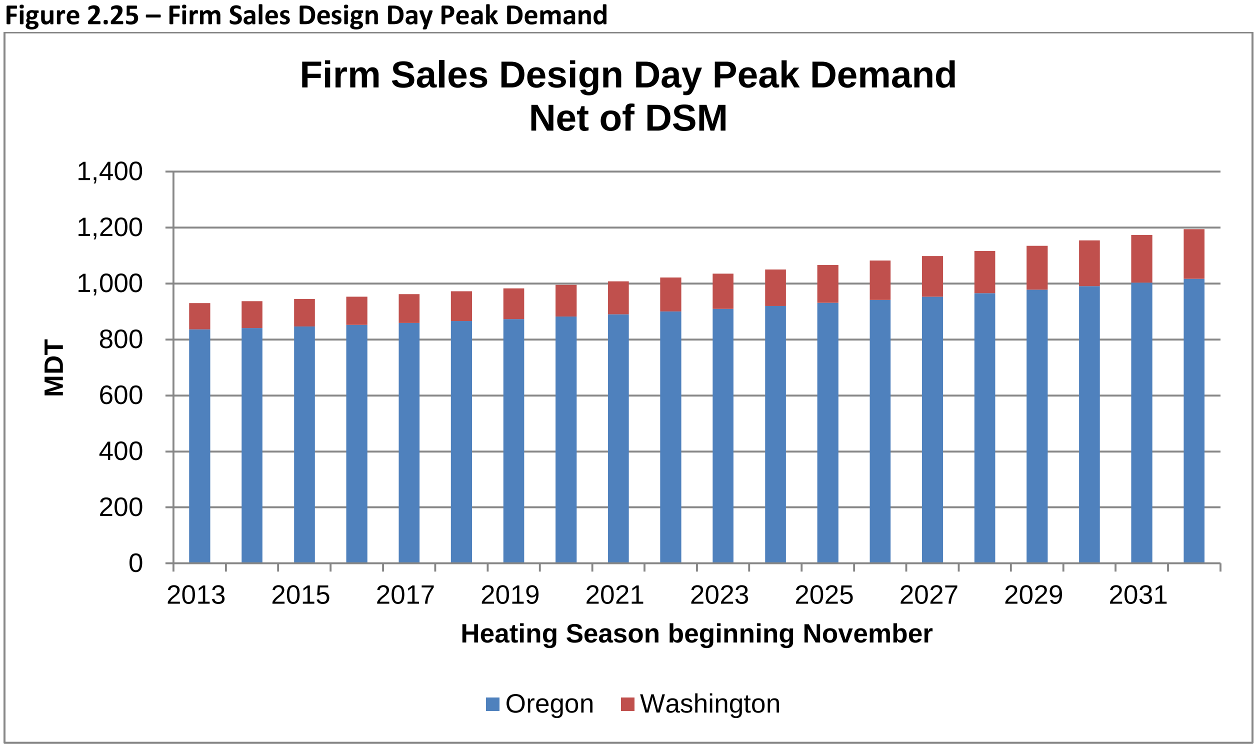


Figure 2.26 – Annual Growth Rates in Firm Sales Design Day Peak Demand

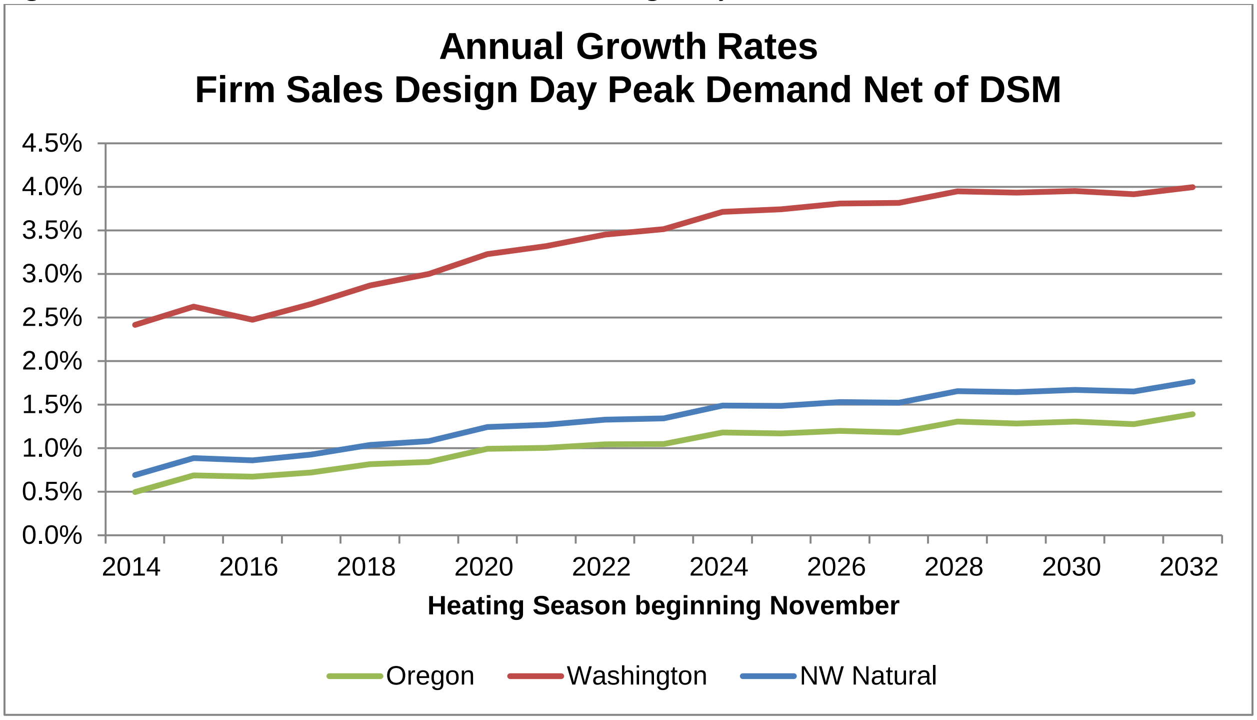


Figure 2.27– Firm Sales and Firm Transportation Design Day Peak Demand

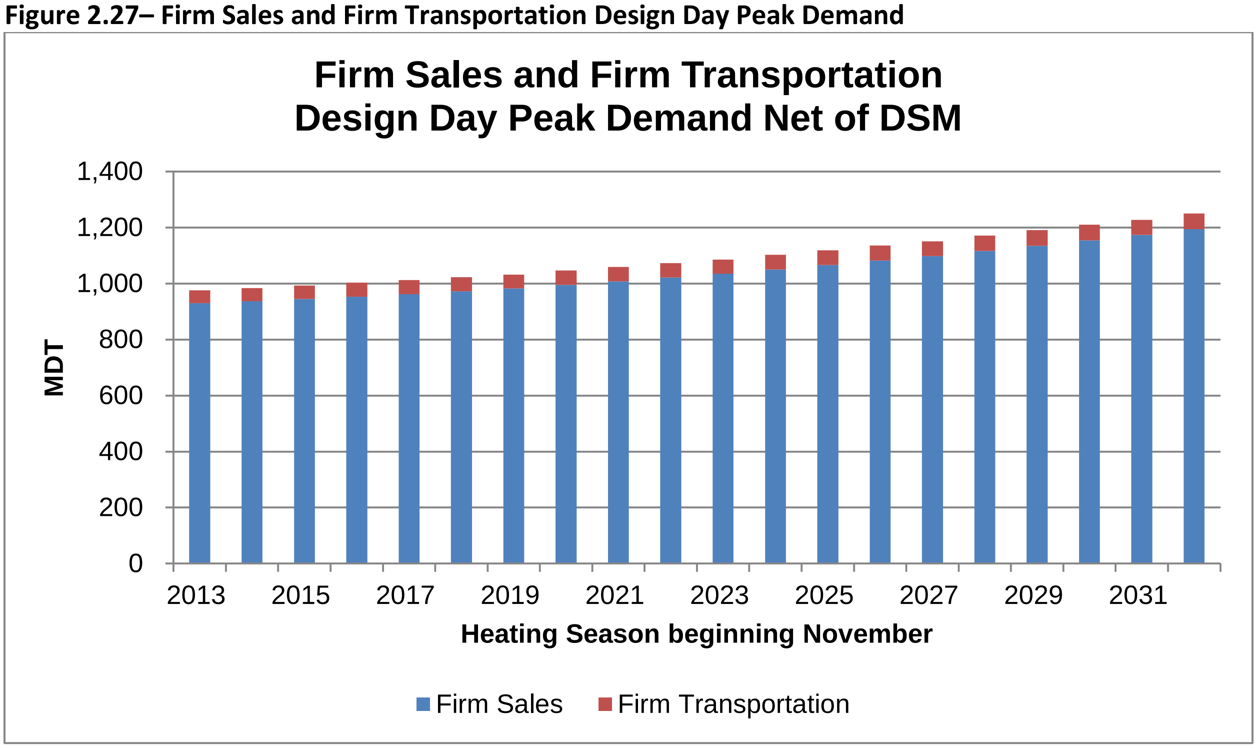


Figure 2.28 shows the Base Case Firm Sales design day peak demand net of DSM by load center. Figure 2.29 shows the Base Case Firm Sales annual load net of DSM by load center. Figure 2.30 shows the Base Case Firm Sales annual load net of DSM by state. See Chapter Four for discussion of the DSM forecast.

Figure 2.28 – Base Case Firm Sales Design Day Peak Demand

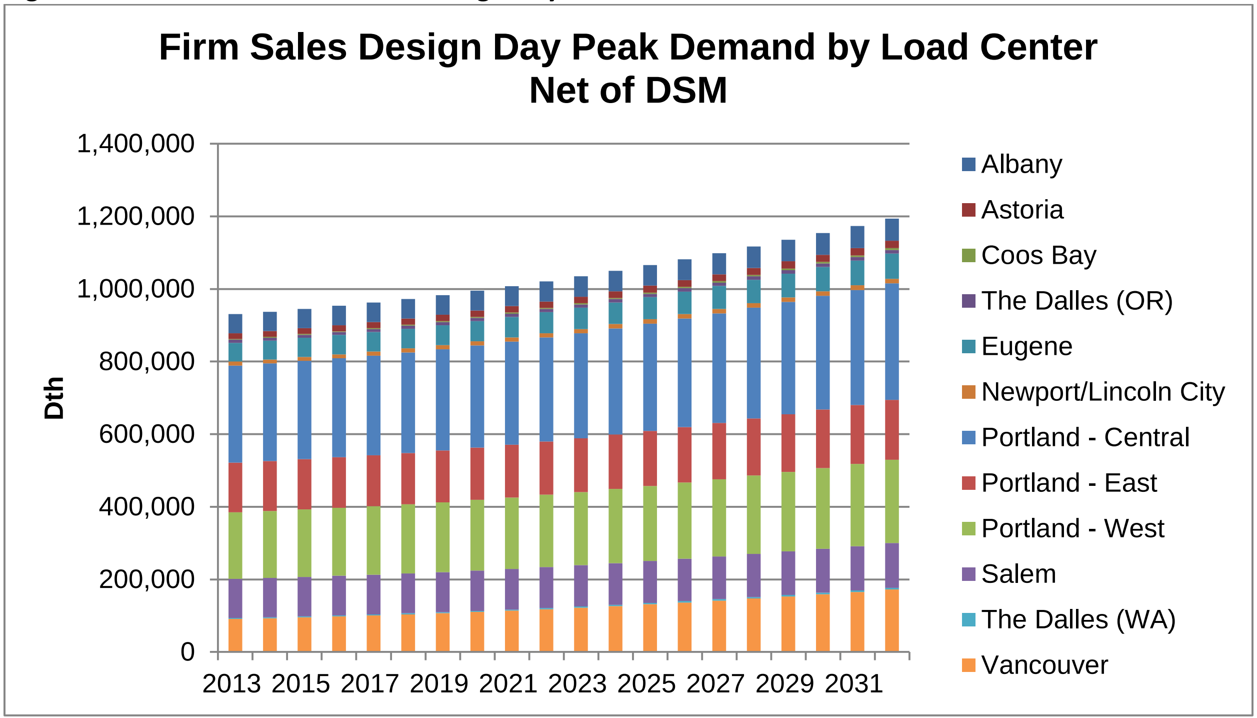


Figure 2.29 - Base Case Firm Sales Annual Load

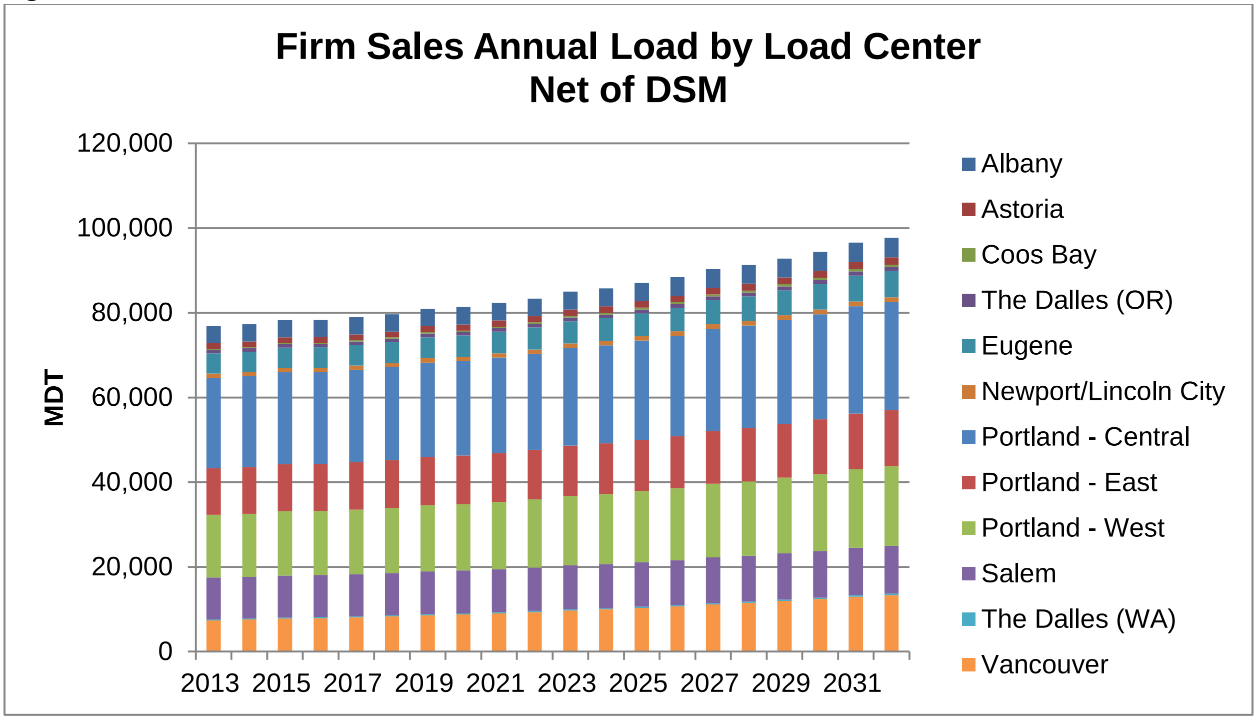
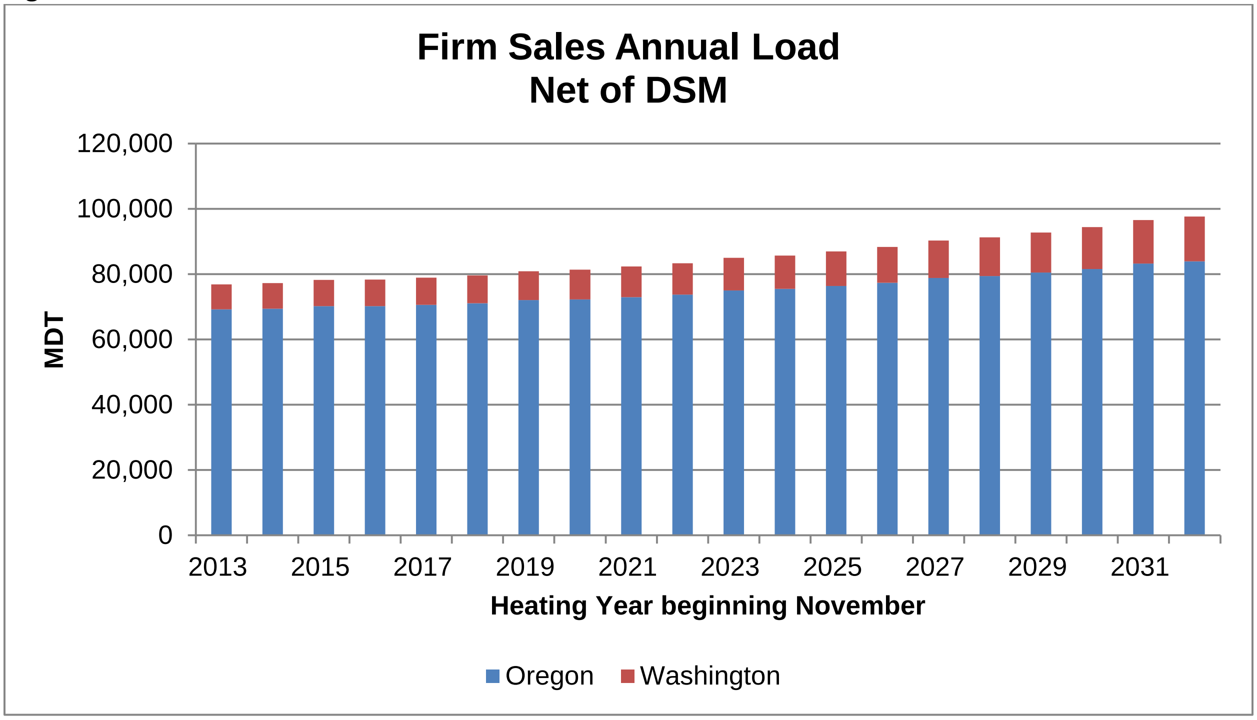


Figure 2.30 – Firm Sales Annual Load



B. Alternative Growth Scenarios

Table 2.5 compares the Firm service design day peak demand average annual growth rates for the Base Case and the High Load Growth and Low Load Growth scenarios described above. 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 2.5 – 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%

Figure 2.31 – NW Natural Firm Sales Customers

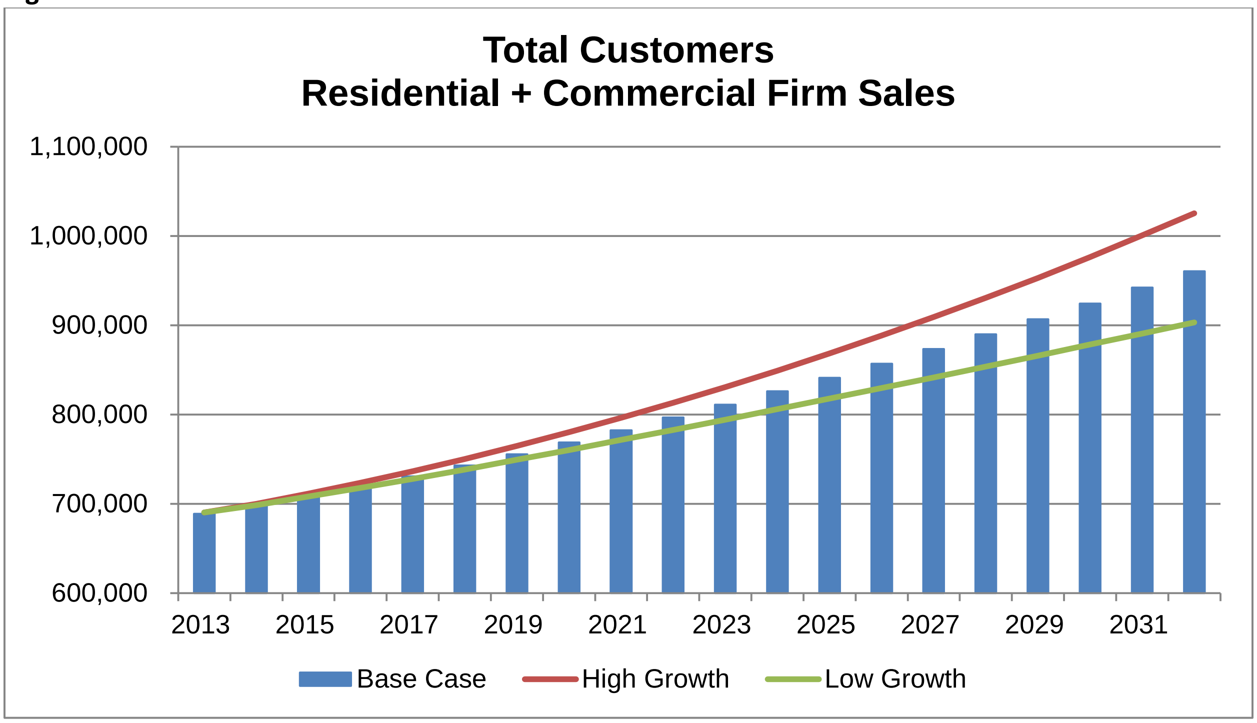


Figure 2.32 – Oregon Firm Sales Customers

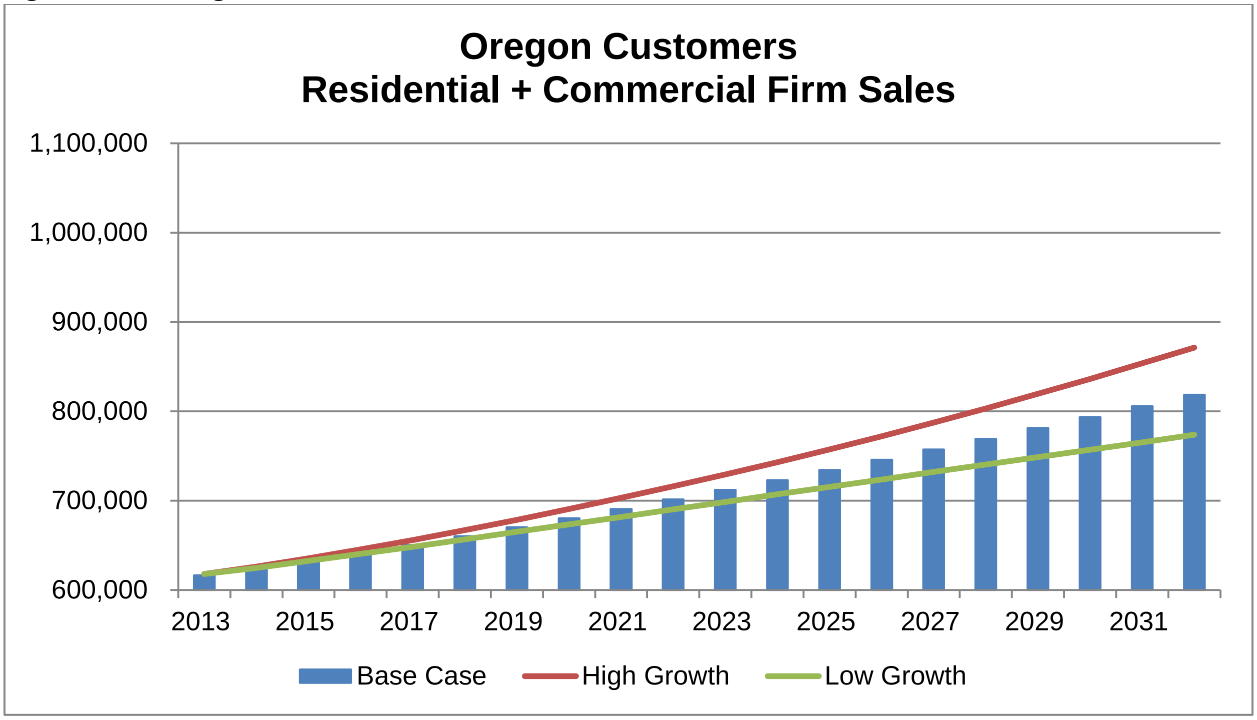


Figure 2.33 – Washington Firm Sales Customers

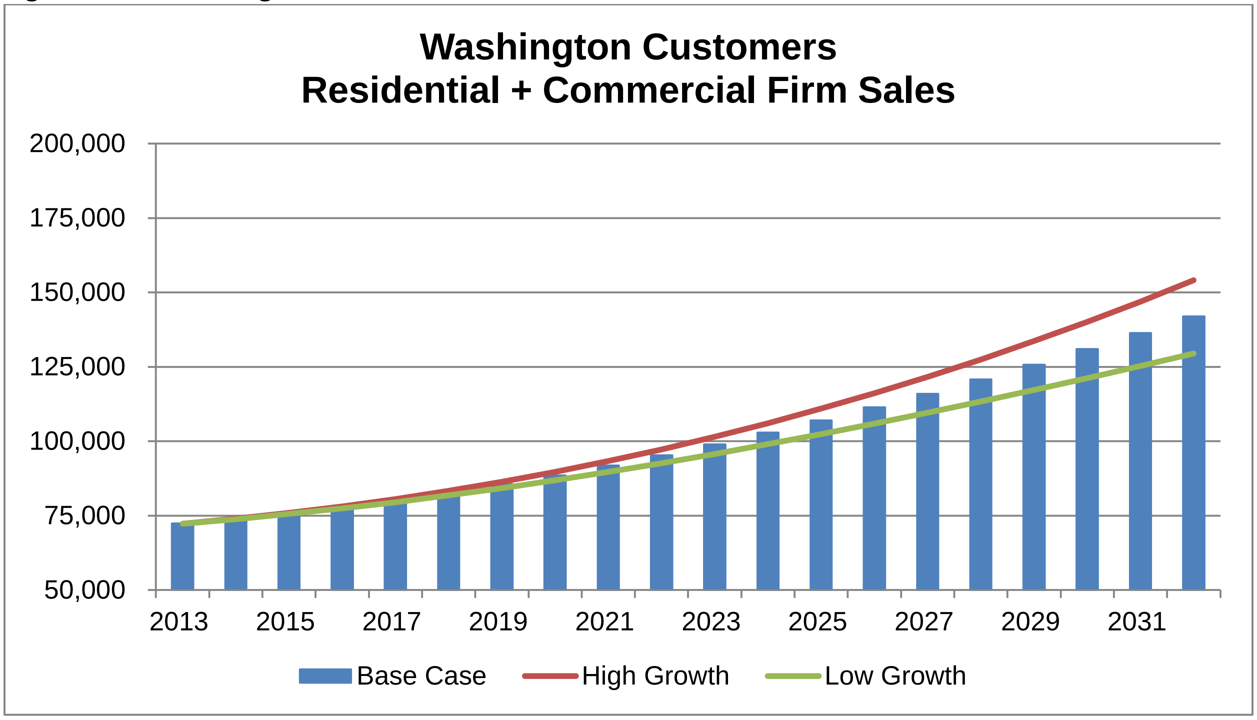


Figure 2.33 shows Firm service (Firm Sales and Firm Transportation) design day peak demand net of DSM for the Base Case and alternative scenarios. The Base Case includes the Low Emerging Markets

scenario, while the Medium and High Emerging Markets scenarios include Base Case 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 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 2.34 shows the scenarios in Figure 2.33 on the basis of Firm service annual loads net of DSM. 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

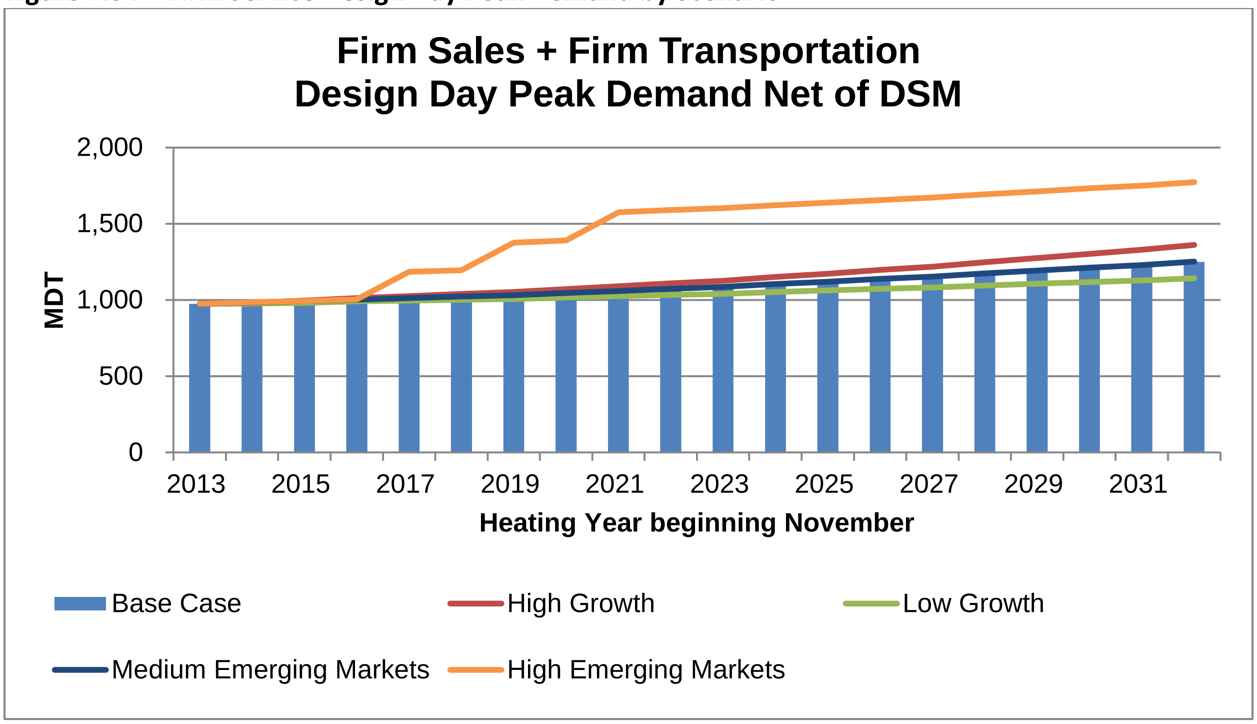
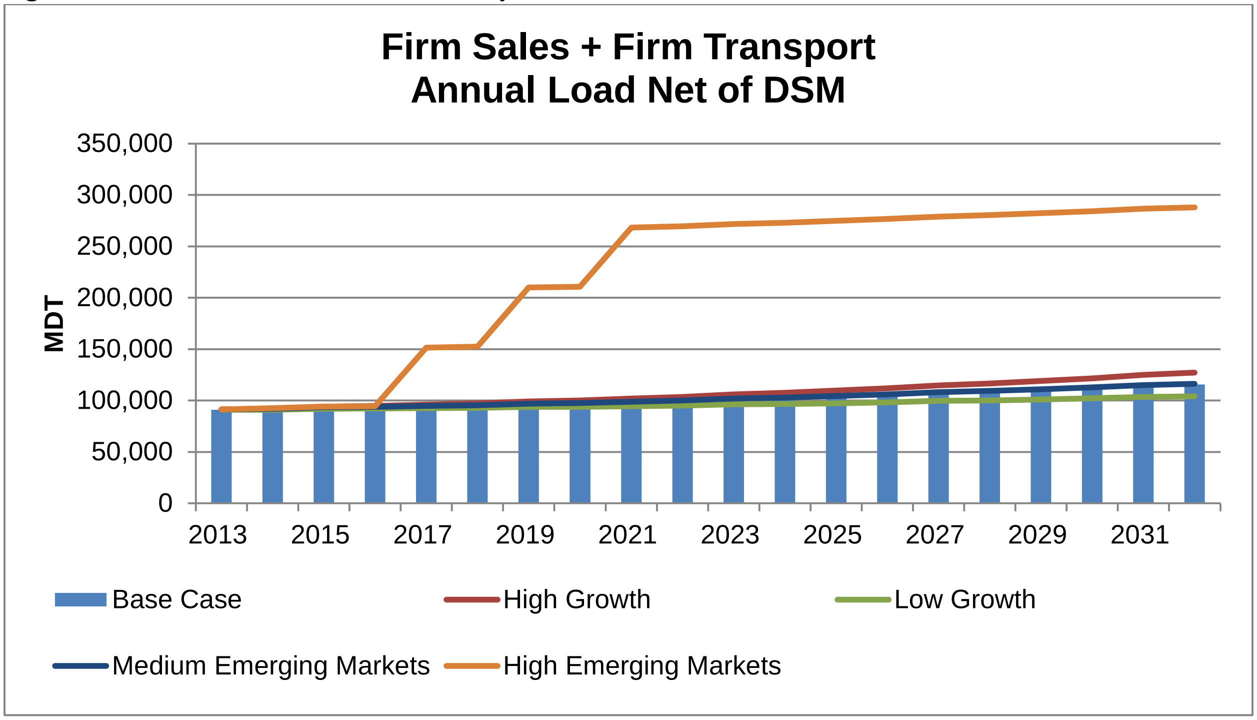


Figure 2.35 – Firm Service Annual Load by Scenario



C. Carbon Scenarios

PLACEHOLDER FOR ADDITIONAL CARBON INFORMATION WHEN AVAILABLE

VIII. FORECAST ACCURACY AND PEAK DAY ANALYSIS

NW Natural monitors the accuracy of its load forecast model by performing a "backcast" of two relatively recent cold weather events. 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, temperatures, and gas rates from the timeframe to calculate a forecast demand, which the Company identifies as a "backcast." NW Natural compares the results with the actual daily "sendout," or amount of gas the Company delivered to all sales customers to meet demand for each of the "backcast" days.

The two most recent cold weather peak events occurred on December 8, 2013, and February 6, 2014. Table 2.7 summarizes the weather conditions, customer numbers, actual demand and forecast demand.

Table 2.7 - "Backcast" Information

Date	Actual Firm Demand (MDT)	Forecast Model Demand	Error (MDT & %)	Customers	Res. Price per therm	HDD	Ave. Wind Speed at PDX	Weather Conditions
Monday Jan. 5, 2004	717.73	707.27	-10.46 -1.5 %	582,721	$0.91	43	24 mph with gusts to 43	Fog, Rain, and Snow
Wednesday, Dec. 9, 2009	697.97	756.90	58.93 +8.4 %	667,456	$1.39	44	2 mph	Sunny and Clear

February 6, 2014 is the Company's all-time single-day record of delivered gas.

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, with the Oregon rate at 1.8% and the Washington rate at 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.
- 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.

Chapter 3: Supply-Side Resources

I. OVERVIEW

This chapter discusses the gas supply resources the Company currently uses to meet existing firm customer supply requirements, as well as 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 system enhancements necessary to distribute the gas. This chapter surveys existing and potential resources that have been included in the analysis without judgment as to the resources that will be chosen. Also, in response to Technical Working Group feedback, an additional section ("The Cutting Room Floor") now describes potential resources that are currently so speculative for one reason or another that they were discarded prior to any analytical treatment. Chapter Six describes the actual linear programming optimization process, which selects the resources that are least cost under a variety of load growth scenarios.

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, 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).[1] 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 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

[1] 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.

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 and other forums. 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 his/her thermostat in response to higher prices, but during an extreme cold weather episode, raise that thermostat rather than risk frozen pipes or endure uncomfortable conditions. This may be a temporary move that has a negligible impact on annual requirements, but, in the aggregate, it could have an 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. 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 holds all rights to all of its firm transportation contracts. Similarly, the Company has released a small portion of its NWP capacity to one customer but has retained certain heating season recall rights. Details of those contracts are provided in Table 3.1.

Table 3.1[2] - Firm Transportation Capacity as of November 2013

Pipeline and Contract	Contract Demand (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	3/31/2015
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	(30,000)	10/31/2014
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	10/31/2014

[2] Notes to Table 3.1:

a. For existing contracts, the SENDOUT® model uses the pipeline rates currently paid by NW Natural.
b. The WEI and SCP contracts are denominated in volumetric units. Accordingly, the above energy units are approximations.
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.

1995 Rationalization	57,417	10/31/2014
Engage Capacity Acquisition	3,708	10/31/2014
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	57,822	10/31/2014
Southern Crossing Pipeline (SCP)	47,343	10/31/2020

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 with a third party to find value-added transactions that benefit customers.

B. Gas Supply Contracts

The Company's portfolio of supply contracts for the 2013-2014 heating season is indicated in Table 3.2. The contracts with near-term expiration dates will either be renegotiated or replaced prior to the next heating season. The contracts are baseloaded, meaning they have a daily delivery obligation, unless labeled as "Swing Supply," which means one party has an option on all, some or none of the indicated volumes at its discretion.

Table 3.2[3] - 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	

[3] Notes to Table 3.2:

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.

C. Storage Resources

The Company relies 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 are located outside the Company's service territory. The Company 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.

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 represents the portion of the present design capacity reserved for utility service. Mist currently has a maximum total daily deliverability of 520,000 Dth/day and a total working gas capacity of about 16 million Dths as contained 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. As core needs grow, existing storage capacity may be recalled and transferred for use by core utility customers. The IRP models the recallable portion of the existing Mist storage capacity as an incremental resource that is discussed in Section V of this chapter.

Table 3.3 – Firm Storage Resources

Facility	Max. Daily Rate (Dth/day)
Jackson Prairie	46,030
Plymouth LNG	60,100
Mist (reserved for core)	275,000
Gasco LNG	120,000
Newport LNG	60,000

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 Purchased Gas Adjustment (PGA) filing rather than the IRP.

A significant change from prior IRPs is the Company's consideration of its Plymouth LNG contract. The table below relates the Company's storage service agreements at Jackson Prairie and Plymouth under NWP's Rate Schedules SGS-2F and LS-1, respectively, along with the associated transportation service under NWP's Rate Schedule TF-2:

Table 3.4 – NWP Storage Resources and Related Transportation Service

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

The subordinate or secondary nature of portions of the TF-2 firm transportation service has been in place for at least the last twenty years (the terms "subordinate" and "secondary" are used synonymously by NWP to denote priorities that are below that of Rate Schedule TF-1 primary firm transportation service). This had not created a concern until December 6, 2013. On that morning, as a cold weather event was enveloping the region, the Company scheduled ("nominated") its Plymouth service (LS-1 and TF-2) 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 be curtailed due to its secondary nature and a lack of available transportation capacity between the Plymouth plant and the Company's system. That is, there was no available capacity through the Columbia River Gorge section of NWP's pipeline system.

The curtailment of 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 peak design.

The Company's conclusion was that it could no longer count on 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 recently removed Plymouth TF-2 deliveries from its firm resource stack in this IRP analysis.

Whether the Plymouth LS-1 storage service itself should be retained is still being evaluated. The 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. Whether those recent spot price spikes were a rare aberration, or something that could be expected to reoccur with some regularity each winter, is the essence of the analysis that will be required.

The Company has until October 31, 2014, to decide whether or not to terminate its Plymouth LS-1 and/or TF-2 service agreements (which would be effective November 1, 2015), so that time will be used to further study this matter in more detail before making any such decision(s). In this regard, we would expect to continue working with NWP in a collaborative fashion.

Interestingly, NWN learned that Puget Sound Energy (PSE) recently came to the same conclusion regarding its own 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 [4].

In those same December 2013 discussions with NWP, the question also arose as to the reliability of that portion of the Company's TF-2 service from Jackson Prairie that is labeled as subordinate. Since Jackson Prairie is north of the Company's service territory, its TF-2 service flows in the same path as gas from British Columbia (the Sumas receipt point), not from the east through the already-constrained Columbia River Gorge section. 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

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

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.

D. Segmented Capacity

The removal of Plymouth created an immediate deficiency in NW Natural's resource stack. Ironically, to deal with this deficiency, at least for the short term, the Company is relying on another NWP transportation resource that also is secondary in nature – segmented 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 3.1), "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 3.1 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 3.1 – 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 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.

E. 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 is to estimate the benefit from the resulting mitigation or elimination of OFOs. In this IRP, the Company will make its first attempt to analyze and estimate that OFO-reduction benefit. That analysis can be found in Chapter Six.

F. Other Supply Resources

As mentioned previously, an additional type of resource in the Company’s portfolio is a variation on storage, *i.e.*, agreements that allow the Company to utilize gas supplies delivered to the Company's service territory for a limited number of days during the heating season. These are supplies that otherwise would be consumed at industrial sites in the Company's service territory. The Company currently has three such recall arrangements, as summarized in Table 3.4 below.

Table 3.4[5] - Recallable Supply Arrangements as of November 2012

Type	Max. Daily Rate (Dth/day)	Max. Annual Recall (days)	Termination Date
Recall 1	30,000	30	10/31/2014
Recall 2	8,000	40	10/31/2015
Recall 3	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. One of these deals (Recall 3) is already in its annual evergreen period. Recall 1 utilizes NWP capacity that the Company releases on a recallable basis and correlates to customer release volumes shown in Table 3.1. Should this arrangement terminate, the released NWP capacity would revert back to the Company. Recalls 2 and 3 utilize NWP capacity held by the providers of the service.

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.

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

The Company also has the option of obtaining a portion of its gas requirements through a joint venture relationship with Encana that is described in more detail in the next section.

G. Joint Venture for Gas Reserves

In April 2011, the Company entered into agreements with Encana Oil & Gas (USA) Inc. (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.[6] Under these agreements, the Company pays a 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.

The Company expects this venture will help provide its Oregon utility sales customers with long-term supplies at stable pricing over about a 30-year period. NW Natural notes, however, that it does not include the costs, or benefits, associated with this joint venture in rates for its Washington customers. Instead, NW Natural 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 projects the volume of gas received under the transaction (or the volumes of gas to which its proceeds from the joint venture will be applied) to be approximately 8-10 percent of the Company's average annual requirements for its utility operations. It also expects its investment to result in the availability of about 93 billion cubic feet (Bcf) of gas at a highly competitive price as compared to equivalent gas supply purchase alternatives over the same term.

In this IRP, the Encana transaction is recognized as being in effect but, for multiple reasons, the transaction does not specifically alter the modeling or analyses of supply options from what would be shown in the absence of the joint venture. The primary reason is that, as described above, the Company has flexibility under its agreements with Encana either to take gas from the joint venture at Opal or to have Encana market the gas and then apply the proceeds to purchases of gas from other locations and suppliers. This means that the Company's decisions about where to purchase gas will continue to be driven by where it can receive the lowest price for gas, rather than by the existence of the joint venture with Encana. In other words, the Company's strategy for purchasing physical supplies is expected to be the same with the Encana joint venture in place as it would be without it.

As done in its prior IRPs, the Company has not specifically modeled gas acquisition options by embedding the expected price of gas under the joint venture with Encana as an available price in its models. It determined that doing so would be problematic and unhelpful. Although one of the building blocks of the IRP analysis is a price forecast applicable to commodity gas purchases, which permits a

[6] 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, Order No. 11-176.

complete evaluation and comparison of different demand-side measures and supply-side resources, embedding the Encana gas supplies and associated price within that forecast would likely skew the results improperly because those prices are available under just this one transaction, which has limited volumes associated with it. If the Company were to use the price from the Encana transaction 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, as explained above, the existence of the Encana transaction does not have an effect on the location at which the Company will purchase gas because it can always choose to apply the proceeds from the transaction to whatever purchases it makes, and it will strive to make those purchases at the lowest cost locations, regardless of the fact that it can apply proceeds from the Encana transaction to those purchases. In David Danner's (then WUTC Executive Director and Secretary) letter to NW Natural, dated January 13, 2012, wherein the WUTC acknowledged the Company's previous IRP filed in Docket No. UG-100245, the WUTC confirmed that NW Natural's approach to limiting the inclusion of the Encana transaction in its analyses was appropriate.

Although the joint venture with Encana does not specifically alter the resource options modeled in this IRP, the above description of the arrangement with Encana is included to ensure that it is included in future analyses if needed. That is, in some future IRP, it is possible that the Encana gas reserves transaction may need to be modeled explicitly in that IRP. For instance, modeling Encana as a resource would be appropriate if unexpected supply constraints in the Rockies caused the Company to rely on the physical supply option received under its agreement with Encana. In that unlikely case, the capacity available to the Company in the Rockies would need to be split between gas received under the Encana transaction and gas purchased under other supply contracts.

Meanwhile, the Company will continue to consider the unique aspects of the joint venture with Encana in future IRPs to ensure that its analysis is complete and that the resource decisions made in the IRP are compatible with the existence of the agreement with Encana.

Furthermore, the Company will continue evaluating the appropriate proportion of its portfolio that should be secured through arrangements like the one with Encana. As described above, such transactions offer benefits that are not likely to be secured through other traditional supply options. Future similar transactions may be desirable to both increase the percentage of the Company's portfolio that is characterized by long-term price certainty and to levelize over time the percentage of the portfolio that is secured through these arrangements. To that end and consistent with its action plan, the Company commissioned Aether Advisors LLC ("Aether") to perform an independent review of its hedging program. Key findings of that study included:

- 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.

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. To ensure that these concepts are understood and supportable, an action item for the Company will be to discuss this approach with regulatory staff prior to any implementation.

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.[7]

H. Supply Diversity

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 (figure 3.2). 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 -

- REX: The completion of the Rockies Express Pipeline (REX) in 2009 to move Rockies gas to markets in Illinois, Indiana, and Ohio, increased competition and prices for those supplies.
- Ruby: The Ruby Pipeline commenced service in mid-2011 from Wyoming to the California/Oregon border, providing another outlet for Rockies gas.
- 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 REX to become bi-directional means that Rockies gas will feel the** impact too[8].
- 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.

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 due to this heavy reliance on term contracts.

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

[8] Seneca Lateral in service in early 2014 (http://www.tallgrassenergylp.com/Pipelines/REX/Seneca/) while the East-to-West Open Season now underway for service starting in 2016 (http://www.tallgrassenergylp.com/Pipelines/REX/E2W/).

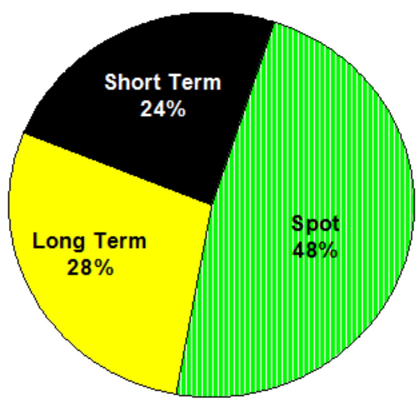
More recently, with the surge in supplies represented by shale gas, the Company has decreased its reliance on term contracts and allowed spot purchases to be much higher.

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.

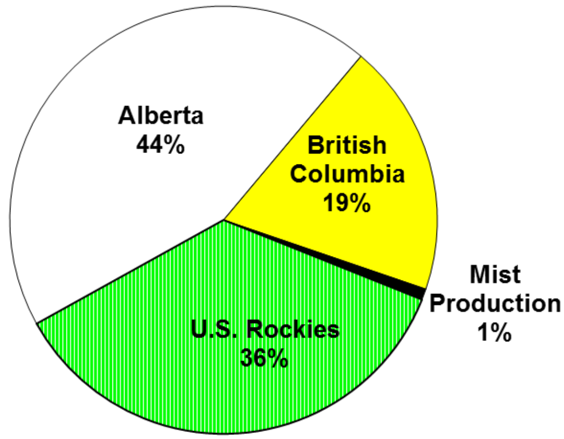
Figures 3.2 and 3.3 provide graphical representations of the Company's physical gas supply resources and diversity during 2013.

FIGURE 3.2 – Gas Supply Diversity by Contract Length for Calendar Year 2013



For Figure 3.2, 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 3.3 – 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.

I. 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.

Four goals guide the physical and financial hedging of gas supplies: 1) reliability, 2) lowest reasonable cost, 3) price stability, and 4) cost recovery. Section VII. B. of this chapter provides definitions of the four goals.

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. 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.

III. LNG Process Improvement and Refurbishment Project

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 considering a major refurbishment of each of these plants. 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).

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 plants that will enhance reliability, reduce maintenance cost and extend the operational life expectancy an additional 25-30 years, and plans to proceed with refurbishment of the Newport facility (see Appendix 3 for further details).

IV. SUPPLY-SIDE RESOURCE DISPATCHING

The Company's Gas Supply Department utilizes SENDOUT® to perform its dispatch modeling each fall. Based on expected conditions, this modeling provides guidance to the department in how it anticipates dispatching from various pipeline supplies and storage facilities. These economic dispatch volumes then flow into the Company's Fall Purchased Gas Adjustment (PGA) filing.

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

V. GATE STATION PLANNING

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 40 gate stations in the Company's system, and they are sometimes collectively referred to as the "citygate". With one exception, all of the gate stations directly connect the Company to NWP. The one exception is the Kelso-Beaver Pipeline (KBPL), and since the Company's service on KBPL is itself dependent on a connection between KBPL and 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 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 contractual amount that NWP is obligated to deliver 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, the Company had a single contract with NWP 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 unnecessary CD subscriptions.

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

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

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: the MDDOs or 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 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 firm deliveries from NWP, then the analysis would indicate the need for new CD subscriptions from NWP. If the 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.

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 percent of forecasted design day demand. This standard would apply to those service areas that are served solely from NWP gate stations (i.e. Vancouver, The Dalles (OR and WA), and Eugene).

VI. 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 year. During summer 2013, the analysis indicated no need for additional resources. This current IRP, along with the events experienced during the winter of 2013/2014, will inform the Mist recall decision to be made in the summer of 2014.

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.*

The Company continues to support development of this option. The timing for a new open season has not yet been announced by the project sponsors, and development of a Precedent Agreement is currently on hold while this current IRP analysis is in progress.

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. 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.

The probability of LNG exports from an Oregon facility continues to wane and have not been studied recently in any detail.

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

For Newport LNG a variety of refurbishment alternatives including a "do-nothing" scenario were considered in this IRP. Options for Portland "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 previously mentioned Aether study is the first step in this effort. Through its recommendations, the Company expects to develop long-term hedging targets for its portfolio. The subsequent step will be to development a standardized methodology for evaluating and comparing long-term hedge structures such as gas reserve acquisitions.

VII. FUTURE RESOURCE ALTERNATIVES

Beyond the existing gas supply resources mentioned previously, the Company considers additional gas supply resource options including Mist recall, the acquisition of new interstate pipeline capacity, satellite LNG 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 Six 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 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 (N-MAX). 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. As depicted by Williams (NWP's parent) in Figure 3.4, both of these projects could serve the Company's service territory.[9] Of course both projects would

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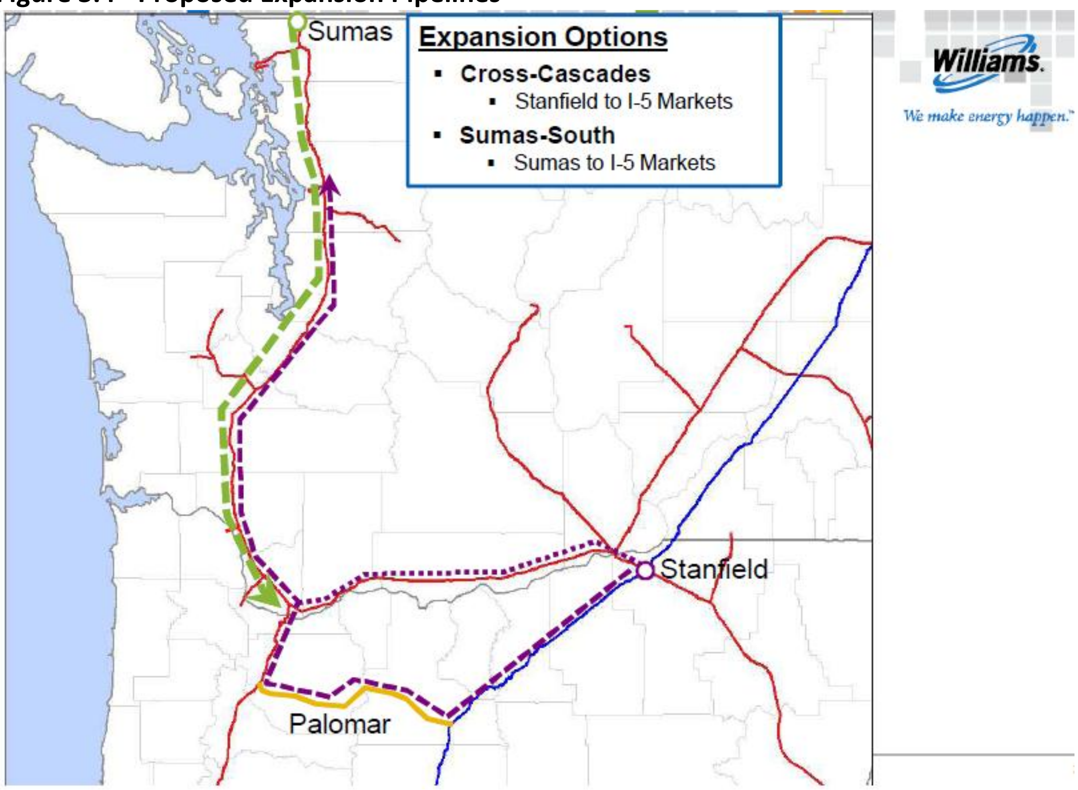
[9] Subsequent to the June 2012 presentation by Williams that included the map in Figure 3.4, Sumas-South was renamed the Washington Expansion. Those two names are used interchangeably in this IRP. The name Sumas-South has been retained here because it more easily conveys the nature of that project.

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.

Figure 3.4 - Proposed Expansion Pipelines



For the purposes of this IRP, it is assumed that the Cross-Cascades project could be in service as early as 2018, which in turn assumes an open season is initiated and indicates sufficient support to re-initiate FERC permitting work. In order to warrant conducting an open season, they need to have at least one anchor shipper signed to a Precedent Agreement. The contract volume under consideration by NW Natural, as reflected in this IRP, is sufficient to meet their needs. In this way, NW Natural's early commitment to the project would act as a catalyst for the region as a whole to be able to determine whether the project should move forward or not.

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. 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 terminals that would export natural gas in the form of LNG. By comparison, meeting regional demand growth via incremental NWP Sumas-South expansions 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.

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. As such, by interconnecting with a Cross-Cascades pipeline at Molalla, the Company would be in position to consider turning back redundant NWP capacity.[10]

As shown in Table 3.5 below, in this IRP, the Company considers the acquisition of interstate pipeline capacity in several forms:

1) Incremental NWP capacity from Sumas designed to serve only the Company's load growth
2) Capacity on NWP's Washington Expansion regional pipeline project
3) Capacity on Cross-Cascades connecting either directly to the Company's system at Molalla or in conjunction with N-MAX
4) Capacity on the GTN system to Madras from either Stanfield or Malin
5) Incremental capacity upstream of NWP mainline capacity providing access to the Rockies[11] and Alberta supply areas

The model also includes capacity of 12,000 Dth/day 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.

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10 Upon the availability of Cross-Cascades capacity, the Company has modeled a turn back of up to 77,000 Dth/day of existing NWP capacity from Stanfield to NW Natural's service territory. The total existing NWP capacity that could be turned back in this time frame is 102,000 Dth/day, but only 77,000 of this could be offset by a Cross-Cascades pipeline, either directly or through an interconnection with the proposed Eastside Loop.

11 NWP capacity upstream of Stanfield, Oregon.

Table 3.5 - Interstate Pipeline Capacity Additions Modeled in SENDOUT®

Interstate Pipeline Segments	Assumed Availability
Incremental NWP Capacity	November 2015
NWP Washington Expansion	November 2018
cross-Cascades Pipeline	November 2018
GTN Malin/Stanfield to Madras	November 2018
Alberta to Stanfield	November 2018

B. Mist Storage 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 storage market, but could be recalled for service to the Company's utility customers as those interstate storage agreements expire. Table 3.6 identifies the recallable Mist capacity and the year the capacity is available given current contractual commitments to interstate market customers.

Table 3.6- Mist Recall Capacity (incremental to existing capacity for utility)

Assumed	Capacity (Dth)		Deliverability (Dth/day)	
Availability	Increment	Cumulative	Increment	Cumulative
2014	627,522	627,522	25,132	25,132
2015	2,440,000	3,067,522	97,719	122,851
2017	1,620,000	4,687,522	64,879	187,730
2018	1,430,000	6,117,522	57,270	245,000

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.

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 Five.

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 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 $10 million.

2. Eastside Loop Expansion

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 the new piping to connect a Cross-Cascades pipeline to customers 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 Storage

Some gas utilities rely on "satellite" LNG tanks to meet a portion of their peaking requirements. LNG facilities are used as peaking resources because they provide only a few days of deliverability. 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.[12]

The Company's interest in this concept has been tempered 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.

In this IRP, the Company has evaluated satellite LNG in Willamette Valley locations near Salem and Eugene, primarily as interim resources that might delay the construction of more expensive pipeline projects and as "reserve margin" resources for reliability. 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. At the maximum vaporization rate, this three-day resource matches well with the Company's design peak criteria.

VIII. The Cutting Room Floor

In this section, the Company identifies 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 for this IRP.

A. 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 percent of natural gas use in the United States.[13]

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.

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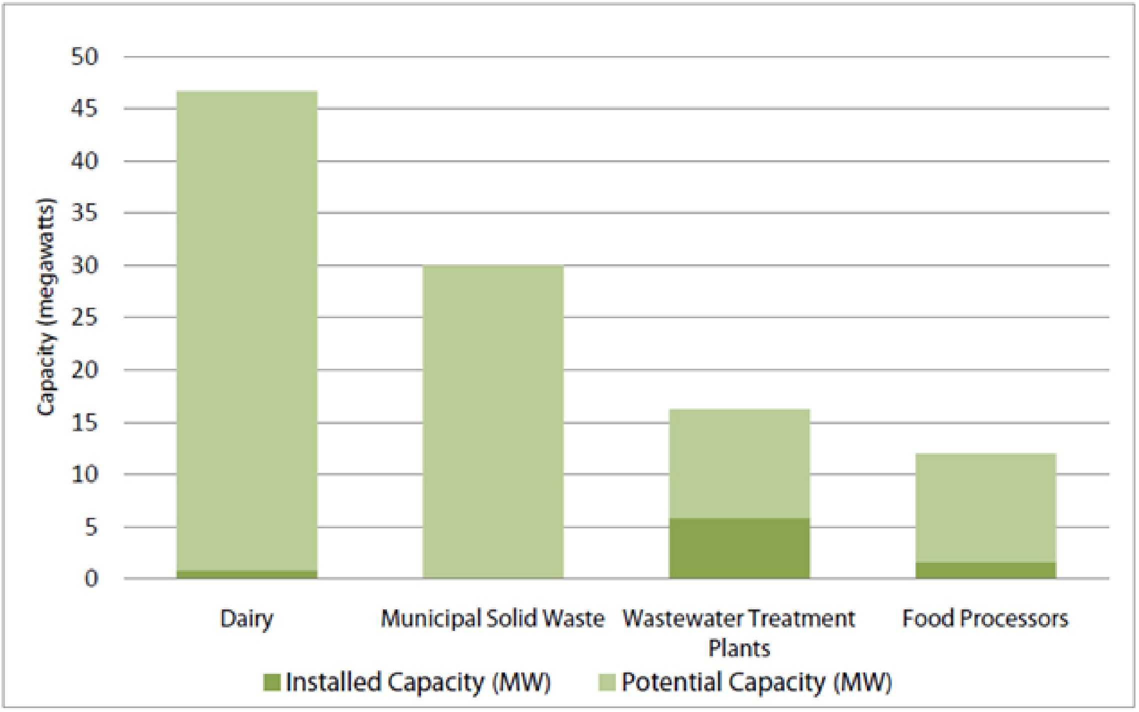
12 *See* http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2003/lng/lng2003.pdf .

13 "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.

A review of the potential for biogas production in Oregon was produced in 2011 by The Energy Trust of Oregon and The Climate Trust.[14] This report found that only 8 MW of installed biogas-related electricity has been developed so far out of a potential 100 MW in the state. Figure 3.5 shows the distribution of potential biogas opportunities.

Figure 3.5 – Oregon's Unrealized Biogas Potential



An analysis completed for the Oregon Department of Energy reviews the use of biogas from several of the state's waste water treatment plants (WWTPs).[15] Among the findings of this report is 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)

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[14] "Growing Oregon's Biogas Industry: A Review of Oregon's Biogas Potential and Benefits", Peter Weisberg (The Climate Trust) and Thad Roth (Energy Trust of Oregon), February 2011.

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

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.[16]

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.

B. 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.[17] However, the "shale gale" and its resulting reduction in natural gas prices, among other reasons, have stifled any recent interest in this potential resource.

C. LNG Imports. It still seems recent history that several LNG import terminals were proposed for Oregon and the Company was including them in its IRP analysis. However, with the proliferation of gas supplies in North America through the development of shale resources, no import proposals currently exist and none are likely for the foreseeable future.

D. Pacific Connector Pipeline. The original LNG import terminal proposals did leave two remnants in the form of projects that reversed direction and now are proposed as LNG export terminals. Both require massive new pipeline infrastructure to supply the gas needed for liquefaction. One project, on the north coast of Oregon (Oregon LNG), has spurred NWP to file its Washington Expansion project. The rates related to that project have been reflected in this IRP analysis since that pipeline could serve the Company's service territory. The other project is in Coos County (Jordan Cove), and the pipeline proposed to serve it is called Pacific Connector. That project is still very speculative, and even if it was built, would not serve any of the Company's service territory except for the extremely small load in Coos County itself. Pacific Connector would cross the NWP Grants Pass Lateral somewhere between Roseburg and Grants Pass, but that NWP lateral has limited capacity as it is only 10" in diameter south of Eugene. Accordingly, an expansion on NWP also would be required to deliver any appreciable quantities of gas from Pacific Connector north to the Company's market area. Both singly and together, there is

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16 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.

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

too much of a speculative nature here to try to model as a resource alternative in the IRP.

E. Southern Crossing Expansion. FortisBC has proposed a reinforcement project for the Southern Crossing Pipeline that would permit more flow of Alberta gas to the 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 Washington Expansion project.

F. Jackson Prairie. The most recent expansion of Jackson Prairie storage was completed in 2012 and the Company is not aware of any further expansion potential at the facility, nor the willingness of owners or customers to release existing service. A further complication now is the reliability of the transportation service from Jackson Prairie as previously discussed, such that any consideration of new storage service should be considered more like a supply-basin contract rather than an addition to the resource stack.

G. Large-scale LNG Plant. While the Company has considered small satellite LNG plants that are targeted to local constraint points, there has been no consideration of a large-scale plant similar to the two existing facilities. While new plants can be built, as witnessed by commissioning of FortisBC's Mt. Hayes LNG plant in 2011, there is no large location in the Company's service territory that would lend itself to such a project without being in direct contention with additional service from Mist. Couple that with the permitting complexities associated with LNG facilities and it was an easy decision not to try to model such an alternative.

H. 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, but its deployment requires considerable effort compared to CNG. These are valuable resources but suited only to serve very small and viable problem areas in the distribution system.

I. 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[18]. However, while intriguing, there are no timelines or cost estimates that can be modeled yet.

J. Industrial recall arrangements. 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.

K. 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

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

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.

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

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.

IX. 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 2013-2014 (GAP). The GAP is reviewed and approved by the 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. However, many resource decisions are of a multi-year nature. Accordingly, a 5-year horizon is used for discussion purposes in several areas of this section.

Below are excerpts from the GAP.

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. Trimming costs by compromising reliability is not acceptable.
2. **<u>Lowest Reasonable Cost</u>**
   The second priority is to acquire gas supplies at the lowest reasonable cost to customers. In so doing, 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>**
   NW Natural uses physical assets (e.g. storage) and financial instruments (e.g. derivatives), as well as its investments in gas reserves to hedge price variability within the contract year and for longer-term periods.

4. **Cost Recovery**
   Aside from its investments in gas reserves, the Company does not earn a return for acquiring and selling gas commodity supplies, yet the cost of these supplies typically amount to over half of the Company's total revenue stream. Accordingly, the risks associated with the payment and recovery of gas acquisition costs need to be fully addressed. 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.

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, 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
Gas acquisition strategies based on the Company's market outlook are summarized as follows:
- Financially and physically hedge up to 75 percent of projected gas sales volumes in accordance with decisions of the GASP Committee.
- Maximize supplies from the regions that afford the lower prices. In prior years, prices of Rocky Mountain gas were lower than prices of Canadian gas due to increased production in preparation for the REX and Ruby pipelines. Since those pipelines went into service, and with the emergence of shale gas in the eastern U.S., Rocky Mountain prices have typically been higher than Alberta but lower than British Columbia prices. Strategies will be continuously re-evaluated as market developments warrant.
- Fill storage at a pace that might present opportunities to purchase gas at times that best benefit customers.
- Maintain a diversity of physical supplies from Alberta, British Columbia and the Rockies to maximize reliability.
- Due to its relative lack of trading liquidity, continue to baseload virtually all pipeline capacity from the Station 2 trading point in British Columbia during the heating season.

E. Market Outlook
Supply increases and demand decreases have crushed prices since the highs of June 2008. Shale gas is the primary impetus for a current supply glut. Gas trapped between dense layers of the world's most prevalent sedimentary rock, shale, became economically accessible in recent years. By some estimates, there are 1,000 trillion cubic feet recoverable in North America alone, enough to supply the nation's natural gas needs for the next 45 years.

Breakeven costs continue to tumble due to advances in drilling and completion techniques. A single drill pad sometimes can be used for a dozen or more horizontal wells, lowering infrastructure costs and speeding the redeployment of drilling rigs. As a result, fewer drilling rigs are required to reach the same volume of gas as in past years.

Shale plays are situated throughout the U.S. and Western Canada. Low-cost methods of horizontal drilling have facilitated the success of shale gas recovery, and undercut the costs of vertical drilling methods used in the Rockies. As a result, drilling decreased in the Rockies while more supplies flowed east via REX, further diminishing the quantity of Rockies gas for the West.

Even more important has been the prominence or lack thereof of NGLs due to the wide spread between NGL and natural gas prices. "Wet" gas is highly sought after while "dry" gas drilling is in great decline, with Haynesville being one such example. This dynamic is likely to continue until a surplus of NGLs develops, which will then dampen the drilling enthusiasm and gradually rein in the production of associated natural gas.

Alberta supplies should continue to decrease due to depleted wells and due to the increase in gas used for oil sands production. However, those supply reductions are not likely to be felt in the West. Alberta gas transportation costs, specifically to the eastern U.S. and Canada, are higher than the transportation costs of shale gas supplies being developed in the eastern U.S. (Marcellus, Utica, etc.). Drops in Alberta supplies should be more than offset by drops in Alberta flows to the East. Alberta supplies to the West should stay level, and Alberta prices to the West are projected to stay below Rockies prices for the next several years.

The development of LNG export terminals in northern British Columbia is validating the emergence of shale gas supplies in that region. The eventual impact on B.C. gas commodity pricing will continue to be debated, but the expectation is that some increase relative to Alberta and the Rockies is likely.

X. EMERGENCY PLANNING

The Company uses the Incident Command System (ICS) as its emergency response methodology. The Incident Management System Plan (IMSP) documents the ICS concept and the responsibilities of those individuals responding to an emergency incident. In addition, this plan provides response alternatives and resource material for a variety of possible emergency events.

This plan is written and maintained by the Business Continuity and Corporate Security Department. Responsibility for planning and coordinating the actions of field and office personnel during emergencies such as floods, earthquakes, pandemics, or severe cold weather is designated to the Incident Command Team (ICT). The Operations section of that team is prepared to take whatever actions are needed to prevent or minimize firm curtailments of service. This includes the operation of regulators to boost pressures, the installation of pipe to tie together sections of the Company's distribution system, the dispatching of mobile CNG and LNG tankers to handle distribution system trouble spots, curtailment notices to interruptible customers, shut-offs and light-ups of firm customers, and public announcements to reduce gas usage.

The ICT conducts periodic exercises to ensure the readiness of the team and gain experience in ICS techniques. One of the most visible uses of ICS occurred during the Y2K rollover transition period. The Company utilized Y2K as both a potential threat and an opportunity for a corporate-wide emergency readiness exercise, with over 300 employees involved in the process. More recent examples include: managing three pre-planned and one unexpected outage of the electrical power at the Company's corporate headquarters; response to a pipeline breach in one of Portland's largest transportation transfer hubs; and the re-light of hundreds of customers on the Central Oregon Coast after service disruptions due to a landslide. The most recent example of significance was the outage of hundreds of customers in Clark County, Washington, on December 9, 2009, due to equipment failures at the GTN interconnection to Northwest Pipeline as well as at the Jackson Prairie storage facility. These real-world examples are in addition to periodic exercises conducted with other regional agencies.

As previously described, the Company designs its resource portfolio to satisfy firm loads through a strenuous design heating season. However, design weather has not been the coldest faced by the Company. There certainly have been colder heating seasons if a longer historical perspective is taken, such as occurred in 1949/50. Also, the IRP assumes perfect foresight of the weather. This may not be important for storage supplies, which can respond to load changes very quickly, but all other supplies require some amount of prior notice for scheduling. This ranges from two hours for curtailment of interruptible sales, to a day for the transportation of most pipeline gas and the use of the recall arrangements. Finally, the IRP assumes reliable equipment behavior; i.e., nothing breaks or freezes up, even in the face of extremely cold temperatures. As in the 2013 Washington IRP, the Company believes this is not an accurate assumption. With this IRP, the Company has included a probabilistic analysis regarding reliability. This is discussed in Chapter Six.

The ICT has to contend with the failure of any or all of the above assumptions in addition to the stresses on the system caused by the emergency itself. The Company's ultimate goal is an emergency management system that will allow for the continued delivery and/or restoration of gas during an emergency situation in a safe and efficient manner. The Company cannot guarantee uninterrupted service at all times to all customers, but the ICT works to make customer outages during emergency events as brief as possible, with public health and safety being the ultimate priority.

XI. KEY FINDINGS

- For this planning cycle, the Company's gas supply procurement strategy will rely on the transportation of supplies priced at negotiated rates that will follow market prices on an annual, seasonal, or monthly basis.

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

- Similar to the recent gas reserves agreement approved by the Oregon PUC at the end of April 2011, additional very long term pricing arrangements may be advantageous due to the current price regime, which reflects a slowly growing economy coupled with surging supplies from shale gas.
    - Financial derivative contracts are limited by credit quality considerations to no more than five years in duration. And under current financial conditions, three years is a more realistic maximum contract length.

  - Arrangements utilizing gas reserves could, in theory, be structured for any duration up to the production life of specified gas production wells. Such arrangements 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).
  - The Company will use the results of the Aether report to help formulate next steps regarding its hedging program in general, and long-term hedging structures in particular.

- The Company's service territory is widespread and it is not practical to consider tying together all customers into a single integrated distribution system. Accordingly, some relatively small amounts of incremental upstream pipeline capacity may be needed throughout the forecast period to serve one or more of these more isolated portions of the Company's system. Conversely, as the cost of upstream pipeline expansions increase, it may be cost-effective for the Company to remove bottlenecks and more fully integrate certain portions of its own distribution system.
  - Development of gate station planning standards will assume greater importance over time as the gap grows between MDDOs and physical gate capacities.

- As approximately two-thirds of its supply can flow through a single pipeline through the Columbia River Gorge, the Company seeks cost-effective resource options to improve supply path diversity, and toward this end, is supporting development of a cross-Cascades pipeline project.
  - Additional benefits were identified by the B&V study related to the mitigation of pressure on Sumas supply availability and pricing should LNG exports from British Columbia proceed as is currently expected.

- In this IRP, the Company is considering a variety of incremental gas supply resource options to serve projected load over the forecast period, including new interstate pipeline capacity, Mist recall capacity, expansion/extension of the Company's distribution system, and satellite LNG.
  - Past reliance on secondary/subordinate firm transportation service on NWP's system needed to be re-evaluated given the curtailment of TF-2 transportation service from Plymouth that was first experienced during a cold weather event in December 2013.
    - The Company's current assessment is that such NWP capacity moving gas from east to west through the Columbia River Gorge (e.g., from Plymouth) can no longer be relied upon in the Company's firm resource stack.
    - Such capacity moving gas from north to south through the I-5 corridor (e.g., from Sumas or Jackson Prairie) continues to be reliable and should be retained in the firm resource stack for the near term, that is, until new load growth or other NWP system changes affect service in that corridor. Five years appears to be a reasonable assumption for that near term period given the likely load growth in the region, especially power generation, which is expected to occur by the year 2020.
    - Similarly, inclusion in the firm resource stack of segmented capacity moving gas south from Sumas in that I-5 corridor also appears to be reasonable for the near term, for the same reasons mentioned above.
    - The Company should continue to work with NWP to evaluate and refine these reliability considerations regarding secondary/subordinate and segmented firm transportation service.

    - Even if the reliability of the Plymouth TF-2 transportation service cannot be improved, the Company should perform a separate evaluation regarding the possible retention of the Plymouth LS-1 storage service. This would not mean adding Plymouth back to the firm resource stack, but instead, as with any other supply-basin storage agreement, decide whether retention would be warranted because of its price arbitrage value.
  - There are a variety of resources that are wildly speculative or otherwise infeasible for inclusion in this analysis, but that determination should be revisited in future IRPs.

Chapter 4: Demand-Side Management

NW Natural®

I. OVERVIEW

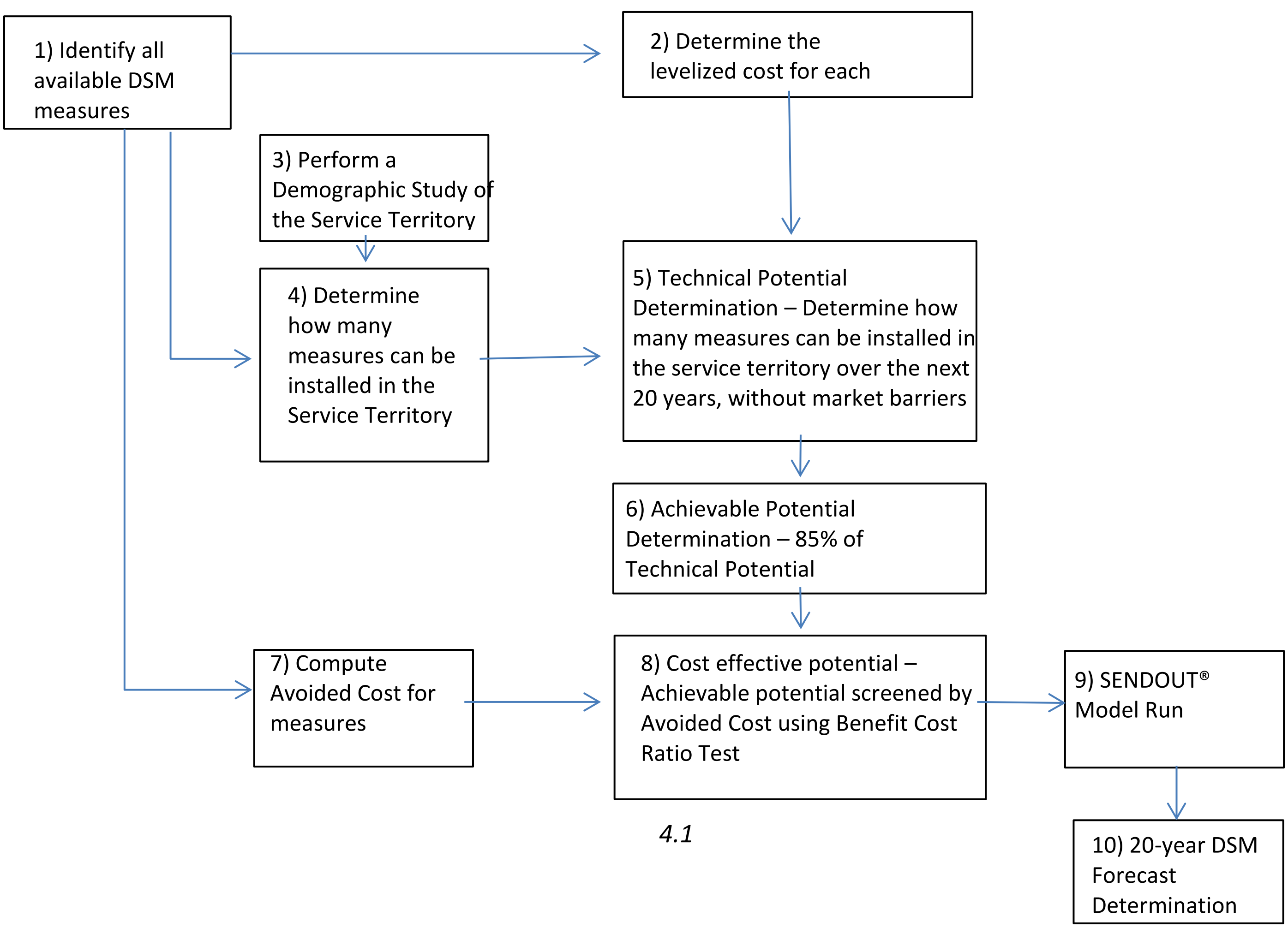
NW Natural worked with Energy Trust of Oregon (Energy Trust) to forecast the 20-year demand-side management (DSM) potential for the Company's service territory. Energy Trust is a non-profit organization that was initially established to provide energy efficiency services and a renewable energy program 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 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 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



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.[1] The annual net measure cost is then divided by the annual net energy savings determined by multiplying therms saved times the Company's avoided cost. 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.

[1] 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

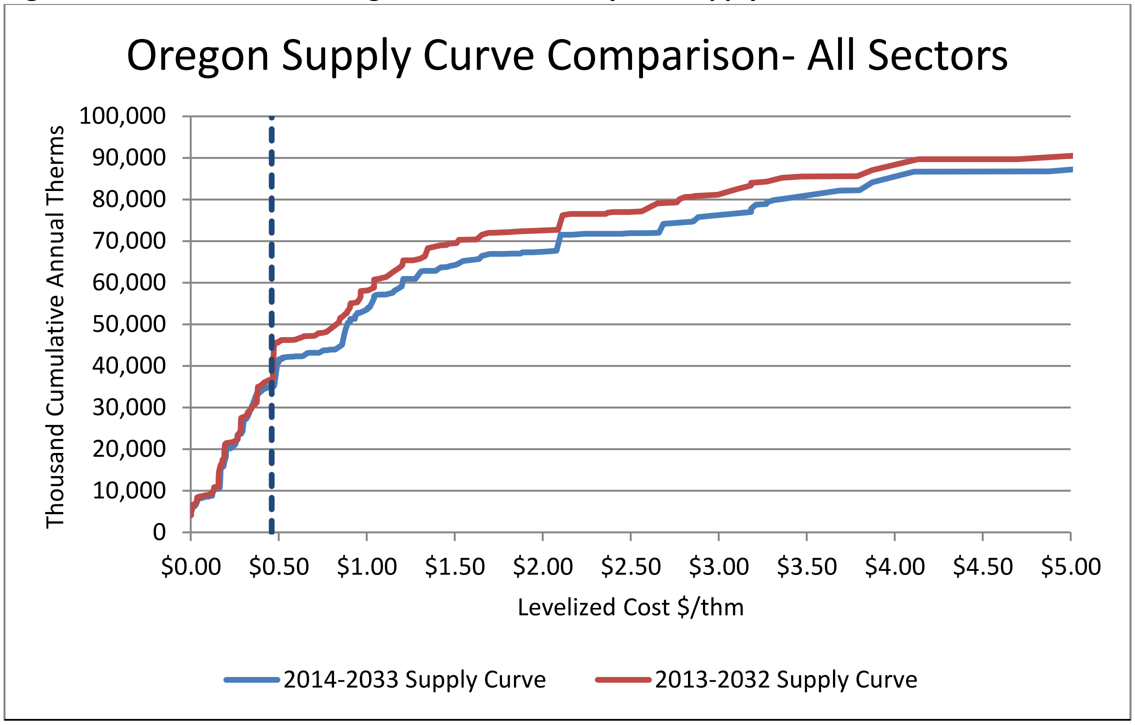
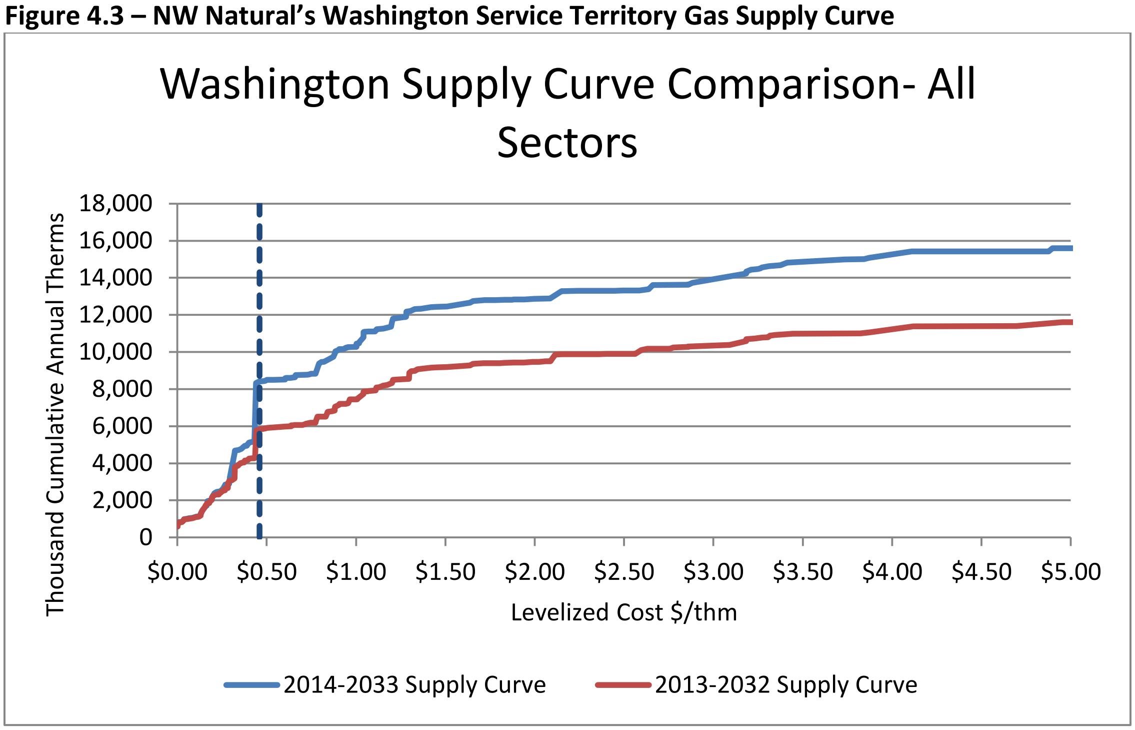


Figure 4.3 – NW Natural's Washington Service Territory Gas Supply Curve



3) 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.

4) Screen the DSM measures using the Benefit Cost Ratio (BCR) test.
   After the avoided cost is determined, a Benefit Cost Ratio (BCR) test was then applied to each measure. The BCR was used to evaluate the total benefits attributable to the measure divided by the sum of all related costs. A BCR 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 BCR is expressed formulaically as follows:

   BCR = Present Value of Benefits / Present Value of Costs

   The Present Value of Benefits includes the sum of the following two components:
   a) The value of gas energy saved determined by the therms saved multiplied by the Company's avoided cost.[2] Note that the total avoided cost for a measure depends upon that measure's lifetime and seasonality.
   b) Non-energy benefits as quantified by a reasonable and practical method.

   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.

5) Demographic Study
   At the same time steps 1 through 3 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 housing stock and building codes to the Company's customer forecast.

   NW Natural serves over 689,000 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.

[2] *See* Chapter Eight for a discussion of NW Natural's avoided cost.

Table 4.1 – FY 2013 Customer Statistics Sector – All Customers

Sector	**Average Number of Customers**	**Actual Sales (therms)**	**Average Use Per Customer**
Residential			
Commercial			
Industrial Firm			
Industrial Interruptible			
Total			

Placeholder for tables. 2014 data cannot be made public until after our 10K filing.

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

Table 4.2 – FY 2013 Customer Statistics Sector - Washington

	Average Number of Customers	**Actual Sales (therms)**	**Average Use Per Customer**
Residential			
Commercial			
Industrial Firm			
Industrial Interruptible			
Total			

Placeholder for tables. 2014 data cannot be made public until after our 10K filing.

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

Table 4.3 - FY 2011 Customer Statistics Sector - Oregon

	Average Number of Customers	**Actual Sales (therms)**	**Average Use Per Customer**
Residential			
Commercial			
Industrial Firm			
Industrial Interruptible			
Total			

Placeholder for tables. 2014 data cannot be made public until after our 10K filing.

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

6) The 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 economic and other 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 realistic constraints on the ability to launch programs as recognized in the deployment scenario.

7) The Cost Effective Achievable Potential
The cost effective achievable potential defines the point on the levelized cost curve where measures no longer pass the societal cost effectiveness test. This is determined by comparing the avoided cost value of the measure savings to the total cost of the measure.

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**

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

Washington	**Technical Potential (Therms)**	**Total Achievable**	**Cost Effective Achievable Potential (Therms)**	**Cost Effective Achievable Potential + Excepted Measures Potential (Therms)**
RES	12,586,997	10,698,947	2,521,237	8,012,232
COM	4,574,032	3,887,927	2,058,009	2,058,009
IND	1,368,373	1,163,117	736,108	736,108
Efficiency Total	**18,529,402**	**15,749,992**	**5,315,354**	**10,806,349**

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

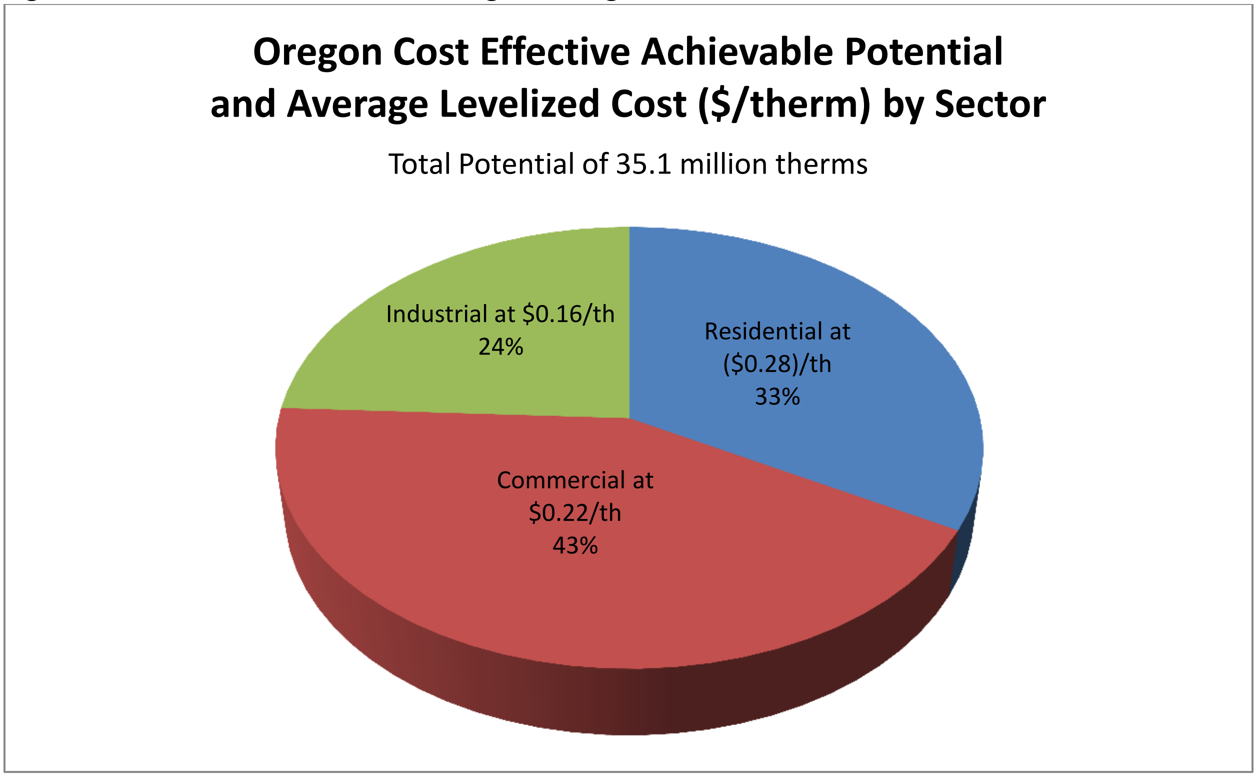
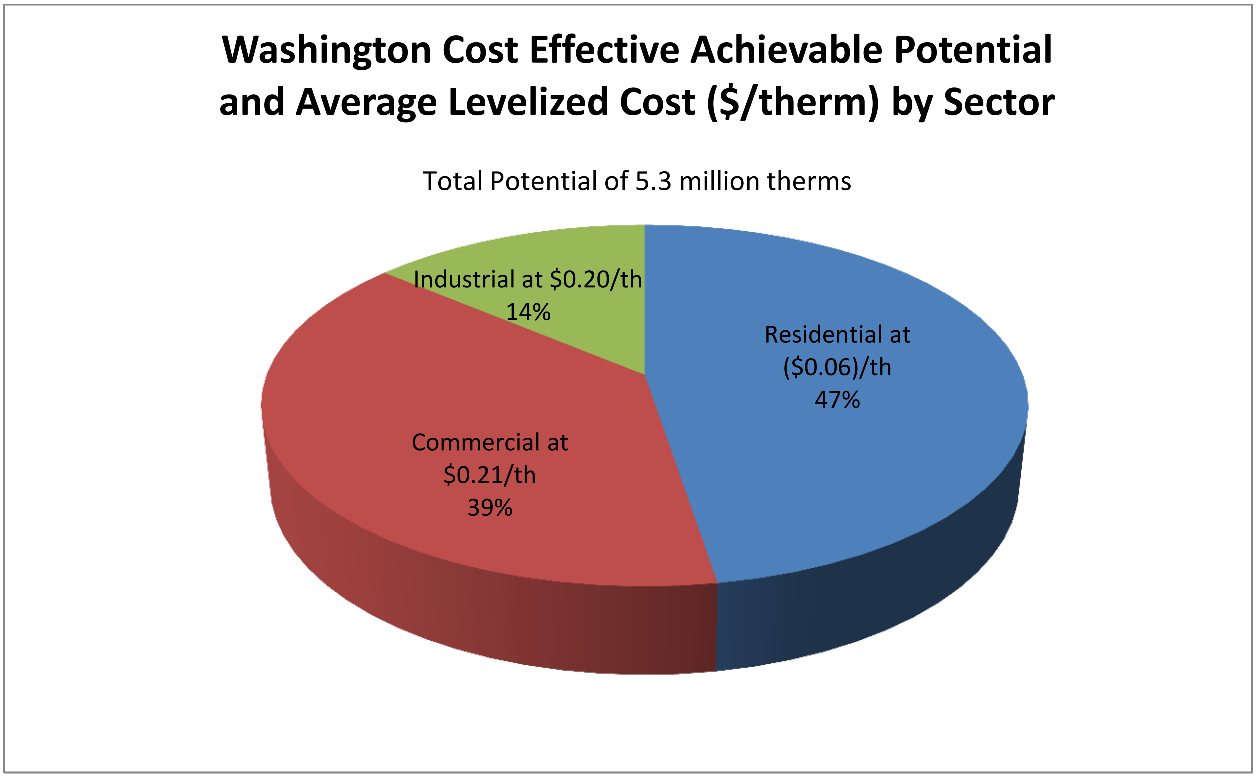


Figure 4.5 – Achievable Potential in Washington through 2033



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

Washington	Average Levelized Cost	Cost Effective Achievable Potential
Residential at ($0.06)/Th	$ (0.06)	2,521,237
Commercial at $0.21/Th	$0.21	2,058,009
Industrial at $0.20/Th	$0.20	736,108

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 BCR 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 BCR 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 BCR 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	86	($0.03)
New Construction	1,381	$0.32
New DHW	0	$0.00
Replace Equipment	76	$0.03
Replace Appliance	48	($0.04)
Replace DHW	474	($1.51)
Weatherize Retrofit	457	$0.24
Total	**2,521**	**($0.06)**

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

Screened by BCR 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 BCR 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

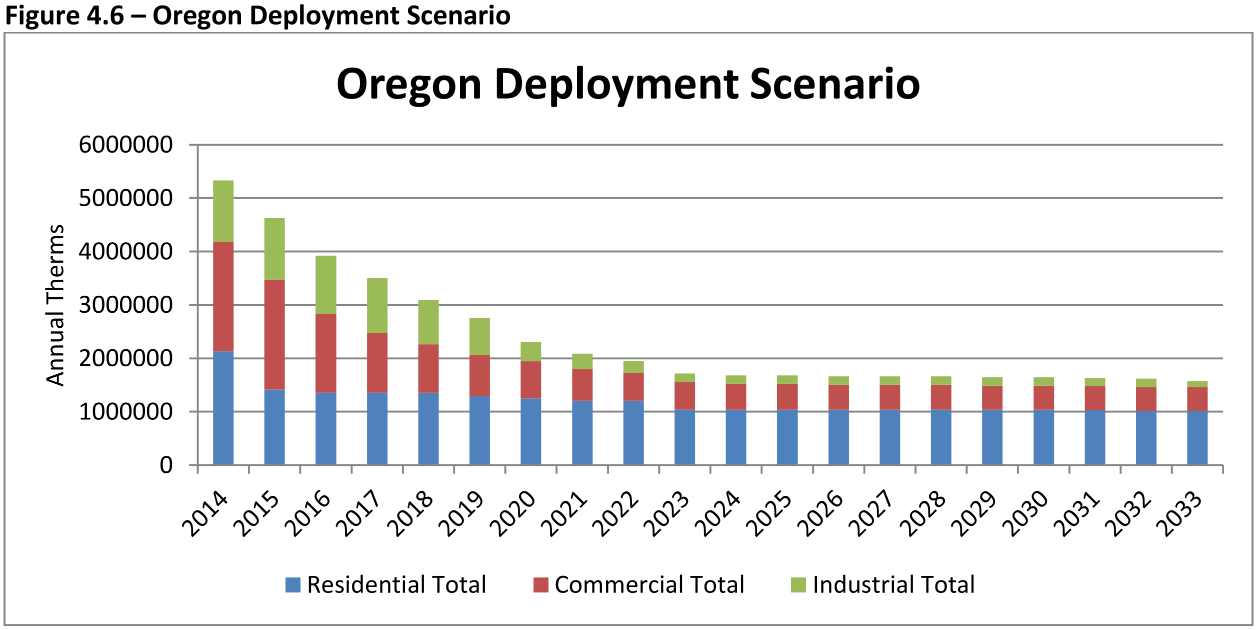
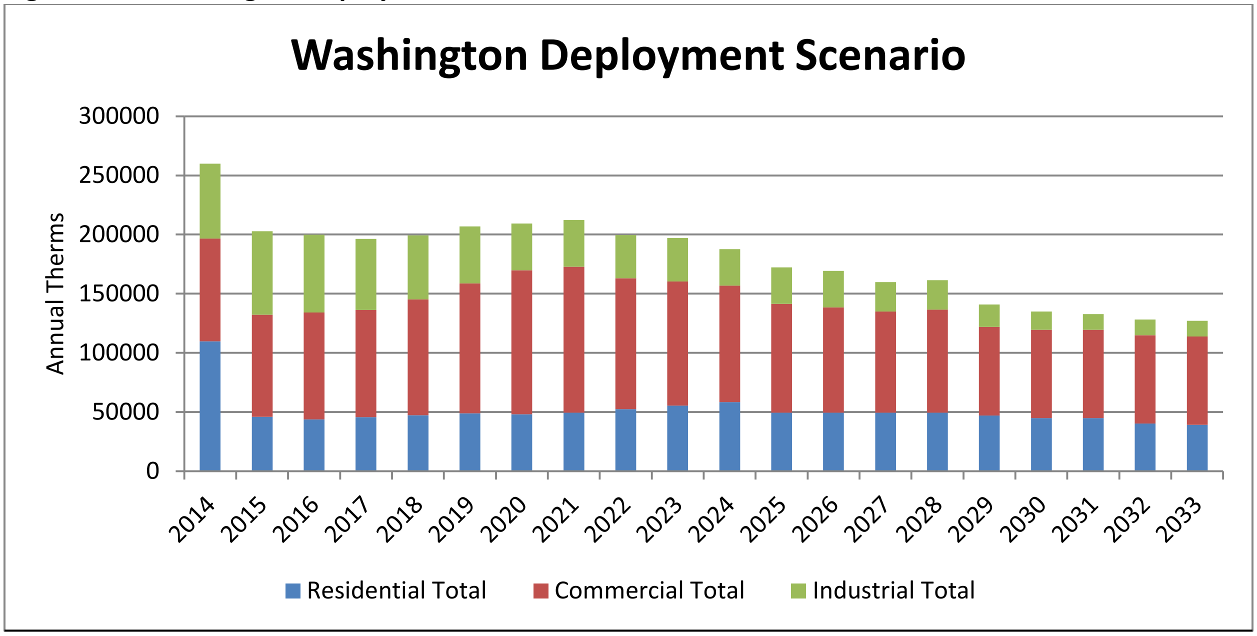


Figure 4.7 – Washington Deployment Scenario



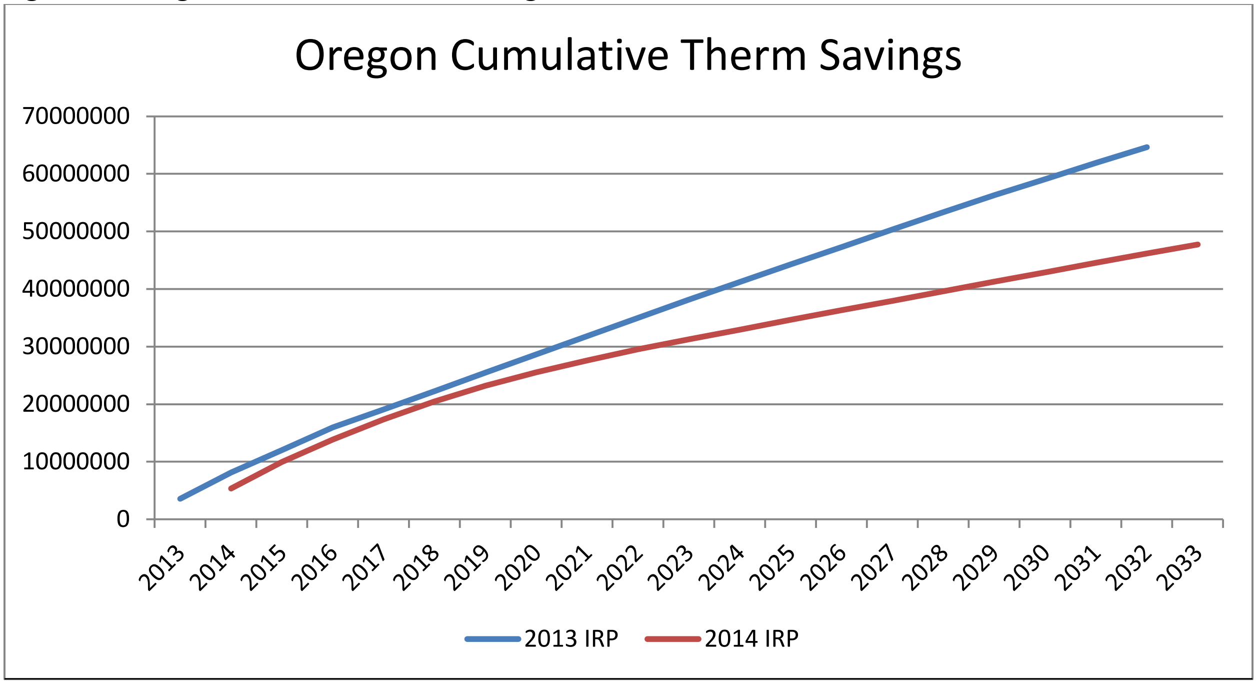
B. Evaluation of Achievable Potential in SENDOUT®

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.

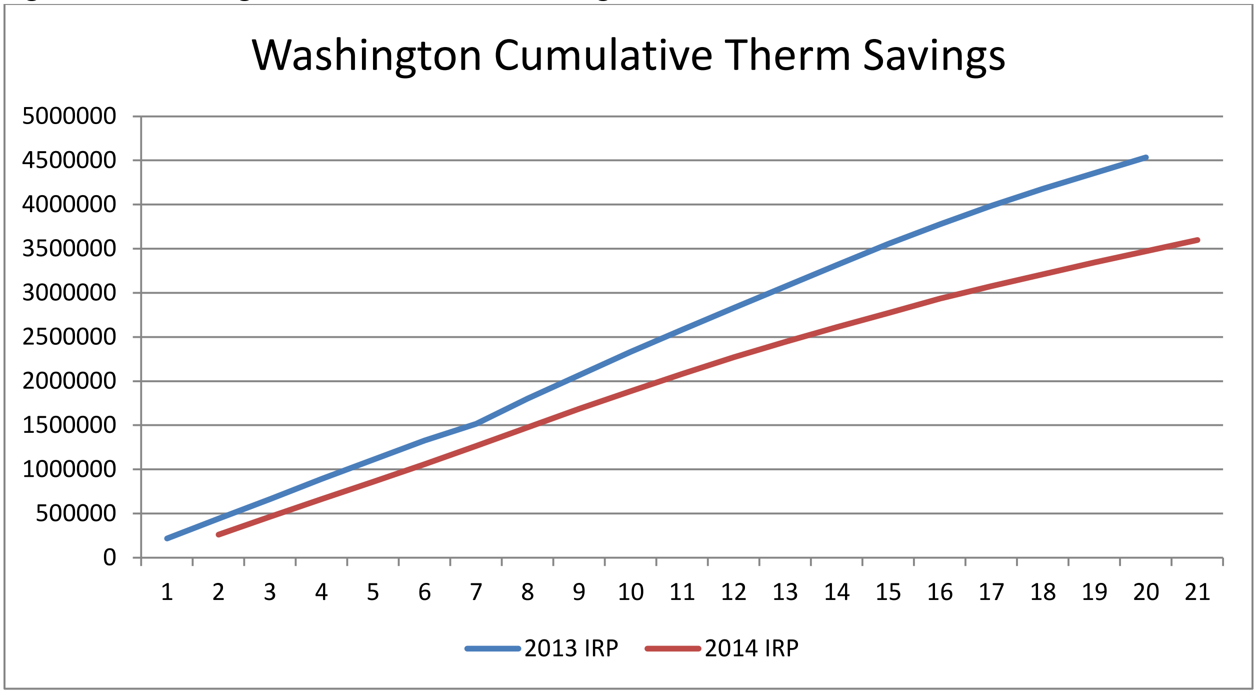
Figure 4.8 Oregon Cumulative Therm Savings



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



Although Figure 4.9 shows the cumulative 20-year deployed savings as less than the 2013 Washington IRP, the cost effective achievable savings potential for Washington is substantially 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.[3]

NW Natural chooses 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 finding in NW Natural's 2008 IRP[4] that cost effective industrial saving were available, the Company worked with Energy Trust to launch an Industrial DSM program that is available to Industrial Firm Sales and Industrial Interruptible Sales customers. Costs for the program, which is 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. From the Order, it is unclear what actions the Commission might take after this report is submitted, if any. 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.

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

4 *See* Docket No. LC 45.

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

	Technical Potential (Therms)	Total Achievable	Cost Effective Achievable Potential (Therms)	Cost Effective Achievable Potential + Excepted Measures Potential (Therms)
RES	67,698,440	57,543,674	14,103,003	29,780,217
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**	**40,378,854**	**56,056,068**

The difference in potential savings is not significant enough to remove or replace other resources in the stack of resources chosen for the Base Case resource portfolio, but NW Natural will track this and provide an update in its Annual IRP Update, due one year from acknowledgement of this Plan.

2. Oregon Low Income Energy Efficiency Program (OLIEE)[5]

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.[6] 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.

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

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

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

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;[7] and to increase the per home incentive 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 in OLIEE per year.

Table 4.15 – Homes Treated through OLIEE Program

Program Year	Homes Treated
2012-13	151
2011-12	541
2010-11	339

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.[8] 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.[9]

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 will be presented to the WUTC and EEAG in April 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

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7 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.

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

9 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.

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 Total Resource Cost (TRC) on a portfolio level, and in lieu of that, the Utility Cost Test (UCT). The Commission further stated that the discount rate used should be appropriate for the risk of the investment being measured in the test used. NW Natural is considering the Policy Statement and Energy Trust is performing an analysis on how the application of the TRC verses the UCT will impact the measure offerings. The Company expects to convene a meeting this year with its EEAG to propose a method that would both comply with the Policy Statement and allow the Company to offer a sound program.

2. Washington Low Income Energy Efficiency Program (WA-LIEE)

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 in WALIEE per year.

Table 4.16 – Homes treated through WALIEE

Year	Homes Treated
2013	20
2012	8
2011	11

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 customers 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**

This chapter reviews energy and environmental policy issues that are pertinent to the development of the company's IRP. NW Natural stays fully engaged in environmental policy development as it has a direct and important impact on our planning and operations. As the landscape for natural gas changes dramatically due to new shale supplies, the company expects to see changes in policy that may have a substantial impact on the use of natural gas in the future.

NW Natural's engagement with environmental policy begins with the fact that environmental stewardship is one of NW Natural's Core Values. We act on this value in a variety of ways, including:

- ✓ Helping our customers use less energy and save money;
- ✓ Becoming the first stand-alone gas utility to offer a carbon offset program;
- ✓ Adjusting our operations to save energy and reduce greenhouse gas emissions;
- ✓ Building pipelines to the highest environmental and safety standards; and
- ✓ Promoting policies that include natural gas in Oregon's efforts to meet its energy and environmental protection goals while providing customers with the assurance of reliable, affordable fuel.

While environmental stewardship permeates our business in these ways and others, this chapter focuses on specific energy and environmental policies that may impact our IRP analysis during the planning period and beyond.

It is important to recognize the much of our current state and federal energy policy was developed during a period of gas scarcity. New natural gas supply from shale and exiting conventional supplies together provide our nation with sufficient natural gas to meet current consumption for up to 150 years.[1] This new supply of gas requires that our energy policy be altered in ways that recognize we have moved from a condition of gas scarcity to one of abundance.

This chapter will explore a variety of policy issues that result both from this new condition of abundance and from the increasing recognition that anthropogenic greenhouse gas emissions are having an impact on the climate. Because of these factors, we expect 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 greenhouse gas emissions. We are already seeing natural gas displace coal in the electric sector, but also expect to see natural gas used to replace other higher carbon intensity fuels such as oil used in heating homes and gasoline and diesel used in the transportation sector.

Besides broadening the use of natural gas into other sectors, more abundant natural gas and new production methods have created a new focus on hydraulic fracturing and the environmental impacts of this production practice. In addition, as natural gas is used to drive down overall greenhouse gas emissions, there is an increased focus on methane emissions from the natural gas supply chain – from production through distribution. The company expects to see both more complete technical analysis of all life cycle impacts and increasing pressure to make sure natural gas is produced responsibly and delivered in a way that minimizes methane emissions.

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[1] Fueling the Future Study, Natural Gas Foundation

Policies in Oregon are evolving to clarify the role of natural gas in the future. The Governor's Ten Year Plan (published in December, 2012) sets out a high level vision for the use of natural gas in the state over the next decade. Further policy direction is provided through the recently passed law, SB 844, which provides incentives for gas utilities to implement projects with greenhouse gas reductions. These actions and others suggest the state is developing a new and evolving vision for the use of abundant natural gas.

II. STATE, REGIONAL, AND FEDERAL ENERGY POLICIES

A. State

1. Washington Energy Policy

Below are the activities in Washington related to energy policy NW Natural is following:

- Washington passed legislation establishing a Climate Workgroup that was charged with developing recommendations and submitting them to the legislature. The workgroup was not able to reach agreement, but issued a report with competing recommendations. The report identifies Residential, Commercial and Industrial use of natural gas as the third largest source of greenhouse gas (GHG) emissions.

- Governor Inslee, Senator Ranker, and Representative Fitzgibbon proposed the following five actions be developed and implemented in Washington:

    1) Set a cap on carbon emission that has binding limits to reduce emissions over time and institute the necessary market mechanisms to meet the cap in the most effective and efficient manner possible. This cap-and-market program should focus on the larger emission sectors such as transportation, buildings and electricity, as they account for most of the forecasted Washington emissions. The program should include allowance policies, cost containment and other options and measures that help offset the cost impact to consumers and workers, protect low-income households and assist energy-intensive, trade-exposed businesses in their transition from carbon-based fuels. It should also establish a clear framework for oversight and regulation of the markets.

    2) Adopt measures to reduce the State's use of electricity generated by coal-powered facilities in other states. The State should seek to negotiate agreements with key utilities and others to reduce and eliminate the use of electrical power produced from coal over time. Though coal is used for a relatively small share of our electricity, it generates most of the carbon pollution emissions from this sector.

    3) Establish an energy smart building program to include promotion of new financing, incentives and support systems. The program should encourage the construction of new buildings that are as energy-neutral as possible, with advanced building design, efficient appliances, on-site power generation and smart controls. For existing buildings, the program should establish cost-effective, energy-efficiency retrofits as the norm, not the exception, with support systems to assist businesses and homeowners.

4) Take actions to help finance the use of clean energy to include dedicated and sustained funding to help the State's research institutions, utilities and businesses develop, demonstrate and deploy new renewable energy and energy-efficiency technologies. These technologies will help reduce carbon pollution emissions, grow the State's economy and maintain our global competitiveness.

5) Adopt measures that will modernize the State's system for transporting goods and people by increasing efficiency and reducing costs and emissions. In addition to providing incentives for the purchase of clean cars, and accelerating the use of cleaner fuels, the State needs to improve how it plans and funds its transportation system to incorporate climate change considerations and to better connect land use and transportation plans.

- Senator Ericksen and Representative Short submitted the following recommendations:

    1) Incentivize hydroelectric power generation
    2) Replace fossils fuels with nuclear generation
    3) Promote research and development (R&D) for new technologies
    4) Encourage conservation under the Energy Independence Act (I-937)
    5) Allow renewable energy credit banking under I-937
    6) Modify fuel mix reporting system

- Proposals for Areas of Additional Study:
    - Study consumption- and generation-based accounting of emissions
    - Complete currently insufficient analysis of costs associated with GHG reduction policies
    - Evaluate 2008 non-binding goals in light of Washington's existing low carbon output

2. Oregon Energy Policy

Below are the activities in Oregon related to energy policy NW Natural is following:

- Oregon has a study underway to analyze the effects of a carbon tax with the results due back to the legislature in time for the 2015 session.

- The 2013 Oregon legislature adopted SB 844 directing the Public Utility Commission to establish a voluntary emissions reduction program to incent natural gas utilities to invest in projects that reduce emissions and provide benefits to customers.

B. Regional Energy Policy

On a regional level, the governors of Oregon, Washington, California, and British Columbia have signed a climate change agreement referred to as the Pacific Coast Collaborative[2] in which they agree to the following:

- Lead national and international policy on climate change with actions to:

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2 *See* http://www.pacificcoastcollaborative.org/Documents/Pacific%20Coast%20Climate%20Action%20Plan.pdf

- 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

Below are the energy-related activities being discussed at the Federal level that the Company is tracking:

- The Energy Savings and Industrial Competitiveness Act of 2013 (S.1392), an energy efficiency bill sponsored by Senators Jeanne Shaheen (D-NH) and Rob Portman (R-OH) will likely be reintroduced in the next few weeks. This measure went to the Senate floor for a vote last fall, but the bill was tabled due to a stalemate on amendments in September 2013. The Senate has worked to craft a revised bill that will include several bipartisan amendments.

- The Residential Energy Savings Act introduced by Sens. Wyden (D-OR), Sanders (I-VT) and Murkowski (R-AK) would authorize the Department of Energy to provide up to $630 million in loans intended to aid homeowners who wish to perform energy efficiency retrofits. To be eligible for the loans, states would have to demonstrate projected energy savings and provide their own money in addition to the DOE dollars.

III. CARBON PRICING IN THE 2014 IRP

NW Natural's Base Case includes a price on carbon as the natural gas price forecast embedded in the Base Case includes, on a supply basin spot price basis, a price on carbon. Figures 4.10 and 4.11 (following) show the levels and timing of the carbon price.

IHS CERA's natural gas price forecast,[3] which NW Natural uses in scenario development, incorporates a carbon price beginning in 2021 at a level of $8.74 per metric ton of CO_2 equivalent ($MTCO_2e$) and increasing annually to $15.70 per $MTCO_2e$ in 2033 (both prices in $2013)[4] 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]

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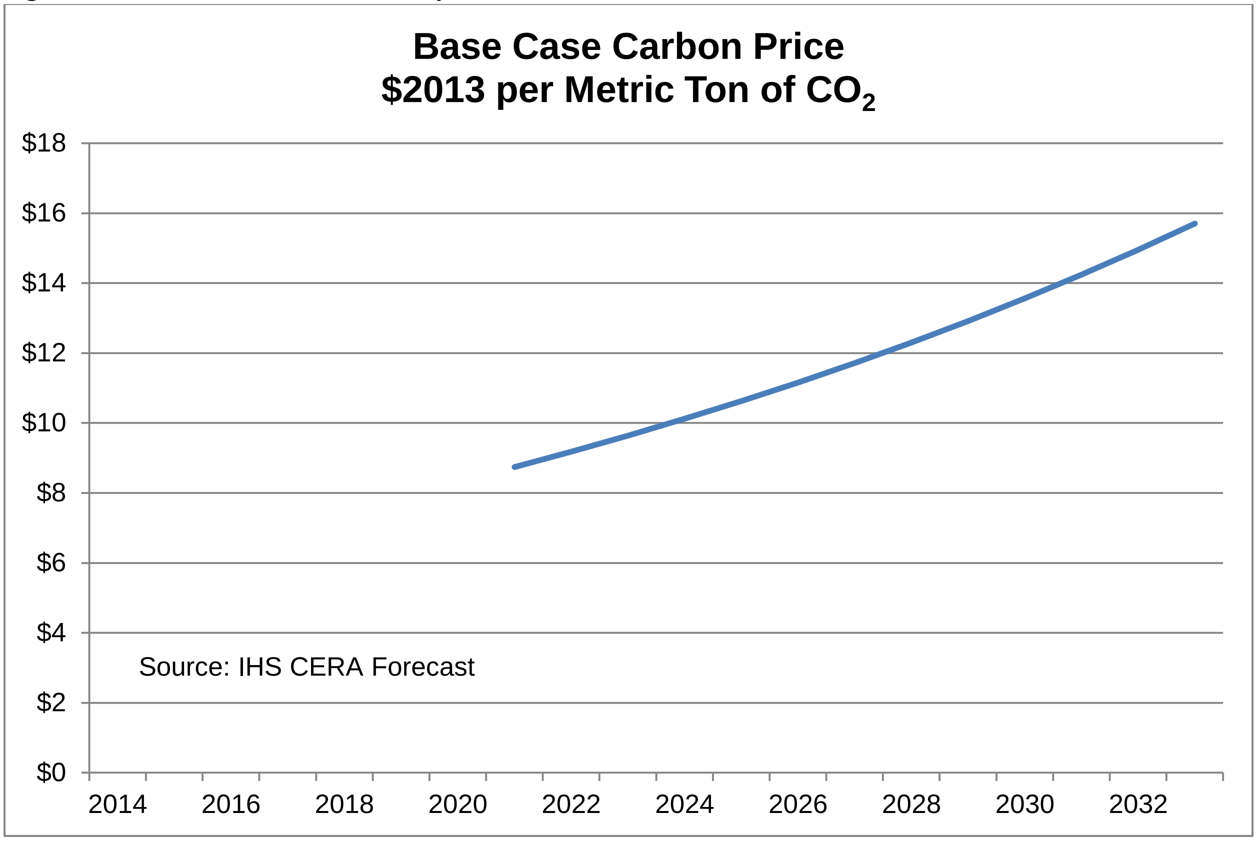
3 Source: IHS Inc. This content is extracted from IHS Energy North America Natural Gas service and was developed as part of an ongoing subscription service. No part of this content was developed for or is meant to reflect a specific endorsement of a policy or regulatory outcome. The use of this content 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.

4 The 2014 IRP assumes an average annual rate of inflation over the planning horizon, as measured by the GDP deflator, to be 1.9 percent. See the footnote in Section C of Chapter Two regarding this assumption.

5 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).

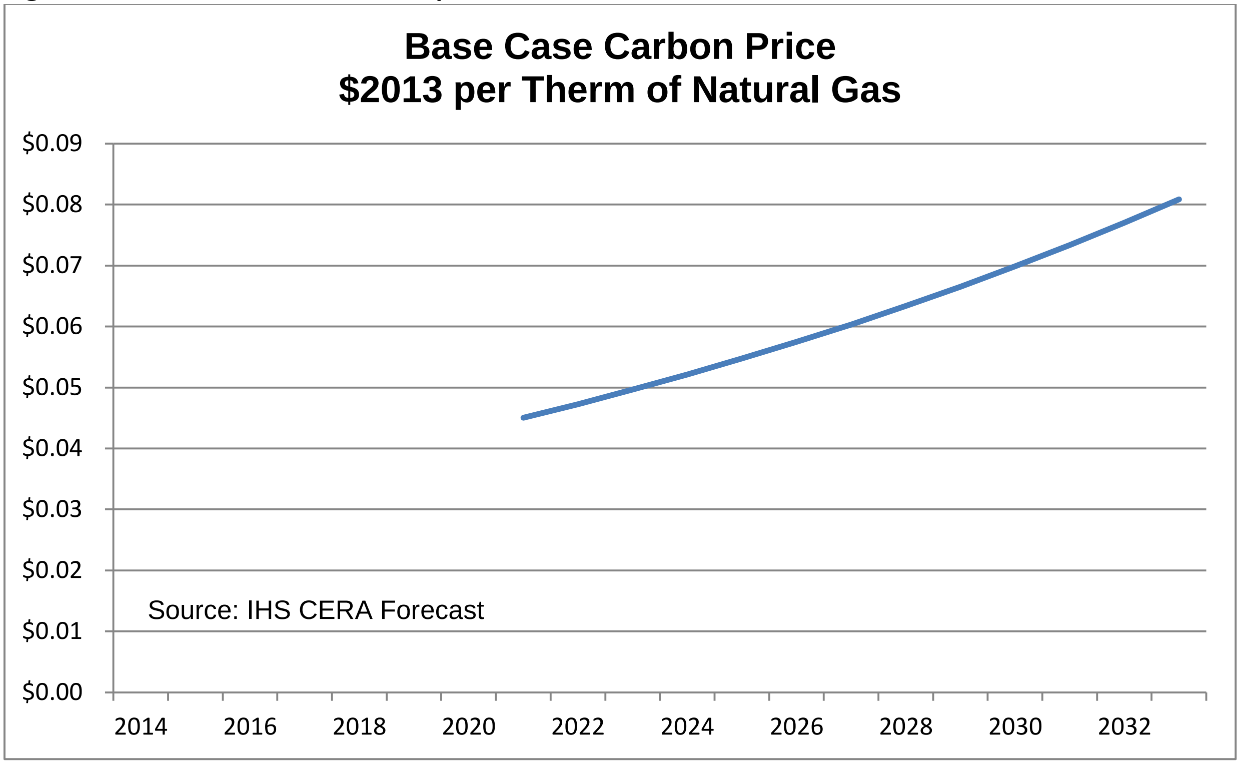
Figure 5.1 - Base Case Carbon Price per $MTCO_2e$



These dollar values per $MTCO_2e$ equate to $0.05 and $0.08 per therm,[6] respectively (both in $2013 and rounded to two decimal places). Figure 5.2 replicates Figure 5.1, with the real price of carbon on a per therm basis.

6 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 metric tons of CO_2 equivalent ($MTCO_2e$) per therm of natural gas. See the EPA website, accessed February 13, 2014, at http://www.epa.gov/cleanenergy/energy-resources/refs.html .

Figure 5.2 - Base Case Carbon Price per Therm



VII. SCENARIOS

Place holder until Carbon Scenarios are completed

VIII. ANALYSIS

Place holder until Carbon Scenarios are completed

IX. RESULTS

Place holder until Carbon Scenarios are completed

X. KEY FINDINGS

Placeholder until Carbon Scenarios are completed

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

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 cost exceeding $10 million.

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.

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 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.

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 and 987 district regulator stations. The Washington service area includes 15 city 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

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[1] 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.

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 complex 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

[1] This IRP discusses load forecasts in Chapter Two.

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. As any one alternative solution may not be the "best" with respect to each criterion, determining the optimal solution 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.

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[2] 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.

[2] SCADA data is transmitted every two minutes.

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 pressures, 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 as part of the process for determining the best alternative.

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.[3] 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,[4] 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.

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3 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.

4 There are specific exceptions to this general guideline.

Figure 6.1 – Distribution System Pressures: Existing System

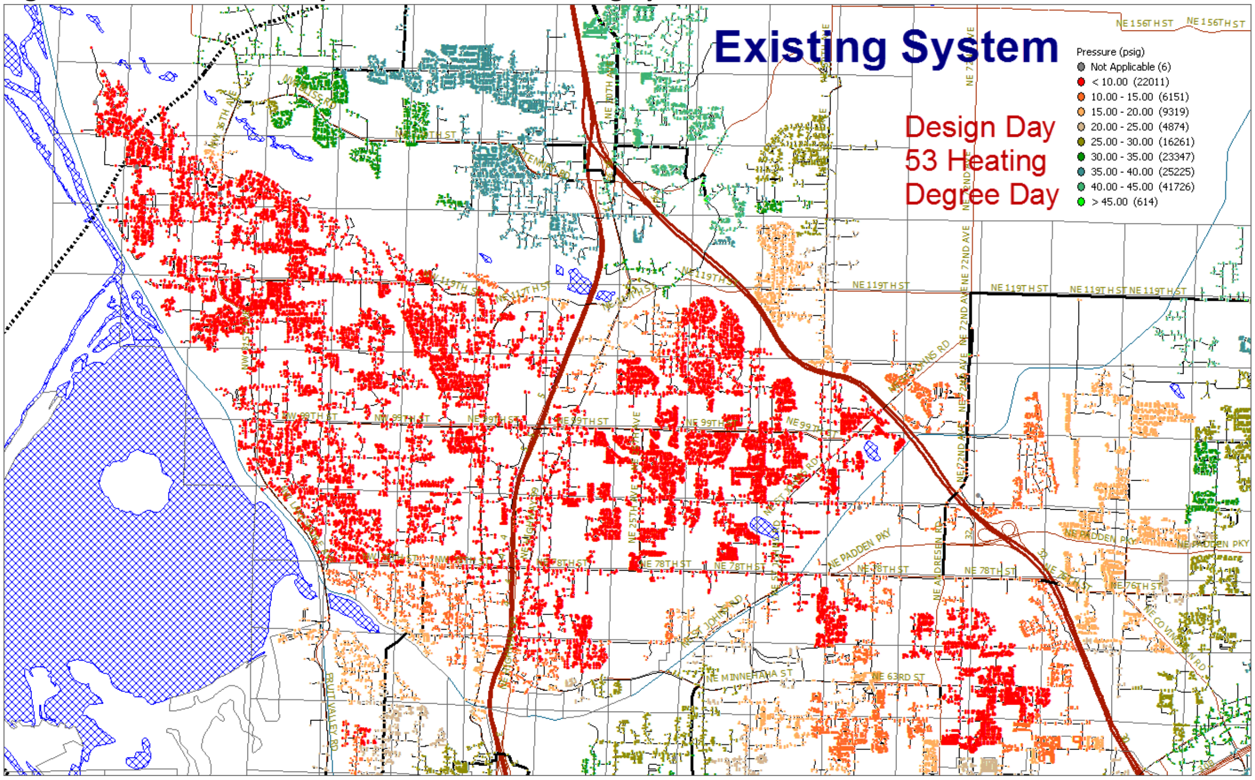
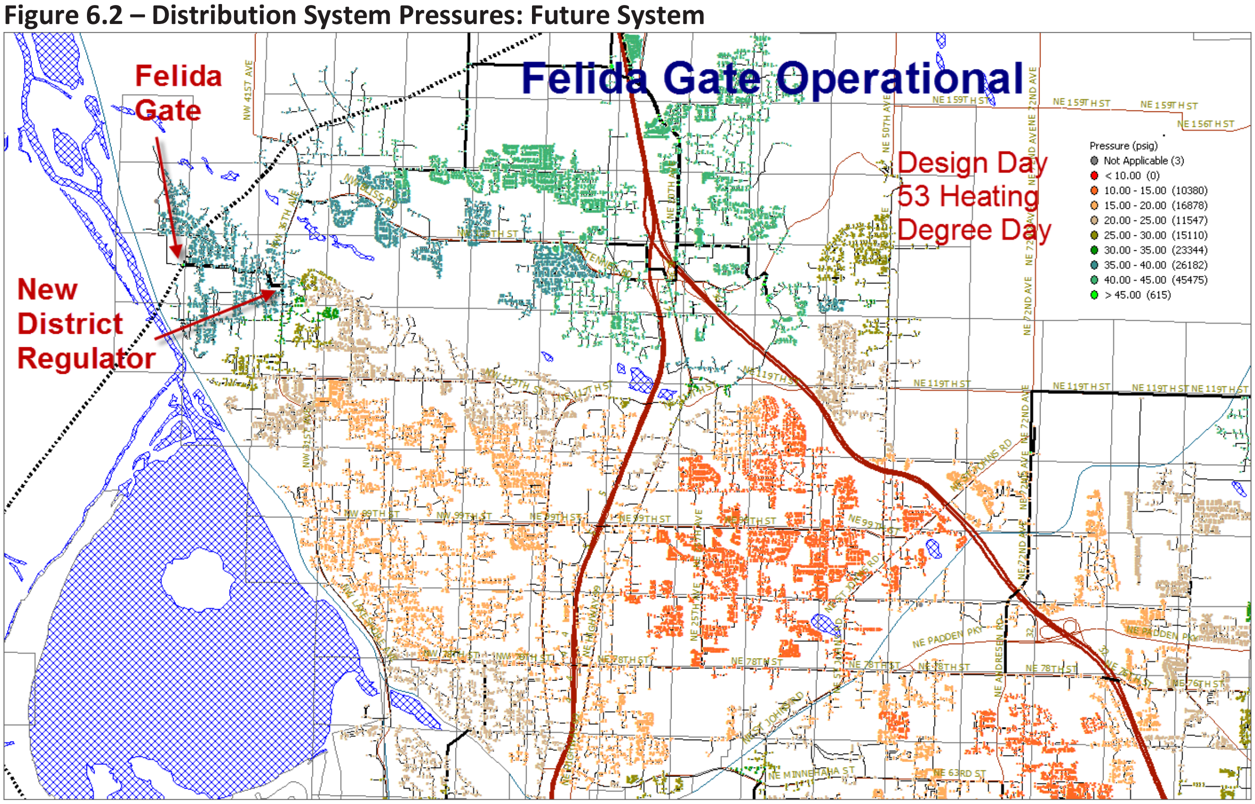


Figure 6.2 – Distribution System Pressures: Future System



Planning Results
NW Natural develops both short- and long-term infrastructure plans based on load growth projections, system integrity issues, 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 variations in realized growth patterns or construction 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.

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-Willamette Valley Feeder to the South Salem feeder system. This project's high level cost estimate is approximately $20 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.[5]

VIII. Other Distribution System Projects

As previously mentioned, the Vancouver load center requires additional system infrastructure investments and NW Natural is currently considering five potential projects that appear to 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.

[5] See Section V of Chapter One.

Chapter 7: Linear Programming and The Company's Resource Choices

NW Natural®

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 their 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 supply-side 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 was 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.

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[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% 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 15 and 16 in the Company's Washington Tariff and Rules 13 and 14 in the Oregon 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 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.

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 price forecast 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 supply is typically the largest cost component of any IRP.

4. Demand-side management resources

As discussed in Chapter Four, the Company worked with the Energy Trust of Oregon (ETO) to generate a 20 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 was integrated into the SENDOUT® resource planning model so that DSM may offset supply-side resources through time. The savings are deducted from the load forecast with the remaining load served by supply-side resources.

ETO 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. In addition, the savings associated with the DSM defined categories were translated into the resource planning model DSM categories.

5. Current supply-side resources

Refer to 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 the future resources that are available in the resource planning model. For additional 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 and consider end effects. 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 Options

Resource Supply Options	Constraint Addressed	Options
Supply Basins	Not enough gas supply	Station Two (BC) Opal (Rockies) AECO (Alberta) Sumas (BC) Malin (Rockies)
Regional Interstate Pipelines	Not enough capacity	Cross-Cascades (CC with N-Max or Eastside Loop) NWP – Washington Expansion (WEX) NWP – Sumas Expansion Additional CD on GTN Additional CD on TransCan (TCPL)
Storage	Not enough supply Not enough capacity More cost effective resource even if enough supply/capacity	Mist Recall Satellite LNG
Supply-side High Pressure Transmission Pipelines (Non-Interstate)	Brings additional supply to load centers from storage or elsewhere	South Willamette Valley Feeder (SWVF) Eastside Loop (ESL) Christenson Compressor Project (CCP)
Distribution System Planning Projects	Not enough capacity behind the city gate	Vancouver distribution projects Aurora Compressor Project (ACP) Newberg to Central Coast Feeder (NCCF) South Salem Feeder (SSF)

Figure 7.1 – Pipeline and Supply Model Diagram

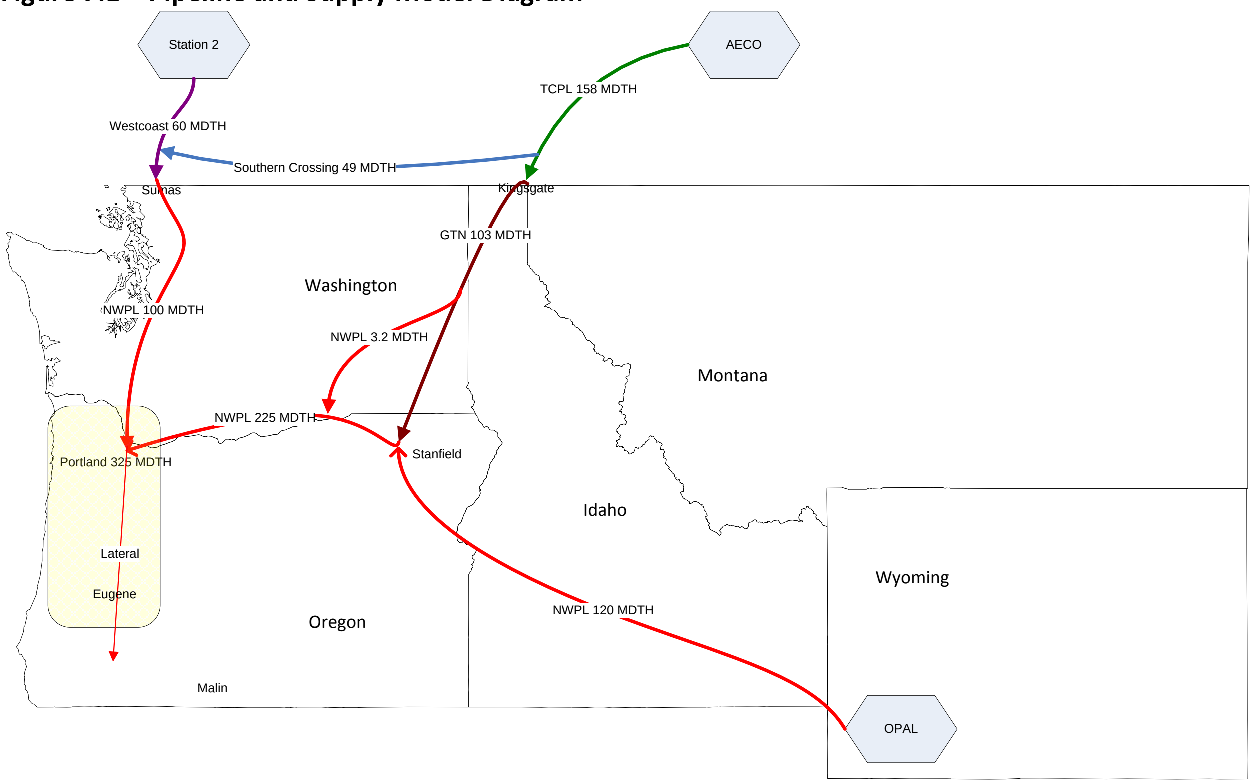


Figure 7.2 – Pipeline and Supply Model Diagram with cross-Cascades

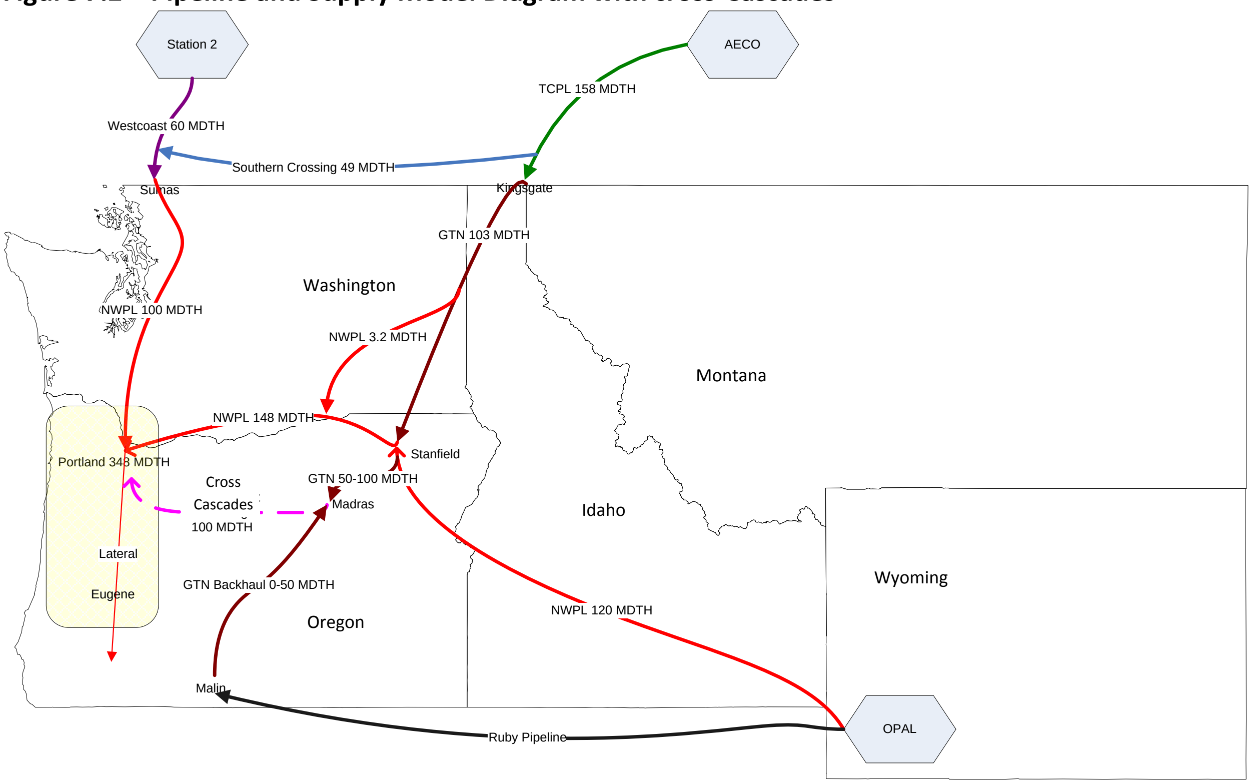
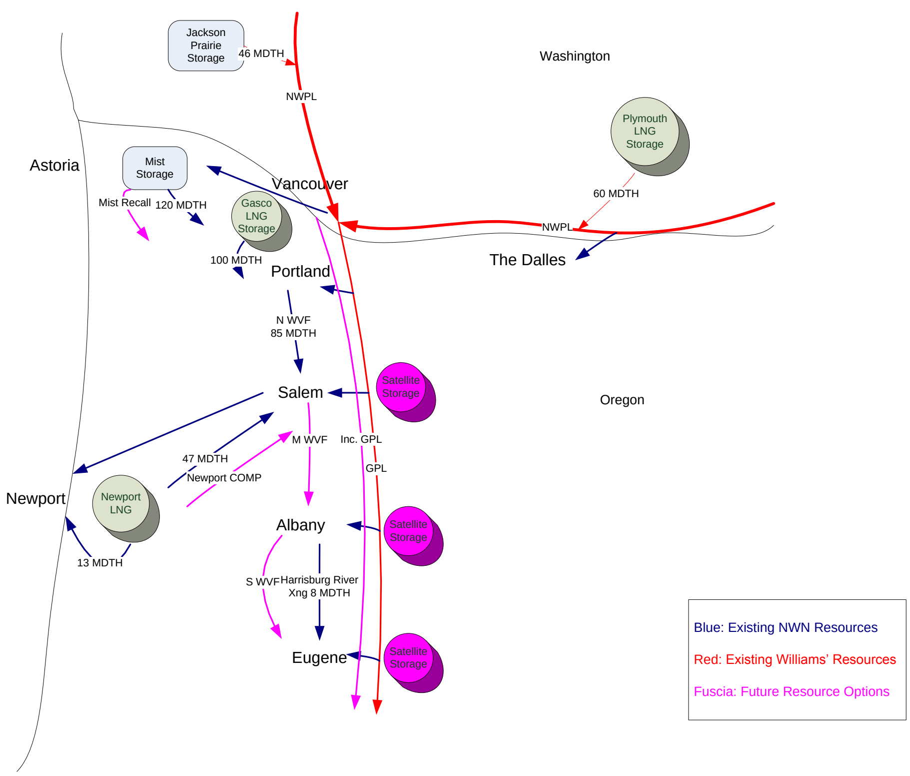


Figure 7.3 – Storage & Service Area Resources Model Diagram



B. System Modeling

SENDOUT® uses a network diagram that represents the pipelines outside of our system and within our system which deliver gas to our 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 our 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 our 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 us to find weak points within our 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 Vancouver service territory (Figure 7.4). We also see that the Salem service area will need additional capacity beginning in 2019 (Figure 7.5).

Figure 7.4 – Vancouver Design Day Load and Physical Delivery Constraints

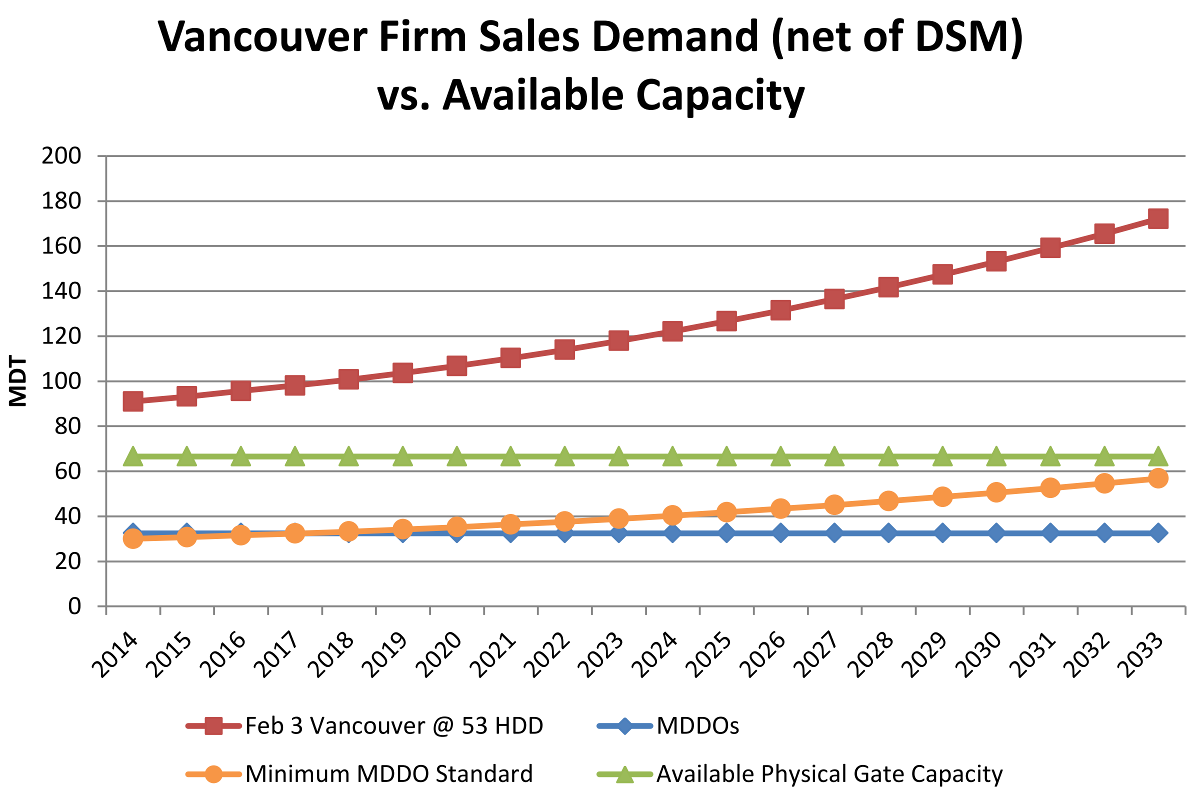
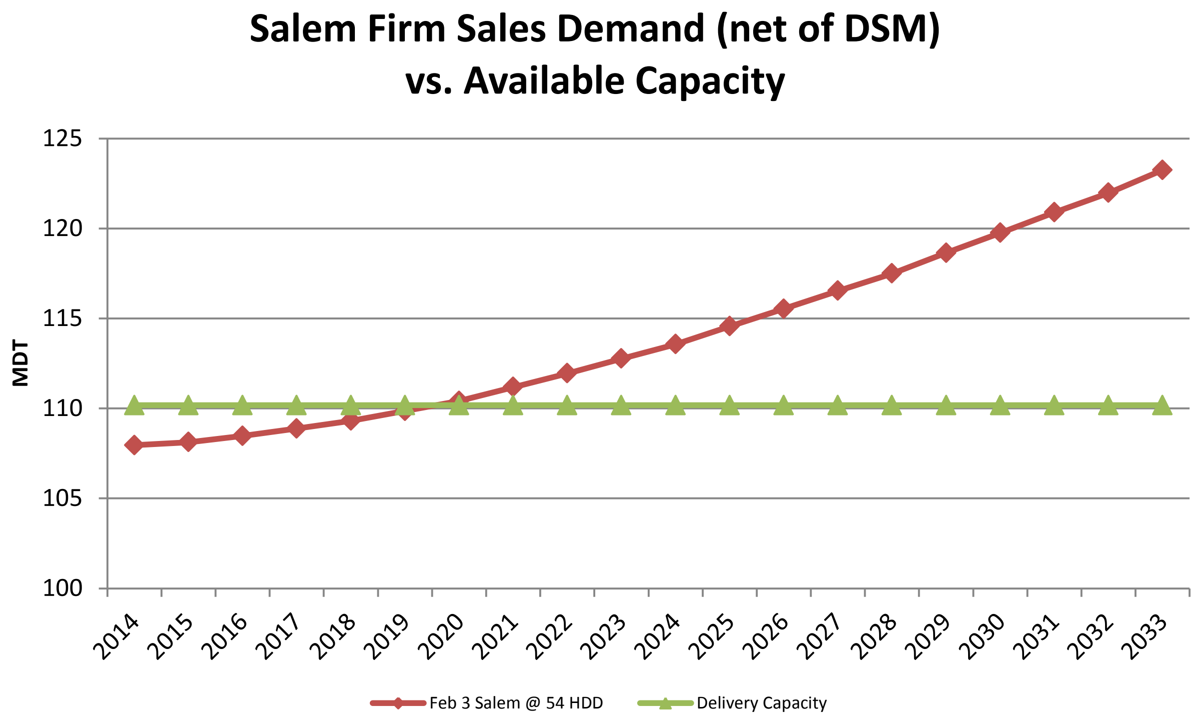


Figure 7.5 – Salem Design Day Load and Physical Delivery Constraints



For this IRP, NW Natural has added the effect of pipeline Operational Flow Orders (OFOs) as a new and important resource planning constraint (OFOs are discussed in more detail in Chapter Three). OFOs are implemented in our model by requiring that 100 percent of contracted capacity of a pipeline segment be used each day during the month of an OFO on that segment. In order to determine which months and which segments would be targeted for an OFO we used the monthly gas price forecasts at the available supply basins. If the forecasted gas price at Sumas is higher than the prices at both Opal and AECO, there will be an OFO on any segments moving south from Sumas. If the forecasted gas price at both Opal and AECO is higher than the Sumas price, there will be an OFO on any segments moving west through the Columbia River Gorge.

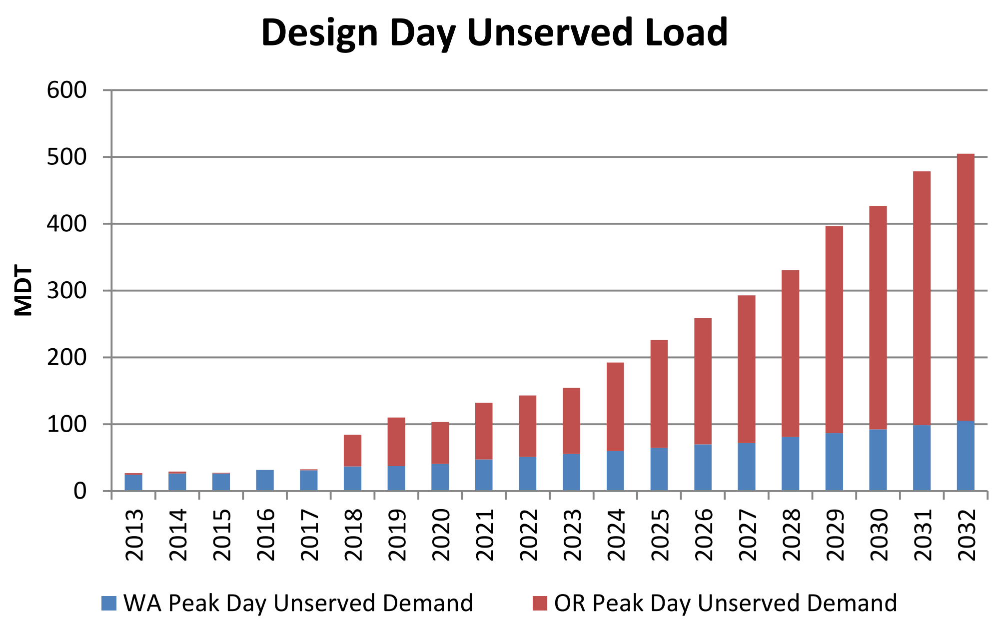
II. RESOURCE PLANNING MODEL RESULTS

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 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 (NPV) of revenue requirements is calculated. For our Base Case and scenarios we are using the traditional planning standard (i.e. design weather and 100 percent resource availability).

A. No New Resources

An initial scenario was run in which all future incremental supply and demand-side resources were excluded. The Base Case load forecast and design weather were used as inputs. The model showed that load growth is large enough that new resources are required. Figure 7.5 displays the design day unserved load through time for both Oregon and Washington. There is a large increase in unserved load in 2018 due to the segmented capacity and secondary firm Jackson Prairie service being removed as design day resources.

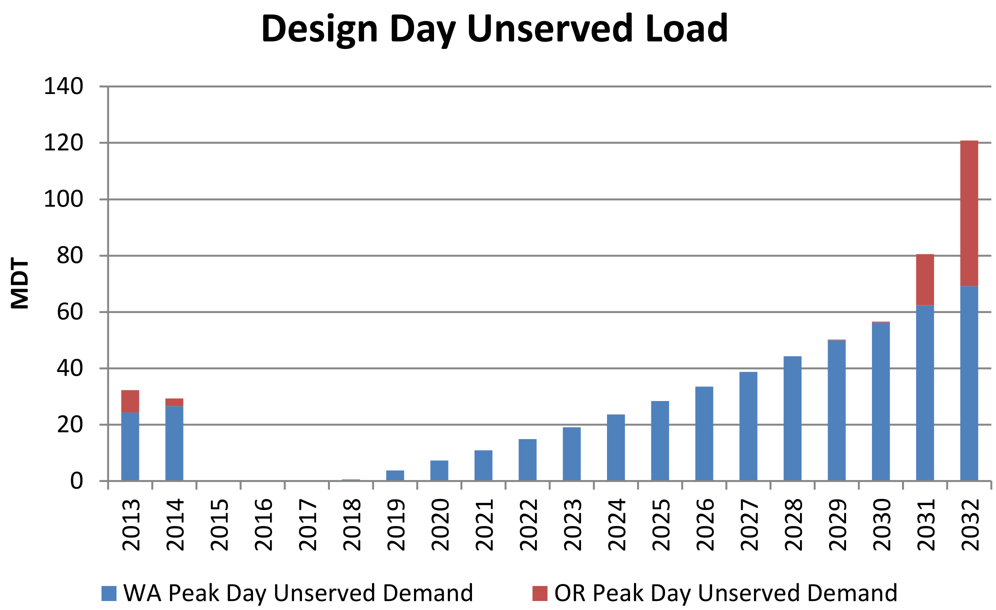
Figure 7.5 – Unserved Load Assuming No New Resources



B. No New Pipeline Capacity

A scenario was run in which all future incremental interstate pipeline capacity resources were excluded. The Base Case load forecast and design weather were used as inputs. The model showed load growth is large enough that new interstate pipeline capacity will need to be added to the system within the planning horizon. Figure 7.6 displays the design day unserved load through time for both Oregon and Washington. The unserved load in the first two years is due to 1) physical limitations of gas delivery to the Vancouver area and 2) physical limitations to gas delivery to the Albany load center. Both of these limitations are overcome in 2015 with gate and distribution improvements combined with Mist Recall for Vancouver and the completion of the final phase of the MWVF for Albany. Beginning with the design day in February 2019, the Vancouver gate MDDOs exceed even our low standard of 33 percent of design day load. Without adding upstream interstate pipeline capacity there is no means of adding MDDOs, creating unserved load in the service area.

Figure 7.6 – Unserved Load Assuming No New Interstate Pipeline Capacity



C. Planning Results with Expected Load

The least cost modeling results show a number of projects are required in order to meet expected load and these are outlined in Table 7.2. The most immediate need to be addressed is the expected shortfall of supply in the Vancouver area due to current physical capacity limitations at NWP's gate stations as well as within the Company's distribution system. Additionally, the Vancouver area is forecasted to have the highest rate of load growth within our system which leads to further supply needs. While NW Natural shows a significant risk of customer outages in the Vancouver area until improvements can be made, the Company plans to continue using LNG and CNG trailers to supplement interstate pipeline deliveries in the service area under cold weather conditions. We also see the need for reinforcement of the Salem area beginning in 2019 and for Newport LNG takeaway improvements in 2025.

The least cost planning selects 110 MDT of capacity on the cross-Cascades (CC) with connection to N-Max in 2018. In the same year 8 MDT of NWP Gorge capacity is turned back and would be put on CC as well as turning back 55 MDT of capacity from Alberta. The large decrease in capacity from Alberta is driven by the turn back of Gorge capacity as well as the termination of the Southern Crossing capacity contract in 2020. The turn back of NWP Gorge capacity is driven by the relatively higher costs of transporting gas from Alberta to Stanfield compared to going from Malin to Madras (0.44 vs 0.14 $/DT/day respectively). Table 7.3 shows the cumulative changes to total system supply resources through 2021. Because we have dropped all of Plymouth LNG and some of Jackson Prairie storage from our firm resource stack, the net supply additions, including CC, amounts to 63 MDT in 2020.

Table 7.2 – Resource Changes

	Resource (DT/day)						
Year	**Alberta Turn back**	**Gorge Turn back**	**CC**	**Mist Recall (Cumulative)**	**Van Dist (Cumulative)**	**SSF**	**CCP**
2013-14							
2014-15							
2015-16				30,291	31,145		
2016-17					31,145		
2017-18				35,298	33,871		
2018-19	(54,888)	(8,396)	110,000		36,893		
2019-20					40,041	19,000	
2020-21					43,738		
2021-22					47,555		
2022-23				46,105	51,653		
2023-24				59,664	55,860		
2024-25				74,933	60,679		
2025-26					65,605		40,000
2026-27					70,801		
2027-28				83,094	76,092		
2028-29				101,166	81,997		
2029-30				119,413	87,995		
2030-31				138,263	94,251		
2031-32				157,170	100,578		
2032-33				191,496	107,522		

Table 7.3 – Cumulative Supply Changes

	Cumulative Supply Additions (Reductions) (MDT/day)							
	2015	2016	2017	2018	2019	2020	2025	2030
Mist Recall	30	30	35	35	35	35	75	138
cross-Cascades capacity				110	110	110	110	110
Segmented capacity	44	44	44	0	0	0	0	0
Plymouth LNG	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)
Jackson Prairie				(14)	(14)	(14)	(14)	(14)
NWP capacity				(8)	(8)	(8)	(8)	(8)
Net Supply Change	14	14	19	63	63	63	103	166

An initial resource portfolio showed the need for additional interstate pipeline capacity beginning in 2018. While there are many possible means of adding this capacity, NW Natural identified three reasonable options for interstate pipeline capacity additions (Table 7.4). Two options are large regional pipelines on which NW Natural would be a minority shipper. The third option is an incremental expansion of NWP from Sumas which would only serve the NW Natural system needs. An incremental expansion could occur in multiple phases as needed by customers. For this reason, the Sumas Expansion option was modeled to allow capacity additions in each of 2018 and 2025.

While a regional pipeline project offers a distinct price advantage over incremental expansion, the timing of such a project is uncertain and the Company may need to subscribe to capacity before it is needed by customers. If a regional project could not be in service until after 2020, NW Natural could potentially continue to rely on secondary resources (Segmented capacity and Jackson Prairie) in addition to additional Mist Recall to meet immediate growth needs.

Table 7.4 – Interstate Pipeline Options

Resource	Assumed Cost ($/DT/day)	Likelihood project could move forward	Timing	Other Effects
NWP WA Expansion	0.56 + BC-Sumas rate	Medium (50%)	Uncertain (2018-2020)	
Cross-Cascades	0.41 + N-Max rate	Medium (50%)	Uncertain (2018-2020)	Eliminates OFOs Reduces Sumas price by $0.09
NWP Sumas Expansion	0.88 + BC-Sumas rate	High	As needed	

Table 7.5 compares the 20-year NPVs of the various interstate pipeline options. Based on these analyses, acquiring capacity on CC is lower cost than any project which expands capacity from Sumas. Much of the increased costs of acquiring capacity south from Sumas is the need to contract capacity upstream into the BC supply basin (i.e. at Station 2). While the WEX option appears to be higher cost than a Sumas Expansion, the NPV analysis does not consider the additional costs beyond 20 years.

Table 7.5 – 20-year Portfolio NPVRR

Portfolio Number	Scenario Description ($/DT/day)	Supply NPV ($000)	Transportation NPV ($000)	Storage NPV ($000)	Total NPV ($000)
1	CC 2018 (0.41)	5,368,509	1,386,568	341,918	7,170,605
2	WEX 2018 (0.56)	5,331,800	1,541,941	341,643	7,288,994
3	Sumas Exp 2018/25 (0.88)	5,345,232	1,499,421	354,520	7,272,782

Because cross-Cascades is a new pipeline, the project sponsors may ask potential shippers to provide funding for the permitting process. However, since there would still be potential for the project to be abandoned after permitting, there exists the potential for sunk costs. NW Natural intends to provide an analysis of the value of keeping the project available as an option given the uncertainty of the pipelines viability.

D. Reliability

1. Design Weather (Traditional Planning Standard)
As discussed in Chapter Two above, NW Natural changed its design weather pattern to reflect a colder winter period while keeping the same 53 HDD design day. A scenario was run using the design weather from the 2013 IRP which reflected an 85th percentile winter period over a 20 year history. The least cost resource portfolio is shown in Table 7.7. The results from this scenario are not significantly different from the Base Case.

Table 7.7 – Resource Changes with 2013 IRP Design Weather Assumptions

	Resource (DT/day)						
Year	**Alberta Turn back**	**Gorge Turn back**	**CC**	**Mist Recall (Cumulative)**	**Van Dist (Cumulative)**	**SSF**	**CCP**
2013-14							
2014-15							
2015-16				32,044	31,483		
2016-17					31,483		
2017-18				37,235	34,218		
2018-19	(49,189)	(2,925)	110,000		37,251		
2019-20					40,411	19,000	
2020-21					44,121		
2021-22					47,951		
2022-23				42,903	52,064		
2023-24				56,736	56,286		
2024-25				72,285	61,121		
2025-26					66,065		40,000
2026-27					71,280		
2027-28				81,309	76,590		
2028-29				99,677	82,515		
2029-30				118,221	88,534		
2030-31				137,371	94,812		
2031-32				156,577	101,162		
2032-33				191,406	108,130		

2. Resource Reliability (Probabilistic Planning)

NW Natural intends to complete a more robust resource plan which considers less than 100 percent resource availability.

E. Scenario Model Runs

NW Natural developed portfolios (Table 7.8) around the potential future load scenarios which are described in Chapter Two. While the Company believes these future loads to be less likely than those in the Base Case, it is important to test the sensitivity of resources to a range of load scenarios. In a low load growth scenario, NW Natural would rely on the flexibility of Mist Recall for primary growth needs throughout the planning horizon instead of adding a lumpy pipeline resource. In a high load growth scenario NW Natural acquires more interstate pipeline capacity in 2018 and completes the SSF and CCP projects at an earlier date.

Table 7.8 – Scenario Model Runs

Scenario	Alberta (DT/day)	NWP Gorge (DT/day)	CC (DT/day)	Mist Recall (2033 DT/day)	SSF (year)	CCP (year)
Low Growth	(46,957)	-	-	237,472	2026	2030
Base Case	(54,888)	(8,396)	110,000	191,406	2019	2025
High Growth	(65,479)	(18,022)	206,673	192,524	2017	2023
Medium EM	(54,267)	(7,800)	110,000	191,750	2019	2025

III. Portfolio Risk Analysis

NW Natural intends to take a stochastic approach to test our base case portfolio and various interstate pipeline options. Risk variables which will be considered include commodity price and weather.

IV. Key Findings

- The Vancouver area needs additional gate and distribution capacity in the short-term as well as supply to serve long-term growth.
- Removing Plymouth LNG as a firm design day resource accelerates the need for additional gas supplies.
- Mist Recall can serve some, but not all, future supply needs. Additional interstate pipeline capacity is required within the planning horizon.
- A regional pipeline project would be the long-term least cost option for interstate pipeline needs.
- NW Natural's analysis indicates that a cross-Cascades pipeline project would be the least cost regional pipeline to serve the Company's service area.
- The Salem area requires additional peak supply even under a low growth scenario.
- Increasing the Central Coast Feeder capacity by installing a compressor at Christenson is needed (and needed even under a low growth scenario).

Chapter 8: Avoided Cost Determination

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), 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.

III. Methodology

The SENDOUT® resource planning model was used to generate the avoided costs. The base case demand parameters were used as inputs, including the design weather pattern, and base case customer and gas price forecasts.

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. In addition to existing supply side resources, the resource options included Mist Storage Recall, Grants Pass Lateral pipeline capacity, Newport Improvements, cross- Cascades with either N-Max or Eastside Loop options, South Salem Feeder, Newberg to Central Coast, Aurora Compressor, South Mist Feeder, and satellite storage. The model determines the lowest cost method for serving the next unit of demand and computes a marginal cost. As discussed above, 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; 4) Peak related on-system transmission costs; and 5) the cost for gas used to push gas through the system.

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[1] The Henry Hub spot price of natural gas IHS CERA forecasts has an embedded projected carbon cost see Chapter Five for more information.

IV. Results
Table 8.1 lists the numerical results for costs in $/DT. Further detail 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

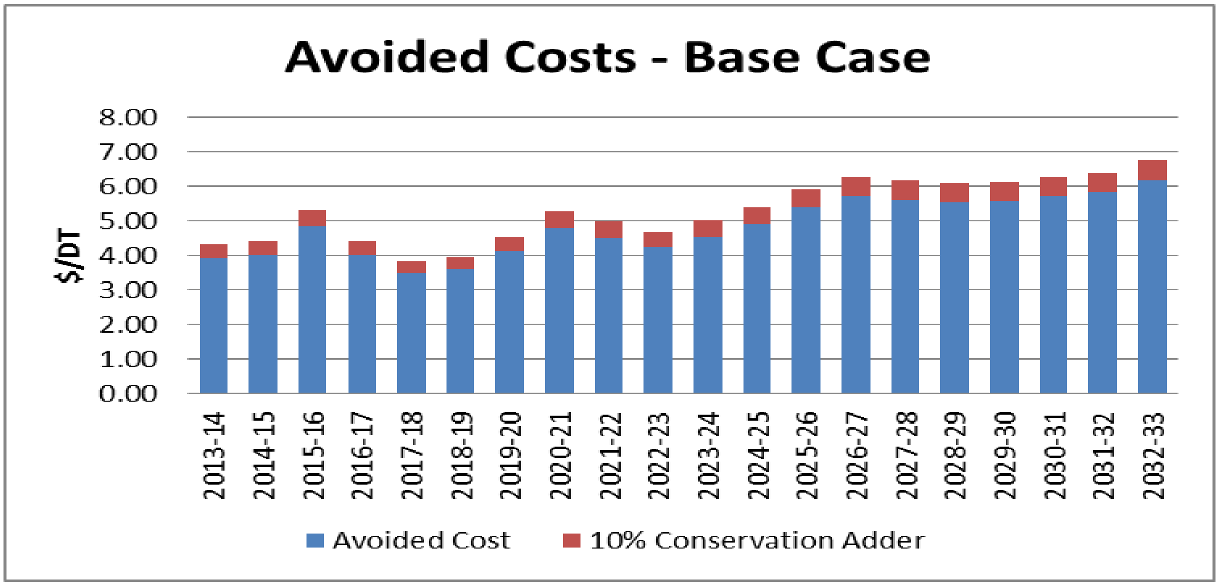

Figure 8.2 below displays the high, low, and Base Case cost scenarios with all costs rolled up—the avoided costs along with the 10 percent conservation adder.

Figure 8.2 – Avoided Cost Scenarios

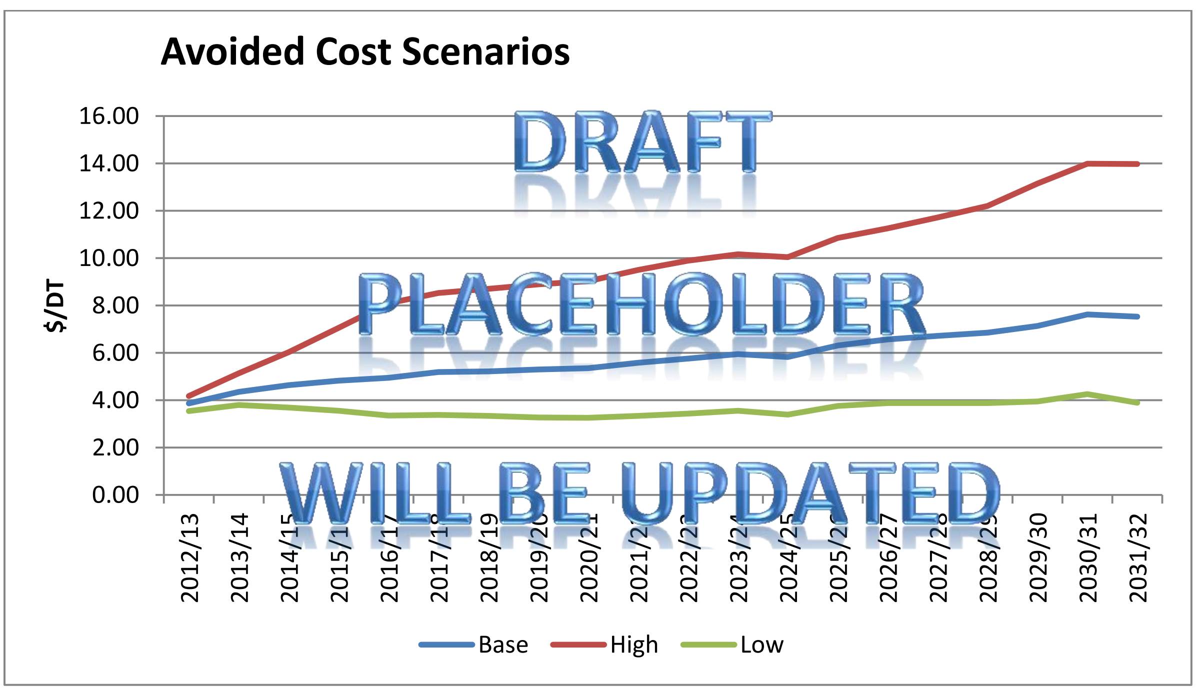

Table 8.2 shows the avoided cost numerical results shown in $/DT and broken down by state. The costs are shown with the 10 percent adder as well.

Table 8.2 - Avoided CostsGas Year	**Avoided Cost ($/DT)**			**With 10% Conservation**		
	OR	**WA**	**System**	**OR**	**WA**	**System**
2012/13	3.51	3.52	3.51	3.86	3.87	3.86
2013/14	3.96	3.96	3.96	4.35	4.36	4.35
2014/1[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	4.63
2015/16	4.39	4.39	4.39	4.82	4.83	4.82
2016/17	4.50	4.51	4.50	4.95	4.96	4.95
2017/18	4.71	4.72	4.71	5.18	5.20	5.19
2018/19	4.74	[illegible]	[illegible]	[illegible]	5.22	5.21
2019/20	4.82	4.83	4.82	5.30	5.31	5.30
2020/21	4.86	4.87	4.86	5.35	5.36	5.35
2021/22	5.08	5.09	5.08	5.59	5.60	5.59
2022/23	5.24	5.25	[illegible]	[illegible]	5.77	5.76
2023/24	5.40	5.41	5.40	5.94	5.96	5.95
2024/25	5.30	5.30	5.30	5.83	5.83	5.83
2025/26	5.74	5.75	5.74	6.32	6.33	6.32
2026/27	5.98	5.99	5.98	6.57	6.59	6.57
2027/28	6.11	6.12	6.11	6.72	6.74	6.72
2028/29	6.23	6.24	6.23	6.85	6.87	6.86
2029/30	6.49	6.50	6.49	7.14	7.15	7.14
2030/31	6.93	6.94	6.93	7.63	7.63	7.63
2031/32	6.84	6.85	6.84	7.53	7.53	7.53

V. Key Findings

Avoided costs were calculated for the base case and included a carbon 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 Oregon Public Utility Commission Staff; the Washington Utilities & Transportation Commission; and the Northwest Gas Association.

NW Natural held three TWG meetings and a workshop in 2013 and early 2014. The Company has two additional TWG's scheduled in 2014. Below is a brief summary of each meeting. The following pages contain more detailed summaries of each meeting including issues, both resolved and outstanding.

- TWG No.1 held on August 22, 2013
  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

- TWG No. 2 held on October 2, 2013
  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.

- Scenario Workshop – November 13, 2013
  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.

- TWG No. 3 scheduled on December 10th – cancelled due to weather
  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.

- TWG No.4 held on January 23, 2014
  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

- TWG No. 5 held on March 7th
  (TBD)

- TWG No.6 held on April 3rd
  (TBD)

Appendix 9 contains the sign in sheets for each TWG meeting

II. PUBLIC PARTICIPATION

NW Natural plans on inviting its customers to participate in the resource planning process. A bill insert that informs customers of the IRP, invites comments, and announces a public meeting, was sent to all customers in December 2013 billings. Customers will be invited to review the draft IRP and provide comments either by mail or email.

Appendix 1: Regulatory Compliance

NW Natural®

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 Septemeber 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 side and supply side resources into Gas Supply and Planning Optimization software. The resulting model acted as a guide to steer the Company toward the least cost resource planning 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, technical working groups were held on August 22, 2013, October 2, 2013, January 23, 2014, March 7, 2014, and April 3, 2014. Additionally a scenario workshop was held on November 22, 2013. Lastly, customers were notified of this IPR process through a December 2013 bill insert included in Appendix Eight. This bill insert welcomed public comments and invited customers to a public meeting that was held on April 15, 2013.
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)	Plan describes mix of natural gas supply resources.	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 provides a commentary of other alternative supply side option such as biogas.
WAC 480-90-238(2)(a)	Plan describes conservation supply.	Chapter Four explains how NW Natural determined the achievable potential of DSM within its service territory for the next 20 years. The achievable potential was then screened with other supply side option in SENDOUT.® The analysis performed showed that through continued administration of energy efficiency programs in Oregon and Washington, 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 and in Washington, 1.1 million therms by 2018 and 3.6 million by Four.
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 then studied future demand uncertainty through a deterministic set of load forecasts of the traditional low, base, and high scenarios. The Company first projected annual customer counts by customer sub-class. Customer growth forecasts were prepared for three scenarios, including low growth, Company projected base case, and high growth forecasts. The Company then statistically estimated gas usage equations for each customer subclass (or market segment). Design year (including peak day) projections were derived from multiple regressions, separating out Base-use and Temperature Sensitive Load-use (TSL-use). Next, the Company applied design weather conditions, projected prices, and customers to gas usage equations to derive firm gas requirements for each 20-year forecast scenario.

NW Natural's 2014 IRP - Washington Compliance

Rule	Requirement	Plan Citation
WAC 480-90-238(2)(a)&(b)	Plan uses lowest reasonable cost (LRC) analysis to select mix of resources.	The Company considered the strictly economic data assessed by the SENDOUT® model, the likelihood of certain resources such as imported or satellite LNG being available, stochastic analysis of demand and price forecasting, and the non-economic but significant reliability benefits offered by certain resources, such as the Cross Cascades. After considering all these factors, the Company selected a Preferred Portfolio and identified for acquisition resources consistent with that portfolio.
WAC 480-90-238(2)(b)	LRC analysis considers resource costs.	Chapter Three of the IRP identifies the costs of supply side resources. Chapter Five discusses how SENDOUT® generated least-cost solutions through the analysis of hundreds of potential solutions made possible by evaluating numerous variables associated with forecast customer demand for gas (customer count forecasts, usage coefficients by customer type (residential, commercial), heating degree days (HDDs), and forecast end use.
WAC 480-90-238(2)(b)	LRC analysis considers market-volatility risks.	TBD
WAC 480-90-238(2)(b)	LRC analysis considers demand side uncertainties.	Chapter Four discusses the effect DSM would have on the resource mix. Additionally, the Company has run a high/low avoided costs scenario
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.	In response to a growing, general interest in risk analysis, the Company recently began using what was initially an add-on module to SENDOUT,® called VectorGasTM, as the platform for performing Monte Carlo simulations. SENDOUT® Version 12 now integrates the full functionality of VectorGas into SENDOUT® providing Monte Carlo simulation capability around weather and price. Through detailed portfolio optimization techniques, the analytical potential of SENDOUT® is enhanced because of its capability to produce probability distribution information.
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 contraints. 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. 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.
WAC 480-90-238(2)(b)	LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	As stated above, 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.

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 sufficent to satisfy core customer requirements. The second priority is to achieve sufficient resources at the lowest cost to customers. Choosing Cross Cascades as a resource demonstrates the Company's efforts to both increase reliability and reduce dependency on one pipeline.
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.	DSM savings per customer in NW Natural's service territory is defined in this plan as the reduction of gas consumption resulting from the installation of a cost effective conseration 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 changing customer base, including the number and types of customers currently served, the types of customers that could be served in the future under varying circumstances including low, base and high recession scenarios, and the amount and pattern of gas usage that can be reasonably expected by those customers.
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's Plan acknowledges that the sustained volatility of natural gas prices and the risk and uncertainty associated with them made it necessary to include price elasticity in its modeling in order to accurately forecast usage per customers. As such, in the Updated Plan, the Company performed high and low price sensitivity studies and compared them with the Base Case in*SENDOUT®*.
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 discusses the projected changes in each customer clases. Forecasts are based on observable trends as well as published studies.
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 demand side management that should be included in the Company's preferred porfolio began with a study of all known commercially available conservatiion measures, including measures that are not fully in the market place. Chatper Four provides an overview of new measures as well as interesting findings. Regarding load management, the Company continues to shave peak load when needed 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 the Company deliveres energy efficinecy programs that offer customers incentives for cost effective demand side management measures. Appendix Four contains the Company's Schedule G, Energy Efficiency Services and Programs--Residential and Commerical. It also includes the Company's Energy Efficiency Plan which further lays out 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.	The best resource mix was determined 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. 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.	The Company's Mist underground storage, imported LNG, as well as Satellite LNG facilities located at various locations within the Company's service territory were assessed 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.	This study finds that with the loss of firm Plymouth LNG resources, the long term uncertianty of Jackson Priaire Firm Resources, greater visibility into specific load center needs, NW Natural should seek cost-effective resource options in addition to using Mist Recall. Cross Cascades has been identified as the least cost option and it also enhances pipeline diversity. Chapters Three and Seven discuss additional pipeline options that were evaluated.
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.	The best resource mix was determined 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. Future developments such as imported LNG and pipeline enhancements were also considered. SENDOUT® determined the least cost resource mix through linear program discussed in Chapter Seven.
WAC 480-90-238(3)(g)	Plan includes at least a 10-year long-range planning horizon.	This IRP contains the Company's long-range analysis of load and resources spanning a 20-year horizon.
WAC 480-90-238(3)(g)	Demand forecasts and resource evaluations are integrated into the long range plan for resource acquisition.	Future Resource investments discussed include: a) Interstate Pipeline Additions, b) Brownsville to Eugene, c) Newport Expansion, d) Willamette Valley Feeder, e) Imported LNG, f) satellite LNG, and g) cost effective demand side resources.
WAC 480-90-238(3)(h)	Plan includes a two-year action plan that implements the long range plan.	The Multi-Year Action Plan details ongoing reiview or work the Company will accomplish specific to Demand Forecasting, Supply-Side Resources, Demand-Side Resources, SENDOUT® Model and Least Cost Plan Integration, 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.	Recent resources decisions discussed include the addition of 28 miles of 24 inch piping to loop the existing South Mist Feeder from Miller Station to a point at the western edge of the Portland metropolitan areas (Bacona), and completion of SMPE, which allows the Company to access more Mist deliverability.
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. Public participation is documented in Appendix Nine.
WAC 480-90-238(5)	Plan includes a description of completion of work plan. (Description not required)	The Key Findings found at the end of each chapter and the Multi-Year Action Plan found in Chapter One provides conclusions drawn from study and successful completion of the Plan.

NW Natural's 2014 IRP - Oregon Compliance

Citation	Requirement	Plan Citation
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 made every effort to include all known supply and demand side options. Supply side options studied include not only the gas itself, 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 potentially available within the Company's service territory. Chapters Three and Four focus on supply and demand side resources, respectively, while the results of NW Natural's analyses can be found in Chapter Seven.
	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 in Chapter Three range from existing and proposed interstate pipeline capacity from multiple providers, the Company's Mist underground storage, to imported LNG, as well as Satellite LNG facilities located at various locations within the Company's service territory. The Company clearly defines each resource's in-service date before which the respective resource could not be a selected resource. Because the Company identified unserved demand in all areas of its service territory within the 20-year planning horizon, it considered a variety of supply side options to meet local, regional, and system-wide demand such as satellite LNG, NW Natural pipeline enhancements (including the Willamette Valley Feeder project), and interstate pipeline expansions. In-service dates considered in the plan range from short term, such as Mist Recall supplies available in Fall 2014, to near-term resources (such as a Cross-Cascades Pipeline, which has been modeled as first available in 2018). All resources are offered each year after they become available throughout 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.
	Consistent assumptions and methods should be used for evaluation of all resources.	To the best of its ability, NW Natural evaluated all resources, both supply and demand side, on a consistent basis in the SENDOUT® model, which programmatically and objectively applied the same common assumptions, approaches and methodology to each supply option. Chapter Seven contains the specific descriptions of the resource evaluation methodology.
	The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	In this IRP, the Company uses a real after-tax discount rate of 4.58 percent.
Guideline 1(b)	Risk and Uncertainty must be considered.	This study is characterized by risk and uncertainty because the Company cannot perfectly predict the contributing data such as future customer counts, economic conditions, market changes and weather conditions. However, this study analyzes risk-related data such that the Company can make reasonable assumptions. Additionally, the company has recently begun to include an analysis the captures the uncertainty of reliability of resources.
	At a minimum, utilities should address the following sources of risk and uncertainty: Natural gas utilities: demand (peak, swing and baseload), commodity supply and price, transportation availability and price, and cost to comply with any regulation of greenhouse gas emissions.	NW Natural analyzes demand uncertainty (peak, swing, and baseload) through a deterministic set of load forecasts of the traditional low, base, and high scenarios. The Company first projected annual customer counts by customer sub-class. Customer growth forecasts were prepared for three scenarios, including high growth, low growth, and the Company's projected base case. The Company then statistically estimated gas usage equations for each customer subclass (or market segment). Design year (including peak day) projections were derived from multiple regressions, separating out Base-use and Temperature Sensitive Load-use (TSL-use). Next, the Company applied design weather conditions, projected prices, and customers to gas usage equations to derive firm gas requirements for each forecast scenario. Additionally three price forecasts were prepared, including high, base case and low forecasts. The price forecasts are discussed in more detail in Chapter 2 . In addition to the three deterministic demand forecasts for High, Low and Base Case Scenarios, the Company is incorporating Monte Carlo simulations (i.e. stochastic analysis) in its evaluation of customer demand. Stochastic analysis (Monte Carlo simulation) and SENDOUT® linear programming analysis are explained in more detail in Chapter Seven. The associated risk and uncertainty of commodity supply, prices and transportation availability are discussed in chapter Six, which includes the results of sensitivity analysis involving price simulations for future supply basin-specific and North American supply restrictions. Finally, the cost to comply with greenhouse gas emissions regulation and the risk and uncertainty associated with potential regulation is discussed in Chapters Four and Five. Chapter 4 contains the Company's evaluation of cost effective demand side management based on an avoided cost that included emission adders. The higher avoided cost resulted in more achievable demand side resource potential. Chapter 6 impacts the results derived in chapter 4 through the development of NW Natural's avoided cost figures.
	Utilities should identify in their plans any additional sources of risk and uncertainty.	In addition to the areas of risk and uncertainty described above that NW Natural has included in this Plan (weather, customer growth, and price), the Company has considered the likely impediments to the ultimate development and siting of certain potential resources such as imported LNG and satellite LNG. These are discussed in Chapter Three. Additionally, the Company is now including a reliability risk analysis as well.

NW Natural's 2014 IRP - Oregon Compliance

Citation	Requirement	Plan Citation
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.	This IRP contains the Company's long-range analysis of load and resources spanning a 20-year horizon.
	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.	The Company's SENDOUT® modeling software uses a PVRR cost metric methodology, which provides resource portfolio costs in both nominal and real (present value) dollars that is applied to resources of varying expected lives.
	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.	Through application of the SENDOUT® software, the Company modeled 200 scenarios around varying gas price and weather inputs via Monte Carlo iterations thereby developing a distribution of annual cost estimates utilizing SENDOUT®'s PVRR methodology. Chapter Seven further describes this analysis. The variability of costs is plotted against the Mean of the Total Cost distribution, while the Unserved Demand distribution captures the severity of bad outcomes.
	Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	Explanation: 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 supply: 1) reliability, 2) lowest reasonable cost, 3) price stability, and 4) cost recovery. This is discussed in greater detail in Chapter Three.
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	For this IRP, the Company has selected a 90% probability coldest winter planning standard augmented by an historic seven-day peak event against which to evaluate the cost and risk trade-off of various supply and demand resources available to SENDOUT.® Although this planning standard incorporates a level of demand that is less than its traditional "design year" planning standard, it reflects the Company's assessment that the costs associated with the higher planning standard were not justified in comparison with the risk of that traditional "design year" occurring. Further analysis of how the Company's resource choices appropriately balance cost and risk can be found in Chapter Six, in the analysis of the Company's selection of its Preferred Portfolio. In short, the Company considered the strictly economic data assessed by the SENDOUT® model, the likelihood of certain resources such as satellite LNG being available, stochastic analysis of demand and price forecasting, and the non-economic but significant reliability benefits offered by certain resources, such as a cross-Cascades pipeline. After considering all these factors, the Company selected a Preferred Portfolio and identified for acquisition resources consistent with that portfolio.
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 contraints. 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.
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.	The public has been given considerable opportunities to participate in the development of NW Natural's 2014 IRP. The Company has held five Technical Working Group (TWG) meetings, one workshop and one public meetings. Customers were notified of the 2014 IRP process in an December 2013 bill insert, which invited the submission of writen or electronic comments and announced the June 17 public meeting. A discussion of the technical working groups and the public meeting can be found in Chapter Nine. Beyond these forums, the Company has been answering parties informal data requests.
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 the material included throughout the plan, the Company has put forth all relevant non-confidential information necessary to produce a comprehensive Plan.

NW Natural's 2014 IRP - Oregon Compliance

Citation	Requirement	Plan Citation
Guideline 2(c)	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	On February 28, 2014, after three TWG meetings, NW Natural submitted an initial draft plan in both Oregon and Washington. A technical working group meeting was held on March 7, 2014, to discuss the draft plan.
Guideline 3(a)	The utility must file an IRP for within two years of its previous IRP acknowledgement order.	NW Natural's 2011 Modified IRP was acknowledged by the Commission on September 11, 2011 *See* OPUC Docket No. LC 51.
Guideline 3(b)	The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	NW Natural will comply with this guideline.
Guideline 3(c)	Commission Staff and parties should complete their comments and recommendations within six months of IRP filing.	The Company looks forward to working with Staff and interested parties in their review of this plan.
Guideline 3(d)	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.	TBD
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 efore the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	The Company plans to file an annual report as required.
Guideline 3(g)	Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that: 1- Describes what actions the utility has taken to implement the plan; 2-Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and 3-Justifies any deviations from the acknowledged action plan.	The Company acknowledges this guideline.
Guideline 4	At a minimum the plan must include the following elements:	
Guideline 4(a)	An explanation of how the utility met each of the substantive and procedural requirements.	This appendix is intended to comply with this guideline by providing an itemized response to each of the substantive and procedural requirements.
Guideline 4(b)	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions	The Base Case demand forecast uses the Company's projected customer growth and projected prices. This IRP considers two departures from the Base Case demand forecast, including a high and low demand growth forecasts. Additionally, the company also has three scenarios that address demand generated from emerging markets as well as stochastic risk analysis. These scenarios are discussed in Chapter Two. Chapter Seven provides the scenario and risk analysis results. Assumptions are detailed in Chapter Two.
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, the Company determined the peaking, swing, and base-load gas supply and associated transportation and storage for each year of the 20-year planning horizon. Please see the appendix to Chapter Seven for the detail behind the distinct scenarios and sensitivities considered by the optimization model, and specific resources selected in each case for each year.

NW Natural's 2014 IRP - Oregon Compliance

Citation	Requirement	Plan Citation
Guideline 4(e)	Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology.	The best resource mix was determined 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. Future developments such as pipeline enhancements were also considered. The various supply side options and their costs are identified and discussed in Chapter Three. Demand side resource options were compiled with assistance from the Energy Trust of Oregon. Demand-side resource options are identified in Chapter Four and its Appendix Four.
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. For planning purposes, the Company uses two approaches. First there is the traditional planning standard that develops a feasible Base Case. Additionally, The Company does a Monte Carlo analysis to probabilistically estiamte the imrpoved reliability value and include reliability as a quantified cost/benefit. The Preferred Portfolio recognizes the importance of the cross Cascades as both a cost-effective resource and an enhancement to overall reliability.
Guideline 4(g)	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered	The Company combined deterministic analysis and stochastic analysis to construct an optimal portfolio that meets specific pre-determined planning criteria, while also stress-testing the decision against a range of future weather and price events. Chapter Six 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 price and gas forecasts that represent key assumptions underlying the Base Case and Preferred Portfolio. The Company also included a cost of carbon in its base case and ran some sensitivities on 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. Finally, the Company identified specific resources that may become available (such as imported LNG), but could not be relied upon to build the Company's Preferred Portfolio. The Company also considered certain alternative supply scenarios, such as a limitation of supply from Canada, and alternative growth scenarios (such as a continued and extensive economic recession).
Guidleine 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, the Company designed a total of _____alternate resource mix scenarios where each scenario allows for a single change to the incremental supply side resources that are available in the Base Case. The development of resource portfolio options evaluated in this IRP is documented in Chapter Seven and results are detailed in Appendix_____.
Guideline 4(i)	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties.	In addition to the alternate scenarios mentioned in 4(h), above, NW Natural developed __Sensitivity cases to the Base Case Scenario. The Sensitivity cases differ from the alternate scenarios in that they do not provide for a new resource mix decision (i.e., the Base Case resource portfolio is locked down). Instead, the purpose of the Sensitivities is to stress test the Base Case resource portfolio to changes in certain underlying Base Case assumptions. Finally, the Company conducted a stochastic analysis of the Base Case and the Company's Preferred Portfolio scenarios using the Monte Carlo functionality of SENDOUT.® The stochastic analysis assesses the resiliency of the Base Case and Preferred Portfolio resource portfolios to variation in the level of demand and prices specified by assuming hundreds of normally distributed potential outcomes around the 20-year average normal weather and forecasted gas prices. The comparative performance results of the stochastic analysis are presented in Chapter Six.
Guideline 4(j)	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Chapters Three, Six, and Seven describes the resource options evaluated, including discussion on uncertainties in lead times and costs as well as viability and resource availability (e.g. LNG). Appendix 3 summarizes the potential resource options identifying investment costs and asset availability dates while results of resources selected are discussed in Chapter Six and tabulated in Appendix 6-X.
Guideline 4(k)	Analysis of the uncertainties associated with each portfolio evaluated.	The Company combined deterministic analysis and stochastic analysis to construct an Preferred Portfolio that meets specific pre-determined planning criteria, while also stress testing the decision against a range of future weather and price events. This is further discussed in Chapter Seven.
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 of the resource mix portfolios considered. Chapter Seven describes the Company's portfolio risk analysis, as well as the determination of its Preferred Portfolio.
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 has any inconsistencies 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 siting / permitting challenges related to the facilities, market viability, and others; such potential barriers are discussed in Chapter Three and Chapter Seven.

NW Natural's 2014 IRP - Oregon Compliance

Citation	Requirement	Plan Citation
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 the Company's multi-year action plan, which identifies the short term actions the Company plans to pursue related to the following: • Demand forecasting • Supply-side resources • Demand-side resources • SENDOUT® modeling • Avoided costs determination • Public involvement
Guideline 5	Transmission	Not applicable to NW Natural's gas utility operations
Guideline 6(a)	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	As discussed in Chapter 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 achiveable potenital study was determined by analyzing customer demographics together with energy efficiency measure data. The results were then compared with other supply side resources through SENDOUT.® A deployment scenario was applied to the total potential. Each year,the Company and Energy Trust review these assumptions when Energy Trust plans it s program budget for the next calendar year.
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 Oregon and Washington. These targets are further broken down by customer segment and program type. NW Natural's Schedule 301, Public Purposes Funding Surcharge, contains a special conditions that requires NW Natural to work with Energy Trust every year to determine if the funding level is appropriate to meet the next year's therm savings targets. At this time. the Company and the Energy Trust evaluate the IRP annual target and consider unforeseen influences that may either increase or reduce the next year's target. A tariff filing is made which proposes adjusting Schedule 301 to sufficiently fund the next year's target with a buffer fund for unexpected expenses.
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 unusually high demand
Guideline 8	Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for CO_2, NO_x, SO_2, and Hg emissions. Utilities should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from \$0 - \$40 (1990\$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for NO_x, SO_2, and Hg, if applicable.	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 the 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 i incorporates a carbon price into its gas price forecast beginning in 2021 at a level of \$8.74 per metric ton of CO_2 equivalent ($MTCO_2e$) and increasing annually to \$15.70 per $MTCO_2e$ 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.
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 comlete 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 base-load system requirements. For this IRP, the Company has selected an 90% probability coldest winter planning standard augmented by an historic seven-day peak event against which to evaluate the cost and risk trade off of various supply and demand resources available to SENDOUT.® This planning standard reflects the Company's evaluation and selection of a planning standard and resulting portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers. Discussion of the Company's planning criteria and the determination of its Preferred Portfolio is in Chapter Six. Stochastic analysis and stress-testing of the Company's results demonstrate the reliability of the Preferred Portfolio and cost/risk balance.
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.

NW Natural's 2014 IRP - Oregon Compliance

Citation	Requirement	Plan Citation
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.	NW Natural's Gas Acquisition Plan detailing the Company's strategies and practices for acquiring gas supplies is described in Chapter 3 and is centered on the following goals: 1) Reliability, 2) Diversity, 3) Price Stability, and 4) Cost Recovery
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.	For purposes of this IRP, the plan to meet normal annual expected demand is seen as a subset of the plan to meet design year demand. That is, since the plan addresses design year demand which includes a peak day, the resource decisions made by the plan are fully adequate to meet demand under normal annual conditions. The Company will seek to clarify the use of the results of a plan to meet normal annual expected demand during the technical working group meetings for the next IRP.

Appendix 2: Gas Requirements Forecast

NW Natural®

Appendix 2.1 Customer Forecast – Base Case: Residential + Commercial Firm Sales

Year	Albany	Astoria	Coos Bay	The Dalles, OR	The 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	The Dalles, OR	The 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	The Dalles, OR	The 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	The Dalles, OR	The 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	The Dalles, OR	The 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	The Dalles, OR	The 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	The Dalles, OR	The 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	The Dalles, OR	The 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	The Dalles, OR	The 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 (MDT)

Year	Albany	Astoria	Coos Bay	The Dalles, OR	The Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013-2014	4,059.58	4,055.30	3,216.93	3,201.31	3,201.12	3,200.68	3,068.62	3,070.71	3,044.89	1,395.42	1,395.44	1,384.69	1,393.27
2014-2015	4,054.39	4,046.35	3,227.31	3,198.05	3,197.69	3,196.94	3,067.85	3,071.58	3,045.96	1,409.76	1,409.93	1,391.08	1,406.95
2015-2016	4,080.44	4,068.49	3,262.81	3,219.41	3,218.92	3,217.92	3,092.94	3,098.27	3,072.60	1,435.77	1,436.19	1,406.79	1,430.34
2016-2017	4,058.77	4,043.12	3,258.61	3,205.51	3,204.84	3,203.59	3,080.64	3,087.50	3,062.21	1,447.21	1,447.86	1,408.95	1,439.93
2017-2018	4,068.60	4,049.21	3,278.22	3,214.26	3,213.35	3,211.78	3,089.14	3,097.59	3,072.45	1,467.73	1,468.61	1,419.89	1,458.38
2018-2019	4,083.73	4,060.64	3,301.84	3,226.11	3,224.86	3,222.91	3,100.21	3,110.31	3,085.33	1,490.72	1,491.84	1,432.97	1,478.95
2019-2020	4,128.42	4,101.48	3,348.77	3,259.71	3,257.98	3,255.57	3,132.47	3,144.27	3,119.21	1,523.05	1,524.39	1,454.71	1,508.39
2020-2021	4,127.90	4,097.50	3,360.72	3,258.63	3,256.23	3,253.26	3,129.25	3,142.80	3,118.11	1,542.45	1,544.04	1,464.57	1,525.46
2021-2022	4,156.37	4,122.33	3,395.62	3,278.91	3,275.58	3,271.94	3,146.86	3,162.22	3,137.67	1,570.99	1,572.81	1,483.06	1,551.39
2022-2023	4,189.03	4,151.38	3,434.25	3,301.97	3,297.37	3,292.90	3,166.62	3,183.83	3,159.42	1,601.46	1,603.53	1,503.51	1,579.26
2023-2024	4,251.83	4,210.33	3,497.67	3,347.81	3,341.53	3,336.09	3,208.50	3,227.62	3,203.11	1,641.96	1,644.25	1,533.15	1,616.68
2024-2025	4,267.71	4,222.90	3,524.34	3,357.96	3,349.60	3,343.05	3,214.13	3,235.19	3,211.02	1,668.56	1,671.11	1,550.53	1,641.07
2025-2026	4,312.19	4,263.85	3,574.27	3,389.35	3,378.56	3,370.78	3,240.50	3,263.56	3,239.51	1,704.69	1,707.48	1,576.53	1,674.44
2026-2027	4,359.34	4,307.49	3,626.70	3,422.22	3,408.83	3,399.75	3,268.10	3,293.19	3,269.26	1,742.02	1,745.05	1,603.68	1,708.94
2027-2028	4,434.29	4,378.59	3,701.76	3,475.15	3,459.21	3,448.84	3,315.80	3,342.98	3,318.94	1,788.44	1,791.67	1,638.71	1,751.81
2028-2029	4,458.28	4,399.47	3,735.88	3,489.18	3,470.92	3,459.37	3,324.92	3,354.22	3,330.51	1,818.24	1,821.76	1,659.37	1,779.28
2029-2030	4,509.10	4,446.85	3,791.60	3,522.22	3,501.96	3,489.35	3,353.48	3,384.93	3,361.34	1,856.47	1,860.22	1,687.24	1,814.45
2030-2031	4,558.76	4,493.10	3,846.07	3,552.95	3,531.10	3,517.61	3,380.30	3,413.94	3,390.46	1,892.91	1,896.91	1,713.29	1,847.76
2031-2032	4,634.09	4,564.60	3,921.18	3,601.09	3,578.04	3,563.83	3,425.06	3,460.93	3,437.36	1,936.42	1,940.61	1,744.89	1,887.27

Appendix 2.11 Annual Load Forecast (post-DSM) – Base Case: Residential (MDT)

Year	Albany	Astoria	Coos Bay	The Dalles, OR	The 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

Appendix 2.12: Annual Load Forecast (post-DSM) – Base Case: Commercial Firm Sales (MDT)

Year	Albany	Astoria	Coos Bay	The Dalles, OR	The 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

Appendix 2.13 Annual Load Forecast (post-DSM) – Base Case: Industrial Firm Sales (MDT)

Year	Albany	Astoria	Coos Bay	The Dalles, OR	The 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

Appendix 2.14 Annual Load Forecast (post-DSM) – Base Case: Firm Transportation (MDT)

Year	Albany	Astoria	Coos Bay	The Dalles, OR	The 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	2.33	2,700.53	1,103.43	5,362.83	363.56	732.31	14,365.95
2014-2015	1,701.58	4.30	0.09	22.72	0.01	2,379.43	3.96	2,869.17	1,166.27	5,487.78	375.89	781.83	14,793.05
2015-2016	1,699.28	5.37	0.13	22.72	0.02	2,373.63	5.21	3,064.87	1,240.86	5,630.23	389.38	841.69	15,273.39
2016-2017	1,702.86	6.43	0.17	23.11	0.03	2,375.53	6.53	3,114.29	1,267.07	5,679.23	396.42	859.56	15,431.23
2017-2018	1,723.17	7.71	0.22	23.44	0.04	2,377.79	8.12	3,140.93	1,284.74	5,715.90	403.02	867.94	15,553.02
2018-2019	1,744.09	9.25	0.28	23.82	0.06	2,380.37	10.03	3,168.24	1,302.87	5,753.78	409.99	876.56	15,679.35
2019-2020	1,765.56	11.10	0.36	24.24	0.08	2,383.32	12.32	3,196.10	1,321.44	5,792.87	417.32	885.41	15,810.11
2020-2021	1,787.76	13.31	0.47	24.71	0.10	2,386.73	15.05	3,224.78	1,340.57	5,833.44	425.14	894.71	15,946.77
2021-2022	1,810.74	15.97	0.60	25.25	0.14	2,390.68	18.33	3,254.27	1,360.27	5,875.62	433.49	904.32	16,089.68
2022-2023	1,834.58	19.15	0.77	25.88	0.18	2,395.27	22.25	3,284.69	1,380.61	5,919.58	442.47	914.33	16,239.77
2023-2024	1,859.32	22.88	0.98	26.59	0.24	2,400.53	26.82	3,316.07	1,401.60	5,965.40	452.11	924.76	16,397.29
2024-2025	1,884.97	27.14	1.22	27.39	0.31	2,406.45	32.04	3,348.41	1,423.26	6,013.08	462.40	935.71	16,562.38
2025-2026	1,911.41	31.85	1.49	28.26	0.38	2,412.93	37.81	3,381.61	1,445.53	6,062.40	473.24	947.04	16,733.95
2026-2027	1,938.37	36.80	1.78	29.18	0.46	2,419.70	43.87	3,415.34	1,468.23	6,112.82	484.42	958.56	16,909.53
2027-2028	1,965.44	41.67	2.07	30.09	0.55	2,426.38	49.83	3,449.18	1,491.13	6,163.58	495.61	970.17	17,085.71
2028-2029	1,992.24	46.19	2.34	30.96	0.62	2,432.63	55.37	3,482.68	1,514.01	6,213.93	506.50	981.68	17,259.16
2029-2030	2,018.66	50.21	2.58	31.76	0.69	2,438.27	60.28	3,515.75	1,536.80	6,263.62	516.95	992.89	17,428.46
2030-2031	2,044.46	53.56	2.78	32.47	0.75	2,443.09	64.38	3,548.13	1,559.35	6,312.18	526.79	1,003.81	17,591.75
2031-2032	2,069.62	56.27	2.94	33.09	0.79	2,447.12	67.69	3,579.77	1,581.67	6,359.64	536.02	1,014.32	17,748.94

Appendix 2.15 Annual Load Forecast (post-DSM) – Base Case: Firm Sales + Firm Transportation (MDT)

Year	Albany	Astoria	Coos Bay	The Dalles, OR	The 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	998.94	24,050.58	12,072.38	20,192.97	10,218.66	3,280.37	86,389.70
2014-2015	5,752.08	1,392.24	224.59	850.21	240.86	7,133.07	997.72	24,309.01	12,177.22	20,401.26	10,229.54	3,398.21	87,106.00
2015-2016	5,774.59	1,408.02	239.29	856.40	245.85	7,160.46	1,001.91	24,770.96	12,389.67	20,764.81	10,315.44	3,545.47	88,472.86
2016-2017	5,755.19	1,410.19	253.32	852.15	246.94	7,172.16	998.99	24,795.81	12,404.76	20,822.47	10,290.87	3,579.82	88,582.67
2017-2018	5,783.74	1,421.14	269.24	855.25	250.41	7,215.01	1,002.25	24,945.40	12,487.32	20,969.73	10,326.96	3,614.59	89,141.04
2018-2019	5,817.88	1,434.23	285.67	859.76	254.39	7,266.69	1,007.42	25,117.73	12,583.40	21,139.70	10,375.47	3,654.14	89,796.48
2019-2020	5,881.73	1,455.97	303.95	871.86	261.16	7,349.12	1,018.39	25,443.56	12,759.37	21,421.00	10,485.99	3,712.43	90,964.55
2020-2021	5,900.66	1,465.85	319.91	872.47	263.88	7,393.32	1,023.17	25,520.77	12,809.92	21,538.32	10,504.33	3,747.98	91,360.57
2021-2022	5,948.76	1,484.35	337.75	880.51	269.44	7,467.22	1,033.88	25,747.47	12,937.88	21,762.97	10,582.04	3,803.11	92,255.38
2022-2023	6,001.28	1,504.80	356.11	889.65	275.61	7,547.95	1,046.70	25,989.43	13,074.99	22,003.72	10,667.75	3,865.17	93,223.18
2023-2024	6,084.14	1,534.45	376.70	906.56	284.94	7,660.09	1,065.93	26,387.68	13,293.21	22,357.83	10,814.85	3,949.56	94,715.95
2024-2025	6,120.30	1,551.84	394.37	911.29	290.02	7,730.22	1,079.10	26,522.54	13,378.57	22,536.01	10,863.62	4,011.25	95,389.15
2025-2026	6,185.29	1,577.85	414.21	923.60	298.34	7,830.34	1,098.20	26,807.04	13,542.07	22,823.55	10,970.43	4,095.35	96,566.26
2026-2027	6,253.16	1,605.01	434.44	936.76	307.49	7,935.79	1,118.69	27,102.77	13,713.15	23,124.63	11,082.44	4,186.16	97,800.48
2027-2028	6,349.04	1,640.05	457.03	957.57	320.39	8,071.40	1,144.12	27,552.24	13,964.79	23,538.12	11,252.53	4,300.60	99,547.87
2028-2029	6,394.12	1,660.71	475.78	965.43	329.08	8,159.27	1,161.59	27,723.07	14,076.40	23,762.46	11,318.28	4,388.00	100,414.18
2029-2030	6,466.29	1,688.59	496.84	980.89	341.75	8,276.50	1,183.22	28,047.23	14,268.59	24,098.28	11,441.35	4,499.12	101,788.66
2030-2031	6,537.53	1,714.65	517.66	995.77	354.85	8,395.43	1,203.31	28,377.71	14,465.35	24,442.20	11,565.05	4,614.59	103,184.10
2031-2032	6,634.60	1,746.26	540.59	1,017.05	371.31	8,543.79	1,226.02	28,865.45	14,743.80	24,900.68	11,745.13	4,752.59	105,087.27

Appendix 2.16 Annual Load Forecast (post-DSM) – Base Case: Interruptible (MDT)

Year	Albany	Astoria	Coos Bay	The Dalles, OR	The 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

Appendix 2.17 Annual Load Forecast (post-DSM) – Base Case: Emerging Markets (Low Case) (MDT)

Year	Albany	Astoria	Coos Bay	The Dalles, OR	The 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 2.18 Design Day Load Forecast (post-DSM) – Base Case: Firm Sales (MDT)

Year	Albany	Astoria	Coos Bay	The Dalles, OR	The Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013-2014	194.92	64.17	8.80	37.05	11.80	232.53	45.05	1,047.18	537.02	722.82	488.39	346.17	3,735.93
2014-2015	194.77	64.50	9.36	37.04	11.93	232.88	45.01	1,051.29	538.75	726.15	488.24	354.20	3,754.12
2015-2016	194.96	64.97	9.94	37.12	12.08	233.82	45.05	1,057.51	541.82	731.67	489.16	363.27	3,781.35
2016-2017	195.18	65.42	10.56	37.24	12.25	235.51	45.11	1,062.85	544.47	736.24	490.16	371.62	3,806.60
2017-2018	195.69	65.97	11.21	37.41	12.43	237.58	45.27	1,069.05	547.58	741.43	491.63	380.71	3,835.96
2018-2019	196.42	66.60	11.88	37.65	12.64	240.06	45.50	1,076.30	551.30	747.63	493.67	390.86	3,870.51
2019-2020	197.35	67.31	12.57	37.92	12.87	242.85	45.80	1,084.40	555.50	754.60	496.12	401.93	3,909.22
2020-2021	198.49	68.09	13.28	38.26	13.12	246.05	46.17	1,093.44	560.26	762.56	499.14	413.87	3,952.72
2021-2022	199.78	68.93	14.00	38.64	13.40	249.51	46.61	1,103.14	565.38	771.09	502.45	426.73	3,999.67
2022-2023	201.24	69.84	14.75	39.06	13.71	253.27	47.12	1,113.51	570.90	780.31	506.11	440.62	4,050.44
2023-2024	202.87	70.83	15.51	39.51	14.05	257.29	47.72	1,124.60	576.80	790.16	510.07	455.47	4,104.87
2024-2025	204.70	71.89	16.30	40.02	14.42	261.68	48.39	1,136.43	583.18	800.87	514.46	471.46	4,163.80
2025-2026	206.62	73.00	17.10	40.55	14.83	266.27	49.13	1,148.68	589.82	812.05	519.00	488.42	4,225.47
2026-2027	208.65	74.14	17.91	41.11	15.27	271.11	49.91	1,161.43	596.79	823.81	523.78	506.38	4,290.30
2027-2028	210.73	75.30	18.73	41.69	15.75	276.09	50.72	1,174.53	603.99	835.96	528.64	525.23	4,357.35
2028-2029	213.73	76.26	19.59	42.35	16.33	281.24	51.61	1,187.77	611.40	848.59	533.15	546.38	4,428.40
2029-2030	215.94	77.42	20.44	42.99	16.92	286.65	52.44	1,201.85	619.30	861.90	538.42	567.28	4,501.53
2030-2031	218.12	78.53	21.27	43.61	17.53	292.18	53.22	1,216.26	627.41	875.61	543.76	589.05	4,576.56
2031-2032	222.54	79.24	21.83	44.02	18.06	290.88	53.94	1,227.05	633.70	886.84	555.27	619.50	4,652.85

Appendix 2.19 Design Day Load Forecast (post-DSM) – Base Case: Residential (MDT)

Year	Albany	Astoria	Coos Bay	The Dalles, OR	The Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013-2014	120.43	36.37	2.74	13.86	7.24	113.17	24.01	674.94	346.37	472.70	285.73	234.59	2,332.17
2014-2015	120.46	36.71	2.89	13.93	7.31	113.99	24.10	679.95	348.22	474.73	286.24	239.75	2,348.30
2015-2016	120.85	37.20	3.06	14.07	7.40	115.33	24.27	686.70	351.23	478.72	287.72	245.81	2,372.36
2016-2017	121.23	37.67	3.21	14.21	7.51	116.62	24.45	693.01	354.21	482.86	289.33	252.67	2,396.99
2017-2018	121.63	38.16	3.38	14.35	7.63	118.01	24.63	699.56	357.31	487.22	291.04	260.39	2,423.31
2018-2019	122.06	38.67	3.55	14.50	7.77	119.54	24.83	706.44	360.62	491.98	292.93	268.95	2,451.84
2019-2020	122.55	39.20	3.73	14.65	7.92	121.20	25.05	713.67	364.13	497.06	294.99	278.28	2,482.44
2020-2021	123.06	39.73	3.93	14.81	8.09	122.96	25.27	721.14	367.76	502.36	297.16	288.14	2,514.41
2021-2022	123.59	40.28	4.12	14.98	8.27	124.82	25.50	728.81	371.51	507.85	299.43	298.74	2,547.90
2022-2023	124.14	40.84	4.33	15.15	8.47	126.77	25.74	736.67	375.35	513.54	301.79	310.08	2,582.87
2023-2024	124.74	41.42	4.54	15.32	8.69	128.87	26.00	744.94	379.41	519.55	304.35	322.15	2,619.98
2024-2025	125.36	42.00	4.76	15.50	8.92	131.05	26.26	753.33	383.54	525.73	306.98	334.93	2,658.35
2025-2026	125.98	42.58	4.99	15.68	9.17	133.33	26.53	761.83	387.75	532.08	309.67	348.44	2,698.04
2026-2027	126.60	43.17	5.23	15.87	9.44	135.69	26.80	770.45	392.04	538.62	312.44	362.65	2,739.00
2027-2028	127.24	43.76	5.47	16.05	9.72	138.15	27.07	779.16	396.41	545.34	315.28	377.55	2,781.22
2028-2029	128.39	44.19	5.73	16.25	10.05	140.63	27.39	787.63	400.68	552.02	317.78	393.96	2,824.71
2029-2030	129.03	44.78	5.98	16.44	10.37	143.28	27.67	796.53	405.20	559.10	320.76	410.24	2,869.39
2030-2031	129.68	45.38	6.25	16.63	10.71	146.02	27.96	805.51	409.79	566.35	323.81	427.19	2,915.27
2031-2032	131.83	45.77	6.42	16.75	11.00	145.09	28.25	811.85	413.05	571.84	331.19	450.99	2,964.04

Appendix 2.20 Design Day Load Forecast (post-DSM) – Base Case: Commercial Firm Sales (MDT)

Year	Albany	Astoria	Coos Bay	The Dalles, OR	The Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013-2014	69.55	27.23	5.56	20.28	4.40	106.76	19.79	352.62	178.64	225.99	182.53	101.36	1,294.71
2014-2015	69.36	27.13	6.05	20.27	4.46	107.01	19.59	350.63	177.84	225.88	181.58	103.04	1,292.83
2015-2016	69.21	27.03	6.55	20.26	4.53	107.36	19.40	348.94	177.17	225.92	180.70	104.66	1,291.73
2016-2017	69.03	26.96	7.03	20.24	4.58	107.76	19.24	347.76	176.65	225.88	179.96	105.78	1,290.85
2017-2018	69.07	26.95	7.52	20.27	4.64	108.45	19.14	347.43	176.59	226.48	179.65	107.07	1,293.26
2018-2019	69.26	27.00	8.02	20.35	4.70	109.35	19.07	347.73	176.87	227.58	179.65	108.54	1,298.12
2019-2020	69.57	27.08	8.52	20.45	4.78	110.42	19.04	348.51	177.43	229.11	179.88	110.17	1,304.97
2020-2021	69.98	27.18	9.03	20.57	4.86	111.63	19.03	349.70	178.23	231.00	180.29	111.98	1,313.46
2021-2022	70.48	27.30	9.54	20.71	4.95	112.98	19.04	351.33	179.28	233.28	180.90	113.99	1,323.78
2022-2023	71.07	27.44	10.05	20.87	5.04	114.46	19.07	353.34	180.56	235.91	181.65	116.23	1,335.71
2023-2024	71.72	27.58	10.57	21.04	5.15	116.04	19.10	355.64	182.02	238.85	182.51	118.70	1,348.92
2024-2025	72.43	27.73	11.09	21.22	5.26	117.73	19.16	358.29	183.68	242.11	183.48	121.39	1,363.56
2025-2026	73.20	27.88	11.60	21.40	5.38	119.51	19.22	361.23	185.53	245.67	184.54	124.33	1,379.49
2026-2027	74.02	28.03	12.12	21.59	5.51	121.39	19.29	364.51	187.57	249.56	185.69	127.50	1,396.79
2027-2028	74.89	28.18	12.63	21.79	5.65	123.37	19.36	368.10	189.81	253.76	186.93	130.90	1,415.38
2028-2029	76.12	28.26	13.15	22.00	5.81	125.40	19.46	371.87	192.17	258.19	187.94	134.91	1,435.27
2029-2030	77.09	28.39	13.65	22.20	5.97	127.58	19.55	376.15	194.82	263.06	189.34	138.83	1,456.63
2030-2031	78.11	28.52	14.16	22.40	6.14	129.86	19.66	380.77	197.68	268.27	190.80	143.00	1,479.35
2031-2032	79.97	28.52	14.48	22.50	6.28	129.12	19.76	384.64	200.17	273.04	194.28	149.14	1,501.91

Appendix 2.21 Design Day Load Forecast (post-DSM) – Base Case: Industrial Firm Sales (MDT)

Year	Albany	Astoria	Coos Bay	The Dalles, OR	The Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013-2014	4.84	0.49	0.50	2.90	0.16	12.50	1.15	19.51	11.96	23.92	20.04	10.18	108.14
2014-2015	4.77	0.51	0.41	2.83	0.15	11.70	1.14	20.51	12.58	25.17	20.28	11.32	111.40
2015-2016	4.65	0.54	0.32	2.76	0.15	10.90	1.13	21.62	13.28	26.54	20.54	12.68	115.12
2016-2017	4.61	0.55	0.30	2.76	0.16	10.83	1.12	21.75	13.43	26.87	20.62	13.02	116.03
2017-2018	4.59	0.54	0.30	2.75	0.16	10.74	1.11	21.64	13.45	26.94	20.62	13.06	115.90
2018-2019	4.59	0.54	0.29	2.75	0.16	10.68	1.11	21.59	13.51	27.09	20.67	13.12	116.09
2019-2020	4.58	0.54	0.28	2.74	0.16	10.61	1.10	21.51	13.55	27.19	20.72	13.14	116.12
2020-2021	4.64	0.54	0.27	2.77	0.16	10.67	1.11	21.70	13.76	27.64	20.99	13.30	117.54
2021-2022	4.67	0.54	0.27	2.78	0.16	10.70	1.11	21.83	13.93	28.01	21.21	13.40	118.61
2022-2023	4.71	0.54	0.26	2.81	0.16	10.74	1.11	21.98	14.12	28.41	21.46	13.51	119.81
2023-2024	4.74	0.54	0.26	2.82	0.16	10.74	1.12	22.05	14.26	28.72	21.65	13.57	120.62
2024-2025	4.81	0.55	0.25	2.85	0.16	10.83	1.12	22.31	14.52	29.27	22.00	13.76	122.44
2025-2026	4.85	0.55	0.24	2.88	0.16	10.88	1.13	22.48	14.72	29.72	22.28	13.90	123.79
2026-2027	4.90	0.55	0.24	2.90	0.16	10.92	1.14	22.66	14.93	30.17	22.56	14.04	125.16
2027-2028	4.93	0.56	0.23	2.92	0.15	10.93	1.14	22.74	15.08	30.50	22.76	14.13	126.06
2028-2029	5.00	0.56	0.23	2.95	0.16	11.02	1.15	23.01	15.36	31.08	23.13	14.36	127.99
2029-2030	5.05	0.56	0.22	2.98	0.16	11.07	1.15	23.19	15.58	31.55	23.42	14.54	129.45
2030-2031	5.10	0.56	0.21	3.00	0.16	11.12	1.16	23.37	15.80	32.03	23.72	14.73	130.94
2031-2032	5.13	0.57	0.20	3.02	0.16	11.12	1.16	23.45	15.95	32.38	23.93	14.86	131.92

Appendix 2.22 Design Day Load Forecast (post-DSM) – Base Case: Firm Transportation (MDT)

Year	Albany	Astoria	Coos Bay	The Dalles, OR	The Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013-2014	55.60	0.10	0.00	0.75	0.00	78.48	0.08	88.85	36.30	176.42	11.95	24.09	472.63
2014-2015	56.00	0.14	0.00	0.75	0.00	78.30	0.13	94.44	38.38	180.57	12.37	25.73	486.81
2015-2016	55.76	0.18	0.00	0.74	0.00	77.83	0.17	100.57	40.71	184.69	12.77	27.62	501.05
2016-2017	56.07	0.21	0.01	0.76	0.00	78.18	0.21	102.54	41.71	186.89	13.05	28.30	507.94
2017-2018	56.74	0.25	0.01	0.77	0.00	78.25	0.27	103.42	42.30	188.10	13.27	28.58	511.95
2018-2019	57.42	0.30	0.01	0.78	0.00	78.34	0.33	104.32	42.89	189.35	13.50	28.86	516.10
2019-2020	57.93	0.36	0.01	0.79	0.00	78.15	0.40	104.88	43.35	190.03	13.69	29.05	518.65
2020-2021	58.86	0.44	0.02	0.81	0.00	78.55	0.49	106.18	44.13	191.97	13.99	29.46	524.90
2021-2022	59.62	0.52	0.02	0.83	0.00	78.68	0.60	107.15	44.78	193.35	14.27	29.77	529.60
2022-2023	60.40	0.63	0.03	0.85	0.01	78.83	0.73	108.15	45.45	194.80	14.56	30.10	534.54
2023-2024	61.01	0.75	0.03	0.87	0.01	78.71	0.88	108.81	45.98	195.69	14.83	30.34	537.91
2024-2025	62.06	0.89	0.04	0.90	0.01	79.19	1.05	110.24	46.85	197.88	15.22	30.81	545.15
2025-2026	62.93	1.05	0.05	0.93	0.01	79.41	1.24	111.34	47.59	199.50	15.58	31.18	550.79
2026-2027	63.82	1.21	0.06	0.96	0.02	79.63	1.44	112.44	48.33	201.16	15.94	31.56	556.57
2027-2028	64.49	1.37	0.07	0.99	0.02	79.56	1.63	113.18	48.92	202.18	16.26	31.83	560.49
2028-2029	65.59	1.52	0.08	1.02	0.02	80.05	1.82	114.66	49.84	204.48	16.67	32.32	568.07
2029-2030	66.46	1.65	0.08	1.04	0.02	80.24	1.98	115.75	50.59	206.12	17.01	32.69	573.64
2030-2031	67.31	1.76	0.09	1.07	0.02	80.40	2.12	116.81	51.33	207.72	17.34	33.05	579.01
2031-2032	67.91	1.84	0.10	1.08	0.03	80.24	2.22	117.46	51.89	208.62	17.58	33.28	582.24

Appendix 2.23 Design Day Load Forecast (post-DSM) – Base Case: Firm Sales + Firm Transportation (MDT)

Year	Albany	Astoria	Coos Bay	The Dalles, OR	The Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013-2014	250.45	64.20	8.80	37.80	11.80	310.94	45.05	1,135.95	573.28	899.09	500.28	370.24	4,207.91
2014-2015	250.64	64.54	9.36	37.78	11.93	311.06	45.01	1,145.59	577.06	906.45	500.52	379.88	4,239.82
2015-2016	250.54	65.01	9.94	37.85	12.08	311.49	45.05	1,157.91	582.43	916.01	501.80	390.81	4,280.93
2016-2017	251.04	65.46	10.56	37.99	12.25	313.49	45.11	1,165.17	586.07	922.69	503.05	399.83	4,312.70
2017-2018	252.16	66.01	11.21	38.17	12.43	315.58	45.27	1,172.20	589.73	928.99	504.70	409.18	4,345.61
2018-2019	253.52	66.64	11.88	38.41	12.64	318.08	45.50	1,180.28	594.01	936.31	506.91	419.58	4,383.77
2019-2020	254.88	67.35	12.57	38.69	12.87	320.61	45.80	1,188.86	598.63	943.81	509.50	430.81	4,424.38
2020-2021	256.86	68.13	13.28	39.04	13.12	324.12	46.17	1,199.11	604.12	953.51	512.75	443.10	4,473.31
2021-2022	258.80	68.97	14.00	39.42	13.40	327.61	46.61	1,209.66	609.83	963.22	516.25	456.23	4,524.00
2022-2023	260.91	69.89	14.75	39.85	13.71	331.39	47.12	1,220.90	615.93	973.62	520.09	470.39	4,578.55
2023-2024	263.00	70.87	15.51	40.30	14.05	335.15	47.72	1,232.49	622.29	984.05	524.20	485.40	4,635.02
2024-2025	265.69	71.93	16.30	40.82	14.42	339.85	48.39	1,245.56	629.43	996.59	528.83	501.77	4,699.60
2025-2026	268.29	73.04	17.10	41.36	14.83	344.47	49.13	1,258.69	636.69	1,009.01	533.57	519.01	4,765.20
2026-2027	271.01	74.18	17.91	41.94	15.27	349.33	49.91	1,272.33	644.29	1,022.03	538.55	537.24	4,833.98
2027-2028	273.56	75.34	18.73	42.52	15.75	354.05	50.72	1,285.95	651.96	1,034.81	543.56	556.27	4,903.20
2028-2029	277.47	76.30	19.59	43.18	16.33	359.52	51.61	1,300.47	660.18	1,049.36	548.32	577.81	4,980.13
2029-2030	280.37	77.47	20.44	43.83	16.92	364.95	52.44	1,315.45	668.72	1,063.97	553.80	598.99	5,057.36
2030-2031	283.27	78.57	21.27	44.47	17.53	370.50	53.22	1,330.78	677.50	1,079.01	559.35	621.05	5,136.53
2031-2032	288.18	79.28	21.83	44.88	18.06	368.94	53.94	1,342.11	684.28	1,090.93	571.01	651.68	5,215.11

Appendix 2.24 Design Day Load Forecast (post-DSM) – Base Case: Emerging Markets Firm Sales (Low Case) (MDT)

Year	Albany	Astoria	Coos Bay	The Dalles, OR	The Dalles, WA	Eugene	Newport	Portland - Central	Portland - East	Portland - West	Salem	Vancouver	System
2013-2014	0.03	0.02	0.00	0.00	0.00	0.03	0.03	0.03	0.02	0.06	0.02	0.02	0.26
2014-2015	0.05	0.04	0.00	0.01	0.00	0.05	0.05	0.06	0.03	0.10	0.05	0.03	0.48
2015-2016	0.07	0.06	0.00	0.01	0.00	0.07	0.07	0.08	0.05	0.14	0.06	0.04	0.67
2016-2017	0.10	0.08	0.01	0.02	0.00	0.10	0.09	0.11	0.06	0.19	0.09	0.06	0.90
2017-2018	0.13	0.10	0.01	0.02	0.00	0.13	0.12	0.15	0.09	0.24	0.12	0.08	1.20
2018-2019	0.18	0.14	0.02	0.04	0.01	0.17	0.16	0.21	0.12	0.32	0.17	0.11	1.62
2019-2020	0.24	0.18	0.02	0.05	0.01	0.23	0.20	0.29	0.16	0.41	0.23	0.16	2.20
2020-2021	0.32	0.24	0.04	0.08	0.01	0.32	0.27	0.40	0.23	0.55	0.32	0.23	3.00
2021-2022	0.43	0.32	0.05	0.12	0.02	0.43	0.36	0.55	0.32	0.72	0.45	0.33	4.11
2022-2023	0.59	0.44	0.08	0.17	0.03	0.59	0.47	0.76	0.45	0.95	0.62	0.46	5.62
2023-2024	0.78	0.58	0.11	0.25	0.05	0.79	0.62	1.04	0.62	1.24	0.86	0.64	7.58
2024-2025	1.04	0.76	0.16	0.35	0.08	1.05	0.80	1.39	0.84	1.61	1.15	0.88	10.10
2025-2026	1.33	0.98	0.21	0.47	0.11	1.35	1.01	1.81	1.11	2.04	1.51	1.16	13.09
2026-2027	1.66	1.22	0.27	0.61	0.15	1.69	1.25	2.28	1.41	2.52	1.91	1.49	16.46
2027-2028	2.01	1.48	0.34	0.77	0.21	2.04	1.51	2.77	1.74	3.02	2.33	1.85	20.06
2028-2029	2.38	1.78	0.41	0.96	0.29	2.41	1.79	3.30	2.13	3.58	2.80	2.26	24.09
2029-2030	2.75	2.08	0.50	1.17	0.40	2.79	2.08	3.84	2.54	4.15	3.27	2.69	28.25
2030-2031	3.07	2.36	0.57	1.37	0.50	3.11	2.34	4.32	2.91	4.65	3.69	3.09	31.95
2031-2032	3.34	2.58	0.63	1.53	0.59	3.37	2.55	4.70	3.22	5.06	4.03	3.41	34.99

Appendix 2.15 Annual Load Forecast (post-DSM) – Base Case: Firm Sales + Firm Transportation (MDT)

Year	Albany	Astoria	Coos Bay	The Dalles, OR	The Dalles, WA	Eugene	Newport	PDX - Central	PDX - East	PDX - West	Salem	Vancouver	System
2013-2014	5,747.60	1,385.77	211.32	852.32	238.69	7,140.10	998.94	24,050.58	12,072.38	20,192.97	10,218.66	3,280.37	86,389.70
2014-2015	5,752.08	1,392.24	224.59	850.21	240.86	7,133.07	997.72	24,309.01	12,177.22	20,401.26	10,229.54	3,398.21	87,106.00
2015-2016	5,774.59	1,408.02	239.29	856.40	245.85	7,160.46	1,001.91	24,770.96	12,389.67	20,764.81	10,315.44	3,545.47	88,472.86
2016-2017	5,755.19	1,410.19	253.32	852.15	246.94	7,172.16	998.99	24,795.81	12,404.76	20,822.47	10,290.87	3,579.82	88,582.67
2017-2018	5,783.74	1,421.14	269.24	855.25	250.41	7,215.01	1,002.25	24,945.40	12,487.32	20,969.73	10,326.96	3,614.59	89,141.04
2018-2019	5,817.88	1,434.23	285.67	859.76	254.39	7,266.69	1,007.42	25,117.73	12,583.40	21,139.70	10,375.47	3,654.14	89,796.48
2019-2020	5,881.73	1,455.97	303.95	871.86	261.16	7,349.12	1,018.39	25,443.56	12,759.37	21,421.00	10,485.99	3,712.43	90,964.55
2020-2021	5,900.66	1,465.85	319.91	872.47	263.88	7,393.32	1,023.17	25,520.77	12,809.92	21,538.32	10,504.33	3,747.98	91,360.57
2021-2022	5,948.76	1,484.35	337.75	880.51	269.44	7,467.22	1,033.88	25,747.47	12,937.88	21,762.97	10,582.04	3,803.11	92,255.38
2022-2023	6,001.28	1,504.80	356.11	889.65	275.61	7,547.95	1,046.70	25,989.43	13,074.99	22,003.72	10,667.75	3,865.17	93,223.18
2023-2024	6,084.14	1,534.45	376.70	906.56	284.94	7,660.09	1,065.93	26,387.68	13,293.21	22,357.83	10,814.85	3,949.56	94,715.95
2024-2025	6,120.30	1,551.84	394.37	911.29	290.02	7,730.22	1,079.10	26,522.54	13,378.57	22,536.01	10,863.62	4,011.25	95,389.15
2025-2026	6,185.29	1,577.85	414.21	923.60	298.34	7,830.34	1,098.20	26,807.04	13,542.07	22,823.55	10,970.43	4,095.35	96,566.26
2026-2027	6,253.16	1,605.01	434.44	936.76	307.49	7,935.79	1,118.69	27,102.77	13,713.15	23,124.63	11,082.44	4,186.16	97,800.48
2027-2028	6,349.04	1,640.05	457.03	957.57	320.39	8,071.40	1,144.12	27,552.24	13,964.79	23,538.12	11,252.53	4,300.60	99,547.87
2028-2029	6,394.12	1,660.71	475.78	965.43	329.08	8,159.27	1,161.59	27,723.07	14,076.40	23,762.46	11,318.28	4,388.00	100,414.18
2029-2030	6,466.29	1,688.59	496.84	980.89	341.75	8,276.50	1,183.22	28,047.23	14,268.59	24,098.28	11,441.35	4,499.12	101,788.66
2030-2031	6,537.53	1,714.65	517.66	995.77	354.85	8,395.43	1,203.31	28,377.71	14,465.35	24,442.20	11,565.05	4,614.59	103,184.10
2031-2032	6,634.60	1,746.26	540.59	1,017.05	371.31	8,543.79	1,226.02	28,865.45	14,743.80	24,900.68	11,745.13	4,752.59	105,087.27
2032-2033	6,676.83	1,760.64	558.40	1,023.22	381.96	8,638.44	1,238.47	29,058.83	14,872.72	25,154.97	11,814.06	4,856.87	106,035.40

Appendix 3: Supply Side Resources

PLACEHOLDER

CONTENT TO BE INCLUDED IN FINAL

Appendix 4: Demand-Side Resources

NW Natural®

OR Deployment, no exception after 2014, Incremental Annual Savings (therms)

Program	Deployment		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Resid New			446,820	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	2,708,617
	New Construction	RES	441,355	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	119,042	2,703,152
	New DHW	RES	5,465	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,465
Existing Residential			1,142,777	672,907	615,118	615,118	615,118	550,799	507,919	465,040	465,040	293,521	293,521	293,521	293,521	293,521	293,521	293,521	293,521	282,802	272,082	272,082	8,824,973
	Retrofit	RES	903,296	465,145	407,356	407,356	407,356	343,036	300,157	257,277	257,277	85,759	85,759	85,759	85,759	85,759	85,759	85,759	85,759	75,039	64,319	64,319	4,638,006
	Replace DHW	RES	203,307	171,588	171,588	171,588	171,588	171,588	171,588	171,588	171,588	171,588	171,588	171,588	171,588	171,588	171,588	171,588	171,588	171,588	171,588	171,588	3,463,479
	Replace equipment	RES	36,174	36,174	36,174	36,174	36,174	36,174	36,174	36,174	36,174	36,174	36,174	36,174	36,174	36,174	36,174	36,174	36,174	36,174	36,174	36,174	723,488
	Appliances, new & replace	RES	37,886	37,886	37,886	37,886	37,886	37,886	37,886	37,886	37,886	37,886	37,886	37,886	37,886	37,886	37,886	37,886	37,886	37,886	37,886	37,886	757,725
	Solar Water heat - Residential	RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Existing			2,003,621	2,011,278	1,422,657	1,071,650	861,045	720,642	650,441	545,139	474,937	474,937	439,836	439,836	422,286	422,286	422,286	404,736	404,736	404,736	404,736	404,736	14,406,557
	Replace Equip	COM	134,147	134,147	134,147	134,147	134,147	134,147	134,147	134,147	134,147	134,147	134,147	134,147	134,147	134,147	134,147	134,147	134,147	134,147	134,147	134,147	2,682,935
	Replace Shell	COM	154,742	154,742	154,742	154,742	154,742	154,742	154,742	154,742	154,742	154,742	154,742	154,742	154,742	154,742	154,742	154,742	154,742	154,742	154,742	154,742	3,094,848
	Retrofit Wx	COM	648,702	651,742	418,056	278,704	195,093	139,352	111,482	69,676	41,806	41,806	27,870	27,870	20,903	20,903	20,903	13,935	13,935	13,935	13,935	13,935	2,784,541
	Retrofit Equip	COM	985,284	989,902	634,966	423,311	296,318	211,655	169,324	105,828	63,497	63,497	42,331	42,331	31,748	31,748	31,748	21,166	21,166	21,166	21,166	21,166	4,229,317
	Cooking Appliances	COM	80,746	80,746	80,746	80,746	80,746	80,746	80,746	80,746	80,746	80,746	80,746	80,746	80,746	80,746	80,746	80,746	80,746	80,746	80,746	80,746	1,614,916
Commercial New			28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	568,292
	New Constr	COM	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	28,415	568,292
Industrial			1,151,420	1,151,420	1,093,820	1,026,941	826,304	692,546	358,151	291,272	224,393	157,514	157,514	157,514	157,514	157,514	157,514	157,514	157,514	157,514	157,514	107,354	8,498,757
	Retrofit	IND	726,383	726,383	689,723	647,156	519,457	434,324	221,492	178,926	136,359	93,793	93,793	93,793	93,793	93,793	93,793	93,793	93,793	93,793	93,793	61,868	5,279,998
	Replacement	IND	425,037	425,037	404,098	379,785	306,847	258,222	136,659	112,346	88,034	63,721	63,721	63,721	63,721	63,721	63,721	63,721	63,721	63,721	63,721	45,486	3,218,759
	RES Market Transformation	RES	502,996	585,749	585,749	585,749	585,749	585,749	585,749	585,749	585,749	585,749	585,749	585,749	585,749	585,749	585,749	585,749	585,749	585,749	585,749	585,749	-
	COM Market Transformation	COM	17,552	17,552	17,552	17,552	17,552	17,552	17,552	17,552	17,552	17,552	17,552	17,552	17,552	17,552	17,552	17,552	17,552	17,552	17,552	17,552	-
Residential Total		**RES**	**2,130,479**	**1,415,585**	**1,357,795**	**1,357,795**	**1,357,795**	**1,293,476**	**1,250,596**	**1,207,717**	**1,207,717**	**1,036,199**	**1,036,199**	**1,036,199**	**1,036,199**	**1,036,199**	**1,036,199**	**1,036,199**	**1,036,199**	**1,025,479**	**1,014,759**	**1,014,759**	**23,923,542**
Commercial Total		**COM**	**2,049,588**	**2,057,245**	**1,468,624**	**1,117,616**	**907,012**	**766,609**	**696,407**	**591,105**	**520,904**	**520,904**	**485,803**	**485,803**	**468,253**	**468,253**	**468,253**	**450,702**	**450,702**	**450,702**	**450,702**	**450,702**	**15,325,889**
Industrial Total		**IND**	**1,151,420**	**1,151,420**	**1,093,820**	**1,026,941**	**826,304**	**692,546**	**358,151**	**291,272**	**224,393**	**157,514**	**157,514**	**157,514**	**157,514**	**157,514**	**157,514**	**157,514**	**157,514**	**157,514**	**157,514**	**107,354**	**8,498,757**
Efficiency Total			**5,331,487**	**4,624,249**	**3,920,239**	**3,502,353**	**3,091,111**	**2,752,631**	**2,305,155**	**2,090,094**	**1,953,013**	**1,714,616**	**1,679,515**	**1,679,515**	**1,661,965**	**1,661,965**	**1,661,965**	**1,644,415**	**1,644,415**	**1,633,695**	**1,622,975**	**1,572,816**	**47,748,187**

WA Deployment, no exception after 2014, Incremental Annual Savings (therms)

Program	Deployment		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Resid New			37,107	292	312	351	390	390	390	390	390	390	390	390	390	390	390	390	390	390	390	390	44,302
	New Construction	RES	36,910	292	312	351	390	390	390	390	390	390	390	390	390	390	390	390	390	390	390	390	44,105
	New DHW	RES	197	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	197
Existing Residential			71,066	43,950	41,830	43,448	44,823	46,197	45,288	46,663	49,412	52,162	54,912	45,774	45,774	45,774	45,774	43,489	41,205	41,205	36,636	35,493	920,872
	Retrofit	RES	56,871	31,819	29,699	29,699	29,699	29,699	27,415	27,415	27,415	27,415	27,415	18,276	18,276	18,276	18,276	15,992	13,707	13,707	9,138	7,996	478,204
	Replace DHW	RES	12,525	10,462	10,462	11,857	13,042	14,228	15,414	16,599	18,970	21,342	23,713	23,713	23,713	23,713	23,713	23,713	23,713	23,713	23,713	23,713	382,031
	Replace equipment	RES	1,670	1,670	1,670	1,892	2,081	2,271	2,460	2,649	3,027	3,406	3,784	3,784	3,784	3,784	3,784	3,784	3,784	3,784	3,784	3,784	60,637
	Appliances, new & replace	RES	1,672	1,693	1,736	1,962	2,167	2,286	2,405	2,524	2,762	3,000	3,238	3,238	3,238	3,238	3,238	3,238	3,238	3,238	3,238	3,238	54,591
	Solar Water heat - Residential	RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Existing			77,575	77,042	80,929	81,202	88,500	100,129	111,758	112,851	99,894	93,962	87,484	81,005	77,258	72,965	74,330	61,647	61,647	61,647	61,647	61,647	1,625,115
	Replace Equip	COM	14,048	14,048	14,248	14,349	14,449	14,850	15,252	15,653	16,055	16,456	16,657	16,857	18,061	19,065	19,566	20,068	20,068	20,068	20,068	20,068	339,954
	Replace Shell	COM	12,380	12,380	12,557	12,646	12,734	13,088	13,442	13,795	14,149	14,503	14,680	14,856	15,918	16,802	17,244	17,686	17,686	17,686	17,686	17,686	299,604
	Retrofit Wx	COM	15,124	14,919	16,203	16,203	18,904	22,954	27,005	27,005	21,604	18,904	16,203	13,503	10,802	8,102	8,102	2,701	2,701	2,701	2,701	2,701	269,038
	Retrofit Equip	COM	24,216	23,888	25,944	25,944	30,268	36,754	43,240	43,240	34,592	30,268	25,944	21,620	17,296	12,972	12,972	4,324	4,324	4,324	4,324	4,324	430,780
	Cooking Appliances	COM	11,807	11,807	11,976	12,060	12,145	12,482	12,819	13,157	13,494	13,832	14,000	14,169	15,181	16,024	16,446	16,868	16,868	16,868	16,868	16,868	285,739
Commercial New			9,209	9,209	9,341	9,406	9,472	9,735	9,998	10,261	10,525	10,788	10,919	11,051	11,840	12,498	12,827	13,156	13,156	13,156	13,156	13,156	222,858
	New Constr	COM	9,209	9,209	9,341	9,406	9,472	9,735	9,998	10,261	10,525	10,788	10,919	11,051	11,840	12,498	12,827	13,156	13,156	13,156	13,156	13,156	222,858
Industrial			63,216	70,749	65,606	59,846	54,050	48,254	39,490	39,561	36,663	36,734	30,867	30,867	30,867	24,929	24,929	18,991	15,429	13,054	13,054	13,054	730,211
	Retrofit	IND	57,168	64,630	59,380	53,442	47,504	41,566	32,659	32,659	29,690	29,690	23,752	23,752	23,752	17,814	17,814	11,876	8,313	5,938	5,938	5,938	593,273
	Replacement	IND	6,048	6,119	6,226	6,404	6,546	6,689	6,831	6,902	6,973	7,044	7,116	7,116	7,116	7,116	7,116	7,116	7,116	7,116	7,116	7,116	136,938
Residential Total		**RES**	**109,845**	**45,936**	**43,879**	**45,761**	**47,380**	**48,873**	**48,083**	**49,577**	**52,564**	**55,552**	**58,540**	**49,402**	**49,402**	**49,402**	**49,402**	**47,117**	**44,833**	**44,833**	**40,264**	**39,121**	**1,019,765**
Commercial Total		**COM**	**86,784**	**86,251**	**90,269**	**90,608**	**97,972**	**109,864**	**121,757**	**123,112**	**110,419**	**104,750**	**98,403**	**92,056**	**89,098**	**85,462**	**87,157**	**74,802**	**74,802**	**74,802**	**74,802**	**74,802**	**1,847,973**
Industrial Total		**IND**	**63,216**	**70,749**	**65,606**	**59,846**	**54,050**	**48,254**	**39,490**	**39,561**	**36,663**	**36,734**	**30,867**	**30,867**	**30,867**	**24,929**	**24,929**	**18,991**	**15,429**	**13,054**	**13,054**	**13,054**	**730,211**
Efficiency Total			**259,845**	**202,936**	**199,754**	**196,215**	**199,401**	**206,992**	**209,329**	**212,250**	**199,646**	**197,036**	**187,810**	**172,325**	**169,367**	**159,794**	**161,488**	**140,911**	**135,064**	**132,689**	**128,119**	**126,977**	**3,597,949**

OR Deployment, no exception after 2014, Cumulative Annual Savings (therms)

Program	Deployment		2014	2015	2016	2017	2018	2019	2020	2021	2022
Resid New			446,820	565,862	684,904	803,945	922,987	1,042,029	1,161,071	1,280,113	1,399,155
	New Construction	RES	441,355	560,397	679,439	798,481	917,523	1,036,565	1,155,607	1,274,649	1,393,691
	New DHW	RES	5,465	5,465	5,465	5,465	5,465	5,465	5,465	5,465	5,465
Existing Residential			1,142,777	1,815,685	2,430,803	3,045,921	3,661,039	4,211,837	4,719,756	5,184,796	5,649,836
	Retrofit	RES	903,296	1,368,441	1,775,797	2,183,152	2,590,508	2,933,544	3,233,701	3,490,978	3,748,255
	Replace DHW	RES	203,307	374,895	546,483	718,071	889,659	1,061,247	1,232,835	1,404,423	1,576,011
	Replace equipment	RES	36,174	72,349	108,523	144,698	180,872	217,046	253,221	289,395	325,570
	Appliances, new & replace	RES	37,886	75,773	113,659	151,545	189,431	227,318	265,204	303,090	340,976
	Solar Water heat - Residential	RES	-	-	-	-	-	-	-	-	-
Commercial Existing			2,003,621	4,014,899	5,437,556	6,509,206	7,370,251	8,090,894	8,741,334	9,286,473	9,761,410
	Replace Equip	COM	134,147	268,294	402,440	536,587	670,734	804,881	939,027	1,073,174	1,207,321
	Replace Shell	COM	154,742	309,485	464,227	618,970	773,712	928,454	1,083,197	1,237,939	1,392,681
	Retrofit Wx	COM	648,702	1,300,443	1,718,499	1,997,203	2,192,295	2,331,647	2,443,129	2,512,805	2,554,610
	Retrofit Equip	COM	985,284	1,975,186	2,610,153	3,033,464	3,329,781	3,541,437	3,710,761	3,816,589	3,880,085
	Cooking Appliances	COM	80,746	161,492	242,237	322,983	403,729	484,475	565,221	645,966	726,712
Commercial New			28,415	56,829	85,244	113,658	142,073	170,488	198,902	227,317	255,731
	New Constr	COM	28,415	56,829	85,244	113,658	142,073	170,488	198,902	227,317	255,731
Industrial			1,151,420	2,302,840	3,396,660	4,423,601	5,249,905	5,942,451	6,300,602	6,591,873	6,816,266
	Retrofit	IND	726,383	1,452,766	2,142,489	2,789,645	3,309,102	3,743,426	3,964,918	4,143,843	4,280,203
	Replacement	IND	425,037	850,074	1,254,171	1,633,956	1,940,803	2,199,025	2,335,684	2,448,030	2,536,064
	RES Market Transformation	RES	502,996	1,088,745	1,674,494	2,260,243	2,845,992	3,431,741	4,017,490	4,603,239	5,188,988
	COM Market Transformation	COM	17,552	35,104	52,656	70,208	87,760	105,312	122,864	140,416	157,968
Residential Total		**RES**	**2,130,479**	**3,546,064**	**4,903,859**	**6,261,654**	**7,619,449**	**8,912,925**	**10,163,522**	**11,371,239**	**12,578,955**
Commercial Total		**COM**	**2,049,588**	**4,106,832**	**5,575,456**	**6,693,072**	**7,600,084**	**8,366,693**	**9,063,101**	**9,654,206**	**10,175,110**
Industrial Total		**IND**	**1,151,420**	**2,302,840**	**3,396,660**	**4,423,601**	**5,249,905**	**5,942,451**	**6,300,602**	**6,591,873**	**6,816,266**
Efficiency Total			**5,331,487**	**9,955,736**	**13,875,975**	**17,378,328**	**20,469,439**	**23,222,070**	**25,527,224**	**27,617,318**	**29,570,331**

Program	Deployment		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Resid New			1,518,197	1,637,239	1,756,281	1,875,323	1,994,365	2,113,407	2,232,449	2,351,491	2,470,533	2,589,575	2,708,617
	New Construction	RES	1,512,733	1,631,775	1,750,817	1,869,858	1,988,900	2,107,942	2,226,984	2,346,026	2,465,068	2,584,110	2,703,152
	New DHW	RES	5,465	5,465	5,465	5,465	5,465	5,465	5,465	5,465	5,465	5,465	5,465
Existing Residential			5,943,357	6,236,879	6,530,400	6,823,922	7,117,443	7,410,965	7,704,486	7,998,008	8,280,809	8,552,891	8,824,973
	Retrofit	RES	3,834,014	3,919,774	4,005,533	4,091,292	4,177,051	4,262,810	4,348,569	4,434,328	4,509,367	4,573,686	4,638,006
	Replace DHW	RES	1,747,599	1,919,187	2,090,775	2,262,363	2,433,951	2,605,539	2,777,127	2,948,715	3,120,303	3,291,891	3,463,479
	Replace equipment	RES	361,744	397,919	434,093	470,267	506,442	542,616	578,791	614,965	651,139	687,314	723,488
	Appliances, new & replace	RES	378,863	416,749	454,635	492,521	530,408	568,294	606,180	644,067	681,953	719,839	757,725
	Solar Water heat - Residential	RES	-	-	-	-	-	-	-	-	-	-	-
Commercial Existing			10,236,347	10,676,184	11,116,020	11,538,306	11,960,592	12,382,878	12,787,614	13,192,350	13,597,085	14,001,821	14,406,557
	Replace Equip	COM	1,341,468	1,475,614	1,609,761	1,743,908	1,878,055	2,012,201	2,146,348	2,280,495	2,414,642	2,548,788	2,682,935
	Replace Shell	COM	1,547,424	1,702,166	1,856,909	2,011,651	2,166,393	2,321,136	2,475,878	2,630,620	2,785,363	2,940,105	3,094,848
	Retrofit Wx	COM	2,596,416	2,624,286	2,652,157	2,673,059	2,693,962	2,714,865	2,728,800	2,742,735	2,756,671	2,770,606	2,784,541
	Retrofit Equip	COM	3,943,582	3,985,913	4,028,244	4,059,993	4,091,741	4,123,489	4,144,655	4,165,820	4,186,986	4,208,151	4,229,317
	Cooking Appliances	COM	807,458	888,204	968,949	1,049,695	1,130,441	1,211,187	1,291,933	1,372,678	1,453,424	1,534,170	1,614,916
Commercial New			284,146	312,561	340,975	369,390	397,805	426,219	454,634	483,048	511,463	539,878	568,292
	New Constr	COM	284,146	312,561	340,975	369,390	397,805	426,219	454,634	483,048	511,463	539,878	568,292
Industrial			6,973,780	7,131,293	7,288,807	7,446,321	7,603,834	7,761,348	7,918,862	8,076,375	8,233,889	8,391,402	8,498,757
	Retrofit	IND	4,373,995	4,467,788	4,561,581	4,655,373	4,749,166	4,842,959	4,936,752	5,030,544	5,124,337	5,218,130	5,279,998
	Replacement	IND	2,599,785	2,663,505	2,727,226	2,790,947	2,854,668	2,918,389	2,982,110	3,045,831	3,109,552	3,173,273	3,218,759
	RES Market Transformation	RES	5,774,737	6,360,486	6,946,235	7,531,984	8,117,733	8,703,482	9,289,231	9,874,980	10,460,729	11,046,478	11,632,227
	COM Market Transformation	COM	175,520	193,072	210,624	228,176	245,728	263,280	280,832	298,384	315,936	333,488	351,040
Residential Total		**RES**	**13,615,154**	**14,651,353**	**15,687,552**	**16,723,750**	**17,759,949**	**18,796,148**	**19,832,346**	**20,868,545**	**21,894,024**	**22,908,783**	**23,923,542**
Commercial Total		**COM**	**10,696,013**	**11,181,816**	**11,667,619**	**12,135,872**	**12,604,125**	**13,072,377**	**13,523,080**	**13,973,782**	**14,424,484**	**14,875,186**	**15,325,889**
Industrial Total		**IND**	**6,973,780**	**7,131,293**	**7,288,807**	**7,446,321**	**7,603,834**	**7,761,348**	**7,918,862**	**8,076,375**	**8,233,889**	**8,391,402**	**8,498,757**
Efficiency Total			**31,284,947**	**32,964,463**	**34,643,978**	**36,305,943**	**37,967,908**	**39,629,873**	**41,274,288**	**42,918,702**	**44,552,397**	**46,175,372**	**47,748,187**

WA Deployment, no exception after 2014, no code change savings, Cumulative Annual Savings (therms)

Program	Deployment		2014	2015	2016	2017	2018	2019	2020	2021	2022
Resid New			37,107	37,400	37,712	38,063	38,453	38,843	39,232	39,622	40,012
	New Construction	RES	36,910	37,202	37,514	37,865	38,255	38,645	39,035	39,425	39,815
	New DHW	RES	197	197	197	197	197	197	197	197	197
Existing Residential			71,066	115,016	156,846	200,294	245,116	291,314	336,601	383,264	432,676
	Retrofit	RES	56,871	88,689	118,388	148,088	177,787	207,486	234,900	262,315	289,729
	Replace DHW	RES	12,525	22,987	33,449	45,305	58,348	72,575	87,989	104,588	123,559
	Replace equipment	RES	1,670	3,339	5,009	6,901	8,982	11,253	13,712	16,361	19,389
	Appliances, new & replace	RES	1,672	3,366	5,102	7,064	9,231	11,517	13,922	16,446	19,208
	Solar Water heat - Residential	RES	-	-	-	-	-	-	-	-	-
Commercial Existing			77,575	154,617	235,546	316,748	405,247	505,376	617,135	729,985	829,879
	Replace Equip	COM	14,048	28,095	42,344	56,693	71,142	85,992	101,244	116,897	132,952
	Replace Shell	COM	12,380	24,761	37,318	49,963	62,698	75,785	89,227	103,022	117,171
	Retrofit Wx	COM	15,124	30,042	46,246	62,449	81,352	104,307	131,312	158,317	179,921
	Retrofit Equip	COM	24,216	48,104	74,048	99,992	130,260	167,014	210,255	253,495	288,087
	Cooking Appliances	COM	11,807	23,615	35,591	47,651	59,796	72,278	85,098	98,254	111,748
Commercial New			9,209	18,418	27,759	37,165	46,637	56,372	66,371	76,632	87,157
	New Constr	COM	9,209	18,418	27,759	37,165	46,637	56,372	66,371	76,632	87,157
Industrial			63,216	133,965	199,571	259,417	313,467	361,721	401,211	440,772	477,435
	Retrofit	IND	57,168	121,798	181,177	234,619	282,123	323,689	356,348	389,006	418,696
	Replacement	IND	6,048	12,168	18,394	24,798	31,344	38,033	44,863	51,766	58,739
Residential Total		**RES**	**109,845**	**155,781**	**199,659**	**245,420**	**292,800**	**341,673**	**389,756**	**439,333**	**491,897**
Commercial Total		**COM**	**86,784**	**173,035**	**263,304**	**353,913**	**451,884**	**561,749**	**683,505**	**806,617**	**917,036**
Industrial Total		**IND**	**63,216**	**133,965**	**199,571**	**259,417**	**313,467**	**361,721**	**401,211**	**440,772**	**477,435**
Efficiency Total			**259,845**	**462,781**	**662,535**	**858,750**	**1,058,151**	**1,265,143**	**1,474,472**	**1,686,722**	**1,886,368**

Program	Deployment		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Resid New			40,402	40,792	41,182	41,572	41,962	42,352	42,742	43,132	43,522	43,912	44,302
	New Construction	RES	40,205	40,595	40,985	41,375	41,765	42,155	42,545	42,935	43,325	43,715	44,105
	New DHW	RES	197	197	197	197	197	197	197	197	197	197	197
Existing Residential			484,839	539,750	585,524	631,298	677,071	722,845	766,334	807,539	848,743	885,379	920,872
	Retrofit	RES	317,144	344,558	362,835	381,111	399,387	417,664	433,655	447,363	461,070	470,208	478,204
	Replace DHW	RES	144,900	168,613	192,326	216,040	239,753	263,466	287,179	310,892	334,605	358,318	382,031
	Replace equipment	RES	22,795	26,579	30,363	34,147	37,932	41,716	45,500	49,284	53,069	56,853	60,637
	Appliances, new & replace	RES	22,208	25,447	28,685	31,923	35,161	38,399	41,638	44,876	48,114	51,352	54,591
	Solar Water heat - Residential	RES	-	-	-	-	-	-	-	-	-	-	-
Commercial Existing			923,841	1,011,324	1,092,330	1,169,588	1,242,552	1,316,882	1,378,529	1,440,176	1,501,822	1,563,469	1,625,115
	Replace Equip	COM	149,407	166,064	182,921	200,983	220,047	239,614	259,682	279,750	299,818	319,886	339,954
	Replace Shell	COM	131,674	146,353	161,210	177,127	193,929	211,173	228,859	246,545	264,232	281,918	299,604
	Retrofit Wx	COM	198,825	215,028	228,530	239,332	247,434	255,536	258,236	260,937	263,637	266,338	269,038
	Retrofit Equip	COM	318,355	344,299	365,919	383,216	396,188	409,160	413,484	417,808	422,132	426,456	430,780
	Cooking Appliances	COM	125,580	139,580	153,749	168,930	184,954	201,400	218,268	235,136	252,003	268,871	285,739
Commercial New			97,944	108,864	119,914	131,754	144,252	157,079	170,235	183,391	196,546	209,702	222,858
	New Constr	COM	97,944	108,864	119,914	131,754	144,252	157,079	170,235	183,391	196,546	209,702	222,858
Industrial			514,169	545,037	575,904	606,771	631,701	656,630	675,622	691,051	704,104	717,158	730,211
	Retrofit	IND	448,386	472,138	495,890	519,642	537,456	555,270	567,146	575,459	581,397	587,335	593,273
	Replacement	IND	65,783	72,899	80,014	87,130	94,245	101,361	108,476	115,592	122,707	129,823	136,938
Residential Total		**RES**	**547,449**	**605,989**	**655,391**	**704,793**	**754,195**	**803,597**	**850,714**	**895,547**	**940,380**	**980,643**	**1,019,765**
Commercial Total		**COM**	**1,021,785**	**1,120,188**	**1,212,244**	**1,301,342**	**1,386,805**	**1,473,962**	**1,548,764**	**1,623,566**	**1,698,368**	**1,773,171**	**1,847,973**
Industrial Total		**IND**	**514,169**	**545,037**	**575,904**	**606,771**	**631,701**	**656,630**	**675,622**	**691,051**	**704,104**	**717,158**	**730,211**
Efficiency Total			**2,083,404**	**2,271,214**	**2,443,539**	**2,612,907**	**2,772,701**	**2,934,189**	**3,075,100**	**3,210,164**	**3,342,852**	**3,470,972**	**3,597,949**

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 wate	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 wate	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 5: Energy Policies and Environmental Considerations

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CONTENT TO BE INCLUDED IN FINAL

Appendix 6: Distribution System Planning

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Appendix 6.1 - Washington Distribution System Projects

Smaller Washington Distribution System Projects					
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 6-inch wrapped steel Class D High-Pressure Main	Reinforce distribution system in this area north of Vancouver	$3 million	To Be Determined
Sierra Drive to Pacific Rim	NW Pacific Rim Blvd to Sierra St in Camas	Approximately 2.4 miles of 12" wrapped steel Class D High-Pressure Main	Reinforce High-Pressure distribution system serving Camas area	$4.6million	To Be Determined
Vancouver Core Replacement	East Access Road to Reserve	Approximately 1.8 miles of 12" wrapped steel Class D High-Pressure Main	Reinforce the High-Pressure distribution system serving S Vancouver. Eliminates a reduction in pressure due to pipe size.	$4 million	To Be Determined
Camas/ N Vancouver Gate Replacement	NE 172nd Ave to Lake Road	Approximately 5.1 miles of 12" wrapped steel Class D High-Pressure Main	Reinforce the High-Pressure distribution system serving N Vancouver and Camas. Eliminates a reduction in pressure due to pipe size.	$9.7million	To Be Determined

Appendix 7: Linear Programming and The Company's Resource Choices

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Figure 7A.1 – System Diagram

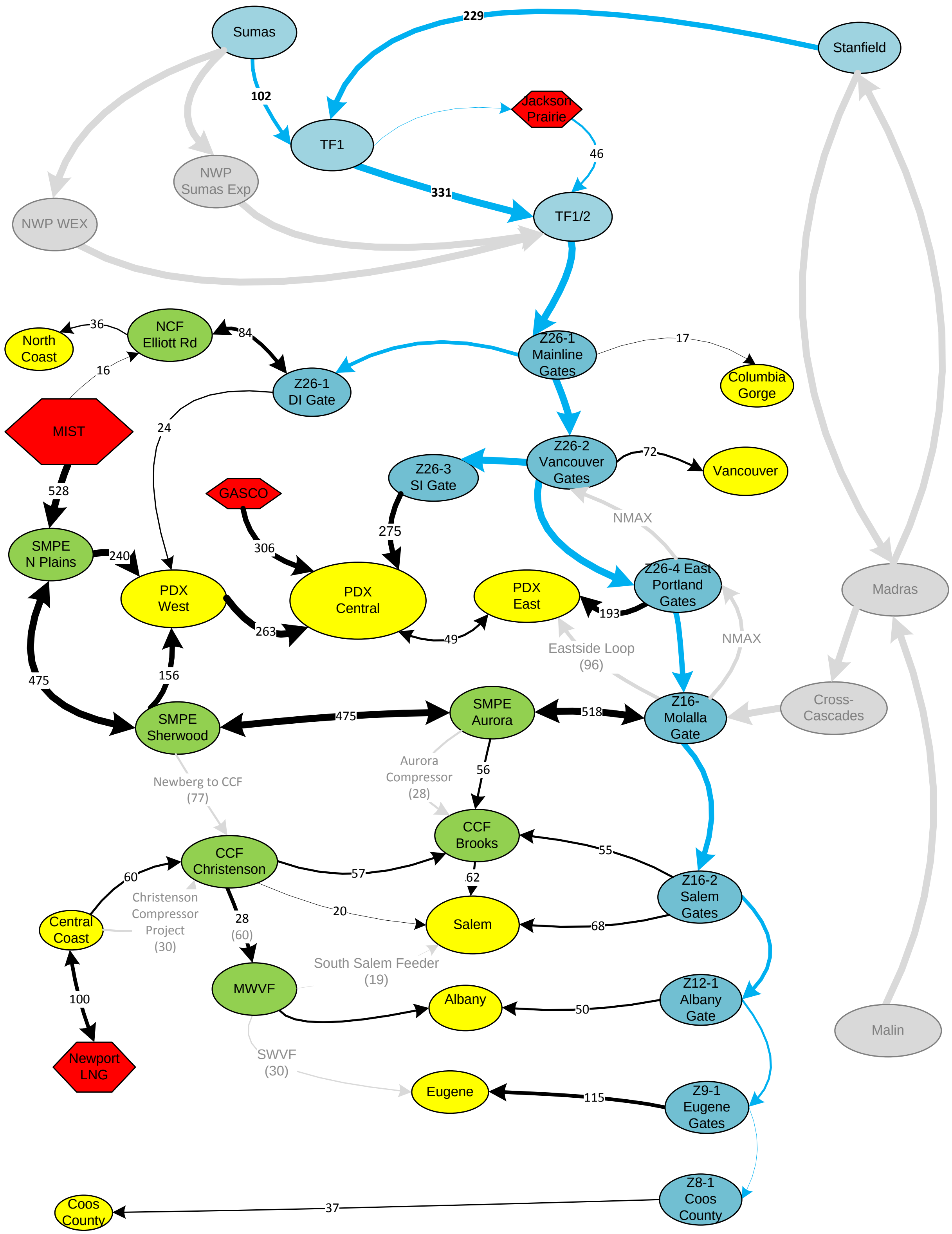

Table 7A.1 – Resource Options

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
CD on cross-Cascades/NMAX Pipeline (CC)	(0/110 – 450 MDT)	0.41 – 0.73	Nov-18
N-MAX	(0-450 MDT)	0.12	Nov-18
Incremental T-South	(0-500 MDT)	Current tariff rate	Nov-15
Incremental CD on NWP Sumas South	(0 – 500 MDT)	0.88	Nov-15
CD on NWP's Washington Expansion (WEX) Project	(0 – 500 MDT)	0.56	Nov-18
GTN backhaul Malin to Madras/Stanfield	(0 – 450 MDT)	Current tariff rates	Nov-18
High Pressure Transmission			
Christenson Compressor Project (CCP)	40 MDT	$3.1 million	Nov-15
South Willamette Valley Feeder (SWVF)	30 MDT	$6.2 million	Nov-18
Eastside Loop (ESL)	96 MDT	$7.5 million	Nov-18
Aurora Compressor Project (ACP)	28 MDT	$1.6 million	Nov-15
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
Satellite LNG Storage projects	30 MDT	$8.1 million	Nov-20

Portfolio 1 (CC 2018)

	Demand (DT, net DSM)			Key Resource Decisions (cumulative DT/day)					Costs ($000 nominal)								
Year	Forecast Demand	Design Day Firm Sales Demand	Design Day Firm Sales Demand Unserved	Vancouver Distribution	Mist Recall	CC	South Salem Feeder	Christenson Compressor	Supply Costs	Transport Fixed Costs	Transport Variable Costs	Total Transport Cost	Storage Fixed Cost	Storage Variable Cost	Total Storage Cost	DSM Annual Utility Cost	Total Costs
2013-2014	97,115,026	930,549	32,274	0	0	0	0	0	277,338	88,000	3,639	91,640	22,445	142	22,587	0	391,564
2014-2015	97,892,715	936,976	29,304	0	0	0	0	0	309,008	78,103	2,916	81,019	23,585	131	23,716	12,079	425,821
2015-2016	99,378,029	945,296	0	31,145	30,291	0	0	0	360,238	84,482	2,736	87,218	23,956	122	24,077	11,635	483,168
2016-2017	99,576,309	953,453	0	31,145	30,291	0	0	0	334,275	86,000	2,981	88,981	24,081	134	24,215	7,160	454,632
2017-2018	100,287,258	962,290	0	33,871	35,298	0	0	0	313,214	86,520	2,948	89,468	24,142	120	24,263	6,562	433,506
2018-2019	101,128,499	972,270	0	36,893	35,298	110,000	0	0	283,439	106,764	2,976	109,740	24,142	263	24,405	6,033	423,617
2019-2020	102,553,173	982,777	0	40,041	35,298	110,000	19,000	0	316,220	109,142	2,949	112,091	24,142	106	24,249	5,425	457,985
2020-2021	103,165,744	995,009	0	43,738	35,298	110,000	19,000	0	367,174	103,442	2,824	106,266	24,142	82	24,224	5,398	503,063
2021-2022	104,348,769	1,007,630	0	47,555	35,298	110,000	19,000	0	403,521	103,716	3,035	106,751	24,412	124	24,537	4,999	539,808
2022-2023	105,644,922	1,021,003	0	51,653	46,105	110,000	19,000	0	376,305	104,011	3,020	107,030	24,884	165	25,049	4,795	513,179
2023-2024	107,554,691	1,034,718	0	55,860	59,664	110,000	19,000	0	383,362	104,313	3,113	107,426	25,432	278	25,710	4,031	520,529
2024-2025	108,609,366	1,050,150	0	60,679	74,933	110,000	19,000	0	417,605	104,660	3,109	107,770	25,619	169	25,787	3,968	555,131
2025-2026	110,266,687	1,065,798	0	65,605	74,933	110,000	19,000	40,000	459,350	108,163	3,132	111,295	25,619	107	25,726	3,865	600,235
2026-2027	112,032,903	1,082,157	0	70,801	74,933	110,000	19,000	40,000	489,733	108,537	3,232	111,769	25,823	298	26,121	3,831	631,453
2027-2028	114,398,744	1,098,681	0	76,092	83,094	110,000	19,000	40,000	512,921	108,918	3,298	112,216	26,375	265	26,640	3,808	655,584
2028-2029	115,795,109	1,116,901	0	81,997	101,166	110,000	19,000	40,000	538,259	109,345	3,336	112,680	27,053	321	27,373	3,812	682,124
2029-2030	117,741,886	1,135,300	0	87,995	119,413	110,000	19,000	40,000	537,030	109,777	3,406	113,183	27,747	366	28,113	3,719	682,045
2030-2031	119,684,977	1,154,306	0	94,251	138,263	110,000	19,000	40,000	554,124	110,229	3,464	113,693	28,451	376	28,828	3,688	700,333
2031-2032	122,167,688	1,173,372	0	100,578	157,170	110,000	19,000	40,000	593,261	110,685	3,550	114,236	29,541	383	29,924	3,639	741,060
2032-2033	123,550,438	1,194,115	0	107,522	191,496	110,000	19,000	40,000	620,270	111,257	3,561	114,817	29,962	392	30,353	3,552	768,993
								20-year NPV ($000) @ 4.58%	5,368,509			1,386,568			341,918	73,609	7,170,605

NW Natural 2014 Integrated Resource Plan Appendix 7 – System Modeling and Portfolio Results

NW Natural 2014 Integrated Resource Plan Appendix 7 – System Modeling and Portfolio Results

Portfolio 2 (WEX 2018)

	Demand (DT, net DSM)			Key Resource Decisions (cumulative DT/day)					Costs ($000 nominal)								
Year	Forecast Demand	Design Day Firm Sales Demand	Design Day Firm Sales Demand Unserved	Vancouver Distribution	Mist Recall	WEX	South Salem Feeder	Christenson Compressor	Supply Costs	Transport Fixed Costs	Transport Variable Costs	Total Transport Cost	Storage Fixed Cost	Storage Variable Cost	Total Storage Cost	DSM Annual Utility Cost	Total Costs
2013-2014	97,115,026	930,549	32,277	0	0	0	0	0	277,338	88,000	3,639	91,639	22,445	142	22,587	0	391,564
2014-2015	97,892,715	936,976	29,304	0	0	0	0	0	309,008	78,103	2,916	81,019	23,585	131	23,716	12,079	425,821
2015-2016	99,378,029	945,296	0	31,145	30,292	0	0	0	360,238	84,482	2,736	87,218	23,956	122	24,077	11,635	483,168
2016-2017	99,576,309	953,453	0	31,145	30,292	0	0	0	334,275	85,999	2,981	88,981	24,081	134	24,215	7,160	454,631
2017-2018	100,287,258	962,290	0	33,871	35,299	0	0	0	310,625	86,519	2,919	89,439	24,142	118	24,260	6,562	430,886
2018-2019	101,128,499	972,270	0	36,893	35,299	107,146	0	0	279,022	127,296	4,540	131,836	24,142	269	24,411	6,033	441,302
2019-2020	102,553,173	982,777	0	40,041	35,299	107,146	19,000	0	308,895	129,675	4,450	134,125	24,142	103	24,245	5,425	472,690
2020-2021	103,165,744	995,009	0	43,738	35,299	107,146	19,000	0	365,136	118,502	4,158	122,660	24,142	79	24,221	5,398	517,416
2021-2022	104,348,769	1,007,630	0	47,555	35,299	107,146	19,000	0	402,368	118,776	4,468	123,244	24,366	122	24,488	4,999	555,099
2022-2023	105,644,922	1,021,003	0	51,653	44,249	107,146	19,000	0	374,188	119,070	4,464	123,534	24,819	170	24,989	4,795	527,505
2023-2024	107,554,691	1,034,718	0	55,860	57,973	107,146	19,000	0	380,935	119,373	4,562	123,934	25,373	277	25,650	4,031	534,550
2024-2025	108,609,366	1,050,150	0	60,679	73,411	107,146	19,000	0	415,958	119,720	4,184	123,904	25,562	153	25,715	3,968	569,545
2025-2026	110,266,687	1,065,798	0	65,605	73,411	107,146	19,000	40,000	457,534	123,222	4,377	127,600	25,562	106	25,668	3,865	614,667
2026-2027	112,032,903	1,082,157	0	70,801	73,411	107,146	19,000	40,000	484,870	123,596	4,325	127,921	25,779	252	26,031	3,831	642,653
2027-2028	114,398,744	1,098,681	0	76,092	82,090	107,146	19,000	40,000	512,711	123,978	4,568	128,546	26,342	281	26,622	3,808	671,687
2028-2029	115,795,109	1,116,901	0	81,997	100,339	107,146	19,000	40,000	534,385	124,404	4,707	129,111	27,026	293	27,319	3,812	694,627
2029-2030	117,741,886	1,135,300	0	87,995	118,764	107,146	19,000	40,000	532,278	124,837	4,902	129,739	27,728	366	28,094	3,719	693,829
2030-2031	119,684,977	1,154,306	0	94,251	137,792	107,146	19,000	40,000	548,255	125,288	4,986	130,274	28,438	407	28,845	3,688	711,062
2031-2032	122,167,688	1,173,372	0	100,578	156,875	107,146	19,000	40,000	586,051	125,744	5,067	130,812	29,538	393	29,931	3,639	750,433
2032-2033	123,550,438	1,194,115	0	107,522	191,496	107,146	19,000	40,000	608,569	126,245	5,069	131,315	29,962	400	30,362	3,552	773,797
								20-year NPV ($000) @ 4.58%	5,331,800			1,541,941			341,643	73,609	7,288,994

Portfolio 3 (Sumas Exp 2018/25)

	Demand (DT, net DSM)			Key Resource Decisions (cumulative DT/day)					Costs ($000 nominal)								
Year	Forecast Demand	Design Day Firm Sales Demand	Design Day Firm Sales Demand Unserved	Vancouver Distribution	Mist Recall	Sumas Expansion	South Salem Feeder	Christenson Compressor	Supply Costs	Transport Fixed Costs	Transport Variable Costs	Total Transport Cost	Storage Fixed Cost	Storage Variable Cost	Total Storage Cost	DSM Annual Utility Cost	Total Costs
2013-2014	97,115,026	930,549	32,277	0	0	0	0	0	277,338	88,000	3,639	91,640	22,445	142	22,587	0	391,564
2014-2015	97,892,715	936,976	29,304	0	0	0	0	0	309,008	78,103	2,916	81,019	23,585	131	23,716	12,079	425,821
2015-2016	99,378,029	945,296	0	31,145	30,292	0	0	0	360,238	84,482	2,736	87,218	23,956	122	24,077	11,635	483,168
2016-2017	99,576,309	953,453	0	31,145	30,292	0	0	0	334,275	86,000	2,981	88,981	24,081	134	24,215	7,160	454,631
2017-2018	100,287,258	962,290	0	33,871	35,299	0	0	0	313,431	86,519	2,951	89,470	24,618	139	24,756	6,562	434,220
2018-2019	101,128,499	972,270	0	36,893	54,311	50,000	0	0	282,435	106,729	3,362	110,091	25,114	257	25,371	6,033	423,929
2019-2020	102,553,173	982,777	0	40,041	64,828	50,000	19,000	0	313,988	109,107	3,319	112,426	25,548	111	25,660	5,425	457,499
2020-2021	103,165,744	995,009	0	43,738	77,069	50,000	19,000	0	363,952	102,395	3,144	105,540	26,014	85	26,100	5,398	500,990
2021-2022	104,348,769	1,007,630	0	47,555	89,701	50,000	19,000	0	411,129	102,669	3,454	106,123	26,504	120	26,624	4,999	548,875
2022-2023	105,644,922	1,021,003	0	51,653	103,085	50,000	19,000	0	375,578	102,964	3,385	106,349	27,011	161	27,172	4,795	513,893
2023-2024	107,554,691	1,034,718	0	55,860	116,808	50,000	19,000	0	384,439	103,266	3,494	106,760	27,565	277	27,842	4,031	523,073
2024-2025	108,609,366	1,050,150	0	60,679	132,246	50,000	19,000	0	417,873	103,613	3,414	107,027	27,754	150	27,904	3,968	556,772
2025-2026	110,266,687	1,065,798	0	65,605	132,246	107,146	19,000	40,000	457,442	135,719	4,046	139,765	27,754	73	27,827	3,865	628,899
2026-2027	112,032,903	1,082,157	0	70,801	132,246	107,146	19,000	40,000	482,907	136,093	3,990	140,083	27,754	225	27,979	3,831	654,800
2027-2028	114,398,744	1,098,681	0	76,092	132,246	107,146	19,000	40,000	510,812	136,474	4,197	140,672	27,754	271	28,025	3,808	683,316
2028-2029	115,795,109	1,116,901	0	81,997	132,246	107,146	19,000	40,000	532,043	136,901	4,309	141,210	27,754	289	28,043	3,812	705,108
2029-2030	117,741,886	1,135,300	0	87,995	132,246	107,146	19,000	40,000	530,632	137,333	4,497	141,830	27,893	366	28,259	3,719	704,440
2030-2031	119,684,977	1,154,306	0	94,251	137,792	107,146	19,000	40,000	548,235	137,784	4,586	142,370	28,438	407	28,845	3,688	723,139
2031-2032	122,167,688	1,173,372	0	100,578	156,875	107,146	19,000	40,000	586,025	138,241	4,662	142,903	29,538	393	29,931	3,639	762,498
2032-2033	123,550,438	1,194,115	0	107,522	191,496	107,146	19,000	40,000	606,357	138,742	4,650	143,391	29,962	399	30,360	3,552	783,660
								20-year NPV ($000) @ 4.58%	5,345,232			1,499,421			354,520	73,609	7,272,782

NW Natural 2014 Integrated Resource Plan Appendix 7 – System Modeling and Portfolio Results

Low Load Growth

	Demand (DT, net DSM)			Key Resource Decisions (cumulative DT/day)												
Year	Forecast Demand	Design Day Firm Sales Demand	Design Day Firm Sales Demand Unserved	Vancouver Distribution	Mist Recall	South Salem Feeder	Christenson Compressor	Supply Costs	Transport Fixed Costs	Transport Variable Costs	Total Transport Cost	Storage Fixed Cost	Storage Variable Cost	Total Storage Cost	DSM Annual Utility Cost	Total Costs
2013-2014	97,014,580	929,617	24,391	0	0	0	0	277,011	88,002	3,637	91,640	22,445	154	22,598	0	391,249
2014-2015	96,880,070	932,176	28,376	0	0	0	0	306,455	78,105	2,894	80,999	23,389	137	23,526	12,079	423,059
2015-2016	97,819,193	937,468	0	29,893	22,463	0	0	356,681	84,385	2,703	87,088	23,664	121	23,785	11,635	479,188
2016-2017	97,972,195	943,178	0	29,893	22,463	0	0	330,012	85,901	2,945	88,846	23,664	139	23,803	7,160	449,821
2017-2018	98,250,391	948,498	0	32,173	22,463	0	0	313,815	86,385	2,959	89,344	25,230	147	25,376	6,562	435,098
2018-2019	98,574,185	954,729	0	34,698	85,081	0	0	276,855	86,587	3,041	89,628	26,161	267	26,428	6,033	398,943
2019-2020	99,453,429	961,284	0	37,292	91,645	0	0	308,406	86,797	2,975	89,772	26,441	125	26,566	5,425	430,169
2020-2021	99,513,355	969,248	0	40,346	99,619	0	0	358,158	77,218	2,719	79,937	26,743	71	26,814	5,398	470,308
2021-2022	100,131,337	977,411	0	43,461	107,792	0	0	397,498	77,470	2,989	80,458	27,060	143	27,203	4,999	510,159
2022-2023	100,840,640	986,061	0	46,780	116,453	0	0	363,483	77,738	2,927	80,665	27,385	174	27,559	4,795	476,502
2023-2024	102,123,515	994,822	0	50,135	125,222	0	0	369,187	78,009	2,997	81,006	27,745	284	28,030	4,031	482,254
2024-2025	102,568,576	1,004,920	0	53,973	135,327	0	0	401,407	78,318	2,984	81,302	28,121	195	28,315	3,968	514,993
2025-2026	103,573,653	1,014,984	0	57,845	145,391	0	0	441,471	78,631	3,014	81,645	28,505	237	28,742	3,865	555,723
2026-2027	104,661,622	1,025,443	0	61,883	155,844	19,000	0	462,933	81,109	3,056	84,165	28,892	330	29,222	3,831	580,151
2027-2028	106,292,734	1,035,806	0	65,933	166,195	19,000	0	484,280	81,437	3,116	84,552	29,628	372	30,000	3,808	602,639
2028-2029	106,986,295	1,047,405	0	70,442	190,547	19,000	0	503,462	81,848	3,134	84,982	30,467	367	30,834	3,812	623,089
2029-2030	108,171,003	1,058,893	0	74,948	212,169	19,000	0	496,654	82,286	3,156	85,442	30,781	382	31,164	3,719	616,978
2030-2031	109,322,888	1,070,634	0	79,592	214,155	19,000	40,000	513,141	85,882	3,210	89,092	31,270	389	31,659	3,688	637,581
2031-2032	110,941,463	1,082,146	0	84,207	232,719	19,000	40,000	543,421	86,327	3,258	89,585	31,616	433	32,049	3,639	668,695
2032-2033	111,512,517	1,094,793	0	89,254	237,472	19,000	40,000	533,356	86,804	3,085	89,889	31,675	366	32,041	3,552	658,838
								20-year NPV ($000) @ 4.58%			1,156,408			365,442	73,609	**6,748,431**

NW Natural 2014 Integrated Resource Plan Appendix 7 – System Modeling and Portfolio Results

NW Natural 2014 Integrated Resource Plan Appendix 7 – System Modeling and Portfolio Results

High Load Growth

	Demand (DT, net DSM)			Key Resource Decisions (cumulative DT/day)					Costs ($000 nominal)								
Year	Forecast Demand	Design Day Firm Sales Demand	Design Day Firm Sales Demand Unserved	Vancouver Distribution	Mist Recall	CC	South Salem Feeder	Christenson Compressor	Supply Costs	Transport Fixed Costs	Transport Variable Costs	Total Transport Cost	Storage Fixed Cost	Storage Variable Cost	Total Storage Cost	DSM Annual Utility Cost	Total Costs
2013-2014	97,162,162	930,930	24,581	0	0	0	0	0	277,519	88,001	3,642	91,643	22,445	155	22,600	0	391,762
2014-2015	97,860,762	939,125	29,372	0	0	0	0	0	310,692	78,103	2,931	81,034	23,713	194	23,907	12,079	427,712
2015-2016	99,679,373	950,433	0	31,888	35,428	0	0	0	365,100	84,537	2,768	87,305	24,150	163	24,314	11,635	488,354
2016-2017	100,744,076	962,553	0	31,888	35,554	0	0	0	337,791	86,059	3,013	89,072	24,455	200	24,654	7,160	458,677
2017-2018	101,962,244	974,669	0	34,990	47,676	0	19,000	0	317,020	88,762	2,984	91,746	24,603	117	24,720	6,562	440,048
2018-2019	103,262,352	988,165	0	38,449	47,676	206,673	19,000	0	289,434	129,656	3,012	132,668	24,603	262	24,865	6,033	452,999
2019-2020	105,180,906	1,002,457	0	42,096	47,676	206,673	19,000	0	323,748	129,919	3,004	132,922	24,603	84	24,687	5,425	486,782
2020-2021	106,287,141	1,018,779	0	46,372	47,676	206,673	19,000	0	379,736	123,248	2,917	126,166	24,603	48	24,652	5,398	535,951
2021-2022	108,023,068	1,035,835	0	50,852	47,676	206,673	19,000	0	420,074	123,570	3,144	126,713	24,603	115	24,718	4,999	576,505
2022-2023	109,902,898	1,053,977	0	55,700	47,676	206,673	19,000	0	392,956	123,919	3,125	127,044	24,603	150	24,753	4,795	549,548
2023-2024	112,448,389	1,072,776	0	60,744	47,676	206,673	19,000	40,000	402,455	128,547	3,216	131,763	24,603	277	24,880	4,031	563,130
2024-2025	114,140,978	1,093,743	0	66,521	47,676	206,673	19,000	40,000	441,112	128,962	3,242	132,204	24,603	160	24,763	3,968	602,048
2025-2026	116,490,402	1,115,287	0	72,512	47,676	206,673	19,000	40,000	487,570	129,393	3,298	132,691	24,603	111	24,715	3,865	648,840
2026-2027	118,985,984	1,137,955	0	78,891	47,676	206,673	19,000	40,000	521,984	129,853	3,394	133,247	24,917	268	25,185	3,831	684,246
2027-2028	122,149,090	1,161,166	0	85,473	60,219	206,673	19,000	40,000	550,757	130,328	3,491	133,820	25,708	277	25,985	3,808	714,369
2028-2029	124,325,407	1,186,633	0	92,836	85,716	206,673	19,000	40,000	580,949	130,970	3,554	134,524	26,673	316	26,989	3,812	746,274
2029-2030	127,123,351	1,212,701	0	100,421	111,810	206,673	19,000	40,000	583,423	131,824	3,642	135,466	27,665	379	28,043	3,719	750,651
2030-2031	129,962,529	1,239,873	325	108,413	138,678	206,673	19,000	40,000	604,999	132,733	3,723	136,456	28,641	393	29,034	3,688	774,176
2031-2032	133,432,723	1,267,550	2,149	116,612	164,548	206,673	19,000	40,000	649,652	133,652	3,828	137,480	29,657	405	30,062	3,639	820,833
2032-2033	135,760,853	1,297,588	4,226	125,640	192,524	206,673	19,000	40,000	659,863	134,679	3,735	138,415	30,000	336	30,336	3,552	832,166
20-year NPV ($000) @ 4.58%									5,615,034			1,584,427			341,342	73,609	7,614,413

2013 Washington IRP Design Weather

	Demand (DT, net DSM)			Key Resource Decisions (cumulative DT/day)					Costs ($000 nominal)								
Year	Forecast Demand	Design Day Firm Sales Demand	Design Day Firm Sales Demand Unserved	Vancouver Distribution	Mist Recall	CC	South Salem Feeder	Christenson Compressor	Supply Costs	Transport Fixed Costs	Transport Variable Costs	Total Transport Cost	Storage Fixed Cost	Storage Variable Cost	Total Storage Cost	DSM Annual Utility Cost	Total Costs
2013-2014	94,214,142	932,118	32,537	0	0	0	0	0	266,432	88,001	3,547	91,548	22,445	118	22,562	0	380,543
2014-2015	94,959,692	938,634	29,574	0	0	0	0	0	298,033	78,103	2,821	80,925	23,628	118	23,746	12,079	414,783
2015-2016	96,335,224	947,049	0	31,483	32,044	0	0	0	341,220	84,510	2,614	87,123	24,021	114	24,135	11,635	464,114
2016-2017	96,562,980	955,297	0	31,483	32,044	0	0	0	323,392	86,027	2,897	88,924	24,151	117	24,267	7,160	443,744
2017-2018	97,233,384	964,228	0	33,871	37,235	0	0	0	299,624	86,520	2,849	89,369	24,214	107	24,322	6,562	419,877
2018-2019	98,031,394	974,305	0	37,251	37,235	110,000	0	0	272,535	108,459	2,881	111,340	24,214	258	24,472	6,033	414,380
2019-2020	99,340,072	984,912	0	40,411	37,235	110,000	19,000	0	303,764	110,839	2,828	113,666	24,214	94	24,309	5,425	447,165
2020-2021	99,975,420	997,246	0	44,121	37,235	110,000	19,000	0	352,130	105,763	2,709	108,471	24,214	46	24,260	5,398	490,260
2021-2022	101,108,749	1,009,972	0	47,951	37,235	110,000	19,000	0	386,938	106,038	2,931	108,968	24,356	105	24,461	4,999	525,366
2022-2023	102,353,666	1,023,453	0	52,064	42,903	110,000	19,000	0	361,286	106,334	2,909	109,242	24,771	145	24,917	4,795	500,240
2023-2024	104,135,899	1,037,277	0	56,286	56,736	110,000	19,000	0	368,160	106,638	3,005	109,643	25,330	281	25,611	4,031	507,446
2024-2025	105,209,661	1,052,820	0	61,121	72,285	110,000	19,000	0	401,080	106,988	3,000	109,988	25,520	143	25,663	3,968	540,699
2025-2026	106,809,896	1,068,581	0	66,065	72,285	110,000	19,000	40,000	440,869	110,493	3,014	113,507	25,520	84	25,604	3,865	583,845
2026-2027	108,517,057	1,085,055	0	71,280	72,285	110,000	19,000	40,000	469,183	110,869	3,109	113,978	25,746	233	25,979	3,831	612,970
2027-2028	110,742,577	1,101,696	0	76,590	81,309	110,000	19,000	40,000	493,383	111,253	3,182	114,434	26,316	264	26,579	3,808	638,205
2028-2029	112,155,380	1,120,034	0	82,515	99,677	110,000	19,000	40,000	516,816	111,680	3,214	114,894	27,004	305	27,310	3,812	662,832
2029-2030	114,037,303	1,138,553	0	88,534	118,221	110,000	19,000	40,000	514,772	112,115	3,286	115,401	27,711	347	28,057	3,719	661,949
2030-2031	115,913,633	1,157,680	0	94,812	137,371	110,000	19,000	40,000	532,327	112,568	3,337	115,905	28,425	368	28,794	3,688	680,714
2031-2032	118,242,333	1,176,870	0	101,162	156,577	110,000	19,000	40,000	567,805	113,026	3,416	116,442	29,532	344	29,876	3,639	717,762
2032-2033	119,639,732	1,197,737	0	108,130	191,406	110,000	19,000	40,000	594,041	113,594	3,431	117,025	29,958	377	30,335	3,552	744,953
								20-year NPV ($000) @ 4.58%	5,150,883			1,404,951			341,628	73,609	6,971,071

NW Natural 2014 Integrated Resource Plan Appendix 7 – System Modeling and Portfolio Results

Appendix 8: Avoided Costs

		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

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NW Natural –2014 Integrated Resource Plan (IRP)
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NW Natural –2014 Integrated Resource Plan (IRP) Scenario Workshop
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