NW Natural

2016 Integrated Resource Plan

LC-64

UG-151776

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Chapter 1
Executive Summary

1. OVERVIEW

This Executive Summary provides an overview of the key findings in NW Natural's 2016 Integrated Resource Plan (IRP) and includes the Company's multiyear action plan. NW Natural develops a long-term resource plan with a 20-year planning horizon on approximately two-year cycles, with this IRP covering the 2016–2035 timeframe. The primary goals of the IRP are to 1) identify customers' future gas needs (i.e., forecast load); 2) determine the options available to meet those needs (i.e., identify supply-side and distribution resource options); and 3) identify the portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers through rigorous analysis of both costs and risks.

1.1. About NW Natural

NW Natural is a 157-year-old natural gas local distribution and storage company headquartered in Portland, Oregon. NW Natural serves over 714,000 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 89 percent of NW Natural's customers reside in Oregon, with the other 11 percent in the state of Washington. Residential customers comprise roughly 90 percent of the customer base.

Figure 1.1 – NW Natural's Service Territory

1.2. Guidelines for Integrated Resource Planning

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

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

1.3. NW Natural's 2014 Integrated Resource Plan

At the time of the 2014 IRP, the Oregon economy and the Clark County, Washington, areas were improving. Clark County had been forecasted to be the third-fastest growing county in the Pacific Northwest.[1] The Company had just experienced 1.3 percent customer growth in 2013. Gas prices were at historic lows, fueling plans for the development of numerous LNG export plants with locations from Coos Bay to the northern British Columbia coast. Equally, lower gas costs were negatively impacting the cost-effectiveness of DSM programs prompting the investigation of cost-effectiveness by both the Oregon and Washington Commissions.[2]

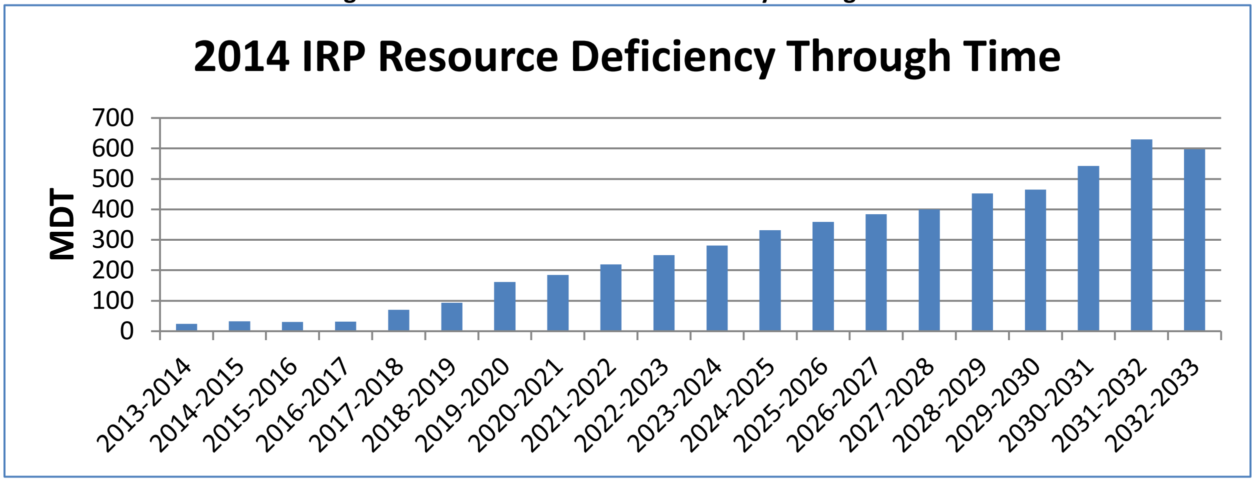
At the same time, during the 2013–2014 heating season the Pacific Northwest experienced a couple of severely cold weather events and for the first time Northwest Pipeline (NWP), the primary interstate pipeline that serves the Company's service territory, curtailed a resource that was previously in the Company's firm resource stack.[3] Against this backdrop and with improved system flow modeling, the 2014 IRP plan indicated that the Company needed immediate resources and would continue to need resources over the planning horizon, as shown in figure 1.2.

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

[2] Public Utility Commission of Oregon, Docket No. UM 1622 and Washington Utilities and Transportation Commission, Docket No. UG-121207.

[3] On Dec. 6, 2013, NWP curtailed service on its pipeline used to transport supplies from the Plymouth LNG Storage.

Figure 1.2: 2014 IRP Resource Deficiency Through Time



This serves as a starting point for NW Natural's planning process associated with the 2016 IRP. The next step is to do an environmental scan and take note of the planning environment.

1.4. Current Planning Environment

Since the 2014 IRP was filed, there have been several significant and continuing trends that should be noted.

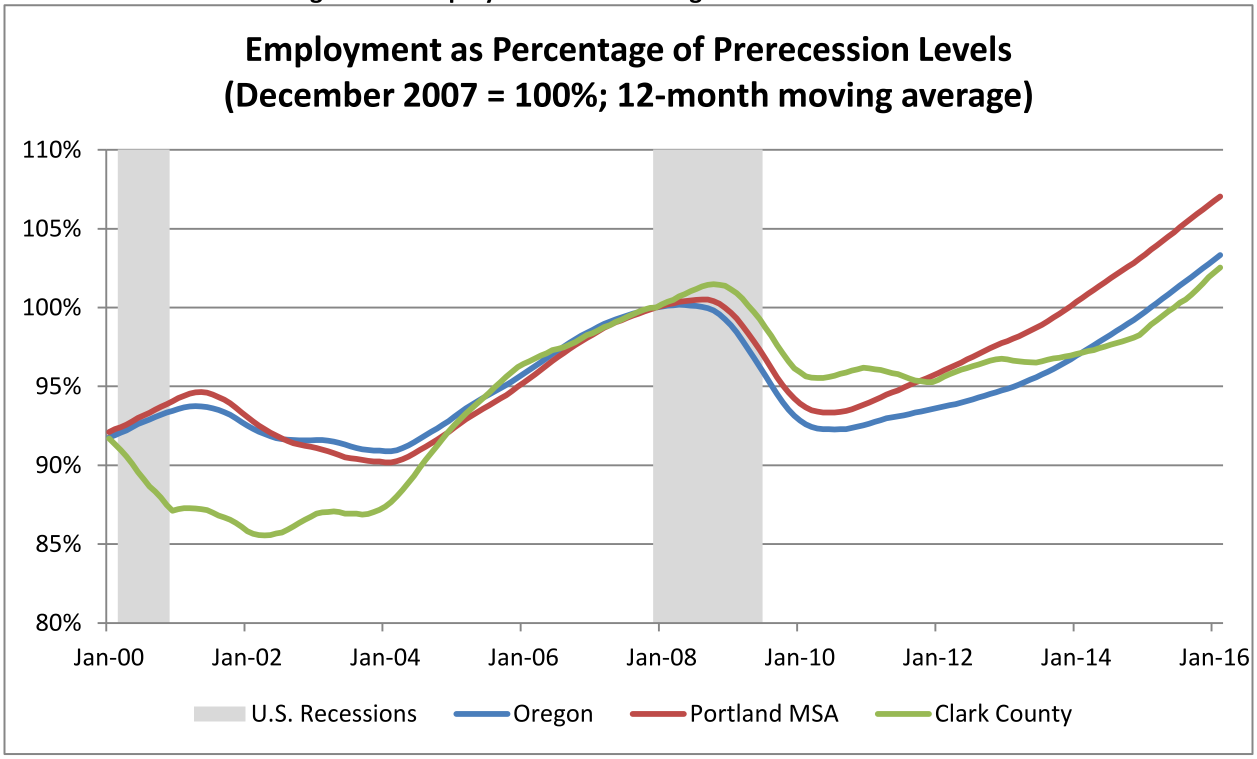
Oregon and Clark County economies continue to improve

The economy of NW Natural's service area is, by some measures and on the whole, now fully recovered from the recession of 2007–2009. Figure 1.3 shows employment[4] indices for certain geographies related to NW Natural's service area.[5]

[4] Employment is nonfarm employment for Oregon and the Portland MSA and total employment for Clark County. Values underlying 12-month moving averages are not seasonally adjusted. Source for Oregon and Portland MSA employment is the Federal Reserve and, for Clark County, the Washington Employment Security Department. Dates of U.S. recessions are from the National Bureau of Economic Research (NBER).

[5] Please see figure 2.1 in chapter 2 for more information on this chart.

Figure 1.3: Employment as Percentage of Prerecession Levels

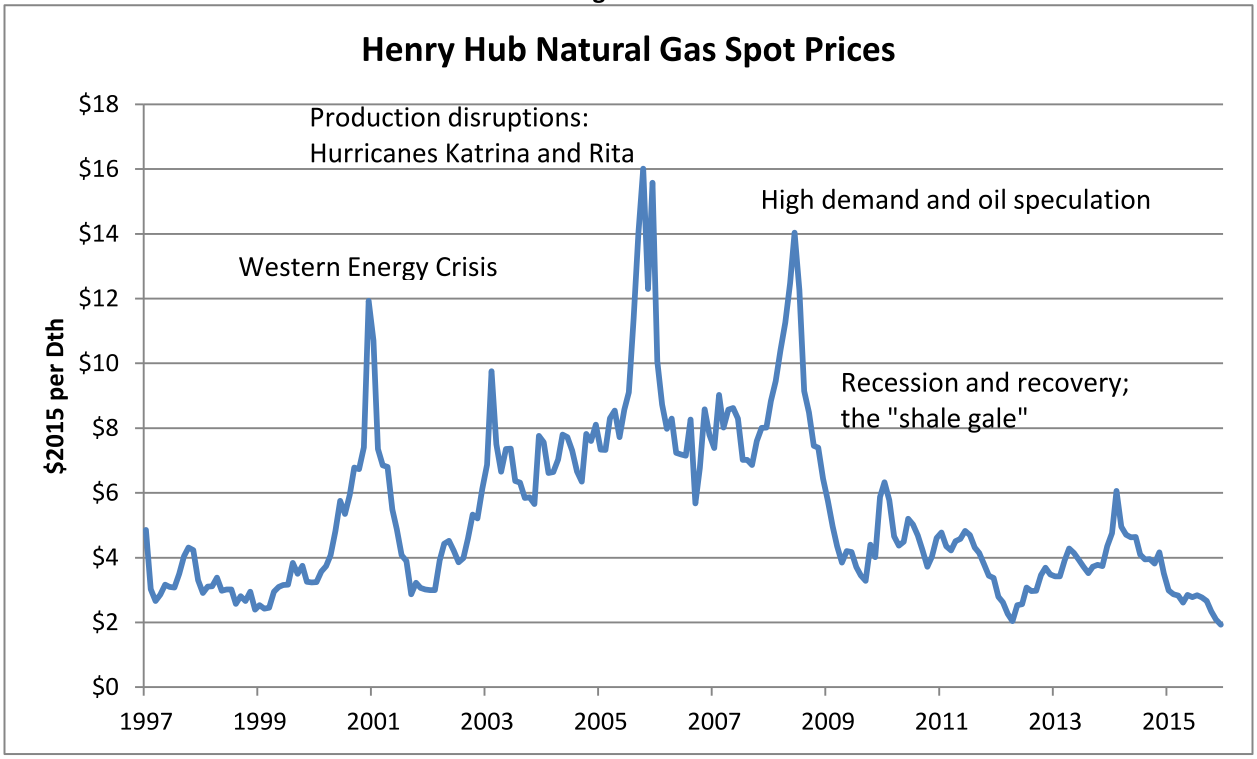


Gas prices continue to decline

As mentioned previously, at the time of the 2014 IRP gas prices were lower than the average price over the previous 20 years. Following the 2014 IRP, gas prices have remained at historically low levels as can be seen in figure 1.4.[6]

[6] Please see figure 2.3 in chapter 2 of this IRP for more information about this chart.

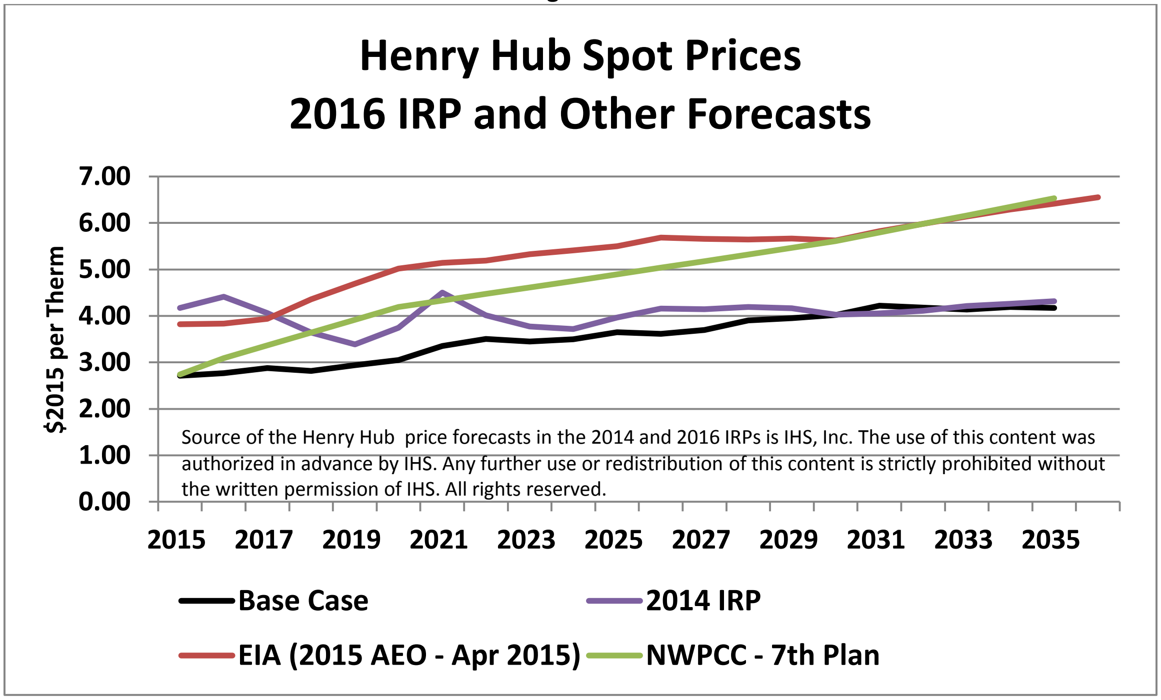
Figure 1.4



Further, while gas prices have remained low, most current gas price forecasts suggest that prices have bottomed out and will begin increasing as can be seen in figure 1.5.[7]

[7] Please see figure 2.5 in chapter 2 for additional information.

Figure 1.5



One significant effect of lower prices from a planning perspective is that it reduces avoided costs and hence the cost-effectiveness of certain DSM measures, and consequent demand-side resources (more on this below).

Potential for new large loads muted, but remains

The shale gale that was alluded to earlier was a dominate theme in the 2014 IRP and a major underlying factor in the numerous proposals for LNG export facilities along the West Coast.[8] In addition, Northwest Innovation Works (NIW) had recently announced their proposal to build three methanol plants.[9] Since that time, there has been a reduction in the number of LNG plants moving forward. Amongst the two planned LNG export facilities most impacting the Company's planning, Oregon LNG and its attendant pipeline (Washington Expansion) have withdrawn from the FERC application process.[10], [11]Although currently in the process of Rehearings for Further Consideration, FERC denied requests for certificate authority to build and operate Jordan Cove and its attendant pipeline, Pacific Connector.[12]

[8] At one time, at least 20 LNG export facilities were proposed for the West Coast of North America.

[9] The Oregonian, Jan. 23, 2014 – Two $1 billion refineries planned for region and the Tacoma News Tribune April 24, 2014.

[10] SNL, May 11, 2016 Northwest Pipeline abandons project tied to canceled Oregon LNG.

[11] NWP refers to the hypothetical successor of the Washington Expansion project as Sumas Express.

[12] FERC Docket Nos. CP13-483-001 and CP13-492-001 and SNL, March 14, 2016 FERC rejects Jordan Cove LNG export project, Pacific Connector pipeline.

Additionally, a similar scaleback in plans has occurred with NIW's methanol plans. In the 2014 IRP, it was envisioned that three plants could be built—two in Washington (Tacoma and Kalama) and one in Oregon (Clatskanie). Recently, NIW announced that it is no longer pursuing the Tacoma site while planning for operations at the Kalama and Clatskanie sites would continue.[13]

The development of any high-pressure transmission pipeline on which the Company could acquire capacity will be primarily driven by one of these large load projects and secondarily by NW Natural and other regional loads.

State-level environmental regulation gains traction

Both Oregon and Washington have seen proposals brought up in their legislative sessions to address carbon emissions. In Oregon, the Clean Electricity and Coal Transition Plan (Senate Bill 1547) passed while Senate Bill 965, which sought to establish a cap and dividend system, failed. Further, the 2015 Oregon Legislature passed Senate Bill 324 allowing Oregon DEQ to fully implement the Clean Fuels Program in 2016.

Likewise, in Washington Governor Inslee directed the Department of Ecology (Ecology) to use its existing authority under Washington's Clear Air Act to adopt a rule limiting GHG emissions. Ecology is expected to have final rules out in the fall of 2016 with compliance requirements effective beginning in January 2017.

Pipelines remain at capacity

While decontracting might be an issue for other pipelines, the situation is different in the Pacific Northwest. Capacity on Northwest Pipeline, which provides most of NW Natural's interstate capacity, is fully contracted northbound through the Roosevelt Compressor station and fully contracted southbound through the Chehalis Compressor station.[14] It is also anticipated that, as more electricity is generated using natural gas, existing pipelines will become even more constrained.[15]

Thus, for planning purposes, the 2014 IRP is the starting point. Then, it is important to do an environmental scan to understand the changes to the planning environment. The next step is to update NW Natural's actual results, assumptions, and to continually improve the Company's planning practices. The following section highlights the improvements NW Natural made in the 2016 IRP.

2. HIGHLIGHTS OF CHANGES IN 2016 INTEGRATED RESOURCE PLAN

NW Natural has made numerous improvements in its 2016 IRP. The Company discusses these in more detail in each relevant chapter, but the following list summarizes these with a brief description of improvements made.

[13] Port of Tacoma, April 19, 2016 news release.

[14] Northwest Pipeline's NW Natural 2016 IRP Technical Working Group Presentation Feb. 10, 2016.

[15] See Northwest Gas Association's 2015 Gas Outlook – Regional System Capacity, page 15.

2.1. Customer Growth

As recommended by NW Natural's stakeholders, the Company increased the timeframe of historical observations used in its residential and commercial customer forecast models from six years in the 2014 IRP to 25 years in the current IRP. The Company also tested additional variables to help provide more explanatory power to its econometric forecasts. The resulting customer growth rates are lower overall from the previous IRP as shown in table 1.1.[16]

Table 1.1: Comparison of System Average Annual Growth Rates

Customer Type	2014 IRP	2016 IRP
Residential[17]	1.8%	1.7%
Commercial[18]	1.4%	1.0%

2.2. Peak Day Use Per Customer

The Company materially revised how it estimated its peak day forecast. Changes were made related to changes in weather measurement, use of SCADA data instead of billing data, and use of an hourly averaged daily data, figure 1.6 is a side-by-side comparison of the major changes in weather measurement.[19]

Figure 1.6

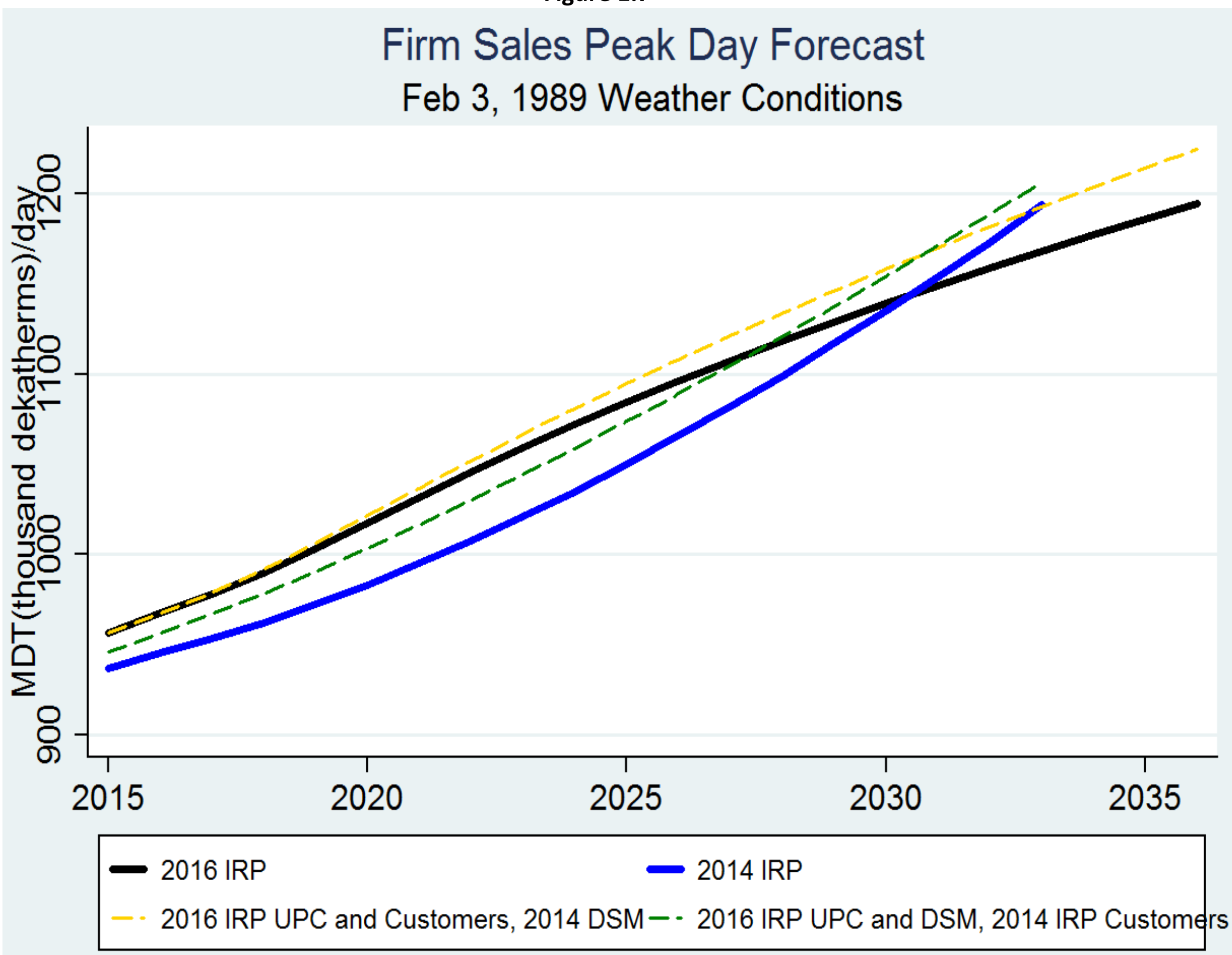
Summary of Peak Day Weather Measurement Change

	2014 IRP		2016 IRP	
Weather Definition	Calendar Day		Gas Day (7am to 7am)	
Weighting	Static System Weighted		Time Adjusted System Weighted	
Drivers of Load	Average of Daily High and Daily Low Temperature in Heating Degree Day (HDD) Form		Average of Hourly Values for (1) Temperature and (2) Wind Speed, Sum of Hourly Values for (3) Precipitation and (4) Solar Radiation, (5) Day of Week, and (6) One Day Lag of Temperature	
Peak Day Definition	Coldest Day in 30 years		Highest Heating Requirement Day in 30 years	
Peak Day	February 3, 1989		February 3, 1989	
Peak Day Measurements	Temperature:	53 HDD (12°F)	Temperature:	10.4°F
	Wind Speed:	N/A	Wind Speed:	21.72 mph
	Precipitation:	N/A	Precipitation:	0.01 inches
	Solar Radiation:	N/A	Solar Radiation:	2536 watt/m^2
	Day of Week:	N/A	Day of Week:	Week Day (M-TH)
	One Day Lag of Temperature:	N/A	One Day Lag of Temperature:	12.0°F

16 Please see table 2.3 in chapter 2 for additional information.
17 For Residential the comparison is between years 2015–2032 for both IRPs.
18 For Commercial the comparison is between years 2015–2030 for both IRPs.
19 Please see Section 8, System Peak Day Usage Forecast in chapter 2 for additional information.

These changes, along with changes in the customer forecasts and the demand-side resources forecast, result in a peak load forecast that is slightly higher in the near-term and lower in the later years of the planning horizon. This comparison, along with the changes to avoided costs and DSM discussed below, can be seen in figure 1.7.

Figure 1.7



2.3. Average Annual Usage Per Customer

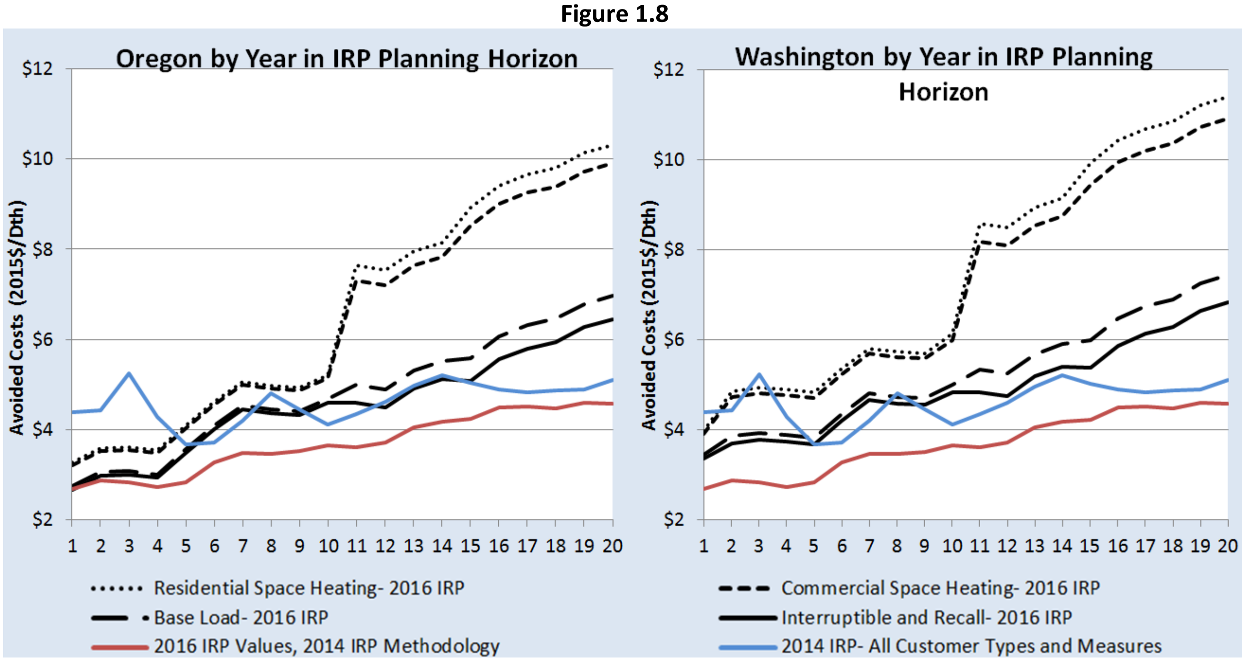
New to the 2016 IRP, the Company moved from modeling this as a nonlinear model to a piecewise linear function of temperature. Additionally, NW Natural included a nonincentivized annual use per customer trend. These changes in addition to updated incentivized cost-effective energy-efficiency result in the residential average annual use per customer declining at an average annual rate of -0.3 percent per year (base load: -1.1 percent; heat load: 0.1 percent). Commercial average annual use per customer is declining at an average annual rate of -1.2 percent per year (base load: -1.9 percent; heat load: -0.3 percent).[20]

[20] Please see chapter 2, section 9 Annual Energy Forecast for more information.

2.4. Avoided Costs

NW Natural made major methodological changes to the avoided cost calculation.[21] Costs associated with incremental supply and distribution capacity resources are now included, which requires that the expected peak day savings of each DSM measure be considered in addition to the total annual savings, as different end uses have dramatically different on-peak implications. A hedge value associated with mitigating price volatility that includes both a risk premium and a credit facility cost is also included. Please see figure 1.8 for a comparison of the change in avoided costs for both Oregon and Washington, where the horizontal axis represents year of the planning horizon (Year One is 2013–14 in the 2014 IRP and Year One is 2016–2017 in the 2016 IRP.[22]

Figure 1.8



2.5. Inclusion of an Incremental Carbon Adder

Carbon regulation at the state level has gained traction and the Company believes there will likely be state carbon regulation in Oregon, Washington, or both states within the planning horizon. It is unknown as to what such regulation will look like for either state at this time.[23] Will it be a carbon tax? A cap and trade system? A cap and invest system? And at what price? And with what levels of allowances or thresholds? There is still a high degree of uncertainty as to what specific regulation will look like.

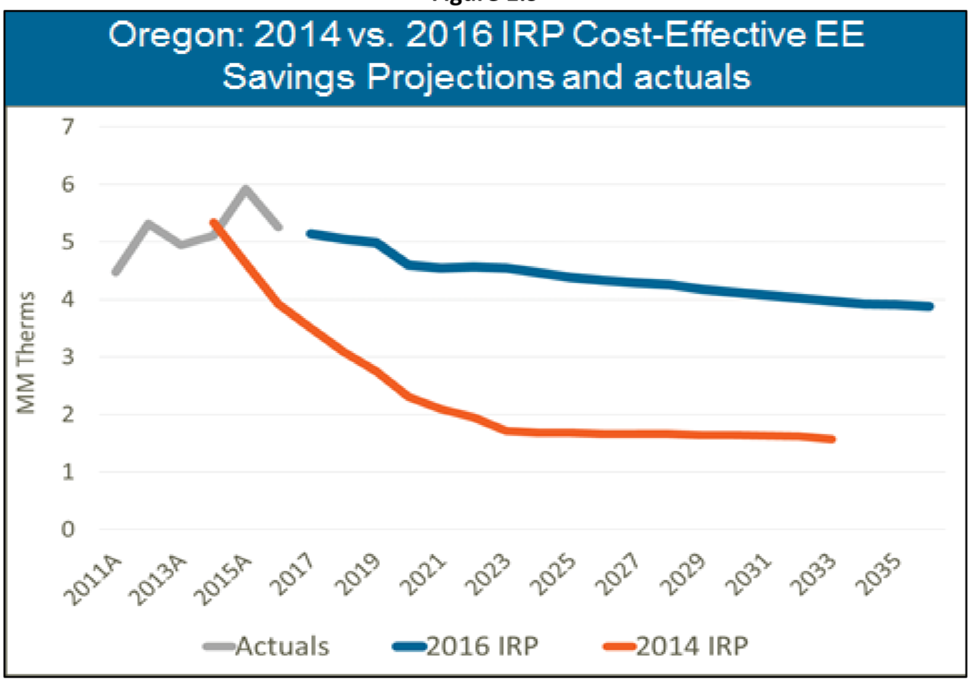
[21] Please see chapter 5 for detailed information on avoided cost calculations.
[22] Please also refer to figure 5.6 in chapter 5 for the similar charts based on calendar years.
[23] As discussed in chapter 4, earlier in this chapter as well as later, the Company does anticipate carbon regulation rules being finalized in Washington by the Department of Ecology with an implementation date of January 2017.

Thus, as a proxy for costs related to complying with future state regulation, the Company included an incremental carbon adder in its Base Case as well as alternative scenarios with varying levels of incremental carbon adders. The Base Case carbon adder was included in avoided cost, increasing the cost-effectiveness of some DSM measures and in turn increasing the level of available demand-side resources.

2.6. DSM Methodology

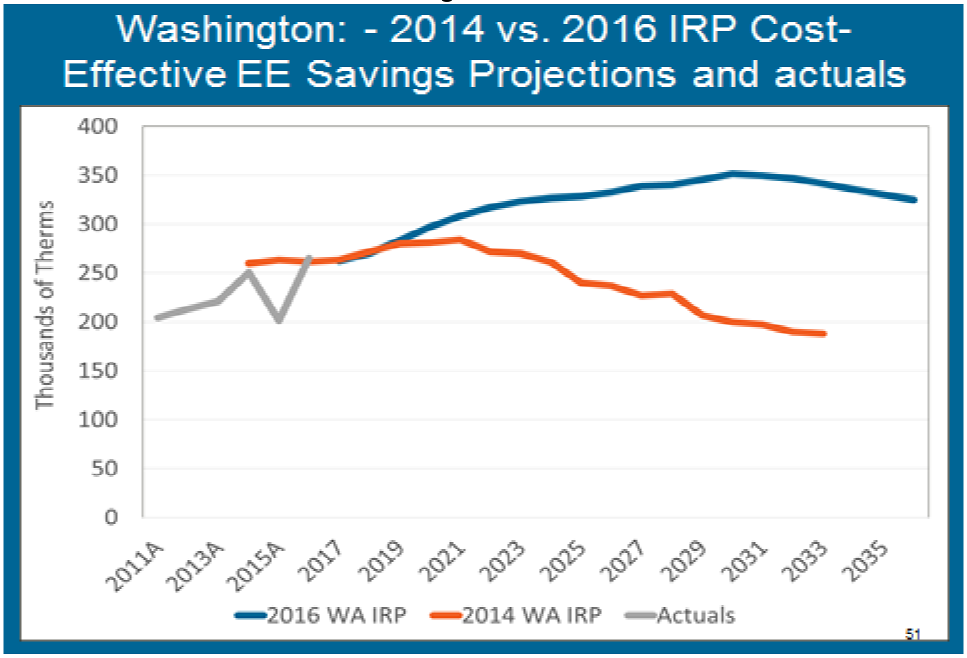
In addition to the aforementioned changes relating to avoided costs, Energy Trust of Oregon is using a new resource assessment model for the 2016 IRP. Figures 1.9 and 1.10 show a comparison of the cost-effective energy-efficiency savings projections between the 2014 and 2016 IRPs for both Oregon and Washington.[24]

Figure 1.9



[24] Please see chapter 6 for more information with regard to demand side forecasts.

Figure 1.10



2.7. Continued Refinement of System Flows in SENDOUT®

The Company continued to refine and improve its modeling of the system in SENDOUT®. As will be explained in detail in chapter 3, the Company has improved its modeling and now certain gate stations are grouped together eliminating previously modeled limitations. Further, the Company continues to disaggregate load centers to have greater visibility into actual flow characteristics as in the case of Salem and discussed in more detail in chapter 8.

2.8. Distribution System Planning

The Company has developed hourly peak loads by load center and has continued to improve the granularity of its system flows. Additionally, when evaluating distribution system reinforcements, NW Natural has (1) implemented a new prospective planning process looking out 10 years and (2) adopted and documented specific criteria to assist in identifying system reinforcement issues and establishing their priority for being addressed for both transmission and high-pressure distribution systems. When combined, these improvements in the planning process require that additional resources be applied to distribution system planning, but these improvements also allow evaluation of accelerated, geographically targeted DSM as a potentially viable option for meeting any projected deficiencies in the distribution system.[25]

[25] Please see chapter 7 for more information on Distribution System Planning.

2.9. Risk Analysis

As recommended by NW Natural's stakeholders, the Company has developed a more sophisticated stochastic risk analysis for this IRP.[26]

These changes represent the highlights of some of the improvements that the Company has made to the 2016 IRP. Numerous other improvements were made and these are covered either in each respective chapter or within the supporting documentation. The Company will continue to work with stakeholders to improve its planning abilities.

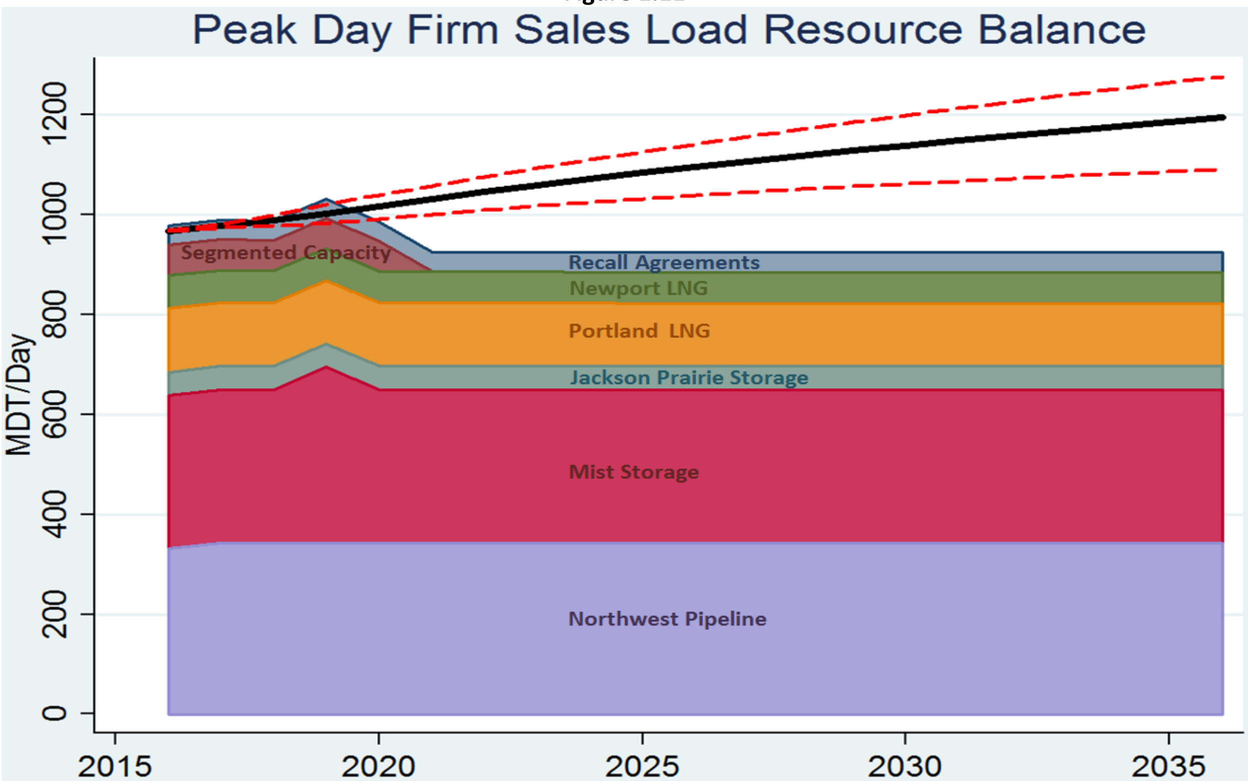
3. PRINCIPAL CONCLUSIONS

Based on these improvements and their attendant analyses, NW Natural has reached the following principal conclusions. While the Company discusses each conclusion, as with the changes, in more detail in the relevant chapter, below is a summary of findings.

Combining the impacts discussed above allows NW Natural to determine its resource position—how resource deficient or sufficient the Company is over the planning horizon—in order to establish the level of resource acquisitions necessary to reliably serve customers. As such, there are resource deficiencies in all scenarios NW Natural examined. As shown in figure 1.11, NW Natural's Base Case shows a resource deficiency of 30,000 Dth/day for the 2019–2020 winter, which grows to 270,000 Dth/day by 2035–2036. This resource deficiency is due to load growth, changes in peak day demand, and changes in the near-term resource stack while being partially offset by an increase in demand-side resources.

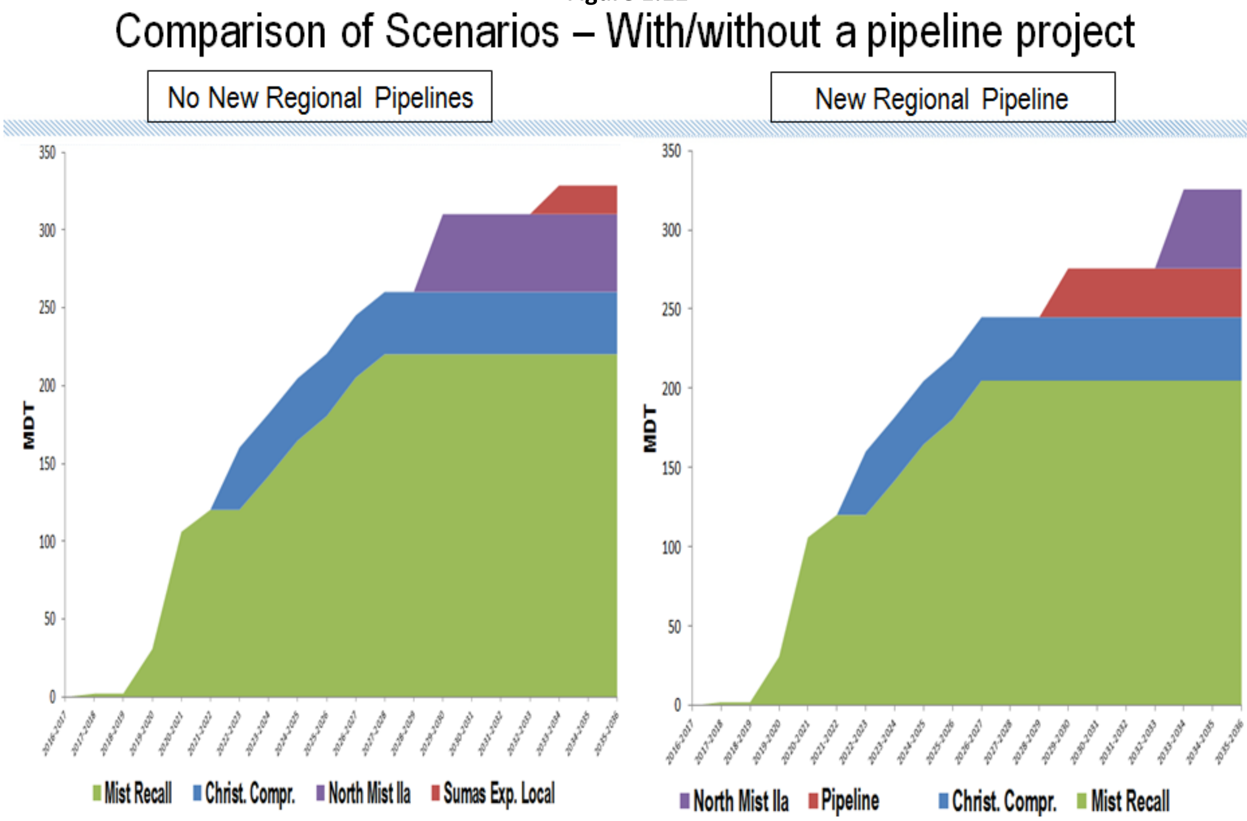
[26] Please see chapter 9, Stochastic Supply Resource Risk Analysis for more detailed information.

Figure 1.11



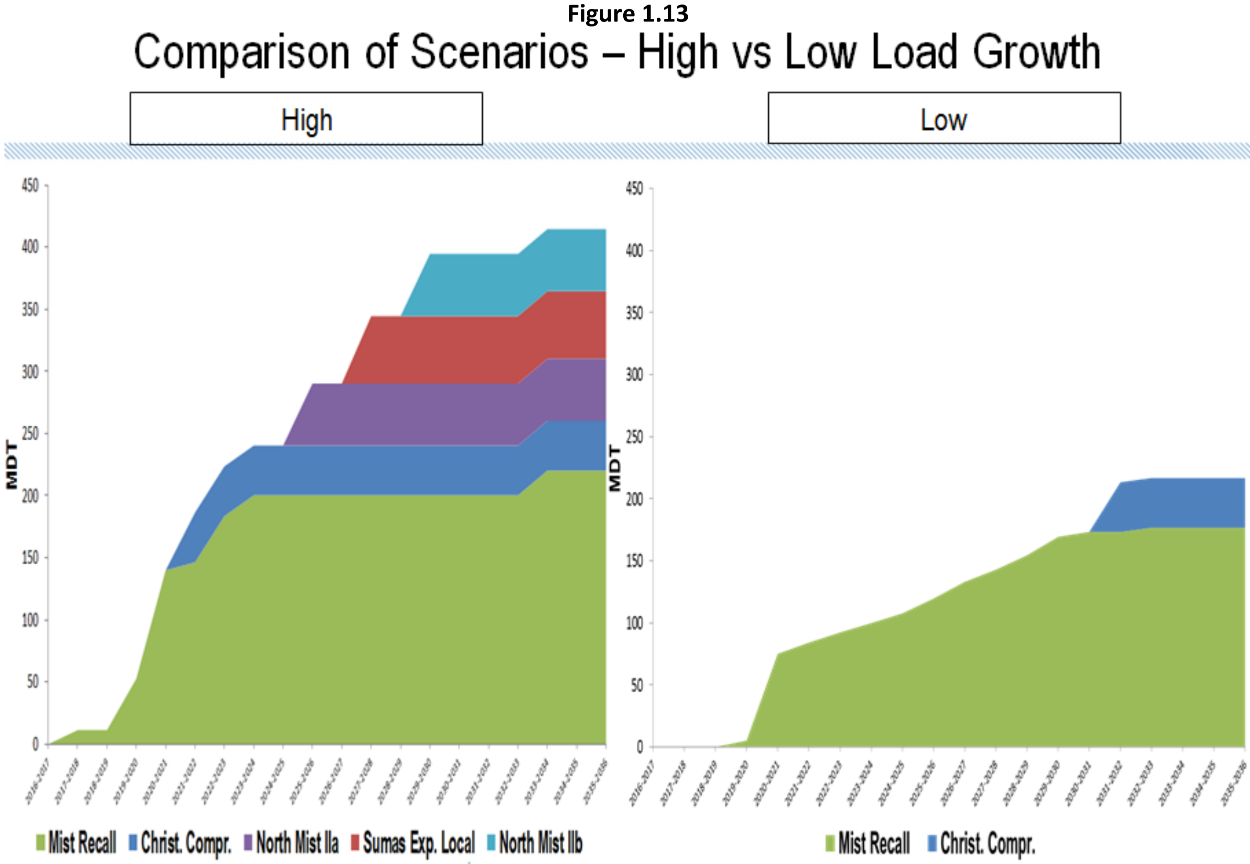
In all cases, NW Natural will use Mist Recall in the short- and medium-term but still requires additional resources over the planning horizon. Figure 1.12 shows what the least-cost portfolio would be both with and without the availability of a new regional pipeline. As can also be seen below and discussed in another principal conclusion, both scenarios, in addition to Mist Recall, select the Christensen Compressor and North Mist IIa as least-cost resources.

Figure 1.12



As mentioned previously, either with or without a new regional pipeline and with the exception of the low-growth scenario, the Christensen Compressor and North Mist IIa are part of the resource portfolios. Further, even in the low-growth scenario (as shown in figure 1.13), the Christensen Compressor is selected as a least-cost resource. In the Base Case scenario, the Christensen Compressor project is needed in the 2022 timeframe (figure 1.12).

Figure 1.13



Except in the low-growth scenario, there is a need for future pipeline capacity to meet future winter energy needs. However, there is still a high degree of uncertainty regarding proposed regional gas projects (such as methanol/feedstock plants and the Jordan Cove LNG export facility) and the prospective interstate pipelines needed to serve them (Trail West, Pacific Connector, or a regional expansion by Northwest Pipeline south from Sumas).

This uncertainty surrounding regional projects—which are beyond NW Natural's control—makes it difficult to select a specific long-term gas supply resource portfolio, as the optimal set of resource additions depends on which scenario unfolds. Additionally, the range of present values of revenue requirement (PVRR) for the various portfolios including prospective resources ranges from $5,275 million to $5.293 million highlighting that there is not much difference in the PVRR between the different prospective pipeline projects.

Mist is a valuable resource that provides customers with unique flexibility. As the Company becomes more reliant on Mist over the planning horizon, it becomes even more imperative that the facility operates as planned. To this end, and as part of NW Natural's other storage plant efforts, the Company commissioned an Asset Management Study for the long-term maintenance of Mist.

Deploying accelerated Demand-Side Management programs may be the least-cost incremental resource and may serve to either defer or possibly eliminate the need for gas distribution system enhancement projects in a timely manner. However, while theoretically sound, it is an unproven resource with respect to peak management. Further, the Company's load profile is getting "peakier" over time with numerous implications for resource planning and specifically for demand-side resources.

Therefore, the Company is working with Energy Trust of Oregon to scope and implement an accelerated demand-side management pilot project to be constrained to a limited geography and focused on peak hour load reductions. The objective of this pilot is to measure and quantify the potential of demand-side management to cost-effectively delay or avoid system enhancement projects. Further, the pilot will assist in providing process-related experience such as screening procedures for candidate areas, assessing the firmness of acquired peak DSM reductions, establishing the timeframes necessary for achieving specific levels of reductions, as well as many other aspects. For additional information on this pilot, please refer to chapter 6, Demand-Side Resources.

NW Natural expects implementation of incremental environmental regulation at the state level. In Washington, Governor Inslee directed the Department of Ecology to adopt a rule that limits greenhouse gas (GHG) emissions. Ecology is expected to have a final rule out in the fall of 2016, with compliance beginning January 2017.

In Oregon, the legislature passed SB 1547, also known as the Oregon Clean Electricity and Coal Transition Bill. While this legislation does not directly impact NW Natural, it is indicative of legislative movement on this front. To assist in understanding the impact of potential future legislation, the Company modeled various levels of carbon prices ranging from $0 to just under $90 per metric ton of carbon dioxide equivalent ($MTCO_2e$).

Aided by favorable regulatory support, NW Natural's overall annual methane emissions in 2013 were approximately 90 percent lower than EPA's factors.[27] Further, in March 2016, the Company joined the U.S. EPA Natural Gas Star Methane Challenge. This voluntary program encourages participants to adopt best practices by sector for reducing methane emissions. As a continuation of NW Natural's efforts to reduce methane emissions and recognizing that most emissions associated with the natural gas system occur upstream of distribution, with the majority occurring in production and transmission, the Company is in the early phases of designing a pilot program with the objective of reducing upstream methane emissions.

The 2014 IRP identified the South Salem Feeder as a project needed to serve the Salem load center. The action plan called for the Company to perform additional analysis prior to moving beyond the pre-construction phase of the project. In addition to the methodology and modeling improvements mentioned above, NW Natural disaggregated the Salem load center into four distinct load centers in order to better understand the complexities of this load center. Additionally, and as discussed further in chapter 3, the Company studied alternatives and consulted with Northwest Pipeline to gain additional flexibility on how it applied the maximum daily delivery obligations (MDDOs) in serving the Salem load centers. As a result, the South Salem Feeder project is no longer necessary.

[27] Calculation based on 2013 emissions as reported using EPA Subpart W emission factors from the EPA's GHGRP compared to 2013 emissions as calculated using the updated emission factors developed from the study, *Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States.*

4. MULTIYEAR ACTION PLAN

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

4.1. Joint Multiyear Action Plan

Resource investments:

1. Plan to recall 30,000 Dth/day of Mist storage capacity from the interstate storage account effective May 2019 to serve the core customer needs, subject to a review based on an update of the annual load forecast in the summer of 2018.
2. Replace or repair, depending on relative cost-effectiveness, the large dehydrator at Mist's Miller Station. Replacement is currently estimated to cost between $6 million and $7 million based on estimates obtained from a third-party engineering consulting firm engaged by NW Natural. NW Natural will evaluate alternatives associated with the Al's Pool and Miller Station small dehydrator systems at Mist to determine if and when additional actions are warranted.
3. Proceed with the SE Eugene Reinforcement project to be in service for the 2018/2019 heating season and at a preliminary estimated cost of $4 million to $6 million.

Demand-side resources and environmental actions:

1. Consistent with methodology in chapter 6, NW Natural will ensure Energy Trust has sufficient funding to acquire therm savings of 5.1 million therms in 2017 and 5 million therms in 2018 or the amount identified and approved by the Energy Trust board.
2. Work with Energy Trust of Oregon to further scope a geographically targeted DSM pilot via accelerated and/or enhanced offerings ("Targeted DSM"pilot) to measure and quantify the potential of demand-side resources to cost-effectively avoid/delay gas distribution system reinforcement projects in a timely manner and make a Targeted DSM pilot filing with the Oregon Public Utility Commission (OPUC) in late 2017 or early 2018.
3. Work with Energy Trust of Oregon to track peak day savings from DSM programs in addition to the typical Energy Trust metric of total annual savings to better understand if the capacity costs projected to be avoided with peak day savings in the DSM savings projection are being saved.
4. Investigate the viability of developing a pilot project to reduce upstream emissions of methane and, if viable, NW Natural will bring this pilot forward for Commission review and approval. The pilot design would test whether reductions can be achieved at a level consistent with the Base Case carbon values incorporated into the IRP and the range of costs for a larger scale effort. If it is determined that the cost to move the market exceeds the carbon values in the IRP, the Company may alternatively consider advancing the work as a project proposal under SB 844.

4.2. Washington-Only Multiyear Action Plan

Washington resources and investigations:

1. Consistent with methodology in chapter 6, NW Natural will ensure Energy Trust has sufficient funding to acquire therm savings of 262,000 therms in 2017 and 270,000 therms in 2018 or the amount agreed to by the Energy Efficiency Advisory Group and approved by the Washington Utilities and Transportation Commission (WUTC).
2. Complete construction of the Clark County distribution projects to address Vancouver load center needs – estimated timing of projects is over the next three years with an estimated cost of $21 million.
3. Comply, as required, with Ecology’s final Clear Air rules, which may include the purchasing of allowances and/or investing in carbon reducing projects located in Washington.

Chapter 2
Gas Requirements Forecast

1. OVERVIEW OF GAS REQUIREMENTS

Chapter 2 provides a brief look at the following: the local economy within NW Natural's service area; certain relevant forecasts; historical and forecasted natural gas prices; and methodologies used in developing gas requirements for the 2016 IRP. These methodologies include those associated with customer forecasts, including alternative forecasts; the industrial load forecast; the emerging markets load forecast; the system-level peak day forecast; the deliverability/distribution peak hour forecast; and the annual energy forecast.

Many of the methodologies used represent a departure from those used in prior NW Natural IRPs. The Company discussed most of these changes in Technical Working Group meetings with stakeholders in the course of developing the 2016 IRP.

2. REGIONAL ECONOMY

The economy of NW Natural's service area is, by some measures and on the whole, now fully recovered from the recession of the late 2000s. Figure 2.1 shows employment[1] indices for certain geographies related to NW Natural's service area.

Other measures, such as housing starts, have yet to fully recover to levels experienced prior to the housing bubble of the last decade.

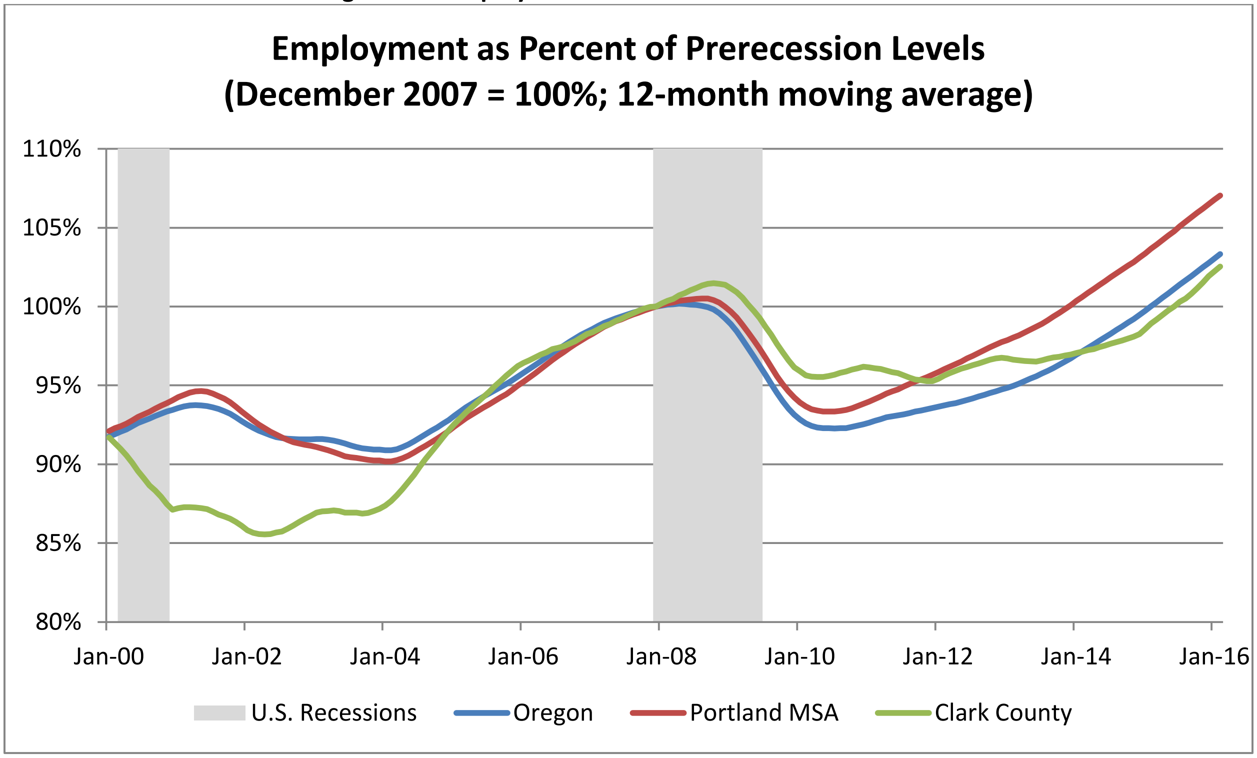
KEY FINDINGS

Key findings in this chapter include the following:

- Relatively slow regional economic growth will continue, with improvements in both Oregon housing starts and employment.
- Forecasted Henry Hub natural gas monthly prices in real terms will increase over the planning horizon from recent levels. Monthly prices at trading hubs where NW Natural procures gas supplies are forecast to almost double in real terms over the planning horizon from recent levels of approximately $2 per Dth to almost $4 by the end of the period.
- Lower than in the 2014 IRP, aggregate Residential and Commercial Firm Sales customer growth averages 1.6 percent annually over the 2016–2035 planning horizon in the Base Case forecast, with Oregon's rate averaging 1.5 percent and Washington's rate averaging 2.6 percent.
- Alternative Firm Sales customer growth scenarios have average annual rates of 2.1 percent in the High-growth scenario and 1.2 percent in the Low-growth scenario.
- Emerging Markets' Firm service load requirements over the planning horizon are small relative to total requirements and Firm Sales requirements are extremely small.
- Firm Sales design day peak demand in the 2016 IRP is, versus the 2014 IRP, up slightly in the near-term and lower in the later years of the planning horizon.
- Annual Firm Sales energy use grows at annual rates over the planning horizon of 0.6 percent in Oregon; 1.5 percent in Washington; and 0.7 percent for NW Natural.
- NW Natural's load is peaky and becoming more so over time.

[1] Employment is nonfarm employment for Oregon and the Portland MSA and total employment for Clark County. Values underlying 12-month moving averages are not seasonally adjusted. Source for Oregon and Portland MSA employment is the Federal Reserve and, for Clark County, the Washington Employment Security Department. Dates of U.S. recessions are from the National Bureau of Economic Research (NBER).

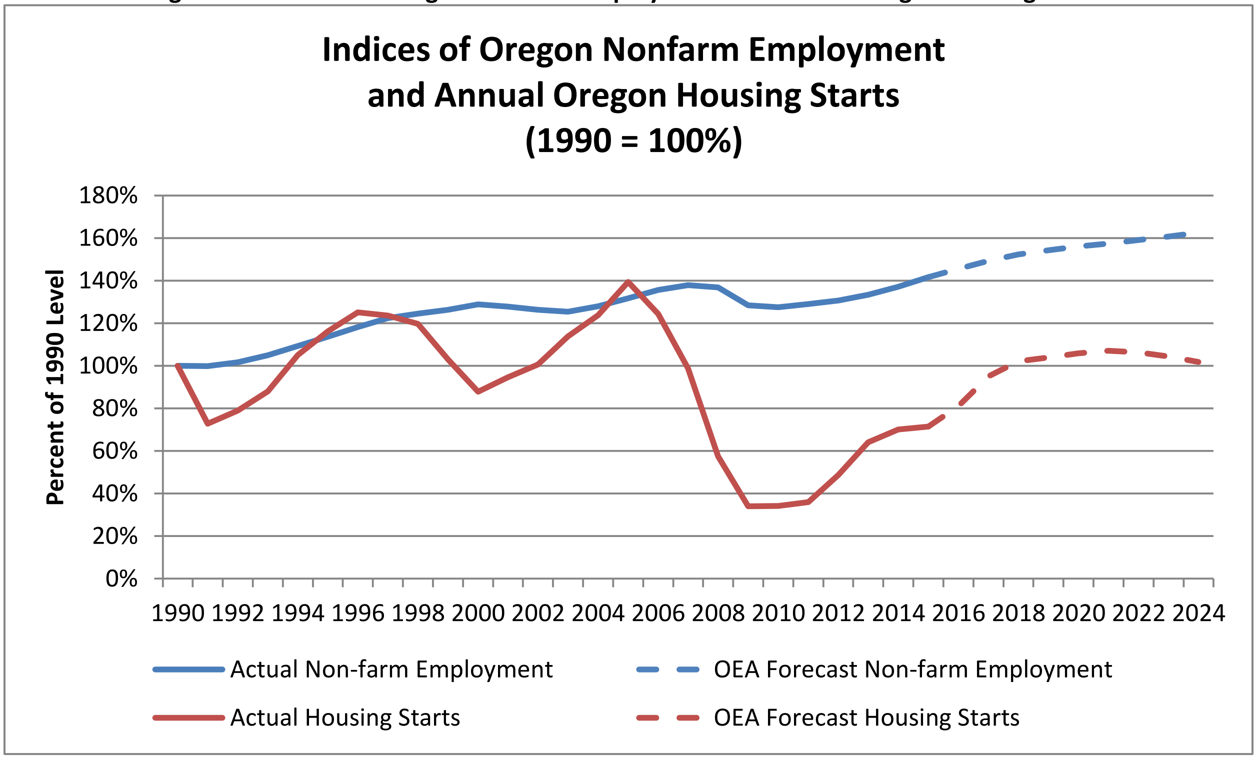
Figure 2.1: Employment Relative to Prerecession Levels



Oregon's Office of Economic Analysis (OEA) forecasts Oregon's employment and housing starts to continue improving over the near to medium term. Figure 2.2 shows actual and forecast values[2] of Oregon nonfarm employment and Oregon housing starts, with each series indexed to its respective 1990 level.

[2] Source is OEA's March 2016 forecast, accessed April 6, 2016 at http://www.oregon.gov/das/OEA/Pages/forecastecorev.aspx .

Figure 2.2: Indices of Oregon Nonfarm Employment and Annual Oregon Housing Starts



3. NATURAL GAS PRICES

NW Natural uses planning horizon forecasts of natural gas prices by trading hub in developing the Company's IRP. These forecasts include monthly price forecasts for Henry Hub, Rockies (using the Opal trading hub), British Columbia (Sumas), and Alberta (Alberta Energy Company, or AECO). Like many commodities, volatility in natural gas prices makes forecasting prices highly uncertain. NW Natural expects future gas prices will be influenced by numerous factors, including economic conditions, demand, increasing use of natural gas to fuel power generation, potential national or regional carbon policies,[3, 4] weather, and new and traditional supplies—such as gas produced using more efficient extraction technologies. The Company reviews several price forecasts and has developed a Base Case gas price forecast as well as high and low price outlooks to represent reasonable ranges of future prices for the trading hubs from which the Company purchases gas supplies.

[3] See Chapter 4 Energy Policies and Environmental Considerations regarding policies related to emissions of greenhouse gases and specifically to emissions of carbon dioxide produced by combustion of fossil fuels. NW Natural is unable to quantify the impact on natural gas prices of new national or regional environmental policies until details of such policies are known.

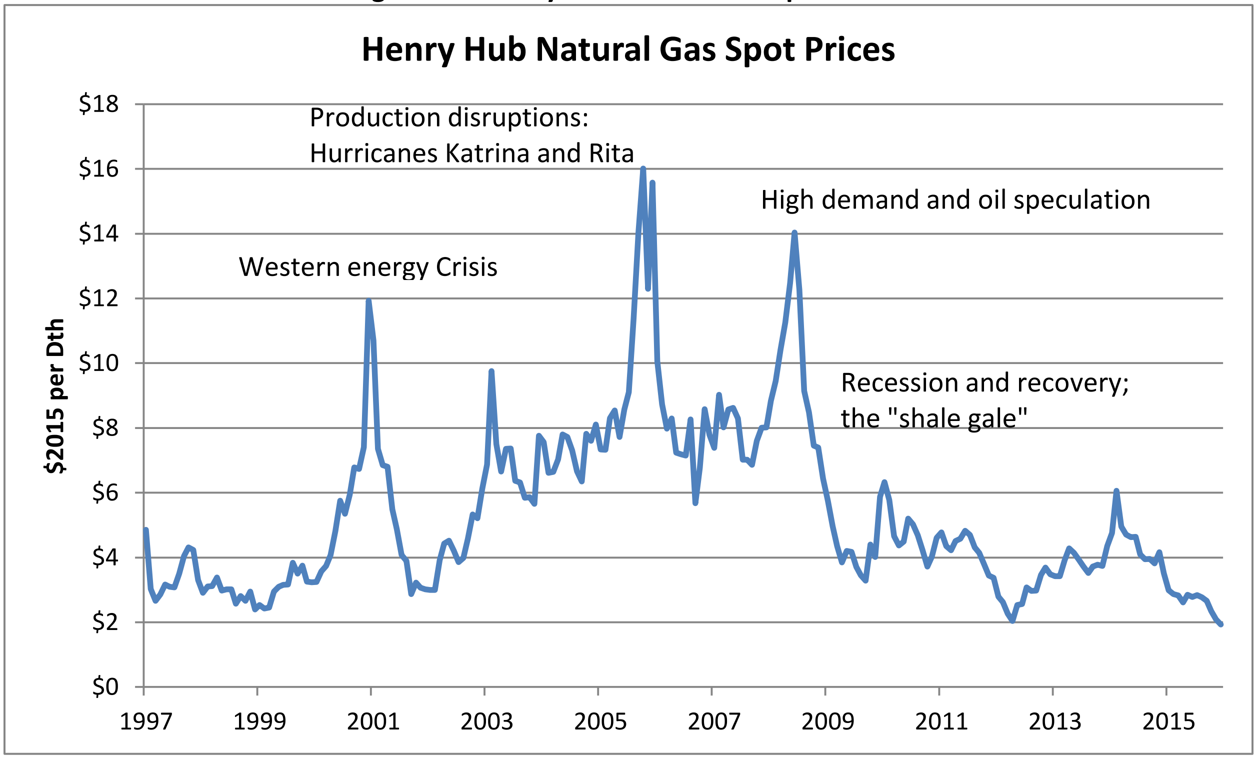
[4] The Base Case natural gas price forecast includes an estimated impact of future regulations of carbon dioxide (CO_2) emissions beginning in 2021. See Chapter 4 for a discussion of alternative carbon prices.

3.1. Historical Prices, Price Volatility, and U.S. Reserves

The combination of lower demand and increased supplies has resulted in generally lower spot prices in the current decade versus the prior decade. Improved drilling technologies have tremendously increased the potential supply of "unconventional" gas from shale deposits throughout North America. The relatively slow U.S. economic expansion since the 2007–2009 recession continues to suppress growth in demand for natural gas.

Figure 2.3 shows the history of monthly natural gas prices since 1997. Monthly average spot prices at Henry Hub, the reference pricing point for the North American natural gas market, exceeded $12 per Dth[5] as recently as June 2008. The Western energy crisis in 2000–2001 spiked prices over $8 per Dth and hurricanes Katrina and Rita drove prices over $13 per Dth in late 2005.[6]

Figure 2.3: Henry Hub Natural Gas Spot Prices



Lower commodity prices have allowed NW Natural to reduce customer rates. The Public Utility Commission of Oregon approved NW Natural's request for a 6.7 percent reduction in Oregon Residential

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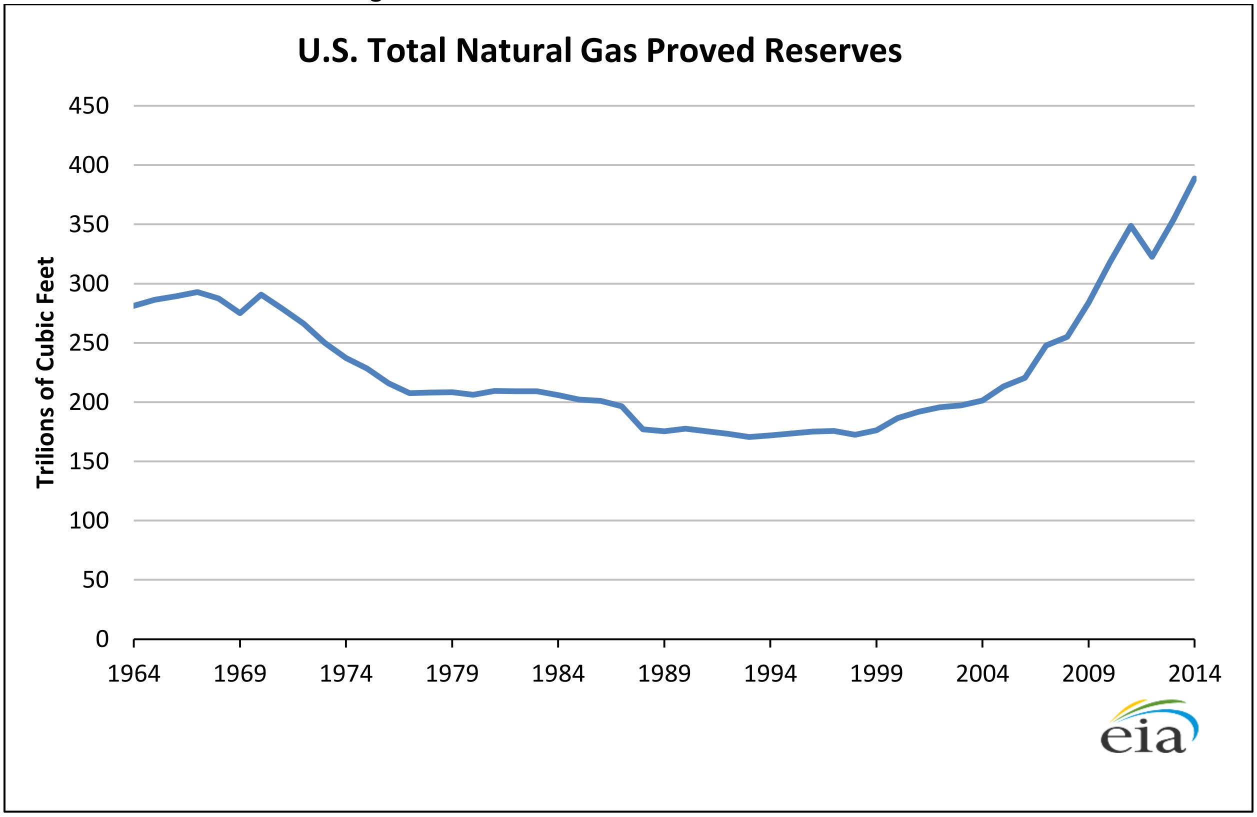
5 One Dth, or dekatherm, equals 10 therms.

6 NW Natural, in figure 2.3, identifies a portion of the late 2000s as a period characterized in part by "high demand and oil speculation." Regarding the latter characterization, see the discussion in "When Oil Prices Jump, Is Speculation To Blame?" by Farley, et al, in the April 2012 issue of *The Regional Economist* published by the Federal Reserve Bank of St. Louis (accessed July 28, 2016 at https://www.stlouisfed.org/~/media/Files/PDFs/publications/pub_assets/pdf/re/2012/b/oil_prices.pdf).

rates in October 2015. In the same month, the Washington Utilities and Transportation Commission approved the Company's request for a 14.4 percent reduction in residential rates. NW Natural customers are now paying less for gas than they did 15 years ago.[7]

According to the U.S. Energy Information Administration (EIA), the estimated total U.S. proved natural gas reserves increased again in 2014, as shown in figure 2.4.[8] EIA's estimated proved natural gas reserves have declined year-over-year only twice since 1994.

Figure 2.4: U.S. Total Natural Gas Proved Reserves



3.2. Natural Gas Price Forecast

NW Natural's 2016 IRP natural gas price forecast is of monthly prices developed by third-party provider IHS Inc., and is based on market fundamentals.[9] NW Natural includes the price forecast in the

[7] See NW Natural's website at https://www.nwnatural.com/aboutnwnatural/ratesandregulations/gaspriceinformation; accessed April 6, 2016.

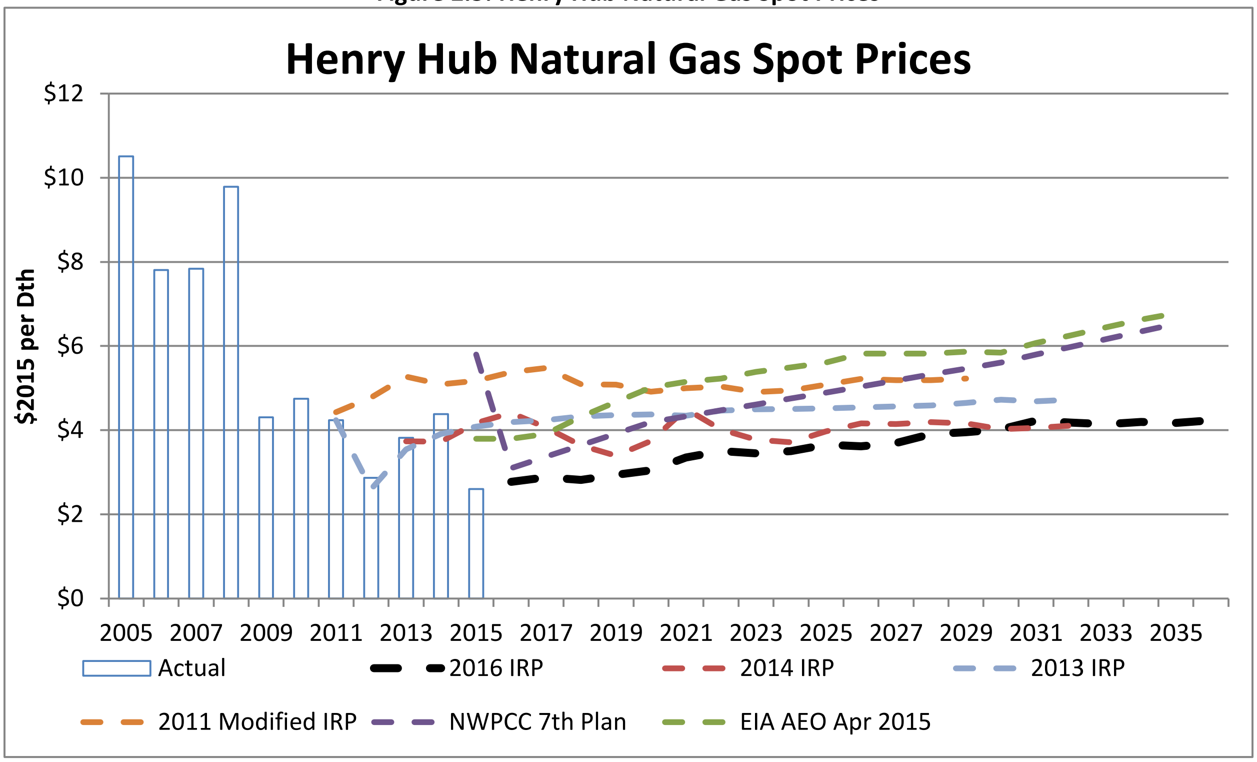
[8] See EIA's U.S. Crude Oil and Natural Gas Proved Reserves, released Nov. 23, 2015 (accessed April 6, 2016 at http://www.eia.gov/naturalgas/crudeoilreserves/). EIA defines proved reserves as the volumes of hydrocarbon resources recoverable under existing economic and operating conditions.

[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

Company's SENDOUT® resource planning modeling software, which is used for analyzing and developing the optimal plan[10] for purchasing and transporting natural gas to the Company's customers. Additionally, future natural gas prices impact avoided cost calculations and thereby the level of predicted Energy Trust of Oregon (ETO) demand-side management energy-efficiency (DSM/EE) savings. Figure 2.5 displays the Henry Hub historical spot prices for 2005–2015, the 2016 IRP price forecast, and the following additional natural gas price forecasts:[11]

1. 2014 IRP
2. 2013 Washington IRP (2013 IRP)
3. 2011 Modified IRP
4. Northwest Power and Conservation Council's Seventh Plan (NWPCC 7th Plan)
5. U.S Energy Information Administration's 2015 Annual Energy Outlook (EIA AEO Apr 2015)

Figure 2.5: Henry Hub Natural Gas Spot Prices



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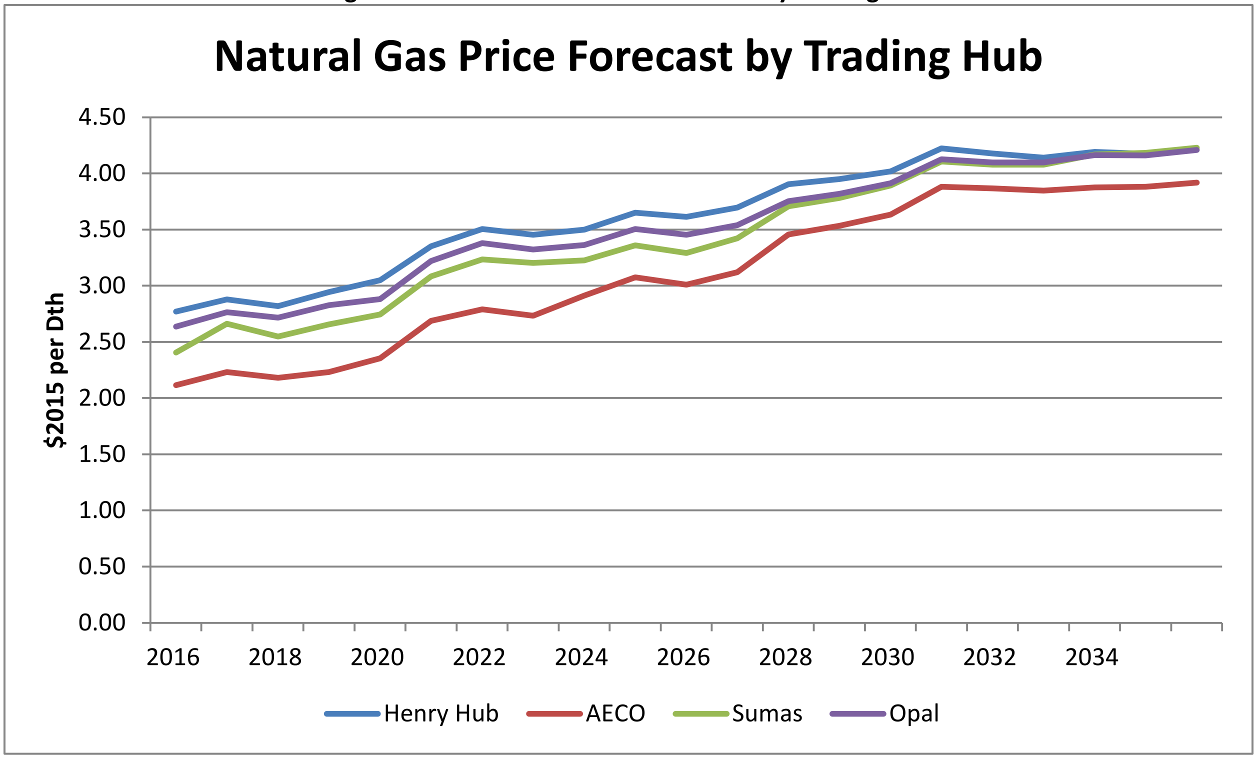
[10] An "optimal plan" is understood in this context to be a part of the larger resource solution that provides the "best mix of cost and risk" in conforming to the Public Utility Commission of Oregon's IRP Guideline 1c. By "optimal," NW Natural means "best or most effective;" with this definition appearing in the online Merriam-Webster at http://www.merriam-webster.com/dictionary/optimal (accessed April 1, 2016). See chapter 8.

[11] Note that the 2016 IRP gas price forecast is a more recent forecast than each of the alternative forecasts. Only the 2016 IRP forecast was compiled after historical price data for several months of 2015 was available. Also note that each forecast may incorporate different assumptions regarding inflation.

NW Natural obtains natural gas from three major supply regions: British Columbia, Alberta, and the U.S. Rockies.[12] Figure 2.6 shows the 2016 IRP price forecast for Henry Hub and representative trading hubs in each region: British Columbia (Sumas), Alberta (AECO), and U.S. Rockies (Opal).

Figure 2.6: Natural Gas Price Forecast[13] by Trading Hub



4. OVERVIEW OF LOAD FORECAST METHODOLOGY

NW Natural's 2016 IRP includes three distinct load forecasts: a system-level peak day usage forecast, a deliverability/distribution peak hour forecast, and an annual energy forecast.

Load forecasts represent the starting point for developing NW Natural's IRP. They represent 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 Firm Sales demand on NW Natural's system, and total gas requirements are therefore weather dependent. Consequently, it is important to develop a design year load forecast which includes a very cold coincident design ("peak") day event. In this way, NW Natural ensures developing a resource plan capable of reliably serving customers under

[12] See chapter 3 for discussions regarding gas supplies and NW Natural's gas procurement policies.

[13] Source: IHS Inc. This content is extracted from IHS Energy North America Natural Gas service and was developed as part of an ongoing subscription service. No part of this content was developed for or is meant to reflect a specific endorsement of a policy or regulatory outcome. The use of this content was approved in advance by IHS. Any further use or redistribution of this content is strictly prohibited without written permission by IHS. Copyright 2013, all rights reserved.

a variety of circumstances, including extremely cold weather. The annual energy forecast is also used in estimating the total amount of energy savings available in the Company's service territory through energy-efficiency programs administered by ETO.

NW Natural provides resource adequacy—upstream pipeline capacity, storage capacity, and the gas commodity itself—for its Firm Sales customers. While Firm Transportation customers provide for their own upstream resource needs, the Company provides distribution services for these customers. NW Natural considers the load requirements of Interruptible Sales customers only with respect to commodity requirements for nonpeak 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 2016 IRP does not consider the loads of Interruptible Transportation customers.

NW Natural bases its load forecasts on 15 load centers: Albany, Astoria, Coos Bay, Eugene, Newport/Lincoln City, three Portland metropolitan area load centers (West, Central, and East), four Salem load centers[14] (currently identified as Salem A, B, C, and D), The Dalles (Oregon), The Dalles (Washington), and Vancouver. This disaggregation of NW Natural's system more closely matches system demands and flows than does the 12-load-center configuration used in the 2014 IRP.

Individual load centers differ by customer composition, rates of customer growth, usage patterns, weather, and resource availability. These 15 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.

4.1. Preparing NW Natural Load Forecasts

NW Natural performs multiple discrete activities in developing the Company's load forecasts for the 2016 IRP. The Company prepares a 20-year estimate of Residential and Commercial customers by load center and customer category at a monthly frequency. The Company separately develops forecasts of Industrial loads and Emerging Market loads. NW Natural describes these activities and their results in the next three sections of chapter 2. The Company uses these forecasts in both the peak load forecasts and the annual energy load forecasts.

NW Natural's 2016 IRP incorporates multiple enhancements in developing the Company's peak usage forecasts. The next section of chapter 2 describes these enhancements, including the peak day weather standard NW Natural uses in the 2016 IRP, the system-level use per customer model, the peak day Firm Sales load forecast, the load resource balance, and the deliverability/distribution peak hour forecast.

The Company follows this with a discussion of its annual energy forecast. Appendix 2 contains detailed information on the different components of the load forecast and models used in its development.

[14] NW Natural disaggregated the Salem load center used in the 2014 IRP into four load centers in order to more accurately model complex interactions between resources and loads in the larger Salem area.

5. CUSTOMER FORECASTS

Customer forecasts[15, 16] are 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 to forecast changes in the number of customers on a monthly basis over the 20-year planning horizon. Cumulative net customer changes for the Residential and Commercial customer classes are added to a historical actual count of customers by class to arrive at the forecast of future customers. Table 2.1 lists the categories of customer change 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 2015.[17] Table 2.2 includes the identifier used for individual load centers in some figures in chapter 2.[18] Table 2.2 aggregates values for the three Portland (POR) load centers of Portland Central (PORC), Portland East (PORE), and Portland West (PORW) and for the four Salem (SAL) load centers.

Table 2.1: Categories of Customer Change

Residential New Construction
Residential Conversion
Residential Losses
Commercial New Construction
Commercial Conversion
Commercial Losses

NW Natural forecasts numbers of customers for each combination of load center and customer category for a total of 105 discrete components of the customer forecasts. New Construction and Conversion categories reflect customer growth as new customers are added. NW Natural forecasts decline over the forecast horizon in the number of existing Residential and Commercial customers as of the beginning of the forecast period as customer losses occur from initial levels. The forecast methodology involves blending near- and long-term economic outlooks. The information sources and methods NW Natural uses to produce the Company's customer forecasts differ by category of customer change.

[15] 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 citygate to a Firm Transport customer's service address.

[16] 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 use per customer. A description of the process of forecasting these loads appears later in this chapter.

[17] As NW Natural developed the Residential and Commercial customer forecasts in the second half of 2015, the latest year of actual values available were those of 2014.

[18] Some figures in appendix 2 also make use of these identifiers.

Table 2.2: 2015 Residential and Commercial Customers by Load Center[19]

Load Center	Identifier	Residential	Residential Percentage of System Total	Commercial	Commercial Percentage of System Total
Albany	ALB	36,777	5.7%	4,134	6.2%
Astoria	AST	11,247	1.7%	1,692	2.5%
Coos Bay	COOS	1,270	0.2%	356	0.5%
Eugene	EUG	35,054	5.4%	5,371	8.1%
Lincoln City	LC	9,205	1.4%	1,251	1.9%
Portland	POR	395,297	61.1%	37,307	56.0%
Salem	SAL	82,718	12.8%	8,980	13.5%
The Dalles (OR)	DALO	4,681	0.7%	1,124	1.7%
The Dalles (WA)	DALW	1,773	0.3%	215	0.3%
Vancouver	VAN	68,819	10.6%	6,154	9.2%
Total		646,841	100.0%	66,584	100.0%

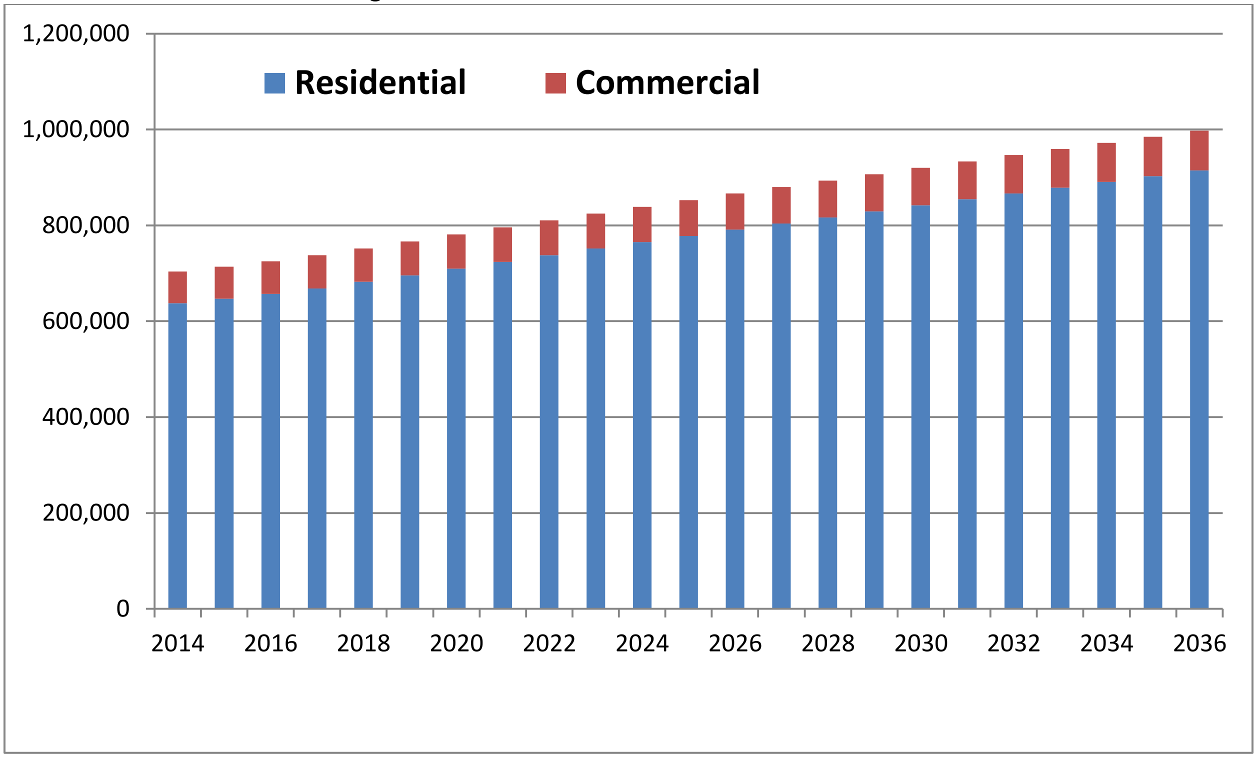
NW Natural uses two separate processes in developing the Company's Residential and Commercial customer forecasts. NW Natural uses an internal subject matter expert (SME) panel for forecasting 2015 and 2016 customer changes and develops econometric forecasts that are used for 2018 forward. Forecasts for 2017 average the 2017 customer forecasts resulting from each approach.

The SME panel members analyze and incorporate into the customer forecast information from multiple internal and external sources, including trends, employment information, economic indices, real estate information, inventories, building and permitting activity, various incentives, and internal programs. Descriptions of the econometric forecasts follow, while charts including customer forecasts incorporate the impact of the SME panel forecasts, unless specified otherwise.

Figure 2.7 shows Residential and Commercial customers on a system basis; i.e., including customer counts for both Oregon and Washington. Values for 2014 are actual results, while values for 2015 forward are forecast.

[19] The December 2015 customer values in table 2.2 are actual values, while numbers of customers for 2015 appearing elsewhere in this chapter are forecast values. As a result of the timing for developing the load forecast, the first year of the forecast period in this IRP is 2015. However, note that reference to a 20-year planning horizon (or similar) does not include calendar year 2015; i.e., the planning horizon is 2016 through 2035.

Figure 2.7: Residential and Commercial Customers



5.1. Residential Customer Forecast

NW Natural forecasts the three components of Residential customer changes in table 2.1: New Construction, Conversions, and Losses. See Appendix 2 for additional information regarding NW Natural's Residential customer forecasts.

Residential New Construction Customer Additions

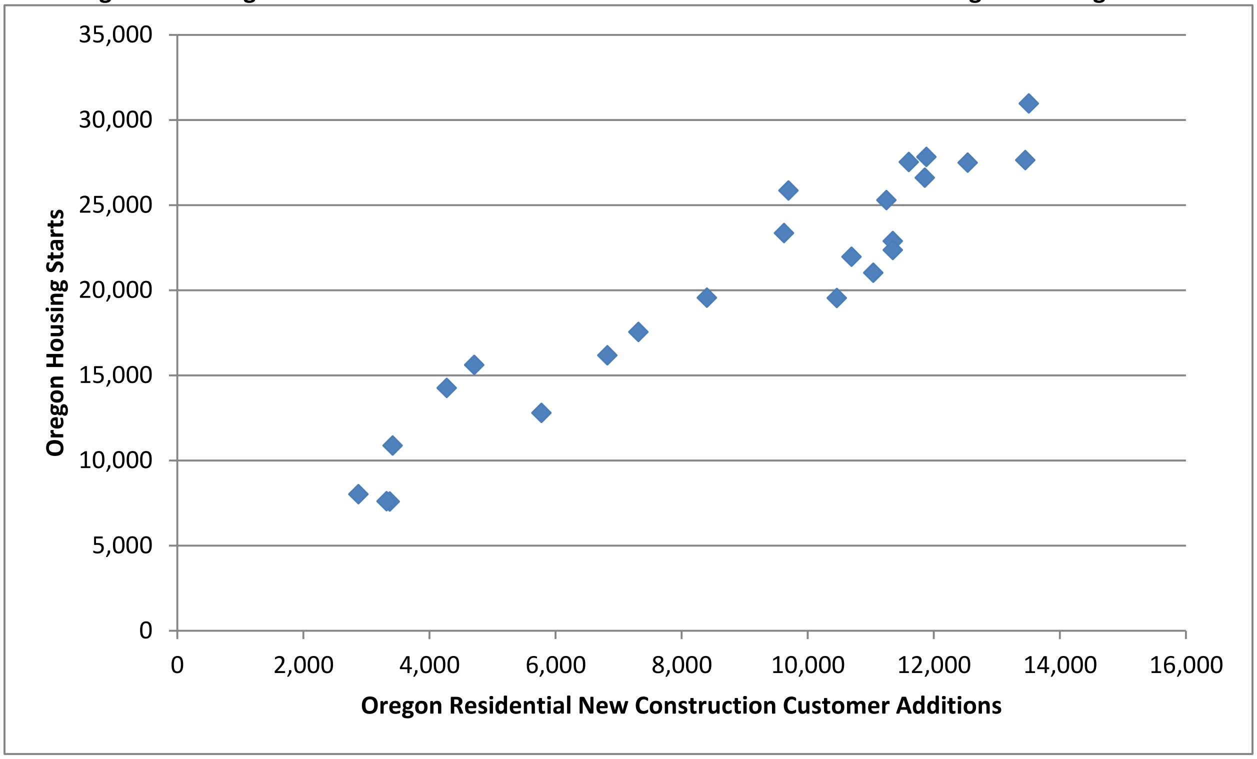
NW Natural's Oregon Residential new construction customer additions have historically had a strong relationship with the level of Oregon housing starts,[20] as shown in figure 2.8.

NW Natural's econometric forecast of Oregon Residential new construction customer additions uses OEA's September 2015 forecast of Oregon housing starts[21] as the primary explanatory variable.

[20] The correlation over the period 1991–2014 using annual data is 0.95.

[21] Housing starts represent units of housing; e.g. OEA's forecast of housing starts would include the start of construction of an apartment structure with 40 apartments as 40 housing starts. OEA notes that the agency uses a methodology for translating residential building permits into housing starts at https://oregoneconomicanalysis.com/2012/10/17/checking-in-on-oregon-housing-starts/ (accessed Aug. 2, 2016). Also see related information at the U.S. Bureau of the Census' website at http://www.census.gov/construction/nrc/index.html (accessed Aug. 2, 2016) and OEA's website at http://www.oregon.gov/das/OEA/Documents/economic_methodology_dec2010.pdf (accessed Aug. 2, 2016).

Figure 2.8: Oregon Residential New Construction Customer Additions versus Oregon Housing Starts



Forecasts of housing starts at lower than the state level (e.g., at the county level) were not available to NW Natural for use in developing the 2016 IRP load forecast. As the time horizon of OEA's September 2015 forecast of Oregon housing starts was through 2024, NW Natural projected the annual average rate of change in Oregon population increases[22] over the period 2025–2035 onto the level of 2024 housing starts forecast by OEA to derive a forecast of housing starts for the 2025–2035 timeframe. Figure 2.9 shows the levels of Oregon Residential new construction customer additions on an actual basis and as predicted by the econometric model. Figure 2.10 shows actual and forecast values for both Oregon housing starts[23] and NW Natural's Oregon Residential new construction customer additions.

[22] The 2015 Regional Projections from Woods and Poole Economics, Inc. is the source of the underlying forecast of Oregon's population. NW Natural uses a three-year moving average of annual population increases as the basis for calculating the average annual rate of change in Oregon population increases.

[23] Note that forecasted levels of Oregon housing starts decline over the period 2025–2035, as shown in figure 2.10, as the annual average rate of change in Oregon's population increases is negative. While Woods and Poole forecast Oregon's population to grow over the 2025–2035 timeframe, their forecast includes that levels of year-over-year population growth will decline over this timeframe.

Figure 2.9: Oregon Residential New Construction Customer Additions: Actual and Predicted

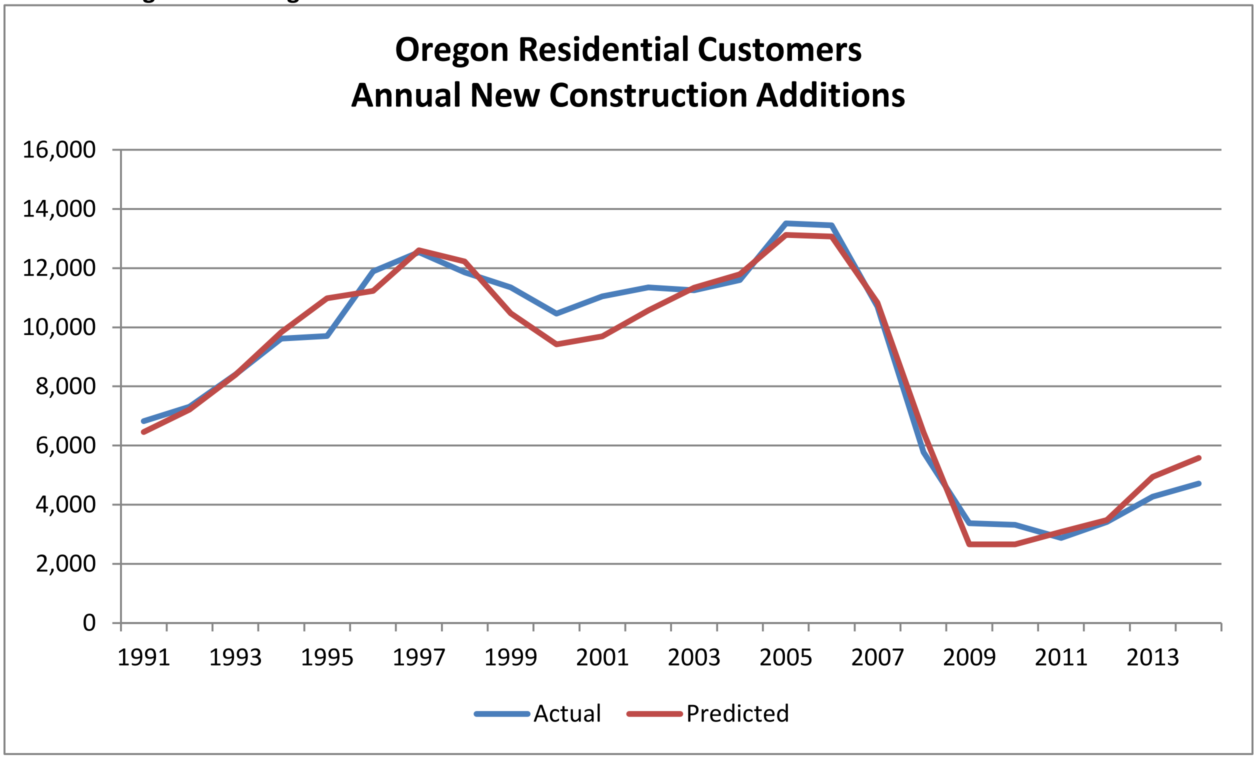
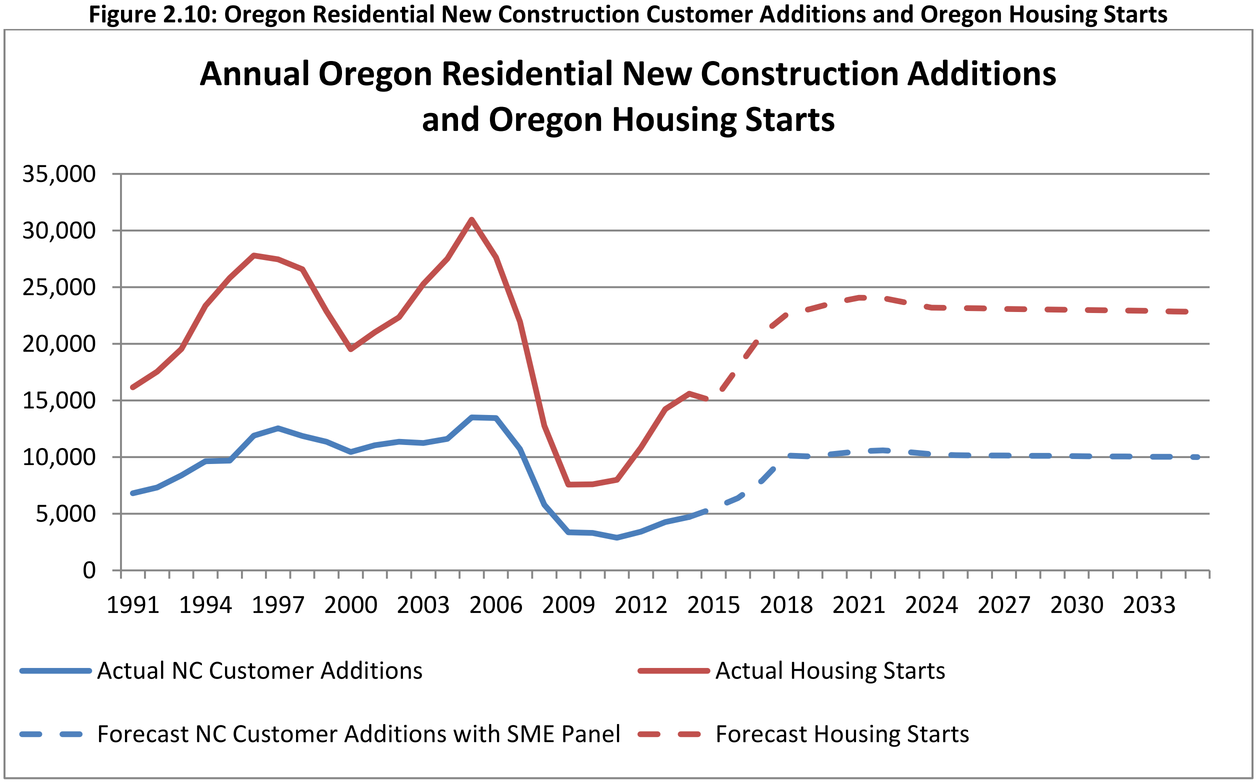


Figure 2.10: Oregon Residential New Construction Customer Additions and Oregon Housing Starts



NW Natural's econometric forecast of Washington Residential new construction customer additions also uses Oregon housing starts as the primary explanatory variable. The Company investigated the use of other explanatory variables for Washington Residential new construction customer additions, including demographic variables such as changes in the aggregate number of households for the three Washington counties in which NW Natural provides service. This investigation established Oregon housing starts[24] as the preferred explanatory variable for forecasting NW Natural's Washington Residential new construction customer additions.[25, 26]

Figure 2.11 shows the historical relationship of NW Natural's Washington Residential new construction customer additions and Oregon housing starts and figure 2.12 shows Washington Residential new construction customer additions on an actual basis and as predicted by the econometric model. Figure 2.13 shows actual and forecast values for NW Natural's Washington Residential new construction customer additions.

[24] NW Natural uses the same forecast of Oregon housing starts to forecast Washington Residential new construction customer additions the Company uses for Oregon.

[25] The correlation between NW Natural's Washington Residential new construction customer additions and Oregon housing starts over the period 1991–2014 using annual data is 0.92.

[26] Washington's Economic and Revenue Forecast Council (ERFC) distributes a forecast which includes statewide housing units authorized by building permits. While ERFC's August 2015 forecast limits the forecast horizon for Washington's residential building permits to the years 2015–2019, the forecast horizon of Oregon OEA's September 2015 forecast of Oregon housing starts extends an additional five years, covering the period 2015–2024.

Figure 2.11: Washington Residential New Construction Customer Additions versus Oregon Housing Starts

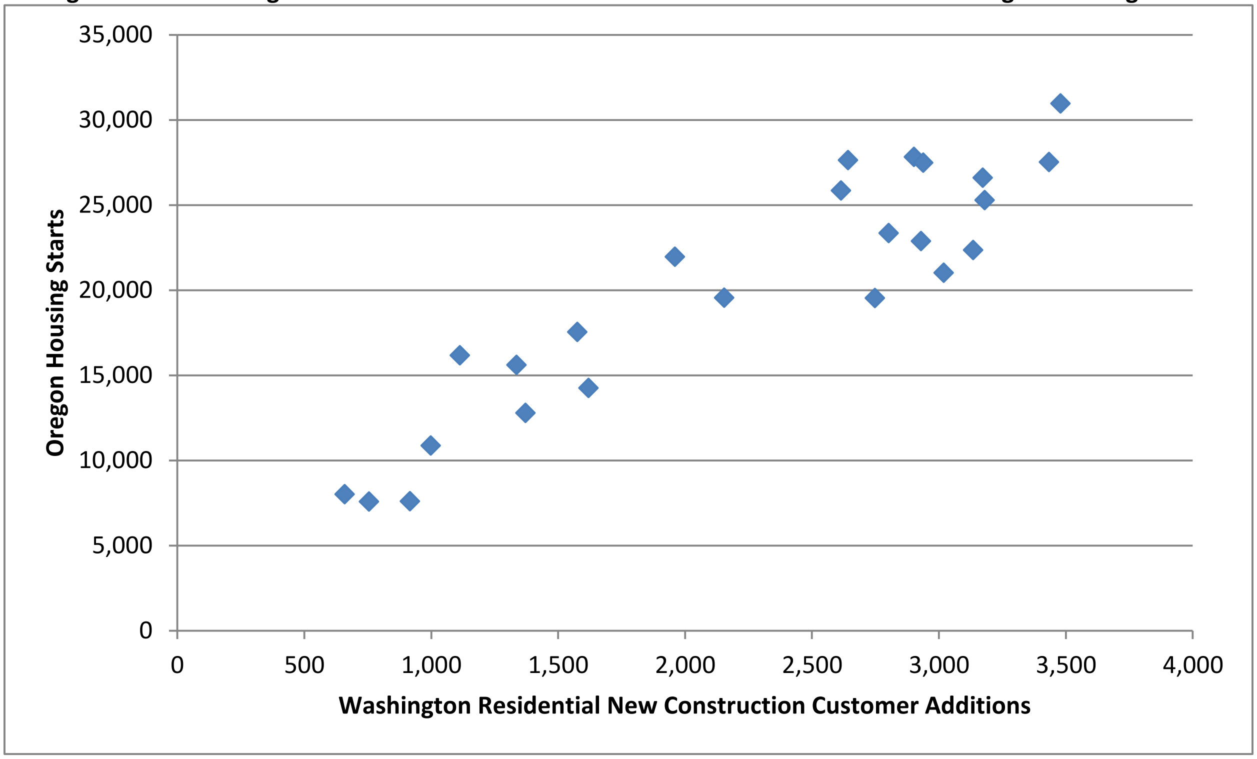


Figure 2.12: Washington Residential New Construction Customer Additions: Actual and Predicted

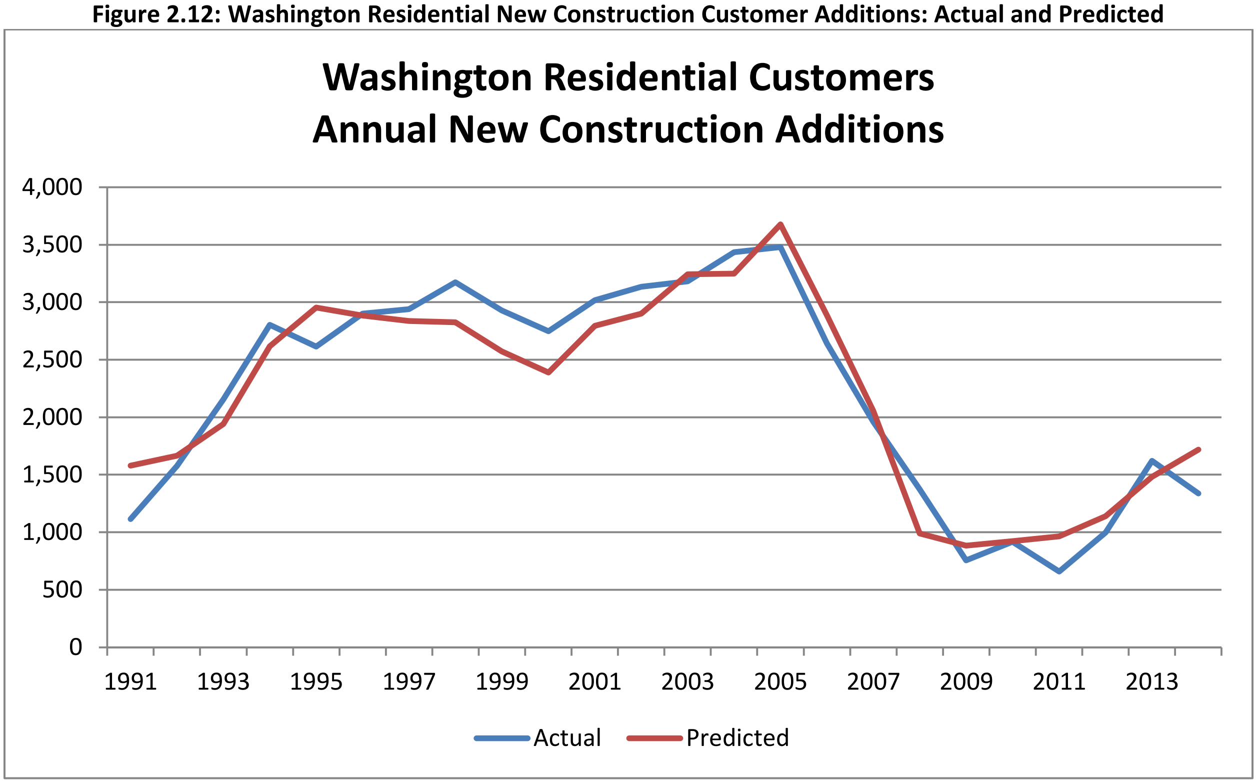
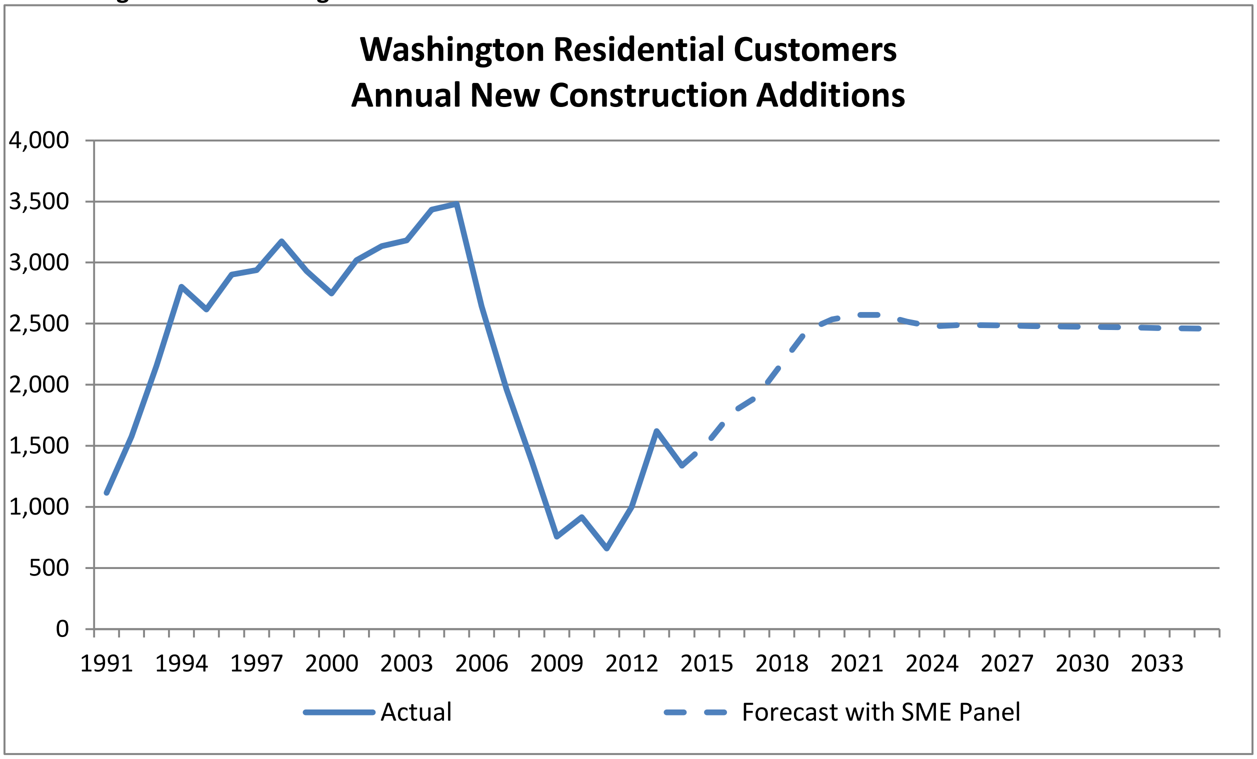


Figure 2.13: Washington Residential New Construction Customer Additions: Actual and Forecast



NW Natural allocates forecasted state-level Residential new construction customer additions between single family and multifamily using state-level econometric forecasts of the proportion of total annual Residential new construction customer additions that will be single family.

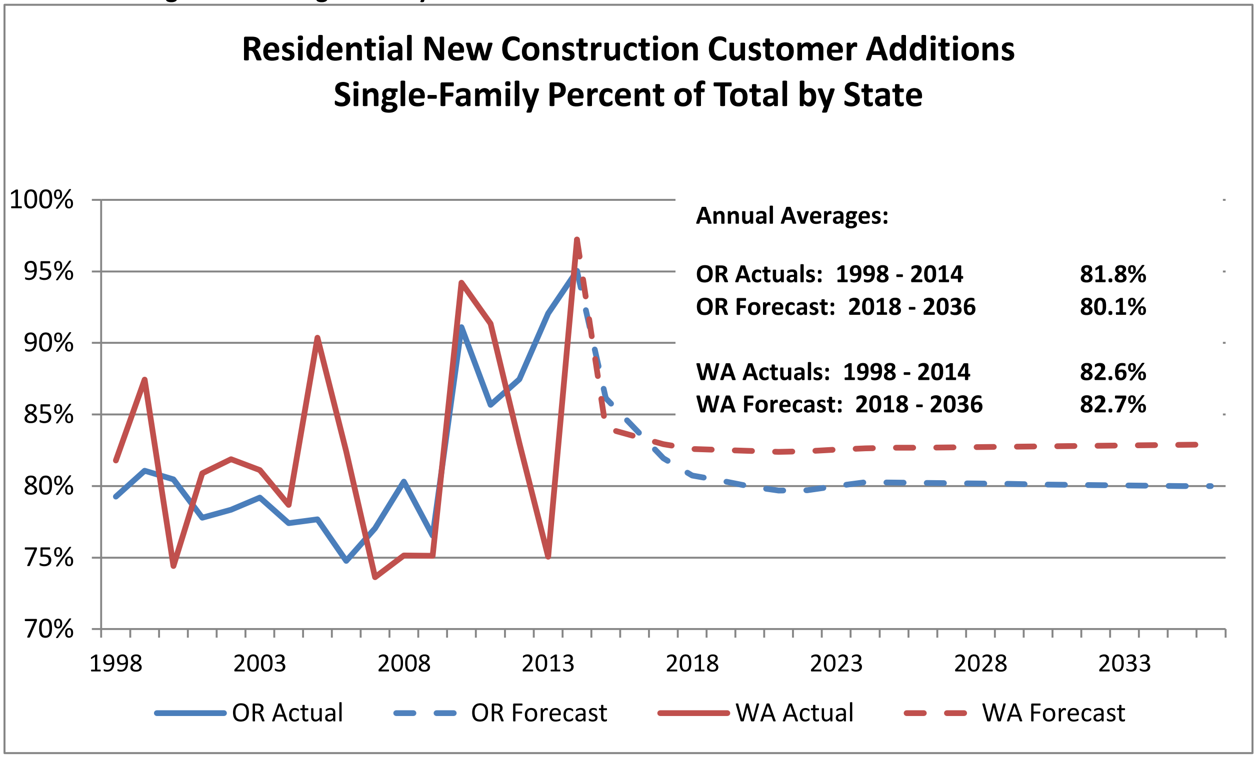
The Oregon model uses as explanatory variables annual Oregon housing starts and the year-over-year change in employment for Oregon counties in which NW Natural provides service. The Washington model uses as explanatory variables annual Oregon housing starts and the change in employment for the Washington counties in which NW Natural provides service.[27]

Figure 2.14 shows for each state actual and forecast values of the single-family percent of NW Natural's total Residential new construction customer additions at the state level. Figure 2.14 includes—for each state—the average annual percent of Residential new construction customer additions that are single family on both a historical basis for 1998–2014 and as projected for 2018–2036.[28]

[27] County-level forecasts of employment are from Woods and Poole's 2015 Regional Projections.

[28] The projected average annual value is for the 2018–2036 timeframe, as this timeframe uses only the econometric forecast for total Residential new construction customer additions. See the earlier discussion on combining the SME Panel's forecasts with econometric forecasts.

Figure 2.14: Single-Family Percent of Residential New Construction Customer Additions



Residential Conversion Customer Additions

NW Natural forecasts Residential conversion customer additions for each state as a time trend,[29] using data for the period 1990–2014. Figures 2.15 and 2.16 show both actual and forecasted Residential conversion customer additions for Oregon and Washington, respectively.[30] See Appendix 2 for additional information regarding the econometric models used for these forecasts.

[29] Residential conversion customer additions were modeled as a time trend after a logarithm transformation.

[30] Figures 2.16 and 2.17 show the econometric time trend forecasts and do not reflect any impact of the SME panel forecasts of Residential conversion customer additions.

Figure 2.15: Oregon Conversion Customer Additions: Actual and Forecast

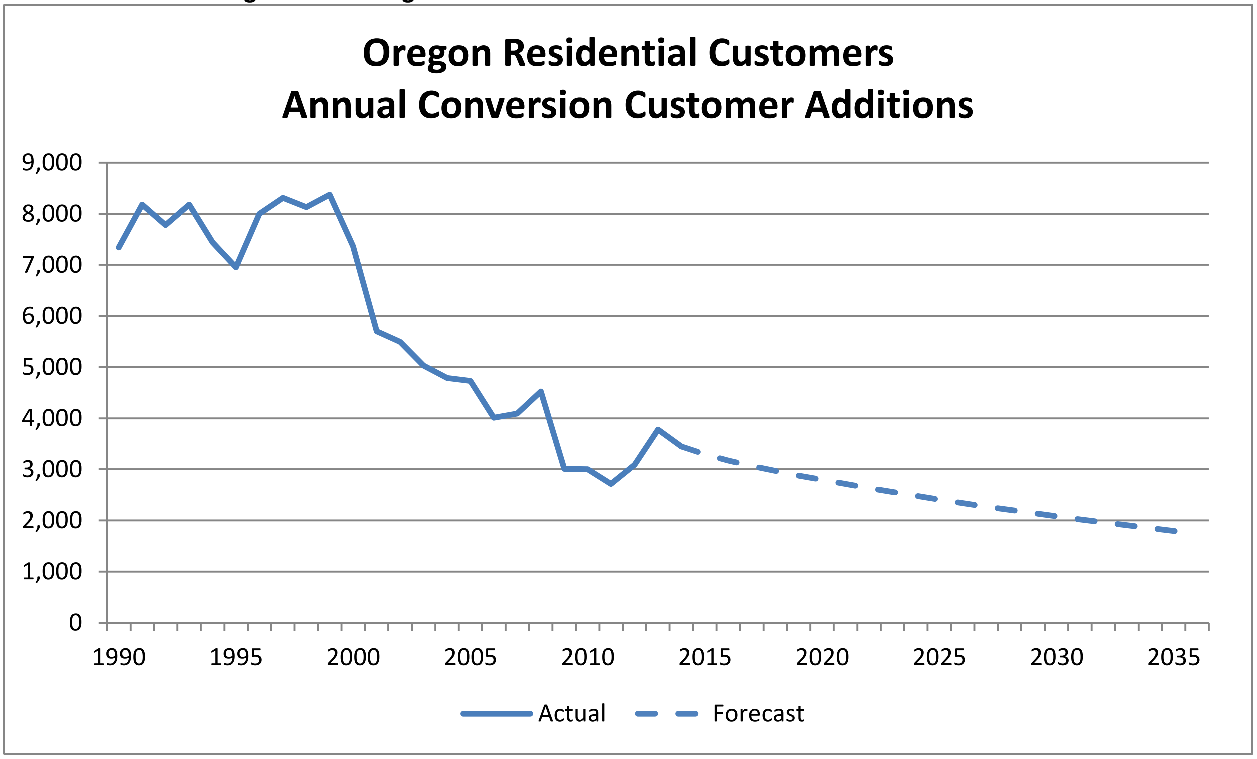
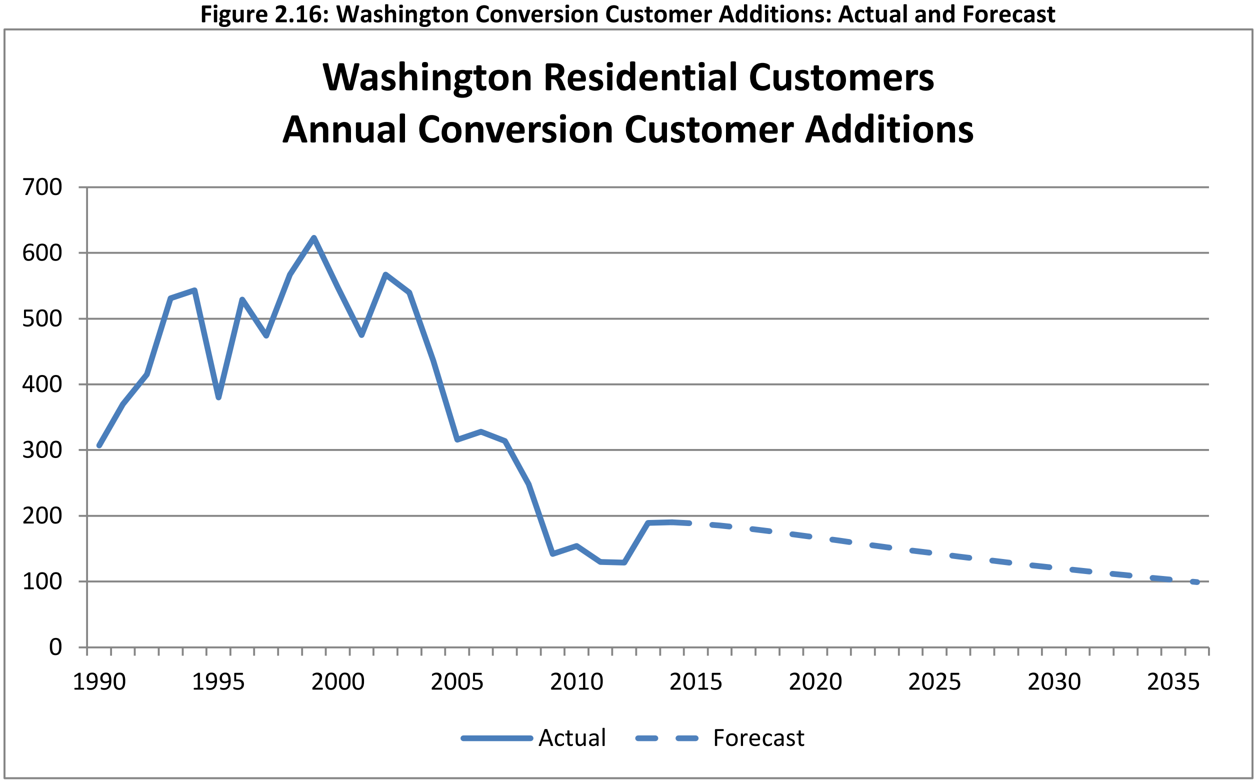


Figure 2.16: Washington Conversion Customer Additions: Actual and Forecast



Residential Customer Losses

NW Natural estimates future Residential customer losses at the state level using each state's average loss rate over the five-year period 2010–2014.

Residential Customer Forecasts

Figure 2.17 shows Residential customers by state and figure 2.18 shows historical values for Residential customers on a system basis and compares the 2016 IRP Residential customer forecast with that in the 2014 IRP.

Figure 2.17: Residential Customers by State

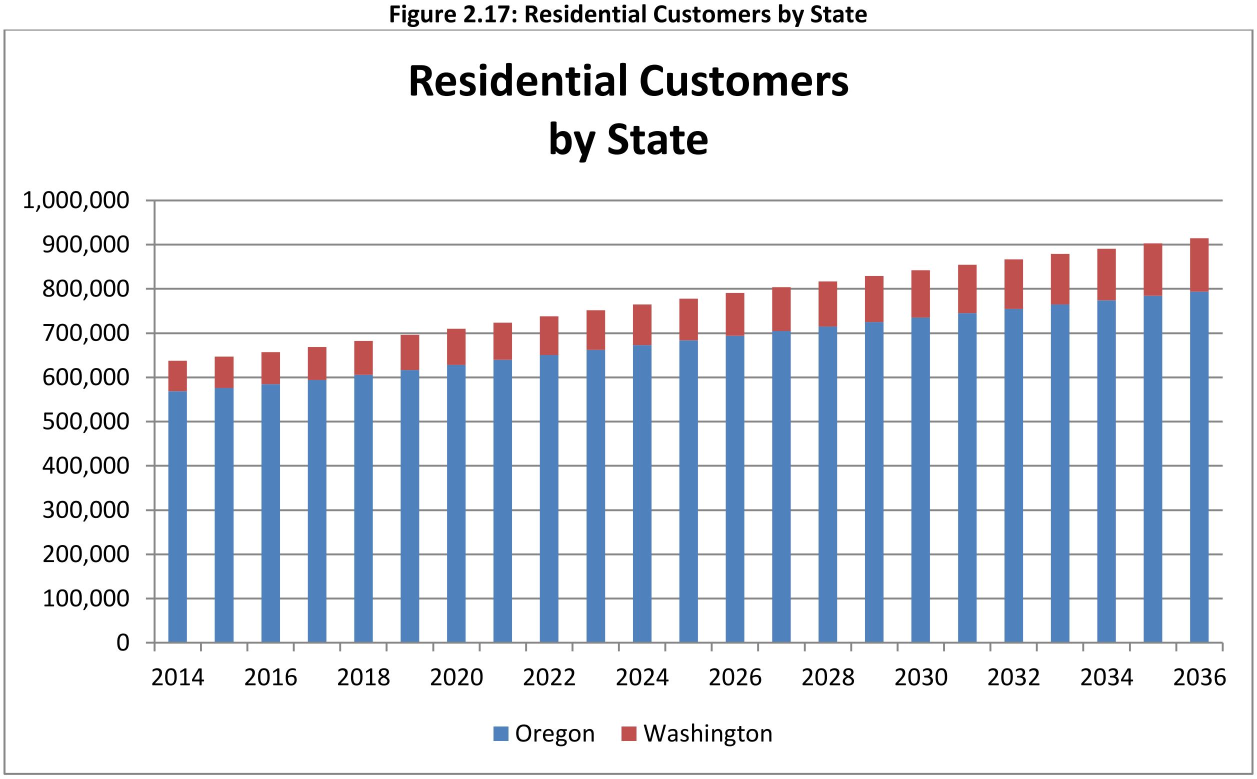
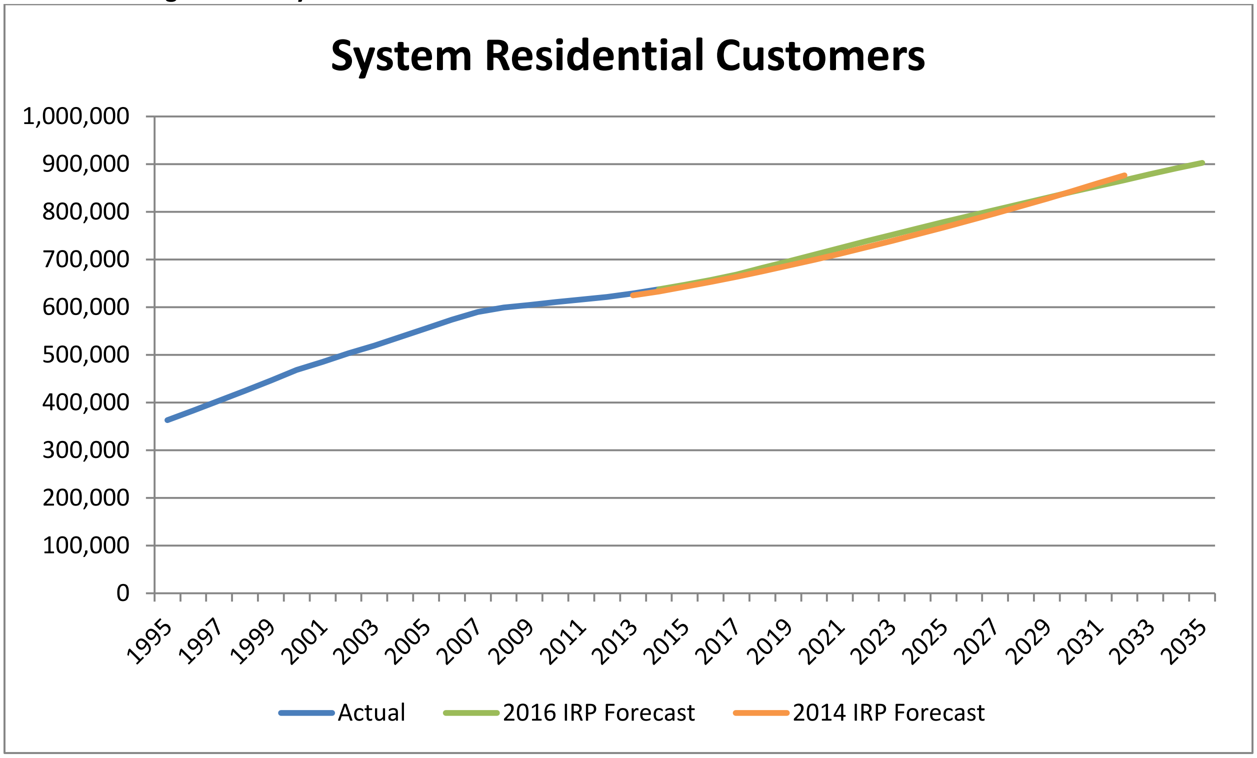


Figure 2.18: System Residential Customers: Actual and 2014 IRP and 2016 IRP Forecasts



The decline in the rate of Residential customer growth following the housing boom of the last decade and during the 2007–2009 recession is easily seen in figure 2.18. Perhaps less easily seen in is that the 2016 IRP Residential customer forecast is marginally greater than the 2014 IRP in the first part of the planning horizon, in part as a result of actual results exceeding levels forecast in the 2014 IRP.

Figures 2.19 and 2.20 show Residential customer annual net additions at the state level, for historical and forecast values, respectively.

Figure 2.19: Historical Residential Customer Annual Net Additions by State

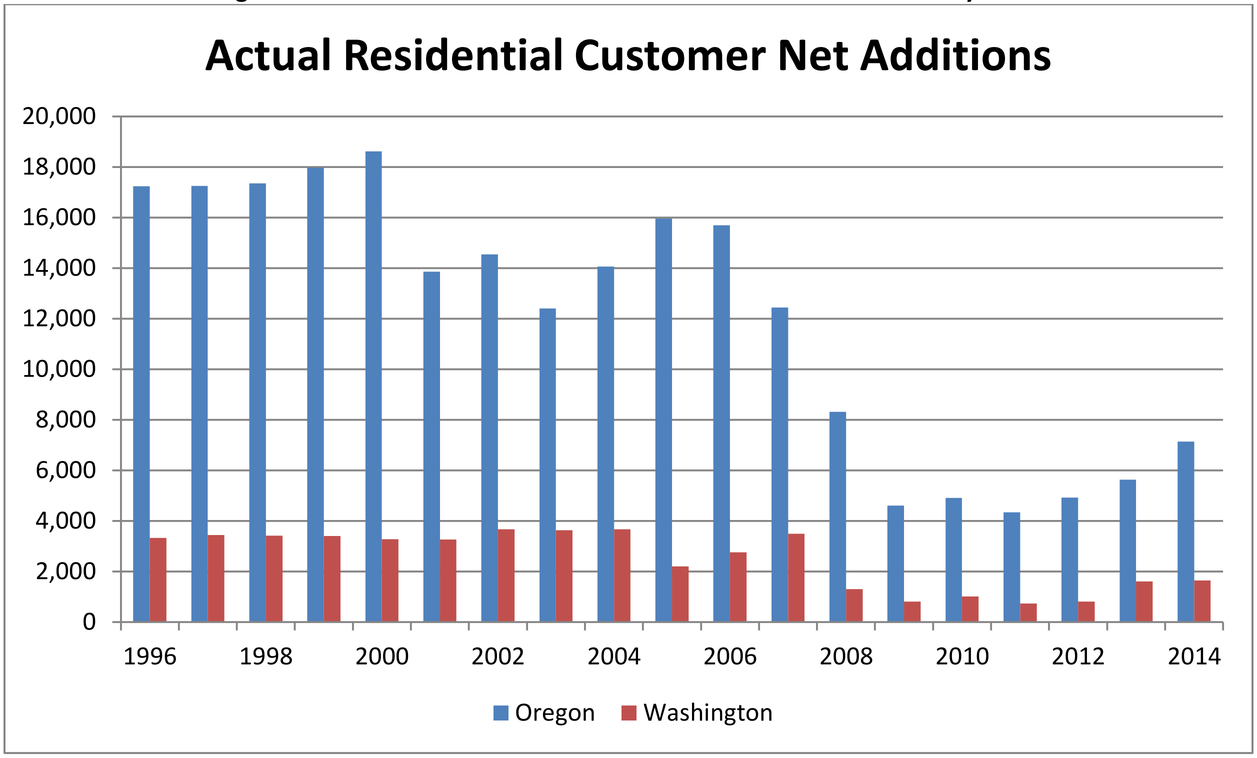
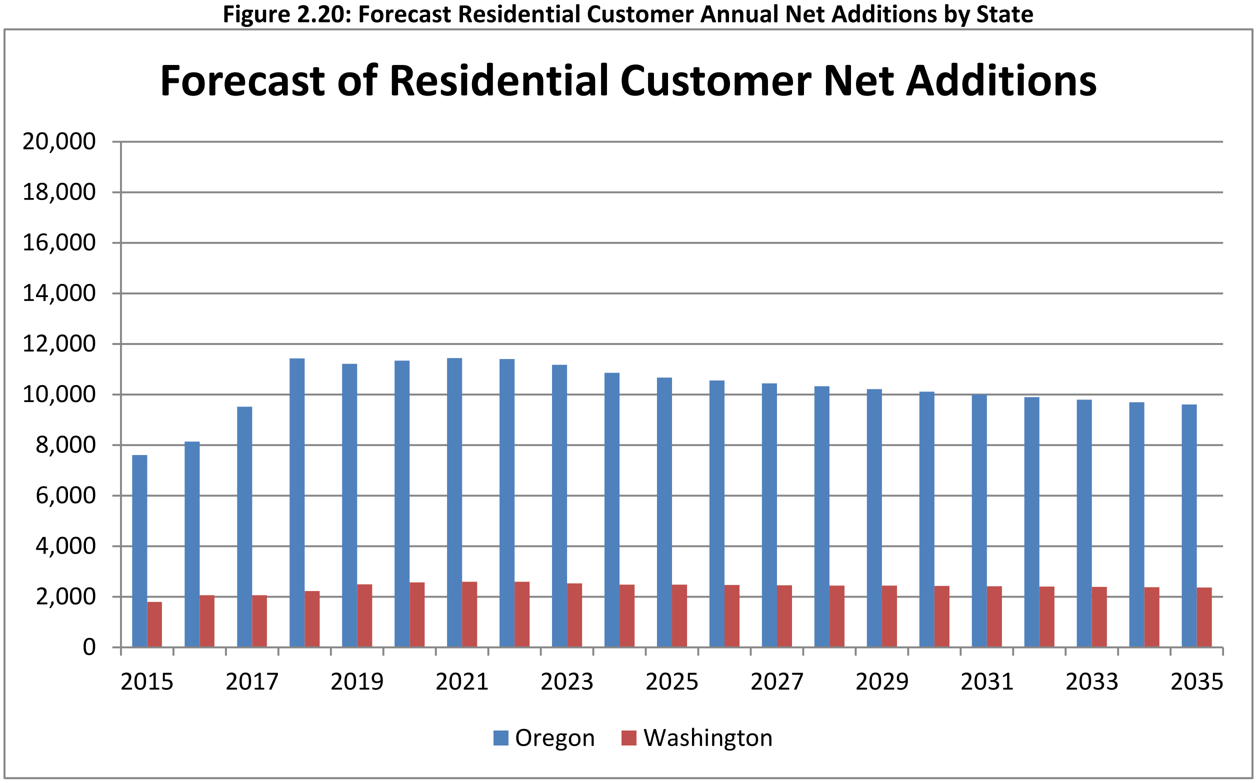


Figure 2.20: Forecast Residential Customer Annual Net Additions by State



5.2. Commercial Firm Sales Customer Forecast

NW Natural forecasts the three components of Commercial customer changes in table 2.1:

1. New Construction
2. Conversions
3. Losses

Commercial New Construction Customer Additions

NW Natural's econometric forecast of Oregon and Washington Commercial new construction customers uses the Woods and Poole Portland MSA nonfarm/nonmanufacturing Employment as the primary explanatory variable. Figure 2.21 shows actual and forecast levels of Oregon Commercial new construction customer additions.

Figure 2.21: Oregon Commercial New Construction Customer Additions: Actual and Forecast

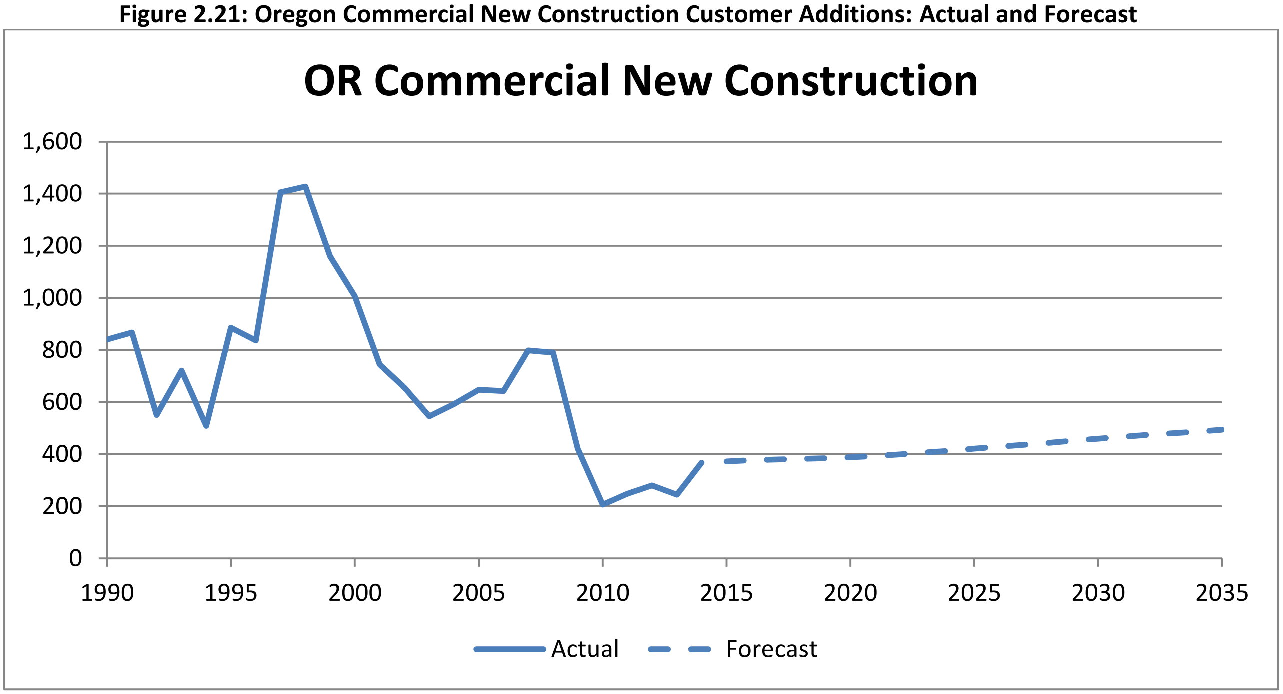
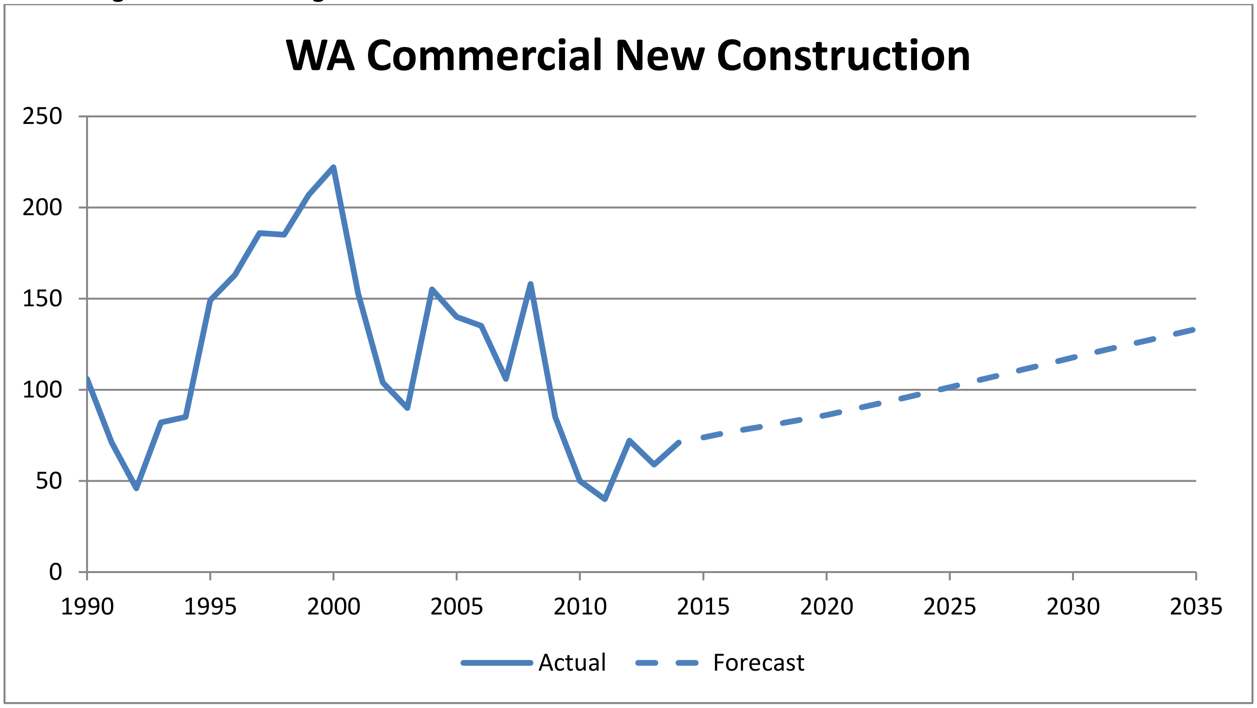


Figure 2.22 shows actual and forecast values for NW Natural's Washington Commercial new construction customer additions.

Figure 2.22: Washington Commercial New Construction Customer Additions: Actual and Forecast



Commercial Conversion Customer Additions

NW Natural forecasts Commercial customer conversions for each state as a time trend, using data for the period 1990–2014. Figures 2.23 and 2.24 show actual and forecast values for Oregon and Washington, respectively.[31]

[31] Figures 2.23 and 2.24 show the econometric time trend forecasts and do not reflect any impact of the SME panel forecasts of Residential customer conversion additions.

Figure 2.23: Oregon Commercial Conversion Customer Additions: Actual and Forecast

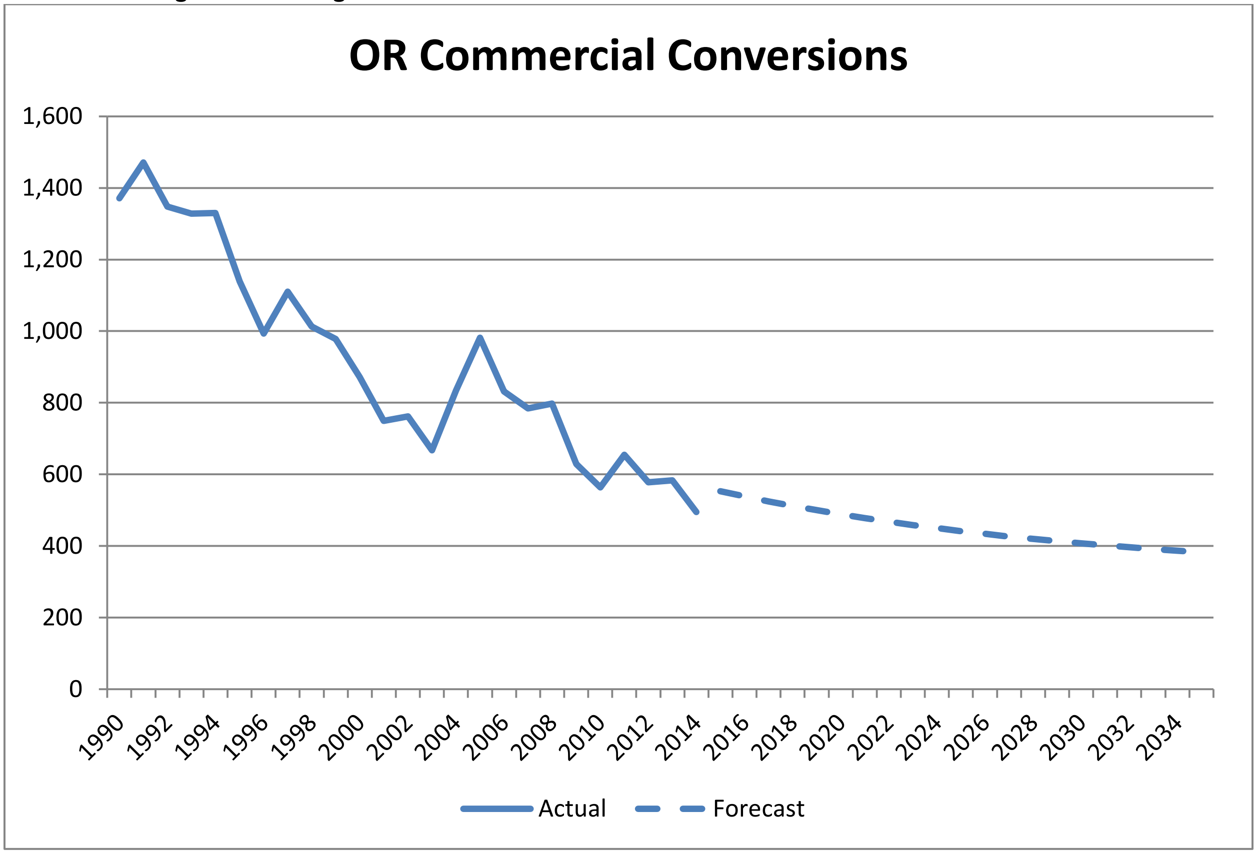
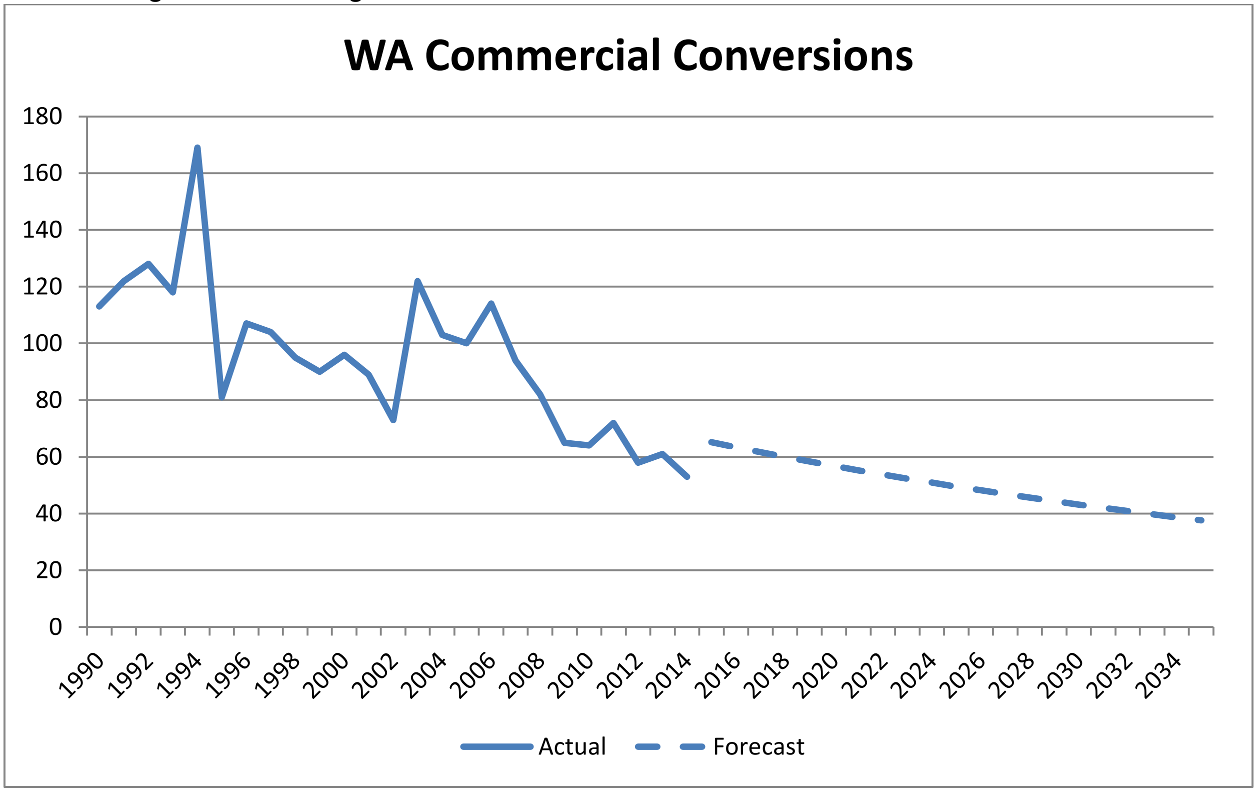


Figure 2.24: Washington Commercial Conversion Customer Additions: Actual and Forecast



Commercial Customer Losses

NW Natural estimates future Commercial customer losses at the state level using each state's average loss rate over the five-year period 2010–2014.

Commercial Customer Forecasts

Figure 2.25 shows historical values for Commercial customers on a system basis and compares the 2016 IRP Commercial customer forecast with that in the 2014 IRP. Figure 2.26 shows Commercial customer additions by state.

Figure 2.25: System Commercial Customers: Actual and 2014 IRP and 2016 IRP Forecasts

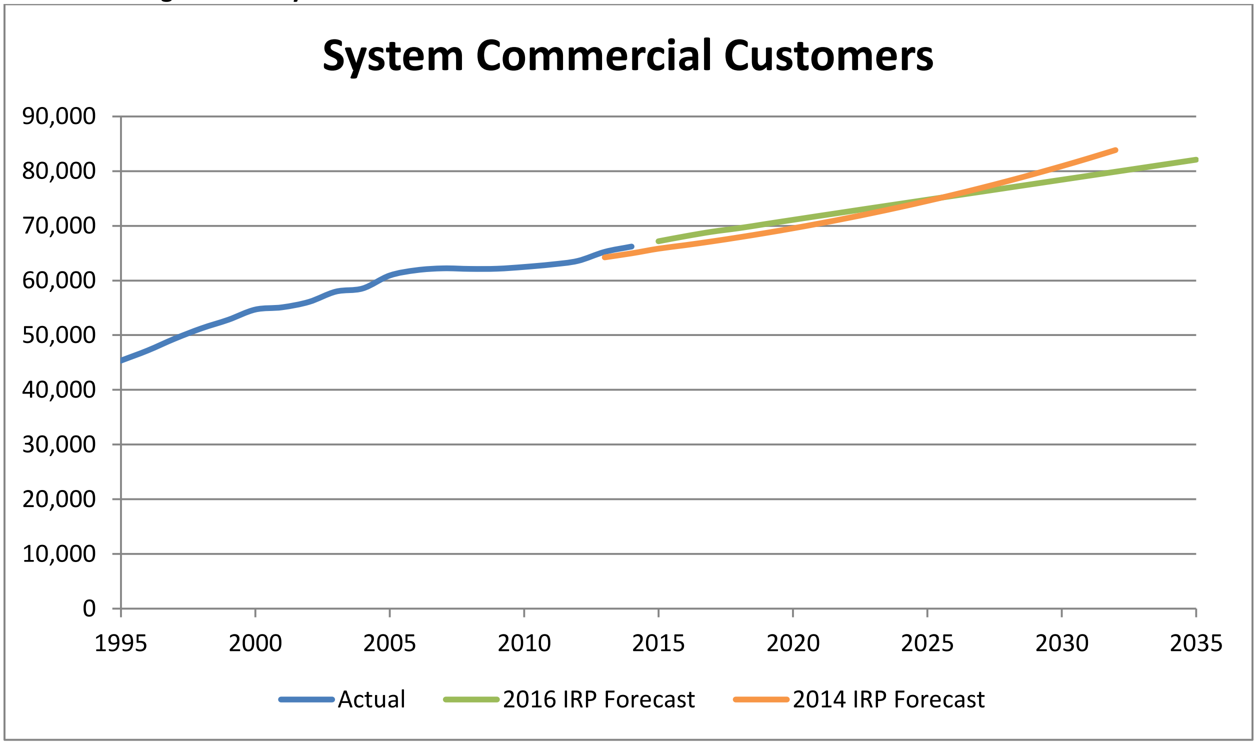
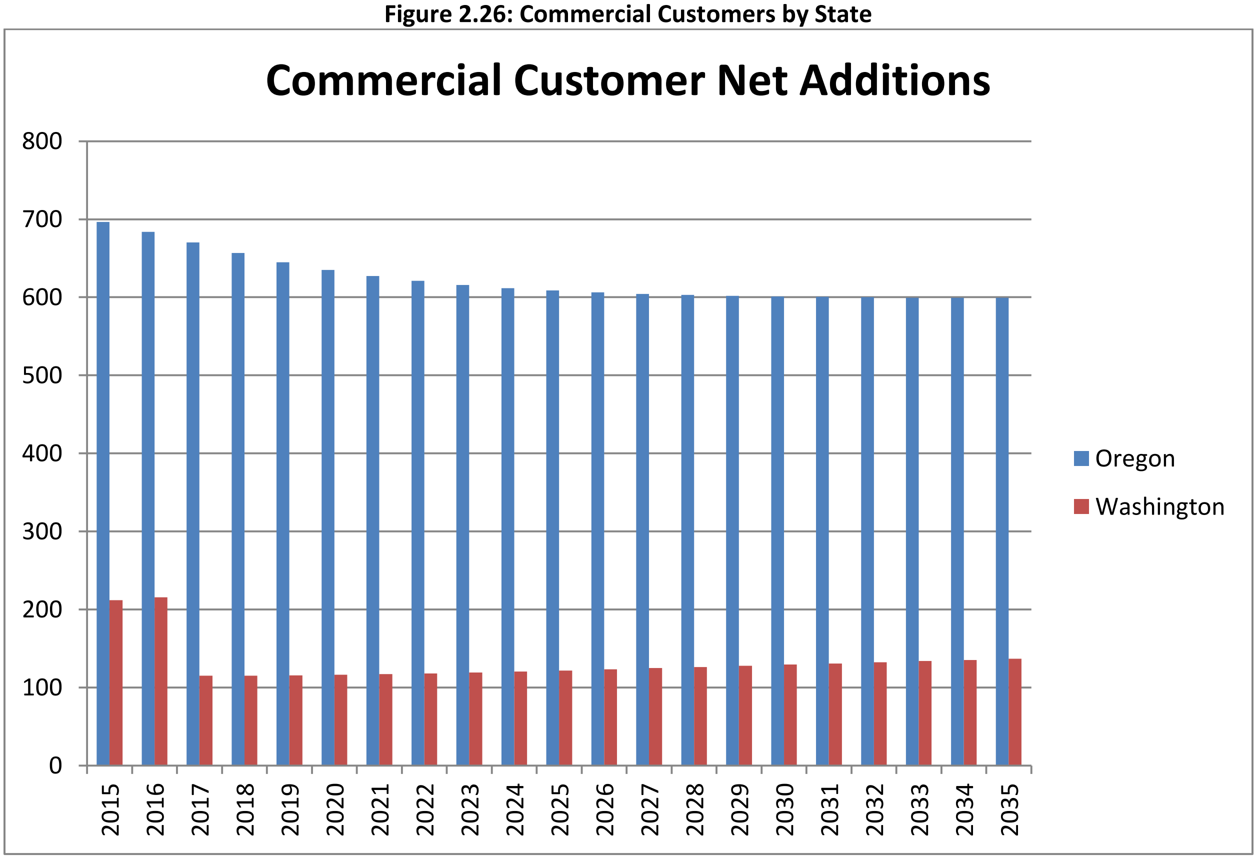


Figure 2.26: Commercial Customers by State



5.3. Residential and Commercial Customer Forecasts by Month and Load Center

NW Natural uses allocation methods to derive monthly load center forecasts of Residential and Commercial customer change components from state-level annual forecasts. The Company allocates each component of customer change from the annual level by state to the 12 months based on system-level average historical experience by month over the 1998–2014 timeframe for that component.

NW Natural allocates the state-level monthly values for each component of customer change to that state's load centers on a *pro rata* basis, using the average annual historical experience over the 1998–2014 timeframe for Washington load centers and the 2004–2014 timeframe for Oregon load centers.[32] The end results are forecasts of each component of customer change at the load center level by month. Using 11- and 17-year historical averages for Oregon and Washington load centers, respectively, presumably captures greater diversity in economic conditions at the load center level than would the use of historical averages from a much shorter period.

Figure 2.27 shows the average annual rate of Residential customer growth by load center[33] over the planning horizon and includes both state-level averages as well as NW Natural's system average. Figure 2.28 shows the same information for Commercial customers. Note that the Coos Bay load center was added to NW Natural's service area relatively recently and, largely due to customer growth resulting from conversions, has historically had and over the planning horizon is expected to have a higher growth rate than other load centers. See table 2.2 for the load center identifier used in these figures.[34]

[32] NW Natural acquired service areas in Coos County, which the Company identifies as the Coos Bay load center, in 2004. Therefore, the longest timeframe with information available for all current Oregon load centers is 2004–2014. Over this period, the Coos Bay load center averaged 2.1 percent of NW Natural's Oregon Residential customer conversion additions. Table 2.2 shows that the Coos Bay load center had 0.2 percent of NW Natural's total Residential customers in 2015.

[33] The multiple Salem load centers are represented in figures 2.27 and 2.28 as aggregated Salem ("SAL") values.

[34] "Portland" (POR) is composed of Portland Central (PORC), Portland East (PORE), and Portland West (PORW).

Figure 2.27: Average Annual Residential Customer Growth Rates by Load Center and State

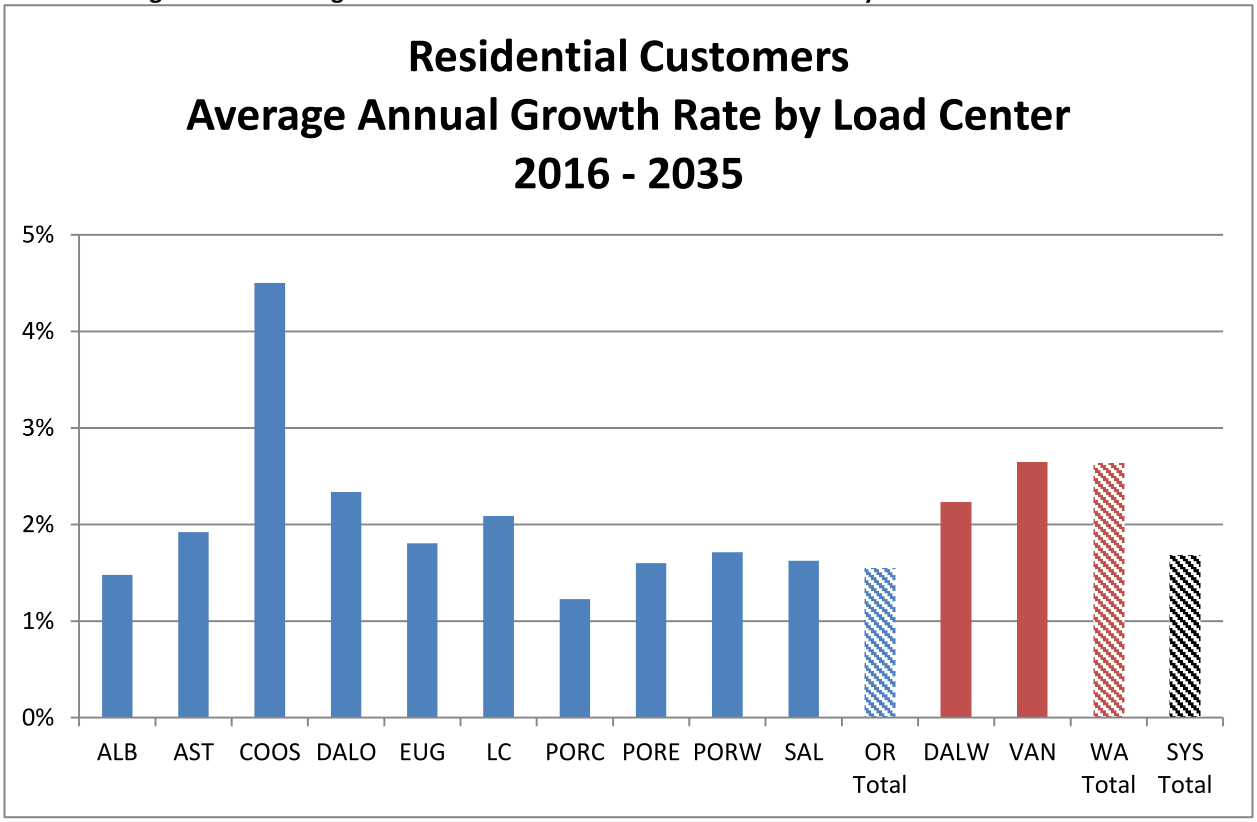
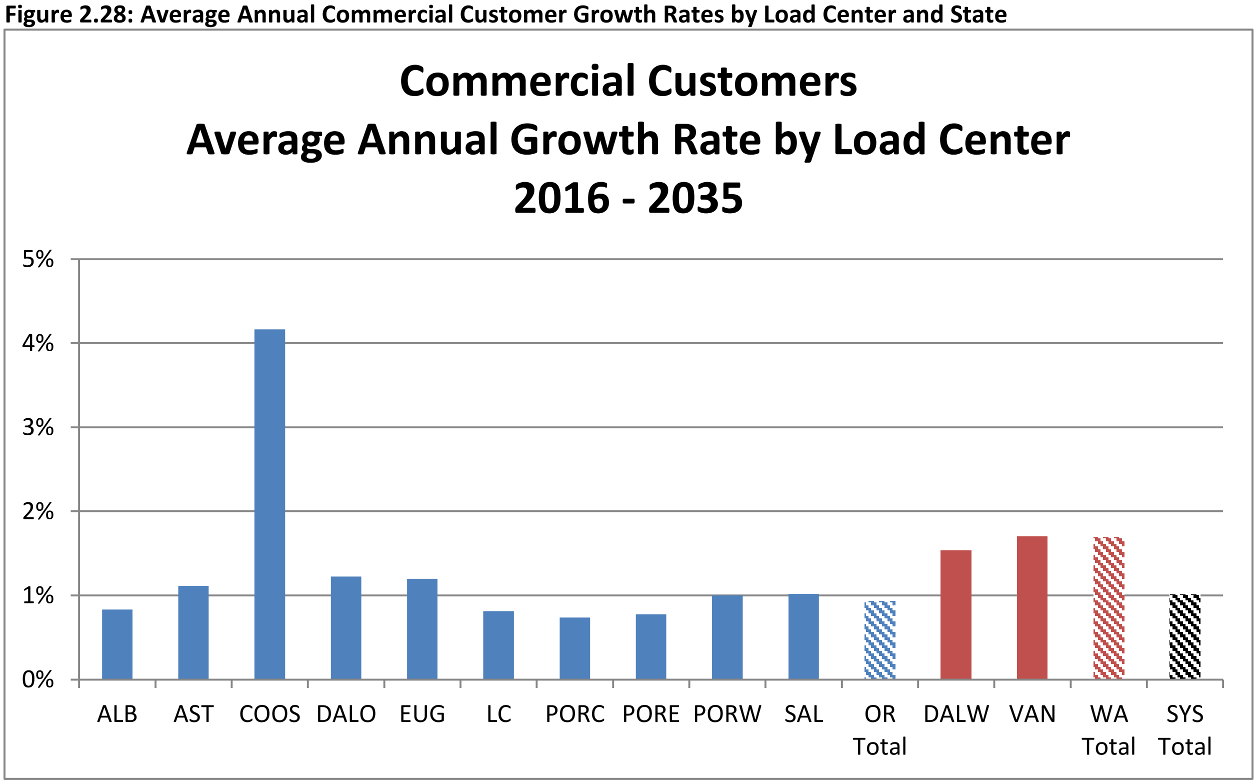


Figure 2.28: Average Annual Commercial Customer Growth Rates by Load Center and State



5.4. Alternative Customer Growth Scenarios

NW Natural believes the Base Case load forecasts using design weather represents the most likely outcomes from a perspective of prudent resource planning. The Company also evaluated resource planning under scenarios having alternative load levels. These scenarios provide alternative load projections based in part on alternatives to the Base Case Residential and Commercial customer forecasts. Scenarios also serve to provide limits to the Base Case load forecast by establishing a floor and a ceiling on expected load. NW Natural developed two alternative load scenarios with respect to customer growth:

1. Low Load Growth: Lower Residential and Commercial customer growth; e.g., as a result of slower than expected service area economic and population growth; and

2. High Load Growth: Higher Residential and Commercial customer growth; e.g., as a result of higher than expected service area economic and population growth.

NW Natural based the Residential High and Low customer forecasts on 90 percent confidence intervals for the Residential econometric models for new construction customer additions and conversion customer additions. Analogous with the Base Case, the SME panel High and Low forecasts are used for 2015 and 2016, and 2017 averages the SME panel and econometric forecasts.

The Commercial High and Low cases use 90 percent confidence intervals for the Commercial conversion customer addition econometric models only, as the Commercial new construction customer addition models have very large confidence intervals. Instead, the Commercial new construction customer additions use plus and minus 50 percent of the Base Case new construction customer additions. The SME panel High and Low forecasts are incorporated into the Commercial High and Low customer forecasts in the same way as for the Residential High and Low forecasts.

Table 2.3 shows the average annual rates of customer growth for the Base Case customer forecast and the high- and low-growth scenarios. Figures 2.29 and 2.30 show historical values and the Base Case, High, and Low customer forecasts for Oregon and Washington, respectively. Figures 2.31 and 2.32 show this information for Commercial customers.

Table 2.3: Average Annual Rates of Residential and Commercial Customer Growth 2016 – 2035

		Base Case	High Growth	Low Growth
Residential				
	Oregon	1.6%	1.9%	1.2%
	Washington	2.6%	3.4%	2.0%
	System	1.7%	2.1%	1.3%
Commercial				
	Oregon	0.9%	1.5%	0.2%
	Washington	1.8%	2.8%	0.7%
	System	1.0%	1.7%	0.3%
Residential plus Commercial				
	Oregon	1.5%	1.9%	1.1%
	Washington	2.6%	3.3%	1.9%
	System	1.6%	2.1%	1.2%

Figure 2.29: Residential Customer Forecast Scenarios: Oregon

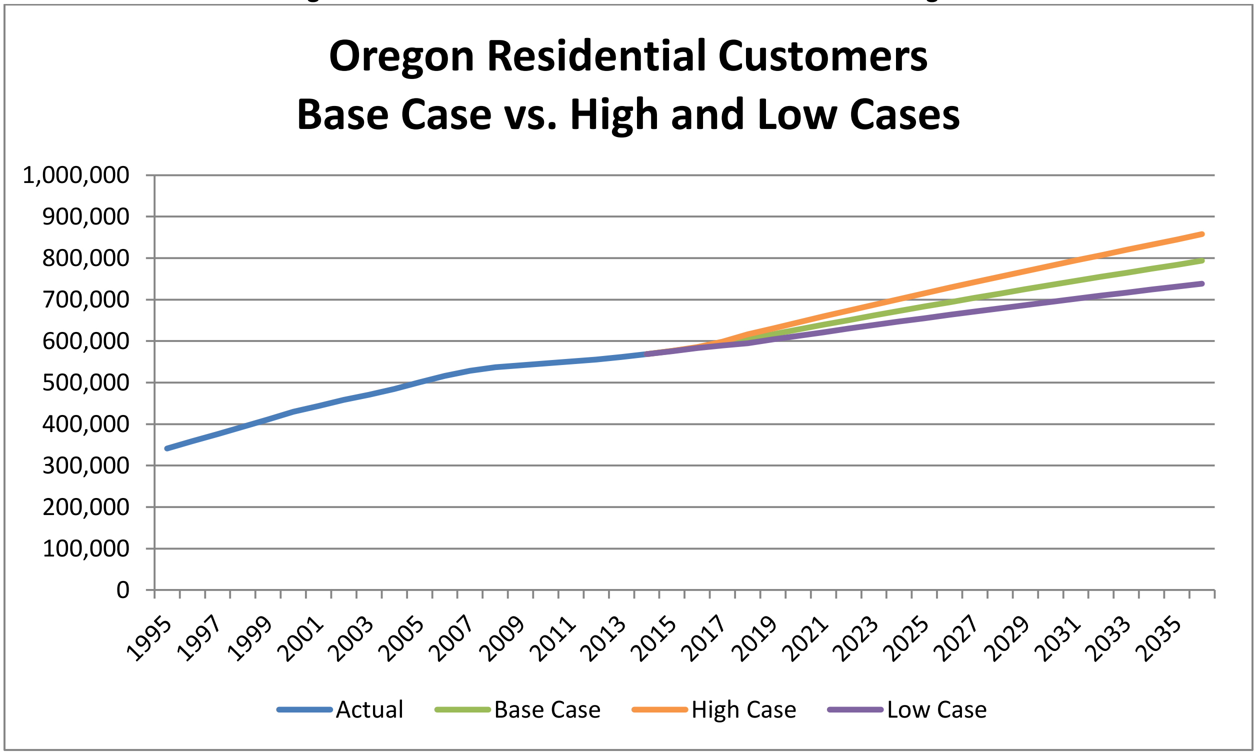


Figure 2.30: Residential Customer Forecast Scenarios: Washington

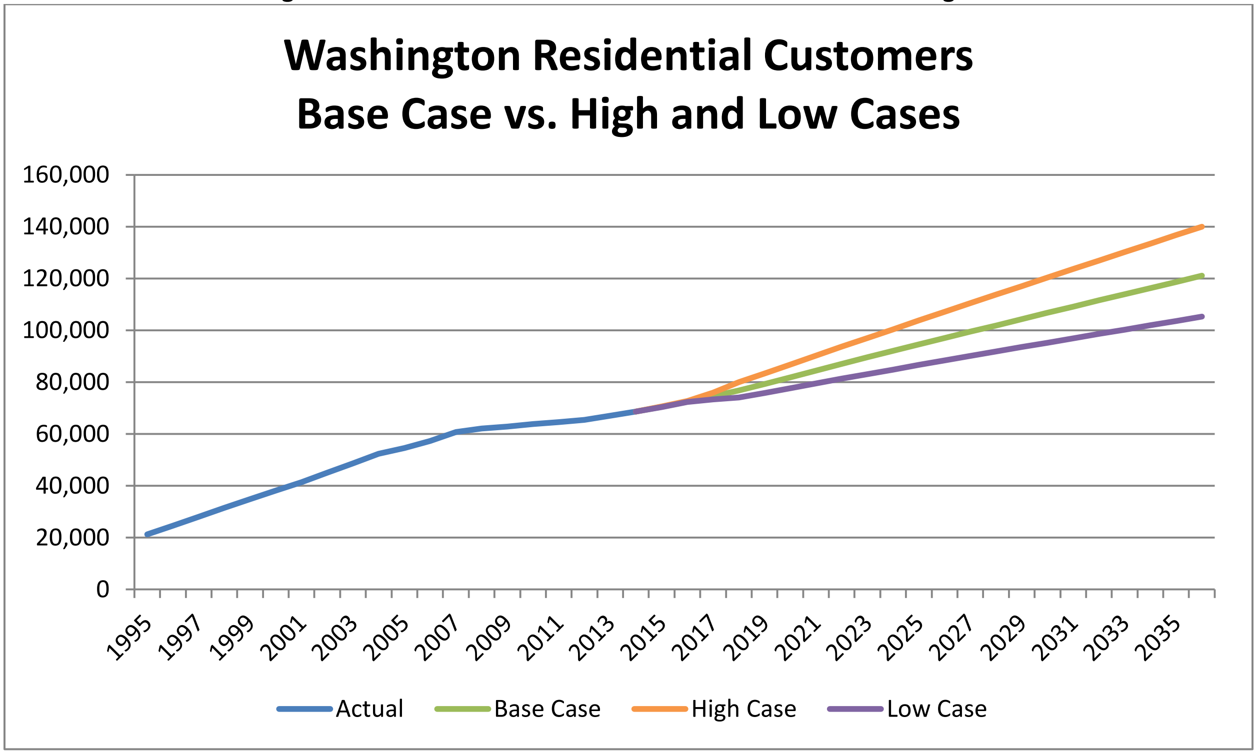


Figure 2.31: Commercial Customer Forecast Scenarios: Oregon

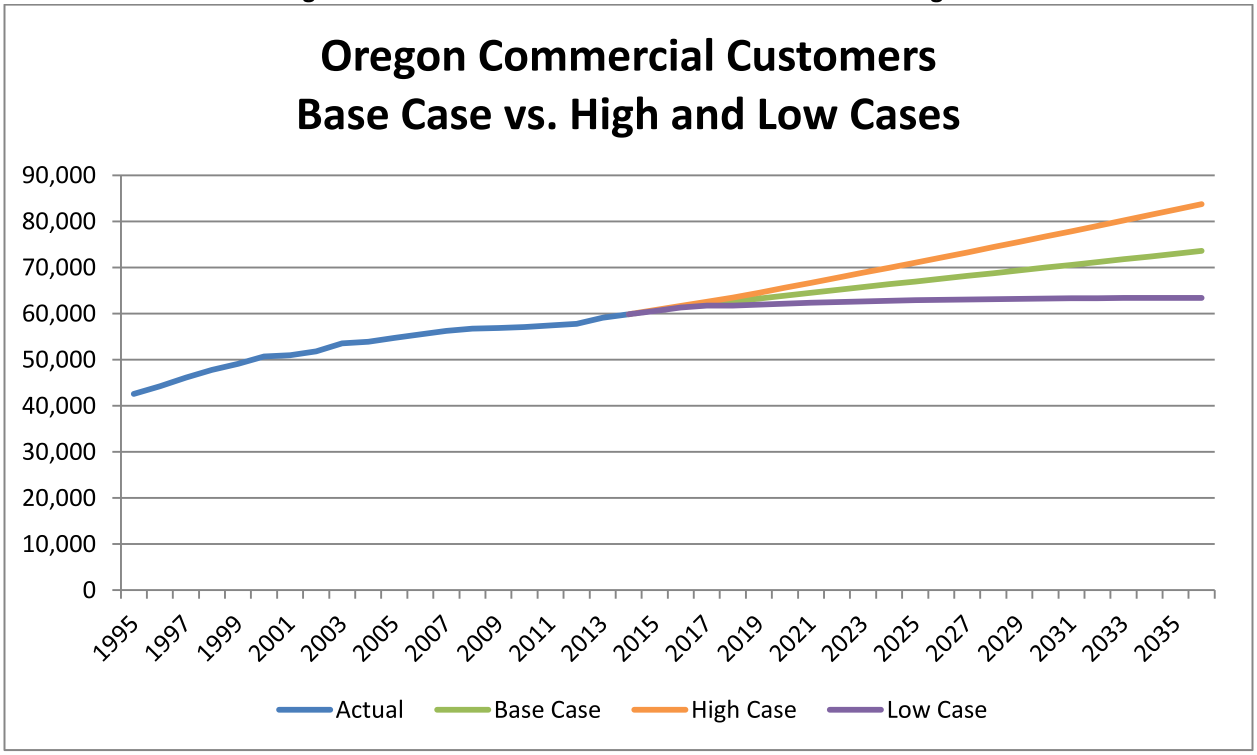
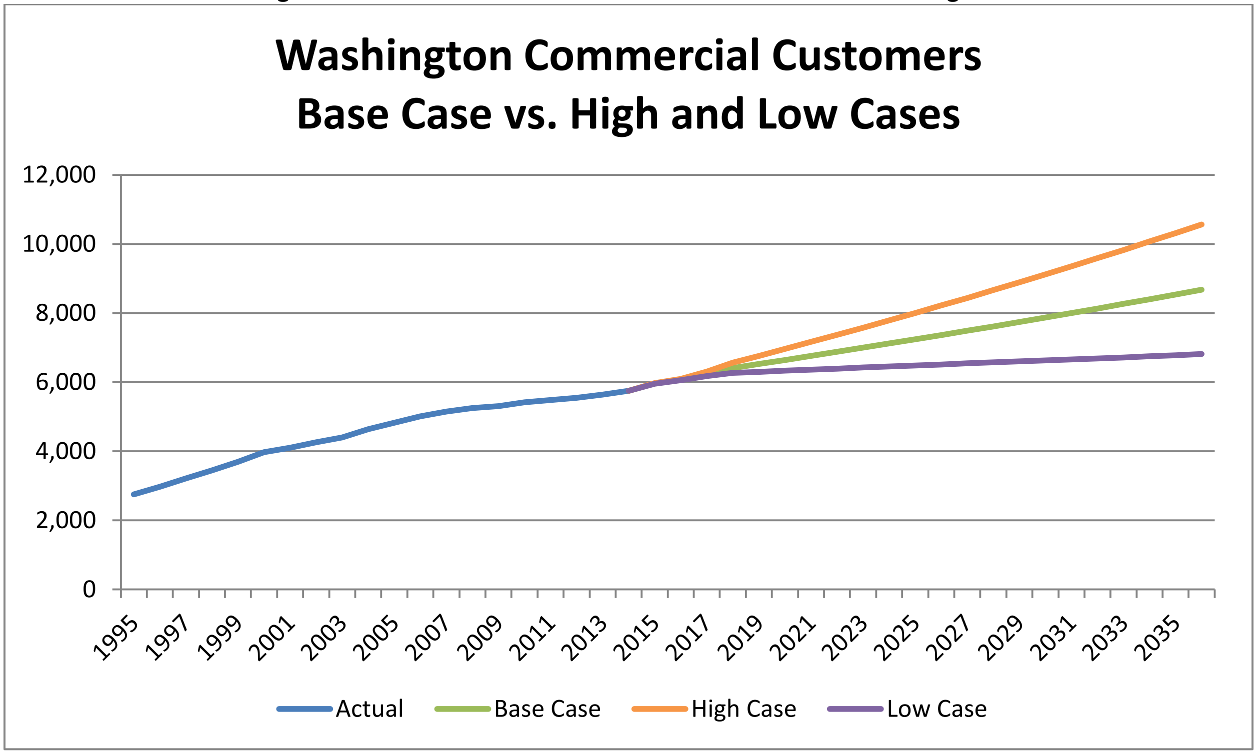


Figure 2.32: Commercial Customer Forecast Scenarios: Washington



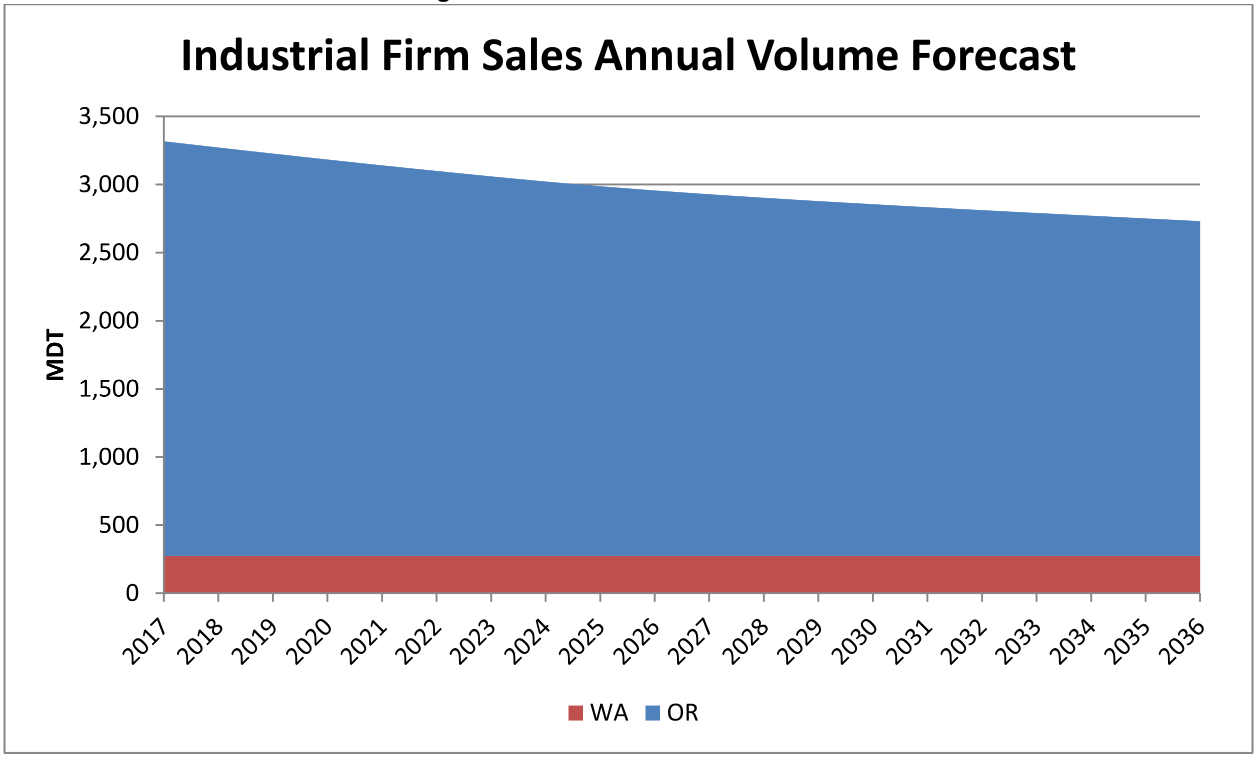
6. INDUSTRIAL LOAD FORECAST

NW Natural has approximately 600 Industrial Firm Sales customers with annual usage ranging from 0.1 to 70 thousand dekatherms (MDT; 1 MDT= 10,000 therms). 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 forecast of both Oregon and Washington Industrial loads. The Company develops a forecast of Industrial load in total, and allocates this to load centers and customer types (Firm Sales, Interruptible Sales, Firm Transportation, and Interruptible Transportation) based on actual 2014–2015 gas year loads.

NW Natural forecasts a Base Case of 0 percent load growth in industrial demand before demand-side management with a high case of 0.5 percent and low case of -0.5 percent load growth. Figure 2.33 depicts the Base Case post-DSM Industrial Firm Sales load.[35] Post-DSM, for post-demand-side management, in this context refers to the Industrial Firm Sales load after decrementing for the forecasted results of ETO's implementation of demand-side management programs. See chapter 6 for discussion of DSM.

[35] Figure 2.33 expresses volumes in thousands of dekatherms, or MDT.

Figure 2.33: Industrial Firm Sales Load



7. EMERGING MARKETS LOAD FORECAST

NW Natural includes forecasted loads from two Emerging Market segments in the 2016 IRP: Compressed Natural Gas (CNG) and Combined Heat and Power (CHP). The predicted annual energy loads from these two segments are relatively small. In particular, the forecast of Emerging Market's Firm Sales load is small, with 417 MDT in 2035 representing approximately 0.6 percent of NW Natural's total Firm Sales load for the year. The Company does not anticipate a material impact on planning for supply resources resulting from these two Emerging Market segments. As an example of this, in 2030 Emerging Markets Firm Sales on a peak day represent 0.06 percent of NW Natural's peak day total Firm Sales. However, the location specifics of one or more relatively large Emerging Markets customers may have an impact on NW Natural's distribution system planning.

Figure 2.34 shows the annual energy forecast for the Firm service CNG and CHP segments and Figure 2.35 shows the breakout of these two segments by either Firm Sales or Firm Transportation loads. Figure 2.36 shows the Firm Sales annual energy forecast, including the Base Case, a High Case, and a Low Case. See also figure 2.51.

Figure 2.34: Emerging Market Annual Energy Forecast by Segment

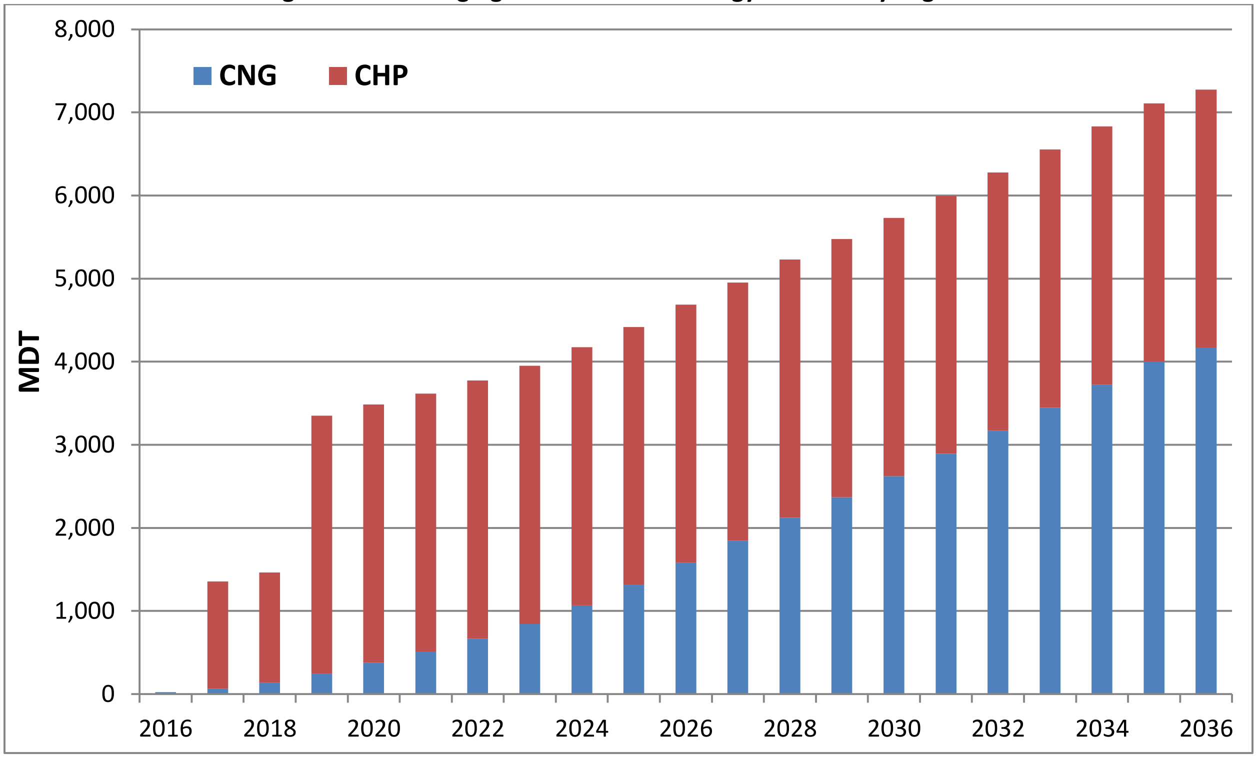


Figure 2.35: Emerging Market Annual Energy Forecast by Class of Service

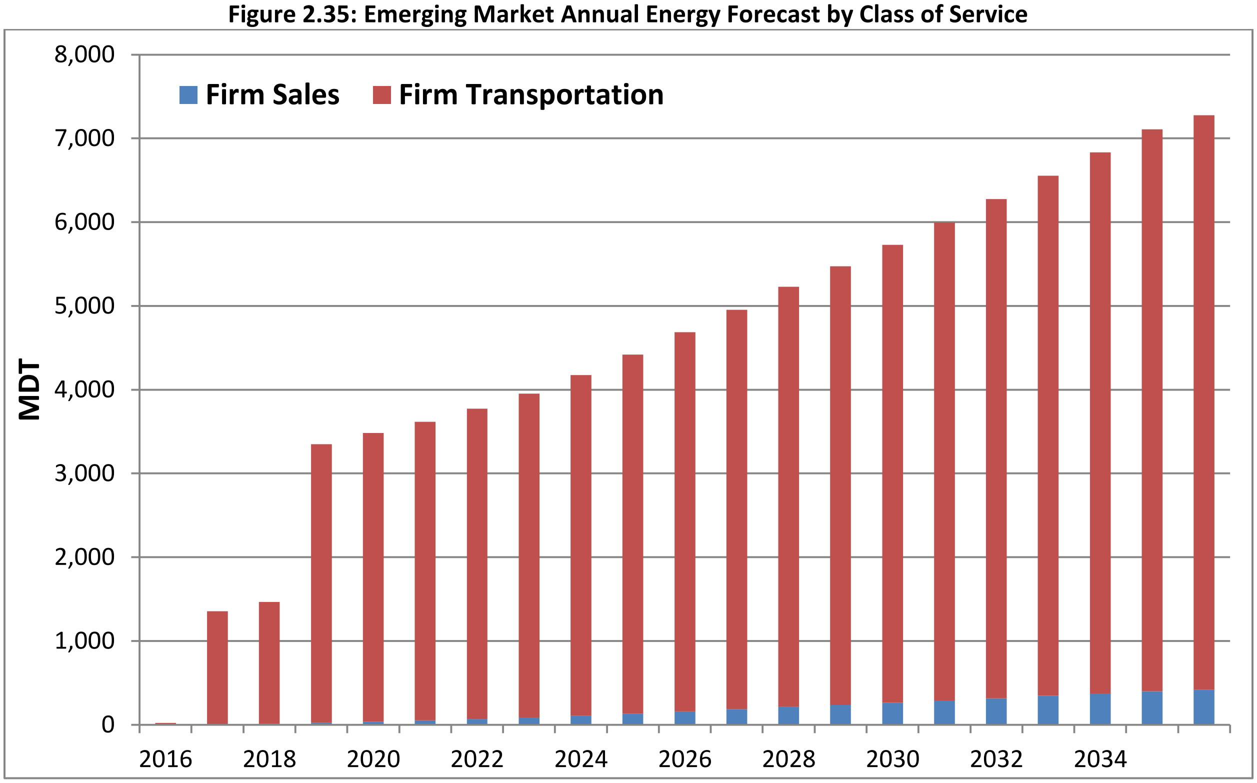
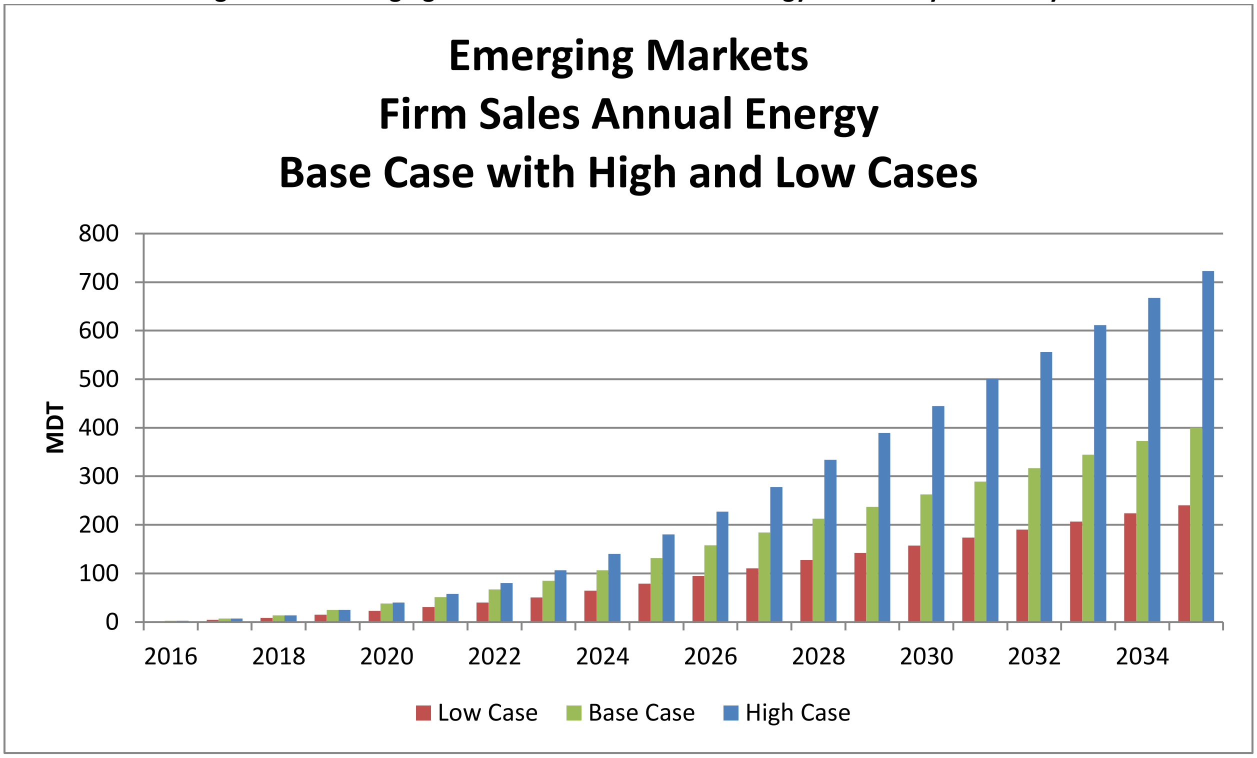


Figure 2.36: Emerging Market Firm Sales Annual Energy Forecast by Sensitivity



8. SYSTEM PEAK DAY USAGE FORECAST

The firm sales peak day usage forecast for each year in the planning horizon determines the expected amount of supply resources[36] NW Natural must hold in order to serve its customers. Like in previous IRPs the peak day load forecast combines the customer count forecast, the peak day weather standard, and the peak day use per customer forecast where:

$$\begin{aligned}&\boldsymbol{Peak\ Day\ System\ Firm\ Sales\ Load_t}\\&= \boldsymbol{Daily\ Use\ Per\ Aggregate\ Firm\ Sales\ Customer\ Under\ Peak\ Day\ Weather\ Conditions_t}\\&* \boldsymbol{Firm\ Sales\ Customer\ Count_t}\end{aligned}$$

The customer count forecasts, the peak day weather standard, and the peak day use per customer model have all seen substantial improvements since the 2014 IRP. The customer count forecasts used for both the peak day and average annual load forecast are those detailed earlier in this chapter, whereas table 2.5 describes key differences between the peak day system firm sales[37] forecast and the annual average energy forecasts detailed later in this chapter.

[36] Note that supply-side resources are divided into supply and distribution resources. Existing and prospective supply resources are detailed in chapter 3 and distribution planning and expected projects are detailed in chapter 7.

[37] Note that interruptible customers are assumed interrupted on a peak day, so the peak day forecast is the firm sales peak day load forecast where interruptible loads are not included.

Table 2.5: Peak Day Forecast vs. Annual Average Energy Forecast Differences

Forecast	Usage Data Source	Data Frequency	Weather Measurement	Geographic Aggregation of Forecast	Customer Aggregation of Forecast
Peak Day Forecast	Gas Control	Daily	Many Variables	System	All Firm Customers
Energy Forecast	Billing	Monthly	Temperature Only	Load Center	Customer Type

A change to the peak day weather standard and peak day use per customer model was made because of the high level of variation in actual daily sales as a function of temperature/heating degree days (HDDs) that led to a high level of uncertainty about the accuracy and precision of the peak day load forecast when temperature/HDDs is the only predictor of usage on a peak day. The new peak day weather standard greatly reduces the variation in firm sales for a given temperature by (1) including more variables- both weather and day of the week- in addition to temperature that are important factors in the gas usage seen on any given day, and (2) using a better measure of temperature. Furthermore, the new peak day use per customer model provides much better information about system usage during extreme cold weather days by (1) using data from the coldest days directly (which cannot be done using billing data that comes in monthly form), (2) forecasting systemwide usage directly, and (3) aligning the forecast with actual gas supply operations by moving weather measurements used to predict usage from a calendar day to a "gas day."[38]

The new peak weather standard and the peak day use per customer model, their benefits relative to the old forecast, and the new peak day forecast will be described briefly below, though a more detailed look into the new peak day forecasting data, methods, benefits, and results can be found in Appendix 2.

Peak Day Weather Standard

Like the previous IRP, the peak day weather standard is based upon the most extreme heating requirement day of the last 30 years. However, while the peak day weather standard in previous IRPs was based upon a standard HDD measure of weather only, the system peak day load forecast in this IRP is based upon a weather standard with factors in addition to temperature that have strong power in predicting customer natural gas usage. These new variables are wind speed, precipitation, solar radiation, the previous day's temperature, time, and day of the week. This new weather standard is made possible by taking advantage of 30 years' worth of load center level hourly weather data new to this IRP to determine gas day (as opposed to temperature only calendar day data) heating requirement measurements to better align forecasting with actual gas supply operations, better capture intraday weather patterns, better capture changes to NW Natural's customer base through time, and to take into account day of the week usage patterns.

While this change to a more complete measure of heating load requirements due to weather conditions could have resulted in a different day of the last 30 years becoming the planning design day for the peak

[38] Interstate pipeline capacity and storage contracts are on gas day (7 a.m. to 7 a.m.) terms rather than calendar day terms and gas supplies are procured and scheduled for gas days, not calendar days. Additionally, the peak hours of usage in a given calendar day are bisected by the 7a.m. gas day delineation.

day forecast, Feb. 3, 1989 weather remains the peak day for supply resource planning purposes.[39] The changes to the planning peak day weather standard are summarized in table 2.6 and the load center level measurements that make up the system-weighted peak measurements are shown in table 2.7.

Table 2.6: Supply Resource Planning Peak Day Weather Standard: 2016 IRP vs. 2014 IRP

	2014 IRP		2016 IRP	
Weather Definition	Calendar Day		Gas Day (7am to 7am)	
Time Weighting	Static System Weighted		Dynamic System Weighted	
Drivers of Load	Average of Daily High and Daily Low Temperature in Heating Degree Day (HDD) Form		Average of Hourly Values for (1) Temperature and (2) Wind Speed, Sum of Hourly Values for (3) Precipitation and (4) Solar Radiation, (5) Day of Week, and (6) One Day Lag of Temperature	
Peak Day Definition	Coldest Day in 30 years		Highest Heating Requirement Day in 30 years	
Peak Day	February 3, 1989		February 3, 1989	
Peak Day Measurements	Temperature:	53 HDD (12°F)	Temperature:	10.5°F
	Wind Speed:	N/A	Wind Speed:	21.72 mph
	Precipitation:	N/A	Precipitation:	0.01 inches
	Solar Radiation:	N/A	Solar Radiation:	2537 watt/m^2
	Day of Week:	N/A	Day of Week:	Week Day (M-TH)
	One Day Lag of Temperature:	N/A	One Day Lag of Temperature:	12.0°F

Table 2.7: Load Center Values for System-weighted Coincident Peak

Weather Measurements for Planning Peak Day Weather (February 3, 1989 Weather)	Vancouver	The Dalles	Salem	Portland-West	Portland-East	Portland-Central	Newport/Lincoln City	Eugene	Corvallis/Albany	Coos County	Astoria	System Weighted- 2016	System Weighted- 2036
Temperature (hourly avg °F)	5.5	4.9	10.6	9.3	10.0	12.8	17.6	12.1	11.3	25.6	14.7	10.5	10.4
Wind Speed (hourly avg mph)	15.1	12.4	8.8	20.8	24.1	31.5	22.6	18.6	9.9	12.5	24.5	21.7	21.4
Solar Radiation (daily sum watt/m^2)	2678	2157	2326	2410	2836	2736	1868	1966	1933	2528	2026	2537	2534
Precipitation (daily sum in inches)	0	0	0.01	0	0	0	0.03	0.11	0.03	0.17	0	0.01	0.01
Temperature Day Before (hourly avg °F)	6.9	5.4	14.1	9.4	11.1	12.8	30.4	17.9	20.4	30.9	16.0	12.0	12.0
Day of Week	M-Th	M-Th	M-Th	M-Th	M-Th	M-Th	M-Th	M-Th	M-Th	M-Th	M-Th	M-Th	M-Th

Table 2.6 points out some of the key improvements of moving from an incomplete HDD measure of weather to a more complete hourly average of numerous factors for the gas day:

1. Averaging the high and low temperatures for a day does not accurately account for the temperature changes within a day that impact heating load and changing from a calendar to a gas day measure of temperature impacts the temperature measurements for any given day.

[39] Where for the purposes of the IRP "Feb. 3, 1989" represents the 7 a.m. on Feb. 3 to 7 a.m. on Feb. 4 time period.

While the system-weighted[40] HDD measure for the planning peak day was 53 HDDs (or 12.0°F) in the last IRP it changed to 10.5°F (54.5 HDDs) in this IRP with the move to the temperature measurement being an average of the 24 hourly temperatures of the gas day.[41]

2. The coldest temperature days in NW Natural's service territory are often windy, sunny days: Feb. 3, 1989 was a very cold day in terms of temperature, but it was also an incredibly windy—albeit clear—day over most of NW Natural's service territory.

3. Day of the week and holidays matter for gas usage and since temperature and day of the week are independent it is not appropriate to assume that peak day weather will occur on one of the lower usage days in a week or year when setting the standard that will ensure adequate resources are available to meet peak day customer needs. While Feb. 3, 1989 was a Friday this was purely random and could have been on a day a day of the week that would see more usage (Monday–Thursday), so the peak day planning standard assumes the peak day occurs on a normal weekday (Monday, Tuesday, Wednesday or Thursday) to ensure that if peak weather conditions are realized that the Company has enough resources to serve customers regardless of the which day of the week the cold weather falls.

4. Due to the lag between the customers' equipment response to cold weather and when there is an "upstream" response at the gate stations and storage facilities that provide the data used by NW Natural to forecast peak load, the previous day's temperature adds significant explanatory power to the model. Though this would not necessarily make sense if the load response were instantaneous (like if NW Natural had high frequency metering for all its customers), this is not the case as there is a lag between when customers' equipment uses more gas and when there is increased flow upstream at gate stations and storage facilities (where the bulk of the data to estimate the peak day forecast is measured).

System-level Use Per Customer (UPC) Model

Regression analysis is used to predict daily aggregate firm sales use per customer (UPC)[42] under different weather conditions through time using the last eight years of actual daily firm sales data[43] and customer counts with the additional weather factors described in the previous section as the explanatory variables.

The additional variables included in the system-level UPC model all proved to be highly useful in predicting gas usage on NW Natural's system for a given day using statistical methods. Consequently,

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[40] Defined as a weighting of load center level peak day weather measurements by the share of noncoincident peak day load to determine a system-weighted peak day weather measurement.

[41] The average absolute value difference in temperature measurement for the 2,841 days included in the analysis between the HDD measurement and the hourly average of gas day temperatures is 1.5° F.

[42] Where $Daily\ Use\ Per\ Aggregate\ Firm\ Sales\ Customer_t = \frac{Daily\ System\ Firm\ Sales_t}{\#\ of\ Firm\ Sales\ Customers_t}$.

[43] From Jan. 1, 2008 through Aug. 31, 2015, representing the entirety of the data available at the time of the analysis.

the results of the model proved to be more accurate and more precise at predicting usage on cold days, particularly extremely cold days, than the model used in the 2014 IRP.

As one would expect more natural gas is used by customers on a given day the colder the temperature, the higher the wind speed, the less solar radiation, and the more precipitation on that day.[44] Additionally, customers use less gas on holidays than nonholidays and less on weekends than on weekdays, with the lowest usage for the system found on holidays, then Saturdays, then Sundays, and then Fridays.[45] There is no statistical difference in usage between Monday, Tuesday, Wednesday and Thursday.

Figure 2.37 shows actual Firm customer gas usage for each day in the 2013–2014 Purchased Gas Adjustment filing (PGA)/Gas Year[46] against the new gas day temperature measure in addition to the gas consumption predicted for all of the days in the gas year with the new system-level forecasting model. The 2013–2014 Gas Year is chosen for exposition purposes since many of the coldest days in the last 20 years[47] were experienced during this heating season.

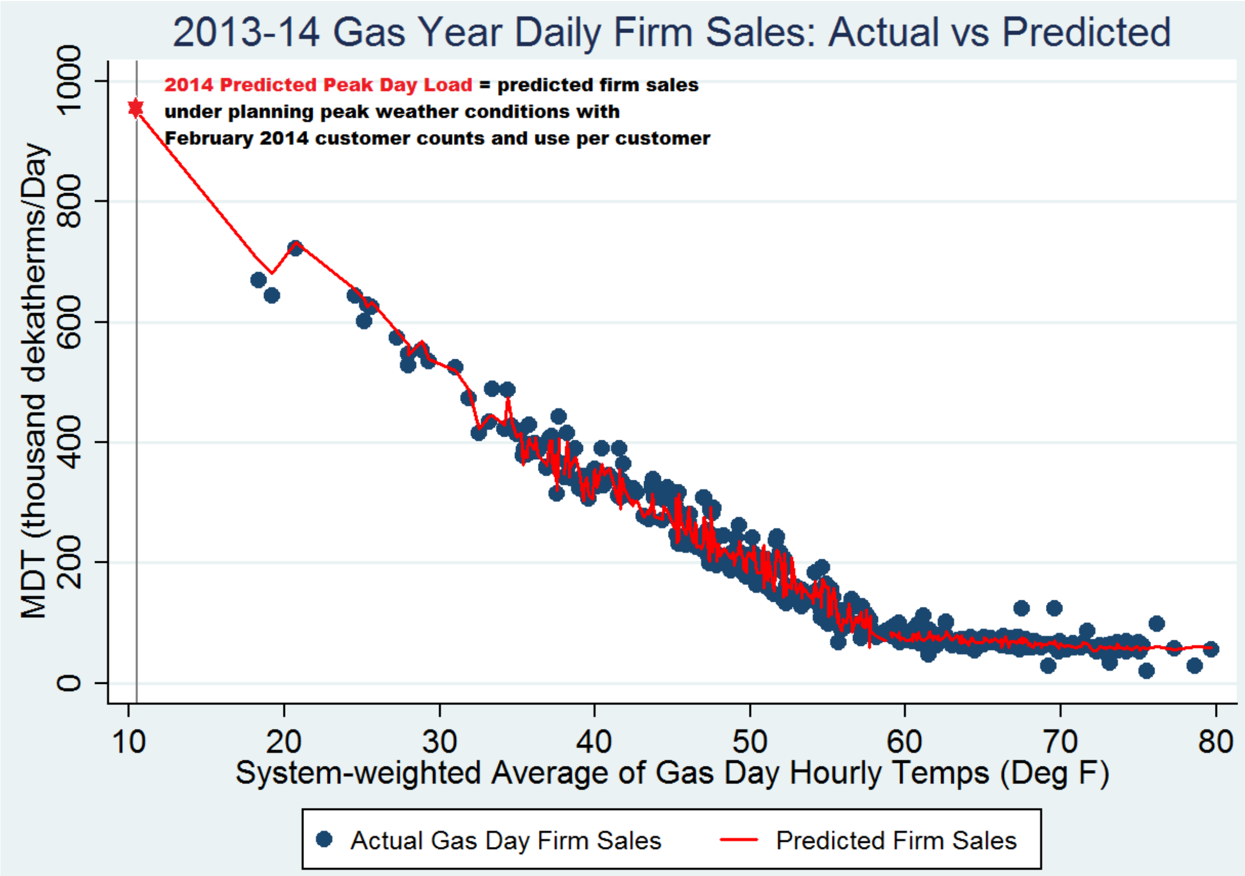
[44] The precise numerical impact of each of these drivers and load can be found in appendix 2.

[45] Note that the Friday gas day represents the 7 a.m. on Friday to 7 a.m. on Saturday timeframe.

[46] A gas year spans Nov. 1 through Oct. 31 of the subsequent year.

[47] On a system-weighted coincident weather basis Dec. 8, 2013 was the most extreme day in the last 30 years for the Eugene and Albany load centers and the most extreme day in recorded history for Eugene.

Figure 2.37: Predicting Firm Gas Usage on a Peak Day



Note that if temperature was the only explanatory variable the prediction line (the red line in figure 2.37) would be linear in temperature rather than adjusting for other factors that cannot be shown on a two-dimensional graph. Since the additional factors discussed above are included in the regression, the prediction "line" takes its irregular shape, which is a visual depiction of how the average prediction error (the difference between the predicted firm sales and the actual firm sales on any given day) is greatly reduced with the new system-level UPC model. In other words, for a day with a given temperature, there is still a wide range of expected firm sales for that day that can be explained by the model depending on wind speed, precipitation, whether it is a weekend, how cold it was the previous day, etc.

It is also pertinent that the peak planning weather conditions are more extreme than would be predicted by temperature alone given that Feb. 3, 1989 was not only the coldest day in NW Natural's service territory in the last 30 years, but also an incredibly windy day that is assumed to fall on either a Monday, Tuesday, Wednesday, or Thursday (even though it was actually Friday, which is associated with lower usage). This correlation between extreme cold and high winds is statistically significant in the Company's service territory.[48]

[48] This, however, does not imply that all days of extreme cold are windy days.

The system-level UPC model also includes time (in days) as an explanatory variable to incorporate trends in system usage due to changing customer composition amongst customer types, changes in expected demand-side management savings, technological change, replacement of old equipment with new equipment, changing code requirements, and numerous other factors. The overall trend is a decrease in aggregate use per customer through time.

A price elasticity of demand measuring price by either the real weighted average cost of gas (WACOG) or the real residential rate was ruled out statistically for days that have the highest heating needs (like a planning peak day).[49]

Peak Day Firm Sales Forecast

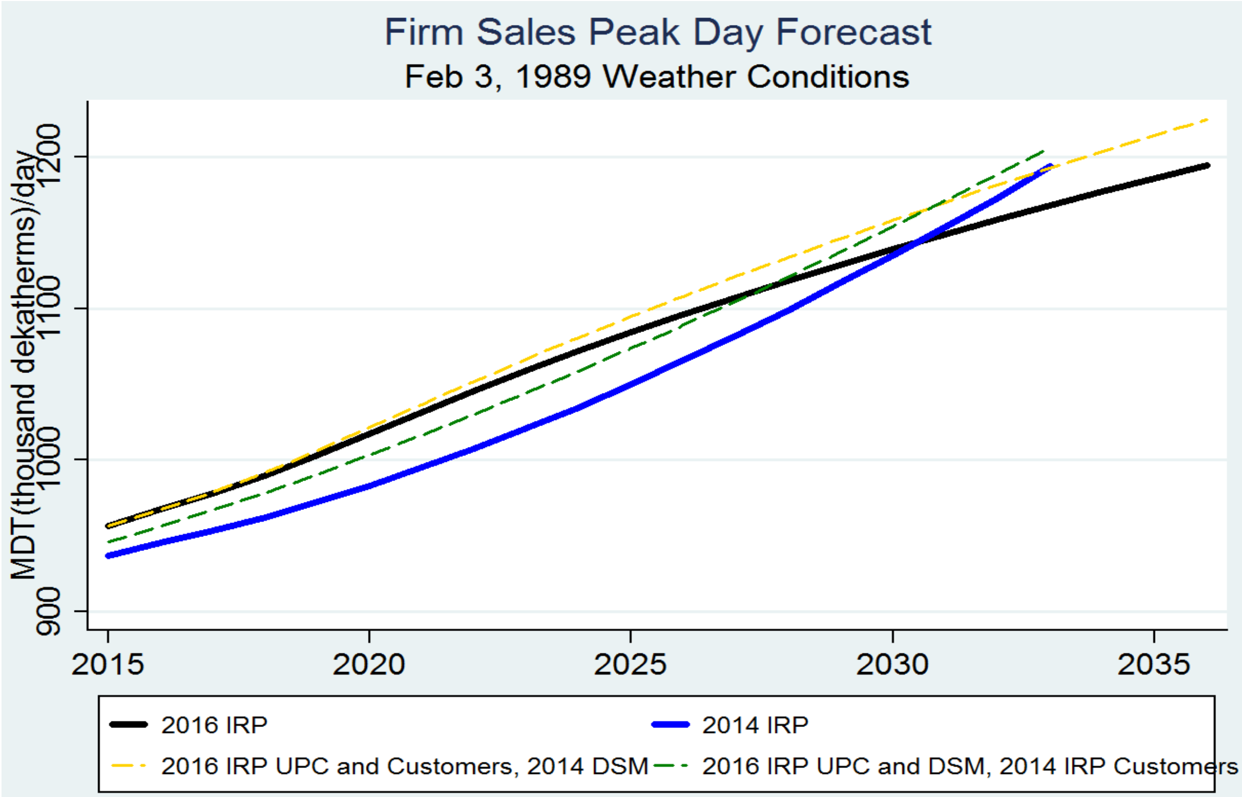
Combining the customer forecast and the system-level UPC model under planning peak conditions provides the basis of the peak day firm sales forecast, though adjustments are made for (1) changes in the DSM/EE deployment projection relative to the 2014 IRP and (2) the small component of the emerging markets forecast that is projected to be firm sales load. The peak day forecast adjustment due to a change in projected DSM/EE relative to the last IRP represents a reduction of 2.4 percent from the firm sales peak day forecast in 2035-36 while the adjustment for the firm sales component of the emerging market forecast represents an increase of 0.08 percent to the firm sales peak day forecast in 2035-36. The DSM/EE deployment projection saw significant changes from the last IRP and its impact on peak day usage is presented in detail in chapter 6 (with the significant changes to the avoided costs calculation that is a key contributing factor to this change detailed in chapter 5).

Figure 2.38 shows the firm sales peak day forecast that represents the amount of supply resources that NW Natural projects it needs to have in order to serve its customers if peak day weather conditions are experienced in any given year of the IRP planning horizon. Note for illustration purposes NW Natural assumes the peak day occurs in February of each heating season so that the 2015 figure represents a peak day in the 2014–2015 heating season that occurs in February of 2015.[50]

[49] Appendix 2 addresses this issue in more detail.

[50] This is relevant since time and customer count are important components of the peak day load forecast. The February customer forecast and time of each year are assumed to be Feb. 3 of the given year.

Figure 2.38: Firm Sales Peak Day Forecast: 2016 IRP versus 2014 IRP



Relative to the 2014 IRP the peak day forecast is slightly higher in this IRP before 2030, and is lower thereafter. A combination of four primary factors drove this change: (1) a change in the peak day UPC methodology, (2) greater customer growth in 2014 and 2015 than predicted in the 2014 IRP, (3) an updated customer forecast, and (4) an updated DSM/EE deployment projection. The change in the peak day UPC methodology represents a slight increase in the peak day forecast (1.7 percent on average over the planning horizon peaking at 2.4 percent in 2024), higher customer growth than predicted in the 2014 IRP for 2014 and 2015 represents an increase of 0.9 percent in the peak day forecast for 2016 relative to the 2014 IRP, the updated customer forecast represents the primary reason for the change in the "shape" of the peak day forecast from the 2014 IRP accounting for an increase until 2029 (0.6 percent on average and peaking at 1.1 percent in 2023) and decrease after 2029 (growing to a 2.1 percent decrease in 2033), and the decrease in the forecast from a change in the DSM/EE deployment projection relative to the 2014 IRP accelerates over the planning horizon and peaks at a 2.5 percent reduction in 2036. This breakdown of the change in the peak day forecast is explored in more detail in appendix 2.

While capacity needs (both supply and distribution/deliverability) are driven by peak usage, the space heating dominance of NW Natural's load means that average daily usage is drastically less than expected usage on a planning peak day. Space heating dominance of load also means that usage is highly dependent upon weather so that the highest usage day in a heating season (or PGA/Gas Year) will vary dramatically from year to year depending on the most extreme weather day experienced in that year[51]

[51] Which is by definition only expected to be as extreme as the planning peak once every 30 years.

and average daily usage for a given PGA (Gas Year) will be highly dependent upon how extreme the weather is (either cold or mild) during the heating season overall.

Figure 2.39 shows that weather for the entire heating season and weather on the most extreme heating requirement day of the year are correlated, but the correlation is not strong.[52] It is not uncommon for a relatively mild heating season to have a single day that is colder than the coldest day in relatively colder gas years or for a relatively cold heating season not to have the coldest day in the year be cold relative to the coldest day in milder heating seasons.

Figure 2.39: Weather and Usage: Peak day Temperatures vs. Annual HDDs by Gas Year

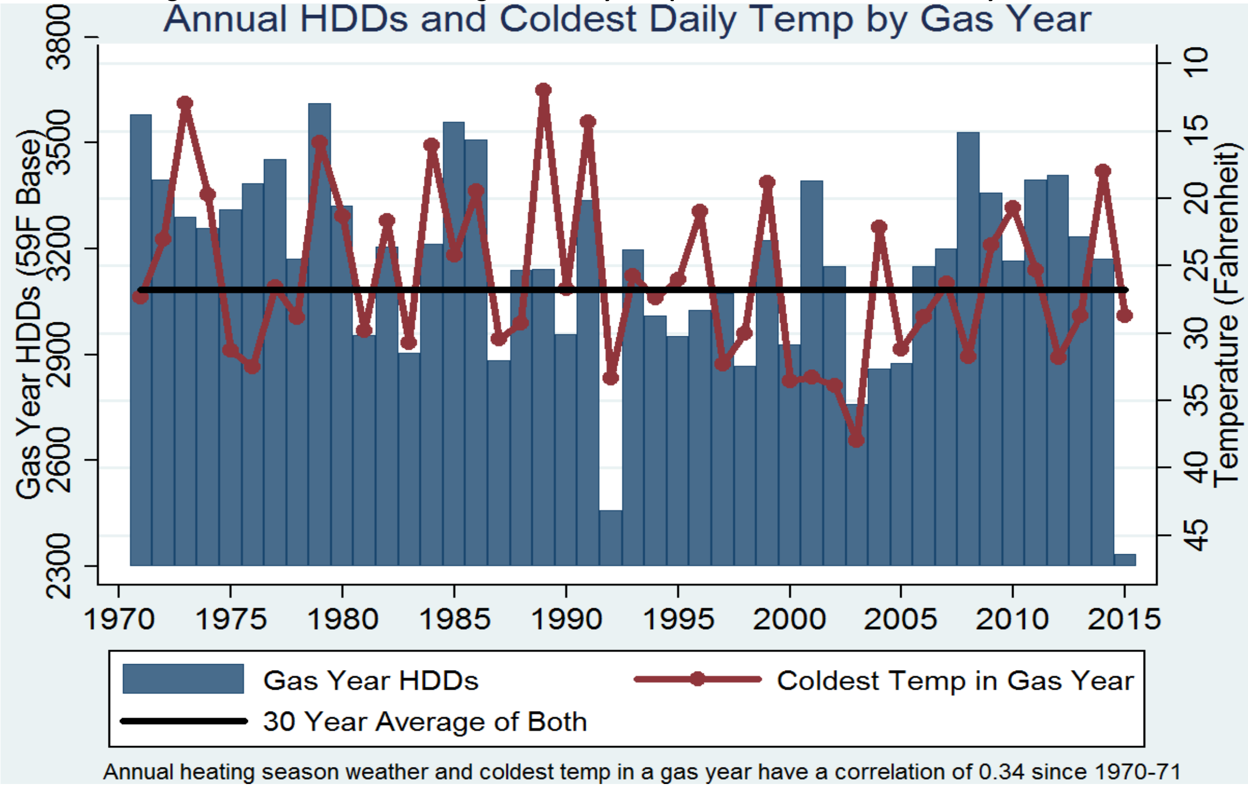


Figure 2.40 shows the "peakiness" of NW Natural's load and the importance of normalizing usage for weather. It depicts (1) the actual values from 2007–2008 to 2014–2015[53] for average daily usage relative to the daily average that would have been expected over the gas year if normal weather[54] had been experienced, (2) the actual peak day usage for the same heating season relative to the "normal" peak day that was expected for the year,[55] and (3) the planning peak for the year that determines the amount

[52] This topic is discussed in more detail in Appendix 2.

[53] These gas years are represented as 2008 (by implication) and 2015, respectively, in figure 2.39.

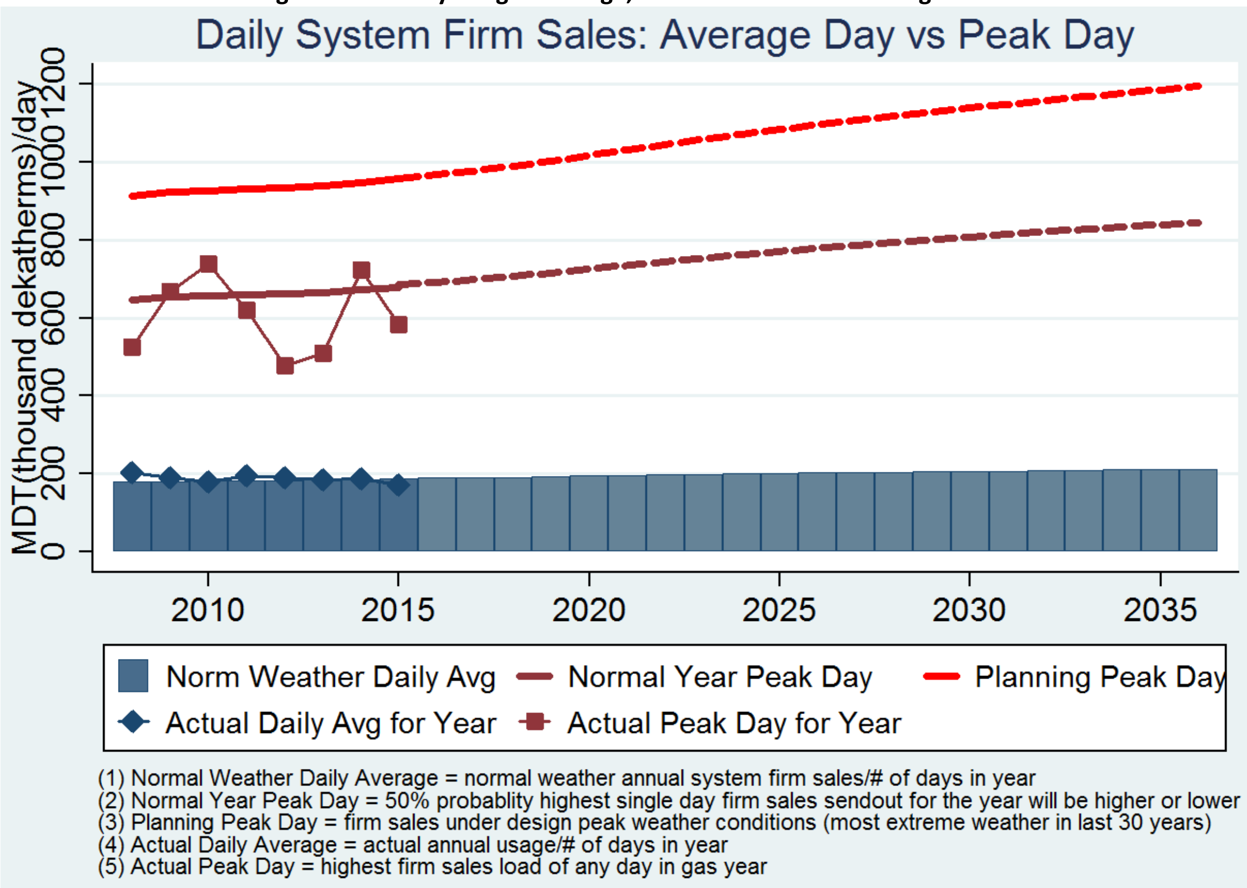
[54] Where normal weather is defined as the average of the last 30 years of data.

[55] Where normal peak is defined as a 1-in-2, or 50 percent, probability the usage for the highest usage day in the gas year will be higher and a 1-in-2, or 50 percent, chance the highest usage day in the gas year will be lower.

of supply resources NW Natural maintains to serve its customers in case of a once in 30-year peak day event. Actuals being higher than normal indicates that weather was colder than normal (for either the peak day for the year of the gas year as a whole) and actual being lower than normal means that weather was milder than normal.

Expected planning peak day load is approximately 40-percent higher than predicted normal year peak day usage and more than five times the average daily usage in a year expected under normal weather conditions. Furthermore, NW Natural's annual load shape is not only "peaky" but growing "peakier" through time as residential and commercial usage grows relative to industrial usage driving an increase in the share of annual load that comes from space heating.[56] This "peaky" load shape has numerous implications for NW Natural's resource planning, the most prominent being the relative attractiveness of storage resources. However, while annual, seasonal, weekly, daily, and hourly load shapes present complications and increased costs in the form of capacity resources, this effect is not as severe as the implications of load shapes for electric utilities that do not have a technically mature and cost-effective ability to store the product they deliver to customers like natural gas LDCs do.

Figure 2.40: Daily Usage: Average, Normal Peak and Planning Peak



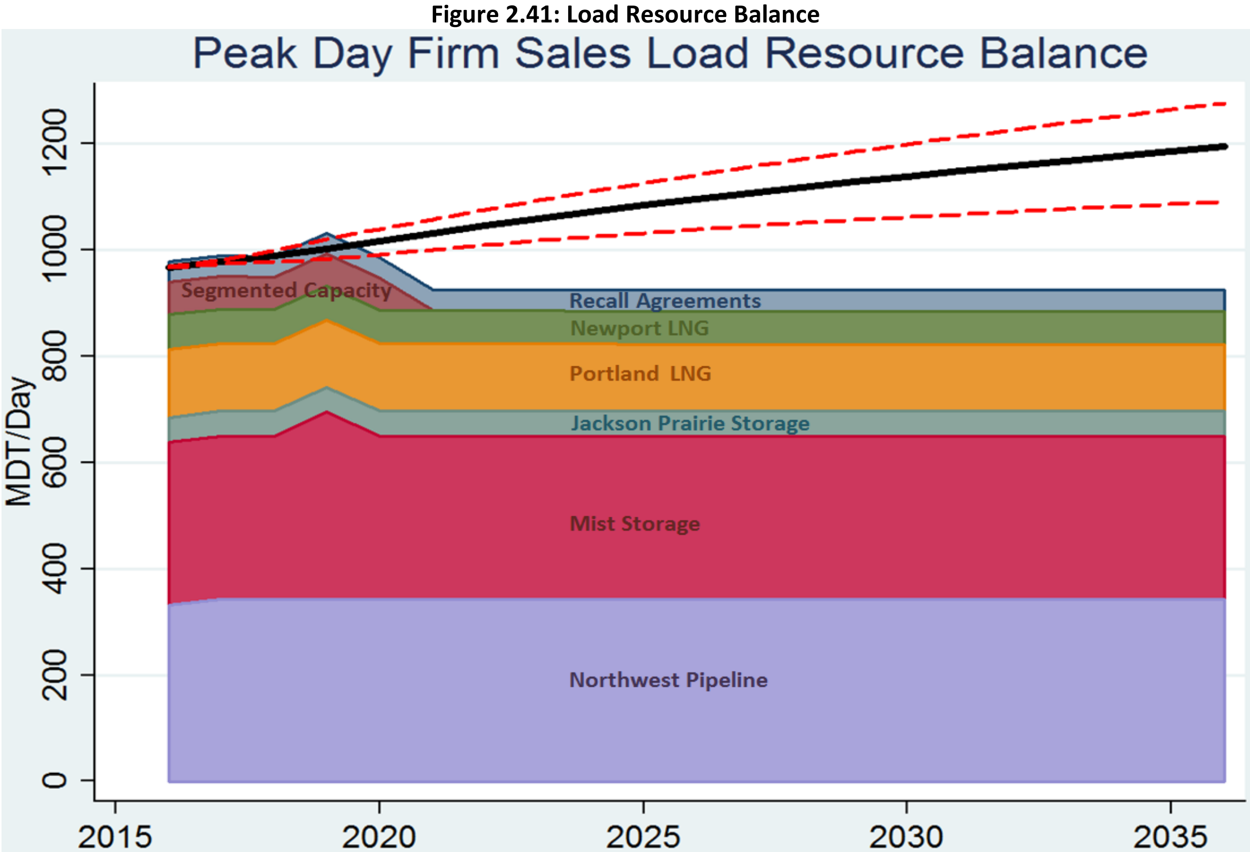
[56] There are other factors contributing to this increased "peakiness" as well, including gas being used as a peaking resource on-site for customers that use gas to back up heat pump systems that cannot be used to serve load at extreme cold temperatures.

Load Resource Balance

NW Natural does not add a reserve margin to its (planning) peak day load forecast, meaning the forecast represents the level of supply resources the Company plans to procure in each year in order to serve its customers in the event of a planning peak day weather event. Therefore, to determine the amount of incremental supply resources that are needed for procurement over the IRP planning horizon the difference between (1) the peak day load forecast and (2) the level of current (and committed to be acquired/retired in the future) supply resources, or the load resource balance, is a critical component of IRP planning. Figures 2.41 and 2.42 depict NW Natural's load resource balance over the 20-year planning horizon and include the high and low peak day forecast sensitivities.[57]

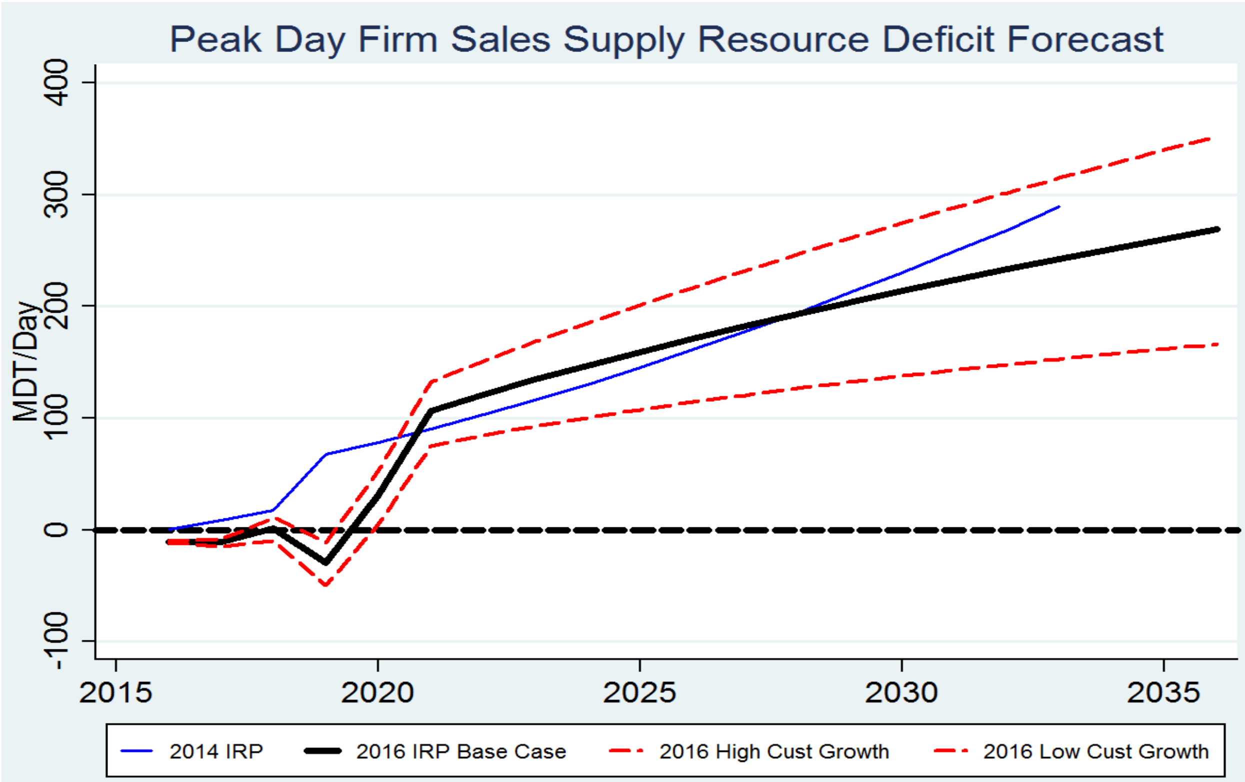
The projected supply resource deficit is lower than that projected in the 2014 IRP through 2020, higher from 2021 through 2027, and lower from 2028 through the end of the planning horizon. A combination of (1) the change in the peak day load forecast described in this chapter and (2) changes to assumptions about the energy content of gas at NW Natural's storage resources and assumptions about the level and timing of segmented capacity included in the Firm supply resource portfolio described in detail in chapter 3 represent the change from the 2014 IRP. The supply options to meet the projected deficit are described in chapter 3, and supply resource optimization and risk analysis are detailed in chapters 8 and 9, respectively.

Figure 2.41: Load Resource Balance



[57] Determined from the high and low sensitivities of the customer forecasts.

Figure 2.42: Supply Resource Deficit Forecast



Deliverability/Distribution Peak Hour Usage Forecasts

The process for determining the need for deliverability (distribution) resources is very similar to that used to determine the need for supply resources, with the key differences being that the peak need forecasted is peak hour firm sales for a specific load center under the peak weather conditions of that load center (as opposed to peak day firm sales for the entire system under system-weighted coincident peak weather conditions). Consequently, the planning peak hourly flow model for each load center is similar to the system-level daily UPC model in that they include temperature, lags of temperature, wind speed, precipitation, solar radiation, day of week, holidays, and time as explanatory variables. The load center hourly flow models are more complex, however, in that they forecast firm sales flows directly[58] using hourly usage and weather data[59] while incorporating additional explanatory variables for number of customers, hours of the day, large customer addition or loss, and additional lags of temperature. This allows the hourly load shape throughout the day for each specific load center to be incorporated into the projection for different weather patterns and days of the week and year.

Load center peak hour forecasts are new to this IRP and are an improvement upon the previous methodology that applied a peak *hour* share from a general load shape to the peak *day* forecast of each

[58] As opposed to forecasting aggregate use per customer and multiplying UPC times number of customers.

[59] Using the same gas control data that was aggregated to the daily level to construct the system-level peak day UPC model.

load center to determine peak hour projected flow. The new methodology for forecasting load center-level peak hour usage and its benefits are discussed in more detail in appendix 2.

Load Center Peak Hour Weather Standard

The peak weather standard is the same for the deliverability system as it is for supply resources, where the most extreme heating requirements in 30 years define the resource planning standard. However, while the coincident peak is used for the system-level peak day forecast, the peak hour weather standards for each load center do not fall on the same hour, or the same day, for all load centers. Table2.8 shows the peak hour weather conditions for each load center.[60]

Table 2.8: Noncoincident Load Center Planning Peak Hour Weather Measurements

	Astoria	Coos County	Corvallis/ Abany	Eugene	Newport	PDX-Central	PDX-East	PDX-West	Salem	The Dalles	Vancouver
Day	12/21/90	12/21/90	12/8/13	12/8/13	12/22/98	2/3/89	2/3/89	2/3/89	2/5/89	1/31/96	2/3/89
Hour	7am	7am	7am	7am	7am	7am	7am	7am	7am	6am	7am
Temperature (°F)	6.1	12.9	2.5	-9.4	6.4	9.0	10.2	11.5	1.0	-3.1	2.5
Temp- 1 hour lag	6.1	12.9	3.0	-7.6	11.3	10.0	8.1	9.5	3.0	-4.5	3.7
Temp- 3 hour lag	8.1	14.0	1.2	-9.4	21.7	10.9	4.1	4.6	3.9	-6.5	4.1
Temp- 5 hour lag	8.1	14.0	1.4	-4.0	28.6	12.0	2.7	5.0	1.9	-4.4	4.6
Temp- 8 hour lag	10.0	15.1	4.5	-2.2	29.1	12.0	7.9	5.4	10.0	0.9	4.8
Temp- 24 hour lag	16.0	19.0	14.0	8.6	21.2	14.0	14.2	15.1	7.0	7.9	6.8
Wind Speed (mph)	6.9	6.9	0	0	3.4	34.4	28.6	20.8	0	5.8	18.3
Precipitation (inches)	0	0	0	0	0	0	0	0	0	0	0
Solar Radiation(w/m^2)	0	0	0	0	0	0	0	0	0	0	0
Day of Week	Mon-Thu	Mon-Thu	Mon-Thu	Mon-Thu	Mon-Thu	Mon-Thu	Mon-Thu	Mon-Thu	Mon-Thu	Mon-Thu	Mon-Thu

As can be seen in table 2.8, NW Natural's service territory is somewhat diverse climatically when discussing extreme heating season weather. While Eugene's planning peak hour is -9.4°F, Coos County's is 12.9°F. Eugene is also interesting to point out as it experienced its coldest day in recorded history stretching back more than 100 years on Dec. 8, 2013.[61] Also, if each factor is isolated, precipitation increases predicted load and solar radiation decreases it, none of the load centers has a planning peak hour that includes precipitation since none of the peak hours saw precipitation since the planning peak hour for each load center falls early in a winter morning before the sun has risen. Much as seasonal, weekly, and daily load shapes are critical for supply resource planning, hourly load shapes are of critical importance when it comes to deliverability/distribution system planning. Due to the combination of weather driven and nonweather driven usage patterns the 7 a.m. to 8 a.m. hour is the typical planning peak hour.

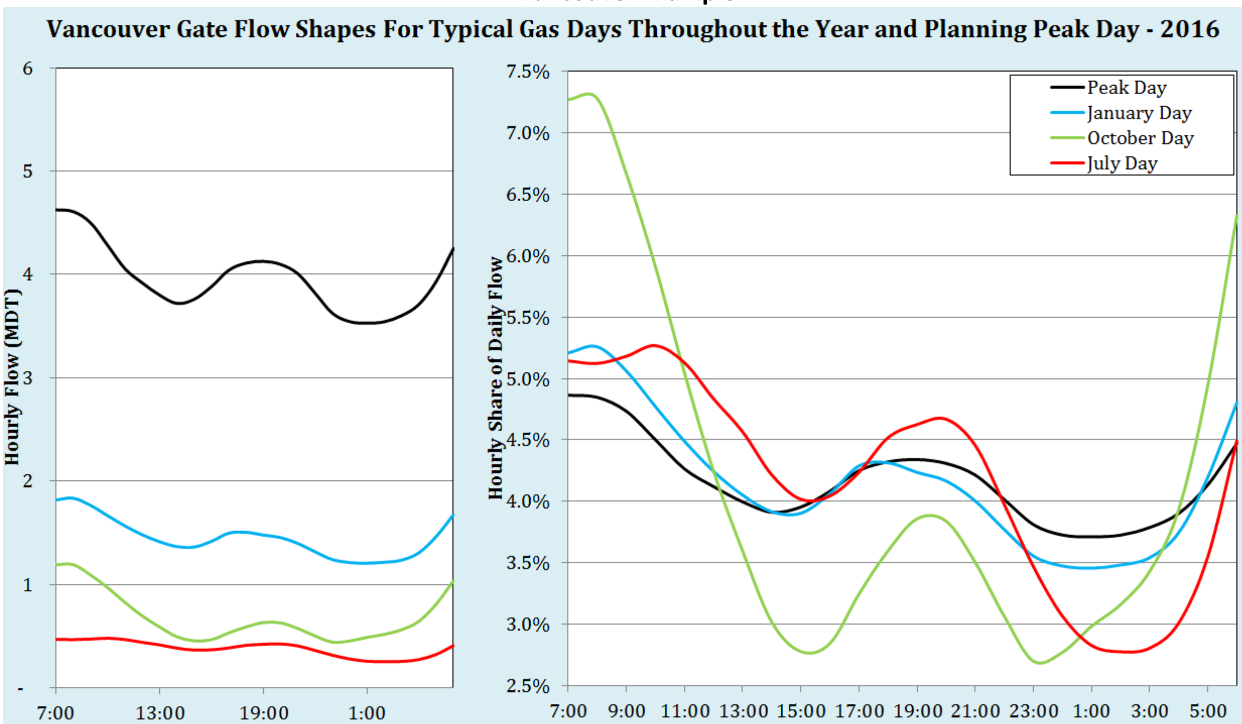
Intra-day hourly load shapes are shown in more detail in figure 2.43, which uses the Vancouver load center as an example[62] to show load shapes for different gas days throughout the year as well as the peak day.

[60] The difference between coincident peak and non-coincident peak can be seen by comparing table 2.7 with table 2.8.

[61] And presumably coldest hour, though it cannot be said with certainty since hourly data is not available for a majority of this period.

[62] Intra-day hourly load shapes for the other load center are found in Appendix 2.

Figure 2.43: Intra-day Hourly Load Shape for Different Days throughout the Year: Vancouver Example



The graph on the left of figure 2.43 shows actual expected flows for each hour of the gas day for a typical day in July, October, and January, as well as the expected flows if the planning peak day weather conditions were to occur in 2016 and points out the drastic difference in daily flows throughout the year as well as peak day usage relative to usage during more typical weather conditions (even those experienced during the winter).

The graph on the right shows the share of the gas day load predicted in each hour of the day. Not surprisingly, the "shoulder months," including September, October, April, and May, show the "peakiest" intra-day load shape as temperatures are often cold enough during the night and early morning to drive space heating usage but warm enough during the late morning, afternoon, and early evening that little space heating load materializes. While one might expect winter loads to be peakier than summer loads, this is not generally true as temperatures are typically cold enough to drive space heating needs throughout the entire gas day and overwhelm the load shape that occurs from the largest source of load that can be expected in any day of the year: water heating. Interestingly, while a lot of hour-to-hour variation is expected on the planning peak day, it has the "flattest" load shape since peak days tend to be extremely cold in all hours of the gas day and the space heating impact relative to water heating impact is even further exacerbated.

The new load center peak hour usage models also allow noncoincident peak hour forecasts to be projected into the future much more accurately than was possible with previous distribution system planning methods, allowing needed distribution projects to be identified earlier and the potential for location specific accelerated DSM/EE to be considered as an option to meet customer needs to be increased. The benefits of the new deliverability/distribution system planning process and a proposed targeted DSM pilot are described in more detail in chapters 7 and 6, respectively.

9. ANNUAL ENERGY FORECAST

NW Natural uses the annual energy forecast to assess the Company's balance between pipeline and storage supply resources versus load requirements. The annual energy forecast integrates the customer forecast, estimated use per customer parameters, and expected weather with energy savings from demand-side energy efficiency and the forecast loads from Firm Sales Industrial customers and from Firm Sales Emerging Markets to establish annual energy requirements. Unlike the 2014 IRP, the 2016 IRP uses separate models from those used to estimate load under peak day conditions to estimate nonpeak use per customer, using temperature as the sole explanatory variable.

NW Natural combines three separate models to estimate energy demand over the planning horizon:

1. Current annual use per customer estimate based on five years of billing data
2. Incentivized cost-effective energy-efficiency trend from Energy Trust
3. Nonincentivized annual use per customer trend for existing residential and commercial customers based on four years of billing data

9.1. Current Annual Use Per Customer

NW Natural uses three years of billing and weather data to estimate nonpeak day energy demand. For the 2016 IRP the billing and weather data are taken from the period 2012 through 2014. Previous results for no-peak day energy demand were estimated using data from 2009 through 2011. NW Natural developed statistical models with an appreciation for the wide variation in customer types and differences in weather patterns between load centers. Demand estimates are created for each of seven customer classes and specified at either the load center or state level (table 2.9).

Table 2.9: Usage Estimate Classes and Locations

Customer Class	Location Specification
Residential Existing	Load Center
Residential Conversion	State
Residential SF New Construction	State
Residential MF New Construction	State
Commercial Existing	Load Center
Commercial Conversion	State
Commercial New Construction	State

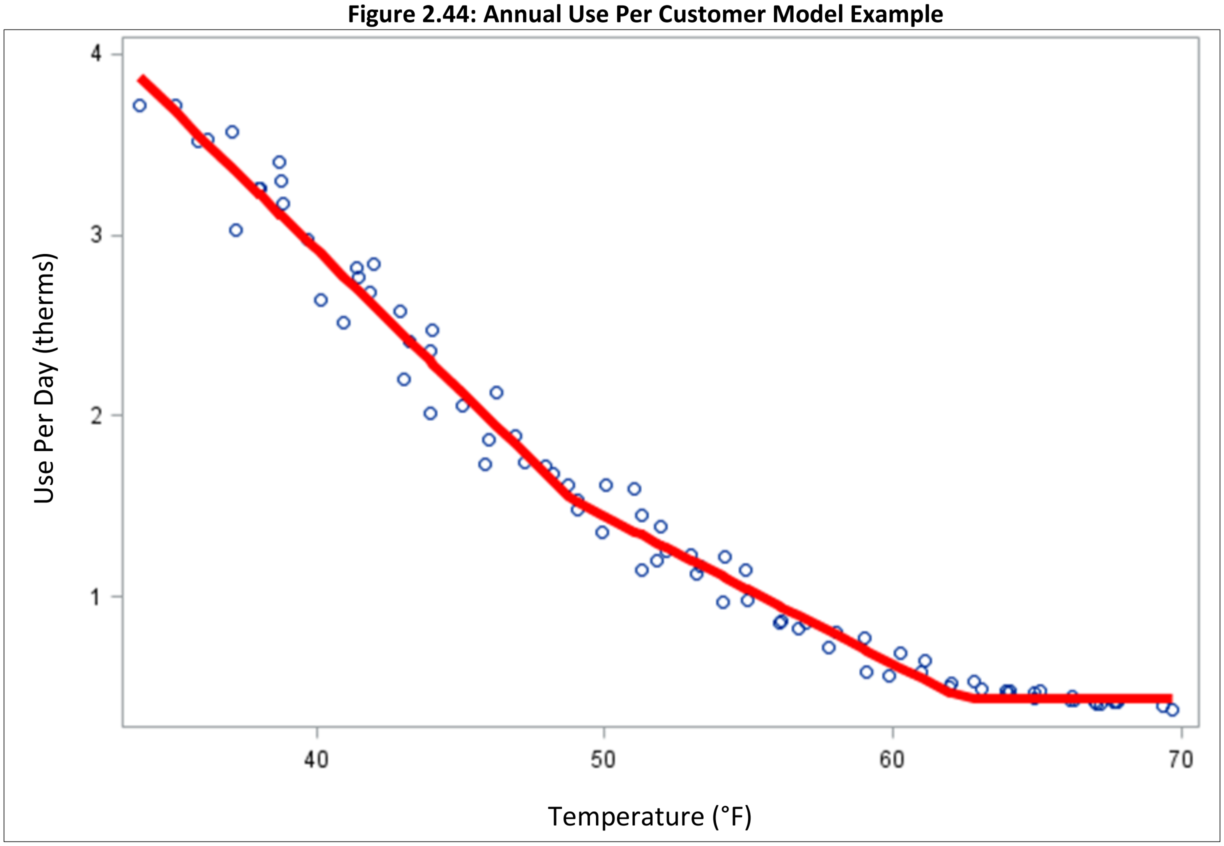
NW Natural previously estimated demand coefficients using a linear regression model with log transformed variables, with results subsequently translated into a piecewise linear function to be used in SENDOUT®. In this IRP the Company directly estimated demand coefficients using a piecewise linear regression function as shown in the equation below. The coefficients resulting from these models can be directly input into SENDOUT®. Figure 2.44 shows an example of the data and resulting model fit.

$$Use\ Per\ Customer = \begin{cases} a, & Temp \geq k_1 \\ a + b_1 * (k_1 - Temp), & k_1 > Temp \geq k_2 \\ a + b_2 * (k_2 - Temp) + b_1 * (k_1 - k_2), & Temp < k_2 \end{cases}$$

Where:

a = baseload (therms)
b_1 = Demand rate 1 (therms/°F)
b_2 = Demand rate 2 (therms/°F)
k_1 = break point 1 (°F)
k_2 = break point 2 (°F)

Figure 2.44: Annual Use Per Customer Model Example



Figures 2.45 through 2.48 show the current weather-normalized annual use per customer results along with comparisons to the results from the 2013 WA IRP which is last time annual use per customer was estimated using billing data.

Figure 2.45: Annual Usage by Existing Residential Customers in the 2013 and 2016 IRPs

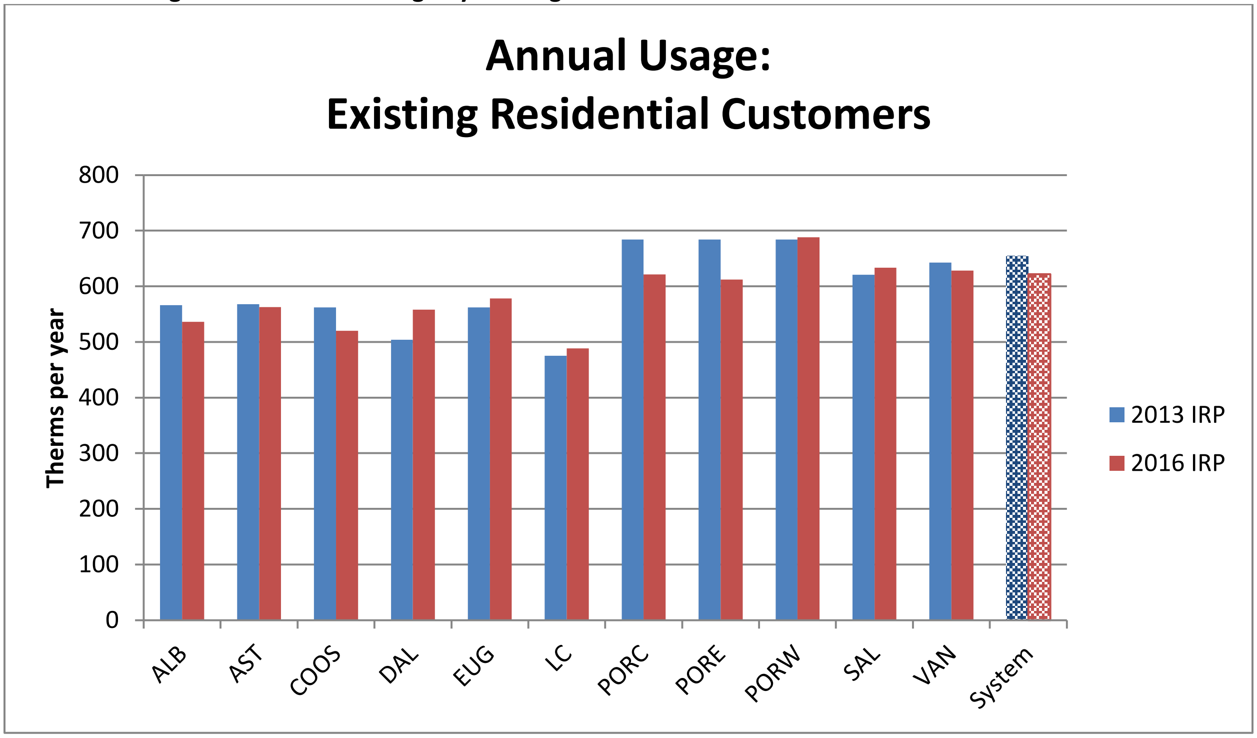


Figure 2.46: Annual Usage by Residential Customer Additions in the 2013 and 2016 IRPs

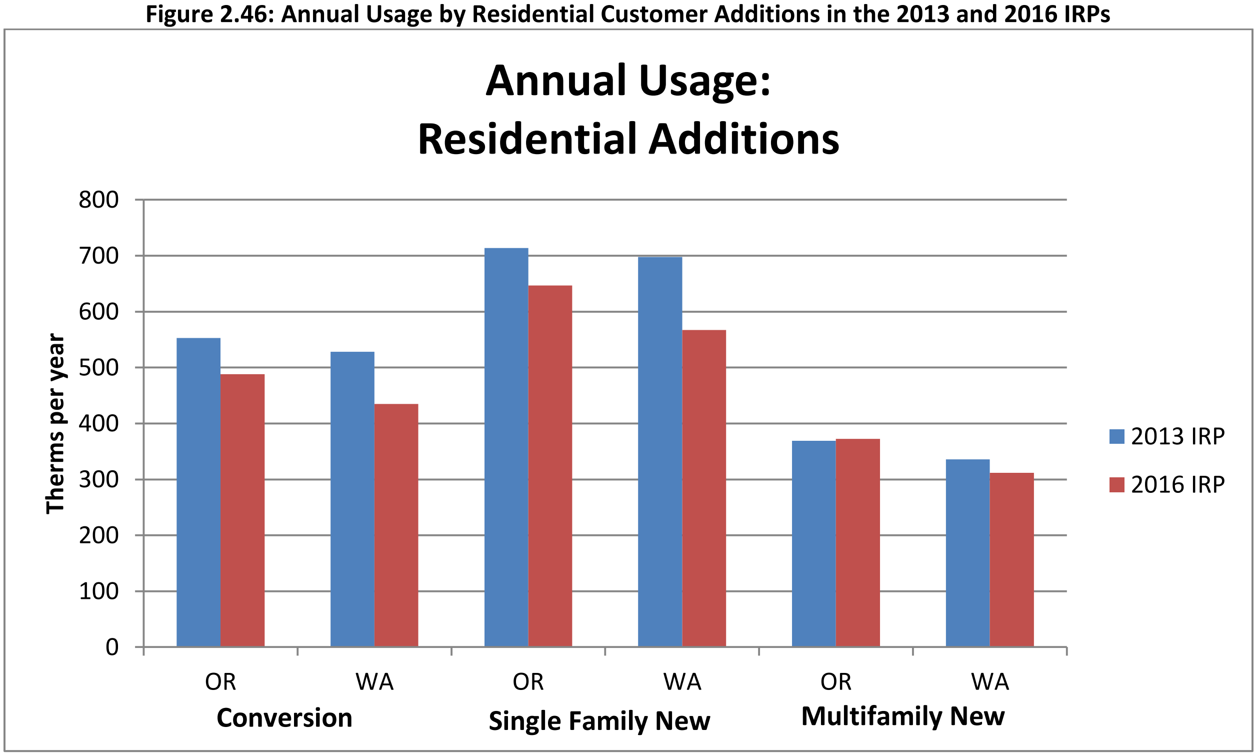


Figure 2.47: Annual Usage by Existing Commercial Customers in the 2013 and 2016 IRPs

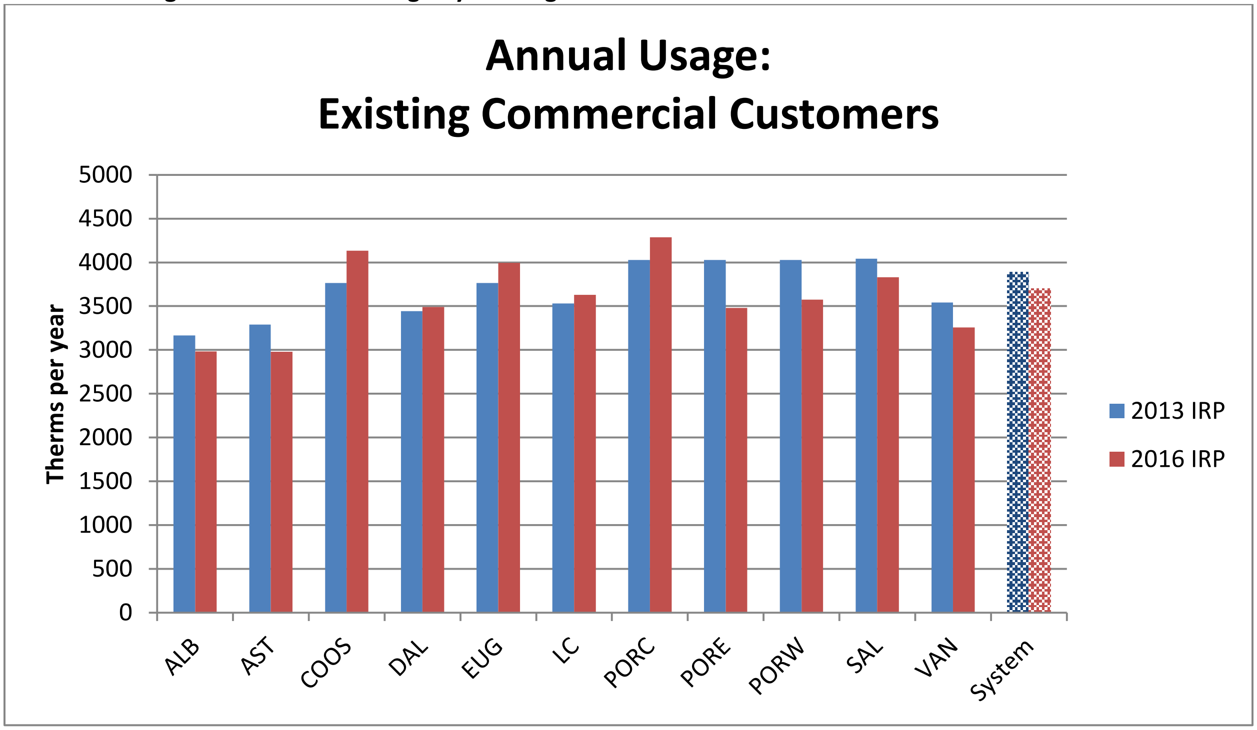
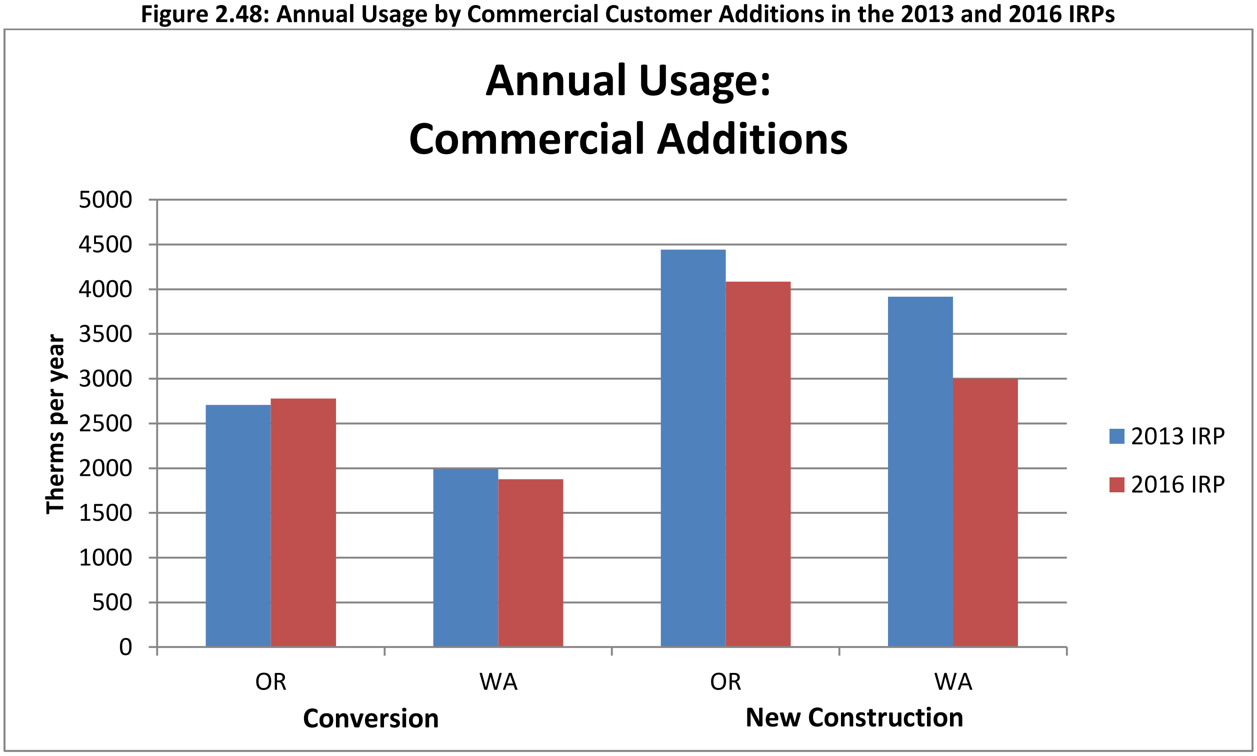


Figure 2.48: Annual Usage by Commercial Customer Additions in the 2013 and 2016 IRPs



9.2. Incentivized Cost-Effective Energy Efficiency

See chapters 5 and 6 for discussion and forecast of incentivized energy efficiency. NW Natural applied the forecasted annual energy savings by adjusting the annual usage coefficients such that the reductions match the projected base load and heat load savings.

9.3. Nonincentivized Annual Use Per Customer Trend

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

To estimate these changes requires that NW Natural look at a large sample of customers who have not participated in Energy Trust programs over a period of time. At the time of the analysis NW Natural had complete billing data dating to 2009 as well as NW Natural customer participation information from Energy Trust dating from 2004 through 2013. Combining these sets results in a data period ranging from 2009–2013. NW Natural has not previously modeled a nonincentivized trend in annual usage. As such, the data and methods used here will need to be updated and refined in future IRPs.

9.4. Final Annual Use Per Customer Trend

Figures 2.49 and 2.50 show NW Natural’s forecast of average annual use per customer for Residential and Commercial customers, respectively. Residential average annual use per customer is declining at an average annual rate of -0.3 percent per year (base load: -1.1 percent; heat load: 0.1 percent). Commercial average annual use per customer is declining at an average annual rate of -1.2 percent per year (base load: -1.9 percent; heat load: -0.3 percent).

While an increase in residential average heat load may seem counterintuitive given the increasing energy efficiency of space heating equipment, the trend could be explained by higher penetration rates of space heating in new construction and conversion customers relative to the current customer base.

Figure 2.49: Residential Annual Usage Trend

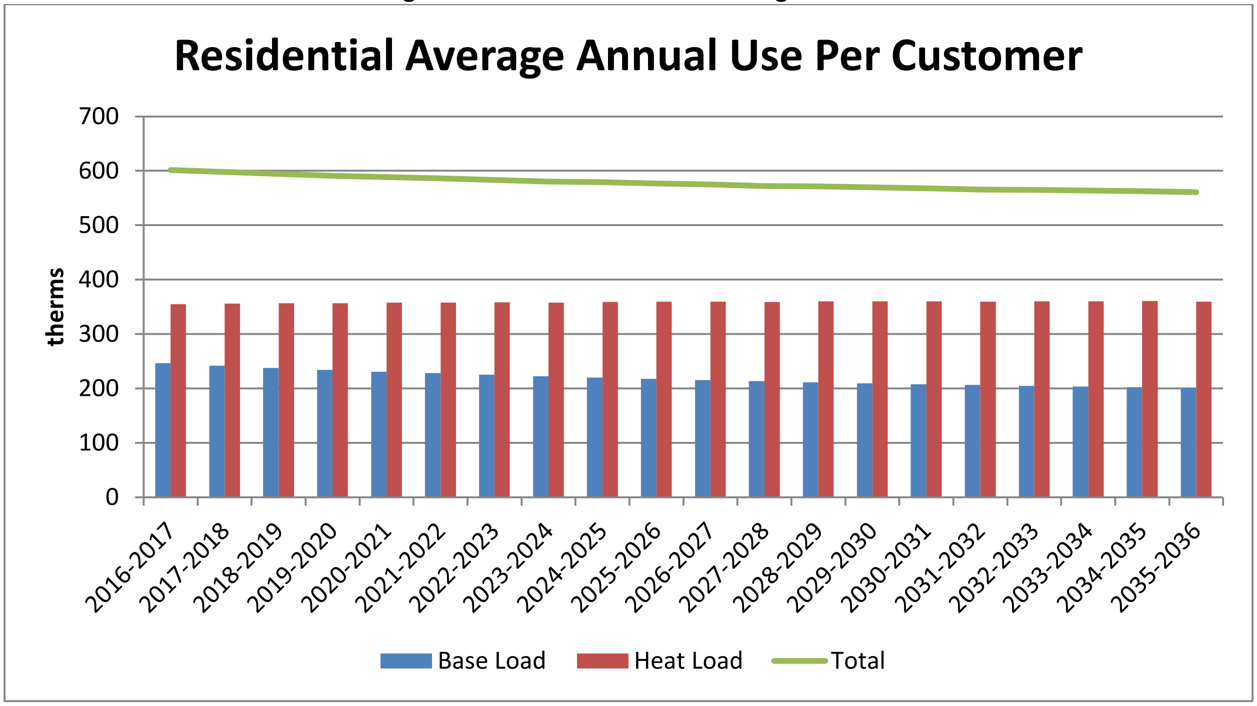
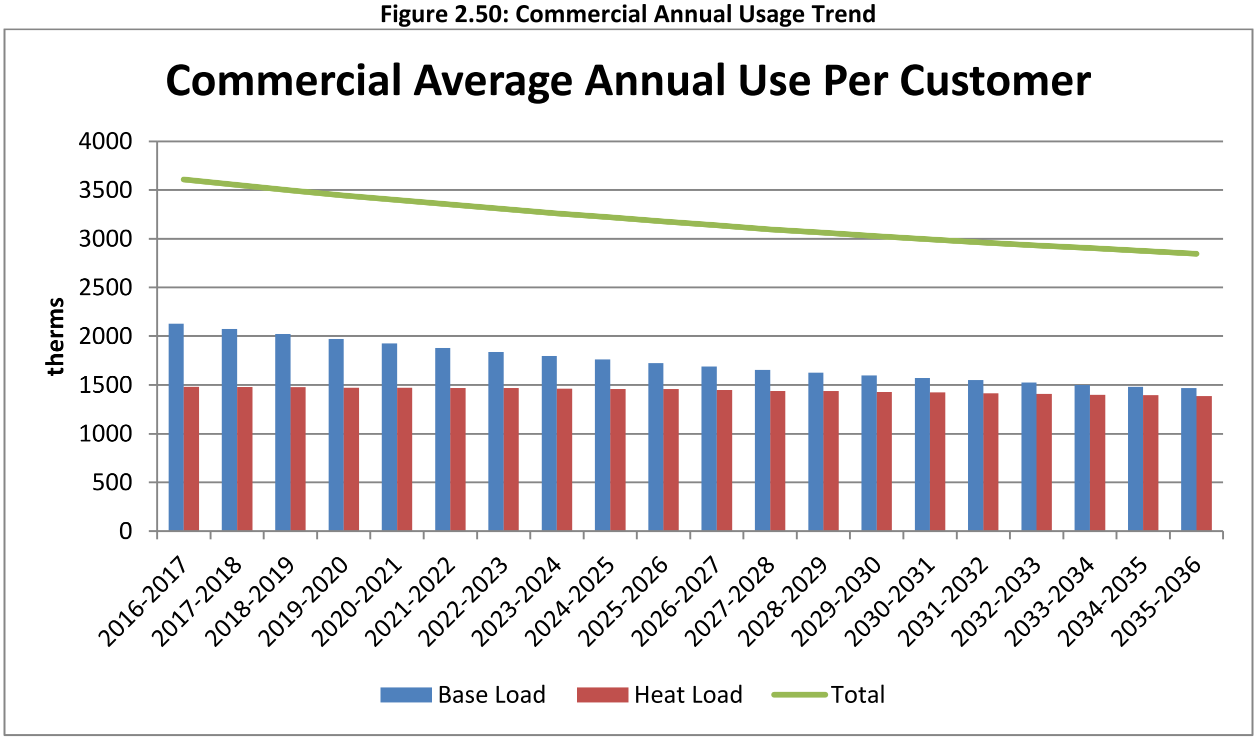


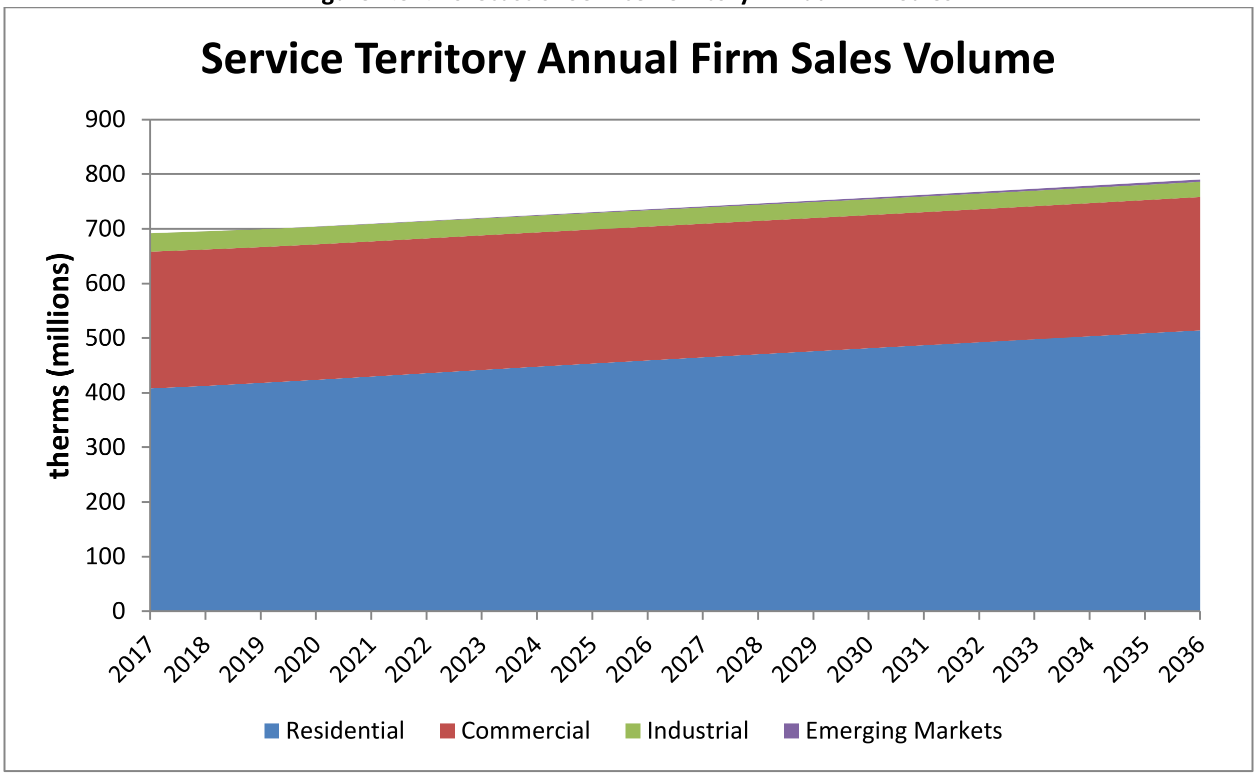
Figure 2.50: Commercial Annual Usage Trend



9.5. Annual Firm Sales Forecast

Figure 2.51 shows the forecast of weather-normalized service territory annual firm sales demand by customer class.

Figure 2.51: Forecast of Service Territory Annual Firm Sales



10. KEY FINDINGS

- Relatively slow regional economic growth will continue, with improvements in both Oregon housing starts and employment.
- Forecasted Henry Hub natural gas monthly prices in real terms will increase over the planning horizon from recent levels. Monthly prices at trading hubs where NW Natural procures gas supplies are forecast to almost double in real terms over the planning horizon from recent levels of approximately $2 per Dth to almost $4 by the end of the period.
- Lower than in the 2014 IRP, aggregate Residential and Commercial Firm Sales customer growth averages 1.6 percent annually over the 2016–2035 planning horizon in the Base Case forecast, with Oregon's rate averaging 1.5 percent and Washington's rate averaging 2.6 percent.
- Alternative Firm Sales customer growth scenarios have average annual rates of 2.1 percent in the High Growth scenario and 1.2 percent in the Low Growth scenario.
- Emerging Markets' Firm service load requirements over the planning horizon are small relative to total requirements and Firm Sales requirements are extremely small.
- Firm Sales design day peak demand in the 2016 IRP is, versus the 2014 IRP, up slightly in the near-term and lower in the later years of the planning horizon.
- Annual Firm Sales energy use grows at annual rates over the planning horizon of 0.6 percent in Oregon; 1.5 percent in Washington; and 0.7 percent for NW Natural.
- NW Natural's load is peaky and becoming more so over time.

Chapter 3
Supply-Side Resources

1. OVERVIEW

This chapter discusses the gas supply resources the Company currently uses to meet existing Firm customer supply requirements, recent changes in that portfolio, and the supply-side alternatives that could be used to meet the forecasted growth in gas requirements as described in chapter 2. Supply-side resources include not only the gas itself, but also the pipeline capacity required to transport the gas, the Company's gas storage options, and the major system enhancements necessary to distribute the gas. This chapter describes these resources without judgment as to the long-term resources that will be chosen, which is performed through the linear programming analysis presented in chapter 7. Also, as done previously, potential resources are discussed in this chapter that ultimately are deemed too speculative to include in the portfolio choice analysis in chapter 7, with explanations for why they ended up on the "cutting room floor." Other sections in this chapter will examine risk elements associated with certain supply resources, as well as a discussion of gas price hedging and other means to mitigate supply risks.

The gas supply planning process focuses on securing and dispatching gas supply resources to ensure reliable service to the Company's sales customers. The amount of gas needed is greatly influenced by customer behavior. Several factors can affect customer behavior and cause hourly, daily, seasonal, and annual variations in the amount of gas required. Much of this variation is due to changes in the

KEY FINDINGS

Key findings in this chapter include the following:

- The Company will increase its reliance on segmented capacity from 43,800 Dth/day (as shown in the 2014 IRP) to 60,700 Dth/day. However, the Company needs to plan for the eventual phase-out of segmented capacity because its peak day reliability is expected to degrade over time. For this IRP, that phase-out date is Nov. 1, 2020.
- Due to concerns regarding firm transportation service reliability, Plymouth LNG was removed from the Company's firm resource stack effective Oct. 31, 2015.
- The Company resolved a similar issue regarding firm transportation service from Jackson Prairie through the execution of a new TF-1 agreement with Northwest Pipeline, which became effective on Nov. 1, 2015.
- A prior concern over maximum daily delivery obligations (MDDOs), that is, firm gate station capacity rights, has been resolved for this IRP's planning period through the creation of additional MDDOs from capacity segmentation along with a methodology change that was adopted after consultations with Northwest Pipeline.
- A glut of natural gas liquids (NGLs) has led to a higher heat content of the gas flowing on the regional pipeline system, which in turn has slightly boosted the capabilities of the Company's storage plants. However, the NGL glut is not expected to persist indefinitely, so this impact has been modeled as gradually phasing out over time.
- As part of the Company's ongoing asset management practice, the action plan of this IRP includes repairs, replacements and/or modifications to the dehydration systems at Mist. Chapter 1 includes this as the following action item:
    - Replace or repair, depending on relative cost-effectiveness, the large dehydrator at Mist's Miller Station. Replacement is currently estimated to cost between $6 million and $7 million based on estimates obtained from a third party engineering consulting firm engaged by NW Natural. NW Natural will evaluate alternatives associated with the Al's Pool and Miller Station small dehydrator systems at Mist to determine if and when additional actions are warranted.

weather. However, changes in business conditions, efficiency measures, changing technology, and the price of natural gas service relative to other fuel alternatives also influence customer gas use. These behavioral factors are accounted for in the Company's gas requirements forecast and are discussed in more detail in chapter 2.

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

For a variety of reasons, these recall agreements most closely resemble the Company’s LNG supplies. First, there is a strict limitation on the number of days in which the recall option is made available to the Company during the heating season. Second, the delivery point is at the citygate[2] or within the Company's service territory, mirroring that of the Company's storage resources. And finally, like LNG, this is a relatively expensive resource on a pure cent per therm basis because prospective suppliers of this service expect it to be called upon during the harshest weather, when alternate fuel costs are highest and resupply is uncertain, and so they must include the possible cost of plant shutdowns and product loss. Most customers are simply unwilling to even consider providing such a service on a negotiated basis, and others may be too small to be of interest to the Company. However, because recall agreements can be cost-effective when looking at overall costs, the Company continues to pursue such resources where feasible.

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

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

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.

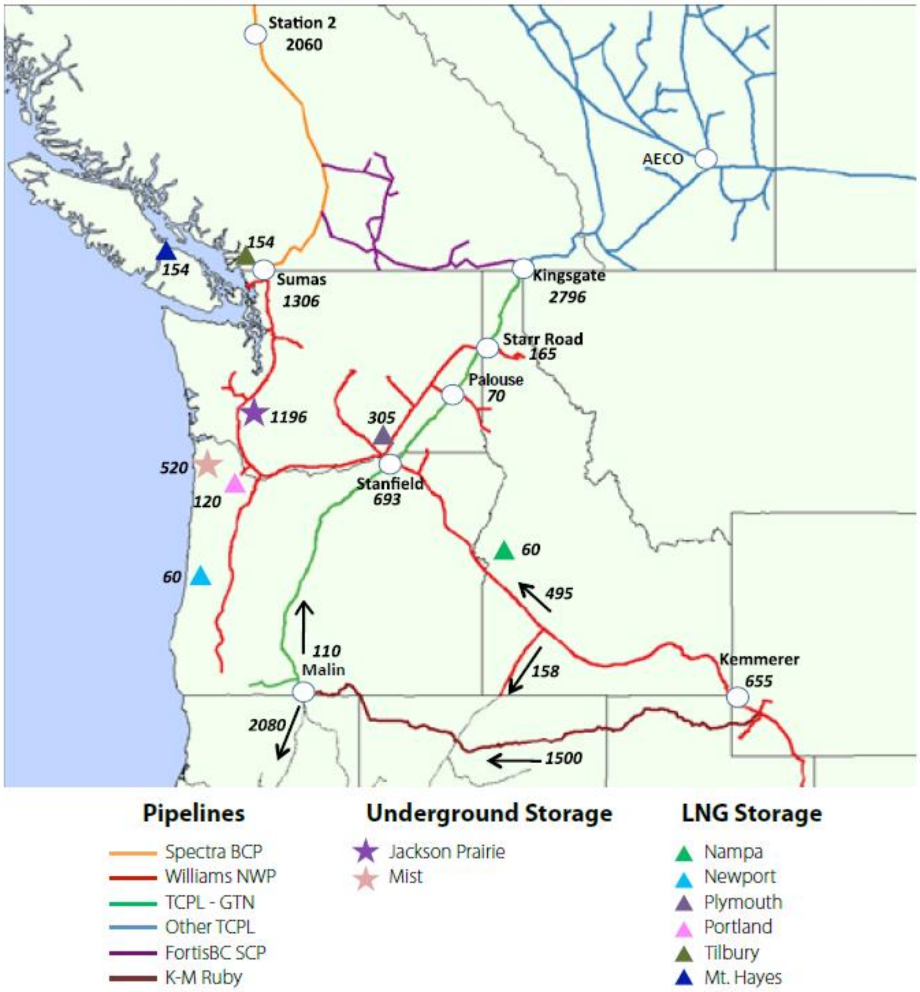
Basic economic theory holds that when the price of a good or service increases, then all else being equal, demand for that good or service should decrease. For natural gas, this could arise from structural changes, such as the installation of higher efficiency appliances and insulating materials. Or,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

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

2. CURRENT RESOURCES

A map showing the existing natural gas pipeline and storage infrastructure in the Pacific Northwest is shown in figure 3.1, which may be helpful as a reference as each component of NW Natural's supply portfolio is described in the following sections. The capacities in the map are shown in thousands of Dths per day (MDth/day). As discussed in section 4.3 of this chapter, the heat content of the gas currently flowing through the Northwest Pipeline system is slightly elevated compared with history, so current capacities are slightly higher than shown in the map.

Figure 3.1: Pacific Northwest Infrastructure and Capacities (in MDth/day)[3]



Source: Northwest Gas Association, 2015 Gas Outlook

2.1. Gas Supply Contracts

The Company's portfolio of supply contracts for the 2015-2016 heating season is indicated in table 3.1. The contracts with recent expiration dates will be renegotiated or replaced for the next heating season. The term "Baseload Quantity" refers to a contract with a daily delivery obligation, while the label "Swing Supply" means one party has an option to deliver or receive (as applicable) all, some or none of the indicated volumes at its sole discretion.

2.2 Current Pipeline Transportation Contracts

The Company holds firm transportation contracts for capacity on the Northwest Pipeline Corporation (NWP) interstate pipeline system, over which all of the Company's supplies must flow except for the

[3] MDth/day stands for thousands of Dekatherms per day.

small amount of natural gas that is locally produced either in the Mist field (less than 2 percent of annual requirements) or from biogas (zero for now).

For its purchases in Alberta and British Columbia, NW Natural also holds transportation contracts on the pipeline systems upstream of NWP, namely Gas Transmission Northwest (GTN, a unit of TransCanada Pipelines Limited), TransCanada's system in southeastern British Columbia (known as Foothills), TransCanada's Alberta system (known as NGTL or Nova), Westcoast Energy Inc. (WEI, a division of Spectra Energy) and the Southern Crossing Pipeline (SCP) owned by FortisBC Inc. (formerly known as Terasen and before that BC Gas). The Company has released a small portion of its NWP capacity to one customer but has retained certain heating season recall rights. Details of the current transportation contracts are provided in table 3.2.

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

As mentioned above, virtually all of the natural gas used by the Company and its customers has to be transported at one time of the year or another over the NWP system, which is fully subscribed in the areas served by the Company. Usage among NWP capacity holders tends to peak in roughly a coincident fashion as cold weather blankets the Pacific Northwest region. Similarly, NWP capacity that may be available during off-peak months tends to be available from many capacity holders at the same time. This means that the Company is rarely in a position to release capacity during high value periods of the year, and it would be unusual for capacity to be available for acquisition during peak load conditions.

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

Table 3.1: Firm Off-System Gas Supply Contracts for the 2015-2016 Tracker Year

Supply Location	Duration	Baseload Quantity (Dth/day)	Swing Quantity (Dth/day)	Contract Termination Date
British Columbia				
Tenaska Marketing Canada	Nov-Oct	10,000		10/31/2016
PetroChina International	Nov-Oct	5,000		10/31/2016
Conoco Phillips	Nov-Oct	5,000		10/31/2016
EDF Trading	Nov-Mar	5,000		3/31/2016
Powerex	Nov-Mar	5,000		3/31/2016
Conoco Phillips	Nov-Mar	5,000		3/31/2016
J. Aron	Nov-Mar	5,000		3/31/2016
PetroChina International	Nov-Mar	2,500		3/31/2016
Alberta:				
Conoco Phillips	Nov-Mar	5,000		3/31/2016
Suncor Energy	Nov-Mar	5,000		3/31/2016
Cargill	Nov-Mar	5,000		3/31/2016
Iberdrola Energy Services	Nov-Mar	5,000		3/31/2016
Husky	Nov-Oct	5,000		10/31/2016
Iberdrola Energy Services	Nov-Mar	5,000		3/31/2016
Husky	Nov-Mar	5,000		3/31/2016
Shell Energy North America (Canada)	Nov-Mar	10,000		3/31/2016
Conoco Phillips	Nov-Mar	5,000		3/31/2016
Suncor Energy	Nov-Mar	5,000		3/31/2016
TD Energy Trading	Nov-Mar	5,000		3/31/2016
TD Energy Trading	Nov-Mar	5,000		3/31/2016
J. Aron	Nov-Mar		10,000	3/31/2016
J. Aron	Apr-Oct		10,000	10/31/2016
Rockies:				
Ultra Resources	Nov-Oct	10,000		10/31/2016
Shell Energy North America (US)	Nov-Mar	5,000		3/31/2016
Iberdrola Energy Services	Nov-Mar	5,000		3/31/2016
QEP Marketing Company	Nov-Oct	5,000		10/31/2016
Macquarie Energy	Nov-Oct	10,000		10/31/2016
Castleton Commodities	Nov-Mar	5,000		3/31/2016
BioUrja Trading	Nov-Mar	5,000		3/31/2016
Macquarie Energy	Nov-Oct	5,000		10/31/2016
Ultra Resources	Nov-Mar	10,000		3/31/2016
Macquarie Energy	Nov-Mar	5,000		3/31/2016
Iberdrola Energy Services	Nov-Oct	5,000		10/31/2016
Anadarko Energy Services	Nov-Oct	5,000		10/31/2016
Total, November-March		**182,500**	**10,000**	
Total, April-October		**65,000**	**10,000**	

Table 3.2[4]: Firm Transportation Capacity as of November 2015

Pipeline and Contract	Contract Demand(Dth/day)	Termination Date
Northwest Pipeline:		
Sales Conversion (#100005)	214,889	10/31/2025
1993 Expansion (#100058)	35,155	9/30/2044
1995 Expansion (#100138)	102,000	10/31/2020
Occidental cap. acq. (#139153)	1,046	10/31/2024
Occidental cap. acq. (#139154)	4,000	3/31/2025
International Paper cap. acq. (#138065)	4,147	10/31/2024
Total NWP Capacity	361,237	
less recallable release to -		
Portland General Electric	(30,000)	10/31/2016
Net NWP Capacity	331,237	
TransCanada - 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	
TransCanada - Foothills:		
1993 Expansion	47,727	10/31/2016
1995 Rationalization	57,417	10/31/2016
Engage Capacity Acquisition	3,708	10/31/2016
2004 Capacity Acquisition	48,669	10/31/2016
Total Foothills Capacity	157,521	
TransCanada - NOVA:		
1993 Expansion	48,135	10/31/2020
1995 Rationalization	57,909	10/31/2020
Engage Capacity Acquisition	3,739	10/31/2020
2004 Capacity Acquisition	49,138	10/31/2020
Total NOVA Capacity	158,921	
T-South Capacity (through Tenaska)	30,000	10/31/2016
Southern Crossing Pipeline	48,000	10/31/2020

[4] Notes to table 3.2:

a. For existing contracts, the SENDOUT® model uses the pipeline rates currently paid by NW Natural, i.e., there are no assumptions regarding future rate increases or decreases for existing pipeline capacity.

b. The Southern Crossing contract is denominated in volumetric units. Accordingly, the above energy units are an approximation.

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.

2.3. Current Storage Resources

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

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

Concerns regarding the continued reliability of this NWP transportation service were discussed in the Company's 2014 IRP, and subsequently resolved with the signing of a new transportation agreement with NWP as covered in the Company's 2014 IRP Update and subsequent Purchased Gas Adjustment (PGA) filings in Oregon and Washington. [5]

Table 3.3 shows the maximum capabilities of these four firm storage resources, while table 3.4 shows the new configuration of agreements that transport the gas from Jackson Prairie on NWP's system.

Table 3.3: Firm Storage Resources as of November 2015[6]

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Capacity (Dth)
Jackson Prairie	46,030	1,120,288
Mist (reserved for core)	305,000	10,960,560*
Gasco LNG	128,880*	644,400*
Newport LNG	65,340*	*980,100*

[5] OPUC 2014 IRP, Docket No. LC 60, Update filing made on May 8, 2015.OPUC 2015 PGA Docket No. UG 298, Advice No. 15-12A, in Exhibit C of the Supporting Materials. WUTC 2015 Docket No. UG-151826.

[6] The numbers in this table with an asterisk originated from volumetric units (e.g., Bcf) that have been converted to energy units (Dth) using the current heat content (Btu per cf) of the applicable facility. The other numbers in this table do not need to be adjusted for heat content because they originate from contracts (Jackson Prairie) or deliverability calculations (Mist) that are specified in energy units.

Table 3.4: Jackson Prairie Related Agreements as of November 2015

NWP Rate Schedule	Maximum Firm Withdrawal Rate (Dth/day)	Primary Firm Transportation (Dth/day)	Subordinate Firm Transportation (Dth/day)
Storage Service:			
SGS-2F	46,030		
Transportation Service:			
TF-1		13,525	
TF-2		23,038	9,586
TF-2		9,467	3,939
Total Transportation		46,030	13,525

The Company's utility customers currently receive underground storage service at Mist through the Miller Station central control and compressor facility using four depleted production reservoirs (Bruer, Flora, Al's Pool and a portion of Reichhold), collectively referred to as Mist storage. The Mist storage deliverability and seasonal capacity shown in table 3.3 represent the portion of the present facilities reserved for utility service. Mist began storage operations in 1989 and currently has a maximum total daily deliverability of 515 million cubic feet[7] per day (MMcf/day) and a total working gas capacity of 16 billion cubic feet (Bcf) in the above mentioned reservoirs plus three newer reservoirs (Schlicker, Busch and Meyer). These volumetric figures are converted to energy values (Dth) using the heat content of the injected gas. That heat content conversion factor had been relatively constant at 1,010 Btu/cf in prior years, but has changed recently and results in some adjustments that will be discussed in detail in a subsequent section.

Capacity in excess of core needs is made available for the nonutility storage business and AMA activities. As core needs grow, existing storage capacity may be recalled and transferred for use by core utility customers, which NW Natural refers to as Mist Recall. The IRP models the recallable portion of Mist as an incremental resource.

The Company also contracts on occasion for storage service in the supply basins, most typically in Alberta due to its relative abundance of merchant storage facilities. These contracts are not modeled in the IRP because they would double-count the same upstream pipeline capacity used for the Company's normal gas purchases. That is, any gas placed in supply-basin storage will use the same pipeline capacity for delivery to the Company's service territory as would normal winter purchases. The decision to contract for supply-basin storage is based on the differentials between winter and summer gas purchase prices versus the cost of the storage service, which change constantly. Accordingly, as with other commodity contracts, financial hedges, etc., the process to review supply-basin storage agreements is part of the annual PGA filing rather than the IRP.

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

At present, the Company has three such supply-basin storage contracts, all in Alberta, with maximum seasonal capacities in the following amounts:

Tenaska Marketing Canada	947,817 Dth
AECO Gas Storage Partnership (Niska)	1,895,634 Dth
J. Aron & Company	1,530,000 Dth

2.4. Other Current Supply Resources

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

Recall Agreements: Not to be confused with Mist recall, but in a sense is a variation on storage; these are third-party agreements that allow the Company to utilize gas supplies delivered to end users in the Company's service territory for a limited number of days during the heating season. These supplies otherwise would be consumed by those end users, but instead, they turn to their own alternatives for energy supplies and/or scale back operations as they so choose.

The Company currently has three such recall arrangements, as summarized in table 3.5.

Table 3.5: Recallable Supply Arrangements as of November 2015[8]

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

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

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

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

Citygate Deliveries: As the name implies, these are contracts for gas supplies delivered directly to the Company's service territory by the supplier utilizing their own NWP transportation service. Such deliveries could be arranged as baseload supplies, or on a swing basis, i.e., delivered or not each day at the option of the Company. The Company had one citygate agreement in place last winter, a swing arrangement that allows up to five days' usage during the December through February time period. If deliveries are utilized, the commodity price for the delivered volumes is index-based and expected to be extremely high.

Mist Production: This is the native gas still being produced from reservoirs in the Mist field about 60 miles northwest of Portland. Production of the local gas allows for the eventual conversion of those underground reservoirs to storage use, and in the meantime, the local gas is being purchased at a competitive price. As previously mentioned the flow rate is small and total Mist production amounts to less than 2 percent of the Company's annual gas purchases.

3. RISK ELEMENTS

An implicit assumption of most prior IRPs has been that supply-side resources function perfectly, i.e., to their design capacities, when and as needed to meet Firm customer requirements. More recently, the topic of resource reliability has been explored by the Company.[9] For example, as customer loads approach the peak day design, the weather conditions are by definition extreme, and so it is not unreasonable to assess some likelihood of equipment or pipeline outages arising from such harsh conditions. The purpose of this section is to make explicit some significant supply-side risk elements, other than the potential for physical equipment/pipeline outages, that also have been part of the Company's implicit assumptions within past resource plans.

3.1. Curtailment of Firm Pipeline Service

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

What is TF-2 service? During the deregulation of the gas industry in the late 1980s, the merchant function of the interstate pipelines was unbundled and firm sales services were converted to firm transportation services. For NWP, this is their Rate Schedule TF-1. Later, in the early 1990s, storage services also became subject to unbundling, that is, separating the service at the storage facility itself from the pipeline transportation service that had been included (bundled) within the storage service rate schedule. While the unbundled pipeline transportation service was considered a firm service, using the same TF-1 rate structure did not seem appropriate since the transportation service associated with a storage facility would not be available year-round, but only when gas was available for withdrawal or vaporization from that storage facility. Thus was born Rate Schedule TF-2 out of a NWP rate case settlement about 20 years ago. In this region, that unbundling applied to Jackson Prairie and Plymouth.[10]

[9] See chapter 5 of NW Natural's 2013 Integrated Resource Plan as filed on March 28, 2013, in WUTC Docket No. UG-120417.
[10] For further details see NWP's FERC Docket No. RP93-5-011.

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

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

The curtailment of this TF-2 service led to numerous discussions with NWP. NWP stated that it performed an historical analysis of NW Natural's Plymouth TF-2 service examining NWP's highest peak day of demand in the I-5 corridor for each of the last 14 years. NWP's analysis indicated that NW Natural's Plymouth TF-2 service would have been reliable in 12 of those prior 14 years. Of course none of these prior 14 years experienced weather conditions comparable to the Company's design weather peak day.

NW Natural concluded that it could no longer count on its 60,100 Dth/day of Plymouth TF-2 service as a firm resource during design cold weather events. It might flow, or it might be curtailed due to its secondary nature—there is no way to know in advance as it depends on the actions of other NWP TF-1 transportation service holders. Accordingly, the Company removed Plymouth TF-2 deliveries from its firm resource stack in the 2014 IRP because they were less reliable than previously believed.[11]

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

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

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

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

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

Over the long term, it did not appear prudent to rely on this type of capacity because eventually the loads on the NWP system being served from Sumas will grow and reduce the reliability of any transportation that is less than TF-1 primary firm service. Subsequent negotiations with NWP yielded a discounted TF-1 service from Jackson Prairie to provide 13,525 Dth/day of additional firm transportation service, as detailed in the Company's 2014 IRP Update filing made in May 2015. This agreement has a primary term until October 31, 2023, with a standard annual bi-lateral evergreen provision thereafter. Hence, the Company believes this issue has been resolved and can model the entire Jackson Prairie storage contract as a firm resource for the full IRP planning period.

3.2. Reliance on "Segmented" Capacity as a Resource

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

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

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

Third, there is the process of segmentation itself. A pipeline contract is used to transport gas from points where gas is received into the NWP system (receipt points) to points when gas is delivered to an interconnecting party such as an Local Distribution Company (LDC), another pipeline or a direct connect customer (delivery points). In the illustration below (figure 3.2), “A” is a circle and denotes the primary receipt point, while “D” is a diamond and indicates the primary delivery point. Between the primary receipt and primary delivery points in a contract (between A and D), there could be numerous other receipt or delivery points (illustrated in figure 3.2 as delivery point “B” and receipt point “C”). These in-between points could be used on a secondary basis as mentioned in the preceding paragraph. That is, gas could be transported from A to B or from C to D.

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

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

Figure 3.2: Capacity Segmentation Illustration

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

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

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

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

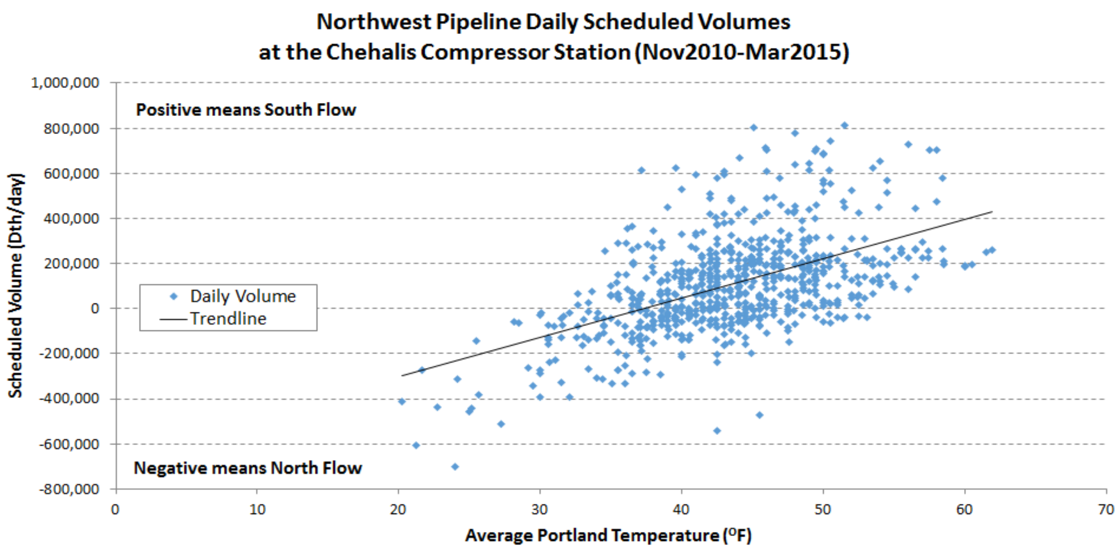
Because of its secondary nature, the Company had refrained from including segmented capacity in its past IRP analyses. The Plymouth situation, however, and the related discussion pertaining to Jackson Prairie, caused a reassessment of this approach in the 2014 IRP. As with the subordinate TF-2 capacity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

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

One question remains: How long to assume this segmented capacity would be available? In the 2014 IRP, the assumption was five years before load changes in the I-5 corridor between the Canadian border and Oregon might totally erode the reliability of this service.

An analysis of NWP flow data in the I-5 corridor over the last five winters shows that as the weather gets colder, the predominant flow direction is south to north through the main constraint point at NWP's Chehalis compressor station (figure 3.3). Hence, gas flowing south from Sumas on segmented capacity should have greater pipeline reliability as design day conditions are approached.

Figure 3.3: Implied Reliability of Segmented Capacity



New load developments between Sumas and the Company's service territory might undermine the reliability of this service, especially if not accompanied by an equivalent capacity expansion of NWP's system and upstream infrastructure to get more gas supplies to Sumas. By 2020, regional coal plant retirements will have started to take place, while very large industrial loads (i.e., methanol production) could conceivably be starting service. Accordingly, this segmented capacity is assumed to be available until, but not beyond, November 2020.

3.3. Impact of Operational Flow Orders

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

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

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

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

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

3.4. MDDO Restrictions at Gate Stations

As previously mentioned, a gate station is a location at which the Company is physically connected to the upstream pipeline network. Gate stations include billing quality metering and pressure regulation equipment, and usually (but not always) include other devices such as odorizers and telemetry. Two particular gate stations—Deer Island and Molalla—also include compressors for redelivery of gas back to NWP. There are over major 40 gate stations in the Company's system, and they are sometimes collectively referred to as the "citygate." With some minor exceptions, all of the gate stations directly connect the Company to NWP. The exceptions are the gate stations that connect to the Kelso-Beaver Pipeline and the Coos County Pipeline. However, since the Company's service on those pipelines is itself dependent on their connections to NWP, it is a distinction without a difference. Accordingly, NWP's operating rules, processes and procedures for deliveries at gate stations are of fundamental importance.

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

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

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

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

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

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

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

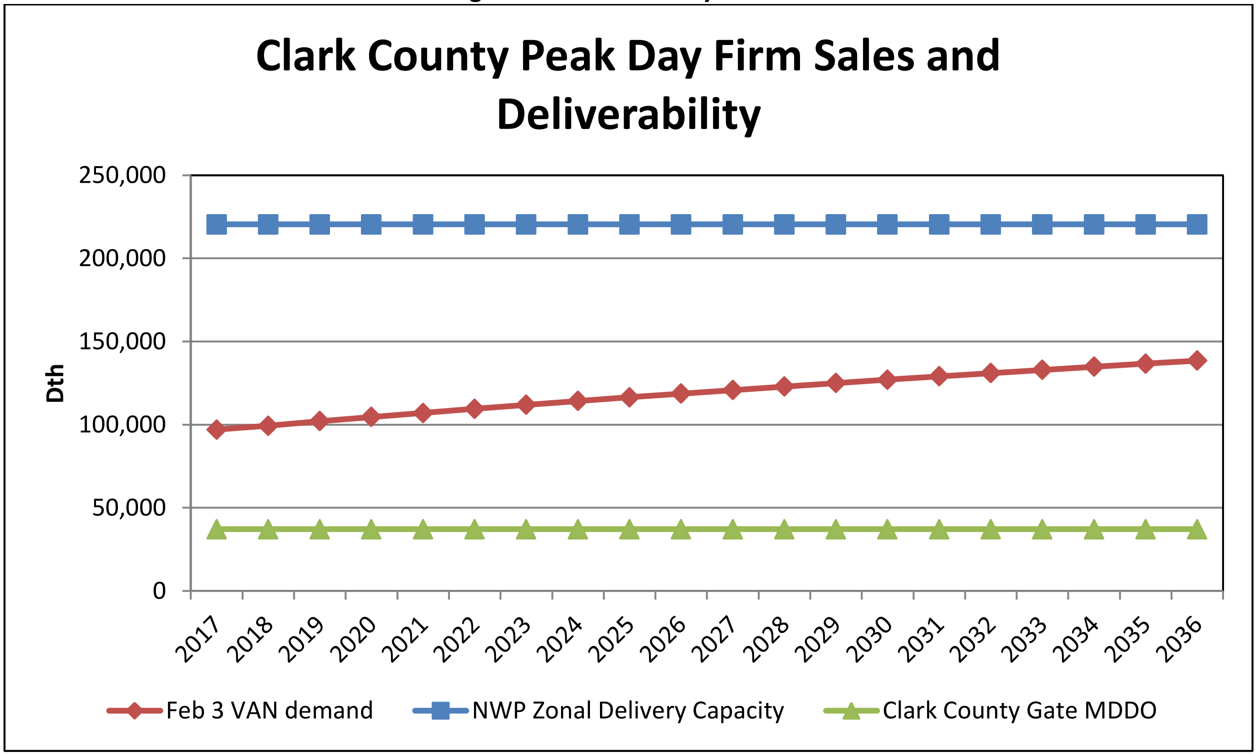
If the Company uses MDDOs to reflect the firm delivery limit from NWP, then the analysis would indicate the need for new CD subscriptions from NWP. If the actual physical capacities are used, the requirement shrinks dramatically, but the Company runs the risk that at some point a new customer on NWP's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

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

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

The most severe MDDO imbalance in the 2014 IRP was the Clark County system. Using this new modeling approach, there is ample capacity available to serve the Clark County system (figure 3.4).

Figure 3.4: Clark County MDDOs



4. CHANGES IN THE EXISTING RESOURCE PORTFOLIO

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

4.1. Jackson Prairie Underground Storage

Rather than drop off after five years, the acquisition of 13,525 Dth/day of firm TF-1 capacity means that all service from Jackson Prairie is retained in the Company's firm resource stack for the full planning horizon.

4.2. Segmented Capacity

The Company will increase its near-term reliance on segmented capacity from 43,800 to 60,700 Dth/day. This capacity then is modeled as dropping off after Nov. 1, 2020.

4.3. Citygate Deliveries

For the 2014/15 winter, as a stopgap to the loss of Plymouth, the Company was able to negotiate a 20,000 Dth/day peak day service. A third party bundled together supplies sourced from Sumas along with their own transportation service on NWP to deliver gas on a limited basis to NW Natural's citygate. This agreement initially was put in place during the December 2014-February 2015 period, as discussed in some detail in the Company's 2014 PGA filing. The Company then was able to recontract this resource for the December 2015–February 2016 winter. It is difficult to model this as an IRP resource if it only can be renewed on a year-to-year basis, so the Company now is determining whether it can be contracted on a multiyear basis.

4.4. T-South Contract Expiration

As shown in table 3.2, WEI T-South capacity of 30,000 Dth/day was acquired from a third party and will expire on Oct. 31, 2016. A replacement contract for 19,000 Dth/day has been acquired, and discussions regarding additional T-South capacity are ongoing. T-South capacity does not affect the overall resource stack. It just changes whether the Company's purchases of gas in British Columbia take place at Sumas or at Station 2. While commodity purchase costs go up if more gas is purchased at Sumas, this must be balanced against the additional pipeline charges incurred by holding T-South capacity. This economic analysis has been and will continue to be included in the Company's PGA filings. It should be noted that other factors also could impact this decision, such as the relative liquidity of supply at Sumas versus Station 2.

4.5. Storage Plant Heat-Content Adjustments

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

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

As oil and gas supplies grew, a glut of natural gas liquids (NGLs) developed in the supply basins. With falling commodity prices, the incentive to process NGLs out of the gas stream has shrunk. In particular, the profit margins for separating ethane are such that a noticeable amount of ethane is being left in the natural gas stream. Noticeable meaning that the heat content on NWP's system has moved from a range around 1020 Btu/cf to a range closer to 1080 Btu/cf.

The higher Btu value of the gas flowing over NWP's system could reverse itself at any time, but probably not until profit margins improve on ethane removal. Accordingly, we have reassessed the heat content used for the storage plant volumetric conversions and concluded that small increases are appropriate.

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

The projected changes in heat content for Mist, Newport and Gasco that have been modeled in this IRP are shown in figures 3.5, 3.6 and 3.7, respectively.

Figure 3.5: Heat Content Projection for Mist

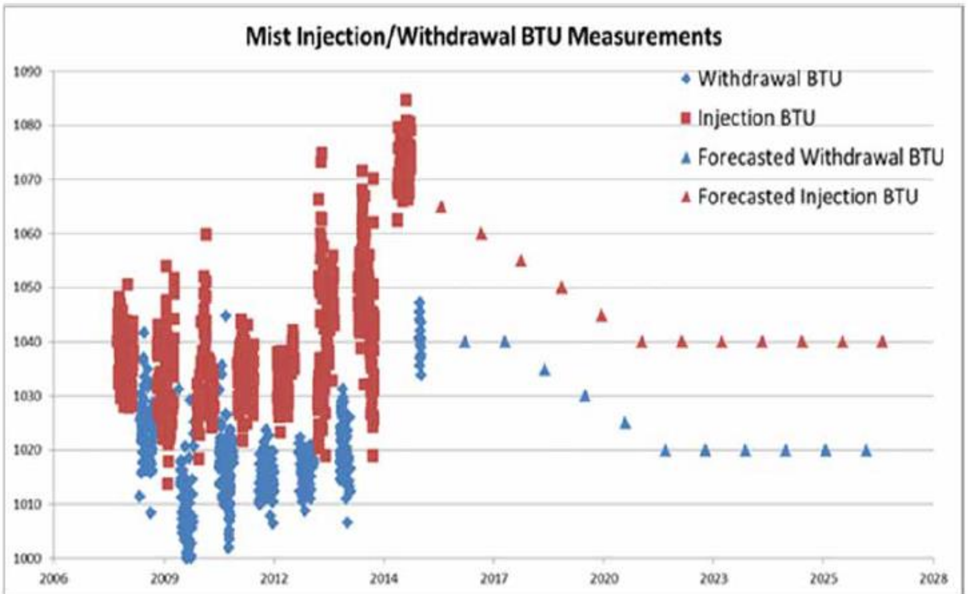


Figure 3.6: Heat Content Projection for Newport LNG

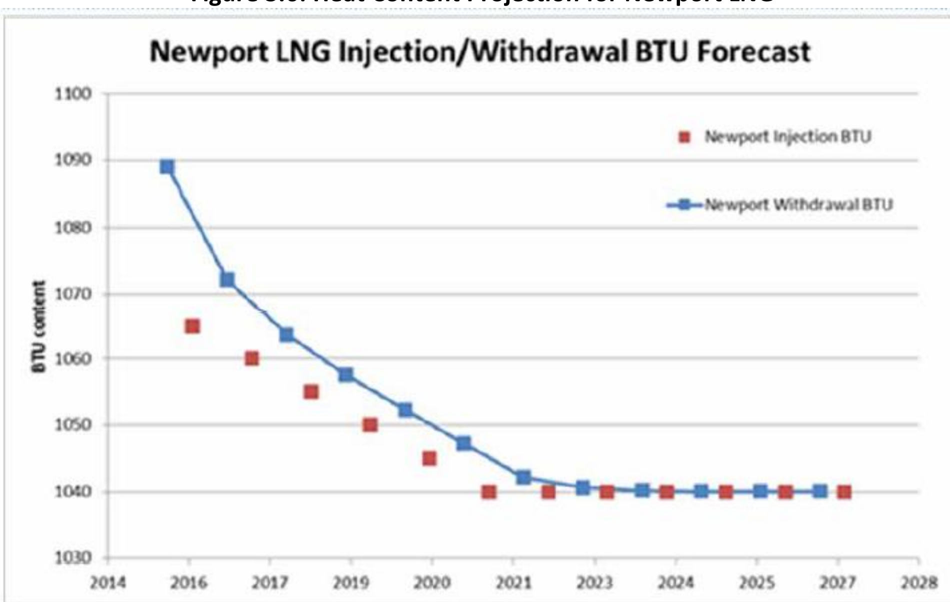
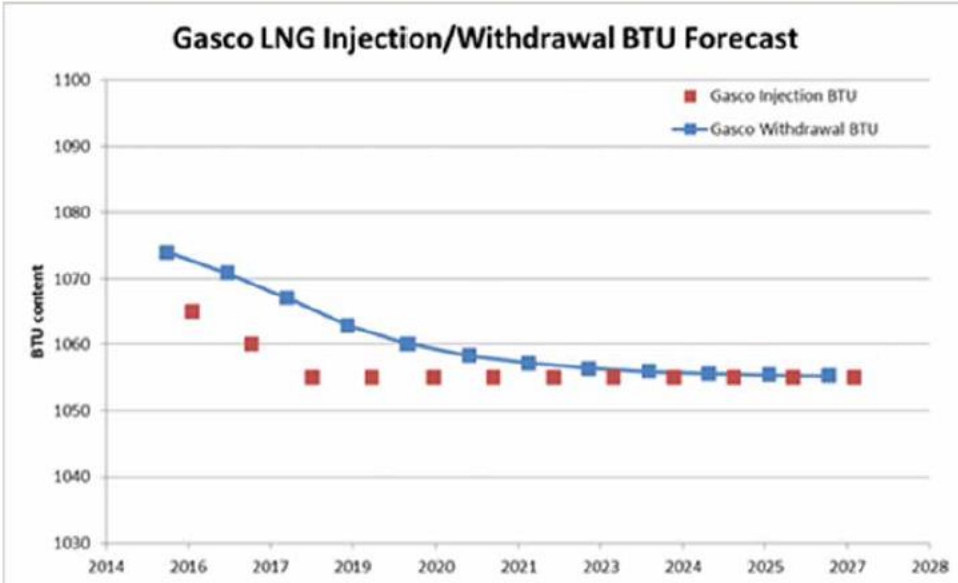


Figure 3.7: Heat Content Projection for Gasco



These heat-content adjustments slightly increase the deliverabilities from Gasco and Newport in the near term. They are projected to tail off over time as commodity prices rise and normal NGL processing resumes. For Mist, there is no immediate adjustment to deliverability because Core requirements and Mist recalls have always been specified on an energy basis. However, the heat-content adjustment does imply a slight increase in the amount of Mist recall that would be available in future years. Figure 3.8 shows the immediate increase in the LNG plant deliverabilities, while figure 3.9 shows the small increase in Mist Recall availability.

Figure 3.8: LNG Plant Deliverability Increase due to Heat-Content Adjustment

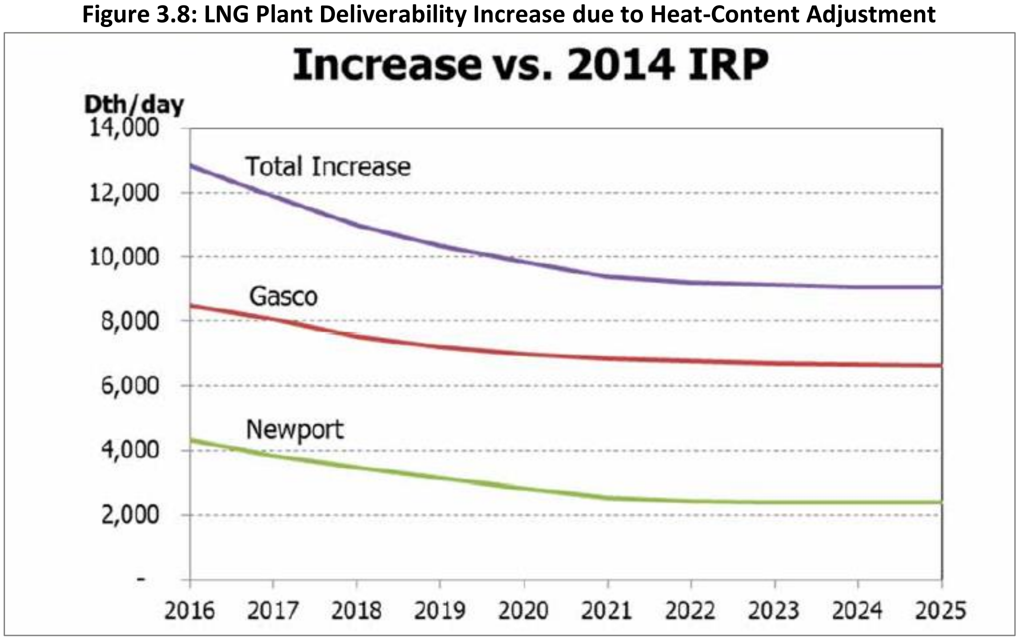
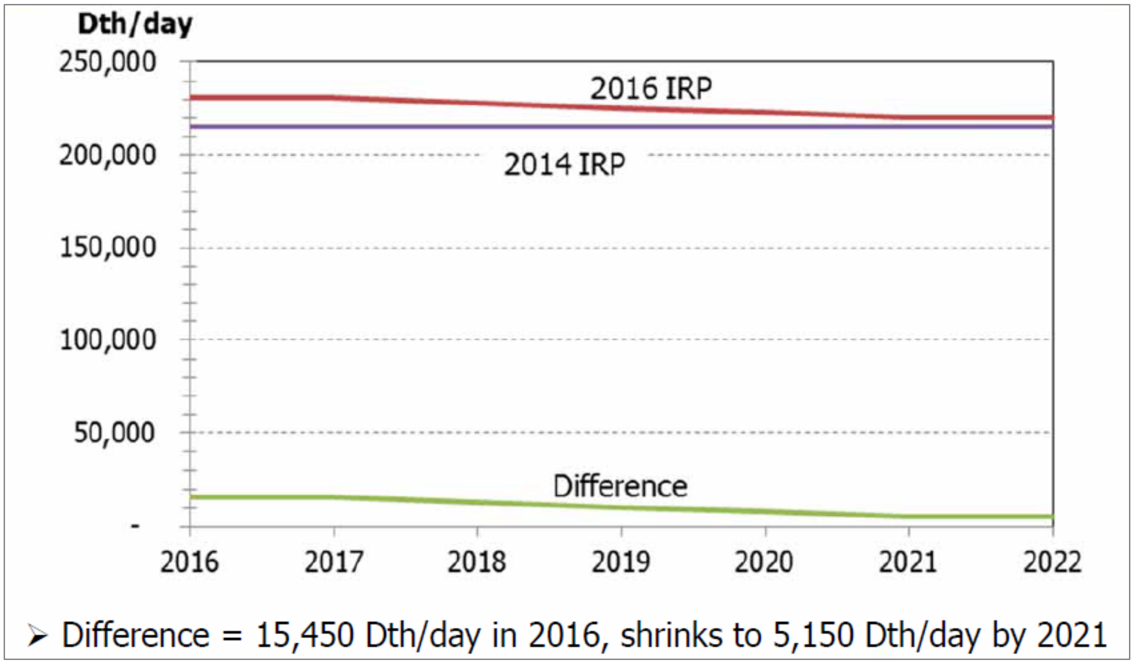


Figure 3.9: Mist Recall Increase Due to Heat-Content Adjustment



5. NW NATURAL'S LNG PLANT PROJECTS

As mentioned above, NW Natural owns and operates two LNG peak shaving facilities. The first is in Newport, Oregon which consists of a 1,000,000 Dth capacity storage tank, liquefaction facilities capable of processing about 5,500 Dth/day, and vaporization capacity of up to 100,000 Dth/day ("Newport"). This facility was constructed by Chicago Bridge and Iron and commissioned in 1977. Because the Company's pipeline system limits Newport to serving the central coast and portions of the Salem and Albany 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.

As resources specifically used for peak shaving, NW Natural requires high availability, reliability and productivity from the LNG plants. The facilities and major process components of these two plants were designed for a nominal 25- to 30-year life. Newport and Gasco are now 37 and 45 years old, respectively.

As identified and acknowledged in the 2014 IRP, Newport is undergoing a major refurbishment to address issues with the liquefaction process including removal of carbon dioxide (CO_2) from the incoming natural gas stream, which very gradually has been collecting in the tank and settling on its floor in solid form (commonly known as dry ice). The dry ice issue at Newport is severe enough that, to avoid weight issues on the floor of the storage tank, the Company has reduced the maximum quantity of LNG to be stored there from 1,000,000 Dth down to 900,000 Dth. Fortunately, so far this issue has not affected the daily vaporization rate and the reliance on Newport within the Company's peak day resource stack.

A similar engineering evaluation of Gasco has determined that a major refurbishment project is not needed. Rather, routine replacement of worn equipment should be sufficient to maintain Gasco's position in NW Natural's resource stack throughout the IRP planning period and beyond. (Note - a similar conclusion also was reached regarding the existing equipment and processes at Mist.)

One additional matter is that studies are just beginning for each LNG plant in regard to Oregon's seismic initiative. It is too soon to know what actions may arise from these studies, but recommendations will be directed to reducing the consequences at each plant from a major Cascadia earthquake/tsunami event, such as minimizing tank leakage. There is no intention of making major changes to the plants, so the cost impact is expected to be modest.

6. MIST ASSET MANAGEMENT PROJECT

6.1. Overview

With NW Natural's Mist storage facility now surpassing 25 years of commercial operation, the Company engaged consulting engineering firm EN Engineering, LLC (ENE) in July 2015 to assess the condition of the facility, analyze its current and likely future reliability, and provide recommendations regarding changes to better enable the productive use of the facility for an additional 25 years. ENE deployed a multi-disciplined team onsite to acquire an understanding of how the facility currently operates and to develop recommendations on improvements that would reduce its operational and maintenance (O&M) costs and potentially improve its overall flexibility.

ENE submitted its draft findings in January 2016, several key items of which were discussed during IRP Technical Working Group meeting #4 held in May 2016. ENE submitted its final report in June 2016, which is included as appendix 3. ENE's report contained multiple recommendations regarding actions to improve efficiency and flexibility at Mist. Many of ENE's recommendations involved upgrades to and replacements of existing equipment. ENE's report included a list of risks Mist will likely experience some or all of which in the following 25 years absent implementation of ENE's recommendations. These include:

- Increased O&M costs as equipment ages and needs to be maintained and replaced;
- Potential for failure of equipment during operations, and especially during peak conditions;
- Inability to meet current rated capacity demands;
- Increased risk and exposure to physical and cyber threats;
- Increased loss of data and communications;
- Potential increased scrutiny from regulators (environmental, federal regulations); and
- Not having the flexibility to react quickly enough to shifts in market demands.

The estimated cost over the 25-year timeframe (2016–2041) associated with implementing ENE's recommendations is currently estimated to average approximately $3 million annually.

Two of ENE's recommendations involve relatively near-term projects associated with equipment replacements. The first project involves replacing or repairing an existing dehydrator at Mist's Miller Station and right-sizing the dehydration capability associated with gas withdrawn from the "wettest" Mist storage reservoir. The second project involves replacing the two oldest compressors located at Miller Station with appropriately sized reciprocating compressors. NW Natural limits discussion below to the dehydration systems project, as the compressor replacement project is not contemplated within the time frame of the action plan of this IRP.

6.2. Dehydration Systems Background

In general, NW Natural receives natural gas from NWP, which then moves through the Company's distribution system to Miller Station, is filtered to remove oil and any contaminates, and then injected into the storage reservoirs. The reservoirs at Mist are "water-drive" systems, meaning that water situated below the gas storage section of each reservoir aids in pressurizing the gas that is being stored. However, the gas also picks up moisture during its time in the reservoir.

The gas is relatively dry when it enters the reservoirs since it must comply with NWP's FERC Gas Tariff that specifies no liquid water and not more than seven pounds of water in vapor phase per million cubic feet of gas. The Company's design criteria include dehydrating the gas withdrawn from Mist so that it can meet this same specification.[12]

Miller Station has two dehydration systems operated in parallel to remove moisture from withdrawn gas: a large dehydration system with a design capacity of 317 MMcf/day of gas flow and a smaller dehydration system with a design capacity of 165 MMcf/day of gas flow.

A dehydration system operates by having the moisture-laden natural gas first flow through a vortex separator to remove any liquid water. Next, the gas runs through a contact tower where the remaining moisture in the gas is absorbed by tri-ethylene glycol (TEG). Finally, the gas flows through a separation tower to remove any TEG carryover in the gas before the gas enters the outbound transmission pipeline. The TEG is reused (regenerated) by heating it to remove the trapped moisture, cooled back down to inlet natural gas temperatures, and then sent back to the contact tower for more moisture absorption.

Miller Station's large dehydration system consists of one vortex separator, two contact towers, one separation tower and one TEG regeneration system. Miller Station's small dehydration system consists of one vortex separator, one contact tower, one separation tower, and one TEG regeneration system.

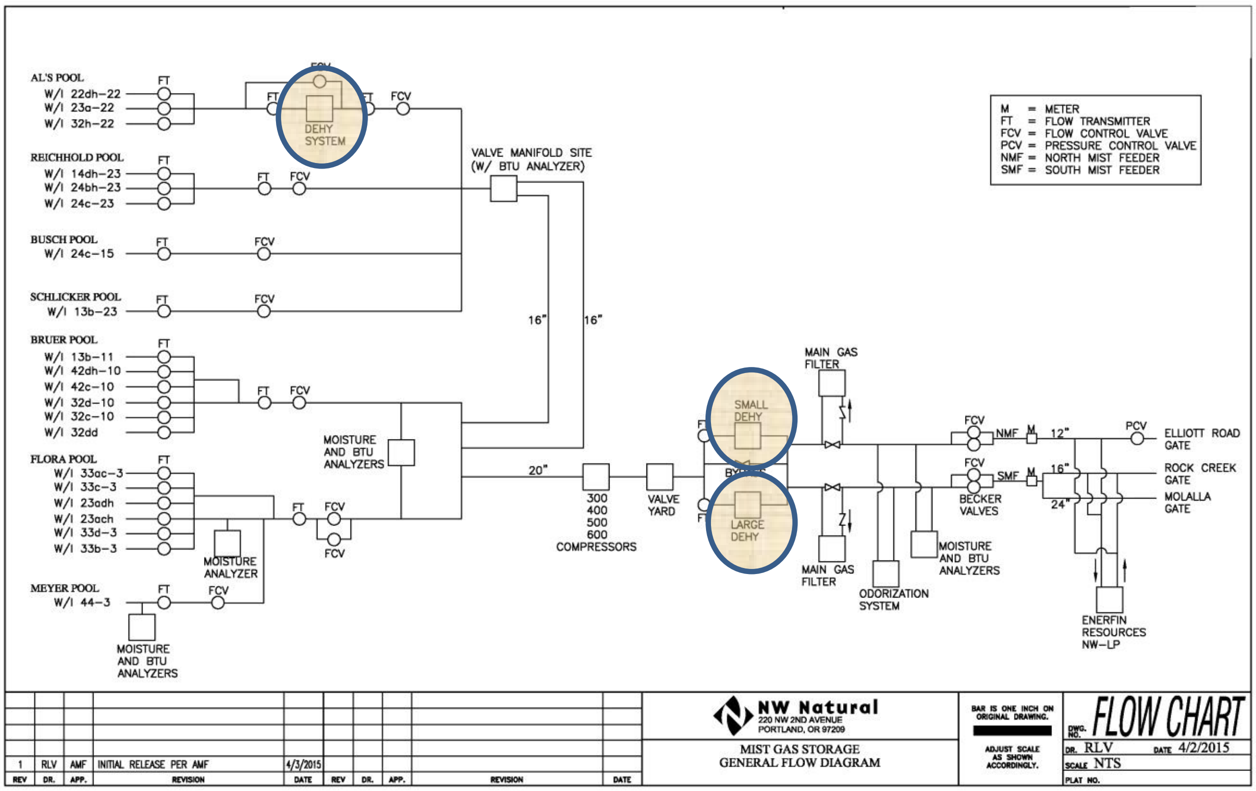
A third dehydration system operates on gas withdrawn from the storage reservoir known as Al's Pool, which has the highest moisture content of any Mist storage reservoir. This was designed to mitigate the

[12] Gas withdrawn from Mist must be capable of transport on NWP's Grants Pass Lateral. Therefore, the withdrawn gas must satisfy NWP's quality requirements.

risk of liquid moisture pooling in the low spots of the pipeline that carries the gas from Al's Pool and three nearby storage reservoirs (known as Schlicker, Reichhold, and Busch) to Miller Station—as well as to reduce the dehydration required of the systems located at Miller Station. The Al's Pool dehydration system consists of one tower (combination inlet scrubber, TEG contact section, outlet scrubber) and one TEG regeneration system.

Figure 3.10 shows a schematic of the Mist storage facilities with the location of the three dehydration systems highlighted.

Figure 3.10: Flow Diagram – Dehydration Systems Replacement



6.3. Current Status

Table 3.6 identifies the capacity and year placed in service for each of the three existing dehydrators associated with the Mist storage facility:

Table 3.6: Mist Storage Facility Dehydrator Capacities and In-service Dates

Dehydrator Unit	Capacity in MMcf/day	In-service
Miller Station - Large	317	1998
Miller Station - Small	165	2004
Al's Pool	28	1997

Performance Issues

There are four primary performance concerns for the Dehydration Systems:

1) Miller Station's large dehydration system shows indirect signs of major internal corrosion indicating the TEG regeneration system is near end of life. Corrosion shows three major signs without completely disassembling the equipment for visual and nondestructive testing:
    a) There is heavy discoloration of the TEG where normal TEG is clear. When corrosion products are present, the TEG will darken and at Miller Station, the TEG is near pitch black.
    b) The frequency of TEG filter changes has increased. There are several filters in the TEG regeneration system that removes contaminates from the TEG. At 300 MMcf/day flow rates, normal filter change frequency has historically been at two week intervals. Miller Station's large dehydration system is now experiencing from one to five days between changes.[13]
    c) Observed wear on the large dehydration system's TEG pumps and heat exchangers. TEG pumps, which cost $34,000 each, are robust and should last the life of the dehydration system. Miller Station was recently forced to replace both system pumps. There are two heat exchangers in the TEG regeneration system. Both heat exchangers have been disassembled and modified in the past two years due to wear and internal corrosion of the heat exchanger tubes.

2) The Al's Pool dehydration system is currently experiencing operational issues. The Al's Pool maximum withdrawal flow rate is 107 MMcf/day. The dehydration system was originally sized to take at minimum one-third of the maximum flow from Al's Pool. However, as experienced, if Al's Pool dehydrator experiences above 10 percent of maximum flow, liquid flow dynamics have resulted in Al's Pool TEG regeneration system becoming moisture saturated. The dehydration system must be taken off-line for the regenerator to recover. This increases the risk of allowing liquid moisture to pool in the low spots of the pipeline that carries the gas from Al's Pool and three nearby reservoirs to Miller Station.

3) The average service life of dehydrator units such as those used at Mist is approximately 20 years, based on the average life of a fire tube heating system.[14]

4) The dehydration systems individually are a single point of failure. There is no backup of critical components for these dehydration systems. All dehydration equipment must be operational to meet the gas flow requirements of Miller Station as well as to comply with the air quality permit requirements of the TEG regeneration equipment. Additionally, because of the extreme saturation issues with gas withdrawn from Al's Pool, the remaining dehydration units at Miller Station do not have the rated capacities to condition the station's maximum designed flow requirements.

[13] Note that filter life increases at lower gas flow rates due to lower required processing rates.
[14] ENE's report confirmed that an average life for natural gas dehydrators is approximately 20 years.

Al's Pool Dehydrator

ENE's report pointed out the lack of a functional moisture analyzer associated with the Al's Pool dehydration system. A detailed study may determine a more accurate operational limitation of the Al's Pool dehydration equipment as the moisture content of the stored gas varies. Additionally, operational issues experienced with oversaturation indicate a full design review is required to incorporate today's operating conditions with alternate solutions created.

ENE noted that there is a high probability of liquids downstream of Al's Pool at the location where the pipeline from the storage area crosses underneath a creek on its way to Miller Station. Too much moisture in the gas could allow water to pool at this low point in the pipeline, which could increase the potential for restricted gas flow from four out of the seven storage reservoirs as well as lead to internal pipeline corrosion.

NW Natural estimates the cost of purchasing and installing a moisture analyzer downstream of Al's Pool at $200,000 and plans to have this accomplished prior to year-end 2017. Once this work is completed, NW Natural will complete a detailed study by no later than 2019; with the cost of this study estimated at $50,000. NW Natural anticipates that the existing dehydrator at Al's Pool will need to be replaced. If so, relocating the smaller of the two dehydrators from Miller Station to Al's Pool will be one of the alternatives examined.

Large and Small Dehydrators at Miller Station

ENE specified the rated capacity of the large and small Miller Station dehydrators, in combination, at 482 MMcf/day. Without repair or replacement of at least the large dehydrator, ENE's report noted that the performance issues listed above will continue and NW Natural will incur higher O&M costs and experience outages.

6.4. ENE Recommendations

ENE made several recommendations related to the dehydration systems at Mist, including repair or replacement of the large dehydration system over the next three years in order to mitigate operating and performance issues.

ENE recommended that the large dehydrator unit be inspected to better understand its overall condition. Completion of the inspection will allow estimating repair costs as well as the expected extension of service life and related maintenance requirements. ENE noted that O&M costs may be higher under a repair scenario than a replace scenario.

6.5. NW Natural Actions

NW Natural plans to repair or replace the existing large dehydration unit at Miller Station because it is at end of life as previously discussed. The Company will engage the services of a specialized consultant within the next year, who will first determine if repair of the unit is possible. If repair is possible, NW Natural will analyze the costs and other tradeoffs of repair versus replace. ENE estimated the cost to acquire and install a new dehydrator at $6 million to $7 million.[15]

The consultant will examine the existing dehydration systems with a focus on alternative ways for optimally sizing and locating these systems. Given their ages, all three dehydration units likely will be replaced within the next decade and NW Natural anticipates including related actions in a future IRP or Update.

7. FUTURE RESOURCE ALTERNATIVES

Beyond the existing gas supply resources mentioned previously, the Company considers additional gas supply resource options including Mist recall, further Mist expansion, the acquisition of new interstate pipeline capacity, satellite LNG and CNG storage, and various extensions/expansions of its own pipeline system. The primary alternatives are described in more detail below. These options will be evaluated in chapter 7 using SENDOUT®.[16]

7.1. Interstate Capacity Additions

The Company holds existing contract demand (CD) and gate station capacity on: (1) NWP's mainline serving the Company's service areas from Portland to the north coast of Oregon, Clark County in Washington, and various small communities located along or near the Columbia River in both Oregon and Washington, and (2) NWP's Grants Pass Lateral (GPL) serving the Company's loads in the Willamette Valley region of Oregon from Portland south to the Eugene area. Therefore, consideration of incremental NWP capacity, separately on the mainline and on the GPL, is a starting point for the Company's assessment of incremental interstate pipeline capacity in this IRP.

Since the Company effectively is interconnected only to NWP, a subscription to more NWP mainline capacity traditionally has been a prerequisite to holding more upstream capacity of equivalent amounts (e.g., from GTN). There could be exceptions when market dynamics indicate some advantage to holding more or less upstream capacity. For example, as upstream pipelines continue to expand into new supply regions and/or to serve new markets, an evolution of trading hubs may occur; opening up the more liquid trading points while others fade into disuse. The construction of an LNG export terminal in the Pacific Northwest or British Columbia and/or the construction of a new pipeline transporting Arctic gas (either from Alaska or the Mackenzie Delta) are examples of market developments that could cause the Company to reconfigure or add to its upstream pipeline contracts. Under these market conditions, it may be beneficial to hold transportation capacity upstream of NWP leading to these new supply points.

In response to its reliance solely on NWP for delivery of interstate gas supplies, NW Natural partnered with TransCanada Corporation in 2007 to form Palomar Gas Transmission LLC (Palomar). Palomar proposed to develop, build, and operate a pipeline connecting GTN's mainline north of Madras, Oregon,

[15] NW Natural anticipates that costs of any repair to or replacement of the large dehydrator at Miller Station will be allocated to utility customers.

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

to the Company at Molalla (the “Eastern Zone”) and continuing from Molalla to a proposed LNG import terminal on the Columbia River west of Portland (the “Western Zone”).

In December 2008, Palomar filed an application for a certificate to build and operate the pipeline with the Federal Energy Regulatory Commission (FERC). However, with the growth of shale gas production and the economy in recession, the plans for the LNG terminal eventually were abandoned and Palomar withdrew its FERC application in March 2011.

Then, in November 2012, NWP announced a new Cross-Cascades project called the Northwest Market Area Expansion (NMAX) that would include just the Eastern Zone of Palomar. Concurrently, NWP solicited interest in an expansion south from the U.S./Canadian border at Sumas to serve the proposed Oregon LNG export terminal in Warrenton, Oregon. This was the Washington Expansion (WEX) project.

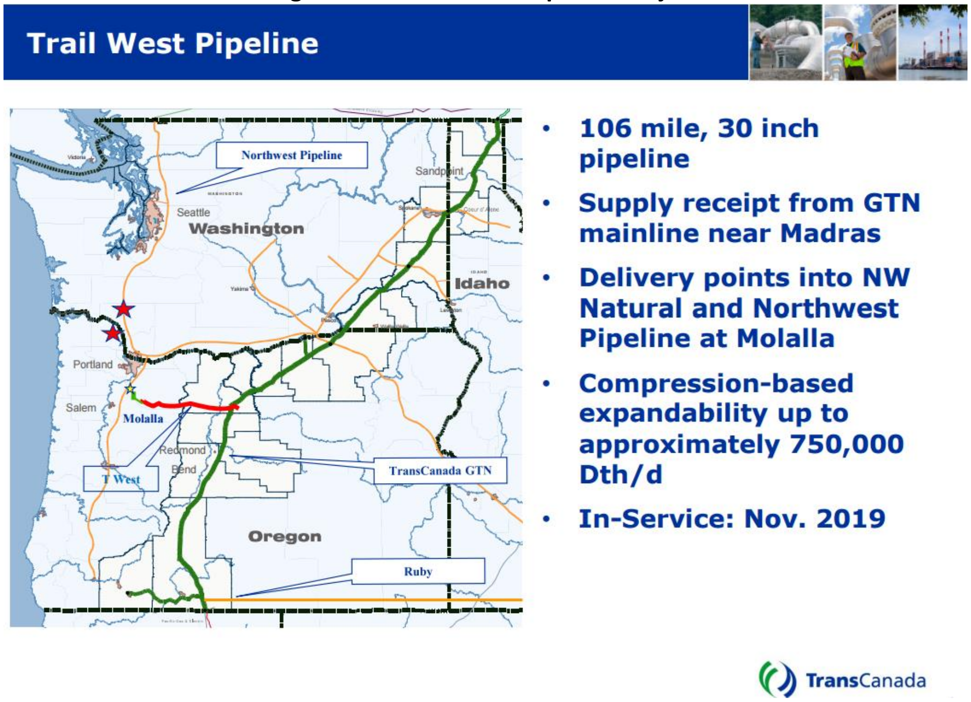
By December 2014, plans were announced for an updated stand-alone version of Palomar, now called the Trail West pipeline (see figure 3.10). As depicted in figure 3.11, both Trail West and WEX could serve the Company’s service territory.

No further activity regarding Trail West has been discernible, so for the purposes of this IRP, it is assumed that the Trail West pipeline could not be in service any earlier than November 2021.

Regarding WEX, NWP had filed a FERC application in June 2013, but Oregon LNG was the only specified customer. In April 2016, Oregon LNG announced that it had cancelled plans for its export terminal project.[17] At a Shipper Advisory Board meeting held on April 19, 2016, NWP stated that it intended to vacate its WEX application. Accordingly, WEX has been dropped from the list of potential future resources to be analyzed in this IRP.

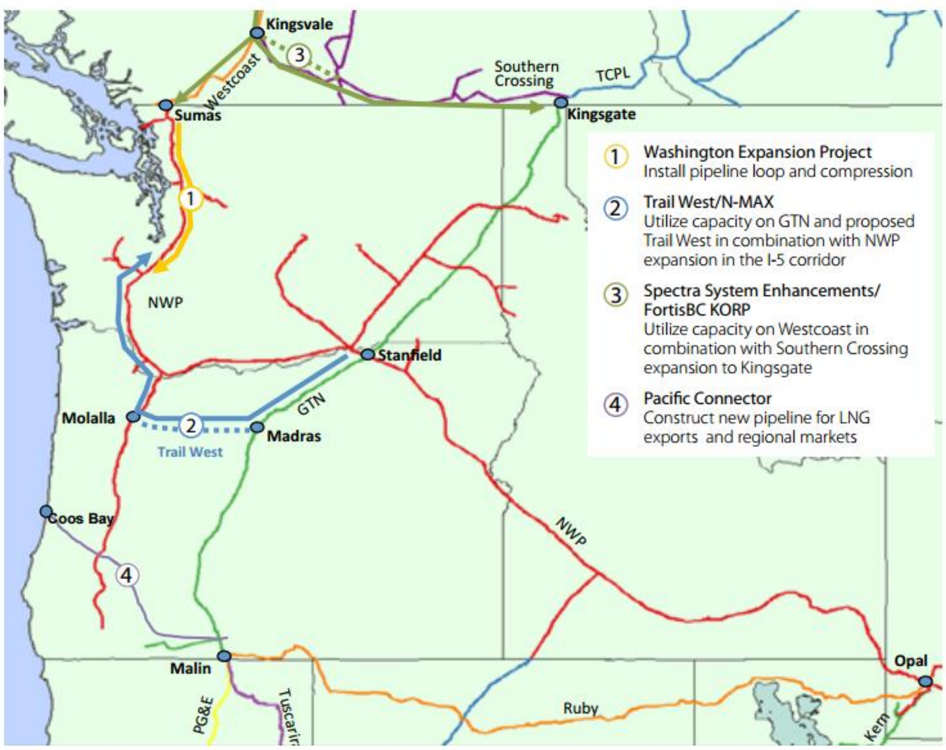
[17] Seehttp://www.oregonlive.com/environment/index.ssf/2016/04/company_cancels_plan_for_warre.html .

Figure 3.10: Trail West Pipeline Project



Source: GTN Collaboration Meeting, December 2014

Figure 3.11: Proposed Regional Pipeline Expansion Projects



Source: Northwest Gas Association, 2015 Gas Outlook

From the Company's perspective, the region most likely will need to add more gas infrastructure within the next 5-10 years to serve growth in regional natural gas demand, primarily from the power generation and industrial sectors.[18] The primary benefit from meeting this growth from development of a Trail West pipeline would be to improve the gas system resiliency and enhance reliability by having greater resource diversity. This is particularly important given the accelerating convergence and interdependency of the electric and gas systems. A second regional benefit is that it would mitigate the Sumas price risk from potential British Columbia LNG export terminals. By comparison, meeting regional demand growth via incremental NWP expansions from Sumas essentially "doubles down" on an existing pathway and, at the same time, is a potential lost opportunity to protect customers from a risk management perspective.

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.

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

- *NWP Sumas Expansion (Local Project):* This is incremental NWP capacity from Sumas that is designed to serve only NW Natural's load growth needs. Accordingly, it would have a relatively small scale and so could be expected to have a relatively high unit cost. On the other, it would offer the best fit to the Company's resource timing.
- *NWP Sumas Expansion (Regional Project)*: [19] This is capacity from Sumas on a hypothetical NWP project that is the successor to WEX. It would bundle NW Natural's subscription with other regional requests from parties such as power generators and large petrochemical projects. The scale of this project is larger than the Local Project mentioned above, potentially resulting in a more favorable unit cost, but with timelines necessarily aligned with the needs of the project's anchor customers, whoever they might be.
- *Pacific Connector*: The Pacific Connector Pipeline project is tied to the development of the Jordan Cove LNG export terminal in Coos Bay, Oregon. This pipeline starts near Malin, Oregon and would cross NWP's Grants Pass Lateral (GPL) in the vicinity of Roseburg, Oregon. Service from NWP would be needed to move the gas from Roseburg northward on the GPL to the Company's service territory, starting with the Eugene area. For this IRP, references to "Pacific Connector" refer to the bundled pipeline service from Malin to the Company's citygate.
- *Trail West*: A pipeline starting at GTN's system near Madras, Oregon, and connecting NWP's Grants Pass Lateral near Molalla, Oregon. Since portions of the Company's distribution system are not connected to Molalla, incremental pipeline capacity would be needed to transport gas northbound to certain load centers. There are two options for this:

[18] There is broad regional support for this perspective, for example, in the Northwest Gas Association's 2015 Gas Outlook, page 15: "Additional capacity is likely to be required within the forecast horizon to serve growing demand for natural gas, particularly on a design day."

[19] In mid-August 2016, NWP began referring to this project as the "Sumas Express" pipeline.

- The Company could construct its own high-pressure transmission facility from the Molalla area to its Portland East load center (Eastside Loop).
- NWP has proposed an NMAX service that would bundle Trail West capacity with northbound GPL capacity. The NMAX proposal is far cheaper than anything NW Natural could build, so an Eastside Loop option is not modeled in this IRP.

The Company would acquire capacity on GTN and/or other applicable upstream pipelines in conjunction with some of the above alternatives in order to secure its gas supplies at liquid trading points. For example, since there are no gas trading activities at Madras, Oregon, consideration of Trail West necessarily includes additional upstream pipeline subscriptions to access the Malin and/or AECO trading hubs.

As in prior IRPs, the model also includes NWP firm TF-1 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 existing vintage-priced capacity is not included in table 3.2 because it does not become part of the Company's portfolio until Jan. 1, 2017. The contract's primary term extends until Dec. 31, 2046.

The acquisition of incremental pipeline capacity spans a wide range of lead times. It is dependent on the length and success of the pipeline's open season process, regulatory permitting times, and the time required to construct the required facilities, which could include restrictive periods due to environmental considerations. Only the NWP Sumas Expansion (Local Project) option is considered flexible and simple enough to be available as early as November 2019. For all other interstate pipeline options mentioned above, November 2021 has been modeled as the very earliest that any of them could be in service.

7.2. Storage Additions

Mist Recall

In addition to the existing Mist storage capacity currently reserved for the core market (see table 3.3); the Company has four reservoirs (a portion of Reichhold and all of Schlicker, Busch and Meyer) that also have been developed for storage services. They currently serve the interstate/intrastate storage (ISS) market, but could be recalled for service to the Company's utility customers as those third-party storage agreements expire.

Mist is ideally located in the Company's service territory, eliminating the need for upstream interstate pipeline transportation service to deliver the gas during the heating season. Due to its location, Mist is particularly well suited to meet incremental load requirements in the Portland area, which is traditionally the area where the majority of the Company's firm load growth lies. Mist gas may also be directly delivered to loads westward along the Columbia River from St. Helens to Astoria, and southward to the Salem and Albany areas. However, Mist recall is not suitable to serve load growth in the Eugene area. This is because Eugene is not physically connected to Mist through the Company's distribution system, nor is Eugene's location on the NWP system such that Mist could have an impact via displacement of NWP deliveries to the Portland area (as is the case for nonconnected Company load centers located in Washington).

There are three practical considerations that apply to Mist recall:

- Recall decisions are made roughly a year prior to the capacity's transition to the utility portfolio. On or about May 1, the Company wants to start filling any recalled capacity so as to have the maximum inventory in place by the start of the heating season. Working backwards from May 1, ISS customers need time to empty their inventory accounts if their capacity is going to be recalled by the Company. And the more prior notice they get, the more value they find in ISS service. So the Company informs an ISS customer in the months before the prior heating season if their contract will not be renewed. Accordingly, the Company has established the prior summer as the time at which it makes its recall decisions.
- Mist ISS contracts are of various durations. While limiting Mist ISS contracts to 1-year terms would maximize the capacity available for recall each year, it also would limit ISS revenues and so, in turn, the customer portion of those revenues. Accordingly, ISS contracts have staggered terms that create a profile of capacity available for recall that increases over time, in effect mirroring expectations of rising resource requirements.
- Recalls are rounded (up or down) to the closest 5,000 Dth/day of deliverability. This is done to simplify the administration of recalls and the marketing of ISS service.

North Mist II

NW Natural is in the midst of a project called North Mist that would combine new underground storage at Mist and a new transmission pipeline to serve Portland General Electric (PGE) at Port Westward.[20] The storage reservoirs currently in service at Mist and those that would be developed as North Mist for PGE do not collectively exhaust Mist's storage potential; other Mist *production reservoirs* remain that theoretically could be developed by NW Natural into additional storage resources. The primary impediment in doing so is not geological, but the challenges associated with developing new pipeline capacity to move the gas from Mist to the Company's load centers.

NW Natural identifies a prospective Mist expansion project for core customer use in this IRP as "North Mist II."[21] North Mist II involves 100 MMcf/day of maximum delivery capacity coupled with a maximum storage capacity of 2.0 billion cubic feet (Bcf), and includes a new compressor station and associated appurtenances. These capabilities would be exclusively for utility use. Should a third party want to subscribe to a North Mist II expansion, total deliverability and storage capacity would increase to match those additional subscribed amounts.

The design of the storage facility itself is relatively straightforward. A larger consideration is transporting the stored gas to NW Natural's load centers during the heating season—the "takeaway" pipeline(s). With exhaustion of all available Mist Recall capacity, the existing primary takeaway pipelines from Mist will be at their maximum capacities and incapable of transporting additional gas during the heating season.[22]

[20] This project is discussed in more detail in NW Natural's 2015 Form 10-K.
[21] NW Natural identifies the project for PGE as "North Mist," and—in the context of this IRP—a different Mist expansion built for core customer usage as "North Mist II."
[22] NW Natural refers to the existing northbound pipeline as the North Mist Pipeline; while the South Mist Pipeline

NW Natural analyzed a North Mist II expansion with three alternatives for takeaway capacity:[23]

1. Expanding and sharing the new pipeline being built for PGE northbound from Mist to the Kelso-Beaver Pipeline (KB Pipeline); and from there onto NWP's system, contracting with NWP for transport to NW Natural's load centers;

2. An expansion of existing pipelines southbound towards Molalla, and from there onto NWP's system, contracting with NWP for transport to NW Natural's load centers as appropriate; and

3. An alternative that, for the first 50 MMcf/day, uses available capacity on both the existing North Mist Pipeline and the existing North Coast Feeder to the Deer Island gate; and from there onto NWP's system, contracting with NWP for transport to NW Natural's load centers. The second 50 MMcf/day uses the existing southbound pipelines, with additional compression providing incremental capacity, to Molalla, and from there onto NWP's system, contracting with NWP for transport to load centers as appropriate.

The analysis assumes NWP is willing to offer a storage-related transportation service on its mainline, and on the GPL moving upstream of Molalla, on a firm basis and at a cost reflective of similar offerings that have occurred in the recent past.

The least cost alternative for takeaway pipeline capacity, as measured by the present values of revenue requirements (PVRR), is the third alternative above.[24] NW Natural estimated the cost of this alternative at approximately $133 million.

A regulatory concern has been raised in the past regarding the direct movement of Mist gas out of Oregon to serve load centers in Washington; specifically, the concern involves the potential violation of the Company's Hinshaw Exemption with FERC.[25] However, preliminary legal analysis has indicated that a viable structure could be created to make this arrangement work without adversely impacting NW Natural's Hinshaw Exemption.

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coupled with the South Mist Pipeline Extension comprise the existing southbound takeaway pipeline capacity.

[23] NW Natural documented the Company's analysis of a North Mist expansion for core customers in an update to the 2014 IRP in the Public Utility Commission of Oregon's Docket No. LC 60 filed May 29, 2015. This filing represented NW Natural's fulfillment of Action Item 2.3a in the 2014 IRP. North Mist II in the 2016 IRP refers to the same North Mist expansion for core customers represented in the May 29, 2015 filing. NW Natural reviewed the potential North Mist II storage expansion in the Technical Working Group meeting with stakeholders held Feb. 10, 2016. See also the discussion appearing later in the chapter.

[24] NW Natural in the 2016 IRP refers to the two components of the least-cost third alternative's takeaway capacity as North Mist IIa (for the northbound takeaway) and North Mist IIb (for the southbound takeaway). The Company used this nomenclature in discussing supply resource portfolios in the Technical Working Group meeting with stakeholders held May 24, 2016. See chapter 8 for the scenarios in which only North Mist IIa is selected as a least-cost resource versus those scenarios in which both North Mist IIa and IIb are selected.

[25] Congress passed the Hinshaw Amendment in 1954 to eliminate uncertainly as to whether, or under what conditions, LDCs would be subject to FERC regulation under the Natural Gas Act of 1938.

Clark County Large-Scale LNG Plant

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

7.3. 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 Trail West pipeline. The Company's Engineering Department plans for these additions.

One on-system project directly associated with potential supply-side resources is described below. Further discussion of smaller on-system pipeline projects is provided in chapter 7.

Christensen Compressor Project: As previously mentioned, the daily deliverability of the Newport LNG plant is modeled at 60 MMcf/day (adjusted slightly upward in the near term for higher heat content) due to pipeline infrastructure limitations, but the Newport plant has all the equipment and permitting necessary to vaporize and deliver up to 100 MMcf/day. To reach this 100 MMcf/day capability, infrastructure additions would be needed on the Newport to Salem pipeline (Central Coast feeder) to deliver an incremental 40 MMcf/day. This project would consist of installing a 2,000 horsepower compressor at Christensen on the Central Coast Feeder and is estimated to cost $30 million.

7.4. Satellite LNG Storage

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

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

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

> Of the 96 LNG storage facilities connected to the pipeline grid, roughly 57 have liquefaction capacity. Most of the remaining 39 storage facilities are located in the Northeast…where many facilities are close enough to the Distrigas import facility to receive LNG by truck. Massachusetts alone accounts for 14 satellite facilities, or roughly 40 percent of all satellite facilities in the United States. In New Jersey, which contains the second highest number of satellites, there are 5 facilities.[26]

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

NW Natural evaluated satellite LNG in Oregon locations in the SW Portland area and in Eugene as interim resources that would delay the construction of high-pressure pipeline projects.[27] The Company has modeled these resources as having a maximum deliverability of approximately 7,700 Dth per day for five days.

NW Natural also examined the economic feasibility of meeting the design day supply shortfalls using satellite LNG facilities. While the small-scale aspect of this approach leads to considerable flexibility with respect to the timing of increments of capacity, as a supply resource satellite LNG has a unit cost roughly equivalent to that of the most expensive pipeline capacity considered in this IRP. Additionally, satellite LNG does not offer the energy capabilities associated with pipeline capacity.[28]

7.5. Satellite CNG Storage

NW Natural also considered the use of satellite compressed natural gas (CNG) facilities. These have some of the same issues in terms of addressing supply needs as do satellite LNG facilities. In particular, the issue of scaling is much larger since CNG physically contains much less natural gas than an equivalent volume of LNG.[29] So while satellite CNG facilities may be cost-effective under some circumstances, such as serving a small community approaching existing pipeline capacity under design day conditions, such facilities are unable to effectively address NW Natural's near-term issues.

7.6. Jackson Prairie

The most recent expansion of Jackson Prairie storage was completed in 2012 and NW Natural is not

[26] See http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2003/lng/lng2003.pdf.
[27] See the related discussion in chapter 7.
[28] See the related discussion in chapter 8 Portfolio Analysis.
[29] One cubic foot of LNG is equivalent to about 640 cubic feet of natural gas at standard conditions. One cubic foot of CNG is equivalent to about 240 cubic feet of natural gas at standard conditions (assuming it has been compressed to 3,600 psig).

aware of any further expansion potential at the facility. The Company has pursued the idea of contacting for service from an existing capacity holder at Jackson Prairie. Besides the cost of the service itself, another consideration is the reliability of the pipeline transportation service between Jackson Prairie and the Company's service territory. Preliminary responses have not been economically attractive, but the Company will continue to explore this opportunity.

7.7. Longer-Term Citygate Deliveries

As previously mentioned, citygate deliveries have been contracted the past two years but only for the immediate heating season, which makes it difficult to model as an IRP resource. The Company is now obtaining bids for a multiwinter citygate delivery contract so that it can be modeled in the IRP.

7.8. Methanol Project Resource Sharing Arrangement

The developer of the methanol project at Kalama has presented an intriguing variation of industrial recall. Analysis is in progress to determine if their proposal could provide customer benefits.

The arrangement involves a year-round NWP capacity release coupled with a limited recall right. However, unlike other recall arrangements, the recall right in this case only extends to a certain portion of the released capacity. Because a portion is not recallable, the Company would need to advance its next resource acquisition to cover the shortfall, presumably Mist recall given the time frame. Whether customer net benefits would result from the avoidance of the year-round NWP costs is under evaluation.

This arrangement is intended only to bridge the gap in time between the commencement of methanol plant operation and the in-service date for an upstream infrastructure expansion, say three years. Accordingly, this arrangement would result in no difference in the Company's resource portfolio by the end of the IRP planning period. Instead, it could be viewed as an optimization of resources within the IRP period. More details regarding this arrangement will be provided if negotiations move forward.

7.9. Alternatives Not Yet Defined Enough for Evaluation

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

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

Additional Industrial Recall Agreements: As previously mentioned, the Company has three long-time recall arrangements with large industrial/generation end-users, two of which bring their own NWP capacity into the portfolio. The Company has had no success finding additional large end-users willing to enter into similar agreements. The Company will continue asking but has no expectation that voluntary curtailment, which is what this amounts to, will garner any interest without an extreme financial commitment. Note that the methanol arrangement mentioned above is a significant variation of this resource since it does not bring new resources to the table but only creates a relatively short-term resource optimization opportunity.

NWP Storage Redelivery Proposal on a Stand-alone Basis: NWP has proposed a firm storage redelivery pipeline service that has been modeled in conjunction with the different North Mist pipeline take-away alternates. A question arose as to whether that service should be evaluated on a stand-alone basis, e.g., to transport existing supplies or gas arising from Mist Recall. However, there appears to be no scenario in which such supplies require NWP transportation service because either (a) load growth in the Portland-area load center consumes all of the Mist gas supplies before they can reach NWP's system, or (2) if there is not enough load growth then it means there is no need for additional Mist Recall.

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

Floating LNG Storage: An idea that came out of a 2014 IRP TWG meeting was to use LNG stored in a vessel that would be anchored in the Columbia River to supply the Clark County load center, which would avoid siting one or more LNG storage facilities on land. However, this also would require the construction of additional pipeline infrastructure since the areas poised for load growth in Clark County are diverse and some are located further away from the Columbia River. Needless to say, there also would be considerable research necessary to ascertain the feasibility of anchoring an LNG vessel in the Columbia River for an extended period. This alternative remains at the conceptual phase right now.

LNG Imports: It has been about 10 years since LNG import terminals were proposed for Oregon. It was suggested at a 2014 Public Meeting that LNG imports from Alaska be evaluated as a resource option in conjunction with shipping carbon emissions from PGE's power plants at Port Westward to Alaska for sequestration and thus offset some of the costs of importing LNG. This is another alternative that remains purely conceptual at this time.

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 percent to 10 percent of natural gas use in the United States.[30]

[30] "The Potential for Renewable Gas: Biogas Derived from Biomass Feedstocks and Upgraded to Pipeline Quality."

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.

An analysis completed for the Oregon Department of Energy reviewed the use of biogas from several of the state's waste water treatment plants (WWTPs).[31] Among the findings of this report was that the RG from several of the plants may be worth more as a vehicle fuel rather than for heating or to make electricity.

To prepare itself for the potential of RG, the Company is updating its gas quality standards and sampling criteria for any proposed RG facilities desiring to interconnect with and deliver gas into the Company's distribution system. However, the proposed pricing for the RG (more than twice the current cost of gas delivered to the Company's system) suggests 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.[32]

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.

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 years ago to better ascertain the extent of these reserves.[33] However, the "shale gale" and its resulting reduction in natural gas prices, among other reasons, have stifled any

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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.

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

[32] Combustion of 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 $4.34/Dth cost of gas purchased and delivered to the Company's system in calendar year 2015, 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.

[33] See http://library.state.or.us/repository/2011/201109010951034/index.pdf .

recent interest in this potential resource.

Southern Crossing Expansion: FortisBC has proposed a reinforcement project for the Southern Crossing Pipeline that would permit more flow of Alberta gas to Sumas (the "KORP" project shown in figure 3.11). This would also require an expansion of NWP from Sumas, and so does not need to be modeled since it essentially is replicated by the current inclusion of the NWP Sumas expansion projects.

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

*Adsorbed Natural Gas (ANG)***:** This technology has been under development for over 10 years and offers the possibility of storing much higher volumes of natural gas at much lower pressures than is now accomplished using CNG[34]. However, while intriguing, there are no timelines or cost estimates that can be modeled yet.

System Leakage Reductions: A topic of interest the last few years has been methane leakage for natural gas infrastructure, sometimes referred to as fugitive gas emissions. The main focus has been on methane as a contributor to greenhouse gas emissions, but a secondary question has been whether this also imposes a current cost on consumers for the wasted volumes.[35] While this may be a general industry concern, NW Natural is in the forefront of leakage reduction due to its past and ongoing efforts to replace older pipelines that are the most susceptible to leakage, and it currently ranks number one among gas utilities with the lowest ratio of leaks per mile of pipe.[36] Accordingly, as a potential supply resource, the reduction of gas leakage is already being fully addressed.

Expansion of Local Production: The Mist underground storage field sits on many reservoirs in which native gas is slowly being produced—or not produced at all—due to its low heat content. The reason for this is the high nitrogen content of the native gas. Efforts to increase production levels would require the removal of some of this nitrogen, for example, by employing a nitrogen rejection unit (NRU) in the field. Ultimately, this decision is under the purview of the third party that possesses the local production rights. If the economics were favorable, that third party would proceed with the NRU or other means to increase the production and sale of their gas. The fact that it is not being pursued at this time is a reflection of the current relatively low market price of natural gas.

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

[34] See, for example, http://www.gl-nobledenton.com/en/consulting/asset_integrity/879.php .
[35] For example, see the article "EPA's 'fugitive methane' data under fire again" in the *Gas Daily* dated Nov. 6, 2013.
[36] See "Leak repairs rose in 2014 at gas utilities modernizing riskier systems" from SNL dated July 13, 2015 (https://www.snl.com/Interactivex/article.aspx?ID=33199640&KPLT=2).

the Portland area with its pipeline system in Clark County? While this would quickly remove a major limitation to serving Clark County, the movement of its own gas across state lines would jeopardize the Company's Hinshaw status, i.e., its exemption from FERC jurisdiction under the Natural Gas Act of 1938.

Winter-only T-South Capacity: Proposals are circulating for the creating of firm capacity on the Spectra pipeline system in British Columbia from Station 2 to Huntingdon/Sumas that would be available only during the heating season. This capacity arises from the higher efficiency of pipeline compressors as ambient temperatures fall, which is why the capacity is not available on a year-round basis. As with other T-South capacity evaluations, this could represent an opportunity to optimize resources if the cost of this capacity is more than offset by the price spread between Station 2 and Sumas. However, since it does not bring incremental resources to NW Natural's service territory, it is not explicitly modeled in the IRP as it is essentially covered already by inclusion of the NWP Sumas expansion projects.

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.

8. GAS SUPPLY PORTFOLIO ACQUISITION STRATEGY

This section provides the Company's strategies for acquiring gas supplies as described in the Company's Gas Acquisition Plan (GAP) for 2016-2017. The GAP is reviewed and approved by the Company's Gas Acquisition Strategy and Policies (GASP) Committee, but such plans are always subject to change based on market conditions. The primary objective of these gas acquisition plans is to ensure that supplies are sufficient to meet expected firm customer load requirements under design year conditions at a reasonable cost. Under other than design year conditions, the Company also expects to serve interruptible sales customers. The focus of the GAP is on the forthcoming gas contracting year which runs from November through the following October, which also coincides with the upcoming PGA "tracker" year. This focus extends for up to two additional contracting years for multiyear hedging considerations. Longer-term resources plans and hedging targets are the focus of the IRP and hence are not covered in the GAP, except of course to assure consistency in the transition from near-term to longer-term planning decisions.

The remainder of this section provides excerpts from the current GAP, and as mentioned above, its focus is on the 2016-17 "tracker" year along with the subsequent two years for hedging considerations.

8.1. Plan Goals

Reliability: The first priority of the Company's GAP is to ensure a gas resource portfolio that is sufficient to satisfy core customer requirements under design year weather conditions as defined in the IRP. Compromising reliability is not acceptable.

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

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

Cost Recovery: With the exception of approved gas reserve purchases, NW Natural does not earn a return for acquiring and selling gas commodity supplies, yet the cost of these supplies typically amounts to the largest item in the company's total revenue stream. Risks associated with the payment and recovery of gas acquisition costs need to be minimized. On the financial hedging side, this means strong credit policies and counterparty oversight. On the legal side, this mandates scrupulous compliance to standards of conduct. Since regulatory disallowances could be devastating, maintaining trust and credibility with state regulatory bodies is imperative.

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

8.2. 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 this document. Nevertheless, there is consistency between the GAP and the IRP to ensure that long-range decisions are reflected in current decisions, and vice versa.

Hedging is the subject of current dockets of the Oregon and Washington state utility commissions.[37] Hedging strategies might be affected by results of those proceedings.

8.3. Strategies

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

- Utilize financial derivative hedges, storage (both market-area and supply-basin), and fixed-price supplies including gas reserves and local production to manage cost risks. For 2016-2017, about 75 percent of expected sales volumes will be hedged with these tools, consistent with recent years, unless the GASP Committee approves a different target. Hedges reflect the assembly of a diverse portfolio and also allows for unhedged purchases to comprise almost half of the total purchases for the period, i.e., the 25 percent of annual expected sales volumes intentionally left unhedged plus all of the gas volumes purchased for injection into storage.

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

At a total hedge target of 75 percent, financial derivative hedges will comprise 41 percent to 48 percent of requirements. The lower end of this range reflects the potential cost-effective acquisition of supply-basin storage (as much as 10 percent of annual requirements per guidelines established by GASP), thereby offsetting (lowering) financial hedges by the equivalent volume. The upper end of this range reflects the possibility of no additional upstream storage deals beyond the current agreements that total 3 percent of sales.

- Maximize supplies from the regions that afford the lowest prices. Gas from Station 2 currently is the lowest-cost gas in the Company's supply region. Alberta is the next lowest. Sumas used to be the highest-priced supply but is now cheaper than the Rockies except for certain times during the winter. Keys to price shifts include production levels (especially in the Eastern U.S. from surging shale gas plays), new pipelines, power generation, regional demand as low energy prices spur an industrial renaissance, growing exports (both LNG and via pipeline to Mexico), and weather.
- Fill storage at a pace that might present opportunities to purchase gas at times that best benefit core customers.
- Maintain a diversity of physical supplies from Alberta, British Columbia and the Rockies.
- Due to its relative lack of trading liquidity, continue to baseload virtually all purchases from British Columbia (Huntingdon/Sumas) during the winter season when spot supply deliveries might be unreliable and prices more volatile.
- Substitute Station 2 for Huntingdon/Sumas purchases to the extent that Westcoast T-South capacity can be obtained at reasonable cost.

9. SUPPLY-SIDE RESOURCE DISPATCHING

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

Perhaps more importantly, SENDOUT® is used to dispatch supplies to meet design day conditions as defined through the IRP process. This leads to the creation of guidelines representing the 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.

10. SUPPLY DIVERSITY AND RISK MITIGATION PRACTICES

10.1. Background

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

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

- *Marcellus and Utica Shale*: Shale gas was well known but considered unconventional and uneconomic up until about 10 years ago. Its emergence and abundance at economic prices directly transformed gas markets in the eastern U.S. and Canada, with ripples extending across the continent. Combined with slow economic growth, shale gas has displaced some of the demand for Rockies and Western Canadian supplies. At the moment, the most bearish impacts have been felt in Alberta.
- *Ruby*: The Ruby Pipeline commenced service in mid-2011 from Wyoming to the California/Oregon border, providing another outlet for Rockies gas. However, only 71 percent of Ruby's capacity is backed up with firm contracts and those contracts had a remaining duration averaging nine years as of late 2014.[38] This situation could serve as further impetus for the Jordan Cove/Pacific Connector project. Indeed, the sponsor of Jordan Cove (Veresen Inc.) bought 50 percent of Ruby in September 2014.[39]
- *NGLs*: Prices for natural gas liquids (NGLs) such as propane and butane have tended to track oil prices more closely than natural gas. As a result, drilling activity generally has shifted to regions where the natural gas is "wetter" (has more NGLs) and market access is available. This then led to a glut of NGLs and the higher heat content on the NWP system that was discussed earlier.
- *Coal Plant Retirements*: As a result of federal air quality mandates, aging coal plant inefficiencies, and low natural gas prices, over 40,000 MW of coal plant retirements are expected by 2040, replaced by a mix of renewables and gas-fired generation.[40]
- *Growth of Exports*: The first large-scale shipment of LNG from the Gulf of Mexico occurred in February 2016, with subsequent shipments occurring about once a week.[41] But it is the export of natural gas via pipeline to Mexico that is likely to have a larger influence on U.S. markets. The U.S. Energy Information Administration (EIA) projects LNG exports will growth to an average of 1.3 Bcf/day in 2017.[42] By comparison, pipeline exports to Mexico are already up to 3 Bcf/day[43] and further growth is expected.

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

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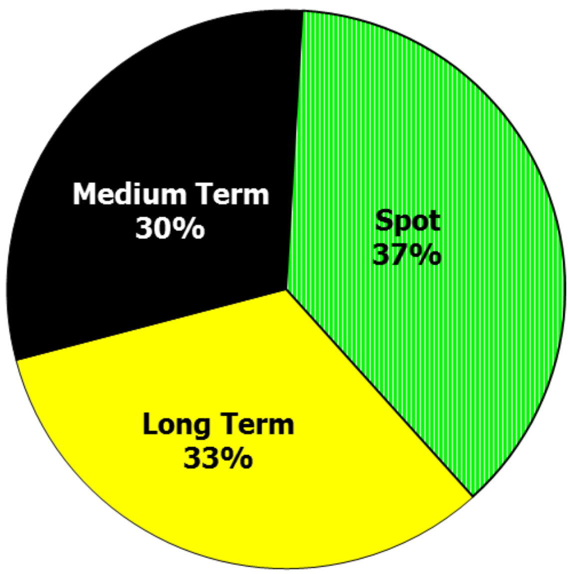
[38] http://www.veresenInc.com/wp-content/uploads/2012/11/Investor-Presentation-Ruby-Pipeline-Acquisition-September-22-2014.pdf.
[39] http://www.bloomberg.com/news/articles/2014-09-22/veresen-to-buy-50-of-ruby-gas-pipeline-for-1-43-billion.
[40] EIA's Annual Energy Outlook 2015, page 26, http://www.eia.gov/forecasts/aeo/pdf/0383%282015%29.pdf.
[41] http://fuelfix.com/blog/2016/04/25/chenieres-sabine-pass-ships-seventh-cargo/.
[42] https://www.eia.gov/forecasts/steo/report/natgas.cfm.
[43] http://www.eia.gov/dnav/ng/hist/n9132mx2M.htm.

Physical gas contracting strategies for 2016-2017 that are consistent with strategies of recent years include:

- Maintaining a diversity of physical supplies from Alberta, British Columbia and U.S. Rockies.
- Buying supplies at trading points with high "liquidity" in order to access the most competitively priced and reliable supplies.
- Continuing to shift the source of physical supplies to the lowest-cost source region.
- Evaluating the cost-effectiveness of "citygate" deliveries similar to the physical call option arrangement that has been in place with a gas marketer over the past two winters, especially as a potential backstop to continued reliance on segmented capacity.

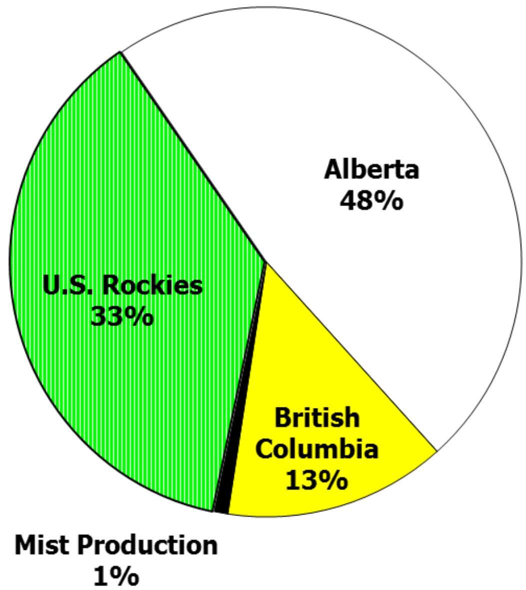
Figures 3.13 and 3.14 provide graphical representations of the Company's physical gas supply resources and diversity during 2015.

Figure 3.13: Gas Supply Diversity by Contract Length for Calendar Year 2015



Note: Long Term means one year or longer, Medium Term is greater than a month but less than a year, and Spot is up to a month.

Figure 3.14: Gas Supply Diversity by Source for Calendar Year 2015



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

10.2. Physical and Financial Hedging

The Company provides its retail sales customers with a gas service that bundles together the gas commodity, upstream pipeline transportation, off-system contracted gas storage, and on-system gas storage owned and controlled by the Company. To accomplish this, the Company aggregates load and acquires gas supplies for its core retail customers through wholesale market physical purchases that may be hedged using physical storage or financial transactions. As previously described in Section VII.B of this chapter, four goals guide the physical and financial hedging of gas supplies: Reliability, Lowest Reasonable Cost, Price Stability and Cost Recovery.

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

The Company's Gas Acquisition Strategy and Policies (GASP) Committee maintains oversight for the development and enforcement of the GSRMP. Within those policies, the Derivatives Policy establishes governance and controls for financial derivative instruments related to natural gas commodity prices including financial commodity hedge transactions.

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

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

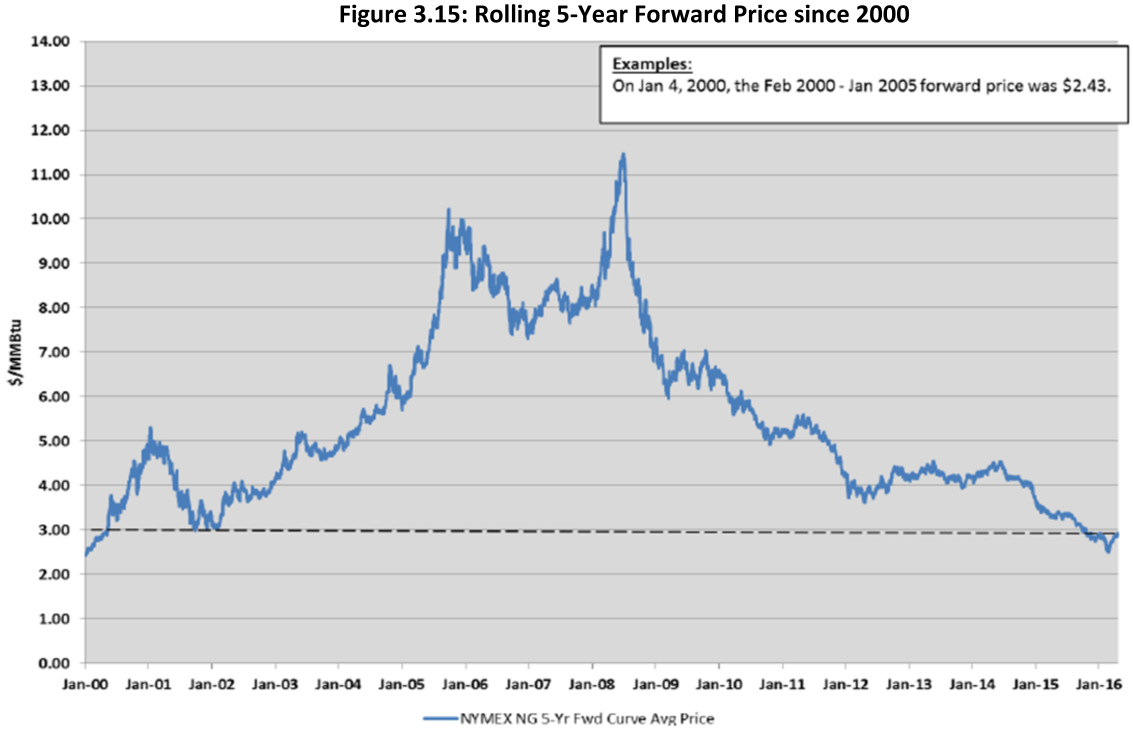
10.3. Hedging Targets

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

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

Hedging targets, that is, the percentage of the portfolio to be hedged and in what manner, are developed for the upcoming PGA "tracker" year as well as future years based on the Company's view of long-term price fundamentals. The growth of shale gas and the country's economic recession resulted in a dramatic reduction of gas prices, with the Company's gas rates now lower than they were in 2004 and future price expectations are currently at historically low levels (see figure 3.15).

Figure 3.15: Rolling 5-Year Forward Price since 2000



BP (Ben Go), North American Energy Markets, April 2016

This downward trend has given rise over the last few years to some basic questions:

- Should the Company attempt to lock in current price expectations for a long-term period?
- If so, for what portion of the portfolio?
- How best to evaluate the attributes of very different types of hedging structures?

One result of course was the 2011 gas reserves purchase agreement with Encana Oil & Gas (USA) Inc. (Encana), which has been discussed in detail in prior IRPs and other proceedings and will be summarized briefly in this IRP in a subsequent section.

Questions regarding the development of hedging targets led the Company to commission Aether Advisors LLC ("Aether") to perform an independent review of its hedging program. Aether issued its first report to the Company in January 2014, which was included in appendix 3 of the 2014 IRP. Key findings of that report were:

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

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

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

10.4. Current Percent Hedged

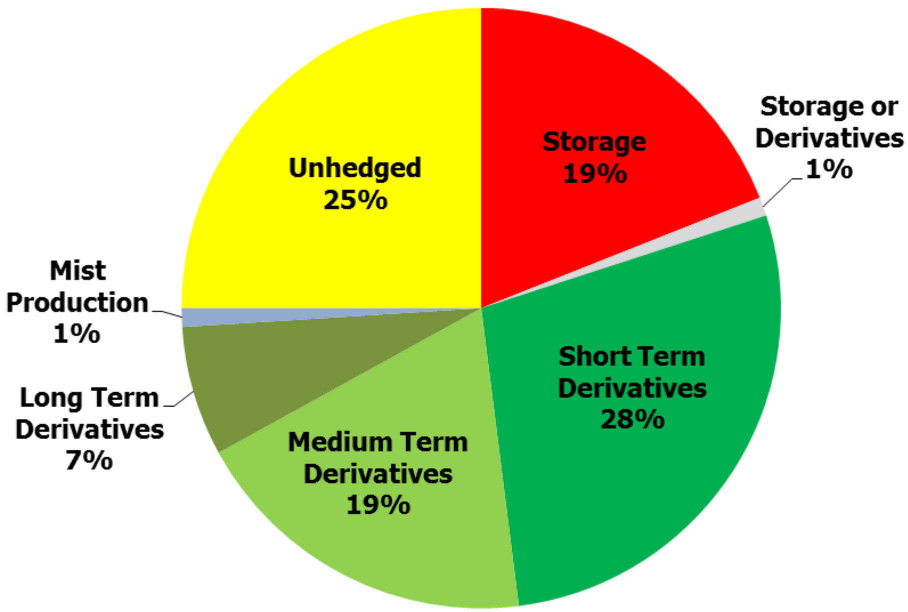
The Company's main hedging target has been to hedge a total of 75 percent of its expected requirements going into each PGA year. In light of the ongoing OPUC and WUTC hedge dockets that are expected to touch on this subject, the Company continues to use 75 percent as its overall hedging target for the time being. (The 75-percent target has been used and approved in OPUC/WUTC regulatory proceedings starting back in 2006.)[44]

The 75-percent target leaves 25 percent to be purchased at unhedged prices during the PGA year. Gas purchased for storage injection (about 20 to 25 percent of total requirements), while considered a type of hedging for the upcoming PGA year, also consists of unhedged purchases made during the

[44] See, for example, OPUC Order No. 06-609 (appendix A, p. 13) and OPUC Order No. 07-456 (appendix, p. 5).

spring/summer months. Accordingly, about half of the Company's total purchases each year are hedged through financial derivatives, fixed price contracts or gas reserves, while the other half of the purchases are made at spot market prices (see figure 3.16). Further targets have been developed, such as for winter versus summer months, as described in the GAP for each year.

Figure 3.16: Gas Supply Portfolio Hedge Targets for 2016-2017



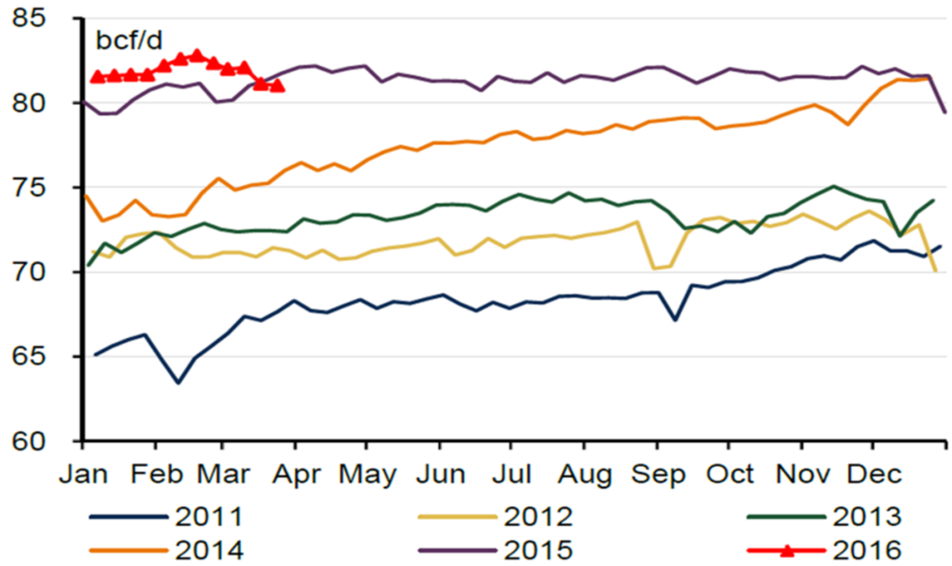
Note: Long Term refers to gas reserves, Medium Term means up to three years, and Short Term means within the 2016-17 tracker year only.

10.5. Long-Term Hedging Strategies and Plans

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

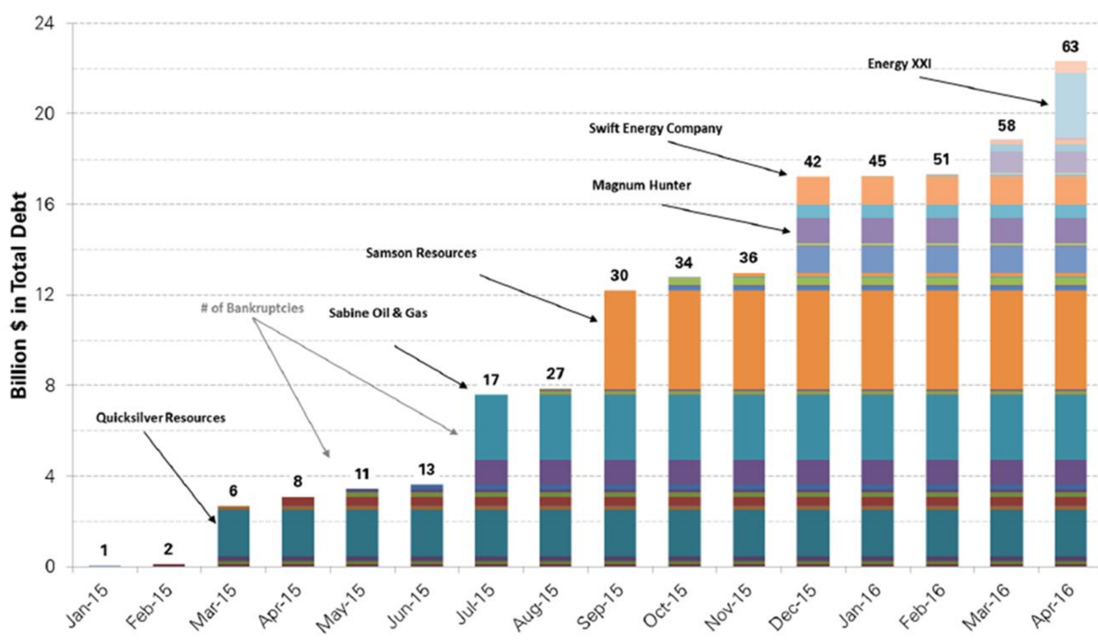
On the supply side, U.S. gas production has been robust, hitting new records with some regularity, but is starting to show signs of plateauing (figure 3.17). It is unlikely that production technology will stagnate, but instead should continue to improve over time. A significant production impediment that might appear would be new (or more stringently enforced existing) regulations that place certain developable lands out of bounds, or add significantly to the cost of production and so eliminate certain areas from development due to declining economics. But an immediate slowdown would be due overwhelmingly to the low price environment, which is leading to reductions in capital spending, layoffs and bankruptcies in the exploration and production section (figure 3.18).

Figure 3.17: U.S. Total Natural Gas Production



*Bank of America, Global Energy Weekly: La Niña Bonita, March 31, 2016

Figure 3.18: Oil and Gas Producer Bankruptcies

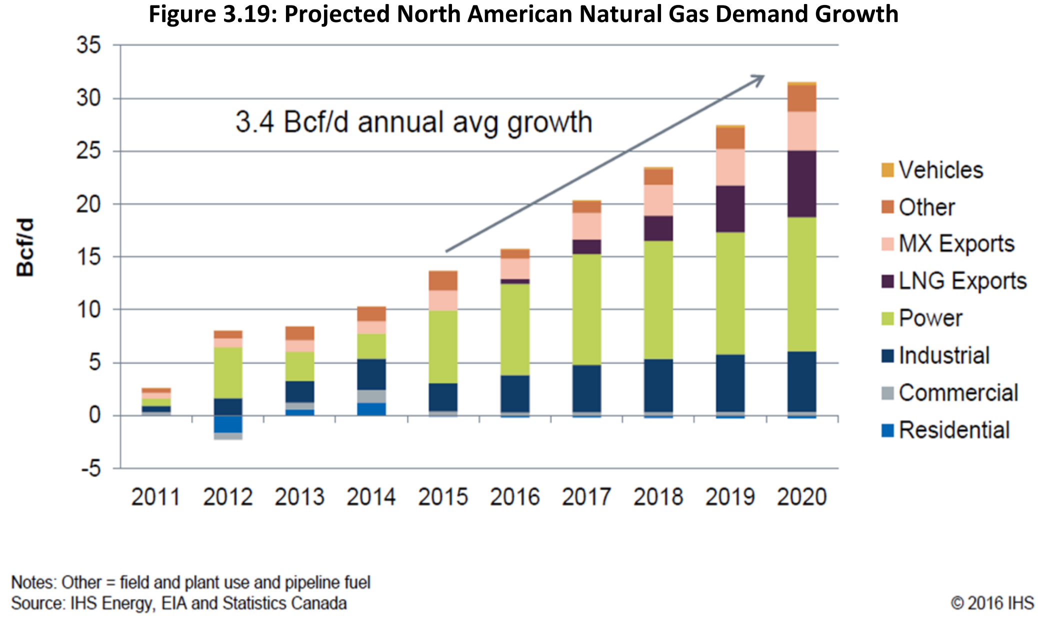


BP (Ben Go), North American Energy Markets, April 2016

On the demand side, the Company's view continues to be that the country is passing an inflection point that will lead to a surge in natural gas consumption. As shown in figure 3.19, power generation will lead the way, spurred by coal plant retirements as well as renewable energy mandates that will push the need for more gas-fired electric generation to replace retired units and support the grid. Gas exports will add to the demand for natural gas in the form of both LNG shipments and via pipeline to Mexico.

Then there is the expected industrial renaissance, with cheap U.S. natural gas fueling a surge in the petrochemical industry. A prime example in our region is the progress being made by a multinational group in the creation of a methanol manufacturing facility at Kalama, Washington, as well as their continuing efforts to site a second facility at Port Westward, Oregon (a third proposed facility in Tacoma has been dropped due to local opposition).[45] And of course there are other possibilities for accelerated natural gas demand growth, for example, as a transportation fuel for ships, trains, trucks and automobiles.

Figure 3.19: Projected North American Natural Gas Demand Growth



While there can never be any guarantees, this appears to be a prime time for locking in longer-term gas prices for a larger portion of the portfolio.

Of course deciding that it is timely to enter into longer-term hedging is only the first step. The second step is deciding the volume to hedge. The July 2014 Aether report recommended a long-term hedging range of up to 35 percent of expected annual requirements.[46]Aether also recommended that the hedge percentage decline over time due to factors such as market liquidity, load forecast uncertainties and the size of the financial commitments involved in these types of transactions. To that end, the Company had proposed guidelines around long-term hedging in the 2014 IRP, which led to the creation of OPUC

[45] See at http://tdn.com/news/local/unlike-tacoma-project-kalama-methanol-plant-gets-warmer-reception/article_55711e3a-92de-52af-ab1c-15b84669dc05.html .

[46] Aether Advisors report dated July 2014, p. 68.

Docket No. UM 1720. Through that docket, the Company hopes to establish consensus guidelines for conducting longer-term hedges. This would include methodologies for evaluating different types of longer-term hedging—financial derivatives instruments, physical supply contracts, gas ownership, etc., starting with, for example, how to evaluate the multitude of different durations that different structures may offer.

Concurrently, Washington State is reviewing hedging practices in WUTC Docket No. UG-132019. This docket appears to be concerned primarily with a program for shorter-term hedging—no more than 24 months into the future from the present month—as a portion of an overall hedging portfolio. Storage would be another portion that is not under discussion so far in the docket, as would be another portion (referred to as "programmatic" hedges) that could encompass longer-term hedging.

As of this writing, there is no coordination between the OPUC and WUTC hedging dockets, but the Company is hopeful that a bridge can be found to ensure some level of consistency between the outcomes of the two dockets and the avoidance of undue administrative complexities and cost.

10.6. Joint Venture for Gas Reserves

In April 2011, the Company entered into a Carry and Earning Agreement with Encana under which the Company and Encana agreed to participate in a joint venture to develop gas reserves located in the Jonah Field, located in the Green River Basin in Sublette County, Wyoming.[47] Under this agreement, the Company paid a portion of the costs of drilling in the Jonah Field, and in return received rights to the production of gas from certain sections of the field.

The gas is produced and marketed to other parties at a monthly index price. The proceeds from the sales are applied as an offset to the Company's own monthly index-based gas purchases. In this way, the gas reserve agreement more closely resembles a financial swap than a physical supply contract. While the Company could choose to bring the gas to its service territory rather than sell it off, that choice has other implications that make it less desirable unless there were some physical constraint in the Rockies that severely limited the Company's access to other gas supplies.

The intent of this venture was to provide Oregon utility sales customers with long-term supplies at stable pricing over the life of the gas reserves, approximately 30 years. By prior agreement, NW Natural does not include this joint venture in rates for its Washington customers but instead maintains two separate portfolios for Oregon and Washington for PGA purposes, as contemplated in the WUTC's Order No. 5 in Docket No. UG-111233.

During the first 10 years of the agreement, the Company projected the volume of gas under the Carry Agreement to be approximately 8-10 percent of the Company's average annual requirements for its utility operations, with a peak of about 15 percent in the years during the height of the drilling program. However, in 2014, Encana sold the agreement to Jonah Energy (Wedge) LLC, and the contemplated

[47] 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.

drilling program ended. Several additional wells were drilled in 2014 with Jonah Energy, referred to as "Post-Carry" wells, and an order was issued by the OPUC in 2015 regarding their regulatory treatment.[48] For the purpose of this IRP, the Carry and the Post-Carry volumes were aggregated and referred to as Long-Term Derivatives in figure 3.16. Unless the Company participates in the drilling of new Post-Carry wells, the natural depletion of the gas reserves should result in its gradual decline each year in terms of its percentage of the Company's hedge volumes.

10.7. Modeling of Gas Acquisition Costs

As done in its prior IRPs, the Company has not specifically modeled the commodity cost of any particular gas acquisition option. For example, it has not embedded the expected price of gas from the Carry and Post-Carry wells. Doing so would be problematic and unhelpful.

One of the building blocks of the IRP analysis is a price forecast applicable to commodity gas purchases at various trading hubs in the region (AECO, Sumas, et al.). This permits a complete evaluation and comparison of different demand-side measures and supply-side resources. Embedding any current financial swap or other agreement within that forecast would likely improperly skew the results because those prices are available only with those particular transactions, which are not unlimited in volume. If the Company were to use past transactional prices as a proxy for the marginal cost of gas, the model would not produce a realistic analysis of the options currently available for purchasing gas. Moreover, the existence of past financial transactions does not necessarily have an effect on the location at which the Company will purchase physical gas in the future because the Company can always choose to apply the proceeds from financial transactions to whatever purchases it does makes, and it will strive to make those purchases at the lowest cost locations. This approach has been approved in the past.[49]

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

[48] OPUC Order No. 15-297 dated September 28, 2015.
[49] For example, in David Danner's (then WUTC Executive Director and Secretary) letter to NW Natural dated Jan. 13, 2012, the WUTC acknowledged the Company's previous IRP filed in Docket No. UG-100245 and confirmed that NW Natural's approach to limiting the inclusion of the Encana transaction in its analyses was appropriate.

11. RECENT ACTION STEPS

The Executive Summary of the Company's 2014 IRP had a Multiyear Action Plan[50] with 10 items related to supply-side resources and hedging. Those items, along with the actions actually undertaken by the Company, are as follows:

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

This was done. Also, since recall decisions are made during the summer for an effective date of May 1of the following year, it was decided in the summer 2015 not to do another Mist recall for 2016, which also fit with the projections in the 2014 IRP.[51]

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

The Company was unable to improve the reliability of its NWP TF-2 transportation service from Plymouth. To assure deliveries, the only option would have been to use TF-1 service from receipt points east of Plymouth (Stanfield or the Rockies). This would have been a "robbing Peter to pay Paul" situation since it would rob the Company of reliable gas deliveries from those other points. Plymouth in essence became a supply-basin storage facility, similar to Alberta storage, and on that basis, the costliness of the LNG service did not justify continuation of our Plymouth contracts. Those contracts were terminated effective Oct. 31, 2015.

The Company was able to negotiate a discounted TF-1 primary firm service applicable to Jackson Prairie to replace the 13,525 Dth/day of subordinate TF-2 service. Details regarding the proposed new agreement were filed with the OPUC on May 8, 2015, as a 2014 IRP Update, as well as in the Company's 2015 PGA filings. Service commenced effective Nov. 1, 2015. Accordingly, this matter is now resolved for the foreseeable future.

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

Two steps were taken that increased MDDOs useable at the Clark County gates. First, the new agreement for Jackson Prairie deliveries mentioned above also created the same volume (13,525 Dth/day) of new MDDOs for the gates. Second, NWP agreed to a segmentation of the March Point TF-1 contract that comes into the Company's possession on Jan. 1, 2017, which will add 12,000 Dth/day of new MDDOs for Clark Country related gates. So MDDOs directly applicable to Clark County have been improved by 25,525 Dth/day compared to the last IRP. In addition, the new methodology for redeploying unused MDDOs described in section III.D resolved any remaining Clark County MDDO concerns for the time horizon of this IRP.

[50] See 2014 IRP, pages 1.201.22.
[51] See 2014 IRP, Table 7.5 on page 7.13

iv. *Provide termination notice to NWP on the Company's existing Plymouth LS-1 and TF-2 service agreements by Oct. 31, 2014 (effective Nov. 1, 2015), unless NWP offers a viable economic alternative solution before that notice cutoff date.*

Done as discussed in item ii above.

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

NW Natural submitted an update to the Company's 2014 IRP to the Public Utility Commission of Oregon in May 2015 related to a North Mist expansion[52] for utility customers. The update included analysis of alternatives, refined cost estimates, and discussed both the real option nature of a specific alternative and the Company's Hinshaw Exemption. Regarding the Hinshaw Exemption, the Company's legal analysis indicated that it may be possible to structure agreements so that the Hinshaw Exemption is not impacted. NW Natural stated in the filing that it did not view the Hinshaw Exemption as an obstacle to further evaluation of the North Mist resource at this time.

NW Natural filed a second update in October 2015,[53] which included additional information regarding a North Mist expansion. The Company included a summary of the analysis with respect to alternative configurations of takeaway pipelines in the context of the Company's 2014 IRP, which appears below as table 3.7.[54] The analysis of alternative configurations of takeaway pipelines concluded that the Alternative 3 hybrid approach, utilizing both northbound and southbound takeaway pipelines, was the least-cost alternative. A related analysis in the October filing concluded the North Mist expansion utilizing the takeaway pipeline configuration contemplated in the 2014 IRP did not have a positive value as a real option.

NW Natural discusses the North Mist II alternatives earlier in this chapter and discussed the project, including alternative takeaway configurations, with stakeholders in the Company's Feb. 10, 2016 Technical Working Group meeting.

[52] NW Natural identifies a North Mist expansion for utility customer in the 2016 IRP as North Mist II.
[53] Both the May and October 2015 filings were in the Public Utility Commission of Oregon's Docket No. LC 60, NW Natural's 2014 IRP proceeding in Oregon.
[54] Table 3.7 appeared as Table 1 on page 8 of the October 2015 filing.

Table 3.7: PVRR Values for North Mist Alternatives and a Clark County LNG Facility in NW Natural's 2014 IRP[55] (Millions of $2015)

	Base Case	High Load	Low Load
2014 IRP Resource Scenarios A1 and A3			
North Mist Alternative 1	201.7	223.0	148.1
North Mist Alternative 2	216.4	240.6	155.8
North Mist Alternative 3	194.1	215.9	139.3
Clark County LNG	295.4	328.3	212.5
2014 IRP Resource Scenarios A2, B1 and B2			
North Mist Alternative 1	148.1	164.4	107.2
North Mist Alternative 2	155.8	174.2	109.4
North Mist Alternative 3	139.3	156.0	97.4
Clark County LNG	212.5	237.7	149.3

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

The Company continues to monitor the progress of the Trail West and Pacific Connector projects, and for a time was in the process of negotiating a precedent agreement with Trail West to preserve it as an option, but that effort has paused and no commitments have been needed so far. More on Pacific Connector in the next item.

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

In March 2016, FERC rejected the applications to build and operate Jordan Cove and Pacific Connector.[56] FERC's rationale was that the sponsors had not lined up enough (if any) commitments for the LNG, so there were no benefits to balance against the adverse impacts argued by landowners and other opponents to the project. The sponsors immediately contacted potential customers and announced the

[55] Please see Section 7.2. Storage Additions, North Mist II for an explanation of the alternatives.
[56] http://www.oregonlive.com/environment/index.ssf/2016/03/feds_deny_jordan_cove_lng_term.html

signing of preliminary agreements covering half of the LNG terminal capacity as well as 75 percent of Pacific Connector capacity, then filed an appeal with FERC in mid-April.[57] On May 9, 2016, FERC issued an order allowing itself more time to consider the rehearing request, but did not specify a timeline.[58] So while Pacific Connector remains a resource option in this IRP analysis, conducting further risk analysis has been put on hold for now.

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

This matter is now being explicitly considered in OPUC docket UM 1720, and is an implicit part of the Company's involvement in WUTC docket UG-132019.

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

Pacific Connector was discussed two items above, and as previously mentioned, NWP's Washington Expansion (WEX) project is considered dead due to the cancellation of the Oregon LNG project.

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

This IRP contains our latest estimates.

12. RECAP AND KEY FINDINGS

- The Company recalled 30,000 Dth/day of Mist deliverability effective May 1, 2015, and a combination of other resources allowed it to avoid further recall in 2016.
- The Company needs to plan for the eventual phase-out of segmented capacity because its peak day reliability is expected to degrade over time. For this IRP, that phase-out date is Nov. 1, 2020, which is based on the estimated timing of new gas-fired power generation and industrial projects significantly impacting gas flows from Sumas. However, in the interim, the Company will increase its reliance on segmented capacity from 43,800 Dth/day (as shown in the 2014 IRP) to 60,700 Dth/day.
- The Company has resolved its concerns regarding firm transportation service reliability from Plymouth and Jackson Prairie storage.
    - For Plymouth, this resolution unfortunately needed to be the removal of Plymouth from the Company's resource stack and the termination of the related NWP agreements, which took effect on Oct. 31, 2015.

[57] http://www.veresininc.com/newsroom/news-releases/?path=/press-releases/veresen-announces-submission-of-request-for-rehearing-to-ferc-and-execution-of-n-tsx-vsn-201604111050082001.
[58] http://veresen.mwnewsroom.com/Files/d8/d8a206f6-6aa8-4324-afcd-02f0a601e8aa.pdf.

  - For Jackson Prairie, a new discounted TF-1 agreement was negotiated with NWP and the affected 13,525 Dth/day now has primary firm pipeline capacity supporting it, thus this resource no longer needs to be phased out.
- Short-term citygate delivery contracts have been cost-effective the past two winters, and the Company is investigating their potential viability on a multiyear basis so that they may be considered in the context of the IRP analysis.
- The prior concern with MDDOs, especially for gate stations serving the Clark County load center, has been resolved for this IRP planning period through a combination of three factors:
  - Consultations with NWP led to a new methodology for considering the conjunctive treatment of MDDOs within a zone, and the redeployment of unused MDDOs from a zone to an upstream zone.
  - The new discounted TF-1 contract from Jackson Prairie created 13,525 Dth/day of new MDDO effective Nov. 1, 2015.
  - Segmentation of the March Point contract creates 12,000 Dth/day of applicable MDDOs effective Jan. 1, 2017.
- Gas market fundamentals appear to support additional long-term pricing arrangements at this time, but any actions must be congruent with the Oregon (UM 1720) and Washington (UG-132019) hedging dockets.
- A glut of NGLs in the region has led to a higher heat content of the gas flowing on NWP's system. This in turn has slightly boosted the capabilities of the Company's on-system storage plants. However, the NGL glut is not expected to persist indefinitely, so this impact also has been modeled as phasing out gradually over time.
- The Oregon LNG export terminal near Astoria has been canceled, so the associated Washington Expansion pipeline project no longer needs to be considered. Meanwhile, Jordan Cove recently suffered a severe setback at FERC, but it is still sufficiently alive to warrant continued inclusion in the IRP analysis.
- Contracting for T-South capacity should be re-evaluated each year due to the potential for changing price spreads between Station 2 and Sumas and other relevant considerations such as supply liquidity.
- There are a variety of resources that are too speculative for inclusion in this analysis, but that determination should be revisited in future IRPs.
  - As part of its ongoing asset management practice, the Company recently received a consultant's study on the Mist storage facility that included a variety of recommendations. Of likely significance within the action plan timeframe of this IRP are repairs, replacements and/or modifications to the dehydration systems at Mist. Chapter 1 includes the following action item:Replace or repair, depending on relative cost-effectiveness, the large dehydrator at Mist's Miller Station. Replacement is currently estimated to cost between $6 million and $7 million based on estimates obtained from a third-party engineering consulting firm engaged by NW Natural. NW Natural will evaluate alternatives associated with the Al's Pool and Miller Station small dehydrator systems at Mist to determine if and when additional actions are warranted.

Chapter 4
Energy Policies and Environmental Considerations

1. OVERVIEW

NW Natural operations are informed and driven by the environmental and regulatory context in which the utility operates. This includes policies that are currently implemented, and also policies likely to take effect sometime in the Company's planning horizon. At the federal level, the Clean Power Plan has the potential to increase demand on natural gas, thereby driving up the cost of gas. And, methane regulation impacts how gas is produced. More locally in the Pacific Northwest, Washington and Oregon have both implemented policies – or are considering policies – that could impact how greenhouse gas emissions are valued. This landscape forms the foundation of NW Natural's carbon scenarios within this IRP.

This chapter explores NW Natural's view of actual or likely legislative and regulatory contexts, and how that assessment informs its current and future actions to address greenhouse gas (GHG) emissions. Stakeholders should understand and weigh in on this view as it creates the framework for the Company's planning efforts. Additionally, the 2014 IRP specifically requested a stakeholder discussion regarding methane and carbon regulation. This technical working group meeting was held on March 17, 2016 and the topics covered in this chapter were reviewed and discussed at that time. The upstream methane pilot project, presented in this chapter, was discussed at the technical working group session on June 22, 2016.

Legislation and regulation to reduce the environmental impacts of the energy system present the Company with both risks and opportunities. It is important that the Company understand emerging policy and how it may impact our customers, our business, and the citizens of the states we serve. More critically, we must work to find alignment with our stakeholders and Commissioners on this view.

KEY FINDINGS

Key findings in this chapter include the following:

- The policy future around carbon pricing is uncertain but NWN believes a price on carbon will be adopted at the state, regional or federal level within the planning horizon.
- NWN is using a carbon price from the NW Power Planning and Conservation Council based on their California cap and trade price forecast.
- NWN is working hard to reduce GHG emissions at all stages of the supply chain and expects to engage in any policy debates around a carbon price.
- Due to completing our pipeline replacement with newer pipe, the Company is among the tightest distribution companies in the country in terms of methane emissions.
- Opportunities for additional methane emissions reductions are largely upstream of distribution – and NWN is exploring a pilot project that would promote the use of best management practices in gas production.

2. GREENHOUSE GAS EMISSIONS OVERVIEW

The GHG emissions that are attributable to the natural gas system come from two places:

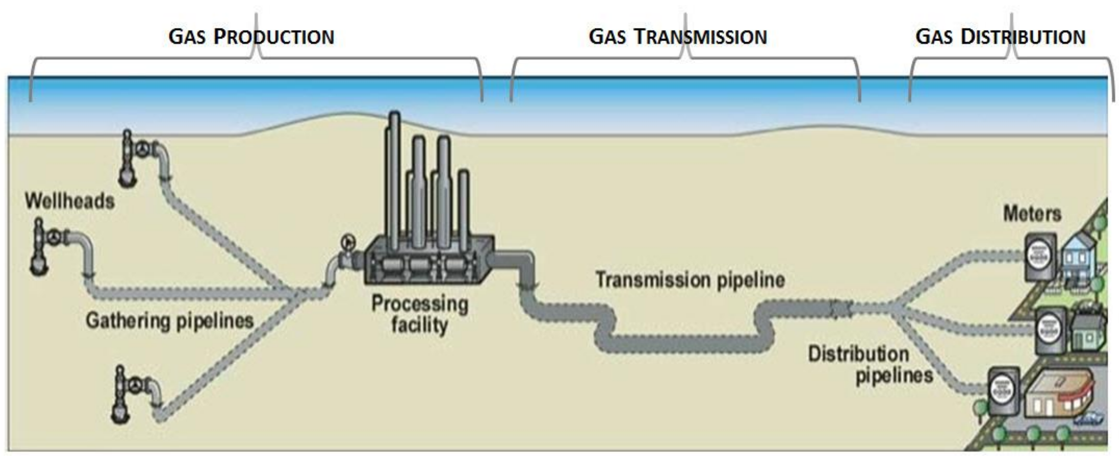
- Methane emissions that escape from production wells, from leaks in pipelines (transmission and distribution lines), storage facilities and from emissions from other equipment (citygate stations, meter sets, etc.); and
- Carbon dioxide emissions that result from the combustion of natural gas when customers use it as a fuel.

While it is not a completely separate category of emissions, the Company also tracks and reports separately to the Public Utility Commission of Oregon NW Natural's specific emissions associated with the Company's fleets, facilities and other operations (e.g., compressors).

2.1. Methane Emissions from the Natural Gas System

There are three parts to the natural gas system—production, transmission (which includes storage) and distribution—and methane emissions occur in varying degrees at the points along this supply chain. Policies and regulation seek to impact these emissions; accordingly, policymakers and regulators need to understand the value chain – where emissions occur and which entity has control over that part of the value chain. Figure 4.1 illustrates the three basic parts of the natural gas system.

Figure 4.1: Natural Gas Sector Breakdown

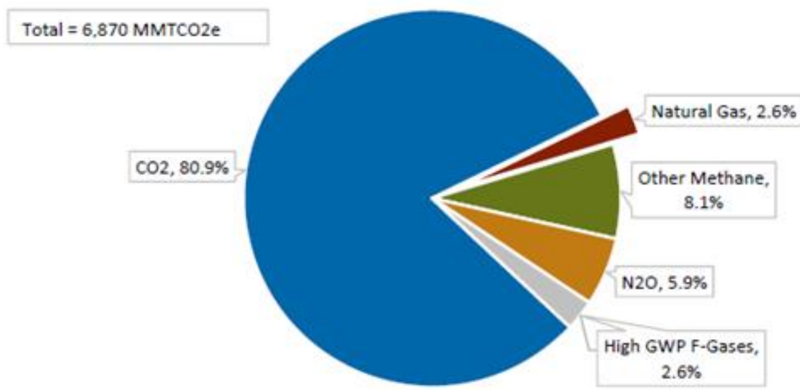


ICF International recently published a comprehensive literature review of a wide variety of sources regarding methane emissions from the natural gas sector.[1] The report indicates that EPA's 2014 Inventory of Emissions shows that agricultural sources of methane such as livestock and farming operations are the largest U.S. sources of methane, accounting for 32 percent of methane emissions and 3.5 percent of total U.S. GHG emissions. Natural gas industries account for 24 percent of methane emissions, or 2.6 percent of all U.S. GHG emissions in 2014.

1 ICF International, Finding the Facts on Methane Emissions: A Guide to the Literature, April 2016, http://www.ngsa.org/download/analysis_studies/NGC-Final-Report-4-25.pdf.

Figure 4.2, drawn from the ICF report, compares the methane emissions from the entire natural gas sector with other sources of total U.S. greenhouse gas emissions.

Figure 4.2: Methane Emissions from Natural Gas Industries[2]



Most methane emissions associated with the natural gas system are upstream of distribution, with the majority occurring in production and transmission. According to the recent ICF literature review, distribution accounts for approximately 21 percent of the fugitive methane emissions, gas production (30 percent), gas processing (14 percent), and transmission (35 percent); (see figure 4.3).

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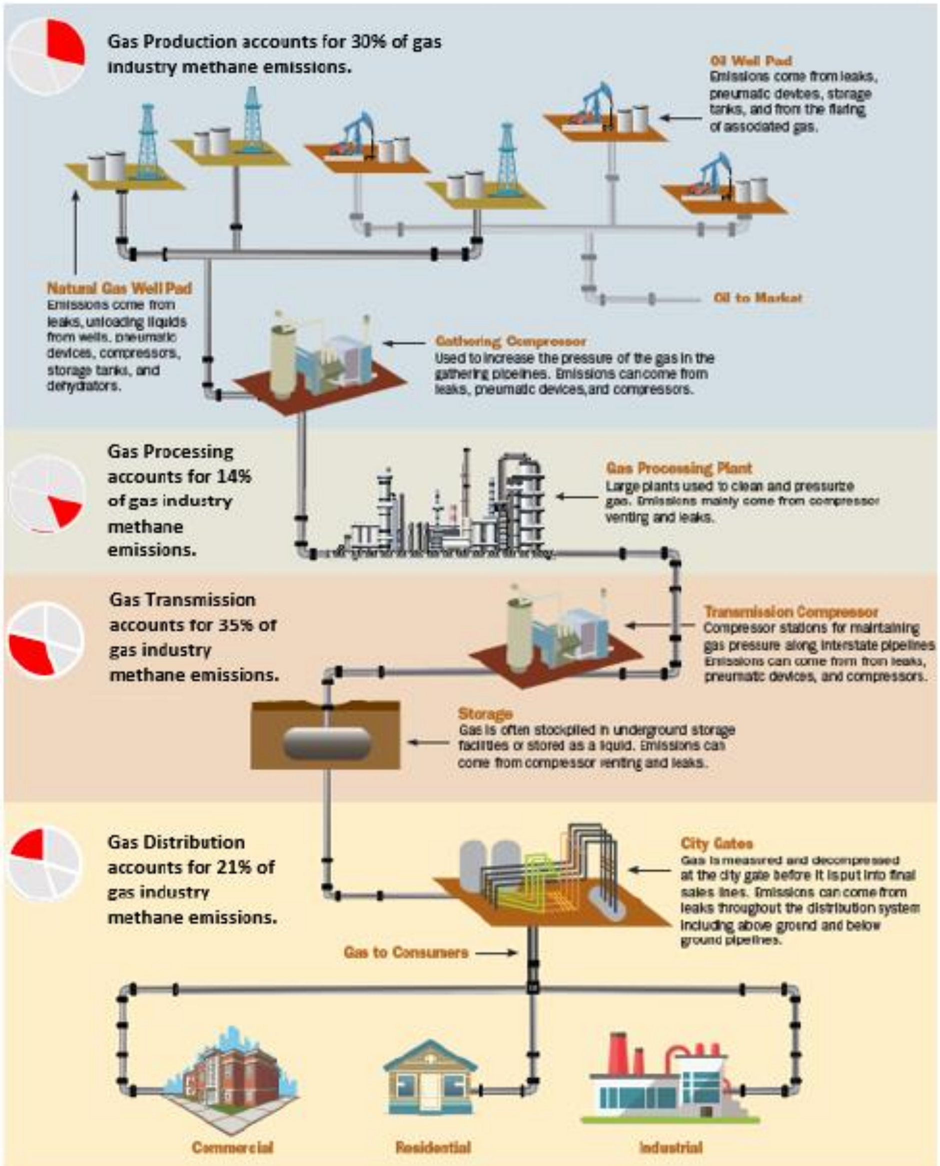
[2] Ibid. ICF International, 2016.

Figure 4.3: Methane Emissions Sources within the Natural Gas Sector



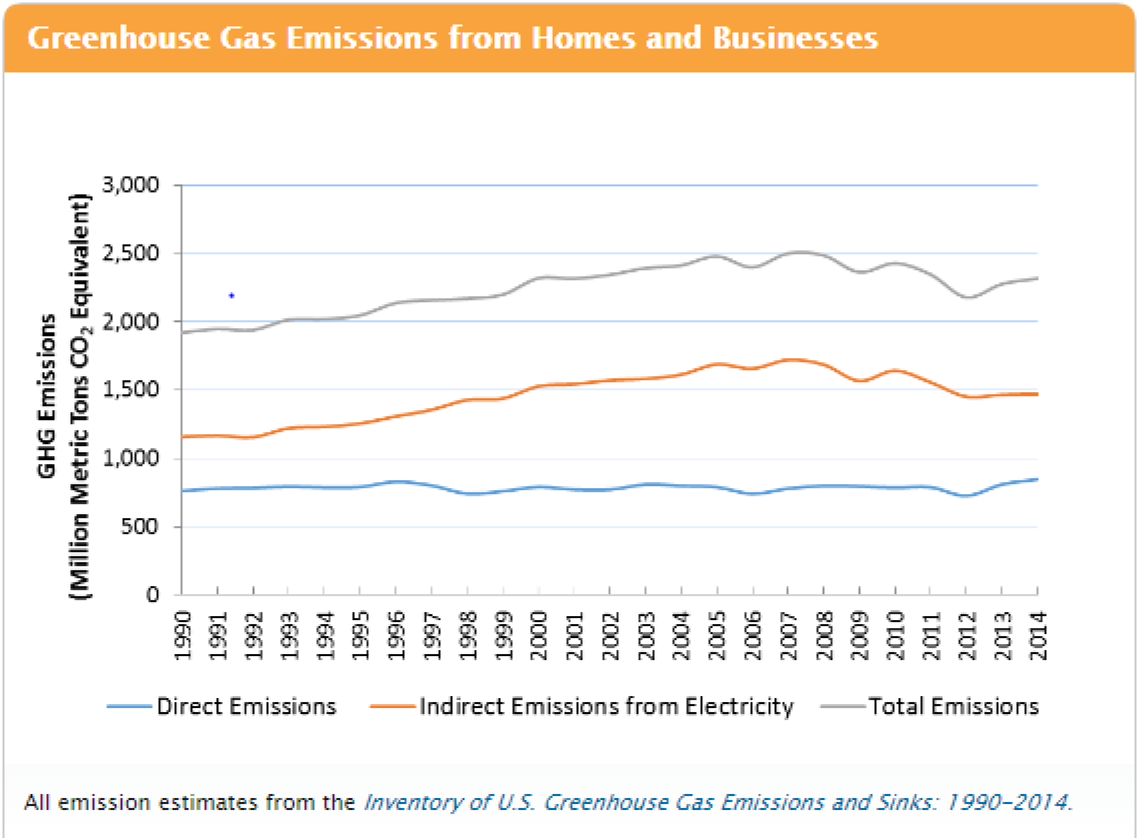
Source: Adapted from Clean Air Task Force "Waste Not"
http://www.catf.us/resources/publications/files/WasteNot.pdf

2.2. GHG Emissions from Natural Gas

Natural gas emits GHGs when combusted by customers in the residential, commercial and industrial sectors. While these emissions are not within the Company's control, NW Natural works hard with our customers to limit their GHG emissions through energy efficiency and our Smart Energy program, described in more detail below.

EPA inventory shows national direct emissions from natural gas and other sources are relatively flat and make up slightly more than one-third of total emissions for homes and businesses (see figure 4.4).

Figure 4.4: U.S. GHG Emissions from Direct Sources and Electricity



2.3. Measuring and Regulating Emissions from the Natural Gas System

Production and Transmission

EPA attempts to measure emissions from the natural gas system in a variety of ways. Upstream emissions that occur during production and transmission fall under the EPA's New Source Performance Standards (NSPS), under Section 111 of the Clean Air Act. The NSPS apply to new, modified and reconstructed facilities in specific source categories.

On May 16, 2016, EPA released final updates to its 2012 NSPS for the oil and gas industry aimed at reducing GHG emissions – most notably methane – along with smog-forming volatile organic compounds (VOCs). The updates apply to equipment at natural gas transmission compressor stations: specifically, they add requirements for detecting and repairing leaks, as well as requirements to limit emissions from compressors, pneumatic controllers and pneumatic pumps used at compressor stations. The rule applies to large emission sources and to emission sources upstream of the point of custody transfer at the citygate. It's unlikely that a source within the NW Natural distribution system would fall within the threshold set by the rule. However, NW Natural continues to work with EPA and the

American Gas Association (AGA) to ensure any new or updated compressors and equipment are operated and maintained in accordance with these regulations.

Distribution

Methane emissions from the distribution system occur at various points within the system. Pipe vintage and pipe material type are the biggest drivers of methane emissions within the distribution system. Older pipe types (e.g., cast iron and bare steel) are much more prone to leaks compared to newer pipe (e.g., coated steel and poly). Additionally, meters, regulators and services account for very small methane emissions. Finally, emissions can occur at gate stations and from equipment like compressors.

Currently, there is no federal regulation addressing emissions from the distribution sector. However, NW Natural participates in the EPA's GHG Reporting Program (GHGRP) under the Clean Air Act by providing emissions data annually to the agency through two pathways, Subpart W and Subpart NN. The GHGRP requires owners or operators of facilities that contain petroleum and natural gas systems and emit 25,000 metric tons carbon dioxide equivalent ($MTCO_2e$) or more per year to report system emission data to EPA.

Subpart W

Under Subpart W, the Company is required to report its fugitive emissions, defined as emissions not discharged through a flue or stack. These are emissions that result from small leaks in equipment or as a result of pipeline corrosion. Under Subpart W, the emission measures are calculated through a combination of EPA-established emission factors based on equipment type and pipeline composition, as well as a few direct measures.

Subpart W relies on various emissions factors that are based on broad industry averages. The section below on current reduction strategies includes additional data derived from recent reports that helps refine and improve these average emissions factors.

Subpart NN

The vast majority of the greenhouse gas emissions associated with natural gas—about 98 percent—occur on the customer's side of the meter when the fuel is combusted. LDCs must report the GHG emissions that would result from the complete combustion or oxidation of the annual volumes of natural gas provided to end users on their distribution systems. Through Subpart NN, NW Natural reports to the EPA on GHG emissions from the final use of natural gas by our customers in Oregon and Washington.

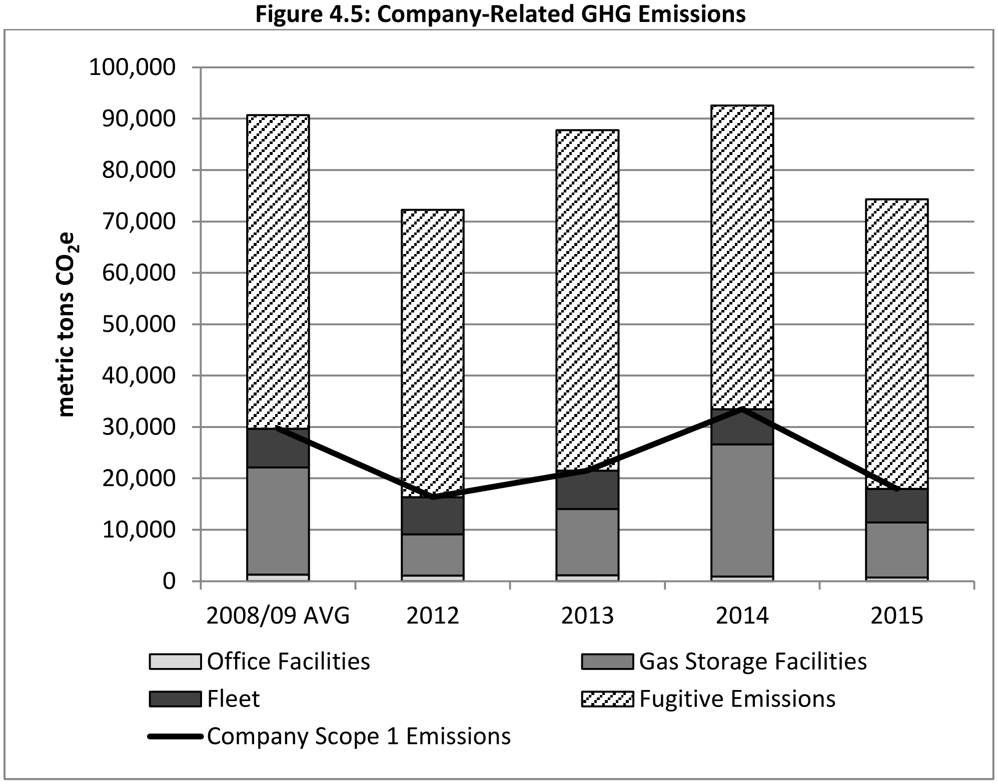
2.4. Company-Specific Emissions

NW Natural also tracks scope one emissions – GHG emissions associated with Company operations – and reports these biennially to the OPUC. These Company emissions, as shown in the graph below, are made up of emissions associated with our fleet operations, the operation of our facilities, and the operation of compressors to operate both our pipelines and Company gas storage (see figure 4.5 from

RG-46, OAR 860-085-0050(1) Greenhouse Gas (GHG) Compliance Report).[3] The baseline for the OPUC report, indicated in the first column of the graph below is the company's average emission from 2008 and 2009. This two-year average is used as the baseline proxy for 1990 and 2005 emission levels required by the OPUC report. The variability of company emissions year on year is primarily due to Company's operational needs that are determined by weather and market price variations. For example, in years with more natural gas throughput and/or more use of storage, the Company sees greater emissions from compressor operations.

The graph below also shows the estimated emissions related to fugitive emissions on our system. While the emissions associated with fleets, facilities and operations are measured, fugitive emissions are derived from the Subpart W emissions factors described above.

Figure 4.5: Company-Related GHG Emissions



3 The emissions for "Storage Facilities" in the graph are from company compressors and not from any fugitive emissions at our storage facilities. Fugitive emissions from NW Natural storage are very low and do not meet the reporting threshold for these emissions under Subpart W of the EPA's Greenhouse Gas Reporting Program. When the emission reporting program was established, NW Natural performed preliminary calculations to determine which facilities required reporting. Under those calculations, NW Natural's storage facilities were significantly under the threshold of 25,000 MT of CO2e.

3. PRICING CARBON: LEGISLATIVE AND REGULATORY LANDSCAPE

State and federal policies that seek to price carbon have the potential to impact end users of natural gas. This section provides a broad overview of some of the policy discussions regarding carbon pricing and GHG reductions that could impact NW Natural customers.

3.1. National Policy

The Clean Power Plan (CPP) – also known as 111(d) – regulates existing Electricity Generating Units (EGUs). It does this by capping GHG emissions from the power sector and mandating a national 32 percent reduction in emissions by 2030. Each state is given a target—Oregon must reduce emissions by 20 percent and Washington by 37 percent—and they may reach that target through a variety of strategies including deploying renewable energy, implementing energy efficiency, and increasing natural gas generation. If a state is unable to meet its goal, it may trade with another state that has excess credit. States can use EPA's trading rules or write their own plan that allows for trades with other "trading-ready" states. Mandatory reductions begin in 2022 with gradual "steps" down in emissions.

Implementation of this rule will likely increase demand for natural gas used in EGUs, as well as peaking plants used to firm up increasing use of intermittent renewable energy. As such, the IHS CERA price forecast that NW Natural uses assumes an increase in demand and a correlating increase in price.[4] However, though the final rule was published in August of 2015, several states are suing and the Supreme Court stayed implementation of the plan until the case had a chance to weave its way through the court system.

3.2. Washington Policy

In 2008, the Washington State Legislature set targets for required statewide GHG reductions. After failing to get the 2015 legislature to adopt a climate bill, Governor Inslee directed the Department of Ecology to use its existing authority under the State Clean Air Act to adopt a rule that limits GHG emissions.

To meet the Governor's directive, Ecology published a draft Clean Air Rule on Jan. 6, 2016 and, after receiving substantive feedback from stakeholders, rescinded it for redrafting. The Department published a new draft of the rules on June 1. The final rule is expected in the Fall of 2016 with compliance beginning in January 2017.

Under the rule, any entity that emits over 100,000 $MTCO_2e$ per year has a compliance obligation. The draft rule establishes a baseline year by taking the average emissions from five years—2012 to 2016—as reported through Subpart NN. Going forward, there are three-year compliance periods, at which time the party must show a 5-percent reduction from the rolling baseline. Reductions may occur through

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[4] The IHS Inc. price forecast used in the 2016 IRP considered the impact on natural gas prices of EPA's draft CPP rules. The draft rule ended up being much more onerous for Oregon and Washington than is expected from the currently drafted final rule. Thus the IHS Inc. price forecast may include a greater price impact than might be expected under the final CPP.

efficiency and retrofits. However, if an obligated party is unable to reduce its emissions onsite, it may invest in emission reductions units (ERUs) within the state of Washington.

As written, the draft rule makes natural gas utilities responsible for their customers' emissions. As such, NW Natural must make investments in emission reduction units to comply with this rule, since the Company has no direct control over how its customers use natural gas.

NW Natural has many concerns about how this rule will be implemented, and how it will impact customers. These include:

- This rule does not take into account customer growth. Clark County has been the second fastest growing county in Washington.[5] Even though use per customer is declining (see chapter 2), customer growth is projected to outweigh this impact in NW Natural's service territory, inclusive of Washington State, and therefore the Company's compliance obligation is expected to increase through time.
- It's unclear how Ecology will treat increased throughput that results from projects that have a net GHG benefit, such as Compressed Natural Gas (CNG) stations. In this scenario, NW Natural would be helping to reduce emissions in another sector (transportation) but would be penalized with increased costs.
- There are questions about Ecology's legal authority to regulate LDCs and there may be a legal challenge depending on what the final rule says and how it treats LDCs.
- It's unclear how the UTC will treat the costs of compliance. The cost to comply is challenging to model since ERUs do not yet exist. Additionally, because the draft rule limits credits to Washington State and does not allow for a broader geographic area, the cost to comply may be much higher than previously thought.

3.3. Oregon Policy

Oregon has been discussing the possibility of creating a carbon pricing policy for a decade but, for various reasons, has not moved forward with an economy-wide program. Instead, the state has passed sector-specific policies that reduce GHGs. Most recently, in the 2016 session, the legislature passed SB 1547 that phases out the use of electricity derived from coal and pushes the state toward a 50 percent (nonhydro) Renewable Portfolio Standard by 2040.

Similarly, the Clean Fuel Standards targets GHG emissions from the transportation sector by mandating a 10 percent decrease in transportation fuel carbon intensity over 10 years. This program, which is modeled closely after California's Low Carbon Fuel Standard, creates a market by allowing vendors of low-carbon fuels like biodiesel, CNG and electricity to create credits, while vendors of more carbon-intensive fuels like diesel and gasoline must purchase credits. The belief is that this market will increase

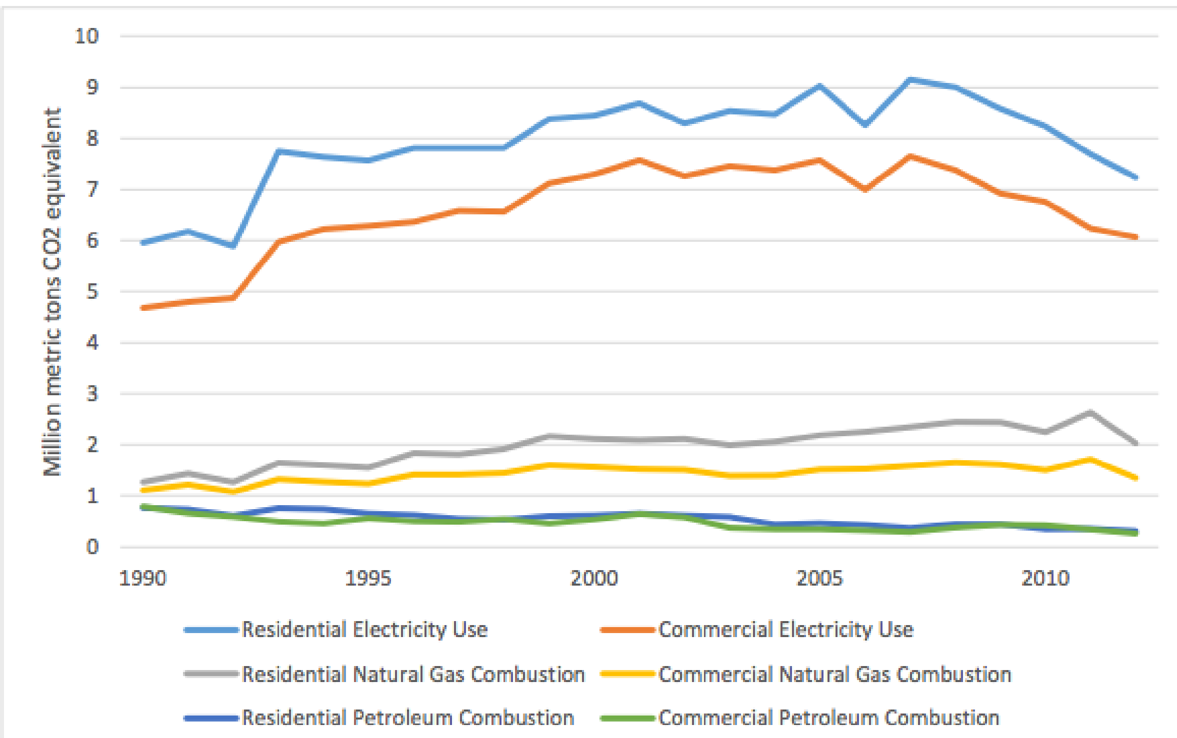
[5] See page 466 of Woods and Poole's 2015 State Profile for Idaho, Oregon, and Washington, where Clark County had the second highest average annual rate of population growth for Washington counties over the period 1970–2010 and also the second highest growth rate of counties within NW Natural's service territory. Woods and Poole, on page 467, forecast Clark County to have the highest average annual rate of population growth of any county in the states of Idaho, Oregon, and Washington over the period 2010–2050.

the availability and usage of low-carbon fuels. With our Schedule H tariff for compression services, NW Natural is poised to provide CNG to customers and generate credits under this program.

Despite this legislative movement on the electricity and transportation fronts, which account for the majority of the state's GHG emissions, there will be much discussion about carbon pricing legislation coming years. Transportation emissions make up the largest sector of emissions at 39 percent of the state's overall emissions and the chart below shows relative emissions from electricity, gas and petroleum for commercial and residential customers[6] (see figure 4.5).

NW Natural believes it is important for states to take action now to reduce emissions and prepare for inevitable federal legislation and regulation on climate. Indeed, with its pipeline replacement program, the Company took early action to reduce emissions associated with natural gas distribution and can now claim one of the tightest distribution systems in the country. Additionally, Smart Energy (discussed in detail below) was one of the first voluntary emission reduction programs offered by an LDC. NW Natural will continue its work to reduce GHG emissions and expects to actively engage in the discussion around carbon pricing as it evolves over coming years.

Figure 4.5: Relative Emissions from Oregon's Residential and Commercial Sectors



3.4. Incorporating Uncertain State Carbon Policy into IRP Planning

6 Transportation emissions make up the largest component of Oregon's GHG emissions at 39 percent in 2012. Oregon Global Warming Commission, Biennial Report to the Legislature, September 2015.

Incorporating expectations of carbon policy into IRP planning is challenging for myriad reasons since forecasting policy is notoriously difficult and policies can have disparate impacts on NW Natural's costs of compliance, depending on their form and structure. For example, a carbon tax affects every unit of natural gas sold but cap and trade programs typically only impact emissions above the specified cap.[7] Moreover, policies that are at least in part carbon policies—like Renewable Portfolio Standards—may not have any costs of compliance for natural gas LDCs like NW Natural.

Given this uncertainty regarding policy type and its implications for cost of compliance, NW Natural has chosen to represent carbon policy uncertainty the way that many utilities represent it in their resource planning: with a range of "carbon prices[8]" that act as a proxy for the cost of compliance with a wide slate of carbon policies. It is important to note that none of the carbon prices modeled in this IRP assume or advocate for any particular policy structure. Instead, NW Natural intends for the modeled carbon prices to reflect policy discussions, and the uncertainty surrounding them, under way in Oregon and Washington and the likelihood of a carbon price occurring at some point within the planning horizon.

Additionally, choosing a slate of carbon prices to serve as a proxy for future state carbon policies — including phase-in dates and ramp-up trajectories—requires a bit of crystal ball gazing that is fairly subjective. Acknowledging this, the carbon modeling team had robust discussions regarding the best option for the Base Case carbon price to represent the momentum in state carbon policy in each of Washington and Oregon. Ultimately, the team decided to use the Northwest Power and Conservation Council's (NWPCC) forecast of carbon prices in the California cap and trade program as a proxy for future state policies within the Base Case.

The team landed on this for a few reasons:

- The NWPCC is an unbiased and respected third party that has a relatively recent and publicly available forecast;
- The first draft of the Washington Clean Air Rule depended largely on credits from the California program. Though this changed in the latest draft, it is possible the final draft will go back to allowing credits from the California market. Either way, ERUs will most likely follow rules created by California; Oregon's Clean Fuels Standard looked to California as a model, and adopts many of the same protocols with the assumption that the California Air Resources Board (CARB) has done due-diligence and is better staffed than Oregon DEQ on these matters; and
- If Oregon adopts a price on carbon, it is reasonably likely the state will look south to California to inform the structure, or even link up with the program and create fungible credits.

The models NW Natural uses in the 2016 IRP for Residential and Commercial customer growth, firm Industrial annual load, annual energy use per customer, and peak day use per customer do not include

[7] Note that the cost of compliance can be as variable with a cap and trade mechanism as with a carbon tax. Just as a tax can be set at $0.01/ton or $1 million dollars/ton of carbon and the costs of compliance would be vastly different, a cap can be set at, for example, 150 percent of 2016 emissions or 50 percent of 1925 emissions and the costs of compliance will be just as drastically different.

[8] The discussion through the remainder of this chapter adopts the common IRP nomenclature of referring to the costs of complying with carbon policy as "carbon prices."

price as an explanatory variable.[9] Therefore, the incorporation of an explicit carbon price does not directly impact the level of load forecast. NW Natural includes alternative carbon prices in the Company's avoided cost, however the level of avoided cost influences the level of cost-effective demand-side management energy efficiency[10] and thereby impacts both the annual energy and peak day load forecasts.

In addition to the NWPCC's forecast of California allowance prices, NW Natural used four additional scenarios of future carbon prices to represent uncertainty regarding future carbon policy. These include: no incremental cost of carbon resulting from state policy, the Council's forecast of the British Columbia carbon tax, and two versions of the Social Cost of Carbon. These last two scenarios involve the July 2015 revised estimates from the federal Interagency Working Group on Social Cost of Carbon (IWG),[11] which are associated with a 3 percent annual discount rate and with a 2.5 percent annual discount rate. NW Natural views the second social cost of carbon as a reasonable "bookend" at the high end of a meaningful range of carbon prices considered by the Company.

The carbon modeling team uses somewhat different approaches for each state since Oregon and Washington have different trajectories on carbon regulation. Washington's carbon price is implemented in 2017 and uses contemporaneous forecast levels while Oregon's carbon price is implemented in 2021 because it assumes policy adoption in 2017 and a five-year implementation period, so it has a corresponding five-year lag from the contemporaneous forecast levels.

As an example of the forecast timing differences, the Base Case Washington carbon price in 2025 reflects the NWPCC's forecasted 2025 price, while the Base Case Oregon carbon price in 2025 reflects the Council's forecasted 2020 price. The primary result is that Oregon's carbon price in any given year over the period 2021–2035 is somewhat lower than Washington's carbon price.

Figures 4.6 and 4.7 show the Base Case and alternative carbon price scenarios[12] for Oregon and Washington, respectively. Each figure shows the various carbon prices in dollars per therm of natural gas on the left axis and dollars per metric ton of CO_2 equivalent ($MTCO_2e$) on the right axis.

9 See the discussion in chapter 2.

10 See chapter 5 for discussion regarding the components of NW Natural's avoided cost. See also chapter 6 for discussion of demand-side resources.

11 See https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf (accessed May 4, 2016).

12 The SCC Medium carbon price in figures 4.6 and 4.7 represents the IWG's social cost of carbon estimated using a 3 percent annual discount rate while the SCC High represents the IWG's social cost of carbon estimated using a 2.5 percent annual discount rate.

Figure 4.6: Oregon Incremental State Carbon Policy Carbon Price Adders

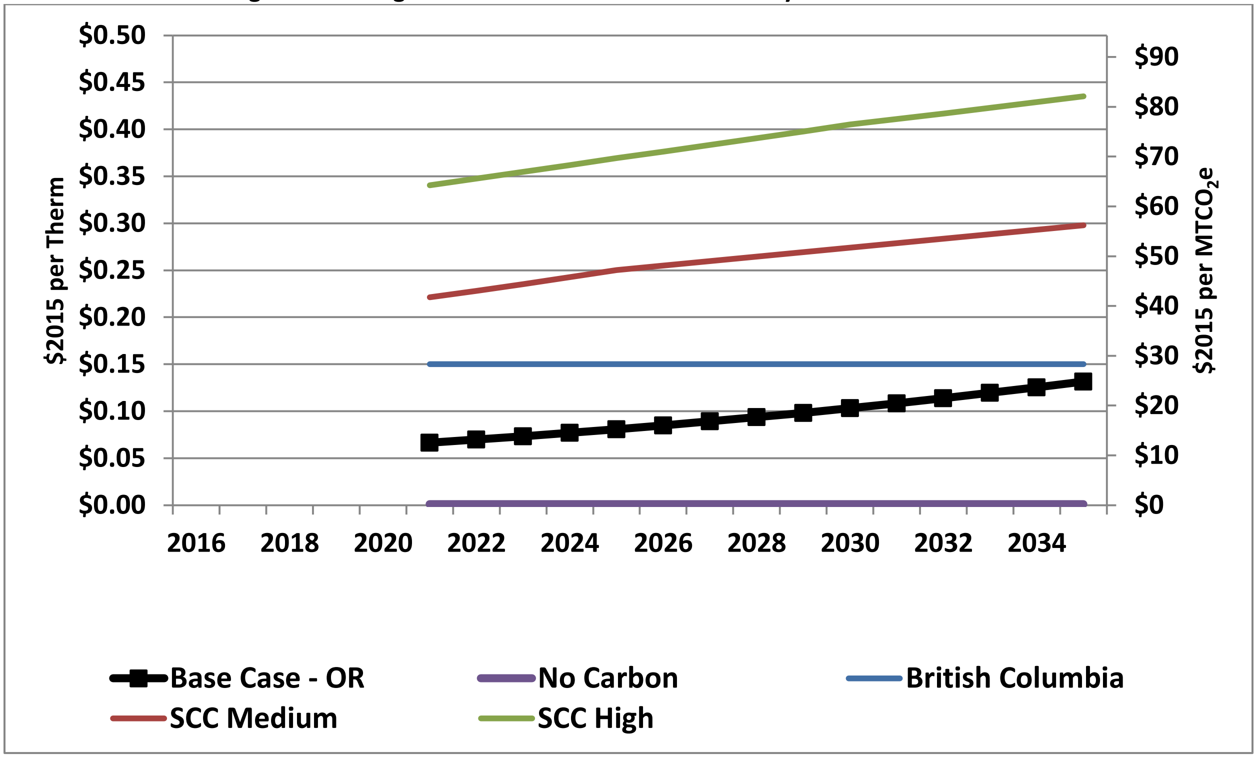
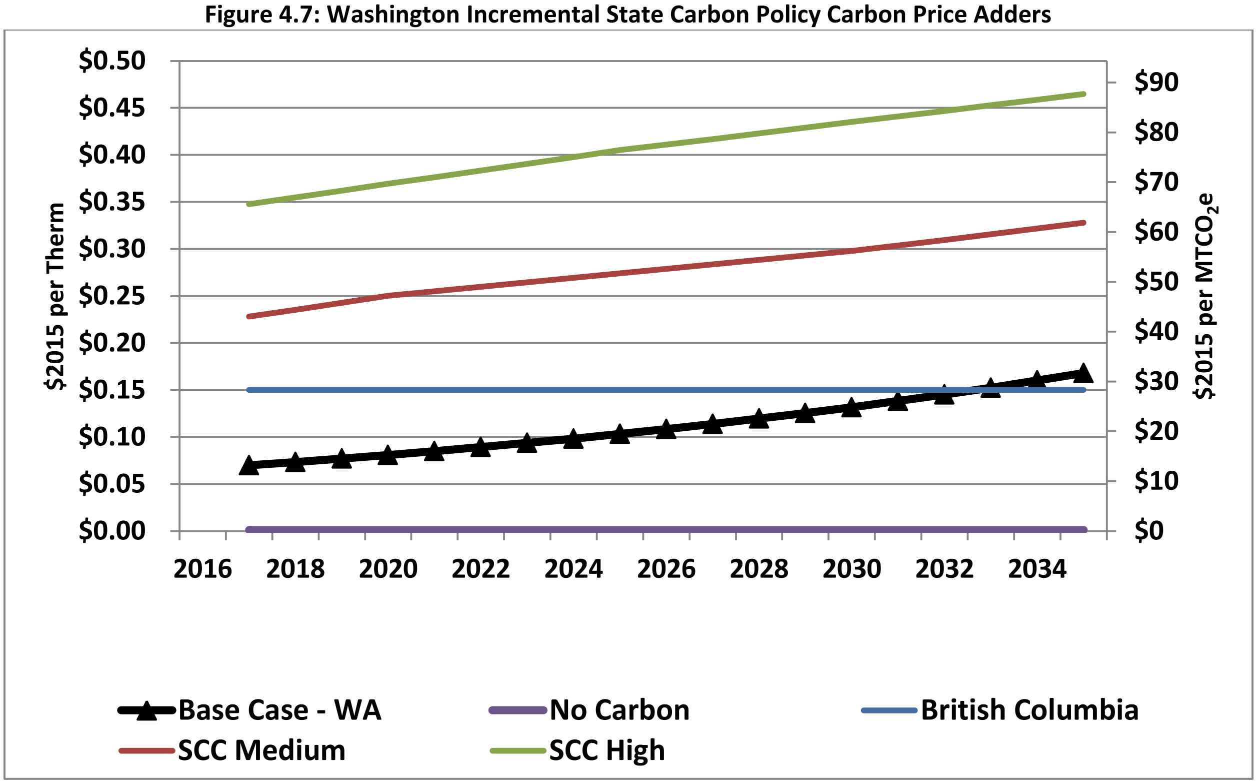


Figure 4.7: Washington Incremental State Carbon Policy Carbon Price Adders



4. CURRENT COMPANY EFFORTS TO ADDRESS GREENHOUSE GAS EMISSIONS

As stated above, NW Natural takes the issue of climate change seriously, is working to limit emissions from our own operations and is partnering with our customers to limit the impacts of their use of natural gas. To the extent possible we want to deploy natural gas in a manner and for end uses that help drive down overall emissions.

Part of this work, of course, is to ensure that our customers use our product as efficiently as possible and we do this both through low-income energy-efficiency programs administered by the Company and through our successful partnership with Energy Trust in both Oregon and Washington to promote and implement a broad set of energy efficiency programs. The details of our energy efficiency work are handled separately in chapter 6.

Though as described above, there are no specific requirements on the Company to reduce GHG emissions, the Company is hard at work to do so in a low-cost manner as this is what NW Natural believes is in the best interest of its customers and society as whole. This section outlines both the efforts in which we are currently engaged as well as potential efforts under consideration. Besides emissions associated directly with our operations, this section also considers efforts underway both with our customers and possible ways to engage upstream of our business to reduce GHG emissions.

4.1. Customer Program: Smart Energy

NW Natural works hard with our customers to reduce their GHG impacts, as well as their bills, through the efficient use of our product. NW Natural was a pioneer among utilities in decoupling rates from usage; in so doing, the Company now is a strong advocate for customer conservation.

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

Customers can either sign up under a fixed rate program for $5.50/per month, based on average usage, or can sign up to offset 100 percent of their emissions based on their actual use. As of today, we have over 33,000 customers enrolled in Smart Energy.

Under the program we partner with The Climate Trust to purchase high-quality offsets, with a focus on dairy digesters located in the Pacific Northwest. The program has funded over 540,000 short tons of CO_2, equal to the annual emissions of about 103,500 passenger vehicles.

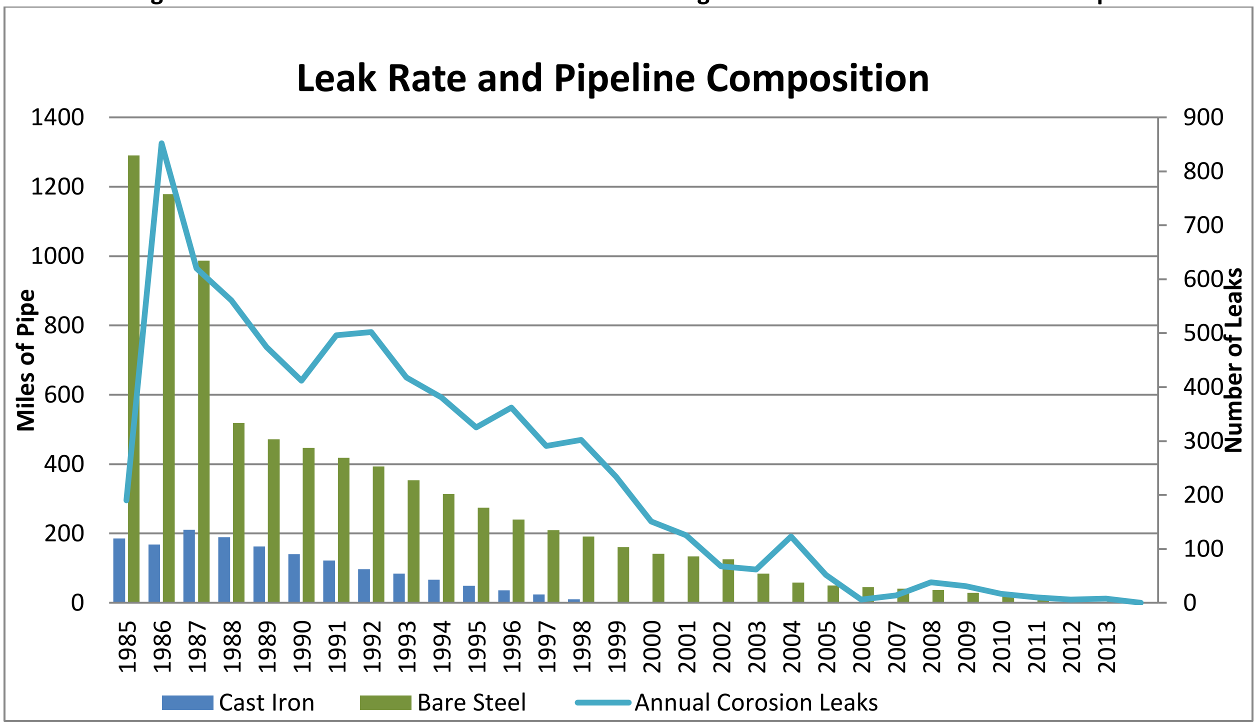
To date, the program has invested in ten projects – five in Oregon, three in Washington, one in Idaho and one in northern California. Nine of these projects capture methane from cow manure and turn it into biogas on dairy farms. The tenth uses wastewater from a potato processing plant to create biogas.

4.2. Voluntary Methane Reductions

Fugitive methane emissions reported to EPA, as described above, are based on emissions factors that are estimates from the EPA based on modeled averages. The Company's pipeline work – with the support and foresight of our state regulators – has resulted in the Company fully completing work in 2015 to change out our older pipe. The result of this work is that NW Natural is among the tightest distribution companies in the country.[13]

As the graph below shows, our pipeline integrity work supported the removal of all known cast iron by 2000 and the last known bare steel being removed in 2015. The graph also shows the dramatic reduction in pipeline leaks per year (see figure 4.8).

Figure 4.8: Leak Reduction Over Time and the Change Out of Cast Iron and Bare Steel Pipe

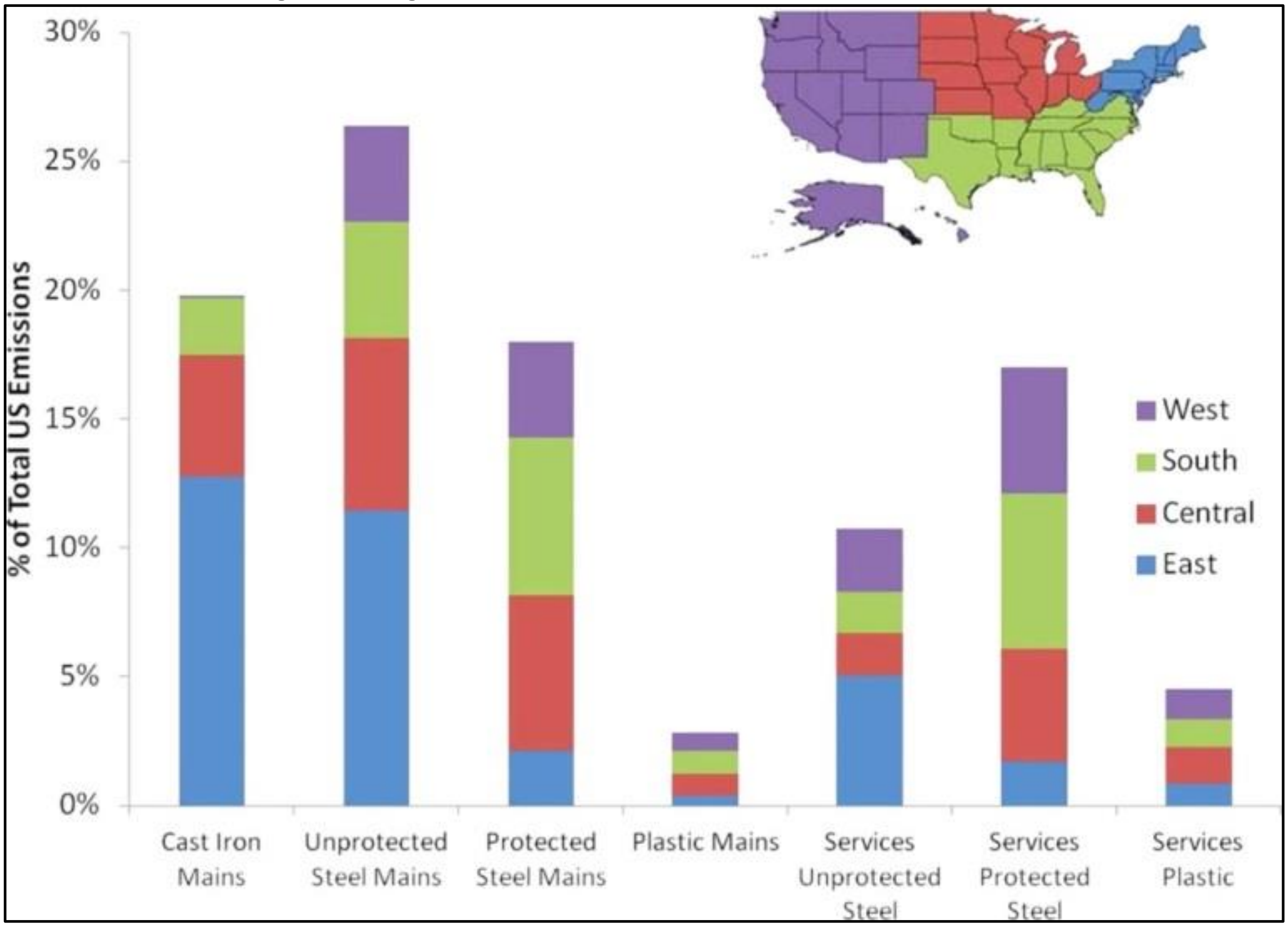


Our work to change out older pipe was motivated by the safety benefits of doing so, but has the additional important benefit of driving related methane reductions. While the Company is among the very first LDCs to be fully free of cast iron and bare steel, newer systems in the west have much less of this older style pipe. As figure 4.9 shows, the newer systems in the West produce relatively little of the nation's emissions from cast iron pipe and unprotected steel pipe, with the large majority of these

[13] An SNL Energy analysis of 2012 Office of Pipeline Safety data ranks utilities by their leak levels and suggests NW Natural is the tightest LDC in the country (Tuesday, March 25, 2014 *Northeast LDCs, led by Con Edison, rank highest in leaks per mile of pipeline)*. The WSU study described in more detail in the following text did not include all LDCs but is consistent with the view that the Company is among the tightest of the LDCs.

emissions coming from older systems in the Northeast region of the United States.[14] This map is instructive because it shows using national averages for leakage rates may not be particularly accurate and may result in over-estimating emissions associated with gas utilities in the West.

Figure 4.9: Regional differences in the sources of methane emissions



While research continues on methane emissions from the natural gas sector, one of the most complete efforts to understand the full methane emissions from the natural gas value chain ("from gas well to burner tip") is a 16-part independent study conducted by the Environmental Defense Fund (EDF) along with various academic institutions.[15]

NW Natural volunteered along with other LDCs to be part of one of these EDF studies as it analyzed emissions from the distribution sector. The LDC study was conducted at 13 companies by Washington State University and was published in *Environmental Science and Technology* (March, 2015). The study

14 Published in: Brian K. Lamb; Steven L. Edburg; Thomas W. Ferrara; Touché Howard; Matthew R. Harrison; Charles E. Kolb; Amy Townsend-Small; Wesley Dyck; Antonio Possolo; James R. Whetstone; *Environ. Sci. Technol.* 2015**,** Copyright © 2015 American Chemical Society.

15 The 16-part study that is independent and rigorously executed is described in more detail on the Environmental Defense Fund site at https://www.edf.org/climate/methane-studies .

used actual field measurements and found EPA's emission factors significantly overestimate actual leakage rates. Titled *Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States*, the report develops updated emissions factors for different types of pipeline. It then assigns the WSU emissions factors to NW Natural based on mileage of different kinds of pipeline, and then compares them to the results from the Gas Research Institute (GRI)/EPA 1992 emission factors. It is expected that these new and improved data on distribution emissions will be incorporated in changes to the EPA's Subpart W reporting program.

Pipeline replacement is the number one strategy for reducing emissions from the LDC system; since the Company has completed this work, we continue to look for additional efforts to further reduce fugitive methane emissions. As part of this continuing work, the Company joined the U.S. EPA Natural Gas Star Methane Challenge in March 2016 as a founding member. Under the Methane Challenge, companies in the natural gas industry adopt best practices that reduce methane emissions by sector. U.S. EPA identified key sector specific best practices that have been demonstrated to reduce emissions.

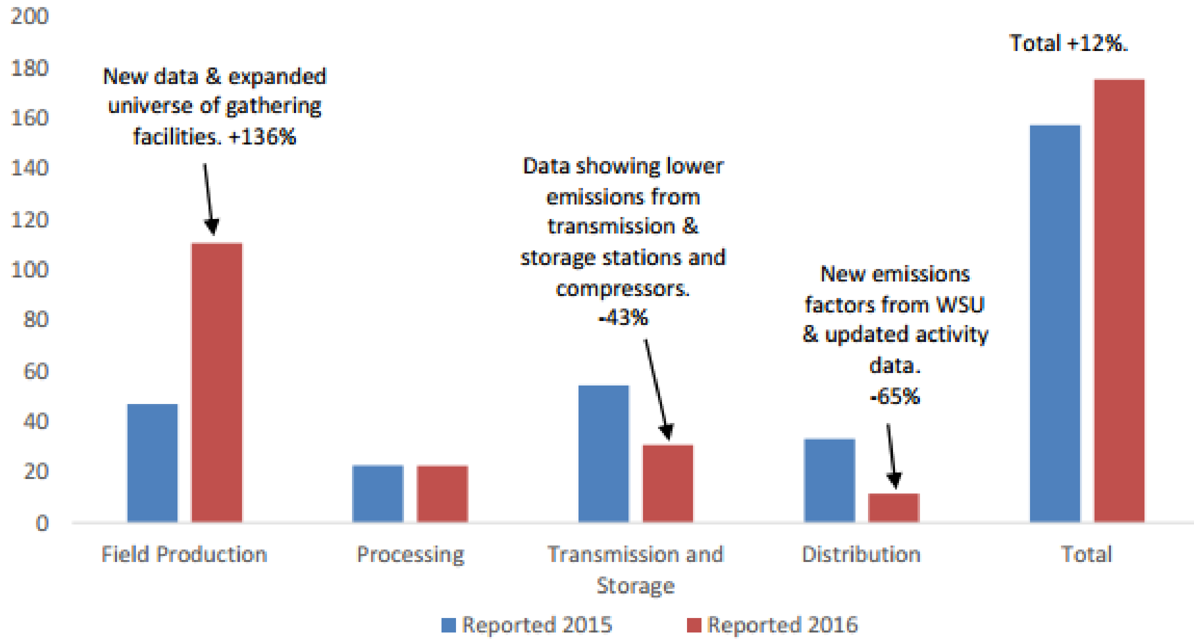
To continue to reduce methane emissions under the challenge, NW Natural will integrate emission reducing best practices associated with pipeline blowdowns. A pipeline blowdown is the evacuation of natural gas from a portion of the system as part of pipeline maintenance, repair or construction. The Company will be including three EPA-identified best practices into pipeline evacuation procedures including system pressure draw down, hot tapping and, when appropriate, the use of a portable flaring unit to combust the released natural gas. NW Natural will be implementing these best practices and reporting on their methane emission reduction outcomes to the EPA annually in conjunction with our current reporting process (under Subpart W).

4.3. Upstream Methane Reductions

As illustrated above in figure 4.3, about 80 percent of methane emissions from the natural gas sector occur upstream of distribution systems based on national figures. For NW Natural this percentage may be even greater given the work we have done and continue to do to tighten our system. For this reason the Company believes it is prudent and responsible to explore options for the Company to drive upstream emissions reductions if and where possible.

Substantial updates, released in April of 2016, to the EPA's estimates of methane emissions in the *Inventory of U.S. Greenhouse Gases and Sinks: 1990–2014*, confirm the benefit of addressing emissions upstream. The Inventory revealed that natural gas distribution systems have a small emissions footprint shaped by a declining trend. Annual emissions from these systems declined 74 percent from 1990 to 2014 even with 30 percent growth in the number of customers served. Conversely, the Natural Gas Production segment had significantly higher emissions than previously estimated. Estimates for field production increased 136 percent due to the use of newly available data. EPA expanded its universe of gathering stations, which were not included in prior inventories.

Figure 4.10: Inventory of GHG Emissions Updated Measures



Source: EPA *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2013* (April 2015) & *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2014* (April 2016) Environmental Protection Agency

Natural gas extraction practices present a range of environmental risks to air, water, land and communities. While current technologies and practices can reduce or eliminate these risks, they have not been uniformly adopted by producers or regulators. In addition, gas may be handled by multiple marketers while passing from wellhead to burner tip. As such, utilities cannot currently make substantive claims about gas origins, let alone production processes in place.

While state or federal requirements for new practices in gas production likely will reduce methane emissions over time, these are largely out of the Company's control. Regulation of existing wells is less stringent but is beginning to receiving some additional scrutiny.[16] The Company believes a practice of certifying gas based on its production practices could provide an avenue to drive best management practices more generally and quite specifically would reduce methane emissions upstream of our business.

In response, NW Natural has worked with the Natural Resources Defense Council (NRDC) to establish a Natural Gas Certification Program to explore how NW Natural as a gas buyer might influence upstream production practices. This set of achievable performance standards developed by NRDC addresses those areas of greatest concern by applying the most effective approach from existing regulations and current industry practices. Gas produced according to these criteria could potentially be certified as "responsibly

[16] U.S. EPA recently released an Information Collection Request (ICR) that will require companies to provide extensive information on existing oil and gas sources. This data gathering step may be an early step towards future regulation of some kind.

produced" by the NRDC framework. The framework would apply to Rocky Mountain producers, the vast majority of which come from Colorado, Wyoming and New Mexico. Currently these producers provide a significant portion of gas to West Coast consumers, including about one-third of NW Natural's gas supply.

Excellent work has been developed that sets out specific performance standards for certification in the areas of well construction, water testing and monitoring, wastewater management and others.[17] To date NRDC has not yet been successful in moving the idea forward with producers. It is challenging in today's low gas price environment to attract producers to a comprehensive voluntary standard that will increase production costs.

4.4. Potential Upstream Methane Reduction Pilot

The Company is exploring a possible effort to "pilot" the idea of driving reductions in methane emissions that occur upstream of Company operations. This effort would draw best management practices in the area of upstream methane reductions from NRDC's work on certification standards. While a broader set of certification standards that would address other impacts of production would be useful, the Company may more easily be able to drive methane reductions through a methane pilot because a proxy value for GHG emissions is specifically set within this IRP.

As described in the previous sections of this chapter, the Company has had an aggressive program to reduce methane emissions from our system; the best opportunities for further reductions are upstream of our business.

NRDC identified six practices that producers could readily adopt to drive down methane emissions associated with production, specifically in the Rocky Mountain region. These production practices include the following six actions:

- Pneumatic Controllers (Continuous Bleed);
- Pneumatic Controllers (Intermittent Bleed);
- Liquid Unloading
- Fugitives (Wellhead, Meters & Piping, Separators, Tanks);
- Pumps (Kimray and Pneumatic); and
- Tank Emissions.

Based on an initial analysis by ICF International, the application of these six techniques can reduce methane emissions from an uncontrolled well by an average of 78 percent. Their analysis of "higher emitting wells" shows an even greater potential reduction.[18]

This early analysis is instructive in showing there are substantial opportunities to deliver upstream reductions within the natural gas value chain. These estimates are based on reductions from an "uncontrolled well" and thus further analysis is required to understand the actual reduction potential

[17] NRDC Natural Gas Certification Program, Performance Standards Statement of Reasons, v. 1.0. Sept. 30, 2015, p. 3.

[18] ICF International Memorandum, Gas Wells Emissions in the Rocky Mountain Region, June 21, 2016.

based on the current practices at production wells. These actual methane emissions are reported to US EPA and will vary by state and by the vintage of the well.

The Company is engaged with ICF to more fully understand the current baseline for upstream emissions and the potential for reducing methane using these six promising upstream strategies identified by NRDC.

Pilot methane reductions based on IRP values

NW Natural has begun the early design of a pilot to reduce upstream methane reduction and has had early discussion with the technical advisory group regarding the pilot.[19] The Company would like the Commission to consider acknowledgement of the following action item in this IRP:

> *Investigate the viability of developing a pilot project to reduce upstream emissions of methane and, if viable, NW Natural will bring this pilot forward for Commission review and approval. The pilot design would test whether reductions can be achieved at a level consistent with the Base Case carbon values incorporated into the IRP and the range of costs for a larger scale effort. If it is determined that the cost to move the market exceeds the carbon values in the IRP, the Company may alternatively consider advancing the work as a project proposal under SB 844.*

The Company believes that if these upstream reductions can be show to be cost-effective – more specifically, that they can be implemented at our below NWN's carbon based case – that the program should appropriately be included as a pilot within the IRP. This follows closely the rationale for energy efficiency, where the Company includes all cost-effective efficiency within the IRP. On the supply side, the logic is similar that we should pursue actions that are shown to be cost-effective based on the assumptions in our IRP.

There is an excellent foundation of analysis for the development of this pilot effort both in the work NRDC has commissioned for the development of their certification standard and in the follow up work by ICF.[20] The action item, as proposed, states that the Company will further refine this work before approaching the Commission with a possible pilot proposal.

The upstream methane pilot would be designed to help answer these two fundamental questions:

1. Can we construct a methane certification program that we feel has the intended impact of reducing methane emissions?
2. How much do we need to pay per tonne of carbon dioxide equivalent (CO_2e) to obtain these emissions reductions?

The Company has not yet analyzed all the necessary data to accurately design this pilot project. To do so, the Company will need to estimate the likely methane emissions associated with current practices in

19 The concept of a pilot in this area was discussed with the Technical Advisory group at our meeting on June 22, 2016.

20 See "Developing Certification Standards for Rocky Mountain Natural Gas Producers," ICF International prepared for Natural Resources Defense Council, May 29, 2015.

the Rockies and compare these methane emissions to gas produced using the voluntary practices set out within the certification standard. Based on this methane benefit, the Company could determine the approximate benefit of purchasing a volume of gas produced using these methane specifications.

It may be possible to use the Base Case carbon pricing proposed in the IRP to allow for the purchase of gas certified to the "methane standard" at a modest premium. If we find this more straightforward "IRP approach" is not adequate to provide an incentive for gas producers, the Company may need additional flexibility, such as that afforded under SB 844, to implement this upstream methane reduction effort.

5. RENEWABLE NATURAL GAS (RNG)

As mentioned in chapter 3, Renewable Natural Gas (RNG) also referred to as biomethane, is methane (CH_4) captured from the decomposition of biomass, most often produced through anaerobic biodigestion, that has been cleaned and conditioned to pipeline quality specifications. Sources of feedstock for the production of RNG include agricultural waste, landfill, food production waste and Waste Water Treatment slurry.

These waste streams are gathered and then, through the use of anaerobic digestion facilities, methane is produced that can be used as a fuel source. In many cases the methane produced from these feed stocks would have been released into the atmosphere during natural decomposition.

RNG can be used in any application that currently uses conventional natural gas. However, due to the cost of cleaning and conditioning RNG to pipeline quality, the price per therm produced greatly exceeds that of conventional natural gas. The greatest environmental benefit from the use of RNG is achieved through the use of compressed RNG as a vehicle fuel displacing more carbon intensive fuels like diesel or gasoline. RNG is currently in high demand as an environmentally preferred fuel alternative in the California market where it is primarily being used in vehicles.[21]

The carbon benefits of using RNG and displacing diesel or gasoline are significant. While moving a heavy duty truck from diesel to Compressed Natural Gas (CNG) drops emissions by about 23 percent, moving that same truck to RNG (from a waste water treatment plant) drops emissions by roughly 92 percent. [22]

In the near term, RNG is more likely to be used in vehicles because of the policy incentives that direct it towards transportation. California's Low-Carbon Fuel Standard (LCFS), as well as the federal Renewable Fuel Standard program (through RIN credits) both provide financial incentives for the purchase of RNG for use as a transportation fuel. For refueling in Oregon, the RIN still applies and the state has a nascent Clean Fuel Standard (CFS) that is expected to mimic over time the more mature California LCFS program.

Despite these significant environmental and financial wins, the lack of a developed CNG vehicle infrastructure in Oregon and the costs to fleet operators to purchase or convert vehicles are two

[21] According to the Renewable Fuel Association, RNG makes up approximately 60 percent of all natural gas used in vehicles in California.

[22] Oregon Department of Environmental Quality fuel look up tables accessed 2016 http://www.deq.state.or.us/aq/CleanFuel/docs/PathwayCodes.pdf.

significant impediments to the development of a transportation fuel market for compressed RNG in Oregon.

Though there are a variety of waste streams that can produce RNG, it appears that waste water treatment facilities may be an ideal first source. Municipal waste water facilities have biodigestion facilities built and operating, and have sophisticated mechanical knowledge on staff. Additionally, municipal facilities have the benefit of a utility structure and higher comfort with longer payback periods associated with the capital investment in cleanup equipment.

While NW Natural does not have any RNG currently injected into our system, we have had interest over the last several years from several customers. The Company currently has an existing tariff (Schedule T – Customer-Owned Natural Gas Transportation Service) that allows the introduction of RNG onto our system for sale within the system. This tariff would need to be modified in order to accommodate RNG to pass through our system to out-of-state markets.

Chapter 5
Avoided Costs

1. OVERVIEW

Chapter 5 details the methodology used to calculate NW Natural's avoided costs and how it has evolved with a focus on better accounting for how energy savings on peak help avoid or delay investments in capacity resources. The results of the avoided costs calculations, which are a key input into the demand-side management energy savings forecast detailed in chapter 6, are also presented.
As part of the IRP process, NW Natural calculates a 20-year forecast of avoided costs. Avoided cost is an estimate of the cost to serve the next unit of demand with supply-side resources. This incremental cost to serve represents the cost that could be avoided if that unit of gas was not demanded, with the most typical reason it is not demanded is because of demand-side management (DSM) energy savings through energy efficiency (EE) or energy conservation.

Therefore, the avoided cost forecast can be used as a guideline for comparing the cost of acquiring and transporting natural gas to meet demand with other options so that the manner that is expected to be the most cost-effective to meet customer needs is implemented. Practically, the avoided cost forecast is a key component of the cost-effectiveness test that is conducted by Energy Trust of Oregon (Energy Trust) to determine the DSM savings projection detailed in chapter 6.

The methodology used by NW Natural to calculate its avoided cost forecast has seen substantial improvements since the 2014 IRP. Furthermore, NW Natural is working with Energy Trust in order to make additional improvements to the avoided cost calculation methodology implementable within the broader IRP process for the 2018 IRP.

KEY FINDINGS

Key findings in this chapter include the following:

- NW Natural has made substantial improvements to the avoided cost methodology from the 2014 IRP in a planned transition to a further refined methodology for the 2018 IRP that will evaluate demand-side and supply-side resources on equal footing in the same integrated resource choice process and make avoided costs an output of the resource planning process.
- NW Natural calculated separate avoided costs for residential space heating usage, commercial space heating usage, base load usage (primarily water heating and cooking), and interruptible usage in this IRP rather than one avoided cost figure for all end uses to better account for the difference in savings on peak which result in avoided costs varying widely by end use.
- The incremental state carbon policy adders discussed in chapter 4 and the hedge value of DSM are also incorporated in the avoided costs for the first time in this IRP, where, all else equal the Base Case state carbon adder represents a significant increase to avoided costs where the increase from the hedge value of DSM is much less significant.
- The results of the changes to the avoided cost calculation methodology If the 2014 IRP methodology were used in this IRP avoided costs would have been down 23 percent in levelized terms, but the changes relative to capacity costs, state carbon policy, and natural gas price risk reduction (hedge value) avoided costs are up 30 percent for space heating measures, down 1 percent for base load measures, and down 6 percent for interruptible measures in Oregon and up 50 percent for space heating measures, up 9 percent for base load measures, and up 2 percent for interruptible measures for Washington.
- Avoided costs scenarios corresponding with the state carbon policy adder scenarios show that avoided costs vary drastically by carbon policy adder, using Oregon residential space heat measures as an example levelized avoided costs with the Base Case carbon adder are 13-percent higher than they would be without an incremental adder and avoided costs under the most extreme carbon policy scenario adder are 62-percent higher than they are with the Base Case adder.

While the benefits of having Energy Trust administer NW Natural's DSM programs far outweigh its complications, the goal of fully integrating demand- and supply-side resource options into the resource planning process[1] is difficult for numerous reasons including:

- There are implementation difficulties with using the SENDOUT® model, which is the optimization model NW Natural and the other LDCs in the regions use for resource choice, to incorporate demand-side resources in the same process as supply-side resources;
- Energy Trust works with multiple gas LDCs that each have their own avoided costs, but runs statewide programs to provide all the customers it serves the same level of services and take advantage of economies of scale;
- The process NW Natural and Energy Trust have used to construct the DSM savings projection since Energy Trust began administering the Company's DSM programs in 2002 has been an independent process that is used as an input to supply-side resource choice through netting expected DSM savings out of the load forecast rather than a fully integrated process; and
- The improvements made by NW Natural in more accurately calculating avoided costs—particularly in regards to the capacity costs avoided with peak savings—are not fully compatible with Energy Trust's current operations of projecting and reporting DSM savings only in total annual savings or with DSM program implementation which sets total annual savings goals.

NW Natural and Energy Trust will continue to collaborate to make further improvements in this area for the next IRP and onwards.

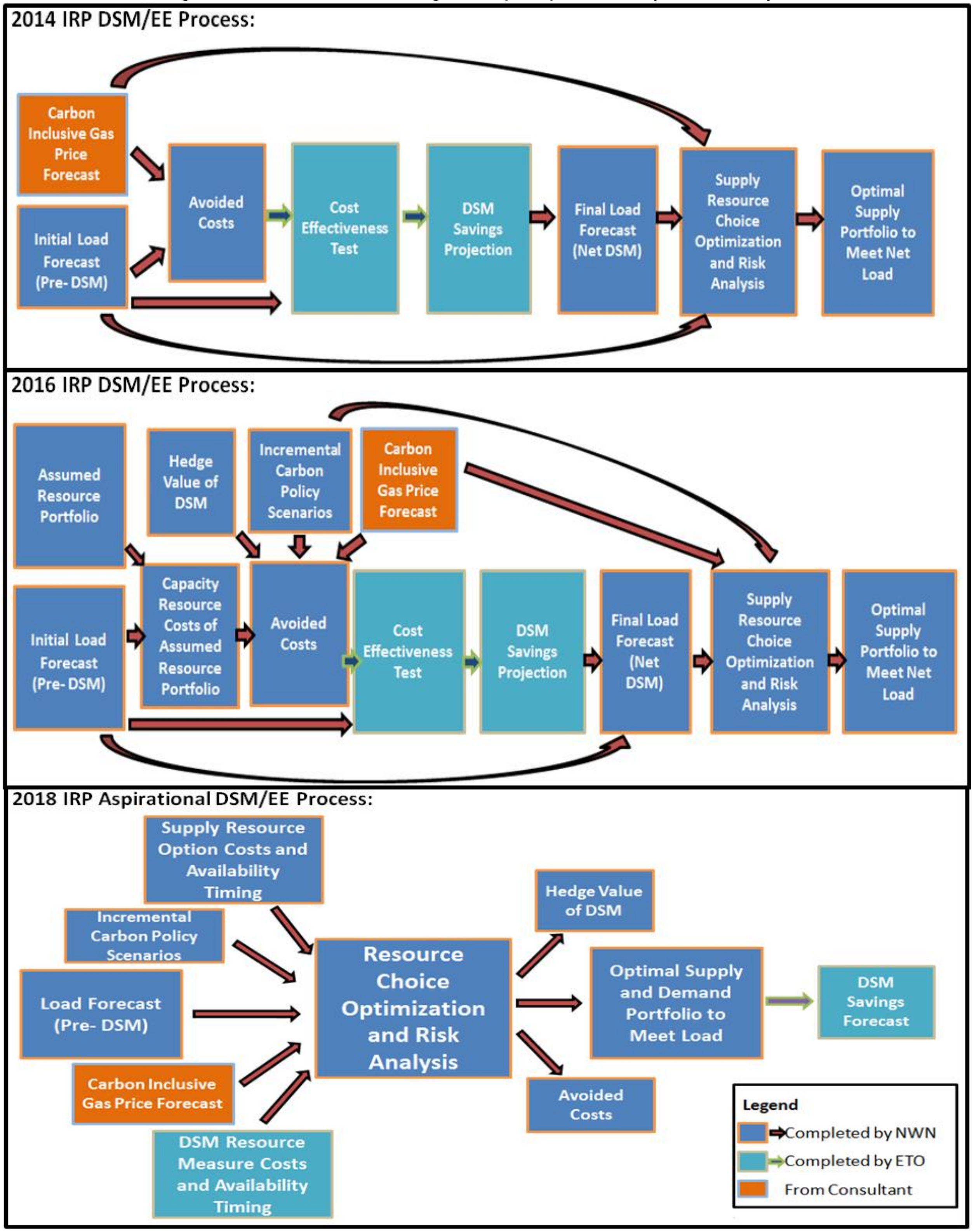
Figure 5.1 details the key changes in how avoided costs and demand-side management (DSM) energy savings were/are/will be integrated into the broader IRP process in the 2014 IRP/2016 IRP/2018 IRP. Note that the cost-effectiveness test and DSM savings projection completed by Energy Trust shown in teal in figure 5.1 are discussed in detail in chapter 6. In the 2014 IRP, the demand-side resource choice process was independent of the supply-side resource process where the DSM savings projection was completed first then netted out of the pre-DSM load forecast to determine the projected resource deficiency to be met with supply-side resources.

For the 2016 IRP, this process is still mostly intact, but capacity costs that can be avoided with energy conservation are more accurately incorporated, complicating the general process of obtaining the DSM savings projection. This complexity arises because in the current process the DSM savings projection is made before supply-side resource choice modeling so assumptions about what supply-side capacity resources will be chosen from the resource choice optimization need to be made before the process has begun in order to complete the cost-effectiveness test and complete the IRP process.

The tentative improvement planned for the 2018 IRP is to use the same resource choice process and optimization model to choose among all resource options—both demand- and supply-side—to meet load. In this case, avoided costs would become an output of an integrated resource choice optimization rather than an input into the *supply-side* resource choice optimization and the process would be "fully-integrated."

1 OPUC Order No. 94-590 states "Avoided cost calculations should be based on the marginal costs of a fully-integrated resource stack, which includes both supply- and demand-side resources."

Figure 5.1: Demand-Side Management (DSM) Process Improvement by IRP



2. AVOIDED COST METHODOLOGY

While a detailed description of each is found below, table 5.1 summarizes the components of avoided costs included in the 2016 IRP and details which components change through time, which ones vary across end uses, which ones differ between Oregon and Washington, and which ones are in energy terms ($/unit of gas) that can be applied directly vs. which ones are in capacity terms (typically expressed as $/Dth of Daily Capacity/Day) that need to be converted into the energy terms in which avoided costs are typically reported.

Table 5.1: Components of Avoided Costs for Demand-Side Management

Category	Cost to be Avoided	Units	State Specific?	Same in all Years?	Same for all end uses?	Explanation
Commodity	Gas and Transport Costs	$/Dth	No	No	Yes	Includes the forecasted price of gas inclusive of expected carbon policy expected with a fair degree of certainty (see Chapter 2 for more details), gas storage carrying costs for inventory, and upstream variable transmission costs
	Hedge Value of DSM	$/Dth	No	No	Yes	Cost of removing long-term price risk by fixing the price of gas and accounting for counterparty risk- See Appendix 8 for more detail
Carbon	Incremental Policy Adder Scenarios	$/Dth	Yes	No, except for "No Carbon" Scenario	Yes	The expected impact of recently proposed and less certain state greenhouse gas (or "carbon") policies on natural gas usage- see Chapter 4 for more details
Deliverability Capacity	Supply	$/Dth of daily withdrawal rights/Day	No	No	No	Cost of securing additional gas supply capacity resources (which are discussed in detail in Chapter 3) in order to serve peak day demand according to the expected supply resource acquisition
	Distribution	$/Dth of daily withdrawal rights/Day	Yes	No in WA, Yes in OR	No	Cost of improvements/additions to the distribution/deliverability system needed to provide gas service to customers- based on the long-run incremental cost of the distribution system in Oregon and long-term plan of distribution system improvements in Clark County for Washington
Conservation Credit	10% Adder	$/Dth	Yes, because other portions of avoided costs differ	No	No	Unquantified environmental benefits adder recommended by the Northwest Power and Conservation Council (NWPCC) applied to all but the hedge value of DSM and the Incremental Policy Adder Scenarios
Total	Summation of All Above	$/Dth	Yes	No	No	The incremental cost required to serve one more Dekatherm of gas with supply-side resources

2.1. Avoided Cost Components Remaining from the 2014 IRP:

Gas and Transport Costs: The primary component of avoided costs remains the cost of the natural gas commodity itself, which is the gas price forecast detailed in chapter 2 that includes the expected impact of federal, regional, and state greenhouse gas ("carbon") policies expected with a reasonable degree of certainty (the most prominent examples being the expected impact of the Clean Power Plan and already ratified state renewable portfolio standards (RPSs) on natural gas prices). In addition to the gas price forecast the relatively minor costs of storage inventory carrying costs and variable transmission costs (which comes from SENDOUT® modeling as in previous IRPs) are also included in the gas and transport cost portion of avoided costs.

Ten Percent Conservation Credit: This component and the gas and transport costs are the only components of the avoided costs figure that are the same as the 2014 IRP. Note, however, that the conservation credit is applied to all but the hedge value of DSM and the incremental carbon policy scenario adders so that the new components in this IRP impact how the credit is applied. Consequently, since a number of the components of avoided costs vary by state, year and end use, even though the 10 percent conservation credit is applied to consistently it results in a different number across these factors (for example 10 percent of 10 and 10 percent of 20 are not the same number even though the 10 percent share is applied to both numbers consistently).

2.2. Avoided Cost Components New to the 2016 IRP:

Hedge value of DSM: While the "cost to achieve natural gas price certainty" is a more accurate representation of this component of avoided costs, the name has been kept for convention and recognition from the Oregon PUC process that led to its inclusion.[2] Natural gas prices are volatile and uncertain, particularly when analyzing long-term price forecasts as is necessary to (1) forecast costs in IRPs and (2) evaluate the cost-effectiveness of DSM measures that tend to provide savings for multiple years and sometimes indefinitely. If price hedging is not used to remove or mitigate this price volatility and uncertainty customers are exposed to changes in the trend of prices in the long-term and price fluctuations around the long-term trend in the short term. DSM savings are a type of long-term hedge, where if the actual energy savings that are going to be acquired and the costs to obtain those savings are known with certainty, acquiring demand-side savings removes the price risk associated with unhedged supply resources that would be necessary if energy savings were not acquired.

The hedge value of DSM, which is explored in more detail in appendix 5, represents the risk premium gas purchasers need to pay (i.e., the cost to fix the price) to obtain a long-term fixed price financial hedge at the time of the IRP analysis.[3] Practically, when the hedge value of DSM is added to the gas and transport costs it represents the fixed price of gas that could be obtained through financial hedging instruments and replaces the spot price forecast as the price of gas for evaluating demand-side resources. The same hedge value is applied in both states and to all end uses, and as can be seen in the figures that follow, the hedge value of DSM is the least significant component of avoided costs.

Incremental State Carbon Policy Adder Scenarios: As is detailed more in chapter 4, incremental state carbon policy adders were deemed appropriate in this IRP due to recent momentum around state carbon policy proposals in Oregon and Washington that has prompted NW Natural to conclude that state carbon policy in some form is likely over the IRP planning horizon and therefore should be modeled explicitly and different from the carbon policy impacts assumed in the gas price forecast provided by the Company's third-party consultant. The incremental state carbon policy adder scenarios detailed in chapter 4 represent the wide range of impact these prospective greenhouse gas ("carbon") policies could have on natural gas users are included in the avoided cost figure in this IRP. Since there

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

are five incremental carbon policy scenarios, five avoided costs scenarios are provided, with the Base Case incremental state carbon policy adder included in the avoided costs that were used in the cost-effectiveness test that determined the DSM savings projection detailed in chapter 6. The Base Case carbon policy adder is a significant addition to the avoided costs figure and varies between Oregon and Washington since the proposed carbon policies are different in each state. Note that while state policy specific carbon policy adders are new to avoided costs in the 2016 IRP, the expected costs to natural gas customers of complying with carbon policy were included in avoided costs in previous IRPs and this has not changed.

Supply Capacity Costs: The most significant improvement to the avoided cost determination in this IRP relative to previous IRPs is the more accurate incorporation of capacity costs that can be avoided with energy savings during peak times. Capacity costs are broken down into two components–supply and distribution-–capacity costs. Supply resources are capacity resources the Company uses to get gas onto its system of pipelines and is primarily interstate pipeline capacity and storage resources while distribution resources are the assets, primarily smaller pipelines, on NW Natural's system that distribute the gas that arrives at NW Natural's system via its supply resources to customers as it is demanded. Note supply resources are kept on a NW Natural portfolio basis and serve both states so supply capacity costs avoided per unit of gas are the same in both states but distribution assets are separate in Oregon and Washington so distribution capacity costs avoided differ by state based upon the expected costs of the distribution system in that state. Supply capacity costs are discussed in this section while distribution capacity costs are detailed in the next section.

As is detailed in chapters 2, 3, 8, and 9, projected planning peak day loads drive supply resource acquisition. If DSM provides savings on a peak day, NW Natural needs to keep less supply resources in its portfolio to serve its customers. These supply capacity costs are, therefore, avoided with the acquisition of peak day DSM savings, regardless of the location on NW Natural's system. However, since avoided costs are given in energy ($/Dth) rather than capacity ($/Dth of daily withdrawal capacity rights) terms, these capacity costs need to be converted to energy terms to be incorporated into the cost-effectiveness test that is used to forecast the DSM savings projection detailed in chapter 6. Therefore, the share of savings from DSM expected in a normal weather year that would be expected on a planning peak day needs to be estimated.

This exercise is complicated by the fact that different DSM measures create savings from different end uses so that different measures have very different impacts relative to peak savings. For example, a significant share of the energy savings achieved through Energy Trust programs come from large industrial customers, but most of these customers are interruptible customers that would be interrupted on a peak day. Therefore, savings acquired for interruptible customers avoid virtually no supply capacity costs. Furthermore, the two end uses that represent a majority of NW Natural's load—space heating and water heating—have very different impacts on peak day load. Water heating that is not for space heating purposes can be thought of as "base load" since it is nearly constant in each day of the year. Consequently, the savings from a water heating measure on a peak day are roughly 1/365th of the expected annual savings. However, measures that reduce gas consumption from space heating have the largest relative share of savings that would be expected on a peak day by a large margin since space heating load is directly related to weather.

Figure 5.2 shows the daily use pattern of the average NW Natural residential customer as a function of temperature[4] and the relative share of planning peak day load that is space heating load and base load. In conjunction with average annual usage under normal weather this information can be used to determine the share of annual space heating load that occurs on a planning peak day and the share of annual base load that occurs on a planning peak day. Assuming that DSM measures have a proportionate impact on both base load and space heating load means one can assume how much of the expected total annual savings from DSM would be expected on a planning peak day, and therefore the level of supply capacity costs avoided per unit of savings from energy efficiency and conservation. Figure 5.3 shows the same information for the average NW Natural commercial customer.

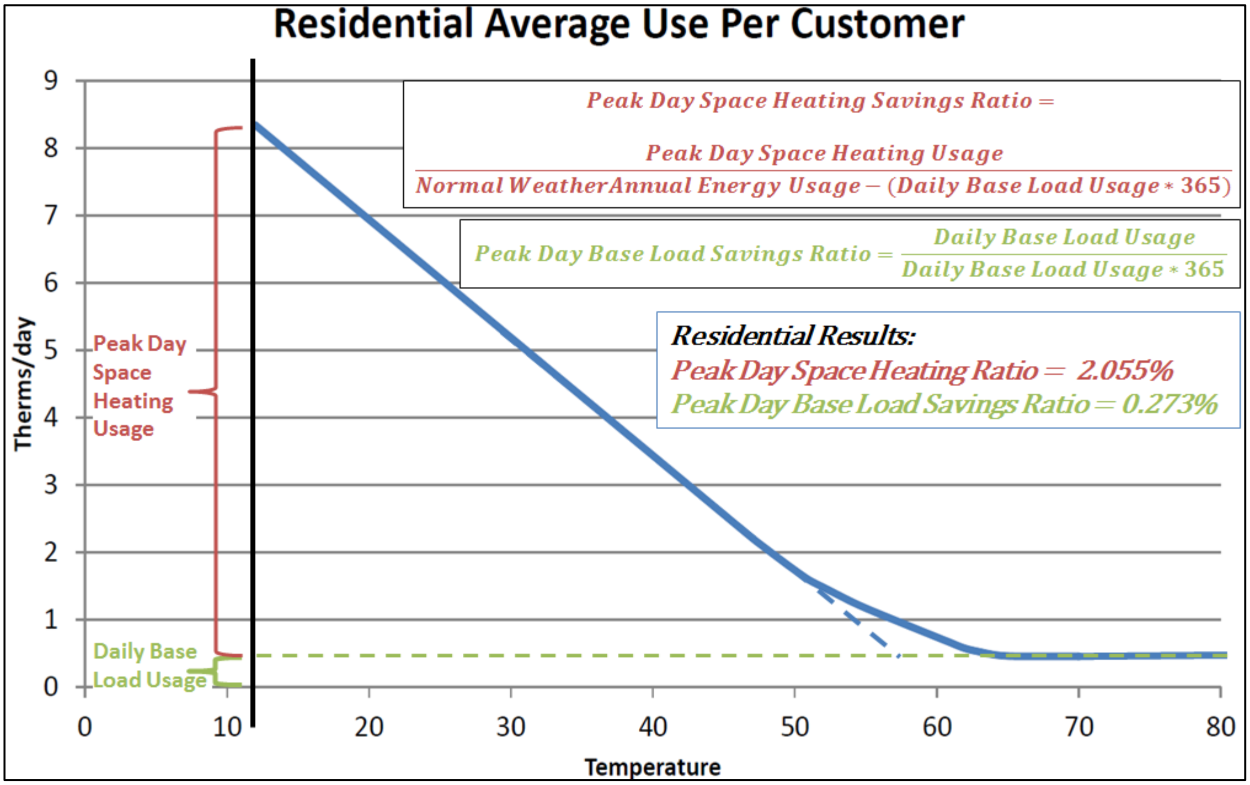
In this IRP NW Natural computed expected capacity avoided costs for four end uses: (1) residential space heating, (2) commercial space heating, (3) base load, and (4) interruptible.[5] While roughly 2 percent of the annual savings for a space heating measure during a normal weather year would be expected on a planning peak day, less than 0.3 percent of normal weather load from base load measures would be expected on a planning peak day, and zero percent savings that come from interruptible customers are expected on a planning peak day as interruptible customers are provided a discount on their rate so that they can be interrupted under extreme conditions, like those on a planning peak day.

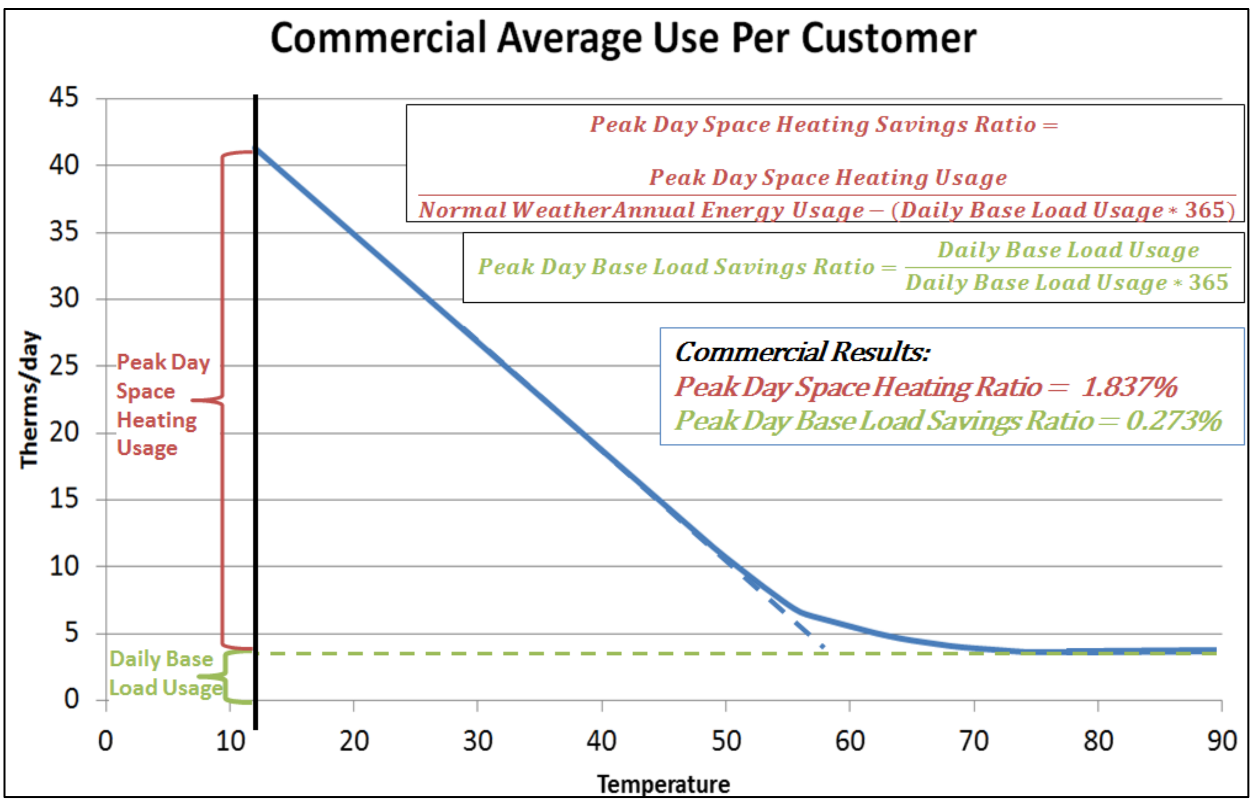
Given the longstanding process of coordination between NW Natural and Energy Trust where the DSM savings projection is completed before the supply resource optimization, the incremental supply resources that would be saved for each year in the planning horizon with DSM needed to be assumed before the supply resource optimization in order to assign a cost for the supply capacity costs being avoided. While the assumptions made about what supply resources would be acquired in each year were not significantly different from the actual supply resource choices detailed in chapter 8, the process of assuming the outcome of the IRP process at the beginning of the analysis is sub-optimal and is the primary impetus for the aspiration that both supply- and demand-side resources be chosen in the same optimization for the next IRP. This is the way that numerous utilities and regional planning organizations throughout the country (including the Northwest Power and Conservation Council) choose resources in a fully integrated process.

It is important to incorporate the capacity costs avoided with energy conservation into the DSM cost-effectiveness process as energy conservation provides real capacity cost savings, but if it is assumed that each unit of *energy* savings provides the same level of *capacity* cost savings, which is the assumption made if all DSM savings are provided the same value for capacity avoided costs, this understates the value of savings from space heating measures and overstates the value of savings from base load and interruptible measures. This would lead to both noncost-effective energy efficiency being acquired (relative to base load and interruptible measures) and cost-effective space heating energy efficiency not being acquired.

4 From a regression analysis of the daily usage of all existing NW Natural residential customers.
5 Base load includes water heating (not for space heating), cooking, and industrial/commercial processes for Firm Sales customers. A place for improvement in the next IRP is determining usage profiles for more end uses or measures.

Figures 5.2. and 5.3: Peak Day Savings from Base Load and Space Heating





Per *Demand-Side Resources and Environmental Action item 3*, NW Natural is working with Energy Trust on a system that tracks and reports not only total annual savings but peak savings so that the value DSM provides in delaying/avoiding capacity resource acquisition costs is better understood and considered in measure cost-effectiveness evaluation and program implementation. Note that the current process assumes that supply resources are incremental rather than “chunky” resources, or in other words that they can be sized and acquired at any level and the costs are the same regardless of the capacity chosen for acquisition and costs are proportional to capacity (for example, if DSM savings on peak represent 10 percent of the savings needed to avoid a project it is assumed in this IRP that 10 percent of the costs of the resource are avoided through DSM savings) even though this is not typically the case. Additionally, since NW Natural secures supply resources for its entire service territory rather than by state, supply capacity costs avoided do not vary by state.

Distribution Capacity Costs: The same process that was completed for supply resource capacity costs avoided is also completed for distribution capacity costs. However, the costs for distribution system capacity are different for Oregon and Washington since the distribution assets that serve customers are distinct for each state. Actually, as is detailed in chapter 6 in the discussion of “Targeted DSM,” NW Natural maintains numerous independent “systems-within-a-system” in its distribution system in each state. However, since rates are typically set at the statewide level with costs shared by all customers in the state, distribution capacity costs avoided with peak savings are provided by state rather than smaller locations. Per OPUC Order No. 94-590 for Oregon the long-run incremental cost of the distribution system from the Company’s last general rate case is used as the distribution capacity costs avoided. In Washington the costs are sourced from the expected costs of the planned distribution system projects in Clark County[6] and the long-run incremental cost of the distribution system from NW Natural’s last general rate case in Oregon. Note the incremental resource assumption used for supply resources applies to distribution resources as well, meaning distribution system project costs are assumed to be incremental and proportional to the capacity provided though this is not the case.

3. AVOIDED COSTS RESULTS

3.1. Summary

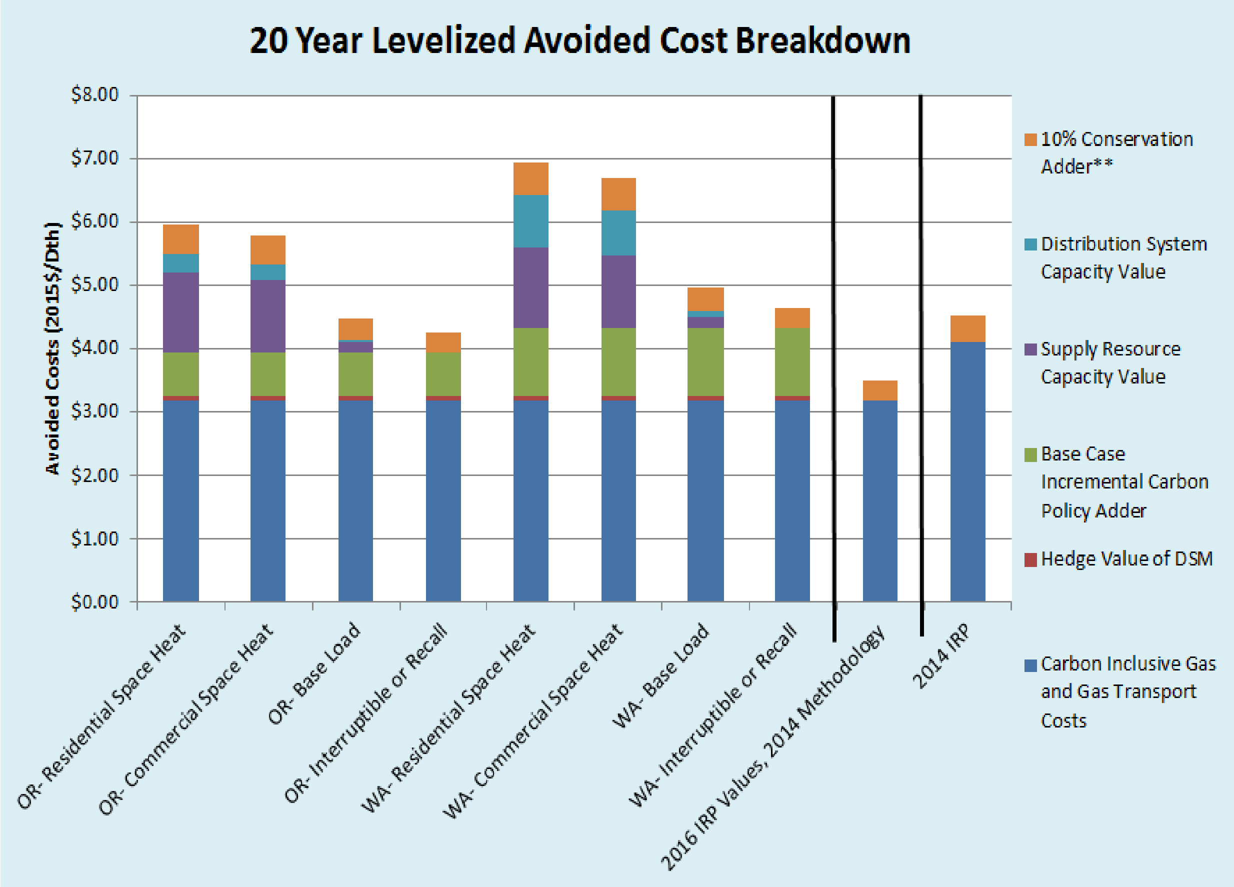
Table 5.2 and figure 5.4 summarize the breakdown of avoided costs by state and across end uses for both the 2016 IRP and the 2014 IRP as well as a comparison of what the avoided costs figure would have been in the 2016 IRP if the methodology from the 2014 IRP were used. Note that in the 2014 IRP all end uses and both states were evaluated for cost-effectiveness with one stream of avoided costs but in the 2016 IRP eight streams of avoided costs were provided by NW Natural to Energy Trust for the cost-effectiveness evaluation. The figures are presented in levelized terms to provide a more succinct summary of the results, though this disguises how the avoided cost figures change through time, which is an important consideration given different DSM measures have very different expected lives.

[6] Note that the current assumption is that the entire cost of each of these projects is avoided through DSM peak savings.

Table 5.2 and Figure 5.4: Avoided Cost Summary results

20 Year Levelized Avoided Cost Breakdown* (2015$/Dth)							
	Carbon Inclusive Gas and Gas Transport Costs	Hedge Value of DSM	Base Case Incremental Carbon Policy Adder	Supply Resource Capacity Value	Distribution System Capacity Value	10% Conservation Adder**	**Total Levelized Avoided Costs**
OR- Residential Space Heat	$3.19	$0.07	$0.67	$1.28	$0.28	$0.48	**$5.98**
OR- Commercial Space Heat	$3.19	$0.07	$0.67	$1.14	$0.25	$0.46	**$5.80**
OR- Base Load	$3.19	$0.07	$0.67	$0.17	$0.04	$0.34	**$4.49**
OR- Interruptible or Recall	$3.19	$0.07	$0.67	X	X	$0.32	**$4.26**
WA- Residential Space Heat	$3.19	$0.07	$1.07	$1.28	$0.81	$0.53	**$6.95**
WA- Commercial Space Heat	$3.19	$0.07	$1.07	$1.14	$0.72	$0.51	**$6.71**
WA- Base Load	$3.19	$0.07	$1.07	$0.17	$0.11	$0.35	**$4.96**
WA- Interruptible or Recall	$3.19	$0.07	$1.07	X	X	$0.32	**$4.66**
2016 IRP Values, 2014	$3.19	X	X	X	X	$0.32	**$3.51**
2014 IRP	$4.13	X	X	X	X	$0.41	**$4.54**

*Values do not incoporate measure lives; ** 10% Conservation adder not applied to hedge value or Carbon Policy Adder



The summary results in table 5.2 and figure 5.4 provide the following key takeaways:

1. Given the decline in expected natural gas prices from the 2014 IRP expected gas and transport costs avoided are down roughly $1/Dth in this IRP relative to the last IRP so that if the same methodology from the 2014 IRP were used in the 2016 IRP avoided costs would have been down 23 percent.
2. The avoided cost components new to this IRP raise the total avoided cost figures substantially, such that the decline in expected gas prices is outweighed by the inclusion of the new components of avoided costs for all DSM savings but those that are obtained from Oregon base load and interruptible uses. Oregon space heating avoided costs are up roughly 30 percent, base load avoided costs are down 1 percent and interruptible avoided costs down 6 percent from the 2014 IRP. Washington space heating avoided costs are up roughly 50 percent, base load avoided costs up 9 percent, and interruptible avoided costs up 2 percent from the 2014 IRP.
3. Avoided costs vary widely by end use, driven by the difference in capacity costs (both supply and distribution) avoided. In Oregon avoided costs for space heating are roughly 30 percent higher than base load avoided costs and 40 percent higher than interruptible avoided costs. In Washington space heating avoided costs are roughly 40 percent higher than base load avoided costs and roughly 45 percent higher than interruptible avoided costs.
4. Washington avoided costs are higher than Oregon avoided costs due the differences in the reference case incremental state carbon policy adder and distribution capacity costs across the states. Relative to Oregon, Washington avoided costs are more than 15 percent higher for space heating, 10 percent higher for base load, and 9 percent higher for interruptible.
5. Including capacity costs and the new expectations about state carbon policy dramatically raise avoided costs relative to what avoided costs would have been in this IRP if the methodological changes were not made, while the inclusion of the hedge value of DSM is much less significant.

3.2. Total Avoided Costs Through Time

While total avoided costs are largely up–and are up substantially for space heating–from the 2014 IRP in levelized terms, how avoided costs vary throughout the planning horizon has important implications for the cost-effectiveness test and the DSM savings projection presented in chapter 6. In the first years of the planning horizon, avoided costs for all end uses are down relative to the 2014 IRP, though avoided costs increase drastically through time in this IRP such that they are substantially higher than the 2014 IRP in the later years of the planning horizon, particularly for space heating measures.

Figure 5.5 shows avoided costs for Oregon for the different end uses evaluated in the 2016 IRP, the avoided costs from the 2014 IRP that applied to all end uses and what avoided costs would have been in this IRP if the same methodology from the 2014 IRP were applied in this IRP. Note that the space heating avoided costs in the 2016 IRP are roughly double those in the 2014 IRP in the last years of the IRP planning horizon.

Figure 5.5: Avoided Costs Through Time: 2016 IRP vs 2014 IRP- Oregon Example

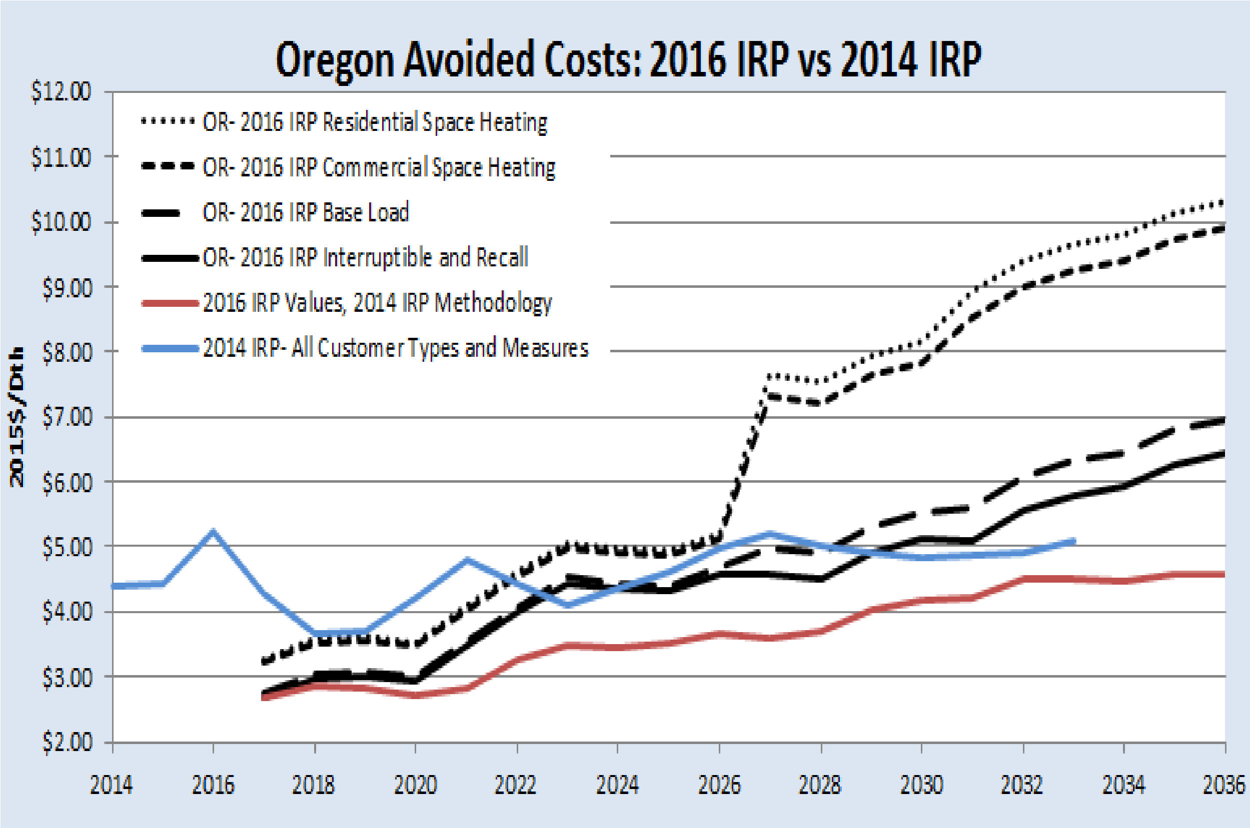
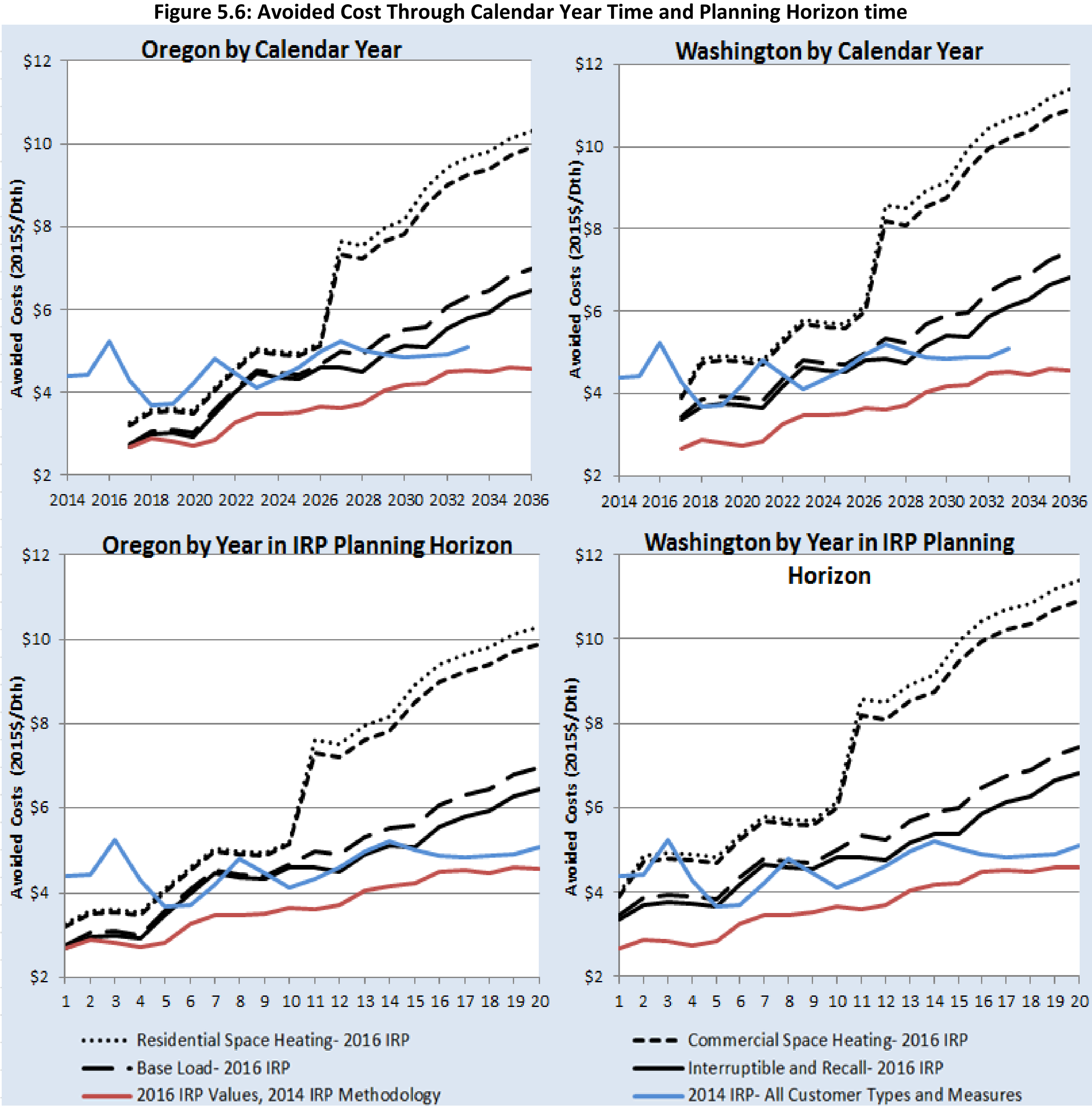


Figure 5.6 includes figure 5.5 (it is the top left graph in figure 5.6) and compares shows the results for both Oregon and Washington. The top two graphs in figure 5.6 use calendar years as the horizontal axis, while the bottom two graphs show the same information but use years in the 20-year IRP planning horizon as the horizontal axis where year 1 in the 2014 IRP was 2013-14 and year 1 in the 2016 IRP is 2016-17.

Figure 5.6: Avoided Cost Through Calendar Year Time and Planning Horizon time



3.3. Avoided Cost Component Breakdown Through Time

In addition to the total avoided costs per end use (by state) through time and the component breakdown in levelized terms, how the different components vary through time is also important. Figure 5.7 uses Oregon residential space heat as an example to show this variation. Much of the incline in the later years of the planning horizon is due to supply capacity costs increasing sharply. This is due to the assumption made about when Mist Recall would be exhausted and North Mist II would be needed to meet peak load.[7] Note that Mist Recall is much cheaper than the other supply capacity options available (see chapter 3, 8, and 9 for more detail).

Figure 5.7: Avoided Cost Component Breakdown through Time- Oregon Res Space Heat Example

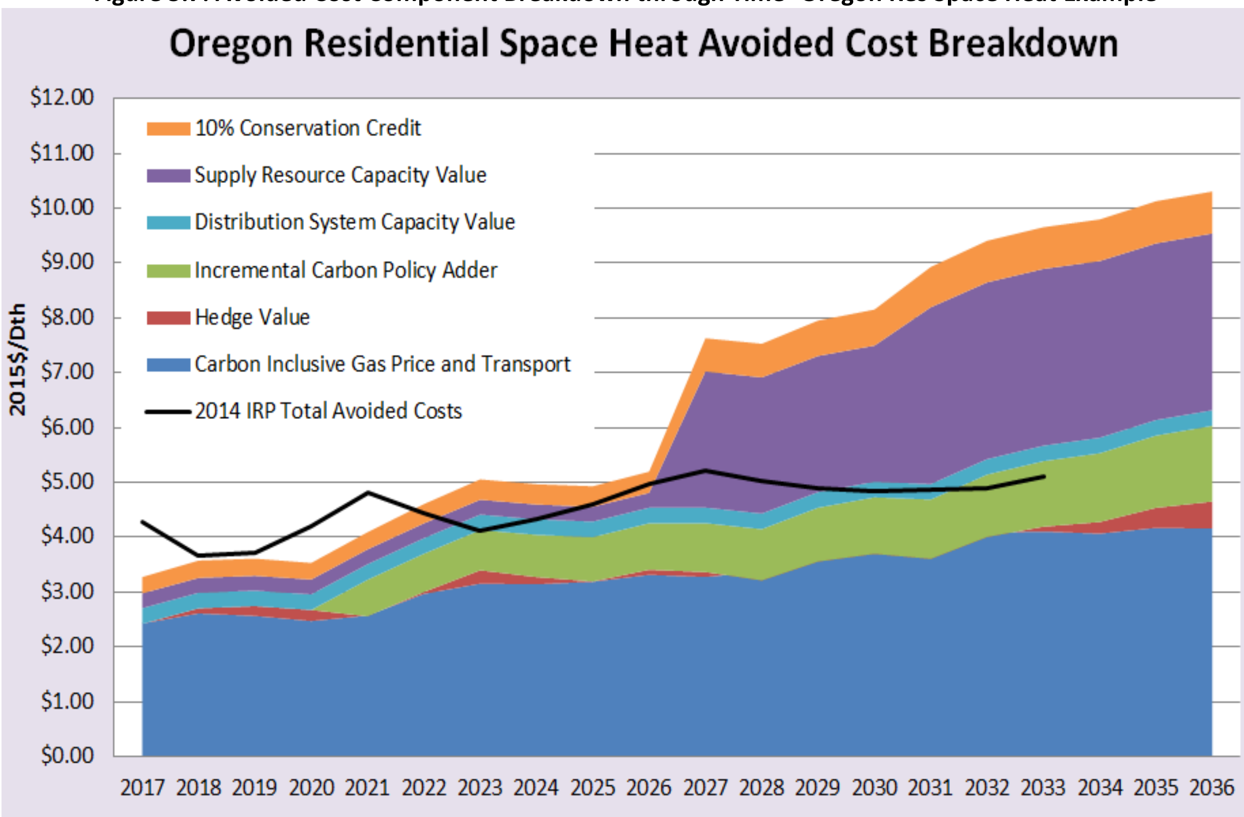
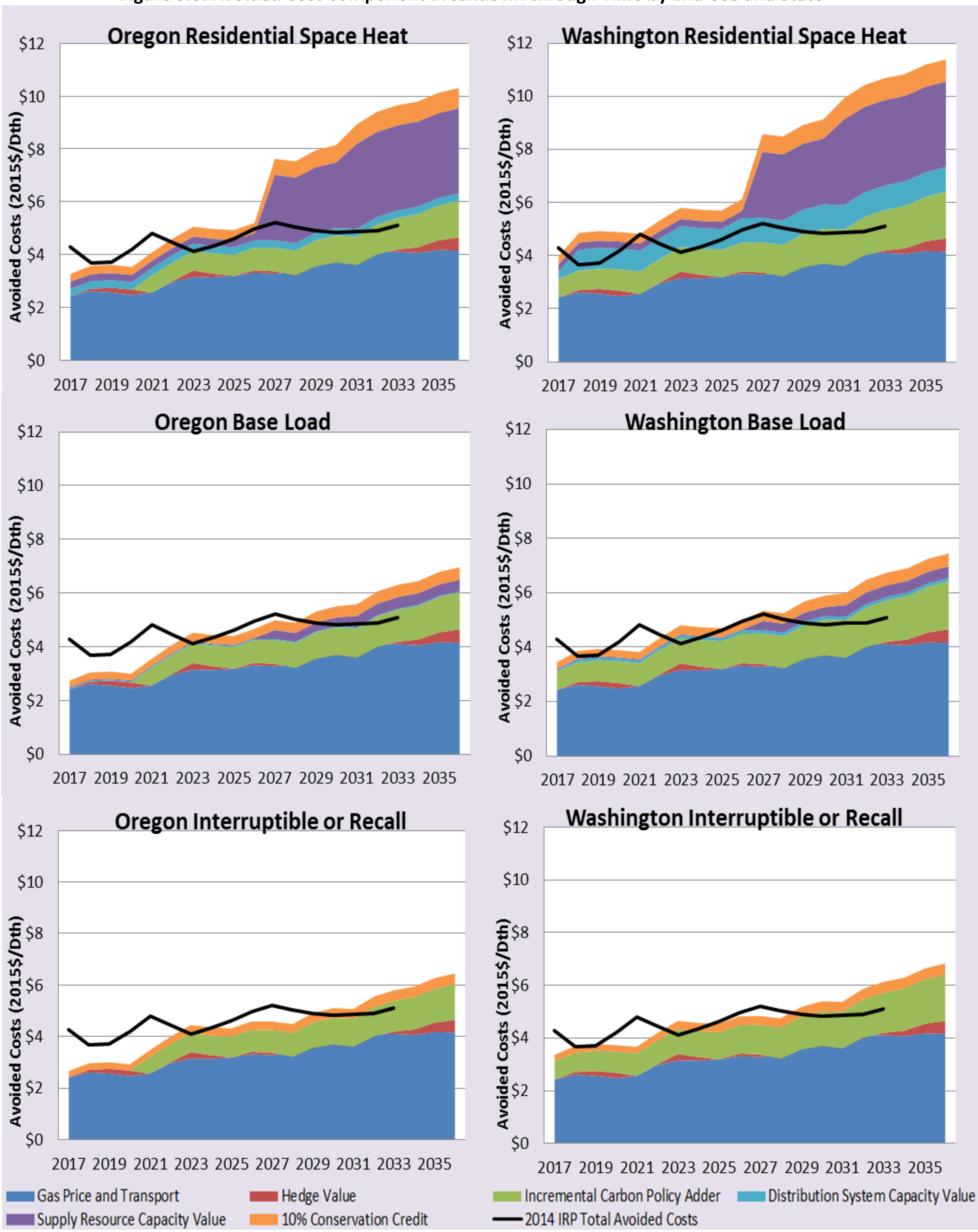


Figure 5.8 details the component breakdown through time for the end uses evaluated in this IRP[8] in comparison to each other and the 2014 IRP. Again note in the 2014 IRP all end uses were assumed to have the same avoided costs. The key driver in the difference in avoided costs across end uses is the difference in savings on peak per unit of overall savings, where space heating measures that provide a much higher share of their total annual savings during peak times provide much more value in terms of avoiding/delaying the acquisition of capacity resources.

[7] Note that this timing does not align perfectly with the timing shown in the portfolios in chapter 8. This discrepancy is explained by the fact that the incremental supply capacity resource and its cost by year needed to be assumed before the supply resource optimization described in chapter 8 in order to obtain the DSM savings projection detailed in chapter 6, as described earlier in this chapter.

[8] With the exception of commercial space heating, which has a very similar profile to residential space heating.

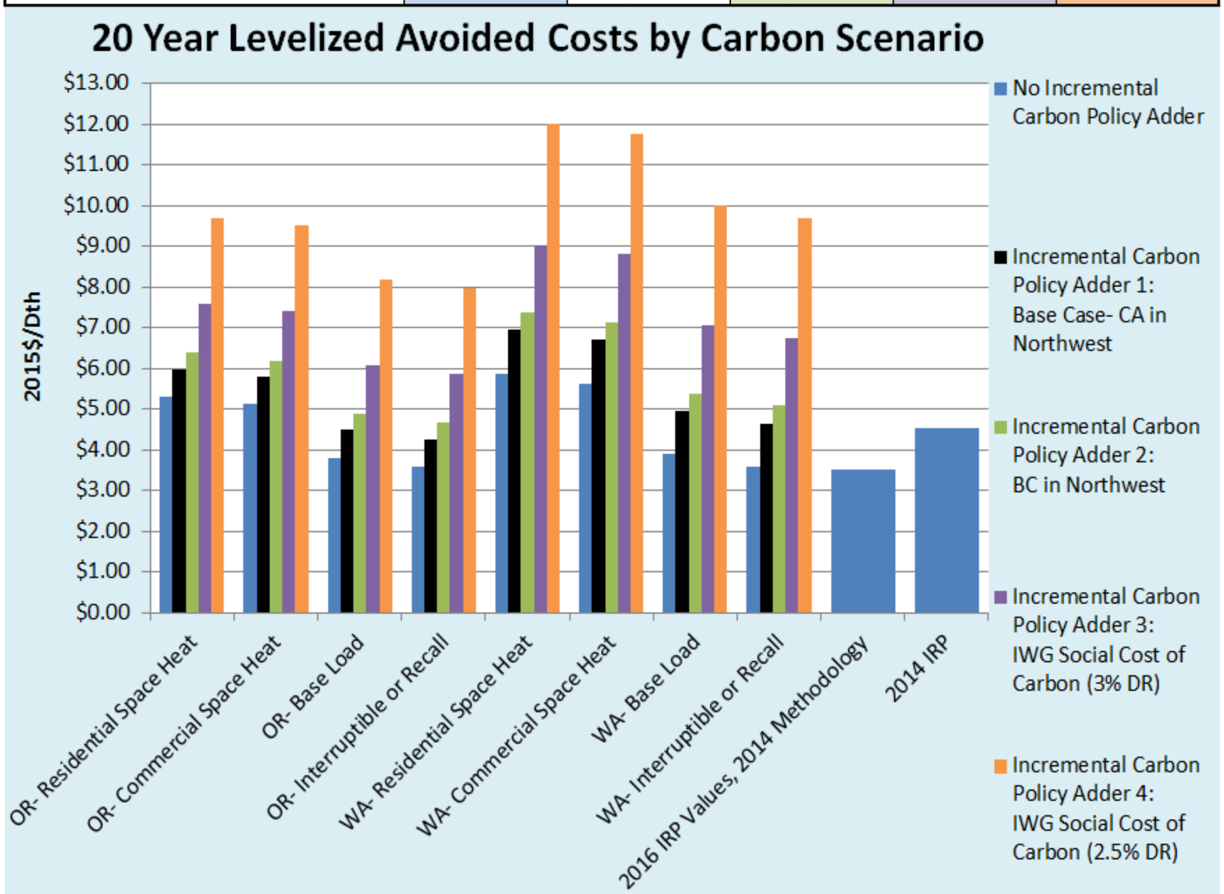
Figure 5.8: Avoided Cost Component Breakdown through Time by End Use and State



3.4. Avoided Cost by Incremental State Carbon Policy Scenario

Table 5.3 and Figure 5.9: Avoided Costs by Incremental State Carbon Policy Scenario

20 Year Levelized Total Avoided Costs By Carbon Scenario (2015$/Dth)					
	No Incremental Carbon Policy Adder	Incremental Carbon Policy Adder 1: **Base Case-** CA in Northwest	Incremental Carbon Policy Adder 2: BC in Northwest	Incremental Carbon Policy Adder 3: IWG Social Cost of Carbon (3% DR)	Incremental Carbon Policy Adder 4: IWG Social Cost of Carbon (2.5% DR)
OR- Residential Space Heat	$5.31	**$5.98**	$6.39	$7.58	$9.69
OR- Commercial Space Heat	$5.12	**$5.80**	$6.20	$7.40	$9.51
OR- Base Load	$3.82	**$4.49**	$4.90	$6.09	$8.20
OR- Interruptible or Recall	$3.59	**$4.26**	$4.67	$5.86	$7.97
WA- Residential Space Heat	$5.88	**$6.95**	$7.38	$9.05	$12.00
WA- Commercial Space Heat	$5.64	**$6.71**	$7.14	$8.80	$11.75
WA- Base Load	$3.89	**$4.96**	$5.39	$7.06	$10.01
WA- Interruptible or Recall	$3.59	**$4.66**	$5.09	$6.75	$9.70
2016 IRP Values, 2014 Methodology	$3.51	**$3.51**	$3.51	$3.51	$3.51
2014 IRP	$4.54	**$4.54**	$4.54	$4.54	$4.54



Greenhouse gas costs are an important component of avoided costs, and therefore the impact of what the current uncertainty around state carbon legislation may mean for DSM is an important consideration. As such, the five incremental carbon policy adder scenarios detailed in chapter 4 are evaluated as avoided cost scenarios. The results of this analysis are presented in table 5.3 and Figure 5.9 on the previous page. Note that there is a substantial increase between no incremental state carbon policy and the Base Case (between 11 and 23 percent depending on the end use and state), and an even larger difference between the Base Case and the most extreme case (Adder 4) evaluated in this IRP.

4. KEY FINDINGS AND ACTION ITEMS

- NW Natural has made substantial improvements to the avoided cost methodology from the 2014 IRP in a planned transition to a further refined methodology for the 2018 IRP that will evaluate demand-side and supply-side resources on equal footing in the same integrated resource choice process and make avoided costs an output of the resource planning process.
- NW Natural calculated separate avoided costs for residential space heating usage, commercial space heating usage, base load usage (primarily water heating and cooking), and interruptible usage in this IRP rather than one avoided cost figure for all end uses to better account for the difference in savings on peak which result in avoided costs varying widely by end use.
- The incremental state carbon policy adders discussed in chapter 4 and the hedge value of DSM are also incorporated in the avoided costs for the first time in this IRP, where, all else equal the Base Case state carbon adder represents a significant increase to avoided costs where the increase from the hedge value of DSM is much less significant.
- The results of the changes to the avoided cost calculation methodology If the 2014 IRP methodology were used in this IRP avoided costs would have been down 23 percent in levelized terms, but the changes relative to capacity costs, state carbon policy, and natural gas price risk reduction (hedge value) avoided costs are up 30 percent for space heating measures, down 1 percent for base load measures, and down 6 percent for interruptible measures in Oregon and up 50 percent for space heating measures, up 9 percent for base load measures, and up 2 percent for interruptible measures for Washington.
- Avoided costs scenarios corresponding with the state carbon policy adder scenarios show that avoided costs vary drastically by carbon policy adder, using Oregon residential space heat measures as an example levelized avoided costs with the Base Case carbon adder are 13 percent higher than they would be without an incremental adder and avoided costs under the most extreme carbon policy scenario adder are 62 percent higher than they are with the Base Case adder.

Demand-Side Resource and Environmental Action 3:

Work with Energy Trust of Oregon to track peak day savings from DSM programs in addition to the typical Energy Trust metric of total annual savings to better understand if the capacity costs projected to be avoided with peak day savings in the DSM savings projection are being saved.

Chapter 6
Demand-Side Management

1. 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 nonprofit organization that was initially established to provide energy-efficiency services and renewable energy programs to customers of Oregon's investor-owned electric utilities. Subsequently, Energy Trust has grown to serve most of Oregon's natural gas customers. As of Oct. 1, 2009, Energy Trust also serves NW Natural's Washington customers.

Energy Trust developed a 20-year DSM forecast for the Company. The forecast of cost-effective therm savings was generated for the Company's service territory using Energy Trust's DSM resource assessment tool and was then included in SENDOUT® as a reduction to demand. The results show that the Company can save 24.3 million therms in the next five years from 2017 to 2021 and over 87.2 million therms by 2036 in its Oregon service territory[1] and 1.4 million therms by 2021 and 6.4 million therms by 2036 in Washington. These results represent a significant increase in cost-effective DSM potential over the prior IRP in 2014. The two most significant factors that led to this increase in potential are the use of a new resource assessment model by Energy Trust, and new, much more valuable avoided costs developed by NW Natural.

KEY FINDINGS

Key findings in this chapter include the following:

- Energy Trust of Oregon used a new resource assessment tool for this DSM forecast to estimate the technical, achievable and cost-effective achievable potential for demand-side resources. The new model shows a bigger potential for DSM in this IRP than the prior IRP, which is largely due to an increase in avoided costs leading to new measures and the addition of emerging technology.
- NW Natural includes the following action items associated with the identified therm savings targets in its action plan:
  - Consistent with the methodology in this chapter, NW Natural will ensure Energy Trust has sufficient funding to acquire therm savings of 5.1 million therms in 2017 and 5 million therms in 2018 or the amount identified and approved by the Energy Trust board.
  - Consistent with the methodology in this chapter, NW Natural will ensure Energy Trust has sufficient funding to acquire therm savings of 262,000 therms in 2017 and 270,000 therms in 2018 or the amount agreed to by the EEAG and approved by the WUTC.
- Contingent on Commission acknowledgment of the idea of a geographically targeted DSM pilot via accelerated or enhanced offerings ("Targeted DSM") to measure and quantify the potential of demand-side resources as a capacity resource to address weaknesses in NW Natural's distribution system, NW Natural and Energy Trust of Oregon will file a detailed pilot project for review.

2. ENERGY TRUST RESOURCE ASSESSMENT ECONOMIC MODELING TOOL

A significant amount of the calculations involved in performing the DSM forecast are completed within Energy Trust's resource assessment tool, an economic modeling software. This tool is used to estimate the technical, achievable and cost-effective achievable potential for demand-side resources in NW Natural's service territory across the residential, commercial, and industrial sectors. The model takes a bottom-up approach and is built up

[1] Includes over 1 million therms of market transformation savings resulting from code changes driven by Energy Trust's New Buildings and New Homes Programs.

from all the measures available across each sector and installed or delivered in homes and businesses. All of these measures have gas savings and costs associated with them, and incorporate NW Natural's customer and load data, as well as many other inputs to determine how many of what measure could potentially be installed into a given building through time. The product of all these factors results in the total 20-year DSM potential available for acquisition to serve NW Natural's customers and associated demand.

After completing the DSM forecast for NW Natural's 2014 IRP, Energy Trust issued an RFP and subsequently hired Navigant Consulting, Inc. to develop a new resource assessment model, which was used for this DSM forecast. The model that resulted from this work is different from the previous model in many significant ways, including the following improvements, which were some of the most significant made in this new model, and contributed to the changes in energy-efficiency potential identified during this DSM forecast:

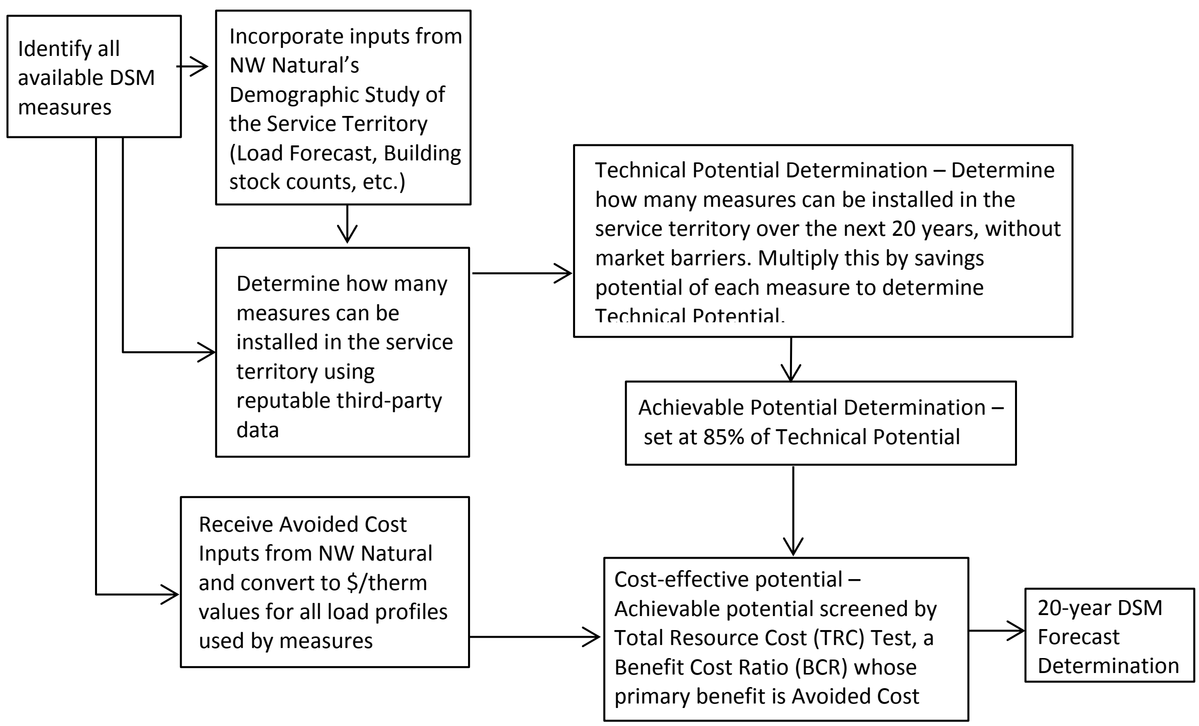
- Refreshed measure assumptions – Navigant reviewed over 530 gas and electric measures across the residential, commercial and industrial sectors. Of these, 135 (82 residential, 37 commercial, and 16 industrial) commercially available gas measures were deemed suitable for Energy Trust's service territory and characterized for use in the model. For all measures characterized, 33 measure inputs across all three customer segments were estimated using a combination of Energy Trust primary data review and analysis, regional secondary sources, and engineering analysis. The bottom-up approach estimates the unit energy savings and costs of each measure and scales the savings potential using measure densities. Navigant also adjusted cost and savings profiles for several measures that are subject to codes and standards.
- Added new measures, including a commercial behavioral measure known as Strategic Energy Management (SEM). SEM contributed a significant amount of potential in this DSM forecast, including approximately 250,000 therms in 2017. Two other new initiatives in the same pool of savings potential include retro commissioning and pay for performance.
- Added a new approach to quantifying future savings from emerging technologies: Emerging Technology is defined as technology that is not commercially available, but in some stage of development with a reasonable chance of becoming commercially available within a 20-year timeframe. The new model is capable of quantifying costs, potential, and risks associated with uncertain, but high-saving emerging technology measures.
- Updated measure saturation rates from third-party research and survey work: The RBSA and CBSA served as the primary resource for developing residential and commercial measure densities and saturation factors, which characterize the existing building stock and identify the number of possible locations for DSM measures to be installed. For instances where data was not available, Navigant reviewed the existing model and conducted secondary research to estimate the density and initial saturation. Energy Trust specific data had the highest priority followed by Oregon and region specific data. Navigant analyzed the industrial measures with a top-down approach. Savings were represented by a percentage reduction of the total customer segment consumption based on data obtained through the Industrial Assessment Center database.
- New method of quantifying incremental savings in end uses with multiple measures of differing efficiency levels: To account for measures with multiple tiers of efficiency that could compete for the same installation, Navigant employed a tiered "incremental" approach where savings and incremental costs of a competing measure were compared with the measure just below it in ranking, from a total resource cost perspective.

Figure 6.1 details the methodology Energy Trust employs to build up, update and run the model, and shape the savings projection, which determines the amount of cost-effective DSM potential that Energy Trust can deliver to NW Natural over the 20-year IRP period.

3. METHODOLOGY FOR DETERMINING THE COST-EFFECTIVE DSM POTENTIAL

The DSM assessment begins by determining the technical resource potential, which in this context refers to the complete penetration of all technically feasible cost-effective DSM measures within NW Natural's service territory. Figure 6.1 below provides an overview of this initial process followed by a more in-depth discussion of each step.

Figure 6.1: Energy Trust's 20-Year DSM Forecast Determination Methodology



3.1. Twenty-Year DSM Forecast

1. *Identify all available DSM measures:* Energy Trust compiles and loads a list of all commercially available and emerging technology measures for residential, commercial, industrial and agricultural applications installed in new or existing structures. Appendix 6 contains tables of the measures studied for each customer class and a summary of the economic assessment for each.
2. *Demographic study:* At the same time step 1 above is being completed, Energy Trust is incorporating data from NW Natural's demographic study to characterize the existing and forecasted building stock in NW Natural's service territory. Using NW Natural's customer load forecasts and counts of building stock and customers, Energy Trust applies its knowledge of existing stock conditions and building codes, compiled from reputable third-party researchers

and Energy Trust's internal data, to the Company's customer forecast. Combining this knowledge allows Energy Trust to develop an estimate of the number of measures that could be deployed in the service territory through the 20-year time horizon. The primary sources used to develop these assumptions include:

   a. NEEA's Residential Building Stock Assessment (RBSA)
   b. NEEA's Commercial Building Stock Assessment (CBSA)
   c. Energy Trust Program Data
   d. Industrial Assessment Centers Database
   e. Assumptions derived from NW Natural customer and load data

3. *Technical Potential Determination:* The technical potential represents the total number of therms that could be saved in NW Natural's service territory when assuming adoption and installation of all technically feasible measures with energy-efficiency potential. All measures are assigned a technical suitability factor to account for physical limitations that exist, which prevent installation. This savings potential does not take into account the various market barriers to a 100 percent adoption rate. These are discussed in the next steps.
4. *Achievable Potential Determination:* Achievable potential is simply a reduction to the technical potential by 15 percent, to account for market barriers that prevent total adoption of all cost-effective measures. Defining the achievable potential as 85 percent of the technical potential is the generally accepted method employed by many industry experts, including the Northwest Power and Conservation Council (NWPCC) and National Renewable Energy Lab (NREL).
5. *Cost-Effective Potential Determination:* Cost-effective potential is determined when Energy Trust screens all DSM measures using the Total Resource Cost (TRC) test, a benefit-cost ratio (BCR) that measures the cost-effectiveness of the investment being made in an efficiency measure. This test evaluates the total present value of benefits attributable to the measure divided by the total present value of all costs. A TRC test value equal to or greater than one means the value of benefits is equal to or exceeds the costs of the measure, and is therefore cost-effective and contributes to the total amount of cost-effective potential. The TRC is expressed formulaically[2] as follows:

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

   a. Avoided Costs: The value of gas energy saved over the life of the measure, as determined by the total therms saved multiplied by the Company's avoided cost. The avoided costs include commodity and transport costs, supply and distribution capacity costs (calculated using an estimate of peak-day savings) plus the 10 percent Regional Conservation Act Credit, which is meant to provide an economic advantage to energy-efficiency. In addition to this value, a hedge value of DSM adder and carbon policy adder are included as well[3].

      The total avoided cost for a given measure also depends upon that measure's expected lifespan (measure life), end use and seasonality of 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. Additionally, measures with end uses that have more peak day savings have a higher capacity cost

[2] TRC = Present Value of Benefits / Present Value of Costs.
[3] See chapter 5 for a discussion of NW Natural's avoided cost.

value. The net present-value of these benefits is calculated based on the measure's expected lifespan using the company's discount rate.

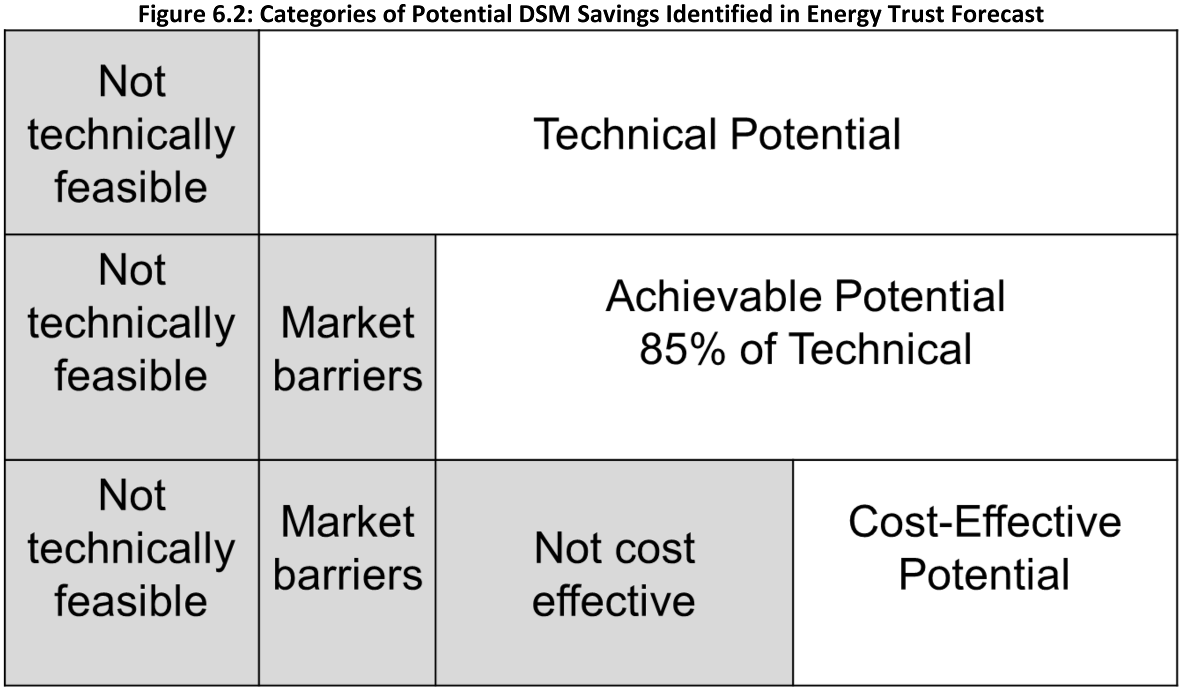
b. Nonenergy benefits are also included when present and quantifiable by a reasonable and practical method (e.g., water savings from low-flow showerheads).

Where the *Present Value of Costs* includes incentives paid to the participant; and

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

Figure 6.2 shows a graphical representation of the three categories of savings potential Energy Trust identifies in its DSM potential forecast.

Figure 6.2: Categories of Potential DSM Savings Identified in Energy Trust Forecast



Tables 6.1 and 6.2 summarize the technical, achievable, and cost-effective potential for each customer class in Oregon and Washington, respectively.

A note on savings: The savings discussed in this chapter, and depicted in all tables and the following figures showing the 20-year savings projections for both states are shown in 'gross' savings. Energy Trust publicly reports its Oregon savings and goals in 'net' savings, which are adjusted for spillover and free rider effects. 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. Free ridership refers to a customer's participating in the program when the program information or incentive did not influence the customer's efficiency decision. In Washington, these adjustments are not made when publically reporting savings, as Washington goals, by Washington Utilities and Transportation Commission (WUTC) direction, are established in units of "gross" savings, not adjusted for free riders.

Table 6.1: Summary of Resource Potential - NW Natural's OR Service Territory 2017–2036

Oregon	Technical Potential (Therms)	Achievable Potential (Therms)	Cost-Effective Achievable Potential (Therms)
Residential	67,486,647	57,363,650	33,533,453
Commercial	93,094,897	79,130,662	51,225,062
Industrial	20,435,004	17,369,754	17,143,392
Efficiency Total	181,016,548	153,864,066	101,901,907

Table 6.2: Summary of Resource Potential—NW Natural's Washington Service Territory 2017–2036

Washington	Technical Potential (Therms)	Achievable Potential (Therms)	Cost-Effective Achievable Potential (Therms)
Residential	11,156,110	9,482,693	5,673,378
Commercial	8,485,655	7,212,807	4,872,871
Industrial	628,461	534,192	524,783
Efficiency Total	20,270,227	17,229,693	11,071,032

The final savings projection of 87.2 million therms by 2036 in the Oregon service territory and 6.4 million therms by 2036 in Washington, which is decremented from NW Natural's load forecast, contains an additional reduction to the full cost-effective potential shown in tables 6.1 and 6.2. This is due to additional market-related constraints on the ability to capture all market activity in a given year for measures meant to replace equipment that fails and measures associated with the construction of new homes and buildings, otherwise known as 'lost opportunity' measures, those which appear in a given year, but if lost, do not reappear again as potential until their useful life has passed. These savings are depicted in the savings potential deployment scenarios.

6. *Determine the levelized cost for each measure*
   Once the list of measures was compiled, Energy Trust determined a levelized cost per therm 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, per therm of energy savings. 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 for the jurisdictional state.[4] The annual measure cost is then divided by the annual energy savings, in therms. This formula produces the levelized cost estimate in dollars per therm saved, as illustrated in the following formula:

$$\textit{Levelized Cost} = \frac{\textit{Annual Cost (\$)}}{\textit{Annual Savings (therms)}}$$

[4] The discount rate used for each state is the real after-tax weighted average cost of capital and reflects the 2016 IRP assumption of an average annual rate of inflation over the planning horizon of approximately 1.6 percent.

Levelized costs can be graphically depicted to demonstrate the total potential therms that could be saved at various costs for all conservation measures. Figures 6.3 and 6.4 show a resource supply curve that can be used for comparing demand-side and supply-side resources. The two cost thresholds shown as vertical dotted lines represent the approximate levelized cost cutoff that corresponds with the amount of cost-effective DSM potential, as determined by the TRC, when ordering all measures based on their levelized cost.

Figure 6.3: NW Natural's Oregon Service Territory 20-Year Gas Supply Curve

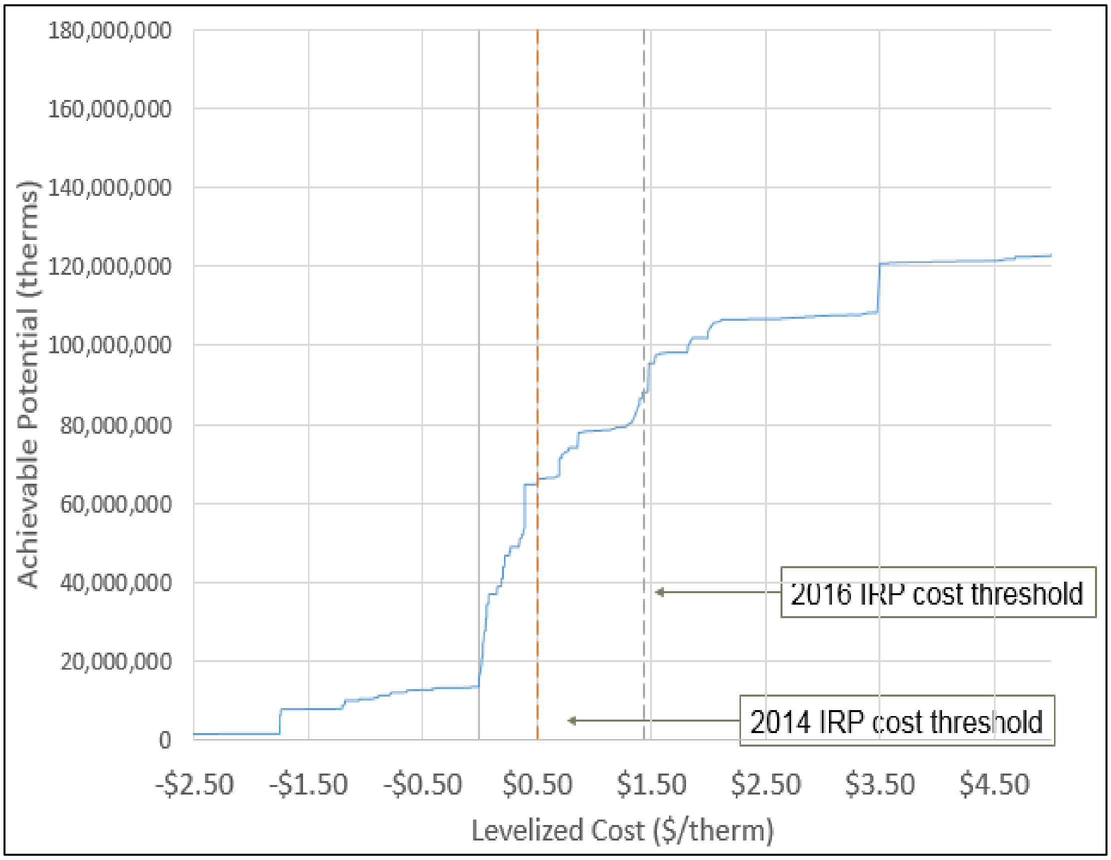
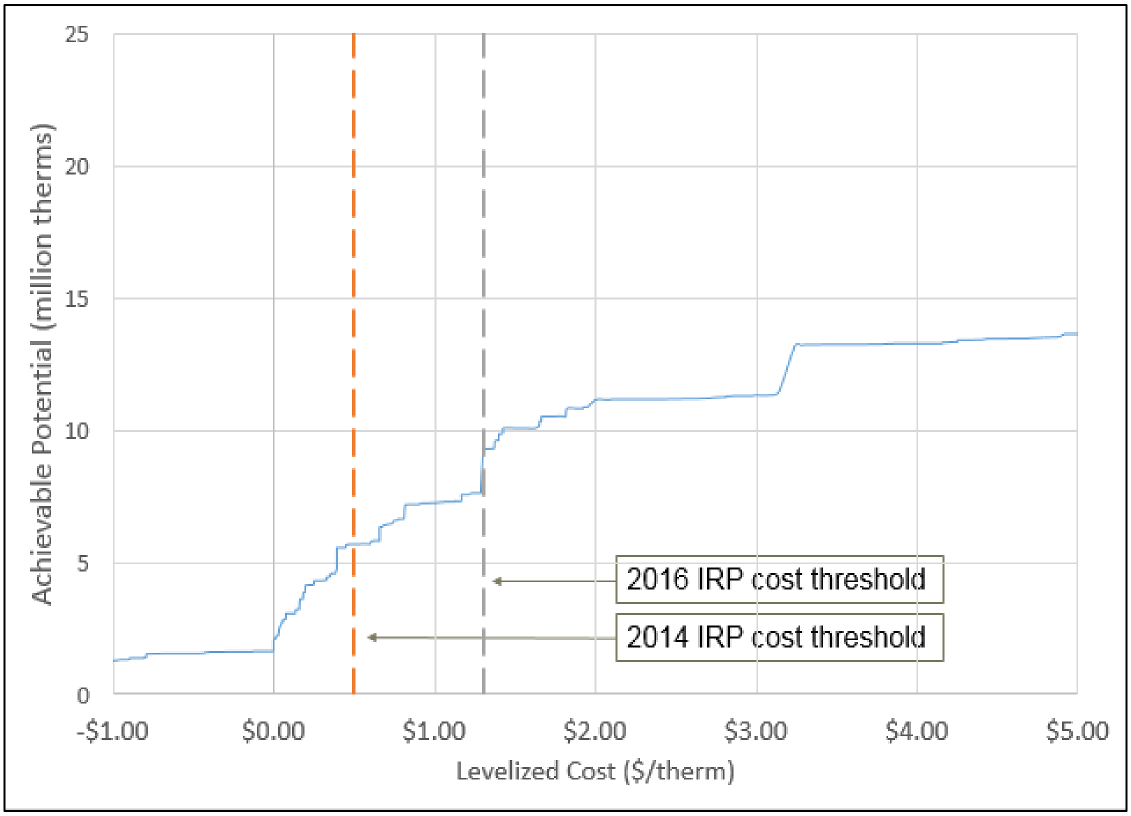


Figure 6.4: NW Natural's Washington Service Territory 20-Year Gas Supply Curve

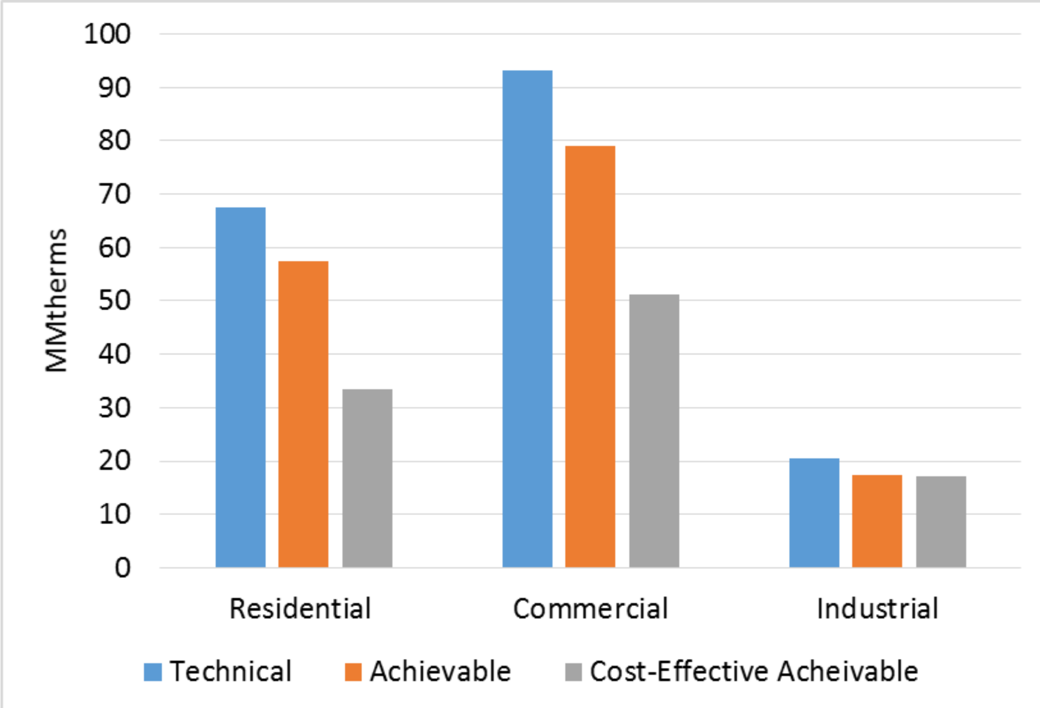


Figures 6.4 and 6.5 show a bigger potential for DSM in this IRP than the prior IRP. This is largely due to an increase in avoided costs, the additional measures the new avoided cost afforded, and inclusion of emerging technology present in Energy Trust's new resource assessment tool. These increases were moderated by other model refinements, including updated modeling assumptions such as saturation rates of efficient technologies in existing building stock and more accurate assessments of commercial square footage.

The tables in appendix 6 depict the 20-year cumulative achievable and cost-effective achievable potential forecast per measure grouped by sector. The tables also include the weighted average levelized cost for the savings of each measure.

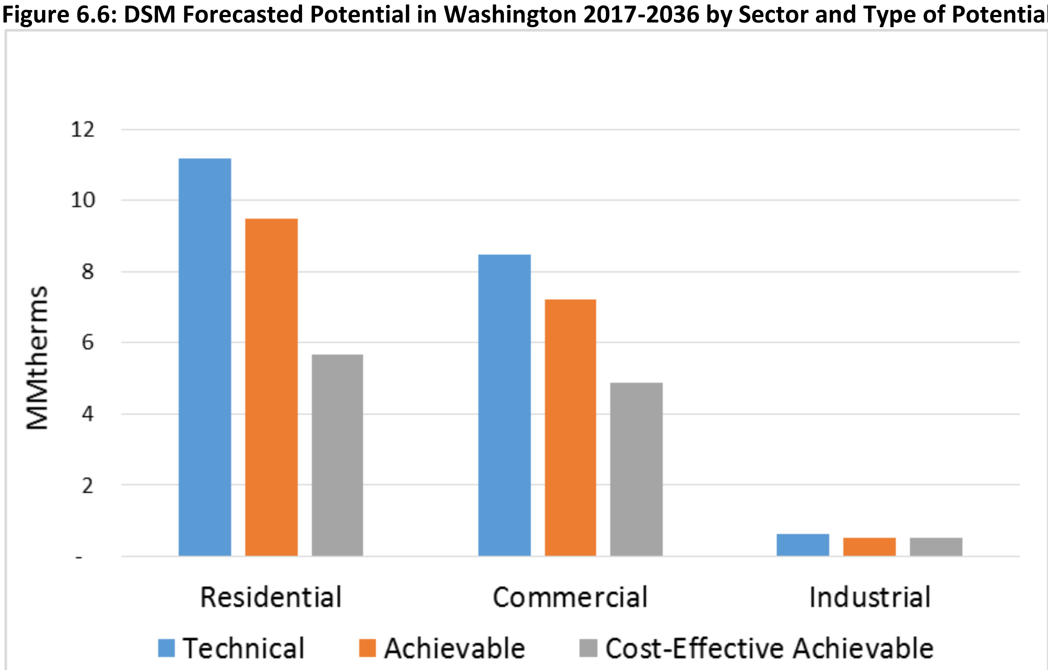
Figures 6.5 and 6.6 show cumulative forecasted savings potential across the various sectors Energy Trust serves, as well as the type of potential identified for Oregon and Washington, respectively.

Figure 6.5: DSM Forecasted Potential in Oregon 2017-2036 by Sector and type of Potential



These Oregon results indicate that for both the Residential and Commercial Sectors approximately half of the technical potential identified in the model is found to be cost-effective, with the majority of the DSM potential coming from the commercial sector. For the Industrial Sector, nearly all of the achievable potential identified is also found to be cost-effective.

Figure 6.6: DSM Forecasted Potential in Washington 2017-2036 by Sector and Type of Potential



These Washington results indicate that for both the Residential and Commercial Sectors approximately half of the technical potential identified in the model is found to be cost-effective, with the majority of the DSM potential coming from the Residential sector. For the Industrial Sector, nearly all of the achievable potential identified is also found to be cost-effective. Note that while industrial potential was identified during this study, because NW Natural does not collect the public purpose charge from its Industrial Customers in Washington, Energy Trust does not serve the industrial sector in NW Natural's Washington service territory.

Figures 6.7 and 6.8 show the amount of emerging technology savings within each category of DSM potential for both the Oregon and Washington portfolios, respectively. In highlighting the contributions of commercially available and emerging technology DSM contributions, the Oregon graph shows that while over 40 MM therms of the DSM technical potential consists of emerging technology, once the cost-effectiveness screen is applied, only a quarter of that remains.

Figure 6.7: Oregon 20-Year Potential by Each Savings Category

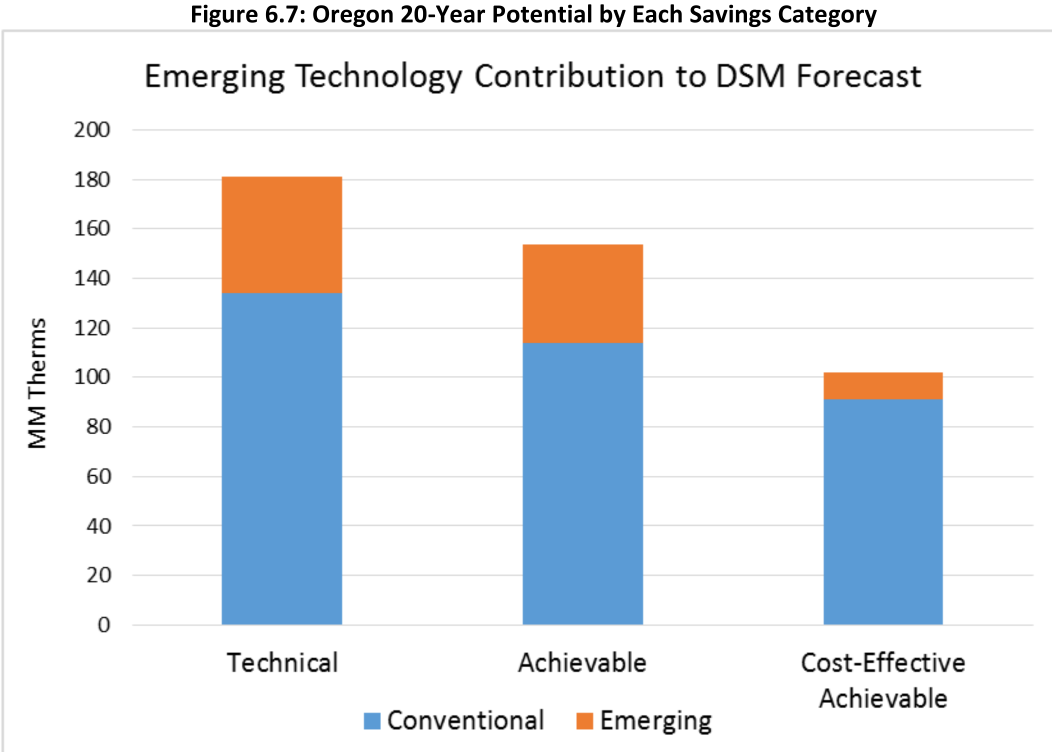
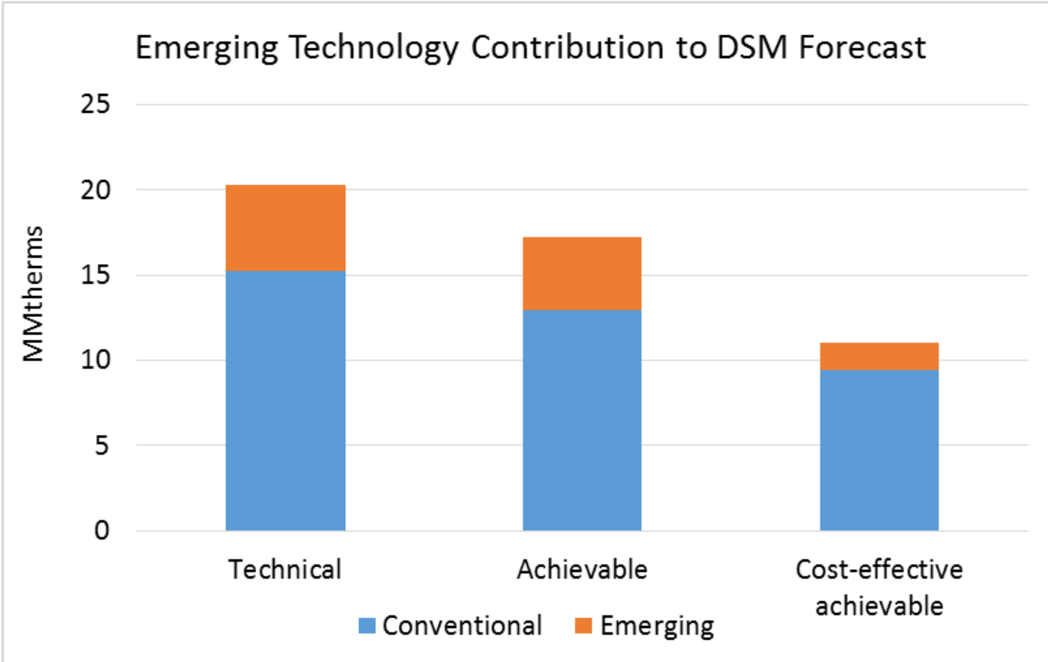


Figure 6.8: Washington 20-Year Potential by Each Savings Category

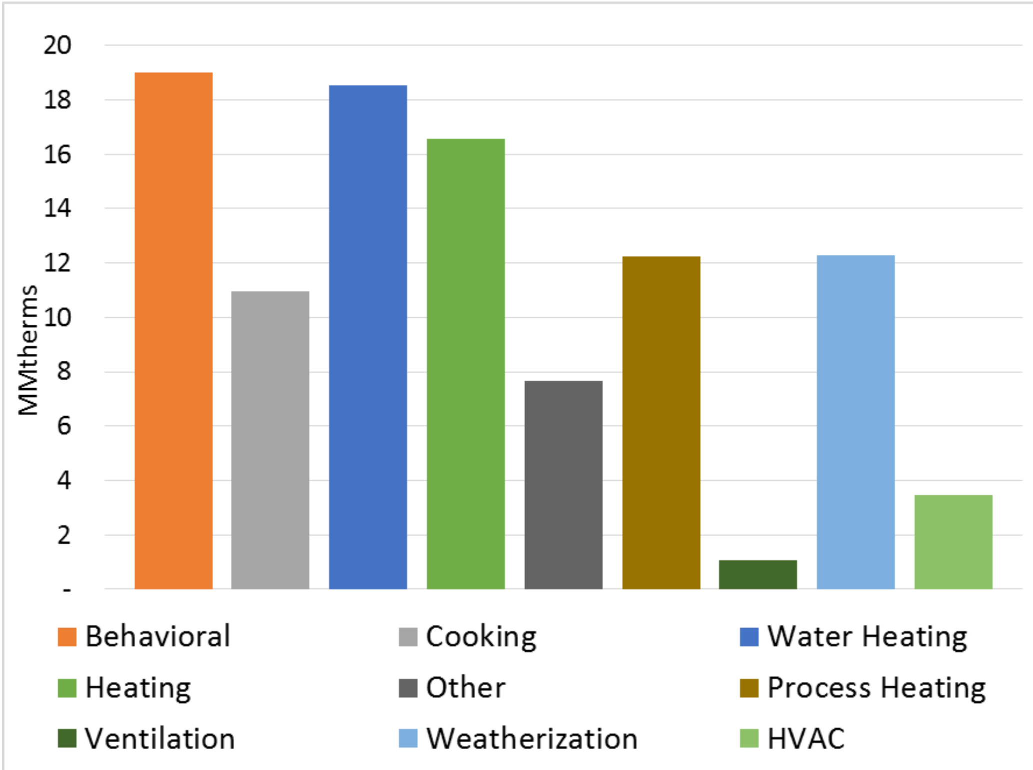


Similar to the Oregon graph, this Washington graph shows that approximately 5 MM therms of the DSM technical potential consists of emerging technology. Once the cost-effectiveness screen is applied, only a quarter of that remains, and with much of it in the out years of the 20-year forecast period.
A list of all emerging technology measures screened in the resource assessment model can be found in appendix 6.

Figures 6.9 through 6.10 below provide a breakdown of Oregon and Washington's 20-year cost-effective DSM savings potential by end use.[5] These figures include total cumulative cost-effective potential as shown in table 6.1 and table 6.2 prior to being reduced by program deployment assumptions.

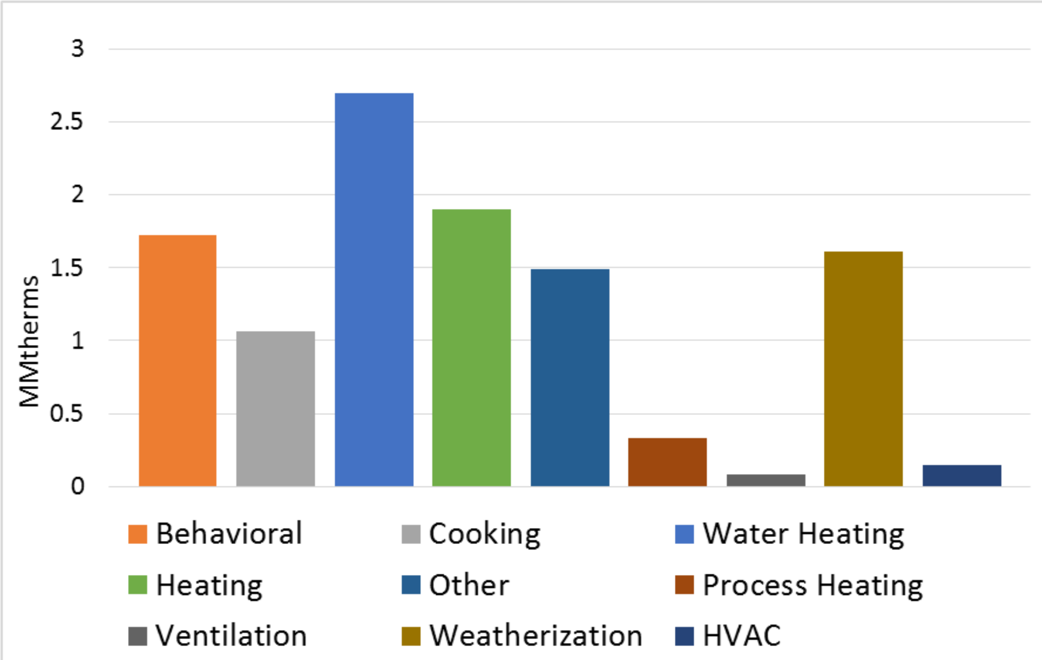
[5] End uses with space heating savings potential include behavioral, heating, ventilation, weatherization, and other (new home construction). End uses with flat savings potential are cooking, other, water heating, process heating, and HVAC. Due to recent interest in quantifying peak savings, which are most directly related to space heating during the winter, Energy Trust recognizes the need to revisit the assumptions and categorization of certain measures in the resource assessment model.

Figure 6.9: Oregon 20-Year Cumulative Cost-Effective DSM Potential by End Use



The behavioral end use tops the list in Oregon and consists primarily of potential from Energy Trust's commercial strategic energy management measure, a service where Energy Trust energy experts provide training to facilities teams and staff to develop the skills to identify operations and maintenance changes that make a difference in a building's energy use. It also includes residential personal energy reports and smart home automation devices. Heating potential is from commercial and residential heating system measures and HVAC is from industrial heating and insulation measures. Water heating includes water heating equipment from all sectors, as well as showerheads and aerators. The other category includes a variety of measures, but the two that make up its cost-effective potential are packages of multiple measures for new homes and greenhouse upgrades for the industrial program.

Figure 6.10: Washington Cumulative Cost-Effective DSM Potential by End Use



The water heating end use tops the list in Washington and includes water heating equipment from all sectors, as well as showerheads and aerators. Heating savings is from commercial and residential heating system measures and HVAC is from industrial heating and insulation measures. Behavioral consists mainly of commercial strategic energy management while also including residential behavior programs and smart home automation devices. Water heating potential is from commercial and residential measures. The other category includes a variety of measures but the only two with cost-effective potential are packages of multiple measures for new homes and greenhouse upgrades for the industrial program.

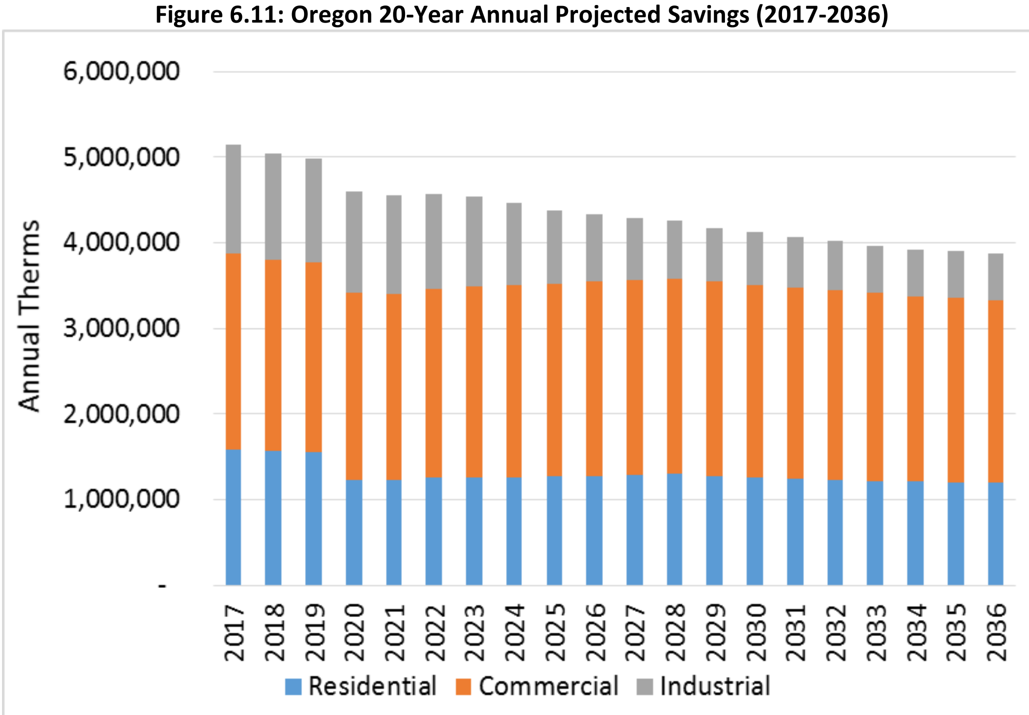
3.2. Final Savings Projection

After determining the 20-year cost-effective achievable potential, Energy Trust develops a savings projection based on past program experience and knowledge of current and developing markets. The savings projection is a 20-year forecast of future market penetration by programs for existing measures and new technologies within the cost-effective potential, plus, in Oregon, forecasted market transformation savings due to Energy Trust's work towards accelerating building codes in Oregon. Market transformation savings are not included in the Washington forecast at this time. The goal is to provide an annual projection of acquisition of the 20-year savings potential identified.

The final reported savings projection is slightly different for Washington and Oregon. The Oregon savings forecast includes over 1 million 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 more stringent building and equipment codes are adopted, it is appropriate to decrement the Company's load forecast accordingly and allow the program to claim 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 savings projection since the WUTC has not acknowledged that this is an appropriate practice. Energy Trust is peripherally engaged in the residential homes code process in Washington through its support of the Northwest Energy Efficiency Alliance (NEEA), but until 2016 was only funding NEEA for code-support work in Oregon. Energy Trust therefore does not think it is appropriate to claim influence on savings based on actions taken prior to 2016, at which point it began funding NEEA gas programs in Washington.

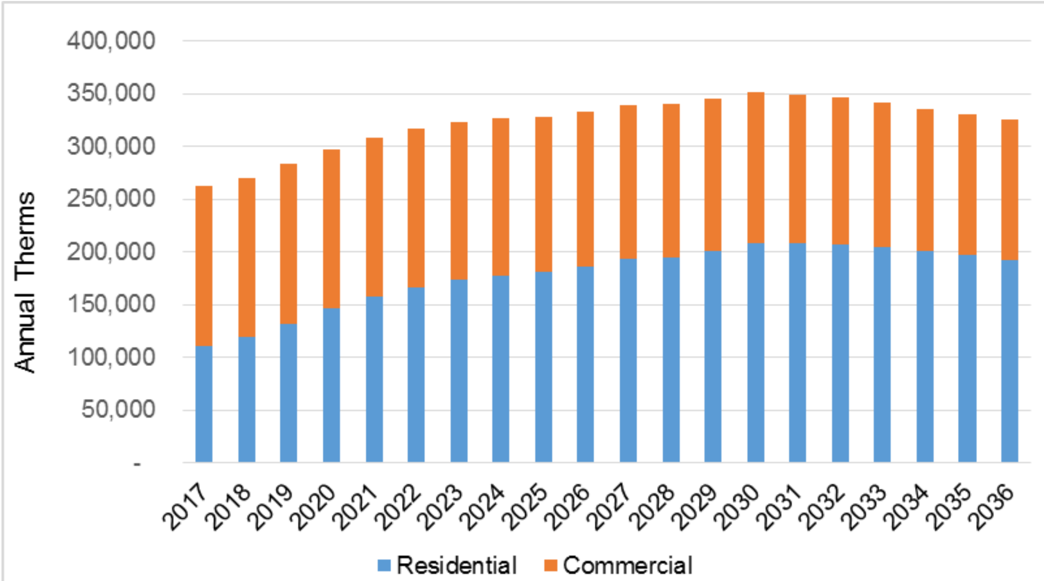
Figures 6.11 and 6.12 depict savings projections for Oregon and Washington, respectively. Note that as previously discussed, while industrial DSM potential was identified in Washington, Energy Trust programs do not currently deliver industrial programs in Washington except where customers in commercial rate classes have industrial end uses. Thus savings for the industrial rate class is not included in the following savings projections.

Figure 6.11: Oregon 20-Year Annual Projected Savings (2017-2036)



The sudden drop in savings from 2019 to 2020 is due to the expiration of savings being claimed by the New Homes and New Buildings programs from work done in the past that contributed to building code changes (otherwise known as market transformation savings) as discussed above. While it is likely that additional savings may occur when building codes are updated again, at this point Energy Trust cannot appropriately forecast the amount that is likely to occur in the future.

Figure 6.12: Washington 20-Year Annual Savings Projection (2017-2036)



Figures 6.13 through 6.14 below provide a breakdown of Oregon and Washington's 20-year projected savings acquisition by whether the savings occur during the heating season (space heat) or all year (flat).

Figure 6.13: Oregon 20-Year Savings Projection by Load Type

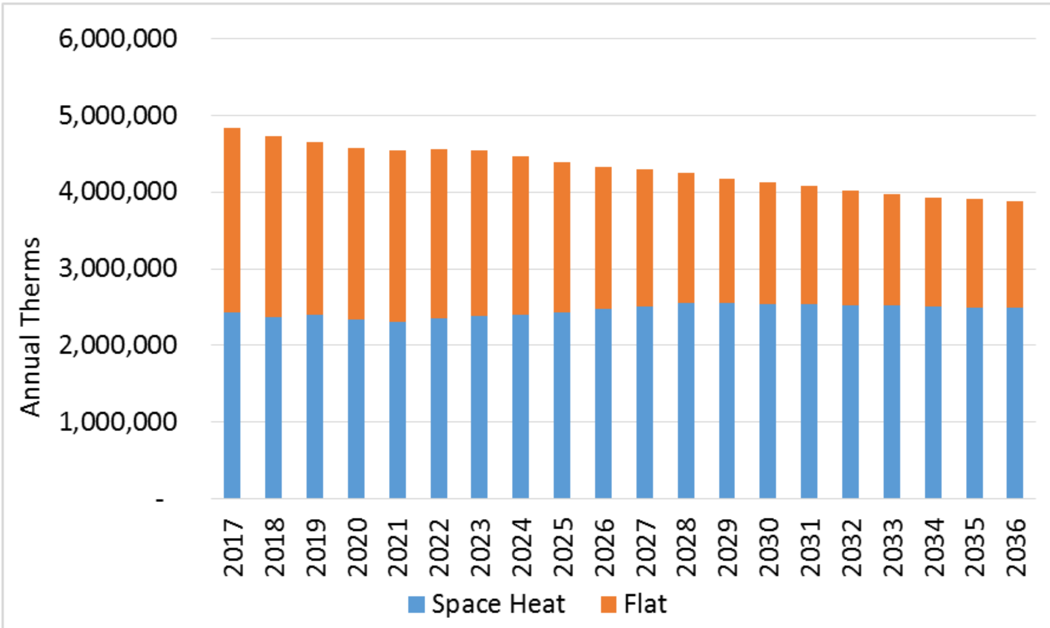


Figure 6.14: Washington 20-Year Savings Projection by Load Type

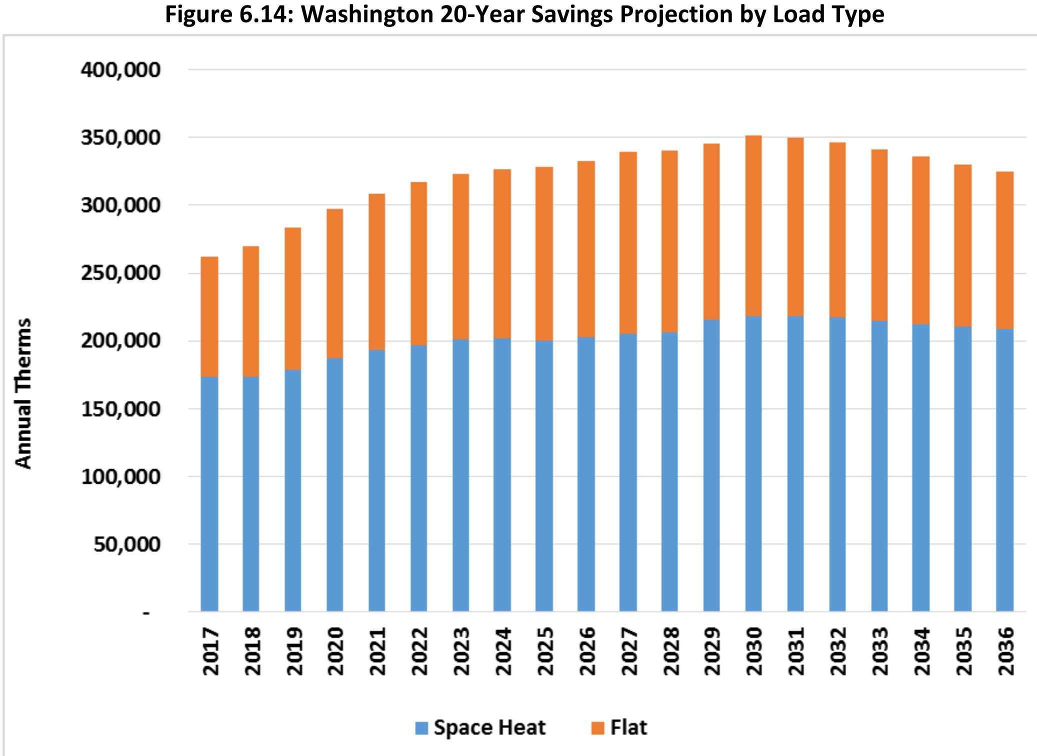


Figure 6.15 shows historic Oregon savings and also compares the Oregon 2016 IRP forecast to the 2014 IRP forecast. The peak in 2015 actuals is due to the acquisition of a very large industrial project, which brought in nearly 1 million therms of savings. Forecasting large projects and the timing of their completion in the commercial and industrial programs is difficult and is often the cause of over performance or under performance in any given year. However, to date, Energy Trust has met or exceeded goals in five of the last six years.

Figure 6.15: Oregon Annual Savings History and Projection Comparison with Recent Actuals

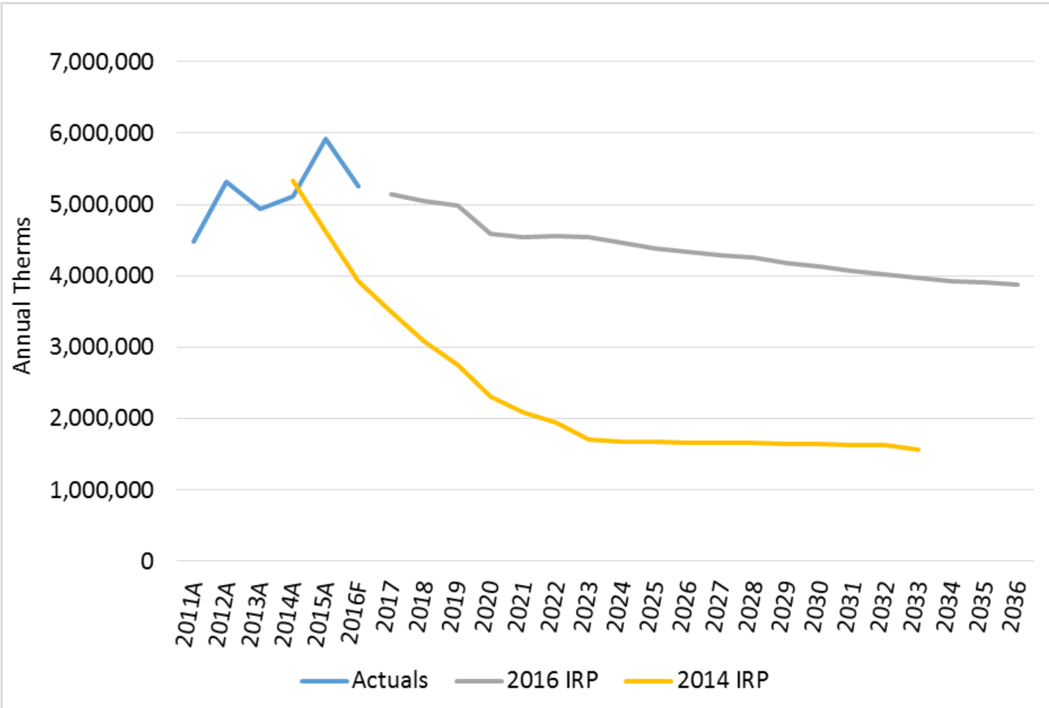
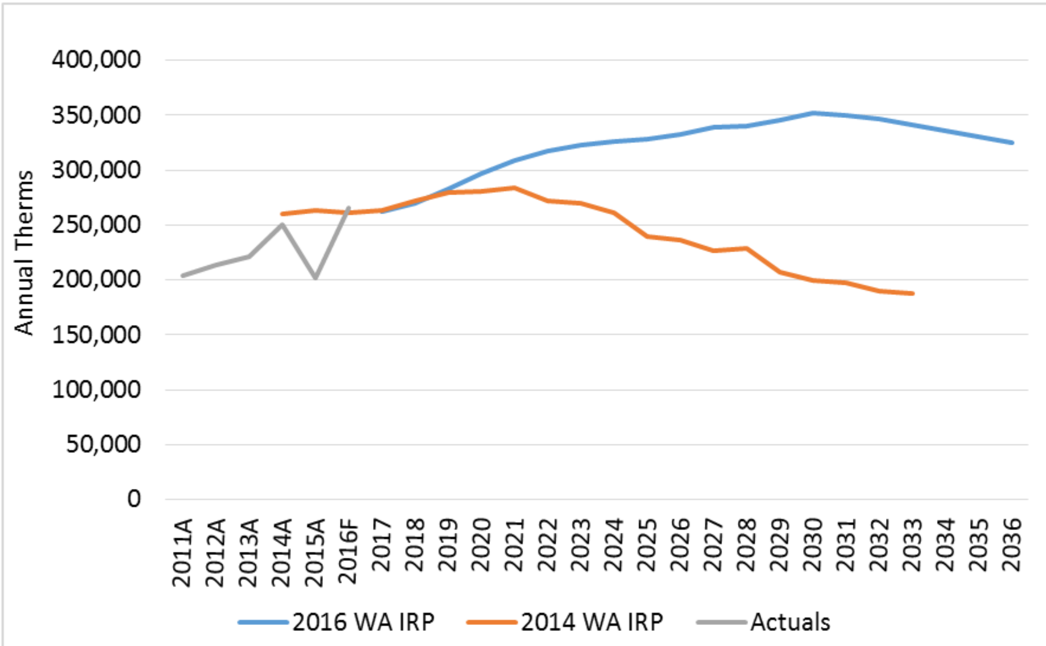


Figure 6.16 shows historic Washington savings and also compares the Washington 2016 IRP forecast to the 2014 IRP forecast. The valley in 2015 in Washington's actuals line is due to several anticipated commercial custom projects which did not complete in time to be included in 2015 results. The commercial strategy for 2016 has been shifted to address the short-comings of the 2015 program, including increased incentives and additional outreach. As discussed above, forecasting large projects in the commercial programs is difficult and is often the cause of over or underperformance in any given year.

Figure 6.16: Washington Annual Savings History and Projection Comparison with Recent Actuals



Overall, the cost-effective achievable savings potential for Oregon and Washington is higher than it was in the Company's last IRP, primarily for the following reasons:

- Increased natural gas avoided costs due to new methodology, which includes capacity resource value from peak savings, premium 'hedge value of DSM', and incremental carbon policy value.
- New Resource Assessment model introduced new savings from the following sources:
    - Emerging Technology (Approx. 10 percent of total cost-effective savings potential)
    - New measures in our programs (e.g., Residential & Commercial Behavioral)

4. PROGRAM FUNDING AND DELIVERY: OREGON

4.1. 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.[6]

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

After NW Natural's 2008 IRP[7] identified that cost-effective industrial saving were available, the Company worked with Energy Trust to launch an Industrial DSM program in Oregon. This program is available to large Firm and Interruptible Sales customers, but not transportation customers. Costs for the program, described in Schedule 360 of the Company's tariff, are deferred for recovery a year later through the charge published annually in Schedule 188.

With the exception of the first few years of the residential and commercial programs in Oregon when gas customers were just learning about the availability of savings incentives, Energy Trust has been meeting and even exceeding the annual savings targets derived through the biannual IRP analysis of the available, cost-effective DSM potential. NW Natural foresees 87.2 million therms of its 20-year demand coming from Oregon demand-side management measures.

The value of gas avoided costs decreased by approximately 50 percent between 2012 and 2015. As the avoided costs value the benefit per therm of savings from energy-efficiency measures, some measures are no longer cost-effective at the current forecasted price of natural gas, including single-family residential ceiling, wall, and floor insulation, the 0.67 EF domestic gas tank water heater and residential single-family duct and air sealing. Energy Trust has been concerned that removing these measures from the gas portfolio could result in costly disruptions to the gas programs in the long run if natural gas prices and forecasts were to rebound in the short term. Part of the rationale of continuing to offer these measures is to maintain consistency in the market and to retain relationships with vendors and trade allies who are relied upon to sell the energy-efficiency products.

Additionally, the majority of the measures meet one of the 7 exception criteria in UM 551, and so Energy Trust filed requests with the Public Utility Commission of Oregon for approval to offer noncost-effective measures in accordance with the exceptions to the cost-effectiveness standard provided in OPUC Order No. 94-590. The Commission has provided exceptions for a number of these measures over the last few years as Energy Trust works to lower costs and design new ways to offer these measures in

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

[7] See Docket No. LC 45.

a more cost-effective way. While there continues to be uncertainty around the future price of gas and whether measure costs can be adequately reduced, the Energy Trust has been allowed ongoing exceptions to many of the noncost-effective measures and felt it appropriate at this time to include the savings potential from these measures in its DSM potential forecast in an effort to not understate the savings potential that exists.

4.2. Oregon Low-Income Energy Efficiency Program (OLIEE)[8]

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.[9] 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 10 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. Various program designs have been attempted but production has never met the original targets. As a result, program funding has accrued.

During 2015, however, the conversation expanded beyond NW Natural and the agencies as representatives from CAPO, Public Utility Commission of Oregon Staff, CUB, Avista Utilities, and Cascade Natural Gas came together to discuss root causes for statewide underperformance of low-income energy-efficiency programs. As a result of these discussions, NW Natural filed tariff changes and the revised program became effective on March 1, 2016. The changes were designed to decouple the local utility program from the federal programs and funding in order to release the agencies from the process and prioritization constraints that make it especially difficult and expensive to weatherize gas homes.

To track the impact of these changes to the program, quarterly reporting will occur for the first two years of the revised program. Table 6.3 below shows the number of homes treated and therms saved in OLIEE per year.

Table 6.3: Homes Treated Through OLIEE Program

Program Year	Homes Treated	Therms Saved (Estimated)
2014–2015	198	45,876
2013–2014	201	46,756
2012–2013	151	36,995
2011–2012	541	92,708[10]
2010–2011	339	108,141

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

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

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

NW Natural expects the program changes will results in home completions near the original goal within five years. The near-term targets, by program year, are as follows:

- 2015–2016: 254 homes (partial year)
- 2016–2017: 450 homes
- 2017–2018: 600 homes

5. PROGRAM FUNDING AND DELIVERY: WASHINGTON

5.1. Residential and Commercial Programs

Since Oct. 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.[11] 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.[12]

Targets are based on IRP savings goals. Program results for 2015 were presented to the WUTC and EEAG in the 2015 Annual Report filed April 22, 2016.

The Company's program portfolio has consistently delivered savings cost-effectively, having a total resource cost of one or greater. With lower gas prices and, consequently, lower avoided costs, other natural gas utilities in the region have struggled to keep their programs cost-effective. The WUTC opened docket No. UG-121207 to investigate methods for evaluating the cost-effectiveness of natural gas energy-efficiency therm savings. NW Natural participated in this docket and expressed a willingness to reconsider aspects of traditional methodologies.

The Commission issued a Policy Statement in October 2013 which states a preference for the use of a balanced TRC on a portfolio level, and when that isn't feasible, the Utility Cost Test (UCT). NW Natural and Energy Trust considered the Commission's Policy Statement; Energy Trust performed analysis on how the application of the TRC verses the UCT would impact the program. The Company met with its EEAG in April of 2014, and proposed using the UCT as the primary cost-effectiveness screening tool for the 2015 program year. Since no party objected to the proposal, the Company revised its tariff and Energy Efficiency Plan to reflect this change, which both complies with the Policy Statement and allows the Company to offer a sound program.

While Energy Trust's Resource Assessment model does use the TRC as its cost-effectiveness screen at the measure level, the model contains a cost-effectiveness override toggle to allow savings potential

[11] See Order No. 4 in Docket UG-080546.

[12] 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.

from any measure in the model to be included without the cost-effectiveness screen. Energy Trust applies the override to all measures in the model that are offered through programs and are likely to fail the TRC screen. As a result, programs in Washington currently contain several measures that are not offered in Oregon because they fail the TRC screen.

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

On Oct. 1, 2009, NW Natural launched a revised low-income program identified as WA-LIEE (Washington Low-Income Energy Efficiency). Modeled after Oregon's OLIEE program, the WA-LIEE program reimburses the two administering Agencies for installing weatherization measures that are cost-effective when analyzed in aggregate. Reimbursements were 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. In an effort to increase program success, the Company worked with its EEAG in 2015 to strengthen the program. The following changes were made to the program effective Jan. 15, 2016:

- The stipulation requiring a customer's dwelling be built before 1991 was removed to allow weatherization services in newer housing stock.
- Program funding up to $11,000 is available for the 2016 program year for customer outreach.
- NW Natural's program administration costs were limited to 5 percent of the total funds distributed during the Program Year, which was insufficient to administer this program. The WUTC granted increasing program administration to $7,700 for the 2016 program year to allow NW Natural staff to provide additional focus on increasing program participation.
- The maximum rebate amount per home has been increased to the greater of $5,000 or the average total installed cost of measures as reported by the Agencies for the prior program year. The WA-LIEE contribution was also increased from 90 to 100 percent of job costs.

NW Natural is monitoring the program and hopeful that these changes will increase the number of homes treated per year.

Table 6.4: Homes Treated Through WALIEE

Year	Homes Treated	Therms Saved (Estimated)
2015	9	3,213
2014	10	3,050
2013	20	7,026
2012	8	2,538
2011	11	3,575

Energy-Efficiency Action Item

NW Natural recognizes the enduring value customers receive as a result of investments in energy efficiency. The revised avoided cost methodology more accurately reflects the true cost-effectiveness and savings of DSM and the Company intends to achieve the therm savings targets identified in this study. As a result, NW Natural is including the following Action Items in its Action Plan in this IRP:

- Demand Side Resources and Environmental Action Item 1: Consistent with the methodology in this chapter, NW Natural will ensure Energy Trust has sufficient funding to acquire therm savings of 5.1 million therms in 2017 and 5 million therms in 2018 or the amount identified and approved by the Energy Trust board. [13]
- Washington Only Demand Side Resources and Environmental Action Item 1: Consistent with the methodology in this chapter, NW Natural will ensure Energy Trust has sufficient funding to acquire therm savings of 262,000 therms in 2017 and 270,000 therms in 2018 or the amount agreed to by the EEAG and approved by the WUTC.[14]

6. 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. 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.

7. DISTRIBUTION SYSTEM PLANNING AND DEMAND-SIDE MANAGEMENT

Along with the increased focus on distribution system planning[15] in IRPs there is growing interest in the potential of DSM to cost-effectively avoid or delay distribution system reinforcements.[16] For DSM to be considered as an option to address distribution system weak spots it will be necessary to make changes to planning processes on the part of NW Natural relative to distribution system planning and it may make sense to examine whether standard Energy Trust cost-effectiveness review protocols should be restructured for this specific purpose. Until this point, NW Natural has used just-in-time distribution system reinforcement planning and Energy Trust has employed statewide programs that will need to be adjusted to target local areas if supply- and demand-side resources[17] are to be evaluated on a fully

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[13] See appendix 6A-1 for 20-year cost-effective DSM savings projection by sector, measure type, and end use.
[14] See appendix 6A-4 for 20-year cost-effective DSM savings projection by sector, measure type, and end use.
[15] See chapter 7 for a detailed description of the difference between supply and distribution system planning.
[16] For example, see OPUC Order Nos. 15-064 and 16-109 and WUTC Acknowledgement Letter in Docket UG-131473.
[17] Note that here the definition for supply-side resources means nondemand-side resources that are used to serve load, which includes both supply and distribution system resources. In other words the supply vs distribution resource distinction is different than the supply-side vs demand-side resource distinction.

integrated basis[18] relative to the distribution system. There are numerous reasons that NW Natural and Energy Trust have operated the way they currently do up to this point in time, which are discussed after a description of what making DSM as a distribution system resource option entails and requires.

"Distribution resource" projects are local in nature rather than the (typically) systemwide considerations of "supply resource" planning. Where supply planning is about the total amount of gas that can be pushed on to NW Natural's system via its interstate pipeline contracts and storage resources (both contracted and NW Natural-owned), distribution/deliverability planning is about getting the gas that makes it *to* NW Natural's system to the places it is needed *on* NW Natural's system via gate stations, regulators, and high- and low-pressure pipelines. Therefore, the load resource balance for supply resource planning shown in figure 1.12 (also shown as figure 2.40) is for NW Natural's system as a whole rather than the many "systems-within-a-system" that characterize NW Natural's distribution system.

The load resource balance shown for the Eugene reinforcement in figures 7.5 and 7.6 is an example of a model of a distribution system within the overall NW Natural system using the Synergi pressure modeling software. While reductions in peak load from any of NW Natural's customers via energy efficiency reduce the amount of *supply* resources needed by the Company to serve its customers, only reductions in peak load from the customers that are fed by the portion of the distribution system that needs reinforcement are relevant to avoiding or delaying supply-*side* distribution projects on the system-within-a-system. For example, peak savings from DSM from customers in Portland have no impact on the need for or timing of a distribution system reinforcement in Eugene or Vancouver. Furthermore, the current DSM annual savings projection for NW Natural in the Energy Trust budget is at the state level and NW Natural incorporates the savings from these statewide goals in the local level load forecast. This means that statewide programs are not, without additional efforts, sufficient to avoid or delay the local distribution system reinforcement or the project would not be anticipated to be needed.

With few exceptions, customer rates are set at the state level so that all NW Natural customers in the state pay for all of the Company's local distribution system reinforcements in that state. Therefore, the question becomes: What is the option that represents the best combination of cost and risk for the customers in the state to address the local distribution system need? For example, if the best supply-side distribution system option (a new pipeline connecting two previously isolated areas) costs customers $5 million in net present value of revenue requirement (PVRR), can less than $5 million in PVRR be spent to acquire DSM savings in the local area to achieve a reduction in peak hour load that is sufficient to delay or avoid the cost of the distribution system enhancement? Answering this question requires a location specific DSM cost-effectiveness test that focuses on peak savings in the area in question.

[18] As is called for by OPUC Order No. 94-590.

7.1. Geographically Targeted DSM via Accelerated and/or Enhanced Offerings

"Geographically Targeted" DSM is defined as savings from offerings that are specific to certain locations within a state in order to achieve additional savings specifically from customers that contribute to the peak load of an area where the distribution system is experiencing weakness and a supply-side project is projected to be needed to serve customer load. Geographically targeted DSM savings can be from DSM programs for measures that are not offered in other areas of the state or from programs that intensify/speed up efforts to acquire savings from measures available elsewhere in the location experiencing the distribution system weakness, but are different than what is offered in the state at large. Given the current method for evaluating DSM cost-effectiveness, special consideration must be given to how to design and deploy a geographically targeted DSM program in order to meet the economic/cost-effectiveness criteria.

Geographically targeted DSM savings can be achieved by either "accelerating" or "enhancing," or accelerating *and* enhancing, DSM offerings in the location in question.

"Accelerated" DSM is defined as speeding up the timeline to acquire savings which meet current Energy Trust cost-effectiveness requirements (based on statewide avoided costs) in a local area with location specific targeted marketing and/or increased incentives. In other words, accelerating DSM is acquiring savings that would be acquired eventually though statewide operations faster in the locality in question.

"Enhanced" DSM savings are savings that do not meet current Energy Trust cost-effectiveness requirements (based on statewide avoided costs) but are cost-effective if location-specific avoided costs[19] are used to represent the value of achieving peak hour savings from DSM in the local area that is experiencing a distribution system weakness. In other words, enhancing DSM is acquiring savings in the local area that are cost-effective using local avoided costs that are not cost-effective under current state-level planning using statewide avoided costs.

Accelerated and/or Enhanced DSM will be required in the geographically targeted area for a project to achieve the required peak hour savings since the "business as usual" process for acquiring DSM savings is already accounted for in the peak hour distribution system planning that shows a project is needed to address a weakness. The demand-side options to evaluate against supply-side options to address weaknesses in NW Natural's distribution system will be referred to as "geographically targeted DSM via accelerated and/or enhanced offerings" or "Targeted DSM" for short. Allowing for Targeted DSM to be a viable option is breaking new ground for LDCs operating in the region and requires major changes to the way NW Natural plans distribution system upgrades and the way Energy Trust evaluates cost-effectiveness and deploys its programs. While NW Natural and Energy Trust are open to these changes to work towards planning as optimally as possible for customers, an explanation for why both organizations operate the way they do is useful in highlighting some of the issues with using Targeted DSM as an option to address distribution system needs.

Additionally, like supply-side options, if multiple enhanced *and/or* accelerated DSM programs are projected to be cheaper than the best supply-side option, the lowest cost option of the demand-side

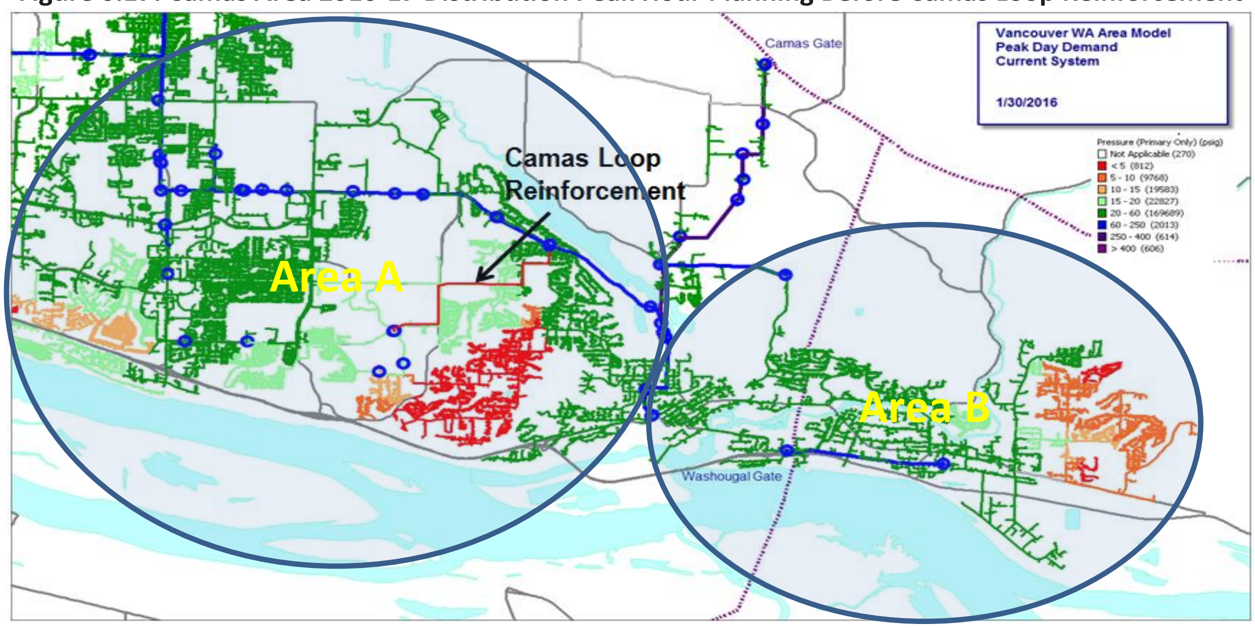
[19] Inclusive of the expected costs of the potential supply-side distribution enhancement.

options would need to be deployed to meet the best combination of cost and risk planning standard for addressing resource acquisitions.

7.2. Example of Geographically Targeting DSM Peak Hour Savings

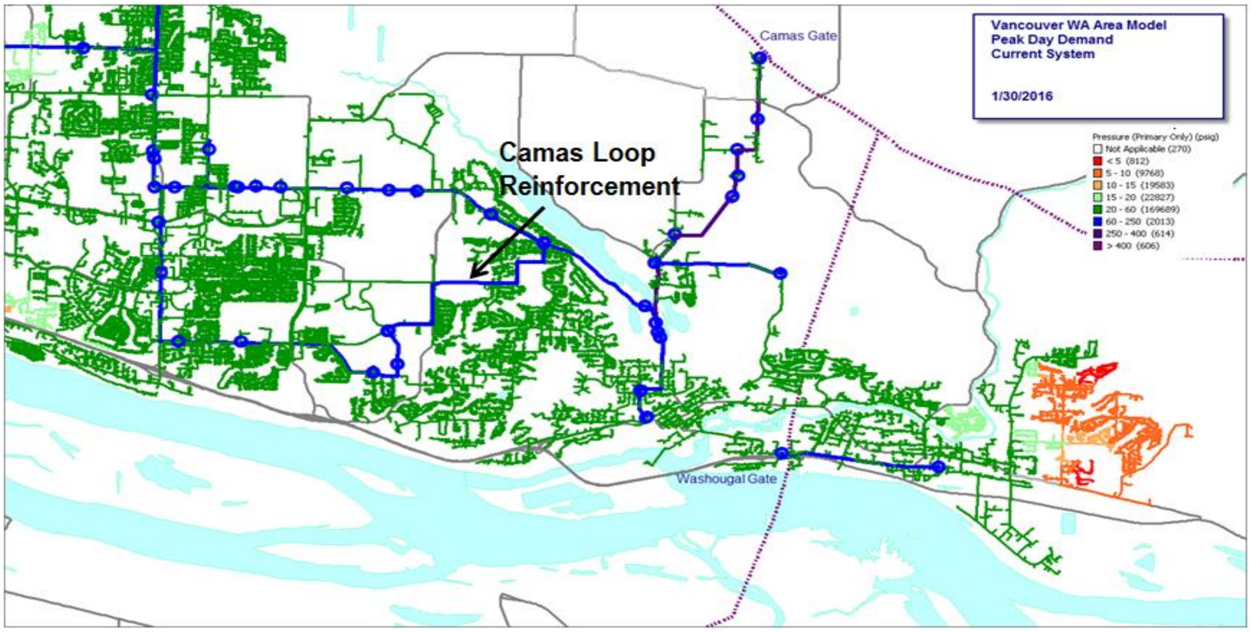
In order to illustrate how a DSM offering would need to be targeted to a specific geographic area to be considered as an alternative to a distribution system project, the Clark County Camas Loop reinforcement that will be in service for the 2016-17 heating season and is detailed in chapter 7 is used as an example.[20] Figure 6.17 shows the weakness in the local distribution system using the Synergi pipeline modeling software[21] without the Camas Loop during planning peak hour conditions.[22] It also overlays circles on the model (*Area A* and *Area B*) that represent the distinct sections of the distribution system that are systems-within-a-system where gas cannot flow between. Note that the Camas Loop Reinforcement pipeline is pointed out and shown in red. Figure 6.18 shows the benefit provided by the reinforcement project by illustrating how the system is expected to perform under peak planning conditions once the Camas Loop reinforcement is complete.

Figure 6.17: Camas Area 2016-17 Distribution Peak Hour Planning Before Camas Loop Reinforcement



[20] Note that this example is for illustration purposes only given there is an immediate need for a solution in the Camas area such that precludes Targeted DSM as an option given the lead times discussed later in this chapter.
[21] Please see chapter 7 for more information and how to interpret Synergi model figures.
[22] Assuming 2016–2017 customer counts and usage.

Figure 6.18: Camas Area 2016-17 Distribution Peak Hour Planning After Camas Loop Reinforcement



To show how the geographic borders would have been determined to evaluate Targeted DSM offerings as an alternative to the Camas Loop reinforcement, had the further-out-in-time distribution planning process discussed later in this chapter and in chapter 7 to be implemented going forward been in effect previously,[23] note that *Area A* and *Area B* in figure 6.17 are both "systems-within-a-system." As such, completing the Camas Loop Reinforcement does not impact *Area B,* which is shown by the orange/red coloring (low pressure) in *Area B* in figure 6.17 remaining the same in figure 6.18. Consequently, had Targeted DSM been chosen as the option to address the weakness seen in *Area A* that the Camas loop is addressing, peak savings from *Area B* or any other location in NW Natural's service territory would not have helped delay or avoid the Camas Loop project. Therefore, for DSM to have been used as the option to address the weakness in *Area A*, the Targeted DSM program, which by definition would go beyond the "business as usual" DSM acquisition activities elsewhere in the state, would have been required to "target" peak hour savings from *Area A* only.

[23] This does not imply that Targeted DSM would have been chosen as the least-cost alternative to address the weakness is Camas, only that it would be evaluated against supply-side options and considered in the least-cost analysis.

7.3. NW Natural Expected Changes and Central Concerns

Until this point, as is detailed in chapter 7, NW Natural has addressed supply-side distribution weaknesses as they are detected in the real world in order to provide just-in-time solutions. This has been preferred relative to a detailed multiyear prospective distribution system enhancement planning and design process[24] for the following reasons:

1. The smaller the area being considered, the more important a change (a gain/loss of a large customer, a new subdivision, etc.) that could impact system loads and the timing of a project becomes. If a Targeted DSM initiative were to be implemented to address a *projected* need customers could end up paying for Targeted DSM peak hour savings that are not necessary because either the savings were ultimately unnecessary or a change necessitated a supply-side solution *in addition to* the Targeted DSM program. An example of each is described below:
    a. Example where project timing is moved up due to an unexpected change: An unexpected new large customer makes the need for a local distribution enhancement immediate
    b. Example where projects that were expected ended up not needed: Numerous planned developments in 2008 did not get built or were delayed substantially due to the Great Recession.
2. Distribution system planning is model based and needs to be verified with field pressure testing, which is not an option for evaluating loads that are projected in the future and are not being experienced today.
3. Combining reasons 1 and 2, using planning resources (people and time) to complete specialized load and project design analysis to determine all the viable options to address the weakness and estimate costs for these options was considered an improper use of resources.
4. Coordination with municipal, county, and state governments to minimize impacts on rights of way may not allow the requisite timing to consider Targeted DSM as an option in all cases.
    a. For example, when constructing or repairing a roadway, the local government may impose a moratorium on construction along the roadway for long periods of time (10 years for example) that forces a decision to construct a pipeline or not be able to use the right of way until after a reinforcement is likely to be required

Even when considering the complications described above NW Natural realizes that demand-side options may be the best way to address distribution system needs. Consequently, to accommodate the highly likely possibility that Targeted DSM initiatives will take multiple years to plan, implement, and complete, NW Natural presents a proposal in chapter 7 to plan distribution system reinforcements further out in time that it will deploy going forward. However, for supply-side and demand-side options to be compared on equal footing there is much to be learned about the firmness/reliability of Targeted DSM peak hour savings, the costs and timing with which they can be acquired, and how they can be measured.

[24] Which is required to evaluate Targeted DSM initiatives as an option to address distribution system needs due to the time needed to allow a DSM program to make the requisite impact.

Additionally, equity issues, both amongst current customers within a state and between "generations" of customers, are major concerns when considering Targeted DSM. Equity issues amongst customers within a state will be discussed within the Energy Trust's concerns below, but intergenerational equity issues could cause complications depending on how Targeted DSM costs are paid for by customers. Note that the impact on customers of supply-side projects is well known as the capital expenditure will be converted into revenue requirement through cost of service mechanisms that typically have very long depreciation lives.

It may not be appropriate and could be detrimental to Targeted DSM from a least-cost planning perspective in net present value terms to use the current DSM savings funding model where costs are borne by customers through the public purpose charge in the year they are accrued by Energy Trust. This model ensures all of the costs of the Targeted DSM initiative are incurred by customers in the years the program is under way even though the benefits are likely to last long beyond the timeframe of the initiative itself given the expected lives or most DSM measures. Cost deferral options would need to be considered as a way to make Targeted DSM more attractive from a financial perspective and address this issue of intergenerational equity.

7.4. Considerations for Energy Trust of Oregon to Provide a Targeted DSM Program

As provided by Energy Trust of Oregon (shown in maroon text)

The Energy Trust runs natural gas energy-efficiency programs throughout NW Natural service territory in Oregon and Southwest Washington to deliver the lowest cost energy solution for NW Natural customers. For Targeted DSM to be a real option to address weaknesses in the NW Natural gas distribution system it would be necessary for Energy Trust to run programs, or campaigns within existing programs, that are specifically targeted to the area in question in order to maximize customer participation levels.

Energy Trust will begin with an intensified focus of the current resource acquisition program offerings, including an examination of how to deploy the current measures with incentives and marketing tactics designed to accomplish meaningful reductions in peak hour demand. This differs from, but is often complementary to, the primary Energy Trust objective of acquiring annual gas savings. As part of the examination, Energy Trust will review how the deployment of a focused program offering will coincide with the current Energy Trust cost-effectiveness framework that is used to review measures and programs. If the offering is not meeting cost-effectiveness requirements then Energy Trust will need guidance from the respective state Commissions to proceed with implementation.

An alternative to Energy Trust's current program structure is one specifically designed to reduce peak hour demand. However, such an offering may be a fundamental shift from Energy Trust's current business model and may require a significant investment to design and implement. If the current programs that Energy Trust offers are not sufficient for the purpose of deferring local distribution system enhancements, then Energy Trust will need guidance from the respective state Commissions regarding how much effort to put into offerings specifically tailored for this purpose.

While annual savings and costs of Energy Trust programs currently can be forecasted and acquired with a high degree of certainty statewide, it is unclear whether Energy Trust's ability to achieve peak demand reductions in a targeted geography can be reliably forecasted; one of the values of pilot activity is to learn more about this. Furthermore, evaluation efforts will need to be specifically scoped and implemented in order to establish the success of Energy Trust offerings at reducing localized peak gas demand.

Additionally, implementing Targeted DSM initiatives presents concerns about equitable distribution of Energy Trust offerings. Successful deployment of Targeted DSM may require that customers in the target area have specific Energy Trust opportunities made available to them; while customers outside of the target area may not have access to these same offerings. Energy Trust will need to design a solution to manage customer expectations in the midst of these differences because customers who are not allowed to participate in the Targeted DSM initiative may feel the program is unfair.

8. GEOGRAPHICALLY TARGETED DSM PILOT VIA ENHANCED AND/OR ACCELERATED DSM OFFERINGS ("TARGETED DSM" PILOT)

Given the concerns and questions regarding Targeted DSM as a viable cost-effective option to delay or avoid distribution system projects NW Natural feels it is inappropriate to "go live" with a Targeted DSM program which has the potential to be quite large and costly in lieu of a supply-side project without more information. Consequently, the Company broached the idea during a Technical Working Group and approached the Energy Trust about a Targeted DSM pilot to answer many of the questions about Targeted DSM so that supply- and demand-side options can be compared on equal footing in an integrated process while keeping customer interests as a priority. The idea of a pilot was well received by stakeholders and is a logical next step in the evolution of Targeted DSM as an option to address distribution system weaknesses.

8.1. Targeted DSM Pilot Purpose and Research Questions

The purpose of the pilot is to answer the following research questions that are currently unanswered so that Targeted DSM timing and cost estimates can be made for any location that is experiencing a weakness in the distribution system to compare against supply-side solutions in an integrated resource planning process:

1. What inputs does Energy Trust require from NW Natural to conduct a Targeted DSM initiative evaluation?
2. What cost-effectiveness framework is appropriate for evaluating Targeted DSM initiatives?
3. What DSM measures should be considered for Targeted DSM initiatives?
4. What amount of peak hour savings do different measures provide?
5. How firm/reliable and long lasting are Targeted DSM peak hour savings?
6. How fast can Targeted DSM peak hour savings be achieved?
7. What levels of incentives and marketing are required to achieve specific levels of uptake for Targeted DSM measures?
8. How much do Targeted DSM peak hour savings cost? (i.e., What is the Targeted DSM peak hour DSM savings supply curve for the area in question?)
9. How viable is it to run location specific DSM programs? (i.e., how do Targeted DSM efforts coincide with current Energy Trust program delivery activities)
10. How do customers respond to offerings that are available to only some customers in specific geographic areas?
11. What is the likelihood changes in load (via unexpected customer additions/losses and/or new development) ultimately render Targeted DSM expenditures unnecessary or inadequate to delay/avoid a supply-side project?
12. What are the appropriate funding mechanisms to fund Targeted DSM programs?

8.2. Initial Parameters for a Targeted DSM Pilot

While more specific parameters and details would need to be scoped through research, NW Natural and Energy Trust have compiled the following parameters as considerations for an appropriate Targeted DXM pilot:

1. Supply-side project expected in area in the next 5 -10 years.
2. DSM programs target peak hour savings as this is what delays/avoids supply-side capital expenditures relative to distribution system reinforcements.
3. Customer group is not unique or atypical, so that learnings can be applied more broadly to other projects, but the size of the effort is scaled to minimize the cost impact on customers.
4. One or two pipelines (as opposed to several) feed all of the gas into the area in question so that minimal meters can be installed to adequately measure the impact of the DSM program on load during extreme cold weather.
5. The location for the pilot should be determined at least one year in advance (preferably two) so that high-frequency load meters can be installed on the pipelines feeding the area before the project begins to accurately measure the impact of the DSM program and have the "before" baseline to measure progress against.
6. A statistically significant number of daily frequency ERT meter reading technology devices are already installed in the area to evaluate customer level usage patterns before, during and after the Targeted DSM initiative.
7. Be able to incorporate pilot planning into Energy Trust budget.
8. Be able to incorporate pilot implementation costs into Energy Trust budgets in the year they are expected to be incurred.
9. Be able to track NW Natural costs to implement Targeted DSM pilot monitoring into rates.

8.3. Targeted DSM Pilot Action Item and Next Steps

In order to facilitate a stakeholder and Commission review before putting more resources (both at NW Natural and the Energy Trust) into Targeted DSM as an option to address distribution system weaknesses NW Natural is seeking acknowledgement of the idea of an information gathering Targeted DSM pilot to help provide insight into the many unknowns about the viability of using demand-side peak hour energy savings as capacity resources for the distribution system:

- *Demand-Side Resources and Environmental Action Item 2:* Work with Energy Trust of Oregon to further scope a geographically targeted DSM pilot via accelerated and/or enhanced offerings ("Targeted DSM" pilot) to measure and quantify the potential of demand-side resources to cost-effectively[25] avoid/delay gas distribution system reinforcement projects in a timely manner and make a Targeted DSM pilot filing with the Public Utility Commission of Oregon (OPUC) in late 2017 or early 2018.

[25] Note that the pilot is for information gaining purposes and is not required that is expected to be cheaper than the supply-side option against which it is being compared, though this standard would be applied for projects going forward.

9. KEY POINTS AND ACTION ITEMS

- Energy Trust used a new resource assessment tool for this DSM forecast to estimate the technical, achievable and cost-effective achievable potential for demand-side resources. The new model shows a bigger potential for DSM in this IRP than the prior IRP, which is largely due to an increase in avoided costs leading to new measures and the addition of emerging technology.
- NW Natural includes the following action items associated with the identified therm savings targets in its action plan:
    - Consistent with the methodology in this chapter, NW Natural will ensure Energy Trust has sufficient funding to acquire therm savings of 5.1 million therms in 2017 and 5.0 million therms in 2018 or the amount identified and approved by the Energy Trust board.
    - Consistent with the methodology in this chapter, NW Natural will ensure Energy Trust has sufficient funding to acquire therm savings of 262,000 therms in 2017 and 270,000 therms in 2018 or the amount agreed to by the EEAG and approved by the WUTC.
- Contingent on Commission acknowledgment of the idea of a geographically targeted DSM pilot via accelerated or enhanced offerings (“Targeted DSM”) to measure and quantify the potential of demand-side resources as a capacity resource to address weaknesses in the NW Natural’s distribution system, NW Natural and Energy Trust of Oregon will file a detailed pilot project for review.

Chapter 7
Distribution System Planning

1. OVERVIEW

Chapter 7 discusses NW Natural's distribution system planning, including an overview, features of the current system, computer modeling methods, and criteria for determining project prioritization. Notably, distribution system planning at NW Natural is evolving to be more forward-looking using growth- and demand-related models as presented in the Integrated Resource Plan.

The chapter also describes two new distribution system projects addressing areas of identified weakness in the distribution system, provides updates regarding the Clark County projects appearing in the 2014 IRP, and ends with Key Findings associated with distribution system planning.

The Company reviewed its distribution system planning process with stakeholders in the Feb. 10, 2016, Technical Working Group meeting.

KEY FINDINGS

Key findings in this chapter include the following:

- NW Natural has enhanced the Company's distribution system planning and adopted specific criteria by which to prioritize distribution system projects.
- The Company's distribution system planning now considers peak hour capacity requirements.
- NW Natural identified two areas requiring system reinforcement: in the Sherwood—Tualatin area of the Portland West load center, and in the Eugene load center. The Company has developed a project for addressing the requirements associated with each of these two areas.
- NW Natural has completed two Vancouver load center distribution system projects identified in the 2014 IRP.
- Complete construction of the Clark County distribution projects to address Vancouver load center needs is expected to occur over the next three years with an estimated cost of $20 million.

2. BACKGROUND AND EXISTING DISTRIBUTION SYSTEM

2.1. NW Natural's Distribution System

NW Natural's gas distribution system consists of approximately 14 thousand miles of distribution mains, of which approximately 87 percent are in Oregon with the remaining 13 percent in Washington.[1] The Company's Oregon service area includes 42 gate stations[2] and approximately 990 district regulator stations. The Washington service area includes 15 gate stations and approximately 75 district regulator stations.

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

[1] Source: 2015 FERC Form 2 Washington Supplement for year ending Dec. 31, 2015.
[2] Gate station values for both Oregon and Washington include all upstream pipeline interconnections, including farm taps.

2.2. Overview of Distribution System Planning

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

- Operates a distribution system capable of meeting peak hour demands;[3]
- Operates and maintains its distribution system in a safe and reliable manner;
- Performs timely maintenance and makes necessary reliability improvements;
- Complies with all applicable state and federal laws and regulations;
- Plans for future needs in a timely fashion; and
- Addresses distribution system needs related to localized customer or demand growth.

The goal of distribution system planning is the design of a distribution system meeting firm service customers' current natural gas needs under peak hour weather conditions, including planning for reinforcement to serve future firm service requirements. Distribution system planning identifies operational problems and areas of the distribution system requiring reinforcement due to existing conditions and/or growth indicators. NW Natural, by knowing where and under what conditions pressure problems may (or do) occur, can incorporate necessary reinforcements into annual budgets and distribution project planning, thereby avoiding costly reactive and potentially emergency solutions.

The Company's Engineering Department—collaborating with the Construction and Marketing departments and incorporating input from economic development and planning agencies—plans the expansion, reinforcement, and replacement of distribution system facilities. This planning process requires forecasting local growth in peak hour demand, determining potential distribution system constraints, analyzing alternative potential solutions, and assessing the costs of each viable alternative.

This planning is ongoing and integrates new requirements associated with customer growth into the Company's construction forecasts.

2.3. New Approach to Distribution System Planning

Development of NW Natural's 2016 IRP takes place during a period in which the Company is transitioning from its previous approach to distribution system planning to one of communicating a more forward-looking emphasis while incorporating specific IRP-related models such as growth, customer demand, and design weather projections into the system performance models. NW Natural has created a ten-year-forward system planning document to identify specific higher cost system "health" concerns and establish long-range budgetary forecasts.

However, given that a distribution system issue frequently involves a relatively small area—often very small in comparison with the load center in which it is located—and relatively small numbers of customers, there is intrinsically more uncertainty associated with estimated future load requirements for such an area than there is at the load center level. The impact of acquiring or losing a single large customer or residential subdivision in a relatively smaller area of focus becomes relatively greater, requiring a certain element of fluidity in the project timing projections and, in some cases, even identifying new projects not previously listed.

[3] See also the discussion in chapter 2 regarding NW Natural's load center peak hour weather standard.

This new approach specifies that, for issues to be addressed within one to three years, NW Natural's distribution system engineers develop a project planning process that includes documentation of system modeling and modeling results, an initial route selection, an associated high-level cost estimate, and an analysis of alternatives including the possibility of customer-specific geographically focused interruptibility agreements.[4]

Projects in this category typically do not include as feasible alternatives demand-side measures such as geographically targeted and enhanced/accelerated DSM energy-efficiency programs.[5] There is typically insufficient lead time in this context in which to develop accelerated DSM programs. NW Natural anticipates considering potential demand-side resources for projects having timing requirements beyond three years.

Projects associated with issues to be addressed in the 4- to 7-year timeframe include a project description, preliminary modeling documentation, a preliminary schedule, and a high-level cost estimate.

Projects in the 8- to 10-year timeframe include preliminary modeling documentation and a high level cost estimate. Project planning associated with issues having this timeframe for resolution is at the conceptual level only.

3. DISTRIBUTION SYSTEM PLANNING METHODOLOGY

3.1. Overview of Methodology

Two primary factors determine required incremental infrastructure investment: load growth and reliability issues. Other factors NW Natural considers include pipeline safety regulations, which may drive the need to replace facilities based on the location and condition of existing pipelines, and relocations of pipelines in order to accommodate public works projects.

The planning process requires determining potential distribution system constraints and identifying reliability issues, analyzing potential solutions, and assessing the costs associated with each alternative solution.

Assumptions regarding customer load growth draw from IRP load forecasts[6] 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

[4] These agreements are similar to Recall Agreements on the supply-side in that they would likely involve larger industrial customers. However, as alternatives for distribution system issues these agreements are individually negotiated with firm sales customers within a defined geographical area who are willing to have interruptible service.

[5] See the related discussion on distribution system planning and demand-side management in chapter 6.

[6] See chapter 2 for a discussion of load forecasts.

planning and strategic outlook that assists in identifying the best alternatives for addressing system needs.

3.2. Computer Modeling

NW Natural uses Synergi software,[7] which is in wide use throughout the industry, to model the Company's network of mains (pipes) and services. A Synergi model helps predict capacity constraints and associated system performance in alternative scenarios differing in assumed weather conditions and future loads resulting from alternative assumptions regarding load growth. Synergi allows graphical analysis and interpretation by system planners.

A Synergi model contains detailed information on NW Natural's system, such as pipe size, length, pipe roughness, and configuration; customer loads;[8] source gas pressures and flow rates; 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, valve status, and key regulator pressure settings.

A Synergi model uses mathematical flow equations and an iterative calculation method to evaluate whether the modeled system is balanced. A Synergi model shows flows and pressures at every point in the modeled system and, when balanced, the relationship between flows and whether pressures at all points in the modeled system are within tolerances specified by NW Natural's Engineering staff.
A properly designed Synergi model has pressure and flow results closely corresponding with those of the observed actual physical system. As with models used in other contexts, Synergi models rely on assumptions about the actual system, and therefore modeling results may vary from actual results; i.e., Synergi models are a representation of the actual system.

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

A validated Synergi™ 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 hour customer demands while maintaining system stability. NW Natural uses the Synergi™ model to project gas requirements at discrete delivery nodes based on observed flow rates during recent cold weather episodes. Flow rates are then calibrated to match design peak weather conditions and to reflect the effects of customer growth.

Synergi simulation capability allows the Company to efficiently evaluate distribution system performance in terms of stability, reliability, and safety under conditions ranging from peak hour delivery requirements to both planned and unplanned temporary service interruptions. Synergi

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7 Synergi software, a product of DNV GL, is the current name for the software identified as SynerGEE® in some previous IRPs.

8 Future customer loads may be informed by the load forecast.

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 additional compression capacity 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 supply-side alternatives 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, improvements to system utilization, the nature of any embedded real optionality, and the ability to meet future gas delivery requirements. The "best" proposed solution is the least cost, safest, and most reliable solution for ratepayers.[9] As any one alternative solution may not be the "best" with respect to each criterion, determining the optimal solution[10] from the available alternatives may include qualitative assessment of the relevant characteristics of each alternative solution.

Once the cost and operating parameters for the preferred supply-side solution are established, NW Natural assesses whether certain demand-side alternatives are potentially viable solutions. Such alternatives can include customer-specific geographically focused defined interruptibility agreements , where NW Natural and one or more large customers in the area of influence agree the customer will curtail gas use upon NW Natural's request, and deployment of geographically targeted and enhanced/accelerated DSM energy-efficiency programs. If the Company assesses one or more of these alternatives as potentially viable, NW Natural performs additional investigation and analysis, and compares such an alternative with the preferred supply-side alternative.

Depending on the requirements for a specific project, Synergi 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 Synergi. NW Natural validates Excel spreadsheet models using the same process used for a Synergi model, so modeling using either method provides similar results.

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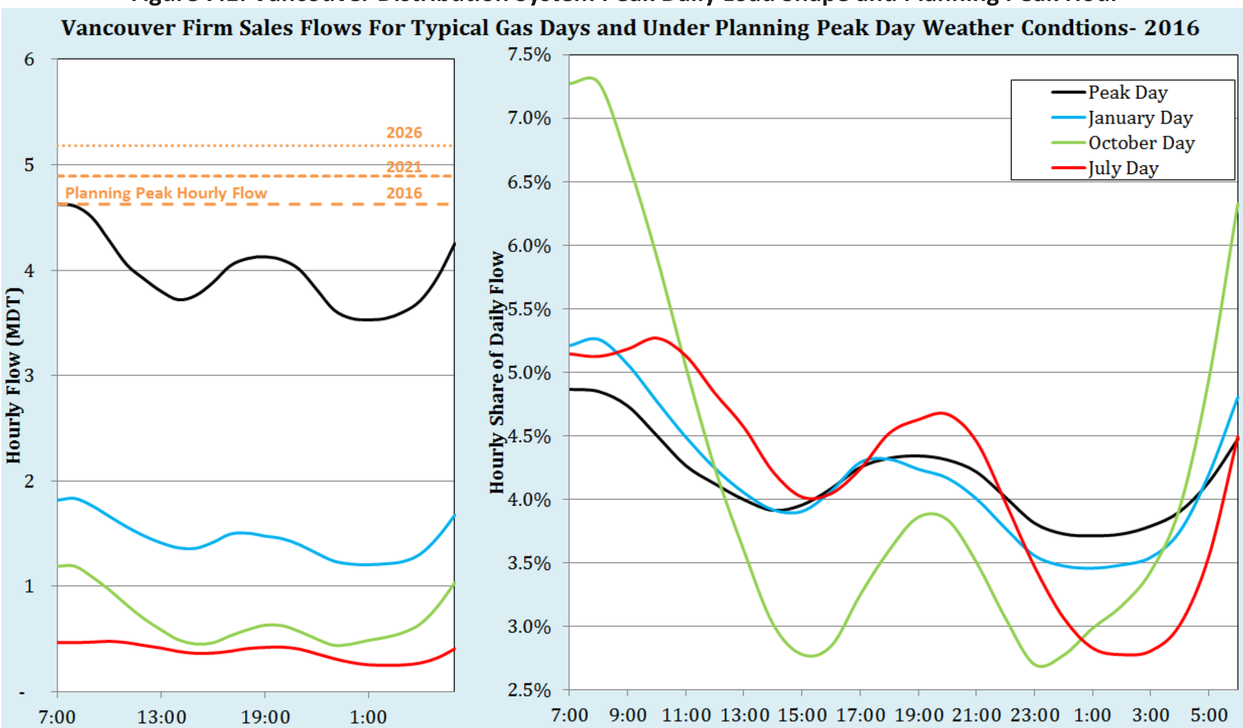
9 NW Natural intends that a solution that is the least cost, safest, and most reliable of alternative solutions is understood to be a solution consistent with the Public Utility Commission of Oregon's goal that "…utility resource plans should identify resources that provide the best mix of cost and risk," as stated on page 1 of Order No. 07-002 in Docket No. UM 1056 and elaborated on in other sections of this Order, including in footnote 3, on pages 5 through 8, and in Guideline 1c on pages 1 and 2 of appendix A (including footnote 1 "…[w]e sometimes refer to this portfolio as the "best cost/risk portfolio." ").

10 NW Natural intends that an "optimal solution" is understood in this context to be a solution that provides the "best mix of cost and risk" in conforming to the Public Utility Commission of Oregon's IRP Guideline 1c. By "optimal," NW Natural means "best and most effective," with this definition appearing in the online Merriam-Webster at http://www.merriam-webster.com/dictionary/optimal (accessed June 4, 2016).

3.3. 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.[11]

Figure 7.1: Vancouver Distribution System Peak Daily Load Shape and Planning Peak Hour



Actual system demand for various times and weather conditions are typically captured from real time[12] 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.

3.4. Criteria for Project Prioritization and Modeling Scenarios

Synergi 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, an additional supply source, etc. The Company enters such changes and then rebalances the model. A typical output is a color-coded map showing system pressure levels, examples of which are shown in figures 7.2 and 7.3 (following). NW Natural can quickly consider a variety of potential solutions for low-pressure areas and

[11] See the discussion of peak hour load forecasting in chapter 2.
[12] SCADA data is transmitted and captured every two minutes.

determine the short- and long-term effectiveness of each. Once identified, the Company can evaluate each potential solution's cost[13] as part of the process for determining the best alternative.

As a general matter, the practical industry standard and NW Natural's standard for computing design capacity of a new pipeline is based on a maximum 20 percent pressure drop. This basis of a maximum design limitation of a 20 percent pressure drop for new pipe design allows for a measured level of growth to occur on this new system generally eliminating the need for near-term system reinforcements. The incremental costs, such as installing a 4-inch pipe instead of a 2-inch pipe to maintain the 20 percent criteria, are *de minimis* when compared to a subsequent reinforcement pipeline project.

Transmission and High-Pressure Distribution Systems

A Synergi modeling result, with design parameters set to peak hour load requirements, of a 30 percent pressure drop on a facility indicates need to initiate an investigation. A result of a 40 percent pressure drop (a 40 percent pressure drop in a high-pressure system equates to 80 percent of the overall pipeline capacity) indicates reinforcement, or an alternative solution, is critical. For high-pressure (HP) pipelines feeding other HP systems, consideration is given to the minimum inlet pressure requirements for proper regulator function to serve the systems being supplied off this high-pressure system in addition to total pressure drop. Additionally, consideration is given for reinforcement on facilities where near-term growth is anticipated or identified by leading indicators. Examples of such leading indicators include the planned construction of a new road, a new subdivision, or a planned industrial development. Additional criteria are to meet a firm service customer's pressure requirements and the identification in IRP analysis of incremental supply requirements. NW Natural reviewed these and other system reinforcement criteria with stakeholders in the Feb. 10, 2016 Technical Working Group meeting.

Distribution Systems

A Synergi modeling result, with design parameters set to peak hour load requirements, of minimum distribution pressures of 15 psig[14] on a facility signals a need to investigate. A result of minimum pressures of 10 psig or lower indicates reinforcement, or an alternative solution, is critical. The 10 psig minimum criterion is directly tied to the design parameters required for the safety systems put in place through federal regulations—specifically the installation of Excess Flow Valves (EFVs) —for Residential and small Commercial customers. Criteria in this context include the same reinforcement for near-term growth, where near-term growth is indicated by leading indicators, and meeting firm service customer requirements as in the previous context.

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13 Synergi does not incorporate cost considerations. The process of determining a potential solution's cost-effectiveness appropriately incorporates analysis reflecting the Public Utility Commission of Oregon's IRP Guideline 1c; i.e., "[t]he planning horizon for analyzing resource choices should be at least 20 years *and account for end effects*. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource." Emphasis added; see Order No. 07-002 in Docket No. UM 1056, appendix A page 2 of 7.

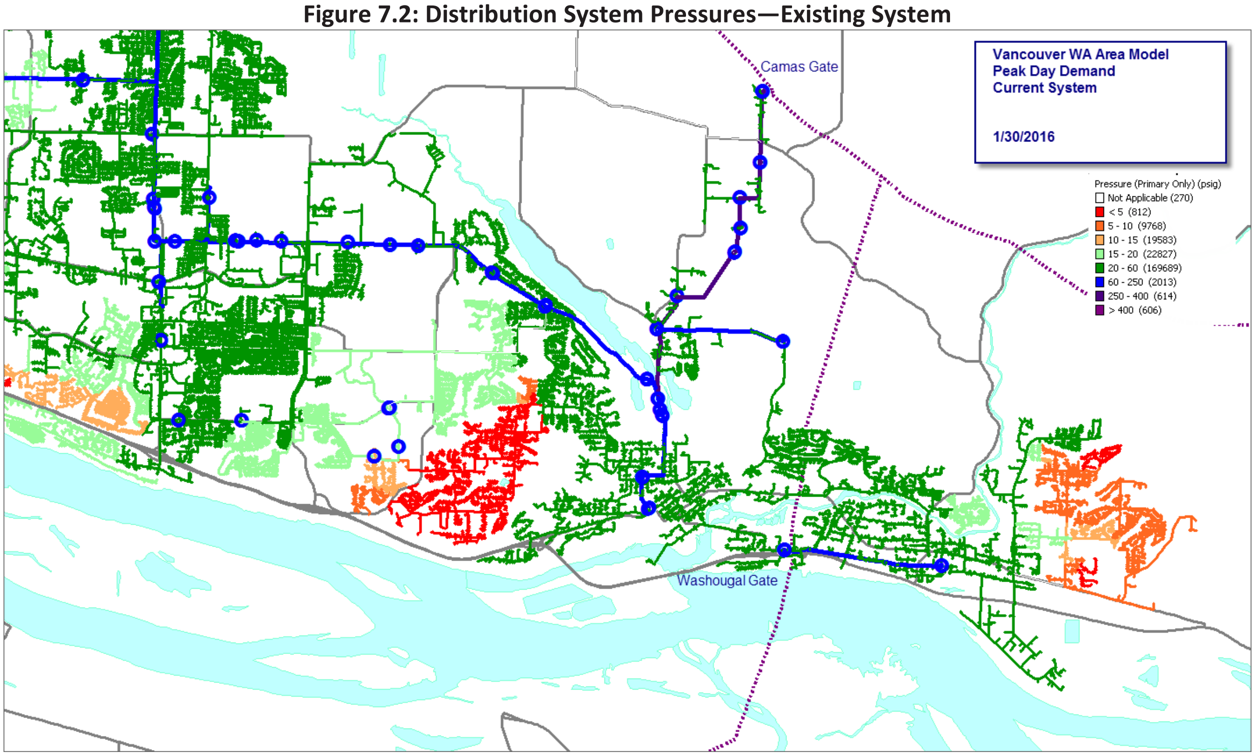
14 The abbreviation "psig," for "pounds per square inch gauge," is a measure of pressure, where the "g" ("gauge") indicates the pressure is relative to ambient atmospheric pressure.

Modeling Scenarios

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.

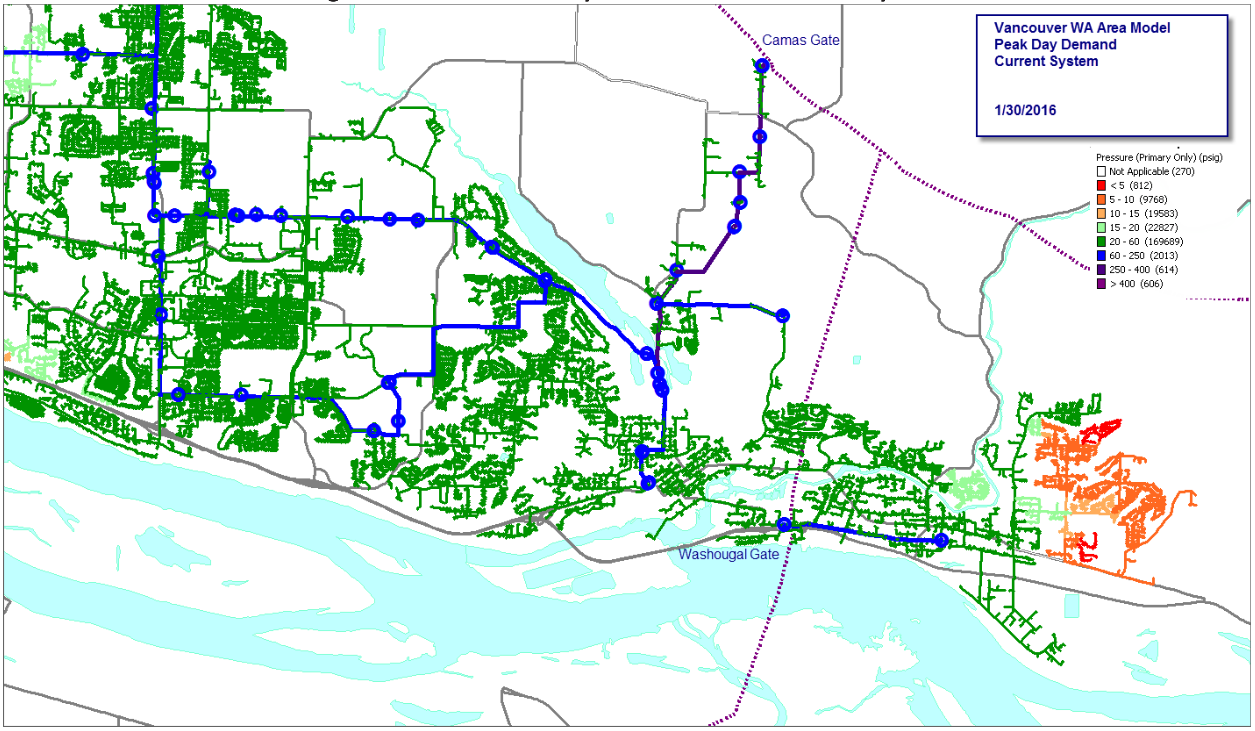
An example of the use of Synergi modeling to identify an issue where taking action is critical is shown in figure 7.2. This figure shows an area of the Vancouver load center with a critical need for reinforcement, as the indicated pressure under design conditions is less than 10 psig.[15] Figure 7.3 shows the modeled result of adding specific infrastructure, allowing incremental gas to flow through the distribution system.

Figure 7.2: Distribution System Pressures—Existing System



[15] Note that pressure in the identified area in the center of the figure is not only less than 10 psig; it is less than 5 psig.

Figure 7.3: Distribution System Pressures—Future System



3.5. Planning Results

NW Natural develops both short- and long-term infrastructure plans based on load growth projections, system integrity issues,[16] and other system-impacting issues. These plans consist of proposed projects the Company includes in its capital budgeting process. NW Natural reviews these plans at least 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 actual conditions that differ from those forecast. The Company integrates annual plans into the Company's budgeting process, which also includes planning for other types of distribution capital expenditures and infrastructure upgrades.

[16] System integrity issues include those associated with the stability, reliability, and safety of NW Natural's system.

4. SIGNIFICANT POTENTIAL HIGH-PRESSURE TRANSMISSION AND DISTRIBUTION SYSTEM PLANNING PROJECTS

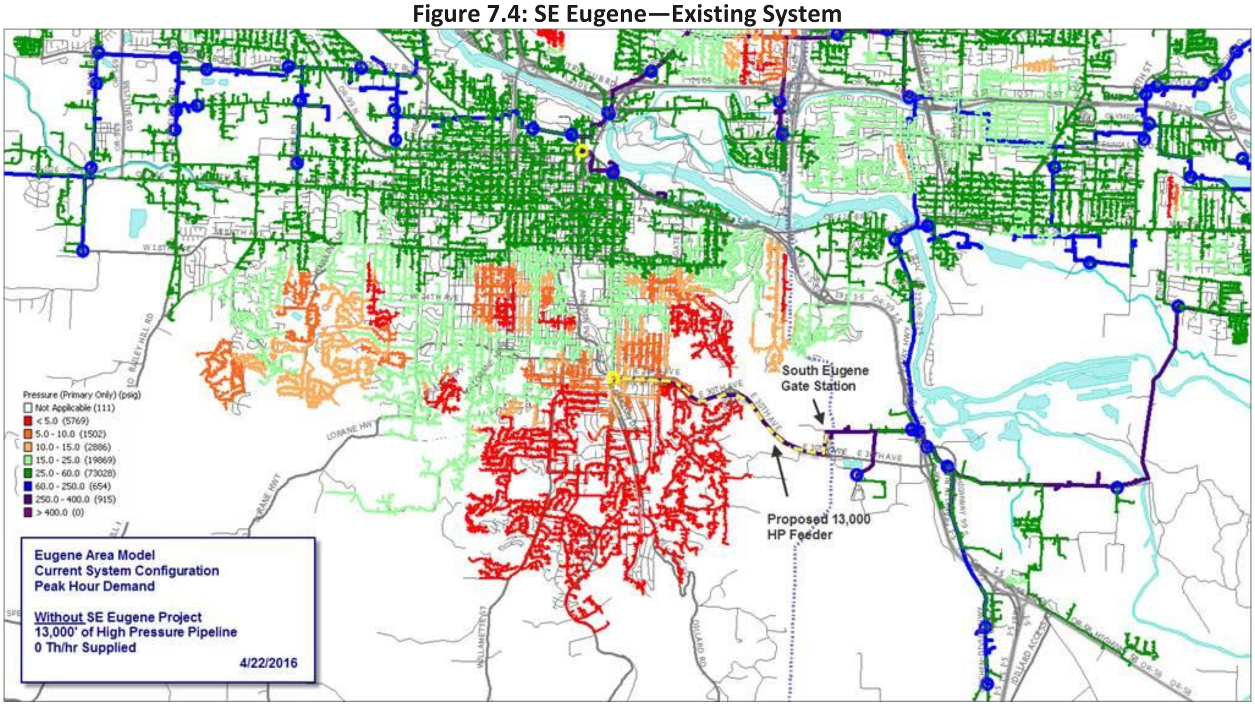
NW Natural discusses two specific distribution system projects below. Both projects are sited in Oregon.[17] The Company reviewed each of these projects with stakeholders in the Feb. 10, 2016 Technical Working Group meeting and provided updates in the June 22, 2016 Technical Working Group meeting.

4.1. Southeast Eugene

The southeast Eugene area has been plagued by low distribution pressures in cold weather for many years. The nearest feeders are many miles away through developed city infrastructure. During this time, NW Natural has been able to address low pressures in small isolated segments by installing main connections that tie the existing mains more closely together, but these opportunities are now fully captured. NW Natural's analysis of this area within the Company's distribution system identified existing weaknesses. Areas colored red in figure 7.4 indicate pressure on the design peak hour is less than five psig.

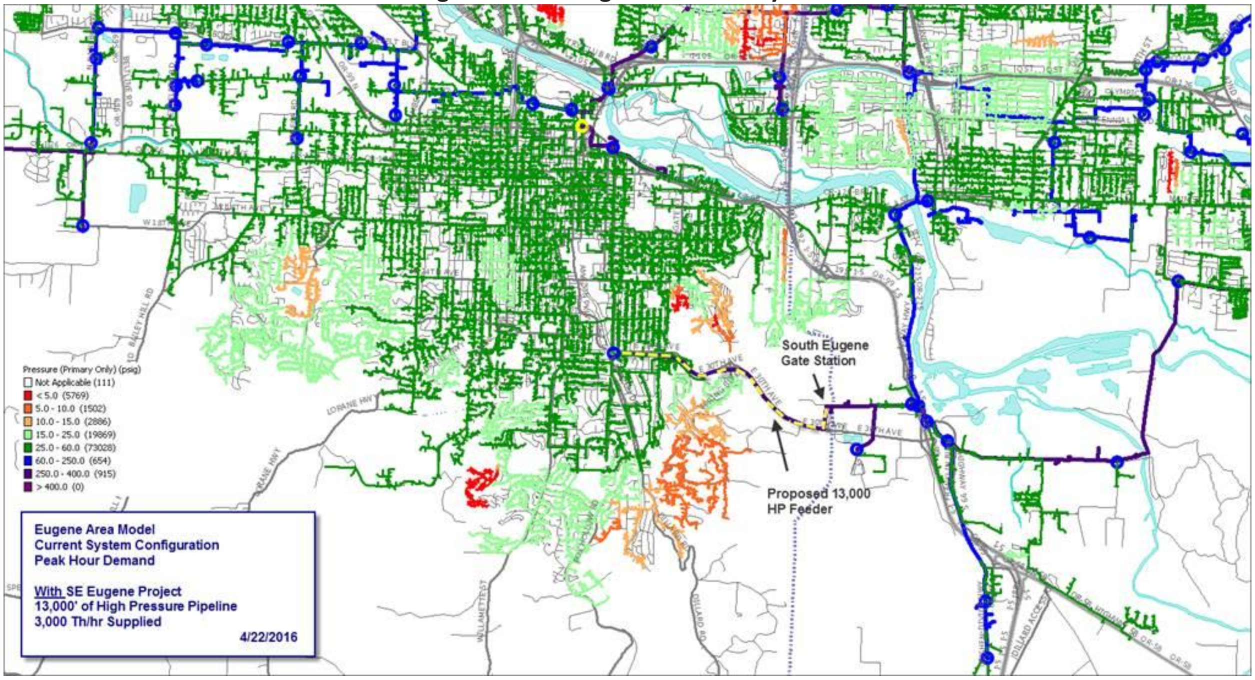
Figure 7.5 shows the same area, again on a peak hour, after construction of approximately 2.5 miles of an 8-inch high-pressure pipeline connecting an existing HP facility with the distribution system in the area projected to experience low pressure on a peak hour.

Figure 7.4: SE Eugene—Existing System



[17] A discussion of Clark County distribution system projects appears later in this chapter.

Figure 7.5: SE Eugene—Future System



As the issue with the distribution system in SE Eugene is an existing condition, construction is planned for 2018. The cost of this project is estimated at $4 million to $6 million, with an associated $10 million point estimate of present value of revenue requirements (PVRR). NW Natural analyzed the placement of a satellite LNG facility in 2019 as an alternative which would defer pipeline construction. As the estimated cost was $23.3 million, with a resulting PVRR of $44.9 million, this potential solution is more costly than the new pipeline facility.

NW Natural considered two additional nonpipeline alternatives to the proposed high-pressure pipeline facility. The first of these is the use of customer-specific geographically focused defined interruptibility agreements within the SE Eugene area of influence. After considering the number of larger non-Residential firm service customers and their usage, versus the load reduction necessary to defer construction of new infrastructure, NW Natural concluded customer-specific geographically focused defined interruptibility agreements are not a feasible solution. The second of these alternatives is accelerated demand-side management (DSM) program deployment—also within the SE Eugene area of influence. Accelerated DSM is not a viable alternative, as even an accelerated deployment could not be implemented in sufficient time to achieve demand-side load reductions which mitigate the risk associated with the existing issue in peak day conditions.

4.2. Sherwood / 124th Avenue Extension

The Tualatin–Sherwood area has experienced rapid growth in recent decades and existing piping infrastructure on a 125 MAOP HP feeder in this area is currently at capacity, as evidenced by a greater than 50 percent pressure drop over the existing facility. This is shown in figure 7.6, where pressure drops from 115 psig to 55 psig, exceeding the 40 percent pressure drop criterion discussed above.

A Washington County project to complete a new street by 2018 in this area will create a major thoroughfare and open up areas for industrial and commercial development. While the reason for the project is to address the existing pressure drop from loads of existing firm service customers, the near-term road construction provides NW Natural an opportunity to not only solve the existing problem at a lower cost than would otherwise be the case, but also to facilitate providing service to future customers locating in areas to be developed following road construction.

NW Natural analyzed two alternative facilities that address the existing issue: constructing approximately 2.5 miles of a 6-inch high-pressure facility in 2017, with timing driven by the timing requirements of the road construction, and constructing a facility somewhat later (2018) with a path generally aligned with the existing Tualatin–Sherwood Road. As a result of greenfield construction advantages, the facility associated with construction of the new road is the least-cost supply-side alternative, with a range in estimated cost of $2.5 million to $3.1 million[18] and an associated PVRR point estimate of $5.9 million. This compares with a $6.4 million point estimate of cost and an associated PVRR point estimate of $13.4 million to construct a HP facility along the Tualatin–Sherwood Road. Additionally, the greenfield nature of the preferred solution provides less cost risk than the alternative. Figure 7.7 shows the least-cost alternative.

NW Natural also analyzed the potential use of a satellite LNG facility to defer pipeline construction. NW Natural estimates the cost of such a facility at $23.3 million with an associated PVRR of $44.9 million. The assumed timing of construction for this alternative is 2019.

Accelerated DSM deployment is not a feasible alternative, as the pressure drop is an existing issue. After evaluating the use of customer-specific geographically focused defined interruptibility agreements within the area of influence to delay system reinforcement, NW Natural concluded this is not a feasible alternative, as the estimated peak load of larger firm service customers in the area of influence is less than the amount of reduction required to resolve the issue.

As road construction is under way in mid-2016, NW Natural will likely implement the least-cost alternative and make a final investment decision prior to the beginning of the 2016–2017 heating season,[19] with this timing driven by the timing requirements associated with the road construction.

[18] Values associated with the preferred solution result in part from estimates NW Natural received from contractors associated with the road construction in mid-2016.
[19] NW Natural, as a result of this timing, does not include an action item associated with this project in the 2016 IRP.

Figure 7.6: Sherwood/124th Avenue Extension—Existing System

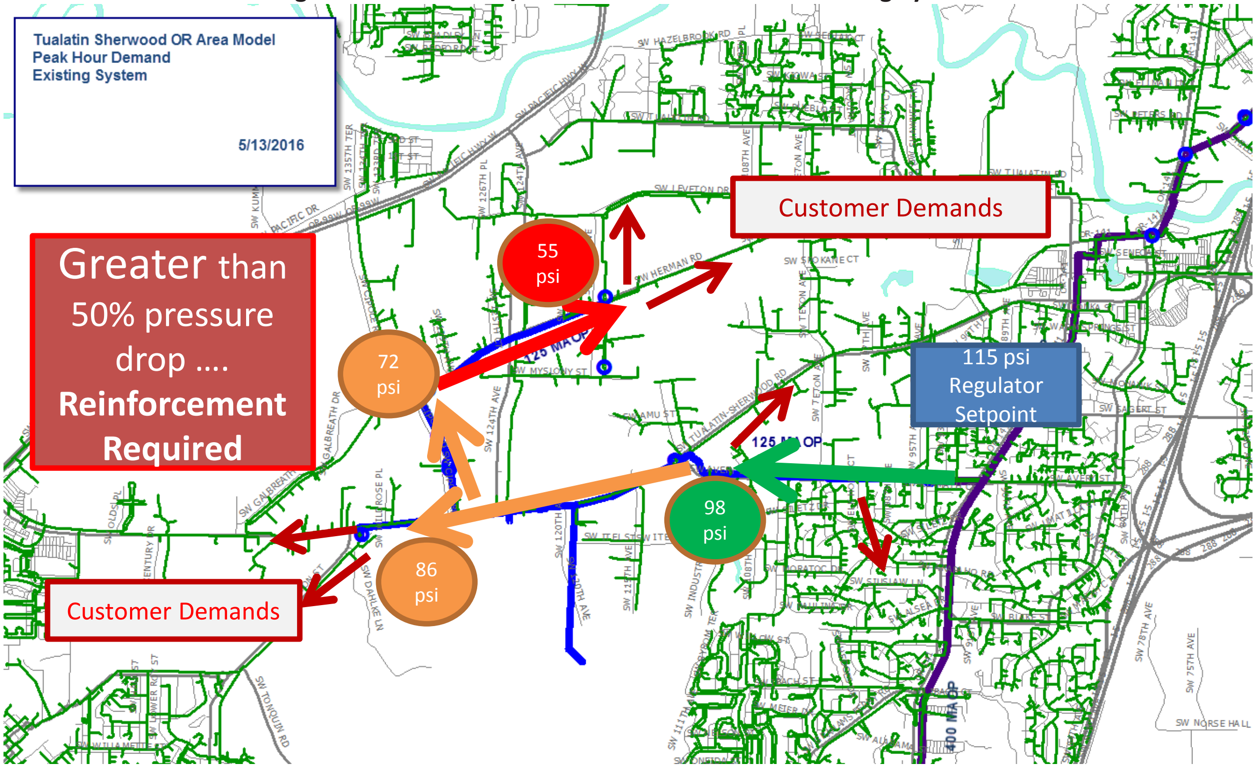
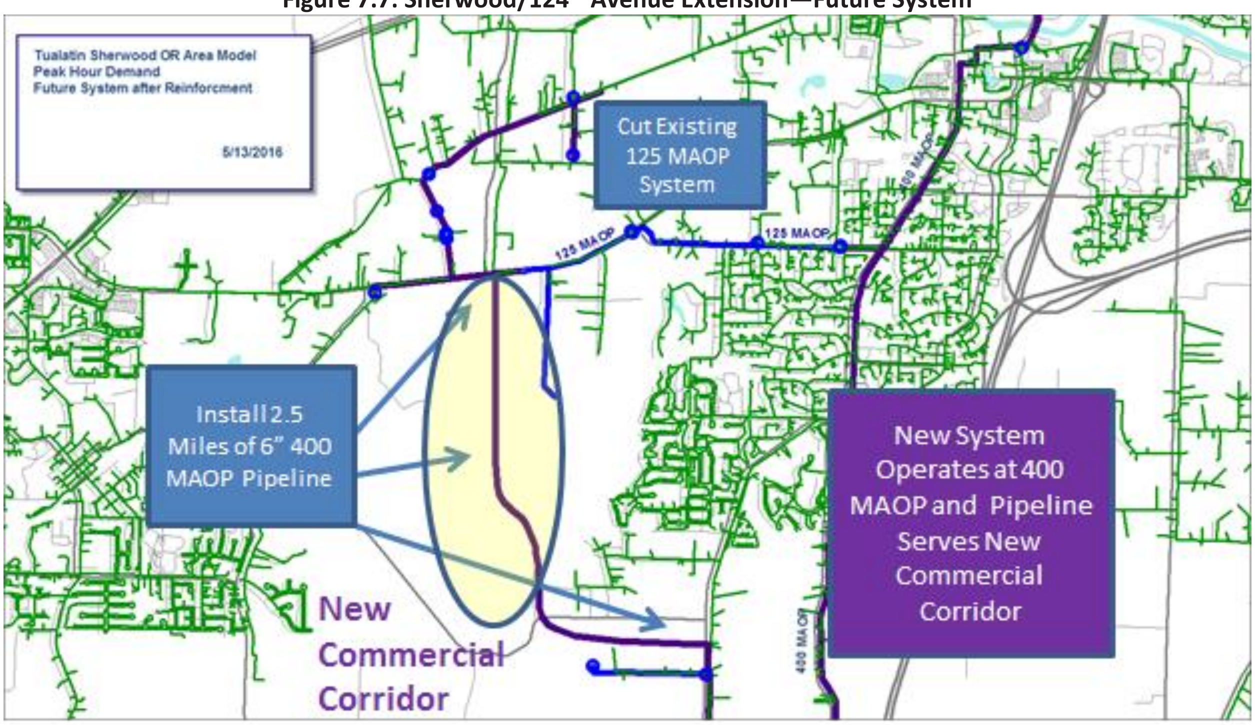


Figure 7.7: Sherwood/124th Avenue Extension—Future System



5. OTHER DISTRIBUTION SYSTEM PROJECTS: CLARK COUNTY, WASHINGTON

A principal conclusion in NW Natural's 2014 IRP was the need to invest in the Company's Clark County infrastructure.[20] Action Item 2.1.b. of the 2014 IRP, repeated below, reflected this need:

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

The 2014 IRP included as a Key Finding, in discussing distribution system planning in chapter 6, that NW Natural had identified five projects to complete within the next five years to address resource needs in the Vancouver load center.[21] A list of these five projects, including each project's name, location, a brief description, an estimated cost and year of anticipated construction, appeared on page 6A.1 in appendix 6 of the 2014 IRP.

There are several aspects of the Vancouver distribution system projects to update in the 2016 IRP. An update for each project, as the project was identified in the 2014 IRP,[22] appears below. NW Natural reviewed the six Clark County distribution system projects[23] with stakeholders in its Feb. 10, 2016 Technical Working Group meeting.

119th Street: The 2014 IRP described this project as installing approximately 1.5 miles of 8-inch high-pressure main in 2014 at an estimated cost of $5.4 million. NW Natural completed this project in late 2014.

Camas Reinforcement: The 2014 IRP described this project as installing approximately 2.4 miles of 12-inch high-pressure main with anticipated completion in 2015 at an estimated cost of $4.6 million. NW Natural deferred this project to 2016 due to design considerations and permitting requirements. The revised estimated cost is about $5.1 million.

Washougal Extension: The 2014 IRP described this project as installing approximately 1.2 miles of 6-inch high-pressure main for feeding the Washougal core area, with anticipated completion in 2015 at an estimated cost of $4.5 million. NW Natural now projects completion in 2018 at an estimated cost of $4.5 million. The Company deferred this project approximately three years as a result of additional analysis indicating that projects such as the Vancouver Core Replacement Phase 1 project have higher priority.

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[20] See page 1.2 of the 2014 IRP.
[21] See page 6.9 of the 2014 IRP. The Vancouver load center is located in Clark County, Washington.
[22] See; e.g., page 6A.1 of appendix 6 in the 2014 IRP.
[23] Six projects result from considering the two phases of the Vancouver Core Replacement project as discrete projects. See slides 74–86 of the presentation.

119th Street to Salmon Creek: The 2014 IRP described this project as installing approximately 2.4 miles of 8-inch high-pressure main connecting the Salmon Creek gate station to the now completed 119th project referenced above. The 2014 IRP anticipated completion in 2017 at an estimated cost of $6.1 million. Completion of this project is still planned for 2017 at an estimated cost of $6.1 million.

Vancouver Core Replacement: The 2014 IRP described the Vancouver Core Replacement project as installing approximately 1.8 miles of 12-inch high-pressure main, with completion anticipated in 2017 at an estimated cost of $4.3 million. Subsequent detailed investigation identified two somewhat independent distribution system issues in the Vancouver core area which require individual solutions. The Phase 1 project involves installing approximately 3,700 feet of 8-inch high-pressure main in 2016 at an estimated cost of $2.4 million. NW Natural completed the Phase 1 project in June of 2016 at a cost of approximately $1.3 million.

The Vancouver Core Phase 2 project will address the existing issues directly east of the Phase 1 project's location, with completion anticipated in 2019. As NW Natural has not developed alternative solutions for addressing the identified issues, estimated costs are yet to be determined. NW Natural deferred the Phase 2 project by two years to 2019 based on other projects having higher priority.

In addition to the distribution system pipeline projects above, several gate stations in the Vancouver load center need upgrading. These are the North Vancouver, Camas, Salmon Creek, and West Vancouver gates. These projects involve capacity increases and equipment upgrades—including meters, regulators, odorizers, and line heaters.

6. KEY FINDINGS

- NW Natural has enhanced the Company's distribution system planning and adopted specific criteria by which to prioritize distribution system projects.
- The Company's distribution system planning now considers peak hour capacity requirements.[24]
- NW Natural identified two areas requiring system reinforcement: in the Sherwood – Tualatin area of the Portland West load center, and in the Eugene load center. The Company has developed a project for addressing the requirements associated with each of these two areas.
- Proceed with the SE Eugene Reinforcement project to be in service for the 2018/2019 heating season and at a preliminary estimated cost of $4 million to $6 million.
- NW Natural has completed two Vancouver load center distribution system projects identified in the 2014 IRP. The estimated timeframe for completing some of the remaining projects has changed as a result of updated consideration of priorities.
- Complete construction of the Clark County distribution projects to address Vancouver load center needs, with the estimated timing of these projects is over the next three years with an estimated cost of $21 million.

[24] See the related discussion in chapter 2.

Chapter 8
Linear Programming and the Company's Resource Choices

1. 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.

KEY FINDINGS

Key findings in this chapter include the following:

- Mist Recall is the primary resource addition to meet growing peak loads. The next Mist Recall is projected to be for 30,000 Dth/day for the 2019-2020 gas year.
- The Christensen Compressor project is needed to serve growing peak loads in the Salem and Albany load centers. With Base Case load growth this project will be needed in 2022.
- Additional pipeline capacity is necessary to fulfill winter energy demand without compromising the maximum deliverability of underground storage resources.

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 ABB for its gas supply planning and optimization software product SENDOUT®.[2] 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 capacity constraints. The resource mix optimization module selects the least-cost 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.

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[1] Hillier, Fredrick S. and Lieberman, Gerald L, Introduction To Operations Research 6th Edition, McGraw-Hill, Inc., 1995, 25.

[2] ABB (**ASEA Brown Boveri**) is a Swedish-Swiss multinational corporation headquartered in Zürich, Switzerland, operating mainly in robotics and the power and automation technology areas. It does business as the ABB Group.

1.1. Resource Planning Model Integration

Five primary components are integrated within the SENDOUT® resource planning model.

1. Load forecast and demand-side management (Chapters 2 and 6)
2. Design weather pattern (Chapter 2)
3. Natural gas price forecast (Chapter 2)
4. Current supply-side resources (Chapter 3)
5. Potential future resources (Chapters 3 and 7)

1. Load Forecast and Demand-side Management

The Company incorporates the demand usage factors and estimated peak day firm sales load (net of DSM) 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. Additionally, a high-cost penalty is attached to unserved firm demand such that the resource model attempts to serve all firm demand using the resource options available to it. For interruptible loads, the penalty is set sufficiently low that the model does not serve this category during cold weather periods, but high enough that the model chooses to serve it otherwise.

2. Design Weather Pattern

The Company has developed a statistically based design weather pattern which is colder than 90 percent of the winters that the service area has experienced in 30 years. In addition, the annual weather pattern was augmented with the very cold seven-day peak event from February 1989.

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 storage resources to take advantage of seasonal variability. Substantial differences between summer and winter prices could, therefore, influence the decision between a pipeline resource and a storage resource. Long-term price differentials between supply basins may drive pipeline resource decisions to steer toward the lower priced basins. The Company used the various price forecasts described in chapter 2 as inputs to the optimization model. Gas price also has a strong influence on the expected overall cost to meet customer load across the planning horizon, since gas commodity costs are typically the largest cost component of any LDC IRP.

4. Current Supply-Side Resources

NW Natural discusses existing supply-side resources in Chapter 3. Existing resources include interstate pipeline capacity (Northwest Pipeline), on-system storage (Mist, Newport LNG, Portland LNG), off-system storage (Jackson Prairie), and a number of industrial recall agreements.

5. Future Supply-Side Resources

The gas requirements for each load center (net of DSM) are met by current a future supply-side resources. The Company's future supply-side resources are incorporated into the SENDOUT® resource planning model as options to be selected based on cost and risk. These resources fall into three basic categories:

a. Interstate pipeline
b. High-pressure transmission
c. Storage

Table 8.1 lists a number of the future resources that are available in the resource planning model. For additional and further descriptions of these resources, refer to chapters 3 and 7 and appendix 8. Interstate pipelines are modeled at either their current tariff rate or an estimated rate for new projects. High-pressure transmission projects are modeled at their estimated annual revenue requirements. "End effects" also are considered, that is, the analysis actually was performed over a period longer than the 20-year IRP planning horizon to ensure that resource choices made in the later years were not affected simply because cost streams were cut off after year 20.

Table 8.1: Future Resource and Portfolio Options

	Resource	Description	Abbrev
Beyond NWN Control	Trail West Pathway	Pipeline service from Malin (and/or Stanfield) on GTN and Trail West delivering up Grants Pass Lateral (or directly onto NWN system at Molalla)	TW
	Sumas Expansion Regional[3]	Pipeline service from Sumas to NWN territory sized and timed for regional demands	SE(R)
	Pacific Connector Pathway	Pipeline service from Malin on GTN and Pacific Connector delivering up the Grants Pass Lateral	PC
Choice of NWN[4]	Mist Recall	Recall capacity contracted to third parties in the interstate/intrastate storage market to be used for service to the Company's utility customers as contracts expire	MR
	North Mist IIa and IIb	Development of new reservoirs, compression station and pipeline facilities located to the north of the existing Mist storage facilities complex. North Mist IIa would be the first expansion followed by IIb.	NM
	Sumas Expansion Local	A local Sumas expansion that is similar to a regional expansion, but is initiated at the request of NW Natural and sized specifically for the Company's needs	SE(L)
	Christensen Compressor	A compressor located between Newport and Salem to increase the takeaway capacity of Newport LNG	CCP
	All others	All others (see chapter 3)	OTHER

[3] NWP now refers to this project as Sumas Express.
[4] Note that NW Natural controls the timing of the in-service date of the resources options under its control, but the in-service times for the projects out of the control of the Company must be assumed (see table 8.1).

The resource options available differ significantly in their cost, size, and delivery pattern. Additionally, a pipeline resource is tied to a specific geographic gas supply location while storage resources may get their supply from the least-cost supply hub which is available to NW Natural. Table 8.2 shows the characteristics of each of the major resources considered in this IRP.

Table 8.2: Future Resource Comparison

Resource	Cost (¢/Dth/Day)	Size (Dth/day)	Type	Supply Location
Mist Recall	5.5	Up to 215,000	Energy/Peak	Variable
Christenson Compressor	21.8	40,000	Peak	Variable
Pacific Connector Pathway	43.6 (from Malin)	Up to 52,000	Energy	Malin
North Mist IIa (Phase 1) North Mist IIb (Phase 2)	50.3 44.6	50,000 50,000	Energy/Peak Energy/Peak	Variable Variable
Sumas Expansion (Regional)	53.0	Variable	Energy	Sumas
Trail West Pathway	55.2 (from Malin)	Variable	Energy	Malin/AECO
LNG Facility	57.5	120,000	Peak	Variable
Sumas Expansion (Local)	88.0	Variable	Energy	Sumas

1.2. System Modeling

SENDOUT® uses a network diagram that represents the pipelines both inside and outside NW Natural's system which deliver gas to the Company's customers (appendix 8A.1). Included in this model are all relevant pipeline capacities, fixed and variable costs, and seasonal or other time-sensitive capacity constraints. Ideally this model will sufficiently reflect the real operating parameters of the Company's system. As part of the IRP process this model is constantly refined to better reflect reality.

The system model in this IRP has been improved in several ways from those used in prior IRPs. As discussed in chapter 3 the delivery capacity from Northwest Pipeline (NWP) to gate stations has been updated to reflect an allocation of MDDOs to a series of gate stations instead of individual gates. Additionally and as discussed later in this chapter, in this IRP the Salem load center has also been disaggregated into four separate load centers to more accurately reflect how the system operates. The model also incorporates the physical capacity limitations of NWP's gate stations as well as the Company's pipeline capacity extending from gate stations into the load centers. This level of granularity allows NW Natural to find weak points within the supply and delivery systems.

2. RESOURCE PLANNING MODEL RESULTS

The process of running SENDOUT® includes three basic steps. First, a set of model inputs is entered into the application. These include the previously discussed load parameters, weather patterns, price forecast, demand-side management factors, and current resources. Next, the set of future resource options with individual decision factors (timing, capacity, cost, etc.) are configured within the model. The application is then run and the output collected. To ensure resource adequacy to meet peak loads, the scenarios are first run under the traditional planning standard (i.e., design weather and 100 percent resource availability) for each planning year. The output results include the timeframe and size of the resource decisions, served and unserved load. After a portfolio of resources has been selected another run is completed with the selected resources under normal weather conditions and the supply, transport, storage and DSM costs and collected. Total costs are tabulated and the net present value of revenue requirements (NPVRR) is calculated.

2.1. Planning Scenarios and Sensitivities

The Company's existing resource base is unable to meet expected peak day demand over the planning horizon (figure 8.1). Under Base Case customer load growth conditions the resource deficit reaches 269 MDT/day by the end of the planning horizon (figure 8.2).

Figure 8.1: Design Day Peak Demand with Existing Resource Portfolio

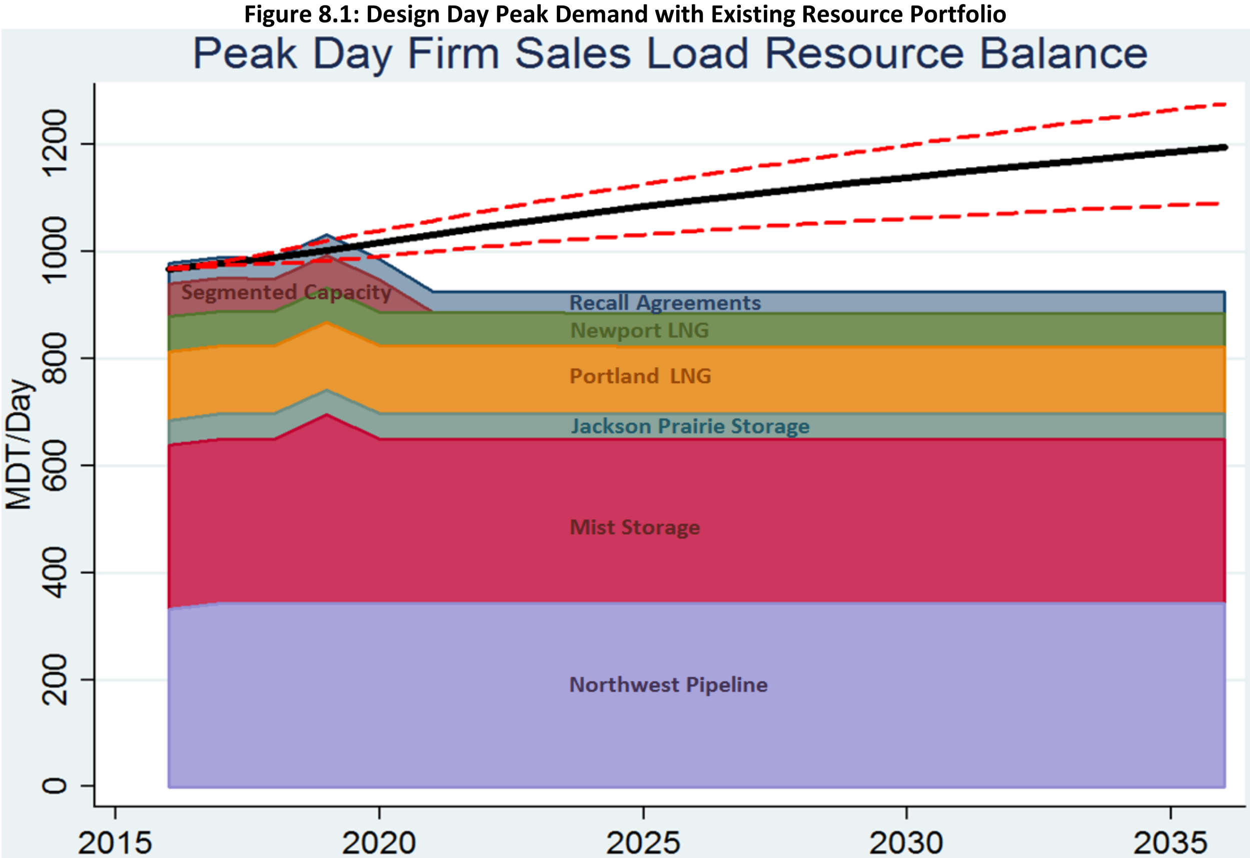
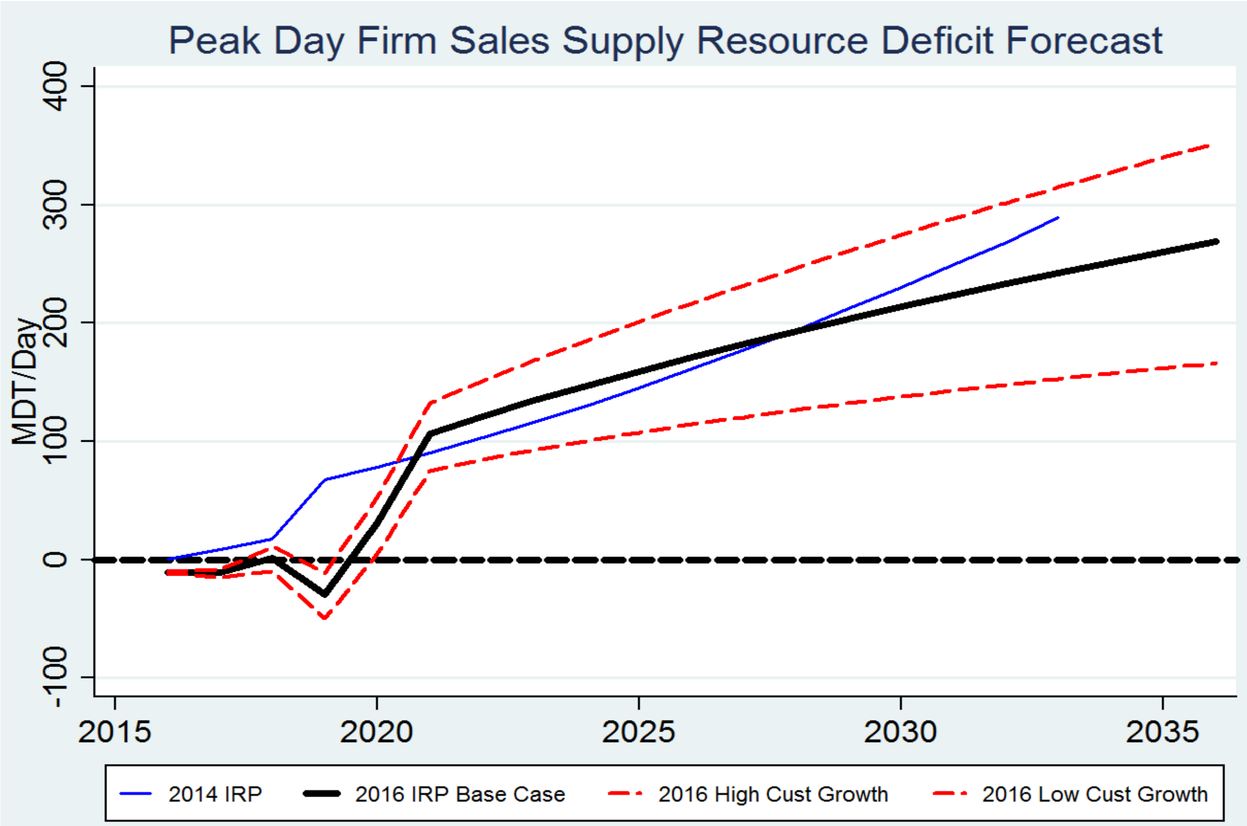


Figure 8.2: System Resource Deficiency on Design Day



A number of currently proposed projects in the Northwest could impact NW Natural's decisions about acquiring resources. This section explores those scenarios and compares the resulting resource portfolios. Table 8.3 contains the scenarios and their attendant set of available resource options. The scenarios are described below in more detail.

Scenario 1: No Regional Pipeline Projects:

Large industrial projects are not sited in the region and there is no need to construct any large regional pipelines. NW Natural's options include contracting for smaller expansions on a Sumas Expansion (Local Project) or invest in on-system storage resources.

Scenario 2: Jordan Cove LNG exports with Pacific Connector Pipeline:

Pacific Connector is built to support LNG exports out of Jordan Cove. NW Natural's options also include contracting for smaller expansions on a Sumas Expansion (Local Project) or invest in on-system storage resources.

Scenario 3: Trail West Pipeline Is Built:

Trail West pipeline is constructed to serve large loads in the Northwest. These loads could be from methanol, power generation, or other large industrial uses. NW Natural may choose to contract on this regional pipeline in addition to the options of contracting for smaller expansions on a Sumas Expansion (Local Project) or investing in on-system storage resources.

Scenario 4: Sumas Expansion (Regional Project) Is Built:

Only SE(R) is constructed to serve large loads in the Northwest. These loads could be from methanol, power generation, or other large industrial uses. NW Natural may choose to contract on this regional pipeline in addition to the options of contracting for smaller expansions on a Sumas Expansion (Local Project) or investing in on-system storage resources.

Scenario 5/6: High/Low Demand Growth and No Regional Pipeline Projects:

Large industrial projects are not sited in the region and there is no need to construct any large regional pipelines. NW Natural experiences high/low demand growth and resource options include contracting for smaller expansions on a Sumas Expansion (Local Project) or invest in on-system storage resources.

Scenario 7/8/9: Early Subscription to Regional Pipeline Projects:

The timing of regional interstate pipeline projects is beyond the control of NW Natural. The Company may need to decide whether or not to subscribe to a regional interstate pipeline before the Company's preferred date to add interstate pipeline capacity. The most likely instance of this would be a binding open season before construction begins on an interstate pipeline where it is expected that upon completion the pipeline would be fully subscribed. In this case the Company would be presented with a "take it or leave it" opportunity to acquire interstate pipeline capacity. In these scenarios, NW Natural uses the year 2021 as the first year a new interstate pipeline could reasonably come in service.

Table 8.3: Scenario Assumptions Matrix

Resources Available	**Scenario**								
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**
Trail West Pathway			X					X	
Pacific Connector Pathway		X					X		
Sumas Expansion Regional				X					X
Sumas Expansion Local	X	X	X	X	X	X	X	X	X
Mist Recall	X	X	X	X	X	X	X	X	X
North Mist II	X	X	X	X	X	X	X	X	X
Christensen Compressor	X	X	X	X	X	X	X	X	X
All others	X	X	X	X	X	X	X	X	X
	Scenario								
Sensitivity	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**
High Load Growth					X				
Low Load Growth						X			
2021 Interstate Pipeline							X	X	X

2.2. Portfolio Results Under Base Load Growth Scenarios

The NPVRR of each scenario under normal weather conditions is shown in table 8.4 below and the specific annual resource additions in each portfolio are shown in figures 8.3 through 8.7. In the Base Case customer growth scenarios (scenarios 1 through 4) Mist Recall is used to meet the peak resource demand over the first six years of the plan. In year 2022 the Christensen Compressor resource is selected in order to provide additional peak supply to the Salem and Albany load centers as only a limited amount of gas from Mist can reach these areas. Following the addition of the Christensen Compressor, Mist Recall is chosen as the resource to meet additional peak day demand until all of Mist Recall is taken in 2027.

Following the addition of all Mist Recall a new resource must be chosen to meet peak day load growth. The resource that is selected at this time depends on whether or not a regional pipeline is available. The next least-cost resources that are available are either a regional pipeline, if available, or North Mist IIa. If a regional pipeline is available it is expected to be lower cost than North Mist IIa and is selected at this time. Otherwise North Mist IIa is added to the portfolio.

Table 8.4: Cost of Resource Portfolios with Base Load Growth

Scenario	Supply NPVRR ($millions)	Transport NPVRR ($millions)	Storage NPVRR ($millions)	CO_2 Cost NPVRR ($millions)	Total NPVRR ($millions)
1	3,243.76	1,192.95	217.09	639.06	5,292.86
2	3,242.80	1,199.73	193.18	639.06	5,274.78
3	3,243.42	1,206.77	193.18	639.06	5,282.43
4	3,243.18	1,205.64	193.18	639.06	5,281.07

Figure 8.3: Scenario 1 Resource Selection

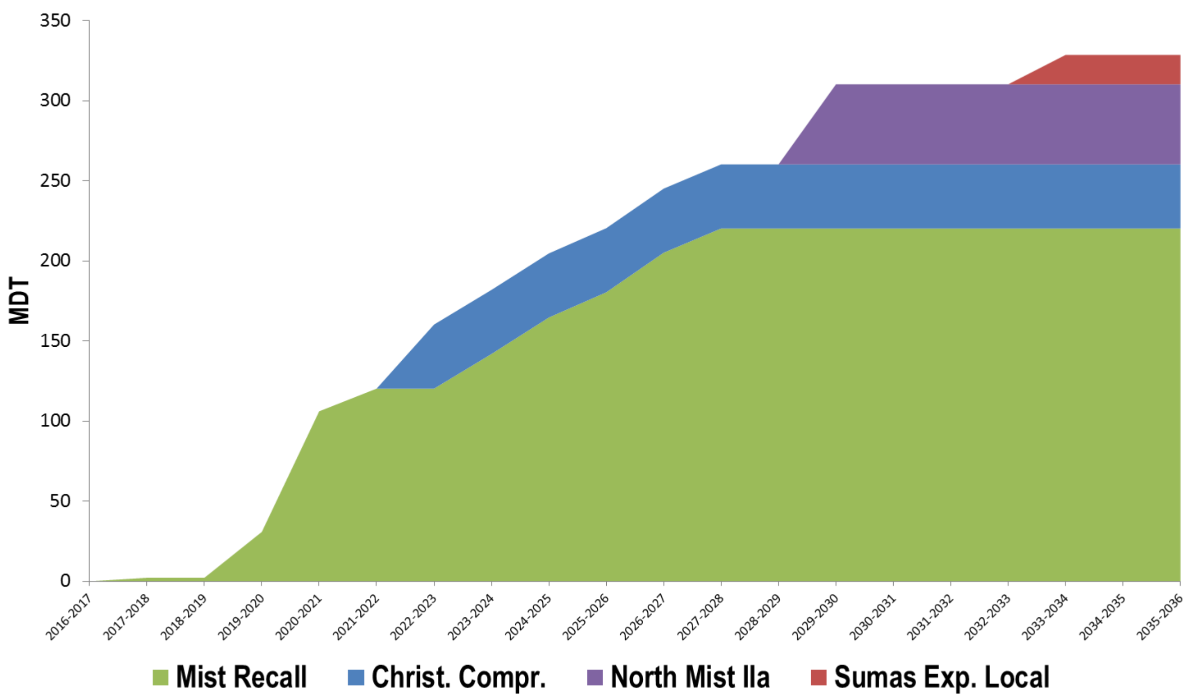


Figure 8.4: Scenario 2 Resource Selection

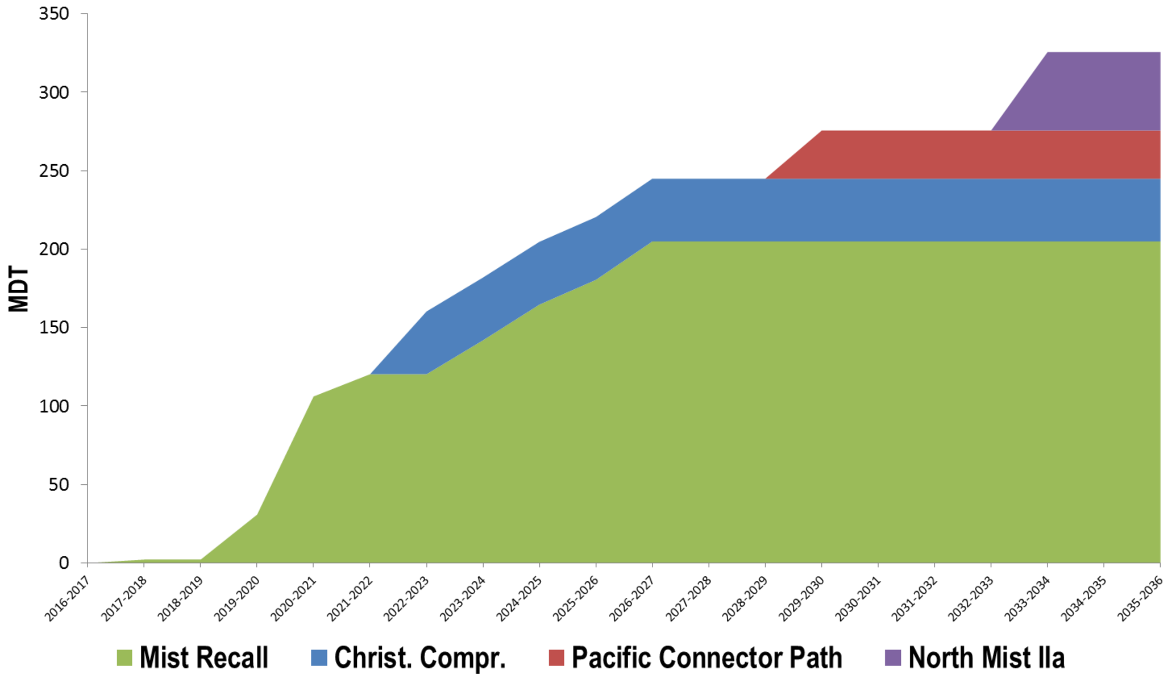


Figure 8.5: Scenario 3 Resource Selection

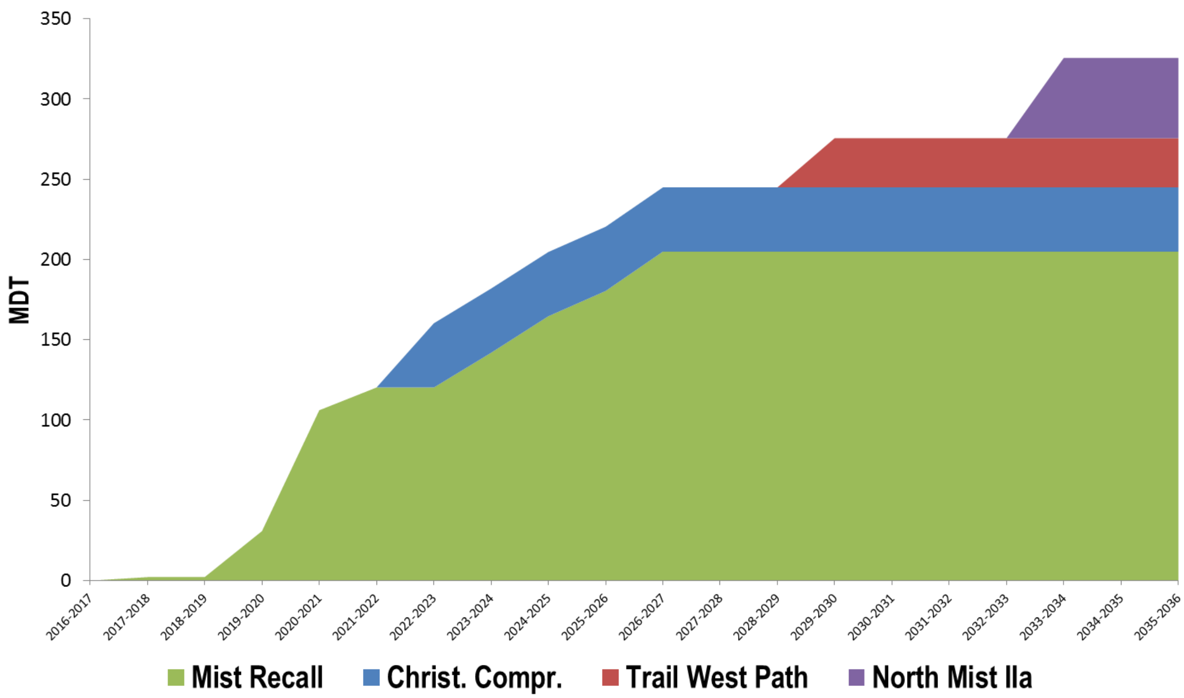


Figure 8.6: Scenario 4 Resource Selection

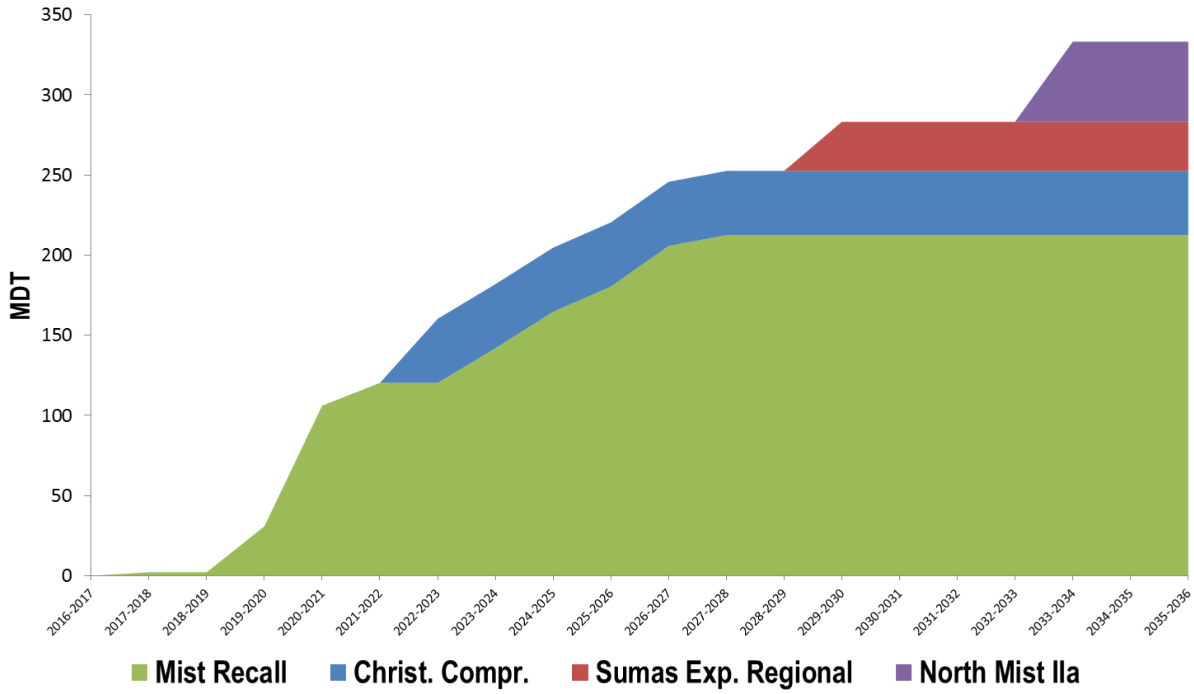
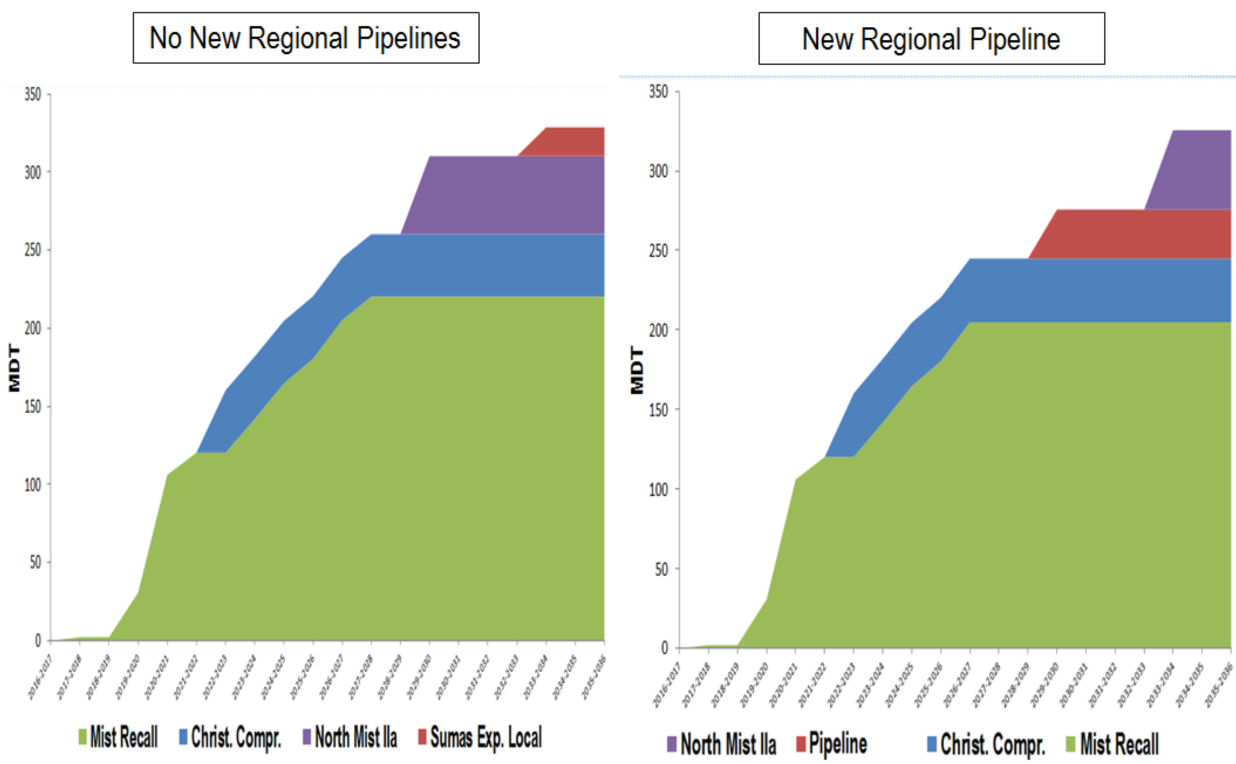


Figure 8.7: Comparison of Scenarios with and Without Regional Pipelines



2.3. Portfolio Results Under Alternative Load Growth Scenarios

NW Natural also tested scenarios with high- and low-demand growth. These demand sensitivity cases were run using the same resource assumptions as Scenario 1 above. The resulting portfolio NPVRRs are shown in table 8.5.

Table 8.5: Cost of Resource Portfolios with Alternative Load Growth

Scenario	Supply NPVRR ($millions)	Transport NPVRR ($millions)	Storage NPVRR ($millions)	CO_2 Cost NPVRR ($millions)	Total NPVRR ($millions)
5	3,435.69	1,292.09	273.27	681.89	5,682.95
6	3,095.87	1,153.99	161.80	598.96	5,010.63

In the high-growth case all resource additions are accelerated in time and more resources are needed (figure 8.8). In this scenario both North Mist IIa and IIb are selected as resources in addition to pipeline capacity.

In the low-demand growth scenario only two resources are needed throughout the planning horizon. Mist Recall is used to meet load growth until the 2031-2032 gas year where the Christensen Compressor project is needed (figure 8.9).

Figure 8.8: Scenario 5 Resource Selection

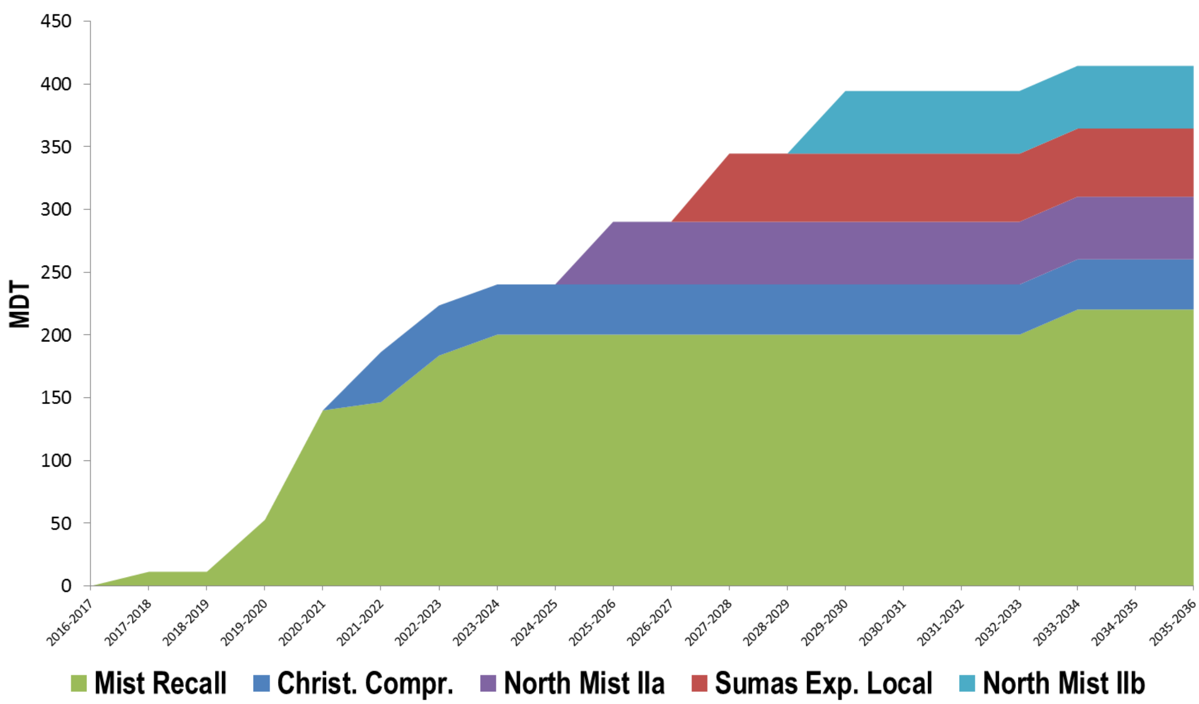
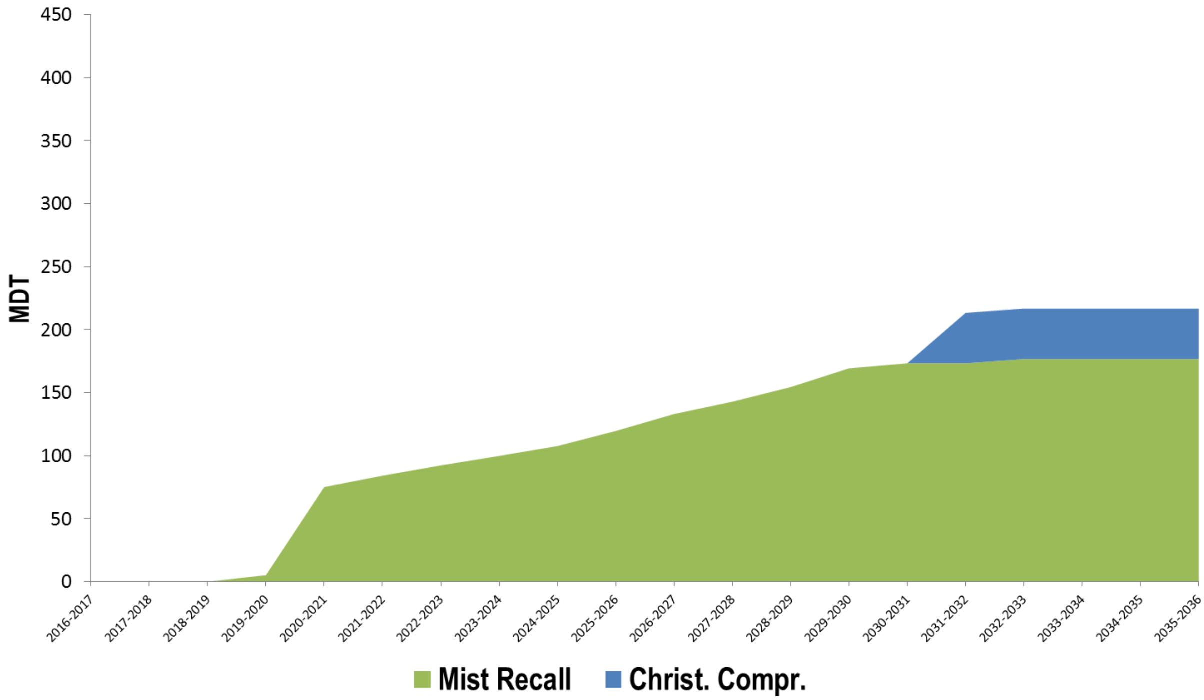


Figure 8.9: Scenario 6 Resource Selection



2.4. Portfolio Results With Early Interstate Pipeline Build Dates

The timing of regional interstate pipeline projects is beyond the control of NW Natural. The Company may need to decide whether or not to subscribe to a regional interstate pipeline before the Company's preferred date to add interstate pipeline capacity. The most likely instance of this would be a binding open season before construction begins on an interstate pipeline where it is expected that upon completion the pipeline would be fully subscribed. In this case the Company would be presented with a "take it or leave it" opportunity to acquire interstate pipeline capacity. Table 8.6 shows the resulting portfolio NPVRRs and figures 8.10-8.12 show the timing and sizing of resource additions.

Table 8.6: Cost of Resource Portfolios with Early Regional Pipeline In-Service Date

Scenario	Supply NPVRR ($millions)	Transport NPVRR ($millions)	Storage NPVRR ($millions)	CO_2 Cost NPVRR ($millions)	Total NPVRR ($millions)
7	3,246.49	1,201.86	191.70	639.06	5,279.11
8	3,245.12	1,217.85	192.71	639.06	5,294.74
9	3,242.42	1,215.80	192.80	639.06	5,290.09

Figure 8.10: Scenario 7 Resource Selection

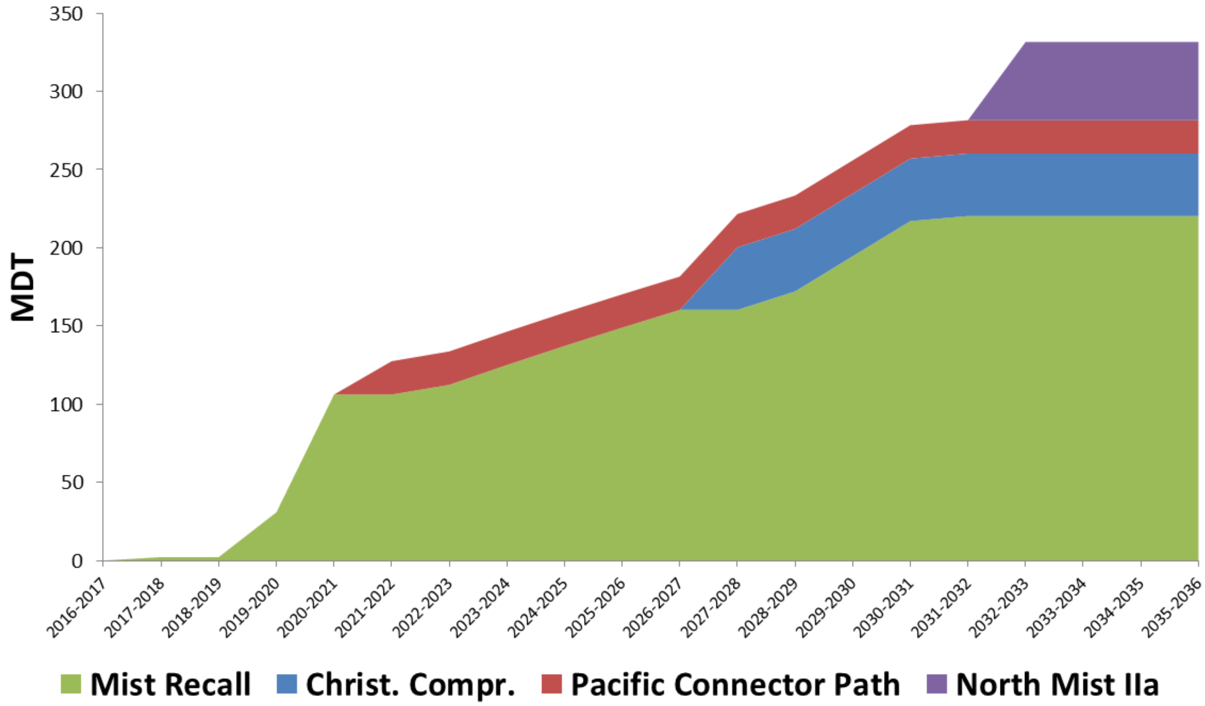


Figure 8.11: Scenario 8 Resource Selection

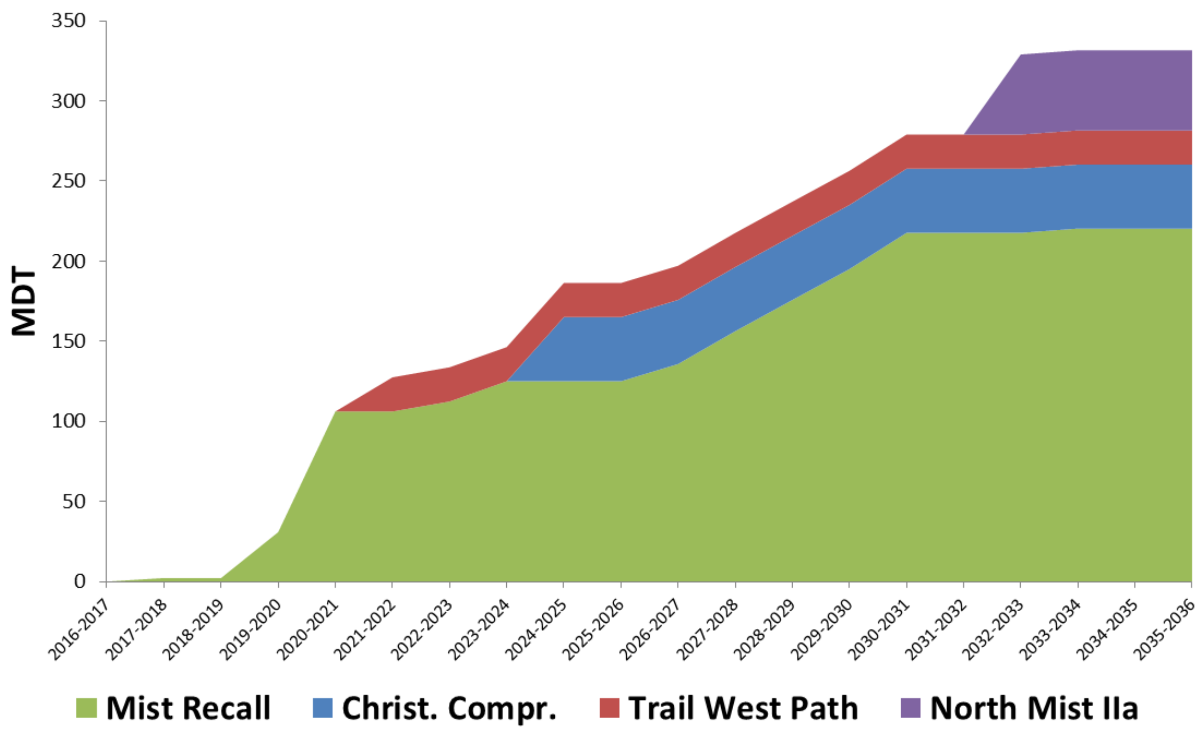
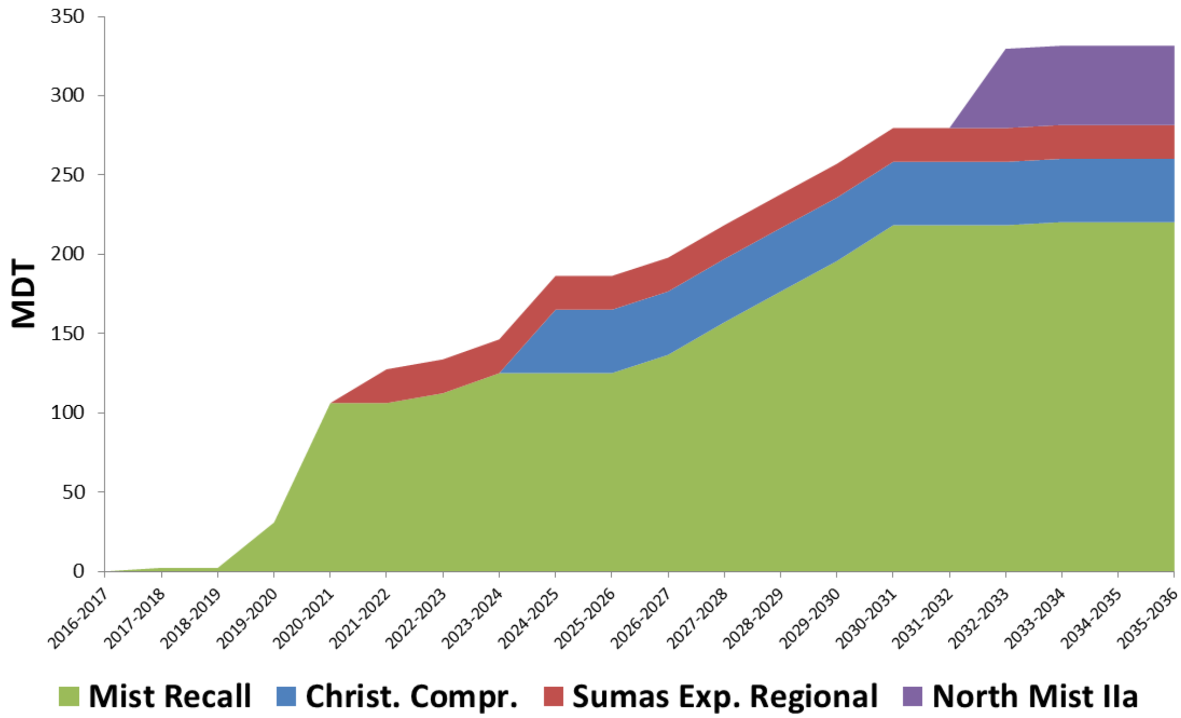


Figure 8.12: Scenario 9 Resource Selection



3. SOUTH SALEM FEEDER

In the 2014 IRP NW Natural identified a deficit of capacity to serve peak day demand in the Salem load center. Capacity to serve the Salem load center is provided by an assortment of high-pressure transmission pipelines as well as Northwest Pipeline gate stations. NW Natural selected a project called the South Salem Feeder to solve the capacity issue. The 2014 action item associated with the South Salem Feeder stated (OPUC Order No. 15-064):

> *Continue the preconstruction phase of the South Salem Feeder Project (e.g., studies, permitting, etc.) and conduct a Request for Proposal (RFP) for Recallable Agreements in the Salem Load Center. Provide the Commission with the results of additional analysis (e.g., results of RFP, accelerated DSM analysis, future load growth specific to the Salem load center) related to the South Salem Feeder Project prior to moving beyond the preconstruction phase of the project. While the studies are being undertaken, Energy Trust of Oregon (ETO) will maintain the current energy-efficiency programs in the Salem area.*

Following the 2014 IRP NW Natural continued to evaluate the load in the Salem area as well as the capacity constraints which lead to the selection of the South Salem Feeder. As described in chapter 3, the Company updated its assumptions about how MDDOs are allocated to either a specific gate station or a zone of Northwest Pipeline. For the Salem area, that change leads to the gate capacity being increased from 26,383 Dth/day (MDDO at the specific gates) to 61,771 Dth/day (MDDO within the zone).

In addition to a new look at MDDO, the Salem load center was disaggregated into smaller load centers to improve the ability to identify capacity issues. In previous IRPs, the Salem load center consisted of the demand from customers covering a large amount of territory in multiple cities spread through Marion, Polk, and Yamhill counties (figure 8.13). This area is also one of the most complex parts of the NW Natural system as there are multiple high-pressure transmission systems (Central Coast Feeder, Mid-Willamette Valley Feeder, North Willamette Valley Feeder, and South Mist Pipeline Extension) and gas supply points (Northwest Pipeline gate stations, Mist, and Newport LNG). This one load center has been transformed into four distinct load centers based on logical divisions which consider the concentration of demand and pipelines serving the demand (figure 8.14).

Figure 8.13: Salem Load Center

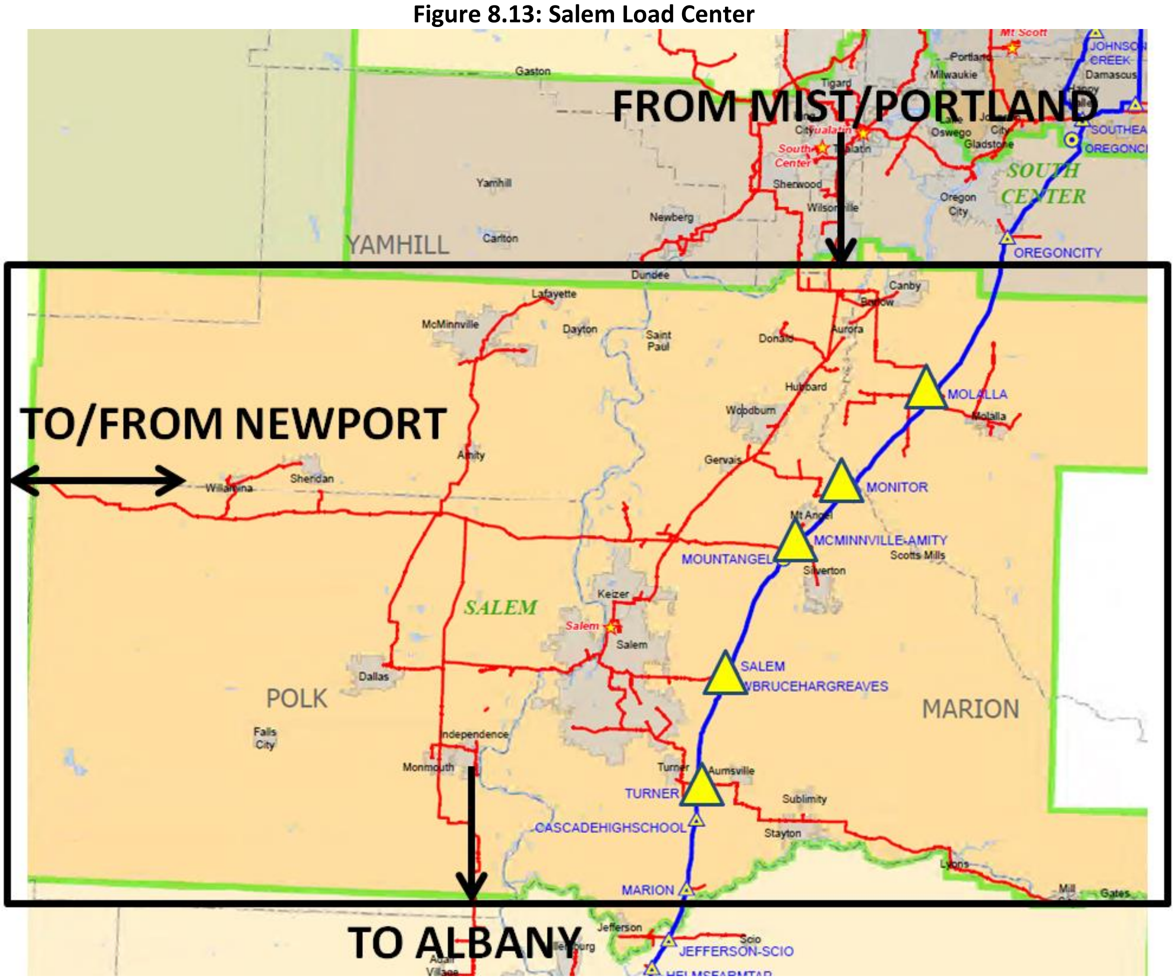


Figure 8.14: Salem Load Center Disaggregation

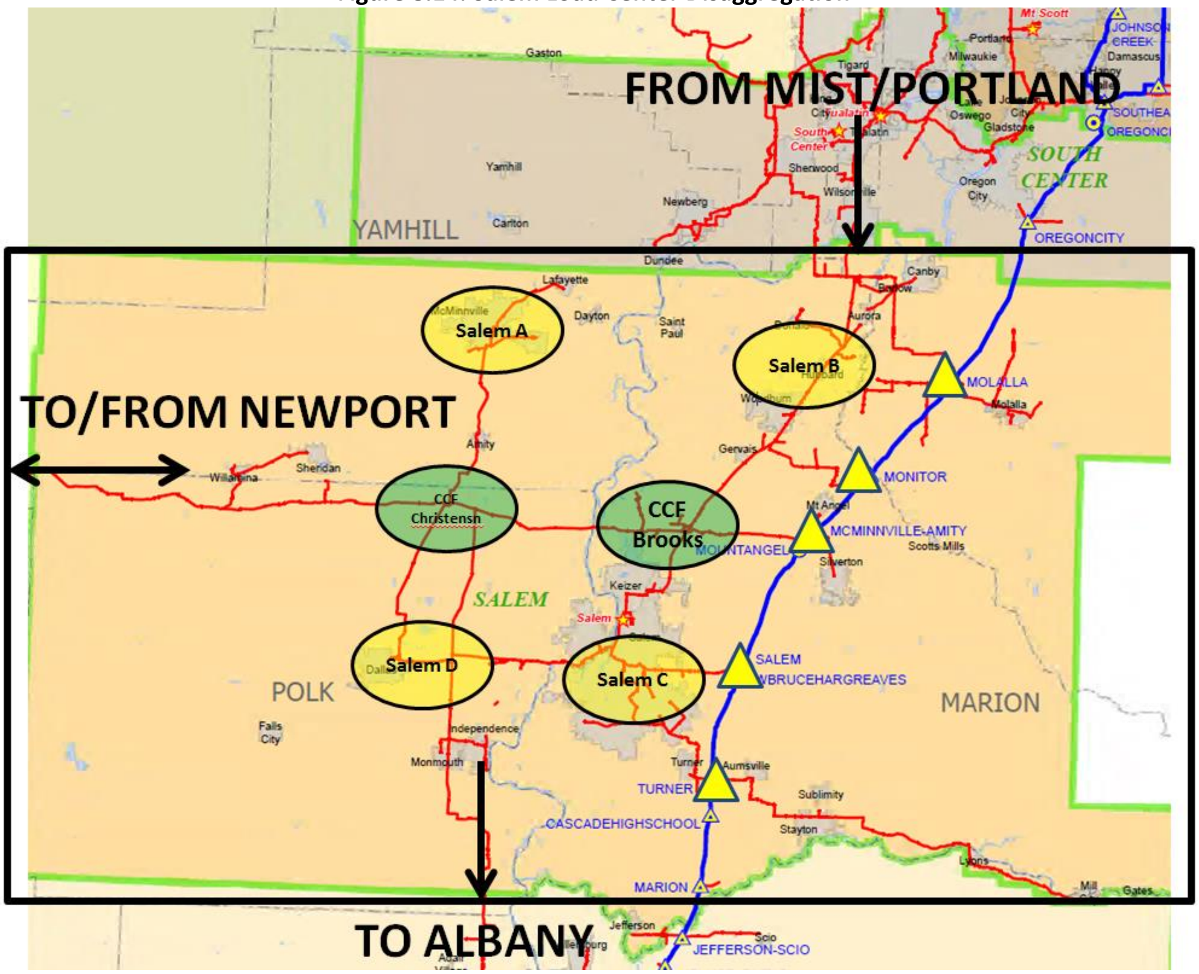


Figure 8.15 below shows the changes in the system flow diagram before and after the load center transformation. Figure 8.16 shows the resulting demands (blue lines) and delivery capacities (red lines) in each of the new Salem areas. As can be seen in each panel, the current delivery capacity exceeds the demand in each area. The Salem C area was most affected by the change in MDDOs as can be seen by comparing the current Salem C delivery capacity to what it would be using the assumptions in the 2014 IRP (figure 8.16 lower right). Under the assumptions present in the 2014 IRP (green line) Salem C would have needed additional delivery capacity beginning in 2025.

Figure 8.15: Salem Load Center Change from Previous IRPs

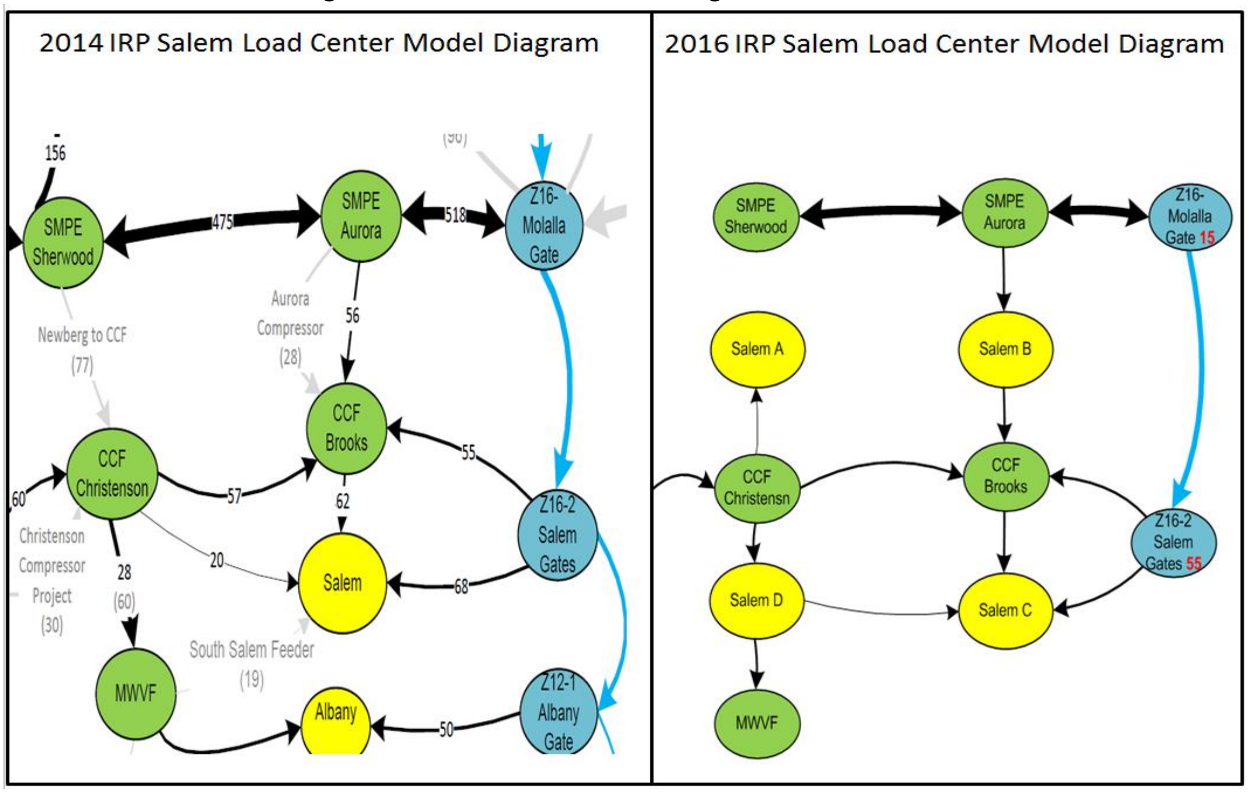
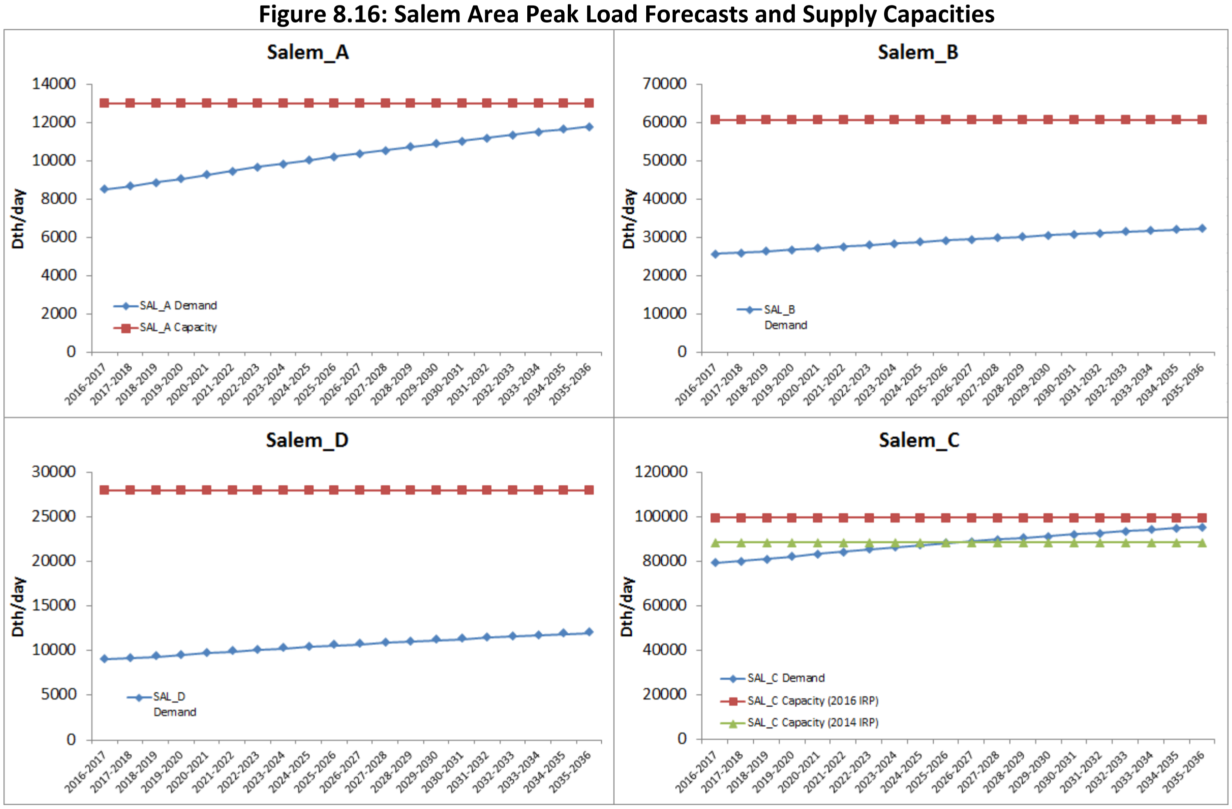


Figure 8.16: Salem Area Peak Load Forecasts and Supply Capacities



4. PLANNING CONCLUSIONS

NW Natural draws the following conclusions from these results:

Mist Recall is very important to customers, as shown by its low cost and flexibility.

In contrast to the many pipeline options where NW Natural must add capacity in large blocks, Mist Recall's flexibility allows the Company to respond to changes in resource needs by adding in small blocks of capacity. This reduces the risk that the NW Natural contracts for more interstate pipeline capacity than is necessary to meet future loads.

Additional pipeline capacity is needed in addition to storage resources—which particular pipeline option is the least-cost option depends upon the future that unfolds.

NW Natural expects that it will need to contract for additional interstate pipeline capacity at some point over the planning horizon. While underground storage resources have lower capacity costs the delivery pattern for these resources (deliverability decreases as storage capacity drops) becomes problematic as the percentage of storage resources in the Company's portfolio increases over time. As loads increase storage resources are heavily used for winter energy needs, compromising peak deliverability and ultimately reducing the cost-effectiveness of the resource.

The availability of any specific regional pipeline does not change the resource portfolio.

As seen in the portfolio results from scenarios 2 through 4, the timing and type of resource additions is not affected by the specific regional pipeline which is available. In all cases the regional pipeline is added to the portfolio in 2029. Additionally, the PVRR of the portfolios with regional pipelines are very similar.

The South Salem Feeder is no longer needed in the planning horizon.

After disaggregating the Salem load center and re-evaluating the capacity constraints, NW Natural determined that the South Salem Feeder is not needed to serve peak day demand.

NW Natural asks acknowledgment of the following Action Item:

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

5. KEY FINDINGS

- Mist Recall is the primary resource addition to meet growing peak loads. The next Mist Recall is projected to be for 30,000 Dth/day for the 2019-2020 gas year.
- The Christensen Compressor project is needed to serve growing peak loads in the Salem and Albany load centers. With Base Case load growth this project will be needed in 2022.
- Additional pipeline capacity is necessary to fulfill winter energy demand without compromising the maximum deliverability of underground storage resources.

Chapter 9
Stochastic Supply Resource Risk Analysis

1. BACKGROUND

The results presented in chapter 8 represent the expected Present Value of Revenue Requirement (PVRR) of a portfolio of resources under a specific set of input assumptions in the form of forecasts and resource availability. It is known, however, that there is a high degree of uncertainty when forecasting load, weather, commodity prices, and resource costs 20 years into the future. Therefore, it is important to test the sensitivity of the expected least-cost supply resource acquisitions detailed in chapter 8 to assumptions about prices, price basin differentials, weather, customer growth, and resource costs. This chapter documents the risk analysis performed using stochastic Monte Carlo simulation to evaluate how resource availability[1] impacts portfolio performance over a wide range of possible futures. Also, since a recall of Mist storage capacity from interstate storage in 2019-20 is the only expected supply resource acquisition planned for the period covered by the Action Plan in this IRP (the next 2-4 years), this chapter will make clear there is very little risk that adding Mist Recall to the Company's supply resource portfolio in flexible amounts as is called for in the Action Plan will result in a portfolio that does not represent the best combination of cost and risk for customers (i.e., resource decisions where risk analysis is more critical will be made in future IRPs-

KEY FINDINGS

Key findings in this chapter include the following:

- NW Natural's stochastic supply resource risk analysis utilizes Monte Carlo simulation methodology that is new to this IRP.
- The goal of stochastic risk analysis is to test the sensitivity of expected resource decisions to assumptions about prices, weather, resource costs, and customer growth that are known to be uncertain.
- NW Natural's current resources serve to mute the difference in PVRR across portfolios in different futures of the stochastic risk analysis as they will make up the majority of the resource stack over the planning horizon even when considering resources acquired to accommodate load growth.
- Since LDCs are in the business of distributing natural gas, variation in costs in different future environments tends to move in concert across resource portfolios as fuel switching is not possible.
    - It is only possible to take advantage of supply basin/trading hub basin differentials if pipeline capacity is held at multiple basins and seasonal price arbitrage through storage resources
- All Base Case load scenarios (1-4 and 7-9) have identical resource portfolios through 2020-21 and scenarios 1-4 have identical resources through 2026-27 and are only significantly different in the last years of the planning horizon.
    - Most variation in costs across portfolios takes place at highly discounted values
- There is little chance Mist Recall will turn out to be more expensive than the other long term resource options considered available (though as-of-now-unknown short term citygate delivery options or recall agreements could be competitive).
- Load growth uncertainty is not a considerable risk to resource choice in the short term since Mist Recall is flexible and the amount recalled can be determined one year in advance of need.
- Resource choices that carry considerable customer risk will be decided in future IRPs.
- Feedback on the stochastic risk analysis methodology is important so the tool is ready to go in case a decision with a reasonable degree of risk needs to be made.

[1] The three resource availability possibilities being considered: (1) no new regional interstate pipeline is constructed during the planning horizon, (2) one of the three new regional interstate pipelines analyzed is constructed and available for subscription on a timeline chosen by NW Natural, and (3) one of the new regional pipelines is constructed and available for subscription starting in 2021-22 only with a decision required in the near future.

likely more than 5 years out in time). However, while resource decisions where stochastic risk analysis is highly valuable will not be made in this IRP, this Chapter is new to the 2016 IRP and a review of the methodology and how NW Natural plans to apply it when resource decisions that carry a reasonable amount of risk are required is relevant and important.

2. STOCHASTIC SIMULATION OVERVIEW

As is detailed in chapter 8, after resource choices are made for each scenario through deterministic peak planning which includes a peak day, a week-long peak weather event, and peak heating season in each year of the planning horizon to ensure adequate resources are available, normal weather optimization is completed on the resulting portfolios to determine the expected PVRR under "Base Case" conditions under each scenario. Stochastic risk analysis is completed on each of these same portfolios through two separate Monte Carlo simulations and their subsequent optimizations to estimate the PVRR for each scenario under a wide variety of possible future environments[2] to determine if the expected least-cost resources remain the best option for customers in a majority of possible future environments. If not, least cost and lowest risk are at odds and the best combination of least cost and risk for customers needs to be decided.

2.1. Simulation 1: Variable Costs with Prices and Weather as Stochastic Inputs

Weather and commodity price (inclusive of trading hub basin differentials) uncertainty are simulated using SENDOUT®'s stochastic Monte Carlo facilities which includes a redispatch (optimization) of the resource portfolio for each simulation draw for each day in the planning horizon. Each of 100 simulation draws generates daily price and weather for each trading hub and load center, respectively, by randomly drawing from defined distributions so that each resulting draw (or "future") is different than the Base Case future but in a way that is consistent with the best approximation of the uncertainty of each component. A correlation matrix defined from historical data also establishes the relationship of the prices between trading hubs, the weather between load centers, and the prices at each trading hub to the weather at each load center so that each draw represents a "future" that is representative of the real world. The same 100 futures are used for each resource portfolio so that the PVRR for each portfolio can be compared for each simulated future/draw/future environment. Note that after the simulation is run a complete cost minimizing optimization is run for each future for each portfolio to determine the PVRR of the variable costs for the portfolio. Now both of the stochastic inputs in the first simulation are described in more detail:

Stochastic Input #1—Commodity Prices: The mean of the distribution for natural gas prices through time at each of the five relevant trading hubs[3] is defined by the consultant price forecast detailed in chapter 2 for each month of the planning horizon. The distribution (lognormal distribution) and standard deviation for the stochastic price draws is defined by historical price variation and an assessment of the current market.[4] Though price distributions are defined on a monthly time frame SENDOUT®'s Monte Carlo

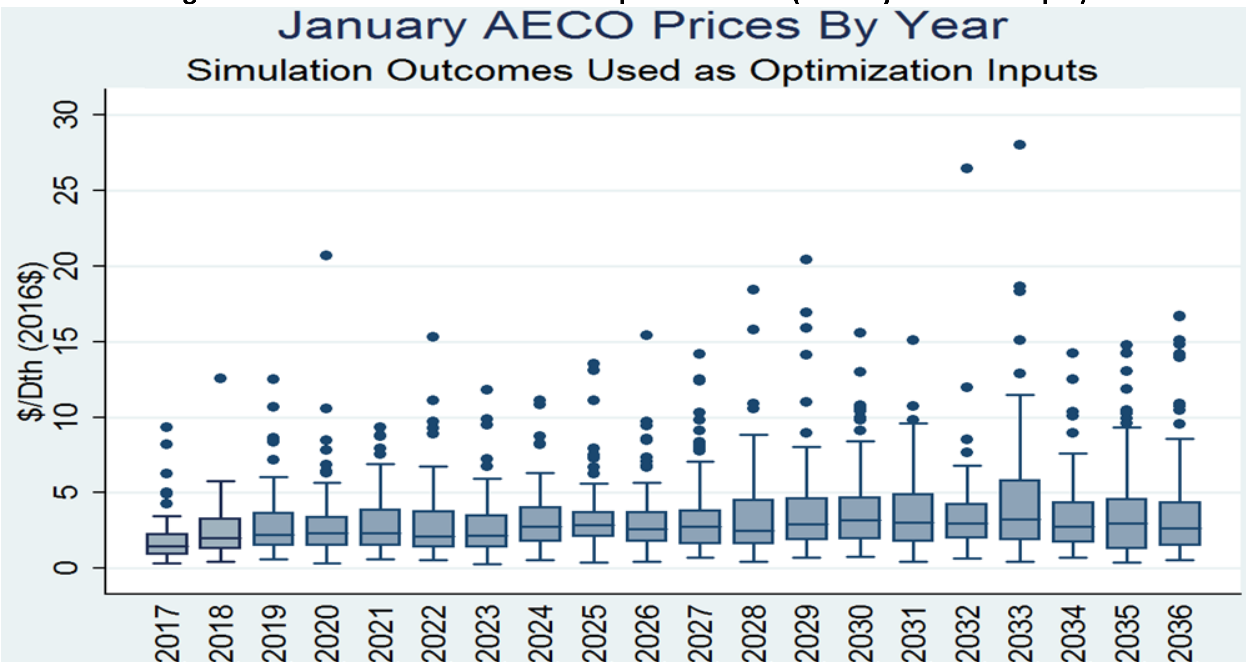
[2] A single "future environment" means one combination of assumed prices, resource costs, and weather and is often called a single "future" which is represented by one "draw" in a Monte Carlo simulation

[3] AECO, Rockies (Opal), Sumas, Malin, and Station 2.

[4] Price volatility has generally been lower since the "shale gale" so volatility in the last three years is more heavily weighted than volatility before this time.

feature simulates a price for each day in the planning horizon at all of the relevant trading hubs. Figure 9.1 is an example used to show the results of the simulation across draws with a box and whisker plot representing the distribution of the average of daily prices in January across the 100 draws of the simulation for each year in the planning horizon at the AECO trading hub in real terms (2016$).[5,6]

Figure 9.1: Variable Cost Stochastic Input #1- Prices (January AECO Example)



Note, consistent with the historical reality of natural gas prices, the shape of the lognormal distribution can be seen with the outliers being on the high end of the scale but most of the price outcomes being much lower.[7] Also important to point out as it relates to storage operations and the option value that storage resources provide is that while in the Base Case price forecast winter prices are higher than prices the previous summer for every year in the planning horizon (which is the expected situation in normal conditions), this is not true for all years in each draw, which is a more realistic representation of reality. It is also key that the draw with the highest price at some point in time at the beginning of the planning horizon is not necessarily (and is in fact unlikely to be) the draw with the highest price later on in the planning horizon, indicating how each simulated price path acts more realistically in that it might "wander" higher and lower throughout the planning horizon as actual prices have shown to do through time.

The contemporaneous difference in prices between trading hubs (or the basin differentials) are highly—though not perfectly—correlated, with the correlations defined by historical relationships. Therefore,

5 January is chosen for exemplary purposes since it is typically the coldest month of the year and NW Natural's load is space heating driven and AECO is the trading hub chosen for representation since in recent years NW Natural has purchased more gas from AECO than other trading hubs.

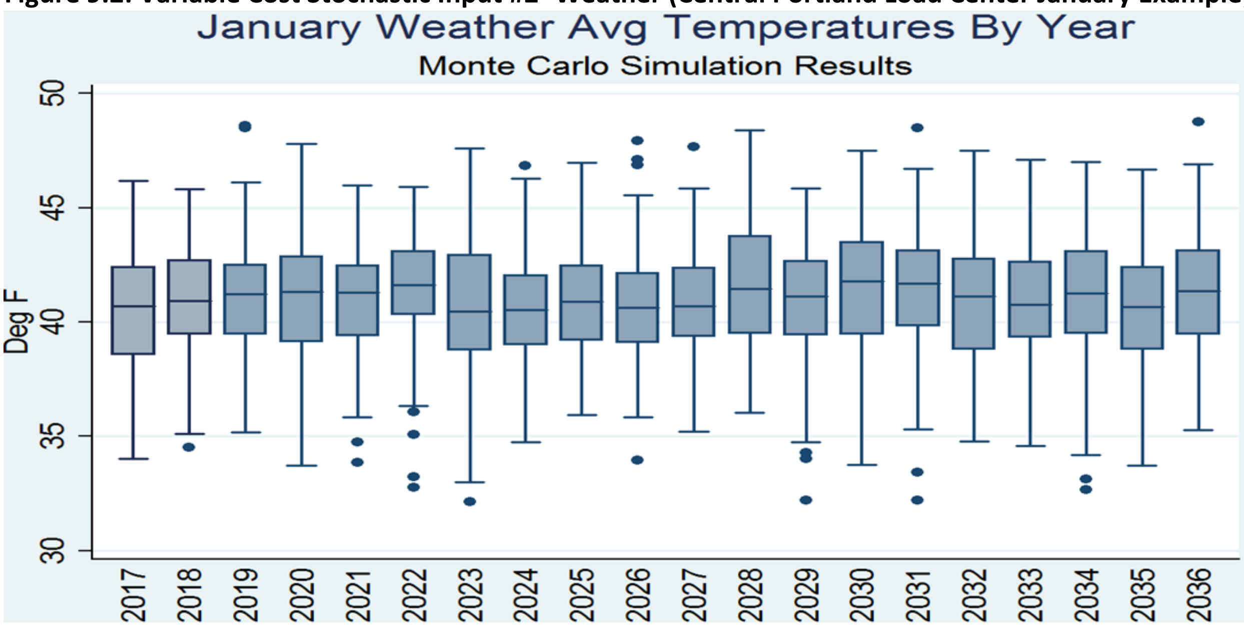
6 The simple average of the daily prices in January at AECO for one draw for each year represents one data point in the distribution summarized by the box and whisker plot.

7 In only 2033 are 75 of the 100 draws not less than $5/Dth.

the basin differentials between trading hubs vary across draws and through time within draws. Basin differentials represent one of the largest sources of relative variation in PVRR between the portfolios across draws, as basin optimization is one of the very limited variables within the an LDCs control to minimize variable costs.

Stochastic Input #2—Weather: The mean, standard deviation, and distribution (normal) for weather are defined by 30 years of daily weather history for each of the load centers modeled by NW Natural and represented by monthly heating degree days (HDDs). To exemplify the variation in weather across draws of the simulation Figure 9.2 shows boxplots of the average monthly temperature for January (though like prices the simulation actually generated daily temperature values) in the Central Portland load center by year in the planning horizon. Since NW Natural's service territory is not drastically diverse climatically weather is highly, though not perfectly, correlated across load centers, with the correlation defined by the actual correlation over the last 30 years. A correlation between the weather at each load center and the price at each trading hub is also defined from historical correlations.

Figure 9.2: Variable Cost Stochastic Input #2- Weather (Central Portland Load Center January Example)



Weather and prices are not highly correlated, even in winter months, because the weather-price relationship is driven primarily by North American weather as a whole. Since weather in the Portland area is not strongly correlated with weather continent-wide, weather in NW Natural's service territory is not strongly correlated with natural gas prices at the relevant trading hubs of the Pacific Northwest.

2.2. Simulation 2: Fixed Costs With Supply Resource Option Costs As the Stochastic Input

Stochastic Input #3—Supply Resource Option Costs: Uncertainty in the costs[8] of the supply resource options considered is simulated with a Monte Carlo analysis separate from Simulation 1.[9] Supply resource costs are typically represented in a dollars per Dth of daily capacity form[10] and are fixed costs since they are typically reservation charge payments paid monthly regardless of the utilization of the contracted capacity. Resource costs are a large driver of the difference in PVRR across portfolios and the assumptions about prospective resource costs could impact the position of a given resource as the expected least-cost option to meet customer needs. For example, if two resource options—one with an expected cost of $0.50/Dth of Daily Capacity and the other with an expected cost of $0.55/Dth of Daily Capacity, with both sourcing gas at the same trading hub so that the expected variable costs associated with either option are equal—have different levels of relative cost risk (so that it is possible with a reasonable degree of certainty that the $0.50/Dth of Daily Capacity option could turn out to be $0.75/Dth of Daily Capacity but highly unlikely the $0.55/Dth of Daily Capacity option could turn out to be above 0.65/Dth of Daily Capacity) it may make sense to choose the option that is not expected to be the least-cost option to mitigate the higher risk associated with the option that is lowest cost in the expected case.

Table 9.1 summarizes the distributions used to simulate the supply resource costs for the options considered in this IRP and figure 9.3 shows the results of the simulation of 100 cost outcomes for each supply resource option considered.

Table 9.1: Supply Resource Option Costs and Potential Deviations (2016$)

Supply Resource Capacity Rates ($/Dth of Daily Capacity)					
	Low	Mid	High	-	+
Mist Recall	$0.050	$0.055	$0.110	10%	100%
Christensen Compressor	$0.189	$0.210	$0.294	10%	40%
North Mist II-A	$0.483	$0.503	$0.584	15%	30%
North Mist II-B	$0.429	$0.446	$0.515	15%	30%
Sumas-Local	$0.774	$0.880	$1.100	12%	25%
Regional Interstate Pipeline	$0.385	$0.499	$0.660	23%	32%

The regional pipeline costs and their distribution (low and high estimates) are defined from a cost study by a third party consultant[11] and information provided by the interstate pipeline companies and combined into one resource notated as the "Regional Interstate Pipeline." Mist Recall costs and

8 In the form of revenue requirement.

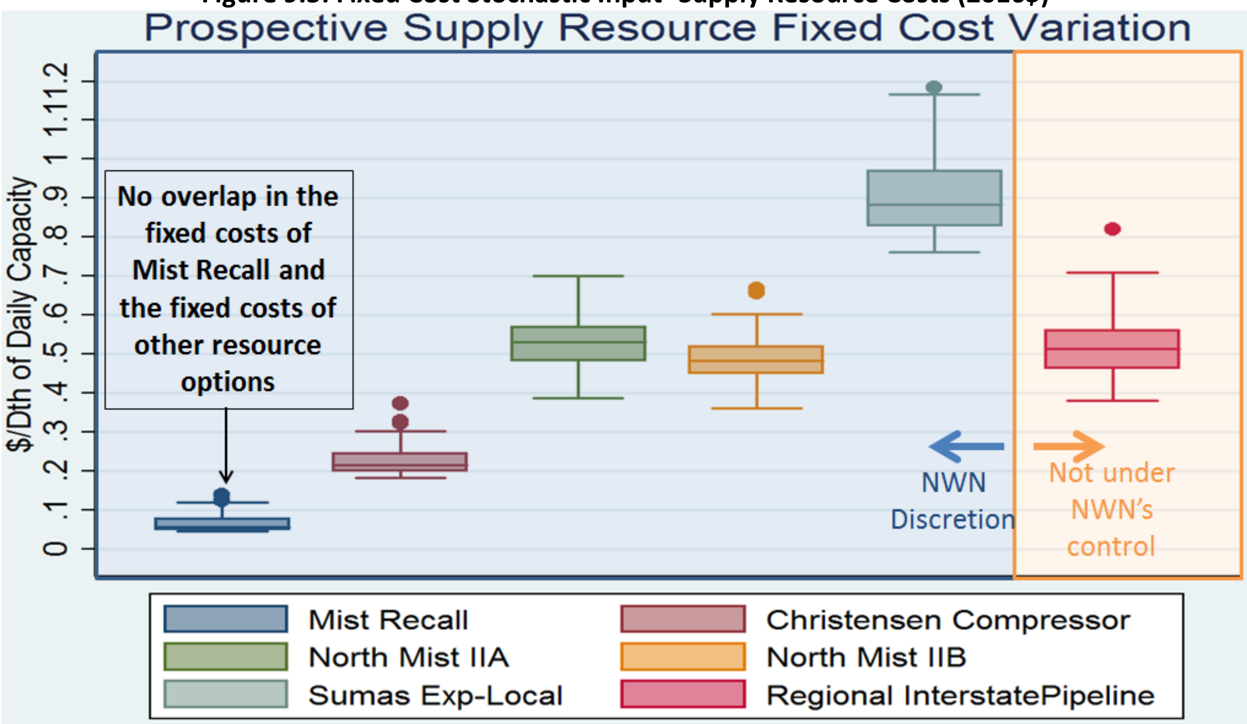
9 Note that this implies that resource cost variation, which is related to permitting and construction cost uncertainty, is not correlated with variation in weather or natural gas prices. Given this independence, separating resource cost uncertainty into a separate simulation provides the exact same results one would obtain by combining fixed and variable cost uncertainty into one simulation within SENDOUT® but would result in 100 times the modeling run time.

10 Meaning, for example, if a resource cost is $0.50/Dth of daily capacity and 10,000 Dth/day are contracted the annual payment for the resource in a nonleap year is $0.50* 10,000 *365 = $1.825 million and is the same in all nonleap years.

11 See Confidential appendix 7 in NW Natural's 2014 IRP for this report from Willbros Group, Inc.

distribution characteristics are defined by current Mist accounts and the potential cost of service impact of the Mist Asset Management program. Christensen Compressor costs have been estimated by NW Natural engineers with the distribution defined by the greenfield definitions for compressor stations in the third-party consultant report. North Mist IIA and North Mist IIB for core customers costs are defined by the most recent available contractor bid for the North Mist Expansion for PGE that includes substantial customer contractual cost risk protections with the distribution defined by NW Natural expertise and stakeholder recommendation. As is typical with large construction projects, each resource option is more likely to experience cost overruns of a given magnitude than they are to experience a savings relative to the current projected cost of the same magnitude (i.e., upside risk is greater than downside risk/benefit for all options). Note, however, that while the risk is asymmetric for all of the resource options, the asymmetry is not equivalent across resources.

Figure 9.3: Fixed Cost Stochastic Input- Supply Resource Costs (2016$)



While keeping in mind that supply resource option costs do not represent all of the difference in cost between portfolios for any given future (as the variable cost component that is estimated in Simulation 1 and its subsequent optimizations must be considered as well to estimate total portfolio PVRR), Mist Recall is the lowest-cost option available to customers and there is no overlap in the range of Mist Recall fixed costs with the cost ranges of the other supply resource options. Additionally, the Christensen Compressor is lower cost than each of the other options other than Mist Recall for the fixed cost component and there is no overlap in the fixed cost outcomes. There is, however, considerable overlap in the fixed-cost estimate ranges of both North Mist IIA and B with that of the prospective regional interstate pipeline projects, making a choice between these options more inherently risky. Note, however, that NW Natural does not face a choice between these resource options in this IRP and is unlikely to face a decision on these resource in the next IRP.

2.3. Combining Simulations 1 and 2

After both simulations are complete every possible combination of outcomes from the two simulations is paired to determine the net present value of costs of each of the nine scenarios under the resulting 10,000 prospective future environments. However, since NW Natural cannot control which interstate pipeline will be built, the results from scenarios 2 (Pacific Connector (PC) is available with timing chosen by NW Natural (NWN)), 3 (Trail West (TW) is available with timing chosen by NWN), and 4 (Sumas Expansion Regional SE(R) is available with timing chosen by NWN) are combined so that the 10,000 PVRR results from each scenario are combined into a “Regional Pipeline NWN Timeline” option that includes 30,000 PVRR outcomes. Each of these outcomes is compared (ranked) against the PVRR of the equivalent future for the “No Regional Pipeline” option (scenario 1). This same process is completed for scenarios 7, 8, and 9 (the “Regional Pipeline-2021” option), which are the same as scenarios 2, 3, and 4 except regional interstate pipeline capacity is available starting in 2021-22 and must be evaluated now or the opportunity to pick up capacity will be foregone forever (which is covered in more detail in chapter 8).[12] These 30,000 PVRR outcomes are also compared against the “No Regional Pipeline” option to evaluate the likelihood that picking up capacity in 2021-22 is preferable to not acquiring any regional pipeline capacity within the planning horizon (which is a more likely scenario than NW Natural being able to bring on capacity on its own timeline).

These results are then tested for customer growth uncertainty by completing both simulations again for the low and high load growth scenarios (5 and 6) under the assumption that none of the three regional pipeline projects goes forward.

3. STOCHASTIC RISK ANALYSIS RESULTS

3.1. Results Framing and Important Considerations

Before proceeding, note again that NW Natural does not have a preferred portfolio and it is not appropriate to compare the PVRR of the portfolios for each of the scenarios detailed in chapter 8 and conclude that one portfolio shows as the least-cost scenario for NW Natural’s customers, as the only interstate pipeline option NW Natural has control over is the Sumas Expansion Local (SE(L)) project, which is a NW Natural specific expansion.[13] If one of the potential regional interstate pipeline projects (of Trail West, Sumas Expansion-Regional, and Pacific Connector) shows as the least-cost alternative it does not mean the Company can plan on subscribing to that pipeline because it may not be built and available for subscription.

Additionally, most of the scenarios considered under the Base Case assumptions (scenarios 1, 2, 3, and 4) result in the exact same resource portfolio through 2026-27 and scenarios 7, 8 and 9 have identical portfolios as the other Base Case assumption portfolios until the forced timeline interstate pipeline acquisition in 2021-22. This means that each of these scenarios will have identical PVRRs through 2020-21 and scenarios 1, 2, 3, and 4 have identical portfolios through 2026-27 in each of the 30,000 futures.

[12] Note again that NW Natural is not currently faced with this decision and, though it is possible, does not expect it will be faced with a similar decision before the next IRP.

[13] Which is another way of saying that NW Natural does not control any of the *Regional* Interstate Pipeline projects.

Moreover, under the high- and low-growth scenarios (5 and 6), only the timing of Mist Recall and the Christensen Compressor are different from the base case assumption portfolios in the first 10 years of the planning horizon and the earliest the Christensen Compressor is called for is 2021-22 (in the high-load growth scenario). Consequently, the only resource decision that is likely to be required before the next (2018) IRP is the level and timing of Mist Recall. As Mist Recall is by far the lowest cost resource option in terms of fixed resource costs and on system storage allows both basin and seasonal optimization so that Mist Recall is also associated with low variable costs, it is hard to imagine a scenario where recalling Mist capacity would retrospectively turn out not to be the least-cost resource.[14] Since the primary function of this risk analysis is to determine the risk that a resource decision will turn out not to be the lowest cost option retrospectively, this means the decision to include an Action Item related to Mist Recall carries little cost risk. Furthermore, Mist Recall is more flexible than most resources since it can be added in small increments on a flexible timeframe with a relatively short lead time (decisions for Mist Recall are made in the summer for a recall the following spring).

Also, since the Company currently holds nearly 1,000 MDT of supply resource capacity for a peak day and gradually adds resources to hold roughly 1,200 MDT of peak day capacity by the end of the planning horizon, most of the costs for each of the portfolios are tied to resources currently held to meet existing needs and therefore do not vary across scenarios. In fact, as is shown in chapter 8, in the last year of the planning horizon (2035-2036) the difference in resources between all of the portfolios using the Base Case assumptions represents less than 3 percent of the total daily capacity expected to be held to meet peak needs.[15]

Lastly, resources in every portfolio distribute the same fuel regardless of the supply resource being considered, so the relative asymmetries in costs of resources that exist in electricity generation fleets, where different resources have drastically different cost profiles and operating/fuel costs, is not present.[16] In summary, the difference in costs across portfolios and across draws for any given future tends to be small in PVRR terms. That being said, the small differences in costs across portfolios are driven primarily by three factors: (1) the difference in fixed costs of the resource options being considered; (2) price basin differentials and the supply basins/trading hubs associated with the different resource options; and (3) the difference between storage and pipeline resources as they relate to seasonal price spreads and the ability to purchase gas at the cheapest available basin for storage resources where pipeline resources are typically tied to purchasing gas at a particular supply basin.

[14] Note that short-term citygate delivery (see chapter 3) contracts may be lower cost than Mist Recall and, if the opportunity to contract a citygate delivery is expected to provide customer benefits relative to Mist Recall, NW Natural will take advantage of this opportunity. The availability and price of citygate deliveries is uncertain.

[15] Less than 32 MDT of daily capacity is different between the portfolios.

[16] Note that the expected carbon intensity of all of the portfolios is also expected be identical so even though carbon policy costs are a major risk to customers they do not impact supply resource choice since differences in the incremental carbon policy adders would impact all of the portfolios in concert rather than asymmetrically.

3.2. Results Part A: Regional Interstate Pipeline Is Available on NW Natural's PreferredTimeline

Again, while a decision on subscription of a regional interstate pipeline is not imminent, this section shows how the Company would analyze the decision if a pipeline were to move forward and it was expected that the pipeline would not be fully subscribed upon completion so that the Company could subscribe on the timeline that is the lowest cost for customers.

Figure 9.4 shows the frequency distribution of the simulation PVRR results for the 30,000 future environments for the "No Regional Pipeline" availability scenario (scenario 1) to provide an example of the final results from combining the fixed and variable cost simulation process results. Notice that the mean of the PVRRs of all the draws as well as the 95th and 99th percentile draws are depicted with vertical lines. The 95th and 99th percentile confidence bands are shown to represent the upside risk of a given resource portfolio.

Figure 9.4: Stochastic Risk Analysis Final Results- No Regional Pipeline Example

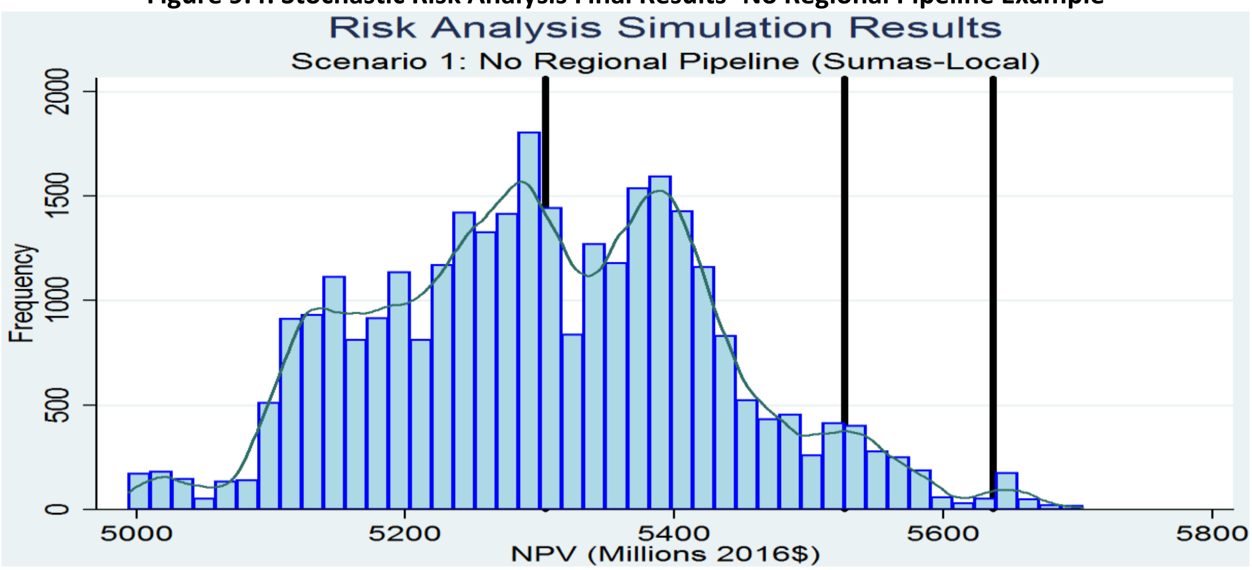
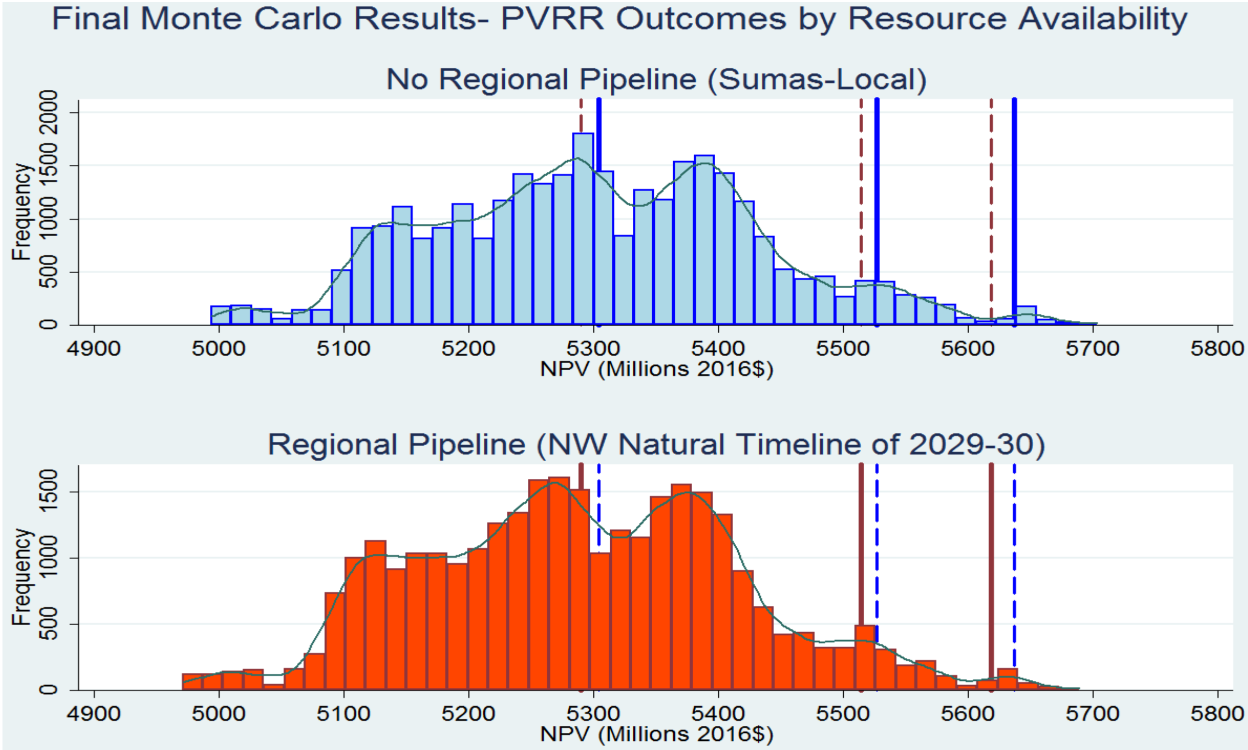


Figure 9.5 compares the frequency distributions of the "No Regional Pipeline" availability scenario (figure 9.4) with the "Regional Pipeline NWN Timeline" availability scenario to compare the relative difference in PVRR distributions across simulation draws as well as compare the means, 95th, and 99th percentiles (shown with the respective colors of the different distributions on each graph segment).

Figure 9.5: Comparing Simulation Distributions with and without a Regional Pipeline Available

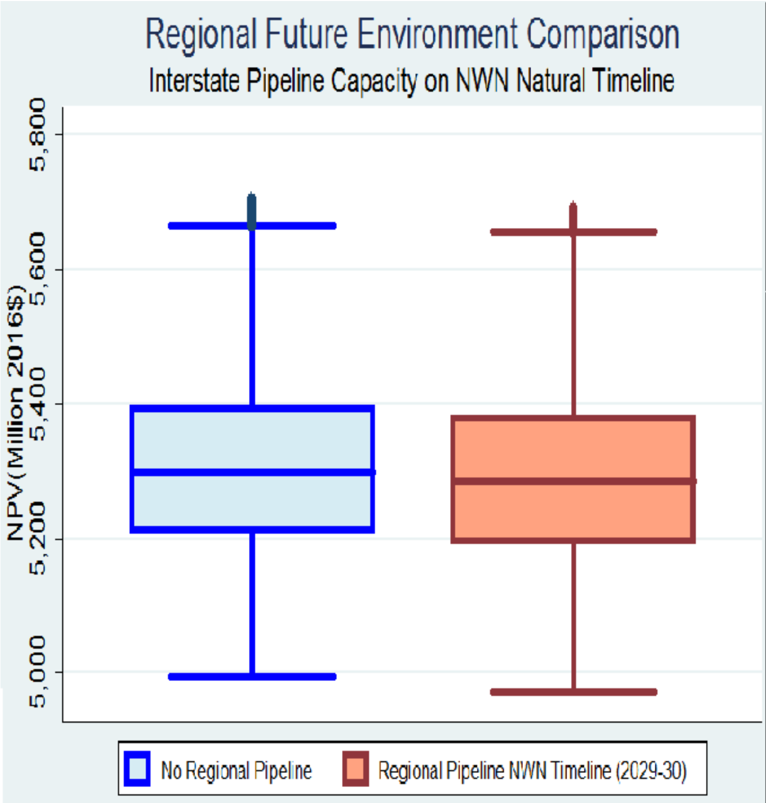


Since the future where the regional pipeline is not available is the result that is expected if a regional pipeline project were constructed and NW Natural decided not to subscribe, comparing the two graphs in the figure is a helpful tool in deciding if it is in customers' interest to subscribe to a regional interstate pipeline were one to be available. As can be seen from the graphs in figure 9.5, if a regional pipeline is available along a timeline of NW Natural's choosing[17] the mean, 95th percentile and 99th percentile PVRRs for the regional interstate pipeline subscription future are all cheaper than if a regional pipeline is not available.

However, it is more enlightening to determine under how many of the 30,000 simulation draws/futures/future environments analyzed it would be least cost to subscribe to the pipeline and how many future environments it would be least cost to *not* subscribe to the regional interstate pipeline were one available. Figure 9.6 shows the same distributions as figure 9.5 in boxplot form and a summary of the ranking of the portfolio's for each draw analyzed (a rank of one means the portfolio is lower cost for that future/draw whereas a rank of two means the portfolio is the higher cost of the two portfolios for that future) and the PVRRs at different points on the distribution of each portfolio.

[17] The most obvious way this would be possible would be a pipeline is built but not fully subscribed so capacity is available for subscription at any time, much like it is possible to contract capacity on TransCanada's Gas Transmission Northwest (GTN) pipeline today as there is capacity available for subscription.

Figure 9.6: Regional Pipeline Capacity Acquisition Decision if Timeline Could be Chosen by NWN



Ranking of Future Environment by Monte Carlo Assumption Draw (NPV in Millions of 2016$)		
Draws with:	No Regional Interstate Pipeline Built	Regional Interstate Pipeline Capacity Acquired on NWN Timeline (2029-2030)
#1 Rank	465	29535
#2 Rank	29535	465
Total	30000	30000

Scenario Monte Carlo Results (NPV in Millions of 2016$)		
	No Regional Interstate Pipeline Built	Regional Interstate Pipeline Capacity Acquired on NWN Timeline (2029-2030)
1%	$5,023	$5,010
5%	$5,110	$5,093
10%	$5,137	$5,117
25%	$5,210	$5,189
50%	$5,298	$5,285
75%	$5,392	$5,379
90%	$5,464	$5,449
95%	$5,527	$5,514
99%	$5,637	$5,619
Mean	**$5,304**	**$5,290**
Std Dev	127.59	127.74

The table in figure 9.6 shows that in more than 98 percent of the future environments it would be least cost for NW Natural to acquire regional interstate pipeline capacity if it were available and not fully subscribed (so that NWN could chose the timing of acquisition). Therefore, there is a high degree of confidence (low risk) this decision would turn out to be the least-cost option for customers. Again, this analysis is primarily for exposition purposes as a decision on pipeline subscription is not imminent and the difference between portfolios is only in the last few years of the 20-year planning horizon. As a decision about acquisition becomes closer in time in future IRPs the variation between portfolios would increase as the differences in portfolios would not be as highly discounted and more years in the PVRR calculation would have cost differences.

3.3. Results Part B: Take It or Leave Decision on Pipeline Capacity Available at One Point inTime

To show an important way the stochastic risk analysis would be applied to a resource decision that would likely carry a fair degree of risk and to analyze one of the major risks NW Natural could face— the in-service timing of regional interstate pipeline projects beyond its control— an example where the Company must decide to subscribe to a regional interstate pipeline under a forced timeline is used. The most likely instance of this would be a binding open season before construction begins on a pipeline where it is expected that upon completion the pipeline would be fully subscribed. In this case the Company would be presented with a “take it or leave it” opportunity to acquire interstate pipeline capacity. While NW Natural believes this situation is highly unlikely to occur within the next couple of years, it is not *entirely* implausible that the Company could face this decision regarding one of the prospective regional pipeline projects before the next IRP, so the method of risk analysis is presented here to detail the risk analysis that would be completed in such a situation (this is the analysis extending scenarios 7, 8, and 9 from chapter 8). Figures 9.7 and 9.8 are the same graphs as figures 9.5 and 9.6 under the constraint that NW Natural must acquire the interstate pipeline capacity in 2021-22 or not have the opportunity to subscribe indefinitely.

Figure 9.7: Comparing Subscribing to a Regional Pipeline Project in 2021-22 or not at all

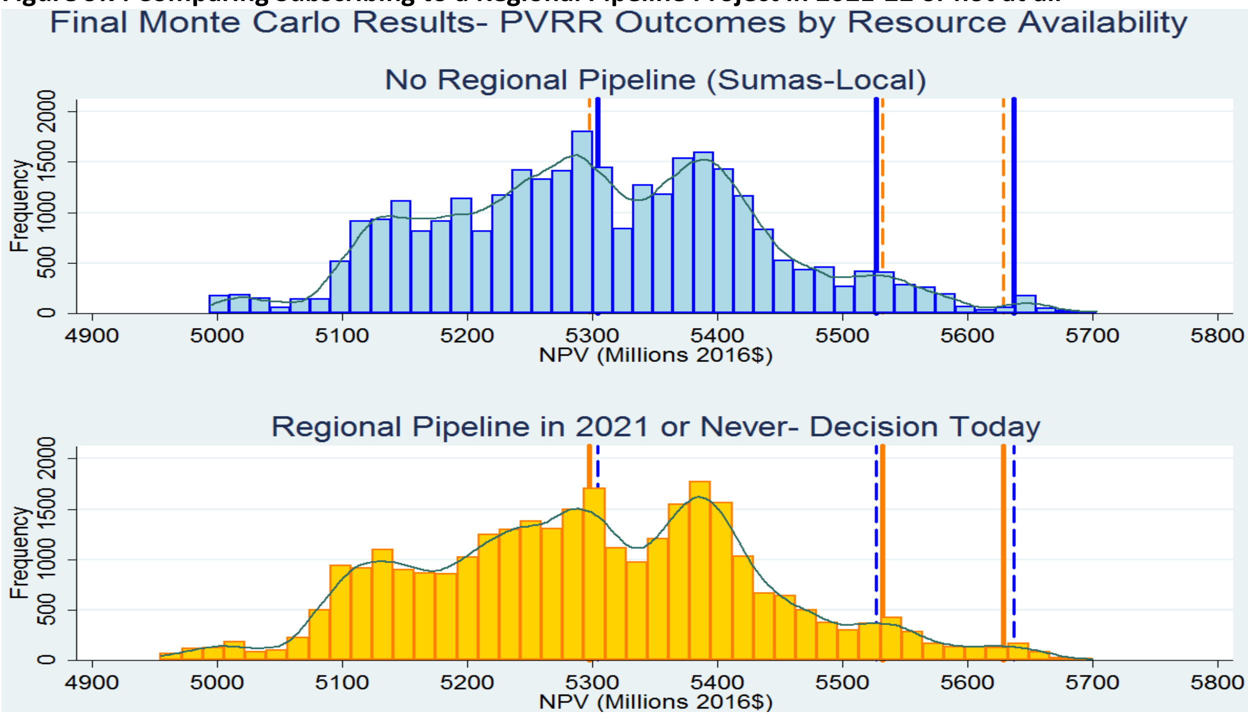
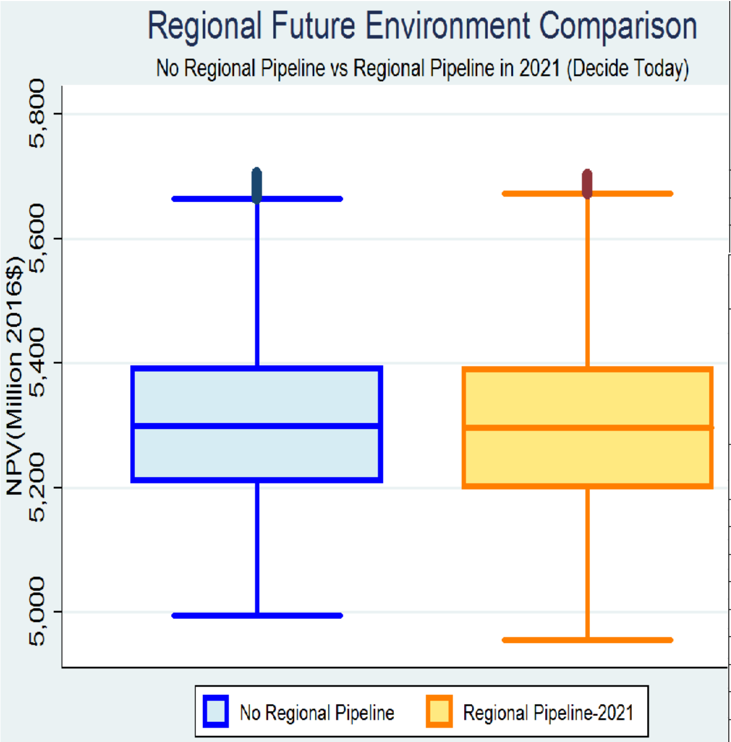


Figure 9.8: Regional Pipeline Capacity if Faced with Take-it-or-Leave-it Starting in 2021-22 Decision



Ranking by Monte Carlo Draw with Pipeline Decision in 2021 (NPV in Millions of 2016$)		
Draws with:	Choose not to Acquire Interstate Pipeline Capacity in 2021	Choose to Acquire Regional Interstate Pipeline Capacity in 2021
#1 Rank	10443	19557
#2 Rank	19557	10443
Total	30000	30000

Scenario Monte Carlo Results with Pipeline Decision in 2021 (NPV in Millions of 2016$)		
	Choose not to Acquire Interstate Pipeline Capacity in 2021	Choose to Acquire Regional Interstate Pipeline Capacity in 2021
1%	$5,023	$5,005
5%	$5,110	$5,092
10%	$5,137	$5,120
25%	$5,210	$5,201
50%	$5,298	$5,296
75%	$5,392	$5,390
90%	$5,464	$5,465
95%	$5,527	$5,532
99%	$5,637	$5,629
Mean	**$5,304**	**$5,297**
Std Dev	127.59	134.07

As figures 9.7 and 9.8 detail, if a decision had to be made to subscribe to a regional pipeline project now for a subscription starting in 2021-22 (or never) the decision is not as clear cut as it is if the Company can choose its own timeline (where the lowest cost option is to choose to pick up pipeline capacity 8 years later in 2029-30). Whereas over 98 percent of the simulation draws show it would make sense to subscribe to the interstate pipeline if NW Natural could chose the timeline, it would be lower cost to subscribe to the pipeline in 2021-22 in roughly 2/3 of the simulation draws. Additionally, while it is expected that subscribing to the pipeline would be the least-cost option (the mean is lower than not acquiring the capacity), at the 95th percentile the least-cost option is choosing to *not* subscribe to the pipeline.[18] While this analysis is informative, should an actual pipeline project that was expected to be fully subscribed upon completion move forward, the Company could use the cost estimates of that specific project to do the deterministic and stochastic risk analysis as opposed to lumping the three potential pipelines into one grouping since it is not known which, if any, project will go forward.

[18] Interestingly, at the 99th percentile it is cheaper to subscribe to the pipeline as opposed to not subscribing.

4. KEY FINDINGS

- NW Natural's stochastic supply resource risk analysis utilizes Monte Carlo simulation methodology that is new to this IRP.
- The goal of stochastic risk analysis is to test the sensitivity of expected resource decisions to assumptions about prices, weather, resource costs, and customer growth that are known to be uncertain.
- NW Natural's current resources will make up the majority of the Company's resource stack over the planning horizon even when considering resources acquired to accommodate load growth and therefore serve to mute the differences in PVRR across portfolios in different futures of the stochastic risk analysis.
- Since LDCs are in the business of distributing natural gas, variation in costs in different future environments tends to move in concert across resource portfolios as fuel switching is not possible.
  - It is only possible to take advantage of supply basin/trading hub basin differentials if pipeline capacity is held at multiple basins and seasonal price arbitrage through storage resources.
- All Base Case load scenarios (1-4 and 7-9) have identical resource portfolios through 2020-21 and scenarios 1-4 have identical resources through 2026-27 and are only significantly different in the last years of the planning horizon.
  - Most variation in costs across portfolios takes place at highly discounted values
- There is little chance Mist Recall will turn out to be more expensive than the other long-term resource options considered available (though as-of-now-unknown short-term citygate delivery options or recall agreements could be competitive).
- Load growth uncertainty is not a considerable risk to resource choice in the short term since Mist Recall is flexible and the amount recalled can be determined one year in advance of need.
- Resource choices that carry considerable customer risk will be decided in future IRPs.
- Feedback on the stochastic risk analysis methodology is important so the tool is ready to go in case a decision with a reasonable degree of risk needs to be made.

Chapter 10
Public Participation

1. TECHNICAL WORKING GROUP

The Technical Working Group (TWG) is an integral part of developing NW Natural's resource plans. During this planning cycle, the Company worked with representatives from Citizens' Utility Board of Oregon; Energy Trust of Oregon; Northwest Industrial Gas Users; Northwest Pipeline Corporation; the Public Utility Commission of Oregon staff; the Washington Utilities and Transportation Commission staff; and the Northwest Gas Association.

NW Natural hosted five TWG meetings and one conference call as part of its 2016 IRP process. Below is a brief summary of each meeting.

- TWG No. 1 held on Jan. 13, 2016
  NW Natural reviewed the 2014 IRP and results of the updated load forecast, including new methodology to forecast customer counts and use per customer.

- TWG No. 2 held on Feb. 10, 2016
  NW Natural reviewed existing resources and invited Northwest Pipeline and TransCanada to discuss regional natural gas resources. The Company also provided an update on Salem and discussed the potential North Mist Expansion for the Core. On the distribution side, the Company provided an overview of distribution system modeling and an update on other resources.

- TWG No. 3 held on March 17, 2016
  NW Natural invited Energy Trust of Oregon to discuss the demand-side management forecast. The Company reviewed environmental regulations, legislation, carbon adders, the natural gas price forecast, avoided costs, and the post DSM load forecast.

- TWG No. 4 held on May 24, 2016
  NW Natural presented the preliminary portfolio results, updated participants on the South Salem feeder project, and discussed Mist Asset Management. The Sherwood and Eugene distribution projects were addressed. Plans for the June 22 TWG agenda and timing for the draft IRP release and review process was also discussed.

- TWG No. 5 held on June 22, 2016
  NW Natural discussed a potential pilot program for geographically targeted accelerated DSM, and a potential methane emissions reduction certification pilot. The draft IRP Action Plan was reviewed and the draft IRP review process was discussed.

Appendix 10 contains the sign-in sheets for each TWG meeting.

- In addition to these meetings, TWG participants were invited to participate in a call on July 18, 2016, to review chapter 9 on the Stochastic Risk Analysis as it was not complete at the time of the June 22 TWG meeting. The call was also an opportunity to ask questions on the draft IRP.

2. PUBLIC PARTICIPATION

NW Natural invited customers to participate in the resource planning process by hosting a public meeting on the evening of July 20, 2016. A bill insert sent to all customers in June 2016 billings informed customers about the IRP process, welcomed customers to submit comments, and invited customers to attend the public meeting. No customers attended the July 20 public meeting or submitted comments.

Appendix 1
Regulatory Compliance

NW Natural's 2016 IRP - Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
Order No. 07-047			
Guideline 1(a)	All resources must be evaluated on a consistent and comparable basis.	NW Natural uses a site-specific cost of service model to estimate the PVRR of NW Natural owned resources. Existing non-NW Natural owned resources use their current tariff rates and future resources costs are developed using estimates from the owner of those facilities.	8
	All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	NW Natural attempted to include all known supply- and demand-side resource options, including some specifically requested by stakeholders. Supply-side options studied include not only the source of gas, but also the pipeline capacity required to transport the gas, the Company's gas storage options, the system enhancements necessary to distribute the gas and recall agreements. The demand-side study looked at all the potential energy savings available within the Company's service territory.	3,6, and 8
	Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling	Chapters Three and Six focus on supply- and demand-side resources, respectively. The supply-side options considered in Chapter Three range from existing and proposed interstate pipeline capacity from multiple providers and NW Natural's Mist underground storage to imported LNG, and includes satellite LNG facilities sited at various locations within the Company's service territory. For those resources evaluated as being sufficiently viable to be included in resource portfolio optimization, the Company clearly defines each resource's in-service date before which the respective resource is unavailable for selection as part of a resource portfolio. Because the Company identified unserved demand occurring in all areas of its service territory within the 20-year planning horizon in the absence of supply-side resource acquisition, it considered a variety of supply-side options to meet local, regional, and system-wide demand. These options included satellite LNG, NW Natural pipeline enhancements, and interstate pipeline expansions. The in-service dates of prospective resources range from short-term, such as Mist Recall supplies to longer-term resources such as new interstate pipelines. The Company also performed analyses varying the in-service dates of different resources. NW Natural's analysis considers all prospective supply-side resources to be available, as of assumed in-service dates, throughout the remainder of the 20-year planning horizon. The Company has also considered technologies such as biogas, which is not currently available but has been identified for continued monitoring and future assessment.	3,6, and 8
	Consistent assumptions and methods should be used for evaluation of all resources.	NW Natural uses a site-specific cost of service model to estimate the PVRR of NW Natural owned resources. Existing non-NW Natural owned resources use their current tariff rates and future resources costs are developed using estimates from the owner of those facilities.	8
	The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	NW Natural uses a real after-tax discount rate of 4.86 percent in this IRP, which it derives using the currently authorized values associated with its cost of capital in Oregon. The Company incorporates a 1.6 percent annual rate of inflation, which it estimated using methods with which the Commission is familiar.	8
Guideline 1(b)	Risk and Uncertainty must be considered.		

NW Natural's 2016 IRP - Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
1.b.2	At a minimum, utilities should address the following sources of risk and uncertainty: Natural gas utilities: demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and cost to comply with any regulation of greenhouse gas emissions.	Risk and uncertainty are intrinsic characteristics in long-term planning and NW Natural performed a wide range of sensitivities and scenarios to evaluate the impact of risk and uncertainty. More specifically, NW Natural analyzed demand uncertainty (peak, swing, and baseload) by using deterministic load forecasts, including forecasts characterized as traditional Base Case and low and high load growth scenarios. The Company first projected annual customer counts by customer sub-class and prepared three scenarios of customer growth, including a Base Case and low and high load growth scenarios. Finally, this IRP discusses the impacts of complying with prospective greenhouse gas emissions regulation and the uncertainty associated with these in Chapters Four and Five. Chapter Four contains the Company's evaluation of cost effective demand-side management based on an avoided cost that included an emission adder (a carbon price). The higher avoided cost resulted in a higher level of achievable demand-side resource potential than would result absent inclusion of an emission adder.	2, 3, 4, 5, 7, 8, and 9
	Utilities should identify in their plans any additional sources of risk and uncertainty.	New to this IRP is a stochastic supply resource risk analysis. This Chapter tests the robustness of the expected resource choices by determining the PVRR under a wide slate of future environments that represent the uncertainty of natural gas prices, weather, and resource costs. Additionally, NW Natural evaluated the PVRR of certain resources choices under different timing assumptions.	8,9
Guideline 1(c)	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers. The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	The primary goal of this IRP is the selection of a portfolio of resources with the best combination of expected costs and risks over a 20 year planning horizon. In this IRP that portfolio selected depends upon the prospective development of a numer of interstate pipeline projects. The analysis considers all costs that could reasonably be included in rates over the long term, which extends beyong the planning horizon and the life of the resource. The robustness of the expected costs was evaluated in the stochastic risk analysis found in Chapter nine.	8,9
	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	NW Natural uses PVRR as the key cost metric in this IRP and includes analysis of current and estimated future costs of both long- and short-lived resources.	8

NW Natural's 2016 IRP - Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
	To address risk, the plan should include, at a minimum:		
	Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	NW Natural assesses both the variability of costs and the severity of bad outcomes in the risk analysis in Chapter Nine and the scenario analysis in Chapter Eight.	8,9
	Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	NW Natural provides retail customers with a bundled gas product including gas storage by aggregating load and acquiring gas supplies through wholesale market physical purchases that may be hedged using physical storage or financial transactions. The following goals guide the physical or financial hedging of gas prices: 1) reliability, 2) lowest reasonable cost, 3) price stability, and 4) cost recovery. Chapter Three discusses hedging.	3
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	This IRP uses a 90th percentile design weather standard augmented by an historic seven-day peak event to evaluate the cost and risk trade-offs of various supply- and demand-side resources. This planning standard reflects the Company's assessment that costs associated with using a higher planning standard are not justified in comparison with the risk of weather occurring that is colder. Further analysis of how the Company's resource choices appropriately balance cost and risk are in Chapter Eight. In short, NW Natural considered not only the strictly economic data the Company assessed using SENDOUT®, but also the likelihood of certain resources such as satellite LNG being available, analysis of demand and price forecasting, and the non-economic but significant reliability benefits offered by certain resources.	1,8, and 9
Guideline 1(d)	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	Policy appears to be trending toward carbon constraints. The Company's underlying gas price forecast provided by our outside consultant includes the cost of compliance with most known environmental regulations. In addition, the Company included as a proxy for future state regulation an incremental carbon adder beginning in 2021 at $12.55 per metric ton of CO2 equivalent (MTCO2e) and increasing annually to $24.84 per MTCO2e in 2035. NW Natural considers the carbon price forecast in scenario development as a carbon tax on the carbon content of combustible fuels implemented on a national (or broad regional) basis and similar in its implementation to that currently in effect in British Columbia, Canada. It is still unknown the extent of the impact from the Environmental Protection Agency's Regulation 111(d) this too is being taken into consideration and monitored as the electric utilities make their plans known. Climate change regulation may also require more DSM or through taxation cause more DSM to be cost effective. Additionally, the Company is taking methane reduction regulation into consideration as well and is proposing to investigate a methane reduction pilot. New and developing state and federal policies are discussed in Chapters Four, Five, and Six.	4,5,and 6
Guideline 2(a)	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.	NW Natural provided the public considerable opportunities for participating in the development of the Company's 2016 IRP. The Company held five Technical Working Group (TWG) meetings, and one public meeting. NW Natural notified customers of the 2016 IRP process in a June 2016 bill insert, which invited the submission of comments and announced the July 20, 2016 public meeting. Chapter Ten discusses the technical working groups and the public meeting.	10

NW Natural's 2016 IRP - Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
Guideline 2(b)	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.	As evidenced by materials included in the plan, NW Natural has put forth all relevant non-confidential information necessary to produce a comprehensive Plan.	
Guideline 2(c)	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	NW Natural submitted on June 28, 2016, after conducting five TWG meetings, an initial draft plan in both Oregon and Washington. The action plan contained within the draft plan was discussed at a technical working group meeting held on June 22, 2016.	10
Guideline 3(a)	The utility must file an IRP for within two years of its previous IRP acknowledgement order.	The Commission acknowledged NW Natural's 2014 IRP on March 5, 2015; see Order No. 15-064 in Docket No. LC 60.	
Guideline 3(b)	The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	NW Natural will comply with this guideline.	
Guideline 3(c)	Commission Staff and parties should complete their comments and recommendations within six months of IRP filing.	The Company looks forward to working with Staff and interested parties in their review of this plan.	
Guideline 3(d)	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.	NW Natural is prepared for this process.	
Guideline 3(e)	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	The Company is prepared to receive direction from the Commission regarding analysis required in its next IRP.	
Guideline 3(f)	Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	The Company plans to file an annual report as required.	

NW Natural's 2016 IRP - Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
Guideline 3(g)	Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that: 1- Describes what actions the utility has taken to implement the plan; 2-Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and 3-Justifies any deviations from the acknowledged action plan.	The Company acknowledges this guideline.	
Guideline 4	At a minimum the plan must include the following elements:		
Guideline 4(a)	An explanation of how the utility met each of the substantive and procedural requirements.	This appendix is intended to comply with this guideline by providing an itemized response to each of the substantive and procedural requirements.	
Guideline 4(b)	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions	The Base Case demand forecast uses NW Natural's projected customer growth and projected prices. However, the IRP also analyzes scenarios associated with both high and low demand growth. Chapter Nine provides the stochastic load risk analysis results.	2, 9
Guideline 4(c)	For electric utilities …	Not applicable to NW Natural's gas utility operations.	
Guideline 4(d)	For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources.	Using the SENDOUT® optimization model, NW Natural determined the peaking, swing, and baseload gas supply and associated transportation and storage for each year of the 20-year planning horizon. Please see the appendix to Chapter Eight for information regarding individual scenarios and sensitivities used in the Company's optimization modeling and the required timing of specific resources in each case.	8
Guideline 4(e)	Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology.	NW Natural determined the best resource mix by studying supply-side options currently used; such as pipeline transportation contracts, gas supply contracts, and physical and financial hedging; as well as alternative options such as additional capacity or infrastructure enhancements. The Company also considered future developments such as pipeline enhancements. Chapter Three discusses the various supply side options and their costs. The Company compiled demand-side resource options with assistance from the Energy Trust of Oregon, and these options are identified in Chapter Six.	3, 6
Guideline 4(f)	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	Explanation: Chapter Three discusses NW Natural's Gas Supply Risk Management Policies, modeling tools, and cost/risk considerations that form the basis for planning and maintaining reliable gas service. For example, the Company's Gas Supply Department uses SENDOUT© to perform its dispatch modeling from various pipeline supplies and storage facilities. The objective is to ensure reliable service during the heating season on an aggregate, system-wide basis as well as achieve the maximum economic benefit from seasonal price differences and varying gas delivery terms. The SynerGEE® software package also provides the Company the opportunity to evaluate performance of the distribution system under a variety of conditions, with the analysis typically focused on meeting growing peak day customer demands while maintaining system stability. Chapter Seven discusses the approach the Company uses to provide reliable service at the Distribution System Planning Level.	3 and 7

NW Natural's 2016 IRP - Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
Guideline 4(g)	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered	Chapter Eight describes the alternative resource mix scenarios and forward looking sensitivities involving commodity availability, commodity cost, transportation cost, and/or load forecast inputs evaluated in the IRP. The Company identified the gas price forecasts, which represent key assumptions. The Company also included a cost of carbon in its Base Case price forecast and analyzed sensitivities related to the price of carbon. Further, The Company identified specific environmental compliance costs that were factored into the determination of the Company's avoided cost, which in turn factored into the identification of cost-effective demand-side resources. The assumptions for the various scenarios included in Chapter Eight may be found in its associated Appendices.	4,5,6 and 8
Guideline 4(h)	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations - system-wide or delivered to a specific portion of the system.	As described above and in more detail in the Plan, NW Natural designed numerous alternate resource mix scenarios, where each scenario allows for changes to the supply-side resources available for selection. Chapter Eight and associated appendices document the resource portfolio options evaluated in this IRP.	8
Guideline 4(i)	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties.	Chapter Nine discusses the results of the stochastic risk analysis and tests the robustness of the expected resource choice over a wide slate of future environments that represent uncerrtainty of natural gas prices, weather and resource costs.	9
Guideline 4(j)	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Chapter Nine discusses the results of the stochastic risk analysis and tests the robustness of the expected resource choice over a wide slate of future environments that represent uncerrtainty of natural gas prices, weather and resource costs.	9
Guideline 4(k)	Analysis of the uncertainties associated with each portfolio evaluated.	Chapters Three, Eight, and Nine discuss the uncertainties associated with the availability and cost of resources.	3, 8, and 9
Guideline 4(l)	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.	Chapter Nine discusses the results of the stochastic risk analysis and selection of the resource portfolio.	9
Guideline 4(m)	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation.	NW Natural does not believe its preferred portfolio is inconsistent with state or federal energy policies. Potential barriers to implementation may relate to the ultimate availability and timing of certain incremental resources selected for the Company's preferred portfolio (e.g., satellite LNG, imported LNG) due to facility siting / permitting challenges, market viability, and others. Chapters Three, Four, and Eight discuss such potential barriers.	3,4,and 8
Guideline 4(n)	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	Chapter One presents NW Natural's multi-year action plan, which identifies the short-term actions the Company intends to pursue within the next two to four years.	1
Guideline 5	Transmission	Not applicable to NW Natural's gas utility operations	

NW Natural's 2016 IRP - Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
Guideline 6(a)	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	As discussed in Chapter Six, NW Natural worked with Energy Trust of Oregon to analyze the potential energy savings that could be cost-effectively procured within the Company's service territory over the next 20 years. The study determined the achievable potential by analyzing customer demographics together with energy efficiency measure data. The results were then evaluated with supply-side resources using SENDOUT®. A deployment scenario was applied to the total potential. The Company and Energy Trust review these assumptions each year when Energy Trust plans its program budget for the subsequent calendar year.	6 and 8
Guideline 6(b)	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	Appendix Six provides annual therm savings targets for NW Natural's Oregon and Washington service areas. These targets are disaggregated to specific customer segment and program type. NW Natural's Schedule 301, Public Purposes Funding Surcharge, contains a special condition requiring NW Natural to work with Energy Trust every year to determine if the funding level is appropriate to meet the subsequent year's therm savings targets. At the time of this review, the Company and Energy Trust evaluate the applicable IRP annual target and consider unforeseen influences that may either increase or reduce the subsequent year's target. NW Natural then files an updated tariff which proposes Schedule 301 adjustments in order to sufficiently fund the subsequent year's target, including a buffer fund for unexpected expenses.	6
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 30 percent of the Company's throughput. This allows the Company to reduce system stress during periods of unusually high demand.	
Guideline 8	Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for CO2, NOx, SO2, and Hg emissions. Utilities should analyze the range of potential CO2 regulatory costs in Order No. 93-695, from \$0 - \$40 (1990\$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for NOx, SO2, and Hg, if applicable.	At present, the only supply-side implication of environmental externalities in the Company's direct gas distribution system is that some methods of natural gas storage require combustion of the gas. Upstream gas system infrastructure (pipelines and gathering systems) do produce some CO_2 emissions from compressors used to pressurize and move gas throughout the system. However, the Company incorporates a carbon price into its gas price forecast beginning in 2021.	4
Guideline 9	Direct Access Loads	Not applicable to NW Natural's gas utility operations	
Guideline 10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.	This plan studies the supply-side needs for NW Natural's complete service territory which includes customers in Oregon and Washington.	

NW Natural's 2016 IRP - Oregon Compliance

Citation	Requirement	NW Natural Compliance	Chapter
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; t+C27o reliably meet peak, swing, and baseload system requirements. For this IRP, the Company utilizes an 90% probability coldest winter planning standard augmented with an historic seven-day cold weather event, which includes the design day, against which to evaluate the cost and risk trade-offs of various supply- and demand-side resources available to SENDOUT®. NW Natural's integrated resource planning reflects the Company's evaluation and selection of a planning standard which provides reliability for customers. Resulting resource portfolios provide the best combinations of expected costs and associated risks and uncertainties for the utility and its customers.	7
Guideline 12	Distributed Generation	Not applicable to NW Natural's gas utility operations.	
Guideline 13(a)	Resource Acquisition	Not applicable to NW Natural's gas utility operations.	
Guideline 13(b)	Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.	Chapter Three describes NW Natural's Gas Acquisition Plan detailing the Company's strategies and practices for acquiring gas supplies. The Company's Gas Acquisition Plan is centered on the following goals: 1) Reliability, 2) Diversity, 3) Price Stability, and 4) Cost Recovery.	3
Order No. 11-196 , UM 1286	For natural gas utilities, each IRP preparation process and final published IRP will address both planning to meet normal annual expected demand (as defined by the LOC - both base-load and swing) by day and planning to meet annual peak demand by day. The planning will include gas supply and associated transportation along with expected use of storage.	NW Natural views its plan to meet normal annual expected demand as being wholly encompassed within the Company's plan to meet demand in a year with design weather. As the plan addresses demand on an annual basis predicated on design weather, which includes a peak day, resource decisions within the plan fully reflect the Company's ability to meet demand under normal conditions on an annual basis.	

NW Natural's 2016 IRP - Washington Compliance

Rule	Requirement	Plan Citation
WAC 480-90-238(4)	Work plan filed no later than 12 months before next IRP due date.	NW Natural filed its original work plan on August 28, 2015 and then filed a revised work plan on October 13, 2015. The Company also filed a supplement to the workplan on May 31, 2016.
WAC 480-90-238(4)	Work plan outlines content of IRP.	The work plan filed on August 28, 2015, outlined the content of the 2016 IRP.
WAC 480-90-238(4)	Work plan outlines method for assessing potential resources. (See LRC analysis below)	The work plan filed on August 28, 2015, provided the methodology used in developing the 2016 IRP. NW Natural developed and integrated demand forecasts, weather patterns, natural gas price forecasts, and demand- and supply-side resources into Gas Supply and Planning Optimization software. The modeling results guided the Company toward the least cost resource portfolio.
WAC 480-90-238(5)	Work plan outlines timing and extent of public participation.	The work plan filed on August 28, 2015, states six technical working group meetings were scheduled: November 3, 2015; November 30, 2015; January 13, 2016; February 10, 2016, March 17, 2016, May 24, 2016, and June 22, 2016. This was revised in October 13, 2015 to remove the two meetings in November. Lastly, customers were notified of this IRP's process through a June 2016 bill insert, a facsimile of which is included in Appendix Ten. This bill insert welcomed public comments and invited customers to a public meeting, which occurred on July 20, 2016.
WAC 480-90-238(4)	Integrated resource plan submitted within two years of previous plan.	NW Natural filed its 2014 IRP on August 29, 2014. *See* Docket No. UG-131473.
WAC 480-90-238(5)	Commission issues notice of public hearing after company files plan for review.	*pending*
WAC 480-90-238(5)	Commission holds public hearing.	*pending*
WAC 480-90-238(2)(a)	Plan describes mix of natural gas supply.	Chapter Three outlines currently held and available supply side options including existing and proposed interstate pipeline capacity from multiple providers, the Company's Mist underground storage, imported LNG and Satellite LNG facilities. The Company has also provided a commentary of other alternative supply side option such as biogas.
WAC 480-90-238(2)(a)	Plan describes conservation supply.	Chapter Six documents how NW Natural determined the achievable potential of DSM within its service territory over the next 20 years.
WAC 480-90-238(2)(a)	Plan addresses supply in terms of current and future needs of utility and ratepayers.	NW Natural analyzed current demand and examined uncertainty regarding future demand using a set of deterministic load forecasts, including the traditional low and high load growth scenarios. The Company projected annual customer counts by customer sub-class and prepared customer forecasts for three scenarios; including low growth, the Company's Base Case, and high growth. NW Natural then statistically estimated gas usage equations for each customer subclass (or market segment). The Company derived design year (including peak day) projections using multiple regression models, and separating base load from temperature-sensitive load. Next, the Company integrated design weather and forecasted customers with gas usage equations to derive firm service design day peak demand requirements for each 20-year forecast scenario.

NW Natural's 2016 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.	NW Natural considered the strictly economic data assessed by the SENDOUT® model; the likely availability of certain resources such as imported or satellite LNG; scenario analysis of demand and gas prices; and the results of an extensive risk analysis to various factors to ensure consideration of resource uncertainties and costs of risks when developing the plan. After considering all these factors, the Company selected a near-term Preferred Portfolio given the various futures and identified resources consistent with that portfolio for that specific future acquisition.
WAC 480-90-238(2)(b)	LRC analysis considers resource costs.	Chapter Eight identifies the costs of alternative supply-side resource portfolios for each of multiple possible futures. A fundamental task associated with this is the estimation of the revenue requirements associated with discrete supply-side resources, including commodity prices.
WAC 480-90-238(2)(b)	LRC analysis considers market-volatility risks.	NW Natural developed several different risk analyses in addition to the Base Case in part to examine risks associated with uncertainty regarding natural gas prices and price volatility. These sensitivities evaluated higher levels of avoided costs, different natural gas prices price paths over the planning horizon, and the effects of alternative futures involving LNG exports on natural gas prices. The Company used the results of these sensitivities to inform its resource acquisition plan.
WAC 480-90-238(2)(b)	LRC analysis considers demand side uncertainties.	Chapter Six discusses DSM's effect on the supply-side resource mix. Additionally, the Company analyzed both high and low avoided cost scenarios.
WAC 480-90-238(2)(b)	LRC analysis considers resource effect on system operation.	Chapter Eight discusses the multiple scenarios studied in this plan.
WAC 480-90-238(2)(b)	LRC analysis considers risks imposed on ratepayers.	NW Natural developed several risk analyses including, the most important of which is which resources and their acquisition timing prevent unserved demand from firm service customers. In addition to sensitivities analyzing the impact of alternative natural gas price paths, NW Natural performed various risk analyses including a risk analysis of construction costs for both new interstate pipelines as well as future underground storage. Please see both Chapters Eight and NIne.

NW Natural's 2016 IRP - Washington Compliance

Rule	Requirement	Plan Citation
WAC 480-90-238(2)(b)	LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government.	NW Natural's 2016 IRP considers adoption of incremental regulation reflecting state or federal policies with respect to GHG emissions. The estimated impact of the Environmental Protection Agency's draft Rule under Section 111(d) of the U.S. Clean Air Act on natural gas prices is incorporated in the natural gas price forecasts the Company obtained from a third-party vendor and uses in the 2016 IRP. NW Natural adds to this price forecast an incremental carbon cost as a Base Case proxy for compliance costs associated with regulation reflecting Washington or regional policies with respect to GHG emissions. This latter cost is first applied to the carbon content of natural gas delivered by NW Natural in 2017 at a level of \$13.18 per $MTCO_2e$ and increases annually to \$31.71 per $MTCO_2e$ in 2035 (dollar values in \$2015). The Company discusses new and developing state and federal policies in Chapter Four.
WAC 480-90-238(2)(b)	LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	As stated above, NW Natural's Base Case natural gas price forecast in the 2016 IRP includes both the estimated impact of the Environmental Protection Agency's draft Rule under Section 111(d) of the U.S. Clean Air Act on natural gas prices and an incremental carbon cost as a proxy for compliance costs associated with regulation reflecting Washington or regional policies with respect to GHG emissions. This latter cost is first applied to the carbon content of natural gas delivered by NW Natural in 2017 at a level of \$13.18 per $MTCO_2e$ and increases annually to \$31.71 per $MTCO_2e$ in 2035 (dollar values in \$2015). Additionally, NW Natural's 2016 IRP includes scenario analyses with a range of incremental carbon costs from no incremental cost to a high incremental cost starting at \$65.56 per $MTCO_2e$ in 2017.
WAC 480-90-238(2)(b)	LRC analysis considers need for security of supply.	The Plan states in Chapter Three that the Company's first priority is to ensure it has a gas resource portfolio sufficient to satisfy core customer requirements. The second priority is to achieve sufficient resources at the lowest cost to customers.
WAC 480-90-238(2)(c)	Plan defines conservation as any reduction in natural gas consumption that results from increases in the efficiency of energy use or distribution.	The Plan defines energy reductions from DSM programs in the Company's service territory as the reduction of gas consumption resulting from the installation of a cost effective conservation measure.
WAC 480-90-238(3)(a)	Plan includes a range of forecasts of future demand.	This Plan evaluates the amount of gas needed to serve the Company's firm service customers, including under future circumstances different from those of the Base Case.
WAC 480-90-238(3)(a)	Plan develops forecasts using methods that examine the effect of economic forces on the consumption of natural gas.	NW Natural analyzed alternative resource portfolios under changes from the Base Case load forecast due to high and low customer growth and, using the resource optimization capabilities of SENDOUT®, compared these with the portfolios produced under the Base Case load forecast.

NW Natural's 2016 IRP - Washington Compliance

Rule	Requirement	Plan Citation
WAC 480-90-238(3)(a)	Plan develops forecasts using methods that address changes in the number, type and efficiency of natural gas end-uses.	The Plan examines the impact of higher and lower loads than those in the Base Case load forecast, which may be thought of as resulting from changes in the number, type and efficiency of natural gas end-uses. NW Natural includes more specific analysis of the impact on resource requirements of alternative futures involving higher loads than in the Base Case load forecast in the industrial and transportation sectors.
WAC 480-90-238(3)(b)	Plan includes an assessment of commercially available conservation, including load management.	The achievable potential study performed to determine the potential of demand-side management programs that should be included in NW Natural's preferred portfolio began with a study of all known commercially available conservation measures, including those not currently in the market place. Chapter Six provides an overview of new measures as well as interesting findings. With respect to demand-side load management, the Company foresees continuing to shave peak load requirements when and where necessary by curtailing interruptible customers.
WAC 480-90-238(3)(b)	Plan includes an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	Chapter Six details how NW Natural delivers energy efficiency programs that offer customers incentives for implementing cost effective demand-side management measures. Additionally, NW Natural in partnership with the Energy Trust is proposing doing an Accelerated/Enhanced Geographically Targeted DSM pilot. This pilot is also discussed in Chapter Six.
WAC 480-90-238(3)(c)	Plan includes an assessment of conventional and commercially available nonconventional gas supplies.	NW Natural determined the best resource mix by studying supply-side options currently used, such as pipeline transportation contracts, gas supply contracts, storage, and physical and financial hedging, as well as future alternatives such as additional capacity or infrastructure enhancements. Potential future developments such as imported LNG, biogas, and pipeline enhancements were also considered.
WAC 480-90-238(3)(d)	Plan includes an assessment of opportunities for using company-owned or contracted storage.	NW Natural assessed its Mist underground storage, imported LNG, as well as Satellite LNG facilities located at various locations within the Company's service territory as resource options.
WAC 480-90-238(3)(e)	Plan includes an assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources.	Chapter Three discusss NW Natural's assessment of pipeline capability, reliability, and additional pipeline resources.
WAC 480-90-238(3)(f)	Plan includes a comparative evaluation of the cost of natural gas purchasing strategies, storage options, delivery resources, and improvements in conservation using a consistent method to calculate cost-effectiveness.	NW Natural determined the best resource mix by studying supply-side options currently used; such as pipeline transportation contracts, gas supply contracts, and physical and financial hedging; as well as alternative options such as additional capacity or infrastructure enhancements. The Company also considered future developments such as imported/exported LNG and pipeline enhancements. SENDOUT® determined the least cost resource mix through linear programing optimization, which the Plan discusses in Chapter Eight.
WAC 480-90-238(3)(g)	Plan includes at least a 10-year long-range planning horizon.	The long-range plans NW Natural discusses in this IRP span a 20-year planning horizon.
WAC 480-90-238(3)(g)	Demand forecasts and resource evaluations are integrated into the long range plan for resource acquisition.	This IRP integrates demand forecasts with the cost, risk, and capabilities of alternative resource portfolios into a long-term plan for resource acquisition.

NW Natural's 2016 IRP - Washington Compliance

Rule	Requirement	Plan Citation
WAC 480-90-238(3)(h)	Plan includes a two-year action plan that implements the long range plan.	The Action Plan in this IRP details NW Natural's actions related to supply- and demand-side resource acquisition over the planning horizon. Additionally, the Action Plan discusses ongoing reviews or other actions to be accomplished by the Company, including those specific to load forecasting, resource portfolio optimization (SENDOUT® modeling), Avoided Cost determination, and Public Involvement.
WAC 480-90-238(3)(i)	Plan includes a progress report on the implementation of the previously filed plan.	Chapters One and Chapter Three discuss progress on each item since the last previously filed plan.
WAC 480-90-238(5)	Plan includes description of consultation with commission staff. (Description not required)	WUTC Commission Staff was a party to the Technical Working Group. NW Natural documents public participation in Appendix Ten.
WAC 480-90-238(5)	Plan includes a description of completion of work plan. (Description not required)	The Key Findings at the end of most chapters and the Multi-Year Action Plan in Chapter One serve to document NW Natural's successful completion of the Plan.

Appendix 2
Gas Requirements Forecast

Residential Customer Forecast Technical Details

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Econometric Models for Residential Customers

- Used augmented Dickey-Fuller (ADF) test for unit roots in variables used in Residential new construction models

Variable	Test	Version	Confidence Level
Oregon Residential New Construction (ORRESNC)	ADF Single Mean	Rho/Tau	Could not reject at > 90%
Washington Residential New Construction (WARESNC)	ADF Single Mean	Rho	99.99%
Oregon Housing Starts (ORHOUS)	ADF Single Mean	Rho	>97%

- SAS' Proc Autoreg (Yule – Walker) used to deal with autocorrelated errors
- Generally relied on values of Akaike Information Criterion (AIC) for choosing between similar models
  - Example: choice of model with 2 AR lags for ORRESNC versus model with 1

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Oregon Residential: New Construction Customer Additions

Yule-Walker Estimates			
SSE	13041308.2	DFE	20
MSE	652065	Root MSE	807.50567
SBC	416.664281	AIC	410.569902
MAE	557.942749	AICC	413.727797
MAPE	7.90496958	HQC	412.260224
Durbin-Watson	1.4223	Regress R-Square	0.8807
		Total R-Square	0.9557

Parameter Estimates					
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	-1512	890.8221	-1.70	0.1052
ORHOUS	1	338.9661	61.7204	5.49	<.0001
L1ORHOUS	1	165.1725	62.5429	2.64	0.0157

Estimates of Autoregressive Parameters			
Lag	Coefficient	Standard Error	t Value
1	-0.679334	0.213643	-3.18
2	0.295179	0.213643	1.38

Model used to forecast OR Residential new construction customer additions (ORRESNC).

Explanatory variables:

ORHOUS
Oregon housing starts in calendar year *t*

L1ORHOUS
Oregon housing starts in calendar year *t-1*

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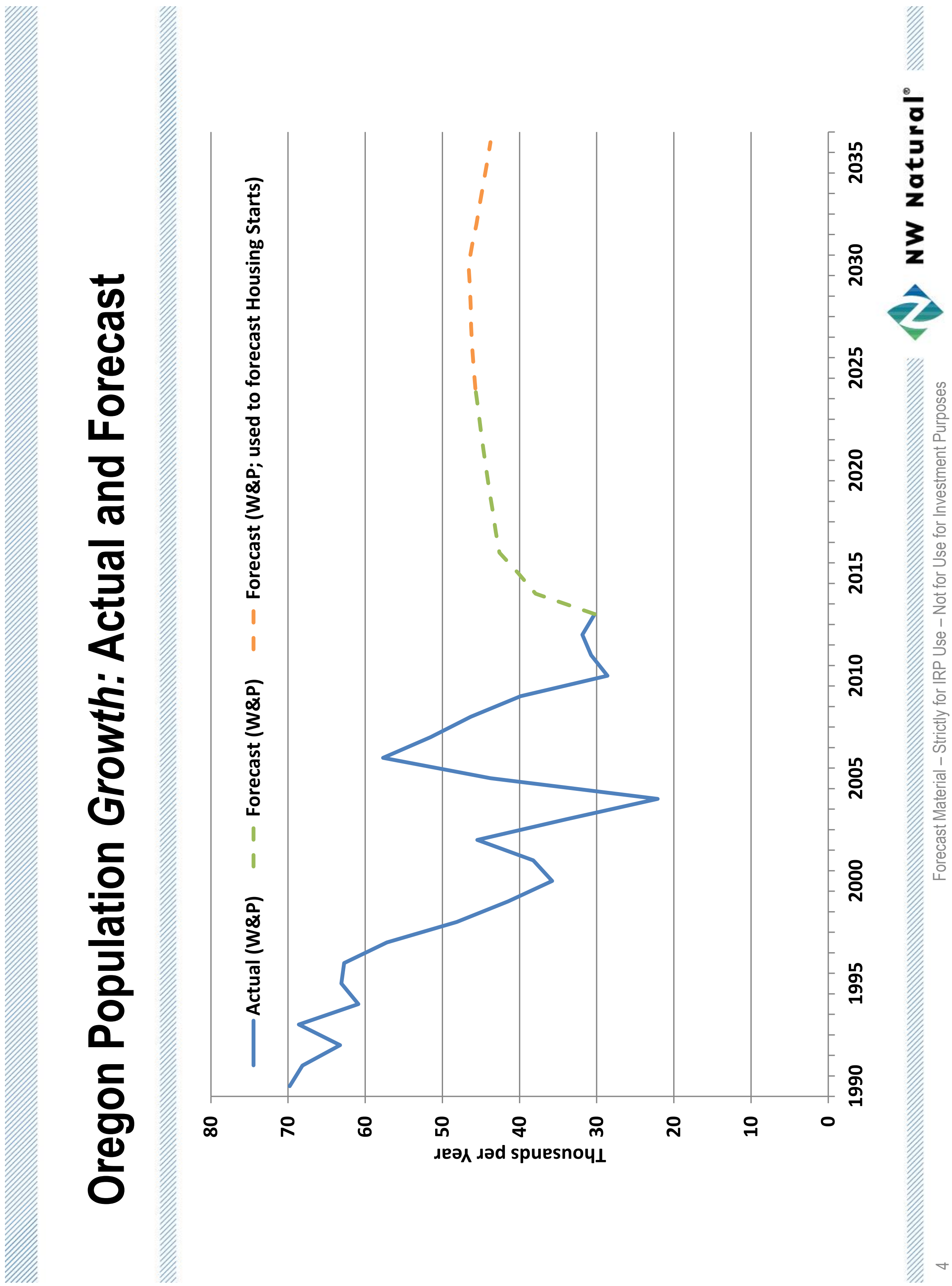
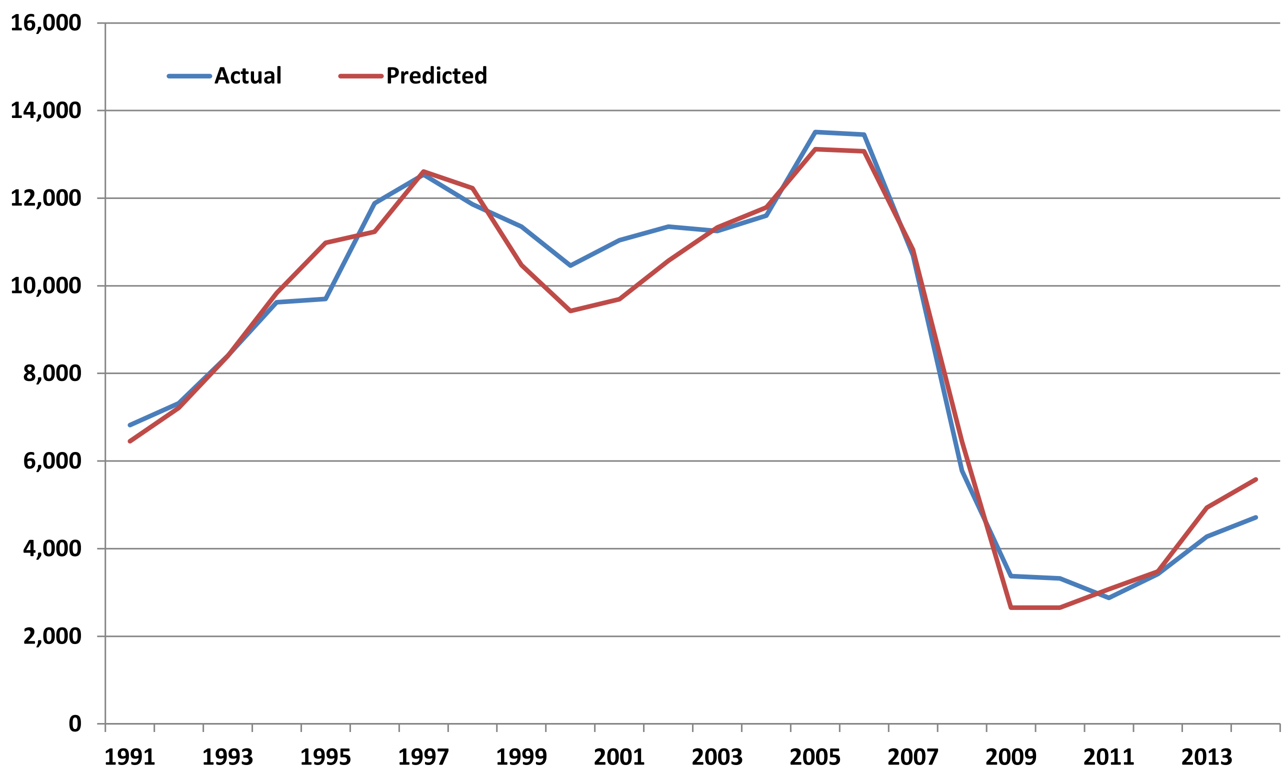

Oregon Population Growth: Actual and Forecast
Actual (W&P)
Forecast (W&P)
Forecast (W&P; used to forecast Housing Starts)
Thousands per Year
0
10
20
30
40
50
60
70
80
1990
1995
2000
2005
2010
2015
2020
2025
2030
2035
NW Natural
Forecast Material – Strictly for IRP Use – Not for Use for Investment Purposes
4

Oregon Residential New Construction Additions: Actual and Predicted



Oregon Residential: Conversion Customer Additions

Yule-Walker Estimates			
SSE	0.29760218	DFE	21
MSE	0.01417	Root MSE	0.11904
SBC	-26.575995	AIC	-31.451498
MAE	0.08500842	AICC	-29.451498
MAPE	1.00138429	HQC	-30.099241
Durbin-Watson	1.8526	Regress R-Square	0.7047
		Total R-Square	0.9167

Parameter Estimates					
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	67.6789	19.0469	3.55	0.0019
SASYEAR	1	-0.0294	0.009540	-3.09	0.0056
POST00	1	-0.2627	0.1278	-2.06	0.0524

Estimates of Autoregressive Parameters			
Lag	Coefficient	Standard Error	t Value
1	-0.558228	0.181053	-3.08

Model used to forecast OR Residential conversion customer additions.

Explanatory variables:

SASYEAR: Calendar year

POST00
Indicator variable: 1 if calendar year > 2000 and 0 otherwise.

POST00 used to model impact of technology implemented in 2000 which allowed standardized review of prospective Residential conversion customers

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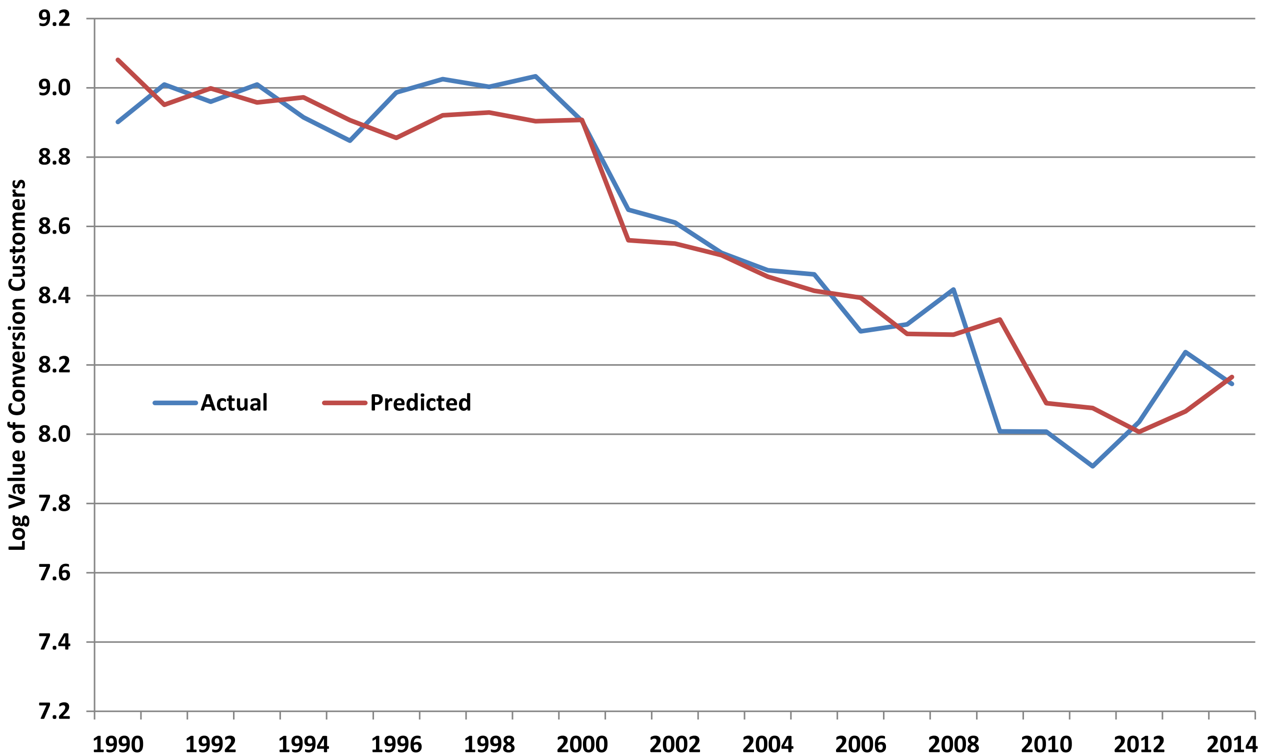
Oregon Residential Conversion Customer Additions: Actual and Predicted



Forecast Material – Strictly for IRP Use – Not for Use for Investment Purposes

Washington Residential: New Construction Customer Additions

Yule-Walker Estimates			
SSE	1409393.08	DFE	20
MSE	70470	Root MSE	265.46121
SBC	344.887212	AIC	340.174996
MAE	212.136917	AICC	342.280259
MAPE	12.1824859	HQC	341.425148
Durbin-Watson	1.3436	Regress R-Square	0.7451
		Total R-Square	0.9300

Parameter Estimates

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	127.5597	340.1728	0.37	0.7116
ORHOUS	1	135.0776	21.2932	6.34	<.0001
L1ORHOUS	1	-32.9649	20.5888	-1.60	0.1250

Estimates of Autoregressive Parameters

Lag	Coefficient	Standard Error	t Value
1	-0.641935	0.171453	-3.74

Model used to forecast WA Residential new construction customer additions.

Explanatory variables:

ORHOUS
Oregon housing starts in calendar year *t*

L1ORHOUS
Oregon housing starts in calendar year *t-1*

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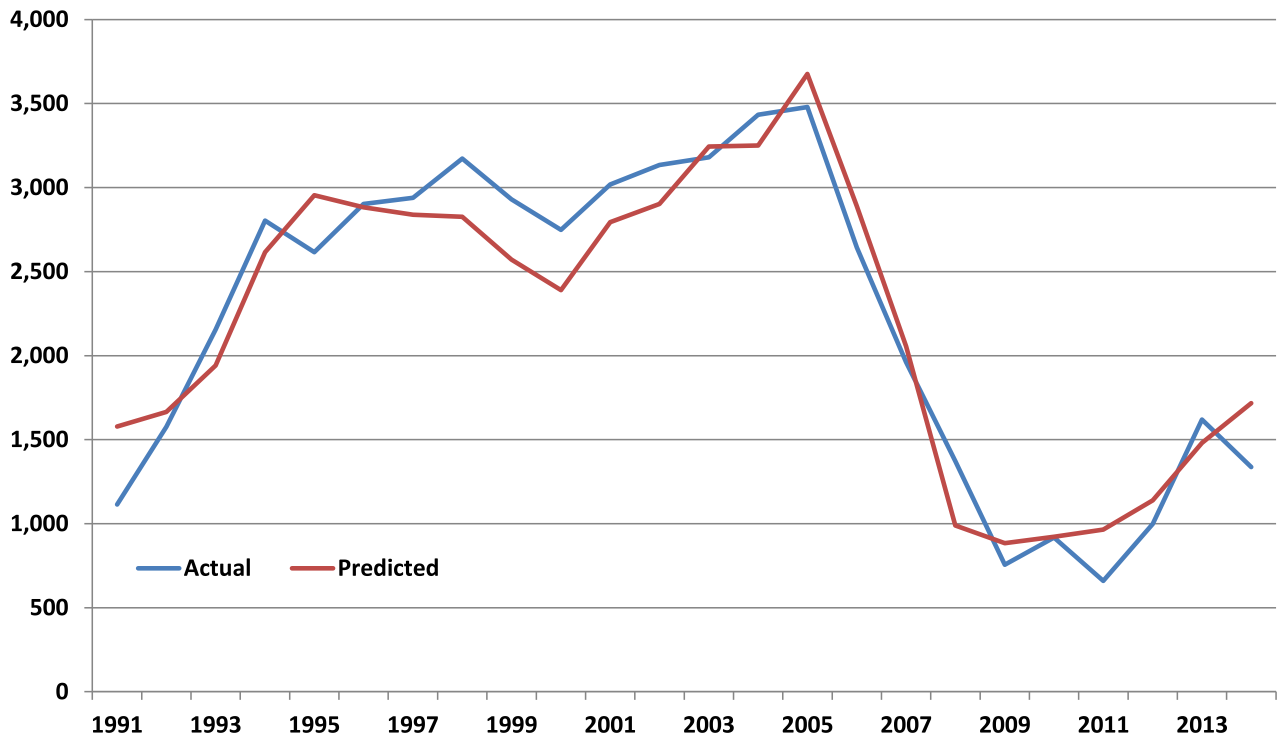
Washington Residential New Construction Additions: Actual and Predicted



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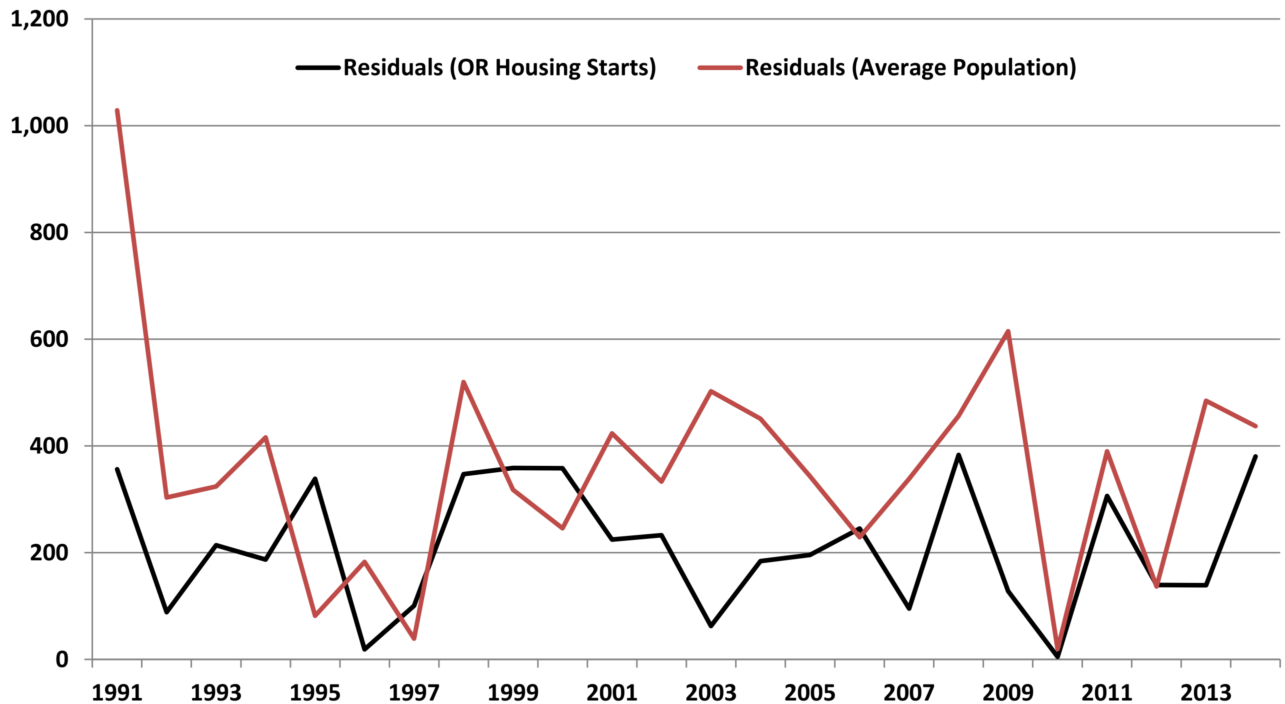
Washington Residential New Construction Additions: Absolute Value of Residuals from Two Models



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Washington Residential: Conversion Customer Additions

Yule-Walker Estimates			
SSE	1.15857731	DFE	21
MSE	0.05517	Root MSE	0.23488
SBC	7.71029012	AIC	2.83478682
MAE	0.17222639	AICC	4.83478682
MAPE	3.00817056	HQC	4.18704422
Durbin-Watson	1.5483	Regress R-Square	0.1997
		Total R-Square	0.8174

Parameter Estimates					
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	72.3025	43.2231	1.67	0.1092
SASYEAR	1	-0.0332	0.0216	-1.53	0.1397
POST00	1	-0.0968	0.2578	-0.38	0.7111

Estimates of Autoregressive Parameters			
Lag	Coefficient	Standard Error	t Value
1	-0.702389	0.155326	-4.52

Model used to forecast WA Residential conversion customer additions.

Explanatory variables:

SASYEAR: Calendar year

POST00
Indicator variable: 1 if calendar year > 2000 and 0 otherwise.

POST00 used to model impact of technology implemented in 2000 which allowed standardized review of prospective Residential conversion customers

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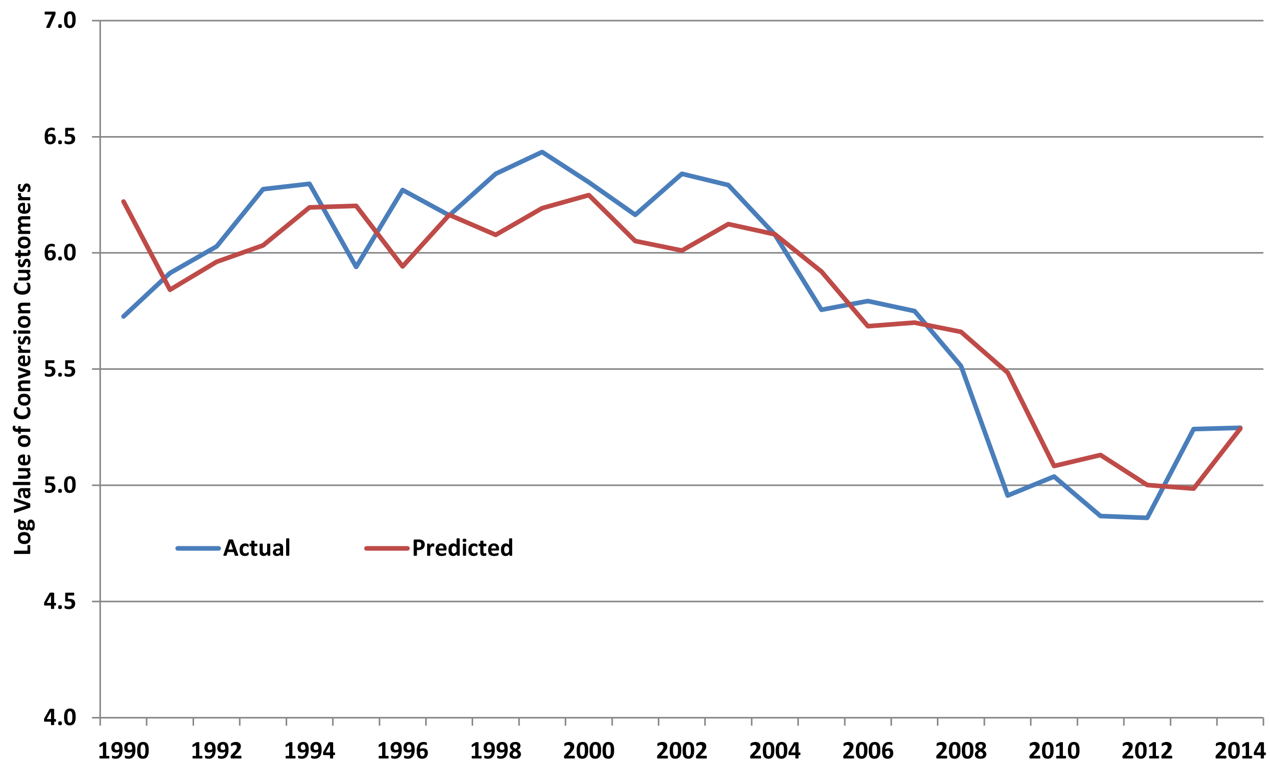
Washington Residential Conversion Customer Additions: Actual and Predicted



Oregon Residential New Construction Customer Additions: Single Family Percent of Total

Ordinary Least Squares Estimates			
SSE	0.02727035	DFE	14
MSE	0.00195	Root MSE	0.04413
SBC	-52.654316	AIC	-55.153956
MAE	0.03246446	AICC	-53.307802
MAPE	3.88494987	HQC	-54.905487
Durbin-Watson	1.2323	Regress R-Square	0.5426
		Total R-Square	0.5426

Parameter Estimates					
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	0.9354	0.0315	29.71	<.0001
ORHOUSSTARTS	1	-0.006957	0.001712	-4.06	0.0012
DNOREMP	1	0.001020	0.000412	2.47	0.0267

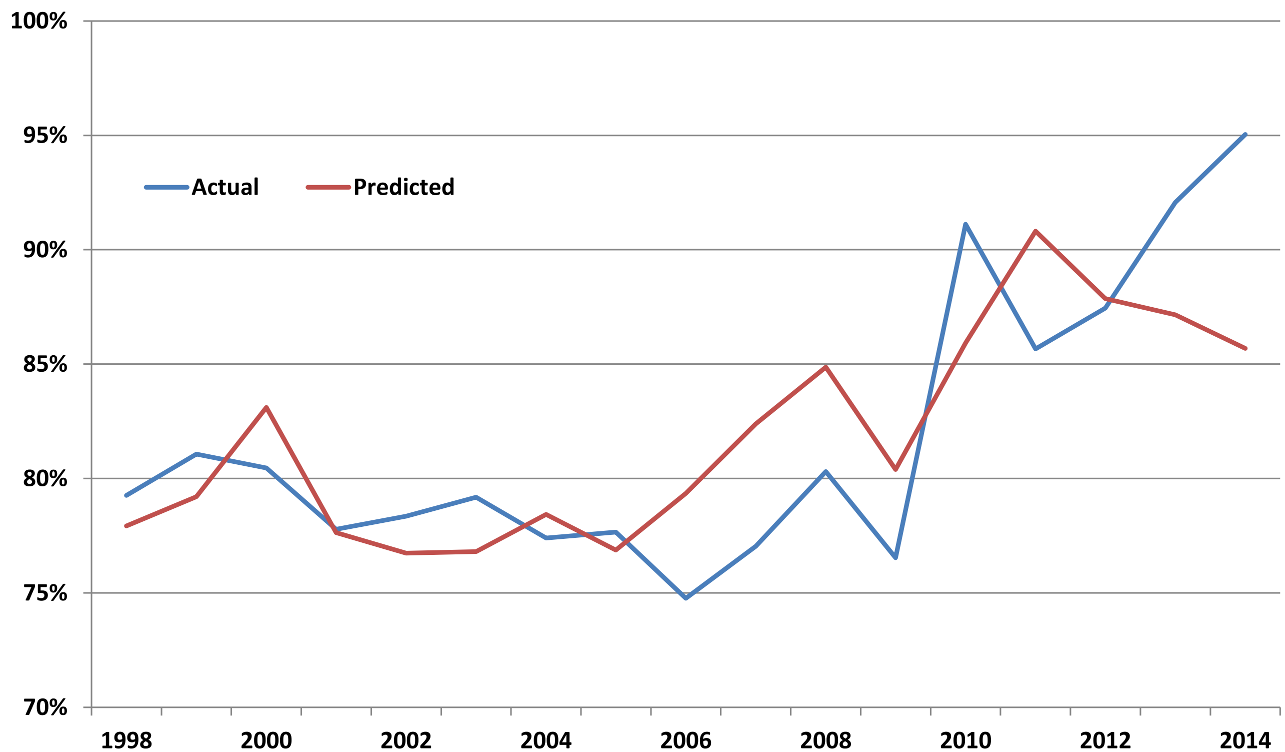
Model used to forecast percent of OR Residential new construction customer additions that are Single Family.

Explanatory variables:

ORHOUSSTARTS
Oregon Housing Starts in year *t*

DNOREMP
Change from year *t-1* to year *t* in total employment collectively for those Oregon counties in which NW Natural provides service.

Oregon Residential New Construction Single Family %: Actuals and Predicted



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Washington Residential New Construction Customer Additions: Single Family Percent of Total

Ordinary Least Squares Estimates			
SSE	0.08212652	DFE	14
MSE	0.00587	Root MSE	0.07659
SBC	-33.912479	AIC	-36.412119
MAE	0.0546399	AICC	-34.565965
MAPE	6.58317618	HQC	-36.16365
Durbin-Watson	1.9604	Regress R-Square	0.0303
		Total R-Square	0.0303

Parameter Estimates					
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	0.8517	0.0528	16.12	<.0001
ORHOUSSTARTS	1	-0.001943	0.003097	-0.63	0.5406
DNWAEMP	1	0.003297	0.006099	0.54	0.5973

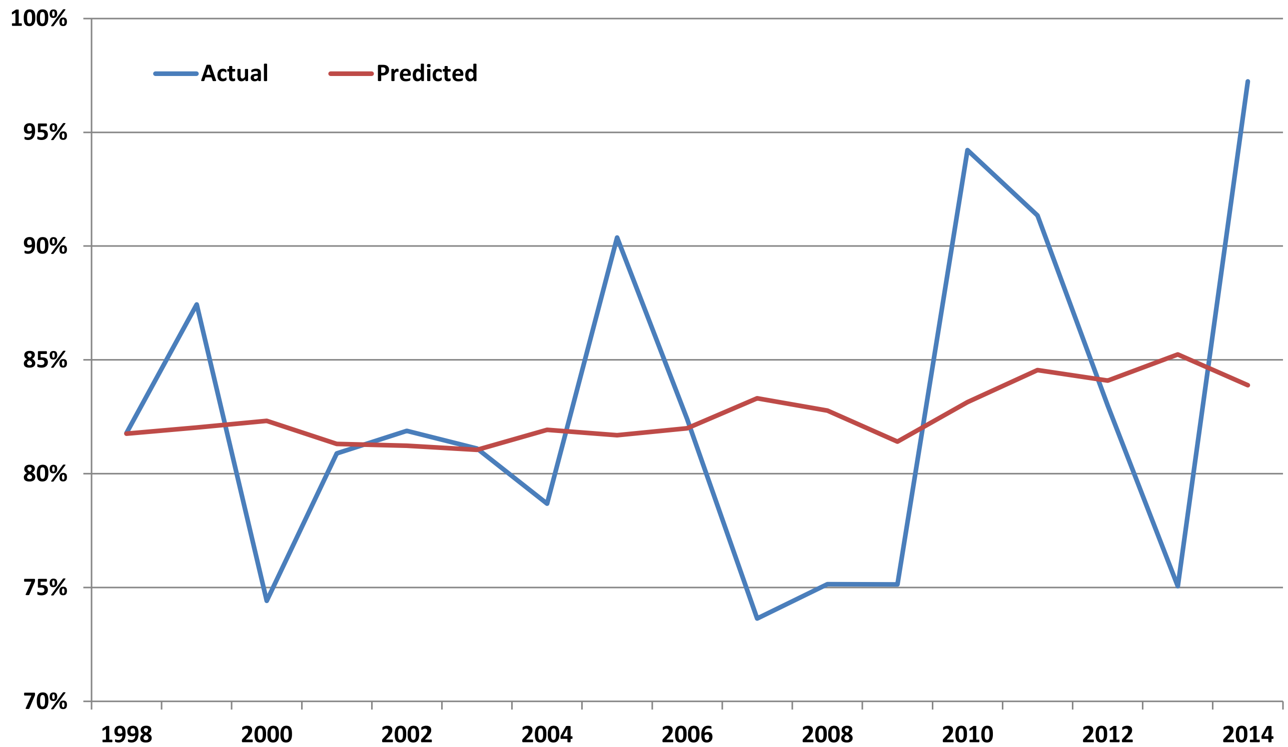
Model used to forecast percent of WA Residential new construction customer additions that are Single Family.

Explanatory variables:

ORHOUSSTARTS
Oregon Housing Starts in year *t*

DNWAEMP
Change from year *t-1* to year *t* in total employment collectively for those Washington counties in which NW Natural provides service.

Washington Residential New Construction Single Family %: Actuals and Predicted



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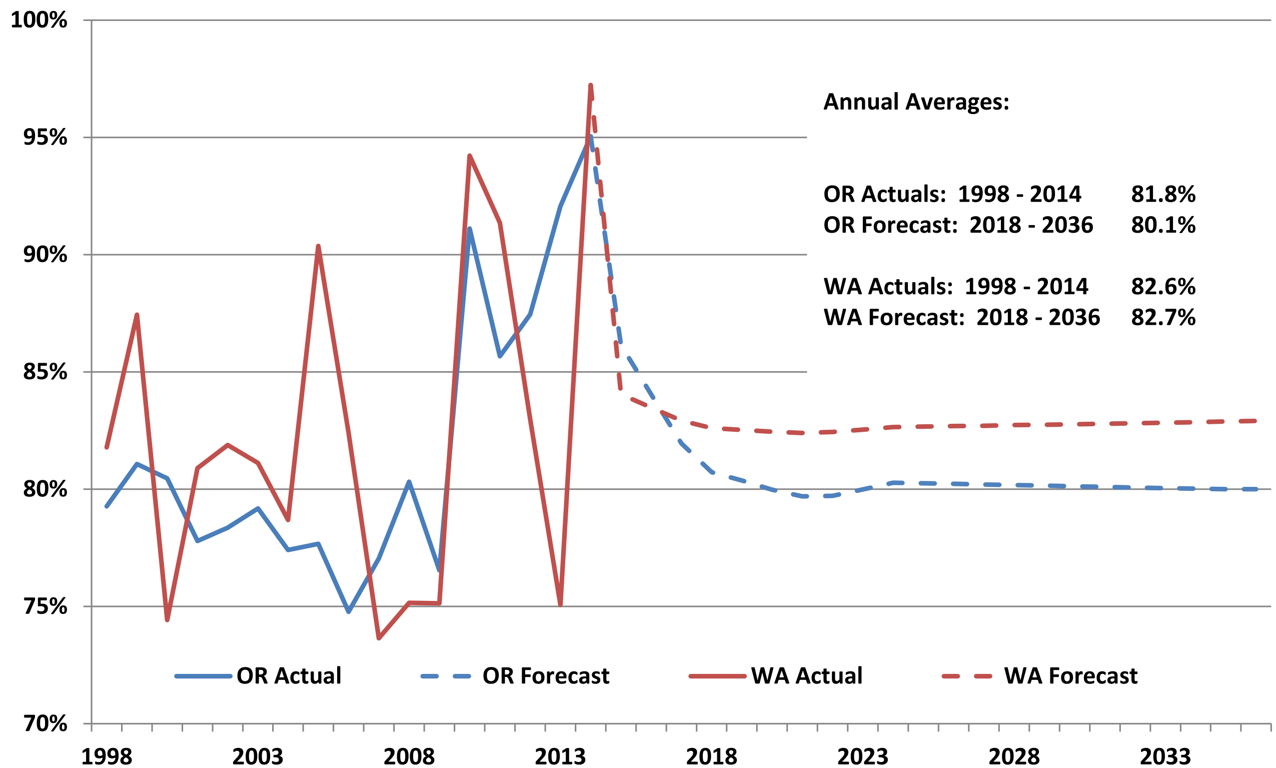
Residential New Construction Customers Single Family %: Actuals and Forecasts by State



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Commercial Customer Forecast Technical Details

Commercial Customer Forecast

Two primary models

- New Construction
  - Linear model
  - ΔNew Construction Additions = a + b * ΔPortland MSA Non-Manufacturing Employment
- Conversion
  - Exponential decay to a constant >=0
  - Conversion Additions$_t$= N_0*e^(λt) + c

New Construction Forecast Driver Variable

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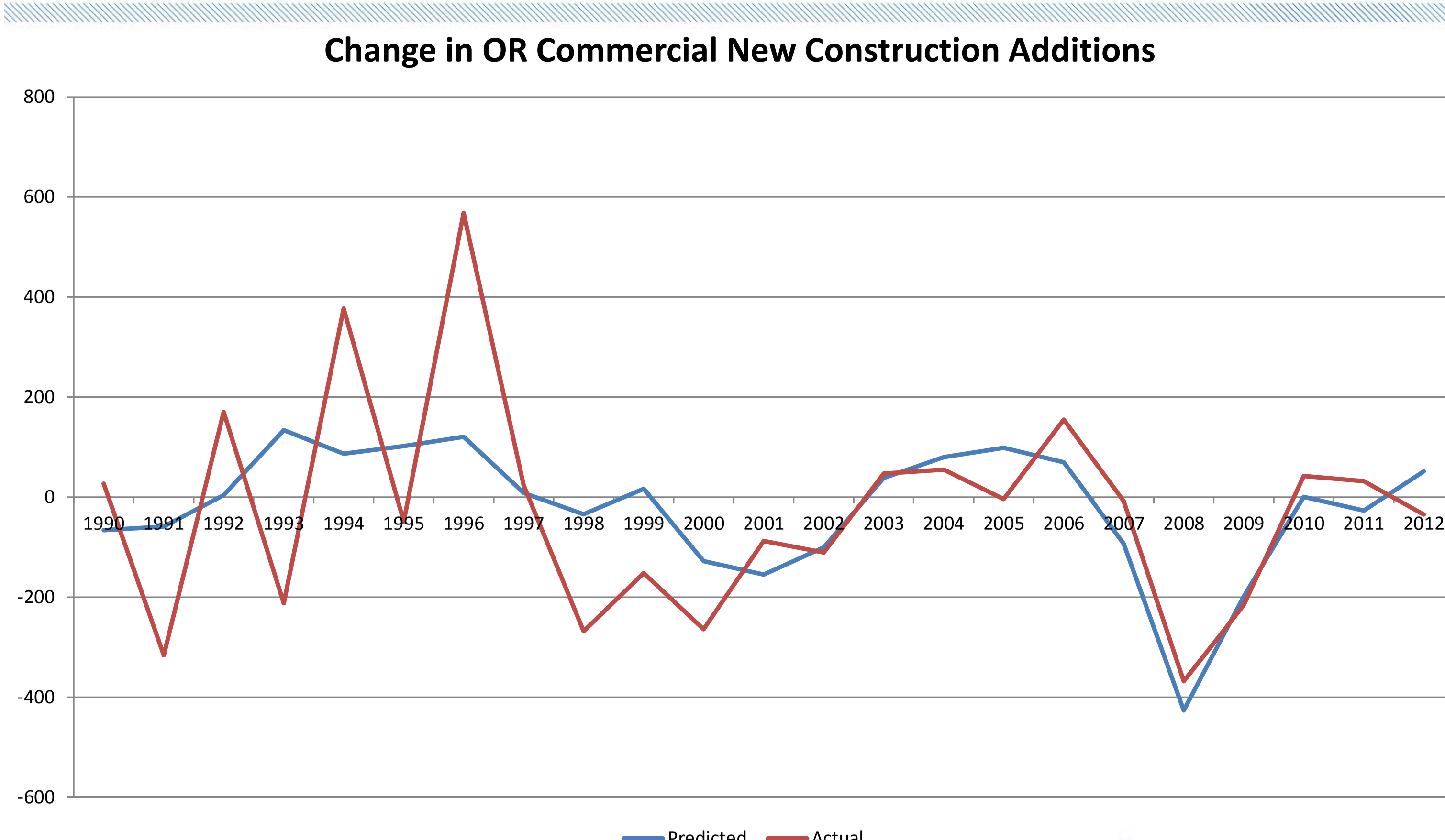
Oregon Commercial New Construction

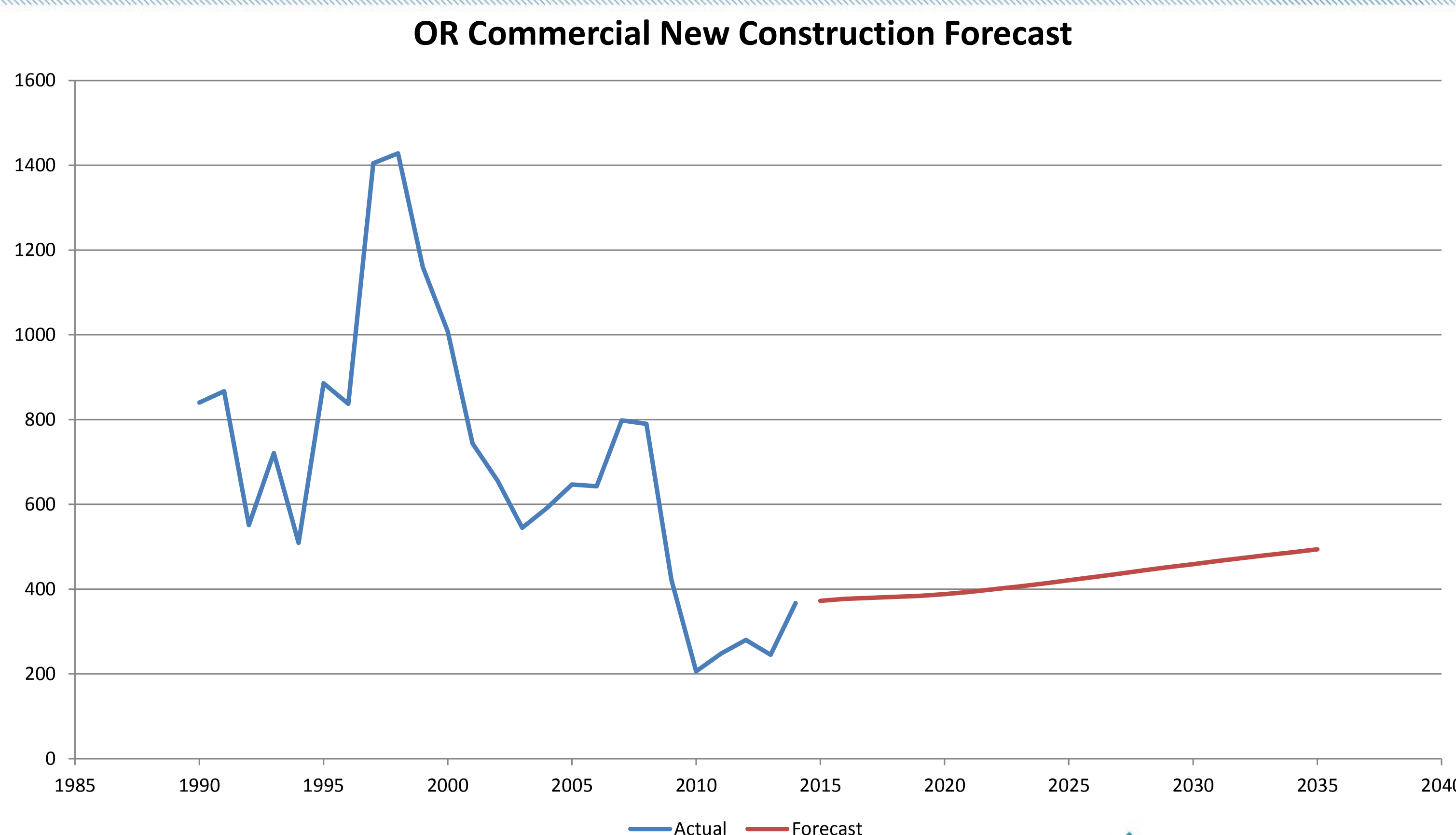
Yule-Walker Estimates			
SSE	691006.658	DFE	22
MSE	31409	Root MSE	177.22695
SBC	320.893579	AIC	318.537471
MAE	127.77654	AICC	319.1089
MAPE	247.537358	HQC	319.162547
Durbin-Watson	2.8037	Regress R-Square	0.3405
		Total R-Square	0.3405

Parameter Estimates					
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	-150.4484	53.0423	-2.84	0.0096
Change in Non-Manufacturing Employment	1	6.3393	1.8809	3.37	0.0028

Oregon Commercial New Construction



OR Commercial Customer New Construction



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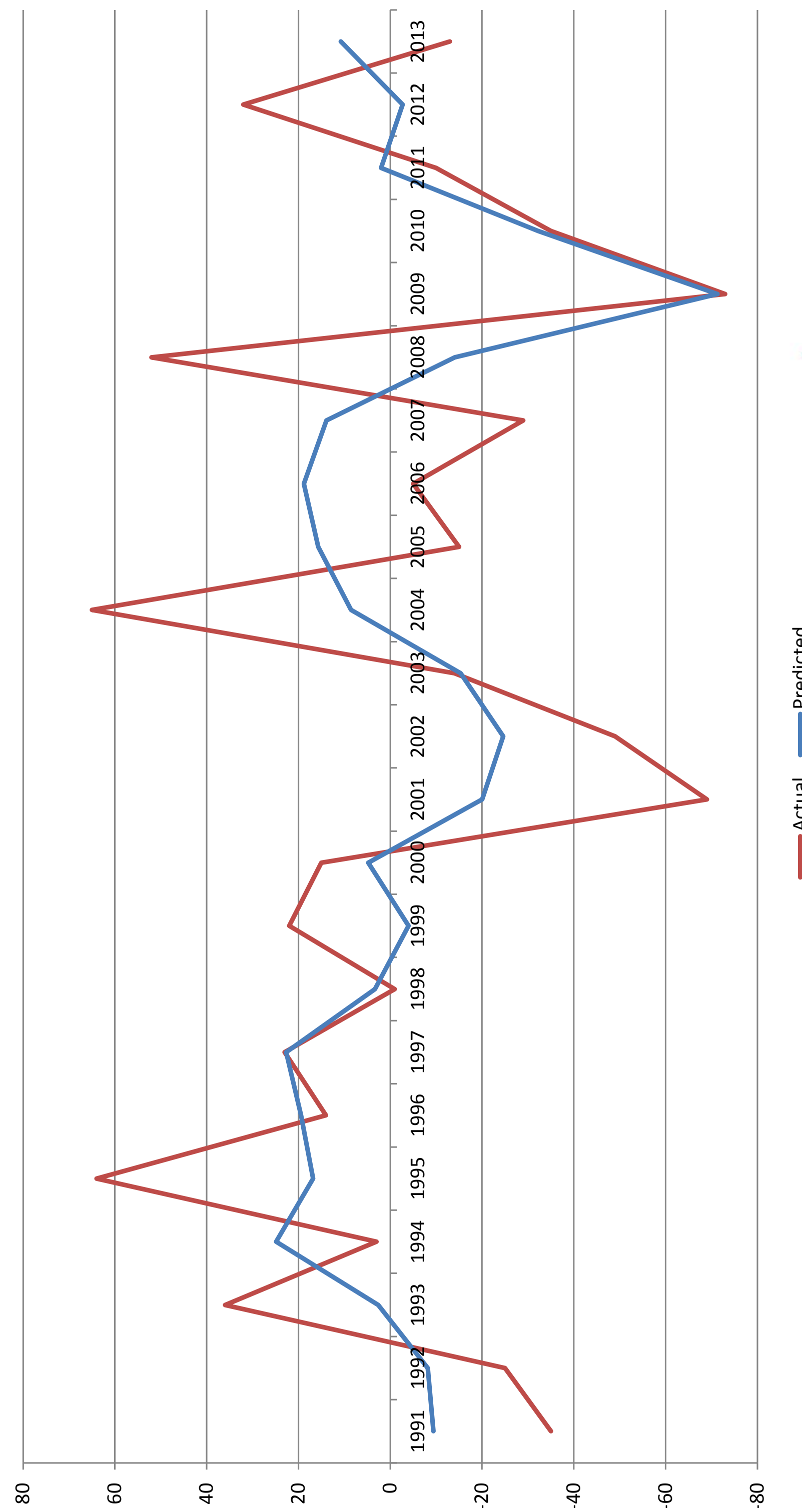
Washington Commercial New Construction

Yule-Walker Estimates			
SSE	21490.643	DFE	22
MSE	976.84741	Root MSE	31.25456
SBC	237.600815	AIC	235.244708
MAE	23.74913	AICC	235.816136
MAPE	140.370729	HQC	235.869784
Durbin-Watson	2.4884	Regress R-Square	0.3285
		Total R-Square	0.3285

Parameter Estimates					
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	-23.9009	9.3542	-2.56	0.0180
Change in Non-Manufacturing Employment	1	1.0882	0.3317	3.28	0.0034

Washington Commercial New Construction

Change in WA Commercial New Construction Additions



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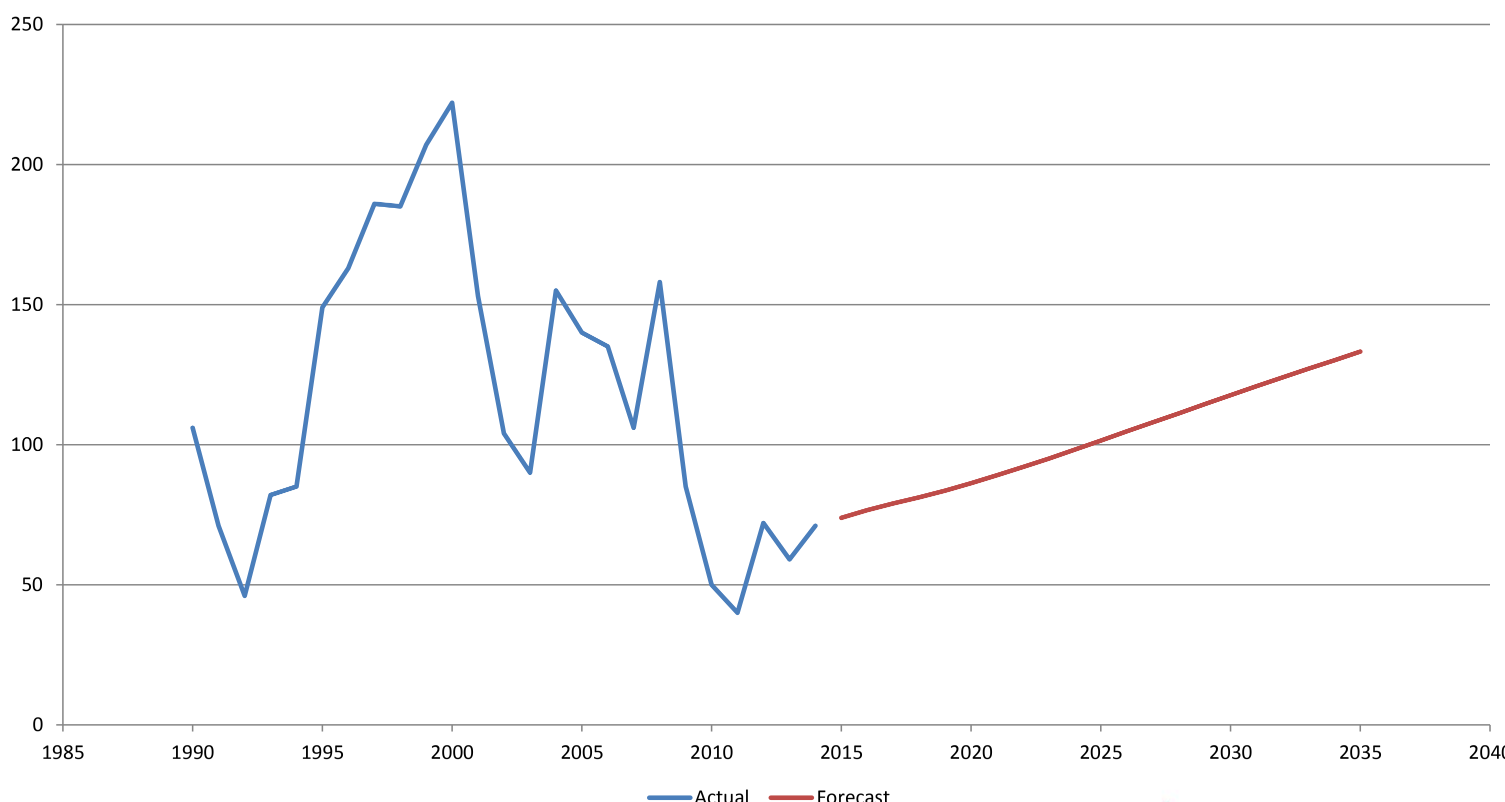
WA Commercial Customer New Construction

WA Commercial New Construction Forecast



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Commercial Conversion Forecasts

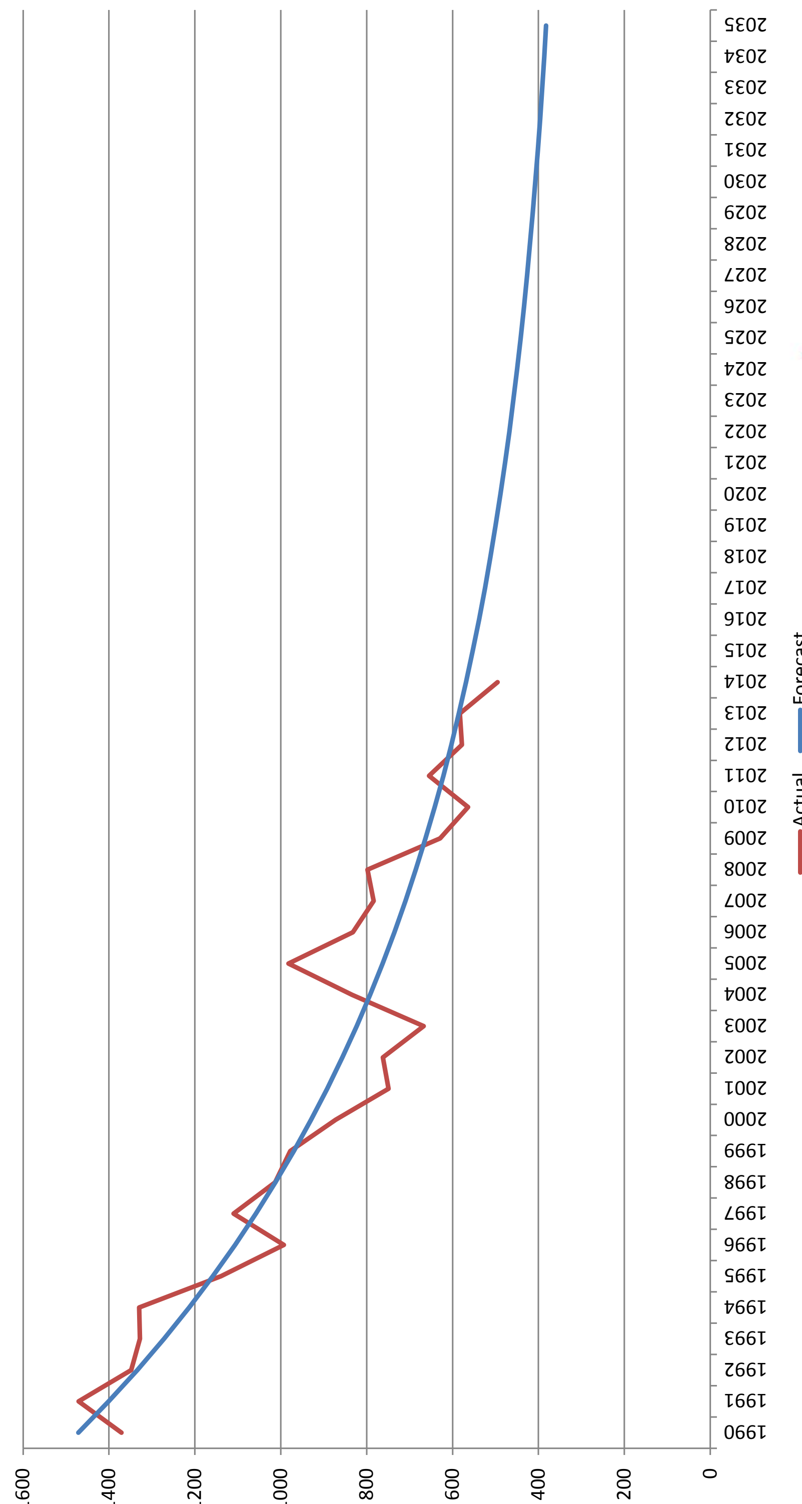
Used non-linear least squares regression to estimate coefficients:

$$\text{Conversion Additions}_t = a\text{*}e\text{^}(b\text{*}t) + c$$

Different from residential model where:

$$\text{Conversion Additions}_t = e\text{^}(a + b\text{*}t + c\text{* Conversion Additions}_{t-1})$$

OR Commercial Customer Conversions



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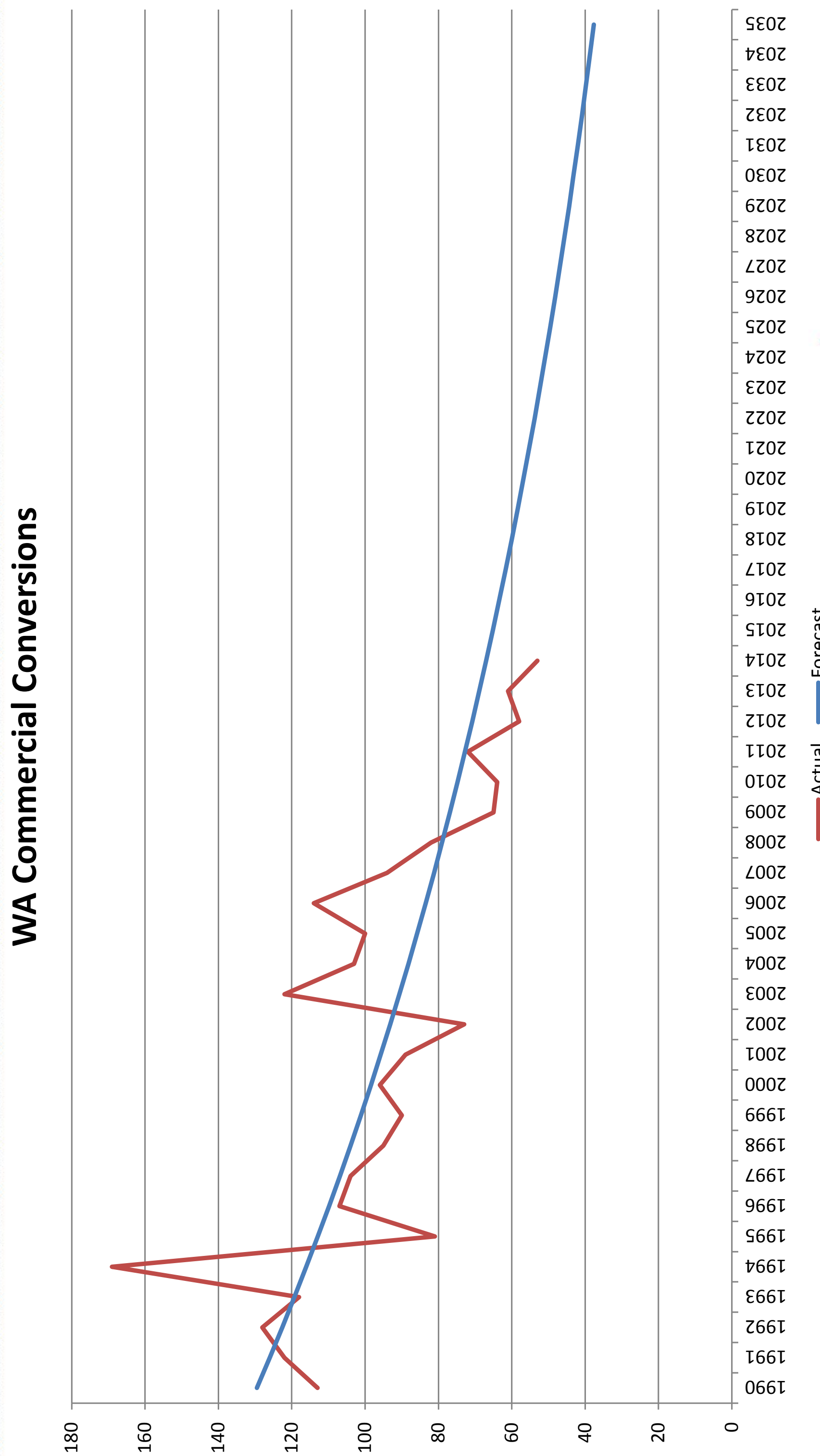
WA Commercial Customer Conversions



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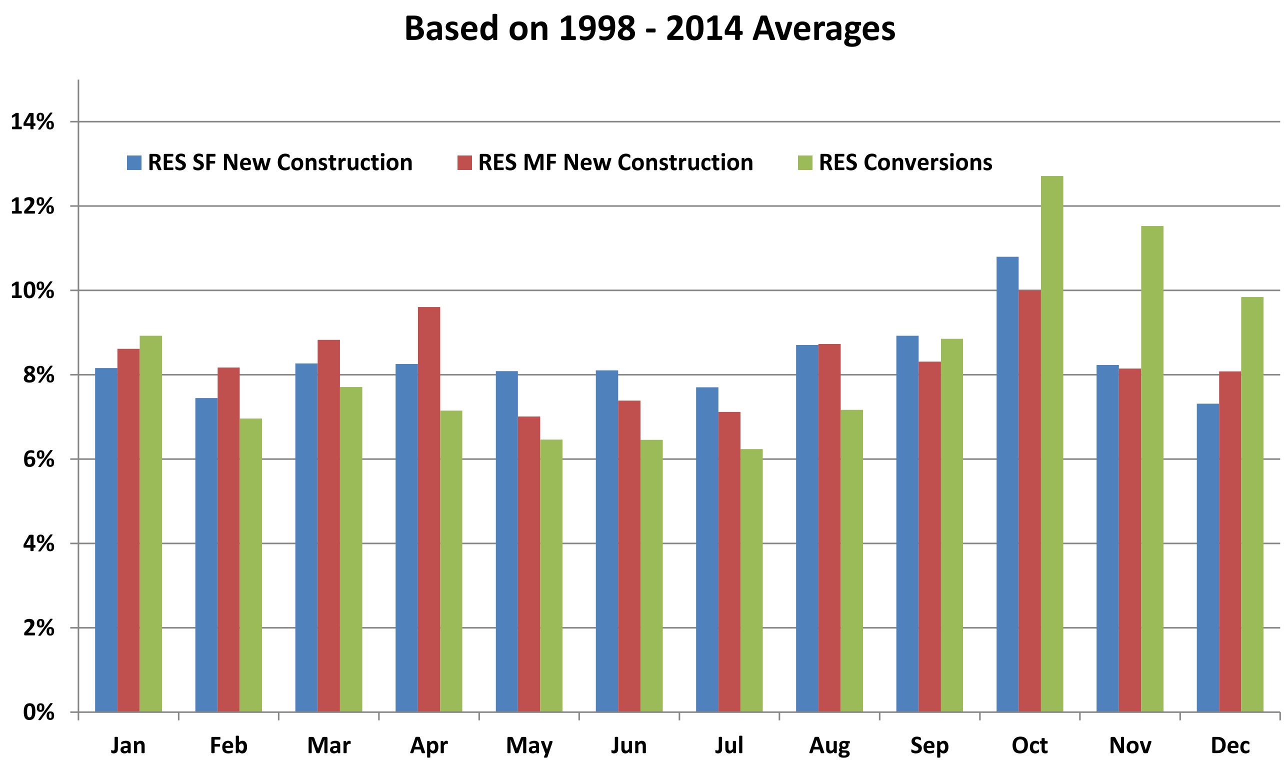
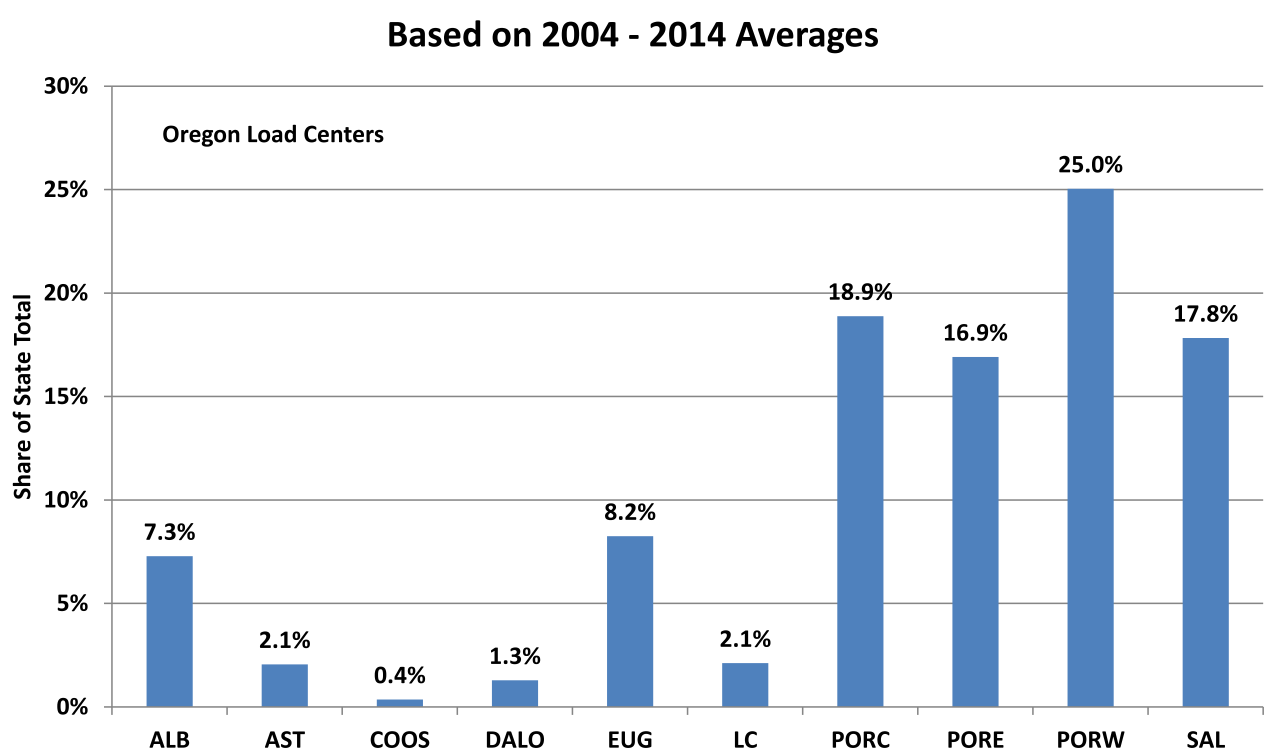
Residential/Commercial Customer Allocation

Allocation from Annual to Monthly: Example of Residential Customer Additions



Allocation from State to Load Centers: Example of OR Residential SF New Construction Customers



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Residential and Commercial Firm Sales Customers: Average Annual Growth Rates by Load Center

Load Center	Residential	Commercial	Total
Albany	1.5%	0.8%	1.4%
Astoria	1.9%	1.1%	1.8%
Coos Bay	4.5%	4.2%	4.4%
Eugene	1.8%	1.2%	1.7%
Lincoln City	2.1%	0.8%	1.9%
Portland – Central	1.2%	0.7%	1.2%
Portland – East	1.6%	0.8%	1.5%
Portland – West	1.7%	1.0%	1.7%
Salem	1.6%	1.0%	1.6%
The Dalles (OR)	2.3%	1.2%	2.1%
The Dalles (WA)	2.2%	1.5%	2.2%
Vancouver	2.6%	1.7%	2.6%

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Peak Day
Aggregate Use Per Customer Forecast
Technical Details

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Outline of Technical Dive into Peak Day Forecast

1. Explanation for why gas control (SCADA) data is better for peak day forecast than billing data
   - Benefits of daily frequency data vs monthly frequency data for extreme temperatures
2. Brief description in the difficulties of predicting planning peak day loads
   - Non-linear relationship between heating load and temperature and reconciliation with linear input needs of SENDOUT
   - Large variation in firm sales to temperature relationship
3. Two-pronged approach to address the large variation in firm sales load by temperature
   - Reducing the variation in load by temperature by finding a better measure of temperature
   - Including more variables to explain some the variation that is not due to temperature
4. Results of change in planning peak day weather measurement
   - Gas day hourly averages vs daily calendar day values
   - Dynamic system weighting vs static system weighting
   - Summary and correlations of new weather data (Temp, Wind Speed, Solar Radiation, and Precipitation)
5. Peak Day UPC Regression Results
   - Choosing “cold day” break point temperature
   - Model choice and results
   - Incorporating UPC trend on peak into the model
   - Inclusion of lag of temperature
   - Exclusion of price elasticity

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Why is SCADA data better than billing data at forecasting needs at cold temperatures?

- The temperature to load relationship is non-linear, but…
- Inputs in SENDOUT must be linear, and….
- SENDOUT is the model we use for resource optimization.
- This mis-match is best addressed by a linear relationship with multiple breaks with a cold temperature “section,” but…
- Billing data is monthly, so coldest temperatures are aggregated with more mild temperatures so that the relationship at the coldest temperatures is difficult to measure, but…
- We have daily frequency data for total system firm sales flows from gate stations, storage facilities, and large customers (including all interruptible customers that can be netted out) that can better incorporate the information we have about load on the coldest days

What data do we have at the coldest temperatures?

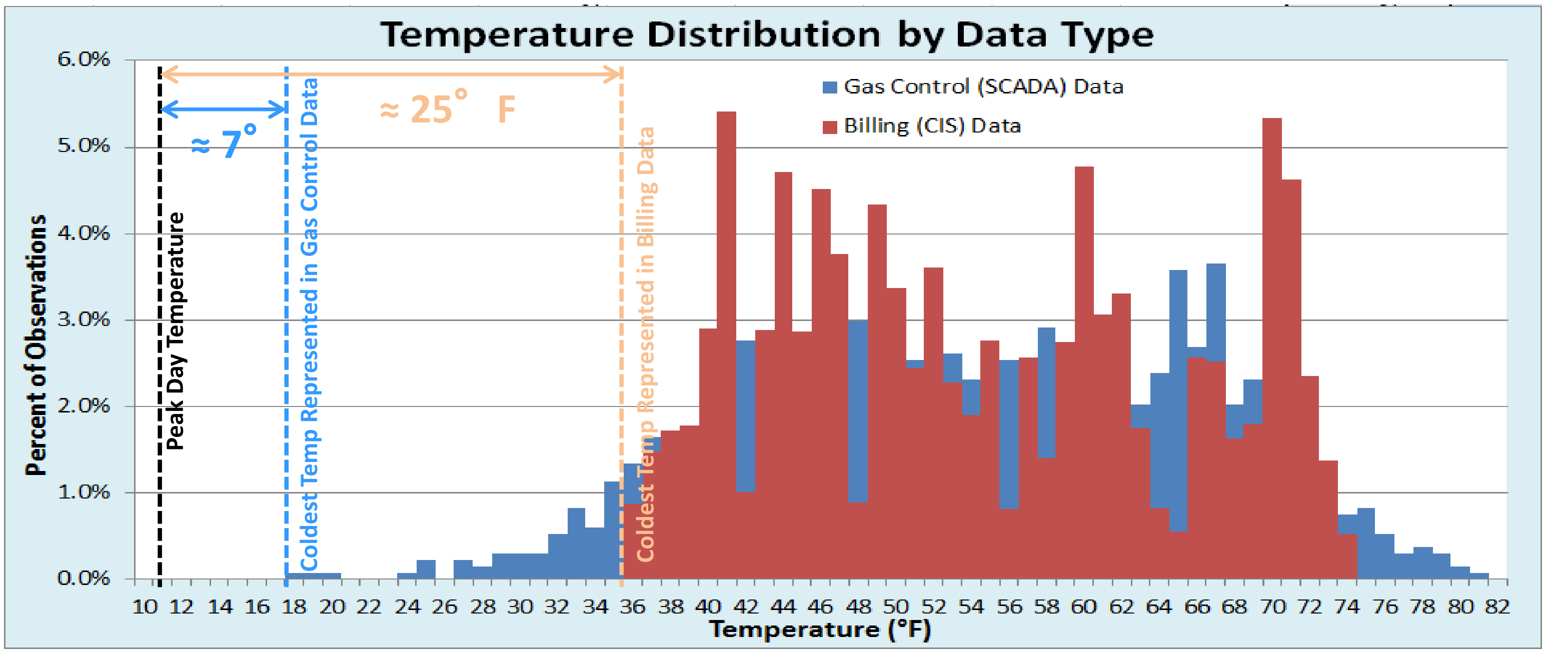
Temperature	Share of Data Last 3 years: Billing*	Share of Data Last 3 years: SCADA†
<24.9	0.0%	0.3%
25-29.9	0.0%	0.9%
30-34.9	0.0%	2.5%
35-39.9	5.8%	7.3%
40-44.9	16.9%	12.2%
45-49.9	16.4%	15.7%
50-54.9	13.6%	14.0%
55-59.9	10.3%	12.6%
60-64.9	13.7%	11.0%
65-69.9	9.1%	14.3%
70-74.9	14.2%	6.6%
>75	0.0%	2.5%

* Billing Data in Portland-Central Load Center;
†System Weighted Data

- With monthly billing data, even with many of the coldest days in 20 years experienced during the 2013-14 heating season, the lowest temperature load data available for use is 36°F because weather must be averaged for the month
- With daily aggregated SCADA data there are 150 days with system weighted temperatures lower than 36°F since 2008 with 5 days less than 25°F during the 2013-14 heating season that can be used to model and calibrate the peak day load forecast

Why does this matter?

- Statistical models are best for prediction over the range of data heavily covered in the sample, but peak day forecasts are predictions for outcomes typically outside the range of available data (and in some cases far outside)



- Using Gas Control Data not only allows other temperature variables to be incorporated in to the peak day forecast, but also greatly reduces the difference between the coldest observations in the data and the weather conditions we need to forecast for when making the peak day forecast (from 25°F to 7°F)

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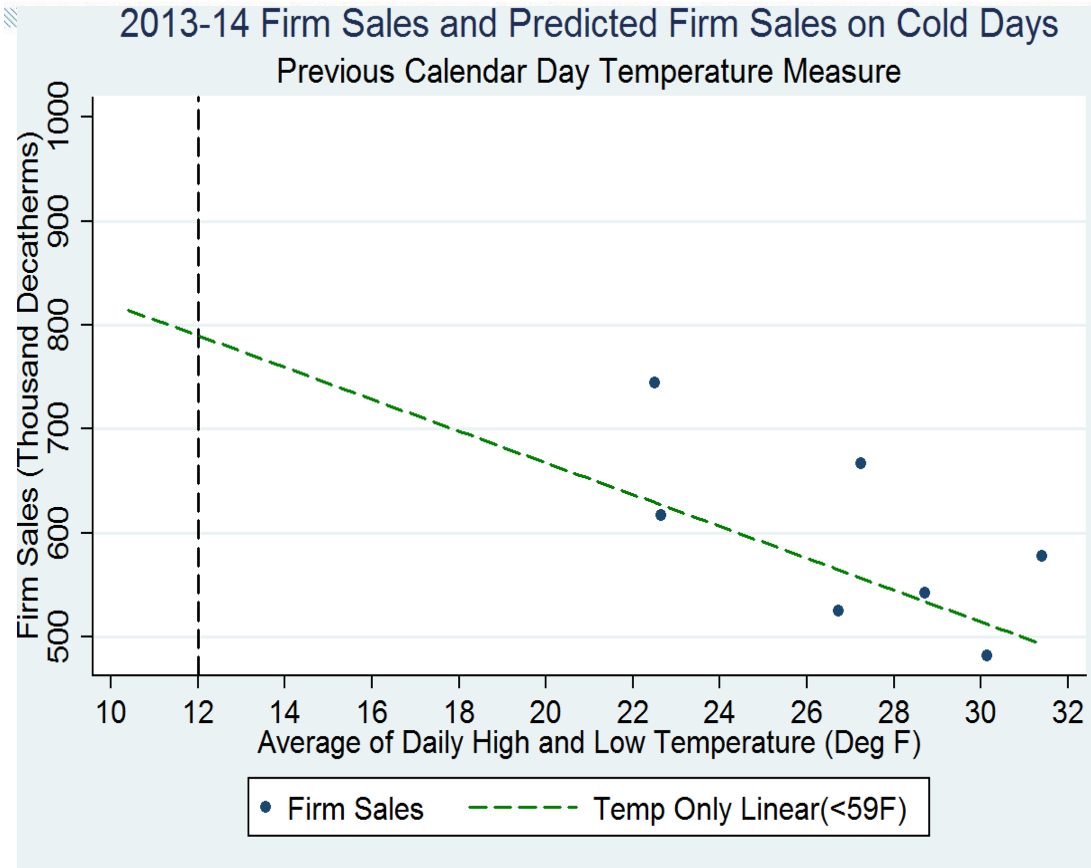
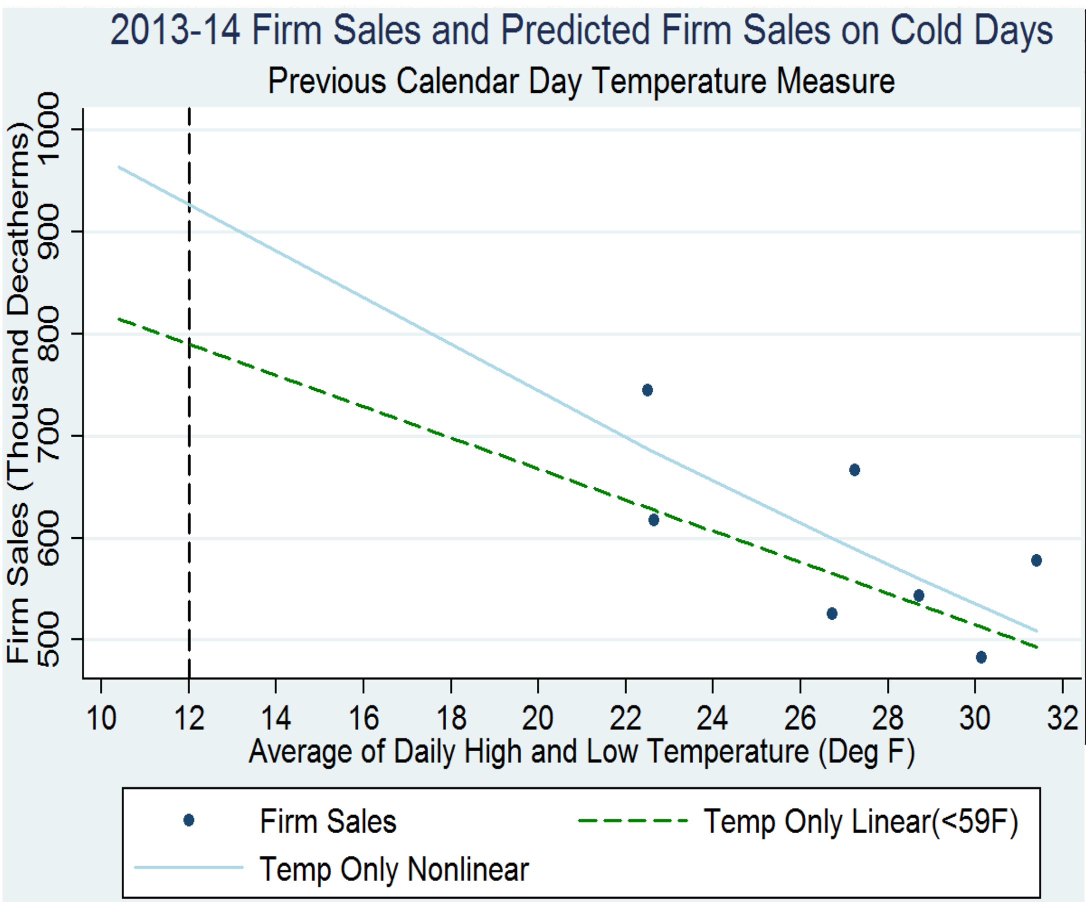
Further Proof a Linear Relationship incorporating all Heating Load Temperatures Underestimates Load on Cold Days?



Residuals at Cold Temperatures (Dth/Gas Day) All Days Since 1/1/2008						
Temperature Cutoff	Number of Observations (Days)		Temperature Only (<59°F)	Temp Only- Nonlinear (<59°F)	All Drivers- Calendar Day High/Low Avg (<38°F)	All Drivers- Gas Day Hourly Avgs (<38°F)
< 38°F	237	Mean of Residuals	-18,122			
		Standard Deviation	40,111			
< 32°F	55	Mean of Residuals	-44,036			
		Standard Deviation	49,784			
< 25°F	12	Mean of Residuals	-85,769			
		Standard Deviation	55,426			

The colder the temperature, the more the model underestimates cold temperature load. 95% confidence band on peak forecast prediction is ± more than 125MDT

Q: Why was a nonlinear relationship used before?
A: The relationship is nonlinear



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Temperature Cutoff	Number of Observations (Days)		Temperature Only (<59°F)	Temp Only- Nonlinear (<59°F)	All Drivers- Calendar Day High/Low Avg (<38°F)	All Drivers- Gas Day Hourly Avgs (<38°F)
< 38°F	237	Mean of Residuals	-18,122	-5,752		
		Standard Deviation	40,111	39,315		
< 32°F	55	Mean of Residuals	-44,036	-7,872		
		Standard Deviation	49,784	53,953		
< 25°F	12	Mean of Residuals	-85,769	-21,983		
		Standard Deviation	55,426	68,377		

Nonlinear model underestimates load at much smaller errors, but 95% confidence band on peak forecast prediction is still ± more than 125MDT

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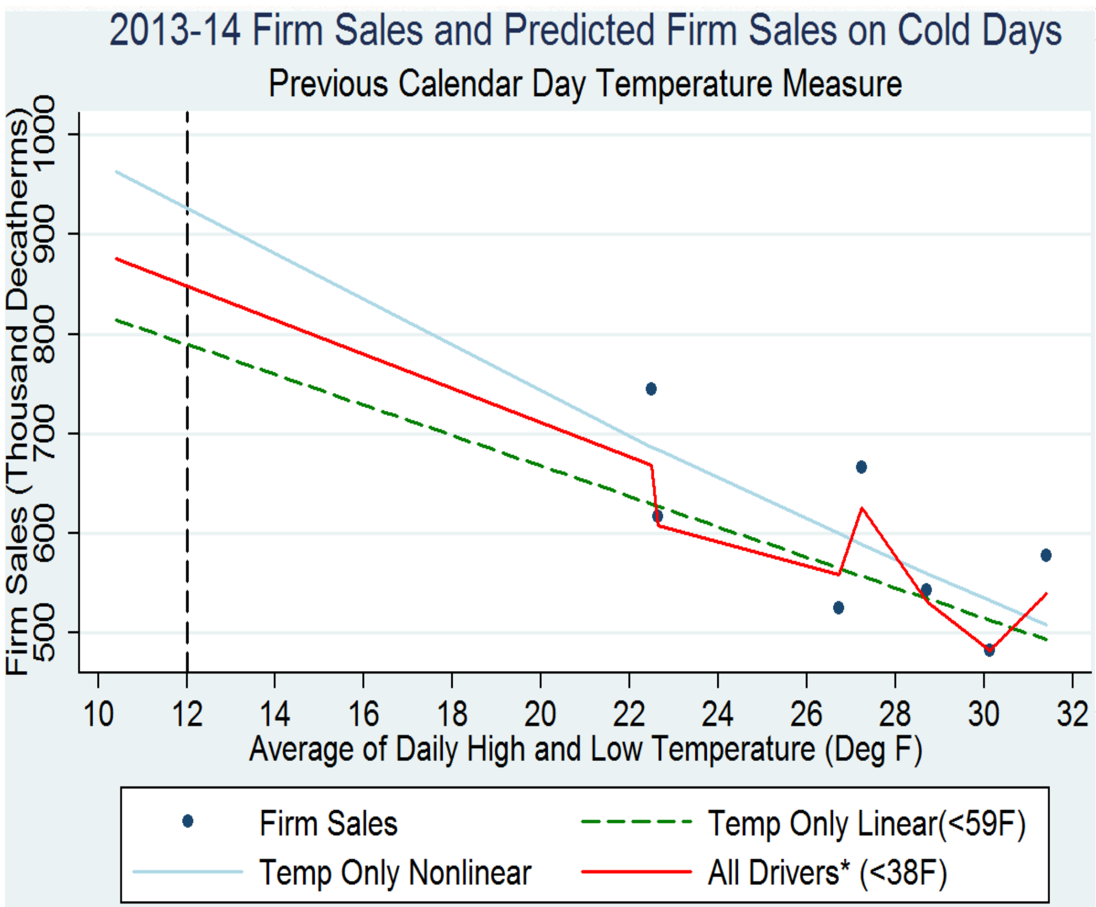
Explaining More of the Variation: Incorporating New Variables that Impact Load



*All drivers includes Temperature, Lag of Temp, Wind Speed, Solar Radiation, Precipitation, and Day of Week

Residuals at Cold Temperatures (Dth/Gas Day) All Days Since 1/1/2008						
Temperature Cutoff	Number of Observations (Days)		Temperature Only (<59°F)	Temp Only- Nonlinear (<59°F)	All Drivers- Calendar Day High/Low Avg (<38°F)	All Drivers- Gas Day Hourly Avgs (<38°F)
< 38°F	237	Mean of Residuals	-18,122	-5,752	2	
		Standard Deviation	40,111	39,315	28,425	
< 32°F	55	Mean of Residuals	-44,036	-7,872	-7,527	
		Standard Deviation	49,784	53,953	35,594	
< 25°F	12	Mean of Residuals	-85,769	-21,983	-20,655	
		Standard Deviation	55,426	68,377	38,446	

Including additional explanatory variables reduces bias in the peak day forecast substantially as well as reduces the 95% confidence band on the peak forecast to ± ~90 MDT

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Summarizing the New Weather Data

Data Summary: Average Daily Weather Measurements by Month					
Month	**Temperature (°F)**	**Wind Speed (mph)**	**Solar Radiation (watt/m^2)**	**Precipitation (inches)**	**Temp - TempLag (°F)**
1	40.6	6.5	1303	0.19	0.16
2	38.1	8.7	2100	0.13	-0.14
3	46.5	6.5	3020	0.20	0.08
4	50.1	6.0	4508	0.14	0.15
5	56.8	5.5	5703	0.12	0.29
6	61.9	5.5	6152	0.09	0.20
7	67.9	5.8	7211	0.02	0.07
8	68.0	5.3	5967	0.03	-0.21
9	63.6	4.9	4441	0.08	-0.12
10	53.9	4.9	2668	0.15	-0.22
11	46.0	6.5	1410	0.23	-0.26
12	39.3	6.7	1079	0.21	-0.24

	Winter (Nov-Mar) Weather Measurements Correlations				
	Temperature	**Wind Speed**	**Solar Radiation**	**Precipitation**	**Temp - TempLag**
Temperature	1.00				
Wind Speed	-0.37	1.00			
Solar Radiation	-0.06	-0.13	1.00		
Precipitation	0.30	0.30	-0.46	1.00	
Temp - TempLag	0.25	0.06	-0.04	0.18	1.00

Summary of data from first of year 2008 through August 2015

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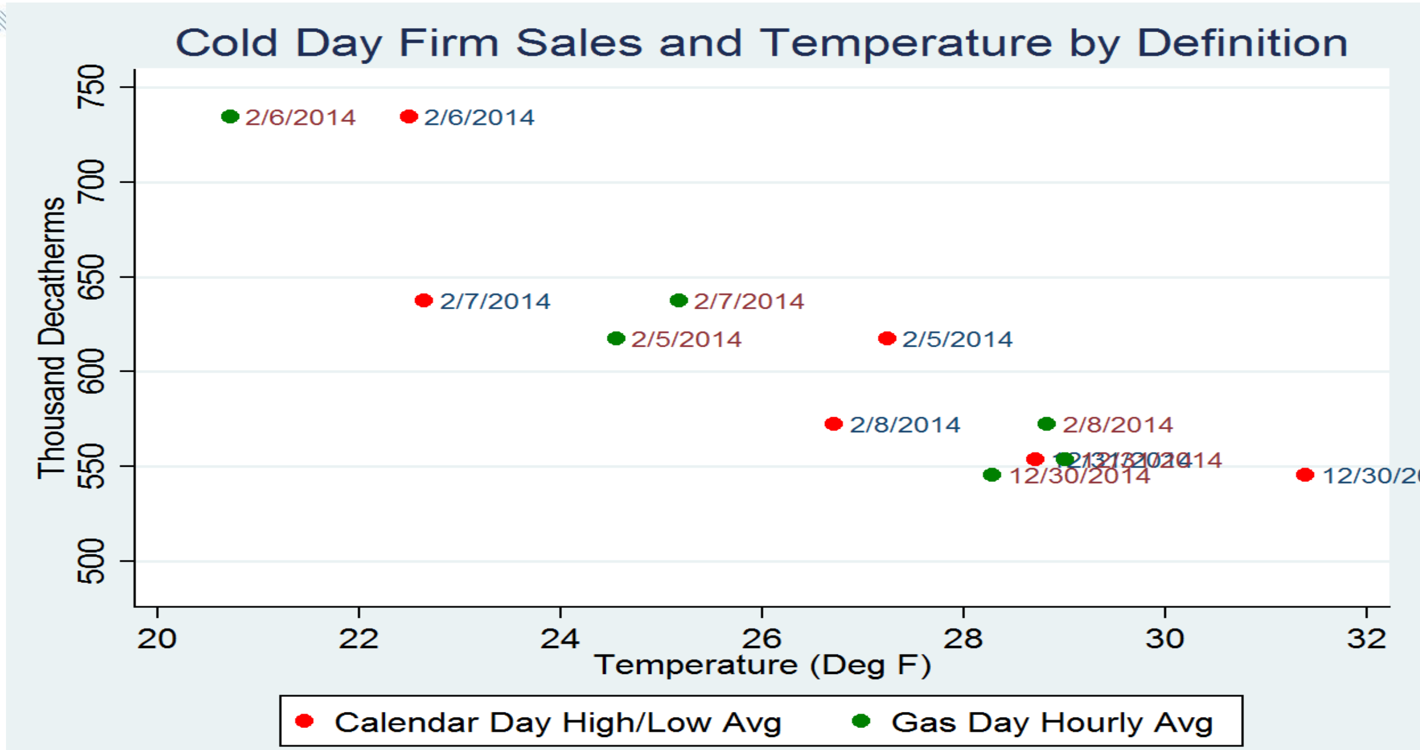
Why does our system show the opposite of the bend over effect?

There are many possible reasons and everyone has their favorite, but it is likely a combination of the following :

1. Temperature is not a complete measure of weather and heating load
   - High wind and cold temperatures often come together
   - The average of hourly temperatures is usually lower than the average of the high and low for the day on cold days
2. Incentivized and non-incentivized Demand-side Management (DSM) and Energy Efficiency (EE)
3. Heat pump with gas back-up penetration
4. Many of the coldest days experienced may be “snow” days where many businesses and schools are closed

Reducing the variation in measurement: Hourly Gas Day vs Daily Calendar Temperatures



	Observations	Mean	Std. Dev.	Min	Max
Absolute Value (Calendar Day High and Low Temp Average - Gas Day Hourly Average Temp) (°F)	2841	1.495	1.094	0.001	7.875

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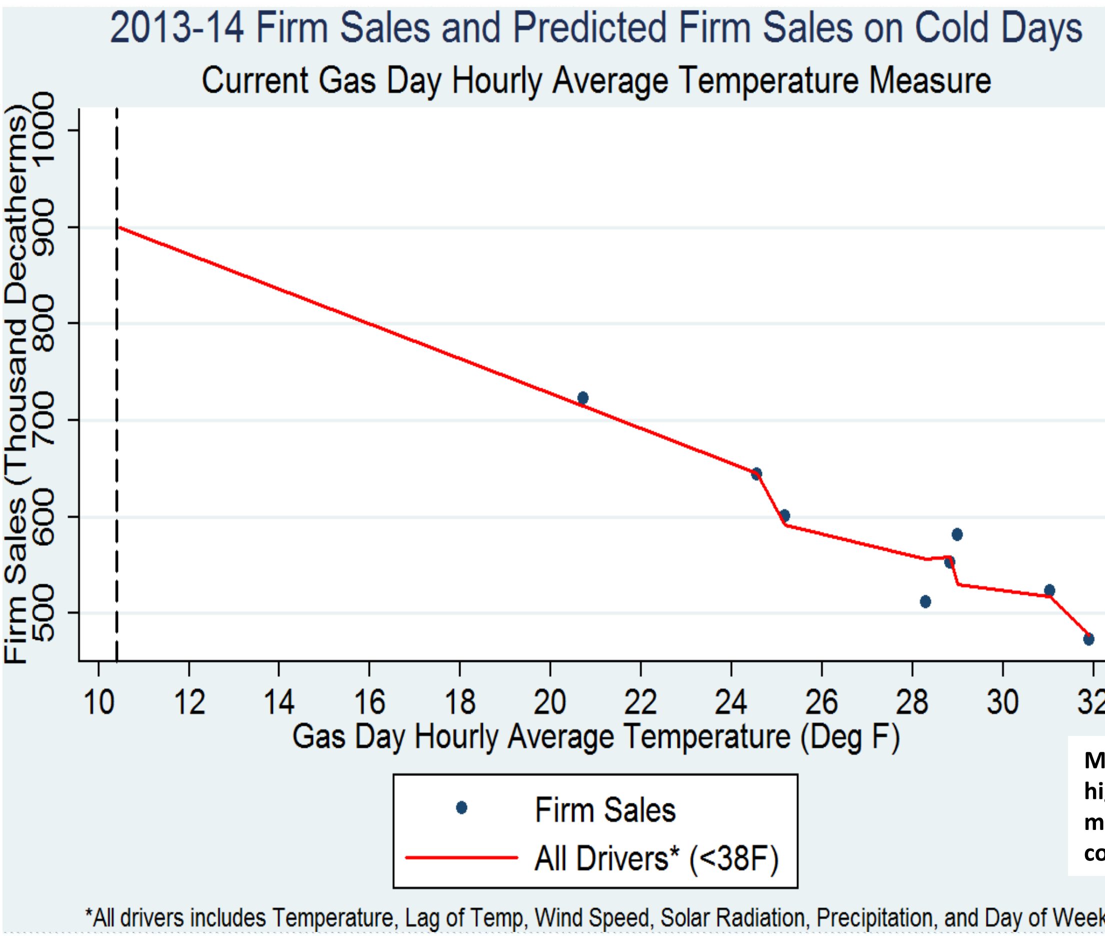
Reducing the Variation to be Explained:
Changing from Daily to Hourly Average Measurements



Residuals at Cold Temperatures (Dth/Gas Day) All Days Since 1/1/2008

Temperature Cutoff	Number of Observations (Days)		Temperature Only (<59°F)	Temp Only- Nonlinear (<59°F)	All Drivers- Calendar Day High/Low Avg (<38°F)	All Drivers- Gas Day Hourly Avgs (<38°F)
< 38°F	237	Mean of Residuals	-18,122	-5,752	2	4
		Standard Deviation	40,111	39,315	28,425	26,257
< 32°F	55	Mean of Residuals	-44,036	-7,872	-7,527	-1,904
		Standard Deviation	49,784	53,953	35,594	34,807
< 25°F	12	Mean of Residuals	-85,769	-21,983	-20,655	-10,932
		Standard Deviation	55,426	68,377	38,446	36,659

Moving from average of Calendar day high/low to average of gas day hourly measurements further reduces bias and confidence bands in the peak day forecast

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Incorporating Time Trend in System Weighting of Weather Measurements

Process:

1. Regress monthly load center shares on time and temperature
2. Forecast share of each load center from regression results in (1) for peak day temperature
3. Normalize shares so they sum to exactly 1
4. Multiply load center share by weather measurement for load center to get the system weighted weather measurements at different points in time

Results for planning peak day:

Peak Day Load Shares Regressions											
	Vancouver	The Dalles	Salem	PDX-West	PDX-East	PDX-Central	Newport/LC	Eugene	Albany	Coos County	Astoria
	b/se	b/se	b/se	b/se	b/se	b/se	b/se	b/se	b/se	b/se	b/se
Years Since 2008	**0.0007788**	**0.0002076**	**0.0004692**	**-0.0005568**	**-0.0003192**	**-0.0006048**	**-0.000048**	**0.0005136**	**-0.0004716**	**0.000186**	**-0.0001548**
	0.0001512	0.0000672	0.0006012	0.000426	0.000768	0.0003372	0.0001104	0.0001968	0.0002136	0.0000396	0.0000612
Temperature	**0.0000187**	**0.0000714**	**0.0003205**	**-0.0003384**	**-0.0004365**	**-0.000802**	**0.0004968**	**0.0004724**	**-0.0001862**	**0.000094**	**0.0002891**
	0.0000252	0.0000112	0.0001004	0.0000712	0.0001284	0.0000564	0.0000184	0.0000329	0.0000358	0.0000067	0.0000103
Constant	**0.0938682**	**0.0093437**	**0.1159524**	**0.2098857**	**0.1572461**	**0.3182306**	**-0.0095917**	**0.0411909**	**0.0622418**	**-0.0020738**	**0.003706**
	0.0013942	0.0006167	0.0055475	0.0039315	0.0070948	0.0031146	0.001018	0.0018182	0.0019772	0.00037	0.0005671
N(Months)	72	72	72	72	72	72	72	72	72	72	72
R Squared	0.29	0.444	0.142	0.272	0.149	0.755	0.914	0.763	0.333	0.772	0.92
Adj R Sq	0.269	0.428	0.117	0.251	0.125	0.748	0.911	0.756	0.314	0.765	0.918
BIC	-673	-791	-474	-524	-439	-558	-719	-635	-623	-864	-803
AIC	-667	-784	-468	-517	-432	-551	-712	-628	-616	-858	-796
F	14	28	6	13	6	106	366	111	17	117	397

Peak Day Year	Vancouver	The Dalles	Salem	PDX-West	PDX-East	PDX-Central	Newport/LC	Eugene	Albany	Coos County	Astoria
2016	10.0%	1.2%	12.3%	20.2%	15.0%	30.4%	0.2%	5.0%	5.7%	0.0%	0.6%
2026	10.7%	1.4%	12.8%	19.6%	14.7%	29.8%	0.1%	5.6%	5.2%	0.2%	0.5%
2036	11.5%	1.6%	13.3%	19.1%	14.3%	29.2%	0.1%	6.1%	4.7%	0.4%	0.3%

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Peak Day Weather Measurements By Load Center

Weather Measurements for Planning Peak Day Weather (February 3, 1989 Weather)	Vancouver	The Dalles	Salem	Portland-West	Portland-East	Portland-Central	Newport/Lincoln City	Eugene	Corvallis/Albany	Coos County	Astoria	System Weighted- 2016	System Weighted- 2036
Temperature (hourly avg °F)	5.5	4.9	10.6	9.3	10.0	12.8	17.6	12.1	11.3	25.6	14.7	10.5	10.4
Wind Speed (hourly avg mph)	15.1	12.4	8.8	20.8	24.1	31.5	22.6	18.6	9.9	12.5	24.5	21.7	21.4
Solar Radiation (daily sum watt/m^2)	2678	2157	2326	2410	2836	2736	1868	1966	1933	2528	2026	2537	2534
Precipitation (daily sum in inches)	0	0	0.01	0	0	0	0.03	0.11	0.03	0.17	0	0.01	0.01
Temperature Day Before (hourly avg °F)	6.9	5.4	14.1	9.4	11.1	12.8	30.4	17.9	20.4	30.9	16.0	12.0	12.0
Day of Week	M-Th	M-Th	M-Th	M-Th	M-Th	M-Th	M-Th	M-Th	M-Th	M-Th	M-Th	M-Th	M-Th

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Peak Day Aggregate Customer UPC OLS Regression Results (Before Adjustments for DSM Change from 2014 IRP and Emerging Market Forecast)

Use Per Customer (for all customers) at Cold Temps (< 38°F) in Therms per Day							
Regressor	**Unit**	**Coeffient**	**Standard Error**	**t-value**	**(P)-value**	**95% Confidence Interval**	
Temperature	Hourly Average (°F)	**-0.0228943**	0.001222	-18.74	0.00%	-0.0253023	-0.0204863
Previous Day Temp	Hourly Average (°F)	**-0.004317**	0.0008818	-4.9	0.00%	-0.0060548	-0.0025793
Wind Speed	Hourly Average (mph)	**0.0001696**	0.0000182	9.31	0.00%	0.0001337	0.0002055
Solar Radiation	Daily Sum (watts/m^2)	**-3.40E-07**	1.10E-07	-3.08	0.20%	-5.57E-07	-1.23E-07
Precipitation	Daily Sum (inches)	**0.0010621**	0.0004349	2.44	1.50%	0.0002051	0.0019192
Friday Dummy	N/A	**-0.0004518**	0.0002356	-1.92	5.60%	-0.0009161	0.0000126
Saturday Dummy	N/A	**-0.0012292**	0.0002035	-6.04	0.00%	-0.0016303	-0.0008282
Sunday Dummy	N/A	**-0.0009806**	0.0001803	-5.44	0.00%	-0.0013359	-0.0006253
Holiday Dummy	N/A	**-0.0019611**	0.0002035	-9.63	0.00%	-0.0023622	-0.00156
Outlier Dummy	N/A	**0.1675795**	0.0149083	11.24	0.00%	0.1382019	0.1969572
Time	Years after 2008	**-0.0056979**	0.0011104	-5.13	0.00%	-0.0078894	-0.0035101
Constant	Therms	**1.598053**	0.0340559	46.92	0.00%	1.530944	1.665162

Peak Day Use Per Aggregate Customer (Total Customer Count Including Residential, Commercial, and Industrial Customer)- Not for Comparison with the Usage of Any Given Customer Type																				
Gas Year	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
Therms/Peak Day	13.44	13.39	13.33	13.27	13.22	13.16	13.11	13.05	13.00	12.94	12.88	12.83	12.77	12.72	12.66	12.61	12.55	12.49	12.44	12.38
Customers (Thousands)	728.06	740.81	755.01	769.49	784.17	798.95	813.66	828.06	842.11	855.98	869.73	883.34	896.84	910.21	923.46	936.6	949.62	962.53	975.34	988.03
Peak Day Load (MDT)	979	992	1006	1021	1037	1052	1066	1081	1094	1108	1121	1133	1145	1157	1169	1181	1192	1203	1213	1223

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Comparing Heating Need Temperature Measurements and Peak Load Forecasting Models for Coldest Days in Recent History		Calendar Day High/Low Average	Gas Day Hourly Average
Friday 12/6/2013	System Weighted Temperature (°F)	26.44	**25.63**
	System Weighted Wind Speed (mph)	-	**15.19**
	System Weighted Daily Solar Radiation (w/m2)	-	**1159**
	System Weighted Daily Precipitation (inches)	-	**0.049**
	System Actual Load (MDT)	**625.67**	
	Temp Only (<38°F) Forecast*	577.9	**597.51**
	Including New Explanatory Variables	-	**633.89**
Saturday 12/7/2013	System Weighted Temperature (°F)	21.31	**19.23**
	System Weighted Wind Speed (mph)	-	**7.43**
	System Weighted Daily Solar Radiation (w/m2)	-	**2076**
	System Weighted Daily Precipitation (inches)	-	**0.001**
	System Actual Load (MDT)	**644.61**	
	Temp Only (<38°F) Forecast*	667.7	**719.22**
	Including New Explanatory Variables	-	**681.58**
Sunday 12/8/2013	System Weighted Temperature (°F)	18.03	**18.39**
	System Weighted Wind Speed (mph)	-	**2.45**
	System Weighted Daily Solar Radiation (w/m2)	-	**1973**
	System Weighted Daily Precipitation (inches)	-	**0**
	System Actual Load (MDT)	**669.43**	
	Temp Only (<38°F) Forecast*	725.1	**735.21**
	Including New Explanatory Variables	-	**701.3**
Thursday 2/6/2014	System Weighted Temperature (°F)	22.49	**20.72**
	System Weighted Wind Speed (mph)	-	**12.41**
	System Weighted Daily Solar Radiation (w/m2)	-	**477**
	System Weighted Daily Precipitation (inches)	-	**0.190**
	System Actual Load (MDT)	**722.93**	
	Temp Only (<38°F) Forecast*	650.25	**694.42**
	Including New Explanatory Variables	-	**732.12**
Planning Peak Day- 2016-17 Gas Year	System Weighted Temperature (°F)	11.99	**10.46**
	System Weighted Wind Speed (mph)	-	**21.72**
	System Weighted Daily Solar Radiation (w/m2)	-	**2536**
	System Weighted Daily Precipitation (inches)	-	**0.009**
	System Actual Load (MDT)	**Irrelevant**	
	Temp Only (<38°F) Forecast*	**854.67**	**914.09**
	Including New Explanatory Variables	**-**	**978.58**
	2014 IRP Forecast	**953.45**	

Notes:

1. Modeling all heating load temperatures (65°F traditionally or 59°F as exhibited by NWN's system) rather than only cold temperatures leads to a result where loads are under-forecasted by a significant margin on cold days
2. "New Explanatory Variables" includes wind speed, solar radiation, precipitation, day of week, one day lag of temperature, and time
3. Models defined using daily SCADA firm sales data from 1/1/2008 to 8/31/2015
4. Average deviation from Actual Load by Model:
   - Temp Only- Calendar Day High/Low: 49.8MDT
   - Temp Only- Hourly Average of Gas Day: 49.2 MDT
   - All Explanatory Variables: 21.6 MDT
5. Not all of the increase in the peak day load forecast from the 2014 IRP is methodological. The 2014 IRP 2016-17 peak day forecast would be higher with actual customers counts (current customer counts are higher than forecasted for this time period in the 2014 IRP) than the figure shown to the left (see slides above)

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Justifying Temperature Lag and Peak Day UPC Trend Inclusion and Price Elasticity Exclusion

	(1) UPC b/se	(2) UPC b/se	(3) UPC b/se	(4) UPC b/se	(5) UPC b/se
TempGHA	-0.022405***	-0.022341***	-0.026628***	-0.022404***	-0.022379***
	(0.001106)	(0.001093)	(0.000918)	(0.001088)	(0.001086)
LagTempGHA	-0.004579***	-0.004634***		-0.004508***	-0.004517***
	(0.000883)	(0.000879)		(0.000873)	(0.000869)
WindGHA	0.005555***	0.005871***	0.005359***	0.005719***	0.005792***
	(0.000601)	(0.000632)	(0.000735)	(0.000616)	(0.000620)
RadGHA	-0.000010**	-0.000011**	-0.000013**	-0.000010*	-0.000010*
	(0.000004)	(0.000004)	(0.000004)	(0.000004)	(0.000004)
PrecGHA	0.041616**	0.039123*	0.041879*	0.040257*	0.039145*
	(0.015735)	(0.016089)	(0.016953)	(0.015879)	(0.015890)
FriDum	-0.015992	-0.015770	-0.014257	-0.015342	-0.015205
	(0.008340)	(0.008338)	(0.009205)	(0.008489)	(0.008482)
SatDum	-0.043462***	-0.043013***	-0.044857***	-0.043425***	-0.043289***
	(0.006868)	(0.006628)	(0.007475)	(0.006918)	(0.006868)
SunDum	-0.036557***	-0.036092***	-0.035616***	-0.036668***	-0.036630***
	(0.006374)	(0.006450)	(0.006928)	(0.006346)	(0.006364)
HolDum	-0.068269***	-0.067730***	-0.057978***	-0.067746***	-0.067649***
	(0.007049)	(0.008001)	(0.005431)	(0.007707)	(0.008007)
Outlier	0.167110***	0.166096***	0.218756***	0.174653***	0.174871***
	(0.015078)	(0.015172)	(0.009841)	(0.016665)	(0.015919)
Day	-0.000015***	0.000009	-0.000016***	-0.000025**	-0.000028***
	(0.000003)	(0.000012)	(0.000003)	(0.000008)	(0.000008)
Day2		-0.000000			
		(0.000000)			
RealRRate				-0.004315	
				(0.003227)	
RealWACOG					-0.005547
					(0.003205)
Constant	1.589422***	1.579119***	1.578528***	1.650544***	1.634412***
	(0.035078)	(0.034421)	(0.035999)	(0.050131)	(0.037964)
N(Days)	237	237	237	237	237
R Squared	0.898	0.900	0.885	0.899	0.900

* p<0.05, ** p<0.01, *** p<0.001

Neither Real WACOG nor Real Residential Rate show as significant at the 5% level of significance

One day lag of temperature is highly significant

Linear Time trend (day, starting from 1/1/2008) is highly significant, but a nonlinear time trend is not significant

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Adjusting Peak Day Forecast for DSM Change and Emerging Market Forecast

Firm Sales Peak Day Load Base Case Forecast (MDT)				
Gas Year	2016 IRP Peak Day Forecast (with 2014 IRP DSM)	Emerging Market Peak Day Firm Sales Forecast	DSM Change from 2014 IRP	2016 Firm Sales Peak Day Forecast
2015-16	967.3	0.0	0.0	967.3
2016-17	978.6	0.0	0.9	977.7
2017-18	991.6	0.0	2.0	989.6
2018-19	1006.4	0.1	3.5	1002.9
2019-20	1021.4	0.1	4.2	1017.3
2020-21	1036.5	0.1	5.0	1031.7
2021-22	1051.6	0.2	6.0	1045.8
2022-23	1066.4	0.2	7.5	1059.2
2023-24	1080.7	0.3	9.0	1072.0
2024-25	1094.3	0.4	10.6	1084.1
2025-26	1107.6	0.4	12.2	1095.8
2026-27	1120.5	0.5	13.9	1107.1
2027-28	1133.1	0.6	15.7	1118.0
2028-29	1145.5	0.6	17.5	1128.6
2029-30	1157.5	0.7	19.4	1138.8
2030-31	1169.2	0.8	21.2	1148.8
2031-32	1180.6	0.9	23.0	1158.5
2032-33	1191.7	0.9	24.8	1167.9
2033-34	1202.6	1.0	26.5	1177.1
2034-35	1213.1	1.1	28.2	1186.0
2035-36	1223.4	1.1	29.9	1194.6

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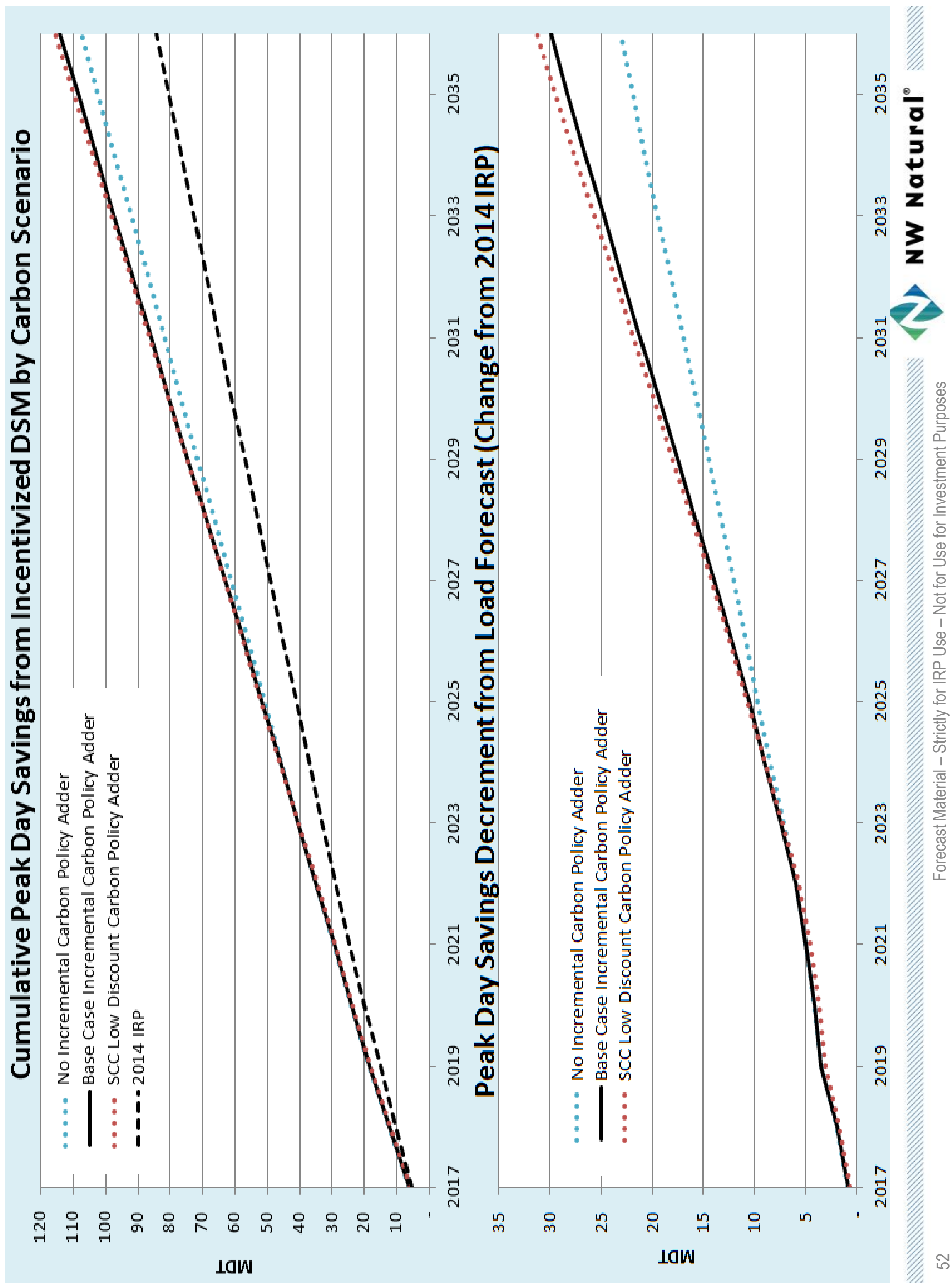
Cumulative Peak Day Savings from Incentivized DSM by Carbon Scenario
No Incremental Carbon Policy Adder
Base Case Incremental Carbon Policy Adder
SCC Low Discount Carbon Policy Adder
2014 IRP
MDT
Peak Day Savings Decrement from Load Forecast (Change from 2014 IRP)
MDT
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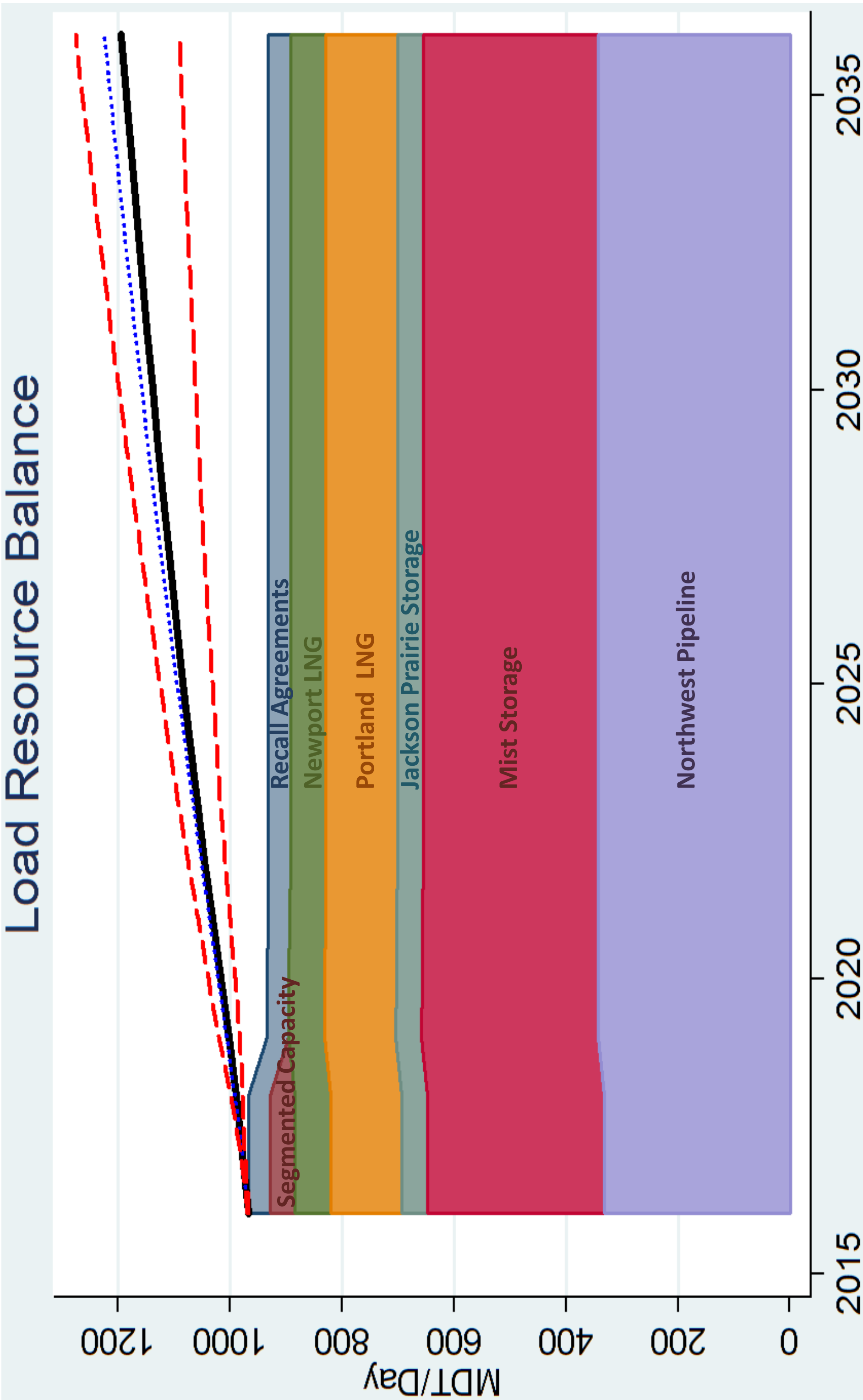

Blue line represents 2016 IRP Load Forecast with 2014 IRP DSM

Black line represents post-DSM 2016 IRP load forecast with high and low cases (seen in red)

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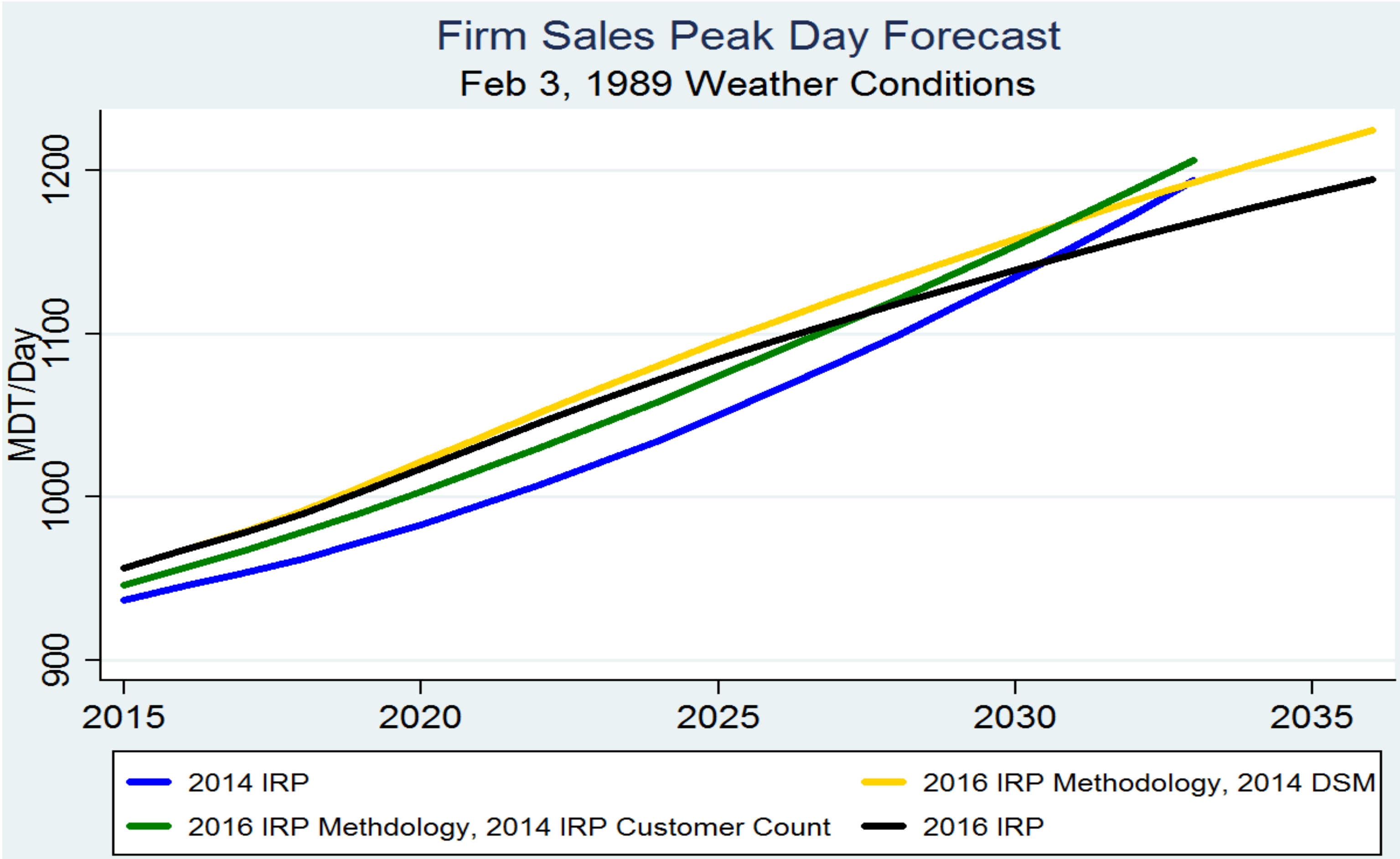
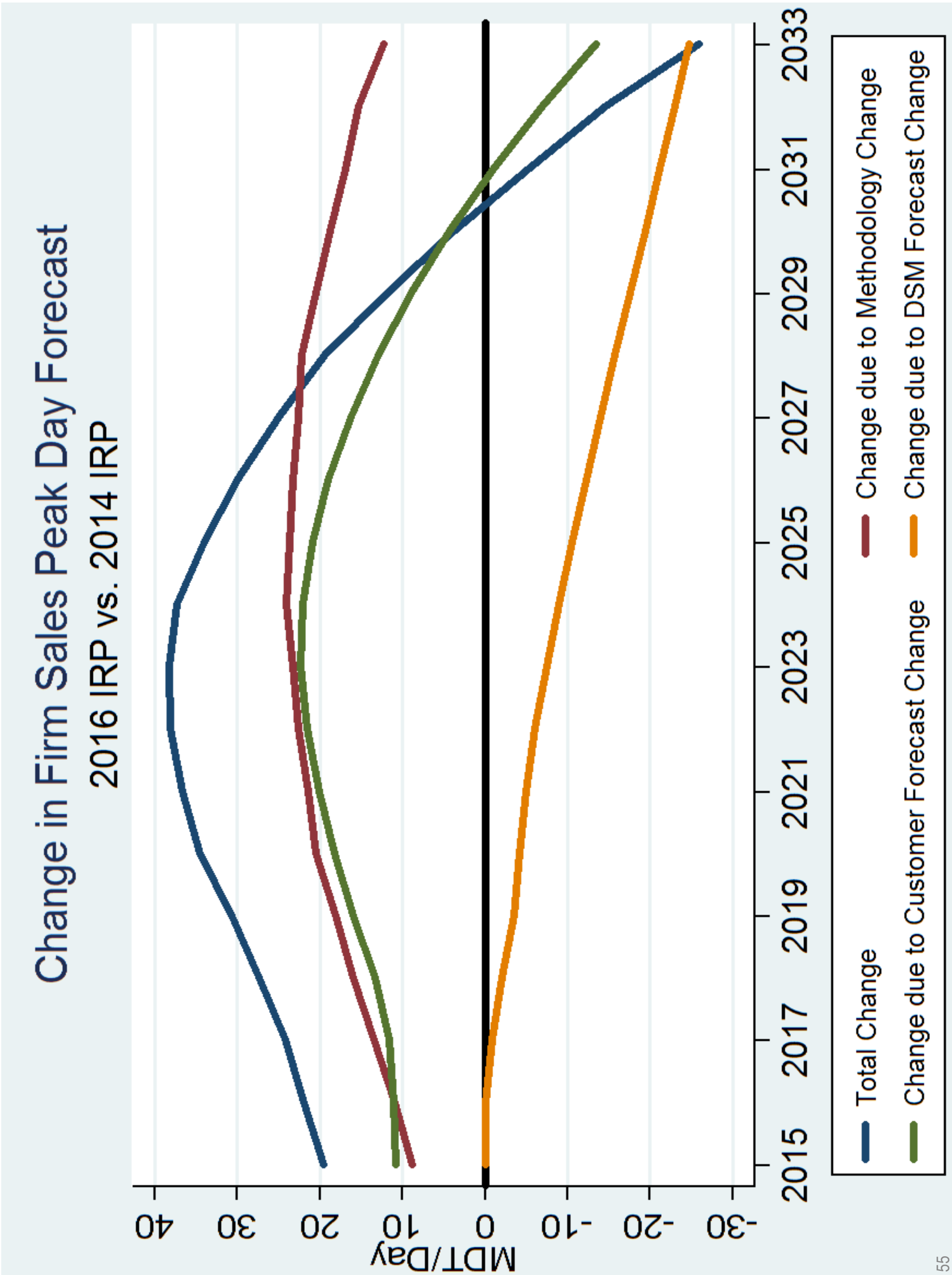
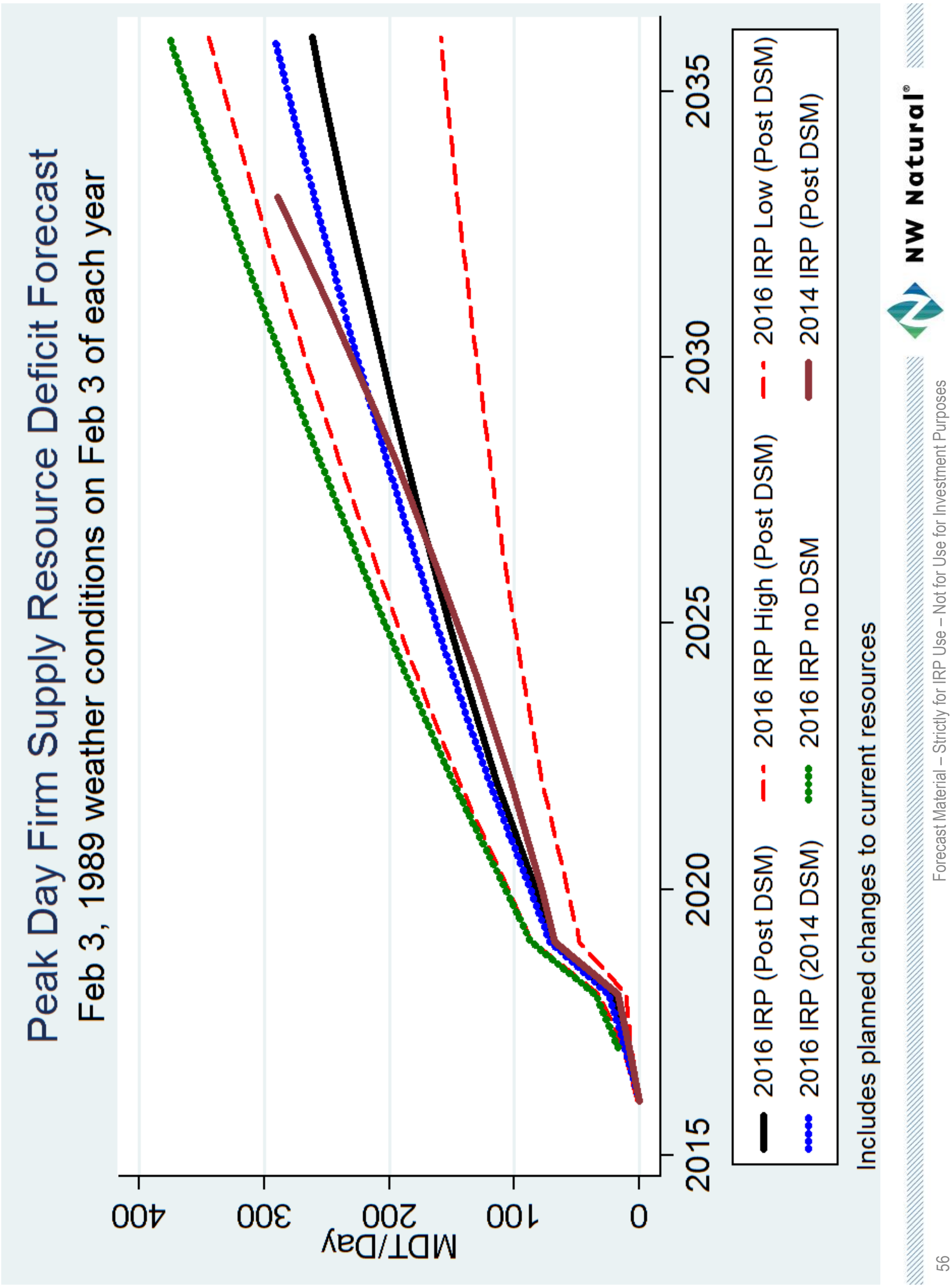


Change in DSM savings forecast from 2014 IRP a major driver of change in load forecast from last IRP (as large as major changes in load forecasting methodology)


Change in Firm Sales Peak Day Forecast
2016 IRP vs. 2014 IRP
MDT/Day
40
30
20
10
0
-10
-20
-30
2015
2017
2019
2021
2023
2025
2027
2029
2031
2033
Total Change
Change due to Methodology Change
Change due to Customer Forecast Change
Change due to DSM Forecast Change
55


Peak Day Firm Supply Resource Deficit Forecast
Feb 3, 1989 weather conditions on Feb 3 of each year
MDT/Day
0
100
200
300
400
2015
2020
2025
2030
2035
2016 IRP (Post DSM)
2016 IRP High (Post DSM)
2016 IRP Low (Post DSM)
2016 IRP (2014 DSM)
2016 IRP no DSM
2014 IRP (Post DSM)
Includes planned changes to current resources
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Annual Energy Forecast Technical Details

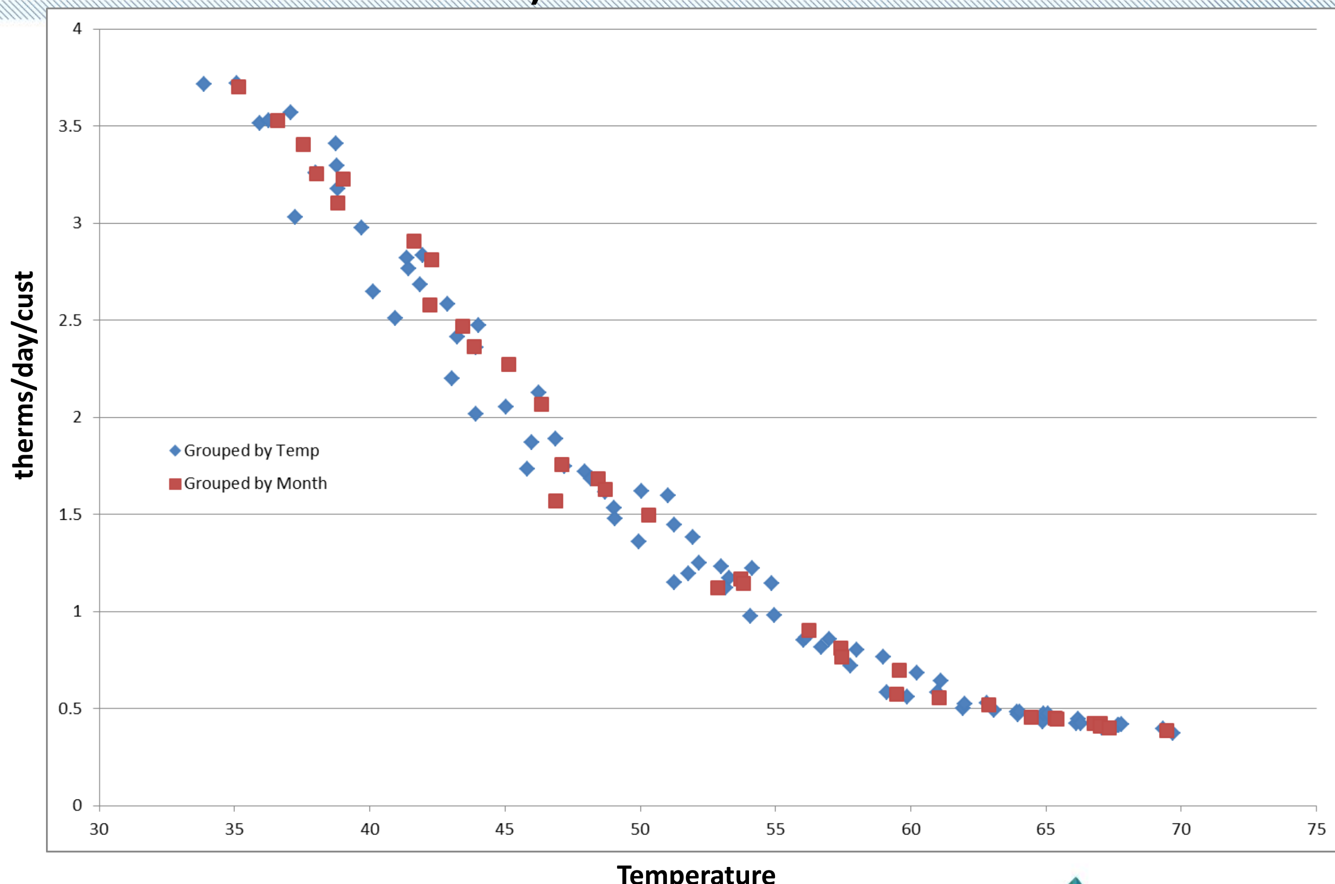
Use Per Customer: Data

Grouped by:
- District
- Segment (Residential/Commercial)
- Temperature rounded to nearest °F
- Year

Previously:
- District
- Segment
- Month
- Year

district_ code	rate_ class	state	year	bill count	avupd	avtemp	rounded temp
ALB	C1	OR	2009	1	0.00	75.96	76
ALB	C1	OR	2009	1	16.38	75.13	75
ALB	C1	OR	2009	3	0.00	74.01	74
ALB	C1	OR	2009	3	0.13	73.17	73
ALB	C1	OR	2009	1	0.14	71.71	72
ALB	C1	OR	2009	176	1.75	70.72	71
ALB	C1	OR	2009	2973	2.82	69.92	70
ALB	C1	OR	2009	510	4.85	68.88	69
ALB	C1	OR	2009	216	2.64	68.13	68
ALB	C1	OR	2009	481	4.14	66.80	67
ALB	C1	OR	2009	1994	3.07	65.87	66
ALB	C1	OR	2009	2664	3.33	65.05	65
ALB	C1	OR	2009	1615	3.48	64.05	64
ALB	C1	OR	2009	1410	6.00	63.16	63
ALB	C1	OR	2009	558	4.16	62.28	62
ALB	C1	OR	2009	1712	3.26	61.23	61
ALB	C1	OR	2009	207	3.81	59.74	60
ALB	C1	OR	2009	1077	4.27	59.08	59
ALB	C1	OR	2009	427	4.59	57.97	58
ALB	C1	OR	2009	497	3.35	56.74	57
ALB	C1	OR	2009	1563	6.11	56.11	56
ALB	C1	OR	2009	236	4.69	55.18	55
ALB	C1	OR	2009	123	11.73	54.15	54
ALB	C1	OR	2009	477	11.04	53.14	53
ALB	C1	OR	2009	2159	7.71	51.94	52
ALB	C1	OR	2009	223	6.26	50.78	51
ALB	C1	OR	2009	1473	10.19	50.15	50
ALB	C1	OR	2009	529	9.13	48.85	49
ALB	C1	OR	2009	4739	14.80	47.94	48
ALB	C1	OR	2009	3483	9.41	46.96	47
ALB	C1	OR	2009	1414	11.50	46.25	46
ALB	C1	OR	2009	363	27.02	45.18	45
ALB	C1	OR	2009	1168	16.75	43.80	44
ALB	C1	OR	2009	3048	14.50	42.92	43
ALB	C1	OR	2009	3004	16.97	42.00	42

Use Per Customer Grouping Example (Albany Residential Customers)



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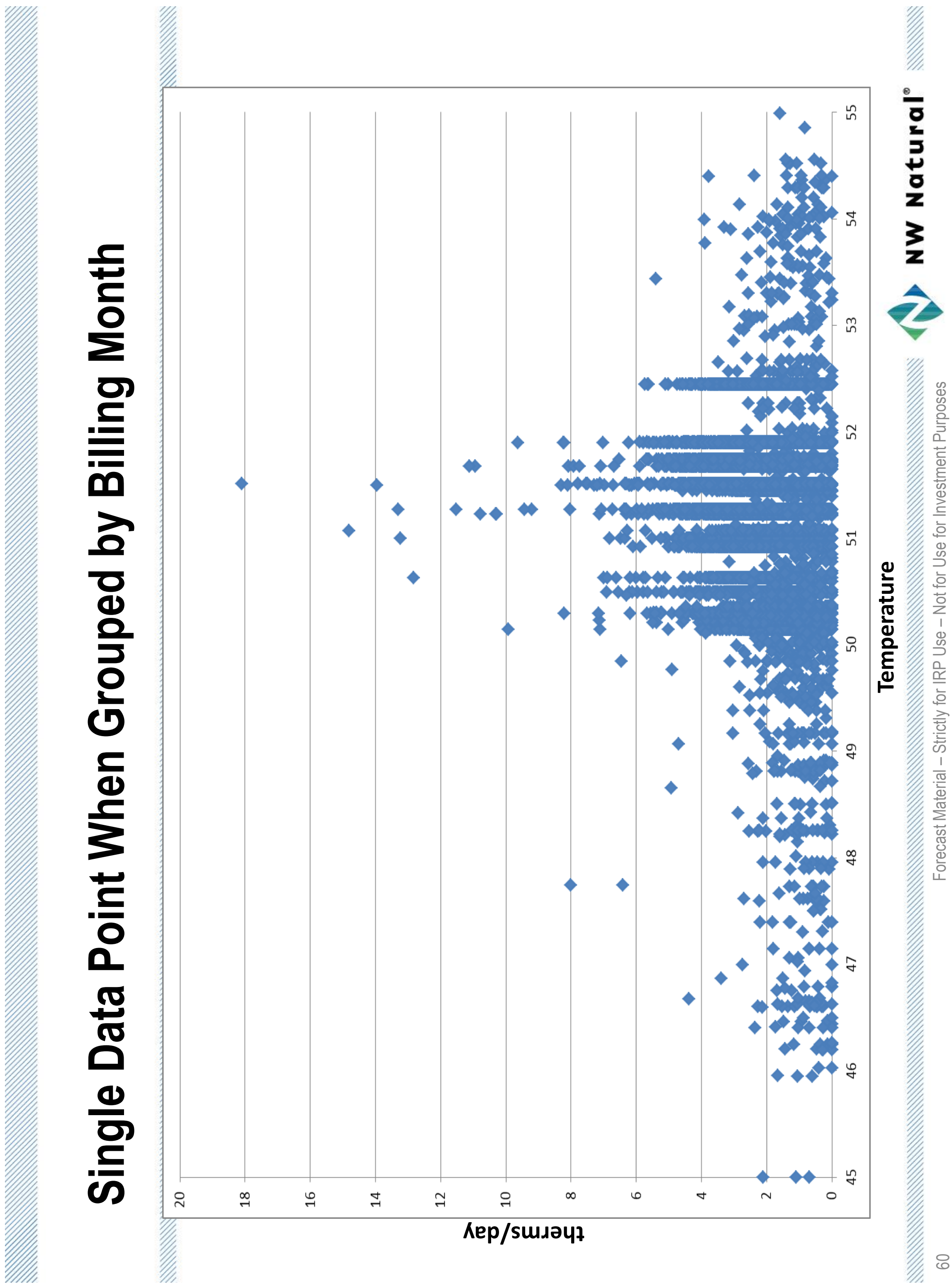
Single Data Point When Grouped by Billing Month
therms/day
0
2
4
6
8
10
12
14
16
18
20
Temperature
45
46
47
48
49
50
51
52
53
54
55
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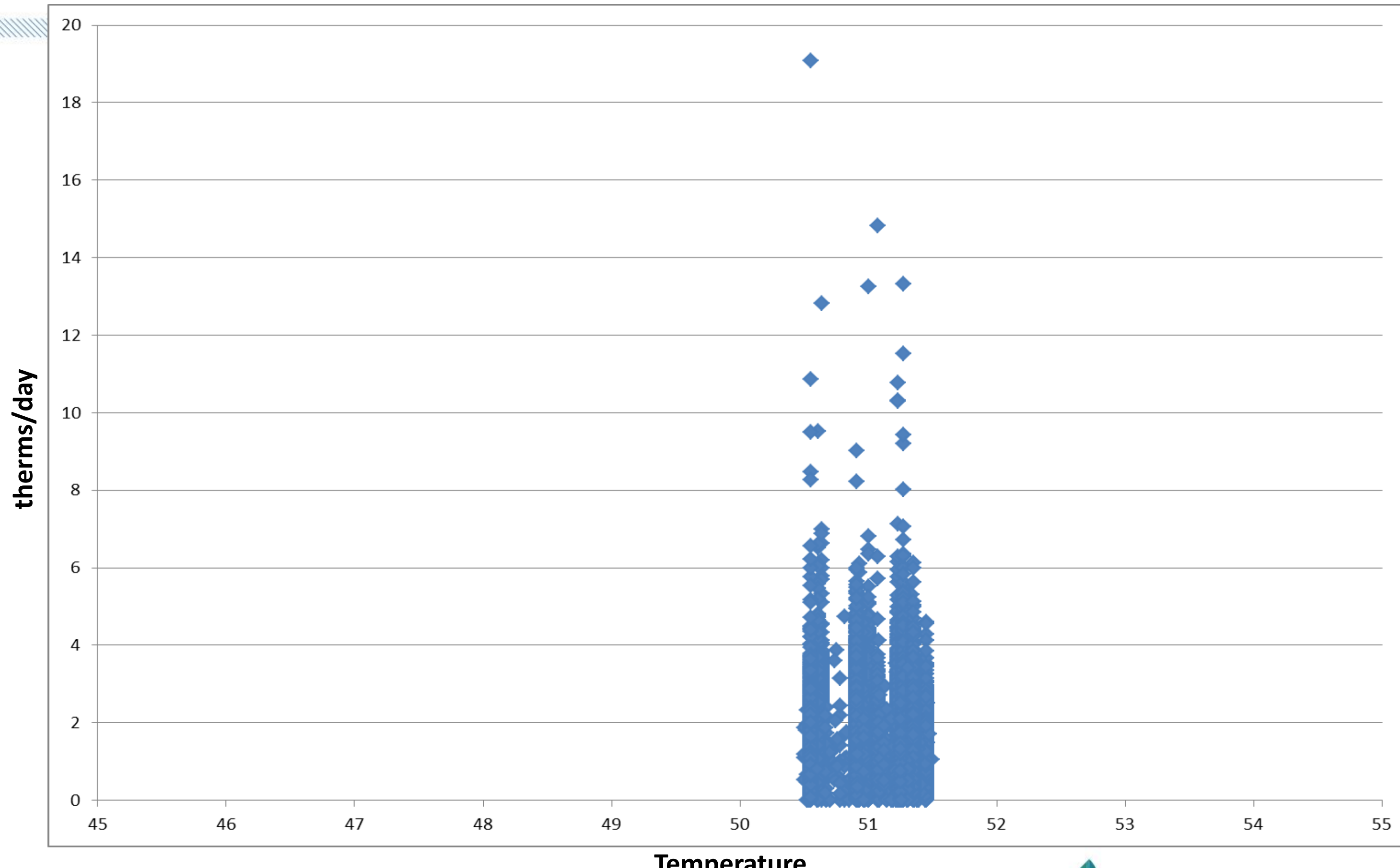
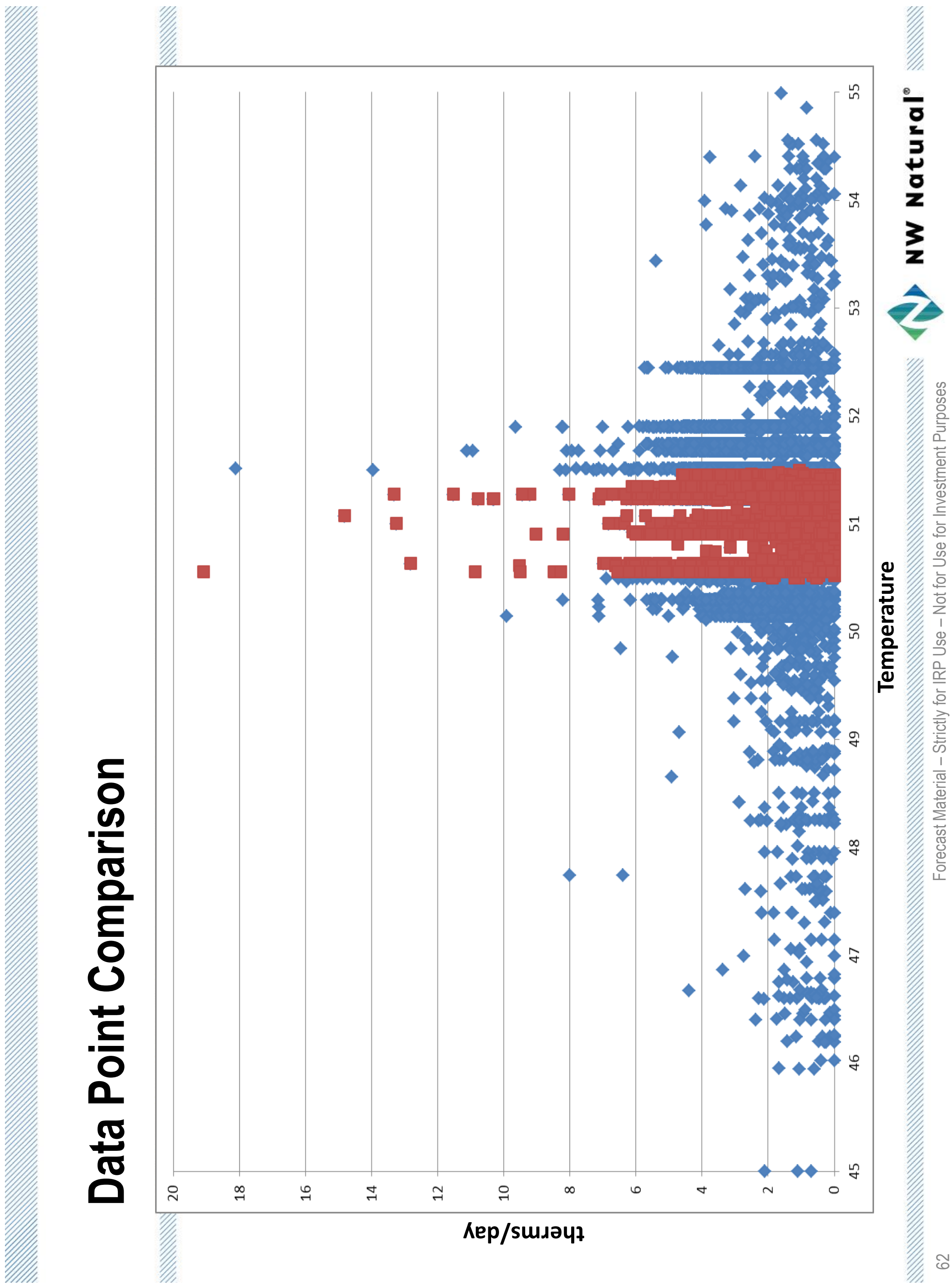
Single Data Point When Grouped by Temperature



Forecast Material – Strictly for IRP Use – Not for Use for Investment Purposes


Data Point Comparison
therms/day
0
2
4
6
8
10
12
14
16
18
20
45
46
47
48
49
50
51
52
53
54
55
Temperature
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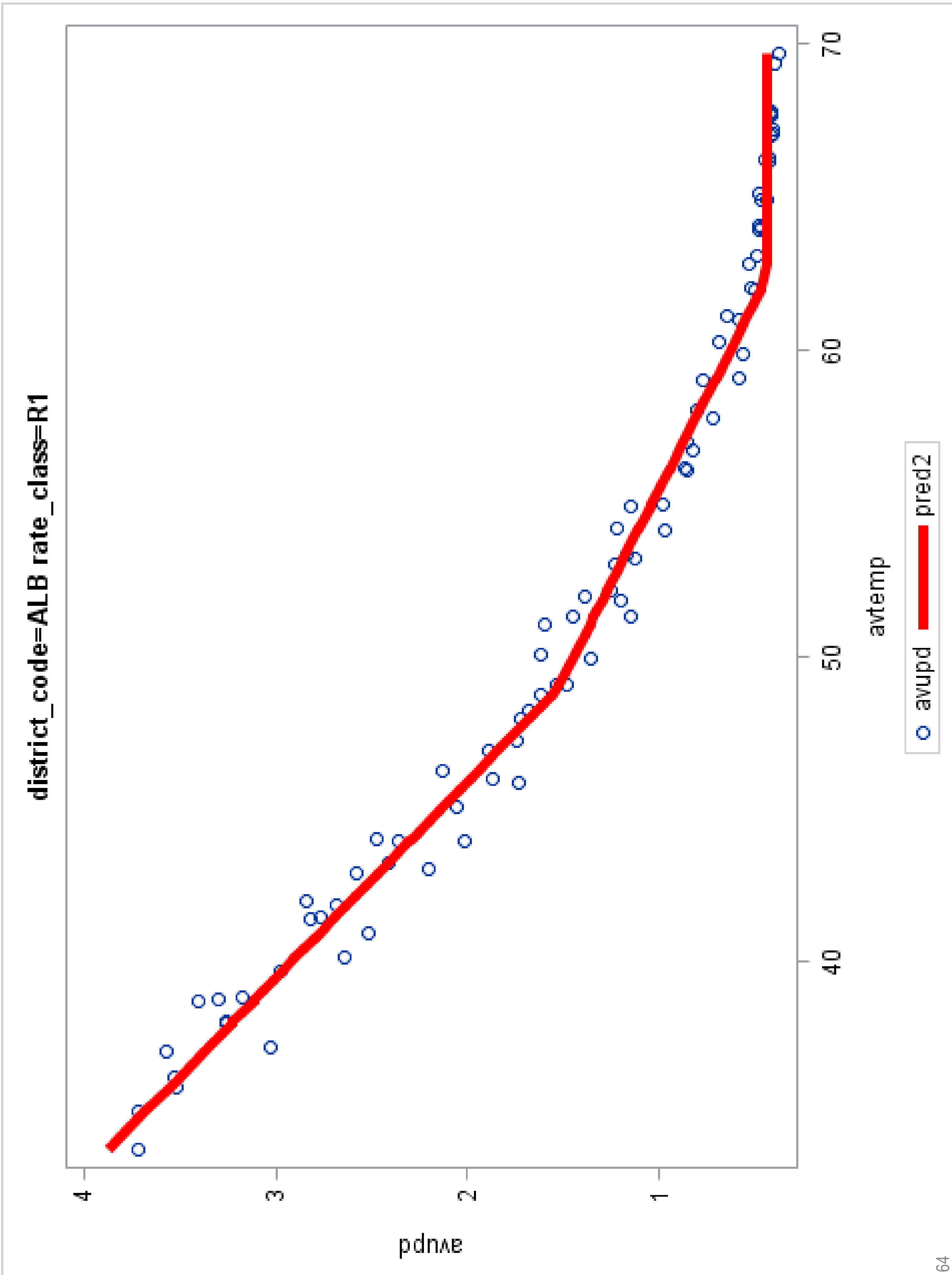
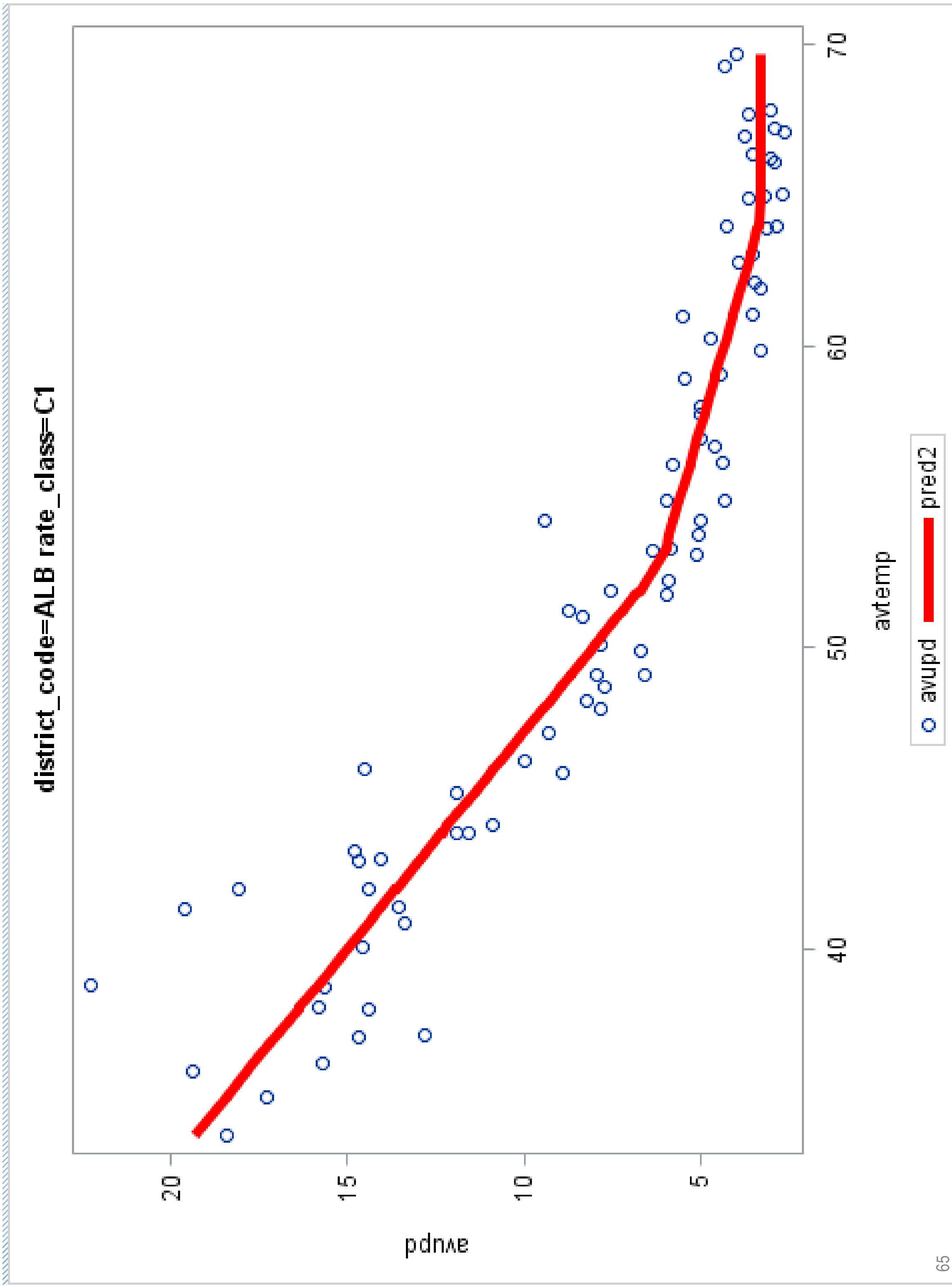
Use Per Customer: New Models

- We need to create linear coefficients to use with our Sendout® software
- Previously we created a nonlinear model then linearized the results
- We are simplifying the process by going directly to a piecewise linear model
- Estimation Model for Residential and Commercial
  - 5 Parameters
    - a = baseload
    - b_1 = HDD rate 1
    - b_2 = HDD rate 2
    - k_1 = break point 1
    - k_2 = break point 2

$$Use\ Per\ Customer\ Per\ Degree\ Day = \begin{cases} a, & HDD \le k_1 \\ a + b_1 * (HDD - k_1), & k_1 < HDD \le k_2 \\ a + b_2 * (HDD - k_2) + b_1 * (k_2 - k_1), & HDD > k_2 \end{cases}$$


district_code=ALB rate_class=R1
avupd
4
3
2
1
40
50
60
70
avtemp
avupd
pred2
64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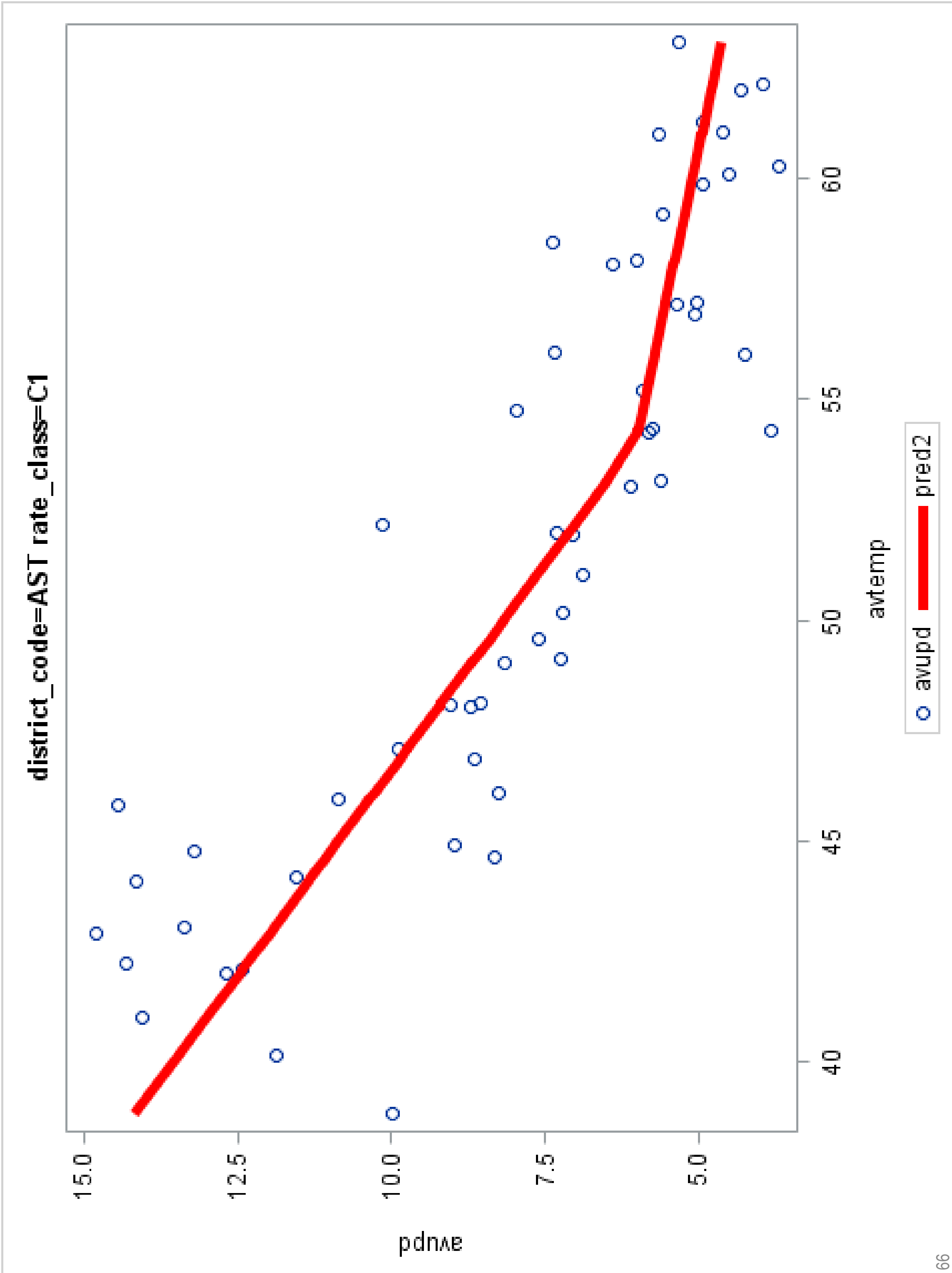
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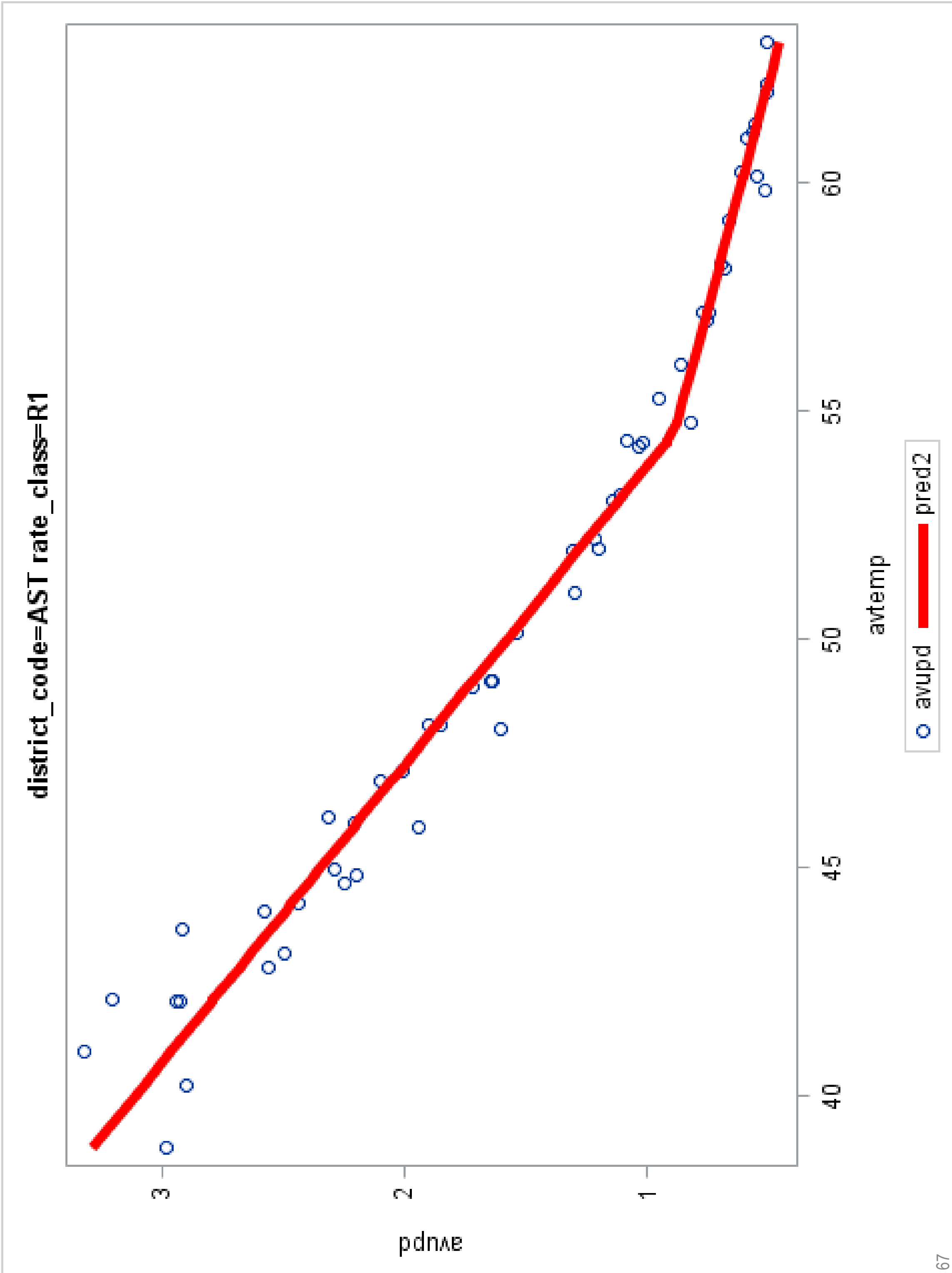
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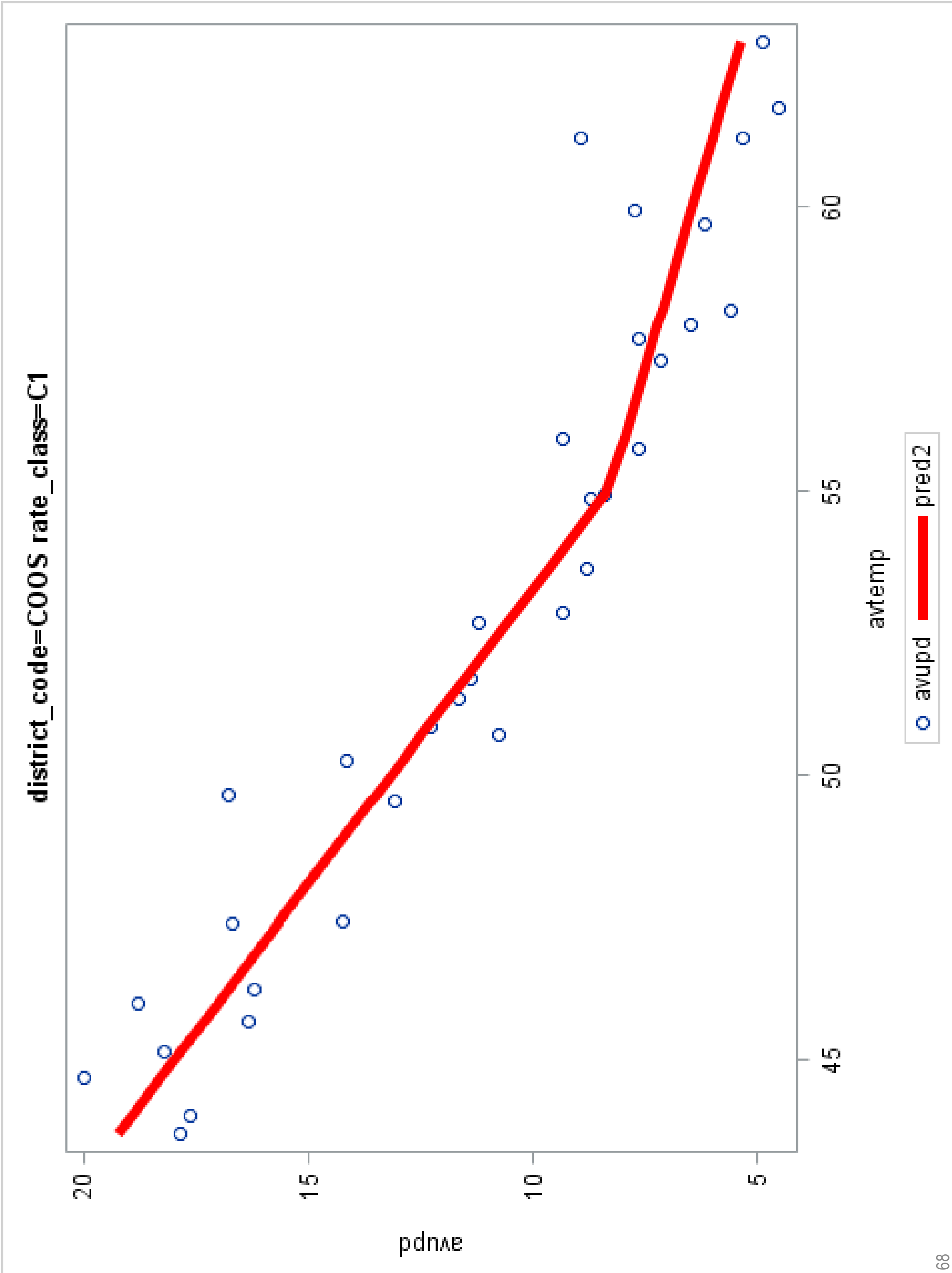
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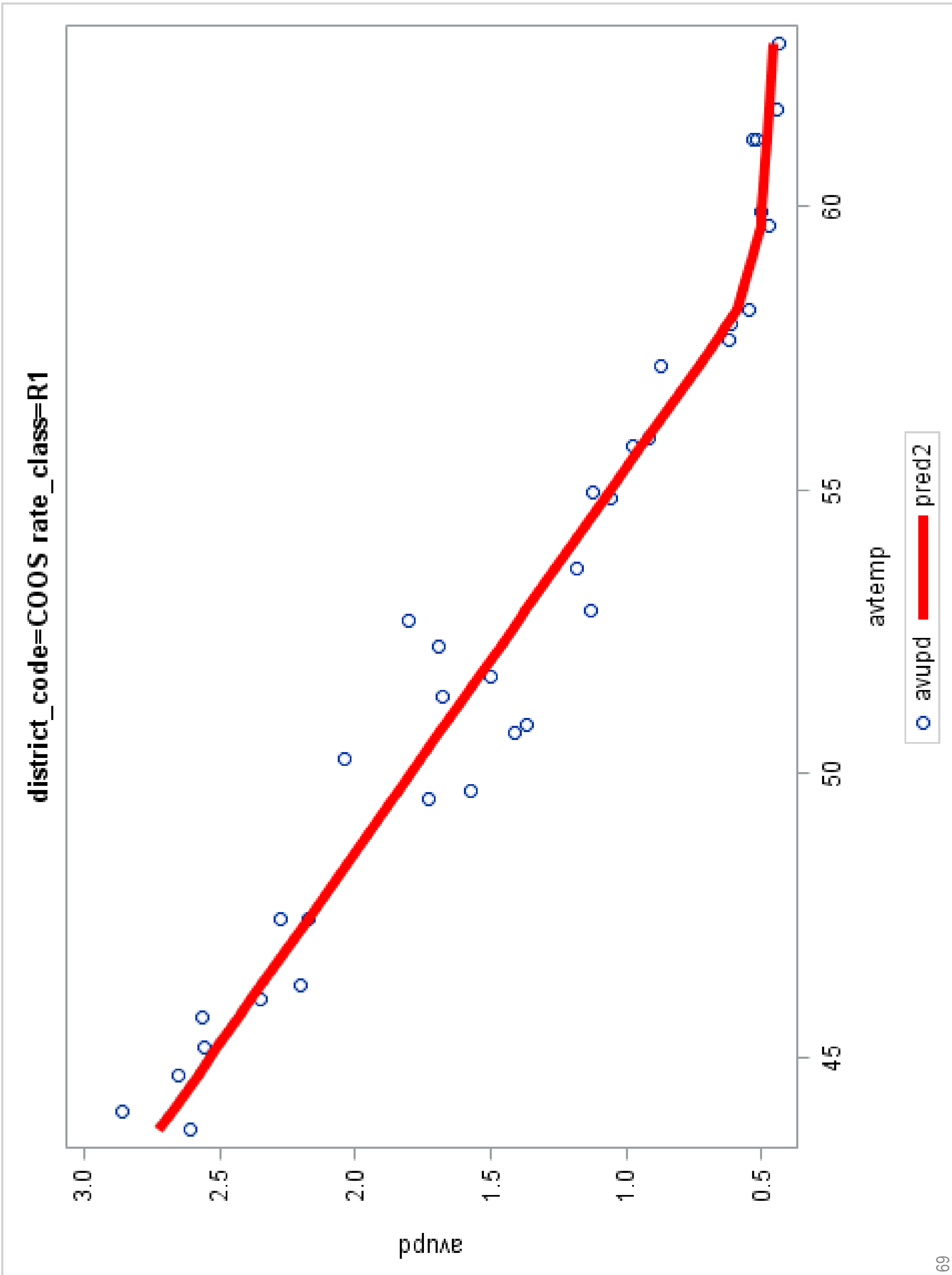
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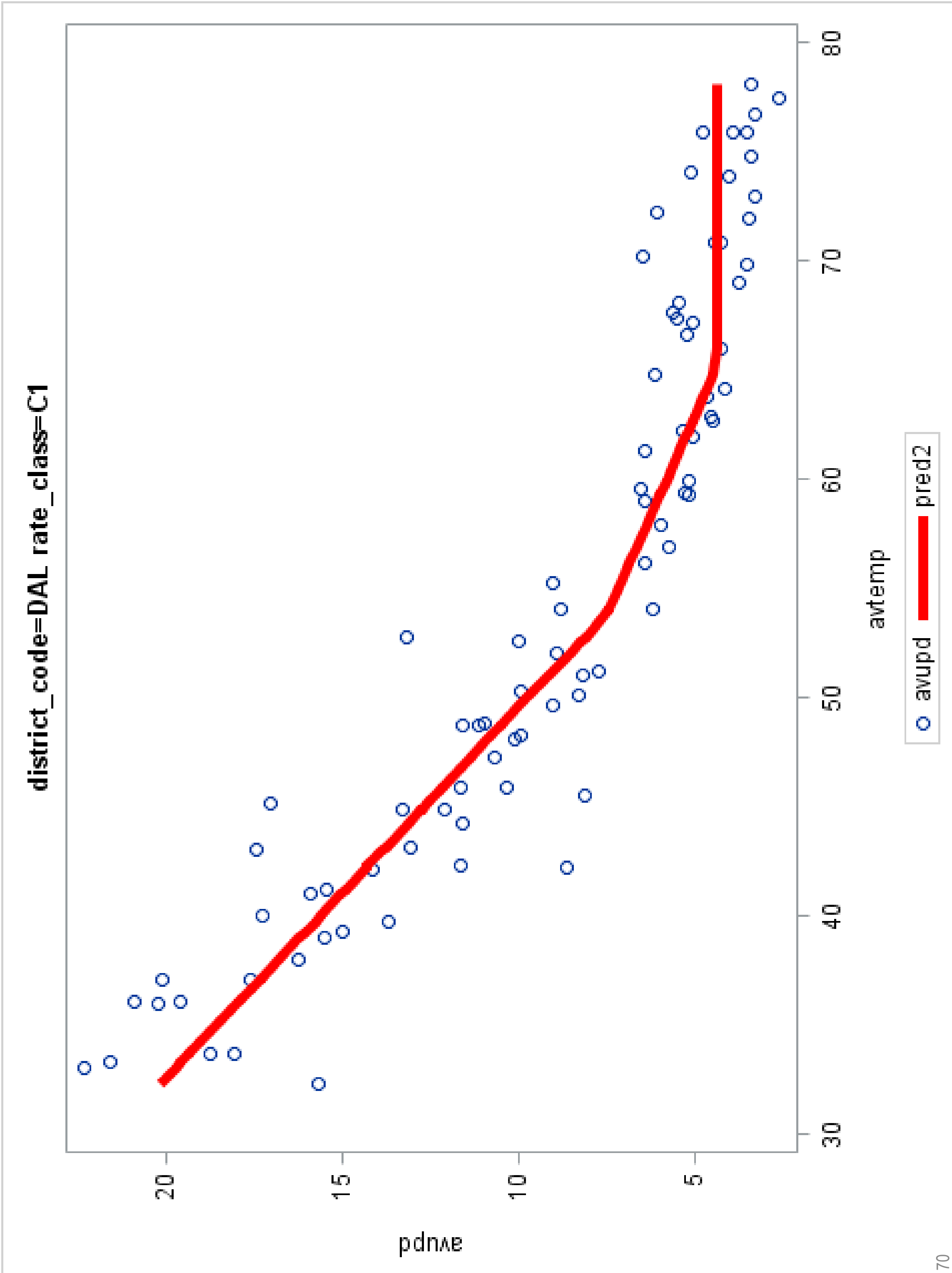
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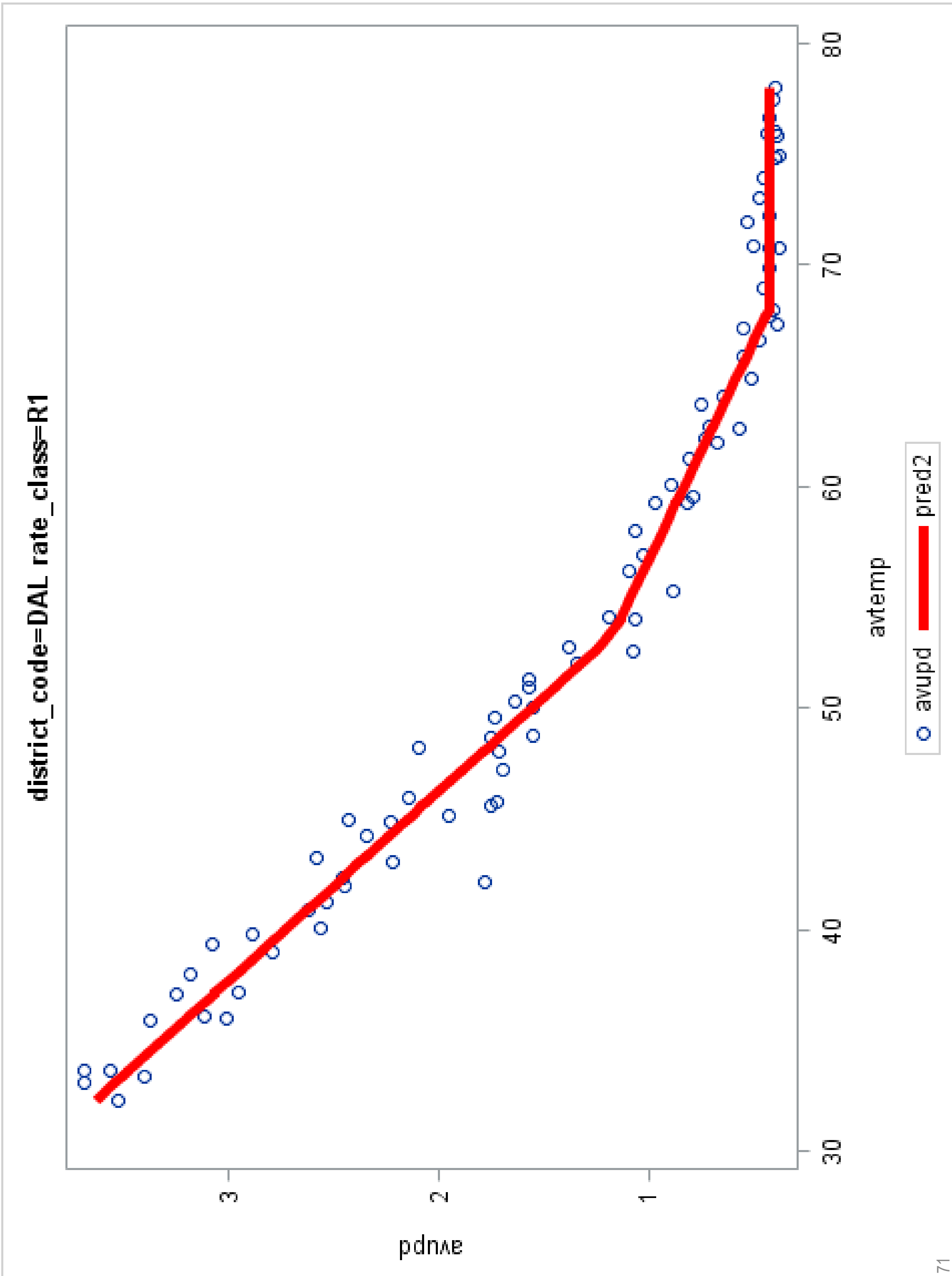
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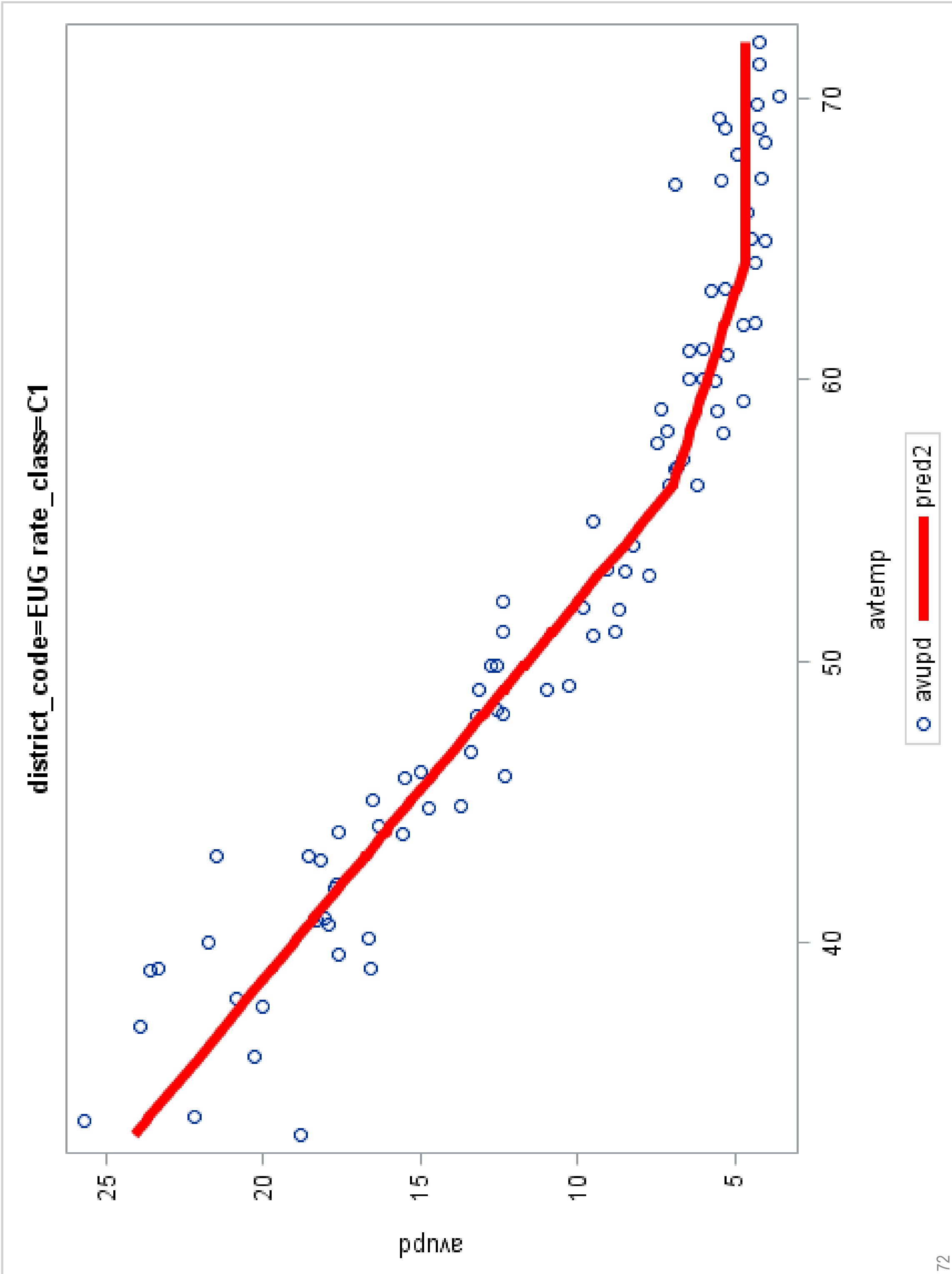
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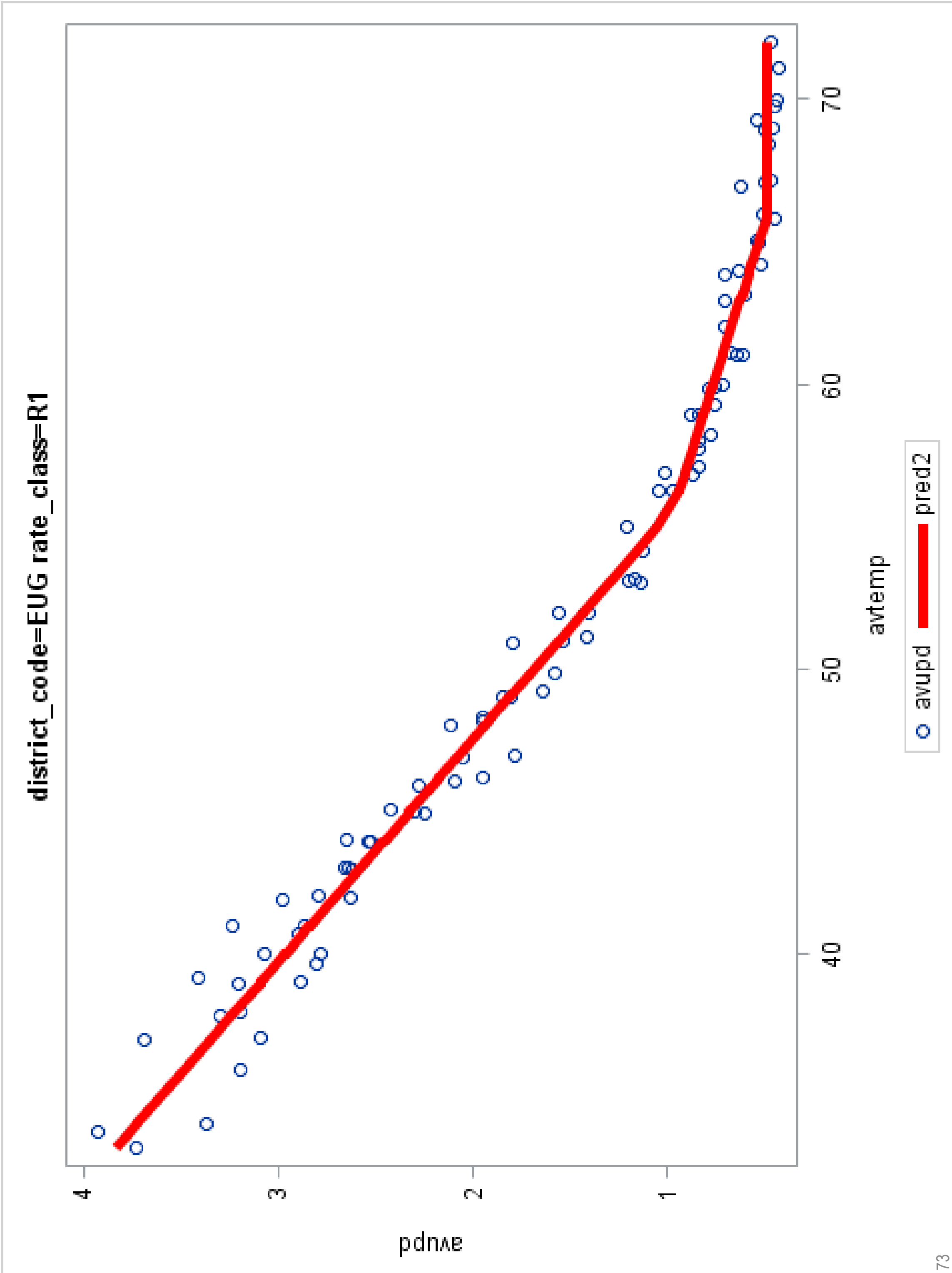
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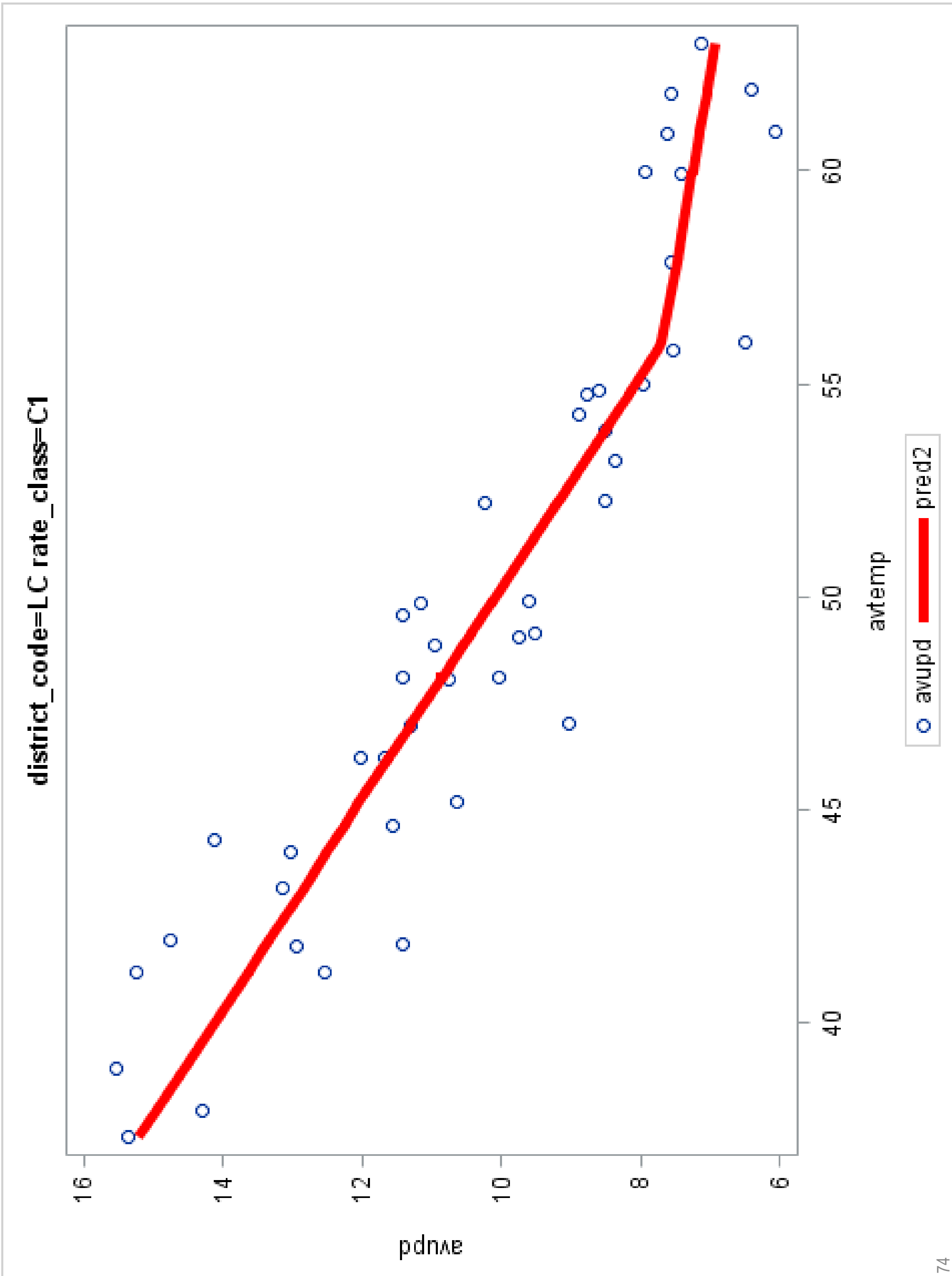
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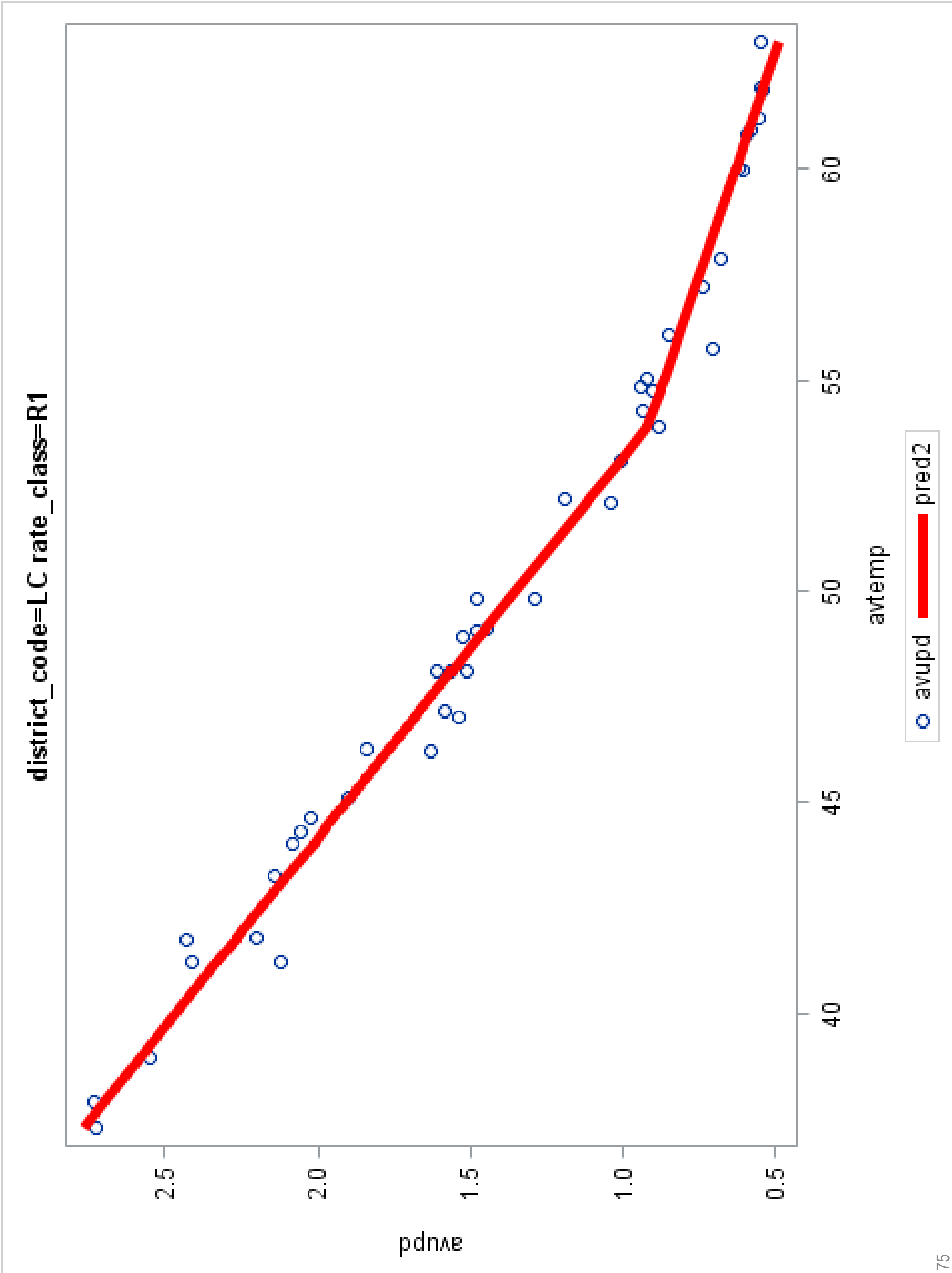
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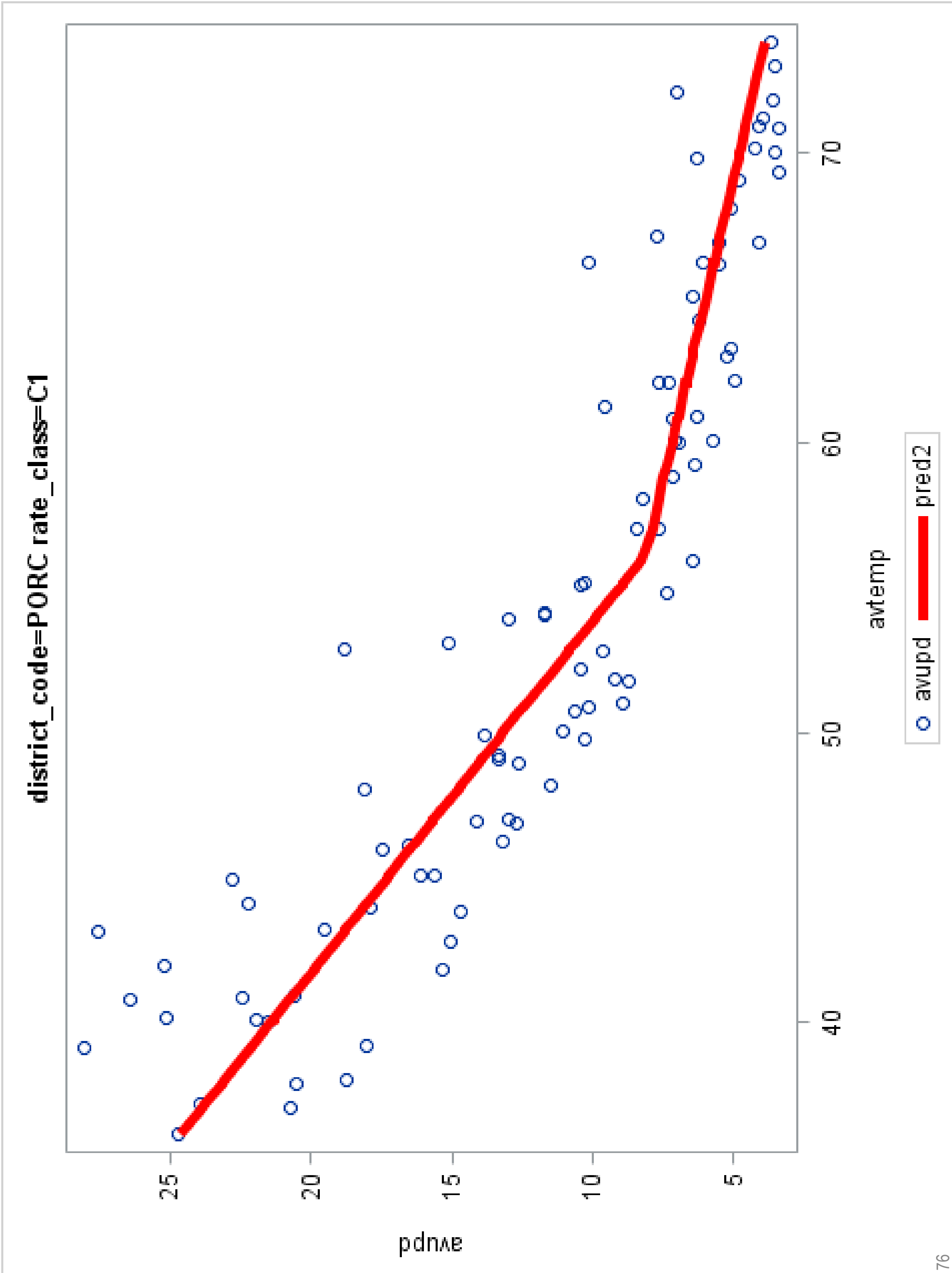
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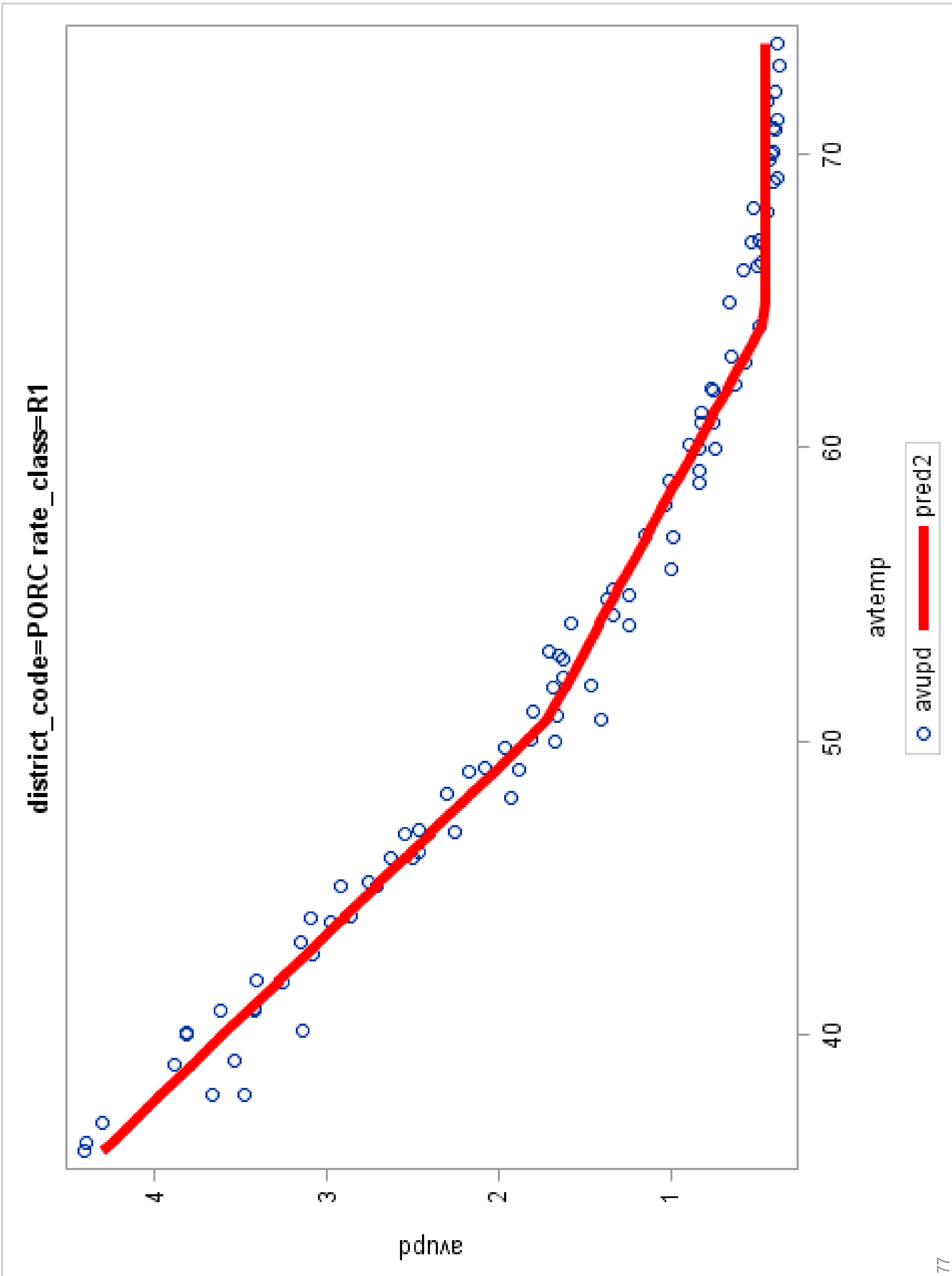
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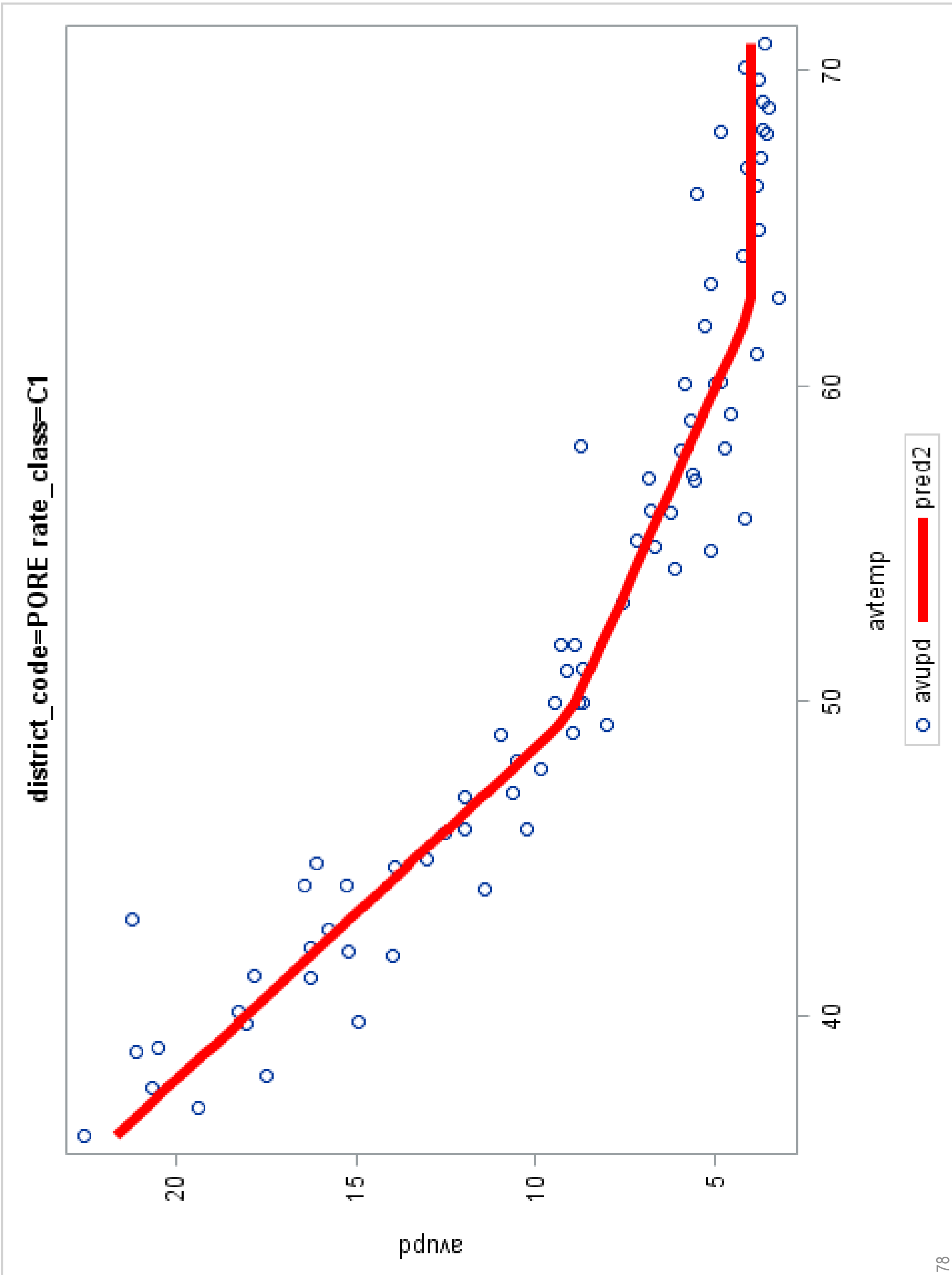
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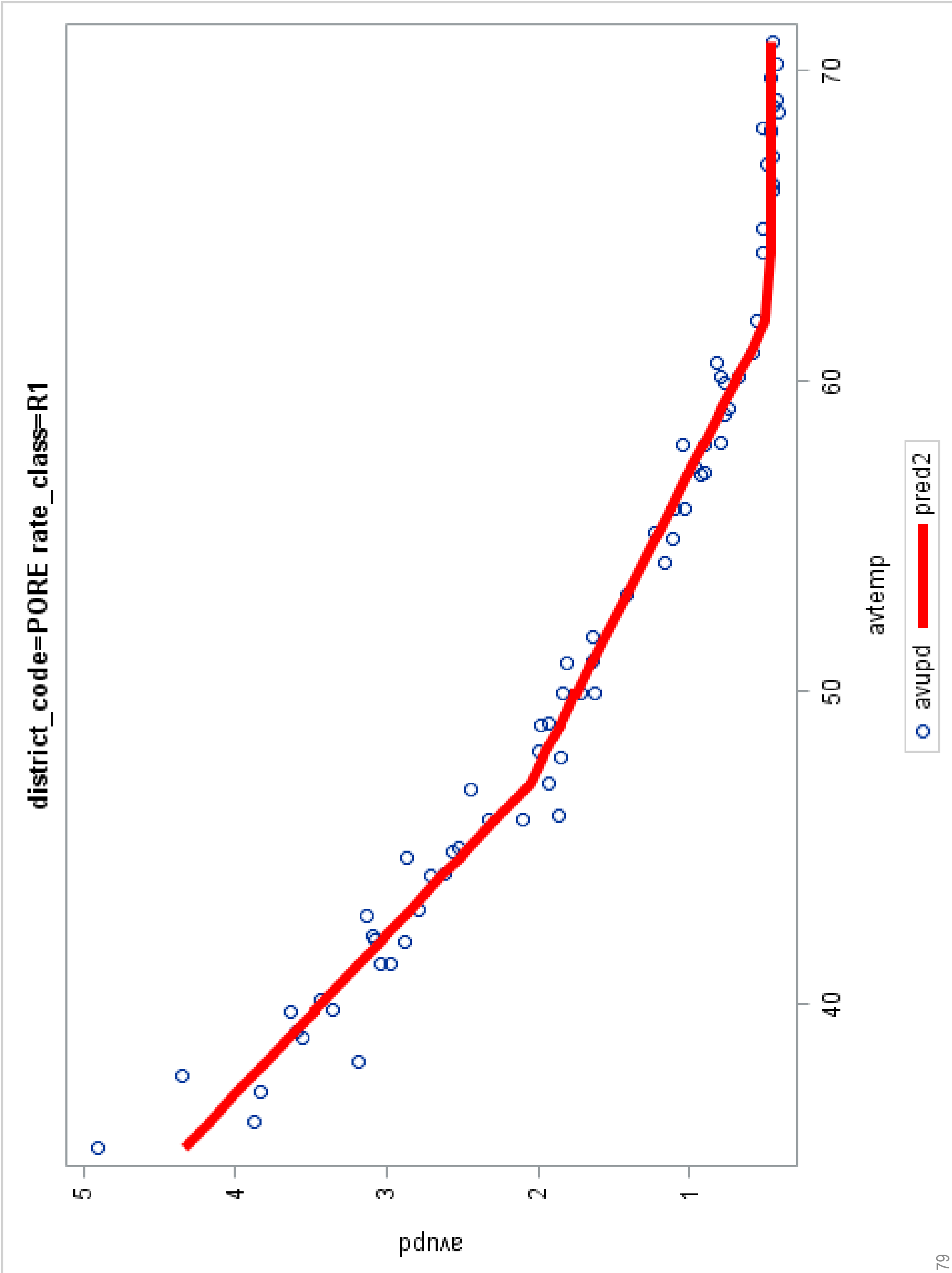
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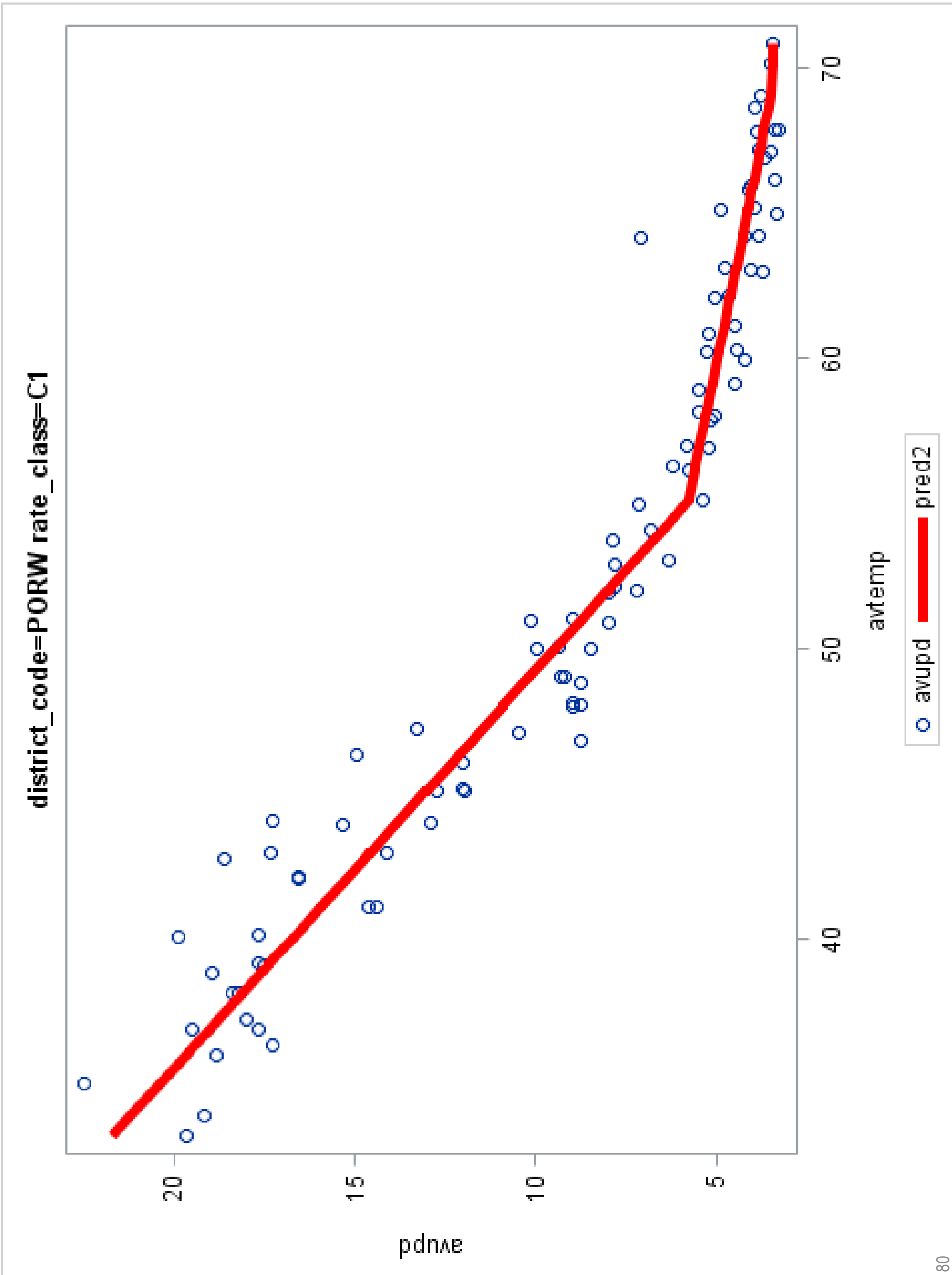
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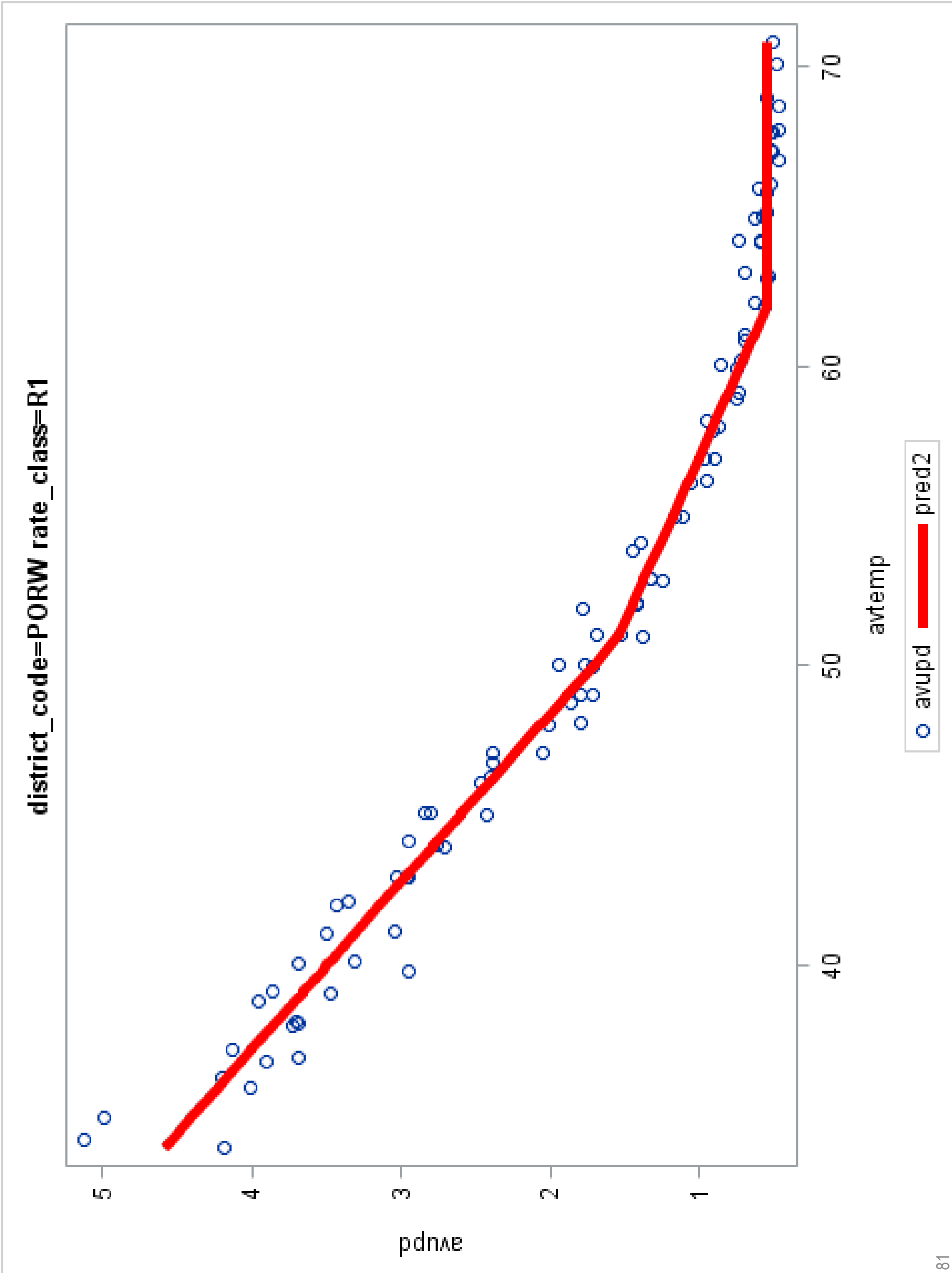
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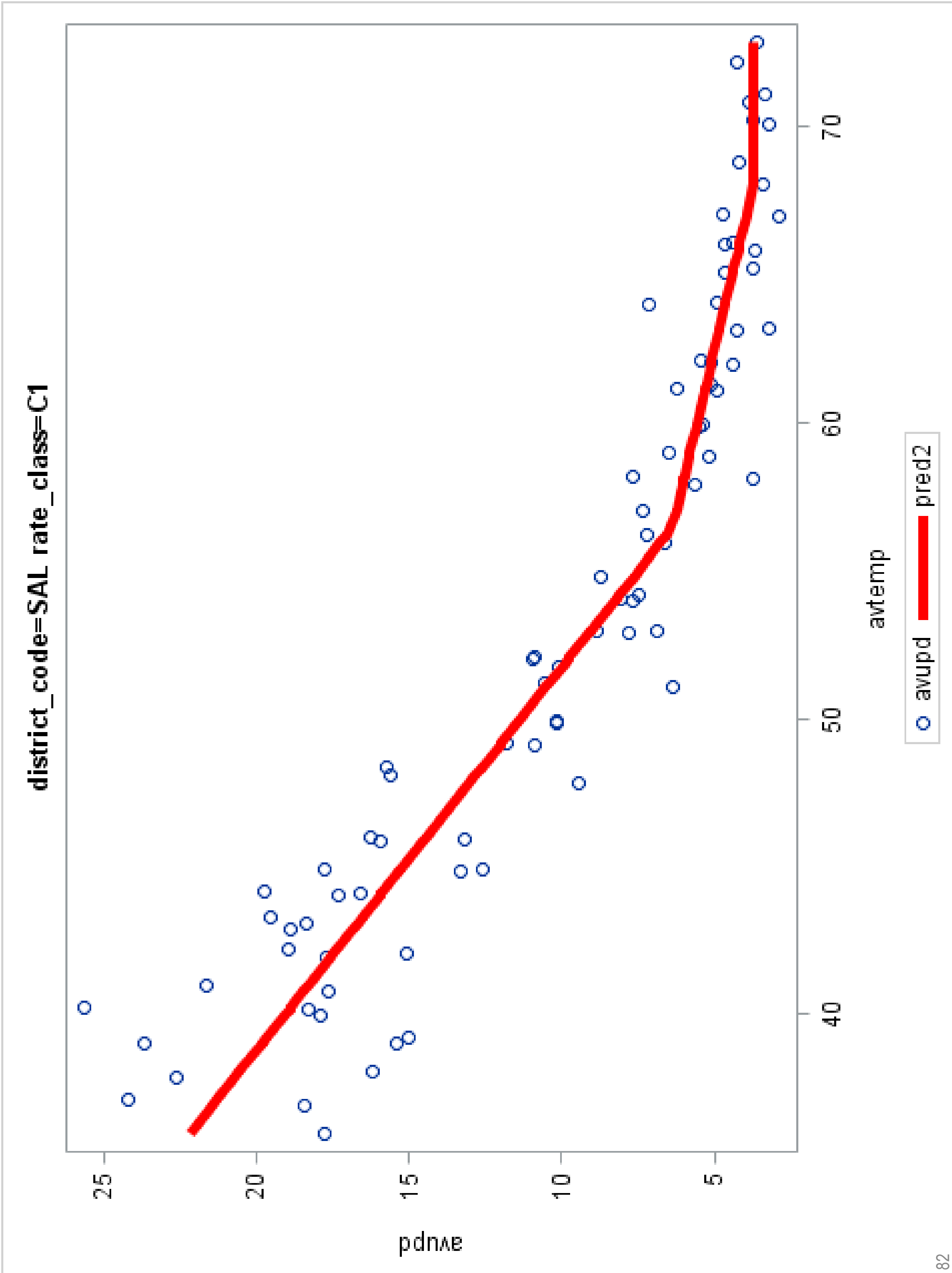
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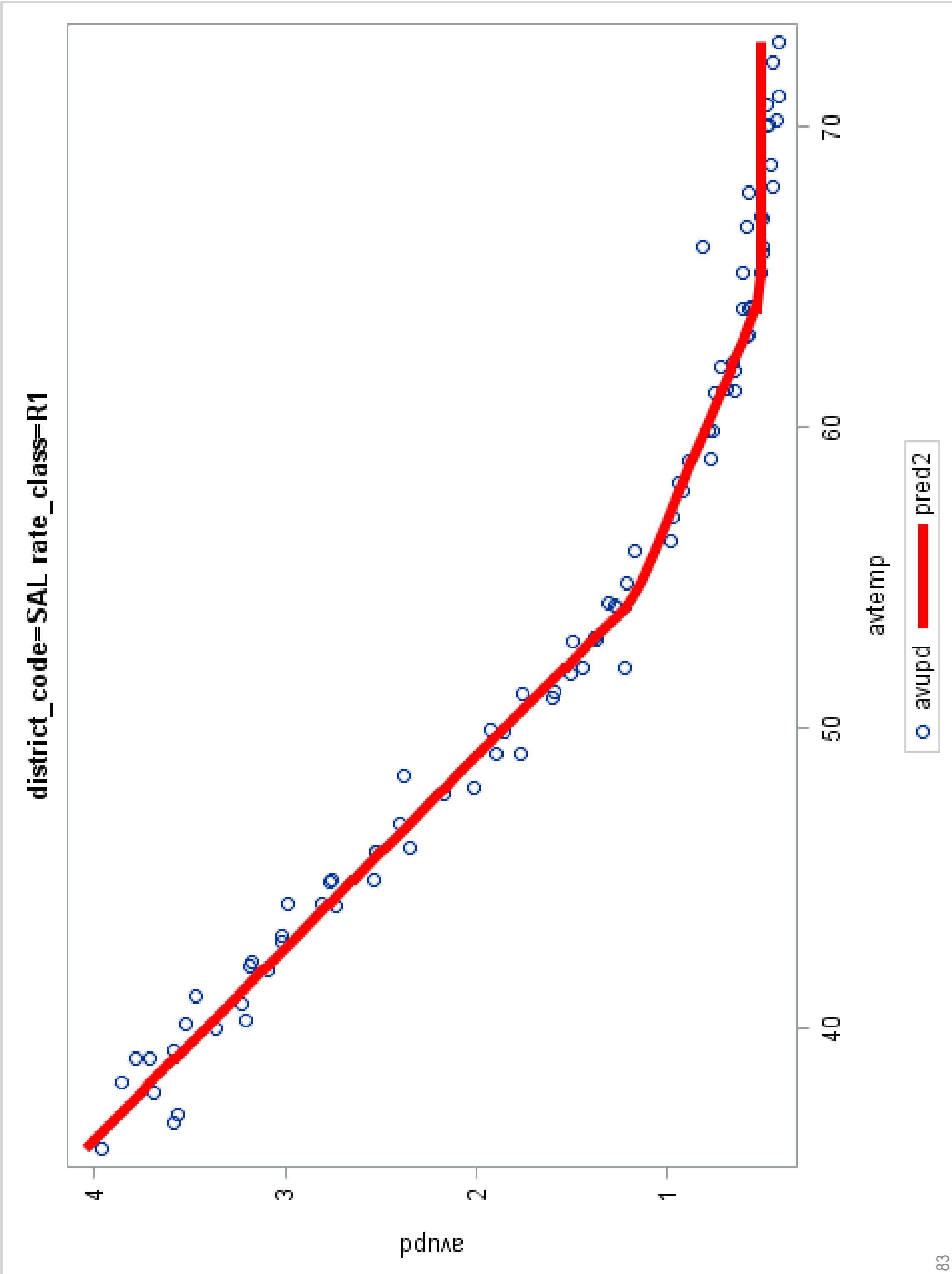
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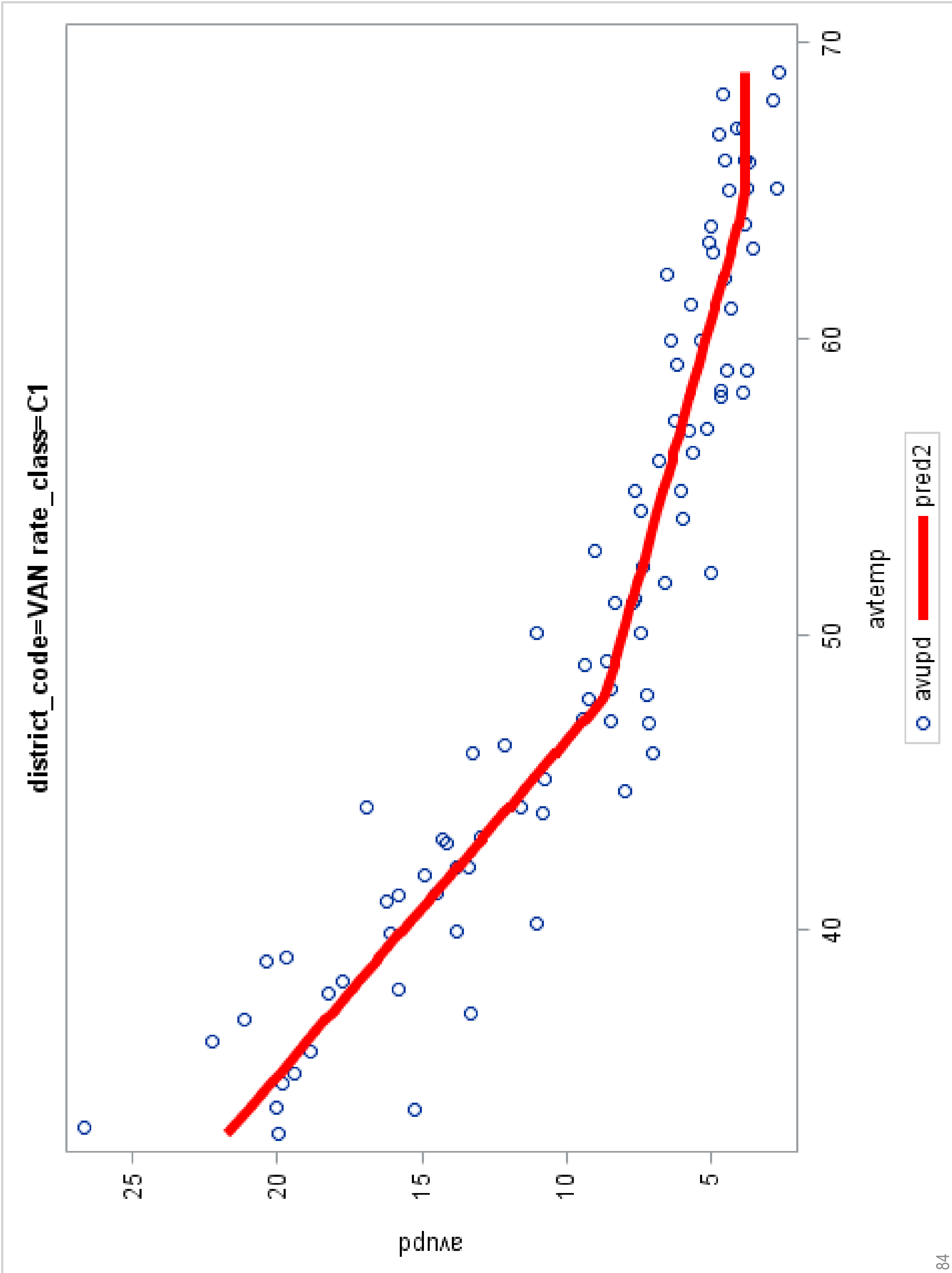
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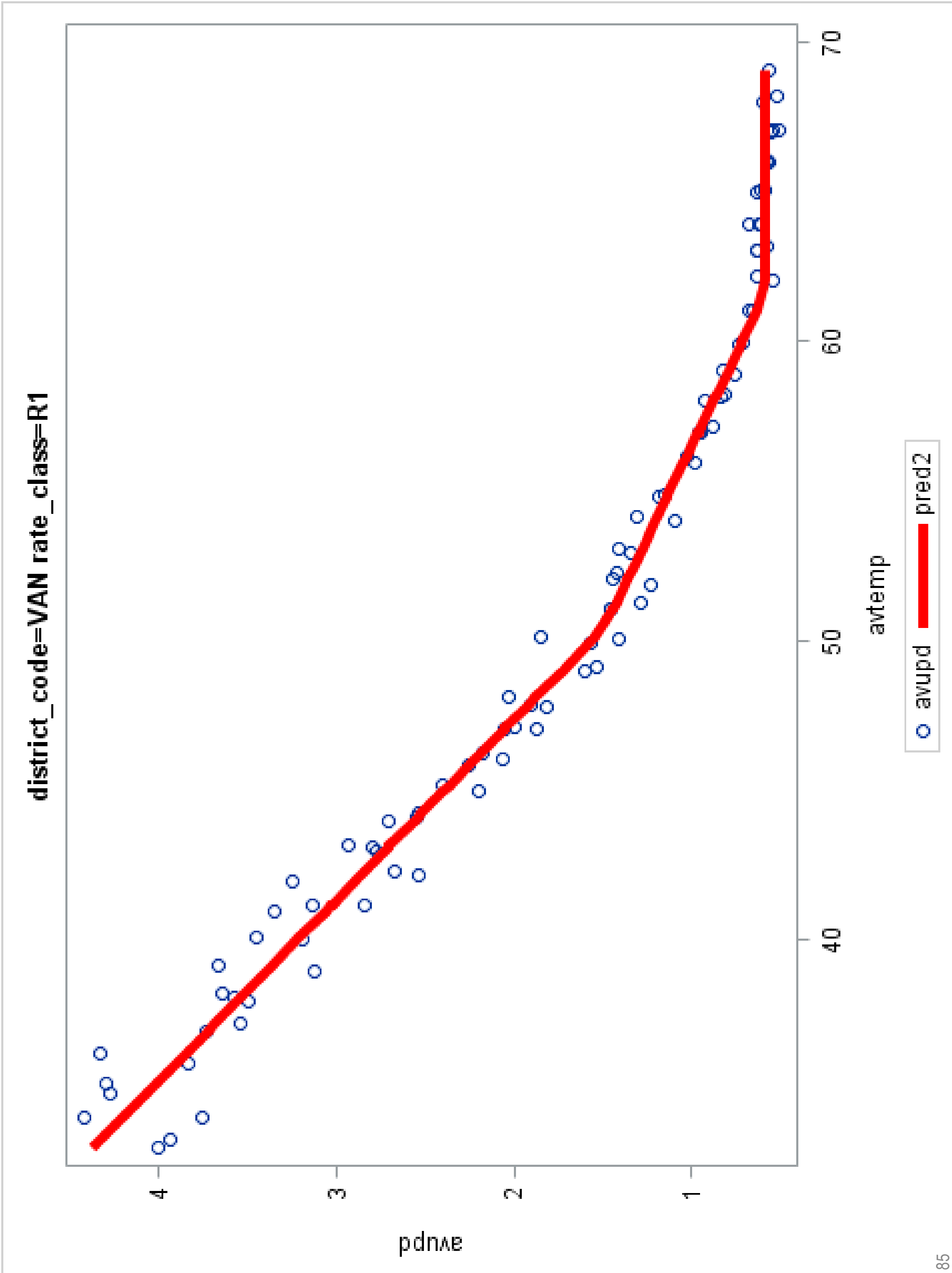
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Use Per Customer: New Models

Trend Component

- Changes in annual usage due to many potential factors
  - DSM, changes in housing stock, etc.
- Isolate changes due to ETO incentivized DSM
- Used data from 2010-2013
- Use only those premises which have not participated in ETO programs over the 4 year period

Results

- Non-significant time trend when using load center data
- When aggregated to the system level, there is a trend
- System level trend is then applied to current housing stock in load centers

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Appendix 3
Supply-Side Resources

Mist Storage Facility Assessment is Confidential

- Subject to General Protective Order No. 16-044 in Oregon
- Subject to WAC 480-07-160 in Washington

Appendix 5
Avoided Costs

Major Methodological Change # 1: Avoided Costs of Capacity Resources

Summary:

- Supply and distribution capacity resource costs are now included
- Usage during peak times is what drives acquisition of supply and distribution resources
  - Hence the focus on the peak day load forecast
- Avoidance of capacity resource costs is determined by the amount of savings on a peak day
  - Each DSM measure has its own load profile with different implications for peak day savings
- New avoided cost methodology in 2016 IRP estimates savings of each DSM/EE measure on a peak day with the following assumptions
  - Supply and distribution capacity resources are incremental resources
  - Peak day savings from DSM/EE are firm capacity resources (assumed to be 100% accurate and reliable) like pipelines, interstate pipeline capacity, natural gas storage service, and our load forecast
  - The distribution of the annual savings targets among measures will be achieved exactly as forecasted by the Energy Trust
- Further improvements planned with additional coordination with the Energy Trust for the 2018 IRP

Calculating Measure Level Capacity Resource Avoided Costs

Process:

1. Determine the peak day savings for each measure from annual savings
2. Determine the annual supply and distribution capacity resource costs avoided for each unit of peak day savings
3. Determine the total annual costs avoided for the measure in question from (1) and (2)
4. Determine the per unit of energy (therm/Dth) avoided capacity resource costs for the measure from (3)

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Peak Day Savings of Each Measure from Annual Savings

1. **Is the customer firm or interruptible**?
   – If interruptible, the customer is assumed interrupted on a peak day and therefore savings from interruptible customers provide no peak day savings (and subsequently avoid no capacity resource costs)

2. **What is the customer class and end use for the respective measure?**
   – End uses in the 2016 IRP: (1) Space Heating, (2) Base Load, and (3) Interruptible

3. **What is the ratio of *design peak day* usage to *normal weather annual* usage for each end use in the 2016 IRP?**

Peak Day to Normal Weather Annual Usage Ratios			
End Use	Residential	Commerical	Industrial
Space Heating	**2.05%**	**1.84%**	**N/A**
Base Load	**0.27%**	**0.27%**	**0.27%**
Interruptible	**N/A**	**N/A**	**0%**

4. **Determine the peak day savings for the measure by multiplying the ratio found in (3) by the estimated total annual savings from the measure**

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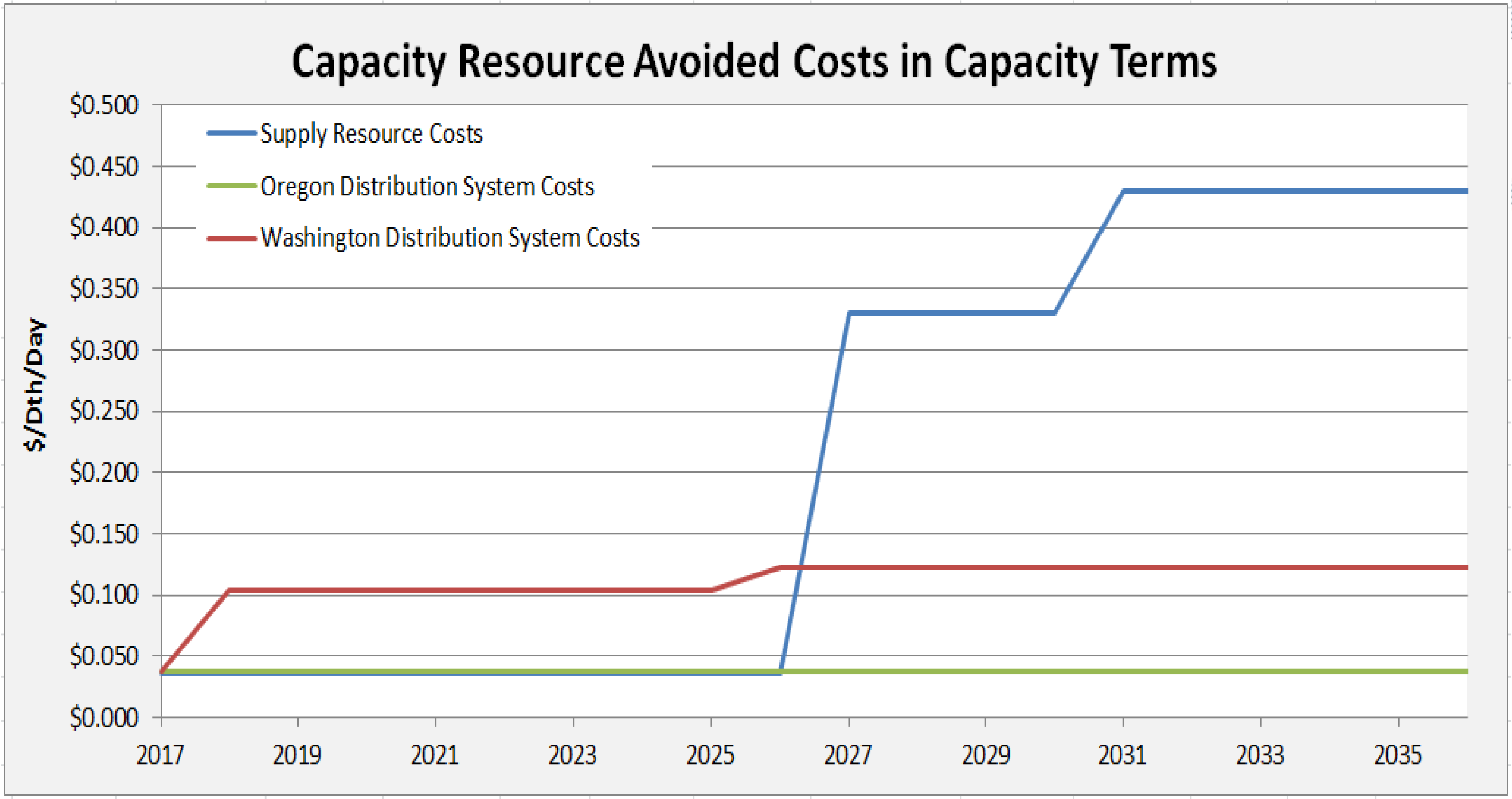
2016 IRP Capacity Resource Avoided Costs Assumptions

- Peak day savings from DSM/EE are a firm resource that is 100% reliable
- Both supply and distribution resources are incremental/divisible and the full value of the incremental resource is avoided for each unit of gas savings from DSM/EE
- Capacity resource costs are represented on a capacity *cost of service* for the marginal resource by year basis
- Supply resource costs are based upon assumptions about the portfolio that will come out of the 2016 IRP process based upon the Company's initial load forecast for the 2016 IRP and initial cost of service estimates for the supply resource options being considered in the 2016 IRP
- Oregon distribution system costs are the long run incremental costs of distribution for the state from the Company's last rate case (per OPUC Order No. 94-590)
- Washington distribution system costs come from cost of service modeling of the planned Clark County Distribution projects over the IRP planning horizon



Supply Resource Cost Assumptions:

– 2017-2026: Mist Recall
– 2027-30: North Mist II Part 1
– 2031-2036: North Mist II Part 2

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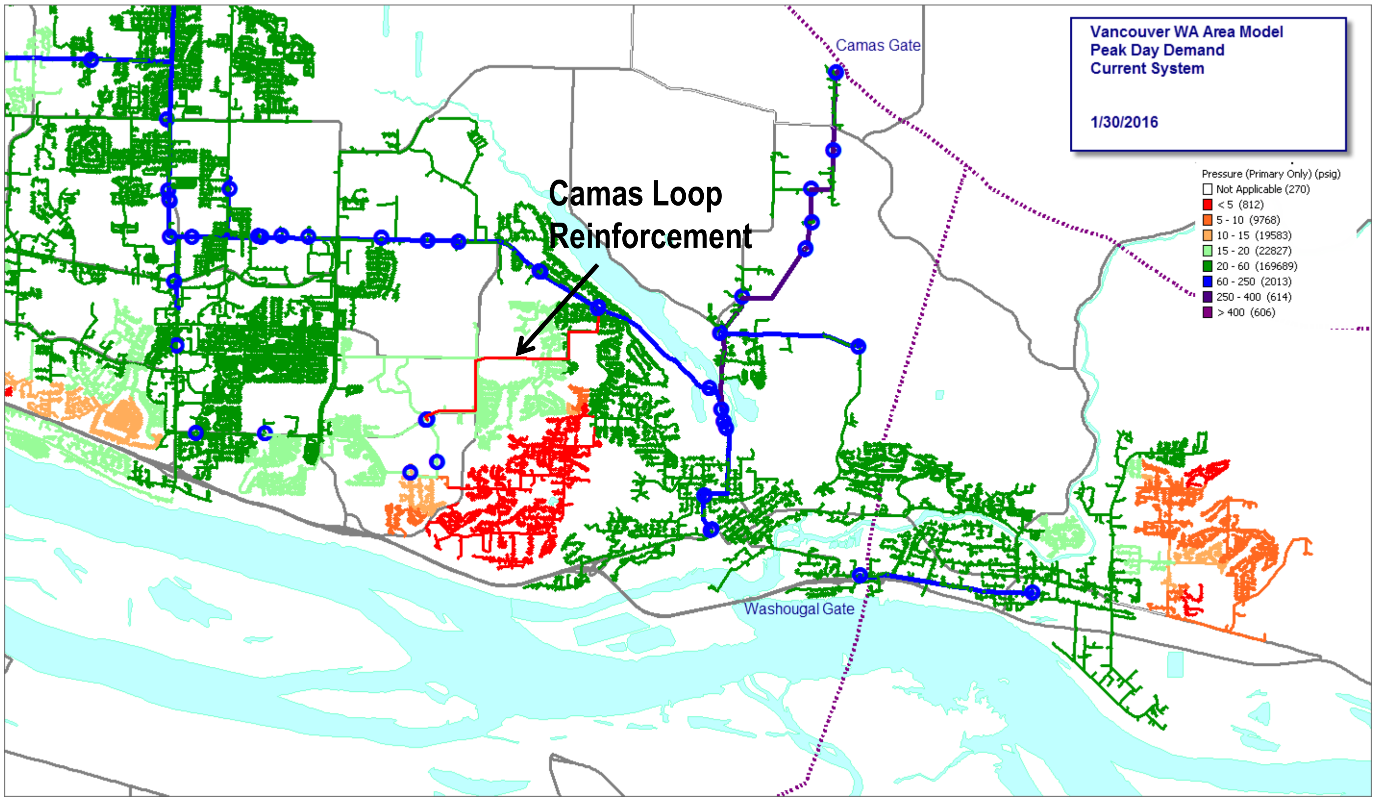
Targeted DSM and Avoiding Distribution System Projects

- How viable is accelerated/targeted DSM/EE as a way to avoid/delay distribution system projects?
  - Has potential, but there are many complexities and considerations

Issues to consider:

- Timing: DSM/EE must be "in time" to meet load- how fast can DSM/EE programs be ramped up?
- Capital projects are not "incremental" resources
  - Without avoiding a project completely, saving costs is difficult since these are construction projects
- Additional costs- what are the incremental costs to the Energy Trust of targeted/accelerated DSM in specific areas?
  - Website, programs, incentives, Staff, education….
- Equity- would a neighborhood specific program that offered high incentives lead to issues with other customers wondering why they aren't given the same opportunity?

Deliverability Model – WA 2016 Camas Reinforcement



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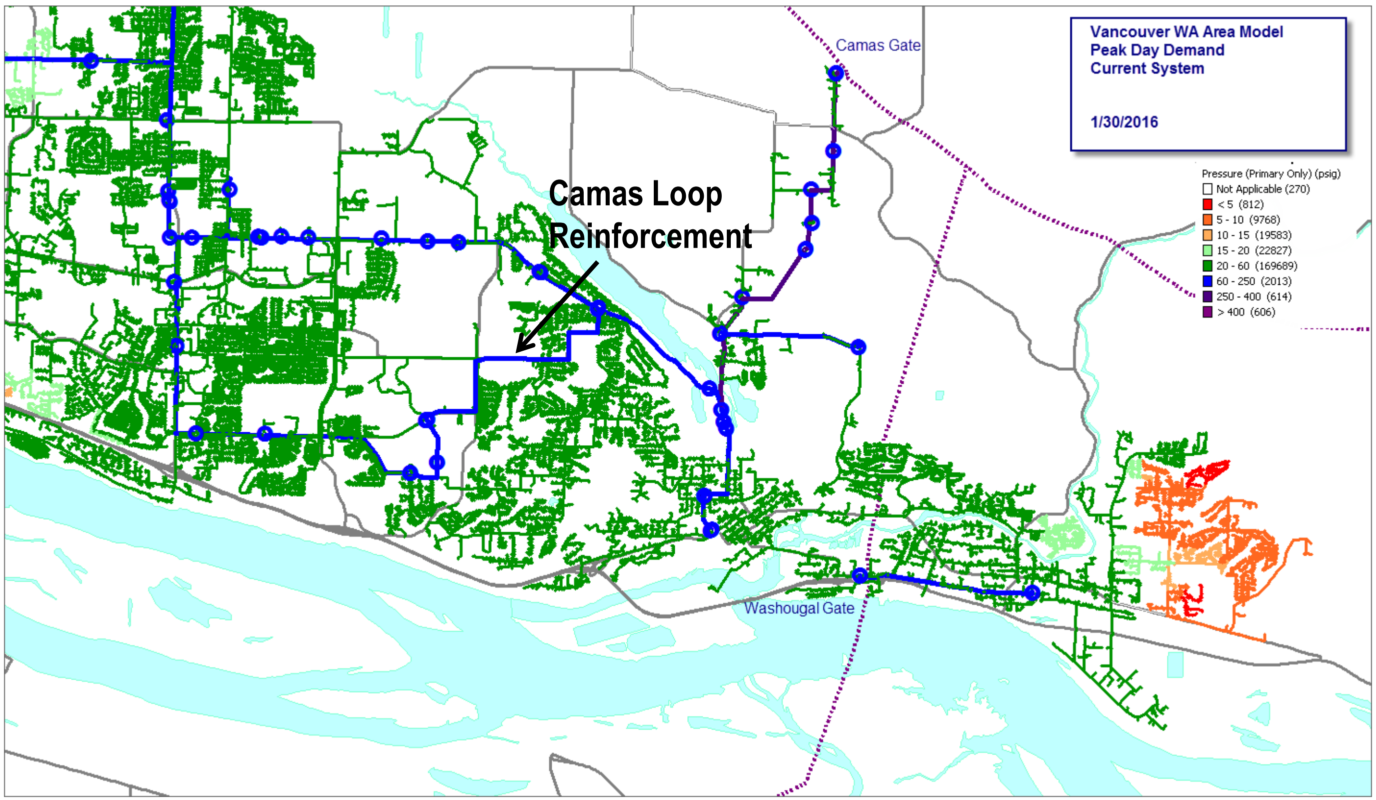
Deliverability Model – WA 2016 Camas Reinforcement



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Capacity Resource Avoided Costs Final Thoughts

- Treatment of capacity resource avoided costs in the 2016 IRP is a substantial improvement from the 2014 IRP
- The idea that each measure has its own avoided cost is not a new concept and is already in use by the NW Power Council and numerous utilities across the country
- The primary reason measures have different avoided costs is the disparate relative peak savings they provide
- Space heating measures provide almost 10 times the value in capacity resource costs avoided relative to water heating, cooking, or industrial processes due to the much greater savings they provide on peak
- Capacity resources are not typically “incremental” resources
- DSM/EE has potential in local distribution system project cost avoidance/deferral, but a number of issues need to be addressed for it to be feasible

Major Methodological Change #2: Hedge Value

Summary:

- Hedge value not included in avoided costs in the 2014 IRP
- In OPUC Docket No. UM 1622 a proxy hedge value methodology for LDCs was adopted by the Commission temporarily for further review in each LDC's next IRP (i.e. this IRP) through a process that took place in 2015
- NW Natural feels appropriate to be consistent and include in avoided costs in Washington
- Proxy methodology: *Risk Premium* + *Credit Facility* = *Hedge Value*
- The proxy methodology was used in the development of the Demand-side Management (DSM)/Energy Efficiency savings in the 2016 IRP
- Further improvements are planned for the hedge value for the 2018 IRP

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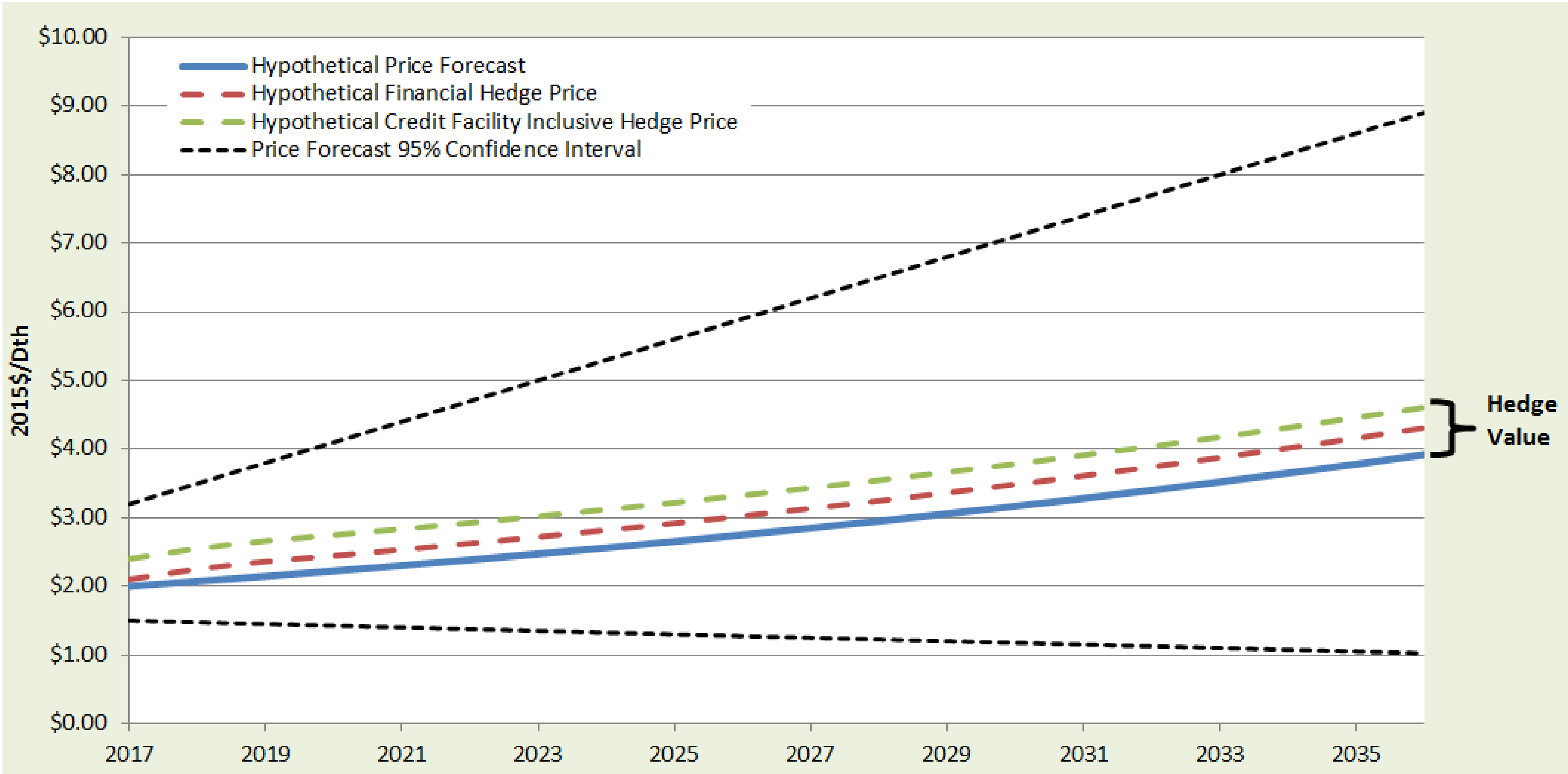
Hedge Value in the 2016 IRP

Hedge Value = (Long-term Fixed Price Financial Hedge Quote Price – IRP gas price forecast) + Credit Facility

- Why does this make sense?
  - DSM provides a long-term hedge, like a long-term financial or physical hedge
  - An LDC could use a financial hedge to lock in the price of gas, and a price quote for this product is the actual risk-free price (aside from counterparty risk, which is accounted for by adding the credit facility cost) at which gas could be secured as of the date of the quote
  - The price of the financial hedge includes any value associated with achieving price certainty
  - Consistent with top studies on the hedge value of DSM with applications to energy, including those from the Lawrence Berkeley National Laboratory and the Nicholas Institute for Environmental Policy Solutions

Why does a hedge have value?

- Hedging is a risk management tool. Without risk, there is no need to hedge
- Natural gas commodity prices are volatile, so customers are exposed to price risk
- If a hedge can mitigate this exposure to price risk, this has value to customers
  - implies either (1) risk aversion or (2) a belief that future prices are more likely to be higher than forecasted prices than they are to be lower than forecasted prices, or (3) both
- Every therm of DSM savings forgoes the need for an LDC to purchase that therm of gas on behalf of customers, removing the price risk for the therms saved
- DSM is a long-term hedge against volatile gas prices



The blue line (and the corresponding confidence intervals) represents the "risky" forecasted spot price

The red line represents the quoted hedge price and the green line represents the "risk free" hedge price (inclusive of credit facility costs)

The difference between the green line and blue line represents the risk premium of hedging (i.e. the cost of turning the risky price into a risk free price), which is the hedge value of DSM in the 2016 IRP

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Hedge Value Calculation Steps with Hypothetical Example

1) Obtain quote for 10 year fixed price financial hedge and add credit facility costs
2) Carry forward the growth rate from years 5-10 of the hedge price for the remainder of the IRP planning period (the next 10 years)
3) Compute the net present value (NPV) of 1 unit of gas for both the IRP price forecast and the hedge price using the IRP discount rate
4) Levelize the price of each the price forecast and the hedge price
5) Subtract the levelized price forecast from the levelized hedge price to obtain the planning hedge value

	IRP Price Forecast	Financial Hedge Price	Credit Facility
Year 1	$2.00	$2.05	$0.10
Year 2	$2.50	$2.65	$0.10
Year 3	$3.00	$3.20	$0.10
Average	$2.50	$2.63	$0.10
NPV*	$6.76	$7.12	$0.27
Levelized	$2.48	$2.61	$0.10
* Discount Rate = 5%			
Hedge Value of DSM			$0.23
	(=$2.71-$2.48)		

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What are credit facility costs?

- To make a financial swap transaction on the Intercontinental Exchange (ICE), a margin (cash deposit) must be placed with the exchange to make the deal based upon credit ratings
- In addition to the initial margin, with long term swaps there potentially could be a variation margin that will need to be placed with the exchange
- Credit facility costs represent the levelized costs of the margin requirements

Must the risk premium for a gas buyer be positive?

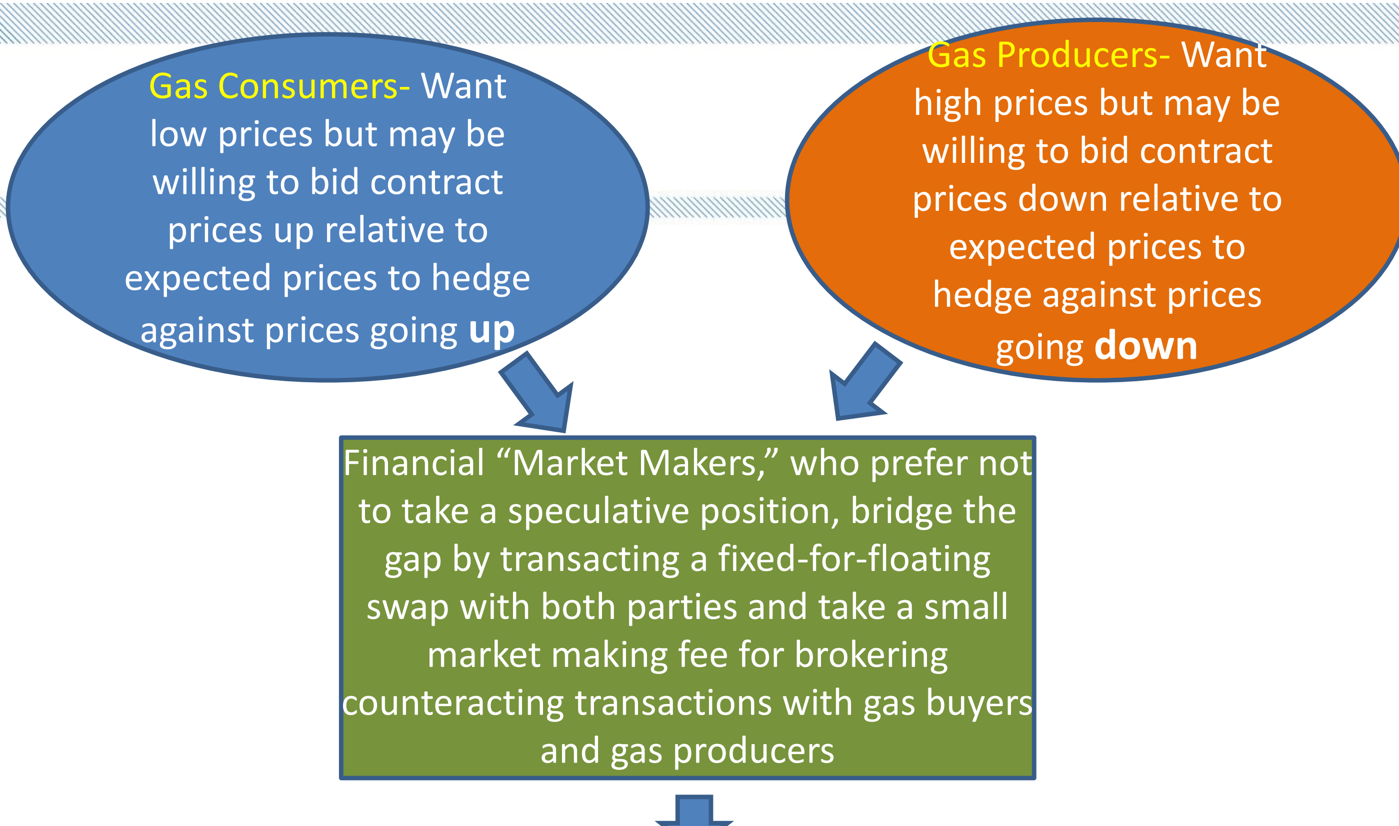
Situation: You are an investor and 2 natural gas producers have come to you looking for funds

Environment: The spot price of gas is expected to be between **$3.30** and **$4.50/Dth** in levelized terms with an expected price of **$4.10/Dth**

Company 1 Proposal: The cost to produce gas will be between **$3.25** and **$3.75/Dth** with an expected cost of **$3.50/Dth**. Production will be sold on the spot market

Company 2 Proposal: The cost to produce gas will also be between **$3.25** and **$3.75/Dth** with an expected cost of **$3.50/Dth**. The Company has a contract (hedge) in place to sell all production at the fixed price of **$4.00/Dth**

Would you rather invest in Company 1 or Company 2?



The price for future delivery (i.e. hedge price) is determined in this market. Depending on the environment, producers may pay a risk premium or consumers may pay a risk premium, but probably not both since natural gas futures/forwards markets over the next few years are a complete and a liquid market (which implies the "market maker" cannot collect a large fee to bring the two sides together).

Does the gas producer or the gas buyer pay a risk premium to hedge natural gas prices?

- The favorite answer of economists applies…. **“It depends”**
- Historically, who pays a risk premium changes over time
- In an oversupplied gas market with falling prices, it is likely that producers’ desire to protect against falling prices will outweigh consumers’ desire to protect against rising prices and producers will pay a risk premium to hedge (the demand for price hedges from producers is greater than the demand for price hedges from consumers)
- In a tight gas market with rising prices, it is likely that consumers’ desire to protect against rising prices will outweigh producers’ desire to protect against falling prices and consumers will pay a risk premium to hedge (the demand for price hedges from consumers is greater than the demand for price hedges from producers)

Remaining Questions and Potential Changes for the 2018 IRP

1. Should the hedge value also include an additional value for risk aversion?
   - Would customers be willing to pay an even higher price than the market price of hedges to mitigate price risk, and if so should this additional value be part of any hedge value of hedging instruments like DSM?
2. Should the hedge value also include an additional value for asymmetric risk?
   - If the upside risk is larger than the downside risk (or vice versa) should the hedge value be adjusted?
3. Should the hedge value be the same for all energy efficiency measures?
   - If prices are more volatile in the winter than the summer, should space heating measures have a larger hedge value than water heating and other base load measures?
4. Should we assume that the entire gas portfolio is hedged for the sake of the hedge value?
5. Is it appropriate to assume that energy efficiency is risk free?
   - Are the assumed costs and resulting savings of DSM/EE 100% accurate as is currently assumed?

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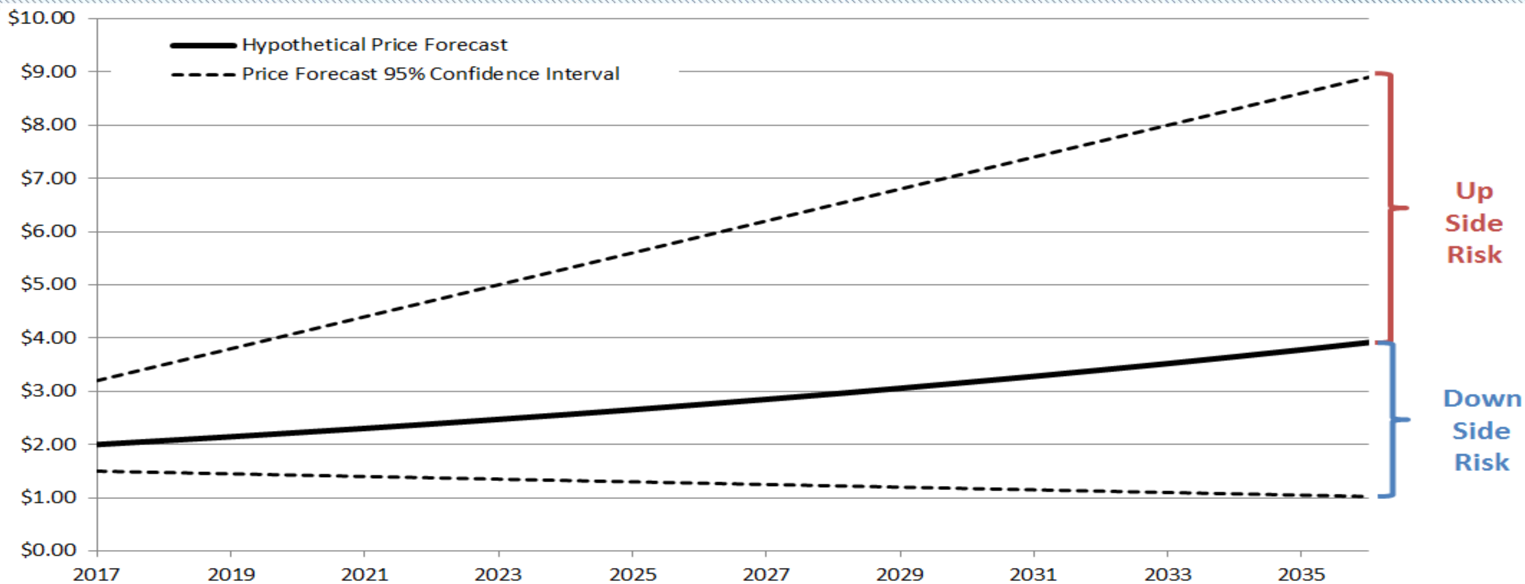
Include Risk Aversion Adjustment to the Hedge Value?

- The current hedge value assumes that the value of achieving price certainty to customers is equal to the market risk premium
  - How much customers are *willing* to pay to mitigate risk does not need to be equal to how much they *need* to pay to mitigate risk
- If risk mitigation is worth more to customers than the market risk premium, this value is not currently being included in the hedge value
- How much would customers be willing to pay to mitigate risk?
  - How risk averse are customers?
  - Quantifying customer risk aversion is incredibly difficult
- Example: 2016-17 gas year hedges at AECO are currently trading at less than 2$/Dth, but how much would customers be willing to pay to be assured of the price they will pay in 2016-17?
- Even if we know what customers *would* pay more to mitigate risk, is this an actual value that *should* be accrued to hedging instruments?

Asymmetric Risk Adjustment to the Hedge Value



This example represents the current environment where the probability that prices will be, for example, $1/Dth higher than the expected price is greater than the probability they will be $1/Dth lower than the expected price → ***Upside risk > Downside risk***

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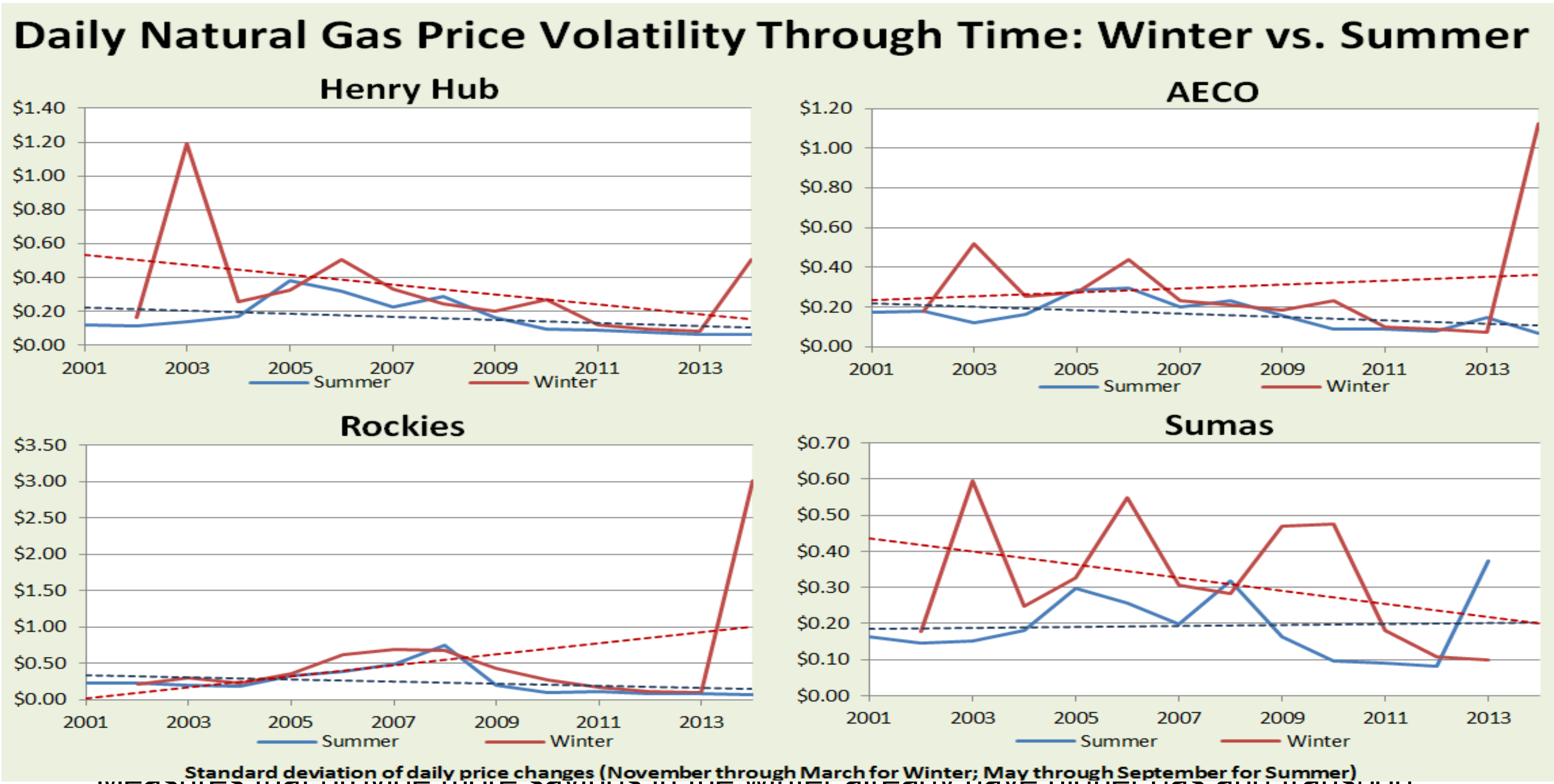
More Hedge Value for Measures that Have Concentrated Winter Savings?



Measures that provide more savings in the winter already have higher gas and transport avoided costs than base load measures since winter prices are higher than summer prices, but hedging is primarily about risk mitigation and price *risk* is greater in the winter as well

Hedge Value Final Thoughts

- Hedges should be treated consistently
  - if a hedge has value, all hedges should be assigned this value in a neutral and consistent manner

- Asymmetric risk and differences in volatility across seasons are known by all participants in the natural gas forward contract market, and are therefore already priced into traded hedging products
  - However, providing a hedge value in annual terms rather than on a monthly basis does not properly account for differences in volatility across seasons
    - NW Natural Proposes to incorporate seasonal volatility into the hedge value for the 2018 IRP by using monthly hedge values, which will lead to hedge values that vary across measures since different measures provide savings at different times

- In many instances the amount customers need to pay for a product/service is less than they would pay for it, and risk mitigation is no different
  - For example, customers would likely be willing to pay more than $0.036/Dth/Day for Mist Recall, but they do not need to so the value of avoiding Mist Recall is $0.036/Dth/Day

Year	Real (2015$)												
	Capital			Commodity		Carbon Sensitivities							
	Supply ($/Dth/Day)	Washington Distribution ($/Dth/Day)	Oregon Distribution ($/Dth/Day)	Gas and Transport Costs ($/Dth)	Hedge Value ($/Dth)	Oregon Incremental Carbon Policy 1 ($/Dth)	Oregon Incremental Carbon Policy 2 ($/Dth)	Oregon Incremental Carbon Policy 3 ($/Dth)	Oregon Incremental Carbon Policy 4 ($/Dth)	Washington Incremental Carbon Policy 1 ($/Dth)	Washington Incremental Carbon Policy 2 ($/Dth)	Washington Incremental Carbon Policy 3 ($/Dth)	Washington Incremental Carbon Policy 4 ($/Dth)
2017	$0.036	$0.038	$0.038	$2.429	-$0.005	$0.000	$0.000	$0.000	$0.000	$0.698	$1.501	$2.282	$3.476
2018	$0.036	$0.104	$0.038	$2.612	$0.094	$0.000	$0.000	$0.000	$0.000	$0.733	$1.501	$2.353	$3.548
2019	$0.036	$0.104	$0.038	$2.566	$0.180	$0.000	$0.000	$0.000	$0.000	$0.770	$1.501	$2.427	$3.621
2020	$0.036	$0.104	$0.038	$2.473	$0.204	$0.000	$0.000	$0.000	$0.000	$0.808	$1.501	$2.503	$3.695
2021	$0.036	$0.104	$0.038	$2.571	-$0.010	$0.665	$1.501	$2.213	$3.406	$0.849	$1.501	$2.549	$3.764
2022	$0.036	$0.104	$0.038	$2.968	$0.035	$0.698	$1.501	$2.282	$3.476	$0.891	$1.501	$2.596	$3.834
2023	$0.036	$0.104	$0.038	$3.155	$0.244	$0.733	$1.501	$2.353	$3.548	$0.936	$1.501	$2.644	$3.906
2024	$0.036	$0.104	$0.038	$3.144	$0.132	$0.770	$1.501	$2.427	$3.621	$0.983	$1.501	$2.692	$3.978
2025	$0.036	$0.104	$0.038	$3.190	$0.005	$0.808	$1.501	$2.503	$3.695	$1.032	$1.501	$2.741	$4.053
2026	$0.036	$0.123	$0.038	$3.315	$0.093	$0.849	$1.501	$2.549	$3.764	$1.083	$1.501	$2.788	$4.111
2027	$0.331	$0.123	$0.038	$3.277	$0.090	$0.891	$1.501	$2.596	$3.834	$1.137	$1.501	$2.834	$4.169
2028	$0.331	$0.123	$0.038	$3.369	-$0.155	$0.936	$1.501	$2.644	$3.906	$1.194	$1.501	$2.882	$4.229
2029	$0.331	$0.123	$0.038	$3.674	-$0.115	$0.983	$1.501	$2.692	$3.978	$1.254	$1.501	$2.931	$4.289
2030	$0.331	$0.123	$0.038	$3.791	-$0.093	$1.032	$1.501	$2.741	$4.053	$1.317	$1.501	$2.980	$4.351
2031	$0.429	$0.123	$0.038	$3.841	-$0.234	$1.083	$1.501	$2.788	$4.111	$1.383	$1.501	$3.037	$4.409
2032	$0.429	$0.123	$0.038	$4.086	-$0.079	$1.137	$1.501	$2.834	$4.169	$1.452	$1.501	$3.096	$4.467
2033	$0.429	$0.123	$0.038	$4.106	$0.089	$1.194	$1.501	$2.882	$4.229	$1.524	$1.501	$3.155	$4.527
2034	$0.429	$0.123	$0.038	$4.068	$0.212	$1.254	$1.501	$2.931	$4.289	$1.600	$1.501	$3.216	$4.587
2035	$0.429	$0.123	$0.038	$4.173	$0.366	$1.317	$1.501	$2.980	$4.351	$1.680	$1.501	$3.278	$4.649
2036	$0.429	$0.123	$0.038	$4.160	$0.493	$1.383	$1.501	$3.037	$4.409	$1.765	$1.501	$3.335	$4.718
2037	$0.429	$0.123	$0.038	$4.174	$0.579	$1.452	$1.501	$3.096	$4.467	$1.853	$1.501	$3.394	$4.788
Levelized	**$0.171**	**$0.108**	**$0.038**	**$3.193**	**$0.073**	**$0.675**	**$1.081**	**$1.873**	**$2.779**	**$1.071**	**$1.501**	**$2.736**	**$4.020**
Oregon Discount Rate	4.86%	Washington Discount Rate	3.61%	System Discount Rate	4.75%	Residential Space Heating Planning Peak Day Usage to Normal Weather Annual Usage Ratio			0.02055	Commercial Space Heating Planning Peak Day Usage to Normal Weather Annual Usage Ratio			0.01837

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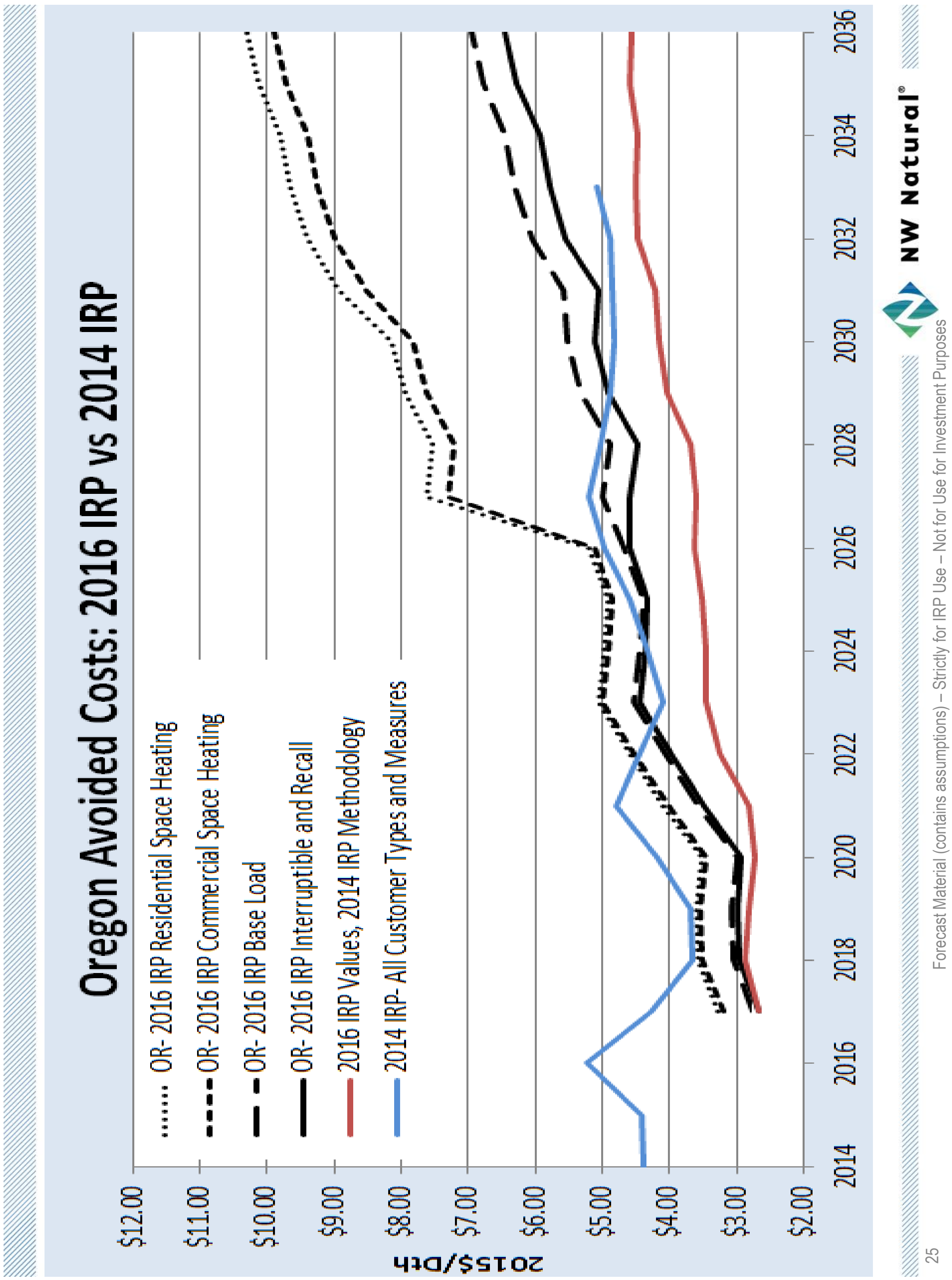
Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes


Oregon Avoided Costs: 2016 IRP vs 2014 IRP
OR- 2016 IRP Residential Space Heating
OR- 2016 IRP Commercial Space Heating
OR- 2016 IRP Base Load
OR- 2016 IRP Interruptible and Recall
2016 IRP Values, 2014 IRP Methodology
2014 IRP- All Customer Types and Measures
2015$/Dth
$12.00
$11.00
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
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NW Natural
Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes
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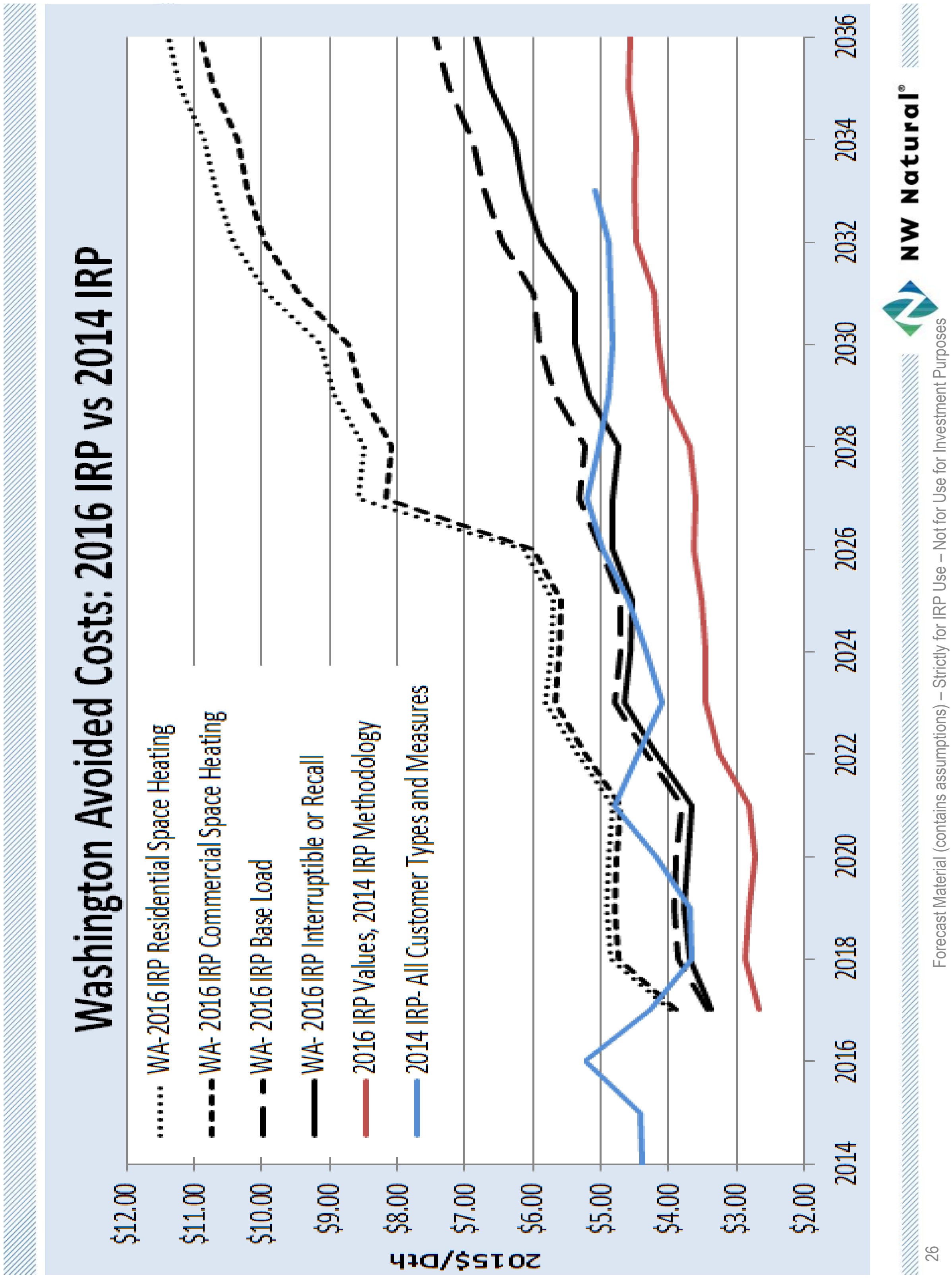
Washington Avoided Costs: 2016 IRP vs 2014 IRP
WA-2016 IRP Residential Space Heating
WA- 2016 IRP Commercial Space Heating
WA- 2016 IRP Base Load
WA- 2016 IRP Interruptible or Recall
2016 IRP Values, 2014 IRP Methodology
2014 IRP- All Customer Types and Measures
2015$/Dth
$12.00
$11.00
$10.00
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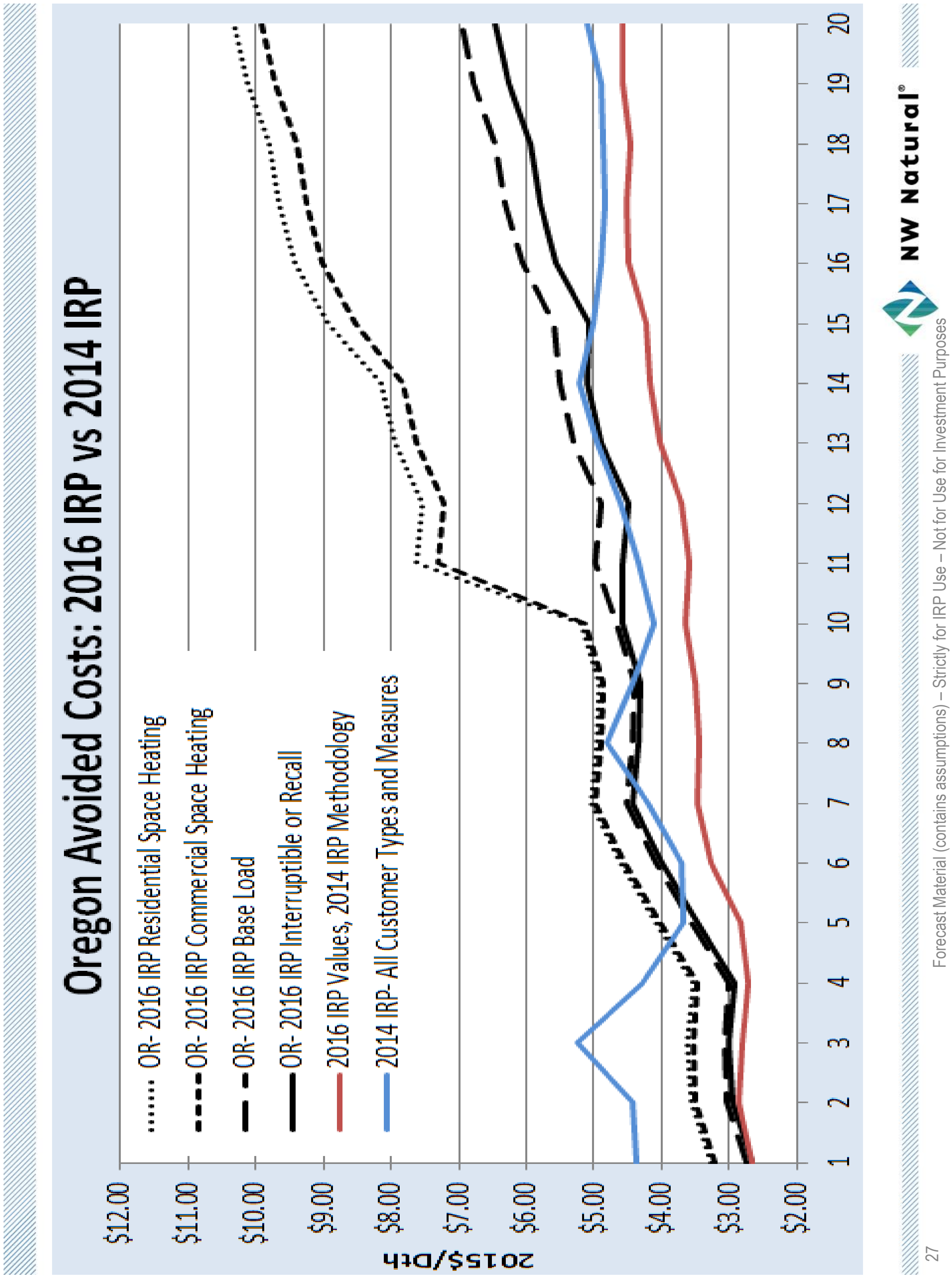
NW Natural
Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes
26


Oregon Avoided Costs: 2016 IRP vs 2014 IRP
OR- 2016 IRP Residential Space Heating
OR- 2016 IRP Commercial Space Heating
OR- 2016 IRP Base Load
OR- 2016 IRP Interruptible or Recall
2016 IRP Values, 2014 IRP Methodology
2014 IRP- All Customer Types and Measures
2015$/Dth
$12.00
$11.00
$10.00
$9.00
$8.00
$7.00
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$5.00
$4.00
$3.00
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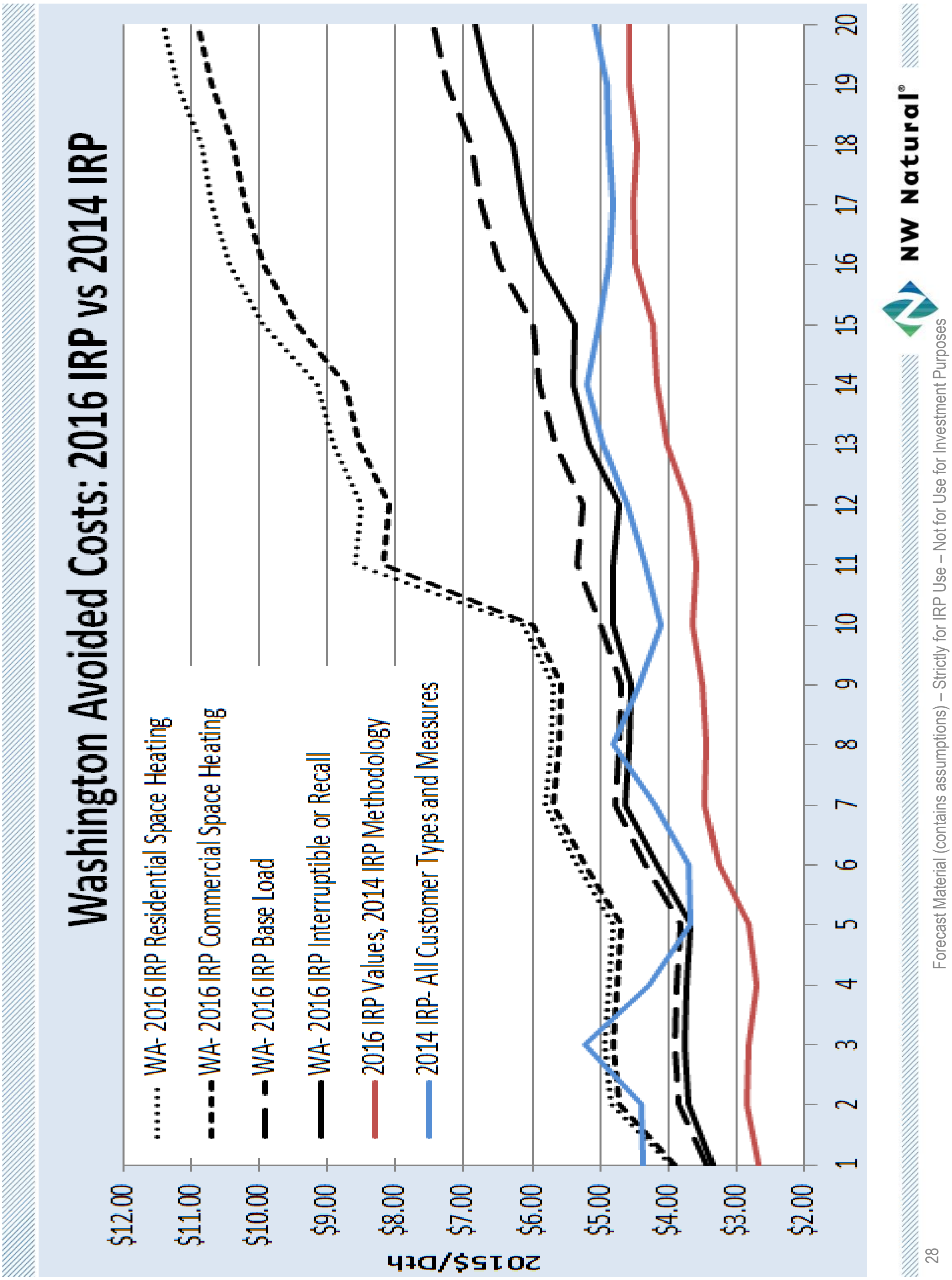
NW Natural
Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes
27


Washington Avoided Costs: 2016 IRP vs 2014 IRP
2015$/Dth
$12.00
$11.00
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
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WA- 2016 IRP Residential Space Heating
WA- 2016 IRP Commercial Space Heating
WA- 2016 IRP Base Load
WA- 2016 IRP Interruptible or Recall
2016 IRP Values, 2014 IRP Methodology
2014 IRP- All Customer Types and Measures
NW Natural®
Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes
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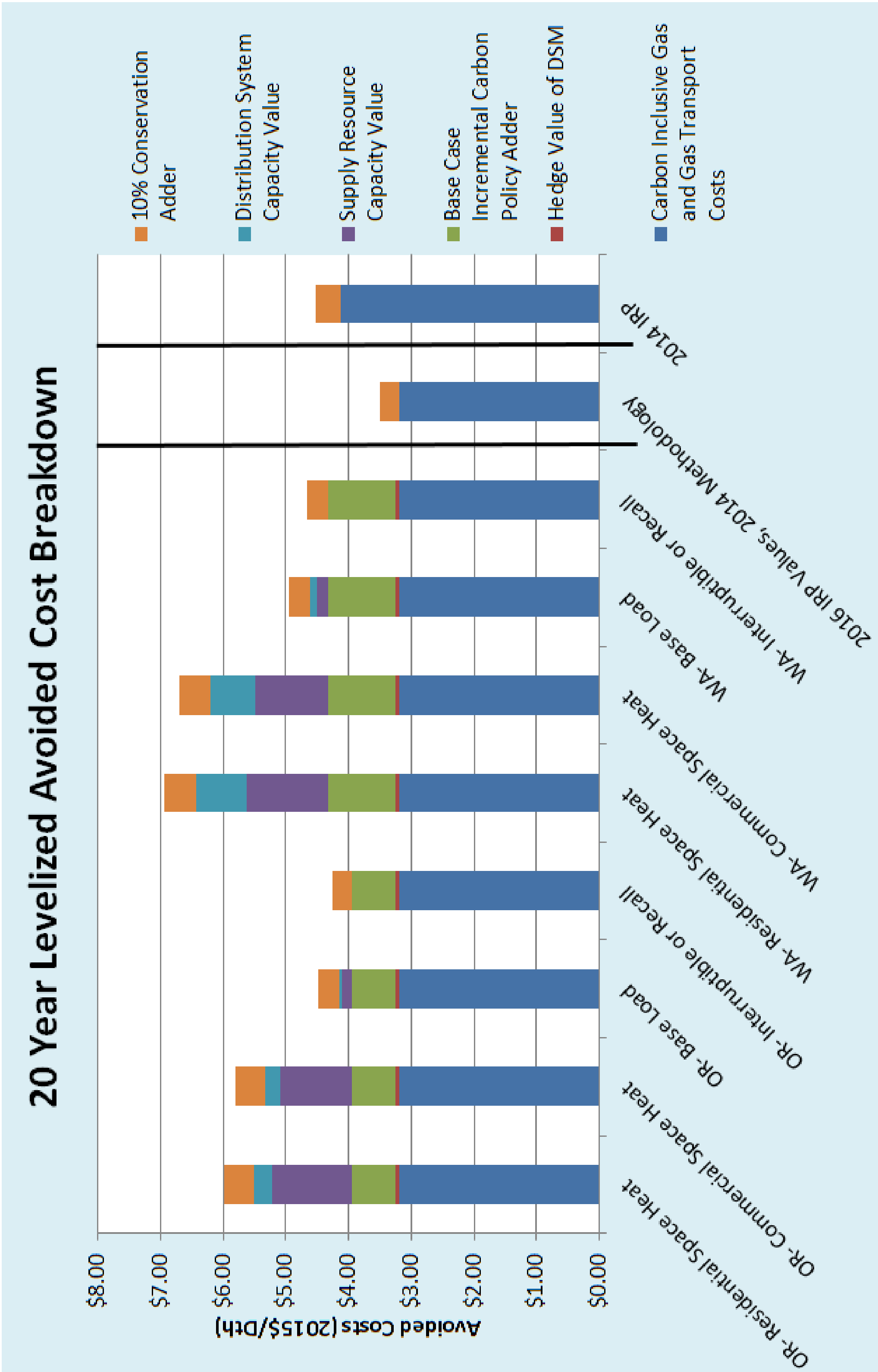

Note that these figures do not incorporate variation in measure lives

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Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes

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20 Year Levelized Avoided Cost Breakdown (2015$/Dth)

	Carbon Inclusive Gas and Gas Transport Costs	Hedge Value of DSM	Base Case Incremental Carbon Policy Adder	Supply Resource Capacity Value	Distribution System Capacity Value	10% Conservation Adder	**Total Levelized Avoided Costs**
OR- Residential Space Heat	$3.19	$0.07	$0.67	$1.28	$0.28	$0.48	**$5.98**
OR- Commercial Space Heat	$3.19	$0.07	$0.67	$1.14	$0.25	$0.46	**$5.80**
OR- Base Load	$3.19	$0.07	$0.67	$0.17	$0.04	$0.34	**$4.49**
OR- Interruptible or Recall	$3.19	$0.07	$0.67	X	X	$0.32	**$4.26**
WA- Residential Space Heat	$3.19	$0.07	$1.07	$1.28	$0.81	$0.53	**$6.95**
WA- Commercial Space Heat	$3.19	$0.07	$1.07	$1.14	$0.72	$0.51	**$6.71**
WA- Base Load	$3.19	$0.07	$1.07	$0.17	$0.11	$0.35	**$4.96**
WA- Interruptible or Recall	$3.19	$0.07	$1.07	X	X	$0.32	**$4.66**
2016 IRP Values, 2014 Methodology	$3.19	X	X	X	X	$0.32	**$3.51**
2014 IRP	$4.13	X	X	X	X	$0.41	**$4.54**

Note that these figures do not incorporate variation in measure lives

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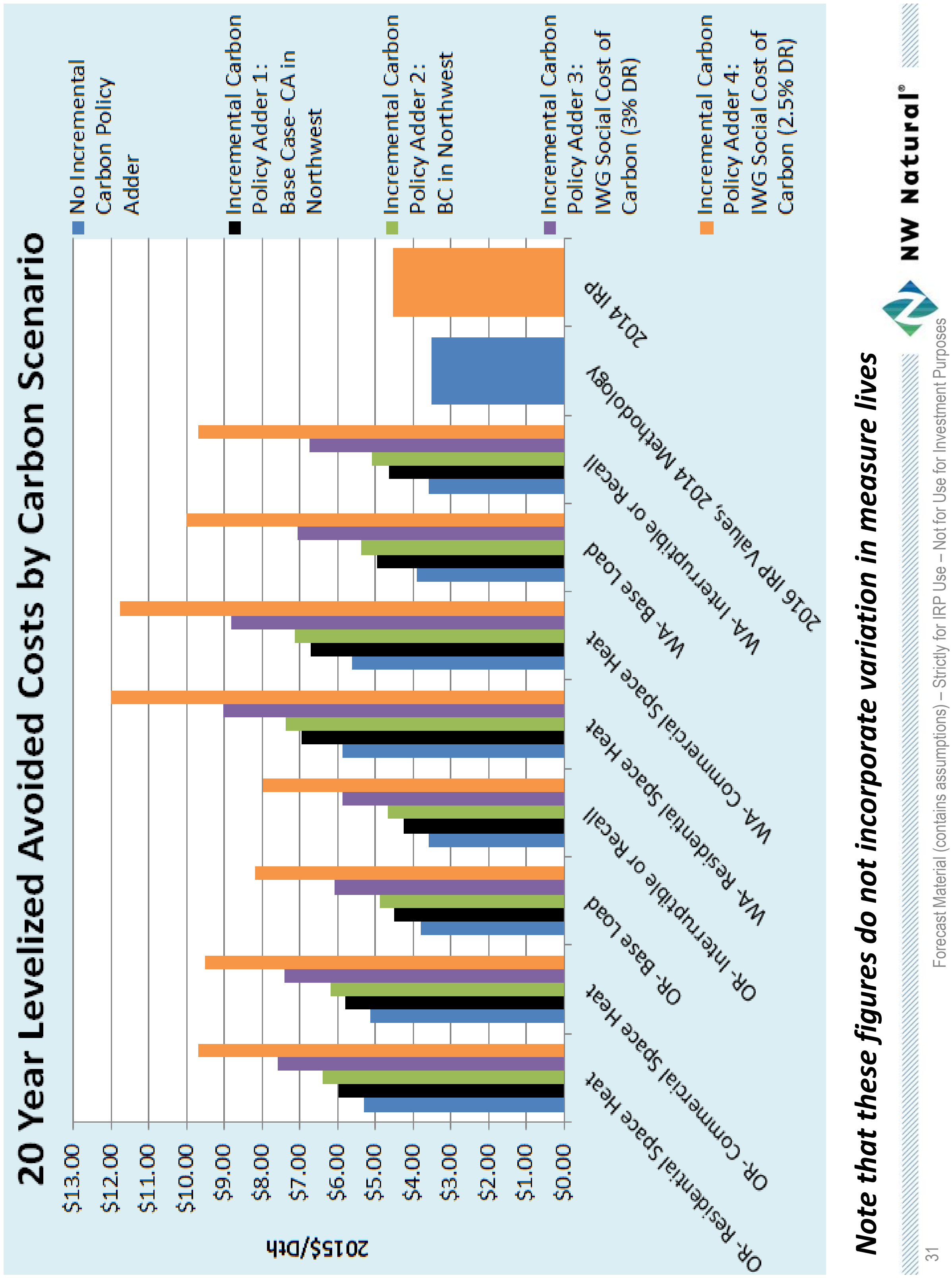
20 Year Levelized Avoided Costs by Carbon Scenario
2015$/Dth
$13.00
$12.00
$11.00
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
OR-Residential Space Heat
OR-Commercial Space Heat
OR-Base Load
OR-Interruptible or Recall
WA-Residential Space Heat
WA-Commercial Space Heat
WA-Base Load
WA-Interruptible or Recall
2016 IRP Values, 2014 Methodology
2014 IRP
No Incremental Carbon Policy Adder
Incremental Carbon Policy Adder 1: Base Case- CA in Northwest
Incremental Carbon Policy Adder 2: BC in Northwest
Incremental Carbon Policy Adder 3: IWG Social Cost of Carbon (3% DR)
Incremental Carbon Policy Adder 4: IWG Social Cost of Carbon (2.5% DR)
Note that these figures do not incorporate variation in measure lives
NW Natural®
Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes
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20 Year Levelized Total Avoided Costs By Carbon Scenario (2015$/Dth)

	No Incremental Carbon Policy Adder	Incremental Carbon Policy Adder 1: **Base Case-** CA in Northwest	Incremental Carbon Policy Adder 2: BC in Northwest	Incremental Carbon Policy Adder 3: IWG Social Cost of Carbon (3% DR)	Incremental Carbon Policy Adder 4: IWG Social Cost of Carbon (2.5% DR)
OR- Residential Space Heat	$5.31	**$5.98**	$6.39	$7.58	$9.69
OR- Commercial Space Heat	$5.12	**$5.80**	$6.20	$7.40	$9.51
OR- Base Load	$3.82	**$4.49**	$4.90	$6.09	$8.20
OR- Interruptible or Recall	$3.59	**$4.26**	$4.67	$5.86	$7.97
WA- Residential Space Heat	$5.88	**$6.95**	$7.38	$9.05	$12.00
WA- Commercial Space Heat	$5.64	**$6.71**	$7.14	$8.80	$11.75
WA- Base Load	$3.89	**$4.96**	$5.39	$7.06	$10.01
WA- Interruptible or Recall	$3.59	**$4.66**	$5.09	$6.75	$9.70
2016 IRP Values, 2014 Methodology	$3.51	**$3.51**	$3.51	$3.51	$3.51
2014 IRP	$4.54	**$4.54**	$4.54	$4.54	$4.54

Note that these figures do not incorporate variation in measure lives

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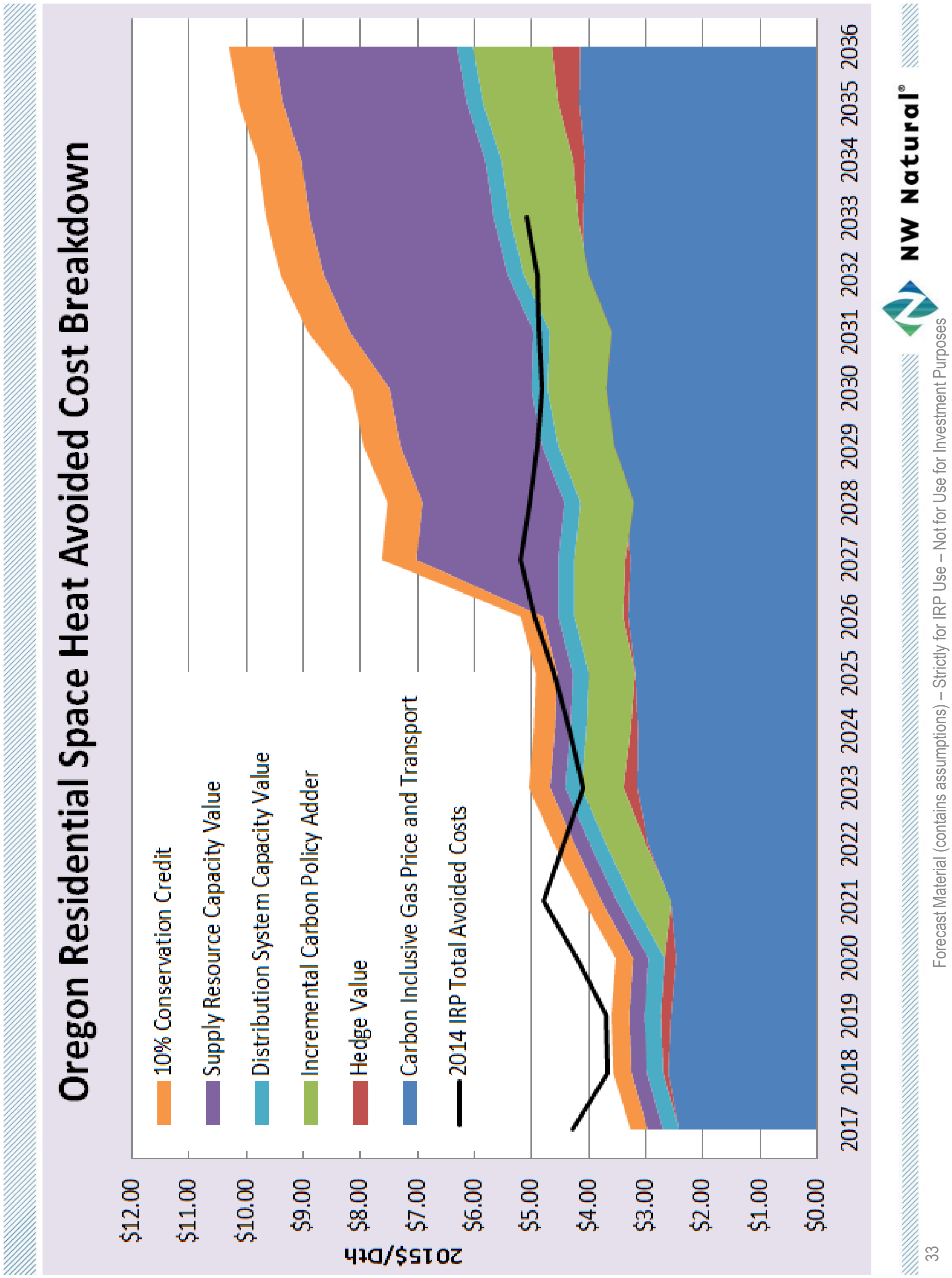
Oregon Residential Space Heat Avoided Cost Breakdown
10% Conservation Credit
Supply Resource Capacity Value
Distribution System Capacity Value
Incremental Carbon Policy Adder
Hedge Value
Carbon Inclusive Gas Price and Transport
2014 IRP Total Avoided Costs
2015$/Dth
$12.00
$11.00
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036
NW Natural®
Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes
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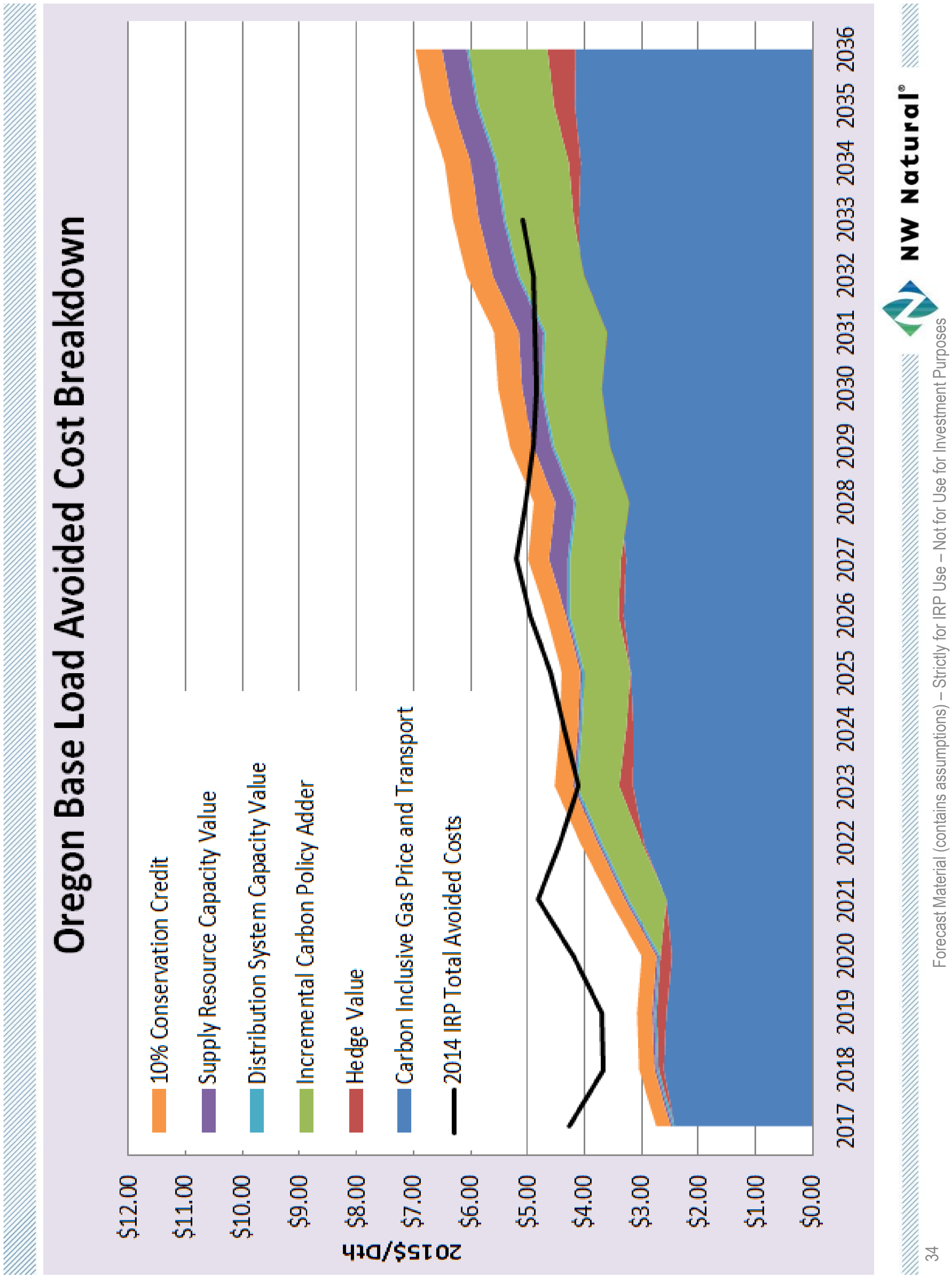
Oregon Base Load Avoided Cost Breakdown
10% Conservation Credit
Supply Resource Capacity Value
Distribution System Capacity Value
Incremental Carbon Policy Adder
Hedge Value
Carbon Inclusive Gas Price and Transport
2014 IRP Total Avoided Costs
2015$/Dth
$12.00
$11.00
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
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2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036
NW Natural®
Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes
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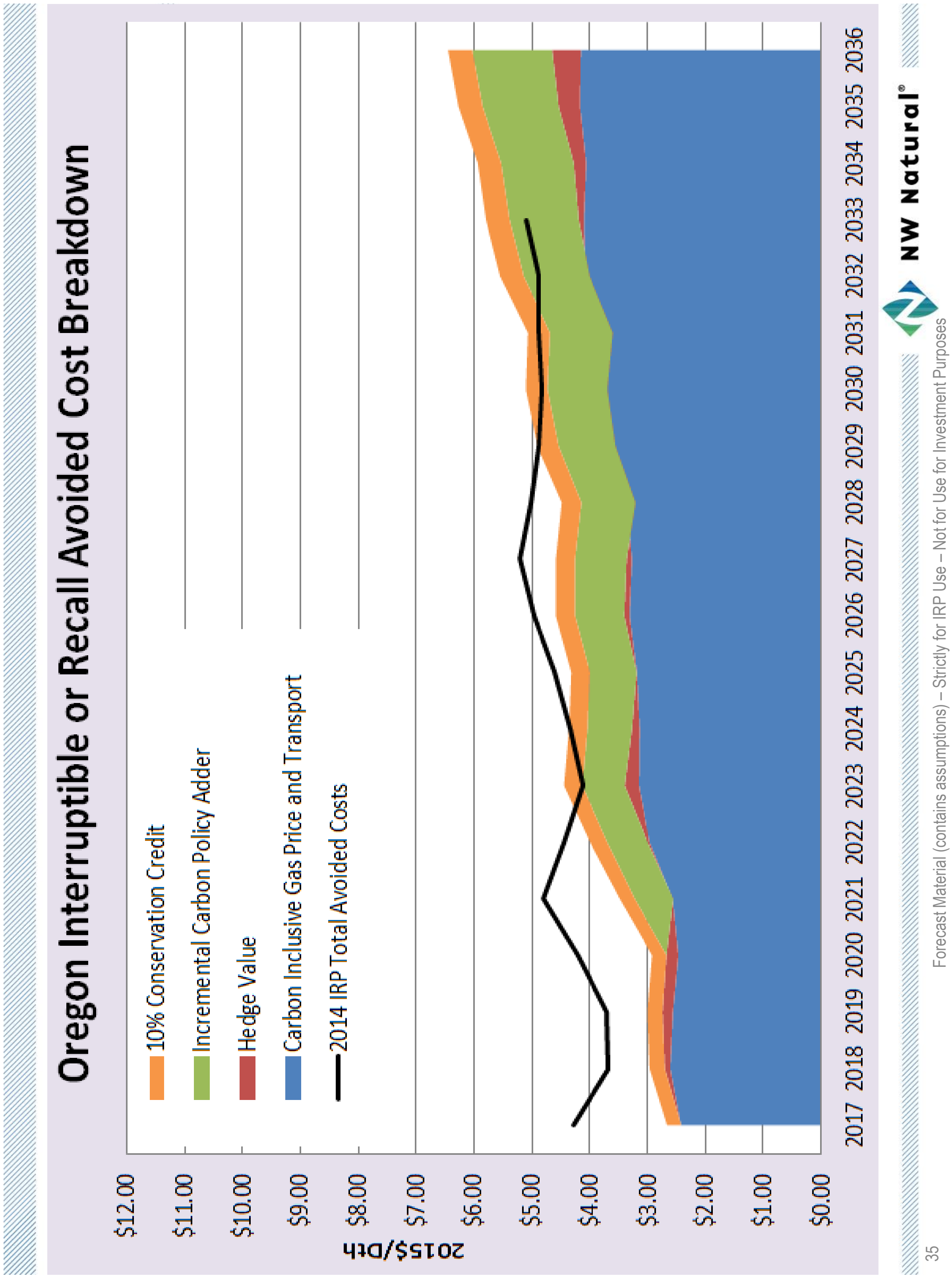
Oregon Interruptible or Recall Avoided Cost Breakdown
10% Conservation Credit
Incremental Carbon Policy Adder
Hedge Value
Carbon Inclusive Gas Price and Transport
2014 IRP Total Avoided Costs
2015$/Dth
$12.00
$11.00
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2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036
NW Natural
Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes
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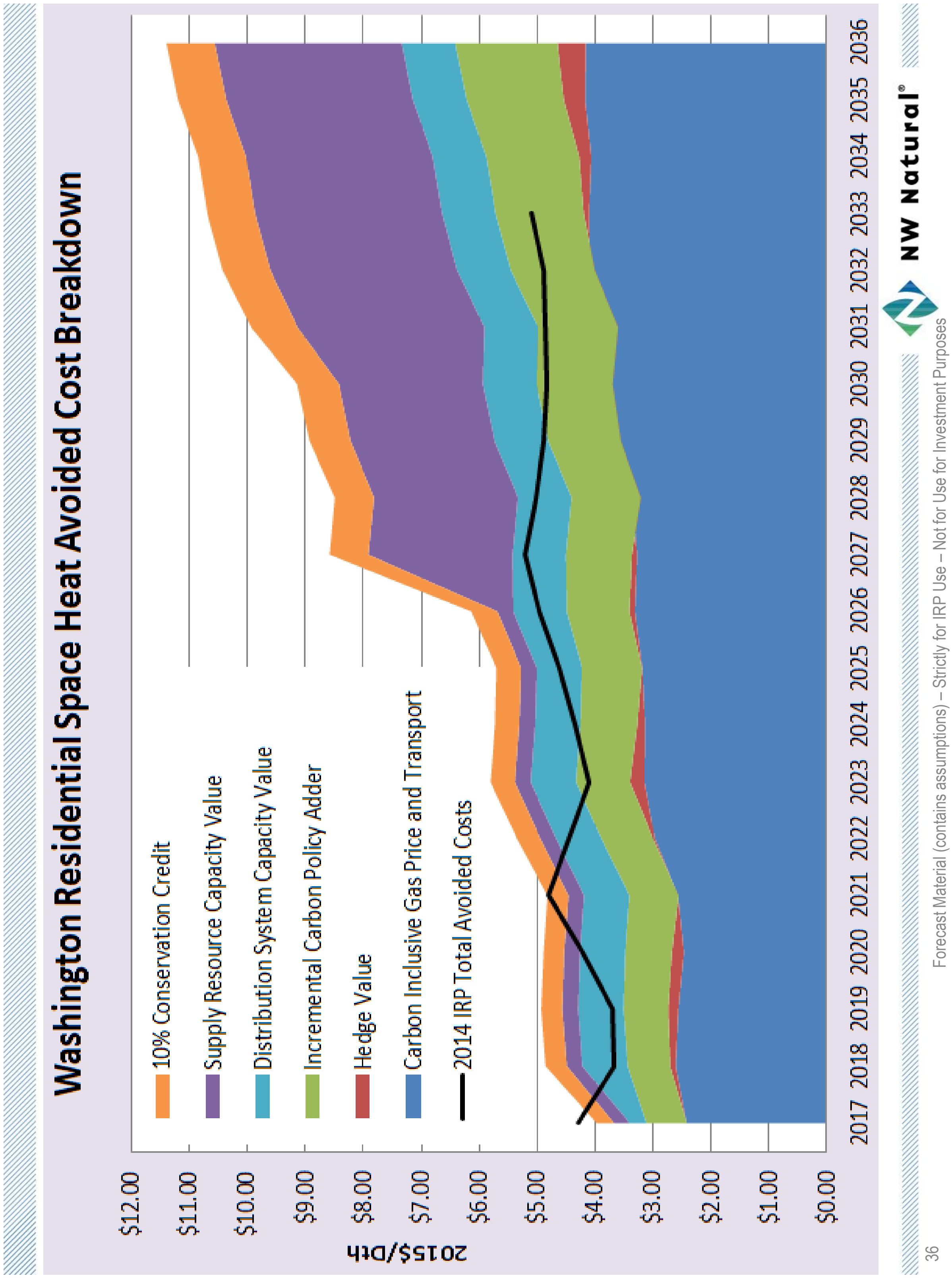
Washington Residential Space Heat Avoided Cost Breakdown
10% Conservation Credit
Supply Resource Capacity Value
Distribution System Capacity Value
Incremental Carbon Policy Adder
Hedge Value
Carbon Inclusive Gas Price and Transport
2014 IRP Total Avoided Costs
2015$/Dth
$12.00
$11.00
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$7.00
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2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036
NW Natural®
Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes
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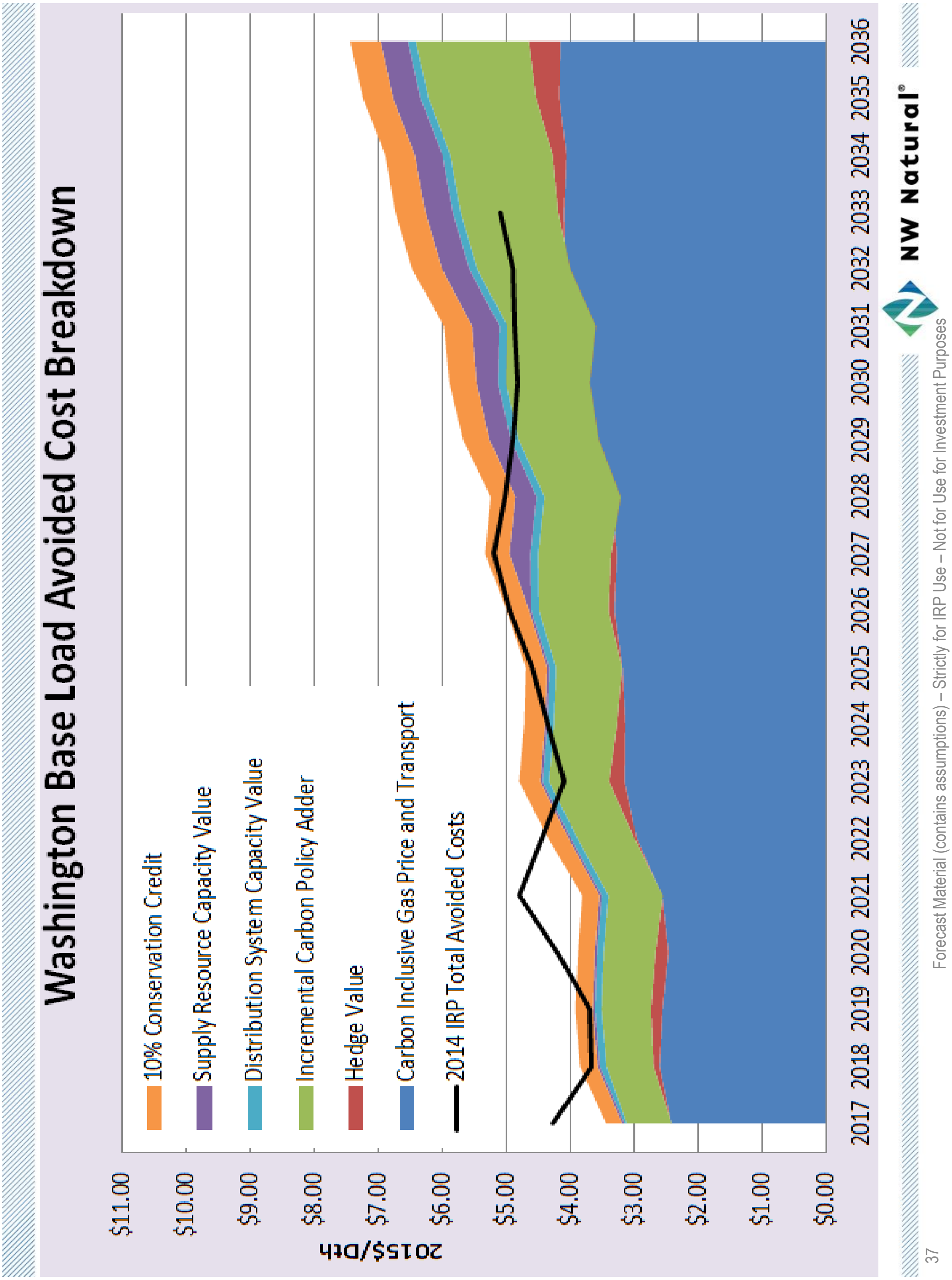
Washington Base Load Avoided Cost Breakdown
10% Conservation Credit
Supply Resource Capacity Value
Distribution System Capacity Value
Incremental Carbon Policy Adder
Hedge Value
Carbon Inclusive Gas Price and Transport
2014 IRP Total Avoided Costs
2015$/Dth
$11.00
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036
NW Natural®
Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes
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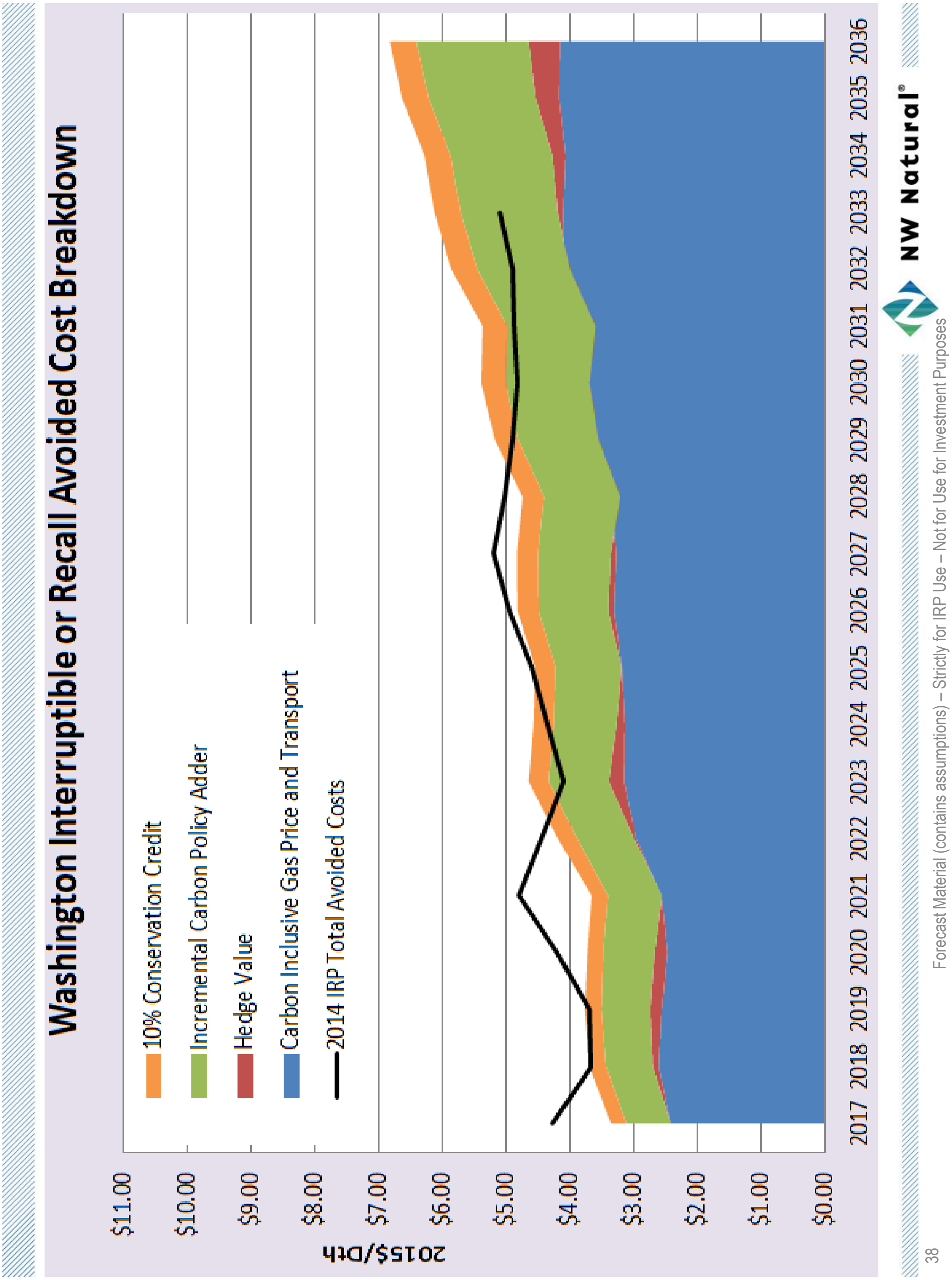
Washington Interruptible or Recall Avoided Cost Breakdown
10% Conservation Credit
Incremental Carbon Policy Adder
Hedge Value
Carbon Inclusive Gas Price and Transport
2014 IRP Total Avoided Costs
2015$/Dth
$11.00
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
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2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036
NW Natural®
Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes
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Appendix 6
Demand-Side Management

Oregon 20-Year Cost-Effective DSM Savings Projection

Sector	Measure Type	End Use	2017	2018	2019	2020	2021	2022	2023	2024	2025
Commercial	New Construction	Heating	420,189	418,695	418,615	412,329	403,979	399,782	398,851	393,926	393,222
		Weatherization	-	1,866	1,840	2,958	2,905	2,881	2,864	2,834	2,827
		Cooling	-	-	-	-	-	-	-	4,590	4,565
		Market Transformation	276,719	289,652	303,189	-	-	-	-	-	-
	Retrofit	Ventilation	57,160	54,788	53,497	52,212	50,934	52,484	53,463	54,436	54,899
		Heating	262,248	251,369	245,443	239,548	296,118	305,132	310,821	316,476	319,169
		Water Heating	68,579	65,734	64,184	62,643	61,109	62,970	64,144	65,311	65,866
		Weatherization	127,119	121,846	118,973	116,116	113,273	119,909	122,144	124,366	125,425
		Behavioral	818,176	784,234	765,746	747,355	729,061	751,254	765,261	779,184	785,813
	Replacement on Burnout	Heating	50,988	53,400	55,152	57,894	59,778	60,486	73,038	74,213	76,522
		Water Heating	83,789	86,370	87,927	90,464	91,992	92,773	110,314	110,490	112,266
		Cooking	375,359	372,597	371,664	366,052	360,269	352,040	326,443	317,363	313,474
Industrial	Retrofit	Process Heating	874,512	850,950	827,951	805,448	782,435	759,422	724,903	655,865	586,826
		HVAC	236,662	230,286	224,062	217,838	211,614	205,390	196,054	177,382	158,710
		Other	42,997	41,839	40,708	39,577	38,446	37,315	35,619	32,227	28,835
	Replacement on Burnout	Water Heating	59,770	59,133	59,009	58,315	54,427	50,799	47,412	44,251	41,301
		Process Heating	37,354	37,615	38,207	38,431	36,510	34,684	32,950	31,303	29,738
		HVAC	20,531	20,554	20,755	20,755	19,602	18,513	17,484	16,513	15,596
Residential	New Construction	Behavioral	19,110	18,525	22,700	21,624	20,895	20,124	19,147	18,459	18,376
		Heating	3,518	3,483	4,263	4,142	4,106	4,036	3,936	3,903	4,001
		Other	164,790	163,173	200,443	194,887	192,040	188,895	184,248	182,697	187,241
		Weatherization	34,835	37,994	55,399	53,890	53,137	52,296	51,018	50,580	51,828
		Water Heating	93,334	92,407	32,592	32,219	32,336	32,339	39,060	38,806	33,064
		Market Transformation	30,261	30,261	30,261	30,261	2,764	2,764	2,764	2,764	-
	Retrofit	Behavioral	114,650	108,568	103,784	99,112	97,633	99,109	97,452	95,745	94,912
		Water Heating	318,597	308,748	302,211	295,683	298,595	310,924	313,818	316,708	322,727
		Weatherization	281,753	273,045	267,265	261,494	264,070	274,975	277,537	280,094	285,419
	Replacement on Burnout	Heating	14,858	15,416	15,754	12,514	12,864	13,430	13,920	14,073	14,392
		Appliance	8,444	1,667	1,673	1,304	1,317	1,352	1,378	1,369	1,376
		Weatherization	58,781	66,973	77,638	62,918	65,532	69,307	72,881	75,012	78,235
		Water Heating	188,071	185,469	174,742	197,174	191,743	189,391	186,053	180,694	176,141
	Commercial	**Total:**	**2,540,325**	**2,500,552**	**2,486,230**	**2,147,571**	**2,169,417**	**2,199,711**	**2,227,343**	**2,243,190**	**2,254,048**
	Industrial	**Total:**	**1,271,826**	**1,240,376**	**1,210,691**	**1,180,364**	**1,143,034**	**1,106,123**	**1,054,423**	**957,541**	**861,006**
	Residential	**Total:**	**1,331,002**	**1,305,729**	**1,288,726**	**1,267,222**	**1,237,034**	**1,258,942**	**1,263,210**	**1,260,906**	**1,267,712**
	Efficiency	**Total:**	**5,143,153**	**5,046,657**	**4,985,647**	**4,595,157**	**4,549,485**	**4,564,777**	**4,544,976**	**4,461,637**	**4,382,765**

Oregon 20-Year Cost-Effective DSM Savings Projection

Sector	Measure Type	End Use	2026	2027	2028	2029	2030	2031	2032	2033	2034
Commercial	New Construction	Heating	392,873	392,748	391,954	391,461	390,347	388,558	387,326	386,234	383,255
		Weatherization	2,828	2,828	2,818	2,739	2,732	2,715	2,709	2,705	2,677
		Cooling	4,563	4,578	4,550	4,426	4,410	4,390	4,377	4,366	4,322
		Market Transformation	-	-	-	-	-	-	-	-	-
	Retrofit	Ventilation	56,363	57,319	57,713	58,105	57,942	57,780	57,618	57,457	56,750
		Heating	327,684	333,237	335,530	337,808	339,151	338,201	337,254	336,310	332,174
		Water Heating	67,624	68,770	69,243	69,713	69,518	69,323	69,129	68,935	68,088
		Weatherization	128,771	130,953	131,854	132,749	132,378	132,007	131,637	131,269	129,655
		Behavioral	806,778	820,450	826,096	831,704	829,375	827,053	824,737	822,428	812,315
	Replacement on Burnout	Heating	77,417	80,574	78,972	78,528	78,124	86,935	85,253	88,496	86,868
		Water Heating	112,002	115,016	111,199	109,228	107,337	118,007	114,461	117,553	114,167
		Cooking	304,303	280,521	264,416	253,362	243,195	208,053	196,813	179,178	169,681
Industrial	Retrofit	Process Heating	525,318	484,909	461,818	427,181	417,483	405,886	394,289	382,693	382,693
		HVAC	141,595	130,703	124,479	115,143	112,031	108,919	105,807	102,695	102,695
		Other	25,725	23,746	22,615	20,919	20,354	19,788	19,223	18,658	18,658
	Replacement on Burnout	Water Heating	38,548	35,978	33,579	31,341	29,251	27,301	25,481	23,782	22,197
		Process Heating	28,251	26,838	25,496	24,221	23,010	21,860	20,767	19,729	18,742
		HVAC	14,729	13,911	13,138	12,408	11,719	11,068	10,453	9,872	9,324
Residential	New Construction	Behavioral	17,741	17,210	27,362	26,305	25,689	25,180	24,907	22,254	22,240
		Heating	3,968	3,956	3,810	3,726	3,703	3,694	3,722	3,734	3,732
		Other	185,724	185,226	178,412	174,527	173,490	173,151	174,481	175,114	175,050
		Weatherization	51,417	51,289	49,412	48,345	48,066	47,982	48,360	48,545	48,537
		Water Heating	32,780	32,728	31,564	30,913	30,768	30,755	31,028	31,188	31,225
		Market Transformation	-	-	-	-	-	-	-	-	-
	Retrofit	Behavioral	93,976	92,940	150,118	147,433	144,751	142,074	139,401	132,453	132,349
		Water Heating	328,736	334,734	312,590	312,345	312,100	311,855	311,610	311,365	311,120
		Weatherization	290,735	296,042	276,459	276,245	276,030	275,815	275,600	275,386	275,171
	Replacement on Burnout	Heating	15,341	15,807	16,223	15,820	15,429	15,231	14,686	14,665	14,471
		Appliance	1,444	1,465	1,482	1,425	1,372	1,337	1,274	1,258	1,228
		Weatherization	84,863	88,821	92,560	91,621	90,677	90,799	88,781	89,872	89,872
		Water Heating	167,706	163,836	159,404	147,349	136,216	127,429	116,425	110,145	102,955
	Commercial	**Total:**	**2,281,206**	**2,286,994**	**2,274,345**	**2,269,823**	**2,254,509**	**2,233,023**	**2,211,317**	**2,194,931**	**2,159,952**
	Industrial	**Total:**	**774,165**	**716,084**	**681,125**	**631,214**	**613,848**	**594,822**	**576,020**	**557,428**	**554,308**
	Residential	**Total:**	**1,274,430**	**1,284,054**	**1,299,397**	**1,276,055**	**1,258,291**	**1,245,301**	**1,230,275**	**1,215,978**	**1,207,949**
	Efficiency	**Total:**	**4,329,801**	**4,287,132**	**4,254,868**	**4,177,091**	**4,126,648**	**4,073,146**	**4,017,612**	**3,968,337**	**3,922,208**

Oregon 20-Year Cost-Effective DSM Savings Projection

Sector	Measure Type	End Use	2035	2036	Total
Commercial	New Construction	Heating	380,190	377,253	**7,921,786**
		Weatherization	2,661	2,642	**51,030**
		Cooling	4,308	4,258	**57,704**
		Market Transformation	-	-	**869,560**
	Retrofit	Ventilation	56,591	56,433	**1,113,944**
		Heating	331,244	330,317	**6,225,237**
		Water Heating	75,311	75,100	**1,351,294**
		Weatherization	129,291	128,929	**2,528,665**
		Behavioral	810,040	807,772	**15,944,833**
	Replacement on Burnout	Heating	86,229	85,696	**1,474,562**
		Water Heating	112,328	110,591	**2,108,274**
		Cooking	162,790	156,440	**5,574,015**
Industrial	Retrofit	Process Heating	382,693	382,693	**11,515,965**
		HVAC	102,695	102,695	**3,107,453**
		Other	18,658	18,658	**564,565**
	Replacement on Burnout	Water Heating	20,717	19,336	**781,928**
		Process Heating	17,805	16,915	**560,426**
		HVAC	8,806	8,317	**294,047**
Residential	New Construction	Behavioral	22,230	22,179	**432,261**
		Heating	3,730	3,722	**76,885**
		Other	175,022	174,664	**3,603,274**
		Weatherization	48,538	48,447	**979,914**
		Water Heating	31,268	31,272	**771,646**
		Market Transformation	-	-	**132,102**
	Retrofit	Behavioral	132,245	132,140	**2,350,844**
		Water Heating	310,875	310,631	**6,255,972**
		Weatherization	274,957	274,742	**5,532,832**
	Replacement on Burnout	Heating	14,434	14,537	**293,864**
		Appliance	1,212	1,210	**34,586**
		Weatherization	90,804	92,605	**1,618,552**
		Water Heating	97,246	92,979	**3,091,169**
	Commercial	**Total:**	**2,150,983**	**2,135,432**	**45,220,903**
	Industrial	**Total:**	**551,373**	**548,613**	**16,824,385**
	Residential	**Total:**	**1,202,562**	**1,199,129**	**25,173,903**
	Efficiency	**Total:**	**3,904,919**	**3,883,174**	**87,219,191**

Washington 20-Year Cost-Effective DSM Savings Projection

Sector	Measure Type	End Use	2017	2018	2019	2020	2021	2022	2023	2024	2025
Commercial	Retrofit	Ventilation	4,684	4,462	4,491	4,519	4,546	4,529	4,512	4,495	4,347
		Water Heating	5,369	5,115	5,147	5,179	5,211	5,192	5,172	5,153	6,728
		Heating	21,996	26,195	26,360	26,524	26,687	26,747	26,647	26,559	25,682
		Cooking	4,932	4,281	3,778	3,297	3,045	2,808	1,877	1,751	1,593
		Weatherization	11,891	11,329	11,401	11,471	11,542	11,499	11,456	11,413	11,036
		Behavioral	66,795	63,640	64,042	64,441	64,835	64,593	64,351	64,111	61,992
	Replacement on Burnout	Heating	8,114	8,454	8,415	8,247	8,548	8,720	8,985	9,252	9,504
		Water Heating	12,251	12,567	12,451	12,143	12,354	12,599	12,779	12,962	13,136
		Cooking	15,026	14,824	14,849	14,896	14,596	14,243	13,848	13,419	12,966
Residential	New Construction	Other	23,061	23,717	23,832	26,576	27,409	27,652	27,550	26,896	26,409
		Heating	506	521	523	583	602	607	605	591	580
		Weatherization	6,231	6,907	7,942	8,856	9,134	9,215	9,181	8,963	8,801
		Water Heating	3,990	4,103	4,990	5,650	5,902	5,726	4,597	4,488	4,407
		Behavioral	2,762	2,776	2,900	3,164	3,188	3,138	3,048	2,894	2,762
	Retrofit	Weatherization	15,911	17,376	19,858	22,340	24,822	27,305	29,787	31,028	32,269
		Water Heating	30,404	33,204	37,947	42,691	47,434	52,178	56,921	59,293	61,665
		Behavioral	7,114	7,592	8,473	9,304	10,084	10,814	11,493	11,655	11,791
	Replacement on Burnout	Heating	1,357	1,553	1,315	1,499	1,648	1,779	1,980	2,153	2,315
		Appliance	744	163	137	155	168	180	198	212	225
		Weatherization	3,530	4,401	4,344	4,855	5,340	5,802	6,524	7,211	7,864
		Water Heating	15,748	16,992	20,031	20,893	21,460	21,775	21,400	22,041	22,406
	Commercial	**Total:**	**151,056**	**150,866**	**150,935**	**150,718**	**151,364**	**150,930**	**149,627**	**149,115**	**146,983**
	Residential	**Total:**	**111,359**	**119,304**	**132,293**	**146,567**	**157,192**	**166,171**	**173,283**	**177,424**	**181,494**
	Efficiency	**Total:**	**262,415**	**270,171**	**283,228**	**297,284**	**308,556**	**317,101**	**322,911**	**326,539**	**328,477**

Washington 20-Year Cost-Effective DSM Savings Projection

Sector	Measure Type	End Use	2026	2027	2028	2029	2030	2031	2032	2033	2034
Commercial	Retrofit	Ventilation	4,331	4,314	4,307	4,325	4,309	4,293	4,277	4,176	4,160
		Water Heating	6,703	6,678	6,666	6,695	6,670	6,645	6,620	6,463	6,439
		Heating	25,795	25,699	25,655	25,765	25,668	25,572	25,477	24,874	24,781
		Cooking	1,496	1,247	1,191	1,145	1,099	722	701	562	548
		Weatherization	10,994	10,953	10,934	10,981	10,940	10,899	10,858	10,602	10,562
		Behavioral	61,761	61,530	61,423	61,687	61,456	61,227	60,998	59,554	59,331
	Replacement on Burnout	Heating	9,756	10,004	10,121	10,258	10,060	9,991	9,919	9,874	9,719
		Water Heating	13,299	13,431	13,492	13,449	13,056	12,860	12,626	12,426	12,201
		Cooking	12,495	12,012	11,395	10,798	9,898	9,172	8,498	7,872	7,216
Residential	New Construction	Other	26,435	26,306	26,178	26,050	25,922	25,794	25,678	25,550	25,422
		Heating	580	578	575	572	569	566	564	561	558
		Weatherization	8,809	8,767	8,724	8,681	8,638	8,596	8,557	8,515	8,472
		Water Heating	4,411	4,389	4,368	4,347	4,325	4,304	4,285	4,263	4,242
		Behavioral	2,688	2,598	2,510	4,180	4,085	3,989	3,896	3,803	3,784
	Retrofit	Weatherization	33,510	35,372	35,993	34,751	37,234	37,544	37,544	37,854	37,234
		Water Heating	64,035	67,593	68,779	66,407	71,150	71,743	71,743	72,335	71,149
		Behavioral	11,902	12,202	12,049	20,045	21,096	20,889	20,505	20,288	19,955
	Replacement on Burnout	Heating	2,480	2,704	2,840	2,895	3,015	3,060	3,069	2,982	2,898
		Appliance	239	258	269	272	282	284	284	274	266
		Weatherization	8,485	9,333	9,886	10,162	10,663	10,900	11,006	10,761	10,522
		Water Heating	22,543	23,130	22,861	21,932	21,484	20,506	19,337	17,661	16,134
	Commercial	**Total:**	**146,629**	**145,868**	**145,184**	**145,102**	**143,156**	**141,381**	**139,974**	**136,404**	**134,958**
	Residential	**Total:**	**186,117**	**193,230**	**195,031**	**200,294**	**208,464**	**208,175**	**206,467**	**204,847**	**200,635**
	Efficiency	**Total:**	**332,746**	**339,098**	**340,215**	**345,396**	**351,620**	**349,556**	**346,441**	**341,251**	**335,593**

Washington 20-Year Cost-Effective DSM Savings Projection

Sector	Measure Type	End Use	2035	2036	Total
Commercial	Retrofit	Ventilation	4,145	4,129	**87,352**
		Water Heating	6,415	6,391	**120,652**
		Heating	24,688	24,596	**511,966**
		Cooking	532	525	**37,130**
		Weatherization	10,522	10,483	**221,765**
		Behavioral	59,109	58,888	**1,245,765**
	Replacement on Burnout	Heating	9,584	9,461	**186,984**
		Water Heating	11,875	11,701	**253,657**
		Cooking	6,615	6,064	**230,701**
Residential	New Construction	Other	25,306	25,191	**516,934**
		Heating	556	553	**11,350**
		Weatherization	8,433	8,395	**169,817**
		Water Heating	4,223	4,203	**91,213**
		Behavioral	3,767	3,751	**65,682**
	Retrofit	Weatherization	36,613	35,993	**620,337**
		Water Heating	69,963	68,778	**1,185,414**
		Behavioral	19,622	19,290	**286,164**
	Replacement on Burnout	Heating	2,819	2,743	**47,104**
		Appliance	258	250	**5,119**
		Weatherization	10,288	10,059	**161,935**
		Water Heating	14,742	13,514	**396,589**
	Commercial	**Total:**	**133,485**	**132,238**	**2,895,973**
	Residential	**Total:**	**196,590**	**192,719**	**3,557,657**
	Efficiency	**Total:**	**330,075**	**324,957**	**6,453,630**

Oregon 20-Year Cumulative Potential

Residential Measures	Measure Type	End Use	20-year Cumulative Technical Potential (therms)	20-year Cumulative Achievable Potential (therms)	20-year Cumulative Cost-Effective Potential (therms)	% of Total Sector C/E Potential	Average Levelized Cost ($/therm)
Res Showerheads - Gas DHW[1]	Retrofit	Water Heating	2,604,394	2,213,735	2,213,735	7%	-$1.75
Res Bathroom Faucet Aerators, 1.0 gpm- Gas[1]	Retrofit	Water Heating	3,269,983	2,779,485	2,779,485	8%	-$1.74
Res Kitchen Faucet Aerators, 1.5 gpm- Gas[1]	Retrofit	Water Heating	1,434,581	1,219,393	1,219,393	4%	-$1.73
Res - Elec Hi-eff Clothes Washer - Gas DHW[1]	Replacement on Burnout	Appliance	65,229	55,444	55,444	0%	-$1.04
Res - Gas Hearth	Replacement on Burnout	Heating	415,443	353,127	353,127	1%	$0.00
Res Absorption Gas Heat Pump Water Heater-Z1	Replacement on Burnout	Water Heating	4,654,349	3,956,197	149,631	0%	$0.00
Res Absorption Gas Heat Pump Water Heater-Z2	Replacement on Burnout	Water Heating	47,040	39,984	1,406	0%	$0.00
Res Absorption Gas Heat Pump Water Heater-Z2 (NEW ONLY)	New Construction	Water Heating	12,597	10,707	9,936	0%	$0.00
Res Tankless Gas Hot Water Heater-Z1	Replacement on Burnout	Water Heating	14,951,460	12,708,741	430,964	1%	$0.00
Res Tankless Gas Hot Water Heater-Z1 (NEW ONLY)	New Construction	Water Heating	4,087,864	3,474,684	282,996	1%	$0.00
Res Tankless Gas Hot Water Heater-Z2	Replacement on Burnout	Water Heating	150,473	127,902	3,884	0%	$0.00
Res Tankless Gas Hot Water Heater-Z2 (NEW ONLY)	New Construction	Water Heating	39,941	33,950	3,262	0%	$0.00
Res Absorption Gas Heat Pump Water Heater-Z1 (NEW ONLY)	New Construction	Water Heating	1,385,440	1,177,624	983,857	3%	$0.01
Res - Window Replacement (U<.20), Gas SH, Z2 (NEW ONLY)	New Construction	Weatherization	29,395	24,986	24,986	0%	$0.15
Res - Window Replacement (U<.20), Gas SH, Z2	Replacement on Burnout	Weatherization	38,280	32,538	32,538	0%	$0.17
Res - Window Replacement (U<.20), Gas SH, Z1 (NEW ONLY)	New Construction	Weatherization	2,077,324	1,765,725	1,765,725	5%	$0.21
Res - Window Replacement (U<.20), Gas SH, Z1	Replacement on Burnout	Weatherization	2,704,431	2,298,766	2,298,766	7%	$0.24
Res - Window Replacement (U=.30), Gas SH, Z2, MH	Replacement on Burnout	Weatherization	32	27	27	0%	$0.36
Res - Window Replacement (U<.20), Gas SH, Z2, MH	Replacement on Burnout	Weatherization	35	30	30	0%	$0.46
Res - Window Replacement (U=.30), Gas SH, Z1, MH	Replacement on Burnout	Weatherization	2,290	1,946	1,946	0%	$0.49
Res - HRV, Gas SH, Z1	New Construction	Heating	179,834	152,859	150,172	0%	$0.52
Res - AFUE 90 to 95 Furnace, Z1 - SF	Replacement on Burnout	Heating	94,618	80,426	80,426	0%	$0.53
Res - AFUE 90 to 95 Furnace, Z2 - SF	Replacement on Burnout	Heating	956	812	812	0%	$0.53
Res 0.67/0.70 EF Gas Storage Water Heater-Z1	Replacement on Burnout	Water Heating	4,947,298	4,205,204	4,205,204	13%	$0.56
Res 0.67/0.70 EF Gas Storage Water Heater-Z2	Replacement on Burnout	Water Heating	47,365	40,261	40,261	0%	$0.58
Res - Window Replacement (U<.20), Gas SH, Z1, MH	Replacement on Burnout	Weatherization	2,507	2,131	2,131	0%	$0.64
Res - Wx insulation (ceiling), Gas SH, Z2	Retrofit	Weatherization	10,016	8,513	8,513	0%	$0.66
Res - AFUE 90 to 95 Furnace, Z1	Replacement on Burnout	Heating	119	101	92	0%	$0.66
Res - AFUE 90 to 95 Furnace, Z2	Replacement on Burnout	Heating	1	1	1	0%	$0.66
Res - Wx insulation (ceiling), Gas SH, Z1	Retrofit	Weatherization	903,072	767,611	767,611	2%	$0.73
Res 0.67/0.70 EF Gas Storage Water Heater-Z1 (NEW ONLY)	New Construction	Water Heating	289,435	246,020	246,020	1%	$0.73
Res - HRV, Gas SH, Z2	New Construction	Heating	1,267	1,077	842	0%	$0.75
Res - Wx insulation (wall), Gas SH, Z2	Retrofit	Weatherization	21,146	17,974	17,974	0%	$1.28
Res - Wx insulation (wall), Gas SH, Z1	Retrofit	Weatherization	1,912,033	1,625,228	1,625,228	5%	$1.40
Res- Behavior Savings (NEW)	New Construction	Behavioral	255,983	217,585	217,585	1%	$1.43
Res- Behavior Savings (RET)	Retrofit	Behavioral	1,760,905	1,496,769	1,496,769	4%	$1.43
Res - Energy Star New Home BOP 1 - Gas SH	New Construction	Other	8,326,099	7,077,184	7,077,184	21%	$1.46
Res Smart Devices Home Automation (RET)	Retrofit	Behavioral	1,448,725	1,231,416	1,146,041	3%	$1.47
Res Smart Devices Home Automation (NEW)	New Construction	Behavioral	761,739	647,478	630,269	2%	$1.49
Res - Duct Sealing, Gas SH, Z2	Retrofit	Weatherization	24,751	21,038	207	0%	$1.53
Res - Duct Sealing, Gas SH, Z1	Retrofit	Weatherization	2,450,334	2,082,784	20,499	0%	$1.53
Res - Wx insulation (floor), Gas SH, Z2	Retrofit	Weatherization	21,196	18,016	18,016	0%	$1.83
Res - Wx insulation (floor), Gas SH, Z1	Retrofit	Weatherization	1,916,585	1,629,097	1,629,097	5%	$2.00
Res - Wx insulation (ceiling), NEW, ET, Gas SH, Z2	New Construction	Weatherization	1,713	1,456	1,456	0%	$4.64
Res - Wx insulation (ceiling), NEW, ET, Gas SH, Z1	New Construction	Weatherization	154,387	131,229	131,229	0%	$5.09
Res - Wx insulation (ceiling), RET, ET, Gas SH, Z2	Retrofit	Weatherization	4,962	4,218	4,218	0%	$7.48
Res - Wx insulation (ceiling), RET, ET, Gas SH, Z1	Retrofit	Weatherization	446,871	379,840	379,840	1%	$8.22
Res - Wx insulation (wall), RET, ET, Gas SH, Z2	Retrofit	Weatherization	13,176	11,200	11,200	0%	$25.56
Res - Wx insulation (wall), RET, ET, Gas SH, Z1	Retrofit	Weatherization	1,191,109	1,012,442	1,012,442	3%	$27.99
Res 0.67/0.70 EF Gas Storage Water Heater for Multi-Family Centralized Hot Water System	Replacement on Burnout	Water Heating	1,145	973	973	0%	$28.89
Residential Totals & Weighted Average Levelized Cost			**65,159,927**	**55,385,938**	**33,533,453**	**100%**	**$1.40**

[1] Non-energy benefit

Oregon 20-Year Cumulative Potential

Commercial Measures	Measure Type	End Use	20-year Cumulative Technical Potential (therms)	20-year Cumulative Achievable Potential (therms)	20-year Cumulative Cost-Effective Potential (therms)	% of Total Sector C/E Potential	Average Levelized Cost ($/therm)
Com - Gas Showerhead[1]	Retrofit	Water Heating	1,531,832	1,302,057	1,302,057	3%	-$2.63
Com - Gas Steamer[1]	Retrofit	Cooking	4,057,163	3,448,589	3,448,589	7%	-$0.73
Com - Gas Combi Oven[1]	Retrofit	Cooking	1,776,394	1,509,935	1,509,935	3%	-$0.28
Com - Cond Furnace	Replacement on Burnout	Heating	673,970	572,874	572,874	1%	$0.00
Com - VFD Venthood	New Construction	Heating	4,491	3,817	3,817	0%	$0.00
Com - Energy Star Convection Oven	Replacement on Burnout	Cooking	897,237	762,652	762,652	1%	$0.00
Com - Demand Control Ventilation	Retrofit	Heating	5,369,008	4,563,656	4,563,656	9%	$0.03
Com - Hot Water Temperature Reset	Retrofit	Heating	363,178	308,701	308,701	1%	$0.06
Com - SPC High efficiency Boiler	Replacement on Burnout	Heating	2,222,933	1,889,493	1,889,493	4%	$0.08
Com - Roof Insulation	Retrofit	Weatherization	1,729,787	1,470,319	1,470,319	3%	$0.16
Com - Gas Fryer	Retrofit	Cooking	1,774,422	1,508,259	1,482,244	3%	$0.21
Com - Energy Star Fryer	Replacement on Burnout	Cooking	3,403,392	2,892,883	2,892,883	6%	$0.21
Com - DHW Condensing Tankless	Replacement on Burnout	Water Heating	4,259,443	3,620,527	3,620,527	7%	$0.32
Com - Gas Griddle	Retrofit	Cooking	783,095	665,631	515,464	1%	$0.34
Com - Steam Trap Maintenance	Retrofit	Heating	1,558,775	1,324,959	1,324,959	3%	$0.40
Com - High Efficiency Unit Heater	Replacement on Burnout	Heating	2,334	1,984	1,980	0%	$0.48
Com - Gas Conv. Oven	Retrofit	Cooking	614,734	522,524	357,348	1%	$0.50
Com - Wall Insulation	Retrofit	Weatherization	1,187,170	1,009,094	1,009,094	2%	$0.52
Com - SEM	Retrofit	Behavioral	18,275,383	15,534,076	15,534,076	30%	$0.70
Com - Steam Balance	Retrofit	Heating	289,157	245,784	151,111	0%	$0.91
Com - Windows Upgrade (New)	New Construction	Weatherization	1,061,290	902,097	47,968	0%	$1.38
Com - DDC HVAC Controls	New Construction	Heating	8,697,858	7,393,180	7,169,785	14%	$1.59
Com - AC Heat Recovery, HW	Retrofit	Water Heating	3,038,523	2,582,744	142,178	0%	$3.72
Com - HVAC System Commissioning	New Construction	Cooling	1,775,007	1,508,756	58,105	0%	$5.92
Com - Advanced Ventilation Controls	Retrofit	Ventilation	1,308,930	1,112,591	1,085,248	2%	$8.62
Commercial Totals & Weighted Average Levelized Cost			**66,655,505**	**56,657,180**	**51,225,062**	**100%**	**$0.59**

[1] Non-energy benefit

Oregon 20-Year Cumulative Potential

Industrial Measures	Measure Type	End Use	20-year Cumulative Technical Potential (therms)	20-year Cumulative Achievable Potential (therms)	20-year Cumulative Cost-Effective Potential (therms)	% of Total Sector C/E Potential	Average Levelized Cost ($/therm)
Ind- Steam line pipe insulation	Retrofit	Process Heating	520,116	442,099	442,099	3%	$0.01
Ind- Vent Damper Control	Retrofit	Process Heating	701,365	596,160	596,160	3%	$0.01
Ind- Boiler Load Control	Retrofit	Process Heating	761,588	647,350	647,350	4%	$0.02
Ind- Process Boiler Insulation	Retrofit	Process Heating	816,418	693,955	693,955	4%	$0.02
Ind- Steam Trap Maintenance	Retrofit	Process Heating	1,124,594	955,905	955,905	6%	$0.02
Ind- High Efficiency Unit Heater	Replacement on Burnout	HVAC	394,887	335,654	335,654	2%	$0.03
Ind- Boiler Tune-up	Retrofit	Process Heating	2,720,375	2,312,319	2,312,319	13%	$0.03
Ind- Boiler Heat Recovery	Retrofit	Process Heating	1,144,900	973,165	973,165	6%	$0.04
Ind- Roof Insulation- R0-R30	Retrofit	HVAC	1,848,770	1,571,455	1,571,455	9%	$0.06
Ind- Wall Insulation- R0- R11	Retrofit	HVAC	1,812,370	1,540,514	1,540,514	9%	$0.06
Ind- Burner upgrades	Retrofit	Process Heating	4,108,395	3,492,136	3,492,136	20%	$0.07
Ind- High Efficiency Boiler	Replacement on Burnout	Process Heating	751,781	639,014	639,014	4%	$0.08
Ind - Greenhouse Upgrade	Retrofit	Other	665,159	565,385	565,385	3%	$0.22
Ind- Gas-fired HP Water Heater	Replacement on Burnout	Water Heating	1,052,501	894,626	894,626	5%	$0.26
Ind- Steam Balance	Retrofit	Process Heating	1,745,478	1,483,656	1,483,656	9%	$0.32
Industrial Totals & Weighted Average Levelized Cost			**20,168,697**	**17,143,392**	**17,143,392**	**100%**	**$0.09**

Washington 20-Year Cumulative Potential

Residential Measures		End Use	20-year Cumulative Technical Potential (therms)	20-year Cumulative Achievable Potential (therms)	20-year Cumulative Cost-Effective Potential (therms)	% of Total Sector C/E Potential	Average Levelized Cost ($/therm)
Res - Elec Hi-eff Clothes Washer - Gas DHW[1]	Replacement on Burnout	Appliance	11,534	9,804	9,804	0%	-$3.33
Res Showerheads - Gas DHW[1]	Retrofit	Water Heating	706,083	600,171	600,171	11%	-$1.75
Res Bathroom Faucet Aerators, 1.0 gpm- Gas[1]	Retrofit	Water Heating	478,957	407,114	407,114	7%	-$1.75
Res Kitchen Faucet Aerators, 1.5 gpm- Gas[1]	Retrofit	Water Heating	210,042	178,535	178,535	3%	-$1.74
Res Tankless Gas Hot Water Heater-Z1	Replacement on Burnout	Water Heating	2,170,436	1,844,870	92,155	2%	$0.00
Res - Gas Hearth	Replacement on Burnout	Heating	64,112	54,495	54,495	1%	$0.00
Res Absorption Gas Heat Pump Water Heater-Z1	Replacement on Burnout	Water Heating	687,896	584,712	21,673	0%	$0.00
Res Absorption Gas Heat Pump Water Heater-Z1 (NEW ONLY)	New Construction	Water Heating	368,810	313,488	257,460	5%	$0.01
Res - Window Replacement (U<.20), Gas SH, Z1 (NEW ONLY)	New Construction	Weatherization	429,911	365,424	365,424	6%	$0.17
Res - Window Replacement (U<.20), Gas SH, Z1	Replacement on Burnout	Weatherization	304,736	259,025	259,025	5%	$0.20
Res - HRV, Gas SH, Z1	New Construction	Heating	38,150	32,427	32,427	1%	$0.46
Res - AFUE 90 to 95 Furnace, Z1 - SF	Replacement on Burnout	Heating	10,824	9,200	9,200	0%	$0.47
Res 0.67/0.70 EF Gas Storage Water Heater-Z1	Replacement on Burnout	Water Heating	742,586	631,198	631,198	11%	$0.57
Res - Wx insulation (ceiling), Gas SH, Z1	Retrofit	Weatherization	101,869	86,588	86,588	2%	$0.60
Res 0.67/0.70 EF Gas Storage Water Heater-Z1 (NEW ONLY)	New Construction	Water Heating	78,983	67,136	3,149	0%	$0.70
Res - Wx insulation (wall), Gas SH, Z1	Retrofit	Weatherization	218,581	185,794	185,794	3%	$1.17
Res - Energy Star New Home BOP 1 - Gas SH	New Construction	Other	1,737,592	1,476,953	1,476,953	26%	$1.30
Res Smart Devices Home Automation (RET)	Retrofit	Behavioral	180,799	153,679	153,679	3%	$1.34
Res Smart Devices Home Automation (NEW)	New Construction	Behavioral	167,634	142,488	142,488	3%	$1.35
Res - AFUE 98/96 Furnace, Z1 - SF	Replacement on Burnout	Heating	16,259	13,820	13,820	0%	$1.39
Res-Behavior Savings (NEW)	New Construction	Behavioral	53,147	45,175	45,175	1%	$1.43
Res-Behavior Savings (RET)	Retrofit	Behavioral	210,477	178,905	178,905	3%	$1.43
Res - Wx insulation (floor), Gas SH, Z1	Retrofit	Weatherization	221,218	188,035	188,035	3%	$1.66
Res - Wx insulation (ceiling), NEW, ET, Gas SH, Z1	New Construction	Weatherization	32,715	27,808	27,808	0%	$4.16
Res - Wx insulation (ceiling), RET, ET, Gas SH, Z1	Retrofit	Weatherization	51,322	43,624	43,624	1%	$6.81
Res - Wx insulation (wall), NEW, ET, Gas SH, Z1	New Construction	Weatherization	108,189	91,960	91,960	2%	$15.35
Res - Wx insulation (wall), RET, ET, Gas SH, Z1	Retrofit	Weatherization	137,081	116,519	116,519	2%	$23.00
Res 0.67/0.70 EF Gas Storage Water Heater for Multi-Family Centralized Hot Water System	Replacement on Burnout	Water Heating	232	197	197	0%	$26.20
Residential Totals & Weighted Average Levelized Cost			**9,540,173**	**8,109,147**	**5,673,378**	**100%**	**$1.08**

[1] Non-energy benefit

Washington 20-Year Cumulative Potential

Commercial Measures	Measure Type	End Use	20-year Cumulative Technical Potential (therms)	20-year Cumulative Achievable Potential (therms)	20-year Cumulative Cost-Effective Potential (therms)	% of Total Sector C/E Potential	Average Levelized Cost ($/therm)
Com - Gas Showerhead[1]	Retrofit	Water Heating	113,641	96,595	96,595	2%	-$2.63
Com - Gas Steamer[1]	Retrofit	Cooking	390,217	331,684	331,684	7%	-$0.74
Com - Gas Combi Oven[1]	Retrofit	Cooking	175,417	149,104	149,104	3%	-$0.28
Com - Cond Furnace	Replacement on Burnout	Heating	64,499	54,824	54,824	1%	$0.00
Com - VFD Venthood	New Construction	Heating	423	360	360	0%	$0.00
Com - Energy Star Convection Oven	Replacement on Burnout	Cooking	77,695	66,040	66,040	1%	$0.00
Com - Demand Control Ventilation	Retrofit	Heating	423,054	359,596	359,596	7%	$0.03
Com - Hot Water Temperature Reset	Retrofit	Heating	30,456	25,888	25,888	1%	$0.05
Com - SPC High efficiency Boiler	Replacement on Burnout	Heating	228,266	194,026	194,026	4%	$0.08
Com - Roof Insulation	Retrofit	Weatherization	157,838	134,163	134,163	3%	$0.14
Com - Energy Star Fryer	Replacement on Burnout	Cooking	310,427	263,863	263,863	5%	$0.20
Com - Gas Fryer	Retrofit	Cooking	170,200	144,670	144,670	3%	$0.21
Com - DHW Condensing Tankless	Replacement on Burnout	Water Heating	403,478	342,956	342,956	7%	$0.30
Com - Gas Griddle	Retrofit	Cooking	73,604	62,564	62,564	1%	$0.35
Com - Steam Trap Maintenance	Retrofit	Heating	116,361	98,907	98,907	2%	$0.39
Com - High Efficiency Unit Heater	Replacement on Burnout	Heating	182	155	155	0%	$0.44
Com - Wall Insulation	Retrofit	Weatherization	93,855	79,776	79,776	2%	$0.45
Com - Gas Conv. Oven	Retrofit	Cooking	58,445	49,678	49,678	1%	$0.52
Com - SEM	Retrofit	Behavioral	1,413,885	1,201,802	1,201,802	25%	$0.64
Com - Steam Balance	Retrofit	Heating	24,639	20,943	17,563	0%	$0.80
Com - Windows Upgrade (New)	New Construction	Weatherization	158,855	135,027	33,517	1%	$1.12
Com - DDC HVAC Controls	New Construction	Heating	1,250,514	1,062,937	1,037,272	21%	$1.51
Com - AC Heat Recovery, HW	Retrofit	Water Heating	222,917	189,480	33,837	1%	$3.23
Com - HVAC System Commissioning	New Construction	Cooling	255,197	216,918	9,761	0%	$5.62
Com - Advanced Ventilation Controls	Retrofit	Ventilation	100,909	85,773	84,269	2%	$8.03
Commercial Totals & Weighted Average Levelized Cost			**6,314,976**	**5,367,729**	**4,872,871**	**100%**	**$0.62**

[1] Non-energy benefit

Washington 20-Year Cumulative Potential

Industrial Measures		End Use	20-year Cumulative Technical Potential (therms)	20-year Cumulative Achievable Potential (therms)	20-year Cumulative Cost-Effective Potential (therms)	% of Total Sector C/E Potential	Average Levelized Cost ($/therm)
Ind- Steam line pipe insulation	Retrofit	Process Heating	13,905	11,819	11,819	2%	$0.01
Ind- Vent Damper Control	Retrofit	Process Heating	18,750	15,938	15,938	3%	$0.01
Ind- Boiler Load Control	Retrofit	Process Heating	20,360	17,306	17,306	3%	$0.01
Ind- Process Boiler Insulation	Retrofit	Process Heating	21,826	18,552	18,552	4%	$0.02
Ind- Steam Trap Maintenance	Retrofit	Process Heating	30,065	25,555	25,555	5%	$0.02
Ind- High Efficiency Unit Heater	Replacement on Burnout	HVAC	22,054	18,746	18,746	4%	$0.03
Ind- Boiler Tune-up	Retrofit	Process Heating	72,726	61,817	61,817	12%	$0.03
Ind- Boiler Heat Recovery	Retrofit	Process Heating	30,608	26,017	26,017	5%	$0.04
Ind- Roof Insulation- R0-R30	Retrofit	HVAC	76,848	65,321	65,321	12%	$0.05
Ind- Wall Insulation- R0- R11	Retrofit	HVAC	75,335	64,035	64,035	12%	$0.05
Ind- Burner upgrades	Retrofit	Process Heating	109,834	93,358	93,358	18%	$0.06
Ind- High Efficiency Boiler	Replacement on Burnout	Process Heating	25,918	22,030	22,030	4%	$0.08
Ind - Greenhouse Upgrade	Retrofit	Other	13,950	11,857	11,857	2%	$0.22
Ind- Gas-fired HP Water Heater	Replacement on Burnout	Water Heating	36,285	30,842	30,842	6%	$0.25
Ind- Steam Balance	Retrofit	Process Heating	48,928	41,589	41,589	8%	$0.25
Industrial Totals & Weighted Average Levelized Cost			**617,392**	**524,783**	**524,783**	**100%**	**$0.08**

The following list depicts all emerging technology measures screened in the resource assessment model.

Measure Name
Com - AC Heat Recovery, HW
Com - Advanced Ventilation Controls
Com - Energy Recovery Ventilator - Gas Heating
Com - Gas-fired HP HW
Com - Gas-fired HP, Heating
Com - Highly Insulated Windows (NEW)
Com - Highly Insulated Windows (RET)
Com - Smart/Dynamic Windows (NEW)
Com - Smart/Dynamic Windows (RET)
Com - VIP, R-35 wall (NEW)
COM - VIP, R-35 wall (RET-no insl'n)
Com - VIP, R-35 wall (RET-R-11)
Ind- Gas-fired HP Water Heater
Ind- Wall Insulation- VIP, R0-R35
Res - AFUE 98/96 Furnace, Z1
Res - AFUE 98/96 Furnace, Z1 - SF
Res - AFUE 98/96 Furnace, Z1 (NEW ONLY)
Res - AFUE 98/96 Furnace, Z2
Res - AFUE 98/96 Furnace, Z2 - SF
Res - AFUE 98/96 Furnace, Z2 (NEW ONLY)
Res - Window Replacement (U<.20), Gas SH, Z1
Res - Window Replacement (U<.20), Gas SH, Z1 (NEW ONLY)
Res - Window Replacement (U<.20), Gas SH, Z1, MH
Res - Window Replacement (U<.20), Gas SH, Z2
Res - Window Replacement (U<.20), Gas SH, Z2 (NEW ONLY)
Res - Window Replacement (U<.20), Gas SH, Z2, MH
Res - Wx insulation (ceiling), NEW, ET, Gas SH, Z1
Res - Wx insulation (ceiling), NEW, ET, Gas SH, Z2
Res - Wx insulation (ceiling), RET, ET, Gas SH, Z1
Res - Wx insulation (ceiling), RET, ET, Gas SH, Z2
Res - Wx insulation (wall), NEW, ET, Gas SH, Z1
Res - Wx insulation (wall), NEW, ET, Gas SH, Z2
Res - Wx insulation (wall), RET, ET, Gas SH, Z1
Res - Wx insulation (wall), RET, ET, Gas SH, Z2
Res Absorption Gas Heat Pump Water Heater-Z1
Res Absorption Gas Heat Pump Water Heater-Z1 (NEW ONLY)
Res Absorption Gas Heat Pump Water Heater-Z2
Res Absorption Gas Heat Pump Water Heater-Z2 (NEW ONLY)
Res Smart Devices Home Automation (NEW)
Res Smart Devices Home Automation (RET)

Final Load Forecast (Post-DSM)

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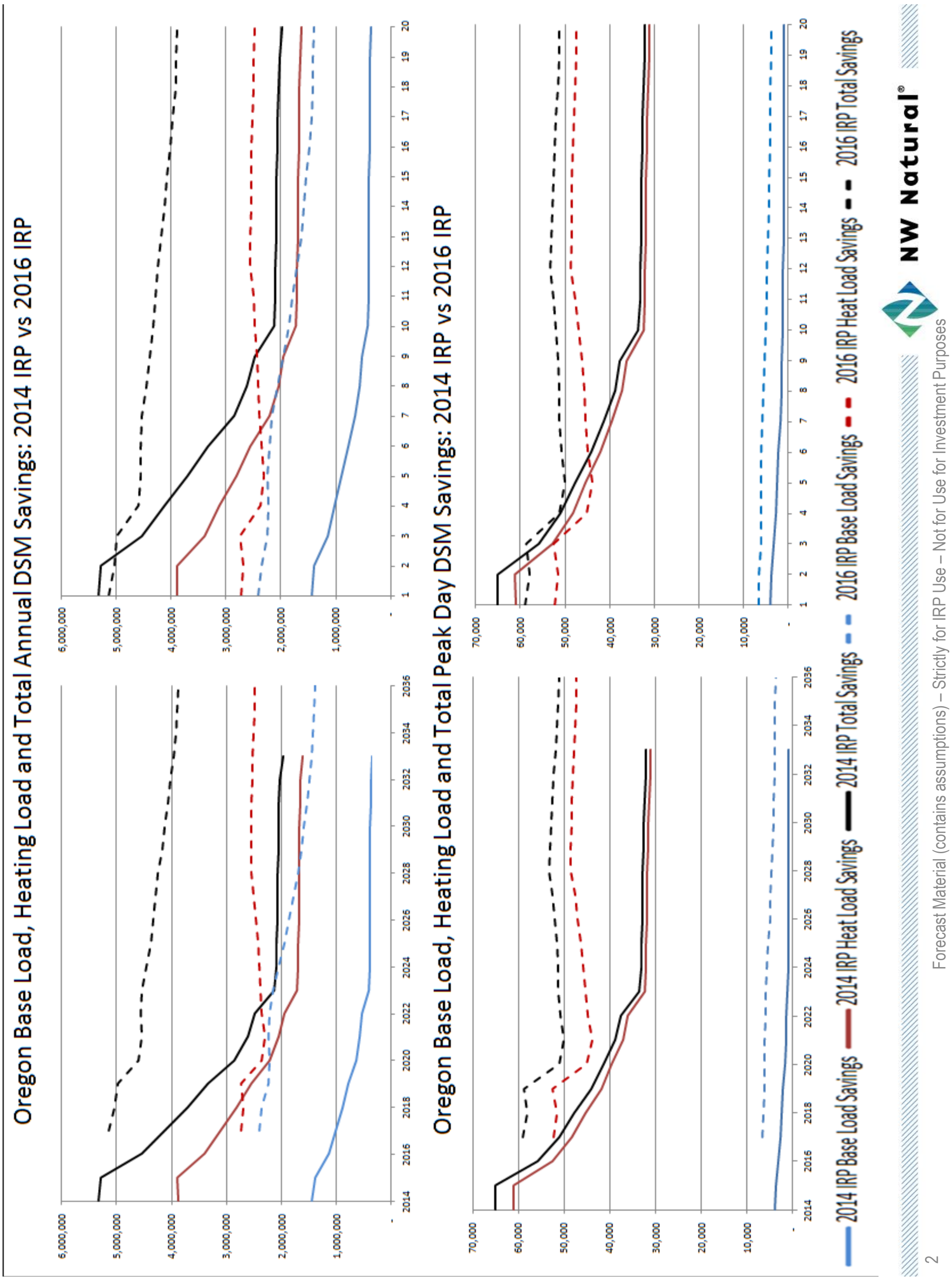
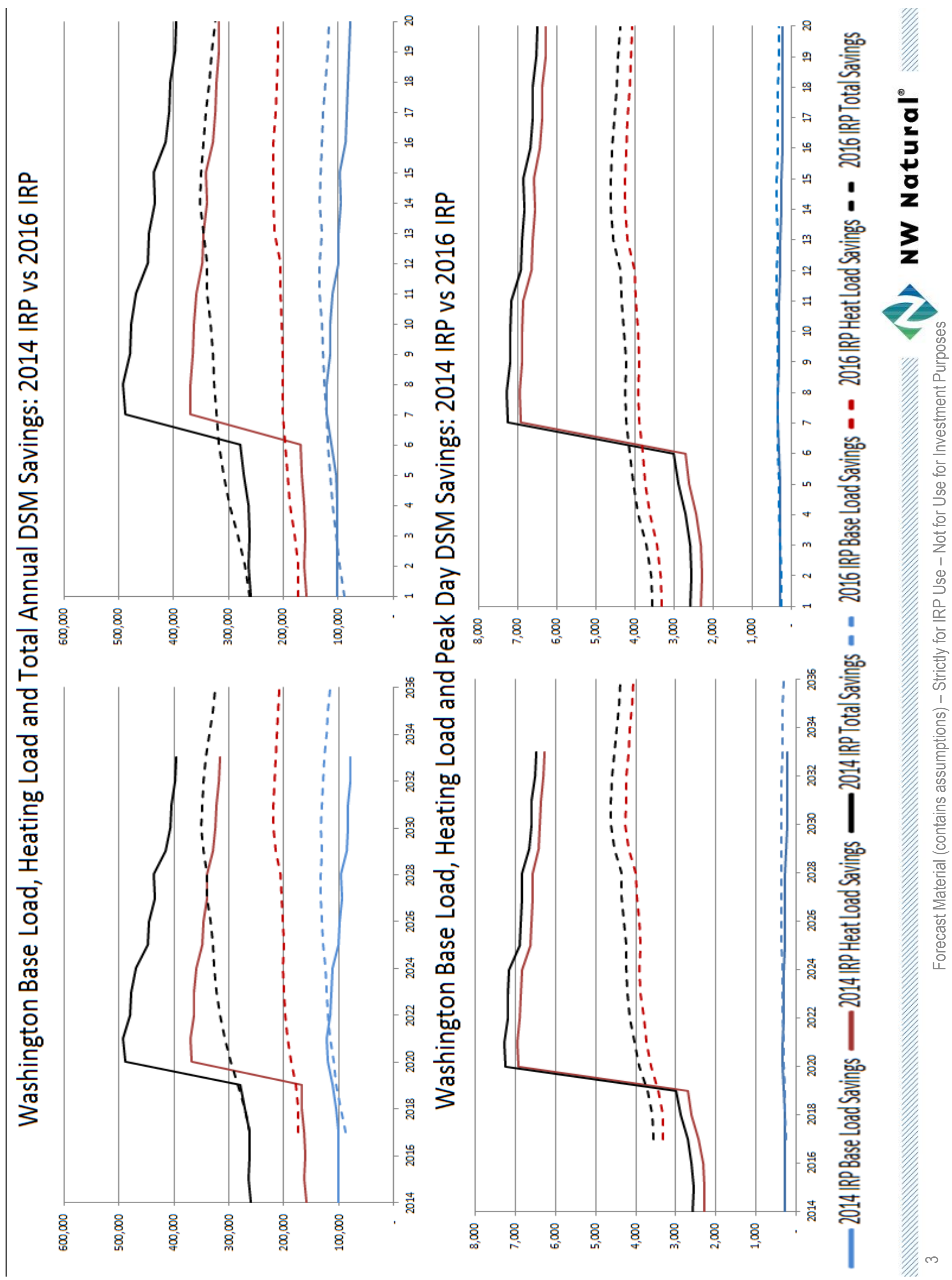
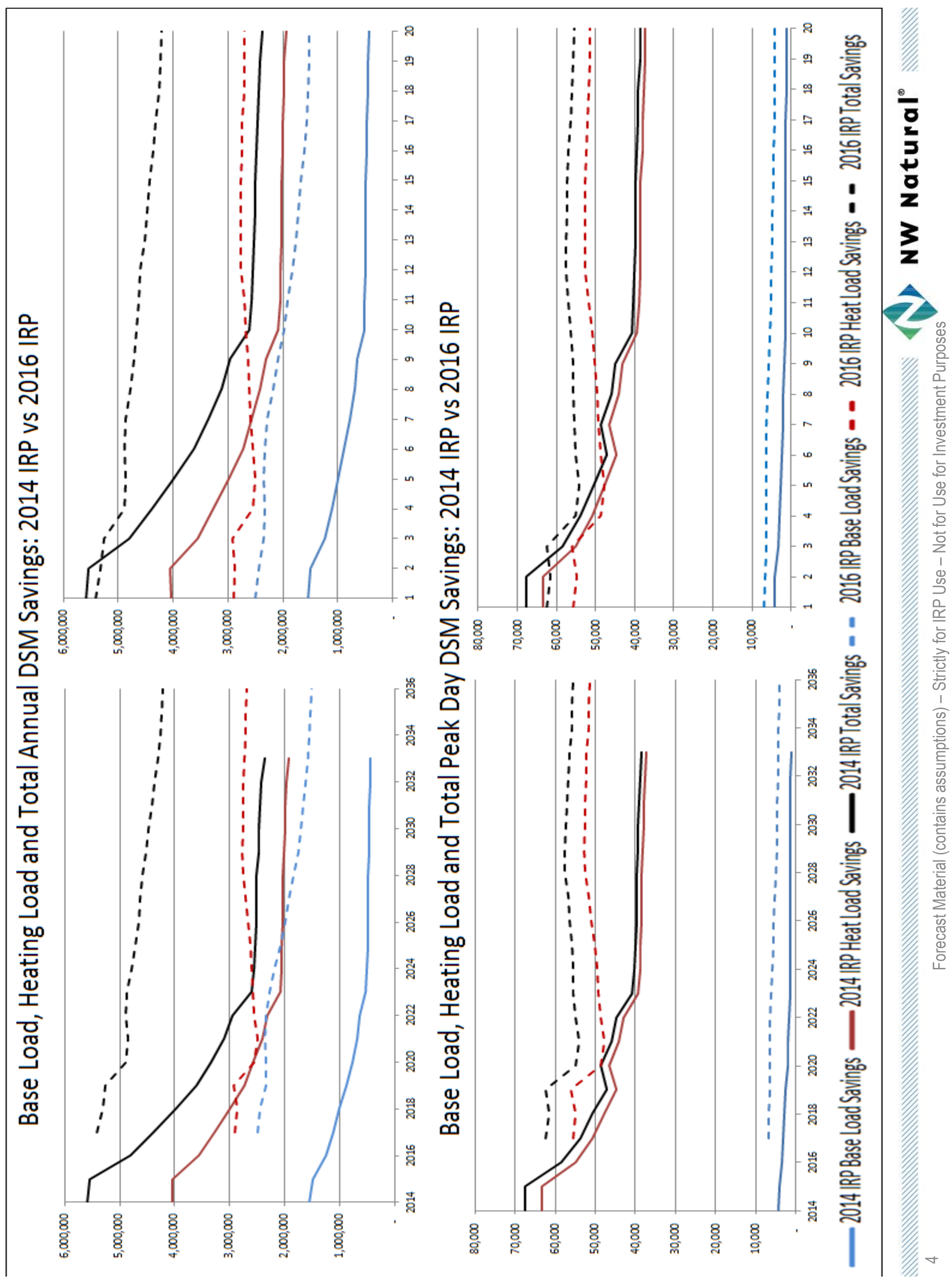
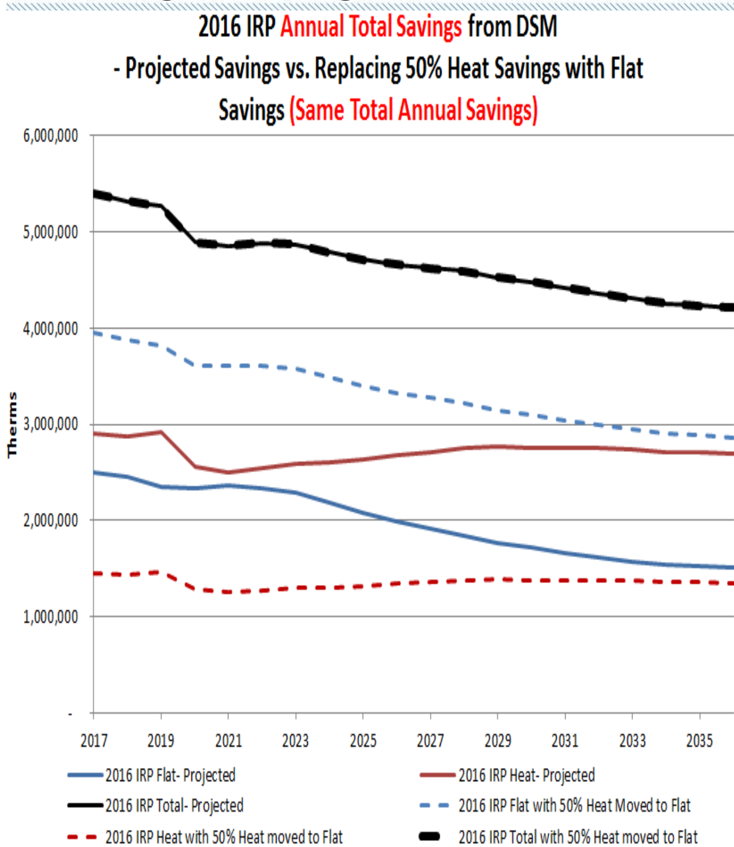
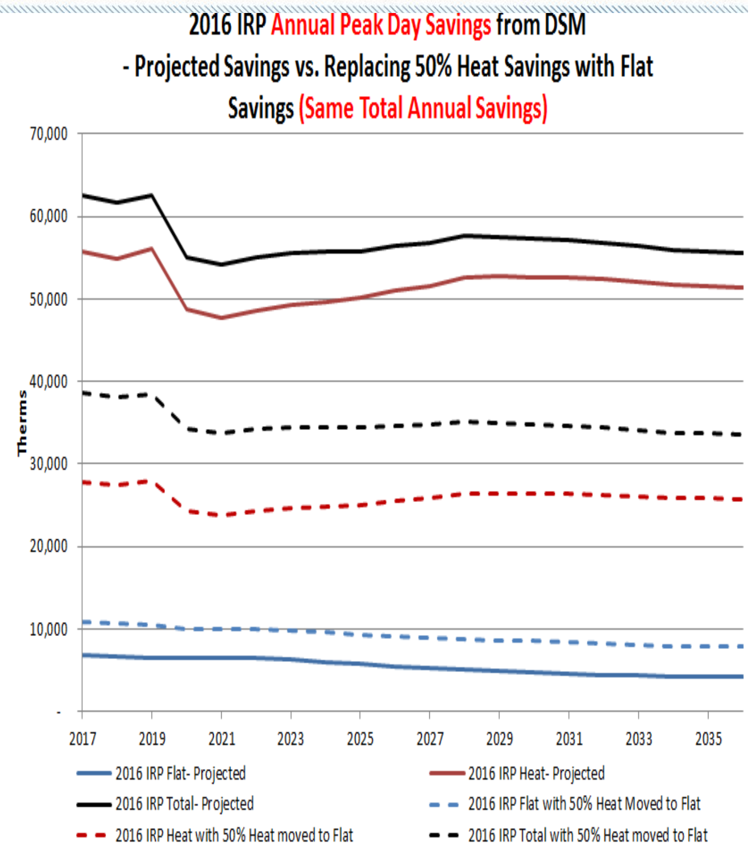

Oregon Base Load, Heating Load and Total Annual DSM Savings: 2014 IRP vs 2016 IRP
Oregon Base Load, Heating Load and Total Peak Day DSM Savings: 2014 IRP vs 2016 IRP
2014 IRP Base Load Savings
2014 IRP Heat Load Savings
2014 IRP Total Savings
2016 IRP Base Load Savings
2016 IRP Heat Load Savings
2016 IRP Total Savings
NW Natural®
Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes
2


Washington Base Load, Heating Load and Total Annual DSM Savings: 2014 IRP vs 2016 IRP
Washington Base Load, Heating Load and Peak Day DSM Savings: 2014 IRP vs 2016 IRP
2014 IRP Base Load Savings
2014 IRP Heat Load Savings
2014 IRP Total Savings
2016 IRP Base Load Savings
2016 IRP Heat Load Savings
2016 IRP Total Savings
NW Natural®
Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes
3


Base Load, Heating Load and Total Annual DSM Savings: 2014 IRP vs 2016 IRP
Base Load, Heating Load and Total Peak Day DSM Savings: 2014 IRP vs 2016 IRP
2014 IRP Base Load Savings
2014 IRP Heat Load Savings
2014 IRP Total Savings
2016 IRP Base Load Savings
2016 IRP Heat Load Savings
2016 IRP Total Savings
NW Natural
Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes
4

Annual Savings are Important, but so are Distribution of Savings Amongst DSM/EE Measures





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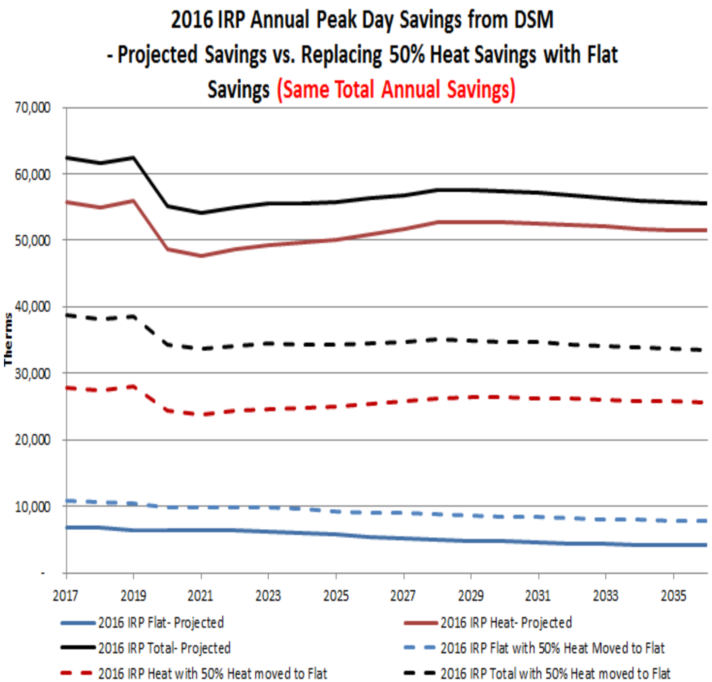
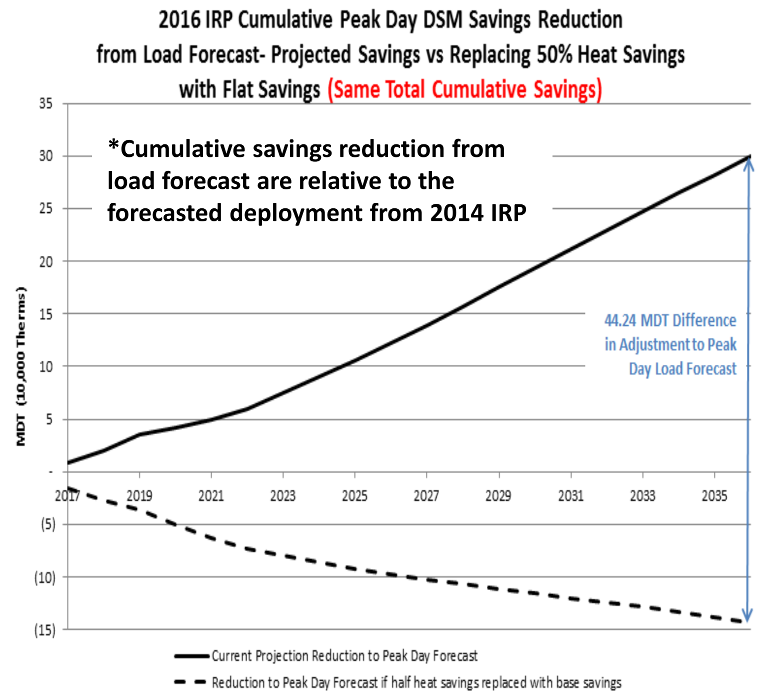
5

Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes

Annual Savings are Important, but so are Distribution of Savings Amongst DSM/EE Measures





44.24 MDT per day is roughly $6 million per year in supply pipeline capacity/deliverability (i.e. capacity resource costs) with an assumption rates capacity rates will be $0.40/Dth/Day for incremental capacity- note these costs are assumed avoided with 100% certainty under current assumptions

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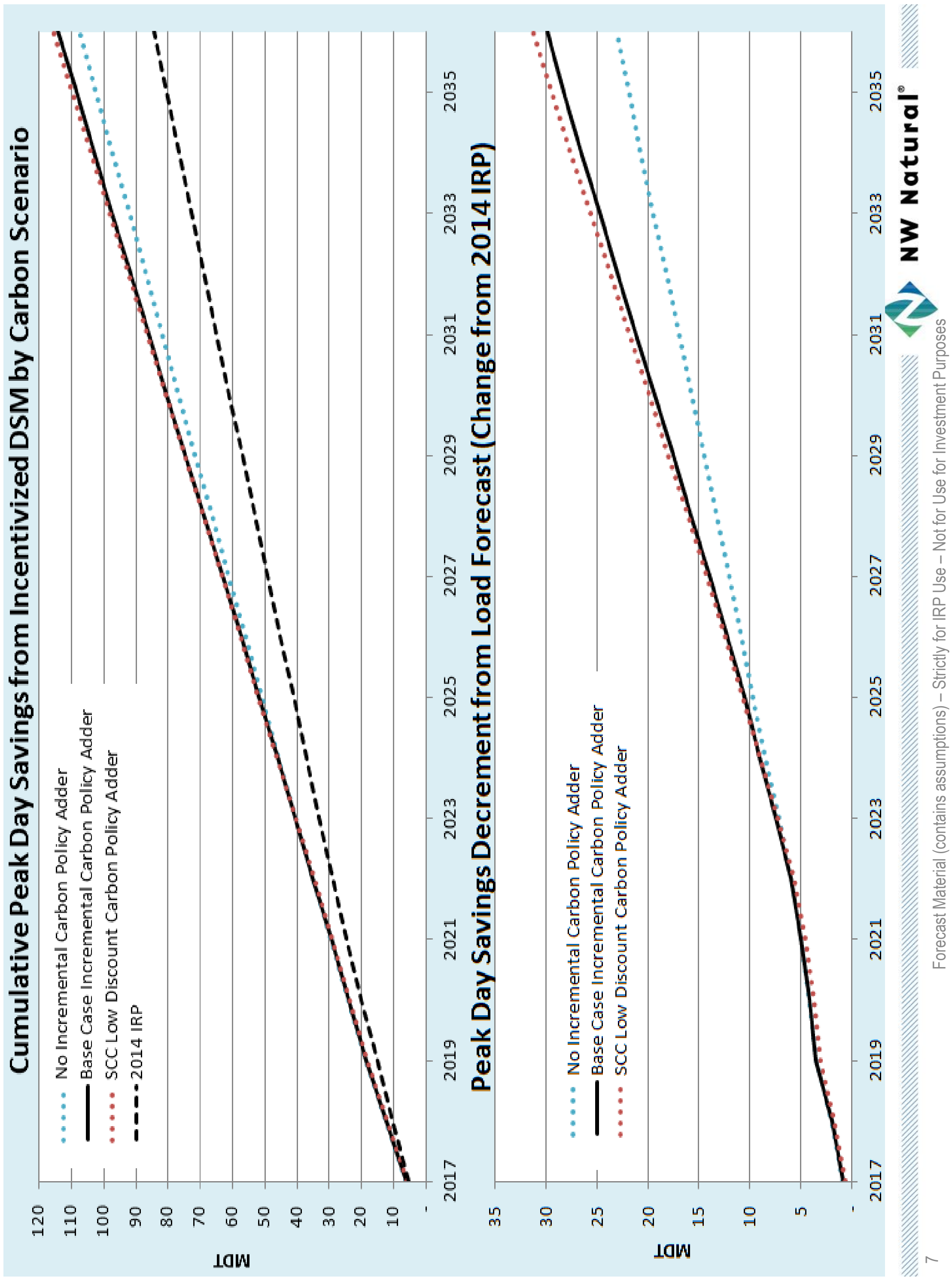
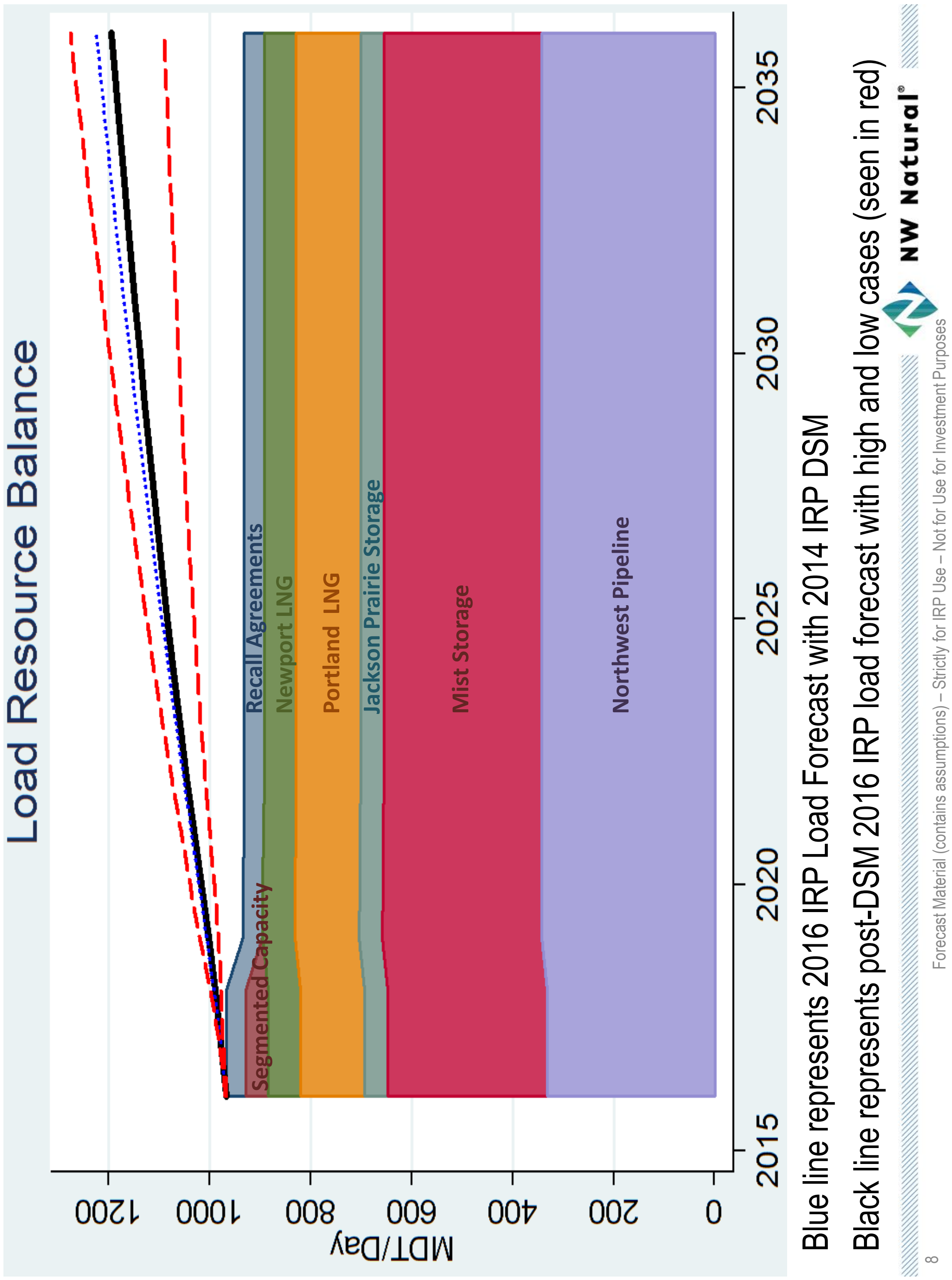
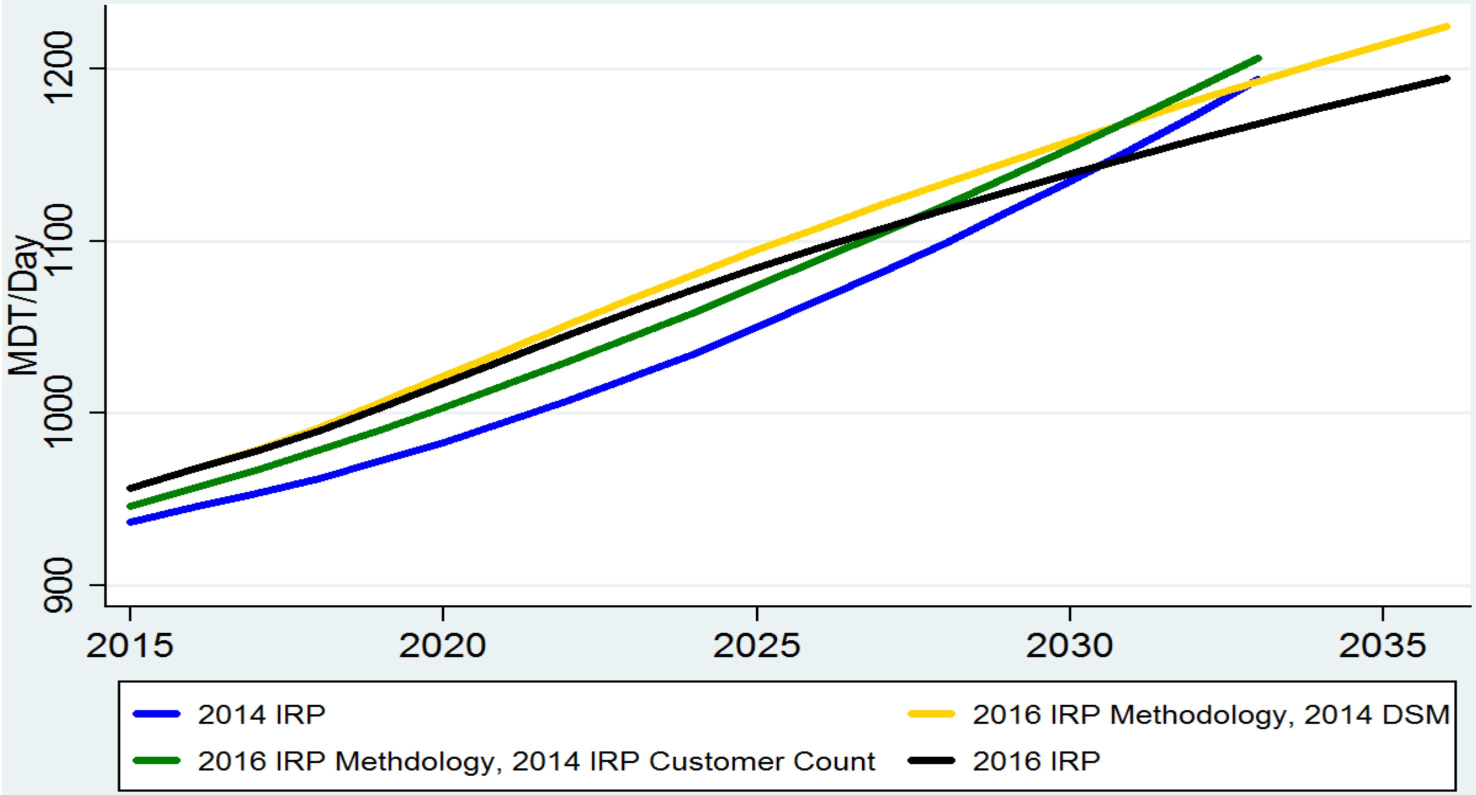
6

Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes

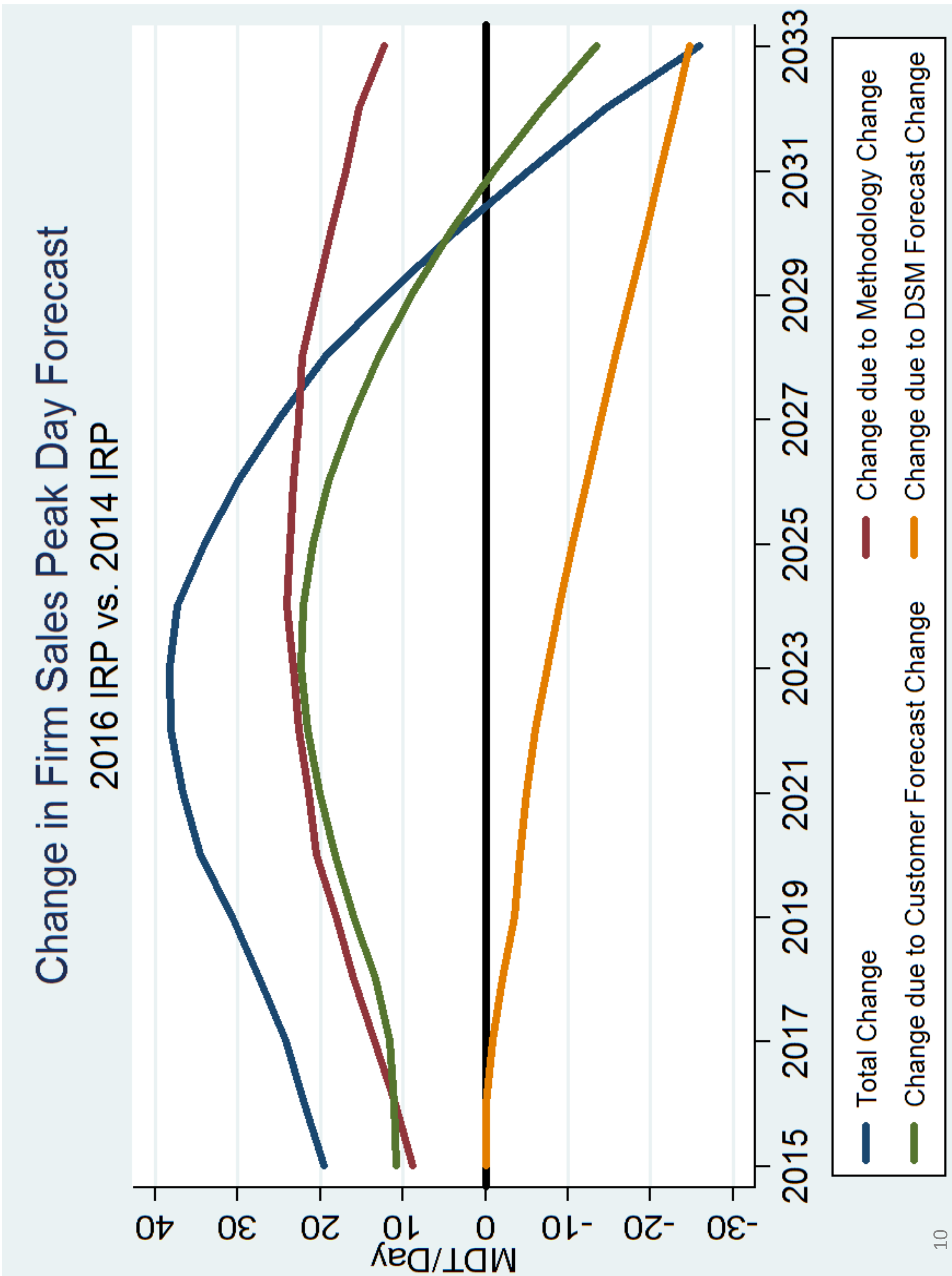

Cumulative Peak Day Savings from Incentivized DSM by Carbon Scenario
No Incremental Carbon Policy Adder
Base Case Incremental Carbon Policy Adder
SCC Low Discount Carbon Policy Adder
2014 IRP
MDT
120
110
100
90
80
70
60
50
40
30
20
10
-
2017
2019
2021
2023
2025
2027
2029
2031
2033
2035
Peak Day Savings Decrement from Load Forecast (Change from 2014 IRP)
No Incremental Carbon Policy Adder
Base Case Incremental Carbon Policy Adder
SCC Low Discount Carbon Policy Adder
MDT
35
30
25
20
15
10
5
-
2017
2019
2021
2023
2025
2027
2029
2031
2033
2035
NW Natural®
Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes
7

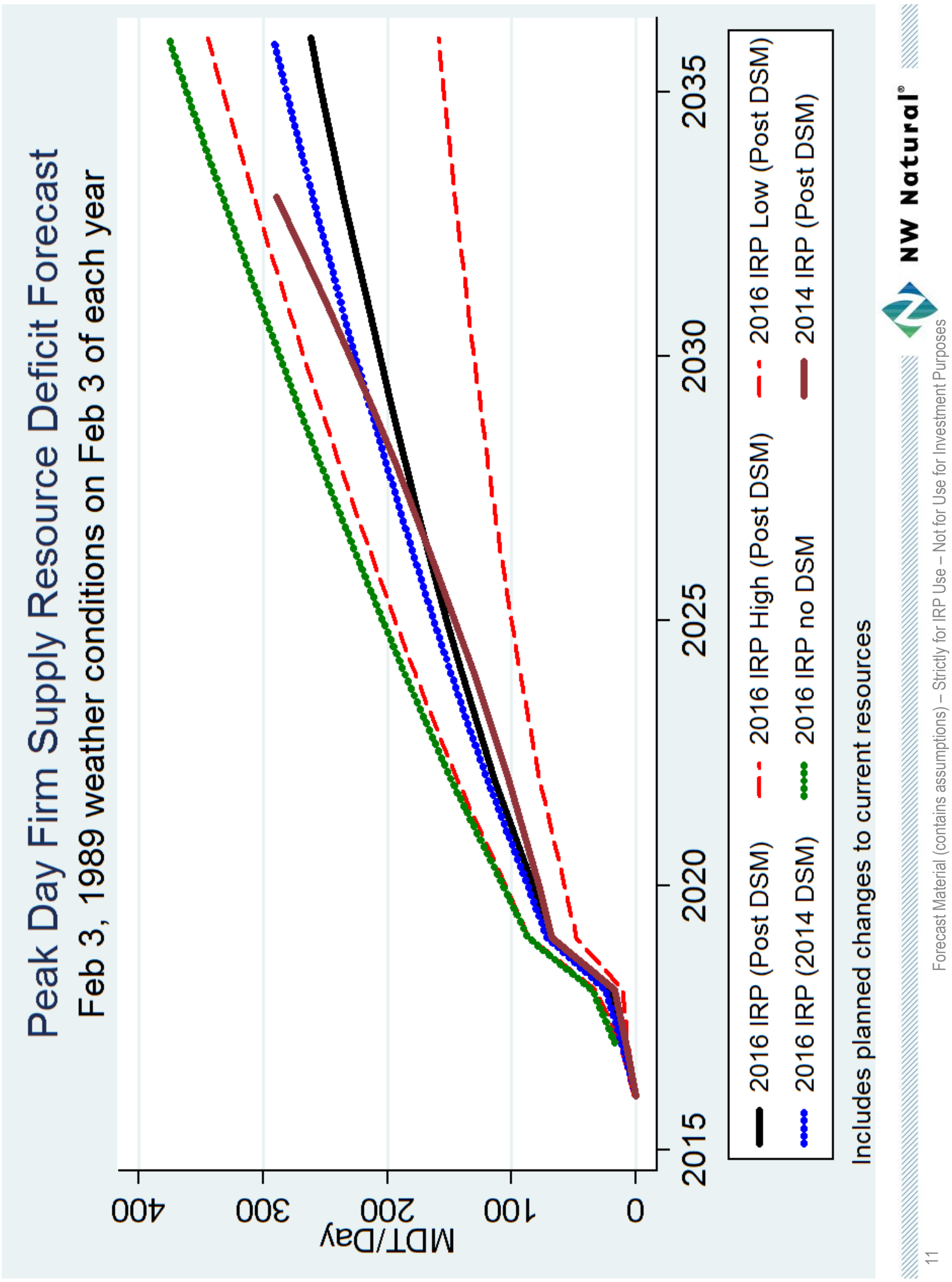

Load Resource Balance
MDT/Day
0
200
400
600
800
1000
1200
2015
2020
2025
2030
2035
Segmented Capacity
Recall Agreements
Newport LNG
Portland LNG
Jackson Prairie Storage
Mist Storage
Northwest Pipeline
Blue line represents 2016 IRP Load Forecast with 2014 IRP DSM
Black line represents post-DSM 2016 IRP load forecast with high and low cases (seen in red)
NW Natural®
Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes
8

Firm Sales Peak Day Forecast
Feb 3, 1989 Weather Conditions



Change in DSM savings forecast from 2014 IRP a major driver of change in load forecast from last IRP (as large as major changes in load forecasting methodology)


Change in Firm Sales Peak Day Forecast
2016 IRP vs. 2014 IRP
MDT/Day
40
30
20
10
0
-10
-20
-30
2015
2017
2019
2021
2023
2025
2027
2029
2031
2033
Total Change
Change due to Methodology Change
Change due to Customer Forecast Change
Change due to DSM Forecast Change
10


Peak Day Firm Supply Resource Deficit Forecast
Feb 3, 1989 weather conditions on Feb 3 of each year
MDT/Day
0
100
200
300
400
2015
2020
2025
2030
2035
2016 IRP (Post DSM)
2016 IRP High (Post DSM)
2016 IRP Low (Post DSM)
2016 IRP (2014 DSM)
2016 IRP no DSM
2014 IRP (Post DSM)
Includes planned changes to current resources
NW Natural
Forecast Material (contains assumptions) – Strictly for IRP Use – Not for Use for Investment Purposes
11

Appendix 7
Distribution System Planning

Appendix 7 includes, for each of the Sherwood and Eugene Reinforcement projects, the estimated cost range and a point estimate of the present value of revenue requirements (PVRR) for the preferred supply-side alternative; an alternative involving an alternate pipeline route (Sherwood/124th Avenue Extension only); and a satellite LNG facility. NW Natural discussed aspects of the different supply-side alternatives appearing in the tables below in the Technical Working Group meeting with Stakeholders held on May 24, 2016.

Table 7A.1: Cost of Alternatives for Sherwood/124th Avenue Extension Project

Solution	Estimated Cost	Estimated PVRR		
	Millions of $2015			
		2017	2018	2019
2.5 miles - 6” HP Pipe	$2.7	$5.9		
Alternate Route	$6.4		$13.4	
Satellite LNG	$23.3			$44.9
Accelerated DSM	Not Feasible			
Defined Interruptibility Agreements	Not Feasible			

The preferred supply-side alternative for the Sherwood project is the alternative identified in table 7A.1 as “2.5 miles of 6-inch high-pressure (HP) pipe.” The alternative identified as “Defined Interruptibility Agreements” refers to the customer-specific geographically focused defined interruptibility agreements mentioned in chapter 7.

Table 7A.2: Cost of Alternatives for Southeast Eugene Project

Solution	Estimated Cost	Estimated PVRR	
	Millions of $2015		
		2018	2019
2.5 miles - 8” HP Pipe	$5.0	$10.0	
Alternate route	Not feasible		
Satellite LNG	$23.3		$44.9
Accelerated DSM	Not Feasible		
Defined Interruptibility Agreements	Not Feasible		

The preferred alternative for the Eugene project is the alternative identified in table 7A.2 as “2.5 miles of 8-inch high-pressure (HP) pipe.” The alternative identified as “Defined Interruptibility Agreement” refers to the customer-specific geographically focused defined interruptibility agreements mentioned in chapter 7.

Appendix 8
Linear Programming and the Company's Resource Choices

Scenario 1	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036	NPV ($000)
Supply Variable Costs	154,731	178,700	194,695	206,297	211,789	216,041	230,194	248,121	262,584	260,308	271,209	282,231	289,762	297,690	307,323	313,261	315,421	319,648	321,929	328,791	3,243,759
Transport Fix Cost	83,239	83,730	83,952	84,143	84,352	84,554	87,926	88,106	88,347	88,587	88,823	89,350	89,895	90,048	90,206	90,340	90,487	96,519	96,654	96,814	1,155,380
Transport Var Cost	2,718	2,720	2,739	2,834	2,775	2,790	2,835	2,848	2,857	2,880	2,874	2,910	2,915	2,933	2,949	2,982	2,968	3,005	3,024	3,051	37,573
Storage Fix Cost	8,415	8,404	9,151	11,360	12,606	12,774	13,302	14,119	14,777	15,571	16,238	16,420	23,315	26,692	26,692	26,692	26,692	26,692	26,692	26,692	215,125
Storage Var Cost	158	137	147	181	115	138	183	103	146	144	150	152	155	155	159	161	154	156	158	157	1,967
System Cost	247,013	271,252	288,023	301,963	308,577	313,035	330,983	349,660	364,833	363,372	374,940	386,182	400,616	411,938	421,591	427,564	429,704	439,864	442,167	449,056	4,600,607
Carbon Policy Cost	-	5,401	5,775	6,201	6,596	49,218	52,108	55,437	58,370	61,764	65,351	69,500	73,155	77,400	81,893	87,103	91,684	97,014	102,654	109,197	639,061

Scenario 1	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036
Mist Recall	0	2,200	2,200	30,863	106,140	120,310	120,310	141,930	164,731	180,466	205,163	220,300	220,300	220,300	220,300	220,300	220,300	220,300	220,300	220,300
ChristensenComp	0	0	0	0	0	0	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
NMist2A	0	0	0	0	0	0	0	0	0	0	0	0	0	50,000	50,000	50,000	50,000	50,000	50,000	50,000
NMist2B	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PacConn	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SumLoc	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	18,355	18,355	18,355
SumReg	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TrailWest	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Scenario 2	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036	NPV ($000)
Supply Variable Costs	154,731	178,700	194,695	206,297	211,789	216,041	230,194	248,121	262,584	260,290	269,940	282,308	289,774	297,814	307,360	313,353	315,599	319,876	322,092	327,304	3,242,800
Transport Fix Cost	83,239	83,730	83,952	84,143	84,353	84,552	87,925	88,104	88,346	88,586	88,822	89,358	89,903	94,530	94,674	94,808	95,213	95,356	95,491	95,676	1,162,970
Transport Var Cost	2,718	2,720	2,739	2,834	2,775	2,790	2,835	2,848	2,857	2,879	2,863	2,910	2,913	2,660	2,699	2,708	2,726	2,799	2,782	2,823	36,761
Storage Fix Cost	8,415	8,404	9,151	11,360	12,606	12,774	13,302	14,119	14,777	15,566	15,859	15,859	15,859	15,859	15,859	15,859	22,754	26,132	26,132	26,132	191,229
Storage Var Cost	158	137	147	181	115	138	183	103	146	144	150	152	149	151	153	155	154	156	158	157	1,956
System Cost	247,013	271,252	288,023	301,963	308,576	313,035	330,983	349,660	364,832	363,348	373,281	385,698	393,163	405,432	415,020	421,023	430,182	437,910	440,111	445,364	4,582,079
Carbon Policy Cost	-	5,401	5,775	6,201	6,596	49,218	52,108	55,437	58,370	61,764	65,351	69,500	73,155	77,400	81,893	87,103	91,684	97,014	102,654	109,197	639,061

Scenario 2	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036
Mist Recall	0	2,199	2,199	30,862	106,139	120,310	120,310	141,930	164,731	180,467	204,946	204,946	204,946	204,946	204,946	204,946	204,946	204,946	204,946	204,946
ChristensenComp	0	0	0	0	0	0	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
NMist2A	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50,000	50,000	50,000
NMist2B	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PacConn	0	0	0	0	0	0	0	0	0	0	0	0	0	30,681	30,681	30,681	30,681	30,681	30,681	30,681
SumLoc	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SumReg	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TrailWest	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Scenario 3	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036	NPV ($000)
Supply Variable Costs	154,731	178,700	194,695	206,297	211,789	216,041	230,194	248,121	262,584	260,290	269,940	282,308	289,774	297,778	307,385	313,360	315,630	319,824	322,044	328,927	3,243,419
Transport Fix Cost	83,239	83,729	83,951	84,143	84,352	84,553	87,925	88,104	88,346	88,586	88,822	89,358	89,904	96,441	96,585	96,719	97,121	97,264	97,399	97,560	1,169,187
Transport Var Cost	2,718	2,720	2,739	2,834	2,775	2,790	2,835	2,848	2,857	2,879	2,863	2,910	2,913	2,933	2,954	2,990	2,974	3,013	3,030	3,052	37,581
Storage Fix Cost	8,415	8,404	9,151	11,360	12,606	12,774	13,302	14,119	14,777	15,566	15,859	15,859	15,859	15,859	15,859	15,859	22,754	26,132	26,132	26,132	191,229
Storage Var Cost	158	137	147	181	115	138	183	103	146	144	150	152	149	151	153	155	154	156	158	157	1,956
System Cost	247,013	271,252	288,023	301,963	308,576	313,035	330,983	349,660	364,832	363,348	373,281	385,699	393,163	407,693	417,323	423,336	432,484	440,095	442,334	449,239	4,590,116
Carbon Policy Cost	-	5,401	5,775	6,201	6,596	49,218	52,108	55,437	58,370	61,764	65,351	69,500	73,155	77,400	81,893	87,103	91,684	97,014	102,654	109,197	639,061

Scenario 3	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036
Mist Recall	0	2,200	2,200	30,863	106,140	120,310	120,310	141,930	164,731	180,467	204,985	204,985	204,985	204,985	204,985	204,985	204,985	204,985	204,985	204,985
ChristensenComp	0	0	0	0	0	0	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
NMist2A	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50,000	50,000	50,000
NMist2B	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PacConn	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SumLoc	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SumReg	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TrailWest	0	0	0	0	0	0	0	0	0	0	0	0	0	30,681	30,681	30,681	30,681	30,681	30,681	30,681

Scenario 4	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036	NPV ($000)
Supply Variable Costs	154,731	178,700	194,695	206,297	211,789	216,041	230,194	248,121	262,584	260,290	269,940	282,308	289,774	297,708	307,300	313,298	315,535	319,747	321,988	328,865	3,243,182
Transport Fix Cost	83,239	83,729	83,951	84,143	84,352	84,554	87,926	88,106	88,347	88,587	88,823	89,359	89,905	96,098	96,242	96,376	96,778	96,921	97,056	97,216	1,168,074
Transport Var Cost	2,718	2,720	2,739	2,834	2,775	2,790	2,835	2,848	2,857	2,879	2,863	2,910	2,913	2,933	2,948	2,981	2,969	3,004	3,024	3,051	37,565
Storage Fix Cost	8,415	8,404	9,151	11,360	12,606	12,774	13,302	14,119	14,777	15,566	15,859	15,859	15,859	15,859	15,859	15,859	22,754	26,132	26,132	26,132	191,229
Storage Var Cost	158	137	147	181	115	138	183	103	146	144	150	152	149	151	153	155	154	156	158	157	1,956
System Cost	247,013	271,252	288,023	301,963	308,577	313,035	330,983	349,660	364,833	363,348	373,281	385,699	393,163	410,975	420,584	426,618	435,736	443,363	445,625	452,528	4,600,796
Carbon Policy Cost	-	5,401	5,775	6,201	6,596	49,218	52,108	55,437	58,370	61,764	65,351	69,500	73,155	77,400	81,893	87,103	91,684	97,014	102,654	109,197	639,061

Scenario 4	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036
Mist Recall	0	2,200	2,200	30,863	106,140	120,310	120,310	141,930	164,731	180,466	205,773	212,562	212,562	212,562	212,562	212,562	212,562	212,562	212,562	212,562
ChristensenComp	0	0	0	0	0	0	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
NMist2A	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50,000	50,000	50,000
NMist2B	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PacConn	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SumLoc	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SumReg	0	0	0	0	0	0	0	0	0	0	0	0	0	30,681	30,681	30,681	30,681	30,681	30,681	30,681
TrailWest	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Scenario 5	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036	NPV ($000)
Supply Variable Costs	156,622	181,450	200,275	212,959	218,572	227,656	239,735	259,071	275,710	274,205	287,402	301,504	311,674	320,767	332,856	340,857	346,532	350,907	354,749	364,477	3,435,689
Transport Fix Cost	83,272	83,860	84,222	84,482	84,765	88,214	88,478	89,042	89,861	90,086	90,302	111,392	111,609	111,820	112,022	112,212	112,483	112,733	112,980	113,293	1,252,795
Transport Var Cost	2,744	2,760	2,804	2,911	2,848	2,911	2,932	2,955	2,974	3,004	3,017	3,082	3,103	3,127	3,161	3,207	3,222	3,256	3,289	3,333	39,299
Storage Fix Cost	8,692	8,817	9,821	12,450	13,653	14,639	15,492	15,691	22,585	25,962	25,962	25,962	30,386	32,553	32,553	32,553	33,043	33,283	33,283	33,283	270,383
Storage Var Cost	207	207	213	252	177	206	231	199	216	217	207	224	243	211	233	237	236	238	242	242	2,886
System Cost	251,538	277,093	297,335	313,054	320,014	333,625	346,868	366,958	391,348	393,475	406,890	442,164	457,015	468,477	480,826	489,066	495,516	500,417	504,543	514,628	5,001,053
Carbon Policy Cost	-	5,490	5,956	6,451	6,918	50,864	54,119	57,854	61,207	65,069	69,167	73,890	78,127	83,023	88,222	94,228	99,602	105,822	112,426	120,056	681,893

Scenario 5	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036
Mist Recall	0	11,316	11,316	52,693	139,963	146,458	183,614	200,300	200,300	200,300	200,300	200,300	200,300	200,300	200,300	200,300	200,300	220,300	220,300	220,300
ChristensenComp	0	0	0	0	0	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
NMist2A	0	0	0	0	0	0	0	0	0	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
NMist2B	0	0	0	0	0	0	0	0	0	0	0	0	0	50,000	50,000	50,000	50,000	50,000	50,000	50,000
PacConn	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SumLoc	0	0	0	0	0	0	0	0	0	0	0	54,253	54,253	54,253	54,253	54,253	54,253	54,253	54,253	54,253
SumReg	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TrailWest	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Scenario 6	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036	NPV ($000)
Supply Variable Costs	155,103	177,958	190,837	202,353	207,049	210,740	220,555	238,792	251,635	247,546	256,940	268,017	274,450	279,014	286,708	291,308	291,726	294,030	294,838	298,458	3,095,872
Transport Fix Cost	83,203	83,585	83,678	83,793	83,924	84,048	84,165	84,268	84,382	84,486	84,588	84,680	84,822	84,985	85,258	88,508	88,593	88,667	88,742	88,816	1,117,733
Transport Var Cost	2,723	2,713	2,696	2,789	2,724	2,736	2,739	2,759	2,756	2,761	2,744	2,784	2,782	2,774	2,773	2,798	2,770	2,797	2,804	2,809	36,259
Storage Fix Cost	8,415	8,404	8,522	10,292	11,348	11,653	11,935	12,216	12,602	13,075	13,476	13,878	14,382	14,658	14,707	14,790	14,832	14,832	14,832	14,832	159,142
Storage Var Cost	215	196	204	224	185	199	194	198	198	198	187	201	216	190	206	207	205	206	207	206	2,659
System Cost	247,448	270,563	283,550	296,948	302,597	306,620	316,715	335,257	348,482	344,872	354,639	366,172	373,121	377,927	385,684	393,572	394,002	396,333	397,150	400,774	4,370,833
Carbon Policy Cost	-	5,318	5,609	5,972	6,300	47,658	50,208	53,156	55,696	58,653	61,763	65,379	68,493	72,134	75,971	80,443	84,291	88,798	93,550	99,092	598,963

Scenario 6	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036
Mist Recall	0	0	0	5,193	75,141	84,120	92,302	99,848	107,681	119,633	133,072	142,892	154,494	169,345	173,366	173,366	176,793	176,793	176,793	176,793
ChristensenComp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	40,000	40,000	40,000	40,000	40,000
NMist2A	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NMist2B	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PacConn	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SumLoc	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SumReg	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TrailWest	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Scenario 7	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036	NPV($000)
Supply Variable Costs	154,731	178,700	194,695	201,117	216,673	217,237	229,162	247,874	262,463	259,477	270,157	283,582	292,265	299,755	307,625	316,822	315,113	319,342	321,721	327,891	3,246,492
Transport Fix Cost	83,239	83,729	83,951	84,143	84,341	87,678	87,873	88,117	88,381	88,908	89,480	92,803	92,961	93,108	93,253	93,717	93,864	94,002	94,137	94,297	1,165,412
Transport Var Cost	2,718	2,720	2,739	2,772	2,820	2,730	2,757	2,735	2,805	2,802	2,773	2,782	2,768	2,759	2,761	2,821	2,796	2,841	2,880	2,908	36,526
Storage Fix Cost	8,415	8,404	9,151	9,515	11,180	12,323	12,793	13,242	13,675	14,093	14,229	14,518	15,212	16,032	16,381	23,315	26,692	26,692	26,692	26,692	189,745
Storage Var Cost	158	137	147	163	136	138	162	119	142	144	147	148	155	147	155	156	154	156	158	157	1,951
System Cost	249,261	273,690	290,683	297,710	315,151	320,107	332,747	352,088	367,466	365,424	376,786	393,834	403,361	411,802	420,174	436,831	438,621	443,033	445,587	451,945	4,640,127
Total Carbon Cost	-	5,401	5,775	6,201	6,596	49,218	52,108	55,437	58,370	61,764	65,351	69,500	73,155	77,400	81,893	87,103	91,684	97,014	102,654	109,197	639,061

Scenario 7	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036
Mist Recall	0	2,200	2,200	30,863	30,863	98,976	112,377	125,045	137,219	148,931	160,282	160,282	172,076	194,632	217,069	220,300	220,300	220,300	220,300	220,300
ChristensenComp	0	0	0	0	0	0	0	0	0	0	0	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
NMist2A	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50,000	50,000	50,000	50,000
NMist2B	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PacConn	0	0	0	0	0	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335
SumLoc	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SumReg	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TrailWest	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Scenario 8	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036	NPV($000)
Supply Variable Costs	154,731	178,700	194,695	205,914	211,212	216,624	229,249	246,830	261,686	259,564	272,124	284,247	291,870	299,900	307,338	313,289	315,681	319,804	322,048	328,908	3,245,115
Transport Fix Cost	83,239	83,729	83,951	84,143	84,352	88,974	89,150	89,328	92,675	92,834	92,990	93,135	93,492	94,000	94,495	94,966	95,120	95,257	95,392	95,553	1,180,290
Transport Var Cost	2,718	2,720	2,739	2,829	2,769	2,795	2,825	2,834	2,844	2,869	2,878	2,925	2,929	2,950	2,948	2,982	2,970	3,004	3,023	3,050	37,562
Storage Fix Cost	8,415	8,404	9,151	11,360	12,259	12,409	12,792	12,943	12,942	13,205	13,836	14,559	15,266	16,053	16,324	23,220	26,661	26,692	26,692	26,692	190,743
Storage Var Cost	158	137	147	159	137	138	167	119	146	144	151	152	154	156	159	161	154	156	158	157	1,967
System Cost	249,261	273,690	290,683	304,405	310,729	320,940	334,183	352,053	370,293	368,616	381,979	395,019	403,710	413,060	421,265	434,617	440,585	444,913	447,312	454,359	4,655,677
Total Carbon Cost	-	5,401	5,775	6,201	6,596	49,218	52,108	55,437	58,370	61,764	65,351	69,500	73,155	77,400	81,893	87,103	91,684	97,014	102,654	109,197	639,061

Scenario 8	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036
Mist Recall	0	2,200	2,200	30,863	106,140	106,140	112,377	125,006	125,006	125,006	135,770	156,262	175,743	195,042	217,691	217,691	217,691	220,300	220,300	220,300
ChristensenComp	0	0	0	0	0	0	0	0	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
NMist2A	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50,000	50,000	50,000	50,000
NMist2B	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PacConn	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SumLoc	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SumReg	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TrailWest	0	0	0	0	0	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335

Scenario 9	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036	NPV($000)
Supply Variable Costs	154,731	178,700	194,695	205,914	211,167	216,335	227,981	246,917	261,262	259,161	271,566	284,004	291,881	299,556	307,238	313,191	315,568	319,643	321,927	328,789	3,242,425
Transport Fix Cost	83,239	83,729	83,951	84,143	84,352	88,735	88,911	89,089	92,436	92,595	92,751	92,897	93,253	93,762	94,256	94,728	94,881	95,018	95,153	95,314	1,178,234
Transport Var Cost	2,718	2,720	2,739	2,829	2,768	2,799	2,817	2,839	2,845	2,871	2,878	2,925	2,931	2,948	2,949	2,982	2,970	3,005	3,024	3,051	37,565
Storage Fix Cost	8,415	8,404	9,151	11,360	12,259	12,409	12,792	12,943	12,942	13,225	13,866	14,588	15,293	16,077	16,349	23,244	26,669	26,692	26,692	26,692	190,847
Storage Var Cost	158	137	147	159	136	151	140	141	142	144	147	148	160	143	155	157	154	156	158	157	1,958
System Cost	249,261	273,690	290,683	304,405	310,683	320,429	332,641	351,929	369,627	367,996	381,208	394,562	403,518	412,486	420,946	434,301	440,242	444,514	446,954	454,003	4,651,029
Total Carbon Cost	-	5,401	5,775	6,201	6,596	49,218	52,108	55,437	58,370	61,764	65,351	69,500	73,155	77,400	81,893	87,103	91,684	97,014	102,654	109,197	639,061

Scenario 9	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036
Mist Recall	0	2,200	2,200	30,863	106,140	106,140	112,377	125,006	125,006	125,006	136,565	157,084	176,509	195,751	218,354	218,354	218,354	220,300	220,300	220,300
ChristensenComp	0	0	0	0	0	0	0	0	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
NMist2A	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50,000	50,000	50,000	50,000
NMist2B	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PacConn	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SumLoc	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SumReg	0	0	0	0	0	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335	21,335
TrailWest	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Appendix 10
Public Participation

NW NATURAL 2016 INTEGRATED RESOURCE PLAN (IRP)
January 13, 2016

NAME	COMPANY	EMAIL
Steve Nelson	NW Natural	sen@nwnatural.com
Lance Kaufman	OPUC	lance.kaufman@state.or.us
Lisa Gorsuch	OPUC	lisa.gorsuch@state.or.us
Suparna Bhattacharya	OPUC	suparna.bhattacharya@state.or.us
Nadine Hanhan	CUB	nadine@oregoncub.org
Sommer Moser	CUB	sommer@oregoncub.org
Erica Nist-Lund	CUB	erica@oregoncub.org
Teresa Hagins	Williams - Northwest Pipeline	Teresa.L.Hagins@williams.com
Mark Thompson	NW Natural	mrt@nwnatural.com
Andy Hudson	Energy Trust of Oregon	andrew.hudson@energytrust.org
JP Batmale	ETO	jp.batmale@energytrust.org
Chris Galati	NWN	cfg@nwnatural.com
Zach Kravitz	NWN	zdk@nwnatural.com
Randy Friedman	NWN	randy.friedman@nwnatural.com
Brian Robertson	Cascade Natural Gas	Brian.Robertson@cngc.com
Keith White	NWN	jkw@nwnatural.com
Doug Tilgner	NWN	dlt@nwnatural.com
Dave Lenar	NWN	dpl@nwnatural.com
Steve Storm	NWN	steve.storm@nwnatural.com
Ryan Bracken	NWN	rjb@nwnatural.com
Brad Cebulko	WUTC	bcebulko@utc.wa.gov
Jennifer Snyder	WUTC	jsnyder@utc.wa.gov
Dan Kirschner	NW Gas Association	dkirschner@nwga.org

Attendees via WebEx/Phone: Ed Finklea, Erik Colville, Tom Pardee, Yochi Zakai

NW NATURAL 2016 INTEGRATED RESOURCE PLAN (IRP)
February 10, 2016

NAME	COMPANY	EMAIL
Tammy S. Linver	NW Nat'l	tsl@nwnatural.com
Gail Hammer	NW Natural	gail.hammer@nwnatural.
Steve Storm	NW Natural	steve.storm@nwnatural.com
Dave Lenar	NW Natural	dpl@nwnatural.com
Ryan Bracken	NW Natural	rjb@nwnatural.com
Doug Tilgner	NW Natural	dlt@nwnatural.com
Zach Kravitz	NW Natural	zdk@nwnatural.com
Shauna Brownstein	NW Natural	ssb@nwnatural.com
David White	TransCanada	david_white@transcanada.com
LISA GORSUCH	OREGON PUC	lisa.gorsuch@state.or.us
Mike Weirich	DOJ / PUC	michael.weirich@state.or.us
Jennifer Snyder	WUTC	~~[illegible]~~ jsnyder@utc.wa.gov
Andy Hudson	Energy Trust	andrew.hudson@energytrust.org
Andy Fortier	NW Natural	amf@nwnatural.com
Randy Friedman	NW Natural	randy.friedman@nwnatural.com
Scott Johnson	NW Natural	szj@nwnatural.com
Chris McGuire	WUTC	cmcguire@utc.wa.gov
Yochi Zakai	WUTC	yzakai@utc.wa.gov
Nadine Hanhan	CUB	~~[illegible]~~ nadine@oregoncub.org
Suparna Bhattacharya	OPUC	suparna.bhattacharya.state.or.us
Max St. Brown	OPUC	max.st.brown@state.or.us
David Weber	NW Natural Gas Storage	DAW@NWNATURAL.COM

Attendees via WebEx/Phone: Ed Finklea, Erik Colville, Brian Robertson, Tom Pardee, Mark Sellers-Vaughn

NW NATURAL 2016 INTEGRATED RESOURCE PLAN (IRP)
March 17, 2016

NAME	COMPANY	EMAIL
Tammy S. Linver	NW Nat'l	tsl@nwnatural.com
Ryan Bracken	NWN	rjb@nwnatural.com
Dave Lenar	NWN	dpl@nwnatural.com
Steve Storm	NWN	sgs@nwnatural.com
Shanna Brownstein	NWN	SSB@NWNatural.com
Mary Moerlins	NWN	mom@nwnatural
Teresa Hagins	Northwest Pipeline	Teresa.L.Hagins@williams.com
Doug Tilgner	NWN	dlt@nwnatural.com
Keith White	NWN	jkw@nwnatural.com
Connor Reiten	NWGA	creiten@nwga.org
Mike Weirich	DOJ/PUC	michael.weirich@state.or.us
Suparna Bhattacharya	OPUC	suparna.bhattacharya@state.or.us
LISA GORSUCH	OREGON PUC STAFF	lisa.gorsuch@state.or.us
MAX ST. BROWN	OREGON PUC STAFF	max.st.brown@state.or.us
Jason Salmi Klotz	" " "	Jason.Klotz@state.or.us
J P BATMALE	ENERGY TRUST of OREGON	jp.batmale@energytrust.org
Jennifer Snyder	UTC	jsnyder@utc.wa.gov
Brad Cebulko	WUTC	bcebulko@utc.wa.gov
Nadine Hanhan	CUB	nadine@oregoncub.org
Bill Edmonds	NWN	wre@nwnatural.com
Andy Hudson	Energy Trust	andrew.hudson@energytrust.org
Gail Hammer	NW Natural	gail.hammer@nwnatural.com

Attendees via WebEx/Phone: Ed Finklea, Erik Colville, Brian Robertson, Tom Pardee, Mark Sellers-Vaughn

NW NATURAL 2016 INTEGRATED RESOURCE PLAN (IRP)
May 24, 2016

NAME	COMPANY	EMAIL
Tommy S. Linver	NW Natural	tsl@nwnatural.com
Gail Hemmer	NW Natural	gth@nwnatural.com
Steve Storm	NW Natural	steve.storm@nwnatural.com
Teresa Hagins	Northwest Pipeline	Teresa.L.Hagins@williams.com
Ryan Bracken	NW Natural	ryan.bracken@nwnatural.com
Dave Lenar	NW Natural	dpl@nwnatural.com
Keith White	NW Natural	jkw@nwnatural.com
Dave Santen	NW Natural	d2s@nwnatural.com
Connor Reiten	NW Gas Association	creiten@nwga.org
LISA GORSUCH	OREGON PUC	lisa.gorsuch@state.or.us
Max St. Brown	Oregon PUC	max.st.brown@state.or.us
Mike Weirich	DOJ / PUC	michael.weirich@state.or.us
Andy Fortier	NW Natural	amf@nwnatural.com
Doug Tilgner	NW Natural	dlt@nwnatural.com
Jennifer Snyder	WUTC	jsnyder@utc.wa.gov
Randy Friedman	NW Natural	randy.friedman@nwnatural.com
Nadine Hanhan	CUB	nadine@oregoncub.org
Gary Bauer	NW NATURAL	GHB@NWNATURAL.COM
Steve Nelson	NWN	sln@nwnatural.com

Attendees via WebEx/Phone: Ed Finklea, Erik Colville, Tom Pardee, Lance Kaufman, Ben Fitch-Fleischmann

NW NATURAL 2016 INTEGRATED RESOURCE PLAN (IRP)
June 22, 2016

NAME	COMPANY	EMAIL
Tamil S. Linver	NW Natural	tsl@nwnatural.com
Gail Hammer	NW Natural	gail.hammer@nwnatural.com
Dave Lenar	NW Natural	dple@nwnatural.com
Steve Storm	NWN	steve.storm@nwnatural.com
Ryan Bracken	NWN	rjb@nwnatural.com
Bill Edmonds	NWN	wre@nwnatural.com
Mary Moerlins	NWN	mom@nwnatural.com
LISA GORSUCH	OPUC STAFF	lisa.gorsuch@state.or.us
Connor Reiten	NW Gas Association	Creiten@nwga.org
Dan Kirschner	"	dkirschner@nwga.org
Teresa Hagins	Northwest Pipeline LLC	Teresa.L.Hagins@williams.com
Jennifer Snyder	UTC	jsnyder@utc.wa.gov
David Nightingale	WUTC	dnightin@utc.wa.gov
Doug Tilgner	NWN	dlt@nwnatural.com
Randy Friedman	NWN	randy.friedman@nwnatural.com
Mike Goetz	CUB	mike@oregoncub.org
Katelyn Fulton	CUB	katelyn@oregoncub.org
Nadine Hanhan	CUB	nadine@oregoncub.org
Anne-Marie Posstinen	NWN	a1p@nwnatural.com
ZACH KRAVITZ	NWN	zdk@nwnatural.com
Andy Fortier	NWN	amf@ "
Andy Hudson	Energy Trust	andrew.hudson@energytrust.org
Spencer Moersfelder	Energy Trust	spencer.moersfelder@energytrust.org
ADAM SHICK	ENERGY TRUST	adam.shick@energytrust.org

Attendees via WebEx/Phone: Ed Finklea, Erik Colville, Max St. Brown, Tom Pardee

NW NATURAL 2016 INTEGRATED RESOURCE PLAN (IRP) PUBLIC MEETING
July 20, 2016

NAME	COMPANY	EMAIL
Gail Hammer	NW Natural	gail.hammer@nwnatural.com
Doug Tilgner	NW Natural	Doug.Tilgner@nwnatural.com
Tamy S. Linver	NW Natural	TSL@nwnatural.com
Ryan Bracken	NW Natural	rjb@nwnatural.com
Dave Lenar	NW Natural	dpl@nwnatural
Andy Fortier	NWN	amf@ "

NW NATURAL'S 2016 INTEGRATED RESOURCE PLAN (IRP)

The IRP being developed this year answers questions like: How much gas will our customers use? How much energy can we save through conservation? Where will NW Natural get its gas supply?

We invite you to join us for a discussion of these and other topics to help us develop the IRP:

Date: Wednesday, July 20, 2016
Time: 6 p.m. to 7 p.m.
Place: One Pacific Square, 4th Floor Hospitality Room Center
220 NW Second Avenue, Portland, Oregon (accessible by MAX)

NW Natural®

You may also mail any questions or comments about the plan to:

NW Natural
Attn: Integrated Resource Plan
220 NW Second Avenue
Portland, OR 97209

A copy of the draft 2016 Integrated Resource Plan will be available on our website by June 30, 2016.
Go to **nwnatural.com**. Click on the *About Us* link, then click on *Rates and Regulations*, then click on *Regulatory Activities*. Toward the bottom half of the page is a link for the *Integrated Resource Plan.*

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