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September 1, 2011

VIA ELECTRONIC FILING

Dave Danner
Secretary & Executive Director
Washington Utilities & Transportation Commission
1300 S Evergreen Park Drive SW
Post Office Box 47250
Olympia, Washington 98504-7250

Re: **UG-100245,** NW Natural's 2011 Modified Integrated Resource Plan

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or "Company"), hereby submits an original and ten copies of its 2011 Modified Integrated Resource Plan, which meets the requirements established in Washington Administrative Code ("WAC") 480-90-238.

If you have any questions regarding this plan, please contact me at (503) 721-2476.

Sincerely,

Mark R. Thompson
Manager, Rates and Regulatory Affairs

Enclosure

2011 Modified

Integrated Resource Plan

NW Natural®

2011 Modified Integrated Resource Plan

NW Natural®

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Chapter 1: Executive Summary

NW Natural®

I. INTRODUCTION AND BACKGROUND

A. Executive Summary and Multi Year Action Plan

This Executive Summary provides an overview of NW Natural's key findings in its 2011 Integrated Resource Plan (IRP) and includes a multi-year action plan. Both the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC) require NW Natural to develop a long-term resource plan every two years.[1] The IRP defines the mix of natural gas supply and conservation designated to meet expected future demand requirements at the lowest reasonable cost to the utility and its ratepayers. NW Natural filed the 2008 IRP with the OPUC on April 15, 2008 and with the WUTC on April 21, 2008.[2] An update to that plan, referred to as the 2009 Annual Update, was provided to the OPUC on January 8, 2010.[3] NW Natural filed its 2009 IRP with the WUTC on March 31, 2009.[4]

B. Description of NW Natural

NW Natural is a 151 year old natural gas local distribution and storage company headquartered in Portland, Oregon, which serves more than 667,000 customers in Oregon and Washington. The service territory includes the Portland-Vancouver metropolitan area, the Willamette Valley, the Oregon Coast from Astoria down through Coos County, the Columbia River Gorge and portions of three counties in Southwest Washington – Clark, Skamania and Klickitat. Approximately 60% of the customers reside in the Portland area, with another 10% in Vancouver WA. Residential customers comprise roughly 90% of the customer base, with commercial at 9% and industrial less than 1%.

FIGURE 1.1 – NW Natural's Service Territory

1 *See* OAR 860-027-0400(3) and WAC 480-90-238(4)
2 *See* OPUC Docket No. LC 45 and WUTC Docket No. 070619.
3 *See* OPUC Docket No. LC 45.
4 *See* WUTC Docket No. UG-080912

C. Overview of Integrated Resource Planning

Integrated Resource Planning is unique to regulated utilities. Oregon and Washington regulators require seven key components. NW Natural's IRP must: 1) examine a range of demand forecasts; 2) examine all feasible means of meeting demand, including traditional supply-side, as well as demand-side, resources; 3) treat supply-side and demand-side resources equally; 4) describe the Company's long-term plan for meeting expected load growth; 5) describe its plan for resource acquisitions between planning cycles; 6) take uncertainties in planning into account; and 7) involve the public in the planning process. These guidelines are delineated for Oregon in Orders No, 07-002 and 07-0047, and in Washington, in WAC 480-90-238.

D. IRP Modification

The 2011 IRP was filed with the state of Oregon on January 12, 2011, and with Washington on March 31, 2011. The proposed Palomar East Cross-Cascades Pipeline was a component of the plan. On March 23, 2011, Palomar Gas Transmission LLC withdrew its application with the Federal Energy Regulatory Commission (FERC) for the pipeline and simultaneously stated its expectation of re-filing for an application at a later date. In addition, new estimates of pipeline rates and service dates for a modified pipeline project called Palomar/Blue Bridge were presented at a public workshop jointly sponsored by the Public Utility Commission of Oregon and the Washington Utility and Transportation Commission on February 3,2011. In April, NW Natural proposed modifying the 2011 IRP in order to evaluate the proposed Cross-Cascades Pipeline with the rate and service date changes, and to perform further resource analysis should the pipeline not materialize in the future at all. Additional resource modeling was performed and the results were presented and discussed at the 5th Technical Working Group Meeting on June 22, 2011.

II. PRINCIPLE CONCLUSIONS

The IRP serves as an important guide for determining how NW Natural intends to serve a growing region with reliable, low cost energy supplies. With this in mind, the Company has come to the following principal conclusions:

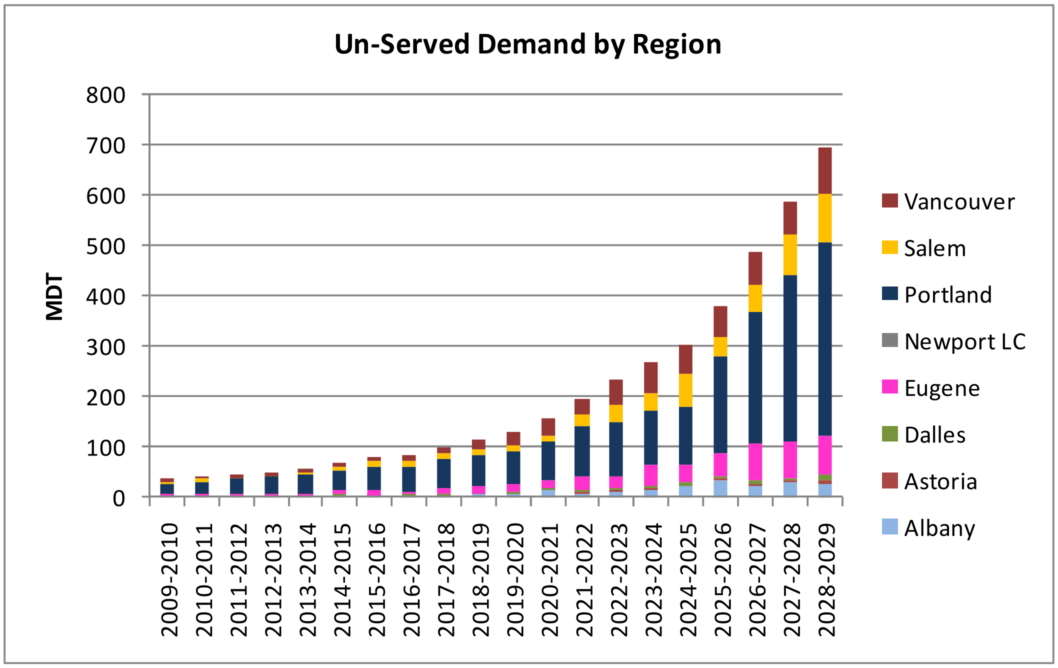
1. The continued economic downturn has impacted the load forecast and resulted in slow customer growth across NW Natural's service area. New construction in the residential and commercial sectors remains sluggish and industrial natural gas usage has dropped. The average annual customer growth rate for the entire planning horizon is projected to be 1.84%, while load is expected to grow annually by an average of 0.61%.

2. Natural gas supply costs are forecast to remain lower than the previous Plan's forecast. The demand dampening effects of the economic slump coupled with plentiful gas supply from increased shale production continue to keep prices low.

3. Even with lower demand forecasts, the Company's existing resources are not sufficient to fully satisfy forecast peak day demand. Figure 1.2 displays the projected resource deficiencies by region

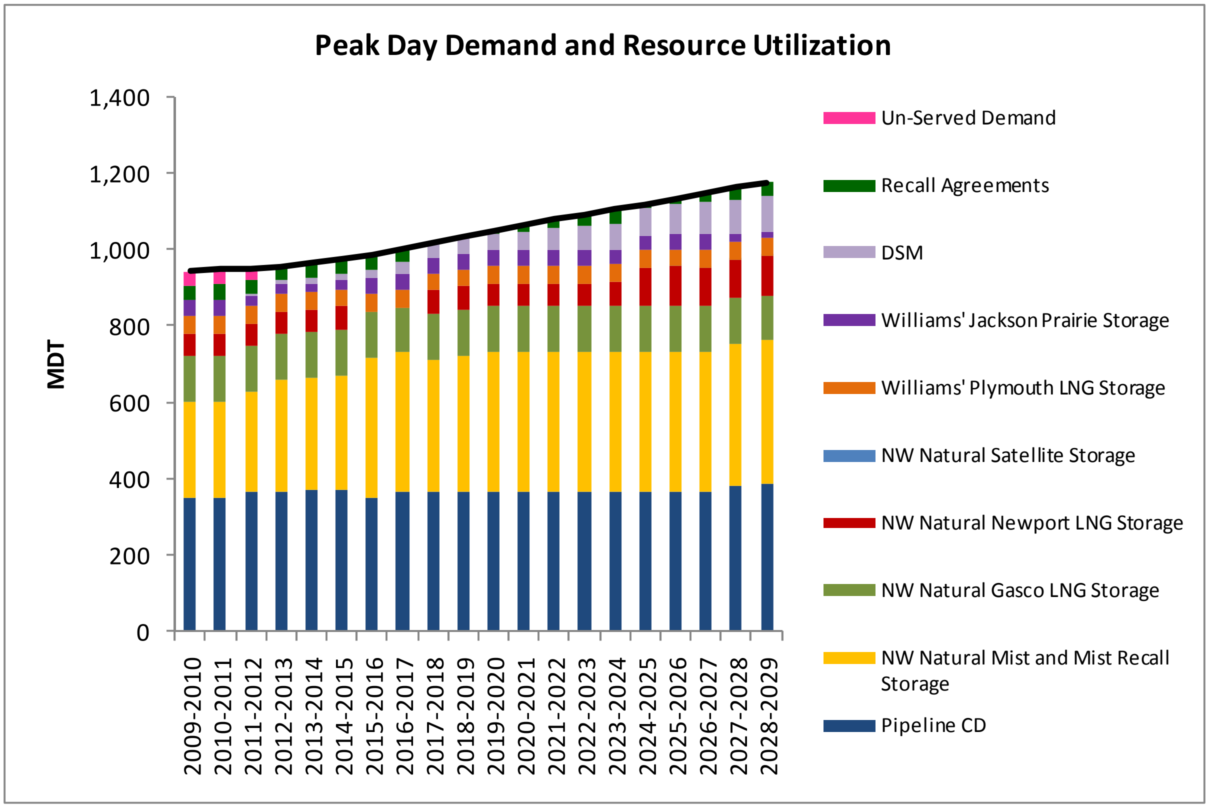
in thousands of dekatherms, assuming no new resources are added to the system. The previously planned projects North Willamette Valley Feeder and Harrisburg River Crossing are included.

FIGURE 1.2 – Un-served Demand by Region



4. The Company's Base Case resource plan address the forecasted gap in service with a mixture of incremental supply-side and demand-side resources. Figure 1.3 depicts the blend of resources that are selected to serve the peak day demand forecast. The Base Case planning path was developed around the assumption that the Palomar/Blue Bridge Cross-Cascades Pipeline is not built. For this plan, in addition to demand-side resources, incremental storage capacity at Mist Storage would be added to the system at various future times, and a new capacity project would be required in the Willamette Valley by 2025. A preferred planning path assumes that the proposed Palomar/Blue Bridge Pipeline is in service beginning in 2017 and additional pipeline capacity is then added to the system. Like the Base Case, additional resources are required in the Willamette Valley beginning in 2026 for this plan. Both planning cases rely on demand-side management savings that reach 10% of demand by 2024/2025. The resource decisions leading up to the year 2017 are identical for the Base Case and the preferred path. As a result, no decision needs to be made right now as to which path to take. Initial modeling and analysis has shown that a future which includes a new Cross-Cascades Pipeline such as the proposed Palomar/Blue Bridge project would increase both reliability and diversity of supply at an additional overall cost ranging from 0.3% to 0.6% over the Base Case.

FIGURE 1.3 – Peak Day Demand and Resource Utilization



III. LOAD FORECASTS

To determine the daily energy requirements for the Company's service area, NW Natural must first generate a load forecast. The forecast incorporates economic trends, supply prices, weather, and natural gas use trends. The load forecast is not intended to predict actual usage during an average or normal winter; rather it is designed to accurately project usage under a design year weather pattern – a much colder than normal winter augmented with the coldest peak event in the past 20 years. Space heating for residential and commercial customers comprises the bulk of demand.

The first step in developing the load forecast is to identify the characteristics of NW Natural's customer base. This includes the number and types of current customers, the amount of customer growth anticipated in each region, and the amount and pattern of natural gas usage expected by those customers. For this IRP, a blend of near term and long term economic outlooks is used to forecast customer growth over the planning horizon. The near term portion is based on recent Company growth trends as well as regional economic data from the State of Oregon Economic Forecast. The long term outlook is based on the Northwest Power and Conservation Council Plan 6 Demand Forecast,[5] as well as NW Natural customer trends. A regression model developed from recent customer usage data is used to formulate a use per customer outlook for each customer type and region.

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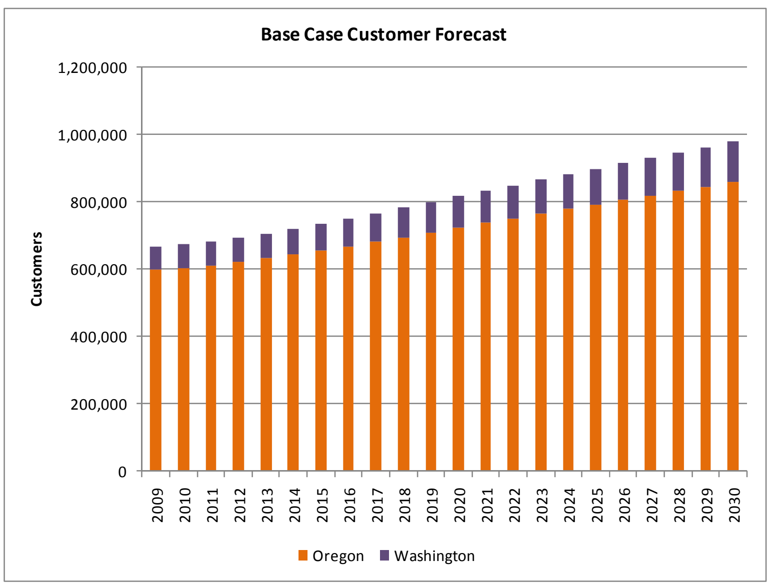
5 *See* http://www.nwcouncil.org/energy/powerplan/6/default.htm

Once the Company generates a customer count forecast and usage per customer forecast, it incorporates a design year weather pattern to generate a complete load forecast. The Company's weather pattern is designed to have a winter season which is colder than 85% of the previous 20 winter seasons. In addition, the design pattern is augmented with the coldest three day peak event in the past 20 years. The Company also develops numerous demand scenarios by varying gas supply price and customer growth rates, and utilizes Monte Carlo simulation to assess the performance of its resource plan over a range of temperature and price conditions.

NW Natural has come to the following principal conclusions with regard to load forecasts:

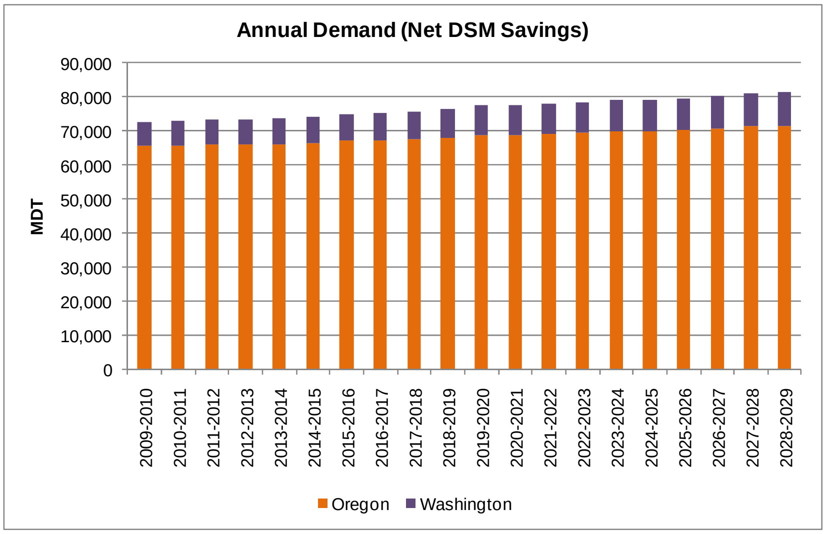
1. Current economic conditions have impacted load forecasts and slowed growth across NW Natural's service area. Customer growth is expected to remain under 2% until 2015. The average annual forecasted customer growth rate across the planning horizon for the entire service area is projected to be 1.84%; with the Oregon customer base growing at a rate of 1.73% and Washington at 2.70%. Figure 1.4 displays the number of customers expected by the end of each year.

FIGURE 1.4 – Base Case Customer Forecast



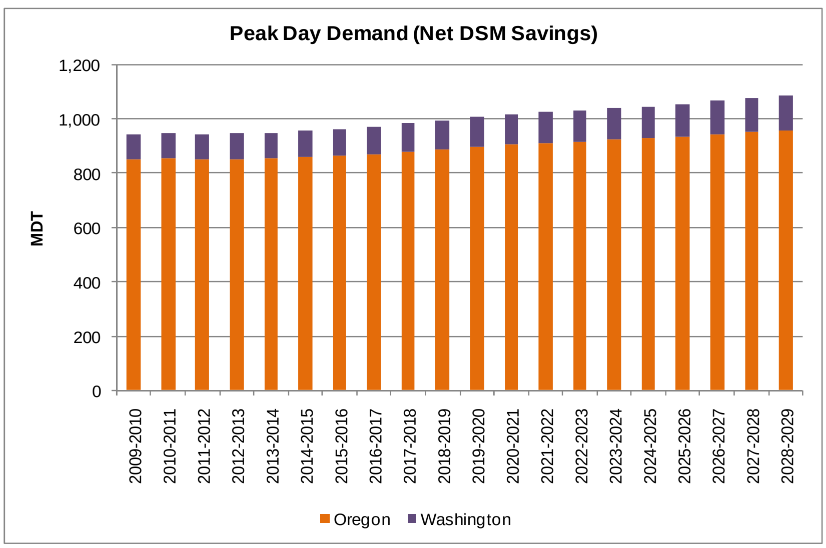
2. Annual demand growth is forecast to be lower than customer growth due to declining use per customer. Excluding Demand-Side Management (DSM) savings, annual demand is forecast to grow at an average of 1.28% over the horizon; with Oregon load growing at an average rate of 1.17% and Washington at 2.22%. Net of DSM, system-wide demand is expected to grow at an average annual rate of 0.61%. Figure 1.5 depicts the annual load forecast for this planning cycle.

FIGURE 1.5 – Annual Demand decremented for DSM savings



3. Peak Day load (net DSM savings) is expected to grow at an average annual rate of 0.74%. Oregon peak day demand growth over the planning horizon is projected to be 0.62% and Washington 1.73%.

FIGURE 1.6 – Peak Day Demand decremented for DSM savings



4. The Company's load forecasts are based on the information presently available to the Company, and are constantly being updated and amended to reflect changing economic conditions. These forecasts are not a guarantee or an absolute prediction of future performance. In today's economic climate, predicting future conditions with a high degree of reliability is particularly difficult. The Company has considered a number of potential events that may impact its base case load forecast and has developed alternative load forecasts accordingly. In addition to low and high forecasts around the base case, the Company has developed two alternative scenarios: first, a forecast resulting from a gas break-though in which a new residential use for natural gas expands demand substantially, and an electric break-through forecast where advances in clean power generation

cause large scale defection to electric space and water heat. The Company will continue to monitor economic conditions and developments in environmental legislation as it updates its future load forecasts.

IV. SUPPLY-SIDE RESOURCES

Supply-side resources include gas, gas storage, interstate pipeline capacity needed to transport the gas to NW Natural's service territory, and investments in the Company's own pipeline/distribution facilities. The gas supply planning process is based on ensuring reliable service to NW Natural's core customers.

Maintaining a variety of supply sources at the Company's disposal is the best means of ensuring reliable service. NW Natural's supply portfolio consists of both contracted natural gas supplies and supplies of stored natural gas. The Company has access to natural gas in underground storage facilities and above-ground liquefied natural gas (LNG) storage tanks. Both storage options can be used as "peaking" resources to augment the Company's upstream acquisition of gas. It is also essential for the Company to identify and act when opportunities arise, as it does during times of low demand on interstate pipelines, to get supplies in the Company's distribution system and into storage to further enhance the security of its overall supply portfolio.

NW Natural's supply requirements will increase as its firm customer population grows, but the characteristics of the increased load are key factors in the resource selection process. For example, additional water heating load can be met most efficiently by a resource that can deliver the same amount of gas year-round - a "base load" resource. Growth in heating load, on the other hand, presents seasonal demands, and is best served with a combination of "base load" and "peaking" resources.

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 supply contracts have staggered terms of up to 3 years 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.

A. Supply Diversification

Over the twenty years since NW Natural began purchasing supplies for its customers directly in the market rather than from the interstate pipeline, the Company has pursued a diversified approach to acquiring supply resources. This includes expanding gas receipt points to allow new gas supplies to be purchased from and stored in Alberta, Canada, as well as traditional supply basins in British Columbia and the U.S. Rockies. Diversification has given the Company competitive options and improved service reliability on the interstate pipeline system. NW Natural believes that the availability of supply, the large existing pipeline infrastructure in Canada, the number of industry players active in the region, and the liquidity of the market will yield reliable, market priced supplies for years to come. However, the Company is always looking for more opportunities to diversify its portfolio.

B. Recent Resource Decisions

1. Mist Storage Recall

   A portion of the capacity at the Mist Storage Facility is under contract to interstate customers. "Mist Recall" is the general term given when the Company recalls storage capacity at Miller Station in order to serve core customers. The 2008 IRP called for a recall of 10 MDT/day in 2008/2009 and an additional 30 MDT/day in 2009/2010. The Company did recall 10 MDT/day in 2008. Due to a reduction in the demand forecast, the 2009 Washington IRP only required 10 MDT/day for 2009/2010, which was recalled in 2009, and in 2011, an additional 100,000 therms per day of deliverability was recalled, along with related annual storage capacity,

2. Harrisburg River Crossing

   This small project allows an additional 8 MDT/day of supply to serve Eugene and is a key resource for meeting peak day demand in the southern Willamette Valley. This link was selected in both the 2008 and 2009 IRPs, and the project was completed in November of 2010.

3. Willamette Valley Feeder (WVF)

   This project can move supplies south from the Mist Storage facility to Salem, and eventually to Albany and Eugene, if necessary. This project was selected in the 2008 IRP. Due to a recent evaluation of Newport LNG capabilities, additional peak day resources are required for Salem, and the North section of this project, from Aurora to Brooks, is expected to be in service by November 2011.

C. Future Resource Alternatives

In this Plan, NW Natural has considered the following incremental resource additions:

1. Interstate Pipeline Capacity Additions
   a. New NWPL Grants Pass Lateral capacity serving Salem, Albany and Eugene,
   b. New capacity upstream of NWPL mainline capacity providing access to the Rockies and Alberta supply areas,
   c. New Palomar East/Blue Bridge pipeline capacity from Madras to Molalla
   d. New GTN pipeline capacity from Malin to Madras
   e. New capacity on the proposed Pacific Connector Pipeline to access re-gasified LNG from the proposed Jordan Cove LNG project at Coos Bay, Oregon.
   f. New capacity on the proposed Oregon Pipeline to access re-gasified LNG from the proposed Oregon LNG project at Warrenton Oregon.

2. NW Natural Infrastructure Enhancements
   a. Newport LNG Compressor Project - The daily deliverability of gas from NW Natural's Newport liquefied natural gas plant could be increased from 60 MDT/day to 100 MDT/day by the addition of a compressor station at Perrydale. The cost of the infrastructure addition would be about $12 million and would allow additional supply to reach Salem to serve peak day demand.

  b. Mid and South Willamette Valley Feeder – A new pipeline could move natural gas from the Mist underground storage facility south down the valley. The mid section would link Salem with Albany, and the south section would link Albany with Eugene. The project is a viable alternative to NWPL's Grants Pass Lateral and would improve reliability of the system.

  c. Satellite Storage – Small-scale LNG storage and vaporization facilities are used as peaking resources because they provide only a few days of deliverability. Where peaking demands are sharpest, the addition of satellite storage could defer significant pipeline infrastructure investments. In this IRP, NW Natural has evaluated satellite storage in three locations in the Willamette Valley (Salem, Albany and Eugene) as interim resources that might delay more expensive pipeline projects such as additions to the NWPL Grants Pass Lateral or construction of the Mid and South WVF.

3. Mist Recall: Additional storage capacity can be recalled as necessary for the core utility through time as interstate contracts roll off.

4. Imported LNG - The Company is evaluating the impact of two LNG import terminals proposed to be sited in Oregon. The Oregon LNG project proposed for Warrenton would connect to NW Natural's system at Molalla. The Jordon Cove project near Coos Bay would connect to the proposed Pacific Connector Gas Pipeline. Neither project has been constructed, and, while NW Natural included them for analysis purposes, imported LNG does not currently appear imminent given recent developments in shale gas supply. In fact, sponsors of the Jordan Cove project have proposed re-permitting their project as an export facility. Neither project is included in the base case planning portfolio.

5. The Company has come to the following principal conclusions with regard to supply-side resources:

    a. The Company's existing supplies are not sufficient to satisfy 100% of projected peak day demand. In the near term, completion of the North section of the Willamette Valley Feeder along with Mist Storage recall will help to resolve that shortfall in the northern reaches of the service area, and completion of the Harrisburg River Crossing project will help to solve supply shortages to the south.

    b. The Newport LNG facility is over 30 years old and may need to be brought down for service for an unknown period of time. NW Natural is assessing a likely timeline for taking the facility offline without disrupting peak day capacity. Once the facility is back in service, the Newport LNG Compressor project is a cost effective way to further serve peak day demand.

    c. In the longer term, additional resources will be required further down the valley. The demand requirements could be met by additional Grants Pass Lateral capacity, the Company's Satellite Storage and/or Willamette Valley Feeder pipeline, or possibly a targeted DSM approach.

    d. The Company continues to pursue strategies to improve supply path diversity, including pursuing the opportunity to take capacity on the proposed Palomar/Blue Bridge Pipeline.

This proposed Cross-Cascades Pipeline would provide an alternative for bringing gas into the Company's system, which is currently served exclusively by the Williams' pipeline. The pipeline would also increase system reliability.

e. NW Natural's supply acquisition strategy will rely on transporting gas with pricing negotiated at market rates on an annual, seasonal, or monthly basis.

V. DEMAND-SIDE RESOURCES

Public purpose funds are collected from Oregon ratepayers and are used by the Energy Trust of Oregon (Energy Trust) to finance energy efficiency investments. In 2009, the Energy Trust saved 2.57 million therms, meeting the IRP target for Oregon DSM programs. In 2009, a new energy efficiency program administered by Energy Trust was implemented in Washington and saved approximately 120,000 therms. The Company's reliance on demand-side management continues to escalate. Figures 1.7 and 1.8 depict DSM achievable annual cumulative savings for this IRP cycle.

FIGURE 1.7 – Oregon Cumulative DSM Savings Projections

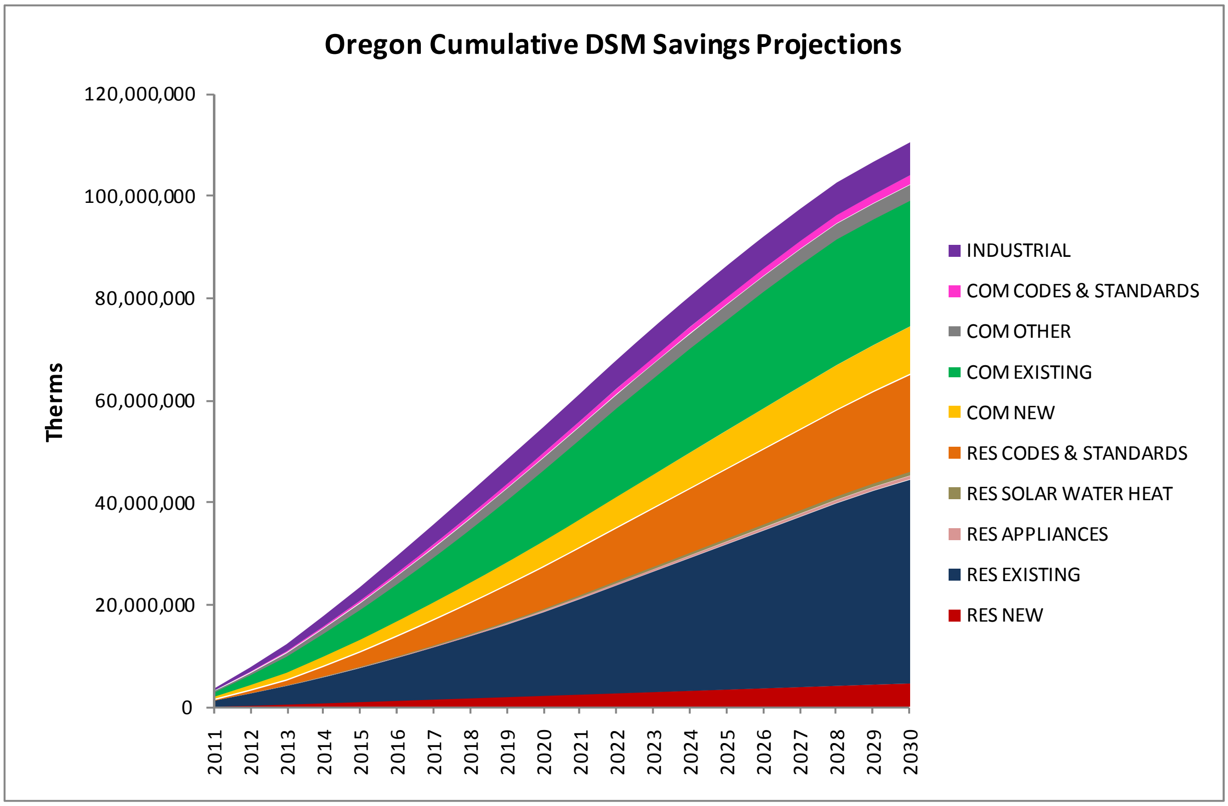
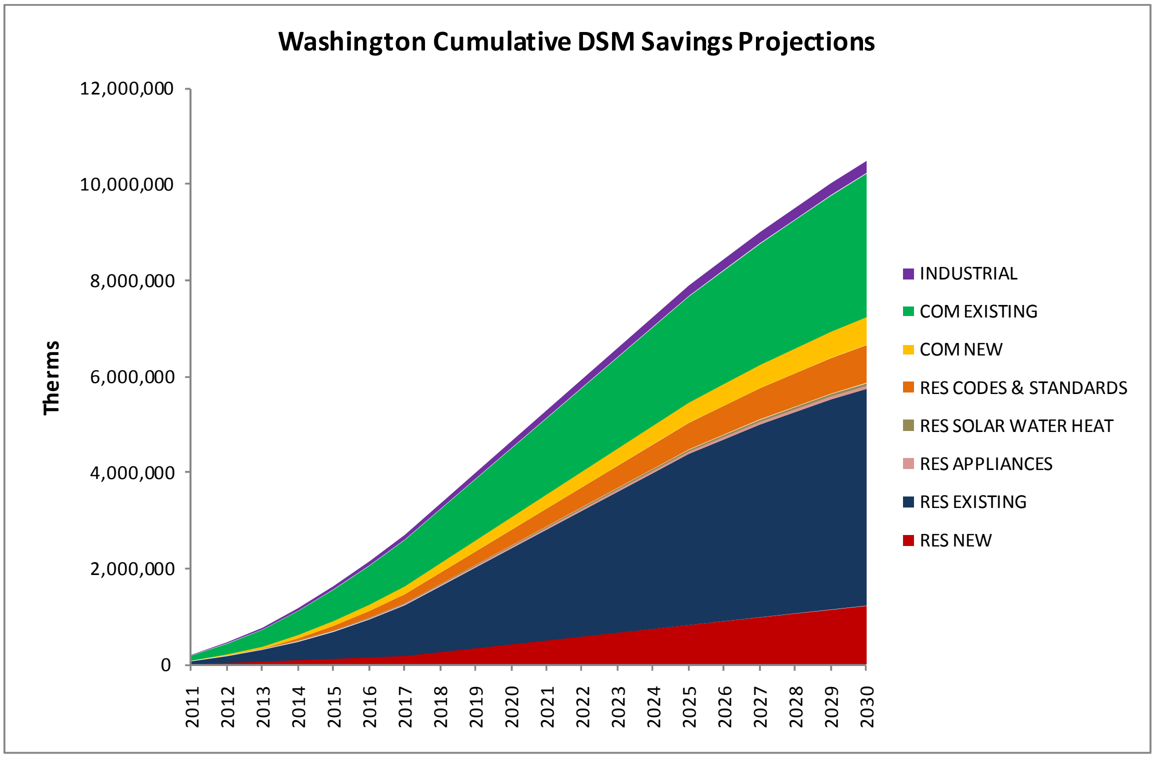


FIGURE 1.8 – Washington Cumulative DSM Savings Projections



VI. IMPACT OF RELATED ENVIRONMENTAL COSTS ON NW NATURAL'S DSM STRATEGY

Environmental externalities associated with natural gas consumption increase the benefit of demand-side resources. Recognizing the cost of carbon dioxide from the combustion of natural gas would have an impact on the Company's avoided costs. The most likely vehicle through which carbon dioxide costs could be imposed on energy users is through a national carbon tax.

If a carbon tax were imposed, more demand-side resource options could be cost-effective. A carbon tax of $15 per metric ton would add $0.08 per therm to the Company's avoided costs, while $50 per metric ton would add nearly $0.27 per therm to the avoided cost. Such a tax could drive up the implicit commodity cost of natural gas and, therefore, could reclassify some otherwise non-cost-effective conservation measures as cost-effective.

VII. OTHER DEMAND-SIDE MANAGEMENT CONSIDERATIONS

Following the 2000-01 energy crisis, energy planners' attention focused on a group of activities generally known as demand response. The general purpose of demand response is to help manage demand during periods of system stress. The term encompasses a number of activities, including interruptible rates and critical peak pricing. To varying degrees, NW Natural currently uses several of these techniques for managing peak demands.

NW Natural customers taking service on interruptible rates represent approximately 40 percent of annual throughput. This includes interruptible sales service, interruptible transportation service and firm transportation service where the transporter, not the Company, is responsible for upstream pipeline capacity arrangements. For peaking arrangements, NW Natural has contracts with several large industrial customers to recall storage volumes under specific conditions, which the Company used to manage high loads during the December 2008 winter snow event.

VIII. PUBLIC COMMUNICATION AND PARTICIPATION

A. Technical Working Group

The Technical Working Group (TWG) brings together professionals representing a variety of entities with an interest in NW Natural's IRP process. NW Natural reached out to a wide audience including representatives from the Citizens' Utility Board, Energy Trust of Oregon, Northwest Power and Conservation Council, TransCanada-Gas Transmission Northwest, Northwest Industrial Gas Users, Northwest Pipeline Corporation, Williams Northwest Pipeline, the Public Utility Commission of Oregon, and the Washington Utilities & Transportation Commission. The Company held Technical Working Group meetings on February 24, May 17, July 28, and November 3 of 2010, and June 22 of 2011.

B. Public Participation

Through an April 2010 bill insert, NW Natural solicited public comments and announced a public meeting held on June 17, 2010.

IX. 2011 IRP MULTI-YEAR ACTION PLAN

1.0 Demand Forecasting

1.1 Continue to review appropriate statistical probabilities in developing design year and peak day demand levels through stochastic analysis. The coldest daily event over the past 20 years date back to 1989, so absent extreme cold weather in the near future, firm peak-day requirements could drop noticeably in the next IRP.

1.2 Recalibrate forecast for changes in gas usage equations and expected customer gains following each heating season.

1.3 Regularly review price volatility and the associated risks within the market. Closely monitor current economic conditions and environmental legislation for potential impacts to future load growth.

1.4 Review the demand forecast methodology for accuracy.

1.5 Investigate data collection requirements to analyze demand forecast error regionally.

1.6 Consider expanding forecasting methods to include environmental scanning, deliberative polling, neural networks, or others that may have value.

2.0 Supply-Side Resources

2.1 Review cost estimates, on an ongoing basis, for resources under consideration to identify potential changes in the composition of previously selected resource mixes.

2.2 Recall daily and annual underground storage capacity from the interstate storage gas market to core market service as needed.

2.3 Support development of the Palomar East Pipeline, primarily for risk management purposes in diversifying the Company's supply path options.

2.4 Monitor LNG terminal developments and evaluate the implications of there being an export LNG terminal in either British Columbia (Kitimat) or Oregon (e.g. Jordan Cove).

2.5 Refine cost estimates, conduct more detailed system modeling, and investigate siting/permitting constraints on satellite LNG facilities and the specific NW Natural distribution system investments--including the Willamette Valley Feeder and Newport LNG Compressor project--identified as potential cost-effective resources in this IRP.

3.0 Demand-Side Resources

3.1 Work with the Energy Trust to acquire all cost-effective therm savings in both Oregon and Washington.

3.2 In Oregon this requires annually assessing forecast collections of the Company's Public Purpose charge to assure that program funding is adequate.

3.3 In Washington, NW Natural will continue to work with the Energy Efficiency Advisory Group (EEAG) to assess its one-year pilot program delivered from October 1, 2009, to September 20, 2010, by Energy Trust in accordance with the terms established in Order No. in UG-080546 and the Company's Energy Efficiency Plan filed under UG-091044. By May 25, 2011, NW Natural will file with the WUTC a third party benchmarking study that will compare the Energy Trust's administration of the Company's program with other Washington-based energy efficiency programs. This filing will include the EEAG's recommendation as to whether or not to retain the Energy Trust as the Company's program delivery arm.

4.0 SENDOUT® Model and Resource Plan Integration

4.1 Update and enhance the optimization model to capture changes in market conditions, refinements of incremental resources, and changes in system characteristics. The SENDOUT® model needs to be regularly updated to address changing market conditions, new pipeline proposals, and other changing characteristics of NW Natural's gas delivery system. The model will also be further refined with additional information about the potential route and cost characteristics of incremental supply-side projects such as the Willamette Valley Feeder, as such details are developed.

4.2 Acquire resources consistent with the Preferred Portfolio.
NW Natural will be seeking to acquire the following resources, a portion of which would be allocated to serve Oregon and Washington customers, in conjunction with its selection of its preferred portfolio:

- Consider reserving capacity on a future Cross-Cascades Pipeline, such as the proposed Palomar/Blue Bridge project if one exists.

- Mist Recall: The Company did not recall capacity in 2010.

- Harrisburg River Crossing was called for in previous IRP cycles and is now in service

- North section of the Willamette Valley Feeder will allow additional Mist Storage supplies to reach Salem – this project is expected to be in service in 2011.

5.0 Avoided Cost Determination

5.1 As regulation of greenhouse gas emissions and other items develop, NW Natural will update its environmental adder levels and costs and assess their impact on demand-side resource decisions.

6.0 Public Involvement

6.1 Conduct Technical Working Group meetings as part of the development of the 2013 IRP.

Chapter 2: Gas Requirements Forecast

Forward Looking Statement

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

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

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

I. OVERVIEW OF DEMAND FORECAST METHODOLOY

The demand or load forecast is the starting point for the IRP process. It determines the future daily firm "sales" gas supply requirements around which the resource plan is developed. Having an accurate gauge of future demand is essential for ensuring that sufficient resources are acquired in an optimal manner. Residential and commercial space heating comprise the bulk of demand on the system. Therefore, it's important to note that the load forecast is designed around a severe winter, one that is much colder than normal and is augmented by a very cold peak day event. This is done to ensure the development of a resource plan that is capable of reliably serving customers under a variety of environments, including extreme cold. The load forecast is also used as the base for determining the amount of energy savings that is available through energy efficiency by the Energy Trust.

NW Natural provides upstream supply capacity, storage capacity, and the gas commodity itself for firm "sales" customers. Firm "transportation" customers provide for their own upstream capacity and gas commodity and are not considered in this IRP. Similarly, the gas requirements of customers served on interruptible rate schedules are not considered because the Company does not plan for upstream pipeline or storage capacity to serve these customers.

The Company continues to use region-specific forecasts in its 2011 IRP reflecting the segmentation of the gas distribution system. The regions are defined as Albany, Astoria, Eugene & Coos Bay, The Dalles (Oregon), Lincoln City & Newport, Portland, Salem, and Vancouver & The Dalles (Washington). Each region is distinguished by unique weather, usage patterns, customer growth, and resource availability. These eight regions also define the separate demand and supply points along with the distribution system connections as modeled in SENDOUT®, the Company's choice for resource planning and modeling software.

NW Natural's demand forecast process is comprised of eight primary steps.

1. Customer forecast: 20 year estimate of customer counts by region and category
2. Customer usage behavior: data collection and analysis of recent usage trends by region and category
3. Load model: non-linear, statistical model fit with the independent variables heating degree day (HDD) and delivered natural gas rate ($)
4. Natural gas price forecast: monthly price forecast by basin with resulting delivered rate estimate
5. Weather pattern and peak day development: Design weather pattern colder than 85% of winters in the past 20 years
6. Demand forecast: the load model is implemented in SENDOUT® to integrate demand with supply side and demand side resource planning options
7. Demand scenarios: development of other potential but less likely demand outcomes
8. Forecast accuracy analysis: measure forecast performance by "backcasting" – using the load forecast model factors to predict historic use and compare the results to actual use

The demand forecasting process kicks off with the projection of customer growth by region and category. Next, recent usage data is collected and analyzed for customer base use and heat use behavior in response to historic weather and gas rates. The data is then used to fit the coefficients for a statistical load model for each category and region. A natural gas price forecast and forward weather pattern is used in combination with the load model and customer forecast to project demand over the 20 year planning horizon. This constitutes the base case demand forecast, which the Company believes is the most likely outcome for natural gas demand during a year with a severe winter. However, other customer growth, natural gas price futures, and usage behavior could occur, so NW Natural also develops other, less likely demand scenarios for planning purposes. Finally, load forecast accuracy is checked against recent, actual customer usage under a variety of conditions.

II. CUSTOMER FORECAST

The customer forecast is the starting point for the demand forecasting process. NW Natural relies on internal business intelligence along with information from outside sources such as the Oregon Office of Economic Analysis (OEA) and the Northwest Power and Conservation Council to project customer numbers across the 20-year planning horizon. The following tables display the forecast regions and categories along with the current customer mix as of December 2009.

Table 2.1 - Forecast Regions

Region	Customers – 2009	% of Total
Portland	406,292	61 %
Salem	86,780	13 %
Vancouver & Dalles WA	68,245	10 %
Albany	39,839	6 %
Eugene & Coos Bay	38,998	6 %
Astoria	12.046	2 %
Lincoln City & Newport	9,880	1 %
The Dalles (OR)	5,376	1 %

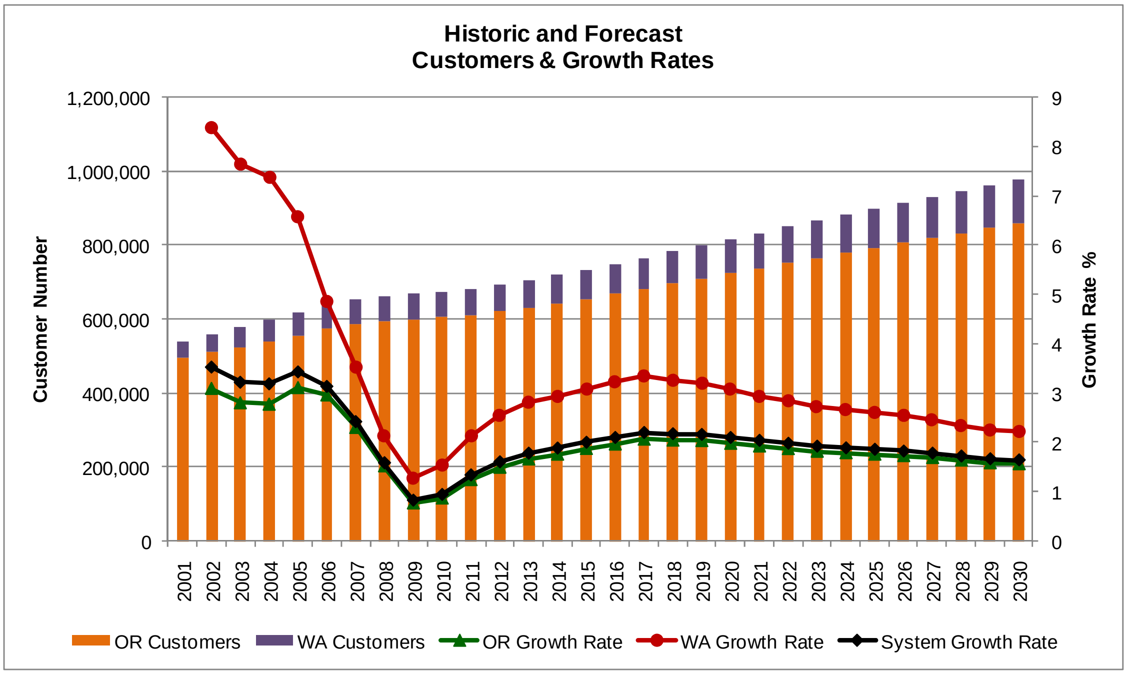
Table 2.2 - Forecast Categories

Category	Customers – 2009	% of Total
Residential Existing	604,692	90.6 %
Residential New Construction Single- Family		
Residential New Construction Multi-Family		
Residential Conversion		
Commercial Existing	62,169	9.3 %
Commercial New Construction		
Commercial Conversion		
Industrial Firm Sales	595	0.1 %

A forecast is developed for each region and category combination – 64 in all. At the starting point of the planning horizon, all the customers fall into the existing category. Over time, the forecast growth occurs in the New Construction and Conversion categories as new customers are added.

The forecast methodology involves blending near and long term economic outlooks. Economic forces such as regional employment, housing starts, and economic leading indicators are the main factors that determine growth. According to the September 2010 Oregon Office of Economic Analysis (OEA) Forecast, Oregon has suffered seven consecutive quarters of job losses. The economic downturn, coined "The Great Recession" has also resulted in housing starts in the state dropping by 41.5% in 2008, 41.1% in 2009 and 0.9% in 2010. NW Natural's customer growth rates have dropped accordingly. In 2006, the customer growth rate was over 3%. In 2009, growth had slowed to less than 1%. Going forward, customer growth is expected to crawl back to 2% by 2015. Overall, the average annual forecast customer growth rate over the next 20 years is 1.84%, with Oregon at 1.73% and Washington at 2.70%.

Figure 2.1 Customer Growth Rates



A. Residential Customer Forecast

Customer growth in the residential sector is allocated among three separate categories:

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

In the forecast, all new residential customers are added to the customer base in one of these categories. Residential attrition, or loss of residential customers, is deducted from the Residential Existing customer bucket.

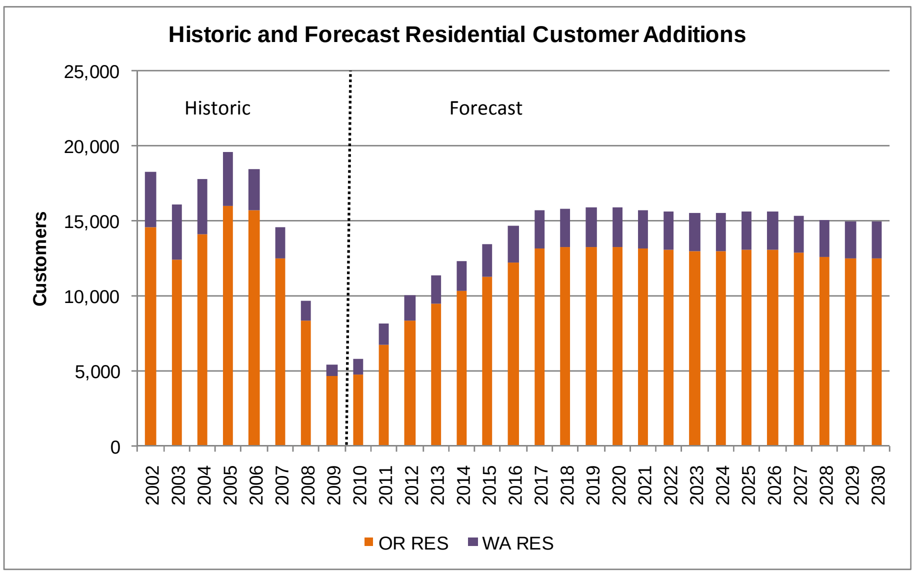
Customer projections in the new residential categories are based on historic regional growth trends, housing starts forecasts, and long term population forecasts. According to the Northwest Power and Conservation Council's 6th Plan, the average annual population growth rate for Oregon is expected to slow from a historic 1.6% (1985 to 2007) to a future 1.0% (2010 to 2030). However, the number of occupants per household has been dropping with the result that housing stock is growing faster than the population.

In addition to forecasting new customer gains, NW Natural projects the number of residential customers expected to convert to natural gas from other energy sources by reviewing historical conversion activity experienced by the Company in prior years. Internal judgment is applied as well, including such factors as:

- Stock of convertible dwellings in the service area currently served by oil and other fuels
- Incentives
- Price of natural gas in relation to other energy sources
- Technology
- Marketing programs
- Economic conditions

The impact of the economic recession on growth in the residential sector can be clearly seen in Figure 2.2, which shows the historical and forecast net residential customer additions by year.

Figure 2.2 - Residential Customer Additions



B. Commercial Customer Forecast

For the commercial sector, growth is concentrated in two categories:

1. New Construction
2. Conversions

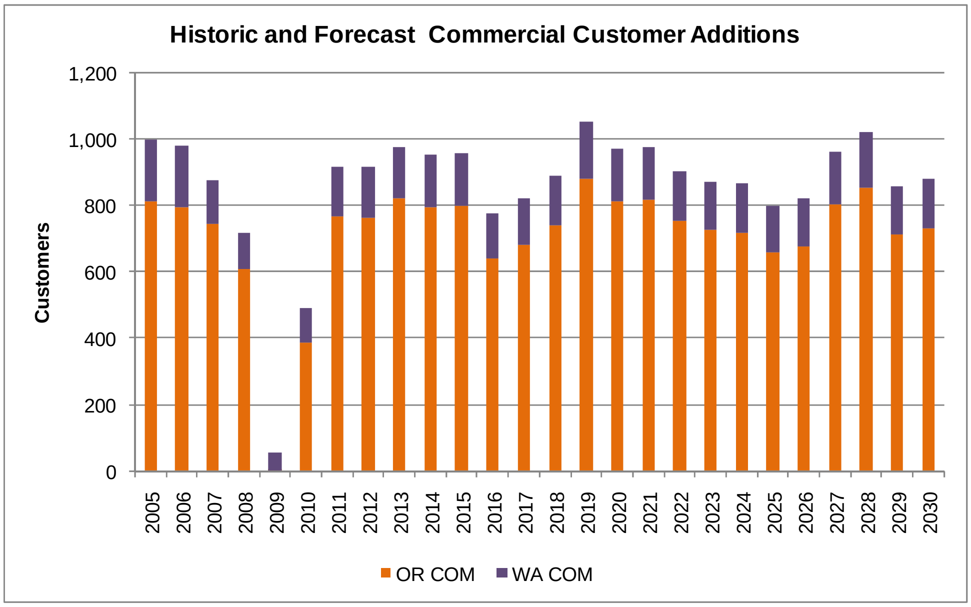
All new commercial customers are added to the customer base in one of these forecast categories. As in the residential category, attrition is deducted from the Commercial Existing customer bucket.

New construction forecasting for the commercial sector is based on historic patterns, along with internal econometric modeling and external economic forecasts from the OEA and the Northwest Power and Conservation Council.

As in the residential forecast, each month NW Natural projects the number of commercial customers expected to convert to natural gas from other energy sources by reviewing historical conversion activity experienced by the Company in prior years. Similar factors are analyzed as in the residential case, but from the commercial business viewpoint.

After bottoming in 2009, growth in the commercial sector is expected to rebound in 2011. Figure 2.3 shows historic and projected commercial additions.

Figure 2.3 - Commercial Customer Additions



C. Industrial Customer Forecast

The Industrial customer base has remained fairly flat through recent years, and this trend is expected to continue. Near term demand growth in the firm sales industrial category is expected to originate more from a higher use per existing customer than new customer additions. The economic slump has caused plants and factories to cut back on shifts and consume less natural gas across the region. As the economy rebounds, it is expected that the use per customer will rebound, and new customers will be added. Transportation service customers could transfer to firm sales in the future as well.

D. Customer Scenarios

NW Natural believes the base case customer forecast and the resulting base case demand forecast to be the most likely outcome from a planning standpoint. The Company will also evaluate resource planning around other potential demand outcomes, or scenarios. Scenarios provide alternative demand projections resulting from alterations to the base case forecast assumptions. Demand scenarios also act as limits to the base case forecast by setting a floor and a ceiling on expected load. Three alternative demand scenarios have been developed around customer growth.

1. Low Growth Case: lower customer growth due to continued economic malaise
2. High Growth Case: higher customer growth resulting from a sharper than expected economic rebound.
3. Low Growth II: significantly lower customer growth due to an unspecified "electric utility breakthrough" where inexpensive, clean electric power makes natural gas direct use less competitive

The customer forecast scenarios were developed by altering the base case residential and commercial customer addition values. Figure 2.4 presents the system wide customer growth rates for the scenarios. Figures 2.5 and 2.6 display the resulting state specific customer outcomes.

Figure 2.4 - Scenario Growth Rates

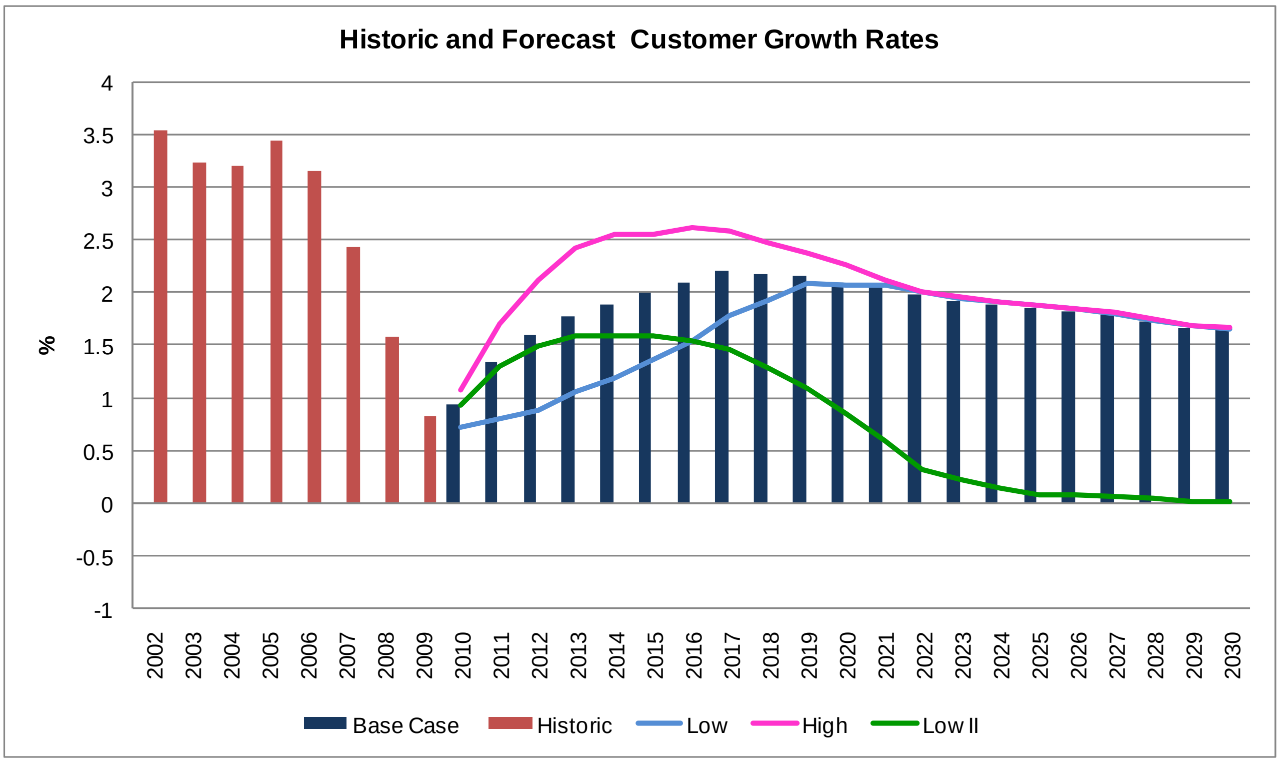


Figure 2.5 - Oregon Customer Forecast

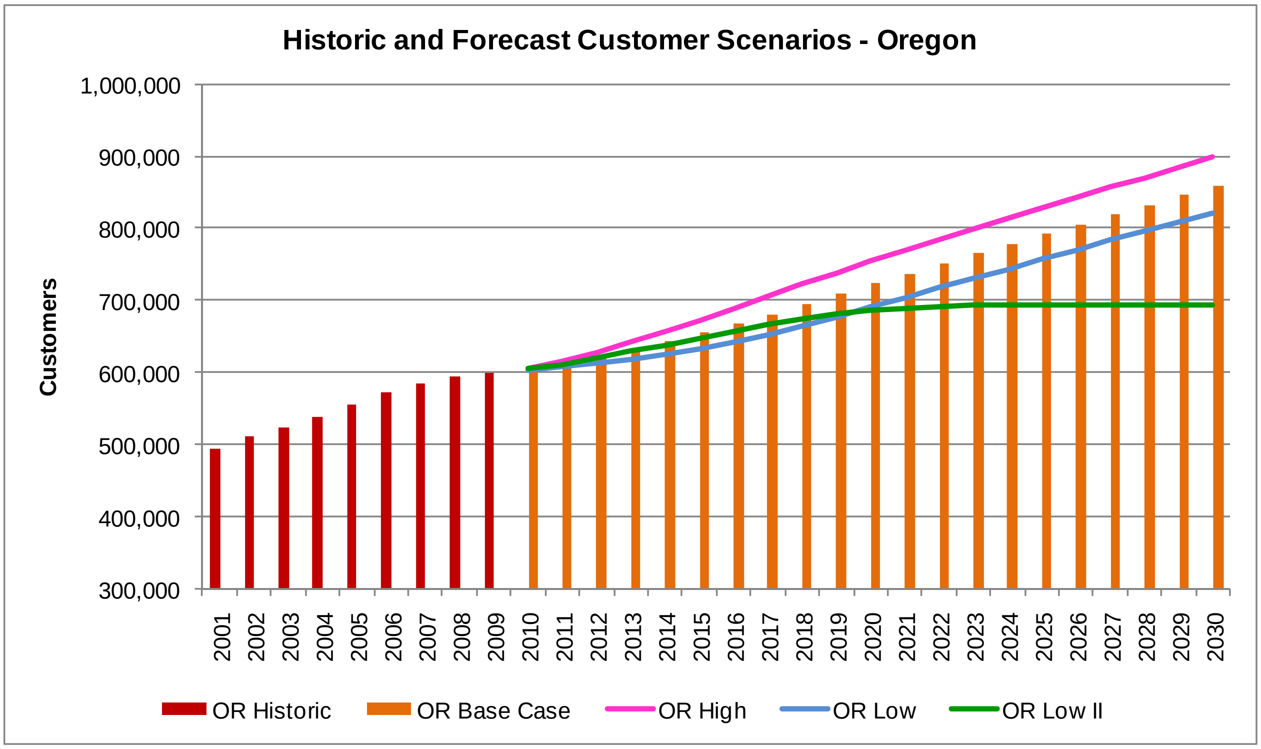
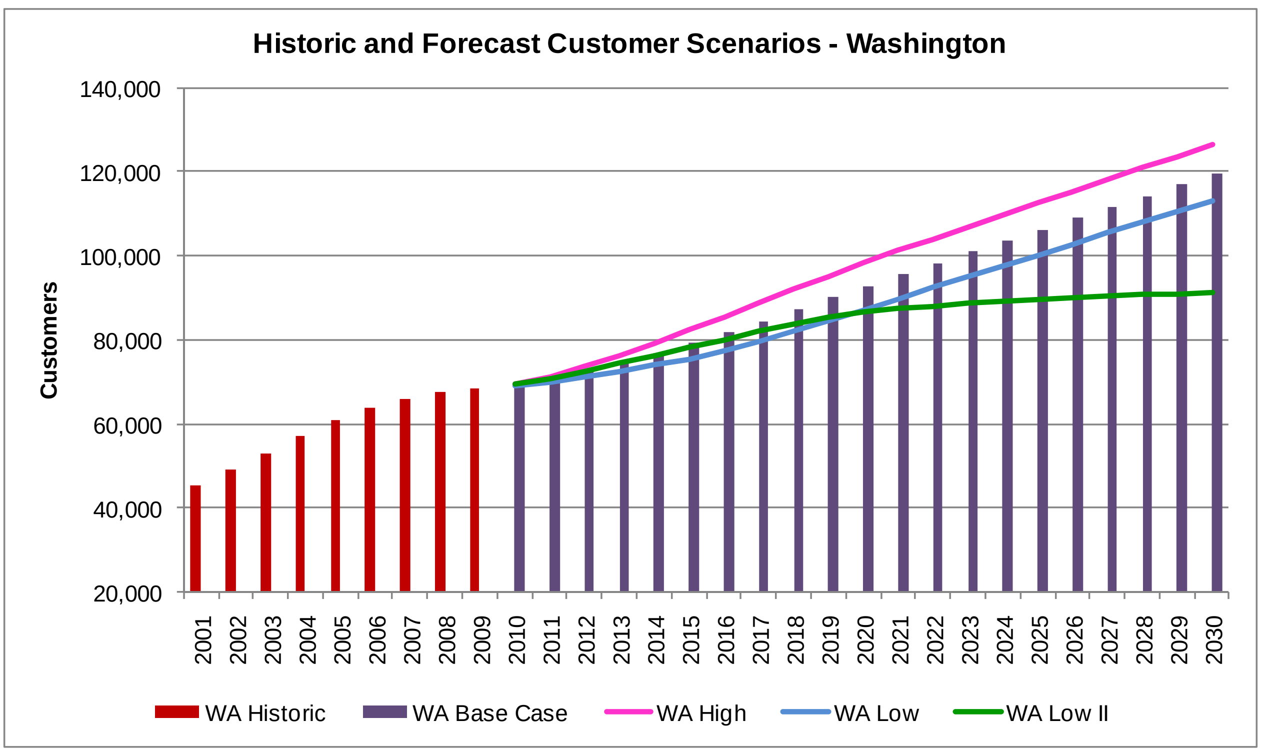


Figure 2.6 - Washington Customer Forecast



III. LOAD FORECAST MODEL

The next step in the demand forecast process is to combine historic natural gas use behaviors with the forecast customer numbers in each category. Historic billing cycle data is collected by category and region and is matched up with both temperature data and delivered price data. Temperature data is available for each region on a daily basis, however, customer usage by region and category is not. Detailed customer usage data is derived from billing cycle information, which is collected throughout each month on a rolling basis. Temperature data is compiled to match the billing cycles. For example, typically there are 22 billing cycles each month. A mid-point cycle will contain aggregated customer usage data from the first half of the current month and the second half of the previous month. A cycle at the beginning will collect usage data primarily from the previous month while a cycle at the very end will be comprised of data from the current month only.

A statistical load forecast model is then fit to the data set. In addition to regional variation in climate, each region's customer base also has unique usage characteristics. These differences in usage patterns and levels of use may be related to the size and age of the dwellings or businesses, as well as the efficiencies of the equipment and appliances that are in use at the location. Therefore the load forecast model is fit to each distinct combination of category and region, 64 in all.

For residential, commercial, and industrial customers, daily use is separated into two components, base load and heat load. The base load component is assumed to be constant throughout the year and is independent of ambient temperatures and delivered gas price. Base load represents demand for uses such as water heating and cooking. Heat load represents demand for space heating. For the heat load component of the load forecast, a non-linear equation is used to model daily customer use as a function of heating degree days (HDD) and, to a lesser extent, delivered gas price. The metric HDD measures the extent to which the daily mean temperature falls below a reference temperature, which in our case is 65° F.

Equation 2.1 Daily Customer Use

$$U = U_B + U_H$$

$$where$$

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

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

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

A. Base Load

The first step in the load model derivation involves estimation of the base load component. This is done by performing a linear regression with daily use per customer as a function of heating degree days, using customer usage data from the summer months - July, August and September. Since there still may be some heating load during cool summer days, the value of the y-intercept (usage where HDD=0) provides the base load factor.

Equation 2.2 Base Load Model

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

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

$$x = hdd\ per\ day$$

$$r = heat\ factor$$

$$c = intercept$$

$$setting\ x = 0$$

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

B. Heat Load

For the non summer months, the base load value is subtracted from the daily customer use data and the heat load factors are calculated. For residential and commercial customers, heat load is modeled as a non-linear function of heating degree days and delivered gas price. The function resembles the "S" Curve. At low heating degree day values, the curve is relatively flat. As the heating degree day value increases (colder temperatures), load increases and the curve becomes steeper. At a heating degree day of 45 (20° F) the load curve begins to flatten out. The delivered price also affects the load function. If the price the customer pays for gas increases, customer use at a given HDD value will drop. Should the price decline, then customer use will rise. The price factor in the model captures this interaction, which can also be thought of as price elasticity.

Following a natural log transformation, heat load is derived by performing a linear regression fit as a function of HDD and delivered gas price.

Equation 2.3 Heat Load Regression

$$\ln\left(\frac{W}{hdd}\right) = d + r_h \times x_1 + r_p \times x_2$$

$$where$$

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

$$x_1 = \ln(hdd)$$

$$x_2 = \ln(price)$$

$$r_h = heat\ rate$$

$$r_p = price\ rate$$

$$d = intercept$$

The function is transformed back by taking the exponent of both sides, resulting in the heat load component.

In the industrial sector, heat load is modeled as a linear function of heating degree days only.

Equation 2.4 Heat Load

$$U_H = (hdd) \times e^{[d + r_h \times \ln(\max(45, hdd)) + r_p \times \ln(price)]}$$

$$where$$

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

C. Implementation

In order to implement NW Natural's load model into SENDOUT®, the non-linear load equation must be transformed into a linear function of HDD. This is accomplished by fitting two piecewise segments to the load function.

Equation 2.5 Linear Transformation

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

$$where$$

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

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

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

D. Peak Day Load

The slope of the non-linear load curve increases as HDD values increase. Historically, natural gas local distribution companies have seen usage begin to flatten at very low temperatures (high HDD values). In the paper titled "Bend-Over", John Little and Jeffrey Rosenbloom[1] (Fortnightly, April 1994) found that this effect- called "bend-over" - does exist, starting at a temperature of 20° F. Customers do not continue to consume natural gas at the same rate at very cold temperatures. However, the reasons for this are not clear. One idea is that in a peak day event, most of the heating appliances are running at maximum capacity and cannot consume any more gas even if temperatures continue to drop. NW Natural has very few data points to verify since its service territory has a relatively mild climate. The few existing data points do seem to indicate that a shift occurs in the load curve. Therefore, in practice the load forecast model does include a bending of the curve beginning at an HDD value of 45 (20° F). This can be seen in Equation 2.4 above.

[1] "Bend-Over", John Little and Jeffrey Rosenbloom, Fortnightly, April 1994

E. Use Per Customer and Price Elasticity

Natural gas use per customer in the residential and commercial sectors has been consistently dropping over the past 10 years. Newer, more energy efficient construction, investment in conservation programs, and natural appliance replacement with more efficient products have all prompted the decline in use.

Since 2000, NW Natural's use per customer for residential and commercial customers has dropped between 1 % and 2 % annually. The demand forecast – including decrements for ETO program savings - projects the following average annual UPC decline rates:

- Oregon Residential = -1.0 %
- Washington Residential = - 0.85 %
- Oregon Commercial = -1.4 %
- Washington Commercial = -0.9 %

A number of factors are at work in the demand forecast which drives this decline. New conversion customer additions tend to have lower use profiles than existing customers. In addition, NW Natural expects significant energy savings to come from programs administered to both new construction and existing customers by the Energy Trust of Oregon. Public purpose funds are collected from Oregon ratepayers to fund these programs. Also, as the existing housing stock ages, water heaters, furnaces and windows are replaced with newer, more efficient versions, furthering the decline in use. Finally, customers may respond to natural gas price increases by actively making improvements to the housing shell, or even changing behavior, such as turning down the thermostat. The price factor r_p in the load model (Eq. 2.3) conveys the demand response to price changes.

Price elasticity measures the response of demand to changes in price, with all other factors held constant. It is defined as the proportionate change in quantity demanded divided by the proportionate change in price. In the base case demand forecast model, a 10% increase in delivered price results in price elasticity values of -0.12 for residential, and -0.11 for commercial. In other words, for a rate increase of 10%, the model projects a drop in use per customer of 1.2% for residential customers and 1.1% for commercial. It's important to note that the value of price elasticity is not constant since it depends on where it is measured on the price curve.

The American Gas Association (AGA) released a study on natural gas use and price elasticity in 2007[2]. The study analyzed residential use per customer (UPC) trends from 50 natural gas local distribution companies (LDC) from across the country. The authors found that since 1980, weather normalized use in the residential sector has been dropping about 1% per year. From 2000 to 2006 though, the decline accelerated to 2.2% per year. The driving force behind the decline in use per customer was the consistent increase of natural gas prices. NW Natural has seen a similar drop in use per customer during that time frame. The AGA study reported a long run price elasticity value of -0.18 for the residential

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

sector. NW Natural's price elasticity over the time frame was less, around -0.13, even though the increase in gas price in the 2000 to 2006 time frame was greater.

F. Usage Scenarios

In addition to the customer forecast scenarios, a demand scenario was developed around higher use per customer. This is called the "Gas Breakthrough" scenario. The case assumes some sort of small unit technological fuel cell breakthrough in the residential sector. The unit would be fueled by natural gas and would provide full electrical power to the household, including space heating and cooling. It is estimated that a converted household would increase its base load gas demand by 37%. In addition to the higher base load, the seasonal load pattern is altered to include a summer cooling load. Both new and converted customers are added slowly over the planning horizon so that the additional break through demand is phased in. This scenario represents the high usage case and provides the ceiling for all demand cases.

IV. GAS PRICE FORECAST

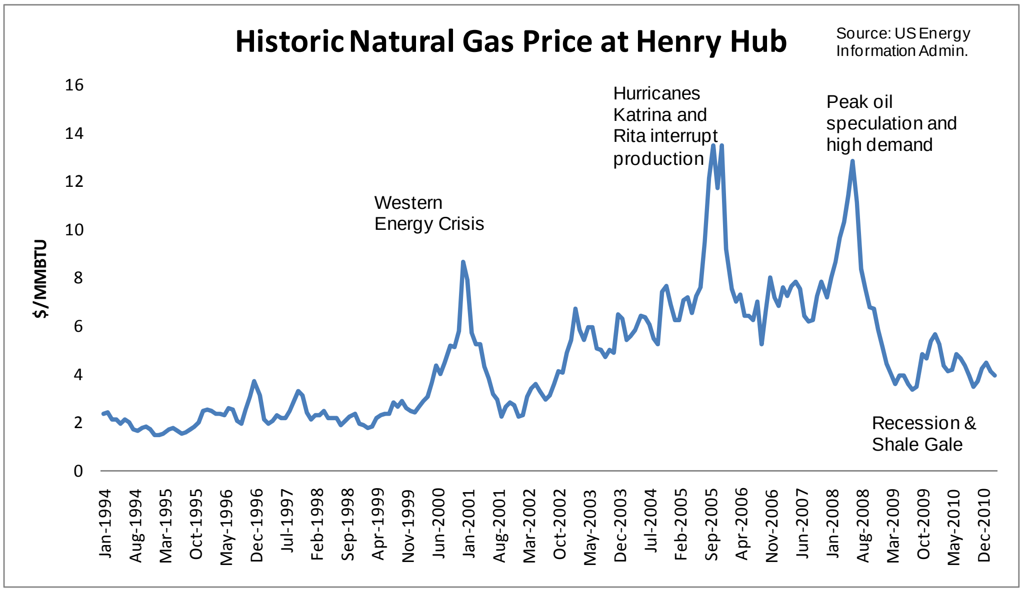
As part of the demand forecast process, NW Natural develops a 20 year natural gas price forecast by basin. The forecast includes a monthly price outlook for Henry Hub, Rockies (Opal), British Columbia (Sumas), Alberta (AECO), and Malin. The volatility inherent in natural gas prices makes forecasting highly uncertain. Future gas prices are expected to be influenced by numerous factors including economic conditions, demand, power generation, potential national carbon policies, weather, and new and traditional supplies, including gas produced using more efficient extraction technologies. NW Natural has reviewed several public and proprietary price forecasts and has developed a base case, as well as a high and low price outlook to represent reasonable pricing possibilities for the basins the company purchases supplies from.

A. Price Volatility

The combination of low demand and vast supplies has recently kept prices low. Improved drilling technologies have opened up vast quantities of "unconventional" gas from shale deposits throughout North America. The economic slump that began in 2008 has continued to dampen natural gas demand. In 2009, spot prices at Henry Hub dipped below $4 per MMBTU while Rockies and Canadian spot prices dropped below $3 per MMBTU. According to IHS CERA Chairman Daniel Yergin, "As recently as 2007 it was widely thought that natural gas was in tight supply and the U.S. was going to become a growing importer of gas. But this outlook has been turned on its head by the shale gale".

Figure 2.7 displays the volatile nature of natural gas prices. As recently as June 2008, prices at the Henry Hub surpassed $12 per MMBTU. Henry Hub is the primary pricing point for the North American natural gas market. In late 2005, Hurricanes Katrina and Rita drove prices up over $13 per MMBTU. The Western energy crisis in 2000/2001 spiked prices over $8. The recent drop in price allowed NW Natural to cut residential rates in Oregon by 20% and by 24% in Washington in late 2009. Rates dropped slightly in late 2010.

Figure 2.7 - Natural Gas Price



B. Forecast

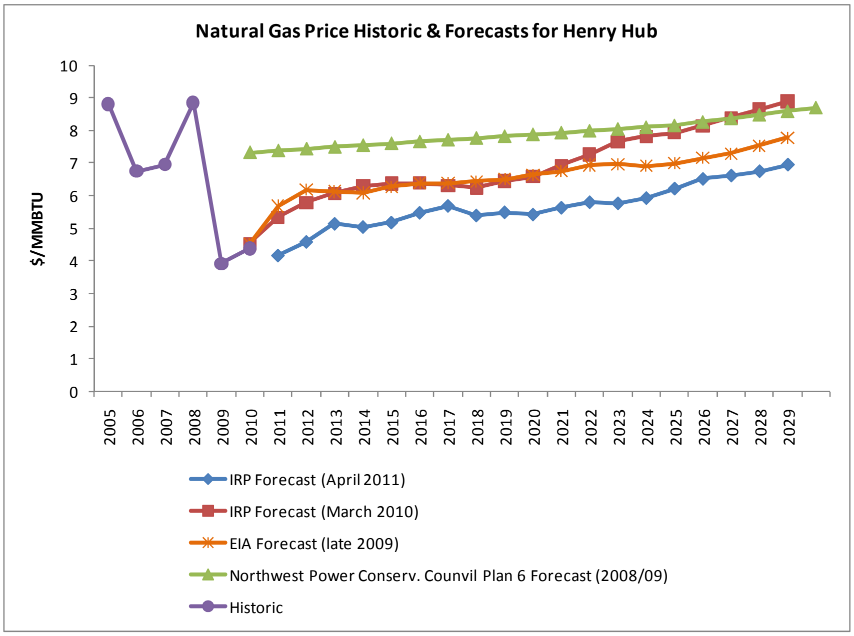
The natural gas price forecast impacts the load forecast, the least cost planning model, and avoided cost calculations. The delivered natural gas price per therm is estimated from the price forecast and fed into the heating load component of the demand model - equation 2.4. The price forecast is also fed into NW Natural's SENDOUT® resource planning model and plays a strong role in determining future resource decisions. The least cost planning model determines the optimal plan for purchasing and transporting supplies to customers across the service region. Supply cost is the dominant component of avoided cost calculations; therefore the price forecast plays a significant role in estimating costs.

The price forecast offers a long term look at the natural gas market. The Company's forecast is derived from a proprietary forecast developed by a third party organization IHS CERA Inc[3]. The base case forecast assumes carbon dioxide legislation which would add a cost for each metric ton of CO_2 emissions beginning in the year 2014. Figure 2.8 displays the price forecast used in this IRP, along with other outlooks:

1. Modified IRP Forecast (April 2011)
2. IRP Forecast (March 2010)
3. U.S Energy Information Administration (EIA) from Dec. 2009
4. Northwest Power and Conservation Council (NWPCC) 6th Plan from 2008/2009

3 The use of this content was authorized in advance by IHS CERA. Any further use or redistribution of this content is strictly prohibited without written permission by IHS CERA. All rights reserved.

Figure 2.8 - Price Forecast



C. Price Scenarios

As mentioned earlier, the base case price forecast assumes a ramp up of carbon dioxide emission cost additions resulting from future but uncertain federal legislation. Such legislation could attach additional costs for CO_2 emissions from the combustion of natural gas and would potentially shift more electrical power generation away from coal and towards natural gas. A natural gas fired power plant has roughly half the CO_2 emissions of a coal fired plan. Higher CO_2 costs could thereby increase demand for natural gas and drive up the price. The abundance of natural gas from shale deposits may also drive up demand from the power generation side as well. Figure 2.9 displays the base case forecast at Henry Hub, along with the high and low price cases. Figure 2.10 displays the corresponding CO_2 emission cost adders.

Figure 2.9 - Price Scenarios

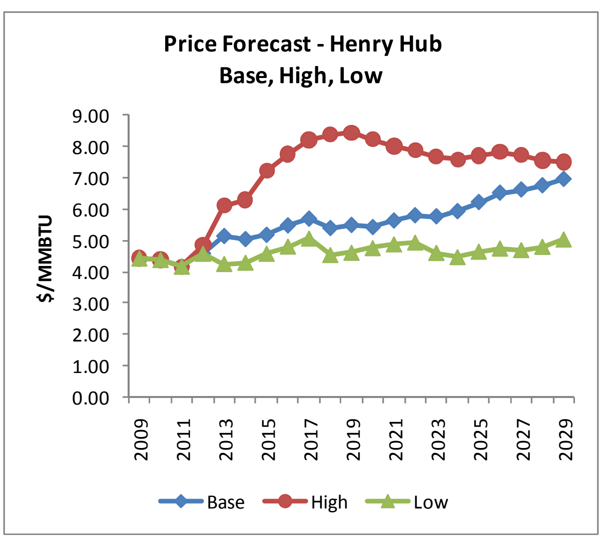
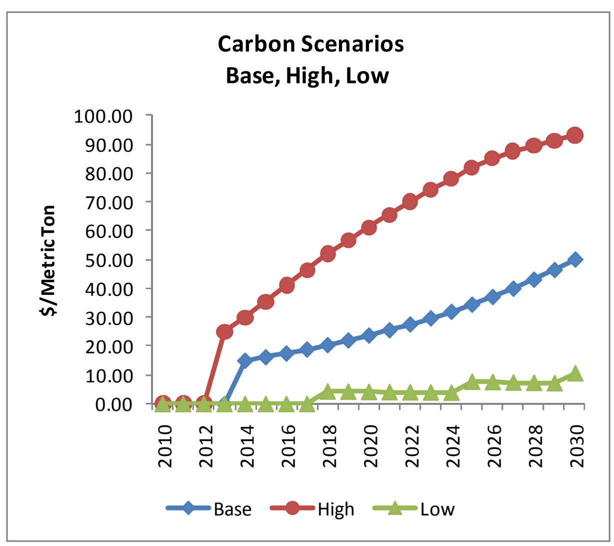


Figure 2.10 - Carbon Scenarios

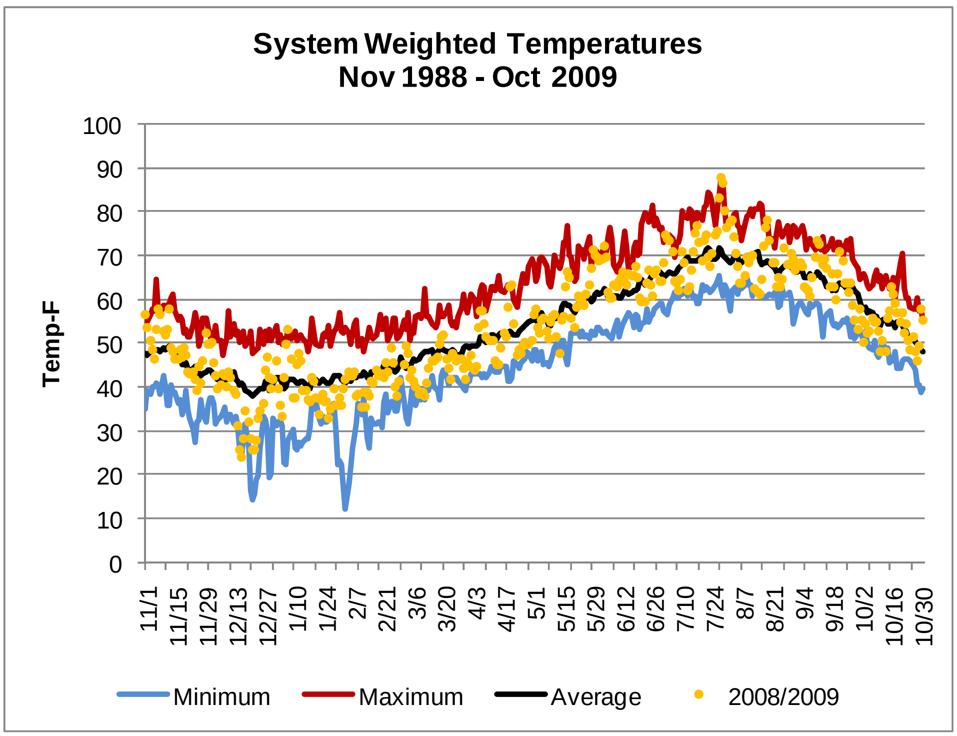


V. WEATHER

Climate plays a large role in the demand forecast. The heating degree day (HDD) variable in the heat load model (Equation 2.4) is a key driver of daily load, and in particular, peak day load. NW Natural has analyzed temperature data from our service area and designed an annual heating degree day pattern resulting in loads which will significantly stress the supply system on both an annual and peak day basis. The design weather pattern is repeated in each year of the plan so that the appropriate resources can be developed to serve customers whenever a severe winter occurs.

NW Natural collects and analyzes temperature data purchased from the National Oceanic and Atmospheric Administration for all eight regions of the service area. Figure 2.11 displays the system weighted average, minimum and maximum temperatures along with the average temperatures from a recent gas year.

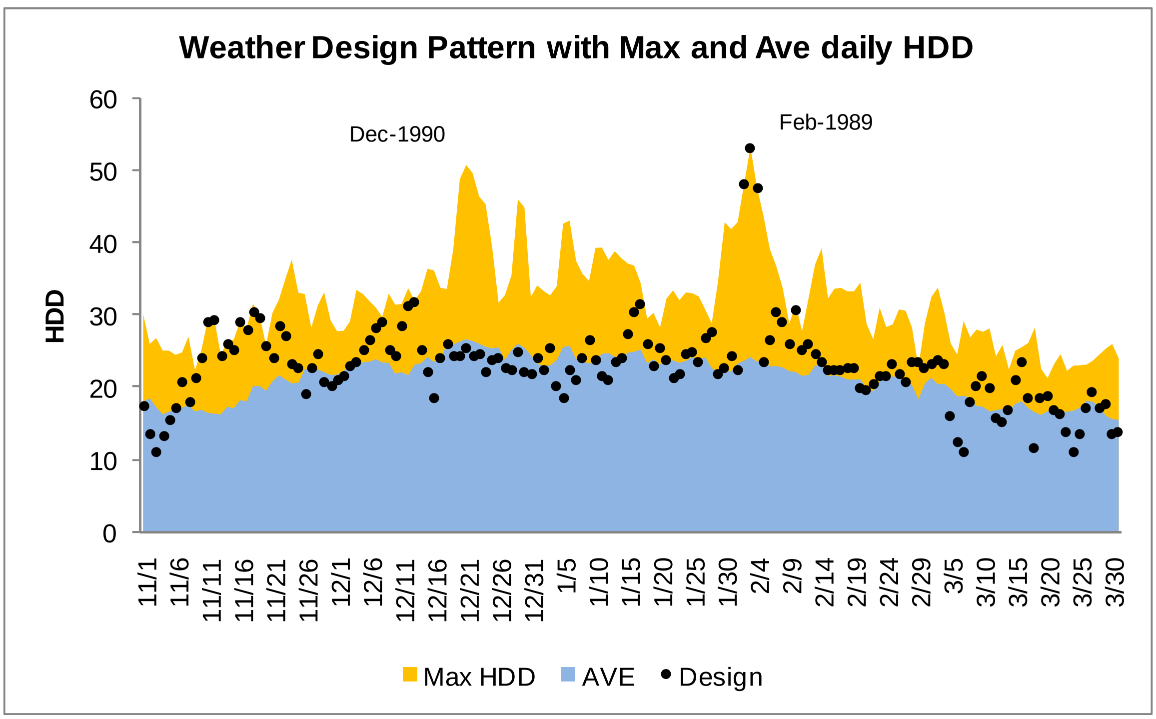
Figure 2.11- Daily Temperatures



The design weather pattern is derived from a data set containing 20 years worth of daily temperatures, including gas years 1988/89 through 2007/08. The daily average temperatures T from each region are transformed to a 65° F based HDD value by a simple conversion: HDD = max(0,65-T). The annual design pattern includes a statistically derived heating season HDD value that is calculated to be colder than 85% of the winters in the data set. The calculated HDD values are layered onto the 2000/01 heating season pattern to provide a realistic weather pattern from which to develop the supply side and demand side resource plan. The 2000/01 heating season is the year that most closely fits the 85% design for cumulative HDD.

In addition to the colder than normal winter, the most extreme peak event in the past 20 years is superimposed onto the design pattern. The coldest peak day from the data set occurred on February 3rd of 1989 when the system weighted HDD value reached 53. This corresponds to an average daily temperature of 12° F. The day before and the day after the peak were very cold and were also superimposed onto the design pattern in order to capture the complete peak event. The design pattern for the heating season is displayed in Figure 2.12, along with daily average and maximum HDD values. NW Natural feels the design pattern provides a robust test for system resources. In the design pattern, the first heating month of the gas year (November) is much colder than average, and the peak weather event occurs very late in the season which forces the plan to retain significant supply in storage until late in the winter. In this pattern, the system is stressed both at the start and toward the end of the heating season.

Figure 2.12 - 0.85 Probability Design Winter Pattern



The resulting HDD values for the design peak day and design heating season, along with normal heating seasons for the regions are shown below in Table 2.3.

Table 2.3 - HDD by Region

Region	Design Peak Day HDD	Sum of Design Heating Season HDD (Nov – Mar)	Sum of Avearge Heating Season HDD (Nov – Mar)
Albany	54.5	3,578	3,289
Astoria	50.0	3,100	3,040
Dalles (OR)	62.0	4,116	3,832
Eugene & Coos Bay	52.3	3,595	3,254
Lincoln City & Newport	48.5	2,788	2,741
Portland	53.0	3,434	3,151
Salem	54.0	3,548	3,243
Vancouver & Dalles (WA)	54.7	3,646	3,399

VI. RESULTS

The four primary components of the forecast – customer forecast, usage model, delivered gas price and weather pattern – are combined to generate a daily load forecast for each region and category.

Equation 2.6 - Daily demand

$$D = \sum_{i}^{region} \sum_{j}^{customer\ category} C(i,j) \times [U_B(i,j) + U_H(i,j)]$$

Cost effective DSM savings are forecast and decremented from the demand. Chapters 4 and 5 provide background on how the DSM savings were estimated and integrated with the demand forecast. The end result is the daily gas requirement around which the resource plan will be developed.

A. Base Case

The planning base case provides the best estimate of future demand for a cold winter with a very cold peak day event. It is derived using the base case customer forecast, the base case price forecast, and the design weather pattern. The average annual load growth rate over the planning horizon is 0.61%. Excluding DSM savings, the average annual load growth is 1.28%. Peak day load is expected to grow at an average annual rate of 0.74%. Figures 2.13 and 2.14 display annual demand and peak day demand by region. MDT stands for thousand dekatherms. A value of 70,000 MDT is equivalent to 700,000,000 therms, and a value of 1,000 MDT is equivalent to 10 million therms. Figure 2.15 shows the % breakout of customers, and demand by category for a single year.

Figure 2.13 - Annual Demand Base Case

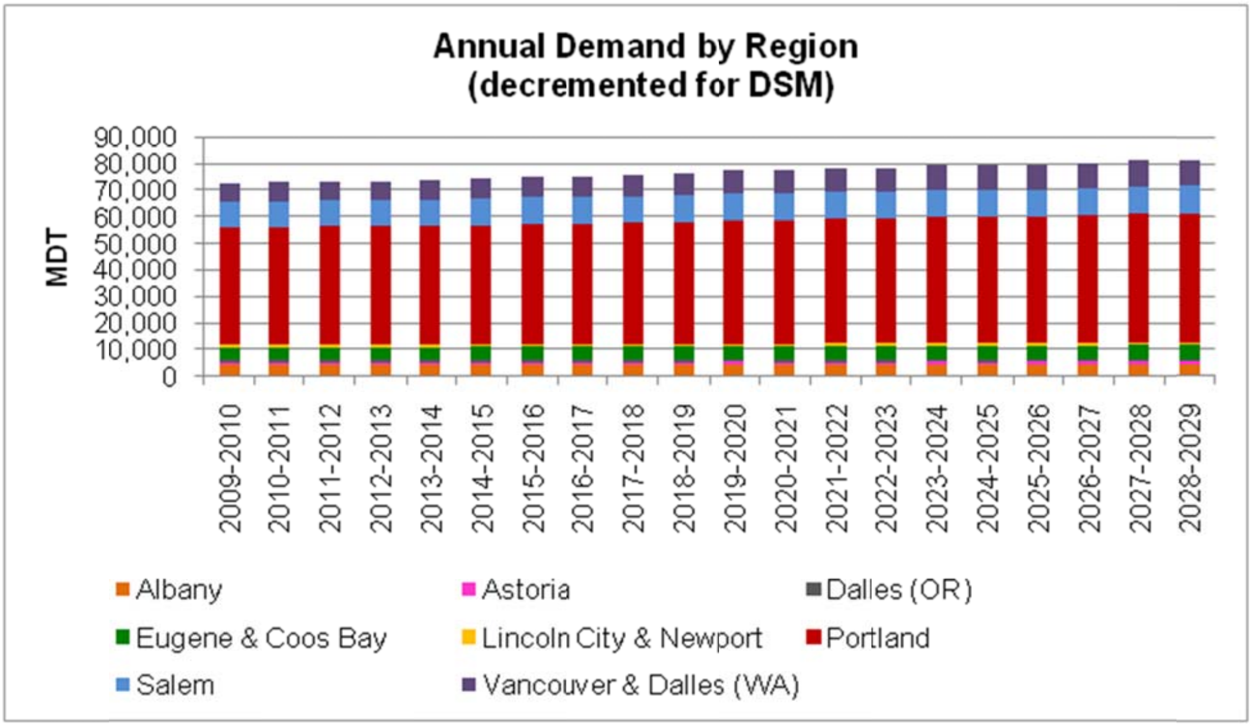


Figure 2.14 - Peak Day Demand Base Case

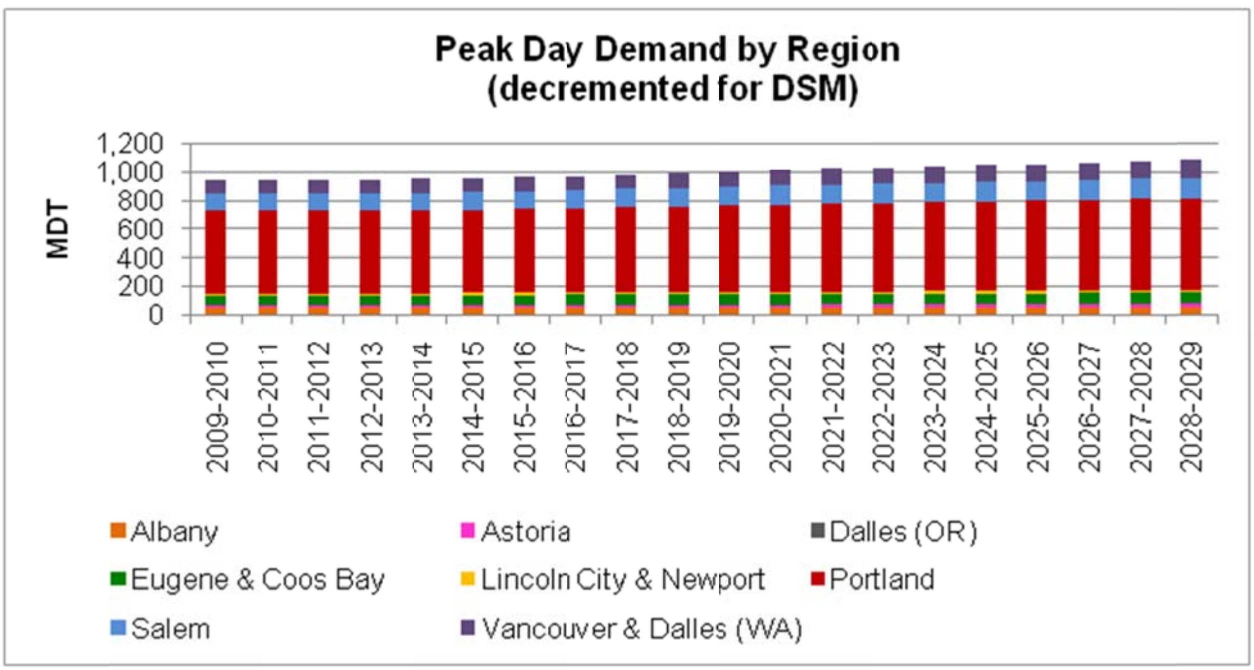
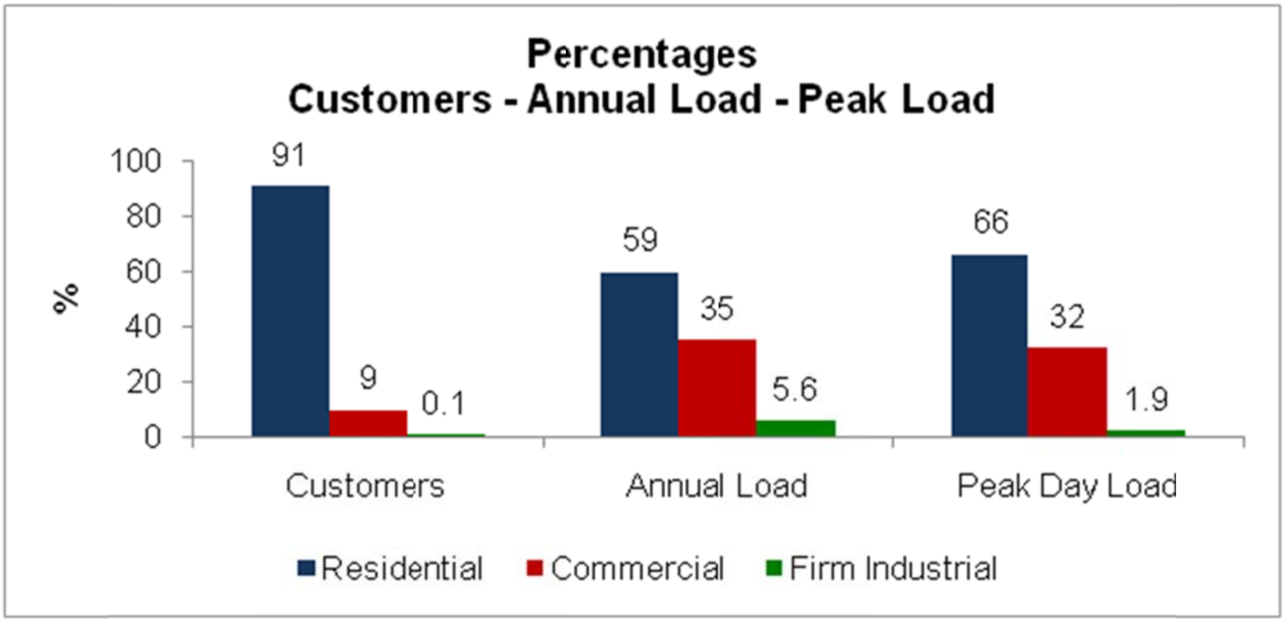
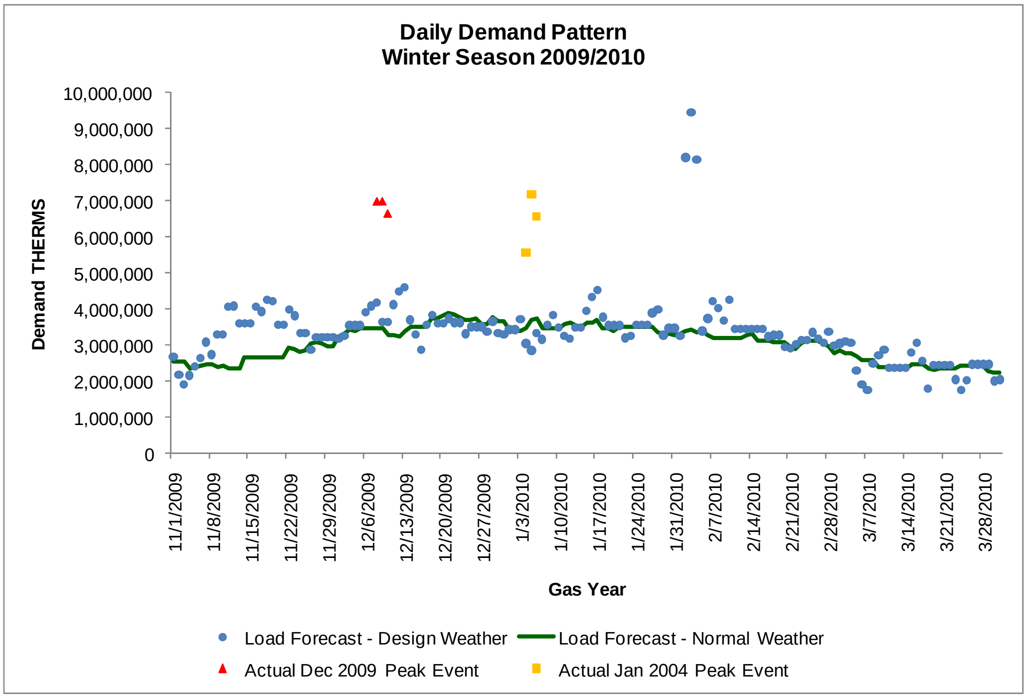


Figure 2.15 - Demand Percentages



Peak day demand is the primary driver of the resource plan. High peaking demand puts a premium on storage, while large base line volumes may drive more pipeline capacity. A typical daily forecast load value for a winter day in gas year 2009/2010 is 355 MDT. The forecast peak day for that gas year is 944 MDT. This is 2.75 times the load for a typical winter day. Clearly, meeting peak day load is of primary consideration for the resource plan. Figure 2.16 shows the daily forecast demand for gas year 2009/2010, along with two recent historic cold winter events. NW Natural served its highest daily firm demand ever (718 MDT) on January 5, 2004. The system weighted average temperature that day was 22 ° F, which corresponds to a HDD value of 43. The cold temperature was accompanied by strong winds, fog, rain and snow. More recently, on December 9, 2009, the region experienced a 44 HDD peak with calm and sunny conditions. Firm demand that day registered 698 MDT. In relation, NW Natural plans for a peak day of 53 HDD.

Figure 2.16 - Demand Forecast Pattern



B. Demand Scenarios

Several demand scenarios were developed around the base case. There are three main forecast ingredients to each demand scenario:

1. Customer Forecast
2. Customer Usage
3. Gas Price Forecast

For the base case, each component is derived from NW Natural's best estimate at the time the forecast was generated. Demand scenarios and "world views" can be generated by mixing and matching forecast cases and run through the SENDOUT® resource model to generate and evaluate resource plans. Table 2.4 presents the demand scenarios and the components that were prepared for this IRP.

Table 2.4 - Scenarios

Case	Customer Forecast	Customer Usage Forecast	Gas Price Forecast	Weather
Base Case	Base Case	Base Case	Base Case	Design
Gas Breakthrough	High	High	High	Design
Gas Dereg.	High	Base Case	Low	Design
Electric Breakthrough	Low II	Base Case	High	Design
Low Customer Growth	Low	Base Case	Base Case	Design
High Customer Growth	High	Base Case	Base Case	Design
Low Gas Price	Base Case	Base Case	Low	Design
High Gas Price	Base Case	Base Case	High	Design

Table 2.5 provides a summary of the forecast results by state. The average annual demand growth rate across the 20 year horizon is shown for both pre-DSM and post-DSM calculations. The annual and peak day forecast for the base case and planning scenarios are graphically represented in Figures 2.17 and 2.18.

Table 2.5 - Scenario Demand Growth Rates

CASE	Ave. Annual Growth Rates - % PRE-DSM				Ave. Annual Growth Rates - % POST-DSM		
	OR	**WA**	**SYSTEM**		**OR**	**WA**	**SYSTEM**
Base Case	1.17	2.22	1.28		0.47	1.74	0.61
Gas Breakthrough	2.51	3.71	2.64		1.95	3.33	2.10
Gas Dereg.	1.45	2.59	1.57		0.76	2.13	0.91
Electric Breakthrough	0.17	0.90	0.25		-0.52	0.40	-0.42
Low Customer Growth	0.93	1.89	1.03		0.23	1.41	0.36
High Customer Growth	1.40	2.53	1.52		0.70	2.06	0.85
Low Gas Price	1.21	2.28	1.33		0.52	1.80	0.66
High Gas Price	1.14	2.19	1.25		0.44	1.71	0.58

Figure 2.17 - Annual Demand Scenarios

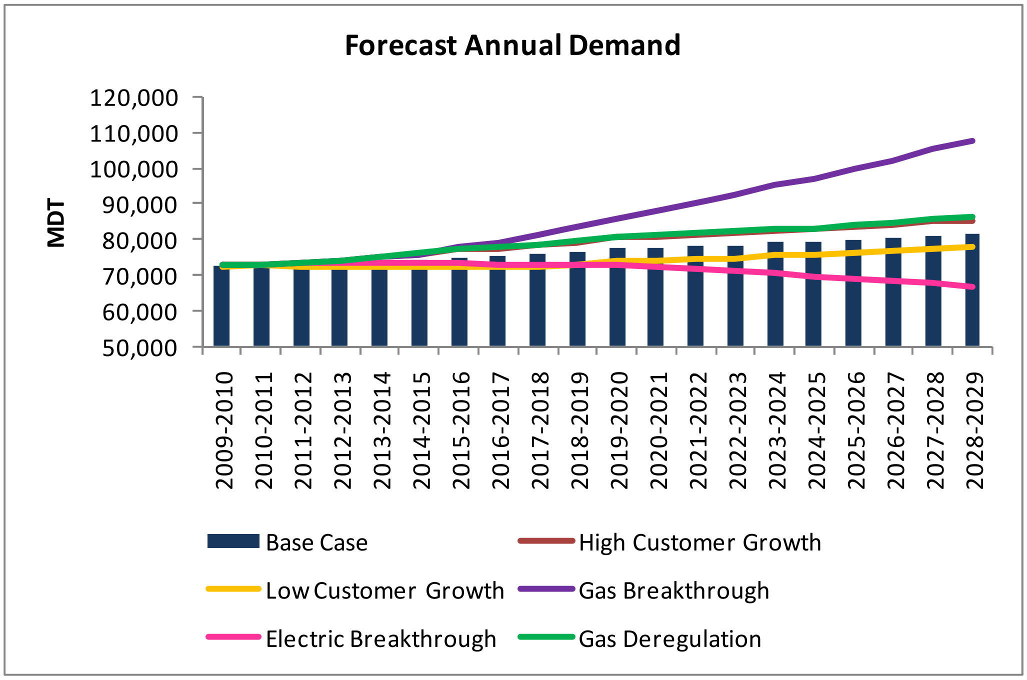
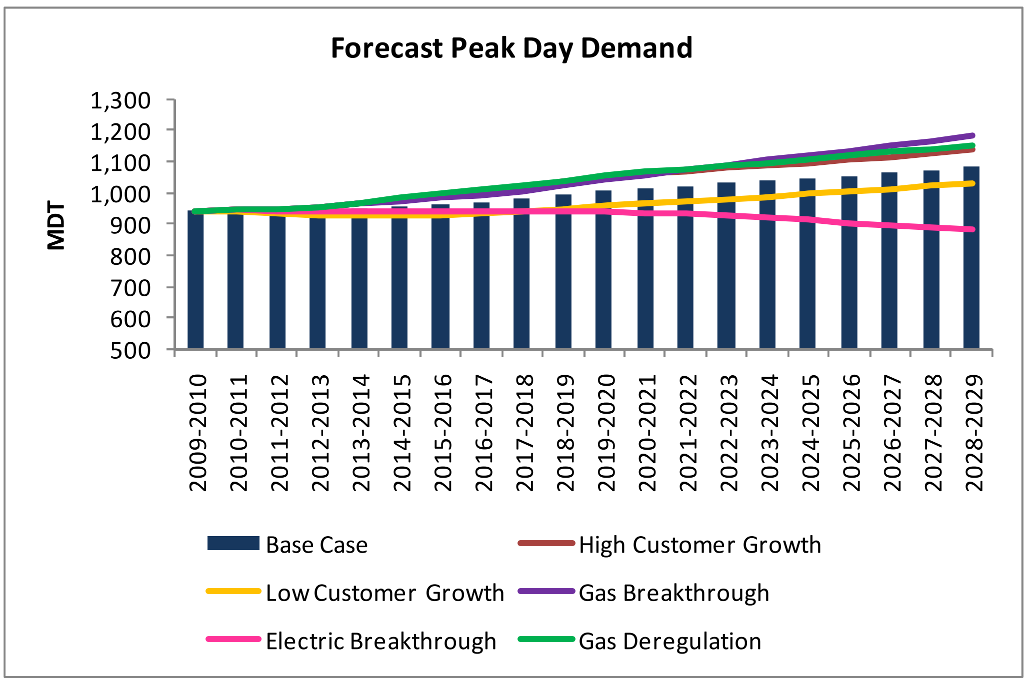


Figure 2.18 - Peak Day Demand Scenarios



VII. FORECAST ACCURACY AND PEAK DAY ANALYSIS

The load forecast model was monitored for accuracy by performing a "backcast" with two relatively recent cold weather events. NW Natural records actual daily gas requirements in aggregate form. The overall quantity of gas required to meet demand is measured on a daily basis along with the daily temperature; however the daily demand data is not differentiated by individual region and category. In order to measure forecast accuracy on a daily system-wide basis, the load forecast model parameters were combined with the actual customer mix, temperatures and gas rates from the time frame to calculate a forecast demand, called a "backcast". The results were compared to the actual daily "sendout", or the amount of gas NW Natural delivered to customers to meet demand.

The two most recent cold weather peak events occurred on January 5, 2004, and December 9, 2009. Table 2.6 summarizes the weather conditions, customer numbers, actual demand and forecast demand.

Table 2.6 - Backcast

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

The January 5th 2004 date represents the all time single day record of delivered gas for NW Natural. Interestingly, demand on the December 9, 2009 peak date was less the than the 2004 peak event, even though the temperatures were nearly identical on the two dates and nearly 85,000 new customers had been added in the meantime. It is believed that the variation in demand response was due to the differences in wind and cloud cover. The 2004 date was very windy with cloud cover while the later peak event was nearly perfectly calm with sunny conditions. In addition, improvements to energy efficiency in the time gap may have played a role in the reduced demand.

Figures 2.19 and 2.20 display the "backcast" for the entire month in which the recent peak events occurred. Along with the actual and predicted demand, the average daily wind speed at PDX is plotted.

Figure 2.19 - Backcast Results for January 2004

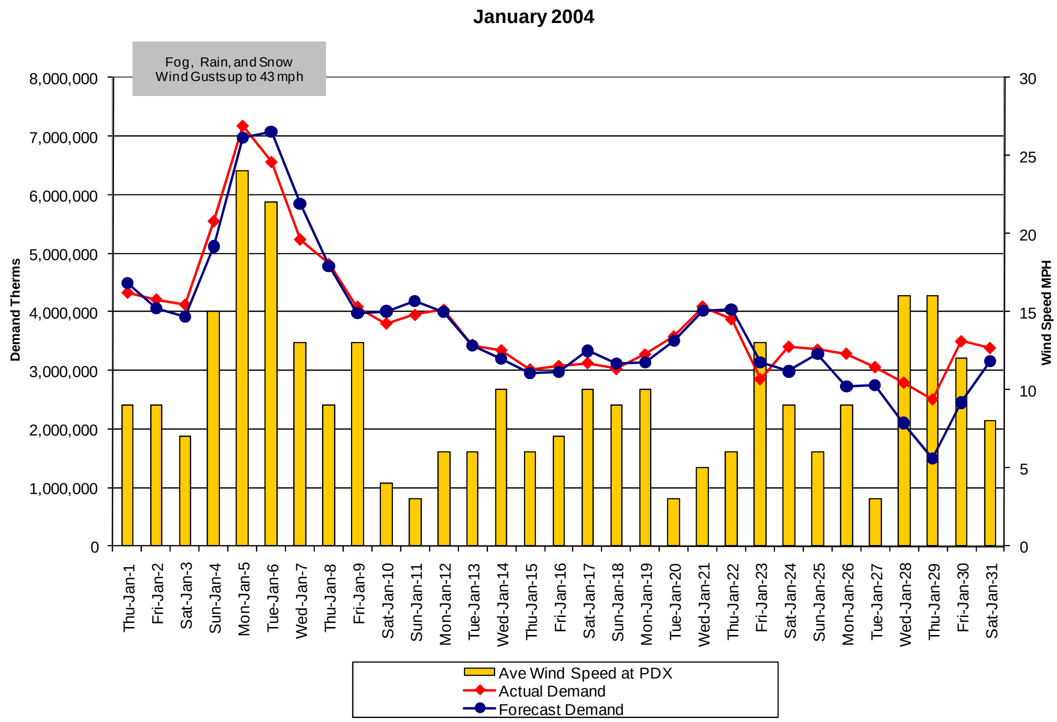
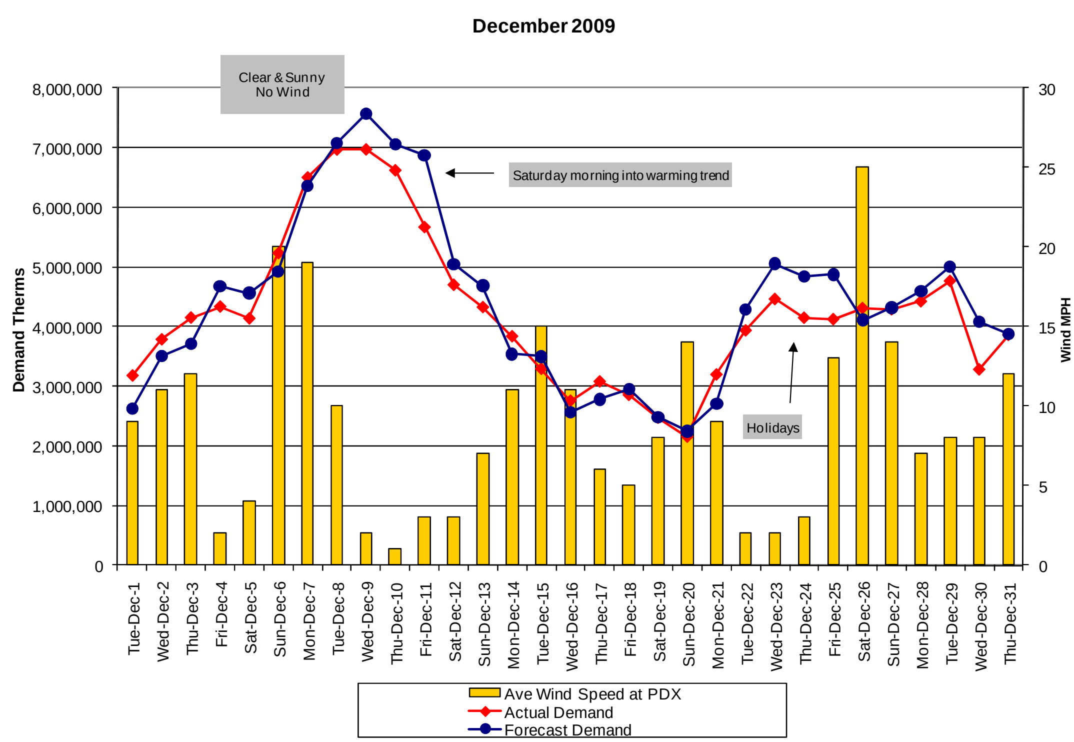


Figure 2.20 - Backcast results for December 2009



It is apparent that wind speed and cloud cover played a role in the demand response. However, wind speed and its effect on demand in combination with temperature is not currently modeled in the load forecast. This may be a topic for further study in a future IRP. Differing demand responses on holidays also contribute to load forecast error, as can be seen in Figure 2.20 in late December**.** Some factories, businesses and schools may be closed at various times in later December which can result in the forecast overshooting actual demand.

Accuracy statistics were calculated from the backcast and are listed in Table 2.7. The error computed over the entire month is shown, along with the daily mean absolute percent error (MAPE).

Table 2.7 – Accuracy Statistics

	January 2004	**December 2009**
Overall monthly error	-3,646,536	4,639,762
Monthly % Error	-3.0 %	+ 3.5 %
Daily MAPE	7.8 %	8.6 %
Peak Day % Error	-1.5 %	+ 8.4 %

VIII. KEY FINDINGS

- The current economic slump continues to affect NW Natural's customer growth. In 2006, growth was over 3%, while in 2009 and 2010 growth came in under 1%. The average annual customer growth over the 20 year horizon for this plan is 1.84%. Growth is expected to remain under 2% until 2015.
- The average annual growth in demand over the planning horizon is expected to be 0.61%, with Peak Day demand increasing at an average rate of 0.74%.
- Use per customer is expected to decline at a rate similar to recent historical rates. In the residential sector, use per customer is forecast to decline by an average annual rate of 1%, and in the commercial sector the average decline is forecast to be 1.3%.
- Natural gas prices are currently at historic lows in North America due to the combination of low demand and plentiful supplies. Going forward, prices are expected to slowly rise.
- NW Natural continues to plan resources around the early February 1989 peak day weather event, along with a design winter pattern as cold or colder than 85% of the winters experienced in the last 20 years.

Chapter 3: Supply Side Resources

NW Natural®

I. OVERVIEW

This chapter discusses the gas supply resources that the Company currently uses to meet existing firm customer supply requirements, as well as the supply-side alternatives that could be used to meet the forecasted growth in gas requirements as described in Chapter 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 system enhancements necessary to distribute the gas. This chapter surveys existing and potential resources without judgment as to the resources that will be chosen. Chapter 5 describes the actual linear programming optimization process, which selects the resources that are least cost under a variety of load growth scenarios.

The gas supply planning process focuses on securing and dispatching gas supply resources to ensure reliable service to the Company's sales customers. The amount of gas needed is greatly influenced by customer behavior. Several factors can affect customer behavior and can cause daily, seasonal, and annual variations in the amount of gas required. Much of this variation is due to changes in the weather. However, changes in business cycles, and the price of natural gas service in relation to other fuel alternatives, may also influence a customer's 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 keeping a variety of supply resources available. The Company's current supply portfolio consists of both contracted natural gas supplies, which can be used year-round and transported on the interstate pipeline system, and storage gas supplies, which are stored either underground or as liquefied natural gas (LNG)[1] in tanks. Both can be used as peaking resources during periods of high demand.

Another resource in the Company's portfolio is a variation on storage. It consists of recallable supply arrangements with industrial customers, gas-fired electric generation plants, and/or with the gas suppliers serving such facilities. The terms of these agreements allow the Company to call on gas supplies controlled by these parties for a limited number of days during the heating season. For a variety of reasons this resource most closely resembles NW Natural’s LNG peaking service. The alternate fuel tanks of the end-users could be thought of as the storage medium. Since the end-users for these gas supplies either have to shut down or switch to alternative fuels, the duration for such service is limited, like LNG. Its delivery to or within the Company's service territory again mirrors that of the Company's LNG plants and related contracts. Finally, like LNG, this is a relatively expensive resource

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1 Liquefied natural gas, or LNG, is natural gas in its liquid form. When natural gas is cooled to minus 258 degrees Fahrenheit (-161 degrees Celsius), it becomes a clear, colorless, odorless liquid. LNG is neither corrosive nor toxic. Natural gas is primarily methane with low concentrations of other hydrocarbons, water, carbon dioxide, nitrogen, oxygen and some sulfur compounds. During the process known as liquefaction, natural gas is cooled to its boiling point, removing most of these compounds. 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.

on a pure cent per therm basis. That is because prospective suppliers of this service expect it to be called upon during the harshest weather, when alternate fuel costs are highest and re-supply is uncertain, and so they must include the possible cost of plant shutdowns and product loss. Most customers are simply unwilling to even consider providing such a service on a negotiated basis, and others may be too small to be of interest to the Company. However, the Company continues to pursue such resources where feasible.

Even with the price of natural gas expected to increase over the next 20 years, NW Natural expects its gas supply requirements to generally 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.

The effects of price elasticity add another layer of complexity onto gas requirements. When prices go up, consumption should decrease to some extent. This may be due to structural changes and choices, such as the installation of higher efficiency appliances and insulating materials. Or, it may be due to behavioral changes, such as turning down thermostat settings and dressing warmer. The structural changes should persist under most conditions, but the behavioral changes could be easily reversed. For example, lowering the thermostat may be a customer's response to high prices, but during an extreme cold weather episode, the customer may decide to raise the thermostat rather than risk frozen pipes or endure uncomfortable conditions. This may be a temporary move that has a negligible impact on annual requirements, but, in the aggregate, it could directly correlate to and have a non-trivial impact on peak day requirements.

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

II. CURRENT RESOURCES

A. Pipeline Transportation Contracts

NW Natural holds firm transportation contracts for capacity on the Northwest Pipeline Corporation (NWPL) interstate pipeline system, over which all of NW Natural's supplies must flow except for the small amount of local gas produced in the Mist field (currently about 2% of annual requirements). For its purchases in Alberta and British Columbia, NW Natural also holds transportation contracts on the pipeline systems upstream of NWPL, namely Gas Transmission Northwest (GTN, a unit of TransCanada Pipelines Limited), TransCanada's BC System (TCPL-BC, also referred to as Foothills and formerly known as ANG), TransCanada's Alberta System (TCPL-Alberta, also known as 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).

NW Natural holds all rights to all of its firm transportation contracts. Similarly, NW Natural has released a small portion of its NWPL capacity to one customer but has retained certain heating season recall rights. Details of those contracts are provided in Table 3.1.

Table 3.1[2] - Firm Transportation Capacity as of November 2011

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
NWPL:		
Sales Conversion	214,889	9/30/2018
1993 Expansion	35,155	9/30/2044
1995 Expansion	102,000	11/30/2016
International Paper Cap. Acquisition	4,147	11/30/2016
Occidental (formerly Duke) Cap. Acq.	5,000	3/31/2012
Total NWPL Capacity	361,191	
less recallable release to -		
Portland General Electric	(30,000)	10/31/2012
Net NWPL Capacity	331,191	
GTN:		
Sales Conversion	3,616	10/31/2023
1993 Expansion	46,549	10/31/2023
1995 Rationalization	56,000	10/31/2012
Total GTN Capacity	106,165	
TCPL BC System:		
1993 Expansion	47,727	10/31/2012
1995 Rationalization	57,417	10/31/2012
Engage Capacity Acquisition	3,708	10/31/2012
2004 Capacity Acquisition	48,187	10/31/2016
Total TCPL-BC Capacity	157,039	
TCPL Alberta System:		
1993 Expansion	48,135	10/31/2012
1995 Rationalization	57,909	10/31/2012
Engage Capacity Acquisition	3,739	Upon 1-year notice
2004 Capacity Acquisition	49,138	10/31/2016
Total TCPL-Alberta Capacity	158,921	
WEI T-South Capacity	57,822	10/31/2014
Southern Crossing Pipeline (SCP)	47,747	10/31/2020

2 Notes to Table 3.1:

a. For each listed capacity resource, the SENDOUT® model includes the cost NW Natural is currently paying for the service.
b. The WEI and Southern Crossing contracts are denominated in volumetric units. Accordingly, the above energy units are approximations.
c. The numbers shown for the 1993 Expansion contracts on GTN and TCPL-BC are for the winter season (October-March) only. Both contracts decline during the summer season (April-September) to approximately 300,000 therms/day.
d. The existing Occidental capacity acquisition of 5,000 Dth/day that terminates 3/31/2012 will be replaced by two new permanent capacity acquisitions from Occidental totaling 5,046 Dth/day.

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 moved towards some standardization of 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 pipelines try to be consistent with most of the NAESB standards since much of the Canadian gas production is destined for export to markets in the United States.

On the pipeline systems utilized by NW Natural, usage among capacity holders tends to peak in roughly a coincident fashion as cold weather blankets the Pacific Northwest region. Similarly, capacity that may be available during off-peak months tends to be available from many capacity holders at the same time. This means that, unfortunately, NW Natural is rarely in a position to release capacity during high value periods of the year, and it would be unusual for capacity to be available for acquisition during peak load conditions. Given the dynamics of market growth and pipeline expansion, the Company will continue to monitor and utilize the capacity release mechanism whenever appropriate, which primarily will mean continuing to post its own capacity for release during off-peak periods to benefit its customers.

B. Gas Supply Contracts

NW Natural's portfolio of supply for the 2010-2011 heating season is indicated in Table 3.2.[3] The contracts with near-term expiration dates will either be renegotiated or replaced prior to the next heating season. The contracts are baseloaded, meaning they have a daily delivery obligation, unless labeled as “Swing Supply,” which means NW Natural has a daily option to take all, some or none of the indicated volumes at its discretion.

3 Table 3.2 excludes local production from the Mist field that is delivered directly to NW Natural’s system. Since the initial gas discoveries in 1979, Mist production flows peaked at approximately 100,000 therms per day. Local production now results from third party exploration efforts and currently runs about 40,000 therms per day. The Company utilizes approximately 40,000 therms per day for modeling purposes. All such production is sold under a long-term contract to NW Natural for the life of the production wells. Due to the relatively low Btu content of the production gas, volumes almost always must be blended with the Company's other supplies to reach an acceptable heating value. This limits the amount of production gas the Company can receive, and so the amount is not likely to change significantly unless higher Btu gas discoveries are made or markets for lower Btu gas can be found.

Table 3.2[4] - Firm Off-System Gas Supply Contracts for the 2011-2012 Tracker Year

Supply Location	Duration	Baseload Quantity (Dth/day)	Swing Quantity (Dth/day)	Contract Termination Date
British Columbia (Station 2):				
IGI Resources	Nov-Oct	5,000		10/31/2012
Macquarie Energy Canada	Nov-Oct	10,000		10/31/2012
TD Energy Trading	Nov-Oct	5,000		10/31/2012
ConocoPhillips Canada	Nov-Oct	5,000		10/31/2012
AltaGas Energy	Nov-Oct	5,000		10/31/2012
Husky Energy Marketing	Nov-Oct	10,000		10/31/2012
Shell Energy Canada	Nov-Mar	5,000		3/31/2012
Suncor Energy Marketing	Nov-Mar	5,000		3/31/2012
Alberta:				
JP Morgan	Nov-Oct	10,000		10/31/2014
Husky Energy Marketing	Nov-Mar	10,000		3/31/2012
Shell Energy North America (Canada)	Nov-Mar	5,000		3/31/2012
ConocoPhillips Canada	Nov-Mar	5,000		3/31/2012
IGI Resources	Nov-Mar	5,000		3/31/2012
Powerex	Nov-Mar	5,000		3/31/2012
Nobel America's Gas & Power	Nov-Mar	5,000		3/31/2012
Macquarie Energy Canada	Nov-Mar	5,000		3/31/2012
pending	Nov-Mar		10,000	3/31/2012
pending	Apr-Oct		10,000	10/31/2012
Rockies:				
Societe General	Nov-Mar	10,000		3/31/2012

4 Notes to Table 3.2:

a. Contract quantities represent deliveries into upstream pipelines. Accordingly, quantities delivered into NW Natural's systems are slightly less due to upstream pipeline fuel consumption.

b. Nov-Mar and Jan-Oct "Swing" contracts represent physical call options at NW Natural's discretion, while the Apr-Oct "Swing" contracts represent physical put options at the supplier's discretion.

c. "Pending" represents contracts to be finalized prior to October 2012 updated PGA filing..

Table 3.2 (continued)

Supply Location	Duration	Baseload Quantity (Dth/day)	Swing Supply (Dth/day)	Contract Termination Date
IGI Resources	Nov-Mar	5,000		3/31/2012
Anadarko Energy Services	Nov-Mar	10,000		3/31/2012
National Fuel Marketing	Nov-Mar	5,000		3/31/2012
Ultra Resources	Nov-Oct	10,000		10/31/2012
Shell Energy North America (US)	Nov-Mar	5,000		3/31/2012
ConocoPhillips Company	Nov-Oct	5,000		10/31/2013
Encana Marketing (USA)	Nov-Oct	5,000		11/1/2015
Encana Marketing (USA)	Jan-Oct		7,500	12/31/2012
ONEOK Energy Services	Nov-Mar		5,000	3/31/2012
Kansas Energy	Nov-Mar		10,000	3/31/2012
Kansas Energy	Nov-Mar		10,000	3/31/2012
ConocoPhillips Company	Nov-Mar		5,000	3/31/2012
Kansas Energy	Apr-Oct		10,000	10/31/2012
pending	Nov-Mar	5,000		3/31/2012
Total Off-System Firm Contract Supply		160,000	67,500	

NW Natural's core customers currently receive underground storage service at NW Natural's Miller Station facility from four depleted production reservoirs (Bruer, Flora, Al's Pool, and a portion of Reichhold), collectively referred to as Mist storage. The Mist storage deliverability and seasonal capacity shown in Table 3-3 represents NW Natural's portion of the present design capacity reserved for core customers. This facility has a maximum total daily deliverability of 519,000 dekatherms and a total working gas capacity of about 16 million dekatherms contained in the above mentioned reservoirs plus three newer reservoirs (Schlicker, Busch, and Meyer). Capacity in excess of core needs is made available for the non-utility storage business. As core needs grow, existing storage capacity may be recalled and transferred for use by core utility customers. The IRP models the recallable portion of the existing Mist storage capacity as an incremental resource that is discussed in Section V of this chapter.

Table 3.3 – Firm Storage Resources

Facility	Max. Daily Rate (Dth/day)
Jackson Prairie	46,030
Plymouth LNG	60,000
Mist (reserved for core)	250,000
Gasco LNG	120,000
Newport LNG	60,000

D. Other Existing Supply Resources

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

Table 3.4[5] - Recallable Supply Arrangements as of November 2010

Type	Max. Daily Rate (Dth/day)	Max. Annual Recall (days)	Termination Date
Recall 1	30,000	30	11/1/2012
Recall 2	8,000	40	11/1/2015
Recall 3	1,000	15	upon 1 year notice
Total Recall Resource	39,000		

All of the above agreements provide for continuation after the termination date if mutually acceptable. One of these deals (Recall 3) is already in its annual "evergreen" period. Recall 1 utilizes NWPL capacity released by NW Natural on a recallable basis, and correlates to customer release volumes shown in Table 3.1. Should this arrangement terminate, the released NWPL capacity reverts back to NW Natural. Recall 2 utilizes NWPL capacity held by the provider of the service.

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

NW Natural also supplies a portion of its gas requirements through a joint venture relationship with Encana Oil & Gas. This relationship is discussed in more detail below.

E. Joint Venture for Gas Reserves

In April of 2011, NW Natural entered into agreements with Encana Oil & Gas, under which NW Natural and Encana agreed to participate in a joint venture to develop gas reserves located in the Jonah Field, located in the Green River Basin in Sublette County, Wyoming.[6] Under these agreements, NW Natural pays a portion of the costs of drilling in the Jonah field, and in return receives rights to the production of gas from certain sections of the field. Under the terms of the agreements, NW Natural has an option to either take the physical gas to which it has rights at the Opal Hub, or to have Encana market the gas and

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

6 On April 28, 2011, the OPUC issued an order finding NW Natural's actions prudent in entering into a joint venture with Encana Oil & Gas (USA) to develop gas reserves on behalf of its Oregon customers. *See* Docket No. UM 1520, Order No. 11-176

for NW Natural to then purchase gas at another location, applying the proceeds from the sale by Encana to the purchase costs.

NW Natural expects that the venture will help provide long-term supplies for NW Natural's Oregon utility customers over about a 30-year period. During the first 10 years of the agreement, NW Natural expects the volume of gas received under the transaction (or the volumes of gas to which its proceeds from the joint venture will be applied) to be approximately 8-10 percent of the company's average annual requirements for its utility operations. It also expects its investment to result in the availability of about 93 billion cubic feet (Bcf) of gas at a highly competitive price as compared to equivalent gas supply purchase alternatives over the same term.

The joint venture with Encana serves an important role in the Company's overall portfolio because it operates somewhat like a long-term physical and financial hedge. And, rather than being limited to a duration of several years, which is the term that is normally available in the market, the transaction gives NW Natural's customers price stability for a portion of their portfolio that is of a much longer term. As was developed in the proceeding where the transaction with Encana was reviewed by the OPUC,[7] NW Natural believes that this transaction offered NW Natural's customers the lowest reasonable cost available for long-term price stability, with a significant expected value benefit to customers relative to fixed price hedging alternatives.

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

In preparing this IRP, NW Natural considered whether it should specifically model gas acquisition options by embedding the expected price of gas under the joint venture with Encana as an available price in its models. It determined that doing so would be problematic and unhelpful. Although one of the building blocks of the IRP analysis is a price forecast applicable to commodity gas purchases, which permits a complete evaluation and comparison of different demand-side measures and supply-side resources, embedding the Encana gas supplies and associated price within that forecast would likely skew the results improperly because those prices are available under just this one transaction, which has limited volumes associated with it. If NW Natural were to use the price from the Encana transaction as a proxy for the marginal cost of gas, the model would not produce a realistic analysis of the options available to NW Natural in purchasing gas. Moreover, as explained above, the existence of the Encana transaction does not have an effect on the location at which NW Natural will purchase gas because it can always choose to apply the proceeds from the transaction to whatever purchases it makes, and it

7 *See* OPUC Docket Nos. UM 1520 and UG 204.

will strive to make those purchases at the lowest cost locations, regardless of the fact that it can apply proceeds from the Encana transaction to those purchases.

Although the joint venture with Encana does not specifically alter the resource options modeled in this IRP, the above description of the arrangement with Encana is included in order to ensure that it is considered under future circumstances, which could differ significantly from today's expectations. In other words, in some future IRP it is possible that some aspect of the Encana transaction may need to be incorporated into analyses required in that IRP. For example, currently NW Natural does not forecast that the Encana transaction will alter the locations at which NW Natural would otherwise purchase gas. However, if, in the future, unforeseen shifts in the gas market caused NW Natural to forecast that it would rely very heavily on market purchases specifically from Opal while at the same time relying on the physical supply option under its agreement with Encana, then it may be important to recognize that the capacity available to NW Natural at Opal would need to be split between gas received under the Encana transaction and gas purchased in the market or under other supply contracts. In other words, in some instances there could be a physical delivery aspect associated with the Encana transaction, which could be important to recognize in future analyses.

NW Natural will continue to consider the unique aspects of the joint venture with Encana in future IRPs to ensure that its analysis is complete, and that the resource decisions made in the IRP are compatible with the existence of NW Natural's agreements with Encana.

Furthermore, NW Natural will continue work to determine the appropriate proportion of our portfolio that should be secured through arrangements like the one with Encana. As described above, such transactions offer benefits that are not likely to be secured through other traditional supply options. Future similar transactions may be desirable in order to both increase the percentage of NW Natural's portfolio that is characterized by long-term price certainty and to levelize over time the percent of the portfolio that is secured through these arrangements.

F. Supply Diversity

NW Natural's pipeline contracts enable it to purchase roughly one-third of its supplies from each of the major supply regions in the area: British Columbia, Alberta and the U.S. Rockies (figure 3.2). Lower liquidity in British Columbia has prompted NW Natural to baseload more of its supplies from this region on a year-round basis, i.e., to rely less on that region for winter term and spot purchases than in the past. NW Natural will continue to favor spot purchases from Alberta and the Rockies due to low prices. However, Rockies prices could change in reaction to the recent completion of two of the largest pipeline projects in decades. In November of 2009, the Rockies Express Pipeline (REX) became fully operational to move Rockies gas to markets in Illinois, Indiana, and Ohio, increasing competition and prices for those supplies. Then, in July 2011, the Ruby Pipeline commenced service from Wyoming to the California/Oregon border, providing another outlet for Rockies gas. However, new supplies from the Marcellus Shale formation will lower East demand from REX with bearish implications on Rockies prices.

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

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

Plans for 2011-2012 continue to shift, with the most significant development being the addition of supplies related to the gas reserves transaction in the Rockies that commenced in May 2011.

Physical gas contracting strategies for 2011-2012 that are consistent with strategies of recent years include:

- Maintain a diversity of physical supplies from Alberta, British Columbia and Rockies.

- Continue to shift the source of physical supplies to the lowest-cost source region. In recent years, Rockies gas offered the best prices as production increased due to anticipation of the Rockies Express Pipeline and Ruby Pipeline. Since those pipelines became fully operational, Rockies term prices have risen higher than Alberta prices. British Columbia gas is typically priced higher than Rockies and Alberta.

Figures 3.1 and 3.2 provide graphical representations of the Company's supply resources and diversity during 2010 (the most recently completed calendar year).

FIGURE 3.1 – Gas Supply Diversity by Contract Length for Calendar Year 2010

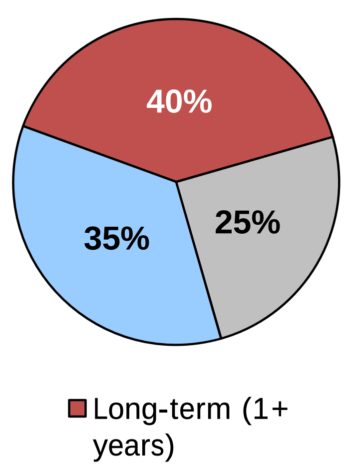
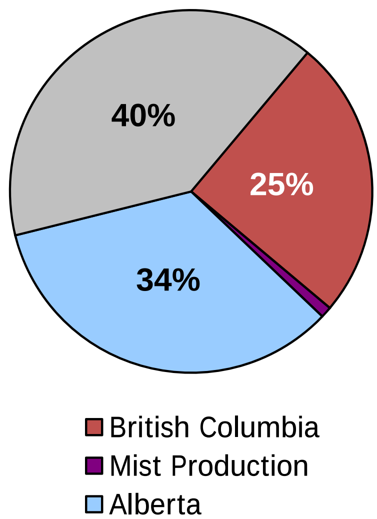


Figure 3.2 – Gas Supply Diversity by Source for Calendar Year 2010



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

G. Physical and Financial Hedging

NW Natural provides its retail customers with a bundled gas product including gas storage for its regulated utility business. To accomplish this, NW Natural aggregates load and acquires gas supplies for its core retail customers through wholesale market physical purchases that may be hedged using physical storage or financial transactions.

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

The use of selected financial derivative products provides NW Natural with the ability to employ prudent risk management strategies within designated parameters for natural gas commodity prices. The objective is to use derivative products to structure hedging strategies as defined by NW Natural's Gas Supply Risk Management Policies (GSRMP). All wholesale gas transactions must be within the limits set forth by those policies. This is intended to prevent speculative risk.

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

III. SUPPLY-SIDE RESOURCE DISPATCHING

The Company's Gas Supply Department utilizes SENDOUT® to perform its dispatch modeling each fall. Based on expected conditions, this modeling provides guidance to the department in how it anticipates dispatching from various pipeline supplies and storage facilities. The objective is to ensure reliable service during the heating season on an aggregate system-wide basis and, at the same time, achieve the maximum economic benefit from seasonal price differences and varying gas delivery terms. With the assistance of SENDOUT,® resource portfolios are developed with the most likely combination of expected costs and associated risks and uncertainties for the utility and its customers. The system is operated as an integrated whole and costs are apportioned accordingly, absent state boundaries.

NW Natural's heavy reliance on storage gas requires routine examination of the Company's ability to meet peaking loads. To test the Company's storage resources, Gas Supply incorporates inventory curves into the SENDOUT® modeling that represent the ideal operation of each storage facility to meet core customer demand. These results provide insight for operational personnel by simulating the effects of dispatch choices on subsequent heating season conditions.

IV. RECENT RESOURCE DECISIONS

In 2009, NW Natural added 100,000 therms per day of core capacity at its Mist storage field, and in 2011, an additional 100,000 therms per day of deliverability, along with related annual storage capacity. In addition to acquiring these new resources, the Company has taken the following steps in accordance with its previously stated action plan:

- 2007 IRP Action Plan 2.1: "Review cost estimates, on an ongoing basis, for those resources under consideration to identify potential changes in the composition of previously selected resource mixes."

  - For this IRP, cost estimates for satellite LNG, the Willamette Valley feeder and basin differentials for the major hubs at which NW Natural purchases gas were updated. The Company engaged in informal discussions with pipeline project sponsors to determine if it was possible to update costs and more accurately model proposed pipeline projects from the Rocky Mountains. However, the Company determined that because the two primary proposed projects (the Ruby and Sunstone Pipelines) were still in flux with regard to capacity and cost, it was premature, and could be potentially misleading, to attempt more specific modeling. When better and more final cost information is available, the Company will model these projects more specifically.

- 2007 IRP Action Plan 2.2: "Recall daily and annual underground storage capacity from the interstate storage gas market to core market service as needed."

  - We have recalled a total of 30,000 Dth/day of withdrawal capacity at the Mist storage field, along with associated annual capacity, since the 2007 IRP for use by the Company's core customers (10,000 Dth/day in 2008 as well as the recalls in 2009 and 2011 mentioned at the beginning of this section).

  - 2007 IRP Action Plan 2.3: "Support development of the Palomar Pipeline, primarily for risk management purposes in diversifying the Company's supply path options.

- The Company continues to support development of the Palomar Pipeline. However, until such time as we are required to commit to contracting for capacity on the pipeline, we will also continue to assess this resource in the IRP to ensure its continued cost-effectiveness.

- 2007 IRP Action Plan 2.4: "Monitor LNG import terminal developments and participate in discussions with project sponsors to preserve the option of purchasing LNG-sourced gas supplies to the extent this proves to be a cost-effective resource option."
  - The Company continues to monitor system supply opportunities from proposed liquefied natural gas import facilities in Oregon and has taken advantage of outside consulting resources with this IRP to better assess the likelihood and timing of LNG imports to the region.
- 2007 IRP Action Plan 2.5: "The Northwest is currently witnessing a variety of proposals to construct new or expand existing interstate pipeline projects, principally related to moving Rocky Mountain and LNG-sourced gas supplies to markets throughout the West Coast. The Company will monitor these proposals and, as appropriate, participate in discussions with project sponsors to preserve the option of securing cost-effective new interstate pipeline capacity."
  - The Company continues to monitor various pipeline projects and the potential development of an imported LNG terminal in the Pacific Northwest.
- 2007 IRP Action Plan 2.6: "Refine cost estimates, conduct more detailed system modeling, and investigate siting/permitting constraints on satellite LNG facilities and the specific NW Natural distribution system investments--including the Willamette Valley Feeder and Newport LNG enhancement--identified as potential cost-effective resources in this IRP."
  - This IRP includes refinements to the modeling of the Willamette Valley Feeder and satellite LNG projects to reflect better cost estimates, more detailed route planning, and more specific information about potential siting constraints for satellite LNG. Specifically, we have postponed the availability of satellite LNG in the model until 2011, to reflect the challenges of siting LNG, and have increased the costs based on more recent information.
- 2007 IRP Action Plan 2.7: "While NW Natural has not included biogas as a resource option in this IRP, the Company will continue to investigate how this resource can be utilized in the future, given the enormous environmental benefits that may accrue to it."
  - Since the 2007 IRP, the Company has invested significant shareholder funds in a biodigester project that may eventually lead to the development of biogas that may be used on site to displace propane, or eventually may be brought to pipeline quality. NW Natural continues to be active in the development of biogas and will monitor this potential source of renewable natural gas.

V. FUTURE RESOURCE ALTERNATIVES

Aside from the existing gas supply resources mentioned previously, NW Natural is now considering additional gas supply resource options including recall or acquisition of existing and new interstate pipeline capacity, recall of existing Mist storage marketed to interstate customers, imported LNG, satellite LNG, and various extensions/expansion of its own pipeline system. The primary alternatives are described in more detail below and summarized in Appendix 3-2. These options will be evaluated in Chapter 5 using SENDOUT.®

A. Interstate Capacity Additions

NW Natural holds existing CD entitlements and citygate station capacity on: 1) NWPL's "mainline" serving NW Natural's service areas in Portland, Astoria, Vancouver and The Dalles, and 2) NWPL's Grants Pass Lateral serving NW Natural's loads in the Willamette Valley south of Portland. Therefore, consideration of incremental NWPL capacity, separately on the mainline and on the Grants Pass Lateral, is a starting point for NW Natural's assessment of incremental interstate pipeline capacity in this IRP.

Since NW Natural is only interconnected to NWPL, a subscription to more NWPL mainline capacity has traditionally been a prerequisite to holding more upstream capacity of equivalent amount (i.e. from GTN). NW Natural considers exceptions to this rule when market dynamics indicate some advantage to holding more, less, or different upstream capacity than it currently has in its possession. 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 import terminal in the Pacific Northwest or British Columbia and/or the construction of a new pipeline transporting Arctic gas (either from Alaska or the Mackenzie Delta) are examples of market developments that could cause NW Natural to reconfigure or add to its upstream pipeline contracts. Under these market conditions, it may be to NW Natural's benefit to hold transportation capacity upstream of NWPL leading to these new supply points.

In response to its reliance solely on NWPL for delivery of interstate gas supplies, NW Natural has partnered with TransCanada Corporation to form Palomar Gas Transmission LLC. As depicted in Figure 3.3, Palomar is proposing to develop, build and operate the proposed Palomar pipeline project. The pipeline would connect GTN's mainline north of Madras, Oregon, to NW Natural's gate station at Molalla . On December 11, 2008, Palomar filed an application for a certificate to build and operate the pipeline with the Federal Energy Regulatory Commission. On March 23, 2011, Palomar Gas Transmission LLC withdrew its original pipeline application with FERC, while stating its expectation of re-filing at a later date. Information for a new Cross-Cascades pipeline project called Palomar/Blue Bridge was presented in February 2011 at a public workshop jointly sponsored by the Public Utility Commission of Oregon and the Washington Utility and Transportation Commission. The information presented included new estimates for pipeline rates and service dates. The proposed Palomar project would be subject to approval by the Federal Energy Regulatory Commission (FERC), as well as the U.S. Forest Service, Bureau of Land Management, and numerous other Federal and State agencies.

Figure 3.3 - Proposed Palomar East Pipeline

From NW Natural's perspective, the primary benefit accruing from construction of Palomar/Blue Bridge would be to manage the risks associated with the delivery of natural gas into the region. The Willamette Valley, including the Portland metro area, is served solely by NWPL. Adding a second interstate pipeline delivery corridor would assure both the security of gas supply as well as reliable gas service well into the future for core customers. As such, by interconnecting with Palomar at Molalla, NW Natural would be in position to consider turning back redundant NWPL capacity.[8]

As shown in Table 3.5 below, in this IRP, NW Natural considers acquisition of incremental interstate pipeline capacity in several forms: 1) new NWPL Grants Pass Lateral capacity serving Salem, Newport, Albany and Eugene, 2) new NWPL "mainline" capacity serving Portland, Astoria, Vancouver, and The Dalles, 3) new capacity upstream of NWPL mainline capacity providing access to the Rockies[9] and Alberta supply areas, 4) new Palomar/Blue Bridge capacity, 5) new capacity on the proposed Pacific Connector Pipeline to access regasified LNG from the proposed Jordan Cove LNG project at Coos Bay, Oregon, 6) recall of existing NWPL mainline capacity from the Rockies and Sumas that NW Natural has released to Georgia Pacific, and 7) existing NWPL mainline capacity from the Rockies that NW Natural has contracted to acquire starting in 2017. The acquisition of incremental pipeline capacity spans a wide

8 NW Natural has modeled a turn back of up to 77,000 Dth/day of existing NWPL capacity from Stanfield to Portland upon the availability of Palomar capacity.

9 NWPL capacity upstream of Stanfield, Oregon.

range of lead times; its availability depends on the availability of existing capacity, the length of the pipeline's open season process, and the completion date of the constructed facilities.

Table 3.5 - Incremental Interstate Pipeline Capacity Additions Modeled in SENDOUT®

Interstate Pipeline Segments	Contract Demand (Dth/d)	Assumed Availability
NWPL Zones 12-9 (Grants Pass Lateral)	74,200	November 2013
NWPL Zones 26-12 ("mainline")	300,000	November 2013
Upstream of NWPL z26-12:		
Rockies-Stanfield	1,062,000	November 2014
Alberta-Stanfield	969,000	November 2012
Palomar/Blue Bridge	300,000	November 2014
Pacific Connector	50,000	November 2014
GP Recall (existing NWPL capacity)	3,500 each from Rockies & Sumas	November 2008
March Point NWPL capacity	12,000 Rockies to Portland	November 2017

B. Mist Storage Recall

In addition to the existing Mist storage capacity currently reserved for the core market (see Table 3.3), the Company has four reservoirs (Reichhold, Schlicker, Busch and Meyer Pools) that are developed for storage services and currently serve the interstate storage market in whole or in part, but could be recalled for service to the Company's core customers. Table 3.6 identifies the recallable Mist capacity and the year the capacity is available given current contractual commitments to interstate market customers.

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

Assumed Availability	Capacity (Dth)		Deliverability (Dth)	
	Increment	Cumulative	Increment	Cumulative
2011	2,060,000	2,060,000	91,110	91,110
2012	1,499,000	3,559,000	66,298	157,407
2013	133,000	3,692,000	5,882	163,290
2015	1,170,000	4,862,000	51,747	215,036
2017	1,260,000	6,122,000	55,727	270,764

Mist is ideally located in NW Natural's service territory, eliminating the need for upstream interstate pipeline transportation service to deliver the gas during the heating season. Due to its location within the Company's service territory, 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 along the Columbia River from St. Helens to Astoria.

C. NW NATURAL INFRASTRUCTURE ADDITIONS

System expansions or reinforcements accompany the need to increase resources to meet load growth, regardless of whether supplies come from Mist or from the Company's numerous gate station interconnections with NWPL. The Company's Engineering Department, in close collaboration with the Construction and Marketing departments, and using input from outside economic development and planning agencies, plans for the expansion, reinforcement and replacement of the distribution system.

The Company uses the Synergy software package[10] to evaluate infrastructure requirements. Synergy provides the platform for digital computer simulation of transient gas flow behavior in any arbitrarily configured piping system. The analysis procedure calculates the time-varying flows, pressures, horsepower and other variables under scenarios that reflect actual service conditions. Studies are conducted to determine the response of the gas distribution system due to load changes, pressure set point changes, compressor performance changes, etc. The software is also sophisticated enough to enable the modeling of high-speed transient conditions, such as instantaneous valve closure and pipeline rupture.

The Company has constructed models based on the Synergy software that are designed to evaluate distribution system capacity constraints, inter-related flow characteristics, and pressure stabilization aspects of distribution system planning that are evaluated under steady-state and transient conditions. Over time the process was streamlined through the integration of geographically referenced system map information and Company data sources. This enhancement enabled Engineering to avoid the formerly tedious and time-consuming effort of manually constructing nodal networks and linking data. System maps from the Geographic Information System provide the physical distribution system data required for basic model construction, and the Customer Information System provides load data.

The Synergy models and software provide the Company the opportunity to evaluate performance of the distribution system under a variety of conditions. Typically the analysis focuses on meeting growing peak day customer demands while maintaining system stability. Gas requirements at delivery nodes are projected based on observed flow rates during recent cold weather episodes. These flow rates are then adjusted to match design peak weather conditions and the effects of customer growth. Alternative system expansion and reinforcement strategies are then evaluated in terms of system stability, cost, and the ability to meet future gas delivery requirements. This computer simulation capability allows the Company to efficiently evaluate distribution system performance in terms of stability, reliability, and safety under varying boundary conditions ranging from peak-day delivery requirements to temporary service interruptions, both planned and unplanned.

System planning takes place continuously, integrating new customer growth requirements into the Company's construction forecasts. Computer simulation testing is used to help validate the need for and timing of specific system expansion, reinforcement, and replacement projects. Near-term (one to two-year) projects are highly likely to occur as specified to meet customer delivery requirements. Mid-term (three to five-year) projects are subject to time slippage based on adjustments to the rate and geographic direction of customer growth. Long-term (beyond five years) will tend to be general

10 This software was formerly known as the Stoner Workstation Service (SWS).

projections based on expected economic development of the region and gas supply resource acquisitions, and thus, subject to change.

With SMPE completed in 2004, future internal infrastructure decisions revolve around two key considerations:

1. The impact on the Company's pipeline system design, reinforcement and replacement projects from the 2002 federally-mandated Integrity Management Program (IMP) and other similar state approved programs regarding bare steel pipeline and geo-hazard mitigation. IMP and similar programs continue to evolve, but compliance is likely to require significant infrastructure investment over the next ten years. Those programs have been and will continue to be the subject of separate proceedings with state regulators and will not be further discussed here, but any infrastructure conclusions reached in the IRP will require further analysis to ensure congruence with the various integrity programs.

2. Alternatives for moving Mist and Newport storage gas to customers outside the current confines of the Portland-area and northern Willamette Valley distribution systems, respectively. The focus of the next three sections will be options for moving storage gas to areas traditionally beyond their reach.

D. Enhancement of Pipeline from Newport

The daily deliverability of the Newport LNG plant is modeled at 60,000 Dth/day due to load and infrastructure limitations. That is, the market areas served by the Newport plant (from the town of Newport north to Lincoln City and then east to Salem) have peak loads ranging up to about 60,000 Dth/day. However, the Newport plant has all the equipment necessary to vaporize and deliver up to 100,000 Dth/day. To reach the 100,000 Dth/day capability, infrastructure additions would be needed on the Newport to Salem pipeline to deliver an incremental 40,000 Dth/day (see Appendix 3-1). In addition, to connect more load centers (*e.g.*, Corvallis/Albany, Eugene) to the Newport plant, NW Natural would need to invest in some or all of the Willamette Valley Feeder project pipeline segments (see below). The additional piping and upgrading required to reach new load centers could be quite costly due to geographical constraints. This cost, though, could be competitive as compared to a subscription to additional upstream pipeline capacity, which also would need to be accompanied by Willamette Valley Feeder project investments to serve customers increasingly distant from NWPL's gate stations.

E. Brownsville to Eugene

To access approximately 8,000 Dth/day of Grants Pass Lateral capacity available at the Brownsville/Halsey gate station, the Company needed a Willamette River crossing near the town of Harrisburg in order to bring that capacity to the Eugene market. The Company completed this project in late 2010.

F. Willamette Valley Feeder

The Willamette Valley Feeder project involves new piping to move Mist gas or other incremental gas supplies delivered to Molalla south to Salem, Albany, and potentially even the Eugene area. This project could also work in conjunction with a pipeline capacity expansion project from Newport as described above. As shown in Table 3.7 below, the project includes a total of three segments serving three load regions, Salem, Albany, and Eugene

Table 3.7 - Willamette Valley Feeder Project Segments

Segment	Assumed Capacity (Dth)	Estimated Capital Cost
North WVF	85,000	$15,000,000
Mid WVF	41,000	$40,000,000
South WVF	14,000	$58,000,000

This project would be an alternative to continued expansion of NWPL's Grants Pass Lateral, which transports gas to NW Natural's system throughout the Willamette Valley. In the past it was thought that the Willamette Valley Feeder project would only proceed if environmental, civic, or other pressures significantly increase the cost or time needed to expand NWPL's lateral. However, the Company has enhanced portions of its pipeline from Portland to Salem over the past few years in the course of routine replacement activities (leakage repair, road grading projects, etc.), and would expect to continue these activities in the future as well as implement additional projects through the IMP mentioned above. Because of the project-specific nature of the Company's pipeline integrity programs, one or more specific segments of a Willamette Valley Feeder project, for example, from Albany to Eugene, could become cost-effective in lieu of incremental NWPL capacity between those two locations. For this reason, the Valley Feeder and NWPL capacity options have been segmented in the IRP analysis. The NWPL expansion capacity project includes three segments: Molalla to Salem, Salem to Albany, and Albany to Eugene. SENDOUT® evaluates the costs of Willamette Valley Feeder segments to the assumed incremental costs of the NWPL's Grants Pass Lateral capacity expansion segments, as well as to the strategic placement of satellite LNG storage discussed below. As of the date of filing this IRP, the Company expects that the North Willamette Valley Feeder will be completed and in service before the end of 2011.

It should also be noted that a Willamette Valley Feeder project offers three advantages over continued expansion of NWPL's Grants Pass Lateral that are qualitative in nature and so have not been modeled in SENDOUT.® These advantages are:

1. Risk management. By providing gas deliveries through pipelines following different routes, NW Natural will be less susceptible to disruptions affecting NWPL's system.

2. New service opportunities. By following new routes, homes and businesses that previously may have been too distant may now be able to access gas service.

3. Lower impact. Further expansion of NWPL's Grants Pass Lateral would necessitate expansion of existing distribution lines emanating from the NWPL gate stations. Prior customer growth along these corridors may make those lines more difficult to expand as compared to the Willamette Valley Feeder, which would approach those communities using alternate routes.

H. Imported and Exported Liquefied Natural Gas (LNG)

As of July 2011, FERC listed one proposed LNG import terminal in Oregon. This is the proposed Oregon LNG project near Astoria Oregon. Another proposed imported LNG facility near Coos Bay called Jordan Cove has now been mentioned as a possible export facility.

The Company continues to monitor the development of LNG sites in the Pacific Northwest. Below is a short description of proposed sites:

1) **Oregon Development Company, LLC (dba Oregon LNG)**
   To be located at the Skipanon peninsula on the Columbia River near Warrenton. On October 10, 2008, Oregon LNG filed a formal certificate application with FERC to site, construct, and operate the LNG terminal. In the same application, the associated pipeline, Oregon Pipeline Company, LLC also filed with FERC for authority to construct, own and operate a new interstate pipeline. A certificate application was filed at FERC in Docket No. CP09-6-000.

2) **Jordan Cove Energy Project, L.P.**
   To be located on the North Spit of Coos Bay, Oregon. On September 4, 2007, this project filed a form certificate application with FERC to site, construct, and operate the terminal and its associated pipeline, the Pacific Connector Gas Pipeline, LP. A certificate application was filed at FERC in Docket No. CP07-441-000.

3) **FortisBCProject (formerly Terasen Project)**
   Located NW of Ladysmith and West of Mt Hayes, this is a peak shaving LNG plant. This project is located on Vancouver island and connects into FortisBC's system. This project was recently completed and the facility commenced operation in June 2011.

4) **Kitimat LNG Inc. Terminal**
   Kitimat LNG Inc. proposes an LNG export terminal located near the private port of Kitimat in British Columbia targeted at Asian markets. In 2006, the Kitimat terminal received an environmental assessment certificate from the BC Environmental Assessment Agency and was granted federal environmental approval as a regasification terminal. Since the project has now become a send-out terminal, the developers are working with the various governmental departments in British Columbia.

I. Satellite Storage

Some gas utilities rely on satellite LNG tanks to meet a portion of their peaking requirements. LNG facilities are used as peaking resource because they provide only a few days of deliverability. The concept is that a small tank serving a remote area would be filled with LNG as winter approaches, and the site manned during cold weather episodes when vaporization is required. Since there is no on-site liquefaction process, the facility is fairly simple in design and operation. Where peaking demands are sharpest, the addition of satellite LNG could defer significant pipeline infrastructure investments.

In recent years, control system improvements at the Newport LNG plant have improved liquefaction performance. Puget Sound Energy installed a satellite LNG facility near Gig Harbor, Washington, to help meet customer growth at the tail end of its distribution system. LNG from NW Natural was used to help fill the Gig Harbor tank, and this has renewed NW Natural's interest in evaluating this concept for remote areas where siting and zoning approvals are conceivable. In this IRP, NW Natural has evaluated satellite LNG in Willamette Valley locations near Salem, Albany, and Eugene, as interim resources that might delay the incursion of more expensive pipeline projects . The Company has modeled these resources as having 90,000 Dth (equivalent) of storage capacity and a maximum deliverability of 30,000 Dth/day for three days. The Company believes these are reasonable assumptions based on industry research of comparable facilities. At maximum vaporization/deliverability, this equates to a three day peaking resource.

J. Potential Future Supply Resources

In this section NW Natural identifies several other potential gas supply resources that could influence the design of NW Natural's future gas resource portfolio. NW Natural concludes that at this time these potential resources are not yet sufficiently well defined commercially or technically to warrant inclusion in the SENDOUT® model for this IRP.

Biogas and the emerging underlying technology have the potential to provide a wide range of benefits far beyond further diversification of the Company's resource portfolio. The Company has invested in local biodiogester development as a means for offsetting our customers' carbon dioxide emissions through methane sequestration and as a study on biogas development and use. The Dairy Farmers of Oregon and the Oregon Department of Agriculture support the development of biodigesters, which anaerobically convert animal waste into methane (natural gas) and composted soil amendment (fertilizer). Biodigesters are seen as helping the farming industry, the economy and the environment

The Company has focused its efforts on an emerging technology that converts animal waste into anaerobic digester gas (ADG). While companies around the world have refined this approach, companies in the Pacific Northwest offer the resources to bring such a program together. Capital expenditure requirement per site are approximately $5 million. However, the natural gas output is limited when compared to the Company's annual load requirements. The program is further enticing because of the other by-product of the process – fertilizer. Regardless of who manages the program, it has the potential to offset the capital costs and provide a consistent revenue stream. These projects could also eliminate the need to manage waste retention ponds, avoid contamination due to run-off, and decrease the need for commercial fertilizers.

In 2008, the Company partnered with Bonneville Environmental Foundation (BEF) and an owner of a local dairy to develop a biodigester that became operational January 2010. This project converts waste into an ADG that can be used to offset onsite propane use for the dairy operations.

This farm is large enough to accommodate another 12-15 biodigesters, potentially capturing an additional 40,000 plus tons of carbon dioxide each year. As this site develops, the Company will consider a more diverse use of the biodigester-produced biogas including using the gas to run a gas chiller (for milk cooling), to generate electricity, or to offset a neighbor's energy needs.

The Company has also invested in a biodigester in Washington, which is using the biogas to generate electricity. This project began producing power on August 30.2009. A third similar project is being developed on a 1,200-cow, dairy farm in Junction City, OR. Three other projects in Oregon and Washington are under consideration.

Because these resources are in their early research and development stage and given their small potential size, we have not included biogas in the SENDOUT® modeling for this IRP.

Supply Basin Storage Developments. Capacity has been available in new and existing production area storage facilities in Alberta, British Columbia, and in the U.S. Rocky Mountain region. NW Natural has made periodic use of these facilities (especially in Alberta) to store off-peak gas and improve supply contract load factors. The stumbling block to increased usage is the upstream pipeline transportation cost required to bring these supplies to NW Natural's service area. Since the supplies would be needed during cold weather episodes, only primary firm transportation service will suffice. Consequently, having gas stored in a supply area can only prove advantageous to NW Natural if winter/summer price differences or favorable benefits compared to financial hedges are sufficient to offset storage facility usage charges. The use of supply area storage is more appropriately addressed in the company's annual Gas Acquisition Plan since the market price and value of the storage varies too much from year to year and the storage is not needed for long-term resource planning.

VI. GAS SUPPLY PORTFOLIO ACQUISITION STRATEGY

A. Overview

This section provides the Company's strategies for acquiring gas supplies as described in NW Natural's Gas Acquisition Plan 2011-2012 ("GAP"). The GAP is reviewed and approved by the GASP Committee, but such plans are always subject to change based on market conditions. The primary objective of these gas acquisition plans is to ensure that supplies are sufficient to meet expected firm customer load requirements under "design" year conditions at a reasonable cost. Under other than "design" year conditions, NW Natural also expects to serve interruptible sales customers. The focus of the GAP is on the forthcoming gas contracting year which runs from November through the following October. However, many resource decisions are of a multi-year nature. Accordingly, a 5-year horizon is used for discussion purposes in several areas of this section.

Below are excerpts from the GAP.

B. Plan Goals

1. <u>Reliability</u>

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

2. **Lowest Reasonable Cost**
   The second priority is to acquire gas supplies at the lowest reasonable cost to customers. In so doing, the Company takes a diversified portfolio approach with gas purchases paced during the contracting season. The Company also optimizes its gas supply resource assets using a third party marketer as well as its own staff in order to lower costs with minimal risk to stakeholders.

3. **Price Stability**
   Customers are sensitive to price volatility in addition to prices. Consequently, the Company makes use of physical assets (e.g. storage) and financial instruments (e.g. derivatives) to hedge price variability both within the contract year and for up to five years.

4. **Cost Recovery**
   NW Natural does not earn a return for acquiring and selling gas commodity supplies, yet the cost of these supplies typically amounts to more than half of 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.

C. Relationship to the Integrated Resource Plan

The IRP contains the Company's long-range analysis of loads and resources spanning a 20-year horizon. It is prepared approximately every two years and involves considerable regulatory and public input. Because the IRP focuses on long-term decisions, it does not include many of the details that are provided in the GAP. Nevertheless, there is consistency between the GAP and the IRP to ensure that long-range decisions are reflected in current decisions, and vice versa.

D. Strategies

Gas acquisition strategies based on the Company's market outlook are summarized as follows:

- Financially and physically hedge up to 75 percent of projected firm sales gas volumes in accordance with decisions of the GASP Committee.

- Maximize supplies from the regions that afford the lower prices. In recent years, prices of Rocky Mountain gas have been lower than prices of Canadian gas due to increased production in preparation for the Rockies Express Pipeline and Ruby Pipeline. Those pipelines are now in service. As a result, the price differential between Rockies and Alberta gas has narrowed or disappeared. Strategies will be re-evaluated as other pipeline projects near completion and alter supply and demand dynamics.

- 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 pipeline capacity from the Station 2 trading point in British Columbia with a mix of seasonal, annual and multi-year commitments.

E. Market Outlook

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

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

Shale plays are situated throughout the U.S. and Western Canada. Low-cost methods of horizontal drilling have facilitated the success of shale gas recovery, and undercut the costs of vertical drilling methods used in the Rockies. As a result, drilling has decreased in the Rockies while more supplies flow east via REX, further diminishing the quantity of Rockies gas for the West. Alberta supplies will continue to decrease due to depleted wells and due to the increase in gas use for oil sands production. But those supply reductions are not likely to be felt in the West. Alberta gas transportation costs, especially to the Eastern U.S., are higher than transportation costs of Rockies supplies. Drops in Alberta supplies should equate to drops in Alberta flows to the East. Alberta supplies to the West should stay level, and Alberta prices to the West are projected to stay below Rockies prices for the next several years.

VII. EMERGENCY PLANNING

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

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

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

As previously described, the Company designs its resource portfolio to satisfy firm loads on the coldest-weather day in the past 20 years and through a strenuous design heating season. However, these assumptions do not always hold true. First, design weather may not be the coldest faced by the Company. There certainly have been colder heating seasons if a longer historical perspective is taken, such as occurred in 1949/50. Second, the IRP assumes perfect foresight of the weather. This may not be important for storage supplies, which can respond to load changes very quickly, but all other supplies require some amount of prior notice for scheduling. This ranges from two hours for curtailment of interruptible sales, to a day for the transportation of most pipeline gas and the use of special industrial customer capacity/supply recall arrangements. Finally, the IRP assumes reliable equipment behavior; i.e., nothing breaks or freezes up, even in the face of extremely cold temperatures.

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

VIII. KEY FINDINGS

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

- A portfolio of fixed price supplies is desirable because it dampens volatility and assures more stable pricing for customers.

- Similar to the recent gas reserves agreement approved at the end of April 2011,additional very long term pricing arrangements may be advantageous due to the current price regime, which reflects a stagnant economy coupled with surging supplies from shale gas.

- The Company's service territory is widespread and it is not practical to consider tying together all of NW Natural's customers into a single integrated distribution system. Accordingly, some amount of incremental upstream pipeline capacity may be needed throughout the forecast period to serve one or more portions of the Company's system. Conversely, as the cost of upstream pipeline expansions increase, it may be cost-effective for NW Natural to remove bottlenecks and more fully integrate certain portions of its own distribution system.

- As a single interstate pipeline utility with two-thirds of its supply flowing through Oregon's Columbia Gorge, NW Natural seeks cost-effective resource options to improve supply path diversity, and toward this end, is supporting development of the Palomar/Blue Bridge Pipeline project.

- In this IRP, NW Natural is considering a variety of incremental gas supply resource options to serve projected load over the forecast period, including new interstate pipeline capacity, Mist recall capacity, expansion/extension of the Company's distribution system, and satellite LNG.

Chapter 4: Demand-Side Resources

NW Natural®

I. OVERVIEW

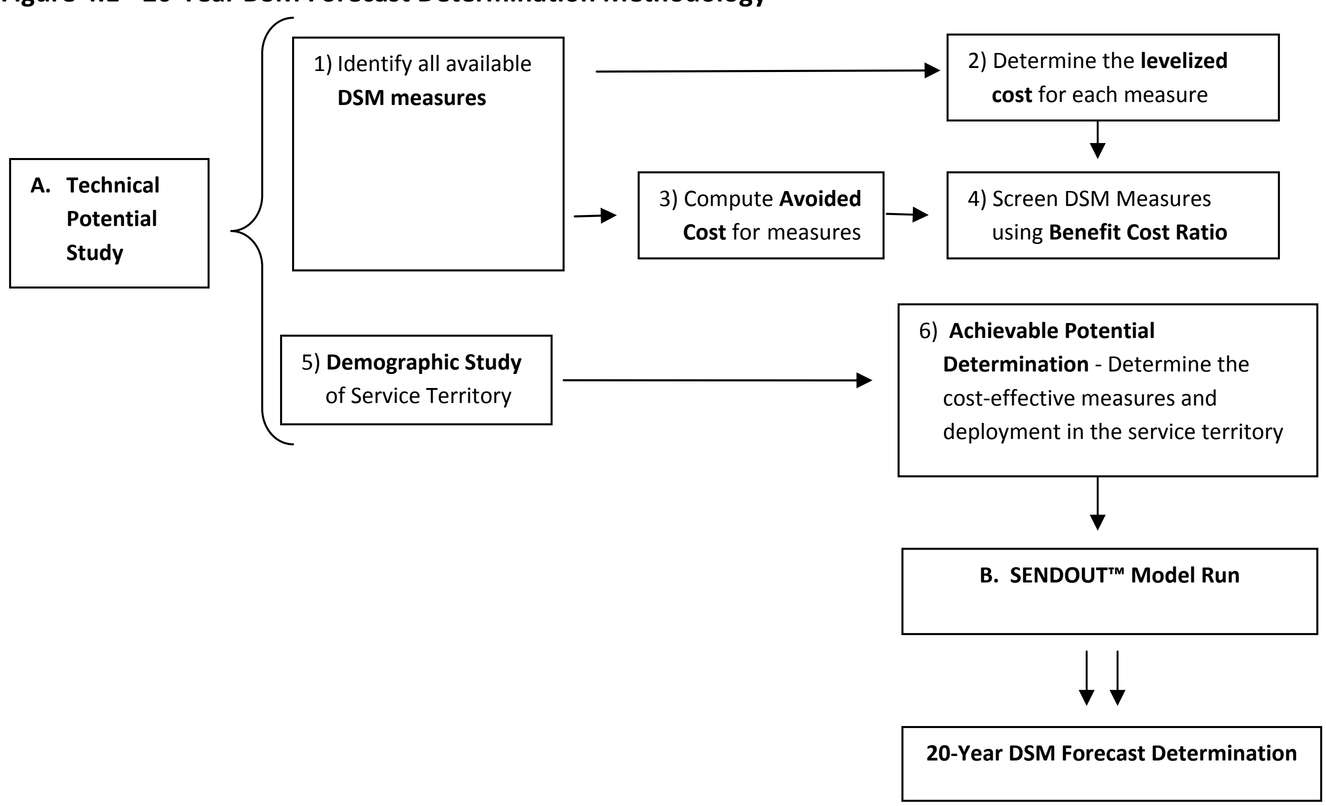
NW Natural worked with the Energy Trust of Oregon (Energy Trust) to forecast the 20-year demand side management (DSM) potential for NW Natural's service territory. Energy Trust is a non-profit organization established to provide energy efficiency services and a renewable energy program to Oregon investor-owned electric utility customers. Since its inception, Energy Trust has grown from serving only electric customers to serving 70% of all electric customers in Oregon as well as most of Oregon's gas customers. As of May 15, 2010, Energy Trust also serves NW Natural's Washington customers.

NW Natural leaned heavily on Energy Trust's expertise in energy efficiency in the development of the 20-year demand side management (DSM) forecast. The forecast was generated for NW Natural's service territory and was then evaluated in SENDOUT™ as a resource on par with other supply side resources. The findings were that the Company can save 25 million therms by 2016 and 117 million therms by 2030. In Washington, this includes savings of approximately 1.6 million therms by 2016 and nearly 10 million therms by 2030.

II. METHODOLOGY

This DSM assessment began by determining the Technical Potential, which for the purposes of this study refers to complete penetration of all cost-effective DSM measures within the Company's service territory. Figure 4.1 below provides an overview of this initial process followed by a more in-depth discussion of each step.

Figure 4.1 - 20-Year DSM Forecast Determination Methodology



A. Technical Potential Study

1) Identify all available DSM measures

Energy Trust compiled a list of all commercially available measures for single family and multi-family residential, commercial and industrial applications installed in new or existing structures. The list below describes the conservation measures that are new to this IRP or have changed significantly since the last IRP:

a) Sub-condensing gas residential tankless water heaters – This technology is in its developmental phase. While it is not in the base case, Energy Trust is currently working with manufacturers, encouraging them to bring a good model to the Northwest market. Energy Trust is also evaluating installation practices and customer satisfaction with various models.

b) Gas hearths – In 2009, Energy Trust began offering incentives on gas hearths after studying the savings potential that high efficiency models have when installed in certain applications

c) High efficiency windows with a U value of <.20 – These higher efficiency windows have been available for some time but only recently has the price gone down enough to make them marketable and cost effective.

d) 0.67 EF water heaters – These hot water heaters hit the market in 2010. It is believed that these water heaters represent a significant source of potential savings because installation costs are equal to that of a standard tank water heater while gas usage can be 15%-20% less.

e) Condensing gas roof top units- These gas-fired rooftop space heaters would offer higher seasonal efficiencies than conventional rooftop heaters. While these units are not yet available commercially, Energy Trust is evaluating their future viability. These units were evaluated as an emerging technology and are not included in the base 20-year deployment scenario.

f) Corridor ventilation in Multi-Family common spaces – This measure is applicable to the common spaces in post-1990, multi-family structures. Often, the ventilation in these buildings can be reduced resulting in significant energy savings.

g) Combination hot water and space heat systems – Combination hot water and space heat systems typically heat water that is also used for radiant heating before it is sent to the faucet. While the majority of configurations fail the cost-effective test, Energy Trust programs continue to evaluate options because the ability to offer both the combination of space heating and water heating may be important as usage per customer goes down.

h) Ozone Treated Laundry – Ozone laundry systems use a nominal amount of electricity and oxygen in a unique way to replace many of the chemicals normally used in a traditional washing process. The process greatly reduces the amount of hot water needed per cleaning cycle. Energy Trust began offering incentives on this measure in 2010.

i) Destratification fan in warehouse – Fans placed in high roofed-commercial buildings push the heated air down reducing space heating requirements. This measure has the potential of producing significant savings at a site, although it is applicable to few locations.

j) Commercial cooking equipment - Energy Star specifications have been established for a variety of new equipment. These high-performing units are now included in the resource potential.

k) Fleet management of heating and cooling - Commercial buildings with multiple HVAC units can save energy by optimizing operations.

The following notable observations were observed on existing measures:

a) Shell measures - Shell measures have been a keystone to residential weatherization efforts, so it is noteworthy that floor and wall insulation are near the upper end of the cost effectiveness test. Savings have been verified with actual results taken from recent Energy Trust evaluations.

b) Gas fired furnaces – 2010 marked the last year Energy Trust offered incentives for 90% efficient furnaces. Energy Trust's studies show that the market for this technology has been transformed. Federal standards will be revised effective 2013 adopting a 90% efficient standard for gas furnaces in the Northwest.

c) Tankless water heaters – The cost for tankless water heaters has remained high compared to energy savings making many retrofit installations non-cost effective. The base case assumes fewer units will be adopted than previously predicted. Energy Trust is tracking the development of sub-condensing water heaters as the possible replacement technology. To this end, Energy Trust is working with manufacturers to encourage the development of more efficient tankless options.

d) 2015 Federal Code change for hot water heaters – Savings from hot water heaters and boilers recognizes a base case efficiency increase due to a change in federal standards scheduled to become effective in 2015.

e) Refrigeration heat reclamation –This measure transfers the heat generated during the refrigeration process to a heating need elsewhere in the same facility. While this is not a new measure, it is being closely monitored because this measure has not had much uptake in the market, but the savings potential is large.

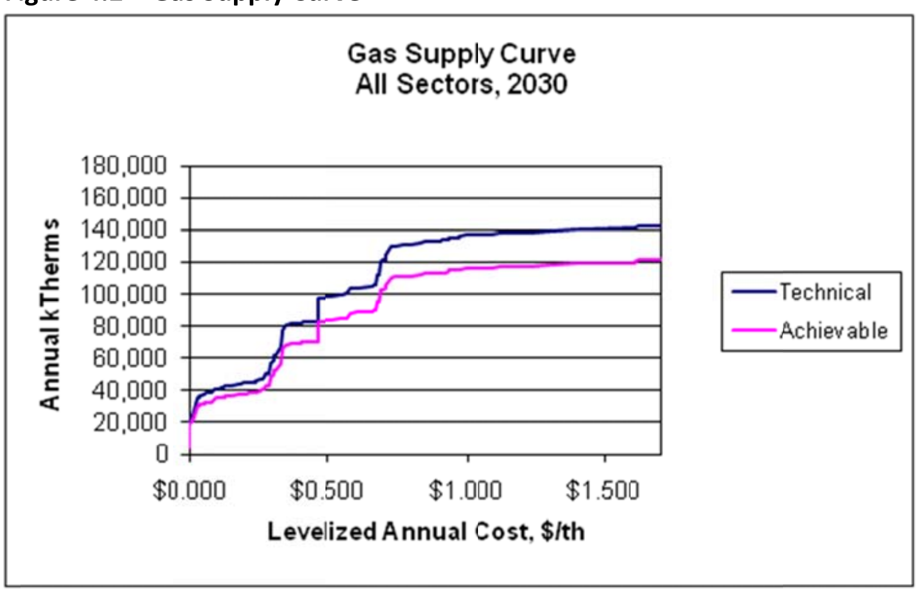
Appendix 4 contains tables of the measures for each customer class and a summary the economic assessment for each.

2) Determine the levelized cost for each measure
Once the list was compiled, Energy Trust determined a levelized cost for each measure. The levelized cost is the present value of the total cost of the measure over its economic life, converted to equal annual payments. The levelized cost calculation starts with the incremental capital cost of a given measure. The total cost is amortized over an estimated measure lifetime using the Company's discount rate of 5.16%. The annual net measure cost is then divided by the annual net energy savings determined by multiplying therms saved times the Company's avoided cost. This formula produces the levelized cost estimate in dollars per therm saved, as illustrated in the following formula.

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

Levelized costs can be graphically depicted to demonstrate the total potential therms that could be saved at various costs for all commercially available conservation measures. Figure 4.2 below shows a resource supply curve that can be used for comparing demand side and supply side resources. A flattening effect is observed above a levelized cost of approximately $0.65.

Figure 4.2 – Gas Supply Curve



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

4) Screen DSM measures using the Benefit Cost Ratio (BCR) test.
   After the avoided cost is determined, a Benefit Cost Ratio (BCR) test is then applied to each measure. The BCR looks at the total benefits attributable to the measure divided by the sum of all related costs. A BCR value equal to or greater than one means the benefits are equal to or exceed the costs, and the program is cost-effective. The BCR is expressed formulaically as follows:

   BCR = Present Value of Benefits / Present Value of Costs

   The Present Value of Benefits includes the sum of the following three components:
   a) The value of gas energy saved determined by the therms saved multiplied by the Company's avoided cost.[1] Note that avoided cost depends on lifetime and seasonality.
   b) Non-energy benefits as quantified by a reasonable and practical method and described in situations where they cannot practically be quantified.

   The Present Value of Costs includes:
   a) Incentives paid to the participant
   b) The program's administrative costs
   c) Monitoring, evaluation and non-incentive costs incurred by Energy Trust staff through their administration of NW Natural's program
   d) The participant's remaining out-of-pocket costs for the installed cost of the measures after incentives, and state and federal tax credits.

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

   NW Natural serves over 660,000 residential, commercial and industrial customers in Oregon and Washington, including interruptible customers. Total customer counts, and overall consumption and average use for firm sales customers are shown in Table 4.1.

[1] *See* Chapter 6 for an explanation of the Company's avoided cost.

Table 4.1 – FY 2009 Customer Statistics Sector – All Customers

	Average Number of Customers	Actual Sales (Therms)	Average Use per Customer
Residential	600,397	420,175,218	700
Commercial	62,002	256,129,144	4,131
Industrial Firm	607	40,044,849	65,954
Industrial Interruptible	172	72,524,569	420,635
Total	**663,179**	**788,873,780**	**1,189**

Table 4.2 below shows the same Customer Statistics for NW Natural's Oregon Service Territory.

Table 4.2 - FY 2009 Customer Statistics Sector - Oregon

	Number of Customers	Sales (Therms)	Average Use per Customer
Residential	538,017	373,910,758	695
Commercial	56,704	235,267,685	4,149
Industrial Firm	568	37,226,591	65,569
Industrial Interruptible	159	66,933,098	420,302
Total	**595,448**	**713,338,132**	**1,198**

Interruptible customers are included since the Company provides energy efficiency programs for these customers.

Table 4.3 below shows the same Customer Statistics for NW Natural's Washington Service Territory.

Table 4.3 – FY 2009 Customer Statistics Sector - Washington

	Number of Customers	Sales (Therms)	Average Use per Customer
Residential	62,381	46,264,460	742
Commercial	5,298	20,861,454	3,938
Industrial Firm	39	2,818,258	71,499
Industrial Interruptible	13	5,591,471	424,669
Total	**67,731**	**75,535,648**	**1,115**

While NW Natural's Washington customer base is expected to grow at a slightly higher rate than the Oregon territory, the Washington housing stock is significantly different. More, newer residential homes and fewer industrial customers are unique characteristics of the Company's Washington service territory. Generally, these attributes mean fewer cost-effective potential savings are achievable.

6) The Achievable Potential Determination
The technical potential determination is the total therms saved from all cost-effective measures that could be installed in NW Natural's service territory. The technical potential assumes 100% adoption, which is not realistic. The technical potential is reduced by 15% to account for economic and other barriers that prevent total adoption of all cost effective measures. This adjusted total is referred to as the achievable potential. Defining the achievable potential as 85% of the technical potential is the generally accepted method employed by many industry experts including Northwest Power and Conservation Council (NWPPC) and National Renewable Energy Lab (NREL). The overall potential is also deceased due to realistic constraints on the ability to launch programs as recognized in the deployment scenario.

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

Table 4.4 –Summary of Technical Potential - NW Natural's 2030 Oregon Service Territory

	Million Therms
Residential	78
Commercial	38
Industrial	22
Total	138

Table 4.5 - Summary of Technical Potential - NW Natural's 2030 Washington Service Territory

	Million Therms
Residential	9.7
Commercial	4.8
Industrial	0.3
Total	14.8

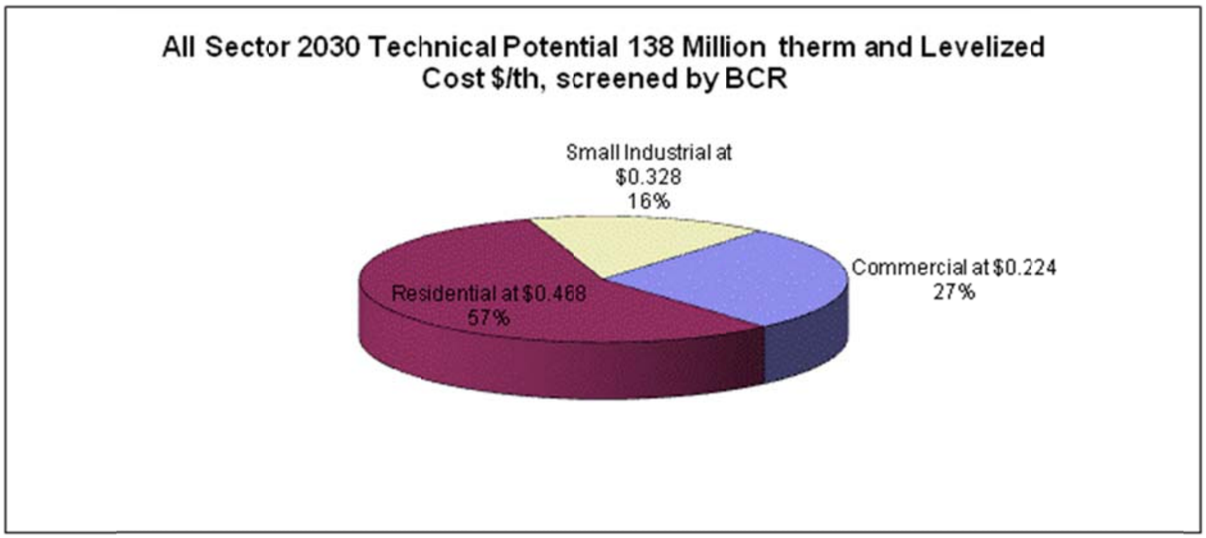
In Oregon, the resource assessment estimated that approximately 117 million therms of cost effective energy savings could be attained over the next 20 years for approximately $640 million from a utility cost perspective. The resource assessment determined that over the next 20 years approximately 10 million therms of potential energy savings could be saved in Washington for about $72 million, again from a utility cost perspective.

The technical potential is assessed differently for Washington and Oregon with respect to codes. In Oregon, potential savings includes therms saved by known changes to future building codes. Since energy consumption is reduced when building codes are adopted, it is appropriate to decrement the Company's load forecast accordingly and allow the program to assume some of the savings since the Energy Trust's work in transforming the market influences the changes in code. This is not done for the Washington technical potential since WUTC has made no determination on whether this is an appropriate practice and the Energy Trust has not been actively engaged in the codes process in Washington. Parties to WUTC's 2010 Investigation into Conservation Incentives, docketed as U-100522, were asked their opinion on this practice, but a conclusion was not issued.

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

Figure 4.3 below depicts the 20-year technical potential of DSM savings and the average levelized cost for the savings acquired for each customer class in Oregon.

Figure 4.3 - Technical Potential through 2030



The figures and tables below provide a more in-depth perspective by customer class.

Figure 4.4 and Table 4.6 show the potential for gas conservation measures in the Oregon Residential sector. The measures are grouped by retrofit or replacement versus new construction. The greatest savings potential is found with retrofit equipment.

Figure 4.4 - Residential Natural Gas Measures

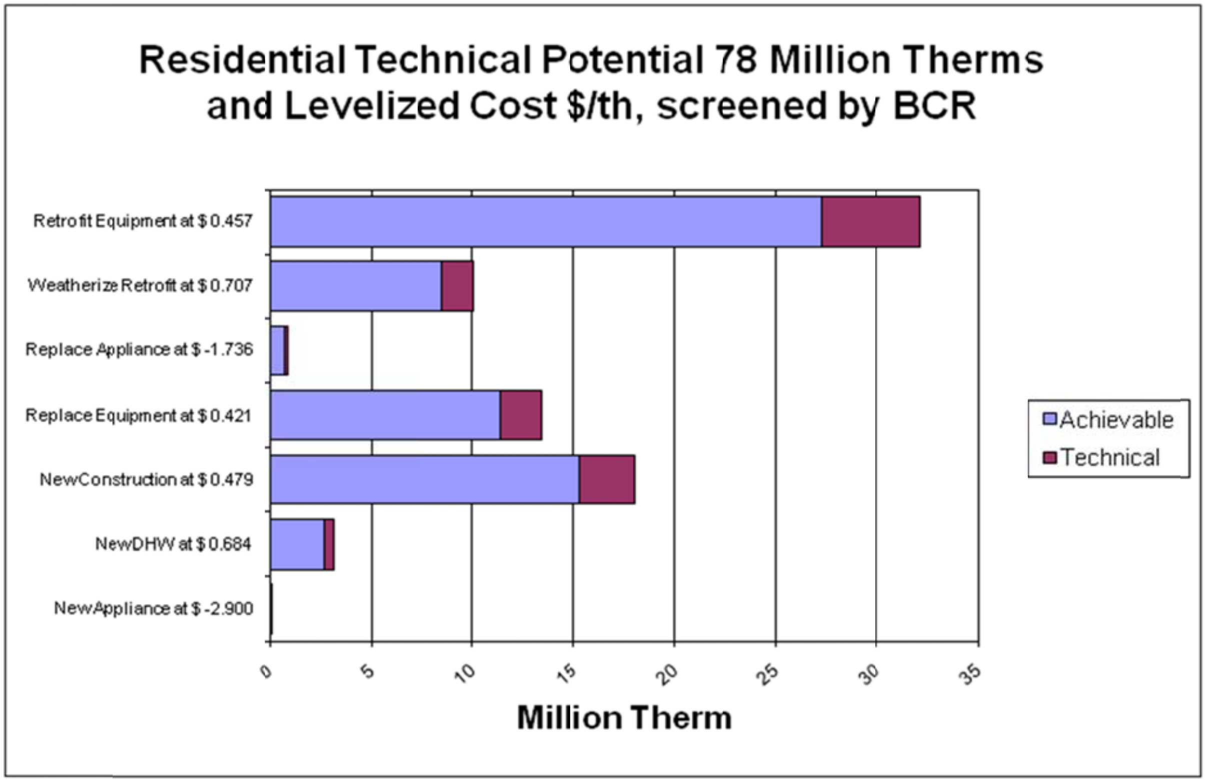


Table 4.6 - Residential Sector Gas Technical Potential Savings for 2030

Screened by BCR Measure Category	Thousand Therm	$/therm
New Appliance	88	-$2.900
New Construction	18,067	$0.479
New DHW	3,127	$0.684
Replace Equipment	13,379	$0.421
Replace Appliance	899	-$1.736
Retrofit Equipment	32,135	$0.457
Weatherize Retrofit	10,038	$0.707
Total	**77,733**	**$0.468**

Figure 4.5 and Table 4.7 demonstrate the conservation potential for natural gas in the Oregon commercial sector. These measures are also grouped by retrofit or replacement versus new construction. The greatest savings potential is found with cooking equipment upgrades.

Figure 4.5 - Commercial Natural Gas Measures

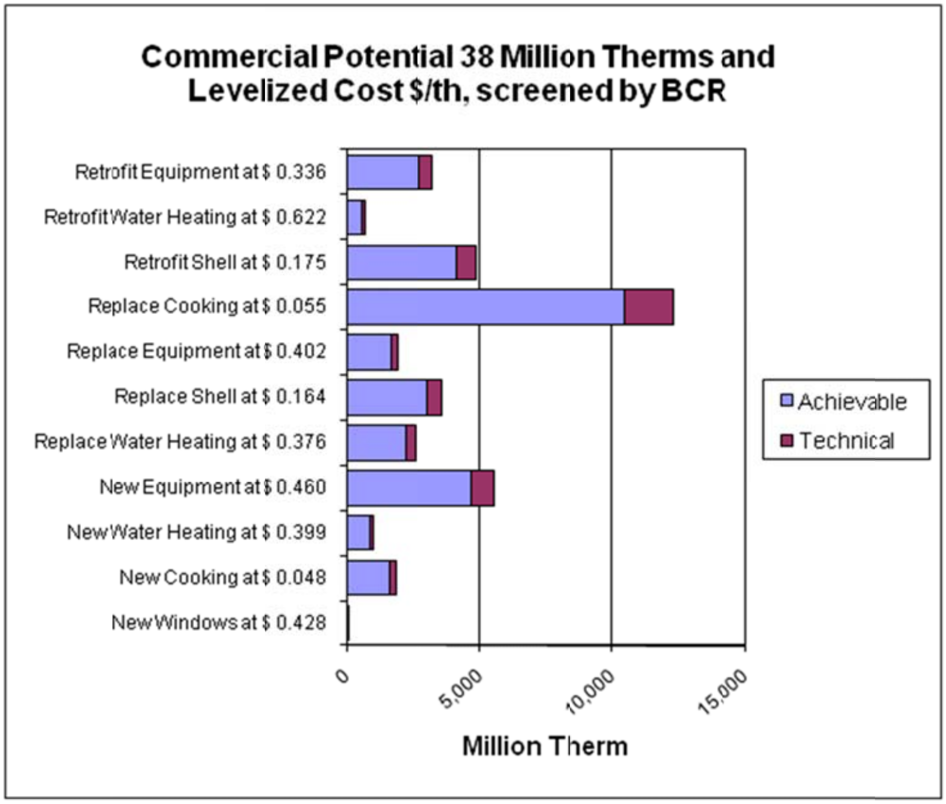


Table 4.7 - Commercial Sector Gas Technical Potential Savings for 2030

Screened by BCR Measure Category	**Thousand therm**	**$/therm**
New Cooking	1,872	$0.048
New Windows	68	$0.428
New Equipment	5,541	$0.460
New Water Heating	1,003	$0.399
Replace Cooking	12,292	$0.055
Replace Shell	3,642	$0.164
Replace Equipment	1,937	$0.402
Replace Water Heating	2,602	$0.376
Retrofit Shell	4,911	$0.175
Retrofit Equipment	3,229	$0.336
Retrofit Water Heating	684	$0.622
Total	**37,781**	**$0.224**

Figure 4.6 and Table 4.8 show the conservation potential for natural gas in the Oregon industrial sector. Again, these measures are grouped by retrofit or replacement versus new construction. The greatest savings potential is found with process boilers.

Figure 4.6 - Industrial Natural Gas Measures

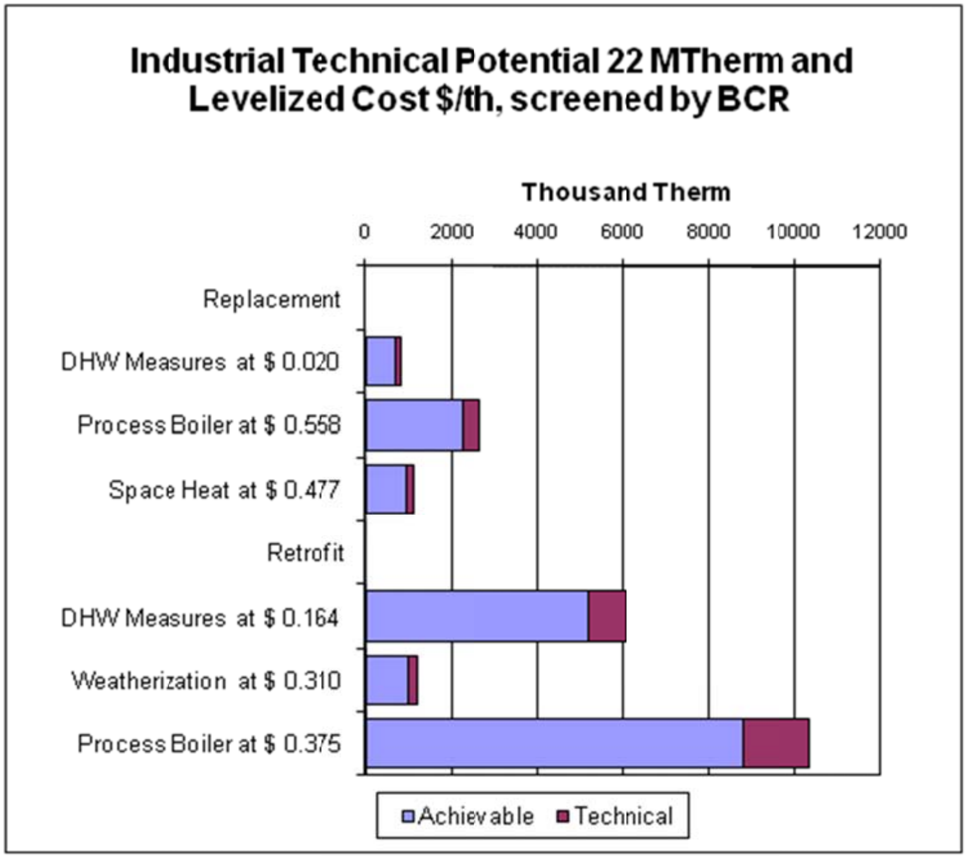


Table 4.8 - Industrial Gas Sector Technical Potential Savings for 2030

	Technical Potential, thousand therms	Levelized Cost, $/therm
Replacement		
Process Boiler	2,653	$0.558
DHW Measures	811	$0.020
Space Heat	1,097	$0.477
Retrofit		
Process Boiler	10,359	$0.375
DHW Measures	6,077	$0.164
Weatherization	1,182	$0.310
Total	**22,179**	**$0.328**

Once the 20-year achievable potential is known, Energy Trust develops a deployment scenario based on past deployment experience and knowledge of the developing market. A deployment scenario is an educated guess on future adoption rates for new technologies and installed measures. It tries to provide a more short-term, annualized perspective on 20-year savings potential. Figure 4.7 and Figure 4.8 depict the deployment scenarios for Oregon and Washington, respectively.

Figure 4.7 - Oregon Deployment Scenario

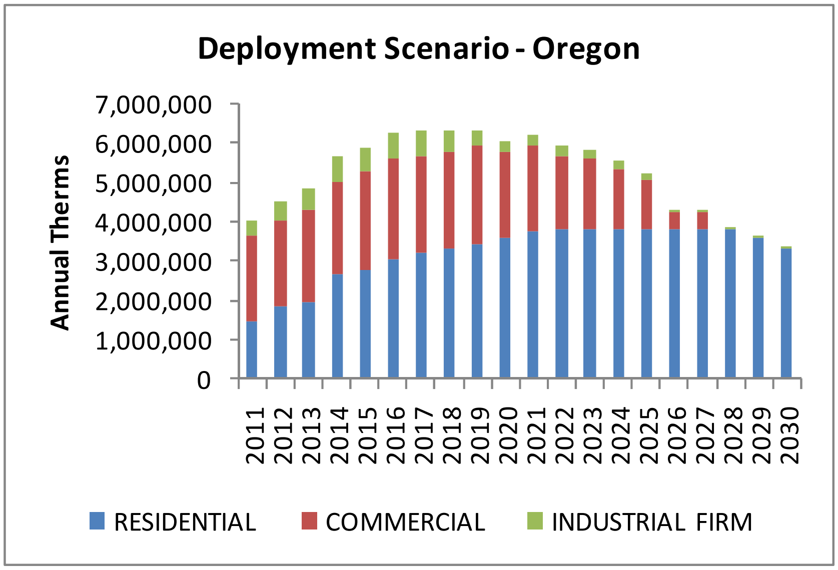


Figure 4.8 – Washington Deployment Scenario

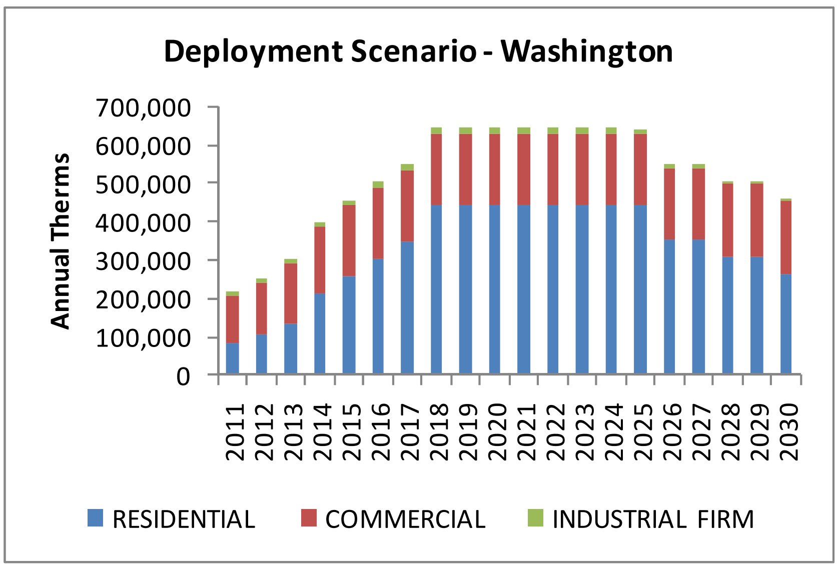
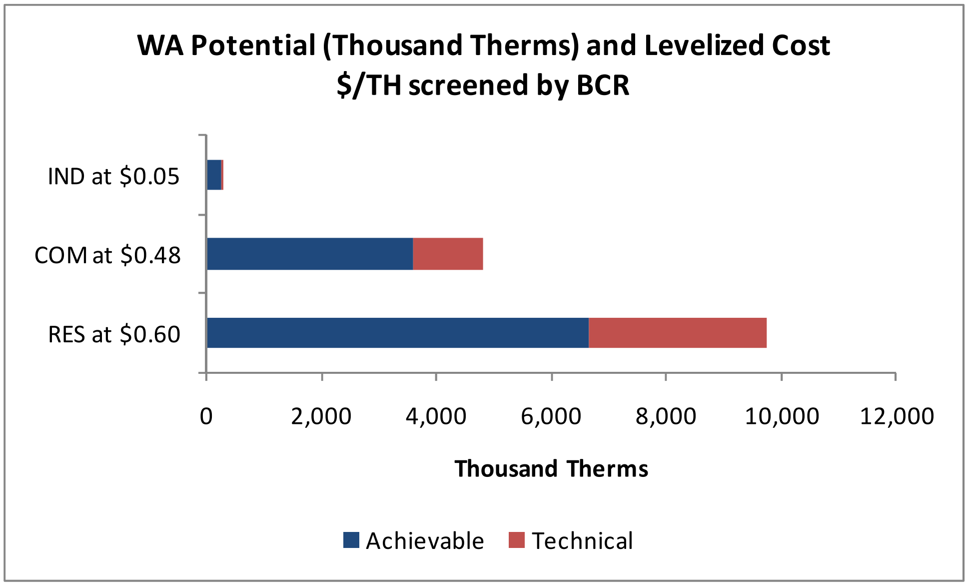


Figure 4.9 displays the conservation potential for Washington along with the levelized cost per therm for the deployment scenario.

Figure 4.9 – Washington Potential and Achievable Gas Savings



B. Evaluation of Achievable Potential in SENDOUT®

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

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

Figure 4.10 and 4.11 below graphically demonstrate the savings potential in Oregon and Washington, respectively, over the next 20 years.

Figure 4.10 – Oregon DSM Savings

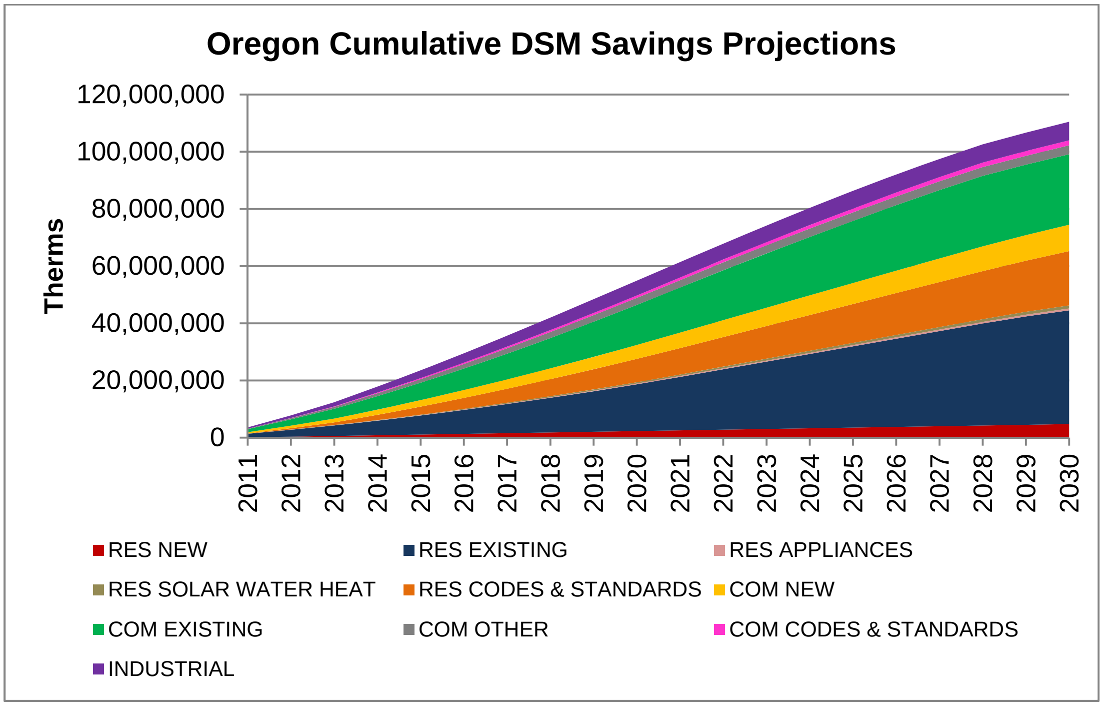
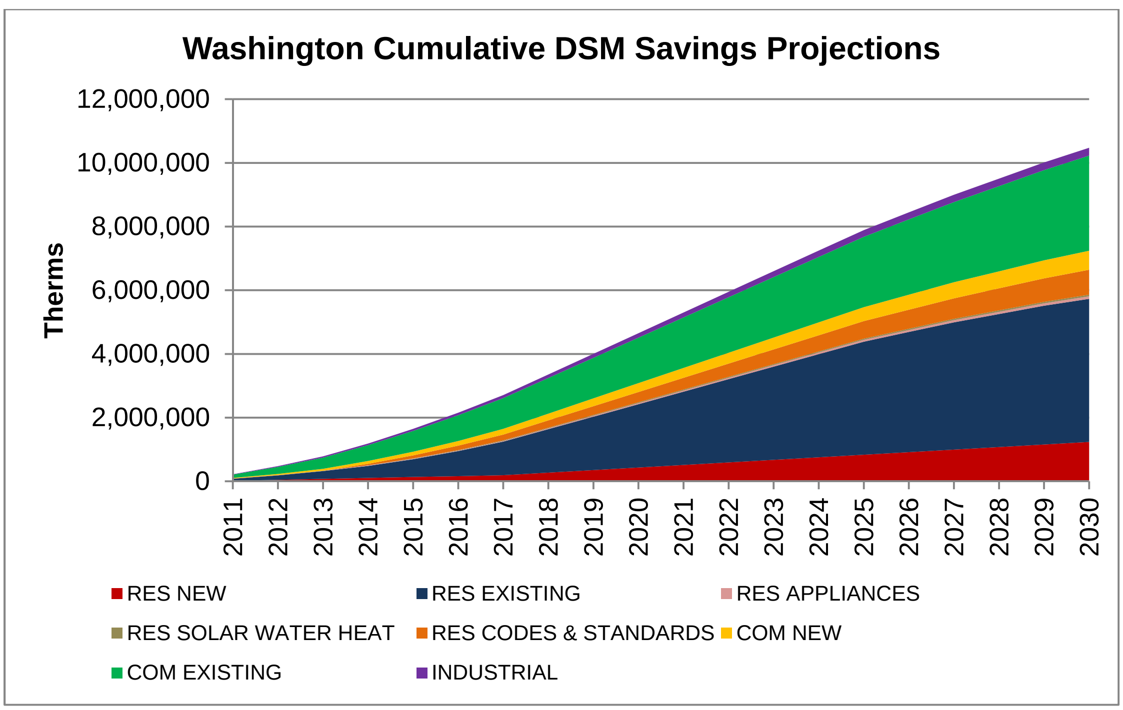


Figure 4.11 – Washington DSM Savings



For the planning base case, NW Natural's SENDOUT™ model selected all discretionary savings.

III. OTHER DSM SENSITIVITIES

A. Lower Avoided Costs

Energy Trust estimated the sensitivity of a decrease in gas avoided costs on the estimate of resource potential in the 2011 IRP. The avoided costs used in the 20-year deployment scenario was based on the price forecast from the 2008 IRP. Participants in the IRP technical work group expressed a concern that long run forecast of gas prices had substantially and structurally changed in the last 2 years, and by using 2008 avoided costs, this IRP may include DSM savings that are no longer cost effective.

Energy Trust used both a gas price forecast created in 2008 and an updated 2010 gas price forecast to determine the impact on the cost-effective, achievable resources in the 20-year deployment plans to be used in the NWN 2011 IRP. The comparison of the two price forecasts at Henry Hub over the years 2010 thru 2028 shows an 8% decrease from 2008 to 2010 on a net present value basis . Using the average price for four delivery points, for the same two forecasts, results in a 10% decrease from 2008 to 2010 on a net present value basis.

The following analysis shows the impact on resource potential using a 10% decrease in avoided costs from those used in the IRP deployment scenarios. The reduction in resource is approximately 2.6%, or 2,537,263 therms out of 97,949,049 therms total in the IRP deployment scenario.

Table 4.9 – Summary of DSM Potential with a Lower Avoided Cost

Therms removed due to 10% lower avoided costs	*2,537,263*
2010 IRP Deployment 20 year Achievable Therms	*97,949,049*
Per cent change in therms due to 10% lower avoided costs	*2.6%*

B. Higher Gas Cost

NW Natural estimated the impact a higher gas cost would have on its cost effective DSM potential. While the change to avoided cost was quite significant, the impact on resource potential was minimal. Table 4.10 below shows the results of this sensitivity. The high gas cost forecast resulted in a 39% increase in the avoided costs over the base case, and a 4% increase in the cost effective achievable resource potential.

Table 4.10 – Summary of DSM Potential with a Higher Gas Cost

Resource Potential (therms)			
Sector	Base Case potential	High Avoided Cost Potential	**% increase**
Residential	78,613,526	79,901,071	**2%**
Commercial	34,278,225	37,444,535	**9%**
Industrial	6,987,564	6,997,427	**0%**
Total	119,879,315	124,347,479	**4%**

IV. PROGRAM FUNDING AND DELIVERY

A. Energy Efficiency Programs

Oregon

As stipulated in OPUC Order No. 02-634, NW Natural transferred the administrative responsibility of its energy efficiency programs funded through the public purpose charge to the Energy Trust as part of the agreement to allow the Company to implement decoupling. From 2002 to 2008, program collections exceeded expenditures. This was not surprising since energy efficiency programs require a ramping up period. It takes time to educate customers on efficiency, available incentives, and efficient heating or other appliance options. By 2009, expenditures exceeded collections. In October 2009, NW Natural filed to increase the portion of the public purpose charge that funds the company's Energy Trust-administered program from 1.25% to 4.16%. This was revised down to 3.51% in Advice No. 10-6, effective June 1, 2010. In 2011, the Energy Trust portion of the Public Purpose Charge is 2.76% which when added to unspent carry over dollars will provide the total program year budget of $22.5 million.

Since 2009, Energy Trust has been meeting –even exceeding– the targets established in NW Natural's 2008 IRP. While economic conditions have reduced discretionary spending, customers are continuing to make energy efficiency investments in their home. In 2011, NW Natural is striving to achieve 3.8 million therm savings.

During the 2002 decoupling proceeding[2] that transferred energy efficiency administration to the Energy Trust, parties agreed that industrial customers would not be subject to the public purpose charge and as a result, energy efficiency programs were not developed for industrial customers. Order No. 02-634 says,

[2] *See* PUC Docket No. UE-143

> The current stipulation makes it clear that these same industrial customers will not be eligible for Energy Trust Funding for natural gas related conservation and efficiency programs. We agree that if the industrial customers are not contributing money, they should not participate. (Page 2)

But in 2008, the Company's IRP demonstrated cost effective savings for firm sales industrial customers. In compliance with the mandate to procure cost-effective resources, the Company began offering an industrial DSM program on May 15, 2009. Before launching this new program, NW Natural consulted with Northwest Industrial Gas Users (NWIGU), Citizens' Utility Board (CUB) and Public Utility Commission of Oregon (PUC) Staff. Parties agreed to pilot the inclusion of interruptible sales customers in the first two years, ending May 15, 2011. Program spending on interruptible customers is capped at $500,000 for each year for the first two years. By the end of this timeframe, parties will have decided if the program will continue to be open to interruptible customers, and if so, at what spending threshold.

Costs for the industrial DSM program are deferred for later amortization under NW Natural's Oregon Tariff Schedule 188.

The tariff schedules that define program parameters and establish funding mechanisms are included in Appendix 4.

<u>Washington</u>

Until 2010, NW Natural's energy efficiency offerings in Washington were limited. The Company offered home furnace rebates and administered a weatherization program that was discontinued in March 2007 due to a low response rate. As agreed in the stipulation signed by parties to NW Natural's 2008 rate case, docketed as UG-080546 and approved by the Commission in Order No. 04, NW Natural began offering energy efficiency programs again in 2009. Energy Trust was retained as the Company's program administrator under the condition that the Energy Efficiency Advisory Group (EEAG), comprised of interested parties to the rate case, will monitor the program development and implementation for a minimum of one year. After one year's time, the program would be evaluated through a third party benchmarking study that will compare the Company's Energy Trust delivered program to other energy efficiency programs offered by Washington-based gas utilities.

The Company's Energy Trust-delivered program was launched October 1, 2009. Under the program, rebates are issued to residential and commercial customers for the installation of cost-effective energy efficient appliances and shell measures. Appendix 4 contains NW Natural's tariff Schedule G which details the offerings as well as the Company's Energy Efficiency Plan, which by reference is part of the tariff and provides annual targets, reporting requirements, and a history of the programs' development.

Costs for the program are being deferred for later recovery under the Company's Washington Tariff Schedule 215.

B. Low Income Programs

Oregon

Since October 2002, NW Natural has collected public purpose funding for its Oregon Low Income Energy Efficiency (OLIEE) program through a 0.25% surcharge to Oregon residential and commercial customers' energy bills.[3] OLIEE funding is used to improve the efficiency of NW Natural's low income customers' homes through the installation of high efficiency equipment and weatherization measures. The program is delivered by ten Community Action Agencies (agencies) within NW Natural's Oregon service territory.

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

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

This approach was successfully piloted for three years. The Company filed a comprehensive pilot review on May 31, 2010 which included a third party impact study. While the realized savings were less than reported, agencies have been able to treat more homes and as a result, they have spent down the reserve of OLIEE funds. On October 1, 2010, NW Natural's Oregon Tariff Schedule 320 was revised to allow the pilot program to be the Company's ongoing offering.

During the 2009-2010 program year, 600 residences were weatherized with an average of 211 annual therms saved per household, about 127,000 therms total. The program is expected to yield similar savings for the next two years while America Recovery and Reinvestment Act (ARRA) funding remains available.

Washington

On October 1, 2009, NW Natural launched a revised low income program entitled, WA-LIEE (Washington Low Income Energy Efficiency). Modeled after its Oregon OLIEE pilot, the WA-LIEE program reimburses the two administering agencies for installing weatherization measures that are cost-effective when analyzed in aggregate. Reimbursements are capped at the lesser of 90% of the job cost or $3,500. In the first year, nineteen homes were weatherized saving 6,839 therms for less than $73,000.

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

V. LOAD MANAGEMENT AND DEMAND RESPONSE

Demand response reduces system load requirements during cold snaps or other times the system is stressed. Demand response can be administered through various means including real time pricing, time-of-use rates, critical-peak pricing, demand buyback, interruptible rates and direct load control. On NW Natural's system, customers' may select an interruptible service rate. Approximately 40 percent of the Company's annual throughput is for interruptible sales service, interruptible transportation service and firm sales transportation. Customers that are required to have a back-up heating system and large volume customers gravitate towards interruptible service because of the low distribution charges.

VI. ENERGY POLICY

A. Federal

<u>Greenhouse Gas (GHG) Emissions Reduction Policies</u>

For some time, utilities have been anticipating the adoption of comprehensive federal GHG legislation that will impact operations and the cost of providing service to customers. However, no requirements have yet been codified in federal legislation. As late as 2008, the Company was assuming that carbon tax or cap and trade legislation would be enacted by 2012. Of the two, cap and trade legislation appears favored based on continued work on various cap and trade models as well as the success of the HB 2454, the American Clean Energy and Security Act (ACES) of 2009, more commonly referred to as the Waxman-Markey Climate Change Bill.

While the Waxman-Markey Bill passed in the House of Representatives, it has not been voted on in the Senate. The Company believes that the Senate's failure to adopt climate legislation is due to continued concerns regarding the national economy and should not be seen as the end to the debate on the issue, but rather a delay in getting to final legislation. At this time, a new federal policy on climate change is not expected until after 2014.

While the Senate has yet to pass a climate change bill, Senate members have introduced a number of proposals including the Lieberman-Warner Climate Bill, the Kerry-Boxer Climate Bill, the Kerry-Graham-Lieberman Climate bill and the Kerry-Lieberman Climate Bill. Still, the Waxman-Markey Climate Change Bill has made the most progress and, interestingly, is the most aggressive in terms of driving deep reductions in GHG emissions on a tight schedule. Waxman-Markey continues to be the guide used when anticipating future legislation. As drafted, this bill would impose the following on gas utilities:

- Beginning in 2016, natural gas utilities would be responsible for addressing GHG emissions related to the natural gas usage of all customers except large industrial and electric generators.

- An emission credit will be required for each ton of carbon dioxide equivalent (CO_2-e) emitted. By 2016, natural gas utilities would receive 9% of emissions credit until 2025 at which time their emission credits would ramp down to zero over a five year period.

- Natural gas utilities would be annually required to spend one-third of the value of their emissions credits on energy efficiency.

- State commissions would convene a proceeding to ensure that emissions credits were used for the benefit of natural gas customers.

- Credits would be allocated based upon retail deliveries during a specified three-year period.

- The Energy Efficiency Resource Standard is analogous to a renewable portfolio standard in that it would establish targets for energy efficiency acquisition and combined heat and power (CHP) installation. As drafted, the Energy Efficiency Resource Standard would not apply to natural gas utilities.

While other versions of cap and trade legislation have been proposed, the fundamental provisions of Waxman-Markey have become the starting place for the continuing debate of federal legislation. Policy experts expect a bill like this to be very difficult to pass in the Senate. It is possible that the Senate will instead opt for a bill that focuses more on the development of "green jobs" rather than on capping emissions. The Senate also has debated passing broad, comprehensive energy legislation that would likely impact GHG emissions but would not specifically rely on a cap and trade proposal to drive these reductions.

Energy Efficiency Policy

Throughout 2010, Congress has been discussing a home and a commercial retrofit proposal known as Home Star and Building Star, respectively. On May 6, 2010, The U.S. House of Representatives passed HR 5019, the Home Energy Retrofit Act of 2010. This bill authorizes the provision of rebates to home and building owners for the installation of various energy efficiency measures. While the bill has passed, the programs authorized need to be funded through the appropriation process which makes the fate of these programs in the current economic climate uncertain. It is possible that by the end of 2010 the Senate may introduce a bill including a version of Home Star.

Renewable Biogas

In HR 5581, the House and Senate tax-writing committees are considering an investment tax credit for facilities that produce biogas made from landfills, biomass and agricultural and animal waste.

The Waxman-Markey energy and climate change bill and the Bingaman energy bill reported out of committee in the Senate (S.1462). Both contain language that qualifies biogas as a renewable for the purposes of a Renewable Electricity Standard (RES).

Alternative Fueled Vehicles

Congress is considering legislation that would offer incentives for natural gas fueled vehicles and associated infrastructure. The incentives would apply toward converting truck fleets to run on natural gas, manufacturing natural gas vehicles, and researching and developing alternative fuel engines.

B. State and Regional

GHG Emissions Reduction Policies

As federal policy temporarily stalls, regional and state policy aimed at reducing GHG emissions continues to be under consideration.

1. Oregon

Oregon adopted legislation, codified in ORS 468A.205, which imposes a GHG reduction target of 10% of 1990 emissions levels by 2020. In accordance with SB 101 (Chapter 751, Oregon Laws 2009), the PUC will submit a report to the Oregon legislature by November 1, 2010, analyzing the impact that the state's GHG reduction targets will have on customers' rates. The Company's preliminary work shows that offset purchases will be necessary to meet these goals.

Other greenhouse gas initiatives include the development of a "roadmap" by the Oregon Global Warming Commission, a group formed in compliance with HB 3543 and comprised of 25 members. This roadmap is intended to outline the actions necessary for the state to reach the legislative reduction target.

2. Washington

The State of Washington has adopted greenhouse reduction targets that are slightly less aggressive than Oregon's. The Washington Legislature has adopted "energy freedom" legislation to encourage the adoption and use of bioenergy. The legislation was adopted to promote research and development in bioenergy and stimulate the construction of facilities to convert organic matter into fuels including liquefied natural gas and liquefied compressed natural gas.

3. Regional

Regional efforts underway include the Western Climate Initiative (WCI). The WCI is a partnership between seven states and four Canadian provinces aimed at reducing regional greenhouse gas emissions 15 percent below 2005 levels by 2020.

The WCI's cap-and-trade is effective on January 1, 2012, and will apply to emissions from electricity generation, industrial sources, transportation, and residential and industrial fuel combustion. The minimum requirements for jurisdictions participating in the WCI market are as follows:

- Participating states and provinces that emit more than 25,000 metric tons of carbon dioxide equivalents annually will be subject to regulation beginning in 2012, or the first year its emissions exceed that threshold. Electricity sources subject to the cap will include facilities located within a member state or province. Fuel suppliers will be incorporated into cap-and-trade in 2015.

- At least once every three years, covered entities are required to submit one emission allowance for each metric ton of carbon dioxide equivalent emissions they emit.

- Beginning in 2012, each participating jurisdiction will establish a cap equal to anticipated 2012 emissions. Annual allowance budgets will then be reduced over time based on each jurisdiction's 2020 emission reduction goal.

- Allowance distribution is left largely to the discretion of each WCI partner. Member jurisdictions retain the ability to allocate emission allowances included in its emission budget for free or via an auction, or a combination of both. Partner jurisdictions will work together on harmonizing allowance distribution for sectors that are trade-exposed to address potential competitiveness issues.

- Participating jurisdictions will retain primary responsibility for implementing and enforcing the cap-and-trade program, including enforcement mechanisms.

- Within the WCI program, offsets may account for up to 49 percent of emission reductions. The WCI's detailed recommendations for the design of offset programs were published in July 2010, and the WCI also released a joint white paper with the Regional Greenhouse Gas Initiative (RGGI) and the Midwest Greenhouse Gas Reduction Accord (MGGRA), recommending standardized concepts that would allow for linking the regional programs' offset programs.

- The Final Design provides recommendations on how participating jurisdictions can link their cap-and-trade programs with other participating jurisdictions, as well as jurisdictions outside the WCI, including the other North American climate initiatives (RGGI and MGGRA states). Specifically, the WCI Design provides that, in the long-term, WCI may accept allowances and offsets from RGGI and the MGGRA.

Neither Oregon nor Washington has adopted legislation implementing the WCI recommendations and it remains unclear if either state will take action before the 2012 implementation date.

The state and regional GHG reduction initiatives discussed above are the result of efforts that have been underway for years. As with federal policy, the states are showing signs of slowing down efforts in response to the deep and lasting economic recession. For instance, California's Assembly Bill (AB) 32, which was passed in 2006 and establishes aggressive GHG emissions reduction goals by 2011, is now facing voter referendum. This measure called, "The California Jobs Initiative," seeks to halt the enforcement of AB 32 until the state's unemployment, which is currently 12%, is reduced to 5.5% or less.

Energy Efficiency Policy

Policies promoting increased investment in energy efficiency continue to be adopted; for example, Oregon's HB 2626 legislation, also referred to as EEAST (Energy Efficiency and Sustainable Technology), was passed in 2009. EEAST provides financing for customers wanting to make energy efficiency improvements to their home. Under this model, utilities will bill the loan repayment charge on the customer's monthly bill for service.

In addition to the efforts of legislators to expand efforts to broaden energy efficiency savings, the Energy Trust is also exploring new models for reaching customers and expanding savings opportunities. In an effort to achieve additional savings, Energy Trust is partnering with OPower to create a letter comparing customers' energy use to other customers in like-homes. This outreach effort, which has been used by Puget Sound Energy, is designed to achieve behavioral savings.

In 2009, the Oregon State legislature approved SB 79 which requires the State Building Codes Division to adopt more efficient building standards, as well as an optional "Reach Code." The reach code encourages contractors to construct buildings significantly more energy efficient than under the present code.

In addition, the legislation called for a report on the adoption and implementation of an energy performance scoring system (EPS) for new and existing commercial and residential buildings. The EPS is a home rating system that enables home buyers to directly compare energy consumption between homes similar to the miles-per-gallon rating for the auto industry.

The EPS Task Force was authorized by Senate Bill 79 of the 75th Oregon Legislative Assembly - 2009 Regular Session. The objective of the Task Force is to make recommendations to the Oregon Department of Energy regarding the establishment of an energy performance scoring system for new and existing residential and nonresidential buildings.

Energy Trust has developed a voluntary EPS for new home construction and is working on one for existing homes.

C. Conclusion

Although the details that will affect the natural gas utility business are not clearly established, a carbon constrained future is inevitable. In preparation for those regulations, the Company continues to strategize for the future. Examples of the Company's forward-thinking include its continued commitment to energy efficiency, its research into developing technologies including CHP and compressed natural gas vehicles, and its development of both the Smart Energy™ carbon offset program and the solar thermal hot water heating pilot. NW Natural recognizes that the future of the fossil fuel industry is changing and the Company plans to change accordingly so that its customers will continue to have their water and space heating needs met in the best possible way.

VII. KEY FINDINGS

- Through continued administration of energy efficiency programs in Oregon and Washington, NW Natural can save 25 million therms by 2016 and 117 million therms by 2030.

- The achievable potential of therm savings is not significantly impacted when measures are screened by either an avoided cost more consistent with 2010 gas prices or a significantly higher avoided cost created to simulate the potential of higher gas prices.

- NW Natural continues to expect the adoption of climate change legislation or policy to impact its business. In preparation for this, the Company continues to develop environmentally friendly options, such as Smart Energy™ offsets or solar thermal water heating, that allow customers to voluntarily address climate change.

Chapter 5: Linear Programming and The Company's Resource Choices

NW Natural®

I. OVERVIEW

NW Natural employs an analytic method utilizing 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, NW Natural's LP model examines all reasonable means for acquiring demand-side and/or supply-side resources to meet growing customer demand and determines the series of resource decisions through time which results in a plan that balances reliability and cost. The LP model acts as a tool to guide NW Natural'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, demand, future resource availability, and supply prices. For example, a decision made in year five may have been informed by an event occurring in year ten. LP modeling also allows for various combinations of resources, called portfolios, to be evaluated under assorted demand scenarios and ranked according to cost.

NW Natural holds a license with Ventyx, an ABB company, for their gas supply planning and optimization software product SENDOUT.® This application is designed to simultaneously analyze and optimize the entire gas supply portfolio – including supply, transportation and storage assets, and conservation programs. The objective function of the linear programming engine within SENDOUT® seeks to minimize system costs associated with meeting daily load. The resource mix optimization module both evaluates and optimally sizes resources to meet load based on the associated fixed and variable costs of the resource. The Monte Carlo module provides risk planning analysis around hundreds of weather and price simulations. This allows portfolios to be evaluated from a probabilistic standpoint.

II. IRP MODIFICATION

The 2011 IRP was filed with the state of Oregon on January 12, 2011 and with Washington on March 31, 2011. The IRP included the proposed Palomar East pipeline project, which was modeled as a potential resource component of the least cost plan. Pipeline rates for reserving capacity were modeled on an existing precedent agreement which included a rate cap. Model runs which excluded capacity on the proposed pipeline were also completed, but the majority of runs included Palomar East. Deterministic modeling indicated that the overall cost of serving demand over the 20 year horizon was slightly less when capacity was reserved on the Palomar East Pipeline. Additional reliability and Monte Carlo modeling also indicated favorable results with a resource portfolio that included capacity on Palomar East.

On March 23, 2011, Palomar Gas Transmission LLC withdrew its pipeline application with FERC, while stating its expectation of re-filing at a later date. Information for a new Cross-Cascades pipeline project called Palomar/Blue Bridge was presented in February 2011 at a public workshop jointly sponsored by the Public Utility Commission of Oregon and the Washington Utility and Transportation Commission. The information included new estimates for pipeline rates and service dates. In light of the uncertainty

[1] Hillier, Fredrick S. and Lieberman, Gerald L, Introduction To Operations Research 6th Edition, McGraw-Hill, Inc., 1995, 25.

regarding the pipeline, in April, NW Natural embarked on an IRP modification phase and presented the modeling and planning results at the Technical Working Group Meeting on June 22, 2011. In this modification phase, additional model runs were completed to evaluate planning under more demand scenarios without the Palomar/Blue Bridge pipeline. New model runs were also completed with the new rate and service date estimates. The SENDOUT® resource planning model was updated with a more recent natural gas price forecast, along with slight updates to a few resource settings. The demand and DSM forecasts were not changed. This chapter includes results from the original modeling phase, and from the modification phase. Where applicable, the results are appropriately labeled as to which phase they originated from.

III. RESOURCE PLANNING MODEL INTEGRATION

Six primary components are integrated within NW Natural's SENDOUT® resource planning model.

A. Demand forecast
B. Temperature pattern
C. Natural gas price forecast
D. Demand side management resources
E. Current supply side resources
F. Potential future supply side resources

A. Demand Forecast

NW Natural uses demand usage factors to incorporate the demand forecast into the resource planning model. The usage factors include the number of customers by region and category, as well as the customer and region specific base and heat load factors. The usage factors are used in combination with temperature data to generate an overall gas requirement for each of the 8 demand centers. The methodology for the derivation of the demand usage factors was presented in Chapter 2. In addition, a high cost penalty is attached to un-served demand so that the resource model is forced to attempt to serve all demand by any means possible.

B. Temperature Pattern

A daily temperature pattern by region is required to calculate region specific demand. The temperature data is converted to heating degree days (65° F based) for the calculation. NW Natural has developed a statistically based pattern which is known as the design weather pattern for the model. Chapter 2 outlines the development of this very cold weather pattern which was designed to be colder than 85% of the winters our service area experiences. In addition, the annual temperature pattern was augmented with the coldest peak day event in the past 20 years. A 20 year data set of temperatures has been included in the resource model to provide a base for the weather portion of the Monte Carlo simulation.

In this IRP, modeling and resource planning is developed around this design winter augmented with the coldest peak day temperature event in the past 20 years. Should capacity become constrained in a service area for any reason, including a weather event that exceeds the Company's planning standard, the Company can balance the system by curtailing service. The guidelines for curtailment are established in Rules 15 and 16 in NW Natural's Washington Tariff and Rules 13 and 14 in the Oregon Tariff. These rules establish a priority for curtailment. Customers on interruptible schedules are curtailed first, followed by non-essential human needs firm sales industrial and commercial customers. The last to be curtailed are firm residential and essential human needs customers. It is not uncommon during the heating season for the Company to call a curtailment event for a portion of its interruptible customers. These customers pay lower distribution charges and they generally provide services in a sector that requires them to have a back-up energy source. Approximately 40 percent of the Company's annual throughput is for interruptible, interruptible transportation, and firm transportation customers

C. Natural Gas Price

A cost is associated with each unit of natural gas supply sourced in the resource model. These costs can drive planning to focus on certain low cost sources and can also allow the model to take advantage of seasonal variability. For instance, one low cost strategy might involve purchasing gas during the summer months when prices are lower and holding the supply in a storage facility until needed to meet high winter demand. Substantial differences between summer and winter prices could therefore influence storage resource decisions, as well as supply purchase decisions. Long term price differentials between supply basins may also drive pipeline resource decisions to steer toward the lower priced basins. NW Natural uses the price forecast as described in Chapter 2 to incorporate supply options and costs. Gas price also has a strong influence on the expected overall cost to meet customer demand across the planning horizon, since supply is typically the largest cost component of any plan.

D. Demand side management resources

As discussed in Chapter 4, NW Natural worked with the Energy Trust of Oregon to generate a 20-year demand side management forecast, which estimates the cost and amount of therm savings that can be procured by providing incentives to NW Natural customers for installing energy efficiency measures at their homes or other facilities. This energy savings and cost forecast was integrated into the SENDOUT® resource planning model so that DSM may be compared directly with supply side resources on a cost basis through time. The savings which are selected by the LP tool are then deducted from the demand forecast with the remaining demand served by supply side resources.

DSM was implemented into NW Natural's SENDOUT® model using the Program Totals method. In this method, DSM savings are represented by customer specific base and heat load factors. Similar to the demand forecast, base load is considered to be independent of weather while heat load is a function of the rate at which energy is saved (heat rate factor) multiplied by the HDD value. The associated costs of the DSM is represented by a total program cost factor on a $ per therm saved basis, as provided by the Energy Trust.

The Energy Trust provided the DSM forecast on an annual and state- wide basis. In order to implement the forecast into the resource model, the energy savings were allocated among the 8 demand regions on a monthly basis. In addition, the savings associated with the DSM defined categories were translated into the resource planning model DSM categories. Table 5.1 demonstrates the relationship between categories.

Table 5.1 - DSM Categories

ETO DSM CATEGORIES	RESOURCE PLANNING MODEL DSM CATEGORIES
Residential New Construction	Residential New Construction Single Family – Must Take
	Residential New Construction Multi Family – Must Take
Residential Existing - Replacement	Residential Existing Must Take
	Residential Conversion Must Take
Residential Existing - Retrofit	Residential Existing Discretionary
	Residential Conversion Discretionary
Commercial New Construction	Commercial New Construction – Must Take
Commercial Existing – Replacement	Commercial Existing Must Take
	Commercial Conversion Must Take
Commercial Existing – Retrofit	Commercial Existing Discretionary
	Commercial Conversion Discretionary
Industrial Replacement	Industrial Must Take
Industrial Retrofit	Industrial Discretionary

DSM savings in the new construction and replacement categories are designated as "must take", which means that the therm savings are locked in and deducted from demand in the resource model. If these programs are not implemented when the opportunity for new construction or equipment replacement occurs, then the savings potential is lost. Savings that fall into the retrofit category are "discretionary." In this case, the resource planning model will make an optimal resource mix decision based on cost. Either the demand will be served with DSM at the program cost, or the demand will be served with the purchase and transport of supply. If DSM is selected, the savings are deducted directly from demand.

Two scenarios were developed around the base case DSM forecast and run through the resource model in order to gauge the effect of forecast uncertainty and to bracket the savings estimate. In the high DSM case, the energy savings forecast was increased by 30%, and in the low DSM case the savings were reduced 15%. Due to the nature of resource assessments, estimates of potential savings tend toward the conservative side. Therefore there may be more room for upside than downside from the base case estimate.

E. Current and future supply side resources

Following the DSM adjustments in the planning model, the remaining gas requirements for each region or demand center are met by supply side resources. NW Natural's current supply side resources are incorporated into the SENDOUT® resource planning model. These resources fall into 3 basic categories:

1. Supply
2. Transport
3. Storage

The supply category includes the gas commodity itself. In the planning model, gas may be purchased from an existing supply source or acquired through a recall agreement. The purchase cost is defined in the gas forecast. Recall agreements allow NW Natural to acquire limited volumes at an elevated cost and are used to augment peak day resources.

Transport involves moving the purchased supply to the demand center or to a storage facility via a pipeline. Pipelines typically have a fixed cost associated with the reservation of a specific, fixed maximum daily capacity. The amount of gas that can be moved on these pipelines is constrained to the amount of capacity that is reserved. Some pipelines also have a variable cost associated with the quantity of supply that is actually moved along that transport path. The pipeline capacity for NW Natural pipeline projects, such as the North Willamette Valley Feeder, is estimated based on pipe diameter and system pressure assumptions.

Gas may be transported to a storage facility where the supply is injected and held in storage until it is withdrawn to serve demand at a later date. Each storage facility is modeled to have an associated maximum physical capacity, as well as individual gas injection and withdrawal rate capabilities. Storage related costs include fixed costs attached to the facility itself, as well as variable costs associated with the amount and value of gas that is stored over time, and costs related to injection and withdrawal. Storage is a valuable asset for meeting peaking demand. Typically, the facilities are filled with supply during the summer and drawn down in the winter.

Demand may be met in the resource model in numerous ways. Each pathway, from supply source to demand center, has a specific constraint and an associated cost. The value of an LP resource planning model is that it will efficiently converge to the least cost method of serving all demand, assuming such a solution exists. As an example, suppose a unit of demand is placed on the system by a residential customer in Salem. The unit of gas may be bought in Alberta Canada at the AECO rate. This unit of gas is brought down the Trans Canada Alberta system pipeline to Kingsgate at the Canadian border with the associated costs. From there it enters the Trans Canada GTN system and is transported to Stanfield Oregon where it enters Williams' NW Pipeline. From there, it may be transported through the Columbia River Gorge to the Portland area and down the lateral, past the Salem city gate and on to Salem. Alternatively, the unit of demand might be sourced from Mist underground storage and moved down to Salem via the North Willamette Valley Feeder. Another option is to withdraw the unit of gas from the Newport LNG facility and transport to Salem, or instead, source the unit of gas from the Rockies and transport by another path. There are numerous other ways of serving the same unit of demand, each with unique costs.

To meet growing demand, future supply side resources need to be added. Future resources fall into the same three categories – supply, transport, and storage. NW Natural's SENDOUT® planning model utilizes the resource mix optimization capability to evaluate new resource options. New supply sources may become available, such as imported LNG, or a new pricing point at Malin. New transportation capabilities could be explored. Additional capacity on existing pipelines could be secured over time with an additional fixed and variable cost. A new pipeline may become available, such as the proposed Palomar/Blue Bridge Cross-Cascades project, which would open up new supply and transport options.

NW Natural pipeline projects could be developed, with the capital costs representing the resource fixed costs. For storage, additional capacity could be added at existing facilities or new facilities could be built with the estimated capital costs serving as the fixed cost.

Table 5.2 lists the current and future resources that are available in the resource planning model, and a discussion of key resources follows. Figures 5.1 and 5.2 display model diagrams for pipeline and supply resources, and Figure 5.3 is a model diagram for Storage and other service area resources.

Table 5.2 - Current and Future Planning Model Resources

DEMAND SIDE MANAGEMENT	SUPPLY	PIPELINE	STORAGE
Current Resources			
Implicit in current demand usage factors	US Rockies (Opal)	CD on TransCanada NOVA/BC/GTN system (TCPL & GTN)	PSE/Avista/Williams' Jackson Prairie underground
	Alberta Canada (AECO)	CD on Terasen Southern Crossing	Williams' Plymouth LNG
	British Columbia Canada (Sumas)	CD on Williams' Mainline through the Gorge (NWPL)	NWN Mist underground
	Recall Agreements	CD on Williams' Grants Pass Lateral	NWN Newport LNG
		NWN Harrisburg River Crossing – 2010	NWN Gasco LNG
		NWN North Willamette Valley Feeder – 2011	
Future Additional Resources			
ETO program deployment	US Rockies (Opal)	Incremental CD on TransCanada NOVA/BC/GTN system (TCPL & GTN)	NWN Mist Recall
	Alberta Canada (AECO)	Incremental CD on Williams' Grants Pass Lateral	NWN Satellite Storage projects in the Willamette Valley
	British Columbia Canada (Sumas)	CD on Palomar Gas Transmission's Palomar/Blue Bridge Pipeline	
	Recall Agreements	Williams' NWPL Opal to Stanfield (generic from Rockies)	
	US Rockies/Alberta Canada at Malin (OR) via Ruby Pipeline	GTN backhaul Malin to Madras	
	Oregon LNG - imported LNG	March Point CD	
	Jordon Cove – imported LNG	NWN Newport LNG Compressor Project	
		NWN Mid & South Willamette Valley Feeder	

1) DEMAND-SIDE MANAGEMENT

The savings performance from previous energy efficiency programs are assumed to be reflected in the current demand usage factors that determine the demand forecast. Future DSM savings from Energy Trust of Oregon programs are deducted from demand according to the deployment forecast. For a detailed discussion on how DSM was integrated into the planning model, refer to part D earlier in this section.

2) SUPPLY

Currently, NW Natural sources gas from three primary pricing points: OPAL in the US Rockies, AECO in Alberta Canada, and Station 2/Sumas in British Columbia Canada. There are a limited number of recall agreements in place for peak day options.

If the Palomar/Blue Bridge Cross-Cascades pipeline is built at a future date, a new supply point option could be opened up at the terminus of the Ruby Pipeline at Malin Oregon. Ruby connects US Rockies supply with northern California via the southern Oregon hub of Malin. Gas could potentially be backhauled up the GTN pipeline to Madras and across the Cascade Mountains to the Willamette Valley via Palomar/Blue Bridge. See Figures 5.1 and 5.2 for model diagrams.

<u>Imported LNG</u>

NW Natural could acquire future supplies from two proposed LNG importation facilities in Oregon. Due to the level of uncertainty, neither project was included in the base case resource portfolio. However two separate model runs were run and evaluated should either project come to fruition.

In southern Oregon, the Jordon Cove LNG project near Coos Bay could deliver up to 1 bcf/day of imported natural gas. The imported LNG facility would connect with the Pacific Connector Gas Pipeline, a proposed 234 mile long pipeline project. The pipeline could potentially deliver gas to the Williams' Grants Pass Lateral pipeline in the southern Willamette Valley and to the GTN system at Malin. The resource is modeled to be available beginning in November of 2014.

OregonLNG is a proposed LNG importation project in the northern part of Oregon near Warrenton, with deliverability reaching 1.5 bcf/day. In conjunction with the import facility, Oregon Pipeline would build a new pipeline from Warrenton to the Molalla gate station, roughly 117 miles in length. This resource is modeled to be available beginning in November of 2015.

3) PIPELINE

<u>Harrisburg River Crossing and North Willamette Valley Feeder</u>

Two recent NW Natural pipeline projects help to serve demand in the service area. The Harrisburg River Crossing pipeline project was a selected resource in the previous two IRPs and is now in service as of November 2010. This is a key project which improves the capability for serving current and future demand in Eugene. The 12-inch diameter pipeline cuts under the Willamette River and provides additional delivery potential of 8 MDT/day of supply to the Eugene demand center. The North

Willamette Valley Feeder (NWVF) is a NW Natural pipeline project (12-inch diameter) running from Aurora to Brooks Oregon. In the model, it is represented by a transport section linking the Portland and Salem demand centers. It could carry up to 85 MDT/day down to Salem and possibly beyond, depending on if the Mid and South sections are also built. It is an important resource since it allows additional storage supplies from Mist, and potentially additional pipeline delivered supply from Palomar/Blue Bridge to reach the Willamette Valley and the coast. The NWVF is planned to be in service by November 2011. See Figure 5.3 for the model diagram.

Mid and South Willamette Valley Feeder

The Mid and South sections of the Willamette Valley Feeder are potential future NW Natural pipeline projects. The mid section (MWVF) is modeled to link Salem with Albany and the south section (SWVF) would link Albany with Eugene. The entire feeder, from Portland to Eugene, would serve as a supplement to the Grants Pass Lateral. The earliest these two sections could be in place is November 2012. The modeled fixed costs represent the estimated capital costs for the projects. The model has the ability to select none, one, or both of the sections at any time after 2012. See Figure 5.3 for the model diagram.

Incremental Capacity on Williams' Grants Pass Lateral

Williams' Grants Pass Lateral transports supplies to the Salem, Albany, and Eugene demand centers. The pipeline is fully subscribed, but pipeline expansion could increase capability. The model estimates the incremental capacity to cost the same as the current rate. The amount of capacity selected can be increased each year. There are additional NW Natural take-away costs associated with increasing the capacity on the Grants Pass Lateral as well. This resource decision is first available in November 2013, and may be resized up in each following year. See Figure 5.3 for the model diagram.

Newport Compressor Project

The Newport Compressor Project is a potential new resource that would allow more Newport LNG storage supplies to reach Salem on a peak day. If the Mid and South Willamette Valley Feeder projects are built, Newport LNG supplies could reach Albany and Eugene as well. In the model, the addition of a new compressor station at Perrydale is represented by a transport link that would allow an additional 40 MDT/day to reach Salem from Newport. The estimated capital costs for such a project are modeled with a fixed cost factor. See Figure 5.3 for the model diagram.

Palomar/Blue Bridge Cross-Cascades Pipeline

Palomar Gas Transmission, a partnership between NW Natural and TransCanada, has proposed a new pipeline which would carry natural gas across the Cascades to western Oregon. The pipeline would connect to GTN near Madras Oregon, and terminate at NW Natural's service area at Molalla Oregon, between Portland and Salem. The modeled service date is November of 2017. Please see Figure 5.2 for the model diagram. The Palomar organization has also been in discussion with Northwest Pipeline (NWPL) about developing a regional solution to pipeline constraints, which is the Blue Bridge portion.

NWPL is fully subscribed through the Columbia River Gorge. Palomar would provide parallel capacity to NWPL, allow the transport of more Alberta supply to western Oregon, and also open up the ability to acquire supply from a new purchase point in Malin. In addition to Palomar capacity, NW Natural would need to secure capacity on GTN from Stanfield to Madras, and if cost effective, capacity on GTN from Malin to Madras.

For the IRP modification phase, the pipeline rates and service date assumptions for the model were sourced directly from the February 2011 Natural Gas Workshop presentation. For model runs that include the project, starting in 2017 the model can decide to select capacity on the pipeline at a fixed daily level between 100 to 200 MDTH. At the same time, the model can elect to turn back as much as 77 MDTH of capacity on NWPL through the gorge. In the early years of the proposed project, the estimated pipeline rates ($/MDTH) for the Palomar/Blue Bridge project are greater than the vintage rate that NW Natural currently pays for capacity with NWPL.

Previous to the announcement of the new Palomar/Blue Bridge project, a significant amount of modeling work was completed with Palomar as a potential resource, but with an earlier in-service date and a lower reservation rate. Operationally, the modeled pipeline provided the same function as in the modified phase. Several reliability model runs were completed, as was a Monte Carlo simulation analysis. These original, pre-modification modeling runs were performed with the original gas price forecast, which dated from March of 2010.

4) STORAGE

Jackson Prairie Storage and Plymouth LNG Storage

NW Natural retains existing capacity on the two storage units on the NWPL system.

Newport LNG & GASCO LNG

The NW Natural Newport LNG storage facility plays an important role in helping to serve peak day demand in the Newport/Lincoln City and Salem demand centers. Through decades of use, a buildup of $C0_2$ has occurred in the storage tank which may need to be cleared. The LNG facility would need to be taken offline for an undetermined amount of time to evaluate and potentially fix the issue. It has been estimated that it would take at most two years. For planning purposes, the resource model assumes Newport LNG is off line from April 2015 to April 2017. Other resources will need to fill in during the down time, including Mist Storage and the NWVF. The Newport LNG compressor project would allow the full potential of the LNG facility to be utilized by transporting additional supply to Salem and possibly beyond.

GASCO is also a NW Natural LNG facility near Portland that provides important peak day capacity.

Mist & Mist Recall

NW Natural's Mist Storage, also known as Miller Station, provides a significant underground storage resource. Additional storage capacity can be recalled from the interstate storage business as a resource decision. The resource options are modeled as individual decisions through time as existing interstate storage contracts expire.

<u>Satellite Storage</u>
NW Natural could build small, above ground storage facilities near the Salem, Albany, and Eugene demand centers to help serve peak day demand in the Willamette Valley. These satellite storage facilities are modeled to be incremental resource options, since storage tanks could be added through time. The estimated capital costs associated with building these small storage facilities are converted to a fixed cost per MDT of deliverability for the model.

Figure 5.1 – Pipeline and Supply Model Diagram

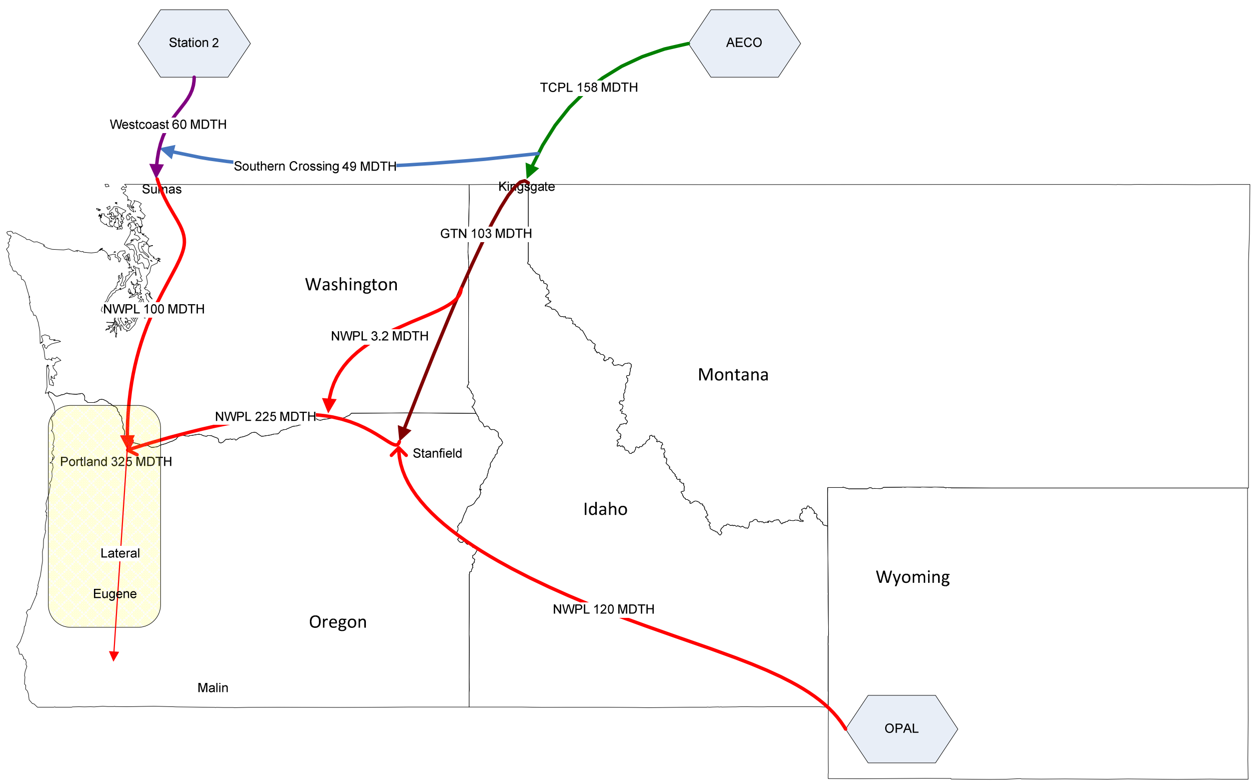


Figure 5.2 – Pipeline and Supply Model Diagram with Palomar/Blue Bridge

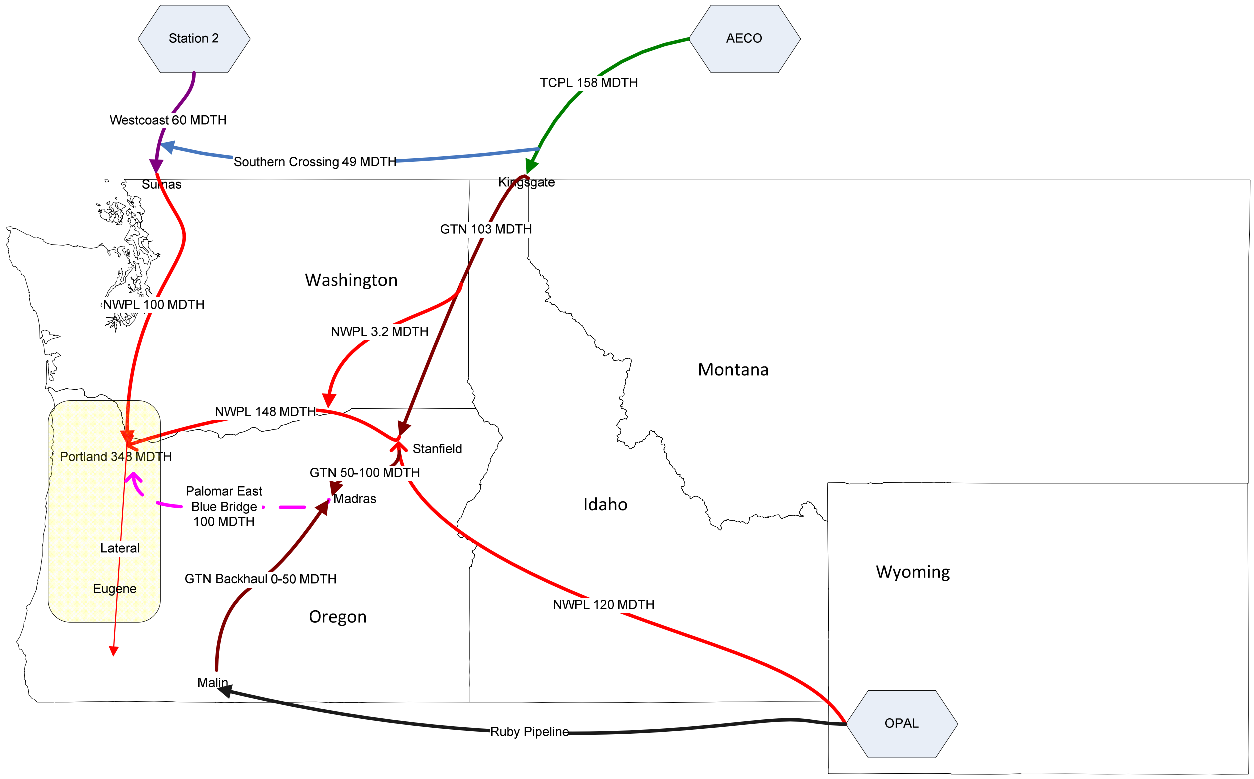
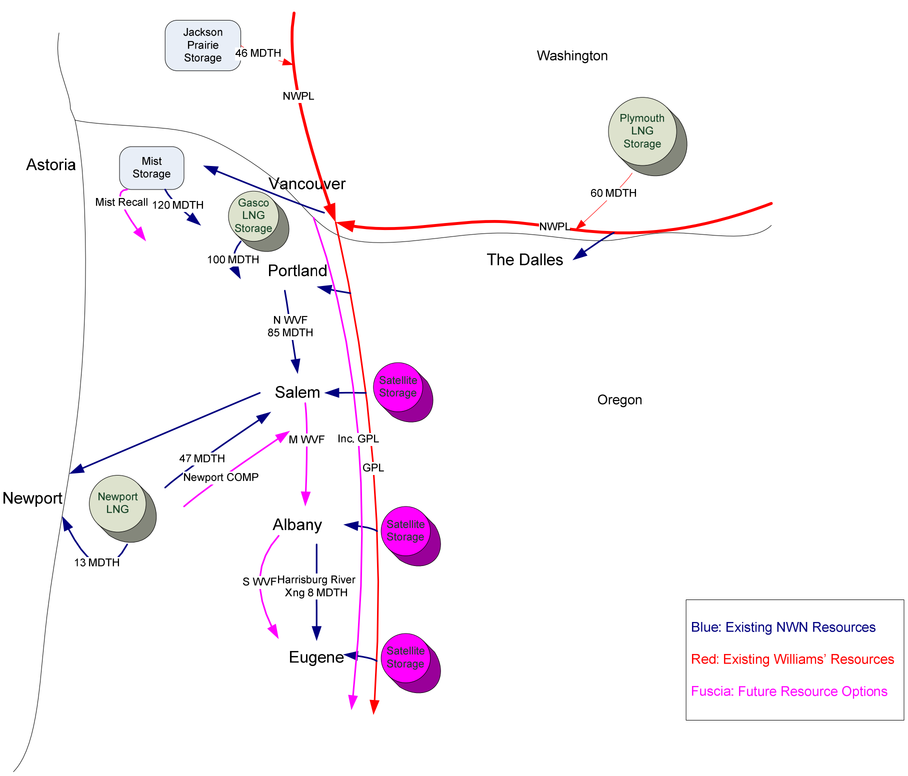


Figure 5.3 – Storage & Service Area Resources Model Diagram



IV. ORIGINAL PHASE RESOURCE PLANNING MODEL RESULTS

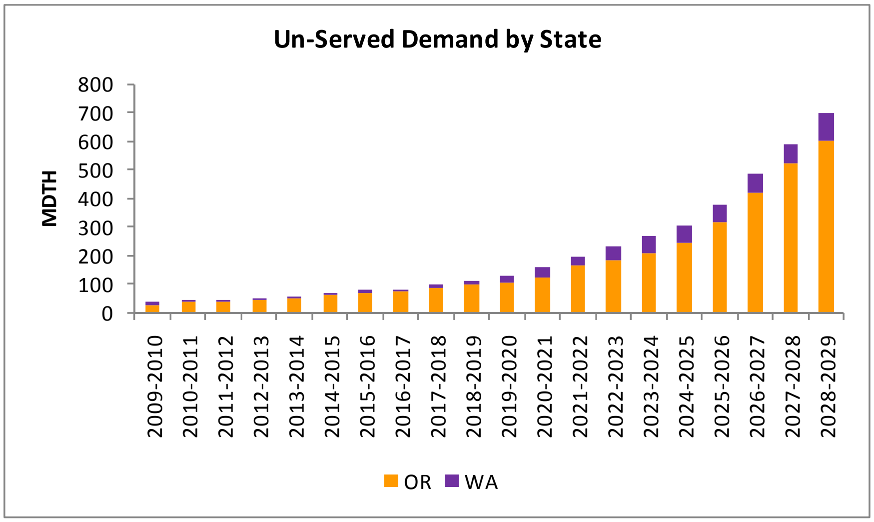
The modeling work for the IRP version that was filed in early 2011 with Oregon and Washington was performed between July and September of 2010. This work was done with the best available resource information at the time. Following the completion of the work, further information regarding the Palomar Pipeline became available. The most significant changes revolved around estimates for the service date and pipeline rates. The capacity estimates for the pipeline remained the same. Beginning in April of 2011, additional modeling work was performed for the modification phase of the IRP. The most significant results from the original modeling work will be covered in this section.

There are three basic steps to the process of running NW Natural's SENDOUT® resource planning model. First, a congruent set of model inputs must be entered into the application. These include the previously covered demand factors, weather patterns, price forecast, demand side management factors, and current resources. Next, the desired set of future resource options with individual decision factors are configured within the model. The application is then run, and the output is collected. The output results include the time frame and size of the resource decisions, served and un-served demand, and the supply, transport, storage and DSM costs. Total costs are tabulated and the net present value of the cost over the 20 year horizon is calculated. The modeling process is an iterative one; several runs are typically required for each unique set of inputs and resource portfolios.

A. No New Resources

The initial step in resource planning involves testing when new resources are required, if at all. A model run was completed in which all future incremental supply and demand side resources were excluded. The planned NW Natural projects – NWVF and Harrisburg River Crossing – were included, and Newport LNG was assumed to be in service the entire time. The base case demand forecast and design weather were used as inputs. The model showed that all of the demand regions, except for Newport/Lincoln City, experienced un-served demand in each year of the planning time frame. Clearly demand growth is large enough that new resources will need to be added to the system. Figure 5.4 displays the un-served demand through time in MDT (thousand dekatherms), broken out by state.

Figure 5.4 – Un-served Demand Assuming No New Resources



B. Planning Results with Base Case Demand and Resources

Once it has been ascertained that current resources are insufficient for meeting all projected demand, the next step is to evaluate potential new resources through SENDOUT®. Deterministic, least cost modeling was performed with the base case inputs (demand forecast, gas price forecast, design weather), around a base case resource portfolio and the results compiled.

The base case resource portfolio was assembled to represent a collection of the most likely new, future resource options. During runs, the model was allowed to select from these resource options at specific levels and points in time. This base case resource portfolio is outlined in Table 5.2 with one exception. The two proposed imported LNG projects were excluded. Separate model runs were set up and run for the imported LNG cases.

The Palomar East pipeline resource was modeled in two ways. In one trial, the model could make a one-time decision to reserve capacity on the pipeline at a size between 100 and 300 MDT/day. In a related decision, the model was allowed to turn back anywhere from 0 to 77 MDT/day of parallel capacity on the Williams' NWPL mainline. In case the Palomar East pipeline is not available in the future, the model was also run with Palomar East at 0 MDT/day, with the rest of the base case resource portfolio remaining unchanged. The pipeline rate used in the model was set to the rate cap level, with an assumed service date of 2014. In the modification phase of the IRP, which is discussed in the next section, the pipeline rate was updated to a higher level and the service date was pushed out to 2017.

Under the base case demand conditions and resource portfolio, Plan 1319-Palomar East produced the least cost. The alternative least cost plan if Palomar East is not built is labeled 1321-No Palomar. These two plans are very similar in resource selections and costs, with the primary exception of the utilization of the Palomar East pipeline. In 1319, 100 MDT/day of capacity is secured on Palomar East starting in November of 2014, accompanied with a turn back of 77 MDT/day of the Williams' NWPL mainline capacity. Least cost modeling indicates that the Plan 1319-Palomar East is slightly less expensive than the least cost plan without Palomar East (1321) in serving base case demand. The difference in net present value over the 20 year horizon is $2.3 million. Table 5.3 provides a summary of the model results for these two plans.

Table 5.3 – Least Cost Modeling Results With Base Case Demand and Resource Portfolio

	1319 – Palomar East	1321 – No Palomar East
Cost $(000) Net Present Value	$ 8,159,819	$ 8,162,089
Resource Timeline		
2010/2011	Harrisburg River Crossing on-line	Harrisburg River Crossing on-line
2011/2012	NWVF on-line Mist Recall	NWVF on-line Mist Recall
2012/2013	Mist Recall	Mist Recall
2014/2015	Palomar East CD and Williams' NWPL turn-back	Mist Recall
2015/2016	Newport LNG down for repairs Mist Recall	Newport LNG down for repairs Mist Recall
2016/2017	March Point CD on-line	March Point CD on-line
2017/2018	Newport LNG back on-line	Newport LNG back on-line
2023/2024	Newport LNG Compressor Project Grants Pass Lateral incremental capacity	Newport LNG Compressor Project Grants Pass Lateral incremental capacity
2028/2029		Williams' NWPL Mainline incremental capacity

In the least cost model runs, all of the DSM resources were selected. As mentioned earlier, DSM energy savings are modeled by a mixture of automatic savings and resource decisions. Figure 5.5 displays the model output for DSM resource savings by category and state. Figure 5.6 expresses DSM savings as a percentage of demand.

Figure 5.5- DSM Savings with Base Case Demand and Resource Portfolio

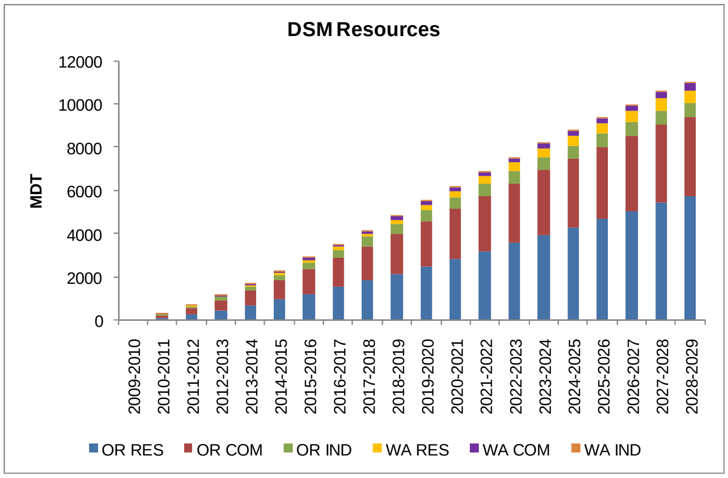
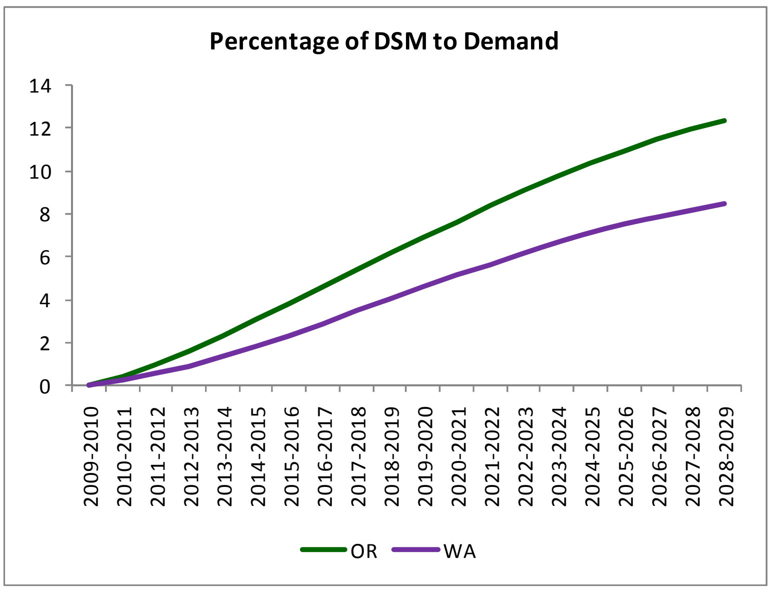


Figure 5.6 - DSM Savings Percentage of Demand



C. Reliability

A series of simple service disruptions were forced into the model to test the planning cases for reliability. For each disruption, gas flows were reduced by one half of the resource's capability for the month of February. This month was chosen because it contains the annual peak day event. The five service disruptions that were modeled include:

1. Williams' NWPL Gorge – 2018
2. Williams' Grants Pass Lateral – 2020
3. Jackson Prairie Storage – 2022
4. NW Natural Mist Storage – 2024
5. NW Natural Gasco LNG - 2026

Three model runs were set up for each case; 1319-Palomar East, and the No Palomar case (1321). First, the resource options were constrained to the fixed decisions from each planning case. Next, resource options were limited to the planning case values until 2023, when the options were opened up. Finally, the resource options were opened up completely to see how the disruptions would be served with and without Palomar East. The model results are summarized in Table 5.4.

Table 5.4 – Service Disruption Model Results (Un-Served Demand in MDT units)

Modeled Disruption		1373 – Palomar East & fixed resources (1319)	1374 – No Palomar East & fixed resources (1321)	1347 – Palomar East & limited resource options	1349 – No Palomar East & limited resource options	1348 – Palomar East & full resource options	1350 – No Palomar East & full resource options
Total Un-Served Demand		508.25 mdt	708.97 mdt	315.7 mdt	597.09 mdt	0 mdt	291.36 mdt
Williams' NWPL Gorge Mainline (2018)	Un-Served Demand	72.37 mdt	140.48 mdt	72.37 mdt	140.48 mdt	0 mdt	0 mdt
	% of Peak Day Served	93 %	86 %	93 %	86 %	100 %	100 %
Williams' Grants Pass Lateral (2020)	Un-Served Demand	149.61 mdt	149.61 mdt	149.61 mdt	149.61 mdt	0 mdt	0 mdt
	% of Peak Day Served	94 %	94 %	94 %	94 %	100 %	100 %
Jackson Prairie Storage (2022)	Un-Served Demand	0 mdt	15.64 mdt	0 mdt	15.64 mdt	0 mdt	0 mdt
	% of Peak Day Served	100 %	98 %	100 %	100 %	100 %	100 %
NWN Mist Storage (2024)	Un-Served Demand	269.25 mdt	363.22 mdt	93.72 mdt	291.36 mdt	0 mdt	291.36 mdt
	% of Peak Day Served	82 %	80 %	91 %	84 %	100 %	84 %
NWN Gasco LNG (2026)	Un-Served Demand	17.02 mdt	40.02 mdt	0 mdt	0 mdt	0 mdt	0 mdt
	% of Peak Day Served	98 %	96 %	100 %	100 %	100 %	100 %

Comparing the fixed resource cases 1373 and 1374, overall un-served demand increased by 39% without Palomar East. The disruption to Mist Storage resulted in the most significant outage in all cases. The only case to serve all demand was 1348, which is Palomar East with full resource options. In this case, Palomar East was selected at 194 MDT/day, Satellite Storage was developed in Salem, Albany and Eugene, and the Mid Willamette Valley Feeder was built.

D. Scenario Model Runs

Table 5.5 contains a partial list of the model runs completed in the original IRP modeling phase. Newport LNG was modeled to be down for repairs in all the cases. The results for scenarios that were re-run in the modification phase are not included in the table, but are shown in a later section. Contract demand on Palomar East was included at the resource portfolio level of 100 to 300 MDT/day.

Table 5.5 - List of Original Model Runs

RUN #	NAME	CUSTOMER GROWTH	CUSTOMER USAGE	WEATHER	GAS PRICE	SUPPLY RESOURCE PORTFOLIO	DSM
1	1319-Palomar East	Base case	Base case	Design	Base case	Base case	Base case
2	1321-No Palomar East	Base case	Base case	Design	Base case	No Palomar East	Base case
3	1373-Outages - PAL E - Fixed RSC	Base case	Base case	Design	Base case	Base case	Base case
4	1347-Outages-PAL E-Semi Fixed RSC	Base case	Base case	Design	Base case	Base case	Base case
5	1348-Outages-PAL E-Full FSC	Base case	Base case	Design	Base case	Base Case	Base case
6	1374-Outages-NO PAL E - Fixed RSC	Base case	Base case	Design	Base case	No Palomar East	Base case
7	1349-Outages-NO PAL E-Semi-Fixed RSC	Base case	Base case	Design	Base case	No Palomar East	Base case
8	1350-Outages-NO PAL E-Full RSC	Base case	Base case	Design	Base case	No Palomar East	Base case
9	1354-Low Gas Price	Base case	Base case	Design	Low	Base case	Base case
10	1355-High Gas Price	Base case	Base case	Design	High	Base case	Base case
19	1368-Imported LNG OregonLNG	Base case	Base case	Design	Base case	Northern Imported LNG	Base case
20	1369-Imported LNG Jordan Cove	Base case	Base case	Design	Base case	Southern Imported LNG	Base case
23	1384-PAL East 10% Higher	Base case	Base case	Design	Base case	Palomar East 10% $ Higher	Base Case
24	1385-PAL East 10% Lower	Base case	Base case	Design	Base case	Palomar East 10% $ Lower	Base case

Table 5.6 provides a summary of resource and cost results from the model runs, ranked by overall cost. Also listed are the resource options that were selected for the case as the least cost solution. Mist Storage recall is selected in all runs. The Newport LNG Compressor project was also selected in all cases except for the Northern Imported LNG case. Additional capacity on the Grants Pass Lateral was usually the resource of choice for serving additional demand down in the Willamette Valley.

Cost variation around the proposed Palomar East pipeline was evaluated in two scenarios. In the first, starting in 2014, the reservation charge on the pipeline was modeled to be 10% higher than the assumed charge while in the second scenario, the reservation charge was modeled to be 10% lower. The results were compared to the least costs plans with and without Palomar – 1319 and 1321.

Neither pipeline cost scenario resulted in significant changes in resource decisions from 1319. With the Palomar East reservation modeled 10% higher, the overall cost of the plan with the pipeline included slightly surpassed the overall cost without the pipeline. In the case with Palomar East higher (1384-PAL E 10% Higher), the overall net present value cost came in $13.4 million over the Plan 1319, and $11.1 million higher than the No Palomar case (1321). This represents a 0.16% and 0.14% increase in overall costs respectively. With Palomar East at a 10% lower reservation charge, the overall costs run $13.3 million less than the Plan 1319 and $15.6 million under the 1321-No Palomar case.

The imported LNG resources were only made available for the imported scenario model runs. In the northern case, the imported LNG supply supplanted the need for the Newport LNG project, and resulted in significantly less Mist Recall. In the southern imported LNG case, Jordan Cove replaced the need for additional capacity in the Willamette Valley.

The Mid and South Sections of the Willamette Valley Feeder were not selected in any of the cases, except in the service disruption model run. The nature of optimization planning across a 20-year time horizon coupled with shallow demand growth favors small incremental resource options. However, over a longer horizon, a significant capacity expansion, such as a pipeline project, may prove to be cost effective.

Table 5.6 – Original Model Runs Ranked by Cost with Selected Resources (*Cost of Un-Served Demand not included)

Run #	Name	Cost $(000) NPV	Mist Recall	Newport LNG Comp. Proj.	Satellite Storage	Mid WVF	South WVF	Palomar East CD	Increm. CD Grants Pass Lateral	Increm. CD NWPL Mainline (Zone 26-16)	Imported LNG
9	1354-Low Gas Price	7,380,577	X	X	X			X	X		
19	1368-Imported LNG ORLNG	7,984,547	X					X	X		X
24	1385-PAL East 10% Lower	8,146,499	X	X				X	X		
20	1369-Imported LNG Jordan Cove	8,151,056	X	X				X			X
6	1374-Outages-No PAL E-Fixed Res.	8,159,049*	X	X					X	X	
1	1319-Palomar East	8,159,819	X	X				X	X		
3	1373-Outages-PAL E-Fixed Res.	8,160,996*	X	X				X	X		
2	1321-No Palomar East	8,162,089	X	X					X	X	
23	1384-PAL East 10% Higher	8,173,181	X	X				X	X		
7	1349-Outages-No PAL E-Semi fixed Res.	8,177,334*	X	X	X						
4	1347-Outages-PAL E-Semi fixed Res.	8,206,069*	X	X	X			X			
8	1350-Outages-No PAL E-Full Res.	8,241,010*	X	X	X	X			X		
5	1348-Outages-PAL E-Full Res.	8,373,054	X	X	X	X		X	X		
10	1355-High Gas Price	9,706,255	X	X				X	X		

E. Monte Carlo Simulation

Section IV covered the results from the deterministic resource planning model runs from the original IRP modeling phase. With deterministic modeling, resource decisions are phased in at optimal levels and times around fixed, predetermined weather patterns and price forecasts. In the deterministic case, a single optimal solution exists for each given set of assumptions. Therefore, an optimal resource plan is developed around one specific future. Further insights into resource planning may be gained by evaluating a given plan's performance under many possible futures through the use of Monte Carlo simulation. In this case, the resource options are fixed at previously specified optimal levels and timeframes, while variability is introduced around weather and supply price. For this IRP, a set of 250 individual simulations of weather patterns and price trajectories over the 20 year planning horizon were computed and fed into the 1319-Palomar East resource plan, and the 1321-No Palomar plan. The results were evaluated for reliability in serving demand and for cost.

1. Statistical generation of inputs

Monte Carlo simulation of weather and supply price was carried out using SENDOUT® during the original modeling phase. A set of 250 simulations were designed around daily temperatures for each demand center, as well as monthly gas prices for the supply points of Rockies/OPAL, AECO, Sumas, and Malin for the full 20 year planning horizon. Each simulation or draw produces a unique combination of weather and gas price resulting in 250 different futures which can be used to test the performance of resource plans under a wide variety of conditions.

The weather simulation was derived from a large data set composed of daily temperatures from the last 20 years for each of the 8 demand regions. The set defines the domain of possible temperature values. Monte Carlo simulation then generates daily temperature values for the 20 year planning horizon drawn from the probability distribution of temperatures in the data set. The data set was also used to set correlation factors between demand regions which informed the simulation as well. The correlation factors limit the possibility of incongruous temperature patterns among the regions. For example, a simulated cold snap in Portland in December is forced to be accompanied by a similar cold snap in neighboring Vancouver WA. Figures 5.7 and 5.8 display daily HDD results for two years from draw number 100 of the 250 simulations developed around weather. The deterministic base case design weather pattern is also shown. Daily HDD is computed by subtracting the average of the daily high and low temperature from the base degree of 65° F.

Figure 5.7 - Monte Carlo Simulation of Weather – Portland

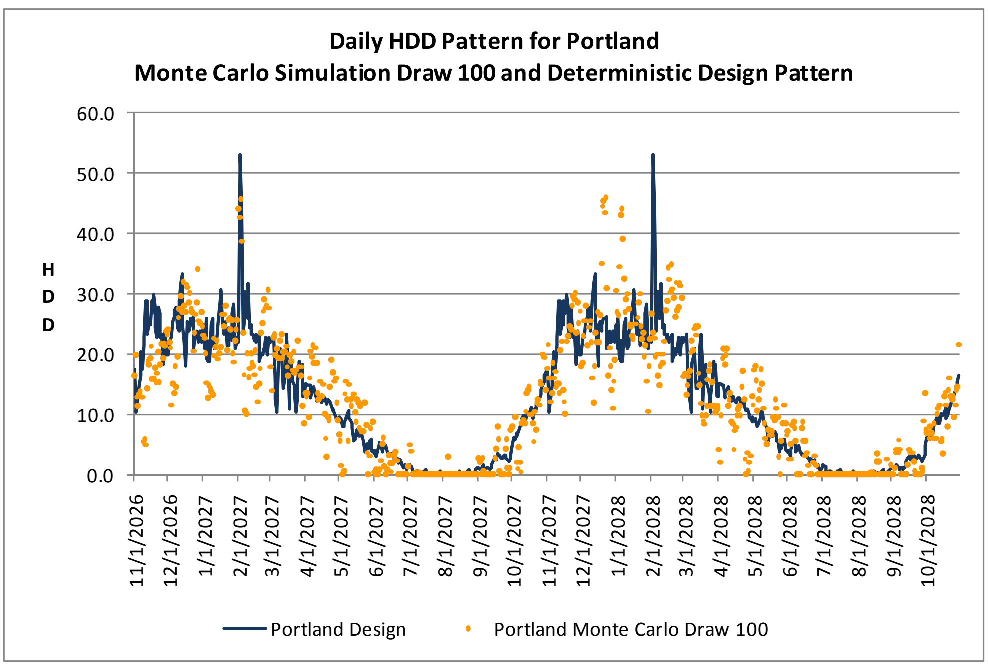
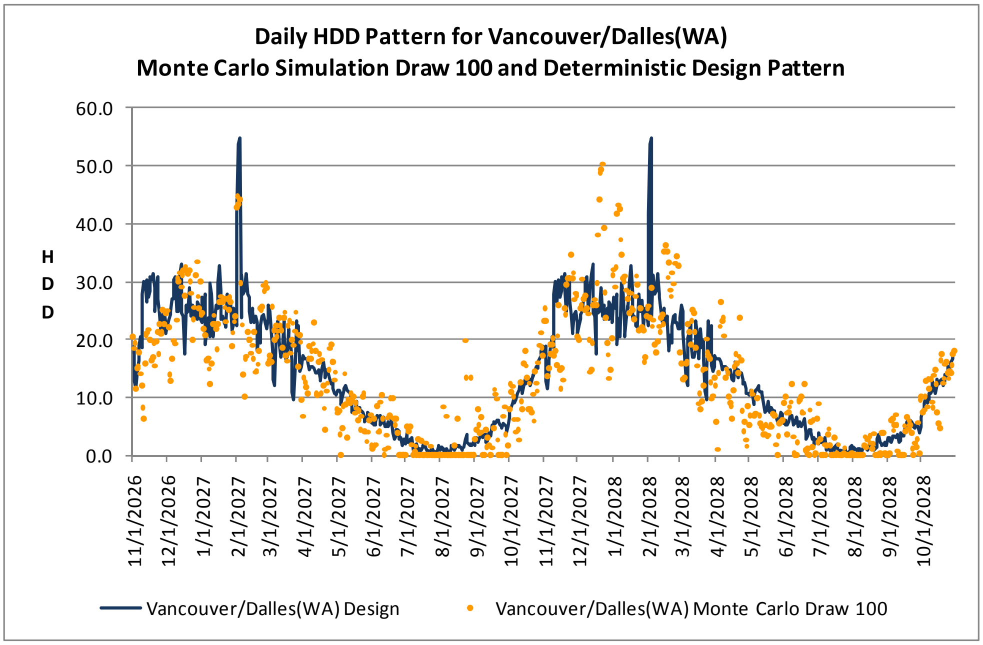


Figure 5.8 - Monte Carlo Simulation of Weather – Vancouver/Dalles WA



In the deterministic case, the annual HDD pattern is repeated every gas year, unlike the Monte Carlo runs which have variable weather. It is especially important to note that in the Monte Carlo runs, peak day can fluctuate in severity and day of occurrence. Since the majority of customer demand is driven by heating requirements, variable weather patterns will result in variable demand patterns which can stress resource deliverability. Table 5.7 summarizes the HDD results from the simulation.

Table 5.7 - Annual Heating Degree Day Summary by Region

Demand Region	Deterministic Design Pattern	Monte Carlo Results – 250 draws and 5000 Annual Patterns			
	Annual HDD	MEAN Annual HDD	MAX Annual HDD	MIN Annual HDD	STANDARD DEVIATION Annual HDD
Albany	4,960	4,706	5,366	3,982	194
Astoria	5,007	4,980	5,699	4,367	187
Dalles OR	5,554	5,334	6,112	4,614	222
Eugene/Coos Bay	4,995	4,698	5,411	3,960	204
Newport/Lincoln City	4,851	4,842	5,579	4,114	202
Portland	4,504	4,262	4,835	3,529	187
Salem	4,862	4,599	5,302	3,899	194
Vancouver/Dalles WA	5,082	4,881	5,591	4,270	192

For gas prices, the Monte Carlo simulation is derived around the mean of the base case gas forecast along with the historic variability for each supply point. The original gas price forecast was used which dated from March 2010. Similar to the weather patterns, gas prices among the supply points are forced to be somewhat correlated among each other. This prevents an unrealistic, singularly high or low price point in one supply region from occurring completely independently from prices in the other regions. Having supply price variability introduced into the planning equation allows for testing around supply diversity and supply cost factors. For example, in the deterministic case, the price differential between Rockies and AECO supply points is always known. This differential can inform resource decisions to follow a specific supply pathway in order to minimize costs. However, with variability introduced, a resource plan may be further evaluated for its versatility in supplying the lowest cost gas under a variety of pricing futures. Figures 5.9 and 5.10 show an example of prices simulated in Draw #100 for the Rockies and AECO supply points for two years.

Figure 5.9 - Monte Carlo Simulation of Gas Prices - Rockies

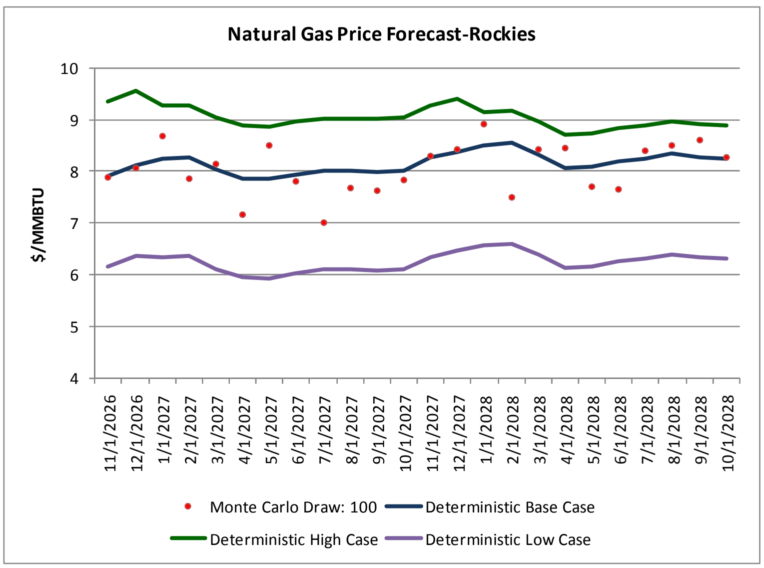
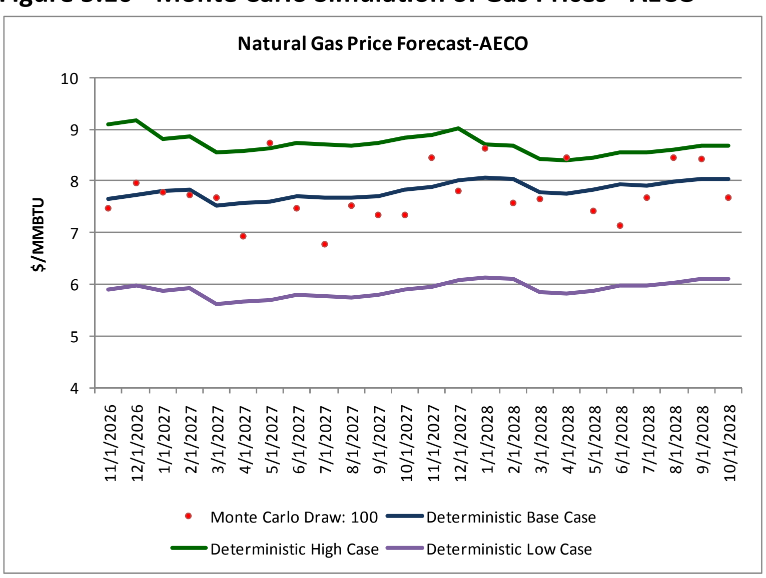


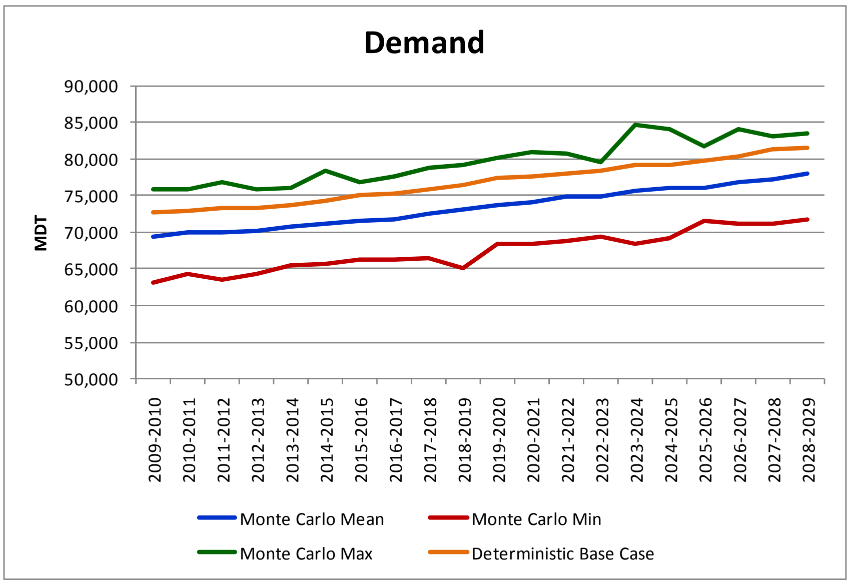
Figure 5.10 - Monte Carlo Simulation of Gas Prices - AECO



2. Optimization Model Runs and Results

Once the Monte Carlo simulation of weather and gas price is complete, these draws may be run through the SENDOUT® optimization model. The variable weather pattern simulations result in various demand futures. The base case customer forecast was used for the optimization runs and the base case DSM savings were locked in. Figure 5.11 displays the summary statistics for demand resulting from the 250 simulations around weather, as well as the deterministic model demand trajectory. As expected, the demand generated in the Monte Carlo runs generally came in under the deterministic model demand since the design weather pattern used for the deterministic runs contains a much colder than normal winter.

Figure 5.11 - Monte Carlo Demand Results



Each of the 250 draws were run through both the 1319-Palomar East and the 1321-No Palomar resource plans. For these optimization runs, the resource options were locked in at the plan's capacity levels and timeline. For example, in the deterministic base case resource portfolio, there is a Mist Storage Recall resource decision point in April of 2015. Additional capacity may be selected at that point, up to a maximum of 4,862 MDT. The 1319-Palomar East planning case did choose to select additional capacity at this decision point, resulting in a total storage inventory level of 2,356 MDT for Mist Recall. In the Monte Carlo model runs, this level of 2,356 MDT is locked in at April 2015; the model cannot make the decision to add more or less, it is assumed that the plan is implemented and the resources locked in. During the Monte Carlo run, the model then optimizes with the resources it has available. In this case, for each run, the model may choose to use up to 2,356 MDT of Mist Recall storage capacity to serve demand, or it may choose some other method of serving demand. However, it will pay for the entire capacity of 2,356 MDT, even if that model run decides not to use it.

The optimization results from the Monte Carlo runs for the Plan 1319-Palomar East and the No Palomar (1321) plans are summarized below in Table 5.8.

Table 5.8 - Monte Carlo Optimization Results

Planning Case	Mean Cost NPV ($000)	Median Cost NPV ($000)	Standard Deviation Cost NPV ($000)	Reliability (serving annual demand)
1319-Palomar East	7,817,100	7,814,951	51,466	98.3 %
1321-No Palomar	7,812,011	7,809,664	51,718	97.9 %

As modeled, both plans deliver a high degree of reliability in serving annual demand. The plan with Palomar (1319) produced a slightly higher degree of reliability (+0.4%) than the No Palomar plan. In terms of average cost, the No Palomar case came in slightly less expensive, by an amount of $5.1 million. In the deterministic case, 1319-Palomar East was slightly less expensive than the No Palomar plan, by an amount of $2.3 million. The differences between the two plans both in terms of reliability and cost are very small; both deliver a low cost plan that consistently meets demand requirements.

The Monte Carlo simulation runs were performed in the original IRP modeling phase. These runs were based on the natural gas price from March of 2010, and included the original pipeline rate estimation for Palomar East.

V. MODIFICATION PHASE RESOURCE PLANNING MODEL RESULTS

A. Overview

The Palomar East Pipeline was an expected resource component in the original modeling phase of the 2011 IRP. The proposed pipeline would connect to the GTN pipeline at Madras Oregon and link to NW Natural's system at Molalla Oregon. Northwest Pipeline (NWPL) is fully subscribed through the Columbia River Gorge. Palomar would provide parallel capacity across the Cascades and would also provide a new option for bringing gas to western Oregon from Malin. In the original IRP modeling phase, the assumed pipeline rate was based on a precedent agreement which included a rate cap. It was assumed that NW Natural would reserve a minimum firm capacity level of 100 MDTH/day on the pipeline and turn back up to 77 MDTH/day of parallel capacity on NWPL through the Gorge. Deterministic and Monte Carlo modeling was performed with and without Palomar East. The deterministic modeling indicated that the overall cost of serving demand over 20 years was slightly less with Palomar East than in the case without Palomar. Modeling also indicated that service reliability was better with Palomar as an option. Monte Carlo modeling tested the plans with and without Palomar under a variety of price and weather conditions. Under this testing, the plan with Palomar was better in reliability but came in a little more costly than the plan without the pipeline. The original modeling for the IRP was completed by November of 2010.

In February 2011, a workshop was held on Natural Gas Infrastructure, which was sponsored by the OPUC and the WUTC. A modified Cross-Cascades pipeline project was discussed – called Palomar/Blue Bridge. In March of 2011, Palomar Gas Transmission LLC withdrew its application with FERC for the pipeline but stated its expectation of re-filing at a later date.

As a result of the uncertainty around Palomar that arose after the completion of the 2011 IRP, NW Natural embarked on a modification phase to the IRP. The modeling work for this phase took place between April and June of 2011. The results were presented and discussed at the June 22, 2011 Technical Working Group meeting. There were two primary purposes for the modification:

1. Further evaluate and analyze planning under assorted demand and natural gas price scenarios without a new Cross-Cascades pipeline such as Palomar/Blue Bridge as a resource option.
2. Evaluate planning with the proposed Palomar/Blue Bridge pipeline project as presented at the Natural Gas Pipeline Infrastructure Workshop, which included new estimations for pipeline rates and service dates. The modeled pipeline path and capacity is the same as in the original modeling phase for Palomar East.

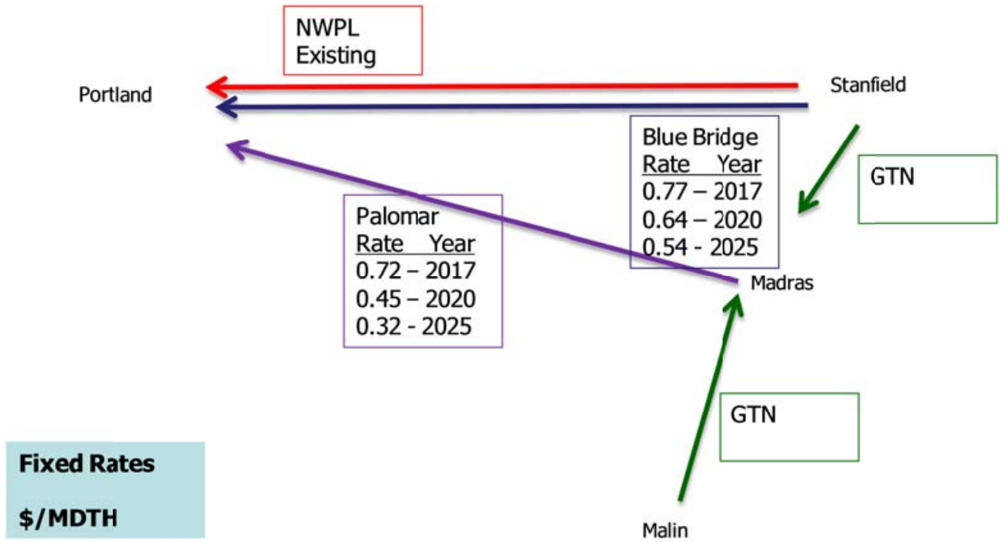
As a result, 17 new model runs were completed, including 12 without Palomar/Blue Bridge. These model runs included an updated natural gas price forecast. The DSM and demand forecasts were left unchanged from the original modeling phase.

B. Model Summary

The same supply side and demand side resources as presented in Section III were made available to the model. Please see Figures 5.1, 5.2 and 5.3 for the model diagrams. Imported LNG was not included as a resource option. To review, the key future resource options include:

1. Cost effective **DSM** as forecast by the ETO is selected first
2. Reserve incremental capacity on the existing **TC/GTN** system to further tap Canadian supplies
3. Reserve capacity on the proposed **Palomar/Blue Bridge Pipeline** beginning in 2017. The pipeline could be used to bring in additional Canadian supplies from the AECO hub, and potentially Rockies gas via Malin. The pipeline rates and service date assumptions used in the model were sourced directly from the estimates presented at the February 2011 Natural Gas Infrastructure Workshop. See Figure 5.12 below.
4. Pay for Williams' to expand the existing **Grants Pass Lateral** to help serve load in Salem, Albany and especially Eugene. This would also include costs for building NW Natural's system to handle the additional takeaway capacity.
5. Build a new NW Natural compressor station near Perrydale Oregon which would enable the delivery of additional supplies to Salem from the Newport LNG facility on peak day
6. NW Natural could bolster its system by building a 12-inch pipeline from Salem to Albany (Mid WVF) and Albany to Eugene (South WVF) to connect the valley with Mist Storage
7. NW Natural could build small 3-day peak storage facilities called **Satellite Storage** in locations such as Salem, Albany, and Eugene
8. NW Natural could **recall Mist Storage** capacity to the core utility to serve demand growth

Figure 5.12 Modeled Pipeline Rates



The model runs that were completed in the modification phase are listed in Table 5.9, along with the combination of inputs and assumptions. The majority of the model runs did not include Palomar/Blue Bridge in order to evaluate planning under various demand and pricing scenarios should the pipeline project not be built.

Table 5.9 Modification Phase Model Runs

Run #	Name	Customer Growth	Customer Usage	Gas Price	DSM	Palomar/Blue Bridge
1	1411-2011 IRP Mod Base Case	Base Case	Base Case	Base Case	Base Case	None
2	1397-2011 IRP Mod Low Customer Growth	Low	Base Case	Base Case	Base Case	None
3	1400-2011 IRP Mod High Customer Growth	High	Base Case	Base Case	Base Case	None
4	1402-2011 IRP Mod Gas Dereg	High	Base Case	Low	Base Case	None
5	1404-2011 IRP Mod Gas Breakthrough	High	High	High	Base Case	None
6	1405-2011 IRP Mod Electric Breakthrough	Very Low	Base Case	High	Base Case	None
7	1408-2011 IRP Mod 15% Less DSM	Base Case	Base Case	Base Case	15% Less	None
8	1406-2011 IRP Mod 30% More DSM	Base Case	Base Case	Base Case	30% More	None
9	1410-2011 IRP Mod Newport LNG Closed	Base Case	Base Case	Base Case	Base Case	None
10	1391-2011 IRP Mod PAL BB 50	Base Case	Base Case	Base Case	Base Case	50/50 MDTH mix of Palomar and Blue Bridge
11	1392-2011 IRP Mod PAL 100	Base Case	Base Case	Base Case	Base Case	100 MDTH Palomar
12	1413-2011 IRP Mod Canada Exp	Base Case	Base Case	SUMAS & AECO export spread	Base Case	None
13	1412-2011 IRP Mod SUMAS Exp	Base Case	Base Case	SUMAS export spread	Base Case	None
14	1414-2011 IRP Mod Canada Exp PAL	Base Case	Base Case	SUMAS & AECO export spread	Base Case	100 MDTH Palomar
15	1415-2011 IRP Mod SUMAS Exp PAL	Base Case	Base Case	SUMAS export spread	Base Case	100 MDTH Palomar
16	1416-2011 IRP Mod Low Gas Fcst PAL BB 50	Base Case	Base Case	Low	Base Case	50/50 MDTH mix of Palomar and Blue Bridge
17	1417-2011 IRP Mod Low Gas Fcst	Base Case	Base Case	Low	Base Case	None

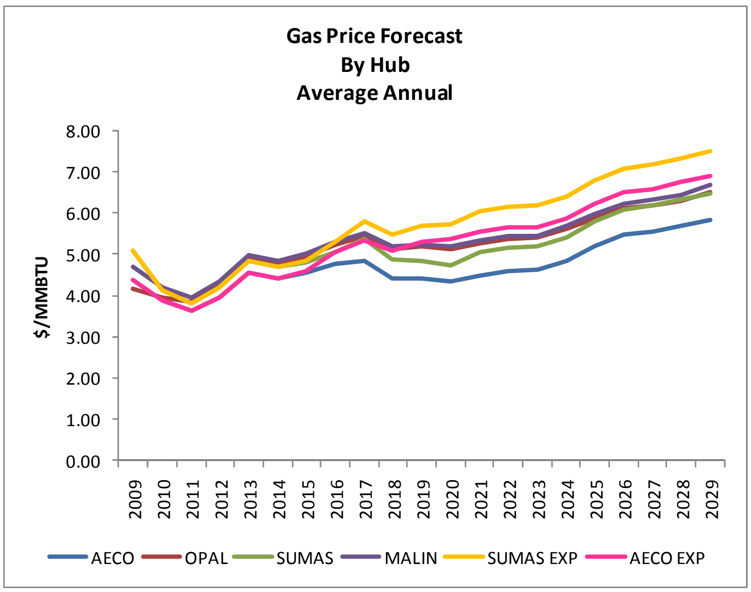
Palomar/Blue Bridge Rate Scenarios

Two different rate scenarios were incorporated for the five model runs that included Palomar/Blue Bridge. In each of these runs, the model was forced to choose a minimum of 100 MDTH of fixed daily capacity on the pipeline beginning in November of 2017. In the 50/50 mix scenario, 50 MDTH is set to the Palomar rate and 50 MDTH is set to the Blue Bridge rate. The other scenario sets the full 100 MDTH at the Palomar rate only. These two scenarios define the expected high and low cost range for reserving capacity on the pipeline project.

Natural Gas Price Scenarios

The natural gas price forecast was updated for the modification phase. The base forecast was developed by IHS-CERA and is proprietary.[2] Two additional price curves were generated for the AECO and Sumas price hubs to evaluate the impact of a potential future price spread between Canadian and US gas. One potential reason for a future spread is completion of the Kitimat B.C. LNG Export terminal. This facility could be in service by 2015 and would export Canadian gas to the world market for the first time. Figure 5.13 displays the base forecast by pricing hub and the Canadian gas spread curves used in the model.

Figure 5.13 Natural Gas Price Forecast



C. Results

The results from the model runs from the modification phase were ranked by cost and summarized below in Table 5.10. A few of the key resource options are also listed; an **X** signifies that the resource was selected at some point in the 20 year planning horizon. For the Palomar/Blue Bridge pipeline resource, **N/A** indicates the project was unavailable for selection. Each model result represents the least cost plan which can be produced under the specific demand, weather, gas pricing scenario, and available resource menu. Please see Appendix 5 for a more detailed summary of each run.

[2] The use of this content was authorized in advance by IHS-CERA. Any further use or redistribution of this content is strictly prohibited without written permission by IHS-CERA. All rights reserved.

Table 5.10 – Model Results Ranked by Cost from Modification Phase

Run #	Name	Cost $(000) NPV	Palomar/Blue Bridge	Mist Recall	Newport LNG Compressor Project	Satellite Storage	Grants Pass Lateral Expansion
17	1417-2011 IRP Mod Low Gas Fcst	5,974,021	N/A	X	X	X	X
16	1416-2011 IRP Mod Low Gas Fcst PAL BB 50	6,016,177	Palomar 50 MDTH Blue Bridge 50 MDTH	X	X	-	X
4	1402-2011 IRP Mod Gas Dereg	6,118,711	N/A	X	X	X	X
2	1397-2011 IRP Mod Low Customer Growth	6,585,860	N/A	X	X	-	-
8	1406-2011 IRP Mod 30% More DSM	6,672,066	N/A	X	X	-	X
1	1411-2011 IRP Mod Base Case	6,772,580	N/A	X	X	X	-
9	1410-2011 IRP Mod Newport LNG Closed	6,777,854	N/A	X	-	X	-
13	1412-2011 IRP Mod SUMAS Exp	6,789,728	N/A	X	X	-	X
11	1392-2011 IRP Mod PAL 100	6,792,363	Palomar 100 MDTH	X	X	-	X
15	1415-2011 IRP Mod SUMAS Exp PAL	6,795,878	Palomar 100 MDTH	X	X	-	X
10	1391-2011 IRP Mod PAL BB 50	6,813,487	Palomar 50 MDTH Blue Bridge 50 MDTH	X	X	-	X
7	1408-2011 IRP Mod 15% Less DSM	6,823,538	N/A	X	X	X	X
3	1400-2011 IRP Mod High Customer Growth	6,947,103	N/A	X	X	X	X
12	1413-2011 IRP Mod Canada Exp	7,089,115	N/A	X	X	X	-
14	1414-2011 IRP Mod Canada Exp PAL	7,128,853	Palomar 100 MDTH	X	X	-	X
6	1405-2011 IRP Mod Electric Breakthrough	7,916,437	N/A	X	-	-	-
5	1404-2011 IRP Mod Gas Breakthrough	9,086,125	N/A	X	X	X	-

D. Base Case and Preferred Path

Run # 1 - 1411-2011 IRP Mod Base Case represents the planning base case for the modification phase of the IRP. This is the least cost plan with base case demand inputs and assumes that the Palomar/Blue Bridge Cross-Cascades pipeline is not built. The plan primarily relies on DSM and Mist Storage recall to serve demand growth in the earlier years. Later, in the 2025/2026 time frame, additional resources are required down the Willamette Valley when the Newport LNG Compressor project and Satellite Storage options are selected. The model NPV cost ($000) for this plan is $6,772,580.

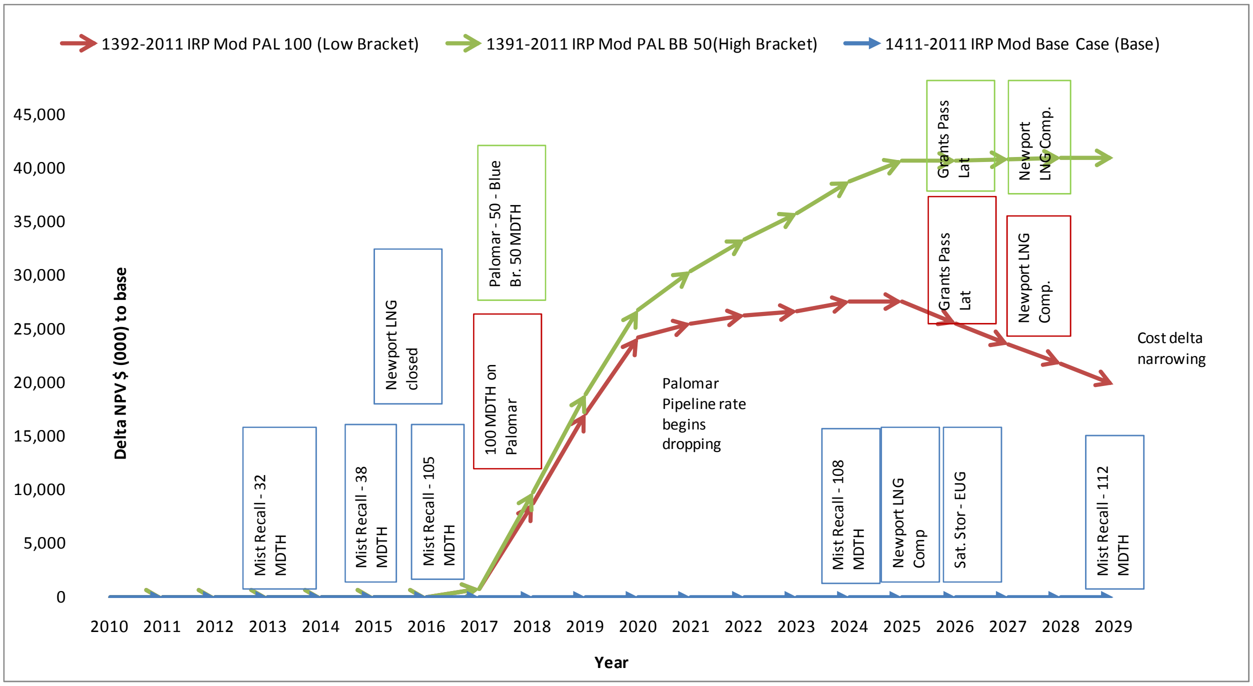
Run # 11 - 1392-2011 IRP Mod PAL 100 represents the low bracket for resource planning that includes capacity on Palomar/Blue Bridge under base case conditions. This case assumes NW Natural takes 100 MDTH/day of firm capacity on the project at the estimated Palomar rate only, beginning in November of 2017. Prior to that date, the resource selections are the same as for the 1411-2011 IRP Mod Base Case. In the later years, additional resources are still required in the Willamette Valley. In this case, the Newport LNG Compressor project is selected, along with expansion of the Grants Pass Lateral. There is less reliance on Mist Storage for this case. The model NPV cost ($000) for this plan over the 20 year horizon is $6,792,363, which is $19.8 million more than the 1411 Base Case – a 0.3% increase.

Run # 10 - 1391-2011 IRP Mod PAL BB 50 represents the high bracket for a resource plan that includes Palomar/Blue Bridge. This case assumes NW Natural takes 100 MDTH/day of firm capacity on the project with 50% at the Palomar rate and 50% at the Blue Bridge rate. The resource selection is the same as the low bracket, run 1392. The model NPV cost ($000) for this plan is $6,813,487. This is $40.9 million more than the Base Case 1411 – a 0.6% increase.

Together, these three plans comprise a potential resource planning pathway for NW Natural's future. Figure 5.14 outlines the pathway, along with the delta in NPV costs.

- 1411-2011 IRP Mod Base Case: Palomar/Blue Bridge is not an option
- 1392-2011 IRP Mod PAL 100: Capacity on Palomar/Blue Bridge starting in 2017 – low cost bracket
- 1391-2011 IRP Mod PAL BB 50: Capacity on Palomar/Blue Bridge starting in 2017 – high cost bracket

Figure 5.14 - Resource Planning Pathway with Costs



The resource decisions leading up to 2017 are identical – there is a single path. If Palomar/Blue Bridge is available around 2017, the preferred resource pathway would include capacity on the pipeline. The benefits of the pipeline include lower risk for service outages due to pipeline failure, and increased options for diversity of supply. One drawback to taking the path with Palomar/Blue Bridge is the increased cost resulting from the new infrastructure. The red and green pathways are an attempt to bracket this expected increase in cost. In the cases when the pipeline is utilized, the model elects to line up additional capacity along the GTN and TCPL pipelines to transport more AECO priced supply. The red pathway begins to narrow the cost differential by purchasing and transporting more AECO supply.

E. Other Scenarios

The results for all the scenarios run in the modification phase are summarized in Table 5.10, and more detailed summaries for each run are available in Appendix 5. Mist Storage Recall is selected in all cases, but at various levels – indicating that it is a key utility resource. The Newport LNG Compressor Project is selected in all scenarios except when the Newport LNG facility is modeled to be retired for good, and under the Electric Breakthrough low demand case.

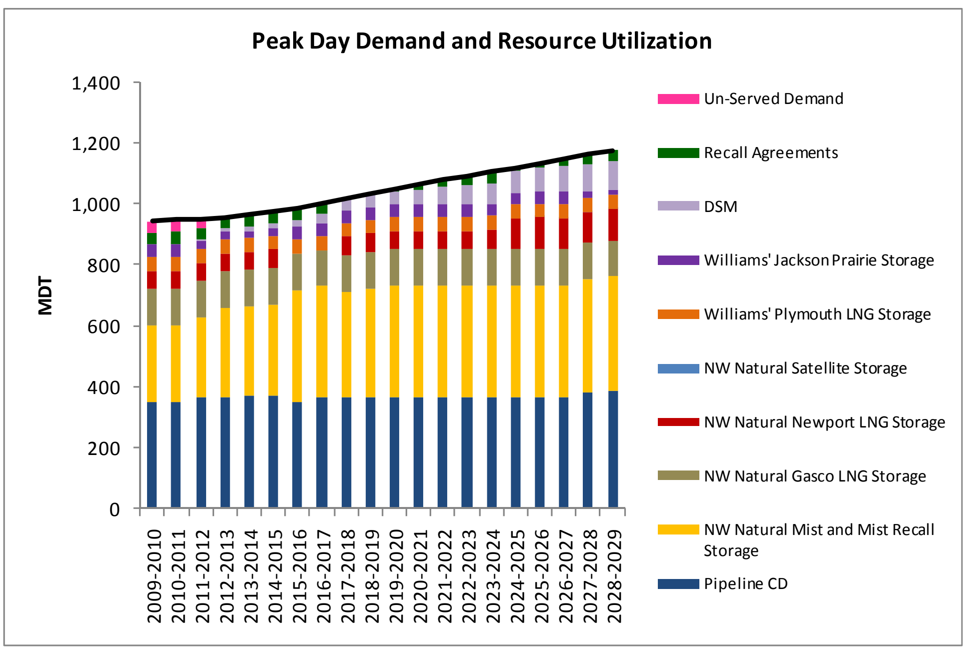
Resource modeling indicates that some sort of new future resource will be required down in the Willamette Valley, except in low growth scenarios. This could be an incremental expansion of the Grants Pass Lateral, incremental capacity from adding Satellite Storage facilities, or building the Willamette Valley Feeder (WVF) pipeline. Expansion of the Grants Pass Lateral has been modeled as if it could be incrementally and gradually expanded to match the timing of NW Natural's needs. This assumption of incremental capacity which may be added just in time makes the resource option very attractive to the optimization model. The validity of this assumption may require further investigation. In the case of Satellite Storage, there is also some uncertainty around the cost estimation. This resource option is assumed to be added incrementally as needed. NW Natural has not built and operated any comparable facilities and the cost estimation may need further refinement in future IRPs.

In contrast with the Grants Pass Lateral expansion and Satellite Storage, the Company has substantially more knowledge of the Willamette Valley Feeder option. We have currently modeled it in a way that may be more realistic; the mid and south sections of the WVF are restricted to their full capacity and costs. They are considered lumpy. The WVF pipeline was modeled this way to avoid an unrealistic planning situation where a pipeline is assumed to grow in capacity over time. NW Natural notes that the Mid-WVF has additional benefits, which are not incorporated into the model, including the replacement of a significant portion of the remaining bare steel on NW Natural's system, and the fact that the Mid-WVF will add system reliability that may be even more important given the delay in the Palomar-East project. It should be noted that when an outage is modeled on the Northwest Pipeline Lateral, the model does select the Mid-WVF to meet load. NW Natural believes that these considerations are important in determining which resource will be relied on to meet load in the Willamette Valley and in determining a reliable operation of its system.

F. Peak Day Utilization

Figure 5.14 displays the peak day resource utilization results from the base case 1411-2011 IRP Mod Base Case.

Figure 5.15 - Peak Day Utilization



Newport LNG drops out of the picture from 2015 through 2017 as it's assumed to be down for repairs. Mist Storage fills in during that time frame. DSM plays an increasingly important role through time while Recall Agreements drop in and out to fill in gaps. Model results for utilization on non-peak day events have a different pattern depending on the season. After taking account for DSM, pipeline CD serves 100% of demand on a typical fall day. Moving into winter, demand for a typical day in December is met with a 60/40 mix of pipeline CD and storage. On peak day, storage serves approximately 60% of demand with pipeline CD at 35% and recall making up the rest. Then on a normal spring day, pipeline CD is back up to 90%, with storage at roughly 10% as the withdrawal season winds down.

VI. Key Findings

- Resource modeling produced a least cost Base Case resource plan to meet current and future demand. The plan's key future resource addition in the near term includes incremental Mist Storage Recall. Energy savings from DSM programs are also important.
- Modeling also generated a preferred path for resource planning that includes future capacity on the proposed Palomar/Blue Bridge project. Modeling has shown that a new Cross-Cascades Pipeline could improve service reliability and open up supply diversity options. However, there is an increased cost for such infrastructure, ranging from 0.3% to 0.6% over the base case for the 20-year planning period.
- Demand Side Management (DSM) is expected to play an increasingly important role in serving future demand.
- Modeling indicates that the Newport LNG Storage facility could be brought down for repairs at a future date without severely limiting service.
- Some sort of new resource is expected to be required down in the Willamette Valley, but not until the 2024/2025 time frame. This requirement could be filled by an expansion of the Grants Pass Lateral, building small Satellite Storage facilities, or building the Willamette Valley Feeder (WVF).

Chapter 6: Avoided Cost Determination

NW Natural®

I. OVERVIEW

As part of the IRP process, NW Natural calculates a 20-year forecast of avoided costs. In this case, the avoided cost is an estimated cost to serve the next unit of demand with a supply side resource option at a point in time. This incremental cost to serve represents the cost that could be avoided through energy conservation. Therefore, the avoided cost forecast can be used as a guideline for comparing energy conservation with the cost of acquiring and transporting natural gas to meet demand. In addition, this IRP evaluates the impact that a range of environmental externalities, including CO_2 emission prices, would have on the avoided costs in terms of cost adders and supply costs. This analysis results in an expected avoided cost case – the base case, as well as a high case, and a low case.

II. Environmental Externalities

The Oregon Public Utility Commission (OPUC) Order No. 07-002 in Docket UM 1056 (Investigation Into Integrated Resource Planning) enhanced the previous decision adopted in the OPUC's Order No. 93-695 in Docket UM 424 (Development of Guidelines for Treatment of External Environmental Costs), which established the following guideline for the treatment of environmental costs used by energy utilities that evaluate demand- and supply-side energy choices:

> *Guideline 8: Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides (NOx), sulfur oxides (SO_2), and mercury (Hg) emissions. Utilities should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from $0 - $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides (NOx), sulfur dioxide (SO_2), and mercury (Hg), if applicable.*

In June 2008, the OPUC issued Order 08-338 (UM1302) which revised Guideline 8 to require a utility to construct a base case portfolio to reflect the most likely regulatory compliance future for various emissions. Additionally, the guideline requires the utility to develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals with each scenario including a time profile of CO_2 costs. The utility is also required to include a ”trigger point” analysis that demonstrates when carbon costs are high enough to result in a significantly different portfolio resource selection.

Future climate change legislation may attempt to constrain CO_2 emissions. Although nothing has passed in both the House and the Senate, all carbon legislation proposed to-date, such as the American Clean Energy and Security Act of 2009 (HR 2454, a.k.a. the Waxman-Markey bill.), may require natural gas utilities to include price adders for CO_2 emissions associated with their customers' combustion of natural gas. Since there is a high level of uncertainty around the legislation that will ultimately be adopted, this IRP considers three cases around CO_2 emission prices: 1) an expected base case, 2) a high case, and 3) a low case. These cases are generated around expected, and high and low natural gas price forecasts, as well as expected, high, and low CO_2 emission adders to the avoided cost per dekatherm.

This IRP considers a base case CO_2 emission price beginning in 2014 at $15/metric ton and reaching $50/metric ton in 2030. In terms of dekatherms (DT), this price scenario translates to a cost adder ranging from $0.80/DT in 2014 to $2.65/DT in the year 2030. In the high case, CO_2 emission prices are assumed to range from $25/metric ton in 2014 to $93/metric ton in 2030, which corresponds to a cost adder of range of $1.33/DT to $4.94/DT. For the low case, the CO_2 emission price ranges from $4/metric ton beginning in 2018 to $10/metric ton in 2030. This results in adders from $0.23/DT to $0.56/DT.

Unlike electric utilities, environmental cost issues rarely impact a gas utility's supply-side resources. For example, NW Natural cannot choose between "dirty" coal-fired generation and "clean" wind energy sources because natural gas is the only supply-side resource. However, environmental externality costs in combination with avoided costs do make a difference in the comparison between supply-side and demand-side resources. The impact of a higher gas cost (and, therefore, higher avoided costs that might result from strict CO_2 emission control) on DSM is examined in Chapter 4. In this case, the Energy Trust found that a 40% increase in avoided costs resulted in a 4% increase in the amount of cost effective achievable resource potential.

NW Natural's analysis also includes a 10% conservation adder to account for the unquantifiable benefits of DSM, as suggested by the Northwest Power and Conservation Council.

III. Methodology

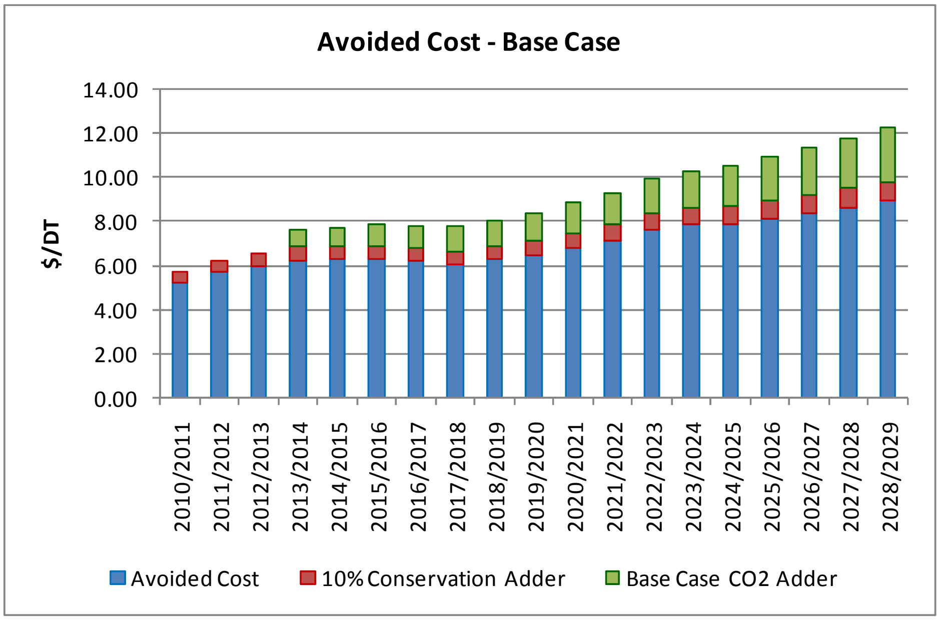
The SENDOUT® resource planning model was used to generate the avoided costs. The base case demand parameters were used as inputs, including the design weather pattern, and base case customer and gas price forecasts. The high and low natural gas price forecasts, along with their accompanying CO_2 emission prices were used to generate the high and low avoided cost scenarios.

SENDOUT® contains a marginal cost report which lists the daily incremental cost to serve the next unit of demand for each demand region. The DSM functionality was turned off so energy conservation was not an option for the model; demand was served with supply side resources only. In addition to existing supply side resources, the resource options included Mist Storage Recall, Grants Pass Lateral pipeline capacity, Palomar East pipeline capacity, and satellite storage. The model determines the lowest cost method for serving the next unit of demand and computes a marginal cost. This computed marginal cost includes the price for the commodity itself, transportation charges, and any related storage costs. Distribution costs were not included.

IV. Results

Figure 6.1 charts the avoided costs resulting from the base case along with the environmental externality cost adders. The blue bars represent the avoided cost expressed in $/ DT, the red details the 10% conservation adder, and green shows the CO_2 emission adder.

Figure 6.1 - Avoided Cost and Environmental Externality Adders



The figure below displays the range of the cost scenarios with all costs rolled up – the avoided costs along with the environmental externalities. Table 6.1 lists the numerical results for costs in $/DT. Further detail around avoided costs are included in Appendix 6.

Figure 6.2 – Scenarios

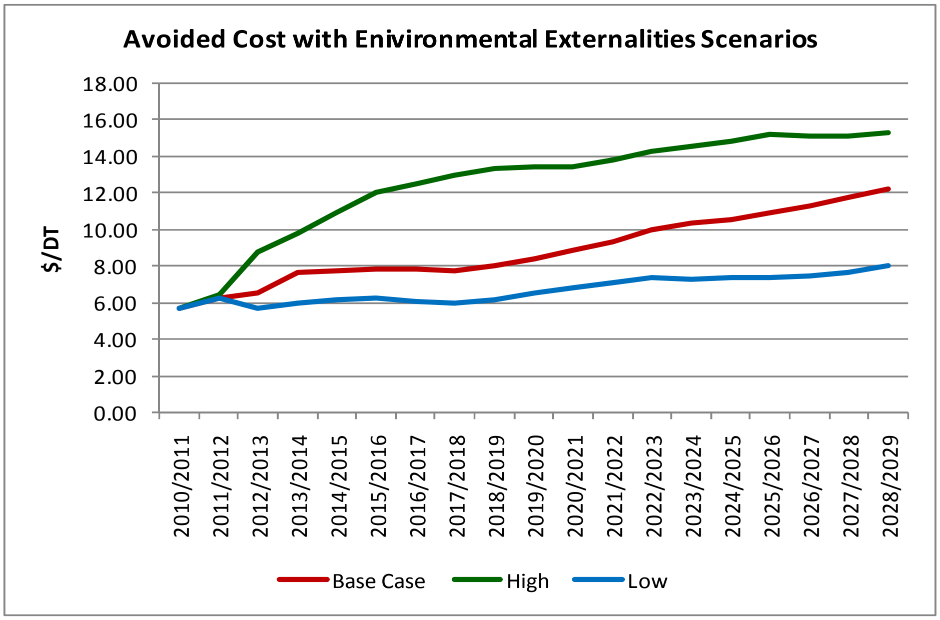


Table 6.1 - Avoided Costs

Gas Year	Avoided Cost ($/DT)			With 10% Conservation adder			With 10% Conservation adder and CO_2 emission adder		
	Base Case	High Case	Low Case	Base Case	High Case	Low Case	Base Case	High Case	Low Case
2010/2011	5.19	5.19	5.19	5.70	5.70	5.70	5.70	5.70	5.70
2011/2012	5.68	5.88	5.68	6.25	6.47	6.25	6.25	6.47	6.25
2012/2013	5.93	6.77	5.17	6.53	7.45	5.69	6.53	8.78	5.69
2013/2014	6.24	7.44	5.43	6.86	8.19	5.98	7.66	9.78	5.98
2014/2015	6.26	8.20	5.59	6.88	9.02	6.15	7.74	10.89	6.15
2015/2016	6.27	8.99	5.66	6.90	9.89	6.23	7.83	12.07	6.23
2016/2017	6.18	9.15	5.54	6.80	10.07	6.10	7.80	12.53	6.10
2017/2018	6.06	9.25	5.20	6.66	10.17	5.72	7.74	12.93	5.95
2018/2019	6.27	9.37	5.36	6.90	10.31	5.89	8.07	13.31	6.12
2019/2020	6.45	9.21	5.74	7.10	10.14	6.32	8.35	13.38	6.54
2020/2021	6.79	9.07	6.02	7.46	9.98	6.63	8.82	13.46	6.84
2021/2022	7.12	9.14	6.26	7.83	10.06	6.89	9.29	13.78	7.10
2022/2023	7.60	9.40	6.48	8.36	10.34	7.13	9.94	14.28	7.34
2023/2024	7.83	9.47	6.39	8.61	10.41	7.03	10.30	14.55	7.23
2024/2025	7.89	9.54	6.29	8.68	10.49	6.92	10.50	14.84	7.32
2025/2026	8.16	9.67	6.38	8.97	10.64	7.01	10.93	15.16	7.41
2026/2027	8.36	9.52	6.41	9.20	10.47	7.05	11.32	15.12	7.44
2027/2028	8.64	9.40	6.63	9.51	10.34	7.30	11.79	15.09	7.68
2028/2029	8.90	9.46	6.91	9.79	10.40	7.60	12.25	15.24	7.98

The high avoided cost scenario includes the high gas price forecast (which drives up the cost of supply), the 10% conservation adder and the high CO_2 emission adders. On average, the high case runs 40% higher than the base case. The low case, which was generated with the low gas price forecast along with lower CO_2 emissions costs and the 10% conservation adder, resulted in costs being an average of 23% lower than the base case.

V. Avoided Costs – Modified

During the modification phase of the IRP, a new natural gas price forecast was generated (April 2011). The original forecast was from March of 2010. New avoided costs were calculated based on the base case plan from the modification phase, and included the new price forecast. As a result of a lower natural gas price forecast, the avoided costs calculated during the modification phase dropped. The results are shown below in Figure 6.3 and Table 6.2.

Figure 6.3 – Modified Base Case Avoided Costs

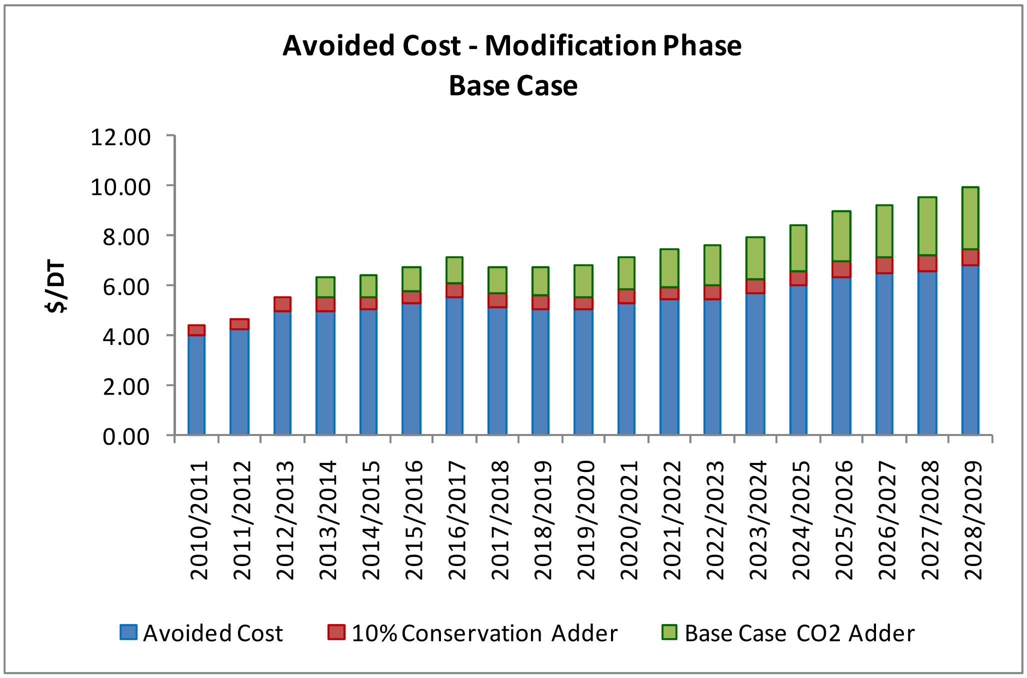


Table 6.2 – Base Case Avoided Costs from Modification Phase by State

Gas Year	Avoided Cost ($/DT)			With 10% Conservation adder			With 10% Conservation adder and CO_2 emission adder		
	OR	WA	System	OR	WA	System	OR	WA	System
2010/2011	4.01	4.01	4.01	4.41	4.41	4.41	4.41	4.41	4.41
2011/2012	4.22	4.22	4.22	4.65	4.65	4.65	4.65	4.65	4.65
2012/2013	5.01	5.01	5.01	5.51	5.51	5.51	5.51	5.51	5.51
2013/2014	5.02	5.02	5.02	5.52	5.52	5.52	6.32	6.32	6.32
2014/2015	5.07	5.07	5.07	5.57	5.57	5.57	6.43	6.43	6.43
2015/2016	5.28	5.28	5.28	5.81	5.81	5.81	6.74	6.74	6.74
2016/2017	5.56	5.56	5.56	6.12	6.12	6.12	7.12	7.12	7.12
2017/2018	5.16	5.16	5.16	5.68	5.68	5.68	6.76	6.76	6.76
2018/2019	5.09	5.09	5.09	5.60	5.60	5.60	6.77	6.77	6.77
2019/2020	5.06	5.06	5.06	5.56	5.56	5.56	6.82	6.82	6.82
2020/2021	5.29	5.29	5.29	5.82	5.82	5.82	7.18	7.18	7.18
2021/2022	5.43	5.43	5.43	5.97	5.97	5.97	7.43	7.43	7.43
2022/2023	5.49	5.49	5.49	6.04	6.04	6.04	7.61	7.61	7.61
2023/2024	5.68	5.68	5.68	6.24	6.24	6.24	7.94	7.94	7.94
2024/2025	6.01	6.01	6.01	6.61	6.61	6.61	8.43	8.43	8.43
2025/2026	6.36	6.36	6.36	6.99	6.99	6.99	8.96	8.96	8.96
2026/2027	6.46	6.46	6.46	7.11	7.11	7.11	9.23	9.23	9.23
2027/2028	6.58	6.58	6.58	7.24	7.24	7.24	9.52	9.52	9.52
2028/2029	6.80	6.80	6.80	7.48	7.48	7.48	9.94	9.94	9.94

VI. Key Findings

- Avoided costs were calculated for the expected case (base case), a high and a low case. High CO_2 emission costs could result in avoided costs that are 40% higher than expected. Lower CO_2 emission costs could lower avoided cost by 23%. This range in avoided cost could affect the amount of cost effective DSM that is achievable in future years. However, at this time, the difference is not expected to be significant.
- Base case avoided costs were calculated in the modification phase of the IRP. This calculation included an updated natural gas price forecast and resulted in lower numbers.

Chapter 7: Public Communication and Participation

NW Natural®

I. TECHNICAL WORKING GROUP

The Technical Working Group (TWG) is an integral part of developing the Company's resource plans. During this planning cycle NW Natural worked with representatives from the Energy Trust of Oregon; Northwest Power and Conservation Council; Northwest Industrial Gas Users; Northwest Pipeline Corporation; TransCanada-Gas Transmission Northwest, the Washington Utilities & Transportation Commission; Washington Public Council; Northwest Gas Association; Oregon Department of Energy; City of Portland; and FLOW.

NW Natural held four TWG meetings. Below is a summary of each meeting

- <u>TWG No.1 held on February 24' 2010</u>

  NW Natural reviewed its 2008 IRP process. From there, NW Natural presented its customer forecasting and demand forecasting methodologies. The group weather pattern developments as well as load forecast equations were discussed as well as the accuracy of demand elasticity. NW Natural ended by giving an overview of its resource planning model.

  Parties asked NW Natural to define its sensitivities and scenarios and explain the basis for portfolio selections. A party suggested adopting the approach used by another local utility of weighing and scoring sensitivies as this method might assist parties in understanding the Company's analysis of the data.

  Some equivocation was expressed regarding LNG but in general, parties told NW Natural to plan a sensitivity with imported LNG and satellite storage resources.

- <u>TWG No. 2 held on May 17, 2010</u>

  NW Natural presented a more in-depth look at its work on customer forecasts and trends, gas price forecasts and load forecasts. The group discussed the 2004 and 2009 peak cold weather events and the multiple factors that influence gas usage on cold weather days, including the day of the week, whether or not it was a holiday, and the wind chill factor. The Company then presented its supply side resources. NW Natural agreed that it would not model the impact of the Ruby Pipeline.

  In discussing scenarios, sensitivities and portfolios to be modeled in this IRP, the group expressed an interest in NW Natural's modeling of targeted DSM in capacity constrained regions like Eugene. A party asked for a sensitivity for increased future pipeline rates. Others expressed interest in seeing a scenario that modeled an outage. NW Natural explained that the IRP assumes all transmission systems are working properly. Potential problems with the distribution system are modeled using different software and are outside of the scope of the IRP.

- <u>TWG No. 3 held on July 28, 2010</u>

  NW Natural recapitulated the learnings and process covered thus far. Demand scenarios were reviewed and initial model results were discussed. Also, the Energy Trust presented its work on determining the achievable potential for demand-side management in the Company's service territory. Matt Braman, analyst at the Energy Trust, detailed their process and discussed the potential as well as the twenty year deployment scenario.

NWIGU expressed concern that the Company's use of 2008 avoided costs in its initial DSM screening might allow non cost-effective DSM to be included in the achievable potential since gas prices have gone down significantly in the past two years. NW Natural said they believe the difference between screening with 2008 or more current avoided costs would be de minimis, but would study this. Other parties were adamant that a high commodity screening for DSM was important to include in this IRP.

In response to the parties wanting an outage modeled, NW Natural presented a scenario where the Williams pipeline was hypothetically out of commission for two years. Parties thought this was too extreme a scenario. However, NW Natural pointed out that this long term planning process does not work for modeling small events.

- TWG No. 4 held on November 3, 2010.
  The Company filed its draft plan with TWG members on October 22, 2010. The group met November 3, 2010, to review the draft and to further discuss model results.

  NW Natural explained its model runs that included scenarios designed to evaluate system reliability under limited service conditions.

  In response to Staff's observation, NW Natural explained that if it added no new resources, unserved demand would be experienced on peak days. The incidence of unserved demand would increase significantly by 2025, and would be experienced on non-peak days.

  The group also discussed recent developments that are affecting natural gas prices. The ability to more cost effectively hydraulically fracture shale and tight sands to release natural gas reserves has resulted in an increased availability of natural gas. The increased supply has reduced prices. This phenomenon in the market is referred to as the "shale gale."

  The TWG also discussed the Mist Storage facility. The cost of developing Mist storage was not included in rates. Shareholders bear the financial risks associated with the site, which has been developed in increments. Besides the benefit of having natural gas storage for peak usage periods, customers are annually credited a percentage of the net margin received from NW Natural's storage business.

- TWG No. 5 held on June 22, 2011.
  On March 23, 2011-- after the Company's IRP was filed in both Oregon and Washington-- Palomar Gas Transmission LCC submitted a filing with the Federal Energy Regulatory Commission (FERC) that announced the company was withdrawing its application for a certificate of public convenience and necessity for the Palomar Gas Transmission Project, referred to herein as Palomar East. With this announcement, it became evident that NW Natural's assumptions regarding Palomar East were no longer accurate. The Company continues to believe a pipeline similar to Palomar East will eventually be sited; however the in-service date and prices for capacity will differ than those modeled in the Company's initial 2011 IRP. Updated assumptions for Palomar/Blue Bridge were modeled and presented to the TWG in June 22, 2011.

  The Company explained that the new model runs did not affect the results of the Scenario Model

Runs included in Table 5.5 in Chapter 5. The purpose of the Scenario Model Runs was to prove an ability to maintain uninterrupted service when certain supply-side resources are not available. It was not a least cost analysis.

Parties reviewed multiple maps that detailed the paths for brining gas to NW Natural's service territory as well as the estimated costs for capacity on these pipelines.

Gas prices were updated and a graph was presented showing the reduction in the price forecast experienced from March 2010 to May 2011.

Parties also discussed the Gas Reserves deal (discussed in Docket Nos. UM 1520/UG 204 in Oregon and Docket No. UG-111233 in Washington) that NW Natural entered into with Encana Oil & Gas. Under the agreement, NW Natural pays to develop natural gas reserves in Jonah Field in Wyoming. In exchange, the Company will receive the rights to the production of gas from certain sections of the field. Parties wanted to see this deal modeled or discussed in the IRP. NWIGU requested that the Company review the deal and assess its value when it is combined with existing capacity contracts.

Appendix 7 contains the sign in sheets for each TWG meeting.

II. PUBLIC PARTICIPATION

NW Natural invited its customers to participate in the resource planning process. A bill insert that informed customers of the IRP, invited comments, and announced the June 17 public meeting, was sent to all customers in April 2010 billings. NW Natural received one written statement and 28 requests for the PowerPoint slides that were presented at the June 17th meeting.

The written customer statement which is included In Appendix 7 supports NW Natural's development of an LNG terminal in Oregon.

The June 17th public participation meeting was attended by seven customers. NW Natural reviewed the IRP process, and then discussed gas price volatility. Customers were interested in understanding the correlation between gas and oil prices and how the gas extracted from shale reserves will impact the northwest market.

A couple attendees expressed concern about the siting of the Palomar pipeline. One asked that NW Natural consider "the culture of the northwest which is passionately against cutting through the forest." It was suggested that the pipeline be sited along Highway 26. Another customer questioned the need for such a big pipeline since the proposed Bradwood LNG terminal is no longer a viable project. NW Natural explained that the IRP modeling process will only choose Palomar if it is the most cost-effective resource for reliably meeting customer demand. NW Natural also pointed to more appropriate forums with FERC for expressing concerns on the pipeline's planned location.

The bill insert and the sign-in sheet for the Public Participation meeting are included in Appendix 7.

Appendix 1: Regulatory Compliance

NW Natural®

NW Natural's 2009 IRP - Oregon Compliance		
Citation	**Requirement**	**Plan Citation**
Order No. 07-047		
Guideline 1(a)	All resources must be evaluated on a consistent and comparable basis.	
	All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	NW Natural made every effort to include all known supply and demand side options. Supply side options studied include not only the gas itself, but also the pipeline capacity required to transport the gas, the Company's gas storage options, and the system enhancements necessary to distribute the gas. The demand side study looked at all the potential energy savings potentially available within the Company's service territory. Chapters 3 and 4 focus on supply and demand side resources, respectively, while the results of NW Natural's analyses can be found in Chapter 5.
	Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling	Chapters 3 and 4 focus on supply and demand side resources, respectively. The Supply-side options in Chapter 3 range from existing and proposed interstate pipeline capacity from multiple providers, the Company's Mist underground storage, to imported LNG, as well as Satellite LNG facilities located at various locations within the Company's service territory. The Company clearly defines each resource's in-service date before which the respective resource could not be a selected resource. Because the Company identified unserved demand in all areas of its service territory within the 20-year planning horizon, it considered a variety of supply side options to meet local, regional, and system-wide demand such as satellite LNG, NW Natural pipeline enhancements (including the Willamette Valley Feeder project), and interstate pipeline expansions. In-service dates considered in the plan range from short term, such as Mist Recall supplies available in Fall 2008, to near-term resources (such as the Palomar Pipeline, which has been modeled as first available in 2010). All resources are offered each year after they become available throughout the 20-year planning horizon. The Company has also considered technologies such as biogas, which is not currently available, but has been identified for continued monitoring and future assessment.
	Consistent assumptions and methods should be used for evaluation of all resources.	To the best of its ability, NW Natural evaluated all resources, both supply and demand side, on a consistent basis in the SENDOUT® model, which programmatically and objectively applied the same common assumptions, approaches and methodology to each supply option. Chapter 5 contains the specific descriptions of the resource evaluation methodology.

NW Natural's 2009 IRP - Oregon Compliance		
Citation	**Requirement**	**Plan Citation**
	The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	In this IRP, the Company uses a real after-tax discount rate of 5.16 percent.
Guideline 1(b)	Risk and Uncertainty must be considered.	This study is characterized by risk and uncertainty because the Company cannot perfectly predict the contributing data such as future customer counts, economic conditions, market changes and weather conditions. However, this study analyzes risk-related data such that the Company can make reasonable assumptions.
	At a minimum, utilities should address the following sources of risk and uncertainty: Natural gas utilities: demand (peak, swing and baseload), commodity supply and price, transportation availability and price, and cost to comply with any regulation of greenhouse gas emissions.	First, NW Natural analyzes demand uncertainty (peak, swing, and baseload) through a deterministic set of load forecasts of the traditional low, base, and high scenarios. The Company first projected annual customer counts by customer sub-class. Customer growth forecasts were prepared for six scenarios, including no growth, negative growth, Company projected base case, and high growth forecasts. The Company then statistically estimated gas usage equations for each customer subclass (or market segment). Design year (including peak day) projections were derived from multiple regressions, separating out Base-use and Temperature Sensitive Load-use (TSL-use). Next, the Company applied design weather conditions, projected prices, and customers to gas usage equations to derive firm gas requirements for each forecast scenario. Price forecasts were prepared for three scenarios, including high, reference and low forecasts. The price forecasts are discussed in more detail in Chapter 2 . Second, in addition to the six deterministic demand forecasts for High, Low and Base Case Scenarios, the Company is incorporating Monte Carlo simulations (i.e. stochastic analysis) in its evaluation of customer demand. The 2008 IRP marks the first time NW Natural is incorporating stochastic analysis, which allows the Company to consider the impact of resource decisions across a range of weather and forward price scenarios, along with evaluating the LP optimized least-cost supply portfolio solution at different levels of probable demand levels. Stochastic analysis (Monte Carlo simulation) and SENDOUT® linear programming analysis are explained in more detail in Chapter 5. Third, the associated risk and uncertainty of commodity supply, prices and transportation availability are discussed in chapter 5, which includes the results of sensitivity analysis involving price simulations for future supply

NW Natural's 2009 IRP - Oregon Compliance		
Citation	**Requirement**	**Plan Citation**
	Utilities should identify in their plans any additional sources of risk and uncertainty.	In addition to the areas of risk and uncertainty described above that NW Natural has included in this Plan (weather, customer growth, and price), the Company has considered the likely impediments to the ultimate development and siting of certain potential resources such as imported LNG and satellite LNG. These are discussed in Chapter 3.
Guideline 1(c)	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers. The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	This IRP contains the Company's long-range analysis of load and resources spanning a 20-year horizon.
	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	The Company's SENDOUT® modeling software uses a PVRR cost metric methodology, which provides resource portfolio costs in both nominal and real (present value) dollars that is applied to resources of varying expected lives.
	To address risk, the plan should include, at a minimum:	
	Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	Through application of the SENDOUT® software, the Company modeled 200 scenarios around varying gas price and weather inputs via Monte Carlo iterations thereby developing a distribution of annual cost estimates utilizing SENDOUT®'s PVRR methodology. Chapter 5 further describes this analysis. The variability of costs is plotted against the Mean of the Total Cost distribution, while the Unserved Demand distribution captures the severity of bad outcomes.

NW Natural's 2009 IRP - Oregon Compliance		
Citation	**Requirement**	**Plan Citation**
	Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	Explanation: NW Natural provides retail customers with a bundled gas product including gas storage by aggregating load and acquiring gas supplies through wholesale market physical purchases that may be hedged using physical storage or financial transactions. The following goals guide the physical or financial hedging of gas supply: 1) reliability, 2) lowest reasonable cost, 3) price stability, and 4) cost recovery. This is discussed in greater detail in Chapter 3.
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	For this IRP, the Company has selected an 85% probability coldest winter planning standard augmented by an historic three-day peak event against which to evaluate the cost and risk trade-off of various supply and demand resources available to SENDOUT.® Although this planning standard incorporates a level of demand that is less than its traditional “design year” planning standard, it reflects the Company’s assessment that the costs associated with the higher planning standard were not justified in comparison with the risk of that traditional “design year” occurring. Further analysis of how the Company’s resource choices appropriately balance cost and risk can be found in Chapter 5, in the analysis of the Company’s selection of its Preferred Portfolio. In short, the Company considered the strictly economic data assessed by the SENDOUT® model, the likelihood of certain resources such as imported or satellite LNG being available, stochastic analysis of demand and price forecasting, and the non-economic but significant reliability benefits offered by certain resources, such as the Palomar East pipeline. After considering all these factors, the Company selected a Preferred Portfolio and identified for acquisition resources consistent with that portfolio.
Guideline 1(d)	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	Policy appears to be trending toward carbon contraints. To this end, the Company's gas forecast includes a carbon cost of $15 per ton beginning in 2014 and escalating 7.8% each year thereafter. Policy also appears to be contemplating ways of increading energy efficiency. This plan assessed the achievable potential for DSM and then separately looked at the effect a 30% increase in DSM would have on the Company's resource mix.

NW Natural's 2009 IRP - Oregon Compliance

Citation	Requirement	Plan Citation
Guideline 2(a)	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.	The public has been given considerable opportunities to participate in the development of NW Natural's 2011 IRP. The Company has held four Technical Working Group (TWG) meetings and one public meetings. Customers were notified of the 2011 IRP process in an April 2010 bill insert, which invited the submission of writen or electronic comments and announced the June 17 public meeting. A discussion of the technical working groups and the public meeting can be found in Chapter 7. Beyond these forums, the Company has been answering parties informal data requests.
Guideline 2(b)	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.	As evidenced by the material included throughout the plan, the Company has put forth all relevant non-confidential information necessary to produce a comprehensive Plan.
Guideline 2(c)	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	On October 22, 2010, after three TWG meetings, NW Natural submitted an initial draft plan in both Oregon and Washington. A technical working group meeting was held on November 3, 2010, to discuss the draft plan.
Guideline 3(a)	The utility must file an IRP for within two years of its previous IRP acknowledgement order.	NW Natural's 2008 IRP was acknowledged by the Commission on January 12, 2009. *See* OPUC Docket No. LC 45.
Guideline 3(b)	The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	NW Natural will comply with this guideline.

NW Natural's 2009 IRP - Oregon Compliance

Citation	Requirement	Plan Citation
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.	The procedural schedule for LC 51 contemplates discussing the Company's plan at a public meeting at the end of January 2012.
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 2009 IRP - Oregon Compliance

Citation	Requirement	Plan Citation
Guideline 3(g)	Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that: 1- Describes what actions the utility has taken to implement the plan; 2-Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and 3-Justifies any deviations from the acknowledged action plan.	The Company acknowledges this guideline.
Guideline 4	At a minimum the plan must include the following elements:	
Guideline 4(a)	An explanation of how the utility met each of the substantive and procedural requirements.	This appendix is intended to comply with this guideline by providing an itemized response to each of the substantive and procedural requirements.
Guideline 4(b)	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions	The Base Case demand forecast uses the Company's projected customer growth and projected prices. This IRP considers five departures from the Base Case demand forecast, including negative, low, medium, and high demand growth forecasts, as well as stochastic risk analysis. This study is discussed in Chapter 2. Chapter 5 provides the scenario and risk analysis results. Assumptions are detailed in Appendix 2.

NW Natural's 2009 IRP - Oregon Compliance		
Citation	**Requirement**	**Plan Citation**
Guideline 4(c)	For electric utilities …	Not applicable to NW Natural's gas utility operations.
Guideline 4(d)	For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources.	Using the SENDOUT® optimization model, the Company determined the peaking, swing, and base-load gas supply and associated transportation and storage for each year of the 20-year planning horizon. Please see the appendix to Chapter 5 for the detail behind the twenty-four distinct scenarios and sensitivities considered by the optimization model, and specific resources selected in each case for each year.

NW Natural's 2009 IRP - Oregon Compliance

Citation	Requirement	Plan Citation
Guideline 4(e)	Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology.	The best resource mix was determined by studying supply side options currently used, such as pipeline transportation contracts, gas supply contracts, and physical and financial hedging, as well as alternative options such as additional capacity or infrastructure enhancements. Future developments such as imported LNG and pipeline enhancements were considered. The various supply side options and their costs are identified and discussed in Chapter 3 and Appendix 3. Demand side resource options were compiled from various local, regional and national sources. The measures that are marketable within NW Natural's service territory were identified through a demographical study of customer specific information such as historical gas usage, appliance holdings, and forecast economic growth. A societal cost was then determined for each measure making the demand side options comparable with supply side options. Demand-side resource options are identified in Chapter 4 and its Appendix 4.
Guideline 4(f)	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	Explanation: Chapter 3 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 SENDOUTÒ 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
Guideline 4(g)	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered	The Company combined deterministic analysis and stochastic analysis to construct an optimal portfolio that meets specific pre-determined planning criteria, while also stress-testing the decision against a range of future weather and price events. Chapter 5 describes the alternative resource mix scenarios and forward looking sensitivities involving commodity availability, commodity cost, transportation cost, and/or load forecast inputs evaluated in the IRP. The Company identified the price and gas forecasts that represent key assumptions underlying the Base Case and Preferred Portfolio. The

NW Natural's 2009 IRP - Oregon Compliance		
Citation	**Requirement**	**Plan Citation**
Guidleine 4(h)	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations - system-wide or delivered to a specific portion of the system.	As described above, and in more detail in the Plan, the Company designed a total of nine alternate resource mix scenarios where each scenario allows for a single change to the incremental supply side resources that are available in the Base Case. The development of resource portfolio options evaluated in this IRP is documented in Chapter 5 and results are detailed in Appendix 5-3.
Guideline 4(i)	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties.	In addition to the alternate scenarios mentioned in 4(h), above, NW Natural developed 14 Sensitivity cases to the Base Case Scenario. The Sensitivity cases differ from the alternate scenarios in that they do not provide for a new resource mix decision (i.e., the Base Case resource portfolio is locked down). Instead, the purpose of the Sensitivities is to stress test the Base Case resource portfolio to changes in certain underlying Base Case assumptions. Finally, the Company conducted a stochastic analysis of the Base Case and the Company's Preferred Portfolio scenarios using the Monte Carlo
Guideline 4(j)	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Chapter 3 describes the resource options evaluated, including discussion on uncertainties in lead times and costs as well as viability and resource availability (e.g. LNG). Appendix 3 summarizes the potential resource options identifying investment costs and asset availability dates while results of resources selected are discussed in Chapter 5 and tabulated in Appendix 5-3.
Guideline 4(k)	Analysis of the uncertainties associated with each portfolio evaluated.	The Company combined deterministic analysis and stochastic analysis to construct an Preferred Portfolio that meets specific pre-determined planning criteria, while also stress testing the decision against a range of future weather and price events. This is further discussed in Chapter 5.

NW Natural's 2009 IRP - Oregon Compliance

Citation	Requirement	Plan Citation
Guideline 4(l)	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.	NW Natural evaluated cost/risk tradeoffs for each of the resource mix portfolios considered. Chapter 5 describes the Company's portfolio risk analysis, as well as the determination of its Preferred Portfolio.
Guideline 4(m)	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation.	NW Natural does not believe its preferred portfolio has any inconsistencies with state or federal energy policies. Potential barriers to implementation may relate to the ultimate availability and timing of certain incremental resources selected for the Company's preferred portfolio (e.g., satellite LNG, imported LNG) due to siting / permitting challenges related to the facilities, market viability, and others; such potential barriers are discussed in Chapter 3 and Chapter 5.
Guideline 4(n)	An action plan with resource activities the utility intends to undertake over the next two to four years to	Chapter 1 presents the Company's multi-year action plan, which identifies the short term actions the Company plans to pursue related to the following:
Guideline 5	Transmission	Not applicable to NW Natural's gas utility operations

NW Natural's 2009 IRP - Oregon Compliance

Citation	Requirement	Plan Citation
Guideline 6(a)	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	As discussed in Chapter 4, NW Natural worked with Energy Trust of Oregon to analyze the potential energy savings that could be cost-effectively procured within the Company's service territory over the next 20 years. The achiveable potenital study was determined by analyzing customer demographics together with energy efficiency measure data. The results were then compared with other supply side resources through SENDOUT.® A deployment scenario was applied to the total potential. Each year,the Company and Energy Trust review these assumptions when Energy Trust plans it s program budget for the next calendar year.
Guideline 6(b)	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	Appendix 4 provides annual therm savings targets for Oregon and Washington. These targets are further broken down by customer segment and program type. NW Natural's Schedule 301, Public Purposes Funding Surcharge, contains a special conditions that requires NW Natural to work with Energy Trust every year to determine if the funding level is appropriate to meet the next year's therm savings targets. At this time. the Company and the Energy Trust evaluate the IRP annual target and consider unforeseen influences that may either increase or reduce the next year's target. A tariff filing is made which proposes adjusting Schedule 301 to sufficiently fund the next year's target with a buffer fund for unexpected expenses.
Guideline 6(c)	To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: 1) determine the amount of conservation resources in the best cost/ risk portfolio without regard to any limits on funding of conservation programs; and 2) identify the preferred portfolio and	Not applicable.

NW Natural's 2009 IRP - Oregon Compliance

Citation	Requirement	Plan Citation
Guideline 7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	NW Natural offers interruptible rates which account for approximately 40 of the Company's throughput. This allows the Company to reduce system stress during unusually high demand
Guideline 8	Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for CO2, NOx,	Unlike electric utilities, environmental cost issues rarely impact a gas utility's supply-side resource choices. At present, the only supply-side implication of
Guideline 9	Direct Access Loads	Not applicable to NW Natural’s gas utility operations
Guideline 10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.	This plan studies the supply side needs for NW Natural's comlete service territory which includes customers in Oregon and Washington.

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Citation	Requirement	Plan Citation
Guideline 11	Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	NW Natural analyzes on an integrated basis gas supply, transportation, and storage, along with demand-side resources to reliably meet peak, swing, and base-load system requirements. For this IRP, the Company has selected an 85% probability coldest winter planning standard augmented by an historic three-day peak event against which to evaluate the cost and risk trade off of various supply and demand resources available to SENDOUT.® Although this planning standard incorporates a level of demand less than its traditional "design year" planning standard, it reflects the Company's evaluation and selection of a planning standard and resulting portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers. Discussion of the Company's planning criteria and the determination of its Preferred Portfolio is in Chapter 5. Stochastic analysis and stress-testing of the Company's results demonstrate the reliability of the Preferred Portfolio and cost/risk balance.
Guideline 12	Distributed Generation	Not applicable to NW Natural's gas utility operations.
Guideline 13(a)	Resource Acquisition	Not applicable to NW Natural's gas utility operations.
Guideline 13(b)	Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.	NW Natural's Gas Acquisition Plan detailing the Company's strategies and practices for acquiring gas supplies is described in Chapter 3 and is centered on the following goals: 1) Reliability, 2) Diversity, 3) Price Stability, and 4) Cost Recovery
Order No. 11-196 , UM 1286	For natural gas utilities, each IRP preparation process and final published IRP will address both planning to meet normal annual expected demand (as defined by the LOC - both base-load and swing) by day and planning to meet annual peak demand by day. The planning will include gas supply and associated transportation along with expected use of storage.	For purposes of this IRP, the plan to meet normal annual expected demand is seen as a subset of the plan to meet design year demand. That is, since the plan addresses design year demand which includes a peak day, the resource decisions made by the plan are fully adequate to meet demand under normal annual conditions. The Company will seek to clarify the use of the results of a plan to meet normal annual expected demand during the technical working group meetings for the next IRP.

NW Natural's 2009 IRP - Washington Compliance

Rule	Requirement	Plan Citation
WAC 480-90-238(4)	Work plan filed no later than 12 months before next IRP due date.	NW Natural filed its work plan on February 9, 2011.
WAC 480-90-238(4)	Work plan outlines content of IRP.	The work plan filed on February 9, 2010, outlined the content of the 2011 IRP.
WAC 480-90-238(4)	Work plan outlines method for assessing potential resources. (See LRC analysis below)	The work plan filed on February 9, 2010, provided the methodology used in developing the 2011 IRP, NW Natural developed and integrated demand forecasts, weather patterns, natural gas price forecasts, and demand side and supply side resources into Gas Supply and Planning Optimization software. The resulting model acted as a guide to steer the Company toward the least cost resource planning portfolio.
WAC 480-90-238(5)	Work plan outlines timing and extent of public participation.	The work plan filed on February 9, 2010, states four technical working group meetings were scheduled: February 24, 2010, April 28, 2010, (this was rescheduled to May 17, 2010); July 17, 2010; and November 3, 2010. It also notes that customers were notified of this IPR process through an April 2010 bill insert included in Appendix 7. This bill insert welcomed public comments and invited customers to a public meeting that was help on July 17, 2010.
WAC 480-90-238(4)	Integrated resource plan submitted within two years of previous plan.	NW Natural filed its 2009 IRP on March 30, 2009. *See* Docket No. UG-080912.
WAC 480-90-238(5)	Commission issues notice of public hearing after company files plan for review.	*pending*
WAC 480-90-238(5)	Commission holds public hearing.	*pending*
WAC 480-90-238(2)(a)	Plan describes mix of natural gas supply resources.	Chapter 3 outlines currently held and available supply side options including existing and proposed interstate pipeline capacity from multiple providers, the Company's Mist underground storage, imported LNG and Satellite LNG facilities. The Company has also provides a commentary of other alternative supply side option such as biogas.
WAC 480-90-238(2)(a)	Plan describes conservation supply.	Chapter 4 explains how NW Natural determined the achievable potential of DSM within its service territory for the next 20 years. The achievable potential was then screened with other supply side option in SENDOUT.® The analysis performed showed that through continued administration of energy efficiency programs in Oregon and Washington, NW Natural can save 25 million therms by 2016 and 117 million therms by 2030. The cost effective measures and program delivery by state is also discussed in Chapter 4.
WAC 480-90-238(2)(a)	Plan addresses supply in terms of current and future needs of utility and ratepayers.	NW Natural analyzed current demand and then studied future demand uncertainty through a deterministic set of load forecasts of the traditional low, base, and high scenarios. The Company first projected annual customer counts by customer sub-class. Customer growth forecasts were prepared for eight scenarios, including low growth, extended low growth, Company projected base case, and high growth forecasts. The Company then statistically estimated gas usage equations for each customer subclass (or market segment). Design year (including peak day) projections were derived from multiple regressions, separating out Base-use and Temperature Sensitive Load-use (TSL-use). Next, the Company applied design weather conditions, projected prices, and customers to gas usage equations to derive firm gas requirements for each 20-year forecast scenario.

NW Natural's 2009 IRP - Washington Compliance

Rule	Requirement	Plan Citation
WAC 480-90-238(2)(a)&(b)	Plan uses lowest reasonable cost (LRC) analysis to select mix of resources.	The Company considered the strictly economic data assessed by the SENDOUT® model, the likelihood of certain resources such as imported or satellite LNG being available, stochastic analysis of demand and price forecasting, and the non-economic but significant reliability benefits offered by certain resources, such as the Palomar East pipeline. After considering all these factors, the Company selected a Preferred Portfolio and identified for acquisition resources consistent with that portfolio.
WAC 480-90-238(2)(b)	LRC analysis considers resource costs.	Chapter 3 of the IRP identifies the costs of supply side resources. Chapter 5 discusses how SENDOUT® generated least-cost solutions through the analysis of hundreds of potential solutions made possible by evaluating numerous variables associated with forecast customer demand for gas (customer count forecasts, usage coefficients by customer type (residential, commercial), heating degree days (HDDs), and forecast end use.
WAC 480-90-238(2)(b)	LRC analysis considers market-volatility risks.	For this IRP, the Company developed eight sensitivity cases to the Base Case scenario. The sensitivity cases evaluated included high demand/low price, low demand/high price, high demand/high price and low demand/low price. Each sensitivity case resulted in differing planning criteria, thus providing the Company with an understanding of reliable and least cost resources available under varying circumstances.
WAC 480-90-238(2)(b)	LRC analysis considers demand side uncertainties.	Chapter 5 discusses the effect 30% more DSM or 15% less would have on the resource mix. With a 30% increase in DSM savings, the model selects the same resources as in the base case, but at lower levels, particularly down in the southern portion of the Willamette Valley. In the case of 15% less DSM, the resource mix is the same, but at different levels. More Mist recall is selected and more capacity is required in the southern Willamette Valley.
WAC 480-90-238(2)(b)	LRC analysis considers resource effect on system operation.	Chapter 5 discusses the multiple scenarios studied in this plan.
WAC 480-90-238(2)(b)	LRC analysis considers risks imposed on ratepayers.	In response to a growing, general interest in risk analysis, the Company recently began using what was initially an add-on module to SENDOUT,® called VectorGasTM, as the platform for performing Monte Carlo simulations. SENDOUT® Version 12 now integrates the full functionality of VectorGas into SENDOUT® providing Monte Carlo simulation capability around weather and price. Through detailed portfolio optimization techniques, the analytical potential of SENDOUT® is enhanced because of its capability to produce probability distribution information.
WAC 480-90-238(2)(b)	LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government.	It appears that natural gas utilities will be most affected by carbon contraints. This plan assumes a carbon tax of $15 per ton that starts in 2014 and then escalates at a rate of 7.8% per year. Climate change regulation may also require more DSM or through taxation cause more DSM to be cost effective. This plan acknowledges this possibility by studying a 30% increase in the potential. New and developing state and federal policy are discussed in Chapter 4.
WAC 480-90-238(2)(b)	LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	As stated above, the Company's gas cost forecast assumes a carbon adder of $15 per ton beginning in 2014 and then escalating at a rate of 7.8% a year thereafter. The Company's avoided cost estimates in Appendix 6 include a $0.099 per therm environmental externality adder to reflect assumed costs in the amount of $15 per ton for CO2 and $2,000 per ton for NOX.

NW Natural's 2009 IRP - Washington Compliance

Rule	Requirement	Plan Citation
WAC 480-90-238(2)(b)	LRC analysis considers need for security of supply.	The Plan states in Chapter 3 that the Company's first priority is to ensure it has a gas resource portfolio sufficent to satisfy core customer requirements. The second priority is to achieve sufficient resources at the lowest cost to customers. Choosing Palomar as a resource demonstrates the Company's efforts to both increase reliability and reduce dependency on one pipeline.
WAC 480-90-238(2)(c)	Plan defines conservation as any reduction in natural gas consumption that results from increases in the efficiency of energy use or distribution.	DSM savings per customer in NW Natural's service territory is defined in this plan as the reduction of gas consumption resulting from the installation of a cost effective conseration measure.
WAC 480-90-238(3)(a)	Plan includes a range of forecasts of future demand.	This plan evaluates the amount of gas needed to serve the Company's changing customer base, including the number and types of customers currently served, the types of customers that could be served in the future under varying circumstances including low, base and high recession scenarios, and the amount and pattern of gas usage that can be reasonably expected by those customers.
WAC 480-90-238(3)(a)	Plan develops forecasts using methods that examine the effect of economic forces on the consumption of natural gas.	NW Natural's Plan acknowledges that the sustained volatility of natural gas prices and the risk and uncertainty associated with them made it necessary to include price elasticity in its modeling in order to accurately forecast usage per customers. As such, in the Updated Plan, the Company performed high and low price sensitivity studies and compared them with the Base Case in *SENDOUT®*.
WAC 480-90-238(3)(a)	Plan develops forecasts using methods that address changes in the number, type and efficiency of natural gas end-uses.	The Plan discusses the projected changes in each customer clases. Forecasts are based on observable trends as well as published studies.
WAC 480-90-238(3)(b)	Plan includes an assessment of commercially available conservation, including load management.	The achievable potential study performed to determine the potential demand side management that should be included in the Company's preferred porfolio began with a study of all known commercially available conservatiion measures, including measures that are not fully in the market place. Chatper 4 provides an overview of new measures as well as interesting findings. Regarding load management, the Company continues to shave peak load when needed by curtailing interruptible customers.
WAC 480-90-238(3)(b)	Plan includes an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	Chapter 4 details how the Company deliveres energy efficinecy programs that offer customers incentives for cost effective demand side management measures. Appendix 4 contains the Company's Schedule G, Energy Efficiency Services and Programs--Residential and Commerical. It also includes the Company's Energy Efficiency Plan which further lays out the policies and parameters governing the Washington programs.
WAC 480-90-238(3)(c)	Plan includes an assessment of conventional and commercially available nonconventional gas supplies.	The best resource mix was determined by studying supply-side options currently used, such as pipeline transportation contracts, gas supply contracts, and physical and financial hedging, as well as alternative options such as additional capacity or infrastructure enhancements. Future developments such as imported LNG, biogas and pipeline enhancements were also considered.
WAC 480-90-238(3)(d)	Plan includes an assessment of opportunities for using company-owned or contracted storage.	The Company's Mist underground storage, imported LNG, as well as Satellite LNG facilities located at various locations within the Company's service territory were assessed as resource options.

NW Natural's 2009 IRP - Washington Compliance

Rule	Requirement	Plan Citation
WAC 480-90-238(3)(e)	Plan includes an assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources.	This study finds that NW Natural should seek cost-effective resource options to improve its supply path diversity. The Palomar pipeline project addresses the Company's current reliance solely on NWPL for delivery of interstate gas supplies. A second interstate pipeline delivery corridor would assure both the security of gas supply as well as reliable gas service. The Preferred Portfolio recognizes the importance of the Palomar Pipeline as both a cost-effective resource (particularly in comparison with the “No Palomar” scenario), and an enhancement to overall reliability.
WAC 480-90-238(3)(f)	Plan includes a comparative evaluation of the cost of natural gas purchasing strategies, storage options, delivery resources, and improvements in conservation using a consistent method to calculate cost-effectiveness.	The best resource mix was determined by studying supply side options currently used, such as pipeline transportation contracts, gas supply contracts, and physical and financial hedging, as well as alternative options such as additional capacity or infrastructure enhancements. Future developments such as imported LNG and pipeline enhancements were also considered. SENDOUT® determined the least cost resource mix through linear program discussed in Chapter 5.
WAC 480-90-238(3)(g)	Plan includes at least a 10-year long-range planning horizon.	This IRP contains the Company’s long-range analysis of load and resources spanning a 20-year horizon.
WAC 480-90-238(3)(g)	Demand forecasts and resource evaluations are integrated into the long range plan for resource acquisition.	Future Resource investments discussed include: a) Interstate Pipeline Additions, b) Brownsville to Eugene, c) Newport Expansion, d) Willamette Valley Feeder, e) Imported LNG, f) satellite LNG, and g) cost effective demand side resources.
WAC 480-90-238(3)(h)	Plan includes a two-year action plan that implements the long range plan.	The Multi-Year Action Plan details ongoing reiview or work the Company will accomplish specific to Demand Forecasting, Supply-Side Resources, Demand-Side Resources, SENDOUT® Model and Least Cost Plan Integration, Avoided Cost Determination, and Public Involvement.
WAC 480-90-238(3)(i)	Plan includes a progress report on the implementation of the previously filed plan.	Recent resources decisions discussed include the addition of 28 miles of 24 inch piping to loop the existing South Mist Feeder from Miller Station to a point at the western edge of the Portland metropolitan areas (Bacona), and completion of SMPE, which allows the Company to access more Mist deliverability.
WAC 480-90-238(5)	Plan includes description of consultation with commission staff. (Description not required)	WUTC Commission Staff was a party to the Technical Working Group. Public participation is documented in Appendix 7.
WAC 480-90-238(5)	Plan includes a description of completion of work plan. (Description not required)	The Key Findings found at the end of each chapter and the Multi-Year Action Plan found in Chapter 1 provides conclusions drawn from study and successuful completion of the Plan.

Appendix 2: Gas Requirements Forecast

Appendix 2.1 Customer Forecast – Base Case - Total Firm

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009	39,839	12,046	5,376	38,998	9,880	406,292	86,780	68,245	667,456
2010	40,127	12,168	5,444	39,511	10,009	409,524	87,593	69,295	673,671
2011	40,583	12,340	5,550	40,255	10,195	414,185	88,785	70,779	682,671
2012	41,160	12,546	5,681	41,124	10,422	419,849	90,248	72,588	693,617
2013	41,824	12,775	5,830	42,087	10,678	426,238	91,906	74,626	705,966
2014	42,548	13,024	5,991	43,091	10,956	433,137	93,698	76,819	719,265
2015	43,338	13,292	6,166	44,170	11,257	440,627	95,640	79,188	733,679
2016	44,191	13,576	6,352	45,294	11,580	448,640	97,718	81,738	749,089
2017	45,111	13,877	6,552	46,487	11,927	457,216	99,945	84,476	765,590
2018	46,032	14,181	6,754	47,686	12,275	465,927	102,173	87,231	782,260
2019	46,960	14,490	6,960	48,902	12,628	474,809	104,416	90,014	799,179
2020	47,877	14,797	7,164	50,101	12,979	483,648	106,630	92,775	815,971
2021	48,781	15,101	7,366	51,288	13,326	492,441	108,817	95,508	832,629
2022	49,671	15,403	7,566	52,458	13,670	501,176	110,972	98,214	849,129
2023	50,548	15,701	7,762	53,612	14,010	509,840	113,097	100,888	865,459
2024	51,425	16,000	7,959	54,767	14,350	518,520	115,223	103,566	881,812
2025	52,310	16,299	8,156	55,923	14,692	527,200	117,365	106,258	898,204
2026	53,196	16,598	8,353	57,083	15,034	535,862	119,511	108,950	914,587
2027	54,072	16,897	8,550	58,243	15,373	544,495	121,635	111,616	930,882
2028	54,927	17,192	8,744	59,386	15,707	553,022	123,711	114,230	946,919
2029	55,763	17,481	8,934	60,501	16,034	561,425	125,746	116,802	962,687
2030	56,605	17,772	9,124	61,622	16,363	569,838	127,793	119,384	978,502

Appendix 2.2 Customer Forecast – Base Case – Residential

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009	35,790	10,381	5,822	33,587	8,602	370,788	78,341	62,897	606,208
2010	36,063	10,499	5,800	34,010	8,726	373,824	79,090	63,846	611,860
2011	36,481	10,658	5,795	34,589	8,901	378,087	80,166	65,180	619,858
2012	37,021	10,850	5,796	35,291	9,117	383,343	81,510	66,838	629,765
2013	37,643	11,065	5,803	36,080	9,361	389,292	83,041	68,716	641,001
2014	38,324	11,298	5,814	36,933	9,626	395,750	84,704	70,750	653,200
2015	39,073	11,552	5,827	37,864	9,916	402,803	86,521	72,960	666,515
2016	39,894	11,824	5,842	38,864	10,230	410,476	88,497	75,374	681,001
2017	40,781	12,114	5,862	39,926	10,566	418,689	90,617	77,970	696,524
2018	41,665	12,405	5,887	40,985	10,904	427,001	92,729	80,575	712,150
2019	42,546	12,697	5,919	42,042	11,243	435,403	94,834	83,188	727,872
2020	43,421	12,988	5,951	43,092	11,580	443,804	96,922	85,788	743,546
2021	44,282	13,278	5,984	44,129	11,915	452,155	98,981	88,361	759,085
2022	45,135	13,566	6,016	45,158	12,247	460,485	101,019	90,914	774,540
2023	45,975	13,852	6,048	46,175	12,577	468,760	103,029	93,441	789,856
2024	46,817	14,138	6,080	47,193	12,907	477,053	105,043	95,972	805,203
2025	47,669	14,426	6,110	48,222	13,239	485,382	107,080	98,525	820,653
2026	48,521	14,713	6,140	49,251	13,571	493,681	109,119	101,075	836,072
2027	49,356	14,997	6,172	50,262	13,898	501,879	111,118	103,582	851,264

2028	50,166	15,276	6,207	51,251	14,217	509,943	113,061	106,029	866,150
2029	50,967	15,553	6,238	52,230	14,535	517,964	114,984	108,456	880,927
2030	51,772	15,830	6,269	53,213	14,853	525,984	116,915	110,889	895,726

Appendix 2.3 Customer Forecast – Base Case – Firm Commercial

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009	4,013	1,658	1,060	5,325	1,274	35,186	8,344	5,309	62,169
2010	4,028	1,662	1,074	5,415	1,279	35,382	8,408	5,410	62,657
2011	4,065	1,675	1,097	5,567	1,290	35,779	8,524	5,560	63,558
2012	4,103	1,689	1,121	5,719	1,301	36,177	8,640	5,710	64,459
2013	4,144	1,703	1,146	5,878	1,313	36,607	8,764	5,868	65,423
2014	4,185	1,718	1,170	6,025	1,325	37,038	8,889	6,026	66,376
2015	4,226	1,733	1,195	6,173	1,337	37,469	9,014	6,184	67,330
2016	4,257	1,743	1,216	6,298	1,347	37,809	9,115	6,320	68,104
2017	4,290	1,755	1,238	6,429	1,357	38,172	9,222	6,462	68,925
2018	4,328	1,768	1,261	6,568	1,368	38,571	9,338	6,612	69,815
2019	4,374	1,785	1,288	6,727	1,382	39,051	9,476	6,782	70,865
2020	4,416	1,800	1,314	6,876	1,394	39,490	9,602	6,943	71,835
2021	4,458	1,815	1,339	7,026	1,407	39,931	9,730	7,103	72,810
2022	4,496	1,829	1,363	7,167	1,418	40,336	9,848	7,255	73,713
2023	4,533	1,842	1,386	7,304	1,429	40,726	9,962	7,403	74,584
2024	4,569	1,854	1,408	7,441	1,440	41,112	10,075	7,551	75,449
2025	4,601	1,865	1,430	7,568	1,449	41,463	10,179	7,689	76,245
2026	4,634	1,877	1,451	7,699	1,459	41,826	10,286	7,831	77,064
2027	4,676	1,892	1,476	7,847	1,472	42,261	10,412	7,990	78,026
2028	4,721	1,908	1,503	8,003	1,485	42,724	10,545	8,156	79,044
2029	4,756	1,921	1,525	8,138	1,496	43,106	10,656	8,302	79,900
2030	4,793	1,934	1,549	8,276	1,507	43,499	10,771	8,451	80,780

Appendix 2.4 Customer Forecast – Base Case – Firm Industrial

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009	36	7	10	86	4	318	95	39	595
2010	36	7	10	86	4	318	95	39	595
2011	36	7	10	86	4	318	95	39	595
2012	37	7	10	89	4	329	98	40	614
2013	38	7	11	92	4	339	101	42	634
2014	40	8	11	95	4	350	105	43	656
2015	40	8	11	96	4	355	106	44	664
2016	40	8	11	96	4	355	106	44	664
2017	40	8	11	96	4	355	106	44	664
2018	40	8	11	96	4	355	106	44	664
2019	40	8	11	96	4	355	106	44	664
2020	40	8	11	96	4	355	106	44	664
2021	40	8	11	96	4	355	106	44	664
2022	40	8	11	96	4	355	106	44	664

2023	40	8	11	96	4	355	106	44	664
2024	40	8	11	96	4	355	106	44	664
2025	40	8	11	96	4	355	106	44	664
2026	40	8	11	96	4	355	106	44	664
2027	40	8	11	96	4	355	106	44	664
2028	40	8	11	96	4	355	106	44	664
2029	40	8	11	96	4	355	106	44	664
2030	40	8	11	96	4	355	106	44	664

Appendix 2.5 Customer Forecast - High Case – Total Firm

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009	39,839	12,046	5,376	38,998	9,880	406,292	86,780	68,245	667,456
2010	40,180	12,187	5,457	39,587	10,028	410,031	87,716	69,425	674,613
2011	40,777	12,409	5,597	40,522	10,264	415,992	89,229	71,257	686,047
2012	41,560	12,684	5,777	41,662	10,564	423,528	91,162	73,582	700,519
2013	42,497	13,005	5,990	42,979	10,917	432,383	93,441	76,308	717,519
2014	43,512	13,349	6,219	44,356	11,296	441,900	95,894	79,236	735,761
2015	44,561	13,703	6,453	45,764	11,689	451,719	98,426	82,261	754,577
2016	45,666	14,068	6,696	47,204	12,101	461,998	101,076	85,457	774,267
2017	46,797	14,437	6,944	48,655	12,521	472,449	103,779	88,733	794,315
2018	47,893	14,797	7,186	50,070	12,932	482,742	106,405	91,940	813,965
2019	48,962	15,152	7,425	51,461	13,335	492,910	108,966	95,088	833,299
2020	49,995	15,497	7,655	52,804	13,727	502,818	111,444	98,150	852,089
2021	50,979	15,828	7,876	54,091	14,103	512,355	113,813	101,092	870,137
2022	51,927	16,148	8,088	55,331	14,467	521,619	116,097	103,946	887,623
2023	52,860	16,465	8,298	56,555	14,827	530,808	118,348	106,767	904,929
2024	53,793	16,783	8,508	57,780	15,188	540,013	120,602	109,592	922,259
2025	54,734	17,101	8,718	59,006	15,551	549,219	122,871	112,431	939,631
2026	55,677	17,418	8,928	60,236	15,913	558,406	125,145	115,271	956,994
2027	56,610	17,736	9,138	61,466	16,272	567,562	127,397	118,083	974,263
2028	57,519	18,049	9,345	62,679	16,625	576,608	129,597	120,839	991,262
2029	58,410	18,357	9,547	63,861	16,972	585,523	131,754	123,553	1,007,978
2030	59,306	18,665	9,750	65,051	17,321	594,449	133,924	126,277	1,024,744

Appendix 2.6 Customer Forecast – High Case – Residential

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009	35,790	10,381	5,822	33,587	8,602	370,788	78,341	62,897	606,208
2010	36,109	10,515	5,806	34,069	8,744	374,261	79,195	63,959	612,656
2011	36,647	10,715	5,814	34,795	8,962	379,642	80,545	65,597	622,717
2012	37,367	10,967	5,834	35,712	9,244	386,543	82,300	67,715	635,681
2013	38,231	11,260	5,864	36,786	9,575	394,675	84,379	70,212	650,982
2014	39,171	11,577	5,900	37,944	9,933	403,468	86,631	72,911	667,535
2015	40,153	11,905	5,935	39,147	10,306	412,616	88,976	75,719	684,757
2016	41,206	12,251	5,970	40,414	10,703	422,359	91,474	78,730	703,107
2017	42,285	12,601	6,007	41,696	11,108	432,289	94,030	81,827	721,841
2018	43,329	12,942	6,047	42,938	11,503	442,047	96,503	84,850	740,159

2019	44,338	13,275	6,092	44,141	11,888	451,617	98,897	87,798	758,045
2020	45,318	13,600	6,134	45,311	12,264	460,990	101,223	90,676	775,518
2021	46,253	13,913	6,174	46,433	12,626	470,019	103,447	93,442	792,307
2022	47,157	14,218	6,211	47,521	12,977	478,832	105,602	96,132	808,650
2023	48,048	14,520	6,249	48,597	13,325	487,587	107,728	98,794	824,848
2024	48,941	14,823	6,286	49,674	13,674	496,362	109,857	101,461	841,078
2025	49,845	15,128	6,321	50,762	14,025	505,173	112,011	104,151	857,416
2026	50,750	15,432	6,356	51,851	14,376	513,954	114,166	106,838	873,721
2027	51,635	15,732	6,394	52,921	14,721	522,627	116,280	109,479	889,789
2028	52,495	16,027	6,434	53,966	15,059	531,161	118,335	112,058	905,535
2029	53,345	16,320	6,470	55,003	15,395	539,650	120,369	114,615	921,166
2030	54,200	16,614	6,506	56,043	15,731	548,137	122,412	117,178	936,822

Appendix 2.7 Customer Forecast – High Case – Firm Commercial

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009	4,013	1,658	1,060	5,325	1,274	35,186	8,344	5,309	62,169
2010	4,036	1,665	1,077	5,432	1,281	35,452	8,426	5,427	62,797
2011	4,093	1,687	1,109	5,629	1,298	36,032	8,589	5,622	64,058
2012	4,156	1,710	1,143	5,836	1,316	36,657	8,764	5,827	65,409
2013	4,228	1,737	1,180	6,064	1,338	37,369	8,961	6,055	66,932
2014	4,301	1,765	1,218	6,280	1,359	38,082	9,159	6,282	68,445
2015	4,368	1,790	1,254	6,484	1,379	38,748	9,344	6,498	69,865
2016	4,421	1,809	1,284	6,657	1,394	39,284	9,496	6,682	71,027
2017	4,472	1,828	1,313	6,826	1,410	39,805	9,644	6,863	72,159
2018	4,525	1,847	1,342	6,999	1,425	40,340	9,795	7,046	73,320
2019	4,584	1,869	1,375	7,187	1,443	40,939	9,963	7,246	74,606
2020	4,637	1,889	1,404	7,359	1,458	41,472	10,114	7,429	75,763
2021	4,686	1,907	1,433	7,525	1,473	41,981	10,259	7,607	76,871
2022	4,730	1,922	1,459	7,677	1,486	42,432	10,389	7,770	77,864
2023	4,771	1,937	1,484	7,826	1,498	42,866	10,514	7,929	78,825
2024	4,812	1,952	1,508	7,973	1,510	43,297	10,639	8,087	79,778
2025	4,849	1,965	1,532	8,111	1,521	43,691	10,754	8,236	80,660
2026	4,888	1,979	1,555	8,252	1,533	44,098	10,873	8,389	81,565
2027	4,934	1,996	1,583	8,412	1,547	44,580	11,011	8,559	82,622
2028	4,984	2,014	1,611	8,579	1,562	45,092	11,156	8,738	83,736
2029	5,025	2,028	1,636	8,725	1,574	45,518	11,280	8,895	84,680
2030	5,067	2,043	1,661	8,874	1,586	45,957	11,406	9,055	85,650

Appendix 2.8 Customer Forecast – High Case – Firm Industrial

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009	36	7	10	86	4	318	95	39	595
2010	36	7	10	86	4	318	95	39	595
2011	36	7	10	86	4	318	95	39	595
2012	37	7	10	89	4	329	98	40	614
2013	38	7	11	92	4	339	101	42	634
2014	40	8	11	95	4	350	105	43	656

2015	40	8	11	96	4	355	106	44	664
2016	40	8	11	96	4	355	106	44	664
2017	40	8	11	96	4	355	106	44	664
2018	40	8	11	96	4	355	106	44	664
2019	40	8	11	96	4	355	106	44	664
2020	40	8	11	96	4	355	106	44	664
2021	40	8	11	96	4	355	106	44	664
2022	40	8	11	96	4	355	106	44	664
2023	40	8	11	96	4	355	106	44	664
2024	40	8	11	96	4	355	106	44	664
2025	40	8	11	96	4	355	106	44	664
2026	40	8	11	96	4	355	106	44	664
2027	40	8	11	96	4	355	106	44	664
2028	40	8	11	96	4	355	106	44	664
2029	40	8	11	96	4	355	106	44	664
2030	40	8	11	96	4	355	106	44	664

Appendix 2.9 Customer Forecast – Low Case – Total Firm

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009	39,839	12,046	5,376	38,998	9,880	406,292	86,780	68,245	667,456
2010	40,047	12,139	5,424	39,398	9,980	408,764	87,409	69,099	672,259
2011	40,292	12,237	5,479	39,854	10,091	411,475	88,118	70,061	677,607
2012	40,581	12,345	5,542	40,343	10,216	414,517	88,925	71,147	683,617
2013	40,945	12,475	5,621	40,918	10,367	418,195	89,899	72,429	690,849
2014	41,369	12,624	5,713	41,536	10,538	422,389	91,008	73,864	699,040
2015	41,868	12,797	5,821	42,245	10,737	427,268	92,290	75,498	708,525
2016	42,457	12,995	5,946	43,042	10,968	432,917	93,769	77,375	719,468
2017	43,155	13,225	6,096	43,962	11,236	439,515	95,494	79,544	732,226
2018	43,925	13,480	6,263	44,974	11,531	446,854	97,379	81,907	746,313
2019	44,771	13,762	6,451	46,088	11,855	454,985	99,435	84,477	761,824
2020	45,629	14,050	6,642	47,215	12,184	463,291	101,518	87,087	777,616
2021	46,498	14,343	6,836	48,359	12,519	471,765	103,627	89,731	793,678
2022	47,354	14,633	7,027	49,486	12,851	480,183	105,705	92,347	809,587
2023	48,197	14,921	7,216	50,599	13,179	488,532	107,754	94,934	825,331
2024	49,041	15,209	7,405	51,711	13,507	496,896	109,804	97,524	841,097
2025	49,892	15,497	7,594	52,826	13,837	505,261	111,868	100,128	856,902
2026	50,744	15,784	7,783	53,943	14,167	513,608	113,937	102,731	872,698
2027	51,586	16,072	7,972	55,061	14,494	521,926	115,986	105,309	888,407
2028	52,408	16,356	8,159	56,163	14,815	530,143	117,987	107,837	903,868
2029	53,212	16,634	8,340	57,237	15,131	538,238	119,948	110,324	919,066
2030	54,021	16,914	8,523	58,317	15,449	546,344	121,921	112,821	934,311

Appendix 2.10 Customer Forecast – Low Case – Residential

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009	35,790	10,381	5,822	33,587	8,602	370,788	78,341	62,897	606,208
2010	35,995	10,474	5,793	33,923	8,701	373,170	78,933	63,676	610,665
2011	36,233	10,572	5,767	34,280	8,810	375,756	79,597	64,555	615,569
2012	36,519	10,681	5,742	34,680	8,934	378,707	80,367	65,569	621,198
2013	36,875	10,810	5,723	35,156	9,082	382,256	81,294	66,767	627,962
2014	37,289	10,956	5,708	35,695	9,251	386,300	82,350	68,114	635,662
2015	37,777	11,126	5,697	36,320	9,446	391,007	83,574	69,653	644,600
2016	38,357	11,322	5,690	37,041	9,674	396,520	85,005	71,444	655,054
2017	39,040	11,548	5,693	37,871	9,938	402,920	86,665	73,512	667,188
2018	39,786	11,795	5,705	38,772	10,226	409,979	88,464	75,755	680,482
2019	40,593	12,064	5,730	39,744	10,538	417,700	90,401	78,172	694,941
2020	41,414	12,339	5,757	40,733	10,856	425,614	92,370	80,633	709,716
2021	42,244	12,618	5,786	41,735	11,180	433,675	94,358	83,123	724,719
2022	43,066	12,896	5,815	42,728	11,501	441,716	96,326	85,594	739,640
2023	43,875	13,172	5,844	43,709	11,819	449,702	98,267	88,039	754,428
2024	44,686	13,448	5,873	44,692	12,137	457,707	100,211	90,489	769,244
2025	45,507	13,726	5,900	45,685	12,458	465,746	102,179	92,960	784,161
2026	46,329	14,003	5,926	46,679	12,779	473,757	104,147	95,428	799,048
2027	47,133	14,277	5,956	47,655	13,095	481,668	106,077	97,854	813,716
2028	47,913	14,546	5,987	48,609	13,403	489,451	107,953	100,223	828,086
2029	48,685	14,814	6,015	49,554	13,710	497,192	109,809	102,571	842,349
2030	49,460	15,081	6,043	50,503	14,017	504,931	111,674	104,925	856,635

Appendix 2.11 Customer Forecast – Low Case – Firm Commercial

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009	4,013	1,658	1,060	5,325	1,274	35,186	8,344	5,309	62,169
2010	4,016	1,657	1,069	5,389	1,275	35,276	8,381	5,383	62,447
2011	4,023	1,658	1,080	5,475	1,278	35,401	8,426	5,467	62,808
2012	4,025	1,658	1,089	5,550	1,278	35,481	8,460	5,539	63,079
2013	4,031	1,658	1,100	5,633	1,281	35,600	8,504	5,620	63,428
2014	4,040	1,660	1,111	5,709	1,283	35,739	8,554	5,707	63,803
2015	4,052	1,663	1,124	5,792	1,287	35,906	8,610	5,800	64,234
2016	4,060	1,664	1,135	5,868	1,290	36,042	8,659	5,886	64,604
2017	4,075	1,669	1,149	5,958	1,294	36,240	8,723	5,987	65,095
2018	4,099	1,677	1,167	6,069	1,302	36,520	8,809	6,109	65,751
2019	4,138	1,690	1,191	6,211	1,313	36,931	8,928	6,262	66,664
2020	4,174	1,703	1,214	6,348	1,324	37,322	9,042	6,410	67,539
2021	4,214	1,717	1,238	6,491	1,336	37,735	9,163	6,564	68,458
2022	4,249	1,729	1,261	6,626	1,346	38,113	9,273	6,709	69,306
2023	4,282	1,741	1,283	6,756	1,356	38,475	9,380	6,851	70,124
2024	4,315	1,753	1,304	6,886	1,366	38,834	9,486	6,991	70,935
2025	4,344	1,763	1,324	7,007	1,375	39,160	9,584	7,124	71,681
2026	4,375	1,773	1,345	7,132	1,384	39,496	9,684	7,259	72,447

2027	4,413	1,787	1,368	7,273	1,396	39,903	9,803	7,411	73,354
2028	4,455	1,802	1,394	7,421	1,408	40,337	9,928	7,570	74,314
2029	4,487	1,813	1,415	7,550	1,418	40,692	10,033	7,710	75,117
2030	4,521	1,825	1,437	7,681	1,428	41,058	10,141	7,852	75,942

Appendix 2.12 Customer Forecast – Low Case – Firm Industrial

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009	36	7	10	86	4	318	95	39	595
2010	36	7	10	86	4	318	95	39	595
2011	36	7	10	86	4	318	95	39	595
2012	37	7	10	89	4	329	98	40	614
2013	38	7	11	92	4	339	101	42	634
2014	40	8	11	95	4	350	105	43	656
2015	40	8	11	96	4	355	106	44	664
2016	40	8	11	96	4	355	106	44	664
2017	40	8	11	96	4	355	106	44	664
2018	40	8	11	96	4	355	106	44	664
2019	40	8	11	96	4	355	106	44	664
2020	40	8	11	96	4	355	106	44	664
2021	40	8	11	96	4	355	106	44	664
2022	40	8	11	96	4	355	106	44	664
2023	40	8	11	96	4	355	106	44	664
2024	40	8	11	96	4	355	106	44	664
2025	40	8	11	96	4	355	106	44	664
2026	40	8	11	96	4	355	106	44	664
2027	40	8	11	96	4	355	106	44	664
2028	40	8	11	96	4	355	106	44	664
2029	40	8	11	96	4	355	106	44	664
2030	40	8	11	96	4	355	106	44	664

Appendix 2.13 Customer Forecast – Low II Case – Total Firm

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009	39,839	12,046	5,376	38,998	9,880	406,292	86,780	68,245	667,456
2010	40,127	12,168	5,444	39,511	10,009	409,524	87,593	69,295	673,671
2011	40,569	12,335	5,547	40,236	10,190	414,055	88,752	70,744	682,428
2012	41,100	12,525	5,666	41,046	10,401	419,308	90,114	72,445	692,604
2013	41,681	12,728	5,796	41,905	10,629	424,965	91,589	74,289	703,584
2014	42,274	12,933	5,927	42,745	10,862	430,705	93,091	76,173	714,710
2015	42,878	13,141	6,058	43,592	11,099	436,551	94,622	78,101	726,043
2016	43,474	13,342	6,185	44,405	11,335	442,304	96,133	80,035	737,212
2017	44,048	13,533	6,305	45,180	11,562	447,837	97,594	81,932	747,990
2018	44,547	13,702	6,410	45,867	11,765	452,794	98,888	83,656	757,627
2019	44,962	13,845	6,497	46,458	11,940	457,072	99,995	85,179	765,949
2020	45,272	13,955	6,560	46,918	12,079	460,428	100,866	86,442	772,520

2021	45,466	14,029	6,596	47,237	12,178	462,759	101,478	87,415	777,158
2022	45,534	14,061	6,604	47,402	12,233	463,963	101,809	88,074	779,681
2023	45,558	14,080	6,601	47,514	12,273	464,783	102,044	88,629	781,481
2024	45,543	14,086	6,588	47,577	12,300	465,245	102,192	89,090	782,621
2025	45,500	14,083	6,569	47,607	12,317	465,450	102,283	89,489	783,297
2026	45,451	14,077	6,548	47,632	12,332	465,601	102,363	89,881	783,886
2027	45,393	14,070	6,526	47,650	12,345	465,696	102,427	90,260	784,367
2028	45,322	14,059	6,501	47,657	12,355	465,714	102,468	90,619	784,695
2029	45,241	14,046	6,472	47,650	12,361	465,649	102,486	90,961	784,867
2030	45,153	14,030	6,443	47,638	12,366	465,535	102,496	91,297	784,959

Appendix 2.14 Customer Forecast – Low II Case – Residential

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009	35,790	10,381	5,822	33,587	8,602	370,788	78,341	62,897	606,208
2010	36,063	10,499	5,800	34,010	8,726	373,824	79,090	63,846	611,860
2011	36,469	10,654	5,794	34,574	8,897	377,976	80,138	65,150	619,651
2012	36,969	10,833	5,790	35,229	9,099	382,875	81,395	66,712	628,902
2013	37,519	11,026	5,787	35,936	9,318	388,189	82,767	68,418	638,960
2014	38,085	11,222	5,784	36,658	9,543	393,631	84,177	70,175	649,275
2015	38,670	11,424	5,777	37,401	9,775	399,234	85,631	71,987	659,899
2016	39,262	11,625	5,766	38,141	10,008	404,879	87,098	73,836	670,615
2017	39,836	11,818	5,751	38,853	10,236	410,349	88,528	75,659	681,030
2018	40,341	11,991	5,733	39,486	10,440	415,283	89,801	77,317	690,391
2019	40,765	12,140	5,711	40,028	10,617	419,565	90,894	78,780	698,500
2020	41,096	12,261	5,678	40,466	10,762	423,038	91,779	80,008	705,088
2021	41,322	12,350	5,634	40,786	10,870	425,582	92,430	80,970	709,943
2022	41,436	12,403	5,578	40,979	10,938	427,118	92,830	81,645	712,928
2023	41,511	12,444	5,517	41,129	10,992	428,316	93,146	82,226	715,281
2024	41,551	12,475	5,451	41,240	11,034	429,197	93,385	82,722	717,055
2025	41,568	12,498	5,380	41,326	11,069	429,860	93,576	83,165	718,441
2026	41,581	12,519	5,307	41,408	11,101	430,480	93,760	83,602	719,759
2027	41,584	12,539	5,233	41,481	11,132	431,040	93,925	84,023	720,957
2028	41,576	12,556	5,158	41,543	11,159	431,529	94,069	84,424	722,015
2029	41,561	12,571	5,080	41,600	11,185	431,971	94,199	84,815	722,981
2030	41,541	12,586	4,999	41,652	11,209	432,375	94,323	85,202	723,887

Appendix 2.15 Customer Forecast – Low II Case – Firm Commercial

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009	4,013	1,658	1,060	5,325	1,274	35,186	8,344	5,309	62,169
2010	4,028	1,662	1,074	5,415	1,279	35,382	8,408	5,410	62,657
2011	4,063	1,675	1,097	5,563	1,289	35,761	8,519	5,555	63,522
2012	4,094	1,685	1,118	5,702	1,298	36,103	8,621	5,693	64,315
2013	4,124	1,695	1,138	5,840	1,307	36,437	8,721	5,829	65,093
2014	4,149	1,703	1,157	5,954	1,315	36,724	8,810	5,955	65,766
2015	4,168	1,709	1,173	6,058	1,321	36,962	8,885	6,070	66,346
2016	4,172	1,709	1,184	6,131	1,322	37,070	8,928	6,155	66,672

2017	4,171	1,707	1,193	6,194	1,322	37,133	8,960	6,229	66,909
2018	4,166	1,702	1,199	6,248	1,321	37,156	8,981	6,295	67,069
2019	4,157	1,697	1,205	6,297	1,319	37,152	8,995	6,356	67,178
2020	4,136	1,686	1,206	6,319	1,313	37,035	8,981	6,390	67,066
2021	4,104	1,671	1,203	6,319	1,304	36,822	8,942	6,401	66,766
2022	4,058	1,651	1,194	6,290	1,291	36,489	8,873	6,385	66,231
2023	4,007	1,628	1,183	6,252	1,277	36,112	8,792	6,359	65,610
2024	3,952	1,603	1,170	6,204	1,261	35,693	8,702	6,324	64,909
2025	3,891	1,577	1,156	6,149	1,244	35,235	8,601	6,280	64,133
2026	3,830	1,550	1,142	6,091	1,227	34,766	8,498	6,236	63,338
2027	3,768	1,523	1,128	6,036	1,209	34,301	8,396	6,194	62,555
2028	3,706	1,495	1,113	5,981	1,191	33,830	8,293	6,151	61,760
2029	3,640	1,466	1,097	5,918	1,173	33,323	8,181	6,102	60,900
2030	3,572	1,436	1,081	5,853	1,153	32,805	8,067	6,051	60,019

Appendix 2.16 Customer Forecast – Low II Case – Firm Industrial

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009	36	7	10	86	4	318	95	39	595
2010	36	7	10	86	4	318	95	39	595
2011	36	7	10	86	4	318	95	39	595
2012	37	7	10	89	4	329	98	40	614
2013	38	7	11	92	4	339	101	42	634
2014	40	8	11	95	4	350	105	43	656
2015	40	8	11	96	4	355	106	44	664
2016	40	8	11	96	4	355	106	44	664
2017	40	8	11	96	4	355	106	44	664
2018	40	8	11	96	4	355	106	44	664
2019	40	8	11	96	4	355	106	44	664
2020	40	8	11	96	4	355	106	44	664
2021	40	8	11	96	4	355	106	44	664
2022	40	8	11	96	4	355	106	44	664
2023	40	8	11	96	4	355	106	44	664
2024	40	8	11	96	4	355	106	44	664
2025	40	8	11	96	4	355	106	44	664
2026	40	8	11	96	4	355	106	44	664
2027	40	8	11	96	4	355	106	44	664
2028	40	8	11	96	4	355	106	44	664
2029	40	8	11	96	4	355	106	44	664
2030	40	8	11	96	4	355	106	44	664

Appendix 2.17 Design Weather HDD Pattern – 65 degree based

Day	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA
11/1	15.4	16.4	17.4	19.3	15.4	17.4	17.9	17.9
11/2	17.4	9.4	15.4	11.4	11.9	12.4	12.9	18.8
11/3	11.4	8.9	14.4	9.9	10.4	10.4	12.9	13.0
11/4	12.9	10.4	16.9	16.3	12.9	12.4	16.4	11.5
11/5	17.4	12.4	16.9	15.9	14.4	14.9	16.9	14.5
11/6	20.4	12.4	18.4	19.3	16.4	16.4	19.4	16.4
11/7	18.9	13.9	21.9	25.2	19.9	20.4	23.3	18.9
11/8	20.4	12.4	23.8	19.3	17.4	17.4	17.4	20.4
11/9	18.9	17.9	22.3	26.7	18.4	21.4	22.3	18.5
11/10	22.9	20.8	24.8	25.8	22.3	22.8	25.8	27.8
11/11	26.3	25.8	33.3	31.2	27.3	28.8	29.8	29.9
11/12	30.8	24.3	33.8	30.2	24.8	28.8	29.8	29.4
11/13	27.3	19.8	30.8	26.2	21.3	23.3	24.8	26.4
11/14	24.8	23.8	30.3	28.2	22.8	24.8	27.8	30.3
11/15	26.8	21.3	30.8	25.7	20.3	24.8	24.8	27.4
11/16	27.8	24.3	31.3	31.6	20.8	28.8	29.8	28.4
11/17	28.3	23.8	33.3	32.1	20.8	26.8	29.3	30.9
11/18	30.8	24.8	29.8	34.0	22.3	29.8	32.7	30.3
11/19	32.3	24.3	33.8	36.0	22.8	27.8	34.2	31.4
11/20	33.8	13.4	33.8	30.5	14.9	24.3	24.8	28.9
11/21	26.3	20.8	29.8	29.1	15.4	22.8	26.8	25.0
11/22	29.3	25.3	32.8	30.6	16.9	27.8	30.8	28.4
11/23	29.3	16.9	34.8	24.2	16.9	26.8	25.8	30.9
11/24	20.9	18.4	32.8	24.7	16.4	22.8	21.8	27.0
11/25	20.4	19.8	30.8	19.3	19.4	23.3	20.8	24.5
11/26	24.3	16.4	30.3	18.3	15.4	18.4	17.9	21.1
11/27	20.9	21.3	23.8	21.3	16.9	22.8	23.8	21.4
11/28	22.4	20.3	26.3	30.6	20.3	23.8	26.8	24.4
11/29	26.3	15.4	30.3	20.7	15.4	19.9	19.4	25.0
11/30	19.9	12.4	30.3	19.3	13.9	19.9	19.8	23.0
12/1	21.9	14.4	26.3	24.2	12.4	19.9	24.8	21.0
12/2	23.8	17.9	27.8	15.3	15.4	22.3	18.4	22.5
12/3	18.4	18.4	26.3	21.2	14.9	22.8	25.3	23.4
12/4	26.3	16.9	27.3	25.2	13.4	22.8	24.8	24.4
12/5	26.8	17.4	27.3	26.6	13.9	25.3	25.3	24.9
12/6	26.3	19.3	29.8	28.6	14.9	26.3	28.8	26.9
12/7	30.8	21.8	30.3	31.5	18.9	27.3	31.8	26.9
12/8	32.8	27.8	30.8	27.2	23.3	27.8	31.8	30.3
12/9	30.8	21.8	31.3	23.3	18.9	24.3	23.3	30.8
12/10	24.3	23.3	24.8	26.2	21.3	23.8	24.3	24.8
12/11	25.3	26.3	29.3	30.7	22.8	28.8	30.3	24.9
12/12	31.3	28.3	37.2	30.6	24.8	31.8	30.8	29.0
12/13	31.3	25.3	38.2	24.2	21.8	33.3	28.8	31.5
12/14	25.8	20.3	39.2	17.8	16.9	24.8	22.8	32.9
12/15	18.4	20.8	29.8	18.8	18.9	22.3	20.3	24.5
12/16	19.9	15.4	28.8	17.3	13.9	17.9	16.4	24.0

12/17	18.9	23.3	27.3	24.7	18.4	24.8	26.8	17.6
12/18	25.3	21.3	29.8	31.1	19.4	25.3	28.8	25.9
12/19	27.8	21.8	30.3	23.2	17.9	23.8	24.8	24.5
12/20	24.3	19.3	25.8	22.7	17.4	24.8	22.3	24.9
12/21	25.8	18.4	32.8	20.8	15.9	25.8	23.3	28.9
12/22	23.4	15.4	34.3	17.3	13.9	25.8	16.9	28.9
12/23	21.4	16.9	32.3	22.8	15.4	26.3	19.4	24.0
12/24	22.4	21.3	30.8	24.7	18.9	20.9	22.3	25.9
12/25	25.8	16.4	29.3	26.2	14.4	23.3	25.8	23.5
12/26	25.3	20.3	32.3	28.2	15.9	23.8	23.3	24.0
12/27	26.8	20.8	33.3	24.7	12.4	21.8	20.8	25.5
12/28	19.4	15.9	29.3	25.7	15.4	21.8	24.8	23.5
12/29	25.8	19.8	29.8	23.3	15.4	23.8	29.3	26.4
12/30	26.8	15.4	30.3	19.7	10.4	21.8	20.8	25.9
12/31	20.4	16.9	29.3	17.8	12.9	23.3	15.9	23.5
1/1	17.4	20.3	28.3	24.2	17.1	24.8	23.8	23.0
1/2	24.8	13.9	28.3	26.1	9.9	20.9	23.3	27.4
1/3	27.3	18.4	28.3	23.7	12.9	25.8	25.3	25.4
1/4	26.3	12.4	30.3	14.3	9.4	19.4	17.9	27.9
1/5	14.4	19.3	26.8	15.9	16.9	18.9	17.4	19.1
1/6	16.4	20.8	23.8	26.6	18.9	22.3	23.3	21.9
1/7	26.3	14.4	23.8	26.1	15.4	18.9	24.3	23.9
1/8	25.3	21.3	29.3	24.7	12.9	24.8	22.8	20.6
1/9	24.8	21.3	29.8	27.7	19.4	25.8	27.8	29.8
1/10	26.8	18.4	30.8	25.7	16.9	22.3	24.8	27.9
1/11	28.8	20.3	29.8	22.8	16.4	20.9	20.8	22.0
1/12	19.9	20.3	28.8	20.3	17.9	21.4	19.8	20.6
1/13	19.4	23.8	23.8	21.3	19.4	23.8	23.3	23.4
1/14	22.4	22.3	28.8	23.3	20.3	24.3	21.3	25.9
1/15	23.4	25.8	28.3	27.2	20.8	27.3	30.3	25.4
1/16	31.3	26.3	29.3	32.6	22.8	29.8	32.3	29.8
1/17	33.3	28.3	31.3	32.6	22.3	30.8	33.7	32.8
1/18	32.8	18.9	31.8	24.7	17.4	25.3	25.3	28.4
1/19	25.3	19.3	31.3	19.8	15.4	23.3	20.3	23.5
1/20	22.9	18.4	31.8	26.7	15.4	25.3	27.8	24.0
1/21	27.3	17.4	31.3	19.8	17.9	24.8	19.8	23.0
1/22	19.9	16.9	29.8	23.7	10.9	21.4	19.4	22.5
1/23	18.9	19.3	28.8	27.2	13.9	21.4	22.3	22.0
1/24	21.9	23.3	29.8	24.7	17.9	24.3	23.3	27.9
1/25	26.3	21.8	29.3	25.2	21.3	23.8	28.8	24.9
1/26	25.8	22.8	27.8	24.7	16.9	22.3	24.3	26.4
1/27	23.8	23.3	27.8	29.6	19.4	26.8	27.3	26.9
1/28	28.3	25.3	28.8	27.2	21.3	28.3	28.8	21.5
1/29	27.8	20.3	30.8	23.3	19.4	20.9	22.3	22.5
1/30	29.3	17.4	27.8	23.3	20.8	21.8	21.3	25.4
1/31	28.3	21.8	26.8	28.7	17.4	22.8	28.3	24.4
2/1	26.8	18.9	22.8	23.2	16.9	21.8	23.3	22.4
2/2	39.5	44.5	46.0	43.9	41.0	50.5	47.5	41.6
2/3	52.0	50.0	60.0	52.3	48.5	53.0	54.0	53.6
2/4	54.5	44.0	62.0	49.9	45.5	44.5	51.5	54.7
2/5	20.4	20.3	18.9	22.8	19.9	23.8	24.3	23.7
2/6	24.8	25.3	25.3	27.7	22.3	25.8	26.3	31.2
2/7	29.8	28.3	31.8	31.2	26.3	30.3	32.3	27.9

2/8	31.3	25.8	29.3	31.2	24.8	28.3	30.8	28.3
2/9	29.3	23.8	30.8	25.2	19.4	25.8	23.3	28.9
2/10	24.8	27.8	32.3	24.8	22.3	31.8	30.8	31.3
2/11	26.8	23.3	32.3	27.8	23.8	24.3	24.3	27.9
2/12	28.3	25.8	31.3	29.2	24.8	24.8	26.8	27.4
2/13	27.8	25.8	28.3	27.7	23.3	23.3	26.3	24.9
2/14	24.3	24.8	28.3	25.7	19.9	23.3	23.3	23.0
2/15	21.4	20.8	25.8	21.8	20.3	22.3	20.3	25.4
2/16	20.9	18.4	26.8	18.3	15.9	23.3	19.4	24.9
2/17	18.9	20.3	31.8	26.2	19.4	21.8	22.8	23.0
2/18	25.3	19.8	31.8	20.3	16.4	22.8	19.8	24.0
2/19	20.9	17.4	26.3	23.7	14.9	23.3	19.8	22.9
2/20	22.4	16.9	26.8	25.7	13.9	18.9	22.3	18.1
2/21	21.9	19.3	21.4	17.4	16.9	19.9	15.9	20.9
2/22	19.9	19.8	26.3	24.3	20.8	19.9	22.3	19.5
2/23	22.9	22.3	27.8	20.8	20.3	20.9	22.8	22.5
2/24	23.4	22.3	26.3	21.8	18.9	20.4	22.8	23.9
2/25	23.8	23.8	23.8	22.8	23.3	22.8	23.8	24.3
2/26	22.9	22.8	24.3	25.7	21.8	20.9	22.3	22.9
2/27	20.9	18.4	27.3	23.7	17.4	19.9	21.3	23.0
2/28	21.9	23.8	27.3	26.2	19.9	22.8	26.3	22.0
2/29	21.9	23.8	27.3	26.2	19.9	22.8	26.3	22.0
3/1	22.4	21.3	24.3	24.2	19.9	21.8	25.3	23.9
3/2	24.8	22.3	26.3	25.3	18.4	22.3	23.8	25.8
3/3	24.8	24.3	26.8	26.7	20.8	22.8	25.3	24.9
3/4	24.3	20.8	22.8	24.2	18.9	23.3	24.3	20.9
3/5	22.9	13.4	25.8	17.8	14.4	15.4	14.9	17.1
3/6	13.9	9.9	22.3	15.3	6.0	12.4	10.9	13.1
3/7	11.9	16.4	17.4	10.5	15.9	10.4	11.4	12.0
3/8	8.9	18.4	12.9	17.9	17.9	18.4	17.4	20.2
3/9	20.4	18.4	20.4	20.3	14.9	19.4	23.3	21.3
3/10	21.9	18.4	19.9	20.3	17.4	20.9	23.8	23.3
3/11	19.4	17.9	20.9	20.3	17.4	19.9	19.8	19.4
3/12	20.9	16.4	17.4	17.8	20.3	14.4	16.4	16.9
3/13	14.9	17.9	17.4	16.9	18.9	14.4	15.4	16.9
3/14	17.9	21.8	15.4	18.3	15.9	15.9	18.4	18.3
3/15	17.9	20.3	17.9	22.8	17.9	20.4	21.8	23.2
3/16	23.4	24.3	23.8	25.2	21.3	23.3	24.8	20.9
3/17	24.3	18.4	23.3	17.4	18.9	18.4	18.4	16.5
3/18	15.4	15.9	17.9	8.5	14.9	10.9	8.9	16.9
3/19	15.4	19.8	14.9	19.3	18.9	17.9	18.9	21.7
3/20	19.9	21.8	23.3	20.3	21.8	18.4	18.9	18.5
3/21	17.9	22.8	19.9	19.8	21.8	15.4	17.9	19.9
3/22	19.9	21.8	17.4	18.4	20.8	14.9	17.9	16.4
3/23	16.9	19.8	13.4	11.9	15.4	13.4	15.4	11.0
3/24	12.4	10.4	10.9	13.8	8.9	10.4	14.4	9.5
3/25	10.9	16.4	10.4	16.9	10.9	12.9	15.4	14.8
3/26	19.4	18.9	13.9	19.3	17.4	15.4	17.4	23.2
3/27	19.9	18.9	21.4	20.8	18.9	18.9	20.3	18.0
3/28	18.9	19.8	18.9	13.4	16.4	16.4	16.4	22.3
3/29	17.9	20.3	17.9	14.4	19.9	18.4	16.4	15.5
3/30	12.4	16.4	14.4	13.9	13.4	12.9	14.4	14.4
3/31	9.9	17.9	15.4	16.8	15.9	12.9	15.9	15.4

4/1	16.4	18.7	17.1	16.7	16.8	15.1	16.5	17.1
4/2	16.3	18.7	17.2	16.7	18.7	15.1	16.6	16.6
4/3	16.3	18.1	16.7	16.3	17.2	14.7	16.3	16.7
4/4	16.7	18.2	16.8	16.1	18.0	14.8	16.3	16.7
4/5	16.4	17.9	16.8	16.3	17.4	14.7	16.4	16.6
4/6	16.2	16.8	16.9	14.7	15.9	12.8	15.1	16.1
4/7	14.2	16.9	15.5	15.0	15.7	13.7	15.3	14.8
4/8	15.2	17.3	16.4	15.4	16.1	14.1	15.8	15.4
4/9	15.7	16.7	16.2	15.2	15.6	14.6	15.4	15.3
4/10	15.5	16.6	16.4	14.7	15.3	13.2	14.4	15.4
4/11	14.8	15.4	16.8	13.6	13.9	12.5	13.6	15.0
4/12	13.9	15.3	14.7	13.5	14.4	12.3	13.9	14.2
4/13	14.5	16.3	13.9	13.8	15.6	12.6	14.0	14.1
4/14	14.8	16.3	15.0	14.7	15.5	13.0	14.8	14.3
4/15	14.6	15.4	15.0	14.1	14.8	12.3	13.8	14.8
4/16	13.7	15.1	14.2	13.8	14.9	11.9	13.7	13.2
4/17	13.8	16.1	13.9	14.5	15.0	12.6	14.4	13.0
4/18	14.2	16.9	13.3	14.1	15.6	12.6	14.5	15.0
4/19	16.0	16.4	15.2	14.4	16.0	12.8	14.8	16.1
4/20	14.5	16.5	13.9	14.0	15.8	11.7	13.5	14.3
4/21	13.6	16.6	12.6	14.5	15.7	12.6	14.8	13.4
4/22	14.5	16.0	13.9	14.2	15.5	12.3	14.0	14.7
4/23	13.9	15.7	14.1	14.5	14.7	12.3	14.0	14.3
4/24	14.6	15.0	14.3	13.4	14.6	11.4	12.8	14.3
4/25	13.1	14.0	13.1	13.0	13.7	10.7	12.8	13.1
4/26	13.1	14.0	12.5	12.5	13.1	10.9	12.7	12.4
4/27	13.0	14.0	12.2	12.8	14.2	10.0	12.6	12.6
4/28	12.1	13.4	11.2	12.2	12.5	9.5	11.4	11.6
4/29	11.4	13.5	11.6	11.5	13.5	9.3	11.2	10.8
4/30	11.1	14.3	11.1	12.2	13.5	8.7	11.8	10.6
5/1	11.7	14.4	10.0	11.9	14.0	9.6	11.3	10.4
5/2	11.0	13.8	10.6	11.1	13.0	8.8	10.9	11.3
5/3	11.3	13.0	11.6	11.2	13.0	9.3	10.9	11.3
5/4	10.5	12.2	10.2	10.3	12.9	7.9	9.3	10.6
5/5	9.6	12.4	9.6	10.1	11.6	7.9	9.9	8.8
5/6	10.2	12.9	9.1	11.0	12.8	8.6	10.5	10.1
5/7	10.6	13.5	10.4	11.3	12.9	9.3	10.7	11.2
5/8	12.3	14.5	11.2	12.1	14.2	10.0	12.3	11.5
5/9	12.1	14.7	11.0	13.0	14.3	10.7	12.1	12.1
5/10	12.5	13.9	11.1	11.9	14.2	9.2	10.9	11.3
5/11	11.0	12.7	9.1	11.2	13.2	9.0	10.0	11.1
5/12	10.8	13.4	9.6	11.7	13.6	8.5	10.3	10.9
5/13	10.3	12.3	10.2	10.1	12.8	7.7	8.8	10.6
5/14	9.2	11.4	8.6	8.8	12.3	5.6	7.6	8.9
5/15	7.4	11.3	6.5	8.2	11.4	5.9	7.4	7.5
5/16	8.7	11.6	7.5	9.2	11.8	6.3	8.0	7.9
5/17	8.1	11.8	7.3	9.6	12.2	7.5	8.5	7.6
5/18	9.6	11.2	8.0	9.0	11.1	6.3	8.2	9.2
5/19	8.7	11.2	7.5	9.2	11.4	6.4	8.1	7.5
5/20	9.0	11.6	7.9	9.7	11.3	7.2	9.0	8.3
5/21	9.3	11.4	8.0	9.7	11.2	6.7	8.6	8.1
5/22	8.9	10.7	7.6	8.8	10.5	5.7	7.4	7.7
5/23	7.8	10.2	7.7	7.6	11.0	5.7	7.1	7.8

5/24	7.0	9.5	7.1	7.2	10.6	3.9	5.8	7.4
5/25	6.2	9.7	4.7	7.0	10.5	5.0	6.7	6.6
5/26	6.8	10.2	5.9	7.0	9.9	4.3	5.7	5.9
5/27	6.3	9.4	5.0	7.4	9.5	5.1	6.7	6.0
5/28	6.9	9.8	6.1	8.3	9.8	5.7	7.3	6.0
5/29	7.5	9.2	7.3	7.5	9.9	5.8	6.8	7.5
5/30	7.7	9.2	7.5	6.4	9.8	4.0	5.6	7.0
5/31	6.1	9.4	4.9	6.5	9.4	3.7	5.5	5.7
6/1	5.5	8.7	4.7	5.9	10.0	4.1	5.6	5.6
6/2	6.4	9.0	4.7	6.3	10.0	3.5	5.0	6.1
6/3	5.8	9.1	4.4	5.8	10.3	3.1	4.5	5.2
6/4	4.7	8.7	3.4	5.2	9.3	4.0	5.5	5.2
6/5	5.6	8.7	5.3	6.8	9.8	5.1	6.9	5.8
6/6	6.7	9.7	6.1	7.2	9.8	5.3	6.5	6.8
6/7	7.6	9.2	6.2	7.3	9.5	4.9	6.3	6.6
6/8	6.6	8.7	6.0	6.6	9.6	3.9	5.5	6.8
6/9	5.8	9.5	4.9	7.2	9.6	4.1	5.8	5.2
6/10	6.9	9.7	5.5	7.3	9.5	4.6	6.5	6.0
6/11	6.2	9.4	5.7	7.3	9.5	4.9	6.1	5.6
6/12	7.3	8.5	5.8	6.8	9.9	3.8	6.0	6.6
6/13	6.2	8.3	4.3	5.9	8.6	3.3	4.9	5.1
6/14	5.8	8.3	4.5	5.5	9.4	3.4	4.4	5.0
6/15	5.5	8.2	4.6	6.1	9.1	3.3	4.7	5.8
6/16	5.8	7.6	5.0	5.7	8.5	3.6	4.6	5.1
6/17	6.1	8.1	4.7	6.1	8.6	3.6	5.0	5.6
6/18	5.6	8.3	4.5	6.0	9.0	3.1	4.7	5.6
6/19	5.4	8.0	5.2	4.8	8.8	2.8	3.4	6.3
6/20	4.1	7.9	3.8	3.6	8.5	2.1	2.8	4.0
6/21	2.7	7.3	2.3	3.8	8.2	2.7	2.9	2.8
6/22	3.6	7.4	2.9	5.2	7.8	2.5	3.9	3.2
6/23	4.4	6.9	3.5	4.7	8.2	2.0	3.4	4.5
6/24	4.2	6.7	3.3	4.3	8.2	2.4	3.6	4.3
6/25	3.7	6.2	3.2	3.6	7.9	1.8	2.7	4.1
6/26	3.2	5.7	1.9	3.2	6.8	1.6	2.4	2.7
6/27	2.8	5.4	3.0	2.6	7.2	1.2	2.2	3.0
6/28	2.0	5.5	1.6	2.3	6.5	1.6	2.2	1.8
6/29	2.6	5.9	1.9	2.4	7.1	0.9	1.7	2.7
6/30	2.5	6.5	1.4	1.9	7.2	0.8	1.6	2.4
7/1	2.4	6.1	1.2	2.1	6.8	1.4	2.0	1.9
7/2	2.7	6.4	2.5	2.0	7.5	1.6	1.7	4.0
7/3	2.1	6.0	2.7	2.6	6.5	1.3	2.3	2.3
7/4	2.1	6.2	1.2	1.8	6.6	1.4	1.8	2.2
7/5	1.8	5.0	2.4	1.6	6.4	0.6	1.3	2.7
7/6	1.7	5.9	1.0	1.2	6.5	0.3	1.2	2.0
7/7	1.6	5.8	1.3	0.8	7.1	0.3	0.8	3.0
7/8	1.0	5.2	0.8	0.7	6.8	0.5	1.0	0.8
7/9	1.1	4.6	1.0	1.4	6.3	0.7	1.4	1.2
7/10	1.6	5.0	1.4	0.7	6.5	0.4	0.8	1.8
7/11	1.2	4.8	1.6	0.7	7.5	0.2	0.5	2.0
7/12	0.7	4.0	0.5	0.4	6.8	0.2	0.5	0.9
7/13	0.6	3.4	0.6	0.4	6.0	0.0	0.5	0.7
7/14	0.7	3.8	0.6	0.9	5.8	0.3	0.5	1.0
7/15	0.9	4.8	1.2	0.6	5.9	0.5	0.4	0.9

7/16	0.5	4.3	0.5	0.9	6.8	0.6	0.8	1.4
7/17	1.0	3.8	1.3	1.2	6.1	0.8	0.7	1.6
7/18	1.2	4.4	1.9	0.7	5.6	0.4	0.5	1.9
7/19	0.7	3.5	0.7	0.6	6.0	0.2	0.2	1.1
7/20	0.6	4.0	0.8	0.5	5.9	0.3	0.5	0.7
7/21	0.6	2.9	0.5	0.4	5.7	0.0	0.3	0.8
7/22	0.5	3.5	1.1	0.7	5.8	0.3	0.5	0.5
7/23	0.8	3.0	0.8	0.4	6.3	0.1	0.2	0.6
7/24	0.6	3.6	0.8	0.3	6.6	0.3	0.2	0.9
7/25	0.6	3.9	0.8	0.2	6.2	0.1	0.1	1.0
7/26	0.5	3.8	0.5	0.2	6.1	0.1	0.2	0.7
7/27	0.4	3.6	0.3	0.1	6.7	0.0	0.1	0.3
7/28	0.2	4.0	0.5	0.4	6.3	0.3	0.3	0.6
7/29	0.5	3.9	0.2	1.2	6.5	0.5	1.0	0.7
7/30	1.7	4.6	0.8	0.9	7.1	0.0	0.5	1.5
7/31	0.7	5.3	1.2	0.7	7.2	0.2	0.5	1.7
8/1	0.6	4.5	0.5	0.8	6.0	0.4	0.7	0.9
8/2	0.5	4.0	0.6	0.6	6.4	0.3	0.3	1.3
8/3	0.8	3.6	1.1	0.9	6.8	0.0	0.8	1.1
8/4	0.4	3.2	0.6	0.6	5.9	0.1	0.6	0.9
8/5	1.2	4.5	0.8	0.6	5.9	0.2	0.4	0.6
8/6	0.7	4.3	0.7	0.7	6.5	0.2	0.4	1.1
8/7	0.5	4.1	0.8	1.1	6.4	0.2	0.8	1.1
8/8	1.2	4.0	1.3	0.5	5.7	0.0	0.3	0.6
8/9	0.5	3.4	0.8	0.1	6.2	0.0	0.1	0.4
8/10	0.7	4.3	0.7	0.8	6.3	0.2	0.5	1.2
8/11	1.1	3.6	1.2	0.7	5.9	0.1	0.6	1.7
8/12	1.1	3.7	0.7	0.9	6.0	0.3	0.8	1.1
8/13	0.7	3.0	0.7	0.5	6.3	0.2	0.5	1.3
8/14	0.5	3.9	0.3	0.4	5.5	0.2	0.2	1.0
8/15	0.8	3.9	0.9	0.8	6.3	0.2	0.6	1.4
8/16	0.6	3.2	0.5	0.9	6.0	0.5	0.9	1.8
8/17	1.4	4.5	1.3	1.2	5.9	0.4	1.0	1.6
8/18	1.3	4.0	1.4	1.6	5.5	0.5	1.1	1.3
8/19	1.5	4.0	1.8	0.9	6.0	0.3	0.7	1.4
8/20	0.6	4.1	0.9	0.9	5.7	0.2	0.5	0.8
8/21	1.0	4.5	1.2	1.0	5.4	0.4	1.1	1.1
8/22	1.2	4.3	1.4	0.7	6.0	0.4	0.7	1.4
8/23	1.3	4.6	1.3	1.3	6.0	0.7	1.0	2.7
8/24	2.6	4.2	3.0	1.6	6.6	1.0	1.9	3.5
8/25	1.8	4.3	2.9	1.5	6.5	0.5	1.3	2.2
8/26	1.2	4.6	1.7	1.1	6.5	0.1	0.8	1.9
8/27	1.0	4.1	1.7	1.5	6.1	0.5	1.0	1.8
8/28	1.1	4.0	2.2	0.3	5.8	0.2	0.5	2.1
8/29	0.4	3.9	1.2	1.2	5.8	0.5	1.0	1.8
8/30	1.8	4.1	1.2	1.3	5.9	0.8	1.4	2.1
8/31	1.9	4.8	2.3	1.9	6.4	1.0	2.0	1.7
9/1	2.1	5.5	2.8	1.9	6.6	1.1	2.0	3.0
9/2	1.9	5.5	2.9	1.9	7.0	1.0	2.0	3.0
9/3	2.1	4.9	2.6	1.9	6.4	0.8	1.8	2.4
9/4	2.3	5.2	2.5	1.8	6.6	1.1	1.8	2.3
9/5	2.5	5.8	2.1	2.7	7.1	1.5	2.3	3.0
9/6	3.1	5.6	3.1	2.9	7.7	1.4	2.5	3.4

9/7	2.4	5.8	3.2	2.8	7.0	1.0	1.9	3.4
9/8	1.9	4.9	3.1	2.4	7.0	1.3	1.9	3.1
9/9	2.2	5.1	3.3	2.3	7.0	1.1	2.1	3.5
9/10	2.6	5.7	3.9	1.9	8.0	1.1	1.9	3.7
9/11	1.6	5.3	2.8	1.3	6.9	0.8	1.5	2.4
9/12	2.3	5.6	2.6	2.3	7.5	1.1	2.3	2.5
9/13	2.5	5.9	3.8	3.0	7.8	1.7	2.5	3.8
9/14	2.6	7.0	3.9	2.7	7.7	2.1	2.8	3.4
9/15	2.6	6.5	3.7	3.0	7.7	2.6	3.4	3.4
9/16	3.5	6.7	4.2	3.5	8.1	3.0	3.8	5.2
9/17	3.8	6.8	5.0	4.5	8.0	2.5	3.7	4.7
9/18	5.2	7.0	5.4	5.0	7.8	3.5	5.0	5.9
9/19	4.9	7.6	5.8	4.9	8.9	3.2	4.3	5.6
9/20	5.1	7.7	6.0	5.2	9.5	3.1	5.0	6.1
9/21	5.0	6.3	6.9	4.8	8.2	2.7	3.8	6.1
9/22	3.9	6.8	6.6	4.4	7.7	2.9	4.3	5.9
9/23	3.9	8.0	6.6	4.2	8.7	2.7	3.6	5.2
9/24	4.7	7.2	5.6	4.9	8.6	3.3	4.7	4.9
9/25	4.0	6.9	4.5	4.8	9.5	3.2	4.5	4.8
9/26	4.8	7.1	5.6	4.5	8.7	2.8	4.2	5.6
9/27	4.3	7.4	5.7	4.3	8.8	2.5	3.6	5.2
9/28	4.3	8.0	5.3	4.2	8.4	2.3	3.4	5.1
9/29	3.2	7.3	5.0	4.7	9.0	2.6	4.0	4.0
9/30	3.9	8.0	4.9	5.0	8.4	3.1	4.4	5.0
10/1	5.5	9.4	6.2	7.7	10.7	4.9	6.3	6.7
10/2	7.5	10.5	8.0	8.1	11.6	6.1	7.8	7.6
10/3	7.6	10.4	10.1	8.3	10.3	6.1	7.5	8.3
10/4	8.1	10.2	9.9	8.8	9.8	5.9	7.9	8.9
10/5	8.5	10.9	10.5	8.5	10.3	6.9	8.4	10.0
10/6	8.3	9.5	10.8	8.2	9.5	6.5	7.9	9.1
10/7	8.8	10.7	10.6	8.9	10.3	7.2	8.8	9.7
10/8	9.3	10.8	11.2	9.5	9.8	8.1	9.8	10.6
10/9	10.0	10.4	11.1	9.6	10.1	8.2	9.9	10.7
10/10	10.0	11.9	12.0	11.6	11.6	9.3	11.3	11.1
10/11	12.3	12.2	13.4	11.9	10.9	9.8	11.9	12.9
10/12	11.6	11.3	13.2	10.3	12.0	8.5	9.9	11.4
10/13	10.2	11.2	11.9	10.8	10.9	8.6	9.7	10.6
10/14	10.7	11.8	11.9	11.9	11.6	9.9	11.6	12.2
10/15	11.7	11.7	14.2	12.8	11.5	10.1	11.9	13.2
10/16	12.1	12.5	14.7	11.9	11.5	9.9	11.7	12.3
10/17	12.1	12.4	15.6	12.1	11.7	10.5	11.9	12.5
10/18	12.0	12.9	15.0	12.7	12.7	11.1	12.8	12.9
10/19	12.7	11.0	15.8	11.4	10.9	9.3	10.7	13.1
10/20	11.1	11.4	14.1	12.6	11.0	9.9	11.4	12.0
10/21	11.9	11.8	14.8	13.5	10.9	10.8	13.0	12.9
10/22	14.0	13.1	16.1	13.4	12.3	10.8	12.8	13.8
10/23	13.8	13.0	16.2	13.9	12.0	11.8	14.3	13.7
10/24	14.5	15.0	17.0	14.0	13.5	12.8	14.1	14.5
10/25	14.1	14.3	17.5	14.9	12.3	12.5	14.2	15.3
10/26	14.6	14.2	18.0	15.2	13.1	13.2	14.4	15.1
10/27	14.7	15.7	18.5	16.4	13.2	14.0	15.7	16.2
10/28	15.7	16.6	18.3	15.9	14.8	14.8	15.7	16.6
10/29	16.3	16.8	19.0	17.5	14.6	15.3	17.4	17.2

10/30	17.7	16.9	21.4	18.4	15.3	16.3	18.1	18.0
10/31	18.3	17.1	22.3	18.4	15.5	16.9	18.2	18.8

Appendix 2.18 Average Weather HDD Pattern – 65 degree based – 20 Gas Years (1988/89 – 2007/08)

Day	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA
11/1	17.8	17.9	22.6	19.8	15.3	17.4	18.6	19.5
11/2	19.0	18.4	23.0	19.2	15.9	17.7	19.1	20.2
11/3	19.2	16.6	22.6	17.6	15.9	16.4	17.3	19.8
11/4	16.9	16.4	20.7	17.1	15.1	15.6	16.4	17.7
11/5	17.3	16.4	20.9	16.2	15.3	16.1	16.6	18.0
11/6	16.8	15.6	20.5	17.3	14.7	16.5	17.1	17.8
11/7	17.1	15.4	20.6	18.4	13.9	16.7	17.9	18.0
11/8	18.0	16.4	21.0	18.4	14.7	17.0	18.5	17.9
11/9	18.7	16.1	20.0	18.1	14.1	15.6	18.0	18.0
11/10	18.0	16.4	20.6	18.2	14.3	16.2	17.6	18.0
11/11	18.3	16.4	20.9	17.7	14.9	15.5	17.3	17.8
11/12	17.5	16.1	20.7	15.8	13.8	15.9	16.4	17.2
11/13	17.4	15.9	20.4	17.2	14.4	15.5	16.9	17.7
11/14	17.7	16.9	21.3	18.2	14.7	16.6	17.8	18.9
11/15	17.8	16.0	21.0	17.7	14.2	16.6	17.6	17.6
11/16	18.3	17.8	21.6	19.2	16.0	17.7	19.0	18.9
11/17	19.0	18.3	22.6	19.1	15.8	17.4	18.3	19.5
11/18	20.0	19.0	22.1	22.1	16.5	19.6	21.4	20.6
11/19	21.7	17.7	23.2	21.1	17.3	19.6	20.6	20.8
11/20	21.4	18.4	24.3	21.3	16.3	18.7	19.6	21.5
11/21	20.5	19.7	23.3	21.7	16.9	20.4	21.6	21.1
11/22	21.7	20.3	24.9	22.4	18.2	21.2	22.2	22.5
11/23	22.5	19.2	25.1	21.4	17.5	20.4	21.6	22.8
11/24	21.4	19.4	25.2	20.7	18.0	20.0	20.5	22.0
11/25	21.0	19.9	25.8	20.8	18.2	20.2	20.0	22.1
11/26	22.1	20.8	26.1	23.1	18.5	22.1	22.8	23.4
11/27	23.3	20.4	27.4	22.3	18.4	22.2	22.1	24.4
11/28	22.5	19.7	26.8	23.3	18.3	22.0	23.1	23.4
11/29	22.9	20.1	26.5	22.5	18.0	21.7	22.4	22.6
11/30	22.9	19.9	26.3	21.3	17.9	21.2	21.5	23.6
12/1	22.1	19.5	25.7	22.1	18.2	21.3	22.1	22.9
12/2	22.5	20.2	26.3	22.8	18.2	21.8	22.9	23.3
12/3	23.8	20.3	27.8	23.5	18.9	22.4	22.8	25.0
12/4	23.3	20.2	27.4	23.2	18.0	22.6	23.4	23.5
12/5	24.1	21.0	27.9	23.5	18.6	23.1	23.7	24.6
12/6	24.1	21.1	28.1	23.8	18.4	23.0	23.6	25.3
12/7	24.1	21.9	28.7	23.3	18.0	23.7	23.6	25.1
12/8	24.0	21.0	29.1	23.3	19.1	22.8	24.0	25.0
12/9	24.7	19.9	28.1	22.7	18.5	23.2	22.9	24.3
12/10	23.0	19.9	27.7	21.9	17.9	21.5	21.5	23.0
12/11	22.4	20.6	27.4	22.7	18.4	21.7	22.5	22.6
12/12	22.8	20.3	27.3	22.1	18.2	21.1	21.6	23.0
12/13	22.5	21.1	25.8	23.6	18.2	22.9	24.1	22.7
12/14	24.5	20.9	27.1	23.5	19.1	22.9	23.5	24.0
12/15	24.3	21.7	27.8	24.6	19.5	23.8	24.8	24.9
12/16	24.5	21.3	28.5	24.2	19.1	22.8	23.8	25.8
12/17	24.8	21.9	27.9	25.1	19.5	23.4	25.4	24.0

12/18	26.3	23.6	29.3	26.8	20.8	25.4	26.9	26.5
12/19	27.5	22.7	30.4	26.1	20.8	25.2	26.8	27.3
12/20	27.0	23.3	30.8	25.9	20.8	26.1	26.5	26.7
12/21	27.0	24.0	31.5	26.7	21.7	26.3	26.4	28.1
12/22	26.8	23.4	31.6	26.8	20.3	25.9	26.6	28.2
12/23	26.9	22.4	31.5	26.7	19.5	25.5	26.3	28.0
12/24	26.1	22.4	30.7	25.9	19.4	25.2	25.9	26.6
12/25	26.2	22.5	31.5	26.1	19.4	24.9	25.6	26.6
12/26	25.8	22.6	30.7	24.9	19.1	25.4	24.7	26.6
12/27	24.8	21.3	30.1	23.7	18.5	23.4	22.8	25.7
12/28	24.2	22.4	29.0	24.8	19.7	25.1	25.5	25.7
12/29	25.5	22.7	30.2	25.9	20.9	25.7	26.1	27.4
12/30	26.2	21.5	31.2	24.3	19.6	25.4	24.6	26.7
12/31	25.3	21.3	31.0	24.0	19.0	24.3	23.1	26.3
1/1	24.3	20.3	28.8	23.6	18.8	22.7	23.4	24.7
1/2	23.8	20.5	28.5	23.7	18.9	22.5	22.6	24.6
1/3	23.3	21.2	27.9	22.7	18.9	22.8	22.5	24.3
1/4	23.4	21.6	29.0	24.5	18.8	23.5	24.0	24.5
1/5	25.3	23.5	30.3	25.7	20.8	25.4	26.1	25.5
1/6	26.1	22.4	31.0	24.7	20.5	25.8	24.4	27.1
1/7	24.4	20.6	29.7	22.9	18.2	23.6	23.3	26.0
1/8	23.4	20.9	28.9	22.5	18.5	23.5	23.3	25.2
1/9	22.7	21.0	29.0	22.8	19.1	23.0	23.2	24.6
1/10	23.5	21.4	28.0	22.9	18.7	23.5	22.9	24.4
1/11	23.8	22.2	28.7	24.1	19.3	24.6	24.6	25.3
1/12	24.3	21.9	29.6	23.8	20.6	24.6	24.2	26.2
1/13	23.9	21.8	29.7	23.7	20.1	24.1	23.9	24.9
1/14	23.6	21.9	29.6	23.4	19.2	23.5	23.4	25.2
1/15	24.6	22.5	29.0	25.1	20.5	24.5	24.9	25.5
1/16	25.2	22.7	29.8	24.7	21.0	24.4	25.4	26.3
1/17	25.4	22.0	29.9	25.0	19.0	24.9	24.6	27.3
1/18	24.6	20.5	29.2	23.0	18.2	22.8	23.3	25.3
1/19	23.6	20.6	28.6	23.3	17.8	23.9	23.0	24.8
1/20	23.4	20.6	28.2	23.5	18.1	22.8	23.2	24.4
1/21	24.2	21.5	28.2	23.4	19.5	23.6	23.8	24.4
1/22	23.8	21.5	28.3	23.5	19.8	23.4	23.3	25.4
1/23	22.9	20.7	28.4	24.3	19.0	23.0	23.4	24.8
1/24	24.0	21.8	27.5	24.5	19.2	23.1	24.1	24.8
1/25	24.8	22.1	27.3	23.8	19.4	23.9	24.2	25.0
1/26	24.3	22.6	28.1	24.1	20.1	23.4	23.7	25.5
1/27	24.2	21.9	28.4	23.5	20.6	23.9	24.1	24.9
1/28	24.3	20.9	27.7	22.2	18.7	22.2	22.4	24.3
1/29	22.5	20.3	26.9	21.6	17.8	22.1	21.6	22.9
1/30	22.8	20.3	26.6	22.5	19.3	22.0	21.8	23.6
1/31	22.3	20.5	27.0	22.7	18.2	21.9	22.0	23.1
2/1	23.0	20.8	27.6	23.1	19.1	23.3	23.1	23.1
2/2	23.6	21.8	28.5	22.5	19.8	23.4	23.5	25.0
2/3	23.7	21.9	29.0	24.1	19.7	23.8	24.4	25.3
2/4	24.4	20.6	28.7	24.0	18.1	23.0	23.7	25.5
2/5	24.6	21.7	27.9	24.9	19.3	23.3	24.5	24.7
2/6	24.4	20.5	29.4	23.8	17.7	22.4	22.7	24.4
2/7	23.1	21.0	27.8	24.0	18.2	22.4	24.0	23.3
2/8	23.8	21.3	28.2	23.8	19.5	21.9	23.7	24.5

2/9	24.2	21.4	27.0	22.7	19.0	21.4	22.4	24.3
2/10	22.6	20.1	25.9	23.2	18.9	21.5	23.2	23.1
2/11	23.3	20.3	25.4	22.4	17.9	21.0	21.3	23.4
2/12	22.4	20.0	26.4	22.0	18.4	21.4	21.4	22.7
2/13	22.3	22.5	25.7	23.2	19.5	22.7	23.2	23.8
2/14	24.1	23.0	26.2	23.1	20.4	22.6	22.9	24.0
2/15	22.9	20.4	26.6	21.5	19.4	20.9	21.5	23.4
2/16	21.2	20.8	25.7	21.7	18.5	21.3	21.6	22.8
2/17	21.2	20.9	25.9	21.4	19.0	21.1	21.4	22.9
2/18	21.2	20.9	26.5	20.1	18.9	20.8	20.3	22.7
2/19	20.7	20.8	25.7	20.1	18.1	20.9	20.7	22.3
2/20	21.2	20.5	24.8	20.7	18.7	20.9	20.9	21.7
2/21	20.6	20.1	23.6	19.7	18.4	19.4	19.3	21.8
2/22	19.9	20.0	22.6	20.5	17.8	18.7	20.1	20.9
2/23	20.8	21.3	23.6	20.7	17.9	20.5	21.0	21.4
2/24	21.3	21.2	24.3	21.3	18.0	21.1	21.6	22.5
2/25	20.7	20.5	24.9	20.9	17.3	21.2	21.6	22.9
2/26	21.0	20.3	24.9	21.4	18.2	21.0	21.3	22.8
2/27	21.0	19.8	25.2	20.3	17.6	20.5	20.5	22.4
2/28	20.0	20.1	24.7	20.1	18.1	19.9	20.3	21.4
2/29	18.5	17.7	21.8	19.8	15.0	17.6	19.4	19.6
3/1	20.1	19.8	24.7	19.7	17.7	20.2	19.9	22.2
3/2	19.8	20.9	24.9	21.3	18.5	21.3	21.5	21.2
3/3	21.6	20.1	24.8	19.7	19.1	20.0	19.6	22.1
3/4	18.9	20.6	22.4	20.2	18.9	20.4	20.7	20.5
3/5	21.3	19.6	23.6	19.3	18.2	19.3	19.4	21.2
3/6	19.5	19.6	22.6	18.8	18.1	18.2	18.6	20.3
3/7	18.3	20.1	21.5	18.7	18.9	18.4	19.3	19.3
3/8	19.2	18.8	21.4	17.8	17.4	18.0	18.2	20.6
3/9	18.5	18.2	20.5	16.7	17.4	16.7	17.4	19.7
3/10	17.8	18.1	19.9	17.5	17.4	16.8	17.8	17.8
3/11	17.9	17.9	19.7	16.9	16.8	16.2	16.4	17.6
3/12	16.7	18.3	18.5	17.5	17.1	16.5	17.1	16.9
3/13	17.8	17.9	19.7	18.0	16.8	16.3	17.5	18.0
3/14	17.8	18.1	18.4	17.2	17.0	16.1	16.8	17.8
3/15	18.0	19.4	18.7	17.3	17.7	17.3	18.1	18.5
3/16	17.6	18.9	19.7	18.0	17.8	17.6	18.5	18.7
3/17	18.1	18.0	19.1	16.7	16.5	16.6	17.5	18.0
3/18	17.1	17.5	19.5	16.2	16.1	16.0	16.6	17.9
3/19	17.0	17.8	18.8	16.9	16.4	15.4	17.0	17.4
3/20	17.3	18.3	19.0	18.1	17.1	15.8	17.5	17.8
3/21	17.7	17.9	18.5	17.9	17.2	16.2	17.7	17.4
3/22	17.5	18.3	19.2	17.9	17.3	15.9	17.1	18.1
3/23	18.2	18.9	18.2	16.9	17.7	15.9	17.3	17.3
3/24	17.0	19.0	18.3	16.7	16.6	16.2	17.2	17.7
3/25	17.5	19.5	19.3	18.2	17.3	16.2	18.2	19.2
3/26	18.3	19.8	19.8	19.0	18.5	17.4	19.0	19.2
3/27	18.5	19.3	19.6	19.1	18.3	17.2	19.0	19.0
3/28	18.5	19.1	19.6	17.8	18.2	16.5	17.8	19.2
3/29	17.7	17.2	18.7	17.0	16.6	15.0	17.3	18.0
3/30	16.8	17.7	17.2	16.5	16.2	14.7	16.5	16.7
3/31	15.4	17.3	16.2	16.4	16.6	14.8	16.4	16.3
4/1	16.4	18.7	17.1	16.7	16.8	15.1	16.5	17.1

4/2	16.3	18.7	17.2	16.7	18.7	15.1	16.6	16.6
4/3	16.3	18.1	16.7	16.3	17.2	14.7	16.3	16.7
4/4	16.7	18.2	16.8	16.1	18.0	14.8	16.3	16.7
4/5	16.4	17.9	16.8	16.3	17.4	14.7	16.4	16.6
4/6	16.2	16.8	16.9	14.7	15.9	12.8	15.1	16.1
4/7	14.2	16.9	15.5	15.0	15.7	13.7	15.3	14.8
4/8	15.2	17.3	16.4	15.4	16.1	14.1	15.8	15.4
4/9	15.7	16.7	16.2	15.2	15.6	14.6	15.4	15.3
4/10	15.5	16.6	16.4	14.7	15.3	13.2	14.4	15.4
4/11	14.8	15.4	16.8	13.6	13.9	12.5	13.6	15.0
4/12	13.9	15.3	14.7	13.5	14.4	12.3	13.9	14.2
4/13	14.5	16.3	13.9	13.8	15.6	12.6	14.0	14.1
4/14	14.8	16.3	15.0	14.7	15.5	13.0	14.8	14.3
4/15	14.6	15.4	15.0	14.1	14.8	12.3	13.8	14.8
4/16	13.7	15.1	14.2	13.8	14.9	11.9	13.7	13.2
4/17	13.8	16.1	13.9	14.5	15.0	12.6	14.4	13.0
4/18	14.2	16.9	13.3	14.1	15.6	12.6	14.5	15.0
4/19	16.0	16.4	15.2	14.4	16.0	12.8	14.8	16.1
4/20	14.5	16.5	13.9	14.0	15.8	11.7	13.5	14.3
4/21	13.6	16.6	12.6	14.5	15.7	12.6	14.8	13.4
4/22	14.5	16.0	13.9	14.2	15.5	12.3	14.0	14.7
4/23	13.9	15.7	14.1	14.5	14.7	12.3	14.0	14.3
4/24	14.6	15.0	14.3	13.4	14.6	11.4	12.8	14.3
4/25	13.1	14.0	13.1	13.0	13.7	10.7	12.8	13.1
4/26	13.1	14.0	12.5	12.5	13.1	10.9	12.7	12.4
4/27	13.0	14.0	12.2	12.8	14.2	10.0	12.6	12.6
4/28	12.1	13.4	11.2	12.2	12.5	9.5	11.4	11.6
4/29	11.4	13.5	11.6	11.5	13.5	9.3	11.2	10.8
4/30	11.1	14.3	11.1	12.2	13.5	8.7	11.8	10.6
5/1	11.7	14.4	10.0	11.9	14.0	9.6	11.3	10.4
5/2	11.0	13.8	10.6	11.1	13.0	8.8	10.9	11.3
5/3	11.3	13.0	11.6	11.2	13.0	9.3	10.9	11.3
5/4	10.5	12.2	10.2	10.3	12.9	7.9	9.3	10.6
5/5	9.6	12.4	9.6	10.1	11.6	7.9	9.9	8.8
5/6	10.2	12.9	9.1	11.0	12.8	8.6	10.5	10.1
5/7	10.6	13.5	10.4	11.3	12.9	9.3	10.7	11.2
5/8	12.3	14.5	11.2	12.1	14.2	10.0	12.3	11.5
5/9	12.1	14.7	11.0	13.0	14.3	10.7	12.1	12.1
5/10	12.5	13.9	11.1	11.9	14.2	9.2	10.9	11.3
5/11	11.0	12.7	9.1	11.2	13.2	9.0	10.0	11.1
5/12	10.8	13.4	9.6	11.7	13.6	8.5	10.3	10.9
5/13	10.3	12.3	10.2	10.1	12.8	7.7	8.8	10.6
5/14	9.2	11.4	8.6	8.8	12.3	5.6	7.6	8.9
5/15	7.4	11.3	6.5	8.2	11.4	5.9	7.4	7.5
5/16	8.7	11.6	7.5	9.2	11.8	6.3	8.0	7.9
5/17	8.1	11.8	7.3	9.6	12.2	7.5	8.5	7.6
5/18	9.6	11.2	8.0	9.0	11.1	6.3	8.2	9.2
5/19	8.7	11.2	7.5	9.2	11.4	6.4	8.1	7.5
5/20	9.0	11.6	7.9	9.7	11.3	7.2	9.0	8.3
5/21	9.3	11.4	8.0	9.7	11.2	6.7	8.6	8.1
5/22	8.9	10.7	7.6	8.8	10.5	5.7	7.4	7.7
5/23	7.8	10.2	7.7	7.6	11.0	5.7	7.1	7.8
5/24	7.0	9.5	7.1	7.2	10.6	3.9	5.8	7.4

5/25	6.2	9.7	4.7	7.0	10.5	5.0	6.7	6.6
5/26	6.8	10.2	5.9	7.0	9.9	4.3	5.7	5.9
5/27	6.3	9.4	5.0	7.4	9.5	5.1	6.7	6.0
5/28	6.9	9.8	6.1	8.3	9.8	5.7	7.3	6.0
5/29	7.5	9.2	7.3	7.5	9.9	5.8	6.8	7.5
5/30	7.7	9.2	7.5	6.4	9.8	4.0	5.6	7.0
5/31	6.1	9.4	4.9	6.5	9.4	3.7	5.5	5.7
6/1	5.5	8.7	4.7	5.9	10.0	4.1	5.6	5.6
6/2	6.4	9.0	4.7	6.3	10.0	3.5	5.0	6.1
6/3	5.8	9.1	4.4	5.8	10.3	3.1	4.5	5.2
6/4	4.7	8.7	3.4	5.2	9.3	4.0	5.5	5.2
6/5	5.6	8.7	5.3	6.8	9.8	5.1	6.9	5.8
6/6	6.7	9.7	6.1	7.2	9.8	5.3	6.5	6.8
6/7	7.6	9.2	6.2	7.3	9.5	4.9	6.3	6.6
6/8	6.6	8.7	6.0	6.6	9.6	3.9	5.5	6.8
6/9	5.8	9.5	4.9	7.2	9.6	4.1	5.8	5.2
6/10	6.9	9.7	5.5	7.3	9.5	4.6	6.5	6.0
6/11	6.2	9.4	5.7	7.3	9.5	4.9	6.1	5.6
6/12	7.3	8.5	5.8	6.8	9.9	3.8	6.0	6.6
6/13	6.2	8.3	4.3	5.9	8.6	3.3	4.9	5.1
6/14	5.8	8.3	4.5	5.5	9.4	3.4	4.4	5.0
6/15	5.5	8.2	4.6	6.1	9.1	3.3	4.7	5.8
6/16	5.8	7.6	5.0	5.7	8.5	3.6	4.6	5.1
6/17	6.1	8.1	4.7	6.1	8.6	3.6	5.0	5.6
6/18	5.6	8.3	4.5	6.0	9.0	3.1	4.7	5.6
6/19	5.4	8.0	5.2	4.8	8.8	2.8	3.4	6.3
6/20	4.1	7.9	3.8	3.6	8.5	2.1	2.8	4.0
6/21	2.7	7.3	2.3	3.8	8.2	2.7	2.9	2.8
6/22	3.6	7.4	2.9	5.2	7.8	2.5	3.9	3.2
6/23	4.4	6.9	3.5	4.7	8.2	2.0	3.4	4.5
6/24	4.2	6.7	3.3	4.3	8.2	2.4	3.6	4.3
6/25	3.7	6.2	3.2	3.6	7.9	1.8	2.7	4.1
6/26	3.2	5.7	1.9	3.2	6.8	1.6	2.4	2.7
6/27	2.8	5.4	3.0	2.6	7.2	1.2	2.2	3.0
6/28	2.0	5.5	1.6	2.3	6.5	1.6	2.2	1.8
6/29	2.6	5.9	1.9	2.4	7.1	0.9	1.7	2.7
6/30	2.5	6.5	1.4	1.9	7.2	0.8	1.6	2.4
7/1	2.4	6.1	1.2	2.1	6.8	1.4	2.0	1.9
7/2	2.7	6.4	2.5	2.0	7.5	1.6	1.7	4.0
7/3	2.1	6.0	2.7	2.6	6.5	1.3	2.3	2.3
7/4	2.1	6.2	1.2	1.8	6.6	1.4	1.8	2.2
7/5	1.8	5.0	2.4	1.6	6.4	0.6	1.3	2.7
7/6	1.7	5.9	1.0	1.2	6.5	0.3	1.2	2.0
7/7	1.6	5.8	1.3	0.8	7.1	0.4	0.8	3.0
7/8	1.0	5.2	0.8	0.7	6.8	0.5	1.0	0.8
7/9	1.1	4.6	1.0	1.4	6.3	0.7	1.4	1.2
7/10	1.6	5.0	1.4	0.7	6.5	0.4	0.8	1.8
7/11	1.2	4.8	1.6	0.7	7.5	0.2	0.5	2.0
7/12	0.7	4.0	0.6	0.4	6.8	0.2	0.5	0.9
7/13	0.6	3.4	0.6	0.4	6.0	0.0	0.5	0.7
7/14	0.7	3.8	0.6	0.9	5.8	0.3	0.5	1.0
7/15	0.9	4.8	1.2	0.6	5.9	0.5	0.4	0.9
7/16	0.5	4.3	0.6	0.9	6.8	0.6	0.9	1.4

7/17	1.0	3.8	1.3	1.2	6.1	0.8	0.7	1.6
7/18	1.2	4.4	1.9	0.7	5.6	0.4	0.5	1.9
7/19	0.7	3.5	0.7	0.6	6.0	0.2	0.2	1.1
7/20	0.6	4.0	0.8	0.5	5.9	0.3	0.5	0.7
7/21	0.6	2.9	0.5	0.4	5.7	0.1	0.3	0.8
7/22	0.5	3.5	1.1	0.7	5.8	0.3	0.5	0.5
7/23	0.9	3.0	0.8	0.4	6.3	0.1	0.2	0.6
7/24	0.6	3.6	0.8	0.3	6.6	0.3	0.2	0.9
7/25	0.6	3.9	0.8	0.2	6.2	0.1	0.1	1.0
7/26	0.5	3.8	0.5	0.2	6.1	0.1	0.2	0.7
7/27	0.4	3.6	0.3	0.1	6.7	0.0	0.1	0.3
7/28	0.2	4.0	0.5	0.4	6.3	0.3	0.3	0.6
7/29	0.5	3.9	0.2	1.2	6.5	0.5	1.0	0.7
7/30	1.7	4.6	0.8	0.9	7.1	0.0	0.5	1.5
7/31	0.7	5.3	1.2	0.7	7.2	0.2	0.5	1.7
8/1	0.6	4.5	0.5	0.8	6.0	0.4	0.7	0.9
8/2	0.5	4.0	0.6	0.6	6.4	0.3	0.4	1.3
8/3	0.8	3.6	1.1	0.9	6.8	0.1	0.8	1.1
8/4	0.4	3.2	0.6	0.6	5.9	0.1	0.6	0.9
8/5	1.2	4.5	0.8	0.6	5.9	0.2	0.4	0.6
8/6	0.7	4.3	0.7	0.7	6.5	0.2	0.4	1.1
8/7	0.5	4.1	0.8	1.1	6.4	0.2	0.8	1.1
8/8	1.2	4.0	1.3	0.5	5.7	0.0	0.3	0.6
8/9	0.5	3.4	0.9	0.1	6.2	0.0	0.1	0.4
8/10	0.7	4.3	0.7	0.8	6.3	0.2	0.5	1.2
8/11	1.1	3.6	1.2	0.7	5.9	0.1	0.6	1.7
8/12	1.1	3.7	0.7	0.9	6.0	0.3	0.8	1.1
8/13	0.7	3.0	0.7	0.5	6.3	0.2	0.5	1.3
8/14	0.5	3.9	0.4	0.4	5.5	0.2	0.2	1.0
8/15	0.8	3.9	0.9	0.8	6.3	0.2	0.6	1.4
8/16	0.6	3.2	0.5	0.9	6.0	0.5	0.9	1.8
8/17	1.4	4.5	1.3	1.2	5.9	0.4	1.0	1.6
8/18	1.3	4.0	1.4	1.6	5.5	0.5	1.1	1.3
8/19	1.5	4.0	1.8	0.9	6.0	0.3	0.7	1.4
8/20	0.6	4.1	0.9	0.9	5.7	0.2	0.5	0.8
8/21	1.0	4.5	1.2	1.0	5.4	0.4	1.1	1.1
8/22	1.2	4.3	1.4	0.7	6.0	0.4	0.7	1.4
8/23	1.3	4.6	1.3	1.3	6.0	0.7	1.0	2.7
8/24	2.6	4.2	3.0	1.6	6.6	1.0	1.9	3.5
8/25	1.8	4.3	2.9	1.5	6.5	0.5	1.3	2.2
8/26	1.2	4.6	1.7	1.1	6.5	0.1	0.9	1.9
8/27	1.0	4.1	1.7	1.5	6.1	0.5	1.0	1.8
8/28	1.1	4.0	2.2	0.3	5.8	0.2	0.5	2.1
8/29	0.4	3.9	1.2	1.2	5.8	0.5	1.0	1.8
8/30	1.8	4.1	1.2	1.3	5.9	0.8	1.4	2.1
8/31	1.9	4.8	2.3	1.9	6.4	1.0	2.0	1.7
9/1	2.1	5.5	2.8	1.9	6.6	1.1	2.0	3.0
9/2	1.9	5.5	2.9	1.9	7.0	1.0	2.0	3.0
9/3	2.1	4.9	2.6	1.9	6.4	0.9	1.8	2.4
9/4	2.3	5.2	2.5	1.8	6.6	1.1	1.8	2.3
9/5	2.5	5.8	2.1	2.7	7.1	1.5	2.3	3.0
9/6	3.1	5.6	3.1	2.9	7.7	1.4	2.5	3.4
9/7	2.4	5.8	3.2	2.8	7.0	1.0	1.9	3.4

9/8	1.9	4.9	3.1	2.4	7.0	1.3	1.9	3.1
9/9	2.2	5.1	3.3	2.3	7.0	1.1	2.1	3.5
9/10	2.6	5.7	3.9	1.9	8.0	1.1	1.9	3.7
9/11	1.6	5.3	2.8	1.3	6.9	0.9	1.5	2.4
9/12	2.3	5.6	2.6	2.3	7.5	1.1	2.3	2.5
9/13	2.5	5.9	3.8	3.0	7.8	1.7	2.5	3.8
9/14	2.6	7.0	3.9	2.7	7.7	2.1	2.8	3.4
9/15	2.6	6.5	3.7	3.0	7.7	2.6	3.4	3.4
9/16	3.5	6.7	4.2	3.5	8.1	3.0	3.8	5.2
9/17	3.8	6.8	5.0	4.5	8.0	2.5	3.7	4.7
9/18	5.2	7.0	5.4	5.0	7.8	3.5	5.0	5.9
9/19	4.9	7.6	5.8	4.9	8.9	3.2	4.3	5.6
9/20	5.1	7.7	6.0	5.2	9.5	3.1	5.0	6.1
9/21	5.0	6.3	6.9	4.8	8.2	2.7	3.8	6.1
9/22	3.9	6.8	6.6	4.4	7.7	2.9	4.3	5.9
9/23	3.9	8.0	6.6	4.2	8.7	2.7	3.6	5.2
9/24	4.7	7.2	5.6	4.9	8.6	3.3	4.7	4.9
9/25	4.0	6.9	4.5	4.8	9.5	3.2	4.5	4.8
9/26	4.8	7.1	5.6	4.5	8.7	2.8	4.2	5.6
9/27	4.3	7.4	5.7	4.3	8.8	2.5	3.6	5.2
9/28	4.3	8.0	5.3	4.2	8.4	2.3	3.4	5.1
9/29	3.2	7.3	5.0	4.7	9.0	2.6	4.0	4.0
9/30	3.9	8.0	4.9	5.0	8.4	3.1	4.4	5.0
10/1	5.5	9.4	6.2	7.7	10.7	4.9	6.3	6.7
10/2	7.5	10.5	8.0	8.1	11.6	6.1	7.8	7.6
10/3	7.6	10.4	10.1	8.3	10.3	6.1	7.5	8.3
10/4	8.1	10.2	9.9	8.8	9.8	5.9	7.9	8.9
10/5	8.5	10.9	10.5	8.5	10.3	6.9	8.4	10.0
10/6	8.3	9.5	10.8	8.2	9.5	6.5	7.9	9.1
10/7	8.8	10.7	10.6	8.9	10.3	7.2	8.8	9.7
10/8	9.3	10.8	11.2	9.5	9.8	8.1	9.8	10.6
10/9	10.0	10.4	11.1	9.6	10.1	8.2	9.9	10.7
10/10	10.0	11.9	12.0	11.6	11.6	9.3	11.3	11.1
10/11	12.3	12.2	13.4	11.9	10.9	9.8	11.9	12.9
10/12	11.6	11.3	13.2	10.3	12.0	8.5	9.9	11.4
10/13	10.2	11.2	11.9	10.8	10.9	8.6	9.7	10.6
10/14	10.7	11.8	11.9	11.9	11.6	9.9	11.6	12.2
10/15	11.7	11.7	14.2	12.8	11.5	10.1	11.9	13.2
10/16	12.1	12.5	14.7	11.9	11.5	9.9	11.7	12.3
10/17	12.1	12.4	15.6	12.1	11.7	10.5	11.9	12.5
10/18	12.0	12.9	15.0	12.7	12.7	11.1	12.8	12.9
10/19	12.7	11.0	15.8	11.4	10.9	9.3	10.7	13.1
10/20	11.1	11.4	14.1	12.6	11.0	9.9	11.4	12.0
10/21	11.9	11.8	14.8	13.5	10.9	10.8	13.0	12.9
10/22	14.0	13.1	16.1	13.4	12.3	10.8	12.8	13.8
10/23	13.8	13.0	16.2	13.9	12.0	11.8	14.3	13.7
10/24	14.5	15.0	17.0	14.0	13.5	12.8	14.1	14.5
10/25	14.1	14.3	17.5	14.9	12.3	12.5	14.2	15.3
10/26	14.6	14.2	18.0	15.2	13.1	13.2	14.4	15.1
10/27	14.7	15.7	18.5	16.4	13.2	14.0	15.7	16.2
10/28	15.7	16.6	18.3	15.9	14.8	14.8	15.7	16.6
10/29	16.3	16.8	19.0	17.5	14.6	15.3	17.4	17.2
10/30	17.7	16.9	21.4	18.4	15.3	16.3	18.1	18.0

10/31	18.3	17.1	22.3	18.4	15.5	16.9	18.2	18.8

Appendix 2.19 Demand Forecast (Post DSM) – Base Case – Firm – MDT (Thousand dekatherms)

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009-2010	3,975	1,135	736	4,785	860	44,544	9,475	7,133	72,643
2010-2011	3,974	1,131	734	4,814	860	44,666	9,501	7,214	72,894
2011-2012	3,972	1,126	733	4,881	861	44,815	9,543	7,337	73,268
2012-2013	3,960	1,115	727	4,934	859	44,790	9,547	7,426	73,357
2013-2014	3,962	1,110	730	5,003	860	44,956	9,590	7,563	73,774
2014-2015	3,977	1,109	728	5,058	864	45,198	9,658	7,710	74,302
2015-2016	3,994	1,112	729	5,122	871	45,601	9,753	7,891	75,074
2016-2017	3,983	1,106	723	5,131	873	45,603	9,756	8,019	75,192
2017-2018	3,994	1,106	722	5,173	879	45,867	9,822	8,187	75,751
2018-2019	4,009	1,107	722	5,221	887	46,174	9,896	8,363	76,378
2019-2020	4,041	1,114	725	5,301	898	46,717	10,027	8,577	77,400
2020-2021	4,029	1,108	720	5,314	900	46,718	10,031	8,701	77,521
2021-2022	4,034	1,107	719	5,353	905	46,937	10,085	8,858	77,998
2022-2023	4,036	1,105	717	5,387	910	47,114	10,131	9,000	78,399
2023-2024	4,054	1,109	718	5,448	919	47,519	10,230	9,178	79,176
2024-2025	4,038	1,102	712	5,451	919	47,453	10,218	9,273	79,165
2025-2026	4,047	1,102	712	5,491	925	47,689	10,277	9,425	79,668
2026-2027	4,061	1,105	713	5,540	933	47,978	10,347	9,587	80,263
2027-2028	4,091	1,113	717	5,620	944	48,493	10,472	9,784	81,234
2028-2029	4,094	1,112	717	5,650	948	48,595	10,494	9,902	81,512

Appendix 2.20 Demand Forecast (Post DSM) – Base Case – Residential – MDT (Thousand dekatherms)

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM

2009-2010	2,356	624	268	2,115	413	27,266	5,410	4,717	43,167
2010-2011	2,359	625	268	2,127	416	27,377	5,430	4,763	43,364
2011-2012	2,359	627	268	2,142	420	27,474	5,457	4,833	43,580
2012-2013	2,352	625	267	2,145	422	27,425	5,452	4,880	43,569
2013-2014	2,360	628	269	2,166	427	27,563	5,488	4,963	43,864
2014-2015	2,373	633	271	2,193	434	27,766	5,540	5,064	44,274
2015-2016	2,400	642	275	2,235	443	28,134	5,631	5,196	44,955
2016-2017	2,413	645	277	2,259	451	28,301	5,676	5,304	45,326
2017-2018	2,439	653	281	2,300	460	28,640	5,761	5,441	45,976
2018-2019	2,467	661	285	2,340	471	28,991	5,847	5,579	46,641
2019-2020	2,502	672	290	2,392	483	29,474	5,963	5,739	47,515
2020-2021	2,510	675	291	2,412	489	29,601	5,998	5,838	47,815
2021-2022	2,528	680	294	2,443	498	29,867	6,065	5,959	48,334
2022-2023	2,542	685	296	2,471	505	30,101	6,124	6,072	48,796
2023-2024	2,567	694	299	2,513	515	30,483	6,217	6,208	49,497
2024-2025	2,569	695	299	2,524	520	30,542	6,236	6,288	49,674
2025-2026	2,586	700	301	2,555	529	30,801	6,301	6,411	50,183
2026-2027	2,604	706	304	2,587	537	31,076	6,369	6,541	50,724
2027-2028	2,631	715	308	2,629	547	31,472	6,466	6,689	51,458
2028-2029	2,635	717	308	2,643	553	31,560	6,490	6,781	51,687

Appendix 2.21 Demand Forecast (Post DSM) – Base Case – Commercial – MDT (Thousand dekatherms)

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009-2010	1,377	500	405	2,208	432	15,022	3,439	2,131	25,513
2010-2011	1,365	493	400	2,211	428	14,967	3,424	2,156	25,446
2011-2012	1,351	487	396	2,242	425	14,917	3,411	2,194	25,422
2012-2013	1,329	476	388	2,255	419	14,758	3,370	2,214	25,210

2013-2014	1,315	468	383	2,281	416	14,692	3,352	2,245	25,153
2014-2015	1,303	461	379	2,293	413	14,650	3,341	2,280	25,119
2015-2016	1,295	455	376	2,312	411	14,665	3,345	2,321	25,181
2016-2017	1,276	446	370	2,306	405	14,542	3,314	2,342	25,002
2017-2018	1,264	438	366	2,314	402	14,500	3,304	2,375	24,964
2018-2019	1,254	431	363	2,326	399	14,480	3,300	2,415	24,968
2019-2020	1,252	427	362	2,356	399	14,549	3,317	2,469	25,131
2020-2021	1,235	419	356	2,355	394	14,449	3,292	2,496	24,997
2021-2022	1,225	412	353	2,366	392	14,418	3,285	2,534	24,983
2022-2023	1,213	405	349	2,374	389	14,376	3,275	2,566	24,947
2023-2024	1,207	401	347	2,395	387	14,403	3,283	2,606	25,030
2024-2025	1,192	393	342	2,390	383	14,297	3,257	2,624	24,877
2025-2026	1,184	388	339	2,401	381	14,280	3,252	2,654	24,879
2026-2027	1,180	384	338	2,419	379	14,296	3,255	2,688	24,939
2027-2028	1,183	383	338	2,455	380	14,408	3,281	2,736	25,165
2028-2029	1,183	381	338	2,473	380	14,435	3,283	2,763	25,235

Appendix 2.22 Demand Forecast (Post DSM) – Base Case – Firm Industrial – MDT (Thousand dekatherms)

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009-2010	243	12	64	462	15	2,255	626	285	3,962
2010-2011	250	12	66	476	16	2,323	647	295	4,084
2011-2012	261	13	69	497	16	2,425	675	310	4,266
2012-2013	279	13	72	534	17	2,606	725	333	4,579
2013-2014	287	13	79	556	17	2,702	749	354	4,757
2014-2015	301	15	79	573	17	2,782	776	366	4,908
2015-2016	299	15	78	575	17	2,802	778	374	4,938

2016-2017	294	15	76	566	17	2,759	766	372	4,865
2017-2018	290	15	75	560	17	2,727	757	371	4,812
2018-2019	288	15	74	554	16	2,703	750	369	4,769
2019-2020	286	14	74	553	16	2,694	747	369	4,754
2020-2021	284	14	73	547	16	2,668	740	366	4,709
2021-2022	282	14	73	544	16	2,651	735	365	4,680
2022-2023	280	14	72	541	16	2,637	732	363	4,656
2023-2024	280	14	72	541	16	2,633	730	363	4,649
2024-2025	277	14	71	536	16	2,613	725	361	4,614
2025-2026	277	14	71	535	16	2,609	724	359	4,606
2026-2027	277	14	71	535	16	2,606	723	359	4,600
2027-2028	277	14	71	536	16	2,612	724	359	4,610
2028-2029	276	14	71	534	16	2,600	721	357	4,589

Appendix 2.23 Peak Day Demand Forecast (Post DSM) – Base Case – Firm – MDT (Thousand dekatherms)

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009-2010	50	18	9	62	13	574	126	92	944
2010-2011	50	18	9	62	13	575	126	93	945
2011-2012	50	17	9	62	13	573	126	93	942
2012-2013	50	17	9	63	13	574	126	94	945
2013-2014	50	17	9	64	13	575	126	96	949
2014-2015	50	17	9	64	13	579	126	97	956
2015-2016	50	17	9	65	13	582	127	99	962
2016-2017	51	17	9	66	13	587	128	101	971
2017-2018	51	17	9	66	14	592	129	104	982
2018-2019	51	17	9	67	14	598	131	106	993

2019-2020	52	18	9	68	14	604	132	109	1,005
2020-2021	52	18	9	69	14	609	133	111	1,014
2021-2022	52	18	9	70	14	613	134	113	1,024
2022-2023	53	18	9	70	14	617	135	115	1,031
2023-2024	53	18	9	71	15	621	136	117	1,039
2024-2025	53	18	9	72	15	624	137	119	1,046
2025-2026	53	18	9	72	15	629	138	121	1,055
2026-2027	54	18	9	73	15	634	139	123	1,065
2027-2028	54	18	9	74	15	639	140	125	1,075
2028-2029	55	18	9	75	15	644	141	127	1,085

Appendix 2.24 Peak Day Demand Forecast (Post DSM) – Base Case – Residential – MDT (Thousand dekatherms)

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009-2010	33	12	4	31	8	386	82	67	622
2010-2011	33	12	4	31	8	387	82	68	624
2011-2012	32	11	4	31	8	386	82	68	622
2012-2013	32	11	4	31	8	387	82	69	624
2013-2014	33	11	4	31	8	388	83	70	628
2014-2015	33	12	4	32	8	391	83	71	634
2015-2016	33	12	4	32	8	395	84	73	641
2016-2017	33	12	4	33	8	400	86	75	650
2017-2018	34	12	4	34	9	405	87	77	660
2018-2019	34	12	4	34	9	410	88	79	671
2019-2020	35	12	4	35	9	416	90	81	681
2020-2021	35	12	4	35	9	420	91	82	690
2021-2022	36	13	4	36	9	425	92	84	698

2022-2023	36	13	4	37	9	428	93	86	706
2023-2024	36	13	4	37	10	432	94	87	713
2024-2025	36	13	4	37	10	436	95	89	720
2025-2026	37	13	4	38	10	440	96	91	728
2026-2027	37	13	4	39	10	444	97	92	737
2027-2028	37	13	4	39	10	448	98	94	745
2028-2029	38	13	4	40	10	452	99	96	753

Appendix 2.25 Peak Day Demand Forecast (Post DSM) – Base Case – Commercial – MDT (Thousand dekatherms)

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009-2010	17	6	5	29	5	177	43	23	304
2010-2011	16	6	5	29	5	177	42	23	303
2011-2012	16	6	5	29	5	175	42	23	301
2012-2013	16	6	5	29	5	174	41	24	300
2013-2014	16	6	5	30	5	174	41	24	299
2014-2015	16	6	5	30	5	174	41	24	299
2015-2016	16	5	5	30	5	174	41	25	299
2016-2017	16	5	5	30	5	174	40	25	299
2017-2018	16	5	5	30	5	174	40	25	300
2018-2019	16	5	5	30	5	174	40	26	301
2019-2020	16	5	5	31	5	175	40	26	302
2020-2021	16	5	5	31	5	175	40	27	303
2021-2022	16	5	5	31	5	176	40	27	304
2022-2023	16	5	5	31	5	176	40	27	304
2023-2024	16	5	5	31	5	176	40	28	304
2024-2025	15	5	5	31	5	176	40	28	305

2025-2026	15	5	5	32	5	176	39	28	305
2026-2027	15	5	5	32	5	177	39	29	307
2027-2028	15	5	5	32	5	178	40	29	308
2028-2029	16	5	5	33	5	179	40	29	311

Appendix 2.26 Peak Day Demand Forecast (Post DSM) – Base Case – Firm Industrial – MDT (Thousand dekatherms)

YEAR	ALBANY	ASTORIA	DALLES OR	EUGENE COOS BAY	NEWPORT LINCOLN CITY	PORTLAND	SALEM	VANCOUVER DALLES WA	SYSTEM
2009-2010	1.10	0.03	0.22	2.22	0.04	10.81	1.91	1.47	17.80
2010-2011	1.14	0.03	0.22	2.30	0.04	11.18	1.96	1.53	18.41
2011-2012	1.19	0.03	0.23	2.40	0.04	11.68	2.04	1.60	19.22
2012-2013	1.28	0.04	0.24	2.61	0.05	12.66	2.19	1.73	20.79
2013-2014	1.32	0.04	0.27	2.71	0.05	13.10	2.26	1.83	21.56
2014-2015	1.39	0.04	0.26	2.80	0.05	13.53	2.33	1.89	22.29
2015-2016	1.37	0.04	0.26	2.80	0.05	13.59	2.32	1.92	22.35
2016-2017	1.35	0.04	0.25	2.77	0.04	13.44	2.28	1.91	22.09
2017-2018	1.34	0.04	0.25	2.75	0.04	13.33	2.24	1.90	21.90
2018-2019	1.33	0.04	0.25	2.73	0.04	13.24	2.22	1.90	21.75
2019-2020	1.33	0.04	0.25	2.72	0.04	13.19	2.20	1.89	21.66
2020-2021	1.32	0.04	0.24	2.71	0.04	13.12	2.18	1.88	21.53
2021-2022	1.31	0.04	0.24	2.69	0.04	13.06	2.17	1.87	21.42
2022-2023	1.31	0.04	0.24	2.68	0.04	13.01	2.15	1.86	21.33
2023-2024	1.30	0.04	0.24	2.68	0.04	12.97	2.14	1.85	21.26
2024-2025	1.30	0.04	0.24	2.67	0.04	12.92	2.13	1.84	21.17
2025-2026	1.29	0.04	0.24	2.67	0.04	12.91	2.13	1.84	21.15
2026-2027	1.29	0.04	0.24	2.66	0.04	12.90	2.12	1.83	21.13
2027-2028	1.29	0.04	0.24	2.66	0.04	12.90	2.12	1.83	21.13

2028-2029	1.29	0.04	0.24	2.66	0.04	12.88	2.12	1.83	21.08

Appendix 2.27 Demand Forecast (Post DSM) – Scenarios – Firm – MDT (Thousand dekatherms)

	1356-Low Customer Growth			1357-High Customer Growth			1360-Gas Breakthrough		
YEAR	**OR**	**WA**	**SYSTEM**	**OR**	**WA**	**SYSTEM**	**OR**	**WA**	**SYSTEM**
2009-2010	65,483	7,128	72,611	65,529	7,136	72,664	65,529	7,136	72,664
2010-2011	65,478	7,179	72,657	65,815	7,237	73,052	65,815	7,237	73,052
2011-2012	65,376	7,240	72,617	66,305	7,402	73,707	66,305	7,402	73,707
2012-2013	64,964	7,253	72,217	66,616	7,549	74,165	66,616	7,549	74,165
2013-2014	64,840	7,314	72,154	67,269	7,755	75,024	67,162	7,742	74,904
2014-2015	64,837	7,387	72,224	68,019	7,973	75,992	67,634	7,923	75,557
2015-2016	65,066	7,499	72,565	68,937	8,217	77,154	69,517	8,286	77,803
2016-2017	64,769	7,568	72,337	69,207	8,401	77,608	70,668	8,580	79,248
2017-2018	64,918	7,689	72,607	69,833	8,616	78,450	72,218	8,913	81,131
2018-2019	65,209	7,833	73,042	70,483	8,831	79,314	74,041	9,282	83,323
2019-2020	65,914	8,026	73,941	71,467	9,079	80,545	76,280	9,697	85,977
2020-2021	65,875	8,142	74,017	71,571	9,224	80,795	77,785	10,034	87,820
2021-2022	66,166	8,293	74,459	71,970	9,397	81,368	79,749	10,425	90,175
2022-2023	66,402	8,431	74,833	72,283	9,551	81,834	81,700	10,811	92,511
2023-2024	66,961	8,601	75,562	72,946	9,741	82,687	84,001	11,235	95,236
2024-2025	66,851	8,693	75,544	72,876	9,843	82,720	85,560	11,574	97,135
2025-2026	67,173	8,839	76,012	73,282	10,006	83,288	87,629	11,981	99,610
2026-2027	67,572	8,995	76,568	73,775	10,180	83,955	89,780	12,400	102,180
2027-2028	68,298	9,184	77,482	74,622	10,391	85,013	92,418	12,878	105,295
2028-2029	68,439	9,298	77,737	74,829	10,517	85,345	94,463	13,281	107,744

Appendix 2.28 Peak Day Demand Forecast (Post DSM) – Scenarios – Firm – MDT (Thousand dekatherms)

	1356-Low Customer Growth			1357-High Customer Growth			1360-Gas Breakthrough		
YEAR	**OR**	**WA**	**SYSTEM**	**OR**	**WA**	**SYSTEM**	**OR**	**WA**	**SYSTEM**
2009-2010	852	92	943	852	92	944	852	92	944

2010-2011	850	92	942	854	93	947	854	93	947
2011-2012	842	92	934	854	94	948	854	94	948
2012-2013	837	92	929	860	96	956	860	96	956
2013-2014	834	93	927	868	98	966	866	98	964
2014-2015	834	93	927	878	101	979	871	100	971
2015-2016	834	94	928	887	103	991	881	103	984
2016-2017	837	96	932	898	106	1,005	890	105	995
2017-2018	841	97	938	910	109	1,019	899	108	1,007
2018-2019	848	99	947	922	112	1,034	913	111	1,024
2019-2020	856	102	957	934	115	1,049	926	114	1,040
2020-2021	862	104	966	942	118	1,060	939	117	1,056
2021-2022	869	106	974	951	120	1,071	953	120	1,073
2022-2023	874	107	982	957	122	1,079	967	123	1,090
2023-2024	880	109	989	964	124	1,088	979	126	1,104
2024-2025	884	111	995	969	126	1,095	990	129	1,118
2025-2026	891	113	1,004	977	128	1,105	1,002	131	1,134
2026-2027	898	115	1,014	986	131	1,117	1,015	134	1,150
2027-2028	905	117	1,023	994	133	1,127	1,029	137	1,166
2028-2029	913	119	1,032	1,004	135	1,139	1,044	141	1,185

Appendix 2.29 Load Forecast Coefficients

Residential	c - Daily Baseload Factor	d - Heat Intercept	r_p - Price Rate	r_h - Heat Rate
Albany | Res-Exist	0.3871	-3.9533	-0.2160	0.5818
Astoria | Res-Exist	0.4140	-4.8435	-0.2160	0.8742
Dalles | Res-Exist	0.3994	-4.5695	-0.2160	0.6869
Eugene-Coos Bay | Res-Exist	0.4379	-4.3251	-0.2160	0.6744
Newport Lincoln City | Res-Exist	0.2668	-4.5858	-0.2160	0.7699
Portland | Res-Exist	0.4533	-3.3260	-0.2160	0.4414
Salem | Res-Exist	0.4476	-4.0559	-0.2160	0.6296
Vancouver Dalles WA | Res-Exist	0.5519	-4.2610	-0.2160	0.6889
System | Res-Exist	0.4416	-3.6319	-0.2160	0.5200
Albany | Res-Conv	0.2905	-3.9043	-0.2160	0.5288

Astoria | Res-Conv	0.3528	-4.8359	-0.2160	0.8366
Dalles | Res-Conv	0.3278	-4.4364	-0.2160	0.6179
Eugene Coos Bay | Res-Conv	0.3195	-4.1507	-0.2160	0.6040
Newport Lincoln City | Res-Conv	0.2962	-4.8711	-0.2160	0.8048
Portland | Res-Conv	0.3101	-3.3122	-0.2160	0.4130
Salem | Res-Conv	0.3070	-3.8848	-0.2160	0.5639
Vancouver Dalles WA | Res-Conv	0.4320	-4.2134	-0.2160	0.6269
System | Res-Conv	0.3065	-3.6199	-0.2160	0.4892
Albany | Res-NC SF	0.5309	-4.5296	-0.2160	0.7558
Astoria | Res-NC SF	0.6298	-5.0499	-0.2160	0.9515
Dalles | Res-NC SF	0.5458	-4.8515	-0.2160	0.7633
Eugene Coos Bay | Res-NC SF	0.6289	-4.9860	-0.2160	0.8802
Newport Lincoln City | Res-NC SF	0.3995	-4.8684	-0.2160	0.8541
Portland | Res-NC SF	0.6539	-3.5270	-0.2160	0.5261
Salem | Res-NC SF	0.5945	-4.4913	-0.2160	0.7599
Vancouver Dalles WA | Res-NC SF	0.6415	-4.2301	-0.2160	0.7065
System | Res-NC SF	0.6137	-3.9768	-0.2160	0.6371

Commercial	**c - Daily Baseload Factor**	**d - Heat Intercept**	**r_p - Price Rate**	**r_h - Heat Rate**
Albany | Com-Exist	2.9012	-2.2827	-0.2165	0.5255
Astoria | Com-Exist	4.3513	-3.3975	-0.2165	0.7828
Dalles | Com-Exist	3.4684	-2.5572	-0.2165	0.5872
Eugene Coos Bay | Com-Exist	4.1698	-2.7740	-0.2165	0.7218
Newport Lincoln City | Com-Exist	5.4040	-3.0985	-0.2165	0.7133
Portland | Com-Exist	4.1418	-1.6070	-0.2165	0.3876
Salem | Com-Exist	3.7106	-2.0169	-0.2165	0.4991
Vancouver Dalles WA | Com-Exist	4.3869	-2.2339	-0.2165	0.5095
System | Com-Exist	3.8869	-1.8569	-0.2165	0.4481
Albany | Com-Conv	1.8022	-2.8041	-0.2165	0.5844
Astoria | Com-Conv	1.8121	-5.0184	-0.2165	1.1524
Dalles | Com-Conv	0.7700	-4.2369	-0.2165	0.9414
Eugene Coos Bay | Com-Conv	3.0721	-2.8155	-0.2165	0.6527
Newport Lincoln City | Com-Conv	3.1672	-5.3788	-0.2165	1.4115
Portland | Com-Conv	3.0072	-2.2883	-0.2165	0.5297
Salem | Com-Conv	1.6470	-2.9451	-0.2165	0.6693
Vancouver Dalles WA | Com-Conv	3.0784	-2.4610	-0.2165	0.4858
System | Com-Conv	2.4802	-2.3744	-0.2165	0.5213
Albany | Com-NC	4.2182	-2.7720	-0.2165	0.7466
Astoria | Com-NC	6.6700	-3.5943	-0.2165	0.7694

Dalles | Com-NC	2.5982	-3.6272	-0.2165	0.8120
Eugene Coos Bay | Com-NC	3.6642	-2.6277	-0.2165	0.6968
Newport Lincoln City | Com-NC	5.5034	-3.4697	-0.2165	0.8822
Portland | Com-NC	6.2947	-1.9696	-0.2165	0.5343
Salem | Com-NC	5.2845	-1.6660	-0.2165	0.3558
Vancouver Dalles WA | Com-NC	5.2713	-1.8679	-0.2165	0.4478
System | Com-NC	5.4143	-1.9050	-0.2165	0.4812

Firm Industrial	**c - Daily Baseload Factor**	**Heat Rate**
Albany | Industrial	128.7251	4.2057
Astoria | Industrial	46.1469	0.0000
Dalles | Industrial	153.9516	1.4871
Eugene Coos Bay | Industrial	97.5881	3.6877
Newport Lincoln City | Industrial	103.4055	0.0000
Portland | Industrial	138.2153	4.6208
Salem | Industrial	172.5099	0.6558
Vancouver Dalles WA| Industrial	117.5289	6.0153
System | Industrial	134.3683	3.7881

Appendix 2.30 Customer Use Profiles

Annual Use Per Customer at Oct 2009 Rates	**Average Weather**			**Design Weather**			
Residential	**Base**	**Heat**	**Total**	**Base**	**Heat**	**Total**	**Peak Day**
Albany | Res-Exist	141	451	593	141	507	648	9.3
Astoria | Res-Exist	151	424	576	151	447	598	10.6
Dalles | Res-Exist	146	418	564	146	465	611	8.6
Eugene Coos Bay | Res-Exist	160	405	565	160	470	630	8.8
Newport Lincoln City | Res-Exist	97	366	463	97	382	480	8.9
Portland | Res-Exist	165	501	666	165	556	721	10.0
Salem | Res-Exist	163	456	619	163	519	682	10.0
Vancouver Dalles WA | Res-Exist	201	479	680	201	532	733	10.4
Albany | Res-Conv	106	406	512	106	453	559	7.9
Astoria | Res-Conv	129	384	513	129	404	532	9.3
Dalles | Res-Conv	120	385	505	120	425	545	7.5
Eugene Coos Bay | Res-Conv	117	392	509	117	450	567	8.0
Newport Lincoln City | Res-Conv	108	302	411	108	317	425	7.7
Portland | Res-Conv	113	468	581	113	518	631	9.0
Salem | Res-Conv	112	446	558	112	503	615	9.2
Vancouver Dalles WA | Res-Conv	158	417	575	158	461	618	8.6
Albany | Res-NC SF	194	425	618	194	487	681	10.3
Astoria | Res-NC SF	230	431	661	230	457	687	11.8
Dalles | Res-NC SF	199	401	600	199	449	648	8.8
Eugene Coos Bay | Res-NC SF	230	385	615	230	460	689	10.1

Newport Lincoln City | Res-NC SF	146	347	493	146	366	511	9.4
Portland | Res-NC SF	239	524	763	239	588	826	11.4
Salem | Res-NC SF	217	434	651	217	502	719	10.8
Vancouver Dalles WA | Res-NC SF	234	521	755	234	579	814	11.5
Albany | Res-NC MF	74	219	293	74	246	320	4.6
Astoria | Res-NC MF	190	139	329	190	161	351	7.8
Dalles | Res-NC MF	140	192	332	140	219	359	4.8
Eugene Coos Bay | Res-NC MF	102	149	251	102	171	273	3.2
Newport Lincoln City | Res-NC MF	195	219	414	195	222	417	3.4
Portland | Res-NC MF	136	246	382	136	278	414	5.8
Salem | Res-NC MF	144	259	403	144	297	441	6.1
Vancouver Dalles WA | Res-NC MF	135	235	370	135	265	399	5.7
Commercial	**Base**	**Heat**	**Total**	**Base**	**Heat**	**Total**	**Peak Day**
Albany | Com-Exist	1,059	2,066	3,125	1,059	2,304	3,363	41.8
Astoria | Com-Exist	1,588	1,410	2,998	1,588	1,475	3,064	35.5
Dalles | Com-Exist	1,266	2,328	3,594	1,266	2,564	3,830	46.0
Eugene Coos Bay | Com-Exist	1,522	2,235	3,757	1,522	2,606	4,128	52.4
Newport Lincoln City | Com-Exist	1,972	1,408	3,380	1,972	1,466	3,438	36.7
Portland | Com-Exist	1,512	2,429	3,941	1,512	2,681	4,193	48.1
Salem | Com-Exist	1,354	2,426	3,780	1,354	2,715	4,070	49.2
Vancouver Dalles WA | Com-Exist	1,601	2,130	3,731	1,601	2,326	3,927	42.2
Albany | Com-Conv	658	1,459	2,117	658	1,638	2,296	30.7
Astoria | Com-Conv	661	807	1,468	661	871	1,532	27.0
Dalles | Com-Conv	281	1,318	1,599	281	1,504	1,785	31.3
Eugene | Com-Conv	1,121	1,749	2,870	1,121	2,020	3,141	38.6
Newport LC | Com-Conv	1,156	993	2,149	1,156	1,110	2,266	48.8
Portland | Com-Conv	1,098	1,858	2,955	1,098	2,083	3,181	41.2
Salem | Com-Conv	601	1,582	2,183	601	1,808	2,409	36.0
Vancouver | Com-Conv	1,124	1,582	2,706	1,124	1,724	2,848	30.6
Albany | Com-NC	1,540	2,435	3,975	1,540	2,789	4,329	59.5
Astoria | Com-NC	2,435	1,114	3,549	2,435	1,165	3,600	31.0
Dalles | Com-NC	948	1,613	2,562	948	1,816	2,765	36.9
Eugene Coos Bay | Com-NC	1,337	2,403	3,741	1,337	2,793	4,130	54.4
Newport Lincoln City | Com-NC	2,009	1,544	3,553	2,009	1,629	3,638	46.6
Portland | Com-NC	2,298	2,589	4,887	2,298	2,905	5,203	59.8
Salem | Com-NC	1,929	2,268	4,197	1,929	2,497	4,426	42.7
Vancouver Dalles WA | Com-NC	1,924	2,559	4,483	1,924	2,778	4,702	48.4
Industrial	**Base**	**Heat**	**Total**	**Base**	**Heat**	**Total**	**Peak Day**
Albany | Industrial	46,985	19,694	66,679	46,985	20,769	67,753	318.0
Astoria | Industrial	16,844	0	16,844	16,844	0	16,844	46.1
Dalles | Industrial	56,192	7,860	64,052	56,192	8,200	64,392	220.9
Eugene Coos Bay | Industrial	35,620	17,214	52,834	35,620	18,350	53,970	263.5
Newport Lincoln City | Industrial	37,743	0	37,743	37,743	0	37,743	103.4
Portland | Industrial	50,449	19,565	70,014	50,449	20,726	71,174	346.2
Salem | Industrial	62,966	2,998	65,964	62,966	3,172	66,139	202.0
Vancouver Dalles WA | Industrial	42,898	29,157	72,055	42,898	30,429	73,327	388.2

Appendix 3: Supply Side Resources

NW Natural®

Appendix 3.1 Incremental Supply-Side Resources as Modeled in SENDOUT® (MDT – daily maximum capacity thousand dekatherms)

Incremental Resource	Maximum Size	Cost or Rate	Earliest Date Available
Pipeline related			
TC/GTN Alberta to Stanfield	969 MDT	Existing rates	Nov-12
GTN Malin to Madras	100 MDT	Existing GTN rates	Nov-17
Williams' NWPL OPAL to Stanfield	1,062 MDT	2.5 times existing rates	Nov-14
Palomar/Blue Bridge	200 MDT	Palomar ($/MDT) 0.72 – 2017 0.45 – 2020 0.32 – 2025 Blue Bridge ($/MDT) 0.77 – 2017 0.64 – 2020 0.54 – 2025	Nov-17
Williams' Grants Pass Lateral	74 MDT	Existing rates plus NWN take away costs - $8,000,000 capital	Nov-13
NWN Newport LNG Compressor Project	40 MDT	$12,000,000 capital	Nov-12
NWN Mid Willamette Valley Feeder	41 MDT	$40,000,000 capital	Nov-12
NWN South Willamette Valley Feeder	14 MDT	$58,000,000 capital	Nov-12
Storage related			
NWN Mist Recall	Up to 6,122 MDT by 2017	Daily Mist Cost of Service rate of $0.0042/DT and inventory carrying rate 5.16%	From 2011 to 2017
NWN Satellite Storage	90 MDT capacity, 30 MDT delivery for 3 days	$44,000,000 capital, $1,000,000 annual O&M, 5.16% inventory carrying rate	Apr-12
Imported LNG related			
Oregon LNG project	100 MDT	FERC Gas Tariff rate for Firm Service on Oregon pipeline, supply cost at Malin rate minus GTN/PAL E to Molalla	Nov-15
Jordan Cove LNG project	20 MDT	FERC Gas Tariff rate for Firm Service on Pacific Connector Pipeline, supply cost at Malin rate minus average of the estimated delivery rate to Williams and GTN	Nov-14

Appendix 4: Demand-Side Resources

NW Natural®

Appendix 4.1: Oregon DSM Deployment Scenario Incremental Annual Savings - THERMS

OR Incremental Annual Savings -	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESIDENTIAL																				
New Construction	150,913	135,822	201,217	261,583	221,339	221,339	221,339	221,339	221,339	221,339	221,339	221,339	221,339	221,339	221,339	221,339	221,339	221,339	221,339	221,339
New DHW	14,972	13,475	19,963	25,952	21,959	21,959	21,959	21,959	21,959	21,959	21,959	21,959	21,959	21,959	21,959	21,959	21,959	21,959	21,959	21,959
Retrofit	942,925	1,024,989	1,026,598	1,119,925	1,231,596	1,409,561	1,473,924	1,538,288	1,634,833	1,763,560	1,892,287	1,956,650	1,956,650	1,956,650	1,956,650	1,956,650	1,956,650	1,956,650	1,769,996	1,544,724
Replace DHW	135,095	146,852	147,083	160,454	176,453	201,950	211,172	220,393	234,226	252,669	271,111	280,333	280,333	280,333	280,333	280,333	280,333	280,333	253,591	221,315
Replace Equipment	74,431	80,909	81,036	88,402	97,217	111,265	116,346	121,426	129,047	139,208	149,370	154,450	154,450	154,450	154,450	154,450	154,450	154,450	139,717	121,934
Appliances New and Replacement	21,221	21,221	21,221	26,526	26,526	26,526	26,526	31,832	34,484	37,137	37,137	37,137	37,137	37,137	37,137	37,137	37,137	37,137	37,137	37,137
Solar Water Heat	24,085	32,114	40,142	48,170	54,593	57,805	57,805	57,805	57,805	57,805	57,805	57,805	57,805	57,805	57,805	57,805	57,805	57,805	57,805	57,805
COMMERCIAL																				
New Construction	295,186	295,186	295,186	295,186	295,186	295,186	295,186	295,186	295,186	295,186	295,186	295,186	295,186	295,186	295,186	295,186	295,186	295,186	295,186	295,186
Replace Shell	142,723	154,476	164,551	177,984	182,013	194,775	201,491	218,282	235,073	235,073	235,073	235,073	201,491	201,491	167,909	167,909	134,327	100,745	0	0
Replace Equipment	223,615	242,031	257,815	278,861	285,175	305,169	315,692	342,000	368,307	368,307	368,307	368,307	315,692	315,692	263,077	263,077	210,461	157,846	0	0
Retrofit Wx	220,062	238,185	253,719	274,431	280,644	300,320	310,676	336,566	362,456	362,456	362,456	362,456	310,676	310,676	258,897	258,897	207,118	155,338	0	0
Retrofit Equipment	355,520	384,798	409,893	443,354	453,392	485,180	501,910	543,736	585,562	585,562	585,562	585,562	501,910	501,910	418,258	418,258	334,607	250,955	0	0
Cooking Appliances	251,451	272,159	289,909	313,575	320,675	343,157	354,990	384,573	414,155	414,155	414,155	414,155	354,990	354,990	295,825	295,825	236,660	177,495	0	0
Commerical Firm Class with IND SIC	191,683	225,961	268,131	302,183	303,130	303,761	292,711	240,168	186,045	131,923	131,923	131,923	104,862	104,862	77,800	23,678	23,678	23,678	23,678	23,678
INDUSTRIAL FIRM																				
Retrofit	384,458	449,002	533,189	600,540	600,540	600,540	561,252	449,002	336,751	224,501	224,501	224,501	168,376	168,376	112,250	0	0	0	0	0
Replacement	13,096	19,643	22,917	26,191	28,156	29,465	45,835	49,109	49,109	49,109	49,109	49,109	49,109	49,109	49,109	49,109	49,109	49,109	49,109	49,109
Codes & Standards																				
Residential	96,143	369,143	439,311	928,917	965,593	1,007,988	1,056,948	1,089,864	1,094,677	1,096,840	1,093,653	1,088,353	1,083,908	1,079,955	1,081,887	1,084,294	1,080,213	1,069,268	1,079,717	1,090,337
Commercial	0	94,084	92,297	96,574	95,707	96,444	85,942	93,639	94,172	101,697	92,326	95,837	92,258	96,408	84,324	86,379	87,991	101,480	86,963	95,849
TOTAL																				
RESIDENTIAL	1,459,785	1,824,524	1,976,570	2,659,930	2,795,277	3,058,394	3,186,019	3,302,906	3,428,370	3,590,516	3,744,661	3,818,027	3,813,581	3,809,628	3,811,561	3,813,967	3,809,886	3,798,941	3,581,260	3,316,551
COMMERCIAL	1,680,240	1,906,879	2,031,501	2,182,147	2,215,923	2,323,992	2,358,599	2,454,148	2,540,956	2,494,358	2,484,988	2,488,498	2,177,065	2,181,215	1,861,276	1,809,209	1,530,028	1,262,723	405,826	414,712
INDUSTRIAL FIRM	397,553	468,645	556,107	626,731	628,695	630,005	607,087	498,110	385,860	273,610	273,610	273,610	217,484	217,484	161,359	49,109	49,109	49,109	49,109	49,109
ALL DSM	3,537,579	4,200,048	4,564,178	5,468,808	5,639,895	6,012,391	6,151,705	6,255,164	6,355,186	6,358,484	6,503,258	6,580,134	6,208,131	6,208,328	5,834,196	5,672,285	5,389,023	5,110,773	4,036,195	3,780,372

Appendix 4.2: Washington DSM Deployment Scenario Annual Incremental Savings - THERMS

WA Incremental Annual Savings - Therms	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESIDENTIAL																				
New Construction	17,753	26,108	26,108	26,108	26,630	26,630	26,630	73,971	73,971	73,971	73,971	73,971	73,971	73,971	73,971	73,971	73,971	73,971	73,971	73,971
New DHW	1,567	2,304	2,304	2,304	2,350	2,350	2,350	6,527	6,527	6,527	6,527	6,527	6,527	6,527	6,527	6,527	6,527	6,527	6,527	6,527
Retrofit	41,051	49,848	67,441	87,967	117,289	146,611	175,933	205,256	205,256	205,256	205,256	205,256	205,256	205,256	205,256	146,611	146,611	117,289	117,289	87,967
Replace DHW	16,996	20,638	27,922	36,420	48,560	60,700	72,840	84,980	84,980	84,980	84,980	84,980	84,980	84,980	84,980	60,700	60,700	48,560	48,560	36,420
Replace Equipment	3,517	4,271	5,778	7,536	10,049	12,561	15,073	17,585	17,585	17,585	17,585	17,585	17,585	17,585	17,585	12,561	12,561	10,049	10,049	7,536
Appliances New and Replacement	1,818	2,424	3,029	3,635	4,241	4,241	4,241	4,241	4,241	4,241	4,241	4,241	4,241	4,241	4,241	4,241	4,241	4,241	4,241	4,241
Solar Water Heat	1,828	2,011	2,194	2,377	2,560	2,560	2,560	2,560	2,560	2,560	2,560	2,560	2,560	2,560	2,560	2,560	2,560	2,560	2,560	2,560
COMMERCIAL																				
New Construction	6,526	7,832	9,790	11,748	13,053	16,316	16,316	16,316	16,316	16,316	16,316	16,316	16,316	16,316	16,316	16,316	16,316	16,316	16,316	16,316
Replace Shell	10,867	11,826	13,424	15,023	15,982	15,982	15,982	15,982	15,982	15,982	15,982	15,982	15,982	15,982	15,982	15,982	15,982	15,982	15,982	15,982
Replace Equipment	30,202	32,866	37,308	41,749	44,414	44,414	44,414	44,414	44,414	44,414	44,414	44,414	44,414	44,414	44,414	44,414	44,414	44,414	44,414	44,414
Retrofit Wx	9,122	9,927	11,269	12,610	13,415	13,415	13,415	13,415	13,415	13,415	13,415	13,415	13,415	13,415	13,415	13,415	13,415	13,415	13,415	13,415
Retrofit Equipment	51,632	56,188	63,781	71,374	75,930	75,930	75,930	75,930	75,930	75,930	75,930	75,930	75,930	75,930	75,930	75,930	75,930	75,930	75,930	75,930
Cooking Appliances	14,758	16,060	18,231	20,401	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703
INDUSTRIAL FIRM																				
Retrofit	8,813	9,792	10,772	11,751	11,751	11,751	11,751	11,751	11,751	11,751	11,751	11,751	11,751	11,751	9,792	7,834	3,917	3,917	1,958	1,958
Replacement	2,138	2,351	2,565	2,779	2,993	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207
Federal Furnace Code Change																				
Residential	0	0	0	46,071	46,071	46,071	46,071	46,071	46,071	46,071	46,071	46,071	46,071	46,071	46,071	46,071	46,071	46,071	46,071	46,071
TOTAL																				
RESIDENTIAL	84,530	107,602	134,776	212,418	257,749	301,724	345,698	441,192	441,192	441,192	441,192	441,192	441,192	441,192	441,192	353,243	353,243	309,268	309,268	265,294
COMMERCIAL	123,108	134,700	153,802	172,905	184,497	187,760	187,760	187,760	187,760	187,760	187,760	187,760	187,760	187,760	187,760	187,760	187,760	187,760	187,760	187,760
INDUSTRIAL FIRM	10,951	12,144	13,337	14,530	14,744	14,957	14,957	14,957	14,957	14,957	14,957	14,957	14,957	14,957	12,999	11,040	7,124	7,124	5,165	5,165
ALL DSM	218,589	254,446	301,915	399,853	456,990	504,441	548,415	643,909	643,909	643,909	643,909	643,909	643,909	643,909	641,951	552,043	548,126	504,152	502,193	458,219

Appendix 4.3: Oregon DSM Deployment Scenario Annual Cumulative Savings – THERMS

OR Cumulative Annual Savings - Therms	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESIDENTIAL																				
New Construction	150,913	286,735	487,952	749,535	970,874	1,192,214	1,413,553	1,634,892	1,856,231	2,077,571	2,298,910	2,520,249	2,741,588	2,962,928	3,184,267	3,405,606	3,626,945	3,848,285	4,069,624	4,290,963
New DHW	14,972	28,447	48,410	74,361	96,320	118,279	140,238	162,197	184,156	206,115	228,074	250,033	271,992	293,951	315,910	337,869	359,828	381,787	403,746	425,705
Retrofit	942,925	1,967,914	2,994,512	4,114,437	5,346,032	6,755,593	8,229,517	9,767,805	11,402,638	13,166,198	15,058,485	17,015,135	18,971,785	20,928,436	22,885,086	24,841,737	26,798,387	28,755,038	30,525,034	32,069,758
Replace DHW	135,095	281,947	429,029	589,483	765,936	967,886	1,179,058	1,399,452	1,633,677	1,886,346	2,157,457	2,437,790	2,718,123	2,998,456	3,278,789	3,559,122	3,839,455	4,119,788	4,373,378	4,594,694
Replace Equipment	74,431	155,339	236,375	324,777	421,995	533,260	649,606	771,032	900,079	1,039,288	1,188,657	1,343,108	1,497,558	1,652,008	1,806,458	1,960,909	2,115,359	2,269,809	2,409,526	2,531,460
Appliances New and Replacement	21,221	42,442	63,663	90,190	116,716	143,243	169,769	201,601	236,085	273,222	310,359	347,496	384,634	421,771	458,908	496,045	533,182	570,319	607,456	644,593
Solar Water Heat	24,085	56,199	96,341	144,511	199,104	256,909	314,714	372,518	430,323	488,127	545,932	603,736	661,541	719,345	777,150	834,954	892,759	950,563	1,008,368	1,066,172
COMMERCIAL																				
New Construction	295,186	590,371	885,557	1,180,743	1,475,928	1,771,114	2,066,299	2,361,485	2,656,671	2,951,856	3,247,042	3,542,228	3,837,413	4,132,599	4,427,784	4,722,970	5,018,156	5,313,341	5,608,527	5,903,713
Replace Shell	142,723	297,199	461,750	639,734	821,747	1,016,522	1,218,013	1,436,294	1,671,367	1,906,440	2,141,513	2,376,585	2,578,076	2,779,567	2,947,476	3,115,385	3,249,713	3,350,458	3,350,458	3,350,458
Replace Equipment	223,615	465,646	723,461	1,002,322	1,287,497	1,592,666	1,908,358	2,250,358	2,618,666	2,986,973	3,355,280	3,723,588	4,039,280	4,354,972	4,618,049	4,881,125	5,091,587	5,249,433	5,249,433	5,249,433
Retrofit Wx	220,062	458,248	711,967	986,397	1,267,042	1,567,362	1,878,039	2,214,605	2,577,060	2,939,516	3,301,972	3,664,428	3,975,104	4,285,780	4,544,677	4,803,574	5,010,692	5,166,030	5,166,030	5,166,030
Retrofit Equipment	355,520	740,317	1,150,210	1,593,564	2,046,956	2,532,136	3,034,046	3,577,782	4,163,343	4,748,905	5,334,467	5,920,028	6,421,938	6,923,848	7,342,107	7,760,365	8,094,972	8,345,927	8,345,927	8,345,927
Cooking Appliances	251,451	523,611	813,519	1,127,094	1,447,769	1,790,926	2,145,916	2,530,489	2,944,644	3,358,800	3,772,955	4,187,111	4,542,101	4,897,091	5,192,916	5,488,742	5,725,402	5,902,897	5,902,897	5,902,897
Commerical Firm Class with IND SIC	191,683	417,644	685,775	987,958	1,291,088	1,594,849	1,887,561	2,127,728	2,313,773	2,445,696	2,577,619	2,709,542	2,814,403	2,919,265	2,997,066	3,020,744	3,044,422	3,068,100	3,091,778	3,115,456
INDUSTRIAL FIRM																				
Retrofit	384,458	833,459	1,366,649	1,967,188	2,567,728	3,168,267	3,729,519	4,178,521	4,515,272	4,739,773	4,964,274	5,188,775	5,357,150	5,525,526	5,637,776	5,637,776	5,637,776	5,637,776	5,637,776	5,637,776
Replacement	13,096	32,739	55,657	81,848	110,004	139,469	185,304	234,412	283,521	332,630	381,738	430,847	479,956	529,065	578,173	627,282	676,391	725,499	774,608	823,717
Codes & Standards																				
Residential	96,143	465,286	904,597	1,833,515	2,799,108	3,807,096	4,864,045	5,953,909	7,048,586	8,145,426	9,239,079	10,327,433	11,411,340	12,491,295	13,573,182	14,657,476	15,737,689	16,806,957	17,886,674	18,977,011
Commercial	0	94,084	186,381	282,955	378,662	475,107	561,048	654,687	748,859	850,556	942,883	1,038,719	1,130,978	1,227,386	1,311,710	1,398,088	1,486,080	1,587,559	1,674,522	1,770,371
TOTAL																				
RESIDENTIAL	1,459,785	3,284,309	5,260,880	7,920,809	10,716,086	13,774,480	16,960,499	20,263,406	23,691,776	27,282,292	31,026,953	34,844,980	38,658,561	42,468,189	46,279,750	50,093,718	53,903,604	57,702,545	61,283,805	64,600,356
COMMERCIAL	1,680,240	3,587,119	5,618,620	7,800,767	10,016,690	12,340,682	14,699,280	17,153,428	19,694,384	22,188,743	24,673,730	27,162,228	29,339,294	31,520,509	33,381,785	35,190,994	36,721,022	37,983,745	38,389,571	38,804,284
INDUSTRIAL FIRM	397,553	866,198	1,422,305	2,049,036	2,677,731	3,307,736	3,914,823	4,412,933	4,798,793	5,072,403	5,346,012	5,619,622	5,837,106	6,054,590	6,215,950	6,265,058	6,314,167	6,363,276	6,412,384	6,461,493
ALL DSM	3,537,579	7,737,627	12,301,805	17,770,613	23,410,507	29,422,898	35,574,603	41,829,767	48,184,953	54,543,437	61,046,696	67,626,830	73,834,961	80,043,289	85,877,485	91,549,769	96,938,792	102,049,566	106,085,761	109,866,133

Appendix 4.4: Washington DSM Deployment Scenario Annual Cumulative Savings – THERMS

WA Cumulative Annual Savings - Therms	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESIDENTIAL																				
New Construction	17,753	43,861	69,968	96,076	122,706	149,335	175,965	249,937	323,908	397,880	471,851	545,823	619,794	693,766	767,737	841,709	915,680	989,652	1,063,623	1,137,595
New DHW	1,567	3,870	6,174	8,478	10,828	13,177	15,527	22,054	28,582	35,109	41,636	48,163	54,690	61,218	67,745	74,272	80,799	87,327	93,854	100,381
Retrofit	41,051	90,899	158,340	246,307	363,595	510,207	686,140	891,395	1,096,651	1,301,906	1,507,162	1,712,418	1,917,673	2,122,929	2,328,184	2,474,795	2,621,406	2,738,695	2,855,984	2,943,951
Replace DHW	16,996	37,634	65,556	101,976	150,536	211,237	284,077	369,057	454,037	539,018	623,998	708,978	793,958	878,939	963,919	1,024,619	1,085,319	1,133,879	1,182,440	1,218,860
Replace Equipment	3,517	7,788	13,566	21,102	31,151	43,711	58,784	76,369	93,955	111,540	129,125	146,710	164,295	181,880	199,465	212,026	224,586	234,635	244,684	252,220
Appliances New and Replacement	1,818	4,241	7,271	10,906	15,147	19,388	23,629	27,871	32,112	36,353	40,594	44,835	49,077	53,318	57,559	61,800	66,041	70,283	74,524	78,765
Solar Water Heat	1,828	3,839	6,033	8,410	10,970	13,529	16,089	18,649	21,208	23,768	26,327	28,887	31,447	34,006	36,566	39,126	41,685	44,245	46,804	49,364
COMMERCIAL																				
New Construction	6,526	14,358	24,148	35,896	48,949	65,265	81,581	97,897	114,214	130,530	146,846	163,162	179,479	195,795	212,111	228,427	244,744	261,060	277,376	293,692
Replace Shell	10,867	22,694	36,118	51,141	67,122	83,104	99,085	115,067	131,048	147,030	163,012	178,993	194,975	210,956	226,938	242,919	258,901	274,882	290,864	306,845
Replace Equipment	30,202	63,068	100,376	142,125	186,540	230,954	275,368	319,782	364,196	408,610	453,025	497,439	541,853	586,267	630,681	675,096	719,510	763,924	808,338	852,752
Retrofit Wx	9,122	19,049	30,318	42,928	56,343	69,758	83,173	96,588	110,004	123,419	136,834	150,249	163,664	177,079	190,494	203,909	217,324	230,739	244,154	257,569
Retrofit Equipment	51,632	107,820	171,601	242,974	318,904	394,833	470,763	546,692	622,622	698,551	774,481	850,411	926,340	1,002,270	1,078,199	1,154,129	1,230,058	1,305,988	1,381,917	1,457,847
Cooking Appliances	14,758	30,819	49,050	69,451	91,154	112,857	134,561	156,264	177,968	199,671	221,374	243,078	264,781	286,484	308,188	329,891	351,594	373,298	395,001	416,704
INDUSTRIAL FIRM																				
Retrofit	8,813	18,605	29,377	41,128	52,879	64,630	76,380	88,131	99,882	111,633	123,384	135,135	146,885	158,636	168,429	176,262	180,179	184,096	186,055	188,013
Replacement	2,138	4,489	7,054	9,833	12,826	16,033	19,239	22,446	25,653	28,859	32,066	35,272	38,479	41,685	44,892	48,099	51,305	54,512	57,718	60,925
Federal Furnace Code Change																				
Residential	0	0	0	46,071	92,143	138,214	184,285	230,357	276,428	322,499	368,571	414,642	460,713	506,785	552,856	598,927	644,999	691,070	737,141	783,213
TOTAL																				
RESIDENTIAL	84,530	192,132	326,908	539,326	797,075	1,098,799	1,444,497	1,885,689	2,326,881	2,768,072	3,209,264	3,650,456	4,091,647	4,532,839	4,974,031	5,327,274	5,680,517	5,989,785	6,299,054	6,564,348
COMMERCIAL	123,108	257,808	411,611	584,515	769,012	956,772	1,144,532	1,332,292	1,520,052	1,707,811	1,895,571	2,083,331	2,271,091	2,458,851	2,646,611	2,834,371	3,022,131	3,209,891	3,397,650	3,585,410
INDUSTRIAL FIRM	10,951	23,095	36,432	50,961	65,705	80,662	95,620	110,577	125,535	140,492	155,449	170,407	185,364	200,322	213,321	224,361	231,485	238,608	243,773	248,938
ALL DSM	218,589	473,035	774,950	1,174,803	1,631,792	2,136,233	2,684,649	3,328,558	3,972,467	4,616,376	5,260,285	5,904,194	6,548,103	7,192,012	7,833,962	8,386,006	8,934,132	9,438,284	9,940,477	10,398,696

Appendix 4: Detailed Measure Description

Table 1: Detailed Measure Table, Residential Sector, Gas Savings, and 2030 Technical Potential

Measure Description	Program	Average Lifetime	Total Incremental Cost	Total O&M Impact ($)	Gas Savings Therms	Level Cost, $/kWh	Level Cost, $/th	BCR
Low Flow Shower	Retro Gas	10	5,262,454	-13,692,180	50,592	na	-$21.788	100.00
Gas Hi-eff Washer	New Appl	12	-1,034,103	-1,384,760	25,876	-$0.282	-$3.097	100.00
Gas MEF 2.0 Washer	New Appl	12	-2,481,846	-2,404,545	58,387	-$0.260	-$2.863	100.00
Gas ETO Dishwasher	New Appl	12	-124,092	-452,266	3,742	-$0.184	-$2.099	100.00
Gas Hi-eff Washer	ReplaceAppl	12	-19,452,035	-26,048,100	401,921	-$0.175	-$1.927	100.00
Gas ETO Dishwasher	ReplaceAppl	12	-6,299,807	-22,960,233	156,862	-$0.164	-$1.865	100.00
Gas MEF 2.0 Washer	ReplaceAppl	12	-17,506,831	-16,961,553	340,087	-$0.132	-$1.450	100.00
Heating upgrade (AFUE 95) (Z A)	New Gas	15	-393,726	0	45,712	-$0.070	-$0.827	100.00
AFUE 92 to condensing combo hydrocoil, Z A	New Gas	45	-484,428	0	138,917	na	-$0.202	100.00
Window, upgrade to CL20, Z A	Replace Gas	45	11,946,385	0	2,289,085	na	$0.302	4.10
E* Insulation, Ducts, DHW, Lights (Gas Z A)	New Gas	45	77,210,485	0	10,261,732	$0.029	$0.331	3.75
Window, MF Retro, Z A	Retro Gas	45	2,481,112	0	432,289	na	$0.332	3.73
High Eff Gas WH after 2015	Replace Gas	15	7,189,358	0	2,307,662	na	$0.304	3.06
High Eff Gas WH	Replace Gas	15	17,323,597	0	5,136,462	na	$0.329	2.83
Move Ducts Inside, E* lights , Z A	New Gas	18	4,808,665	0	1,148,261	$0.000	$0.364	2.72
Duct Sealing, Z A	Retro Gas	20	82,346,214	0	14,610,809	na	$0.460	2.19
Upgrade Gas Hearth	Replace Gas	10	1,029,322	0	292,714	na	$0.460	2.05
HRV, Z A	Retro Gas	36	24,328,012	9,768,397	3,648,656	na	$0.579	2.01
Wx insulation (ceiling, floor, walls), Z A	Retro Gas	45	102,333,179	0	8,574,030	na	$0.691	1.79
Near Net Zero (Gas Z A)	New Gas	45	71,007,947	0	5,674,224	na	$0.725	1.71
Tank upgrade (50 gal gas)	New Gas	15	2,307,762	0	373,092	na	$0.604	1.54
Tankless Gas heater replace	Replace Gas	15	1,846,078	0	271,614	na	$0.664	1.40
AFUE 95 Furnace, Z A	Replace Gas	18	13,100,964	5,260,414	2,252,021	na	$0.708	1.39
Tankless Gas heater replace after 2015	Replace Gas	15	3,847,655	0	541,107	na	$0.694	1.34
Tankless Gas heater	New Gas	15	1,266,406	0	174,137	na	$0.710	1.31
Solar hot water heater (50 gal) - With gas backup.	Retro Gas	20	221,303,602	-197,103,629	6,809,494	na	$0.290	1.25
Wx insulation (ceiling, floor), Z A	Retro Gas	45	17,699,475	0	1,031,431	na	$0.994	1.25
Solar hot water heater (50 gal) - With gas backup.	New Gas	20	13,937,219	-12,414,383	402,049	na	$0.309	1.22
Window U=.2 (Gas Z A)	New Gas	45	6,026,625	0	320,825	na	$1.088	1.14

Measure Description	Program	Average Lifetime	Total Incremental Cost	Total O&M Impact ($)	Gas Savings Therms	Level Cost, $/kWh	Level Cost, $/th	BCR
Tankless Gas heater after 2015	New Gas	15	11,041,666	0	1,274,713	na	$0.846	1.10
Solar hot water heater (50 gal) - With gas aft 2015	New Gas	20	35,484,223	-28,268,521	903,058	na	$0.652	1.09
Solar hot water heater (50 gal) - With gas backup aft 2015	Retro Gas	20	227,653,868	-176,969,838	6,113,917	na	$0.677	1.09
MF Corridor Ventilation	New Gas	15	4,543,573	0	477,075	na	$0.930	1.04
MF Corridor Ventilation	Retro Gas	15	8,587,830	0	901,722	na	$0.930	1.04
Condensing Tankless Gas heater	Replace Gas	15	2,689,105	0	288,676	na	$0.910	1.02

Table 2: Detailed Measure Table, Commercial Sector, Gas Savings, 2030 Technical Potential

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
EStar Fryer	Install EStar in place of conventional	New	Cooking	8	124,802	0	1,646	10,128	na	$0.0118	75.76
Roof Insulation - Attic R0-30	Roof Insulation - Attic R0-30. Application: Buildings with uninsulated attics	Retrofit	Heating	45	426,170	0	190	1,503	$0.0231	$0.0393	31.54
EStar Fryer	Replace with EStar in place of conventional	Replace	Cooking	8	2,288,120	0	11,059	84,111	na	$0.0323	27.77
Heat Reclaim	Large Grocery - Heat recovery to space heating. Assumes floating head control exists and must be changed to allow HR.	New	Refrigeration	18	1,446,271	0	306	1,310	$0.0259	$0.0349	27.10
Heat Reclaim	Large Grocery - Heat recovery to space heating. Assumes floating head control exists and must be changed to allow HR.	Replace	Refrigeration	18	4,612,688	0	974	4,178	$0.0259	$0.0350	27.06

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
Roof Insulation - Rigid R0-11	Roof Insulation - Rigid R0-11- not including re-roofing costs but including deck preparation. Application: Old buildings with flat roofs and no attics	Replace	Heating	45	2,424,420	0	564	4,514	$0.0331	$0.0562	22.03
Roof Insulation - Rigid R0-22	Roof Insulation - Rigid R0-22-- not including re-roofing costs but including deck preparation and ~4" rigid.. Application: Old buildings with flat roofs and no attics	Replace	Heating	45	4,187,634	0	642	4,514	$0.0501	$0.0852	14.54
Estar Convection Oven	Replace with EStar in place of conventional	Replace	Cooking	12	246,585	0	444	51,866	na	$0.0634	14.52
Wall Insulation - Blown R11	Wall Insulation - Blown R11. Application: Old buildings	Retrofit	Heating	45	5,946,143	0	1,937	15,461	$0.0529	$0.0899	13.77
Estar Commercial Clothes Washer	Install high performance commercial clothes washers - coin op	New	Water Heat	10	1,097	-10,214	0	0	($1.0847)	($1.8071)	13.50
Estar Commercial Clothes Washer	Install high performance commercial clothes washers - coin op	Replace	Water Heat	10	326,011	########	22	23,820	($0.4201)	($0.6999)	13.27
Windows - Add Low E to Vinyl Tint	Windows - Add Low E to Vinyl Tint. Application: Old buildings	Replace	Heating	20	2,412,435	0	220	34,030	$0.0492	$0.0791	12.74
DCV	Applicable to single zone packaged systems with large make -up air fractions either because of intermittent occupancy or because of code requirements. In most cases the outdoor air is reset to 5% or less with CO2 build-up modulating ventilation.	Retrofit	Heating	15	7,916,457	0	779	36,450	$0.0381	$0.0559	11.20

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
Windows - Tinted AL Code to Class 45	Windows - Tinted AL Code to Class 45. Application: Old buildings	Replace	Heating	20	1,223,205	0	15	18,534	$0.0648	$0.1043	9.67
HW Boiler Tune	Tune up in accordance with Minneapolis Energy Office protocol. Can include derating the burner, adjusting the secondary air, adding flue restrictors, cleaning the fire-side of the heat exchanger, cleaning the water side, or installing turbulators. Other modifications may include uprating the burner to reduce oxygen or derating the burner to reduce stack temperature. Note: In gas systems, excess air and stack temperatures are often within reasonable ranges, so the technical potential for this measure is limited. Combining this measure with the vent damper and power burner measures increases both applicability and cost effectiveness, and was assumed for this analysis.	Retrofit	Heating	5	9,066	0	22	1,152	na	$0.0940	9.46
Windows - Add Low E and Argon to Vinyl Tint	Windows - Add Low E and Argon to Vinyl Tint. Application: Old buildings	Replace	Heating	20	3,772,831	0	307	34,030	$0.0733	$0.1180	8.54
DHW Shower Heads	Install low flow shower heads (2.0 gallons per minute) to replace 3.4 GPM shower heads.	Retrofit	Water Heat	8	73,492	0	97	2,608	na	$0.1187	7.55

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
Ducts	Duct retrofit of both insulation and air sealing	Retrofit	Heating	15	3,217,074	0	281	12,912	$0.0879	$0.1290	7.47
Hot Water Temperature Reset	Controller automatically resets the delivery temperature in a hot water radiant system based on outside air temperature. The reset reduces the on-time of the heating equipment and the occurrence of simultaneous heating and cooling through instantaneous adjustments.	Retrofit	Heating	10	692,854	0	706	29,912	na	$0.1283	7.36
Roof Insulation - Rigid R11-22	Roof Insulation - Rigid R11-22 2" rigid added to an existing foam roof insulation at re-roof, includes some surface prep. Application: Old buildings with flat roofs, no attics, and some insulation	Replace	Heating	45	10,597,588	0	1,225	14,285	$0.1018	$0.1731	7.15
Windows - Tinted AL Code to Class 40	Windows - Tinted AL Code to Class 40. Application: Old buildings	Replace	Heating	20	1,839,405	0	68	18,534	$0.0890	$0.1432	7.04
Roof Insulation - Attic 11-30	Roof Insulation - Attic 11-30. Application: Buildings with partially insulated attics	Retrofit	Heating	45	2,868,703	0	377	10,822	$0.1145	$0.1947	6.36
Steam Balance	Single-pipe steam systems are notorious for uneven heating, which wastes energy because the thermostat must be set to heat the coldest spaces & overheating other spaces. Steam balances corrects these problems by: 1) Adding air venting on the main line or at the radiators; 2) Adding boiler cycle controls; 3) Adding or subtracting radiators. Energy savings accrue from lowering the overall building temperature.	Retrofit	Heating	15	697,197	0	377	11,756	na	$0.1808	5.33

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
Roof Insulation - Blanket R0-19	Roof Insulation - Blanket R0-19. Application: Buildings with open truss unfinished interior	Retrofit	Heating	45	3,793,376	0	868	5,126	$0.1399	$0.2379	5.21
Roof Insulation - Blanket R0-30	Roof Insulation - Blanket R0-30. Application: Buildings with open truss unfinished interior	Retrofit	Heating	45	4,267,549	0	910	5,126	$0.1496	$0.2543	4.87
Wall Insulation - Spray On for Metal Buildings	Wall Insulation - Spray On for Metal Buildings (Cellulose) Unfinished. Application: Old buildings	Retrofit	Heating	45	2,219,822	0	630	6,430	na	$0.2649	4.68
Rooftop Condensing Burner	Install condensing burner	New	Heating	10	6,017,823	0	314	11,890	$0.1285	$0.2142	4.43
Roof Insulation - Roofcut 0-22	Roof Insulation - Roofcut 0-22. Application: Buildings with uninsulated flat roofs at reroofing time	Replace	Heating	45	7,462	0	1	15	$0.1659	$0.2821	4.39
DHW Wrap	Insulate the surface of the storage water heater or an unfired storage tank to R-5 to reduce standby losses.	Retrofit	Water Heat	7	14,327	0	12	3,725	na	$0.2041	4.34
Windows - Tinted AL Code to Class 40	Windows - Tinted AL Code to Class 40. Application: New Construction	New	Heating	20	791,876	0	26	8,518	$0.1528	$0.2353	4.10
Estar Convection Oven	Install EStar in place of conventional	New	Cooking	12	201,885	0	97	9,490	na	$0.2376	3.87
EStar Steam Cooker	Replace with EStar in place of conventional	Replace	Cooking	10	129,629	-352,474	18	127,848	na	($1.6047)	3.70
EStar Steam Cooker	Install EStar in place of conventional	New	Cooking	10	23,605	-64,169	3	19,243	na	($1.6195)	3.69

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
DHW Condensing Tank (new)	Costs and savings are incremental over a Code-rated tank (combustion efficiency of 80%) for a condensing tank with a minimum combustion efficiency of 94% and an R-16 tank wrap.	New	Water Heat	15	1,564,889	0	588	31,699	na	$0.2598	3.58
DHW Condensing Tank (repl)	Costs and savings are incremental over a Code-rated tank (combustion efficiency of 80%) for a condensing tank with a minimum combustion efficiency of 94% and an R-16 tank wrap.	Replace	Water Heat	15	4,981,535	0	1,786	104,306	na	$0.2724	3.42
Roof Insulation - Rigid R11-33	Roof Insulation - Rigid R11-33: add 4' of insulation at reroof. Application: Old buildings with flat roofs, no attics, and some insulation	Replace	Heating	45	15,896,382	0	482	14,285	$0.2377	$0.4043	3.06
Windows - Tinted AL Code to Class 36	Windows - Tinted AL Code to Class 36. Application: Old buildings	Replace	Heating	20	4,598,513	0	118	18,534	$0.2064	$0.3319	3.04

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
HVAC controls	Control set up and algorithm. This assumes the development of an open source control package aimed at describing scheduling and control points throughout the HVAC system, properly training operators so that scheduling can be maintained and adjusted as needed, and providing operator back up so that temperature reset, pressure reset, and minimum damper settings are set at optimum levels for the current occupancy.	New	Heating	5	16,702,714	0	2,335	66,851	$0.1649	$0.3432	2.48
Vent Damper	Install vent damper downstream of the draft relief to prevent airflow up the stack, while allowing warm air from the boiler to spill into the conditioned space as heat or into the boiler room to reduce jacket losses. This measure is most cost-effective when combined with the boiler tune up and power burner measures.	Retrofit	Heating	12	344,021	0	94	6,248	na	$0.4172	2.29
Hot Food Holding Cabinet	Install EStar in place of conventional	New	Cooking	8	237,124	0	92	19,243	na	$0.4011	2.23
Hot Food Holding Cabinet	Install EStar in place of conventional	Replace	Cooking	8	1,597,458	0	621	159,810	na	$0.4015	2.23
DHW Hieff Boiler (new)	Replace existing boiler with unit meeting OR Code requirements of 80% combustion efficiency.	New	Water Heat	20	506,178	0	87	7,914	na	$0.4746	2.05

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
DHW Hieff Boiler (repl)	Replace existing boiler with unit meeting OR Code requirements of 80% combustion efficiency.	Replace	Water Heat	20	1,490,657	0	247	25,152	na	$0.4929	2.04
EStar Griddle	Install EStar in place of conventional	New	Cooking	12	133,613	0	33	19,243	na	$0.4553	2.02
EStar Griddle	Replace with EStar in place of conventional	Replace	Cooking	12	604,622	0	150	106,540	na	$0.4597	2.00
SPC Hieff Boiler Replace	Install near condensing boiler. Assumed seasonal combustion efficiency of 85% over base of 80%	Replace	Heating	20	554,660	0	89	5,233	na	$0.5058	1.99
Waste Water Heat Exchanger	Install HX on waste water	New	Water Heat	15	478,211	0	97	2,561	na	$0.4806	1.94
Waste Water Heat Exchanger	Install HX on waste water	Retrofit	Water Heat	15	184,461	0	37	1,124	na	$0.4846	1.92
Combo Hieff Boiler (new)	Replace existing boiler with unit meeting OR Code requirements of 80% combustion efficiency.	New	Heating	20	355,188	0	57	3,411	na	$0.5110	1.90
Combo Hieff Boiler (repl)	Replace existing boiler with unit meeting OR Code requirements of 80% combustion efficiency.	Replace	Heating	20	1,287,011	0	191	10,953	na	$0.5506	1.83
Windows - Tinted AL Code to Class 36	Windows - Tinted AL Code to Class 36. Application: New Construction	New	Heating	20	1,979,690	0	42	8,518	$0.3542	$0.5457	1.77

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
HVAC System Commissioning	HVAC system commissioning. Includes testing and balancing, damper settings, economizer settings, and proper HVAC heating and compressor control installation. This measure includes the proper set-up of single zone package equipment in simple HVAC systems. The majority of the Commercial area is served by this technology. Work done in Eugene (Davis, et al, 2002) suggests higher savings than the other documented commissioning on more complex systems.	New	Heating	15	49,630,922	0	1,334	76,402	$0.3864	$0.5433	1.70
Cond Furnace (new)	Condensing / pulse package or residential-type furnace with a minimum AFUE of 92%. Base case: AFUE 80	New	Heating	18	2,067,805	0	315	10,663	na	$0.5712	1.66
SPC Hieff Boiler (new)	Install near condensing boiler. Assumed seasonal combustion efficiency of 82% over base of 75%	New	Heating	20	952,110	0	117	7,915	na	$0.6624	1.46
DHW Cond Boiler (new)	Replace with boiler using condensing or pulse technology to achieve steady-state combustion efficiencies of 89% to 94% (this analysis used 92% efficiency for savings calculations).	New	Water Heat	20	1,585,617	0	193	7,914	na	$0.6705	1.45

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
DHW Cond Boiler (repl)	Replace with boiler using condensing or pulse technology to achieve steady-state combustion efficiencies of 89% to 94% (this analysis used 92% efficiency for savings calculations).	Replace	Water Heat	20	4,736,383	0	547	25,152	na	$0.7063	1.43
SPC Cond Boiler Replace	Install condensing boiler. Assumed seasonal combustion efficiency of 92% over base of 80%	Replace	Heating	20	2,248,985	0	259	5,652	na	$0.7074	1.42
DHW Recirc Controls	Install electronic controller to hot water boiler system that turns off the boiler and circulation pump when the hot water demand is reduced (usually in residential type occupancies) or can be reset to meet the hot water load. (Steel boilers also require a mixing valve to prevent water temperatures from dropping below required levels).	Retrofit	Water Heat	10	567,062	0	109	4,258	na	$0.6833	1.33
DHW Faucets	Add aerators to existing faucets to reduce flow from 2.2 gallons per minute to 1.5 GPM.	Retrofit	Water Heat	8	28,625	0	6	1,739	na	$0.6937	1.29
DHW Faucets	Add aerators to existing faucets to reduce flow from 2.2 gallons per minute to 1.5 GPM.	New	Water Heat	8	11,206	0	3	679	na	$0.6954	1.29
Hi Eff Unit Heater (new)	Install power draft units (83% seas. Eff) in place of natural draft (80% seas. Eff) per ASHRAE 90.1-2007	New	Heating	18	910,331	0	103	14,129	na	$0.7671	1.23
Ozone Laundry Treatment	Ozone treatment allows use of cold water	Retrofit	Water Heat	10	2,530,371	-167,016	338	17,398	$0.4423	$0.7369	1.22
Computerized Water Heater Control	Install intelligent controls on the hot water circulation loops.	Retrofit	Water Heat	15	675,690	0	85	5,990	na	$0.7763	1.20

Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
Computerized Water Heater Control	Install intelligent controls on the hot water circulation loops.	New	Water Heat	15	212,492	0	26	1,467	na	$0.7950	1.17
Power burner	Replace standard burner with a power burner to optimize combustion and reduce standby losses in the stack. Note: Costs and savings assume that this measure will be performed in conjunction with a boiler tune up when appropriate.	Retrofit	Heating	12	7,044,489	0	971	43,734	na	$0.8280	1.15
SPC Cond Boiler (new)	Install condensing boiler. Assumed seasonal combustion efficiency of 88% over base of 75%	New	Heating	20	2,977,733	0	281	8,548	na	$0.8651	1.12
Cond Unit Heater From Power Draft (new)	Install condensing power draft units (90% seas. Eff) in place of power draft (80% seas. Eff)	New	Heating	18	2,542,755	0	254	11,303	na	$0.8713	1.09
Combo Cond Boiler (new)	Replace with boiler using condensing or pulse technology to achieve steady-state combustion efficiencies of 89% to 94% (this analysis used 92% efficiency for savings calculations).	New	Heating	20	1,414,501	0	126	3,411	na	$0.9178	1.06
Combo Cond Boiler (repl)	Replace with boiler using condensing or pulse technology to achieve steady-state combustion efficiencies of 89% to 94% (this analysis used 92% efficiency for savings calculations).	Replace	Heating	20	5,023,358	0	423	10,953	na	$0.9691	1.04
DHW Pipe Ins	Add 1" insulation to pipes used for steam or hydronic distribution; particularly effective when pipes run through unheated spaces.	New	Water Heat	15	79,440	0	9	4,212	na	$0.9004	1.03

Table 3: Detailed Measure Description, Industrial Natural Gas Technical Potential

Conservation Measure	Potential Savings (th/yr)	Annual O&M Cost	Levelized Cost ($/th)	Initial Cost, k$	BCR
Process Boiler Water Treatment	211,950	$0	$0.001	$1	1,650.85
Process Boiler Controls	263,230	$0	$0.001	$3	890.47
Process Boiler Load Control	847,800	$0	$0.002	$10	778.47
Process Boiler Insulation	1,695,600	$1,999	$0.008	$88	186.52
DHW Wrap	27,175	$0	$0.000	$0	100.00
Process Boiler Maintenance	423,900	$212	$0.001	$0	100.00
Process Boiler Steam Trap Maintenance	1,377,675	$48,219	$0.035	$0	100.00
DHW Pipe Ins	61,144	$0	$0.019	$9	67.92
DHW Condensing Tank (repl)	272,351	$0	$0.025	$48	53.23
DHW Hieff Boiler (repl)	199,635	$0	$0.047	$81	29.06
DHW Cond Boiler (repl)	334,084	$0	$0.151	$435	9.09
HW Boiler Tune	1,543,561	$0	$0.172	$800	7.08
Hot Water Temperature Reset	2,806,502	$0	$0.186	$2,802	6.93
DHW Std. Boiler (retro)	9,058	$0	$0.222	$18	6.07
Wall Insulation - Blown R11	235,604	$0	$0.243	$665	5.65
Ozone Treated Laundry	525,615	($35,853)	$0.171	$892	5.61
Wall Insulation - Spray On for Metal Buildings	258,681	$0	$0.270	$813	5.08
Heat Recovery to HW	2,578,209	($333,922)	$0.150	$5,121	4.82
Combo Hieff Boiler (repl)	643,939	$0	$0.332	$1,858	4.10
Roof Insulation - Blanket R0-19	335,420	$0	$0.335	$1,307	4.09

Conservation Measure	Potential Savings (th/yr)	Annual O&M Cost	Levelized Cost ($/th)	Initial Cost, k$	BCR
Hi Eff Unit Heater (replace)	794,853	$0	$0.329	$2,201	3.93
HiEff Clothes Washer (repl)	4,612	($54,003)	($10.974)	$24	3.84
HiEff Clothes Washer (retro)	4,612	($54,003)	($10.974)	$24	3.84
Roof Insulation - Blanket R0-30	351,916	$0	$0.359	$1,471	3.82
Steam Balance (Wood Prod)	50,720	$0	$0.359	$129	3.71
Vent Damper	1,543,561	$0	$0.463	$4,392	2.81
Combo Cond Boiler (repl)	1,257,213	$0	$0.611	$6,674	2.23
Steam Trap Maint (Wood Prod)	62,696	$0	$0.622	$206	2.10
SPC Hieff Boiler Replace	197,730	$0	$0.682	$1,162	2.01
Waste Water Heat Exchanger	65,083	$0	$0.671	$390	1.98
Roof Insulation - Rigid R11-22 repl	301,768	$0	$0.869	$3,051	1.58
Upgrade Process Heat	275,130	$0	$0.966	$1,942	1.34
SPC Cond Boiler Replace	341,976	$0	$1.065	$3,135	1.29
Power burner	2,275,208	$0	$1.107	$15,482	1.18

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 24 Original Sheet 350-1

SCHEDULE 350

ENERGY EFFICIENCY SERVICES AND PROGRAMS – RESIDENTIAL AND COMMERCIAL

APPLICABLE:

This program is intended to provide an economical and effective means of conserving Natural Gas through the reduction of heat loss in Residential dwellings and Commercial buildings and in the improvement of the efficiency of space heating, water heating, and energy utilization of the dwellings. This Tariff is in compliance with ORS 469.631 et seq. and with Orders No. 81-778, No. 85-619, No. 85-639, No. 85-891, No. 85-896, No. 91-822, and No. 02-624 of the Commission.

AVAILABLE:

In all territory served by the Company under the Tariff of which this program is a part.

INFORMATION TO CUSTOMERS:

The Company will provide to its Residential and Commercial Customers, general and technical information about energy efficiency services offered by the Company, and about energy efficiency programs available through the Energy Trust of Oregon (Energy Trust), that will improve the efficiency of space heating and energy utilization of Residential dwellings and Commercial buildings. This information may be provided through the use of bill inserts, displays (all offices), booklets, handouts, advertisements, and industry and public agency literature.

Advice concerning the advantages or disadvantages of various methods of saving energy will be available through trained Company personnel upon request of Residential and Commercial Customers. Thermal insulation standards of the American National Standards Institute, the International Conference of Building Officials, and American Society of Heating, Refrigeration and Air Conditioning Engineers will be the basis for any technical advice. The Company will provide qualified speakers on energy efficiency subjects for any group desiring this assistance.

ENERGY EFFICIENCY PROGRAMS:

The Energy Trust of Oregon has been approved to deliver and administer energy efficiency programs to NW Natural's Customers. Customers may participate in such programs by contacting the Energy Trust directly, or a NW Natural representative will connect the Customer upon request.

CUSTOMER NOTIFICATION:

Residential and Commercial Customers will be notified annually by "bill insert" that (1) information on energy efficiency is available from the Company; (2) that energy efficiency programs are available through the Energy Trust; (3) how to obtain energy efficiency information from the Company; and (4) how to contact the Energy Trust.

Notification to rental unit owners will be made by mail when a tenant who is a Customer: (a) requests that the material be mailed to the owner; and (b) furnishes the owner's name and address with the request.

GENERAL TERMS:

This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

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NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 24

First Revision of Sheet 360-1
Cancels Original Sheet 360-1

SCHEDULE 360
INDUSTRIAL DEMAND SIDE MANAGEMENT (DSM) PROGRAMS

APPLICABLE:
Service under this Schedule is applicable to Industrial Customers, which for the purposes of this Schedule is defined as the following:
1) Industrial Firm Sales Customers, served on Rate Schedules 3, 31 or 32;
2) Industrial Interruptible Sales Customers served on Rate Schedule 31 or 32;
3) Commercial Sales Customers served on Rate Schedule 32; and
4) Combination Service Customers where neither service option is Transportation.

AVAILABLE:
In all territory served by the Company under the Tariff of which this program is a part.

PURPOSE:
This program is intended to provide an economical and effective means of conserving Natural Gas through the reduction of heat loss in certain commercial and industrial buildings.

INFORMATION TO CUSTOMERS:
The Company will provide to its Industrial Customers, general and technical information about energy efficiency services offered by the Company, and about energy efficiency programs available through the Energy Trust of Oregon (Energy Trust), that will improve the efficiency of natural gas usage. This information may be provided through various channels such as electronic newsletters, letters, direct communications, etc.

ENERGY EFFICIENCY PROGRAMS:
The Energy Trust of Oregon has been approved to deliver and administer energy efficiency programs to NW Natural's Customers. Customers may participate in such programs by contacting the Energy Trust directly, or a NW Natural representative will connect the Customer upon request.

PROGRAM COSTS
Program costs will be deferred annually and amortized for recovery through Schedule 188 of this Tariff.

SPECIAL PROVISIONS
If a Customer who chooses to receive service under this schedule switches any part of his/her service to a Transportation Service Type within two Years from the date the most recent incentive was issued, such Customer may incur a one-time charge equal to the two-year proration of the total incentive(s) amount received. The charge will be calculated as follows:

Charge= A x B

A= the total amount of Energy Trust incentives paid to Customer
B= 24 minus the number of months that have elapsed since the last incentive was issued, divided by 24

(continue to Sheet 360-2)

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SCHEDULE 360
INDUSTRIAL DEMAND SIDE MANAGEMENT (DSM) PROGRAMS

SPECIAL PROVISIONS (continued)
A charge will not be assessed when the total incentive amounts received by such customer are $25,000 or less. This provision will not apply to Customers who committed to participating in Energy Trust programs prior to September 8, 2010.

The collections from this charge will offset program costs collected under Schedule 188.

When applicable, the charge must be paid in full as a condition of the Company's approval to change Service Type. The Customer must meet all other conditions for the change in Service Type as set forth in the respective Rate Schedule.

GENERAL TERMS
Service under this Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 24

Fourth Revision of Sheet 320-1
Cancels Third Revision of Sheet 320-1

SCHEDULE 320

OREGON LOW-INCOME ENERGY EFFICIENCY (OLIEE) PROGRAMS

PURPOSE:
To describe the Oregon Low-Income Energy Efficiency (OLIEE) program which is funded through a designated portion of the Schedule 301 “Public Purposes Funding Surcharge.” The OLIEE program includes two parts: 1) the Community Action Program (CAP) and 2) the Open Solicitation Program (OSP).

AVAILABLE:
This program is available to income-eligible Residential Customer Class dwellings located within NW Natural’s Oregon service territory where (1) a gas Service Line is installed at the Premise; (2) the primary space heating equipment is fueled by Natural Gas, and (3) and the occupant has an active account with the Company, or will have an active account upon completion of work performed under this Schedule 320. Any residential dwelling that received assistance for the installation of the same or similar measures under any other energy efficiency program may not be eligible for assistance under this program.

PROGRAM YEAR and REPORTING:
The OLIEE program year will extend from October 1 through September 30 (Program Year). The Company will submit an Annual Report of the OLIEE Programs to the Commission by December 31 following the end of each Program Year.

The Annual Report will consistently include the same Program Year results from year to year. Beginning in 2011, the Annual Report will include the number of homes targeted for completion in the next Program Year, and beginning in 2012, the Annual Report will include the average pre-installation usage and average post-installation usage for each agency.

PROGRAM FUNDING:
Each month, the Company will bill and collect Public Purposes funds in accordance with Schedule 301 of this Tariff. By the 20th of the month following the billing month, the amount collected, net of an allowance for uncollectibles, will be deposited into a market-based interest bearing bank account dedicated to the OLIEE program (OLIEE Account). The reserve for uncollectibles shall be in an amount equal to NW Natural’s average percentage of residential net write-offs.

PROGRAM ADMINISTRATION, EVALUATION AND VERIFICATION:
All OLIEE programs are to be administered by the Company in accordance with this **SCHEDULE 320**. The Company will be reimbursed from the OLIEE Account each month for actual program administration costs incurred, except that such reimbursement will not exceed the lesser of $90,000 or 6% of the total funds available during each Program Year.

In addition, the Company will be reimbursed from the OLIEE Account each month for actual project verification costs incurred for the OSP, except that such reimbursement will not exceed 5% of the total available funds collected during each Program Year.

(continue to Sheet 320-2)

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NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 24

Third Revision of Sheet 320-2
Cancels Second Revision of Sheet 320-2

SCHEDULE 320
OREGON LOW-INCOME ENERGY EFFICIENCY (OLIEE) PROGRAMS
(continued)

PROGRAM ADMINISTRATION, EVALUATION AND VERIFICATION (continued):
Following the end of each Program Year, the Company and the OLIEE Advisory Committee (OAC) will evaluate the need for an independent organization to conduct a process and/or impact evaluation for the OLIEE programs. Such evaluation shall be paid from the OLIEE account in an amount not to exceed $50,000.

PROGRAM ADVISORY COUNCIL:
An OLIEE Advisory Council (OAC) will assist in advising the Company on OLIEE program implementation, and evaluation. The OAC will be comprised of at least one member each from the Company, the Commission staff, the Community Action Partnership of Oregon (CAPO), plus two or more representatives from the CAP, and when appropriate, one or more representatives from the OSP. The OAC will have no decision-making authority. The OAC will meet at least twice each program year.

ALLOCATION OF FUNDS:
The amount of funds available to support each OLIEE program will be determined by NW Natural as follows:

1. At the beginning of each Program Year, the Company will determine the allocation of funds between the CAP and the OSP based on an estimate of the amount of funds available for that Program Year. Funds will be allocated first to the CAP and second to the OSP.

2. Any amounts not disbursed in the Program Year will carry over to the next Program Year.

I. COMMUNITY ACTION PROGRAM (CAP) DESCRIPTION

The CAP is designed to leverage other funding sources with OLIEE funds to increase the overall energy efficiency in low-income households within NW Natural's service territory by providing rebates for the installation of certain energy efficiency measures in qualifying residential dwellings following the completion of a home energy evaluation performed by qualifying Agencies that contract with NW Natural, and when authorized by the Company, by providing funding for energy education programs.

(continue to Sheet 320-3)

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Fifth Revision of Sheet 320-3
Cancels Fourth Revision of Sheet 320-3

SCHEDULE 320
OREGON LOW-INCOME ENERGY EFFICIENCY (OLIEE) PROGRAMS
(continued)

Agency Qualifications and Responsibilities for CAP Funds:

1. In order to qualify to participate in the OLIEE program, an Agency must be a legal entity that has been in the business of providing energy efficiency services to low-income customers for at least one year. Any Agency that is contracting or subcontracting with the State of Oregon, Department of Housing and Community Services (OHCS), which is eligible to administer funding under the Federal Low Income Energy Assistance Program (LIEAP) is automatically authorized to participate. All other Agencies must first apply to the Company for authorization to participate. The conditions upon which the Company will approve an application will include, but are not necessarily limited to (a) availability of funds, (b) Agency location, and (c) number of Residential Customer Class dwellings served by NW Natural.
2. All Agencies must enter into a written contract with the Company in order to participate in the administration and delivery of funds under this program.
3. Each participating Agency will have sole responsibility to screen and approve applicants for eligibility. Each Agency shall follow the established protocols for the qualification of and disbursement to eligible participants in accordance with the guidelines of this program and the guidelines promulgated by OHCS and the Low-Income Energy Assistance Act of 1981 and subsequent amendments, as outlined in the OHCS Omnibus Contract.
4. Each participating Agency shall be responsible to complete and return to the Company, all required paperwork and other documentation as may be necessary for the Company to process the rebate request in a form prescribed by the Company.
5. Each participating Agency must agree to abide by the program parameters established in this Schedule including using the Department of Energy (DOE) approved, residential, energy analysis software tool (Energy Analyzer Software) in its determination of all measures that qualify for a rebate under CAP.
6. An Agency that fails to abide by the terms and conditions set forth in this tariff schedule may be removed from participating in the CAP Program.
7. To improve the accuracy of the program's realization rates (i.e. the ratio between verified savings and deemed savings) each participating Agency must attend a training workshop offered in collaboration with the Company, OHCS and CAPO. The workshop will be designed to ensure agencies are consistently and accurately entering data into the Energy Analyzer Software. The Company shall inform Staff of the selected workshop trainer and provide a summary report on the workshop's accomplishments.

Customer Qualifications for CAP Funds

All CAP funds collected under this program will be used to weatherize homes inhabited by qualifying income-eligible residential customers of NW Natural. In the event the Company receives a rebate request for a single customer from two or more Agencies, the Company will process only one request.

(continue to Sheet 320-4)

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Fourth Revision of Sheet 320-4
Cancels Third Revision of Sheet 320-4

SCHEDULE 320
OREGON LOW-INCOME ENERGY EFFICIENCY (OLIEE) PROGRAMS
(continued)

CAP Administration and Delivery Costs

Each Agency will be reimbursed from the OLIEE Account for administrative costs and direct program costs incurred by them in their administration and delivery of the OLIEE program in the amount of $225.00 per household. The Agency fee will be paid to each Agency along with the measure rebate payments. The Company will process measure rebate payments and Agency payments within thirty (30) days from the date the Company receives all completed documentation in support of such rebate request(s).

Annual Program Year Targets (households).

At the beginning of each Program Year, each participating Agency will be assigned a home completion target that supports the achievement of an annual program target. Agency targets may be adjusted from time to time throughout a Program Year, as necessary. Nothing precludes Agencies from serving more than the annual target of homes in any program year provided sufficient funds are available.

The total household target for the 2010-2011 Program Year will be 600 homes. For each Program Year thereafter, the Company will include the following year's target, by Agency, in the Annual Report.

Energy Efficiency Measures and Rebates.

Qualifying energy efficiency measures shall be those recommended by the Energy Analyzer Software. To qualify for a rebate under the CAP Program, the total group of measures prescribed by the Energy Analyzer Software for the whole house must meet or exceed a Savings to Investment Ratio (SIR) of 1.0 or better, and except for certain approved exceptions, measures must be chosen in the ranked order of the Energy Analyzer Software's prescriptions.

Rebates under the CAP Program will be paid based on the cost of the total group of qualifying measures for the whole house, as recommended by the Energy Analyzer Software and installed by the Agency. At the beginning of each program year, the maximum rebate amount per home shall be reset to an amount equal to ninety percent (90%) of the average total installed cost of measures as reported by the Agencies for the prior program year. To accommodate timing differences between measure installations, the rebate may be disbursed through one or more reimbursement requests provided all of the work is based on the same audit. Only one energy efficiency audit per home will be eligible for rebates under the OLIEE Program. Under no circumstances will the rebate exceed the actual installed cost of the measure(s).

(continue to Sheet 320-5)

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Third Revision of Sheet 320-5
Cancels Second Revision of Sheet 320-5

SCHEDULE 320
OREGON LOW-INCOME ENERGY EFFICIENCY (OLIEE) PROGRAMS
(continued)

Health, Safety and Repair (HSR) Allowance and Reimbursement.
In addition to the rebate for qualifying energy efficiency measures, a rebate will be available for the costs of health, safety and repair (HSR) measures. HSR measures are those items that if not completed would adversely impact the safety and health of the occupants or the effectiveness of the energy efficiency measures. Standard efficiency furnace replacements may qualify for HSR funds if the existing furnace is broken, is found to produce an unsafe level of CO emissions, is back-drafting, or has a cracked heat exchanger and a high-efficiency furnace is not cost-effective or if it is physically impossible to install a high-efficiency furnace. When a furnace is replaced with a standard efficiency furnace, the Agency must specify the reasons for the replacement in the reimbursement request.

The maximum annual HSR disbursement available to each Agency will be $440 times the actual number of households treated by the Agency in the Program Year (HSR Allowance).

Each Agency will have discretion in the use of their individual HSR Allowance such that they may use more or less than the $440 on any one home. Each Agency must manage their HSR funds to ensure that the average HSR amount per home is not more than $440.

Agency Reporting Requirements
For each home treated under the OLIEE Program, each Agency will be required to report to the Company, the following information:

- Customer Name (as shown on NW Natural Account)
- NWN Account Number
- Service Address
- Phone Number
- Owner or Property Manager Name
- Owner or Property Manager Phone Number
- Audit Date
- Installation Completion Date
- Reimbursement Request Date
- Agency and Agency Representative
- Size of home in square feet and Year Built
- Measure description
- Installed cost per measure
- Estimated therm savings per measure
- Energy Analyzer Software SIR per measure
- Total Energy Analyzer Software SIR for Measure Group
- Total Cost of all energy efficiency measures installed (EEMC)
- Total Energy Analyzer Software estimated savings for each household (Total therms)
- Total job cost to Agency (OLIEE and non-OLIEE measure costs)
- Cost per therm saved for each household (Cost/Savings)
- Requested reimbursement (90% of EEMC up to annual limit)
- Total HSR measure cost
- HSR Related Savings (i.e. – furnace replacements)
- Total Reimbursement Request: (90% of energy efficiency measure costs up to annual limit + Admin)
- Prior 12 months of gas usage
- Projected savings as a percentage of the last 12 months gas usage

(continue to Sheet 320-6)

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P.U.C. Or. 24

Second Revision of Sheet 320-6
Cancels First Revision of Sheet 320-6, Original Sheet 320-7
and Original Sheet 320-8

SCHEDULE 320
OREGON LOW-INCOME ENERGY EFFICIENCY (OLIEE) PROGRAMS
(continued)

II. OPEN SOLICITATION PROGRAM (OSP) DESCRIPTION

The overall goal of the OSP is to cost-effectively provide energy efficiency assistance to a greater number of low-income households in NW Natural's Oregon service territory through a broad and diverse network of delivery channels. The Company will invite proposals that include projects for new affordable housing, existing retrofit opportunities, and owner-occupied or rental dwellings, and will encourage proposals that include a component for energy education, environmentally sustainable practices, and collaboration with other entities or programs.

The Company will make the final determination as to which proposals will be awarded contracts under the OSP.

GENERAL TERMS:
This schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

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Issued by: NORTHWEST NATURAL GAS COMPANY
d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 24 Sixth Revision of Sheet 301-1
Cancels Fifth Revision Sheet 301-1

SCHEDULE 301
PUBLIC PURPOSES FUNDING SURCHARGE

PURPOSE:
To specify the method of billing of a Public Purposes surcharge that is to fund public purposes activities to be administered through one or more independent entities. Public purposes activities include, but may not necessarily be limited to, energy efficiency programs, market transformation programs, residential low-income energy efficiency programs, and residential low-income bill payment assistance programs designed to benefit Residential and Commercial Customers within NW Natural's service territory in Oregon.

APPLICABLE:
To Residential and Commercial Customers served on the following Rate Schedules of this Tariff:

Residential	Commercial
Schedule 1	Schedule 1
Schedule 2	Schedule 3
	Schedule 31 (CSF)
	Schedule 31 (CSI)

ADJUSTMENT TO RATES: Effective: January 1, 2011 (T)
A Public Purposes surcharge will be assessed on the total energy use billed (the total of the Customer Charge plus the per therm usage charges) and shown as a line item on each customer's monthly bill as follows:

Residential: 3.59% of the total energy use billed (R)
Commercial: 3.01% of the total energy use billed (R)

The funds collected from such Public Purposes surcharge shall be allocated to specific separate accounts to fund the specified public purposes program(s) as follows:

RESIDENTIAL:

2.76% will support public purpose funding for Schedule 350 energy efficiency programs delivered and administered by the Energy Trust of Oregon (Energy Trust). (R)

0.58% will support public purpose funding for Schedule 310 low-income bill payment assistance activities.

0.25% will support public purpose funding for Schedule 320 low-income energy efficiency activities.

COMMERCIAL:

2.76% will support public purpose funding for Schedule 350 energy efficiency programs delivered and administered by the Energy Trust. (R)

0.25% will support public purpose funding for Schedule 320 low-income energy efficiency activities.

(continue to Sheet 301-2)

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P.U.C. Or. 24

Fourth Revision of Sheet 301-2
Cancels Third Revision of Sheet 301-2

SCHEDULE 301
PUBLIC PURPOSES FUNDING SURCHARGE
(continued)

DETERMINATION OF RATE

At least annually, effective November 1, or such other date as the Commission may approve, the Company will determine if the Public Purpose Funding Surcharge for the Schedule 350 energy efficiency programs needs to be adjusted so that forecasted collections, plus unspent collections held by the Energy Trust are sufficient for acquiring cost-effective demand side management based upon resource portfolio and conservation supply curve methodologies consistent with the Company's last acknowledged Integrated Resource Plan or Integrated Resource Plan update, plus a spending reserve appropriately sized for economic conditions and forecasted growth.

SPECIAL CONDITIONS:

1. Each month, the Company will bill the Public Purposes surcharge on all Residential and Commercial Customer bills. By the 20th of the month following the billing month, the Company will forward the amount of funds expected to be collected from billings issued for the prior calendar month, less a reserve for uncollectibles in an amount equal to NW Natural's average percentage of net write-offs, to the respective fund administrator or program account. Funds retained in the accounts after the 20th of the month will earn interest at the Company's currently authorized rate of return until distributed, unless otherwise specified in an approved program or other agreement,

2. The Company will retain an amount not to exceed $50,000 per year from the monies collected to fund Schedule 320 low-income energy efficiency programs to be used for the purpose of an independent program performance evaluation.

3. The monies collected for Schedule 350 programs will be transferred to the Energy Trust. The Energy Trust is the entity approved by the Oregon Public Utility Commission (OPUC) to receive such public purposes funds, and to use such funds to design, promote and administer Natural Gas energy efficiency programs in accordance with agreements executed between the Company and the Energy Trust.

4. The monies collected for Schedule 310 and Schedule 320 programs will be transferred to the appropriate internal program accounts (OLGA and OLIEE, respectively) based on the allocation set forth in this Schedule 301.

5. Each year, to be effective October 1, or such other date as the Commission may approve, the Company will determine the amount of residential low-income public purposes funds that will be allocated between Schedule 310 and Schedule 320 programs. In making this determination, the Company will consult with at least one representative from: (a) the staff of the Public Utility Commission, (b) Citizens Utility Board, and (c) Community Action Partnership of Oregon. The minimum public purposes fund allocation for Schedule 310 programs shall be 0.58% of monthly residential customer bills.

(continue to Sheet 301-3)

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SCHEDULE 301
PUBLIC PURPOSES FUNDING SURCHARGE
(continued)

6. The Company, and any independent entity selected to administer public purposes programs under this Tariff, will report program results as directed by the Commission. Copies of all reports provided by the fund administrators to the Commission shall also be submitted to the Company for review.

7. All funds collected from NW Natural Customers will be allocated only to programs that are available within the Company's service territory in Oregon.

GENERAL TERMS:
This Schedule is governed by the terms of this Rate Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

Cancels Original Sheet 188-1

SCHEDULE 188
INDUSTRIAL DEMAND SIDE MANAGEMENT (DSM) PROGRAM COST RECOVERY

PURPOSE
This Schedule recovers the costs of the Company's Industrial Energy Efficiency Program offered under Schedule 360 "Industiral Demand side Management (DSM) Programs."

APPLICABILITY
This schedule applies to Industrial customers, who for the purposes of this Schedule are defined as:

a) Industrial Firm Sales Customers, served on Rate Schedules 3, 31 or 32;
b) Industrial Interruptible Sales Customers served on Rate Schedule 31 or 32;
c) Commercial Sales Customers served on Rate Schedule 32; and
d) Combination Service Customers where neither service option is Transportation.

APPLICATION TO RATES Effective: November 1, 2010

The Temporary Adjustments in the applicable Rate Schedules include the adjustment shown below. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

$0.00983 per therm

GENERAL TERMS
Service under this Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

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Issued by: NORTHWEST NATURAL GAS COMPANY
d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

NORTHWEST NATURAL GAS COMPANY

WN U-6 Fifth Revision of Sheet G.1
Cancels Fourth Revision of Sheet G.1

SCHEDULE G
ENERGY EFFICIENCY SERVICES AND PROGRAMS – RESIDENTIAL AND COMMERCIAL

APPLICABLE:
This program is intended to provide an economical and effective means for conserving Natural Gas through reduced heat loss and improved efficiencies in Residential dwellings and Commercial buildings.

AVAILABLE:
To all Residential Customers served on Rate Schedules 1, 2 and 27; and all Commercial Firm Sales and Interruptible Sales Customers served on Rate Schedules 3, 41 and 42 in all territory served by the Company under the Tariff of which this program is a part.

DESCRIPTION:
The Energy Trust of Oregon (Energy Trust) will deliver and administer a cost-effective energy efficiency program to NW Natural's Residential and Commercial Firm Sales and Interruptible Sales Customers. Energy Trust administered programs will offer applicable Customers incentive dollars for installing specific, cost-effective energy efficient measures, including rebates for energy efficient retrofit or replacement appliances. Program offerings may vary from time-to-time. Current offerings are described on the following Company webpage:
https://www.nwnatural.com/content_yourhome.asp?id=228

OVERSIGHT
Oversight of these programs will be provided by the Energy Efficiency Advisory Group (EEAG), which is a group comprised of interested parties to the Company's 2008 general rate case. EEAG oversight is required per the stipulated agreement attached to Commission Order No. 04 to the Company's rate case, docketed as UG-080546. The Company will consult with the EEAG prior to making any significant program changes such as changing an incentive amount or adding program measures.

REPORTING
Energy Trust will provide the EEAG and WUTC with Quarterly and an Annual Reports demonstrating total program costs, therms saved and levelized costs of measures offered. Reporting will be consistent with the Company's Energy Efficiency Plan, revised on December 6, 2011. (C)

COST-EFFECTIVE STANDARD
The portfolio of programs offered through the Energy Trust will be deemed cost-effective if the program meets the following Benefit Cost Ratio (BCR) tests: 1) Total Resource Cost (TRC) test; and 2) the Utility Cost (UC) test. The program is cost-effective when the end value for each of the following test is greater than one (1):

1) Total Resource Cost (TRC) looks at the total benefits attributable to the program divided by the total program costs. A TRC value equal to or greater than one means the benefits are equal to or exceed the costs, and the program is cost-effective.

   TRC is expressed formulaically as follows:

   TRC = Present Value of Benefits / Present Value of Costs

(continue to Sheet G.2)

Issued December 6, 2010 Effective with service on
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NORTHWEST NATURAL GAS COMPANY

WN U-6 First Revision of Sheet G.2
Cancels Original Sheet G.2

SCHEDULE G
ENERGY EFFICIENCY SERVICES AND PROGRAMS – RESIDENTIAL AND COMMERCIAL

The Present Value of Benefits includes
1. The value of gas energy saved based on the Company's avoided costs as established in its most current Integrated Resource Plan (IRP).
2. Non-energy benefits as quantified by a reasonable and practical method and described in situations where they cannot practically be quantified.
3. The 10% credit for energy efficiency as required under the Northwest Power Act. This credit recognizes the benefits of conservation in addressing risk and uncertainty.
4. A credit for carbon as defined in the most current version of the Northwest Power and Conservation Planning Council's (NWPPC) Conservation Plan.

The Present Value of Costs includes:
1. Incentives paid to the participant
2. Administrative costs
3. Monitoring, evaluation and non-incentive costs of Program Management Contractors (PMCs) and Energy Trust staff
4. The participant's remaining out-of-pocket costs for the installed cost of the measures after incentives and Federal tax credits.

2. Utility Cost (UC) measures the present value of the energy savings divided by the net costs incurred by the program, including incentive costs and excluding any net costs incurred by the participant. The UC is expressed with the same formula as the TRC but Present Value of Benefits and Present Value of Costs are defined as follows:

The Present Value of Benefits includes
1. The value of gas energy saved based on the Company's avoided costs as established in its most current IRP.
2. The 10% credit for energy efficiency as required under the Northwest Power Act. This credit recognizes the benefits of conservation in addressing risk and uncertainty.
3. A credit for carbon as defined in the most current version of the NWPPC's Conservation Plan.

The Present Value of Costs includes:
1. Incentives paid to the participant
2. Administrative costs
3. Monitoring, evaluation and non-incentive costs of PMCs and Energy Trust staff

Natural gas capacity benefits as well as lost and unaccounted for gas will not be included in the calculation except to the extent that they are included in NW Natural price forecasts.

(continue to Sheet G-3)

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SCHEDULE G
ENERGY EFFICIENCY SERVICES AND PROGRAMS – RESIDENTIAL AND COMMERCIAL

LEVELIZED COST METRIC
The portfolio of measures promoted through the program will also meet the following Levelized Cost metric, which is determined as follows:

The levelized cost is the present value of the total cost of a measure over its economic life, converted to equal annual payments. The levelized cost calculation starts with the incremental capital cost of a given measure or package of measures. The total cost is amortized over an estimated measure lifetime using the discount rate established in the Company's most current IRP. The annual net measure cost is then divided by the annual net energy savings (therms) from the measure application (again relative to a standard technology) to produce the levelized cost estimate in dollars per therm saved, as illustrated in the following formula.

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

The levelized cost of an energy efficiency measure is cost-effective if it is less than the average levelized costs of other supply-side options. A cost-effective threshold is established in the Company's most current Integrated Resource Plan (IRP) and further refined through the BCR test.

CUSTOMER NOTIFICATION
This information may be provided through the use of bill inserts, displays, booklets, handouts, advertisements, and industry and public agency literature.

FUNDING
The costs incurred for the administration and delivery of the services and programs offered under this Schedule will be deferred as allowed by Washington Utility and Transportation Commission (WUTC) Orders to UG-011230 and UG-011231. Each year, the Company will seek recovery of ongoing program costs from Residential and Commercial customers through Schedule 215, coincident with the Company's Annual Purchased Gas Adjustment filing made in accordance with Schedule P. Deferred balances will accrue interest.

(continue to Sheet G. 4)

SCHEDULE G
ENERGY EFFICIENCY SERVICES AND PROGRAMS – RESIDENTIAL AND COMMERCIAL

RESIDENTIAL PROGRAM INCENTIVES

The following are offerings for Residential customers:

DESCRIPTION	INCENTIVE
Weatherization	
Air Sealing	50% of cost, up to $275
Air Leakage Test	$35.00 per site tested
Attic/Celing Insulation	$0.25 per square foot
Duct Insulation	50% of cost, up to $100
Floor Insulation	$0.30per square foot
Knee-Wall Insulation	$0.30 per square foot
Boiler Pipe Insulation	$0.50 per linear foot
Wall Insulation	$0.30 per square foot
Duct Sealing	50% of cost up to $325
Duct Leakage Test	$35.00 per duct system tested
Windows	$2.25 per square foot
Heating	
Gas Furnace	$100.00
Direct Vent Gas Unit Heater	$100.00
Direct Vent Gas Fireplace	$100.00 to $150.00
Gas Boiler	$200.00
Water Heating	
Gas Tankless Water Heater	$200.00
Gas Water Heater	$35.00
Home Energy Review Measures	
Faucet Aerator	Free to customer
Home Energy Review	Free to customer
Showerhead	Free to customer
Shower wand	Free to customer
Water Heater Set Back	Free to customer

(continue to Sheet G.5)

Cancels Original Sheet G.4

SCHEDULE G
ENERGY EFFICIENCY SERVICES AND PROGRAMS – RESIDENTIAL AND COMMERCIAL

RESIDENTIAL PROGRAM INCENTIVES

The following are offerings for Residential customers:

DESCRIPTION	INCENTIVE
Weatherization	
Air Sealing	50% of cost, up to $275
Air Leakage Test	$35.00 per site tested
Attic/Ceiling Insulation	$0.25 per square foot
Duct Insulation	50% of cost, up to $100
Floor Insulation	$0.30per square foot
Knee-Wall Insulation	$0.30 per square foot
Boiler Pipe Insulation	$0.50 per linear foot
Wall Insulation	$0.30 per square foot
Duct Sealing	50% of cost up to $325
Duct Leakage Test	$35.00 per duct system tested
Windows (U.30 or better)	$2.25 to $3.50 per square foot
Heating	
Gas Furnace	$100.00
Direct Vent Gas Unit Heater	$100.00
Direct Vent Gas Fireplace	$100.00 to $150.00
Intermittent Pilot Ignition	$100.00
Gas Boiler	$200.00
Water Heating	
Gas Tankless Water Heater	$200.00
Gas Water Heater	$35.00
Home Energy Review Measures	
Faucet Aerator	Free to customer
Home Energy Review	Free to customer
Showerhead	Free to customer
Shower wand	Free to customer
Water Heater Set Back	Free to customer
Distributor or Retail Buy Down	
Showerhead	$8.50

(continue to Sheet G.5)

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NORTHWEST NATURAL GAS COMPANY

WN U-6 Second Revision of Sheet G.5
Cancels First Revision Sheet G.5

SCHEDULE G

ENERGY EFFICIENCY SERVICES AND PROGRAMS – RESIDENTIAL AND COMMERCIAL

RESIDENTIAL NEW CONSTRUCTION

Tankless Hot Water Heating	$ 200.00 per unit
Energy Star Builder Option Package*	$ 600.00 per home

* Building requirements are as stated on this site: http://www.energystar.gov/index.cfm?c=bop.pt_bop_washington

COMMERCIAL (N)

General		(N)
Custom	$1 per therm	(N)

Heating

Steam Traps, Small Commercial, <12 hrs/day, small-med pressure	$ 100.00 per trap*
Gas-fired Condensing Boiler > 2500 kbtuh 0.9 EC	$ 4.00 per kBtu hr in
Gas-fired Condensing Boiler < 300 kbtuh 0.9 AFUE	$ 4.00 per kBtu hr in
Gas-fired Condensing Boiler >= 300 kbtuh, <= 2500 kbtuh 0.9 ET	$ 4.00 per kBtu hr in
Boiler Vent Damper	$ 1,000.00 per unit
High Efficiency Unit Heater - Non-Condensing with Electronic Ign	$ 1.50 per kBtu hr in
High Efficiency Condensing Furnace <225,000 kBtuh	$ 3.00 per kBtu hr in
Direct-fired Radiant Heating	$ 6.50 per kBtu hr in
Pipe Insulation	$2.00 to $6.00 per linear foot

* Pre-verification of steam traps required for dry cleaners

Water Heating

Domestic Tankless/Instantaneous Water Heater with Electronic Ignit	$ 2.00 per kBtu hr in	
Domestic Tankless/Instantaneous Water Heater with Standing Pilot	$ 1.50 per kBtu hr in	(C)
Condensing Tank	$ 2.50 per kBtu hr in	
Commercial Clothes Washer, Gas Water Heat, Partial Gas	$ 200.00 per unit	
Showerhead Gas	$ 6.00 to $10 per unit	
Commercial Bathroom Faucet Aerators (0.5 gal per minimum; 15 unit minimum)	$3.00 each	
Commercial Kitchen Faucet Aerators (1.5 gal per minimum; 15 unit minimum)	$5.00 each	
Ozone Laundry System	$40 per pound of washing capacity up to a max of 35% of cost of system	

(M)

(continue to Sheet G.6)

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NORTHWEST NATURAL GAS COMPANY

WN U-6 First Revision of Sheet G.6
Cancels Original Sheet G.6

SCHEDULE G
ENERGY EFFICIENCY SERVICES AND PROGRAMS – RESIDENTIAL AND COMMERCIAL

Food Service (M)

Gas Full-Size Convection Oven	$ 300.00 per unit
Gas Fryer	$ 1,000.00 per unit
Gas Griddle	$ 150.00 per unit
Gas Steam Cooker	$ 1,300.00 per unit
Dishwasher - Single Tank Conveyor - Low temp - Gas hot water	$ 500.00 per unit
Dishwasher - Single Tank Door/Upright - Low Temp - Gas water heat	$ 400.00 per unit
Dishwasher - Single Tank Conveyor - High temp - Gas hot water	$ 500.00 per unit
Dishwasher - Single Tank Door/Upright - High Temp - Gas water heat	$ 400.00 per unit
Dishwasher - Undercounter - high temp - Gas water heat	$ 200.00 per unit
Turbo Pot – limit one per applicant	$40 per pot*

* Customers installing one other food service measure may receive one free turbo pot while promotional quantities last. (M)

SPECIAL PROVISIONS

1. One time bonuses or coupons may be periodically offered to supplement standard incentives. (C)
2. Limited time incentive offerings for cost effective measures may be offered from time to time. (N)

GENERAL TERMS:

This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

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*Issued by: **NORTHWEST NATURAL GAS COMPANY***
d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

NORTHWEST NATURAL GAS COMPANY

WN U-6 Second Revision of Sheet I.1
Cancels First Revision Sheet I.1

SCHEDULE I
WASHINGTON LOW-INCOME ENERGY EFFICIENCY (WA-LIEE) PROGRAMS

PURPOSE:
To set forth the terms and conditions of a low-come energy efficiency program available to qualifying low-income Residential customers.

AVAILABLE:
This program is available to income-eligible residential dwellings located within NW Natural's Washington service territory where (1) a gas Service Line is installed at the Premise; (2) the primary space heating equipment is fueled by Natural Gas, and (3) the occupant has an active account with the Company, or will have an active account upon completion of work performed under this Schedule I. Any residential dwelling that received assistance for the installation of the same or similar measures under any other energy efficiency program will not be eligible for assistance under this program.

PROGRAM YEAR:
The program year will extend from October 1 through September 30.

PROGRAM FUNDING:
1. Each Agency will be reimbursed by the Company for administrative costs and direct program costs incurred by them in their administration and delivery of the WA-LIEE program in the amount of 15% of the total job cost for each household. The Agency fee will paid to each Agency along with each rebate payment. The Company will process rebates and Agency payments within thirty (30) days from the date the Company receives all completed documentation in support of such rebate request(s).
2. The Company will be reimbursed for actual program administration costs incurred, except that such reimbursement will not exceed 5% of the total funds distributed during each Program Year.
3. Program Costs will be deferred and recovered through rates in **Schedule 230** in accordance the terms agreed to in Docket No. U-091044.

PROGRAM ADVISORY COUNCIL:
The Energy Efficiency Advisory Group (EEAG), that was formed by parties to the Company's 2008 Washington rate case, docketed as UG-080546, will assist in advising the Company on the WA-LIEE program development, implementation, and evaluation. The EEAG will have no decision-making authority.

PROGRAM ADMINISTRATION, EVALUATION AND VERIFICATION:
During the first quarter after the end of a program year, the Company will present to the EEAG program year results including the costs incurred and therms saved during the program year.

(continue to Sheet I.2)

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NORTHWEST NATURAL GAS COMPANY

WN U-6 First Revision of Sheet I.2

Cancels Original Sheet I.2

SCHEDULE I

WASHINGTON LOW-INCOME ENERGY EFFICIENCY PROGRAM (WA-LIEE)

(continued)

MEASURE INCENTIVES:

Energy Efficiency Measures and Rebates.

Qualifying energy efficiency measures shall be those recommended by an approved, residential energy analysis software tool that complies with the Department of Energy's standard for cost-effective energy efficiency; hereafter, this software tool will be referred to as Conservation Software. To qualify for a rebate, the total group of measures prescribed by Conservation Software for the whole house must meet or exceed a Savings to Investment Ratio (SIR) of 1.0 or better, and except for certain approved exceptions, measures must be chosen in the ranked order of Conservation Software prescriptions.

Rebates will be paid based on the cost of the total group of qualifying measures for the whole house, as recommended by Conservation Software, and installed by the Agency. At the beginning of each program year, the maximum rebate amount per home shall be reset to the greater of either $3,500 or an amount equal to ninety percent (90%) of the average total installed cost of measures as reported by the Agencies for the prior program year. To accommodate timing differences between measure installations, the rebate may be disbursed through one or more reimbursement requests provided all of the work is based on the same audit. Only one energy efficiency audit per home will be eligible for rebates under this program.

Health, Safety and Repair (HSR) Allowance and Reimbursement.

In addition to the rebate for qualifying energy efficiency measures, a rebate will be available for the costs of health, safety and repair (HSR) measures. HSR measures are those items that if not completed would adversely impact the safety and effectiveness of the energy efficiency measures or the health of the occupants. Standard efficiency furnace replacements may qualify for HSR funds if the existing furnace is broken, is found to produce an unsafe level of CO emissions, is back-drafting, or has a cracked heat exchanger and a high-efficiency furnace is not cost-effective or if it is physically impossible to install a high-efficiency furnace. When a furnace is replaced with a standard efficiency furnace, the Agency must specify the reasons for the replacement in the reimbursement request.

The maximum annual HSR disbursement available to each Agency will be $440 times the actual number of households treated by the Agency in the Program Year (HSR Allowance).

Each Agency will have discretion in the use of their individual HSR Allowance such that they may use more or less than the $440 on any one home. Each Agency must manage their HSR funds to ensure that the average HSR amount per home is not more than $440.

(continue to Sheet I.3)

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SCHEDULE I
WASHINGTON LOW-INCOME ENERGY EFFICIENCY PROGRAM (WA-LIEE)
(continued)

AGENCY QUALIFICATIONS AND RESPONSIBILITIES:

1. In order to qualify to participate in this program, an Agency must be a legal entity, contracting or subcontracting with Washington Department of Community Trade and Economic Development (DCTED), which is eligible to administer funding under the Federal Department of Energy Weatherization Assistance Program (DOE-WAP). Each participating Agency will have sole responsibility to screen and approve applicants for eligibility. Each Agency shall follow the established protocols for the qualification of and disbursement to eligible participants in accordance with the guidelines of this program and the guidelines promulgated by DCTED in the DCTED Policies and Procedures for Managing the low-income weatherization program.
2. Each participating Agency shall be responsible to complete and return to the Company, all required paperwork and other documentation as may be necessary for the Company to process the rebate request. The Company will provide the documentation forms to each participating agency in electronic or hard copy form, whichever is requested. At a minimum, the documentation must include the Agency name, customer name, the landlord name and address, if applicable, the address of the qualifying households, the square footage of the home, a list of the measures installed, the rebate amount per measure and total rebate per household.

CUSTOMER QUALIFICATIONS:
A qualifying customer is one who meets income eligibility standards established by DCTED for low-income weatherization programs and who resides in a dwelling built before 1991, in which the primary heating equipment is fueled by natural gas.

Agency Reporting Requirements.
For each home treated under this program, each Agency will be required to report to the Company, the following information:

Customer Name (as shown on NW Natural Account);	NWN Account #
Service Address	Phone
Owner/Prop Mgr	Owner/Prop Mgr Phone
Audit Date	Installation (completion) Date
Reimbursement Request Date	Agency and Agency Representative
Size of home in square feet and Year Built	Measure description
Installed Cost per Measure	Estimated therm savings per measure
Conservation Software SIR per measure	Total Conservation Software SIR for Measure Group
Total Cost of all energy efficiency measures installed (EEMC)	Total Conservation Software estimated savings for each household (Total therms)
Total job cost to Agency (WA-LIEE and non-WA-LIEE measure costs)	Cost per therm saved for each household (Cost/Savings)
Requested reimbursement (90% of EEMC up to $3,500)	HSR Measure description/explanation
Total HSR Measure cost	Related Savings (furnace replacements)
Total Reimbursement Request: (90% of EEMC up to $3,500 + H&S + Admin):	

(Continue to Sheet I.4)

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SCHEDULE I
WASHINGTON LOW-INCOME ENERGY EFFICIENCY PROGRAM (WA-LIEE)
(continued)

GENERAL TERMS:
This schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

NORTHWEST NATURAL GAS COMPANY

WN U-6 Tenth Revision of Sheet 215.1
Cancels Ninth Revision of Sheet 215.1

SCHEDULE 215
ADJUSTMENT TO RATES
ENERGY EFFICIENCY SERVICE AND PROGRAMS

PURPOSE:
To identify adjustments to rates in the Rate Schedules listed below for the amortization, with interest, of balances in a deferred account that recover costs associated with providing energy conservation services offered under Schedule G "Energy Efficiency Services and Programs", of this Tariff.

APPLICABLE:
To Sales Service Customers throughout the Company's service territory in Washington that take service under the Rate Schedules listed herein.

Schedule 1	Schedule 3	Schedule 41 CSF/CSI
Schedule 2	Schedule 27	Schedule 42CSF/CSI

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2010
Each year, in accordance with the terms agreed to in Docket No. U-091044, Sales Service rates for the Rate Schedules listed below will be adjusted on an equal cents per therm basis, to recover the actual costs of energy conservation programs incurred during the most recent 12-month period October 1 through September 30. Adjustments to rates shall be made coincident with the Company's annual Purchased Gas Adjustment (PGA) filing, or at such other time as the Commission may authorize.

The rates in the Rate Schedules listed below include the following adjustments:

Schedule	Block	Schedule G Energy Efficiency
1R		$0.03168
1C		$0.02478
2		$0.01871
3 (CSF)		$0.01672
27		$0.01241
41 (CSF)	Block 1	$0.01306
	Block 2	$0.01151
41 (CSI)	Block 1	$0.01257
	Block 2	$0.01108
42(CSF)	Block 1	$0.00963
	Block 2	$0.00862
	Block 3	$0.00661
	Block 4	$0.00529
	Block 5	$0.00353
	Block 6	$0.00132
42(CSI)	Block 1	$0.00578
	Block 2	$0.00517
	Block 3	$0.00396
	Block 4	$0.00317
	Block 5	$0.00211
	Block 6	$0.00079

GENERAL TERMS:
This schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

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d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

NORTHWEST NATURAL GAS COMPANY

WN U-6 Second Revision of Sheet 230.1

Cancels First Revision of Sheet 230.1

SCHEDULE 230

TEMPORARY ADJUSTMENTS TO RATES FOR LOW-INCOME PROGRAMS

PURPOSE:

To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred account balances for each of the Company's low-income programs (Schedule J and Schedule I).

APPLICABLE:

To the following Rate Schedules (Sales Service only) of this Tariff:

Schedule 1 Schedule 2 Schedule 3 Schedule 41 Schedule 42

APPLICATION TO RATE SCHEDULES: **Effective: November 1, 2010**

The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Schedule J GREAT	Schedule I WA-LIEE	Total Temporary Adjustment
1R		$0.01542	$0.00171	$0.01713
1C		$0.01207	$0.00134	$0.01341
2		$0.00910	$0.00101	$0.01011
3 (CSF)		$0.00814	$0.00090	$0.00904
3 (ISF)		$0.00724	$0.00080	$0.00804
27		$0.00604	$0.00067	$0.00671
41 (CSF)	Block 1	$0.00636	$0.00070	$0.00706
	Block 2	$0.00560	$0.00062	$0.00622
41 (CSI)	Block 1	$0.00633	$0.00070	$0.00703
	Block 2	$0.00558	$0.00062	$0.00620
41 (ISF)	Block 1	$0.00886	$0.00098	$0.00984
	Block 2	$0.00781	$0.00086	$0.00867
41 (ISI)	Block 1	$0.00633	$0.00070	$0.00703
	Block 2	$0.00558	$0.00062	$0.00620
42(CSF)	Block 1	$0.00469	$0.00052	$0.00521
	Block 2	$0.00420	$0.00046	$0.00466
	Block 3	$0.00322	$0.00036	$0.00358
	Block 4	$0.00257	$0.00028	$0.00285
	Block 5	$0.00172	$0.00019	$0.00191
	Block 6	$0.00064	$0.00007	$0.00071
42(ISF)	Block 1	$0.00388	$0.00043	$0.00431
	Block 2	$0.00348	$0.00038	$0.00386
	Block 3	$0.00267	$0.00029	$0.00296
	Block 4	$0.00213	$0.00024	$0.00237
	Block 5	$0.00142	$0.00016	$0.00158
	Block 6	$0.00053	$0.00006	$0.00059

Issued October 13, 2010 Effective with service on

NWN Advice No. WUTC 10-8A and after November 1, 2010

Issued by: NORTHWEST NATURAL GAS COMPANY

d.b.a. NW Natural

220 N.W. Second Avenue

Portland, Oregon 97209-3991

SCHEDULE 230
TEMPORARY ADJUSTMENTS TO RATES FOR LOW-INCOME PROGRAMS
(continued)

APPLICATION TO RATE SCHEDULES (continued): **Effective: November 1, 2010**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	**Block**	**Schedule J GREAT**	**Schedule I WA-LIEE**	**Total Temporary Adjustment**
42(CSI)	Block 1	$0.00281	$0.00031	$0.00312
	Block 2	$0.00252	$0.00028	$0.00280
	Block 3	$0.00193	$0.00021	$0.00214
	Block 4	$0.00154	$0.00017	$0.00171
	Block 5	$0.00103	$0.00011	$0.00114
	Block 6	$0.00039	$0.00004	$0.00043
42(ISI)	Block 1	$0.00284	$0.00031	$0.00315
	Block 2	$0.00254	$0.00028	$0.00282
	Block 3	$0.00195	$0.00022	$0.00217
	Block 4	$0.00156	$0.00017	$0.00173
	Block 5	$0.00104	$0.00011	$0.00115
	Block 6	$0.00039	$0.00004	$0.00043

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

NW Natural's
Energy Efficiency Plan
For Washington

Background
This Energy Efficiency Plan was developed in consultation with the Energy Efficiency Advisory Group (EEAG), which is a group consisting of interested parties to the Company's 2008 rate case, formed in accordance with the stipulated agreement attached to Commission Order No. 04, in Docket UG-080546. The EEAG is comprised of representatives from NW Natural, Energy Trust of Oregon (Energy Trust), Washington Utility and Transportation Commission (WUTC) Staff, Washington Public Counsel, Northwest Industrial Gas Users (NWIGU), The Energy Project, and NW Energy Coalition. The EEAG discussed this plan during meetings on February 5, 2009 and April 17, 2009, and teleconferences held on May 7, 2009 and June 15, 2009.

Energy Trust of Oregon
The Energy Trust will deliver the Company's Washington programs for at least 12 months, beginning October 1, 2009 Programs will be provided to all residential and commercial customers within the Company's Washington service territory.

First Year Metrics[1]
In the first program year, the Energy Trust will strive to meet the following metrics

- 97,500 to 130,000 total therms saved
- $780,000 to $1,040,000 total program costs
- Average levelized cost for measures not to exceed $0.65 per therm
- First year therms cost less than $8 per therm
- At least 60% of total dollars spent are paid out in incentives[2]
- Total Resource Cost (TRC) and Utility Cost (UC) at the portfolio level are greater than 1.0

Reporting
The EEAG will serve as on-going advisors to the Company's Washington Energy Efficiency (EE) program. To that end, the Energy Trust will provide the EEAG with Quarterly and Annual Reports. These reports will include
(a) the Total Portfolio Cost (TRC),
(b) a Total Portfolio percentage of Incentive Dollars versus total program costs,
(c) total program costs,
(d) therms saved, and
(e) a total levelized cost for all program activities.
Quarterly reports will be provided no later than 55 days after the end of each calendar quarter (February 25, May 25, and August 25).

1 Please note that these metrics, including total program costs, do not consider the new Homes Program that was implemented on July 1, 2010 and is discussed in more detail in Attachment F.
2 Total program costs must be adjusted down by 15% to account for costs that a utility delivered program would be recovering through base rates.

The first Annual Report will be provided on or before January 25, 2011. The report will provide the information for the October 1, 2009, through September 30, 2010 program year. It will give a total portfolio report of cost benefit ratios and measure lives. In the first program year, the Energy Trust will report on the following performance indicators:

- Number of new trade allies in the Clark County area that the Energy Trust trains and certifies
- Number of residential customers receiving Home Energy Reviews (HERs) in the first program year.
- Percentage of customers implementing an incentivized measure resulting from a HER
- A discussion of customer communications used to roll out programs.

These indicators are valuable in that they demonstrate market penetration and an earnest effort to connect with Washington customers.

If Energy Trust continues to administer NW Natural's programs beyond the first program year, reports will be based on a calendar year. Three quarterly reports will continue to be provided no later than 55 days after the end of each calendar quarter and Annual Reports will be provided on April 25th.

Process after First Program Year

The Energy Trust began administering NW Natural's DSM programs on October 1, 2009. After one program year, the EEAG will begin the process of evaluating the cost-effectiveness of the programs and will eventually recommend whether the Company should continue using the Energy Trust as its program delivery arm.[3] This decision will be based on the Energy Trust's achievement of its first year metrics and the cost-effectiveness of the program using the benefit cost ratio tests, as defined in Schedule G.

This decision of whether NW Natural should continue using the Energy Trust as its DSM program delivery arm will be based, in part, on the comparison of estimated costs for other DSM program delivery options such as delivering DSM programs in-house or using a third-party administrator located in Washington. To this end, NW Natural will provide the EEAG with a paper benchmarking its Energy Trust delivered program against other Washington utility-delivered DSM programs. The Company will use benchmarking efforts to extrapolate what it might cost the Company to deliver its own DSM program, as well as potential costs to use a Washington-based DSM program administrator. This benchmarking study will be prepared by a third-party and will be distributed to the EEAG no later than March 25, 2011.

A third party will be solicited to prepare the benchmarking report to provide parties with the assurance that the information contained the report will be objective. To choose the party who will prepare the benchmarking report, the Company will issue a request for proposal (RFP) to multiple third parties and then bid the contract to the party who presents itself as having the ability to deliver the most value for a reasonable cost.

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[3] *See* Page 5 of the Full Settlement Stipulation, filed on October 21, 2008, in UG-080546, which states, "Following this pilot period, the Company will, in consultation with EEAG, evaluate the cost-effectiveness of the continued use of ETO for delivering the Company's energy efficiency programs in Washington."

By April 25, 2011, NW Natural will convene with the EEAG to review the Energy Trust's Annual Report and a third-party's benchmarking study, and to determine whether or not the Energy Trust should continue delivering the Company's Washington EE programs. By May 25, 2011, the Company will file with the WUTC under Docket No. UG-080546, the third party benchmarking study along with the EEAG's recommendation regarding ongoing program administration. The recommendation filed will represent the majority opinion among EEAG members (where each organization, including the Company, has one vote).[4]

A timeline detailing the key dates in this process is included as Attachment A.

In accordance with the Commission's approval of NW Natural's Petition for Reconsideration of Order No. 04 in UG-080546, the Energy Trust will continue administering the Company's energy efficiency programs throughout the period that the cost-effectiveness decision is being made[5], and in the event the decision is made not to retain the Energy Trust as program administrator, throughout the period during which a new program administrator is selected and established. The program targets and costs for 2011, which were developed under the assumption that Energy Trust would deliver services for the whole year, are as stated in Attachment E.

Programs

In the first year, Energy Trust will offer Home Energy Reviews (HERs) to NW Natural residential customers in cooperation with Clark Public Utility District (Clark PUD).

Clark PUD will be working with the Energy Trust to provide combined gas and electric services. This effort will require that the Energy Trust Program Management Contractors (PMC) install compact fluorescent lamps during HERs. Clark PUD will then reimburse the PMCs for labor and material cost under a separate contract. Similarly, if domestic hot water is heated electrically, flow restricting shower heads and faucet aerators will be installed and the PMC would be compensated accordingly.

Energy Trust contractors will be available to provide HERs to NW Natural customers in Skamania and Klickitat counties, areas outside of the Clark PUD service territory.

Beyond HERs, residential rebates will be offered for retrofit and replacement high efficiency gas furnaces and domestic hot water heaters. Rebates will also be offered for energy efficient retrofits and replacements in the commercial sector/existing building sector. . Incentives will be offered for weatherization and other shell measures for both residential and commercial customers.

The energy efficiency measures offered in the first year will focus on residential and commercial retrofit opportunities and will mirror what is currently available to NW Natural's

4 The public process allows parties to separately or collectively advocate for a different recommendation than that which is filed. Also, this year-end process is independent from the prudency review of costs deferred which occurs when the Company files to amortize the amounts deferred for recovery in rates.

5 The program year ends September 30,2010, and the deadline for filing the EEAG recommendation with the Commission is May 25, 2011.

Oregon customers. The offerings in Washington may differ in that one-time bonuses or coupon offers may be offered to Washington customers to supplement standard incentives. This will enable the Energy Trust to more rapidly adapt to the Washington market during the first year. It will also minimize costs required for making Washington specific forms and program marketing materials.

The Company will offer the following programs during the first program year:

Residential Retrofit:

- Home Energy Reviews (HERs)
- Furnaces[6]
- Weatherization
- Duct Sealing
- Water Heaters (tank type)
- Water Heaters (tankless)

Commercial Retrofit:

- Boilers for small commercial
- Spray rinse valves for commercial kitchens
- Weatherization
- Commercial cooking measures

Program Modifications

All program offerings are listed in the Schedule G. If the Company chooses to make any additions, changes or revisions to the program offerings, it will file tariff advice filing with the Commission requesting to modify Schedule G. The Company will inform the EEAG when it makes such a filing.

Before the Company files to requesting to add revise or change a measure, that proposal will be scrutinized by the Energy Trust. The Energy Trust identifies measures for potential implementation, tracks them, then prioritizes them based on a number of factors including energy savings potential compared to costs, ability to deploy, and market demand. Measures may originate from industry trade shows when new high-efficiency products are introduced, Energy Trust's resource assessments, and the Regional Technical Forum (a group of industry experts, professional engineers and economists) led by the Northwest Power Planning Council. Detailed measure information used to screen a measure for cost-effectiveness is largely dependent on the following criteria: estimated savings, estimated cost and benefits, avoided costs, benefits to society, measure life, and longevity of savings. After measures are initially screened for cost-effectiveness, a number of other contributing factors are identified and documented, including the quality of the measure, product specifications for qualification, assumptions, market application, ways to qualify potential applications, and results of monitoring and verification of savings. Measures that emerge from this initial screening process go through additional research and testing to determine applicability to the market to determine appropriate incentive levels and deployment scenarios, based on program design and targeted markets. When research and screening is complete, measures are presented to the Energy Trust Conservation Advisory Council (CAC) and a measure

[6] *See* Attachment B for study results on the savings potential for the furnace measure.

acceptance memo is circulated documenting the CACs formal approval to adopt the measure.

Existing measures may be modified due to incoming changes to the following; building code, cost to society, measure life, available technology, quality control, appliance and equipment standards, and market demand. These types of modifications are made at the program level and may be based on market adoption rates, available budget, and other factors that may emerge.

Significant measure changes traditionally occur at the beginning of the calendar year, although measure additions and changes to existing measures may be necessary due to changes in the information available at the time or management of program budgets.

A NW Natural tariff filing to add or modify a measure will include support information generated during the Energy Trust's processes described above.

How First Year Programs were Determined

The Energy Trust currently offers programs in Oregon that can be leveraged and offered in Washington. Energy Trust began assessing which of their offerings in Oregon would be transferable to Washington.

Energy Trust considered Clark County demographics. NW Natural has approximately 60,500 customers in Washington: 56,000 are residential, 4500 are commercial and 35 are industrial[7].

With so few industrial customers in Clark County, Energy Trust decided that it would be wise to forestall offering Industrial programs and, rather, to focus dollars and efforts on penetrating the residential and commercial markets. After the residential and commercial markets are well established, NW Natural and Energy Trust will discuss with the EEAG the possibility of adding an Industrial EE program. However, this is not planned in the first year.

Upon its initial publication, this plan stated the following:

> Since new construction starts have diminished significantly in 2008 as evidenced by census data for Clark County single family building permits, the Energy Trust does not plan to deliver new construction programs in Washington in the first program year. Costs would be incurred to launch this program-- additional contractors would be needed and marketing materials would have to be revised for Washington building codes. Making an investment with no clear return would be unwise. However, Clark County has historically had above average housing starts per year and we want to enter the market as it recovers so as to avoid any lost opportunities associated with new construction. To balance these objectives, the Energy Trust will enter the market when the activity justifies the costs. They will closely monitor new housing starts through contractor networks active in Energy Trust's Oregon programs and by tracking Washington housing starts statistics. If Clark County building permits exceed 200 per quarter for two consecutive quarters, Energy Trust will begin offering

[7] Numbers are rounded.

programs. This trigger was determined by looking at historical building permits in Clark County as reported by the census bureau. Should the threshold be met, we will expect that total program costs will increase due to costs associated with program launch, enlisting additional contractors and developing new marketing materials.

Since the residential and commercial programs were implemented on October 1, 2009, this threshold was met: Clark County had 205 housing starts in the program's first quarter and 309 in its second. On May 28, 2010, NW Natural filed Advice No. 10-4 to revise Schedule G to include a provision for a New Homes program. This program as well as expected costs and therm savings are discussed in more detail in Attachment D.

Clark PUD staff would like to coordinate efforts in the commercial and residential new construction markets once the market shows indications of gaining momentum likely to occur in mid-2010. Clark PUD currently offer services through Energy Star New Homes program as does the Energy Trust. Clark PUD does not currently have a robust commercial new construction service offering and would like to benefit from coordinating with NW Natural when market indications warrant service offerings. The Company is hopeful that these opportunities to coordinate with Clark PUD will enhance its future cost effective DSM offerings.

Therms Saved

The savings goals are initially derived from the resource evaluation that was done in preparation for the Company's 2009 Integrated Resource Plan (IRP). The Energy Trust generally forecasts two scenarios: a stretch case and a conservative case. The stretch case in Table 1 below, which is taken from the Company's 2009 IRP, is an aggressive goal. Table 2 is the conservative case, which is 75% of the stretch case. While the stretch case in the IRP is useful in preparing a long-term, 20 year forecast, the conservative case is valuable for short term planning.

Table 1 – IRP Stretch Case Forecast, March 2009
Achievable DSM Therm Savings in NW Natural's Washington Service Territory

DSM Program	2009	2010	2011	2012	2013	2014
Res - New	14,088	14,088	28,176	42,264	42,264	42,264
Res - Retrofit	15,233	121,863	137,096	152,328	167,561	182,794
Res - Replacement	412	412	824	1,235	1,235	1,235
Res - Appliance Replacement	248	248	372	372	372	372
Res - Solar dhw	284	284	378	568	568	568
Comm - New	-	17,398	18,980	20,561	22,143	22,143
Comm - Retrofit	2,434	38,938	43,805	48,673	53,540	58,407
Comm - Replacement	2,151	38,725	43,028	47,331	51,634	55,936
Ind - Retrofit	590	9,444	10,624	11,805	12,985	14,166
Ind - Replacement	76	1,361	1,512	1,663	1,814	1,965
Residential Total	30,265	136,895	166,846	196,767	212,000	227,233
Commercial Total	4,585	95,061	105,813	116,565	127,317	136,486
Industrial Total	666	10,805	12,136	13,468	14,799	16,131
All DSM	35,516	242,761	284,795	326,800	354,116	379,850

Table 2 – IRP Conservative Case Forecast, March 2009
Achievable DSM Therm Savings in NW Natural's Washington Service Territory

DSM Program	2009	2010	2011	2012	2013	2014
Res - New	10,566	10,566	21,132	31,698	31,698	31,698
Res - Retrofit	11,425	91,397	102,822	114,246	125,671	137,096
Res - Replacement	309	309	618	926	926	926
Res - Appliance Replacement	186	186	279	279	279	279
Res - Solar dhw	213	213	284	426	426	426
Comm - New	1,825	29,204	32,854	36,504	40,155	43,805
Comm - Retrofit	-	13,048	14,235	15,421	16,607	16,607
Comm - Replacement	1,614	29,044	32,271	35,498	38,725	41,952
Ind - Retrofit	443	7,083	7,968	8,854	9,739	10,624
Ind - Replacement	57	1,020	1,134	1,247	1,361	1,474
Residential Total	22,698	102,670	125,134	147,575	159,000	170,424
Commercial Total	3,439	71,296	79,360	87,424	95,487	102,365
Industrial Total	499	8,103	9,102	10,101	11,100	12,098
All DSM	26,636	182,070	213,596	245,100	265,587	284,888

Savings goals for the Energy Trust's first program year are based on the conservative case deployment scenario presented above in Table 2. The first year metric is comprised of achievable potential for applicable residential and commercial retrofit and replacement programs for the fourth quarter of the 2009 potential, plus the first three quarters of 2010. No adjustments are made for economic conditions or for ramp up beyond those assumptions used when determining the achievable potential for the 2009 IRP.

Attachment C demonstrates different ways of assessing the achievable potential in the Company's Washington service territory. Sheet C-1 takes the savings experienced in NW Natural's Oregon service territory, multiples that by 11% to determine likely results in Clark County. Sheet C-2 shows the therm savings received in Cascade Natural Gas's Washington service territory, proportioned down to reflect the size of NW Natural's service territory. Neither worksheet is to be used as a measure-by-measure guide for savings targets, but when used together, these different perspectives verify that current market results are relatively consistent with the IRP's achievable potential for NW Natural's Washington customers.

Evaluation and Verification of Therms Saved

Deemed savings by measure will be used to determine total therms saved per program year. The deemed savings used in program analysis will reflect the findings in the most current verification study. Program impact and process evaluations will be completed on an ongoing basis. The EEAG will be notified if deemed savings by measure are modified.

As the program matures, when sufficient historical billing data becomes available, Energy Trust will periodically perform a pre- and post-billing analysis to verify savings for specific program measures. Pre- and post-billing analysis will not be done during the first program year because measures must be installed at least 12 months so that a meaningful pre- and post-billing analysis can be performed. These studies compare data for like seasons (i.e. – a January 2009 bill before a measure is installed is compared to a January 2010 bill after a measure is installed.) A study will not be performed until a significant number of measures have been installed for at a minimum of 12-months.

Incentive Dollars

The Company's energy efficiency tariff (Schedule G) is intentionally silent on incentive dollars. The Company would like the Energy Trust to change incentives offers as necessary to move the market. Before any changes are made to incentive amounts, the Company will seek EEAG for approval.

The following four tables give an overview of the costs and incentives paid for Energy Trust's Oregon gas programs as well as estimates for the Company's Washington program.

Table 3 shows the Energy Trust incentives for its 2008 Oregon programs as a percent of fully loaded cost by sector.

Table 3 - 2008 Gas incentives in Oregon as Percentage of Total Program Cost

Programs	Incentives	Total Program Costs	% Incentives
New homes and products	$1,038,491	$2,478,934	42%
Existing homes	$4,576,953	$8,202,591	56%
Existing buildings	$1,883,897	$3,312,031	57%
New buildings	$603,331	$1,087,379	55%
Production Efficiency	$27,922	$86,010	32%
Total	$8,130,594	$15,166,945	54%

In Oregon, the Energy Trust's percent of incentives to total program costs is below the 70% to 80% that other Washington utility programs report spending on incentives[8]. Possibly, this incongruity with Washington's programs may be because utility-delivered program do not account for costs that are otherwise rate-based, whereas all Energy Trust costs are considered incremental program costs. The Energy Trust will account for this by adjusting its total costs down by 15%, the amount that would be rate based if programs were delivered by the utility.

Table 4 – Estimate of Washington Incentives as Percentage of Fully Loaded Costs

Program	Incentives	Program Costs	% Incentives
Existing Homes (Residential)	$268,950	$415,650	65%
Existing Buildings (Commercial)	$211,900	$277,100	76%
Total	$480,850	$692,750	69%

* Program costs do not include NW Natural's costs or start-up costs. Program costs are further reduced by 15% which represents Energy Trust's administrative costs that would be rate based were this an utility delivered program.

After the Energy Trust adjusts its total costs down by 15%, it expects incentives paid in the first year of its Washington programs will account for 69% of total costs which is in line with other Washington energy efficiency programs. Energy Trust believes the percentage of

[8] *See* Avista's "Triple E Report: January 1, 2008 through December 31, 2008."

incentives paid verses total costs will still be on the low end of the spectrum compared to the 70-90 percent experienced by other Washington DSM programs because NW Natural's program is not mature and does not currently include industrial customers, a customer class that is generally less costly to serve but has larger incentive pay outs.

The Energy Trust will track and report on the level of incentives paid. It is willing to respond to the market if program results suggest that incentive amounts are not appropriately set. Energy Trust is planning to use additional coupons for Washington customers which would offer more incentive dollars for specific measures for limited periods of time. Responsiveness to such campaigns will be tracked and Energy Trust will report if the campaigns prove to move the market more quickly.

Levelized Cost

Table 5 shows the type and activity level achieved by various gas EE programs in Oregon in 2008 for NWN. Table 6 shows the estimated activity for Company's first program year in Washington.

Table 5 - Gas efficiency savings in Oregon 2008 and OPUC Performance Metrics

Gas Efficiency Savings	NWN Therms	Cascade Natural Gas	Avista	Total Savings Therms	Expenses	$ / Therm	Levelized Cost/
Commercial	1,156,018	51,298	0	1,207,316	$4,399,409	$3.6	33 ¢
Industrial	12,600	0	0	12,600	$86,009	$6.8	53 ¢
Residential	1,260,916	82,505	9,793	1,353,214	$10,681,527	$7.9	54 ¢
Total Energy Efficiency Programs	2,429,534	133,803	9,793	2,573,130	$15,166,945	$5.9	45 ¢

Energy Trust predicts the per-therm cost and average levelized cost in Washington to be somewhat higher than the Oregon average. This deviation is due to a small industrial sector (approximately 35 customers) which the Company does not intend to serve in the first program year and a large residential retrofit sector which is the most costly to serve.

Table 6 – Estimate of Washington Efficiency Savings and Levelized Costs

Sector	Savings (therms)	Fully Loaded Costs	$/Therm	Levelized Cost
Residential	58,500	$ 505,450	$ 8.6	$ 0.58
Commercial	71,500	$ 342,450	$ 4.8	$ 0.43
Total	**130,000**	**$ 847,900**	**$ 6.5**	**$ 0.50**

*** Expenses include Energy Trust administrative costs (15%) and NW Natural Administration.**
**** $/Therm and levelized cost calculations are based on achieving the stretch case scenario**

Start Up Costs

One-time start-up costs of $150,000 are estimated below in Table 7. Costs include the incremental labor costs for certain Energy Trust Employees who are temporarily working on the start up of NW Natural's Washington program.

Table 7 – Start Up Budget Summary

Legal	$	20,000
Information Technology	$	30,000
Planning & Evaluation	$	15,000
Finance & Accounting	$	10,000
HERs and ETO Home energy Services	$	30,000
Marketing and Communications	$	30,000
Existing Buildings Start Up Activities	$	15,000
TOTAL	**$**	**150,000**

Table 7 represents costs incurred by the Energy Trust. Start-up cost include setting up of new accounting and technical processes that will allow Energy Trust to separately track the Washington program; extending marketing efforts into Washington; making any forms or ads specific to Washington as building codes and available tax incentives differ; evaluating the DSM potential in more detail to set appropriate program metrics; amending existing contracts; developing trade ally agreements; and making the appropriate applications so that the Energy Trust can do business in Washington.

Start-up and ongoing costs will be captured and analyzed separately. Start-up costs will not be included in the annual cost effectiveness analysis.

Ongoing Costs

The ongoing program delivery phase will require approximately 1.75 full time Energy Trust employees (FTE) which will be included in the total cost per therm.

Energy Trust will carefully segregate costs associated with the delivery of programs in Washington and Oregon, ensuring that customers pay for delivery of their own programs.

Table 8 below shows the break out of the first year budget. The first year budget includes start-up costs which will be allocated over the first five years. NW Natural's costs are based on 10% of fully loaded costs for both a Grade 19 Consultant and a Grade 23 Manager. NW Natural's costs are allocated equally to both customer classes.

Table 8 – First Year Budget Summary

Budget	Residential	Commercial	Total
Incentives	$268,950	$211,900	$480,850
Delivery	$146,700	$65,200	$211,900
Energy Trust	$73,350	$48,900	$122,250
NW Natural	$16,450	$16,450	$32,900
Start Up Budget	$90,000	$60,000	$150,000
Total	**$595,450**	**$402,450**	**$997,900**

Washington Low Income Energy Efficiency Program

The Company's has modified its Washington Low Income Energy Efficiency program (WA-LIEE) in an effort to stimulate greater program participation. The program will be administered by Clark County Community Services and the Washington Gorge Action Program (agencies). WA-LIEE will mirror the low income program that the Company currently offers in Oregon. The current Oregon program was developed in April 2006 in a similar effort to serve more customers and to better use program funding. The changes adopted in Oregon have proved to be successful. Homes weatherized have increased from 253 in 2006 to 460 in 2008, and therm savings per home is up by 21% over the same time period. The Company is hopeful it will see similar success with its Washington Program.

The program will encourage the leveraging of other funding sources with WA-LIEE funds to increase the overall energy efficiency of low-income homes within the Company's Washington service territory.

Rebates paid under the WA-LIEE program will be based on the cost of the total group of measures recommended by energy analysis software that complies with the Department of Energy's standard for cost-effective energy efficiency. To qualify for a rebate, the total of all measures selected for each individual home must meet or exceed a Savings to Investment Ratio (SIR) of 1.0 or better. The rebate amount per home will be ninety percent (90%) of the documented installed cost of all measures, up to a maximum of $3,500 per home.

In addition to the qualifying rebate, the administrating agencies will be reimbursed for Health, Safety and Repair (HSR) costs, defined as home repairs that if not completed would adversely impact the safety and effectiveness of the energy efficiency measures or the health of the occupants. Standard efficiency furnace replacements may qualify for HSR funds if the existing furnace is broken, is found to produce an unsafe level of CO emissions, is back-drafting, or has a cracked heat exchanger and a high-efficiency furnace is not cost-effective or if it is physically impossible to install a high-efficiency furnace. HSR funds will be disbursed upon receipt of a completed reimbursement request. The maximum annual HSR disbursement available will be $440 times the actual number of homes treated by the agency in the Program Year.

The agencies will have discretion in the use of their HSR Allowance such that they may use more or less than the $440 on any one home. However, they must manage their HSR funds to ensure that the average HSR amount per home is not more than $440.

The program targets and achievements will be reviewed, and modified as necessary.

WA-LIEE Costs and Savings Projections

Table 9 below estimates WA-LIEE program costs and therm savings for the first program year.

Table 9

Estimated total qualifying homes:	6,960
Estimated homes served per year:	20
Estimated average cost per home:	$3,431
Estimated total utility cost/year*:	**$68,620**
Estimated therms saved/year**	4,380

*The total annual cost is based on the number of homes we estimate we will serve times the cost per home. In accordance with WUTC Staff's recommendation, NW Natural's administration costs are not included.

**219 therms per home is based on a 77% realization rate of RemRate's average of 285 therms saved per home. The Company's most recent impact evaluation performed on The Company's Oregon Low Income Energy Efficiency (OLIEE) Program in 2006 found RemRate results have a program realization rate of 77 percent.

.

Total Cost Recovery for Both EE Programs

The Company will use deferral accounts established in Docket Nos. UG-011230, UG-011231 and UG-080546 to track costs associated with these programs. The WUTC will perform an annual review before allowing the Company to amortize prudently incurred costs for recovery from Washington customers who may participate in the program. For the EE program, costs will be recovered from customers who can participate, which in the first year will be residential and commercial customers. WA-LIEE costs will be recovered from all firm sales customers. For both programs, costs will be collected on an equal percentage of margin basis.

In the first year, we expect the costs for the energy efficiency program to result in average monthly impact of $1.00 for residential customers and $3.97 for commercial customers.

The WA-LIEE program will result in average monthly impact of $0.07 for residential customers and $0.27 for commercial customers.

The combined monthly rate impact for both energy efficiency programs in the first year is forecast as being $1.07 for a typical residential customer and $4.24 for a typical commercial customer.

ATTACHMENT A

FIRST-YEAR PROGRAM TIMELINE

Washington Program Timeline

- October 1, 2009
  - Program begins
- September 30, 2010
  - End of first program year

Standard Reporting Schedule

- February 25, 2010
  - 1st quarterly report due
- May 25, 2010
  - 2nd quarterly report due
- August 25, 2010
  - 3rd quarterly report due
- January 25, 2011
  - Comprehensive annual report due

First-Year Benchmarking Study

- By March 25, 2011
  - Email third-party report with company's draft recommendations to EEAG
- By April 25, 2011
  - Consult with EEAG on final recommendation
- By May 25, 2011
  - File report/recommendation with WUTC

ATTACHMENT B

Energy Trust commissioned a survey of gas furnace installers and distributors in Clark, Co., Washington[9]. The survey team interviewed three installers and three distributors.

The results show that in 2008, 1,000 out of 1,700 total furnaces sold in NW Natural's Clark County gas service territory were high efficiency furnaces (less than 60%). By contrast, these same interviewees sold high efficiency furnaces in Oregon more than 67% of the time. (More than 2,000 of their 3,000 sales of furnaces in Oregon were high-efficiency.)

The percentage of high-efficiency units sold has increased significantly over the past five years. The percentage of units sold in each efficiency category is fairly similar to the percentages in NW Natural's Oregon service territory but in the 90-94% efficiency category, a higher percentage of units are sold in NW Natural's Washington service territory than its Oregon service area.

Weighted and Un-weighted Average Percentage of Units Sold in 2004 and in 2008 in Each Efficiency Category in NWN Clark County

Efficiency Category	2004 Percentage of Total Units		2008 *Percentage of Total Units*	
Weighted/ Un-weighted Averages	*Un-weighted*	*Weighted*	*Un-weighted*	*Weighted*
80-89% AFUE:	62%	77%	36%	36%
90-94% AFUE:	30%	22%	52%	59%
95% AFUE or higher:	8%	1%	12%	5%

**The percentages of units sold with an ECM motor are shown in Table 4 and 5 of the Appendix.*
Source: Summit Blue interviews of furnace vendors in NWN Clark County service territory

Note: The unweighted percentages reflect the sample taken. The weighted values are estimates of the population percentages calculated by using the relative fractions of the sample found in the population to adjust the sample to the population.

AFUE is the Annual Fuel Utilization Efficiency (AFUE) rating

[9] Survey is available upon request.

Table 5. Percentage of units in the AFUE category in 2008.

2008									
Respondent	Total # of units sold in 2008	Percentage of units in each category				Percentage of units in each category with an ECM motor			
		Less than 80%	*80-89% AFUE*	*90-94% AFUE*	*95% AFUE or higher*	*Less than 80%*	*80-89% AFUE*	*90-94% AFUE*	*95% AFUE or higher*
1	0	?	?	?	?	?	?	?	?
2	25	0%	30%	55%	15%	0%	0%	30%	30%
3	100	0%	20%	70%	10%	0%	10%	60%	100%
4	500	0%	50%	40%	10%	0%	20%	20%	20%
5	1001	0%	30%	70%	0%	0%	15%	15%	0%
6	55	0%	50%	25%	25%	0%	0%	100%	100%
Average	**1,681**	**0%**	**36%**	**52%**	**12%**	**0%**	**9%**	**45%**	**50%**
Weighted Average		**0%**	**36%**	**59%**	**5%**	**0%**	**15%**	**22%**	**16%**

Note: numbers for ECM motors are percentages of the percentage of units in that AFUE category.

Although the survey respondents represent a small sample of installers and distributors, they account for a high percentage of the furnaces installed. It appears that the gas furnace market is in the process of being transformed in Clark County, as it is in Oregon. Therefore, niche markets need to be studied further to determine where additional opportunities for market transformation exist.

In Washington, the housing stock is quite new: nearly 80% of homes were built after 1990. Of these, 47% (over 17,000 units) were built from 1990-94 and these furnaces will reach the end of their life in the next 10 years. In contrast, the Oregon housing stock (see Table III.2) shows approximately 50% of single family homes were built in the 1980’s.

ATTACHMENT C

ATTACHMENT C-1 – NW Natural's Oregon DSM Savings Proportioned to Demonstrate the DSM Potential in NW Natural's Washington Service Territory.

attachment c-1		11%		immature program factor ===>	0.75		
ratio OR/WA	**2008 NWN OR Actuals**	**WA/OR Ratio**	**NWN WA Mature Program Estimate**	**NWN WA**	**Immature Program Estimate # of Units**	**Working Therms per Unit**	**Total Annual Therms**
RESIDENTIAL MEASURES							
furnace	5,781	11%	614	furnace	461	70	32,240
tankless	860	11%	91	tankless	69	65	4,454
tank type	72	11%	8	tank type	6	16	93
Wall Insul	633	11%	67	Wall Insul	50	52	2,644
Ceiling Insul	1,911	11%	203	Ceiling Insul	152	64	9,811
Floor Insul	1,077	11%	114	Floor Insul	86	61	5,272
Air sealing	1,172	11%	124	Air sealing	93	26	2,384
Duct sealing	1,173	11%	125	Duct sealing	93	21	1,999
HER showerhead	2,537	11%	270	HER showerhead	202	22	4,348
HER Aerator	4,894	11%	520	HER Aerator	390	6.1	2,378
SUB TOTAL RESIDENTIAL						**Therms**	**65,622**
COMMERCIAL MEASURES		**9%**					
Custom Chillers	5	9%	0	Custom Chillers	0.3	5,872	1,984
Custom Building Controls	23	9%	2	Custom Building Controls	1.6	5,998	9,321
Custom Ducting/Filters	5	9%	0	Custom Ducting/Filters	0.3	749	253
Custom Economizers	10	9%	1	Custom Economizers	0.7	608	411
Custom Gas Boiler	4	9%	0	Custom Gas Boiler	0.3	15,745	4,255
Custom Heat Recovery	4	9%	0	Custom Heat Recovery	0.3	6,463	1,747
Custom HVAC	8	9%	1	Custom HVAC	0.5	416	225
Custom Other	120	9%	11	Custom Other	8.1	293	2,380
Custom VAV System	9	9%	1	Custom VAV System	0.6	1,188	722
Custom VFDs	19	9%	2	Custom VFDs	1	2,882	3,700
Attic Insulation (per SQFT)	205724	9%	18534	Attic Insulation (per SQFT)	13900	0.18	2,433
Roof Insulation (per SQFT)	470901	9%	42424	Roof Insulation (per SQFT)	31818	0.19	5,954
Wall Insulation (per SQFT)	73787	9%	6648	Wall Insulation (per SQFT)	4986	0.20	997
PT Heat Pump	418	9%	38	PT Heat Pump	28	7	203
Showerhead Gas	300	9%	27	Showerhead Gas	20	7	142
Steam Traps, Small Commercial, <12 hrs/d	2156	9%	194	Steam Traps, Small Commercial, <12 hrs/day, :	146	139	20,249
Direct-Fired Convection Oven	164	9%	15	Direct-Fired Convection Oven	11	543	6,021
Condensing Tank	25	9%	2	Condensing Tank	2	678	1,145
High Efficiency Unit Heater - Non-Conden:	9	9%	1	High Efficiency Unit Heater - Non-Condensing	1	170	103
Infrared Gas Fryer	31	9%	3	Infrared Gas Fryer	2	548	1,148
Direct-fired Radiant Heating	160	9%	14	Direct-fired Radiant Heating	11	367	3,971
High Efficiency Condensing Boiler with El	229	9%	21	High Efficiency Condensing Boiler with Electr	15	171	2,640
High Efficiency Condensing Furnace <225,	27	9%	2	High Efficiency Condensing Furnace <225,000	2	96	176
Domestic Tankless/Instanaeous Water Heat	16	9%	1	Domestic Tankless/Instanaeous Water Heater v	1	620	671
Commercial dishwashers	15	9%	1	Commercial dishwashers	1	334	338
SUB TOTAL COMMERCIAL						**Therms**	**71,189**
TOTAL RESIDENTIAL and COMMERCIAL						**Therms**	**136,811**

Notes:
Unless otherwise noted, all estimates for NWN WA are ratioed down fro NWN OR actuals in 2008; res uses ratio of households, commercial uses ratios of loads.
WA/OR Ratio - residential (11%) ratio is reflective of the proportion of residential households between NWN service territory in the 2 states
WA/OR Ratio - commercial (9%) ratio is reflective of the proportion of commercial loads in the two states

Attachment C-2 –Cascade Natural Gas's DSM Savings Proportioned to Demonstrate Potential Therm Savings in NW Natural's Washington Service Territory

Attachment C-2

immature program factor ===> 0.75

ratio CNG/NWN WA	2008 CNG WA Actuals	NWNWA/ CNGWA	NWN WA Mature Program Estimate	Measures	NWN WA Immature Program Estimate # of Units	Working Therms per Unit	Total Annual Therms
RESIDENTIAL MEASURES							
furnace	652	0.375	245	furnace	425	70	29,750
tankless	250	0.375	94	tankless	70	43	3,023
tank type	87	0.375	33	tank type	24	13	318
E* clothes washer	507	0.375	190	E* clothes washer	143	6	856
Wall Insul	126	0.375	47	Wall Insul	35	52	1,858
Ceiling Insul	284	0.375	107	Ceiling Insul	80	64	5,148
Floor Insul	328	0.375	123	Floor Insul	92	61	5,668
Aerator	656	0.375	246	Aerator*	185	17	3,137
Showerhead	2960	0.375	1110	Showerhead*	833	31	25,808
				SUB TOTAL RESIDENTIAL		**Therms**	**75,565**
COMMERCIAL MEASURES							
Warm-air Furnace < 225 kBtu/hr	31	0.375	12	Warm-air Furnace < 225 kBtu/hr	9	111	966
Radiant heating	7	0.375	3	Radiant heating	2	526	1,035
Attic Insulation	3	0.375	1	Attic Insulation	1	329	278
Roof Insulation	6	0.375	2	Roof Insulation	2	2745	4,632
Wall Insul	5	0.375	2	Wall Insul	1	566	795
Domestic Hot Water	3	0.375	1	Domestic Hot Water	1	158	133
Domestic Tankless	15	0.375	6	Domestic Tankless	4	184	777
Boiler	6	0.375	2	Boiler	2	1093	1,844
Gas Convection Oven	10	0.375	4	Gas Convection Oven	3	564	1,586
Clothes Washer	3	0.375	1	Clothes Washer	1	90	76
custom measures	28	0.375	11	custom measures	8	5312	41,833
				SUB TOTAL COMMERCIAL		**Therms**	**53,954**
				TOTAL		**Therms**	**129,519**

Note: *Showerheads and Aerators make up over 1/3 of CNG's residential savings and were achieved through a mail out kit. ETO will acquire these measures through HERs, in collaboratio with Clark PUD and expects a much lower volume compared to a mass mailing of kits.

ATTACHMENT D

NW Natural SW Washington
New Homes Potential

The New Homes program, implemented July 1, 2010, will costs approximately $187,500 in the first 12 months. The targets for this program are outlined in the tables below. Please note that this program will be evaluated separately from the residential and commercial programs that were implemented on October 1, 2009; The costs and therm savings targets below are in addition to those established for the residential and commercial programs and stated on page 1 of this Plan.

	Costs	**Percentage**
Estimated Incentives	$ 130,000.00	69%
Estimated Delivery	$ 34,500.00	18%
Estimated ETO Costs*	$ 23,000.00	12%
Total	**$ 187,500.00**	**100%**
Levelized Cost	**$.48 per Therm**	

* ETO Estimated Costs To Be Determined

	Qty.	**Incentive**	**Therm Savings**
Builder Option Package	150	$ 600.00	100
Tankless Hot Water	200	$ 200.00	65
Total Therm Savings	**28,000**		

SUMMARY

NW Natural's new construction in NW Natural's SW Washington service territory will provide a cost effective fixed incentive for builders who construct an ENERGY STAR certified home. In addition, the program will offer a cost effective fixed incentive for builders who install natural gas tankless hot water heaters.

BACKGROUND

The Northwest Energy Efficiency Alliance (NEEA) currently operates the Northwest ENERGY STAR for Homes Program in NW Natural's Washington service territory. This program recruits builders and provides them with training, technical assistance, and marketing support. To receive ENERGY STAR certification, the builders must follow a prescriptive builder option package (BOP) that ensures the home will be at least 15% more energy efficient than code requires.

Earlier this year, Washington increased the efficiency required in new construction homes through a code change taking effect June 1, 2010. NEEA is currently negotiating with the US EPA who runs the national ENERGY STAR program to update the BOP paths to maintain performance at 15% above the new code. The new ENERGY STAR BOPs will go into effect January 1, 2011.

Currently, the ENERGY STAR for Homes program has a 20% market share in SW Washington. However, the new code and new BOPs, which will raise the building standard, may result in builder attrition from the program. The introduction of new construction incentives for homes being built to the new ENERGY STAR BOP paths will help maintain market share and help recruit new builders.

PROGRAM DESIGN AND IMPACT

For SW Washington builders to receive ENERGY STAR certification on a new home the following steps take place:

- The builder must hire an independent verifier that is trained and certified by the state certification organization for ENERGY STAR in Washington (which is WSU).
- The builder must construct the home following one of the ENERGY STAR BOP paths.
- The verifier inspects each home twice; once before drywall is installed and once at completion.
- The verifier enters select data about the home into the ENERGY STAR database, including location, builder, and which BOP path they followed.
- The builder pays the verifier a fee for the inspection services, and pays the state certification organization a fee to process their certification, for their ENERGY STAR label, and to cover quality control activities.

Energy Trust will leverage the existing infrastructure, training, outreach and marketing efforts currently in the marketplace through NEEA's ENERGY STAR for Homes program. To reinforce the importance of ENERGY STAR after the code change and new BOPs, the program will offer $600 for each home certified in the ENERGY STAR database that uses the new BOP paths. And for those builders who are unwilling or unable to build to the ENERGY STAR levels, a $200 incentive for the installation of a .82 EF gas tankless hot water heater will also be offered. This program will claim 100 therms per ENERGY STAR home and 65 therms per tankless hot water heater.

NW Natural believes it is reasonable to strive to incent 150 ENERGY STAR homes and 200 tankless hot water heaters in the first program year.

IMPLEMENTATION

The program will utilize the ENERGY STAR database to track and pay for ENERGY STAR certified homes. Builders applying for tankless hot water heater incentives will be required to fill out a simple form that includes the serial number for the installed unit; they will then submit the form with a copy of their invoice proving purchase and delivery.

The Company estimates that program data entry will be around 60 minutes for processing and paying incentives for each ENERGY STAR home and 30 minutes for processing each tankless incentive. In addition, NW Natural forecasts that it will take 1 hour per ENERGY STAR home plus direct expenses to outreach and consult with builders and the independent verifiers working in SW Washington who have not participated in Energy Trust incentive programs. Key marketing collateral, including an FAQ will be developed to help customers to understand the program options.. The labor costs are estimated to be $31,500 and the direct costs are $3,000.

ATTACHMENT E

Attachment E
2011 Program Metrics

The Schedule G Residential and Commercial Energy Efficiency Program:

In order to deliver consistent and good energy efficiency services to Washington customers, NW Natural has set the following metrics assuming Energy Trust will deliver its program for the complete 2011 calendar year. The Company acknowledges that the EEAG and WUTC may require a change in administrators before the end of the year which will necessitate modifying the metrics below.

- Total program costs will be between $1,212,000 and $1,380,616*
- Therms saved will be between 158,822 and 186,849*
- Average levelized cost for measures not to exceed $0.65 per therm
- Second year therms will cost less than $7 per therm

Total Resource Cost (TRC) and Utility Cost (UC) at the portfolio level are greater than 1.0

*A breakdown of these targets by program is provided in the table below

	TOTAL	Commercial	Residential	
		Retrofit	Retrofit	New Homes
Total Program Costs	$1,212,000 to $1,380,616	$510,000 to $566,205	$512,000 to $568,205	$190,000 to $246,205
Total Savings Targets	158,822 – 186,849	89,250-105,000	54,090-63,635	15,482 to 18,214
** includes administrative costs				

Schedule I, Washington Low Income Energy Efficiency (WA-LIEE)

In 2011, the WA-LIEE program will strive to weatherize 30 homes

Estimated homes served per year:	30
Estimated average cost per home:	$3,500
Estimated total utility cost/year:	**$105,000**
Estimated therms saved/year***	6330

***Based on an average savings of 211 therms per home.

Appendix 5: Linear Programming and The Company's Resource Choices

NW Natural®

Resource Model Output – Original Modeling Phase

(July – September 2010)

Run 1: 1319-Palomar East

1319-Palomar East	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	269	684	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,894	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,604	72,854	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Unserved Demand	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	905	905	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Unserved	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	323,699	364,813	402,800	422,867	443,575	446,167	450,190	449,361	439,983	455,627	477,809	501,945	532,851	572,529	584,882	607,313	622,319	645,063	673,758	693,548	
Total Supply Costs	323,759	364,873	402,860	422,926	443,634	446,226	450,250	449,420	440,043	455,686	477,868	502,005	532,910	572,588	584,942	607,372	622,378	645,123	673,817	693,607	**6,174,361**
Transport Fixed Costs	82,955	83,081	84,664	84,688	84,688	90,354	91,199	92,583	92,860	92,860	92,959	92,959	92,959	92,959	94,296	94,396	94,521	94,668	94,813	96,216	
Transport Variable Costs	2,967	3,156	3,267	3,171	3,047	2,182	2,197	2,266	2,326	2,277	2,305	2,295	2,346	2,349	2,319	2,344	2,427	2,449	2,466	2,483	
Total Transport Cost	85,922	86,237	87,931	87,858	87,735	92,536	93,397	94,849	95,186	95,137	95,264	95,254	95,305	95,308	96,615	96,740	96,948	97,117	97,279	98,699	**1,195,763**
Storage Fixed Cost	24,104	24,763	25,516	25,619	25,619	25,913	26,122	27,060	27,723	27,723	27,723	27,723	27,723	27,723	27,723	27,723	27,723	27,723	27,723	27,723	
Storage Variable Cost	1,966	1,953	2,001	2,169	2,151	2,387	2,185	2,100	2,539	2,478	1,907	1,984	2,112	2,138	2,171	2,389	2,315	2,361	2,536	2,696	
Total Storage Cost	26,071	26,715	27,517	27,788	27,770	28,300	28,307	29,160	30,262	30,201	29,630	29,707	29,835	29,861	29,894	30,112	30,038	30,083	30,259	30,419	**371,756**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	**417,939**
Total Levelized Utility Cost	0	807	2,089	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	435,751	501,272	543,860	566,296	590,274	599,688	607,666	610,499	604,002	620,832	643,686	669,441	701,303	739,621	753,315	774,693	788,416	810,224	837,661	853,359	**8,159,819**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	37.5225	43.4970	43.4970	43.4970	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	
NWP Zones 26-16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Zones 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4136	0.9906	1.7189	2.5705	3.4131	4.3131	
Palomar East	-	-	-	-	-	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
NWP Vintage TF1	102.0000	102.0000	102.0000	102.0000	102.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	23.2452	23.2169	23.4370	65.1266	85.0000	85.0000	74.3215	28.3964	77.0924	32.3985	73.3559	81.5681	-	-	-	41.1850	42.3157	42.6701	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	287.5224	293.4970	293.4970	293.4970	353.9282	353.9281	334.7474	345.1546	353.9282	353.9282	353.9282	353.9282	348.0465	353.9282	353.9282	353.9282	353.9282	353.9282	
Newport LNG	59.9501	59.9445	59.8906	59.9114	59.9680	60.0751	-	-	60.5290	60.7286	60.9366	61.1011	61.2702	61.4193	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 2: 1321-No Palomar East

1321 NO PAL E	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	269	684	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,894	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,604	72,854	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Unserved Demand	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	905	905	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Unserved	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	323,699	364,813	402,800	422,867	444,517	450,799	454,200	453,587	444,242	459,734	481,503	507,943	537,478	577,691	597,207	606,136	627,364	651,257	681,305	699,880	
Total Supply Costs	323,759	364,873	402,860	422,926	444,577	450,859	454,260	453,646	444,301	459,793	481,562	508,002	537,537	577,750	597,266	606,195	627,423	651,316	681,365	699,939	**6,216,939**
Transport Fixed Costs	82,955	83,081	84,664	84,688	84,688	84,688	84,739	86,122	86,399	86,399	86,399	86,399	86,399	86,399	87,737	87,836	87,962	88,109	88,254	89,957	**1,108,166**
Transport Variable Costs	2,967	3,156	3,267	3,171	3,052	3,151	3,161	3,343	3,404	3,369	3,382	3,379	3,452	3,428	3,449	3,441	3,514	3,535	3,573	3,522	
Total Transport Cost	85,922	86,237	87,931	87,858	87,740	87,839	87,900	89,465	89,803	89,768	89,781	89,778	89,851	89,827	91,185	91,277	91,476	91,644	91,827	93,479	**1,150,719**
Storage Fixed Cost	24,104	24,763	25,516	25,619	25,755	26,268	26,562	27,500	28,163	28,163	28,163	28,163	28,163	28,163	28,163	28,163	28,163	28,163	28,261	28,331	
Storage Variable Cost	1,966	1,953	2,001	2,168	2,162	2,428	2,296	2,127	2,675	2,651	1,941	2,115	2,140	2,234	2,375	2,427	2,386	2,514	2,881	2,776	
Total Storage Cost	26,071	26,715	27,517	27,787	27,917	28,696	28,858	29,627	30,838	30,815	30,105	30,279	30,303	30,397	30,539	30,591	30,549	30,677	31,142	31,107	**376,492**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	807	2,089	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	435,751	501,272	543,860	566,295	591,368	600,019	606,731	609,808	603,453	620,184	642,371	670,534	700,944	739,839	760,854	768,533	788,501	811,539	840,640	855,158	**8,162,089**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	37.5225	43.4970	43.4970	50.1856	116.5782	116.5782	116.5782	116.5782	116.5782	116.5782	116.5782	116.5782	116.5782	116.5782	116.5782	116.5782	116.5782	121.3921	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	
NWP Zones 26-16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5360	
NWP Zones 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4136	0.9906	1.7189	2.5705	3.4131	4.3131	
Palomar East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	23.2452	43.2419	43.4997	24.1016	85.0000	85.0000	46.5586	48.3619	51.0638	51.5525	31.8433	32.7024	-	17.7257	-	-	-	1.2419	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	287.5224	293.4970	293.4970	300.1856	366.5782	366.5782	347.3975	357.8047	366.5782	366.5782	366.5782	366.5782	360.7247	366.5782	366.5782	366.5782	366.5782	371.3921	
New port LNG	59.9501	59.9445	59.8906	59.9114	59.9680	60.0751	-	-	60.5290	60.7286	60.9366	61.1011	61.2702	61.4193	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 3: 1373-Outages –fixed resources with Palomar East

1373	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	**0.0516**
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	269	684	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,894	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,604	72,854	73,268	73,357	73,774	74,302	75,074	75,192	75,679	76,378	77,251	77,521	77,998	78,399	78,906	79,165	79,651	80,263	81,234	81,512	
Unserved Demand	39	40	0	0	0	0	0	0	72	0	150	0	0	0	269	0	17	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	905	905	942	945	949	956	962	971	910	993	944	1,014	1,024	1,031	855	1,046	1,038	1,065	1,075	1,085	
Peak Day Demand Unserved	39	40	0	0	0	0	0	0	72	0	61	0	0	0	184	0	17	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	54	59	58	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	323,699	364,813	402,800	422,867	443,575	447,179	450,513	450,507	440,081	453,316	478,654	501,916	533,238	570,584	582,352	608,769	621,549	643,659	672,903	693,145	
Total Supply Costs	323,759	364,873	402,860	422,926	443,634	447,238	450,572	450,566	440,135	453,376	478,712	501,975	533,298	570,643	582,411	608,829	621,608	643,719	672,962	693,204	**6,172,471**
Transport Fixed Costs	82,955	83,081	84,664	84,688	84,688	90,354	90,413	91,796	91,272	92,469	92,700	92,700	92,499	92,746	95,472	95,643	95,643	95,916	96,061	96,216	**1,161,754**
Transport Variable Costs	2,967	3,156	3,267	3,171	3,047	2,187	2,193	2,265	2,314	2,261	2,302	2,285	2,339	2,331	2,361	2,417	2,484	2,506	2,528	2,483	
Total Transport Cost	85,922	86,237	87,931	87,858	87,735	92,541	92,606	94,061	93,586	94,730	95,001	94,984	94,838	95,077	97,834	98,061	98,127	98,422	98,589	98,699	**1,195,446**
Storage Fixed Cost	24,104	24,763	25,516	25,619	25,619	26,037	26,332	27,405	28,163	28,163	28,163	28,163	28,163	28,163	28,163	28,163	28,163	28,163	28,163	28,163	
Storage Variable Cost	1,966	1,953	2,001	2,169	2,151	2,404	2,251	2,090	2,598	2,487	1,852	2,046	2,157	2,229	1,986	2,361	2,361	2,458	2,573	2,755	
Total Storage Cost	26,071	26,715	27,517	27,788	27,770	28,441	28,583	29,495	30,762	30,650	30,016	30,209	30,320	30,393	30,150	30,524	30,524	30,621	30,736	30,918	**375,140**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	807	2,089	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	435,751	501,272	543,860	566,296	590,274	600,846	607,474	611,193	602,994	618,563	644,652	669,645	701,709	737,977	752,259	777,883	789,312	810,663	838,594	853,454	**8,160,996**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	37.5225	43.4970	43.4970	43.4970	109.9728	109.9728	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	
NWP Zones 26-16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Zones 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9906	0.9906	2.5705	3.4131	4.3131	
Palomar East	-	-	-	-	-	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
NWP Vintage TF1	-	-	-	-	-	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	23.2452	43.2419	23.4370	70.5466	85.0000	85.0000	20.2540	77.2656	74.4819	75.3389	40.7633	32.7024	-	1.4078	-	39.6004	-	34.1959	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	-	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	287.5224	293.4970	293.4970	293.4970	359.9728	359.9728	366.5781	348.8928	308.1255	366.5781	366.5781	366.5781	124.0000	344.6123	366.5781	363.9165	366.5781	366.5781	
New port LNG	59.9501	59.9445	59.8906	59.9114	59.9680	60.0751	-	-	60.5290	60.7286	60.9366	61.1011	61.2702	61.4193	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	6.1056	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 4: 1347-Outages with limited resources and Palomar East

1347	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	269	684	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,894	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,604	72,854	73,268	73,357	73,774	74,302	75,074	75,192	75,679	76,378	77,251	77,521	77,998	78,399	79,082	79,165	79,668	80,263	81,234	81,512	
Unserved Demand	39	40	0	0	0	0	0	0	72	0	150	0	0	0	94	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	905	905	942	945	949	956	962	971	910	993	944	1,014	1,024	1,031	945	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Unserved	39	40	0	0	0	0	0	0	72	0	61	0	0	0	94	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	54	59	58	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	323,699	364,813	402,800	422,867	443,575	447,179	450,513	450,507	440,081	453,316	478,654	501,916	533,238	572,704	581,449	608,809	620,807	643,613	668,287	697,638	
Total Supply Costs	323,759	364,873	402,860	422,926	443,634	447,238	450,572	450,566	440,135	453,376	478,712	501,975	533,298	572,763	581,508	608,868	620,866	643,672	668,346	697,697	**6,172,655**
Transport Fixed Costs	82,955	83,081	84,664	84,688	84,688	90,354	90,413	91,796	91,272	92,469	92,700	92,700	92,499	92,746	95,472	95,472	95,472	95,472	95,472	95,472	**1,160,884**
Transport Variable Costs	2,967	3,156	3,267	3,171	3,047	2,187	2,193	2,265	2,314	2,261	2,302	2,285	2,339	2,584	2,725	2,606	2,592	2,648	2,699	2,746	
Total Transport Cost	85,922	86,237	87,931	87,858	87,735	92,541	92,606	94,061	93,586	94,730	95,001	94,984	94,838	95,330	98,197	98,078	98,064	98,120	98,171	98,218	**1,195,255**
Storage Fixed Cost	24,104	24,763	25,516	25,619	25,619	26,037	26,332	27,405	28,163	28,163	28,163	28,163	28,163	36,654	43,664	43,664	43,664	43,664	43,664	43,664	
Storage Variable Cost	1,966	1,953	2,001	2,169	2,151	2,404	2,251	2,090	2,598	2,487	1,852	2,046	2,157	2,272	2,028	2,287	2,377	2,456	2,519	2,688	
Total Storage Cost	26,071	26,715	27,517	27,788	27,770	28,441	28,583	29,495	30,761	30,650	30,015	30,209	30,321	38,926	45,693	45,951	46,041	46,121	46,184	46,352	**420,220**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	807	2,089	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	435,751	501,272	543,860	566,296	590,274	600,846	607,474	611,193	602,994	618,563	644,652	669,645	701,709	748,883	767,262	793,367	804,024	825,814	849,007	872,901	**8,206,069**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	37.5225	43.4970	43.4970	43.4970	109.9728	109.9728	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.0000	30.0000	30.0000	30.0000	30.0000	30.0000	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.0000	30.0000	30.0000	30.0000	30.0000	30.0000	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.0000	30.0000	30.0000	30.0000	30.0000	30.0000	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	
NWP Zones 26-16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Zones 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Palomar East	-	-	-	-	-	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
NWP Vintage TF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	23.2452	23.2169	23.4370	65.1266	85.0000	85.0000	22.2111	28.3964	53.9819	32.6831	37.2143	82.6474	-	12.5903	13.9388	2.3657	-	-	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	0.6866	8.0000	8.0000	8.0000	-	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	287.5224	293.4970	293.4970	293.4970	359.9728	359.9728	366.5781	348.8928	308.1255	366.5781	366.5781	366.5781	124.0000	262.5948	348.8645	324.5338	318.1880	301.8522	
New port LNG	59.9501	59.9445	59.8906	59.9114	59.9680	60.0751	-	-	60.5290	60.7286	60.9366	61.1011	61.2702	61.4193	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	6.1056	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 5: 1348-Outages with full resources and Palomar East

1348	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	269	684	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,894	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,604	72,854	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Unserved Demand	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	905	905	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Unserved	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	54	59	58	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	323,699	364,813	402,800	422,867	443,560	441,369	447,671	449,058	436,315	451,399	465,733	495,921	527,445	558,283	576,970	600,681	612,155	637,531	664,177	681,688	
Total Supply Costs	323,759	364,873	402,860	422,926	443,620	441,428	447,731	449,117	436,369	451,458	465,792	495,980	527,504	558,342	577,029	600,740	612,214	637,591	664,236	681,747	**6,119,059**
Transport Fixed Costs	82,955	83,081	84,664	84,688	84,688	105,424	109,559	111,152	116,247	117,444	122,164	122,164	121,918	122,944	127,183	127,183	127,183	127,183	127,183	127,183	**1,382,749**
Transport Variable Costs	2,967	3,156	3,267	3,171	3,047	2,116	2,033	2,025	1,999	2,101	1,965	1,996	2,023	2,043	1,939	2,223	2,126	2,230	2,273	2,323	
Total Transport Cost	85,922	86,237	87,931	87,858	87,735	107,540	111,593	113,177	118,246	119,545	124,129	124,160	123,941	124,987	129,122	129,407	129,309	129,413	129,456	129,507	**1,414,354**
Storage Fixed Cost	24,104	24,763	25,516	25,619	25,619	25,374	25,200	26,489	27,444	29,896	31,940	31,940	31,940	37,629	42,303	42,303	42,303	42,303	42,303	42,303	
Storage Variable Cost	1,966	1,953	1,997	2,160	2,141	2,296	1,999	1,882	2,198	2,217	1,860	2,099	2,393	2,382	2,047	2,345	2,410	2,560	2,560	2,552	
Total Storage Cost	26,071	26,715	27,513	27,779	27,760	27,669	27,199	28,371	29,642	32,112	33,800	34,039	34,333	40,012	44,350	44,648	44,712	44,862	44,863	44,855	**421,702**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	807	2,089	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	435,751	501,272	543,856	566,287	590,249	609,263	622,235	627,736	622,768	642,923	664,644	696,656	729,031	765,205	792,366	815,264	825,289	849,767	874,862	886,742	**8,373,054**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	37.5225	43.4970	43.4970	43.4970	77.4683	77.4683	77.4683	77.4683	77.4683	77.4683	77.4683	77.4683	77.4683	77.4683	77.4683	77.4683	77.4683	77.4683	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.0000	30.0000	30.0000	30.0000	30.0000	30.0000	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	3.7487	3.7487	30.0000	30.0000	30.0000	30.0000	30.0000	30.0000	30.0000	30.0000	30.0000	30.0000	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.0000	30.0000	30.0000	30.0000	30.0000	30.0000	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	41.0000	41.0000	41.0000	41.0000	41.0000	41.0000	41.0000	41.0000	41.0000	41.0000	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	
NWP Zones 26-16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Zones 12-9	-	-	-	-	-	-	-	-	-	-	2.9018	2.9018	2.9018	2.9018	2.9018	2.9018	2.9018	2.9018	2.9018	2.9018	
Palomar East	-	-	-	-	-	193.7174	193.7174	193.7174	193.7174	193.7174	193.7174	193.7174	193.7174	193.7174	193.7174	193.7174	193.7174	193.7174	193.7174	193.7174	
NWP Vintage TF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	23.2452	43.2419	23.4370	70.5466	85.0000	85.0000	34.0144	37.1581	68.0174	79.3600	40.3295	-	11.5833	41.6228	13.6327	-	-	21.1640	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	5.4861	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	287.5224	293.4970	293.4970	293.4970	327.4683	327.4683	327.4683	241.3570	232.1171	236.9907	268.3118	253.4370	124.0000	231.2589	240.2137	220.6018	201.1643	210.7758	
New port LNG	59.9501	59.9445	59.8906	59.9114	59.9680	60.0751	-	-	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	6.1056	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 6: 1374-Outages with fixed resources and no Palomar East

1374	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	269	684	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,894	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,604	72,854	73,268	73,357	73,774	74,302	75,074	75,192	75,611	76,378	77,251	77,521	77,982	78,399	78,812	79,165	79,628	80,263	81,234	81,512	
Unserved Demand	39	40	0	0	0	0	0	0	140	0	150	0	16	0	363	0	40	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	905	905	942	945	949	956	962	971	848	993	944	1,014	1,008	1,031	832	1,046	1,015	1,065	1,075	1,085	
Peak Day Demand Unserved	39	40	0	0	0	0	0	0	134	0	61	0	16	0	207	0	40	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	54	59	58	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	323,699	364,813	402,800	422,867	444,517	450,799	454,200	454,005	443,498	459,751	480,340	507,984	537,521	578,208	595,040	606,187	627,296	651,257	681,305	699,880	
Total Supply Costs	323,759	364,873	402,860	422,926	444,576	450,859	454,260	454,065	443,552	459,810	480,398	508,043	537,580	578,267	595,100	606,247	627,355	651,316	681,364	699,939	**6,215,278**
Transport Fixed Costs	82,955	83,081	84,664	84,688	84,688	84,688	84,739	86,122	84,791	86,399	86,399	86,399	86,089	86,399	87,665	87,836	87,836	88,109	88,254	89,957	**1,106,829**
Transport Variable Costs	2,967	3,156	3,267	3,171	3,052	3,151	3,161	3,346	3,369	3,369	3,377	3,379	3,450	3,429	3,426	3,441	3,511	3,535	3,573	3,522	
Total Transport Cost	85,922	86,237	87,931	87,858	87,740	87,839	87,900	89,468	88,160	89,768	89,777	89,778	89,538	89,829	91,091	91,278	91,347	91,644	91,827	93,479	**1,149,346**
Storage Fixed Cost	24,104	24,763	25,516	25,619	25,755	26,268	26,562	27,500	28,163	28,163	28,163	28,163	28,163	28,163	28,163	28,163	28,163	28,163	28,261	28,331	
Storage Variable Cost	1,966	1,953	2,001	2,169	2,164	2,431	2,297	2,134	2,712	2,653	1,939	2,121	2,144	2,296	2,187	2,438	2,386	2,521	2,888	2,784	
Total Storage Cost	26,071	26,715	27,517	27,788	27,920	28,698	28,859	29,634	30,875	30,817	30,103	30,285	30,308	30,459	30,351	30,601	30,549	30,684	31,149	31,114	**376,487**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	807	2,089	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	435,751	501,272	543,860	566,296	591,371	600,022	606,732	610,237	601,098	620,203	641,201	670,582	700,679	740,419	758,406	768,595	788,303	811,546	840,647	855,165	**8,159,049**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	37.5225	43.4970	43.4970	50.1851	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	121.3897	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	
NWP Zones 26-16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5360	
NWP Zones 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9906	0.9906	2.5705	3.4131	4.3108	
Palomar East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	23.2452	43.2419	23.4370	43.5533	85.0000	85.0000	16.7911	49.1979	53.9819	51.5525	31.8433	32.7024	-	-	16.6182	21.0206	-	6.6619	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	-	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	287.5224	293.4970	293.4970	300.1851	366.5781	366.5781	366.5781	357.8047	360.8644	366.5781	366.5781	366.5781	124.0000	366.5781	366.5781	366.5781	366.5781	371.3897	
New port LNG	59.9501	59.9445	59.8906	59.9114	59.9680	60.0751	-	-	60.5290	60.7286	60.9366	61.1011	61.2702	61.4193	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	6.1056	12.2113	12.2113	12.2113	6.1056	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 7: 1349- Outages with limited resources and no Palomar East

1349	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	269	684	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,894	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,604	72,854	73,268	73,357	73,774	74,302	75,074	75,192	75,611	76,378	77,251	77,521	77,982	78,399	78,884	79,165	79,668	80,263	81,234	81,512	
Unserved Demand	39	40	0	0	0	0	0	0	140	0	150	0	16	0	291	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	905	905	942	945	949	956	962	971	848	993	944	1,014	1,024	1,031	871	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Unserved	39	40	0	0	0	0	0	0	134	0	61	0	0	0	168	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	54	59	58	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	323,699	364,813	402,800	422,867	444,517	450,799	454,200	454,005	443,498	459,751	480,340	507,984	537,521	578,425	594,849	606,788	627,731	650,785	679,439	700,186	
Total Supply Costs	323,759	364,873	402,860	422,926	444,576	450,859	454,260	454,065	443,552	459,810	480,398	508,043	537,580	578,484	594,908	606,847	627,790	650,844	679,498	700,245	**6,214,935**
Transport Fixed Costs	82,955	83,081	84,664	84,688	84,688	84,688	84,739	86,122	84,791	86,399	86,399	86,399	86,089	86,399	87,665	87,665	87,665	87,665	87,665	87,665	**1,105,365**
Transport Variable Costs	2,967	3,156	3,267	3,171	3,052	3,151	3,161	3,346	3,369	3,369	3,377	3,379	3,450	3,599	3,511	3,535	3,606	3,631	3,664	3,617	
Total Transport Cost	85,922	86,237	87,931	87,858	87,740	87,839	87,900	89,468	88,160	89,768	89,777	89,778	89,538	89,998	91,177	91,200	91,272	91,297	91,330	91,283	**1,148,213**
Storage Fixed Cost	24,104	24,763	25,516	25,619	25,755	26,268	26,562	27,500	28,163	28,163	28,163	28,163	28,163	31,834	34,874	34,970	35,047	35,047	35,047	35,047	
Storage Variable Cost	1,966	1,953	2,001	2,169	2,164	2,431	2,297	2,134	2,712	2,653	1,940	2,121	2,144	2,308	2,186	2,402	2,406	2,516	2,886	2,808	
Total Storage Cost	26,071	26,715	27,517	27,788	27,920	28,698	28,859	29,634	30,875	30,816	30,103	30,284	30,308	34,142	37,061	37,372	37,453	37,563	37,933	37,855	**396,247**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	807	2,089	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	435,751	501,272	543,860	566,296	591,371	600,022	606,732	610,237	601,098	620,202	641,201	670,581	700,679	744,489	765,009	775,888	795,567	817,605	845,068	860,016	**8,177,334**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	37.5225	43.4970	43.4970	50.1851	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	116.5781	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.0000	30.0000	30.0000	30.0000	30.0000	30.0000	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.0297	9.0297	10.0234	10.0234	10.0234	10.0234	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	
NWP Zones 26-16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Zones 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Palomar East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	23.2452	43.2419	23.4370	24.1016	85.0000	85.0000	33.6229	28.3964	53.9819	52.3886	52.9446	32.7024	-	-	-	-	-	-	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	-	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	287.5224	293.4970	293.4970	300.1851	366.5781	366.5781	366.5781	357.8047	360.8644	366.5781	366.5781	366.5781	124.0000	336.5651	366.5781	354.8479	364.4382	366.5781	
New port LNG	59.9501	59.9445	59.8906	59.9114	59.9680	60.0751	-	-	60.5290	60.7286	60.9366	61.1011	61.2702	61.4193	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	6.1056	12.2113	12.2113	12.2113	6.1056	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 8: 1350- Outages with full resource options and no Palomar East

1350	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	**0.0516**
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	269	684	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,894	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,604	72,854	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	78,884	79,165	79,668	80,263	81,234	81,512	
Unserved Demand	39	40	0	0	0	0	0	0	0	0	0	0	0	0	291	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	905	905	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	871	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Unserved	39	40	0	0	0	0	0	0	0	0	0	0	0	0	168	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	54	59	58	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	323,699	364,813	402,800	422,867	444,517	450,913	454,206	462,086	443,933	458,679	482,489	507,245	535,522	576,679	586,356	614,783	627,151	649,678	678,715	697,894	
Total Supply Costs	323,759	364,873	402,860	422,926	444,577	450,972	454,265	462,145	443,987	458,738	482,547	507,304	535,581	576,738	586,415	614,842	627,210	649,737	678,774	697,953	**6,216,848**
Transport Fixed Costs	82,955	83,081	84,664	84,688	84,688	84,688	84,688	86,071	86,006	87,614	92,335	92,335	92,088	92,335	92,386	92,386	92,386	92,386	92,386	92,386	**1,132,639**
Transport Variable Costs	2,967	3,156	3,267	3,171	3,052	3,152	3,159	3,443	3,384	3,483	3,446	3,381	3,446	3,590	3,469	3,535	3,597	3,617	3,665	3,605	
Total Transport Cost	85,922	86,237	87,931	87,858	87,740	87,840	87,847	89,514	89,390	91,098	95,781	95,716	95,535	95,925	95,855	95,921	95,983	96,002	96,051	95,991	**1,175,638**
Storage Fixed Cost	24,104	24,763	25,516	25,619	25,755	26,285	26,591	31,628	35,544	35,544	35,544	35,544	35,544	36,388	37,091	37,091	37,091	37,091	37,091	37,091	
Storage Variable Cost	1,966	1,953	2,001	2,168	2,162	2,429	2,299	2,245	2,925	2,739	2,098	2,172	2,349	2,483	2,307	2,531	2,696	2,812	3,097	3,102	
Total Storage Cost	26,071	26,715	27,517	27,787	27,917	28,714	28,890	33,873	38,469	38,283	37,642	37,716	37,893	38,871	39,398	39,622	39,787	39,903	40,188	40,192	**430,585**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	807	2,089	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	435,751	501,272	543,860	566,295	591,369	600,152	606,715	622,603	610,357	627,927	656,893	683,212	712,261	753,399	763,532	790,854	802,032	823,544	851,321	864,770	**8,241,010**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	37.5225	43.4970	43.4970	50.1856	117.4096	117.4096	180.9812	180.9812	180.9812	180.9812	180.9812	180.9812	180.9812	180.9812	180.9812	180.9812	180.9812	180.9812	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.0297	9.0297	9.0297	9.0297	9.0297	9.0297	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	30.0000	30.0000	30.0000	30.0000	30.0000	30.0000	30.0000	30.0000	30.0000	30.0000	30.0000	30.0000	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	41.0000	41.0000	41.0000	41.0000	41.0000	41.0000	41.0000	41.0000	41.0000	41.0000	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	
NWP Zones 26-16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Zones 12-9	-	-	-	-	-	-	-	-	-	-	2.9018	2.9018	2.9018	2.9018	2.9018	2.9018	2.9018	2.9018	2.9018	2.9018	
Palomar East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	23.2452	43.2419	43.4997	24.1016	85.0000	85.0000	34.0144	10.7578	43.2193	-	-	-	-	1.4078	-	-	-	1.2419	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	5.4861	8.0000	8.0000	-	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	287.5224	293.4970	293.4970	300.1856	367.4096	367.4096	430.9812	319.3646	353.0548	314.9983	372.1574	357.0796	124.0000	336.5651	405.5718	355.8416	365.4319	375.8225	
New port LNG	59.9501	59.9445	59.8906	59.9114	59.9680	60.0751	-	-	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	6.1056	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 9: 1354-Low Gas Price

1354	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,446	76,930	78,329	78,984	80,205	81,479	83,286	84,079	85,153	86,228	87,738	88,429	89,664	90,901	92,546	93,308	
Forecast DSM	0	269	684	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,894	73,268	73,357	73,773	74,682	75,458	75,491	76,062	76,674	77,791	77,931	78,316	78,728	79,549	79,648	80,282	80,943	81,998	82,342	
Served Demand	72,604	72,854	73,268	73,357	73,773	74,682	75,458	75,491	76,062	76,674	77,791	77,931	78,316	78,728	79,549	79,648	80,282	80,943	81,998	82,342	
Unserved Demand	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	962	969	977	987	999	1,012	1,022	1,029	1,037	1,045	1,054	1,066	1,077	1,088	1,100	
Peak Day Demand Served	905	905	942	945	949	962	969	977	987	999	1,012	1,022	1,029	1,037	1,045	1,054	1,066	1,077	1,088	1,100	
Peak Day Demand Unserved	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	323,699	364,811	400,868	374,464	384,632	400,571	403,370	404,396	379,609	389,908	423,194	447,474	469,686	486,587	482,573	478,174	485,850	494,887	517,488	538,896	
Total Supply Costs	323,758	364,870	400,927	374,523	384,692	400,630	403,429	404,456	379,668	389,967	423,253	447,534	469,745	486,647	482,632	478,233	485,909	494,947	517,547	538,955	**5,396,591**
Transport Fixed Costs	82,955	83,081	84,664	84,688	84,688	90,050	90,413	91,796	92,074	92,074	92,074	92,543	92,543	92,576	93,964	94,090	94,254	94,418	94,881	96,114	**1,158,019**
Transport Variable Costs	2,967	3,156	3,255	3,253	3,125	2,213	2,213	2,281	2,358	2,345	2,382	2,351	2,391	2,370	2,411	2,411	2,437	2,488	2,550	2,611	
Total Transport Cost	85,922	86,237	87,919	87,941	87,813	92,263	92,626	94,077	94,432	94,419	94,455	94,894	94,934	94,946	96,375	96,501	96,690	96,906	97,431	98,725	**1,192,150**
Storage Fixed Cost	24,104	24,762	25,445	25,795	26,018	26,337	26,563	27,502	28,165	28,165	28,165	28,165	28,165	28,165	28,165	28,165	28,165	28,254	28,430	28,514	
Storage Variable Cost	1,966	1,953	1,768	2,118	2,017	2,150	1,967	1,866	2,213	2,172	2,032	1,948	2,054	1,933	2,006	2,034	1,993	2,011	2,102	2,280	
Total Storage Cost	26,071	26,715	27,214	27,913	28,034	28,487	28,530	29,367	30,377	30,337	30,197	30,113	30,219	30,098	30,170	30,199	30,157	30,266	30,532	30,794	**373,897**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	807	2,089	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	435,750	501,270	541,612	518,100	531,673	554,006	560,298	564,971	542,989	554,530	588,828	615,016	638,151	653,555	651,041	645,402	651,809	660,019	681,817	699,107	**7,380,577**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	37.5131	39.4981	54.9497	54.9497	116.6162	116.6162	116.6162	116.6162	116.6162	116.6162	116.6162	116.6162	116.6162	116.6162	116.6162	116.6162	116.6162	116.6162	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0683	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9621	1.9706	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	
NWP Zones 26-16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Zones 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1918	0.9024	1.6314	2.5440	3.4952	3.4952	3.7454	
Palomar East	-	-	-	-	-	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
NWP Vintage TF1	-	-	-	-	-	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	23.2441	43.2395	43.4965	24.9657	85.0000	85.0000	30.2066	75.5105	72.5522	76.2658	32.5656	33.4479	-	44.9458	2.2425	5.7201	1.8320	3.3561	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	287.5131	289.4981	304.9496	304.9497	366.6162	366.6162	345.7340	355.9170	366.6162	366.6162	366.6162	366.6162	360.5180	366.6162	366.6162	366.6162	366.6162	366.6162	
New port LNG	59.9501	59.9444	59.8904	59.9112	59.9677	60.1658	-	-	60.6046	60.8016	61.0333	61.2040	61.3512	61.5037	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 10: 1355-High Gas Price

1355	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,328	76,127	77,376	77,824	78,725	79,918	81,550	82,380	83,708	84,967	86,542	87,234	88,398	89,573	91,186	92,034	
Forecast DSM	0	269	684	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,894	73,268	73,357	73,655	73,879	74,504	74,331	74,582	75,113	76,056	76,231	76,871	77,468	78,353	78,453	79,016	79,616	80,638	81,068	
Served Demand	72,604	72,854	73,268	73,357	73,655	73,879	74,504	74,331	74,582	75,113	76,056	76,231	76,871	77,468	78,353	78,453	79,016	79,616	80,638	81,068	
Unserved Demand	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	947	948	953	956	962	971	982	992	1,004	1,015	1,025	1,033	1,043	1,054	1,064	1,077	
Peak Day Demand Served	905	905	942	945	947	948	953	956	962	971	982	992	1,004	1,015	1,025	1,033	1,043	1,054	1,064	1,077	
Peak Day Demand Unserved	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	323,699	364,811	425,148	491,931	539,186	590,677	656,627	678,299	679,376	687,188	689,901	677,827	690,986	712,283	710,844	745,287	743,241	740,800	736,838	740,979	
Total Supply Costs	323,758	364,870	425,207	491,990	539,245	590,737	656,686	678,358	679,435	687,247	689,960	677,887	691,045	712,342	710,904	745,347	743,300	740,859	736,897	741,038	**7,719,568**
Transport Fixed Costs	82,955	83,081	84,664	84,688	84,688	90,050	90,942	92,325	92,603	92,603	92,823	92,823	92,823	92,823	92,823	94,095	94,233	94,380	94,536	96,109	**1,159,638**
Transport Variable Costs	2,967	3,156	3,255	3,128	3,018	2,154	2,176	2,225	2,273	2,184	2,255	2,248	2,299	2,301	2,263	2,328	2,386	2,406	2,426	2,454	
Total Transport Cost	85,922	86,237	87,919	87,816	87,706	92,204	93,118	94,550	94,876	94,787	95,078	95,070	95,122	95,123	95,086	96,423	96,619	96,785	96,962	98,564	**1,192,800**
Storage Fixed Cost	24,104	24,762	25,445	25,520	25,548	25,724	25,848	26,786	27,449	27,449	27,449	27,449	27,449	27,449	27,449	27,449	27,449	27,449	27,449	27,449	
Storage Variable Cost	1,966	1,953	2,091	2,444	2,584	3,098	3,146	2,890	3,954	3,735	2,663	2,711	2,750	2,637	2,518	2,817	2,722	2,766	2,907	2,789	
Total Storage Cost	26,071	26,715	27,536	27,964	28,132	28,822	28,994	29,676	31,403	31,184	30,112	30,160	30,199	30,086	29,967	30,266	30,171	30,215	30,357	30,238	**375,948**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	807	2,089	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	435,750	501,270	566,215	635,493	686,218	744,388	814,511	839,654	844,225	853,026	856,073	845,593	859,619	879,416	877,820	912,505	909,143	905,761	900,522	900,473	**9,706,255**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	37.5131	39.4981	41.4646	41.4646	96.0646	96.0646	96.0646	96.0646	96.0646	96.0646	96.0646	96.0646	96.0646	96.0646	96.0646	96.0646	96.0646	96.0646	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	40.0000	
NWP Zones 26-16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Zones 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0385	0.8377	1.6876	2.5957	3.6941	
Palomar East	-	-	-	-	-	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
NWP Vintage TF1	-	-	-	-	-	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	23.2441	43.2395	43.1211	23.1357	85.0000	85.0000	24.3845	71.9702	68.4033	72.4147	32.7919	30.5915	31.7293	38.7109	-	40.3676	-	0.1126	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	287.5131	289.4981	291.4646	291.4646	346.0646	346.0646	318.1068	326.9842	336.4692	345.4040	346.0646	346.0646	346.0646	344.3371	346.0646	346.0646	346.0646	346.0646	
New port LNG	59.9501	59.9444	59.8904	59.9112	59.9397	59.9737	-	-	60.2425	60.4158	60.6026	60.7760	60.9833	61.1797	61.3433	100.0000	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 19: 1368-Imported LNG Oregon LNG

1368-Imported LNG ORLNG	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	269	684	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,894	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,604	72,854	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Unserved Demand	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	905	905	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Unserved	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	323,699	364,813	402,801	422,867	444,230	433,963	429,193	427,104	416,266	433,207	448,160	479,168	512,715	540,371	562,223	583,560	595,896	622,263	649,834	668,610	
Total Supply Costs	323,759	364,873	402,860	422,926	444,289	434,022	429,252	427,163	416,326	433,266	448,219	479,228	512,774	540,431	562,283	583,620	595,956	622,323	649,893	668,669	**5,982,229**
Transport Fixed Costs	82,955	83,081	84,664	84,688	84,688	90,050	97,319	98,702	98,979	98,979	98,979	98,979	98,979	98,979	99,051	99,150	99,276	99,423	99,871	101,316	**1,204,998**
Transport Variable Costs	2,967	3,156	3,267	3,171	3,051	2,125	1,171	1,216	1,225	1,222	1,216	1,254	1,288	1,220	1,227	1,291	1,283	1,326	1,362	1,362	
Total Transport Cost	85,922	86,237	87,931	87,858	87,739	92,175	98,490	99,918	100,205	100,202	100,195	100,233	100,267	100,199	100,278	100,441	100,559	100,749	101,234	102,679	**1,230,330**
Storage Fixed Cost	24,104	24,763	25,516	25,619	25,720	24,853	24,190	25,128	25,792	25,792	25,792	25,792	25,792	25,792	25,792	25,792	25,792	25,792	25,792	25,792	
Storage Variable Cost	1,966	1,953	2,001	2,169	2,160	2,198	1,807	1,708	2,056	2,088	1,543	1,761	1,969	1,959	2,050	2,129	2,182	2,338	2,363	2,318	
Total Storage Cost	26,071	26,715	27,517	27,788	27,881	27,051	25,998	26,837	27,847	27,880	27,335	27,552	27,760	27,751	27,841	27,921	27,973	28,130	28,155	28,110	**354,049**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	807	2,089	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	435,751	501,272	543,860	566,296	591,043	585,875	589,452	590,989	582,889	601,155	616,672	649,489	684,054	710,245	732,266	752,451	763,540	789,103	815,589	830,090	**7,984,547**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	37.5225	43.4970	43.4970	48.4556	48.4556	48.4556	48.4556	48.4556	48.4556	48.4556	48.4556	48.4556	48.4556	48.4556	48.4556	48.4556	48.4556	48.4556	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Zones 26-16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Zones 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4136	0.9906	1.7189	2.5705	3.4131	4.3131	
Palomar East	-	-	-	-	-	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
NWP Vintage TF1	-	-	-	-	-	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	
OregonLNG Pipeline (imported LNG)	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	23.2452	43.2419	23.4370	70.5466	85.0000	85.0000	27.0404	75.6775	76.2564	77.2589	31.8433	79.1474	39.0027	80.7408	82.6112	41.9537	78.7101	85.0000	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	287.5224	293.4970	293.4970	298.4556	298.4556	297.6610	246.4988	256.9060	267.6093	275.8041	284.0103	290.9774	298.2704	298.4556	298.4556	298.4556	298.4556	298.4556	
New port LNG	59.9501	59.9445	59.8906	59.9114	59.9680	60.0751	-	-	60.5290	60.7286	60.9366	61.1011	61.2702	61.4193	61.5557	61.6920	61.8577	62.0417	62.2159	62.4117	
March Point	0	0	0	0	0	0	0	12.211255	12.211255	12.211255	12.2112551	12.2112551	12.2112551	12.2112551	12.2112551	12.2112551	12.2112551	12.2112551	12.2112551	12.2112551	

Run 20: 1369-Imported LNG Jordan Cove

1369-Imported LNG JC	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	269	684	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,894	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,604	72,854	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Unserved Demand	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	905	905	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Unserved	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)									100.00		100.00				100.00						
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	323,699	364,813	402,801	422,867	442,926	443,110	446,341	451,545	439,921	455,603	475,992	502,586	530,507	571,260	582,126	607,452	620,882	643,461	672,220	693,292	
Total Supply Costs	323,759	364,873	402,860	422,926	442,985	443,169	446,401	451,604	439,981	455,663	476,051	502,645	530,567	571,320	582,185	607,511	620,941	643,520	672,279	693,351	**6,164,073**
Transport Fixed Costs	82,955	83,081	84,664	84,688	84,688	91,362	91,889	93,272	93,550	93,550	94,019	94,019	94,019	94,019	95,285	95,285	95,285	95,285	95,401	96,088	**1,168,920**
Transport Variable Costs	2,967	3,156	3,267	3,171	3,043	2,056	2,042	2,127	2,183	2,141	2,143	2,148	2,178	2,185	2,153	2,195	2,254	2,274	2,286	2,283	
Total Transport Cost	85,922	86,237	87,931	87,858	87,731	93,418	93,932	95,399	95,733	95,691	96,162	96,167	96,196	96,204	97,437	97,480	97,538	97,558	97,687	98,371	**1,201,212**
Storage Fixed Cost	24,104	24,763	25,516	25,619	25,619	25,679	25,721	26,659	27,322	27,322	27,322	27,322	27,322	27,322	27,322	27,322	27,322	27,322	27,322	27,322	
Storage Variable Cost	1,966	1,953	1,997	2,160	2,116	2,345	2,057	2,019	2,506	2,431	1,800	1,903	2,024	2,090	2,051	2,271	2,238	2,316	2,441	2,644	
Total Storage Cost	26,071	26,715	27,513	27,779	27,735	28,024	27,778	28,678	29,828	29,753	29,122	29,225	29,346	29,412	29,373	29,593	29,560	29,638	29,763	29,966	**367,832**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	807	2,089	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	435,751	501,272	543,856	566,287	589,586	597,237	603,823	612,751	604,053	620,914	642,259	670,513	699,361	738,799	750,859	775,054	787,092	808,618	836,035	852,322	**8,151,056**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	37.5225	43.4970	43.4970	43.4970	92.4152	92.4152	92.4152	92.4152	92.4152	92.4152	92.4152	92.4152	92.4152	92.4152	92.4152	92.4152	92.4152	92.4152	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	
NWP Zones 26-16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Zones 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Palomar East	-	-	-	-	-	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
NWP Vintage TF1	-	-	-	-	-	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	
Pacific Connector Pipeline (Jordan Cove LNG)	0	0	0	0	0	15.6082811	17.5575523	17.557552	17.557552	17.557552	17.5575523	17.5575523	17.5575523	17.5575523	17.5575523	17.5575523	17.5575523	17.5575523	18.9412918	18.9412918	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	23.2452	43.2419	23.4370	69.5360	85.0000	85.0000	27.0404	74.8414	38.7314	80.7589	40.7633	32.7024	39.6633	42.4328	45.6489	7.4954	8.8211	48.5230	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	8.0000	8.0000	8.0000	7.1962	5.8309	-	5.9016	8.0000	5.4113	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	287.5224	293.4970	293.4970	293.4970	342.4152	342.4152	326.9831	338.2871	342.4152	342.4152	342.4152	342.4152	342.4152	342.4152	342.4152	342.4152	342.4152	342.4152	
New port LNG	59.9501	59.9445	59.8906	59.9114	59.9680	60.0751	-	-	60.5290	60.7286	60.9366	61.1011	61.2702	61.4193	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
March Point	0	0	0	0	0	0	0	12.211255	12.211255	12.211255	12.2112551	12.2112551	12.2112551	12.2112551	12.2112551	12.2112551	12.2112551	12.2112551	12.2112551	12.2112551	

Run 23: 1384-PAL East 10% Higher

1384-PAL East 10% Higher	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	269	684	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,894	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,604	72,854	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Unserved Demand	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	905	905	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Unserved	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)									100.00		100.00				100.00						
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	323,699	364,813	402,800	422,867	443,575	446,167	450,190	449,361	439,983	455,627	477,809	501,945	532,851	572,529	584,882	607,313	622,319	645,063	673,758	693,548	
Total Supply Costs	323,759	364,873	402,860	422,926	443,634	446,226	450,250	449,420	440,043	455,686	477,868	502,005	532,910	572,588	584,942	607,372	622,378	645,123	673,817	693,607	**6,174,361**
Transport Fixed Costs	82,955	83,081	84,664	84,688	84,688	91,946	92,792	94,175	94,452	94,452	94,551	94,551	94,551	94,551	95,888	95,988	96,113	96,260	96,406	97,808	**1,175,529**
Transport Variable Costs	2,967	3,156	3,267	3,171	3,047	2,182	2,197	2,266	2,326	2,277	2,305	2,295	2,346	2,349	2,319	2,344	2,427	2,449	2,466	2,483	
Total Transport Cost	85,922	86,237	87,931	87,858	87,735	94,128	94,989	96,441	96,778	96,729	96,856	96,846	96,897	96,900	98,207	98,332	98,540	98,709	98,871	100,292	**1,209,131**
Storage Fixed Cost	24,104	24,763	25,516	25,619	25,619	25,913	26,122	27,060	27,723	27,723	27,723	27,723	27,723	27,723	27,723	27,723	27,723	27,723	27,723	27,723	
Storage Variable Cost	1,966	1,953	1,998	2,166	2,151	2,387	2,186	2,100	2,539	2,478	1,907	1,984	2,113	2,138	2,171	2,389	2,315	2,360	2,536	2,695	
Total Storage Cost	26,071	26,715	27,513	27,785	27,770	28,300	28,307	29,159	30,262	30,201	29,629	29,707	29,835	29,861	29,894	30,112	30,038	30,083	30,258	30,418	**371,750**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	807	2,089	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	435,751	501,272	543,856	566,293	590,274	601,280	609,258	612,091	605,594	622,425	645,277	671,033	702,895	741,213	754,907	776,285	790,008	811,816	839,253	854,950	**8,173,181**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	37.5225	43.4970	43.4970	43.4970	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	
NWP Zones 26-16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Zones 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4136	0.9906	1.7189	2.5705	3.4131	4.3131	
Palomar East	-	-	-	-	-	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
NWP Vintage TF1	-	-	-	-	-	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	24.0813	29.4730	43.4997	24.1016	85.0000	85.0000	27.0404	74.8414	29.8114	37.8185	73.3559	34.2870	-	-	-	47.4410	-	2.0780	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	287.5224	293.4970	293.4970	293.4970	353.9282	353.9281	334.7474	345.1546	353.9282	353.9282	353.9282	353.9282	348.0465	353.9282	353.9282	353.9282	353.9282	353.9282	
Newport LNG	59.9501	59.9445	59.8906	59.9114	59.9680	60.0751	-	-	60.5290	60.7286	60.9366	61.1011	61.2702	61.4193	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 24: 1385-PAL East 10% Lower

1385-PAL East 10% Lower	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	269	684	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,894	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,604	72,854	73,268	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Unserved Demand	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	905	905	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Unserved	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)									100.00		100.00				100.00						
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	323,699	364,813	402,800	422,867	443,575	446,167	450,190	449,361	439,983	455,627	477,809	501,945	532,851	572,529	584,882	607,313	622,319	645,063	673,758	693,548	
Total Supply Costs	323,759	364,873	402,860	422,926	443,634	446,226	450,250	449,420	440,043	455,686	477,868	502,005	532,910	572,588	584,942	607,372	622,378	645,123	673,817	693,607	**6,174,361**
Transport Fixed Costs	82,955	83,081	84,664	84,688	84,688	88,769	89,614	90,997	91,274	91,274	91,373	91,373	91,373	91,373	92,710	92,810	92,936	93,083	93,228	94,631	**1,148,848**
Transport Variable Costs	2,967	3,156	3,267	3,171	3,047	2,182	2,197	2,266	2,326	2,277	2,305	2,295	2,346	2,349	2,319	2,344	2,427	2,449	2,466	2,483	
Total Transport Cost	85,922	86,237	87,931	87,858	87,735	90,950	91,811	93,263	93,600	93,552	93,679	93,668	93,719	93,722	95,030	95,154	95,362	95,532	95,693	97,114	**1,182,450**
Storage Fixed Cost	24,104	24,763	25,516	25,619	25,619	25,913	26,122	27,060	27,723	27,723	27,723	27,723	27,723	27,723	27,723	27,723	27,723	27,723	27,723	27,723	
Storage Variable Cost	1,966	1,953	1,998	2,166	2,151	2,386	2,185	2,099	2,539	2,478	1,907	1,984	2,112	2,138	2,171	2,389	2,315	2,361	2,536	2,695	
Total Storage Cost	26,071	26,715	27,513	27,785	27,770	28,300	28,307	29,159	30,262	30,201	29,629	29,706	29,835	29,861	29,894	30,112	30,038	30,083	30,258	30,418	**371,749**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	807	2,089	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	435,751	501,272	543,856	566,293	590,274	598,102	606,080	608,913	602,416	619,246	642,100	667,855	699,717	738,036	751,729	773,107	786,831	808,639	836,075	851,773	**8,146,499**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	37.5225	43.4970	43.4970	43.4970	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	103.9282	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	
NWP Zones 26-16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Zones 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4136	0.9906	1.7189	2.5705	3.4131	4.3131	
Palomar East	-	-	-	-	-	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
NWP Vintage TF1	-	-	-	-	-	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	24.0813	29.4730	43.4997	24.1016	85.0000	85.0000	27.0404	74.8414	29.8114	30.8139	73.3559	34.2870	44.0040	-	-	45.8565	-	2.0780	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	287.5224	293.4970	293.4970	293.4970	353.9282	353.9281	334.7474	345.1546	353.9282	353.9282	353.9282	353.9282	348.0465	353.9282	353.9282	353.9282	353.9282	353.9282	
Newport LNG	59.9501	59.9445	59.8906	59.9114	59.9680	60.0751	-	-	60.5290	60.7286	60.9366	61.1011	61.2702	61.4193	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Resource Model Output – Modification Modeling Phase (April – June 2011)

Run 1: 1411-2011 IRP Mod Base Case

1411	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	268	682	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,895	73,270	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,605	72,856	73,243	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Unserved Demand	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	906	906	915	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Unserved	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	302,917	281,494	293,899	350,382	353,613	359,324	377,614	397,072	371,901	363,697	365,618	375,123	388,238	396,783	411,603	434,084	468,717	479,487	497,558	515,612	
Total Supply Costs	302,977	281,553	293,958	350,441	353,672	359,384	377,674	397,131	371,960	363,757	365,677	375,183	388,297	396,842	411,662	434,143	468,776	479,546	497,617	515,672	**4,821,021**
Transport Fixed Costs	83,034	83,161	84,747	84,774	84,839	84,839	84,839	87,224	87,502	87,502	87,502	87,830	87,830	87,830	87,830	89,096	89,096	89,096	89,096	89,096	**1,115,587**
Transport Variable Costs	2,992	3,202	3,343	3,329	3,362	3,433	3,440	3,534	3,522	3,534	3,573	3,593	3,607	3,620	3,642	3,646	3,666	3,702	3,744	3,738	
Total Transport Cost	86,026	86,363	88,090	88,103	88,201	88,272	88,279	90,758	91,023	91,036	91,075	91,423	91,437	91,450	91,472	92,742	92,762	92,798	92,839	92,834	**1,160,318**
Storage Fixed Cost	24,104	24,277	25,706	25,638	25,742	26,412	26,783	27,721	28,384	28,384	28,384	28,384	28,384	28,440	28,480	28,547	28,683	28,828	29,073	29,210	
Storage Variable Cost	1,292	1,275	2,125	1,815	1,283	1,835	1,740	1,839	1,834	1,809	1,826	1,814	1,946	1,949	2,003	2,247	2,121	2,264	2,372	2,593	
Total Storage Cost	25,396	25,552	27,831	27,453	27,025	28,247	28,522	29,560	30,219	30,193	30,211	30,199	30,330	30,389	30,483	30,794	30,804	31,092	31,445	31,803	**373,301**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	803	2,079	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	414,399	416,915	435,431	493,720	500,032	508,528	530,188	554,520	531,713	524,793	527,886	539,280	553,317	560,546	575,482	598,148	631,395	641,337	658,208	670,942	**6,772,580**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	-	32.0457	32.0457	38.7342	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	108.5418	108.5418	108.5418	108.5418	108.5418	112.9191	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7189	1.5705	2.4131	3.3131	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	40.0000	
NWP Zones 12-9 (Grants Pass Lat.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Palomar East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Blue Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	33.3277	43.6219	43.0483	43.1025	85.0000	85.0000	27.0404	33.8164	35.2314	30.8139	32.6794	32.7024	33.5827	-	-	-	23.9029	25.6721	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	5.4913	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	260.0000	292.0457	292.0457	298.7342	365.9582	365.9582	347.7775	358.1847	365.9582	365.9582	365.9582	365.9582	368.5418	366.9842	368.5418	368.5417	368.5418	372.9191	
Newport LNG	59.9501	59.9570	59.9168	59.9114	59.9680	60.0751	-	-	60.5290	60.7286	60.9366	61.1011	61.2702	61.4193	61.5557	100.0000	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 2: 1397-2011 IRP Mod Low Customer Growth

1397	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,611	72,922	73,278	73,302	73,727	74,320	75,229	75,573	76,449	77,511	79,071	79,782	80,893	81,914	83,314	83,877	84,932	86,051	87,544	88,212	
Forecast DSM	0	264	660	1,085	1,573	2,096	2,664	3,236	3,842	4,469	5,130	5,765	6,435	7,081	7,752	8,333	8,920	9,483	10,062	10,474	
Forecast Demand (net DSM)	72,611	72,658	72,619	72,217	72,154	72,224	72,565	72,337	72,607	73,042	73,941	74,017	74,459	74,833	75,562	75,544	76,012	76,568	77,482	77,737	
Served Demand	72,574	72,622	72,600	72,217	72,154	72,224	72,565	72,337	72,607	73,042	73,941	74,017	74,459	74,833	75,562	75,544	76,012	76,568	77,482	77,737	
Unserved Demand	38	36	18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	943	942	934	929	927	927	928	932	938	947	957	966	974	982	989	995	1,004	1,014	1,023	1,032	
Peak Day Demand Served	906	905	915	929	927	927	928	932	938	947	957	966	974	982	989	995	1,004	1,014	1,023	1,032	
Peak Day Demand Unserved	38	36	18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	302,769	280,668	289,332	344,517	345,201	348,180	364,225	382,892	355,664	347,221	348,349	356,457	369,379	376,395	391,578	412,923	445,412	455,558	472,411	489,959	
Total Supply Costs	302,828	280,727	289,392	344,576	345,261	348,239	364,284	382,951	355,723	347,281	348,408	356,516	369,438	376,454	391,637	412,982	445,471	455,617	472,471	490,018	**4,651,610**
Transport Fixed Costs	83,034	83,161	84,747	84,808	84,818	84,818	84,839	86,675	86,952	86,952	86,952	87,830	87,830	87,830	87,830	87,830	89,096	89,096	89,096	89,096	**1,113,552**
Transport Variable Costs	2,990	3,195	3,299	3,283	3,295	3,357	3,357	3,416	3,388	3,395	3,428	3,473	3,496	3,501	3,527	3,525	3,541	3,560	3,596	3,596	
Total Transport Cost	86,024	86,356	88,046	88,091	88,113	88,175	88,196	90,091	90,340	90,347	90,380	91,303	91,326	91,330	91,357	91,355	92,636	92,656	92,692	92,691	**1,157,135**
Storage Fixed Cost	24,104	24,277	25,461	24,940	24,940	25,275	25,512	26,451	27,114	27,114	27,114	27,114	27,114	27,114	27,114	27,114	27,114	27,114	27,114	27,114	
Storage Variable Cost	1,289	1,275	2,100	1,775	1,224	1,699	1,675	1,749	1,721	1,715	1,721	1,731	1,833	1,838	1,871	2,113	2,046	2,127	2,237	2,468	
Total Storage Cost	25,394	25,552	27,561	26,715	26,163	26,974	27,187	28,200	28,835	28,829	28,835	28,845	28,947	28,951	28,985	29,226	29,159	29,241	29,350	29,582	**359,176**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	785	1,981	3,303	4,861	6,561	8,388	10,327	12,391	14,557	16,788	19,075	21,404	23,679	25,933	28,127	30,227	32,255	34,197	35,923	
Total Costs	414,246	416,082	430,550	487,105	490,671	496,014	515,380	538,313	513,409	506,264	508,547	519,140	532,963	538,600	553,844	574,033	606,319	615,415	630,819	642,925	**6,585,860**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	-	13.2682	13.2682	13.2682	71.7668	71.7668	71.7668	71.7668	71.7668	71.7668	71.7668	71.7668	71.7668	71.7668	71.7668	71.7668	71.7668	71.7668	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	
NWP Zones 12-9 (Grants Pass Lat.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Palomar East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Blue Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	37.6291	40.2859	39.3442	38.2352	80.2612	74.2726	39.0121	22.3733	28.9966	24.4612	26.2555	26.2196	33.3008	33.1357	10.2454	-	13.4549	-	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	260.0000	273.2682	273.2682	273.2682	331.7668	331.7668	307.8841	316.4514	326.0652	331.7668	331.7668	331.7668	331.7668	331.7668	328.6934	331.7668	331.7668	331.7668	
New port LNG	59.9460	59.9024	59.7628	59.6418	59.5805	59.5721	-	-	59.7604	59.9137	60.0858	60.2404	60.3945	60.5361	60.6686	60.7981	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 3: 1400-2011 IRP Mod High Customer growth

1400	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,664	73,323	74,406	75,341	76,775	78,365	80,198	81,318	82,852	84,416	86,372	87,304	88,588	89,737	91,301	91,942	93,128	94,386	96,052	96,811	
Forecast DSM	0	271	697	1,177	1,751	2,373	3,044	3,710	4,402	5,103	5,826	6,509	7,220	7,903	8,613	9,222	9,840	10,432	11,039	11,466	
Forecast Demand (net DSM)	72,664	73,052	73,709	74,165	75,024	75,992	77,154	77,608	78,450	79,314	80,545	80,795	81,368	81,834	82,687	82,720	83,288	83,955	85,013	85,345	
Served Demand	72,626	73,011	73,677	74,165	75,024	75,992	77,154	77,608	78,450	79,314	80,545	80,795	81,368	81,834	82,687	82,720	83,288	83,955	85,013	85,345	
Unserved Demand	38	41	33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	947	948	956	966	979	991	1,005	1,019	1,034	1,049	1,060	1,071	1,079	1,088	1,095	1,105	1,117	1,127	1,139	
Peak Day Demand Served	906	906	916	956	966	979	991	1,005	1,019	1,034	1,049	1,060	1,071	1,079	1,088	1,095	1,105	1,117	1,127	1,139	
Peak Day Demand Unserved	38	41	33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	303,019	282,236	297,201	354,686	360,318	367,948	388,949	410,423	385,005	378,335	381,685	392,782	407,652	416,060	432,094	455,553	491,877	503,178	521,839	540,700	
Total Supply Costs	303,079	282,295	297,260	354,745	360,377	368,007	389,008	410,483	385,064	378,394	381,744	392,842	407,711	416,119	432,153	455,612	491,936	503,237	521,899	540,759	**4,977,160**
Transport Fixed Costs	83,034	83,161	84,747	84,774	84,839	84,839	84,839	87,552	87,830	87,830	87,830	87,830	87,830	87,854	87,854	87,854	89,260	89,330	89,330	89,330	**1,116,243**
Transport Variable Costs	2,993	3,209	3,376	3,368	3,420	3,488	3,511	3,634	3,622	3,649	3,700	3,713	3,735	3,751	3,780	3,779	3,809	3,841	3,890	3,886	
Total Transport Cost	86,027	86,370	88,123	88,142	88,260	88,328	88,350	91,187	91,452	91,479	91,530	91,543	91,564	91,604	91,634	91,632	93,069	93,171	93,220	93,216	**1,162,053**
Storage Fixed Cost	24,104	24,277	25,916	26,255	26,452	27,377	27,876	28,843	29,506	29,539	29,653	29,833	30,157	30,586	31,006	31,205	31,314	31,509	31,787	31,929	
Storage Variable Cost	1,293	1,276	2,145	1,839	1,351	1,883	1,828	1,909	1,899	1,877	1,904	1,901	2,039	2,065	2,129	2,390	2,201	2,396	2,492	2,760	
Total Storage Cost	25,398	25,553	28,061	28,094	27,803	29,260	29,704	30,752	31,405	31,416	31,556	31,733	32,196	32,650	33,135	33,595	33,515	33,905	34,278	34,689	**389,951**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	815	2,145	3,711	5,658	7,812	10,089	12,455	14,904	17,394	19,881	22,383	24,886	27,311	29,710	32,037	34,264	36,410	38,459	40,273	
Total Costs	414,503	417,665	438,996	498,704	507,574	518,220	542,775	569,492	546,432	541,097	545,754	558,594	574,724	582,238	598,786	621,309	657,573	668,214	685,703	699,297	**6,947,103**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	-	48.6485	48.6485	61.3433	134.3006	136.1494	136.1494	136.1494	136.1494	136.1494	137.4137	145.1949	152.5652	159.2304	159.2304	159.2304	159.2304	161.0369	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	0.3538	1.2729	2.1400	2.8627	3.8573	4.7596	5.0361	5.9706	7.2783	8.7447	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	
NWP Zones 12-9 (Grants Pass Lat.)	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1548	0.1548	0.1548	1.0596	1.5071	1.5071	1.5071	
Palomar East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Blue Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	35.5257	45.5758	46.1113	47.2830	85.0000	85.0000	53.7566	33.7099	40.9172	36.7692	38.8181	38.9577	45.3761	46.2008	28.7176	7.0712	31.7364	10.0227	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	6.9329	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	7.7331	7.4645	8.0000	8.0000	7.6185	7.1385	
Mist & Mist Recall	250.0000	250.0000	260.0000	308.6485	308.6485	321.3433	394.3006	396.1494	381.1697	394.6594	396.1495	396.1495	397.4137	405.1949	412.5652	419.2304	419.2304	419.2304	419.2304	421.0369	
New port LNG	59.9519	59.9909	60.0216	60.1032	60.2654	60.4823	-	-	61.1912	61.4539	61.7037	61.9101	62.1034	62.2612	62.4211	62.5690	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 4: 1402-2011 IRP Mod Gas Dereg

1402	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,664	73,323	74,406	75,341	76,775	78,757	80,598	81,632	83,180	84,731	86,788	87,742	88,931	90,091	91,704	92,461	93,790	95,120	96,878	97,708	
Forecast DSM	0	271	697	1,173	1,746	2,367	3,044	3,710	4,402	5,103	5,826	6,509	7,220	7,903	8,613	9,222	9,840	10,432	11,039	11,466	
Forecast Demand (net DSM)	72,664	73,052	73,709	74,168	75,029	76,390	77,554	77,922	78,778	79,629	80,962	81,234	81,711	82,187	83,091	83,239	83,950	84,688	85,839	86,243	
Served Demand	72,626	73,011	73,677	74,168	75,029	76,390	77,554	77,922	78,778	79,629	80,962	81,234	81,711	82,187	83,091	83,239	83,950	84,688	85,839	86,243	
Unserved Demand	38	41	33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	947	948	956	966	986	998	1,010	1,025	1,040	1,056	1,068	1,077	1,085	1,095	1,105	1,117	1,130	1,142	1,155	
Peak Day Demand Served	906	906	916	956	966	986	998	1,010	1,025	1,040	1,056	1,068	1,077	1,085	1,095	1,105	1,117	1,130	1,142	1,155	
Peak Day Demand Unserved	38	41	33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	303,019	282,236	296,207	303,111	299,909	319,817	338,405	361,483	320,664	307,432	324,361	334,311	338,871	325,158	314,934	326,269	345,664	342,595	356,398	375,033	
Total Supply Costs	303,079	282,295	296,266	303,170	299,968	319,876	338,464	361,542	320,723	307,491	324,420	334,370	338,930	325,217	314,994	326,329	345,723	342,654	356,457	375,092	**4,149,126**
Transport Fixed Costs	83,034	83,161	84,747	84,839	84,839	84,839	84,839	87,552	87,830	87,830	87,830	87,830	87,857	87,903	87,951	87,951	89,463	89,723	89,977	90,062	**1,117,235**
Transport Variable Costs	2,993	3,209	3,365	3,415	3,442	3,514	3,544	3,649	3,651	3,659	3,747	3,729	3,746	3,779	3,810	3,818	3,829	3,859	3,927	3,911	
Total Transport Cost	86,027	86,370	88,112	88,254	88,281	88,353	88,383	91,202	91,481	91,489	91,577	91,559	91,603	91,683	91,762	91,769	93,292	93,582	93,903	93,973	**1,163,305**
Storage Fixed Cost	24,104	24,277	25,793	26,101	26,557	27,631	28,102	29,046	29,709	29,792	29,950	30,122	30,443	30,881	31,366	31,588	31,588	31,588	31,945	32,211	
Storage Variable Cost	1,293	1,276	2,135	1,621	1,155	1,707	1,593	1,724	1,562	1,554	1,686	1,651	1,696	1,608	1,550	1,744	1,679	1,662	1,839	2,048	
Total Storage Cost	25,398	25,553	27,928	27,723	27,712	29,338	29,696	30,770	31,271	31,346	31,636	31,773	32,139	32,489	32,916	33,332	33,267	33,250	33,784	34,259	**388,342**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	815	2,145	3,694	5,634	7,781	10,089	12,455	14,904	17,394	19,881	22,383	24,886	27,311	29,710	32,037	34,264	36,410	38,459	40,273	
Total Costs	414,503	417,665	437,858	446,870	447,096	470,194	492,255	520,585	481,986	470,133	488,556	500,178	505,925	491,253	481,535	491,899	511,335	507,387	520,451	533,957	**6,118,711**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	-	38.6812	48.6485	68.0629	141.2366	141.6173	141.6173	141.6173	141.6173	141.6173	142.8944	150.8662	159.2653	167.7320	167.7320	167.7320	167.7320	179.4070	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	0.8842	1.8410	2.5891	3.3314	4.1254	5.3019	5.3019	5.3019	5.3019	6.4067	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	
NWP Zones 12-9 (Grants Pass Lat.)	-	-	-	-	-	-	-	-	-	-	-	-	0.1764	0.4736	0.7830	0.7830	2.2952	3.8517	5.3693	5.9199	
Palomar East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Blue Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	35.1541	44.7445	46.1113	48.5292	85.0000	85.0000	32.6467	34.4233	36.4359	61.7912	39.5953	40.5995	46.2871	41.9596	11.7909	8.1010	9.8030	11.4778	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	6.5613	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	7.6239	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	260.0000	298.6813	308.6485	328.0629	401.2367	401.6173	366.3489	399.6753	401.6173	401.6174	402.8944	410.8663	419.2653	427.7320	427.7320	427.7320	427.7320	439.4070	
New port LNG	59.9519	59.9909	60.0216	60.1430	60.3202	60.6481	-	-	61.2726	61.5330	61.8087	62.0223	62.1922	62.3537	62.5263	62.7071	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 5: 1404-2011 IRP Mod Gas Breakthrough

1404	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,664	73,323	74,406	75,341	76,654	77,931	80,847	82,958	85,533	88,425	91,804	94,329	97,395	100,415	103,849	106,357	109,450	112,612	116,335	119,210	
Forecast DSM	0	271	697	1,177	1,751	2,373	3,044	3,710	4,402	5,103	5,826	6,509	7,220	7,903	8,613	9,222	9,840	10,432	11,039	11,466	
Forecast Demand (net DSM)	72,664	73,052	73,709	74,165	74,904	75,557	77,803	79,248	81,131	83,323	85,977	87,820	90,175	92,511	95,236	97,135	99,610	102,180	105,295	107,744	
Served Demand	72,626	73,011	73,677	74,165	74,904	75,557	77,803	79,248	81,131	83,323	85,977	87,820	90,175	92,511	95,236	97,135	99,610	102,180	105,295	107,744	
Unserved Demand	38	41	33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	947	948	956	964	971	984	995	1,007	1,024	1,040	1,056	1,073	1,090	1,104	1,118	1,134	1,150	1,166	1,185	
Peak Day Demand Served	906	906	916	956	964	971	984	995	1,007	1,024	1,040	1,056	1,073	1,090	1,104	1,118	1,134	1,150	1,166	1,185	
Peak Day Demand Unserved	38	41	33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	303,019	282,734	312,495	414,996	457,909	505,059	573,821	630,115	647,038	666,175	668,237	661,975	662,161	662,905	677,539	700,068	735,140	743,631	748,856	751,042	
Total Supply Costs	303,079	282,793	312,554	415,056	457,969	505,118	573,880	630,174	647,097	666,234	668,296	662,035	662,220	662,964	677,599	700,127	735,199	743,690	748,915	751,102	**7,094,621**
Transport Fixed Costs	83,034	83,161	84,747	84,825	84,825	84,839	84,839	86,222	87,830	87,830	87,830	87,830	87,830	87,830	87,830	87,830	87,830	87,830	89,096	89,096	**1,113,842**
Transport Variable Costs	2,993	3,214	3,372	3,406	3,466	3,477	3,537	3,617	3,704	3,777	3,880	3,954	4,048	4,139	4,259	4,328	4,411	4,482	4,881	4,740	
Total Transport Cost	86,027	86,375	88,119	88,230	88,291	88,316	88,376	89,840	91,534	91,607	91,710	91,784	91,877	91,969	92,088	92,158	92,241	92,312	93,977	93,836	**1,162,242**
Storage Fixed Cost	24,104	24,277	25,881	26,178	26,849	27,655	27,567	28,505	29,168	29,168	29,231	29,709	30,513	31,318	32,193	33,412	34,856	35,882	40,775	44,513	
Storage Variable Cost	1,293	1,496	2,103	2,236	1,977	2,488	2,575	2,600	2,954	3,016	2,951	2,950	2,823	2,715	2,895	3,145	3,222	3,332	3,376	3,162	
Total Storage Cost	25,398	25,773	27,984	28,414	28,827	30,143	30,142	31,105	32,123	32,184	32,182	32,659	33,336	34,032	35,088	36,556	38,078	39,214	44,151	47,676	**411,322**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	815	2,145	3,711	5,658	7,812	10,089	12,455	14,904	17,394	19,881	22,383	24,886	27,311	29,710	32,037	34,264	36,410	38,459	40,273	
Total Costs	414,503	418,388	454,208	559,423	606,220	656,203	728,111	788,189	809,265	829,833	833,111	828,953	830,686	830,829	846,639	869,311	904,571	913,116	923,350	923,246	**9,086,125**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	-	46.5893	46.5893	89.7037	127.0517	127.0517	127.0517	127.0517	127.0517	127.0517	140.2261	154.2653	167.0167	184.9644	214.4942	245.1636	255.2252	260.0000	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	0.1839	0.8867	1.1094	1.1094	1.1094	1.1094	1.1094	1.1094	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	0.6767	1.9775	3.1931	4.7042	6.3484	8.1823	10.1028	12.0840	29.1409	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.0000	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	
NWP Zones 12-9 (Grants Pass Lat.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Palomar East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Blue Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	35.1541	44.7445	45.7277	45.8980	85.0000	85.0000	52.4593	32.3420	39.8308	36.2761	39.2182	40.3491	47.5769	44.6259	45.6710	48.4500	37.4641	-	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	6.5613	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	7.6101	6.9953	6.3156	5.6028	4.9018	4.0021	
Mist & Mist Recall	250.0000	250.0000	260.0000	306.5893	306.5893	349.7037	387.0517	387.0517	370.2616	385.1994	387.0517	387.0517	400.2261	414.2653	427.0167	439.0564	452.4143	466.1500	443.8908	415.8466	
Newport LNG	59.9519	59.9909	60.0216	60.1032	60.2366	60.3772	-	-	61.0303	61.3179	61.6016	61.8774	62.1753	62.4507	62.7092	62.9574	63.2292	63.5123	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 6: 1405-2011 IRP Mod Electric Breakthrough

1405	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,157	73,908	74,354	75,022	75,576	76,484	76,499	76,830	77,316	78,063	77,894	78,024	77,938	78,078	77,372	77,053	76,724	76,739	76,099	
Forecast DSM	0	268	680	1,133	1,657	2,213	2,807	3,388	3,981	4,570	5,163	5,704	6,252	6,754	7,264	7,677	8,083	8,459	8,839	9,068	
Forecast Demand (net DSM)	72,643	72,889	73,227	73,221	73,366	73,363	73,677	73,111	72,849	72,746	72,901	72,190	71,772	71,184	70,814	69,696	68,970	68,265	67,900	67,031	
Served Demand	72,605	72,850	73,201	73,221	73,366	73,363	73,677	73,111	72,849	72,746	72,901	72,190	71,772	71,184	70,814	69,696	68,970	68,265	67,900	67,031	
Unserved Demand	38	39	26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	943	943	941	942	940	938	939	939	937	934	928	921	912	904	896	888	882	
Peak Day Demand Served	906	906	915	943	943	941	942	940	938	939	939	937	934	928	921	912	904	896	888	882	
Peak Day Demand Unserved	38	39	26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	302,917	282,075	308,414	409,429	447,249	487,395	542,218	578,988	579,959	583,677	563,449	537,394	518,892	500,043	490,088	487,021	494,700	483,257	473,025	458,413	
Total Supply Costs	302,976	282,134	308,473	409,488	447,308	487,454	542,277	579,047	580,018	583,736	563,508	537,453	518,951	500,103	490,147	487,081	494,760	483,316	473,085	458,473	**5,973,284**
Transport Fixed Costs	83,034	83,161	84,747	84,776	84,776	84,839	84,839	86,222	86,500	86,538	86,538	87,830	87,830	87,830	87,830	87,830	87,830	87,830	87,830	87,830	**1,110,270**
Transport Variable Costs	2,992	3,208	3,332	3,362	3,398	3,401	3,404	3,410	3,362	3,367	3,371	3,424	3,410	3,387	3,376	3,335	3,316	3,288	3,289	3,246	
Total Transport Cost	86,026	86,369	88,079	88,138	88,174	88,240	88,244	89,633	89,862	89,905	89,909	91,253	91,240	91,217	91,206	91,164	91,146	91,117	91,119	91,076	**1,153,271**
Storage Fixed Cost	24,104	24,277	25,637	25,454	26,008	26,325	26,006	26,944	27,607	27,607	27,607	27,607	27,607	27,607	27,607	27,607	27,607	27,607	27,607	27,607	
Storage Variable Cost	1,291	1,495	2,082	2,210	1,902	2,429	2,519	2,562	2,733	2,665	2,539	2,588	2,521	2,440	2,415	2,462	2,493	2,440	2,421	2,546	
Total Storage Cost	25,395	25,772	27,719	27,664	27,911	28,754	28,525	29,506	30,340	30,272	30,147	30,196	30,128	30,048	30,023	30,069	30,101	30,047	30,029	30,153	**371,943**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	803	2,072	3,515	5,236	7,092	9,033	11,016	13,031	15,032	16,970	18,854	20,663	22,324	23,914	25,395	26,744	28,000	29,151	30,099	
Total Costs	414,397	417,722	449,824	553,013	594,527	637,074	694,759	735,256	738,731	743,721	724,487	701,378	683,571	663,231	653,240	648,784	655,059	642,382	630,539	610,335	**7,916,437**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	-	27.1029	27.1029	62.7140	85.0527	85.0527	85.0527	85.0527	85.0527	85.0527	85.0527	85.0527	85.0527	85.0527	85.0527	85.0527	85.0527	85.0527	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Zones 12-9 (Grants Pass Lat.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Palomar East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Blue Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	33.6151	43.2579	42.7601	22.2330	82.2325	85.0000	39.6931	21.2626	27.3714	38.4298	25.4862	19.1942	23.5235	16.7691	16.4050	28.2646	13.2362	12.2563	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	5.8503	8.0000	8.0000	8.0000	8.0000	4.4349	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	7.4490	6.6252	
Mist & Mist Recall	250.0000	250.0000	260.0000	287.1029	287.1029	322.7140	345.0527	345.0527	307.3595	308.4504	308.3852	305.8869	303.1659	297.8342	290.5971	281.9711	274.1044	266.3638	258.5859	252.7358	
New port LNG	59.9501	59.9552	59.9053	59.8851	59.8782	59.8511	-	-	59.8354	59.8578	59.8503	59.8068	59.7570	59.6633	59.5367	59.3944	59.2600	59.1313	59.0014	58.9040	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 7: **1408-2011 IRP Mod 15% Less DSM**

1408	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	228	580	968	1,422	1,911	2,441	2,969	3,521	4,085	4,670	5,227	5,811	6,375	6,960	7,464	7,975	8,464	8,966	9,321	
Forecast Demand (net DSM)	72,643	72,935	73,373	73,528	74,025	74,639	75,504	75,716	76,372	77,099	78,225	78,443	79,023	79,524	80,404	80,483	81,075	81,757	82,817	83,156	
Served Demand	72,605	72,896	73,345	73,528	74,025	74,639	75,504	75,716	76,372	77,099	78,225	78,443	79,023	79,524	80,404	80,483	81,075	81,757	82,817	83,156	
Unserved Demand	38	40	28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	943	946	951	958	966	976	987	999	1,012	1,022	1,032	1,040	1,049	1,057	1,066	1,077	1,088	1,099	
Peak Day Demand Served	906	906	916	946	951	958	966	976	987	999	1,012	1,022	1,032	1,040	1,049	1,057	1,066	1,077	1,088	1,099	
Peak Day Demand Unserved	38	40	28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	302,919	281,638	294,533	351,434	354,853	360,881	379,939	400,078	374,743	367,114	369,899	380,065	393,976	403,711	418,362	441,961	477,750	489,214	508,630	526,493	
Total Supply Costs	302,978	281,697	294,592	351,493	354,912	360,940	379,999	400,137	374,803	367,174	369,958	380,124	394,035	403,771	418,422	442,021	477,809	489,274	508,689	526,552	**4,868,815**
Transport Fixed Costs	83,034	83,161	84,747	84,774	84,839	84,839	84,839	87,342	87,620	87,620	87,620	87,830	87,830	87,830	87,830	89,205	89,205	89,205	89,205	89,205	**1,116,128**
Transport Variable Costs	2,992	3,204	3,349	3,338	3,373	3,443	3,454	3,560	3,546	3,564	3,608	3,629	3,642	3,661	3,682	3,691	3,714	3,751	3,802	3,795	
Total Transport Cost	86,026	86,365	88,096	88,112	88,212	88,282	88,293	90,902	91,166	91,184	91,227	91,458	91,472	91,491	91,512	92,896	92,919	92,956	93,007	93,000	**1,161,165**
Storage Fixed Cost	24,104	24,277	25,731	25,714	25,829	26,530	26,913	27,851	28,514	28,514	28,514	28,514	28,527	28,726	28,862	28,935	29,080	29,236	29,601	29,825	
Storage Variable Cost	1,292	1,275	2,127	1,817	1,296	1,839	1,749	1,852	1,852	1,814	1,839	1,841	1,962	1,979	2,039	2,264	2,117	2,286	2,391	2,642	
Total Storage Cost	25,396	25,552	27,858	27,531	27,125	28,369	28,662	29,703	30,366	30,329	30,353	30,355	30,489	30,705	30,901	31,199	31,197	31,522	31,992	32,467	**375,618**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	682	1,767	3,010	4,513	6,162	7,919	9,756	11,680	13,653	15,644	17,664	19,705	21,696	23,667	25,581	27,413	29,179	30,867	32,364	
Total Costs	414,401	417,061	436,098	494,859	501,384	510,217	532,666	557,813	534,846	528,494	532,462	544,414	559,248	567,831	582,698	606,585	640,977	651,653	669,994	682,652	**6,823,538**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	-	34.1000	34.1000	41.4559	109.4549	109.4549	109.4549	109.4549	109.4549	109.4549	109.4549	110.0408	118.2583	118.2583	118.2583	118.2583	118.2583	125.6920	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4982	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1205	0.1205	0.9019	1.8041	2.7269	3.6332	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	40.0000	
NWP Zones 12-9 (Grants Pass Lat.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.6318	0.6318	0.6318	0.6318	0.6318	
Palomar East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Blue Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	33.6021	43.9292	43.4933	43.6894	85.0000	85.0000	27.7464	34.6322	36.1556	31.8557	33.8369	33.9714	34.9579	-	-	0.4531	1.8816	28.1842	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	5.6100	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	7.9670	8.0000	
Mist & Mist Recall	250.0000	250.0000	260.0000	294.1000	294.1000	301.4559	369.4549	369.4549	352.3690	363.5123	369.4549	369.4549	369.4549	370.0408	378.2583	377.6276	378.2583	378.2583	378.2583	385.6921	
New port LNG	59.9501	59.9612	59.9264	59.9328	59.9992	60.1164	-	-	60.6041	60.8157	61.0364	61.2132	61.3952	61.5565	61.7056	100.0000	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 8: 1406-2011 IRP Mod 30% More DSM

1406	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	349	886	1,480	2,175	2,923	3,733	4,540	5,386	6,247	7,143	7,994	8,887	9,750	10,645	11,416	12,196	12,944	13,713	14,255	
Forecast Demand (net DSM)	72,643	72,815	73,066	73,016	73,272	73,627	74,212	74,145	74,508	74,936	75,752	75,676	75,947	76,149	76,719	76,531	76,854	77,276	78,070	78,222	
Served Demand	72,605	72,776	73,041	73,016	73,272	73,627	74,212	74,145	74,508	74,936	75,752	75,676	75,947	76,149	76,719	76,531	76,854	77,276	78,070	78,222	
Unserved Demand	38	39	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	944	941	942	945	950	956	963	972	982	992	999	1,007	1,013	1,019	1,024	1,032	1,041	1,049	1,058	
Peak Day Demand Served	906	906	915	942	945	950	956	963	972	982	992	999	1,007	1,013	1,019	1,024	1,032	1,041	1,049	1,058	
Peak Day Demand Unserved	38	39	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	302,914	281,207	292,631	348,645	351,064	355,896	373,003	391,816	365,504	356,383	357,268	365,202	377,167	383,617	397,967	418,685	450,562	459,972	476,212	492,737	
Total Supply Costs	302,973	281,266	292,690	348,704	351,123	355,956	373,063	391,875	365,563	356,442	357,327	365,261	377,227	383,676	398,026	418,744	450,621	460,031	476,271	492,796	**4,725,849**
Transport Fixed Costs	83,034	83,161	84,747	84,774	84,839	84,839	84,839	87,050	87,328	87,328	87,328	87,830	87,830	87,830	87,830	87,830	89,096	89,096	89,197	89,339	**1,114,672**
Transport Variable Costs	2,992	3,200	3,330	3,314	3,342	3,411	3,410	3,492	3,472	3,477	3,509	3,526	3,543	3,544	3,565	3,556	3,567	3,584	3,616	3,609	
Total Transport Cost	86,026	86,360	88,077	88,088	88,181	88,250	88,249	90,542	90,799	90,805	90,836	91,356	91,373	91,373	91,394	91,386	92,662	92,679	92,813	92,948	**1,158,793**
Storage Fixed Cost	24,104	24,277	25,655	25,485	25,568	26,176	26,523	27,461	28,124	28,124	28,124	28,124	28,124	28,124	28,124	28,124	28,124	28,124	28,124	28,124	
Storage Variable Cost	1,291	1,275	2,120	1,812	1,268	1,804	1,722	1,822	1,809	1,782	1,802	1,782	1,935	1,914	1,951	2,234	2,095	2,213	2,325	2,547	
Total Storage Cost	25,395	25,552	27,775	27,297	26,837	27,980	28,245	29,283	29,934	29,906	29,927	29,906	30,059	30,038	30,076	30,358	30,219	30,337	30,449	30,671	**369,485**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	1,044	2,702	4,604	6,903	9,425	12,111	14,921	17,863	20,882	23,926	27,015	30,138	33,182	36,197	39,125	41,926	44,628	47,209	49,498	
Total Costs	414,395	416,625	434,095	491,812	497,275	504,811	525,270	548,771	524,807	516,961	519,014	528,999	541,911	546,952	561,360	580,958	612,555	620,948	635,840	647,048	**6,672,066**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	-	27.9372	27.9372	33.2916	98.9644	98.9644	98.9644	98.9644	98.9644	98.9644	98.9644	98.9644	98.9644	98.9644	98.9644	98.9644	98.9644	98.9644	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Newport to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	
NWP Zones 12-9 (Grants Pass Lat.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5875	1.4096	
Palomar East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Blue Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	34.2558	43.0067	42.1588	41.9288	85.0000	85.0000	25.6281	26.7647	27.9635	49.6496	29.5282	30.1647	36.2527	31.3222	-	-	-	-	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	5.5102	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	260.0000	287.9372	287.9372	293.2916	358.9644	358.9644	338.5939	347.5294	356.7219	358.9644	358.9644	358.9644	358.9644	358.9644	353.8343	358.9644	358.9644	358.9644	
Newport LNG	59.9501	59.9487	59.8977	59.8685	59.9055	59.9923	-	-	60.3785	60.5541	60.7372	60.8768	61.0203	61.1449	61.2560	61.3693	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 9: 1410-2011 IRP Mod Newport LNG Closed

1410	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	268	682	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,895	73,270	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,605	72,856	73,243	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Unserved Demand	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	906	906	915	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Unserved	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	302,917	281,494	293,899	350,382	353,613	359,324	377,614	392,902	374,809	366,219	367,826	376,360	389,379	397,287	412,160	435,658	470,222	480,647	498,524	514,057	
Total Supply Costs	302,977	281,553	293,958	350,441	353,672	359,384	377,674	392,961	374,869	366,278	367,885	376,420	389,438	397,346	412,219	435,717	470,281	480,707	498,583	514,117	**4,826,543**
Transport Fixed Costs	83,034	83,161	84,747	84,774	84,839	84,839	84,839	87,004	87,281	87,281	87,281	87,830	87,830	87,830	87,830	87,830	87,830	87,830	87,830	87,830	**1,112,314**
Transport Variable Costs	2,992	3,202	3,343	3,329	3,362	3,433	3,440	3,484	3,510	3,524	3,562	3,595	3,606	3,616	3,640	3,641	3,664	3,690	3,741	3,714	
Total Transport Cost	86,026	86,363	88,090	88,103	88,201	88,272	88,279	90,488	90,791	90,806	90,843	91,425	91,436	91,446	91,469	91,470	91,494	91,520	91,571	91,544	**1,156,967**
Storage Fixed Cost	24,104	24,277	25,706	25,638	25,742	26,412	26,783	26,922	27,309	27,745	28,127	28,465	28,775	29,061	29,329	29,683	30,151	30,632	31,123	31,339	
Storage Variable Cost	1,292	1,275	2,125	1,814	1,283	1,835	1,740	1,790	1,788	1,764	1,826	1,846	2,008	2,037	2,114	2,357	2,223	2,408	2,522	2,753	
Total Storage Cost	25,396	25,552	27,831	27,452	27,025	28,247	28,523	28,712	29,097	29,509	29,952	30,312	30,783	31,098	31,443	32,040	32,374	33,040	33,645	34,092	**376,405**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	803	2,079	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	414,399	416,916	435,431	493,719	500,032	508,528	530,188	549,232	533,268	526,401	529,603	540,632	554,909	561,755	576,996	599,697	633,202	643,167	660,105	670,385	**6,777,854**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	-	32.0457	32.0457	38.7342	105.9582	105.9582	113.3807	124.8890	136.7802	145.8863	155.0175	162.7862	170.4477	177.3284	185.6201	195.0428	203.7947	213.2900	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7189	1.5705	2.4131	3.3131	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Zones 12-9 (Grants Pass Lat.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Palomar East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Blue Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	33.3277	43.6219	43.0483	43.1025	85.0000	85.0000	85.0000	85.0000	85.0000	85.0000	85.0000	85.0000	85.0000	85.0000	85.0000	85.0000	85.0000	85.0000	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	5.4913	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	260.0000	292.0457	292.0457	298.7342	365.9582	365.9582	373.3806	384.8890	396.7802	405.8863	415.0175	422.7862	430.4477	437.3284	445.6201	455.0428	463.7947	473.2900	
New port LNG	59.9501	59.9570	59.9168	59.9114	59.9680	60.0751	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 10: 1391-2011 IRP Mod PAL BB 50

1391	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	268	682	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,895	73,270	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,605	72,856	73,243	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Unserved Demand	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	906	906	915	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Unserved	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	302,917	281,494	293,899	350,382	353,613	359,324	377,614	397,673	366,802	359,745	360,300	369,163	381,502	389,495	405,489	427,581	462,122	472,152	490,399	508,064	
Total Supply Costs	302,977	281,553	293,958	350,441	353,672	359,384	377,674	397,732	366,861	359,804	360,359	369,222	381,561	389,555	405,548	427,641	462,181	472,212	490,458	508,124	**4,783,463**
Transport Fixed Costs	83,034	83,161	84,747	84,774	84,839	84,839	84,839	87,552	107,001	107,001	107,001	100,940	100,982	100,988	100,988	100,988	96,911	98,324	98,469	98,625	**1,201,582**
Transport Variable Costs	2,992	3,202	3,343	3,329	3,362	3,433	3,440	3,558	2,477	2,491	2,520	2,599	2,618	2,628	2,654	2,652	2,669	2,690	2,724	2,724	
Total Transport Cost	86,026	86,363	88,090	88,103	88,201	88,272	88,279	91,110	109,478	109,492	109,521	103,538	103,600	103,616	103,641	103,639	99,580	101,014	101,194	101,348	**1,240,069**
Storage Fixed Cost	24,104	24,277	25,706	25,638	25,742	26,412	26,783	27,721	28,384	28,384	28,384	28,384	28,384	28,384	28,384	28,384	28,384	28,384	28,384	28,384	
Storage Variable Cost	1,292	1,275	2,125	1,815	1,283	1,835	1,740	1,881	1,800	1,768	1,741	1,887	1,877	1,917	1,963	2,100	2,194	2,228	2,278	2,536	
Total Storage Cost	25,396	25,552	27,831	27,453	27,025	28,247	28,523	29,602	30,184	30,152	30,125	30,271	30,261	30,301	30,348	30,484	30,579	30,612	30,662	30,921	**372,016**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	803	2,079	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	414,399	416,916	435,431	493,720	500,032	508,528	530,188	555,515	545,035	539,257	540,929	545,508	558,674	565,336	581,401	602,234	631,393	641,738	658,621	671,026	**6,813,487**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	-	32.0457	32.0457	38.7342	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	
NWP Zones 12-9 (Grants Pass Lat.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7189	1.5705	2.4131	3.3131	
Palomar East	-	-	-	-	-	-	-	-	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	
Blue Bridge	-	-	-	-	-	-	-	-	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	
NWP Vintage TF1	-	-	-	-	-	-	-	-	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	33.5844	43.6219	43.0483	43.1025	85.0000	85.0000	57.0817	28.3964	77.0924	77.2589	31.8433	63.6818	39.0027	34.2958	67.9101	4.8315	5.3211	1.2419	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	5.7480	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	260.0000	292.0457	292.0457	298.7342	365.9582	365.9582	324.7775	335.1847	345.8879	354.0827	362.2890	365.9582	365.9582	365.9582	365.9582	363.2789	365.9582	365.9582	
New port LNG	59.9501	59.9570	59.9168	59.9114	59.9680	60.0751	-	-	60.5290	60.7286	60.9366	61.1011	61.2702	61.4193	61.5557	61.6920	61.8577	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 11: 1392-2011 IRP Mod PAL 100

1392	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	268	682	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,895	73,270	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,605	72,856	73,243	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Unserved Demand	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	906	906	915	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Unserved	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	302,917	281,494	293,899	350,382	353,613	359,324	377,614	397,673	365,332	358,303	358,876	367,700	380,006	387,982	403,913	425,916	460,339	470,345	488,540	506,143	
Total Supply Costs	302,977	281,553	293,958	350,441	353,672	359,384	377,674	397,732	365,391	358,362	358,935	367,759	380,065	388,041	403,973	425,975	460,398	470,405	488,599	506,202	**4,773,639**
Transport Fixed Costs	83,034	83,161	84,747	84,774	84,839	84,839	84,839	87,552	107,102	107,102	107,102	98,484	98,526	98,532	98,532	98,532	93,908	95,320	95,466	95,621	**1,190,385**
Transport Variable Costs	2,992	3,202	3,343	3,329	3,362	3,433	3,440	3,558	2,471	2,485	2,514	2,592	2,611	2,621	2,647	2,645	2,663	2,683	2,718	2,717	
Total Transport Cost	86,026	86,363	88,090	88,103	88,201	88,272	88,279	91,110	109,572	109,587	109,616	101,076	101,138	101,153	101,179	101,177	96,570	98,003	98,183	98,338	**1,228,831**
Storage Fixed Cost	24,104	24,277	25,706	25,638	25,742	26,412	26,783	27,721	28,384	28,384	28,384	28,384	28,384	28,384	28,384	28,384	28,384	28,384	28,384	28,384	
Storage Variable Cost	1,292	1,275	2,125	1,815	1,283	1,835	1,740	1,881	1,795	1,760	1,732	1,877	1,867	1,907	1,953	2,088	2,182	2,215	2,265	2,523	
Total Storage Cost	25,396	25,552	27,831	27,453	27,025	28,247	28,523	29,602	30,180	30,144	30,116	30,261	30,251	30,291	30,337	30,473	30,566	30,600	30,650	30,908	**371,953**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	803	2,079	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	414,399	416,916	435,431	493,720	500,032	508,528	530,188	555,515	543,654	537,900	539,590	541,572	554,706	561,349	577,352	598,094	626,587	636,909	653,739	666,081	**6,792,363**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	-	32.0457	32.0457	38.7342	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	
NWP Zones 12-9 (Grants Pass Lat.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7189	1.5705	2.4131	3.3131	
Palomar East	-	-	-	-	-	-	-	-	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
Blue Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	33.5844	43.6219	43.0483	43.1025	85.0000	85.0000	57.0817	28.3964	77.0924	77.2589	31.8433	63.6818	39.0027	34.2958	67.9101	4.8315	5.3211	1.2419	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	5.7480	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	260.0000	292.0457	292.0457	298.7342	365.9582	365.9582	324.7775	335.1847	345.8879	354.0827	362.2890	365.9582	365.9582	365.9582	365.9582	363.2789	365.9582	365.9582	
New port LNG	59.9501	59.9570	59.9168	59.9114	59.9680	60.0751	-	-	60.5290	60.7286	60.9366	61.1011	61.2702	61.4193	61.5557	61.6920	61.8577	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 12: 1413-2011 IR Mod Canada Exp

1413	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	268	682	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,895	73,270	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,605	72,856	73,243	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Unserved Demand	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	906	906	915	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Unserved	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	302,917	281,494	293,978	350,370	353,643	358,686	394,232	423,548	409,121	410,102	419,269	427,040	441,456	448,559	462,779	482,403	515,249	526,899	543,586	559,640	
Total Supply Costs	302,977	281,553	294,038	350,430	353,702	358,745	394,292	423,607	409,181	410,161	419,328	427,099	441,515	448,619	462,838	482,462	515,309	526,958	543,646	559,699	**5,148,731**
Transport Fixed Costs	83,034	83,161	84,747	84,774	84,774	84,774	84,774	86,157	86,434	86,434	86,434	86,434	86,434	86,434	86,434	87,700	87,700	87,700	87,700	87,763	**1,106,715**
Transport Variable Costs	2,992	3,202	3,344	3,329	3,359	3,424	3,410	3,311	3,108	2,984	3,029	3,041	3,072	3,089	3,105	3,117	3,154	3,182	3,231	3,200	
Total Transport Cost	86,026	86,363	88,091	88,103	88,133	88,198	88,184	89,468	89,542	89,419	89,463	89,476	89,507	89,523	89,539	90,817	90,854	90,882	90,931	90,963	**1,148,040**
Storage Fixed Cost	24,104	24,277	25,716	25,669	25,773	26,443	26,814	27,752	28,415	28,415	28,415	28,415	28,415	28,471	28,511	28,578	28,714	28,859	29,086	29,210	
Storage Variable Cost	1,292	1,275	2,126	1,816	1,286	1,826	1,655	1,698	1,860	1,901	1,896	1,971	2,168	2,231	2,074	2,645	2,425	2,487	2,531	2,524	
Total Storage Cost	25,396	25,552	27,842	27,485	27,059	28,269	28,469	29,451	30,275	30,316	30,311	30,386	30,583	30,702	30,585	31,224	31,139	31,346	31,617	31,734	**374,405**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	803	2,079	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	414,399	416,915	435,522	493,741	500,028	507,837	546,657	579,596	567,509	569,703	580,025	589,437	604,858	610,708	624,827	644,972	676,355	687,087	702,500	713,029	**7,089,115**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	-	32.8770	32.8770	39.5656	106.7896	106.7896	106.7896	106.7896	106.7896	106.7896	106.7896	106.7896	109.3731	109.3731	109.3731	109.3731	109.3731	112.9191	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7189	1.5705	2.4131	3.3131	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	40.0000	
NWP Zones 12-9 (Grants Pass Lat.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Palomar East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Blue Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	33.3277	43.6219	43.8797	43.9338	85.0000	85.0000	27.0404	33.8164	35.2314	30.8139	32.6794	32.7024	33.5827	-	-	-	24.7343	25.6721	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	5.4913	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	260.0000	292.8770	292.8770	299.5656	366.7896	366.7896	348.6088	359.0160	363.9437	366.7896	354.2352	361.8512	369.3731	337.8062	346.0939	355.5121	364.2599	372.9191	
New port LNG	59.9501	59.9570	59.9168	59.9114	59.9680	60.0751	-	-	60.5290	60.7286	60.9366	61.1011	61.2702	61.4193	61.5557	100.0000	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 13: 1412-2011 IR Mod Sumas Exp

1412	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	268	682	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,895	73,270	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,605	72,856	73,243	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Unserved Demand	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	906	906	915	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Unserved	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	302,917	281,494	293,899	350,383	353,613	358,620	378,848	397,101	372,013	367,746	369,918	379,566	390,070	398,707	415,171	434,941	470,312	480,863	498,563	514,673	
Total Supply Costs	302,977	281,553	293,958	350,442	353,672	358,679	378,907	397,161	372,073	367,806	369,977	379,625	390,129	398,766	415,230	435,000	470,371	480,922	498,622	514,732	**4,834,723**
Transport Fixed Costs	83,034	83,161	84,747	84,774	84,839	84,839	86,169	87,552	87,830	87,830	87,830	87,830	87,830	87,830	87,830	89,096	89,220	89,367	89,512	89,667	**1,117,986**
Transport Variable Costs	2,992	3,202	3,343	3,329	3,362	3,429	3,511	3,552	3,533	3,559	3,599	3,608	3,615	3,628	3,657	3,652	3,668	3,688	3,726	3,711	
Total Transport Cost	86,026	86,363	88,090	88,103	88,201	88,268	89,681	91,104	91,363	91,389	91,429	91,437	91,445	91,457	91,486	92,748	92,888	93,055	93,238	93,378	**1,162,823**
Storage Fixed Cost	24,104	24,277	25,706	25,638	25,742	26,412	26,783	27,721	28,384	28,384	28,384	28,609	28,768	28,768	28,768	28,768	28,768	28,768	28,768	28,768	
Storage Variable Cost	1,292	1,275	2,125	1,815	1,283	1,818	1,724	1,873	1,757	1,719	1,834	1,898	1,982	1,989	2,044	2,536	2,287	2,570	2,655	2,616	
Total Storage Cost	25,396	25,552	27,831	27,453	27,025	28,230	28,507	29,594	30,141	30,103	30,219	30,507	30,750	30,757	30,812	31,304	31,056	31,339	31,423	31,384	**374,243**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	803	2,079	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	414,399	416,915	435,431	493,720	500,032	507,802	532,807	554,930	532,088	529,105	532,548	544,046	555,576	562,845	579,393	599,521	633,367	643,217	659,590	670,126	**6,789,728**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	-	32.0457	32.0457	38.7342	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	116.2906	116.2906	116.2906	116.2906	116.2906	116.2906	116.2906	116.2906	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	40.0000	
NWP Zones 12-9 (Grants Pass Lat.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7189	1.5705	2.4131	3.3131	
Palomar East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Blue Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	33.3277	43.6219	43.0483	43.1025	85.0000	85.0000	27.0404	33.8164	35.2314	30.8139	31.8433	32.7024	39.0027	-	-	3.9954	-	25.6721	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	5.4913	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	260.0000	292.0457	292.0457	298.7342	365.9582	365.9582	347.7775	344.6833	335.5082	344.4458	353.4038	361.0199	368.5418	336.9748	345.9941	356.2789	365.8841	376.2905	
New port LNG	59.9501	59.9570	59.9168	59.9114	59.9680	60.0751	-	-	60.5290	60.7286	60.9366	61.1011	61.2702	61.4193	61.5557	100.0000	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 14: 1414-2011 IRP Mod Canada Exp PAL

1414	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	268	682	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,895	73,270	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,605	72,856	73,243	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Unserved Demand	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	906	906	915	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Unserved	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	302,917	281,494	293,975	350,371	353,642	358,683	394,230	424,179	405,701	409,327	416,921	426,726	437,701	445,972	461,716	478,412	512,726	524,291	540,099	556,731	
Total Supply Costs	302,977	281,553	294,034	350,430	353,701	358,742	394,289	424,238	405,761	409,387	416,980	426,785	437,760	446,031	461,776	478,471	512,785	524,350	540,159	556,790	**5,134,223**
Transport Fixed Costs	83,034	83,161	84,747	84,774	84,776	84,776	84,776	86,159	103,821	103,821	103,821	93,960	93,961	93,961	95,227	95,227	90,734	90,918	91,097	92,049	**1,165,903**
Transport Variable Costs	2,992	3,202	3,344	3,329	3,360	3,425	3,410	3,315	2,299	2,369	2,437	2,456	2,464	2,476	2,486	2,473	2,488	2,501	2,523	2,529	
Total Transport Cost	86,026	86,363	88,091	88,103	88,135	88,200	88,186	89,474	106,121	106,190	106,258	96,415	96,425	96,437	97,713	97,700	93,222	93,419	93,620	94,577	**1,203,212**
Storage Fixed Cost	24,104	24,277	25,716	25,667	25,771	26,441	26,813	27,751	28,414	28,414	28,414	28,414	28,414	28,414	28,414	28,414	28,414	28,414	28,414	28,414	
Storage Variable Cost	1,292	1,275	2,126	1,817	1,286	1,826	1,655	1,712	1,730	1,920	1,866	2,167	2,206	2,249	2,256	2,553	2,447	2,505	2,545	2,548	
Total Storage Cost	25,396	25,552	27,842	27,484	27,057	28,267	28,468	29,462	30,144	30,334	30,280	30,580	30,620	30,663	30,670	30,967	30,861	30,919	30,959	30,962	**373,479**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	803	2,079	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	414,399	416,916	435,519	493,740	500,028	507,836	546,656	580,245	580,537	585,718	594,441	596,257	608,058	614,996	632,023	647,608	675,920	686,589	701,044	712,963	**7,128,853**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	-	32.8435	32.8435	39.5320	106.7560	106.7560	106.7560	106.7560	106.7560	106.7560	106.7560	106.7560	106.7560	106.7560	106.7560	106.7560	106.7560	106.7560	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	
NWP Zones 12-9 (Grants Pass Lat.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7189	1.5705	2.4131	3.3131	
Palomar East	-	-	-	-	-	-	-	-	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
Blue Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	33.3277	43.6219	43.8461	43.9002	85.0000	85.0000	68.0654	29.2325	36.0674	71.8389	31.8433	73.7274	42.4194	37.0128	38.2127	-	40.9261	6.6619	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	5.4913	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	260.0000	292.8435	292.8435	299.5320	366.7560	366.7560	327.0509	348.1560	334.9645	366.7560	352.8601	360.4762	329.5537	336.4311	345.3494	355.6056	365.1848	366.7560	
New port LNG	59.9501	59.9570	59.9168	59.9114	59.9680	60.0751	-	-	60.5290	60.7286	60.9366	61.1011	61.2702	61.4193	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 15: 1415-2011 IRP Mod Sumas Exp PAL

1415	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,447	76,550	77,945	78,685	79,894	81,183	82,895	83,670	84,834	85,899	87,364	87,947	89,050	90,220	91,783	92,477	
Forecast DSM	0	268	682	1,139	1,673	2,249	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,895	73,270	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Served Demand	72,605	72,856	73,243	73,357	73,774	74,302	75,074	75,192	75,751	76,378	77,400	77,521	77,998	78,399	79,176	79,165	79,668	80,263	81,234	81,512	
Unserved Demand	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Served	906	906	915	945	949	956	962	971	982	993	1,005	1,014	1,024	1,031	1,039	1,046	1,055	1,065	1,075	1,085	
Peak Day Demand Unserved	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)																					
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	302,917	281,494	293,899	350,383	353,613	358,620	378,848	397,853	364,293	357,185	359,060	368,460	379,793	387,982	404,249	426,217	460,647	469,930	487,345	504,743	
Total Supply Costs	302,977	281,553	293,958	350,442	353,672	358,679	378,907	397,912	364,352	357,244	359,120	368,520	379,852	388,041	404,309	426,276	460,706	469,989	487,404	504,802	**4,772,405**
Transport Fixed Costs	83,034	83,161	84,747	84,774	84,839	84,839	86,169	87,552	108,322	108,333	108,333	98,523	98,532	98,532	98,532	98,532	93,908	95,822	96,770	96,943	**1,194,987**
Transport Variable Costs	2,992	3,202	3,343	3,329	3,362	3,429	3,511	3,555	2,539	2,552	2,586	2,596	2,610	2,621	2,648	2,649	2,664	2,675	2,684	2,685	
Total Transport Cost	86,026	86,363	88,090	88,103	88,201	88,268	89,681	91,108	110,861	110,886	110,919	101,119	101,141	101,152	101,180	101,181	96,571	98,498	99,454	99,629	**1,233,588**
Storage Fixed Cost	24,104	24,277	25,706	25,638	25,742	26,412	26,783	27,721	28,384	28,384	28,384	28,384	28,384	28,384	28,384	28,384	28,384	28,384	28,384	28,384	
Storage Variable Cost	1,292	1,275	2,125	1,815	1,283	1,818	1,724	1,877	1,815	1,741	1,752	1,842	1,858	1,897	1,950	2,094	2,183	2,226	2,336	2,532	
Total Storage Cost	25,396	25,552	27,831	27,453	27,025	28,230	28,507	29,598	30,199	30,125	30,136	30,226	30,242	30,281	30,334	30,478	30,567	30,611	30,721	30,916	**371,946**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	803	2,079	3,541	5,310	7,250	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	414,399	416,916	435,431	493,721	500,032	507,802	532,807	555,688	543,923	538,063	541,098	542,341	554,487	561,339	577,687	598,404	626,897	636,999	653,886	665,980	**6,795,878**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	-	32.0457	32.0457	38.7342	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	105.9582	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	
NWP Zones 12-9 (Grants Pass Lat.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7189	1.5705	2.4131	3.3131	
Palomar East	-	-	-	-	-	-	-	-	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	101.9091	105.6795	105.6795	
Blue Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	33.5844	43.6219	43.0483	43.1025	85.0000	85.0000	57.0817	28.3964	77.0924	77.2589	31.8433	63.6818	39.0027	34.2958	67.9101	4.8315	5.3211	1.2419	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	5.7480	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	260.0000	292.0457	292.0457	298.7342	365.9582	365.9582	324.7775	335.1847	345.8879	354.0827	362.2890	365.9582	365.9582	365.9582	365.9582	361.3698	365.9582	355.7329	
New port LNG	59.9501	59.9570	59.9168	59.9114	59.9680	60.0751	-	-	60.5290	60.7286	60.9366	61.1011	61.2702	61.4193	61.5557	61.6920	61.8577	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 16: 1416-2011 IRP Mod Low Gas Fcst PAL BB 50

1416	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,446	76,930	78,329	78,984	80,205	81,479	83,286	84,079	85,153	86,228	87,738	88,429	89,664	90,901	92,546	93,308	
Forecast DSM	0	268	682	1,135	1,668	2,242	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,895	73,270	73,361	73,778	74,688	75,458	75,491	76,062	76,674	77,791	77,931	78,316	78,728	79,549	79,648	80,282	80,943	81,998	82,342	
Served Demand	72,605	72,856	73,243	73,361	73,778	74,688	75,458	75,491	76,062	76,674	77,791	77,931	78,316	78,728	79,549	79,648	80,282	80,943	81,998	82,342	
Unserved Demand	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	962	969	977	987	999	1,012	1,022	1,029	1,037	1,045	1,054	1,066	1,077	1,088	1,100	
Peak Day Demand Served	906	906	915	945	949	962	969	977	987	999	1,012	1,022	1,029	1,037	1,045	1,054	1,066	1,077	1,088	1,100	
Peak Day Demand Unserved	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)									100.00		100.00				100.00						
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	302,917	281,493	293,492	299,036	294,326	311,863	328,720	349,330	304,964	290,716	306,084	313,091	316,537	303,443	292,953	303,338	323,619	319,324	331,171	350,634	
Total Supply Costs	302,976	281,552	293,551	299,096	294,385	311,922	328,780	349,389	305,023	290,775	306,143	313,150	316,596	303,502	293,012	303,397	323,678	319,383	331,230	350,693	**3,987,043**
Transport Fixed Costs	83,034	83,161	84,747	84,839	84,839	84,839	84,839	87,552	107,001	107,001	107,001	100,988	100,988	100,988	100,988	101,097	97,054	98,484	98,650	98,873	**1,202,020**
Transport Variable Costs	2,992	3,202	3,337	3,384	3,389	3,451	3,467	3,570	2,487	2,490	2,544	2,615	2,632	2,643	2,660	2,665	2,688	2,713	2,748	2,749	
Total Transport Cost	86,026	86,363	88,084	88,223	88,228	88,290	88,306	91,122	109,488	109,491	109,545	103,602	103,619	103,630	103,648	103,762	99,741	101,196	101,398	101,622	**1,240,704**
Storage Fixed Cost	24,104	24,277	25,665	25,576	25,842	26,656	27,030	27,968	28,631	28,631	28,631	28,631	28,631	28,631	28,631	28,631	28,631	28,631	28,631	28,631	
Storage Variable Cost	1,292	1,275	2,123	1,557	1,125	1,634	1,517	1,684	1,470	1,432	1,616	1,612	1,575	1,444	1,388	1,495	1,540	1,536	1,588	1,858	
Total Storage Cost	25,396	25,552	27,788	27,133	26,967	28,290	28,547	29,652	30,101	30,063	30,247	30,243	30,206	30,075	30,019	30,126	30,171	30,167	30,219	30,489	**370,491**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	803	2,079	3,524	5,286	7,219	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	414,398	416,915	434,975	442,174	440,715	461,128	481,345	507,234	483,123	470,137	486,858	489,472	493,674	479,071	468,543	477,755	492,643	488,647	499,154	513,438	**6,016,177**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	-	28.0468	32.0279	45.2283	112.6017	112.6017	112.6017	112.6017	112.6017	112.6017	112.6017	112.6017	112.6017	112.6017	112.6017	112.6017	112.6017	112.6017	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	
NWP Zones 12-9 (Grants Pass Lat.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.6314	1.5440	2.4952	3.4574	4.7843	
Palomar East	-	-	-	-	-	-	-	-	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	
Blue Bridge	-	-	-	-	-	-	-	-	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	50.0000	
NWP Vintage TF1	-	-	-	-	-	-	-	-	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	25.0000	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	33.5832	42.7881	43.0451	44.3075	85.0000	85.0000	27.7438	29.0655	77.9722	78.1858	32.5656	64.7222	39.8451	35.3885	69.8555	6.5561	7.2520	3.3561	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	5.7472	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	260.0000	288.0467	292.0279	305.2283	372.6017	372.6017	294.8484	339.9024	352.0863	360.6146	367.3835	356.4481	372.6017	372.6017	372.6017	372.6017	372.6017	372.6017	
New port LNG	59.9501	59.9569	59.9166	59.9511	60.0225	60.2369	-	-	60.6046	60.8016	61.0333	61.2040	61.3512	61.5037	61.6519	61.8180	62.0200	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Run 17: 1417-2011 IRP Mod Low Gas Fcst

1417	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	NPV - 5.16%
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	0.0516
DEMAND (MDT)																					
Forecast Demand	72,643	73,163	73,952	74,496	75,446	76,930	78,329	78,984	80,205	81,479	83,286	84,079	85,153	86,228	87,738	88,429	89,664	90,901	92,546	93,308	
Forecast DSM	0	268	682	1,135	1,668	2,242	2,872	3,493	4,143	4,805	5,494	6,149	6,836	7,500	8,188	8,781	9,382	9,957	10,548	10,966	
Forecast Demand (net DSM)	72,643	72,895	73,270	73,361	73,778	74,688	75,458	75,491	76,062	76,674	77,791	77,931	78,316	78,728	79,549	79,648	80,282	80,943	81,998	82,342	
Served Demand	72,605	72,856	73,243	73,361	73,778	74,688	75,458	75,491	76,062	76,674	77,791	77,931	78,316	78,728	79,549	79,648	80,282	80,943	81,998	82,342	
Unserved Demand	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Day Demand (net DSM)	944	945	942	945	949	962	969	977	987	999	1,012	1,022	1,029	1,037	1,045	1,054	1,066	1,077	1,088	1,100	
Peak Day Demand Served	906	906	915	945	949	962	969	977	987	999	1,012	1,022	1,029	1,037	1,045	1,054	1,066	1,077	1,088	1,100	
Peak Day Demand Unserved	38	39	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
COST ($000 Nominal)									100.00		100.00				100.00						
Supply Fixed Costs	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	
Supply Variable Costs	302,917	281,493	293,492	299,036	294,326	311,863	328,720	349,570	308,925	294,817	310,197	318,835	322,724	309,495	300,506	310,119	329,141	325,816	337,946	357,357	
Total Supply Costs	302,976	281,552	293,551	299,096	294,385	311,922	328,780	349,629	308,984	294,877	310,256	318,894	322,784	309,554	300,565	310,178	329,200	325,875	338,005	357,416	**4,022,262**
Transport Fixed Costs	83,034	83,161	84,747	84,839	84,839	84,839	84,839	87,552	87,830	87,830	87,830	87,830	87,830	87,830	87,830	87,830	89,253	89,417	89,583	89,633	**1,116,516**
Transport Variable Costs	2,992	3,202	3,337	3,384	3,389	3,451	3,467	3,572	3,567	3,558	3,642	3,604	3,619	3,649	3,683	3,661	3,683	3,708	3,764	3,763	
Total Transport Cost	86,026	86,363	88,084	88,223	88,228	88,290	88,306	91,124	91,397	91,388	91,472	91,434	91,449	91,479	91,513	91,491	92,936	93,125	93,347	93,395	**1,161,542**
Storage Fixed Cost	24,104	24,277	25,665	25,576	25,842	26,656	27,030	27,968	28,631	28,631	28,631	28,631	28,631	28,683	28,953	29,126	29,126	29,126	29,359	29,536	
Storage Variable Cost	1,292	1,275	2,123	1,557	1,125	1,634	1,517	1,686	1,509	1,473	1,629	1,587	1,620	1,507	1,467	1,615	1,563	1,558	1,686	1,949	
Total Storage Cost	25,396	25,552	27,788	27,133	26,967	28,290	28,547	29,654	30,140	30,104	30,260	30,218	30,251	30,190	30,420	30,741	30,689	30,684	31,045	31,484	**372,278**
DSM Annual Utility Cost		23,447	25,552	27,723	31,134	32,626	35,713	37,071	38,511	39,808	40,923	42,476	43,252	41,864	41,864	40,470	39,053	37,901	36,307	30,633	
Total Levelized Utility Cost	0	803	2,079	3,524	5,286	7,219	9,316	11,478	13,741	16,063	18,405	20,781	23,183	25,525	27,844	30,096	32,250	34,329	36,315	38,076	
Total Costs	414,398	416,915	434,975	442,174	440,715	461,128	481,345	507,478	469,032	456,177	472,912	483,022	487,736	473,087	464,363	472,880	491,878	487,585	498,704	512,929	**5,974,021**
Key Resource Decisions (increm. MDT/day)																					
Mist Recall	-	-	-	28.0468	32.0279	45.2283	112.6017	112.6017	112.6017	112.6017	112.6017	112.6017	112.6017	112.6017	114.9691	123.0126	123.0126	123.0126	123.0126	129.3847	
Satellite Storage - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Satellite Storage - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.6314	0.6314	0.6314	0.6314	1.6399	
Satellite Storage - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Mid WVF (SAL to ALB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
South WVF (ALB to EUG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
New port to Salem Compressor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0000	40.0000	40.0000	40.0000	
NWP Zones 12-9 (Grants Pass Lat.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9126	1.8638	2.8260	3.1445	
Palomar East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Blue Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NWP Vintage TF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Other Key Resources (Peak Day MDT/day)																					
North WVF (POR to SAL)	-	-	33.5832	42.7881	43.0451	44.3075	85.0000	85.0000	27.7438	29.0655	52.6713	32.5769	33.4017	56.2513	34.4251	35.3885	22.5685	5.7201	1.8320	3.3561	
Harrisburg River Crossing (ALB to EUG)	-	8.0000	5.7472	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
Mist & Mist Recall	250.0000	250.0000	260.0000	288.0467	292.0279	305.2283	372.6017	372.6017	328.4201	362.9024	372.6017	372.6017	372.6017	372.6017	374.9691	383.0126	383.0126	383.0126	383.0126	389.3847	
New port LNG	59.9501	59.9569	59.9166	59.9511	60.0225	60.2369	-	-	60.6046	60.8016	61.0333	61.2040	61.3512	61.5037	61.6519	61.8180	100.0000	100.0000	100.0000	100.0000	
March Point	-	-	-	-	-	-	-	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	12.2113	

Appendix 6: Avoided Cost Determination

NW Natural®

Appendix 6.1 Avoided Costs – Base Case (Without Environmental Externalities)

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2010/2011	Nov	5.14	5.24	5.22	5.14	5.27	5.25	5.15	5.24	5.22	5.24	5.22
2010/2011	Dec	5.53	5.53	5.53	5.53	5.53	5.53	5.53	5.54	5.53	5.54	5.53
2010/2011	Jan	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.59	5.58	5.59	5.58
2010/2011	Feb	5.94	5.94	5.94	5.94	5.41	5.94	5.98	5.93	5.94	5.93	5.94
2010/2011	Mar	5.12	5.12	5.12	5.12	5.25	5.12	5.12	5.12	5.12	5.12	5.12
2010/2011	Apr	4.86	4.86	4.86	4.86	4.99	4.86	4.86	4.86	4.87	4.86	4.87
2010/2011	May	4.89	4.91	4.89	4.89	5.02	4.89	4.89	4.89	4.90	4.89	4.89
2010/2011	Jun	4.93	4.95	4.93	4.93	5.06	4.93	4.93	4.93	4.93	4.93	4.93
2010/2011	Jul	4.99	5.01	4.99	4.99	5.12	4.99	4.99	4.99	4.99	4.99	4.99
2010/2011	Aug	5.03	5.05	5.03	5.03	5.17	5.03	5.03	5.03	5.04	5.03	5.04
2010/2011	Sep	5.08	5.10	5.08	5.08	5.22	5.08	5.08	5.08	5.08	5.08	5.08
2010/2011	Oct	5.18	5.20	5.18	5.18	5.31	5.18	5.18	5.18	5.18	5.18	5.18
2010/2011	Annual Ave	5.19	5.20	5.19	5.19	5.25	5.19	5.19	5.19	5.19	5.19	5.19
	Winter Ave	5.45	5.47	5.47	5.45	5.41	5.48	5.46	5.48	5.47	5.48	5.47
Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2011/2012	Nov	5.99	5.99	5.99	5.99	6.02	5.99	5.99	6.00	5.99	6.00	5.99
2011/2012	Dec	6.24	6.24	6.24	6.24	6.24	6.24	6.24	6.26	6.24	6.26	6.24
2011/2012	Jan	6.29	6.29	6.29	6.29	6.30	6.30	6.29	6.31	6.29	6.31	6.30
2011/2012	Feb	6.62	6.62	6.63	6.62	6.14	6.62	6.62	6.64	6.62	6.64	6.62
2011/2012	Mar	5.77	5.77	5.77	5.77	5.92	5.77	5.77	5.77	5.77	5.77	5.77
2011/2012	Apr	5.31	5.31	5.31	5.31	5.45	5.31	5.31	5.31	5.31	5.31	5.31
2011/2012	May	5.21	5.23	5.21	5.21	5.35	5.21	5.21	5.21	5.21	5.21	5.21
2011/2012	Jun	5.25	5.27	5.25	5.25	5.39	5.25	5.25	5.25	5.25	5.25	5.25
2011/2012	Jul	5.30	5.32	5.30	5.30	5.44	5.30	5.30	5.30	5.31	5.30	5.31
2011/2012	Aug	5.35	5.37	5.35	5.35	5.49	5.35	5.35	5.35	5.36	5.35	5.36
2011/2012	Sep	5.40	5.42	5.40	5.40	5.54	5.40	5.40	5.40	5.40	5.40	5.40
2011/2012	Oct	5.45	5.47	5.45	5.45	5.60	5.45	5.45	5.45	5.46	5.45	5.46
2011/2012	Annual Ave	5.68	5.69	5.68	5.68	5.74	5.68	5.68	5.68	5.68	5.68	5.68
	Winter Ave	6.18	6.18	6.18	6.18	6.12	6.18	6.18	6.19	6.18	6.19	6.18
Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System

2012/2013	Nov	6.33	6.33	6.33	6.33	6.37	6.33	6.33	6.35	6.33	6.35	6.34
2012/2013	Dec	6.60	6.60	6.60	6.60	6.60	6.60	6.60	6.62	6.60	6.62	6.60
2012/2013	Jan	6.65	6.65	6.65	6.65	6.65	6.65	6.65	6.67	6.65	6.67	6.65
2012/2013	Feb	6.84	6.84	6.85	6.84	6.45	6.84	6.84	6.86	6.84	6.86	6.84
2012/2013	Mar	6.04	6.04	6.04	6.04	6.20	6.04	6.04	6.04	6.05	6.04	6.05
2012/2013	Apr	5.51	5.51	5.51	5.51	5.65	5.51	5.51	5.51	5.51	5.51	5.51
2012/2013	May	5.42	5.44	5.42	5.42	5.56	5.42	5.42	5.42	5.43	5.42	5.43
2012/2013	Jun	5.46	5.48	5.46	5.46	5.60	5.46	5.46	5.46	5.46	5.46	5.46
2012/2013	Jul	5.51	5.53	5.51	5.51	5.66	5.51	5.51	5.51	5.52	5.51	5.52
2012/2013	Aug	5.56	5.58	5.56	5.56	5.71	5.56	5.56	5.56	5.57	5.56	5.56
2012/2013	Sep	5.61	5.63	5.61	5.61	5.76	5.61	5.61	5.61	5.62	5.61	5.61
2012/2013	Oct	5.71	5.73	5.71	5.71	5.86	5.71	5.71	5.71	5.71	5.71	5.71
2012/2013	Annual Ave	5.93	5.94	5.93	5.93	6.00	5.93	5.93	5.94	5.93	5.94	5.93
	Winter Ave	6.49	6.49	6.49	6.49	6.46	6.49	6.49	6.50	6.49	6.50	6.49

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2013/2014	Nov	6.62	6.71	6.70	6.62	6.75	6.71	6.64	6.72	6.69	6.72	6.69
2013/2014	Dec	7.02	7.02	7.02	7.02	7.02	7.02	7.02	7.04	7.02	7.04	7.02
2013/2014	Jan	7.07	7.08	7.07	7.07	7.08	7.08	7.07	7.09	7.07	7.09	7.08
2013/2014	Feb	7.13	7.13	7.14	7.13	6.74	7.13	7.13	7.15	7.13	7.15	7.13
2013/2014	Mar	6.30	6.30	6.30	6.30	6.47	6.30	6.30	6.31	6.31	6.31	6.31
2013/2014	Apr	5.80	5.80	5.80	5.80	5.95	5.80	5.80	5.80	5.80	5.80	5.80
2013/2014	May	5.70	5.72	5.70	5.70	5.85	5.70	5.70	5.70	5.71	5.70	5.71
2013/2014	Jun	5.73	5.75	5.73	5.73	5.88	5.73	5.73	5.73	5.73	5.73	5.73
2013/2014	Jul	5.78	5.80	5.78	5.78	5.93	5.78	5.78	5.78	5.78	5.78	5.78
2013/2014	Aug	5.84	5.86	5.84	5.84	5.99	5.84	5.84	5.84	5.84	5.84	5.84
2013/2014	Sep	5.89	5.91	5.89	5.89	6.04	5.89	5.89	5.89	5.89	5.89	5.89
2013/2014	Oct	6.02	6.04	6.02	6.02	6.18	6.02	6.02	6.02	6.02	6.02	6.02
2013/2014	Annual Ave	6.24	6.26	6.24	6.24	6.32	6.25	6.24	6.25	6.24	6.25	6.25
	Winter Ave	6.82	6.84	6.84	6.83	6.81	6.84	6.83	6.86	6.84	6.86	6.84

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2014/2015	Nov	6.58	6.58	6.59	6.58	6.63	6.58	6.58	6.60	6.58	6.60	6.58
2014/2015	Dec	6.80	6.80	6.80	6.80	6.80	6.80	6.80	6.81	6.80	6.81	6.80
2014/2015	Jan	6.85	6.85	6.85	6.85	6.85	6.85	6.85	6.87	6.85	6.87	6.85
2014/2015	Feb	7.42	7.40	7.42	7.43	6.63	7.40	7.40	7.42	7.39	7.42	7.40

2014/2015	Mar	6.22	6.22	6.22	6.22	6.38	6.22	6.22	6.22	6.22	6.22	6.22
2014/2015	Apr	5.75	5.75	5.75	5.75	5.90	5.75	5.75	5.75	5.75	5.75	5.75
2014/2015	May	5.77	5.79	5.77	5.77	5.92	5.77	5.77	5.77	5.77	5.77	5.77
2014/2015	Jun	5.82	5.84	5.82	5.82	5.97	5.82	5.82	5.82	5.82	5.82	5.82
2014/2015	Jul	5.87	5.89	5.87	5.87	6.02	5.87	5.87	5.87	5.87	5.87	5.87
2014/2015	Aug	5.98	5.96	5.98	5.98	6.10	5.94	5.94	5.98	5.95	5.98	5.95
2014/2015	Sep	6.02	6.03	6.02	6.02	6.17	6.01	6.01	6.02	6.02	6.02	6.02
2014/2015	Oct	6.10	6.12	6.10	6.10	6.26	6.10	6.10	6.10	6.11	6.10	6.11
2014/2015	Annual Ave	6.26	6.26	6.26	6.26	6.30	6.25	6.25	6.26	6.25	6.26	6.25
	Winter Ave	6.76	6.76	6.76	6.76	6.66	6.76	6.76	6.77	6.76	6.77	6.76

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2015/2016	Nov	6.58	6.58	6.59	6.58	6.75	6.58	6.58	6.61	6.59	6.61	6.59
2015/2016	Dec	6.77	6.77	6.77	6.77	6.94	6.77	6.77	6.79	6.77	6.79	6.77
2015/2016	Jan	6.83	6.83	6.83	6.83	7.01	6.83	6.83	6.85	6.83	6.85	6.83
2015/2016	Feb	7.43	7.40	7.43	7.45	7.59	7.40	7.40	7.43	7.41	7.43	7.41
2015/2016	Mar	6.18	6.18	6.18	6.18	6.34	6.18	6.18	6.18	6.18	6.18	6.18
2015/2016	Apr	5.77	5.77	5.77	5.77	5.92	5.77	5.77	5.77	5.77	5.77	5.77
2015/2016	May	5.80	5.82	5.80	5.80	5.95	5.80	5.80	5.80	5.80	5.80	5.80
2015/2016	Jun	5.84	5.86	5.84	5.84	5.99	5.84	5.84	5.84	5.84	5.84	5.84
2015/2016	Jul	5.90	5.92	5.90	5.90	6.05	5.90	5.90	5.90	5.90	5.90	5.90
2015/2016	Aug	6.04	5.97	6.01	6.04	6.11	5.95	5.95	5.99	5.97	5.99	5.97
2015/2016	Sep	6.00	6.02	6.00	6.00	6.16	6.00	6.00	6.00	6.01	6.00	6.01
2015/2016	Oct	6.16	6.18	6.16	6.16	6.32	6.16	6.16	6.16	6.16	6.16	6.16
2015/2016	Annual Ave	6.27	6.27	6.27	6.27	6.42	6.26	6.26	6.27	6.26	6.27	6.27
	Winter Ave	6.75	6.74	6.75	6.75	6.92	6.74	6.74	6.76	6.75	6.76	6.75

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2016/2017	Nov	6.45	6.45	6.46	6.45	6.62	6.45	6.45	6.47	6.45	6.47	6.45
2016/2017	Dec	6.58	6.58	6.58	6.58	6.75	6.58	6.58	6.60	6.58	6.60	6.58
2016/2017	Jan	6.63	6.63	6.63	6.63	6.81	6.63	6.63	6.64	6.64	6.64	6.64
2016/2017	Feb	7.29	6.74	6.77	7.31	6.90	6.74	6.74	6.77	6.82	6.77	6.82
2016/2017	Mar	5.98	5.98	5.98	5.98	6.14	5.98	5.98	5.98	5.98	5.98	5.98
2016/2017	Apr	5.81	5.81	5.81	5.81	5.96	5.81	5.81	5.81	5.81	5.81	5.81
2016/2017	May	5.75	5.75	5.75	5.75	5.90	5.75	5.75	5.75	5.75	5.75	5.75
2016/2017	Jun	5.85	5.82	5.84	5.85	5.95	5.80	5.80	5.84	5.81	5.84	5.81

2016/2017	Jul	5.89	5.87	5.88	5.89	6.00	5.85	5.85	5.88	5.86	5.88	5.86
2016/2017	Aug	5.90	5.90	5.90	5.90	6.05	5.90	5.90	5.90	5.90	5.90	5.90
2016/2017	Sep	5.95	5.95	5.95	5.95	6.11	5.95	5.95	5.95	5.95	5.95	5.95
2016/2017	Oct	6.14	6.15	6.14	6.14	6.29	6.14	6.14	6.14	6.15	6.14	6.15
2016/2017	Annual Ave	6.18	6.13	6.14	6.18	6.29	6.13	6.13	6.14	6.14	6.14	6.14
	Winter Ave	6.57	6.47	6.48	6.58	6.64	6.47	6.47	6.49	6.49	6.49	6.49
Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2017/2018	Nov	6.32	6.32	6.32	6.32	6.37	6.32	6.32	6.33	6.32	6.33	6.32
2017/2018	Dec	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45
2017/2018	Jan	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50
2017/2018	Feb	7.28	6.69	6.72	7.49	6.45	6.70	6.70	6.71	6.79	6.71	6.78
2017/2018	Mar	5.67	5.67	5.67	5.67	5.81	5.67	5.67	5.67	5.67	5.67	5.67
2017/2018	Apr	5.65	5.65	5.65	5.65	5.79	5.65	5.65	5.65	5.65	5.65	5.65
2017/2018	May	5.65	5.65	5.65	5.65	5.80	5.65	5.65	5.65	5.65	5.65	5.65
2017/2018	Jun	5.71	5.71	5.71	5.71	5.86	5.71	5.71	5.71	5.71	5.71	5.71
2017/2018	Jul	5.76	5.76	5.76	5.76	5.91	5.76	5.76	5.76	5.76	5.76	5.76
2017/2018	Aug	5.86	5.85	5.86	5.86	5.98	5.83	5.83	5.86	5.84	5.86	5.84
2017/2018	Sep	5.92	5.91	5.91	5.92	6.05	5.90	5.90	5.91	5.91	5.91	5.91
2017/2018	Oct	6.02	6.02	6.02	6.02	6.18	6.02	6.02	6.02	6.02	6.02	6.02
2017/2018	Annual Ave	6.06	6.01	6.01	6.07	6.09	6.01	6.01	6.01	6.02	6.01	6.02
	Winter Ave	6.43	6.32	6.32	6.47	6.31	6.32	6.32	6.32	6.34	6.32	6.33
Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2018/2019	Nov	6.25	6.25	6.25	6.25	6.30	6.25	6.25	6.26	6.25	6.26	6.25
2018/2019	Dec	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.38	6.37	6.38	6.37
2018/2019	Jan	6.43	6.43	6.43	6.43	6.43	6.43	6.43	6.43	6.43	6.43	6.43
2018/2019	Feb	7.51	6.94	6.97	7.53	6.47	6.94	6.94	6.97	7.01	6.97	7.00
2018/2019	Mar	6.04	6.04	6.04	6.04	6.20	6.04	6.04	6.04	6.05	6.04	6.04
2018/2019	Apr	6.03	6.03	6.03	6.03	6.19	6.03	6.03	6.03	6.03	6.03	6.03
2018/2019	May	5.97	5.97	5.97	5.97	6.13	5.97	5.97	5.97	5.97	5.97	5.97
2018/2019	Jun	5.97	5.97	5.97	5.97	6.13	5.97	5.97	5.97	5.97	5.97	5.97
2018/2019	Jul	6.03	6.03	6.03	6.03	6.19	6.03	6.03	6.03	6.03	6.03	6.03
2018/2019	Aug	6.21	6.15	6.19	6.21	6.29	6.13	6.13	6.17	6.14	6.17	6.14
2018/2019	Sep	6.26	6.21	6.24	6.26	6.35	6.19	6.19	6.23	6.20	6.23	6.20
2018/2019	Oct	6.29	6.29	6.29	6.29	6.45	6.29	6.29	6.29	6.29	6.29	6.29

2018/2019	Annual Ave	6.27	6.22	6.23	6.27	6.29	6.21	6.21	6.23	6.22	6.23	6.22
	Winter Ave	6.50	6.40	6.40	6.51	6.35	6.40	6.40	6.41	6.41	6.41	6.41
Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2019/2020	Nov	6.56	6.56	6.56	6.56	6.61	6.56	6.56	6.57	6.56	6.57	6.56
2019/2020	Dec	6.69	6.69	6.69	6.69	6.69	6.69	6.69	6.69	6.69	6.69	6.69
2019/2020	Jan	6.74	6.74	6.74	6.74	6.74	6.74	6.74	6.75	6.74	6.75	6.74
2019/2020	Feb	7.53	7.00	7.03	7.55	6.63	7.00	7.00	7.02	7.07	7.02	7.06
2019/2020	Mar	6.23	6.23	6.23	6.23	6.39	6.23	6.23	6.23	6.23	6.23	6.23
2019/2020	Apr	6.18	6.18	6.18	6.18	6.34	6.18	6.18	6.18	6.18	6.18	6.18
2019/2020	May	6.12	6.12	6.12	6.12	6.28	6.12	6.12	6.12	6.13	6.12	6.13
2019/2020	Jun	6.18	6.18	6.18	6.18	6.33	6.17	6.17	6.18	6.17	6.18	6.17
2019/2020	Jul	6.27	6.24	6.27	6.27	6.38	6.22	6.22	6.26	6.23	6.26	6.23
2019/2020	Aug	6.27	6.27	6.27	6.27	6.43	6.27	6.27	6.27	6.27	6.27	6.27
2019/2020	Sep	6.33	6.33	6.33	6.33	6.49	6.33	6.33	6.33	6.33	6.33	6.33
2019/2020	Oct	6.38	6.38	6.38	6.38	6.55	6.38	6.38	6.38	6.38	6.38	6.38
2019/2020	Annual Ave	6.45	6.41	6.41	6.45	6.49	6.40	6.40	6.41	6.41	6.41	6.41
	Winter Ave	6.74	6.64	6.64	6.74	6.61	6.64	6.64	6.65	6.65	6.65	6.65
Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2020/2021	Nov	6.78	6.78	6.78	6.78	6.84	6.78	6.78	6.79	6.78	6.79	6.78
2020/2021	Dec	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.98	6.97	6.98	6.97
2020/2021	Jan	7.03	7.03	7.03	7.03	7.03	7.03	7.03	7.04	7.03	7.04	7.03
2020/2021	Feb	7.89	7.34	7.36	7.90	6.96	7.34	7.34	7.36	7.41	7.36	7.41
2020/2021	Mar	6.65	6.65	6.65	6.65	6.83	6.65	6.65	6.65	6.66	6.65	6.66
2020/2021	Apr	6.50	6.50	6.50	6.50	6.67	6.50	6.50	6.50	6.50	6.50	6.50
2020/2021	May	6.51	6.51	6.51	6.51	6.64	6.51	6.51	6.51	6.51	6.51	6.51
2020/2021	Jun	6.54	6.54	6.54	6.54	6.69	6.53	6.53	6.54	6.53	6.54	6.53
2020/2021	Jul	6.57	6.57	6.57	6.57	6.74	6.57	6.57	6.57	6.58	6.57	6.57
2020/2021	Aug	6.63	6.63	6.63	6.63	6.81	6.63	6.63	6.63	6.64	6.63	6.64
2020/2021	Sep	6.69	6.69	6.69	6.69	6.86	6.69	6.69	6.69	6.69	6.69	6.69
2020/2021	Oct	6.75	6.75	6.75	6.75	6.92	6.75	6.75	6.75	6.75	6.75	6.75
2020/2021	Annual Ave	6.79	6.74	6.75	6.79	6.83	6.74	6.74	6.75	6.75	6.75	6.75
	Winter Ave	7.05	6.95	6.95	7.05	6.93	6.95	6.95	6.96	6.96	6.96	6.96

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2021/2022	Nov	7.12	7.12	7.13	7.12	7.19	7.12	7.12	7.14	7.12	7.14	7.12
2021/2022	Dec	7.31	7.31	7.31	7.31	7.32	7.31	7.31	7.32	7.31	7.32	7.31
2021/2022	Jan	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.38	7.37	7.38	7.37
2021/2022	Feb	8.33	7.78	7.80	8.35	7.91	7.78	7.78	7.80	7.86	7.80	7.85
2021/2022	Mar	7.04	7.04	7.04	7.04	7.22	7.04	7.04	7.04	7.04	7.04	7.04
2021/2022	Apr	6.79	6.79	6.79	6.79	6.96	6.79	6.79	6.79	6.79	6.79	6.79
2021/2022	May	6.80	6.80	6.80	6.80	6.94	6.80	6.80	6.80	6.80	6.80	6.80
2021/2022	Jun	6.86	6.84	6.85	6.86	6.99	6.82	6.82	6.85	6.83	6.85	6.83
2021/2022	Jul	6.91	6.89	6.90	6.91	7.05	6.87	6.87	6.90	6.88	6.90	6.88
2021/2022	Aug	6.93	6.93	6.93	6.93	7.11	6.93	6.93	6.93	6.93	6.93	6.93
2021/2022	Sep	6.98	6.98	6.98	6.98	7.16	6.98	6.98	6.98	6.98	6.98	6.98
2021/2022	Oct	7.04	7.04	7.04	7.04	7.23	7.04	7.04	7.04	7.05	7.04	7.05
2021/2022	Annual Ave	7.12	7.07	7.07	7.12	7.20	7.07	7.07	7.08	7.08	7.08	7.08
	Winter Ave	7.42	7.32	7.32	7.42	7.39	7.32	7.32	7.33	7.33	7.33	7.33
Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2022/2023	Nov	7.72	7.72	7.72	7.73	7.75	7.72	7.72	7.73	7.72	7.73	7.72
2022/2023	Dec	7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.92	7.90	7.92	7.90
2022/2023	Jan	7.96	7.96	7.96	7.96	7.96	7.96	7.96	7.97	7.96	7.97	7.96
2022/2023	Feb	8.85	8.30	8.32	8.86	8.46	8.30	8.30	8.32	8.38	8.32	8.37
2022/2023	Mar	7.56	7.56	7.56	7.56	7.76	7.56	7.56	7.56	7.56	7.56	7.56
2022/2023	Apr	7.27	7.27	7.27	7.27	7.45	7.27	7.27	7.27	7.27	7.27	7.27
2022/2023	May	7.21	7.21	7.21	7.21	7.37	7.21	7.21	7.21	7.22	7.21	7.22
2022/2023	Jun	7.33	7.26	7.30	7.33	7.43	7.24	7.24	7.28	7.26	7.28	7.26
2022/2023	Jul	7.32	7.31	7.31	7.32	7.49	7.30	7.30	7.31	7.30	7.31	7.31
2022/2023	Aug	7.36	7.36	7.36	7.36	7.55	7.36	7.36	7.36	7.36	7.36	7.36
2022/2023	Sep	7.41	7.41	7.41	7.41	7.60	7.41	7.41	7.41	7.41	7.41	7.41
2022/2023	Oct	7.48	7.48	7.48	7.48	7.67	7.48	7.48	7.48	7.48	7.48	7.48
2022/2023	Annual Ave	7.60	7.56	7.56	7.61	7.69	7.55	7.55	7.56	7.56	7.56	7.56
	Winter Ave	7.98	7.88	7.88	7.98	7.96	7.88	7.88	7.89	7.90	7.89	7.89
Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2023/2024	Nov	7.88	7.88	7.89	7.90	7.95	7.88	7.88	7.91	7.89	7.91	7.89

2023/2024	Dec	8.07	8.07	8.07	8.07	8.07	8.07	8.07	8.09	8.07	8.09	8.07
2023/2024	Jan	8.13	8.13	8.13	8.13	8.13	8.13	8.13	8.15	8.13	8.15	8.13
2023/2024	Feb	8.93	8.74	8.75	8.95	8.92	8.74	8.74	8.76	8.77	8.76	8.77
2023/2024	Mar	7.80	7.80	7.80	7.80	8.00	7.80	7.80	7.80	7.80	7.80	7.80
2023/2024	Apr	7.48	7.48	7.48	7.48	7.67	7.48	7.48	7.48	7.48	7.48	7.48
2023/2024	May	7.50	7.50	7.50	7.50	7.65	7.50	7.50	7.50	7.50	7.50	7.50
2023/2024	Jun	7.57	7.52	7.56	7.57	7.70	7.50	7.50	7.54	7.52	7.54	7.52
2023/2024	Jul	7.55	7.55	7.55	7.55	7.74	7.55	7.55	7.55	7.55	7.55	7.55
2023/2024	Aug	7.64	7.63	7.63	7.64	7.82	7.62	7.62	7.63	7.63	7.63	7.63
2023/2024	Sep	7.68	7.68	7.68	7.68	7.87	7.68	7.68	7.68	7.68	7.68	7.68
2023/2024	Oct	7.74	7.74	7.74	7.74	7.94	7.74	7.74	7.74	7.74	7.74	7.74
2023/2024	Annual Ave	7.83	7.81	7.81	7.83	7.95	7.80	7.80	7.81	7.81	7.81	7.81
	Winter Ave	8.16	8.12	8.12	8.16	8.21	8.12	8.12	8.13	8.13	8.13	8.13
Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2024/2025	Nov	7.97	7.97	7.97	7.99	8.04	7.97	7.97	7.99	7.97	7.99	7.97
2024/2025	Dec	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.12	8.10	8.12	8.10
2024/2025	Jan	8.16	8.16	8.17	8.16	8.16	8.16	8.16	8.18	8.16	8.18	8.17
2024/2025	Feb	8.99	9.19	9.20	9.02	9.36	9.19	9.19	9.21	9.17	9.21	9.17
2024/2025	Mar	7.77	7.77	7.77	7.77	7.97	7.77	7.77	7.77	7.77	7.77	7.77
2024/2025	Apr	7.56	7.56	7.56	7.56	7.76	7.56	7.56	7.56	7.56	7.56	7.56
2024/2025	May	7.57	7.57	7.57	7.57	7.74	7.57	7.57	7.57	7.57	7.57	7.57
2024/2025	Jun	7.63	7.62	7.63	7.63	7.79	7.60	7.60	7.63	7.61	7.63	7.61
2024/2025	Jul	7.69	7.68	7.68	7.69	7.85	7.66	7.66	7.68	7.67	7.68	7.67
2024/2025	Aug	7.71	7.71	7.71	7.71	7.91	7.71	7.71	7.71	7.71	7.71	7.71
2024/2025	Sep	7.78	7.78	7.78	7.78	7.98	7.78	7.78	7.78	7.78	7.78	7.78
2024/2025	Oct	7.84	7.84	7.84	7.84	8.04	7.84	7.84	7.84	7.84	7.84	7.84
2024/2025	Annual Ave	7.89	7.90	7.91	7.89	8.05	7.90	7.90	7.91	7.90	7.91	7.90
	Winter Ave	8.18	8.22	8.23	8.19	8.31	8.22	8.22	8.24	8.22	8.24	8.22
Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2025/2026	Nov	8.23	8.23	8.24	8.25	8.29	8.23	8.23	8.25	8.23	8.25	8.23
2025/2026	Dec	8.38	8.38	8.38	8.38	8.38	8.38	8.38	8.40	8.38	8.40	8.39
2025/2026	Jan	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.46	8.45	8.46	8.45
2025/2026	Feb	9.34	9.36	9.38	9.36	9.52	9.36	9.36	9.39	9.36	9.39	9.37
2025/2026	Mar	8.08	8.08	8.08	8.08	8.29	8.08	8.08	8.08	8.08	8.08	8.08

2025/2026	Apr	7.86	7.86	7.86	7.86	8.06	7.86	7.86	7.86	7.86	7.86	7.86
2025/2026	May	7.80	7.80	7.80	7.80	7.98	7.80	7.80	7.80	7.80	7.80	7.80
2025/2026	Jun	7.86	7.85	7.86	7.86	8.04	7.84	7.84	7.86	7.84	7.86	7.84
2025/2026	Jul	7.93	7.92	7.93	7.93	8.10	7.90	7.90	7.93	7.90	7.93	7.91
2025/2026	Aug	7.95	7.95	7.95	7.95	8.15	7.95	7.95	7.95	7.95	7.95	7.95
2025/2026	Sep	8.01	8.01	8.01	8.01	8.22	8.01	8.01	8.01	8.01	8.01	8.01
2025/2026	Oct	8.08	8.08	8.08	8.08	8.29	8.08	8.08	8.08	8.08	8.08	8.08
2025/2026	Annual Ave	8.16	8.16	8.16	8.16	8.30	8.15	8.15	8.16	8.16	8.16	8.16
	Winter Ave	8.48	8.49	8.49	8.49	8.57	8.49	8.49	8.50	8.49	8.50	8.49

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2026/2027	Nov	8.40	8.40	8.41	8.43	8.46	8.40	8.40	8.43	8.41	8.43	8.41
2026/2027	Dec	8.55	8.55	8.55	8.55	8.55	8.55	8.55	8.57	8.55	8.57	8.55
2026/2027	Jan	8.61	8.61	8.61	8.61	8.61	8.61	8.61	8.63	8.61	8.63	8.61
2026/2027	Feb	9.53	9.61	9.62	9.55	9.76	9.61	9.61	9.63	9.60	9.63	9.61
2026/2027	Mar	8.22	8.22	8.22	8.22	8.43	8.22	8.22	8.22	8.22	8.22	8.22
2026/2027	Apr	8.04	8.04	8.04	8.04	8.25	8.04	8.04	8.04	8.04	8.04	8.04
2026/2027	May	8.03	8.03	8.03	8.03	8.23	8.03	8.03	8.03	8.03	8.03	8.03
2026/2027	Jun	8.13	8.10	8.12	8.13	8.29	8.08	8.08	8.12	8.09	8.12	8.10
2026/2027	Jul	8.16	8.16	8.16	8.16	8.35	8.14	8.14	8.16	8.15	8.16	8.15
2026/2027	Aug	8.19	8.19	8.19	8.19	8.40	8.19	8.19	8.19	8.20	8.19	8.20
2026/2027	Sep	8.26	8.26	8.26	8.26	8.47	8.26	8.26	8.26	8.26	8.26	8.26
2026/2027	Oct	8.33	8.33	8.33	8.33	8.54	8.33	8.33	8.33	8.33	8.33	8.33
2026/2027	Annual Ave	8.36	8.37	8.37	8.37	8.52	8.36	8.36	8.38	8.37	8.38	8.37
	Winter Ave	8.65	8.66	8.67	8.66	8.74	8.66	8.66	8.68	8.66	8.68	8.66

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2027/2028	Nov	8.74	8.74	8.75	8.76	8.80	8.74	8.74	8.76	8.74	8.76	8.74
2027/2028	Dec	8.89	8.89	8.90	8.89	8.90	8.89	8.89	8.92	8.89	8.92	8.90
2027/2028	Jan	8.96	8.96	8.96	8.96	8.96	8.96	8.96	8.98	8.96	8.98	8.96
2027/2028	Feb	9.78	9.81	9.82	9.80	9.99	9.81	9.81	9.83	9.81	9.83	9.81
2027/2028	Mar	8.51	8.51	8.51	8.51	8.73	8.51	8.51	8.51	8.51	8.51	8.51
2027/2028	Apr	8.24	8.24	8.24	8.24	8.45	8.24	8.24	8.24	8.25	8.24	8.25
2027/2028	May	8.28	8.28	8.28	8.28	8.49	8.28	8.28	8.28	8.28	8.28	8.28
2027/2028	Jun	8.38	8.36	8.38	8.38	8.56	8.34	8.34	8.38	8.35	8.38	8.35
2027/2028	Jul	8.41	8.42	8.41	8.41	8.62	8.41	8.41	8.41	8.41	8.41	8.41

2027/2028	Aug	8.47	8.49	8.47	8.47	8.69	8.47	8.47	8.47	8.47	8.47	8.47
2027/2028	Sep	8.53	8.53	8.53	8.53	8.75	8.53	8.53	8.53	8.53	8.53	8.53
2027/2028	Oct	8.60	8.60	8.60	8.60	8.82	8.60	8.60	8.60	8.60	8.60	8.60
2027/2028	Annual Ave	8.64	8.65	8.65	8.65	8.81	8.64	8.64	8.65	8.65	8.65	8.65
	Winter Ave	8.97	8.97	8.98	8.97	9.06	8.97	8.97	8.99	8.97	8.99	8.98

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2028/2029	Nov	9.03	9.03	9.03	9.05	9.08	9.03	9.03	9.04	9.03	9.04	9.03
2028/2029	Dec	9.18	9.18	9.18	9.18	9.18	9.18	9.18	9.19	9.18	9.19	9.18
2028/2029	Jan	9.25	9.25	9.25	9.25	9.25	9.25	9.25	9.25	9.25	9.25	9.25
2028/2029	Feb	10.02	9.50	9.50	10.17	9.69	9.50	9.50	9.50	9.58	9.50	9.57
2028/2029	Mar	8.84	8.84	8.84	8.84	9.06	8.84	8.84	8.84	8.84	8.84	8.84
2028/2029	Apr	8.49	8.49	8.49	8.49	8.70	8.49	8.49	8.49	8.49	8.49	8.49
2028/2029	May	8.53	8.53	8.53	8.53	8.74	8.53	8.53	8.53	8.53	8.53	8.53
2028/2029	Jun	8.59	8.59	8.59	8.59	8.80	8.58	8.58	8.59	8.58	8.59	8.58
2028/2029	Jul	8.66	8.66	8.66	8.66	8.86	8.64	8.64	8.66	8.65	8.66	8.65
2028/2029	Aug	8.70	8.70	8.70	8.70	8.92	8.70	8.70	8.70	8.71	8.70	8.70
2028/2029	Sep	8.77	8.77	8.77	8.77	8.99	8.77	8.77	8.77	8.77	8.77	8.77
2028/2029	Oct	8.84	8.84	8.84	8.84	9.06	8.84	8.84	8.84	8.84	8.84	8.84
2028/2029	Annual Ave	8.90	8.86	8.86	8.91	9.02	8.86	8.86	8.86	8.87	8.86	8.87
	Winter Ave	9.25	9.15	9.15	9.28	9.24	9.15	9.15	9.16	9.17	9.16	9.17

Appendix 6 – Modified Base Case Avoided Costs

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2010/2011	Nov	4.20	4.24	4.22	4.20	4.25	4.25	4.21	4.24	4.23	4.24	4.24
2010/2011	Dec	4.37	4.43	4.42	4.37	4.42	4.43	4.37	4.44	4.41	4.44	4.41
2010/2011	Jan	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.49	4.47	4.49	4.47
2010/2011	Feb	4.70	4.71	4.71	4.71	4.27	4.71	4.74	4.72	4.71	4.72	4.71
2010/2011	Mar	3.96	3.96	3.96	3.96	4.07	3.96	3.96	3.96	3.96	3.96	3.96
2010/2011	Apr	3.79	3.79	3.79	3.79	3.89	3.79	3.79	3.79	3.79	3.79	3.79
2010/2011	May	3.70	3.72	3.70	3.70	3.81	3.70	3.70	3.70	3.71	3.70	3.71
2010/2011	Jun	3.65	3.67	3.65	3.65	3.75	3.65	3.65	3.65	3.65	3.65	3.65
2010/2011	Jul	3.70	3.72	3.70	3.70	3.80	3.70	3.70	3.70	3.70	3.70	3.70
2010/2011	Aug	3.74	3.76	3.74	3.74	3.84	3.74	3.74	3.74	3.74	3.74	3.74
2010/2011	Sep	3.78	3.80	3.78	3.78	3.89	3.78	3.78	3.78	3.78	3.78	3.78
2010/2011	Oct	4.07	4.09	4.07	4.07	4.17	4.07	4.07	4.07	4.07	4.07	4.07
2010/2011	Annual Ave	4.01	4.03	4.01	4.01	4.05	4.02	4.01	4.02	4.02	4.02	4.02
	Winter Ave	4.34	4.36	4.35	4.34	4.30	4.36	4.34	4.36	4.35	4.36	4.35
Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2011/2012	Nov	4.22	4.22	4.22	4.22	4.23	4.22	4.22	4.23	4.22	4.23	4.22
2011/2012	Dec	4.24	4.32	4.31	4.24	4.31	4.32	4.24	4.33	4.29	4.33	4.30
2011/2012	Jan	4.14	4.36	4.34	4.14	4.26	4.36	4.16	4.36	4.30	4.36	4.31
2011/2012	Feb	4.71	4.72	4.72	4.75	4.27	4.72	4.71	4.73	4.71	4.73	4.72
2011/2012	Mar	3.70	3.94	3.90	3.70	3.80	3.96	3.70	3.92	3.88	3.92	3.89
2011/2012	Apr	3.93	3.98	3.94	3.93	4.03	4.00	3.93	3.96	3.98	3.96	3.98
2011/2012	May	3.95	4.00	3.96	3.95	4.06	4.02	3.95	3.98	4.00	3.98	4.00
2011/2012	Jun	4.09	4.11	4.09	4.09	4.20	4.09	4.09	4.09	4.09	4.09	4.09
2011/2012	Jul	4.29	4.31	4.29	4.29	4.41	4.29	4.29	4.29	4.30	4.29	4.30
2011/2012	Aug	4.30	4.32	4.30	4.30	4.42	4.30	4.30	4.30	4.31	4.30	4.31
2011/2012	Sep	4.37	4.39	4.37	4.37	4.48	4.37	4.37	4.37	4.37	4.37	4.37
2011/2012	Oct	4.75	4.77	4.75	4.75	4.88	4.75	4.75	4.75	4.75	4.75	4.75
2011/2012	Annual Ave	4.22	4.29	4.26	4.23	4.28	4.28	4.22	4.27	4.27	4.27	4.27
	Winter Ave	4.20	4.31	4.29	4.20	4.17	4.31	4.20	4.31	4.28	4.31	4.28
Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2012/2013	Nov	5.12	5.12	5.12	5.12	5.14	5.12	5.12	5.13	5.12	5.13	5.12
2012/2013	Dec	5.28	5.29	5.29	5.28	5.29	5.29	5.28	5.30	5.28	5.30	5.29
2012/2013	Jan	5.27	5.33	5.32	5.27	5.33	5.33	5.27	5.34	5.32	5.34	5.32
2012/2013	Feb	5.68	5.69	5.69	5.68	5.27	5.69	5.68	5.70	5.68	5.70	5.68
2012/2013	Mar	4.97	4.97	4.97	4.97	5.11	4.97	4.97	4.97	4.98	4.97	4.97
2012/2013	Apr	4.68	4.68	4.68	4.68	4.80	4.68	4.68	4.68	4.68	4.68	4.68

2012/2013	May	4.69	4.71	4.69	4.69	4.81	4.72	4.69	4.69	4.71	4.69	4.71
2012/2013	Jun	4.77	4.79	4.77	4.77	4.90	4.77	4.77	4.77	4.78	4.77	4.78
2012/2013	Jul	4.82	4.84	4.82	4.82	4.95	4.82	4.82	4.82	4.82	4.82	4.82
2012/2013	Aug	4.87	4.89	4.87	4.87	5.00	4.87	4.87	4.87	4.87	4.87	4.87
2012/2013	Sep	4.91	4.93	4.91	4.91	5.04	4.91	4.91	4.91	4.92	4.91	4.92
2012/2013	Oct	5.13	5.15	5.13	5.13	5.25	5.13	5.13	5.13	5.13	5.13	5.13
2012/2013	Annual Ave	5.01	5.03	5.02	5.01	5.07	5.02	5.01	5.02	5.02	5.02	5.02
	Winter Ave	5.26	5.27	5.27	5.26	5.23	5.27	5.26	5.28	5.27	5.28	5.27

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2013/2014	Nov	5.27	5.27	5.27	5.27	5.29	5.27	5.27	5.28	5.27	5.28	5.27
2013/2014	Dec	5.31	5.38	5.38	5.31	5.38	5.38	5.31	5.40	5.36	5.40	5.37
2013/2014	Jan	5.42	5.43	5.43	5.42	5.43	5.43	5.42	5.45	5.43	5.45	5.43
2013/2014	Feb	6.62	6.62	6.62	6.66	5.34	6.62	6.62	6.64	6.61	6.64	6.61
2013/2014	Mar	4.86	4.86	4.86	4.86	4.99	4.86	4.86	4.86	4.86	4.86	4.86
2013/2014	Apr	4.80	4.80	4.80	4.80	4.93	4.80	4.80	4.80	4.80	4.80	4.80
2013/2014	May	4.68	4.70	4.68	4.68	4.77	4.68	4.68	4.68	4.69	4.68	4.69
2013/2014	Jun	4.65	4.67	4.65	4.65	4.77	4.65	4.65	4.65	4.65	4.65	4.65
2013/2014	Jul	4.64	4.66	4.64	4.64	4.76	4.64	4.64	4.64	4.64	4.64	4.64
2013/2014	Aug	4.68	4.70	4.68	4.68	4.81	4.68	4.68	4.68	4.69	4.68	4.69
2013/2014	Sep	4.70	4.72	4.70	4.70	4.82	4.70	4.70	4.70	4.70	4.70	4.70
2013/2014	Oct	4.72	4.76	4.72	4.72	4.84	4.78	4.72	4.74	4.76	4.74	4.76
2013/2014	Annual Ave	5.02	5.04	5.02	5.02	5.01	5.03	5.02	5.03	5.03	5.03	5.03
	Winter Ave	5.47	5.49	5.49	5.48	5.29	5.49	5.47	5.50	5.48	5.50	5.49

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2014/2015	Nov	4.99	5.02	5.00	4.99	5.04	5.02	4.99	5.02	5.01	5.02	5.01
2014/2015	Dec	5.13	5.13	5.14	5.13	5.13	5.13	5.13	5.16	5.13	5.16	5.14
2014/2015	Jan	5.10	5.18	5.18	5.10	5.18	5.18	5.10	5.19	5.16	5.19	5.16
2014/2015	Feb	6.09	6.09	6.09	6.13	5.19	6.09	6.09	6.11	6.08	6.11	6.08
2014/2015	Mar	4.92	4.92	4.92	4.92	5.05	4.92	4.92	4.92	4.92	4.92	4.92
2014/2015	Apr	4.89	4.89	4.89	4.89	5.02	4.89	4.89	4.89	4.89	4.89	4.89
2014/2015	May	4.83	4.85	4.83	4.83	4.96	4.83	4.83	4.83	4.83	4.83	4.83
2014/2015	Jun	4.87	4.89	4.87	4.87	5.00	4.87	4.87	4.87	4.88	4.87	4.88
2014/2015	Jul	4.92	4.94	4.92	4.92	5.05	4.92	4.92	4.92	4.92	4.92	4.92
2014/2015	Aug	4.97	4.99	4.97	4.97	5.10	4.97	4.97	4.97	4.97	4.97	4.97
2014/2015	Sep	5.02	5.04	5.02	5.02	5.15	5.02	5.02	5.02	5.02	5.02	5.02
2014/2015	Oct	5.14	5.16	5.14	5.14	5.28	5.14	5.14	5.14	5.14	5.14	5.14
2014/2015	Annual Ave	5.07	5.09	5.07	5.07	5.10	5.08	5.07	5.08	5.07	5.08	5.07
	Winter Ave	5.23	5.25	5.25	5.24	5.12	5.26	5.23	5.27	5.25	5.27	5.25

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2015/2016	Nov	5.37	5.37	5.37	5.37	5.51	5.37	5.37	5.38	5.37	5.38	5.37
2015/2016	Dec	5.33	5.47	5.46	5.33	5.49	5.47	5.35	5.48	5.43	5.48	5.44
2015/2016	Jan	5.40	5.52	5.51	5.40	5.55	5.52	5.41	5.53	5.49	5.53	5.49
2015/2016	Feb	5.91	5.91	5.91	5.95	6.05	5.91	5.91	5.93	5.92	5.93	5.92
2015/2016	Mar	5.31	5.31	5.31	5.31	5.45	5.31	5.31	5.31	5.31	5.31	5.31
2015/2016	Apr	5.19	5.19	5.19	5.19	5.32	5.19	5.19	5.19	5.19	5.19	5.19
2015/2016	May	5.03	5.05	5.03	5.03	5.17	5.03	5.03	5.03	5.03	5.03	5.03
2015/2016	Jun	5.07	5.09	5.07	5.07	5.20	5.07	5.07	5.07	5.07	5.07	5.07
2015/2016	Jul	5.12	5.14	5.12	5.12	5.25	5.12	5.12	5.12	5.12	5.12	5.12
2015/2016	Aug	5.17	5.19	5.17	5.17	5.30	5.17	5.17	5.17	5.17	5.17	5.17
2015/2016	Sep	5.21	5.23	5.21	5.21	5.35	5.21	5.21	5.21	5.22	5.21	5.22
2015/2016	Oct	5.32	5.34	5.32	5.32	5.46	5.32	5.32	5.32	5.32	5.32	5.32
2015/2016	Annual Ave	5.28	5.31	5.30	5.29	5.42	5.30	5.29	5.31	5.30	5.31	5.30
	Winter Ave	5.46	5.51	5.51	5.47	5.61	5.51	5.46	5.52	5.50	5.52	5.50

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2016/2017	Nov	5.59	5.62	5.61	5.60	5.74	5.62	5.59	5.63	5.61	5.63	5.62
2016/2017	Dec	5.73	5.75	5.75	5.73	5.88	5.75	5.73	5.77	5.75	5.77	5.75
2016/2017	Jan	5.78	5.80	5.80	5.78	5.93	5.80	5.78	5.80	5.80	5.80	5.80
2016/2017	Feb	6.16	6.16	6.16	6.20	6.32	6.16	6.16	6.17	6.16	6.17	6.17
2016/2017	Mar	5.53	5.53	5.53	5.53	5.68	5.53	5.53	5.53	5.54	5.53	5.54
2016/2017	Apr	5.43	5.43	5.43	5.43	5.57	5.43	5.43	5.43	5.43	5.43	5.43
2016/2017	May	5.30	5.32	5.30	5.30	5.44	5.30	5.30	5.30	5.30	5.30	5.30
2016/2017	Jun	5.35	5.37	5.35	5.35	5.49	5.35	5.35	5.35	5.35	5.35	5.35
2016/2017	Jul	5.40	5.42	5.40	5.40	5.54	5.40	5.40	5.40	5.40	5.40	5.40
2016/2017	Aug	5.45	5.47	5.45	5.45	5.59	5.45	5.45	5.45	5.45	5.45	5.45
2016/2017	Sep	5.47	5.49	5.47	5.47	5.62	5.50	5.47	5.47	5.49	5.47	5.49
2016/2017	Oct	5.59	5.60	5.59	5.59	5.72	5.59	5.59	5.59	5.60	5.59	5.60
2016/2017	Annual Ave	5.56	5.58	5.57	5.57	5.71	5.57	5.56	5.57	5.57	5.57	5.57
	Winter Ave	5.75	5.77	5.76	5.76	5.90	5.77	5.75	5.78	5.76	5.78	5.77

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2017/2018	Nov	5.74	5.74	5.74	5.74	5.77	5.74	5.74	5.74	5.74	5.74	5.74
2017/2018	Dec	5.82	5.82	5.82	5.82	5.82	5.82	5.82	5.83	5.82	5.83	5.82
2017/2018	Jan	5.87	5.88	5.87	5.87	5.88	5.88	5.87	5.88	5.87	5.88	5.87
2017/2018	Feb	5.97	5.97	5.97	6.09	5.62	5.97	5.97	5.98	5.97	5.98	5.97
2017/2018	Mar	5.07	5.07	5.07	5.07	5.21	5.07	5.07	5.07	5.07	5.07	5.07
2017/2018	Apr	4.88	4.88	4.88	4.88	5.01	4.88	4.88	4.88	4.89	4.88	4.89

2017/2018	May	4.65	4.67	4.65	4.65	4.77	4.65	4.65	4.65	4.65	4.65	4.65
2017/2018	Jun	4.69	4.71	4.69	4.69	4.82	4.69	4.69	4.69	4.70	4.69	4.70
2017/2018	Jul	4.73	4.75	4.73	4.73	4.86	4.73	4.73	4.73	4.73	4.73	4.73
2017/2018	Aug	4.79	4.81	4.79	4.79	4.91	4.79	4.79	4.79	4.79	4.79	4.79
2017/2018	Sep	4.83	4.85	4.83	4.83	4.96	4.83	4.83	4.83	4.83	4.83	4.83
2017/2018	Oct	4.94	4.96	4.94	4.94	5.07	4.94	4.94	4.94	4.95	4.94	4.95
2017/2018	Annual Ave	5.16	5.17	5.16	5.17	5.22	5.16	5.16	5.16	5.16	5.16	5.16
	Winter Ave	5.69	5.69	5.69	5.71	5.66	5.69	5.69	5.69	5.69	5.69	5.69

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2018/2019	Nov	5.37	5.37	5.37	5.37	5.39	5.37	5.37	5.37	5.37	5.37	5.37
2018/2019	Dec	5.42	5.49	5.48	5.42	5.49	5.49	5.42	5.50	5.47	5.50	5.48
2018/2019	Jan	5.47	5.54	5.53	5.47	5.54	5.54	5.47	5.55	5.52	5.55	5.52
2018/2019	Feb	5.63	5.63	5.64	5.94	5.46	5.63	5.63	5.65	5.65	5.65	5.65
2018/2019	Mar	5.11	5.11	5.11	5.11	5.24	5.11	5.11	5.11	5.11	5.11	5.11
2018/2019	Apr	4.95	4.95	4.95	4.95	5.08	4.95	4.95	4.95	4.95	4.95	4.95
2018/2019	May	4.74	4.76	4.74	4.74	4.87	4.74	4.74	4.74	4.74	4.74	4.74
2018/2019	Jun	4.79	4.81	4.79	4.79	4.91	4.79	4.79	4.79	4.79	4.79	4.79
2018/2019	Jul	4.83	4.85	4.83	4.83	4.96	4.83	4.83	4.83	4.83	4.83	4.83
2018/2019	Aug	4.88	4.90	4.88	4.88	5.01	4.88	4.88	4.88	4.88	4.88	4.88
2018/2019	Sep	4.93	4.95	4.93	4.93	5.06	4.93	4.93	4.93	4.93	4.93	4.93
2018/2019	Oct	5.04	5.06	5.04	5.04	5.17	5.04	5.04	5.04	5.05	5.04	5.05
2018/2019	Annual Ave	5.09	5.12	5.10	5.12	5.18	5.11	5.09	5.11	5.11	5.11	5.11
	Winter Ave	5.40	5.43	5.42	5.45	5.43	5.43	5.40	5.43	5.42	5.43	5.42

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2019/2020	Nov	5.40	5.40	5.40	5.40	5.43	5.40	5.40	5.41	5.40	5.41	5.40
2019/2020	Dec	5.50	5.54	5.54	5.50	5.54	5.54	5.50	5.55	5.53	5.55	5.53
2019/2020	Jan	5.53	5.59	5.58	5.53	5.59	5.59	5.53	5.60	5.58	5.60	5.58
2019/2020	Feb	6.46	5.95	5.95	6.48	5.51	5.95	5.95	5.97	6.01	5.97	6.01
2019/2020	Mar	5.11	5.11	5.11	5.11	5.25	5.11	5.11	5.11	5.11	5.11	5.11
2019/2020	Apr	4.76	4.76	4.76	4.76	4.89	4.76	4.76	4.76	4.76	4.76	4.76
2019/2020	May	4.53	4.55	4.53	4.53	4.65	4.53	4.53	4.53	4.53	4.53	4.53
2019/2020	Jun	4.57	4.59	4.57	4.57	4.69	4.57	4.57	4.57	4.57	4.57	4.57
2019/2020	Jul	4.61	4.63	4.61	4.61	4.74	4.61	4.61	4.61	4.62	4.61	4.62
2019/2020	Aug	4.66	4.68	4.66	4.66	4.78	4.66	4.66	4.66	4.66	4.66	4.66
2019/2020	Sep	4.71	4.73	4.71	4.71	4.83	4.71	4.71	4.71	4.71	4.71	4.71
2019/2020	Oct	4.88	4.90	4.88	4.88	5.01	4.88	4.88	4.88	4.89	4.88	4.89
2019/2020	Annual Ave	5.06	5.03	5.02	5.06	5.08	5.02	5.01	5.03	5.03	5.03	5.03
	Winter Ave	5.59	5.52	5.51	5.60	5.46	5.52	5.49	5.52	5.52	5.52	5.52

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2020/2021	Nov	5.27	5.39	5.38	5.27	5.42	5.39	5.31	5.40	5.37	5.40	5.37
2020/2021	Dec	5.57	5.59	5.59	5.57	5.59	5.59	5.57	5.60	5.59	5.60	5.59
2020/2021	Jan	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.65	5.64	5.65	5.64
2020/2021	Feb	6.58	6.04	6.05	6.59	5.59	6.04	6.04	6.06	6.11	6.06	6.10
2020/2021	Mar	5.29	5.29	5.29	5.29	5.43	5.29	5.29	5.29	5.29	5.29	5.29
2020/2021	Apr	5.10	5.10	5.10	5.10	5.24	5.10	5.10	5.10	5.10	5.10	5.10
2020/2021	May	4.90	4.92	4.90	4.90	5.03	4.90	4.90	4.90	4.90	4.90	4.90
2020/2021	Jun	4.95	4.97	4.95	4.95	5.08	4.95	4.95	4.95	4.95	4.95	4.95
2020/2021	Jul	4.99	5.01	4.99	4.99	5.13	4.99	4.99	4.99	5.00	4.99	5.00
2020/2021	Aug	5.04	5.06	5.04	5.04	5.17	5.04	5.04	5.04	5.04	5.04	5.04
2020/2021	Sep	5.09	5.11	5.09	5.09	5.22	5.09	5.09	5.09	5.09	5.09	5.09
2020/2021	Oct	5.17	5.19	5.17	5.17	5.30	5.17	5.17	5.17	5.17	5.17	5.17
2020/2021	Annual Ave	5.29	5.27	5.26	5.29	5.32	5.26	5.25	5.26	5.27	5.26	5.27
	Winter Ave	5.65	5.58	5.58	5.66	5.53	5.58	5.56	5.59	5.59	5.59	5.59

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2021/2022	Nov	5.58	5.60	5.59	5.58	5.64	5.60	5.59	5.61	5.60	5.61	5.60
2021/2022	Dec	5.74	5.77	5.77	5.74	5.77	5.77	5.74	5.78	5.76	5.78	5.76
2021/2022	Jan	5.82	5.82	5.82	5.82	5.82	5.82	5.82	5.83	5.82	5.83	5.82
2021/2022	Feb	6.74	6.20	6.21	6.76	5.76	6.20	6.20	6.22	6.27	6.22	6.27
2021/2022	Mar	5.39	5.39	5.39	5.39	5.53	5.39	5.39	5.39	5.39	5.39	5.39
2021/2022	Apr	5.21	5.21	5.21	5.21	5.34	5.21	5.21	5.21	5.21	5.21	5.21
2021/2022	May	5.00	5.02	5.00	5.00	5.13	5.00	5.00	5.00	5.00	5.00	5.00
2021/2022	Jun	5.04	5.06	5.04	5.04	5.18	5.04	5.04	5.04	5.05	5.04	5.05
2021/2022	Jul	5.09	5.11	5.09	5.09	5.23	5.09	5.09	5.09	5.09	5.09	5.09
2021/2022	Aug	5.14	5.16	5.14	5.14	5.28	5.14	5.14	5.14	5.14	5.14	5.14
2021/2022	Sep	5.19	5.21	5.19	5.19	5.33	5.19	5.19	5.19	5.19	5.19	5.19
2021/2022	Oct	5.31	5.33	5.31	5.31	5.45	5.31	5.31	5.31	5.31	5.31	5.31
2021/2022	Annual Ave	5.43	5.40	5.39	5.43	5.45	5.39	5.39	5.40	5.40	5.40	5.40
	Winter Ave	5.84	5.75	5.75	5.84	5.70	5.75	5.74	5.76	5.76	5.76	5.76

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2022/2023	Nov	5.76	5.81	5.80	5.76	5.85	5.81	5.77	5.82	5.80	5.82	5.80
2022/2023	Dec	5.96	6.00	5.99	5.96	6.00	6.00	5.96	6.01	5.99	6.01	5.99
2022/2023	Jan	6.05	6.05	6.05	6.05	6.05	6.05	6.05	6.06	6.05	6.06	6.05
2022/2023	Feb	6.88	6.35	6.35	6.89	5.90	6.35	6.35	6.36	6.41	6.36	6.41
2022/2023	Mar	5.35	5.35	5.35	5.35	5.49	5.35	5.35	5.35	5.35	5.35	5.35
2022/2023	Apr	5.20	5.20	5.20	5.20	5.33	5.20	5.20	5.20	5.20	5.20	5.20

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2022/2023	May	5.00	5.02	5.00	5.00	5.13	5.00	5.00	5.00	5.00	5.00	5.00
2022/2023	Jun	5.04	5.06	5.04	5.04	5.17	5.04	5.04	5.04	5.04	5.04	5.04
2022/2023	Jul	5.08	5.10	5.08	5.08	5.22	5.08	5.08	5.08	5.09	5.08	5.09
2022/2023	Aug	5.14	5.16	5.14	5.14	5.27	5.14	5.14	5.14	5.14	5.14	5.14
2022/2023	Sep	5.19	5.21	5.19	5.19	5.32	5.19	5.19	5.19	5.19	5.19	5.19
2022/2023	Oct	5.32	5.34	5.32	5.32	5.46	5.32	5.32	5.32	5.32	5.32	5.32
2022/2023	Annual Ave	5.49	5.46	5.45	5.49	5.51	5.45	5.45	5.46	5.46	5.46	5.46
	Winter Ave	5.98	5.90	5.90	5.99	5.86	5.90	5.89	5.91	5.91	5.91	5.91

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2023/2024	Nov	5.74	5.75	5.75	5.74	5.79	5.76	5.74	5.76	5.75	5.76	5.75
2023/2024	Dec	5.87	5.93	5.92	5.87	5.93	5.93	5.87	5.94	5.91	5.94	5.92
2023/2024	Jan	5.98	5.98	5.98	5.98	5.98	5.98	5.98	5.99	5.98	5.99	5.98
2023/2024	Feb	6.93	6.42	6.42	6.94	5.99	6.42	6.42	6.43	6.48	6.43	6.48
2023/2024	Mar	5.73	5.73	5.73	5.73	5.88	5.73	5.73	5.73	5.73	5.73	5.73
2023/2024	Apr	5.49	5.49	5.49	5.49	5.63	5.49	5.49	5.49	5.49	5.49	5.49
2023/2024	May	5.27	5.29	5.27	5.27	5.41	5.27	5.27	5.27	5.28	5.27	5.28
2023/2024	Jun	5.32	5.34	5.32	5.32	5.46	5.32	5.32	5.32	5.32	5.32	5.32
2023/2024	Jul	5.37	5.39	5.37	5.37	5.51	5.37	5.37	5.37	5.37	5.37	5.37
2023/2024	Aug	5.42	5.44	5.42	5.42	5.56	5.42	5.42	5.42	5.42	5.42	5.42
2023/2024	Sep	5.47	5.49	5.47	5.47	5.62	5.47	5.47	5.47	5.47	5.47	5.47
2023/2024	Oct	5.59	5.61	5.59	5.59	5.73	5.59	5.59	5.59	5.59	5.59	5.59
2023/2024	Annual Ave	5.68	5.65	5.64	5.68	5.71	5.64	5.64	5.65	5.65	5.65	5.65
	Winter Ave	6.04	5.96	5.96	6.04	5.91	5.96	5.94	5.97	5.97	5.97	5.97

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2024/2025	Nov	5.95	6.03	6.02	5.95	6.06	6.03	5.97	6.04	6.01	6.04	6.01
2024/2025	Dec	6.21	6.21	6.21	6.21	6.21	6.21	6.21	6.21	6.21	6.21	6.21
2024/2025	Jan	6.19	6.26	6.25	6.19	6.26	6.26	6.19	6.27	6.24	6.27	6.24
2024/2025	Feb	6.83	6.30	6.30	7.06	6.43	6.30	6.30	6.31	6.39	6.31	6.38
2024/2025	Mar	5.82	5.82	5.82	5.82	5.97	5.82	5.82	5.82	5.82	5.82	5.82
2024/2025	Apr	5.78	5.78	5.78	5.78	5.93	5.78	5.78	5.78	5.78	5.78	5.78
2024/2025	May	5.76	5.78	5.76	5.76	5.92	5.76	5.76	5.76	5.77	5.76	5.77
2024/2025	Jun	5.78	5.78	5.78	5.78	5.93	5.78	5.78	5.78	5.78	5.78	5.78
2024/2025	Jul	5.86	5.88	5.86	5.86	6.02	5.86	5.86	5.86	5.87	5.86	5.87
2024/2025	Aug	5.92	5.94	5.92	5.92	6.07	5.92	5.92	5.92	5.92	5.92	5.92
2024/2025	Sep	5.97	5.99	5.97	5.97	6.12	5.97	5.97	5.97	5.97	5.97	5.97
2024/2025	Oct	6.09	6.09	6.09	6.09	6.25	6.09	6.09	6.09	6.09	6.09	6.09
2024/2025	Annual Ave	6.01	5.99	5.98	6.02	6.09	5.98	5.97	5.98	5.98	5.98	5.98
	Winter Ave	6.19	6.12	6.12	6.23	6.18	6.12	6.09	6.13	6.13	6.13	6.13

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2025/2026	Nov	6.45	6.57	6.56	6.46	6.60	6.57	6.48	6.58	6.54	6.58	6.54
2025/2026	Dec	6.69	6.75	6.74	6.69	6.75	6.75	6.69	6.76	6.73	6.76	6.74
2025/2026	Jan	6.80	6.81	6.81	6.80	6.81	6.81	6.80	6.82	6.81	6.82	6.81
2025/2026	Feb	7.65	7.12	7.12	7.66	7.26	7.12	7.12	7.14	7.19	7.14	7.18
2025/2026	Mar	6.23	6.23	6.23	6.23	6.39	6.23	6.23	6.23	6.23	6.23	6.23
2025/2026	Apr	6.10	6.10	6.10	6.10	6.26	6.10	6.10	6.10	6.11	6.10	6.11
2025/2026	May	5.95	5.97	5.95	5.95	6.11	5.95	5.95	5.95	5.96	5.95	5.96
2025/2026	Jun	6.01	6.01	6.01	6.01	6.16	6.01	6.01	6.01	6.01	6.01	6.01
2025/2026	Jul	6.06	6.07	6.06	6.06	6.22	6.06	6.06	6.06	6.06	6.06	6.06
2025/2026	Aug	6.10	6.11	6.10	6.10	6.26	6.10	6.10	6.10	6.10	6.10	6.10
2025/2026	Sep	6.16	6.18	6.16	6.16	6.32	6.16	6.16	6.16	6.16	6.16	6.16
2025/2026	Oct	6.22	6.22	6.22	6.22	6.38	6.22	6.22	6.22	6.22	6.22	6.22
2025/2026	Annual Ave	6.36	6.34	6.33	6.36	6.45	6.33	6.32	6.34	6.34	6.34	6.34
	Winter Ave	6.75	6.69	6.68	6.75	6.75	6.69	6.65	6.70	6.69	6.70	6.69

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2026/2027	Nov	6.59	6.75	6.73	6.60	6.78	6.75	6.64	6.75	6.71	6.75	6.72
2026/2027	Dec	6.87	6.96	6.95	6.87	6.95	6.96	6.87	6.97	6.93	6.97	6.94
2026/2027	Jan	7.01	7.01	7.01	7.01	7.01	7.01	7.01	7.03	7.01	7.03	7.01
2026/2027	Feb	7.75	7.22	7.23	7.76	7.37	7.22	7.22	7.24	7.29	7.24	7.29
2026/2027	Mar	6.26	6.26	6.26	6.26	6.42	6.26	6.26	6.26	6.26	6.26	6.26
2026/2027	Apr	6.18	6.18	6.18	6.18	6.34	6.18	6.18	6.18	6.18	6.18	6.18
2026/2027	May	6.03	6.05	6.03	6.03	6.19	6.03	6.03	6.03	6.04	6.03	6.04
2026/2027	Jun	6.08	6.08	6.08	6.08	6.24	6.08	6.08	6.08	6.09	6.08	6.09
2026/2027	Jul	6.14	6.15	6.14	6.14	6.30	6.14	6.14	6.14	6.14	6.14	6.14
2026/2027	Aug	6.19	6.19	6.19	6.19	6.35	6.19	6.19	6.19	6.19	6.19	6.19
2026/2027	Sep	6.24	6.26	6.24	6.24	6.40	6.24	6.24	6.24	6.24	6.24	6.24
2026/2027	Oct	6.33	6.33	6.33	6.33	6.49	6.33	6.33	6.33	6.33	6.33	6.33
2026/2027	Annual Ave	6.46	6.45	6.44	6.47	6.56	6.44	6.43	6.45	6.45	6.45	6.45
	Winter Ave	6.88	6.83	6.83	6.89	6.90	6.83	6.79	6.84	6.83	6.84	6.83

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2027/2028	Nov	6.73	6.89	6.87	6.74	6.92	6.89	6.78	6.89	6.85	6.89	6.86
2027/2028	Dec	7.02	7.10	7.10	7.02	7.10	7.10	7.02	7.12	7.08	7.12	7.08
2027/2028	Jan	7.15	7.16	7.16	7.15	7.16	7.16	7.15	7.17	7.16	7.17	7.16
2027/2028	Feb	7.86	7.35	7.36	7.87	7.50	7.35	7.35	7.37	7.42	7.37	7.42
2027/2028	Mar	6.35	6.35	6.35	6.35	6.51	6.35	6.35	6.35	6.35	6.35	6.35
2027/2028	Apr	6.26	6.26	6.26	6.26	6.42	6.26	6.26	6.26	6.26	6.26	6.26

2027/2028	May	6.14	6.16	6.14	6.14	6.30	6.14	6.14	6.14	6.15	6.14	6.14
2027/2028	Jun	6.18	6.18	6.18	6.18	6.34	6.18	6.18	6.18	6.18	6.18	6.18
2027/2028	Jul	6.25	6.25	6.25	6.25	6.41	6.25	6.25	6.25	6.25	6.25	6.25
2027/2028	Aug	6.30	6.30	6.30	6.30	6.46	6.30	6.30	6.30	6.30	6.30	6.30
2027/2028	Sep	6.35	6.37	6.35	6.35	6.52	6.35	6.35	6.35	6.36	6.35	6.36
2027/2028	Oct	6.42	6.42	6.42	6.42	6.59	6.42	6.42	6.42	6.42	6.42	6.42
2027/2028	Annual Ave	6.58	6.56	6.56	6.58	6.68	6.56	6.54	6.56	6.56	6.56	6.56
	Winter Ave	7.01	6.97	6.96	7.02	7.03	6.97	6.93	6.98	6.97	6.98	6.97

Gas Year	Month	Albany	Astoria	Dalles (OR)	Eugene Coos Bay	Newport Lincoln City	Portland	Salem	Vancouver Dalles WA	OR	WA	System
2028/2029	Nov	6.87	7.03	7.02	6.89	7.07	7.03	6.93	7.04	7.00	7.04	7.00
2028/2029	Dec	7.16	7.24	7.24	7.16	7.24	7.24	7.16	7.26	7.22	7.26	7.23
2028/2029	Jan	7.28	7.30	7.30	7.28	7.30	7.30	7.28	7.32	7.30	7.32	7.30
2028/2029	Feb	8.10	7.57	7.57	8.10	7.72	7.57	7.57	7.59	7.64	7.59	7.64
2028/2029	Mar	6.57	6.57	6.57	6.57	6.74	6.57	6.57	6.57	6.58	6.57	6.57
2028/2029	Apr	6.55	6.55	6.55	6.55	6.72	6.55	6.55	6.55	6.55	6.55	6.55
2028/2029	May	6.40	6.42	6.40	6.40	6.56	6.40	6.40	6.40	6.40	6.40	6.40
2028/2029	Jun	6.44	6.44	6.44	6.44	6.61	6.44	6.44	6.44	6.44	6.44	6.44
2028/2029	Jul	6.50	6.50	6.50	6.50	6.67	6.50	6.50	6.50	6.51	6.50	6.51
2028/2029	Aug	6.56	6.56	6.56	6.56	6.73	6.56	6.56	6.56	6.56	6.56	6.56
2028/2029	Sep	6.61	6.63	6.61	6.61	6.78	6.61	6.61	6.61	6.61	6.61	6.61
2028/2029	Oct	6.67	6.67	6.67	6.67	6.84	6.67	6.67	6.67	6.68	6.67	6.68
2028/2029	Annual Ave	6.80	6.79	6.78	6.80	6.91	6.78	6.77	6.79	6.79	6.79	6.79
	Winter Ave	7.18	7.14	7.13	7.19	7.21	7.14	7.09	7.15	7.14	7.15	7.14

Appendix 7: Public Participation

NW Natural – 2011 IRP Technical Working Group Meeting
February 24, 2010

Name	Company	Email
LISA GORSUCH	OPUC STAFF (503)378-3778	lisa.gorsuch@state.or.us
MOSHREK SOBHY	OPUC STAFF	moshrek.sobhy@state.or.us
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Steve Weiss	NW Energy Coalition	Steve@nwenergy.org
Ryan Dyer	Wash. U.T.C.	rdyer@utc.wa.gov
Deborah Reynolds	Washington UTC	dreynold@utc.wa.gov
Ken Zimmerman	Oregon PUC	Ken.Zimmerman@state.or.us
Teresa Hagins	Northwest Pipeline GP	Teresa.L.Hagins@williams.com
Jane Harrison - not at meeting	Northwest Pipeline GP	Jane.F.Harrison@williams.com
Mark Sellers-Vaughn	Cascade Natural Gas	mark.sellers-vaughn@cngc.com
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Dan Kirschner	NWGA	dkirschner@nwga.org
ROGER HALEY	NW NAT.	rmh@nwnatural.com
MARGARET LOCKE	NW NAT.	MLL@ " ABSENT
KERRY SHAMPINE	"	KFS@ " ABSENT
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NW Natural – 2011 IRP Technical Working Group Meeting
May 17, 2010

Name	Company	Email
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Ken Zimmerman	OPUC	
Vanda Novak	UTC WA	
Kip Pheil	ODOE	

NW Natural – 2011 Integrated Resource Plan (IRP) Technical Working Group Meeting
July 28, 2010

NAME - please print	Company	Email
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RUBER Haley	NW NATURAL	
Margaret Locke	NW NATURAL	
Randy Friedman	NW Natural	
Jon Huddleston	NW Natural	

NW Natural – 2011 Integrated Resource Plan (IRP) Technical Working Group Meeting
November 3, 2010

NAME - please print	Company	Email
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Deborah Reynolds	WUTC	

NW Natural's TWG - June 22, 2011

Name	Company	email
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On the phone:		
Bob Jenks	CUB	

NW NATURAL'S 2011 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: June 17
Time: 6pm to 7pm
Place: One Pacific Square, 4th Floor Hospitality Room East
220 NW Second Avenue, Portland, Oregon
(accessible by MAX)

Unable to Attend?
We can email a PowerPoint presentation to you.
Send your email request to IRPlan@nwnatural.com.

NW Natural®
We grew up here.

You may also mail any questions or comments about the plan to:

NW Natural
Attn: Integrated Resource Plan
220 NW Second Avenue
Portland, OR 97209

A copy of the draft 2011 Integrated Resource Plan will be available on our Web site after October 4, 2010. Go to **www.nwnatural.com**. Click on the *About Us* link, then click on *Rates and Regulations*, then click on *Regulatory Affairs*. Toward the bottom half of the page is a link for the *Integrated Resource Plan*.

April 30, 2010

NW Natural Gas
ATTN: INTEGRATED RESOURCE PLAN
230 NW Second Avenue
Portland, OR 97209

COMMENTARY:

As a long-time NNW customer, I have been pleased with natural gas and have felt that NNG has dealt fairly with its customers over the years.

I AM EMPHATICALLY IN FAVOR OF A LIQUID NATURAL GAS FACILITY IN OREGON—AND IN THE LOCATION THAT NNG HAS CHOSEN. THE SOONER, THE BETTER.

IT IS DISGUSTING THAT NATIONAL POLITICIANS AND STATE OF OREGON AND REGIONAL POLITICIANS ARE TRYING TO BLOCK AND BADMOUTH THIS PROJECT AND RESOURCE.

THE LNG FACILITY IS IMPORTANT TO THE STATE OF OREGON FROM THE ECONOMIC DEVELOPMENT AND JOBS STANDPOINT, AS WELL AS FROM AN ENERGY RESOURCE FOR OREGONIANS.

I am tired of hearing about all this electric car nonsense. It is fine for golf carts and limited mobility. The technology is not here yet, and the cost and maintenance (not to mention the environmental disposal issues of batteries) would be exceptionally high. With excellent electricity resources being eliminated for political reasons, the cost of electricity will only go up.

Tri-Met has had a few buses over the years that operated on natural gas. Light Rail is an expensive boondoggle that has also killed and maimed many local residents. Tri-Met could have saved taxpayers a huge amount of money over time by converting al buses to natural gas, and using natural-gas-run, 15-passenger vans for Downtown and short-term shuttles instead of incredibly expensive street cars—or for handicapped transport instead of the current options. All city, county and state vehicles could have been converted to natural gas.

Instead, all we have had is boondoggles (with huge government bureaucracies) that have saddled and will continue to saddle taxpayers with huge bills.

PLEASE ENSURE THAT THE LNG FACILITY IS BUILT IN OREGON, AT YOUR DESIGNATED SITE.

NW Natural – 2011 Integrated Resource Plan (IRP) Public Participation Meeting
June 17, 2010 - 6 p.m. to 7 p.m.

NAME - please print	NW Natural Customer Yes or No	Email
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Kyra Plume	Yes	standingbesideamountain@gmail.com
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