NW Natural

2009 Integrated Resource Plan

Executive Summary and Multi-Year Action Plan Technical Appendix

March 2009

2009 Integrated Resource Plan

Chapter 1:

Executive Summary and
Multi-Year Action Plan

The Washington Utilities and Transportation Commission (WUTC) requires NW Natural (NW Natural or the Company) to develop a Integrated Resource Plan (IRP or Plan) that describes "the strategies for purchasing gas and improving the efficiencies of gas use that will meet current and future needs at the lowest reasonable cost to the utility and its ratepayers consistent with needs for security of supply."[1] Typically, a Plan must be filed with the Commission within two years of the date of the filing of the previous plan.[2]

NW Natural filed its previous IRP with the WUTC on March 28, 2007. However, after significant staffing changes and improvements in the Company's planning resources, the Company also filed a complete update to the 2007 IRP in April of 2008. The Commission reviewed the Company's 2007 IRP, and the 2008 Update, in 2008. On October 9, 2008, the Company received a letter stating that the Commission found that, "as a whole" the Plan met the requirements of WAC 480-90-238.

Due the unusual procedural posture of the 2007 IRP, this 2009 IRP has proceeded on a compressed timeline. Some items identified for consideration by the Commission in its letter of October 9, and by the Technical Working Group in meetings regarding this 2009 IRP, have been addressed directly, while others, which required a longer timeframe to conclude, have been included as action items for the Company's 2011 IRP.

This Executive Summary provides an overview of NW Natural's key findings in its 2009 IRP and includes a multi-year action plan. The Appendix to this Executive Summary provides a description of the steps taken since the last Plan, and includes a detailed analysis of the IRP rules at WAC 480-90-238 and how this Plan meets those requirements.

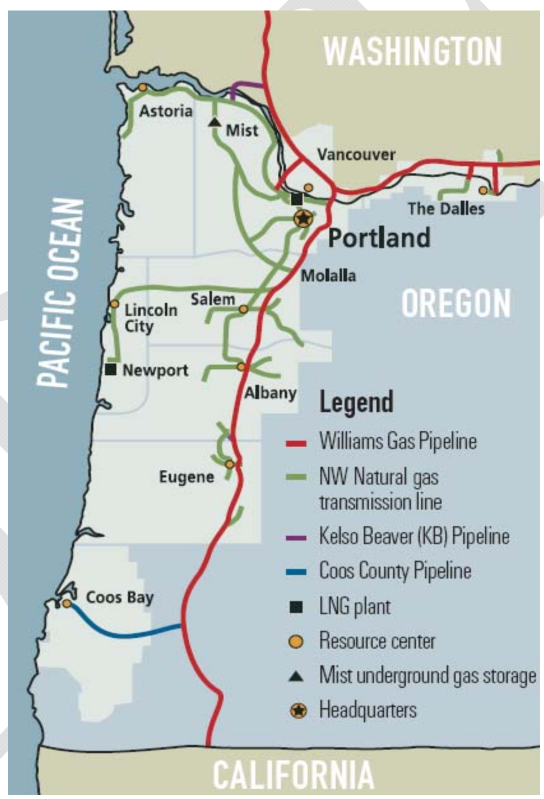
[1] WAC 480-90-238(2)(a).
[2] WAC 480-90-238(4).

I. INTRODUCTION & BACKGROUND

A. Description of NW Natural

NW Natural is headquartered in Portland, Oregon. The Company currently serves approximately 662,341 residential, commercial and industrial customers in Oregon and southwest Washington; approximately 67,404 or 10.18% are in the Company's Washington service territory. NW Natural's service territory includes the Portland-Vancouver metropolitan area, the Willamette Valley, the Oregon coast – from Astoria down through Coos County, and the Columbia River Gorge. NW Natural's southwest Washington service territory covers portions of Clark, Skamania and Klickitat counties.

FIGURE ES-1



B. Overview of Integrated Resource Planning

Integrated Resource Planning is unique to regulated utilities. In Washington, administrative rules note that the Company has a responsibility to meet its system demand at the "lowest reasonable cost" to the utility and its customers.[3] The purpose of the IRP is to develop strategies for purchasing gas and improving efficiencies of gas

3 *See* WAC 480-90-238(1).

use to meet current and future needs, consistent with this "lowest reasonable cost" approach.[4]

At a minimum, the Plan must include: 1) a range of demand forecasts; 2) assessment of energy efficiency improvements for each customer classes, including an assessment of currently employed and new policies and programs needed to obtain the improvements; 3) an analysis of gas supply options; 4) an analysis of gas purchasing options, with and without explicit consideration of supply and market risks and improvements in the efficient use of gas; 5) the integration of demand forecasts and resource evaluations into a long-range plan; 6) a short-term plan with specific actions toward implementing the long-range plan.[5]

II. PRINCIPAL CONCLUSIONS FROM THIS PLAN

NW Natural operates its system as an integrated whole, and as such it would be impossible to model strategies for purchasing gas or improving efficiencies of gas use on a state-by-state basis. However, not all resources are necessary or available to meet the needs of Washington customers. With this in mind, while the Company compiles and analyzes system-wide data, it also considers data at the state and regional level, and sets rates on a state-by-state basis. The Company has made every effort to present data in this plan both at the system level and the state level.

The Company has come to the following principal conclusions from this Plan, as it specifically relates to its Washington customers:

1. The current economic recession has significantly affected NW Natural. While the Company's Washington customer base continues to grow at 3.4 percent annually over the twenty-year planning horizon, near-term customer demand has dropped off sharply, requiring less resources to meet demand than previously anticipated.

2. On a system wide basis, we now predict the Company's total customer base to grow at 2.4 percent over the planning horizon; as we finalize our demand forecast to reflect current economic conditions, we believe this number may decline further. Although this is a lower level of growth than that predicted in the 2007 IRP, we continue to see rising peak day (1.3 percent) and annual (1.7 percent) gas requirements.

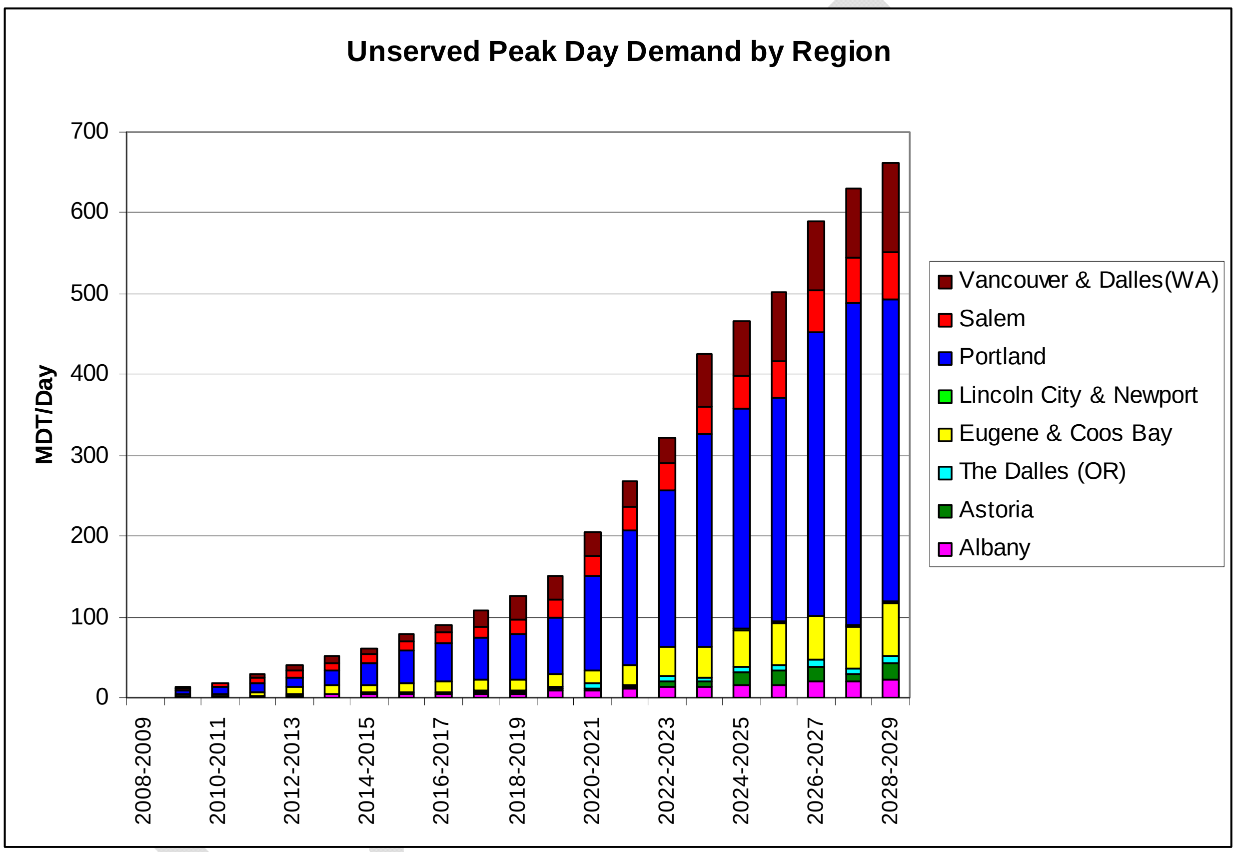
3. In the 2007 IRP, the Company selected an 85 percent probability coldest winter augmented by a three-day peak event as its planning standard against which to evaluate the cost and risk trade off of various supply and demand resources available to *SENDOUT*®. Upon further review of this standard, we continue to believe it provides the best risk/cost ratio for our customers, and meets the requirement that we provide security of supply at the "lowest reasonable cost."

4 *See* WAC 480-90-238(2)(a).
5 *See* WAC 480-90-238(3).

4. Even with lower demand forecasts, we continue to find that the Company's existing resources are not sufficient to fully satisfy peak day demand.

   Figure ES-2 demonstrates the inability of the Company's existing resources to meet projected loads. Peak day resource deficiencies occur in all regions except Newport, totaling about 13 MDT in 2009-2010, and rising to 506 MDT by the end of the planning horizon.

Figure ES-2



   Annual unserved demand is forecast to increase from MDT in 2009-2010 year to 4,454 MDT by 2028-2029.

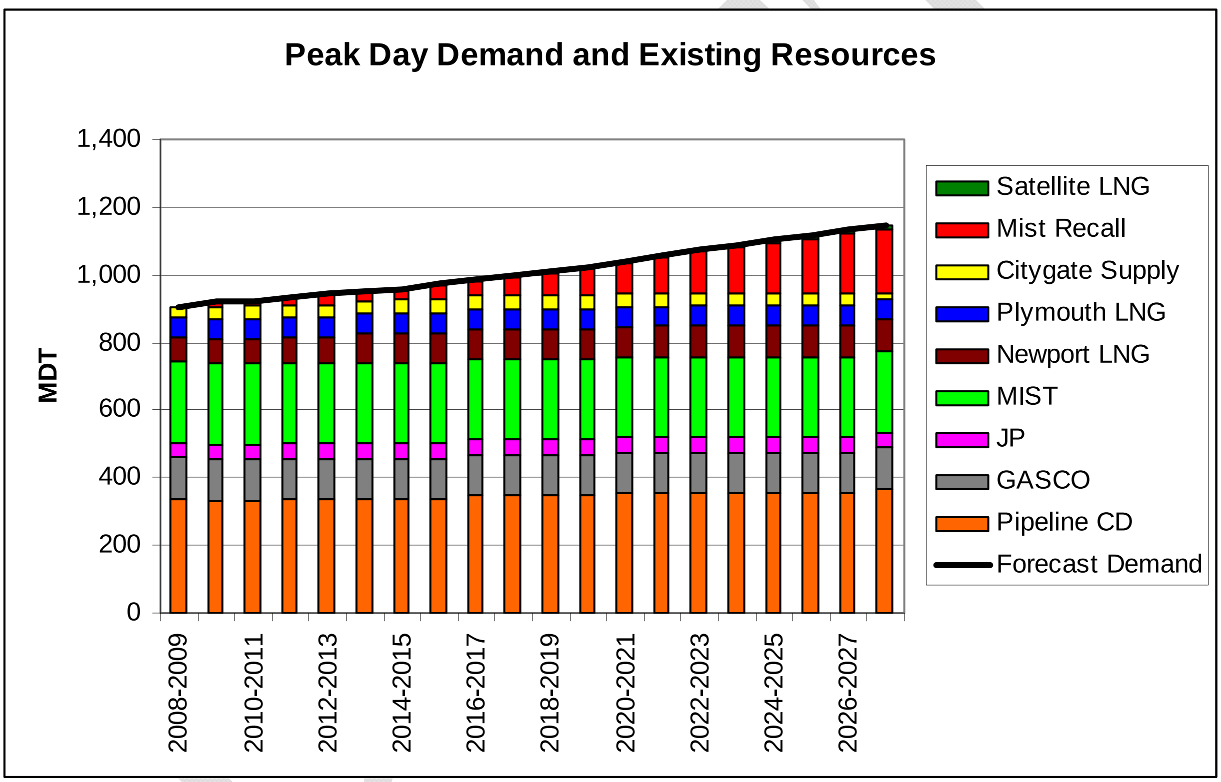
5. The Company's Preferred Portfolio addresses the forecast unserved demand. The Company's Preferred incremental resource portfolio includes both demand and supply side resources. By the final year of the 20-year planning horizon, the Preferred Portfolio includes an aggregate level of design weather adjusted DSM savings in Washington of 863 MDT.

6. To serve the Company's Washington customers, the Preferred Portfolio also includes incremental Mist recall, and capacity on the Palomar Pipeline. As a result of current economic conditions, the company has reduced its near-term

demand forecast, and now predicts a need for less Mist Recall than was called for in the previous IRP.

Figure ES-3 summarizes the blend of supply-side resources selected to satisfy the Company's Preferred Portfolio 20-year peak day demand forecast (net of DSM), on a system-wide basis. The new resources selected for addition to NW Natural's existing portfolio include capacity on the Palomar Pipeline, NW Natural distribution investment, and the recall of existing Mist underground storage resources to core-market service. As noted in (5) above, however, only the incremental Mist recall and a portion of the capacity on the Palomar Pipeline will be allocated to serve Washington customers. These supply-side resources are discussed more fully in Chapters 3 and 5.

FIGURE ES-3



III. LOAD FORECASTS

To determine the energy requirements for the Company's service area, NW Natural must generate a load forecast. The load forecast is not intended to predict actual usage during an average or normal winter; rather, it is a load forecast given the design weather characteristics used in the IRP process.

The first step in developing our load forecast is to identify the characteristics of our customer base. This includes the number and types of current customers, the amount of customer growth anticipated in the region, and the amount and pattern of gas usage expected by those customers.

For this 2009 IRP, a new customer count forecast was built based on internal business intelligence, information from the credit and building communities, the State of Oregon Economic Forecast, and Clark County WA housing permit information. Following feedback from the WUTC in response to our 2007 IRP and from the TWG, two separate forecasts, generated with differing methodologies, were compared for NWN's Washington customers. The first used the State of Oregon's Housing Starts Forecast; the second was based on historic Clark County permit data and population growth estimates, as a housing starts forecast for Clark County was not available. The forecasts drove to similar customer count projections over the planning horizon. However, the Portland/Oregon housing starts-based forecast was judged to be more appropriate since it reflected the expected downturn in new construction from the on-going recession more distinctly. The Company did consider a housing starts forecast for Washington state, but found that historic Vancouver new customer additions correlated better to Oregon housing starts.

Once the Company generates a customer count forecast and usage per customer forecast, it incorporates design year weather temperatures to generate a complete load forecast. The Company's load forecast incorporates design year temperatures based on an 85% probability coldest winter and the highest three-day peak load event over the past twenty years. In addition, the Company utilizes stochastic modeling to assess the performance of its selected gas supply portfolio under a range of temperature and price conditions.

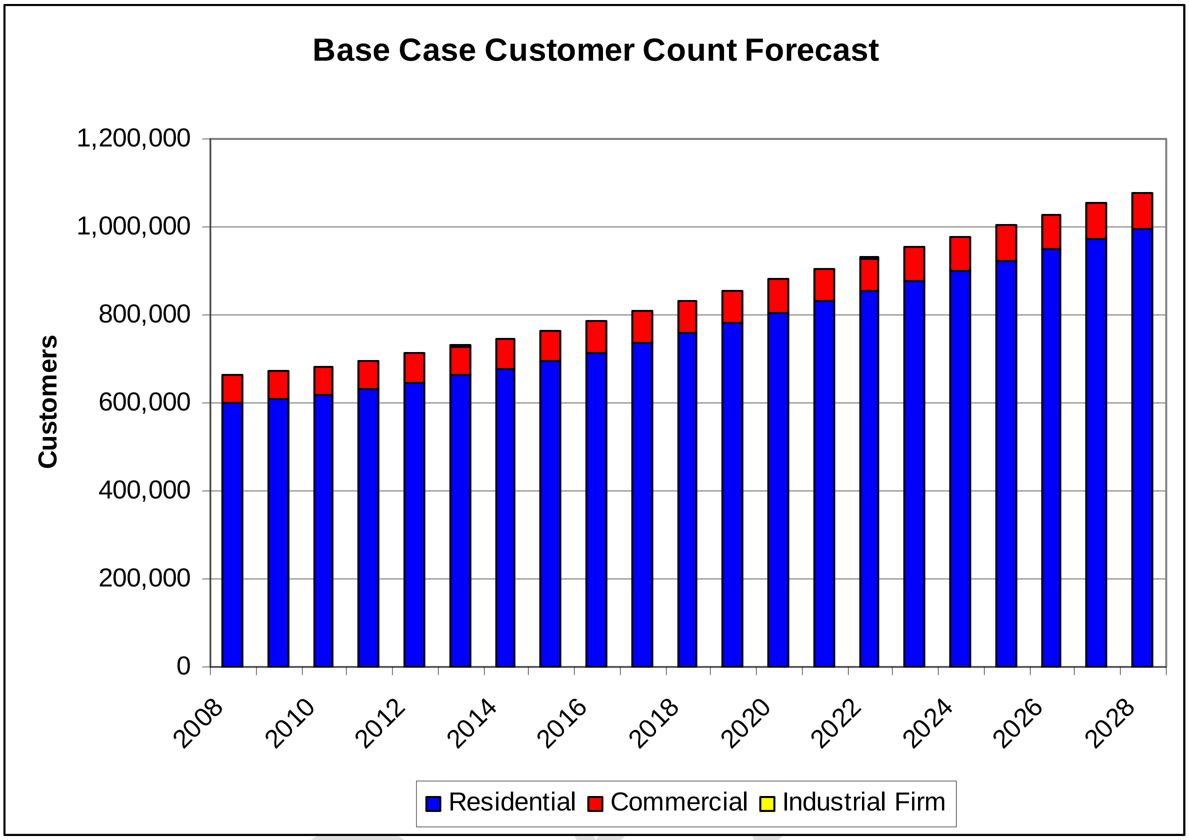
The Company has come to the following principal conclusions from this Plan with regard to load forecasts, as they specifically relate to its Washington customers:

1. Current economic conditions have significantly impacted load forecasts and slowed growth across NWN's system, including in its Washington service territory.

2. During the next 20 years, the Company forecasts a 3.4 percent annual growth in the number of Washington core customers. However, due to the current economic recession, growth rates are substantially different in the near-term. Customer growth is expected to remain under 2% until the year 2012. The Company continues to examine this demand forecast in light of current economic conditions, and may further reduce its demand forecast for the final IRP.

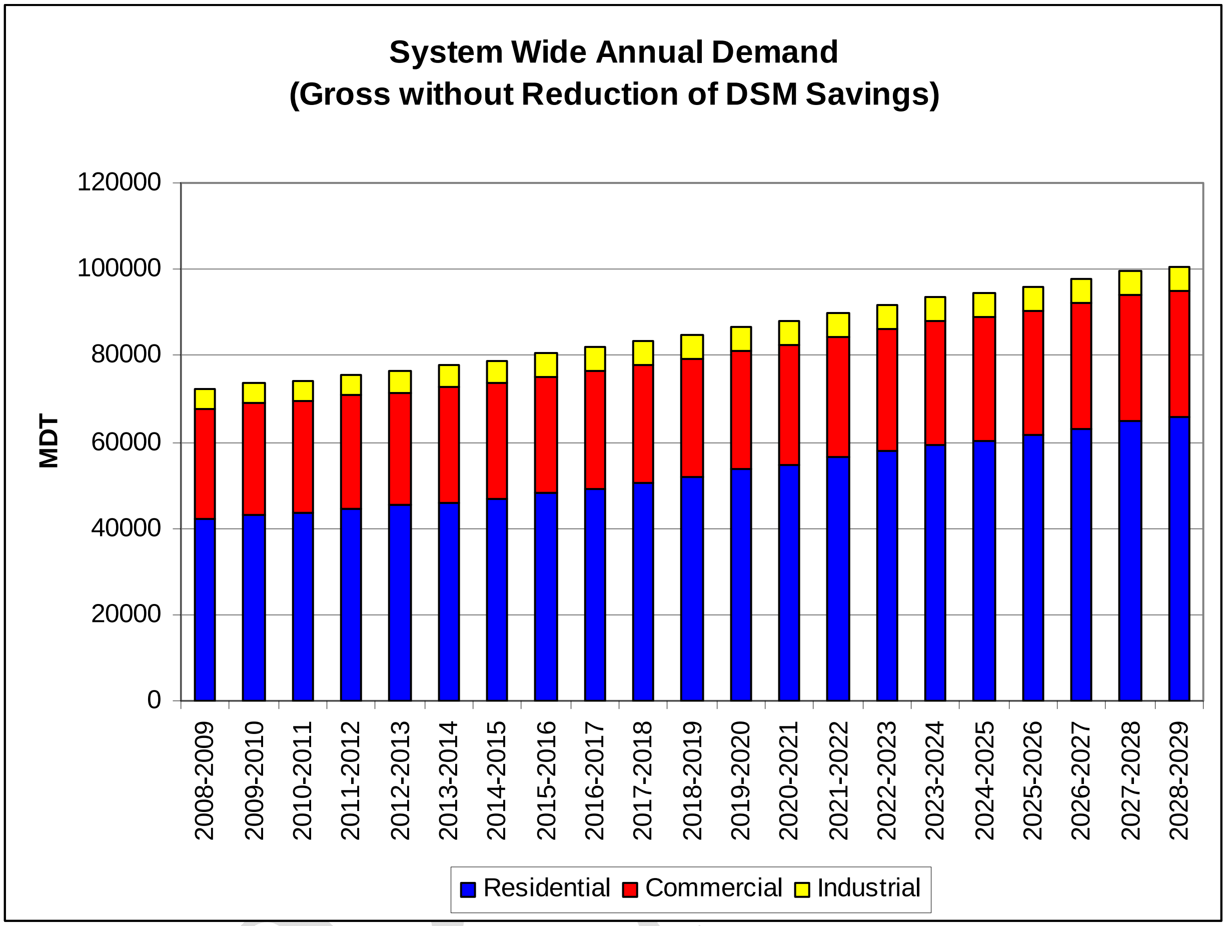
3. During the next 20 years, the Company forecasts a 2.4 percent annual growth in the number of system-wide core customers.

FIGURE ES-4



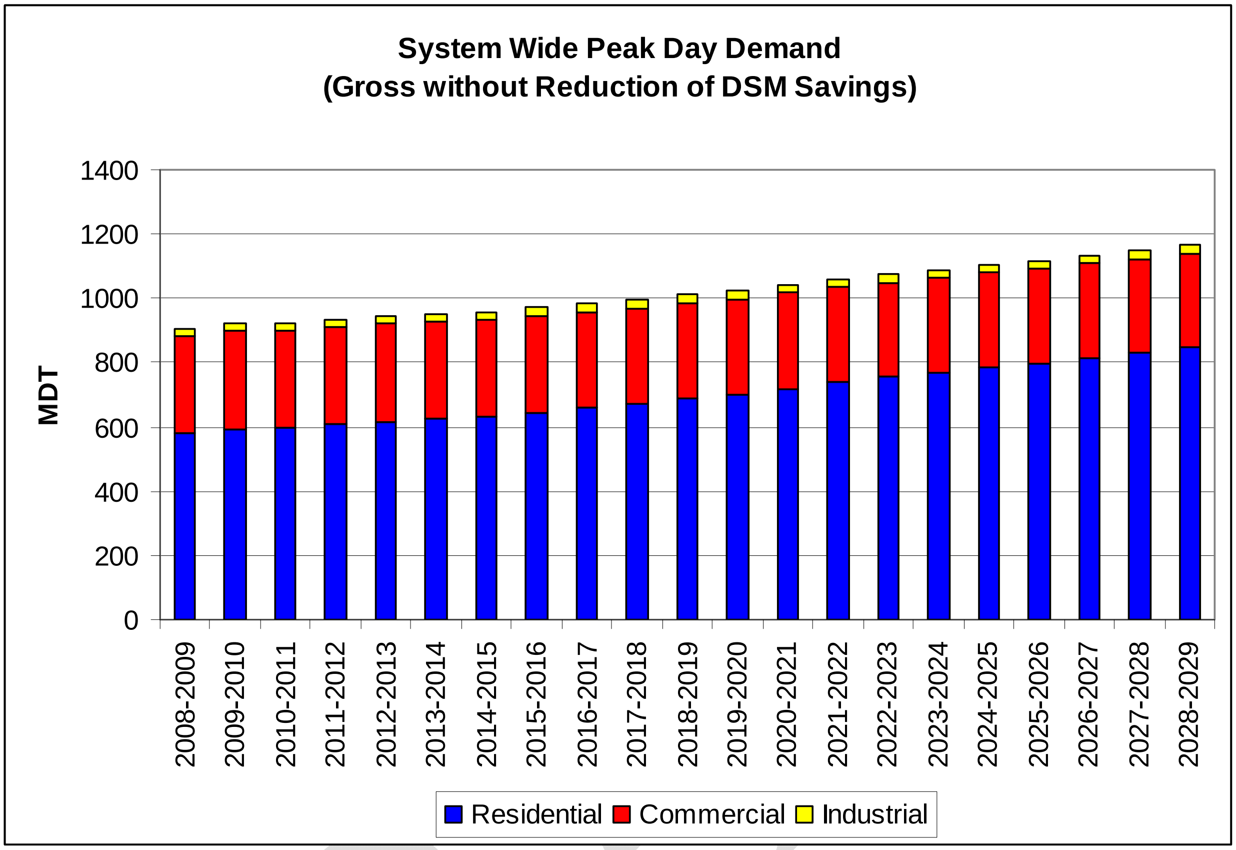
4. While customer counts continue to grow, the Company is forecasting average residential and commercial use per customer to decline by approximately 0.33 percent and 0.70 percent per year, respectively. Washington residential and commercial use per customer is expected to decline by 0.55 percent and 0.43 percent respectively. These trends partially offset load growth attributable to the forecast growth in customers. However, overall, the Company is forecasting a 1.7 percent average growth rate in annual firm demand over the 20 year planning horizon, reaching approximately 99.5 Bcf by 2027-2028. Figure ES-5 depicts the annual gas requirements forecast for this planning cycle.

FIGURE ES-5



5. System-wide, the Company is projecting peak day gas requirements to increase at 1.3 percent annually during the next 20 years; rising from 903 MDT to 1,149 MDT (refer to Figure ES-6).

FIGURE ES-6



6. The Company has considered a number of potential events that may impact its base case load forecast, and 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 for an extended recession, with a return to previous levels of growth expected later in the planning cycle than in the base case; and second, an extended recession paired with a continued lower level of demand, as could potentially occur in the case of an extended recession paired with demand destruction and/or significant levels of renewable resource penetration. The Company will continue to monitor economic conditions and developments in environmental legislation as it updates its load forecasts in the future.

IV. SUPPLY-SIDE RESOURCES

Supply-side resources include the gas itself, gas storage, the interstate pipeline capacity needed to transport the gas to NW Natural's service area, 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.

The amount of gas required at any given time depends on customer behavior. This behavior is greatly influenced by weather, but can also be impacted by changing business conditions and the price of natural gas as compared to alternative fuels.

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 distribution system. It is also essential for the Company to identify and act when opportunities arise, as they do during times of low demand on interstate pipelines, to get supplies onto our system and into storage in order to further enhance the security of our overall supply portfolio.

Obviously, 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 heater 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 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.

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. Most recently, as we continue to learn more about the potential for declining supplies from Canada, the Company is considering new opportunities to diversity its supply away from Canada.

B. Recent Resource Decisions

Included in the Company's portfolio of current gas supply is one specific resource added since the Company's 2007 IRP and 2008 Update: additional capacity at the Company’s Mist storage field. This resource addition followed supply-related conclusions and action plan steps developed in the 2004 and 2007 IRP.

Mist, which is located in Oregon, is an exceptional resource for NW Natural due primarily to its location within the service territory. Because of its location, the resource is available without the need for winter re-delivery on the interstate pipelines, which both reduces cost to customers and enhances service reliability. Underground storage and related infrastructure developments in Oregon provide equivalent benefits for Washington customers, as storage permits the Company to displace north to south flowing pipeline supplies to more northerly delivery points in Washington.

C. Future Resource Alternatives

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

1. <u>Interstate Pipeline Capacity Additions</u>

   a. New NWPL Grants Pass Lateral capacity serving Salem, Newport, Albany and Eugene,
   b. New NWPL “mainline” capacity serving Portland, Astoria, Vancouver, and The Dalles,
   c. New capacity upstream of NWPL mainline capacity providing access to the Rockies and Alberta supply areas,
   d. New Palomar pipeline capacity both east and west of Molalla,
   e. New capacity on the proposed Pacific Connector Pipeline to access regasified LNG from the proposed Jordan Cove LNG project at Coos Bay, Oregon.

2. <u>NW Natural Infrastructure Enhancements: *Please note that these resource additions would not be used to serve Washington customers, but are modeled in this IRP as part of the “integrated whole system” approach described above.*</u>

   a. <u>Brownsville to Eugene</u> – With a relatively modest capital investment ($420,000), the Company can construct a river crossing thereby allowing up to 5,000 Dth/day of existing NWPL capacity to be delivered to Eugene.

   b. <u>Newport Expansion</u> - The daily deliverability of gas from NW Natural's Newport liquefied natural gas plant could be increased from 60,000 Dth/day to 100,000 Dth/day. The cost of infrastructure additions would be about $15 million. While this would enhance NW Natural's system reliability during periods of peak demand, NW Natural would have to add or upgrade major segments of its distribution system to move the gas.

c. Willamette Valley Feeder – A new pipeline could move natural gas from the Mist underground storage facility south to the Salem area, and then continue further south to Albany or Eugene if necessary. This project would work in conjunction with a new pipeline from Newport and is an alternative to continued expansion of NWPL's Grant's Pass Lateral.

d. Satellite LNG – 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 LNG could defer significant pipeline infrastructure investments. In this IRP, NW Natural has evaluated satellite LNG in three locations in the Willamette Valley (Salem, Albany and Eugene) as interim resources that might delay the incursion of more expensive pipeline projects.

3. Mist Recall: As noted above, "Mist Recall' is the general term given when the Company recalls for use by core customers storage capacity at the Company's Mist Storage fields that has previously been under contract to interstate storage customers. A portion of such capacity would be allocated to Washington customers.

4. Imported LNG - The Company is evaluating the impact of two LNG import terminals proposed to be sited in Oregon; if built, these terminals could provide a portion of the gas used by both Washington and Oregon customers. The Bradwood Landing terminal would have an estimated average production capacity of 1.0 Bcf per day and has proposed a 35-mile export pipeline to Northwest Pipeline in addition to the proposed interconnect with the Palomar pipeline. The Jordan Cove terminal is also sized at 1.0 Bcf/day and would connect to the proposed Pacific Connector Gas Pipeline. Although neither Bradwood nor Jordan Cove has been constructed, for analysis purposes, NW Natural is including them in its modeling.

The Company has come to the following principal conclusions from this Plan with regard to supply-side resources, as they specifically relate to its Washington customers:

a. The Company's existing supplies are not sufficient to satisfy 100% of projected peak day demand. For Washington customers, customer growth can be met in the near term by adding storage capacity at the Company's Mist storage fields.

b. As noted in the 2007 IRP, the Company is pursuing strategies to improve supply path diversity, including pursuing the opportunity to take capacity on the Palomar East Pipeline. Palomar would provide an alternative to bringing gas into the Company's system, which is currently served exclusively by the Williams pipeline.

c. The Company will continue to keep a close watch on developments in the area of imported LNG, and proposals in the Pacific Northwest to develop terminals to bring imported LNG into the region. This IRP demonstrates that in addition to enhancing the Company's gas supply reliability, both of these resource options, should they be developed, are likely to be cost-effective resource choices.

d. 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

The 2009 IRP marks a time of significant change for NW Natural's DSM programs in Washington. As part of a settlement approved by the WUTC on December 26, 2008[6] the Company has recently started to take steps toward bringing the Energy Trust of Oregon ("ETO") to Washington to implement a new and revitalized DSM program to the Company's Washington customers. In 2009, the Company will be working with an Energy Efficiency Advisory Group (EEAG) to develop specific programs and initiatives. In the future, the Company may also seek a new rate design structure to address the problem of lost margins associated with energy conservation.

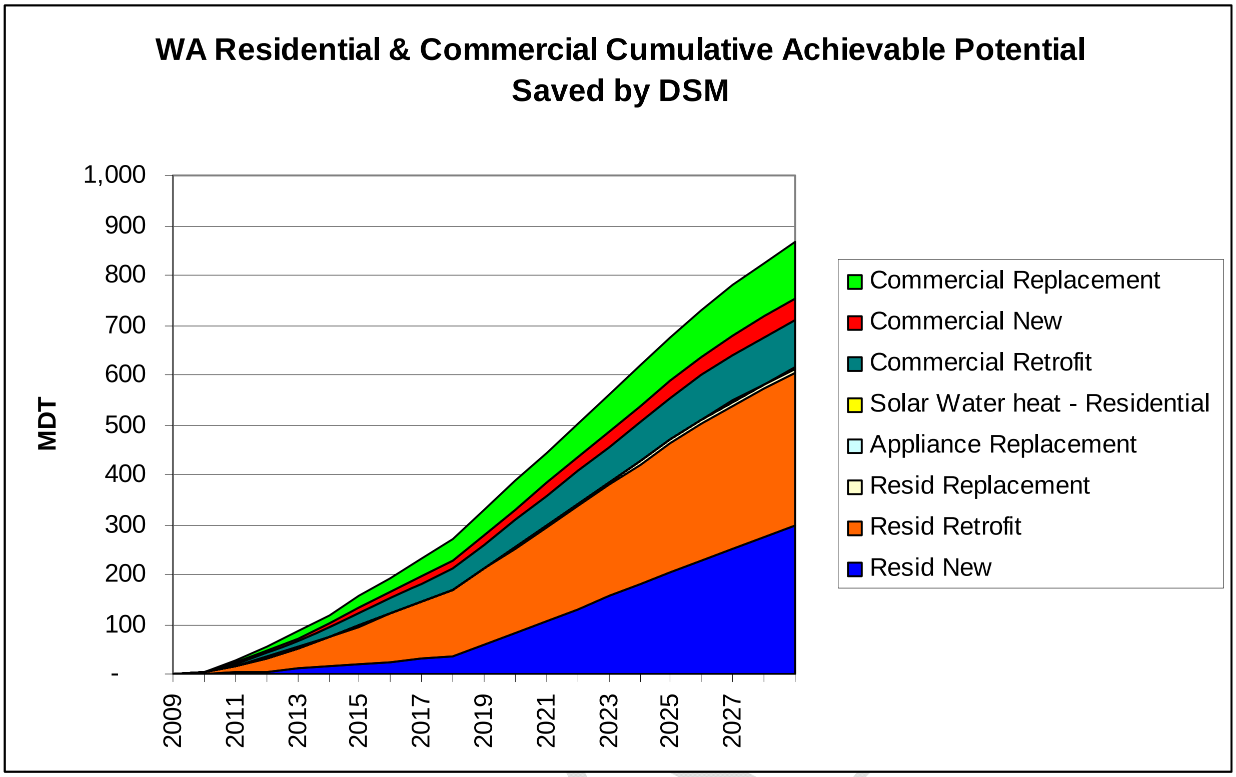
In the context of this IRP, however, the Company has considered, pursuant to WAC 480-90-238(3)(b), an assessment of currently available DSM resources and an assessment of a variety of policies and programs needed to obtain the efficiency improvements forecast as achievable in the resource assessment.

The Company has come to the following near term action-items from this Plan with regard to demand-side resources, as they specifically relate to its Washington customers:

1. Figure ES-7 depicts DSM "achievable" annual savings targets by customer sector. The appendices to Chapter 4 contain more detailed information on DSM "achievable" annual savings targets.

[6] *See* Docket UG-080546, Order No. 4.

FIGURE ES-8



2. In 2009, the Company will develop cost effective energy efficiency programs, assess the cost-effectiveness of offering those programs through the Energy Trust of Oregon, and work with the EEAG to develop and file tariffs to offer those programs to its Washington customers.

3. In 2009 and 2010, the Company will examine the results of Avista's pilot decoupling program, and consider ways to recover lost margins associated with conservation and remove any potential impediments to the Company's support of conservation programs.

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

Related environmental costs do impact demand-side resource choices. Recognizing the cost of carbon dioxide damage could have the greatest 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 or greenhouse gas mitigation strategies coming out of the West Coast Governors' Task Force on Green House Gases.

If a carbon tax were imposed, more of the demand-side resource options would be cost-effective. Adding a carbon tax of as little as $7 per ton adds $0.04 to the

Company's avoided costs, while $40 per ton adds nearly $0.24 per therm to the avoided cost figures. This could drive up the implicit commodity cost of natural gas and therefore make some non-cost-effective conservation measures cost-effective.

VII. OTHER DEMAND-SIDE MANAGEMENT CONSIDERATIONS

A. Load Management

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, several of these techniques to manage peak demands are used by Northwest Natural.

On the NWN system, customers taking service on interruptible rates represent approximately 42 percent of annual throughput. This includes interruptible sales service, interruptible transportation service and firm on our system transportation service where the transporter, not the Company, is responsible for the firmness of upstream pipeline capacity arrangements. For peaking arrangements, NWN has contracts with several large industrial customers to recall storage volumes under specific conditions, which the Company recently used to manage a high loads during the December 2008 winter snow event.

B. Rate Design

In general, the Company believes that rate design policies should encourage year-round energy efficiency and cause customers to not place excessive demands on the system during severe weather episodes. The Company also believes that revenue stability is desirable. Toward these ends, a variety of rate design alternatives are examined in Chapter 4.

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, Energy Trust of Oregon, Northwest Power and Conservation Council, TransCanada-Gas Transmission Northwest, Northwest Industrial Gas Users, Northwest Pipeline Corporation, Williams Northwest Pipeline, and the Washington Utilities & Transportation Commission. This group continues to be an integral part of plan development.

B. Public Participation

The Company has held two technical working group meetings. In addition to these meetings the Company has periodically emailed draft IRP chapters and other information to the Technical Working Group. We have been able to use email under this compressed timeline to solicit feedback and review comments from the TWG.

In addition, Washington customers received a January bill insert that notified them of the IRP process and solicited their comments.

NW Natural

2009 Integrated Resource Plan

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 events over the past 20 years date back to 1989 and 1990, so absent extreme cold weather in the near future, firm peak-day requirements could drop noticeably in the 2011 IRP.

1.2 Recalibrate forecast for changes in gas usage equations and expected customer gains following each heating season. Assess implications and report to state Public Utility Commissions as appropriate.

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 Monitor the spread of hybrid heat systems, because of the implications that has for demand forecasting.

1.5 Review the demand forecast to ensure that it performs well under warmer days; consider whether demand forecasts have been consistently high or low and report findings in the 2011 IRP.

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

2.0 Supply-Side Resources

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.

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 Pipeline, primarily for risk management purposes in diversifying the Company's supply path options.

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.

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. These pipelines could provide an opportunity for the Company to further diversify its portfolio away from a reliance on Canadian gas. 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.

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.

3.0 Demand-Side Resources

3.1 Work with the ETO and the EEAG to develop energy efficiency program offerings.

3.2 Review the results of Avista's pilot decoupling program and consider methods for recovery of lost margin due to conservation efforts.

4.0 *SENDOUT*® Model and Integrated 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 Washington customers, in conjunction with its selection of its preferred portfolio:

- Palomar East capacity: Per the terms of the Precedent Agreement, assuming the Palomar project proceeds as currently scheduled, the Company plans to commit to 100,000 Dth/day of capacity on Palomar East.

- Mist Recall: the Company plans to recall 11,000 Dth/day of capacity in the fall of 2009 and no additional capacity in the fall of 2010.

5.0 Avoided Cost Determination

5.1 As regulation of greenhouse gas emissions and other items develops, 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 2011 IRP.

CHAPTER 02: GAS REQUIREMENTS FORECAST

CHAPTER 2: GAS REQUIREMENTS FORECAST

Forecasting future requirements for gas service is the starting point of resource planning. This ensures that resources will be available when needed and it provides a basis for acquiring them in an optimal manner. Therefore, useful forecasting requires that all factors that might impact future gas requirements, or "loads," be thoroughly considered on a daily, seasonal, and annual basis.

I. OVERVIEW OF DEMAND FORECAST METHODOLOGY

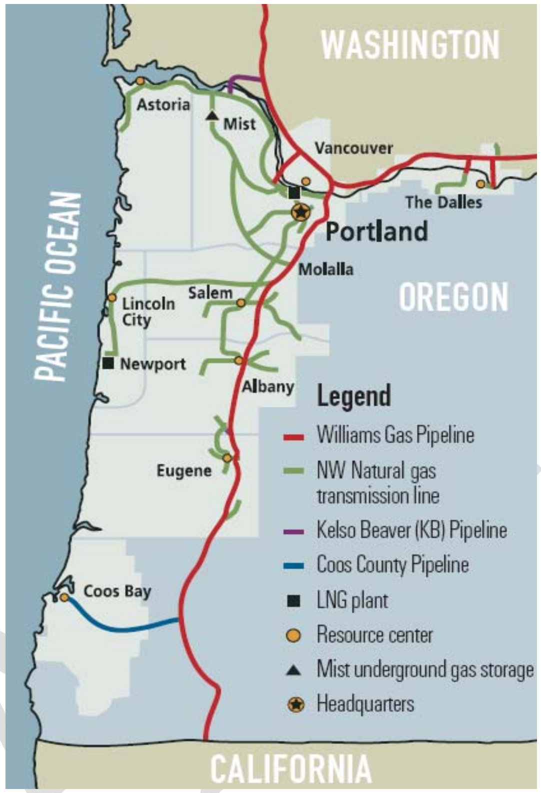
The forecasting process evaluates the amount of gas needed to serve the Company's changing customer base. In order to do this, NW Natural first identifies the characteristics of its customer base, including the number and types of customers currently served, the number and types of customers that could be served in the future, and the amount and pattern of gas usage that can reasonably be expected by those customers. Appendix 2-5 highlights historical usage by customer class.

The forecast focuses on “core market” customers, a group of customers defined as those customers taking firm service on “sales” rate schedules, where the Company provides both upstream supply capacity and storage gas capacity, and also provides for the commodity gas itself. Firm “transportation” customers provide for their own upstream capacity and commodity gas, and are not explicitly considered in this IRP. Similarly, the gas requirements of customers served on interruptible sales and/or transportation rate schedules are not considered, because the Company does not plan for upstream pipeline capacity or storage capacity to serve these customers.

NW Natural continues to use region-specific forecasts in the 2009 IRP reflecting the Company’s segmentation of its gas distribution system into eight primary geographic regions defined herein as Albany, Astoria, Eugene & Coos Bay, The Dalles (Oregon), Lincoln City & Newport, Portland, Salem, and Vancouver & The Dalles (Washington). These regions differ in terms of weather, customer gains, usage patterns by customers, and resource availability. The results of the individual regional level forecasts are presented in detail in the appendices to Chapter 2.

Figure 2-1
NW Natural Service Territory
Major Geographic Regions

Region
1. Albany
2. Astoria
3. Eugene & Coos Bay
4. The Dalles (OR)
5. Lincoln City & Newport
6. Portland
7. Salem
8. Vancouver & The Dalles (WA)



Dividing NW Natural's service territory into these eight major geographic regions reflects the different demand and supply points, and the distribution system connections between these respective points as analyzed in *SENDOUT.*® Specifically, the regional demand forecasts are compared against current supply resources in *SENDOUT*®., resulting in a Base Case forecast of unserved demand by region. These results of unserved demand by region are presented in Appendix 5-2 and provide useful information to guide infrastructure planning.

A. TRADITIONAL DETERMINISTIC APPROACH

The process for developing gas requirement forecasts utilized by the Company follows the several stages outlined below.

- The Company first projects customer counts by customer sub-class for each year of the forecast time horizon as explained in Section II. Customer growth forecasts were prepared for eleven scenarios, including the Company projected Base Case and ten other sensitivities as listed in Table 2-1.

- The Company then statistically estimates gas usage for each customer subclass (or market segment) as explained in Section III. Design year (including peak day) projections are derived from multiple regressions, separating out Base-use and Temperature Sensitive Load-use (TSL-use).

- Next, the Company applies 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 Section V.

The Base Case demand forecast utilizes the Company's projected customer growth and projected prices. This IRP also considers ten departures from the Base Case to place reasonable bounds on the range of demand forecast outcomes. These various forecasts represent our attempt to capture a number of extremely complex and difficult to predict forces that will be at work over the course of the twenty year planning horizon. These forces include: changes in housing markets and construction practices, effects of environmental legislation, consumer responses to economic conditions, including price signals, and changes in supply. As any participant in today's complex markets knows, events are moving quickly and it is extremely difficult to predict what the future may hold for NW Natural and its customers. However, we have made some attempt to put together reasonable potential future portfolios, based on potential future events.

The Company believes its Base Case to be "mostly likely" and therefore makes planning decisions around the Base Case. However, given current market conditions, we also believe it is possible that the Company could experience 1) lower than expected growth (the Low Growth sensitivity); 2) a longer recession, followed by a return to base case growth rates (the Low Growth Alternative 1 sensitivity); or 3) a prolonged recession, followed by continued low growth rates (the Low Growth

Alternative 2 sensitivity). A number of factors could contribute to these low growth scenarios. As described in greater detail later in this chapter, current economic recession has led to significantly lower growth rates for the Company. If the region is unable to recover as predicted (in the 2010 timeframe), the effects may continue to be felt in residential, commercial, and industrial demand, leading to lower growth throughout the planning period. Prolonged lower growth rates may make it difficult to ever recover to previous growth rates. It is also possible that significant changes in legislation regarding energy efficiency, an economic stimulus package aimed at market transformation in demand side measures, or a shift in commercial or industrial demand away from natural gas toward other forms of energy could lead to long-term lower demand forecasts. While we do not believe these to be the most likely cases, again, we believe they are worth further study.

On the other side of the coin, we believe it is important to consider higher growth scenarios. We have developed a high growth scenario to test the need for additional infrastructure if the economy should recover quickly and send demand spiking. While we have modeled this possibility, we do not believe it is as likely as a lower growth scenario.

Finally, in the area of commodity pricing, we have modeled both high and low price scenarios, and paired them with high and low growth scenarios. We can foresee potential legislative and economic world views that would result in these scenarios. For example, in our Low Growth, High Price sensitivity, we imagine a world in which a recession is paired with increased energy efficiency, resulting in lowered demand; we pair this with higher prices, as may result from a rush toward natural gas required by a cap and trade or other carbon constraint, particularly where electric utilities need to replace existing coal plants and are unable to do so with renewables, nuclear power, and clean coal.

In our Low Growth, Low Price sensitivity, we imagine a world with lower demand, for reasons described above, but lower prices, which may be fueled by increased supply (perhaps from imported LNG or newly developed unconventional supplies such as shale gas), or significant penetration of renewable resources into a market that also sees development in areas of nuclear plants and possibly clean coal technology.

A description of each sensitivity is provided in Table 2-1 below. The Company ran *SENDOUT*®. under all ten of these demand sensitivities in addition to the Base Case to determine how supply resource selection varies with different demand levels. A comparison of *SENDOUT*®. sensitivity results is presented in Chapter 5 with supporting detail provided in Appendix 5-3.

Table 2 – 1
Demand Forecasts - Base Case & Sensitivities

Base Case Demand: Expected Base Case customer growth and reference per therm usage charge forecast.

1. **High Growth Sensitivity**: High customer growth with reference per therm usage charge forecast. Average annual growth rates roughly 1% higher than Base Case.

2. **Low Growth Sensitivity**: Low customer growth with reference per therm usage charge forecast. Average annual growth rates roughly 1% lower than base.

3. **High Price Sensitivity**: Expected customer growth and high per therm usage charge forecast.

4. **Low Price Sensitivity**: Expected customer growth and low per therm usage charge forecast.

5. **High Growth & High Price Sensitivity**: High customer growth with high per therm usage charge forecast. This scenario could occur if environmental controls drive up natural gas pricing, while economic stimulus and a rebounding economy result in high growth.

6. **High Growth & Low Price Sensitivity**: High customer growth with low per therm usage charge forecast. This scenario might occur under a combination of a significant economic recovery paired with new discoveries in unconventional supplies or significant penetration of renewable resources and a decline in adoption of gas-fired generation by electric utilities.

7. **Low Growth & Low Price Sensitivity**: Low customer growth with low per therm usage charge forecast. Lower growth caused by recession or significant energy efficiency advances; lower prices caused by lower demand and increased supplies from shale gas or imported LNG.

8. **Low Growth & High Price Sensitivity**: Low customer growth with high per therm usage charge forecast. This scenario could occur with a

continued recession and with environmental controls that drive up the price, as electric utilities are driven to adopt gas-fired generation to replace existing coal plants.

9. **Low Growth 1 & Low Price Sensitivity:** Low customer growth due to a longer and more pronounced recession followed by a recovery to expected customer levels.

10. **Low Growth 2 & Low Price Sensitivity:** Low customer growth due to an excoriating recession, followed by recovery only to low growth levels.

Figure 2-2 below compares the Base Case demand forecast and four of the sensitivities for annual design year firm requirements. Design year annual firm demand is projected to increase from 72,331 MDth in 2008-2009 to 99,522 MDth in 2027-2028 at an annual average growth rate of 1.7%. Figure 2-3 displays the Base Case demand forecast by state. On average, Washington customers account for 10.8% of the annual system wide demand.

Figure 2-2

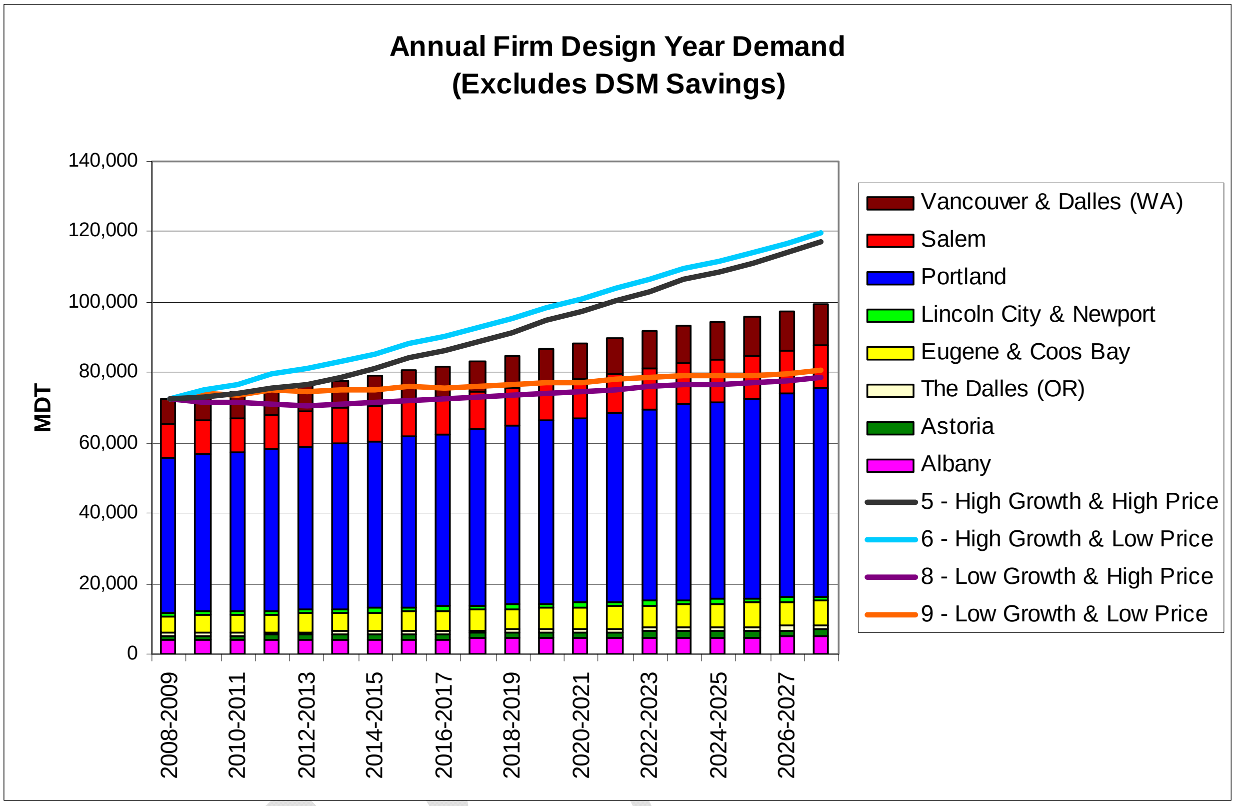
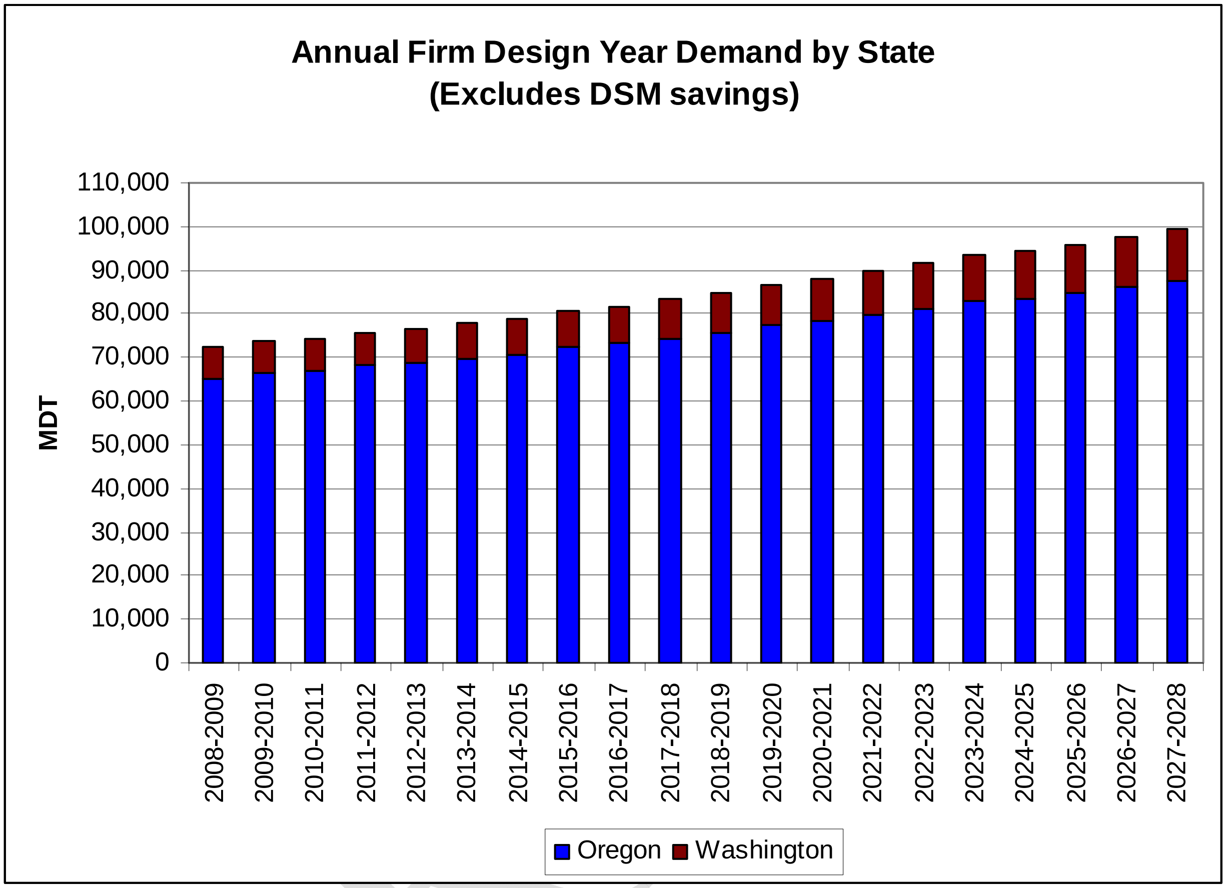

Annual Firm Design Year Demand
(Excludes DSM Savings)
MDT
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
2008-2009
2010-2011
2012-2013
2014-2015
2016-2017
2018-2019
2020-2021
2022-2023
2024-2025
2026-2027
Vancouver & Dalles (WA)
Salem
Portland
Lincoln City & Newport
Eugene & Coos Bay
The Dalles (OR)
Astoria
Albany
5 - High Growth & High Price
6 - High Growth & Low Price
8 - Low Growth & High Price
9 - Low Growth & Low Price

Figure 2-3



B. STOCHASTIC APPROACH

In addition to the eleven deterministic demand forecasts listed in Table 2-1, the Company incorporates Monte Carlo simulations (i.e. stochastic analysis) in its evaluation of customer demand. The 2008 IRP marked the first time NW Natural incorporated stochastic analysis. In response to a growing general interest in risk analysis, the Company has begun using *SENDOUT®* Version 12 as the platform for performing Monte Carlo simulations. *SENDOUT®.* Version 12 supports Monte Carlo simulations around weather and price.

In the context of the IRP, NW Natural is interested in evaluating 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. Monte Carlo simulation and *SENDOUT*®. are explained in more detail in Chapter 5.

Although the calculations that yield the stochastically produced load forecasts differ significantly from the traditional deterministic approach, most of the underlying assumptions are identical to the Base Case, including the customer growth forecast and the use per customer regression coefficients. The primary difference is in how HDDs are treated in the Monte Carlo simulations versus using the traditional deterministic approach of evaluating one design year. By describing the expected variability, behavior, and correlation among potential events in the Monte Carlo simulation, *SENDOUT*®. performs hundreds of iterations to produce a robust numerical representation of the many possible future weather and price scenarios, their resulting demand requirements and associated probabilities or likelihood of occurrence.

The timing of the peak event also supports the use of a stochastic model. Given the progressive depletion of storage levels and deliverability throughout a heating season, the later the peak event occurs in the heating season, the more difficult it is to successfully serve peak demand. Therefore, the stochastic model is allowed to treat the peak day as a moving target to replicate a more likely outcome where peaking weather does not show up on the same day every year. Results of the Monte Carlo simulation are presented in Chapter 5.

II. CUSTOMER FORECASTS

NW Natural utilizes internal business intelligence along with information from outside sources, such as the Oregon Office of Economic Analysis[1] (OEA) for Oregon, the Washington Employment Security Department (ESD) for Clark County WA, and the Washington State Economic & Revenue Forecast Council[2] to develop a 20 year Base Case customer forecast. The forecast projects customer counts for each region and includes the categories:

- Residential Existing
- Residential New Construction – Single and Multi Family
- Residential Conversions
- Commercial Existing
- Commercial New Construction
- Commercial Conversions
- Industrial Firm

System wide annual customer growth over the planning horizon (2008/2009 – 2028/2029) is expected to average 2.42%. This compares well with the average annual growth rate of 2.43% from the previous IRP. Residential growth, which is comprised of new construction and conversion, is forecast to average 2.53% annual growth, while the commercial rate is 1.33%. These values are also similar to the previous IRP. However, due to the current economic recession, the shape of the growth is substantially different. Customer growth is expected to remain under 2% until the year 2012. The company's process for developing the Base Case customer growth forecast for residential, commercial, and industrial customers is outlined in Table 2-2 below. Please note that due to the continued economic uncertainty, NW Natural will continue to analyze customer forecast options and may make changes to the Base Case forecast and scenarios before the IRP is finalized.

1 Quarterly Economic and Revenue Forecast, Oregon Office of Economic Analysis, November 2008. Available at http://www.oea.das.state.or.us

2 Quarterly Economic and Revenue Forecast, Washington State Economic & Revenue Forecast Council, November 2008. Available at http://www.erfc.wa.gov

Table 2-2
Base Case Customer Growth Forecast
Methodology

Residential:

Attrition

- Projected residential attrition is derived from the aggregate set of historical customer counts, net of gross customer adds, inclusive of any activity among new construction and conversion customers.
- Existing customer base is reduced for the projected attrition over the forecast period.

New Construction customer gains (single family and multi-family):

Through the 2008 to 2015 period

- Internal econometric modeling in conjunction with the OR and WA State Forecasts is used to project housing starts.
- Estimated housing starts are allocated to the eight major geographic regions of NW Natural's service territory according to market share of customers within each territory.

For 2016 to end of forecast in 2029

- Analysis of historic growth rates are used to complete the horizon

Conversion customer gains:

Through the 2008 to 2014 period

- Internal analysis of incentives, technology, and marketing programs, along with state economic forecasts yield a conversion estimate.
- Conversions are allocated to the regions by market share

For 2015 to end of forecast in 2029

- Assumes conversion gains remain flat at 2014 levels.

<u>Commercial</u>:

Attrition

- Projected commercial attrition is derived from the aggregate set of historical customer counts, net of gross customer adds, inclusive of any activity among new construction and conversion customers.
- Existing customer base is reduced for the projected attrition over the forecast period.

New Construction customer gains (single family and multi-family):

Through the 2008 to 2015 period

- Internal econometric modeling in conjunction with the OR and WA State Forecasts is used to project new commercial projects.
- Estimated customers are allocated to the eight major geographic regions of NW Natural's service territory according to market share of customers within each territory.

For 2016 to end of forecast in 2029

- Gains are expected to remain flat at 2015 levels.

Conversion customer gains:

- Assumes flat growth based on average historical customer gains.

<u>Industrial Firm:</u>

- Internal econometric modeling, along with Oregon Manufacturing Employment data was used to forecast customers through 2015.
- For the remainder of the forecast period, flat growth was assumed.

The customer forecast, broken out by category, is show in Figure 2-4. The customer growth rate has cooled significantly from previous years. From 2005 through 2007, the company averaged roughly 3% annual growth. Due to the economic situation, growth is forecast to average 1.7% per year from 2008 through 2011, with a rebound occurring in 2012. The worst year in terms of growth is expected to be 2009, with an expected growth rate of 1.5%. Figure 2.5 displays the actual customer counts by state from 2004 through 2007, and the forecast from 2008 through 2028. Washington customers comprise roughly 11% of the annual system wide customer base. The average annual growth rate system wide is forecast to be 2.4%, while the Washington customer base is expected to average 3.4%.

Figure 2-4

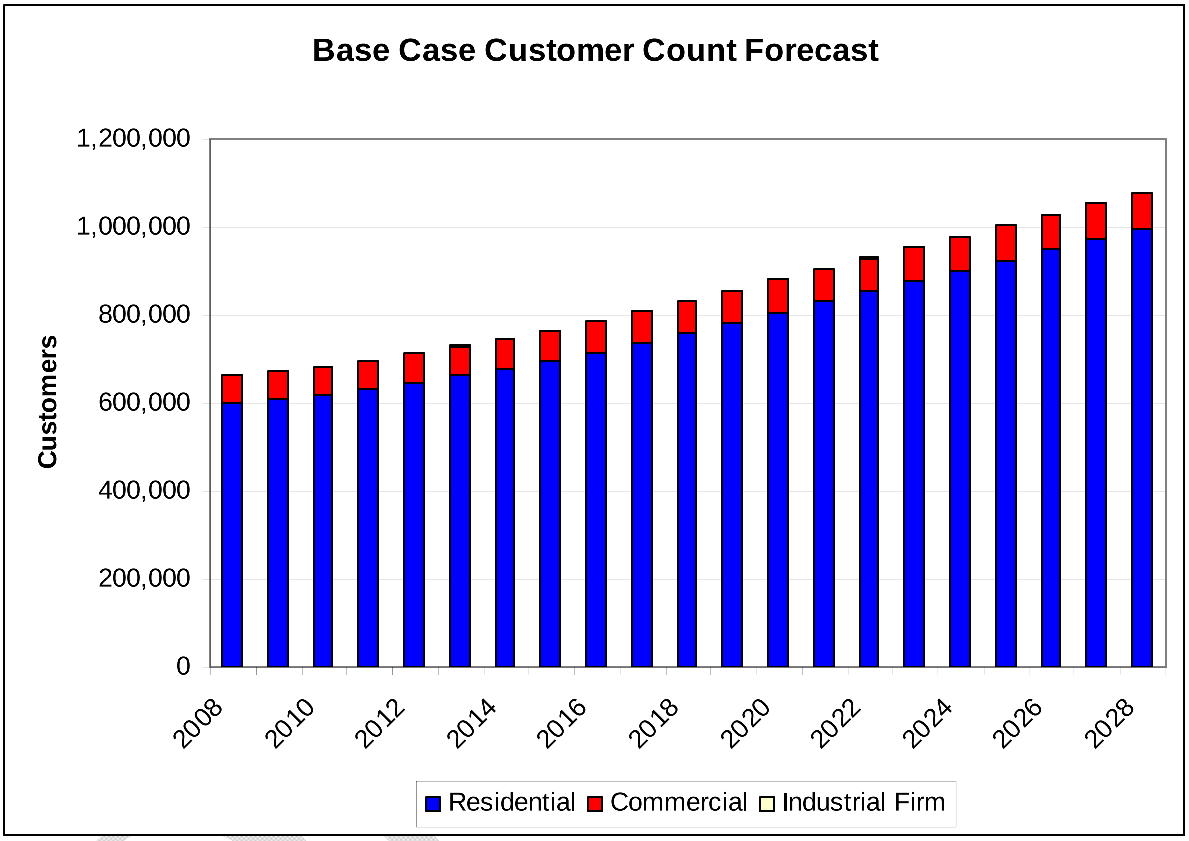
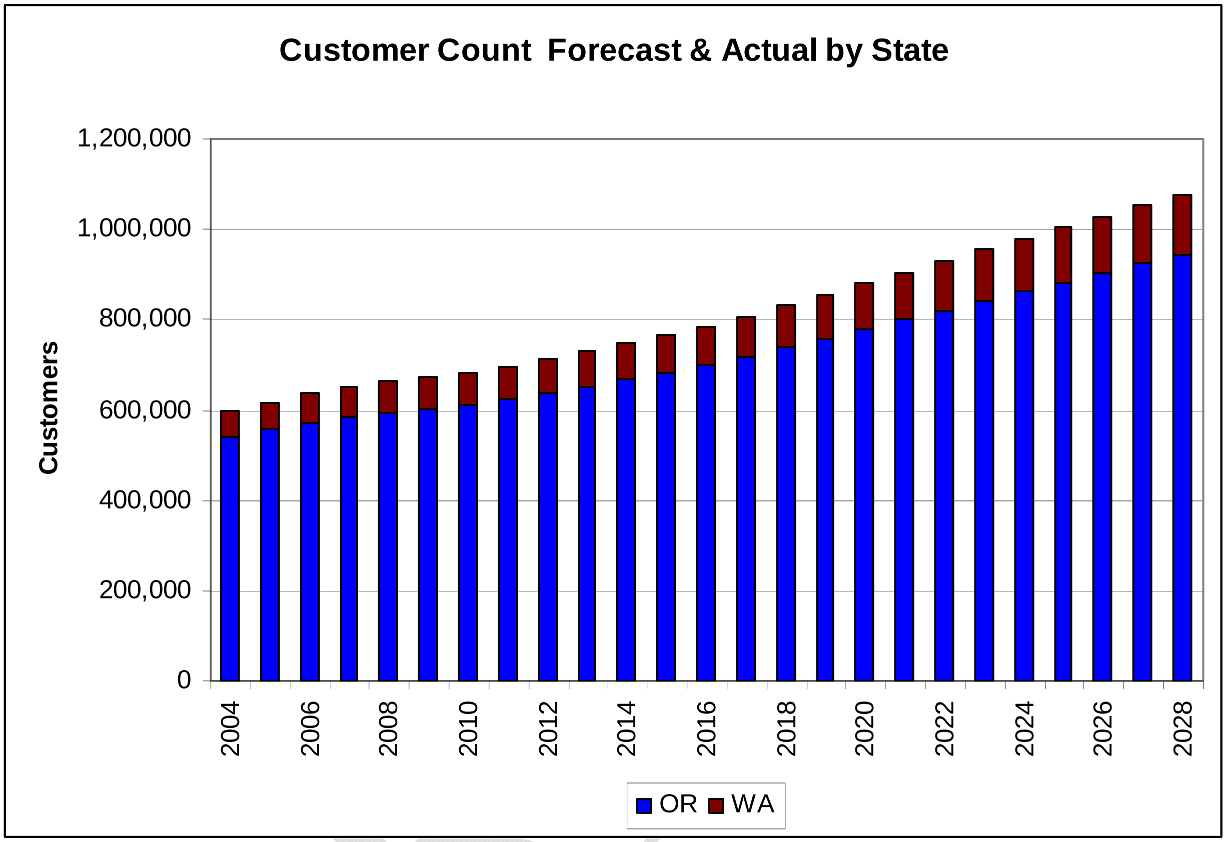


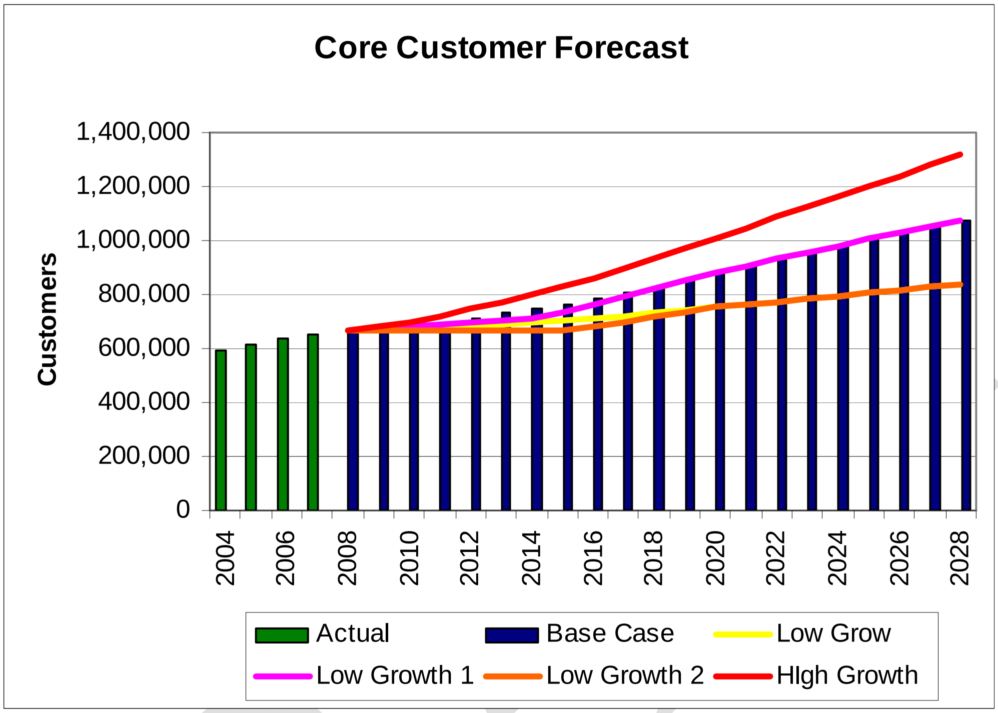
Figure 2-5



The Company has developed four departures (High Growth, Low Growth, Low Growth 1, Low Growth 2) from the Base Case customer forecast in order to place reasonable bounds on the range of potential growth outcomes in a mature industry. These sensitivities around the Base Case customer growth forecast are outlined in Table 2-1.

Figure 2-6 displays Base Case forecast, which is the most likely outcome, along with the alternative customer patterns and historic counts. A more detailed discussion of the Base Case forecast and driving factors by customer class is provided in the following Sections A through E.

Figure 2-6



A. NEW CONSTRUCTION – RESIDENTIAL

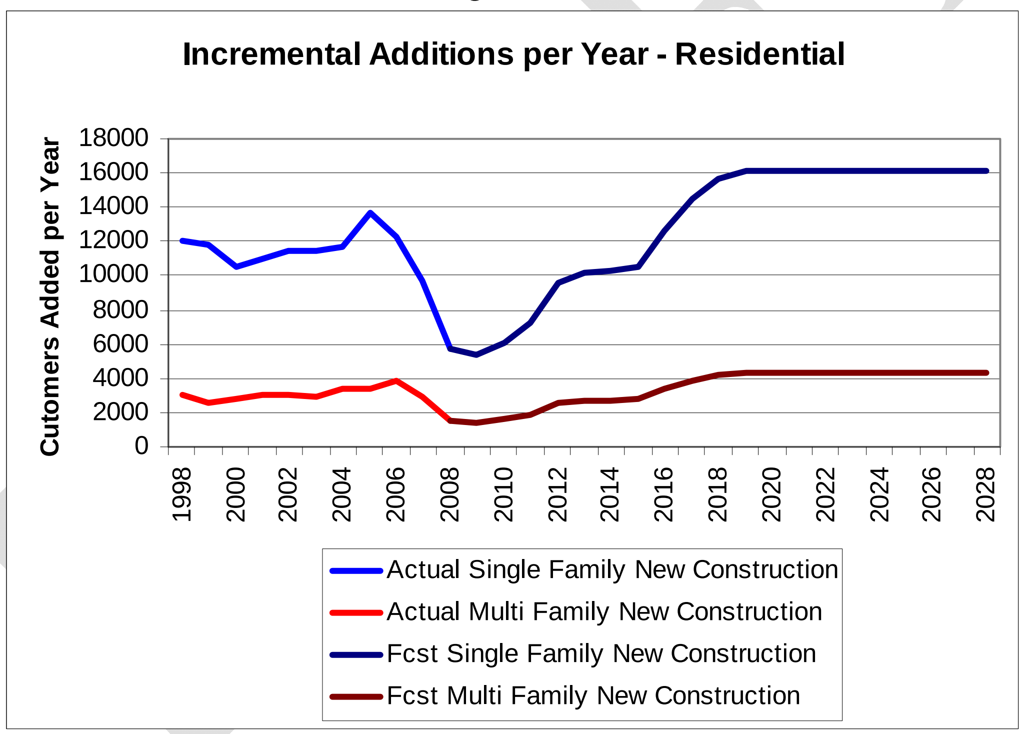
The residential forecast for new construction gains is broken out for single-family and multi-family market segments. For the years of 2008 through 2015, new customers were forecast based on the housing starts forecast from the Oregon Office of Economic Analysis. Internal econometric modeling was also applied to massage the data, including information from the credit and building communities, the Washington State Economic Employment Security Department, and the Washington State Economic & Revenue Forecast Council. The forecast for the rest of the horizon is based on historic growth rates.

Two separate forecasts generated with differing methodologies were compared for the Vancouver WA area. The first treated Vancouver as an extension of Portland and used the State of Oregon's Housing Starts Forecast. The second was based on historic Clark County permit data and population growth estimates. A housing starts forecast for Clark County was not available. The forecasts drove to similar customer count projections over the planning horizon. However, the Portland/Oregon housing starts based forecast was judged to be more appropriate since it reflected the expected downturn in new construction from the on going recession more distinctly. There was a housingstarts forecast for Washington state, but historic Vancouver starts correlated better to Oregon housing starts.

Following the forecasting of system and state level customer gains, existing market share drives the allocation of new construction customer gains by market segment (i.e. single family versus multi-family) and by major geographic region.

Figure 2-7 show residential new construction hookups added per year since 1998 and forecast into the year 2028 for single-family and multi-family residential dwellings.

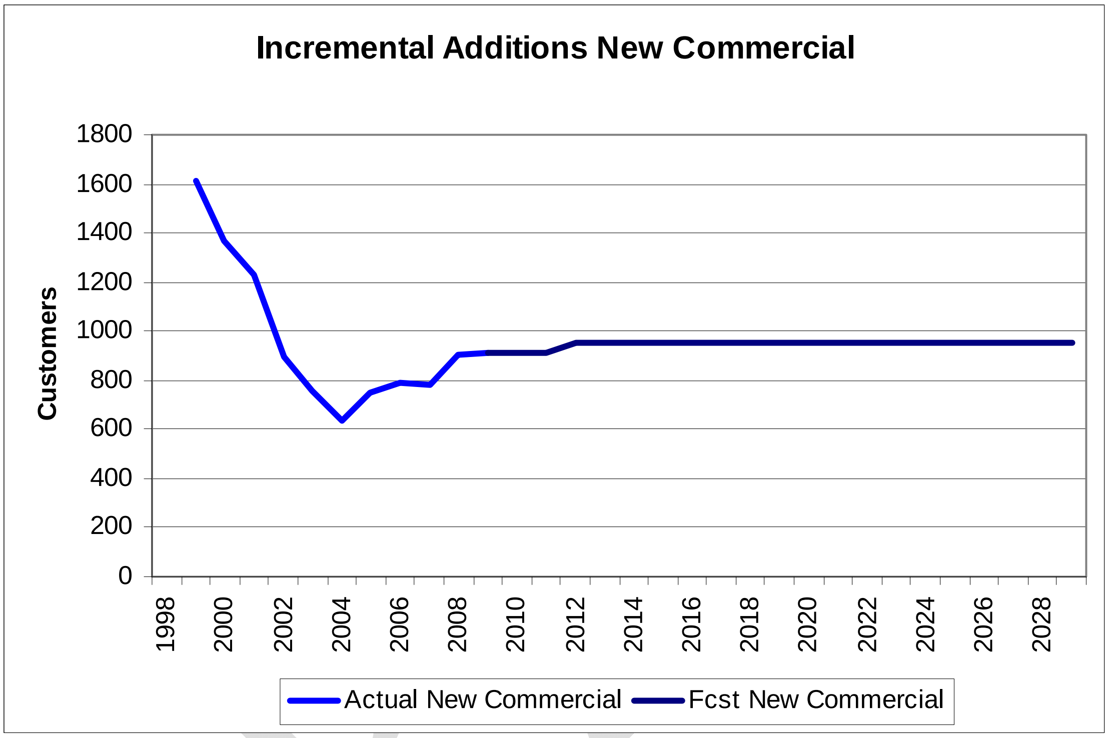
Figure 2-7



B. NEW CONSTRUCTION – COMMERCIAL

The new commercial forecast is based on historic patterns, along with internal econometric modeling and external economic forecasts. New commercial customer additions are allocated to regional centers in the same manner as the residential new construction customers.

Figure 2-8



C. NEW CONSTRUCTION – INDUSTRIAL FIRM

The industrial sector has shown slower output growth than the economy as a whole in recent decades, with imports meeting a growing share of demand for industrial goods. NW Natural anticipates a continuation of this trend throughout its service area. Within the industrial sector, the expectation is that the output of manufacturing industries will grow more rapidly than that of non-manufacturing industries, which include agriculture, mining and construction. However, with higher energy prices and more foreign competition, the expectation is that the energy-intensive manufacturing sectors will remain relatively flat.

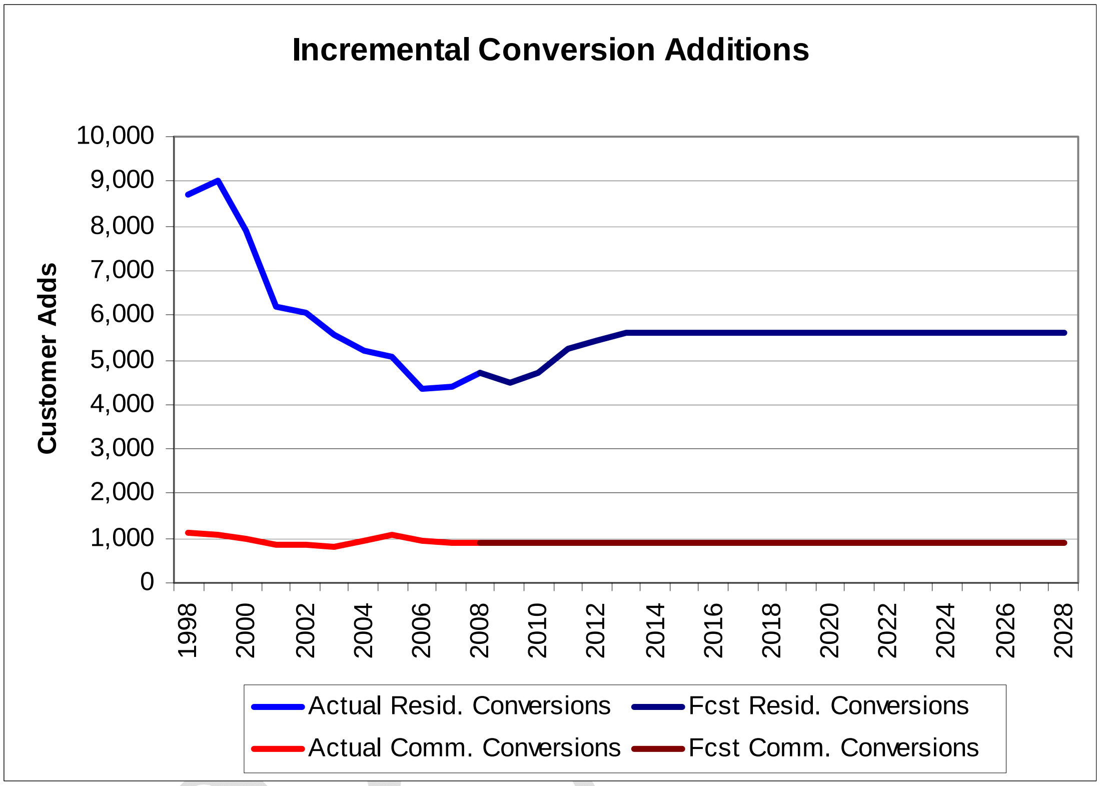
D. CONVERSIONS FROM OTHER FUELS – RESIDENTIAL AND COMMERCIAL

In addition to forecasting new construction customer gains, each year NW Natural projects the number of residential and commercial 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:

- Incentives
- Price of gas in relation to other energy sources
- Technology
- Marketing programs
- Economic conditions

Figure 2-9 shows the incremental number of residential and commercial conversion customer additions per year.

Figure 2-9



E. HYBRID HEAT CUSTOMERS

NW Natural is monitoring the spread of hybrid heat systems, a heat pump sold with natural gas back up because of their recent gain in market share. A discussion of hybrid heat customers and their implications to demand forecasting and rate design is presented in Appendix 2 - 24.

III. USE PER CUSTOMER FORECASTS

It is widely accepted that NW Natural's resource planning revolves around meeting peak load. In order to better identify resources needed to serve peak loads it is necessary to identify fuel use as a function of temperature by separating temperature-sensitive use from non-temperature-related use. Non-temperature-sensitive use represents gas requirements for water heating, cooking, and other miscellaneous uses that are largely unresponsive to temperature variations. Non-temperature-sensitive use is expressed as the number of therms used per customer per day for these purposes and is often referred to as base use. The level of base use for residential and commercial customers has remained relatively constant throughout time. However, emerging technologies now exist that provide opportunities for end-use customers to adopt conservation measures to decrease their Base Case use. And in time there will be opportunities to influence overall base use through market transformation efforts – commonly defined as a shift towards stricter efficiency standards through regulation.

The concept of Heating Degree Days (HDDs or Degree Days) is used to measure temperature. HDDs are a measure of the coldness of the weather experienced, based on the extent to which the daily mean temperature falls below a reference temperature, usually 65 degrees Fahrenheit. For example, on a day when the mean outdoor temperature is 35 degrees F, 30-degree days would be experienced. Following National Weather Service conventions, daily mean temperature represents the sum of the high and low readings for the day divided by two, with days defined as the 24 hour period between midnight for each day. While midnight-to-midnight is different than the 7 a.m.-to 7a.m. (Pacific Time) "gas day" used for scheduling deliveries in the gas pipeline industry, that difference is not meaningful here. Consistent with past IRPs, the Company uses a 65-degree balance point assumption in this Plan for both design year and normal annual forecasting.

Developing a method to match usage data to temperature data is vitally important because the capturing of customer usage data and temperature data occur at different intervals. Meters are read for groups of customers over the course of a month rather than at month-end. This results in the availability of customer usage data on a billing cycle basis, thus creating a unique relationship between usage data for any customer group, and number of days and degree-days within the billing period being examined. To reveal the relationship for each customer sub-class between base use and number of days and temperature-sensitive use and heating degree days (HDD), for a given month, the number of days and heating degree days undergo a transformation to reflect the same aggregation of various periods as the monthly billing cycle usage data. By summing the heating degree days associated with each meter read date in a month and aligning them with the respective volumes and customer counts, the heating degree days are matched up against usage for the period in which they occur and provides a basis for determining the necessary relationships.

Temperature-sensitive use is expressed as the number of therms used per customer per HDD. On average a residential customer uses 0.46 therms per day for base use purposes and an average of 0.12 therms per HDD for space heating purposes. The major sources of differences between various customers' space heating use per degree-day are dwelling size, appliance efficiency, and the thermal integrity of the structure (how well it is insulated). Customer usage profiles for each sub-class and geographic region combination for base year 2008-2009 are provided in Appendix 2-5.

A. RESIDENTIAL AND COMMERCIAL LOAD EQUATIONS

Equations for forecasting daily use per customer ("UPC") gas requirements for each residential and commercial customer sub-class all use the same general functional form shown below. They are derived from regression analyses of historic data, and numerically represent the relationships between energy use, and weather and price changes. Equations are used to forecast demand for 2008-09 and later heating seasons.

Residential & Commercial Load Equation

Daily UPC = [INT-Base Coeff + HDD/D_a x EXP{INT-TSL Coeff + HDD Coeff x LN(MIN(45, HDD/D_a)) + Price Coeff x LN(Price)}]

Where:

- HDD/D_a = Regional HDDs for a specified day;
- Price Coeff is assumed to be –0.1798 and -0.1947 for residential and commercial customers, respectively
- Price is the Per Therm Usage Charge billed to residential and commercial customers.
- EXP(A) is e to the power A
- LN(A) is the Natural Log of A

For residential and commercial customers, base load is determined by running a linear regression of therm usage during summer months (i.e. July, August, and

September) against HDDs. Base load is then estimated by the resulting constant coefficient. Consequently, the temperature sensitive use or heat load for each month of the year is estimated by subtracting from total use (1) the estimated base load and (2) the price effect, where the price effect is calculated as the assumed price coefficient multiplied by the natural log of the per therm usage charge billed to customers. Residential and commercial price coefficients are assumed to be -0.1798 and -0.1947, respectively. Further discussion of these price coefficients is presented in Section V. For the 2008-2009 base year, the resulting price effect on demand is equivalent to price elasticities[3] of negative 0.13 and negative 0.11 for residential and commercial customers, respectively. A discussion of price elasticity and the per therm usage charge forecast follows in Section V.

To determine temperature sensitive load, the natural log of heat use net of price effects is then regressed against the natural log of heating degree days for heating months (i.e. October through May). NW Natural's core market forecasting methods include an element of "bend over" for the residential and commercial classes. While residential and commercial bend over has not been observed empirically, it is necessary to recognize the phenomenon when extrapolating use factor equations calibrated using monthly observations that never exceed an average 35 heating degree days per day to more severe weather. The Company has assumed that when HDDs exceed 45, an increasing number of gas heating appliances are running at full capacity and that gas use per heating degree day (unit consumptions) will not increase further as the weather gets colder. The resulting regression coefficients have been used to estimate demand for the 2008-2009 gas year and are shown in Appendix 2-1. Summaries of the residential and commercial regression model statistics are provided in Appendix 2-2 and Appendix 2-3, respectively.

Over time, conservation investments change usage for existing and conversion dwellings. To incorporate conservation effects not included by DSM programs, the demand forecast assumes a 10%, 5%, 15%, and 100% annual decrease in Int-Base, Int-TSL, HDD, and Price coefficients, respectively.[4] Over the 20 year forecast period, average residential and commercial use per customer is expected to decline by approximately -0.3% and -0.7% per year, respectively. Figures 2-10 and 2-11 display the expected decline in load per customer.

Figure 2-10

3 Price Elasticity of negative 0.13 means that if prices increase by 10%, demand is expected to decrease by 1.3%.

4 Each coefficient decline is calculated for each forecast year 2 (i.e. 20010) through year 20 (i.e. 2028) as the previous year coefficient * EXP(-Annual % Decrease / 20 years * current year). All coefficients, with the exception of the Int-Base Coefficient are in Lognormal terms.

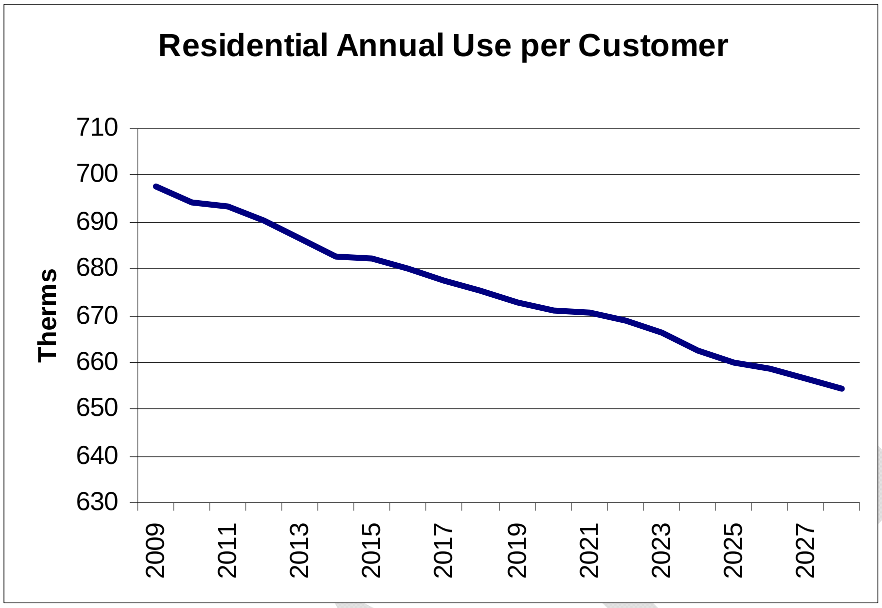
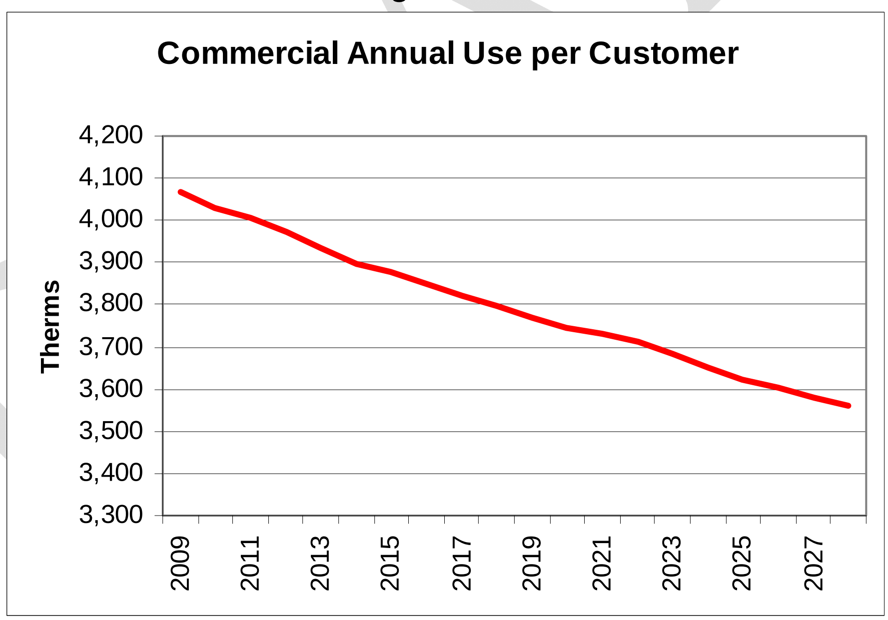


Figure 2-11



B. INDUSTRIAL FIRM LOAD EQUATIONS

Industrial base load and temperature sensitive load are derived from a linear regression analysis of historical monthly industrial firm usage and temperature data. The resulting usage factors are assumed to remain constant over the forecast period. A summary of the industrial regression model statistics is provided in Appendix 2-4.

Industrial Firm Load Equation

Daily UPC = Base Load + Temperature Sensitive Load x HDD/D_a

Where:

HDD/D_a = Regional HDDs for a specified day;

C. INTERRUPTIBLE CUSTOMER REQUIREMENTS

The Company carefully examines the best mix of side supply resources in order to meet the needs of its firm sales customers. NW Natural is not obligated to dedicate resources to interruptible customers, with the serving of Interruptible load occurring only with capacity in excess of that required for core market customers. While not considered by the Company for IRP planning purposes, the interruptible sales demand forecast is described below for informative purposes only.

The interruptible sales forecast assumes an average daily UPC of 1,284 therms. This assumed average daily use per interruptible customer is held constant over the forecast period. The use of an almost unchanging fixed volume forecast reflects the basic nature of the load in question. Large industrial and institutional users generate most of the interruptible load, and research shows that these customers exhibit constant usage.

Interruptible Load Equation

Daily UPC = 1,284 therms

The number of interruptible customers is held flat, and similar to the industrial forecast, the Company assumes no conversions to gas from other fuels for the interruptible customer class.

IV. FORECAST EQUATION PERFORMANCE

NW Natural focuses primarily on gas usage behavior during severe weather episodes for capacity planning purposes. It is difficult to measure forecast accuracy for design day forecasts unless the Company experiences near term cold spells. Fortunately, a significant "cold snap" took place in the Company's service area during January 2008. Even more recent was the snow storm that hit the area in December of 2008. These months provide a good opportunity to judge the effectiveness of the forecasting methodology.

Figure 2-12 displays actual firm gas *SENDOUT®* in MDT along with the forecast load for each day of December 2008. The storm hit the area on 12/14. The system wide load peak occurred 12/15 when gas *SENDOUT®* hit 661 MDT. This was also the peak day in terms of system weighted Heating Degree Days (HDD) when the day reached a value of 43.4 (21.6 deg F). As can be seen from the chart, a forecast bias occurs at the peak, and for the days of 12/21, 12/22 and 12/23. Many businesses and schools were shut down during this time, which may have contributed to the over forecast of load. The mean absolute percent error (MAPE) for the month was 8.9%. MAPE is a metric that is commonly used to track forecast accuracy. The average daily gas *SENDOUT®* for the month was 396 MDT while the average daily HDD was 27.5. With a MAPE value of 8.9%, on any given day the forecast could be expected to be off by 35 MDT. Figure 2-13 displays an alternate look at the same data. This figure shows the daily actual gas *SENDOUT®* as a function of HDD along with the forecast model.

Clearly there may be other factors affecting demand than heating degree days. For instance, on 12/14 the system weighted HDD value was 34.14 and the daily gas *SENDOUT®* was 559 MDT. On 12/22, the HDD value was 38.65 and daily gas *SENDOUT®* hit 489 MDT. So even though 12/22 was colder (a 13% increase in HDD), demand dropped by 13%. We believe this period may have too many unique variables to be an appropriate test of forecast accuracy. Prior to the snowfall (12/01 through 12/14), forecast accuracy was high. Following the snowfall and during the holiday vacation period, the accuracy fell off.

Figure 2-12

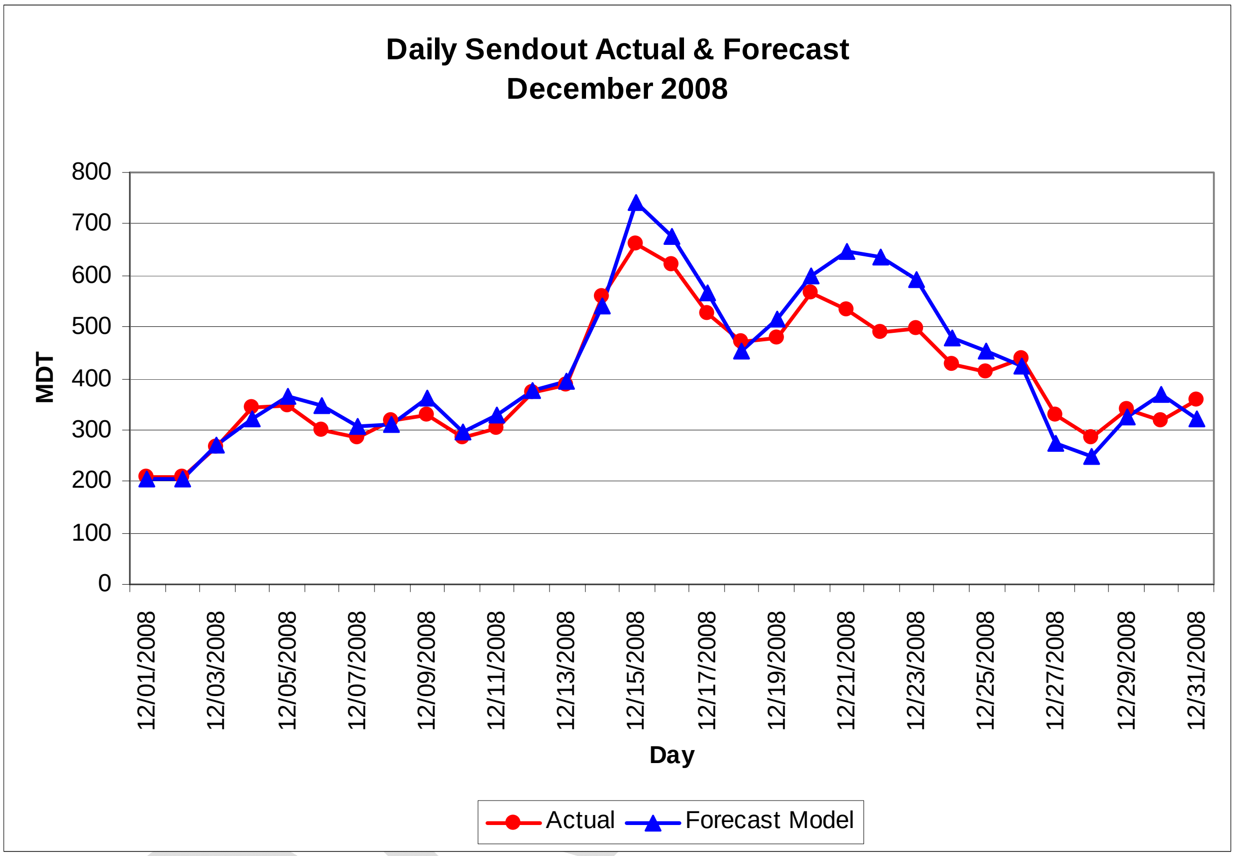
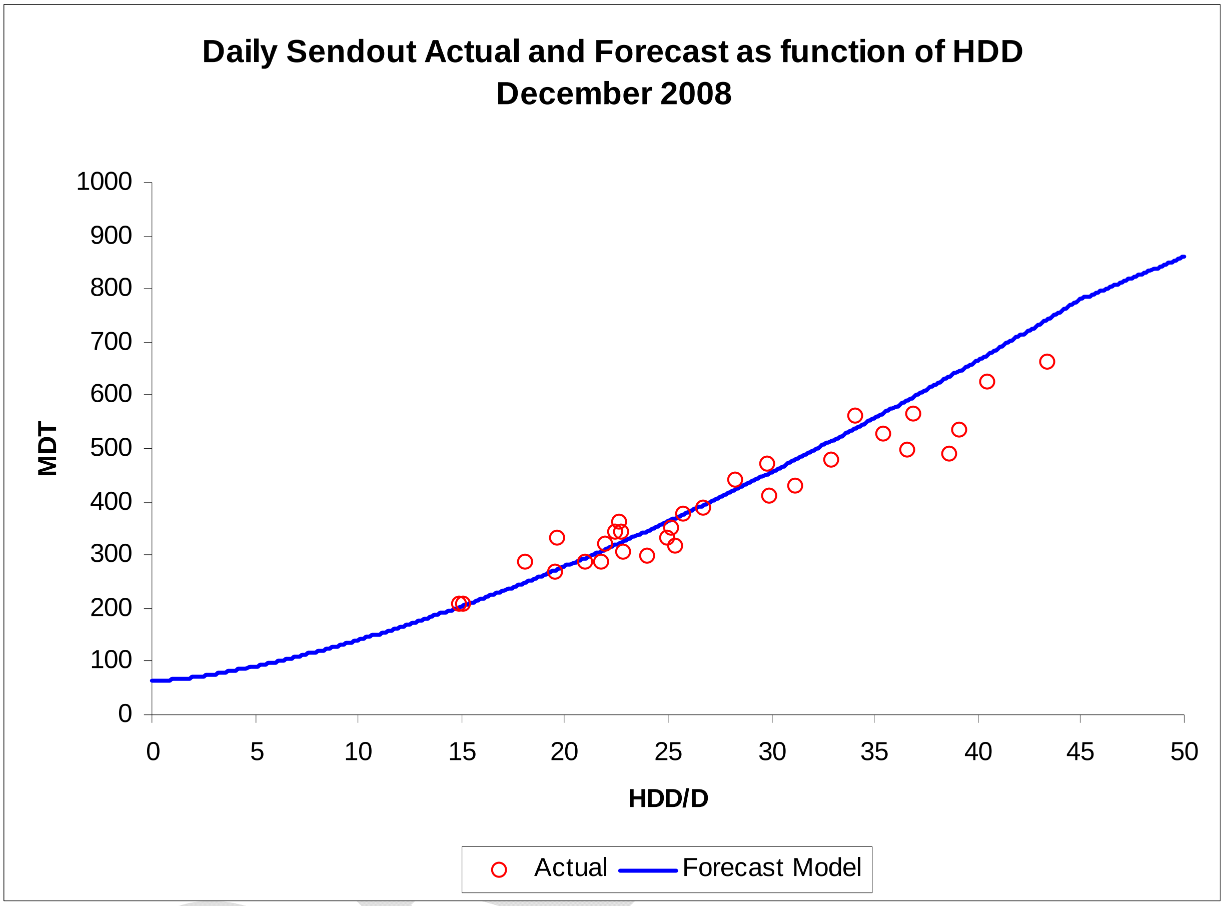

Daily Sendout Actual & Forecast
December 2008
MDT
800
700
600
500
400
300
200
100
0
12/01/2008
12/03/2008
12/05/2008
12/07/2008
12/09/2008
12/11/2008
12/13/2008
12/15/2008
12/17/2008
12/19/2008
12/21/2008
12/23/2008
12/25/2008
12/27/2008
12/29/2008
12/31/2008
Day
Actual
Forecast Model

Figure 2-13



To further evaluate forecast performance, a similar comparison was completed for January 2008. These results are shown in Figures 2-14 and 2-15.

Figure 2-14

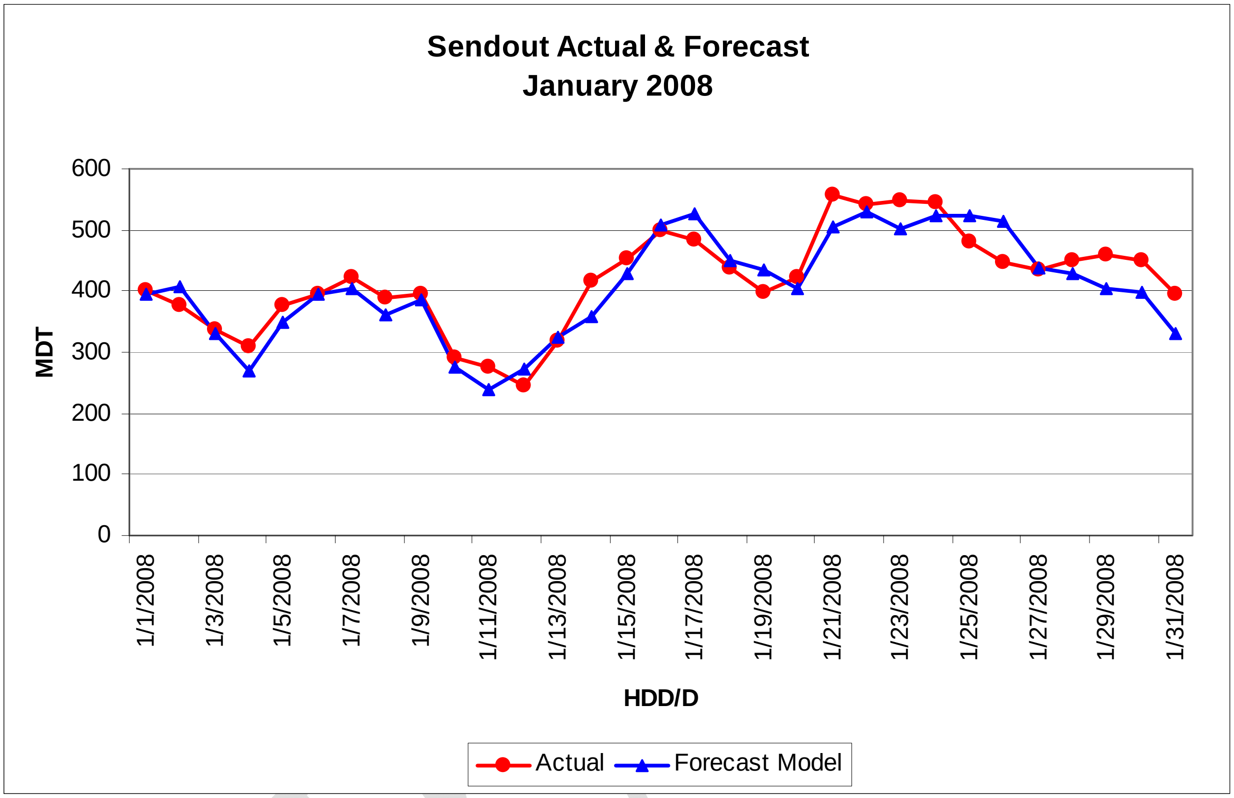
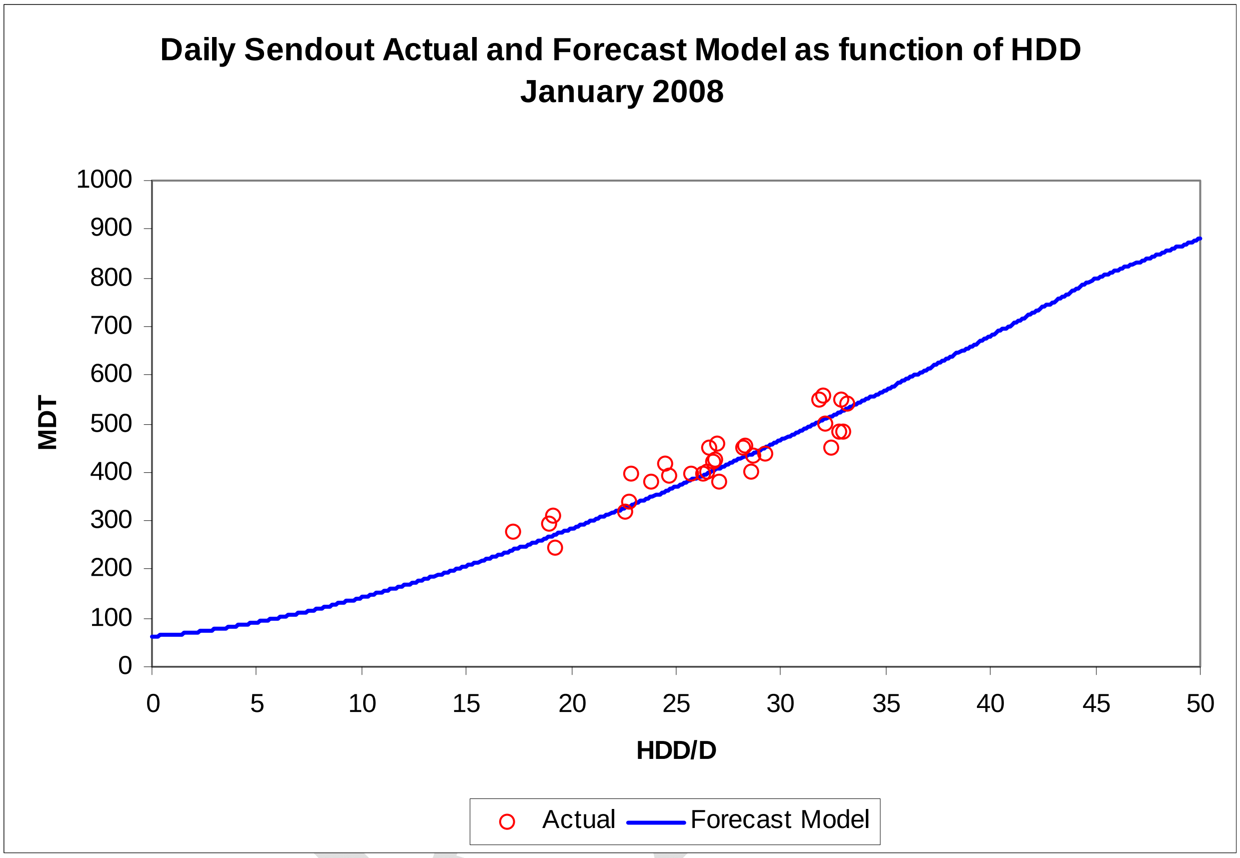

Sendout Actual & Forecast
January 2008
MDT
600
500
400
300
200
100
0
1/1/2008
1/3/2008
1/5/2008
1/7/2008
1/9/2008
1/11/2008
1/13/2008
1/15/2008
1/17/2008
1/19/2008
1/21/2008
1/23/2008
1/25/2008
1/27/2008
1/29/2008
1/31/2008
HDD/D
Actual
Forecast Model

Figure 2-15



The forecast performed better for the January 2008 cold snap. The average HDD for the month was 26.9 and the average daily gas *SENDOUT*® was 407 MDT. MAPE came in at 7.0%, which means the average daily error was 29 MDT. The peak day of gas *SENDOUT*® occurred on 1/21 with a value of 556 MDT. The forecast load for that day was 506 MDT; a 9% error. The peak HDD hit the following day when gas *SENDOUT*® came in at 541 MDT while the forecast was 530 MDT; a 2% error. There is a cluster of days between 30 and 35 HDD containing a large variation in load response. Again, this points to factors other than HDD affecting demand. Future efforts will continue to be directed towards measuring and improving forecast accuracy.

The information from both cold snaps were combined to form a single data set and analyzed. Table 2-3 summarizes the statistics. For the complete time period, the cumulative forecast error was 4.0%. By segmenting the data by HDD into two groups (<30 HDD, >= 30 HDD), it is clear that the forecast accuracy drops as the temperature drops. The cumulative forecast error for days less than 30 HDD is 2.6%, while for those days equal or over 30 HDD the error jumps to 6.4%. The table also lists the daily MAPE, which shows a similar trend.

We will continue work to improve the forecast. Additional factors could be included, such as holiday schedules, HDD run ups, day of week, snow and wind to generate a less generic and more accurate load model. However, planning model software may limit input forecast capabilities.

Table 2-3

Forecast Accuracy Statistics

Data Set	Days	Actual Load MDT	Forecast Load MDT	% Error	Daily MAPE
Entire	62	24,886	25,893	4.0 %	8.0 %
Days < 30 HDD	44	15,398	15,799	2.6 %	7.0 %
Days >= 30 HDD	18	9,488	10,094	6.4 %	10.4 %

V. PRICE FORECAST

A. CUSTOMER PER THERM USAGE CHARGE FORECAST

The sustained volatility of natural gas prices and the risk and uncertainty associated with them makes it necessary to include price elasticity in NW Natural's modeling in order to accurately forecast use per customer. Trends in usage by Company-specific customers have been directly linked to changes in their natural gas rates, and this trend is anticipated to persist. Analysis of the historical responses to price changes over the past 13 years has yielded a -0.1798 price coefficient estimate for the Company's residential customers and -0.1947 for its commercial customers. For the 2008-2009 base year, the resulting price effect on demand is equivalent to price elasticities of negative 0.13 and negative 0.11 for residential and commercial customers, respectively.[5]

The 2009 customer per therm usage charges for Oregon and Washington are developed by taking the current monthly billing rate for residential sales service and the customer weighted average of the commercial sales service rate schedules, excluding the customer charge component. For 2010 and later, the difference between these rates and an assumed allowed margin[6] is escalated by the forecasted annual change in the Company's cost of gas supply. For purposes of this analysis, the Company's cost of gas supply is estimated as a weighted average of wholesale market prices assuming 32.3% of purchases are from Sumas, 32.3% from AECO, and 35.4% from NW Rockies/Opal. In additional to a Base Case wholesale gas price forecast, NW Natural also produces forecasts for high and low price scenarios. A discussion of the wholesale market price forecasts follows in Section B.

5 The price elasticity factors are estimated for the 2008/2009 year by increasing the per therm usage charge by 10% and observing the forecasted percentage decrease in demand for the 2008/2009 year assuming price coefficients equal to -0.1798 and -0.1947 for residential and commercial customers, respectively.

6 Residential margins are assumed to be \$0.5810/therm and \$0.4990/therm for Oregon and Washington, respectively. Commercial margins are assumed to be \$0.3814/therm and \$0.4837/therm for Oregon and Washington, respectively.

Figure 2–16

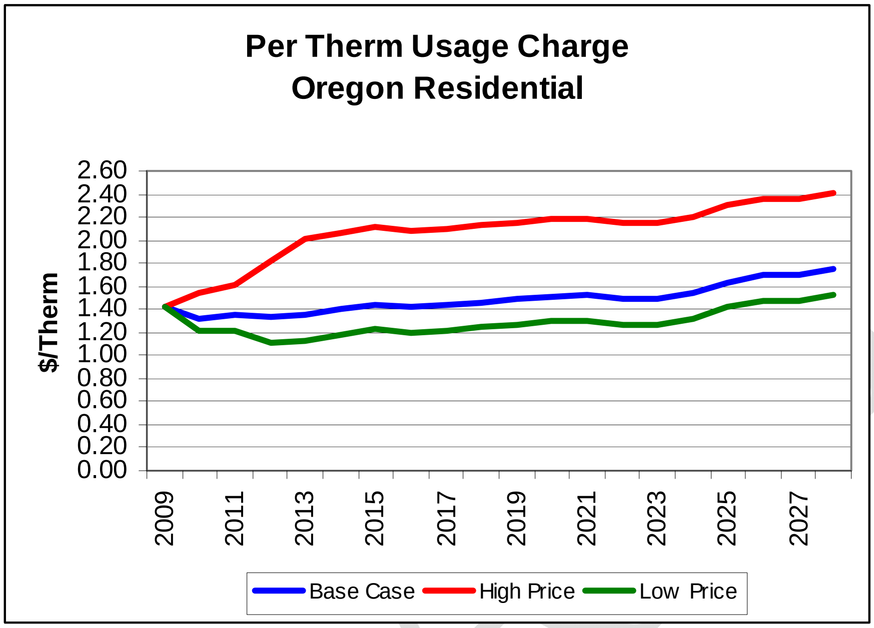
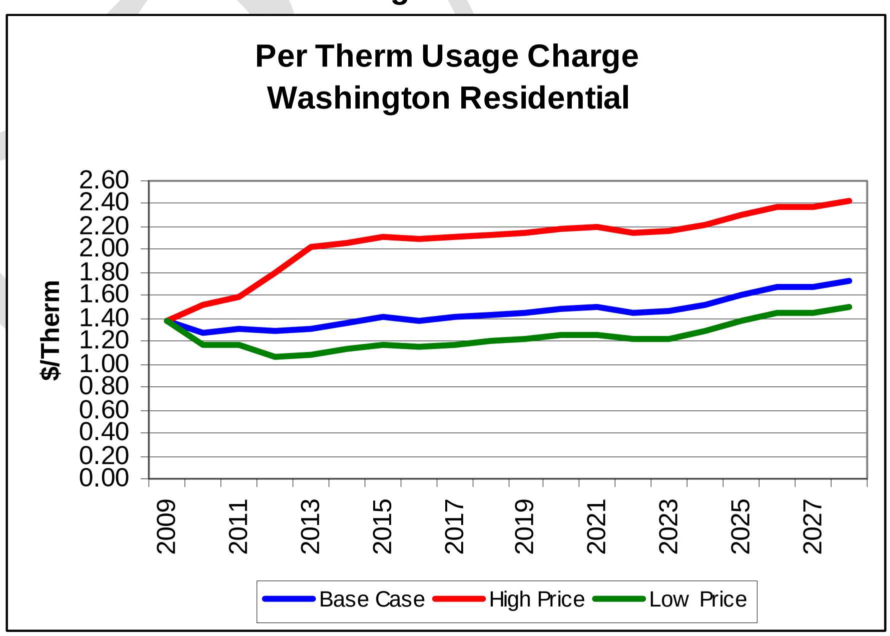


Figure 2-17



B. NATURAL GAS PRICE FORECASTS

During the past seven years price fluctuations in the natural gas market have shouldered the shut-in of supplies due to hurricanes, direct and indirect influences related to domestic and international terrorist attacks, and ongoing political instability within countries that retain the rights to the major fuel reserves. In addition, the role of non-commercial trading by price speculators and the level of influence they have on both spot market prices and the futures market has yet to be fully vetted, although there has been an increased concern over their role in the last decade. This uncertainty surrounding the natural gas market makes forecasting natural gas prices extremely difficult.

Future gas prices are influenced by long-term factors such as changing demand, development of LNG infrastructure, and the likelihood of additional frontier supplies coming to market. Supplies are expected to grow over the next five years from LNG imports and from domestic production, especially in Texas and Wyoming. The debate over pipelines from the Arctic Circle may be resolved, but the pipelines are not likely to be in service in this time frame. If the Mackenzie Delta pipeline is built, all of its gas deliveries are likely to be consumed in northern Alberta for oil-sands production. Diversity among supply basins will also continue to be important if Rockies supplies find new outlets to the East and price differentials evaporate. These long term effects are further coupled with short term factors such as actual weather, anticipated near term weather, as well as storage inventories in various supply and demand areas affect short-term gas prices.

Pipeline de-contracting could pose a major concern in the Pacific Northwest. Decisions by shippers to not renew pipeline capacity contracts with Gas Transmission Northwest (GTN) led to a major rate increase on that system in 2007. Projects such as the Ruby Pipeline and Jordan Cove LNG terminal create additional opportunities for de-contracting on GTN and other pipeline systems. However, recent long-term contract renewals on the Northwest Pipeline (NWP) system in February 2008 may be the first signal that this trend is easing. The March 2008 announcement of the NWP/GTN Sunstone pipeline project could even reverse this trend, i.e., lead to the re-subscription of currently unutilized pipeline capacity, if that project is successful.

Although NW Natural does not believe that they can accurately predict future prices for a 20-year planning horizon, the Company has reviewed several public and proprietary price forecasts and has selected high, base, and low price forecasts to represent reasonable pricing possibilities for AECO, NW Rockies, Sumas and Malin indices. NW Natural tracks a number of public price forecasts including those available from the U.S. Energy Information Administration (EIA) and NYMEX futures. The Company relies on the Wood Mackenzie Long Term Outlook for its Base Case natural gas price forecast for Henry Hub and basis differentials for NW Rockies, Sumas, AECO and Malin pricing points, as it has traditionally outperformed projections released by the EIA. This consulting firm produces both a long-term market outlook as well as monthly and weekly updates. NW Natural is therefore able to rely on forecasts that have a long-term perspective – incorporating those elements that drive long range views, and also up to date information as the markets change.

The Base Case price forecast relies on NYMEX futures for the first two years of the horizon. In year three, the average of NYMEX futures and the Wood Mackenzie forecast was used to segue into the Wood Mackenzie forecast for year four on out. High and low scenarios were developed for each basin and were based on historic quantitative variation and internal judgment. The high case assumes price one standard deviation above the forecast in year one and two, followed by a two standard deviation adder in year three, and a three standard deviation adder for year four on out. The low price scenario is not a mirror image of the high since, realistically, production would drop before prices became too low. In the first two years, the forecast is dropped by one half standard deviation, followed by a one full standard deviation drop in year three on out.

Figure 2-18 below presents the resulting annual average Base Case, high, and low forecasts for Henry Hub. For comparative purposes, the EIA forecasts for Heny Henry Hub are also shown. Figure 2-19 shows monthly Base Case price forecast with basis differentials for NW Rockies, Sumas, and AECO indices.

Figure 2–18

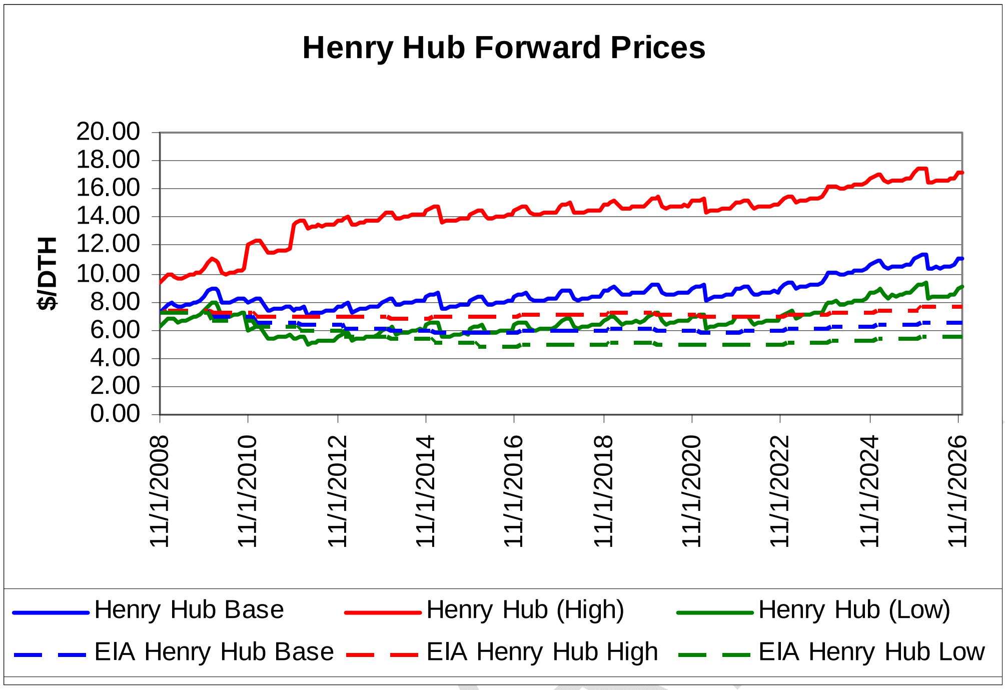
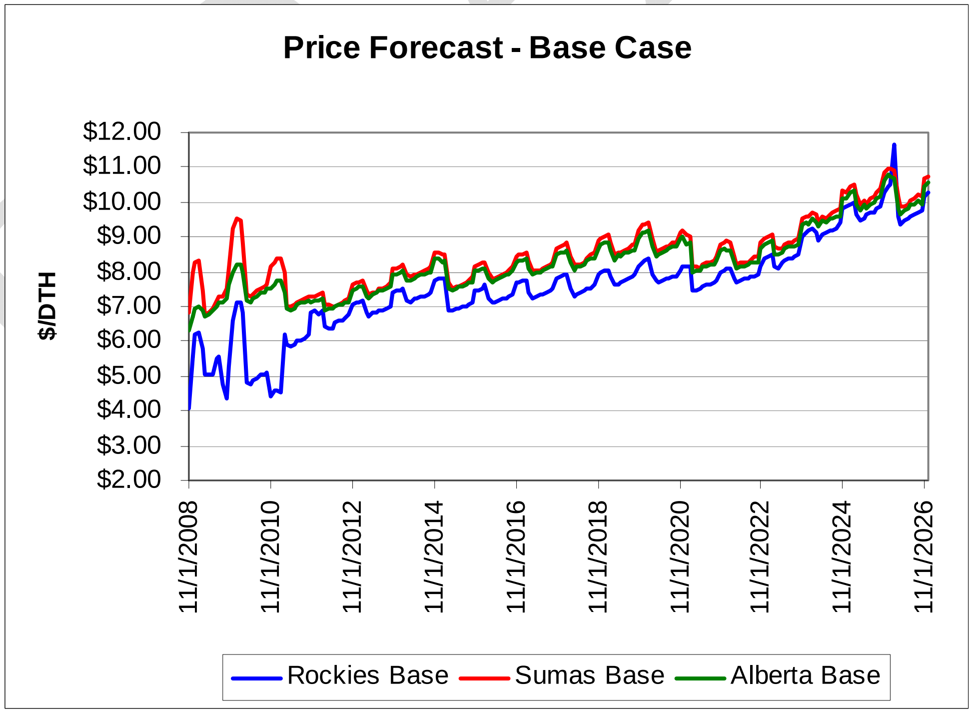


Figure 2–19



NW Natural evaluated the impact of the high and low price forecasts compared to the Base Case in *SENDOUT*®*.* A comparison of supply cost results are presented in Chapter 5. In addition to the two high and low price forecast sensitivities, NW Natural also evaluated a wide probabilistic range of potential prices and the effect on supply cost through Monte Carlo simulations in *SENDOUT.*®. Results of this analysis are also presented in Chapter 5.

VI. WEATHER PLANNING STANDARDS

In order to generate the weather patterns, a data set containing twenty years of weather temperatures (1988 through 2007) was collected for all the regions. Average daily temperatures were computed and converted to heating degree days (HDD) for each region. System weighted HDDs were also developed based on customer and demand allocation. For planning purposes, a design peak day event, and a design year weather pattern was derived from the data set.

A. DESIGN DAY

For design day planning purposes, NW Natural relies on the coldest historical system-wide coincident day observed during the last twenty years. This coincident system-weighted coldest average day of 53.0 HDD occurred on February 3, 1989 and was identified by examining for each day, the system-wide customer weighted average of the regional observed HDDs. Design day for each region is then defined as the actual HDD observed for that region on February 3, 1989. Further analysis revealed that the shoulder day leading into the average peak day and the shoulder day following it represent two out of the top ten average coldest days during the design year. Therefore, this plan includes peaking shoulder days that also occurred in 1989, to better account for the ramp-up to the peak day and the ramp-out from it.

Over the last twenty years, the system weighted average peak day HDD for each year is 37.95 with a standard deviation of 6.9 HDD. Looking forward, in any one year there is a 1% chance of a peak event reaching 53 HDD or higher. On average, the yearly peak even occurs in mid to late December. For our planning standard, we continue to use the early February peak event because a later winter event stresses the system more. Roughly 25% of the winters experienced a peak event over 40 HDD, and no winter contained two separate peak events.

B. CURRENT DESIGN YEAR PLANNING CRITERIA

To evaluate annual demand requirements for least cost planning purposes, the Company developed for each geographic region a design year with daily HDD levels based on the 85% probability coldest winter[7] (i.e. November through March), where the statistically generated total HDDs are allocated to days based on the historical pattern observed during the 2000/01 winter. The winter of 2000/01 most closely matches the statistically generated total. Design year is augmented by the coldest historical coincident system-weighted average day observed during the last twenty years from 1988 to 2007. In addition, the day prior to and following the peak day are also included in design year to model a consecutive three day cold snap. For the non-heating season (i.e. April through October), daily HDD values are assumed equal to the 20-year daily average.

The resulting design day, design year and 20-year average normal year heating degree days are shown below in Table 2-5 for each geographic region. Temperature patterns vary by region and are not correlated. The Portland metropolitan area represents approximately 61 percent of total customers in NW Natural's service territory, and therefore dominates calculated system weighted averages. However, matching cold temperatures in other regions do not always accompany a cold day in Portland. For example, the record cold 54 HDD-event observed for Portland on December 30, 1968, involved only 40 HDDs at the Eugene weather station. Similarly, the record cold 64 HDD event observed for Eugene was accompanied by 48 HDDs in Portland. The coastal regions of Coos Bay, Lincoln City & Newport and Astoria typically have milder winters. In contrast, winters in Vancouver and The Dalles are usually colder than the rest of NW Natural's service territory.

7 Assuming a normal distribution of winter HDD subtotals, the 85% probability coldest winter is equal to approximately the average winter HDD subtotal + (1.0364 x Standard Deviation of Winter HDD subtotals. Averages and standard deviations for winter HDD subtotals are derived from 20 years of historical weather data for 1988 to 2007.

Table 2-4

HDD by Region

HDD by Region	Design Day (02/03/19989)	Design Year	Normal Year
Albany	52.0	4,979	4,710
Astoria	50.0	5,299	5,017
The Dalles (OR)	60.0	5,658	5,324
Eugene	52.5	4,991	4,701
Lincoln City & Newport	48.5	5,155	4,865
Portland	53.0	4,538	4,265
Salem	54.0	4,881	4,606
Vancouver	53.5	5,136	4,877

C. PRIOR DESIGN YEAR PLANNING CRITERIA – 20 YEAR COLDEST HISTORICAL

While NW Natural currently bases its least cost planning decisions on an augmented 85 percent probability coldest winter design year, in the past the Company had relied upon the historical coldest season observed in the most recent 20 years, augmented to represent a very cold weather scenario. Demand over the 20 year planning horizon would increase 7.5 % over the 85 percent probability coldest winter design year, and the cost to serve this demand increases by 7.4%. For purposes of this IRP, NW Natural evaluated in *SENDOUT*® both the 85 percent probability coldest winter and the historical coldest season observed in the past 20 years. A discussion of cost and risk trade off in the two resulting supply resource selections is presented in Chapter 5.

The 20 year coldest historical weather scenario is developed for each geographic region with daily HDD levels based on the colder of the historical coldest season experienced in the last 20 years from 1988 to 2007 and the daily corresponding 20 year normal. With this 2009 IRP, the 1985-1986 winter drops out of the 20-year time frame and is replaced by the 1992-1993 heating season as the coldest historical season experienced in the last 20 years. In addition, the historical coldest year is augmented by the coldest historical coincident system-weighted average coldest day observed during the last twenty years from 1988 to 2007. As discussed in the prior section, this coincident system-weighted coldest average day occurred on February 3, 1989. To model a consecutive three day cold snap, the day prior to and following the peak day (i.e. February 2 and February 4) are also included.

In contrast to the 85% probability design year, the 1992-93 heating season has presented the most demanding period faced by NW Natural in the last 20 years. Before the 1992-93 heating season, the 1985-86 period was most demanding. Although the extreme cold weather experienced in February 1989 had a much colder peak day, it occurred during a very mild heating season. Going back more than 50 years, the 1949-50 heating season was the most severe of all. The distribution of heating degree days for these selected cold heating seasons are compared in Table 2-6 using Portland data as the basis for the comparison.

Table 2-5
Historical Heating Degree Days (HDDs)[8]

Heating	Peak	Number of Days Colder Than:		
Season	HDD	49 HDD	38 HDD	29 HDD
1949-50[9]	58	7	19	32
1968-69	54	2	9	29
1978-79	49	0	8	60
1985-86	46	0	8	38
1988-89	53	2	4	16
1992-93	38	0	1	32

8 As reported at Portland International Airport.

9 NW Natural does not plan for a repeat of the 1949-50 weather episode that falls within a coldest-in-fifty-nine-year time frame. It would be considerably more expensive to base the Company's design weather year on the 1949-50 episode instead of the 85% probability coldest winter planning weather criteria currently used by the Company. Rather than commit to the expense of obtaining the additional supply-side resources necessary to meet a repeat of the 1949-50 experience, NW Natural could call upon a variety of highly publicized voluntary curtailment strategies to meet short-term demand in the event that NW Natural experiences extreme weather at a level similar to the 1949-50 winter conditions. If historic winter conditions such as 1949-50 occur, or if resources do not perform as expected, then the possibility exists to take emergency actions to prevent outages to firm customers. For example, carte blanche may be given to suppliers to round up additional supplies. In addition, emergency capacity exists at the storage plants permitting withdrawals at higher-than-planned rates, albeit at the risk of temporary or permanent damage to the facilities. The Public appeals broadcasting of lower thermostat settings is also an option. Finally, if absolutely necessary to avert firm outages the preempting of gas transported to interruptible customers is an option. Therefore, a certain amount of emergency capacity exists in the system that provides NW Natural a buffer in meeting the extraordinary requirements of firm customers.

In addition to the two design year weather scenarios, NW Natural also evaluated the cost and risk trade off of its supply options with hundreds of Monte Carlo simulations assuming a normal distribution around the 20-year normal. The three deterministic weather scenarios (i.e. 85% probability coldest winter design year, augmented coldest historical year, and normal year) are provided in Appendix 2-14 through 2-16. Results of the cost and risk trade off analyses against the 85% probability coldest design year, 20 year historical coldest weather and the Monte Carlo simulations are presented in Chapter 5.

VII. KEY FINDINGS

Appendices 2-6 through 2-19 summarize NW Natural's customer class and total firm requirements forecasts under each of the Company's six primary load growth scenarios. The demand forecast from the expected Base Case revealed the following:

- The number of system-wide core customers is expected to increase from 652,000 in 2007 to 1,053,000 by 2027. This is an annual average growth rate of 2.4 percent.
- Coincident system-wide design day core demand is projected to increase from a peak of 915 MDth/day in 2007-2008 to 1,223 MDth/day in 2027-2028. This is an annual growth rate of 1.5% in peak day requirements.
- Annual system-wide design year demand assuming the 85% probability coldest winter is projected to increase from 73,201 MDth in 2007-2008 to 100,132 MDth in 2027-2028. This is an annual growth rate of 1.6% in annual requirements.

VIII. ACTION ITEMS

- The Company will investigate data collection requirements to analyze demand forecast error regionally, similar to the system-wide analysis presented in Figures 2-12 through and 2-15.

CHAPTER 3: SUPPLY-SIDE RESOURCES

CHAPTER 3: SUPPLY-SIDE RESOURCES

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

1 Liquefied natural gas, or LNG, is natural gas in its liquid form. When natural gas is cooled to minus 259 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 below 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.

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 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 prices 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 or 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 other discomforts. This may be a temporary move that has a negligible impact on annual requirements, but 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 less than 1% 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, 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 Terasen Inc. (formerly known as BC Gas).

NW Natural holds all rights to most of its firm transportation contracts. The exception is one small volume NWPL contract that was acquired by NW Natural from another party who retained the right to re-acquire the contract at a future date. 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 2008

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
NWPL:		
Sales Conversion	216,044	9/30/2013
1993 Expansion	34,000	9/30/2044
1995 Expansion	102,000	11/30/2011
Weyerhaeuser Cap. Acquisition	5,200	Annual Evergreen
Duke Capacity Acquisition	5,000	Annual Evergreen
Total NWPL Capacity	362,244	
less recallable release to -		
Portland General Electric	(30,000)	10/31/2010
Net NWPL Capacity	332,244	
GTN:		
Sales Conversion	3,616	10/31/2023
1993 Expansion	46,549	10/31/2023
1995 Rationalization	56,000	Annual Evergreen
Total GTN Capacity	106,165	
TCPL BC System:		
1993 Expansion	47,000	Annual Evergreen
1995 Rationalization	56,500	Annual Evergreen
Engage Capacity Acquisition	3,814	Annual Evergreen
2004 Capacity Acquisition	48,200	10/31/2016
Total TCPL-BC Capacity	155,514	
TCPL Alberta System:		
1995 Rationalization	57,000	Annual Evergreen

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 TCPL-BC and TCPL-Alberta 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. NW Natural also has a 2,500,000 therm/day interruptible NWPL contract with a monthly evergreen term.

Burlington/Summit Cap. Assignments	23,561	Annual Evergreen
Engage Capacity Acquisition	3,861	Annual Evergreen
Engage Capacity Assignments	24,121	Annual Evergreen
2004 Capacity Acquisition	48,910	10/31/2016
Total TCPL-Alberta Capacity	157,453	
WEI T-South Capacity	60,000	10/31/2014
Southern Crossing Pipeline (SCP)	47,200	10/31/2020

Since the implementation of FERC Order 636 in 1993, capacity rights on U.S. interstate pipelines have been commoditized; *i.e.*, capacity can be bought and sold like other commodities. These releases and acquisitions occur over electronic bulletin board systems maintained by the pipelines, under rules laid out by FERC. To further facilitate transactional efficiency and a national market, interstate pipelines have 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 by 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 2008-2009 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 less than 20,000 therms per day. The Company utilizes approximately 12,000 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]

Upstream Supplier Portfolio as of November 2008

Supply Location	Duration	Baseload Quantity (Dth/day)	Swing Supply (Dth/day)	Contract Termination Date
British Columbia (Station 2):				
BP Canada	Nov-Oct	5,000		10/31/2009
Coral Energy Canada	Nov-Oct	10,000		10/31/2010
Husky Energy Marketing	Nov-Oct	5,000		10/31/2009
AltaGas Energy Limited	Nov-Oct	5,000		10/31/2010
Nexen	Nov-Oct	10,000		10/31/2010
Nexen	Nov-Oct	10,000		10/31/2009
TD Commodities	Nov-Oct	5,000		10/31/2009
Alberta:				
BP Canada	Nov-Oct	10,000		10/31/2009
Sempra Energy Trading	Nov-Oct	10,000		10/31/2014
BP Canada	Nov-Oct	10,000		10/31/2009
Sequent Energy (NWN Call Option)	Nov-Mar		10,000	3/31/2009
Sequent Energy (Sequent Put Option)	Apr-Oct		10,000	10/31/2009
Husky Energy Marketing	Nov-Mar	10,000		3/31/2009
Suncor	Nov-Mar	10,000		3/31/2009
Sequent	Nov-Mar	10,000		3/31/2009
Rockies:				
Western Gas Resources	Nov-Oct	5,000		10/31/2010
Sempra	Nov-Oct	5,000		10/31/2009
BP	Nov-Oct	10,000		10/31/2011
Iberdrola	Nov-Oct	10,000		10/31/2009
Western Gas Resources	Nov-Mar	10,000		3/31/2009
Sempra	Nov-Mar	10,000		3/31/2009
Sempra	Nov-Mar	5,000		3/31/2009
Coral Energy (NWN Call Option)	Nov-Mar		10,000	3/31/2009
Coral Energy (Coral Put Option)	Apr-Oct		11,500	10/31/2009
BP	Nov-Mar	5,000		3/31/2009
BP	Nov-Mar		10,000	3/31/2009
Questar	Nov-Mar	5,000		3/31/2009
ONEOK	Nov-Mar		10,000	3/31/2009
Total Off-System Firm Contract Supply		175,000	40,000	

4 Notes to Table 3-2:

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

b. Almost all term contracts contain a price formula tied to a published monthly index price. Those index prices may be hedged using financial instruments.

c. *SENDOUT*® assumes all spot and term gas supplies are priced at 100% of the proprietary forecast of monthly gas commodity prices for Sumas, Aeco, and Opal.

C. STORAGE RESOURCES

The key characteristics of existing storage options available to NW Natural from its own facilities, or contracted from NWPL on a firm basis, are shown in Table 3-3[5]:

Table 3-3[6]

Firm Storage Resources as of November 2008

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)	Termination Date
Jackson Prairie:			
SGS-2F	46,030	1,120,288	Upon 1-Year Notice
TF-2 (redelivery service)	32,624	839,046	Upon 1-Year Notice
TF-2 (redelivery service)	13,406	281,242	3/31/2008
Plymouth LNG:			
LS-1	60,100	478,900	Upon 1-Year Notice
TF-2 (redelivery service)	60,100	478,900	Upon 1-Year Notice
Total Firm Off-system Storage:			
Withdrawal/Vaporization	106,130	1,599,188	
TF-2 Redelivery	106,130	1,599,188	
Firm On-System Storage Plants:			
Mist (reserved for core)	240,000	9,197,000	n/a
Portland LNG Plant	120,000	600,000	n/a
Newport LNG Plant	60,000	1,000,000	n/a
Total On-System Storage	420,000	10,797,000	
Total Firm Storage Resource	526,130	12,396,188	

5 SGS refers to the Storage Gas Service available from NWPL at the Jackson Prairie underground storage facility near Chehalis, Washington. LS refers to the Liquefaction Service offered at NWPL's Plymouth LNG plant in Washington, just across the Columbia River from Umatilla, Oregon. SGS-2F and LS-1 exclude NWPL transportation service to NW Natural's system. TF-2 is the firm transportation service offered by NWPL for redelivery of gas from certain storage facilities to customers on its system.

6 Notes:

a. For the JP and Plymouth storage resources listed herein, the *SENDOUT®* model includes the cost NW Natural is currently paying NWPL for the service. For each of the on-system storage resources, the *SENDOUT®* model includes a carrying charge on the carried gas inventory equal to 5.16%. In addition, for the Mist capacity, the *SENDOUT®* model includes a daily deliverability charge of $0.004/Dth (the same cost assumed for Mist recall capacity).

b. All of the above agreements continue year-to-year after termination at NW Natural's sole option.

c. On-system storage peak deliverability based on design criteria.

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 plus three newer reservoirs (Schlicker, Busch, and Meyer). Capacity in excess of core needs is made available for 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.

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[7]

Recallable Supply Arrangements as of November 2008

Type	Max. Daily Rate (Dth/day)	Max. Annual Recall (days)	Termination Date
Recall Agreements:			
Recall 1	30,000	30	11/1/2010
Recall 2A	3,000	40	upon 1 year notice
Recall 2B	5,000	40	upon 1 year notice
Total Recall Resource	38,000		

All of the above agreements provide for continuation after the termination date if mutually acceptable. Two of these deals (Recall 2A/B) are already in their annual "evergreen" period. Recall 1 utilizes NWPL capacity released by NW Natural on a

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

recallable basis, and correlates to customer release volumes shown in Table 3-1. When this arrangement terminates, the released NWPL capacity reverts back to NW Natural. Recall 2A and 2B utilize NWPL capacity held by the providers of the service.

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

E. SUPPLY DIVERSITY

The Company buys its supplies from a variety of supply basins, including a small amount of local production in the Mist field as mentioned above. The underlying purchase contracts are weighted towards long-term (one year or more) durations to ensure reliability of supply and simplify contract administration. A significant number of the contracts are medium-term (less than one year but at least one month) arrangements, primarily five-month contracts, to match the seasonal increase in customer requirements during the winter. A small portion is purchased on the spot (less than one month) market, typically during the non-heating season to meet fluctuating storage injection requirements and if favorable pricing is available during other periods of the year.

The Company is also pursuing additional methods of acquiring gas supplies. A "gas reserves purchase" would be an outright acquisition of supplies. A "volumetric production payment" agreement would be an advance purchase of reserves owned by another party. Both differ from typical supply contracts in two ways. First, the Company would prepay for all of the gas. Second, supplies would be tied to a specific reservoir. These deals are attractive to producers who prefer to monetize their assets up front in exchange for potentially lower prices. The Company will continue to pursue these if purchase prices are attractive for customers.

The second potential new supply resource is imported liquefied natural gas. If an LNG terminal is built on or near the Columbia River, the Company will likely extend the Palomar Pipeline to connect the terminal with NW Natural's distribution system.

Figures 3-1 and 3-2 provide graphical representations of the Company's supply resources and diversity during 2007.

FIGURE 3-1

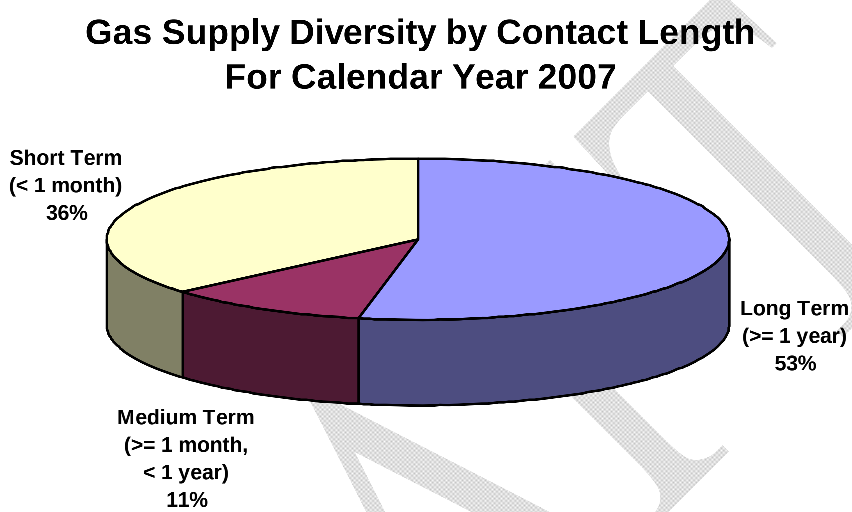
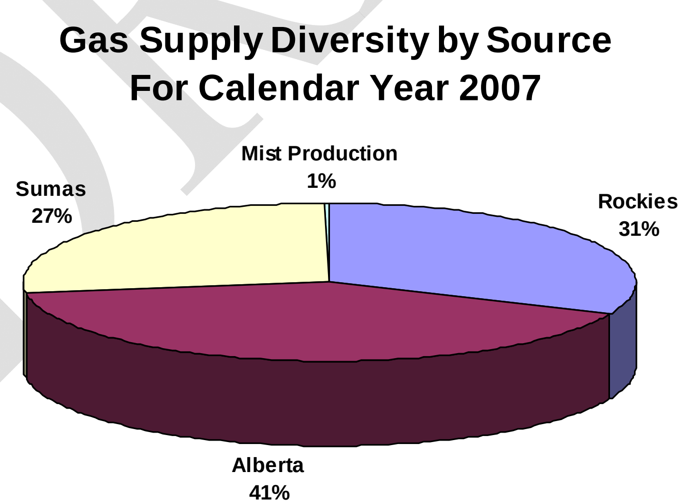


FIGURE 3-2



Two transitions began in 2003 that have altered the appearance of these graphs in recent years. First, the Company had five long-term (10 to 15- year) supply contracts that all expired in October or November 2003. These contracts previously accounted for over 60% of total annual purchases. They began during the onset of deregulation in the late 1980s and early 1990s and reflected concerns at the time regarding supply reliability, as well as regulatory requirements to demonstrate market support for upstream pipeline expansions. They were cumbersome, however, in that they required annual price renegotiation subject to binding arbitration. Over time, these contracts evolved to using price formulas based on monthly price indexes, but annual renegotiation was still needed every year to determine the factor (usually a small premium) to be applied to the monthly index for the coming year. Replacement supply contracts also reference monthly price indexes, but the factor to be applied to the index has been negotiated for the term of the agreement, so no further negotiations are required.

The second transition concerns sources of supply. While NW Natural originally was dependent on British Columbia for roughly half of its gas purchases, there are far greater supplies of gas available in the province of Alberta. Alberta markets are far more liquid and hence exhibit less volatility than British Columbia trading points. NW Natural's subscription to capacity on SCP and associated TCPL capacity allowed it to shift some of its current British Columbia purchases to Alberta starting in November 2004. Figure 3-2 reflects the movement away from British Columbia supply and more towards Alberta supply.

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

F. 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 Gas Supply Risk Management Policies. 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 Committee has oversight for the development and enforcement of the Gas Supply Risk Management Policies. 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 now 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 best 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.

Appendix 3-1 shows the inventory guidelines for the 2007-2008 heating season at Mist, the Newport LNG plant, the Portland LNG plant ("Gasco"), and under the Jackson Prairie (SGS-2F) and Plymouth (LS-1) contracts with NWPL.

IV. RECENT RESOURCE DECISIONS

In the short time since the 2007 IRP and the 2008 update thereto, NW Natural has added a small amount of new capacity at its Mist storage field. In addition to acquiring that new resource, 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 10,000 Dth/day of capacity at the Mist storage field as called for in the 2007 IRP for use by the Company's core customers.
- 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 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 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

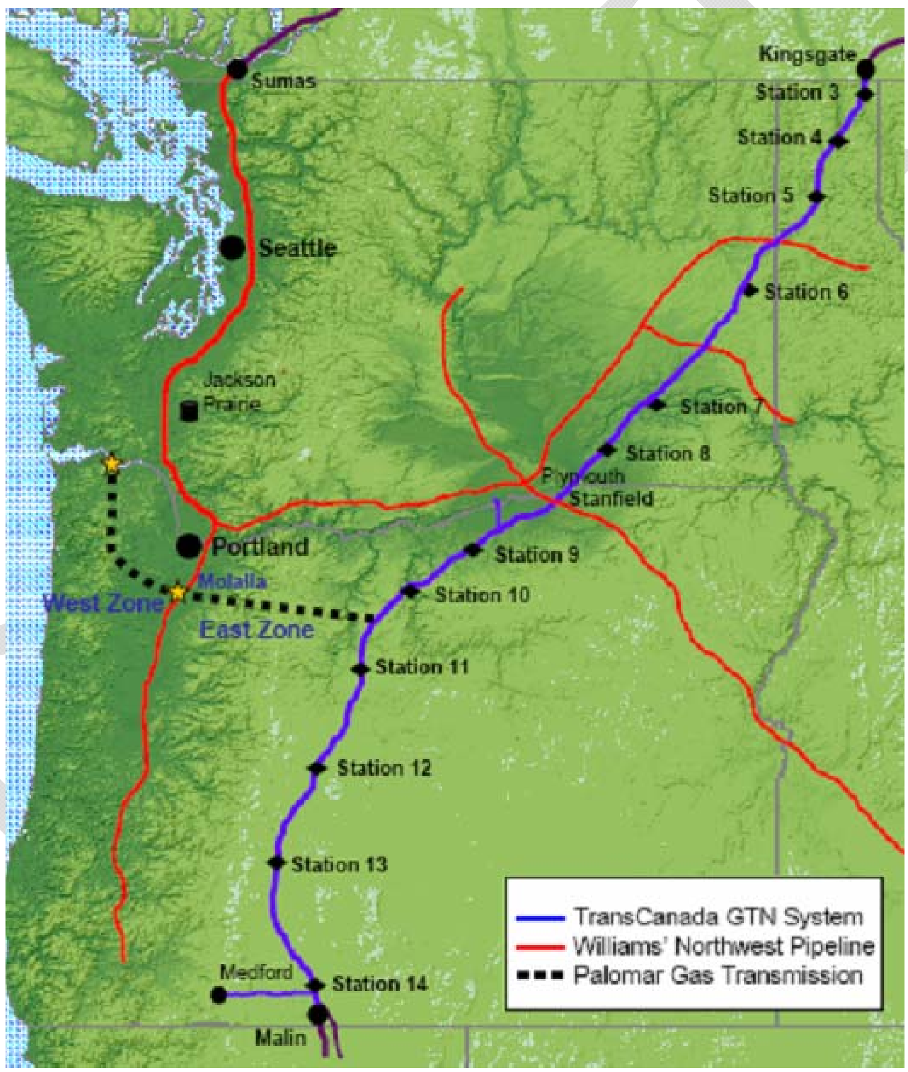
NW Natural holds existing CD entitlements and citygate station capacity on: (i) NWPL's "mainline" serving NW Natural's service areas in Portland, Astoria, Vancouver and The Dalles, and (ii) NWPL's Grants Pass Lateral serving NW Natural's loads in the Willamette Valley south of Portland. Therefore, consideration 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 in two segments. The eastern segment would connect GTN's mainline north of Madras, Oregon, to NW Natural's gate station at Molalla ("Palomar East"), and the western segment would continue this connection to NW Natural facilities near Mist, Oregon ("Palomar West"). On December 11, 2008, Palomar filed an application for a certificate to build and operate the pipeline with the Federal Energy Regulatory Commission. Pending approval by the FERC, Palomar could begin construction of the pipeline in 2010, and be on-line in 2011.

Separate from its ownership interest in Palomar, NW Natural has entered into a Precedent Agreement with Palomar for 100,000 Dth/day of capacity on the proposed pipeline for delivery of gas from Madras to Molalla (Palomar East) and from Molalla to Mist (Palomar West). 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 Pipeline



From NW Natural's perspective, the primary benefit accruing from construction of Palomar East 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, effectively lowering the net cost of this incremental resource.[8] As a secondary benefit, the second phase (Palomar West) would be well positioned to effectively interconnect with any LNG terminals that might be constructed along the lower Columbia River in order to transport gas from these terminals to the Portland area and the interstate natural gas pipeline network in central Oregon.[9]

As shown in Table 3-5 below, in this IRP, NW Natural considers acquisition of incremental interstate pipeline capacity in several forms: (i) new NWPL Grants Pass Lateral capacity serving Salem, Newport, Albany and Eugene, (ii) new NWPL "mainline" capacity serving Portland, Astoria, Vancouver, and The Dalles, (iii) new capacity upstream of NWPL mainline capacity providing access to the Rockies[10] and Alberta supply areas, (iv) new Palomar capacity both east and west of Molalla, (v) new capacity on the proposed Pacific Connector Pipeline to access regasified LNG from the proposed Jordan Cove LNG project at Coos Bay, OR, (vi) recall of existing NWPL mainline capacity from the Rockies and Sumas that NW Natural has released to Georgia Pacific, and (vii) existing NWPL mainline capacity from the Rockies currently held by that NW Natural has contracted to acquire starting in 2017. The acquisition of incremental pipeline capacity spans a wide 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.

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 As previously discussed, we have included the Palomar West pipeline segment serving the Bradwood LNG project in the *SENDOUT®* model.

10 NWPL capacity upstream of Stanfield, Oregon.

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 2011
NWPL Zones 26-12 ("mainline")	2,031,000	November 2011
Upstream of NWPL z26-12:		
Rockies-Stanfield	1,062,000	November 2011
Alberta-Stanfield	969,000	November 2011
Palomar East	200,000	November 2011
Palomar West	100,000	November 2011
Pacific Connector	100,000	November 2011
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, 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
2008	1,710,000		75,630	
2010	600,000	2,310,000	26,537	102,167
2011	1,560,000	3,870,000	68,996	171,163
2012	320,200	4,190,000	14,153	185,316
2015	1,089,000	5,279,000	48,165	233,481
2017	1,260,000	6,539,000	55,727	289,208

Mist is ideally located in the center of 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 and north Oregon coast 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 input from outside economic development and planning agencies, performs the planning for the expansion, reinforcement, and replacement of elements of the distribution system.

The Company uses the Synergy software package[11] 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.

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

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 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 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 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 3-2). 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 versus 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 5,000 Dth/day of Grants Pass Lateral capacity available at the Brownsville/Halsey gate station, the Company needs a Willamette River crossing near the town of Harrisburg in order to bring that capacity to the Eugene market. The Company estimates this project would cost approximately $420,000 and could be placed in-service by November 2012.

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 six segments serving three load regions, as follows: (i) Salem area segments: Sherwood-Perrydale, Perrydale-Independence; (ii) Albany area segments: Independence-N. Albany, N. Albany-S. Albany; and (iii) Eugene area segments: S. Albany-Halsey, Halsey-Eugene.

Table 3-7
Willamette Valley Feeder Project Segments

Segment	Assumed Capacity (Dth)	Estimated Capital Cost
Sherwood-Perrydale	120,000	$16,600,000
Perrydale-Independence	82,000	$14,400,000
Independence-N. Albany	50,000	$13,700,000
N. Albany-S. Albany	38,000	$8,800,000
S. Albany-Halsey	26,000	$12,300,000
Halsey-Eugene	26,000	$16,700,000

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.

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 LNG

Natural gas liquefaction dates back to the 19th century, when British chemist and physicist Michael Faraday experimented with liquefying different types of gases, including natural gas. German engineer Karl van Linde built the first practical compressor refrigerator machine in Munich in 1873. The first liquefied natural gas plant dates back to 1912 and was built in West Virginia, with the first commercial liquefaction plant being built in Cleveland, Ohio, in 1941. Today there are over 100 active LNG facilities spread across the United States, with most concentrating in the northeastern United States.

Ocean transport of LNG began in 1959[12]. U.S. natural gas companies built four land-based marine liquefied natural gas import terminals between 1971 and 1981: Lake Charles – operated by Southern Union[13]; Everett, MA – operated by Tractebel[14]; Elba Island, GA – operated by El Paso[15]; and Cove Point, MD – operated by Dominion[16]. From a high of 253 Bcf in 1979, LNG imports saw a sharp decline. This was caused by natural gas industry restructuring that led to increased North American domestic natural gas production and price disputes with Algeria, then the sole LNG exporter to the U.S. These events resulted in the owners of the Elba Island and Cove Point facilities mothballing their terminals for over 20 years. Not until the first new Atlantic Basin LNG liquefaction plant came on line in Trinidad and Tobago, combined with increased U.S.

12 That first cargo of LNG was shipped from the United States to England.
13 The Lake Charles terminal was completed in 1981, and has a max send-out rate of 2.1 Bcf per day or a firm sustained baseload of 1.8 Bcf per day (13.1 mmtpa)
14 The Everett terminal was completed in 1971, and has a max send-out rate of 1 Bcf per day (nameplate) or a firm sustained baseload of 715 Mcf per day.
15 The Elba Island terminal was completed in 1978, and has a max send-out rate of 1.2 Bcf per day or a firm sustained baseload of 1 Bcf.
16 The Cove Point terminal was completed in 1978, and has a max send-out rate of 1 Bcf per day or a firm sustained baseload of 750 Mcf.

natural gas demand and increased natural gas prices, were these two facilities reactivated. The EIA estimates the combined annual baseload capacity of the four land-based import terminals is 880 Bcf, and each facility has either recently completed an expansion or announced plans to expand their capacity over the next few years. Reflecting its new-found competitiveness in North American markets, U.S, LNG imports exceeded 780 Bcf in 2007.

In response to current and forecast gas market conditions, North America has witnessed a second wave of LNG import terminal project development. Excelerate Energy completed the Gulf Gateway offshore Louisiana LNG import terminal in 2005 and the Northeast Gateway offshore Massachusetts terminal in 2008. Several other projects are under construction and there are several dozen proposed new LNG terminals that are in various stages of development. The EIA predicts that by 2010, projects could be located in and around the U.S., including the Gulf of Mexico, Bahamas, the U.S. west coast, Mexico’s west coast, and varying points along the U.S. and Canadian east coasts.

While most of the activity focused on LNG is taking place in the Gulf of Mexico and along the U.S. east coast, there are a number of viable west coast LNG projects and proposals that could become operational within the next five to ten years that would have a direct impact on NW Natural’s resource planning and acquisition. As of March 24, 2008, the FERC lists three proposed or potential LNG import terminal projects within Oregon. They are Bradwood (Northern Star LNG) in Bradwood, Jordan Cove in Coos Bay and Oregon LNG in Astoria. The two projects that are furthest along are the Bradwood and Jordan Cove facilities.

The Bradwood terminal would be a re-gasification facility consisting of two storage tanks and an estimated average production capacity of 1.0 Bcf per day, with a possible expansion up to 1.5 Bcf per day. Bradwood has proposed a 35-mile export pipeline to interconnect with Northwest Pipeline near Kelso, Washington. The proposed Palomar Pipeline, which is a separate project, would link to the Bradwood Landing Pipeline a few miles east of the terminal. This second alternative pipeline path would support LNG deliveries into the NW Natural system and to the GTN pipeline in central Oregon. The developer has filed with both FERC and the OPUC.

The Jordan Cove terminal would also be a re-gasification facility consisting of two storage tanks, a 25 MW gas-fired cogeneration plant, and a 250 mile Pacific Connector Gas Pipeline. It is estimated to have an average production capacity of 1.0 Bcf per day, with the ability to host six to seven tankers per month. Jordan Cove and Pacific Connector each filed applications for approval from the FERC in September 2007.

Although neither Bradwood nor Jordan Cove has been constructed, for analysis purposes, NW Natural is including them in its modeling (see Appendix 3-2). As depicted in Figure 3-4, we model the Bradwood project as feeding the Company's intrastate distribution system by way of the proposed Palomar West pipeline. As depicted in Figure 3-5, we model the Jordan Cove project as feeding the Company's distribution system by way of the proposed Pacific Connector Pipeline with further delivery by either NWPL or Palomar. NW Natural would be able to receive some portion of the Jordan Cove-sourced supply into the south end of its system (Eugene) via NWPL's Grants Pass Lateral. Due to capacity constraints on the Grants Pass Lateral, we assume Jordan Cove volumes greater than 25,000 Dth/day are delivered to NW Natural via Pacific Connector, GTN and Palomar East. Absent more definitive information from project developers, we assume that import LNG supply will be priced competitively alongside any of the Company's other gas supply contracts (see Appendix 3-2 for assumed LNG pricing).

Figure 3-4: Bradwood Landing Schematic

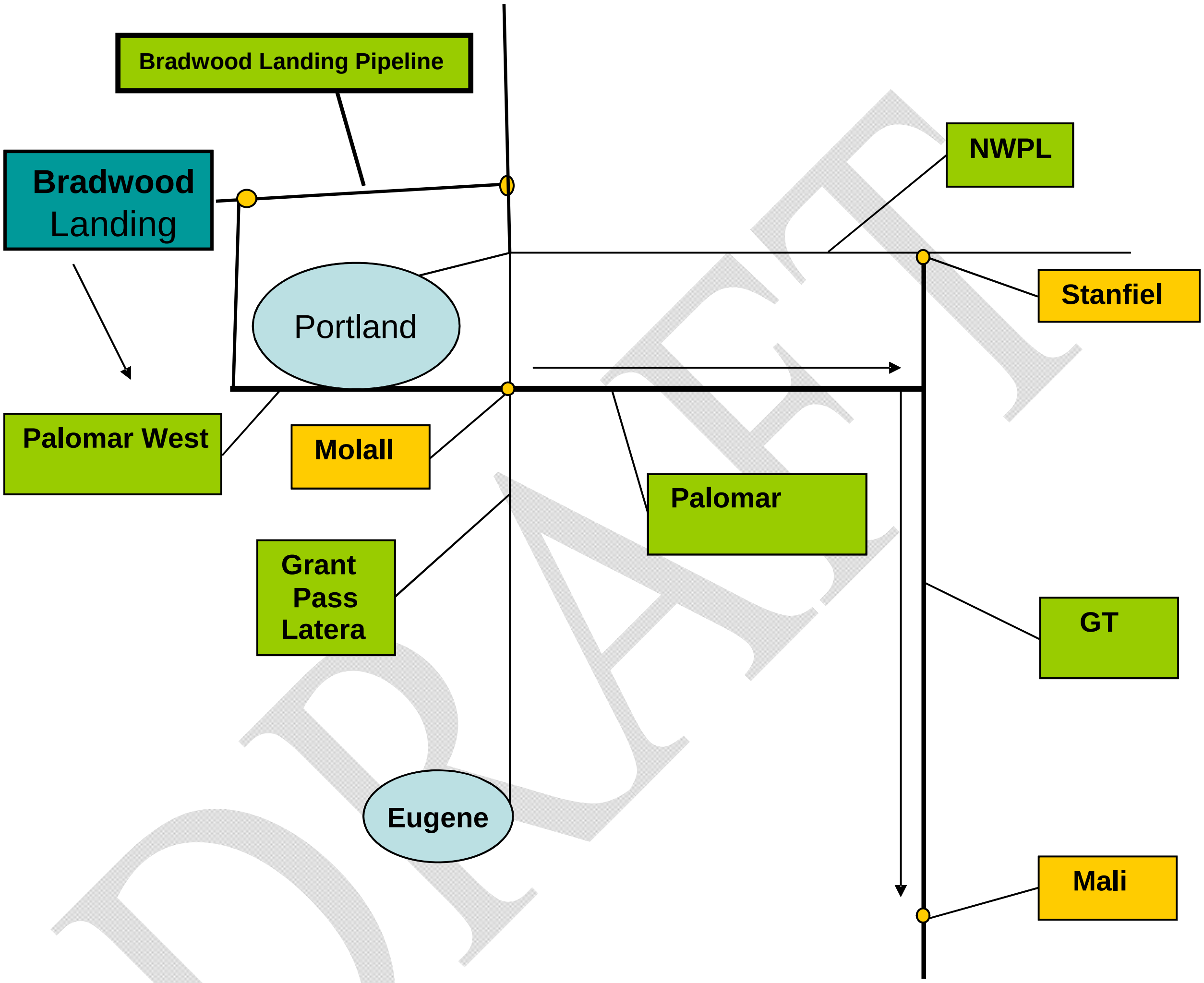
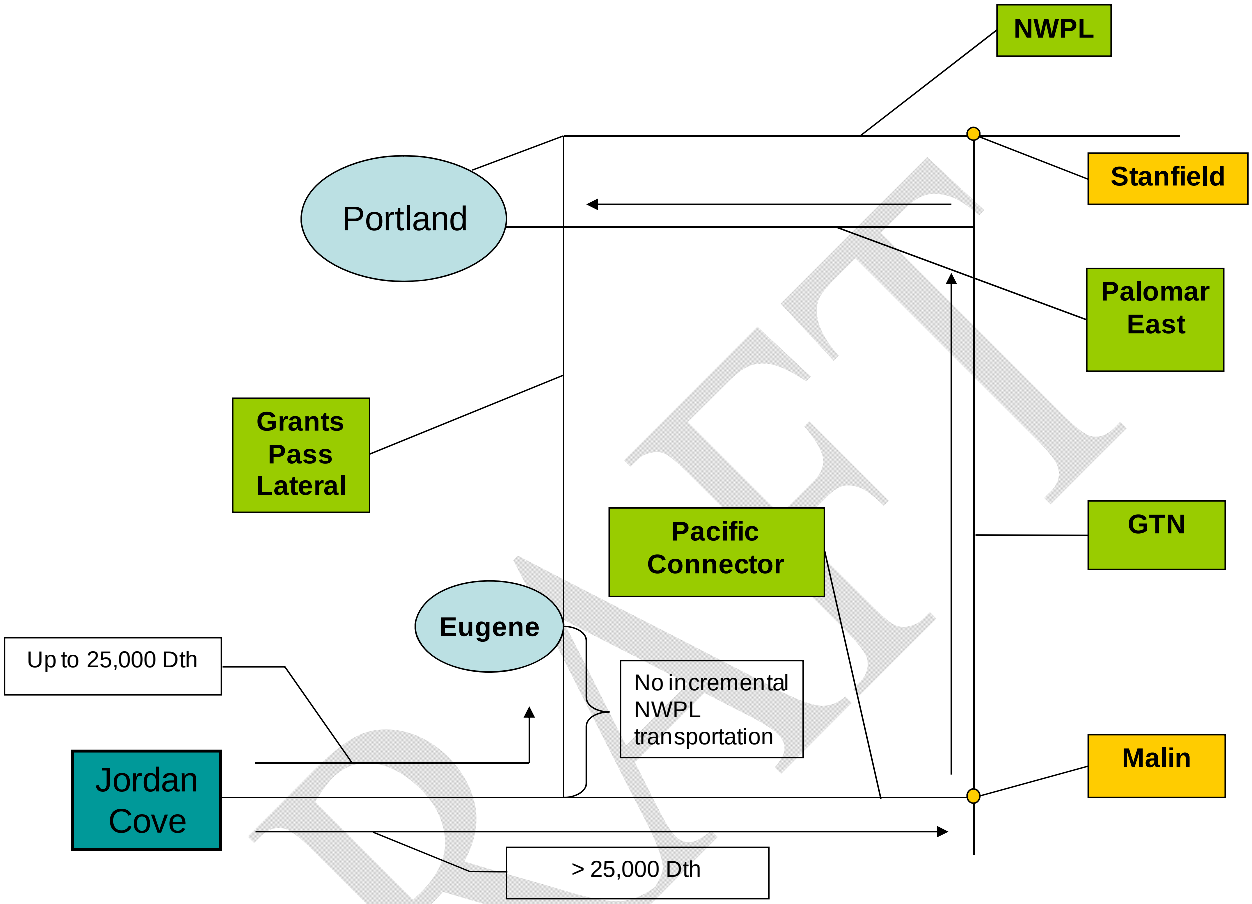


Figure 3-5: Jordan Cove Schematic



The future of imported LNG is difficult to predict, but it appears likely that LNG imports to the US will increase during the planning horizon. While recent development in the shale plays has increased domestic production of gas, many industry experts predict that demand for natural gas will increase throughout the planning horizon, particularly if natural gas becomes the incremental resource addition for electric utilities seeking to respond to carbon constraints, and particularly where electric utilities must seek a way to reduce dependence on existing coal plants. The recession and credit crisis have resulted in decreased drilling activity, which may ultimately impact available domestic supplies of natural gas. Meanwhile, worldwide production capability of LNG is increasing, and suppliers may see the United States as a flexible market for gas that is otherwise targeted for higher priced Asian and European markets. As a result of these forces, while it appears likely that the current global recession will slow the development of the LNG market in the United States, experts still predict that LNG imports will increase significantly in the United States in the 2012-2016 timeframe.

As an alternative view, a number of recent studies have suggested that adoption of a federal renewable portfolio standard (RPS), adoption of state RPSs, and/or increased penetration of renewables such as wind power may result in a long-term decrease in natural gas demand.[17] Decreasing demand could result in lower prices, and a less robust LNG market. However, these studies generally rely upon assumptions regarding development of infrastructure to support renewables, a commitment to new nuclear projects, or developments in clean coal technologies. In the absence of such assumptions, if carbon constraints are introduced, or even if the status quo simply continues, it seems likely that natural gas will be needed to meet demand and provide the “blue bridge” to future clean energy projects. Moreover, decreased demand for natural gas may or may not affect LNG imports; if domestic supplies of conventional gas are exhausted, and producers must look to higher priced shale gas, imported LNG could retain a price advantage, even considering transportation costs. Ultimately, the future of imported LNG is difficult to predict with certainty, and for this reason the Company has not included an imported LNG terminal in its Base Case.

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

1) Bradwood Landing LLC

To be located at River Mile 38 east of Astoria on the Columbia River. On June 5, 2006, this project filed a formal certificate application with FERC to site, construct, and operate the terminal and its associated pipeline, FERC Docket No. CP06-365-000. On September 18, 2008, FERC issued an order granting the requested authority and issuing certificates to the terminal and associated pipeline. 124 FERC ¶ 61,257 (2008). Subsequently, on November 17, 2008, FERC granted rehearing of the September 18 order for the limited purpose of further consideration.

2) Oregon Development Company, LLC (dba Oregon LNG)

To be located at the Skipanon peninsula on the Columbia River near Warrenton.

17 *See* Design Recommendations for the WCI Regional Cap-and-Trade Program (September 23, 2008), predicting substantial declines in natural gas use and energy use overall, if a regional cap and trade program is adopted, along with aggressive energy efficiency programs that would reduce demand by 1% annually; Weighing the Costs and Benefits of State Renewable Portfolio Standards: A Comparable Analysis of State-Level Policy Impact Projections, Environmental Energy Technologies Division of the US Department of Energy (LBNL-61580; March 2007); 20% Wind Energy by 2030: Increasing Wind Energy’s Contribution to U.S. Electricity Supply, US Department of Energy, Energy Efficiency and Renewable Energy (prepublication version, May 2008).

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.

3) 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.

4) Terasen Project

Located NW of Ladysmith and West of Mt Hayes, this is a peak shaving LNG terminal. Originally this was going to be an import terminal but it is now planed to be an export terminal due to the shale projects in British Columbia. This project is located on Texada island and will connect into Terasen's system. The plan is to have gas flow to Huntingdon/Sumas and to barge LNG to communities on the Westcoast. Its capacity is 2 Bcf and 200 mmcf/d. This project is under construction and has received BCUC approval.

5) Kitimat LNG Inc. Terminal

Kitimat LNG Inc. proposes an LNG export terminal located near the private port of Kitmat in British Colombia 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.

NW Natural views LNG as a key resource in providing further diversification among its supply side resources, and will continue to monitor developments in this area. If an LNG import terminal is sited in Oregon, the Company foresees subscribing 20-25% of its supply portfolio through LNG supplies at some point in the future. With current load hovering around 2 million therms per day, this would translate into approximately 400,000 to 500,000 therms per day of LNG.

I. SATELLITE LNG

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 (see Appendix 3-2). 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 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 a 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 load requirements – 410,000 annual therms. The program is further enticing because of the other by-product of the process – fertilizer. While peat moss is a high-dollar market, over time it is unsustainable due to the limited supply of peat. Advocacy groups have begun to bring this issue to the forefront, and ADG provides a very appealing substitute. 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 is expected to be operational by March 2009. This project will convert waste into an ADG that can be used to offset onsite propane use for the dairy operations. Conservative estimates suggest this first test unit will reduce carbon emissions by 3,300 tons annually.

This farm is large enough to accommodate another 12-15 biodigesters, potentially capturing an additional 40,000 plus tons of carbon 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 is also discussing siting two more biodesters at a second local dairy farm that has 1,500 cows. This proposed project could annually capture 4,500 tons of carbon and offset some on-site gas or electricity requirements.

Because these resources are in their early R&D 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. While NW Natural has made periodic use of these facilities (especially in Alberta) to store off-peak gas and improve supply contract load factors, there are no plans for NW Natural to become involved on a long-term equity and contractual basis with any of these facilities. The stumbling block 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 advantage NW Natural if winter/summer price differences are sufficient to offset storage facility usage charges.

Assuming NW Natural continues to expand Mist, utilization of upstream pipeline capacity and year-round supply contracts should improve because storage injection requirements will grow. This will further decrease the need for supply area storage. Due to these factors, supply basin storage will probably never be more than a year-to-year gas supply portfolio structuring option, rather than a long-term resource acquisition.

VII. GAS SUPPLY PORTFOLIO ACQUISITION STRATEGY

A. OVERVIEW

This section provides the Company's strategies for acquiring gas supplies as presented in NW Natural's Gas Acquisition Plan 2008-2009 ("GAP"). The GAP is the Company's most recently approved resource acquisition plan, 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 2008-2009 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

Reliability

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

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.

Price Stability

Customers are sensitive to price volatility in addition to the expected price level. 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 up to five years.

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. Consequently, the 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 any and all standards of conduct. And because any 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. While the IRP focuses on identifying the best resource portfolio over the 20-year horizon, the GAP focuses on satisfying the Plan Goals in the short-term, given the existing resource portfolio. Because the IRP focuses on long-term decisions, it does not include many of the details relating to gas supply contracts, hedging, etc. that are provided in the GAP.

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 NW Natural Gas Acquisition Strategy and Policies Committee.

- Maximize supplies from the Rockies to take advantage of lower prices there. Over the past several years, Rockies gas has been abundant and favorably priced compared to other basins. The Company has maximized its purchase of Rockies gas primarily through spot purchases with a few short-term (typically winter season) contracts. However, those lower prices were caused by increased production in that region in anticipation of the Rockies Express East Pipeline. That pipeline will extend the existing Rockies Express West pipeline on to Ohio with a projected in-service date of June 2009. As that and other pipelines go into service, competition for Rockies supply will escalate. Accordingly, moving some purchases into longer-term contracts will help mitigate the volatility that is likely to increase for daily and short-term purchases. Evaluate other strategies as that and other new pipeline projects near completion and fundamentally alter the supply/demand dynamic in the Rockies.

- Fill storage at a pace that might present opportunities to purchase gas at times when storage around the country is likely to be full and a price drop could occur.

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

The historic high differential in price between the Rockies and the eastern U.S. will narrow as new pipelines such as the Rockies Express enable more access to supplies in the Rockies. At the same time, Rockies producers will drill more vigorously to find production to fill the new pipelines. A parallel situation existed in the early 1990s prior to the construction of the Kern River Pipeline.

Domestic supplies of recoverable natural gas are increasing. Gas trapped between dense layers of the world's most prevalent sedimentary rock, shale, is now accessible with new methods of horizontal drilling and fracturing. This has increased estimated U.S. natural gas resources by 18 percent over estimates of four years ago.[18] Meanwhile, the economic recession has decreased demand. Less demand coupled with more supply resulted in significant natural gas price drops since July 2008.

The debate over pipelines from the Arctic Circle may be resolved, but it is uncertain whether or not the pipelines will be in service in this time frame. This assumption is consistent with the Wood Mackenzie reports. If the Mackenzie Delta pipeline is built, all of its gas deliveries are likely to be consumed in northern Alberta for oil-sands production.

LNG will provide additional supplies, nudging prices down to stem demand destruction.[19]

Pipeline de-contracting could pose a major concern in the Pacific Northwest. Decisions by shippers not to renew pipeline capacity contracts with Gas Transmission Northwest (GTN) led to a major rate increase on that system in 2007. Projects such as the Ruby Pipeline and Jordan Cove LNG terminal create additional opportunities for decontracting on GTN and other pipeline systems. However, recent long-term contract renewals on the Northwest Pipeline system in February 2008 may be the first signal that this trend is easing. The March 2008 announcement of the NWPL/GTN Sunstone pipeline project could even reverse this trend (i.e., lead to the resubscription of currently unutilized pipeline capacity, if that project is successful).

In light of the above, hedging will continue to be an important and necessary tool to manage volatility. Physical hedging through storage will only grow in importance, especially if pipeline rates increase to cover a shrinking customer base. Diversity among supply basins will also continue to be important if Rockies supplies find new outlets to the East and price differentials evaporate.

NW Natural has tested the impacts of a number of alternative outlooks, including, but not limited to: high and low demand and price scenarios; significant economic recession and decline in customer growth; the introduction of LNG into the region; significant increases in the rates of certain pipelines; and the stochastic analysis as

18 "Accessing Buried Treasure, " American Gas Magazine, June 2008, page 30.
19 "North American Power Forum," Wood Mackenzie, December 2, 2008, pages 89-122.

explained in chapter 5.

VIII. EMERGENCY PLANNING

NW Natural uses 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 two 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.

As previously described, the Company designs its resource portfolio to satisfy firm loads on the coldest-weather day and through the most strenuous heating season (as measured by HDDs) experienced during the past 20 years. 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 and painless as possible, with public health and safety being the ultimate priority.

IX. 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 ranging three years from the current period is desirable because it dampens volatility and assures more stable pricing for customers. The three year limit could be extended if deemed desirable and if counterparties are found who meet risk and credit standards.

- 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 Pipeline project.

- After greater analysis, the Company believes the availability of liquefaction capability, domestic demand for natural gas, and global need for flexible markets for LNG supplies will bring LNG imports to the United States in greater quantities in the 2012-2016 timeframe. We continue to believe that these supplies will be priced "at market," meaning that the price point for imported LNG will follow from the price for local domestic supplies.

- 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, contracting for supply from proposed new LNG import terminals, and satellite LNG.

CHAPTER 4: DEMAND-SIDE RESOURCES

Table of Contents

I. DEMAND SIDE MANAGEMENT OVERVIEW

NW Natural strives to be an environmentally responsible company. As such, the Company values the role of energy efficiency as a means for reducing customers' bills, supply-side needs and greenhouse gas (GHG) emissions. Because the societal value is so great, the Company looks at DSM potential with earnest.

This chapter demonstrates the Company's consideration of demand side management (DSM) as a least cost resource. In addition, this chapter meets the following content requirements for an IRP as set forth in WAC 480-90-238 (3) (b):

The IRP must provide:

1) *an assessment of commercially available conservation;*
2) *including load management;*
3) *as well as an assessment of currently employed and new policies; and*
4) *Programs needed to obtain the conservation improvements.*

Demand Side Management (DSM) and energy efficiency (EE) are used interchangeably in this chapter.

II. METHODOLOGY – DEMAND SIDE MANAGEMENT

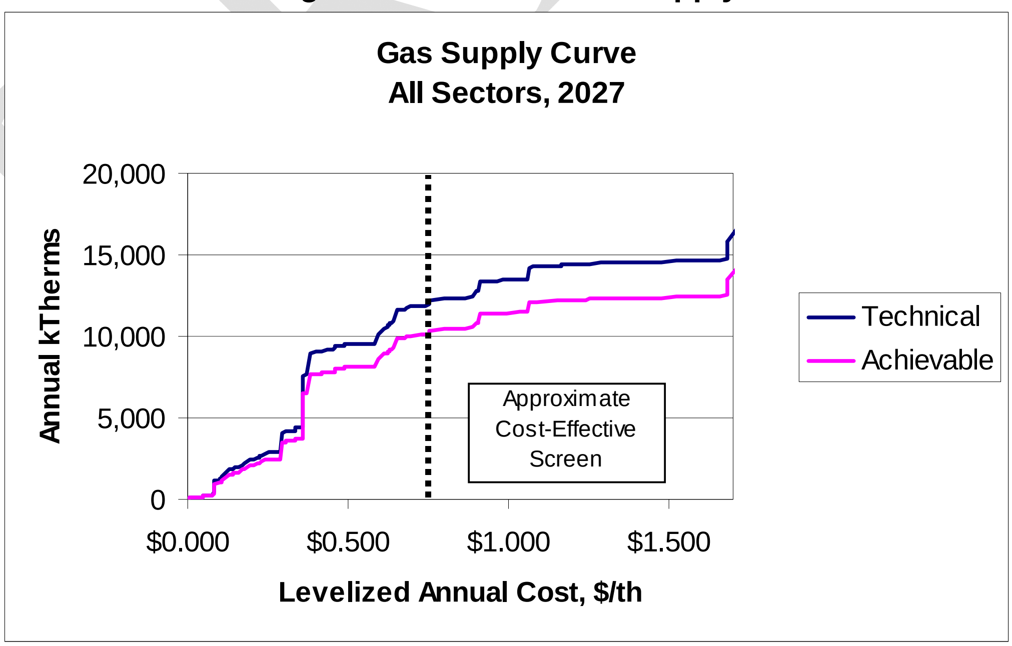
A. TECHNICAL AND ACHIEVABLE POTENTIAL OVERVIEW

NW Natural worked with the Energy Trust of Oregon ("Energy Trust") to project the amount of cost-effective DSM available in the Company's Washington Service territory for the next 20 years. The study began with a demographical study, involving the collection of area-specific information including home vintages, building codes and customer segment served. This information reveals which efficiency measures are most appropriate for the area. By knowing when the homes were built, the Company can generally know the efficiency of installed windows, the R-value of installed insulation, and the age of the heating systems.

The next phase of this study required a comprehensive look at all commercially available conservation measures. Measures were complied for all customer segments and for both new and old building structures. The measures that are marketable within NW Natural's service territory were assessed at a Total Resource Costs (TRC), which is a value is based on the measure's projected therm savings, the installation cost, and the present value of operations and maintenance ("O&M") costs less any non-energy offsetting benefit determined using the Company's real after tax discount rate of 5.16.

TRCs allow the Company to graphically demonstrate the potential therms that could be saved at various costs. Below is a resource supply curve that is useful for comparing demand side and supply side resource options. As conditions cause the avoided cost to rise, more measures may become cost-effective.

Figure 4-1: Natural Gas Supply Curve



The supply curve method is necessarily crude because the estimated DSM measure costs and savings are based on averages and are not adjusted for site specific cost-effective deviations. The blue line in Figure 1 depicts the technical potential which is the sum of all cost-effective DSM over the twenty-year planning period. The technical potential demonstrates all energy savings that could be accomplished immediately without the influence of any market barriers such as cost and customer awareness. Technical potential does not present what can be saved through actual programs; it would be impossible to get every customer to install every possible measure. The achievable potential, represented with the pink line in Figure 4-1, is a measured percentage of the technical potential. The economic barriers affecting the various customer segments are quantified to determine the percentage of variance between technical and achievable potential. The achievable potential is a more realistic assessment of what can be expected because it considers that not all consumers can be persuaded to participate and other real world limitations

This study finds that by 2027, the Company's Washington service territory has an achievable potential of 11 million annual therms of gas savings. Table 4-1 below shows how this technical potential breaks down by customer class.

Table 4-1 Summary of Achievable Potential

Northwest Natural Gas's Washington Service Territory	Million Therms
Residential	7
Commercial	3
Industrial	0.3
Total	11

Below is a more detailed discussion on how these 11 million therms of savings were identified.

B. WASHINGTON CUSTOMER DEMOGRAPHICS

NW Natural serves approximately 60,000 residential, small commercial and industrial customers across Washington. Customers and overall consumption by customer sector and average use are shown in Table 4-1.

Table 4-2: FY 2007 Customer Statistics

Sector	Number of Customers	Sales (Therms)	Average per Customer
Residential	56,132	41,200,888	734
Small Commercial	4,468	18,175,824	4,068
Small Industrial	12	2,195,984	183,000
Total	**60,612**	**61,572,626**	

NW Natural's Washington-based customers are primarily in Clark County with a small percentage located in Skamania, Cowlitz, and Wahkiakum Counties. The sum of NW Natural's Washington customers is equivalent to approximately 10% of the Company's Oregon customers.

After studying 1% of the population and creating disaggregated data sets on geographic areas containing 100,000 people, we determined the following:

- 46,041 gas heated homes in the SW Washington Counties are served by NW Natural
- 90% of these homes are located in Clark County
- 10% qualify as low income
- The housing stock is very new: 80% of the homes were built after 1990.
  - o Of these, 47% (over 17,000 units) were built from 1990-1994.
- Gas heated homes outside of Clark county account for less than 10% of the total stock of gas heated homes in the NW Natural Washington service territory.
  - o Of those gas heated homes in the area, almost 90% are owner occupied housing units.

C. THE TECHNICAL POTENTIAL STUDY

1. Methodology

The following steps were taken to determine the inputs required for the technical potential study:

a. Established Energy Consumption Baseline.

A baseline usage was established for customer types using utility estimates of sales. Understanding how much energy is currently consumed for specific end uses and market segments is instrumental in identifying the eventual savings estimates.

b. Estimated Energy Consumption by End Use for Each Customer Type.

The methods varied by customer group: For the industrial sector, the Energy Trust estimated the incremental consumption for specific processes. For the commercial sector, the Energy Use Intensity ("EUI") factors provided consumption by end use. For the residential sector, prototype models were used to estimate major end use consumption, calibrated to actual sector consumption

c. Forecasted future consumer population.

The utility forecasted growth rate was used to estimate the customer base available in future years.

d. Compiled And Screen List Of Measures, Develop Measure Details

Data Collection

Varied resources were used to develop the required inputs. A literature review was conducted to collect equipment and O&M costs as well as estimates of energy savings. This review was augmented by data the Energy Trust had compiled for prior projects. Where available, the Northwest Power & Conservation Council's (NPCC) Regional Technical Forum (RTF) data was used in the residential sector to collect costs and energy benefits. In addition, the NPCC libraries provided cost and benefit data for many of the commercial sector measures. Other resources included various technical papers, manufacturer-provided data, and the Energy Trust's historical program data and measure screening analyses.

In residential sector, 25 different measures were chosen. Each measure was developed separately for three building types. 90 measures were used for the commercial sector. Each measure was then developed separately for 12 building types.

To determine the applicability and marketability of DSM measures in the Company's Washington service territory, economic and census data was collected from Economy.com, the U.S. Census Bureau, and the Department of Housing and Urban Development. Population estimates were also collected from the Portland State University Center for Population Studies and from the Manufactured Housing Association.

Where available, utility-prepared public documents were used to generate end use or device saturation and penetration rates for the service territory. Where not available, these rates were extrapolated from county- or state-level data.

The study then classified each measure's efficiency potential according to whether the installation is marketable as *New Construction*, *Retrofit*, and or *Replacement*. *Replacement* applies to the annual end-of-life turnover of equipment that occurs in any year. *Retrofit* applies to upgrading existing equipment that has not yet reached its useful life. *New Construction* refers to installations made as a dwelling is being built.

The measure cost was calculated using actual equipment and labor costs. In addition, incremental costs (or savings) related to differences in operations and maintenance were considered in the cost analysis. Program administrative costs, marketing or other overhead expenses were not factors. For New Construction and Replacement markets, the measure cost was determined by using the incremental difference between the cost of the equipment being installed and that required by the applicable energy code. The entire cost of the equipment was considered for Retrofit markets. Incremental costs were also included when it was determined that additional installation costs would be associated with the equipment. O&M expenses were calculated and included in the cost-effectiveness analysis. In some cases, O&M costs were negative, meaning that the non energy benefits exceeded the equipment cost. The sum of these related costs determined the measure cost -- or the Total Resource Costs (TRC) – which provided a means for cost effective screening.

As stated above, the technical potential is a study of all potential energy savings regardless of economic or other barriers. So, for this study, it was assumed that a measure would be applied in every instance where our demographical information suggested that it was possible.

For retrofit measures, a useful life was applied relative to date houses were constructed. For replacement measures, a replacement rate was determined and then applied. For *new* measures in new construction, we assumed that all of the applicable new construction was treated every year. Retrofit and replacement measures can be in conflict. When a retrofit measure is installed, it no longer is a candidate for a replacement measure. Often, the retrofit is much more expensive because the replacement is only an incremental cost over replacement with a less efficient but otherwise similar piece of equipment. An opportunity was counted for the replacement market when retrofit was clearly more expensive and a replacement was feasible.

Checks were employed to prevent double counting measures as both retrofit and replacement. When competing technologies were available, like heat pump water heaters and solar water heaters, the market was divided between the two options to avoid double-counting.

Another consideration was that measures will often save both electricity and gas at the same site (e.g. building energy management system). Many markets can only be effectively approached by a dual-fuel program (e.g. new homes.) In cases where the same measure provided multiple savings, the Energy Trust divided the measure cost to the two fuels based on the relative Net Present Value (NPV) of their respective avoided costs. Thus, both fuels saw a reduced levelized cost because they were only “charged” for part of the measure cost.

New Measure Development

New or emerging measures considered in this study include the following:

- Heat reclamation from commercial refrigeration has been identified as a new measure because of recent regional market research. Although still not widely practiced, it is recognized as a significant category for gas savings in this study.

- Heat recovery to hot water heating is low cost, easy to implement and enjoys wide market acceptance. Heat recovery for space heating is more complicated and, hence, perceived as more risky and less attractive to customers. It is one of relatively few measures with large potential for gas conservation.

- Similarly, Heat Recovery Ventilation (HRV) has a large technical potential in both the residential and the commercial sector. In both cases, HRV is currently available but local builders have been reluctant to adopt it.

- Prototype units of condensing natural gas packaged heaters have been demonstrated in Canada. However, the condensing feature of theses units was not the primary source of their savings – rather savings were experienced because exposed ductwork was better insulated. Furthermore, manufacturers have not indicated willingness to bring these units into production due to the higher cost of the hardware.

- One area of interest was the application of residential gas water heating systems for combined space heat and water heat. The Energy Trust considered various combinations of available technology. Although cost savings would be experienced by eliminating the furnace, the added cost of a hydronic heating system would be comparable. And, although a tankless water heater would be higher efficiency, it would be competing against an already-efficient gas furnace for space heating. Only a low-cost hydrocoil applied to an air distribution system appears to be cost effective. The study also included a high efficiency combination system based on the Polaris water heater. However, the base assumption was that a conventional gas boiler and hydronic slab heating system would otherwise be installed and the efficiency improvement is small relative to the incremental cost.

- A new set of high efficiency gas water heaters is becoming available. The study includes a low-cost gas water heater with 0.70 Energy Factor ("EF") rating that will shortly be available as emerging technology. Tankless gas water heaters have an EF rating of 0.85. Navien tankless heater at 0.89 EF rating are a cost-effective upgrade.

- Waste heat recovery from wastewater has been previously reviewed as a potential measure. This technology is not well suited for residential applications, as it is a relatively expensive retrofit limited to full basements. As a result, this study only considered this measure for commercial facilities.

- Low flow spray valves are a low cost commercial application that is rapidly being deployed within the current program.

e. Implement Worksheet Tool To Aggregate And Sum Conservation Potential.

A series of worksheets were developed to compute the savings potential and cost for each measure and customer type, and then results were aggregated for an estimate of the total technical potential.

Appendix 4 contains a list of measures evaluated for each customer class.

<u>Tool Selection and Use</u>

One of the primary goals of this project was for the Energy Trust to improve upon the method of analyzing measures across segments and technology types that would provide a means of comparing anticipated costs and benefits associated with a variety of program options. The Assessment Tool used by the Energy Trust includes several favorable features:

- Standardized program assumptions. This spreadsheet tool allows the same set of program assumptions for each measure, so that differences in the results of the analysis of any two measures were impacted only by the variables of interest (cost, benefits, and technical potential).
- Updateable. The measure cost and performance, market penetration and other inputs into the tool can be easily changed to analyze a particular measure under a variety of program and cost conditions.
- Consistent analysis approach. Team members individually assessed the measures with expertise in particular areas. The use of this tool ensured that measure assessments performed by different analysts were comparable.

- Record of assumptions, sources, etc. The input requirements of the tool provide a record of the data and processes used by the analysts to develop levelized costs. This will be extremely informative and provide insights that will be helpful during program design, particularly in cases where multiple measures are combined into a single conservation package targeted at a particular customer, segment or building type.

Tool Limitations

While the strict data input structure of the Assessment Tool provides a consistent way to compare measures across sectors, it does impose some limitations:

- The total measure costs and benefits calculations are based on an estimated number of times when installing the measure is applicable; i.e., the program participation was estimated to be the total technical potential. These figures will need to be adjusted for programs that target only a portion of the identified market.
- The tool does not allow multiple-measure "what if" analysis. While the Energy Trust assessed a number of combined-measure packages, the costs and benefits must be calculated and combined outside the tool and entered as one set of assumptions.
- The tool provides limited flexibility. The tool did not provide optimum flexibility to analyze measures by segment or across segments without creating multiple worksheets. While this did impose some limits on the analysis methodology, the strict requirements of the tool ensure that comparable computations across all types of measures and sectors are made.

Benefit Cost Ratio (BCR)

In previous studies, the levelized cost was used as a screening criterion to determine cost-effectiveness. One problem is that the levelized cost fails to take into account Time-Of-Use (TOU), meaning that energy savings during a peak period may have higher value and, hence, be more cost-effective. In order to better account for this feature, the total benefit was compiled using the net present value of lifetime savings and Non Energy Benefits (NEB) evaluated at each measure's load shape. This lifetime benefit can then be compared to the total resource cost. If the benefits are greater than cost, the benefit-cost ratio is greater than one. This ratio offers a simple comparison.

$$\text{BCR} = \frac{\text{Net Present Value of Benefits (including TOU, NEB, and externality value)}}{\text{Total Resource Cost}}$$

In general, screening by BCR rarely results in a different cost-effectiveness determination than that afforded by the levelized cost. The exception occurs with some residential sector end uses that occur during peak periods.

In cases where the total resource cost is actually negative due to non-energy benefits that offset cost, the calculation for BCR returns a negative value. While this is technically correct, it could be confusing. For this reason, the Energy Trust defined the BCR to be 100 whenever total cost is negative. This allowed for the sorting of measures by declining BCR.

One complication with computing BCR lies in obtaining realistic estimates of the utility system avoided cost at different times of the day. For this purpose, the Energy Trust used values estimated by the Northwest Power and Conservation Council (NPCC). The NPCC's methodology involved modeling the West Coast energy markets to forecast the market price by time of day for future years. To get this estimate of market value, a value for future cost of CO2 mitigation was added. NPCC also recommends adding a "hedge value" due to the fact that DSM investments decrease financial risk. However, no consensus has yet emerged on what should be the appropriate hedge value for natural gas. Hence, no hedge value has been included in this report. As further information is developed, the estimates of avoided cost can be further updated.

<u>Levelized Cost Calculation</u>

To compare and prioritize measures, the levelized cost was calculated for each measure opportunity. The levelized cost calculation starts with the incremental capital cost of a given measure or package of measures. The present value of any net operation and maintenance (O&M) cost is added. The total cost is amortized over an estimated measure lifetime using a discount rate (in this case a real discount rate of 5.2 percent per year). This 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 kWh saved, as illustrated in the following formula.

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

The levelized cost can be compared with the full cost of delivering power from supply side options. The levelized cost approach was chosen as the most practical and useful method of comparing measures of various types and applications.

f. Summary of Measures Screened by Customer Class

1. Industrial Sector

Only small firm industrial gas customers are included in this analysis. Generally, large industrial customers buy natural gas through transportation contracts. Those customers receiving industrial firm sales gas service tend to be small facilities similar to the commercial sector.

Figure 4-2 and Table 4-3 show the potential for gas conservation measures. These measures tend to be upgrades for hot water and steam boilers.

Figure 4-2 - Small Industrial Natural Gas Measures

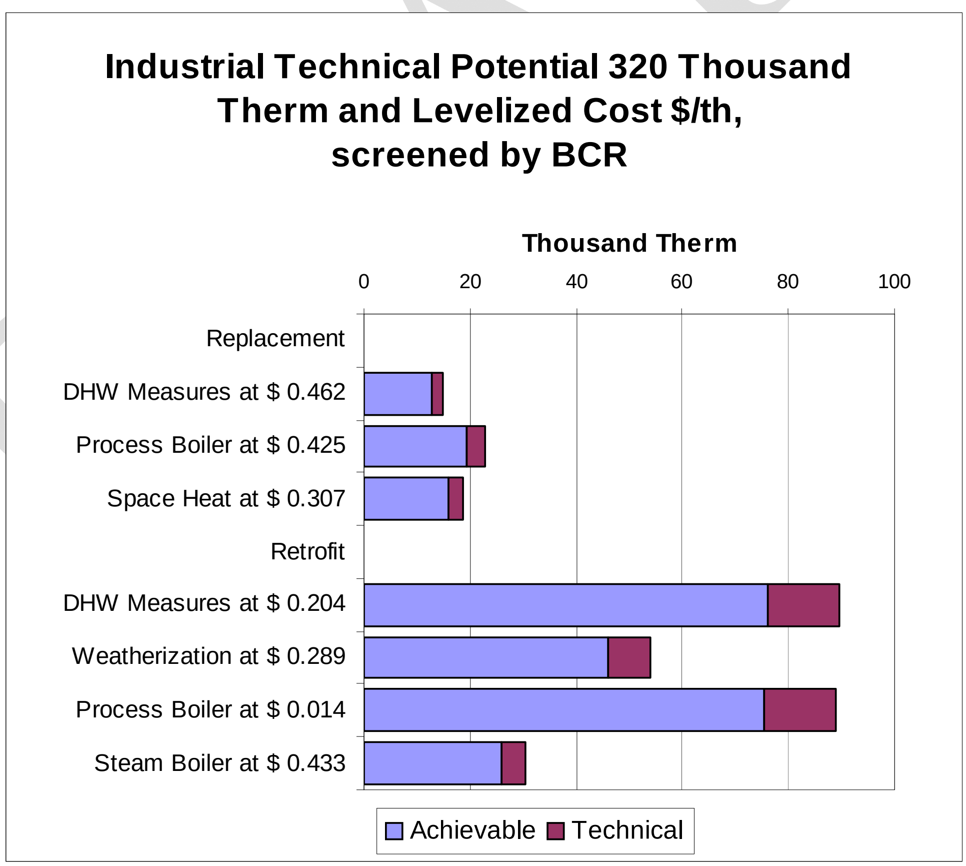


Table 4-3 - Small Industrial Gas 2027 Technical Potential Savings, Screened by BCR

Measure Category	Technical Potential, therms	Levelized Cost, $/therm
Replacement		
Process Boiler	23	$0.425
DHW Measures	15	$0.462
Space Heat	19	$0.307
Retrofit		
DHW Measures	90	$0.204
Process Boiler	89	$0.014
Weatherization	54	$0.289
Steam Boiler	31	$0.433
Total	320	$0.221

2. Commercial Sector

Figure 4-3 and Table 4-4 show the conservation potential for natural gas in the 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 4-3 - Major Commercial Sector Measures, Gas

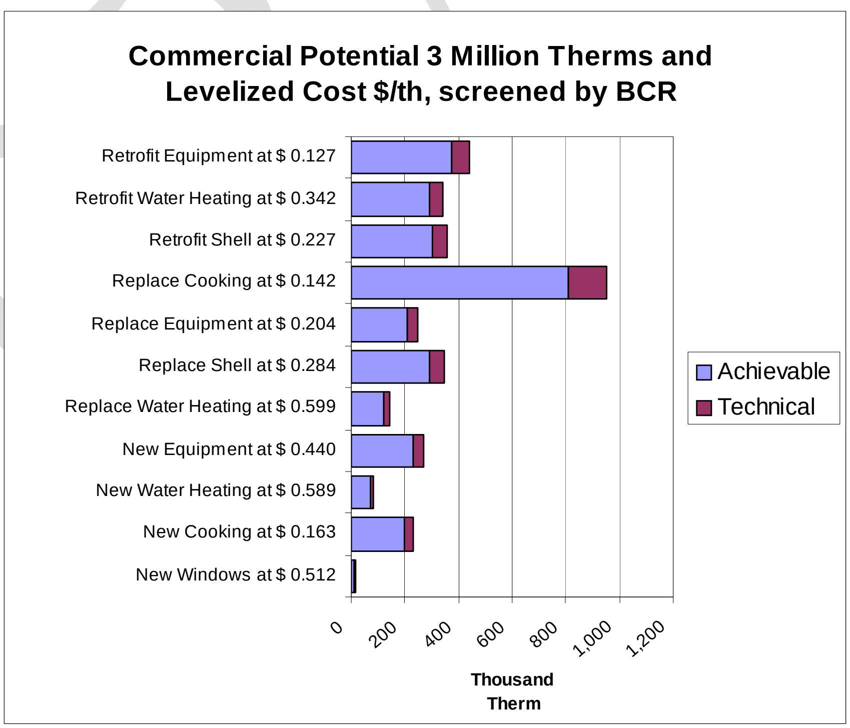


Table 4-4 - Commercial Sector Gas Technical Potential Savings for 2027, Screened by BCR

Measure Category	Thousand therm	$/therm
New Cooking	233	$0.163
New Windows	14	$0.512
New Equipment	272	$0.440
New Water Heating	86	$0.589
Replace Cooking	958	$0.142
Replace Shell	347	$0.284
Replace Equipment	247	$0.204
Replace Water Heating	145	$0.599
Retrofit Shell	360	$0.227
Retrofit Equipment	442	$0.127
Retrofit Water Heating	343	$0.342
Total	**3,446**	**$0.244**

3. Residential Sector

For natural gas, the greatest opportunity lies in weatherization of existing buildings, retrofit of existing heating equipment, and increased efficiency for new construction. Opportunities during new construction include more insulation, better windows, duct sealing, high efficiency furnaces and heat recovery ventilation. Some appliances have a negative cost because of the accrual of non-energy benefits, such as water savings; in this analysis, the savings offset the initial investment.

III. EVALUATION OF ACHIEVABLE POTENTIAL IN *SENDOUT®*

The Energy Trust's deployment scenario was evaluated within the *SENDOUT®.* model, which determines the optimal resource portfolio necessary to meet both base and heat sensitive load. During that process, the DSM savings were adjusted to more extreme weather conditions to create a more realistic and dynamic evaluation. New construction and replacement programs were designated as "must take" because the opportunity to save therms is lost if these measures are not implemented as they occur. "Must take" programs were inputted as mandatory in *SENDOUT®.* meaning "must takes" were automatically implemented and their savings were reduced from demand. Retrofit programs were designated as "discretionary" and evaluated in *SENDOUT®.* against other supply-side resources. *SENDOUT®.* then sized the implementation percentage for each discretionary DSM program based on levelized costs. Demand was further reduced for savings obtained from cost-effective discretionary DSM.

For the Company's Base Case and all sensitivities with the exception of the two low price sensitivities[1] presented in Chapter 5, the Resource Mix functionality of *SENDOUT*® selected all available Oregon and Washington discretionary programs at 100% participation. Since the DSM programs with the highest average levelized program cost are discretionary programs (i.e. Retrofit HVAC program), the *SENDOUT*® results confirm that all DSM programs identified in the Achievable Potential study are indeed cost-effective compared against the Company's other resource supply options. The evaluation of DSM in *SENDOUT*® and associated results are discussed in more detail in Chapter 5.

IV. PROGRAM DELIVERY

A. OVERVIEW

Historically, NW Natural has had a limited energy efficiency program in Washington that included both home weatherization programs and furnace efficiency programs. In March of 2007, however, NW Natural cancelled its home weatherization program due to lack of interest and low overall demand for home treatments. Historically the program experienced approximately 50 audits per year as compared to the furnace efficiency program, which delivers approximately 350 audits per year. In 2005 and 2006 the Company performed 71 and 50 audits, respectively. However, these audits yielded only five home treatments in 2005, and seven in 2006. The Company believes significant improvement is possible.

As agreed to in a Stipulation signed by parties to the Company's general rate case in Washington docketed as UG 08054 and approved by the Commission in Order No. 04, NW Natural has contracted with the Energy Trust to study the achievable potential and develop a deployment scenario for delivering DSM programs in Washington. The Energy Trust will begin by developing a detailed scope of work and budget to be completed by May 26, 2009 as stated in the Washington Utilities and Transportation Commission's (WUTC) Order No. 04, the final order in NW Natural's general rate[2].

---

1 For the two low price sensitivities (i.e. Sensitivity 1: High Demand/Low Price Scenario with Mist Expansion and Sensitivity 4: Low Demand/Low Price Scenario), the Resource Mix functionality of *SENDOUT*® did not select Commercial Conversion Discretionary DSM programs specifically in the Dalles (OR) geographic region for some years.

2 *See* page 5 of UG 080546 Stipulation which states, "**Conservation:** The Parties agree that the Company will convene an Energy Efficiency Advisory Group ("EEAG") of all interested parties, including the Parties. The Company shall develop energy efficiency programs in consultation with the EEAG. Not earlier than six (6) months after approval of the tariff filings to implement such energy efficiency programs, the Company may seek approval of a mechanism to address the issue of lost margins associated with reduced usage attributable to energy efficiency. The Company shall not propose to implement a decoupling mechanism in Washington prior to the filing of the evaluation required under Avista's pilot decoupling program (expected no later than March 31, 2009). Subject to the resolution of any outstanding issues regarding the legal capacity of the Energy Trust of Oregon ("ETO") to deliver the Company's energy efficiency programs in Washington in a cost-effective manner, the Parties agree that the Company has demonstrated a prima facie case supporting the

This stipulated agreement determines the program delivery channel that will be used in the short term. In support of this choice and to acknowledge that the Company will need to continue considering the best and most cost-effective delivery channels, the following analysis compares using the Energy Trust with the Company delivering its own programs:

B. PROGRAM DELIVERY OPTIONS:

1) The Company could deliver its own DSM programs.

Utility delivered DSM programs have historically been controversial because absent a lost margin recovery mechanism, the utility is conflicted in its goals to attain energy savings for its customers and to earn profits for shareholders. (Lost margin recovery options are discussed in detail later in this chapter.) Because of the inherent contradiction, third party administration is generally considered the most sincere and aggressive approach to EE acquisition.

The Company believes delivering its own DSM programs would be the most costly approach since no efficiencies could be realized in serving its Washington customers, who total approximately 56,000 residential, 4,500 commercial and 12 industrial customers. To test these assumptions, the Company considered Cascade Natural Gas's ("Cascade") Washington DSM program, which is delivered in-house. Cascade is a good model because it is a Washington and Oregon based, comparably sized, gas-only utility.

Cascade has 5.5 employees managing its energy efficiency programs. Their Energy Efficiency Department consists of one Director of Conservation, a Conservation Specialist, two contract coordinators, a low income weatherization administrator and a part time analyst. They also hired 2.5 full time employees to manage regulatory and energy efficiency related reporting.

A well run DSM program needs expertise in the following:

- On site inspections (audits)
- Rebates/incentives
- Marketing & promotion
- Trade Shows, Community Events, Association meetings

retention of ETO to deliver energy efficiency programs for the Company in Washington, and will support the Company retaining ETO for this purpose on a pilot basis for a one-year period. Following this pilot period, the Company will, in consultation with the EEAG, evaluate the cost-effectiveness of continued use of ETO for delivering the Company's energy efficiency programs in Washington."

- Direct contact with customers
- Certifying preferred installation contractors

Cascade has chosen to contract with Energy Efficiency providers for much of this expertise. But in spite of relying on outside expertise, Cascade needs an in-house knowledge to develop the programs, manage the contracts, and analyze the cost effectiveness of their programs.

If NW Natural followed Cascade's model, the Company projects that it would also have to hire approximately 2.5 employees. The Company expects that its operations and administrative costs would be larger because the planning requirements, contract management and regulatory reporting would not diminish in accordance with the relatively small number of Washington customers. Economies of scale are experienced when more customers can be served with the same resources. The Company would need the same in-house expertise for a third of the customer base. Currently, the Company does not have this in-house expertise because the Energy Trust provides it.

Cascade estimates that they pay $6 to $7 per therm saved. Their Washington DSM program serves 167,000 residential customers and 13,000 commercial customers, for a total of 180,000 customers. NW Natural's Washington service territory has 56,132 residential customers and 4,468 commercial customers (60,600 in total, almost a third of customers Cascade serves.) Assuming that few efficiencies of scale are available, NW Natural estimates that it would cost up to $18 a therm to deliver DSM to its Washington customers. At this rate, DSM ceases to be a cost effective resource.

2) A second option would be to <u>hire a third party administrator</u>. As mentioned, the stipulated agreement to NW Natural's rate case allows the Energy Trust to deliver programs for one year. After the first program year, parties will review program results and recommend whether or not the Energy Trust should continue to administer the Company's Washington programs.

The Energy Trust is a third party established by the Commission per ORS 757.612(3)(b)(A)&(B) to administer energy efficiency programs for customers of independently owned electric utilities. While they were established to provide DSM opportunities to electric customers, their expertise was tapped to serve the Company's gas customers when the Commission approved a decoupling mechanism, which broke the link between earnings and customer usage.[3] Energy Efficiency proponents

[3] Oregon Public Utility Commission Order No. 02-634 required that the Company turn over the administration of its energy efficiency programs to a third party.

generally consider third party administration to be a more aggressive, more sincere approach to utility offered energy efficiency.

Outsourcing with the Energy Trust requires that the Company hire one FTE to manage the contract and act as a liaison for communications and data requests. However, since the Company already uses the Energy Trust's services in its Oregon service Territory, a number of efficiencies can be immediately experienced.

The Company believes using The Energy Trust is the most efficient and costs effective means available. Because the Energy Trust serves DSM programs to most gas and electric customers in Oregon, they know the EE market and regional considerations very well. Also, they are able to be fuel blind as they consider a customer's best options. The Energy Trust's programs are competitively bid which allows for competition and lower costs. In Oregon, the OPUC oversees the Energy Trust's work and hold them accountable through a service agreement.

The Company's Washington Service Territory is contiguous with its Oregon Service Territory and is only 10% of the Company's whole service territory. Therefore, using the same delivery channel allows the Company to more seamlessly and consistently serve its customers.

The Energy Trust's ability to deliver cost-effective DSM programs in Washington will be reviewed after the first program year. While it takes approximately 3 years for a DSM program to mature, this review allows the Commission and interested parties to monitor the programs' progress, to establish benchmarks and hold the Energy Trust accountable for program delivery.

The Energy Trust's 2008 third quarter report states that they procure energy savings for $5 a therm. This beats Cascade's projected cost of $6 to $7 a therm and the Company's estimate of $18 a therm. These cost comparisons are not able to quantify breath and value of each program.

The Company respects the Energy Trust's expertise both in efficiency and market transformation. The Energy Trust is actively involved with the Gas Committee if the Consortium for EE to encourage development of new technologies that expand the potential for energy efficiency improvements in Oregon and regionally. The Energy Trust recognizes that these investments can be leveraged to make additional measures available to NW Natural's Washington customers.

The Company is pleased with their 2008 rate case settlement (UG 080546) agreed to by the Commission in Order No. 04, which names the

Energy Trust as their Washington administer of EE. While this decision will be reviewed, the Company expects this decision to prove to be prudent and cost-effective.

V. RATE DESIGN

A. COST RECOVERY

The stipulated agreement to the Company's 2008 rate case says the Company will begin funding its Washington DSM programs by deferring its cost for future amortization in rates. After these initial decisions are reviewed, the Company may consider collecting the money upfront rather than deferring costs. Any such decision will need to agreeable to parties to the Company's UG 080546 Washington rate case. Alternative methods for cost recovery include the following:

1) **Public Purpose Charge** - The Company could consider implementing a public purpose charge as it does in Oregon. The Oregon public purpose charge is billed on a percentage basis, thus earmarking a portion of the Company's gross revenues for energy efficiency programs. The determination of the percentage charged was based on an estimate of needed, informed by electric DSM market. While this charge is easy to apply, the Company has experienced an over-collection of funds in the first few years of its Oregon public purpose charge collection. However, the Energy Trust expects to spend down the over-collection within the next two years. Any over- or under-collection could easily be mitigated with a timely review and a tariff filing to revise the collected percentage as needed.

A public purpose charge could also be a flat per meter based fee. Again, this would be easy to apply. A progressive collection, however, seems more even handed as those who use more tend to have more DSM potential. Also, the Company would not want to choose a cost recovery mechanism that was burdensome on small gas users or on low income customers.

It is worth noting that Industrial customers may require separate treatment if per therm or percentage of bill charge is imposed. As has been done in its Oregon service territory, the Company would consider employing a second method for these customers. Currently, Oregon Industrial customers are exempt from the decoupling mechanism and from the percentage based public purpose charge. Costs for Oregon Industrial DSM are deferred and amortized annually in the Company's Purchased Gas Adjustment (PGA) filing.

2) **Defer costs until the next rate base** – A utility can annually request authorization to defer DSM related expenses. These expenses can then be folded into base rates during the next rate case. This method requires that the utility have a surplus cash flow to cover the incurred expenses. If this method is employed, the utility should be granted a carrying cost for fronting the investment capital. This method also encourages more frequent general rate cases, which may be hard for customers to absorb. In addition, general rate cases are administratively burdensome and costly for all parties.

3) **Rate base the costs** – A utility can file to include the projected costs for creating and administering DSM programs in its rate base. This method creates a higher revenue requirement which is appealing to utility shareholders. However, opponents do not consider it the most cost effective approach. Also, it is inconsistent with the pass-through rate treatment of market purchases of gas.

4) **Flow through costs to an adjustment mechanism** – This method provides adequate DSM funding without reducing the utility's cash flow. Costs incurred are collected through an automatic adjustment mechanism which is trued up annually. Costs are subject to disallowance during a Commission review but the relative immediacy of the cost recovery means that carrying costs are not required. A balancing account may be needed for over- or under-collections.

B. LOST MARGIN

As an investor owned, publicly-traded utility, the Company must balance the interests of its customers and shareholders, and ensure that shareholder earn a rate of return. Company decisions must consider the financial bottom line. Traditional ratemaking recovers fixed costs through a per therm rate that is based on the costs divided by the forecasted annual therm sales. Fixed cost recovery is embedded in a utility's per therm rate. Energy efficiency, which reduces the number of therms used per year, reduces the utilities ability to redeem fixed costs. The more successful an EE program is, the more a utility with traditional rate making falls behind.

The Company has tried to mitigate the conflict between its responsibility to earn a fair return for shareholders with big picture goals of reducing dependence on fossil fuels and lessening carbon emissions by requesting Commission approval of weather normalization and revenue decoupling mechanisms. As part of the stipulated agreement to the NW Natural's 2008 rate case, the Company agreed to withdraw its request for a decoupling mechanism until after March 31, 2009, when the results of Avista's decoupling pilot program (Avista Schedule 159) will be available. The WUTC has clearly stated that a decision on lost margin recovery will need to be analyzed thoroughly, must be looked at on a case-by-case basis, and must include safeguards to protect the customers. As the Company awaits the completion of Avita's decoupling pilot, the Company will concurrently consider the following options for lost margin recovery:

1) **Decoupling -** NW Natural favors some form of decoupling because it guarantees the recovery of at least a portion of fixed costs. When a decoupling mechanism is in place, conservation efforts do not conflict with the Company's goal to remain financially whole. Adversaries argue that decoupling shifts risk to customers because when a utility is guaranteed the recovery of costs, its service may deteriorate. Upon approval of this mechanism, the OPUC safeguarded customers against diminished service quality by simultaneously adopting service quality measures which define minimum service standards to which the Company must attain.

At the time this mechanism became effective in Oregon, decoupling was unheard of in the natural gas retail sector. OPUC Commission Order No.02-634 documents the adoption of partial decoupling in 2002. In 2005, an independent third-party evaluation was performed on the Company's decoupling mechanism. The evaluation credited decoupling as an agent in helping Oregon become the nation's leader in highest efficiency furnace installations. The report noted that customers had not complained about the mechanism, and further recommended revising the mechanism from recovering only 90% of margin to recovering 100%.[4] Full decoupling was adopted in OPUC Commission Order No. 05-934.

The American Gas Association ("AGA") sees NW Natural's decoupling mechanism as a solution to for gas utilities conflicting goals of encouraging conservation while recovering its distribution margin.[5] The AGA credits decoupling for the overall net reduction in natural gas usage experienced over time, a possible reduction in uncollectibles and potentially helping to reduce overall gas prices due to reduced demand.

2) **Lost Margin Adjustment Schedule** - An alternative to decoupling is a lost margin adjustment schedule. This mechanism establishes a threshold that the utility must be meet before the Company can file for consideration of lost margin recovery. This method proves to be administratively complex because it requires that the Company prove that losses associated with reduced consumption are a result of added efficiency measures. Analysts must be dedicated to tracking and measuring losses and savings on a dwelling by dwelling basis.

4 *A Review of Distribution Margin Normalization as Approved by the Oregon Public Commission for Northwest Natural*, by Daniel G Hansen and Stephan Braithwait, Christensen Associates Energy Consulting, LLC, March 31, 2005.

5 *Creating a Win/Win Gas Distribution Energy Efficiency Program: Recognizing and Aligning Stakeholder Interests*, presented by Roger Cooper, AGA, 2005 Western Conference of Public Service Commissioners, June 22, 2005.

3) **Fixed Variable Rate Design** - Fixed Variable Rate design is a form of decoupling because it removes the recovery of fixed costs from gas sales. This method recovers all fixed costs in one lump sum called a service or demand charge. Historically, opponents have argued that this approach is burdensome to small users and low income customers. Proponents like that it is simple and guarantees recovery of a utility's costs. FERC adopted this rate design for most of its pipelines. Opponents believe that this option reduces a utility's motivation to provide good service and that the reduced commodity costs encourages increased consumption. A Commission could mitigate this concern by adopting service quality measures.

In "A Rate Design to Encourage Energy Efficiency and Reduce Revenue Requirement" (July 2008), David Magnus Boonin of National Regulatory Research Institute, argues the benefits of Fixed Variable Rate Design.[6] However, he notes that this method reduces the per therm cost of gas, thus removing the price signals which encourage customers to reduce usage. He suggests complementing Fixed Variable Rate Design with a secondary component he calls "feebates", a revenue neutral rebate or charge assessed to customers based on usage. This is an interesting proposal. The Company presumes larger users would challenge this rate design since it might prove punitive to industries that cannot reduce their consumption. Also, it might be difficult proposal to prove this mechanism is allowable since it could be viewed as a discounted gas rate or as retroactive ratemaking since it is the application of a credit or rebate based on past usage.

4) **Performance Based Ratemaking** - Finally, another means for lost margin recovery is performance based ratemaking which allows performance incentives and in some instances, applies penalties. In some states, incentives are allowed when certain savings targets are met. Examples include the following:

a) **Rate of Return Adjustment** – This method adjusts a utility's total return or just the equity portion based on the utility's annual DSM performance. This conditional bonus requires Commission oversight but it encourages a least-cost approach to DSM delivery. Generally, the incentive is capped.

b) **Rate Base Premium** –This approach allows a utility to rate based its DSM expenses and receive a return over and above the rate allowed on supply-side options. This practice has been considered severe since not meeting a target could result in a significant under-earning. Conversely, the reward of an increased

[6] Available on request.

return provides utilizes with the intended motivation to encourage EE, but opponents to this approach say it penalizes customers.

c) **Bounty** –A bounty is a predetermined amount of money the utility can collect on behalf of shareholders if it exceeds a set goal. This is similar to the rate of return adjustment because earnings are based on performance.

d) **Sharing Formula** – A sharing mechanism allows a utility to keep a portion of the difference between the cost of administering a DSM program and the avoided costs. This mechanism is hard to administer because much like proving that lost margin is based on EE, quantifying the values is difficult.

e) **Penalties** - Penalties can be imposed when targets are missed. In 1993, Puget Power and Light had performance based penalties associated with their electric DSM program: They were required to achieve 10 aMW in savings or pay a $1 million penalty. If they achieved less than 6 aMW, they were to pay an additional $1.25 for each aMW below the 6 aMW threshold.

C. OTHER RATE DESIGN CONSIDERATIONS

Generally, the Company believes that its non-DSM specific rate design policies should also encourage a reduction in required load. Rate design policy may often complement specific DSM programs. Because the capacity to support cold weather usage levels is more expensive than in the past, the Company continues to explore pricing mechanism to moderate peak day gas requirements. A discussion of the five key rate designs follows:

1) **Demand Charge Rate Design** - Demand Charge rate designs based on a charge per unit of peak day usage encourage customers to reduce their demands on system capacity during severe cold weather. To the extent that a substantial fraction of rate class revenue is recovered in demand charges, energy rates may be quite low when compared to a two-part customer charge and energy charge rate design.

Demand rates have traditionally been applied to large-volume industrial customers. Residential and commercial customers demand rates are rare in the gas industry, but the Company believes they could have a positive impact on customer use patters. The customer would pay a demand charge in addition to more traditional per-therm energy charge. Based on a predetermined maximum daily usage, demand rates would discourage violation of this limit on peak use by customers. This type of demand charge rate design is compatible with Straight Fixed Variable pricing and would appropriately signal customer that adding capacity is costly. Demand charge rate designs would contribute greatly to revenue and earnings stability since less revenue recovery is tied to temperature-sensitive consumption.

However, demand charge rate designs are the least effective rate form for the mitigation of global warming through reducing energy use. Since capacity costs are removed from energy rates, the cost of additional off-peak gas use is reduced on an annual basis and would encourage customers to burn more natural gas on an annual basis when compared to a two-part rate with a flat energy charge.

2) **Seasonal Rate Design** - A second alternative would be seasonal rates for residential and commercial customers. Seasonal rates would offer customers with a lower per unit cost during shoulder and summer months, while imposing a higher per-unit cost during peak hearing season months. Seasonal rate designs would increase revenue and earning instability in comparison to a two-part rate and be slightly better than a one-part rate with respect to minimizing carbon dioxide releases.

3) **Inverted Rate Design** - Inverted Rates involve higher prices per unity of energy as monthly consumption rises. This can be structured to encourage customers to reduce their gas consumption during both peak and non peak periods. However, the price signal for reducing gas use during the coldest days of a severe weather episode is weaker than with a demand charge rate design. In the context of a carbon dioxide mitigation strategy, inverted rate designs offer the greatest promise since the cost of additional energy consumption during any month of the year increases as consumption levels increase. The result is much like a carbon tax on energy use. Unfortunately, inverted rate designs create a high degree of revenue instability.

4) **Declining Block Rate Design** - Declining Block rate designs involve sequentially lower prices per unit of energy as consumption within a month increases. Consequently, when used in a two-part rate, customers receive the weakest price signals to ration their use of capacity and energy. Revenue instability is reduced but not to the extent possible with a demand charge rate design. CO2 releases are higher under declining block rate designed but not quite as high as is possible with a demand charge rate design.

5) **Interruptible Rate Design** - Interruptible rates are used extensively by large volume customers with and without backup fuel capacity. In consideration for paying a lower rate that avoids or reduces capacity costs, the customer agrees to curtail their gas use with certainty when required to do so. The Company does not develop firm capacity for

interruptible customers, thus shifting loads from firm to interruptible can be though of as a source of peaking capacity during severe weather.

The Company offers interruptible service to its non-residential Washington customers under Rate Schedules 41 and 42. Interruptible service costs less because the Company does not reserve capacity for these customers; interruptible customers can have service curtailed when system constraints are experienced.

VII. OTHER DEMAND-SIDE MANAGEMENT CONSIDERATIONS

A. LOAD MANAGEMENT AND DEMAND RESPONSE

Demand response reduces system load requirements during periods of high demand and system stress. Due to previous severe disruptions in the western electric energy markets, demand response programs were largely developed to correct market failures in deregulated electric energy markets. Demand response encompasses a number of activities including real time pricing, time-of-use rates, critical-peak pricing, demand buyback, interruptible rates and direct load controls. To varying degrees, NW Natural manages peak demands using several of these techniques.

On NW Natural's system, customers taking service on interruptible rates represent approximately 42 percent of annual throughput. This includes interruptible sales service, interruptible transportation service and firm service on our system transportation service. Large volume customers gravitate towards interruptible service because of the low distribution margin.

The Federal Energy Regulatory Commission (FERC) pricing policies for interstate pipeline service influence the loads NW Natural serves. The straight fixed variable pricing of pipeline capacity creates an incentive for the Company to encourage gas use by high load factor customers and discourage low load factor use.

B. CUSTOMER COMMUNICATIONS AND EFFICIENCY INCENTIVES

In Oregon, NW Natural annually dedicates shareholder funds to promoting high efficiency appliances. Campaigns are run seasonally and they tend to correspond with available Energy Trust rebates. The Company is considering offering similar campaigns in Washington. For instance, the Company plans to market hydronic heating systems in Clark County to test their marketability. This and other offerings will be considered promotional advertising per WAC 480-90-223. NW Natural values these campaigns as a means for supporting Energy Trust programs and as a stimulus for local market transformation.

The Company is also considering other ways to encourage a market saturation of energy efficiency appliances, including on-the-bill financing for customers who want to buy qualifying energy efficiency equipment. Details that need to be fully vetted include whether or not the Company would finance the equipment with shareholder dollars or through bank loans, and how the Company would have recourse against defaults. Again, this is part of the Company's brainstorming with the intended goal of encouraging efficiency and communicating the message to customer to reduce usage when possible.

VII. LOW-INCOME WEATHERIZATION IN OREGON AND WASHINGTON

Low Income Weatherization is not studied as a least cost supply option. While it helps reduce heating bills for participants and provides a value to all rate payers through reduced arrearages, the Company works with interested parties in determining the appropriate level of low income weatherization. A brief summary of NW Natural's offerings is listed below by state:

Following the completion of the Company's 2004 Washington general rate, the WUTC authorized NW Natural to administer its Washington low-income weatherization program. The Company will recover the funds distributed to Community Action Agencies ("CAAs") through deferred accounting for later inclusion in rates through the Company's PGA mechanism. NW Natural expects expenditure levels in Washington to amount to approximately $0.1 million per year.

NW Natural's low income weatherization program has not been widely utilized. In the 2008 general rate case, the Company agreed to convene a low income assistance working group to review the program and determine the appropriate design of a new low income rate assistance program.[7]

Approximately 10% of customers meet low-income eligibility requirements established by the Department of Energy. While the Energy Trust programs would not specifically target this customer group, they would not be precluded from participating.

[7] *See* page 6 of the UG 080546 Stipulation which says, "**Low-Income Programs:** The existing low-income weatherization program shall be reviewed, evaluated and modified as necessary in consultation with the EEAG."

NW Natural's Conservation and Low-Income Weatherization Plan includes provisions to serve these customers with programs delivered through local CAAs that provide incentives equal to the full measure costs to address the significant first-cost barriers of this segment. In Washington, NW Natural will partner with Clark County and the Skamania-Klickitat County CAA in implementing the low income weatherization programs.

VIII. FEDERAL AND STATE POLICY AFFECTING NATURAL GAS USAGE

DSM is not only useful in reducing costs, reduced natural gas demand also means less carbon dioxide released in the atmosphere. Climate change and the need to limit greenhouse gas (GHG) emissions will undoubtedly transform the natural gas industry. NW Natural acknowledges its role as a fossil fuel utility in this global conversation and takes seriously its responsibility to help customers reduce GHG impacts and to help policy makers shape future GHG constraints.

NW Natural has taken a leadership role in the development of both federal and state climate rules. The Company's Chief Executive Officer, Mark Dodson, has served as the chair of the American Gas Association's Climate Change Task Force. With his leadership the group adopted a unanimous position calling for responsible federal action to reduce GHG emissions. The gas industry adopted broad principles for the consideration of federal policy makers.[8] NW Natural's President, Gregg Kantor serves on the Oregon Global Warming Commission, a group created by the Oregon legislature to vet proposals addressing climate change. The Company has dedicated its resources to the development of well thought out climate legislation because the Company recognizes the long term impact this will have on its customers.

To date, the Federal Government has discussed but has not imposed substantive requirements that will drive economy-wide reductions in GHG emissions. However, the energy industry anticipates the enactment of Federal emissions reduction targets as well as a cap and trade program within the next five years. But in the absence of Federal law, local governments have been addressing this issue to varying degrees.

In April 2007, the Washington legislature approved SB 6001 which established state goals to reduce greenhouse gas emissions. This legislation calls for statewide reduction of GHG emissions to 1990 levels by 2020 and to 50% below 1990 levels by 2050. The Bill was adopted as RCW Chapter 80.70, Carbon Dioxide Mitigation and it applies to electric generation facilities. While NW Natural is not immediately affected by this legislation, it marks an awareness that will eventually impact prices to natural gas.

Subsequent to Washington passing this initial goal, the Western Climate Initiative (WCI) developed and published design recommendations for a regional cap and trade program. WCI is a regional entity comprised of seven US states and four Canadian provinces. The design principles issued in September, 2008 call for an economy-wide

[8] Available upon request.

program that covers electric utilities in its first phase (beginning in 2012). Fuel uses, such as residential and commercial natural gas customers, are added to the system in the second phase (beginning in 2015). The WCI principles will now be used by participating states to help shape state adopted cap and trade programs. Washington State has recently drafted a proposed bill that would enact the WCI principles for the state.[9]

Industry experts speculate that Federal or additional state climate change legislation will affect natural gas utilities in several critical ways. First, legislation that restricts coal plant development will drive additional natural gas plant construction as natural gas becomes the overwhelming fuel of choice to meet needs for new base load needs. This growing demand for natural gas generation will put strains on supplies and potentially drive up commodity costs for natural gas customers. Granted, either a successful Renewable Portfolios Standards (RPS), such as the Oregon law requiring 20% renewables by 2020, or cap and trade legislation might abate this high demand, high cost scenario.

Secondly, many policy makers believe that efficient, direct use of natural gas at the residential level may be deemed a good interim step toward reducing carbon emissions. To this end, there are some federal proposals that allow residential and commercial customers to remain outside of the cap and trade system if this sector continues to show increasing efficiency per captia. Lastly, when natural gas customers are added to a cap and trade system, the system may add compliance costs to gas customers. Unlike with electricity production, reductions in emissions from the gas sector are only possible from reducing energy use with conservation. If the government decides to impose a more general tax on carbon emissions, this also would increase the cost of natural gas. Again, where these additional revenues will be invested, is speculation. These monies might be invested in efficiency, renewables or low income assistance, in which case, these revenues will be transfer payments and not new customer costs.

Besides contributing to the policy discussion around climate, NW Natural has also been taking steps to help customers reduce their GHG emissions. Primarily these reductions are accomplished with energy efficiency programs such as those outlined in this chapter. When surveyed our customers have suggested we should help them do still more to help them reduce their overall carbon footprint. This interest led the Company to become the first stand alone gas utility to offer a carbon offset product that allows customers to voluntarily offset the GHG emissions associated with their gas use. This product, called Smart Energy, is available to our Oregon customers but has not yet been approved by the WUTC to be offered to Washington customers.

The fervor to reduce GHG emission as well as to move the Country toward energy independence will drive gas utilities to continue to find new, more aggressive ways to offer energy efficiency programs to our customers. The same desires also will drive efforts to find less carbon intensive resources, such as biogas, that can be used to

[9] Available upon request.

displace fossil fuels. Together these forces will over time transform our industry. The Company knows it must continue to monitor developments in this area and be willing to adapt its business to a changing market.

IX. FUEL SWITCHING

On June 5, 2008, the Washington Utility and Transportation Commission hosted a workshop on fuel switching. At this meeting, Snohomish Public Utility District and Puget Sound Energy presented the benefits of converting electric appliances to natural gas where possible. The direct use of natural gas is efficient and results in less carbon emissions than electric generation. However, the benefits of imposing a fuel switching mandate were disputed. Opponents pointed out the regional predominance of hydro-electricity which emits no carbons and has little price volatility. As such, a regionally forced conversion may not prove beneficial to customers. Commissioner Chair Mark Sidran responded by saying that climate change needs to be looked at more broadly than regionally. No conclusions were drawn.

Since that meeting, President-elect Barack Obama has named his energy team. Steven Chu was named Secretary of Energy, Lisa Jackson will be the Environmental Protection Agency administrator, and Carol Browner will be Assistant to the President on Climate and Energy issues. Chu has voiced a strong dislike for fossil fuels and supports government-mandated energy market transformation. Obama's promise to invest in the energy industry coupled with the notable absence of a fossil fuels expert on his energy team suggests the incoming administration will move the nation away fossil fuel dependence. Energy experts expect the Obama administration to move the heating and electricity markets toward renewable resources. In which case, natural gas may not be the interim fuel of choice as assumed at the WUTC's June 2008 workshop. However, Emmanuel Rahm's influence may make natural gas an interim fuel of choice for vehicles. (In July 2008, Rahm introduced legislation that seeks to transform the automotive market toward natural gas cars.) Beyond this potential use of natural gas, shifting heating load requirements to renewable resources will likely be the focus. Granted, energy resources that do not emit carbons, such as wind, solar or nuclear, have hurdles to clear before they will be sufficient, cost-effective and available. Remedies include government subsidies and renewable portfolio standards which seek to require certain renewable standards such as the 20%standard by 2020 required in Oregon.

The Company is willing to support any policy that is deemed beneficial. If the Commission deemed fuel switching to natural gas is appropriate, the increased supply side needs would be minimal and the Company would be able to serve the additional load without making any changes to its resource plan. The NW Council is currently conducting a study on direct use of gas. If State or Federal policy results in an overall reduction in natural gas used, the Company's customers' load requirements will have sufficient gas available to them which is the purpose of this study. Further speculation regarding the effect on the utility, its future, etc. is beyond the scope of this plan. If any policy significantly affects our customers' load requirements, it will be addressed in a future IRP or an update.

On a more regional level, if the market becomes saturated with heat pumps and heat pump water heaters, which are energy efficient options, residential gas requirements will fall, but the Company does not predict this would produce a substantial change. [10]

X. SUMMARY

In Washington, the resource assessment determined that approximately 8.9 million therms of potential energy savings could be cost-effectively attained over the next 20 years for approximately $58.5 million.

XI. ACTION ITEMS

- Continue efforts to comply with the stipulated agreement to UG 080546 which states the Company will form an Energy Efficiency Advisory Group that will serve as advisor to the Company as it works with the Energy Trust to develop Washington energy efficiency programs and works with agencies to improve its Washington low income energy efficiency program.

10 "Analysis of Heat Pump Installation Process and Performance" by Ecotope and Stellar Processes, December 2005.

CHAPTER 5: LINEAR PROGRAMMING AND THE COMPANY'S RESOURCE CHOICES

CHAPTER 5: LINEAR PROGRAMMING AND THE COMPANY'S RESOURCE CHOICES

This chapter describes the analytic method NW Natural employed to combine the demand forecast with the supply and demand side resources to determine whether the Company has a resource deficiency and to select the least cost mix of resources required to serve forecast demand over the planning horizon. This chapter also defines a set of modeling scenarios, including stochastic analysis, designed to assist the Company's selection of future resources under alternative specifications of future demand and price levels and resource availability.

The resulting resource mix demonstrates the Company's consideration of State and Federal policy. State policy, as evidenced in SB 838, seeks to provide additional funding mechanisms for energy efficiency. Federal policy, likewise, is trending toward energy market transformation and environmental protection. This IRP supports aggressive energy efficiency acquisition, incorporates carbon adders in its avoided cost, and does not shift reliance onto LNG supplies which directly demonstrate the influence of State and Federal policies in the development of this Plan.

I. OVERVIEW – THE APPROACH TO OPTIMALITY

As loads grow across the Company's eight primary geographic regions, various methods exist for meeting them. Options available to the Company include DSM initiatives, acquiring additional pipeline capacity, recalling existing storage capacity, or putting new pipe in the ground that improves the interconnectivity between districts. None of these activities preclude the others, so there are a large number of potential resource combinations that could be adopted to serve new customer needs. The task at hand is to choose the best (in this case, lowest reasonable cost) combination of existing and potential resources. In making this choice, NW Natural uses a linear programming methodology.

Linear programming (LP) is an analytic technique that examines every possible means of acquiring demand or supply-side resources to meet growing customer needs and determines the least cost solution within. The LP model selects that combination of resources that satisfies customer load in the least cost manner over the planning horizon, considering operational constraints and economic parameters. The Company uses a linear programming package called *SENDOUT®* which provides enhanced analytical capabilities and additional modeling detail, compared to previously employed methodologies.

NW Natural's *SENDOUT*® database includes the following components and options:

17	Supply Options
10	Storage Facilities
57	Interconnects (receipt, delivery and intermediate nodes)
113	Transportation Segments
8	Demand Areas
72	Demand Area –Classes
128	DSM Options
1841	Time-dependent Resource Mix (capacity sizing) Decisions

The components listed above are employed differently for scenario analysis, depending on the assumptions and objectives of each scenario.

II. LEAST COST OPTIMIZATION

The least cost aspect of the Company's network LP model attempts to minimize an equation representing the present value cost of meeting customer demand over the 20 year planning period. With respect to gas supply resources, two different types of supply options currently exist for meeting customer demand: (i) pipeline gas delivered on a real time basis to demand centers, or (ii) injecting gas into storage facilities during relatively low demand periods and withdrawing the gas from storage for delivery to demand centers during the highest demand days and for extended periods of high demand.

NW Natural applies constraints (or limitations) to this cost minimization exercise. For example, the Company's ability to deliver gas on a pipeline from a supply source to its city gate stations (points of interconnection between the pipeline and the Company's distribution facilities) is limited by the amount and type of pipeline capacity the Company has reserved. Typically, the Company buys pipeline capacity on a firm daily basis. That is, a 200,000 therm purchase of pipeline contract demand (CD) means that the buyer possess rights to 200,000 therms of gas deliveries per day for each day of the year. This constraint limits the model to only the capacity currently owned by the Company. Similarly, storage capacity and delivery services are limited by contractual entitlements. The Company cannot deliver more gas from storage than the quantity of gas it placed into storage. The modeling is similarly constrained to reflect the limitations with respect to take-away capacity on the downstream side of the city gates in the southern part of the Company's distribution system. In other words, the mere addition of pipeline CD in the southern Willamette Valley will not always be the sole solution to meeting the area's increasing demand.

The model meets customer requirements with existing pipeline CD and storage resources in a least-cost manner. Eventually, as projected demand exceeds capacity, the model finds there is not enough CD or storage capacity in the existing portfolio of resources to serve the ever-growing gas requirements. When the model identifies constraints beyond existing pipeline CD and storage, the model begins choosing new resource alternatives. The incremental resources are selected and sized optimally, subject to availability and constraints.

The Company meets expected additional supply side resource requirements in one of three different ways: (i) buying more pipeline CD, (ii) buying or building more storage (including LNG storage and vaporization facilities), or (iii) building new distribution facilities that meet the growing customer needs. The model considers both fixed costs and commodity costs associated with each of the incremental resource options. The model assesses and calculates the fixed cost to be paid by the company based on the capacity level selected. The model also calculates the commodity and variable costs associated with the supply sources that can serve that pipeline section. Similarly, if the model selects a storage expansion facility, that choice triggers the carrying charges associated with the investment costs of the facility, as well as fixed costs paid regardless of use levels throughout the entirety of the analysis. The model will also calculate the cost of the commodity and variable costs used to fill the storage facility. The entire model, then, consists of an objective function (which sums up the costs of meeting load) and a large number of constraint equations designed to solve for a set of resource use levels that minimize total cost.

In network analysis, the model moves product (natural gas) from supply "nodes" to demand "nodes" over transport "arcs." For example, the model identifies gas storage facilities and gas receipt points as nodes, and the model treats a pipeline like a transport arc. The Company inputs all the necessary information about how gas currently flows from supply sources to market centers, the capacity of the current "arcs" and supply "nodes," and the range of possible new supply nodes and arcs and the constraints on what capacity can be added to the network model. Then the network model examines all possible outcomes and yields an optimal solution. Unlike previous LP models, the *SENDOUT*® application provides the opportunity for the Company to choose to not meet load, but at very high cost. When curtailment is unavoidable, *SENDOUT*® reports these unmet loads as unserved demand. This facilitates identification of capacity deficiencies.

Another change over previous IRP analytical methods relates to the structure of the gas year. Previous IRP studies used what is called “mixed integer analysis” as opposed to a more typical “continuous solution” analysis. Mixed integer programming (MIP) allows resource decisions to be “binary” in nature; that is, if the model chose a storage facility, then the model commits the full cost and it cannot be reduced or eliminated. This means that the model either takes the entire resource (binary = 1) or the model does not take the resource (binary = 0), and this prevents the analysis from including “continuous” solutions. With MIP analysis, the entire LP model solves once with each binary integer switched to zero, and then a second time with the switches at one. Depending on the number of switches this approach quickly becomes very computationally costly. An MIP model solves 2^n times where “n” equal the number of integers. For example, if a model includes 64 resources that are specified as integers, the model calculates 2^{64} intervals. Two to the sixty fourth power equals 18,466,744,073,709,600,000 complete recalculations. Obviously, MIP analysis requires careful specification.

To solve this problem and better manage the MIP analysis, NW Natural’s previous MIP analyses divided the year into 15 “bins.” The first 5 bins each contained one day arranged from the coldest in bin one to the fifth coldest in bin 5. The next 5 bins each contained 5 days in descending order of coldness, each of the next three bins (bins number 11, 12, and 13) contained 30 days, again in descending coldness. Bin 14 was 90 days in length, and bin 15 contained the 185 days modeled as the summer period. Thus, each design year started out with its coldest day, and proceeded monotonically to its warmest. This approach ignores the daily up and down swing and seasonal patterns inherent in a realistic load profile.

In the 15 bin, load duration curve approach, the coldest, most demanding weather always occurs first. This tends to overstate the capability of a storage laden system because storage facilities are full and have the ability to deliver at their greatest rate during the beginning of each cycle. In the Company’s current IRP, the peak day occurs on February 3rd, after several months of winter weather and significant heating load. If the Company positions this specific peak day first, followed immediately by the coldest to warmest weather, the storage biased system easily meets the load. However, if the model analyzes the identical winter load as it historically occurred, the storage based system may not meet the peak day requirements because storage inventory and deliverability becomes depleted throughout the winter season. For local distribution companies (LDCs) that have few resource options beyond pipeline capacity, this difference in approaches may be of little significance. For NW Natural, the difference is critical because the Company heavily relies on storage to satisfy peak demand.

III. *SENDOUT®* – PORTFOLIO OPTIMIZATION AND CAPACITY EVALUATION APPLICATION

The Company licensed *SENDOUT®* in 2005. Ventyx (formerly New Energy Associates, acquired by Ventyx in 2007) developed the *SENDOUT®* Gas Planning System. *SENDOUT®* is a comprehensive gas portfolio and optimization application designed to simultaneously analyze and optimize the entire gas supply portfolio - including supply, transportation and storage assets and conservation programs. It generates best-cost strategic plans that consider economic parameters along with operational constraints. *SENDOUT®* is used by approximately 70 energy companies in North America, including all of the natural gas utilities serving Oregon and Washington. SENDOUT is considered the industry standard strategic planning application for gas portfolio planning and analysis.

SENDOUT® generates 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 rates), demand-side management programs, and existing and potential supply options. Please refer to Chapters 2 (demand forecast), 3 (existing and potential supply side resources), and 4 (DSM) for complete descriptions of these model inputs.

In response to a growing, general interest in risk analysis, with the 2008 Update to the 2007 IRP, the Company began using what was initially an add-on module to *SENDOUT®*, called VectorGas™, 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, which drives demand, and price. Through detailed portfolio optimization techniques, the analytical potential of *SENDOUT®* is enhanced because of its capability to produce probability distribution information. Additional details of *SENDOUT®*'s Monte Carlo risk analysis capabilities, as employed in this IRP, are provided later in Chapter 5, Section H.

With *SENDOUT®*, NW Natural abandoned the previous MIP, load duration curve approach. *SENDOUT®* specifies an entire 365 day per year analysis, and, more importantly, the model analyzes weather patterns as they actually occur, rather than in declining order of coldness. The move to *SENDOUT®* in the 2007 IRP increased planning detail and realism, and, as originally discussed in that IRP, revealed a need for increased resources sooner than in previous plans. NW Natural is still "catching-up" from the change in modeling techniques and the level of resources now called for in the

SENDOUT® modeling. Specifically, *SENDOUT®* reveals that under the Base Case Scenario assumptions (see section V below), NW Natural has insufficient existing resources to serve 100% of the forecast load across its system in the second forecast year (i.e., 2009-2010). By the fourth forecast year, due to the availability of adequate incremental resource options, *SENDOUT®* is able to secure sufficient incremental capacity and demand resources to fully satisfy forecast load for the remainder of the 20 year planning horizon.

IV. DSM EVALUATION IN *SENDOUT®*

As discussed in Chapter 4, in fall of 2008 NW Natural worked with the Energy Trust of Oregon (ETO) and Stellar Processes to analyze the potential energy savings it can cost-effectively procure within its Washington service territory. This IRP includes a new DSM deployment scenario to reflect an updated screening of DSM measures based on the Base Case avoided cost forecast.

For this IRP, NW Natural utilized the Program Totals method of DSM evaluation in *SENDOUT®*, which provides direct input of DSM program impact, allowing comparison of DSM options with supply options. Specifically, the Usage Factor method of calculating DSM demand reduction was used in *SENDOUT®*. These usage factors represent the decrement to demand, both base and heat sensitive, associated with the Region/Class to which the DSM program is assigned. The utilization of heat sensitive DSM usage factors allows the achievable potential DSM savings to change with temperature assumptions and is a more realistic dynamic evaluation of DSM potential savings.

To estimate the *SENDOUT®* DSM usage factors for the DSM deployment scenario, NW Natural first allocated the Oregon and Washington annual achievable potential DSM saving estimates for each DSM program type to each month in the year based on monthly load distribution estimates, which are shown in Appendix 4-6. For each year, the base DSM savings is estimated as the minimum monthly average DSM savings per day. The heat sensitive DSM savings for each month are then calculated by subtracting base DSM savings from total savings.

The percentage of base DSM savings to forecasted total base load demand is calculated for each state (i.e. Oregon and Washington), where residential and commercial base DSM saving estimates for New Construction programs are applied to the forecasted base load demand for new construction customers. Similarly, base DSM savings estimates for Replacement and Retrofit programs are applied to the forecasted demand for existing and conversion customers. This process is repeated to calculate the percentage of heat sensitive DSM savings to forecasted normal temperature sensitive load (assuming 20-year normal weather) for each state.

DSM base and heat sensitive usage factors are than estimated for each region and customer sub-class combination, by multiplying the customer base load and temperature sensitive usage factors by the respective percentage of estimated DSM savings to normal demand.

Lost opportunity DSM programs in this analysis are locked in as “must run”, while the other programs are discretionary. The New Construction and Replacement programs designated as “must run” are inputted into *SENDOUT*® as mandatory programs to be automatically utilized at 100% and reduced from demand. Retrofit programs are designated as “discretionary” and are treated differently. Using the Resource Mix functionality of *SENDOUT*®, discretionary DSM programs are evaluated based on levelized societal costs on a comparable basis with supply side options to calculate the most economical levels of utilization. Levelized societal costs were developed by Stellar Processes and are specified for each program in Appendix 4-5. *SENDOUT*® optimally sizes the implementation percent for each discretionary DSM program, by demand area and customer class, taking into account the total cost and demand reduction. *SENDOUT*® reduces the demand and includes monthly program costs based on user inputs. While sizing of discretionary DSM programs is based on levelized program costs, the Company values all DSM programs at the annual utility program cost for purposes of estimating cost of supplying customer demand. These annual utility program costs were developed by the Energy Trust and are provided in Appendix 4.

For all model runs presented in this chapter with the exception of the Low Growth case, the Resource Mix functionality of *SENDOUT*® selected all available discretionary programs at 100% participation based on the levelized societal DSM program costs. These programs were already pre-screened at avoided cost estimates by Stellar Processes to represent “achievable” programs. These *SENDOUT*® results suggest that all DSM programs identified as achievable are indeed cost-effective compared against other resource options. The resulting DSM cost-effective therm savings adjusted for design weather as selected by the *SENDOUT*® Resource Mix DSM allocated by customer sub-class and region over the 20 year IRP planning period are presented in Appendix 5-1.

V. *SENDOUT®* SCENARIOS, PORTFOLIOS & RESULTS

A. PLANNING CRITERIA

Prior to the 2007 IRP, the Company had relied upon the historical coldest season observed in the past 20 years augmented by the coldest peak day event in 20 years to represent a very cold weather scenario. Based on analysis of the historical distribution of weather conditions over the last 20 years, the likelihood of this prior winter design criteria occurring in any one year is only 0.08%. Because the previous IRP model, using a load duration curve, tended to overestimate the Company's ability to meet a late winter peak event, in the past this planning standard may have been the most reasonable one. However, when the Company moved away from load duration curves, the model showed a need for significantly more resources than it had in the past to meet this planning standard. Using stochastic analysis, the Company was able to determine the extreme nature of the previous planning standard, and the high cost of using this planning standard to make resource selections.

After considering this analysis, NW Natural concluded that the planning standard used for the previous model was no longer appropriate on a cost/risk basis. In the 2008 Update to the 2007 IRP, the Company instead utilized a new design criteria: an 85% probability coldest winter again augmented by the coldest peak day event in 20 years plus two shoulder days (see Chapter 2 for a more detailed description of this approach). Implementation of this change in this IRP cycle results in an approximate 5,371 MDth reduction in forecasted annual 2008-2009 firm requirements and a reduction of 7,257 MDth by year 2027-2028. Later in this chapter we test the sensitivity of our selected base case portfolio to the previous historic coldest winter season design criteria. (Sensitivity 6 shown in Appendix 5-3). The scenario analysis reveals the Base Case portfolio at 85% probability of winter demand, provides NPV cost savings $726 million compared to the Coldest Winter scenario over the 20 year study-period.

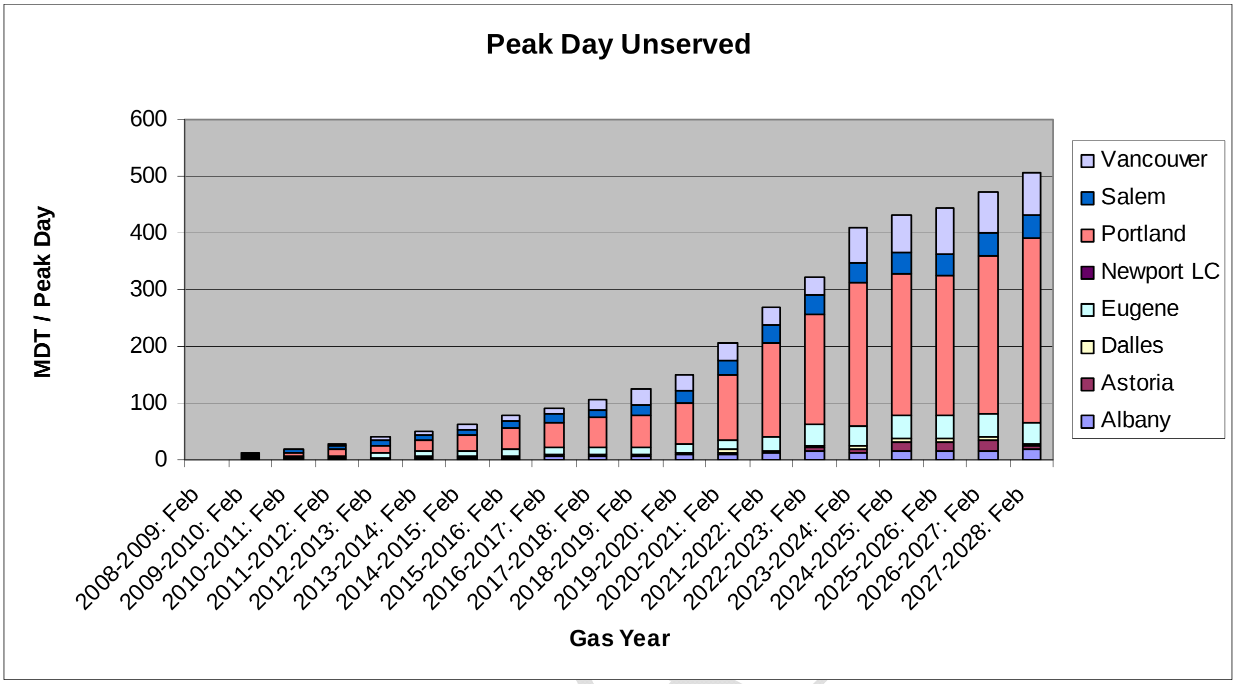
The likelihood of the augmented 85% probability winter design criteria occurring in any one year is 5.9%, based on analysis of the historical distribution of weather conditions over the last 20 years. This probability of occurrence is equivalent to a 1 in 17 year event. In addition, NW Natural also uses *SENDOUT®* to assess the cost and risk trade off associated with adoption of the augmented 85% probability coldest winter planning standard by running hundreds of Monte Carlo simulations assuming a normal distribution around 20-year normal HDDs and around its base case gas commodity price forecast. The stochastic analysis presented later in this chapter shows that the selected least-cost Base Case resource mix that meets the augmented 85% probability coldest winter criteria results in unserved demand in only 2.7% of the 5,000 annual demand profiles generated by the 250 Monte Carlo simulations (250 simulations x 20 years = 5,000 annual demand profiles). The Company believes that this change in design weather assumptions represents the best combination of risk/cost for planning criteria. The analysis provided in this chapter includes a comparison of the new design weather planning standard of (85% probability) and the old design weather planning standard (20-year coldest winter).

B. DEVELOPMENT OF INCREMENTAL SUPPLY-SIDE RESOURCE OPTIONS

NW Natural's evaluation of its need for incremental resources over the 20 year planning horizon begins with its **Current Portfolio Scenario.** Here, the Company applies its planning criteria demand forecast to its existing supply-side resource portfolio (i.e., assuming there are no incremental supply or demand side resources available to NW Natural). The objective of this analysis is to test the ability of the Company's existing resource portfolio to satisfy forecasted load and determine whether and where the Company has an existing resource deficiency.

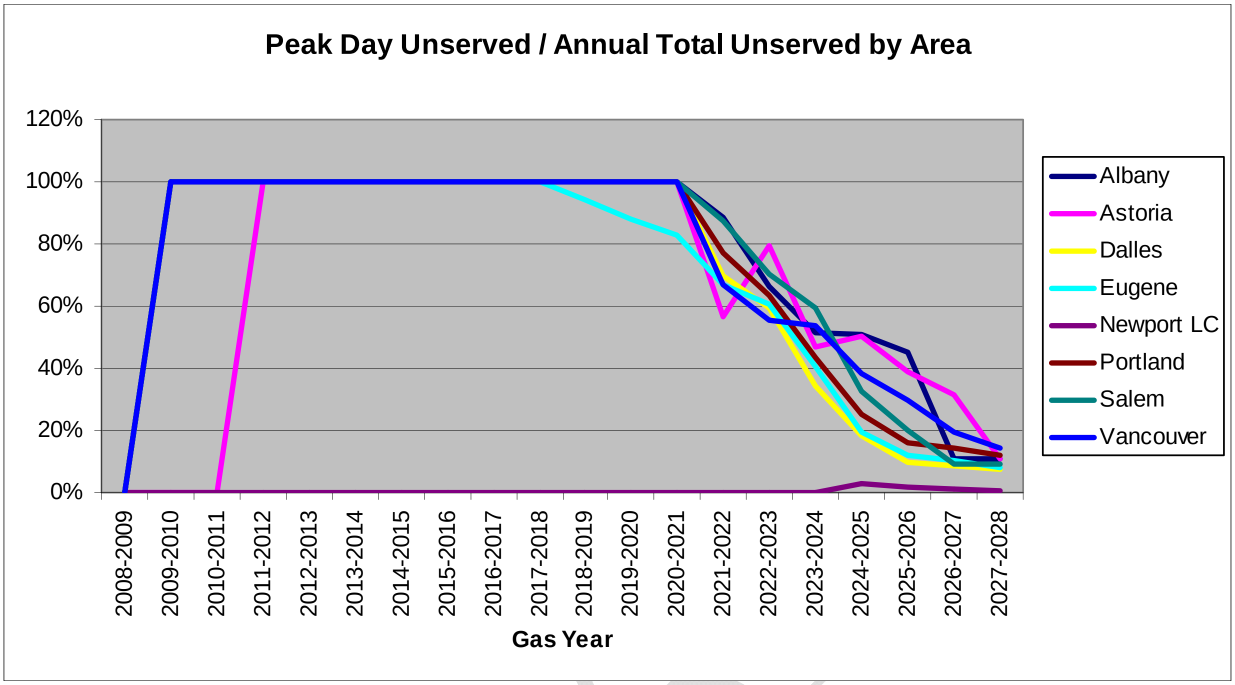
Figure 5-1 demonstrates that NW Natural's existing resource portfolio is not sufficient to serve aggregate forecasted load under the augmented 85% probability coldest winter planning criteria. *SENDOUT®* estimates peak day unserved demand in all areas except Astoria and Newport, totaling 13.41 MDT/day in the initial year, rising to greater than 500 MDT/day, across all areas, by the end of the planning horizon.

Figure 5-1



Appendix 5-2 contains the forecasted peak day and annual unserved demand results for each region. Forecasted annual unserved demand on an aggregate basis grows from 13.4 MDT in 2009-2010 (1.34 in the Vancouver demand area) to 4,453 MDT by 2027-2028 (521.12 in the Vancouver demand area). In Figure 5-2 we compare the characteristics of unserved demand across regions and time by calculating the ratio of peak day unserved demand to annual unserved demand by region throughout the planning horizon.

Figure 5-2



This analysis reveals that peak day unserved demand initially comprises 100% of total unserved demand on an aggregate basis, and remains at this level through 2018-2019. Beginning in 2018-2019, seasonal unserved occurs, and the ratio of peak day to annual unserved demand steadily falls throughout the planning horizon. The ratio of peak day to annual unserved demand reaches levels less than 20% in 2027-2028. On a regional basis, this ratio shows significant variation. Over time, unserved demand begins to expand beyond the peak day, appearing earlier in the southern regions and a few years later in the north. By the end of the planning horizon, however, all regions exhibit a peak day unserved to annual unserved ratio within the 10% to 20% range. This suggests that on an aggregate system-wide basis, the need for incremental peaking resources is more significant in the initial years of the study. In the out-years, the resource preference is expected to shift increasingly towards incremental seasonal (e.g., Mist recall) and baseload (e.g., new pipeline CD) resources. However, gas delivery constraints and resource availability will affect system-wide resource selection, resulting in region-specific resource decisions.

Based on these results, the Company concludes that it is necessary to assess a wide variety of incremental demand and supply-side resources to address forecast unserved demand. Section IV of this chapter describes NW Natural's approach for assessing incremental DSM resources. As described in Chapter 3, the Company is also investigating a variety of incremental baseload, seasonal, and peaking supply resources (see Appendix 3-2 for a summary of expected costs and availability dates for each supply-side resource option). Baseload resources include contracting for incremental pipeline capacity from existing pipeline service providers (e.g., NWPL CD held by March Point), contracting for capacity on proposed new pipelines (e.g., Palomar East), or investing in expansion of the Company's own distribution system (e.g., the Willamette Valley Feeder). Seasonal resources include continued recall of the Company's existing Mist storage capacity. Peaking resources include locating Satellite LNG facilities in Salem, Albany, and Eugene. Lastly, the Company is assessing the economics of contracting for gas sourced from two different proposed LNG import terminals in Oregon. These facilities have the potential to provide baseload, seasonal, or peaking resource needs depending on the Company's market alternatives and contracting strategy. Although Appendix 3-2 indicates an expected availability date for each supply-side resource, the Company certainly has a higher degree of confidence in the timing for those resources that are currently in place (e.g., Mist recall, March Point capacity) or under its direct development control (Willamette Valley Feeder) than those resources that currently represent proposed third party project developments (e.g., LNG import terminals).

C. BASE CASE SCENARIO

NW Natural's evaluation of its selection of incremental resources over the 20 year planning horizon begins with its **Base Case Scenario**. In this IRP, the Base Case Scenario is also the Company's **Preferred Portfolio**.

This portfolio starts with the demand forecast and price forecasts identified by the Company as the base case. While we tested a number of different high and low price and demand forecast, we continue to believe the base case represents our best and most reliable forecast of future load and price.

As explained previously, as in the 2007 IRP, the Company has selected an augmented 85% probability coldest winter planning standard against which to evaluate the cost and risk trade off of various supply and demand resources available to *SENDOUT*®. With the "85% weather" demand specified for each region and customer class, *SENDOUT*® seeks to satisfy demand utilizing the demand-side resources represented by the Base Case DSM deployment scenario described in Chapter 4, the Company's existing portfolio of supply side resources, and the incremental resources described in Chapter 3, except for supplies sourced from the two LNG import terminals.

The Company has chosen to exclude imported LNG from the Base Case Scenario because, relative to the other incremental supply side resources considered, the LNG import terminals are: 1) subject to a greater degree of development/availability risk, and 2) outside the control of the Company in terms of facility development.

As described in greater detail in the 2007 IRP, the Company has contracted in a Precedent Agreement for 100,000 Dth/day of capacity on the Palomar East pipeline, based on our assessment of the commitment necessary to make the project economic, even in the absence of an LNG terminal. After testing a variety of scenarios and sensitivies, in the 2008 Update to the 2007 IRP, the Company determined that capacity on the Palomar Pipeline, at a minimum level of 100,000 Dth/day, was a component of its preferred portfolio. The Company's primary objective in pursuing this portfolio selection is to facilitate a second direct connection to the interstate pipeline network in order to enhance long-term gas supply delivery reliability for its growing distribution system. Based on this conclusion, the Company included Palomar East at 100,000 Dth/day in the Base Case for this 2009 IRP.

In the *SENDOUT*® analysis described below, Base Case scenario is slightly more cost-effective than the "No Palomar" scenario. The Company believes it is unlikely that Palomar East would be available as a resource option had the Company not agreed to the 100 MDT Precedent Agreement.

Future Segmentation of NWP Capacity

One of the primary drivers for the decision to agree to a Precedent Agreement for 100,000 Dth/day of capacity on Palomar East was fact that that amount of capacity matched the amount of NWP Gorge capacity – 102,000 Dth/day – that NW Natural could potentially turn back to NWP. Hence, the Company could acquire capacity on Palomar East and still keep its net pipeline capacity position neutral.

NW Natural had hoped that NWP would be agreeable to our being able to reallocate Willamette Valley delivery points to our other capacity contracts that we planned to retain. Unfortunately, NWP has thus far not been agreeable to this reallocation. Hence, to be conservative we have assumed that we will need to retain 25,000 Dth/day of our NWP Gorge capacity to retain these delivery points. In the coming months, NW Natural plans to explore creative ways of reducing this requirement. If we could reduce this requirement, then we may ultimately be able to further improve upon the cost-effectiveness of the Preferred Case.

Specific Resource Acquisitions and Action Items Related to the Base Case/Preferred Portfolio

NW Natural will be seeking to acquire the following resources, in conjunction with its selection of its Base Case portfolio:

Washington Resources:

1. Palomar East capacity: Per the terms of the Precedent Agreement, assuming the Palomar project proceeds as currently scheduled, the Company plans to commit to 100,000 Dth/day of capacity on Palomar East. To make this resource even more economical, NW Natural plans to investigate creative ways of further reducing capacity on NWP. Costs for a portion of this capacity would be allocated to Washington customers.

2. Mist Recall: the Company recalled 10,000 Dth/day of Mist capacity in the fall of 2008. The Base Case calls for an additional 11,000 Dth/day of capacity in the fall of 2009. Costs for a portion of this capacity would be allocated to Washington customers. The company will continue to evaluate the need to recall additional Mist capacity from interstate markets as it updated demand forecasts in subsequent years.

D. OTHER SCENARIOS AND BASE CASE SENSITIVITIES

After defining the Base Case resource portfolio, NW Natural constructs a series of alternate scenarios in which it modifies the supply side resources made available to *SENDOUT*®. *SENDOUT*® re-optimizes and selects the optimal portfolio of resources (a process known as “resource mix”) to satisfy forecast demand in each of the alternate scenarios. A variety of alternate scenarios are evaluated to measure resource selection and related system costs and reliability given different assumptions for incremental resource options and operating conditions.

There are two alternate scenarios which evaluate the implementation of incremental resources at different levels than the Base Case. The **Current Portfolio** scenario identifies the system breaking-points associated with the existing portfolio of resources. No incremental resources are available. The purpose of this scenario is to identify system breaking points and capacity shortfalls. The economic and operational viability of Palomar East is evaluated by comparing the Base Case, with Palomar at a minimum of 100,000 Dth per day, to the **No Palomar Scenario.** The No Palomar Scenario assumes that the Palomar pipeline is not developed during the 20 year planning horizon.

Two scenarios evaluate potential LNG projects. The **Northern LNG Scenario** includes supplies sourced from the Bradwood Landing. The **Southern LNG Scenario** adds supplies sourced from the Jordan Cove project, as well as capacity from the Pacific Connector. The Company believes that given the scale, cost and supply commitments required to develop one of these projects, it is reasonable to assume that only one such project could be successfully developed in the region.

In addition to the alternate scenarios discussed above, NW Natural develops Sensitivity cases to the Base Case Scenario. The Sensitivity cases differ from the alternate resource Scenarios in that they include different planning criteria, such as alternate weather patterns, various levels of load growth and alternate forward price curves. There are eight sensitivity scenarios evaluated using the Base Case resource assumptions. These sensitivies are described in more detail in Chapter 2.

As noted in Chapter 2, the Company is giving significant attention to the current changing economic conditions and the impact on the Company's demand forecast. While, again, the Company considers the Base Case to be the most likely outcome, given current market conditions, we also believe it is possible that the Company could experience 1) lower than expected growth (the Low Growth sensitivity); 2) a longer recession, followed by a return to base case growth rates (the Low Growth Alternative 1 sensitivity); or 3) a prolonged recession, followed by continued low growth rates (the Low Growth Alternative 2 sensitivity). We have paired these demand scenarios with potential price scenarios to simulate potential future portfolios, or outcomes.

Table 5-1 summarizes NW Natural's alternate Scenarios and Base Case Sensitivities. In this chapter we provide a brief summary of the modeling results. Appendix 5-3 provides detailed results of the model runs.

Table 5-1: NW Natural Modeling Scenarios & Base Case Sensitivities

<table>
<tr><td colspan="2">Base Case Scenario
• Revised Design “85% weather”
• Base demand growth
• Base price forecasts
• Incremental resources available include: new pipeline CD, Mist recall, Palomar East, TF-1 capacity turnback, Satellite LNG, Willamette Valley feeder, Newport LNG enhancement, and Brownsville to Eugene capacity, various upstream options.</td></tr>
<tr><td colspan="2"></td></tr>
<tr><td>Alternate Scenarios
(resource mix options)</td><td>Base Case Sensitivities (modifications of commodity availability, commodity cost, transportation cost, and/or load forecast inputs)</td></tr>
<tr><td>1. Current Portfolio (no incremental resources available)

2. No Palomar (and no CD turnback)

3. Northern LNG (Bradwood Landing is available, Palomar West is available)

4. Southern LNG (Jordan Cove and Pacific Connector are available)</td><td>1. Historical Coldest (Previous Design Weather): Uses previous design planning standard of coldest peak event in 20 years + coldest total winter demand in 20 years (see Chapter 2). Base growth and price.
2. High Growth/Low Price: Significant new gas supplies (e.g., strong domestic exploration), relaxed environmental protections, and increased use of coal for electric generation with new technologies (e.g., carbon capture) drive gas prices lower, coupled with strong economic growth and higher demand.
3. Low Growth/High Price: Prolonged economic down turn, increased gas-fired electric generation, new environmental regulation (e.g., a significant carbon tax), and a decrease in supplies lead to higher prices, which in turn drives down demand.
4. High Growth/High Price: Significant new environmental regulations drive increased demand and price, but strong economic growth leads to continued high demand.
5. Low Growth/Low Price: A lengthy economic downturn, coupled with significant new sources of supply such as imported LNG and shale gas, lead to depressed price and demand.
6. Low Price: Base growth with low price
7. Low Growth Alternative 1 / Low Price: A prolonged</td></tr>
</table>

	recession with a healthy rebound to previous growth rates later in the planning horizon, coupled with alternative supply such as shale and imported LNG leading to lower prices 8. **Low Growth Alternative 2 / Low Price**: A prolonged recession that never returns to previous growth rates, substantial changes in production and housing markets result in continued low demand on NW Natural's system, while nationwide factors such as significant renewable penetration, progressive energy efficiency policies, and significant nuclear development result in lower gas demand and lower prices overall.

The Company also conducts a stochastic analysis of the Base Case Scenario and the Historical Coldest (previous Design Criteria) scenario to "stress test" the selected portfolios against a range of future demand and price outcomes. The stochastic process generates hundreds of potential outcomes around the 20-year average normal weather and the forecasted gas prices. By comparing the Base Case and Historical Coldest resource mix decisions across a range of potential operating conditions and economic out-comes, we can assess the reliability and cost tradeoff associated with changing the design planning criteria from historical coldest to 85%.

E. HIGHLIGHTS OF DETERMINISTIC RESULTS - SCENARIOS

Appendix 5 identifies the aggregate projected unserved demand; the incremental resources selected; and the present value cost of the resource portfolio over the 20 year planning horizon. With the exception of the Current Portfolio scenario, the Company expects to have adequate incremental capacity and demand side resources available to satisfy 100% of forecast demand, except in the second and third years of the planning horizon where approximately .03% of peak-day demand is unserved. All regions except Astoria and Newport show peak day unserved demand in the second and third year.

SENDOUT® selects the following incremental resources in the Base Case Scenario:

- Mist Recall: *SENDOUT*® begins selecting this resource in 2009-2010 at a level of 11,000 Dth/day. *SENDOUT*® continues to take increasing amounts of Mist Recall, reaching a level of 189,000 Dth/day in 2027-2028.

- Incremental pipeline CD: In 2011-2012, *SENDOUT*® elects to turn back existing NWPL CD capacity at a level of 77,000 Dth/day, the maximum amount that is first made available to the model. This is a one-time economic decision for the model; it must size the amount of capacity turn-back for the balance of the planning horizon, as opposed to turning back smaller increments that may increase over time. At the same time, *SENDOUT*® replaces the turned-back capacity by selecting Palomar East capacity at the minimum level of 100,000 Dth/day.
- Oregon Only Facilities: *SENDOUT*® also selects the following NW Natural incremental facility projects, all of which are specific to NW Natural's Oregon customers:
    - o Brownsville to Eugene: 5,000 Dth/day 2011-2012 (one-time decision for remaining study-period).
    - o Newport pipeline enhancement: 14,000 Dth/day 2012-2013 (one-time decision for remaining study-period).
    - o Willamette Valley Feeder from Perrydale through Halsey: 2,000 Dth/day 2011-2012.
    - o Satellite LNG: In Eugene, *SENDOUT*® begins selecting this resource in 2015-2016 at a level of 1,114 Dth/day, rising to 14,000 Dth/day by 2027-2028

Appendix 5-3 identifies the incremental resources selected by *SENDOUT*® for each of the alternative portfolio scenarios. The 20 year NPVRR of total system costs for the Company's Base Case Scenario equals approximately $9.934 billion ($2008). The No Palomar Scenario is slightly more expensive at $9.937 billion (approximately NPV $3 million more expensive over 20 years). The Bradwood LNG Project Scenario is estimated to be $9.6 billion, while the Jordon Cove LNG Project Scenario is estimated to cost $9.75 billion under the same demand and forward price assumptions.

F. HIGHLIGHTS OF DETERMINISTIC RESULTS – BASE CASE SENSITIVITIES

Appendix 5-3 also identifies the aggregate projected unserved demand, the changes to the Base Case resource portfolio, and the present value cost of the resource portfolio over the 20 year planning horizon for each of the Base Case Sensitivity cases. The Sensitivity cases are applied to the Base Case resource portfolio options.

For all sensitivity cases, *SENDOUT*® reevaluates the optimal resource mix for each scenario. Notable adjustments to the Base Case portfolio include:

- Mist Recall: *SENDOUT*® continues to begin selecting this resource in April of 2008 in all cases, except the Low Growth, High Price scenario. By the end of the 20 year planning horizon in 2027-2028, Mist Recall levels vary considerably, from a low of 0 Dth/day in the Low Growth, High Price case, to a high of the maximum 279,200 Dth/day in the High Growth, High Price and the High Growth, Low Price cases.

- Satellite LNG: Satellite LNG is selected at various levels. Typically, *SENDOUT*® does not select Satellite LNG upon its initial availability, with the exception of the **Low Growth Alt 1. Low Price**, **Low Price**, and **High Growth / Low Price** scenarios, where a small amount of Satellite LNG is chosen in Eugene. Many scenarios indicate no need for Satellite LNG at any time during the study horizon. These include: **Low Growth Alt. 2 Low Price**; **Low Growth, Low Price**; and **Low Growth, High Price.** The remaining scenario select Satellite LNG at various levels by the end of the study period, including: **Low Growth Alt 1, Low Price; Low Price, High Growth, High Price; Bradwood LNG; Jordon Cove LNG; Base Case; No Palomar; Coldest; High Growth, High Price.** In most cases where Satellite LNG is selected, the sizing decisions emphasizes the need for capacity in Eugene.

- Incremental pipeline CD: In all Sensitivities, *SENDOUT*® elects the one-time turn back of 77,000 Dth/day of existing NWPL CD capacity in 2011-2012, except for the No Palomar case, where turnback is not available. In all cases *SENDOUT*® replaces the turned-back capacity by selecting Palomar East capacity at the minimum level starting in 2011-2012. All of the High Growth cases, select more than the minimum level of Palomar by the end of the study horizon, ranging from 127.5 MDT per day to 172.5 MDT.

As shown in Appendix 5-3, the 20 year NPVRR of total system costs for the Company's Sensitivity cases range from approximately $17.2 billion ($2008) for the High Growth, High Price Sensitivity to a low of approximately $7 billion ($2008) for the Low Growth Alternative 2, Low Price case. These two Sensitivities mark the upper and lower ends, respectively, of the range of NPVRR estimates for all the tested Scenarios and Sensitivities.

G. STOCHASTIC ANALYSIS OVERVIEW

The deterministic analysis described above represent specific "what if" scenarios, which include predetermined assumptions for weather and price, as well as portfolio options and available incremental resources. To better understand the selected portfolio's response to weather and price criteria beyond the forecasts evaluated in the deterministic scenario analysis, the Company applies stochastic analysis to generate a variety of future weather and price events. Thus, by combining deterministic analysis and stochastic analysis, NW Natural is able to construct an optimal portfolio that meets specific pre-determined planning criteria, while also "stress testing" the deterministic resource mix decision against a range of future weather and price events.

Deterministic analysis is valuable for selecting the optimal portfolio of available resources required to meet specific planning criteria. The model selects resources that meet pre-determined design seasonal demand, while also meeting peak-day projections in each of the 20 years. However, due to the recurrence of design conditions in each of the 20 years, total system costs over the run horizon are overstated due to: 1) annual recurrence of design conditions; 2) annual recurrence of peak day; 3) recurrence of price increase in the forward price curve. In addition, deterministic analysis does not provide a comprehensive evaluation of reliability because only a single recurring weather profile is assessed within each scenario. As a result, deterministic analysis does not provide a comprehensive view of future events, and does not provide the range or expected performance across multiple weather and price profiles. Utilizing Monte Carlo[1] simulation to generate numerous weather profiles and price curves, the Company is able to measure a portfolio's performance over a range of future probable events not captured in the deterministic analysis. The following is a comparison of the benefits, limitations and applications of the two types of analyses for resource modeling purposes:

<u>Deterministic Analysis (as employed in this IRP)</u>

Primary Benefits:

- Assures pre-determined planning criteria are considered in each of the 20 years within the study horizon.
- Provides the basis for "what if" analysis to determine the optimal least-cost portfolio mix for a variety of pre-determined scenarios
- Provides a high level of flexibility to change assumptions based on specific objectives for each scenarios

[1] *SENDOUT®* uses Monte Carlo simulation to support stochastic analysis, which is a mathematical technique for evaluating risk and uncertainty. Monte Carlo simulation is a statistical modeling method used to imitate the many future possibilities that exist within a real-life system. By defining the expectation, variability, behavior, and correlation among potential events it is possible through repeated random "draws" to derive a numerical landscape of the many potential futures. Monte Carlo provides a quantitative landscape to reflect both the magnitude and the likelihood of these events, thereby providing a risk based viewpoint from which to base decisions.

- Provides the basis for resource mix / asset sizing decisions assuring key planning criteria is met throughout the study period.

Limitations:

- Weather patterns recur on an annual basis which is inconsistent with real world behavior. For example, Design Weather is applied to each of the 20 years within the study period, providing no variance in daily, monthly or annual heating degree days.
- Aggregate costs over the study horizon are over stated due to annual recurrence of design conditions year after year. Though the costs for any year within the study period are reasonable, the prospect of 20 consecutive Design years produces an exaggerated 20-year total cost.
- The portfolio is not evaluated against a comprehensive range of weather and price patterns.

Applications:

- Resource mix /asset sizing
- Comparison of various portfolio options and decisions under similar pre-determined planning criteria
- Decision and impact analysis given identical operating and economic conditions

Stochastic analysis (as employed in this IRP)

Primary Benefits:

- Provides a thorough stress test of the selected portfolio's performance under a variety of real world weather and price events
- Generates probabilistically weighted measures, such as costs, served demand, and unserved demand across a range of economic and operating conditions
- Provides a probabilistic view of expected costs and distribution of costs

Limitations:

- Randomness may not produce weather and price profiles consistent with planning criteria

- Will not necessarily capture desired peak day, due to low probability of occurrence

Applications:

- Stress testing for reliability against various weather patterns & related demand levels
- Provide expected costs and a range of costs over a normal distribution
- Used to confirm the selected portfolio's performance given real world economic and operational conditions.

The Company's application of deterministic and stochastic analysis in this IRP emphasizes the benefits of each, while minimizing the limitations. To this end, deterministic analysis provides the basis for resource sizing decisions and optimal portfolio construction, while stochastic analysis measures the selected assets under real world conditions, providing a comprehensive evaluation of portfolio performance.

The objective of stochastic analysis for the purposes of this IRP is to measure the reliability and cost of the Base Case (85%) decision and the Coldest (previous design) decision against a wide range of weather and price outcomes. The approach (simplified) includes:

1) run deterministic Base Case
2) "lock in" resource mix decision from Base Case
3) "Stress test" Base Case resource mix using Monte Carlo simulation
4) Repeat steps 1-3 for Coldest (previous design criteria)
5) Compare reliability and cost results

Monte Carlo techniques generate multiple (250 in this case) weather and price forecasts over the 20 year period. For each of the 250 "draws", *SENDOUT*® solves for the least cost dispatch solution for resources selected from the Base Case and Coldest portfolios. The stochastic analysis provides performance measures, such as system costs, served, and unserved demand under each of the 250 draws, and produces a distribution of Base Case portfolio results. Thus, stochastic analysis is used to evaluate the resource sizing decisions from the deterministic Base Case and Coldest scenarios against a range of weather profiles and forward prices.

Unlike the deterministic Scenarios and Sensitivities described previously, the stochastic analysis generates draws characterized by weather profiles with more variability from month to month and year to year. Generally, deterministic scenarios are constructed to include annually recurring weather profiles and related peak events to satisfy desired planning criteria. This type of traditional scenario analysis is valuable to assess the portfolio's ability to serve a pre-determined level of demand at various levels of growth over time. Any given year for a deterministic scenario may be representative of its associated probability, but the probability of consecutive years with the exact same weather profile is improbable.

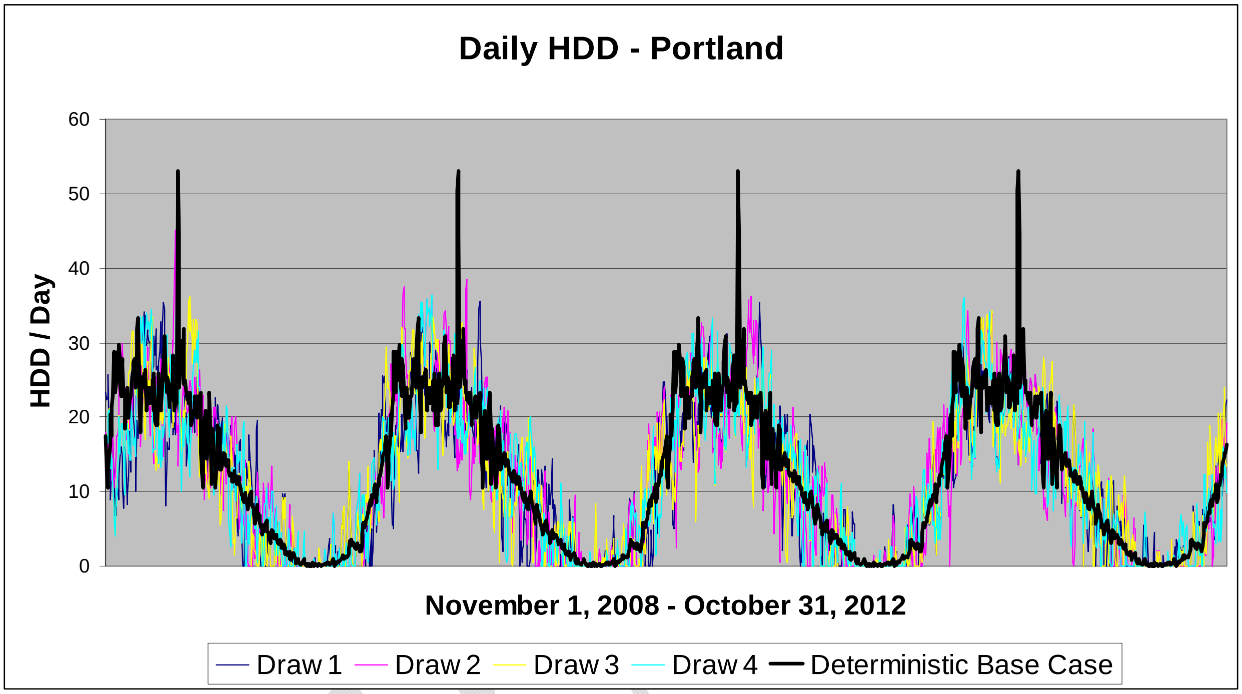
For example, the Coldest (previous design) weather is constructed of 20 consecutive design years, each with a fixed peak day event. The same pattern is presented each and every year over the study horizon. However, assuming the design year is based on a 5% probability of occurrence, the probability of consecutive design years occurring is:

(P) Probability of Design Year = 5%
(n) Number of years in planning horizon
Probability of consecutive Design Years = $P^{(n)}$
Probability of Design Year in 2 consecutive years = $.05^{(2)}$ = 0.25%
Probability of Design Year in 20 consecutive years = $.05^{(20)}$ = statistically insignificant

Stochastic analysis, as employed by *SENDOUT*®, produces random monthly total HDD draw values, subject to Monte Carlo parameters. Monthly draw values are distributed on a daily basis based on a month from history with similar HDD totals. This procedure is repeated for every month of the study period. The resulting weather profile provides variability in the total HDD values, as well as variability in the shape of the weather pattern. As a result, stochastic analysis produces weather patterns that vary from month to month and year to year, which is more consistent with real-world behavior. This provides a more robust basis for stress testing than deterministic scenario analysis, because results can be evaluated based on their relative probabilities.

The graph below illustrates the recurring deterministic weather profile for Portland, compared to four random draw values produced by Monte Carlo simulations. The deterministic pattern remains constant year after year. This is important when selecting an optimal portfolio of resources, to assure design conditions and peak are met in each of the 20 years. The recurrence of the resulting high level of demand, along with the recurring peak event yields a high reliability portfolio, but also exaggerates costs over the 20 year period. On the other hand, Monte Carlo simulation generates a number of realistic weather patterns, which vary from year to year and draw to draw. Evaluating the selected portfolio over a number of random patterns provides a more realistic projection of expected costs and optimal dispatch. Ultimately, Monte

Carlo assures the resources selected from the Base Case demonstrate reasonable costs and high reliability given a range of future weather and price events.



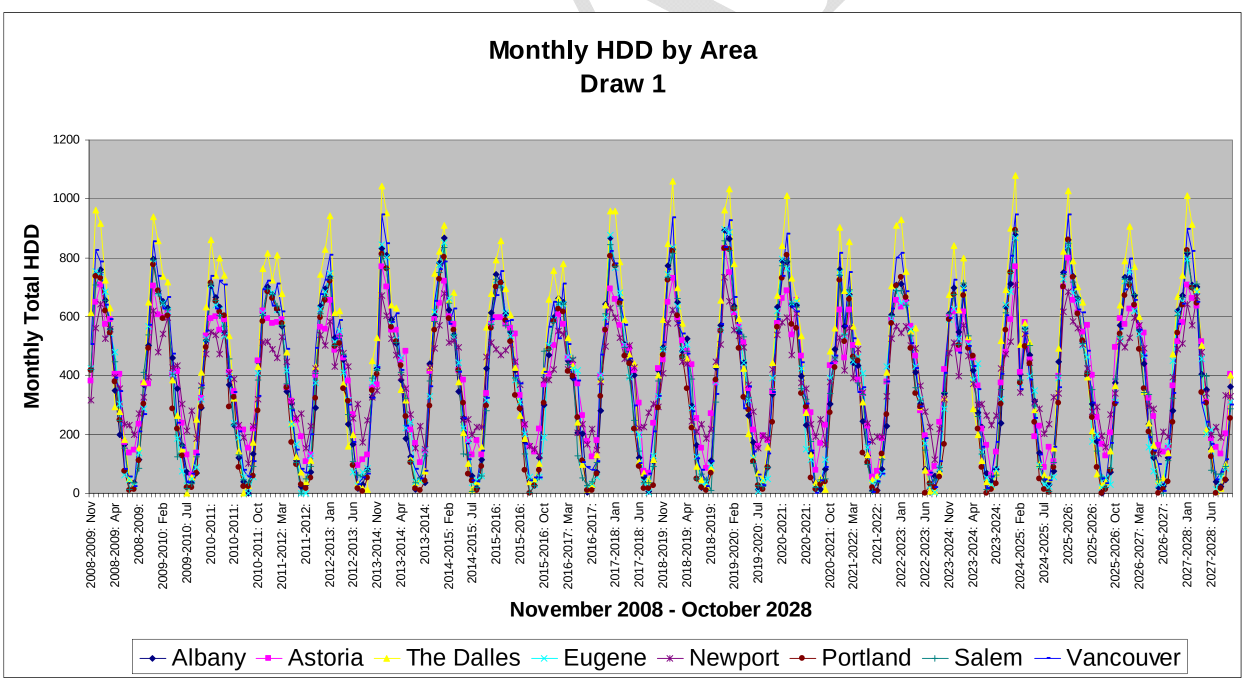
The design winter and peak event pattern recurs annually in the deterministic analysis, providing no "down-time," typical in real world weather patterns. Monte Carlo simulation, on the other hand, generates weather profiles that better represent real world activity, where a cold month may be followed by a warm month, producing monthly and annual profiles that vary throughout the study period.

SENDOUT® also supports correlation of Monte Carlo variables. Correlation assures the behavior of draws from different variables and from month to month maintain reasonable consistency between one-another. A correlation of "1" assures draw results are in "lock step" with one another, while a correlation of "0" indicates there is no relationship between the two variables.

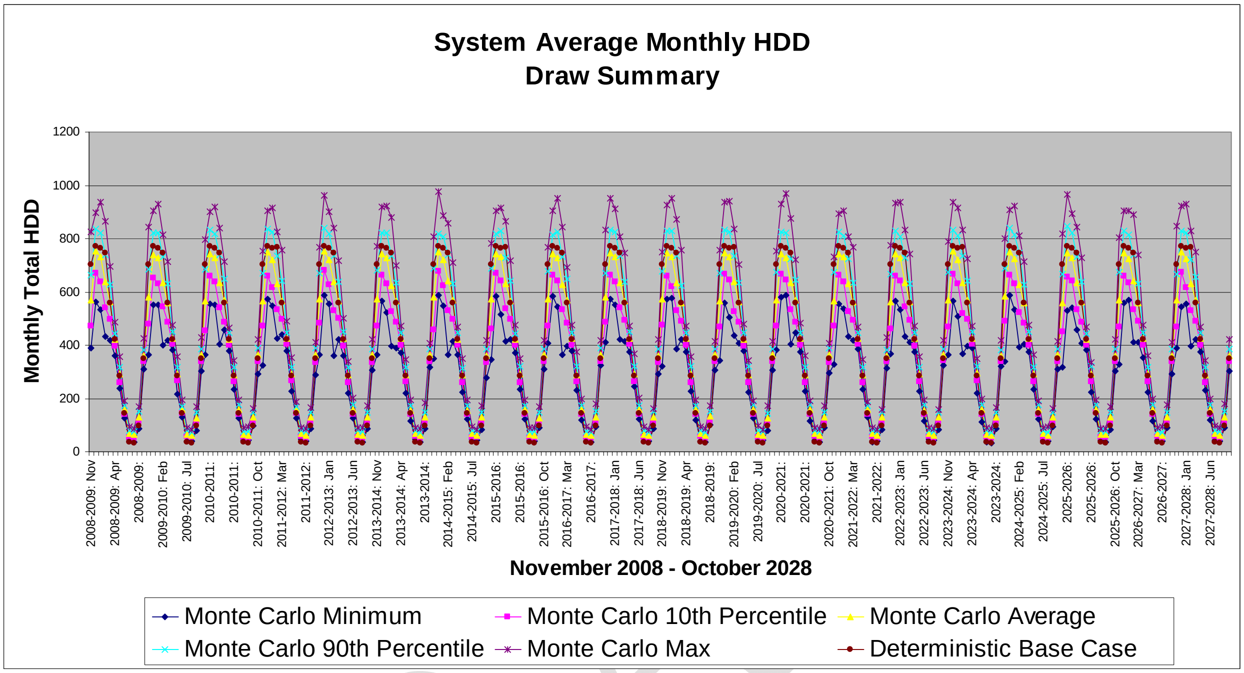
Weather correlations are based on statistics calculated from 20 years of historical data. In contrast, historical price correlations typically are not a reliable predictor of future price movement and in some cases, like Bradwood and Jordon Cove LNG, historical pricing does not exist. As a result, historical relationships cannot be accurately calculated. From a historical perspective, relative price patterns do not follow similar patterns, diminishing correlations over time. Due to the inconsistency of historical price correlation matrixes, the Company has included correlations for price indexes at a factor of 0.75, allowing reasonable variation from price to price while also assuring prices maintain a relatively consistent pattern in relationship to one another. This approach also assures that draw results across indexes do not gravitate toward the expected value. Rather, correlating at a consistent rate assures a reasonable level of draw results will produce a robust range of simulations. In addition, the Company correlates each price index to its prior month draw value at 0.5. This allows month to month price movement, while minimizing the "saw tooth" effect associated with uncorrelated random draws.

NW Natural applies Monte Carlo simulation to the weather patterns of the eight areas modeled (Portland, Astoria, The Dalles, Vancouver, Salem, Albany, Newport and Eugene) and three price indexes (Rockies, Sumas, and AECO) available in the Base Case. Results of the Monte Carlo simulation produce the following ranges of forecasted aggregate demand and average index price.

HDD Draw Results by Area – Draw 1 of 200 (example):

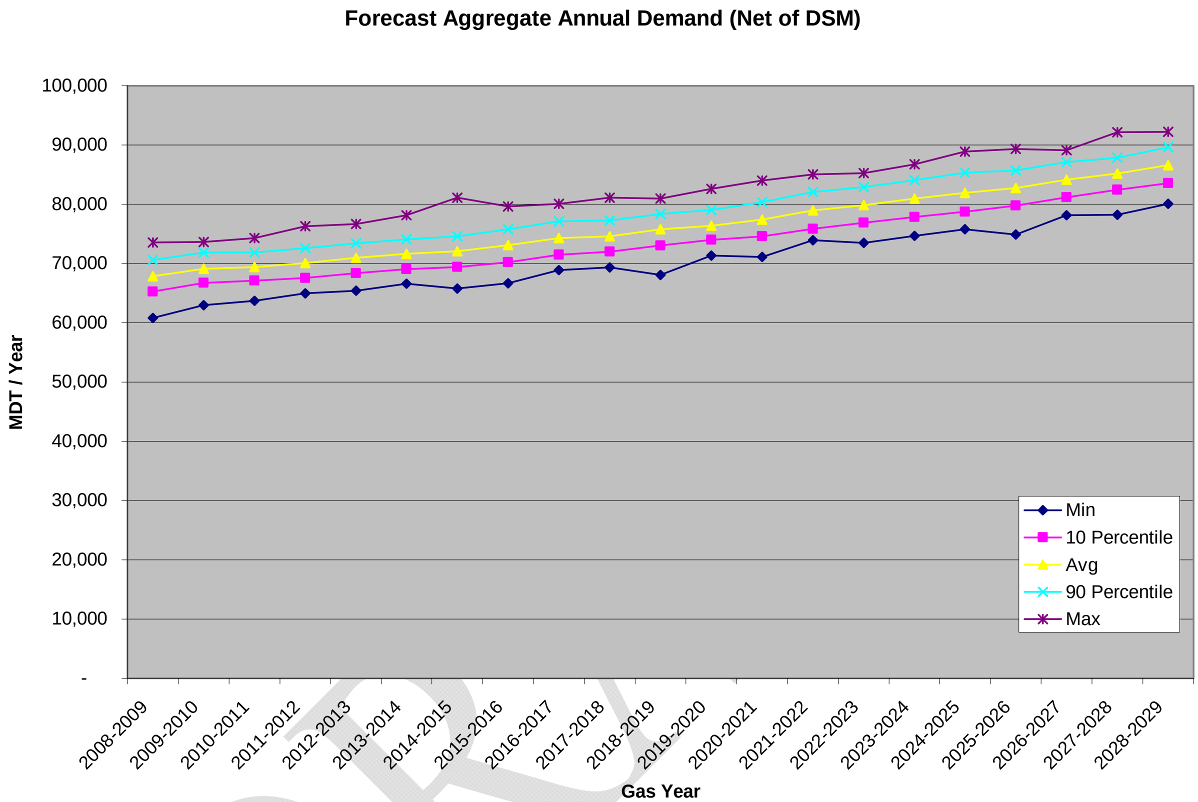


System Average Monthly HDD Statistics across 200 Draws.[2]



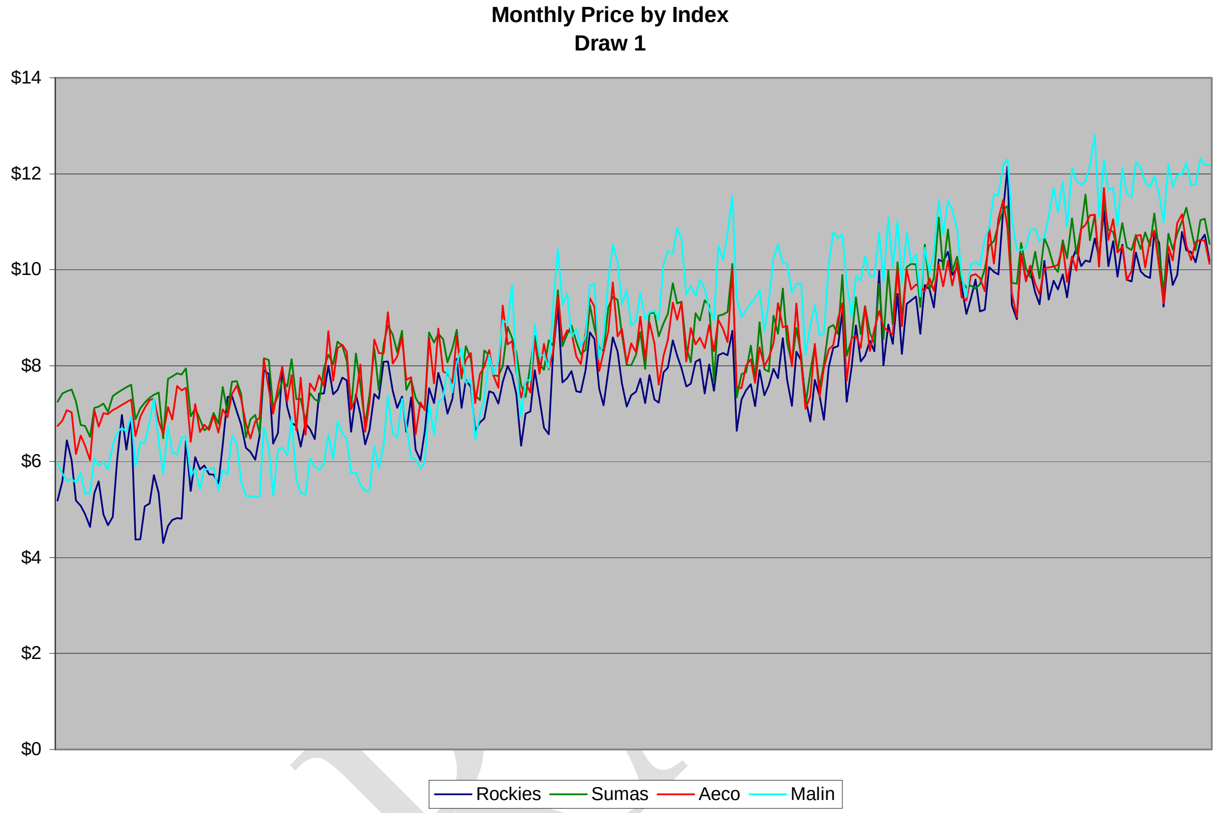
2 Note: the statistical summary graphs do not represent a particular draw; rather, they represent statistics across all draws. For example, the minimum for January, 2008 occurred in draw 91, while the minimum for February, 2008 occurred in draw 126; and the maximum for January, 2008 occurred in draw 186, while the maximum for February 2008 occurred in draw 76.

Resulting Aggregate Demand Forecast (Net of DSM) Statistics across 250 Draws

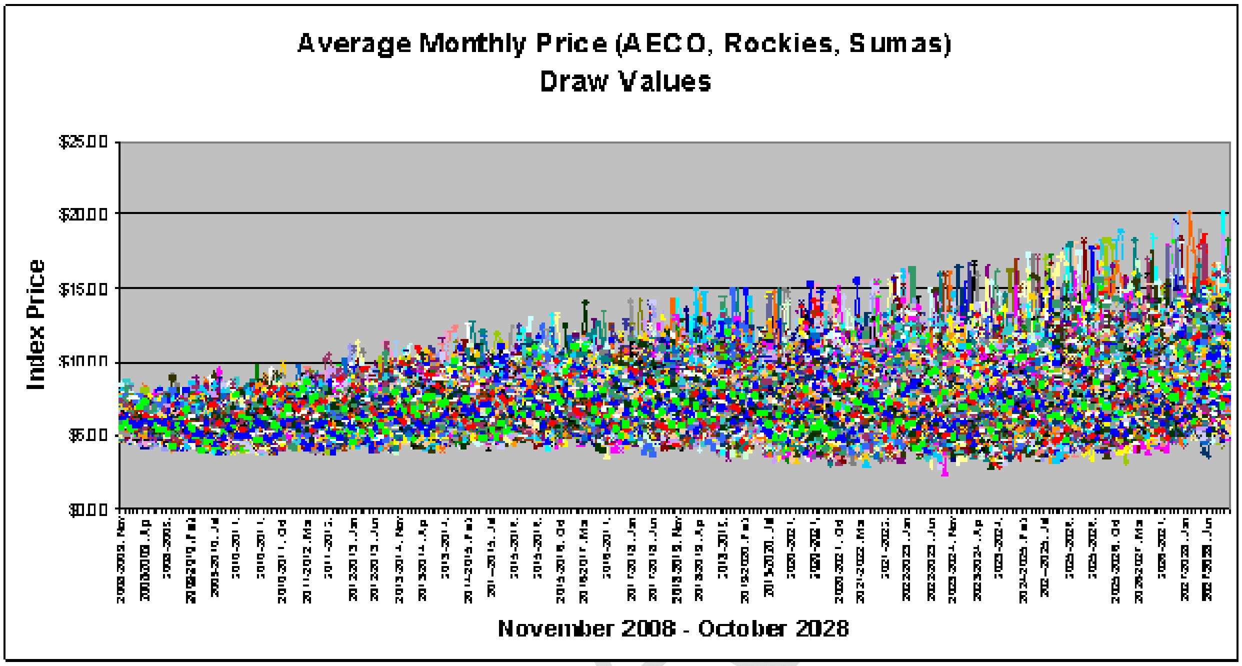


Similarly to the weather profile explanation, deterministic analysis is generally limited to evaluation of a subset of potential forward price curves. Monte Carlo simulation produces forward price curves with a wider range of month to month and year to year variability, compared to typical deterministic price forecasts. A range of forward prices and price patterns supports a more robust assessment of potential cost ranges and related cost risks. The following charts depict Monte Carlo price draw results.

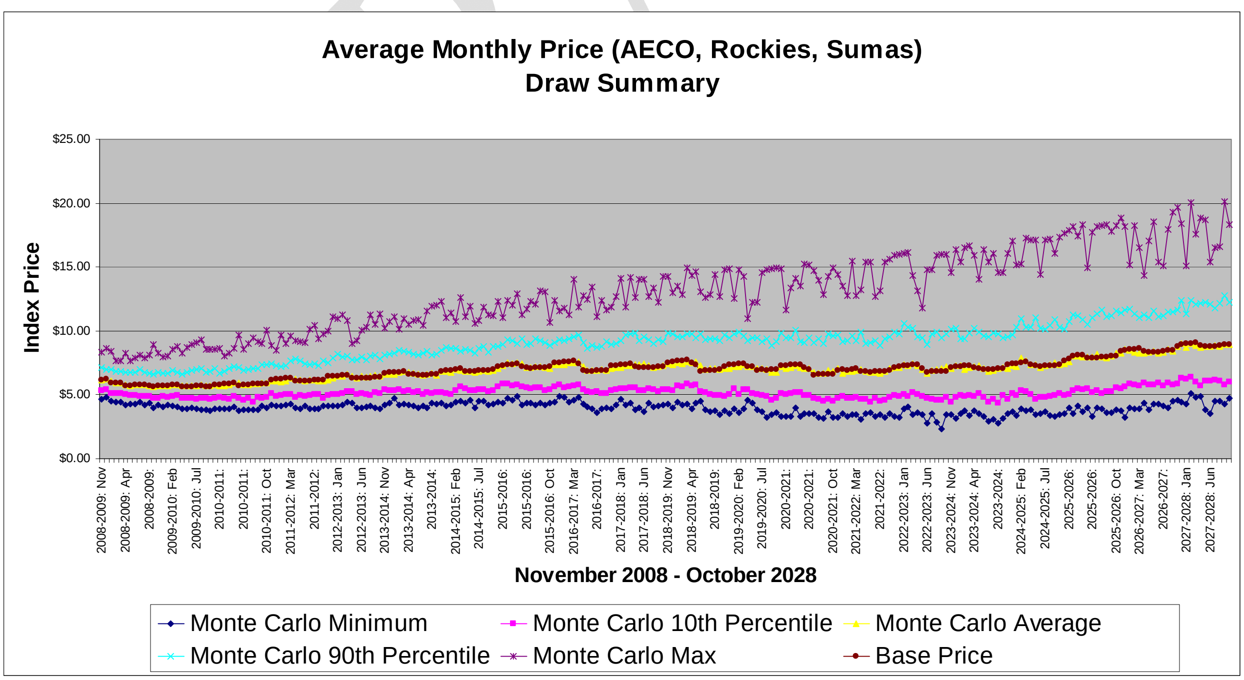
Price Draw Results – Draw 1 of 250 (example):



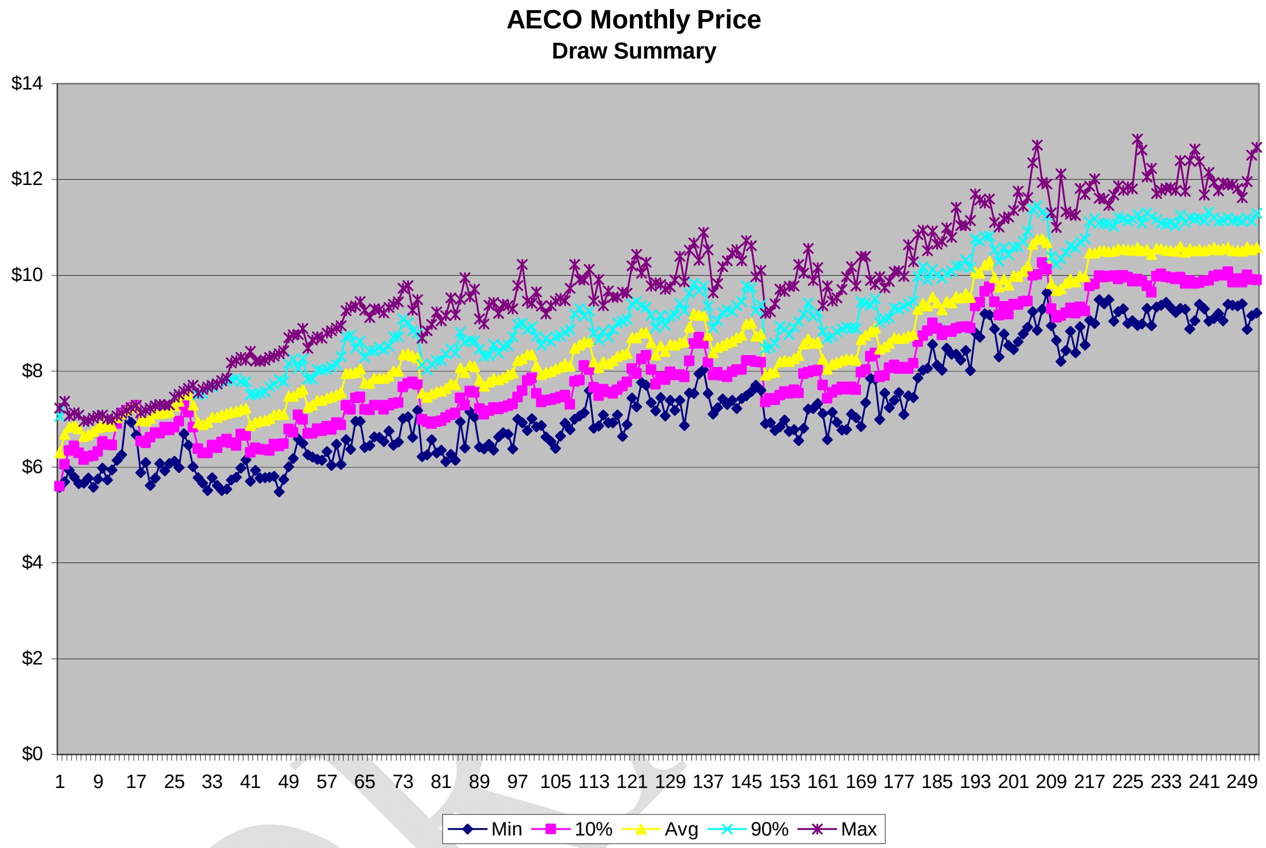
System Average Monthly Price Results for all Indexes (250 Draws):



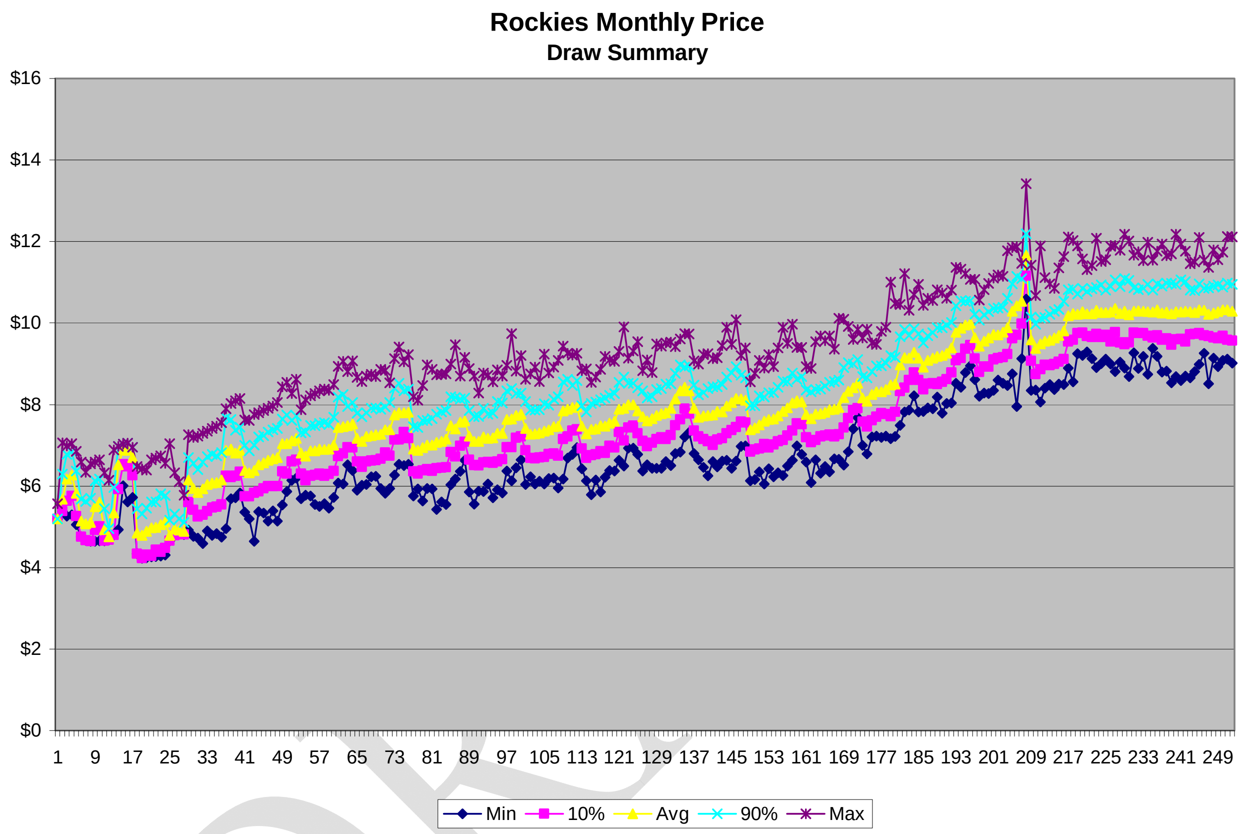
System Average Monthly Price Statistics across 200 Draws:



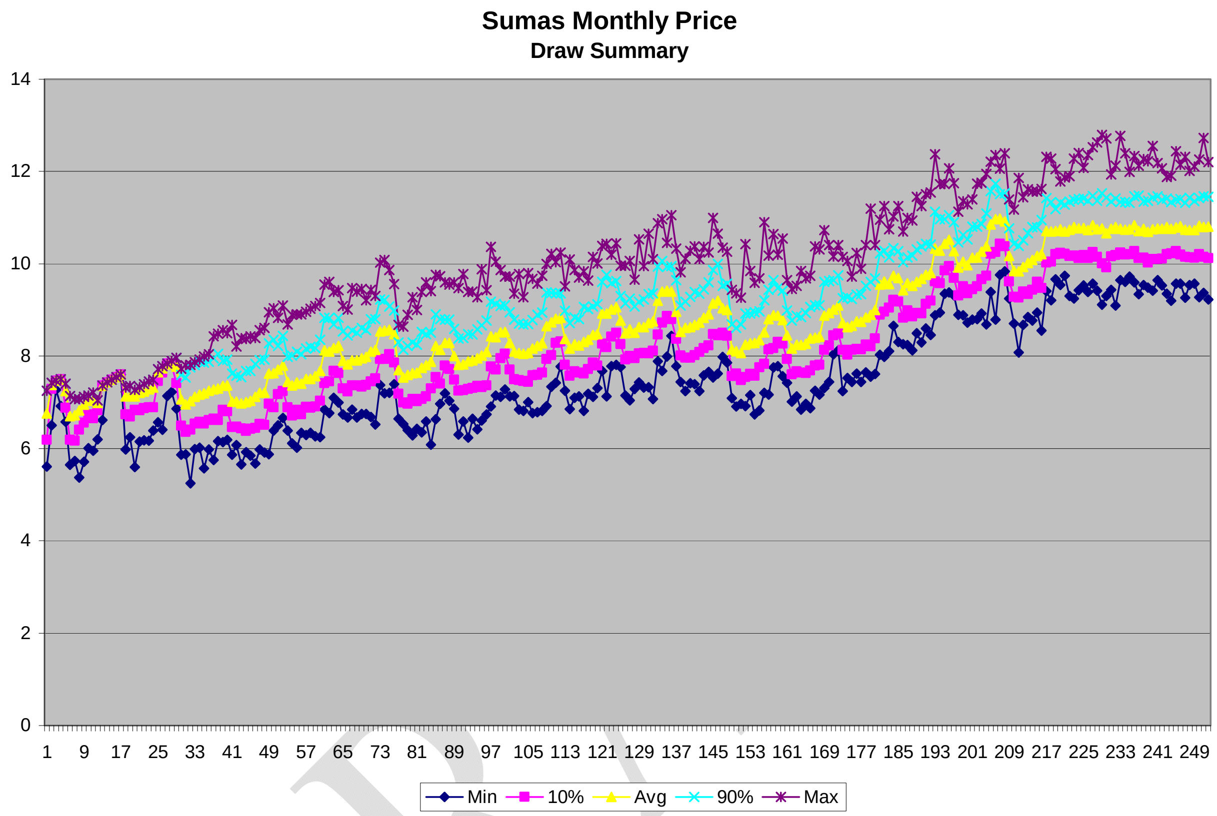
AECO Monthly Price Statistics across 200 Draws:



Rockies Monthly Price Statistics across 200 Draws:



Sumas Monthly Price Statistics across 200 Draws:



.

H. STOCHASTIC ANALYSIS RESULTS

The weather and price draw results presented above are the basis for the Company's stochastic analysis of both the Base Case portfolio and the Coldest (previous design planning criteria). The stochastic analysis reveals that the Base Case portfolio results in lower expected costs over the 20-year planning period, while providing reliability comparable to the portfolio selected by the Coldest planning criteria.

This section depicts high level results of the Company's comparative stochastic analysis of the reliability and cost of the Base Case and Preferred Portfolio by use of histograms. The histogram graphs depicted in this section include a number of meaningful statistics, including:

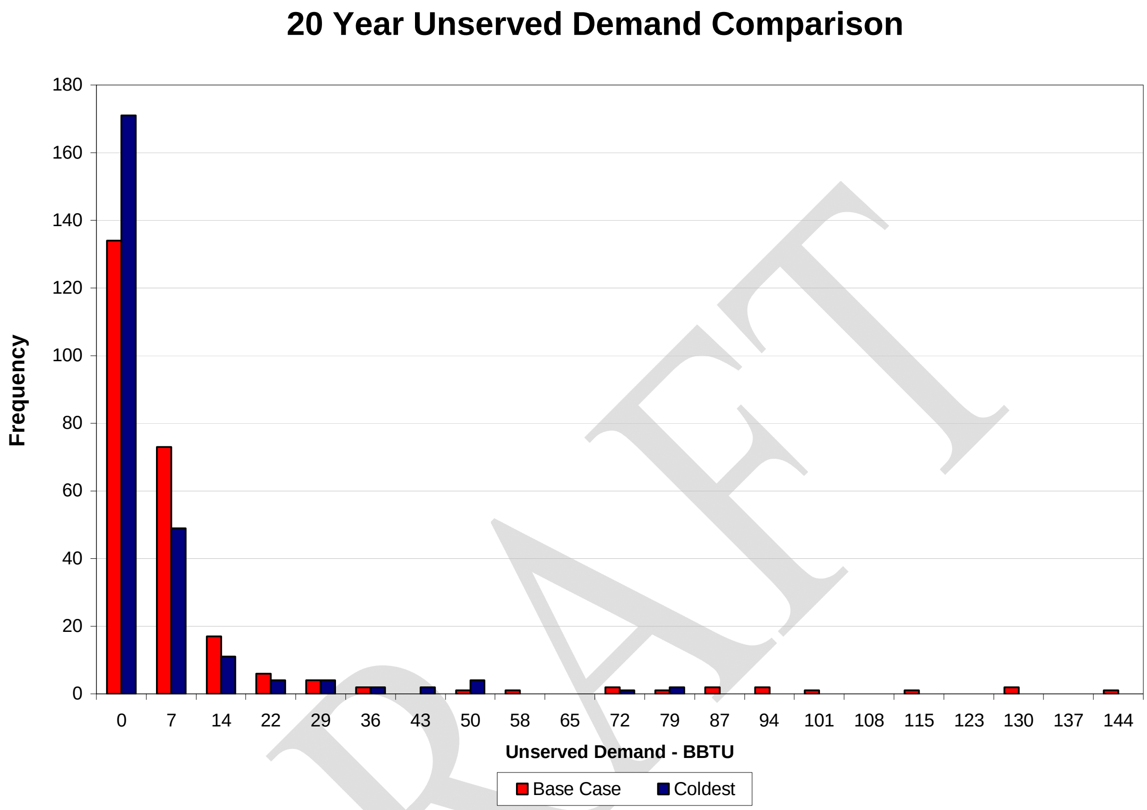
- Range: provides the minimum to maximum value across all draws

- Expected Value: the average of all draws of the simulation
- Standard deviation: provides a measure of the distribution of results around the mean. A low standard deviation indicates the draws are close to the mean, while a high standard deviation indicates the results are spread out away from the mean
- Percentile ranges: provides the value at various levels of probability.

Reliability

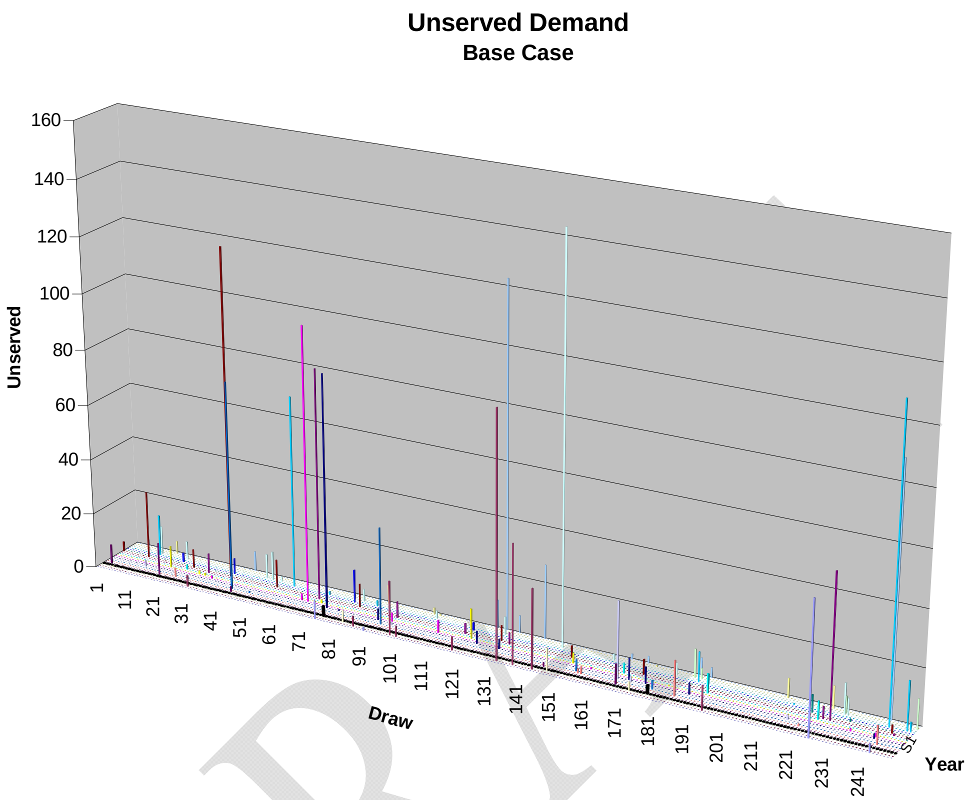
The histograms illustrate the range and distribution of results across draws. For example, the graph below compares the total unserved demand over the 20 year run horizon. The X Axis represents the range of total unserved demand over the 20 year period, where the first bin includes draws with zero unserved; the second bin includes draws with unserved between zero and 10, the third bin includes draws with unserved between 10 and 20, etc. The Y Axis represents the number of draws, from a total of 250, which are included in a particular bin. The analysis indicates that the Coldest portfolio provides a slightly higher level of reliability than the Base Case. The Coldest portfolio has fewer non-zero unserved observations and the Base Case includes some observations with higher levels of unserved demand. However, these differences are minor from a statistical perspective.

Unserved Demand – Comparison

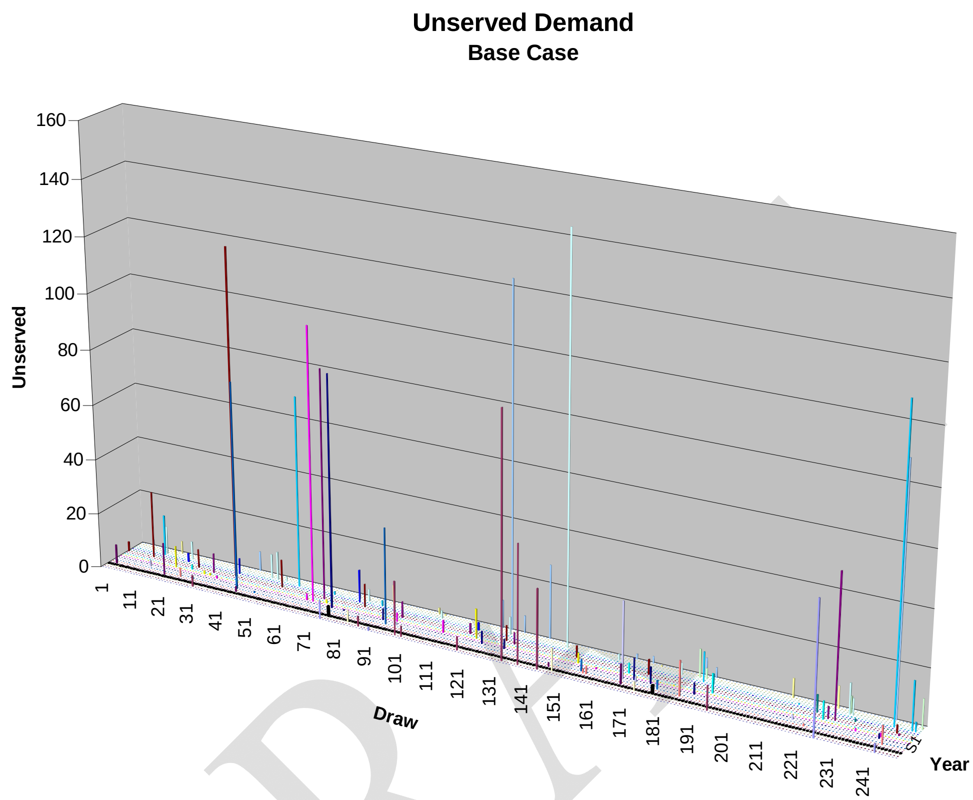


The three dimensional graphs below illustrate the relative infrequency of unserved demand in both portfolios. The graphs include three axes: the horizontal X Axis represents the draw (200 total), the horizontal Z Axis represents the year within each draw (20 total), and the vertical Y Axis represents total unserved demand in each year for each draw.

Unserved by Year by Draw – Base Case



Unserved by Year by Draw – Coldest Portfolio

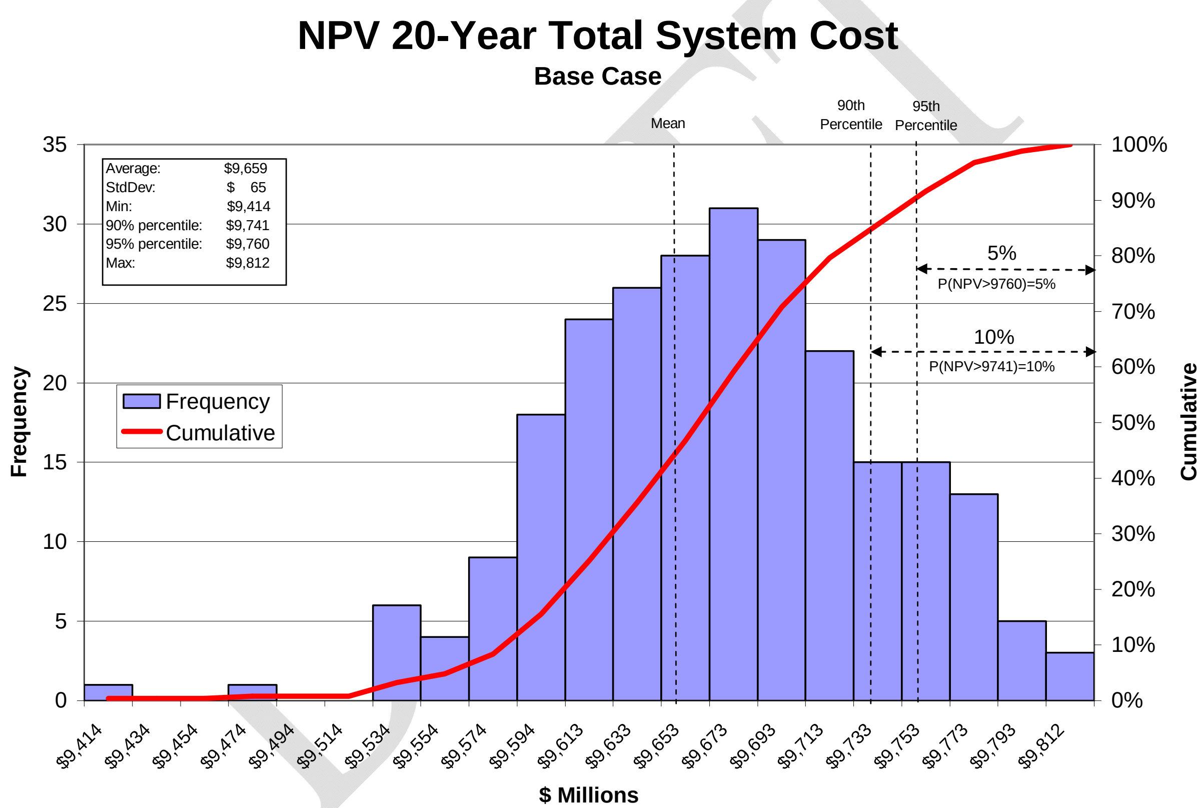


The stochastic analysis includes includes 250 draws, each of which includes 20 years of distinct weather patterns. Thus, 5,000 distinct annual demand profiles are produced by the Monte Carlo simulation and subsequently evaluated by *SENDOUT*® (20 years x 250 draws = 5,000). The Base Case yields non-zero unserved demand in 133 of 5,000 draw years, providing 97.34% confidence the portfolio will meet annual demand throughout the study period. The Coldest portfolio yields non-zero unserved demand in 84 of 5,000 draw years, providing 98.32% confidence the portfolio will meet annual demand throughout the study period. Both portfolios provide a high level of reliability, with the Coldest portfolio providing less than 1% more reliability on an annual basis throughout the study horizon.

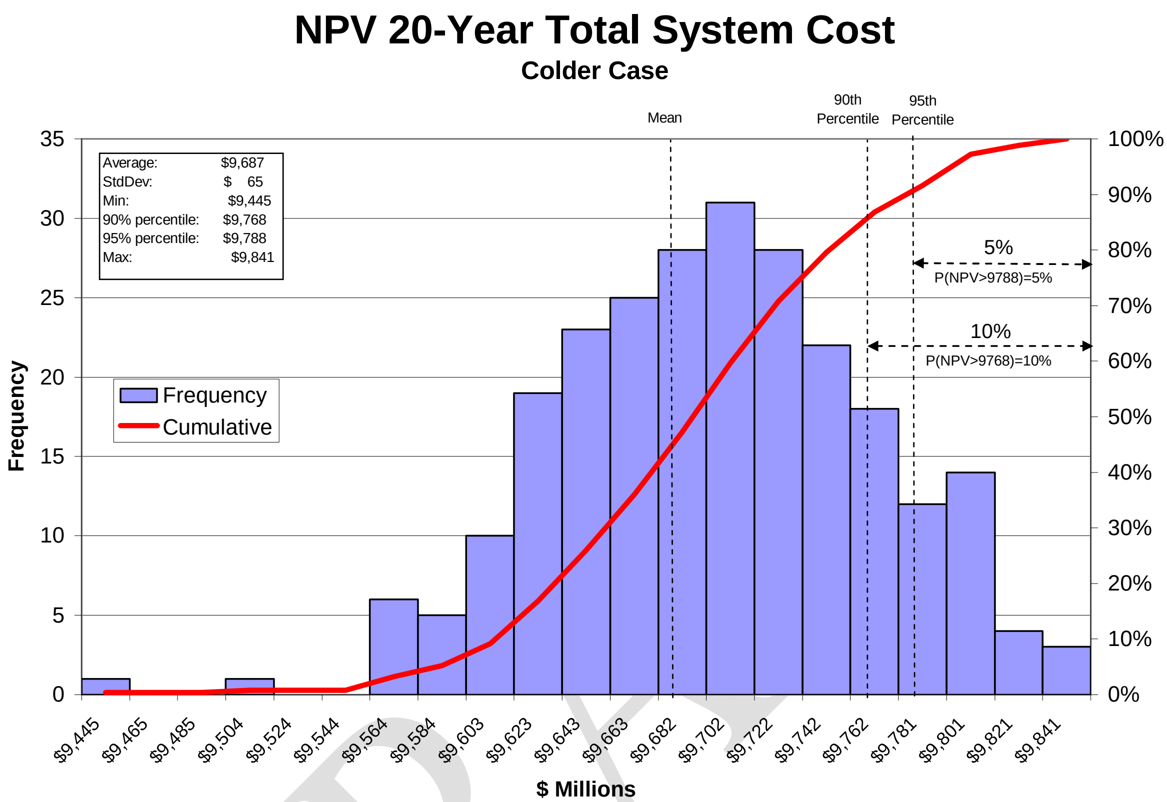
Total Resource Costs

The graphs below compare 20 year total costs between the Base Case and the Coldest Portfolio. The Base Case portfolio has an expected cost of $9,659 million, with a standard deviation of $65 million and a cost range between $9,414 million and $9,812 million. The Coldest portfolio has an expected cost of $9,687 million, with a standard deviation of $65 million and a cost range between $9,445 million and $9,841 million.

Base Case



Coldest Portfolio



Comparison ($Millions)

		Coldest		Base Case		Difference / Improvement
Average / Expected Cost	$	9,687	$	9,659	$	28
Standard Deviation	$	65	$	65	$	-
Minimum	$	9,445	$	9,414	$	31
90% Percentile	$	9,768	$	9,741	$	27
95% Percentile	$	9,788	$	9,760	$	28
Maximum	$	9,841	$	9,812	$	29

The savings associated with the Base Case portfolio (based on 85% winter probability), compared to the Coldest Portfolio (previous design standard) is NPV $28 Million over the 20 year study period. In addition, the Base Case provides more low cost potential and less high cost potential. The company believes the $28 Million of additional expected cost associated with increasing reliability by only 1% justifies the move from the previous design planning standard (coldest in history) to the revised design planning standard of 85% probability.

VI. KEY FINDINGS

- The use of *SENDOUT®* as a modeling tool provides considerably more analytical capability compared to the previous Mixed Integer and load duration curve approach previously employed. The use of the chronological daily demand forecast and late winter peak event provides NW Natural a more realistic look at demand levels and capacity requirements than was previously possible. The added detail included in *SENDOUT®* exposes demand areas specific peak-day delivery limitations also revealed in the 2007 IRP and 2008 Update thereto.

- After additional analysis, the Company has reaffirmed its commitment to the 85% probability winter planning standard against which to evaluate the cost and risk trade off of various supply and demand resources available to *SENDOUT®*. The stochastic analysis reveals the Company's Base Case portfolio maintains a high level of reliable at a lower cost than the previous Design planning standard.

- The Base Case portfolio best balances reliability and cost over the 20-year planning horizon. The incremental resources included in the Base Case represent a high likelihood of occurrence.

- Subscribing to capacity on the proposed Palomar pipeline serves a dual purpose of securing cost-effective incremental pipeline resources to satisfy growth and enhancing reliability by adding a second path for delivering interstate gas supplies directly into the heart of the Company's distribution system. For this reason, the Company has included Palomar at the minimum level of 100 MDT / day, as a component of the Base Case incremental resources. At this level, the NPVRR costs are lower than the No Palomar scenario. The Company has determined that in order to improve the long-term reliability of its distribution system, it must subscribe to a minimum level of capacity with Palomar and facilitate the development of this new pipeline.

- With a subscription to new capacity on the proposed Palomar pipeline, the Company would be able to shed existing interstate pipeline capacity on NWPL, which notwithstanding the attendant reliability enhancements may provide cost savings over the 20 year planning horizon. The Company would then have the added flexibility to procure incremental interstate pipeline capacity as needed, in a potentially more competitive environment, at the then prevailing subscription rates

- Recall of pre-built Mist storage resources currently dedicated to the interstate storage service market into core-market service is an attractive choice to meet growing peak-day requirements and annual working gas requirements. This is a service that provides both seasonal and peak day deliverability benefits by displacement to the Vancouver demand area.

- Contracting for re-gasified LNG from the proposed Bradwood Landing or Jordon Cove LNG import terminals, should either be successfully developed, fits well with the Company's resource portfolio as it allows NW Natural to take advantage of likely favorable supply pricing associated with the Company's location adjacent to the regasification terminals while further reducing the Company's reliance on a single interstate pipeline for citygate delivery of supplies. The modeling results clearly demonstrate that gas supplies sourced from Oregon LNG import terminals are projected to be cost effective. Given the preliminary development status of the proposed terminals and NW Natural's inability to control their successful development, the Company is not predicating its resource selections on the availability of imported LNG. However, NW Natural believes imported LNG is an important long-term supply resource and would provide significant benefits to our customers.

CHAPTER 6: AVOIDED COST DETERMINATION

CHAPTER 6: AVOIDED COST DETERMINATION

I. OVERVIEW

As part of the IRP process, NW Natural produces a 20-year forecast of monthly avoided costs for the eight geographic regions in its service territory. These avoided cost estimates represent the changes in gas supply costs that result from changes in load served. For example, if DSM conservation measures reduced customer gas requirements, the Company theoretically sheds or “avoids” certain transmission and gas supply costs. Likewise, serving additional load leads to increased gas supply and infrastructure costs.

Avoided cost determination is an important part of the IRP process, as these estimates serve as the basis by which the Energy Trust evaluates the cost-effectiveness of individual DSM measures and identifies the achievable level of DSM conservation in NW Natural’s service territory. The identification of achievable DSM conservation is discussed in more detail in Chapter 4.

II. METHODOLOGY

The Company’s avoided cost method focuses on the cost impact of small load changes. With load growth, the Company adds resources from time to time to serve these new requirements. As one of its functions, the IRP determines the least cost means of serving this growth. When load increases by a small amount, the incremental resource serves the increased load. The incremental resource’s cost is the cost of meeting load increments. Avoided cost, then, is the marginal cost of serving small load increments (or the cost avoided by load decreases) as defined by the current incremental gas supply resource in each time period.

Computing marginal costs requires a forecast of probable load growth, a forecast of future trends in commodity gas costs, and a menu of capacity-augmenting investments or purchases that are optimal for meeting those load requirements. The Company generated a range of load growth forecasts and commodity price forecasts, which are presented in Chapter 2. The Company adopts the expected demand forecast and commodity price forecast as its Base Case, which underlies the Base Case avoided cost estimates.

SENDOUT® determines the least cost resource mix required to meet forecasted demand through linear programming and provides marginal cost data for each of the

Company's geographic demand areas, by day, month, and year. This marginal cost data includes the cost of the next supply unit, transportation charges, and related storage costs. NW Natural used the *SENDOUT*® model's functionality to produce marginal cost data for the selected Base Case resource portfolio under the design year weather planning criteria assuming no DSM conservation effects. To estimate avoided cost, the Company added an environmental compliance cost adder of $0.099 per therm to the marginal cost estimates provided by *SENDOUT*® to equally compare supply-side and demand-side resources.[1] Also, as required by the NW Power Act, the Company included a ten percent adder to its avoided cost to account for the unquantifiable benefits of demand side management.[2]

III. AVOIDABLE CAPACITY RESOURCES

To meet growing loads, the Company draws upon storage or pipeline capacity. Increased capacity on Northwest Pipeline Corporation (NPC), the Company's primary supplier, requires that NPC make physical investments to expand peak delivery capability into the various NW Natural market areas. It is the point of delivery that drives the pricing of the pipeline capacity additions. For example, since NPC would need to build more additional pipe to add deliveries at Eugene than it would at Portland, the rate for incremental pipeline capacity is greater at the southern end of the system than it is at Portland in the north. On the other hand, further investments by NPC north of Molalla could be postponed if the Palomar pipeline is built. In any case, incremental pipeline capacity down the valley is an essential incremental resource.

Incremental storage facilities that provide significant amounts of annual deliverability will most likely be underground storage. However, as described in Chapter 3, the west coast has a number of viable LNG projects that could become operational within the next five to ten years providing a direct impact on NW Natural's resource planning and acquisition. The two projects that are furthest along are the Bradwood and Jordan Cove facilities. Because neither Bradwood nor Jordan Cove has been constructed, NW Natural is including them in its modeling for scenario analysis purposes but has not included them for avoided cost determination.

Satellite LNG is an additional supply-side resource for the avoided cost analysis. This concept involves portable LNG tanks that can deliver 30,000 therms a day for three days. When placed at strategic points on the system, these facilities provide local capacity on peak load days.

1 The $0.099 per therm environmental cost adder assumes a $15 per ton adder for CO_2 and $2,000 per ton adder for NOx.

2 *See* http://www.nwcouncil.org/LIBRARY/poweract/default.htm.

As an alternative to purchased pipeline capacity, the Company includes the option of building enhanced transmission capacity between the Portland area and Eugene. This 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 the Company's Newport LNG facility to the Company's Willamette Valley service area, as further described in Chapter 3.

IV. AVOIDABLE GAS COMMODITY COSTS

The avoidable commodity costs are based on the possible resource decisions made to serve incremental increases to load, as discussed above. The related supply-side costs were developed by using several sources of long-term gas price forecasts, as discussed in Chapter 2. NW Natural is able to rely on forecasts that have a long-term perspective – incorporating those elements that drive long range views and also up-to-date information as the markets change.

V. ENVIRONMENTAL COSTS AND EXTERNALITIES

The Oregon Public Utility Commission's (OPUC) Order No. 07-002 in Docket UM 1056 (Investigation Into Integrated Resource Planning) 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.*

Unlike electric utilities, environmental cost issues rarely impact a gas utility's supply-side resource choices. For example, NW Natural cannot choose between "dirty" coal-fired generation and "clean" wind energy sources. The Company's only supply-side energy resource is natural gas. At present, the only supply-side implication of environmental externalities in the Company's direct gas distribution system is that some methods of natural gas storage require the combustion of the gas. An LNG facility, such as Newport, burns one therm of gas to liquefy five therms. Underground storage, such as Mist, uses one therm of gas to compress 100 therms of gas into storage. While upstream gas system infrastructure (i.e. pipelines, storage facilities and gathering systems) produce more CO_2 emissions via compressors, NW Natural concluded that it does not make an appreciable difference in supply-side resource selection. However, due to the energy requirements necessary to bring imported LNG to domestic markets, the Company sees the need to fully evaluate imported LNG, because of its potentially significant impact on gas supply resource decisions.

Environmental externality costs do make a difference in the comparison between supply-side and demand-side resources. To facilitate such comparisons, the Company's avoided cost estimates include a $0.099 per therm environmental externality adder to reflect assumed costs in the amount of $15 per ton for CO_2 and $2,000 per ton for NOx. These levels are similar to what the electric utilities are currently using. The derivation of this $0.099 per therm adder is illustrated in Table 6-2.

Table 6-1
Natural Gas Environmental Externality Adders
Included in Avoided Cost Estimates

Compound	Emissions in Lbs./MMBtu	Damage Cost In $/Lb.	Externality Adder $/Therm
NOx $2000/ton	0.11	$1.00	$0.011
CO_2 $15/ton	118	$0.007	$0.088
Total			$0.099

Given the regulatory uncertainty surrounding the potential of a national carbon tax and specific tax level, Table 6-2 provides a range of potential alternative natural gas environmental externality adders.[3]

3 OPUC Order No. 07-002 established the environmental adders.

Table 6-2
Range of Potential
Natural Gas Environmental Externality Adders
OPUC Order No. 07-002

Compound	Emissions in Lbs./MMBtu	Damage Cost In $/Lb.	Externality Adder $/Therm
NOx $2000/ton	0.11	$1.00	$0.011
CO_2 $10/ton	118	$0.005	$0.059
Total			$0.070
NOx $2000/ton	0.11	$1.00	$0.011
CO_2 $15/ton	118	$0.007	$0.088
Total			$0.099
NOx $2000/ton	0.11	$1.00	$0.011
CO_2 $25/ton	118	$0.0125	$0.148
Total			$0.159
NOx $2000/ton	0.11	$1.00	$0.011
CO_2 $40/ton	118	$0.02	$0.236
Total			$0.247
NOx $5000/ton	0.11	$2.50	$0.0275
CO_2 $10/ton	118	$0.005	$0.059
Total			$0.0865
NOx $5000/ton	0.11	$2.50	$0.0275
CO_2 $15/ton	118	$0.007	$0.088
Total			$0.12
NOx $5000/ton	0.11	$2.50	$0.0275
CO_2 $25/ton	118	$0.0125	$0.148
Total			$0.1755
NOx $5000/ton	0.11	$2.50	$0.0275
CO_2 $40/ton	118	$0.02	$0.236
Total			$0.2635

VIII. AFTER-TAX REAL DISCOUNT RATE

SENDOUT® determines the least cost resource mix that meets forecasted demand for the 20-year planning period using a present value revenue requirement methodology. NW Natural discounts all future resource costs with the Company's after-tax real discount rate of 5.16 percent, the derivation of which is presented in Appendix 6-3.

In addition to determining the least cost resource mix, the after-tax real discount rate of 5.16 percent is also used by the Energy Trust to determine the appropriate cost-effective screening levels to apply to specific DSM measures. These Screening Costs vary by DSM measure to reflect lifetime and seasonality (i.e. conservation load factor). Specifically, the Screening Costs reflect the present value of avoided cost over the lifetime of each DSM measure, using either the winter or annual averages of avoided cost estimates depending on the DSM measure load factor. DSM cost-effective screening methodology is presented in more detail in Chapter 4.

IX. KEY FINDINGS

- Base Case avoided cost estimates associated with gas supply resources. . . .
- The downward adjustment of the inflation rate caused an increase in the real after-tax discount rate (2004 IRP: 4.12 percent; 2007 & 2009: 5.16 percent).

CHAPTER 7: PUBLIC COMMUNICATION AND PARTICIPATION

CHAPTER 7: PUBLIC COMMUNICATION AND PARTICIPATION

This chapter describes the steps NW Natural took to involve the public in developing this Plan.

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; and Northwest Gas Association.

NW Natural held two TWG meetings: November 5, 2008 and February 11, 2008. The second meeting was held after the Company filed its draft plan on January 23, 2009. After the first meeting and prior to this initial filing, the Company emailed draft IRP chapters to TWG members. The sign-in sheets to the TWG meetings as well as the email correspondences are included in Appendix 7.

II. PUBLIC PARTICIPATION

NW Natural invited its customers, TWG members, and interested parties to participate in the public process. The Company notified Washington customers about the IRP process by way of a bill insert in customers' January billings. The bill insert as well as all customer responses are included in Appendix 7.

EXECUTIVE SUMMARY APPENDIX

Response to NW Natural's 2007 IRP, UG-070619

Below are the recommendations the Commission gave NW Natural in a letter dated October 9, 2008, and the Company's response:

I. Executive Summary

NW Natural should examine the IRP rules at WAC 480-238-90 and updates its description of the IRP requirements,

Response:

Part 2 of this Appendix contains the requirements of WAC 480-238-90 as well as a comment or citation verifying that this plan complies with the rules.

II. Demand Forecast of Retail Gas Requirements (Chapter 2)

- *In its next IRP, NW Natural should continue to examine the adequacy of its input data and assumptions in light of the requirements of the newly adopted modeling software.*

Response:

In Chapter 5, the Company has considered the adequacy of its planning assumptions using the stochastic capabilities of the new modeling software, and determined that the 85% probabilistically-determined weather year is a better planning determinant than previous inputs based on actual weather conditions. As noted in the Action Plan, the Company plans to consider in a future IRP whether to replace the current actual peak day planning standard with a similar probabilistically-determined peak day input.

- *In the next IRP, NW Natural should include an explicit explanation of the data source for the regression analysis for the Washington demand projection.*

Response:

Washington customers are forecast by category. Residential existing and residential conversions are projected using overall NW Natural company projections and WA market share. The same method is used for commercial existing, commercial conversions, and commercial new. Three modeling approaches were taken for predicting residential new construction in WA. Historic data of new residential customers from WA was regressed against historic Oregon state housing starts data. Historic customer data was also regressed against historic Washington state housing starts data. Oregon housing starts provided the better fit for our WA customers than the Washington state data. Finally, historic customer data was regressed against historic Clark County housing starts. As expected, the fit was good. However, a forecast of Clark County housing starts was unavailable. Therefore, a model was developed to project Clark County housing starts as a function of Clark County population, since a population forecast was available. Then new residential customers were projected from this regression. The overall results from the regression to the Clark County population forecast and the regression to Oregon housing starts were similar. However, the Oregon housing starts based forecast reflected the downturn from the current recession much better, hence this was the method selected for projecting WA residential new.

Historic Vancouver and Dalles WA usage data was regressed against historic Vancouver and Dalles area heating degree days to develop the usage parameters. A WA specific weather pattern was developed from twenty years worth of region temperatures. Washington demand was then projected from the customer forecast, WA specific usage parameters, and WA specific weather.

- *In the next IRP, NW Natural should consider alternatives to the data sources it uses to project demand and provide an explanation for the data source it chooses.*

Response:

In Chapter 2, the Company describes how it examined various data sources that could be used to determine the customer count forecast for its Washington customers, and explains its choice.

- *NW Natural should consider changes to the graphic illustrations to improve communications with outside parties and NW Natural Management.*

Response:

The Company has modified the text and illustrations in this 2009 IRP to better communicate with outside parties.

- *The Commission encourages NW Natural to examine in its next IRP the previous IRP demand forecasts for consistently high or low forecasts and determine whether and to what extent there is a bias in the forecasting model.*

Response:

Given the compressed timeline of this IRP, the Company has determined to undertake a more complete examination of this issue in the 2011 IRP.

- *Future IRPs should include an explanation of the basis for choosing demand scenarios.*

Response:

In Chapter 5, the Company provides more explanation for the basis for the various demand scenarios it ran through the model.

III. Supply-Side Resources

- Consideration of the LNG supplies in the next IRP must take a hard look at world demand and price competition

Response:

Chapter 3 provides more information about the Company's assessment of LNG supplies and the potential for LNG imports to increase in the United States in the 2015-2016 timeframe.

- *The Commission encourages NW Natural to model the impact of long-term resource choices on the ability of the GAP to mitigate costs and risks.*

Response:

The Company believes that providing the model with a variety of pipeline, supply basin, imported and domestic LNG options, and distribution infrastructure resource decisions, explicitly provides for modeling of the impact of long-term resource choices. This long-term modeling enables the gas acquisition team to structure the Company's Gas Acquisition Plan to react quickly to address current market conditions.

IV. Demand Side Management (Chapter 4)

- *The Commission is concerned that the IRP failed to address adequately "new policies and programs needed to obtain the conservation improvements "as required under WAC 480-90-238(3)." In particular, the company's failure to examine any alternative to the Energy Trust of Oregon as a conservation program administrator and the failure to evaluate "new policies and programs" in the absence of decoupling were notable, especially in comparison to the robust analyses of demand forecast and supply* *side resources. The Commission expects that these matters will be addressed in the next IRP.*

Response:

Chapter 4 contains a cost comparison between Energy Trust delivered DSM programs and in-house programs. This chapter also includes a more robust discussion of DSM-related regulatory strategies including different mechanisms for lost margin cost recovery and an examination of new rate design policies and programs that the Company has investigated and could be alternatives to the decoupling proposal made in the Company's 2007 IRP.

V. Resource Choices (Chapter 5)

- *The next IRP should review closely the adoption of the new planning standard and its use in the model. Analysis of the 2007-2008 winter or other analyses may help affirm (or bring into question) the new standard.*

Response:

Please see Chapter 5 for a comparison of the prior planning standard with the current standard, and a stochastic analysis of the comparative cost and reliability differences between the two options.

- *In the next IRP, NW Natural must provide explanation of the derivation of the price correlations it uses.*

Response:

Please see Chapter 5 (pages 25-26) for a discussion of the derivation of the price correlations used in the Monte Carlo simulations.

NW Natural

2007 Integrated Resource Plan
Multi-Year Action Plan Follow-Up

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 events over the past 20 years date back to 1989 and 1990, so absent extreme cold weather in the near future, firm peak-day requirements could drop noticeably in the 2009 or subsequent IRP.

Response: Through stochastic analysis, presented in Chapter 5 of this 2009 IRP, the Company has reaffirmed its commitment to the statistically derived 85% probability annual demand planning standard. In future IRPs, the Company intends to continue to review this standard, and also to consider whether to apply a statistical standard to the peak day component of its planning standard.

1.2 Recalibrate forecast for changes in gas usage equations and expected customer gains following each heating season. Assess implications and report to state Public Utility Commissions as appropriate.

Response: The 2009 IRP demand forecast shows a significant change in demand, particularly in the near-term, reflecting the current recession and difficult economic climate. Chapter 2 describes in greater detail the revised forecast and the implications for the Company's anticipated need for additional resources within the planning horizon.

1.3 Regularly review price volatility and the associated risks within the market.

Response: The 2009 IRP price forecast has been updated, as have the high and low forecasts, to reflect current price trends. The methodology for the forecast has also been changed to utilize current market prices for the first two years of the planning horizon, to better capture current market risks and volatility.

1.4 The Company will monitor the spread of hybrid heat systems, because of the implications that increase has for demand forecasting.

Response: The Company has not undertaken a specific analysis of the spread of hybrid heat systems since the 2008 Update of the 2007 IRP, but will continue to monitor the development of this technology in the marketplace to determine future implications for demand forecasting.

1.5 Review the demand forecast to ensure that it performs well under warmer days and report findings in the IRP Update in 2009.

Response: The Company was able to collect some back-cast data from the December 2008 winter storm, and a cold snap from January 2008. We found that in the lower heating degree days the forecast was extremely reliable. The results are listed in Chapter 2. Overall, we believe the forecast could be further improved, and we will continue to examine the forecast in the 2011 IRP.

1.6 The Company will investigate data collection requirements to analyze demand forecast error regionally.

Response: Currently we have limited opportunity to analyze demand forecast error regionally. We are able to roll up billing cycle usage data by region and match to temperatures by month. In fact, this is how the forecast usage factors are generated. However on a daily basis, we are currently unable to match up gas sendout with customer category and region. We will continue to look at ways of improving our data collection processes..

2.0 Supply-Side Resources

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.

Response: Cost estimates for new supply-side resources have been updated, as described in greater detail in Chapter 3. These updates have resulted in significant difference to the supply-side resource mix for the system as a whole. However, they have not had a significant impact on the resources selected by the model to serve Washington customers.

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

Response: In 2008, the Company recalled 10,000 Dth/day of capacity at Mist to serve core customers, a portion of which was allocated for the service of Washington customers.

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

Response: The Company is committed under a precedent agreement to 100,000 Dth/day of capacity on the Palomar Pipeline. We continue to support development of the Palomar Pipeline project and will also continue to examine that resource decision until it is necessary to commit to capacity on the pipeline

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.

Response: The Company continues to monitor the development of imported LNG terminals, and has presented additional information about imported LNG and LNG pricing in Chapter 3.

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.

Response: The Company has participated in discussions with project sponsors with regard to the pipeline projects described above. At this time, the capacity and price of these projects remain in flux, and as a result the Company continues to be in a position to monitor but not commit to any particular project.

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.

Response: These are primarily Oregon-specific issues. However, for this 2009 IRP the Company has refined cost estimates for the NW Natural distribution system investments, and has made some additional investigation into potential constraints in siting and permitting satellite LNG facilities. Based on these considerations, the modeling for these supply-side resources has been updated.

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.

Response: The Company recently invested significant shareholder funds in the development of a biodigester project in Oregon. As a result, the Company will be well positioned in the future to monitor and facilitate the development of biogas.

3.0 Demand-Side Resources

3.1 Work with the Energy Trust of Oregon in efforts to improve energy efficiency delivery programs and program participation rates.

Response: Chapter 4 reflects an updated study of energy efficiency potential in Washington conducted by the Energy Trust of Oregon, and a discussion of options related to the delivery of energy efficiency programs.

3.2 Pursue revenue per customer decoupling in the state of Washington.

Response: In the Company's recent general rate case in Washington, it ultimately withdrew its request for a revenue decoupling program as part of an all-party settlement. Chapter 4 describes a variety of alternative programs and policies that may be used in addition to or as an alternative to decoupling in the future to address the Company's concerns related to lost margins associated with conservation.

3.3 In Oregon, provide periodic updates of the Company's conservation resource assessments to determine adequacy of public purpose funding.

Response: Oregon-specific issue.

3.4 In Washington, provide periodical updates of the Company's conservation resource assessments to determine any changes in what is technically achievable.

Response: Chapter 4 includes an update of the conservation resource potential from the previous IRP.

3.5 In Oregon, pursue energy efficiency for industrial sales customers consistent with the Company's independent assessment that indicated that there are cost-effective resources that can be acquired for this customer class.

Response: Oregon-specific issue.

4.0 *SENDOUT®* Model and Integrated 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.

Response: The optimization model used in the 2009 IRP includes a number of updates to the model used in the 2008 update to the 2007 IRP. These updates include: updated demand and price information; updated cost estimates for Company-specific projects (including the Willamette Valley Feeder project and Satellite LNG projects); updated DSM projections; and revised time estimates for projects to be available and on-line.

4.2 Acquire resources consistent with the Preferred Portfolio.

NW Natural will be seeking to acquire the following resources, in conjunction with its selection of its preferred portfolio:

- Palomar East capacity: Per the terms of the Precedent Agreement, assuming the Palomar project proceeds as currently scheduled, the Company plans to commit to 100,000 Dth/day of capacity on Palomar East.

- Newport LNG Enhancement: Preferred Portfolio selected this resource to be on-line in 2012. The Company will report the progress that has been made on this project in the 2009 Annual IRP Update.

- Willamette Valley Feeder (WVF): In order to get the WVF on-line in 2010, as called for in the Preferred Portfolio, the Company must proceed immediately to refine and finalize cost projections, develop final route plans, and investigate any impediments to proceeding with the project. The Company will report the progress that has been made on this project in the 2009 Annual IRP Update.

- Brownsville to Eugene River Crossing: This project is called for by the model in 2011 and provides a supply alternative to Satellite LNG in Eugene. The relatively smaller nature of the project gives the Company some time to update model runs prior to committing resources to the project. It also provides the opportunity to evaluate this project within the scope of a larger Willamette Valley Feeder project. The Company will update the OPUC with its 2009 Annual IRP Update as to progress that has been made on this project.

- Mist Recall: the Company plans to recall 10,000 Dth/day of Mist capacity in the fall of 2008, and an additional 30,000 Dth/day of capacity in the fall of 2009.

Response: Since the Company's 2007 IRP, it acquired 10,000 Dth/day of capacity at the Company's Mist storage field, as called for above. The Palomar Pipeline project is still in progress, and the Company will continue to examine that resource decision until it is necessary to commit to capacity on the pipeline. The Company continues to refine its modeling and cost-estimates with regard to the other projects described above.

5.0 Avoided Cost Determination

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

Response: NW Natural anticipates significant changes may occur in the future with regard to greenhouse gas regulation. However, no significant changes have occurred since the 2008 Update to the 2007 IRP that would warrant a change in environmental adder levels to the 2009 IRP.

6.0 Public Involvement

6.1 Conduct additional Technical Working Group meetings as necessary to address the Oregon Public Utility Commission's requirement for a 2009 update to this 2008 IRP.

Response: Oregon-specific action item.

NW Natural's 2009 IRP - Executive Summary Appendix

Rule	Requirement	Plan Citation
WAC 480-90-238(4)	Work plan filed no later than 12 months before next IRP due date.	NW Natural informally filed it's Work Plan on May 16, 2008. A revised Work Plan with the WUTC Records center on October 8, 2008. Admittedly, this was filed less than 12 months prior to the the 2009 IRPs due date. At the time, the Company believed it's 2008 IRP would be acknowledged as a filed IRP, moving the due date out for the next IRP. When we learned this was not the case, the Company filed a 2009 IRP Work Plan.
WAC 480-90-238(4)	Work plan outlines content of IRP.	Yes, the Work Plan filed on May 16, 2008 and the revised Work Plan filed October 8, 2008 both outline the content of the 2009 IRP.
WAC 480-90-238(4)	Work plan outlines method for assessing potential resources. (See LRC analysis below)	Yes, the Work Plan filed on May 16, 2008 and the revised Work Plan filed October 8, 2008 both outline the methodology of the 2009 IRP. The methodology used is a manual input of compiled data into SENDOUT, a linear based programming model that stochastically assesses potential resources.
WAC 480-90-238(5)	Work plan outlines timing and extent of public participation.	The revised Work Plan dated October 8, 2008, states that two technical working group meetings were scheduled, one on November 5, 2008, and the second on February 11, 2009. It also notes that email communications with the TWG would be used to supplement the meetings. It also states a public meeting for customers was scheduled February 17, 2009.
WAC 480-90-238(4)	Integrated resource plan submitted within two years of previous plan.	NW Natural filed it's 2007 IRP on March 28, 2007. On April 21, 2008, the Company filed an update to this plan. The WUTC's letter, dated October 9, 2008, that states the Company's 2007 IRP was reviewed and found to be in compliance with the Washington Adminisntrative Code states that our next IRP is due March 31, 2009.
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.	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 has also considered technologies such as bio-gas, which are not currently available, but have been identified for continued monitoring and future assessment.
WAC 480-90-238(2)(a)	Plan describes conservation supply.	Data for achievable conservation was 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. Cost-effective conservation levels are identified in Chapter 4 and its Appendix 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 five 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.
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 10 sensitivity cases to the Base Case scenario. The scensitivity 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.	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(2)(b)	LRC analysis considers resource effect on system operation.	Chapter 5 discusses the muliptle scenarios that were studied to determine the optimal resource mix under varying circumstances.
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.	Both State and Federal policy, evidenced in SB 6001 and the Lieberman Warner Climate Securty Act, seek to provide incentives for carbon reduction and energy efficiency. This IRP supports aggressive energy efficiency acquisition and incorporates carbon adders in its avoided cost.

NW Natural's 2009 IRP - Executive Summary Appendix

Rule	Requirement	Plan Citation
WAC 480-90-238(2)(b)	LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	The Company's consideration of the environmental effects of carbon dioxide is evidenced in the inclusion of carbon adders in its avoided cost and the subsequent increased level of cost effective energy efficiency. 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.
WAC 480-90-238(2)(b)	LRC analysis considers need for security of supply.	The Plan states (page 3-26) 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.	Achievable potential energy efficiency savings per customer class in NW Natural's service territory is defined in the IRP 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 studies such as The Quarterly Economic and Revenue Forecast created by The Oregon Office of Economic Analysis.
WAC 480-90-238(3)(b)	Plan includes an assessment of commercially available conservation, including load management.	The Energy Trust of Oregon analyzed the potential energy savings it can cost-effectively procure within its service territory. Their study began by estimating all energy savings that could be acquired immediately without considering market constraints such as customer awareness. This was determined by analyzing customer demographics together with energy efficiency measure data. Cost-effective DSM measures were identified by comparing each measure's levelized program cost against its expected levelized value of avoided cost with adjustments for measure specific lifetime and load factor. This Plan also acknowledges the Company's use of Interruptible rates as a means for managing system peaks.
WAC 480-90-238(3)(b)	Plan includes an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	This Plan discusses the limited participation historically experienced in the Company's Washington based energy efficiency programs. To improve this, the Company is seeking approval of a decoupling mechanism in its 2008 rate case. Without this, energy efficiency threatens the Company's recovery of its fixed costs. When this issue of lost revenue is addressed, the Company would like to then model its funding mechanism and the Energy Trust's administration of DSM programs in Washington. Please see UG-080546 for more details about the Company's decoupling and conversation program proposals.
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 and pipeline enhancements were 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.
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.
WAC 480-90-238(5)	Plan includes 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 demonstrate conclusions drawn from study and successuful completion of the Plan.

APPENDIX 2
GAS REQUIREMENTS FORECAST

Coming soon.

APPENDIX 3
SUPPLY SIDE RESOURCES

Incremental Supply-Side Resources Modeled in *SENDOUT®*

Incremental Resources	Assumed Size (Dth)	Assumed Cost/Rates[1]	Assumed Availability
Interstate Pipeline Segments			
NWPL Zones 12-9 (Grants Pass Lat.)	74,200/d	Existing NWPL fixed rate X 1.5 Note Rate in SENDOUT is $.5751 / day	November 2011
NWPL Zones 26-12 (“mainline”)	2,031,000/d	Existing NWPL fixed rate X 1.5	November 2011
Upstream of NWPL z26-12:			
Rockies-Stanfield	1,062,000/d	Existing NWPL fixed rate X 2.0 + monthly basis differential adder (Rockies – avg. of Aeco & Malin)	November 2011
Alberta-Stanfield	969,000/d	Existing rates on TCPL-Alberta, TCPL-BC, and GTN	November 2011
Palomar East	200,000/d	Precedent Agreement rate ceiling	November 2011
Palomar West	50,000/d in 2011, increasing by 5,000/d each year	Precedent Agreement rate	November 2011
Pacific Connector	50,000/d in 2011, increasing by 5,000/d each year	Assumed cost = $0.25 East, $0.25 West	November 2011
Mist Storage Recall (incremental to existing Mist for core):			
1,440,000 capacity	65,498/d delivery	Daily rate based on capacity cost = $0.004/Dth	2009
400,000 capacity; (cumulative = 1,880,000)	17,702/d delivery (cum. = 83,198)	“	2010
3,240,000 capacity; (cumulative = 3,640,000)	143,388/d delivery (cum. = 161,085)	“	2011
639,000 capacity; (cumulative = 3,879,000)	28,279/d delivery (cum. = 171,662)	“	2012
4,410,000 capacity; (cumulative = 5,049,000)	195,167/d delivery (cum. = 223,440)	“	2015
1,899,000 capacity; (cumulative = 6,309,000)	84,041/d delivery (cum. = 279,200)	“	2017
Imported LNG Projects:			
Bradwood Landing LNG	50,000/d in 2011, increasing by 5,000/d each year until 2015, then increasing by 10,000/d	Netback commodity price = 50/50 Rockies/Malin spot less transport: • Rockies = NWPL (Opal-Stanfield) + GTN (Stanfield-Madras) + Palomar E & W • Malin = GTN (Malin–Madras) + Palomar E & W	November 2011
Transportation from LNG terminal	50,000/d in 2011, increasing by 5,000/d each year until 2015, then increasing by 10,000/d	Palomar W	November 2011
Jordan Cove LNG	50,000/d in 2011, increasing by 5,000/d each	Netback commodity price = Malin spot less Pacific	November 2011

1 All NWPL rates also include the existing variable charge and fuel %.

	year	Connector transport	
Transportation from LNG terminal	• Up to 20,000 Dth/d into Grants Pass Lateral via Pacific Connector West • > 50,000/d in 2011, increasing by 5,000/d each year until 2015, then increasing by 10,000/d to Portland via Pacific Connector, GTN, and Palomar E	• PC West $0.25 • To Palomar $0.25	November 2011
Satellite LNG (available for installation in Albany, Salem and Eugene)	90,000 capacity; 30,000/d delivery for 3 days for Each location	$44 million capital $1,000,000 annual O&M	April 2011
NWN Projects:			
Newport Pipeline enhancement	40,000/d	$15 million capital	November 2012
Brownsville to Eugene (restore river crossing)	5,000/d	$420,000 capital	November 2011
Willamette Valley Feeder:			
Phase I (Portland to Salem)	15,000/d	$2,150,000 capital	November 2010
Sherwood-Perrydale	120,000/d	$34,279,000 million capital	November 2014
Perrydale-Independence	82,000/d	$14.4 million capital	November 2011
Independence-N. Albany	50,000/d	$13.7 million capital	November 2011
N. Albany-S. Albany	38,000/d	$8.8 million capital	November 2011
S. Albany-Halsey	26,000/d	$12.3 million capital	November 2011
Halsey-Eugene	26,000/d	$16.7 million capital	November 2011

APPENDIX 4
DEMAND SIDE RESOURCES

Appendix: Detailed Measure Description

Table 1: Detailed Measure Description, Industrial Natural Gas

Conservation Measure	Potential Savings (th/yr)	Levelized Cost ($/th)	Initial Cost, k$	Lifetime	BCR	Program
Chiller heat recovery (Electronics)	1,219	$1.479	$14	10	0.48	Retrofit
Combo Cond Boiler (repl)	9,799	$0.571	$69	20	1.23	Replacement
Combo Cond Boiler (retro)	0	$1.536	$0	20	0.46	Retrofit
Combo Hieff Boiler (repl)	5,019	$0.311	$19	20	2.27	Replacement
Combo Hieff Boiler (retro)	0	$1.617	$0	20	0.44	Retrofit
Cond Furnace (repl)	34,432	$2.491	$882	15	0.28	Replacement
Cond Unit Heater from Nat draft (replace)	0	$0.956	$0	18	0.74	Replacement
Cond Unit Heater from power draft (replace)	6,946	$1.934	$155	18	0.36	Replacement
Heat Recovery to HW	0	$0.132	$0	15	5.32	Retrofit
DHW Cond Boiler (repl)	6,211	$0.141	$11	20	4.99	Replacement
DHW Cond Boiler (retro)	0	$0.443	$0	20	1.59	Retrofit
DHW Condensing Tank (repl)	5,063	$0.023	$1	15	30.40	Replacement
DHW Condensing Tank (retro)	0	$0.104	$0	15	6.76	Retrofit
DHW Hieff Boiler (repl)	3,711	$0.044	$2	20	15.94	Replacement
DHW Hieff Boiler (retro)	0	$0.346	$0	20	2.04	Retrofit
DHW Pipe Ins	1,007	$0.018	$0	15	39.57	Retrofit
DHW Std. Boiler (retro)	149	$0.208	$0	20	3.39	Retrofit
DHW Wrap	448	$0.000	$0	7	1,587.90	Retrofit
Ducts	51,661	$2.774	$1,473	15	0.25	Retrofit
Hi Eff Unit Heater (replace)	18,772	$0.307	$67	18	2.29	Replacement
Hi Eff Unit Heater (retro)	0	$1.871	$0	18	0.38	Retrofit
HiEff Clothes Washer (retro)	0	($0.890)	$0	15	100.00	Retrofit
HiEff Clothes Washer (repl)	0	($1.160)	$0	15	100.00	Replacement
Hot Water Temperature Reset	55,636	$0.174	$74	10	4.10	Retrofit
HW Boiler Tune	30,600	$0.161	$21	5	4.73	Retrofit
Power burner	45,104	$1.035	$410	12	0.68	Retrofit
Process Boiler Controls	7,067	$0.001	$0	15	513.68	Retrofit
Process Boiler Insulation	31,940	$0.008	$2	15	88.82	Retrofit
Process Boiler Load Control	15,970	$0.002	$0	15	445.19	Retrofit
Process Boiler Maintenance	7,985	$0.001	$0	15	1,407.77	Retrofit
Process Boiler Steam Trap Maintenance	25,952	$0.035	$0	15	20.11	Retrofit
Process Boiler Water Treatment	3,993	$0.001	$0	15	953.98	Replacement
Roof Insulation - Blanket R0-19	15,325	$0.313	$73	30	2.28	Retrofit
Roof Insulation - Blanket R0-30	16,079	$0.336	$82	30	2.13	Retrofit
Roof Insulation - Blanket R11-30	5,583	$2.292	$194	30	0.31	Retrofit

Conservation Measure	Potential Savings (th/yr)	Levelized Cost ($/th)	Initial Cost, k$	Lifetime	BCR	Program
Roof Insulation - Blanket R11-41	6,699	$2.149	$218	30	0.33	Retrofit
Roof Insulation - Rigid R11-22 repl	13,131	$0.812	$161	30	0.88	Replacement
Roof Insulation - Rigid R11-33 repl	6,476	$2.470	$242	30	0.29	Replacement
Solar Hot Water	0	$4.210	$0	20	0.17	Retrofit
SPC Cond Boiler Replace	6,779	$0.996	$83	20	0.71	Replacement
SPC Cond Boiler Retro	0	$2.113	$0	20	0.33	Retrofit
SPC Hieff Boiler Replace	3,920	$0.638	$31	20	1.11	Replacement
SPC Hieff Boiler Retro	0	$2.232	$0	20	0.32	Retrofit
Steam Balance (Wood Prod)	0	$0.336	$0	15	2.10	Retrofit
Steam Trap Maint (Wood Prod)	0	$0.582	$0	10	1.23	Retrofit
Upgrade Process Heat	11,294	$0.903	$105	15	0.78	Retrofit
Vent Damper	30,600	$0.433	$116	12	1.63	Retrofit
Wall Insulation - Blown R11	10,765	$0.227	$37	30	3.15	Retrofit
Wall Insulation - Spray On for Metal Buildings	11,819	$0.253	$45	30	2.83	Retrofit
Waste Water Heat Exchanger	1,741	$0.628	$13	20	1.12	Retrofit

Table 2: Detailed Measure Table, Commercial Sector, Gas Savings, 2027 Technical Potential

Measure Code	Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Total MWh Savings	Winter MW	Summer mW	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
Co116	EStar Steam Cooker	Install Energy Star Steam Cooker	New	Cooking	10	12,508	0	0	-	-	37	4,107	na	$0.044	16.13
Co116rep	EStar Steam Cooker	Install Energy Star Steam Cooker	Replace	Cooking	10	45,555	0	0	-	-	134	14,957	na	$0.044	16.13
H105	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	Retrofit	Heating	5	823	0	0	-	-	3	103	na	$0.076	10.53

Measure Code	Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Total MWh Savings	Winter MW	Summer mW	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
		and cost effectiveness, and was assumed for this analysis.													
Co112	Infrared Fryer	0	New	Cooking	8	81,114	0	0	-	-	151	3,650	na	$0.084	8.64
Co107	Infrared Fryer	0	Replace	Cooking	8	369,289	0	0	-	-	686	16,619	na	$0.084	8.64
H104	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	64,751	0	0	-	-	85	2,726	na	$0.099	7.54
E111	Roof Insulation - Attic R0-30	Roof Insulation - Attic R0-30. Application: Buildings with uninsulated attics	Retrofit	Heating	30	55,293	0	92	0.03	0.00	24	169	$0.014	$0.101	7.44
R106	Heat Reclaim	Large Grocery - Heat recovery to space heating. Assumes floating head control exists and must be changed to allow HR.	New	Refrigeration	18	156,414	0	630	0.09	0.11	44	196	$0.014	$0.106	6.94
R106rep	Heat Reclaim	Large Grocery - Heat recovery to space heating. Assumes floating head control exists and must be changed to allow	Replace	Refrigeration	18	316,493	0	1,274	0.17	0.23	89	396	$0.014	$0.106	6.94

Measure Code	Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Total MWh Savings	Winter MW	Summer mW	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
		HR.													
H102	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	766,520	0	1,207	0.30	0.26	442	3,513	$0.016	$0.127	5.89
H106	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 and 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	63,564	0	0	-	-	44	1,059	na	$0.142	5.21
E103	Roof Insulation - Rigid R0-11	Roof Insulation - Rigid R0-11-not	Replace	Heating	30	285,107	0	398	0.14	0.01	73	375	$0.020	$0.149	5.05

Measure Code	Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Total MWh Savings	Winter MW	Summer mW	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
		including re-roofing costs but including deck preparation. Application: Old buildings with flat roofs and no attics													
E101	Wall Insulation - Blown R11	Wall Insulation - Blown R11. Application: Old buildings	Retrofit	Heating	30	587,061	0	276	0.09	0.01	189	1,796	$0.024	$0.172	4.36
W101	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	7,311	0	0	-	-	6	1,537	na	$0.205	3.58
W127r	Waste Water Heat Exchanger	Install HX on waste water	Retrofit	Water Heat	15	28,161	0	0	-	-	13	127	na	$0.207	3.41
H119	Hi Eff Unit Heater (new)	Install power draft units (80% seas. Eff) in place of natural draft (64% seas. Eff)	New	Heating	18	183,315	0	0	-	-	73	1,231	na	$0.219	3.37
W102	DHW Shower Heads	Install low flow shower heads (2.0 gallons per minute) to replace 3.4 GPM shower heads.	Retrofit	Water Heat	8	35,362	0	0	-	-	25	663	na	$0.224	3.24
E104	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	30	492,457	0	451	0.15	0.01	83	375	$0.031	$0.226	3.32
H114	Hi Eff Unit Heater (replace)	Install power draft units (80% seas. Eff) in place of natural draft (64% seas. Eff)	Replace	Heating	18	410,024	0	0	-	-	147	2,490	na	$0.242	3.05
E102	Wall Insulation - Spray On for	Wall Insulation - Spray On for Metal	Retrofit	Heating	30	96,353	0	-2	(0.00)	(0.00)	27	279	na	$0.243	3.09

Measure Code	Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Total MWh Savings	Winter MW	Summer mW	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
	Metal Buildings	Buildings (Cellulose) Unfinished. Application: Old buildings													
E107	Roof Insulation - Blanket R0-19	Roof Insulation - Blanket R0-19. Application: Buildings with open truss unfinished interior	Retrofit	Heating	30	164,654	0	4	0.00	0.00	38	222	$0.039	$0.287	2.62
E108	Roof Insulation - Blanket R0-30	Roof Insulation - Blanket R0-30. Application: Buildings with open truss unfinished interior	Retrofit	Heating	30	185,236	0	5	0.00	0.00	40	222	$0.042	$0.307	2.45
H107	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	31,612	0	0	-	-	12	608	na	$0.308	2.41
E105	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	Replace	Heating	30	1,180,431	0	494	0.17	0.02	165	1,533	$0.046	$0.337	2.23

Measure Code	Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Total MWh Savings	Winter MW	Summer mW	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
		some insulation													
W121	Combo Hieff Boiler (new)	Replace existing boiler with unit meeting OR Code requirements of 85% combustion efficiency.	New	Heating	20	75,837	0	0	-	-	17	694	na	$0.358	1.98
W124r	Computerized Water Heater Control	Install intelligent controls on the hot water circulation loops.	Retrofit	Water Heat	15	119,895	0	0	-	-	32	648	na	$0.369	1.92
W119	Combo Hieff Boiler (repl)	Replace existing boiler with unit meeting OR Code requirements of 85% combustion efficiency.	Replace	Heating	20	153,487	0	0	-	-	32	1,264	na	$0.397	1.87
E112	Roof Insulation - Attic 11-30	Roof Insulation - Attic 11-30. Application: Buildings with partially insulated attics	Retrofit	Heating	30	325,204	0	82	0.03	0.00	42	1,156	$0.055	$0.402	1.87
W103	DHW Faucets	Add aerators to existing faucets to reduce flow from 3.4 gallons per minute to 2.0 GPM.	Retrofit	Water Heat	8	8,801	0	0	-	-	3	442	na	$0.418	1.74
E114	Windows - Add Low E to Vinyl Tint	Windows - Add Low E to Vinyl Tint. Application: Old buildings	Replace	Heating	20	151,911	0	145	0.05	0.00	10	2,236	$0.055	$0.418	1.77
E123	Windows - Add Low E to Vinyl Tint	Windows - Add Low E to Vinyl Tint. Application: New Construction	New	Heating	20	83,418	0	78	0.03	0.00	6	1,228	$0.056	$0.420	1.76
H117	SPC Hieff Boiler (new)	Install near condensing boiler. Assumed seasonal combustion efficiency of 82% over base of 75%	New	Heating	20	165,511	0	0	-	-	30	1,210	na	$0.450	1.64

Measure Code	Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Total MWh Savings	Winter MW	Summer mW	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
Co110	Power Range Burner	0	Replace	Cooking	12	330,272	0	0	-	-	82	12,464	na	$0.457	1.55
Co115	Power Range Burner	0	New	Cooking	12	108,816	0	0	-	-	27	4,107	na	$0.457	1.55
H111	SPC Hieff Boiler Replace	Install near condensing boiler. Assumed seasonal combustion efficiency of 82% over base of 75%	Replace	Heating	20	65,357	0	0	-	-	11	441	na	$0.488	1.52
E115	Windows - Add Low E and Argon to Vinyl Tint	Windows - Add Low E and Argon to Vinyl Tint. Application: Old buildings	Replace	Heating	20	237,575	0	143	0.05	0.00	15	2,236	$0.075	$0.566	1.31
E124	Windows - Add Low E and Argon to Vinyl Tint	Windows - Add Low E and Argon to Vinyl Tint. Application: New Construction	New	Heating	20	130,458	0	78	0.03	0.00	8	1,228	$0.077	$0.580	1.28
W109	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	297,450	0	0	-	-	47	5,625	na	$0.624	1.13
W108	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	541,682	0	0	-	-	85	10,244	na	$0.624	1.13
Co109	Infrared Griddle	0	Replace	Cooking	12	302,385	0	0	-	-	55	11,079	na	$0.625	1.14

Measure Code	Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Total MWh Savings	Winter MW	Summer mW	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
Co114	Infrared Griddle	0	New	Cooking	12	99,628	0	0	-	-	18	3,650	na	$0.625	1.14
H108	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	669,066	0	0	-	-	121	4,258	na	$0.631	1.17
H120a	Cond Unit Heater from Nat Draft (new)	Install condensing power draft units (90% seas. Eff) in place of natural draft (64% seas. Eff)	New	Heating	18	988,039	0	0	-	-	126	1,477	na	$0.682	1.08
W127	Waste Water Heat Exchanger	Install HX on waste water	New	Water Heat	15	154,641	0	0	-	-	22	700	na	$0.697	1.01
W122	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 90% efficiency for savings calculations).	New	Heating	20	301,266	0	0	-	-	34	694	na	$0.727	0.97
W115	DHW Hieff Boiler (new)	Replace existing boiler with unit meeting OR Code requirements of 85% combustion efficiency.	New	Water Heat	20	143,767	0	0	-	-	16	1,737	na	$0.744	0.95
W113	DHW Hieff Boiler (repl)	Replace existing boiler with unit meeting OR Code requirements of 85%	Replace	Water Heat	20	261,813	0	0	-	-	29	3,163	na	$0.744	1.00

Measure Code	Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Total MWh Savings	Winter MW	Summer mW	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
		combustion efficiency.													
H118	SPC Cond Boiler (new)	Install condensing boiler. Assumed seasonal combustion efficiency of 88% over base of 75%	New	Heating	20	516,373	0	0	-	-	56	1,307	na	$0.752	0.98
H115a	Cond Unit Heater from Nat draft (replace)	Install condensing power draft units (90% seas. Eff) in place of natural draft (64% seas. Eff)	Replace	Heating	18	2,209,962	0	0	-	-	255	2,988	na	$0.754	0.98
E129	Windows - Tinted AL Code to Class 45	Windows - Tinted AL Code to Class 45. Application: New Construction	New	Heating	20	45,094	0	35	0.01	0.00	0	686	$0.101	$0.758	0.98
W120	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 90% efficiency for savings calculations).	Replace	Heating	20	603,211	0	0	-	-	62	1,264	na	$0.800	0.93
E121	Windows - Tinted AL Code to Class 40	Windows - Tinted AL Code to Class 40. Application: Old buildings	Replace	Heating	20	123,488	0	73	0.03	0.00	3	1,249	$0.106	$0.803	0.92
H112	SPC Cond Boiler Replace	Install condensing boiler. Assumed seasonal combustion efficiency of 88% over base of 75%	Replace	Heating	20	203,064	0	0	-	-	20	476	na	$0.812	0.91
W104	DHW Pipe Ins	Add 1" insulation to pipes used for steam or hydronic distribution; particularly effective when pipes run	Retrofit	Water Heat	15	56,286	0	0	-	-	7	2,281	na	$0.840	0.84

Measure Code	Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Total MWh Savings	Winter MW	Summer mW	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
		through unheated spaces.													
E130	Windows - Tinted AL Code to Class 40	Windows - Tinted AL Code to Class 40. Application: New Construction	New	Heating	20	67,810	0	35	0.01	0.00	2	686	$0.115	$0.865	0.86
H123	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	2,798,740	0	3,102	0.77	0.67	386	11,195	$0.098	$0.899	0.88
H103	Ducts	Duct retrofit of both insulation and air sealing	Retrofit	Heating	15	533,124	0	146	0.04	0.03	40	1,066	$0.111	$0.905	0.82
W105	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	Retrofit	Water Heat	10	163,206	0	0	-	-	23	936	na	$0.947	0.75

Measure Code	Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Total MWh Savings	Winter MW	Summer mW	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
		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).													
E113	Roof Insulation - Roofcut 0-22	Roof Insulation - Roofcut 0-22. Application: Buildings with uninsulated flat roofs at reroofing time	Replace	Heating	30	2,457	0	0	0.00	0.00	0	4	$0.132	$0.962	0.78
H101	Warm Up Control	This measure is designed to implement a shut down of outside air when the building is coming off night setback. Usually the capability for this is available in a commercial t-stat but either the extra control wire is not attached or the unit itself has not been set up to receive the signal. Cost is based on labor cost to enable this ability in existing controllers	Retrofit	Heating	10	727,879	0	0	-	-	97	3,860	na	$0.980	0.76
W124	Computerized Water Heater Control	Install intelligent controls on the hot water circulation loops.	New	Water Heat	15	65,837	0	0	-	-	6	356	na	$1.045	0.68
W123	Hi Eff Clothes Washer	Install high performance commercial clothes washers - residential	New	Water Heat	10	32,442	0	2	0.00	0.00	4	3	$0.125	$1.059	0.68

Measure Code	Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Total MWh Savings	Winter MW	Summer mW	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
		sized units													
W123r	Hi Eff Clothes Washer	Install high performance commercial clothes washers - residential sized units	Replace	Water Heat	10	118,158	0	0	-	-	14	11	na	$1.091	0.66
E106	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	30	1,770,647	0	339	0.12	0.01	56	1,533	$0.158	$1.152	0.65
W116	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 90% efficiency for savings calculations).	New	Water Heat	20	439,159	0	0	-	-	31	1,737	na	$1.164	0.61
W114	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 90% efficiency for savings calculations).	Replace	Water Heat	20	799,745	0	0	-	-	56	3,163	na	$1.164	0.64
H129	Steam Trap Maintenance	Set up a in-house steam trap maintenance program with equipment, training, and trap replacement. An alternative procedure is to just	Retrofit	Heating	10	92,803	380,446	0	-	-	49	848	na	$1.252	0.60

Measure Code	Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Total MWh Savings	Winter MW	Summer mW	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
		pay for an outside contractor to conduct a steam survey.													
E116	Windows - Add Argon to Vinyl Lowe	Windows - Add Argon to Vinyl Lowe. Application: Old buildings	Replace	Heating	20	631,098	0	-49	(0.02)	(0.00)	44	9,591	na	$1.287	0.58
H120b	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	512,040	0	0	-	-	32	984	na	$1.379	0.54
E125	Windows - Add Argon to Vinyl Lowe	Windows - Add Argon to Vinyl Lowe. Application: New Construction	New	Heating	20	346,551	0	-22	(0.01)	(0.00)	21	5,267	na	$1.466	0.50
H115b	Cond Unit Heater from power draft (replace)	Install condensing power draft units (90% seas. Eff) in place of power draft (80% seas. Eff)	Replace	Heating	18	1,145,288	0	0	-	-	65	1,992	na	$1.525	0.49
H121	Cond Furnace (new)	Condensing / pulse package or residential-type furnace with a minimum AFUE of 92%.	New	Heating	18	1,215,573	0	0	-	-	68	1,859	na	$1.545	0.48
E122	Windows - Tinted AL Code to Class 36	Windows - Tinted AL Code to Class 36. Application: Old buildings	Replace	Heating	20	308,719	0	72	0.02	0.00	6	1,249	$0.219	$1.656	0.45
W125r	Solar Hot Water	Install solar water heaters on large use facility such as multifamily or lodging	Retrofit	Water Heat	15	1,073,243	65,557	0	-	-	66	570	na	$1.680	0.42
E131	Windows - Tinted AL Code to Class 36	Windows - Tinted AL Code to Class 36. Application: New Construction	New	Heating	20	169,525	0	36	0.01	0.00	3	686	$0.237	$1.783	0.42
H116	Cond Furnace	Condensing / pulse	Replace	Heating	18	2,897,523	0	0	-	-	138	3,762	na	$1.820	0.41

Measure Code	Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Total MWh Savings	Winter MW	Summer mW	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
	(repl)	package or residential-type furnace with a minimum AFUE of 92%.													
H122	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	8,316,257	0	1,773	0.44	0.38	221	12,794	$0.228	$1.853	0.40
E110	Roof Insulation - Blanket R11-41	Roof Insulation - Blanket R11-41. Application: Buildings with open truss unfinished interior	Retrofit	Heating	30	463,089	0	2	0.00	0.00	15	556	$0.269	$1.960	0.38
E118	Windows - Non-Tinted AL Code to Class 40	Windows - Non-Tinted AL Code to Class 40. Application: Old buildings	Replace	Heating	20	580,668	0	-26	(0.01)	(0.00)	25	3,202	na	$1.969	0.38
E127	Windows -	Windows - Non-	New	Heating	20	318,858	0	-10	(0.00)	(0.00)	14	1,758	na	$1.996	0.37

Measure Code	Measure Name	Measure Description	Construction Type	Measure End Use	Average Lifetime	Total Incremental Cost	Total O&M	Total MWh Savings	Winter MW	Summer mW	Gas Impacts kTherms	Floor Area	Levelized Cost, $/kWh	Levelized Cost, $/th	BCR
	Non-Tinted AL Code to Class 40	Tinted AL Code to Class 40. Application: New Construction													
E109	Roof Insulation - Blanket R11-30	Roof Insulation - Blanket R11-30. Application: Buildings with open truss unfinished interior	Retrofit	Heating	30	411,635	0	2	0.00	0.00	13	556	$0.286	$2.084	0.36
E119	Windows - Non-Tinted AL Code to Class 36	Windows - Non-Tinted AL Code to Class 36. Application: Old buildings	Replace	Heating	20	1,451,669	0	-46	(0.02)	(0.00)	38	3,202	na	$3.207	0.23
E128	Windows - Non-Tinted AL Code to Class 36	Windows - Non-Tinted AL Code to Class 36. Application: New Construction	New	Heating	20	797,145	0	-20	(0.01)	(0.00)	20	1,758	na	$3.283	0.23
E117	Windows - Non-Tinted AL Code to Class 45	Windows - Non-Tinted AL Code to Class 45. Application: Old buildings	Replace	Heating	20	386,144	0	-12	(0.00)	(0.00)	10	3,202	na	$3.426	0.22
E126	Windows - Non-Tinted AL Code to Class 45	Windows - Non-Tinted AL Code to Class 45. Application: New Construction	New	Heating	20	212,041	0	-5	(0.00)	(0.00)	5	1,758	na	$3.491	0.21
H128	Rooftop Condensing Burner	Install condensing burner	Retrofit	Heating	10	5,225,135	0	744	0.18	0.16	98	3,513	$0.426	$3.736	0.20
W125	Solar Hot Water	Install solar water heaters on large use facility such as multifamily or lodging	New	Water Heat	15	589,343	35,999	0	-	-	12	313	na	$4.956	0.14

Table 3: Detailed Measure Table, Residential Sector, Gas Savings, and 2027 Technical Potential

Measure Code	Measure Description	Program	Average Lifetime	Total Incremental Cost	Total O&M Impact ($)	Gas Savings Therms	Level Cost, $/th	BCR	No. Units
N-A105	Hi-eff Washer	New	12	3,223	-11,268	213	-$4.303	100.00	65
N-A102	MEF 2.0 Washer	New	12	5,731	-19,566	513	-$3.079	100.00	173
R-A102	MEF 2.0 Washer	Replace	12	9,995	-11,370	356	-$0.441	100.00	88
R-A105	Hi-eff Washer	Replace	12	6,811	-10,860	6,503	-$0.071	100.00	44
R-GH112	AFUE 92 to hydrocoil combo, Z 1-2	Retro Gas	45	860,155	0	255,179	$0.195	3.87	2,867
R-GW118	Wx insulation (add walls), Z 1-2	Retro Gas	45	6,098,253	0	1,212,123	$0.291	2.59	4,717
N-GH128	Ducts Indoor, DHW, Lights (Gas Z 1-2)	New Gas	45	22,811,431	0	3,211,228	$0.358	1.84	29,434
R-GW117	Wx insulation (ceiling, floor), Z 1-2	Retro Gas	45	9,112,629	0	1,373,018	$0.384	1.96	4,571
N-GH125	Heating upgrade (AFUE 90) (Z 1-2)	New Gas	15	735,853	0	137,988	$0.458	1.42	4,906
R-GH120	AFUE 90+ Furnace, Z 1-2	Replace Gas	18	441,584	283,607	128,458	$0.491	1.50	2,354
N-GH139	Tank upgrade (50 gal gas)	New Gas	15	3,679,263	0	532,040	$0.593	1.04	18,396
N-GH127	HRV, E* (Gas Z 1-2)	New Gas	15	2,759,447	0	386,323	$0.613	1.06	9,198
R-GH111	Duct Sealing, Z 1-2	Retro Gas	20	467,202	0	59,214	$0.644	1.15	755
N-GD106	Tank upgrade (50 gal gas) Hi Eff Alternative	New Gas	15	5,919,014	0	777,539	$0.653	0.94	10,118
R-GD111	Tank upgrade (50 gal gas) Hi Eff Alternative	Replace Gas	15	22,452	0	2,949	$0.676	0.94	47
N-GD109	Upgrade to Navien Tankless Gas heater	New Gas	20	819,556	0	75,112	$0.890	0.79	5,464
N-GD108	Tankless Gas heater	New Gas	20	5,736,891	0	514,231	$0.910	0.77	5,464
R-GH113	Boiler to Polaris Combo radiant, Z 1-2	Retro Gas	45	12,615,599	0	685,256	$1.066	0.71	2,867
R-GW120	Window replace (U=.35), Z 1-2	Replace Gas	45	688,505	0	36,991	$1.078	0.70	2,136

Measure Code	Measure Description	Program	Average Lifetime	Total Incremental Cost	Total O&M Impact ($)	Gas Savings Therms	Level Cost, $/th	BCR	No. Units
N-A103	Estar Dishwasher	New	12	1,476	-357	103	$1.240	0.60	39
N-GH126	Window U=.3 (Gas Z 1-2)	New Gas	45	339,779	0	12,015	$1.423	0.46	1,859
N-GH124	E* Insulation, Ducts, DHW, Lights (Gas Z 1-2)	New Gas	45	36,831,520	0	1,103,441	$1.680	0.39	26,467
R-GW119	Window, retro (U=.35), Z 1-2	Retro Gas	45	27,586,138	0	928,680	$1.720	0.44	6,532
R-A103	Estar Dishwasher	Replace	12	80,213	-19,425	3,224	$2.152	0.34	2,111
R-GW121	HRV, Z 1-2	Retro Gas	36	8,680,692	3,668,743	251,635	$3.043	0.25	4,568
N-GD107	Solar hot water heater (50 gal) - With gas backup.	New Gas	20	13,012,291	0	236,324	$4.493	0.15	2,024

Incremental Annual Savings by Year, Therms

WASHINGTON: Incremental Annual Savings by Year, Therms

DSM Program	Total Potential	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Resid New	4,789,919	14,088	14,088	28,176	42,264	42,264	42,264	56,352	56,352	56,352	239,496	239,496	239,496	239,496	239,496	239,496	239,496	239,496	239,496	239,496	239,496	2,986,656
Resid Retrofit	3,046,569	15,233	121,863	137,096	152,328	167,561	182,794	182,794	182,794	182,794	182,794	182,794	182,794	182,794	182,794	182,794	182,794	152,328	121,863	91,397	76,164	3,046,569
Resid Replacement	140,003	412	412	824	1,235	1,235	1,235	1,647	1,647	1,647	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	87,296
Appliance Replacement	8,421	248	248	372	372	372	372	372	372	372	372	372	372	372	372	372	372	372	372	372	372	7,183
Solar Water heat - Residential	18,919	284	284	378	568	568	568	568	568	568	568	568	568	568	568	568	568	568	568	568	568	10,595
Commercial Retrofit	973,452	2,434	38,938	43,805	48,673	53,540	58,407	58,407	58,407	58,407	58,407	58,407	58,407	58,407	58,407	58,407	58,407	50,620	38,938	29,204	24,336	972,966
Commercial New	632,654	-	17,398	18,980	20,561	22,143	22,143	23,725	23,725	23,725	23,725	23,725	23,725	23,725	23,725	23,725	23,725	23,725	23,725	23,725	23,725	433,368
Commercial Replacement	1,721,121	2,151	38,725	43,028	47,331	51,634	55,936	60,239	64,542	64,542	64,542	64,542	64,542	64,542	64,542	64,542	64,542	64,542	64,542	64,542	64,542	1,138,091
Industrial Retrofit	236,097	590	9,444	10,624	11,805	12,985	14,166	14,166	14,166	14,166	14,166	14,166	14,166	14,166	14,166	14,166	14,166	11,805	9,444	7,083	5,902	235,507
Industrial Replacement	60,471	76	1,361	1,512	1,663	1,814	1,965	2,116	2,268	2,268	2,268	2,268	2,268	2,268	2,268	2,268	2,268	2,268	2,268	2,268	2,268	39,986
Residential Total	8,003,831	30,264	136,894	166,845	196,767	212,000	227,233	241,732	241,732	241,732	430,229	430,229	430,229	430,229	430,229	430,229	430,229	399,764	369,298	338,832	323,599	6,138,297
Commercial Total	3,327,228	4,585	95,061	105,813	116,565	127,316	136,486	142,371	146,674	146,674	146,674	146,674	146,674	146,674	146,674	146,674	146,674	138,886	127,205	117,470	112,603	2,544,425
Industrial Total	296,568	666	10,804	12,136	13,468	14,799	16,131	16,282	16,433	16,433	16,433	16,433	16,433	16,433	16,433	16,433	16,433	14,073	11,712	9,351	8,170	275,493
All DSM	**11,627,626**	**35,515**	**242,760**	**284,794**	**326,799**	**354,116**	**379,850**	**400,386**	**404,839**	**404,839**	**593,336**	**593,336**	**593,336**	**593,336**	**593,336**	**593,336**	**593,336**	**552,722**	**508,214**	**465,653**	**444,372**	**8,958,216**

Incremental Measure Cost, Annual dollars by Year, Real Dollars

DSM Program	Unit Cost, $/the	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Resid New	$7.537	$ 106,176	$ 106,176	$ 212,352	$ 318,528	$ 318,528	$ 318,528	$ 424,704	$ 424,704	$ 424,704	$ 1,804,992	$ 1,804,992	$ 1,804,992	$ 1,804,992	$ 1,804,992	$ 1,804,992	$ 1,804,992	$ 1,804,992	$ 1,804,992	$ 1,804,992	$ 1,804,992	$ 22,509,316
Resid Retrofit	$8.123	$ 123,741	$ 989,926	$ 1,113,666	$ 1,237,407	$ 1,361,148	$ 1,484,889	$ 1,484,889	$ 1,484,889	$ 1,484,889	$ 1,484,889	$ 1,484,889	$ 1,484,889	$ 1,484,889	$ 1,484,889	$ 1,484,889	$ 1,484,889	$ 1,237,407	$ 989,926	$ 742,444	$ 618,704	$ 24,748,143
Resid Replacement	$6.659	$ 2,742	$ 2,742	$ 5,484	$ 8,226	$ 8,226	$ 8,226	$ 10,967	$ 10,967	$ 10,967	$ 46,611	$ 46,611	$ 46,611	$ 46,611	$ 46,611	$ 46,611	$ 46,611	$ 46,611	$ 46,611	$ 46,611	$ 46,611	$ 581,272
Appliance Replacement	$3.120	$ 773	$ 773	$ 1,159	$ 1,159	$ 1,159	$ 1,159	$ 1,159	$ 1,159	$ 1,159	$ 1,159	$ 1,159	$ 1,159	$ 1,159	$ 1,159	$ 1,159	$ 1,159	$ 1,159	$ 1,159	$ 1,159	$ 1,159	$ 22,406
Solar Water heat - Residential	$37.933	$ 10,765	$ 10,765	$ 14,353	$ 21,530	$ 21,530	$ 21,530	$ 21,530	$ 21,530	$ 21,530	$ 21,530	$ 21,530	$ 21,530	$ 21,530	$ 21,530	$ 21,530	$ 21,530	$ 21,530	$ 21,530	$ 21,530	$ 21,530	$ 401,890
Commercial Retrofit	$2.836	$ 6,902	$ 110,432	$ 124,236	$ 138,040	$ 151,844	$ 165,649	$ 165,649	$ 165,649	$ 165,649	$ 165,649	$ 165,649	$ 165,649	$ 165,649	$ 165,649	$ 165,649	$ 165,649	$ 143,562	$ 110,432	$ 82,824	$ 69,020	$ 2,759,429
Commercial New	$4.988	$ -	$ 86,777	$ 94,666	$ 102,555	$ 110,444	$ 110,444	$ 118,333	$ 118,333	$ 118,333	$ 118,333	$ 118,333	$ 118,333	$ 118,333	$ 118,333	$ 118,333	$ 118,333	$ 118,333	$ 118,333	$ 118,333	$ 118,333	$ 2,161,541
Commercial Replacement	$4.068	$ 8,753	$ 157,553	$ 175,059	$ 192,564	$ 210,070	$ 227,576	$ 245,082	$ 262,588	$ 262,588	$ 262,588	$ 262,588	$ 262,588	$ 262,588	$ 262,588	$ 262,588	$ 262,588	$ 262,588	$ 262,588	$ 262,588	$ 262,588	$ 4,630,300
Industrial Retrofit	$2.077	$ 1,226	$ 19,613	$ 22,064	$ 24,516	$ 26,968	$ 29,419	$ 29,419	$ 29,419	$ 29,419	$ 29,419	$ 29,419	$ 29,419	$ 29,419	$ 29,419	$ 29,419	$ 29,419	$ 24,516	$ 19,613	$ 14,710	$ 12,258	$ 489,094
Industrial Replacement	$5.253	$ 397	$ 7,147	$ 7,942	$ 8,736	$ 9,530	$ 10,324	$ 11,118	$ 11,912	$ 11,912	$ 11,912	$ 11,912	$ 11,912	$ 11,912	$ 11,912	$ 11,912	$ 11,912	$ 11,912	$ 11,912	$ 11,912	$ 11,912	$ 210,056
Residential Total		$ 244,196	$ 1,110,381	$ 1,347,014	$ 1,586,850	$ 1,710,590	$ 1,834,331	$ 1,943,249	$ 1,943,249	$ 1,943,249	$ 3,359,181	$ 3,359,181	$ 3,359,181	$ 3,359,181	$ 3,359,181	$ 3,359,181	$ 3,359,181	$ 3,111,700	$ 2,864,218	$ 2,616,737	$ 2,492,996	$ 48,263,027
Commercial Total		$ 15,655	$ 354,762	$ 393,961	$ 433,160	$ 472,358	$ 503,668	$ 529,063	$ 546,569	$ 546,569	$ 546,569	$ 546,569	$ 546,569	$ 546,569	$ 546,569	$ 546,569	$ 546,569	$ 524,482	$ 491,353	$ 463,745	$ 449,941	$ 9,551,269
Industrial Total		$ 1,623	$ 26,760	$ 30,006	$ 33,252	$ 36,498	$ 39,743	$ 40,537	$ 41,332	$ 41,332	$ 41,332	$ 41,332	$ 41,332	$ 41,332	$ 41,332	$ 41,332	$ 41,332	$ 36,428	$ 31,525	$ 26,622	$ 24,170	$ 699,150
All DSM		**$ 261,474**	**$ 1,491,904**	**$ 1,770,981**	**$ 2,053,261**	**$ 2,219,446**	**$ 2,377,743**	**$ 2,512,849**	**$ 2,531,149**	**$ 2,531,149**	**$ 3,947,082**	**$ 3,947,082**	**$ 3,947,082**	**$ 3,947,082**	**$ 3,947,082**	**$ 3,947,082**	**$ 3,947,082**	**$ 3,672,611**	**$ 3,387,096**	**$ 3,107,104**	**$ 2,967,107**	**$ 58,513,447**

Appendix 4: Achievable DSM Screened at Base Case Avoided Cost - Oregon

Cumulative Savings by Year, Thousands of Therms

DSM Program	Applicable Customer Class	Applicable Customer Sub-Class(es)	Must Take / Discretionary	2008 2009	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
MF New DHW	Residential	New Const MF	*Must Take*	12	44	79	115	150	186	221	257	292	328	363	399	434	470	505	541	576	612	648	683
Replace DHW	Residential	Existing & Conv	*Must Take*	133	284	459	665	902	1,167	1,463	1,793	2,122	2,452	2,782	3,111	3,441	3,770	4,100	4,430	4,759	5,089	5,418	5,748
SF New DHW	Residential	New Const SF	*Must Take*	164	334	533	772	1,052	1,378	1,746	2,160	2,574	2,988	3,403	3,817	4,231	4,645	5,059	5,473	5,887	6,301	6,715	7,129
SF New Heating	Residential	New Const SF	*Must Take*	153	308	475	657	865	1,098	1,359	1,649	1,939	2,229	2,519	2,809	3,099	3,389	3,679	3,969	4,259	4,549	4,839	5,129
Retro Wx	Residential	Existing & Conv	*Discretionary*	530	1,135	1,837	2,660	3,605	4,665	5,850	7,035	8,219	9,404	10,589	11,485	12,382	12,382	12,382	12,382	12,382	12,382	12,382	12,382
Retro HVAC	Residential	Existing & Conv	*Discretionary*	92	196	317	459	622	806	1,010	1,215	1,419	1,624	1,828	2,033	2,237	2,237	2,237	2,237	2,237	2,237	2,237	2,237
Coml Retro	Commercial	Existing & Conv	*Discretionary*	337	674	720	1,165	1,687	2,287	2,959	3,711	4,462	5,214	5,965	6,717	7,468	8,220	8,220	8,220	8,220	8,220	8,220	8,220
Coml Replace	Commercial	Existing & Conv	*Must Take*	635	1,355	2,192	3,163	4,276	5,507	6,881	8,227	9,724	11,194	12,634	14,074	15,470	16,866	18,216	19,565	20,866	22,166	23,415	24,664
Coml New	Commercial	New Const	*Must Take*	222	469	757	1,089	1,471	1,897	2,373	2,844	3,368	3,888	4,402	4,916	5,422	5,928	6,424	6,920	7,407	7,893	8,368	8,843
Industrial Retro	Industrial	N/A	*Discretionary*	20	42	68	99	134	173	218	262	306	350	394	438	482	482	482	482	482	482	482	482
Industrial Repl	Industrial	N/A	*Must Take*	2	5	8	12	16	20	25	30	35	40	45	50	55	60	65	70	75	80	85	85
Subtotal - Residential				1,084	2,301	3,700	5,328	7,196	9,300	11,649	14,109	16,565	19,025	21,484	23,654	25,824	26,893	27,962	29,032	30,100	31,170	32,239	33,308
Subtotal - Commercial				1,194	2,498	3,669	5,417	7,434	9,691	12,213	14,782	17,554	20,296	23,001	25,707	28,360	31,014	32,860	34,705	36,493	38,279	40,003	41,727
Subtotal - Residential & Commercial				2,278	4,799	7,369	10,745	14,630	18,991	23,862	28,891	34,119	39,321	44,485	49,361	54,184	57,907	60,822	63,737	66,593	69,449	72,242	75,035
Subtotal - Industrial				22	47	76	111	150	193	243	292	341	390	439	488	537	542	547	552	557	562	567	567
Total - All DSM				2,300	4,846	7,445	10,856	14,780	19,184	24,105	29,183	34,460	39,711	44,924	49,849	54,721	58,449	61,369	64,289	67,150	70,011	72,809	75,602

Incremental Annual Savings per Year, Thousands of Therms

DSM Program	Applicable Customer Class	Applicable Customer Sub-Class(es)	Must Take / Discretionary	2008 2009	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
MF New DHW	Residential	New Const MF	*Must Take*	12	32	35	36	35	36	35	36	35	36	35	36	35	36	35	36	35	36	36	35
Replace DHW	Residential	Existing & Conv	*Must Take*	133	151	175	206	237	265	296	330	329	330	330	329	330	329	330	330	329	330	329	330
SF New DHW	Residential	New Const SF	*Must Take*	164	170	199	239	280	326	368	414	414	414	415	414	414	414	414	414	414	414	414	414
SF New Heating	Residential	New Const SF	*Must Take*	153	155	167	182	208	233	261	290	290	290	290	290	290	290	290	290	290	290	290	290
Retro Wx	Residential	Existing & Conv	*Discretionary*	530	605	702	823	945	1,060	1,185	1,185	1,184	1,185	1,185	896	897	-	-	-	-	-	-	-
Retro HVAC	Residential	Existing & Conv	*Discretionary*	92	104	121	142	163	184	204	205	204	205	204	205	204	-	-	-	-	-	-	-
Coml Retro	Commercial	Existing & Conv	*Discretionary*	337	337	46	445	522	600	672	752	751	752	751	752	751	752	-	-	-	-	-	-
Coml Replace	Commercial	Existing & Conv	*Must Take*	635	720	837	971	1,113	1,231	1,374	1,346	1,497	1,470	1,440	1,440	1,396	1,396	1,350	1,349	1,301	1,300	1,249	1,249
Coml New	Commercial	New Const	*Must Take*	222	247	288	332	382	426	476	471	524	520	514	514	506	506	496	496	487	486	475	475
Industrial Retro	Industrial	N/A	*Discretionary*	20	22	26	31	35	39	45	44	44	44	44	44	44	-	-	-	-	-	-	-
Industrial Repl	Industrial	N/A	*Must Take*	2	3	3	4	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	-
Subtotal - Residential				1,084	1,217	1,399	1,628	1,868	2,104	2,349	2,460	2,456	2,460	2,459	2,170	2,170	1,069	1,069	1,070	1,068	1,070	1,069	1,069
Subtotal - Commercial				1,194	1,304	1,171	1,748	2,017	2,257	2,522	2,569	2,772	2,742	2,705	2,706	2,653	2,654	1,846	1,845	1,788	1,786	1,724	1,724
Subtotal - Residential & Commercial				2,278	2,521	2,570	3,376	3,885	4,361	4,871	5,029	5,228	5,202	5,164	4,876	4,823	3,723	2,915	2,915	2,856	2,856	2,793	2,793
Subtotal - Industrial				22	25	29	35	39	43	50	49	49	49	49	49	49	5	5	5	5	5	5	-
Total - All DSM				2,300	2,546	2,599	3,411	3,924	4,404	4,921	5,078	5,277	5,251	5,213	4,925	4,872	3,728	2,920	2,920	2,861	2,861	2,798	2,793

APPENDIX 5
LINEAR PROGRAMING AND THE COMPANY'S RESOURCE CHOICES

Scenario	NPV 20-year cost	20 year served demand	20 year unserved demand	Incremental Rmix Selection	Mist Recall	Sat LNG Albany	Sat LNG Eugene	Sat LNG Salem	CD via Stanfield	Palomar East	Palomar West	Pacific Connector East	Pacific Connector West	TF-1 Turnback	Brownsville to Eugene	Newport LNG Enhancment	CD 12-9	WVF Phase 1	WVF Phase 2	WVF NA	WVF SA	WVF to H	WVF to E
				Available	2009-2010	2011-2012	2011-2012	2011-2012	2011-2012	2011-2012				2011-2012	2011-2012	2012-2013	2011-2012	2010-2011	2014-2015	2011-2012	2011-2012	2011-2012	2011-2012
				Year Selected	2009-2010	-	-	-	-	2011-2012				2011-2012	2011-2012	-	-	-	-	-	-	-	-
				First Year MDT	10.487	-	-	-	-	100.000	-	-	-	(77.000)	2.810	-	-	-	-	-	-	-	-
Rmix 1 - Low Growth Alt 2, Low Price	$ 7,036,467	1,450,268	6	Max MDT	10.487	-	-	-	-	100.000	-	-	-	(77.000)	2.810	-	-	-	-	-	-	-	-
				Available	2009-2010	2011-2012	2011-2012	2011-2012	2011-2012	2011-2012				2011-2012	2011-2012	2012-2013	2011-2012	2010-2011	2014-2015	2011-2012	2011-2012	2011-2012	2011-2012
				Year Selected	2009-2010	-	-	-	-	2011-2012				2011-2012	2011-2012	-	-	-	-	-	-	-	-
				First Year MDT	20.496	-	-	-	-	100.000	-	-	-	(77.000)	3.583	-	-	-	-	-	-	-	-
Rmix 1 - Low Growth, Low Price	$ 7,107,262	1,464,050	6	Max MDT	20.496	-	-	-	-	100.000	-	-	-	(77.000)	3.583	-	-	-	-	-	-	-	-
				Available	2009-2010	2011-2012	2011-2012	2011-2012	2011-2012	2011-2012				2011-2012	2011-2012	2012-2013	2011-2012	2010-2011	2014-2015	2011-2012	2011-2012	2011-2012	2011-2012
				Year Selected	2009-2010	-	2011-2012	2027-2028	-	2011-2012				2011-2012	2011-2012	2012-2013	-	-	-	-	-	-	-
				First Year MDT	33.689	-	0.198	2.913	-	100.000	-	-	-	(77.000)	5.000	9.863	-	-	-	-	-	-	-
Rmix 1 - Low Growth Alt 1, Low Price	$ 7,772,695	1,618,032	8	Max MDT	196.099	-	18.085	2.913	-	100.000	-	-	-	(77.000)	5.000	9.863	-	-	-	-	-	-	-
				Available	2009-2010	2011-2012	2011-2012	2011-2012	2011-2012	2011-2012				2011-2012	2011-2012	2012-2013	2011-2012	2010-2011	2014-2015	2011-2012	2011-2012	2011-2012	2011-2012
				Year Selected	2009-2010	-	2011-2012	2027-2028	-	2011-2012				2011-2012	2011-2012	2012-2013	-	-	-	2011-2012	2011-2012	2011-2012	-
				First Year MDT	36.397	-	1.380	0.370	-	100.000	-	-	-	(77.000)	5.000	12.406	-	-	-	2.042	2.042	2.042	-
Rmix 1 - Low Price	$ 7,867,476	1,636,408	9	Max MDT	196.099	-	18.085	0.370	-	100.000	-	-	-	(77.000)	5.000	12.406	-	-	-	2.042	2.042	2.042	-
				Available	2009-2010	2011-2012	2011-2012	2011-2012	2011-2012	2011-2012				2011-2012	2011-2012	2012-2013	2011-2012	2010-2011	2014-2015	2011-2012	2011-2012	2011-2012	2011-2012
				Year Selected	2009-2010	2026-2027	2011-2012	2024-2025	-	2011-2012				2011-2012	2011-2012	2012-2013	2027-2028	2010-2011	2014-2015	2011-2012	2011-2012	2011-2012	-
				First Year MDT	50.493	6.779	4.178	1.971	-	100.000	-	-	-	(77.000)	5.000	19.073	3.821	15.000	1.834	2.907	2.907	2.907	-
Rmix 1 - High Growth, Low Price	$ 8,664,964	1,808,765	12	Max MDT	279.200	30.000	30.000	30.000	-	185.547	-	-	-	(77.000)	5.000	19.073	3.821	15.000	1.834	2.907	2.907	2.907	-
				Available	2009-2010	2011-2012	2011-2012	2011-2012	2011-2012	2011-2012	2011-2012			2011-2012	2011-2012	2012-2013	2011-2012	2010-2011	2014-2015	2011-2012	2011-2012	2011-2012	2011-2012
				Year Selected	2009-2010	-	2015-2016	2027-2028	-	2011-2012	2011-2012			2011-2012	2011-2012	2012-2013	-	2010-2011	-	2011-2012	2011-2012	2011-2012	-
				First Year MDT	11.443	-	1.114	1.225	-	100.000	50.000	-	-	(77.000)	5.000	5.796	-	4.490	-	1.941	1.941	1.941	-
Rmix 3, Bradwood LNG & Palomar West	$ 9,624,595	1,616,814	7	Max MDT	93.149	-	16.910	1.225	-	100.000	100.000	-	-	(77.000)	5.000	5.796	-	4.490	-	1.941	1.941	1.941	-
				Available	2009-2010	2011-2012	2011-2012	2011-2012	2011-2012	2011-2012		2011-2012	2011-2012	2011-2012	2011-2012	2012-2013	2011-2012	2010-2011	2014-2015	2011-2012	2011-2012	2011-2012	2011-2012
				Year Selected	2009-2010	-	2027-2028	2027-2028	-	2011-2012		2011-2012	2011-2012	2011-2012	-	2012-2013	-	-	-	-	-	-	-
				First Year MDT	11.443	-	1.397	3.166	-	100.000	-	5.162	20.000	(77.000)	-	8.345	-	-	-	-	-	-	-
Rmix 4, Jordon Cove LNG & Pacific Connector	$ 9,759,971	1,616,814	7	Max MDT	156.676	-	1.397	3.166	-	127.496	-	5.162	20.000	(77.000)	-	8.345	-	-	-	-	-	-	-
				Available	2009-2010	2011-2012	2011-2012	2011-2012	2011-2012	2011-2012				2011-2012	2011-2012	2012-2013	2011-2012	2010-2011	2014-2015	2011-2012	2011-2012	2011-2012	2011-2012
				Year Selected	2009-2010	-	2011-2012	-	-	2011-2012				2011-2012	2011-2012	2012-2013	-	-	-	2011-2012	2011-2012	2011-2012	-
				First Year MDT	11.443	-	1.114	-	-	100.000	-	-	-	(77.000)	5.000	13.964	-	-	-	1.941	1.941	1.941	-
Rmix 1 - Base Case	$ 9,934,062	1,616,814	7	Max MDT	188.659	-	14.456	-	-	100.000	-	-	-	(77.000)	5.000	13.964	-	-	-	1.941	1.941	1.941	-
				Available	2009-2010	2011-2012	2011-2012	2011-2012	2011-2012					2011-2012	2011-2012	2012-2013	2011-2012	2010-2011	2014-2015	2011-2012	2011-2012	2011-2012	2011-2012
				Year Selected	2009-2010	-	2015-2016	-	2027-2028	-				2011-2012	2011-2012	2012-2013	-	-	-	2011-2012	2011-2012	2011-2012	-
				First Year MDT	11.443	-	1.114	-	14.667	-	-	-	-	-	5.000	13.964	-	-	-	1.941	1.941	1.941	-
Rmix 2 - No Palomar	$ 9,937,096	1,616,814	7	Max MDT	196.992	-	14.456	-	14.667	-	-	-	-	-	5.000	13.964	-	-	-	1.941	1.941	1.941	-
				Available	2009-2010	2011-2012	2011-2012	2011-2012	2011-2012	2011-2012				2011-2012	2011-2012	2012-2013	2011-2012	2010-2011	2014-2015	2011-2012	2011-2012	2011-2012	2011-2012
				Year Selected	2009-2010	-	2015-2016	-	-	2011-2012				2011-2012	2011-2012	2012-2013	2026-2027	2010-2011	-	2011-2012	2011-2012	2011-2012	-
				First Year MDT	61.053	-	1.114	-	-	100.000	-	-	-	(77.000)	5.000	1.941	1.143	12.853	-	1.941	1.941	1.941	-
Rmix 1 - Coldest (Previous Design)	$ 10,660,091	1,737,546	7	Max MDT	214.045	-	13.314	-	-	135.938	-	-	-	(77.000)	5.000	1.941	1.143	12.853	-	1.941	1.941	1.941	-
				Available	2009-2010	2011-2012	2011-2012	2011-2012	2011-2012	2011-2012				2011-2012	2011-2012	2012-2013	2011-2012	2010-2011	2014-2015	2011-2012	2011-2012	2011-2012	2011-2012
				Year Selected	-	-	-	-	-	2011-2012				2011-2012	2011-2012	-	-	-	-	-	-	-	-
				First Year MDT	-	-	-	-	-	100.000	-	-	-	(77.000)	3.071	-	-	-	-	-	-	-	-
Rmix 1 - Low Growth, High Price	$ 14,459,669	1,408,635	1	Max MDT	-	-	-	-	-	100.000	-	-	-	(77.000)	3.071	-	-	-	-	-	-	-	-
				Available	2009-2010	2011-2012	2011-2012	2011-2012	2011-2012	2011-2012				2011-2012	2011-2012	2012-2013	2011-2012	2010-2011	2014-2015	2011-2012	2011-2012	2011-2012	2011-2012
				Year Selected	2009-2010	2026-2027	2014-2015	2026-2027	-	2011-2012				2011-2012	2011-2012	2012-2013	2026-2027	2010-2011	-	2011-2012	2011-2012	2011-2012	-
				First Year MDT	3.666	2.435	1.871	0.520	-	100.000	-	-	-	(77.000)	5.000	18.931	1.513	15.000	-	2.279	2.279	2.279	-
Rmix 1 - High Growth, High Price	$ 17,244,826	1,743,191	6	Max MDT	279.200	25.261	30.000	7.473	-	172.472	-	-	-	(77.000)	5.000	18.931	1.513	15.000	-	2.279	2.279	2.279	-

(BBtu / $000 Nominal)	2008-2009	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
Forecast Demand	72,331	73,722	74,329	75,720	76,566	77,765	78,927	80,823	81,785	83,264	84,853	86,819	88,085	89,936	91,578	93,477	94,419	95,893	97,552	99,522
DSM Impact	-	(218)	(449)	(761)	(1,117)	(1,541)	(2,009)	(2,542)	(3,064)	(3,721)	(4,333)	(4,975)	(5,495)	(6,071)	(6,504)	(6,883)	(7,179)	(7,549)	(7,886)	(8,245)
Total Annual Demand (net of DSM)	**72,331**	**73,504**	**73,880**	**74,959**	**75,449**	**76,224**	**76,917**	**78,280**	**78,721**	**79,543**	**80,520**	**81,844**	**82,590**	**83,865**	**85,074**	**86,593**	**87,240**	**88,343**	**89,666**	**91,277**
Annual Demand Served	72,331	73,501	73,876	74,959	75,449	76,224	76,917	78,280	78,721	79,543	80,520	81,844	82,590	83,865	85,074	86,593	87,240	88,343	89,666	91,277
Annual Demand Unserved	-	3	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Peak Day Demand (net of DSM)	**903**	**920**	**924**	**934**	**943**	**951**	**958**	**972**	**984**	**996**	**1,010**	**1,024**	**1,042**	**1,059**	**1,076**	**1,090**	**1,104**	**1,116**	**1,134**	**1,149**
Peak Day Demand Served	903	917	920	934	943	951	958	972	984	996	1,010	1,024	1,042	1,059	1,076	1,090	1,104	1,116	1,134	1,149
Peak Day Demand Unserved	-	3	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Supply Fixed Costs	$ 61	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59
Supply Variable Costs	$ 436,542	$ 481,982	$ 468,890	$ 537,115	$ 553,059	$ 591,326	$ 598,409	$ 608,580	$ 627,435	$ 646,050	$ 674,825	$ 701,741	$ 686,657	$ 700,539	$ 743,211	$ 825,306	$ 890,313	$ 914,160	$ 948,880	$ 977,547
Total Supply Costs	**$ 436,603**	**$ 482,041**	**$ 468,949**	**$ 537,174**	**$ 553,118**	**$ 591,385**	**$ 598,468**	**$ 608,638**	**$ 627,494**	**$ 646,109**	**$ 674,884**	**$ 701,800**	**$ 686,716**	**$ 700,598**	**$ 743,269**	**$ 825,364**	**$ 890,372**	**$ 914,219**	**$ 948,939**	**$ 977,605**
Transportation Fixed Costs	$ 83,187	$ 82,955	$ 82,955	$ 87,922	$ 88,474	$ 88,474	$ 88,474	$ 88,474	$ 89,857	$ 90,135	$ 90,135	$ 90,135	$ 90,493	$ 90,493	$ 90,493	$ 90,493	$ 90,493	$ 90,493	$ 90,522	$ 92,654
Transportation Variable Costs	$ 2,872	$ 2,905	$ 2,868	$ 2,317	$ 2,263	$ 2,284	$ 2,315	$ 2,350	$ 2,405	$ 2,425	$ 2,464	$ 2,519	$ 2,530	$ 2,576	$ 2,615	$ 2,650	$ 2,680	$ 2,725	$ 2,714	$ 2,831
Total Transportation Costs	**$ 86,058**	**$ 85,860**	**$ 85,823**	**$ 90,239**	**$ 90,737**	**$ 90,758**	**$ 90,789**	**$ 90,824**	**$ 92,263**	**$ 92,559**	**$ 92,599**	**$ 92,653**	**$ 93,022**	**$ 93,068**	**$ 93,108**	**$ 93,142**	**$ 93,173**	**$ 93,218**	**$ 93,236**	**$ 95,485**
Storage Fixed Costs	$ 23,080	$ 23,252	$ 23,466	$ 23,815	$ 23,952	$ 24,011	$ 24,415	$ 24,773	$ 25,134	$ 25,722	$ 26,357	$ 26,950	$ 27,645	$ 28,406	$ 29,090	$ 29,734	$ 30,339	$ 31,003	$ 31,315	$ 32,174
Storage Variable Costs	$ 2,415	$ 1,944	$ 1,599	$ 1,924	$ 2,078	$ 2,189	$ 2,191	$ 2,251	$ 2,301	$ 2,507	$ 2,516	$ 2,688	$ 2,860	$ 2,691	$ 2,988	$ 3,361	$ 4,105	$ 4,154	$ 3,908	$ 4,184
Total Storage Costs	**$ 25,495**	**$ 25,196**	**$ 25,064**	**$ 25,739**	**$ 26,030**	**$ 26,200**	**$ 26,606**	**$ 27,024**	**$ 27,436**	**$ 28,229**	**$ 28,873**	**$ 29,638**	**$ 30,504**	**$ 31,097**	**$ 32,079**	**$ 33,096**	**$ 34,443**	**$ 35,157**	**$ 35,223**	**$ 36,358**
DSM Annual Utility Costs ($2007)	**$ -**	**$ 7,853**	**$ 8,941**	**$ 10,394**	**$ 12,116**	**$ 13,843**	**$ 15,509**	**$ 17,297**	**$ 17,683**	**$ 17,793**	**$ 17,504**	**$ 17,489**	**$ 17,488**	**$ 17,465**	**$ 5,573**	**$ 5,548**	**$ 5,548**	**$ 5,443**	**$ 5,361**	**$ 5,281**
Total Levelized DSM Costs	$ -	$ 488	$ 1,051	$ 1,734	$ 2,559	$ 3,525	$ 4,622	$ 5,864	$ 7,213	$ 9,105	$ 10,716	$ 12,406	$ 13,921	$ 15,417	$ 16,833	$ 18,172	$ 19,511	$ 20,828	$ 22,146	$ 23,442
Grand Total System Costs	**$ 548,156**	**$ 600,950**	**$ 588,777**	**$ 663,545**	**$ 682,001**	**$ 722,186**	**$ 731,372**	**$ 743,783**	**$ 764,876**	**$ 784,691**	**$ 813,860**	**$ 841,581**	**$ 827,731**	**$ 842,228**	**$ 874,029**	**$ 957,151**	**$ 1,023,536**	**$ 1,048,036**	**$ 1,082,759**	**$ 1,114,730**

NPV @ 5.16% Discount Rate	
	5.16%
$	9,934,062

Net Incremental Daily Citygate Deliverability	2008-2009	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
1 Mist Recall	-	11	11	23	31	31	33	46	46	55	68	81	91	107	122	135	148	160	175	189
2 Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3 Satellite LNG - Eugene	-	-	-	-	-	-	-	1	2	3	4	5	6	7	8	9	10	11	12	14
4 Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Incremental CD via Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8 Palomar East	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
9 Palomar West (Bradwood)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10 Pacific Connector East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11 Pacific Connector West (Jordan Cove)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12 Existing TF-1 Turnback	-	-	-	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)
Total Incremental Daily Citygate Capacity	**-**	**11**	**11**	**46**	**54**	**54**	**56**	**70**	**71**	**81**	**95**	**109**	**120**	**137**	**154**	**167**	**182**	**194**	**210**	**226**
Incremental Storage Capacity																				
Mist Recall	-	259	259	522	693	693	756	1,030	1,030	1,249	1,544	1,828	2,055	2,414	2,759	3,052	3,351	3,622	3,957	4,263
Satellite LNG - Albany	-	-	-	-	- -	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Satellite LNG - Eugene	-	-	-	-	-	-	-	3	6	9	12	15	18	22	25	28	31	34	37	43
Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Incremental Storage Capacity	**-**	**259**	**259**	**522**	**693**	**693**	**756**	**1,034**	**1,037**	**1,258**	**1,556**	**1,843**	**2,074**	**2,436**	**2,784**	**3,081**	**3,383**	**3,656**	**3,994**	**4,306**
Misc. Upstream & Downstream Components																				
Brownsville to Eugene	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Newport LNG Enhancement to Salem	-	-	-	-	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Incremental CD 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Opal to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Willamette Valley Feeder Components																				
Portland to Salem (Phase 1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Portland to Perrydale (Phase 2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Perrydale to Independence	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Independance to North Albany	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
North Albany to South Albany	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
South Albany to Halsey	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Halsey to Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

1172 - RMix 1 Base Case.xls

(BBtu / $000 Nominal)	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018
Forecast Demand	72,331	73,722	74,329	75,720	76,566	77,765	78,927	80,823	81,785	83,264
DSM Impact	-	-	-	-	-	-	-	-	-	-
Total Annual Demand (net of DSM)	**72,331**	**73,722**	**74,329**	**75,720**	**76,566**	**77,765**	**78,927**	**80,823**	**81,785**	**83,264**
Annual Demand Served	72,331	73,708	74,310	75,692	76,526	77,714	78,865	80,744	81,695	83,156
Annual Demand Unserved	-	13	19	29	40	51	62	79	90	107
Total Peak Day Demand (net of DSM)	**903**	**922**	**927**	**940**	**952**	**963**	**974**	**992**	**1,007**	**1,025**
Peak Day Demand Served	903	908	909	911	912	912	912	913	917	917
Peak Day Demand Unserved	-	13	19	29	40	51	62	79	90	107
Supply Fixed Costs	$ 61	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59
Supply Variable Costs	$ 434,850	$ 483,923	$ 469,055	$ 543,555	$ 564,869	$ 606,366	$ 616,122	$ 632,542	$ 658,912	$ 685,066
Total Supply Costs	**$ 434,912**	**$ 483,981**	**$ 469,114**	**$ 543,614**	**$ 564,927**	**$ 606,425**	**$ 616,181**	**$ 632,601**	**$ 658,970**	**$ 685,125**
Transportation Fixed Costs	$ 83,187	$ 82,955	$ 82,969	$ 99,399	$ 99,439	$ 99,439	$ 99,469	$ 99,469	$ 100,852	$ 101,129
Transportation Variable Costs	$ 2,864	$ 2,916	$ 2,857	$ 3,045	$ 3,046	$ 3,106	$ 3,167	$ 3,262	$ 3,304	$ 3,379
Total Transportation Costs	**$ 86,051**	**$ 85,871**	**$ 85,826**	**$ 102,444**	**$ 102,484**	**$ 102,545**	**$ 102,635**	**$ 102,730**	**$ 104,156**	**$ 104,509**
Storage Fixed Costs	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836
Storage Variable Costs	$ 2,373	$ 1,916	$ 1,533	$ 1,826	$ 1,982	$ 2,077	$ 2,077	$ 2,045	$ 2,186	$ 2,550
Total Storage Costs	**$ 25,209**	**$ 24,752**	**$ 24,369**	**$ 24,662**	**$ 24,818**	**$ 24,913**	**$ 24,913**	**$ 24,881**	**$ 25,022**	**$ 25,386**
DSM Annual Utility Costs ($2007)	**$ -**	**$ 7,853**	**$ 8,941**	**$ 10,394**	**$ 12,116**	**$ 13,843**	**$ 15,509**	**$ 17,297**	**$ 17,683**	**$ 17,793**
Total Levelized DSM Costs	$ 546,172	$ 594,604	$ 579,309	$ 670,720	$ 692,230	$ 733,882	$ 743,730	$ 760,212	$ 788,148	$ 815,020
Grand Total System Costs	**$ 546,172**	**$ 602,457**	**$ 588,249**	**$ 681,114**	**$ 704,346**	**$ 747,725**	**$ 759,239**	**$ 777,509**	**$ 805,831**	**$ 832,813**

(BBtu / $000 Nominal)	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Forecast Demand	84,853	86,819	88,085	89,936	91,578	93,477	94,419	95,893	97,552	99,522
DSM Impact	-	-	-	-	-	-	-	-	-	-
Total Annual Demand (net of DSM)	**84,853**	**86,819**	**88,085**	**89,936**	**91,578**	**93,477**	**94,419**	**95,893**	**97,552**	**99,522**
Annual Demand Served	84,726	86,665	87,876	89,584	91,069	92,580	92,833	93,425	94,090	95,069
Annual Demand Unserved	127	154	209	352	509	897	1,586	2,468	3,462	4,454
Total Peak Day Demand (net of DSM)	**1,044**	**1,062**	**1,082**	**1,105**	**1,125**	**1,141**	**1,156**	**1,173**	**1,193**	**1,210**
Peak Day Demand Served	918	911	876	838	803	732	726	730	721	704
Peak Day Demand Unserved	126	151	206	267	322	410	430	443	472	506
Supply Fixed Costs	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59
Supply Variable Costs	$ 725,463	$ 765,838	$ 754,704	$ 770,929	$ 817,653	$ 904,379	$ 966,445	$ 994,336	$ 1,032,009	$ 1,044,549
Total Supply Costs	**$ 725,522**	**$ 765,896**	**$ 754,763**	**$ 770,988**	**$ 817,712**	**$ 904,438**	**$ 966,504**	**$ 994,395**	**$ 1,032,067**	**$ 1,044,608**
Transportation Fixed Costs	$ 101,129	$ 101,129	$ 101,129	$ 101,129	$ 101,129	$ 101,129	$ 101,129	$ 101,129	$ 101,129	$ 101,129
Transportation Variable Costs	$ 3,427	$ 3,488	$ 3,548	$ 3,613	$ 3,685	$ 3,761	$ 3,775	$ 3,803	$ 3,837	$ 3,882
Total Transportation Costs	**$ 104,556**	**$ 104,617**	**$ 104,677**	**$ 104,742**	**$ 104,814**	**$ 104,890**	**$ 104,904**	**$ 104,932**	**$ 104,966**	**$ 105,011**
Storage Fixed Costs	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836
Storage Variable Costs	$ 2,497	$ 2,591	$ 2,644	$ 2,373	$ 2,629	$ 2,663	$ 3,019	$ 3,080	$ 2,740	$ 2,750
Total Storage Costs	**$ 25,333**	**$ 25,427**	**$ 25,480**	**$ 25,209**	**$ 25,465**	**$ 25,499**	**$ 25,855**	**$ 25,916**	**$ 25,576**	**$ 25,586**
DSM Annual Utility Costs ($2007)	**$ 17,504**	**$ 17,489**	**$ 17,488**	**$ 17,465**	**$ 5,573**	**$ 5,548**	**$ 5,548**	**$ 5,443**	**$ 5,361**	**$ 5,281**
Total Levelized DSM Costs	$ 855,411	$ 895,940	$ 884,919	$ 900,939	$ 947,991	$ 1,034,828	$ 1,097,264	$ 1,125,243	$ 1,162,610	$ 1,175,205
Grand Total System Costs	**$ 872,915**	**$ 913,430**	**$ 902,408**	**$ 918,404**	**$ 953,565**	**$ 1,040,376**	**$ 1,102,812**	**$ 1,130,685**	**$ 1,167,971**	**$ 1,180,486**

NPV @ 5.16% Discount Rate
5.16%
$ 10,454,792

1173 - Current Resources No DSM.xls

(BBtu / $000 Nominal)	2008-2009	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
Forecast Demand	72,331	73,722	74,329	75,720	76,566	77,765	78,927	80,823	81,785	83,264	84,853	86,819	88,085	89,936	91,578	93,477	94,419	95,893	97,552	99,522
DSM Impact	-	(218)	(449)	(761)	(1,117)	(1,541)	(2,009)	(2,542)	(3,064)	(3,721)	(4,333)	(4,975)	(5,495)	(6,071)	(6,504)	(6,883)	(7,179)	(7,549)	(7,886)	(8,245)
Total Annual Demand (net of DSM)	**72,331**	**73,504**	**73,880**	**74,959**	**75,449**	**76,224**	**76,917**	**78,280**	**78,721**	**79,543**	**80,520**	**81,844**	**82,590**	**83,865**	**85,074**	**86,593**	**87,240**	**88,343**	**89,666**	**91,277**
Annual Demand Served	72,331	73,501	73,876	74,959	75,449	76,224	76,917	78,280	78,721	79,543	80,520	81,844	82,590	83,865	85,074	86,593	87,240	88,343	89,666	91,277
Annual Demand Unserved	-	3	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Peak Day Demand (net of DSM)	**903**	**920**	**924**	**934**	**943**	**951**	**958**	**972**	**984**	**996**	**1,010**	**1,024**	**1,042**	**1,059**	**1,076**	**1,090**	**1,104**	**1,116**	**1,134**	**1,149**
Peak Day Demand Served	903	917	920	934	943	951	958	972	984	996	1,010	1,024	1,042	1,059	1,076	1,090	1,104	1,116	1,134	1,149
Peak Day Demand Unserved	-	3	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Supply Fixed Costs	$ 61	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59
Supply Variable Costs	$ 436,542	$ 481,982	$ 466,225	$ 541,346	$ 556,067	$ 594,663	$ 601,701	$ 612,190	$ 630,692	$ 650,140	$ 678,819	$ 705,133	$ 691,467	$ 704,985	$ 747,698	$ 830,202	$ 895,417	$ 925,309	$ 954,374	$ 981,582
Total Supply Costs	**$ 436,603**	**$ 482,041**	**$ 466,284**	**$ 541,405**	**$ 556,126**	**$ 594,722**	**$ 601,760**	**$ 612,249**	**$ 630,751**	**$ 650,199**	**$ 678,878**	**$ 705,192**	**$ 691,526**	**$ 705,043**	**$ 747,757**	**$ 830,261**	**$ 895,476**	**$ 925,368**	**$ 954,433**	**$ 981,641**
Transportation Fixed Costs	$ 83,187	$ 82,955	$ 82,955	$ 83,236	$ 83,788	$ 83,788	$ 83,788	$ 83,788	$ 85,171	$ 85,448	$ 85,448	$ 85,448	$ 85,472	$ 85,472	$ 85,472	$ 85,472	$ 85,523	$ 85,523	$ 85,523	$ 90,156
Transportation Variable Costs	$ 2,872	$ 2,905	$ 2,846	$ 3,032	$ 3,001	$ 3,041	$ 3,095	$ 3,145	$ 3,109	$ 3,150	$ 3,196	$ 3,264	$ 3,324	$ 3,383	$ 3,449	$ 3,529	$ 3,589	$ 3,697	$ 3,662	$ 3,771
Total Transportation Costs	**$ 86,058**	**$ 85,860**	**$ 85,801**	**$ 86,267**	**$ 86,789**	**$ 86,829**	**$ 86,883**	**$ 86,933**	**$ 88,280**	**$ 88,598**	**$ 88,644**	**$ 88,713**	**$ 88,797**	**$ 88,855**	**$ 88,922**	**$ 89,001**	**$ 89,112**	**$ 89,220**	**$ 89,186**	**$ 93,926**
Storage Fixed Costs	$ 23,080	$ 23,252	$ 23,497	$ 23,878	$ 24,015	$ 24,074	$ 24,478	$ 24,836	$ 25,197	$ 25,784	$ 26,420	$ 27,129	$ 27,905	$ 28,667	$ 29,351	$ 29,978	$ 30,594	$ 31,499	$ 31,971	$ 32,477
Storage Variable Costs	$ 2,411	$ 1,939	$ 1,574	$ 1,928	$ 2,086	$ 2,197	$ 2,201	$ 2,232	$ 2,317	$ 2,555	$ 2,544	$ 2,689	$ 2,902	$ 2,687	$ 3,031	$ 3,419	$ 4,097	$ 4,235	$ 3,881	$ 4,125
Total Storage Costs	**$ 25,491**	**$ 25,191**	**$ 25,071**	**$ 25,806**	**$ 26,100**	**$ 26,271**	**$ 26,679**	**$ 27,067**	**$ 27,515**	**$ 28,340**	**$ 28,964**	**$ 29,818**	**$ 30,807**	**$ 31,354**	**$ 32,382**	**$ 33,396**	**$ 34,690**	**$ 35,734**	**$ 35,852**	**$ 36,602**
DSM Annual Utility Costs ($2007)	**$ -**	**$ 7,853**	**$ 8,941**	**$ 10,394**	**$ 12,116**	**$ 13,843**	**$ 15,509**	**$ 17,297**	**$ 17,683**	**$ 17,793**	**$ 17,504**	**$ 17,489**	**$ 17,488**	**$ 17,465**	**$ 5,573**	**$ 5,548**	**$ 5,548**	**$ 5,443**	**$ 5,361**	**$ 5,281**
Total Levelized DSM Costs	$ -	$ 488	$ 1,051	$ 1,734	$ 2,559	$ 3,525	$ 4,622	$ 5,864	$ 7,213	$ 9,105	$ 10,716	$ 12,406	$ 13,921	$ 15,417	$ 16,833	$ 18,172	$ 19,511	$ 20,828	$ 22,146	$ 23,442
Grand Total System Costs	**$ 548,152**	**$ 600,945**	**$ 586,096**	**$ 663,872**	**$ 681,132**	**$ 721,665**	**$ 730,831**	**$ 743,546**	**$ 764,228**	**$ 784,930**	**$ 813,991**	**$ 841,212**	**$ 828,618**	**$ 842,718**	**$ 874,634**	**$ 958,207**	**$ 1,024,827**	**$ 1,055,764**	**$ 1,084,831**	**$ 1,117,449**

NPV @ 5.16% Discount Rate
5.16%
$ 9,937,096

Net Incremental Daily Citygate Deliverability	2008-2009	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
1 Mist Recall	-	11	11	25	32	32	35	47	47	57	70	83	98	114	129	142	155	168	193	197
2 Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3 Satellite LNG - Eugene	-	-	-	-	-	-	-	1	2	3	4	5	6	7	8	9	10	11	12	14
4 Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Incremental CD via Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15
8 Palomar East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9 Palomar West (Bradwood)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10 Pacific Connector East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11 Pacific Connector West (Jordan Cove)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12 Existing TF-1 Turnback	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Incremental Daily Citygate Capacity	**-**	**11**	**11**	**25**	**32**	**32**	**35**	**48**	**49**	**60**	**74**	**88**	**104**	**121**	**138**	**152**	**165**	**179**	**205**	**226**
Incremental Storage Capacity																				
Mist Recall	-	259	259	561	733	733	795	1,070	1,070	1,288	1,583	1,867	2,217	2,576	2,921	3,214	3,495	3,791	4,365	4,451
Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Satellite LNG - Eugene	-	-	-	-	-	-	-	3	6	9	12	15	18	22	25	28	31	34	37	43
Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Incremental Storage Capacity	**-**	**259**	**259**	**561**	**733**	**733**	**795**	**1,073**	**1,076**	**1,297**	**1,595**	**1,882**	**2,236**	**2,598**	**2,946**	**3,243**	**3,526**	**3,825**	**4,402**	**4,495**
Misc. Upstream & Downstream Components																				
Brownsville to Eugene	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Newport LNG Enhancement to Salem	-	-	-	-	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Incremental CD 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Opal to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Willamette Valley Feeder Components																				
Portland to Salem (Phase 1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Portland to Perrydale (Phase 2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Perrydale to Independence	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Independance to North Albany	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
North Albany to South Albany	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
South Albany to Halsey	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Halsey to Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

1177 - RMix 2 No Palomar.xls

(BBtu / $000 Nominal)	2008-2009	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
Forecast Demand	77,702	79,209	79,844	81,388	82,222	83,482	84,704	86,788	87,754	89,335	91,035	93,201	94,492	96,480	98,237	100,331	101,259	102,828	104,603	106,779
DSM Impact	-	(227)	(470)	(798)	(1,170)	(1,613)	(2,103)	(2,662)	(3,205)	(3,890)	(4,529)	(5,201)	(5,739)	(6,341)	(6,790)	(7,187)	(7,490)	(7,877)	(8,227)	(8,602)
Total Annual Demand (net of DSM)	**77,702**	**78,982**	**79,374**	**80,591**	**81,052**	**81,869**	**82,601**	**84,126**	**84,549**	**85,445**	**86,506**	**88,000**	**88,754**	**90,139**	**91,448**	**93,144**	**93,769**	**94,951**	**96,377**	**98,177**
Annual Demand Served	77,702	78,979	79,370	80,591	81,052	81,869	82,601	84,126	84,549	85,445	86,506	88,000	88,754	90,139	91,448	93,144	93,769	94,951	96,377	98,177
Annual Demand Unserved	-	3	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Peak Day Demand (net of DSM)	**904**	**921**	**925**	**935**	**945**	**952**	**960**	**973**	**985**	**997**	**1,012**	**1,025**	**1,043**	**1,060**	**1,077**	**1,091**	**1,106**	**1,118**	**1,135**	**1,150**
Peak Day Demand Served	904	918	921	935	945	952	960	973	985	997	1,012	1,025	1,043	1,060	1,077	1,091	1,106	1,118	1,135	1,150
Peak Day Demand Unserved	-	3	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Supply Fixed Costs	$ 61	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59
Supply Variable Costs	$ 489,464	$ 531,733	$ 512,359	$ 575,664	$ 597,013	$ 640,090	$ 649,112	$ 656,746	$ 676,688	$ 700,800	$ 731,510	$ 761,401	$ 744,912	$ 757,817	$ 797,349	$ 886,543	$ 952,123	$ 985,660	$ 1,021,947	$ 1,047,300
Total Supply Costs	**$ 489,525**	**$ 531,792**	**$ 512,418**	**$ 575,723**	**$ 597,072**	**$ 640,149**	**$ 649,171**	**$ 656,805**	**$ 676,747**	**$ 700,859**	**$ 731,569**	**$ 761,460**	**$ 744,971**	**$ 757,876**	**$ 797,408**	**$ 886,601**	**$ 952,182**	**$ 985,719**	**$ 1,022,006**	**$ 1,047,359**
Transportation Fixed Costs	$ 83,187	$ 82,955	$ 83,143	$ 88,134	$ 88,220	$ 88,517	$ 88,544	$ 88,544	$ 89,927	$ 90,205	$ 90,205	$ 90,205	$ 90,234	$ 90,234	$ 90,328	$ 91,329	$ 92,367	$ 94,643	$ 97,570	$ 102,714
Transportation Variable Costs	$ 3,147	$ 3,162	$ 3,128	$ 2,484	$ 2,451	$ 2,483	$ 2,511	$ 2,550	$ 2,598	$ 2,635	$ 2,663	$ 2,710	$ 2,727	$ 2,770	$ 2,800	$ 2,877	$ 2,909	$ 2,939	$ 2,950	$ 2,979
Total Transportation Costs	**$ 86,334**	**$ 86,117**	**$ 86,270**	**$ 90,617**	**$ 90,671**	**$ 91,000**	**$ 91,055**	**$ 91,094**	**$ 92,526**	**$ 92,840**	**$ 92,868**	**$ 92,914**	**$ 92,961**	**$ 93,004**	**$ 93,128**	**$ 94,206**	**$ 95,276**	**$ 97,583**	**$ 100,520**	**$ 105,693**
Storage Fixed Costs	$ 24,136	$ 25,056	$ 25,056	$ 25,056	$ 25,056	$ 25,244	$ 25,814	$ 26,224	$ 26,434	$ 27,116	$ 28,094	$ 29,206	$ 30,425	$ 31,592	$ 32,157	$ 32,323	$ 32,473	$ 32,534	$ 32,534	$ 32,901
Storage Variable Costs	$ 2,805	$ 2,189	$ 1,857	$ 2,228	$ 2,358	$ 2,539	$ 2,779	$ 2,774	$ 2,843	$ 3,094	$ 3,171	$ 3,309	$ 3,598	$ 3,537	$ 3,918	$ 4,085	$ 4,503	$ 4,620	$ 4,147	$ 4,357
Total Storage Costs	**$ 26,941**	**$ 27,245**	**$ 26,912**	**$ 27,284**	**$ 27,414**	**$ 27,782**	**$ 28,593**	**$ 28,999**	**$ 29,277**	**$ 30,210**	**$ 31,265**	**$ 32,515**	**$ 34,024**	**$ 35,129**	**$ 36,074**	**$ 36,409**	**$ 36,976**	**$ 37,154**	**$ 36,681**	**$ 37,258**
DSM Annual Utility Costs ($2007)	**$ -**	**$ 7,853**	**$ 8,941**	**$ 10,394**	**$ 12,116**	**$ 13,843**	**$ 15,509**	**$ 17,297**	**$ 17,683**	**$ 17,793**	**$ 17,504**	**$ 17,489**	**$ 17,488**	**$ 17,465**	**$ 5,573**	**$ 5,548**	**$ 5,548**	**$ 5,443**	**$ 5,361**	**$ 5,281**
Total Levelized DSM Costs	$ -	$ 868	$ 1,809	$ 3,055	$ 4,533	$ 6,235	$ 8,145	$ 10,277	$ 12,534	$ 15,329	$ 17,931	$ 20,598	$ 23,004	$ 25,377	$ 27,280	$ 28,889	$ 30,498	$ 32,067	$ 33,619	$ 35,128
Grand Total System Costs	**$ 602,800**	**$ 653,007**	**$ 634,541**	**$ 704,018**	**$ 727,273**	**$ 772,774**	**$ 784,328**	**$ 794,195**	**$ 816,233**	**$ 841,702**	**$ 873,206**	**$ 904,379**	**$ 889,444**	**$ 903,475**	**$ 932,184**	**$ 1,022,764**	**$ 1,089,981**	**$ 1,125,898**	**$ 1,164,569**	**$ 1,195,591**

NPV @ 5.16% Discount Rate
5.16%
$ 10,660,091

Net Incremental Daily Citygate Deliverability	2008-2009	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
1 Mist Recall	-	61	61	61	61	61	70	86	86	88	111	133	160	188	214	214	214	214	214	214
2 Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3 Satellite LNG - Eugene	-	-	-	-	-	-	-	1	2	3	4	5	6	7	8	9	10	11	11	13
4 Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Incremental CD via Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8 Palomar East	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	108	116	136
9 Palomar West (Bradwood)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10 Pacific Connector East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11 Pacific Connector West (Jordan Cove)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12 Existing TF-1 Turnback	-	-	-	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)
Total Incremental Daily Citygate Capacity	-	**61**	**61**	**84**	**84**	**84**	**93**	**110**	**111**	**114**	**138**	**161**	**189**	**219**	**246**	**246**	**247**	**256**	**266**	**286**
Incremental Storage Capacity																				
Mist Recall	-	1,380	1,380	1,380	1,380	1,380	1,579	1,933	1,933	1,990	2,499	2,996	3,623	4,255	4,837	4,837	4,837	4,837	4,837	4,837
Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Satellite LNG - Eugene	-	-	-	-	-	-	-	3	6	9	12	15	18	22	25	28	31	34	34	40
Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Incremental Storage Capacity	-	**1,380**	**1,380**	**1,380**	**1,380**	**1,380**	**1,579**	**1,936**	**1,939**	**1,999**	**2,511**	**3,011**	**3,642**	**4,277**	**4,862**	**4,865**	**4,868**	**4,870**	**4,870**	**4,877**
Misc. Upstream & Downstream Components																				
Brownsville to Eugene	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Newport LNG Enhancement to Salem	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Incremental CD 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
Opal to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Willamette Valley Feeder Components																				
Portland to Salem (Phase 1)	-	-	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Portland to Perrydale (Phase 2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Perrydale to Independence	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Independance to North Albany	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
North Albany to South Albany	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
South Albany to Halsey	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Halsey to Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

1179 - RMix 1 Coldest.xls

(BBtu / $000 Nominal)	2008-2009	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
Forecast Demand	72,331	73,030	74,255	75,416	76,523	78,818	81,079	83,964	86,041	88,712	91,530	94,781	97,233	100,250	103,105	106,303	108,441	111,134	113,970	117,218
DSM Impact	-	(218)	(463)	(793)	(1,175)	(1,633)	(2,142)	(2,726)	(3,307)	(4,069)	(4,778)	(5,530)	(6,143)	(6,822)	(7,363)	(7,859)	(8,261)	(8,752)	(9,206)	(9,697)
Total Annual Demand (net of DSM)	**72,331**	**72,812**	**73,792**	**74,623**	**75,348**	**77,186**	**78,936**	**81,238**	**82,734**	**84,643**	**86,752**	**89,251**	**91,090**	**93,428**	**95,742**	**98,444**	**100,180**	**102,383**	**104,764**	**107,521**
Annual Demand Served	72,331	72,810	73,789	74,623	75,348	77,186	78,936	81,238	82,734	84,643	86,752	89,251	91,090	93,428	95,742	98,444	100,180	102,383	104,764	107,521
Annual Demand Unserved	-	2	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Peak Day Demand (net of DSM)	**903**	**905**	**916**	**918**	**928**	**951**	**973**	**998**	**1,025**	**1,052**	**1,082**	**1,111**	**1,144**	**1,175**	**1,207**	**1,236**	**1,266**	**1,293**	**1,324**	**1,354**
Peak Day Demand Served	903	903	912	918	928	951	973	998	1,025	1,052	1,082	1,111	1,144	1,175	1,207	1,236	1,266	1,293	1,324	1,354
Peak Day Demand Unserved	-	2	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Supply Fixed Costs	$ 61	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59
Supply Variable Costs	$ 608,473	$ 651,004	$ 807,543	$ 1,056,016	$ 1,073,327	$ 1,134,285	$ 1,158,838	$ 1,188,479	$ 1,235,049	$ 1,276,029	$ 1,327,811	$ 1,380,641	$ 1,387,710	$ 1,425,028	$ 1,482,898	$ 1,593,918	$ 1,682,489	$ 1,730,357	$ 1,796,877	$ 1,859,829
Total Supply Costs	**$ 608,535**	**$ 651,063**	**$ 807,602**	**$ 1,056,075**	**$ 1,073,386**	**$ 1,134,343**	**$ 1,158,897**	**$ 1,188,538**	**$ 1,235,108**	**$ 1,276,088**	**$ 1,327,870**	**$ 1,380,700**	**$ 1,387,769**	**$ 1,425,087**	**$ 1,482,957**	**$ 1,593,977**	**$ 1,682,548**	**$ 1,730,416**	**$ 1,796,936**	**$ 1,859,888**
Transportation Fixed Costs	$ 83,187	$ 82,955	$ 83,174	$ 88,182	$ 88,931	$ 88,931	$ 88,955	$ 88,955	$ 90,338	$ 90,616	$ 90,803	$ 90,949	$ 91,527	$ 91,975	$ 91,975	$ 93,097	$ 97,092	$ 100,865	$ 105,379	$ 113,811
Transportation Variable Costs	$ 2,858	$ 2,879	$ 2,857	$ 2,300	$ 2,286	$ 2,347	$ 2,404	$ 2,467	$ 2,550	$ 2,607	$ 2,672	$ 2,754	$ 2,830	$ 2,915	$ 2,966	$ 3,044	$ 3,090	$ 3,157	$ 3,103	$ 3,404
Total Transportation Costs	**$ 86,045**	**$ 85,834**	**$ 86,031**	**$ 90,482**	**$ 91,217**	**$ 91,279**	**$ 91,359**	**$ 91,422**	**$ 92,888**	**$ 93,222**	**$ 93,476**	**$ 93,703**	**$ 94,356**	**$ 94,890**	**$ 94,941**	**$ 96,141**	**$ 100,182**	**$ 104,022**	**$ 108,482**	**$ 117,215**
Storage Fixed Costs	$ 22,914	$ 22,969	$ 23,045	$ 23,258	$ 23,507	$ 24,169	$ 25,296	$ 26,264	$ 27,310	$ 28,543	$ 29,793	$ 31,084	$ 32,571	$ 34,571	$ 36,156	$ 36,821	$ 37,405	$ 38,236	$ 38,639	$ 43,765
Storage Variable Costs	$ 3,064	$ 2,865	$ 2,558	$ 3,443	$ 3,882	$ 4,091	$ 4,274	$ 4,441	$ 4,598	$ 5,193	$ 5,355	$ 5,584	$ 6,295	$ 6,447	$ 6,980	$ 7,284	$ 7,519	$ 7,487	$ 6,921	$ 6,769
Total Storage Costs	**$ 25,979**	**$ 25,834**	**$ 25,603**	**$ 26,702**	**$ 27,389**	**$ 28,261**	**$ 29,571**	**$ 30,704**	**$ 31,908**	**$ 33,736**	**$ 35,147**	**$ 36,668**	**$ 38,866**	**$ 41,019**	**$ 43,135**	**$ 44,105**	**$ 44,924**	**$ 45,723**	**$ 45,560**	**$ 50,534**
DSM Annual Utility Costs ($2007)	**$ -**	**$ 7,853**	**$ 8,941**	**$ 10,394**	**$ 12,116**	**$ 13,843**	**$ 15,509**	**$ 17,297**	**$ 17,683**	**$ 17,793**	**$ 17,504**	**$ 17,489**	**$ 17,488**	**$ 17,465**	**$ 5,573**	**$ 5,548**	**$ 5,548**	**$ 5,443**	**$ 5,361**	**$ 5,281**
Total Levelized DSM Costs	$ -	$ 2,901	$ 6,432	$ 10,803	$ 16,077	$ 22,207	$ 29,169	$ 37,019	$ 45,476	$ 55,272	$ 64,938	$ 74,778	$ 84,355	$ 93,877	$ 103,007	$ 111,812	$ 120,664	$ 129,420	$ 138,198	$ 147,234
Grand Total System Costs	**$ 720,558**	**$ 770,583**	**$ 928,176**	**$ 1,183,652**	**$ 1,204,108**	**$ 1,267,725**	**$ 1,295,336**	**$ 1,327,962**	**$ 1,377,588**	**$ 1,420,839**	**$ 1,473,998**	**$ 1,528,562**	**$ 1,538,480**	**$ 1,578,461**	**$ 1,626,606**	**$ 1,739,771**	**$ 1,833,202**	**$ 1,885,604**	**$ 1,956,339**	**$ 2,032,918**

NPV @ 5.16% Discount Rate
5.16%
$ 17,244,826

Net Incremental Daily Citygate Deliverability	2008-2009	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
1 Mist Recall	-	4	4	8	15	21	40	63	75	99	123	148	173	207	259	279	279	279	279	279
2 Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	25
3 Satellite LNG - Eugene	-	-	-	-	-	-	2	4	6	8	10	12	15	17	19	21	23	28	30	30
4 Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	7
7 Incremental CD via Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8 Palomar East	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	114	128	142	172
9 Palomar West (Bradwood)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10 Pacific Connector East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11 Pacific Connector West (Jordan Cove)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12 Existing TF-1 Turnback	-	-	-	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)
Total Incremental Daily Citygate Capacity	**-**	**4**	**4**	**31**	**38**	**44**	**65**	**90**	**104**	**130**	**157**	**183**	**211**	**247**	**301**	**323**	**340**	**358**	**378**	**437**
Incremental Storage Capacity																				
Mist Recall	-	83	83	176	348	466	900	1,425	1,700	2,246	2,787	3,338	3,910	4,670	5,852	6,309	6,309	6,309	6,309	6,309
Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	76
Satellite LNG - Eugene	-	-	-	-	-	-	6	12	18	24	31	37	44	51	57	64	70	83	90	90
Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	22
Total Incremental Storage Capacity	**-**	**83**	**83**	**176**	**348**	**466**	**906**	**1,437**	**1,719**	**2,270**	**2,818**	**3,375**	**3,954**	**4,721**	**5,909**	**6,373**	**6,379**	**6,392**	**6,408**	**6,497**
Misc. Upstream & Downstream Components																				
Brownsville to Eugene	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Newport LNG Enhancement to Salem	-	-	-	-	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Incremental CD 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
Opal to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Willamette Valley Feeder Components																				
Portland to Salem (Phase 1)	-	-	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Portland to Perrydale (Phase 2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Perrydale to Independence	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Independance to North Albany	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
North Albany to South Albany	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
South Albany to Halsey	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Halsey to Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

1191 - RMix 1 High Growth High Price xls

(BBtu / $000 Nominal)	2008-2009	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
Forecast Demand	72,331	75,262	76,710	79,656	81,335	83,376	85,373	88,263	90,169	92,701	95,395	98,514	100,850	103,894	106,650	109,666	111,529	114,037	116,800	119,900
DSM Impact	-	(227)	(479)	(821)	(1,217)	(1,690)	(2,218)	(2,822)	(3,424)	(4,208)	(4,938)	(5,711)	(6,342)	(7,041)	(7,590)	(8,087)	(8,488)	(8,980)	(9,434)	(9,918)
Total Annual Demand (net of DSM)	**72,331**	**75,035**	**76,231**	**78,835**	**80,118**	**81,686**	**83,155**	**85,441**	**86,746**	**88,494**	**90,457**	**92,803**	**94,508**	**96,853**	**99,060**	**101,578**	**103,041**	**105,057**	**107,365**	**109,982**
Annual Demand Served	72,331	75,030	76,225	78,635	80,118	81,686	83,155	85,441	86,746	88,494	90,457	92,803	94,508	96,853	99,060	101,578	103,041	105,057	107,365	109,982
Annual Demand Unserved	-	5	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
Total Peak Day Demand (net of DSM)	**903**	**944**	**958**	**990**	**1,010**	**1,028**	**1,045**	**1,071**	**1,095**	**1,119**	**1,146**	**1,173**	**1,203**	**1,235**	**1,265**	**1,291**	**1,316**	**1,340**	**1,370**	**1,396**
Peak Day Demand Served	903	938	951	990	1,010	1,028	1,045	1,071	1,095	1,119	1,146	1,173	1,203	1,235	1,265	1,291	1,316	1,340	1,370	1,396
Peak Day Demand Unserved	-	5	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Supply Fixed Costs	$ 61	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59
Supply Variable Costs	$ 356,055	$ 400,883	$ 334,217	$ 381,010	$ 408,771	$ 454,806	$ 465,717	$ 481,373	$ 502,110	$ 530,804	$ 567,084	$ 599,804	$ 578,675	$ 597,404	$ 648,184	$ 746,404	$ 822,344	$ 865,481	$ 909,534	$ 937,147
Total Supply Costs	**$ 356,116**	**$ 400,942**	**$ 334,276**	**$ 381,069**	**$ 408,830**	**$ 454,864**	**$ 465,776**	**$ 481,432**	**$ 502,169**	**$ 530,863**	**$ 567,143**	**$ 599,863**	**$ 578,734**	**$ 597,463**	**$ 648,243**	**$ 746,463**	**$ 822,403**	**$ 865,540**	**$ 909,593**	**$ 937,206**
Transportation Fixed Costs	$ 83,187	$ 82,955	$ 83,174	$ 88,283	$ 89,037	$ 89,037	$ 89,426	$ 89,426	$ 90,809	$ 91,087	$ 91,087	$ 91,087	$ 91,329	$ 93,248	$ 96,645	$ 100,179	$ 103,418	$ 107,991	$ 114,539	$ 118,110
Transportation Variable Costs	$ 2,881	$ 2,900	$ 3,108	$ 2,401	$ 2,415	$ 2,472	$ 2,530	$ 2,591	$ 2,665	$ 2,731	$ 2,790	$ 2,861	$ 2,905	$ 3,015	$ 3,065	$ 3,110	$ 3,135	$ 3,199	$ 3,269	$ 3,458
Total Transportation Costs	**$ 86,068**	**$ 85,855**	**$ 86,282**	**$ 90,684**	**$ 91,452**	**$ 91,510**	**$ 91,956**	**$ 92,018**	**$ 93,474**	**$ 93,818**	**$ 93,877**	**$ 93,948**	**$ 94,234**	**$ 96,264**	**$ 99,709**	**$ 103,289**	**$ 106,552**	**$ 111,190**	**$ 117,807**	**$ 121,568**
Storage Fixed Costs	$ 23,912	$ 24,672	$ 25,497	$ 26,562	$ 26,930	$ 27,338	$ 28,286	$ 29,174	$ 30,101	$ 31,584	$ 33,421	$ 35,328	$ 36,348	$ 36,718	$ 37,240	$ 38,050	$ 38,952	$ 39,973	$ 40,505	$ 48,503
Storage Variable Costs	$ 2,382	$ 1,432	$ 1,281	$ 1,443	$ 1,692	$ 1,813	$ 1,827	$ 2,062	$ 2,118	$ 2,600	$ 2,671	$ 2,818	$ 2,841	$ 2,778	$ 3,102	$ 3,323	$ 3,861	$ 4,089	$ 3,395	$ 3,664
Total Storage Costs	**$ 26,293**	**$ 26,103**	**$ 26,778**	**$ 28,004**	**$ 28,623**	**$ 29,151**	**$ 30,113**	**$ 31,236**	**$ 32,219**	**$ 34,184**	**$ 36,092**	**$ 38,146**	**$ 39,189**	**$ 39,496**	**$ 40,341**	**$ 41,373**	**$ 42,813**	**$ 44,063**	**$ 43,900**	**$ 52,167**
DSM Annual Utility Costs ($2007)	**$ -**	**$ 7,853**	**$ 8,941**	**$ 10,394**	**$ 12,116**	**$ 13,843**	**$ 15,509**	**$ 17,297**	**$ 17,683**	**$ 17,793**	**$ 17,504**	**$ 17,489**	**$ 17,488**	**$ 17,465**	**$ 5,573**	**$ 5,548**	**$ 5,548**	**$ 5,443**	**$ 5,361**	**$ 5,281**
Total Levelized DSM Costs	$ -	$ 910	$ 1,942	$ 3,321	$ 4,979	$ 6,905	$ 9,082	$ 11,533	$ 14,165	$ 17,586	$ 20,745	$ 24,026	$ 26,977	$ 29,903	$ 32,350	$ 34,490	$ 36,640	$ 38,753	$ 40,857	$ 42,923
Grand Total System Costs	**$ 468,477**	**$ 520,754**	**$ 456,276**	**$ 510,151**	**$ 541,021**	**$ 589,368**	**$ 603,354**	**$ 621,983**	**$ 645,546**	**$ 676,658**	**$ 714,617**	**$ 749,446**	**$ 729,645**	**$ 750,688**	**$ 793,867**	**$ 896,674**	**$ 977,316**	**$ 1,026,235**	**$ 1,076,661**	**$ 1,116,222**

NPV @ 5.16% Discount Rate	
	5.16%
$	8,664,964

Net Incremental Daily Citygate Deliverability	2008-2009	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
1 Mist Recall	-	50	50	74	91	92	101	124	134	155	194	237	279	279	279	279	279	279	279	279
2 Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	30
3 Satellite LNG - Eugene	-	-	-	4	4	5	6	8	10	12	14	16	18	21	23	27	30	30	30	30
4 Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	7	7	30
7 Incremental CD via Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8 Palomar East	-	-	-	100	100	100	100	100	100	100	100	100	100	100	112	125	136	152	176	186
9 Palomar West (Bradwood)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10 Pacific Connector East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11 Pacific Connector West (Jordan Cove)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12 Existing TF-1 Turnback	-	-	-	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)
Total Incremental Daily Citygate Capacity	**-**	**50**	**50**	**102**	**118**	**119**	**131**	**155**	**167**	**191**	**231**	**276**	**321**	**323**	**337**	**353**	**370**	**392**	**422**	**478**
Incremental Storage Capacity																				
Mist Recall	-	1,141	1,141	1,679	2,058	2,072	2,291	2,803	3,021	3,511	4,383	5,354	6,309	6,309	6,309	6,309	6,309	6,309	6,309	6,309
Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	90
Satellite LNG - Eugene	-	-	-	13	13	14	19	25	31	37	43	48	55	62	68	80	90	90	90	90
Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	21	21	90
Total Incremental Storage Capacity	**-**	**1,141**	**1,141**	**1,692**	**2,071**	**2,086**	**2,310**	**2,828**	**3,052**	**3,547**	**4,426**	**5,402**	**6,364**	**6,371**	**6,377**	**6,389**	**6,405**	**6,420**	**6,440**	**6,579**
Misc. Upstream & Downstream Components																				
Brownsville to Eugene	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Newport LNG Enhancement to Salem	-	-	-	-	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Incremental CD 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4
Opal to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Willamette Valley Feeder Components																				
Portland to Salem (Phase 1)	-	-	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Portland to Perrydale (Phase 2)	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Perrydale to Independence	-	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Independance to North Albany	-	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
North Albany to South Albany	-	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
South Albany to Halsey	-	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Halsey to Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

1192 - RMix 1 High Growth Low Price.xls

(BBtu / $000 Nominal)	2008-2009	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
Forecast Demand	72,331	73,811	73,744	74,950	74,776	74,919	75,034	75,917	75,800	76,107	76,489	77,194	77,301	77,963	78,417	79,071	78,914	79,235	79,742	80,483
DSM Impact	-	(209)	(422)	(708)	(1,028)	(1,406)	(1,820)	(2,286)	(2,734)	(3,267)	(3,767)	(4,282)	(4,695)	(5,153)	(5,472)	(5,737)	(5,930)	(6,182)	(6,403)	(6,639)
Total Annual Demand (net of DSM)	**72,331**	**73,602**	**73,321**	**74,242**	**73,747**	**73,513**	**73,214**	**73,631**	**73,066**	**72,840**	**72,722**	**72,912**	**72,606**	**72,810**	**72,945**	**73,333**	**72,984**	**73,053**	**73,339**	**73,844**
Annual Demand Served	72,331	73,599	73,318	74,242	73,747	73,513	73,214	73,631	73,066	72,840	72,722	72,912	72,606	72,810	72,945	73,333	72,984	73,053	73,339	73,844
Annual Demand Unserved	-	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Peak Day Demand (net of DSM)	**903**	**925**	**920**	**931**	**927**	**921**	**915**	**916**	**914**	**912**	**911**	**910**	**913**	**916**	**918**	**918**	**919**	**917**	**921**	**923**
Peak Day Demand Served	903	922	917	931	927	921	915	916	914	912	911	910	913	916	918	918	919	917	921	923
Peak Day Demand Unserved	-	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Supply Fixed Costs	$ 61	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59
Supply Variable Costs	$ 351,695	$ 390,875	$ 312,936	$ 355,002	$ 371,434	$ 401,787	$ 397,901	$ 401,645	$ 408,081	$ 415,191	$ 432,734	$ 448,509	$ 426,554	$ 430,854	$ 463,687	$ 519,928	$ 565,706	$ 584,053	$ 601,184	$ 615,961
Total Supply Costs	**$ 351,756**	**$ 390,934**	**$ 312,995**	**$ 355,061**	**$ 371,493**	**$ 401,846**	**$ 397,960**	**$ 401,704**	**$ 408,140**	**$ 415,250**	**$ 432,793**	**$ 448,568**	**$ 426,613**	**$ 430,912**	**$ 463,746**	**$ 519,987**	**$ 565,765**	**$ 584,112**	**$ 601,243**	**$ 616,020**
Transportation Fixed Costs	$ 83,187	$ 82,955	$ 82,955	$ 87,673	$ 87,673	$ 87,673	$ 87,673	$ 87,673	$ 89,056	$ 89,333	$ 89,333	$ 89,333	$ 89,333	$ 89,333	$ 89,333	$ 89,333	$ 89,333	$ 89,333	$ 89,333	$ 89,333
Transportation Variable Costs	$ 2,859	$ 2,824	$ 2,904	$ 2,273	$ 2,235	$ 2,231	$ 2,204	$ 2,229	$ 2,267	$ 2,242	$ 2,254	$ 2,269	$ 2,198	$ 2,233	$ 2,269	$ 2,240	$ 2,238	$ 2,224	$ 2,235	$ 2,279
Total Transportation Costs	**$ 86,045**	**$ 85,779**	**$ 85,859**	**$ 89,946**	**$ 89,908**	**$ 89,904**	**$ 89,877**	**$ 89,902**	**$ 91,323**	**$ 91,575**	**$ 91,587**	**$ 91,603**	**$ 91,532**	**$ 91,566**	**$ 91,603**	**$ 91,573**	**$ 91,572**	**$ 91,557**	**$ 91,569**	**$ 91,612**
Storage Fixed Costs	$ 23,273	$ 23,581	$ 23,581	$ 23,581	$ 23,581	$ 23,581	$ 23,581	$ 23,581	$ 23,581	$ 23,581	$ 23,581	$ 23,581	$ 23,581	$ 23,581	$ 23,581	$ 23,581	$ 23,581	$ 23,581	$ 23,581	$ 23,581
Storage Variable Costs	$ 2,291	$ 1,347	$ 1,125	$ 1,284	$ 1,577	$ 1,555	$ 1,557	$ 1,533	$ 1,609	$ 1,690	$ 1,744	$ 1,821	$ 1,654	$ 1,707	$ 2,039	$ 2,075	$ 2,438	$ 2,256	$ 2,274	$ 2,555
Total Storage Costs	**$ 25,563**	**$ 24,928**	**$ 24,706**	**$ 24,865**	**$ 25,158**	**$ 25,136**	**$ 25,138**	**$ 25,114**	**$ 25,190**	**$ 25,271**	**$ 25,325**	**$ 25,402**	**$ 25,236**	**$ 25,288**	**$ 25,620**	**$ 25,656**	**$ 26,019**	**$ 25,837**	**$ 25,855**	**$ 26,136**
DSM Annual Utility Costs ($2007)	**$ -**	**$ 7,853**	**$ 8,941**	**$ 10,394**	**$ 12,116**	**$ 13,843**	**$ 15,509**	**$ 17,297**	**$ 17,683**	**$ 17,793**	**$ 17,504**	**$ 17,489**	**$ 17,488**	**$ 17,465**	**$ 5,573**	**$ 5,548**	**$ 5,548**	**$ 5,443**	**$ 5,361**	**$ 5,281**
Total Levelized DSM Costs	$ -	$ 826	$ 1,675	$ 2,790	$ 4,087	$ 5,565	$ 7,207	$ 9,022	$ 10,903	$ 13,073	$ 15,116	$ 17,169	$ 19,030	$ 20,850	$ 22,211	$ 23,289	$ 24,357	$ 25,381	$ 26,380	$ 27,333
Grand Total System Costs	**$ 463,365**	**$ 509,495**	**$ 432,501**	**$ 480,266**	**$ 498,676**	**$ 530,728**	**$ 528,483**	**$ 534,018**	**$ 542,337**	**$ 549,890**	**$ 567,210**	**$ 583,062**	**$ 560,869**	**$ 565,232**	**$ 586,542**	**$ 642,765**	**$ 688,905**	**$ 706,949**	**$ 724,027**	**$ 739,049**

NPV @ 5.16% Discount Rate
5.16%
$ 7,107,262

Net Incremental Daily Citygate Deliverability	2008-2009	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
1 Mist Recall	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
2 Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3 Satellite LNG - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4 Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Incremental CD via Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8 Palomar East	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
9 Palomar West (Bradwood)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10 Pacific Connector East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11 Pacific Connector West (Jordan Cove)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12 Existing TF-1 Turnback	-	-	-	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)
Total Incremental Daily Citygate Capacity	-	**20**	**20**	**43**	**43**	**43**	**43**	**43**	**43**	**43**	**43**	**43**	**43**	**43**	**43**	**43**	**43**	**43**	**43**	**43**
Incremental Storage Capacity																				
Mist Recall	-	463	463	463	463	463	463	463	463	463	463	463	463	463	463	463	463	463	463	463
Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Satellite LNG - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Incremental Storage Capacity	-	**463**	**463**	**463**	**463**	**463**	**463**	**463**	**463**	**463**	**463**	**463**	**463**	**463**	**463**	**463**	**463**	**463**	**463**	**463**
Misc. Upstream & Downstream Components																				
Brownsville to Eugene	-	-	-	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Newport LNG Enhancement to Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incremental CD 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Opal to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Willamette Valley Feeder Components																				
Portland to Salem (Phase 1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Portland to Perrydale (Phase 2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Perrydale to Independence	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Independance to North Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Albany to South Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
South Albany to Halsey	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Halsey to Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

1194 - RMix 1 Low Growth Low Price.xls

(BBtu / $000 Nominal)	2008-2009	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
Forecast Demand	72,331	71,623	71,387	70,968	70,364	70,838	71,277	72,241	72,351	72,854	73,413	74,292	74,552	75,253	75,836	76,670	76,752	77,240	77,832	78,704
DSM Impact	-	(209)	(422)	(708)	(1,028)	(1,406)	(1,820)	(2,286)	(2,734)	(3,267)	(3,767)	(4,282)	(4,695)	(5,153)	(5,472)	(5,737)	(5,930)	(6,182)	(6,403)	(6,639)
Total Annual Demand (net of DSM)	**72,331**	**71,414**	**70,965**	**70,260**	**69,335**	**69,432**	**69,457**	**69,954**	**69,617**	**69,587**	**69,646**	**70,010**	**69,857**	**70,100**	**70,363**	**70,932**	**70,821**	**71,058**	**71,429**	**72,066**
Annual Demand Served	72,331	71,413	70,965	70,260	69,335	69,432	69,457	69,954	69,617	69,587	69,646	70,010	69,857	70,100	70,363	70,932	70,821	71,058	71,429	72,066
Annual Demand Unserved	-	1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Peak Day Demand (net of DSM)	**903**	**887**	**880**	**863**	**852**	**852**	**851**	**854**	**856**	**857**	**859**	**862**	**867**	**871**	**875**	**878**	**883**	**884**	**889**	**894**
Peak Day Demand Served	903	887	880	863	852	852	851	854	856	857	859	862	867	871	875	878	883	884	889	894
Peak Day Demand Unserved	-	1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Supply Fixed Costs	$ 61	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59
Supply Variable Costs	$ 607,736	$ 636,307	$ 767,903	$ 1,003,678	$ 991,493	$ 1,021,444	$ 1,020,374	$ 1,029,322	$ 1,043,710	$ 1,054,534	$ 1,072,527	$ 1,089,530	$ 1,070,560	$ 1,077,964	$ 1,109,048	$ 1,174,084	$ 1,216,987	$ 1,227,409	$ 1,244,206	$ 1,291,703
Total Supply Costs	**$ 607,797**	**$ 636,366**	**$ 767,962**	**$ 1,003,737**	**$ 991,552**	**$ 1,021,503**	**$ 1,020,432**	**$ 1,029,380**	**$ 1,043,769**	**$ 1,054,593**	**$ 1,072,586**	**$ 1,089,589**	**$ 1,070,619**	**$ 1,078,023**	**$ 1,109,107**	**$ 1,174,143**	**$ 1,217,046**	**$ 1,227,468**	**$ 1,244,265**	**$ 1,291,762**
Transportation Fixed Costs	$ 83,187	$ 82,955	$ 82,955	$ 87,668	$ 87,668	$ 87,668	$ 87,668	$ 87,668	$ 89,052	$ 89,329	$ 89,329	$ 89,329	$ 89,329	$ 89,329	$ 89,329	$ 89,329	$ 89,329	$ 89,329	$ 89,329	$ 89,329
Transportation Variable Costs	$ 2,855	$ 2,808	$ 2,702	$ 2,178	$ 2,097	$ 2,100	$ 2,083	$ 2,115	$ 2,130	$ 2,123	$ 2,127	$ 2,139	$ 2,128	$ 2,148	$ 2,161	$ 2,161	$ 2,160	$ 2,197	$ 2,144	$ 2,226
Total Transportation Costs	**$ 86,042**	**$ 85,763**	**$ 85,657**	**$ 89,846**	**$ 89,766**	**$ 89,768**	**$ 89,751**	**$ 89,784**	**$ 91,182**	**$ 91,452**	**$ 91,456**	**$ 91,468**	**$ 91,457**	**$ 91,477**	**$ 91,490**	**$ 91,490**	**$ 91,489**	**$ 91,526**	**$ 91,473**	**$ 91,555**
Storage Fixed Costs	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836	$ 22,836
Storage Variable Costs	$ 3,044	$ 2,844	$ 2,485	$ 3,289	$ 3,731	$ 3,824	$ 3,872	$ 3,796	$ 3,998	$ 4,200	$ 4,179	$ 4,396	$ 4,306	$ 4,215	$ 4,567	$ 4,480	$ 5,234	$ 4,928	$ 4,405	$ 4,749
Total Storage Costs	**$ 25,880**	**$ 25,680**	**$ 25,321**	**$ 26,125**	**$ 26,567**	**$ 26,660**	**$ 26,708**	**$ 26,632**	**$ 26,834**	**$ 27,036**	**$ 27,015**	**$ 27,232**	**$ 27,142**	**$ 27,051**	**$ 27,403**	**$ 27,316**	**$ 28,070**	**$ 27,764**	**$ 27,241**	**$ 27,585**
DSM Annual Utility Costs ($2007)	**$ -**	**$ 7,853**	**$ 8,941**	**$ 10,394**	**$ 12,116**	**$ 13,843**	**$ 15,509**	**$ 17,297**	**$ 17,683**	**$ 17,793**	**$ 17,504**	**$ 17,489**	**$ 17,488**	**$ 17,465**	**$ 5,573**	**$ 5,548**	**$ 5,548**	**$ 5,443**	**$ 5,361**	**$ 5,281**
Total Levelized DSM Costs	$ -	$ 826	$ 1,675	$ 2,790	$ 4,087	$ 5,565	$ 7,207	$ 9,022	$ 10,903	$ 13,073	$ 15,116	$ 17,169	$ 19,030	$ 20,850	$ 22,211	$ 23,289	$ 24,357	$ 25,381	$ 26,380	$ 27,333
Grand Total System Costs	**$ 719,719**	**$ 755,662**	**$ 887,880**	**$ 1,130,102**	**$ 1,120,001**	**$ 1,151,775**	**$ 1,152,400**	**$ 1,163,093**	**$ 1,179,468**	**$ 1,190,874**	**$ 1,208,561**	**$ 1,225,779**	**$ 1,206,706**	**$ 1,214,017**	**$ 1,233,574**	**$ 1,298,497**	**$ 1,342,154**	**$ 1,352,201**	**$ 1,368,339**	**$ 1,416,183**

NPV @ 5.16% Discount Rate
5.16%
$ 14,459,669

Net Incremental Daily Citygate Deliverability	2008-2009	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
1 Mist Recall	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2 Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3 Satellite LNG - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4 Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Incremental CD via Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8 Palomar East	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
9 Palomar West (Bradwood)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10 Pacific Connector East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11 Pacific Connector West (Jordan Cove)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12 Existing TF-1 Turnback	-	-	-	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)
Total Incremental Daily Citygate Capacity	-	-	-	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**
Incremental Storage Capacity																				
Mist Recall	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Satellite LNG - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Incremental Storage Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Misc. Upstream & Downstream Components																				
Brownsville to Eugene	-	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Newport LNG Enhancement to Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incremental CD 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Opal to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Willamette Valley Feeder Components																				
Portland to Salem (Phase 1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Portland to Perrydale (Phase 2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Perrydale to Independence	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Independance to North Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Albany to South Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
South Albany to Halsey	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Halsey to Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

1195 - RMix 1 Low Growth High Price xls

(BBtu / $000 Nominal)	2008-2009	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
Forecast Demand	72,331	74,537	75,227	77,303	78,055	79,147	80,204	82,090	82,984	84,404	85,942	87,854	89,075	90,929	92,533	94,368	95,222	96,636	98,271	100,191
DSM Impact	-	(218)	(451)	(764)	(1,123)	(1,548)	(2,019)	(2,554)	(3,079)	(3,737)	(4,352)	(4,997)	(5,518)	(6,097)	(6,531)	(6,912)	(7,209)	(7,581)	(7,919)	(8,278)
Total Annual Demand (net of DSM)	**72,331**	**74,319**	**74,776**	**76,539**	**76,933**	**77,600**	**78,185**	**79,536**	**79,906**	**80,667**	**81,589**	**82,857**	**83,557**	**84,832**	**86,002**	**87,456**	**88,013**	**89,055**	**90,352**	**91,913**
Annual Demand Served	72,331	74,315	74,772	76,539	76,933	77,600	78,185	79,536	79,906	80,667	81,589	82,857	83,557	84,832	86,002	87,456	88,013	89,055	90,352	91,913
Annual Demand Unserved	-	4	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Peak Day Demand (net of DSM)	**903**	**934**	**939**	**961**	**969**	**975**	**980**	**993**	**1,004**	**1,015**	**1,029**	**1,041**	**1,058**	**1,075**	**1,091**	**1,104**	**1,118**	**1,129**	**1,146**	**1,160**
Peak Day Demand Served	903	930	934	961	969	975	980	993	1,004	1,015	1,029	1,041	1,058	1,075	1,091	1,104	1,118	1,129	1,146	1,160
Peak Day Demand Unserved	-	4	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Supply Fixed Costs	$ 61	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59
Supply Variable Costs	$ 354,000	$ 396,387	$ 322,666	$ 367,779	$ 390,418	$ 427,408	$ 432,809	$ 440,694	$ 454,764	$ 471,983	$ 498,920	$ 522,096	$ 506,010	$ 517,440	$ 559,328	$ 636,558	$ 698,977	$ 724,570	$ 761,177	$ 776,750
Total Supply Costs	**$ 354,061**	**$ 396,446**	**$ 322,725**	**$ 367,838**	**$ 390,477**	**$ 427,467**	**$ 432,868**	**$ 440,753**	**$ 454,823**	**$ 472,042**	**$ 498,979**	**$ 522,154**	**$ 506,069**	**$ 517,499**	**$ 559,387**	**$ 636,617**	**$ 699,036**	**$ 724,628**	**$ 761,236**	**$ 776,809**
Transportation Fixed Costs	$ 83,187	$ 82,955	$ 82,955	$ 87,934	$ 88,425	$ 88,425	$ 88,425	$ 88,425	$ 89,808	$ 90,085	$ 90,085	$ 90,110	$ 90,443	$ 90,443	$ 90,443	$ 90,443	$ 90,443	$ 90,443	$ 91,058	$ 92,605
Transportation Variable Costs	$ 2,871	$ 2,867	$ 2,996	$ 2,332	$ 2,324	$ 2,341	$ 2,371	$ 2,398	$ 2,452	$ 2,476	$ 2,505	$ 2,541	$ 2,565	$ 2,603	$ 2,640	$ 2,675	$ 2,696	$ 2,732	$ 2,790	$ 2,855
Total Transportation Costs	**$ 86,057**	**$ 85,822**	**$ 85,951**	**$ 90,266**	**$ 90,749**	**$ 90,766**	**$ 90,796**	**$ 90,823**	**$ 92,260**	**$ 92,561**	**$ 92,590**	**$ 92,650**	**$ 93,008**	**$ 93,046**	**$ 93,083**	**$ 93,118**	**$ 93,139**	**$ 93,175**	**$ 93,848**	**$ 95,460**
Storage Fixed Costs	$ 23,611	$ 24,159	$ 24,506	$ 24,939	$ 25,047	$ 25,063	$ 25,428	$ 25,773	$ 26,080	$ 26,609	$ 27,192	$ 27,749	$ 28,437	$ 29,181	$ 29,821	$ 30,406	$ 31,167	$ 31,642	$ 31,729	$ 33,131
Storage Variable Costs	$ 2,336	$ 1,404	$ 1,194	$ 1,355	$ 1,652	$ 1,648	$ 1,669	$ 1,697	$ 1,736	$ 1,987	$ 1,941	$ 2,168	$ 2,141	$ 2,044	$ 2,478	$ 2,830	$ 3,379	$ 3,444	$ 3,131	$ 3,397
Total Storage Costs	**$ 25,947**	**$ 25,563**	**$ 25,700**	**$ 26,293**	**$ 26,699**	**$ 26,711**	**$ 27,096**	**$ 27,470**	**$ 27,817**	**$ 28,596**	**$ 29,133**	**$ 29,917**	**$ 30,577**	**$ 31,225**	**$ 32,300**	**$ 33,235**	**$ 34,546**	**$ 35,086**	**$ 34,860**	**$ 36,528**
DSM Annual Utility Costs ($2007)	**$ -**	**$ 7,853**	**$ 8,941**	**$ 10,394**	**$ 12,116**	**$ 13,843**	**$ 15,509**	**$ 17,297**	**$ 17,683**	**$ 17,793**	**$ 17,504**	**$ 17,489**	**$ 17,488**	**$ 17,465**	**$ 5,573**	**$ 5,548**	**$ 5,548**	**$ 5,443**	**$ 5,361**	**$ 5,281**
Total Levelized DSM Costs	$ -	$ 868	$ 1,809	$ 3,055	$ 4,533	$ 6,235	$ 8,145	$ 10,277	$ 12,534	$ 15,329	$ 17,931	$ 20,598	$ 23,004	$ 25,377	$ 27,280	$ 28,889	$ 30,498	$ 32,067	$ 33,619	$ 35,128
Grand Total System Costs	**$ 466,066**	**$ 515,684**	**$ 443,316**	**$ 494,792**	**$ 520,042**	**$ 558,786**	**$ 566,269**	**$ 576,342**	**$ 592,583**	**$ 610,993**	**$ 638,207**	**$ 662,212**	**$ 647,143**	**$ 659,235**	**$ 690,344**	**$ 768,519**	**$ 832,270**	**$ 858,332**	**$ 895,305**	**$ 914,079**
Net Incremental Daily Citygate Deliverability	2008-2009	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
1 Mist Recall	-	36	36	48	54	54	55	67	67	75	87	98	108	124	138	150	162	183	183	196
2 Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3 Satellite LNG - Eugene	-	-	-	1	1	1	1	2	3	4	5	6	7	8	9	10	11	12	13	18
4 Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0
7 Incremental CD via Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8 Palomar East	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
9 Palomar West (Bradwood)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10 Pacific Connector East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11 Pacific Connector West (Jordan Cove)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12 Existing TF-1 Turnback	-	-	-	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)
Total Incremental Daily Citygate Capacity	**-**	**36**	**36**	**73**	**79**	**79**	**79**	**92**	**93**	**102**	**115**	**127**	**138**	**155**	**171**	**184**	**196**	**218**	**219**	**238**
Incremental Storage Capacity																				
Mist Recall	-	822	822	1,092	1,227	1,227	1,244	1,511	1,511	1,686	1,961	2,215	2,436	2,795	3,126	3,395	3,664	4,138	4,138	4,431
Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Satellite LNG - Eugene	-	-	-	4	4	4	4	7	10	12	15	18	22	25	28	31	34	36	39	54
Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
Total Incremental Storage Capacity	**-**	**822**	**822**	**1,096**	**1,231**	**1,231**	**1,248**	**1,518**	**1,521**	**1,698**	**1,976**	**2,233**	**2,458**	**2,820**	**3,154**	**3,426**	**3,698**	**4,174**	**4,177**	**4,487**
Misc. Upstream & Downstream Components																				
Brownsville to Eugene	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Newport LNG Enhancement to Salem	-	-	-	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Incremental CD 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Opal to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Willamette Valley Feeder Components																				
Portland to Salem (Phase 1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Portland to Perrydale (Phase 2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Perrydale to Independence	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Independance to North Albany	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
North Albany to South Albany	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
South Albany to Halsey	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Halsey to Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

NPV @ 5.16% Discount Rate
5.16%
$ 7,867,476

1196 - RMix 1 Low Price.xls

(BBtu / $000 Nominal)	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018
Forecast Demand	72,331	74,392	74,778	76,303	76,191	76,362	76,622	78,695	80,502	82,646
DSM Impact	-	(216)	(442)	(741)	(1,069)	(1,455)	(1,882)	(2,407)	(2,958)	(3,636)
Total Annual Demand (net of DSM)	**72,331**	**74,175**	**74,336**	**75,563**	**75,122**	**74,907**	**74,740**	**76,288**	**77,544**	**79,009**
Annual Demand Served	72,331	74,171	74,332	75,563	75,122	74,907	74,740	76,288	77,544	79,009
Annual Demand Unserved	-	4	4	-	-	-	-	-	-	-
Total Peak Day Demand (net of DSM)	**903**	**932**	**933**	**948**	**945**	**939**	**935**	**951**	**974**	**994**
Peak Day Demand Served	903	928	929	948	945	939	935	951	974	994
Peak Day Demand Unserved	-	4	4	-	-	-	-	-	-	-
Supply Fixed Costs	$ 61	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59
Supply Variable Costs	$ 353,605	$ 395,357	$ 318,727	$ 361,722	$ 379,821	$ 410,306	$ 407,599	$ 419,922	$ 440,619	$ 461,780
Total Supply Costs	**$ 353,666**	**$ 395,416**	**$ 318,786**	**$ 361,781**	**$ 379,880**	**$ 410,365**	**$ 407,658**	**$ 419,981**	**$ 440,678**	**$ 461,839**
Transportation Fixed Costs	$ 83,187	$ 82,955	$ 82,955	$ 87,686	$ 88,076	$ 88,076	$ 88,076	$ 88,076	$ 89,459	$ 89,736
Transportation Variable Costs	$ 2,869	$ 2,860	$ 2,957	$ 2,304	$ 2,277	$ 2,268	$ 2,251	$ 2,315	$ 2,398	$ 2,441
Total Transportation Costs	**$ 86,055**	**$ 85,814**	**$ 85,911**	**$ 89,989**	**$ 90,353**	**$ 90,343**	**$ 90,327**	**$ 90,391**	**$ 91,857**	**$ 92,177**
Storage Fixed Costs	$ 23,554	$ 24,061	$ 24,141	$ 24,218	$ 24,218	$ 24,218	$ 24,272	$ 24,507	$ 25,195	$ 26,151
Storage Variable Costs	$ 2,327	$ 1,394	$ 1,159	$ 1,317	$ 1,612	$ 1,588	$ 1,577	$ 1,596	$ 1,665	$ 1,933
Total Storage Costs	**$ 25,881**	**$ 25,455**	**$ 25,301**	**$ 25,535**	**$ 25,890**	**$ 25,806**	**$ 25,849**	**$ 26,103**	**$ 26,860**	**$ 28,084**
DSM Annual Utility Costs ($2007)	**$ -**	**$ 7,853**	**$ 8,941**	**$ 10,394**	**$ 12,116**	**$ 13,843**	**$ 15,509**	**$ 17,297**	**$ 17,683**	**$ 17,793**
Total Levelized DSM Costs	$ -	$ 860	$ 1,768	$ 2,943	$ 4,279	$ 5,793	$ 7,495	$ 9,588	$ 11,973	$ 14,862
Grand Total System Costs	**$ 465,602**	**$ 514,539**	**$ 438,938**	**$ 487,699**	**$ 508,179**	**$ 540,356**	**$ 539,343**	**$ 553,772**	**$ 577,078**	**$ 599,894**
Net Incremental Daily Citygate Deliverability	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018
1 Mist Recall	-	34	34	37	37	37	37	37	38	56
2 Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-
3 Satellite LNG - Eugene	-	-	-	0	0	0	0	1	3	4
4 Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-
7 Incremental CD via Stanfield	-	-	-	-	-	-	-	-	-	-
8 Palomar East	-	-	-	100	100	100	100	100	100	100
9 Palomar West (Bradwood)	-	-	-	-	-	-	-	-	-	-
10 Pacific Connector East	-	-	-	-	-	-	-	-	-	-
11 Pacific Connector West (Jordan Cove)	-	-	-	-	-	-	-	-	-	-
12 Existing TF-1 Turnback	-	-	-	(77)	(77)	(77)	(77)	(77)	(77)	(77)
Total Incremental Daily Citygate Capacity	**-**	**34**	**34**	**60**	**60**	**60**	**60**	**61**	**64**	**83**
Incremental Storage Capacity										
Mist Recall	-	761	761	838	838	838	838	838	857	1,264
Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-
Satellite LNG - Eugene	-	-	-	1	1	1	1	2	8	13
Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-
Total Incremental Storage Capacity	**-**	**761**	**761**	**838**	**838**	**838**	**838**	**840**	**865**	**1,276**
Misc. Upstream & Downstream Components										
Brownsville to Eugene	-	-	-	5	5	5	5	5	5	5
Newport LNG Enhancement to Salem	-	-	-	-	10	10	10	10	10	10
Incremental CD 12-9	-	-	-	-	-	-	-	-	-	-
Opal to Stanfield	-	-	-	-	-	-	-	-	-	-
Malin to Stanfield	-	-	-	-	-	-	-	-	-	-
Willamette Valley Feeder Components										
Portland to Salem (Phase 1)	-	-	-	-	-	-	-	-	-	-
Portland to Perrydale (Phase 2)	-	-	-	-	-	-	-	-	-	-
Perrydale to Independence	-	-	-	-	-	-	-	-	-	-
Independance to North Albany	-	-	-	-	-	-	-	-	-	-
North Albany to South Albany	-	-	-	-	-	-	-	-	-	-
South Albany to Halsey	-	-	-	-	-	-	-	-	-	-
Halsey to Eugene	-	-	-	-	-	-	-	-	-	-

(BBtu / $000 Nominal)	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Forecast Demand	84,800	87,283	89,075	90,929	92,533	94,368	95,222	96,636	98,271	100,191
DSM Impact	(4,280)	(4,958)	(5,518)	(6,097)	(6,531)	(6,912)	(7,209)	(7,581)	(7,919)	(8,278)
Total Annual Demand (net of DSM)	**80,519**	**82,326**	**83,557**	**84,832**	**86,002**	**87,456**	**88,013**	**89,055**	**90,352**	**91,913**
Annual Demand Served	80,519	82,326	83,557	84,832	86,002	87,456	88,013	89,055	90,352	91,913
Annual Demand Unserved	-	-	-	-	-	-	-	-	-	-
Total Peak Day Demand (net of DSM)	**1,015**	**1,035**	**1,058**	**1,075**	**1,091**	**1,104**	**1,118**	**1,129**	**1,146**	**1,160**
Peak Day Demand Served	1,015	1,035	1,058	1,075	1,091	1,104	1,118	1,129	1,146	1,160
Peak Day Demand Unserved	-	-	-	-	-	-	-	-	-	-
Supply Fixed Costs	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59
Supply Variable Costs	$ 492,308	$ 519,219	$ 506,001	$ 517,435	$ 559,273	$ 636,571	$ 698,968	$ 724,556	$ 761,178	$ 776,655
Total Supply Costs	**$ 492,367**	**$ 519,278**	**$ 506,059**	**$ 517,494**	**$ 559,332**	**$ 636,630**	**$ 699,027**	**$ 724,615**	**$ 761,236**	**$ 776,714**
Transportation Fixed Costs	$ 89,736	$ 89,760	$ 90,094	$ 90,094	$ 90,094	$ 90,094	$ 90,094	$ 90,094	$ 90,691	$ 92,256
Transportation Variable Costs	$ 2,487	$ 2,539	$ 2,572	$ 2,610	$ 2,648	$ 2,683	$ 2,702	$ 2,740	$ 2,793	$ 2,871
Total Transportation Costs	**$ 92,223**	**$ 92,299**	**$ 92,666**	**$ 92,704**	**$ 92,742**	**$ 92,777**	**$ 92,796**	**$ 92,834**	**$ 93,485**	**$ 95,127**
Storage Fixed Costs	$ 27,085	$ 27,976	$ 28,805	$ 29,550	$ 30,190	$ 30,774	$ 31,538	$ 32,015	$ 32,102	$ 33,574
Storage Variable Costs	$ 1,928	$ 2,166	$ 2,152	$ 2,053	$ 2,485	$ 2,836	$ 3,386	$ 3,449	$ 3,149	$ 3,403
Total Storage Costs	**$ 29,013**	**$ 30,143**	**$ 30,957**	**$ 31,603**	**$ 32,675**	**$ 33,610**	**$ 34,925**	**$ 35,464**	**$ 35,251**	**$ 36,977**
DSM Annual Utility Costs ($2007)	**$ 17,504**	**$ 17,489**	**$ 17,488**	**$ 17,465**	**$ 5,573**	**$ 5,548**	**$ 5,548**	**$ 5,443**	**$ 5,361**	**$ 5,281**
Total Levelized DSM Costs	$ 17,600	$ 20,420	$ 23,004	$ 25,377	$ 27,280	$ 28,889	$ 30,498	$ 32,067	$ 33,619	$ 35,128
Grand Total System Costs	**$ 631,108**	**$ 659,209**	**$ 647,171**	**$ 659,267**	**$ 690,322**	**$ 768,565**	**$ 832,296**	**$ 858,355**	**$ 895,333**	**$ 914,099**
Net Incremental Daily Citygate Deliverability	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
1 Mist Recall	75	92	108	124	139	151	163	184	184	196
2 Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-
3 Satellite LNG - Eugene	6	7	9	10	11	12	13	14	15	18
4 Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	3
7 Incremental CD via Stanfield	-	-	-	-	-	-	-	-	-	-
8 Palomar East	100	100	100	100	100	100	100	100	100	100
9 Palomar West (Bradwood)	-	-	-	-	-	-	-	-	-	-
10 Pacific Connector East	-	-	-	-	-	-	-	-	-	-
11 Pacific Connector West (Jordan Cove)	-	-	-	-	-	-	-	-	-	-
12 Existing TF-1 Turnback	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)
Total Incremental Daily Citygate Capacity	**104**	**123**	**141**	**158**	**173**	**186**	**199**	**221**	**222**	**240**
Incremental Storage Capacity										
Mist Recall	1,693	2,088	2,448	2,806	3,137	3,406	3,676	4,152	4,152	4,431
Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-
Satellite LNG - Eugene	18	22	28	31	34	37	40	42	45	54
Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	9
Total Incremental Storage Capacity	**1,711**	**2,110**	**2,475**	**2,837**	**3,172**	**3,443**	**3,715**	**4,194**	**4,198**	**4,494**
Misc. Upstream & Downstream Components										
Brownsville to Eugene	5	5	5	5	5	5	5	5	5	5
Newport LNG Enhancement to Salem	10	10	10	10	10	10	10	10	10	10
Incremental CD 12-9	-	-	-	-	-	-	-	-	-	-
Opal to Stanfield	-	-	-	-	-	-	-	-	-	-
Malin to Stanfield	-	-	-	-	-	-	-	-	-	-
Willamette Valley Feeder Components										
Portland to Salem (Phase 1)	-	-	-	-	-	-	-	-	-	-
Portland to Perrydale (Phase 2)	-	-	-	-	-	-	-	-	-	-
Perrydale to Independence	-	-	-	-	-	-	-	-	-	-
Independance to North Albany	-	-	-	-	-	-	-	-	-	-
North Albany to South Albany	-	-	-	-	-	-	-	-	-	-
South Albany to Halsey	-	-	-	-	-	-	-	-	-	-
Halsey to Eugene	-	-	-	-	-	-	-	-	-	-

NPV @ 5.16% Discount Rate
5.16%
$ 7,772,695

1197 - Low Growth Alt 1 Low Price.xls

Appendix 5

(BBtu / $000 Nominal)	2008-2009	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
Forecast Demand	72,331	73,595	73,274	74,135	73,524	73,204	72,856	73,242	73,781	74,646	75,531	76,715	77,301	77,963	78,417	79,071	78,914	79,235	79,742	80,483
DSM Impact	-	(207)	(416)	(694)	(1,002)	(1,363)	(1,757)	(2,199)	(2,660)	(3,200)	(3,718)	(4,256)	(4,695)	(5,153)	(5,472)	(5,737)	(5,930)	(6,182)	(6,403)	(6,639)
Total Annual Demand (net of DSM)	**72,331**	**73,388**	**72,858**	**73,440**	**72,522**	**71,841**	**71,098**	**71,043**	**71,121**	**71,446**	**71,812**	**72,459**	**72,606**	**72,810**	**72,945**	**73,333**	**72,984**	**73,053**	**73,339**	**73,844**
Annual Demand Served	72,331	73,385	72,856	73,440	72,522	71,841	71,098	71,043	71,121	71,446	71,812	72,459	72,606	72,810	72,945	73,333	72,984	73,053	73,339	73,844
Annual Demand Unserved	-	3	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Peak Day Demand (net of DSM)	**903**	**922**	**914**	**919**	**910**	**897**	**885**	**880**	**887**	**892**	**898**	**904**	**913**	**916**	**918**	**918**	**919**	**917**	**921**	**923**
Peak Day Demand Served	903	919	911	919	910	897	885	880	887	892	898	904	913	916	918	918	919	917	921	923
Peak Day Demand Unserved	-	3	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Supply Fixed Costs	$ 61	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59
Supply Variable Costs	$ 350,273	$ 389,958	$ 309,897	$ 350,660	$ 364,006	$ 390,984	$ 383,677	$ 385,027	$ 394,676	$ 405,567	$ 425,833	$ 445,282	$ 426,881	$ 431,094	$ 464,056	$ 520,120	$ 565,904	$ 584,442	$ 602,462	$ 615,239
Total Supply Costs	**$ 350,334**	**$ 390,017**	**$ 309,956**	**$ 350,719**	**$ 364,065**	**$ 391,043**	**$ 383,736**	**$ 385,086**	**$ 394,735**	**$ 405,626**	**$ 425,892**	**$ 445,341**	**$ 426,940**	**$ 431,153**	**$ 464,115**	**$ 520,179**	**$ 565,963**	**$ 584,501**	**$ 602,521**	**$ 615,298**
Transportation Fixed Costs	$ 83,187	$ 82,955	$ 82,955	$ 87,666	$ 87,666	$ 87,666	$ 87,666	$ 87,666	$ 89,049	$ 89,327	$ 89,327	$ 89,327	$ 89,327	$ 89,327	$ 89,327	$ 89,327	$ 89,327	$ 89,327	$ 89,327	$ 89,327
Transportation Variable Costs	$ 2,851	$ 2,815	$ 2,878	$ 2,252	$ 2,203	$ 2,185	$ 2,141	$ 2,159	$ 2,203	$ 2,201	$ 2,222	$ 2,256	$ 2,205	$ 2,237	$ 2,272	$ 2,241	$ 2,239	$ 2,225	$ 2,240	$ 2,277
Total Transportation Costs	**$ 86,038**	**$ 85,770**	**$ 85,833**	**$ 89,918**	**$ 89,869**	**$ 89,851**	**$ 89,807**	**$ 89,825**	**$ 91,252**	**$ 91,527**	**$ 91,549**	**$ 91,582**	**$ 91,532**	**$ 91,563**	**$ 91,599**	**$ 91,568**	**$ 91,566**	**$ 91,552**	**$ 91,566**	**$ 91,603**
Storage Fixed Costs	$ 23,059	$ 23,217	$ 23,217	$ 23,217	$ 23,217	$ 23,217	$ 23,217	$ 23,217	$ 23,217	$ 23,217	$ 23,217	$ 23,217	$ 23,217	$ 23,217	$ 23,217	$ 23,217	$ 23,217	$ 23,217	$ 23,217	$ 23,217
Storage Variable Costs	$ 2,263	$ 1,329	$ 1,116	$ 1,264	$ 1,547	$ 1,527	$ 1,514	$ 1,505	$ 1,577	$ 1,655	$ 1,702	$ 1,789	$ 1,647	$ 1,688	$ 2,022	$ 2,013	$ 2,383	$ 2,224	$ 2,238	$ 2,514
Total Storage Costs	**$ 25,323**	**$ 24,546**	**$ 24,333**	**$ 24,481**	**$ 24,764**	**$ 24,744**	**$ 24,732**	**$ 24,722**	**$ 24,794**	**$ 24,873**	**$ 24,920**	**$ 25,006**	**$ 24,864**	**$ 24,905**	**$ 25,239**	**$ 25,230**	**$ 25,600**	**$ 25,441**	**$ 25,455**	**$ 25,732**
DSM Annual Utility Costs ($2007)	**$ -**	**$ 7,853**	**$ 8,941**	**$ 10,394**	**$ 12,116**	**$ 13,843**	**$ 15,509**	**$ 17,297**	**$ 17,683**	**$ 17,793**	**$ 17,504**	**$ 17,489**	**$ 17,488**	**$ 17,465**	**$ 5,573**	**$ 5,548**	**$ 5,548**	**$ 5,443**	**$ 5,361**	**$ 5,281**
Total Levelized DSM Costs	$ -	$ 817	$ 1,642	$ 2,715	$ 3,941	$ 5,329	$ 6,863	$ 8,546	$ 10,504	$ 12,709	$ 14,855	$ 17,028	$ 19,030	$ 20,850	$ 22,211	$ 23,289	$ 24,357	$ 25,381	$ 26,380	$ 27,333
Grand Total System Costs	**$ 461,695**	**$ 508,186**	**$ 429,062**	**$ 475,511**	**$ 490,814**	**$ 519,481**	**$ 513,784**	**$ 516,930**	**$ 528,465**	**$ 539,819**	**$ 559,865**	**$ 579,419**	**$ 560,824**	**$ 565,087**	**$ 586,527**	**$ 642,526**	**$ 688,677**	**$ 706,937**	**$ 724,903**	**$ 737,914**

NPV @ 5.16% Discount Rate
5.16%
$ 7,036,467

Net Incremental Daily Citygate Deliverability	2008-2009	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
1 Mist Recall	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
2 Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3 Satellite LNG - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4 Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Incremental CD via Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8 Palomar East	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
9 Palomar West (Bradwood)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10 Pacific Connector East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11 Pacific Connector West (Jordan Cove)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12 Existing TF-1 Turnback	-	-	-	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)
Total Incremental Daily Citygate Capacity	**-**	**10**	**10**	**33**	**33**	**33**	**33**	**33**	**33**	**33**	**33**	**33**	**33**	**33**	**33**	**33**	**33**	**33**	**33**	**33**
Incremental Storage Capacity																				
Mist Recall	-	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237
Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Satellite LNG - Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Incremental Storage Capacity	**-**	**237**	**237**	**237**	**237**	**237**	**237**	**237**	**237**	**237**	**237**	**237**	**237**	**237**	**237**	**237**	**237**	**237**	**237**	**237**
Misc. Upstream & Downstream Components																				
Brownsville to Eugene	-	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Newport LNG Enhancement to Salem	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incremental CD 12-9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Opal to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Malin to Stanfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Willamette Valley Feeder Components																				
Portland to Salem (Phase 1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Portland to Perrydale (Phase 2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Perrydale to Independence	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Independance to North Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Albany to South Albany	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
South Albany to Halsey	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Halsey to Eugene	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

1198 - Low Growth Alt 2 Low Price.xls

(BBtu / $000 Nominal)	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018
Forecast Demand	72,331	73,722	74,329	75,720	76,566	77,765	78,927	80,823	81,785	83,264
DSM Impact	-	(218)	(449)	(761)	(1,117)	(1,541)	(2,009)	(2,542)	(3,064)	(3,721)
Total Annual Demand (net of DSM)	**72,331**	**73,504**	**73,880**	**74,959**	**75,449**	**76,224**	**76,917**	**78,280**	**78,721**	**79,543**
Annual Demand Served	72,331	73,501	73,876	74,959	75,449	76,224	76,917	78,280	78,721	79,543
Annual Demand Unserved	-	3	4	-	-	-	-	-	-	-
Total Peak Day Demand (net of DSM)	**903**	**920**	**924**	**934**	**943**	**951**	**958**	**972**	**984**	**996**
Peak Day Demand Served	903	917	920	934	943	951	958	972	984	996
Peak Day Demand Unserved	-	3	4	-	-	-	-	-	-	-
Supply Fixed Costs	$ 61	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59
Supply Variable Costs	$ 436,542	$ 481,973	$ 461,932	$ 503,642	$ 513,076	$ 540,137	$ 556,190	$ 567,175	$ 590,394	$ 612,689
Total Supply Costs	**$ 436,603**	**$ 482,032**	**$ 461,991**	**$ 503,701**	**$ 513,135**	**$ 540,196**	**$ 556,249**	**$ 567,234**	**$ 590,453**	**$ 612,748**
Transportation Fixed Costs	$ 83,187	$ 82,955	$ 83,020	$ 91,640	$ 92,235	$ 92,600	$ 92,965	$ 93,696	$ 95,809	$ 96,817
Transportation Variable Costs	$ 2,872	$ 2,905	$ 2,815	$ 1,858	$ 1,742	$ 1,692	$ 1,658	$ 1,582	$ 1,493	$ 1,429
Total Transportation Costs	**$ 86,058**	**$ 85,860**	**$ 85,835**	**$ 93,498**	**$ 93,976**	**$ 94,292**	**$ 94,623**	**$ 95,278**	**$ 97,303**	**$ 98,246**
Storage Fixed Costs	$ 23,080	$ 23,252	$ 23,252	$ 23,252	$ 23,252	$ 23,252	$ 23,356	$ 23,531	$ 23,686	$ 23,850
Storage Variable Costs	$ 2,411	$ 1,941	$ 1,542	$ 1,866	$ 2,147	$ 1,994	$ 2,173	$ 2,035	$ 1,975	$ 2,232
Total Storage Costs	**$ 25,490**	**$ 25,193**	**$ 24,794**	**$ 25,118**	**$ 25,399**	**$ 25,246**	**$ 25,529**	**$ 25,566**	**$ 25,661**	**$ 26,082**
DSM Annual Utility Costs ($2007)	**$ -**	**$ 7,853**	**$ 8,941**	**$ 10,394**	**$ 12,116**	**$ 13,843**	**$ 15,509**	**$ 17,297**	**$ 17,683**	**$ 17,793**
Total Levelized DSM Costs	$ -	$ 488	$ 1,051	$ 1,734	$ 2,559	$ 3,525	$ 4,622	$ 5,864	$ 7,213	$ 9,105
Grand Total System Costs	**$ 548,152**	**$ 600,938**	**$ 581,561**	**$ 632,710**	**$ 644,626**	**$ 673,576**	**$ 691,910**	**$ 705,375**	**$ 731,100**	**$ 754,870**
Net Incremental Daily Citygate Deliverability	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018
1 Mist Recall	-	11	11	11	11	11	11	11	11	11
2 Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-
3 Satellite LNG - Eugene	-	-	-	-	-	-	-	1	2	3
4 Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-
7 Incremental CD via Stanfield	-	-	-	-	-	-	-	-	-	-
8 Palomar East	-	-	-	100	100	100	100	100	100	100
9 Palomar West (Bradwood)	-	-	-	50	55	60	65	75	85	95
10 Pacific Connector East	-	-	-	-	-	-	-	-	-	-
11 Pacific Connector West (Jordan Cove)	-	-	-	-	-	-	-	-	-	-
12 Existing TF-1 Turnback	-	-	-	(77)	(77)	(77)	(77)	(77)	(77)	(77)
Total Incremental Daily Citygate Capacity	**-**	**11**	**11**	**84**	**89**	**94**	**99**	**111**	**122**	**132**
Incremental Storage Capacity										
Mist Recall	-	259	259	259	259	259	259	259	259	259
Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-
Satellite LNG - Eugene	-	-	-	-	-	-	-	3	6	9
Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-
Total Incremental Storage Capacity	**-**	**259**	**259**	**259**	**259**	**259**	**259**	**262**	**265**	**267**
Misc. Upstream & Downstream Components										
Brownsville to Eugene	-	-	-	5	5	5	5	5	5	5
Newport LNG Enhancement to Salem	-	-	-	-	6	6	6	6	6	6
Incremental CD 12-9	-	-	-	-	-	-	-	-	-	-
Opal to Stanfield	-	-	-	-	-	-	-	-	-	-
Malin to Stanfield	-	-	-	-	-	-	-	-	-	-
Willamette Valley Feeder Components										
Portland to Salem (Phase 1)	-	-	4	4	4	4	4	4	4	4
Portland to Perrydale (Phase 2)	-	-	-	-	-	-	-	-	-	-
Perrydale to Independence	-	-	-	2	2	2	2	2	2	2
Independance to North Albany	-	-	-	2	2	2	2	2	2	2
North Albany to South Albany	-	-	-	2	2	2	2	2	2	2
South Albany to Halsey	-	-	-	2	2	2	2	2	2	2
Halsey to Eugene	-	-	-	-	-	-	-	-	-	-

(BBtu / $000 Nominal)	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Forecast Demand	84,853	86,819	88,085	89,936	91,578	93,477	94,419	95,893	97,552	99,522
DSM Impact	(4,333)	(4,975)	(5,495)	(6,071)	(6,504)	(6,883)	(7,179)	(7,549)	(7,886)	(8,245)
Total Annual Demand (net of DSM)	**80,520**	**81,844**	**82,590**	**83,865**	**85,074**	**86,593**	**87,240**	**88,343**	**89,666**	**91,277**
Annual Demand Served	80,520	81,844	82,590	83,865	85,074	86,593	87,240	88,343	89,666	91,277
Annual Demand Unserved	-	-	-	-	-	-	-	-	-	-
Total Peak Day Demand (net of DSM)	**1,010**	**1,024**	**1,042**	**1,059**	**1,076**	**1,090**	**1,104**	**1,116**	**1,134**	**1,149**
Peak Day Demand Served	1,010	1,024	1,042	1,059	1,076	1,090	1,104	1,116	1,134	1,149
Peak Day Demand Unserved	-	-	-	-	-	-	-	-	-	-
Supply Fixed Costs	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59
Supply Variable Costs	$ 645,055	$ 673,007	$ 667,807	$ 681,201	$ 721,922	$ 796,458	$ 855,719	$ 889,656	$ 929,277	$ 955,307
Total Supply Costs	**$ 645,114**	**$ 673,065**	**$ 667,866**	**$ 681,260**	**$ 721,981**	**$ 796,517**	**$ 855,777**	**$ 889,715**	**$ 929,336**	**$ 955,366**
Transportation Fixed Costs	$ 97,182	$ 97,182	$ 97,182	$ 97,182	$ 97,182	$ 97,182	$ 97,182	$ 97,182	$ 97,182	$ 99,702
Transportation Variable Costs	$ 1,414	$ 1,448	$ 1,526	$ 1,521	$ 1,558	$ 1,605	$ 1,641	$ 1,712	$ 1,717	$ 1,815
Total Transportation Costs	**$ 98,596**	**$ 98,630**	**$ 98,709**	**$ 98,703**	**$ 98,741**	**$ 98,787**	**$ 98,824**	**$ 98,894**	**$ 98,899**	**$ 101,517**
Storage Fixed Costs	$ 24,022	$ 24,211	$ 24,616	$ 25,280	$ 25,964	$ 26,608	$ 27,195	$ 27,869	$ 28,198	$ 29,336
Storage Variable Costs	$ 2,338	$ 2,318	$ 2,135	$ 2,381	$ 2,745	$ 2,930	$ 3,079	$ 3,115	$ 3,098	$ 3,465
Total Storage Costs	**$ 26,359**	**$ 26,528**	**$ 26,751**	**$ 27,661**	**$ 28,709**	**$ 29,538**	**$ 30,274**	**$ 30,985**	**$ 31,297**	**$ 32,801**
DSM Annual Utility Costs ($2007)	**$ 17,504**	**$ 17,489**	**$ 17,488**	**$ 17,465**	**$ 5,573**	**$ 5,548**	**$ 5,548**	**$ 5,443**	**$ 5,361**	**$ 5,281**
Total Levelized DSM Costs	$ 10,716	$ 12,406	$ 13,921	$ 15,417	$ 16,833	$ 18,172	$ 19,511	$ 20,828	$ 22,146	$ 23,442
Grand Total System Costs	**$ 787,574**	**$ 815,713**	**$ 810,813**	**$ 825,089**	**$ 855,004**	**$ 930,391**	**$ 990,423**	**$ 1,025,036**	**$ 1,064,893**	**$ 1,094,964**
Net Incremental Daily Citygate Deliverability	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
1 Mist Recall	11	11	11	21	36	49	62	73	89	93
2 Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-
3 Satellite LNG - Eugene	4	5	6	7	8	9	10	11	12	17
4 Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-
7 Incremental CD via Stanfield	-	-	-	-	-	-	-	-	-	1
8 Palomar East	100	100	100	100	100	100	100	100	100	100
9 Palomar West (Bradwood)	100	100	100	100	100	100	100	100	100	100
10 Pacific Connector East	-	-	-	-	-	-	-	-	-	-
11 Pacific Connector West (Jordan Cove)	-	-	-	-	-	-	-	-	-	-
12 Existing TF-1 Turnback	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)
Total Incremental Daily Citygate Capacity	**138**	**139**	**141**	**151**	**168**	**181**	**196**	**208**	**225**	**234**
Incremental Storage Capacity										
Mist Recall	259	259	259	471	815	1,109	1,408	1,660	2,020	2,105
Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-
Satellite LNG - Eugene	12	15	18	22	25	28	31	34	37	51
Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	4
Total Incremental Storage Capacity	**270**	**273**	**277**	**492**	**841**	**1,137**	**1,439**	**1,694**	**2,057**	**2,159**
Misc. Upstream & Downstream Components										
Brownsville to Eugene	5	5	5	5	5	5	5	5	5	5
Newport LNG Enhancement to Salem	6	6	6	6	6	6	6	6	6	6
Incremental CD 12-9	-	-	-	-	-	-	-	-	-	-
Opal to Stanfield	-	-	-	-	-	-	-	-	-	-
Malin to Stanfield	-	-	-	-	-	-	-	-	-	-
Willamette Valley Feeder Components										
Portland to Salem (Phase 1)	4	4	4	4	4	4	4	4	4	4
Portland to Perrydale (Phase 2)	-	-	-	-	-	-	-	-	-	-
Perrydale to Independence	2	2	2	2	2	2	2	2	2	2
Independance to North Albany	2	2	2	2	2	2	2	2	2	2
North Albany to South Albany	2	2	2	2	2	2	2	2	2	2
South Albany to Halsey	2	2	2	2	2	2	2	2	2	2
Halsey to Eugene	-	-	-	-	-	-	-	-	-	-

NPV @ 5.16% Discount Rate
5.16%
$ 9,624,595

1199 - RMix 3 Bradwood LNG.xls

(BBtu / $000 Nominal)	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018
Forecast Demand	72,331	73,722	74,329	75,720	76,566	77,765	78,927	80,823	81,785	83,264
DSM Impact	-	(218)	(449)	(761)	(1,117)	(1,541)	(2,009)	(2,542)	(3,064)	(3,721)
Total Annual Demand (net of DSM)	**72,331**	**73,504**	**73,880**	**74,959**	**75,449**	**76,224**	**76,917**	**78,280**	**78,721**	**79,543**
Annual Demand Served	72,331	73,501	73,876	74,959	75,449	76,224	76,917	78,280	78,721	79,543
Annual Demand Unserved	-	3	4	-	-	-	-	-	-	-
Total Peak Day Demand (net of DSM)	**903**	**920**	**924**	**934**	**943**	**951**	**958**	**972**	**984**	**996**
Peak Day Demand Served	903	917	920	934	943	951	958	972	984	996
Peak Day Demand Unserved	-	3	4	-	-	-	-	-	-	-
Supply Fixed Costs	$ 61	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59
Supply Variable Costs	$ 436,542	$ 481,973	$ 461,631	$ 471,445	$ 475,564	$ 506,889	$ 551,652	$ 591,362	$ 617,733	$ 644,870
Total Supply Costs	**$ 436,603**	**$ 482,032**	**$ 461,690**	**$ 471,504**	**$ 475,623**	**$ 506,948**	**$ 551,711**	**$ 591,421**	**$ 617,792**	**$ 644,929**
Transportation Fixed Costs	$ 83,187	$ 82,955	$ 82,955	$ 97,222	$ 97,790	$ 97,790	$ 97,790	$ 97,790	$ 99,173	$ 99,451
Transportation Variable Costs	$ 2,872	$ 2,905	$ 2,814	$ 1,263	$ 1,194	$ 1,219	$ 1,268	$ 1,821	$ 2,131	$ 2,280
Total Transportation Costs	**$ 86,058**	**$ 85,860**	**$ 85,768**	**$ 98,484**	**$ 98,984**	**$ 99,009**	**$ 99,058**	**$ 99,611**	**$ 101,305**	**$ 101,731**
Storage Fixed Costs	$ 23,080	$ 23,252	$ 23,252	$ 23,252	$ 23,252	$ 23,252	$ 23,252	$ 23,252	$ 23,463	$ 23,911
Storage Variable Costs	$ 2,411	$ 1,941	$ 1,526	$ 2,089	$ 1,782	$ 1,888	$ 2,015	$ 2,970	$ 2,470	$ 2,349
Total Storage Costs	**$ 25,490**	**$ 25,193**	**$ 24,778**	**$ 25,342**	**$ 25,035**	**$ 25,140**	**$ 25,267**	**$ 26,222**	**$ 25,933**	**$ 26,260**
DSM Annual Utility Costs ($2007)	**$ -**	**$ 7,853**	**$ 8,941**	**$ 10,394**	**$ 12,116**	**$ 13,843**	**$ 15,509**	**$ 17,297**	**$ 17,683**	**$ 17,793**
Total Levelized DSM Costs	$ -	$ 488	$ 1,051	$ 1,734	$ 2,559	$ 3,525	$ 4,622	$ 5,864	$ 7,213	$ 9,105
Grand Total System Costs	**$ 548,152**	**$ 600,938**	**$ 581,176**	**$ 605,724**	**$ 611,758**	**$ 644,939**	**$ 691,545**	**$ 734,551**	**$ 762,713**	**$ 790,714**
Net Incremental Daily Citygate Deliverability	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018
1 Mist Recall	-	11	11	11	11	11	11	11	11	21
2 Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-
3 Satellite LNG - Eugene	-	-	-	-	-	-	-	-	-	-
4 Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-
7 Incremental CD via Stanfield	-	-	-	-	-	-	-	-	-	-
8 Palomar East	-	-	-	100	100	100	100	100	100	100
9 Palomar West (Bradwood)	-	-	-	-	-	-	-	-	-	-
10 Pacific Connector East	-	-	-	5	5	5	5	5	5	5
11 Pacific Connector West (Jordan Cove)	-	-	-	20	20	20	20	20	20	20
12 Existing TF-1 Turnback	-	-	-	(77)	(77)	(77)	(77)	(77)	(77)	(77)
Total Incremental Daily Citygate Capacity	**-**	**11**	**11**	**60**	**60**	**60**	**60**	**60**	**60**	**70**
Incremental Storage Capacity										
Mist Recall	-	259	259	259	259	259	259	259	259	482
Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-
Satellite LNG - Eugene	-	-	-	-	-	-	-	-	-	-
Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	-
Total Incremental Storage Capacity	**-**	**259**	**259**	**259**	**259**	**259**	**259**	**259**	**259**	**482**
Misc. Upstream & Downstream Components										
Brownsville to Eugene	-	-	-	-	-	-	-	-	-	-
Newport LNG Enhancement to Salem	-	-	-	-	8	8	8	8	8	8
Incremental CD 12-9	-	-	-	-	-	-	-	-	-	-
Opal to Stanfield	-	-	-	-	-	-	-	-	-	-
Malin to Stanfield	-	-	-	70	70	70	70	70	70	70
Willamette Valley Feeder Components										
Portland to Salem (Phase 1)	-	-	-	-	-	-	-	-	-	-
Portland to Perrydale (Phase 2)	-	-	-	-	-	-	-	-	-	-
Perrydale to Independence	-	-	-	-	-	-	-	-	-	-
Independance to North Albany	-	-	-	-	-	-	-	-	-	-
North Albany to South Albany	-	-	-	-	-	-	-	-	-	-
South Albany to Halsey	-	-	-	-	-	-	-	-	-	-
Halsey to Eugene	-	-	-	-	-	-	-	-	-	-

(BBtu / $000 Nominal)	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Forecast Demand	84,853	86,819	88,085	89,936	91,578	93,477	94,419	95,893	97,552	99,522
DSM Impact	(4,333)	(4,975)	(5,495)	(6,071)	(6,504)	(6,883)	(7,179)	(7,549)	(7,886)	(8,245)
Total Annual Demand (net of DSM)	**80,520**	**81,844**	**82,590**	**83,865**	**85,074**	**86,593**	**87,240**	**88,343**	**89,666**	**91,277**
Annual Demand Served	80,520	81,844	82,590	83,865	85,074	86,593	87,240	88,343	89,666	91,277
Annual Demand Unserved	-	-	-	-	-	-	-	-	-	-
Total Peak Day Demand (net of DSM)	**1,010**	**1,024**	**1,042**	**1,059**	**1,076**	**1,090**	**1,104**	**1,116**	**1,134**	**1,149**
Peak Day Demand Served	1,010	1,024	1,042	1,059	1,076	1,090	1,104	1,116	1,134	1,149
Peak Day Demand Unserved	-	-	-	-	-	-	-	-	-	-
Supply Fixed Costs	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59
Supply Variable Costs	$ 675,720	$ 702,058	$ 688,345	$ 701,974	$ 744,050	$ 824,785	$ 885,924	$ 916,465	$ 948,064	$ 977,231
Total Supply Costs	**$ 675,779**	**$ 702,117**	**$ 688,404**	**$ 702,032**	**$ 744,109**	**$ 824,844**	**$ 885,983**	**$ 916,524**	**$ 948,123**	**$ 977,290**
Transportation Fixed Costs	$ 99,451	$ 99,451	$ 99,451	$ 99,451	$ 99,451	$ 99,451	$ 99,451	$ 99,451	$ 99,451	$ 104,026
Transportation Variable Costs	$ 2,357	$ 2,468	$ 2,515	$ 2,556	$ 2,581	$ 2,544	$ 2,496	$ 2,571	$ 2,644	$ 2,701
Total Transportation Costs	**$ 101,807**	**$ 101,919**	**$ 101,966**	**$ 102,006**	**$ 102,032**	**$ 101,995**	**$ 101,947**	**$ 102,021**	**$ 102,094**	**$ 106,727**
Storage Fixed Costs	$ 24,412	$ 24,980	$ 25,601	$ 26,207	$ 26,751	$ 27,264	$ 27,732	$ 28,275	$ 28,532	$ 29,324
Storage Variable Costs	$ 2,401	$ 2,532	$ 2,773	$ 2,668	$ 2,999	$ 3,212	$ 3,779	$ 3,831	$ 3,728	$ 4,052
Total Storage Costs	**$ 26,813**	**$ 27,512**	**$ 28,374**	**$ 28,875**	**$ 29,749**	**$ 30,476**	**$ 31,511**	**$ 32,106**	**$ 32,260**	**$ 33,375**
DSM Annual Utility Costs ($2007)	**$ 17,504**	**$ 17,489**	**$ 17,488**	**$ 17,465**	**$ 5,573**	**$ 5,548**	**$ 5,548**	**$ 5,443**	**$ 5,361**	**$ 5,281**
Total Levelized DSM Costs	$ 10,716	$ 12,406	$ 13,921	$ 15,417	$ 16,833	$ 18,172	$ 19,511	$ 20,828	$ 22,146	$ 23,442
Grand Total System Costs	**$ 821,903**	**$ 849,037**	**$ 836,232**	**$ 850,379**	**$ 881,464**	**$ 962,863**	**$ 1,024,989**	**$ 1,056,094**	**$ 1,087,838**	**$ 1,122,672**
Net Incremental Daily Citygate Deliverability	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
1 Mist Recall	35	49	66	83	99	113	128	140	157	157
2 Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-
3 Satellite LNG - Eugene	-	-	-	-	-	-	-	-	-	1
4 Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	3
7 Incremental CD via Stanfield	-	-	-	-	-	-	-	-	-	-
8 Palomar East	100	100	100	100	100	100	100	100	100	127
9 Palomar West (Bradwood)	-	-	-	-	-	-	-	-	-	-
10 Pacific Connector East	5	5	5	5	5	5	5	5	5	5
11 Pacific Connector West (Jordan Cove)	20	20	20	20	20	20	20	20	20	20
12 Existing TF-1 Turnback	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)
Total Incremental Daily Citygate Capacity	**84**	**97**	**114**	**131**	**148**	**162**	**176**	**188**	**205**	**237**
Incremental Storage Capacity										
Mist Recall	800	1,106	1,493	1,878	2,248	2,564	2,885	3,155	3,540	3,540
Satellite LNG - Albany	-	-	-	-	-	-	-	-	-	-
Satellite LNG - Eugene	-	-	-	-	-	-	-	-	-	4
Satellite LNG - Salem	-	-	-	-	-	-	-	-	-	9
Total Incremental Storage Capacity	**800**	**1,106**	**1,493**	**1,878**	**2,248**	**2,564**	**2,885**	**3,155**	**3,540**	**3,554**
Misc. Upstream & Downstream Components										
Brownsville to Eugene	-	-	-	-	-	-	-	-	-	-
Newport LNG Enhancement to Salem	8	8	8	8	8	8	8	8	8	8
Incremental CD 12-9	-	-	-	-	-	-	-	-	-	-
Opal to Stanfield	-	-	-	-	-	-	-	-	-	-
Malin to Stanfield	70	70	70	70	70	70	70	70	70	70
Willamette Valley Feeder Components										
Portland to Salem (Phase 1)	-	-	-	-	-	-	-	-	-	-
Portland to Perrydale (Phase 2)	-	-	-	-	-	-	-	-	-	-
Perrydale to Independence	-	-	-	-	-	-	-	-	-	-
Independance to North Albany	-	-	-	-	-	-	-	-	-	-
North Albany to South Albany	-	-	-	-	-	-	-	-	-	-
South Albany to Halsey	-	-	-	-	-	-	-	-	-	-
Halsey to Eugene	-	-	-	-	-	-	-	-	-	-

NPV @ 5.16% Discount Rate
5.16%
$ 9,759,971

1200 - RMix 4 Jordon Cove LNG Pacific Connector.xls

APPENDIX 6
AVOIDED COSTS

Gas Year	Month	Albany	Astoria	Dalles	Eugene	Newport LC	Portland	Salem	Vancouver
2008-2009	Nov	$ 7.07	$ 7.22	$ 7.21	$ 7.08	$ 7.27	$ 7.22	$ 7.22	$ 7.22
2008-2009	Dec	$ 7.50	$ 7.50	$ 7.50	$ 7.50	$ 7.50	$ 7.50	$ 7.50	$ 7.52
2008-2009	Jan	$ 7.52	$ 7.53	$ 7.53	$ 7.52	$ 7.53	$ 7.53	$ 7.52	$ 7.54
2008-2009	Feb	$ 7.89	$ 7.88	$ 7.88	$ 7.91	$ 7.49	$ 7.88	$ 7.90	$ 15.04
2008-2009	Mar	$ 7.20	$ 7.20	$ 7.20	$ 7.20	$ 7.39	$ 7.20	$ 7.20	$ 7.20
2008-2009	Apr	$ 7.07	$ 7.07	$ 7.07	$ 7.07	$ 7.25	$ 7.07	$ 7.07	$ 7.07
2008-2009	May	$ 7.10	$ 7.12	$ 7.10	$ 7.10	$ 7.28	$ 7.10	$ 7.10	$ 7.10
2008-2009	Jun	$ 7.13	$ 7.15	$ 7.13	$ 7.13	$ 7.31	$ 7.13	$ 7.13	$ 7.13
2008-2009	Jul	$ 7.16	$ 7.18	$ 7.16	$ 7.16	$ 7.34	$ 7.16	$ 7.16	$ 7.16
2008-2009	Aug	$ 7.19	$ 7.21	$ 7.19	$ 7.19	$ 7.37	$ 7.19	$ 7.19	$ 7.19
2008-2009	Sep	$ 7.22	$ 7.24	$ 7.22	$ 7.22	$ 7.40	$ 7.22	$ 7.22	$ 7.22
2008-2009	Oct	$ 7.52	$ 7.54	$ 7.52	$ 7.52	$ 7.72	$ 7.52	$ 7.52	$ 7.52
Average 2008-2009		$ 7.30	$ 7.32	$ 7.31	$ 7.30	$ 7.40	$ 7.31	$ 7.31	$ 7.91
Winter		$ 7.44	$ 7.47	$ 7.46	$ 7.44	$ 7.44	$ 7.47	$ 7.47	$ 8.90
2009-2010	Nov	$ 8.35	$ 8.52	$ 8.50	$ 8.46	$ 8.57	$ 8.52	$ 8.37	$ 8.51
2009-2010	Dec	$ 8.84	$ 8.84	$ 8.84	$ 8.84	$ 8.84	$ 8.84	$ 8.84	$ 8.84
2009-2010	Jan	$ 8.90	$ 8.90	$ 8.90	$ 8.90	$ 8.91	$ 8.90	$ 8.90	$ 8.91
2009-2010	Feb	$ 9.15	$ 9.15	$ 9.15	$ 10.13	$ 8.83	$ 9.15	$ 9.18	$ 16.31
2009-2010	Mar	$ 8.35	$ 8.35	$ 8.35	$ 8.35	$ 8.57	$ 8.35	$ 8.35	$ 8.35
2009-2010	Apr	$ 7.51	$ 7.51	$ 7.51	$ 7.51	$ 7.70	$ 7.51	$ 7.51	$ 7.51
2009-2010	May	$ 7.47	$ 7.49	$ 7.47	$ 7.47	$ 7.66	$ 7.47	$ 7.47	$ 7.47
2009-2010	Jun	$ 7.53	$ 7.55	$ 7.53	$ 7.53	$ 7.72	$ 7.53	$ 7.53	$ 7.53
2009-2010	Jul	$ 7.59	$ 7.61	$ 7.59	$ 7.59	$ 7.79	$ 7.59	$ 7.59	$ 7.59
2009-2010	Aug	$ 7.65	$ 7.67	$ 7.65	$ 7.65	$ 7.85	$ 7.65	$ 7.65	$ 7.65
2009-2010	Sep	$ 7.72	$ 7.74	$ 7.72	$ 7.72	$ 7.91	$ 7.72	$ 7.72	$ 7.72
2009-2010	Oct	$ 7.82	$ 7.84	$ 7.82	$ 7.82	$ 8.02	$ 7.82	$ 7.82	$ 7.82
Average 2009-2010		$ 8.07	$ 8.10	$ 8.09	$ 8.16	$ 8.20	$ 8.09	$ 8.08	$ 8.68
Winter		$ 8.72	$ 8.75	$ 8.75	$ 8.94	$ 8.74	$ 8.75	$ 8.73	$ 10.18
2010-2011	Nov	$ 8.46	$ 8.48	$ 8.47	$ 8.48	$ 8.51	$ 8.48	$ 8.46	$ 8.48
2010-2011	Dec	$ 8.64	$ 8.70	$ 8.70	$ 8.64	$ 8.70	$ 8.70	$ 8.64	$ 8.72
2010-2011	Jan	$ 8.77	$ 8.77	$ 8.77	$ 8.77	$ 8.77	$ 8.77	$ 8.77	$ 8.79
2010-2011	Feb	$ 9.07	$ 9.06	$ 9.07	$ 10.01	$ 8.45	$ 9.06	$ 9.12	$ 16.22
2010-2011	Mar	$ 7.72	$ 7.72	$ 7.72	$ 7.72	$ 7.92	$ 7.72	$ 7.72	$ 7.72
2010-2011	Apr	$ 7.23	$ 7.23	$ 7.23	$ 7.23	$ 7.41	$ 7.23	$ 7.23	$ 7.23
2010-2011	May	$ 7.21	$ 7.23	$ 7.21	$ 7.21	$ 7.37	$ 7.21	$ 7.21	$ 7.21
2010-2011	Jun	$ 7.24	$ 7.26	$ 7.24	$ 7.24	$ 7.43	$ 7.24	$ 7.24	$ 7.24

Gas Year	Month	Albany	Astoria	Dalles	Eugene	Newport LC	Portland	Salem	Vancouver
2010-2011	Jul	$ 7.30	$ 7.32	$ 7.30	$ 7.30	$ 7.49	$ 7.30	$ 7.30	$ 7.30
2010-2011	Aug	$ 7.36	$ 7.38	$ 7.36	$ 7.36	$ 7.55	$ 7.36	$ 7.36	$ 7.36
2010-2011	Sep	$ 7.43	$ 7.45	$ 7.43	$ 7.43	$ 7.62	$ 7.43	$ 7.43	$ 7.43
2010-2011	Oct	$ 7.50	$ 7.52	$ 7.50	$ 7.50	$ 7.68	$ 7.50	$ 7.50	$ 7.50
Average 2010-2011		$ 7.83	$ 7.84	$ 7.83	$ 7.91	$ 7.91	$ 7.83	$ 7.83	$ 8.43
Winter		$ 8.53	$ 8.55	$ 8.55	$ 8.72	$ 8.47	$ 8.55	$ 8.54	$ 9.99
2011-2012	Nov	$ 7.57	$ 7.57	$ 7.58	$ 7.58	$ 7.75	$ 7.57	$ 7.59	$ 7.59
2011-2012	Dec	$ 7.63	$ 7.63	$ 7.65	$ 7.63	$ 7.82	$ 7.63	$ 7.66	$ 7.67
2011-2012	Jan	$ 7.70	$ 7.70	$ 7.71	$ 7.71	$ 7.88	$ 7.70	$ 7.71	$ 7.73
2011-2012	Feb	$ 8.92	$ 8.88	$ 8.88	$ 8.95	$ 7.68	$ 8.88	$ 8.94	$ 15.79
2011-2012	Mar	$ 7.11	$ 7.11	$ 7.11	$ 7.11	$ 7.29	$ 7.11	$ 7.11	$ 7.11
2011-2012	Apr	$ 7.11	$ 7.11	$ 7.11	$ 7.11	$ 7.30	$ 7.11	$ 7.11	$ 7.11
2011-2012	May	$ 7.11	$ 7.13	$ 7.11	$ 7.11	$ 7.28	$ 7.11	$ 7.11	$ 7.11
2011-2012	Jun	$ 7.11	$ 7.13	$ 7.11	$ 7.11	$ 7.30	$ 7.11	$ 7.11	$ 7.11
2011-2012	Jul	$ 7.17	$ 7.19	$ 7.17	$ 7.17	$ 7.36	$ 7.17	$ 7.17	$ 7.17
2011-2012	Aug	$ 7.24	$ 7.26	$ 7.24	$ 7.24	$ 7.42	$ 7.24	$ 7.24	$ 7.24
2011-2012	Sep	$ 7.30	$ 7.32	$ 7.30	$ 7.30	$ 7.48	$ 7.30	$ 7.30	$ 7.30
2011-2012	Oct	$ 7.38	$ 7.40	$ 7.38	$ 7.38	$ 7.57	$ 7.38	$ 7.38	$ 7.38
Average 2011-2012		$ 7.45	$ 7.45	$ 7.45	$ 7.45	$ 7.51	$ 7.44	$ 7.45	$ 8.03
Winter		$ 7.78	$ 7.78	$ 7.79	$ 7.80	$ 7.68	$ 7.78	$ 7.80	$ 9.18
2012-2013	Nov	$ 7.89	$ 7.89	$ 7.89	$ 7.89	$ 7.92	$ 7.89	$ 7.89	$ 7.90
2012-2013	Dec	$ 8.02	$ 8.02	$ 8.02	$ 8.02	$ 8.02	$ 8.02	$ 8.02	$ 8.04
2012-2013	Jan	$ 8.08	$ 8.08	$ 8.08	$ 8.08	$ 8.09	$ 8.08	$ 8.08	$ 8.10
2012-2013	Feb	$ 9.33	$ 9.31	$ 9.31	$ 9.35	$ 8.02	$ 9.31	$ 9.36	$ 16.47
2012-2013	Mar	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.67	$ 7.48	$ 7.48	$ 7.48
2012-2013	Apr	$ 7.41	$ 7.41	$ 7.41	$ 7.41	$ 7.60	$ 7.41	$ 7.41	$ 7.41
2012-2013	May	$ 7.49	$ 7.51	$ 7.49	$ 7.49	$ 7.65	$ 7.49	$ 7.49	$ 7.49
2012-2013	Jun	$ 7.51	$ 7.53	$ 7.51	$ 7.51	$ 7.70	$ 7.51	$ 7.51	$ 7.51
2012-2013	Jul	$ 7.57	$ 7.59	$ 7.57	$ 7.57	$ 7.76	$ 7.57	$ 7.57	$ 7.57
2012-2013	Aug	$ 7.63	$ 7.65	$ 7.63	$ 7.63	$ 7.83	$ 7.63	$ 7.63	$ 7.63
2012-2013	Sep	$ 7.70	$ 7.72	$ 7.70	$ 7.70	$ 7.89	$ 7.70	$ 7.70	$ 7.70
2012-2013	Oct	$ 7.79	$ 7.81	$ 7.79	$ 7.79	$ 7.99	$ 7.79	$ 7.79	$ 7.79
Average 2012-2013		$ 7.82	$ 7.83	$ 7.82	$ 7.83	$ 7.84	$ 7.82	$ 7.83	$ 8.42
Winter		$ 8.16	$ 8.16	$ 8.16	$ 8.16	$ 7.94	$ 8.16	$ 8.17	$ 9.60
2013-2014	Nov	$ 8.34	$ 8.34	$ 8.35	$ 8.34	$ 8.37	$ 8.34	$ 8.34	$ 8.36
2013-2014	Dec	$ 8.48	$ 8.48	$ 8.49	$ 8.48	$ 8.48	$ 8.48	$ 8.48	$ 8.51

Gas Year	Month	Albany	Astoria	Dalles	Eugene	Newport LC	Portland	Salem	Vancouver
2013-2014	Jan	$ 8.54	$ 8.54	$ 8.55	$ 8.54	$ 8.55	$ 8.54	$ 8.54	$ 8.57
2013-2014	Feb	$ 8.82	$ 8.79	$ 8.80	$ 8.83	$ 8.48	$ 8.79	$ 8.85	$ 15.96
2013-2014	Mar	$ 7.96	$ 7.96	$ 7.96	$ 7.96	$ 8.17	$ 7.96	$ 7.96	$ 7.96
2013-2014	Apr	$ 7.91	$ 7.91	$ 7.91	$ 7.91	$ 8.11	$ 7.91	$ 7.91	$ 7.91
2013-2014	May	$ 7.99	$ 8.01	$ 7.99	$ 7.99	$ 8.15	$ 7.99	$ 7.99	$ 7.99
2013-2014	Jun	$ 7.99	$ 8.01	$ 7.99	$ 7.99	$ 8.20	$ 7.99	$ 7.99	$ 7.99
2013-2014	Jul	$ 8.06	$ 8.08	$ 8.06	$ 8.06	$ 8.26	$ 8.06	$ 8.06	$ 8.06
2013-2014	Aug	$ 8.12	$ 8.14	$ 8.12	$ 8.12	$ 8.33	$ 8.12	$ 8.12	$ 8.12
2013-2014	Sep	$ 8.19	$ 8.21	$ 8.19	$ 8.19	$ 8.40	$ 8.19	$ 8.19	$ 8.19
2013-2014	Oct	$ 8.28	$ 8.30	$ 8.28	$ 8.28	$ 8.49	$ 8.28	$ 8.28	$ 8.28
Average 2013-2014		$ 8.22	$ 8.23	$ 8.22	$ 8.22	$ 8.33	$ 8.22	$ 8.23	$ 8.83
Winter		$ 8.43	$ 8.42	$ 8.43	$ 8.43	$ 8.41	$ 8.42	$ 8.43	$ 9.87
2014-2015	Nov	$ 8.87	$ 8.87	$ 8.88	$ 8.87	$ 8.90	$ 8.87	$ 8.87	$ 8.89
2014-2015	Dec	$ 8.97	$ 8.97	$ 8.98	$ 8.97	$ 8.97	$ 8.97	$ 8.97	$ 9.00
2014-2015	Jan	$ 9.03	$ 9.04	$ 9.05	$ 9.04	$ 9.04	$ 9.03	$ 9.04	$ 9.07
2014-2015	Feb	$ 9.76	$ 9.74	$ 9.74	$ 13.38	$ 8.81	$ 9.74	$ 9.80	$ 16.90
2014-2015	Mar	$ 7.74	$ 7.74	$ 7.74	$ 7.74	$ 7.94	$ 7.74	$ 7.74	$ 7.74
2014-2015	Apr	$ 7.60	$ 7.60	$ 7.60	$ 7.60	$ 7.80	$ 7.60	$ 7.60	$ 7.60
2014-2015	May	$ 7.67	$ 7.69	$ 7.67	$ 7.67	$ 7.83	$ 7.67	$ 7.67	$ 7.67
2014-2015	Jun	$ 7.68	$ 7.70	$ 7.68	$ 7.68	$ 7.88	$ 7.68	$ 7.68	$ 7.68
2014-2015	Jul	$ 7.74	$ 7.76	$ 7.74	$ 7.74	$ 7.94	$ 7.74	$ 7.74	$ 7.74
2014-2015	Aug	$ 7.81	$ 7.83	$ 7.81	$ 7.81	$ 8.01	$ 7.81	$ 7.81	$ 7.81
2014-2015	Sep	$ 7.87	$ 7.89	$ 7.87	$ 7.87	$ 8.07	$ 7.87	$ 7.87	$ 7.87
2014-2015	Oct	$ 7.97	$ 7.99	$ 7.97	$ 7.97	$ 8.17	$ 7.97	$ 7.97	$ 7.97
Average 2014-2015		$ 8.23	$ 8.23	$ 8.23	$ 8.53	$ 8.28	$ 8.22	$ 8.23	$ 8.83
Winter		$ 8.87	$ 8.87	$ 8.88	$ 9.60	$ 8.73	$ 8.87	$ 8.88	$ 10.32
2015-2016	Nov	$ 8.50	$ 8.50	$ 8.51	$ 8.50	$ 8.53	$ 8.50	$ 8.50	$ 8.53
2015-2016	Dec	$ 8.64	$ 8.64	$ 8.66	$ 8.64	$ 8.64	$ 8.64	$ 8.64	$ 8.68
2015-2016	Jan	$ 8.71	$ 8.71	$ 8.72	$ 8.71	$ 8.71	$ 8.71	$ 8.71	$ 8.74
2015-2016	Feb	$ 10.00	$ 9.98	$ 9.99	$ 15.24	$ 8.58	$ 9.98	$ 10.04	$ 16.90
2015-2016	Mar	$ 8.05	$ 8.05	$ 8.05	$ 8.05	$ 8.26	$ 8.05	$ 8.05	$ 8.05
2015-2016	Apr	$ 7.86	$ 7.86	$ 7.86	$ 7.86	$ 8.06	$ 7.86	$ 7.86	$ 7.86
2015-2016	May	$ 7.93	$ 7.95	$ 7.93	$ 7.93	$ 8.11	$ 7.93	$ 7.93	$ 7.93
2015-2016	Jun	$ 7.97	$ 7.99	$ 7.97	$ 7.97	$ 8.17	$ 7.97	$ 7.97	$ 7.97
2015-2016	Jul	$ 8.03	$ 8.05	$ 8.03	$ 8.03	$ 8.24	$ 8.03	$ 8.03	$ 8.03
2015-2016	Aug	$ 8.09	$ 8.11	$ 8.09	$ 8.09	$ 8.30	$ 8.09	$ 8.09	$ 8.09

Gas Year	Month	Albany	Astoria	Dalles	Eugene	Newport LC	Portland	Salem	Vancouver
2015-2016	Sep	$ 8.16	$ 8.18	$ 8.16	$ 8.16	$ 8.37	$ 8.16	$ 8.16	$ 8.16
2015-2016	Oct	$ 8.27	$ 8.29	$ 8.27	$ 8.27	$ 8.47	$ 8.27	$ 8.27	$ 8.27
Average 2015-2016		$ 8.35	$ 8.36	$ 8.35	$ 8.79	$ 8.37	$ 8.35	$ 8.35	$ 8.93
Winter		$ 8.78	$ 8.78	$ 8.79	$ 9.83	$ 8.54	$ 8.78	$ 8.79	$ 10.18
2016-2017	Nov	$ 8.75	$ 8.76	$ 8.76	$ 8.76	$ 8.78	$ 8.75	$ 8.75	$ 8.78
2016-2017	Dec	$ 8.89	$ 8.89	$ 8.90	$ 8.89	$ 8.89	$ 8.89	$ 8.89	$ 8.92
2016-2017	Jan	$ 8.95	$ 8.96	$ 8.96	$ 8.96	$ 8.96	$ 8.95	$ 8.96	$ 8.96
2016-2017	Feb	$ 9.15	$ 9.12	$ 9.13	$ 15.73	$ 8.83	$ 9.12	$ 9.18	$ 16.27
2016-2017	Mar	$ 8.32	$ 8.32	$ 8.32	$ 8.32	$ 8.53	$ 8.32	$ 8.32	$ 8.32
2016-2017	Apr	$ 8.09	$ 8.09	$ 8.09	$ 8.09	$ 8.30	$ 8.09	$ 8.09	$ 8.09
2016-2017	May	$ 8.09	$ 8.09	$ 8.09	$ 8.09	$ 8.27	$ 8.09	$ 8.09	$ 8.09
2016-2017	Jun	$ 8.12	$ 8.12	$ 8.12	$ 8.12	$ 8.33	$ 8.12	$ 8.12	$ 8.12
2016-2017	Jul	$ 8.19	$ 8.19	$ 8.19	$ 8.19	$ 8.40	$ 8.19	$ 8.19	$ 8.19
2016-2017	Aug	$ 8.25	$ 8.25	$ 8.25	$ 8.25	$ 8.47	$ 8.25	$ 8.25	$ 8.25
2016-2017	Sep	$ 8.32	$ 8.32	$ 8.32	$ 8.32	$ 8.53	$ 8.32	$ 8.32	$ 8.32
2016-2017	Oct	$ 8.41	$ 8.41	$ 8.41	$ 8.41	$ 8.62	$ 8.41	$ 8.41	$ 8.41
Average 2016-2017		$ 8.46	$ 8.46	$ 8.46	$ 9.01	$ 8.58	$ 8.46	$ 8.46	$ 9.06
Winter		$ 8.81	$ 8.81	$ 8.81	$ 10.13	$ 8.80	$ 8.81	$ 8.82	$ 10.25
2017-2018	Nov	$ 8.98	$ 8.98	$ 8.98	$ 8.98	$ 9.01	$ 8.98	$ 8.98	$ 8.98
2017-2018	Dec	$ 9.12	$ 9.12	$ 9.12	$ 9.12	$ 9.13	$ 9.12	$ 9.12	$ 9.13
2017-2018	Jan	$ 9.19	$ 9.19	$ 9.19	$ 9.19	$ 9.20	$ 9.19	$ 9.19	$ 9.19
2017-2018	Feb	$ 9.95	$ 9.94	$ 9.94	$ 15.99	$ 9.09	$ 9.94	$ 10.01	$ 17.08
2017-2018	Mar	$ 8.46	$ 8.46	$ 8.46	$ 8.46	$ 8.68	$ 8.46	$ 8.46	$ 8.46
2017-2018	Apr	$ 8.23	$ 8.23	$ 8.23	$ 8.23	$ 8.44	$ 8.23	$ 8.23	$ 8.23
2017-2018	May	$ 8.30	$ 8.30	$ 8.30	$ 8.30	$ 8.48	$ 8.30	$ 8.30	$ 8.30
2017-2018	Jun	$ 8.33	$ 8.33	$ 8.33	$ 8.33	$ 8.54	$ 8.33	$ 8.33	$ 8.33
2017-2018	Jul	$ 8.40	$ 8.40	$ 8.40	$ 8.40	$ 8.61	$ 8.40	$ 8.40	$ 8.40
2017-2018	Aug	$ 8.46	$ 8.46	$ 8.46	$ 8.46	$ 8.68	$ 8.46	$ 8.46	$ 8.46
2017-2018	Sep	$ 8.53	$ 8.53	$ 8.53	$ 8.53	$ 8.75	$ 8.53	$ 8.53	$ 8.53
2017-2018	Oct	$ 8.63	$ 8.63	$ 8.63	$ 8.63	$ 8.85	$ 8.63	$ 8.63	$ 8.63
Average 2017-2018		$ 8.72	$ 8.71	$ 8.71	$ 9.22	$ 8.79	$ 8.71	$ 8.72	$ 9.31
Winter		$ 9.14	$ 9.14	$ 9.14	$ 10.35	$ 9.02	$ 9.14	$ 9.15	$ 10.57
2018-2019	Nov	$ 9.22	$ 9.22	$ 9.22	$ 9.22	$ 9.26	$ 9.22	$ 9.22	$ 9.23
2018-2019	Dec	$ 9.38	$ 9.38	$ 9.38	$ 9.38	$ 9.39	$ 9.38	$ 9.38	$ 9.39
2018-2019	Jan	$ 9.45	$ 9.45	$ 9.45	$ 9.45	$ 9.46	$ 9.45	$ 9.45	$ 9.46
2018-2019	Feb	$ 10.16	$ 10.15	$ 10.15	$ 16.24	$ 9.35	$ 10.15	$ 10.22	$ 17.30

Gas Year	Month	Albany	Astoria	Dalles	Eugene	Newport LC	Portland	Salem	Vancouver
2018-2019	Mar	$ 8.85	$ 8.85	$ 8.85	$ 8.85	$ 9.07	$ 8.85	$ 8.85	$ 8.85
2018-2019	Apr	$ 8.51	$ 8.51	$ 8.51	$ 8.51	$ 8.73	$ 8.51	$ 8.51	$ 8.51
2018-2019	May	$ 8.62	$ 8.62	$ 8.62	$ 8.62	$ 8.78	$ 8.62	$ 8.62	$ 8.62
2018-2019	Jun	$ 8.61	$ 8.61	$ 8.61	$ 8.61	$ 8.83	$ 8.61	$ 8.61	$ 8.61
2018-2019	Jul	$ 8.68	$ 8.68	$ 8.68	$ 8.68	$ 8.90	$ 8.68	$ 8.68	$ 8.68
2018-2019	Aug	$ 8.74	$ 8.74	$ 8.74	$ 8.74	$ 8.97	$ 8.74	$ 8.74	$ 8.74
2018-2019	Sep	$ 8.81	$ 8.81	$ 8.81	$ 8.81	$ 9.04	$ 8.81	$ 8.81	$ 8.81
2018-2019	Oct	$ 8.91	$ 8.91	$ 8.91	$ 8.91	$ 9.14	$ 8.91	$ 8.91	$ 8.91
Average 2018-2019		$ 9.00	$ 8.99	$ 8.99	$ 9.50	$ 9.07	$ 8.99	$ 9.00	$ 9.59
Winter		$ 9.41	$ 9.41	$ 9.41	$ 10.63	$ 9.31	$ 9.41	$ 9.42	$ 10.84
2019-2020	Nov	$ 9.57	$ 9.57	$ 9.57	$ 9.58	$ 9.63	$ 9.57	$ 9.57	$ 9.58
2019-2020	Dec	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.80
2019-2020	Jan	$ 9.86	$ 9.86	$ 9.86	$ 9.86	$ 9.86	$ 9.86	$ 9.86	$ 9.87
2019-2020	Feb	$ 10.43	$ 10.42	$ 10.42	$ 16.35	$ 9.72	$ 10.42	$ 10.49	$ 17.32
2019-2020	Mar	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.23	$ 9.00	$ 9.00	$ 9.00
2019-2020	Apr	$ 8.61	$ 8.61	$ 8.61	$ 8.61	$ 8.83	$ 8.61	$ 8.61	$ 8.61
2019-2020	May	$ 8.70	$ 8.70	$ 8.70	$ 8.70	$ 8.88	$ 8.70	$ 8.70	$ 8.70
2019-2020	Jun	$ 8.72	$ 8.72	$ 8.72	$ 8.72	$ 8.95	$ 8.72	$ 8.72	$ 8.72
2019-2020	Jul	$ 8.79	$ 8.79	$ 8.79	$ 8.79	$ 9.01	$ 8.79	$ 8.79	$ 8.79
2019-2020	Aug	$ 8.86	$ 8.86	$ 8.86	$ 8.86	$ 9.08	$ 8.86	$ 8.86	$ 8.86
2019-2020	Sep	$ 8.93	$ 8.93	$ 8.93	$ 8.93	$ 9.15	$ 8.93	$ 8.93	$ 8.93
2019-2020	Oct	$ 9.03	$ 9.03	$ 9.03	$ 9.03	$ 9.25	$ 9.03	$ 9.03	$ 9.03
Average 2019-2020		$ 9.19	$ 9.19	$ 9.19	$ 9.68	$ 9.28	$ 9.19	$ 9.20	$ 9.77
Winter		$ 9.73	$ 9.73	$ 9.73	$ 10.91	$ 9.65	$ 9.73	$ 9.74	$ 11.11
2020-2021	Nov	$ 9.49	$ 9.49	$ 9.49	$ 9.49	$ 9.53	$ 9.49	$ 9.49	$ 9.50
2020-2021	Dec	$ 9.62	$ 9.62	$ 9.62	$ 9.62	$ 9.63	$ 9.62	$ 9.62	$ 9.63
2020-2021	Jan	$ 9.70	$ 9.70	$ 9.70	$ 9.70	$ 9.70	$ 9.70	$ 9.70	$ 9.70
2020-2021	Feb	$ 10.47	$ 10.44	$ 10.45	$ 16.28	$ 9.43	$ 10.44	$ 10.57	$ 21.16
2020-2021	Mar	$ 8.24	$ 8.24	$ 8.24	$ 8.24	$ 8.45	$ 8.24	$ 8.24	$ 8.24
2020-2021	Apr	$ 8.19	$ 8.19	$ 8.19	$ 8.19	$ 8.40	$ 8.19	$ 8.19	$ 8.19
2020-2021	May	$ 8.18	$ 8.18	$ 8.18	$ 8.18	$ 8.39	$ 8.18	$ 8.18	$ 8.18
2020-2021	Jun	$ 8.25	$ 8.25	$ 8.25	$ 8.25	$ 8.46	$ 8.25	$ 8.25	$ 8.25
2020-2021	Jul	$ 8.31	$ 8.31	$ 8.31	$ 8.31	$ 8.53	$ 8.31	$ 8.31	$ 8.31
2020-2021	Aug	$ 8.38	$ 8.38	$ 8.38	$ 8.38	$ 8.59	$ 8.38	$ 8.38	$ 8.38
2020-2021	Sep	$ 8.45	$ 8.45	$ 8.45	$ 8.45	$ 8.66	$ 8.45	$ 8.45	$ 8.45
2020-2021	Oct	$ 8.55	$ 8.55	$ 8.55	$ 8.55	$ 8.77	$ 8.55	$ 8.55	$ 8.55

Gas Year	Month	Albany	Astoria	Dalles	Eugene	Newport LC	Portland	Salem	Vancouver
Average 2020-2021		$ 8.82	$ 8.82	$ 8.82	$ 9.30	$ 8.88	$ 8.82	$ 8.83	$ 9.71
Winter		$ 9.51	$ 9.50	$ 9.50	$ 10.67	$ 9.35	$ 9.50	$ 9.53	$ 11.65
2021-2022	Nov	$ 9.12	$ 9.12	$ 9.12	$ 9.13	$ 9.16	$ 9.12	$ 9.12	$ 9.13
2021-2022	Dec	$ 9.29	$ 9.29	$ 9.29	$ 9.29	$ 9.30	$ 9.29	$ 9.30	$ 9.31
2021-2022	Jan	$ 9.36	$ 9.36	$ 9.36	$ 9.36	$ 9.37	$ 9.36	$ 9.37	$ 9.37
2021-2022	Feb	$ 10.04	$ 10.02	$ 10.02	$ 16.05	$ 9.19	$ 10.02	$ 10.12	$ 20.74
2021-2022	Mar	$ 8.48	$ 8.48	$ 8.48	$ 8.48	$ 8.70	$ 8.48	$ 8.48	$ 8.48
2021-2022	Apr	$ 8.23	$ 8.23	$ 8.23	$ 8.23	$ 8.44	$ 8.23	$ 8.23	$ 8.23
2021-2022	May	$ 8.34	$ 8.34	$ 8.34	$ 8.34	$ 8.51	$ 8.34	$ 8.34	$ 8.34
2021-2022	Jun	$ 8.33	$ 8.33	$ 8.33	$ 8.33	$ 8.54	$ 8.33	$ 8.33	$ 8.33
2021-2022	Jul	$ 8.40	$ 8.40	$ 8.40	$ 8.40	$ 8.61	$ 8.40	$ 8.40	$ 8.40
2021-2022	Aug	$ 8.46	$ 8.46	$ 8.46	$ 8.46	$ 8.68	$ 8.46	$ 8.46	$ 8.46
2021-2022	Sep	$ 8.53	$ 8.53	$ 8.53	$ 8.53	$ 8.75	$ 8.53	$ 8.53	$ 8.53
2021-2022	Oct	$ 8.64	$ 8.64	$ 8.64	$ 8.64	$ 8.86	$ 8.64	$ 8.64	$ 8.64
Average 2021-2022		$ 8.77	$ 8.77	$ 8.77	$ 9.27	$ 8.84	$ 8.77	$ 8.78	$ 9.66
Winter		$ 9.26	$ 9.26	$ 9.26	$ 10.46	$ 9.14	$ 9.26	$ 9.28	$ 11.41
2022-2023	Nov	$ 9.25	$ 9.25	$ 9.25	$ 9.27	$ 9.29	$ 9.25	$ 9.25	$ 9.27
2022-2023	Dec	$ 9.44	$ 9.44	$ 9.44	$ 9.44	$ 9.44	$ 9.44	$ 9.44	$ 9.45
2022-2023	Jan	$ 9.51	$ 9.51	$ 9.51	$ 9.51	$ 9.51	$ 9.51	$ 9.51	$ 9.52
2022-2023	Feb	$ 10.20	$ 10.18	$ 10.19	$ 16.29	$ 9.49	$ 10.18	$ 10.34	$ 20.91
2022-2023	Mar	$ 8.80	$ 8.80	$ 8.80	$ 8.80	$ 9.02	$ 8.80	$ 8.80	$ 8.80
2022-2023	Apr	$ 8.70	$ 8.70	$ 8.70	$ 8.70	$ 8.92	$ 8.70	$ 8.70	$ 8.70
2022-2023	May	$ 8.75	$ 8.75	$ 8.75	$ 8.75	$ 8.98	$ 8.75	$ 8.75	$ 8.75
2022-2023	Jun	$ 8.82	$ 8.82	$ 8.82	$ 8.82	$ 9.04	$ 8.82	$ 8.82	$ 8.82
2022-2023	Jul	$ 8.89	$ 8.89	$ 8.89	$ 8.89	$ 9.11	$ 8.89	$ 8.89	$ 8.89
2022-2023	Aug	$ 8.95	$ 8.95	$ 8.95	$ 8.95	$ 9.18	$ 8.95	$ 8.95	$ 8.95
2022-2023	Sep	$ 9.02	$ 9.02	$ 9.02	$ 9.02	$ 9.25	$ 9.02	$ 9.02	$ 9.02
2022-2023	Oct	$ 9.16	$ 9.16	$ 9.16	$ 9.16	$ 9.39	$ 9.16	$ 9.16	$ 9.16
Average 2022-2023		$ 9.12	$ 9.12	$ 9.12	$ 9.63	$ 9.22	$ 9.12	$ 9.14	$ 10.02
Winter		$ 9.44	$ 9.43	$ 9.44	$ 10.66	$ 9.35	$ 9.43	$ 9.47	$ 11.59
2023-2024	Nov	$ 9.96	$ 9.96	$ 9.97	$ 9.98	$ 10.02	$ 9.96	$ 9.97	$ 9.99
2023-2024	Dec	$ 10.18	$ 10.18	$ 10.18	$ 10.18	$ 10.18	$ 10.18	$ 10.18	$ 10.20
2023-2024	Jan	$ 10.25	$ 10.25	$ 10.26	$ 10.26	$ 10.26	$ 10.25	$ 10.26	$ 10.27
2023-2024	Feb	$ 10.67	$ 10.64	$ 10.66	$ 16.68	$ 10.20	$ 10.64	$ 10.85	$ 21.01
2023-2024	Mar	$ 9.66	$ 9.66	$ 9.66	$ 9.66	$ 9.91	$ 9.66	$ 9.66	$ 9.66
2023-2024	Apr	$ 9.48	$ 9.48	$ 9.48	$ 9.48	$ 9.72	$ 9.48	$ 9.48	$ 9.48

Gas Year	Month	Albany	Astoria	Dalles	Eugene	Newport LC	Portland	Salem	Vancouver
2023-2024	May	$ 9.63	$ 9.63	$ 9.63	$ 9.63	$ 9.82	$ 9.63	$ 9.63	$ 9.63
2023-2024	Jun	$ 9.62	$ 9.62	$ 9.62	$ 9.62	$ 9.86	$ 9.62	$ 9.62	$ 9.62
2023-2024	Jul	$ 9.69	$ 9.69	$ 9.69	$ 9.69	$ 9.94	$ 9.69	$ 9.69	$ 9.69
2023-2024	Aug	$ 9.76	$ 9.76	$ 9.76	$ 9.76	$ 10.01	$ 9.76	$ 9.76	$ 9.76
2023-2024	Sep	$ 9.84	$ 9.84	$ 9.84	$ 9.84	$ 10.08	$ 9.84	$ 9.84	$ 9.84
2023-2024	Oct	$ 9.99	$ 9.99	$ 9.99	$ 9.99	$ 10.24	$ 9.99	$ 9.99	$ 9.99
Average 2023-2024		$ 9.89	$ 9.89	$ 9.89	$ 10.40	$ 10.02	$ 9.89	$ 9.91	$ 10.76
Winter		$ 10.15	$ 10.14	$ 10.15	$ 11.35	$ 10.11	$ 10.14	$ 10.18	$ 12.23
2024-2025	Nov	$ 10.77	$ 10.77	$ 10.78	$ 10.79	$ 10.84	$ 10.77	$ 10.78	$ 10.80
2024-2025	Dec	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.02
2024-2025	Jan	$ 11.08	$ 11.08	$ 11.08	$ 11.08	$ 11.08	$ 11.08	$ 11.08	$ 11.09
2024-2025	Feb	$ 11.54	$ 11.52	$ 11.53	$ 17.76	$ 11.06	$ 11.52	$ 11.75	$ 22.26
2024-2025	Mar	$ 10.27	$ 10.27	$ 10.27	$ 10.27	$ 10.53	$ 10.27	$ 10.27	$ 10.27
2024-2025	Apr	$ 9.94	$ 9.94	$ 9.94	$ 9.94	$ 10.19	$ 9.94	$ 9.94	$ 9.94
2024-2025	May	$ 10.10	$ 10.10	$ 10.10	$ 10.10	$ 10.29	$ 10.10	$ 10.10	$ 10.10
2024-2025	Jun	$ 10.08	$ 10.08	$ 10.08	$ 10.08	$ 10.34	$ 10.08	$ 10.08	$ 10.08
2024-2025	Jul	$ 10.15	$ 10.15	$ 10.15	$ 10.15	$ 10.41	$ 10.15	$ 10.15	$ 10.15
2024-2025	Aug	$ 10.23	$ 10.23	$ 10.23	$ 10.23	$ 10.49	$ 10.23	$ 10.23	$ 10.23
2024-2025	Sep	$ 10.30	$ 10.30	$ 10.30	$ 10.30	$ 10.56	$ 10.30	$ 10.30	$ 10.30
2024-2025	Oct	$ 10.50	$ 10.50	$ 10.50	$ 10.50	$ 10.76	$ 10.50	$ 10.50	$ 10.50
Average 2024-2025		$ 10.50	$ 10.49	$ 10.50	$ 11.02	$ 10.63	$ 10.49	$ 10.51	$ 11.39
Winter		$ 10.93	$ 10.93	$ 10.93	$ 12.18	$ 10.90	$ 10.93	$ 10.98	$ 13.09
2025-2026	Nov	$ 11.43	$ 11.43	$ 11.44	$ 11.44	$ 11.52	$ 11.43	$ 11.44	$ 11.46
2025-2026	Dec	$ 11.70	$ 11.70	$ 11.70	$ 11.70	$ 11.71	$ 11.70	$ 11.70	$ 11.72
2025-2026	Jan	$ 11.79	$ 11.79	$ 11.79	$ 11.79	$ 11.79	$ 11.79	$ 11.79	$ 11.80
2025-2026	Feb	$ 12.31	$ 12.09	$ 12.14	$ 18.64	$ 11.83	$ 12.09	$ 12.45	$ 22.84
2025-2026	Mar	$ 10.25	$ 10.25	$ 10.25	$ 10.25	$ 10.51	$ 10.25	$ 10.25	$ 10.25
2025-2026	Apr	$ 9.87	$ 9.87	$ 9.87	$ 9.87	$ 10.12	$ 9.87	$ 9.87	$ 9.87
2025-2026	May	$ 9.97	$ 9.97	$ 9.97	$ 9.97	$ 10.20	$ 9.97	$ 9.97	$ 9.97
2025-2026	Jun	$ 10.01	$ 10.01	$ 10.01	$ 10.01	$ 10.26	$ 10.01	$ 10.01	$ 10.01
2025-2026	Jul	$ 10.08	$ 10.08	$ 10.08	$ 10.08	$ 10.34	$ 10.08	$ 10.08	$ 10.08
2025-2026	Aug	$ 10.16	$ 10.16	$ 10.16	$ 10.16	$ 10.41	$ 10.16	$ 10.16	$ 10.16
2025-2026	Sep	$ 10.23	$ 10.23	$ 10.23	$ 10.23	$ 10.49	$ 10.23	$ 10.23	$ 10.23
2025-2026	Oct	$ 10.40	$ 10.40	$ 10.40	$ 10.40	$ 10.66	$ 10.40	$ 10.40	$ 10.40
Average 2025-2026		$ 10.68	$ 10.67	$ 10.67	$ 11.21	$ 10.82	$ 10.67	$ 10.70	$ 11.57
Winter		$ 11.50	$ 11.45	$ 11.46	$ 12.77	$ 11.47	$ 11.45	$ 11.53	$ 13.62

Gas Year	Month	Albany	Astoria	Dalles	Eugene	Newport LC	Portland	Salem	Vancouver
2026-2027	Nov	$ 11.29	$ 11.29	$ 11.31	$ 11.32	$ 11.38	$ 11.29	$ 11.30	$ 11.32
2026-2027	Dec	$ 11.56	$ 11.56	$ 11.57	$ 11.56	$ 11.56	$ 11.56	$ 11.56	$ 11.59
2026-2027	Jan	$ 11.64	$ 11.64	$ 11.65	$ 11.65	$ 11.65	$ 11.64	$ 11.64	$ 11.66
2026-2027	Feb	$ 12.52	$ 12.49	$ 12.51	$ 21.83	$ 11.46	$ 12.49	$ 12.88	$ 23.23
2026-2027	Mar	$ 10.79	$ 10.79	$ 10.79	$ 10.79	$ 11.09	$ 10.79	$ 10.82	$ 10.79
2026-2027	Apr	$ 10.75	$ 10.75	$ 10.75	$ 10.75	$ 11.02	$ 10.75	$ 10.75	$ 10.75
2026-2027	May	$ 10.75	$ 10.75	$ 10.75	$ 10.75	$ 11.00	$ 10.75	$ 10.75	$ 10.75
2026-2027	Jun	$ 10.68	$ 10.68	$ 10.68	$ 10.68	$ 10.94	$ 10.68	$ 10.68	$ 10.68
2026-2027	Jul	$ 10.75	$ 10.75	$ 10.75	$ 10.75	$ 11.02	$ 10.75	$ 10.75	$ 10.75
2026-2027	Aug	$ 10.83	$ 10.83	$ 10.83	$ 10.83	$ 11.10	$ 10.83	$ 10.83	$ 10.83
2026-2027	Sep	$ 10.90	$ 10.90	$ 10.90	$ 10.90	$ 11.18	$ 10.90	$ 10.90	$ 10.90
2026-2027	Oct	$ 11.07	$ 11.07	$ 11.07	$ 11.07	$ 11.34	$ 11.07	$ 11.07	$ 11.07
Average 2026-2027		$ 11.13	$ 11.13	$ 11.13	$ 11.91	$ 11.23	$ 11.13	$ 11.16	$ 12.03
Winter		$ 11.56	$ 11.56	$ 11.56	$ 13.43	$ 11.43	$ 11.56	$ 11.64	$ 13.72
2027-2028	Nov	$ 11.24	$ 11.24	$ 11.25	$ 11.35	$ 11.40	$ 11.24	$ 11.29	$ 11.27
2027-2028	Dec	$ 11.37	$ 11.37	$ 11.39	$ 11.40	$ 11.48	$ 11.37	$ 11.41	$ 14.63
2027-2028	Jan	$ 11.46	$ 11.46	$ 11.47	$ 11.49	$ 11.56	$ 11.46	$ 11.49	$ 14.72
2027-2028	Feb	$ 11.61	$ 11.55	$ 11.57	$ 11.83	$ 11.45	$ 11.55	$ 11.97	$ 21.93
2027-2028	Mar	$ 10.82	$ 10.82	$ 10.82	$ 10.82	$ 11.12	$ 10.82	$ 10.84	$ 10.82
2027-2028	Apr	$ 10.75	$ 10.75	$ 10.75	$ 10.75	$ 11.02	$ 10.75	$ 10.75	$ 10.75
2027-2028	May	$ 10.75	$ 10.75	$ 10.75	$ 10.75	$ 11.00	$ 10.75	$ 10.75	$ 10.75
2027-2028	Jun	$ 10.68	$ 10.68	$ 10.68	$ 10.68	$ 10.94	$ 10.68	$ 10.68	$ 10.68
2027-2028	Jul	$ 10.75	$ 10.75	$ 10.75	$ 10.75	$ 11.02	$ 10.75	$ 10.75	$ 10.75
2027-2028	Aug	$ 10.83	$ 10.83	$ 10.83	$ 10.83	$ 11.10	$ 10.83	$ 10.83	$ 10.83
2027-2028	Sep	$ 10.90	$ 10.90	$ 10.90	$ 10.90	$ 11.18	$ 10.90	$ 10.90	$ 10.90
2027-2028	Oct	$ 11.06	$ 11.06	$ 11.06	$ 11.06	$ 11.34	$ 11.06	$ 11.06	$ 11.06
Average 2027-2028		$ 11.02	$ 11.01	$ 11.02	$ 11.05	$ 11.22	$ 11.01	$ 11.06	$ 12.42
Winter		$ 11.30	$ 11.29	$ 11.30	$ 11.38	$ 11.40	$ 11.29	$ 11.40	$ 14.67

Development of the Real After-Tax Discount Rate

NORTHWEST NATURAL
INVESTMENT CARRYING CHARGE

30 YEAR INVESTMENT

CARRYING COST ASSUMPTIONS

DESCRIPTION	AMOUNT	
FINANCING		
COMPOSITION		
DEBT	49.82	
PREFERRED	0.68	
COMMON	49.5	
	100	
COST		
DEBT	7.07	
PREFERRED	7.16	
COMMON	10.25	
TOTAL	8.64	
TAXES		
TAX LIFE	30	
MONTH(REAL PROP)	6	
DRDB RATE	100	
COMPOSITE RATE	39.12	
DEFERRED RATE	0	
PROPERTY TAX RATE	1.56	
FACILITY		
BOOK LIFE	30	
INVESTMENT	100	
SUMMARY OF RESULTS		
RETURN	5.949	
DEPRECIATION	3.333	
INCOME TAX	2.351	
PROP TAX	1.074	
A & G	0.000	
GEN PLT @	0.000	

NOMINAL CARRYING CHARGE	12.71	%
INFLATION	2.00	%
REAL CARRYING CHARGE	10.54	%
AFTER TAX DISCOUNT RATE	7.27	%
REAL AFTER-TAX DISC RATE	5.16	%
Gross Up Factor	1.405	

YEAR	EARNINGS BASE	RETURN	BOOK DEPR	TAX BASE	TAX DEPR	INTEREST	DEFERRED TAXES	CURRENT TAXES	TOTAL TAXES	PROP TAX	REV REQT
1	98.333	8.499	3.333	100.000	1.667	3.462	0.000	4.308	4.308	1.534	17.674
2	95.000	8.211	3.333	98.333	3.333	3.344	0.000	3.127	3.127	1.482	16.153
3	91.667	7.922	3.333	95.000	3.333	3.227	0.000	3.017	3.017	1.430	15.703
4	88.333	7.634	3.333	91.667	3.333	3.110	0.000	2.908	2.908	1.378	15.253
5	85.000	7.346	3.333	88.333	3.333	2.992	0.000	2.798	2.798	1.326	14.803
6	81.667	7.058	3.333	85.000	3.333	2.875	0.000	2.688	2.688	1.274	14.354
7	78.333	6.770	3.333	81.667	3.333	2.758	0.000	2.578	2.578	1.222	13.904
8	75.000	6.482	3.333	78.333	3.333	2.640	0.000	2.469	2.469	1.170	13.454
9	71.667	6.194	3.333	75.000	3.333	2.523	0.000	2.359	2.359	1.118	13.004
10	68.333	5.906	3.333	71.667	3.333	2.406	0.000	2.249	2.249	1.066	12.554
11	65.000	5.618	3.333	68.333	3.333	2.288	0.000	2.140	2.140	1.014	12.105
12	61.667	5.330	3.333	65.000	3.333	2.171	0.000	2.030	2.030	0.962	11.655
13	58.333	5.042	3.333	61.667	3.333	2.053	0.000	1.920	1.920	0.910	11.205
14	55.000	4.753	3.333	58.333	3.333	1.936	0.000	1.810	1.810	0.858	10.755
15	51.667	4.465	3.333	55.000	3.333	1.819	0.000	1.701	1.701	0.806	10.305
16	48.333	4.177	3.333	51.667	3.333	1.701	0.000	1.591	1.591	0.754	9.856
17	45.000	3.889	3.333	48.333	3.333	1.584	0.000	1.481	1.481	0.702	9.406
18	41.667	3.601	3.333	45.000	3.333	1.467	0.000	1.371	1.371	0.650	8.956
19	38.333	3.313	3.333	41.667	3.333	1.349	0.000	1.262	1.262	0.598	8.506
20	35.000	3.025	3.333	38.333	3.333	1.232	0.000	1.152	1.152	0.546	8.056
21	31.667	2.737	3.333	35.000	3.333	1.115	0.000	1.042	1.042	0.494	7.607
22	28.333	2.449	3.333	31.667	3.333	0.997	0.000	0.933	0.933	0.442	7.157
23	25.000	2.161	3.333	28.333	3.333	0.880	0.000	0.823	0.823	0.390	6.707
24	21.667	1.873	3.333	25.000	3.333	0.763	0.000	0.713	0.713	0.338	6.257
25	18.333	1.584	3.333	21.667	3.333	0.645	0.000	0.603	0.603	0.286	5.807
26	15.000	1.296	3.333	18.333	3.333	0.528	0.000	0.494	0.494	0.234	5.357
27	11.667	1.008	3.333	15.000	3.333	0.411	0.000	0.384	0.384	0.182	4.908
28	8.333	0.720	3.333	11.667	3.333	0.293	0.000	0.274	0.274	0.130	4.458
29	5.000	0.432	3.333	8.333	3.333	0.176	0.000	0.165	0.165	0.078	4.008
30	1.667	0.144	3.333	5.000	3.333	0.059	0.000	0.055	0.055	0.026	3.558
31	0.000	0.000	0.000	1.667	1.667	0.000	0.000	-1.071	-1.071	0.000	-1.071
32	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
33	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
34	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
35	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
36	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
37	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
38	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
39	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
40	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
41	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
42	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
43	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
44	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
45	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
46	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
47	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
48	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
49	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
50	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
51	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NET PRESENT VALUE	761.131	65.782	36.857	796.522	35.391	26.794	0.000	25.995	25.995	11.874	140.508

APPENDIX 7
PUBLIC COMMUNICATION AND PARTICIPATION

NAME	ORGANIZATION	E-MAIL ADDRESS
Deborah Reynolds	UTC	dreynold@utc.wa.gov
Jane Harrison	Northwest Pipeline	jane.f.harrison@williams.com
Teresa Hagins	Northwest Pipeline	Teresa.L.Hagins@williams.com
Dan Kirschner	Northwest Gas Association	dkirschner@nwga.org
Paula Pyron	NWIGU	ppyron@nwigu.org
Lea Daeschel	Public Counsel	lead@atg.wa.gov
Terry Morlan	NWPCC	tmorlan@nwcouncil.org
Randy Friedman	NWN	
Pete Catching	Energy Trust of Oregon	pete.catching@energytrust.org
DAVE SLOAN	TRANSCANADA-GTN	dave_sloan@transcanada.com

11-5-08 TWG Mtg

Gross, Jennifer

To: 2009 Washington IRP TWG

Subject: NW Natural's 2009 IRP Technical Working Group Meeting on Nov. 5th

Attachments: TWG Letter dated October 21, 2008.doc; 2008 IRP Letter from WUTC, Docket UG-070619, 10-9-08.pdf

Good Morning,

Please see the attached letter from Inara Scott regarding NW Natural's Technical Working Group that convenes on November 5th to discuss NW Natural's 2009 IRP.

Please call or email me if you have questions.

Thanks.

Jennifer Gross
Tariff and Regulatory Compliance, NW Natural
220 NW Second Ave
Portland, Oregon 97209
(503) 226-4211 x3590
(800)422-4012 x3590

Rates and Regulatory Affairs
Facsimile: 503.721.2532

NW Natural
220 NW 2ND AVENUE
PORTLAND, OR 97209
TEL 503.226.4211
www.nwnatural.com

October 21, 2008

Dear Technical Working Group Members,

NW Natural is preparing its 2009 Integrated Resource Plan for filing with the Washington Utilities and Transportation Commission (WUTC) on March 31, 2009.

We would like to remind you that you have been invited to two Technical Working Group Meetings: one on **November 5, 2008** and the second on **February 11, 2009**. Both meetings will be held on the 4th floor of the Company's downtown corporate office which is located at **220 NW 2nd Ave, Portland, Oregon**. The meetings will begin at 8:30 a.m and will finish by 12:00 p.m.

Most of you were involved in the review of our 2008 IRP that was filed April 2008 in both Oregon and Washington, so recognize that we have a short timeframe between the filing our last IRP and our next one. In respect of time constraints, I ask that you review the 2008 IRP prior to the November 5th meeting. If you retained a copy, please bring it with you. You can find links to the 2008 version on our webpage or under Docket No. UG-070619 on the WUTC web page.

Also, I have attached a copy of the WUTC's letter wherein the Commission states that it has reviewed the Company's 2008 IRP and that it meets the requirements of the Washington Administration Code 480-90-238. The letter also offers suggestions for the Company's next IRP. Please consider their comments and bring with you any questions or concerns that you would like addressed in our 2009 IRP.

Our first Technical Working Group meeting is rapidly approaching so please start considering the issues now so that our meeting will be productive. We will email you an agenda as we draw closer to November 5th. In the meantime, please email Jennifer Gross at jennifer.gross@nwnatrual.com with any items you would like added to the agenda.

We look forward to talking with you. We trust these technical working group meetings will result in meaningful updates and improvements to our 2009 IRP.

If you have any questions about this process or about the meeting logistics, please call Jennifer Gross at (503) 226-4211 ext. 3590.

Thank you.

Sincerely,

/s/ Inara K. Scott

Inara K. Scott
Manager, Regulatory Affairs

SERVICE DATE
OCT 0 9 2008

STATE OF WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION
1300 S. Evergreen Park Dr. S.W., PO Box 47250 • Olympia, Washington 98504-7250•
(360) 664-1160 • TTY (360) 586-8203

RECEIVED

October 9, 2008

OCT 14 2008

RATES &
REGULATORY AFFAIRS
C2M
JGG
S7S
TRIM

Inara K. Scott
NW Natural Gas Company
220 NW Second Avenue
Portland, Oregon 97209

Re: NW Natural's 2007 Natural Gas Integrated Resource Plan
Docket UG-070619

Dear Ms. Scott:

The Utilities and Transportation Commission ("Commission") has reviewed NW Natural Gas Company's ("NW Natural's or "company's") 2007 draft Integrated Resource Plan ("IRP") and 2008 update.[1] After careful review and consideration, the Commission finds as a whole that it meets the requirements of Washington Administrative Code 480-90-238.

The Commission emphasizes that this finding does not pre-approve for ratemaking any expenditures for resources or actions identified in the IRP. The Commission will give due weight to the information, analysis, and strategies contained in the IRP along with other pertinent information during any evaluation of NW Natural's services and rates.

Attached are specific comments from the Commission regarding the IRP. Although there are many improvements in the IRP, the Commission is concerned that the IRP failed to address adequately "new policies and programs needed to obtain the conservation improvements" as required under WAC 480-90-238(3). In particular, the company's failure to examine any alternative to the Energy Trust of Oregon as a conservation program administrator and the failure to evaluate "new policies and programs" in the absence of decoupling were notable, especially in comparison to the robust analyses of demand forecast and supply side resources. The commission expects that these matters will be addressed in the next IRP.

---

[1] NW Natural timely filed its 2007 IRP work plan on March 28, 2006, and 2007 draft IRP on March 28, 2007. On April 21, 2008, the company filed its 2008 update of the draft IRP. The Commission took public comment on the updated IRP at a recessed open meeting on September 11, 2008.

Inara K. Scott
October 9, 2008
Page Two

NW Natural's 2009 IRP is due on or before March 31, 2009. Commission Staff will provide additional detailed comments as NW Natural develops its next IRP.

We regret that review and acknowledgment of the 2007 IRP were delayed. Please be advised that staff has put in place internal procedures to ensure that IRPs are brought before the Commission in a timely manner.

Sincerely,

David W. Danner
Executive Director and Secretary

Attachment

Attachment

Utilities and Transportation Commission Comments on

NW Natural Gas Company's 2007 Natural Gas Integrated Resource Plan

As a natural gas utility operating in Washington, NW Natural Gas Company (NW Natural) has a fundamental responsibility to manage the risks and opportunities associated with acquiring and delivering natural gas on behalf of its customers. This responsibility is particularly important in an era of high and volatile natural gas prices. The planning requirements specified in WAC 480-90-238 are intended to help each utility develop a strategic approach to navigate marketplace opportunities and risks based on that utility's unique attributes. NW Natural's 2008 update (the Plan) to its 2007 Integrated Resource Plan (IRP) represents such a strategic approach. As such, it is consistent with the Utilities and Transportation Commission's (Commission's) planning regulations. Below we discuss how the Plan addresses the elements specified in WAC 480-90-238 for integrated resource plans.

Executive Summary and Multi-Year Action Plan

The Executive Summary contains a description of the Washington IRP guidelines.

- NW Natural should examine the IRP rules at WAC 480-238-90 and update its description of the IRP requirements.

The supply-side resource options in the multi-year action plan are generally good, but the commitment in item 2.1 to review cost estimates on an ongoing basis should be considered paramount. With several high-cost, supply-side alternatives still several years away, NW Natural has time to revise its cost estimates.

Demand Forecast of Retail Gas Requirements (Chapter 2)

In its 2004 IRP, NW Natural used a deterministic demand forecast. The 2008 Plan, by contrast, uses a stochastic modeling technique to forecast natural gas load to create a probabilistic distribution of natural gas demand as a function of price and weather. This was a necessary improvement in modeling capability. It now allows the modeling of a three-day peak event instead of simple single-day peak. It also allows the peak day and its shoulder days to be modeled throughout the winter heating season, providing more realistic representations of possible demand conditions NW Natural faces.

A number of refinements in the company's modeling have been identified as a result of the newly adopted modeling software. For example, the software uncovered shortcomings in the way NW Natural has measured demand forecast error by region.

- In its next IRP, NW Natural should continue to examine the adequacy of its input data and assumptions in light of the requirements of the newly adopted modeling software.

NW Natural's reliance on the Oregon Office of Economic Analysis' "Quarterly Economic and Revenue Forecast" needs justification. It is unclear how demand growth is projected for Washington service territories ("Vancouver and the Dalles") using the Oregon data base or whether some other unnamed data source is used to derive the Washington demand projection.[1]

- In the next IRP, NW Natural should include an explicit explanation of the data source for the regression analysis for the Washington demand projection.
- In the next IRP, NW Natural should consider alternatives to the data sources it uses to project demand and provide an explanation for the data source it chooses.

The Plan does an excellent job of identifying variation in the demand forecast accuracy due to Heating Degree Days (HDD). The identification of lower forecast accuracy for "warm" day demand is the type of sensitivity analysis IRP planning should contain. However, the graphs used on page 2-22 and 2-23 could be improved to more clearly illustrate the lower forecast accuracy to the reader.

- NW Natural should consider changes to the graphic illustrations to improve communication with outside parties and NW Natural management.

It is not clear whether NW Natural compared the previous IRP demand forecasts to actual demand. A forecast will seldom be perfect, but consistently high or low forecasts may indicate a bias in the forecast modeling.

- The Commission encourages NW Natural to examine in its next IRP the previous IRP demand forecasts for consistently high or low forecasts and determine whether and to what extent there is a bias in the forecasting model.

The demand forecast scenarios in the Plan are varied. The Plan does not discuss the relative likelihood of these various scenarios or whether growth scenarios such as those used in the Plan have occurred historically.

- Future IRPs should include an explanation of the basis for choosing demand scenarios.

---

[1] Page 2-8 describes the database used for the demand forecasts but provides no explanation of how the "Vancouver and the Dalles" regional center forecast is derived from that data.

Supply Side Resources (Chapter 3)

The Plan provides an excellent description of current resources. The use of the Synergy software package, integrated with the company GIS data system, is an important tool. The Plan identifies several trade-offs between distribution system upgrades and other supply resources such as a recall of storage or pipeline capacity

The discussion of liquid natural gas (LNG) resources is complete with respect to the physical infrastructure. The Plan provides good descriptions of facilities options, citing needs of accompanying pipelines for the facilities and permitting information. However, the IRP does not provide an economic analysis to show that once built, the LNG facilities would have any LNG delivered to them. The Company states, "absent more definitive information from project developers, we assume that import LNG supply will be priced competitively alongside any of [NW Natural's] other gas supply contracts."

The amount of LNG delivered to the United States has decreased significantly due to better prices at other delivery points in the world market. Long-term contracts for LNG deliveries not tied to world-indexed prices appear increasingly uncommon.

- Consideration of LNG supplies in the next IRP must take a hard look at world demand and price competition for LNG supplies.

While the Commission recognizes the IRP's SENDOUT model and the Gas Acquisition Plan (GAP) have different time horizons, they have the same ultimate purpose. The choices in the GAP are related to the choices made about long-term resource acquisition.

- The Commission encourages NW Natural to model the impact of long-term resource choices on the ability of the GAP to mitigate cost and risks.

Company's Resource Choices (Chapter 5)

The Commission supports NW Natural's adoption of SENDOUT Version 12 that integrates VectorGas into SENDOUT. The ability of the software to perform Monte Carlo simulations is essential to assessing risk.

NW Natural has adopted the augmented its simulations by adopting a 85 percent probability coldest winter design year, in place of the historically coldest season/coldest peak day out of the last 20 years. This change was in part enabled by the new software capabilities, but as NW Natural points out, it also reduces the present value of 20-year supply costs by $792 million. We are concerned that the simultaneous adoption of a new planning standard and the new version of SENDOUT may produce unintended consequences in the implementation of this Plan.

- The next IRP should review closely the adoption of the new planning standard and its use in the model. Analysis of the 2007-2008 winter or other analyses may help affirm (or bring into question) the new standard.

NW Natural describes the diminished correlation of relative price patterns with the inclusion of greater amounts of historical price data. While this might be the case – and substitute price correlation factors might be appropriate – NW Natural does not explain how it derived such price correlation factors. The offering of 0.8 as a correlation factor for price indices and 0.5 as a correlation factor for price indices to its prior-month draw are unsupported in the IRP.

- In the next IRP, NW Natural must provide explanations of the derivation of the price correlations it uses.

Conclusion

The Commission acknowledges that NW Natural's 2008 natural gas integrated resource plan complies with current regulatory requirements. The Plan advances the analytical work of the IRP with advances in software modeling. The Commission believes that further improvement may be achieved by incorporating the recommendations or suggestions identified in this attachment and addressing deficiencies identified in the acknowledgement letter.

Gross, Jennifer

From:	Gross, Jennifer
Sent:	Wednesday, October 01, 2008 2:14 PM
To:	'Dan Kirschner'; Dave Robison; 'Dave Sloan'; 'Dave Swenson'; Deborah Reynolds (DReynold@utc.wa.gov); 'Douglas Kilpatrick'; 'Fred Gordon'; Friedman, Randy; Huddleston, Jon; 'Joe Ross'; 'John Slocum'; Lea Daeschel; Matt Braman; 'Matthew T. McNeil'; McVay, Kevin; Miller, C. Alex; Miller, Kelley; 'Paula Pyron'; 'Pete Catching'; 'Phil Carver'; Scott, Inara; Shampine, Kerry; Shifley, Sarah (ATG); Simmons, Steven; Simon ffitch; 'Steve Johnson'; 'Steve Weiss'; Stinson, Charlie; 'Teresa Hagins'; 'Terry Morlan'; 'Vanda Novak'; White, Keith; Yoshihara, Grant
Subject:	TRIM: NW Natural's 2009 IRP - Technical Working Group (TWG) Meeting Invitation
TRIM Dataset:	P1
TRIM Record Number:	RAT36-261/00066
TRIM Record URI:	20163

NW Natural's 2009 IRP - Technical Working Group (TWG) Meeting Invitation

NW Natural is preparing it's 2009 Washington IRP and would like to invite you to participate in its Technical Working Group (TWG) meetings. In these meetings, we will discuss the Company's plan to provide the best and least cost portfolio of supply- and demand-side resources that are sufficient to meet its customers' future usage needs. We welcome your input at these meetings.

MEETING DATES:

TWG Meetings are scheduled for **8:30 a.m. to 12:00 p.m.** on

November 5th Wednesday

and

February 11th, Wednesday

MEETING LOCATION

These meetings will be held on the 4th Floor, in the Hospitality Room at NW Natural's corporate office located at

220 NW Second Avenue
Portland, Oregon 97209

PARKING & TRANSPORTATION

A public Smart Park parking lot is located at the corner of NW Naito (Front) and NW Davis. This is just across the street from NW Natural's corporate office.

Also, you can get to NW Natural by riding the MAX light rail. The OLD TOWN/ CHINA TOWN Max Stop (1st and Davis) is right in front of NW Natural's building.

MEETING PREPARATION

In preparation for the November 5th meeting, please review NW Natural's IRP, that you can find at the following link:

https://www.nwnatural.com/content_aboutus.asp?id=480

This IRP was filed on April 17, 2008, as an update to the Company's 2007 IRP. While we expect to update and improve this 2007 updated IRP, it is current enough to be an excellent starting point for our November 5th meeting.

NW Natural looks forward to working with you. Please call me at (503)226-4211 ext. 3590 if you have questions.

Thanks

Jennifer Gross
Tariff and Regulatory Compliance, NW Natural
220 NW Second Ave
Portland, Oregon 97209
(503) 226-4211 x3590
(800)422-4012 x3590

Gross, Jennifer

Subject: Technical Working Group (TWG) NWN 2009 IRP - Draft Chapter 4, DSM

Attachments: DRAFT NWN 2009 IRP Chapter 4 Demand-Side Resources.DOC

Hello,

As a member of the 2009 Technical Working Group (TWG) that is participating in the development of NW Natural's 2009 Integrated Resource Plan, you know that the we have little time before our plan is due to the WUTC on March 31, 2008. As promised, NW Natural is supplementing the TWG meetings by emailing you early drafts of our IRP Chapters. We hope these emails prove to be a useful and time-efficient way for you to review our work and offer comments. Expect to receive these emails between now and early January 2009.

Attached is a Draft Chapter 4, Demand Side Resources. Please review this and email me your suggestions or questions. Please note that this is a working draft. We know the estimated potential therms saved will change as refinements to the study are being made. Also, we will add insights and action items after SENDOUT runs are completed.

Thank you.

Jennifer Gross
Tariff and Regulatory Compliance, NW Natural
220 NW Second Ave
Portland, Oregon 97209
(503) 226-4211 x3590
(800)422-4012 x3590

Gross, Jennifer

From: Steve Weiss [weiss.steve@comcast.net]

Sent: Monday, December 22, 2008 1:52 PM

To: Gross, Jennifer; Dan Kirschner; Dave Robison; Dave Sloan; Dave Swenson; DReynold@utc.wa.gov; Douglas Kilpatrick; Fred Gordon; Friedman, Randy; Huddleston, Jon; Joe Ross; John Slocum; Matt Braman; Matthew T. McNeil; McVay, Kevin; Miller, C. Alex; Miller, Kelley; Paula Pyron; Pete Catching; Phil Carver; Scott, Inara; Shampine, Kerry; Shifley, Sarah (ATG); Simmons, Steven; Simon ffitch; Steve Johnson; Steve Weiss; Stinson, Charlie; Teresa Hagins; Terry Morlan; Vanda Novak; White, Keith; Yoshihara, Grant

Subject: Re: Technical Working Group (TWG) NWN 2009 IRP - Draft Chapter 4, DSM

Attachments: NWECcommentsCh4DSM.doc

Attached are brief comments from NWEC on Chapter 4. Thank you.

Steve Weiss
Sr. Policy Associate
NW Energy Coalition
503-851-4054

From: "Gross, Jennifer" <Jennifer.Gross@nwnatural.com>
Date: Fri, 19 Dec 2008 13:54:25 -0800
To: Dan Kirschner <dkirschner@nwga.org>, Dave Robison <drobison@teleport.com>, Dave Sloan <Dave_Sloan@transcanada.com>, Dave Swenson <Dswenson@intgas.com>, <DReynold@utc.wa.gov>, Douglas Kilpatrick <dkilpatr@wutc.wa.gov>, Fred Gordon <fred@energytrust.org>, "Friedman, Randy" <Randy.Friedman@nwnatural.com>, "Huddleston, Jon" <Jon.Huddleston@nwnatural.com>, Joe Ross <joe_ross@transcanada.com>, John Slocum <jslocum@ceadvisors.com>, Lea Daeschel <lead@stg.wa.gov>, Matt Braman <matt.braman@energytrust.org>, "Matthew T. McNeil" <mmcneil@newenergyassoc.com>, "McVay, Kevin" <ksm@nwnatural.com>, "Miller, C. Alex" <c2m@nwnatural.com>, "Miller, Kelley" <kelley.miller@nwnatural.com>, Paula Pyron <ppyron@nwigu.org>, Pete Catching <pete.catching@energytrust.org>, Phil Carver <philip.h.carver@state.or.us>, "Scott, Inara" <Inara.Scott@nwnatural.com>, "Shampine, Kerry" <kfs@nwnatural.com>, "Shifley, Sarah (ATG)" <Sarah.Shifley@atg.wa.gov>, "Simmons, Steven" <Steven.Simmons@nwnatural.com>, Simon ffitch <simonf@atg.wa.gov>, Steve Johnson <sjohnson@utc.wa.gov>, Steve Weiss <steve@nwenergy.org>, "Stinson, Charlie" <ces@nwnatural.com>, Teresa Hagins <teresa.l.hagins@williams.com>, Terry Morlan <tmorlan@nwcouncil.org>, Vanda Novak <vnovak@utc.wa.gov>, "White, Keith" <jkw@nwnatural.com>, "Yoshihara, Grant" <gmy@nwnatural.com>
Conversation: Technical Working Group (TWG) NWN 2009 IRP - Draft Chapter 4, DSM
Subject: Technical Working Group (TWG) NWN 2009 IRP - Draft Chapter 4, DSM

Hello,

As a member of the 2009 Technical Working Group (TWG) that is participating in the development of NW Natural's 2009 Integrated Resource Plan, you know that the we have little time before our plan is due to the WUTC on March 31, 2008. As promised, NW Natural is supplementing the TWG meetings by emailing you early drafts of our IRP Chapters. We hope these emails prove to be a useful and time-efficient way for you to review our work and offer comments. Expect to receive these emails between now and early January 2009.

Attached is a Draft Chapter 4, Demand Side Resources. Please review this and email me your suggestions or questions. Please note that this is a working draft. We know the estimated potential therms saved will change as refinements to the study are being made. Also, we will add insights and action items after SENDOUT runs are completed.

Thank you.

Jennifer Gross
Tariff and Regulatory Compliance, NW Natural

Comments of the NW Energy Coalition
NW Natural's 2009 IRP, Chapter 4, DSM
Steve Weiss – December 22, 2008

The NW Energy Coalition (NWEC or "Coalition") is pleased to offer these brief interim comments on the chapter 4 draft.

- In calculating the avoided cost benefit of conservation measures, NWN should use an additional 10% adder as used by the Power Council to recognize unquantifiable benefits of conservation, and required by the NW Power Act. This 10% adder is in addition to any quantifiable avoided benefits such as CO2 costs, avoided system deferral costs, etc.

- It would be helpful for NWN to list the costs of all measures, whether deemed cost-effective or not (at this time), so the reader can see what measures might be "on the cusp" if avoided costs increased.

- On p. 4-11 it is noted that conservation can provide risk benefits. The text points to work by the Power Council to quantify this benefit, but NWN at this time does not have a value. It is true that the Council is revising this "hedge" benefit (the benefit that higher cost conservation plays in possible higher cost futures, even for measures not cost effective at presently *expected* costs) for its 6th Plan. However, NWN should use the value the Council assumed in its 5th Plan until the new analysis is complete, rather than giving a zero hedging benefit.

- The Coalition believes that fuel-switching measures—*both toward and away* from natural gas—should be analyzed in the IRP. While current policy tends to discourage fuel switching for single-fuel utilities, nothing prohibits including fuel-switching measures in this analysis. In fact, such analysis will help inform possible changes in the policies. In particular, heat pumps and heat-pump water heaters should be analyzed.

- Page 4-28 makes a couple of statements that we think are open to question. First:

> Industry experts speculate that Federal or additional state climate change legislation will affect natural gas utilities in several critical ways. First, legislation that restricts coal plant development will drive additional natural gas plant construction as natural gas becomes the overwhelming fuel of choice to meet needs for new base load needs. This growing demand for natural gas generation will put strains on supplies and potentially drive up commodity costs for natural gas customers.

NWEC agrees with this statement as far as it goes, but it fails to take into account other probable responses to global warming concerns that will most likely counteract the conclusion. Those responses include greater amounts of renewables (e.g., RPS mandates) and energy efficiency. A recent study by USDOE of a 20% by 2020 penetration rate of renewables estimated that US gas use for electricity generation would fall by half. The recent WCI economic analysis released this September estimated that the RPS requirements would also reduce natural gas use even in the business-as-usual case. Also, both of these studies did not factor in additional actions that would likely occur if a cap and trade mechanism were implemented, or massive new "green investment" was made by the Obama Administration.

We wish to bring these countervailing factors into the discussion, to dispel fears of lack of natural gas supply.

Second, p. 4-28 has this statement:

> ...when natural gas customers are added to a cap and trade system, the system will add compliances costs to gas customers. Unlike with electricity production, reductions in emissions from the gas sector are only possible from reducing energy use with conservation. If the government decides to impose a more general tax on carbon emissions, this also would increase the cost of natural gas.

This statement also needs clarification. It implies that carbon regulation will increase the cost of natural gas, but omits mention of where, or for what purpose, the revenues collected from the regulation will go. Most proposals for either a carbon tax or cap and trade mechanism propose to use revenues collected to be used for investments in efficiency, renewables, low-income assistance, and for mitigation of economic dislocation. Perhaps some of the money will also be used to offset other tax revenues or to fund debt reduction. In any case, it is wrong to only talk about the costs of providing good price signals, without mentioning any uses for the revenues collected. In many ways, these revenues should be thought of transfer payments, not cost increases.

Thank you for this opportunity to comment.

Gross, Jennifer

To: 2009 Washington IRP TWG

Subject: Technical Working Group (TWG) NWN 2009 IRP- DRAFT Chapter 3, Supply Side Resources

Attachments: 2009 IRP Chapter 3 Supply Side Resources v 12.23.08.doc

Hello TWG members,

Attached for your review is NW Natural's DRAFT Chapter 3, Supply Side Resources. Please note that this is a working draft. Please email me your comments or questions.

Thank you and Merry Christmas!

Jennifer Gross
Tariff and Regulatory Compliance, NW Natural
220 NW Second Ave
Portland, Oregon 97209
(503) 226-4211 x3590
(800)422-4012 x3590

Gross, Jennifer

From: Simmons, Steven

Sent: Wednesday, December 24, 2008 9:45 AM

To: Gross, Jennifer; Dan Kirschner; Dave Robison; Dave Sloan; Dave Swenson; Deborah Reynolds (DReynold@utc.wa.gov); Douglas Kilpatrick; Fred Gordon; Friedman, Randy; Huddleston, Jon; Joe Ross; John Slocum; Lea Daeschel; Matt Braman; Matthew T. McNeil; McVay, Kevin; Miller, C. Alex; Miller, Kelley; Paula Pyron; Pete Catching; Phil Carver; Scott, Inara; Shampine, Kerry; Shifley, Sarah (ATG); Simon ffitch; Steve Johnson; Steve Weiss; Stinson, Charlie; Teresa Hagins; Terry Morlan; Vanda Novak; White, Keith; Yoshihara, Grant

Subject: Technical Working Group (TWG) NWN 2009 IRP - Demand Forecast Update

Attachments: TWG DMD FCST DEC 22 2008.doc

Hello TWG members,

Attached for your review is an update on the Demand Forecast for the 2009 IRP. A Chapter 2 draft will be coming out at a later date. Email your comments or questions.

Thanks

-Steve

Steven Simmons
Rates & Regulatory Affairs
NW Natural
503-226-4211, ext 3584
steven.simmons@nwnatural.com

Demand Forecast Update for the Technical Working Group

2009 Washington Integrated Resource Plan

Steven Simmons
NW Natural
steven.simmons@nwnatural.com
503-226-4211, ext 3584

December 23, 2008

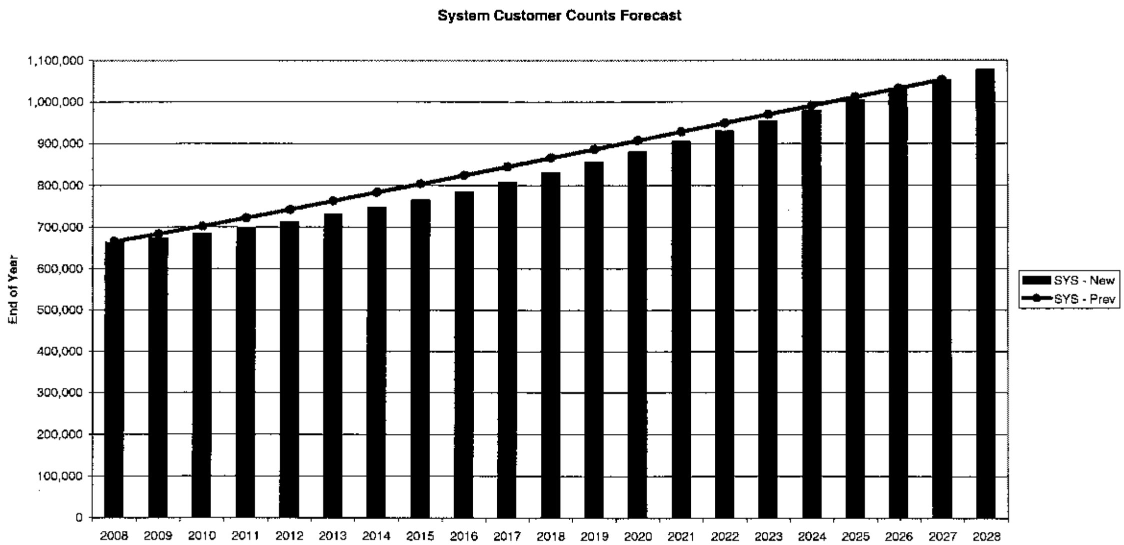
This is an informal progress report on the Demand Forecast portion of NW Natural's 2009 Integrated Resource Plan (IRP). A more complete report will be compiled at a later date and sent for review as a Chapter 2 Gas Requirement Forecast draft.

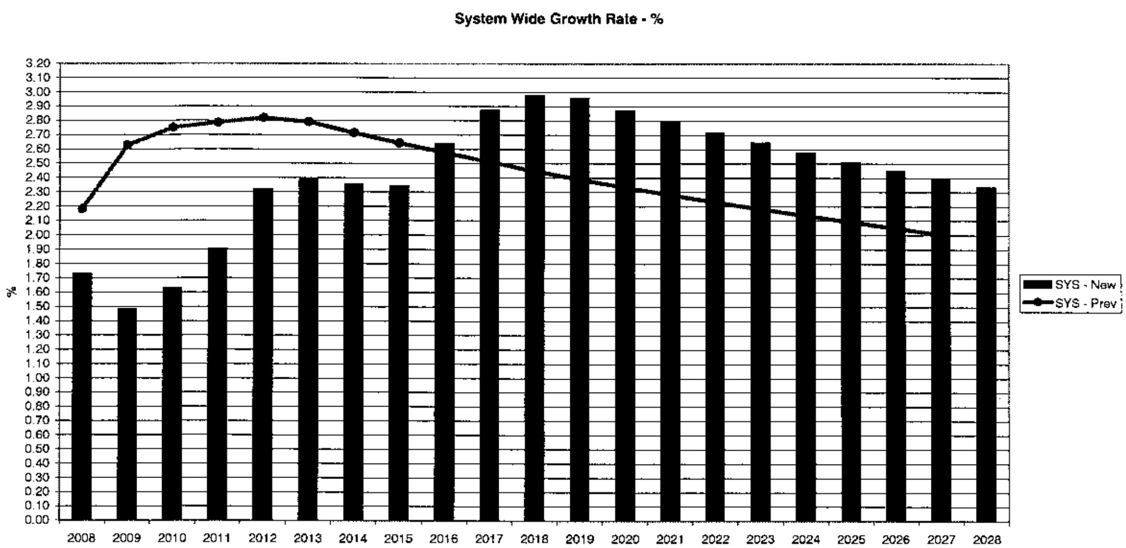
As we discussed at the Technical Working Group (TWG) meeting in November, there has been a delay in the completion of the Customer Count Forecast. We were waiting for some of the volatile economic news to sort out before developing this important component of the demand forecast. We now have a working forecast for projecting customers that we feel is sound. We have a new Natural Gas Price Forecast, and an update on gas usage factors and the incorporation of inputs for the modeling software Sendout.

Customer Forecast

System-wide annual customer growth over the planning horizon (2008/09 – 2028/29) is expected to average 2.42%. This compares well with the previous IRP's growth rate of 2.43%. Residential growth rate, comprised of new construction and conversions, is expected to average 2.53%, while the commercial rate is 1.33%. These are also very similar to the numbers from the previous IRP. However, due to the current economic recession, the shape of the growth is substantially different.

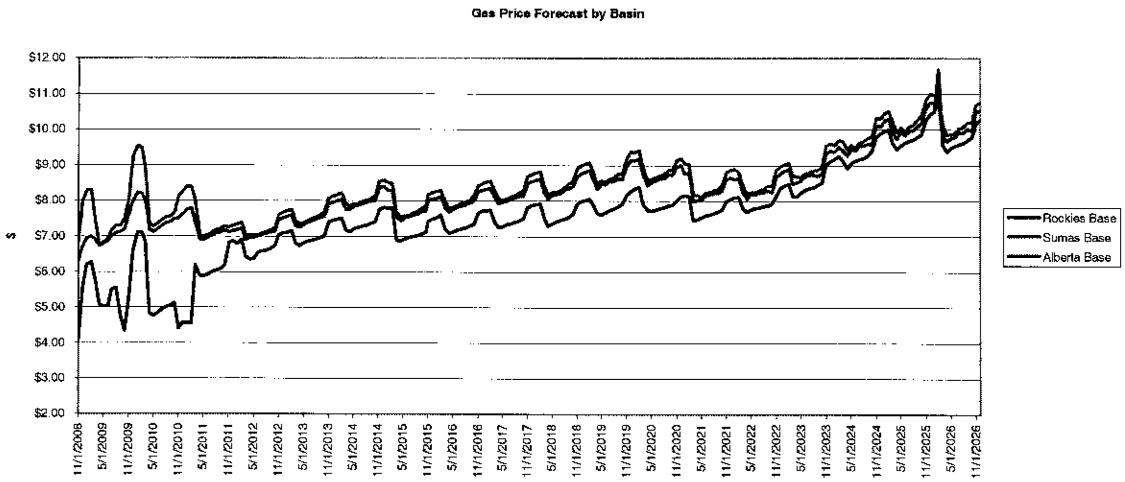
The forecast was built based on internal business intelligence, information from the credit and building communities, the State of Oregon Economic Forecast, and Clark County WA housing permit information. Two separate forecasts generated with differing methodologies were compared for the Vancouver WA area. The first treated Vancouver as an extension of Portland and used the State of Oregon's Housing Starts Forecast. The second was based on historic Clark County permit data and population growth estimates. A housing starts forecast for Clark County was not available. The forecasts drove to similar customer count projections over the planning horizon. However, the Portland/Oregon housing starts based forecast was judged to be more appropriate since it reflected the expected downturn in new construction from the on going recession more distinctly. There was a housing starts forecast for Washington state, but historic Vancouver starts correlated better to Oregon housing starts. In terms of economics, geography and culture, Portland and Vancouver may have more in common than, say Vancouver and Seattle.





Price Forecast

A new base case price forecast has been developed for Henry Hub, Rockies, Sumas and Alberta. NYMEX prices were used to forecast the first two years. The Wood Mackenzie long term forecast was used for year four and onward. In year three, a mix of the NYMEX futures and a Wood Mackenzie forecast was used to segue into the complete Wood Mackenzie forecast. High and low forecasts were also completed for each basin using historic variation and internal judgment.



Usage Factors and Sendout

The usage factor (daily use per customer) development was covered at the November TWG meeting. There are no changes to the factors. Currently, we are converting these factors into the Sendout software format to begin model runs.

Gross, Jennifer

From: Steve Weiss [weiss.steve@comcast.net]

Sent: Friday, January 02, 2009 12:42 PM

To: Gross, Jennifer; Dan Kirschner; Dave Robison; Dave Sloan; Dave Swenson; DReynold@utc.wa.gov; Douglas Kilpatrick; Fred Gordon; Friedman, Randy; Huddleston, Jon; Joe Ross; John Slocum; Matt Braman; Matthew T. McNeil; McVay, Kevin; Miller, C. Alex; Miller, Kelley; Paula Pyron; Pete Catching; Phil Carver; Scott, Inara; Shampine, Kerry; Shifley, Sarah (ATG); Simmons, Steven; Simon ffitch; Steve Johnson; Steve Weiss; Stinson, Charlie; Teresa Hagins; Terry Morlan; Vanda Novak; White, Keith; Yoshihara, Grant

Subject: Re: Technical Working Group (TWG) NWN 2009 IRP- DRAFT Chapter 3, Supply Side Resources

Attachments: NWEConNWNchapter3.doc

Attached are our brief comments on Chapter 3. Thank you.

Steve Weiss
Sr. Policy Associate
NW Energy Coalition
503-851-4054

From: "Gross, Jennifer" <Jennifer.Gross@nwnatural.com>
Date: Tue, 23 Dec 2008 12:38:29 -0800
To: Dan Kirschner <dkirschner@nwga.org>, Dave Robison <drobison@teleport.com>, Dave Sloan <Dave_Sloan@transcanada.com>, Dave Swenson <Dswenson@intgas.com>, <DReynold@utc.wa.gov>, Douglas Kilpatrick <dkilpatr@wutc.wa.gov>, Fred Gordon <fred@energytrust.org>, "Friedman, Randy" <Randy.Friedman@nwnatural.com>, "Huddleston, Jon" <Jon.Huddleston@nwnatural.com>, Joe Ross <joe_ross@transcanada.com>, John Slocum <jslocum@ceadvisors.com>, Lea Daeschel <lead@stg.wa.gov>, Matt Braman <matt.braman@energytrust.org>, "Matthew T. McNeil" <mmcneil@newenergyassoc.com>, "McVay, Kevin" <ksm@nwnatural.com>, "Miller, C. Alex" <c2m@nwnatural.com>, "Miller, Kelley" <kelley.miller@nwnatural.com>, Paula Pyron <ppyron@nwigu.org>, Pete Catching <pete.catching@energytrust.org>, Phil Carver <philip.h.carver@state.or.us>, "Scott, Inara" <Inara.Scott@nwnatural.com>, "Shampine, Kerry" <kfs@nwnatural.com>, "Shifley, Sarah (ATG)" <Sarah.Shifley@atg.wa.gov>, "Simmons, Steven" <Steven.Simmons@nwnatural.com>, Simon ffitch <simonf@atg.wa.gov>, Steve Johnson <sjohnson@utc.wa.gov>, Steve Weiss <steve@nwenergy.org>, "Stinson, Charlie" <ces@nwnatural.com>, Teresa Hagins <teresa.l.hagins@williams.com>, Terry Morlan <tmorlan@nwcouncil.org>, Vanda Novak <vnovak@utc.wa.gov>, "White, Keith" <jkw@nwnatural.com>, "Yoshihara, Grant" <gmy@nwnatural.com>
Conversation: Technical Working Group (TWG) NWN 2009 IRP- DRAFT Chapter 3, Supply Side Resources
Subject: Technical Working Group (TWG) NWN 2009 IRP- DRAFT Chapter 3, Supply Side Resources

Hello TWG members,

Attached for your review is NW Natural's DRAFT Chapter 3, Supply Side Resources. Please note that this is a working draft. Please email me your comments or questions.

Thank you and Merry Christmas!

Jennifer Gross
Tariff and Regulatory Compliance, NW Natural
220 NW Second Ave
Portland, Oregon 97209
(503) 226-4211 x3590
(800)422-4012 x3590

Comments of the NW Energy Coalition
on NW Natural's IRP
Chapter 3, Supply Side Resources
January 2, 2009

The NW Energy Coalition (NWEC) appreciates this opportunity to comment on NW Natural's IRP. We are not experts on the details of natural gas acquisition, so these comments are limited to one, albeit important, issue: the Company's natural gas supply/price forecast. Because of the impact on NWN's plans, it is very important that the Company correctly analyze this issue.

We are confused by the following two apparently contradictory statements about future demand:

> While recent development in the shale plays has increased domestic production of gas, supplies out of the US Rockies remain tight, **and demand is expected to significantly increase, particularly if environmental and carbon constraints are enacted.** [p. 3-31, emphasis added]

> The implementation of new technologies, spurred by high energy prices, will enable continued GNP growth **without an associated increase in energy usage.** If not through better technology, then an economic recession such as occurred after the 2000-2001 energy crisis (and the September 11 disaster, Enron bankruptcy, etc.) will be the other means for a demand response to manifest itself. In either case, **demand will grow modestly at best, keeping gas prices in check overall** but with wide volatility.... [p. 3-38, emphasis added]

Which scenario is NW Natural assuming, and why?

Several recent studies (WCI September, 2008 economic analysis, and a USDOE study that models a 20% renewable penetration, also in 2008) argue that carbon policies (a combination of incentives, RPS and carbon caps) will result in significantly *lower* demand for natural gas, especially from the electricity generation sector. These studies show that the increased amount of renewables and energy efficiency spurred by carbon policies will result in lower demand for natural gas for the country overall. (These studies also show lower capacity factors for gas generators as they are increasingly used to integrate renewables as opposed to base load use.)

NWEC urges NWN to analyze this issue more deeply, because the conclusions may have a large effect on the Company's future resource needs.

Thank you,
Steven Weiss
Sr. Policy Associate
503-851-4054

Comments of the NW Energy Coalition
on NW Natural's IRP
Chapter 3, Supply Side Resources
January 2, 2009

The NW Energy Coalition (NWEC) appreciates this opportunity to comment on NW Natural's IRP. We are not experts on the details of natural gas acquisition, so these comments are limited to one, albeit important, issue: the Company's natural gas supply/price forecast. Because of the impact on NWN's plans, it is very important that the Company correctly analyze this issue.

We are confused by the following two apparently contradictory statements about future demand:

> While recent development in the shale plays has increased domestic production of gas, supplies out of the US Rockies remain tight, **and demand is expected to significantly increase, particularly if environmental and carbon constraints are enacted.** [p. 3-31, emphasis added]

> The implementation of new technologies, spurred by high energy prices, will enable continued GNP growth **without an associated increase in energy usage**. If not through better technology, then an economic recession such as occurred after the 2000-2001 energy crisis (and the September 11 disaster, Enron bankruptcy, etc.) will be the other means for a demand response to manifest itself. In either case, **demand will grow modestly at best, keeping gas prices in check overall** but with wide volatility.... [p. 3-38, emphasis added]

Which scenario is NW Natural assuming, and why?

Several recent studies (WCI September, 2008 economic analysis, and a USDOE study that models a 20% renewable penetration, also in 2008) argue that carbon policies (a combination of incentives, RPS and carbon caps) will result in significantly *lower* demand for natural gas, especially from the electricity generation sector. These studies show that the increased amount of renewables and energy efficiency spurred by carbon policies will result in lower demand for natural gas for the country overall. (These studies also show lower capacity factors for gas generators as they are increasingly used to integrate renewables as opposed to base load use.)

NWEC urges NWN to analyze this issue more deeply, because the conclusions may have a large effect on the Company's future resource needs.

Thank you,
Steven Weiss
Sr. Policy Associate
503-851-4054

Gross, Jennifer

From: Steve Weiss [weiss.steve@comcast.net]

Sent: Wednesday, January 07, 2009 10:08 PM

To: Scott, Inara; Gross, Jennifer; Dan Kirschner; Dave Robison; Dave Sloan; Dave Swenson; DReynold@utc.wa.gov; Douglas Kilpatrick; Fred Gordon; Friedman, Randy; Huddleston, Jon; Joe Ross; John Slocum; Matt Braman; Matthew T. McNeil; McVay, Kevin; Miller, C. Alex; Miller, Kelley; Paula Pyron; Pete Catching; Phil Carver; Shampine, Kerry; Shifley, Sarah (ATG); Simmons, Steven; Simon ffitch; Steve Johnson; Steve Weiss; Stinson, Charlie; Teresa Hagins; Terry Morlan; Vanda Novak; White, Keith; Yoshihara, Grant

Cc: Friedman, Randy; Gross, Jennifer; Simmons, Steven

Subject: Re: Technical Working Group (TWG) NWN 2009 IRP- DRAFT Chapter 3, Supply Side Resources

Not really. I was actually more concerned with the longer term outlook. The two studies I cited showed reduced demand for natural gas, especially for power generation. The reason was the affect of increasing amounts of renewables reducing the amount of electricity generated by combustion turbines. I'm not saying that these studies are true—for example, one might argue that a carbon cap or tax will tend to reduce coal generation most, not gas generation—but only that they contradict the Company's view, and thus should be discussed more thoroughly. You shouldn't just say gas use will increase without some stronger data, modeling or other justification.

Steve Weiss
Sr. Policy Associate
NW Energy Coalition
503-851-4054

From: "Scott, Inara" <Inara.Scott@nwnatural.com>
Date: Wed, 7 Jan 2009 16:40:54 -0800
To: Steve Weiss <weiss.steve@comcast.net>, "Gross, Jennifer" <Jennifer.Gross@nwnatural.com>, Dan Kirschner <dkirschner@nwga.org>, Dave Robison <drobison@teleport.com>, Dave Sloan <Dave_Sloan@transcanada.com>, Dave Swenson <Dswenson@intgas.com>, <DReynold@utc.wa.gov>, Douglas Kilpatrick <dkilpatr@wutc.wa.gov>, Fred Gordon <fred@energytrust.org>, "Friedman, Randy" <Randy.Friedman@nwnatural.com>, "Huddleston, Jon" <Jon.Huddleston@nwnatural.com>, Joe Ross <joe_ross@transcanada.com>, John Slocum <jslocum@ceadvisors.com>, Matt Braman <matt.braman@energytrust.org>, "Matthew T. McNeil" <mmcneil@newenergyassoc.com>, "McVay, Kevin" <ksm@nwnatural.com>, "Miller, C. Alex" <c2m@nwnatural.com>, "Miller, Kelley" <kelley.miller@nwnatural.com>, Paula Pyron <ppyron@nwigu.org>, Pete Catching <pete.catching@energytrust.org>, Phil Carver <philip.h.carver@state.or.us>, "Shampine, Kerry" <kfs@nwnatural.com>, "Shifley, Sarah (ATG)" <Sarah.Shifley@atg.wa.gov>, "Simmons, Steven" <Steven.Simmons@nwnatural.com>, Simon ffitch <simonf@atg.wa.gov>, Steve Johnson <sjohnson@utc.wa.gov>, Steve Weiss <steve@nwenergy.org>, "Stinson, Charlie" <ces@nwnatural.com>, Teresa Hagins <teresa.l.hagins@williams.com>, Terry Morlan <tmorlan@nwcouncil.org>, Vanda Novak <vnovak@utc.wa.gov>, "White, Keith" <jkw@nwnatural.com>, "Yoshihara, Grant" <gmy@nwnatural.com>
Cc: "Friedman, Randy" <Randy.Friedman@nwnatural.com>, "Gross, Jennifer" <Jennifer.Gross@nwnatural.com>, "Simmons, Steven" <Steven.Simmons@nwnatural.com>
Conversation: Technical Working Group (TWG) NWN 2009 IRP- DRAFT Chapter 3, Supply Side Resources
Subject: RE: Technical Working Group (TWG) NWN 2009 IRP- DRAFT Chapter 3, Supply Side Resources

Steve,

Thanks so much for reviewing our drafts and providing comments. I hope you don't mind if I reply to the entire group on this one, because I think it may be helpful for everyone. The first section you quote, with regard to significantly increasing demand for natural gas, refers to a long-term outlook for importation of LNG based on demand for domestic natural gas. The second section is part of our short-term gas acquisition plan, and refers primarily to the 2008-2009 gas year. So they really are not inconsistent -- in the short term, we do see the recession and potential implementation of new technologies to result in modest demand growth, at best. However, in the longer term, we would expect to see that gas demand for power generation would grow significantly, which our consultants predict will result in a rise in LNG imports in the 2012-2016 timeframe.

I hope this addresses your questions, at least in some part.

Thanks,
Inara

Inara K. Scott
Manager, Regulatory Affairs
NW Natural
220 NW Second Avenue
Portland, OR 97209
(503) 721-2476
inara.scott@nwnatural.com

From: Steve Weiss [mailto:weiss.steve@comcast.net]
Sent: Friday, January 02, 2009 12:42 PM
To: Gross, Jennifer; Dan Kirschner; Dave Robison; Dave Sloan; Dave Swenson; DReynold@utc.wa.gov; Douglas Kilpatrick; Fred Gordon; Friedman, Randy; Huddleston, Jon; Joe Ross; John Slocum; Matt Braman; Matthew T. McNeil; McVay, Kevin; Miller, C. Alex; Miller, Kelley; Paula Pyron; Pete Catching; Phil Carver; Scott, Inara; Shampine, Kerry; Shifley, Sarah (ATG); Simmons, Steven; Simon ffitch; Steve Johnson; Steve Weiss; Stinson, Charlie; Teresa Hagins; Terry Morlan; Vanda Novak; White, Keith; Yoshihara, Grant
Subject: Re: Technical Working Group (TWG) NWN 2009 IRP- DRAFT Chapter 3, Supply Side Resources

Attached are our brief comments on Chapter 3. Thank you.

Steve Weiss
Sr. Policy Associate
NW Energy Coalition
503-851-4054

From: "Gross, Jennifer" <Jennifer.Gross@nwnatural.com>
Date: Tue, 23 Dec 2008 12:38:29 -0800
To: Dan Kirschner <dkirschner@nwga.org>, Dave Robison <drobison@teleport.com>, Dave Sloan <Dave_Sloan@transcanada.com>, Dave Swenson <Dswenson@intgas.com>, <DReynold@utc.wa.gov>, Douglas Kilpatrick <dkilpatr@wutc.wa.gov>, Fred Gordon <fred@energytrust.org>, "Friedman, Randy" <Randy.Friedman@nwnatural.com>, "Huddleston, Jon" <Jon.Huddleston@nwnatural.com>, Joe Ross <joe_ross@transcanada.com>, John Slocum <jslocum@ceadvisors.com>, Lea Daeschel <lead@stg.wa.gov>, Matt Braman <matt.braman@energytrust.org>, "Matthew T. McNeil" <mmcneil@newenergyassoc.com>, "McVay, Kevin" <ksm@nwnatural.com>, "Miller, C. Alex" <c2m@nwnatural.com>, "Miller, Kelley" <kelley.miller@nwnatural.com>, Paula Pyron <ppyron@nwigu.org>, Pete Catching <pete.catching@energytrust.org>, Phil Carver <philip.h.carver@state.or.us>, "Scott, Inara" <Inara.Scott@nwnatural.com>, "Shampine, Kerry" <kfs@nwnatural.com>, "Shifley, Sarah (ATG)" <Sarah.Shifley@atg.wa.gov>, "Simmons, Steven" <Steven.Simmons@nwnatural.com>, Simon ffitch <simonf@atg.wa.gov>, Steve Johnson <sjohnson@utc.wa.gov>, Steve Weiss <steve@nwenergy.org>, "Stinson, Charlie" <ces@nwnatural.com>, Teresa Hagins <teresa.l.hagins@williams.com>, Terry Morlan <tmorlan@nwcouncil.org>, Vanda Novak <vnovak@utc.wa.gov>, "White, Keith" <jkw@nwnatural.com>, "Yoshihara, Grant" <gmy@nwnatural.com>
Conversation: Technical Working Group (TWG) NWN 2009 IRP- DRAFT Chapter 3, Supply Side Resources
Subject: Technical Working Group (TWG) NWN 2009 IRP- DRAFT Chapter 3, Supply Side Resources

Hello TWG members,

Attached for your review is NW Natural's DRAFT Chapter 3, Supply Side Resources. Please note that this is a working draft. Please email me your comments or questions.

Thank you and Merry Christmas!

Jennifer Gross
Tariff and Regulatory Compliance, NW Natural
220 NW Second Ave
Portland, Oregon 97209
(503) 226-4211 x3590
(800)422-4012 x3590

NW Natural

welcomes your ideas, comments and suggestions

NW Natural's 2008 Integrated Resource Plan outlines how the company will provide energy and services to you at the least cost.

The plan answers questions like: How much gas will our customers use? How much energy can we save through conservation? Where will NW Natural's gas supplies come from?

We welcome your participation as we develop this plan.

You can find the draft plan on our web site. Go to **nwnatural.com.** under "About Us" - "Rates and Regulations" - then click on "Regulatory Activities". The link to view a draft of the plan is located at the bottom half of the page called "Integrated Resource Plan".

For a copy of the Final Draft Plan Summary, write

Jennifer Gross
Rates Department
NW Natural
220 NW 2nd Avenue
Portland, OR 97209

Phone: 503-226-4211, Ext. 3590
e-mail: Jennifer.gross@nwnatural.com

NW Natural®