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October 22, 2010

VIA ELECTRONIC FILING

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

Re: UG-100245 – Draft 2011 Integrated Resource Plan

Dear Mr. Danner:

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), hereby files it draft 2011 Integrated Resource Plan (IRP) in Docket No. UG-100245.

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

Sincerely,

NW NATURAL

/s/ Jennifer Gross

Jennifer Gross
Rates & Regulatory Affairs

enclosures

2011

Integrated Resource Plan

NW Natural®

2011 Integrated Resource Plan

NW Natural®

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Chapter 1: Executive Summary

I. INTRODUCTION AND BACKGROUND

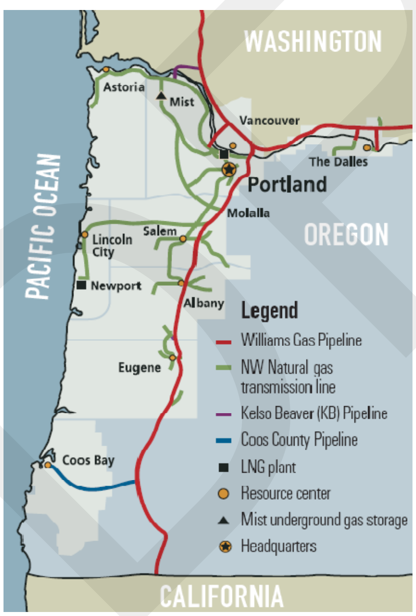
A. Executive Summary and Multi Year Action Plan

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

B. Description of NW Natural

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

FIGURE 1.1 – NW Natural's Service Territory



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

B. Overview of Integrated Resource Planning

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

II. PRINCIPAL CONCLUSIONS

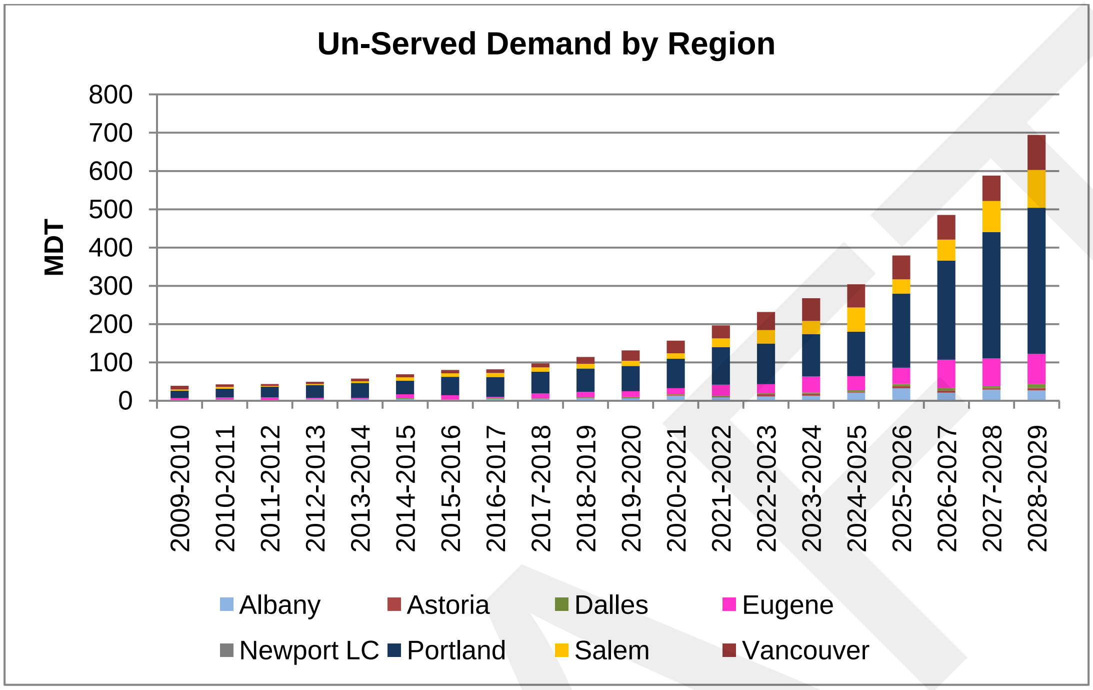
The IRP serves as an important guide for determining how NW Natural intends to serve a growing region with reliable, low cost energy supplies. With this in mind, the Company has come to the following principal conclusions:

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

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

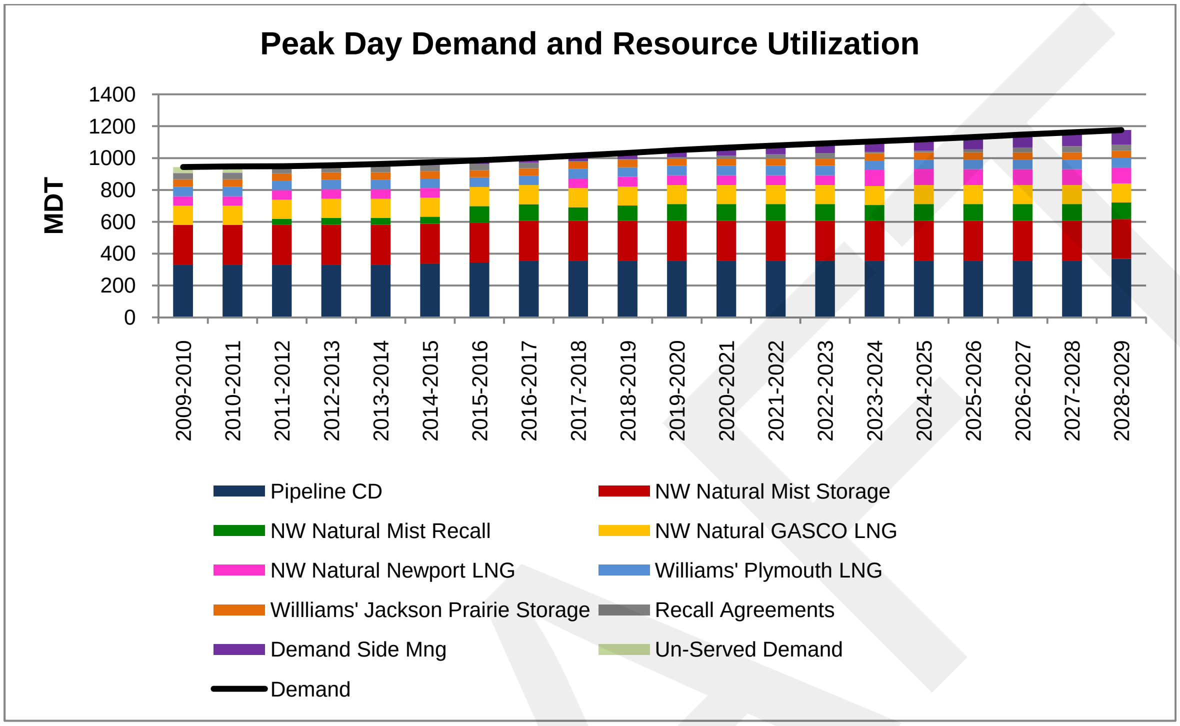
3. Even with lower demand forecasts, the Company's existing resources are not sufficient to fully satisfy peak day demand. Figure 1.2 displays the projected resource deficiencies by region, assuming no new resources will be added to the system (but including DSM energy savings and the previously planned projects, North WVF and the Harrisburg River Crossing).

FIGURE 1.2 – Unserved Demand by Region



4. The Company's Planning Base Case Portfolio addresses the forecasted gap in service with a mixture of incremental supply side and demand side resources. The incremental supply side resources in the portfolio include Mist Storage Recall, capacity on Palomar East Pipeline, Newport LNG Pipeline Compressor Project, and additional capacity on Williams' Grants Pass Lateral. By 2024, DSM is expected to reduce demand by as much as 10%. Figure 1.3 summarizes the blend of supply side and demand side resources selected to meet the peak day forecast.

FIGURE 1.3 – Peak Day Demand and Resource Utilization



III. LOAD FORECASTS

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

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

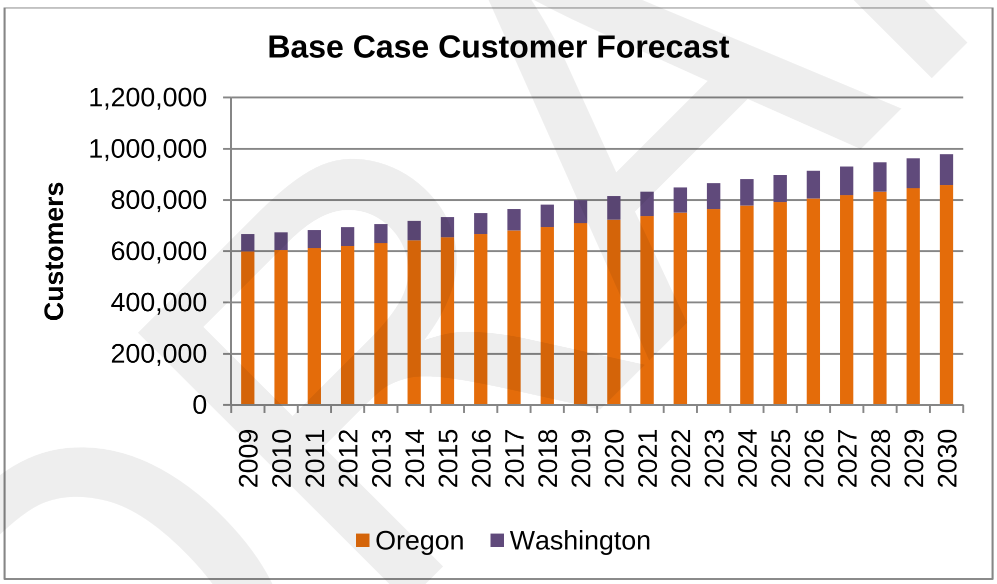
[5] *See* http://www.nwcouncil.org/energy/powerplan/6/default.htm

Once the Company generates a customer count forecast and usage per customer forecast, it incorporates 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 coldest three-day peak event over the past twenty years. The Company develops numerous demand scenarios by varying gas supply price and customer growth rates, and utilizes stochastic modeling to assess the performance of its selected gas supply portfolio over a range of temperature and price conditions.

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

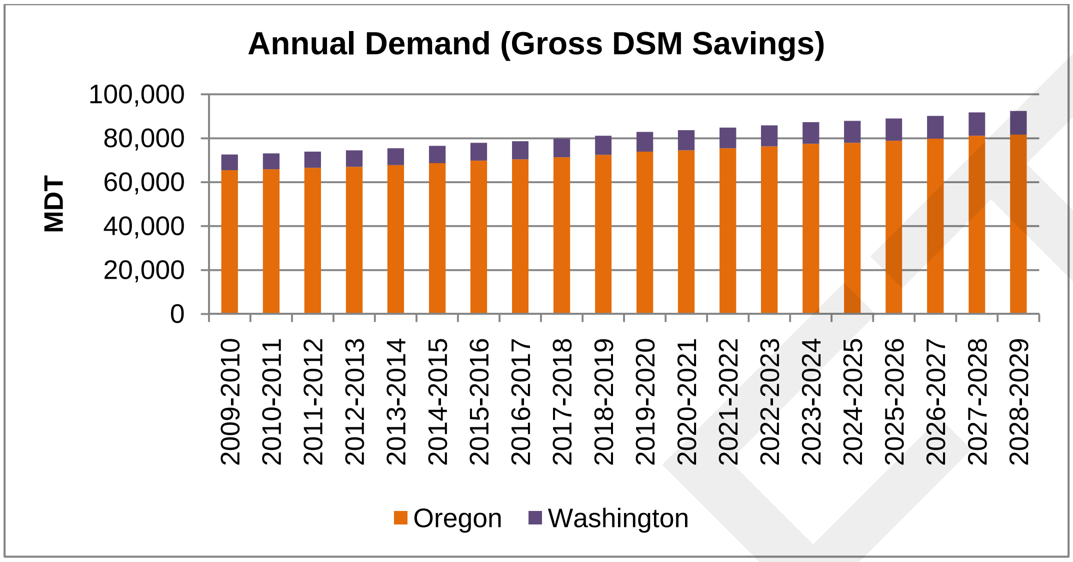
1. Current economic conditions have impacted load forecasts and slowed growth across NW Natural's service area. Customer growth is expected to remain under 2% until 2015. The average annual forecasted customer growth rate across the planning horizon for the entire service area is projected to be 1.84%;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

FIGURE 1.4 – Base Case Customer Forecast



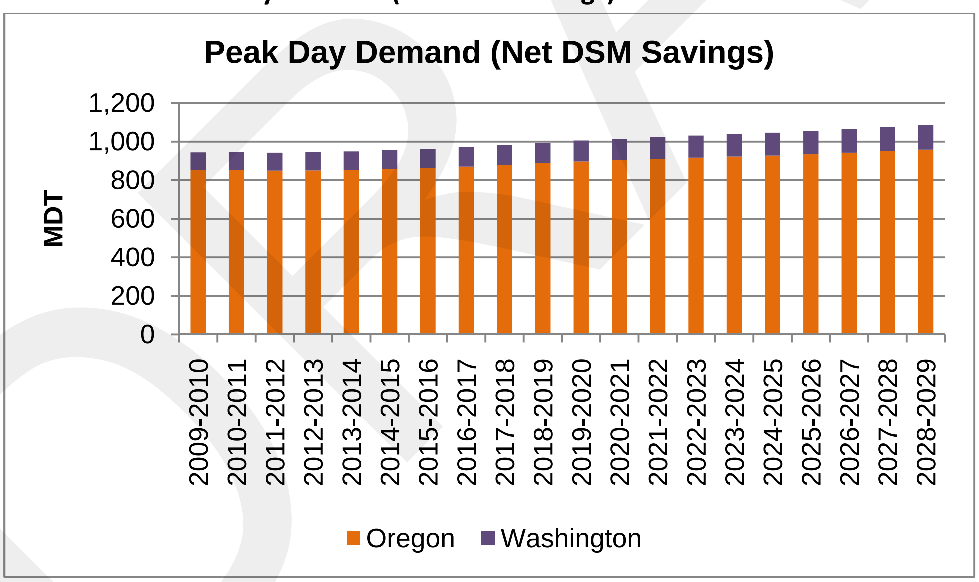
2. Annual demand growth is forecast to be lower than customer growth due to declining use per customer. Excluding Demand Side Management (DSM) savings, annual demand is forecast to grow at an average of 1.28% over the horizon; with Oregon load growing at an average rate of 1.17% and Washington at 2.22%.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

FIGURE 1.5 – Annual Demand (Gross DSM Savings)



3. Peak Day load (net DSM savings) is expected to grow at an average annual rate of 0.74%. Oregon peak day demand growth over the planning horizon is projected to be 0.62% and Washington 1.73% (refer to Figure 1.6).

FIGURE 1.6 – Peak Day Demand (Net DSM Savings)



4. The Company's load forecasts are based on the information presently available to the Company, which is constantly being updated and amended to reflect changing economic conditions. These forecasts are not a guarantee or an absolute prediction of future performance. In today's economic climate, predicting future conditions with a high degree of reliability is particularly difficult. The Company has considered a number of potential events that may impact its base case load forecast and developed alternative load forecasts accordingly. In addition to low and high forecasts around the base case, the Company has developed two alternative scenarios: first, a forecast resulting from

a gas break-though in which a new residential use for natural gas expands demand substantially, and an electric break-through forecast where advances in clean power generation cause large scale defection to electric space and water heat. The Company will continue to monitor economic conditions and developments in environmental legislation as it updates its future load forecasts.

IV. SUPPLY SIDE RESOURCES

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

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

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

Given these complexities, the Company has assembled a portfolio of supplies to meet the projected needs of its firm customers. At the same time, this portfolio is flexible enough to enable the Company to negotiate better opportunities as they arise. Existing supply contracts have staggered terms of up to 3 years to very short-term arrangements of 30 days or less. This variety gives the Company the security of longer-term agreements, but still allows the Company to seek more economic transactions in the shorter term.

A. Supply Diversification

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

B. Recent Resource Decisions

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

2. Harrisburg River Crossing
   This small project allows an additional 8 MDT/day of supply to serve Eugene and is a key resource for meeting peak day demand in the southern Willamette Valley. This link was selected in both the 2008 and 2009 IRPs, and the completion date has been moved up to November of 2010.

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

C. Future Resource Alternatives

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

1. Interstate Pipeline Capacity Additions
   a. New NWPL Grants Pass Lateral capacity serving Salem, Albany and Eugene,
   b. New 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 East pipeline capacity from Madras to Molalla
   e. New GTN pipeline capacity from Malin to Madras
   f. New capacity on the proposed Pacific Connector Pipeline to access re-gasified LNG from the proposed Jordan Cove LNG project at Coos Bay, Oregon.
   g. New capacity on the proposed Oregon Pipeline to access re-gasified LNG from the proposed Oregon LNG project at Warrenton Oregon.

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

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

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

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

4. Imported LNG - The Company is evaluating the impact of two LNG import terminals proposed to be sited in Oregon. The Oregon LNG project proposed for Warrenton would connect to NW Natural's system at Molalla. The Jordon Cove project near Coos Bay would connect to the proposed Pacific Connector Gas Pipeline. While neither project has been constructed, NW Natural includes them for analysis purposes. Neither project is included in the base case planning portfolio.

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

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

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

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

   d. The Company continues to pursue strategies to improve supply path diversity, including pursuing the opportunity to take capacity on the 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. The pipeline would also increase system reliability.

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

V. DEMAND SIDE RESOURCES

Public purpose funds are collected from Oregon ratepayers and are used by the Energy Trust of Oregon (Energy Trust) to finance energy efficiency investments. In 2009, the Energy Trust saved 2.57 million therms, meeting the IRP target for DSM programs. In 2010, a new energy efficiency program administered by Energy Trust was implemented in Washington and is expected to save 97,500 to 130,000 therms. The Company's reliance on demand side management continues to escalate. Figures 1.7 and 1.8 depict DSM achievable annual cumulative savings for this IRP cycle.

FIGURE 1.7 – Oregon Cumulative DSM Savings Projections

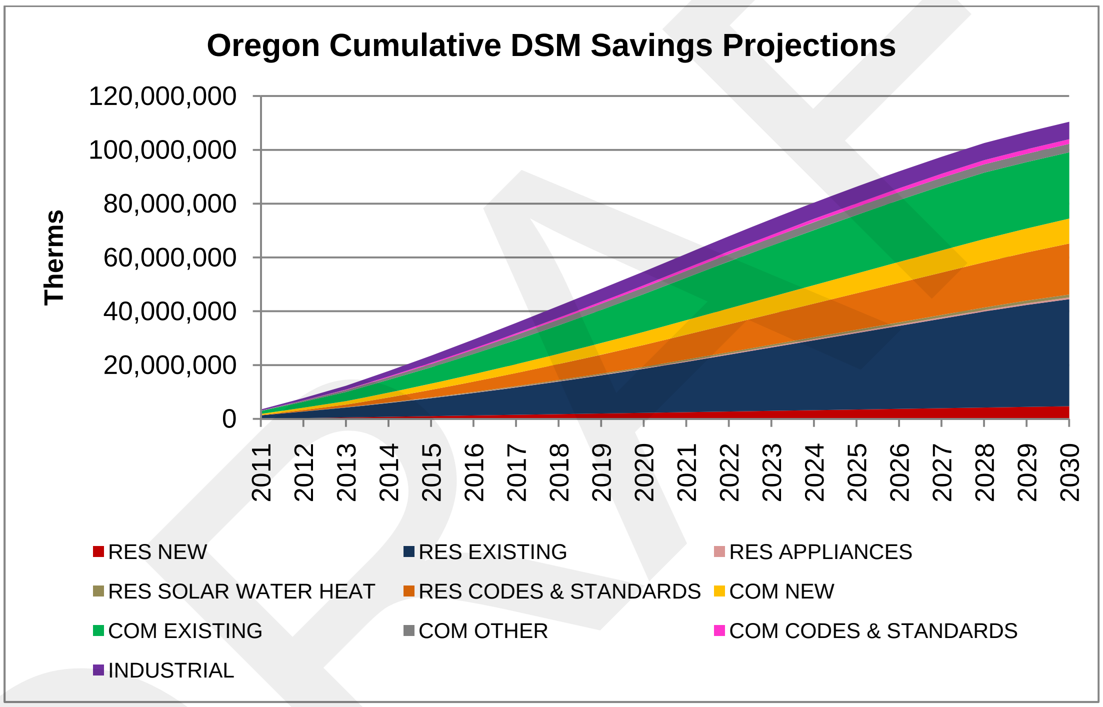
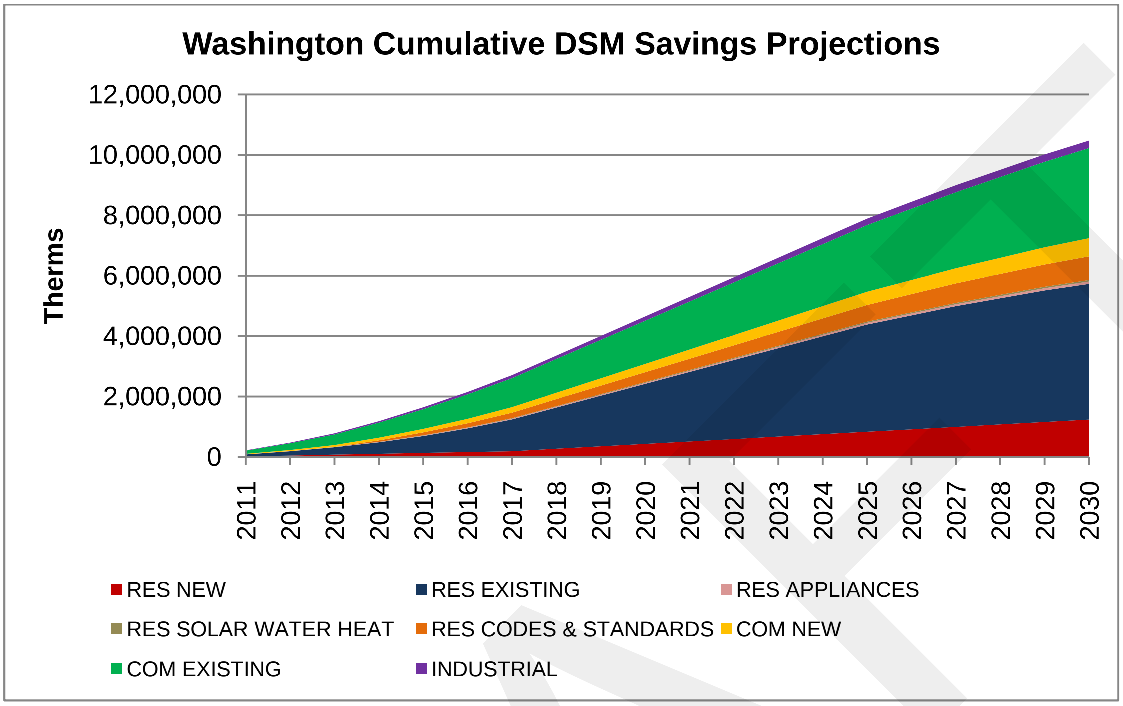


FIGURE 1.8 – Washington Cumulative DSM Savings Projections



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

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

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

VII. OTHER DEMAND-SIDE MANAGEMENT CONSIDERATIONS

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

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

VIII. PUBLIC COMMUNICATION AND PARTICIPATION

A. Technical Working Group

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

B. Public Participation

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

XI. 2011 IRP MULTI-YEAR ACTION PLAN

1.0 Demand Forecasting

1.1 Continue to review appropriate statistical probabilities in developing design year and peak day demand levels through stochastic analysis. The coldest daily 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 next IRP.

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

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

1.4 Review the demand forecast methodology for accuracy.

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

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

2.0 Supply-Side Resources

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

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

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

2.4 Monitor LNG 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 Compressor project--identified as potential cost-effective resources in this IRP.

3.0 Demand Side Resources

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

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

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

4.0 SENDOUT® Model and 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 Oregon and 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 does not plan to recall capacity in 2010.

- Harrisburg River Crossing was called for in previous IRP cycles and is expected to be in service in 2010

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

5.0 Avoided Cost Determination

5.1 As regulation of greenhouse gas emissions and other items 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 2013 IRP.

Chapter 2: Gas Requirements Forecast

Forward Looking Statement

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

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

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

I. OVERVIEW OF DEMAND FORECAST METHODOLOY

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

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

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

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

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

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

II. CUSTOMER FORECAST

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

Table 2.1 - Forecast Regions

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

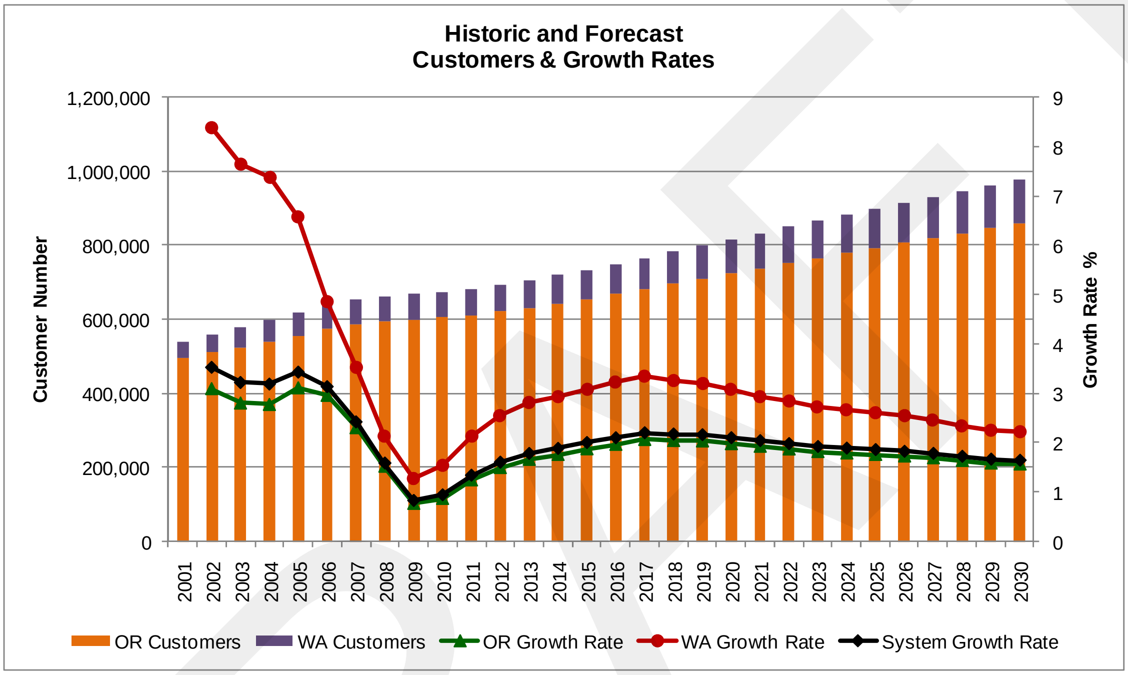
Table 2.2 Forecast Categories

Category	Customers – 2009	% of Total
Residential Existing	604,692	91 %
Residential New Construction Single- Family		
Residential New Construction Multi-Family		
Residential Conversion		
Commercial Existing	62,169	9 %
Commercial New Construction		
Commercial Conversion		
Industrial Firm Sales	595	0.1 %

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

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

Figure 2.1 Customer Growth Rates



A. Residential Customer Forecast

Customer growth in the residential sector is assigned to three separate categories:

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

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

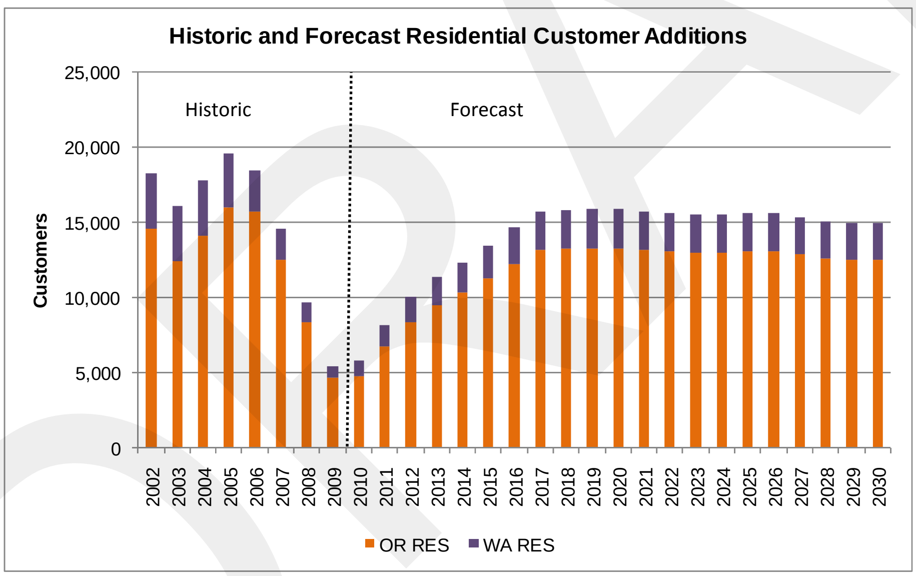
Customer projections in the new residential categories are based on historic regional growth trends, housing starts forecasts, and long term population forecasts. According to the Northwest Power and Conservation Council's 6th Plan, the average annual population growth rate for Oregon is expected to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

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

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

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

Figure 2.2 - Residential Customer Additions



B. Commercial Customer Forecast

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

1. New Construction
2. Conversions

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

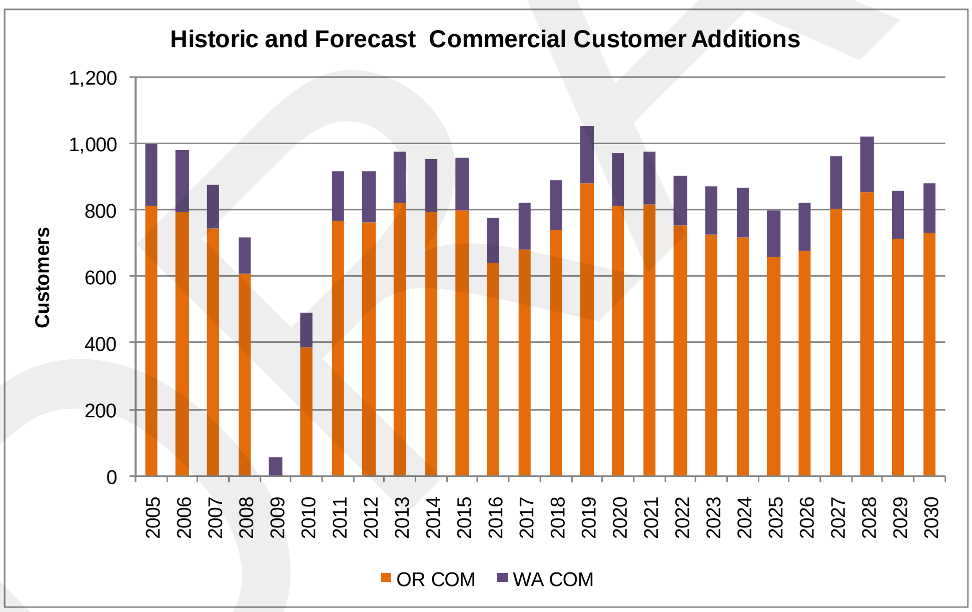
New construction in the commercial sector is based on historic patterns, along with internal econometric modeling and external economic forecasts from the OEA and the Northwest Power and Conservation Council.

As in the residential forecast, each month NW Natural projects the number of commercial customers expected to convert to natural gas from other energy sources by reviewing historical conversion activity experienced by the Company in prior years. Internal judgment is applied as well, including such factors as:

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

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

Figure 2.3 - Commercial Customer Additions



C. Industrial Customer Forecast

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

D. Customer Scenarios

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

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

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

Figure 2.4 - Scenario Growth Rates

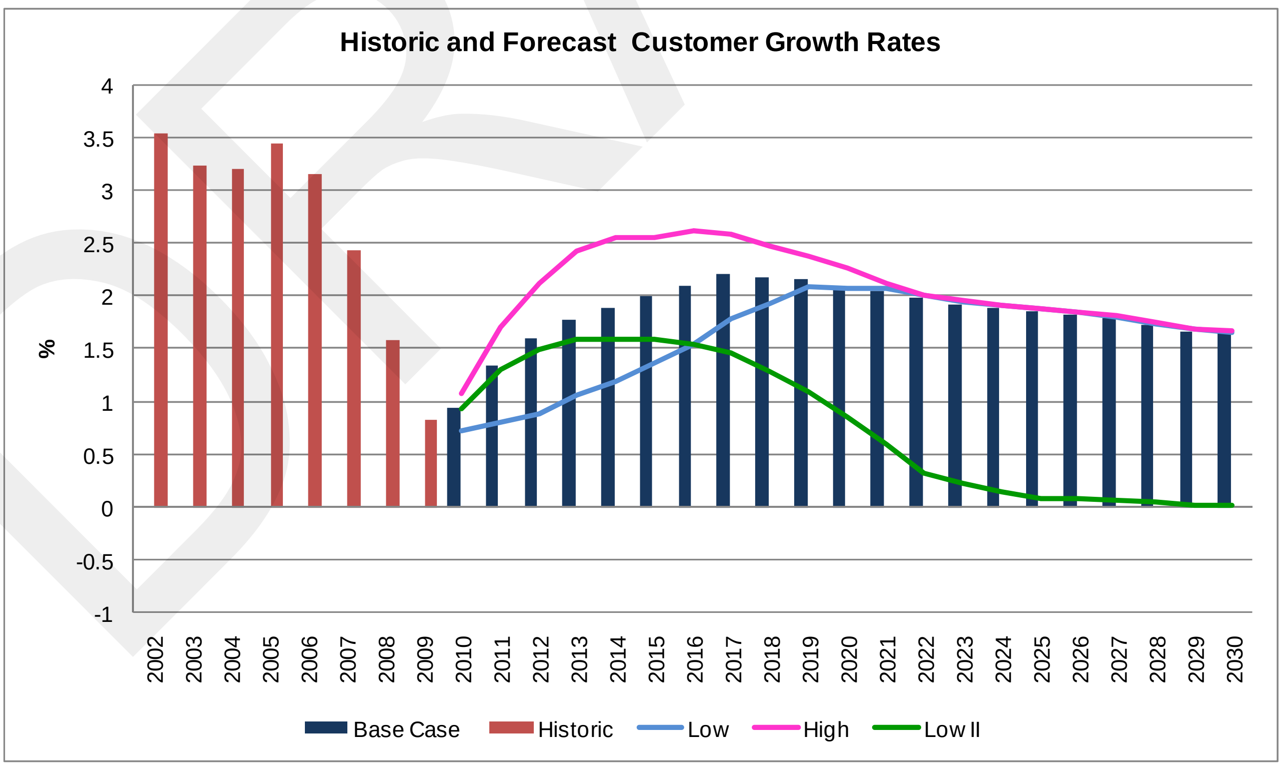


Figure 2.5 - Oregon Customer Forecast

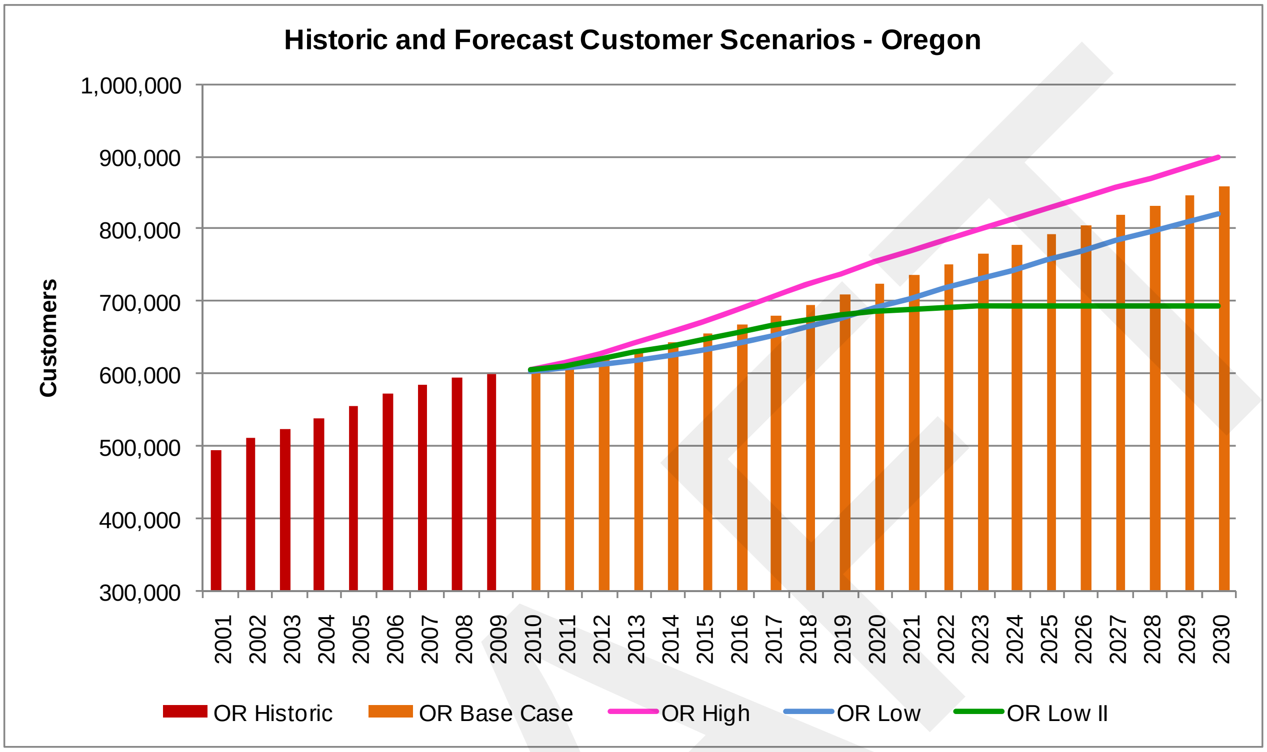
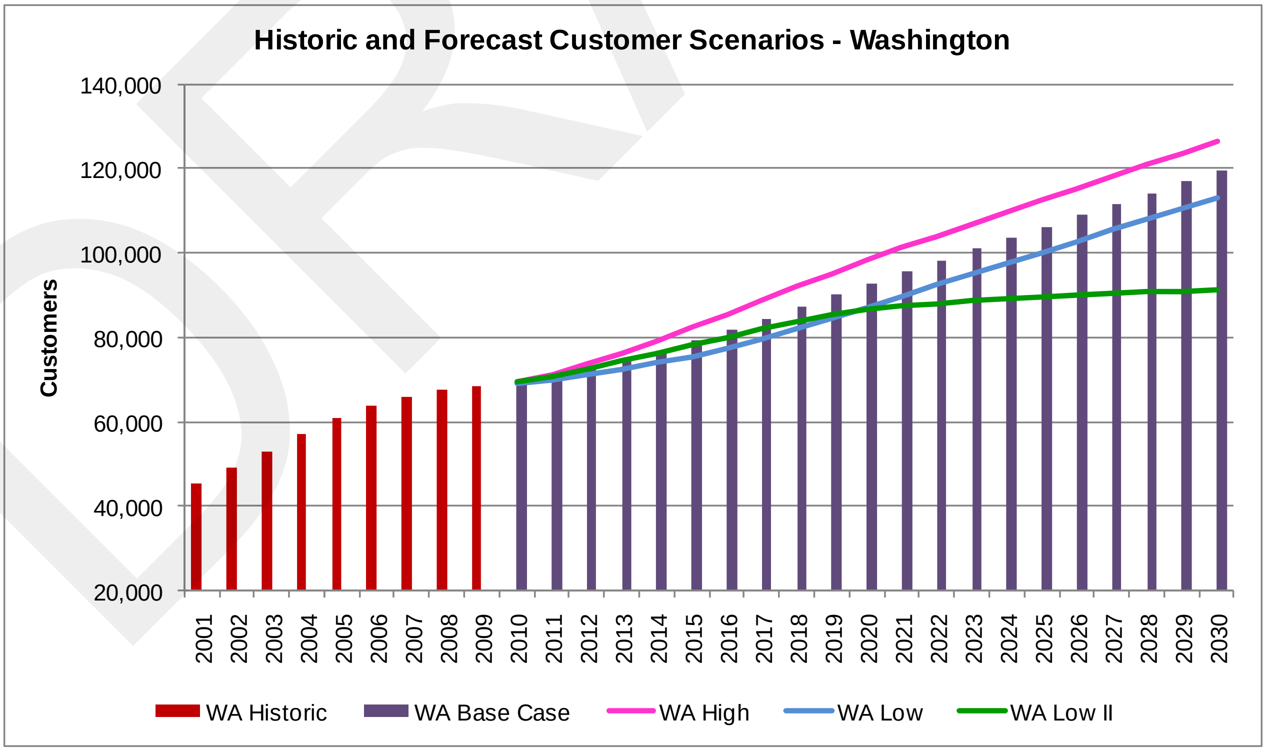


Figure 2.6 Washington Customer Forecast



III. LOAD FORECAST MODEL

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

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

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

Equation 2.1 Daily Customer Use

$$U = U_B + U_H$$

$$where$$

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

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

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

A. Base Load

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

Equation 2.2 Base Load Model

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

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

$$x = hdd\ per\ day$$

$$r = heat\ factor$$

$$c = intercept$$

$$setting\ x = 0$$

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

B. Heat Load

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

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

Equation 2.3 Heat Load Regression

$$\ln(U) = d + r_h \times x_1 + r_p \times x_2$$

$$where$$

$$U = non - summer\ daily\ use\ per\ customer\ excluding\ base\ load$$

$$x_1 = \ln(hdd)$$

$$x_2 = \ln(price)$$

$$r_h = heat\ rate$$

$$r_p = price\ rate$$

$$d = intercept$$

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

Equation 2.4 Heat Load

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

$$where$$

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

C. Implementation

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

Equation 2.5 Linear Transformation

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

$$where$$

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

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

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

D. Peak Day Load

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

E. Use Per Customer and Price Elasticity

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

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

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

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

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

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

The American Gas Association (AGA) released a study on natural gas use and price elasticity in 2007[2]. The study analyzed residential use per customer (UPC) trends from 50 natural gas local distribution companies (LDC) from across the country. The authors found that since 1980, weather normalized use in the residential sector has been dropping about 1% per year. From 2000 to 2006 though, the decline accelerated to 2.2% per year. The driving force behind the decline in use per customer was the consistent increase of natural gas prices. NW Natural has seen a similar drop in use per customer in that time frame. The AGA study reported a long run price elasticity value of -0.18 for the residential sector. NW Natural's price elasticity over the time frame was less, around -0.13, even though the increase in gas price in the 2000 to 2006 time frame was greater.

F. Usage Scenarios

In addition to the customer forecast scenarios, a demand scenario was developed around higher use per customer. This is called the "Gas Breakthrough" scenario. The case assumes some sort of small unit technological fuel cell breakthrough in the residential sector. The unit would be fueled by natural gas

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

and would provide full electrical power to the household, including space heating and cooling. It is estimated that a converted household would increase its base load gas demand by 37%. In addition to the higher base load, the seasonal load pattern is altered to include a summer cooling load. Both new and converted customers are added slowly over the planning horizon so that increased demand is phased in. This scenario represents the high usage case and provides the ceiling for all demand cases.

IV. GAS PRICE FORECAST

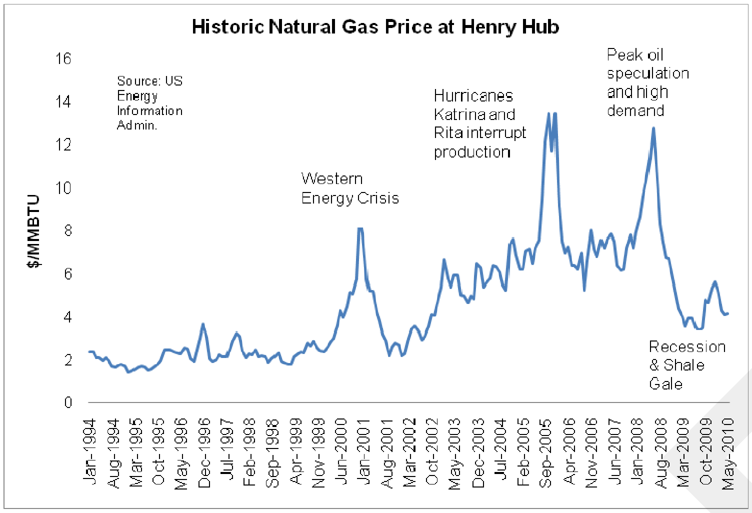
As part of the demand forecast process, NW Natural develops a 20 year natural gas price forecast by basin. The forecast includes a monthly price outlook for the Henry Hub, Rockies (Opal), British Columbia (Sumas), Alberta (AECO), and Malin. The volatility inherent in natural gas prices makes forecasting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

A. Price Volatility

The combination of low demand and vast supplies has recently kept prices low. Improved drilling technologies have opened up vast quantities of “unconventional” gas from shale deposits throughout North America. The economic slump that began in 2008 has continued to dampen natural gas demand into 2010. In 2009, spot prices at Henry Hub dipped below $4 per MMBTU while Rockies and Canadian spot prices dropped below $3 per MMBTU. According to IHS CERA Chairman Daniel Yergin, “As recently as 2007 it was widely thought that natural gas was in tight supply and the U.S. was going to become a growing importer of gas. But this outlook has been turned on its head by the shale gale”.

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

Figure 2.7 - Natural Gas Price



B. Forecast

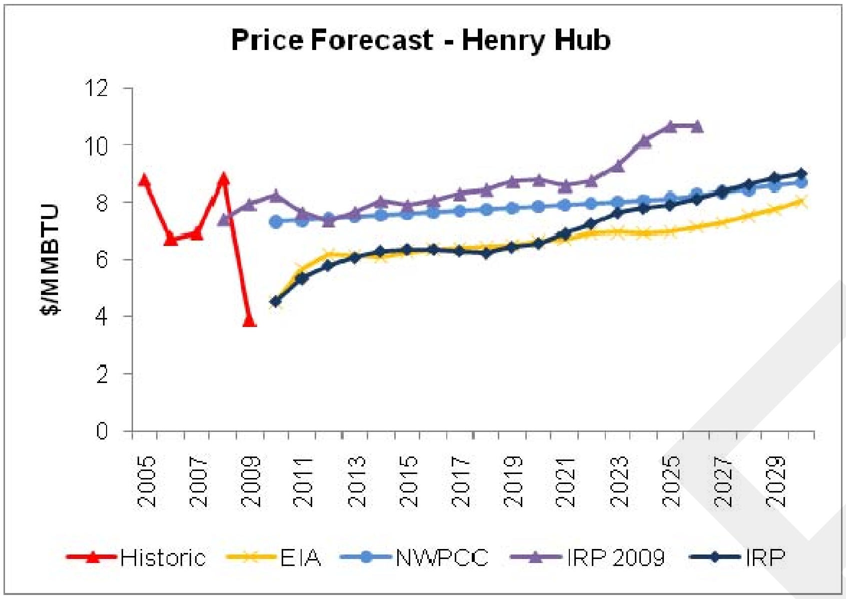
The natural gas price forecast is an important component of the load forecast model. The delivered natural gas price per therm is estimated from the price forecast and fed into the heating load component of the demand model - equation 2.4. The price forecast is also fed into NW Natural's SENDOUT® resource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

The base case price forecast is a blend of near term and long term outlooks. In the near term, the forecast is developed from price futures on the New York Mercantile Exchange (NYMEX). The long term component is derived from a proprietary forecast developed by a third party organization IHS CERA Inc[3]. The base case forecast assumes some sort of carbon legislation which would add a cost for each metric ton of emitted CO_2 beginning in the year 2014. Figure 2.8 displays the price forecast used in this IRP, along with three other outlooks:

1. 2009 IRP: forecast from the previous IRP from late 2008
2. Northwest Power and Conservation Council (NWPCC) 6th Plan from 2008/2009
3. U.S Energy Information Administration (EIA) from Dec. 2009

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

Figure 2.8 - Price Forecast



C. Price Scenarios

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

Figure 2.9 - Price Scenarios

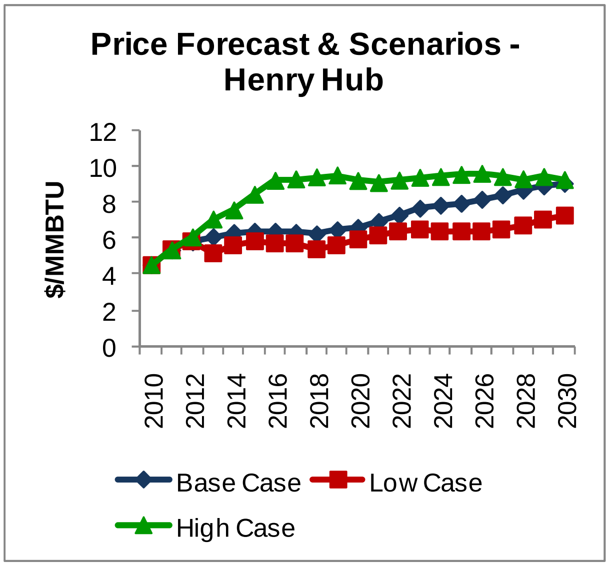
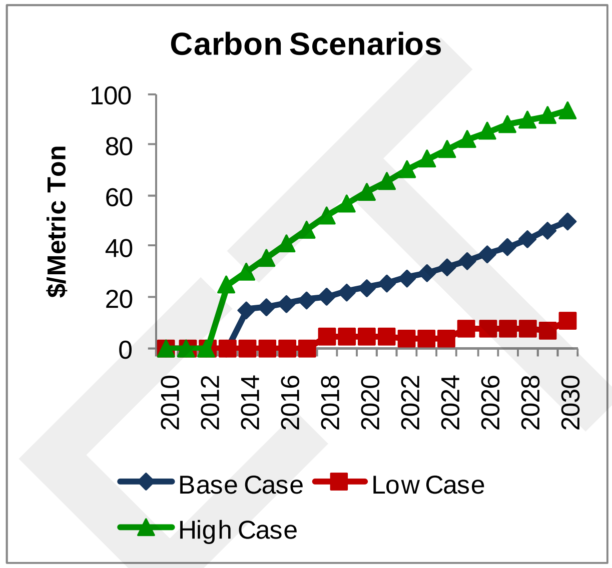


Figure 2.10 - Carbon Scenarios

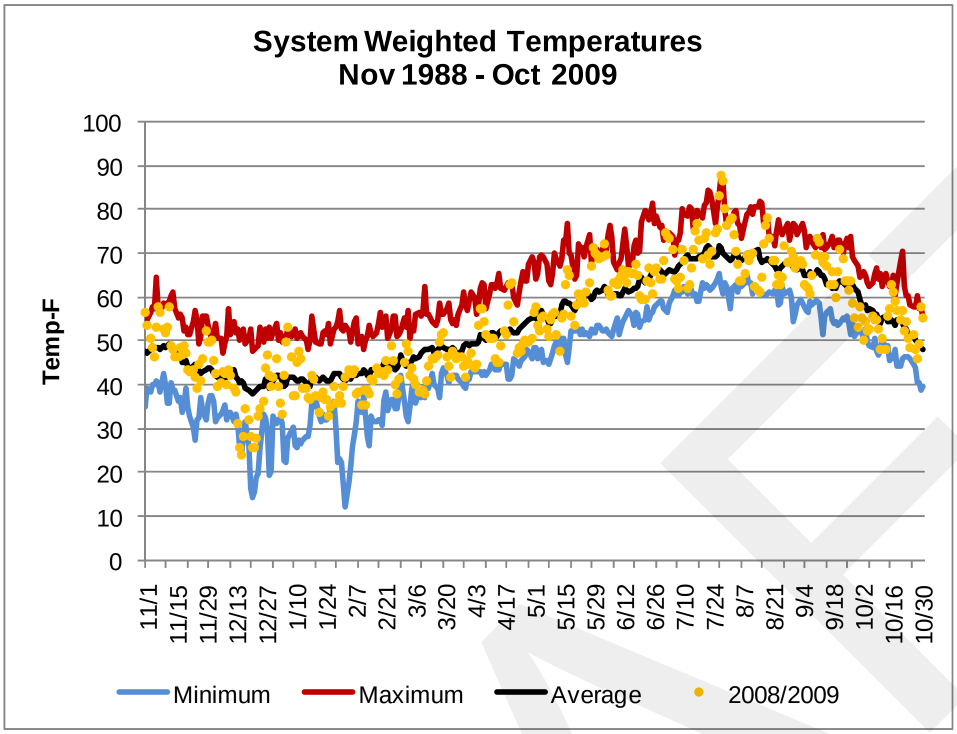


V. WEATHER

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

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

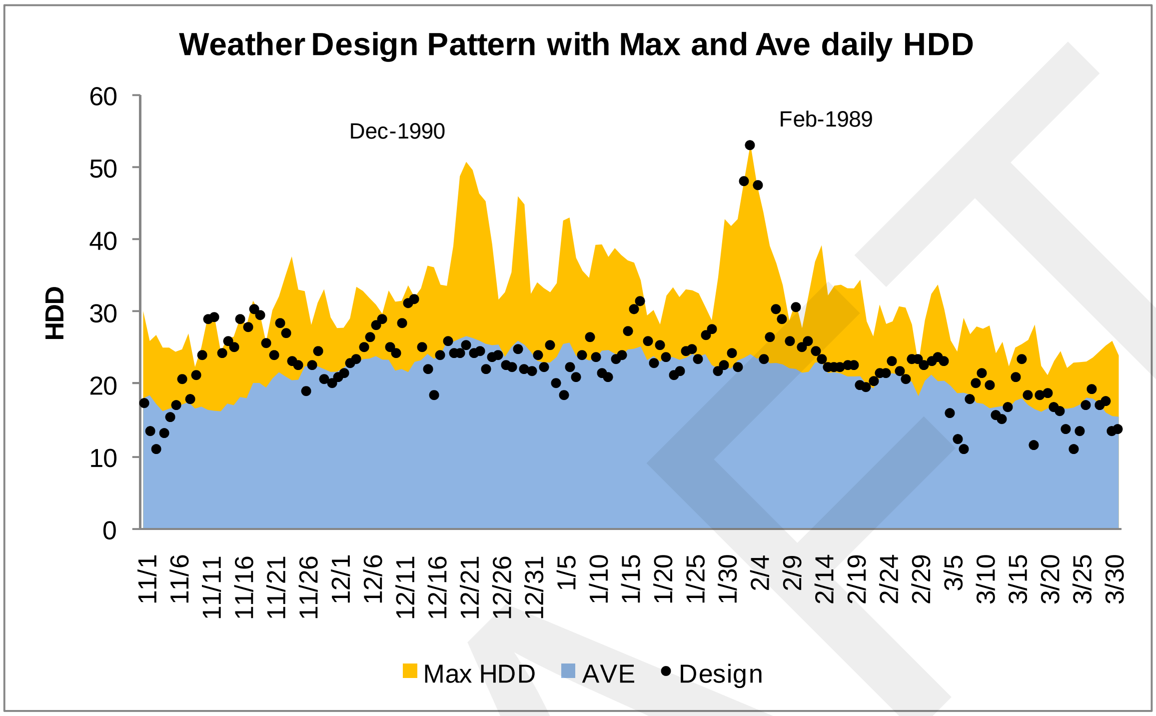
Figure 2.11- Daily Temperatures



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

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

Figure 2.12 - 0.85 Probability Design Winter Pattern



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

Table 2.3 - HDD by Region

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

VI. RESULTS

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

Equation 2.6 - Daily demand

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

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

A. Base Case

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

Figure 2.13 - Annual Demand Design Weather

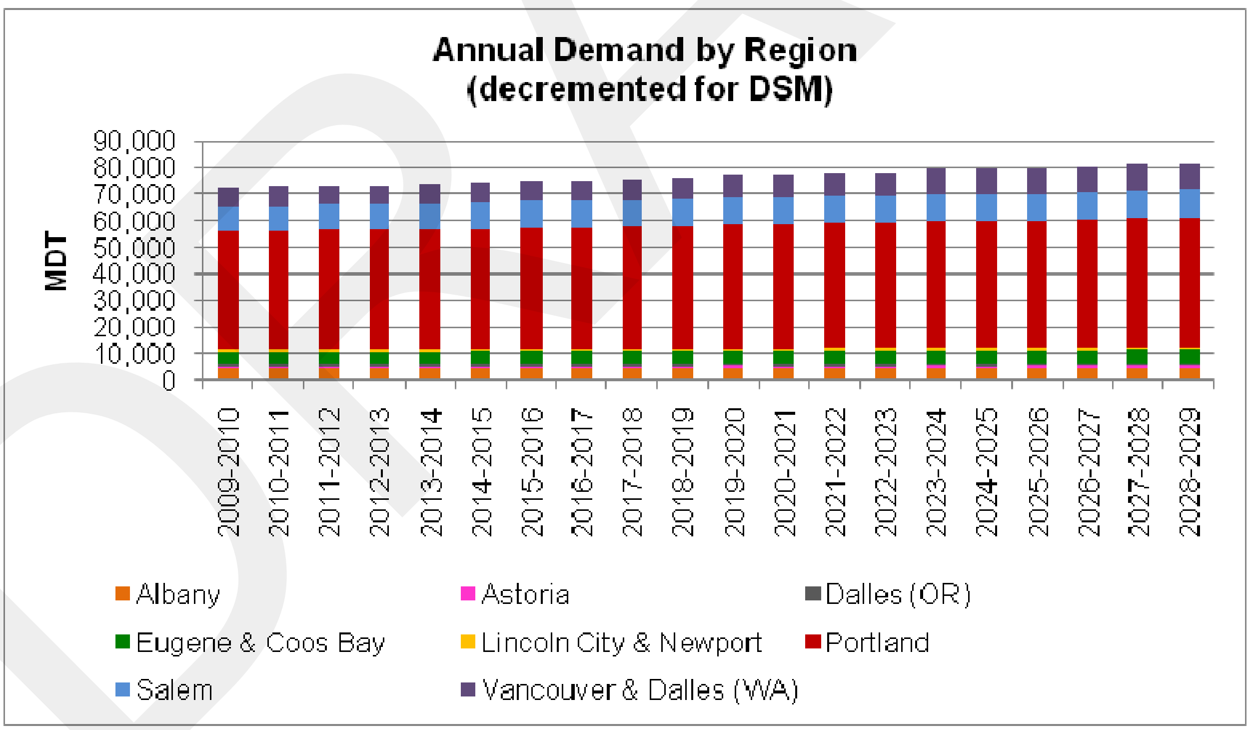


Figure 2.14 - Peak Day Demand

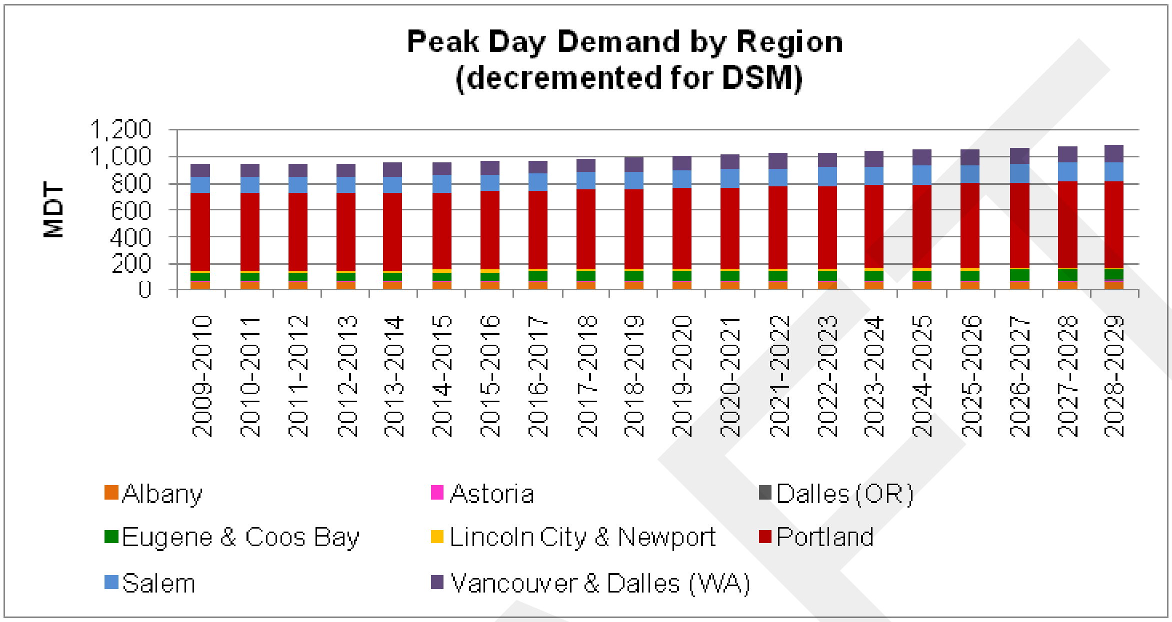
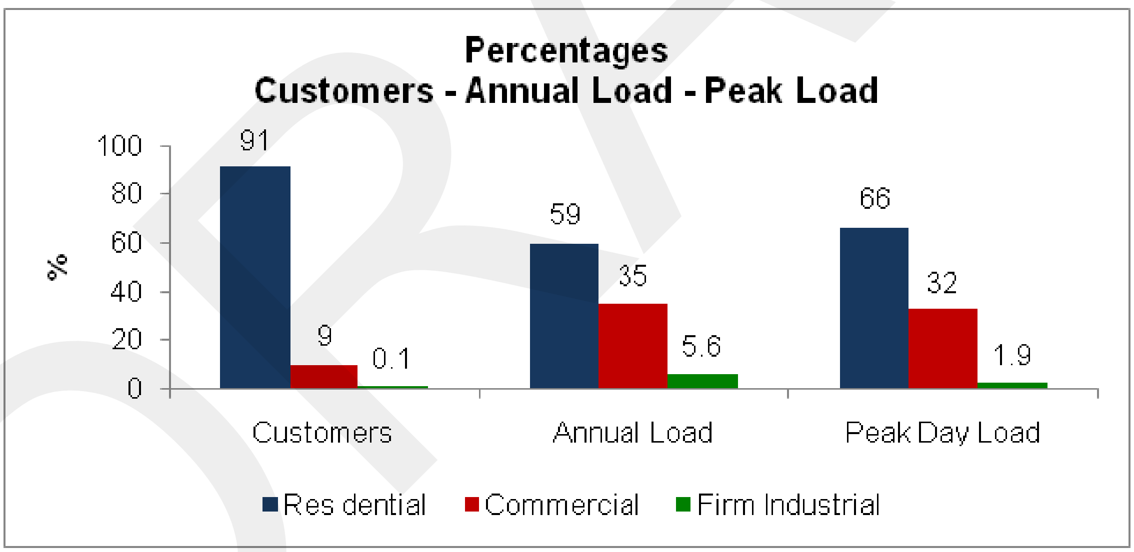
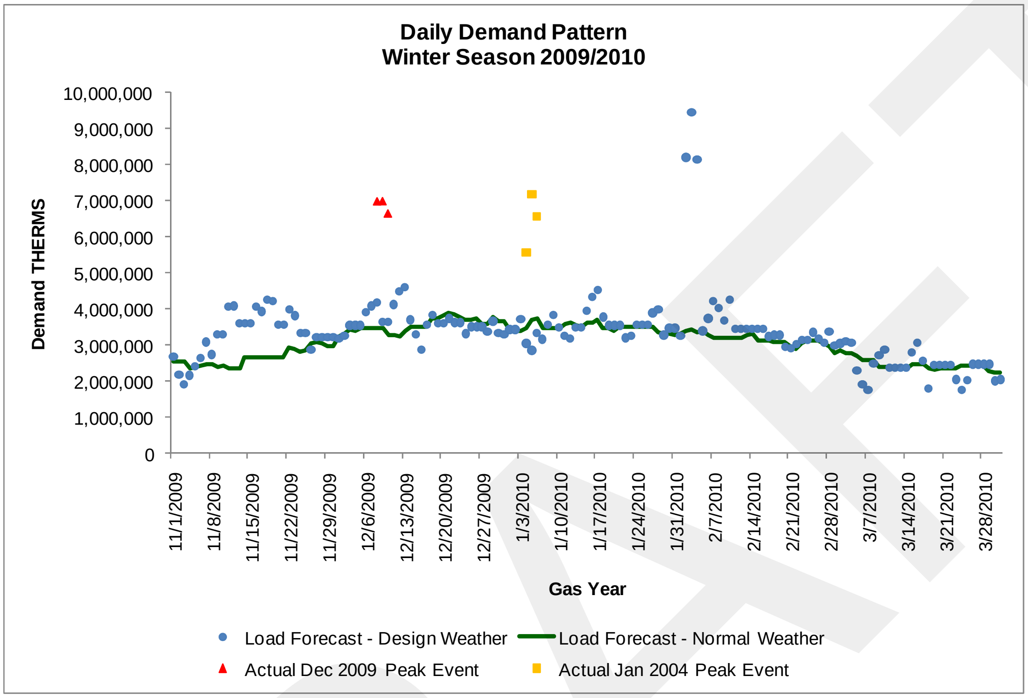


Figure 2.15 - Demand Percentages



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

Figure 2.16 - Demand Forecast Pattern



B. Demand Scenarios

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

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

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

Table 2.4 - Scenarios

Case	Customer Forecast	Customer Usage Forecast	Gas Price Forecast	Weather
1319-Base Case	Base Case	Base Case	Base Case	Design
1360-Gas Breakthrough	High	High	High	Design
1358-Gas Dereg.	High	Base Case	Low	Design
1363-Electric Breakthrough	Very Low	Base Case	High	Design
1356-Low Customer Growth	Low	Base Case	Base Case	Design
1357-High Customer Growth	High	Base Case	Base Case	Design
1354-Low Gas Price	Base Case	Base Case	Low	Design
1355-High Gas Price	Base Case	Base Case	High	Design

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

Table 2.5 - Scenario Demand Growth Rates

CASE	Ave. Annual Growth Rates - % PRE-DSM				Ave. Annual Growth Rates - % POST-DSM		
	OR	**WA**	**SYSTEM**		**OR**	**WA**	**SYSTEM**
1319-Base Case	1.17	2.22	1.28		0.47	1.74	0.61
1360-Gas Breakthrough	2.51	3.71	2.64		1.95	3.33	2.10
1358-Gas Dereg.	1.45	2.59	1.57		0.76	2.13	0.91
1363-Electric Breakthrough	0.17	0.90	0.25		-0.52	0.40	-0.42
1356-Low Customer Growth	0.93	1.89	1.03		0.23	1.41	0.36
1357-High Customer Growth	1.40	2.53	1.52		0.70	2.06	0.85
1354-Low Gas Price	1.21	2.28	1.33		0.52	1.80	0.66
1355-High Gas Price	1.14	2.19	1.25		0.44	1.71	0.58

Figure 2.17 - Annual Demand Scenarios

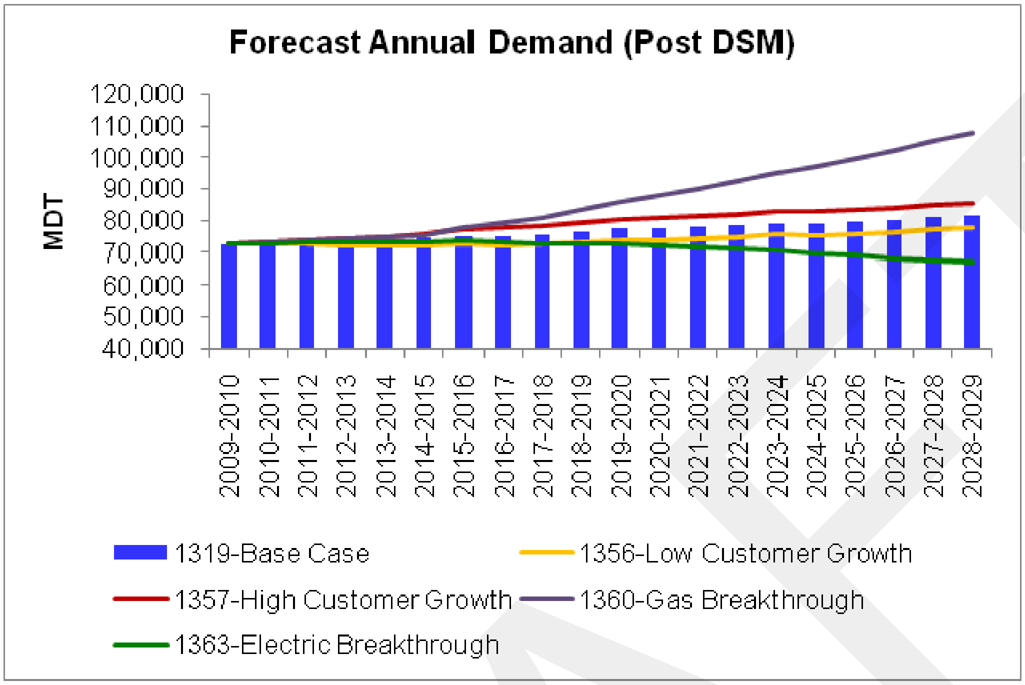
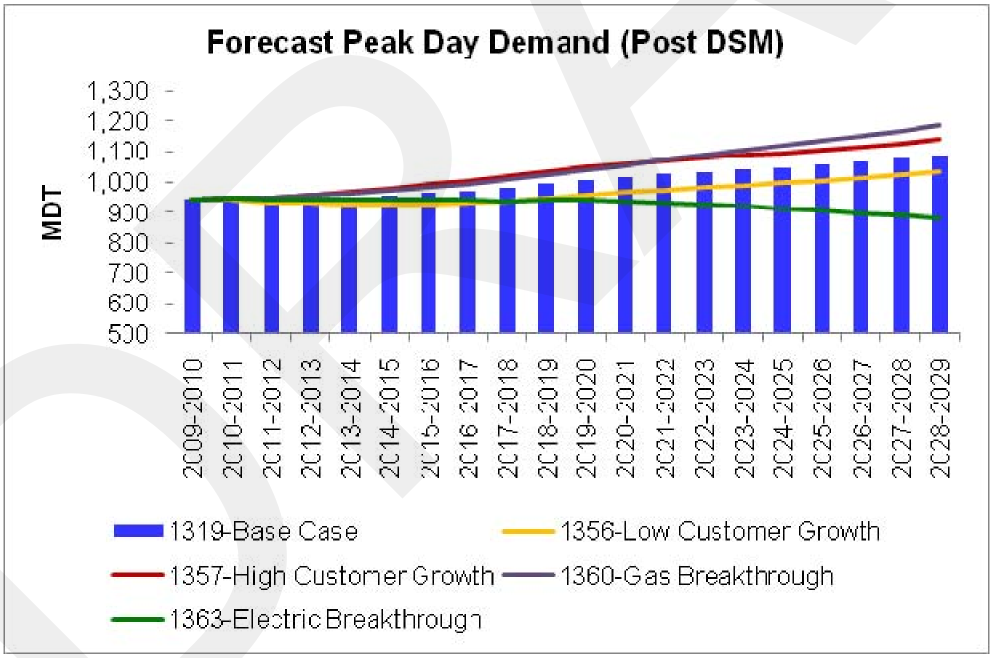


Figure 2.18 - Peak Day Demand Scenarios



VII. FORECAST ACCURACY AND PEAK DAY ANALYSIS

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

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

Table 2.6 Backcast

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

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

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

Figure 2.19 - Backcast Results for January 2004

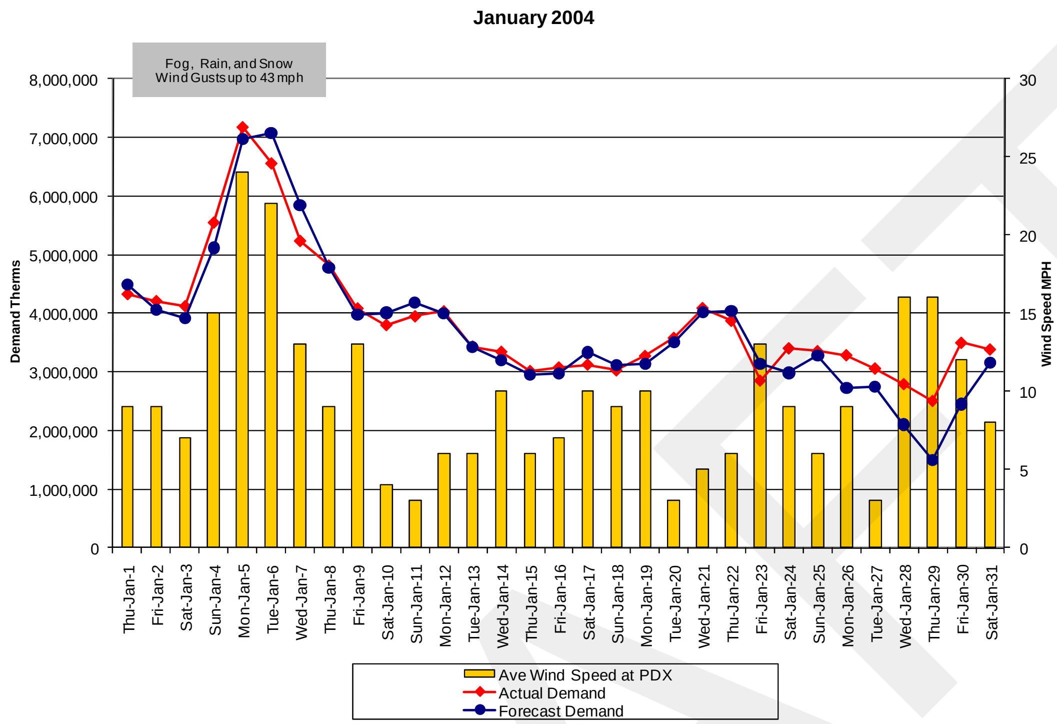
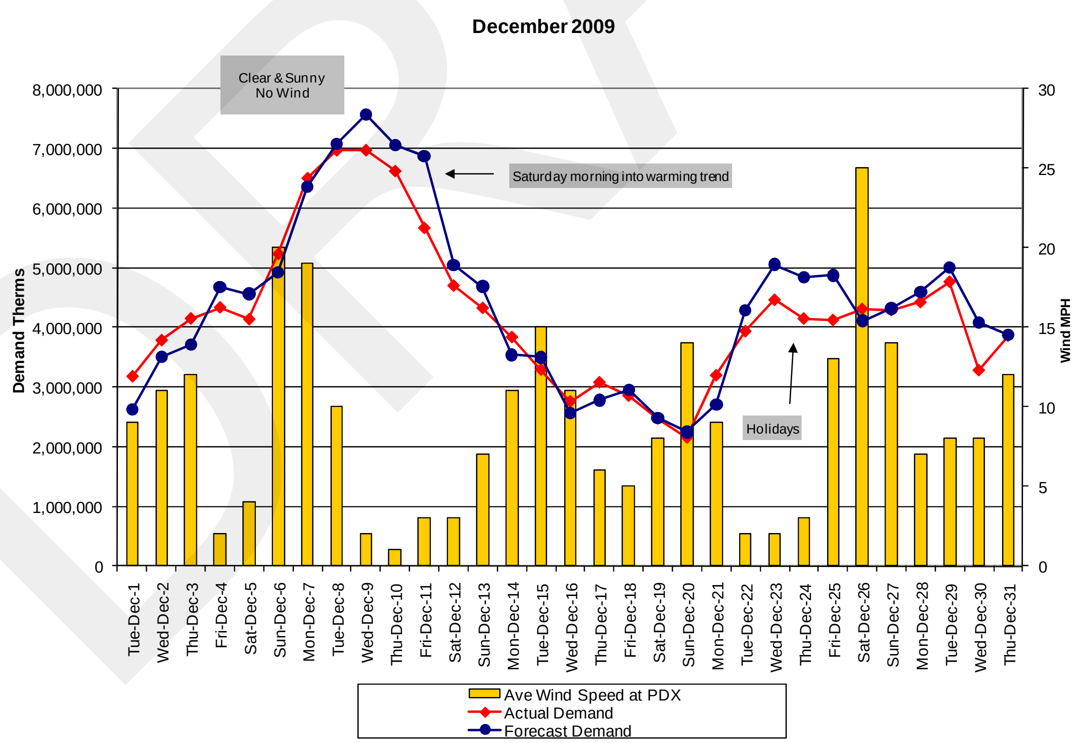


Figure 2.20 - Backcast results for December 2009



It is apparent that wind speed and cloud cover played a role in the demand response. However, wind speed and its effect on demand in combination with temperature is not currently modeled in the load forecast. This may be a topic for further study in a future IRP. Differing demand responses on holidays also contribute to load forecast error, as can be seen in Figure 2.21**.** Some factories, businesses and schools may be closed at various times in later December which can result in the forecast overshooting actual demand.

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

Table 2.7 – Accuracy Statistics

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

VIII. KEY FINDINGS

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

Chapter 3: Supply Side Resources

I. OVERVIEW

This chapter discusses the gas supply resources that the Company currently uses to meet existing firm customer supply requirements, as well as the supply-side alternatives that could be used to meet the forecasted growth in gas requirements as described in Chapter 2. Supply-side resources include not only the gas itself, but also the pipeline capacity required to transport the gas, the Company's gas storage options, and the system enhancements necessary to distribute the gas. This chapter surveys existing and potential resources without judgment as to the resources that will be chosen. Chapter 5 describes the actual linear programming optimization process, which selects the resources that are least cost under a variety of load growth scenarios.

The gas supply planning process focuses on securing and dispatching gas supply resources to ensure reliable service to the Company's sales customers. The amount of gas needed is greatly influenced by customer behavior. Several factors can affect customer behavior and can cause daily, seasonal, and annual variations in the amount of gas required. Much of this variation is due to changes in the weather. However, changes in business cycles, and the price of natural gas service in relation to other fuel alternatives, may also influence a customer's gas use. These behavioral factors are accounted for in the Company's gas requirements forecast and are discussed in more detail in Chapter 2.

The ability to plan for customer requirement variations while maintaining reliability of service is best accomplished by keeping a variety of supply resources available. The Company's current supply portfolio consists of both contracted natural gas supplies, which can be used year-round and transported on the interstate pipeline system, and storage gas supplies, which are stored either underground or as liquefied natural gas (LNG)[1] in tanks. Both can be used as peaking resources during periods of high demand.

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

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.

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 and dressing warmer. The structural changes should persist under most conditions, but the behavioral changes could be easily reversed. For example, lowering the thermostat may be a customer's response to high prices, but during an extreme cold weather episode, the customer may decide to raise the thermostat rather than risk frozen pipes or endure uncomfortable conditions. This may be a temporary move that has a negligible impact on annual requirements, but, in the aggregate, it could directly correlate to and have a non-trivial impact on peak day requirements.

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

II. CURRENT RESOURCES

A. Pipeline Transportation Contracts

NW Natural holds firm transportation contracts for capacity on the Northwest Pipeline Corporation (NWPL) interstate pipeline system, over which all of NW Natural's supplies must flow except for the small amount of local gas produced in the Mist field (currently less than 2% of annual requirements). For its purchases in Alberta and British Columbia, NW Natural also holds transportation contracts on the pipeline systems upstream of 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 2010

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
NWPL:		
Sales Conversion	214,889	9/30/2018
1993 Expansion	35,155	9/30/2044
1995 Expansion	102,000	11/30/2016
International Paper Cap. Acquisition	4,147	11/30/2016
Occidental (formerly Duke) Cap. Acq.	5,000	10/31/2012
Total NWPL Capacity	361,191	
less recallable release to -		
Portland General Electric	(30,000)	11/01/2011
Net NWPL Capacity	331,191	
GTN:		
Sales Conversion	3,616	10/31/2023
1993 Expansion	46,549	10/31/2023
1995 Rationalization	56,000	10/31/2012
Total GTN Capacity	106,165	
TCPL BC System:		
1993 Expansion	47,727	10/31/2012
1995 Rationalization	57,417	10/31/2012
Engage Capacity Acquisition	3,708	10/31/2012
2004 Capacity Acquisition	48,187	10/31/2016
Total TCPL-BC Capacity	157,039	

2 Notes to Table 3.1:

a. For each listed capacity resource, the SENDOUT® model includes the cost NW Natural is currently paying for the service.
b. The WEI and Southern Crossing contracts are denominated in volumetric units. Accordingly, the above energy units are approximations.
c. The numbers shown for the 1993 Expansion contracts on GTN and TCPL-BC are for the winter season (October-March) only. Both contracts decline during the summer season (April-September) to approximately 300,000 therms/day.

Table 3.1 (continued)

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
TCPL Alberta System:		
1993 Expansion	48,135	10/31/2012
1995 Rationalization	57,909	10/31/2012
Engage Capacity Acquisition	3,739	Upon 1-year notice
Engage Capacity Assignments	24,121	Annual Evergreen
2004 Capacity Acquisition	49,138	10/31/2016
Total TCPL-Alberta Capacity	158,921	
WEI T-South Capacity	57,822	10/31/2014
Southern Crossing Pipeline (SCP)	47,747	10/31/2020

Since the implementation of FERC Order 636 in 1993, capacity rights on U.S. interstate pipelines have been commoditized; *i.e.*, capacity can be bought and sold like other commodities. These releases and acquisitions occur over electronic bulletin board systems maintained by the pipelines, under rules laid out by FERC. To further facilitate transactional efficiency and a national market, interstate pipelines have moved towards some standardization of definitions and procedures through the efforts of the industry-supported North American Energy Standards Board (NAESB), with the direction and approval of FERC. Capacity trades also can occur on the Canadian pipelines. In general, Canadian pipelines try to be consistent with most of the NAESB standards since much of the Canadian gas production is destined for export to markets in the United States.

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

B. Gas Supply Contracts

NW Natural's portfolio of supply for the 2010-2011 heating season is indicated in Table 3.2.[3] The contracts with near-term expiration dates will either be renegotiated or replaced prior to the next

3 Table 3.2 excludes local production from the Mist field that is delivered directly to NW Natural's system. Since the initial gas discoveries in 1979, Mist production flows peaked at approximately 100,000 therms per day. Local production now results from third party exploration efforts and currently runs about 40,000 therms per day. The Company utilizes approximately 40,000 therms per day for modeling purposes. All such production is sold under a long-term contract to NW Natural for the life of the production wells. Due to the relatively low

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.

Table 3.2[4] - Upstream Supplier Portfolio as of November 2010

Supply Location	Duration	Baseload Quantity (Dth/day)	Swing Supply (Dth/day)	Contract Termination Date
British Columbia (Station 2):				
IGI Resources	Nov-Oct	5,000		10/31/2012
AltaGas Energy	Nov-Oct	5,000		10/31/2011
Shell Energy	Nov-Oct	5,000		10/31/2011
Husky Energy	Nov-Oct	5,000		10/31/2011
Macquarie Energy Canada	Nov-Oct	5,000		10/31/2011
ConocoPhillips Canada	Nov-Oct	10,000		10/31/2011
Suncor Energy	Nov-Mar	5,000		3/31/2011
EDF Trading NA	Nov-Mar	5,000		3/31/2011
Alberta:				
Sempra Energy Trading	Nov-Oct	10,000		10/31/2014
Shell Energy NA – Canada	Nov-Mar			3/31/2011
Sequent Energy Canada	Nov-Mar	5,000		3/31/2011
ConocoPhillips	Nov-Mar	10,000		3/31/2011
Husky Energy	Nov-Mar	5,000		3/31/2011
Suncor Energy	Nov-Mar	5,000		3/31/2011
Tenaska Marketing Canada	Nov-Mar	5,000		3/31/2011
TD Energy Trading	Nov-Mar	5,000		3/31/2011
IGI Resources	Nov-Mar	5,000		3/31/2011
Husky Energy	Nov-Mar	5,000		3/31/2011
Powerex	Nov-Mar	5,000		3/31/2011
Iberdrola Canada	Nov-Mar	5,000		3/31/2011
Sequent Energy Canada	Nov-Mar	5,000	10,000	3/31/2011
Sequent Energy Canada	Apr-Oct		10,000	10/31/2011

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.

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.

Table 3.2[5] (continued)

Supply Location	Duration	Baseload Quantity (Dth/day)	Swing Supply (Dth/day)	Contract Termination Date
Rockies:				
BP		10,000		
Iberdrola Renewables	Nov-Mar	5,000		3/31/2011
IGI Resources	Nov-Mar	5,000		3/31/2011
Anadarko	Nov-Mar	5,000		3/31/2011
National Fuel Marketing	Nov-Mar	5,000		3/31/2011
Macquarie Energy	Nov-Mar	5,000		3/31/2011
Ultra Resources	Nov-Mar	10,000		3/31/2011
Oneok Energy	Nov-Mar	5,000		3/31/2011
Occidental Energy	Nov-Mar	5,000		3/31/2011
Shell NA – US	Nov-Mar	5,000		3/31/2011
Kansas Energy	Nov-Mar		10,000	3/31/2011
ConocoPhillips	Nov-Mar		5,000	3/31/2011
Oneok	Nov-Mar		5,000	3/31/2011
Kansas Energy	Nov-Mar		5,000	3/31/2011
Kansas Energy	Apr-Oct		5,000	10/31/2011
Sequent	Nov-Mar		5,000	3/31/2011
Sequent	Apr-Oct		5,000	10/31/2011
Total Off-System Firm Contract Supply		180,000	40.000	

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 the non-utility storage business. As core needs grow, existing storage capacity may be recalled and transferred for use by core utility customers. The IRP models the recallable portion of the existing Mist storage capacity as an incremental resource that is discussed in Section V of this chapter.

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

5 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 costs 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-storage peak deliverability is based on design criteria.

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 3.3 below.

Table 3.3[6] - Recallable Supply Arrangements as of November 2010

Type	Max. Daily Rate (Dth/day)	Max. Annual Recall (days)	Termination Date
Recall 1	30,000	30	11/1/2011
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 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 it would not be economic to dispatch unless weather conditions were extremely cold.

E. Supply Diversity

NW Natural’s pipeline contracts enable it to purchase roughly one-third of its supplies from each of the major supply regions in the area: British Columbia, Alberta and the U.S. Rockies (figure 33). Lower liquidity in British Columbia has prompted NW Natural to baseload more of its supplies from this region on a year-round basis, i.e., to rely less on that region for winter term and spot purchases than in the past. NW Natural will continue to favor spot purchases from Alberta and the Rockies during 2010-2011 due to low prices. However, Rockies prices could change in reaction to the recent completion of one of the largest pipeline projects in decades. In November of 2009, the new Rockies Express Pipeline (REX) became fully operational to move Rockies gas to markets in Illinois, Indiana, and Ohio, increasing competition and prices for those supplies. However, new supplies from the Marcellus Shale formation will lower East demand from REX with bearish implications on Rockies prices.

The tight nationwide balance between supplies and demand over the past few years resulted in lower confidence in spot markets during cold weather or other extreme load periods. Reflecting that concern, the company’s previous contracting practice was to select a minimal summer load, including storage injections, as an amount suitable for year-round baseload (take-or-pay) supply contracting. It would then fill up most of its remaining pipeline capacity with winter term (November-March) supply

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

contracts. Some of these Nov-Mar contracts would be baseload (take-or-pay) in nature, while others would provide optionality on purchases to avoid over-contracting in the event of a mild winter. In general, spot purchases have been less than 10% of total purchases due to this heavy reliance on term contracts. The flexibility of storage and term contracts in recent years has allowed spot purchases to be much higher when conditions are favorable.

Plans for 2010-2011 continued to shift based on trends preceding the 2009-2010 tracker year. Developments include:

1. Reductions in customer growth,
2. Declining usage per customer, and
3. Potential further migration of interruptible industrial sales customers to transportation service.

Those factors are expected to create "peakier" load patterns than in the past, meaning that gas usage will be more influenced by daily weather. As a result, less gas in 2010-11 will be purchased under year-round supply contracts than in 2008-09 and prior. Instead, the company will be more reliant on winter term purchases or on spot purchases in order to adapt to the changing load pattern.

Physical gas contracting strategies for 2010-2011 that are consistent with strategies of recent years include:

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

- Continue to shift the source of physical supplies to the lowest-cost source region. In recent years, Rockies gas offered the best prices as production increased due to anticipation of the Rockies Express Pipeline. Since that pipeline became fully operational in 2009, Rockies term prices have risen higher than Alberta prices. British Columbia gas is typically priced higher than Rockies and Alberta.

Figures 3.1 and 3.2 provide graphical representations of the Company's supply resources and diversity during 2009 (the most recently completed calendar year).

FIGURE 3.1 – Gas Supply Diversity by Contract Length for Calendar Year 2009

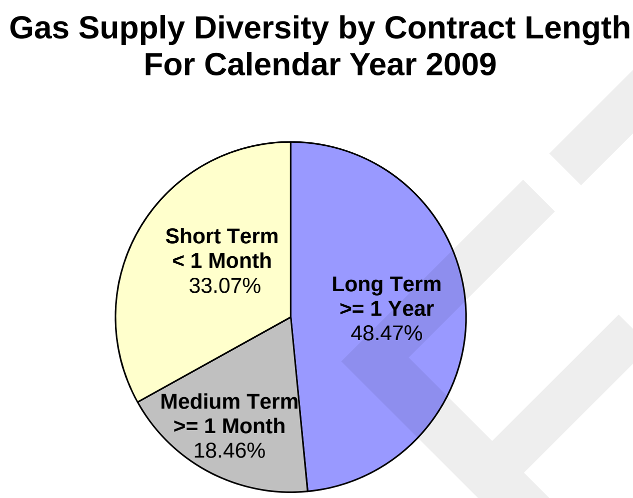
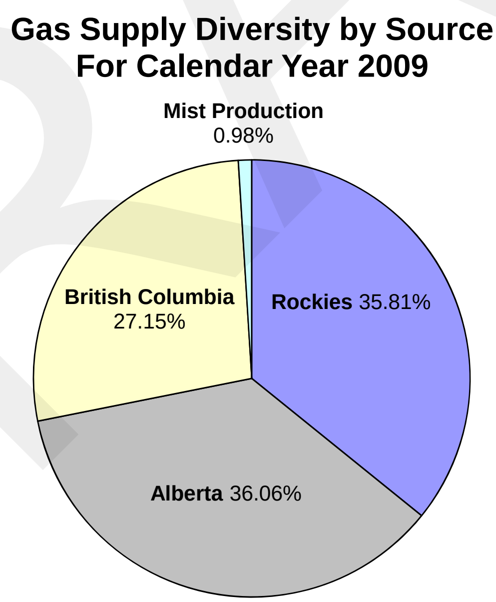


Figure 3.2 – Gas Supply Diversity by Source for Calendar Year 2009



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 maintain 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 most likely combination of expected costs and associated risks and uncertainties for the utility and its customers. The system is operated as an integrated whole and costs are apportioned accordingly, absent state boundaries.

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

Appendix 3.1 shows the inventory guidelines for the 2010-2011 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 2009, NW Natural added 100,000 therms per day of core 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."

  - o The Company continues to monitor various pipeline projects and the potential development of an imported LNG terminal in the Pacific Northwest.

- o 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."

  - o 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.

- o 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."

  - o Since the 2007 IRP, the Company has invested significant shareholder funds in a biodigester project that may eventually lead to the development of biogas that may be used on site to displace propane, or eventually may be brought to pipeline quality. NW Natural continues to be active in the development of biogas and will monitor this potential source of renewable natural gas.

V. FUTURE RESOURCE ALTERNATIVES

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

A. Interstate Capacity Additions

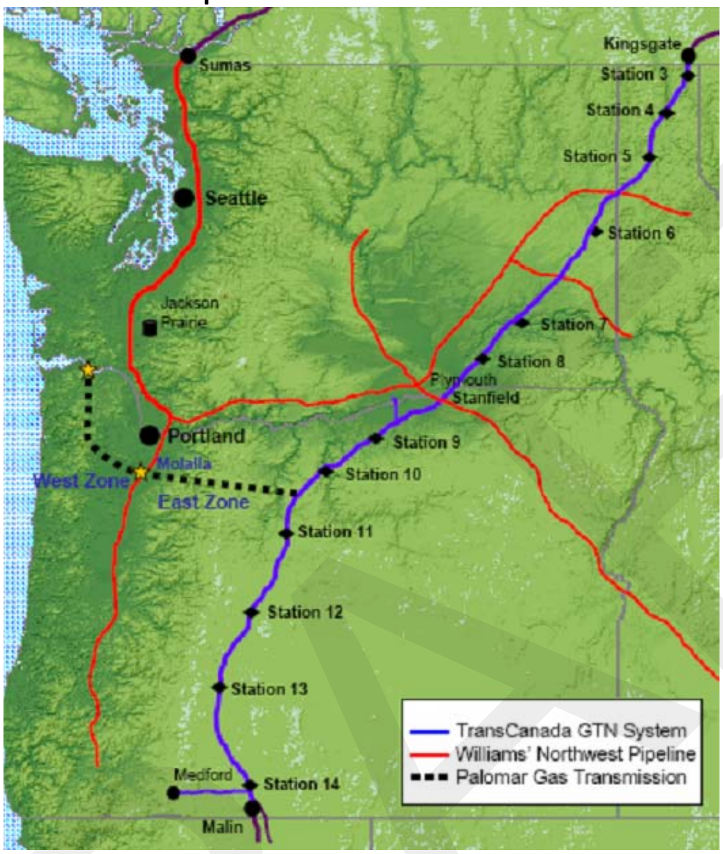
NW Natural holds existing CD entitlements and citygate station capacity on: 1) NWPL's "mainline" serving NW Natural's service areas in Portland, Astoria, Vancouver and The Dalles, and 2) NWPL's Grants Pass Lateral serving NW Natural's loads in the Willamette Valley south of Portland. Therefore, consideration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

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

In response to its reliance solely on NWPL for delivery of interstate gas supplies, NW Natural has partnered with TransCanada Corporation to form Palomar Gas Transmission LLC. As depicted in Figure 3-3, Palomar is proposing to develop, build and operate the proposed Palomar pipeline project 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.[7]

As shown in Table 3.5 below, in this IRP, NW Natural considers acquisition of incremental interstate pipeline capacity in several forms: 1) new NWPL Grants Pass Lateral capacity serving Salem, Newport, Albany and Eugene, 2) new NWPL "mainline" capacity serving Portland, Astoria, Vancouver, and The Dalles, 3) new capacity upstream of NWPL mainline capacity providing access to the Rockies[8] and Alberta supply areas, 4) new Palomar capacity both east and west of Molalla, 5) new capacity on the proposed Pacific Connector Pipeline to access regasified LNG from the proposed Jordan Cove LNG project at Coos Bay, Oregon, 6) recall of existing NWPL mainline capacity from the Rockies and Sumas

7 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.

8 NWPL capacity upstream of Stanfield, Oregon.

that NW Natural has released to Georgia Pacific, and 7) existing NWPL mainline capacity from the Rockies that NW Natural has contracted to acquire starting in 2017. The acquisition of incremental pipeline capacity spans a wide range of lead times; its availability depends on the availability of existing capacity, the length of the pipeline's open season process, and the completion date of the constructed facilities.

Table 3.4 - Incremental Interstate Pipeline Capacity Additions Modeled in SENDOUT®

Interstate Pipeline Segments	Contract Demand (Dth/d)	Assumed Availability
NWPL Zones 12-9 (Grants Pass Lateral)	74,200	November 2013
NWPL Zones 26-12 ("mainline")	2,031,000	November 2013
Upstream of NWPL z26-12:		
Rockies-Stanfield	1,062,000	November 2014
Alberta-Stanfield	969,000	November 2012
Palomar East	200,000	November 2014
Pacific Connector	100,000	November 2013
GP Recall (existing NWPL capacity)	3,500 each from Rockies & Sumas	November 2008
March Point NWPL capacity	12,000 Rockies to Portland	November 2017

B. Mist Storage Recall

In addition to the existing Mist storage capacity currently reserved for the core market (see Table 3.3), the Company has four reservoirs (Reichhold, Schlicker, Busch and Meyer Pools) that are developed for storage services and currently serve the interstate storage market in whole or in part, but could be recalled for service to the Company's core customers. Table 3.5 identifies the recallable Mist capacity and the year the capacity is available given current contractual commitments to interstate market customers.

Table 3.5- Mist Recall Capacity (incremental to existing capacity for core)

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

Mist is ideally located in NW Natural's service territory, eliminating the need for upstream interstate pipeline transportation service to deliver the gas during the heating season. Due to its location within the Company's service territory, Mist is particularly well suited to meet incremental load requirements in the Portland area, which is traditionally the area where the majority of the Company's firm load growth lies. Mist gas may also be directly delivered to loads along the Columbia River from St. Helens to Astoria.

C. NW NATURAL INFRASTRUCTURE ADDITIONS

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

The Company uses the Synergy software package[9] 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.

9 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 the ability to meet future gas delivery requirements. This computer simulation capability allows the Company to efficiently evaluate distribution system performance in terms of stability, reliability, and safety under varying boundary conditions ranging from peak-day delivery requirements to temporary service interruptions, both planned and unplanned.

System planning takes place continuously, integrating new customer growth requirements into the Company's construction forecasts. Computer simulation testing is used to help validate the need for and timing of specific system expansion, reinforcement, and replacement projects. Near-term (one to two-year) projects are highly likely to occur as specified to meet customer delivery requirements. Mid-term (three to five-year) projects are subject to time slippage based on adjustments to the rate and geographic direction of customer growth. Long-term (beyond five years) will tend to be general 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 8,000 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 $1,200,000 and will 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 3.6 below, the project includes a total of three segments serving three load regions, Salem, Albany, and Eugene

Table 3.6 - Willamette Valley Feeder Project Segments

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

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

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 Liquefied Natural Gas (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 was built in West Virginia in 1912. The first commercial liquefaction plant was built in Cleveland, Ohio, in 1941. Today, over 100 active LNG facilities spread across the United States, with the greatest concentration in the northeastern United States.

Ocean transport of LNG began in 1959.[10] 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,[11] Everett, MA – operated by Tractebel,[12] Elba Island, GA – operated by El Paso,[13] and Cove Point, MD – operated by Dominion.[14] 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. 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.

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10 That first cargo of LNG was shipped from the United States to England.

11 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)

12 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.

13 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.

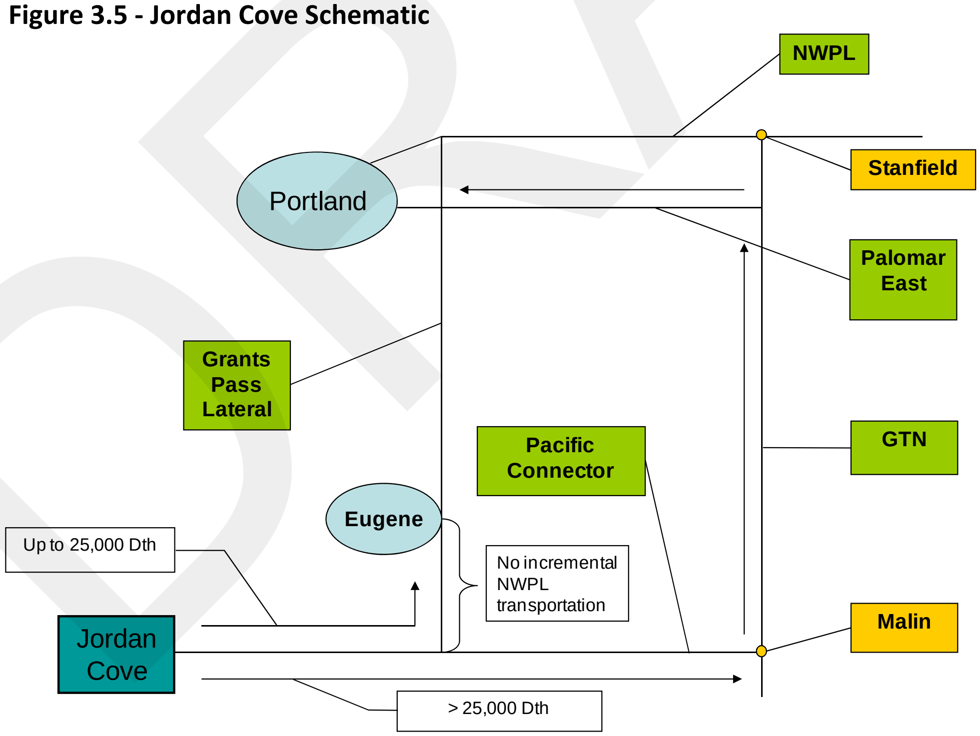
14 The Cove Point terminal was completed in 1978, and has a max send-out rate of 1 Bcf per day or a firm sustained baseload of 750 Mcf.

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 several dozen proposed LNG terminals 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, a number of viable west coast LNG projects and proposals 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 listed three proposed or potential LNG import terminal projects within Oregon. They are Bradwood (Northern Star LNG) in Bradwood (which filed for bankruptcy in 2010), Jordan Cove in Coos Bay and Oregon LNG in Astoria. The project that is furthest along appears to be Jordan Cove.

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.

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 dioxide 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.[15] 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 dioxide 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 proposed sites:

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

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15 *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).

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

3) **Terasen Project**
Located NW of Ladysmith and West of Mt Hayes, this is a peak shaving LNG terminal. This project is located on Texada island and will connect into Terasen's system. This project is under construction and has received BCUC approval.

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

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% to 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 Storage

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

In recent years, control system improvements at the Newport LNG plant have improved liquefaction performance. Puget Sound Energy installed a satellite LNG facility near Gig Harbor, Washington, to help meet customer growth at the tail end of its distribution system. LNG from NW Natural was used to help fill the Gig Harbor tank, and this has renewed NW Natural's interest in evaluating this concept for remote areas where siting and zoning approvals are conceivable. In this IRP, NW Natural has evaluated satellite LNG in Willamette Valley locations near Salem, Albany, and Eugene, as interim resources that might delay the incursion of more expensive pipeline projects (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 dioxide emissions through methane sequestration and as a study on biogas development and use. The Dairy Farmers of Oregon and the Oregon Department of Agriculture support the development of biodigesters, which anaerobically convert animal waste into methane (natural gas) and composted soil amendment (fertilizer). Biodigesters are seen as helping the farming industry, the economy and the environment

The Company has focused its efforts on an emerging technology that converts animal waste into anaerobic digester gas (ADG). While companies around the world have refined this approach, companies in the Pacific Northwest offer the resources to bring such a program together. Capital expenditure requirement per site are approximately $5 million. However, the natural gas output is limited when compared to the Company's load requirements – 410,000 annual therms. The program is further enticing because of the other by-product of the process – fertilizer. While peat moss generates revenue, 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 became operational January 2010. This project converts waste into an ADG that can be used to offset onsite propane use for the dairy operations.

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

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

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

Supply Basin Storage Developments. Capacity has been available in new and existing production area storage facilities in Alberta, British Columbia, and in the U.S. Rocky Mountain region. 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 prove advantageous to 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.

VI. 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 2010-2011 ("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 2010-2011 gas contracting year which runs from November through the following October. However, many resource decisions are of a multi-year nature. Accordingly, a 5-year horizon is used for discussion purposes in several areas of this section.

Below are excerpts from the GAP.

B. Plan Goals

1. <u>Reliability</u>

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

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

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

4. **<u>Cost Recovery</u>**
   NW Natural does not earn a return for acquiring and selling gas commodity supplies, yet the cost of these supplies typically amounts to more than half of the Company's total revenue stream. Risks associated with the payment and recovery of gas acquisition costs need to be minimized. On the financial hedging side, this means strong credit policies and counterparty oversight. On the legal side, this mandates scrupulous compliance to standards of conduct. Since regulatory disallowances could be devastating, maintaining trust and credibility with state regulatory bodies is imperative.

C. Relationship to the Integrated Resource Plan

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

D. Strategies

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

- Financially and physically hedge up to 75 percent of 2010-2011 projected firm sales gas volumes in accordance with decisions of the NW Natural Gas Acquisition Strategy and Policies Committee.

- Maximize supplies from the regions that afford the lower prices. In recent years, prices of Rocky Mountain gas have been lower than prices of Canadian gas due to increased production in preparation for the Rockies Express Pipeline (REX). That pipeline went into service in November 2009. As a result, the price differential between Rockies and Alberta gas has narrowed or disappeared. Strategies will be re-evaluated as other pipeline projects near completion and alter supply and demand dynamics.

- Fill storage at a pace that might present opportunities to purchase gas at times that best benefit core customers.
- Maintain a diversity of physical supplies from Alberta, British Columbia and the Rockies.

- Due to its relative lack of trading liquidity, continue to baseload virtually all pipeline capacity from the Station 2 trading point in British Columbia with a mix of seasonal, annual and multi-year commitments.

E. Market Outlook

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

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

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

VII. EMERGENCY PLANNING

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

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

The Incident Command Team (ICT) conducts periodic exercises to ensure the readiness of the team and gain experience in ICS techniques. One of the most visible uses of ICS occurred during the Y2K rollover transition period. The Company utilized Y2K as both a potential threat and an opportunity for a corporate-wide emergency readiness exercise, with over 300 employees involved in the process. More recent examples include: managing 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 in the past 20 years and through a strenuous design heating season. However, these assumptions do not always hold true. First, design weather may not be the coldest faced by the Company. There certainly have been colder heating seasons if a longer historical perspective is taken, such as occurred in 1949/50. Second, the IRP assumes perfect foresight of the weather. This may not be important for storage supplies, which can respond to load changes very quickly, but all other supplies require some amount of prior notice for scheduling. This ranges from two hours for curtailment of interruptible sales, to a day for the transportation of most pipeline gas and the use of special industrial customer capacity/supply recall arrangements. Finally, the IRP assumes reliable equipment behavior; i.e., nothing breaks or freezes up, even in the face of extremely cold temperatures.

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

VIII. KEY FINDINGS

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

- A portfolio of fixed price supplies 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.

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

Chapter 4: Demand Side Resources

I. OVERVIEW

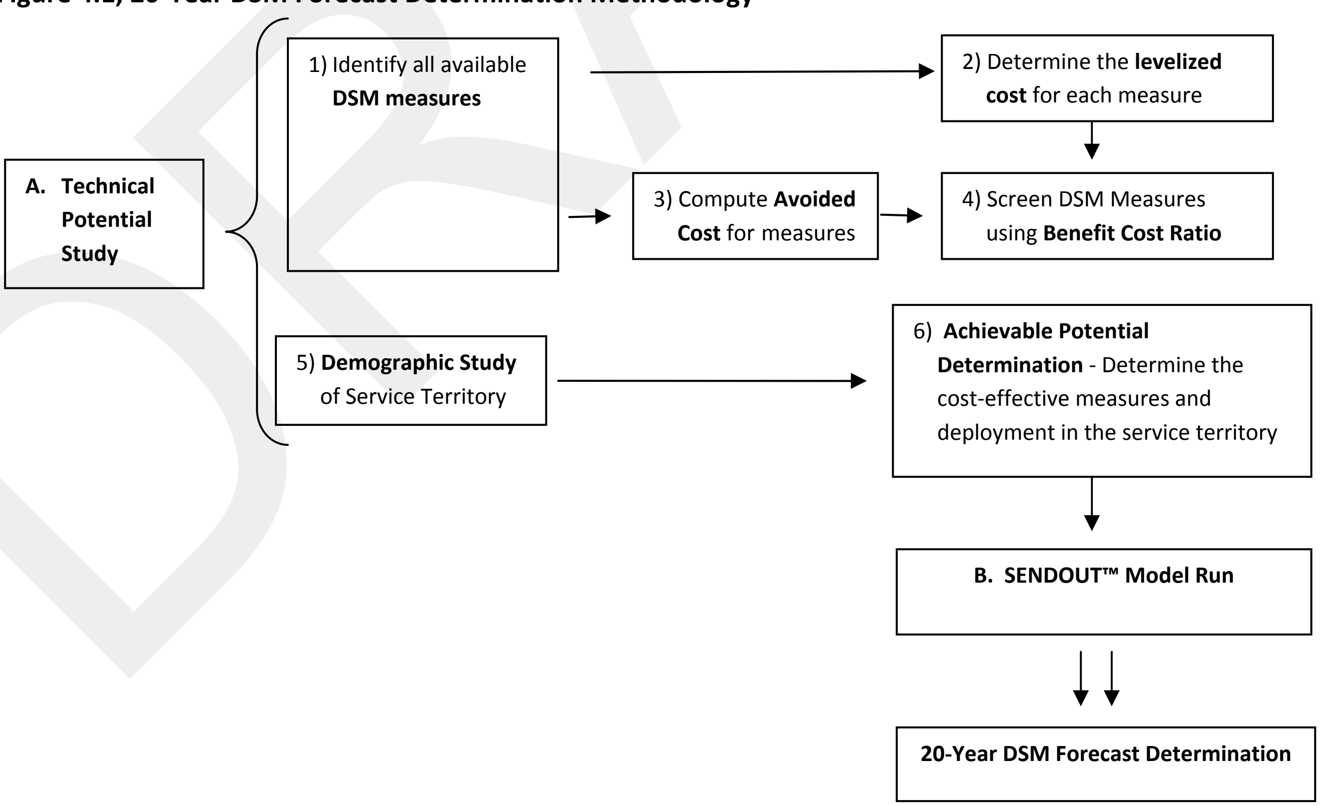
NW Natural worked with the Energy Trust of Oregon (Energy Trust) to forecast the 20-year demand side management (DSM) potential for NW Natural's service territory. Energy Trust is a non-profit organization established to provide energy efficiency services and a renewable energy program to Oregon investor-owned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

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

II. METHODOLOGY

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

Figure 4.1, 20-Year DSM Forecast Determination Methodology



A. Technical Potential Study

1) Identify all available DSM measures

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

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

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

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

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

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

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

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

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

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

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

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

The following notable observations were observed on existing measures:

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

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

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

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

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

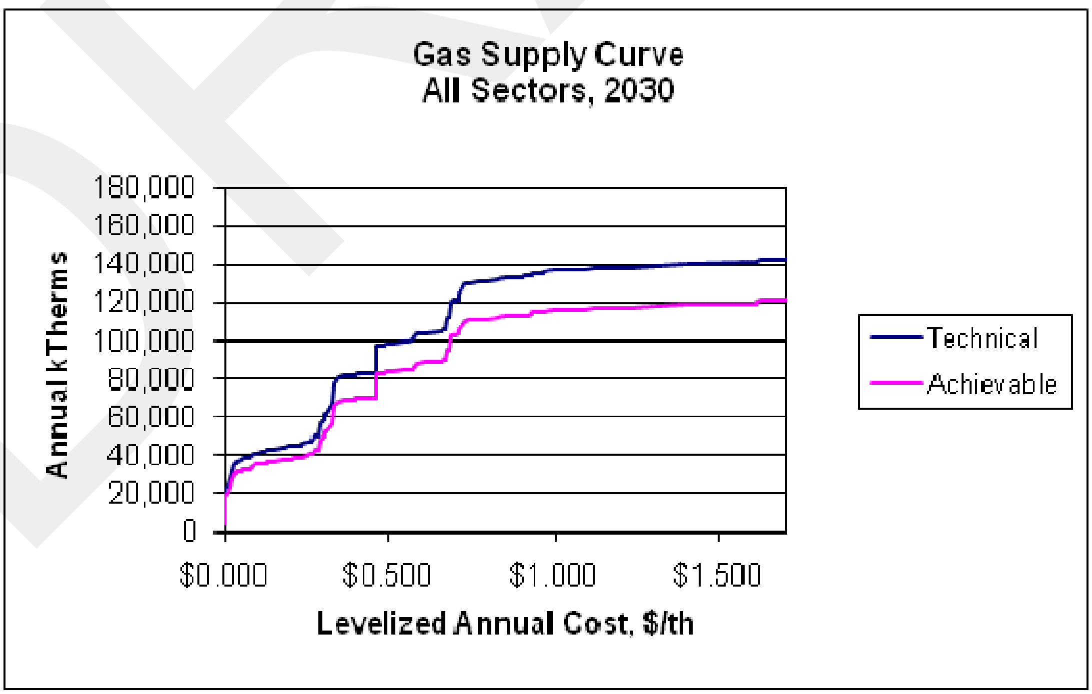
Appendix 4 contains tables of the measures for each customer class and a summary the economic assessment for each.

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

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

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

Figure 4.2 – Gas Supply Curve



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

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

   BCR = Present Value of Benefits / Present Value of Costs

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

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

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

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

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

Table 4.1 – FY 2009 Customer Statistics Sector – All Customers

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

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

Table 4.2 - FY 2009 Customer Statistics Sector - Oregon

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

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

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

Table 4.3 – FY 2009 Customer Statistics Sector - Washington

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

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

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

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

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

	Million Therms
Residential	78
Commercial	38
Industrial	22
Total	138

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

	Million Therms
Residential	11
Commercial	5.6
Industrial	.33
Total	17

In Oregon, the resource assessment estimated that approximately 117 million therms of cost effective energy savings could be attained over the next 20 years for approximately $640 million from a utility cost perspective. The resource assessment determined that over the next 20 years approximately 15 million therms of potential energy savings could be saved in Washington for about $72 million, again from a utility cost perspective.

The technical potential is assessed differently for Washington and Oregon with respect to codes. In Oregon, potential savings includes therms saved by known changes to future building codes.

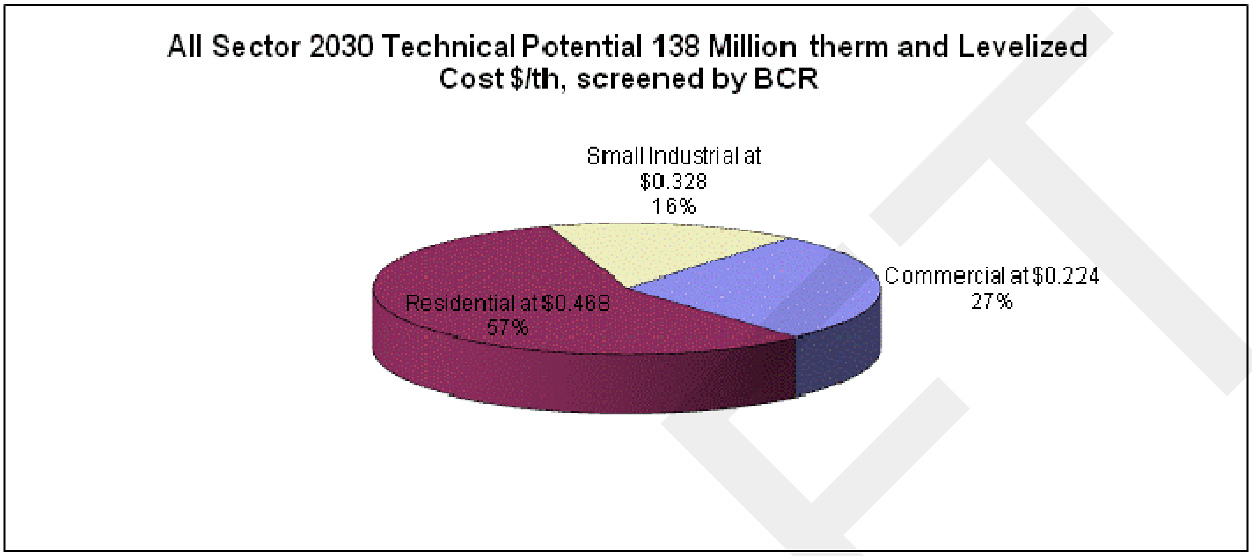
Since energy consumption is reduced when building codes are adopted, it is appropriate to decrement the Company's load forecast accordingly and allow the program to assume some of the savings since the Energy Trust's work in transforming the market influences the changes in code. This is not done for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

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

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

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

Figure 4.3 - Technical Potential through 2030



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

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

Figure 4.4 - Residential Natural Gas Measures

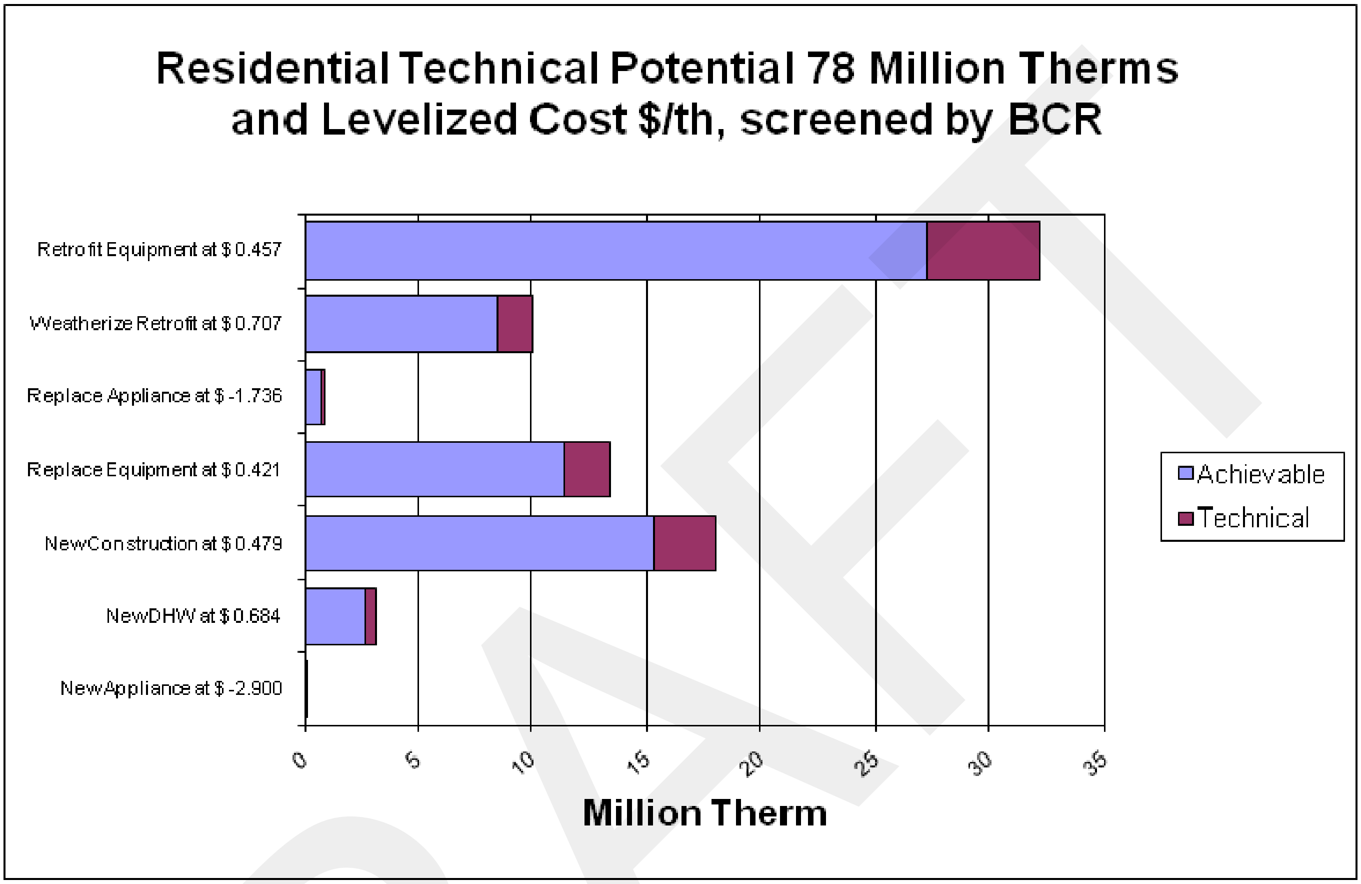


Table 4.6 - Residential Sector Gas Technical Potential Savings for 2030

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

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

Figure 4.5 - Commercial Natural Gas Measures

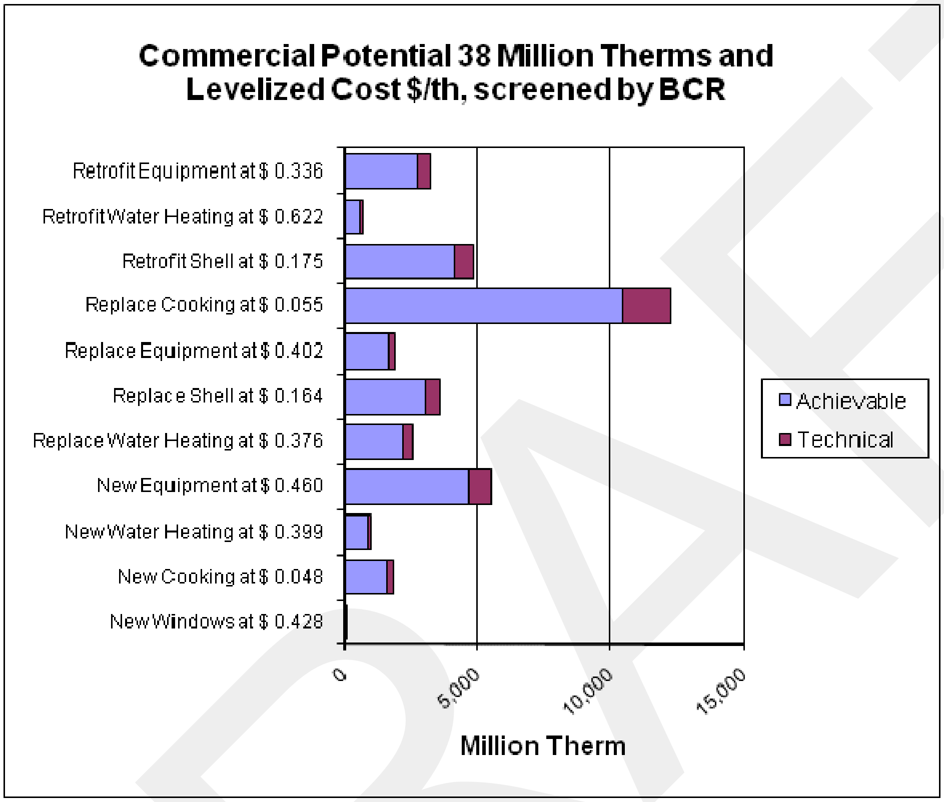


Table 4.7 - Commercial Sector Gas Technical Potential Savings for 2030

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

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

Figure 4.6 - Industrial Natural Gas Measures

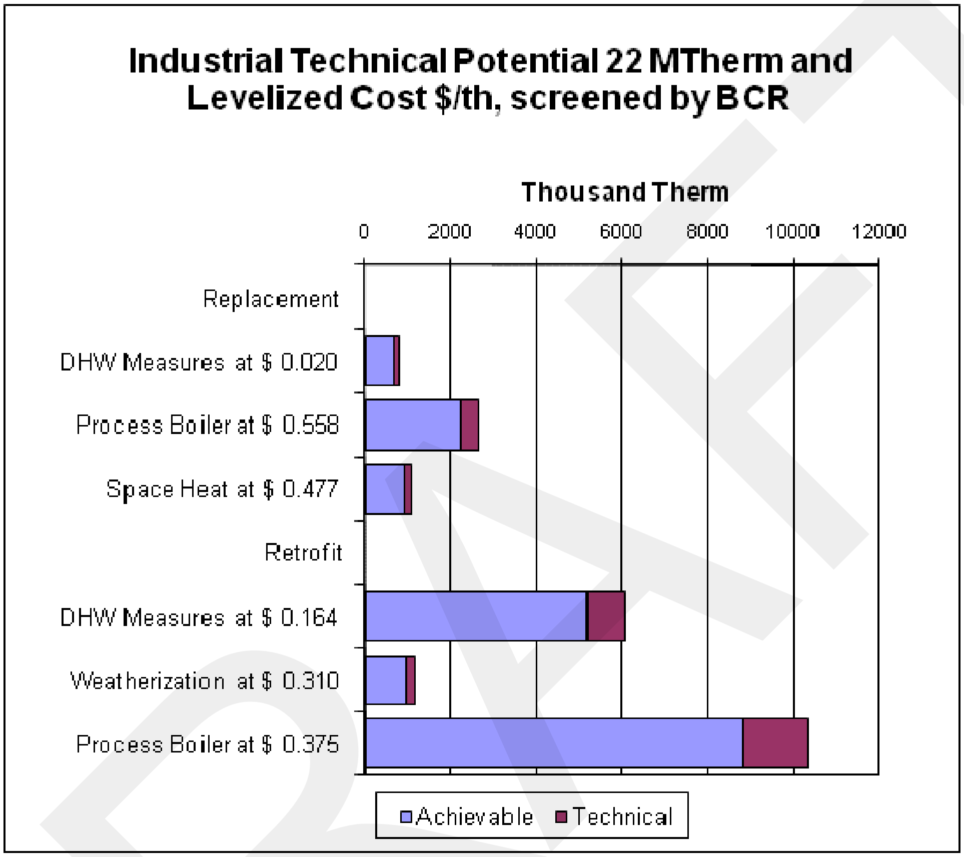


Table 4.8 - Industrial Gas 2030 Technical Potential Savings, Screened by BCR Measure Category

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

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

Figure 4.7 - Oregon Deployment Scenario

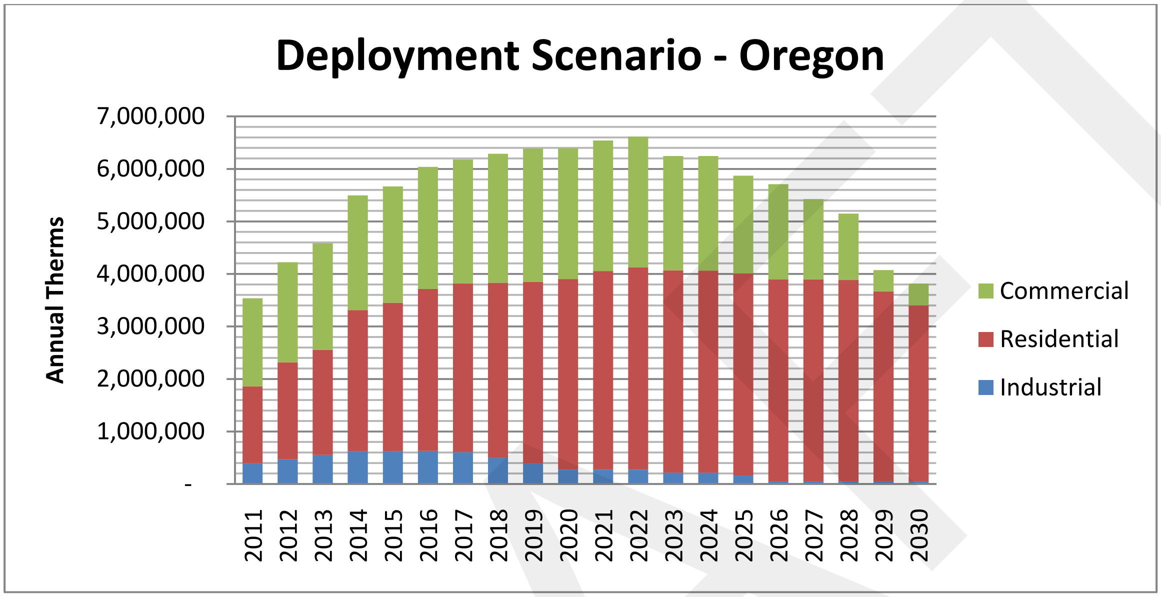
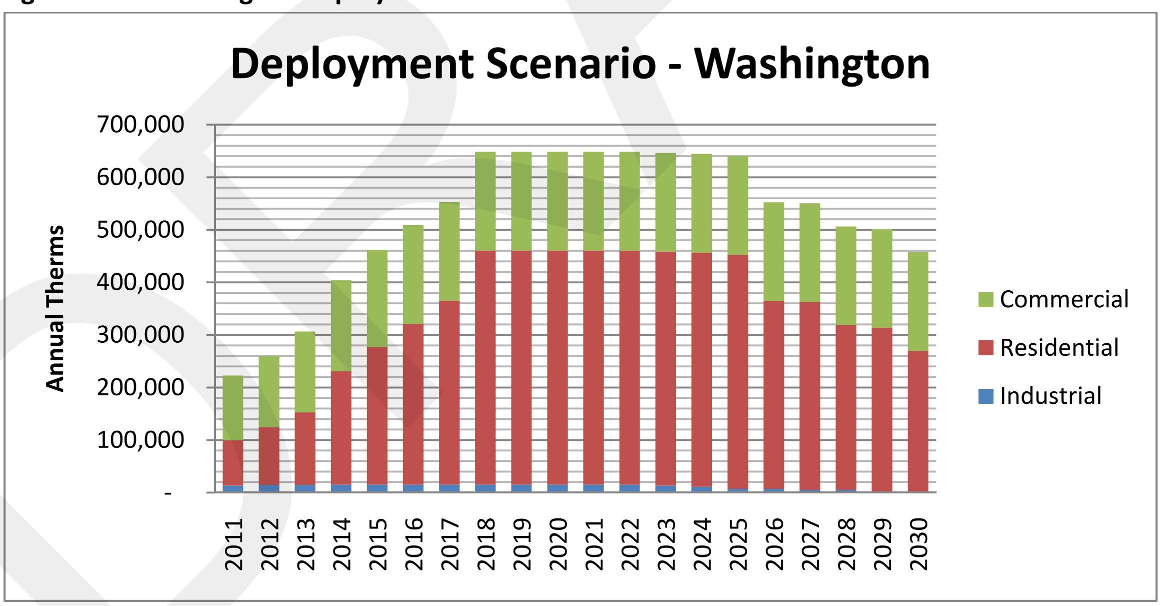


Figure 4.8 – Washington Deployment Scenario



B. Evaluation of Achievable Potential in SENDOUT®

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

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

Figure 4.8 and F.9 below graphically demonstrate the savings potential in Oregon and Washington, respectively, over the next 20 years.

Figure 4.8 – Oregon DSM Savings

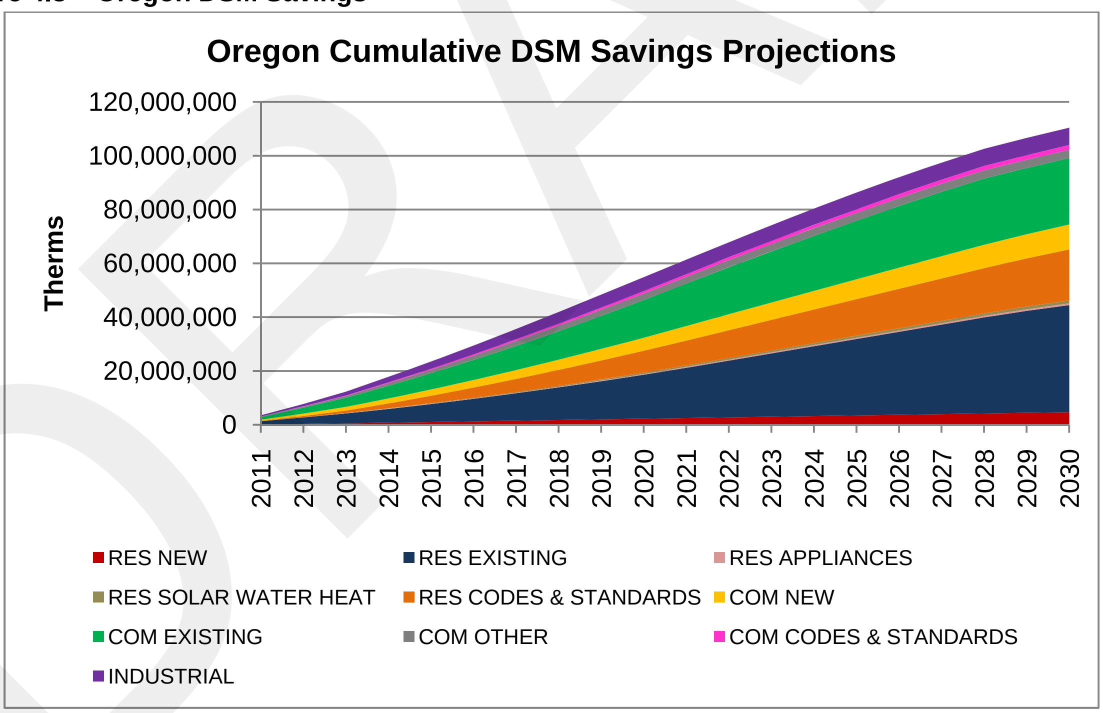
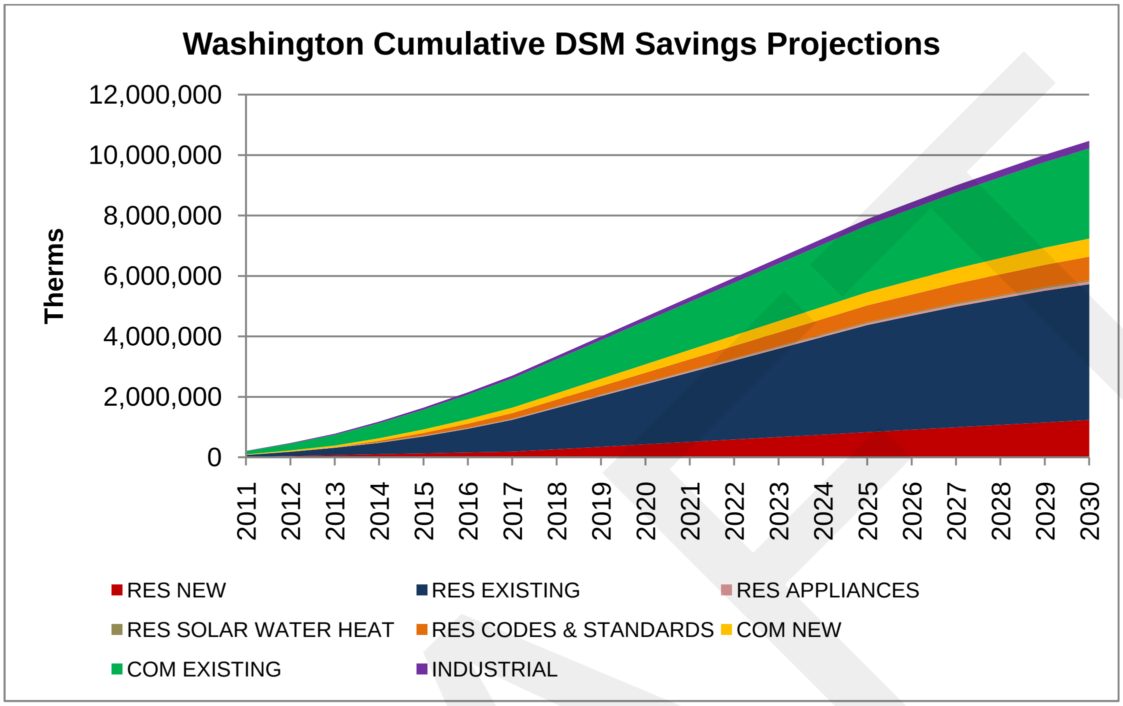


Figure 4.9 – Washington DSM Savings



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

III. OTHER DSM SENSITIVITIES

A. Lower Avoided Costs

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

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

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

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

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

B. Higher Gas Cost

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

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

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

IV. PROGRAM FUNDING AND DELIVERY

A. Energy Efficiency Programs

Oregon

As stipulated in OPUC Order No. 02-634, NW Natural transferred the administrative responsibility of its energy efficiency programs funded through the public purpose charge to the Energy Trust as part of the agreement to allow the Company to implement decoupling. From 2002 to 2008, program collections exceeded expenditures. This was not surprising since energy efficiency programs require a ramping up period. It takes time to educate customers on efficiency, available incentives and efficient heating or other appliance options. By 2009, expenditures exceeded collections. In October 2009, NW Natural filed to increase the portion of the public purpose charge that funds the company's ETO-administered program to 4.16%. This was revised down to 3.51% in Advice Nol. 10-6, effective June 1, 2010. In 2011, NW Natural forecasts collecting $21 million for its Oregon based program.

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

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

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

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

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

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

Washington

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

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

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

B. Low Income Programs

Oregon

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

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

In response to the growing OLIEE balance and the lack of OLIEE market penetration, the Company collaborated with the Agencies, Community Action Partnership of Oregon (CAPO), OPUC Staff and the Citizens' Utility Board (CUB) to revise the program and liberalize its funding for qualifying homes. The

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

OLIEE program was redesigned from paying prescriptive amounts for the installation of specific measures, to paying for all energy efficiency measures deemed cost-effective when analyzed in aggregate. The OLIEE pilot's new "whole house" perspective was adopted in conjunction with a series of annually escalating agency targets. This re-design made OLIEE more comparable to the state legislated low income program offered to customers with electrically heated homes.

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

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

Washington

On October 1, 2009, NW Natural launched a revised low income program entitled WA-LIEE (Washington Low Income Energy Efficiency). Modeled after its Oregon OLIEE pilot, the WA-LIEE program refunds the two administering agencies for weatherizing qualifying homes when all measures analyzed in aggregate are cost-effective. YEAR END DETAILS WILL BE IN FINAL VERSION.

V. LOAD MANAGEMENT AND DEMAND RESPONSE

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

VI. ENERGY POLICY

A. Federal

Greenhouse Gas (GHG) Emissions Reduction Policies

For some time, utilities have been anticipating the adoption of comprehensive federal GHG legislation that will impact operations and the cost of providing service to customers. However, no requirements have yet been codified in federal legislation. As late as 2008, the Company was assuming that carbon tax or cap and trade legislation would be enacted by 2012. Of the two, cap and trade legislation appears favored based on continued work on various cap and trade models as well as the success of the

HB 2454, the American Clean Energy and Security Act (ACES) of 2009, more commonly referred to as the Waxman-Markey Climate Change Bill.

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

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

- Beginning in 2016, natural gas utilities would be responsible for addressing GHG emissions related to the natural gas usage of all customers except large industrial and electric generators.
- An emission credit will be required for each ton of carbon dioxide equivalent (CO2-e) emitted. By 2016, natural gas utilities would receive 9% of emissions credit until 2025 at which time their emission credits would ramp down to zero over a five year period.
- Natural gas utilities would be annually required to spend one-third of the value of their emissions credits on energy efficiency.
- State commissions would convene a proceeding to ensure that emissions credits were used for the benefit of natural gas customers.
- Credits would be allocated based upon retail deliveries during a specified three-year period.
- The Energy Efficiency Resource Standard is analogous to a renewable portfolio standard in that it would establish targets for energy efficiency acquisition and combined heat and power (CHP) installation. As drafted, the Energy Efficiency Resource Standard would not apply to natural gas utilities.

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

Energy Efficiency Policy

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

Renewable Biogas

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

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

Alternative Fueled Vehicles

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

B. State and Regional

GHG Emissions Reduction Policies

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

1. Oregon

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

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

2. Washington

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

3. Regional

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

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

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

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

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

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

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

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

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

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

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

Energy Efficiency Policy

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

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

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

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

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

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

C. Conclusion

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

VII. KEY FINDINGS

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

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

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

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

I. OVERVIEW

NW Natural employs an analytic method utilizing Linear Programming to integrate the important planning components, and to generate and evaluate long term resource plans. Linear Programming (LP) is a mathematical optimization technique which solves the "general problem of allocating limited resources among competing activities in the best possible way."[1] For the IRP, NW Natural's LP model examines all reasonable means for acquiring demand-side and/or supply-side resources to meet growing customer demand and determines the series of resource decisions through time which results in a plan that balances reliability and cost. The LP model acts as a tool to guide NW Natural's resource decisions; it is not the final answer. The deterministic model makes resource decisions based on perfect knowledge of all aspects across the 20-year planning horizon, including weather, demand, future resource availability, and supply prices. For example, a decision made in year five may have been informed by an event occurring in year 10. LP modeling also allows for various combinations of resources, called portfolios, to be evaluated under assorted demand scenarios and ranked according to cost.

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

II. RESOURCE PLANNING MODEL INTEGRATION

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

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

A. Demand Forecast

NW Natural uses demand usage factors to incorporate the demand forecast into the resource planning model. The usage factors include the number of customers by region and category, as well as the unique base and heat load factors for each region and customer category. The usage factors are used in combination with temperature data to generate an overall gas requirement for each of the 8 demand centers. The usage factors are derived from NW Natural's load forecast presented in Chapter 2. In

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

addition, an extremely high cost is attached to un-served demand so that the resource model is forced to attempt to serve all demand by any means possible.

B. Temperature Pattern

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

C. Natural Gas Price

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

D. Demand side management resources

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

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

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

Table 5.1 - DSM Categories

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

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

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

E. Current and future supply side resources

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

1. Supply
2. Transport

3. Storage

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

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

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

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

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

Table 5.2 lists the current and future resources that are available in the resource planning model, and a discussion of key resources follows.

Table 5.2 - Current and Future Planning Model Resources

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

<u>Harrisburg River Crossing</u>

This NW Natural pipeline project was a selected resource in the previous two IRPs and is planned to be in service by November 2010. This is a key project which improves the capability for serving current and future demand in Eugene. The pipeline will cross the Willamette River and will be six inches in diameter providing the additional delivery potential of 8 MDT/day of supply to the Eugene demand center.

North Willamette Valley Feeder (NWVF)

The NWVF is also a NW Natural pipeline project (12-inch diameter) running from Aurora to Brooks Oregon. In the model, it is represented by a transport section linking the Portland and Salem demand centers. It could carry up to 85 MDT/day to down to Salem and possibly beyond. It is an important resource since it allows additional storage supplies from Mist, and additional pipeline delivered supply from Palomar East to reach the Willamette Valley and the coast. The NWVF is planned to be in service by November 2011.

Palomar East Pipeline

Palomar East (Palomar Gas Transmission LLC) is a proposed new pipeline which would carry natural gas across the Cascades. This transport link is represented in the model by a one-time resource mix decision. In 2014, the model may select additional contract demand following the Precedent Agreement fixed cost rate and minimum daily capacity of 100 MDT/day. At the same time, the model can turn back up to 77 MDT/day of capacity on Williams' NWPL gorge pipeline. Palomar East provides transport between Madras Oregon and Molalla Oregon. Supply is modeled to be transported from both Alberta and US Rockies to Stanfield, down to Madras, and across to Molalla and NW Natural's distribution system. In addition, with Palomar East in use, additional US Rockies supplies could be transported from Malin up to Madras and then West to the Portland area.

Newport LNG & Newport Compressor Project

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

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

Mid and South Willamette Valley Feeder

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

Incremental Capacity on Williams' Grants Pass Lateral

Williams' Grants Pass Lateral transports supplies to the Salem, Albany, and Eugene demand centers. The pipeline is fully subscribed, but pipeline additions could increase capability. The model estimates the incremental capacity to cost the same as the current rate. The amount of capacity selected can be increased each year. Additional NW Natural take-away costs are associated with increasing the capacity on the Grants Pass Lateral as well. This resource decision is available starting in November 2013.

Satellite Storage

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

Mist Recall

Additional storage capacity can be recalled from the interstate storage business as a resource decision. The resource options are modeled as individual decisions through time as existing interstate storage contracts roll off.

Imported LNG

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

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

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

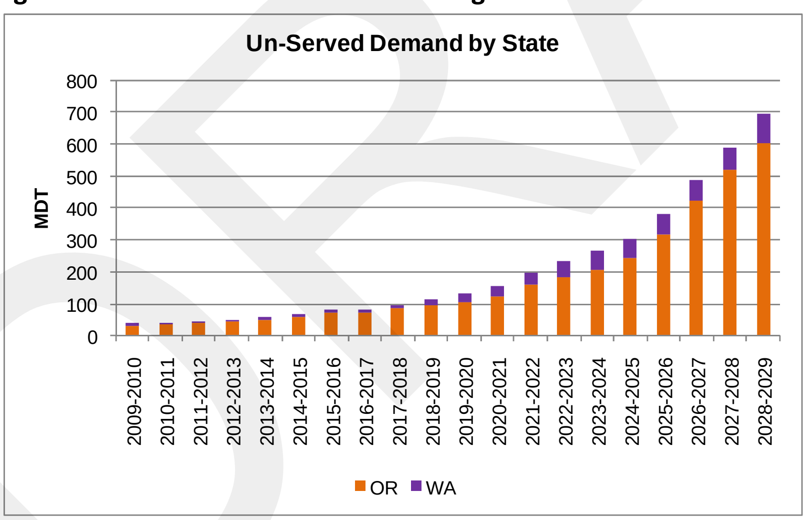
III. RESOURCE PLANNING MODEL RESULTS

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

A. No New Resources

The initial step in resource planning involves testing when new resources are required, if at all. A model run was completed in which all new demand and supply side resources were excluded. The planned NW Natural projects – NWVF and Harrisburg River Crossing – were included, and Newport LNG was assumed to be in service the entire time. The base case demand forecast and design weather were used as inputs. The model showed that all of the demand regions, except for Newport/Lincoln City, experienced un-served demand in each year of the planning time frame. Clearly demand growth is large enough that new resources will need to be added to the system. Figure 5.1 displays the results, broken out by state.

Figure 5.1 - Unserved Demand Assuming No New Resources



B. Planning Base Case Results

Once it has been ascertained that current resources are unable to meet all the projected demand, the next step is to evaluate potential new resources. A SENDOUT® model run was set up with the base case demand forecast inputs and the design weather, as well as all the potential new resources listed in Table 5.2, but excluding imported LNG. The imported LNG facilities were evaluated in a separate model run.

Palomar East was included as a resource mix option with a minimum allowed capacity of 100 MDT/day. Multiple iterations of the model were run and analyzed for least cost results.

<u>DSM</u>

All of the DSM resources were selected by the resource model. As mentioned earlier, DSM energy savings are modeled by a mixture of automatic savings and model resource options. Figure 5.2 displays the base case model output for DSM resource savings by category and state. Figure 5.3 expresses system wide DSM savings as a percentage of demand.

Figure 5.2 - Base Case DSM Savings

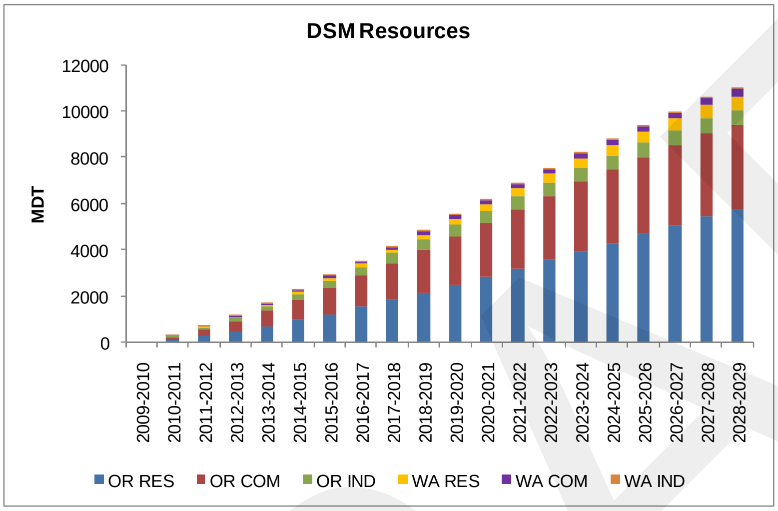
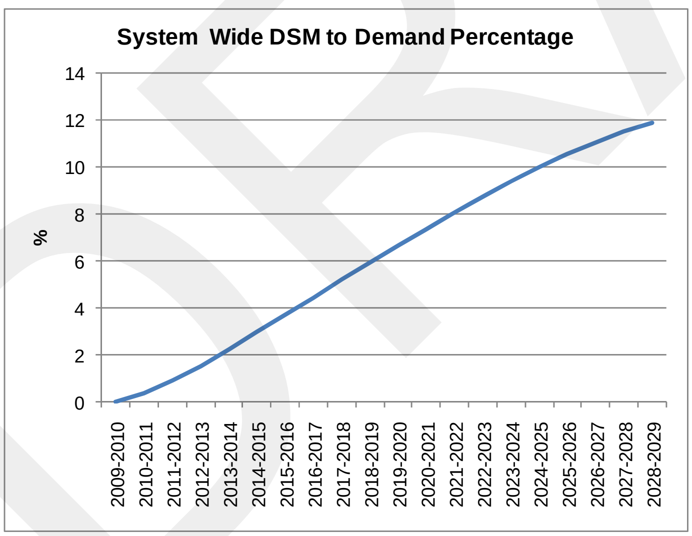


Figure 5.3 - System Wide DSM Savings Percentage



<u>Supply Side Resources</u>

With the base case demand and weather conditions, the model shows a small quantity of un-served demand on-peak day for the 2009/2010 and 2010/2011 gas years. The Harrisburg River Crossing and North Willamette Valley Feeder projects help to remedy the supply gap. All demand is served following the 2010/2011 year. Mist Storage Recall is selected to serve peak day demand, especially when Newport LNG is modeled to be out of service. Palomar East is selected at the minimum capacity of 100 MDT/day in 2014, and 77 mdt/day of Williams' NWPL gorge capacity is turned back. Additional resources are required in the Willamette Valley by 2023 when the Newport Compressor Project is selected, along with incremental capacity on Williams' Grants Pass Lateral.

<u>Utilization</u>

Figure 5.4 displays the peak day resource utilization results from the base case model run. Pipeline CD, storage, and DSM resources are added over time to meet peak day demand growth.

Figure 5.4 - Peak Day Utilization

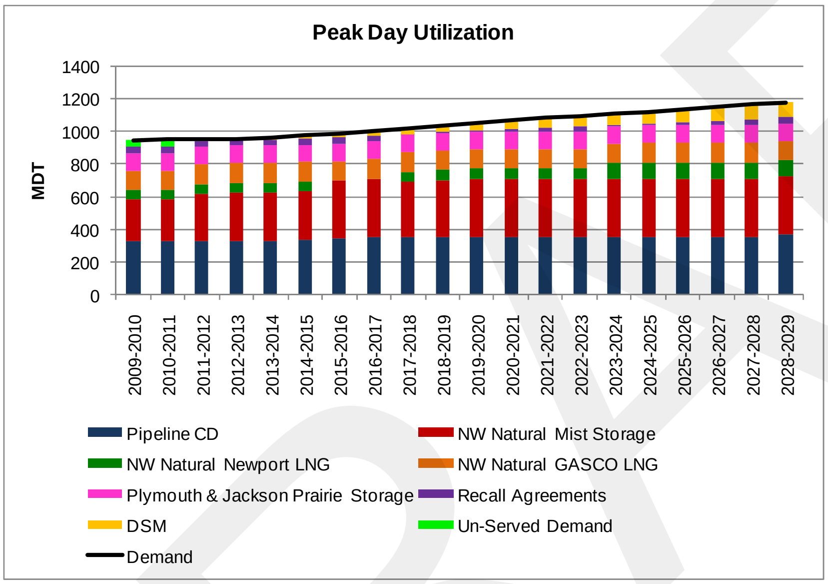
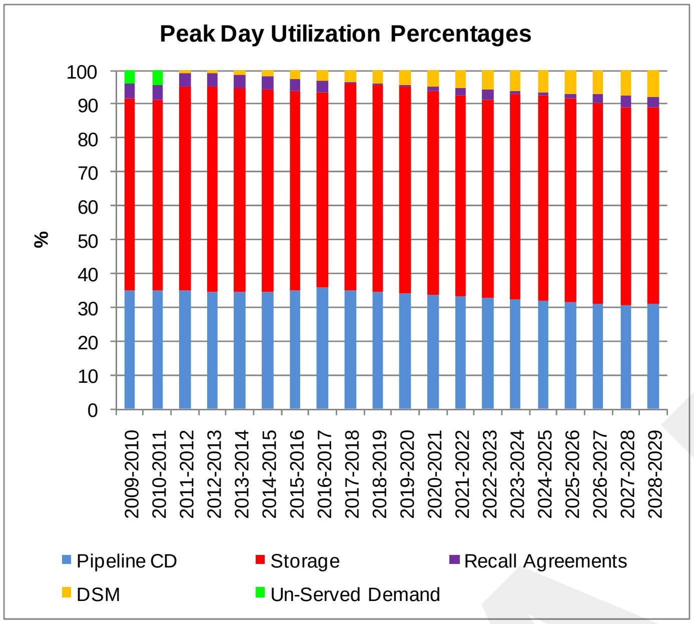


Figure 5.5 offers an alternative look at peak day utilization by charting the percentage of the peak day demand that the resource categories meet. The growth in DSM for meeting peak day demand is clearly evident.

Figure 5.5 - Peak Day Utilization as a function of Demand



Model results for utilization on non-peak day events have a different pattern, depending on the season. After taking account for DSM, pipeline CD serves 100% of the demand on a typical fall day. Moving into winter, demand in a typical day in December is met with a 60% pipeline CD and 40% storage mix. On peak day, storage serves up to approximately 60% of peak day demand, with pipeline CD at 35% and recall making up the rest. Then, on a normal early spring day, pipeline CD is back up to 90% with storage at roughly 10% as withdrawal winds down.

Palomar East was included in the base case planning portfolio. An alternative run was performed with the base case demand inputs, but without Palomar East. The results were very similar to the case with Palomar. More Mist Storage recall was selected and additional pipeline CD was required on Williams' NWPL through the gorge at the end of the horizon. The overall portfolio costs came in slightly higher for the case without Palomar East. The resource planning results at summarized in Table 5.3 below.

Table 5.3 - Base Case Planning Results

	1319 – Planning Base Case	**1321 – No Palomar East**
Cost $(000) Net Present Value	$ 8,159,819	$ 8,162,089
Resource Timeline		
2009/2010	Un-served Demand	Un-served Demand
2010/2011	Un-Served Demand Harrisburg River Crossing on-line	Un-Served Demand Harrisburg River Crossing on-line
2011/2012	NWVF on-line Mist Recall	NWVF on-line Mist Recall
2012/2013	Mist Recall	Mist Recall
2014/2015	Palomar East and Williams' Gorge turn-back	Mist Recall
2015/2016	Newport LNG down for repairs Mist Recall	Newport LNG down for repairs Mist Recall
2016/2017	March Point CD on-line	March Point CD on-line
2017/2018	Newport LNG back on-line	Newport LNG back on-line
2023/2024	Newport LNG Compressor Project Grants Pass Lateral incremental capacity	Newport LNG Compressor Project Grants Pass Lateral incremental capacity
2028/2029		Williams' NWPL Gorge incremental capacity

C. Reliability

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

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

Two model runs were set up for each case; the planning base case (1319), and the No Palomar case (1321). First, the resource options were constrained to the fixed decisions from each planning case.

Next, the resource options were opened up to see how the disruptions would be served with and without Palomar East. The model results are summarized in Table 5.4.

Table 5.4 - Service Disruption Model Run Results

Modeled Disruption	1347 – Base Case fixed resources with Palomar East	1349 – No Palomar East case with fixed resources	1348 – Palomar East and full resource options	1350 – No Palomar East and full resource options
NWPL Gorge	72 MDT un-served 93% of peak day demand met	140 MDT un-served 86% of peak day demand met	0 MDT un-served 100% of peak day demand met	0 MDT un-served 100% of peak day demand met
Grants Pass Lateral	151 MDT un-served 94% of peak day demand met	151 MDT un-served 94% of peak day demand met	0 MDT un-served 100% of peak day demand met	0 MDT un-served 100% of peak day demand met
Jackson Prairie Storage	0 MDT un-served 100% of peak day demand met	0 MDT un-served 100% of peak day demand met	0 MDT un-served 100% of peak day demand met	0 MDT un-served 100% of peak day demand met
Mist Storage	94 MDT un-served 91% of peak day demand met	291 MDT un-served 84% of peak day demand met	0 MDT un-served 100% of peak day demand met	291 MDT un-served 84% of peak day demand met
Gasco LNG Storage	0 MDT un-served 100% of peak day demand met	0 MDT un-served 100% of peak day demand met	0 MDT un-served 100% of peak day demand met	0 MDT un-served 100% of peak day demand met

Comparing the fixed resource cases 1347 and 1349, overall u-served demand increased by 84% without Palomar East. The disruption to Mist Storage resulted in the most significant outage in all cases. Without Palomar East and assuming the current suite of potential future resources, only 84% of peak day load could be met if Mist were restricted. The only case to serve all demand was 1348, which is Palomar East with full resource options. In this case, Palomar East was selected at 194 MDT/day, Satellite Storage was developed in Salem, Albany and Eugene, and the Mid Willamette Valley Feeder was built.

D. Scenario Model Runs

Table 5.5 contains a list of completed model runs with the scenario model inputs. Newport LNG was modeled to be down for repairs in all the cases. Palomar East was assumed at the minimum contractual CD for all the runs, except for the No Palomar case.

Table 5.5 - List of Completed Model Runs

RUN	NAME	CUSTOMER GROWTH	CUSTOMER USAGE	WEATHER	GAS PRICE	SUPPLY RESOURCE PORTFOLIO	DSM
1	1319-Planning Case	Base case	Base case	Design	Base case	Base case	Base case
2	1321-No Palomar East	Base case	Base case	Design	Base case	No Pal. East	Base case
3	1347-Outages-PAL E-Fixed RSC	Base case	Base case	Design	Base case	Base case	Base case
4	1348-Outages-PAL E-Full RSC	Base case	Base case	Design	Base case	Base case	Base case
5	1349-Outages-No PAL E-Fixed RSC	Base case	Base case	Design	Base case	No Pal. East	Base case
6	1350-Outages-No PAL E-Full RSC	Base case	Base case	Design	Base case	No Pal. East	Base case
7	1354-Low Gas Price	Base case	Base case	Design	Low	Base case	Base case
8	1355-High Gas Price	Base case	Base case	Design	High	Base case	Base case
9	1356-Low Customer Growth	Low	Base case	Design	Base case	Base case	Base case
10	1357-High Customer Growth	High	Base case	Design	Base case	Base case	Base case
11	1358-Gas Deregulation	High	Base case	Design	Low	Base case	Base case
12	1359-Newport LNG Permanently Down	Base case	Base case	Design	Base case	Base case	Base case
13	1360-Gas Breakthrough	High	High	Design	High	Base case	Base case
14	1361-Normal Weather	Base case	Base case	Normal	Base case	Base case	Base case
15	1362-Recall Analysis	Base case	Base case	Design	Base case	Firm capacity	Base case
16	1363-Electric Breakthrough	Very Low	Base case	Design	High	Base case	Base case
17	1368-Imported LNG OregonLNG	Base case	Base case	Design	Base case	Northern Imported LNG	Base case
18	1369-Imported LNG Jordan Cove	Base case	Base case	Design	Base case	Southern Imported LNG	Base case
19	1370-15% Less DSM	Base case	Base case	Design	Base case	Base case	15% Less DSM
20	1371-30% More DSM	Base case	Base case	Design	Base case	Base case	30% More DSM

Table 5.5 provides a summary of resource and cost results from the model runs, ranked by overall cost. Also listed are the resource options that were selected for the case as the least cost option. Mist Storage recall is selected in all runs. The Newport LNG Compressor project was also selected in all cases

except for the Electric Breakthrough case and the Northern Imported LNG case. Additional capacity on the Grants Pass Lateral was usually the resource of choice for serving additional demand down in the Willamette Valley. When demand exceeded the base case, the Satellite Storage project in Eugene was also selected.

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

With a 30% increase in DSM savings, the model selects the same resources as in the base case, but at lower levels, particularly down in the southern portion of the Willamette Valley. In the case of 15% less DSM, the resource mix is the same, but at different levels. More Mist recall is selected and more capacity is required in the southern Willamette Valley.

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

Table 5.5 – Cost Results from Model Runs

Model Run	Cost $(000) NPV	Mist Recall	Palomar East CD	Newport LNG Compressor	Grants Pass Lateral Incremental CD	Satellite Storage in Eugene	Imported LNG
1354-Low Gas Price	7,380,577	X	X	X	X	X	
1358-Gas Dereg.	7,567,085	X	X	X	X	X	
1356-Low Customer Growth	7,929,197	X	X	X			
1368-Imported LNG OregonLNG	7,984,547	X	X		X		X
1369-Imported LNG Jordan Cove	8,151,056	X	X	X			X
1371-30% More DSM	8,158,962	X	X	X	X		
1319-Base Case	8,159,819	X	X	X	X		
1370-15% Less DSM	8,160,968	X	X	X		X	
1321-No Palomar East	8,162,089	X		X	X		
1357-High Customer Growth	8,374,964	X	X	X	X	X	
1363-Electric Breakthrough	9,289,253	X	X				
1355-High Gas Price	9,706,255	X	X	X	X		
1360-Gas Breakthrough	10,698,775	X	X	X	X	X	

IV. Key Findings

- DSM savings estimates were incorporated into the resource model and the discretionary measures were selected as a cost effective alternative to supply side resources.

- Palomar East has been identified as cost effective addition to the supply portfolio. Securing CD on the pipeline allows for a greater diversity of supply and increases system reliability.

- NW Natural's Newport LNG storage facility may need to be brought down for an uncertain time frame in order to be evaluated and potentially repaired. The resource planning model suggests that demand may continue to be served without Newport LNG being in service.

- Recall of pre-built Mist Storage currently dedicated to the interstate storage service market into core-market service continues to be a valuable option for helping to meet peak day demand.

- Some sort of new resource is eventually required in the Willamette Valley. In past IRP models, this need has been met by a combination of a Willamette Valley Feeder project, incremental capacity on the Grants Pass Lateral, or Satellite Storage facilities. In this plan, in most cases, additional capacity on the Grants Pass Lateral is the resource of choice.

Chapter 6: Avoided Costs

Chapter 7: Public Participation

I. TECHNICAL WORKING GROUP

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

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

- <u>TWG No.1 held on February 24′ 2010</u>
  NW Natural reviewed its 2008 IRP process. From there, NW Natural presented its customer forecasting and demand forecasting methodologies. The group weather pattern developments as well as load forecast equations were discussed as well as the accuracy of demand elasticity. NW Natural ended by giving an overview of its resource planning model.

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

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

- <u>TWG No. 2 held on May 17, 2010</u>
  NW Natural presented a more in-depth look at its work on customer forecasts and trends, gas price forecasts and load forecasts. The group discussed the 2004 and 2009 peak cold weather events and the multiple factors that influence gas usage on cold weather days, including the day of the week, whether or not it was a holiday, and the wind chill factor. The Company then presented its supply side resources. NW Natural agreed that it would not model the impact of the Ruby Pipeline.

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

- <u>TWG No. 3 held on July 28, 2010</u>
  NW Natural recapitulated the learnings and process covered thus far. Demand scenarios were reviewed and initial model results were discussed. Also, the Energy Trust presented its work on determining the achievable potential for demand-side management in the Company's service territory. Matt Braman, analyst at the Energy Trust, detailed their process and discussed the potential as well as the twenty year deployment scenario.

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

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

- <u>TWG No. 4 held on November 3, 2010</u>.

The Company filed its draft plan on October 22, 2010.

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

II. PUBLIC PARTICIPATION

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

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

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

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

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