AVISTA
Utilities

2006 NATURAL GAS INTEGRATED RESOURCE PLAN

MARCH 31, 2006

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AVISTA'S ELECTRIC AND NATURAL GAS SERVICE AREAS

RETAIL ELECTRIC CUSTOMERS BY STATE

Washington: 225,000

Idaho: 113,000

Total Retail Electric Customers: 338,000

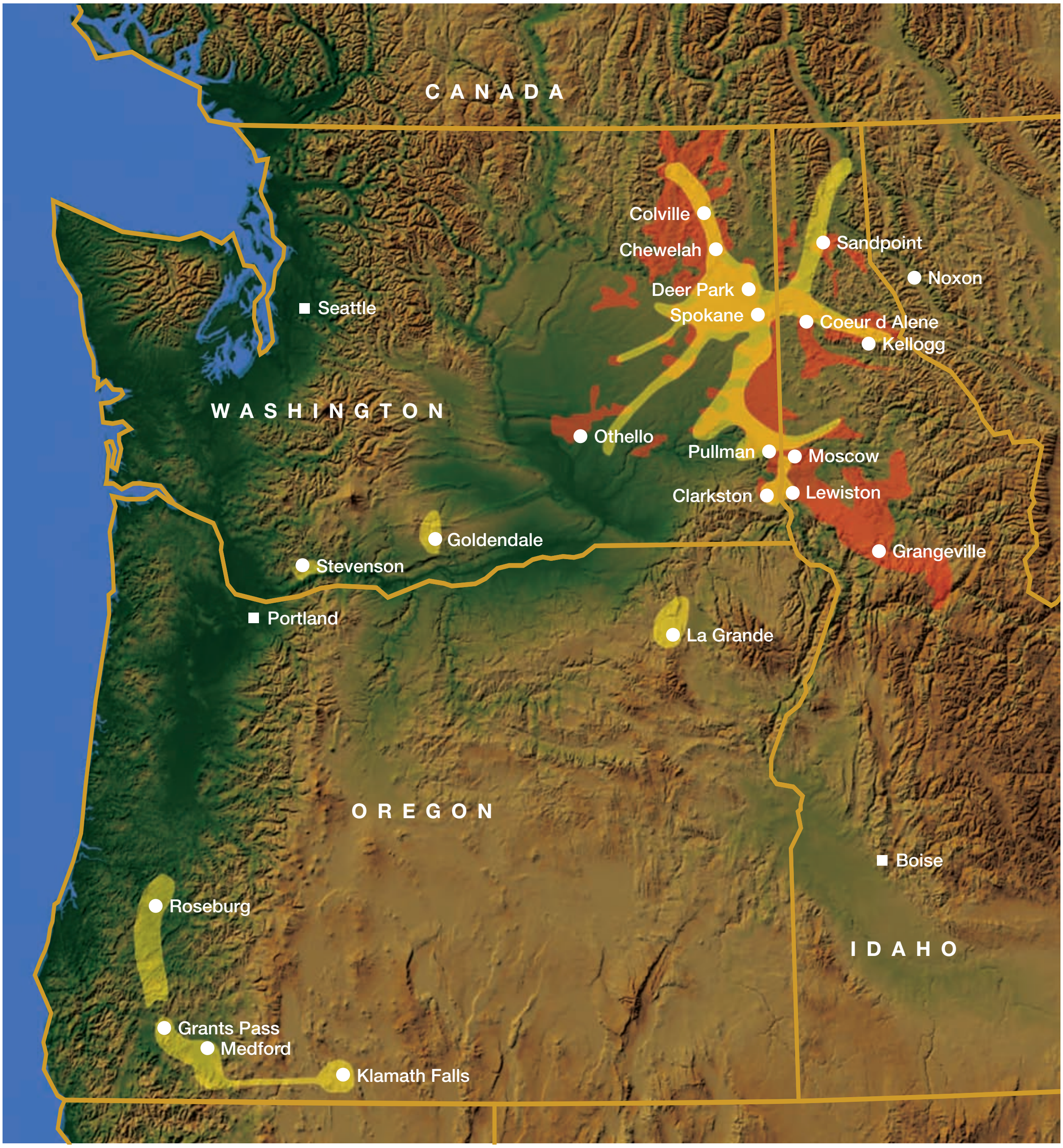
RETAIL NATURAL GAS CUSTOMERS BY STATE

Washington: 137,000

Idaho: 68,000

Oregon: 92,000

Total Retail Natural Gas Customers: 297,000



(Data as of December 31, 2005)

Electric Service Areas

Natural Gas Service Areas

SECTION 1 – EXECUTIVE SUMMARY

SECTION 1 – EXECUTIVE SUMMARY

Avista's Utilities 2006 Natural Gas Integrated Resource Plan (IRP) identifies a strategic gas-supply portfolio that meets future demand requirements. The foundation for integrated resource planning is the demand planning criteria utilized for the development of demand forecasts. The formal exercise of bringing forecasts of customer demand together with comprehensive analyses of resource options, which include both supply-side and demand-side measures, is valuable to the company, its customers and its regulatory commissions for long-range planning activities.

The company submits an IRP to public utility commissions in Idaho, Washington and Oregon every two years as required by state regulation. The company has a statutory obligation to provide reliable natural gas service to customers at rates, terms and conditions that are fair, just, reasonable and sufficient. Avista regards the IRP as a methodology for identifying and evaluating various resource options and as a process by which to establish a plan of action for resource decisions. Through ongoing and evolving investigation and research, the company may determine that alternative resources are more cost-effective than those resources selected in this IRP. The company will continue to review and refine its knowledge of resource options and will act to secure least-cost options at the appropriate point in time.

The IRP identifies and establishes an action plan that will steer the company toward the least-cost method of serving Avista's natural gas customers. There are a number of factors that must be considered within the context of least-cost, including an assessment of risks associated with each alternative. Therefore, actions resulting from the IRP process represent risk-adjusted, least-cost results.

Avista's management and stakeholders in the Technical Advisory Committee (TAC) play a key role and have a significant impact in guiding the plan to its conclusions. TAC members include customers, commission staff, consumer advocates, academics, utility peers, governmental agencies and other interested parties. The TAC provides important input on modeling, planning assumptions and the general direction of the planning process.

* In Washington, IRP requirements are outlined in WAC 480-90-238 entitled "Integrated Resource Planning." In Idaho, the IRP requirements are outlined in Case No.GNR-G-93-2,Order No. 25342. In Oregon, the IRP requirements are outlined in Order No. 89-507.

IRP PROCESS AND STAKEHOLDER INVOLVEMENT

Preparation of the IRP is a coordinated effort by several departments within the company and includes input from Commission Staff, customers and other stakeholders. Topics leading to the development of the IRP include natural gas sales forecasts, demand-side management, distribution planning, supply-side resources and computer modeling tools, resulting in an integrated resource portfolio.

To facilitate stakeholder involvement in the 2006 IRP, the company sponsored six TAC meetings. The first meeting convened on Oct. 4, 2005, and the last meeting was held on Dec. 8, 2005. A broad spectrum of people were invited to each meeting. The meetings focused on specific planning topics, reviewed the status and progress of planning activities and solicited ongoing input on the IRP development. In addition to the TAC meetings, the company and the TAC members met via conference call to discuss natural gas pricing issues. Furthermore, there were a number of phone and e-mail discussions about various other topics. Lastly, the company provided a draft of this IRP to TAC members on Jan. 13, 2006. Avista received comments on this draft from all interested parties and has incorporated these comments into the final version of this IRP. The company gained valuable input from the TAC interaction and appreciated the positive contribution of the participants.

MODELING APPROACH

The company applied its SENDOUT® model (a PC-based linear programming model widely used to solve natural gas supply and transportation optimization questions) to develop the least-cost resource mix for the

20-year planning period. This model performs the least-cost optimization based upon daily, monthly, seasonal and annual assumptions related to:

- Customer growth and customer natural gas usage that ultimately form demand forecasts;
- Existing and potential transportation and storage options;
- Existing and potential natural gas supply availability and pricing;
- Weather assumptions; and
- Demand-side management opportunities.

DEMAND AND SCENARIOS

The company developed a multi-step approach to demand forecasting by using a three-by-three matrix using low, medium and high price scenarios crossed with low, medium and high customer growth scenarios, to represent a wide range of future end-states. These scenarios look at the range of possible outcomes over the planning horizon given the unprecedented price spikes in the natural gas markets and the uncertainty of the sustainability of the prices as well as customer impact. From an analytical standpoint, after developing each scenario, the company then selected three main cases to review in more detail. These three cases, from this point forward, are known as the Expected Case (Case #2), the Low Demand Case (Case #6) and the High Demand Case (Case #7). The Expected Case revealed:

- The number of core customers is expected to increase from an average of 314,205 in 2006-2007 to 552,924 in 2025-2026. This is an annual average growth rate of 4.0 percent.
- Average day core demand, net of model selected demand-side management measures, is projected to increase from an average of 93,670 Dth/day in 2006-2007 to 160,190 Dth/day in 2025-2026. This is an annual average growth rate of 3.7 percent.
- Coincidental peak day core demand, net of model selected demand-side management measures, is projected to increase from a peak of 368,530 Dth/day in 2006-2007 to 642,970 Dth/day in 2025-2026. This is a growth rate of over 3.9 percent in peak day requirements.

Figure 1.1 shows average annual system demand for the three main scenarios over the planning horizon.

Figure 1.1 – System-Wide Average Annual Demand
(Net of DSM Savings) MDth/d – November to October

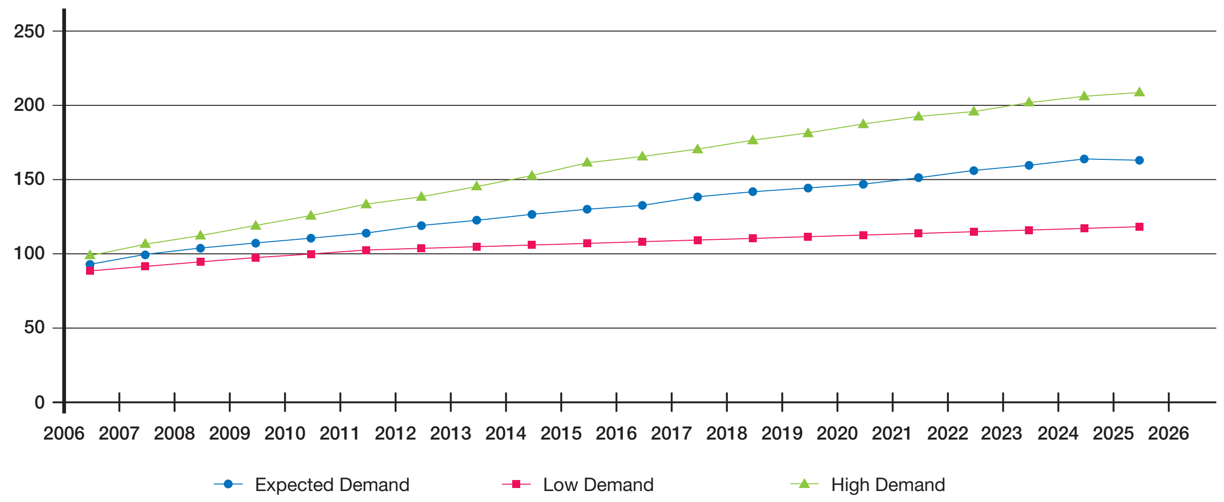


Figure 1.2 – Henry Hub Forward Prices for Avista 2006 IRP

2005$/Dth

NATURAL GAS PRICE FORECASTS

The market for natural gas supply has undergone dramatic changes over the last several years, as the commodity market has transitioned from a regionally based market to a national, and perhaps global, market. Regional and national natural gas prices have recently risen to unprecedented levels. The industry in general, and price forecasting organizations in particular, did not forecast these unprecedented increases. Oil price increases and the price relationship with natural gas, demand growth, natural gas use for electric generation, hurricane activity and other weather events are believed to be some of the reasons for these price increases. Given that these increases were not predicted and that these price levels have not been witnessed before on a sustained basis, it is very difficult to determine the length of the price run-up, as well as the expected impact on customer loads. Although the company does not believe that it can accurately predict future prices for the 20-year horizon of this IRP, it has reviewed a variety of price forecasts provided by credible sources and has selected high, medium and low price forecasts to best represent the realm of reasonable pricing possibilities. Figure 1.2 depicts the selected price forecasts.

RESOURCES

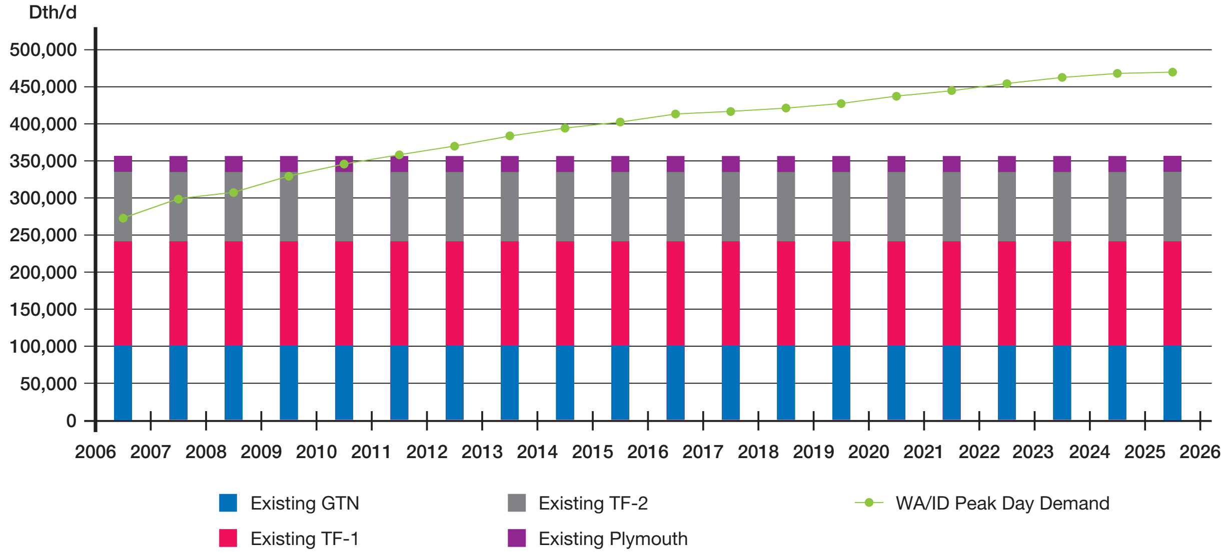
Avista has a diversified portfolio of natural gas supply resources, including owned and contracted storage, firm capacity rights on six pipelines, and contracts in place to purchase natural gas from several different supply basins. Avista has modeled a number of conservation measures or programs that, if cost effective, could further reduce demand.

In addition to conservation measures as supply resources, Avista evaluated incremental pipeline transportation, storage options, distribution enhancements and various forms of liquefied natural gas storage or service.

DEMAND-SIDE MANAGEMENT

Avista actively promotes and offers energy-efficiency programs to all (non-transport) retail electric and natural gas customers. These demand-side management (DSM) programs are one component of a comprehensive strategy to provide customers with a least-cost energy resource. The IRP is used as an opportunity to evaluate that resource mix with the intent to refine approaches to the management of both supply-side and demand-side management portfolios.

Figure 1.3 – WA/ID Existing Resources vs. Peak Day Demand
(Net of DSM Savings) Expected Case – November to October



Based on the projected natural gas prices and the estimated cost of alternative supply resources, the SENDOUT® model selected certain DSM programs for further review and implementation. In Oregon, demand-side management measures are targeted to reduce demand by over 441,000 therms in the first year. In Washington and Idaho, demand-side measures are targeted to reduce demand by over 1,062,000 therms in the first year.

RESOURCE NEEDS

The SENDOUT® model was run utilizing existing resources and the demand cases to determine whether resource deficiencies exist during the planning period.

- In the Expected Case (Case #2) for Washington and Idaho, the system first becomes capacity deficient in 2012-2013. Given this timing, Avista is afforded sufficient time to carefully monitor, plan and take action on potential resource additions.
- In the Expected Case for Oregon, the system first becomes capacity deficient in 2010-2011. Given this timing, Avista is afforded sufficient time to carefully monitor, plan and take action on potential resource additions.

Figures 1.3 and 1.4 compare existing peak day resources to expected peak day demand and show the timing and extent of resource deficiencies for the Expected Case.

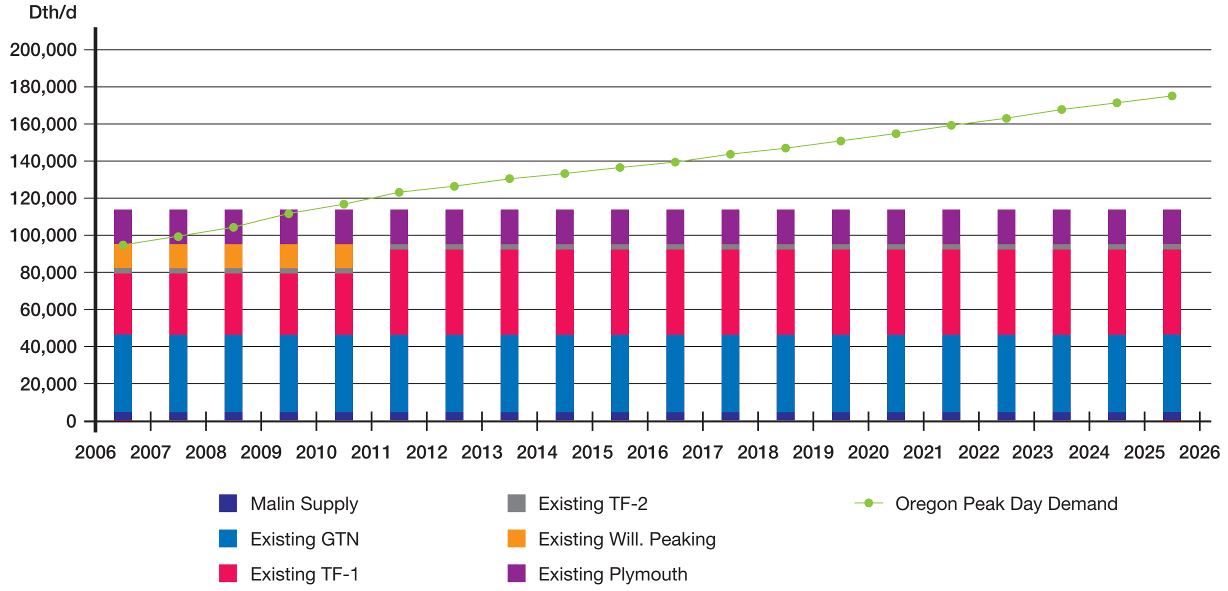
The company identified possible resource options and placed those options into the SENDOUT® model to allow SENDOUT® to select the least-cost incremental resources over the 20-year timeframe of the IRP. Figures 1.5 and 1.6 depict the optimum solution selected by SENDOUT® to meet the identified capacity deficiencies.

As indicated in Figures 1.5 and 1.6, for Washington/Idaho and Oregon, the model shows a preference for incremental transportation resources from existing supply basins to resolve capacity deficiencies.

SUMMARY OF KEY FINDINGS AND ACTION ITEMS

The company's 2006-2007 Action Plan outlines the activities developed by the company's staff with advice from its management and TAC members.

Figure 1.4 – Oregon Existing Resources vs. Peak Day Demand
(Net of DSM Savings) Expected Case – November to October



These actions, in many instances, have already begun and will be completed in the next two years. The purpose of these action items is to position the company to provide the least-cost resource portfolio and to support and improve IRP planning. Key components of the Action Plan include:

- Avista will explore further separating out and forecasting demand areas. Avista will research whether it is possible, and whether or not it would improve upon the forecasting quality, to

Figure 1.5 – WA/ID Existing & Least Cost Resources vs. Peak Day Demand
(Net of DSM Savings) Expected Case – November to October

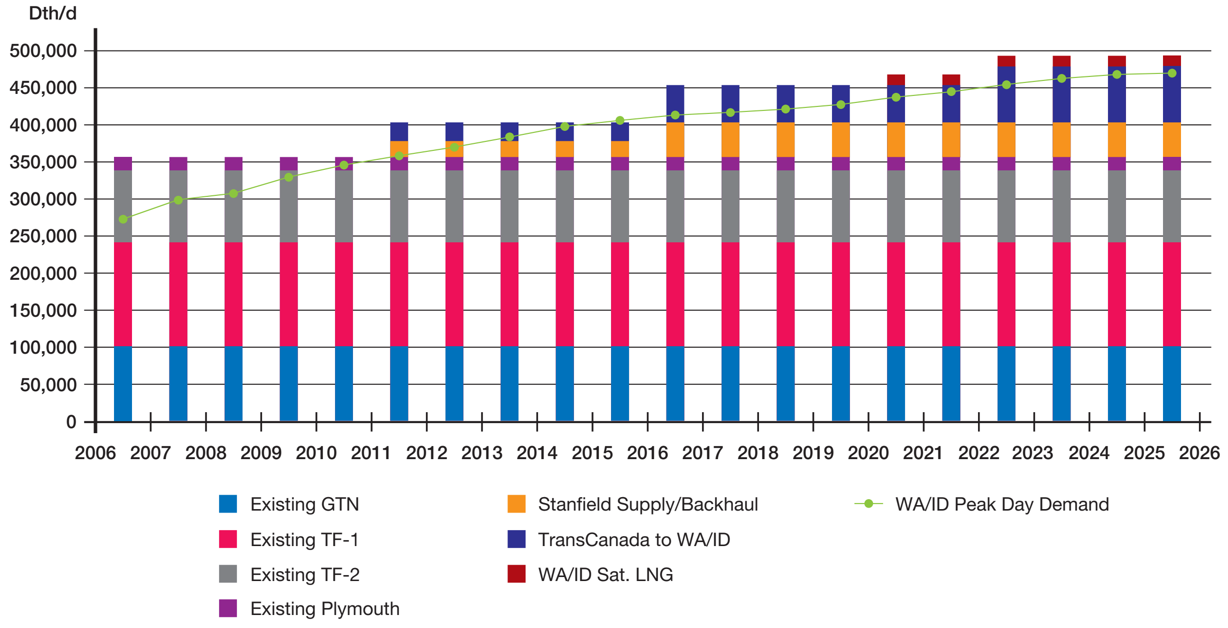
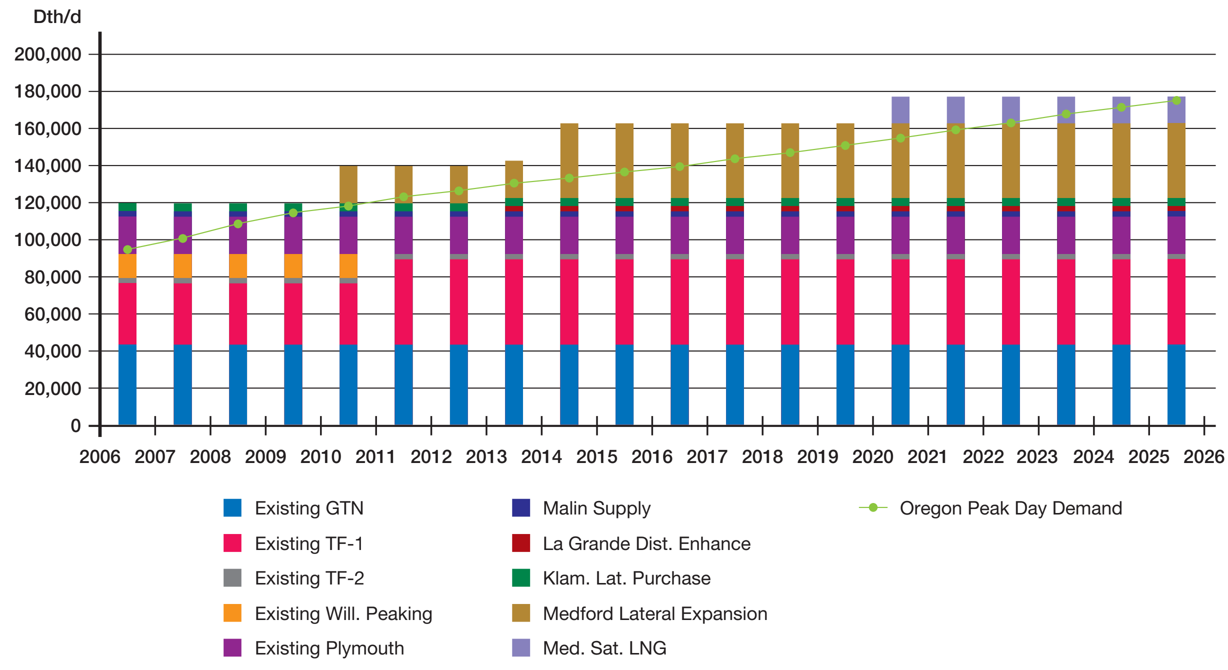


Figure 1.6 – Oregon Existing & Least Cost Resources vs. Peak Day Demand
(Net of DSM Savings) Expected Case – November to October



forecast demand levels in sub-areas beyond the regional areas discussed in this IRP.

- Avista will assess methods for capturing additional value related to existing storage assets, including but not limited to recalling some or all of the current releases.
- Avista will further develop its storage strategy with particular focus on storage opportunities for Oregon customers and will research non-Jackson Prairie storage prospects for all customers.
- Avista will meet regularly with Commission Staff members with the intent to provide information on market updates, any material changes to risk management programs, and significant changes in assumptions and status of company activity related to the IRP.
- The company will complete its evaluation of VectorGas™. If purchased, the company will utilize VectorGas™ to strengthen Avista's ability to analyze the financial impacts under varying load and price scenarios.
- Avista explicitly recognizes the obligation to achieve all natural gas-efficiency resources available through the intervention of cost-effective utility programs.
- DSM measures target first-year savings of over 441,000 therms in Oregon and over 1,062,000 therms in Washington and Idaho.

SECTION 2 – NATURAL GAS DEMAND FORECAST

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OVERVIEW

In 2005, Avista served 297,253 core natural gas customers with 33,594,800 Dth of natural gas. By the end of the planning period for this IRP, Avista projects that it will have over 550,000 core natural gas customers with an annual demand over 58,000,000 Dth.
In Washington and Idaho, the number of customers is projected to increase at an average annual rate of 3.1 percent per year with demand growing at a projected rate of 2.8 percent per year. In Oregon, the number of customers is projected to increase at an average annual rate of 3.3 percent per year with demand growing at a projected rate of 3.0 percent per year.

Avista presented its 2005 natural gas forecast to the Technical Advisory Committee (TAC) in October 2005. This forecast was completed in July 2005, and it had assumptions and results that were driven by national and service-area economic forecasts. Based on discussions with the TAC about changes in natural gas pricing and natural gas rate increases in the fall of 2005, Avista revised use-per-customer assumptions for this IRP.

Avista manages its demand forecast through two distinct operating divisions – North and South:

- The North Operating Division of Avista covers about 26,000 square miles, primarily in eastern Washington and northern Idaho. More than 600,000 people live in Avista's Washington/Idaho service area. The service territory includes urban areas, highly productive farm and timberlands, as well as the Coeur d'Alene mining district. Spokane is the largest metropolitan area with a regional population of approximately 450,000, followed by the Lewiston, Idaho, and Clarkston, Wash., areas and Coeur d'Alene, Idaho. The North Operating Division consists of about 3,000 miles of natural gas distribution mains. Natural gas is received at more than 40 points along the interstate pipelines and distributed to

more than 200,000 residential, commercial and industrial customers.

- The South Operating Division of Avista serves five counties in Oregon. The population of this area is greater than 400,000. The South Operating Division includes urban areas and highly productive farm and timberlands. The Medford, Ashland and Grants Pass area, located in Jackson and Josephine Counties, is the largest single area served by Avista, with a regional population of around 120,000. The South Operating Division consists of about 67 miles of natural gas transmission mains and 2,000 miles of natural gas distribution mains. Natural gas is received at more than 20 points along the interstate pipelines and distributed to more than 90,000 residential, commercial and industrial customers.

DEMAND FORECAST METHODOLOGY

For this IRP, the SENDOUT® model is used to produce the Avista demand forecast. The key inputs to the model for the demand forecast are a forecast of the number of customers, a set of demand coefficients (Dth consumed per customer per heating degree-day) and a forecast of heating degree-days. The daily demand forecasts are calculated as follows:

# of Customers	X	Daily Dth / Degree-Day / Customer	X	# of Daily Degree-Days

This calculation is performed for each day for each firm customer class and demand area. The customer classes are the residential, commercial and firm industrial classes. The demand areas are Medford, Ore., Roseburg, Ore., Klamath Falls, Ore., La Grande, Ore. and the eastern Washington/northern Idaho area. The climate and the economy in each of these five areas vary enough to make a meaningful difference in the demand profiles for these areas. In the two-year action plan, Avista will explore further separating out sub-areas in these demand areas, particularly in the Washington/Idaho natural gas service areas.

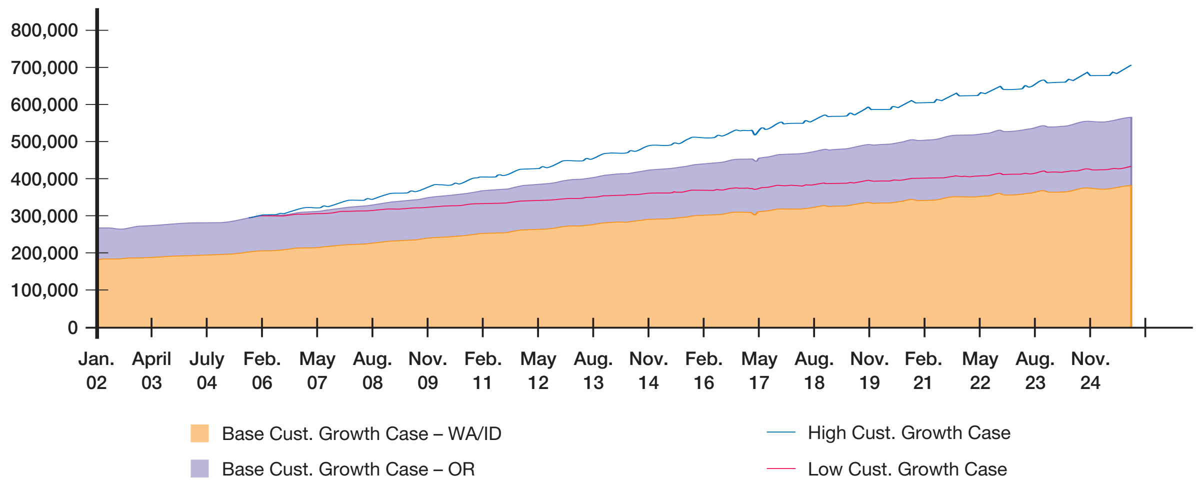
Due to the volatility of natural gas prices, and based on lengthy discussions with the TAC, Avista has incorporated the use of price elasticity when determining use per customer.

The purpose of the IRP is to balance forecasted demand with existing supply and new supply alternatives. Since new supply sources include conservation resources, which act as a demand reduction, the demand forecasts prepared and described in this section include existing efficiency standards and normal market acceptance levels. Incremental conservation measures modeled are described in Section 3.

CUSTOMER FORECASTS

The foundation of any demand forecast is the forecast of the number and types of customers expected over the planning horizon. The company develops its customer forecast by reviewing and understanding national economic forecasts and then drilling down into regional economics. Population growth expectations and

Figure 2.1 – Customer Growth Rate Scenarios
(Number of Customers by Period)



employment are the key drivers in understanding regional economics and ultimately estimating natural gas customers. The company contracts with Global Insight, Inc. (formerly known as DRI-McGraw Hill) for both its long-term economic and regional forecasts. A company narrative description of the Global Insight forecasts can be found in Appendix 2.1. The company combines this data, along with company-specific knowledge about sub-regional construction activity, trends and historical knowledge to develop the 20-year customer forecast.

Avista acknowledges that forecasting customer growth is an inexact science and believes it is important to consider alternatives to this forecast. Therefore, Avista has developed two additional outcomes for consideration in this IRP. During the last 25 years, customer growth during five-year periods has ranged between one-half and one-and-a-half times the 25-year average customer growth rate. Since both patterns have been observed in the past, Avista has created low customer growth and high customer growth scenarios with these parameters. The three customer growth forecasts are shown in Figure 2.1. Detailed customer count data, by region and by class, for all three scenarios can be found in Appendix 2.2.

HEATING DEGREE-DAY DATA

Heating degree-day data is obtained from the National Weather Service. For Oregon, Avista uses four weather stations as the weather basis, corresponding to the areas within which natural gas services are provided. Heating degree-day weather patterns between these areas are uncorrelated. For the eastern Washington and northern Idaho portion of Avista's service area, weather data for the Spokane International Airport are used, as heating degree-day monthly weather patterns within that region are correlated. Actual heating degree-day weather is discussed in more detail in Section 6 and the actual heating degree-days used in SENDOUT® can be found in Appendix 6.1.

USE PER CUSTOMER

The forecasts of use per customer are based on daily heating degree-days, which shape customer use with the seasons' variation. Avista uses multiple regressions to compute the forecast coefficients by customer classes. The regression includes a non-heat amount (the constant in the regression) and two variables for heating degree-days. The first heating degree-day coefficient is the shoulder-month estimate. It includes heating degree-

days for the months of March, April, May, June, September, October and November. Summer heating degree-days are excluded during the air-conditioning months. The second heating degree-day coefficient is the winter-period estimate. This variable includes degree-days for December, January and February only.

These coefficients can be seen in Table 2.1. The actual regression calculations producing these coefficients can be found in Appendix 2.3.

The shoulder-month regression coefficient is about one-half the winter-period coefficient. This means that, for example, a shoulder-month heating degree-day produces about one-third as many therms per customer as a winter-period heating degree-day. The coefficients are estimated separately for each area.

VALIDATION OF CUSTOMER GROWTH AND COEFFICIENT INFORMATION

The heating degree-day coefficients are average responses over a 60-month period. In order to true up the coefficients to the latest data, a back cast over the previous 12 months is conducted. Through SENDOUT®, actual demand data over the previous 12 months was compared to calculated demand based on actual customers, actual heating degree-days and the coefficients to ensure accuracy of the demand forecast.

With respect to the customer growth assumptions, residential customer growth is in proportion to population growth, and commercial customer growth is in proportion to employment growth. This gives Avista further comfort that the company-specific forecasts are aligned with the regional and national economic forecasts.

DEMAND FORECAST SCENARIOS FOR IRP

Avista acknowledges it has become very difficult to project (or predict) future natural gas prices and uses a price elasticity of demand factor to allow use per customer to vary into the future as natural gas price forecasts change. Given the unprecedented recent price spikes in the natural gas commodity markets and the uncertainty and sustainability of the prices, the company has created three price response demand forecasts in

Table 2.1 – Demand Coefficients

	Non-Heat Dth/Cust/Day	Shoulder Dth/Cust/HDD	Dec.-Jan.-Feb. Dth/Cust/HDD
Residential – WA/ID	0.0536	0.0077	0.0104
Commercial – WA/ID	0.3757	0.0346	0.0506
Industrial – WA/ID	4.1648	0.1375	0.1798
Residential – Medford	0.0457	0.0070	0.0113
Commercial – Medford	0.3158	0.0276	0.0467
Residential – Roseburg	0.0682	0.0087	0.0115
Commercial – Roseburg	0.4395	0.0288	0.0456
Residential – Klamath Falls	0.0509	0.0051	0.0079
Commercial – Klamath Falls	0.0388	0.0186	0.0305
Residential – La Grande	0.0462	0.0079	0.0099
Commercial – La Grande	0.2483	0.0282	0.0395

(Each coefficient above is significant at the 95 percent level) addition to three customer growth forecasts.

Avista has assumed that its customers' usage responds to significant changes in their natural gas rates. Through the concept of price elasticity, if customer rates continue to rise as they have over the last few years, natural gas use per customer is expected to decline. Conversely, if rates drop, use per customer is expected to increase. Based on company historical trends and other research and analysis, Avista has estimated price elasticity to be -0.15 for residential customers and -0.10 for commercial customers. Avista estimates income elasticity is +0.75, and electricity cross-price elasticity is estimated to be +0.10. The firm industrial sector is very small, and no estimates have been determined for this sector. Avista's assumed price elasticity estimates are based on a review of recent studies and were discussed at the TAC meetings.

What these price elasticity estimates mean is if the real (adjusted for inflation) price of natural gas increases by 10 percent, Avista would expect residential therms per customer per heating degree-day to decline by 1.5 percent. Similarly, if real personal income per customer increases by 10 percent, Avista would expect natural gas consumption would increase by 7.5 percent. And finally, if real electricity prices increase by 10 percent, Avista would expect natural gas consumption would increase by 1 percent. The elasticity estimates assumed are expected to see adjustments over a period of years, and since Avista's IRP covers 20 years, Avista treats these elasticity estimates as long-run estimates.

Table 2.2 – Price-Related Demand Adjustments for Demand Scenarios

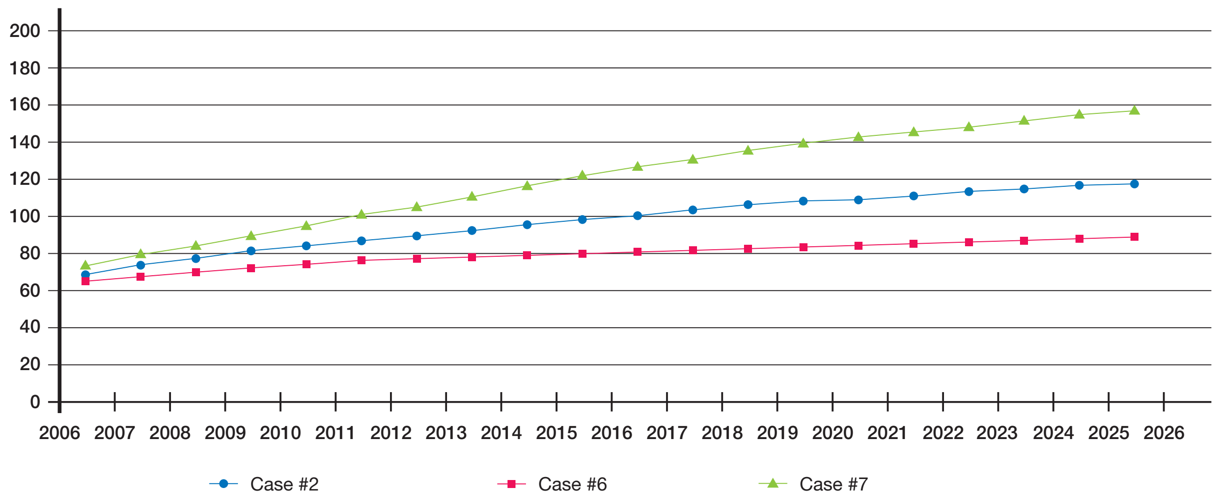
	Low Price	Medium Price	High Price
2006	106.30%	98.51%	95.84%
2007	101.10%	104.31%	101.84%
2008	101.13%	101.11%	101.80%
2009	101.12%	101.59%	101.51%
2010	101.15%	100.77%	100.55%
2011	100.25%	100.29%	99.74%
2012	100.26%	99.80%	99.64%
2013	100.25%	99.82%	99.62%
2014	100.24%	99.83%	99.57%
2015	100.24%	99.96%	99.59%
2016	99.82%	99.42%	99.61%
2017	99.83%	99.16%	99.64%
2018	99.84%	99.53%	99.64%
2019	99.84%	99.57%	99.65%
2020	99.83%	99.60%	99.66%
2021	99.89%	99.66%	99.66%
2022	99.89%	99.67%	99.67%
2023	99.89%	99.67%	99.67%
2024	99.89%	99.67%	99.67%
2025	99.89%	99.68%	99.68%

The three customer use demand forecasts developed by the company were derived utilizing the above elasticity assumptions and the natural gas price curves that the company discusses in detail in Section 6 and that are shown in Figure 6.16. Avista calculated customer response for each scenario by adjusting the demand coefficients shown in Table 2.1 for each case. The price-related coefficient adjustment factors calculated as described previously are shown in Table 2.2.

Table 2.3 – Demand Scenarios

Case #1 – Low natural gas price adjustment - elasticity (-.15)	Case #2 – Medium natural gas price adjustment - elasticity (-.15)	Case #3 – High natural gas price adjustment - elasticity (-.15)
Case #4 – Case #1 with a reduction of customer growth by 50%	Case #5 – Case #2 with a reduction of customer growth by 50%	Case #6 – Case #3 with a reduction of customer growth by 50%
Case #7 – Case #1 with an increase of customer growth by 50%	Case #8 – Case #2 with an increase of customer growth by 50%	Case #9 – Case #3 with an increase of customer growth by 50%

Figure 2.2 – WA/ID Average Annual Demand
(Net of DSM Savings) MDth/d – November to October



IRP DEMAND SCENARIOS

As described above, Avista has elected to analyze three customer growth rate scenarios and has also elected to analyze three different customer use rate scenarios. The result of this approach, when each potential outcome is considered, is that nine total scenarios are produced. Crossing the high, medium and low use per customer demand coefficients discussed above with the high, medium and low customer growth rate scenarios shown in Figure 2.1, derives these nine scenarios. Table 2.3 shows this in detail.

The top row of the matrix incorporates the high, medium and low natural gas price curve adjustments. As previously discussed, for each of these cases in this row, the demand coefficients were adjusted annually based on the comparison of each of the price curves selected by the company and the associated elasticity calculations. For the middle row of the matrix, the coefficients remain the same as the top row of the matrix but the customer growth rates were adjusted

Figure 2.3 – Oregon Average Annual Demand
(Net of DSM Savings) MDth/d – November to October

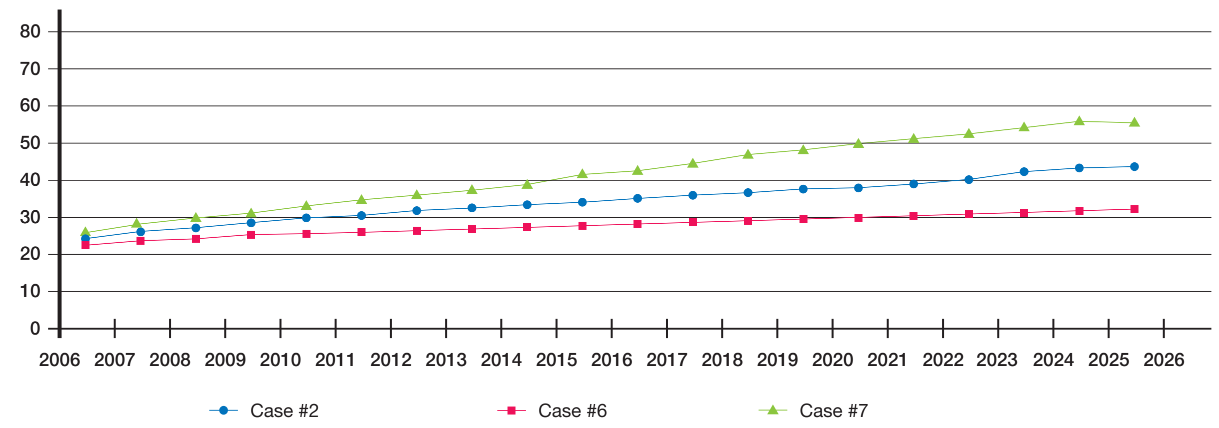
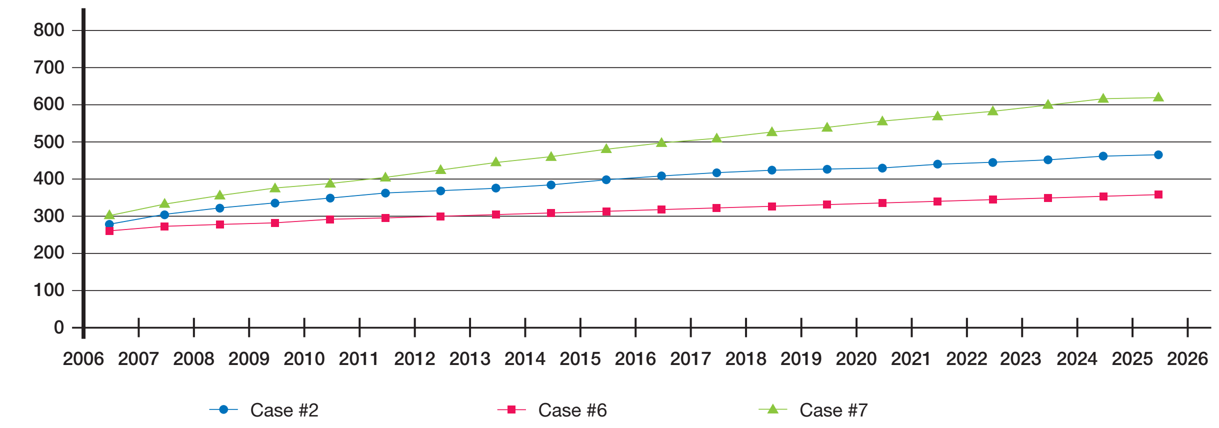


Figure 2.4 – WA/ID Peak Day Demand
(Net of DSM Savings) MDth/d – November to October



downward by 50 percent. For the bottom row of the matrix, the coefficients remain the same as the top row of the matrix but the customer growth rates were adjusted upward by 50 percent.

RESULTS

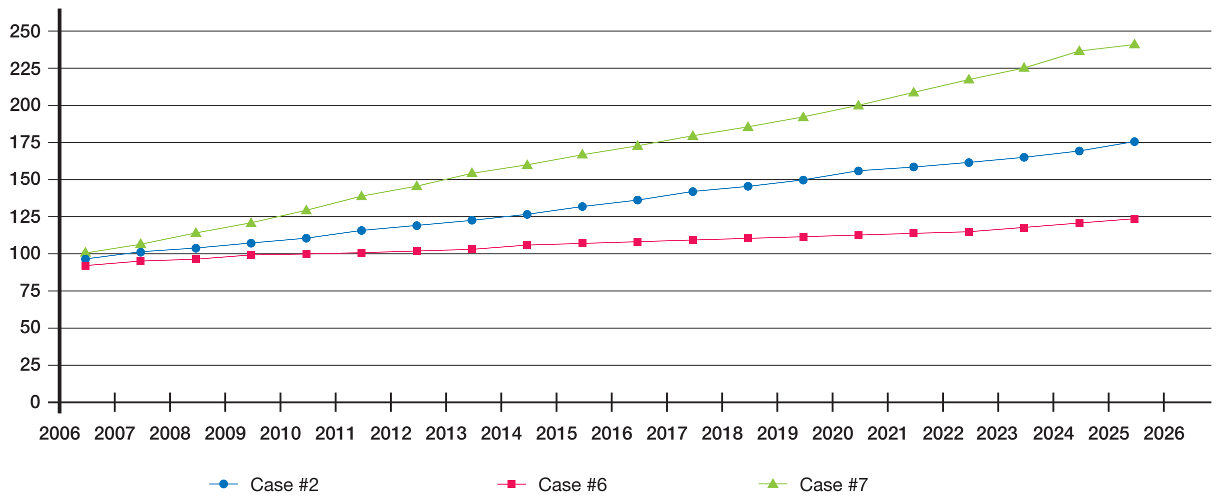
Figures 2.2 and 2.3 show Washington/Idaho and Oregon forecasted demand for the highest growth, lowest growth and mid-growth cases on an average daily basis for each year of this IRP.

Figures 2.4 and 2.5 show Washington/Idaho and Oregon forecasted demand for the highest growth, lowest growth and mid growth cases on a peak day basis for each year of this IRP.

Looking in more detail, Table 2.4 depicts annual demand increases by class of customer and area for the highest growth, lowest growth and mid growth cases for this IRP.

Additional detailed data depicting annual and peak day demand data is attached in Appendix 2.4.

Figure 2.5 – Oregon Peak Day Demand
(Net of DSM Savings) MDth/d – November to October



CONCLUSION

Through the scenario planning process, Avista has considered the potential demand impacts of both changing natural gas prices and a changing economy. The result of those considerations is a reasonable range of outcomes with respect to core consumption of natural gas. While Avista recognizes that the actual level of demand is dependent on a variety of factors, reviewing the range of potential outcomes allows the company to plan more effectively as economic or pricing conditions change on a dynamic basis.

TWO-YEAR ACTION PLAN

In addition to updating the forecast methodology for the latest actual data (including customer growth rates and demand coefficients), Avista plans to evaluate sub-area planning at the city-gate level. The development of a city-gate forecasting system is a major undertaking, and Avista will provide periodic progress reports addressing issues surrounding this project.

Table 2.4 - Annual Average Demand Percentage Increases
11/2006 - 10/2026

Area	Residential	Commercial	Firm Industrial
Case #2			
Klamath Falls	2.3%	2.3%	
La Grande	2.0%	1.5%	0.0%
Medford	3.3%	2.8%	
Medford NWP	3.3%	2.8%	
Roseburg	4.1%	2.6%	0.0%
OR Sub-total	**3.2%**	**2.6%**	**0.0%**
Spokane	3.0%	2.3%	1.2%
Spokane NWP	3.0%	2.3%	1.2%
WA/ID Sub-total	**3.0%**	**2.3%**	**1.2%**
Scenario #2 Total	**3.0%**	**2.4%**	**1.2%**
Case #6			
Klamath Falls	1.1%	1.2%	
La Grande	0.9%	0.8%	0.0%
Medford	1.8%	1.6%	
Medford NWP	1.8%	1.6%	
Roseburg	2.4%	1.5%	0.0%
OR Sub-total	**1.7%**	**1.4%**	**0.0%**
Spokane	1.6%	1.2%	0.6%
Spokane NWP	1.6%	1.2%	0.6%
WA/ID Sub-total	**1.6%**	**1.2%**	**0.6%**
Scenario #6 Total	**1.7%**	**1.2%**	**0.6%**
Case #7			
Klamath Falls	3.2%	3.1%	
La Grande	2.8%	2.2%	0.0%
Medford	4.3%	3.7%	
Medford NWP	4.3%	3.7%	
Roseburg	5.3%	3.5%	0.0%
OR Sub-total	**4.2%**	**3.5%**	**0.0%**
Spokane	4.0%	3.2%	1.7%
Spokane NWP	4.0%	3.2%	1.7%
WA/ID Sub-total	**4.0%**	**3.2%**	**1.7%**
Scenario #7 Total	**4.1%**	**3.3%**	**1.6%**

SECTION 3 – DEMAND-SIDE MANAGEMENT

SECTION 3 – DEMAND-SIDE MANAGEMENT

Avista actively offers energy-efficiency programs to all (non-transport) retail electric and natural gas customers. These demand-side management (DSM) programs are one component of a comprehensive strategy to provide customers with a least-cost energy resource. The IRP is used as an opportunity to evaluate that resource mix with the intent to refine approaches to the management of both supply-side and demand-side management portfolios.

The DSM function within Avista is organizationally split into a North (Washington and Idaho) division offering both electric and natural gas efficiency programs and a South (Oregon) division providing solely natural gas efficiency programs. For purposes of modeling DSM within the IRP process, the Oregon division was segmented into five areas and the Washington/Idaho division was segmented into two areas consistent with the company's approach to SENDOUT® modeling.

The analysis presented as a part of this IRP is the first step toward identifying cost-effective natural gas efficiency measures. Immediately following the completion of this analysis, but outside the scope of this IRP document, the company will review the existing DSM portfolio and business plan in light of the results of this analysis. This process will incorporate refinements and additional analysis of measures, revisions to existing and prospective program plans, and potentially the termination of measures that are determined not to be cost-effective. Included within this effort will be a determination of the optimal approach to each identified cost-effective measure to include the potential for cooperative acquisition or market transformation efforts.

It is possible that there will be measures accepted within this IRP that will subsequently be determined to be unsuitable for inclusion within the company's DSM portfolio based on post-IRP analysis, business planning and program planning efforts. It is also possible that programs will be developed for measures that were rejected by this IRP as a result of this same process. Though the IRP is the company's best opportunity to complete a comprehensive re-evaluation of the DSM portfolio and its integration into the overall resource mix, it is necessary to incorporate an ongoing business planning process to ensure that the best resource decisions are made.

Ultimately the company is committed to achieving

all natural gas-efficiency measures that can be cost-effectively acquired through utility intervention. This commitment supersedes any numerical goals established within the IRP or the company's business planning efforts.

THE METHODOLOGY

The development of a methodology for characterizing and evaluating DSM within the IRP was based on four key requirements. It was determined that the analysis must:

- Provide a comprehensive evaluation of all significant natural gas-efficiency options that are currently commercially available;
- Evaluate those natural gas-efficiency options in a process that is as interactive with supply-side options as possible;
- Maximize portfolio net total resource value; and,
- Deliver analytical results that are meaningful and actionable for the business planning process to follow the completion of the IRP analysis.

The methodology that was adopted to fulfill these requirements divided the process into five key phases:

- **Definition phase –** Defining and characterizing potential DSM resource options;
- **Preliminary evaluation phase –** Performing a preliminary evaluation of each measure using a spreadsheet model based on its ability to contribute to portfolio cost-effectiveness;
- **Packaging and optimization phase –** Packaging these measures into marketable DSM programs by iteratively optimizing these programs and testing alternative measure packages and implementation approaches (to include alternative ramp rates, program outreach, target marketing, etc.);
- **Program characterization phase –** Dividing those optimized programs into three categories for further testing within the SENDOUT® model:
  - Defining those programs that are certain to favorably contribute to portfolio net total resource value as "must take" options within the IRP model;
  - Specifying the resource characteristics of those programs that are of indeterminate cost-effectiveness and incorporating them into SENDOUT® for possible selection (or rejection) by the model itself; and
  - Excluding programs that are highly cost-ineffective based on preliminary total resource cost analysis from further consideration within SENDOUT®.
- **Program technical and acquirable potential –** Determine the size of the resource block acquirable through the adoption of the measure. This must be consistent with the non-incentive utility cost and program packaging effort previously defined.

Additional analysis, business planning, development of regional and ad hoc partnerships, and local DSM program implementation efforts will be triggered by the findings of this IRP effort. These efforts may modify the findings contained within this IRP document based on improved information and the timely assessment of opportunities. The nature of the process and the timelines of these ongoing efforts necessitate their omission from this document. Nevertheless they have been represented, in simplified form, in the methodology flowchart contained in Figure 3.1.

The incorporation of specific DSM resource options into the SENDOUT® model will be described as part of the overall integration of the IRP planning effort. This will include a compilation of the DSM measures selected by SENDOUT®, as well as their estimated therm acquisition and aggregate DSM goals for Washington/Idaho and Oregon.

PHASE ONE: CHARACTERIZING THE DSM MEASURES

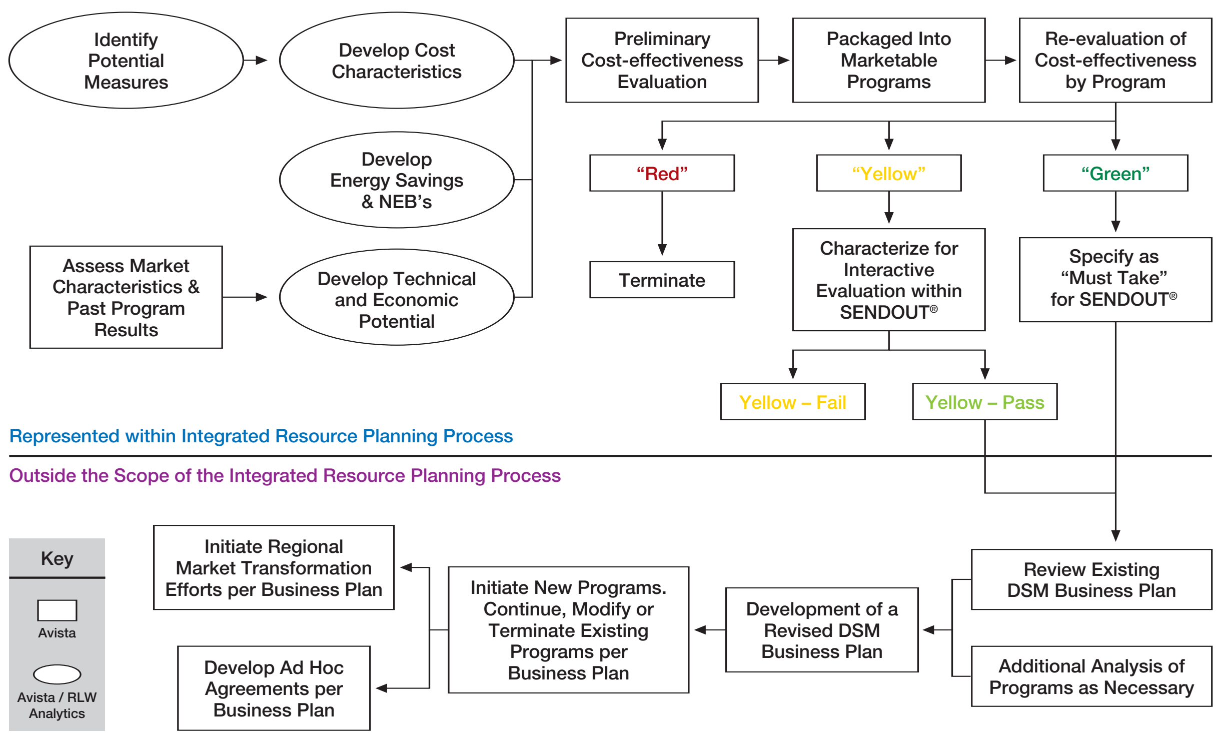
Avista retained the services of RLW Analytics to provide much of the basic data regarding the cost, energy-efficiency and technical potential characteristics of the 74 residential and 67 non-residential measures tested within the IRP. RLW Analytics was able to leverage previous work that it had performed for the Energy Trust of Oregon and the Northwest Energy Efficiency Alliance to develop these estimates.

A summary of the measures that were tested is contained within Appendix 3.1. Energy efficiency, incremental cost and other measure characteristics were generally evaluated in comparison to industry standards or code minimums, whichever were higher. These measures were tested under new construction, replace-on-burnout, replace-before-burnout scenario assumptions, and sometimes all three, as appropriate.

Each measure tested included an assessment of the technical resource acquisition potential provided by RLW Analytics. This estimate assumes that a natural gas-efficiency measure was installed in all applications where it would physically function regardless of the economic viability at that individual site, the likelihood of achieving the acquisition through utility programs or the length of time that would be required to reach total saturation of the market, and the ability of non-utility trade allies to support the sale and installation of the measure. Since the assumptions made in reaching the technical potential are obviously unrealistic, and sometimes grossly unrealistic, the acquirable potential is naturally lower than the theoretical technical potential.

The majority of the RLW Analytics work was specific to Avista's Oregon service territory, though it was consistent with and in a large part derived from regional market research performed by the Northwest Energy Efficiency Alliance. Thus, this raw data provided a sound foundation for determining the measure

Figure 3.1 – Integration of DSM within the 2006 Gas IRP



characteristics within Avista's Washington/Idaho service territory as well. This translation began by designating weather-dependent measures and establishing a default adjustment to North division energy savings based on the relative heating degree-days between the weighted average of the four Oregon divisions (Medford, Klamath, Roseburg and La Grande) as compared to that of the combined North division (Washington/Idaho) service territory. This default was then reviewed and adjusted as necessary based on the characteristics of Washington/Idaho (e.g. housing stock, end-use measure performance, differences in customer operations, etc.).

Avista DSM engineers, program implementers and analysts also reviewed incremental measure costs, measure lives, energy savings and other inputs and assumptions in the evaluation process with the staff of RLW Analytics and made revisions as necessary. Great care was taken to ensure that there was symmetric treatment of the costs and benefits of base case and high-efficiency scenarios for each measure.

Notably, the potential energy savings per unit does not include consideration for customer "take-back" (e.g. increased usage in response to the reduced incremental cost of end-use as a result of higher efficiency). The energy savings of individual measures will again be reviewed within the program planning phase to determine if there is any need for reducing the per unit savings to account for interactive effects between measures.

Program implementation staff estimated incremental, non-incentive utility costs for each measure. Since it was assumed that there would be a substantial portfolio of programs passing the total resource cost (TRC) test, the incremental utility cost was generally low or zero. This reflects the minimal incremental utility administrative cost associated with incorporating an individual DSM measure or program into a pre-existing portfolio of cost-effective programs. This approach has been previously presented to the IRP TAC and others as a "sub-TRC" test in that it excludes one cost element (fixed non-incentive utility cost) that is typically included in a full calculation of the TRC test.

Incremental measure cost was based on the customer cost over and above the assumed base case for new construction and replacement options. The incremental measure cost for retrofit (replace-before-burnout) options were based on the full cost of the measure on the presumption that there was an existing operational unit in place at the time of change-out (this being part of the definition of replace-before-burnout). This assumption made retrofit measures considerably more costly than replacement or new construction scenarios. Consequently the retrofit measures were generally not cost-effective or, at best, of marginal cost-effectiveness.

Clearly, the replacement and new construction alternatives would be strongly favored in the preliminary evaluation and SENDOUT® modeling phases of this study. However, this simplification did not adequately reflect the nature of the majority of retrofit situations. Typically the replacement of existing operational end-use equipment occurs when that equipment is nearing the end of its physical or economic life. For cost-effectiveness purposes, Avista has traditionally defined the replacement of equipment that is in "impending failure" as being a replace-on-burnout situation for purposes of estimating incremental costs for cost-effectiveness reporting. The term "impending failure" is generally defined as equipment that is likely to have less than one year of remaining useful physical life or equipment that has reached or exceeded its economic life.

Discussions in preparation for program design have often identified the targeting of replacement-shortly-before-burnout as an attractive market segment given the greatly reduced likelihood of customer installation of efficient equipment when the customer is in a water-out or space heat-out situation. This topic and its relationship to technical and economic potential therm acquisition will be revisited at a later point in the documentation of the IRP analysis and during business planning and program development.

Avista has traditionally adopted a conservative approach to the treatment of non-energy benefits or costs. Those non-energy impacts that are quantifiable in a reasonably rigorous manner are incorporated into the analysis as an adjustment to the incremental cost of the measure. Fundamentally, this assumes that part of the premium that the customer is purchasing within the incremental cost of a high-efficiency end-use is for the acquisition of the non-energy benefit. (An adverse non-energy impact would be represented as a negative non-energy benefit). The incremental cost attributable to the energy-efficiency component of the purchase is only that which is over the sum of the base case cost and the net value of the non-energy benefit. Within the set of measures analyzed for this IRP only the horizontal-axis washing machine was deemed to have a significant quantifiable non-energy benefit.

The company did perform a preliminary calculation of a revealed-preference approach to quantifying the non-energy benefits of shell measures (insulation and energy-efficiency windows). This methodology assumes that any participant payment in excess of the present value of future reductions in the energy bill is a minimum valuation of the non-energy benefit. Performing this analysis on a sample of floor, ceiling and attic weatherization participants indicated that the present value of the customers' energy savings was sufficiently high to offset the total measure cost in the vast majority of cases. This does not indicate a lack of non-energy benefits; it simply means that the energy benefits were sufficiently high to fully offset the measure cost in most cases, and consequently, the customer was not forced to 'reveal' a valuation of non-energy benefits. The company has successfully employed this approach to quantifying non-energy benefits in the past, however these evaluations occurred in an era of lower retail natural gas rates.

PHASE TWO: PERFORMING A PRELIMINARY EVALUATION

Based on the incremental customer cost, incremental non-incentive utility cost, incremental annual energy savings, measure life and the application of a discount rate consistent with the IRP process, a levelized "sub-TRC" cost was calculated for each individual measure. This calculation allowed for the comparison of costs across different measures with varying measure lives and was the foundation for the measure and program selection and portfolio optimization to follow.

This analysis was augmented with estimates of the full TRC levelized costs (including those that were not incremental to the program) to provide estimates of long-term portfolio cost-effectiveness. This information was used as a diagnostic tool to obtain an understanding of the magnitude and cost-effectiveness of a portfolio, including fully loaded non-incentive utility costs. The sub-TRC calculations drove decisions regarding the incorporation of individual measures into programs or into the overall portfolio.

This preliminary evaluation was performed within an Excel spreadsheet model to permit easy manipulation of the data. This process facilitated the identification of data elements that were out of the norm or in need of further research, the calculation of a number of different diagnostic statistics, and the testing of measures and programs under alternative approaches to program planning. It also greatly reduced the effort necessary to reformat the results of each program entered into SENDOUT®.

PHASE THREE: PROGRAM PACKAGING AND OPTIMIZATION

It is in this stage that the art of program design and implementation begins to enter the evaluation process. The intent is to maximize the net TRC value of each individual measure and then package these measures into marketable programs (e.g., a weatherization program composed of attic, wall and floor insulation, as well as possibly window measures and infiltration measures). It was therefore necessary to broadly define how these programs would be offered to Avista's customers.

The measure optimization and subsequent packaging of measures into programs were necessarily intertwined in this process. For example, the inclusion of a window measure as part of a residential shell program may have the impact of enhancing program throughput, however the ultimate impact on the program cost-effectiveness depends on the cost-effectiveness of each individual measure and its weighting within the program. Alternative program planning efforts, such as high and low ramp-rates and large or small outreach investments, were generally defined and evaluated as part of the program optimization. Using the inputs and diagnostic statistics previously described in the first two phases of this analysis made it possible to provide program planners with useful information regarding program benefit-to-cost ratios, net total resource value, as well as TRC and sub-TRC levelized costs under a number of different scenarios. This work is not a substitute for post-IRP program planning efforts, but it did allow us to realistically represent the most likely implementation approach within the IRP analysis.

To the extent possible, there was the desire to ensure that generally cost-effective measures were not packaged in non-cost-effective programs (and vice-versa). Table 3.1 illustrates the dekatherms of acquirable potential for individual measures and programs when disaggregated into broadly defined cost-effective, marginally cost-effective and non-cost-effective categories. These categories were described as "green," "yellow" and "red" respectively in discussions with the IRP TAC. These terms are also used within Table 3.1.

The final cost-effectiveness of the portfolio not only depends on the package of measures within each program, it also depends on the package of programs in the overall DSM portfolio. There is arguably a value to retaining certain "flagship" programs (such as the residential shell program) to provide a meaningful anchor program around which other programs (such as residential HVAC efficiency, domestic hot water measures, etc.) can leverage. Additionally, in the development of the Oregon DSM portfolio those measures that were mandated by legislation were designated as a "must take" option in all scenarios for purposes of the SENDOUT® model.

Though the calculations of levelized costs are made

Table 3.1 – Measure vs. Program Categorization Matrix

First-year Therms achievable by IRP testing category

Oregon residential measures	*Must take*	*"Green"*	*"Yellow"*	*"Red"*	*TOTAL*
"Green" measures	14,349	294,109	0	0	308,458
"Yellow" measures	40,609	544	46,793	20,622	108,568
"Red" measures	2,883	0	4,810	987,546	995,239
TOTAL	57,840	294,653	51,603	1,008,168	1,412,265

Oregon non-residential measures	*Must take*	*"Green"*	*"Yellow"*	*"Red"*	*TOTAL*
"Green" measures	0	52,301	390	0	52,691
"Yellow" measures	0	586	1,634	50	2,270
"Red" measures	0	0	0	72,986	72,986
TOTAL	0	52,887	2,024	73,036	127,947

Washington/Idaho residential measures	*Must take*	*"Green"*	*"Yellow"*	*"Red"*	*TOTAL*
"Green" measures	0	101,125	252,397	940	354,462
"Yellow" measures	0	0	270,824	165,432	436,256
"Red" measures	0	0	0	1,890,874	1,890,874
TOTAL	0	101,125	523,221	2,057,246	2,681,593

Washington/Idaho non-residential measures	*Must take*	*"Green"*	*"Yellow"*	*"Red"*	*TOTAL*
"Green" measures	0	38,495	19,992	0	58,488
"Yellow" measures	0	780	1,634	67	2,481
"Red" measures	0	0	0	74,398	74,398
TOTAL	0	39,275	21,626	74,465	135,367

"Green" measures were those with the highest cost-effectiveness
"Yellow" measures were considered to be marginally cost-effective
"Red" measures were deemed to be non-cost-effective

on a reasonably objective basis, there is of necessity a certain element of subjectivity within the majority of the packaging and optimization phase. Consequently much of this process was left to the program planners who will ultimately be responsible for developing and fielding the measures and programs selected in the IRP and future business planning processes.

PHASE FOUR: PROGRAM CHARACTERIZATION PHASE

The objective of this process was to develop marketable programs, generally composed of several measures related by common infrastructure or some other close tie, and to characterize these programs in a manner suitable for entry into the SENDOUT® model. Each program was split into five geographic segments (in Oregon) or two geographic segments (in Washington/Idaho) to be consistent with the modeling of the natural gas transmission system within SENDOUT®. This disaggregation was based on residential households, non-residential natural gas throughput and the climatic conditions for each of the geographic areas. The heating degree-days used for these purposes are summarized in Table 3.2. These heating degree-days are consistent with those used for demand planning in this IRP, discussed in Section 6 and can be found in Appendix 6.1.

The levelized costs of a given program are identical in each of the Spokane and Medford geographic areas, although SENDOUT® will not necessarily reach the same accept or reject decision due to differences in supply-side resource costs.

The five geographic areas within Oregon have a 71 percent range in heating degree-days from the warmest (Roseburg) to the coldest (Klamath Falls). This results in significantly different energy savings and cost-effectiveness levels for weather dependent measures.

The almost certain probability that some DSM programs would be accepted by SENDOUT® in some geographic areas and rejected in others within the same

Table 3.2 – Geographic Area Characteristics

	HDDs
Oregon	
Klamath Falls	7,201
La Grande	6,751
Medford	4,786
Medford NWP	4,786
Roseburg	4,216
Washington/Idaho	
Spokane	6,997
SNWP	6,997

HDDs = heating degree-days
SNWP = the area within Washington/Idaho that can be served only off of NWP.
Spokane = the area within Washington/Idaho outside of the SNWP area.
Medford NWP = the area in Medford that can only be served off of NWP.
Medford = the area in Medford outside of the Medford NWP.

jurisdiction will pose program development difficulties. Only very rarely has Avista offered programs that were not available throughout the entire jurisdiction. Though this issue was discussed with stakeholders as part of the IRP process, it is generally deferred to the program-planning phase.

Avista will complete analysis of the prospective cost-effectiveness of each program in each of the five Oregon geographic areas as part of the program planning efforts. This analysis may lead to an improvement in the overall cost-effectiveness of selected measures through geographically targeting the program. The distinction between the two Washington/Idaho geographic areas (designated SNWP and Spokane) is based on pipeline delivery areas that are not meaningful in a DSM program planning sense (but are meaningful to Avista supply-side planning).

Prior to the development of the methodology used in this analysis the company had discussions with utilities experienced in incorporating DSM packages into the SENDOUT® model. Based upon those discussions, it was determined that the SENDOUT® model quickly becomes unwieldy if too many DSM options are submitted for interactive evaluation within the model. This is particularly true when those DSM options must be subdivided into seven geographic areas and evaluated in all nine of the original IRP scenarios.

Avista minimized this problem by identifying several categories of DSM programs in a preliminary evaluation process. These included:

- "Must take" programs composed of
  - Legislatively-mandated Oregon programs
  - Programs with sub-TRC levelized costs so low that acceptance by SENDOUT® was virtually guaranteed
- Programs with levelized costs so high that rejection of the program in all SENDOUT® scenarios was virtually assured
- Programs that could not be clearly accepted or rejected based on the preliminary evaluation results.

A ranking of measures and programs by sub-TRC cost-effectiveness was initially completed in the preliminary evaluation process. This ranking is not necessarily the precise ranking that SENDOUT® would apply for selection since it was composed of programs with varying annual load profiles. The ranking was nevertheless suitable for establishing an initial disaggregation of the optimized programs into the three categories defined above.

Measures in the "must take" category were aggregated into base load measures (not dependent upon heating degree-day levels) and weather sensitive measures (those that were heating degree-day sensitive) to establish the annual load profiles necessary for evaluation within SENDOUT®. This aggregation and mandatory acceptance significantly reduced the input and computational time required to complete the modeling process without compromising the final results.

Programs that were clearly not going to be accepted were eliminated from further consideration and not entered into SENDOUT®. This also reduced input and computational time without compromising the validity of the final results.

Those programs whose acceptance or rejection by SENDOUT® was uncertain were individually entered into the model with all of the necessary geographic disaggregations discussed earlier. Indeterminate programs were defined as programs with sub-TRC levelized cost-to-benefit ratios between 0.6 and 1.5 when compared against a levelized avoided cost of $1.00 per therm. The use of a cost-benefit ratio and a hypothesized avoided cost was necessary since the programs were frequently composed of measures with varying measure lives. It was believed that this range was sufficiently broad to fully capture the range of indeterminate programs in the medium-price IRP scenarios.

At the time that this evaluation was being performed, it was assumed that all measures would be implemented through local program delivery. The opportunity for the development of any of these measures as regional market transformation programs was not sufficiently mature at this time to represent within the IRP analysis. The company is committed to pursuing all cost-effective measures in the manner that is most appropriate given the available opportunities, including the potential for cooperative or regional efforts.

The disaggregation of programs into these categories is represented in Appendix 3.2. These programs consist of multiple measures as well as replace-on-burnout, replace-before-burnout and new construction options. Thus, the same measure may appear in multiple programs based on these characteristics. This is an unfortunate but unavoidable level of detail necessary to ensure that individual measures were not inappropriately combined with other separable measures with very different cost-effectiveness characteristics.

PHASE FIVE: TECHNICAL AND ACQUIRABLE POTENTIALS

At this point in the analysis, the evaluation, ranking and selection of measures has been independent of the potential acquisition of each resource. The acquirable resource available from a selected measure is only important to the extent that the business planning process will need to establish sufficient infrastructure flexibility to respond to customer demand for the program. Even this importance is minimized considering Avista's commitment to funding the acquisition of all available cost-effective gas-efficiency resources.

Avista will carry forward into the post-IRP business planning process the intent to establish an infrastructure sufficient to achieve the level of cost-effective resource acquisition identified within the IRP. Adjustments will be made based on differing approaches to program implementation and actual customer response to the DSM portfolio. These adjustments will reflect the company's commitment to delivering all cost-effective resources achievable through utility programs.

The estimates of the resource potential for each individual measure were initiated with Oregon division technical potential provided by RLW Analytics. These estimates were based on generally available demographic information, as well as the results of market research performed for the Energy Trust of Oregon and Northwest Energy Efficiency Alliance. The Oregon estimates were reviewed and modified for service territory-specific information known to the company.

The Oregon technical potential served as a starting point for the development of Washington/Idaho technical potentials. A default calculation translating Oregon technical potential to Washington/Idaho was made based on the number of residential customers for residential measures and non-residential load for non-residential measures. These default calculations were then reviewed and modified as necessary by Avista staff based on service territory-specific market knowledge, particularly in regard to multi-family housing and industry-specific non-residential measures.

Estimates of the technical potential for a measure were used as starting points in the development of realistically acquirable and sustainable resource acquisition. At this point, earlier questions regarding the disaggregation of measures into new construction, replace-on-burnout and replace-before-burnout were revisited. For purposes of developing estimates of acquirable resources, it was determined that replacements of equipment very close to the end of their life would be considered to be a replace-on-burnout scenario.

Acquirable resource potential estimates were based on the technical potential available, available trade ally infrastructure, estimated participant economics and market opportunities to include the ability to leverage programs being implemented elsewhere within the region, customer interest and satisfaction with the technology, placement of the measure within a product life cycle continuum, and related issues. The subjectivity involved in this estimate is unavoidable given the nature of the programs and the market. Given this subjectivity, Avista has incorporated within the IRP a commitment to innovatively seek and acquire all cost-effective DSM resources available to the company and to establish and maintain the necessary utility infrastructure to do so. This commitment is elaborated on elsewhere within this IRP.

All of the previous analysis was focused on the acquisition of a portfolio of measures that could be offered on a prescriptive basis. In recent years Avista has been successful at deriving substantial therm savings from large customers with unique natural gas-efficiency opportunities captured through the company's site-specific program. This has been particularly true in the Washington/Idaho division, as many Oregon customers are transport-only customers who do not qualify for assistance through utility DSM programs.

It is exceptionally difficult to develop estimates of the potential within this site-specific market for a number of reasons. The site-specific program was developed to create an all-inclusive means of capturing unique projects; however, by definition, unique projects are difficult to generically categorize and extrapolate. In recent history both the Oregon and the Washington/Idaho divisions have substantially exceeded previously established therm acquisition goals with projects that have either been completed or are currently underway. It is uncertain whether or not the enhanced acquisition of these large projects is solely the result of recent increases in retail rates that will perhaps subside once a relatively finite inventory of efficiency opportunities is acquired. Alternatively the same retail rates could be generating a new tier of economically attractive efficiency opportunities that are sustainable in the long-term.

In previous natural gas IRP proceedings, Avista has expressed a reluctance to assume a long-term continuation of these recent site-specific acquisition achievements. As time progresses and the acquisition level has remained at a highly favorable level, the company is of the opinion that the market may be able to sustain these achievements in the long run. Consequently, within this IRP analysis, Avista has used recent history as a baseline for future achievements.

Two alternative methodologies for establishing acquirable therm acquisition targets for the Washington/Idaho division were undertaken.

The first approach was to review the last three years (2002 to 2004 inclusive) of non-residential DSM program acquisition and to remove the prescriptive measures incorporated elsewhere within the analysis. This resulted in an estimate of 48,000 first-year dekatherms acquired on an annual basis. Prior to the initiation of the IRP process, a different approach was used to develop 2006 budget and labor requirements. This second approach identified a 45,800 first-year dekatherms annual acquisition. Based on this range, an acquisition of 46,900 first-year dekatherms was incorporated into SENDOUT® as a "must take" option for the Washington/Idaho division.

The nature of Avista's Oregon retail customer base is fundamentally different from that of the Washington/Idaho division. More of the large commercial and small industrial customers have already become natural gas transportation customers in Oregon. As these customers purchase their own natural gas supplies, the proportionately smaller number of industrial customers that do purchase gas through the utility naturally limits the potential acquisition level.

Avista's previous Oregon goal of 10,000 first-year dekatherms of annual acquisition is significantly less than the company's expectation of future potential. However, due to the large size of the individual projects and the relatively small service territory, it is difficult to develop a reasonable acquisition target based on recent history. This difficulty was described to the TAC as a problem with the "lumpiness" of the historical data. Consequently, Avista is proposing that the therm acquisition achievements be based on a five-year moving average rather than the results of a single year.

Given an analysis of projects underway, as well as possible opportunities that are being pursued, the company believes that the acquirable potential for this program should be increased from 10,000 first-year dekatherms to 30,000 first-year dekatherms.

The company believes that this increase is obtainable as a result of the participant economics at current and expected future retail rates, as well as increased DSM program outreach efforts to be incorporated into the 2006 DSM business plan. This estimate of 30,000 first-year dekatherms was entered into SENDOUT® as a "must take" resource option.

ADVANCE DSM OPTIONS FOR THE SENDOUT® MODELING PROCESS

This concluded the portion of the analysis that was necessary to prepare for the integration of DSM resource options into the SENDOUT® modeling process.

The results of the SENDOUT® modeling, discussed in Section 6, is used as an input into a re-evaluation of the Oregon and Washington/Idaho DSM portfolios and business plans described later. Though the DSM options were represented as closely as possible to the manner in which the program is likely to be offered, additional revisions and updates to the SENDOUT® results will undoubtedly occur. The results of this additional analysis and any modifications will be communicated within the Oregon DSM Annual Report and the Washington/Idaho Triple-E proceedings.

OVERVIEW OF CURRENT OREGON DSM PORTFOLIO

Avista's residential programs are available to approximately 79,000 customers (Avista Rate Schedule 410) with an annual consumption of 48 million therms. The commercial programs are available to 10,600 mostly small-to-medium-sized customers (Avista Rate Schedules 420 and 424) with an annual consumption of approximately 76 million therms. The largest segment of qualified commercial customers use gas for space and water heat, and cooking with an average consumption of 2,600 therms each.

The company has offered a mix of mandated and non-mandated natural gas efficiency programs to Oregon customers since the late 1970s. Five separate programs are offered at the present time: residential space heat efficiency, residential water heater efficiency, residential shell measures (insulation and windows), commercial/industrial natural gas-efficiency and commercial energy audits. These five programs and their recent history are described in greater detail.

Residential Space Heat Efficiency

This program offers a direct incentive of $200 to $250 for residential customers installing a natural gas furnace, boiler or combination space/water heating systems with a 90 percent or higher Annual Fuel Utilization Efficiency (AFUE). The current federal minimum furnace efficiency is 78 percent.

The company currently applies a 25-year measure life to residential natural gas furnaces and boilers. This is toward the high-end of the range of measure life typically applied by other utilities.

Current program participation is roughly equally split between the replacement of existing natural gas appliances (34 percent), new natural gas appliances (29 percent) and new construction (37 percent). Retrofit opportunities most frequently occur upon start-up at the outset of the heating season.

Residential Water Heat Efficiency

Forty-gallon natural gas water heaters with an Energy Factor (EF) rating of 60 percent or higher and 50-gallon water heaters with an EF of 62 percent or higher qualify for a $50 incentive under the company's current program. The current federal minimum efficiency level is an EF rating of 59 percent for 40-gallon water heaters and 58 percent for 50-gallon units.

Past program participation data indicates that approximately 43 percent of participants are new construction, 24 percent are replacing an existing gas appliance and 33 percent are replacing an electric appliance. A 12-year measure life has been applied to water heaters in the past. That assumption has been retained for purposes of this analysis and is consistent with the physical life of the appliances.

Due to the limited availability of high-efficiency water heaters customers must frequently endure a "no water heat" period of one to five days in order to obtain a high-efficiency water heater. Water heaters typically do not fail during a period of time when such a "heat out" situation is tolerable to the customer. The company has

identified this lack of availability as a market barrier in the past. Informal surveys have indicated that DSM programs have had some favorable impact on HVAC dealer stocking patterns, but the improvement has been modest and seems to have reached a plateau. Large retailers on the other hand are not stocking qualified models indicating a regional effort may be necessary.

The analysis culminating in the DSM supply curve presented in this IRP substantiate that the lack of availability of high-efficiency water heating equipment is a major barrier to improvements in market saturation. The intent of the current program, which carries an incentive virtually equal to the then-assumed cost premium, was to encourage dealers to stock the high-efficiency equipment as a matter of standard practice, secure in the knowledge that the post-incentive customer cost for the high-efficiency equipment would be no higher than that of the standard-efficiency equipment. Though this program has had an impact on the market, it is clearly insufficient to achieve any significant transformation.

The need for more rigorous baseline information on availability, cost premiums and possible program enhancements to address these market barriers has been identified as a future deliverable.

Residential Shell Measures

The company is mandated to offer residential shell audits and provide shell incentives. The program includes an attic, wall and floor weatherization program, as well as an efficient window component. The cost associated with the mandated audit is not included in the TRC costs of this program since it is not an incremental resource decision.

Though the customer costs of the shell measures are not notably different across the four service districts in Oregon, the therm savings are dramatically different. That difference is driven by the heating degree-days, as well as the order that the individual shell measures and space heat efficiency measures are incorporated into the home. Shell measures receive the greatest savings when they are adopted in colder climates, when they are the first shell measure adopted and when they are adopted prior to HVAC efficiency measures.

For purposes of developing therm savings estimates for each of the individual shell components, it was assumed that participants adopted attic insulation, floor insulation, wall insulation and window improvements in that order. This order is based on a combination of the cost-effective potential of the individual shell measures and a realistic review of customer behavior. Notably windows are often replaced as "stand-alone" measures, generally driven by non-energy motivations.

The vintage of a home has a significant bearing on whether a home is identified as a weatherization opportunity. Building code improvements during the 1980s and 1990s brought many homes in the housing inventory to an R-value that is consistent with the current program standards. Consequently homes deemed to be program opportunities will gradually decrease over time as these older homes are removed from the housing inventory or retrofitted to meet existing shell standards.

Table 3.3 shows current residential shell program standards.

Table 3.3 – Avista Residential Shell Program Requirements

Shell Component	Program Requirement
Attic insulation	R-38
Floor insulation	R-19
Wall insulation	R-11
Windows	U-40

Shell measure savings are presumed to have a 30-year life with no degradation, although windows have been considered a 25-year measure. This is a simplification of reality in that a certain amount of degradation certainly does occur, however it is also true that a substantial portion of the energy savings persist beyond the specified measure life.

Commercial/Industrial Natural Gas Efficiency

This program encompasses all TRC-cost-effective measures that can be applied to the company's non-residential/non-transport customers. Any natural gas efficiency measure qualifies provided that it passes a "sub-TRC" calculation. The "sub-TRC" calculation excludes the allocation of utility fixed costs to individual projects. Projects that pass the "sub-TRC" test are enhancements to the TRC cost-effectiveness of the overall portfolio even though some may be so marginally cost-effective that they could not bear a share of fixed utility cost without becoming cost-ineffective.

Measure lives for these projects are individually calculated. The program life-to-date weighted average measure life (weighted by the therm savings of each project) of the program is 18 years.

Historically this program has exhibited a significant year-to-year variance in therm acquisition. This is the result of the relative small size of the qualified customer base and natural gas-efficiency opportunities and the relative large size of some individual projects.

Customers qualifying for assistance through DSM programs within the Oregon service territory have a higher proportion of small commercial customers than is evident in Avista's Washington/Idaho service territory. Consequently the technical and realistic savings potential are disproportionately lower due to the difficulties associated with acquiring energy savings from the small commercial customer segment.

Table 3.4 – Summary of 2004 Natural Gas Efficiency Program Results

Program	Res Shell	Res W/H	Res S/H	C/I efficiency
Measure life	30 years	15 years	25 years	18 years
Incentive per unit	variable	$50	$200/$250	variable
TRC cost per unit	variable	$50	$496	variable
Therm savings per unit	variable	27	90	variable
Annual target therm savings	45,000	13,600	42,000	10,000
2004 actual therm savings	70,802	6,858	123,750	14,693

MEASUREMENT AND EFFECTIVENESS OF CURRENT PROGRAMS

The results of the company's DSM programs are summarized in an Annual DSM Report. The reporting includes therm acquisition, number of customers impacted, and the information necessary to substantiate the TRC and Utility Cost Test (UCT) analysis contained within the report. Two of these programs, residential water heater natural gas efficiency and commercial/industrial natural gas efficiency, have consistently been cost effective under both the TRC and UCT test. The mandated residential weatherization and the residential space-heat natural gas efficiency programs are not TRC cost effective on a life-to-date basis, however they are life-to-date UCT cost effective.

A summary of the 2004 program results is contained in Table 3.4. Results for 2005 operations will be filed as part of the 2005 DSM Annual Report.

Derivation of Residential Building Characteristics

In order to estimate potential natural gas savings for the retrofit and replacement sectors, a fundamental characterization of the residential populations is required. Residential accounts have been classified as either single family or multifamily homes. Avista residential audit data and a secondary data source were used to estimate saturations of natural gas-powered end-uses and system types. Basic characterizations are used to estimate applicable populations for residential natural gas savings measures and the technical potential savings.

The data sources used in this analysis include 2004 Department of Energy Building Energy Data Book, Census 2000, Residential Energy Consumption Survey (RECS) 2001, GAMA Gas Appliance Database, and Database of Energy Efficient Resources (DEER) 2001 and 2005, and preliminary data from RLW residential surveys for the Northwest Energy Alliance. Characteristics of new construction are detailed by

Oregon Dwelling Code and the Northwest Energy Alliance's 2001 Residential New Construction Baseline study.

Gas measure savings and costs were primarily drawn from the Energy Trust of Oregon, the Database of Energy Efficient Resources (DEER) 2005 and surveys that RLW Analytics conducted with local equipment suppliers and from HVAC and plumbing contractors. Weatherization costs were taken from Avista retrofit program data and were validated against other available cost data.

DERIVATION OF GAS SAVINGS POTENTIAL FOR COMMERCIAL ACCOUNTS

In order to determine the energy savings potential for the commercial sector, a statistical characterization of the market was necessary. RLW Analytics completed this analysis through telephone surveys of a random sample of the population.

Account data, for the entire commercial sector was provided, including contact information and billing information from the past year. Addressees with multiple accounts were aggregated to bring the accounts to the "site" or building level. The population of sites was then stratified by usage and a sample design was created to optimize the precision of the final estimates.

The site contacts for the sample were called and asked a series of questions about the nature of business, the natural gas equipment used at the facility and building characteristics. The survey data was entered into a database along with site annual base and heat load that was approximated from analysis of one year of monthly site billing data. In most cases, the base load was extrapolated from the billed July/August usage, and the heat load was considered to be the remainder. Schools and other seasonally operated buildings required individual base load allocation analysis based upon survey responses.

CLIMATE

The Oregon service territory is subdivided into four separate service districts primarily based on climatic differences. These four areas, from warmest to coldest, are Roseburg, Medford, La Grande and Klamath Falls. The heating degree-days used in this IRP (discussed in Section 6) for the four service districts are shown in Table 3.5.

Notably there is a significant difference (71 percent) in heating degree-days from the warmest to the coldest Oregon district.

Table 3.5 – Heating Degree-Days by Service District

Roseburg	4,216
Medford	4,786
La Grande	6,751
Klamath Falls	7,201

Table 3.6 – Annual Distribution of Heating Degree-Days (HDDs)

Month	Percent of Annual HDDs
January	16.9%
February	12.9%
March	11.6%
April	8.5%
May	4.6%
June	1.5%
July	0.2%
August	0.3%
September	2.1%
October	7.0%
November	13.5%
December	21.1%

To determine the seasonal pattern of energy savings of heating-related efficiency measures (weatherization and space heating measures), the monthly heating degree-day patterns of Medford were ascribed to each service territory's annual heating degree-day level. This monthly pattern is represented in Table 3.6.

PROGRAM DEVELOPMENT

Based on RLW Analytics DSM potential study and subsequent analysis, there will be a number of new programs developed. Avista will begin the development process in advance of the IRP acknowledgement.

A new prescriptive program for commercial customers will be developed along with the addition of measures to the existing residential prescriptive program. Residential weatherization measures and incentives will also be evaluated to reflect cost effectiveness calculations and promote additional participation.

Avista will also look at the "best fit" for program implementation. Implementation options could include a combined effort between Avista's North and South divisions, additional staffing, Energy Trust of Oregon (ETO), trade partners, and if developed, a natural gas Northwest Energy Efficiency Alliance (NEEA). Additional avenues for implementation will be evaluated as they are identified.

OVERVIEW OF THE CURRENT WASHINGTON/IDAHO DSM PORTFOLIO

Program Overview

Avista offers a portfolio of electric and natural gas efficiency programs to Washington and Idaho customers. Electric efficiency programs have been available since 1978. Natural gas efficiency programs have been offered without interruption since 2001 and periodically prior to that time based on cost-effective opportunities within the market.

The company has established a non-binding external oversight group, the External Energy Efficiency ("Triple-E") Board to provide guidance for the implementation of DSM programs. This board is provided with a quarterly written update, convenes twice a year, and receives a comprehensive annual evaluation of acquisition and cost-effectiveness.

Table 3.7 – WA/ID Rate Schedule 190 Incentive Tiers

Customer Simple Payback	Incentive per 1st yr Therm
Zero to 17 months	$0.00
18 to 48 months	$2.00
49 to 71 months	$2.50
72 months or more	$3.00

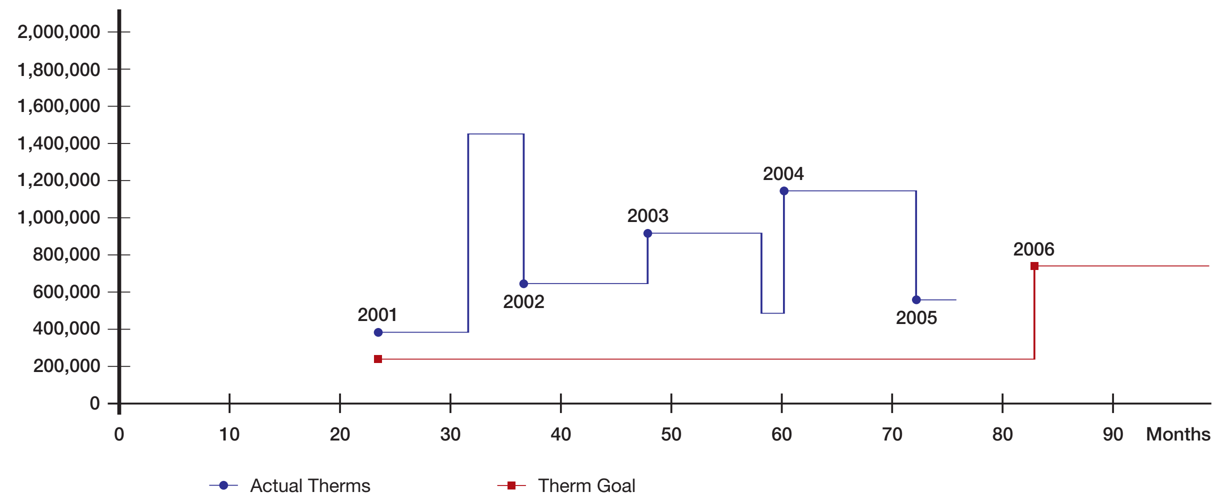
Incentives are capped at 50 percent of incremental measure cost in Idaho and 30 percent of incremental measure cost in Washington.

Avista's Rate Schedule 190 provides the regulatory guidelines for the implementation of the natural gas DSM programs. This tariff prescribes a set of tiered, direct financial incentives, as illustrated in Table 3.7, based on the customer simple payback of the measure.

Selected exceptions to these tiered incentives allow the company sufficient flexibility to respond to unexpected or unique opportunities. This flexibility includes an additional set of tiered incentives, permitting higher incentives for the development of new technologies and market transformation efforts.

Avista Rate Schedule 190 also establishes an annual goal of 240,000 first-year therms. This goal was set in late 2000 as a natural gas efficiency program was being

Figure 3.2 – Gas DSM Acquisition



reestablished in response to increases in the weighted average cost of natural gas. After the approval of the tariff, natural gas commodity costs and retail rates continued to escalate. Additionally, the 2001 regional electric crisis resulted in a substantial enhancement to electric DSM programs. The strong electric efficiency message and increasing natural gas retail rates prompted a much larger natural gas efficiency response than was anticipated when the original Schedule 190 goal was established.

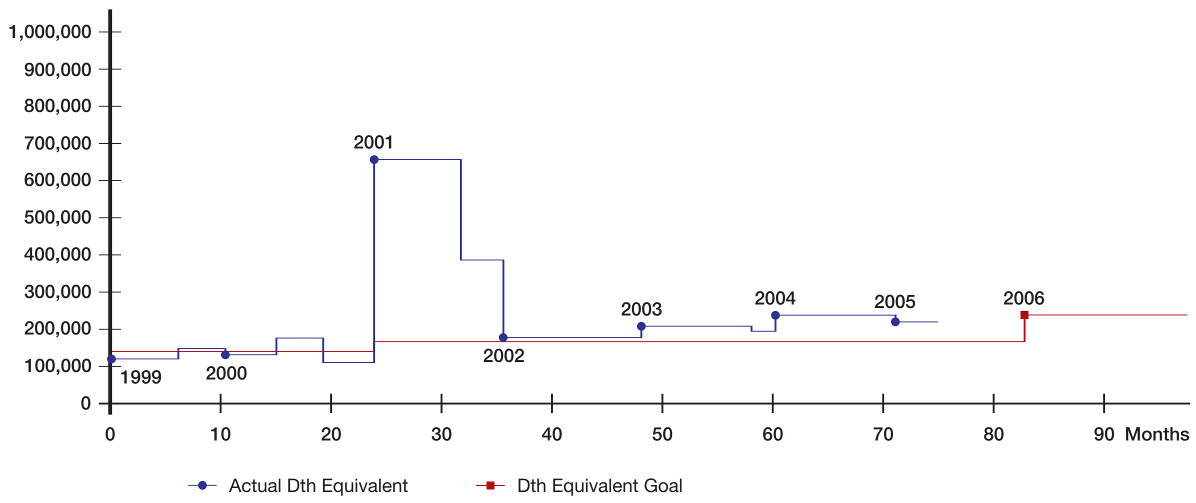
Despite the unexpected volume of acquisition through Schedule 190, the company was well positioned to respond. In the nearly five years since Avista reinitiated its natural gas DSM programs, the company has been communicating its uncertainty regarding the sustainability of this level of acquisition. Given the lack of historical precedent, it has not been possible to determine if this is a one-time response to acquire measures that have become cost-effective at higher retail rates or if it will be a sustained response for the foreseeable future. Based on five years of experience and the analytical results of this IRP, the company is proceeding on the presumption that this is a sustainable level of acquisition.

Funding for the natural gas efficiency programs is derived through a surcharge on retail rates authorized under Schedule 191. In Washington this surcharge will fall from an amount equal to 0.96 percent of retail rates to a 0.50 percent surcharge. The higher surcharge was necessary to allow for the recovery of a persistent negative balance within this tariff rider. The negative balance was accumulated as a result of unexpectedly high demand for DSM projects during the 2001 and 2002 period. Since over 90 percent of the natural gas DSM funding was going to direct customer incentives required under Schedule 190, it was not possible to address this negative tariff rider through utility cost efficiency actions.

Natural gas DSM funding within Idaho is also funded through Schedule 191 surcharges.
This surcharge was set at 0.50 percent when it was re-initiated in early 2001 and has not been modified. The tariff rider balance as of November 2005 is negative (customers owe shareholders) in an amount equal to 26 months of typical revenue. As in the case of the Washington tariff rider balance, customer demand since 2001 has exceeded the original 2001 expectations.

Avista's greatly enhanced electric and natural gas DSM response to the 2001 regional energy crisis resulted in an aggregate tariff rider balance (both

Figure 3.3 – Combined Gas and Electric DSM Acquisition



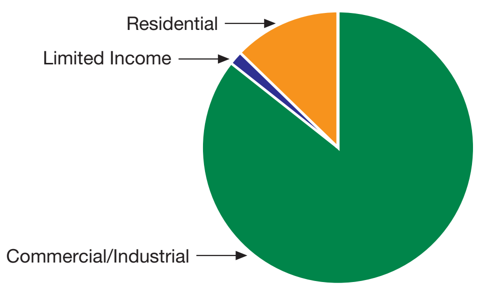
jurisdictions, both fuels) of negative (customers owe shareholders) $12.4 million. Under a business plan emphasizing utility cost-control and the targeting of DSM program outreach to cost-effective and lost-opportunity measure applications, the company was able to return this tariff rider to a zero balance in August 2005, all while exceeding tariffed BTU acquisition goals during that period.

In the future, the company plans to pursue an annual adjustment to DSM tariff rider levels to ensure funding that is sufficient to fund continuing DSM operations, as well as to recover or disburse any tariff rider balance carried into that year. The planned 2006 filing will be the first of these revisions. Since this is the company's first opportunity to individually fine-tune tariff rider balances through this mechanism, it may be necessary to extend the recovery of some negative balances over more than one year to provide for reasonable stability of tariff rider levels.

Only those customers contributing to the program funding through Avista Rate Schedule 191 are eligible to receive financial incentives. This limits availability to core customers. Since 2001, Avista has claimed acquisition credit for one natural gas efficiency project from a transport customer as a result of the project being tightly interwoven with an electric-efficiency project that was being evaluated and funded under the company's electric DSM program.

DSM implementation efforts within Washington and Idaho are separated into three different portfolios: (1) the commercial/industrial portfolio, (2) the residential portfolio and (3) the limited income residential portfolio. The approaches to the implementation of these three portfolios differ significantly in recognition of the differences in these markets.

Figure 3.4 – Portfolio Distribution of Natural Gas Efficiency Therm Acquisition, 2004



Portfolio Overview – Commercial/Industrial

This portfolio is characterized by its all-encompassing approach to this market. Any natural gas efficiency measure qualifies for assistance through this portfolio. Incentives are offered based on the previously described tiered incentive structure applied to each individual project.

This approach to the market ensures that unique and unexpected efficiency measures are never excluded from acquisition through utility programs. The company restricts the development of prescriptive programs to measures and applications that are reasonably uniform in their energy savings and cost characteristics. This has generally not been found to be the case for even relatively common natural gas DSM measures. (Several prescriptive electric DSM programs have been developed for the commercial/industrial market).

In 2004 the company acquired 934,239 therms from this portfolio (87 percent of the total acquisition of all three portfolios, 389 percent of the total Avista Rate Schedule 190 tariffed goal) as depicted in Figure 3.4. Fifty percent of the total non-interactive energy (electric and natural gas) acquisition within this portfolio is attributable to therm savings.

Notably several multifamily housing measures are incorporated within the commercial/industrial portfolio due to the non-residential electric and natural gas rate schedules that many of these customers are billed. Many of the multifamily measures evaluated as part of this IRP analysis (e.g. pool and spa water heating efficiencies in multifamily housing) will be forwarded to the commercial/industrial portfolio segment for further evaluation.

Large projects, those resulting in incentives of $100,000 or larger, are disclosed to the Triple-E board to provide them with the information necessary to provide oversight of DSM programs.

Portfolio Overview – Residential

Due to the large volume and relatively small size of individual projects, the residential portfolio is exclusively composed of prescriptive programs. In 2004 this portfolio was responsible for the acquisition of 124,865 first-year therms (12 percent of the total portfolio, 52 percent of the Schedule 190 tariffed goal). Of the non-interactive total energy (electric and natural gas) savings in 2004 from this portfolio, 17 percent are attributable to therm savings.

Incentives available for residential programs are calculated based on the application of the measure in a typical residential home. Calculations are made in accordance with Avista Rate Schedule 190 tiered incentives with appropriate modifications for potential differences in application, multiple measure programs and rounding for purposes of offering a customer and trade ally-friendly program. The prescriptive residential programs currently available are outlined in Table 3.8.

Additional residential incentives are available for the conversion of space or water heating appliances from electric to natural gas.

Avista has recently undertaken an enhanced outreach effort for the residential portfolio. This is composed of a media and print campaign driving customers to a revised residential online energy audit. This audit tool will be enhanced to allow the customer the ability to automatically input their personal usage data to provide more detailed and accurate audit results. The website will ultimately allow customers to access program information and incentive application forms over the Internet, as well as provide them with educational energy efficiency messages and tips appropriate for the season.

This new online outreach, auditing and education program will be followed up with a measurement and evaluation effort intended to provide the information necessary to determine therm (and kWh) acquisition and cost-effectiveness, as well as management information necessary for evaluating ongoing improvements to the program.

Portfolio Overview – Limited Income Residential

Avista's Washington and Idaho limited income programs are implemented in cooperation with six community action partnership (CAP) agencies. These CAP agencies are awarded an annual funding contract specifying the maximum funding amounts and the conditions for program implementation. Contracts can be revised with 30 days' notice, a provision that allows Avista to reallocate funds among the CAP agencies during the year to maximize their value to the customer base.

The CAP agencies and 2006 funding levels are summarized in Table 3.9. These amounts include a $200,000 increase above calendar year 2005 funding.

The company has approached the limited income segment with the intent to provide the maximum flexibility possible. This permits the agencies to respond to unexpected urgent needs and energy-efficiency opportunities that may not have been anticipated when the annual contracts were signed.

Table 3.8 – WA/ID Prescriptive Residential Gas Measures

High-efficiency natural gas furnace ($200 for AFUE 90% or better)
High-efficiency natural gas boiler ($200 for AFUE of 85% or better)
High-efficiency natural gas water heater ($25 for EF 0.60 [50 gallon] or 0.62 [40 gallon] or better)
Ceiling insulation (14 cents/SF for an added R-10 or more)
Attic insulation (14 cents/SF for an added R-10 or more)
Floor insulation (14 cents/SF for an added R-10 or more)
Wall insulation (14 cents/SF for an added R-10 or more)
High-efficiency windows (70 cents/SF of window for U-.35 or better)$3.00

Additional residential incentives are available for the conversion of space or water heating appliances from electric to natural gas.

Table 3.9 – WA/ID Community Action Program Contracts

Spokane Neighborhood Action Program (Spokane area)	$539,812
Community Action Agency (Idaho and Washington)	$447,772
Pullman Community Action (Whitman County)	$83,048
Grant County/North Columbia CAA (Grant County area)	$72,667
Northeast Rural Resources	$71,107
Klickitat CAA (Goldendale/Stevenson)	$2,300

As part of this flexibility, Avista allows the CAP agencies to expend up to 100 percent of their total funding on electric efficiency projects or up to 75 percent of their funds on natural gas efficiency projects. The funding available includes an allowable 15 percent remuneration to the agency for administrative and outreach costs. Up to 15 percent of the funds can be expended for health and human safety measures with an emphasis on the safe use of energy, and maintenance and repairs necessary to ensure the longevity of installed efficiency measures and continued habitability of the home.

The limited income residential segment delivered 17,277 first-year therms to the overall natural gas DSM program in 2004 (2 percent of the total acquisition that year). This therm acquisition represented 42 percent of the total BTU's acquired by the combined electric and natural gas programs.

AVISTA DSM COMMITMENT

Avista recognizes its obligation to meet the resource needs of customers in the most cost-effective manner. The delivery of natural gas efficiency programs is anticipated to represent an increasing portion of the optimal natural gas resource portfolio. The IRP process is an opportunity for the company to comprehensively review the natural gas efficiency program portfolio and make the revisions necessary to meet those commitments in the years to follow.

This document summarizes a broad evaluation of applicable natural gas efficiency opportunities and identifies those worthy of testing against all other possible resources to assist the company in making decisions about which of those natural gas efficiency resources are suitable to carry forward into program development.

The company solicited comments of key stakeholders regarding the selection, characterization and testing of natural gas efficiency opportunities within the IRP process. After much discussion and some revision, the general consensus of those stakeholders was that this approach was sufficient to represent natural gas efficiency opportunities within the IRP.

The company also agrees that it is cost-effective and appropriate to substantially ramp-up Oregon natural gas DSM programs, as well as to reconsider the approach to the implementation of those programs. This analysis has also established a tentative goal far in excess of previous commitments represented in Washington and Idaho Schedule 190 and slightly above recent acquisition levels.

Complete agreement was not possible regarding the likely customer reaction to several components of the enhanced Oregon natural gas DSM portfolio.
The company is concerned that market barriers will constrain participation. Avista is, and will remain, open to alternative approaches to overcoming those market barriers to include enhanced outreach efforts, revised incentives, and innovative marketing of natural gas efficiency programs and cooperative arrangements with other agents in the market, with particular attention to other natural gas utilities, the Energy Trust of Oregon and regional market transformation organizations with an interest in natural gas efficiency.

Additionally, the company is committed to maintaining a collaborative relationship with all stakeholders who may contribute to the improvement of natural gas DSM efforts as programs are further developed and launched. Additional metrics will be developed to improve the active management of these programs over time, as well as to provide better benchmarks for determining the regulatory prudence of these programs.

The company recognizes that this commitment to acquiring all cost-effective natural gas-efficiency potential is not limited by the therm acquisition goals established within this IRP. Avista's implementation of the results of this planning effort will be sufficiently flexible to realize those opportunities even if they are well in excess of expectations. Human and financial resources will be made available to the extent necessary to achieve the cost-effective potential without regard to those goals.

ACTION ITEMS

The completion of the IRP analysis is the midpoint, not the ending point, of a larger reassessment of the DSM resource portfolio. The IRP analysis presented has generally indicated a set of cost-effective measures and acquirable resource potential for a future DSM portfolio. These results remain in need of further evaluation to facilitate the development of program plans and to incorporate them into an updated DSM business plan.

The DSM analysis that occurred during the IRP process is the launching point for a more detailed investigation of the natural gas-efficiency technologies identified as cost-effective resource options.
The company initiated this additional evaluation and development of programs in January 2006 with the expectation that program revisions, and the launch of new programs will occur thereafter. The timing of partnership arrangements and the seasonality of the customer adoption of particular measures may influence the timing of those launches.

The company has explicitly recognized within this IRP the obligation to achieve all natural gas-efficiency resources available through the intervention of cost-effective utility programs. Given the rapid changes within the natural gas market, there are many new efficiency opportunities in the market. Considerable uncertainty remains regarding the customer response to these programs, however. This uncertainty does not preclude the company from pursuing the planned aggressive ramp-up of natural gas-efficiency programs throughout the service territory. Additionally, the company has, and will actively seek, opportunities for new or enhanced resource acquisition through the development of cooperative regional programs.

One of the results of the IRP process is a 20-year forecast of monthly avoided costs for each of the seven geographic areas. The detailed nature of these avoided costs makes it possible to continue to evaluate measures and programs as technology and markets change without the need to await the next IRP process. This is of value in determining program cost-effectiveness based on updated inputs, revised program plans and the ability to determine the value of targeting specific markets. Avoided cost determination is discussed in detail in Section 7.

As part of the program planning process, Avista will calculate all individually-evaluated measures and other measures, as necessary, for their cost-effectiveness in each of the individual Oregon divisions as well as within the Washington/Idaho division.

UPDATING THE PARAMETERS OF THE OREGON SITE-SPECIFIC COST-EFFECTIVENESS LITMUS TEST

For the past two years the company has made site-specific financial incentives available only to those projects that have passed a sub-TRC cost-effectiveness test. Upon the OPUC approval of revised avoided costs, this model will be updated and applied to future projects.

The potential energy savings from a programmable natural gas thermostat program is, in the opinion of the company, uncertain. Many credible sources have come to the conclusion that there are no energy savings from these devices based on the assumption that (a) many customers adjust non-programmable thermostats to obtain a degree of control that is equal or superior to that achievable from programmable thermostats; (b) many customers with programmable thermostats do not effectively use them as control devices; and (c) the ramping down of interior temperature when the thermostat sets back and the make-up heating required when it ends the set back period causes a loss in much of the expected efficiency impact.

Avista has past experience with a combined residential electric and natural gas programmable thermostat program. Based on an evaluation of these results and an updated survey of available literature, the company will reconsider previous conclusions regarding energy savings.

Participation in consideration of regional natural gas market transformation organization

Based on the company's assessment of natural gas efficiency programs in all three state jurisdictions, Avista has come to the tentative conclusion that there is a need for a regional natural gas efficiency market transformation organization similar to the Northwest Energy Efficiency Alliance. Partially based on Avista's actions, the Alliance will be initiating that discussion in 2006. Avista will be an active participant in that discussion.

CONCLUSION

This IRP provides Avista the necessary resource analysis to proceed to the further development and ultimate implementation of natural gas efficiency programs. In this process there will be additional evaluation of measures and programs and consideration of all alternatives, including, for the Oregon jurisdiction, cooperative arrangements with the ETO. Additionally, Avista intends to investigate the potential for wider regional cooperation among natural gas utilities for the implementation of selected efficiency measures based upon either a resource acquisition or market transformation business plan.

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SECTION 4 – DISTRIBUTION PLANNING

The primary goal of distribution system planning is to design for present needs and to plan for future expansion to serve demand growth. This allows the company to satisfy current demand-serving requirements while taking steps toward meeting future needs. Distribution system planning identifies potential problems and areas of the distribution system that require reinforcement either in the near- or mid-term. Knowing when and where pressure problems may occur, the necessary reinforcements can be incorporated into normal maintenance. Thus, more costly "reactive" and emergency solutions can be avoided.

COMPUTER MODELING

When designing new main extensions, computer modeling can help determine the optimum size facilities for present and future needs. Undersized facilities are costly to replace, and oversized facilities incur unnecessary expenses to the company and its customers.

THEORY AND APPLICATION OF STUDY

Natural gas network load studies have evolved in recent years to become a highly technical and useful means of analyzing the operation of a distribution system. Using a pipeline fluid flow formula, a specified parameter of each pipe element can be simultaneously solved. A variety of pipeline equations exist, each tailored to a specific flow behavior. Through years of research, these equations have been refined to the point where solutions obtained closely represent actual system behavior.

Avista conducts network load studies using Advantica Stoner's SynerGEE® 4.13 software. This is a computer-based modeling tool that runs on a Windows operating system and allows users to analyze and interpret solutions graphically.

CREATING A MODEL

To properly study the distribution system, all natural gas main information is entered (length, pipe roughness, and ID) into the model. "Main" refers to all pipelines supplying services.

Nodes (points where natural gas enters or leaves the system) are placed at all pipe intersections, beginnings and ends of mains, changes in pipe diameter/material and to identify all large commercial customers.

A model element connects two nodes together. Therefore, a "to node" and a "from node" will represent an element between those two nodes. Almost all of the elements in a model are pipes.

In the model, regulators are treated like adjustable valves in which the downstream pressure is set to a known value. Although specific regulator types can be entered for realistic behavior, the "expected" flow passing through the actual regulator is determined, and the modeled regulator is forced to accommodate such flows.

FLUID MECHANICS OF MODEL

Pipe flow equations are used to determine the relationships between flow, pressure drop, diameter and pipe length. For all models, the Fundamental Flow equation (FM) is used due to its demonstrated reliability.

Efficiency factors are used to account for the equivalent resistance of valves, fittings and angle changes within the distribution system. Starting with a 95 percent factor, the efficiency can be changed to fine tune the model to match field results.

Pipe roughness along with flow conditions creates a friction factor for all pipes within a system. Thus, each pipe may have a unique friction factor, minimizing computational errors associated with generalized friction values.

STEADY STATE COMPUTER SIMULATION

All studies are considered "steady state:" all natural gas entering the distribution system must equal the natural gas exiting the distribution system at any given time.

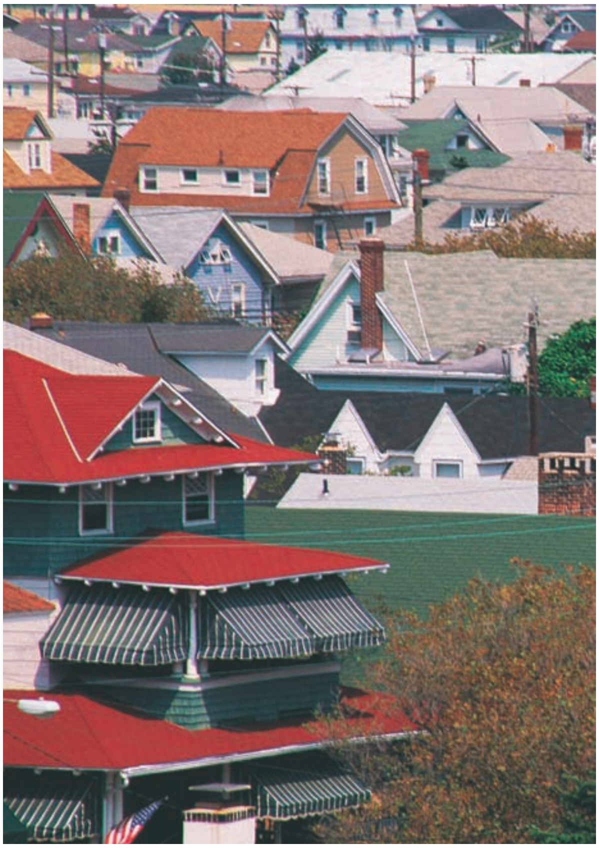
Customer loads are obtained from Avista's customer billing system and transferred to an algebraic format so loads can be generated for various conditions.

In the event of a peak day or an extremely cold weather condition, it will be assumed that all curtailable loads are interrupted. Therefore, the models will be conducted with only core loads unless otherwise stated.

DETERMINING NATURAL GAS CUSTOMERS' MAXIMUM HOURLY USAGE

Determining a Base Load

Base loads are not temperature dependent; they remain relatively constant regardless of temperature. A reasonable base load can be calculated from customer billing information. The billing month, which has the



lowest amount of heating degree-days is usually August. Usage during this month will reflect nearly all natural gas loads exclusive of space heating.

By determining the amount of days in the billing period and applying a "peaking factor," the "peak hourly base load" of each customer can be estimated as shown in Table 4.1.

Table 4.1 – Determining a Base Load

Customer Usage Billing Period	X	Days In Billing Period	X	0.0625*	=	**Peak Hourly Base Load**

*Note: The average residential customer's peak usage was found to be 6.25 percent of the total daily load. This "peaking factor" was estimated by studying the ratio of the peak hourly flow and the total daily flow at the pipeline gate stations (result = 6.25 percent of total daily load) in past years (1994-99). The peaking factor is periodically discussed with other utilities and has been shown as consistent with other utilities of similar size.

DETERMINING A HEAT LOAD

A heat load will be proportional to heating degree-days (HDDs); at 0 HDD, the load will be zero. A heat load can be reasonably calculated from customer billing information. The billing month with the greatest consumption is usually January. This month reflects maximum space heating loads as well as non-space heating loads.

Customer's usage for January (winter) billing, minus usage for August (summer) billing, leaves a reasonable estimate for heat load. This load can be divided by the amount of HDDs that occurred in January, leaving usage per HDD. Customer needs can be calculated by applying the peaking factor, resulting in a "peak hourly heat load" per HDD. This is shown in Table 4.2.

Table 4.2 – Determining a Heat Load

Customer Usage Winter Billing Period	–	Customer Usage Summer Billing Period	=	Heat Load Winter Billing Period

Heat Load Winter Billing Period	X	Winter Billing Period Degree Days	X	Design Degree Days Day	X	0.0625*	=	**Peak Hourly Heat Load**

DETERMINING A DESIGN PEAK HOURLY LOAD

Adding the hourly base load and hourly heat load for a design temperature results in the design peak hourly load for a customer. This estimate reflects highest system hourly demands, as shown in Table 4.3.

This method differs from the approach that the company takes for peak day/design day load planning. The primary reason for this difference is due to the hourly peak importance in distribution planning, while IRP resource planning is performed based on peak day requirements.

Table 4.3 – Determining a Design Peak Hourly Load

Peak Hourly Base Load	+	Peak Hourly Heat Load	=	**Design Peak Hourly Load**

APPLYING LOADS

Having estimated the peak loads for all customers in a particular service area, the model can be loaded. The first step is to assign each load to the respective node or element.

GENERATING LOADS

Temperature-based and non-temperature-based loads are established for each node, thus loads can be varied based on any temperature (HDD). Such a tool is necessary to evaluate the difference in flow and pressure due to different weather conditions.

GEOGRAPHIC INFORMATION SYSTEM (GIS)

The company is in the process of converting its natural gas facility maps to GIS. While a GIS can provide a variety of map products, its power lies in its analytical capability. A GIS consists of three components: spatial operations, data association and map production.

A GIS allows analysts to conduct spatial operations. A spatial operation is possible if a facility displayed on a map maintains a relationship to other facilities. Spatial relationships allow analysts to perform a multitude of queries, including:

- Identify electric customers adjacent to natural gas mains and who are not currently using natural gas;
- Display the ratio of customers to length of pipe in Emergency Operating Procedure zones (geographical areas defined by the number of customers and their safety in the event of an emergency); and
- Classify high-pressure pipeline proximity criteria.

The second component of a GIS is data association. Data association allows analysts to model relationships between facilities displayed on a map to tabular information residing in a database. Databases store facility information such as pipe size, pipe material, pressure rating, or related information (e.g., customer databases, equipment databases, and work management systems). Data association allows interactive queries within a map-like environment.

Finally, a GIS provides a means to create maps of existing facilities in different scales, projections and displays. In addition, the results of a comparative or spatial analysis can be presented pictorially. This allows users to present abstract analyses in a more intuitive context.

BUILDING SYNERGEE® MODELS FROM A GIS

A GIS can provide additional benefits through the ease of creation and maintenance of load studies. Avista can create load studies from a GIS based on tabular data (attributes) installed during the mapping process.

MAINTENANCE USING A GIS

A GIS helps maintain the existing distribution facility by allowing a design to be initiated on a GIS. Currently, design jobs for the company's natural gas system are managed through Avista's Work Management System (WMS). This system is being integrated with GIS, allowing jobs to be designed directly within a GIS. Once completed, the as-built information is submitted to GIS, and the facility is immediately updated. This eliminates the need to convert physical maps to a GIS at a later date. Because the facility is updated on GIS, load studies can remain current by refreshing the analysis.

DEVELOPING A PRESENT CASE LOAD STUDY

In order for any model to have accuracy, a "present case" model has to be developed that reflects what the system was doing when downstream pressures and flows are known. To establish the "present case," pressure charts located throughout the distribution are used.

Pressure charts plot pressure (some include temperature) versus time over several days. Various locations recording simultaneously are used to validate the model. Customer loads on SynerGEE® are generated to correspond with the actual temperatures recorded on the pressure charts. An accurate model's downstream pressures will match the corresponding location's "field" pressure chart. To further refine the model's pressures, efficiency factors are fine-tuned.

Since telemetry at the gate stations record hourly flow, temperature and pressure, such known values are also used to validate the model. All loads are representative of the average daily temperature and are defined as hourly flows. If the load generating method is truly accurate, all natural gas entering the "actual system" (physical) equals total natural gas demand solved by the "simulated" system (model).

DEVELOPING A PEAK CASE LOAD STUDY

Using the calculated peak loads, a model can be analyzed to identify the behavior during a peak day. The efficiency factors established in the "present case" are used throughout subsequent models.

ANALYZING RESULTS

After a model has been balanced, several features within the SynerGEE® model are used to translate results. Color plots are generated to depict flow direction, pressure, pipe diameter and gradient with specific break points. Thus, attributes of a reinforcement can be queried by visual inspection. When user edits are completed and the model is re-balanced, pressure changes can be visually displayed, helping identify optimum reinforcements.

An optimum reinforcement will have the largest pressure increase per unit length. Reinforcements can also be deferred and occasionally eliminated through load mitigation of DSM efforts.

PLANNING CRITERIA

In most instances, models resulting in node pressures below 15 psig indicate a likelihood of distribution failure and therefore necessitate reinforcements.

For most Avista distribution systems, a minimum of 15 psig will ensure deliverability as natural gas exits the distribution mains and travels through service pipelines to a customer's meter.

Some Avista distribution areas operate at lower pressures and are assigned a minimum pressure of 5 psig for model results. Given a lower operating pressure, service pipelines in such areas are sized accordingly to maintain reliability.

DETERMINING MAXIMUM CAPACITY FOR A SYSTEM

Using a peak day model, loads can be prorated at intervals until area pressures drop to 15 psig. At that point, the total amount of natural gas entering the system equals the maximum capacity before new construction is necessary. The difference between natural gas entering the system in this scenario and a peak day model is the maximum "additional" capacity that can be added to the system.

Since the approximate natural gas usage for the average customer is known, it can be determined how many new customers can be added to the distribution system before necessitating system reinforcements.

The above models and procedures are utilized with new construction proposals or pipe reinforcements to determine a potential increase in facilities.

FIVE-YEAR FORECASTING

The intent of Avista's load study forecasting is to predict the system's behavior and what reinforcements will be necessary within the next five years. Various Avista personnel provide information to determine where and why certain areas may experience growth.

By combining information from Avista's demand forecast, IRP planning efforts, regional growth plans and

Table 4.4 – Capital Reinforcement Projects with Estimated Costs in 2005$

Project Description	STATE	2005	2006	2007	2008	2009	2010
Bruce Rd. H.P. Reinforcement	WA	$2,050,000					
Klamath Falls H.P. Feeder Re-route	WA	$40,190		$950,000	$1,500,000		
Transmission Reinforcement – Medford	OR		$1,194,388	$10,000,000			
Diamond Lake Reinforcement	OR		$1,622,472	$1,500,000			
Grants Pass South Side Reinforcement	OR		$304,556				
Eagle Pt High Pressure Reinforcement	OR	$1,100,000					
Elgin Line H.P. Reinforcement	OR					$1,600,000	$1,700,000
Medford Airport H.P. crossing	OR				$1,000,000		
Sutherlin 6"	OR	$170,000					
Merlin Gate Station Rebuild	OR	$102,714		$450,000			
Dover Gate Station	ID		$615,813				
Klamath Falls Lateral Acquisition	OR			$3,100,000			
La Grande/Elgin H.P. Reinforcement	OR				$1,000,000	$1,000,000	$1,000,000

area developments, proposals for pipeline reinforcements and expansions can be evaluated with SynerGEE®. A current list of management approved proposed reinforcement projects for the company is shown in Table 4.4.

SUMMARY

The company's goal is to maintain its distribution systems in order to reliably deliver natural gas to every customer with the most cost-effective investment. This goal can be better achieved with computer modeling.

Computer modeling increases the reliability of the distribution system by identifying specific areas within the system that may require changes.

SynerGEE® models are constantly used to look at different areas within the company's natural gas service area. Natural gas system planning, construction, budgeting and prioritization are conducted from these analyses. Additionally, pipeline constraints and improvements are reviewed internally to facilitate supply and demand optimization.

SECTION 5 – SUPPLY-SIDE RESOURCES

Avista's supply philosophy is to reliably provide natural gas to its customers with an appropriate balance of price stability and prudent cost. To that end, Avista continuously evaluates a variety of supply resources and attempts to build a portfolio that is appropriately balanced and diversified to achieve cost effectiveness. The hedging program resulting from that continuous evaluation addresses physical and financial risks, both of which are covered in this section.

This section describes natural gas commodity resources, transportation arrangements used to connect those supply resources to Avista's demand regions, and market-related risks and ways that Avista mitigates those risks.

COMMODITY RESOURCES

Avista has a number of supply options available to serve Avista's core customers. These include firm and non-firm supplies, firm and interruptible transportation on six interstate pipelines, and two storage projects. Because Avista's core customers span three states, the diversity of delivery points and demand requirements adds to the options available to meet customers' needs. The utilization of these components varies depending on demand and operating conditions.

Avista is located near several liquid hubs and supply basins in western North America, including Alberta and British Columbia in Canada, and the Rocky Mountain region in the United States. Avista's unique access to a diverse group of supply basins, coupled with the diversity of delivery points, allows the company to purchase at the lower-priced trading hubs on any given day, subject to operational and contractual constraints.

The three major supply points near Avista's service area are Sumas (located north of Seattle at the U.S./Canadian border), AECO (northeast of Spokane in Alberta, Canada) and the Rockies (a number of natural gas production pools in Wyoming, Utah, Colorado and New Mexico). The price for natural gas at these three supply points generally moves together. However the basis differential among the supply points can change depending on a variety of market or

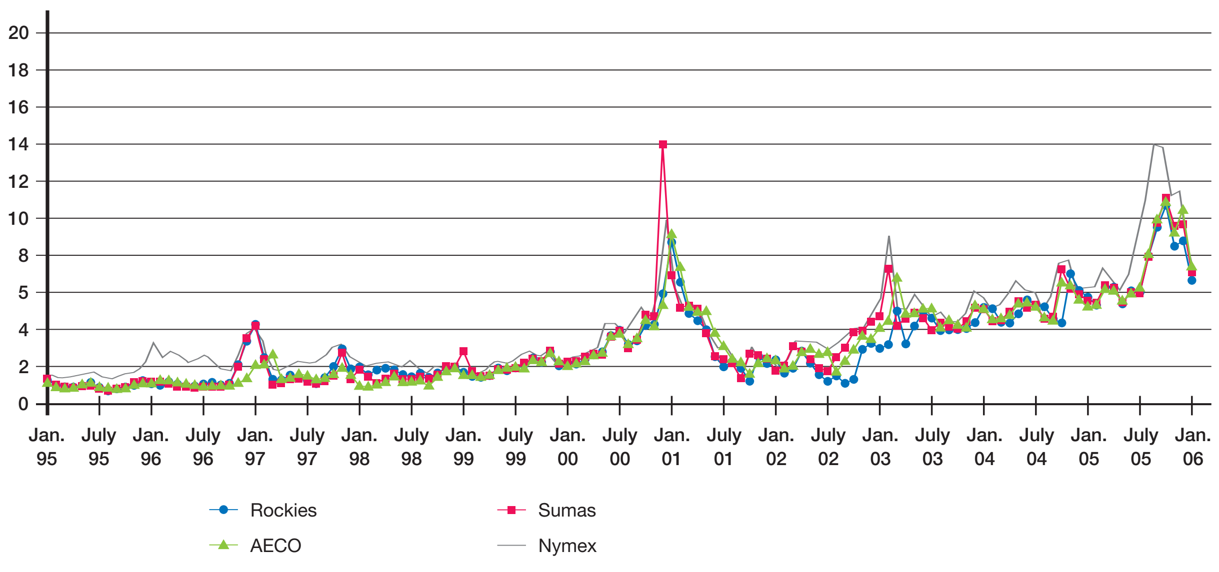
operational factors, including differences in weather patterns, pipeline constraints at different locations and the ability to shift supplies to higher-priced delivery points elsewhere in the United States or Canada. Based on market information and analysis, Avista believes there is sufficient liquidity at the three supply points such that there will be as much commodity available as the company requires to meet demand.

Given the transportability of natural gas to other portions of North America, natural gas pricing is often compared to the Henry Hub price for natural gas. Henry Hub is a natural gas trading point located in Louisiana and is widely recognized as the primary natural gas pricing point in the United States. NYMEX futures contracts are priced at Henry Hub. Figure 5.1 illustrates the tight relationship among the various locations and shows historic natural gas prices for physical purchases at Henry Hub, AECO, Sumas and the Rockies.

Contract Provisions – There are a number of contract specifics that vary from transaction to transaction, and many of those terms or conditions have an impact on the pricing of the commodity. Some of the agreed-upon terms and conditions include:

- **Firm vs. Non-Firm –** Most term contracts specify that supplies are firm except for *force majeure* conditions, and the standard provision for daily transactions is that they may be cut for reasons other than force majeure conditions.
- **Fixed vs. Floating Pricing –** The agreed-upon price for the delivered gas may be a fixed price or based upon a daily or monthly index.
- **Physical vs. Financial –** Certain counterparties, such as banking institutions, do not trade physical natural gas but are still active in the natural gas markets. Rather than managing physical supplies, those counterparties choose to transact financially rather than physically. Financial transactions provide another way for Avista to financially hedge price.
- **Load Factor/Variable Take –** Some contracts have fixed reservation charges assessed during each of the winter months, while others have minimum daily or monthly take requirements. Depending on the specific provisions, the resulting commodity price will contain a

Figure 5.1 – January 1995 to Freburary 2006 Monthly Index Nymex/Rockies/Sumas/AECO



- discount or premium when compared to a standard product.
- **Liquidated Damages** – Most contracts contain provisions for symmetrical penalties for failure to take or supply natural gas according to contract terms.

For the purposes of this IRP, the SENDOUT® model assumes the natural gas is purchased as a firm, physical, fixed-price contract regardless of when the contract is executed and what type of contract it is. However, in reality, Avista explores a variety of contractual terms and conditions in order to capture the most value from each transaction.

STORAGE RESOURCES

The company is one-third owner, with NWP and Puget Sound Energy (PSE), in the Jackson Prairie Storage Project for the benefit of its Washington and Idaho customers. Avista has contracted for service in this underground natural gas storage project for its Oregon customers and has contracted for LNG storage at Plymouth to serve core customers in all three states. Jackson Prairie Storage is an underground reservoir project located near NWP's mainline near Chehalis, Wash. Plymouth LNG is a liquefied natural gas storage facility located near NWP's mainline near Plymouth, Wash.

Storage is a strategic resource due to the company's low load factor. Storage provides the following benefits:

- Provides invaluable peaking capability;
- Reduces the need for higher cost annual firm transportation;
- Increases the load factor of existing firm transportation; and
- Provides access to normally lower cost summer supplies.

Table 5.1 recaps the current storage resources by area.

JACKSON PRAIRIE STORAGE PROJECT

In the early 1980s, Avista determined it did not then need its entire Jackson Prairie storage capacity to meet firm system requirements. In 1982, Avista released half of its capacity and deliverability at Jackson Prairie to BC Hydro. The primary term of the original contract was set to expire in 1996, with a provision for year-to-year continuation thereafter. The new contract with Terasen, successor to BC Hydro for natural gas operations, has been in place since 1996, with recall provisions after 2000. This arrangement retains the storage capacity for Avista's future use, while providing a return on Avista's investment in the form of rental payments until such time as the additional capacity is needed. The annual renewal of this contract is analyzed each year to determine the appropriateness of continuing this agreement with Terasen.

In 1990, Avista made a similar, although smaller, release to Cascade Natural Gas Company (Cascade). As with the Terasen release, this release to Cascade retains the storage capacity for Avista's future need and is analyzed each year to determine the appropriateness of continuing this arrangement. The release of storage rights includes a similar amount of firm transportation, whereas the Terasen release does not include a transportation release. In March 2006, Avista notified Cascade that this release will be terminated pursuant to the contractual provisions. The recall will be effective April 30, 2007.

In 1999, and again in 2002, Avista participated in capacity expansions of the Jackson Prairie Storage Project with NWP and Puget Sound Energy. It was determined that the additional capacity for core utility customers was not needed at that time, and it went under the management of Avista Energy. The company has an option to take this capacity back as soon as November 2009.

The 2002 expansion is a phased, ongoing project to increase the storage capacity of the field. The 2002 expansion has progressed at a slower pace than originally planned and will be approximately 50 percent complete in mid-2006. Additionally, the partners in Jackson Prairie are currently studying the feasibility of expanding the daily withdrawal capability. The target of this expansion study is to increase daily deliverability by 300 MMcfd by the fall of 2008.

Avista continues to evaluate its Jackson Prairie capacity and deliverability requirements to determine if it should continue present releases, call back some or all capacity, negotiate additional releases or participate in future expansions of the project.

TRANSPORTATION RESOURCES

Although proximity to the liquid hubs is important from a cost perspective, those supplies are only as reliable or firm as the pipeline transportation that moves the supplies from the hubs to Avista's service territory. Consequently, Avista has contracted for a sufficient amount of firm pipeline capacity so that firm deliveries will meet design day demand. Avista believes the combination of firm transportation rights to its service territory, storage facilities and access to liquid supply basins will ensure peak supplies are available to its core customers.

The company has many contracts with NWP and GTN for firm and interruptible transportation to serve the core customers. In addition to this capacity, Avista also contracts for capacity on upstream pipelines to flow natural gas to NWP and GTN. Table 5.1 details the firm transportation/ resource services contracted by Avista. These contracts are of different vintages, thus different expiration dates. However, all have the right to be renewed by Avista. This gives the company and its customers the knowledge that Avista will have available capacity to meet core load demand now and in the future.

NWP and GTN also provide interruptible transportation service to the company. The level of service of interruptible transportation is subject to curtailment when pipeline capacity constraints limit the amount of natural gas that may be moved. Although the commodity cost per dekatherm transported is the same as firm transportation, there are no demand or reservation charges connected with these transportation contracts. Since the marketplace for capacity release of transportation capacity has become so prevalent, the use of interruptible transportation services has diminished. Avista does not rely on interruptible capacity to meet design day core demand requirements.

The company's strategy is to contract for firm transportation to serve core customers should a design peak day occur in the near-term planning horizon. Too much firm transportation could keep the company from achieving its goal of being a low-cost energy

Table 5.1 – Current Maximum Available Firm Transportation/Resources
Dth/Day

	Avista North		Avista South	
Firm Transportation 1/	*Winter*	*Summer*	*Winter*	*Summer*
NWP TF-1	143,270	143,270	33,731	33,731
GTN T-1	100,605	75,782	42,260	20,640
NWP TF-2 (JP) 3/	91,200		2,654	
NWP TF-2 (LNG)	22,000		19,200	
Total	**357,075**	**219,052**	**97,845**	**54,371**
Upstream Transportation 1/				
Duke	7,914	7,914	1,856	1,856
TransCanada Alberta Sys.	103,434	90,565	43,489	24,658
TransCanada BC System	101,953	94,084	42,867	25,616
Firm Storage Resources 1/				
JPSP (SG) 3/	127,667		2,623	
NWP LNG (LS-1)	22,000		19,200	
Total	**134,667**		**21,823**	
Other Peaking Arrangements				
Williamette Ind. Agreement 2/			12,000	

1/ Contract expiration dates vary but in each instance, other than with the Williamette Peaking Agreement, Avista holds a unilateral evergreen or right of first refusal to retain the capacity indefinately. All figures are net of non-recallable currently effective releases.
2/ This peaking arrangement allows for up to 20 days of deliveries in the Medford area served off of NWP. This contract expires in 2010. Upon expiration, 12,000 Dth/day of released annual capacity will return to Avista under NWP's TF-1 rate schedule.
3/ Includes JP Storage/Capacity recall for 15,000 Dth/d of TF-2 transportation and 15,000 Dth/d of deliveribility from JP (along with 480,000 Dth of Capacity).

Table 5.2 – Current Transportation/Storage Rates and Assumptions
Rates in US$/Dth/Day

	Reservation	*Commodity*	*Fuel Rate 4/*	*Rate Change Assumptions*
TransCanada Alberta System Firm Rates -				
Postage Stamp Rates				
AECo/NIT to ABC	0.1340	-	0.00%	Change annually at GDP
AECo/NIT to ABC Winter Only	0.1675	-	0.00%	Change annually at GDP
TransCanada BC System Firm Rates -				
Postage Stamp Rates				
ABC to Kingsgate	0.0550	0.0030	1.00%	Change annually at GDP
GTN FTS-1 Rates -				
Mileage Based - Representative Example				
Kingsgate to Spokane	0.0690	0.0015	0.32%	10% rate increase on 11/06 and GDP thereafter
Kingsgate to Medford	0.2499	0.0078	1.80%	10% rate increase on 11/06 and GDP thereafter
Meford Lateral	0.5607	-	0.00%	10% rate increase on 11/06 and GDP thereafter
Duke/Westcoast System Firm Rates -				
Postage Stamp Rates				
Station 2 to Huntington/Sumas	0.2650	-	2.00%	Change annually at GDP
Williams NWP				
Postage Stamp Rates				
TF-1 1/	0.2776	0.0319	1.77%	25.22% rate increase on 11/06 and GDP thereafter
TF-2 1/	0.2776	0.0319	1.77%	25.22% rate increase on 11/06 and GDP thereafter
SGS-2F 2/	0.5137	0.0189	0.16%	25.22% rate increase on 11/06 and GDP thereafter
LS-1 3/	0.8918	0.5569/0.0303	2.66%	25.22% rate increase on 11/06 and GDP thereafter

1/ TF-1 based upon annual delivery capability. TF-2 based upon approximately 32 days of delivery capability
2/ Not applicable for WA/ID Customers
3/ The commodity rate for LS-1 service is for injection and withdrawals
4/ Fuel retained in-kind

provider, but it is important to maintain an appropriate time cushion such that Avista allows for required lead times for new capacity. The ability to release capacity acts to offset the cost of holding underutilized capacity. Too little firm transportation impairs the company's goal of being a reliable energy provider.

Note about the Rate Change Assumptions in Table 5.2: Forecasting future pipeline rates is difficult, if not impossible. Avista's assumptions for future rate changes were the result of market information and concurrence by members of the TAC. Williams NWP has indicated to various parties that it intends to file a pipeline rate case in mid-2006, and it is commonly anticipated that GTN will also file a rate case in 2006. Beyond those expectations, it is assumed that the pipelines will file to recover costs at rates equal to the GDP.

Determining the appropriate level of firm transportation is a complex evaluation of many factors, including the projected number of firm customers and their expected demand on an annual and peak day basis, opportunities for future pipeline or storage expansions, and relative costs between pipelines and their upstream supplies.

MARKET-RELATED RISKS AND RISK MANAGEMENT

While risk management can be defined in a variety of ways, this IRP focuses on two areas of risk: the financial risk under which the cost to supply customers will be unreasonably high or unreasonably volatile, and the physical risk that there may not be enough natural gas (either the transportation capacity or the commodity) to serve Avista's core customers.

Avista has a risk management policy that describes in more detail the policies and procedures associated with financial and physical risk management. The risk management policy addresses, among other things, issues related to management oversight and responsibilities, internal reporting requirements, documentation and transaction tracking and credit risk.

Additionally, there are three internal organizations that assist in the establishment, reporting and review of Avista's business activities as they relate to management of natural gas business risks:

- The Risk Management Committee consists of several corporate officers and other senior-level management. The Risk Management Committee receives regular reports on natural gas activity and meets regularly to discuss market conditions, hedging activity and other natural gas-related matters.
- The Strategic Oversight Group (SOG) exists to coordinate natural gas matters among internal natural gas-related stakeholders and to serve as a reference/sounding board for strategic decisions, including hedges, made by the Natural Gas Supply department. Members include representatives from the Accounting, Rates and Risk Management departments. While the Natural Gas Supply department is responsible for implementing hedge transactions, the SOG provides input and advice.
- A Natural Gas Coordination Committee involves Natural Gas Supply, Demand-Side Management, Natural Gas Engineering, Rates, Accounting, Natural Gas Operations and customer representatives to ensure that the various departments are maintaining lines of communication and coordinating efforts with respect to natural gas-related projects.

MARKET FACTORS AND AVISTA'S PROCUREMENT PLAN

Avista cannot predict future natural gas prices. The company has designed a natural gas procurement plan that attempts to competitively acquire natural gas supplies while reducing exposure to short-term volatile movements in prices. Although the specific provisions of the procurement plan will change over time as a result of ongoing analysis and experience, the following principles reflect Avista's philosophy of its procurement plan:

- **Avista employs a time-diversified approach to hedging its loads –** It is appropriate to hedge over a period of time, and Avista establishes windows within which portions of its future loads are financially hedged. While this means that the financial hedges may not be completed at the lowest possible price, it also protects Avista and its customers from price spikes.
- **Avista establishes a disciplined approach to hedging its loads –** In addition to establishing windows within which hedges are to be completed, there are also upper and lower pricing points. In a rising market, this reduces the company's exposure to extreme price spikes. In a declining market, this encourages the company to capture the value associated with the lower price.
- **Avista regularly reviews its procurement plan in light of current market conditions and opportunities –** Avista has a dynamic plan with ongoing review of the assumptions leading to the procurement plan. For example, Avista historically hedged seasonal and annual loads up to one year out. Avista has been conducting research with respect to multiple-year contracts and has recently increased the tenor on a portion of its hedges beyond one year. Another recent area of focus has been the percentage of load that is financially hedged. Over the last several years, Avista hedged approximately 50 percent of its

load. More recently, Avista has modified its procurement plan to increase that percentage in an effort to reduce the volatility of its portfolio.

A number of tools are available to the company to help mitigate its financial risks. Many of these tools are financial instruments or derivatives that can be utilized to provide fixed prices or dampen price volatility. Avista will further evaluate how to manage daily load volatility, whether through option tools available from counterparties or through access to additional storage capacity.

Avista believes it can strengthen the analysis leading to certain hedges and future modifications to its natural gas procurement plan. Accordingly, staff will be evaluating the addition of a planning model called VectorGas™ during the two-year action period for this plan. VectorGas™ was developed by New Energy Associates as an addition to the SENDOUT® model that facilitates the ability to model price and load uncertainty. VectorGas™ will allow Avista to model various hedging strategies and evaluate their different impacts on cost and volatility of the overall portfolio. If Avista elects to purchase VectorGas™, the product would likely be implemented in 2006.

EMERGING SUPPLY ISSUES

The market for natural gas has undergone dramatic changes over the last several years, as the commodity market has transitioned from a regionally-based market to a nationally-based, and perhaps globally-based, market. This transition can be attributed to several reasons, including:

- **Growing national pipeline infrastructure –** Pipeline capacity out of the supply regions has increased, both in volume and delivery points. As a result, natural gas prices in the Pacific Northwest have become more dependent on demand and prices in regions as far away as the east coast.
- **Increasing correlation among natural gas and oil prices –** The relatively recent run-up in natural gas prices has in some ways mirrored the sharp increase in crude oil prices over the last year. This can be explained by fuel switching capabilities of some industrial consumers in the United States and the increased presence of non-utility energy investors that may simply be trading BTUs.
- **The potential of LNG to be the marginal source of natural gas in the United States –** Several projections indicate that over the next 10 years there will be a growing gap between North American natural gas production and North American demand for natural gas. The consensus is that LNG will supply the gap. Should this occur, there will naturally be global price competition for LNG. Avista has been, and will continue to be, involved in discussions about LNG as a potential supply resource.
- **Pipeline rate increases –** There is more pipeline capacity from supply sources to markets than is currently needed in many regions in North America. This excess capacity has caused capacity holders with expiring contracts to consider relinquishing this capacity back to the pipelines.

Many capacity holders have shown a preference to turn-back transportation contracts where transportation expenses exceed the value of this transportation. The result of this action from a pipeline perspective is to cause affected pipelines to consider filing rate cases to recover some or all of the lost revenues. Distribution companies that rely on firm supplies and transportation will likely continue to hold their transportation contracts and may end up paying higher transportation rates depending on the FERC's approach to this issue.

- **Pipeline constraints –** Although there now may be, or will be in the future, excess pipeline capacity in many parts of the country, the market or delivery portion of most pipelines remains heavily contracted. This is due to the fact that end-users such as LDC's and industrial customers prefer certainty of supply. Avista and other consumers in the Pacific Northwest continue to hold all of the NWP capacity and existing lateral capacity on NWP and GTN. Of particular concern to Avista is NWP's Grants Pass Lateral in Western Oregon. This lateral is fully contracted, demand is continuing to grow in the demand centers along this lateral, and it is not easily or inexpensively expanded.

SECTION 6 – INTEGRATED RESOURCE PORTFOLIO

This section describes how the company brings together all the previously discussed components that are part of the IRP process, the model the company utilizes for this process, and determines if, over the 20-year planning horizon, the company is resource deficient. This section also provides an analysis of potential resource options and displays the model-selected least cost resource options to serve resource deficiencies.

The foundation for integrated resource planning is the demand planning criteria utilized for the development of demand forecasts. Avista believes that the appropriate planning standard for peak day demand is the "coldest day on record" standard utilized by many other natural gas utilities. Given this approach, Avista utilizes historic peak and average weather data for each demand region as a basis for this IRP. It is also important to note that Avista plans to serve this expected peak for each demand region utilizing only firm resources. These firm resources include natural gas supplies, pipeline transportation and storage resources. It is also important to note that, in addition to planning for peak requirements, the company also plans for non-peak periods such as winter, shoulder and summer demand. The company's modeling process includes running the optimization every day of the 20-year planning period.

It is assumed that on a peak day all interruptible customers have left the system in order to provide service to firm customers. The company does not make firm commitments to serve interruptible customers. Therefore, the company IRP analysis of demand serving capabilities only focuses on the residential, commercial and firm industrial classes. These three customer classes are collectively referred to as "core" customers.

Avista supply forecasts are increased between 1.0 percent and 3.0 percent on both an annual and peak day basis to account for additional supplies that are purchased primarily for pipeline fuel for compressor stations. The percentage of additional supply that must be purchased is governed through the FERC and National Energy Board tariff filings of the pipelines.

NATURAL GAS RESOURCE MODEL

The natural gas resource optimization model used by the company is the SENDOUT® Gas Planning System from New Energy Associates (NEA), a subsidiary of the Siemens Westinghouse Power Corp. The SENDOUT® model was purchased in April 1992 and has been used in the preparation of all IRPs since then. The company has a long-term maintenance agreement with NEA that allows Avista to receive updates to the software as enhancements are made. These enhancements encompass software corrections and improvements, and enhancements to the software brought on by industry change.

SENDOUT® is a PC-based linear programming model widely used to solve natural gas supply and transportation optimization questions. Linear programming is a proven technique used to solve minimization/maximization problems. SENDOUT® looks at the complete problem at one time within the study horizon, taking into account physical limitations and contractual constraints. The software looks at thousands of variables and evaluates thousands of possible solutions in order to generate the least-cost solution. Among the variables required by the model are:

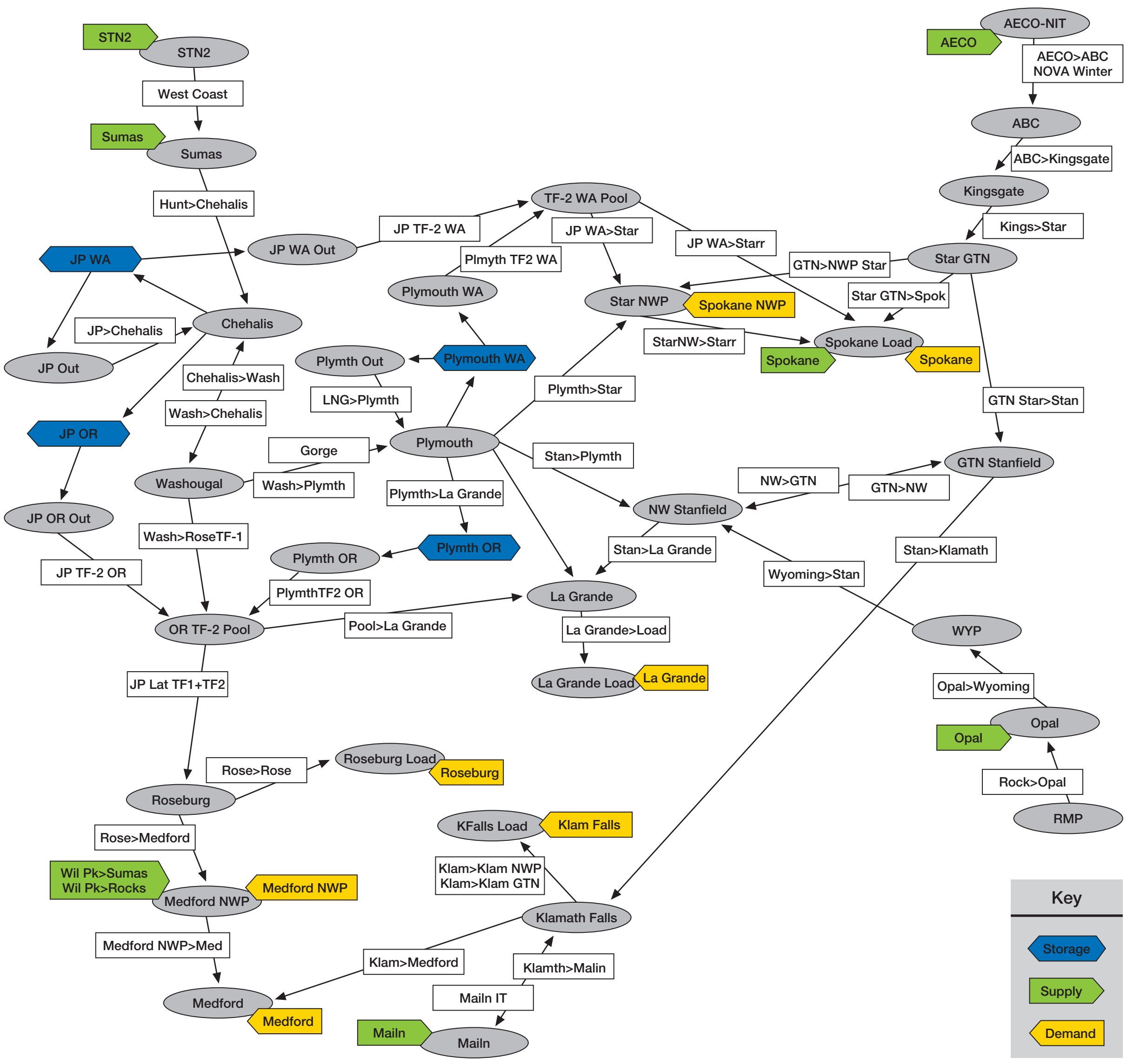
- Demand data such as customer count forecasts and demand coefficients by customer type, e.g. residential, commercial, industrial;
- Heating degree-day (HDD) weather information;
- Existing and potential transportation data which describes to the model the network for the physical movement of the natural gas and associated pipeline costs;
- Existing and potential supply options, including supply basins and prices;
- Natural gas storage options with injection/withdrawal rates, capacities and costs; and
- Demand-side management programs.

The SENDOUT® model gives the company a flexible tool with which to analyze a multitude of potential scenarios such as:

- Analysis of pipeline capacity needs and capacity releases;
- Effects of different weather patterns upon demand;
- Effects of natural gas price increases upon total natural gas costs;
- Storage optimization studies;
- Resource mix analysis for demand-side management programs;
- Analysis of transportation costs; and
- Short-term planning comparisons.

The SENDOUT® model provides the company with valuable information used as the framework for developing numerous studies relating to capacity release, storage optimization, peaking supply needs, DSM resource mix, avoided cost calculations, and weather

Figure 6.1 – SENDOUT® Model Diagram



pattern testing and analysis. An example of some of the information used in the model is illustrated in Figure 6.1, which is the SENDOUT® Model Diagram. This diagram illustrates the company's current transportation and storage assets, flow paths and constraint points.

As discussed previously, the company is evaluating the addition of the VectorGas™ software package from NEA. VectorGas™ is an add-on to the SENDOUT® model that facilitates the ability to model price and demand uncertainty through Monte Carlo simulation and detailed portfolio optimization techniques that ultimately produces probability distribution information. This additional software package may enhance Avista's IRP analytical capabilities, and the evaluation will be completed before the next IRP process commences.

ANALYSIS FRAMEWORK

The approach used to analyze Avista's long-range natural gas planning options focuses on the sensitivity of the optimization model to periodic (daily, monthly, seasonal and/or annual) changes in:

- Assumptions related to customer growth and customer natural gas usage that ultimately form demand forecasts;
- Existing and potential transportation and storage options;
- Existing and potential natural gas supply availability and pricing;
- Weather assumptions; and
- Demand-side management and avoided cost.

Avista has reviewed and performed rigorous analysis on each of the aforementioned areas and provides the following detail.

DEMAND FORECASTING APPROACH

Avista's demand forecasting approach is described in Section 2.

Avista forecasts demand in the SENDOUT® model in five areas due to the existence of distinct weather and demand patterns for each area. The areas within SENDOUT® are Washington/Idaho (further disaggregated to two sub-areas due to pipeline flow limitations), Medford (further disaggregated to two sub-areas due to pipeline flow limitations), Roseburg, Klamath Falls and La Grande. In addition to area distinction, Avista also models demand by customer class within each of these areas. The relevant customer classes within the Avista service territory for this IRP are residential, commercial and firm industrial sales. It is important to note that not all classes of customers currently exist or are forecasted to exist in each demand area.

Figures 6.2 and 6.3 show historic non-weather normalized average demand for core customers by region for January 1998 through June 2005.

Figure 6.2 – WA/ID Historical Monthly Average Demand
(1/98 - 6/05)

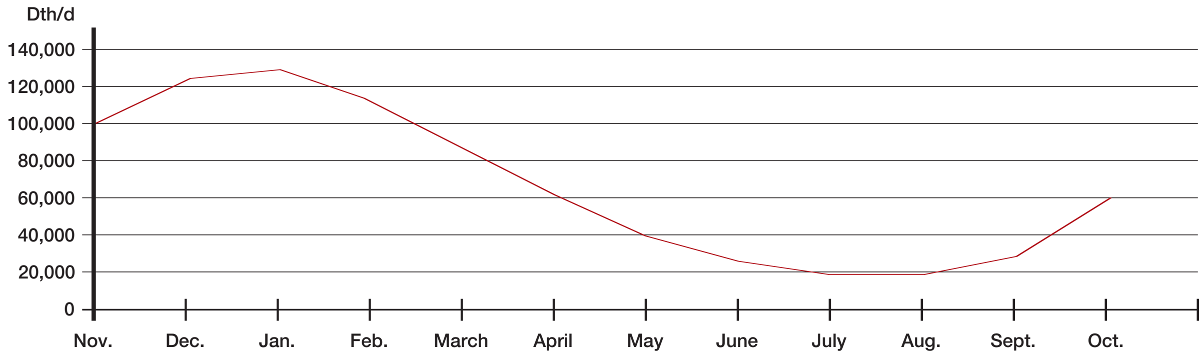
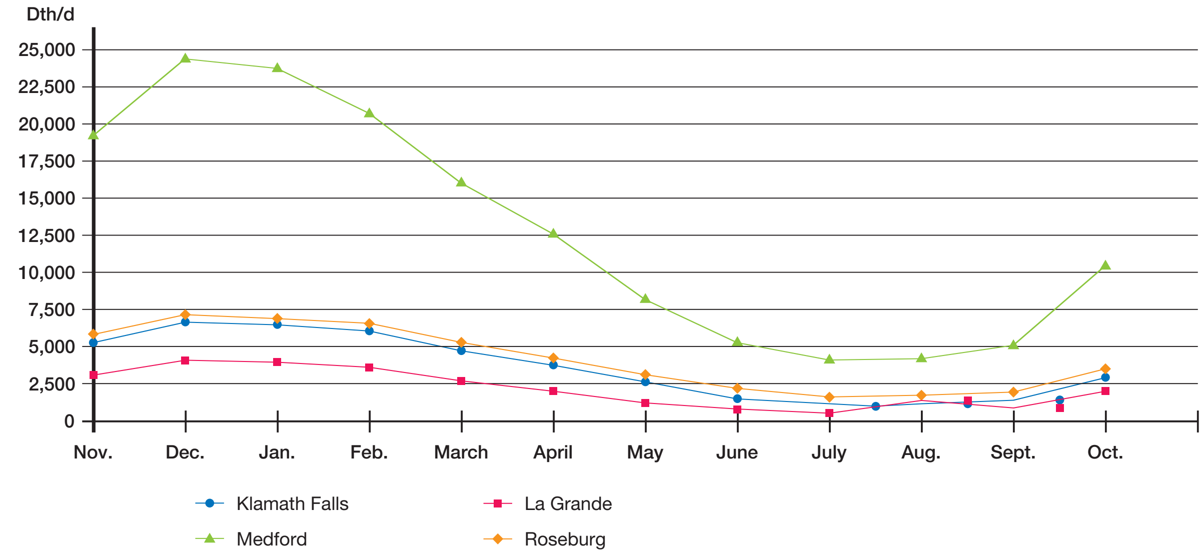


Figure 6.3 – Oregon Historical Monthly Average Demand
(1/98 - 6/05)



The company uses its SENDOUT® model to forecast customer demand and has calibrated the demand forecasting component of the SENDOUT® model through a meticulous back casting process. A back cast uses the algorithm developed for forecasting purposes and applies it to known historical data as a means of testing the validity of that algorithm.

As described in Section 2, and given experience with customers' price elasticity, Avista believes it is possible that the current and future high prices will impact natural gas demand in a lasting fashion.

As stated in Section 2, Avista created nine scenarios as a three-by-three matrix using low, medium and high price scenarios crossed with low, medium and high customer growth scenarios to better explore demand forecasts for this IRP.

Figure 6.4 – Average vs. Coldest vs. Warmest (84/85 plus 82 HDD, NOAA) Spokane Weather
(November - October)

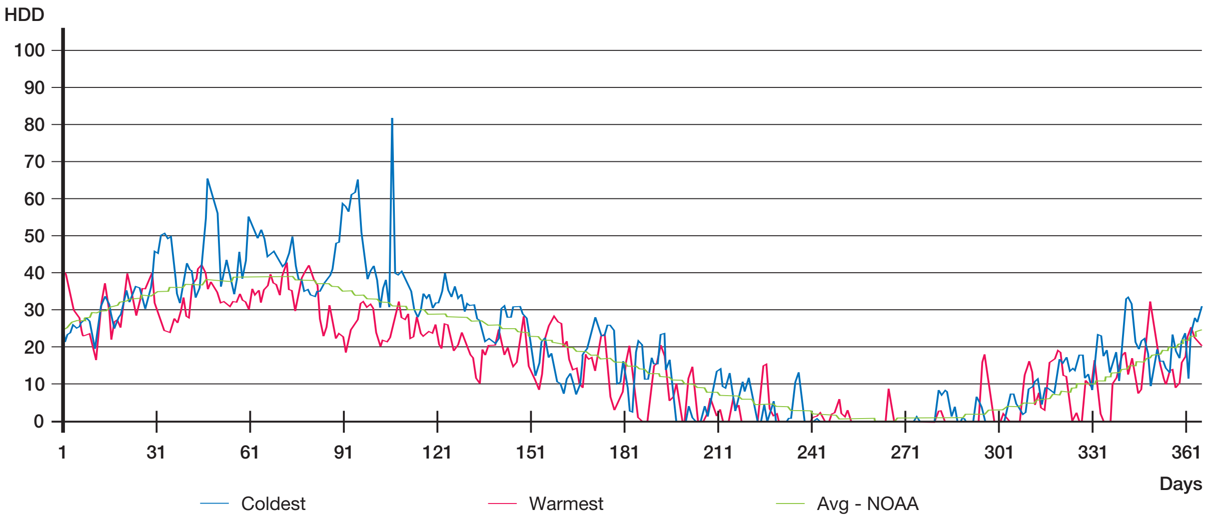
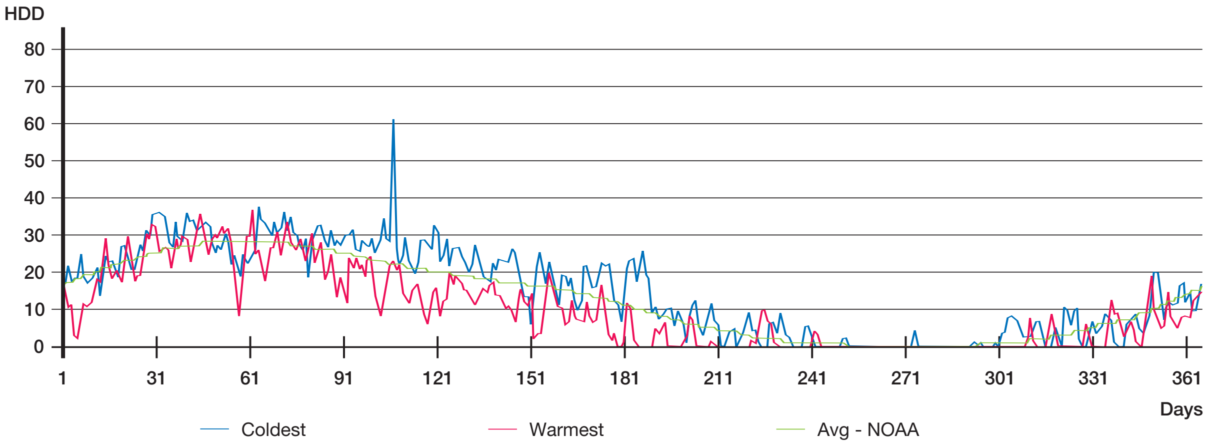


Figure 6.5 – Average vs. Coldest vs. Warmest (63/64 plus 61 HDD, NOAA) Medford Weather
(November - October)



WEATHER ASSUMPTIONS

Avista demand reflects a weather dependent customer base. Therefore, the study of weather becomes very important in integrated resource planning. The figures below show core demand compared to actual HDDs. The analysis in this IRP is based on the weather data as published by the National Oceanic Atmospheric Administration (NOAA). This is a 30-year weather study spanning 1971-2000. Figures 6.4 and 6.5 show the NOAA 30-year average weather data in comparison to the coldest and warmest planning year in history for the Spokane and Medford areas. Measurements of historical average weather do not represent the range of potential future weather patterns, including days that may differ substantially from that average pattern.

Figures 6.6 and 6.7 compare the NOAA 30-year average weather with a company-selected composite of weather months that form a weather year based on average heating degree-days with the variability of actual weather.

On Dec. 30, 1968, the North Operating Division area experienced the coldest day on record, an 82

Figure 6.6 – NOAA 30-year Average vs. Planning Weather (added 82 HDD on Feb. 15) Spokane Weather
(November - October)

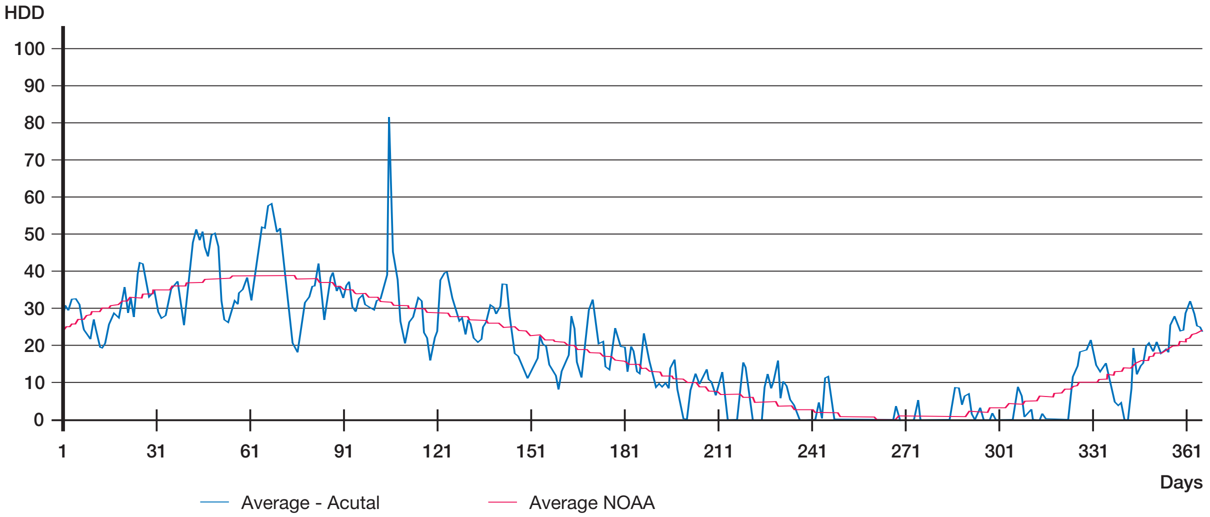
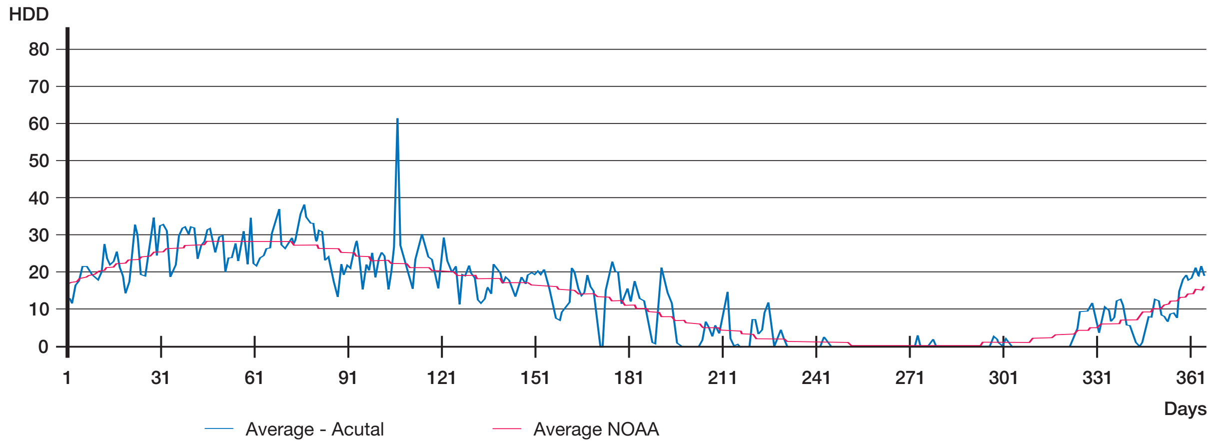


Figure 6.7 – NOAA 30-year Average vs. Planning Weather (added 61 HDD on Feb. 15) Medford Weather
(November - October)



heating degree-day for Spokane. This is equal to an average daily temperature of -17 degrees Fahrenheit. For the purpose of forecasting, this day is used as the design-day for cold conditions in the Washington/Idaho service area. Only one 82 heating degree-day has been experienced in the last 30-plus years for this area; however, within that same time period, 80 and 79 heating degree day events occurred on Dec. 29, 1968, and Dec. 31,1978, respectively.

On Dec. 9, 1972, Medford experienced the coldest day on record, a 61 heating degree-day. This is equal to an average daily temperature of 4 degrees Fahrenheit. For the purpose of forecasting, this day is used as the design-day for cold conditions in Medford. Medford has experienced only one 61 heating degree-day in the last 30-plus years; however, it has also experienced 59 and 58 heating degree day events in the same time period on Dec. 8, 1972, and Dec. 21, 1990, respectively. The other three areas in Oregon have similar weather data. For Klamath Falls, a 72 heating degree-day occurred on Dec. 21, 1990, in La Grande a 74 heating degree-day occurred on Dec. 23, 1983, and a 55 heating degree-day occurred in Roseburg on Dec. 22, 1990. As with Washington/Idaho and Medford, these days are used as

Figure 6.8 – Existing Firm Transportation & Storage Resource Stack
WA/ID

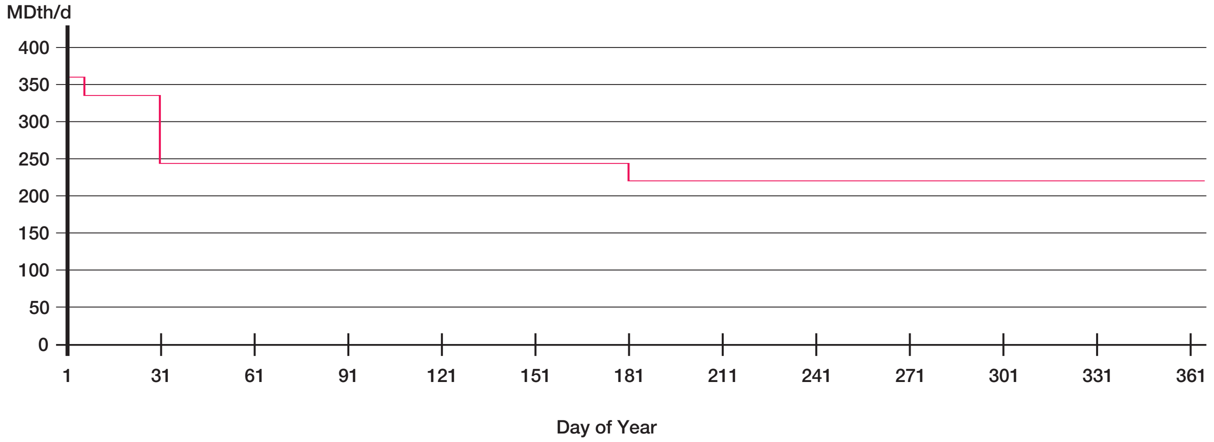
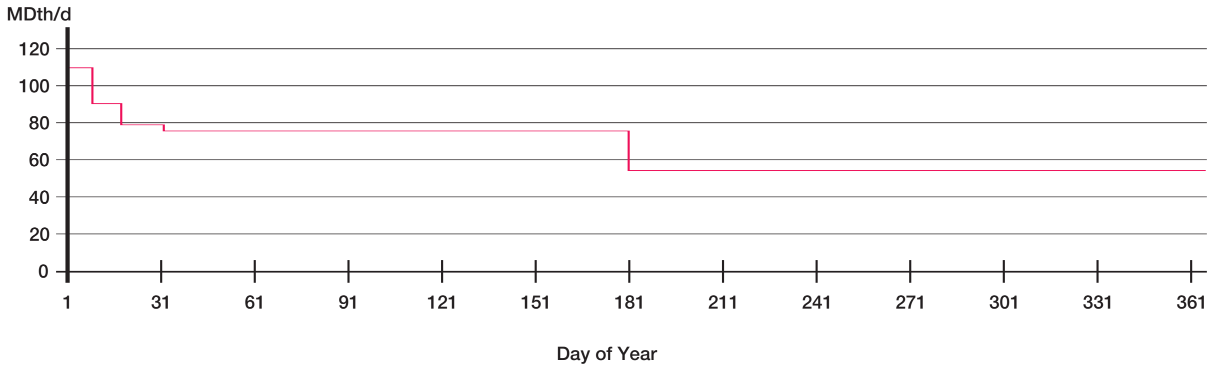


Figure 6.9 – Existing Firm Transportation & Storage Resource Stack
Oregon (includes Willamette Firm Peaking Arrangement)



the design-day for modeling purposes.

The actual HDDs, by area and by day, entered into SENDOUT® can be found in Appendix 6.1.

TRANSPORTATION AND STORAGE

Avista's existing transportation and storage resources are described in Section 5 (summarized in Table 5.1) and are represented by the firm resource duration curves depicted in Figure 6.8 and 6.9. Avista considers these firm transportation and storage resources as the starting point for SENDOUT® infrastructure. When modeling future transportation and storage rates, the company modified existing rates for expected rate increases and then escalated these rates annually at the Global Insight inflation rate (summarized in Table 5.2). The expected rate increases are based on industry discussions regarding yet-to-be-filed interstate pipeline rate cases.

DEMAND-SIDE MANAGEMENT

As discussed in Section 3, the identification and total resource characterization of available natural gas efficiency measures completed using the previously described methodology allows the construction of a natural gas DSM supply curve. This supply curve is simply a graphical depiction of the measures in ascending order of total resource cost. The horizontal axis indicates the cumulative resource obtainable at or below that cost.

Figure 6.10 – Oregon Natural Gas DSM Supply Curve
(Non-site-specific programs)

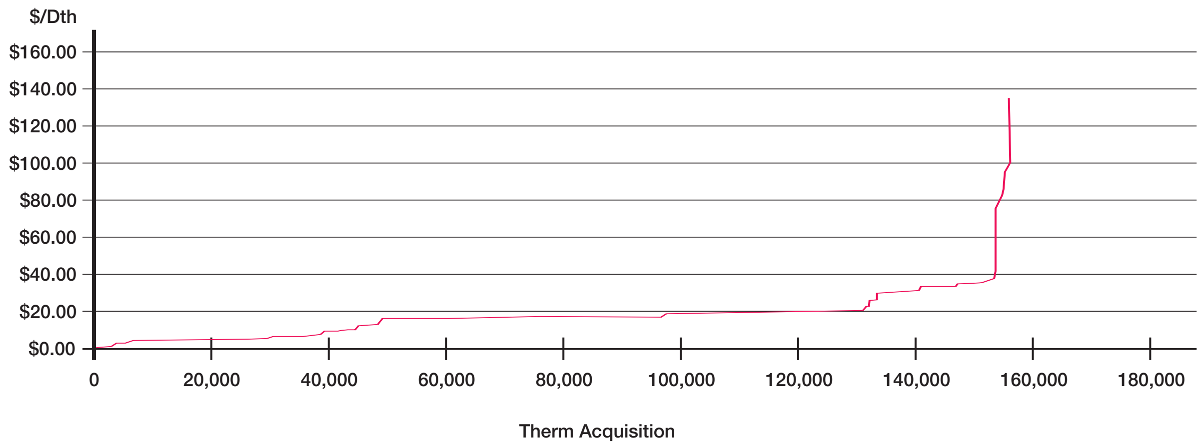
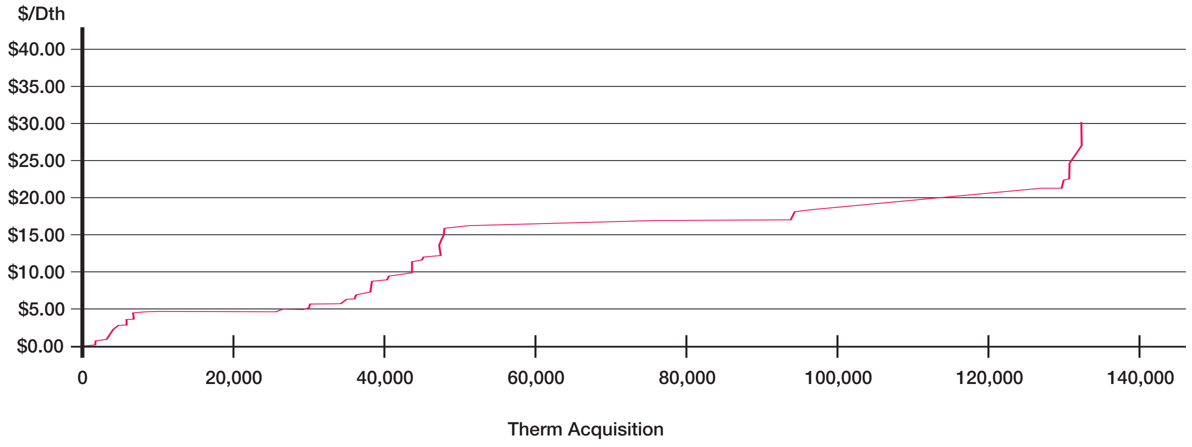


Figure 6.11 – Oregon Gas DSM Supply Curve
(Up to $30/Dth, non-site-specific programs)



Two supply curves are presented for each division (Figures 6.10 through 6.13). Figures 6.10 and 6.12 focus only on measures available at levelized sub-TRC cost of $30 per Dth or less to allow for greater detail of this range of the supply curve.

SELECTED MEASURES

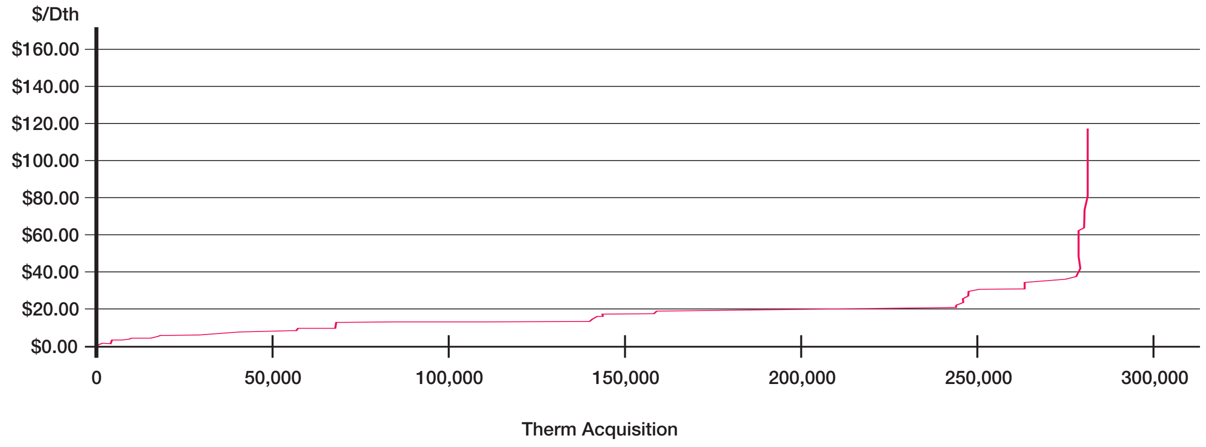
Based on the methodology described Section 3, the "must take" and indeterminate measures were input into the SENDOUT® model. The three key price scenarios (see Figure 6.16) reviewed for resource planning purposes are discussed later in this section and are based on a high natural gas price curve, mid natural gas price curve and low natural gas price curve. The medium price scenario is the reasonably expected scenario; however the availability of the acceptance of DSM measures under alternative price scenarios is useful information for incorporation into future DSM business planning efforts.

Tables 6.1 through 6.4 summarize the acceptance and rejection of all DSM measures evaluated in the IRP process. These results have been disaggregated into six geographic areas. (The two Medford geographic areas had identical resource decisions and therefore were not separately reported in Table 6.1 or Table 6.2).

As expected, some DSM measures were accepted in some geographic areas and rejected in others. This was particularly true in the case of Oregon given the significant climatic differences. These cases were primarily heating degree-day-dependent measures that were accepted in cold climates and rejected in warmer climates. For purposes of developing therm acquisition goals, measure packages that were cost-effective in 50 percent or more of the Oregon service territory were accepted into the portfolio on a statewide basis. Application of this approach requires a program to pass in Medford to be accepted statewide since that district is over 50 percent of the total jurisdictional usage and customer base. Post-IRP program planning efforts will include an assessment of the ability to cost-effectively offer those measure packages that passed in less than 50 percent of the Oregon service territory through geographic, climatic or building type target marketing.

In only one occasion was an individually tested measure accepted in one Washington/Idaho geographic area and not in the other. In this case, the difference in the resource selection was not based on climate, which was identical for these two areas, but it was instead attributable to the cost of alternative supply-side resources.

Figure 6.12 – WA/ID Natural Gas DSM Supply Curve
(Non-site-specific programs)



THERM ACQUISITION GOALS

Avista's fundamental commitment is toward the acquisition of cost-effective natural gas-efficiency resources achievable through utility intervention. The analysis within this IRP has provided the opportunity for a comprehensive assessment of efficiency opportunities in an analysis that integrates supply-side options as well.

OREGON GOALS

Based on the analysis completed within this IRP, the company believes that a cost-effective annual acquisition of 441,000 first-year therms is achievable through utility intervention. This is a significant increase from historical actual acquisition levels. In order to incorporate a reasonable ramp rate into the programs and in recognition of the timing of this analysis, the company is proposing a calendar year 2006 acquisition goal that is the midpoint between the 2004 actual acquisition level and the IRP identified annual acquisition level. In 2007 and thereafter, the annual acquisition goal would be regarded as the full annual acquisition level that has been identified as cost-effective within this IRP. Figure 6.14 and Table 6.5 represent the annual goal of 298,000

Figure 6.13 – WA/ID Natural Gas DSM Supply Curve
(up to $30/Dth, non-site-specific programs)

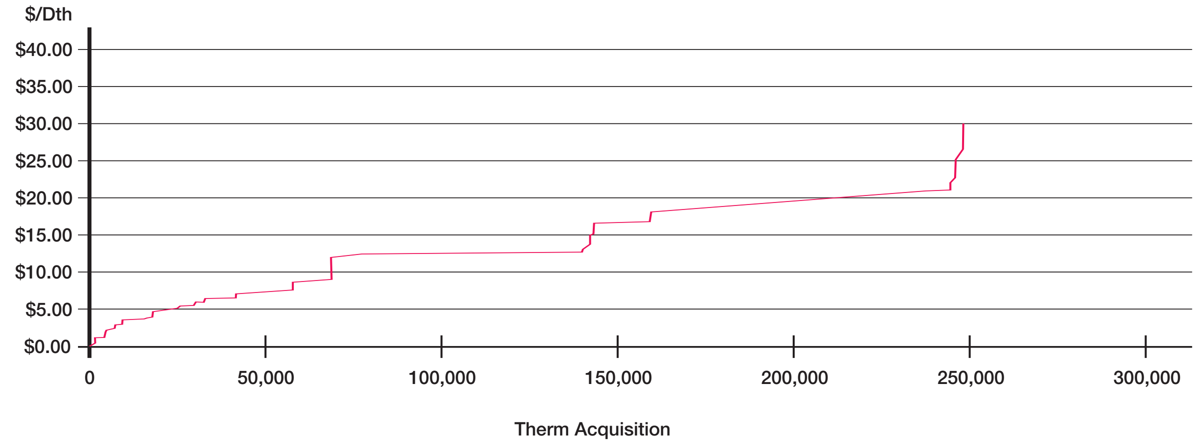


Table 6.1 – Oregon Program Preliminary Evaluation Results

Program	Roseburg	Medford	LaGrande	Klamath Falls
MFH shell pgm	Mandated	Mandated	Mandated	Mandated
SFH shell pgm	Mandated	Mandated	Mandated	Mandated
Comm dryer pgm	Must Take	Must Take	Must Take	Must Take
Energy Star® cooking pgm	Must Take	Must Take	Must Take	Must Take
Comm kiln pgm	Must Take	Must Take	Must Take	Must Take
Non-Res Low-Flow Showerhead pgm	Must Take	Must Take	Must Take	Must Take
Non-res pool / spa pgm	Must Take	Must Take	Must Take	Must Take
Comm shell pgm	Must Take	Must Take	Must Take	Must Take
Comm space heat pgm	Must Take	Must Take	Must Take	Must Take
Comm pre-rinse sprayer pgm	Must Take	Must Take	Must Take	Must Take
Comm water heat pgm	Must Take	Must Take	Must Take	Must Take
Res hot water heating pgm	Must Take	Must Take	Must Take	Must Take
Res Low-Flow Showerhead pgm	Must Take	Must Take	Must Take	Must Take
MFH boiler pgm	Must Take	Must Take	Must Take	Must Take
MFH duct insulation pgm	Must Take	Must Take	Must Take	Must Take
MFH space heat pgm	Must Take	Must Take	Must Take	Must Take
Res pool / spa pgm	Must Take	Must Take	Must Take	Must Take
SFH duct insulation pgm	Must Take	Must Take	Must Take	Must Take
SFH space heat pgm	Must Take	Must Take	Must Take	Must Take
Res programmable thermostat pgm	Must Take	Must Take	Must Take	Must Take
Res tankless water heater pgm	Must Take	Must Take	Must Take	Must Take
Res resource efficient washing machine pgm	Must Take	Must Take	Must Take	Must Take
SFH space heat pgm	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
MFH space heat pgm	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
MFH water heating pgm	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Energy Star® residential package	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Crematory pgm	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Res pool / spa pgm	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Res passive solar water heating pgm	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Comm prescriptive cooking pgm	SENDOUT®	SENDOUT®	SENDOUT®	SENDOUT®
Comm cooking pgm	Screened Out	Screened Out	Screened Out	Screened Out
Comm dryer pgm	Screened Out	Screened Out	Screened Out	Screened Out
Comm kiln pgm	Screened Out	Screened Out	Screened Out	Screened Out
Non-Res pool / spa pgm	Screened Out	Screened Out	Screened Out	Screened Out
Non-Res passive solar water heating pgm	Screened Out	Screened Out	Screened Out	Screened Out
Comm washing machine pgm	Screened Out	Screened Out	Screened Out	Screened Out
Non-Res window pgm	Screened Out	Screened Out	Screened Out	Screened Out
Res water heating pgm	Screened Out	Screened Out	Screened Out	Screened Out
Res door pgm	Screened Out	Screened Out	Screened Out	Screened Out
MFH water heating pgm	Screened Out	Screened Out	Screened Out	Screened Out
MFH window pgm	Screened Out	Screened Out	Screened Out	Screened Out
Res pool / spa pgm	Screened Out	Screened Out	Screened Out	Screened Out
SFH water heating pgm	Screened Out	Screened Out	Screened Out	Screened Out
SFH window pgm	Screened Out	Screened Out	Screened Out	Screened Out

first-year therms in calendar year 2006 and 441,000 therms in 2007 in relation to the 155,000 therms actually acquired in 2004.

The IRP-identified cost-effective market segments and the estimated acquirable first-year therm acquisition are represented in Table 6.6.

A more detailed identification of measures, including a breakout of the mandated and "must take" categorizations, are included in Appendix 3.2.

WASHINGTON/IDAHO GOALS

The current 240,000 annual therm acquisition goal specified in the company's Schedule 190 filing was originally developed in late 2000 based on historical experience in natural gas DSM. The 2001 energy crisis and subsequent increases in retail natural gas rates occurred shortly after these tariffs were approved and very quickly changed the natural gas-efficiency environment. In the last four years of gas DSM program

Table 6.2 – Results of Oregon SENDOUT®-Tested Programs

SENDOUT®-tested (high price scenarios)

Program	Roseburg	Medford	LaGrande	Klamath Falls
SFH space heat pgm	Pass	Pass	Pass	Pass
MFH space heat pgm	Fail	Pass	Pass	Pass
MFH water heating pgm	Pass	Pass	Pass	Pass
Energy Star® residential package	Fail	Fail	Pass	Pass
Crematory pgm	Pass	Pass	Pass	Pass
Res pool/spa pgm	Fail	Fail	Pass	Pass
Res passive solar water heating pgm	Fail	Fail	Fail	Fail
Comm prescriptive cooking pgm	Fail	Fail	Fail	Fail

SENDOUT®-tested (mid price scenarios)

Program	Roseburg	Medford	LaGrande	Klamath Falls
SFH space heat pgm	Fail	Pass	Pass	Pass
MFH space heat pgm	Fail	Fail	Pass	Pass
MFH water heating pgm	Fail	Fail	Fail	Fail
Energy Star® residential package	Fail	Fail	Fail	Pass
Crematory pgm	Fail	Fail	Fail	Fail
Res pool/spa pgm	Fail	Fail	Fail	Fail
Res passive solar water heating pgm	Fail	Fail	Fail	Fail
Comm prescriptive cooking pgm	Fail	Fail	Fail	Fail

SENDOUT®-tested (low price scenarios)

Program	Roseburg	Medford	LaGrande	Klamath Falls
SFH space heat pgm	Fail	Pass	Fail	Fail
MFH space heat pgm	Fail	Fail	Fail	Fail
MFH water heating pgm	Fail	Fail	Fail	Fail
Energy Star® residential package	Fail	Fail	Fail	Fail
Crematory pgm	Fail	Fail	Fail	Fail
Res pool/spa pgm	Fail	Fail	Fail	Fail
Res passive solar water heating pgm	Fail	Fail	Fail	Fail
Comm prescriptive cooking pgm	Fail	Fail	Fail	Fail

Note: Similar measures may be split into multiple programs to create consistent cost-effectiveness characteristics.
"Mandated" = Programs legislatively mandated within Oregon
"Must Take" = Programs with sufficient cost-effectiveness to be passed in preliminary evaluation process.
"SENDOUT®" = Programs with indeterminate cost-effectiveness to be individually tested in SENDOUT®.
"Rejected" = Programs with cost-effectiveness so low as to be rejected in the preliminary evaluation.
"Pass" = Those programs individually tested in SENDOUT® that passed.
"Fail" = Those programs individually tested in SENDOUT® that failed.

activity (2002 through 2005, excluding the aberrant 2001 energy crisis period), Avista has averaged over 800,000 first-year therm savings per year. The market has clearly changed for natural gas-efficiency.

Recent events within the market do create a significant degree of uncertainty in forecasting achievable results. The company has on several occasions indicated that it is difficult to determine if the extraordinary level of acquisition that has been experienced since 2001 is sustainable. At this point, given five years of sustained acquisition, the assumptions made within this IRP are that the recent history is representative of what is obtainable in the future. This conclusion will lead to a considerable increase in estimates of acquirable DSM resources.

Based on the measures that were designated as "must take" and the addition of measure packages that were individually tested within SENDOUT®, a total estimated therm acquisition level of 1,062,000 first-year therms has been identified. Table 6.7 summarizes these measures.

NATURAL GAS SUPPLY AVAILABILITY AND PRICING

The company attempts to balance the need for both low cost and low volatility with high reliability in its natural gas procurement efforts. Section 5 contains a

Table 6.3 – WA/ID Preliminary Evaluation Results

Program	Spokane	SNWP
Res pool/spa pgm	Must Take	Must Take
SFH space heating pgm	Must Take	Must Take
Res programmable thermostat pgm	Must Take	Must Take
Res programmable thermostat pgm	Must Take	Must Take
Comm dryer pgm	Must Take	Must Take
Comm Energy Star® cooking pgm	Must Take	Must Take
Comm kiln pgm	Must Take	Must Take
Comm low-flow showerhead pgm	Must Take	Must Take
Comm pool/spa pgm	Must Take	Must Take
Comm shell pgm	Must Take	Must Take
Comm space heat pgm	Must Take	Must Take
Comm pre-rinse sprayer pgm	Must Take	Must Take
Res hot water heating pgm	SENDOUT®	SENDOUT®
MFH boiler pgm	SENDOUT®	SENDOUT®
MFH duct pgm	SENDOUT®	SENDOUT®
MFH shell pgm	SENDOUT®	SENDOUT®
MFH windows pgm	SENDOUT®	SENDOUT®
SFH duct pgm	SENDOUT®	SENDOUT®
SFH shell pgm	SENDOUT®	SENDOUT®
SFH windows pgm	SENDOUT®	SENDOUT®
Comm water heating pgm	SENDOUT®	SENDOUT®
MFH furnace pgm	SENDOUT®	SENDOUT®
MFH space heating pgm	SENDOUT®	SENDOUT®
Res low-flow showerhead pgm	SENDOUT®	SENDOUT®
MFH hot water heating pgm	SENDOUT®	SENDOUT®
Res pool/spa pgm	SENDOUT®	SENDOUT®
Res tankless water heater pgm	SENDOUT®	SENDOUT®
Res resource-efficient washing machine pgm	SENDOUT®	SENDOUT®
Crematory pgm	SENDOUT®	SENDOUT®
Comm prescriptive cooking pgm	SENDOUT®	SENDOUT®
Res hot water heating pgm	Screened Out	Screened Out
Res door pgm	Screened Out	Screened Out
Res Energy Star® Package pgm	Screened Out	Screened Out
MFH hot water heating pgm	Screened Out	Screened Out
MFH pipe insulation pgm	Screened Out	Screened Out
Res pool/spa pgm	Screened Out	Screened Out
SFH hot water heating pgm	Screened Out	Screened Out
SFH space heating pgm	Screened Out	Screened Out
SFH pipe insulation pgm	Screened Out	Screened Out
Res passive solar water heating pgm	Screened Out	Screened Out
Comm cooking pgm	Screened Out	Screened Out
Comm dryer pgm	Screened Out	Screened Out
Comm kiln pgm	Screened Out	Screened Out
Comm pool/spa pgm	Screened Out	Screened Out
Comm passive solar water heating pgm	Screened Out	Screened Out
Comm washing machine pgm	Screened Out	Screened Out
Comm window pgm	Screened Out	Screened Out

description of supply options available to the company.

Regional and national natural gas prices have recently risen to unprecedented levels. The industry in general and price forecasting organizations in particular did not forecast these unprecedented increases. Oil price increases and a correlation between natural gas and the price relationship with natural gas, demand growth, stagnating U.S. supply growth, natural gas use for electric generation, hurricane activity and other weather events are believed to be some of the reasons for these price increases. Given that these increases were not predicted and that these price levels have not been witnessed before on a sustained basis, it is very difficult to determine the length of the price run-up, as well as

Table 6.4 – Results of WA/ID SENDOUT®-Tested Programs

	SENDOUT®-tested (high price scenarios)	
Program	**Spokane**	**SNWP**
Res hot water heating pgm	Pass	Pass
MFH boiler pgm	Pass	Pass
MFH duct pgm	Pass	Pass
MFH shell pgm	Pass	Pass
MFH windows pgm	Pass	Pass
SFH duct pgm	Pass	Pass
SFH shell pgm	Pass	Pass
SFH windows pgm	Pass	Pass
Comm water heating pgm	Pass	Pass
MFH furnace pgm	Pass	Pass
MFH space heating pgm	Pass	Pass
Res low-flow showerhead pgm	Pass	Pass
MFH hot water heating pgm	Pass	Pass
Res pool / spa pgm	Pass	Pass
Res tankless water heater pgm	Pass	Pass
Res resource-efficient washing machine pgm	Pass	Pass
Crematory pgm	Pass	Pass
Comm prescriptive cooking pgm	Pass	Pass

	SENDOUT®-tested (mid price scenarios)	
Program	**Spokane**	**SNWP**
Res hot water heating pgm	Pass	Pass
MFH boiler pgm	Pass	Pass
MFH duct pgm	Pass	Pass
MFH shell pgm	Pass	Pass
MFH windows pgm	Pass	Pass
SFH duct pgm	Pass	Pass
SFH shell pgm	Pass	Pass
SFH windows pgm	Pass	Pass
Comm water heating pgm	Pass	Pass
MFH furnace pgm	Pass	Pass
MFH space heating pgm	Fail	Pass
Res low-flow showerhead pgm	Pass	Pass
MFH hot water heating pgm	Pass	Pass
Res pool / spa pgm	Fail	Fail
Res tankless water heater pgm	Fail	Fail
Res resource-efficient washing machine pgm	Pass	Pass
Crematory pgm	Pass	Pass
Comm prescriptive cooking pgm	Fail	Fail

the expected impact on customer loads. Although the company does not believe that it can accurately predict future prices for the 20-year horizon of this IRP, it has reviewed a variety of price forecasts provided by credible sources.

A number of these price forecasts are provided in the Figure 6.15.

As Figure 6.15 shows, there are many price forecasts with a large variation in overall price levels. Although some of these forecasts are more plausible than others, most of them are at least possible. Therefore, Avista, with the assistance and concurrence of the TAC Committee, selected a high, medium and low price curve as the best way to consider possible outcomes and the impact that this volatile and high pricing environment might have on planning.

Table 6.5 – Oregon 1st-year Therm Acquisition by Customer Segment

Year	Residential	Non-Residential	Total
2004 actual acquisition	140,000	15,000	155,000
2006 acquisition goal	249,000	49,000	298,000
2007 acquisition goal	**358,000**	**83,000**	**441,000**

Table 6.4 continued – Results of WA/ID SENDOUT®-Tested Programs

	SENDOUT®-tested (low price scenarios)	
Program	**Spokane**	**SNWP**
Res hot water heating pgm	Fail	Fail
MFH boiler pgm	Pass	Pass
MFH duct pgm	Pass	Pass
MFH shell pgm	Pass	Pass
MFH windows pgm	Pass	Pass
SFH duct pgm	Pass	Pass
SFH shell pgm	Fail	Fail
SFH windows pgm	Fail	Fail
Comm water heating pgm	Pass	Pass
MFH furnace pgm	Pass	Pass
MFH space heating pgm	Fail	Pass
Res low-flow showerhead pgm	Fail	Fail
MFH hot water heating pgm	Fail	Fail
Res pool/spa pgm	Fail	Fail
Res tankless water heater pgm	Fail	Fail
Res resource-efficient washing machine pgm	Fail	Fail
Crematory pgm	Fail	Fail
Comm prescriptive cooking pgm	Fail	Fail

Note: Similar measures may be split into multiple programs to create consistent cost-effectiveness characteristics.
"Mandated" = Programs legislatively mandated within Oregon
"Must Take" = Programs with sufficient cost-effectiveness to be passed in preliminary evaluation process.
"SENDOUT®" = Programs with indeterminate cost-effectiveness to be individually tested in SENDOUT®.
"Rejected" = Programs with cost-effectiveness so low as to be rejected in the preliminary evaluation.
"Pass" = Those programs individually tested in SENDOUT® that passed.
"Fail" = Those programs individually tested in SENDOUT® that failed.

Table 6.6 – Oregon Programs Accepted within the IRP Analysis

Multifamily home shell measures	1,800	1st year therms
Single-family home shell measures	56,000	1st year therms
Residential domestic hot water	8,400	1st year therms
Residential low-flow showerheads	11,700	1st year therms
Residential tankless water heaters	40,200	1st year therms
Horizontal-axis washing machines	29,300	1st year therms
Multifamily home high-efficiency boilers	600	1st year therms
Residential pool and spa measures	10,400	1st year therms
Single-family home duct measures	7,100	1st year therms
Single-family home HVAC measures	180,000	1st year therms
Residential programmable thermostats	6,700	1st year therms
Multifamily home duct measures	0	1st year therms
Multifamily home HVAC measures	100	1st year therms
Commercial dryers	1,600	1st year therms
Commercial Energy Star® cooking measures	600	1st year therms
Kiln	0	1st year therms
Non-residential low-flow showerheads	2,100	1st year therms
Non-residential pre-rinse sprayers	16,100	1st year therms
Non-residential water heating measures	16,300	1st year therms
Non-residential pool measures	8,200	1st year therms
Non-residential shell measures	2,600	1st year therms
Non-residential space heat measures	5,400	1st year therms
Single-Family Home HVAC program	5,700	1st year therms
Total identified cost-effective measures	**441,100**	**1st year therms**

(Components may not sum due to rounding to nearest 100 therms)

These curves are shown in Figure 6.16.

Each of the forecasts illustrated in Figure 6.16 are at the Henry Hub. The Henry Hub is found in Louisiana just onshore from the Gulf of Mexico. It is the physical location that is widely recognized as the most important pricing point in the United States because of the sheer volume traded both on a daily or spot basis, as well as a forward basis and the proximity to a large portion of United States production. All other producing and market area-pricing points tend to be set off of the Henry Hub as it is the New York Mercantile Exchange's (NYMEX) trading hub for futures contracts. Although the Henry Hub is certainly relevant to pricing natural gas in the United States and the Pacific Northwest, the physical supply points closer to Avista's service territory are Sumas, Wash., AECO Alberta, Canada, and the U.S. Rockies. Pricing of these points is set or based upon Henry Hub, although they typically trade at a significant

Figure 6.14 – Annual Oregon Acquisition Goals

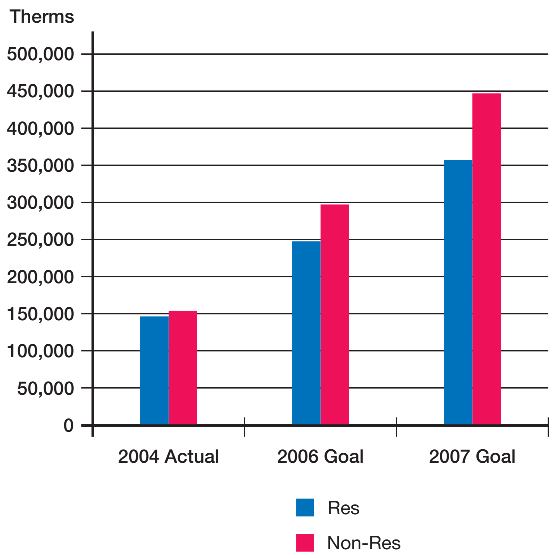
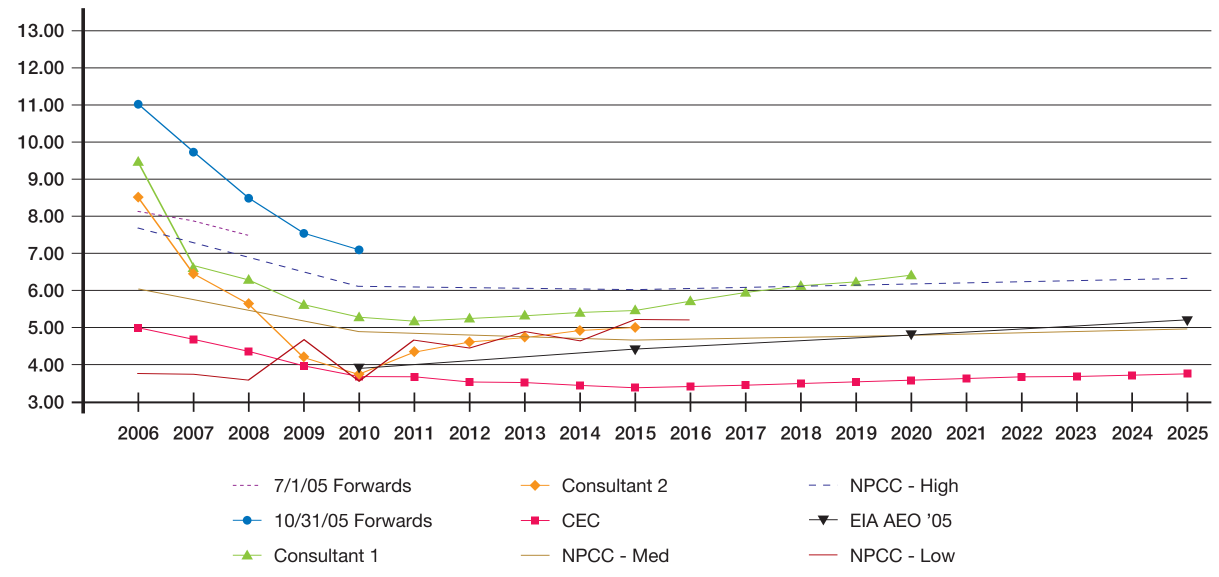


Table 6.7 – WA/ID Programs Accepted within the IRP Analysis

Residential pool/spa measures	19,000	1st year therms
Single-family home HVAC measures	56,000	1st year therms
Residential thermostat measures	27,000	1st year therms
Non-residential clothes dryers	2,000	1st year therms
Non-residential cooking measures	1,000	1st year therms
Kiln	0	1st year therms
Non-residential low-flow showerheads	2,000	1st year therms
Non-residential pre-rinse sprayers	16,000	1st year therms
Non-residential pool measures	8,000	1st year therms
Non-residential shell measures	4,000	1st year therms
Non-residential space heat measures	7,000	1st year therms
Non-residential site-specific program	469,000	1st year therms
Residential domestic hot water measures	13,000	1st year therms
Residential low-flow showerhead measures	53,000	1st year therms
Multifamily boiler measures	1,000	1st year therms
Multifamily domestic how water measures	0	1st year therms
Multifamily home duct measures	1,000	1st year therms
Multifamily furnace measures	0	1st year therms
Multifamily HVAC measures	14,000	1st year therms
Multifamily shell measures	4,000	1st year therms
Multifamily window measures	1,000	1st year therms
Single-family home duct program	41,000	1st year therms
Single-family home shell program	234,000	1st year therms
Single-family home window measures	44,000	1st year therms
Horizontal-axis washing machine program	26,000	1st year therms
Non-residential water heat program	20,000	1st year therms
Crematoria program	1,000	1st year therms
Total identified cost-effective measures	**1,062,000**	**1st year therms**

(Components may not sum due to rounding to nearest 1,000 therms)

Figure 6.15 – Henry Hub Forward Price Forecasts
2005$/Dth



discount. This discount is commonly referred to as the basis differential. Some of the reasons for the basis differential are a more favorable supply/demand balance in the West, better physical proximity to these supplies and distance from the very large demand centers in the eastern United States.

Since most price forecasters do not forecast regional pricing points, Avista needed to estimate the basis differential between Henry Hub and the pricing points on which the company relies. As discussed at the TAC meetings, the company believes that an average of the most recent differentials is an appropriate approach to estimate basis differentials. This is because the company believes that recent history better represents the current

Figure 6.16 – Henry Hub Forward Prices for Avista 2006 IRP
2005$/Dth

structure of the natural gas market. This structure may change in the future, particularly out of the U.S. Rockies producing region; however, at this point in time, it is the best predictor of what future differentials may look like. Therefore, Avista has adopted Table 6.8 showing the percentage of Henry Hub, for AECO, Sumas and the Rockies pricing points. Avista calculated these percentages by comparing the actual monthly index prices from November 2003 through October 2005. The beginning date for this comparison was chosen because there were a number of pipeline expansions that went into service in 2003, and Avista felt it appropriate to select a date, beginning with the winter heating season, after those potentially basis altering expansions went into service.

Each of the price forecasts provides annual (not monthly) prices by year. For modeling purposes, given Avista's heavily winter-weighted demand profile, it is more accurate for the company to break these annual figures down to monthly figures. As discussed with the TAC, Avista believes that utilizing available forward price differentials, by month, is an appropriate way to compute monthly prices. Table 6.9 depicts the monthly shape that the company is applying to the annual prices in the price curves. Avista calculated these percentages by taking the average of the monthly forward prices available on July 1, 2005. The reason the company chose July 1 is that the company felt it appropriate to attempt to avoid the potentially skewed forward prices in the aftermath of the 2005 hurricane activity and associated price run-up.

Appendix 6.1 displays the detailed monthly price data as calculated by the company when the Henry Hub price forecasts are incorporated with the basis and seasonal factor adjustments discussed above.

DEMAND FORECASTS AND SENSITIVITIES

As discussed in Section 2, given the unprecedented price spikes in the natural gas markets and the uncertainty of the sustainability of the prices, as well as the customer impact, the company has created nine scenarios to better look at the range of possible outcomes over the planning horizon. These nine scenarios were developed by crossing the high, medium and low price curves depicted in Figure 6.16 with the high, medium and low customer growth scenarios discussed in Section 2 (Figure 2.1). This effort produced the three-by-three matrix shown in Table 6.10.

The top row of the matrix incorporates the high, medium and low price curves. For each of these cases in this row, the heat coefficient was adjusted annually based upon the comparison of each of the price curves selected by the company. The calculation of these coefficients is discussed in Section 2 and can be seen in Appendix 2.3. For the middle row of the matrix, the coefficients remain the same as the top row of the matrix but the customer growth rates were adjusted by decreasing the customer growth rate by 50 percent. For the bottom row of the matrix, the coefficients remain the same as the top row of the matrix but the customer growth rates were adjusted by increasing the customer growth rate by 50 percent. The customer growth rate figures are further discussed in Section 2 and can be seen in Figure 2.1 and Appendix 2.2.

Therefore, Case #6 has the lowest demand because it has the highest price and associated demand coefficients

Table 6.8 – Basis Differential Assumptions

Pricing Point	AECO	Sumas	Rockies
Percentage	85.5%	86.4%	85.7%

Table 6.9 – Monthly Pricing Allocation

January	February	March	April	May	June
111%	111%	109%	96%	94%	95%
July	**August**	**September**	**October**	**November**	**December**
95%	96%	95%	96%	100%	104%

Table 6.10 – Demand Scenarios

Case #1 – Low natural gas price adjustment - elasticity (-.15)	Case #2 – Medium natural gas price adjustment - elasticity (-.15)	Case #3 – High natural gas price adjustment - elasticity (-.15)
Case #4 – Case #1 with a reduction of customer growth by 50%	Case #5 – Case #2 with a reduction of customer growth by 50%	Case #6 – Case #3 with a reduction of customer growth by 50%
Case #7 – Case #1 with an increase of customer growth by 50%	Case #8 – Case #2 with an increase of customer growth by 50%	Case #9 – Case #3 with an increase of customer growth by 50%

and the lowest customer growth rates. Case #7 has the highest demand because it has the lowest price and associated demand coefficients and the highest customer growth rates. All other cases fall in between these "bookends."

PRELIMINARY RESULTS

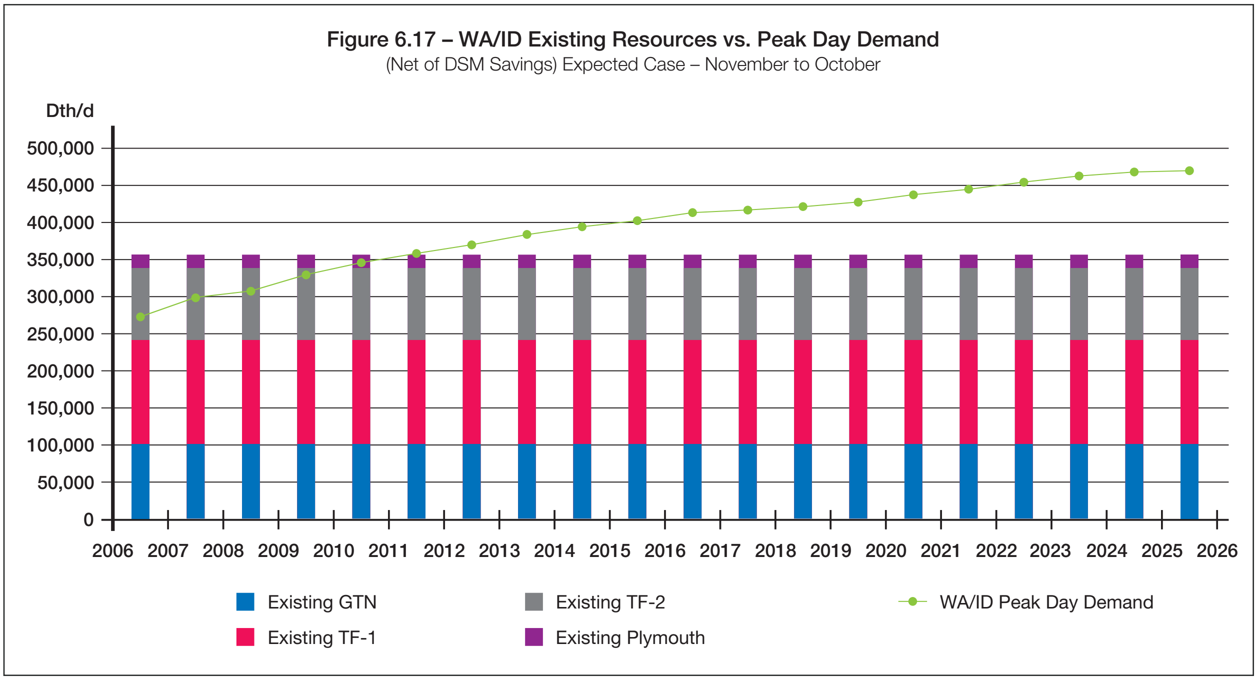
Avista generated results from SENDOUT® utilizing these nine cases and existing transportation and storage resources. The purpose of this initial exercise is to first determine if Avista has sufficient resources to meet peak day requirements in all scenarios. The second purpose of this exercise is to determine, in scenarios where the company has insufficient resources, as well as where, when and how much of a deficiency exists.

From an analytical standpoint, after creating and running each scenario, the company then honed the group down to three main cases to review in more detail. These cases are the highest customer growth and demand level case (#7), the lowest customer growth and demand level case (#6), and the middle demand and customer growth case (#2). Case #2 is known as the Expected Case, Case # 6 is known as the Low Demand Case and Case #7 is known as the High Demand Case. The demand results of these cases are further discussed in Section 2 and additional details of these cases can be seen in Appendix 2.4. The company believes that these cases best explore the realm of reasonable possible outcomes while at the same time minimizing the number of cases the company analyzes all the way through the conclusion of this IRP process.

Figures 6.17 and 6.18 graphically represent a regional summary of Expected Case peak day demand compared to existing resources. This comparison shows, on a regional bases, when and how much the company is deficient over the planning horizon. Similar figures for the Low and High Demand cases can be found in Appendix 6.2.

It is important to note that this summarized or rolled-up approach can "mask" regional deficiencies. Therefore, the company prepared Table 6.11 to provide more detail. Table 6.11 identifies when the company first becomes resource constrained and the amount of that deficiency by demand region on that region's design day. This table further shows the growth in deficiencies over time. Similar figures for the Low and High Demand cases can be found in Appendix 6.3.

Each case depicts at least one deficiency in at least one demand area sometime during the planning horizon. Given that the company does not anticipate resource shortages until at least the 2008/2009 heating season in the most robust case, and given that the mid case is not deficient until the 2010/2011 heating season, Avista is afforded sufficient time to carefully monitor, plan and take action on potential resource additions. That being said, for purposes of the IRP process, the company attempted to identify all reasonable resource options given current information and placed these options in the SENDOUT® model in order to allow the model to pick the least cost incremental resources.



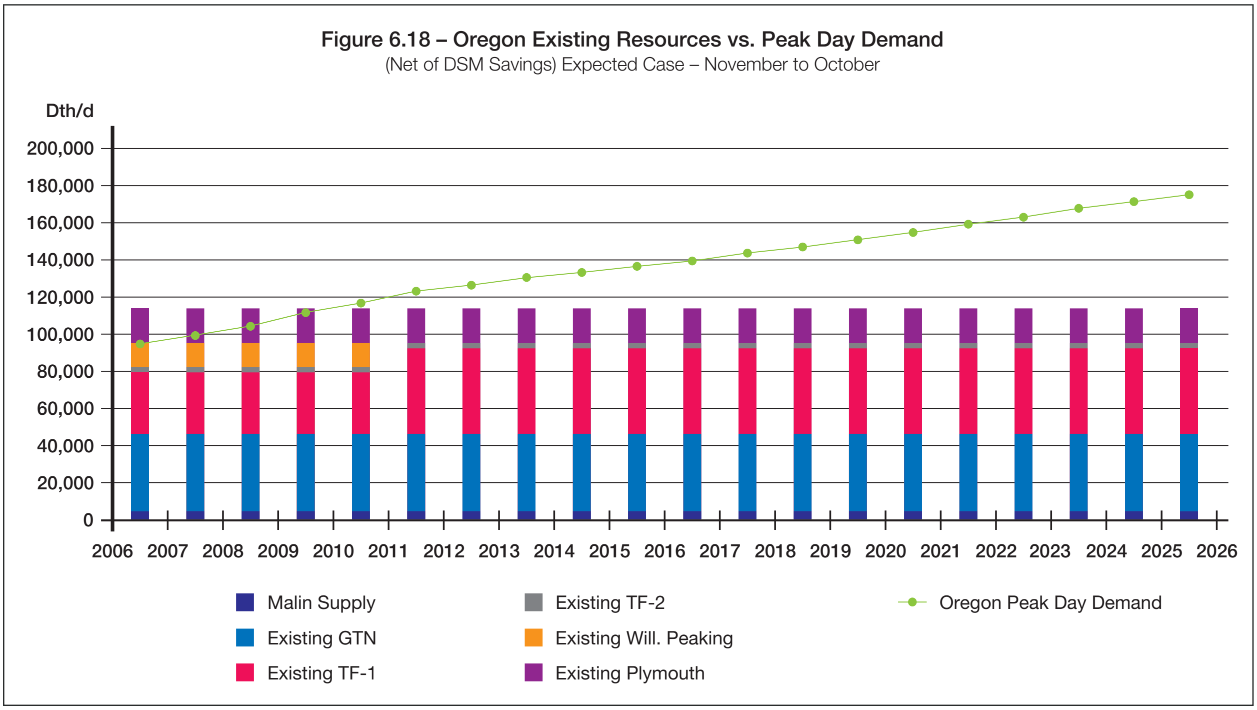
NEW RESOURCE OPTIONS

When researching options, the company determined that the following considerations are important when evaluating the appropriateness of potential resources.

CONSIDERATIONS

Resource Cost

The company strives for the least-cost resource portfolio, so resource cost is the primary consideration when evaluating resource options. It is important to note that the other considerations mentioned below



influence resource decisions. Avista has found that it is often true that newly constructed resources are more expensive than existing resources, but existing resources are in shorter supply. Newly constructed resources provided by a third party such as a pipeline may require a significant commitment for contract length. The company believes that newly constructed resources by a third party are often less expensive per unit cost given the larger the total facility constructed is.

Peak Versus Base Load

As previously stated, Avista's planning efforts include the ability to serve a design or peak day as well as all other demand periods. The company's core loads are considerably higher in the winter than the summer. Due to the winter-peaking nature of Avista's demand,

Table 6.11 – Peak Day Demand - Served and Unserved (MDth/d)
Before Resource Additions & Net of DSM Savings

Case	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	WA/ID Served	WA/ID Unserved	WA/ID Total
2	2006-2007	8.39	-	8.39	274.06	-	274.06
2	2007-2008	8.91	-	8.91	295.96	-	295.96
2	2008-2009	9.18	-	9.18	310.11	-	310.11
2	2009-2010	9.50	-	9.50	326.79	-	326.79
2	2010-2011	9.75	-	9.75	341.37	-	341.37
2	2011-2012	9.96	-	9.96	354.71	-	354.71
2	2012-2013	10.12	-	10.12	357.29	9.07	366.37
2	2013-2014	10.25	0.03	10.28	373.80	3.58	377.38
2	2014-2015	10.25	0.18	10.43	373.05	14.83	387.88
2	2015-2016	10.25	0.34	10.60	386.99	11.80	398.80
2	2016-2017	10.25	0.49	10.74	387.37	19.75	407.12
2	2017-2018	10.25	0.60	10.85	386.46	27.61	414.07
2	2018-2019	10.25	0.76	11.01	385.41	37.08	422.49
2	2019-2020	10.25	0.91	11.16	384.34	46.28	430.62
2	2020-2021	10.25	1.06	11.32	383.37	54.93	438.30
2	2021-2022	10.25	1.22	11.47	382.84	62.74	445.58
2	2022-2023	10.25	1.38	11.63	382.84	70.30	453.14
2	2023-2024	10.25	1.54	11.80	382.84	77.55	460.39
2	2024-2025	10.25	1.71	11.96	382.84	85.16	468.00
2	2025-2026	10.25	1.74	11.99	382.84	85.33	468.18

Case	Gas Year	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Medford / Roseburg Served	Medford / Roseburg Unserved	Medford / Roseburg Total
2	2006-2007	12.82	-	12.82	73.18	-	73.18
2	2007-2008	13.66	-	13.66	79.19	-	79.19
2	2008-2009	14.18	-	14.18	83.43	-	83.43
2	2009-2010	14.77	-	14.77	88.05	-	88.05
2	2010-2011	15.03	0.22	15.25	87.24	4.64	91.88
2	2011-2012	15.03	0.56	15.59	87.24	8.08	95.32
2	2012-2013	15.03	0.84	15.87	87.24	11.13	98.37
2	2013-2014	15.03	1.13	16.16	87.24	14.27	101.51
2	2014-2015	15.03	1.45	16.48	87.24	17.47	104.71
2	2015-2016	15.03	1.79	16.82	87.24	21.00	108.24
2	2016-2017	15.03	2.14	17.18	87.24	24.30	111.54
2	2017-2018	15.03	2.46	17.49	87.24	27.17	114.41
2	2018-2019	15.03	2.83	17.86	87.24	30.51	117.75
2	2019-2020	15.03	3.21	18.25	87.24	33.93	121.17
2	2020-2021	15.03	3.60	18.63	87.24	37.25	124.49
2	2021-2022	15.03	3.96	18.99	87.24	40.57	127.81
2	2022-2023	15.03	4.34	19.37	87.24	44.01	131.25
2	2023-2024	15.03	4.76	19.79	87.24	47.40	134.64
2	2024-2025	15.03	5.16	20.20	87.24	50.81	138.05
2	2025-2026	15.03	5.69	20.72	87.24	54.85	142.09

resources that cost-effectively serve the winter without an associated summer commitment may be preferable. It is important to remember that it is possible that the costs of a winter-only resource may exceed the cost of annual resources after capacity release or optimization opportunities are considered.

Lead-Time Requirements

New resource options can take anywhere from a year to more than four years to put in service. Open season processes, planning and permitting, environmental review, design, construction and testing are just some of the many aspects that contribute to lead-time requirements associated with new physical facilities. Recalls of storage or transportation release capacity typically require advance notice of up to two years. Even DSM programs require a significant amount of time from program rollout to the point in time at which natural gas savings are realized.

Resource Usefulness

It is paramount that an available resource effectively delivers natural gas to the intended geographical region. Given Avista's unique service territories, it is often impossible to deliver resources from a resource option such as storage without acquiring additional pipeline transportation to deliver storage volumes.

"Lumpiness" of Resource Options

Newly constructed resource options are often "lumpy." This means that new resources may only be available in larger than needed quantities and only available every few years. This lumpiness of resources is driven by the cost dynamics of new construction, the fact that lower unit costs are available with larger expansions, and the economics of expansion of existing pipelines or the construction of new resources dictate additions only every few years. This lumpiness does provide a cushion for future growth. Given the economies of scale for pipeline construction costs, the company is afforded the opportunity to assure that resources are in place for future increases in demand.

OPTIONS REVIEWED

The following narrative summarizes the company research and analysis on a number of demand serving options. Actual supply-side resources placed into the SENDOUT® model are detailed in Appendix 6.4.

Demand-Side Management

As part of the IRP process, a comprehensive assessment was made of potentially cost-effective demand-side management opportunities. This assessment resulted in the conclusion that there is significant additional resource potential beyond Oregon historical acquisitions and the goals specified in the tariffs governing the Washington and Idaho natural gas DSM programs. The SENDOUT® model, through the evaluation of all the measures described in Section 3, selects the lowest cost resource, whether that resource is a supply- or demand-side resource. In instances where cost-effective DSM resources are available, these resources will be selected before more expensive supply-side resources.

Avista System Enhancements

In certain instances, through a modification or upgrade of Avista's facilities, the company can facilitate additional peak and base load-serving capabilities. These opportunities are geographically specific and require case-by-case study. Avista has begun preliminary review of several of these enhancements and although this review hasn't been finalized, preliminary findings indicate that the following opportunities may be beneficial.

- **NWP Klamath Falls Lateral –** Avista has the opportunity to purchase and operate the NWP Klamath Falls lateral as a high-pressure distribution system. While incurring the capital cost associated with the purchase price, Avista will be able to avoid current NWP transportation charges at Klamath Falls and relocate the transportation contract deliverability on NWP to areas where additional deliverability is needed. This solution would also facilitate additional deliveries into the Klamath Falls area off of GTN. The potential transaction is subject to a number of terms and conditions that have not yet been satisfied.

- **Medford System Enhancement** - Avista may be able to construct a high-pressure distribution reinforcement from the GTN system off of the Medford lateral to deliver additional quantities of natural gas off of GTN to Medford. This solution would also allow existing supply and capacity to be diverted from Medford on the NWP Grants Pass Lateral to the Roseburg area. Through this enhancement, potential resource shortages in the Medford and Roseburg areas can be addressed. The company is likely to proceed with the change, whether needed for demand-serving purposes or not, due to the recently enacted Office of Pipeline Safety Integrity Management rules. Avista is required by these rules to assess and manage potential risks of transmission pipeline rupture in areas of high consequence; i.e. areas of dense population or gathering places with regular use. The above option currently appears to be the company's best option in dealing with Medford-area high consequence area issues.
- **La Grande Distribution System Enhancement** – Avista has the option to enhance the distribution system in the La Grande area with high-pressure distribution looping from an adjacent city-gate station such that the distribution system would be reinforced. This solution would allow additional deliveries off of the NWP system to La Grande.

Utilization of Backhauls

On the GTN system, due to the north-to-south flow dynamics and the large amount of natural gas flowing that direction, backhauling supply purchases to Avista's service territory can be done on a firm basis. For example, Avista can purchase cost-effective supplies at Malin, Ore., and transport those supplies to Avista's service territory at either Klamath Falls or Medford. Malin-based natural gas supplies typically price at a small premium to AECO, Rockies and Sumas supplies and are generally less expensive than the cost of both transporting those traditional supplies and paying the associated reservation charges. The GTN system is a mileage-based system, and therefore Avista only pays a fraction of the forward rate if it is transporting supplies from Malin to Medford and Klamath Falls. The GTN system is approximately 612 miles long and the distance from Malin to the Medford lateral is only about 12 miles. Thus, Avista can decrease costs by avoiding paying full reservation charges on an annual or seasonal basis and/or by avoiding potentially expensive peaking resources.

Storage

Storage allows the company to deliver natural gas supply when needed most. Storage provides many advantages when storage deliveries can be made to Avista's city-gate points. Storage also allows the company to take advantage of summer/winter pricing differentials, as well as provide the company with arbitrage opportunities within individual months. The latter advantages do not offer peak load serving capabilities although they certainly allow the company to offset natural gas supply expenses with these revenues. Although storage can be a valuable resource, without deliverability to Avista's service territory, storage cannot be considered a firm peak serving resource.

Storage resources are limited in the Pacific Northwest; however, there are a number of options available to the company.

- **Jackson Prairie** – As discussed in Section 5, Jackson Prairie is a tremendous resource for both existing services and expansion opportunities.

  For Washington and Idaho customers, the company has provided notice of its intent to recall storage capacity and associated NWP transportation capacity from Cascade Natural Gas Company. The company will retake possession of this capacity on April 30, 2007.

  This recall will further facilitate peak and winter deliveries at no cost for the storage and very little cost for the transportation in addition to providing ratepayers with the opportunity to capture current arbitrage opportunities that far exceed the release revenues that Avista is currently receiving from Cascade.

  The remaining storage release to Terasen and the future expansion capacity discussed in Section 5 do not include transportation and therefore cannot directly serve system demand. However, the company will continue to look for swap and transportation release opportunities to fully utilize these additional resources. Even without deliverability, it may make financial sense in the future for the company to fully develop/recall Jackson Prairie capacity to optimize time spreads within the natural gas market.

  For Oregon customers, transportation from Jackson Prairie and rate base issues continue to be the main reasons that more storage is not available for peak and winter load requirements. It may be possible that some of the Jackson Prairie expansion capacity could be allocated to Oregon in the future, and the company will continue to assess that opportunity. Further, through the acquisition of cost effective pipeline capacity to the various Oregon demand centers, Oregon customers may have the ability to benefit from storage resources for peak needs.
- **Plymouth LNG** – As mentioned previously, Avista currently holds LNG needle peaking capacity contracts with NWP for both Washington/Idaho customers as well as Oregon customers. Although this is a valuable peaking resource, it is fairly costly per unit delivered. Furthermore, this resource is fully contracted and not available for contracting at this time. Given this situation, this option is not being modeled within SENDOUT® for this IRP.

  Due to the fact that many of the current capacity holders are on one-year rolling evergreen contracts, it is possible that this option will again become viable in the future. In order for this option to become a preferred resource, transportation to and from Plymouth will need to be acquired.
- **Other Storage** – Other regional storage facilities exist and may be cost-effective. Northwest Natural's Mist facility in Northwest Oregon, Alberta area storage, Questar's Clay Basin facility in Northeast Utah and Northern California storage are all possibilities. Again, transportation to and from these facilities to Avista's service territory continues to be the largest impediment to contracting for these options. Currently the most attractive non-Jackson Prairie resource that the company reviewed is storage potential in Northern California. This concept needs to be further analyzed, although it appears that through backhaul transportation, deliveries could be made to some of the Washington/Idaho and Oregon customers. Storage capacity is currently available in Northern California, as well as transport capacity to and from these locations.

  Unfortunately, current sellers of storage capacity in Northern California are not offering multi-year contracts or contracts with beginning dates during the timeframes that the company may need these incremental resources.

Company-Owned Liquefied Natural Gas Storage

LNG facilities could be constructed within the company's service area. By locating within the Avista service area and not on the interstate pipelines, Avista could avoid annual pipeline charges. Such construction would be dependent on regulatory and environmental approval, as well as cost effectiveness requirements.

Preliminary estimates of the construction, environmental, right of way, legal, operating and maintenance, and inventory costs for a needle-peaking resource indicate that company-owned LNG facilities do not appear to be cost effective. Although the company is not modeling this option at this time, Avista will continue to seek cost effective opportunities utilizing this resource option.

Satellite LNG

Company-owned satellite liquefied natural gas storage is another option. Satellite LNG facilities could be constructed within the company's service area. Unlike LNG facilities described earlier, satellite LNG uses natural gas that is trucked to the facilities in liquid form rather than liquefying on site. By locating within the Avista service area and not on the interstate pipelines, Avista could avoid annual pipeline charges.

Estimates for this type of needle-peaking resource look interesting, and the company will continue to monitor and evaluate the cost and benefit of satellite LNG as new supply increments are needed.

Propane-Air

Propane-air facilities are yet another option. Propane-air and natural gas interchangeability concerns may limit the cost-effective application of a propane-air system to individual industrial customer facilities or to metropolitan areas. Interchangeability concerns about the blending of too great a concentration of propane-air with natural gas can pose service, maintenance and safety problems. Avista has had experience with propane-air systems in the Medford, Ore., service area for peaking in the past, however the company does not operate a propane-air plant at this time.

Pipeline Transportation

Additional firm pipeline transportation resources are very viable resource options for the company. Determining the appropriate level, supply source and associated pipeline path, costs and timing, as well as determining whether or not existing resources will be available at the appropriate time make this resource very difficult to analyze. Firm pipeline capacity provides several advantages: it provides the ability to receive firm supplies at the production basin; it is generally a low-cost option given optimization and capacity release opportunities; and it provides for base-load demand. Pipeline capacity also has several drawbacks, including typically long-dated contract requirements, limited need in the summer months (many pipelines require annual contracts) and limited availability.

As discussed in Section 5, many pipelines currently have available pipeline capacity on the mainline portion of their systems. Unfortunately, NWP does not have any available capacity on its mainline or on any of the relevant laterals that serve Avista's requirements. GTN has mainline capacity currently available and may be able to provide additional service to some Washington/Idaho and Oregon customers without an expansion. Further, longer-term permanent capacity release options may be available on both pipelines.

Pipeline expansions can be more expensive than existing pipeline capacity and often require long-term annual contracts. Even though expansions may be more expensive than existing capacity, this approach may still provide the best option to the company given that most of the other options discussed in this section require pipeline transportation anyway.

Avista has dated information from the pipelines for a number of expansion scenarios and locations. This information was used as a basis for the transportation analysis. If and when Avista determines that additional transportation capacity is necessary, the company will request thorough estimates from the appropriate pipeline companies, search the release market for capacity that may include winter-only service, and seek capacity on constrained segments.

Large-scale LNG

There has been a considerable amount of national discussion regarding LNG gasification terminals. At today's natural gas prices, LNG can be competitively transported, stored and marketed. To date, at least 60 terminals have been proposed in the U.S., Mexico and Canada with seven or more terminals proposed for Washington, Oregon and British Columbia. Obviously, not all of these terminals will advance, and it may be possible that none of the Pacific Northwest terminals will proceed. The siting of LNG terminals is a difficult endeavor. In order for a terminal to advance, it will require economies of scale, the ability to move regasified supplies to markets, a favorable environmental review and public reception, secure LNG supply, long-term output/sales agreements and financing. Although the Pacific Northwest may not provide sponsors with these requirements, the recent announcement by PG&E Corporation, NWP and Fort Chicago Energy Partners to construct a pipeline from the proposed Coos Bay LNG facility to Malin, Ore., is certainly encouraging. This pipeline, assuming it and the LNG facility are built, may allow LNG to be directly delivered to Avista's service territory around Roseburg, Medford and Klamath Falls.

Industry experts believe that if additional LNG terminals are built and receive incremental supply, natural gas prices may trend downward or at least become less volatile. These experts also believe that it generally does not matter where the LNG terminals are located because the national natural gas markets are so tightly connected. Therefore, if the Pacific Northwest facilities do not proceed, Avista will likely benefit from increasing amounts of imported LNG.

For this IRP, Avista is not making LNG available to the model in any case other than the most robust demand case. This is because LNG in the Pacific Northwest is highly speculative, the region is not considered to be as premium of a market as other locations in North America and because it will take at least four years before it is known if this option would move forward in the Pacific Northwest. Each of the price forecasts the company has reviewed make assumptions regarding increasing LNG imports to North America so LNG commodity impacts are imbedded in those forecasts.

Avista will continue to monitor this intriguing option and will take action if a Pacific Northwest terminal begins to look promising.

RESULTS – PORTFOLIO INTEGRATION

After performing the preliminary analysis, the company focused on the question of how to cost effectively solve resource constraints for the Expected, High, and Low Demand cases (#2, 6 & 7). In order to answer this question, the company entered the new resource options as described above, and detailed in Appendix 6.4, into the SENDOUT® model and allowed the model to pick the least-cost approach to meeting resource deficiencies.

Figures 6.19 and 6.20 summarize the results of this modeling effort by comparing regional peak day demand against existing and incremental resources for the Expected Case over the 20-year period of the plan. Companion figures similar to Figures 6.19 and 6.20 are available in Appendix 6.5.

Figures 6.21 and 6.22 show the load duration curves, as well as the resource stacks for Case #2 for three different yearly intervals. These graphics are useful to review because an entire year of demand is compared to the resource stack for that same year. This enables a review of not just peak day sufficiency but also allows the opportunity to compare all demand days within that year. Similar figures for the High and Low Demand

Figure 6.19 – WA/ID Existing & Least Cost Resources vs. Peak Day Demand
(Net of DSM Savings) Expected Case – November to October

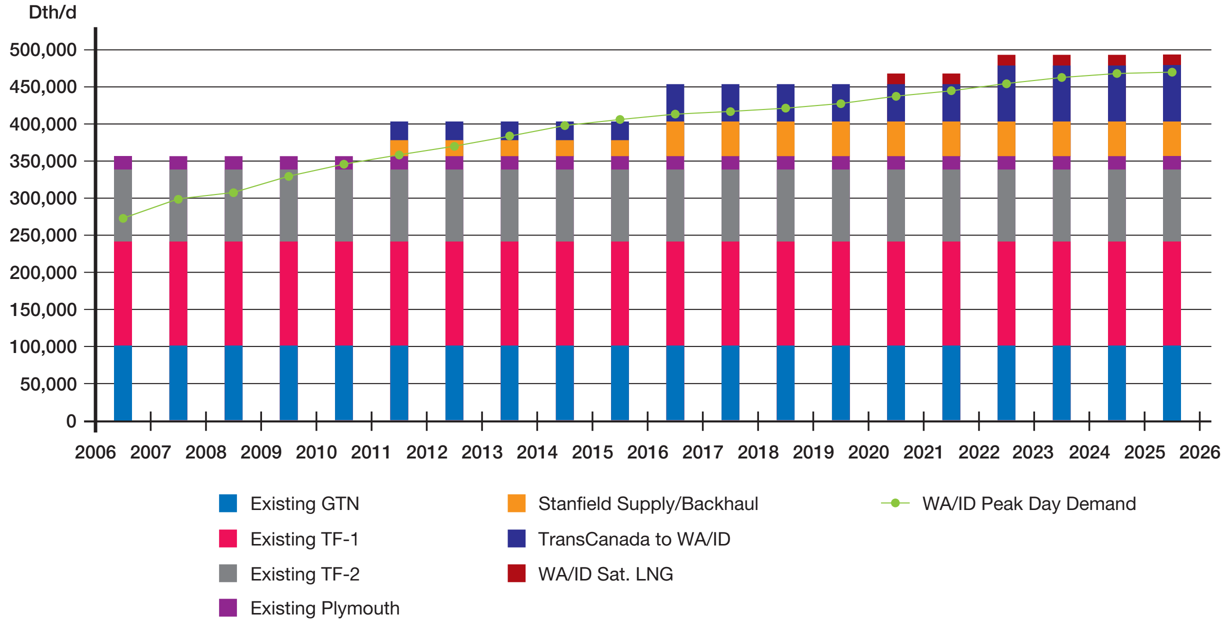
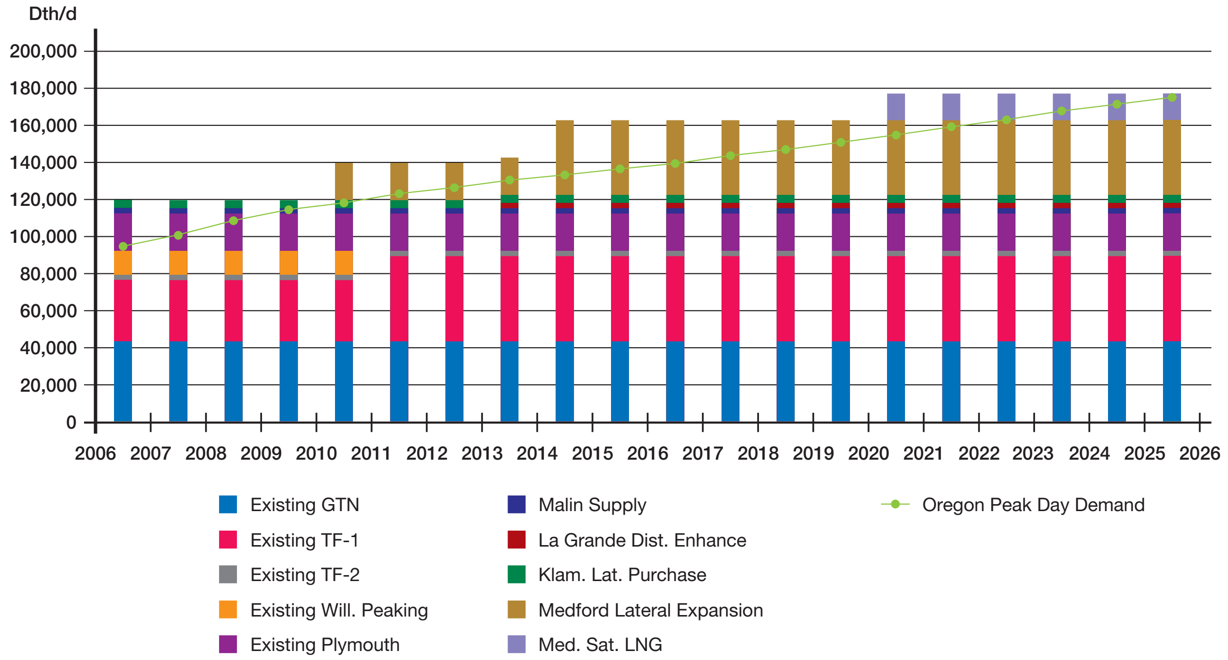


Figure 6.20 – Oregon Existing & Least Cost Resources vs. Peak Day Demand
(Net of DSM Savings) Expected Case – November to October



cases can be found in Appendix 6.6.

SENDOUT® considered all options entered into the program and determined when and what resources were needed. SENDOUT® also rejected options that were not cost effective. These selected resources represent the least-cost solution, within given constraints, to serve anticipated customer requirements. Table 6.12 shows the SENDOUT® selected supply-side resources for the Expected Case. The High and Low Demand case selections can be found in Appendix 6.7. Table 6.13 shows the SENDOUT® selected DSM savings for the Expected Case. The High and Low Demand case DSM savings can be found in Appendix 6.8.

Through ongoing and evolving investigation and research, the company may determine that alternative resources are more cost effective than those resources selected in this IRP. The company will continue to review and refine its knowledge of resource options and will act to secure these least-cost options at the appropriate point in time.

Avista has chosen to utilize the mid demand case (Case #2) as the most likely or "Expected Case" for its planning activities. Avista believes that this is the most likely outcome given company experience, industry knowledge and the company's understanding of future gas markets. This case provides for reasonable demand growth given current expectations of natural gas prices over the planning horizon. The company believes this case, if realized, is at a level that allows the company to be reasonably well protected against resource shortages and at the same time does not over commit to additional long-term resources. Further, given the extreme increase and decrease in demand levels over the full planning horizon for the Low Demand Case and the High Demand Case, the company believes that these cases, although possible, are less likely.

Avista will continue to diligently monitor demand levels and peak day requirements for "signposts" that indicate that demand levels are moving toward one of these other cases. Avista believes that through this monitoring process, and given that the company has sufficient time before potential resource shortages, there is little chance of being surprised by resource shortages.

Avista's portfolio and resource analysis indicates

Figure 6.21 – Load Duration Curve & Resource Stack (with DSM) Average/Actual Weather with Design Day Expected Case – WA/ID

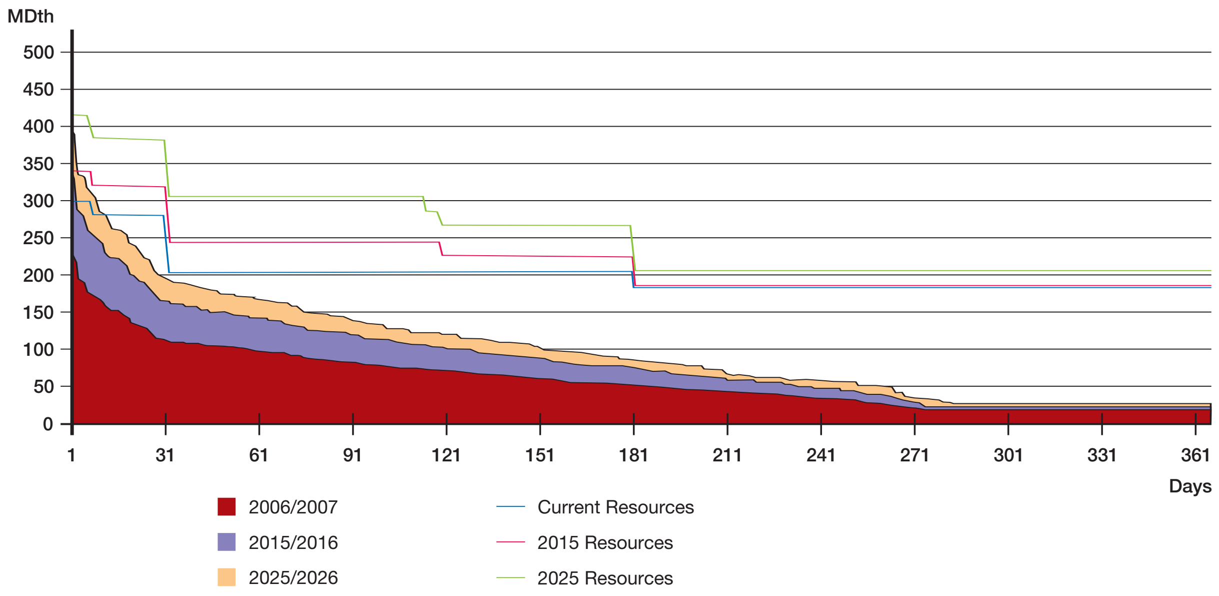
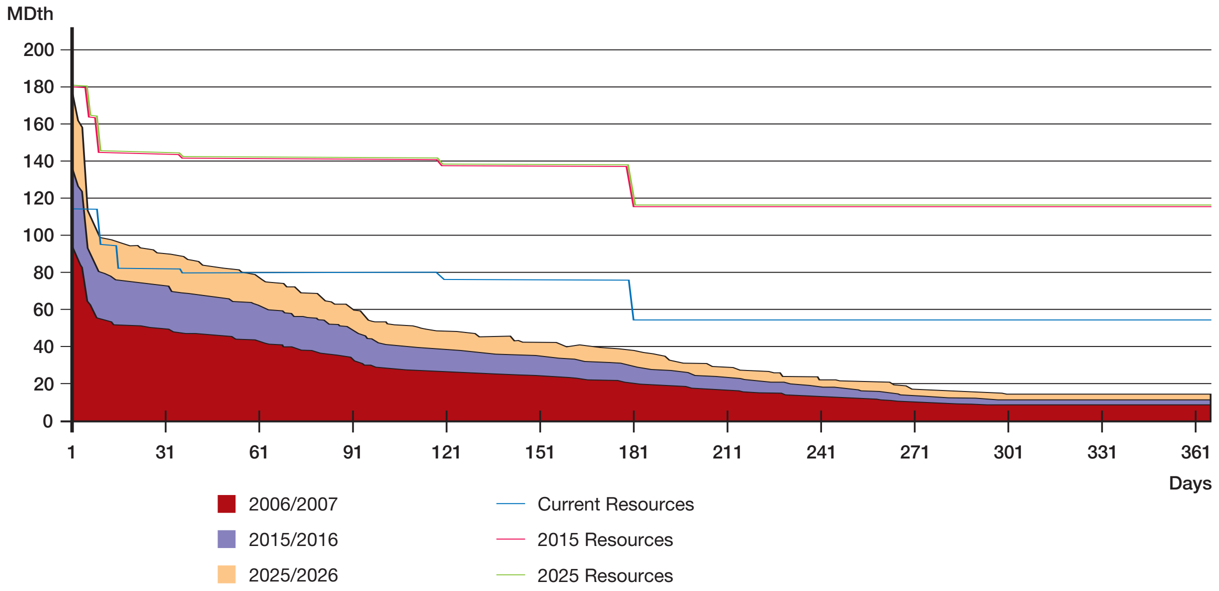


Figure 6.22 – Load Duration Curve & Resource Stack (with DSM) Average/Actual Weather with Design Day Expected Case – Oregon



several strategies that should be pursued in order to fully optimize available resources. The effectiveness of any strategy will be in the flexibility to take advantage of market opportunities. These strategies indicate that:

- Because of the diverse weather within Avista's service territory, a total system supply portfolio should be maintained to provide the greatest flexibility for dispatching resources while maintaining lower supply costs;
- Avista will continue to benefit from pursuing diversification of its firm transportation sources via GTN and NWP. Flexibility is again the key to being able to cost-effectively utilize the lowest priced delivered supply; and
- Capacity releases, both long-term and short-term, should continue to be reviewed periodically.

The company has also identified a number of resource areas that merit additional review prior to the next IRP. These areas include but are not limited to:

- Assessing methods for capturing additional existing storage asset value, including but not limited to recalling some or all of the current releases;
- Seeking low-cost peaking resources that do not require annual commitments;
- Investigating acquisition of winter capacity releases from third-party providers;
- Furthering the company's understanding of satellite LNG options;
- Researching low-cost transportation options to marry with storage assets to enable better utilization of the whole portfolio;
- Investigating the potential to balance Avista's storage portfolio among its various jurisdictions/service territories;
- Researching Northern California storage opportunities; and
- Continuing to analyze natural gas procurement practices.

Table 6.12 – Least Cost Supply-Side Resource Additions Selected by SENDOUT®
Case 2 - Expected Case

Item #	Region	Type	Quantity Dth/d	Timing	Rates/Charges
Washington/Idaho					
1	WA/ID	Transportation	22,000	November 2012	$4.7 MM Capital Cost Plus Commodity and NWP Transportation Rate
		Notes: WA/ID area expansions to facilitate the delivery in and around Spokane, Lewiston, etc. from GTN into NWP			
2	WA/ID	Transportation	22,000	November 2012	TransCanada and GTN Transportation Rates Plus Commodity
		Notes: Provides delivery to Item #1			
3	WA/ID	Transportation	25,000	November 2016	$5.0 MM Capital Cost Plus Commodity and NWP Transportation Rate
		Notes: WA/ID area expansions to facilitate the delivery in and around Spokane, Lewiston, etc. from GTN into NWP			
4	WA/ID	Transportation	25,000	November 2016	TransCanada and GTN Transportation Rates Plus Commodity
		Notes: Provides delivery to Item #3			
5	WA/ID	Satellite LNG	15,000	November 2020	$10MM Capital Cost/$1.5MM Annual Expense Plus Commodity
6	WA/ID	Transportation	25,000	November 2022	$5.0 MM Capital Cost Plus Commodity and NWP Transportation Rate
		Notes: WA/ID area expansions to facilitate the delivery in and around Spokane, Lewiston, etc. from GTN into NWP			
7	WA/ID	Transportation	25,000	November 2022	TransCanada and GTN Transportation Rates Plus Commodity
		Notes: Provides delivery to Item #6			
Oregon					
8	Klamath Falls	Purchase	n/a	November 2006	$3MM Capital Cost
		Notes: Purchase of NWP Klamath pipeline segment. Transportation and fuel cost savings more than offset the revenue requirement and capital cost of the investment. Payoff is approximately 3 years			
9	Klamath Falls	Reclassification	6,000	November 2006	No Incremental Charges
		Notes: Companion to Item #8. Ownership of lateral allows Avista to operate this lateral as distribution transmission system which provides aproximately 6,000 Dth/d incremental capacity			
10	Medford/Roseburg	Distribution Enhancement	n/a	November 2007	$11MM Capital Cost/$1.3MM Annual Revenue Requirement
		Notes: Companion item to Item #11 and 13 below			
11	Medford/Roseburg	Transportation	20,000	November 2010	GTN's Med. Lat. Rate
		Notes: GTN expansion of the Medford Lateral. Assumed current lateral rates, escalated for inflation, for expansion. Item #10 above required to facilitate this option.			
12	La Grande	Distribution Enhancement	4,000	November 2013	$3MM Capital Cost/$.360MM Annual Revenue Requirement
13	Medford/Roseburg	Transportation	20,000	November 2014	GTN's Med. Lat. Rate
		Notes: GTN expansion of the Medford Lateral. Assumed current lateral rates, escalated for inflation, for expansion. Item #10 above required to facilitate this option.			
14	Medford/Roseburg	Satellite LNG	15,000	November 2020	$10MM Capital Cost/$1.5MM Annual Expense Plus Commodity

Table 6.13 – Annual and Average Daily Demand Served by Demand-Side Management
Actual peak day DSM is greater than annual average DSM

Case	Gas Year	Annual Klamath DSM (MDth)	Daily Klamath DSM (MDth/day)	Annual La Grande DSM (MDth)	Daily La Grande DSM (MDth/day)	Annual Medford DSM (MDth)	Daily Medford DSM (MDth/day)	Annual Roseburg DSM (MDth)	Daily Roseburg DSM (MDth/day)
2	2006-2007	9.991	0.027	4.280	0.012	24.781	0.068	5.933	0.016
2	2007-2008	20.043	0.055	8.586	0.024	49.768	0.136	11.903	0.033
2	2008-2009	29.972	0.082	12.841	0.035	74.342	0.204	17.799	0.049
2	2009-2010	39.963	0.109	17.121	0.047	99.122	0.272	23.732	0.065
2	2010-2011	49.953	0.137	21.402	0.059	123.903	0.339	29.665	0.081
2	2011-2012	60.129	0.165	25.757	0.071	149.304	0.409	35.708	0.098
2	2012-2013	69.934	0.192	29.962	0.082	173.464	0.475	41.531	0.114
2	2013-2014	79.925	0.219	34.243	0.094	198.245	0.543	47.464	0.130
2	2014-2015	89.916	0.246	38.523	0.106	223.026	0.611	53.397	0.146
2	2015-2016	100.214	0.275	42.928	0.118	248.840	0.682	59.513	0.163
2	2016-2017	100.872	0.276	45.431	0.124	271.991	0.745	65.678	0.180
2	2017-2018	100.259	0.275	45.142	0.124	269.794	0.739	65.103	0.178
2	2018-2019	99.646	0.273	44.853	0.123	267.597	0.733	64.529	0.177
2	2019-2020	98.970	0.271	44.530	0.122	265.653	0.728	63.951	0.175
2	2020-2021	97.684	0.268	43.948	0.120	261.452	0.716	62.976	0.173
2	2021-2022	95.132	0.261	43.460	0.119	252.750	0.692	60.728	0.166
2	2022-2023	92.581	0.254	42.973	0.118	244.048	0.669	58.480	0.160
2	2023-2024	90.289	0.247	42.599	0.117	236.314	0.647	56.391	0.154
2	2024-2025	87.037	0.238	41.801	0.115	225.549	0.618	53.727	0.147
2	2025-2026	79.393	0.218	39.059	0.107	204.712	0.561	48.678	0.133

Case	Gas Year	Annual Oregon DSM (MDth)	Daily Oregon DSM (MDth/day)	Annual WA/ID DSM (MDth)	Daily WA/ID DSM (MDth/day)	Annual Total System DSM (MDth)	Daily Total System DSM (MDth/day)
2	2006-2007	44.98	0.12	105.038	0.288	150.02	0.41
2	2007-2008	90.30	0.25	210.723	0.577	301.02	0.82
2	2008-2009	134.95	0.37	315.115	0.863	450.07	1.23
2	2009-2010	179.94	0.49	420.153	1.151	600.09	1.64
2	2010-2011	224.92	0.62	525.192	1.439	750.11	2.06
2	2011-2012	270.90	0.74	621.538	1.703	892.44	2.45
2	2012-2013	314.89	0.86	712.033	1.951	1,026.92	2.81
2	2013-2014	359.88	0.99	804.429	2.204	1,164.31	3.19
2	2014-2015	404.86	1.11	896.826	2.457	1,301.69	3.57
2	2015-2016	451.49	1.24	992.248	2.718	1,443.74	3.96
2	2016-2017	483.97	1.33	1,089.136	2.984	1,573.11	4.31
2	2017-2018	480.30	1.32	1,087.088	2.978	1,567.39	4.29
2	2018-2019	476.62	1.31	1,082.768	2.966	1,559.39	4.27
2	2019-2020	473.10	1.30	1,077.291	2.951	1,550.39	4.25
2	2020-2021	466.06	1.28	1,065.283	2.919	1,531.34	4.20
2	2021-2022	452.07	1.24	1,054.580	2.889	1,506.65	4.13
2	2022-2023	438.08	1.20	1,045.926	2.866	1,484.01	4.07
2	2023-2024	425.59	1.17	1,040.305	2.850	1,465.90	4.02
2	2024-2025	408.11	1.12	1,017.861	2.789	1,425.98	3.91
2	2025-2026	371.84	1.02	998.575	2.736	1,370.42	3.75

SECTION 7 – AVOIDED COST DETERMINATION

Avista's avoided cost estimates represent the marginal cost of natural gas usage incremental to the forecasted demand. In other words, avoided cost is the unit cost to serve the next unit of demand during any given period of time. If demand-side management measures reduce customer demand, the company is able to "avoid" certain commodity and transportation costs.

METHODOLOGY

To develop avoided cost figures associated with the reduction of natural gas usage, a demand forecast, existing and future supply-side resources, and demand-side resources are required. Avista utilizes the SENDOUT® model data used throughout this IRP to produce its avoided cost figures. In particular, the company assumes the Expected Case (Case #2) as the appropriate data set.

SENDOUT® functionality provides for marginal cost data by day, month and year for each demand area. This marginal cost data includes the cost of the next unit of supply and the associated transportation charges to move this unit.

AVOIDED COST DETERMINATIONS

Avista has summarized the SENDOUT® calculated avoided cost data in Appendix 7.1. This has been divided into annual and winter costs and is averaged accordingly. Winter season costs are most appropriate when considering heat-related avoided costs. Annual costs are most appropriate when considering non-heat (base load) related avoided costs.

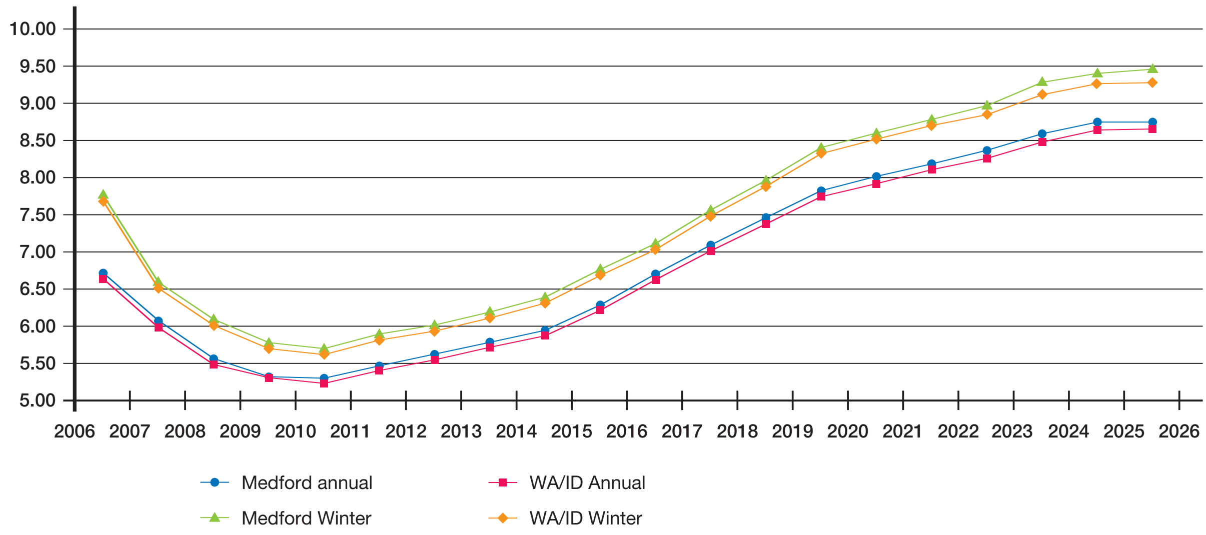
Note that Appendix 7.1 displays avoided cost figures for each of the demand regions discussed in this IRP. Also note that figures are stated in nominal dollars per dekatherm and are not discounted.

A graphical depiction of the avoided costs for the Medford and Washington/Idaho areas for annual and winter-only dekatherm usage is represented in Figure 7.1. These avoided costs exclude consideration of environmental externality adders.

ENVIRONMENTAL COSTS AND EXTERNALITIES (OREGON JURISDICTION ONLY)

The methodology employed to develop the avoided costs associated with the reduction of natural gas usage has been based upon the monetary value associated with

Figure 7.1 – Natural Gas Avoided Costs - $/Dth
Includes Commodity & Trans. Costs/Excludes Env. Ext. Adder – November to October



commodity and transportation costs only. These avoided cost streams do not include a valuation of the environmental externality costs related to the gathering, transmission, distribution or end-use of natural gas.

Per traditional economic theory and industry practice, an environmental externality factor is typically added to the monetary avoided cost when there is an opportunity to displace traditional supply-side resources with an alternative resource lacking this adverse environmental impact. Per the requirements established within UM 424 (see excerpt below) a 10 percent conservation cost advantage environmental externality factor must be added to the above stream of avoided costs when evaluating natural gas-efficiency options.

UM 424, SECTION 9

"We base our decision in part on the conclusion by the Northwest Power Planning Council in 1987 that the 10 percent cost advantage should be continued. The Council identified a number of conservation benefits not then quantified in its analysis, including the elimination of fish and wildlife impacts and other environmental effects of displaced generating resources, load stability and predictability, flexibility to adapt to changing circumstances, and increased customer comfort. We believe these benefits are not fully recognized in utility planning and resource decisions, so electric and gas utilities should continue to apply the 10 percent conservation cost advantage."

In compliance with this clear directive, the company will incorporate this 10 percent environmental externality "adder" into our assessment of the cost-effectiveness of existing and proposed demand-side management programs. Additionally our assessment of prospective demand-side management opportunities will be based upon an avoided cost stream that includes the same consideration of environmental externalities. When appropriate these evaluations and resource decisions will be based upon program impacts, markets and environmental impacts that are as geographically specific as possible.

Avista's natural gas DSM business planning process will continue to incorporate full consideration of the required environmental externality factor.

SECTION 8 – ACTION PLAN

AVISTA UTILITIES 2003 ACTION PLAN REVIEW

The 2003 action plan focused on six key areas:

- Sales Forecasting
- Modeling/Forecasting
- Supply/Capacity
- Demand-Side Management
- Distribution Planning
- Public Involvement

SALES FORECASTING

Action Item:

Avista will continue to track the price elasticity customer use responses over the action plan period to validate or modify the lag structure.

Results:

Price elasticity response rates were tracked during the action plan period. Despite dramatic reductions in usage after the 2001 energy crisis, elasticity response rates have returned to pre-2001 levels. This was discussed at the Oct. 4, 2005 TAC meeting.

MODELING/DAILY FORECASTING

Action Item:

Avista will continue to use the SENDOUT® Gas Planning Model and the Nostradamus® Forecasting Model to evaluate capacity requirements, storage requirements, supply requirements, monthly guidance for Natural Gas Supply, etc.

Results:

Avista utilized and continues to utilize these tools for the above-mentioned purposes since the 2003 IRP was filed. The company employs these models on a regular basis and has refined them to meet changing business needs on a proactive basis.

SUPPLY/CAPACITY

Action Item:

Avista will continue to monitor Avista Energy as part of the "bench marking" agreement. Avista will continue to supply the State Commission Staffs with quarterly reports as stipulated in the "bench marking" agreement. Avista will also continue to analyze the need for additional interstate pipeline capacity and to evaluate the renewal of transportation contracts as they expire.

Results:

The "Benchmark Mechanism" expired on March 31, 2005.

DEMAND-SIDE MANAGEMENT

Action Item:

Within the company's Washington and Idaho service territory, the company will work toward achieving available cost-effective natural gas efficiency opportunities while simultaneously bringing the tariff rider balance back to zero in a timely manner. Toward these ends Avista has identified the following action items for these two jurisdictions:

- Continue to target low-cost/no-cost and lost opportunity measures in the commercial/industrial segments.
- Evaluate the rotation of programs contained within the residential portfolio to create a sense of urgency on the part of customers and dealer infrastructure.
- Leverage regional and local electric efficiency programs to realize natural gas-efficiency opportunities.

Within the Oregon jurisdiction the company has identified the following action items:

- Evaluate the impact of the space and water heating natural gas efficiency programs, to include an evaluation of the market transformation effects.

- Avista will continuously reevaluate the company's approach to meeting mandated residential weatherization, commercial audit and commercial incentive program responsibilities. The company will work with external stakeholder groups to meet common objectives and optimize implementation.

Results:

Within the North Division, the company committed to the acquisition of cost-effective natural gas efficiency opportunities while simultaneously returning the DSM tariff rider balance back to zero. Since that commitment, Avista has exceeded achieved acquisition levels up to and exceeding four times the goal specified within Avista Rate Schedule 190. The aggregate tariff rider balance was successfully returned to zero in August 2005, although the Idaho natural gas tariff rider balance retains a negative balance. The company is currently executing a business plan that incorporates periodic revisions to tariff rider levels to maintain a near-zero balance in all tariff riders while providing the necessary funding for the substantial increase in the acquisition goals specified within this IRP.

The company also committed to an evaluation of space and water heating appliance efficiency programs. Based on a review of engineering calculations and revisions to the baseline standard efficiency the per unit savings claims were updated for purposes of calculating program cost-effectiveness.

Additional commitments were made to continue the continuous reevaluation of the optimal approach to meeting the company's responsibilities for mandated residential and commercial programs. This work has, and will continue to be, an ongoing effort. To date, this program has included establishing a dialogue with the Energy Trust of Oregon regarding the potential for cooperative programs.

DISTRIBUTION PLANNING

Action Item:

Avista will continue to use the Stoner Workstation in activities of distribution planning and continue to integrate the GIS system into the planning functions.

Results:

Avista continues to improve its GIS system through the conversion of each service territory's facility and mapping records. After conversion, distribution models can be generated using standardized load study practices, resulting in consistency and accuracy.

PUBLIC INVOLVEMENT

Action Item:

Avista will continue to participate in the energy planning efforts of other organizations in the Northwest, as well as any national studies that may occur. This includes but is not limited to studies being performed under the guidance of the American Gas Association, the Northwest Gas Association and the FERC.

Avista will also look to other utilities in the northwest to find better ways to get active, meaningful participation in the TAC.

Results:

Avista is active with the Northwest Gas Association, American Gas Association, Western Energy Institute and the Northwest Power and Conservation Council as well as with many other industry organizations. Avista's participation allows for the sharing of best practices and the enhancement of valuable relationships with industry participants and stakeholders.

AVISTA UTILITIES 2006-2007 ACTION PLAN

The 2006 action plan is focused on the following key areas:

- Sales Forecasting
- Supply/Capacity
- Forecasting
- Demand-Side Management
- Distribution Planning

SALES FORECASTING

Action Items:

During 2006, the company will update customer forecasting models, incorporating the most recent data. The dramatic increase in natural gas retail prices will provide improved information on price elasticity and weather sensitivity coefficients.

Avista anticipates making two changes to the forecasting methodology, one in 2006 and the other in 2007. The company currently uses county-level forecasts for eight counties in the three states it serves. During 2006, Avista will add five counties, two in Washington and three in Idaho. This will help identify differential growth patterns between the core areas (Spokane and Coeur d'Alene) and the more rural and resort areas of the service area.

In 2007, utilizing the data and forecasts from these additional counties, Avista will develop a "gate-station" forecasting system that will allocate the sales and customer forecast to the various pipeline delivery points in the service area. Avista anticipates having this system available so that the company can utilize the results for the next IRP.

SUPPLY/CAPACITY

Action Items:

Avista will conduct regular meetings with Commission Staff members with the intent to provide information on market updates, any material changes to the hedging program, and significant changes in assumptions and status of company activity related to the IRP.

Avista will continue to seek low-cost peaking resources that do not require annual contractual commitments and will investigate acquisition of winter capacity releases from third-party providers.

The company will further its understanding of LNG opportunities, including satellite and company-owned LNG resources. Avista will further consider and evaluate the Coos Bay LNG/Pacific Connector Pipeline opportunity.

The company will assess methods for capturing additional value related to existing storage assets, including but not limited to recalling some or all of the current releases.

Avista will further develop its storage strategy with particular focus on storage opportunities for Oregon customers and will research non-Jackson Prairie storage prospects for all customers.

FORECASTING

Action Item:

The company will complete its evaluation of VectorGas™. If purchased, the company will utilize VectorGas™ to strengthen Avista's ability to analyze the financial impacts under varying load and price scenarios.

DEMAND-SIDE MANAGEMENT

Action Item:

The DSM analysis that occurred during the IRP process is the launching point for a more detailed investigation of the natural gas-efficiency technologies identified as cost-effective resource options.

The company initiated this additional evaluation and development of programs in January 2006 with the expectation that program revisions and the launch of new programs will occur in the spring of that same year.

The company has explicitly recognized within this IRP the obligation to achieve all natural gas-efficiency resources available through the intervention of cost-effective utility programs. Given the rapid changes within the natural gas market, there are many new efficiency opportunities within the market. Considerable uncertainty remains regarding the customer response to these programs. This uncertainty does not preclude the company from pursuing the planned aggressive ramp-up of natural gas-efficiency programs. Additionally, the company has and will actively seek opportunities for new or enhanced resource acquisition through the development of cooperative regional programs.

DISTRIBUTION PLANNING

Action Item:

Avista will continue to utilize computer modeling to facilitate distribution-planning efforts and identify least-cost opportunities to meet growth and reinforcement needs. Avista will determine the benefit and feasibility of using city-gate station forecasts as a method for improving distribution planning.

SECTION 9 – GLOSSARY

SECTION 9 – GLOSSARY OF TERMS AND ACRONYMS

Avista Corporation (Avista Corp.)

An energy company engaged in the generation, transmission and distribution of energy as well as other energy-related businesses; Avista is located in the Pacific Northwest with corporate headquarters located in Spokane, Wash.

Avista Energy

The non-regulated energy marketing and trading affiliate of Avista Corporation.

Avista Utilities (Also referred to as Avista or the company)

The regulated operating division of Avista Corp., separated into North (Washington and Idaho) and South (Oregon) operating divisions; Avista Utilities generates, transmits and distributes electricity in addition to the transmission and distribution of natural gas.

Backhaul

A transaction where gas is transported the opposite direction of normal flow on a unidirectional pipeline.

Base Load

As applied to natural gas, a given demand for natural gas that remains fairly constant over a period of time, usually not temperature sensitive.

Basis Differential

The difference in price between any two natural gas pricing points or time periods. One of the more common references to basis differential is the pricing difference between Henry Hub and any other pricing point in the continent.

British Thermal Unit (BTU)

The amount of heat required to raise the temperature of one pound of pure water one degree Fahrenheit under stated conditions of pressure and temperature; a therm (see below) of natural gas has an energy value of 100,000 BTUs and is approximately equivalent to 100 cubic feet of natural gas.

Cascade Natural Gas Corporation

A natural gas local distribution company headquartered in Seattle, Wash., serving customers in Washington and Oregon.

City-Gate (Also known as gate station or pipeline delivery point)

The point at which natural gas deliveries transfer from the interstate pipelines to Avista's distribution system.

Commodity Price

The current price for a supply of natural gas that is charged for each unit of natural gas supplied as determined by market conditions.

Compression

Increasing the pressure of natural gas in a pipeline by means of a mechanically driven compressor station to increase flow capacity.

Contract Demand (CD)

The maximum daily, monthly, seasonal or annual quantities of natural gas, which the supplier agrees to furnish, or the pipeline agrees to transport, and for which the buyer or shipper agrees to pay a demand charge.

Core Load

Firm delivery requirements of Avista, which are comprised of residential, commercial and firm industrial customers.

CPI

Consumer Price Index, as calculated and published by the U.S. Department of Labor, Bureau of Labor Statistics.

Cubic Foot (cf)

A measure of natural gas required to fill a volume of one cubic foot under stated conditions of temperature, pressure and water vapor; one cubic foot of natural gas has the energy value of approximately 1,000 BTUs and 100 cubic feet of natural gas equates to one therm (see below).

Curtailment

A restriction or interruption of natural gas supplies or deliveries; may be caused by production shortages, pipeline capacity or operational constraints or a combination of operational factors.

Dekatherm (Dth)

Unit of measurement for natural gas; a dekatherm is 10 therms, which is one thousand cubic feet (volume) or one million BTUs (energy).

Demand-Side Resources

Energy resources obtained through assisting customers to reduce their "demand" or use of natural gas.

Demand-Side Management (DSM)

The activity of implementing demand-side measures to minimize customers' energy usage in their facilities.

Design Day

A 24-hour period of demand, which is used as a basis for planning peak natural gas capacity requirements. For purposes of this plan, the company calculates design day demand based upon the coldest day on record for each of several service regions.

Econometric Model

A set of equations developed through regression analysis and other quantitative techniques, as well as intuitive judgment that mathematically represents and forecasts economic relationships.

End User

The ultimate consumer of natural gas; the end user purchases the natural gas for consumption, not for resale or transportation purposes.

Externalities

Cost and benefits that are not reflected in the price paid for goods or services.

Federal Energy Regulatory Commission (FERC)

The government agency charged with the regulation and oversight of interstate natural gas pipelines, wholesale electric rates and hydroelectric licensing; the FERC regulates the interstate pipelines with which Avista does business and determines rates charged in interstate transactions.

Firm Service

Service offered to customers under schedules or contracts that anticipate no interruptions; the highest quality of service offered to customers.

Force Majeure

An unexpected event or occurrence not within the control of the parties to a contract, which alters the application of the terms of a contract; sometimes referred to as "an act of God;" examples include severe weather, war, strikes, pipeline failure and other similar events.

Forward Price

The future price for a quantity of natural gas to be delivered at a specified time.

Gas Day

A period of 24 consecutive hours commencing at 9 a.m. Central Clock Time (7 a.m. Pacific Clock Time); this is an industry standard throughout North America.

GasSolutions

A relational database system developed by Avista to nominate, track and report flows of natural gas.

Gas Transmission Northwest (GTN)

One of the six natural gas pipelines the company deals with directly; GTN is headquartered in Portland, Ore., and it is a subsidiary of TransCanada Pipeline; owns and operates a natural gas pipeline that runs from Canada to the Oregon/California border.

Geographic Information System (GIS)

A system of computer software, hardware and spatially referenced data that allows information to be modeled and analyzed geographically.

Global Insight, Inc.

A national economic forecasting company.

Heating Degree-Day (HDD)

A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below 65 degrees Fahrenheit; a daily average temperature represents the sum of the high and low readings divided by two.

Henry Hub

The physical location found in Louisiana that is widely recognized as the most important pricing point in the United States. It is also the trading hub for the New York Mercantile Exchange (NYMEX).

Injection

The process of putting natural gas into a storage facility; also called liquefaction when the storage facility is a liquefied natural gas plant.

Integrity Management Plan (IMP)

A federally regulated program that requires companies to evaluate the integrity of their natural gas pipelines based on population density. The program requires companies to identify high consequence areas, assess the risk of a pipeline failure in the identified areas and provide appropriate mitigation measures when necessary.

Interruptible Service

A service of lower priority than firm service offered to customers under schedules or contracts that anticipate and permit interruptions on short notice; the interruption happens when the demand of all firm customers exceeds the capability of the system to continue deliveries to all of those customers.

IPUC

Idaho Public Utilities Commission

Integrated Resource Plan (IRP)

The document that explains Avista's plans and preparations to maintain sufficient resources to meet customer needs at a reasonable price; also known as a Least Cost Plan (see LCP).

Jackson Prairie Storage Project (JP or JPSP)

An underground storage project jointly owned by Avista Corp., Puget Sound Energy, and NWP; the project is a naturally occurring aquifer near Chehalis, Wash., which is located some 1,800 feet beneath the surface and capped with a very thick layer of dense shale.

Liquefaction

Any process in which natural gas is converted from the gaseous to the liquid state; for natural gas, this process is accomplished through lowering the temperature of the natural gas (see LNG).

Liquefied Natural Gas (LNG)

Natural gas that has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure.

Linear Programming

A mathematical method of solving problems by means of linear functions where the multiple variables involved are subject to constraints; this method is utilized in the SENDOUT® Gas Model.

Load Duration Curve

An array of daily sendouts observed that is sorted from highest sendout day to lowest to demonstrate both the peak requirements and the number of days it persists.

Load Factor

The average load of a customer, a group of customers, or an entire system, divided by the maximum load; can be calculated over any time period.

Local Distribution Company (LDC)

A utility that purchases natural gas for resale to end-use customers and/or delivers customers' natural gas or electricity to end users' facilities.

Looping

The construction of a second pipeline parallel to an existing pipeline over the whole or any part of its length, thus increasing the capacity of that section of the system.

LS-1

NWP rate schedule covering its LNG service; also used to refer to the natural gas (as in "LS-1" natural gas).

MCF

A unit of volume equal to a thousand cubic feet.

MDQ

Maximum Daily Quantity.

MMBTU

A unit of heat equal to one million British thermal units (BTUs) or 10 therms. Can be used interchangeably with Dth.

National Energy Board (NEB)

The Canadian equivalent to the Federal Energy Regulatory Commission (FERC).

National Oceanic Atmospheric Administration (NOAA)

Publishes the latest weather data; the 30-year weather study included in this IRP is based on this information.

Natural Gas

A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in porous geologic formations beneath the earth's surface, often in association with petroleum; the principal constituent is methane, and it is lighter than air.

New Energy Associates

The developers of the SENDOUT® Gas Planning System, a Siemens Company.

New York Mercantile Exchange (NYMEX)

An organization that facilitates the trading of several commodities including natural gas.

Nomination

The scheduling of daily natural gas requirements.

Non-Coincidental Peak Demand

The demand forecast for a 24-hour period for multiple regions that includes at least one design day and one non-design day.

Non-Firm Open Market Supplies

Natural gas purchased via short-term purchase arrangements; may be used to supplement firm contracts during times of high demand or to displace other volumes when it is cost-effective to do so; also referred to as spot market supplies.

Northwest Pipeline Corporation (NWP)

The principal interstate pipeline serving the Pacific Northwest and one of six natural gas pipelines the company deals with directly; NWP is Avista's primary transporter of natural gas; headquartered in Salt Lake City, Utah, NWP is a subsidiary of The Williams Companies.

NOVA Gas Transmission (NOVA)

See TransCanada Alberta System

Northwest Power and Conservation Council (NWPPC)

A regional energy planning and analysis organization headquartered in Portland, Ore.

OPUC

Public Utility Commission of Oregon

Peak Day

The 24-hour day period of greatest total natural gas sendout; may be used to represent historical actual or projected requirements. Sometimes referred to as a Design Day.

Peak Day Curtailment

Curtailment imposed on a day-to-day basis during periods of extremely cold weather when demands for natural gas exceed the maximum daily delivery capability of a pipeline system.

Peaking Capacity

The capability of facilities or equipment normally used to supply incremental natural gas under extreme demand conditions (i.e., peaks); generally available for a limited number of days at this maximum rate.

Peaking Factor

A ratio of the peak hourly flow and the total daily flow at the city-gate stations used to convert daily loads to hourly loads.

Propane

An alternative hydrocarbon fuel which has a higher heat value than natural gas (2550 BTUs vs. 1000 BTUs per cubic foot), however it also has higher safety concerns including being heavier than air (i.e., doesn't dissipate) and being more easily ignited.

Propane Air

Propane mixed with air and natural gas to allow burning in a natural gas system to supplement natural gas supplies for customers on peak days.

PSI

Pounds per square inch – a measure of the pressure at which natural gas is delivered (see Delivery Pressure)

Rate Base

The investment value established by a regulatory authority upon which a utility is permitted to earn a specified rate of return; generally this represents the amount of property used and useful in service to the public.

Resource Stack

Sources of natural gas infrastructure or supply available to serve Avista's customers.

Seasonal Capacity

Natural gas transportation capacity designed to service in the winter months.

Sendout

The amount of natural gas consumed on any given day.

SENDOUT®

Natural gas planning system from New Energy Associates; a linear programming model used to solve gas supply and transportation optimization questions.

Service Area

Territory in which a utility system is required or has the right to provide natural gas service to ultimate customers.

SGS

NWP rate schedule covering storage natural gas from Jackson Prairie; also used to refer to storage natural gas supply.

Shoulder Months

Generally defined as the months of March, April and May (in the spring) or September and October (in the fall) when the temperatures are moderate and customer demand is unpredictable.

Spot Market Gas

Natural gas purchased under short-term agreements as available on the open market; prices are set by market pressure of supply and demand.

Storage

The utilization of facilities for storing natural gas which has been transferred from its original location for the purposes of serving peak loads, load balancing and the optimization of basis differentials; the facilities are usually natural geological reservoirs such as depleted oil or natural gas fields or water-bearing sands sealed on the top by an impermeable cap rock; the facilities may be man-made or natural caverns. LNG storage facilities generally utilize above ground insulated tanks.

Tariff

A published volume of regulated rate schedules plus general terms and conditions under which a product or service will be supplied.

TF-I

NWP's rate schedule under which Avista moves natural gas supplies on a firm basis.

TF-2

NWP's rate schedule under which Avista moves natural gas supplies out of storage projects on a firm basis.

Technical Advisory Committee (TAC)

Industry, customer and regulatory representatives that advise Avista during the IRP planning process.

Terasen

A natural gas LDC headquartered in Vancouver, British Columbia, serving customers in Canada. Formerly known as BC Gas.

Therm

A unit of heating value used with natural gas that is equivalent to 100,000 British thermal units (BTU); also approximately equivalent to 100 cubic feet of natural gas.

TransCanada Alberta System (TCPL-AB)

Previously known as NOVA Gas Transmission; a natural gas gathering and transmission corporation in Alberta that delivers natural gas into the TransCanada BC System pipeline at the Alberta/British Columbia border; one of six natural gas pipelines Avista deals with directly.

TransCanada BC System (TCPL-BC)

Previously known as Alberta Natural Gas; a natural gas transmission corporation of British Columbia that delivers natural gas between the TransCanada-Alberta System and GTN pipelines that runs from the Alberta/British Columbia border to the US border; one of six natural gas pipelines Avista deals with directly.

Transportation Gas

Natural gas purchased either directly from the producer or through a broker and is used for either system supply or for specific end-use customers, depending on the transportation arrangements; NWP and GTN transportation may be firm or interruptible.

Tuscarora Gas Transmission Company

One of the six natural gas pipelines the company deals with directly; Tuscarora is a subsidiary of Sierra Pacific Resources and TransCanada; this natural gas pipeline runs from the Oregon/California border to Reno, Nevada.

Vaporization

Any process in which natural gas is converted from the liquid to the gaseous state.

WACOG

Weighted Average Cost of Gas; the price paid for a volume of natural gas and associated transportation based on the prices of individual volumes of natural gas that make up the total quantity supplied over an established time period.

Weather Normalization

The estimation of the average annual temperature in a typical or “normal” year based on examination of historical weather data; the normal year temperature is used to forecast utility sales revenue under a procedure called sales normalization.

Withdrawal

The process of removing natural gas from a storage facility, making it available for delivery into the connected pipelines; vaporization is necessary to make withdrawals from an LNG plant.

WUTC

Washington Utilities and Transportation Commission.

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