2012 Natural Gas Integrated Resource Plan

August 31, 2012

www.avistautilities.com

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Note: Appendices provided under separate cover.

II SAFE HARBOR STATEMENT

This document contains forward-looking statements, including statements regarding our current expectations for future financial performance and cash flows, capital expenditures, financing plans, our current plans or objectives for future operations and other factors, which may affect the company in the future. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond our control and many of which could have significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in such statements.

For a further discussion of these factors and other important factors please refer to the Company's reports filed with the Securities and Exchange Commission, which are available on our website at www.avistacorp.com. The forward-looking statements contained in this document speak only as of the date hereof. We undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on our business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

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2012 IRP KEY MESSAGES

- Avista has a diversified portfolio of existing natural gas supply resources including owned and contracted storage, firm capacity rights on six pipelines and purchase contracts from several different supply basins. Our philosophy is to reliably provide natural gas to customers with an appropriate balance of price stability and prudent cost.
- Avista's 2012 Integrated Resource Plan (IRP) forecasts lower demand for all service territories than our previous plans. These reductions are driven by lower growth rates and declining use-per-customer in our service territories than originally anticipated driven primarily by the recession.
- Additional resource needs do not occur until well into the future. In Oregon, the first resource deficits occur in 2029 and in Washington and Idaho in 2030. Demand growth averages 1.3 percent per year in the respective jurisdictions. Customer accounts are expected to grow at an annual average rate of 1.6 percent and 1.7 percent, respectively. Our plan indicates incremental pipeline transportation capacity is the preferred resource to meet the identified needs.
- An important risk with the identified future resource deficits is the relatively flat slope of forecasted demand growth. Implied in this outlook is existing resources will be sufficient to meet demand for most of the 20 year planning horizon. However, should demand growth accelerate, the steepening of the demand curve could quickly accelerate resource shortages by several years.
- Other risks evaluated include long term natural gas pricing levels, potential impacts of carbon legislation and hydraulic fracturing, future availability of existing regional resources, implication of exporting LNG, alternate weather planning standard, and potential NGV/CNG demand.
- Conservation potential is an integral component of our IRP process and a starting point for the DSM business planning process, as these programs result in multiple benefits including reduced customers' bills, reduced supply-side resource needs and reduced greenhouse gas (GHG) emissions. Lower avoided costs have challenged the cost-effectiveness of natural gas DSM programs, resulting in filings to suspend programs in Washington and Idaho. The Oregon DSM portfolio is currently under evaluation.
- The IRP identifies and establishes an Action Plan that continues to guide us toward the risk-adjusted, least-cost method of providing service to our natural gas customers. Included in this Action Plan are efforts to closely monitor avoided costs and the cost effectiveness of natural gas DSM, evaluate current price elasticity adjustment, watch LNG export trends, and perform gate station analysis.

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CHAPTER 1 ‖ EXECUTIVE SUMMARY

Avista's 2012 Natural Gas Integrated Resource Plan (IRP) identifies a strategic natural gas resource portfolio that meets future customer demand requirements over the next 20 years. While the primary focus of the IRP is ensuring our ability to meet customer's needs under peak weather conditions, this process also provides a methodology for evaluating customer needs under normal or average conditions. The formal exercise of bringing together customer demand forecasts with comprehensive analyses of resource options, including supply-side resources and demand-side measures, is valuable to Avista, its customers, Regulatory Commissions and other stakeholders for long-range planning.

IRP PROCESS AND STAKEHOLDER INVOLVEMENT

The IRP is a coordinated effort by several Avista departments along with input from our Technical Advisory Committee (TAC), which includes Commission Staff, peer utilities, customers and other stakeholders. This group is a vital component of our IRP process, as it provides a forum for the exchange of ideas from multiple perspectives, identifies issues and risks and improves analytical methods. Topics discussed with the TAC include natural gas demand forecasts, demand-side management (DSM), supply-side resources, computer modeling tools and distribution planning. The end result is an integrated resource portfolio designed to serve our customers' natural gas needs well into the future while balancing cost and risk.

PLANNING ENVIRONMENT

Uncertainty is a factor in any forecast, and while there are many uncertainties to consider in this IRP there is one element that has become clear. Shale gas has changed the landscape for North American supply and turned the price of natural gas on its head. While shale is not new, the technological improvements for extraction, the value of natural gas liquids and the amount of gas associated with oil extraction have significantly impacted the volume and cost of the supply mix. Couple this with declining use-per-customer and stagnant customer growth due to the prolonged effect of the recession and you have a supply glut driving prices to lows not seen in the last decade. Even though we are hopeful that low-cost natural gas will be available for many years to come, there are no guarantees, so we continue to challenge key assumptions and perform our "what if" analysis in order to cover a broad range of possibilities.

DEMAND FORECASTS

In this IRP, we define eight distinct demand areas, which are structured around the pipeline transportation and storage resources that serve them. Our demand areas are aggregated into four large service territories (Washington/Idaho; Medford/Roseburg, Oregon; Klamath Falls, Oregon and La Grande, Oregon) and then disaggregated by the pipelines that serve them. The Washington/Idaho service territory is disaggregated into areas that can be served only by Northwest Pipeline (NWP), only by Gas Transmission Northwest (GTN) and by both pipelines. The Medford service territory is also disaggregated into an area that can only be served by NWP and GTN.

Avista's approach to demand forecasting focuses on customer growth and use-per-customer as the base components of demand. We recognize and have accounted for weather as the most significant direct demand-influencing factor. We also study other factors that influence demand, including population, employment trends, age and income demographics, construction trends, conservation technology, new uses development (e.g. natural gas vehicles) and use-per-customer trends.

Recognizing that customers adjust consumption in response to price, we also analyzed factors that could influence natural gas prices and demand through price elasticity. These included:

- Supply Trends – Shale gas, Canadian supply availability, and export LNG
- Infrastructure Trends – regional pipeline projects, national pipeline projects, and storage
- Regulatory Trends – subsidies, market transparency/speculation, and carbon legislation
- Other Trends – thermal generation, and energy correlations (i.e. oil/gas, coal/gas, liquids/gas)

We developed a historical-based reference case and conducted sensitivity analysis on key demand drivers by varying assumptions to understand how demand changes. Using this information and incorporating input from the TAC, we formed several alternate demand scenarios for detailed analysis. Table 1.1 summarizes these scenarios, which do not represent the maximum bounds of possible cases, but frame a range of potential outcomes. Within this range, we define an Average Case, which represents our demand forecast for normal planning purposes. Then we define an Expected Case, which we view as the most likely scenario for peak day planning purposes.

Table 1.1 Demand Scenarios
Average Case
Expected Case
High Growth, Low Price
Low Growth, High Price
Alternate Weather Standard

The IRP process defines the methodology and is the basis for the development of two primary types of demand forecasts – annual average daily and peak day. First is an evaluation of annual average daily demand forecasts which are useful for preparing revenue budgets, developing natural gas procurement plans and preparing purchased gas adjustment filings. Peak day demand forecasts are critical for determining the adequacy of existing resources or the timing for new resource acquisitions to meet our customers' natural gas needs in extreme weather conditions. The demand forecasts from the Average and Expected Cases revealed the following:

ANNUAL AVERAGE DAILY DEMAND – Average day, system-wide core demand is projected to increase from an average of 96,160 dekatherms per day (Dth/day) in 2012 to 117,660 Dth/day in 2031. This is an annual average growth rate of 1.1 percent and is net of projected conservation savings from DSM programs.[1]

PEAK DAY DEMAND – Coincidental peak day, system-wide core demand is projected to increase from a peak of 365,720 Dth/day in 2013 to 474,670 Dth/day in 2031. Forecasted non-coincidental peak day demand peaks at 341,850 Dth/day in 2012 and increases to

[1] Appendix 3.9 shows gross demand, DSM savings and net demand.

440,630 Dth/day in 2031, a 1.3 percent compounded growth rate in peak day requirements. This is also net of projected conservation savings from DSM programs.

Figure 1.1 shows forecasted **average daily demand** for the five main demand scenarios modeled over the planning horizon.

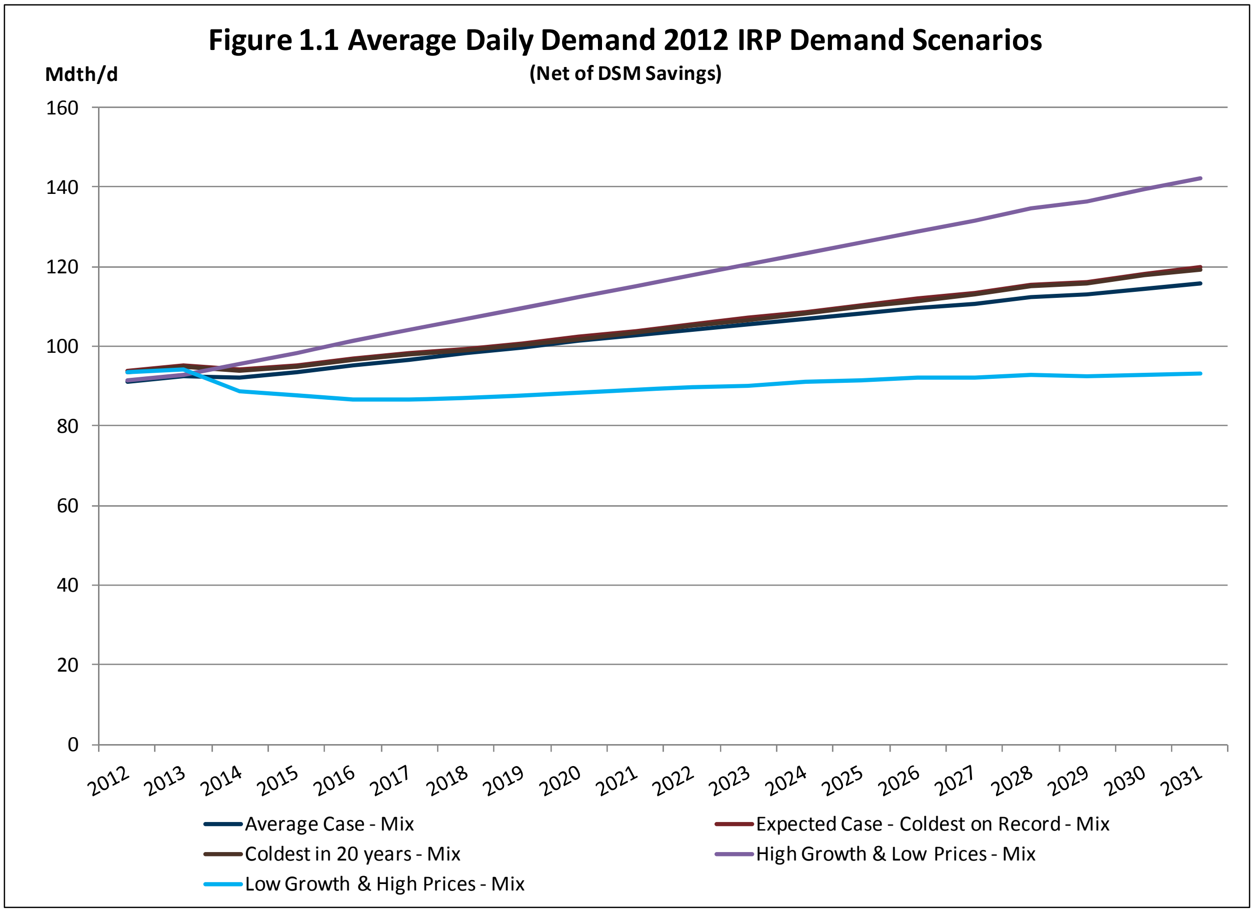
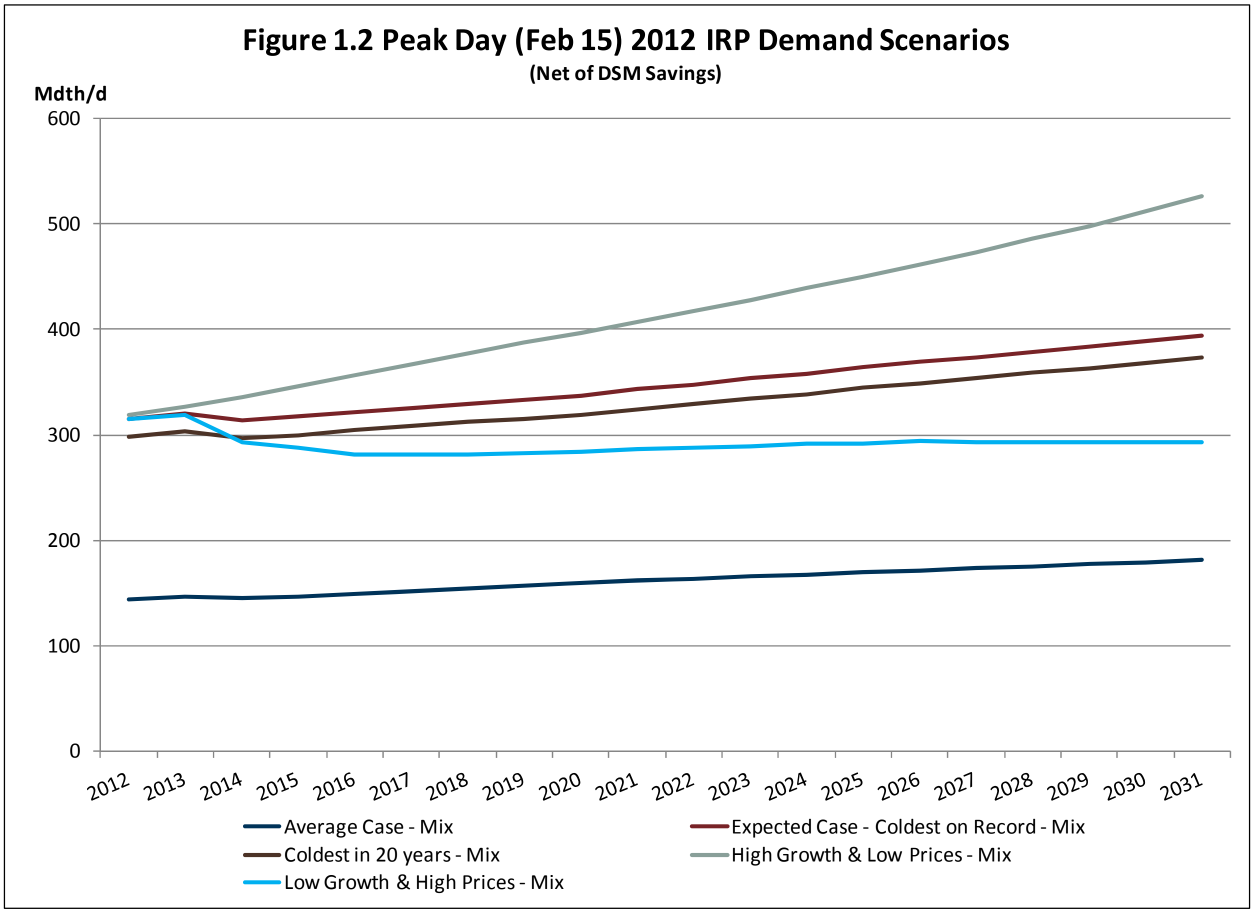


Figure 1.2 shows forecasted system-wide **peak day demand** for the five main demand scenarios modeled over the planning horizon.



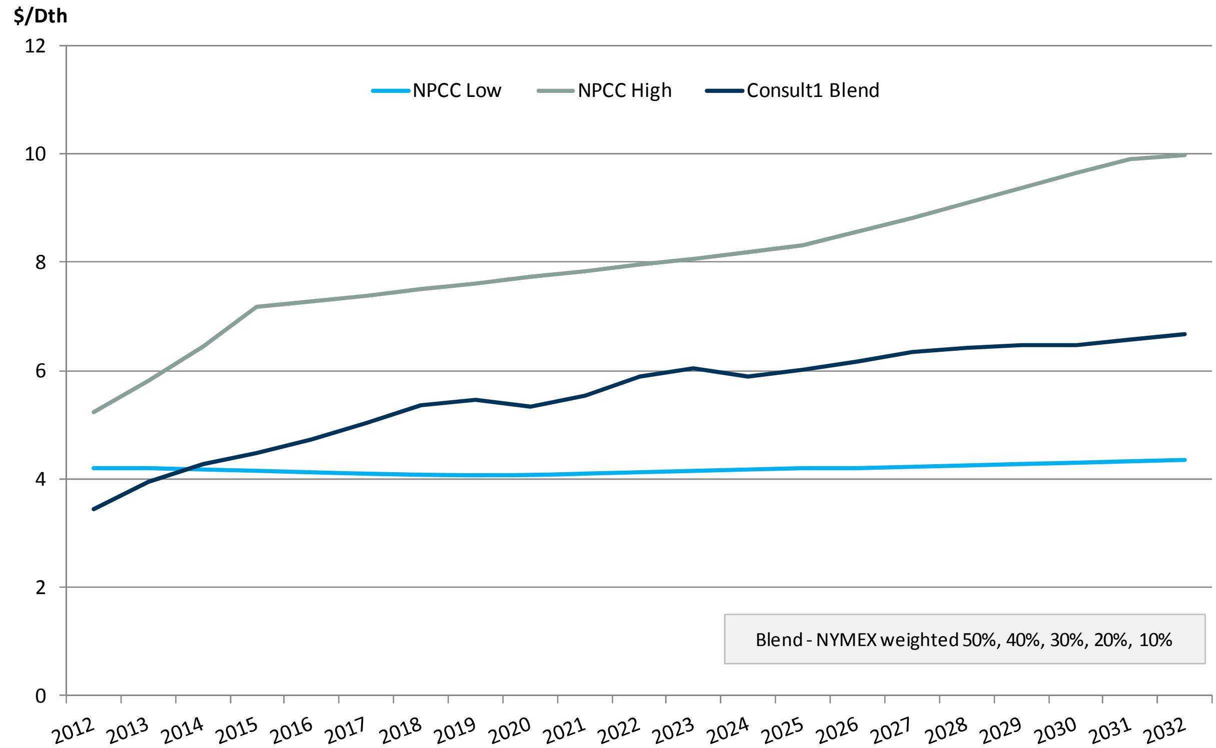
NATURAL GAS PRICE FORECASTS

Natural gas prices are a fundamental component of integrated resource planning because the commodity price is a significant component of the total cost of a resource option. This affects the avoided cost threshold for determining cost-effectiveness of conservation measures. The price of natural gas also influences the consumption of natural gas by customers. A price elasticity adjustment to use per customer is modeled to reflect customer response to changing natural gas prices.

At the end of our last planning cycle the impacts of shale gas on market prices were just beginning to be realized. Forecasters anticipated that this resource could have a significant impact on lowering prices over the long term. However, a faster recovery of customer growth, aggressive carbon legislation in the near term, and sizeable coal switching creating significant gas-fired demand were also anticipated. These factors produced price forecasts, while lower than previous forecasts, higher than current trends. Now more information is known about the costs and volumes produced by shale gas and there appears to be consensus that production costs will continue to stay low for quite some time.

Although we do not believe we can accurately predict future prices for the 20-year horizon of this IRP, we have reviewed several price forecasts from credible sources and have selected high, medium and low price forecasts to represent a reasonable range of pricing possibilities for our analysis. The range of prices provides necessary variation for addressing uncertainty of future prices. Figure 1.3 depicts the price forecasts used in our IRP.

Figure 1.3 – Henry Hub Price Forecasts for IRP Low/Medium/High Forecasted Price
(Real $ per Dth)



Long run statistical analysis shows a consumption response to changes in price. In order to model a consumption response to these price curves, we utilized an expected elasticity response factor, which was applied under various scenarios. We will monitor this assumption over the IRP cycle and make any necessary adjustments.

EXISTING AND POTENTIAL RESOURCES

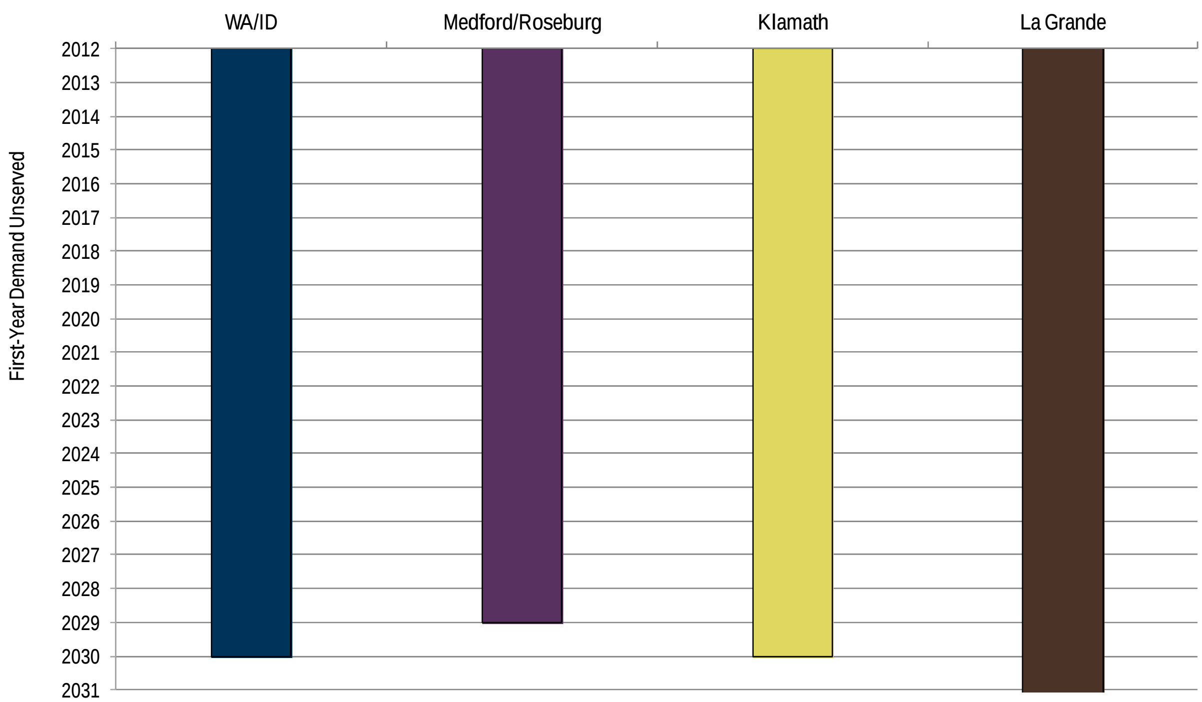
Avista has a diversified portfolio of natural gas supply resources, including contracts to purchase natural gas from several supply basins; owned and contracted storage providing flexibility of supply sources; and firm capacity rights on six pipelines diversifies delivery of supply to our service territory city gates. For potential resource additions, we also consider incremental pipeline transportation, storage options, distribution enhancements and various forms of liquefied natural gas storage or service.

In our IRP process, we model aggregated conservation potential that reduce demand if they are cost-effective over the planning horizon. Based on the projected natural gas prices and the estimated cost of alternative supply resources, our computer planning model (SENDOUT®) selects conservation savings for further review and implementation. Utilizing IRP selected savings as a starting point the operational business planning process ultimately determines the DSM programs cost-effectiveness. Given current avoided costs, programs in Washington and Idaho have proven to be cost ineffective and filings were made to suspend programs in Washington and Idaho. In Oregon we are able to offer limited programs on a cost-effective basis. We actively promote these measures to our customers as one component of a comprehensive strategy to arrive at mix of best cost/risk adjusted resources.

RESOURCE NEEDS

In our Average Case demand scenario matched with our existing supply resources scenario, we determined we are not resource deficient in the 20 year planning horizon. Using our Expected Case demand scenario, matched with our existing resources supply scenario, we assessed when the first year peak day demand is not fully served. The results of this portfolio are summarized in Figure 1.4.

Figure 1.4 - First-Year Peak Demand Not Met with Existing Resources Expected Case



In Washington and Idaho, this system first becomes unserved in 2030 in the Expected Case. In Oregon, the first unserved year is in Medford/Roseburg in 2029 and 2030 in Klamath Falls. The La Grande system does not go unserved at any time during the 20-year planning horizon.

Figures 1.5 through 1.8 illustrate when our peak day demand first goes unserved by service territory for both this IRP and our prior IRP. These charts compare existing peak day resources to expected peak day demand by year and show timing and extent of resource deficiencies for the Expected Case. Given this information, it appears we have ample time to carefully monitor, plan and take action on potential resource additions.

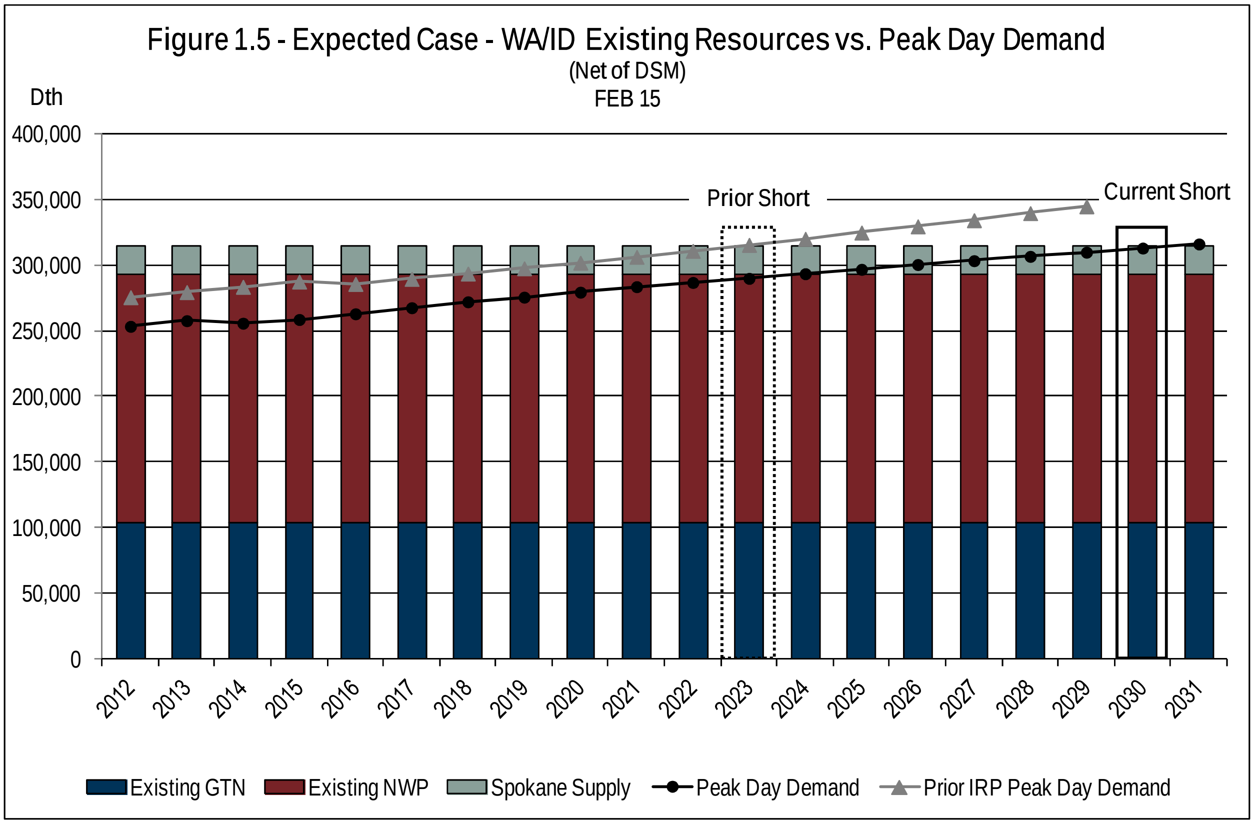


Figure 1.5 - Expected Case - WA/ID Existing Resources vs. Peak Day Demand
(Net of DSM)
FEB 15
Dth
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
Prior Short
Current Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Existing GTN
Existing NWP
Spokane Supply
Peak Day Demand
Prior IRP Peak Day Demand

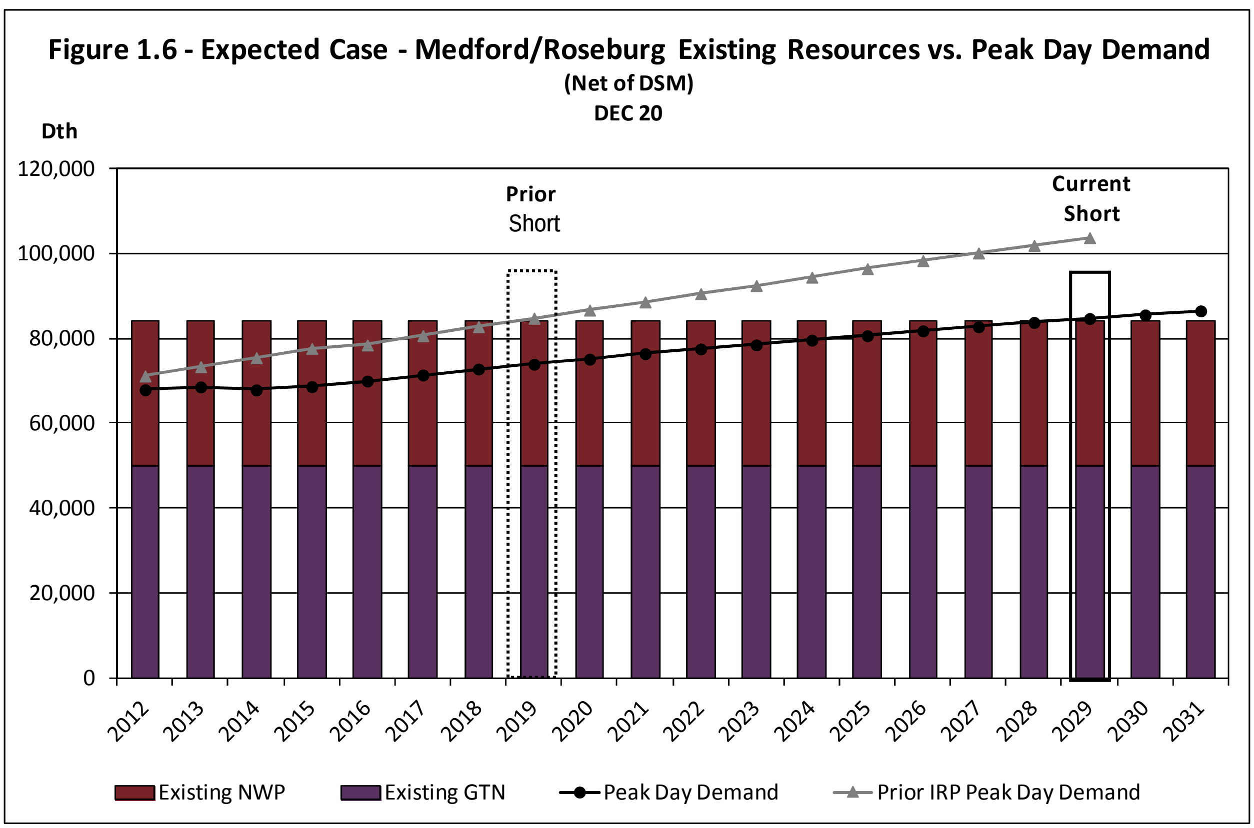


Figure 1.6 - Expected Case - Medford/Roseburg Existing Resources vs. Peak Day Demand
(Net of DSM)
DEC 20
Dth
120,000
100,000
80,000
60,000
40,000
20,000
0
Prior Short
Current Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Existing NWP
Existing GTN
Peak Day Demand
Prior IRP Peak Day Demand

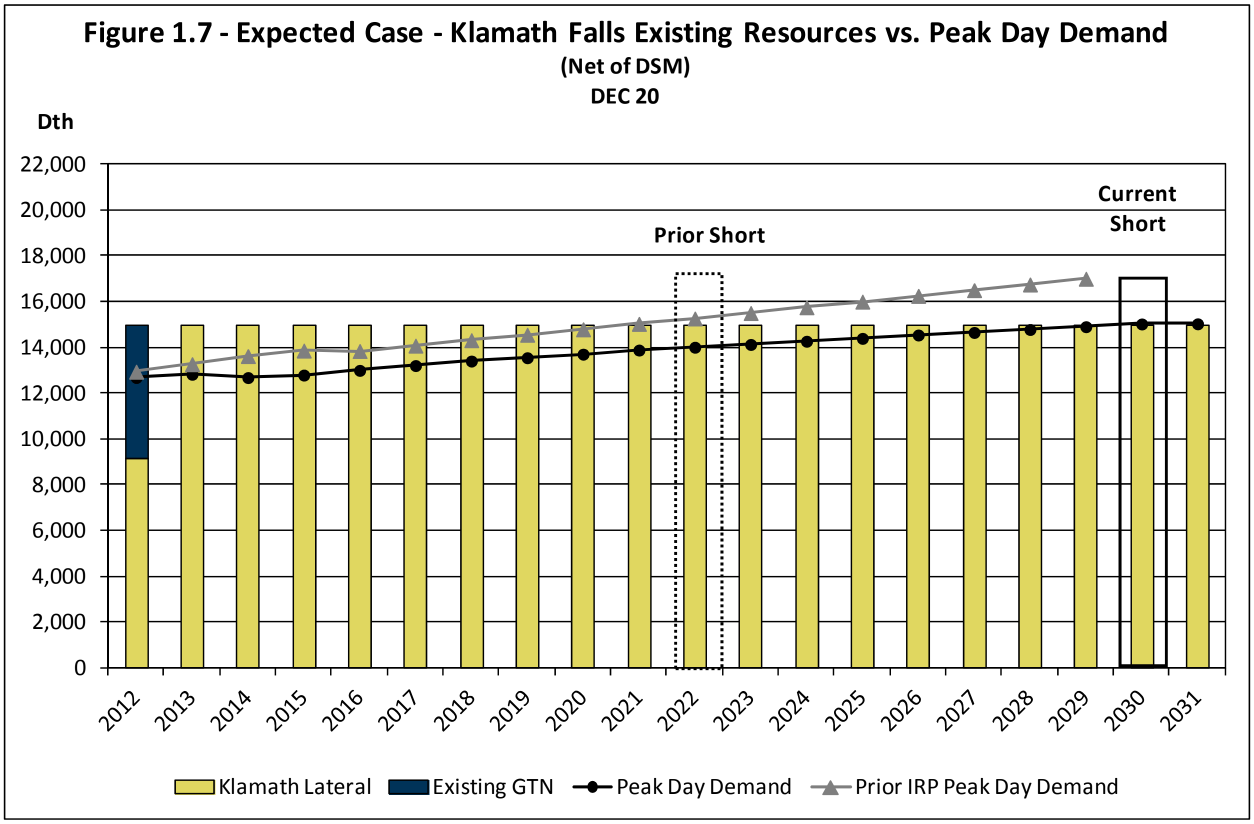


Figure 1.7 - Expected Case - Klamath Falls Existing Resources vs. Peak Day Demand
(Net of DSM)
DEC 20
Dth
22,000
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
Prior Short
Current Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Klamath Lateral
Existing GTN
Peak Day Demand
Prior IRP Peak Day Demand

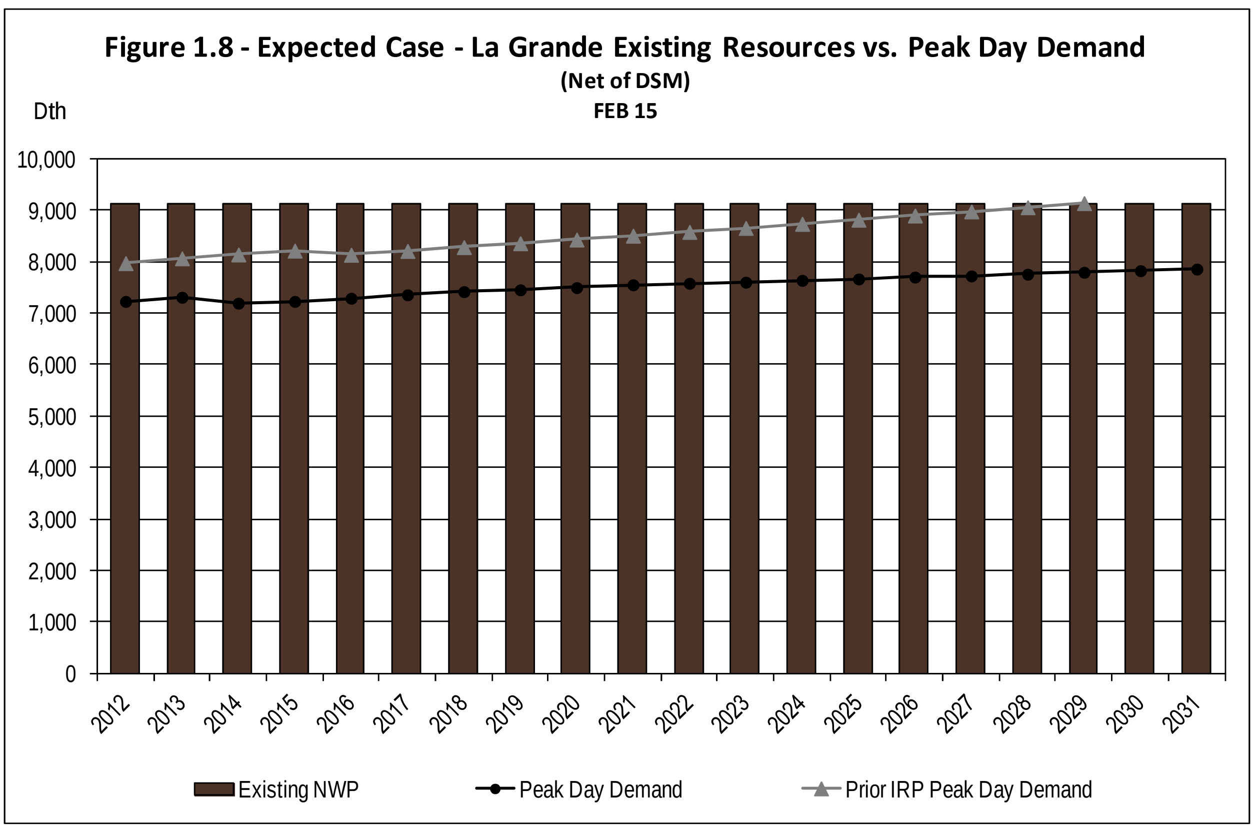
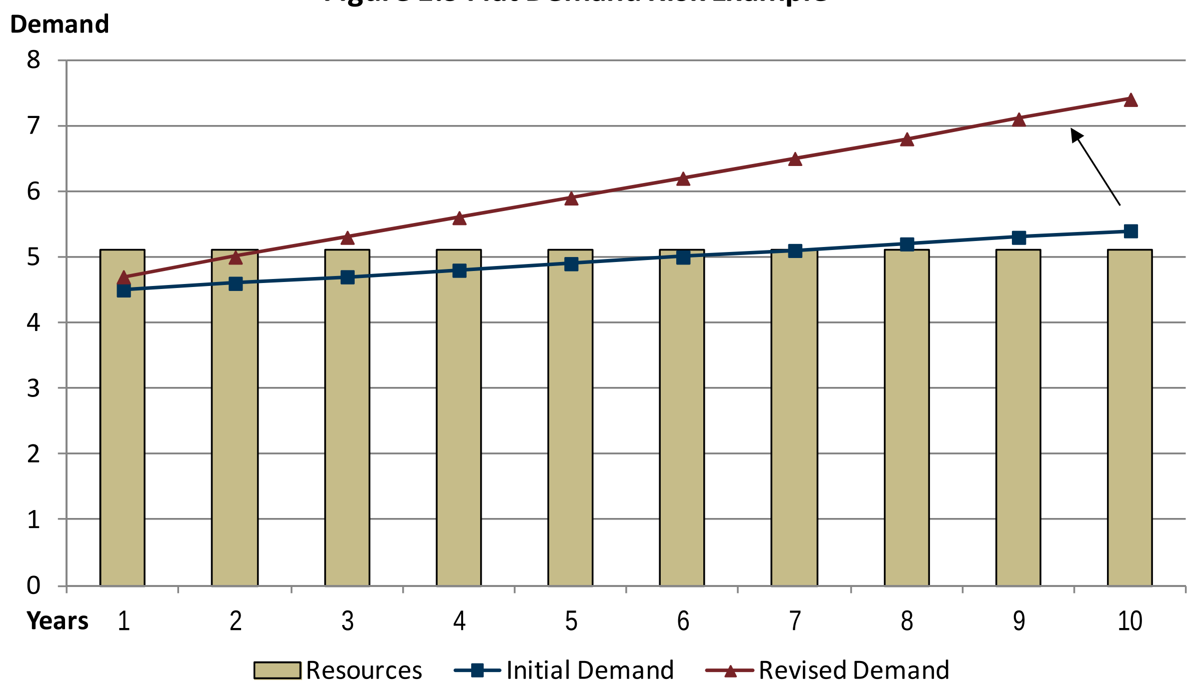


Figure 1.8 - Expected Case - La Grande Existing Resources vs. Peak Day Demand
(Net of DSM)
FEB 15
Dth
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Existing NWP
Peak Day Demand
Prior IRP Peak Day Demand

A critical risk with respect to our identified resource shortages is the slope of forecasted demand growth, which is almost flat. This outlook implies that existing resources will be sufficient for quite some time to meet demand. However, if demand growth accelerates, the steeper demand curve could quickly accelerate resource shortages by several years. Figure 1.9 conceptually illustrates this risk. In this hypothetical example, a resource shortage does not occur until year eight in the initial demand case. However, the shortage dramatically accelerates by five years under the revised demand case to year three. This "flat demand risk" necessitates close monitoring of accelerating demand as well as careful evaluation of lead times to acquire the preferred incremental resource.

Figure 1.9 Flat Demand Risk Example



RESOURCE SELECTIONS

The next step is to determine how to resolve resource deficiencies. For this step, we identified possible resource options, placed them into the SENDOUT® model and allowed it to select the best cost/risk incremental resources over the 20-year planning horizon. Figures 1.10 through 1.12 depict the best cost/risk portfolio selected by SENDOUT® to meet the identified resource shortages. As previously mentioned, the La Grande service territory does not have resource shortages over our planning horizon in the Expected Case.

Figure 1.10 - Expected Case - WA/ID Selected Resources vs. Peak Day Demand
(Net of DSM)
FEB 15

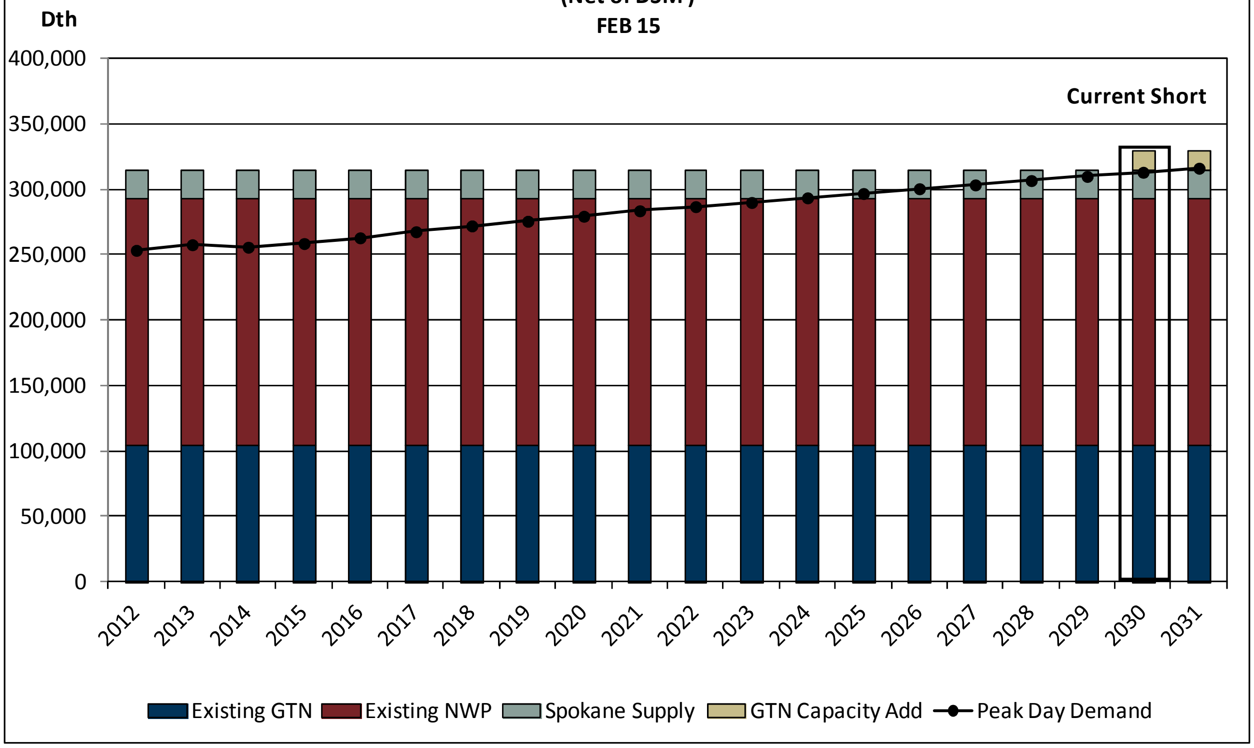


Figure 1.11 - Expected Case - Medford/Roseburg Selected Resources vs. Peak Day Demand
(Net of DSM)
DEC 20

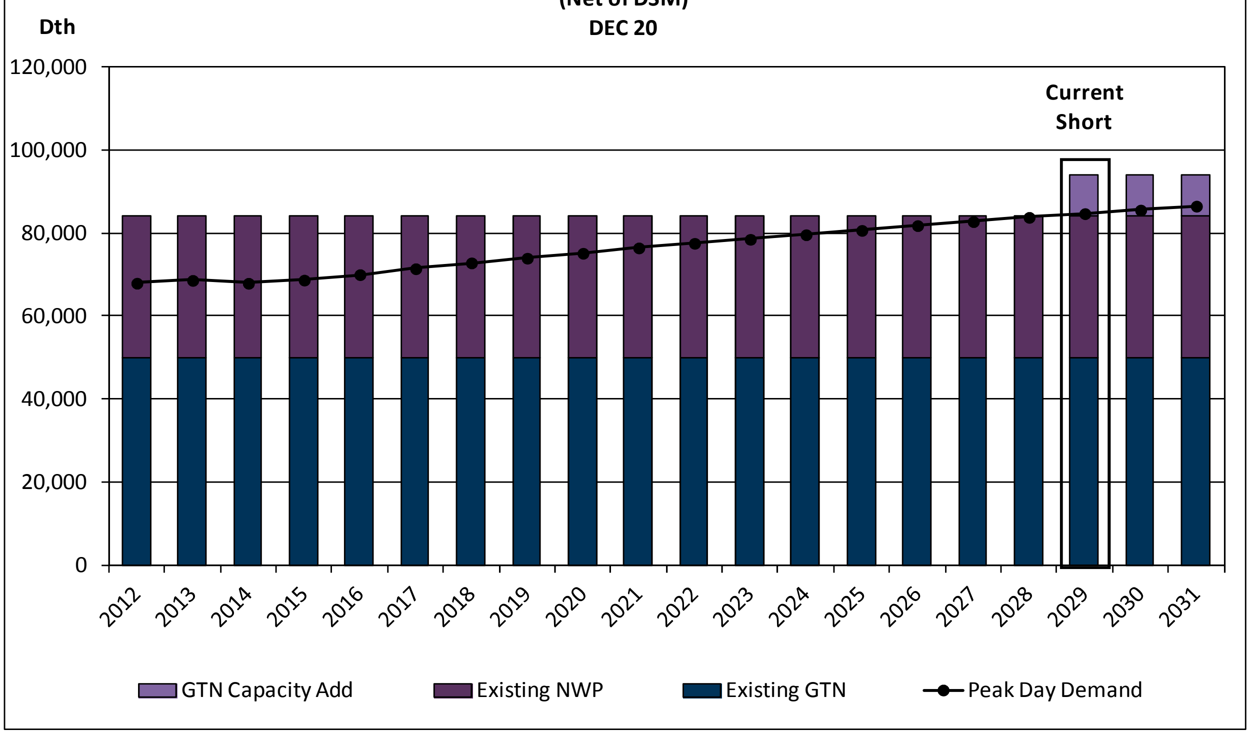
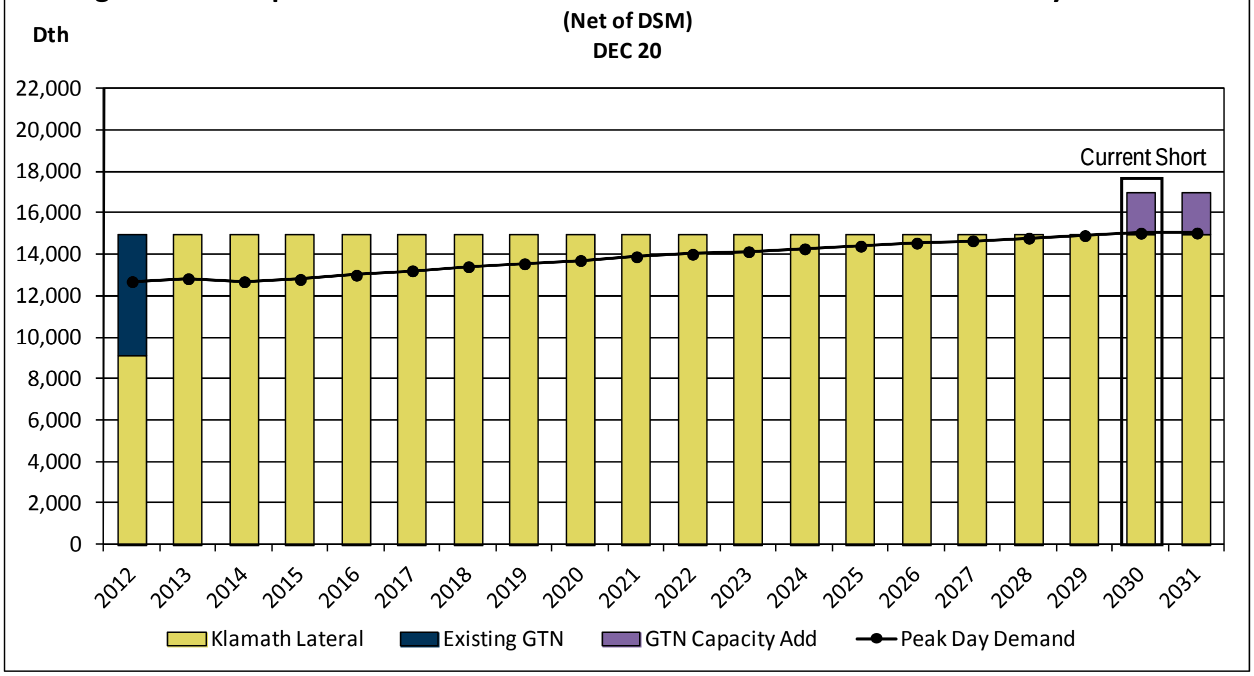


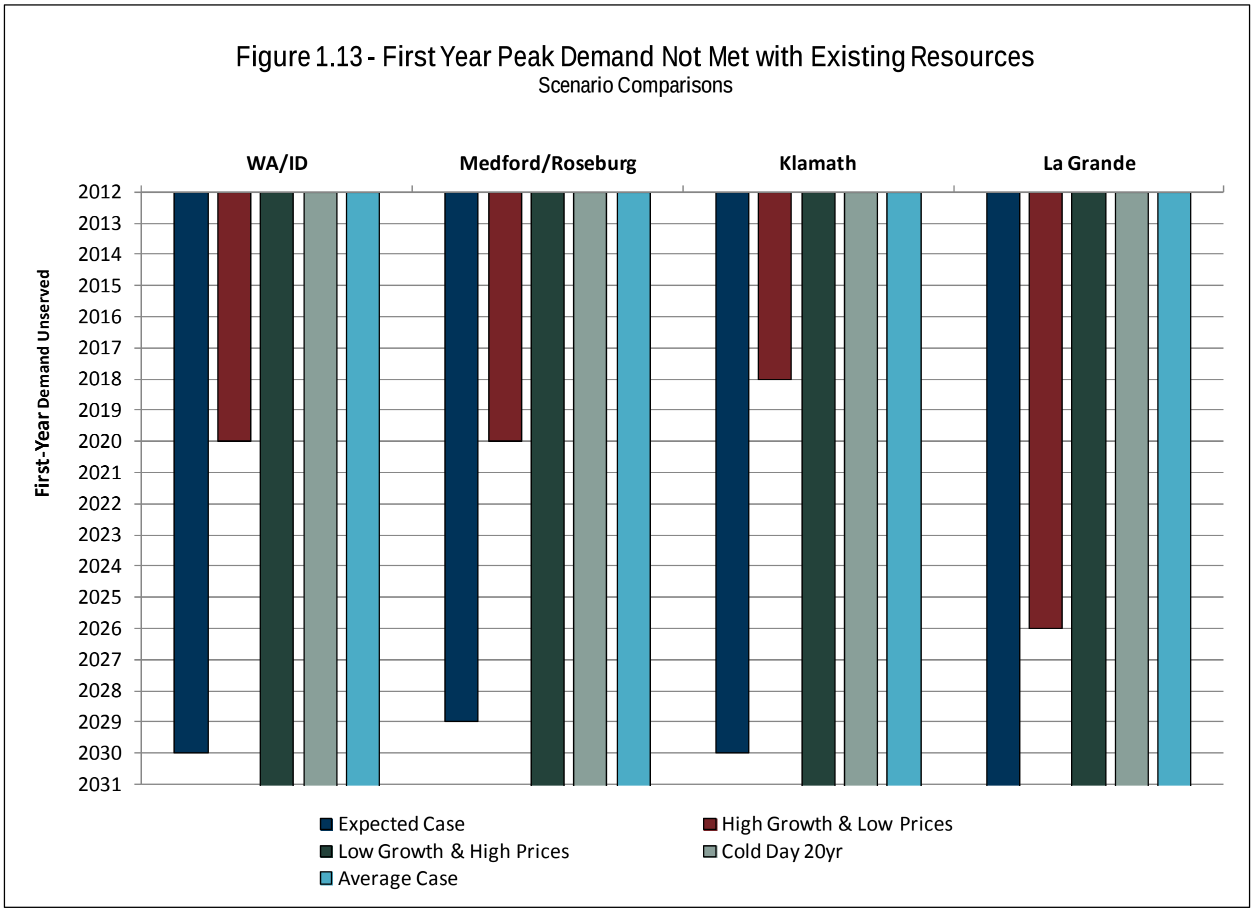
Figure 1.12 - Expected Case - Klamath Falls Selected Resources vs. Peak Day Demand



As indicated in the figures, after DSM savings, the model shows a general preference for incremental transportation resources from existing pipelines and supply basins to resolve resource shortages.

ALTERNATE DEMAND SCENARIOS

We performed the same SENDOUT® process for three other demand scenarios, which identified first year unserved dates for each scenario by service territory (Figure 1.13). As expected, the High Growth, Low Price scenario has the most rapid growth and the earliest first year unserved dated. This "steeper" demand lessens the "flat demand risk" discussed above, but the earlier unserved dates warrant close monitoring of demand trends and resource lead times.



‖ ISSUES AND CHALLENGES

Although we are satisfied with the planning, analysis and conclusions reached in this IRP, we recognize wide spread uncertainty exists requiring diligent monitoring of the following issues and challenges:

CONTINUED ECONOMIC UNCERTAINTY

Whether it is through plummeting home prices, empty retail spaces, unemployment, or lack of consumer spending, evidence of the struggling economy was seen and felt throughout our service territory and region. Growth across our service territory has been paltry at best and use-per-customer has continued to decrease. As the country continues to work through the repercussions of the recession, low to moderate growth is anticipated in our region for many years to come.

With uncertainty about the timing and magnitude of economic recovery, it is prudent to evaluate alternative growth scenarios. We sought to capture the variability of recovery through a wide range of scenarios in our modeling and analysis. Monitoring will be required to see how events unfold and if there are outcomes we did not consider, requiring adjustment of our analysis and Action Plan.

FIVE DOLLAR GAS FOREVER?

The reality of shale gas has changed the face of North American supply. The abundance of shale along with lagging demand has created a near term supply glut driving prices to lows not seen in the last decade. Shale production over the last few years has grown to 25% of total North American production. The unexpected amounts of gas extracted from shale wells, drilling induced by held-by-production (HBP) clauses in leases, increasing drilling efficiencies, and the tie in of previously drilled wells caused a significant increase in production. The excess production was able to be absorbed by the market due to a couple of colder than normal winters and hotter than normal summers. This year's warmer than normal winter highlighted the oversupply sending prices into a freefall. Forecasters anticipate prices to rebound from current lows; with forecasted prices averaging $5.50 per dekatherm at Henry Hub over the planning horizon.

For our customers we hope that the forecaster's expectations come to fruition, but we are mindful of past experiences and understand that markets can change quickly and dramatically. To address this uncertainty, our plan includes high and low price scenarios along with stochastic price analysis to capture a range of possible pricing outcomes.

EXPORTING LNG

A few short years ago importing LNG was the answer to meet North America's growing gas demand needs. Enter shale gas. Now the availability of plentiful amounts of natural gas in North America has changed LNG dynamics. Import LNG facilities are now switching gears and looking to export low cost North American gas to the higher priced Asian and European markets. One export terminal has been approved on the coast of British Columbia and another in the Gulf of Mexico. Many more applications to export are sitting at FERC for review and the same is true in Canada. In the Northwest, there are two proposed terminals in Oregon. How many of these terminals actually get approval is yet to be determined. However, exporting has the potential to alter the price and flows of natural gas across all regions in North America .

NATURAL GAS VEHICLES (NGV)

High oil prices have heightened the desire to reduce reliance on foreign oil. Aided by efforts to reduce emissions and the low cost of natural gas interest in natural gas vehicles has once again been rekindled. The transportation sector is the nation's largest consumer of foreign oil therefore changing the nation's vehicle fleet will be essential in achieving this goal.

Historically, NGV market penetration of a meaningful size has been challenging due to the lack of infrastructure and prices higher than competing alternatives. Now, lower anticipated long term natural gas prices have improved the economics and investments are being made to build out the infrastructure. Most forecasters believe the largest market will be long haul trucking followed by repetitive route fleets (e.g. public transportation, school busses, and refuse trucks) and that widespread adoption/conversion will not be immediate.

Analysis and evaluation of Avista's role in the NGV initiative is underway. Future IRP's will contain the results of this analysis and include our assessment of the potential demand and our level of participation in this market segment. For this IRP we have included in our High Growth scenario additional demand from the NGV market.

▌▌ ACTION PLAN

Our 2013-2014 Action Plan outlines activities identified by our IRP team, with advice from management and TAC members, for development and inclusion in this IRP. The purpose of these action items is to position Avista to provide the best cost/risk resource portfolio and to support and improve IRP planning. The Action Plan identifies needed supply and demand side resources and also highlights key analysis that needs to be completed in the near term. It also highlights essential ongoing planning initiatives and gas industry trends Avista will be monitoring as a part of its routine planning processes.

The analysis indicates there is no near term needs to acquire additional supply side resources to meet customer demand. However, Avista will perform its gate station analysis to assess if individual gate station deficiencies exist and discuss findings and potential solutions with Commission Staff. We will continue to coordinate the analytic efforts between Gas Supply, Gas Engineering and the interstate pipelines to conduct this analysis and if deficiencies are identified seek least-cost solutions.

Avista also believes in the pursuit of cost-effective demand-side solutions, but recognizes the challenges of the current low cost environment. IRP modeling versus operational business planning are different. Within the IRP, Washington and Idaho conservation measures are targeted to reduce demand by approximately 120,000 dekatherms in the first year (2013). In Oregon, conservation measures are targeted to reduce demand by approximately 24,600 dekatherms in the first year. When these aggregated savings and resultant avoided costs were incorporated into the business planning process, natural gas programmatic DSM was cost-ineffective. This resulted in Avista filing to suspend natural gas DSM programs in Washington and Idaho. An evaluation of Oregon program offerings is currently under evaluation.

We will monitor natural gas prices a signpost for increasing avoided costs. Should avoided costs increase we will evaluate our demand side programs for cost-effectiveness and be proactive in submitting to resume our natural gas demand side management options.

Key ongoing components of the Action Plan include:

- Monitor actual demand for indications of growth exceeding our forecast to respond aggressively to address potential accelerated resource deficiencies arising from exposure to "flat demand" risk. This will include providing Commission Staff with IRP demand forecast-to-actual variance analysis on customer growth and use per customer. This information will be provided in Avista's updates to each Commission Staff at least bi-annually.
- Pursue the possibility of a regional elasticity study through the Northwest Gas Association or possibly the American Gas Association.
- Assess potential demand impact from NGV/CNG vehicles and other new uses of natural gas to Avista.
- Continue to monitor supply resource trends including the availability and price of natural gas to the region, exporting LNG, Canadian natural gas supply availability and interprovincial consumption, as well as pipeline and storage infrastructure availability.
- Monitor availability of current resource options and assess new resource lead time requirements relative to when resources are needed to preserve flexibility.
- Regularly meet with Commission Staff members to provide information on market activities and significant changes in assumptions and/or status of Avista activities related to the IRP or natural gas procurement practices.

CONCLUSION

Continued slow growth and the declining use- per- customer resulted in lower demand when compared to our last IRP. Current IRP analysis indicates no near-term need for the acquisition of additional supply-side resources. While Avista believes adoption of conservation is the best strategy for minimizing costs to our customers and promoting a cleaner environment, current and forecasted low prices challenge the cost-effectiveness of demand side measures at the program level. The IRP process has many objectives, but foremost, is to ensure that proper planning will enable us to continue delivering safe, reliable and economic natural gas service to our customers well into the future. We are confident this plan delivers on that objective.

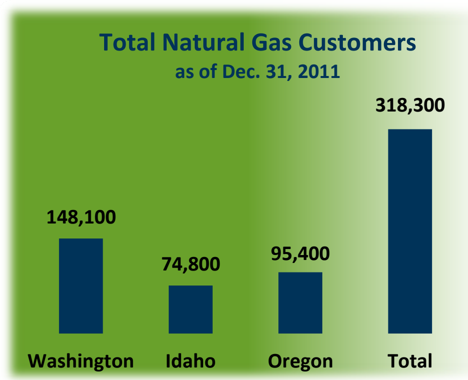
CHAPTER 2 ‖ INTRODUCTION

OUR COMPANY

Avista is involved in the production, transmission and distribution of energy as well as other energy-related businesses. Avista was founded in 1889 as Washington Water Power and has been providing reliable, efficient and competitively priced energy to customers for over 120 years.

Avista entered the natural gas business with the purchase of Spokane Natural Gas Company in 1958. In 1970 it expanded into natural gas storage with Washington Natural Gas (now Puget Sound Energy) and El Paso Natural Gas (its interest subsequently purchased by Williams-Northwest Pipeline (NWP)) to develop the Jackson Prairie natural gas underground storage facility in Chehalis, Wash. In 1991 we added 63,000 customers with the acquisition of CP National Corporation's Oregon and California properties. Avista subsequently sold the California properties and its 18,000 South Lake Tahoe customers to Southwest Gas in 2005. Avista currently provides natural gas service to approximately 318,000 customers in eastern Washington, northern Idaho and several communities in northeast and southwest Oregon.

SERVICE TERRITORIES AND NUMBER OF CUSTOMERS



Avista manages its natural gas operation through two operating divisions – North and South:

- The North Division covers about 26,000 square miles, primarily in eastern Washington and northern Idaho. Over 840,000 people live in Avista's Washington/Idaho service area. It includes urban areas, farms, timberlands and 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/Clarkston, Wash. and Coeur d'Alene, Idaho. The North Division has about 74 miles of natural gas distribution mains and 5,000 miles of distribution lines. Natural gas is received at more than 40 points along interstate pipelines and distributed to over 222,000 customers.
- The South Division serves four counties in southwest Oregon and one county in northeast Oregon. The combined population of these two areas is over 480,000 residents. The South

Division includes urban areas, farms and timberlands. The Medford, Ashland and Grants Pass areas, located in Jackson and Josephine Counties, is the largest single area served by Avista in this division, with a regional population of approximately 280,000 residents. The South Division consists of about 67 miles of natural gas distribution mains and 2,000 miles of distribution lines. Natural gas is received at more than 20 points along interstate pipelines and distributed to almost 96,000 residential, commercial and industrial customers.

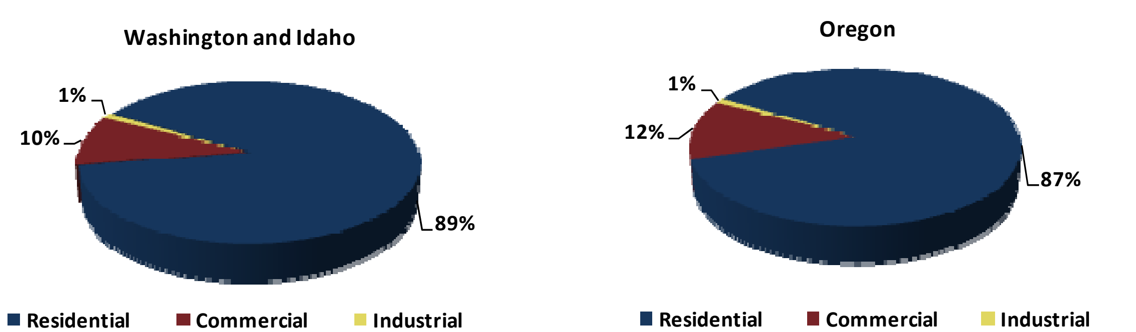
OUR CUSTOMERS

We provide natural gas services to two customer classifications – "core" and "transportation only." Core or retail customers purchase natural gas directly from us with delivery to their home or business under a bundled rate. Those core customers on firm rate schedules are entitled to receive whatever volume of gas is needed. There are some core customers who are on interruptible rate schedules. These customers pay a lesser rate than firm customers since their service can be interrupted. These interruptible customers are not considered in our peak day IRP planning.

Transportation-only customers purchase natural gas from third parties who deliver their gas to our distribution system. We then deliver this gas to their business charging a distribution rate only. This delivery service can be interrupted by Avista following our priority of service tariff. Since our transportation-only customers purchase their own gas and utilize their own interstate pipeline transportation contracts they are excluded from this long-term resource planning exercise.

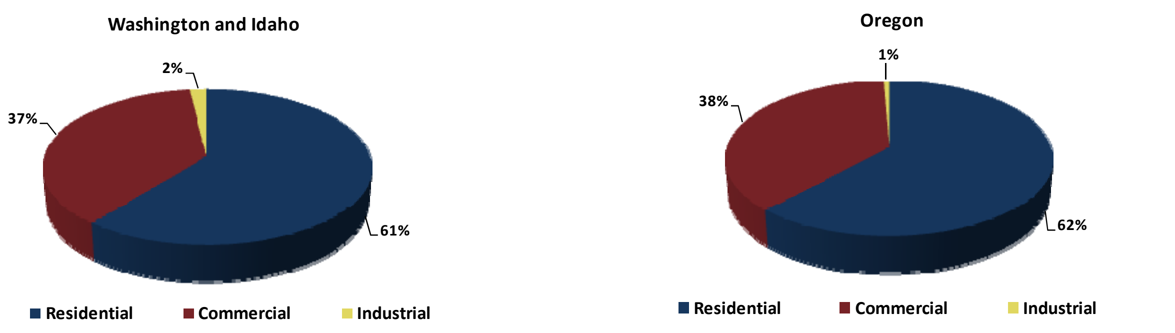
Our core or retail customers are further divided into three categories – residential, commercial and industrial. Most of our customers are residential, followed by commercial. Relatively few are industrial accounts (Figure 2.1).

Figure 2.1 Firm Customer Mix



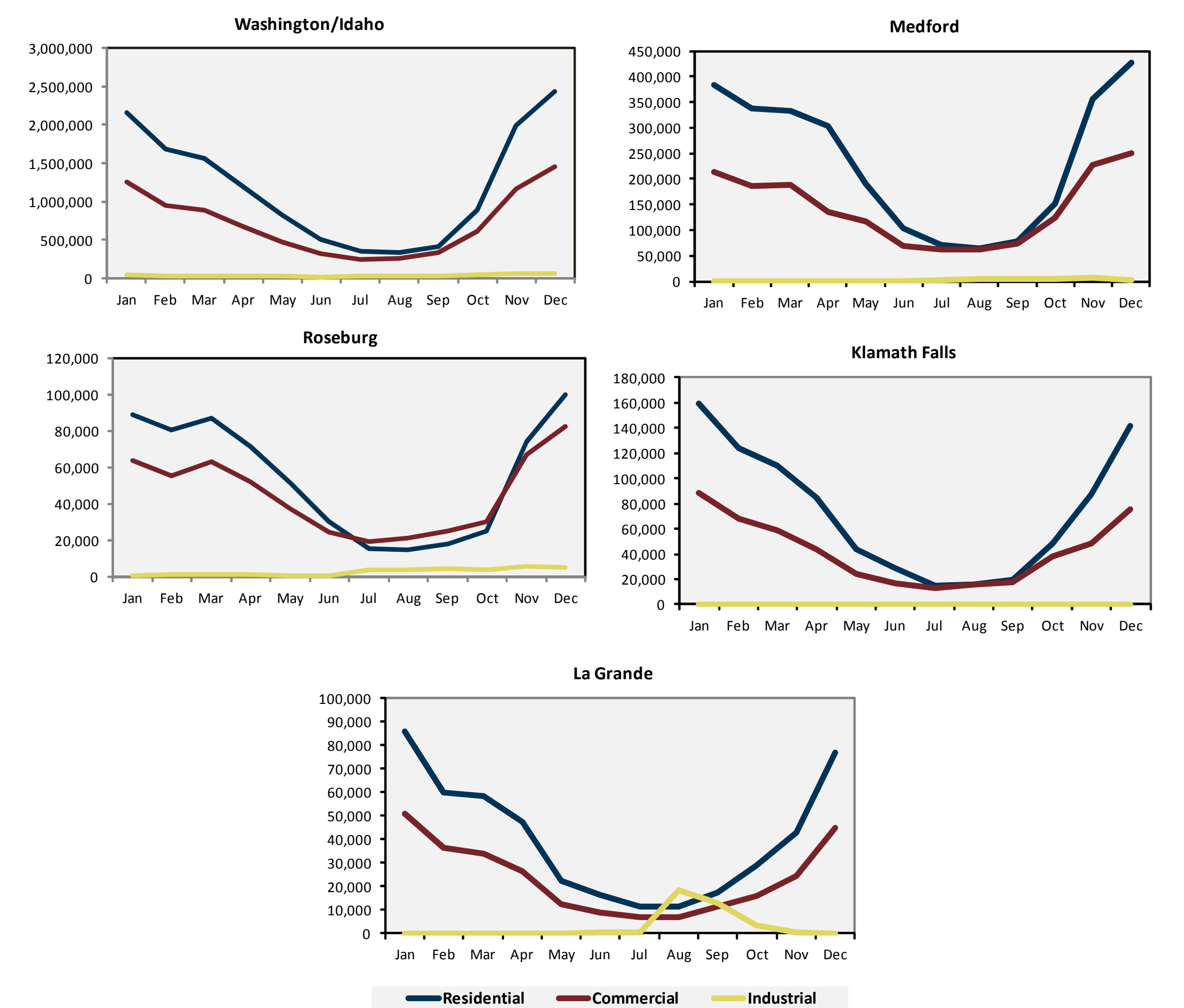
The mix is more balanced between residential and commercial accounts on an annual volume basis (Figure 2.2). Volume consumed by core industrial customers is not significant to the total, partly because most industrial customers in our service territories are transportation only customers.

Figure 2.2 Therms by Class



Core customer demand is seasonal, especially by our residential accounts in our service territories with colder winters (Figure 2.3). Industrial demand, which is typically not weather sensitive, has very little seasonality. However, our La Grande service territory has several agricultural processing facilities, classified as industrial, that produce a late summer season al demand spike.

Figure 2.3 Customer Demand by Service Territory
(Dekatherms)



INTEGRATED RESOURCE PLANNING

In order to ensure that our core firm customers are provided with long-term reliable natural gas service at a competitive price, we undertake a comprehensive analytical process through the IRP. We evaluate, identify and plan for the acquisition of the best-risk, least-cost portfolio of existing and future resources to meet average daily and peak-day demand delivery requirements over a 20-year planning horizon.

PURPOSE OF THE IRP

This document has several objectives:

- Provides a comprehensive long-range planning tool
- Fully integrates forecasted requirements with existing and potential resources
- Determines the most cost-effective, risk-adjusted means for meeting demand requirements
- Responds to Washington, Idaho and Oregon rules and orders

AVISTA'S IRP PROCESS

The IRP process considers:

- Customer growth and usage
- Weather planning standard
- DSM opportunities
- Existing and potential supply-side resource options
- Current and potential legislation/regulation
- Risk

PUBLIC PARTICIPATION

Members of Avista's TAC play a key role and have a significant impact in development of the IRP. TAC members include Commission Staff, peer utilities, public interest groups, customers, academics, government agencies and other interested parties. A list of TAC members is in Appendix 1.1 TAC members provide important input on modeling, planning assumptions and the general direction of the process.

Avista sponsored four TAC meetings to facilitate stakeholder involvement in the 2012 IRP. The first meeting convened on Jan. 17, 2012 and the last meeting was held on April 17, 2012. A broad spectrum of stakeholders was represented at each meeting. The meetings focused on specific planning topics, reviewed the status and progress of planning activities and solicited input on the IRP development. A draft of this IRP was provided to TAC members on May 25, 2012. We gained valuable input from the interaction and communication with TAC members and express our sincere thanks and appreciation for their contributions and participation.

Preparation of the IRP is a coordinated endeavor by several departments within Avista with involvement and guidance from management. We are grateful for these efforts and contributions.

REGULATORY REQUIREMENTS

Avista submits an IRP to the public utility commissions in Washington, Idaho and Oregon every two years as required by state regulation.[1] We will file our IRP with all three Commissions on or before Aug. 31, 2012. We have a statutory obligation to provide reliable natural gas service to customers at rates, terms and conditions that are fair, just, reasonable and sufficient. We regard the IRP as a means for identifying and evaluating potential resource options and as a process to establish an Action Plan for resource decisions. Ongoing investigation, analysis and research may cause us to determine that alternative resources are more cost effective than resources selected in this IRP. We will continue to review and refine our understanding of resource options and will act to secure these risk-adjusted, least-cost options when appropriate.

PLANNING MODEL

Consistent with prior IRPs is the use of SENDOUT®, the computer planning model we use to perform comprehensive and effective natural gas supply planning and analysis. SENDOUT® is a linear programming-based model that is widely used in the industry to solve natural gas supply, storage and transportation optimization problems. This model uses present value revenue requirement (PVRR) methodology to perform least-cost optimization based on daily, monthly, seasonal and annual assumptions related to:

- Customer growth and customer natural gas usage to form demand forecasts
- Existing and potential transportation and storage options
- Existing and potential natural gas supply availability and pricing
- Revenue requirements on all new asset additions
- Weather assumptions
- Demand-side management

We have also incorporated the Monte Carlo simulation module within SENDOUT® to simulate weather and price uncertainty. The module uses Monte Carlo functionality to generate simulations of weather and price to provide a probability distribution of results from which decisions can be made. Some examples of the types of analysis Monte Carlo simulation provides include:

- Price and weather probability distributions
- Probability distributions of costs (i.e. system costs, storage costs, commodity costs)
- Resource mix (optimally sizing a contract or asset level of various and competing resources)

These computer-based planning tools were used to develop our 20-year best cost/risk resource portfolio plan to serve customers.

1 In Washington the 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 Nos. 07-002, 07-047 and 08-339. Appendix 2.2 provides details of these requirements and how they are met.

PLANNING ENVIRONMENT

Although we prepare and publish an IRP biannually, the process is ongoing, taking into account new information and developments. In "normal" circumstances, the process can become complex as underlying assumptions evolve and impact previously completed analyses. Every planning cycle has challenges and uncertainties; this cycle was no different. The demand for natural gas has undergone extraordinary changes due to recessionary impacts. Residential, commercial and industrial demand has flattened. Renewable portfolio standards and the announcement of coal plant retirements have increased the need for future gas-fired generation and natural gas vehicles are once again in vogue. The supply picture has also undergone a makeover. The "Shale Gale" – in its infancy during the last planning cycle – has since grown up. While there continues to be questions about how vast the resource base is, its environmental impacts and how much can continue to be produced at these pricing levels, it has proved to be a "game changer."

‖ IRP PLANNING STRATEGY

Planning for an uncertain future requires robust analysis that encompasses a wide range of possibilities. We have determined our approach needs to:

- Recognize historical trends may be fundamentally altered
- Critically review all assumptions
- Stress test assumptions via sensitivity analysis
- Pursue a spectrum of possible scenarios
- Develop a flexible analytical framework to accommodate changes
- Maintain a long-term perspective

With these objectives in mind we believe we have developed a strong strategy encompassing all required planning criteria that allowed us to produce a complete IRP that effectively analyzes risks and resource options, which sufficiently ensure our customers will receive safe and reliable energy delivery services well into the future with the best-risk, lease-cost, long-term solutions.

CHAPTER 3 ‖ DEMAND FORECASTS

OVERVIEW

The integrated resource planning process begins with the development of forecasted demand. Understanding and analyzing key demand drivers and their potential impact on our forecasts is vital to the planning process. Utilization of historical data provides a reliable baseline, however it is important to remember that past trends may not be indicative of future trends. The permanent long term effects of the recession will not be fully realized for many years. This uncertainty leads us to consider a range of scenarios to evaluate and prepare for a broad spectrum of outcomes.

DEMAND AREAS

Eight demand areas, structured around the pipeline transportation resources that serve them, were defined with the SENDOUT® computer model (Table 3.1). These demand areas are aggregated into four service territories and further summarized into two divisions for presentation throughout this IRP.

Table 3.1 Geographic Demand Classifications

Demand Area	Service Territory	Division
Spokane NWP	Washington/Idaho	North
Spokane GTN	Washington/Idaho	North
Spokane Both	Washington/Idaho	North
Medford NWP	Medford/Roseburg	South
Medford GTN	Medford/Roseburg	South
Roseburg	Medford/Roseburg	South
Klamath Falls	Klamath Falls	South
La Grande	La Grande	South

DEMAND FORECAST METHODOLOGY

Avista uses the IRP process to develop two types of demand forecasts – “annual” and “peak day.” Annual average demand forecasts are useful for several purposes, including preparing revenue budgets, developing natural gas procurement plans and preparing purchased gas adjustment filings. Peak day demand forecasts are critical for determining the adequacy of existing resources or the timing for acquiring new resources to meet our customers’ natural gas needs in extreme weather conditions throughout the planning period.

In general, if existing resources are sufficient to meet peak day demand, they will be sufficient to meet annual average day demand. Developing annual average demand first and evaluating it against existing resources is an important step in understanding the performance of the portfolio under normal circumstances. It also facilitates synchronization of modeling processes and assumptions for all planning purposes.

Peak weather analysis aids in assessing not only resource adequacy but differences, if any, in resource utilization. For example, storage may be dispatched differently under peak weather scenarios.

DEMAND MODELING EQUATION

Because natural gas demand can vary widely from day to day, especially in winter months when heating demand is at its highest, developing daily demand forecasts is essential. In its most basic form, demand is a function of customer base usage (non-weather sensitive usage) plus customer weather sensitive usage. This can be expressed by the following general formula:

Table 3.2 Basic Demand Formula

# of customers **x** Daily **base usage** / customer
Plus
# of customers **x** Daily **weather sensitive** usage / customer

More specifically, SENDOUT® requires inputs as expressed in the below format to compute daily demand in dekatherms (Dth):

Table 3.3 SENDOUT® Demand Formula

# of customers **x** Daily **Dth base usage** / customer
Plus
# of customers **x** Daily Dth **weather sensitive** usage / customer **x** # of daiy degree days

This calculation is performed by SENDOUT® for each day for each customer class and each demand area. The base and weather sensitive usage (heating degree day usage) factors are customer demand coefficients developed outside the SENDOUT® model and capture a variety of demand usage assumptions. This is discussed in more detail in the Use-per-Customer Forecast section below. The number of daily degree days is simply heating degree days (HDDs), which are further discussed in the Weather Forecast section later in this chapter.

CUSTOMER FORECASTS

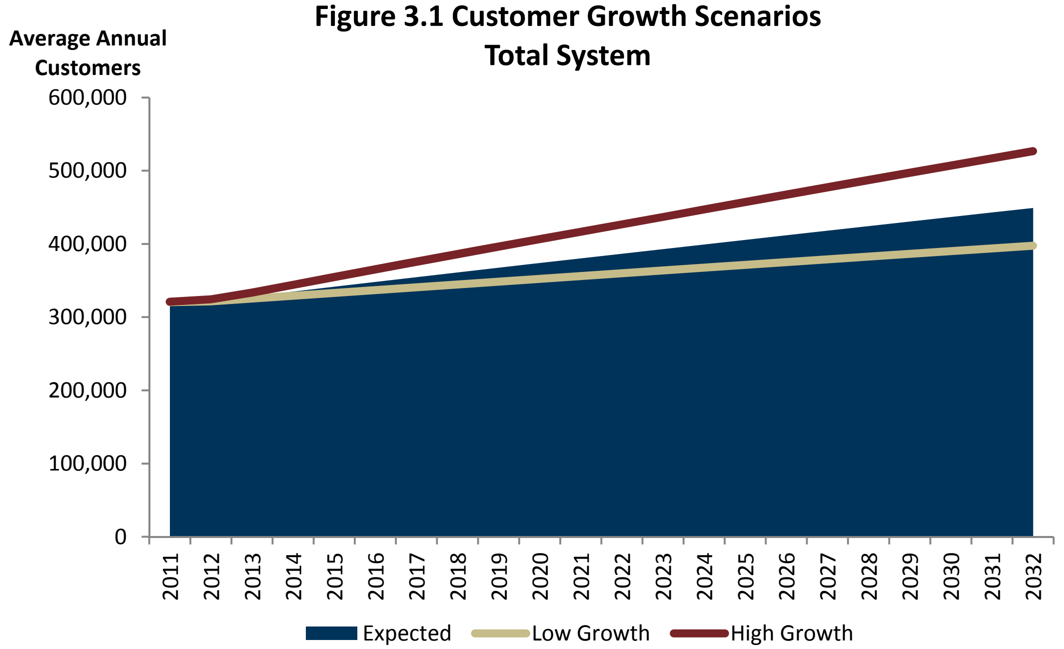
Avista's customer base is segregated into three categories: residential, commercial and industrial. For each of the customer categories we develop our customer forecasts by starting with national economic forecasts and then drilling down into regional economies. Population growth expectations and employment are key drivers in regional economic forecasts and are useful in estimating natural gas customers. We contract with Global Insight, Inc. for long-term regional economic forecasts. A description of the Global Insight forecasts is found in our customer forecasts detail in Appendix 3.1. We combine this data with local knowledge about sub-regional construction activity, age and other demographic trends and historical data to develop our 20-year customer forecasts.

The annual growth for each state is allocated so that the total equals the sum of the parts. These forecasts are used by the distribution engineering group for optimizing decisions within these geographic sub-areas and facilitating integrated forecasting and planning within Avista (see further discussion in Chapter 8 – Distribution Planning).

Forecasting customer growth is an inexact science so it is important to consider alternative forecasts. Two alternative growth forecasts were developed for consideration in this IRP. In past IRPs we have used 25 years of historical growth rates to derive our low and high growth sensitivities. This historical look back gave us growth assumptions of 50% greater than expected and 50% lower than expected for our high and low growth sensitivities. Utilizing historical data provided some comfort with the reasonableness of these growth forecasts.

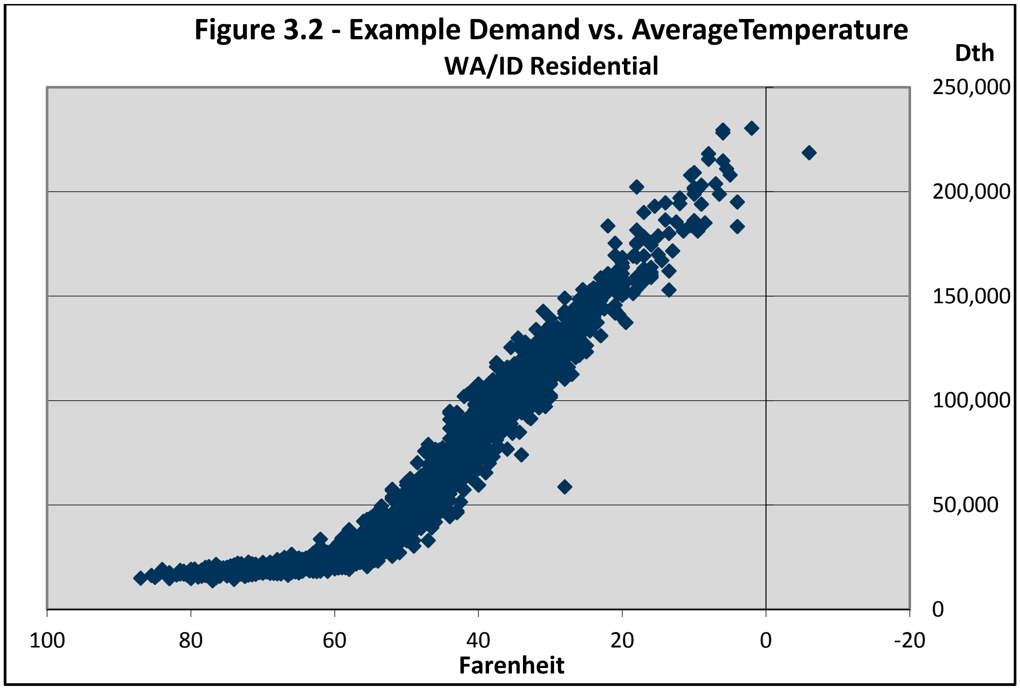
However, recent events have impacted our economy and there is much uncertainty about when and how much recovery will occur. The past may not be indicative of future behaviors. Growth experienced in the last couple of years is low. In examining recent trends and comparing to history the range of growth seems asymmetric. To this end we utilized forecasted information from the Washington State Office of Financial Management (OFM) to prepare the high and low growth sensitivities. The OFM forecasts the potential for growth rates 40% below and 60% above current growth rates. These three customer growth forecasts are shown in Figure 3.1. Detailed customer count data by region and class for all three scenarios is in Appendix. 3.2.

Figure 3.1 Customer Growth Scenarios Total System



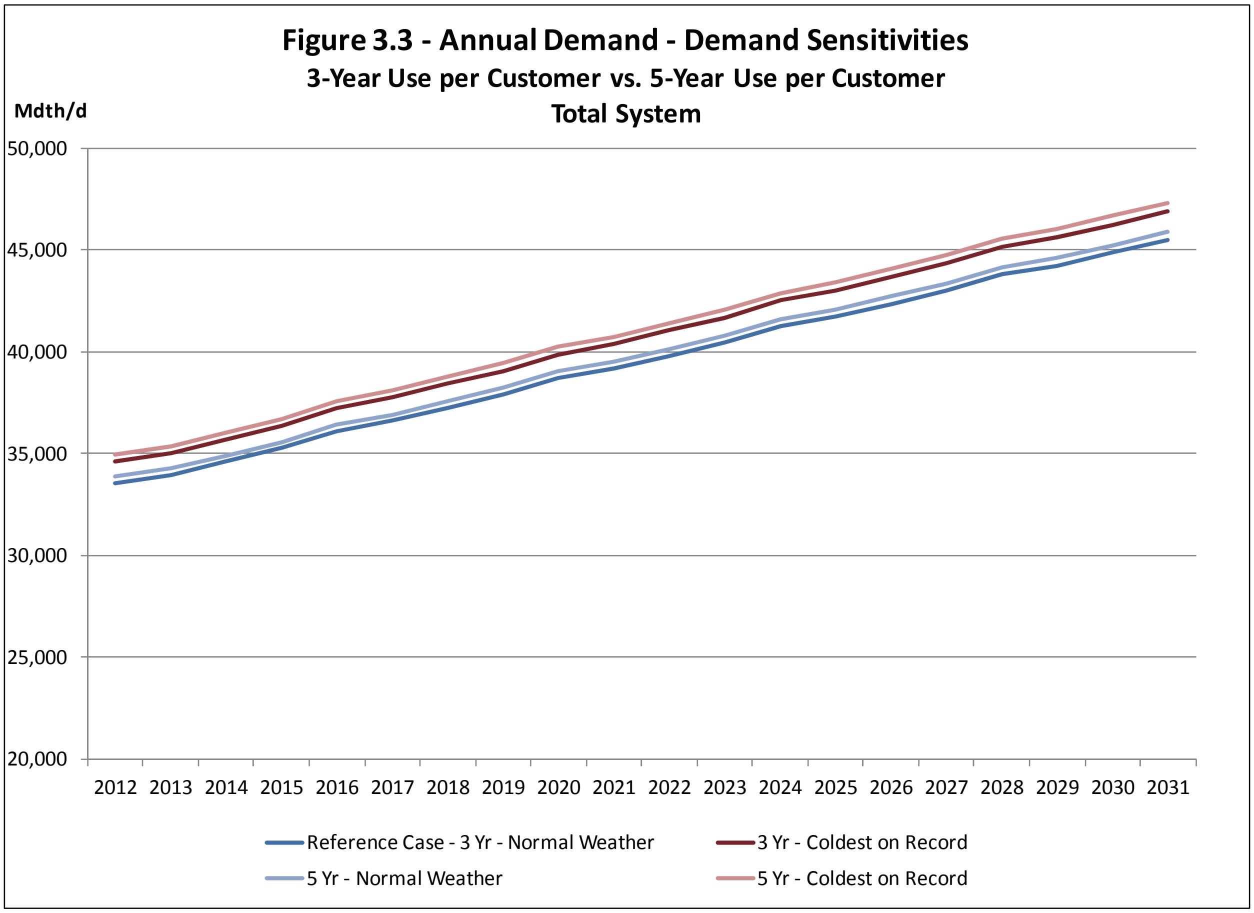
USE-PER-CUSTOMER FORECAST

The goal for a use-per-customer forecast is to develop base and weather sensitive demand coefficients that can be combined and applied to HDD weather parameters to reflect average use per customer. This produces a very reliable forecast because of the high correlation between usage and temperature as depicted in the example scatter plot in Figure 3.2.



The first step in developing demand coefficients was gathering daily historical gas flow data for all of our city gates. Our preference to use city gate data over revenue data is due to the tight correlation between weather and demand. Our revenue system does not capture data on a daily basis and therefore, makes a statistical analysis with tight correlations virtually impossible. We do reconcile city gate flow data to revenue data to ensure that we are properly capturing total demand.

The historical city gate data was gathered, segregated by service territory/temperature zone and then by month. In our last IRP we used three years of historical data to derive our use per customer coefficients. Continuing with our theme of challenging each assumption we looked at varying the number of years of historical data. We analyzed five years, three years and two years of use per customer. We decided that two years was not necessarily indicative of future use per customer behavior nor does it incorporate enough data points to make a comprehensive long term analysis. Five years incorporated some years of higher use per customer, which may overstate use due to current recessionary impacts and conservation savings. Three years seemed to strike the right balance between historical and contemporaneous customer usage patterns. Figure 3.3 illustrates the annual demand differences between the three year and five year use per customer with normal and peak weather conditions.



To calculate base usage, three years of July and August data was used to derive coefficients. Average usage in these months divided by average number of customers provides the base usage coefficient input into SENDOUT®.This calculation is done for each area and customer class based on customer billing data demand ratios.

To derive weather sensitive demand coefficients, for each monthly data subset, we removed base demand from the total and plotted usage by HDD in a scatter plot chart to visually verify correlation. We then applied linear regression to the data by month to capture the linear relationship of usage to HDD. The slopes of the resulting lines are the monthly weather sensitive demand coefficients input into SENDOUT®. Again, this calculation is done by area and by customer class using allocations based on customer billing data demand ratios.

In extreme weather conditions, demand can sometimes begin to flatten out relative to the linear relationships at less extreme temperatures. This occurs, for example, when appliances such as furnaces reach maximum output and do not consume any more natural gas regardless of how much colder temperatures get. We sought to capture this phenomenon through development of super peak coefficients.

The methodology for deriving super peak coefficients was exactly the same as deriving weather sensitive demand coefficients except, instead of forming data subsets by month, a dataset was created using temperature (specifically HDD's greater than 65). The line slope from the regression on this data was typically flatter relative to the other monthly weather sensitive demand coefficients. One inherent drawback to this methodology is the lack of sufficient data points to develop a strong linear relationship.

More years of data can help, but the older data becomes less and less relevant to current demand relationships. We will continue to test this theory and monitor trends.

As a final step, to check coefficient reasonableness, we applied the coefficients to actual customer count and weather data to backcast demand. This was compared to actual demand with satisfactory results. The regression calculations and coefficients can be found in Appendix 3.3.

WEATHER FORECAST

The last input in the demand modeling equation is weather (specifically HDDs). We obtain the most current 30 years of daily weather data from the National Oceanic Atmospheric Administration (NOAA), convert it to HDDs and compute an average for each day to develop our weather forecast. For Oregon we use four weather stations, corresponding to the areas where natural gas services are provided. HDD weather patterns between these areas are uncorrelated. For the eastern Washington and northern Idaho portions of our service area weather data for the Spokane Airport is used, as HDD weather patterns within that region are correlated.

The NOAA 30-year average weather (adjusted for global warming – see below) serves as the base weather forecast that is used to prepare the annual average demand forecast. In preparing the peak day demand forecast we adjust average weather to reflect a five-day cold weather event. This consists of adjusting the middle day of the five-day cold weather event to the coldest temperature on record for a service territory, as well as adjusting the two days either side of the coldest day to temperatures slightly warmer than the coldest day. For our Washington/Idaho and La Grande service territories, we model this event on and around February 15 each year. For our southwestern Oregon service territories (Medford, Roseburg, Klamath Falls) we model this event on and around December 20 each year.

The following describes specific details on the coldest days on record for each service territory:

- On Dec. 30, 1968, the Washington/Idaho service area experienced the coldest day on record, an 82 HDD for Spokane. This is equal to an average daily temperature of -17 degrees Fahrenheit. Only one 82 HDD has been experienced in the last 40 years for this area; however, within that same time period, 80, 79 and 74 HDD events occurred on Dec. 29, 1968, Dec. 31,1978, and January 5, 2004, respectively.
- On Dec. 9, 1972, Medford experienced the coldest day on record, a 61 HDD. This is equal to an average daily temperature of 4 degrees Fahrenheit. Medford has experienced only one 61 HDD in the last 40 years; however, it has also experienced 59 and 58 HDD events on Dec. 8, 1972, and Dec. 21, 1990, respectively.
- The other three areas in Oregon have similar weather data. For Klamath Falls, a 72 HDD occurred on Dec. 21, 1990, in La Grande a 74 HDD occurred on Dec. 23, 1983, and a 55 HDD occurred in Roseburg on Dec. 22, 1990. As with Washington/Idaho and Medford, these days are used as the peak day weather standard for modeling purposes.

Utilizing a peak planning standard of the coldest temperature on record may seem aggressive given we are using, in some cases, a temperature experienced only once. Given the potential impacts of an extreme weather event on our customers’ personal safety and property damage to customer appliances and company infrastructure, we believe it is a prudent planning standard.

We do analyze an alternate planning standard using the coldest temperature in the last twenty years For our Washington/Idaho service area we use a 74 HDD, which is equal to an average daily temperature of -9 degrees Fahrenheit. In Medford the coldest in twenty year is a 54 HDD, equivalent to a temperature of 11 degrees Fahrenheit. In Roseburg the coldest in twenty year is a 48 HDD, equivalent to a temperature of 17 degrees Fahrenheit. In Klamath Falls the coldest in twenty is a 64 HDD, equivalent to a temperature of 1 degree Fahrenheit. In La Grande the coldest in twenty years is a 68 HDD, equivalent to a temperature of -3 degrees Fahrenheit.

These HDDs by area, class and by day entered into SENDOUT® can be found in Appendix 3.4.

GLOBAL WARMING

Consistent with past IRPs, we adjusted the NOAA weather data to incorporate estimates for global warming in developing our HDD forecasts. This was based on extensive analysis of historical weather data in each of the areas we serve. Adjustments were applied to daily NOAA normal weather data and include a phase-in over the first ten years of our planning horizon. The effect of the adjustments, all else equal, results in declining annual demand over time. Appendix 3.5 summarizes our historical analysis and adjustment factors.

The analysis identified a gradual warming trend in the historical data; however we were unable to discern any definitive evidence to support a peak day warming trend. We continue to search but have be unsuccessful in finding supporting studies or analysis on the topic and, after discussion with our TAC, determined we would not make warming trend adjustments to our peak day weather events in our HDD forecast. Therefore, our modeling and analysis with respect to peak day planning is unaffected by global warming. Additional information on this topic is in Appendix 3.5.

DEVELOPING A REFERENCE CASE

To adjust for uncertainty, we developed a dynamic demand forecasting methodology that is flexible to changing assumptions. To understand how various alternative assumptions influence forecasted demand we needed a reference point for comparative analysis. For this we define a reference case demand forecast (Figure 3.4). We stress that this case is not intended to reflect anything other than a simple assumption start point.

Figure 3.4 - Reference Case Assumptions

1. Customer Annual Average Growth Rates

State	Residential	Commerical	Industrial
Washington	1.50%	1.60%	1.00%
Idaho	2.00%	1.70%	0.40%
Oregon	1.70%	1.30%	0.74%

2. Use Per Customer Coefficients

Flat Across All Classes

3-year Average Use per Customer per HDD by Area/Class

3. Weather

30-year Normal - NOAA (1981-2010)

Global Warming Adjustment

4. Elasticity

None

5. Demand Side Management

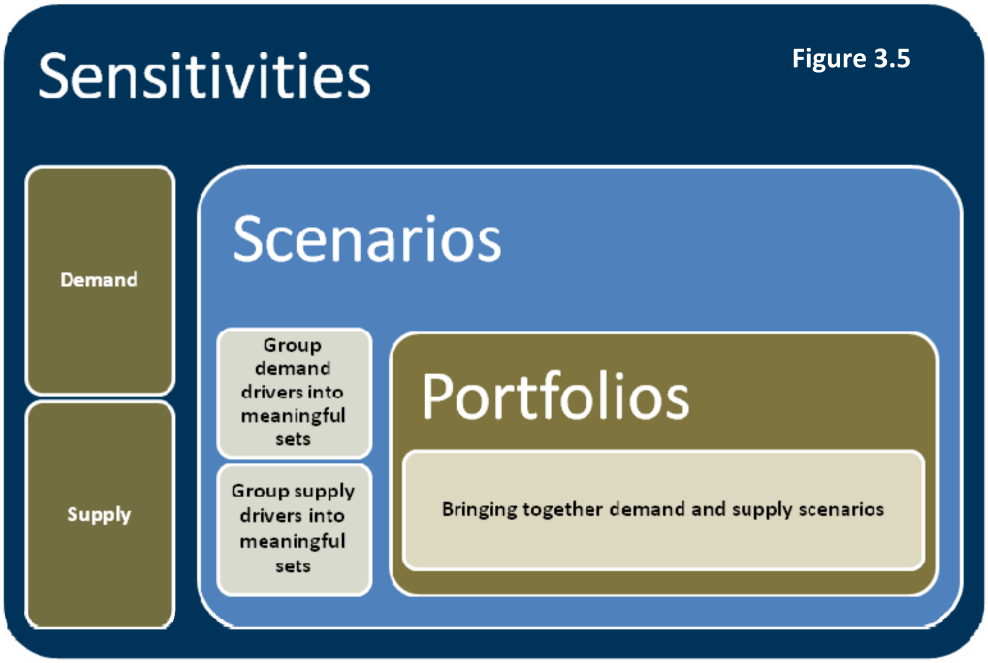
None

DYNAMIC DEMAND METHODOLOGY

The dynamic demand planning strategy critically examines a wide range of potential outcomes. The approach developed consists of:

- Identifying key demand drivers behind natural gas consumption
- Performing sensitivity analysis on each demand driver
- Combining demand drivers under various scenarios to develop alternative potential outcomes for forecasted demand
- Matching demand scenarios with supply scenarios to identify unserved demand

Figure 3.5 represents our methodology of starting with sensitivities, progressing to scenarios, and ultimately creating portfolios.



SENSITIVITY ANALYSIS

In analyzing demand drivers, we grouped them into two categories based on:

- **DEMAND INFLUENCING FACTORS** – Factors that directly influence the volume of natural gas consumed by our core customers
- **PRICE INFLUENCING FACTORS** – Factors that, through price elasticity response, indirectly influence the volume of natural gas consumed by our core customers

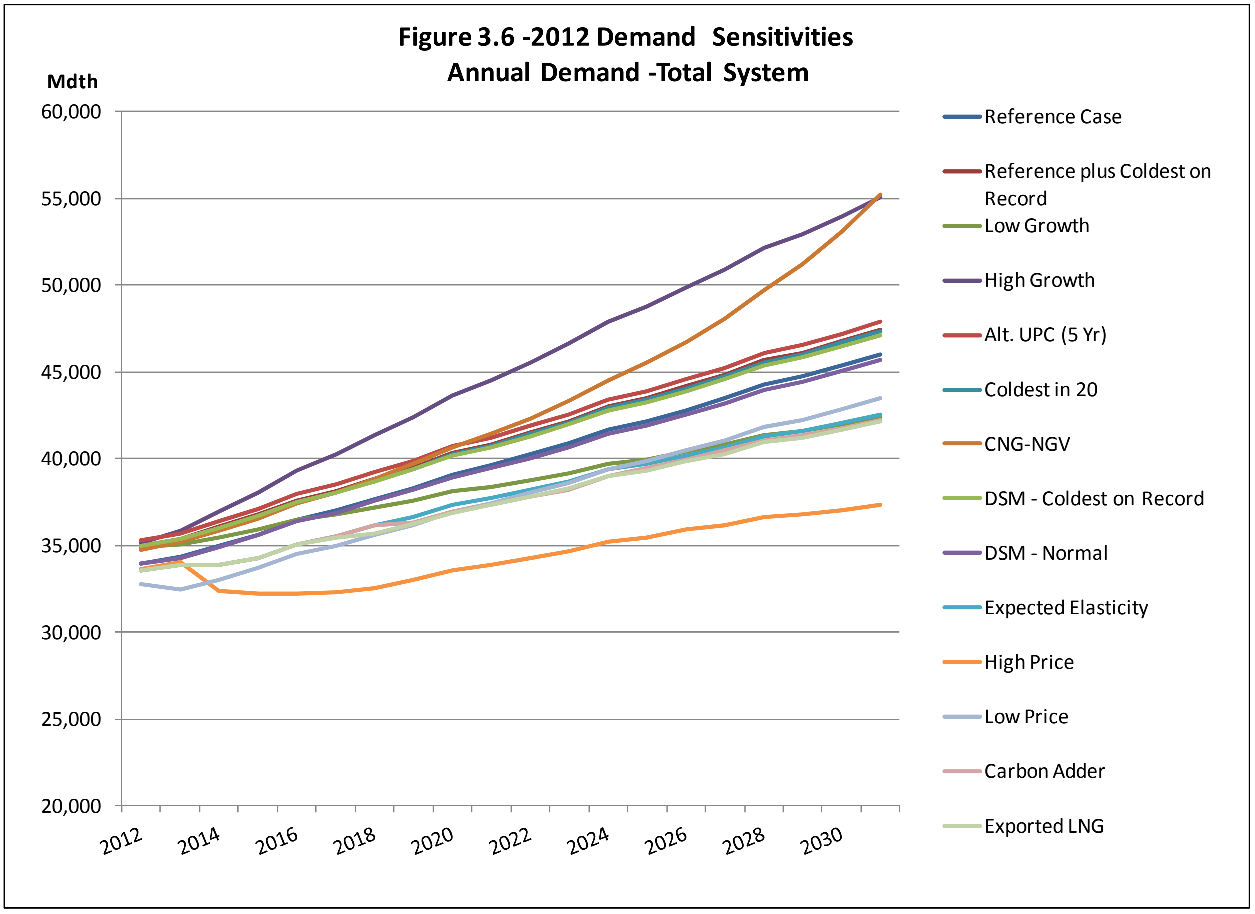
Once factors were identified, we developed sensitivities which we define as focused analysis of a specific natural gas demand driver and its impact on forecasted demand relative to our Reference Case when the underlying input assumptions are modified

Sensitivity assumptions reflect incremental adjustments we estimate are not captured in the underlying Reference Case forecast. We analyzed 14 demand sensitivities to determine the resultant effect relative to the reference case. Table 3.4 lists these sensitivities. More detailed information about these sensitivities can be found in Appendix 3.6.

Table 3.4 - Demand Sensitivities

Scenario	Influence	Weather	Growth	Use per Customer	Price Curve	Carbon Adder	LNG Adder	DSM	CNG/NGV	Elasticity
Reference Case	Direct	Normal	Expected	3 year	Expected	No	No	No	No	No
Reference Case plus Peak Weather	Direct	Peak	Expected	3 year	Expected	No	No	No	No	No
High Growth Case	Direct	Peak	High	3 year	Expected	No	No	No	No	No
Low Growth Case	Direct	Peak	Low	3 year	Expected	No	No	No	No	No
Alternate Use per Customer	Direct	Peak	Expected	5 year	Expected	No	No	No	No	No
CNG/NGV Case	Direct	Peak	Expected	3 year	Expected	No	No	No	Yes	No
DSM	Direct	Normal	Expected	3 year	Expected	No	No	No	No	No
Peak plus DSM	Direct	Peak	Expected	3 year	Expected	No	No	Yes	No	No
Alternate Weather Planning Standard	Direct	Coldest in 20	Expected	3 year	Expected	No	No	Yes	No	No
Expected Elasticity	Indirect	Peak	Expected	3 year	Expected	No	No	No	No	Yes
Low Price	Indirect	Peak	Expected	3 year	Low	No	No	No	No	No
High Price	Indirect	Peak	Expected	3 year	High	No	No	No	No	No
Carbon Legislation	Indirect	Peak	Expected	3 year	Expected	Yes	No	No	No	No
Exported LNG	Indirect	Peak	Expected	3 year	Expected	No	Yes	No	No	No

Figure 3.6 shows the annual demand from each of the sensitivities we modeled.



SCENARIO ANALYSIS

Following our testing of the various sensitivities we grouped them into meaningful combinations of demand drivers to develop demand forecasts representing scenarios. Table 3.5 identifies the scenarios we developed. Our Average Demand Case is representative of what we would consider for normal planning purposes, such as corporate budgeting, procurement planning, and PGA/General Rate Cases. The

Expected Case reflects the demand forecast we believe is most likely given peak weather conditions. The High Growth/Low Price and Low Growth/High Price represent a forecasted range of possibilities for customer growth and future prices. The Alternate Weather Standard utilizes the coldest day in the last twenty years. Each of these scenarios helps provide us with sufficient “what if” analysis given the volatile nature of many key assumptions including weather and price. Appendix 3.6 lists the specific assumptions within the scenarios while Appendix 3.7 contains a detailed description of each scenario.

Table 3.5

Demand Scenarios
Average Demand
Expected Demand - Peak
High Growth/Low Price
Low Growth/High Price
Alternate Weather Standard

PRICE ELASTICITY

Historic natural gas price volatility has created challenges in projecting future natural gas prices. Now that shale gas has fundamentally altered the market for natural gas historic analysis may not be indicative of future behavior. Some believe price volatility will decrease due to the widespread availability of natural gas while others feel volatility could become greater as shale production profiles are much less predictable than conventional gas production. We acknowledge changing price levels influence usage so we incorporate a price elasticity of demand factor into our modeling assumptions to allow use per customer to vary into the future as our natural gas price forecast changes.

Price elasticity is usually expressed as a numerical factor that defines the relationship of a consumer’s consumption change in response to price change. Typically, the factor is a negative number as consumers normally reduce their consumption in response to higher prices or will increase their consumption in response to lower prices. For example, a price elasticity factor of negative 0.13 means a 10% price increase will prompt a 1.3% consumption decrease and a 10% price decrease will prompt a 1.3% consumption increase.

We noted complex relationships influence price elasticity and given the new economic environment, we question whether current behavior will be considered normal or if customers will return historic usage patterns.

AGA PRICE ELASTICITY STUDY

From our participation in the 2007 AGA long-run price elasticity study, we received regional elasticity factors which compared favorably to our past estimates. Based on this corroboration we used a factor of negative .13 as our expected case factor to adjust use per customer coefficients.

In our last IRP we modeled a high and low price elasticity assumption due to the uncertainty in how our customers would respond to their evolving economic conditions. Utilizing the high elasticity assumption resulted in significant curtailment of demand which was much greater than historical experience. Alternatively low elasticity resulted in no meaningful reduction in demand. Our recent usage data indicates that even with declines in the retail rate for natural gas, use-per-customer continues to decline.

This is likely driven by a confluence of factors including high unemployment, increased investments in energy efficiency measures, building code improvements, behavioral changes and overall heightened focus of consumers' household budgets.

Based on our analysis of data since our 2009 IRP we find that the expected elasticity factor is a reasonable assumption and have decide to forgo utilizing a high or low elastic response in this IRP.

RESULTS

During 2012, our Average Case demand forecast indicates we will serve an average of 327,300 core natural gas customers with 33,200,000 dekatherms of natural gas. By 2031, we project 448,100 core natural gas customers with an annual demand of over 42,200,000 dekatherms. In Washington/Idaho, the number of customers is projected to increase at an average annual rate of 1.6 percent with demand growing at a compounded average annual rate of 1.3 percent. In Oregon, the number of customers is projected to increase at an average annual rate of 1.7percent, with demand growing 1.3 percent per year.

During 2012 our Expected Case demand forecast indicates we will serve an average of 327,300 core natural gas customers with 34,700,000 dekatherms of natural gas. By 2031 we project 448,100 core natural gas customers with an annual demand of over 43,744,000 dekatherms.

Figure 3.7 shows system forecasted demand for the demand scenarios on an **average daily basis** for each year[1].

[1] Appendix 3.9 shows gross demand, DSM savings, and net demand.

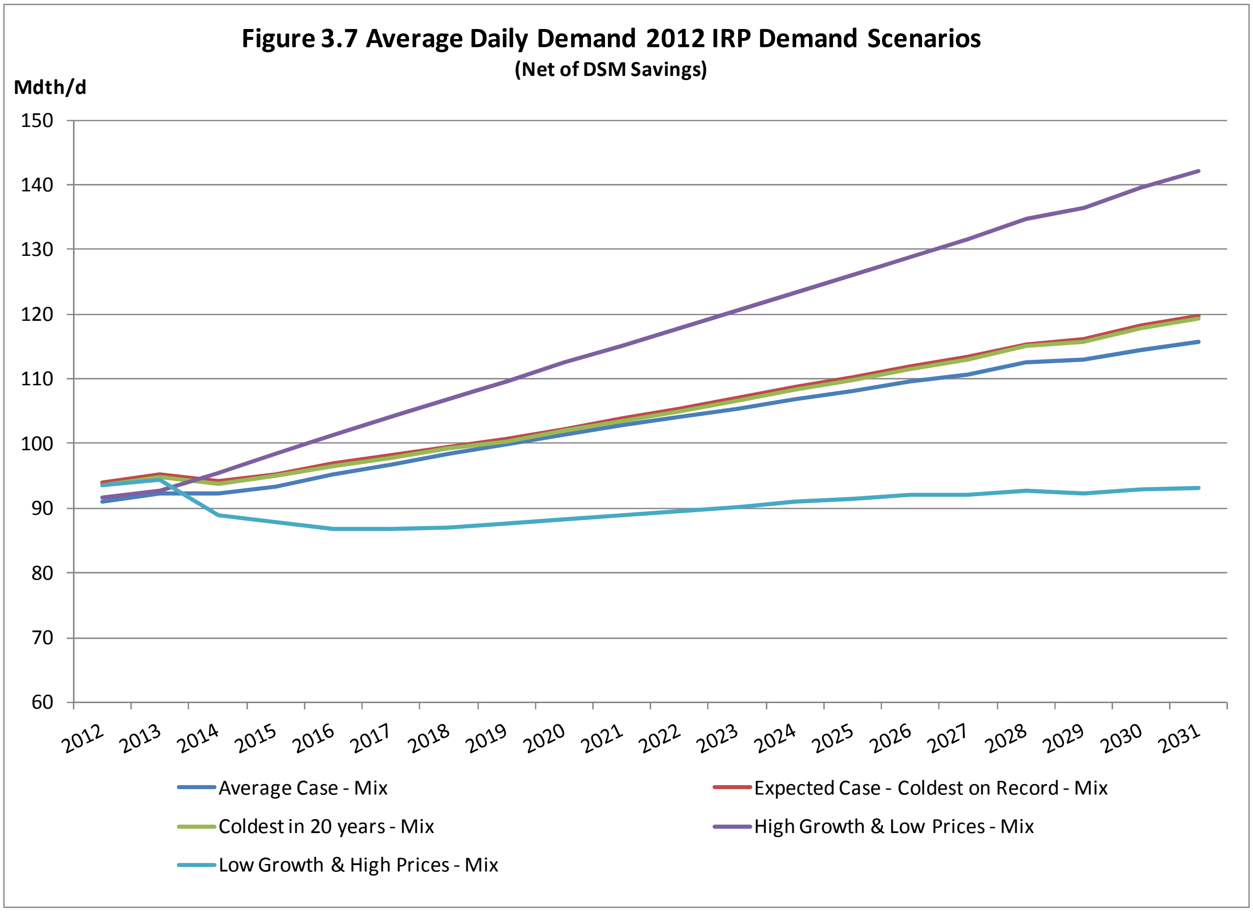
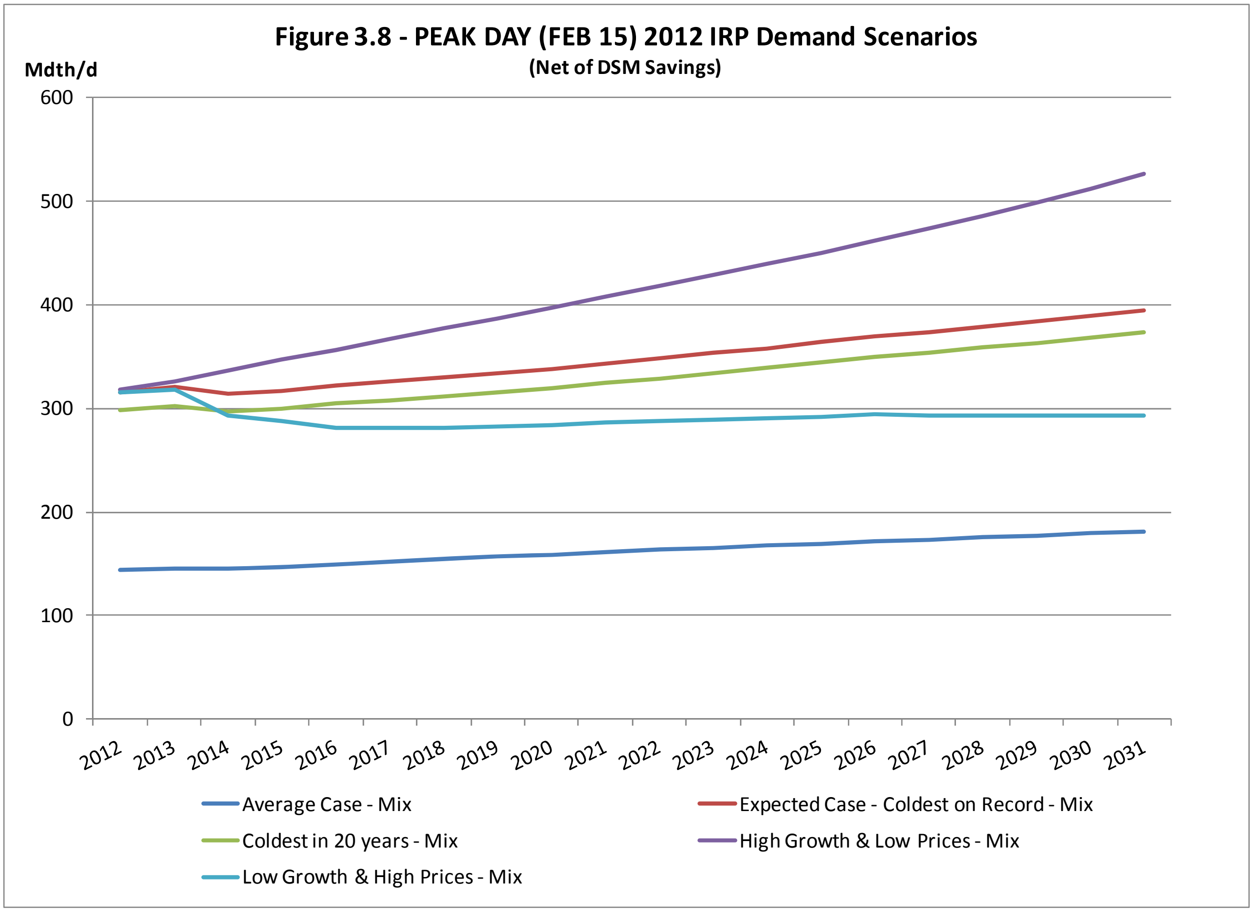


Figure 3.8 shows system forecasted demand for the Expected, High and Low Demand cases on a **peak day basis** for each year relative to the Average case average daily winter demand. Detailed data for all demand scenarios is in Appendix 3.8.



The purpose of the IRP is to balance forecasted demand with existing 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. The methodology for modeling demand side management initiatives is described in Chapter 4 - Demand-Side Resources.

ALTERNATIVE FORECASTING METHODOLOGIES

There are many forecasting methods available and used throughout different industries.. We strive to use methods that enhance forecast accuracy, facilitate meaningful variance analysis and allow for modeling flexibility to incorporate differing assumptions. We believe our statistical methodology to be sound and provide us with a robust range of demand considerations. Our methodology allows for us to vary the results of our statistical inputs by considering both qualitative and quantitative factors. These factors can be derived from data or surveys of market information, fundamental forecasters, and industry experts. We are always open to new methods of forecasting demand and we continually assess which, if any, alternative methodologies to include in our dynamic demand forecasting methodology.

II ACTION ITEM

Demand forecasting is a critical component, careful evaluation of the current methodology and sufficient scenario planning is essential. The change in demand over recent years has been dramatic causing a heightened focus on variance analysis and trend monitoring. Current techniques have provided sound forecasts with appropriate variance capabilities. In the near term we have identified three key issues to investigate and monitor.

PRICE ELASTICITY

Our price elasticity analysis raised several issues. First, we noted the AGA factors were derived from annual demand data. This was satisfactory for our annual demand forecasting, but this raised a question whether the factors were applicable to peak demand analysis. We also use the same factors for residential and commercial customer classes even though the AGA factors were derived from residential customer data only.

We also noted that price signals to core customers are lagged and they are often insulated from volatile prices due to their exposure to tariff rates versus wholesale prices.

During our planning cycle we realized the effects of the recession and our demand forecast once again is lower than previous IRPs. Natural gas prices are at lows not seen in the last decade. Prices throughout this forecast are intended to increase, albeit moderately. The question still remains, how much more can/will customers curtail?

An action item from our last IRP had us make an inquiry to the AGA for an updated study. The AGA declined due to budget constraints. For the upcoming IRP cycle, we will consider working with a third-party, such as the NWGA, to conduct a price elasticity study and assess interest of other utilities in pursuing a regional study.

FLAT DEMAND RISK

Demand once again has “flattened” when compared to previous IRPs. The flattening of demand is due to many factors including moderate forecasted customer growth over the 20-year planning horizon (especially when compared to previous IRP customer forecasts) and declining use per customer due to behavioral changes driven by challenging economic conditions, increased investments in energy efficiency measures and enhanced building codes improving the efficiency of homes. The reduced demand pushes the need for resources out further into the future which is a good thing for customers, as no new investments in resources will be necessary in the foreseeable future. However, should there be a significant rebound in demand our resource needs become more imminent. We need continued visibility into our demand trends in order to identify signposts of accelerated recovery or changing usage behavior.

NATURAL GAS VEHICLE POTENTIAL

Robust availability of natural gas at economic prices has stimulated investments in NGV infrastructure. How much market penetration occurs nationally and regionally remains uncertain. Analysis and evaluation of our role in the NGV initiative is underway. We have included a scenario where NGV demand is served by Avista.

‖ CONCLUSION

Through our dynamic demand modeling process, we have considered a wide range of potential demand impacts of both changing natural gas prices and a changing economy. The result of those considerations is a reasonable array of outcomes with respect to core consumption of natural gas. While we recognize that the actual level of demand is dependent on a variety of factors, reviewing a range of potential outcomes allows us to plan more effectively as economic or pricing conditions change.

CHAPTER 4 DEMAND-SIDE RESOURCES

OVERVIEW

Avista has been offering natural gas Demand-Side Management (DSM) to its residential, commercial and industrial customers since 2001[1]. These programs result in multiple benefits including, but not limited to, reductions in customers' energy bills, reductions in natural gas supply-side resource needs and reductions in Green House Gas (GHG) emissions. These benefits make acquiring cost-effective demand-side efficiencies an appealing resource alternative which Avista believes is the best strategy for minimizing energy service costs to our customers while promoting a cleaner environment.

In response to the Washington Transportation and Utilities Commission (UTC) staff request of an independent, external Conservation Potential Assessment (CPA) pursuant to the Company's next IRP, Avista issued a Request for Proposal (RFP) for a CPA. Consequently, in preparation for this IRP, Global Energy Partners, an EnerNOC Company, was selected to conduct a CPA to forecast the 20-year DSM potential for Avista's natural gas service territory within Washington, Idaho, and Oregon. The DSM potential that was generated for Avista's service territory was then evaluated in SENDOUT® as a resource on par with other supply-side resources.

The SENDOUT® model understands that investments made in DSM are a long-term resource decision. Within SENDOUT® the aggregated potential and costs by region and class are tested against supply side resources. The model also understands that some potential may not be cost-effective in the initial forecast years; however the total cost over the life of the measure, coupled with the cumulative therms savings, is economic. Due to this modeling nuance, SENDOUT® typically selects most of the DSM potential.

The changing natural gas supply picture and lower prices have resulted in the decline of natural gas avoided costs. While this is good news for customers, these lower avoided costs add new challenges to offering a comprehensive natural gas DSM portfolio. The Company's 2012 DSM Business Plan forecasted non-cost-effective natural gas using the avoided costs from the 2009 Natural Gas IRP. A subsequent study done in February 2012 entitled "Review of Prospects and Strategies for the 2012 Avista Regular Income Natural Gas DSM Portfolio" projected that, with substantial modifications, the natural gas DSM portfolio could potentially be marginally cost-effective using a presumed 25 percent reduction in avoided cost.

Avista's originally anticipated assumption of 25 percent lower natural gas avoided costs was replaced with current IRP avoided costs which is a decrease of approximately 50 percent. Given these avoided costs, the Company's business planning projections indicate that the natural gas DSM portfolio will not be cost-effective. Evaluation of a number of scenarios to include additional adders for carbon/green house gases, distribution capacity adders, various allocations and categorizations of non-incentive utility cost, realization rates and net-to-gross ratios, as well as, evaluating the portfolio on a gross (including all program participants) rather than net (including only participants who adopted the measure as a result of the program) did not change the projected unfavorable portfolio cost-effectiveness.

[1] The Company operated natural gas DSM programs from 1995-1997 until natural gas avoided costs declined to the point at which natural gas DSM programs became cost-ineffective. At that time, the natural gas DSM Tariff Rider, Schedule 191, was reduced to $0 until the avoided costs increased and natural gas programs could again be offered. In 2001 Schedule 191 rider amount was increased and natural gas DSM programs were again implemented. The Company has had uninterrupted natural gas DSM since 2001.

CPA METHODOLOGY

Prior to the development of potential estimates, Global developed a baseline end-use forecast to quantify the use of natural gas by end use, in the base year, and projections of consumption in the future in the absence of utility programs and naturally occurring conservation. The end-use forecast includes the relatively certain impacts of codes and standards that will unfold over the study timeframe. All such mandates that were defined as of January 2011 are included in the baseline. The baseline forecast is the foundation for the analysis of savings from future DSM efforts, as well as, the metric against which potential savings are measured.

Inputs to the baseline forecast include current economic growth forecasts (e.g. customer growth, income growth), natural gas price forecasts, trends in fuel shares and equipment saturations developed by Global, existing and approved changes to building codes and equipment standards, and Avista's internally developed sales forecasts.

According to the natural gas CPA completed for Avista, the residential sector natural gas consumption for all end uses and technologies increases, mainly due to the projected 1.7 percent annual growth in the number of households, but also due to the slight increase in the average home size. Other heating, which includes unit wall heaters and miscellaneous loads, have a relatively high growth rate compared to other loads. However, at the end of the 20-year planning period, these loads represent only a small part of overall use.

For the commercial and industrial (C&I) sectors, natural gas use continues to grow slowly over the 20-year planning horizon as new C&I construction increases the overall square footage in the commercial sector. In addition, existing buildings are renovated to incorporate additional amenities such as full-scale kitchens. Growth in the HVAC and water heating end uses is moderate. Food preparation, though a small percentage of total usage, grows at a higher rate than other end uses. Consumption by miscellaneous equipment and process heating are also projected to increase.

Table 4.1 illustrates the system-wide baseline forecast and how natural gas use across all sectors is expected to increase by 28 percent during the 20-year planning horizon, for an average annual growth of 1.1 percent. Overall, the forecast for the next 20 years grows steadily, dominated by growth in the residential sector. Further, growth is forecasted to be highest in Idaho followed by Oregon.

Table 4.1 Baseline Forecast Summary (1000 therms*)*

Sector	2010	2013	2014	2017	2022	2027	2032	% Change (2010-2032)	Avg. Growth Rate (2010-2032)
Residential	188,894	196,073	197,449	204,112	219,778	241,292	269,274	43%	**1.5%**
Sm. Commercial	50,693	50,130	50,530	51,271	52,378	53,494	55,120	9%	**0.4%**
Lg. Commercial	71,176	69,274	69,647	70,392	71,667	73,191	75,295	6%	**0.2%**
Industrial	5,141	5,026	5,067	5,156	5,274	5,409	5,560	8%	**0.3%**
Total	**315,906**	**320,503**	**322,693**	**330,932**	**349,097**	**373,385**	**405,250**	**28%**	**1.1%**

State	2010	2013	2014	2017	2022	2027	2032	% Change (2010-2032)	Avg. Growth Rate (2010-2032)
Washington	167,021	168,616	169,523	173,064	180,908	191,260	205,302	23%	**0.9%**
Idaho	72,017	73,767	74,426	76,910	82,427	89,742	99,277	38%	**1.4%**
Oregon	76,867	78,120	78,744	80,958	85,762	92,383	100,671	31%	**1.2%**
Total	**315,906**	**320,503**	**322,693**	**330,932**	**349,097**	**373,385**	**405,250**	**28%**	**1.1%**

The next step in the study is the development of the three types of potential: technical, economic and achievable. Technical potential is the theoretical upper limit of conservation potential. This assumes that all customers replace equipment with the most efficient option available regardless of cost, as well as, the adoption of every available non-equipment measure, where applicable. Economic potential represents the adoption of cost-effective conservation measures based on the Total Resource Cost (TRC) test and assumes that customers purchase the most cost-effective and applicable measure. Finally, achievable potential takes into account market maturity, customer preferences for energy efficiency technologies and expected program participation. Achievable potential establishes a realistic target for conservation savings that a utility can expect to achieve through its programs.

DSM measures that achieve generally uniform year round energy savings, independent of weather are considered base load measures. Examples include high efficiency water heaters, cooking equipment and front load clothes washers. Weather sensitive measures are those which are influenced by heating degree day factors and include higher efficiency furnaces, ceiling/wall/floor insulation, weather stripping, insulated windows, duct work improvements (tighter sealing to reduce leaks) and ventilation heat recovery systems (capturing chimney heat). Weather sensitive measures are desirable in resource planning, as they save the most energy during the coldest periods, thus displacing the more expensive peaking or seasonal supply resources. Weather sensitive measures are often referred to as “winter measures” and are typically valued using a higher avoided cost (due to summer to winter pricing differentials) while base load measures often called “annual measures” are valued at a lower avoided cost.

Conservation measures are offered to residential, non-residential and low-income[2] customers. Conservation measures offered to residential customers are classified as prescriptive, meaning they have a standardized therm savings which can be generalized across the customer class and all customers receive the same financial incentive for the same measures. Low income customers receive a more holistic, customized approach through

[2] For purposes of tables, figures and targets, low income is a subset of residential class.

a handful of Community Action Agency partnerships. Non-residential customers have access to prescriptive and site-specific conservation measures. Site-specific measures are customized to the facility and have cost and therm savings that are unique to the individual facility.

Finally, some conservation measures in Oregon are required by law and are therefore designated "mandatory" or "must take" measures in the modeling tool, which means they are offered to customers without regard to their current cost-effectiveness relative to the utility's supply resources. An example of a mandated measure is a walk-through energy audit, which would not be accompanied by energy savings unless a customer chooses to participate in a program. In addition, a customer may choose to delay participating in a program for many years. In these cases, the audit would be non-cost effective since there is no savings benefit to offset the cost of the audit.

See Table 4.2 for Residential and C&I Measures evaluated in this study for all three states.

Table 4.2 Conservation Measures

Residential Measures	C&I Measures
Furnace – Maintenance	Furnace – Maintenance
Boiler – Pipe Insulation	Boiler – Maintenance
Insulation – Ducting	Boiler – Hot Water Reset
Insulation – Infiltration Control	Boiler – High Efficiency Hot Water Circulation
Insulation – Ceiling	Space Heating – Heat Recovery Ventilator
Insulation – Wall Cavity	Insulation – Ducting
Insulation – Attic Hatch	Insulation – Ceiling
Insulation – Foundation (new only)	Insulation – Wall Cavity
Ducting – Repair and Sealing	Ducting – Repair and Sealing
Doors – Storm and Thermal	Windows – High Efficiency
Windows – ENERGY STAR	Energy Management System
Thermostat – Clock/Programmable	Thermostat – Clock/Programmable
Water Heating – Faucet Aerators	Water Heating – Faucet Aerators
Water Heating – Low Flow Showerheads	Water Heating – Pipe Insulation
Water Heating – Pipe Insulation	Water Heating – Tank Blanket/Insulation
Water Heating – Tank Blanket/Insulation	Water Heating – Hot Water Saver
Water Heating – Thermostat Setback	Advanced New Construction Designs (new only)
Water Heating – Timer	Comprehensive Commissioning
Water Heating – Hot Water Saver	Process – Boiler Hot Water Reset (industrial only)
Water Heating – Drain Water Heat Recovery (new only)	
Home Energy Management System	
Advanced new Construction Designs (new only)	
ENERGY STAR Homes (new only)	

POTENTIAL RESULTS

The technical potential reflects the adoption of all DSM measures regardless of cost effectiveness and represents the upper limit on savings. Over the 20 years considered by the CPA, technical potential reaches 38.9 percent of the baseline end-use forecast.

Economic potential applies the TRC test to measures identified within the technical potential and reflect the adoption of DSM measures that are cost-effective. By the end of the 20-year timeframe this represents 14.6 percent of the baseline energy forecast. The significant difference between the technical and economic potential reflects the lower natural gas avoided costs resulting from shale gas, as well as, the influence of

Avista's long-running history of operating DSM programs that have already achieved much of the cost-effective conservation. Consequently, the remaining conservation measures are becoming incrementally more expensive on a per-therm basis and many, therefore, do not pass the cost-effectiveness screen based on current avoided costs.

Finally, achievable potential across the residential, commercial and industrial sectors is 12.9 percent of the baseline energy forecast by the end of 2032.

For the Oregon service territory, it should be noted that both economic and achievable potential include residential weatherization measures that are mandated by Oregon legislation to be provided regardless of cost effectiveness and other factors. Many of these measures did not pass the TRC benefit-cost ratio analysis but were nevertheless included in economic and achievable potential.

Tables 4.3 and 4.4 summarize cumulative conservation for each potential type for selected years across the 20-year CPA and IRP horizon. Initially, the large commercial sector provides a relatively higher percentage of the achievable savings compared with its share of sales, but over time, this situation reverses so that the residential sector's share of savings is the greatest, due to growth in residential customer count. For more specific detail, please refer to the natural gas CPA provided in Appendix 4.1.

Table 4.3 Summary of Cumulative Achievable, Economic and Technical Conservation Potential

	2013	2014	2017	2022	2027	2032
Baseline Forecast (1000 thm)						
	320,503	322,693	330,932	349,097	373,385	405,250
Cumulative Natural Gas Savings (1000 thm)						
Achievable	1,546	3,738	12,794	28,216	41,349	52,381
Economic	1,797	4,333	14,785	31,757	45,809	58,965
Technical	7,623	15,844	46,189	91,655	131,422	157,520
Cumulative Natural Gas Savings (% of Baseline)						
Achievable	0.5%	1.2%	3.9%	8.1%	11.1%	12.9%
Economic	0.6%	1.3%	4.5%	9.1%	12.3%	14.6%
Technical	2.4%	4.9%	14.0%	26.3%	35.2%	38.9%

Furthermore, overall potential is presented first by state and then for each sector in the following table.

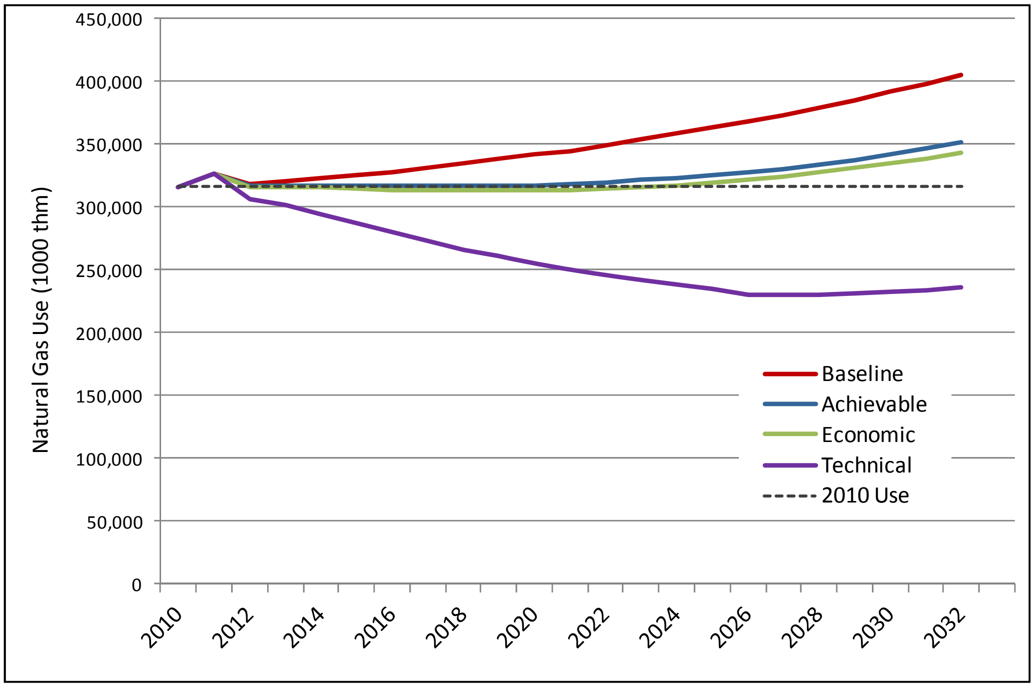
Table 4.4 Summary of Cumulative Achievable, Economic and Technical Conservation Potential by State and Sector

Cumulative Savings (1000 them)	2013	2014	2017	2022	2027	2032
Washington	893	2,203	6,923	15,364	21,885	26,909
Idaho	364	821	2,734	5,601	8,758	11,914
Oregon	289	715	3,136	7,251	10,706	13,559
Total	**1,546**	**3,738**	**12,794**	**28,216**	**41,349**	**52,381**

Cumulative Savings (1000 them)	2013	2014	2017	2022	2027	2032
Residential	515	1,567	6,507	14,903	22,278	29,960
Small Commercial	206	469	1,588	3,557	5,709	7,018
Large Commercial	801	1,654	4,548	9,436	13,007	15,027
Industrial	25	49	151	319	354	377
Total	**1,546**	**3,738**	**12,794**	**28,216**	**41,349**	**52,381**

Figure 4.1 below illustrates the potential forecasts compared with the end-use baseline forecast that was projected to occur in the absence of utility DSM programs. The dotted black line depicts the 2010 usage level. By the end of the 20-year period, achievable potential (indicated by the blue line) offsets 60 percent of the growth in the baseline forecast.

Figure 4.1 - Conservation
Potential Energy Forecast (1000 therm)



POTENTIAL RESULTS – RESIDENTIAL

Single-family homes represent 79 percent of Avista's residential natural gas customers, but accounts for 84 percent of the sector's consumption in the study base year 2010. While Oregon represents only about one-quarter of the baseline forecast, it makes up between 28 and 35 percent of the achievable potential savings. This is due to the inclusion of the legislatively mandated weatherization and insulation measures within Oregon's achievable potential.

Table 4.5 provides a distribution of achievable potential by state for the residential sector.

Table 4.5 Residential Cumulative Achievable Potential by State, Selected Years

	2013	2014	2017	2022	2027	2032
Baseline Forecast (1000 thm)						
Washington	100,894	101,415	104,274	110,964	119,962	132,043
Idaho	46,065	46,424	48,209	52,647	58,832	67,038
Oregon	49,114	49,609	51,629	56,167	62,498	70,193
Total	**196,073**	**197,449**	**204,112**	**219,778**	**241,292**	**269,274**
Natural Gas Savings (1000 thm)						
Washington	237	838	3,017	7,268	10,634	13,894
Idaho	121	306	1,248	2,337	4,002	6,246
Oregon	156	422	2,242	5,298	7,642	9,819
Total	**515**	**1,567**	**6,507**	**14,903**	**22,278**	**29,960**
% of Total Residential Savings						
Washington	46.2%	53.5%	46.4%	48.8%	47.7%	46.4%
Idaho	23.6%	19.6%	19.2%	15.7%	18.0%	20.8%
Oregon	30.3%	26.9%	34.5%	35.5%	34.3%	32.8%

The bulk of the residential potential exists primarily with space heating followed by water heating applications. Appliances and miscellaneous contribute a small percentage of potential. Based on measure-by-measure finding of the potential study, the greatest sources of residential achievable potential across all three states are:

- Shell measures and insulation
- Thermostats and home energy monitoring systems
- Water-saving devices such as low-flow showerheads and faucet aerators
- Water heater tank blankets and pipe insulation

POTENTIAL RESULTS – COMMERCIAL AND INDUSTRIAL

The baseline forecast for the C&I sector grows steadily during the forecast period as the region begins to recover from the economic downturn. Consequently, energy efficiency opportunities are significant for this sector. However, similar to the residential sector, many conservation opportunities do not pass the TRC economic screen given the low natural gas avoided costs.

The large commercial sector provides the greatest opportunities for savings. Although potential as a percentage of baseline use varies from one sector to the next, results do not vary greatly among the three states. See Table 4.6 for achievable potential by sector for selected years.

Table 4.6 C&I Cumulative Achievable Potential by Selected Years

	2013	2014	2017	2022	2027	2032
Baseline Forecast (1000 thm)						
Small Commercial	50,130	50,530	51,271	52,378	53,494	55,120
Large Commercial	69,274	69,467	70,392	71,667	73,191	75,295
Industrial	5,026	5,067	5,156	5,274	5,409	5,560
Total	**124,429**	**125,244**	**126,819**	**129,319**	**132,094**	**135,976**
Natural Gas Savings (1000 thm)						
Small Commercial	206	469	1,588	3,557	5,709	7,018
Large Commercial	801	1,654	4,548	9,436	13,007	15,027
Industrial	25	49	151	319	354	377
Total	**1,031**	**2,172**	**6,287**	**13,312**	**19,071**	**22,422**
% of Total C&I Savings						
Small Commercial	20.0%	21.6%	25.3%	26.7%	29.9%	31.3%
Large Commercial	77.6%	76.2%	72.3%	70.9%	68.2%	67.0%
Industrial	2.4%	2.2%	2.4%	2.4%	1.9%	1.7%

Similar to Residential, the bulk of the C&I potential exists within space heating and water heating applications. Food preparation, process and miscellaneous represents a smaller proportion of potential. Primary sources of commercial achievable savings are:

- Energy management systems and programmable thermostats
- Boiler operating measures such as maintenance
- Hot water reset and efficient circulation
- Equipment upgrades for furnaces, boilers and unit heaters
- Food service equipment

SENDOUT® MODELING METHODOLOGY

The SENDOUT® model understands that investments made in DSM are a long-term resource decision. The model also understands that some programs may not be cost-effective in the initial forecast years; however the total cost over the life of the measure, coupled with the cumulative therms savings, is economic. Due to this modeling nuance, SENDOUT® typically selects most of the DSM potential.

While the IRP process evaluates demand-side and supply-side resources for a 20-year planning horizon, the process also results in a starting point for the two year operational business plan and goal for natural gas DSM. The business plan sets targets specific to each state and sector – residential and C&I. The following three tables provide the 2013-2014 CPA identified DSM opportunity for Idaho, Oregon and Washington, respectively.

Table 4.7 Idaho Natural Gas Target (2013-2014)

Incremental Annual Savings (1000 therm)	2013	2014
Residential	121	185
Commercial & Industrial	246	271
Total	**364**	**456**

Table 4.8 Oregon Natural Gas Target (2013-2014)

Incremental Annual Savings (1000 therm)	2013	2014
Residential	156	266
Commercial & Industrial	133	160
Total	**289**	**426**

Table 4.9 Washington Natural Gas Target (2013-2014)

Incremental Annual Savings (1000 therm)	2013	2014
Residential	237	601
Commercial & Industrial	655	709
Total	**893**	**1,310**

There are substantial methodological differences between the Global Energy Partners CPA and Avista's operational business planning process. These include how measures are aggregated into programs offerings and evaluated, how non-incentive infrastructure costs are treated, and how specific the results are to Avista's service territory and program offerings. The CPA provides substantial guidance in evaluating the entire spectrum of efficiency options and illustrating trends in equipment and technologies, however the business planning process is a reflection of the likely results of actual DSM operations.

Key analytical differences between the CPA and the business planning process include the 'splintering' of measures into numerous scenarios (by building type, replace-before-burnout vs. replace-on-burnout, by jurisdiction, etc.). These splintered measures may pass and generate the expectation of the cost-effective acquisition of resources, but if the measures are not collectively cost-effective when aggregated into a program that can be operationally delivered, there are no realistic prospects for achieving these projections. Additionally there are differences in non-incentive utility cost levels driven by program design approaches and how these costs are distributed. Fundamentally these differences are driven by the use of an independent third-party packaged model intended to provide general guidance regarding resource acquisition economics versus a utility-specific business planning approach incorporating operational details, program-specific assumptions and indexed to past actual results. These differences can lead to different results under many conditions, especially under challenging cost-effectiveness scenarios.

THE BUSINESS PLANNING PROCESS AND CONSERVATION GOALS

Each fall, Avista develops a DSM business plan where CPA-identified measure applications are re-cast into operational DSM programs and goals are developed. For example, a CPA could identify that 3-pan and 5-pan commercial cookware would be cost-effective while 4-pans may not. However, programmatically, since the 4-pan cookware is such a small slice of the market, the program would ultimately incent all of these non-residential cookware options. As explained above, the 'splintered' approach utilized in the evaluation of natural gas efficiency options within the CPA can lead to substantially different results than can be operationally achieved. Under those circumstances Avista has found that the business planning process is more indicative of what is operationally achievable.

Evaluation of the Washington/Idaho natural gas portfolio using these latest avoided costs have not resulted in any scenarios where Washington/Idaho natural gas programs are cost-effective, on either a gross or net basis. Consequently, Avista has filed in both states for an indefinite suspension of its Washington/Idaho natural gas DSM programs.

The Company has history of suspending natural gas DSM when avoided costs have decreased rendering programs cost-ineffective. Since Washington and Idaho electric DSM portfolio continues to be cost-effective and operate, it is fairly easy for the Company to ramp up the natural gas programs again should there be a change in the natural gas avoided costs. Avista's natural gas DSM programs were suspended in 1997 due to decreased avoided costs and were reinstated when avoided costs increased three years later. The Company will continue to monitor Weighted Average Cost of Gas (WACOG) as a proxy to determine changes in avoided costs.

The Oregon natural gas DSM portfolio is undergoing portfolio evaluation. This evaluation will incorporate the continuation of mandated audit services, as well as, any programs which can be redesigned to meet the required criteria. Additional review of appropriate methodologies will occur to include discussions of the appropriate discount rate and base case. This work is being expedited in recognition of the need to implement program redesigns or suspensions in a responsible manner and timeline.

While the lower natural gas avoided costs can be viewed as disappointing news for DSM, the good news for customers translates to lower retail rates. In addition, some electric efficiency programs such as fuel conversions become even more cost-effective and there may be potential for increases in customer incentives to enhance participation in these programs and encourage customers to make the appropriate fuel choice. Avista continues to support energy efficiency efforts where cost-effectiveness allows.

ENVIRONMENTAL EXTERNALITIES

The impact of utilizing energy on the environment continues to be a subject of societal concern and debate. If there are impacts that cannot be repaired naturally within a reasonable period of time, damage cost to the environment occurs for which society will have to pay in some future undetermined form. The question of who pays, how much and when payment should be made, are complicated issues. This longstanding debate is trying to be addressed through a variety of public policy initiatives and legislation. Regulatory guidelines in Oregon[3] advocate specific analysis in the IRP process to better understand these issues. Avista included an evaluation of the impacts of environmental externalities in the context of this evolving legislative environment. Appendix 4.2 discusses the analysis.

DEMAND RESPONSE

Demand response is a peak demand management concept where customers adjust the timing of their energy consumption away from consumption peaks in exchange for lower rates. Implementation strategies encompass a number of activities including real-time pricing, time- of-use rates, critical- peak pricing, demand buyback, interruptible rates and direct-load controls. When effectively implemented, acquisition of costly supply resources can be deferred.

Demand response works best when it is a quick solution to an immediate problem. When demand peaks, system operators need the ability to either quickly notify customers to curtail consumption or do it themselves via control systems to physically manage/restrict gas flow to increase distribution system pressures.

This mechanism exists with respect to our interruptible transportation-only customers, which make up approximately one third of Avista's total annual throughput. However, because we do not purchase supply for these customers, they do not represent an incremental supply resource alternative. Only core customers with high winter consumption profiles would provide an incremental supply resource using demand response curtailment strategies. Unfortunately, we currently have very few core customers with a complying consumption profile. As a result, we believe that all customers who can manage their operations on interruptible service are currently served on an interruptible basis, leaving little opportunity to reduce peak loads through expanded interruptible service.

While little demand response opportunity exists on our natural gas system, we continue to monitor the progress of other natural gas utilities and their efforts of peak load shifting to offset hourly and/or daily flow constraints. Whereas electric demand response technologies have been in place for over two decades, major differences exist between electric and natural gas supply/delivery systems. The economics of the timing of natural gas usage are much more forgiving than electric due to underground storage and line packing. Furthermore, natural gas curtailment is not an option since a natural gas company cannot restart service without a technician on-site to ensure all pilots are properly lit for safety reasons.

At times natural gas providers may find implementing a demand response program helpful in offsetting or postponing a pipeline upgrade or in price balancing. However, mandatory participation in the affected areas would be vital to fund the necessary investment in enabling technologies.

‖ CONCLUSION

By encouraging customers to change their demand for natural gas, Avista can displace the need to purchase additional natural gas supplies, displace or delay contracting for incremental pipeline capacity and possibly displace or delay the need for upgrades to our distribution system. This IRP process provides the utility with the necessary resource analysis to evaluate demand-side resource options on par with supply-side resources,

[3] Oregon IRP regulations require that a 10% cost advantage accrues to DSM resources relative to supply resources for environmental externalities costs. Appendix 4 describes our analysis.

periodically review and update DSM operations and finally, develop and implement improved natural gas energy efficiency programs.

The completion of the IRP analysis is not the end point, but rather the midpoint of a much larger evaluation of the DSM natural gas resource portfolio. The IRP analysis presented has generally indicated a conservation potential for a future DSM program design and delivery. However, differences in modeling methodologies require further evaluation through Avista's annual business planning process in order to facilitate the development of a cost-effective program portfolio to be incorporated into overall DSM operations.

Even though applications to suspend gas DSM have been filed, Avista is committed to closely monitoring proxies for the natural gas avoided cost and returning the natural gas DSM programs to our menu of offerings if commodity costs and efficiency technologies or program delivery options change in such a manner as to make these programs cost-effective under the Total Resource Cost test. This monitoring will be performed on an ongoing basis in addition to our regularly scheduled annual DSM business plans and the biennial IRP process.

Chapter 5 ‖ Supply-Side Resources

OVERVIEW

We have analyzed a range of anticipated future demand scenarios and a variety of possible conservation measures to reduce demand. This chapter discusses possible supply options to meet net demand. Our objective is to reliably provide natural gas to customers with an appropriate balance of price stability and prudent cost while navigating continuously changing market conditions. To achieve this, we evaluate a variety of supply-side resources and attempt to build a supply portfolio that is appropriately diversified. The resource acquisition and commodity procurement programs resulting from our evaluation consider physical and financial risks, market-related risks and procurement execution risks and identify the methods we deploy to mitigate these risks.

We manage our natural gas procurement and related activities on a system-wide basis. We have a number of regional supply options available to serve our core customers. These include firm and non-firm supplies, firm and interruptible transportation on six interstate pipelines and storage. 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. In this chapter, we discuss the available regional commodity resources and our procurement plan strategies, the regional pipeline resource options available to deliver the commodity to our customers, and the storage resource options available which provide additional supply diversity, enhanced reliability, favorable price opportunities and flexibility to meet a varied demand profile. Beyond these traditional supply-side resources we discuss non-traditional resources which are also considered.

COMMODITY RESOURCES

SUPPLY BASINS

Avista is fortunate to be located in relatively close proximity to the two largest natural gas producing regions in North America – the Western Canadian Sedimentary Basin (WCSB), which is located primarily in the Canadian provinces of Alberta and British Columbia, and the Rocky Mountain (Rockies) gas basin, located primarily in Wyoming, Utah and Colorado. Avista sources virtually all of its natural gas supplies from these two basins.

The WCSB and Rockies gas basins used to have limited pipeline export potential, which has historically resulted in lower regional natural gas prices when compared to other parts of the country. Over the last decade, however, several large pipelines have been completed (or capacities of existing pipelines increased) connecting the WCSB and Rockies gas basins to the Southwest, Midwest and Northeast sections of the continent. This has at times diminished the discounted price advantage the Region has enjoyed. Furthermore, the prolific amounts of shale gas located across North America (particularly in the East) have and will continue to change the flow dynamics. Forecasts show a continued price advantage for the region in both the WCSB and Rockies basins as the need for these supplies to move East diminishes.

Increased availability of North American natural gas has prompted a change in the LNG landscape. More supply than demand has changed the plans of many LNG import facilities. Now owners of these facilities are looking to switch from importing to exporting gas in order to capture better pricing in the Asian and European markets. Regionally, Kitimat LNG has received authorization to export natural gas off the coast of British Columbia. Two proposed import LNG facilities in Oregon have petitioned FERC to become export facilities. While there is much uncertainty about how many facilities actually get built the bigger question is how regional markets will be impacted by potential exports.

REGIONAL MARKET HUBS

Extending out from the two primary basins are numerous regional market hubs where natural gas is traded. These typically are located at pipeline interconnects. Avista is located near and transacts at most of the Pacific Northwest regional market hubs, enabling flexible access to a diversity of supply points. These supply points include:

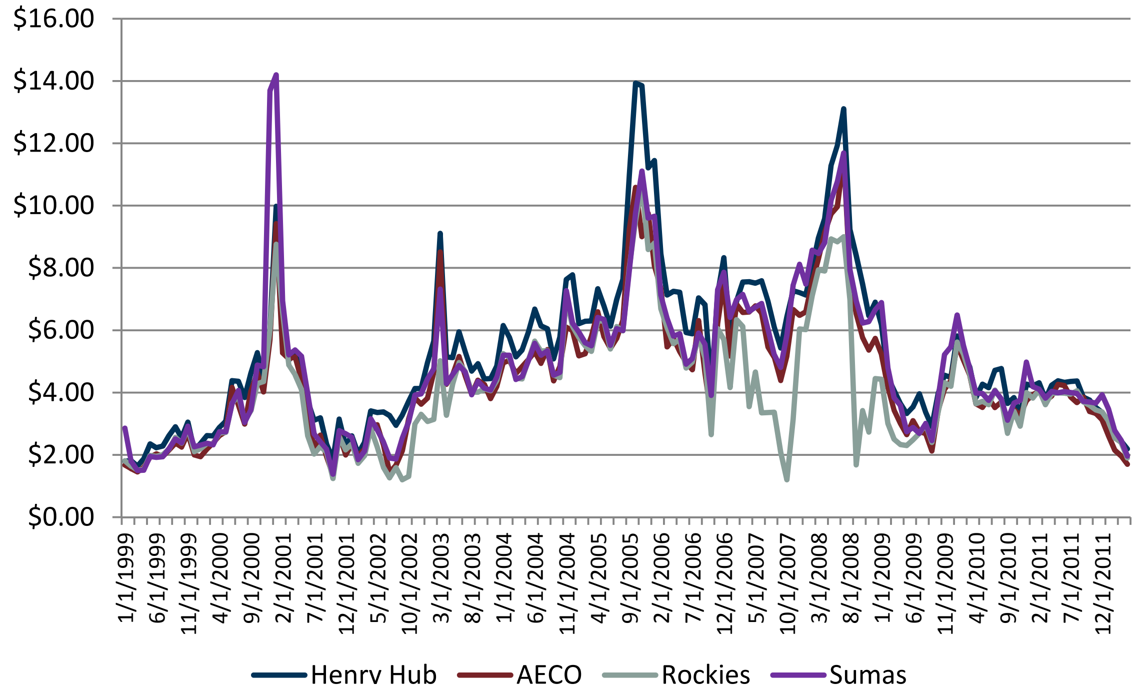
- **AECO –** The AECO-C/Nova Inventory Transfer market center is a major connection region to long-distance transportation systems, which take gas to points throughout Canada and the United States. Alberta has historically produced 90% of Canada's natural gas and is the source of most Canadian natural gas exports to the U.S. representing volume that accounts for approximately 13% of U.S. natural gas requirements.
- **ROCKIES** – This pricing “point” actually represents several locations on the southern end of the NWP system in the Rocky Mountain region. The system draws on Rocky Mountain gas-producing areas clustered in areas of Colorado, Utah, and Wyoming.
- **SUMAS/HUNTINGDON** – This pricing point at Sumas, Wash., is on the U.S./Canadian border where the northern end of the NWP system connects with Spectra Energy’s Westcoast Pipeline, and is predominantly Canadian gas coming south from Northern British Columbia.
- **MALIN** – this pricing point is at Malin, Ore. on the California/Oregon border where the pipelines of TransCanada Gas Transmission Northwest (GTN) and Pacific Gas & Electric Co. connect.
- **STATION 2** – Located at the center of the Spectra Energy/Westcoast Pipeline system connecting to northern British Columbia production.
- **STANFIELD** – Located near the Washington/Oregon border at the intersection of the NWP and GTN pipelines
- **KINGSGATE** – Located at the U.S./Canadian (Idaho) border where the GTN pipeline connects with the TransCanada Foothills pipeline.

Given the ability to transport 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 is widely recognized as the primary natural gas pricing point in the U.S. and is also the trading point used in NYMEX futures contracts.

Figure 5.1 shows historic natural gas prices for first-of-month index physical purchases at AECO, Sumas, Rockies and Henry Hub. The figure illustrates there is usually a tight relationship among the various locations; however, there have been periods where one or more price points have disconnected. In winter 2000-2001 Sumas rallied on a combination of the Western energy crisis and unusually cold local weather conditions. In fall of 2005 hurricanes Katrina and Rita disrupted significant Gulf of Mexico regional production causing the Henry Hub to spike disproportionately to Northwest hubs. Since 2007 increased production in the Rocky Mountain basin has exceeded the takeaway pipeline capacity forcing concessions on Rockies prices pending completion of major phases of the Rockies Express pipeline project. This significant project – completed in late summer 2009 – enables substantial volumes to reach Midwestern and

Northeastern demand centers. Consequently, Rockies prices have resumed tighter tracking with Henry Hub prices. As prices have declined the pricing differentials among the basins have tightened.

Figure 5.1 - Monthly Index Prices



Natural gas prices among the Northwest regional supply points typically move together as well; however, the basis differential can change depending on market or operational factors. This includes differences in weather patterns, pipeline constraints at different locations and the ability to shift supplies to higher-priced delivery points in the U.S. or Canada. By monitoring these price shifts we are often able to purchase at the lowest-priced trading hubs on a given day, subject to operational and contractual constraints.

Liquidity is generally sufficient in the day-markets at most northwest supply points. AECO continues to be the most liquid supply point, especially for longer-term transactions. Sumas has historically been the least liquid of the four major supply points (AECO, Rockies, Sumas, Malin). This illiquidity contributes to generally higher relative prices in the high demand winter months.

Procurement of natural gas is done via contracts. There are a number of contract specifics that vary from transaction-to-transaction, and many of those terms or conditions impact commodity pricing. 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. In the case of non-firm supplies the standard provision 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 fixed or based upon a daily or monthly index.
- **PHYSICAL VS. FINANCIAL** – Certain counterparties, such as banking institutions, may 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 discount or premium compared to standard terms.
- **LIQUIDATED DAMAGES** – Most contracts contain provisions for symmetrical penalties for failure to take or supply natural gas.

For 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, we pursue a variety of contractual terms and conditions in order to capture the most value from each transaction.

AVISTA'S PROCUREMENT PLAN

We cannot accurately predict future natural gas prices but market conditions and experience help shape our overall approach. Avista has designed a natural gas procurement plan process that seeks to competitively acquire natural gas supplies while reducing exposure to short-term price volatility. Our procurement strategy includes hedging, storage utilization and index purchases. Although the specific provisions of the procurement plan will change as a result of ongoing analysis and experience, the following principles guide Avista's development of its procurement plan:

Avista employs a time, location and counterparty diversified hedging strategy. It is appropriate to hedge over a period of time and we establish hedge periods within which portions of future demand are physically and/or financially hedged. The hedges may not be completed at the lowest possible price but they will protect our customers from price volatility. With access to multiple supply basins, when we transact we seek the lowest priced basin. Furthermore, we transact with a range of counterparties.

Avista establishes a disciplined but flexible hedging approach. In addition to establishing hedge periods within which hedges are to be completed we also set upper and lower pricing points. In a rising market this reduces Avista's exposure to extreme price spikes. In a declining market this encourages capturing the benefit associated with lower prices.

Avista regularly reviews its procurement plan in light of changing market conditions and opportunities. Avista's plan is open to change in response to ongoing review of the assumptions that led to the procurement plan. Although we establish various targets in the initial plan design, policies provide flexibility to exercise judgment to revise/adjust targets in response to changing conditions.

A number of tools are utilized to help mitigate financial risks. Avista purchases gas in the spot market as well as the forward market. Spot purchases are made on a day for the next day or weekend. Forward purchases are made on a day for a designated future delivery period. Many of these tools are financial instruments or derivatives that can be utilized to provide fixed prices or dampen price volatility. We continue to evaluate how to manage daily demand volatility, whether through option tools available from counterparties or through access to additional storage capacity and/or transportation.

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 from the hubs to Avista's service territories. Capturing favorable price differentials and mitigating price and operational risk can also be realized by holding multiple pipeline transport options. Consequently, we have contracted for a sufficient amount of diversified firm pipeline capacity from various receipt and delivery points (including out of storage facilities) so that firm deliveries will meet peak day demand. We believe the combination of firm transportation rights to our service territory, storage facilities and access to liquid supply basins will ensure peak supplies are available to our core customers.

The major pipelines servicing our region are as follows:

- **WILLIAMS - NORTHWEST PIPELINE (NWP)**
  A natural gas transmission pipeline serving the Pacific Northwest moving natural gas from the US/Canadian border in Washington and from the Rocky Mtn. region of the US.
- **TRANSCANADA GAS TRANSMISSION NORTHWEST (GTN)**
  A natural gas transmission pipeline originating at Kingsgate, Idaho (Canadian/U.S. border) and terminating at the California/Oregon border close to Malin, Ore.
- **TRANSCANADA ALBERTA SYSTEM**
  A natural gas gathering and transmission pipeline in Alberta Canada that delivers natural gas into the TransCanada Foothills pipeline at the Alberta/British Columbia border.
- **TRANSCANADA FOOTHILLS SYSTEM**
  A natural gas transmission pipeline that delivers natural gas between the Alberta, British Columbia border and the Canadian/U.S. border at Kingsgate, Idaho.
- **TRANSCANADA TUSCARORA GAS TRANSMISSION**
  A natural gas transmission pipeline originating at Malin, Ore and terminating at Wadsworth, Nev.
- **SPECTRA ENERGY - WESTCOAST PIPELINE**
  A natural gas transmission pipeline originating at Fort Nelson, British Columbia and terminating at the Canadian/U.S. border at Huntington, British Columbia/Sumas, Wash.
- **EL PASO NATURAL GAS– RUBY PIPELINE**
  A natural gas transmission pipeline bringing supplies from the Rocky Mountain region of the U.S. to interconnections near Malin, Ore. Ruby Pipeline began operating in July 2011.

Avista has contracts with all of the above pipelines (with the exception of Ruby Pipeline) for firm transportation to serve our core customers. 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 Avista and its customers the knowledge that Avista will have available capacity to meet existing core demand now and in the future.

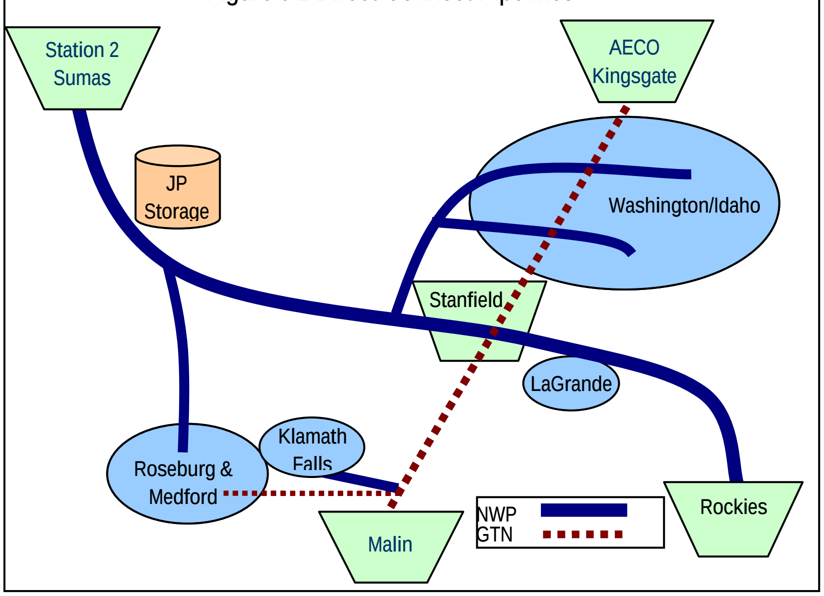
Table 5.1
Firm Transportation/Resources Contracted*
Dth/Day

	Avista North		Avista South	
Firm Transportation	**Winter**	**Summer**	**Winter**	**Summer**
NWP TF-1	157,869	157,869	42,699	42,699
GTN T-1	100,605	75,782	42,260	20,640
NWP TF-2	91,200		2,623	
Total	**349,674**	**233,651**	**87,582**	**63,339**
Firm Storage Resources - Max Deliverability				
Jackson Prairie (Owned and Contracted)	346,667		54,623	
Total	**346,667**		**54,623**	

** Represents original contract amounts after releases expire.*

Avista defines two categories of interstate pipeline capacity. "Direct-connect" pipelines deliver supplies directly to our local distribution system from production areas, storage facilities or interconnections with other pipelines. "Upstream" pipelines deliver natural gas to the direct-connect pipelines from remote production areas, market centers and out of area storage facilities. Figure 5.2 illustrates the direct-connect pipeline network relative to our supply sources and service territories1.

Figure 5.2 Direct-Connect Pipelines



1 Avista has a small amount of pipeline capacity with TransCanada Tuscarora Gas Transmission, a natural gas transmission pipeline originating at Malin, Oregon, to service a small number of Oregon customers near the southern border of the state.

Supply-side resource decisions focus on where to purchase natural gas and how to deliver it to customers. Each LDC has distinctive service territories and geography relative to supply sources and pipeline infrastructure. Solutions that deliver supply to service territories among regional LDCs are similar but are rarely generic – instead they are almost always unique.

The NWP system for the most part is a fully contracted system. With the exception of La Grande our service territories lie at the end of various NWP pipeline laterals. Washington/Idaho is served via the Spokane, Coeur d' Alene and Lewiston laterals while Roseburg and Medford are served by the Grants Pass lateral. Capacity expansions on each of these laterals are lengthy and costly endeavors which Avista would likely bear most of the incremental costs.

The GTN system, on the other hand, currently has ample unsubscribed capacity. This pipeline runs directly through or lies in close proximity to most of our service territories. Mileage based rates and backhaul potential provide attractive options for securing incremental resource needs.

Peak day planning aside, both pipelines provide an array of options to flexibly manage daily operations. Our two largest service territories are directly served by both pipelines providing diversification and risk management with respect to supply source, price and reliability. The NWP system (a bi-directional, fixed reservation fee-based pipeline) provides direct access to Rockies and British Columbian supply and facilitates excellent optionality for storage facility management. The Stanfield interconnect of the two lines is also geographically well situated to our service territories.

The rates we use in our planning model start with filed rates that are currently in effect (See Appendix 5.1). Forecasting future pipeline rates is challenging. Our assumptions for future rate changes are the result of market information on comparable pipeline projects, prior rate case experience and informal discussions. It is generally assumed that the pipelines will file to recover costs at rates equal to the GDP with adjustments made for specific project conditions.

NWP and GTN also offer interruptible transportation services. 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 in these transportation contracts. As the marketplace for release of transportation capacity by the pipeline companies and other third parties has become more prevalent, the use of interruptible transportation services has diminished. We do not rely on interruptible capacity to meet peak day core demand requirements.

Avista's transportation acquisition strategy is to contract for firm transportation to serve core customers should a peak day occur in the near-term planning horizon. Since contracts for pipeline capacity are often lengthy in tenor and core customer demand needs can vary over time determining the appropriate level of firm transportation is a complex analysis of many factors. The analysis includes the projected number of firm customers and their expected annual and peak day demand, opportunities for future pipeline or storage expansions and relative costs between pipelines and their upstream supplies. This analysis is done on an annual basis as well as through the IRP. Active management of underutilized capacity through the capacity release market and engaging in optimization transactions offsets some of the transportation costs. Timely analysis is also important in order to maintain an appropriate time cushion to allow for required lead times should the need for securing new capacity arise.

STORAGE RESOURCES

Storage is a valuable strategic resource that enables improved management of a highly seasonal and varied demand profile. Storage benefits include:

- Flexibility to serve peak period needs
- Access to typically lower cost off-peak supplies
- Reduced need for higher cost annual firm transportation
- Improved utilization of existing firm transportation via off-season storage injections
- Additional supply point diversity

While there are a number of different storage facilities available to the region, Avista's existing storage resources consist solely of ownership and leasehold rights at the Jackson Prairie storage facility.

JACKSON PRAIRIE STORAGE

Avista is one-third owner, with NWP and Puget Sound Energy (PSE) in the Jackson Prairie storage project for the benefit of its core customers in all three states. Jackson Prairie Storage is an underground reservoir facility located near Chehalis, Wash. approximately 30 miles south of Olympia, Wash. The total working gas capacity of the facility is approximately 25 Bcf. Avista's current share of this capacity for core customers is approximately 8.5 Bcf and includes 398,667 Dth of daily deliverability rights.

Outside of Avista's ownership rights, we have leased an additional 95,565 Dth of Jackson Prairie capacity with 2,623 Dth of deliverability from NWP to serve Oregon customers.

INCREMENTAL SUPPLY-SIDE RESOURCE OPTIONS

Our existing portfolio of supply-side resources provides a good mix of assets to manage demand requirements for an average day and peak day events. But in anticipation of growing and changing demand requirements, we monitor the following potential resource options to meet future requirements.

SYSTEM ENHANCEMENTS

Within the context of the IRP, distribution planning plays a role but is not the primary focus. Distribution works hand in hand with supply to ensure that customer demand is met on both and average day and a peak day. There are modifications, enhancements, or upgrades that occur on the distribution system that are routine projects enhancing reliability of our system. However, in certain instances, Avista can facilitate additional peak and base load-serving capabilities through a modification or upgrade of our distribution facilities. These projects would enable more takeaway capacity from the interstate pipelines. These opportunities are geographically specific and require case-by-case study. Costs of these types of enhancements are included in the context of the IRP. A more detailed description of system enhancements (including both routine and non-routine) can be found in Chapter 8.

CAPACITY RELEASE RECALL

As discussed earlier, pipeline transportation that is not utilized to serve core customer demand can be released to other parties or optimized through daily or term transactions. Released capacity is generally marketed through a competitive bidding process and can be done on a short-term (month-to-month) or long-term basis.

We actively participate in the capacity release market and have both short-term and long-term capacity releases.

We assess the need to recall capacity or extend a release of capacity on an on-going basis. The IRP process also helps evaluate if or when we need to recall some or all of our long-term releases.

EXISTING AVAILABLE CAPACITY

In some instances there is currently available capacity on existing pipelines. NWP's mainline is currently fully subscribed; however GTN mainline has available capacity. There is some uncertainty about the future capacity availability as the demand needs of utilities and end-users vary across the region. We do model access to the GTN forward- haul and backhaul capacity as an option to meet our future demand needs.

GTN BACKHAULS

GTN backhaul services have always been available on a relatively reliable basis via displacement. However, the interconnection with the Ruby Pipeline has enabled GTN the physical capability to provide this service with minor modifications to their system. Effective in April 2012 the GTN system offers long-term firm backhaul services. Fees for utilizing this service will be provided under the existing Firm Rate Schedule (FTS-1) and currently no fuel charges will be assessed. Additional requests for firm backhaul service may necessitate the need for additional facilities and compression (i.e. fuel).

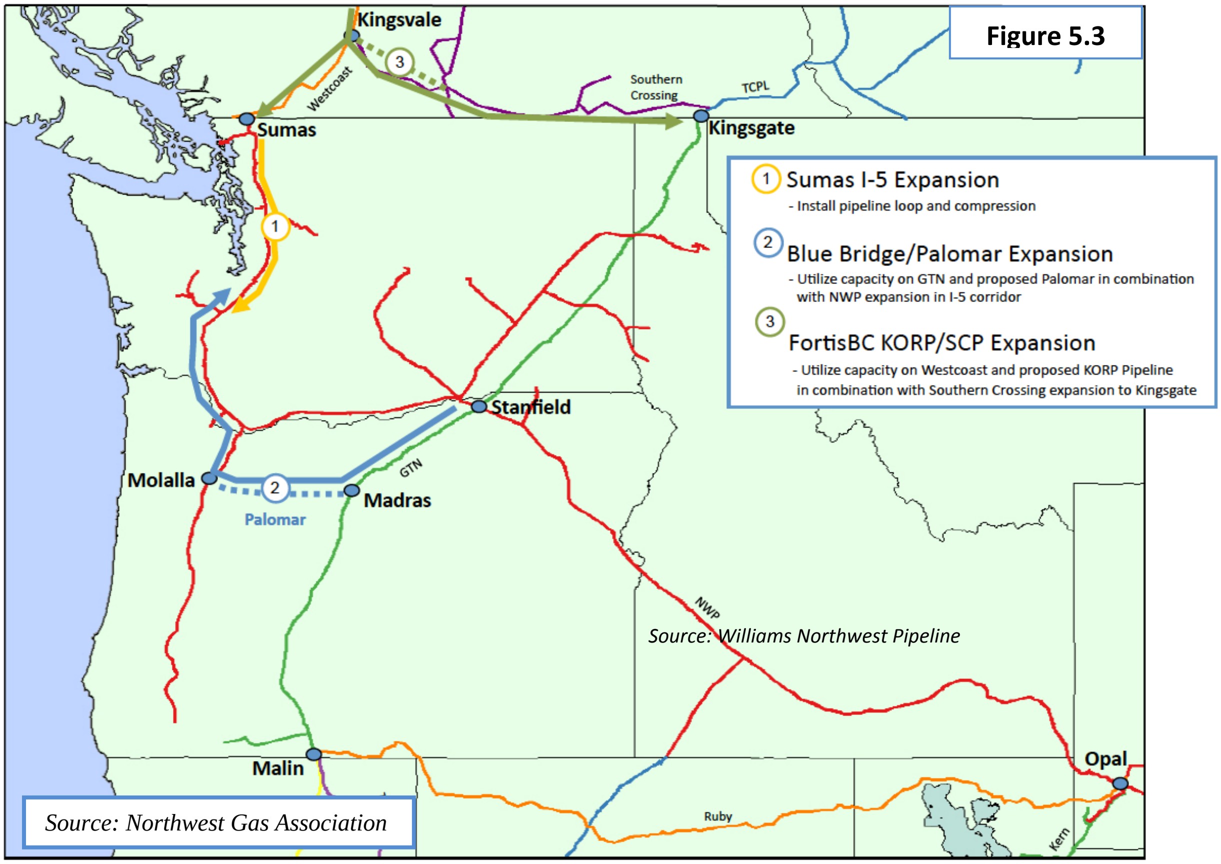
This service has the potential to be a particularly interesting solution for our Oregon customers. For example, Avista can purchase supplies at Malin, Ore. and transport those supplies to our service territory at either Klamath Falls or Medford. Malin-based natural gas supplies typically price at a premium to AECO supplies but are generally less expensive than the cost of forward-haul transporting those traditional supplies and paying the associated demand charges. The GTN system is a mileage-based system so we pay only 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.

NEW PIPELINE TRANSPORTATION

Additional firm pipeline transportation resources are viable and attractive resource options. However, determining the appropriate level, supply source and associated pipeline path, costs and timing and determining whether or not existing resources will be available at the appropriate time, make this resource difficult to analyze. Firm pipeline capacity provides several advantages; it provides the ability to receive firm supplies at the production basin, it provides for base-load demand and it can be a low-cost option given optimization and capacity release opportunities. 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 and/or inconvenient sizing/timing relative to resource need.

Pipeline expansions are typically 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 us given that some of the other options discussed in this section require matching pipeline transportation anyway. Expansions may also provide reliability or access to supply that cannot otherwise be obtained through existing pipelines.

Several specific projects have been proposed for the region. The following summaries describe these projects while Figure 5.3 illustrates their location:



- **SUMAS I-5 EXPANSION**
  NWP continues to explore options to expand its service from Sumas, WA to markets along the I-5 corridor. Looping sections of 36-inch diameter pipeline with the existing pipeline and additional compression at existing compressor stations can add incremental capacity. Actual miles of pipe and incremental compression will determine the amount of capacity created, but can be scaled to meet market demand.

- **BLUE BRIDGE/PALOMAR EXPANSION**
  NWP has begun working with Palomar Gas Transmission (a partnership between NW Natural and TransCanada) to develop the Cascade (eastern) section of the previously proposed Palomar in conjunction with an expansion of NWP's existing system. The proposed 106-mile, 30-inch-diameter pipeline would extend from TransCanada's GTN's mainline, to NW Natural's system near Molalla, Ore. It would be a bi-directional pipeline with an initial capacity of up to 300 MMcf/d expandable up to 750 MMcf/d.

- **KINGSVALE-OLIVER REINFORCEMENT EXPANSION**
  Fortis, British Columbia and Spectra Energy are considering a 100-mile, 24-inch expansion project from Kingsvale to Oliver, British Columbia to expand service to the Pacific Northwest and California markets. Removing constraints will allow expansion of Spectra's T-South enhanced service offering, which provides shippers the options of delivering to Sumas or the Kingsgate market. Expansion of the bi-directional Southern Crossing system would increase capacity at Sumas during peak demand periods. Initial capacity from the Spectra system to Kingsgate would be 300 MMcf/d, expandable to 450 MMcf/d. Expanded east-to-west flow will increase delivery of supply to Sumas by an additional 150 MMcf/d.

Avista is supportive of proposals that bring supply diversity and reliability to the region. We actively engage in discussions and analysis of the potential impact to Avista of each regional proposal from a demand serving and reliability/supply diversity perspective. None of the above projects provide direct delivery connection to any of our service territories. For Avista to consider them to be a viable incremental resource to meet demand needs would require combining with additional capacity on existing pipeline resources. Given this situation we did not model these specific projects. However we do model a generic NWP expansion that extends beyond the proposed I-5 expansion to Avista's service territories.

IN-GROUND STORAGE

In-ground storage provides many advantages when gas from storage can be delivered to Avista's service territory city-gates. It can enable deliveries of natural gas to customers during cold weather events when they need it most. It also facilitates potentially lower cost supply for our customers by capturing peak/non-peak pricing differentials and potential arbitrage opportunities within individual months. Although additional storage can be a valuable resource, without deliverability to Avista's service territory, this storage cannot be considered an incremental firm peak serving resource.

JACKSON PRAIRIE

Jackson Prairie is a potential resource for expansion opportunities. Any future storage expansion capacity does not include transportation and therefore cannot be considered an incremental peak day resource. However, we will continue to look for exchange and transportation release opportunities that could fully utilize these additional resource options. Even without deliverability, we believe it can make financial sense to utilize Jackson Prairie capacity to optimize time spreads within the natural gas market and provide net revenue offsets to customer gas costs. There are no current plans for immediate expansion of Jackson Prairie. Should those plans materialize Avista would evaluate its cost-effectiveness within the context of future IRP's.

OTHER IN-GROUND STORAGE

Other regional storage facilities exist and may be cost-effective. Additional capacity at Northwest Natural's Mist facility, capacity at one of the Alberta area storage facilities, Questar's Clay Basin facility in northeast Utah, Ryckman Creek in Uinta County, Wyoming, and northern California storage are all possibilities. Again, transportation to and from these facilities to Avista's service territories continues to be the largest impediment to contracting for these options. Northern California storage opportunities may be able to overcome this hurdle by using backhaul transportation for deliveries to some of the Washington/Idaho and Oregon customers. Another issue is whether sellers of storage capacity will offer multi-year contracts or contracts with beginning dates during the timeframes that we may need these incremental resources.

SATELLITE LNG

Satellite LNG is another storage option that could be constructed within Avista's service territories and is ideal for meeting peak day or cold weather events. Satellite LNG uses natural gas that is trucked to the facilities in liquid form rather than liquefying on site. Locating the facility in the service area would avoid interstate pipeline transportation and related charges. Permitting issues notwithstanding, facilities could be located in optimal locations within the distribution system.

Estimates for this type of resource are somewhat varied because of sizing and location issues. For our modeling, we have used estimates from other facilities constructed in the area and believe these to be reasonable estimates for planning purposes. We will continue to monitor and refine the costs of developing satellite LNG while remaining mindful of lead time requirements and environmental issues.

PLYMOUTH LNG

NWP owns and operates an LNG storage facility located at Plymouth, Washington, which provides a gas liquefaction, storage, and vaporization service under its LS-1 and LS-2F tariffs. An example ratio of injection and withdrawal rates are such that it can take more than 200 days to fill to capacity, but only 3-5 days to empty. As such, the resource is best suited for needle-peak demands. Incremental transportation capacity to our service territories would have to be obtained in order for it to be a truly effective peaking resource.

This peaking resource is fully contracted and not available for contracting at this time. Given this situation, this option is not being modeled in SENDOUT® for this IRP. However, 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.

COMPANY OWNED LIQUEFACTION LNG

Instead of leasing LNG capacity from Plymouth, Avista could construct a liquefaction LNG facility within our service area. Doing so could use excess transportation during off-peak periods to fill the facility but avoid tying up transportation during peak weather events. Additional annual pipeline charges could probably be avoided.

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, required lead times, and inventory costs indicate company-owned LNG facilities have significant development risks. Due to these risks we did not include this resource in our modeling, recognizing this type of project is highly complex and there are many risk considerations that require evaluation and monitoring.

BIOGAS

Biogas typically refers to a gas produced by the biological breakdown of organic matter in the absence of oxygen. One type of biogas is produced by anaerobic digestion or fermentation of biodegradable materials such as biomass, manure or sewage, municipal waste, green waste and energy crops. This type of biogas comprises primarily methane and carbon dioxide.

Biogas is a renewable fuel so it sometimes attracts renewable energy subsidies in some parts of the world. We are not aware of any current subsidies but future stimulus or energy policies could lead to some form of financial incentives at a later time.

Biogas projects are inherently individualized, making reasonable and reliable cost estimates difficult to obtain. Project sponsorship has many complex issues and the more likely participation in such a project is as a long-term contracted purchaser. We did not consider biogas as a resource in this planning cycle but remain receptive to such projects as they are proposed.

SUPPLY SCENARIOS

For this IRP we modeled three supply scenarios. Table 5.2 lists the supply scenarios and Appendix 5.2 provides the details on what is included in each of these scenarios. Additional detail about the results of these supply scenarios modeled is included in Chapters 6 and 7.

Table 5.2
Supply Scenarios
Existing Resources
Existing + Expected Available
GTN Fully Subscribed

- **EXISTING RESOURCES**
  Represents all resources currently owned or contracted by Avista.
- **EXISTING + EXPECTED AVAILABLE**
  Existing resources plus supply resource options expected to be available when resource needs are identified. This includes: currently available forward and backhaul GTN, capacity release recalls, NWP expansions and satellite LNG.
- **GTN FULLY SUBSCRIBED**
  Availability of GTN capacity is unavailable due to significant contracting driven by increased demand.

SUPPLY ISSUES

The importance of shale gas in the North American supply mix has fundamentally altered current and the outlook of future natural gas prices and infrastructure. While it appears certain that North American supply is in good shape there are issues that can impact the cost and availability.

- **HYDRAULIC FRACTURING**
  "Fracking" has become the bad word of the natural gas and oil industry. Improvements in hydraulic fracturing (HF), a sixty-year-old technique used to extract oil and natural gas from shale rock formations, has enabled access to previously uneconomic resources. However, the process does not come without its challenges. Movies and articles in the national newspapers have further fueled a movement to cease this drilling practice. There is worry that HF is contaminating aquifers, increasing air pollution, and most recently causing earthquakes. The wide spread publicity generated interest in the production process and caused some states to issue bans or moratoriums on drilling until further research was conducted.

  To that end many levels of government, industry, and universities have or are engaged in conducting studies to better understand the actual and potential impacts of HF. Industry has been working to refute these claims by focusing on ensuring companies use "best practices" for well drilling, disclosing the fluids used in the HF processing, and implementing "green completions" for wells. The state governments are participating in independent audits of their regulations to ensure that proper oversight is in place. The EPA is engaged in a study and will issue a report in late 2012 to determine the effects of HF on water and air. Finally, the United States Geological Survey (USGS) has begun to study the correlation between seismic activity and HF. The outcome of these audits, studies, and further research could greatly impact both the cost and availability of natural gas and oil.

- **LNG – EXPORT IS THE NEW IMPORT**
  A few short years ago, North America was going to be reliant on importing LNG in order to fill the supply and demand gap and the gas market was heading to a more global pricing structure. Now wide

spread shale availability and low production costs have upended the US importing LNG industry. Europe and Asia have prices that are more favorable so in an effort to maximize margins many import facilities have petitioned to become exporters.

On a national level, in April 2012 Sabine Pass LNG was granted the authority by FERC to export 2.2 Bcf/d. Sabine Pass LNG is the first in the US to be granted permission, however there are many more in the queue. Regionally, two proposed LNG terminals in Oregon, Jordan Cove LNG and Oregon LNG are looking to export. In Canada, the National Energy Board (NEB) granted Kitimat LNG in British Columbia a twenty year license to export LNG to serve international markets. When and where this happens, how many, what volume and how our natural gas prices are affected are continuing to be debated.

GREEN TURNS TO BLUE

The desire to reduce reliance on fossil fuels, improve the carbon footprint, and lessen our need for foreign oil sparked a flurry of legislative activity. State mandated renewable portfolio standards (RPS), carbon taxes or cap and trade programs, and natural gas vehicles (NGV) became common news.

RPS mandates required electric utilities to "green up" their portfolios. In many cases, this means reducing reliance on coal and investing in renewable sources of energy such as wind, solar, and nuclear. Wind and solar in particular became the resource of choice for most utilities, unfortunately these are intermittent and would require reliable and controllable backup. Additional gas fired power generation will be necessary to support the renewable fleet.

Helping to encourage the change to cleaner and greener energy was the concept of a carbon tax. This would provide a means to make the cost of renewable on par with less expensive fossil fuels. There were many different plans proposed on how to implement the additional costs. However, rapid adoption of such legislation did not occur. As the depth of the recession began to be felt, legislators realized burdening already strapped taxpayers would be detrimental to an already fragile economy. The economy is still healing, but that does not change the importance of reducing our carbon footprint. There continues to be discussion about a carbon tax. The timing and magnitude of the tax has been pushed out many years and is at a much lower level than originally proposed.

With oil prices surging and driving high gasoline prices, many are looking to reduce the nation's need for foreign oil. This push has renewed investments in NGV infrastructure. T. Boone Pickens and Clean Energy are often in the headlines discussing how NGV can play an important role in the energy and transportation future. Much of the transportation focus has been on long haul trucks and fleet vehicles such as refuse trucks and public transportation. The cost to convert these vehicles is significant, however many are making the switch.

PIPELINE AVAILABILITY

The pipeline infrastructure of the Northwest is sparse when compared to the Gulf or East Coast. As we move closer and closer to a more renewable energy future demand for natural gas via gas-fired generation will increase. Pipeline capacity is the link between gas and power. LDCs will have to compete with power generators for pipeline capacity. The new mix could alter current pipeline operations and the potential availability of infrastructure to the region.

MARKET-RELATED RISKS AND RISK MANAGEMENT

While risk management can be defined in a variety of ways, the integrated resource plan 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 resources (either the transportation capacity or the commodity) to serve core customers.

Avista has a Risk Management Policy that describes 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.

There are two 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 senior-level management. The committee establishes the Risk Management Policy and monitors compliance. They receive regular reports on natural gas activity and meet regularly to discuss market conditions, hedging activity and other natural gas-related matters.
- The Strategic Oversight Group 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, Regulatory, Credit, Power Resources and Risk Management departments. While the Natural Gas Supply department is responsible for implementing hedge transactions, the Group provides input and advice.

ACTION ITEMS

With no immediate need to acquire incremental supply side resources to meet peak day demands Avista's focus in the near term will include the following:

- Continue to monitor supply resource trends including the availability and price of natural gas to the regions, exporting LNG, Canadian natural gas imports, regional plans for gas fired generation and its affect on pipeline availability, as well as future regional pipeline and storage infrastructure plans.
- We will also monitor new resource lead time requirements relative to when resources are needed to preserve resource option flexibility.

CONCLUSION

Avista is committed to providing reliable supplies of natural gas to its customers. We procure these supplies with a diversified plan that seeks to competitively acquire natural gas supplies while reducing exposure to short-term price volatility through a strategy that includes hedging, storage utilization and index purchases. We have long-term contracts for firm pipeline transportation capacity from many supply points and also own and lease firm natural gas storage capacity sufficient to serve customer demand during peak weather events and throughout the year.

CHAPTER 6 – INTEGRATED RESOURCE PORTFOLIO

OVERVIEW

This chapter combines all previously discussed IRP components and the model used to determine resource deficiencies during the 20-year planning horizon. This chapter also provides an analysis of potential resource options and displays the model-selected best cost/risk resource options to meet resource deficiencies.

The foundation for integrated resource planning is the demand planning criteria used for developing demand forecasts. Avista currently uses the “coldest day on record” as its weather planning standard for determining peak-day demand. This is consistent with our past IRPs and is more fully described in Chapter 3 – Demand Forecasts. We utilize historic peak and average weather data for each demand region for this IRP. We plan to serve our expected peak day in each demand region with firm resources. Firm resources include natural gas supplies, pipeline transportation and storage resources. In addition to planning for peak requirements, we also plan for non-peak periods such as winter, shoulder and summer demand. Our modeling process includes running an optimization for 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. Avista does not make firm commitments to serve interruptible customers. Therefore, our IRP analysis of demand-serving capabilities only focuses on the residential, commercial and firm industrial classes.

Our 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 compressor station fuel. The percentage of additional supply that must be purchased is governed through FERC and National Energy Board approved tariffs.

SENDOUT® PLANNING MODEL

The SENDOUT® Gas Planning System from Ventyx is used to perform integrated resource optimization. The SENDOUT® model was purchased in April 1992 and has been used in preparing all IRPs since then. Avista has a long-term maintenance agreement with Ventyx that allows us to receive software updates and enhancements. These enhancements include software corrections and improvements brought on by industry change.

SENDOUT® is a 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, while taking into account physical limitations and contractual constraints

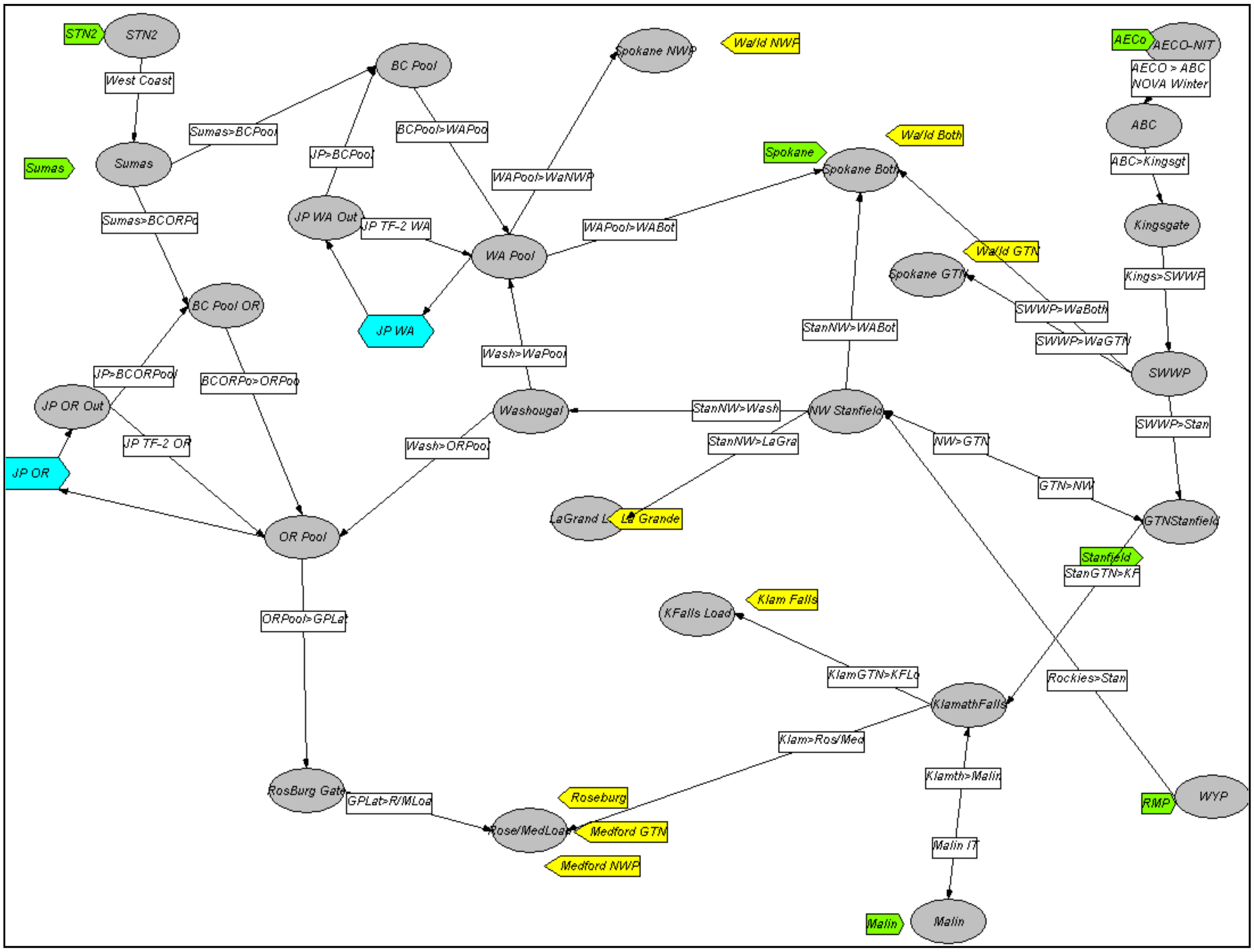
The software analyzes thousands of variables and evaluates possible solutions to generate a least cost solution. The model uses the following variables:

- Demand data, such as customer count forecasts and demand coefficients by customer type (e.g. residential, commercial and industrial)
- Weather data – minimum, maximum and average temperatures
- 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, revenue requirements as the key cost metric for all asset additions, and prices
- Natural gas storage options with injection/withdrawal rates, capacities and costs
- DSM potential

Figure 6.1 is a SENDOUT® network diagram of our demand centers and resources. This diagram illustrates Avista's current transportation and storage assets, flow paths and constraint points.

FIGURE 6.1 SENDOUT® MODEL DIAGRAM



The SENDOUT® model also provides a flexible tool to analyze potential scenarios such as:

- 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 DSM
- Weather pattern testing and analysis
- Transportation cost analysis

- Avoided cost calculations
- Short-term planning comparisons

SENDOUT® also includes Monte Carlo capabilities, which facilitates price and demand uncertainty modeling and detailed portfolio optimization techniques to produce probability distributions. More information and analytical results are located in Chapter 7 – Alternate Scenarios, Portfolios and Stochastic Analysis.

RESOURCE INTEGRATION

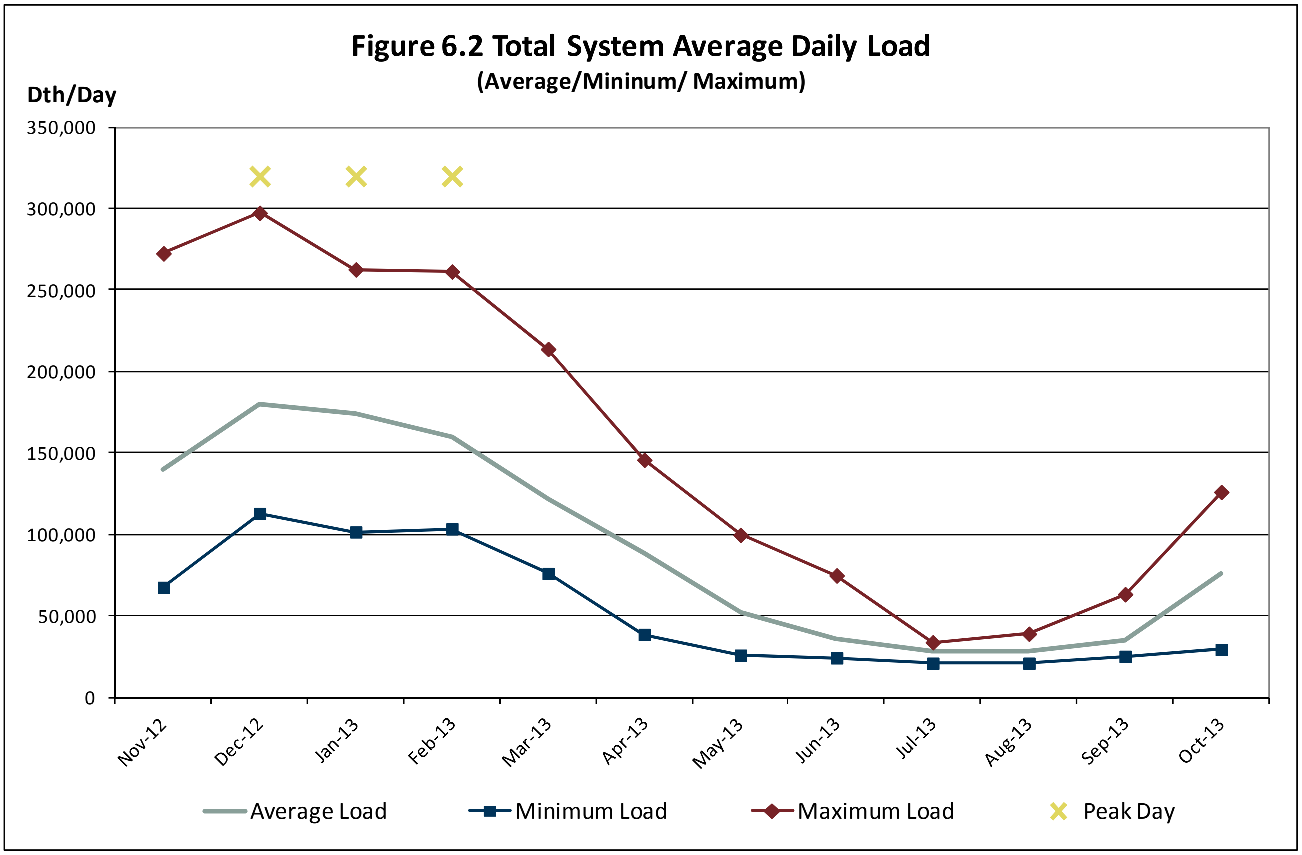
We have defined the planning methodologies, described the modeling tools and identified the existing and potential resources. The following summarizes the comprehensive analysis of bringing demand forecasting and existing and potential supply and demand-side resources together to form our 20-year, risk adjusted least-cost plan.

DEMAND FORECASTING

Avista's demand forecasting approach is described in detail in the Chapter 3 - Demand Forecasts.

We forecast demand in the SENDOUT® model in eight service areas given the existence of distinct weather and demand patterns for each area and pipeline infrastructure dynamics. The SENDOUT® areas are Washington/Idaho (disaggregated into three sub-areas because of pipeline flow limitations), Medford (disaggregated into two sub-areas because of pipeline flow limitations) and Roseburg, Klamath Falls and La Grande. In addition to area distinction, we also model demand by customer class within each area. The relevant customer classes in Avista's service territories are residential, commercial and firm industrial customers.

Customer demand reflects a highly weather-sensitive component. Avista's customer demand is not only highly seasonable but also highly variable. Figure 6.2 captures this variability showing our monthly system-wide average demand, minimum demand day observed in each month, and maximum demand day observed in each month, and our winter projected peak day demand for the first year of our Expected Case forecast as determined in SENDOUT®.



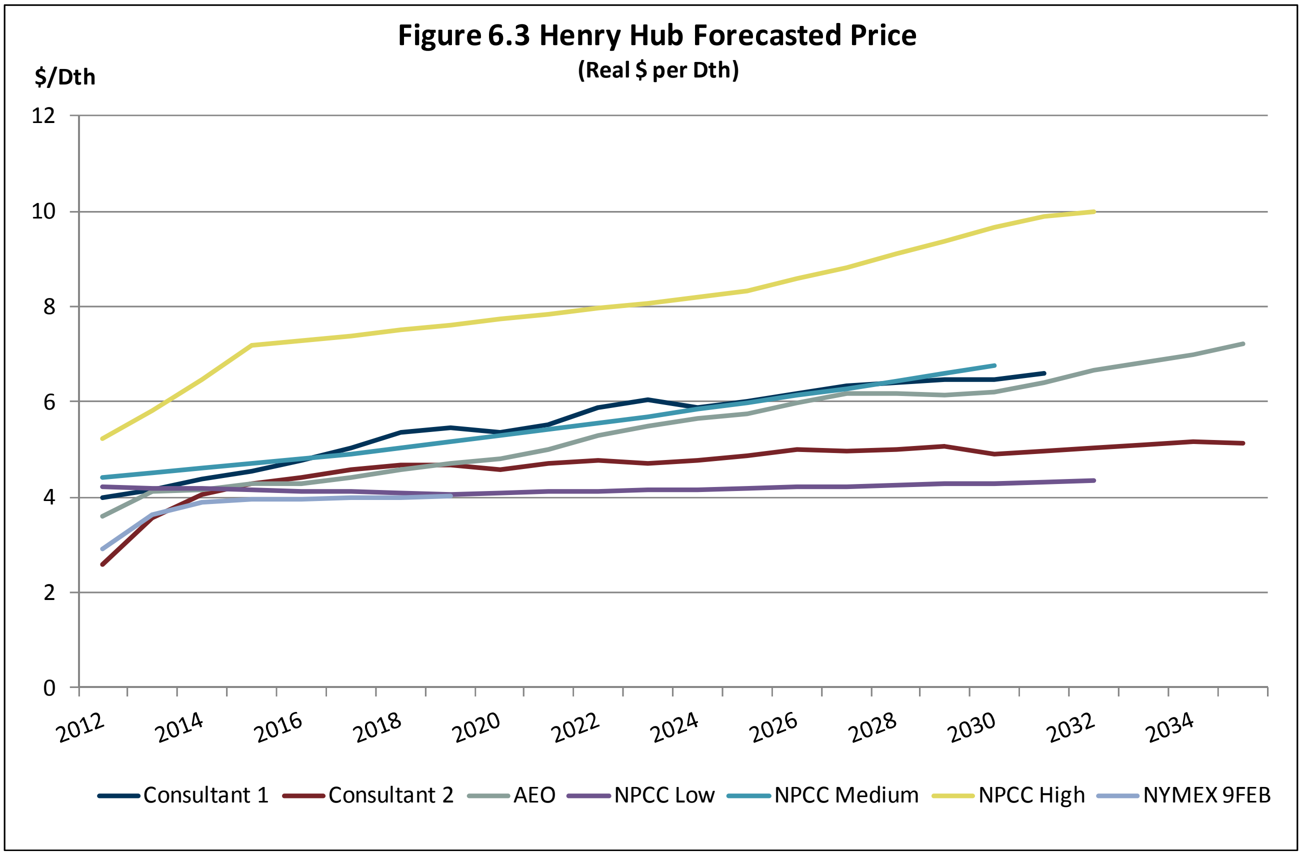
NATURAL GAS PRICE FORECASTS

Natural gas prices are a fundamental component of the IRP. The commodity price is a significant component of the total cost of a resource option. This in turn affects the avoided cost threshold for determining cost-effectiveness of conservation measures. We also recognize the price of natural gas influences consumption, so we include price elasticity analysis in our demand evaluation (see Chapter 3 – Demand Forecasts).

The natural gas price outlook has changed dramatically in recent years in response to several influential events and trends affecting the industry. The recession, shale gas production and potential climate change legislation encouraging natural gas-fired power generation to replace coal burning power plants. Due to the rapidly changing environment and uncertainty in predicting future events and trends, modeling a range of forecasts is necessary.

Many additional factors influence natural gas pricing and volatility, such as regional supply/demand issues, weather conditions, hurricanes/storms, storage levels, gas-fired generation, infrastructure disruptions and infrastructure additions (e.g. new pipelines, LNG terminals).

Even though we continually monitor these factors, we cannot accurately predict future prices for the 20-year horizon of this IRP. We have reviewed several price forecasts from credible sources. Figure 6.3 depicts the price forecasts we considered in our analyses.



Selecting the price curves can be more art than science. With assistance and concurrence of the TAC we selected high, expected and low price curves to consider possible outcomes and the impact on resource planning. The price curves we have selected have variation and provide reasonable upper and lower bounds, which is consistent with our theme of stretching modeling assumptions to address uncertainty in the planning environment. These curves are shown in real dollars in Figure 6.4 and nominal dollars in Figure 6.5. Additionally, stochastic modeling of natural gas prices is also completed. The results from that analysis are shown in Chapter 7 – Alternate Scenarios, Portfolios, and Stochastic Analysis.

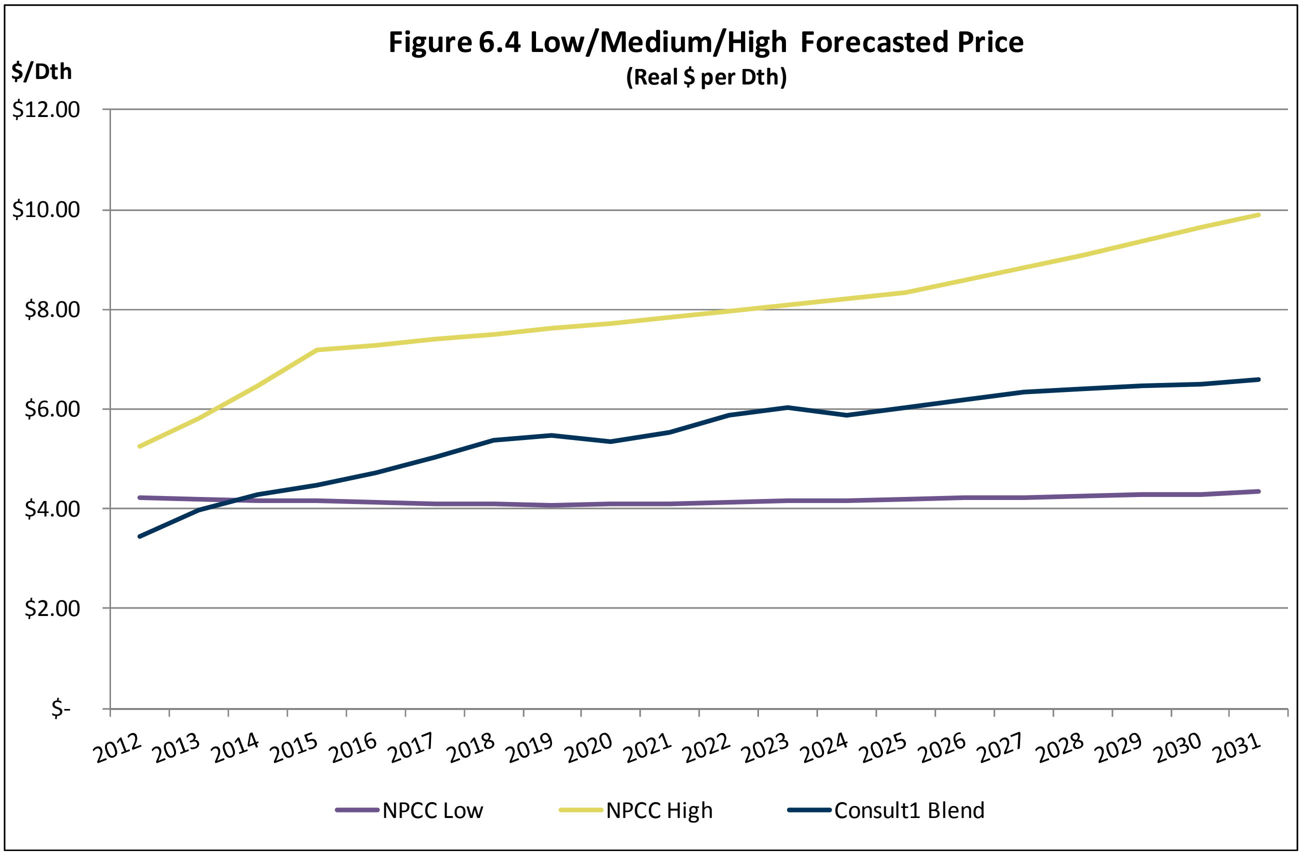


Figure 6.4 Low/Medium/High Forecasted Price
(Real $ per Dth)
$/Dth
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$-
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
NPCC Low
NPCC High
Consult1 Blend

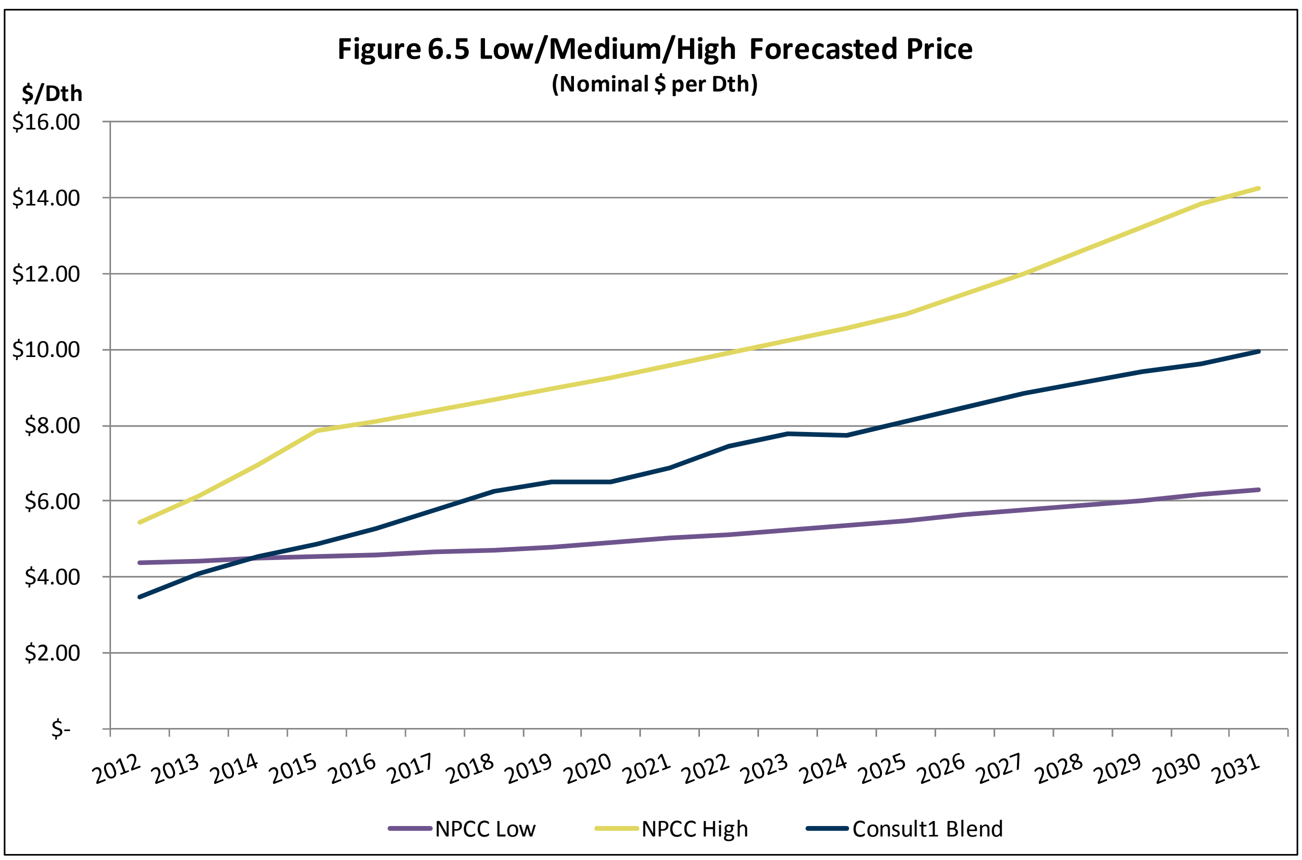


Figure 6.5 Low/Medium/High Forecasted Price
(Nominal $ per Dth)
$/Dth
$16.00
$14.00
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$-
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
NPCC Low
NPCC High
Consult1 Blend

Each of the price forecasts above are for Henry Hub, which is located in Louisiana just onshore from the Gulf of Mexico. Henry Hub is widely recognized as the most important pricing point in the U.S. because of its proximity to a large portion of U.S. natural gas production and the sheer volume traded in the daily or spot market as well as the forward markets via the New York Mercantile Exchange's (NYMEX) futures contracts. Consequently, all other trading points tend to be priced off of the Henry Hub.

The primary physical supply points at Sumas, AECO, and the Rockies (and other secondary regional market hubs) ultimately determine Avista's costs. Prices at these points typically trade at a discount or negative basis differential to Henry Hub primarily because of their relative close proximity to the two largest natural gas basins in North America (the WCSB and the Rockies).

Table 6.1 shows the Pacific Northwest regional prices from our consultants, historic averages, and the prior IRP as a percent of Henry Hub price along with historical comparisons.

Table 6.1 Regional Price as a Percent of Henry Hub Price

	AECO	Sumas	Rockies	Malin	Stanfield
Consultant1 Forecast Average	88.60%	89.90%	90.80%	92.30%	91.40%
Consultant2 Forecast Average	86.20%	92.50%	92.80%	94.10%	92.60%
Historic Cash Three-Year Average	89.90%	95.50%	88.10%	97.00%	95.60%
Prior IRP	92.70%	95.20%	85.60%	94.10%	93.70%

This IRP used monthly prices for modeling purposes because of our heavily winter-weighted demand profile. Table 6.2 depicts the monthly price shape we used in this IRP. A slight change to the shape of the pricing curve has occurred since the last IRP. Driven primarily by supply availability, the forecasted differential between winter and summer pricing has come in to some extent when compared to historic data.

Table 6.2 Monthly Price as a Percent of Average Price

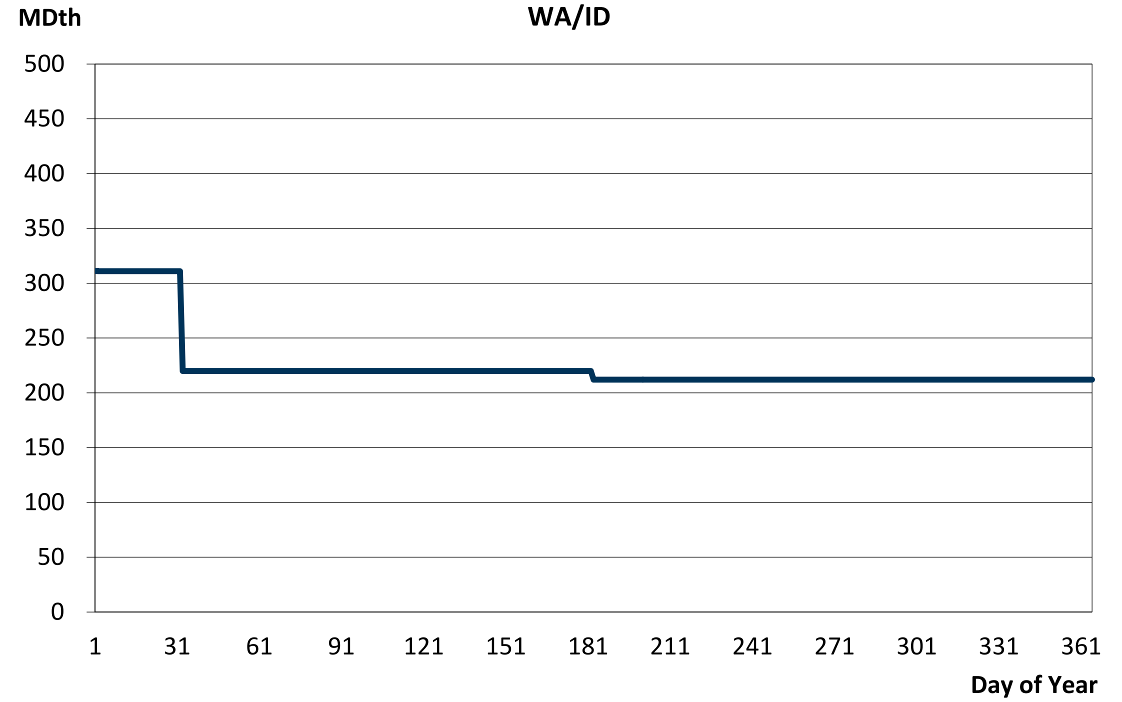
	Jan	Feb	Mar	Apr	May	Jun
Consult1	101%	101%	98%	98%	98%	100%
Consult2	103%	102%	99%	98%	99%	101%
Historic First of Month Index Three-Year Average	130%	113%	101%	94%	96%	96%
Prior IRP	107%	108%	103%	93%	93%	94%
	Jul	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Consult1	102%	103%	100%	100%	100%	102%
Consult2	101%	101%	97%	97%	98%	104%
Historic First of Month Index Three-Year Average	104%	100%	84%	93%	92%	97%
Prior IRP	94%	94%	95%	96%	101%	106%

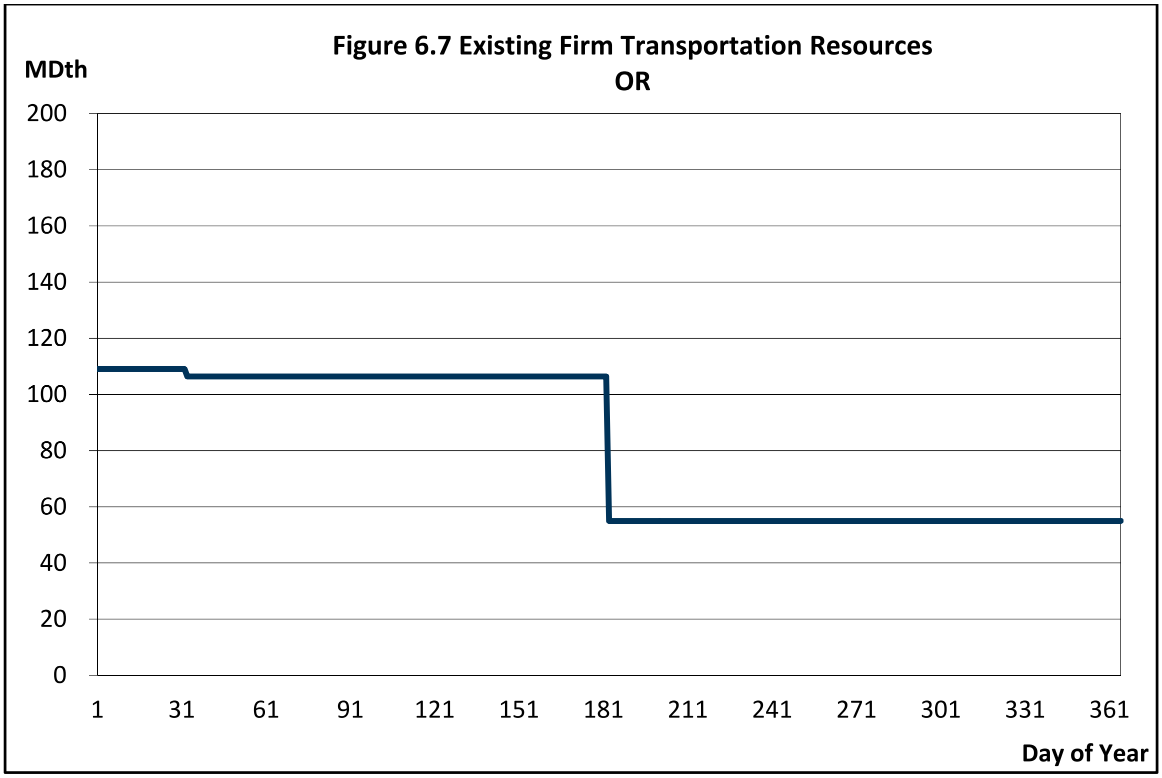
Consistent with our selection for Henry Hub prices, we selected Consultant 1's forecast of regional prices and monthly shape. Appendix 6.1 contains detailed monthly price data behind the summary table information discussed above.

TRANSPORTATION AND STORAGE

Valuing natural gas supplies is a critical first step in resource integration. Equally important is capturing all costs to deliver the gas to the customer. Daily capacity of our existing transportation resources (described in Chapter 5 – Supply-Side Resources) is represented by the firm resource duration curves depicted in Figures 6.6 and 6.7.

Figure 6.6 Existing Firm Transportation Resources WA/ID





Current rates for capacity are in Appendix 5.1. Forecasting future pipeline rates can be a challenge as we need to estimate the amount and timing of rate changes. Our estimates and timing of future rate increases are based on knowledge obtained from industry discussions and participation in various pipeline rate cases. This IRP assumes that pipelines will file to recover costs at rates equal to increases in GDP (see Appendix 6.2 – General Assumptions).

DEMAND-SIDE MANAGEMENT

Chapter 4 – Demand-side Resources describes the methodology used to identify conservation potential and the interactive process deployed in SENDOUT® that computes avoided cost thresholds for determining cost effectiveness of conservation measures on an equivalent basis with supply-side resources.

PRELIMINARY RESULTS

After incorporating the above data into the SENDOUT® model, we then generate an assessment of demand compared to existing resources for several scenarios. The demand results from these cases are discussed in Chapter 3 – Demand Forecasts, with additional details supported in the Appendices 3.1 through 3.10.

Figures 6.8 through 6.11 graphically represent summaries of Average Case demand compared to existing resources. This demand is net of DSM savings and shows the adequacy of our resources under normal weather conditions. For this case, current resources meet our demand needs over the planning horizon.

Figure 6.8 Average Case - WA/ID Existing Resources vs. Average Day Demand
(Net of DSM)
February

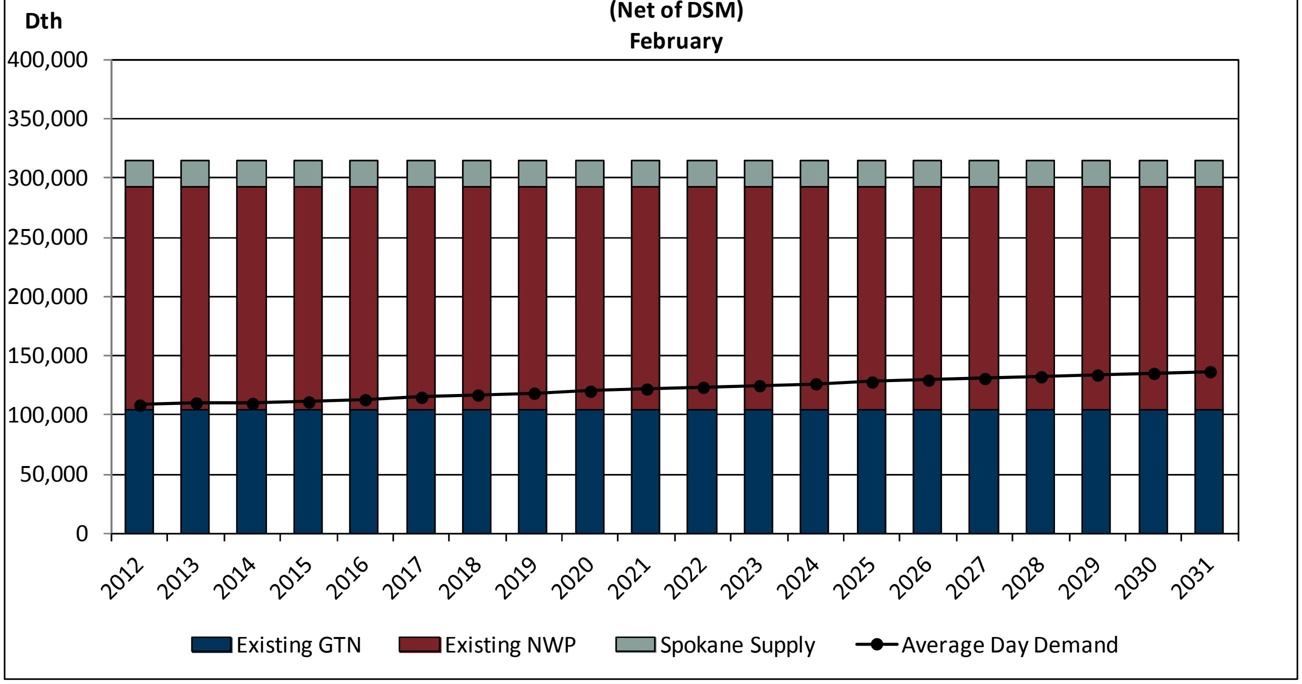
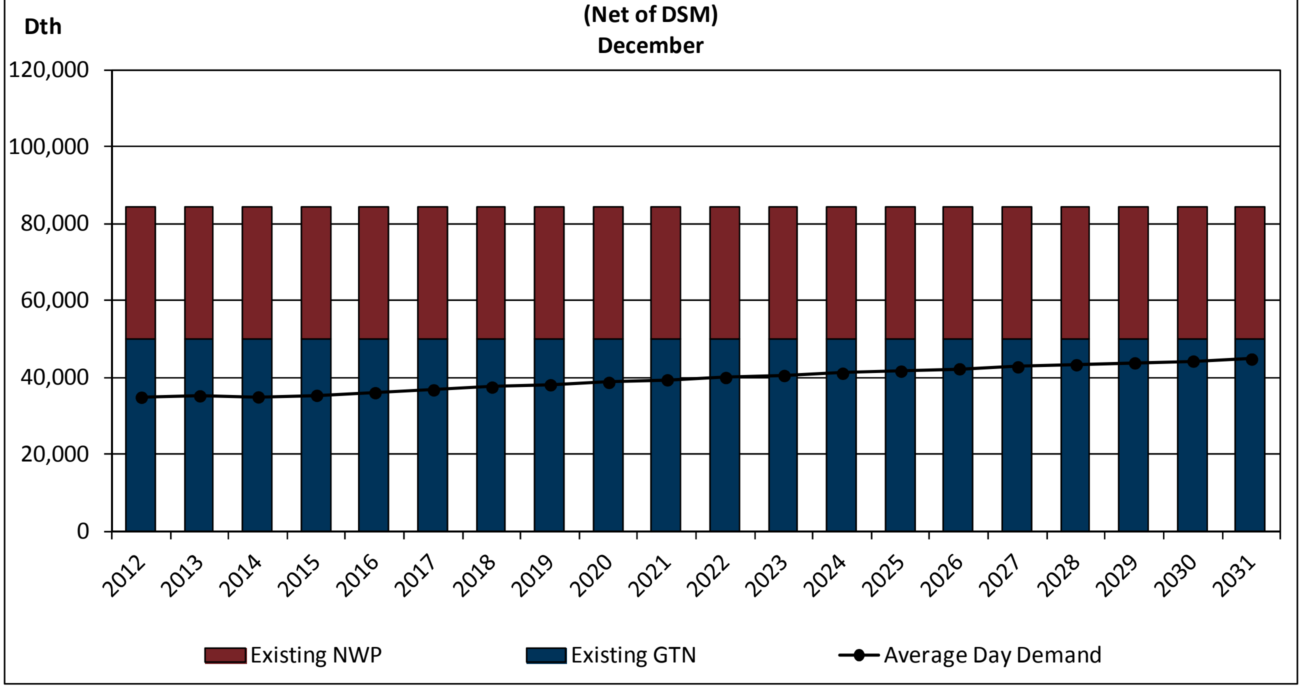
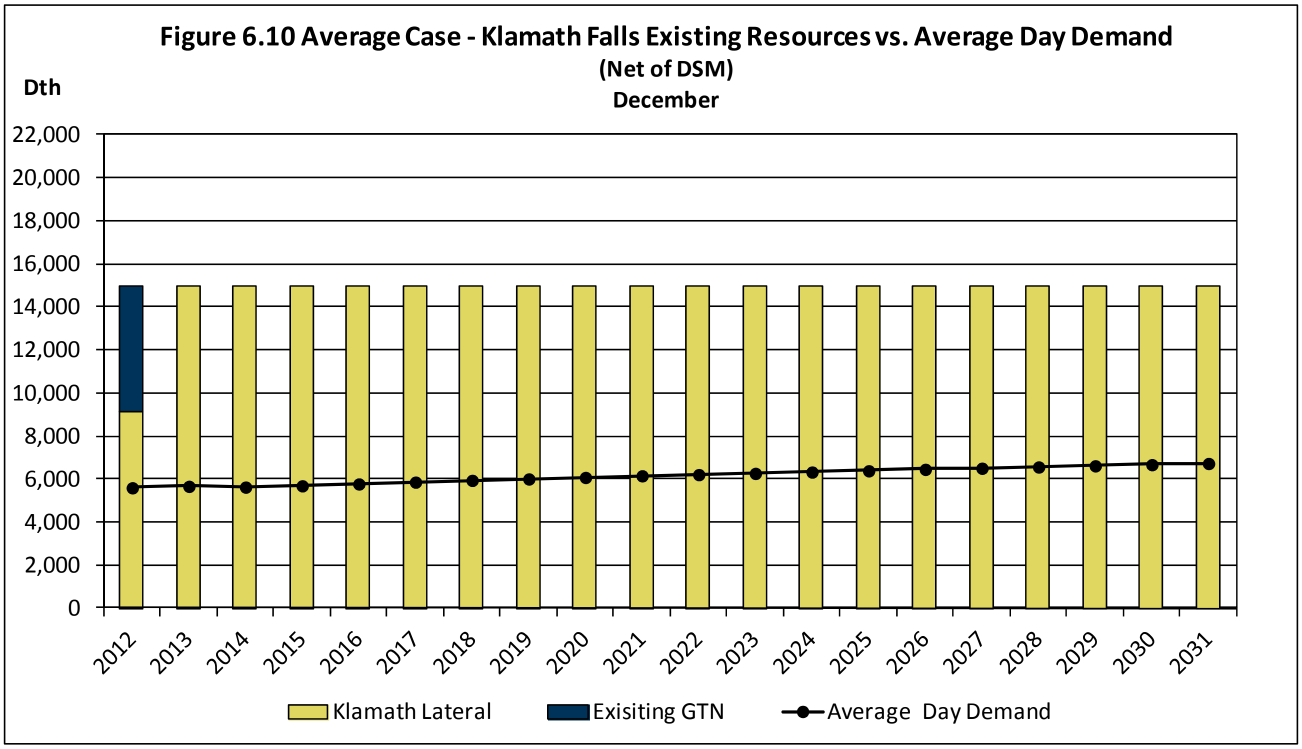
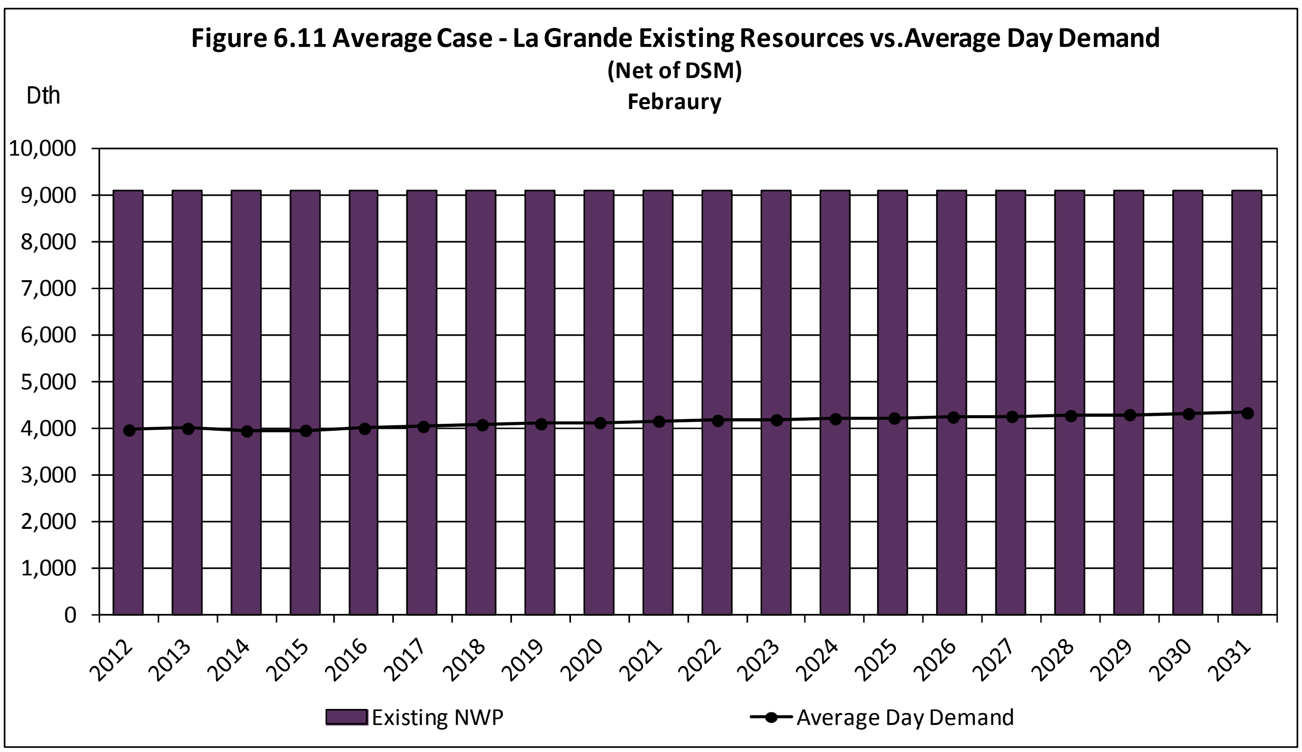


Figure 6.9 Average Case - Medford/Roseburg Existing Resources vs. Average Day Demand
(Net of DSM)
December







Figures 6.12 through 6.15 graphically represent summaries of Expected Case peak day demand compared to existing resources, as well as demand comparisons to our prior IRP. This demand is net of DSM savings. This comparison shows by service territory the amount and timing of deficits over the planning horizon.

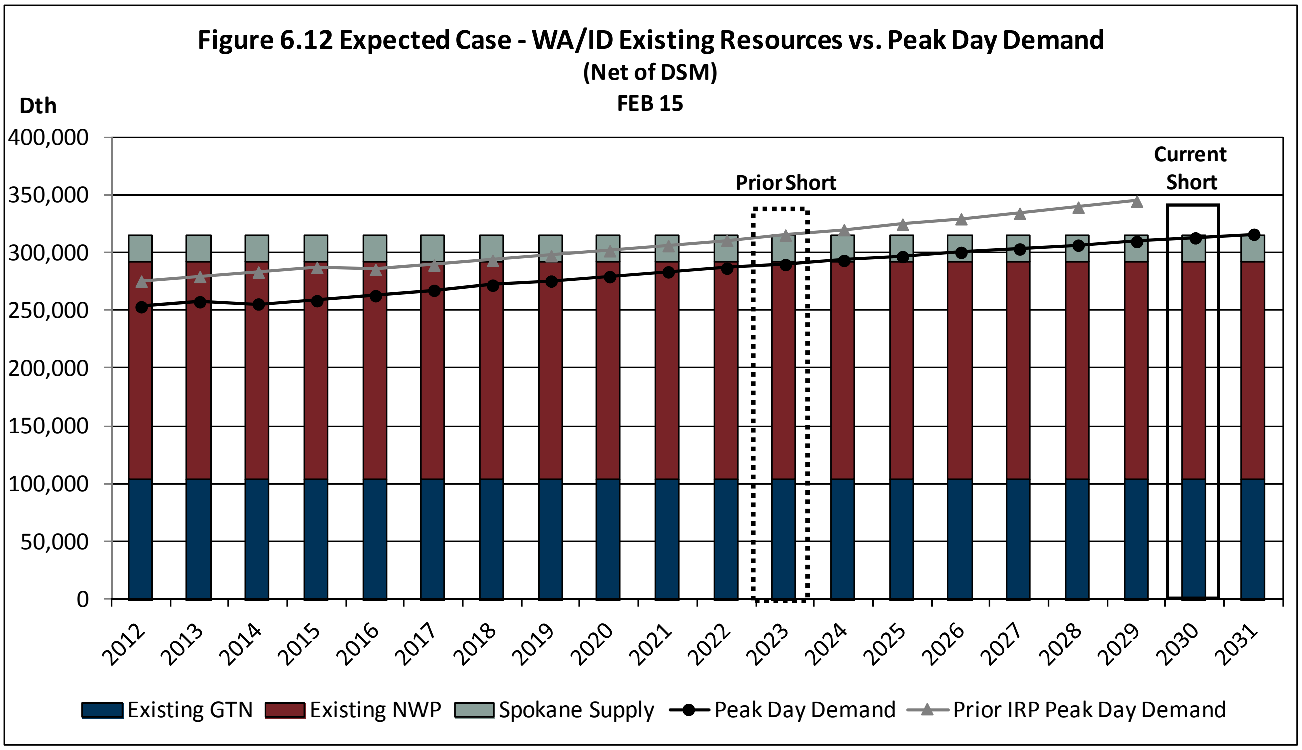


Figure 6.12 Expected Case - WA/ID Existing Resources vs. Peak Day Demand
(Net of DSM)
FEB 15
Dth
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
Prior Short
Current Short
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Existing GTN
Existing NWP
Spokane Supply
Peak Day Demand
Prior IRP Peak Day Demand

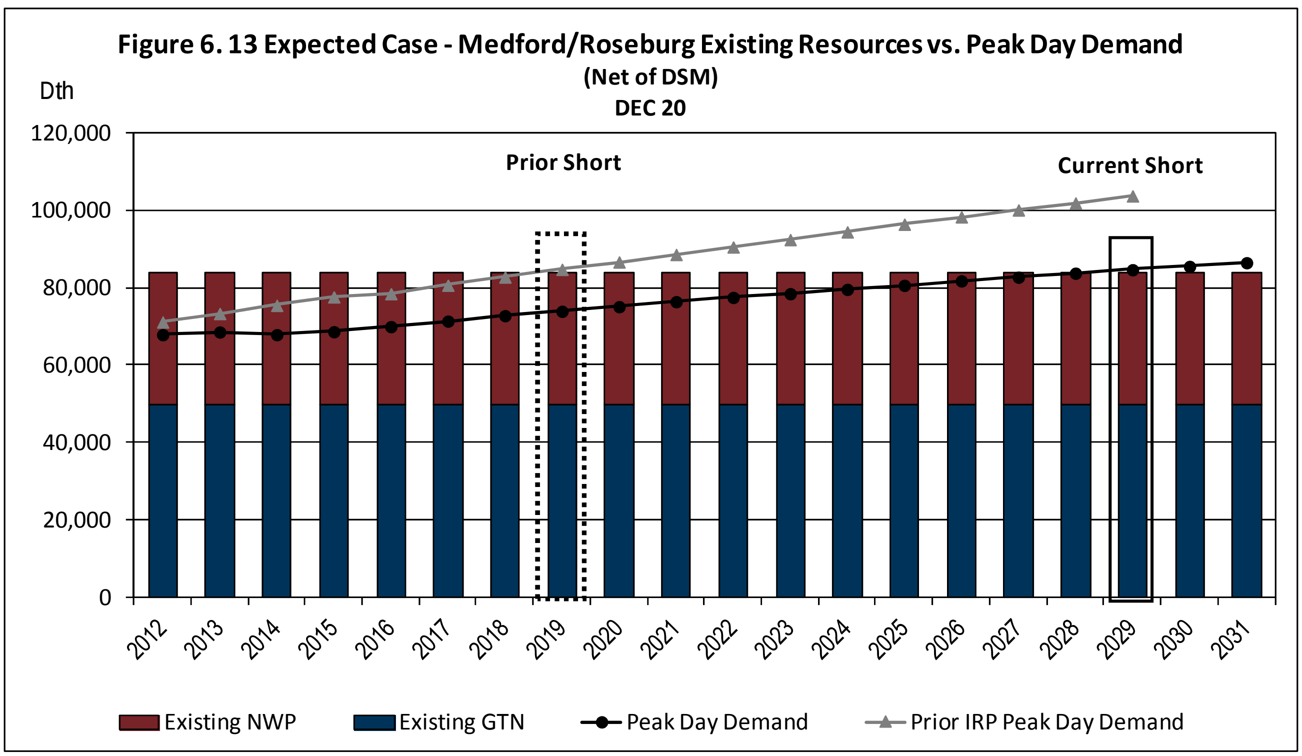


Figure 6. 13 Expected Case - Medford/Roseburg Existing Resources vs. Peak Day Demand
(Net of DSM)
DEC 20
Dth
120,000
100,000
80,000
60,000
40,000
20,000
0
Prior Short
Current Short
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Existing NWP
Existing GTN
Peak Day Demand
Prior IRP Peak Day Demand

Figure 6.14 Expected Case - Klamath Falls Existing Resources vs. Peak Day Demand
(Net of DSM)
DEC 20

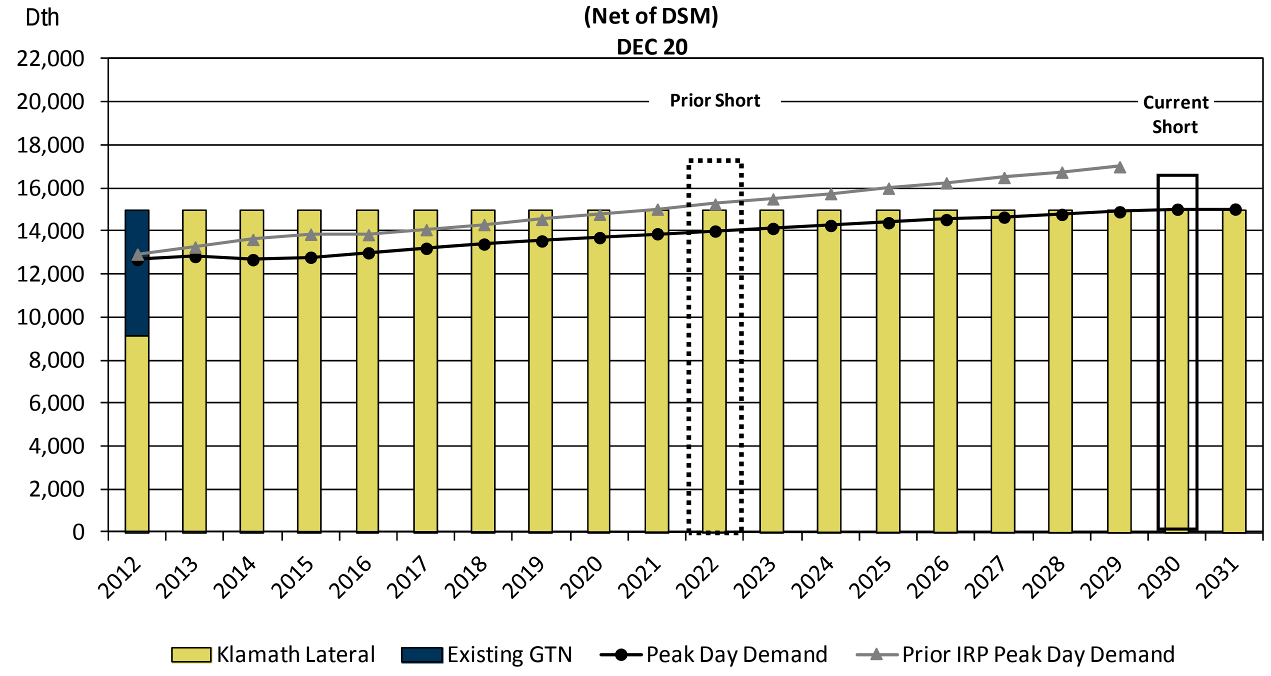
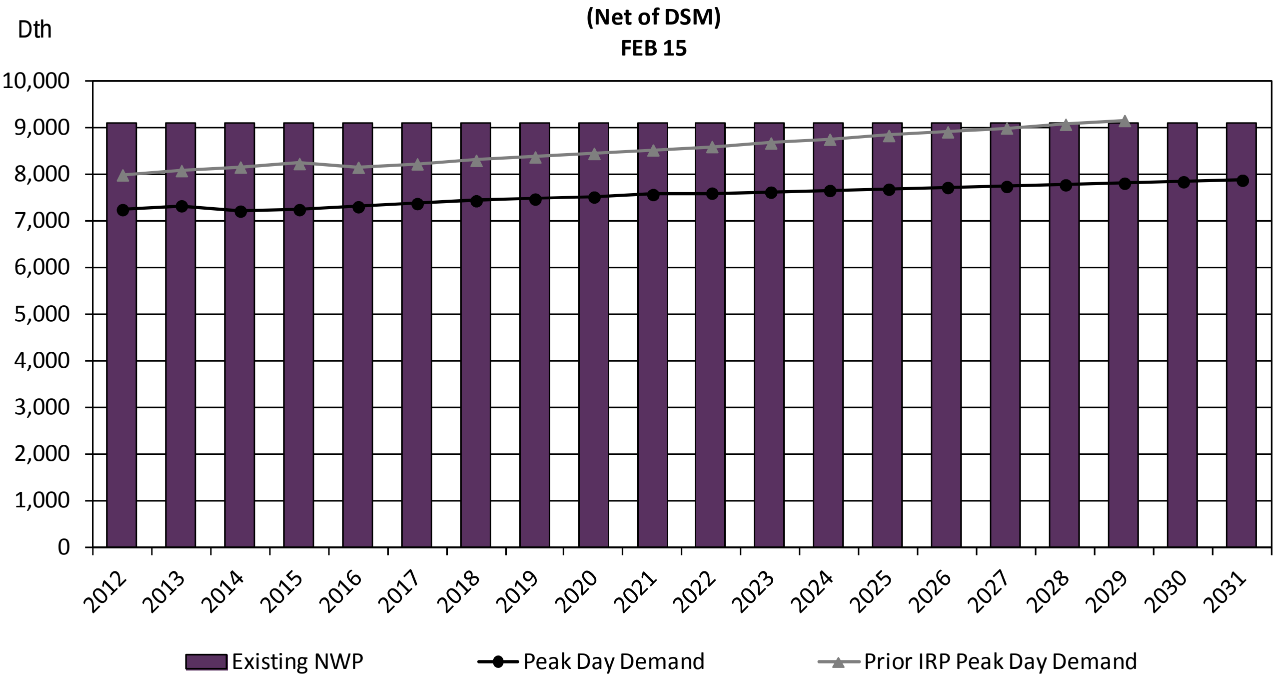


Figure 6.15 Expected Case - La Grande Existing Resources vs. Peak Day Demand
(Net of DSM)
FEB 15



These charts show that when resource shortages occur they are well into the future. In the Expected Case for Washington and Idaho, the system first becomes unserved in 2030. In Oregon, the first unserved year is in Medford/Roseburg in 2029 followed by Klamath Falls in 2030. The La Grande service territory does not go unserved at any time during the 20-year planning horizon. This surplus resource situation provides ample time to carefully monitor, plan and act on potential resource additions.

However, an important risk with respect to identified capacity shortages is the slope of forecasted demand growth which is almost flat. However, if demand accelerates the need for additional resources will also accelerate by several years. This "flat demand risk" necessitates close monitoring of signs of accelerating demand and careful evaluation of lead times to acquire preferred incremental resources.

Table 6.3 quantifies the forecasted total demand (net of DSM savings) and unserved demand from the above charts, identifying the amount of deficiencies by region and growth in deficiencies over time. The next step is to determine the best risk/least cost resources to satisfy these deficiencies.

Table 6.3 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	La Grande % of Peak Day Served	WA/ID Served	WA/ID Unserved	WA/ID Total	WA/ID % of Peak Day Served
Expected	2012	7.23	-	7.23	100%	253.37	-	253.37	100%
Expected	2013	7.31	-	7.31	100%	257.65	-	257.65	100%
Expected	2014	7.20	-	7.20	100%	255.77	-	255.77	100%
Expected	2015	7.23	-	7.23	100%	258.58	-	258.58	100%
Expected	2016	7.29	-	7.29	100%	262.92	-	262.92	100%
Expected	2017	7.36	-	7.36	100%	267.56	-	267.56	100%
Expected	2018	7.42	-	7.42	100%	272.04	-	272.04	100%
Expected	2019	7.46	-	7.46	100%	275.59	-	275.59	100%
Expected	2020	7.50	-	7.50	100%	279.39	-	279.39	100%
Expected	2021	7.56	-	7.56	100%	283.59	-	283.59	100%
Expected	2022	7.58	-	7.58	100%	286.78	-	286.78	100%
Expected	2023	7.61	-	7.61	100%	289.92	-	289.92	100%
Expected	2024	7.64	-	7.64	100%	293.46	-	293.46	100%
Expected	2025	7.67	-	7.67	100%	296.78	-	296.78	100%
Expected	2026	7.70	-	7.70	100%	300.44	-	300.44	100%
Expected	2027	7.73	-	7.73	100%	303.38	-	303.38	100%
Expected	2028	7.76	-	7.76	100%	306.66	-	306.66	100%
Expected	2029	7.80	-	7.80	100%	309.85	-	309.85	100%
Expected	2030	7.83	-	7.83	100%	311.74	1.25	312.99	100%
Expected	2031	7.86	-	7.86	100%	311.74	4.38	316.12	98.6%

Case	Gas Year	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Klamath Falls % of Peak Day Served	Medford/ Roseburg Served	Medford/ Roseburg Unserved	Medford/ Roseburg Total	Medford/ Roseburg % of Peak Day Served
Expected	2012	12.69	-	12.69	100%	67.91	-	67.91	100%
Expected	2013	12.83	-	12.83	100%	68.59	-	68.59	100%
Expected	2014	12.68	-	12.68	100%	67.90	-	67.90	100%
Expected	2015	12.79	-	12.79	100%	68.66	-	68.66	100%
Expected	2016	13.00	-	13.00	100%	69.98	-	69.98	100%
Expected	2017	13.21	-	13.21	100%	71.41	-	71.41	100%
Expected	2018	13.40	-	13.40	100%	72.81	-	72.81	100%
Expected	2019	13.55	-	13.55	100%	73.94	-	73.94	100%
Expected	2020	13.70	-	13.70	100%	75.13	-	75.13	100%
Expected	2021	13.88	-	13.88	100%	76.42	-	76.42	100%
Expected	2022	14.01	-	14.01	100%	77.53	-	77.53	100%
Expected	2023	14.13	-	14.13	100%	78.49	-	78.49	100%
Expected	2024	14.27	-	14.27	100%	79.60	-	79.60	100%
Expected	2025	14.40	-	14.40	100%	80.65	-	80.65	100%
Expected	2026	14.54	-	14.54	100%	81.80	-	81.80	100%
Expected	2027	14.65	-	14.65	100%	82.76	-	82.76	100%
Expected	2028	14.78	-	14.78	100%	83.79	-	83.79	100%
Expected	2029	14.91	-	14.91	100%	84.09	0.60	84.69	99.3%
Expected	2030	15.00	0.02	15.02	99.9%	84.08	1.46	85.54	98.3%
Expected	2031	15.00	0.14	15.14	99.1%	84.09	2.41	86.50	97.2%

NEW RESOURCE OPTIONS

When existing resources are not sufficient to meet expected demand, there are many considerations that are important in determining the appropriateness of potential resources.

RESOURCE COST

Resource cost is the primary consideration when evaluating resource options although other factors mentioned below also influence resource decisions. We have found that newly constructed resources are typically 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 contractual commitment. Newly constructed resources are often less expensive per unit if a larger facility is constructed, because of economies of scale.

LEAD TIME REQUIREMENTS

New resource options can take from one to five or more years to put in service. Open season processes, planning and permitting, environmental review, design, construction and testing are some of the aspects contributing to lead time requirements for new physical facilities. Recalls of released pipeline capacity typically require advance notice of up to a year. Even DSM programs require significant time from program development and rollout to the point when natural gas savings are realized.

PEAK VERSUS BASE LOAD

Our planning efforts include the ability to serve a peak day as well as all other demand periods. Avista's core loads are considerably higher in the winter than the summer. Due to the winter-peaking nature of Avista's demand, resources that cost-effectively serve the winter without an associated summer commitment may be preferable. Alternatively, 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.

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. Pairing together resources increases the cost. Other key factors that can contribute to the usefulness of a resource are viability and reliability. If the potential resource is either not available currently (e.g., new technology) or not reliable on a peak day (e.g., firm) then may not be considered as an option for meeting unserved demand.

"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 infrequently. Lumpiness provides a cushion for future growth. Given the economies of scale for pipeline construction, we are afforded the opportunity to secure resources to serve future demand increases.

COMPETITION

LDCs, end-users and marketers all compete for regional resources. The Northwest has been particularly efficient in the utilization of existing resources, which means the system is neither overbuilt nor under built.

Currently, the region is able to sufficiently handle the demand needs of varying parties. However, the future needs vary and regional LDCs may find they are competing with each other and other parties in order to secure firm resources for customers.

RISKS AND UNCERTAINTIES

Investigation, identification and assessment of risks and uncertainties are critical considerations when evaluating supply resource options. For example, resource costs determinations are subject to various degrees of estimation, partly influenced by the expected timeframe of the resource need and degree of rigor determining estimates or estimation difficulties because of the uniqueness of a resource. Lead times can have varying degrees of certainty ranging from securing currently available transport (high certainty) to building in service territory underground storage (low certainty).

RESOURCE SELECTION

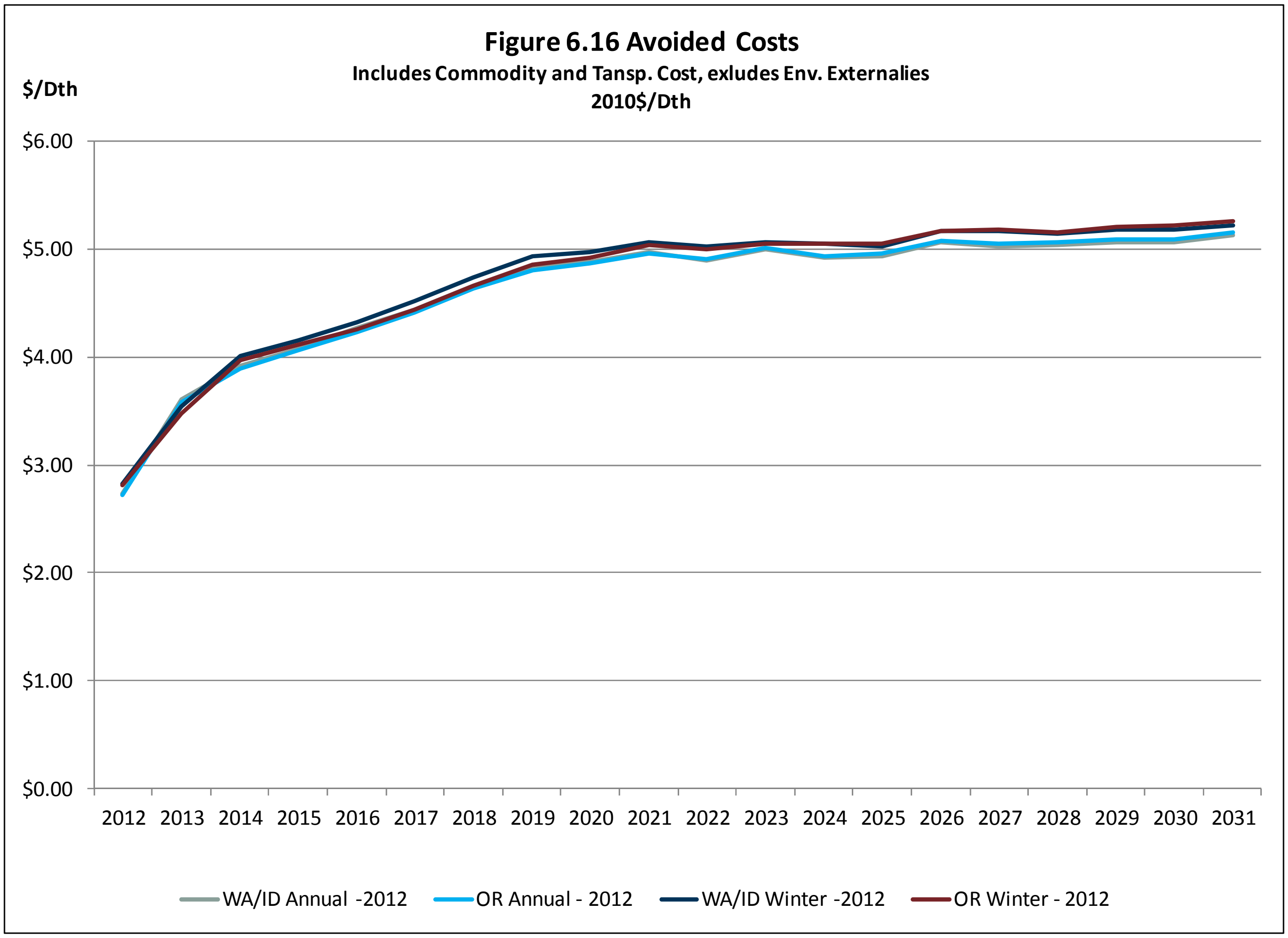
After identifying supply-side resource options and evaluating them based on the above considerations, we entered these supply-side scenarios (see Table 5.2) along with conservation measures (see Chapter 4 - Demand-side Resources) into the SENDOUT® model for it to select the least cost approach to meeting resource deficiencies. SENDOUT® compares demand-side and supply-side resources (see Appendix 6.3 for a list of supply-side resource options) using PVRR analysis to determine which resource is the best risk adjusted/least cost resource.

DEMAND-SIDE RESOURCES

AVOIDED COST

The SENDOUT® model determined avoided cost figures represent the unit cost to serve the next unit of demand with a supply-side resource option during a given period. If a conservation measure's total resource cost is less than this avoided cost, it will cost effectively reduce customer demand and Avista can "avoid" possible commodity, storage, transportation and other supply resource costs.

SENDOUT® calculates marginal cost data by day, month and year for each demand area. A summarized graphical depiction of avoided annual and winter costs for the Washington/Idaho and Oregon areas is in Figure 6.16. The detailed data is presented in Appendix 6.4. The avoided costs do not include environmental externality adders to monetarily recognize adverse environmental impacts. Appendix 4.2 discusses this concept more fully and includes specific requirements required in our Oregon service territory.



SELECTED MEASURES

Using the above avoided cost thresholds; SENDOUT® selected all DSM potential. Table 6.4 details the potential DSM savings in each region from the selected conservation potential for our Expected Case.

Table 6.4 Annual, Annual Average and Peak Day Demand Served by DSM

Case	Gas Year	Annual Klamath DSM (Dth)	Daily Klamath DSM (Dth/day)	Peak Day Klamath DSM (Dth/day)	Annual La Grande DSM (Dth)	Daily La Grande DSM (Dth/day)	Peak Day La Grande DSM (Dth/day)	Annual Medford/ Roseburg DSM (Dth)	Daily Medford/ Roseburg DSM (Dth/day)	Peak Day Medford/ Roseburg DSM (Dth/day)
Expected	2012	3.804	0.010	0.041	1.125	0.003	0.017	17.318	0.047	0.218
Expected	2013	9.197	0.025	0.085	3.762	0.010	0.036	39.691	0.109	0.456
Expected	2014	17.066	0.047	0.152	7.479	0.020	0.064	73.108	0.200	0.797
Expected	2015	28.448	0.078	0.249	12.841	0.035	0.104	121.001	0.332	1.295
Expected	2016	43.646	0.120	0.377	19.585	0.054	0.157	184.206	0.505	1.938
Expected	2017	61.501	0.168	0.530	27.493	0.075	0.221	258.310	0.708	2.703
Expected	2018	80.223	0.220	0.690	35.789	0.098	0.286	336.087	0.921	3.517
Expected	2019	98.644	0.270	0.853	43.949	0.120	0.354	412.643	1.131	4.334
Expected	2020	117.151	0.321	1.015	52.118	0.143	0.421	489.317	1.341	5.158
Expected	2021	127.102	0.348	1.111	56.567	0.155	0.460	531.201	1.455	5.649
Expected	2022	137.231	0.376	1.205	61.086	0.167	0.499	573.753	1.572	6.132
Expected	2023	148.183	0.406	1.308	65.943	0.181	0.542	619.449	1.697	6.663
Expected	2024	162.586	0.445	1.442	72.437	0.198	0.597	680.881	1.865	7.362
Expected	2025	175.765	0.482	1.567	78.308	0.215	0.651	736.135	2.017	8.025
Expected	2026	189.001	0.518	1.691	84.187	0.231	0.701	791.406	2.168	8.633
Expected	2027	200.574	0.550	1.788	89.385	0.245	0.743	840.303	2.302	9.160
Expected	2028	212.097	0.581	1.881	94.588	0.259	0.783	889.359	2.437	9.620
Expected	2029	221.425	0.607	1.962	98.711	0.270	0.817	927.903	2.542	10.060
Expected	2030	231.638	0.635	2.050	103.227	0.283	0.853	970.169	2.658	10.492
Expected	2031	242.347	0.664	2.141	107.971	0.296	0.890	1,014.565	2.780	10.937

Case	Gas Year	Annual Oregon DSM (Dth)	Daily Oregon DSM (Dth/day)	Peak Day Oregon DSM (Dth/day)	Annual WA/ID DSM (Dth)	Daily WA/ID DSM (Dth/day)	Peak Day WA/ID DSM (Dth/day)	Annual Total System DSM (Dth)	Daily Total System DSM (Dth/day)	Peak Day Total System DSM (Dth/day)
Expected	2012	22.247	0.061	0.275	116.058	0.318	1.198	138.305	0.379	1.474
Expected	2013	52.650	0.144	0.577	244.960	0.671	2.432	297.610	0.815	3.009
Expected	2014	97.653	0.268	1.013	425.533	1.166	4.149	523.186	1.433	5.162
Expected	2015	162.291	0.445	1.648	631.464	1.730	5.994	793.755	2.175	7.642
Expected	2016	247.438	0.678	2.472	869.181	2.381	7.975	1,116.619	3.059	10.447
Expected	2017	347.304	0.952	3.454	1,102.398	3.020	10.193	1,449.702	3.972	13.647
Expected	2018	452.098	1.239	4.493	1,333.820	3.654	12.440	1,785.918	4.893	16.934
Expected	2019	555.236	1.521	5.540	1,570.968	4.304	14.837	2,126.204	5.825	20.377
Expected	2020	658.587	1.804	6.594	1,818.742	4.983	17.303	2,477.328	6.787	23.897
Expected	2021	714.870	1.959	7.220	2,060.492	5.645	19.892	2,775.361	7.604	27.112
Expected	2022	772.070	2.115	7.836	2,260.822	6.194	21.888	3,032.892	8.309	29.724
Expected	2023	833.575	2.284	8.513	2,453.430	6.722	23.941	3,287.005	9.005	32.454
Expected	2024	915.904	2.509	9.402	2,661.143	7.291	25.837	3,577.047	9.800	35.240
Expected	2025	990.208	2.713	10.243	2,855.741	7.824	27.887	3,845.949	10.537	38.130
Expected	2026	1,064.594	2.917	11.025	3,052.666	8.363	29.847	4,117.260	11.280	40.872
Expected	2027	1,130.262	3.097	11.692	3,251.635	8.909	31.865	4,381.898	12.005	43.556
Expected	2028	1,196.045	3.277	12.284	3,469.294	9.505	33.928	4,665.338	12.782	46.212
Expected	2029	1,248.039	3.419	12.839	3,617.612	9.911	35.500	4,865.651	13.331	48.339
Expected	2030	1,305.035	3.575	13.395	3,779.664	10.355	36.994	5,084.699	13.931	50.390
Expected	2031	1,364.884	3.739	13.968	3,928.219	10.762	38.536	5,293.102	14.502	52.504

DSM ACQUISITION GOALS

The avoided cost established in SENDOUT®, the demand-side potential selected and the resulting calculated therm savings is the basis for determining DSM acquisition goals and subsequent program implementation planning. While the model selected essentially all DSM potential, the subsequent business planning process yielded different results. Chapter 4 – Demand-Side Resources has additional details on this process.

SUPPLY-SIDE RESOURCES

SENDOUT® considered all options entered into the model, determined when and what resources were needed and rejected options that were determined to not be cost effective. These selected resources represent the least cost solution, within given constraints, to serve anticipated customer requirements. Table 6.5 shows the SENDOUT® selected supply-side resources for the Expected Case.

Table 6.5 Supply Side Resource Selected in SENDOUT®

Case	Additional Resources	Jurisdiction	Size	Cost/Rates	Availability	Notes
Expected Case						
	GTN Capacity	WA/ID	25,000 Dth/d	GTN rate	Currently	Currently available unsubscribed capacity.
	GTN Medford Lateral Expansion	OR	10,000 Dth/d	GTN rate	2014	Additional compression to allow more gas to flow from GTN mainline to the lateral.
	Malin Backhaul	OR	10,000 Dth/d	GTN rate	Currently	Backhaul capacity is provided by tarrif. In order to facilitate additional deliveries to our OR properties an expansion of the Medford Lateral is necessary.
	Klamath Falls Lateral Purchase	OR	15,000 Dth/d	Net Book Value	12/31/2012	Purchase of the NWP Klamath Falls Lateral. This was the perferred resource identified in the 2009 IRP.
	GTN Capacity	OR	2,000 Dth/d	GTN rate	Currently	Currently available unsubscribed capacity.

With additional research and investigation, we may later determine that alternative resources are more cost effective than those resources selected in this IRP. Since resource additions are not anticipated until late in the planning horizon, we will continue to review and refine knowledge of resource options and will act to secure these best cost/risk options when necessary or advantageous.

RESOURCE SELECTION RESULTS

Figures 6.17 through 6.19 summarize modeling results when comparing regional peak day demand against existing and incremental resources for the Expected Case over the 20-year planning period.

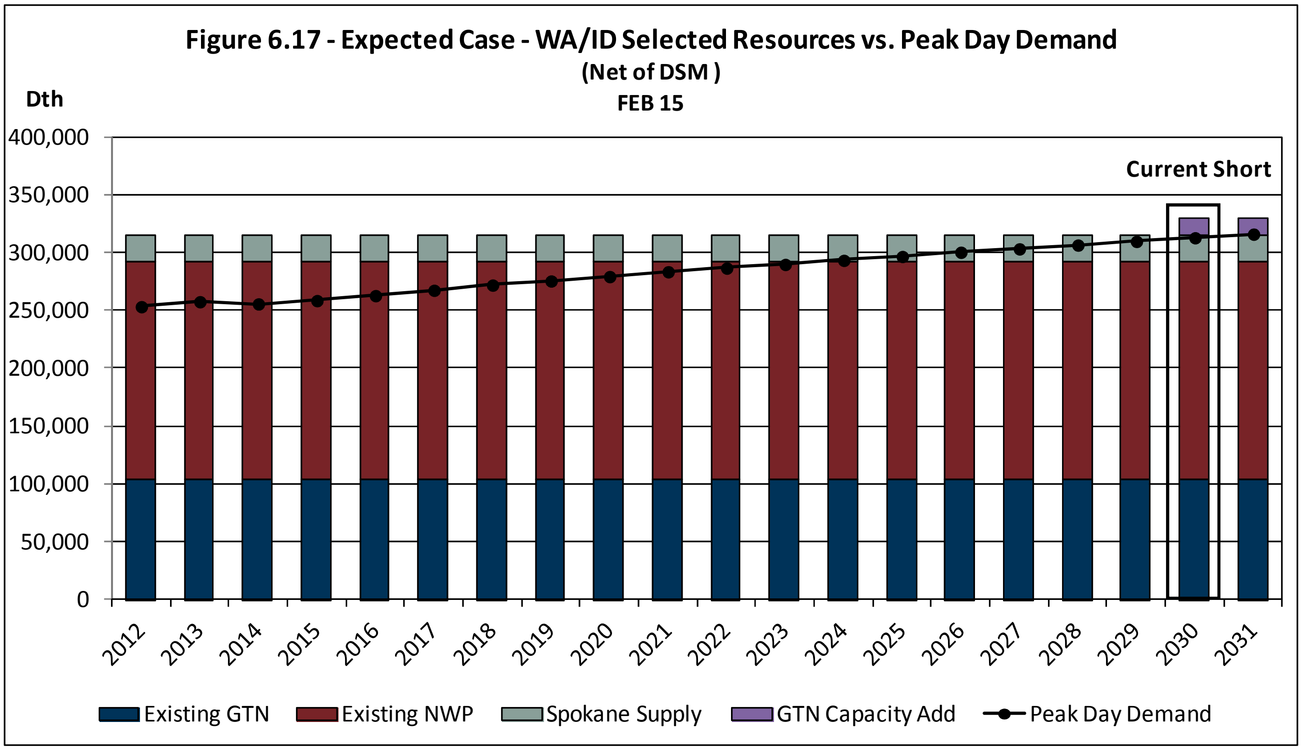


Figure 6.17 - Expected Case - WA/ID Selected Resources vs. Peak Day Demand
(Net of DSM)
FEB 15
Dth
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
Current Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Existing GTN
Existing NWP
Spokane Supply
GTN Capacity Add
Peak Day Demand

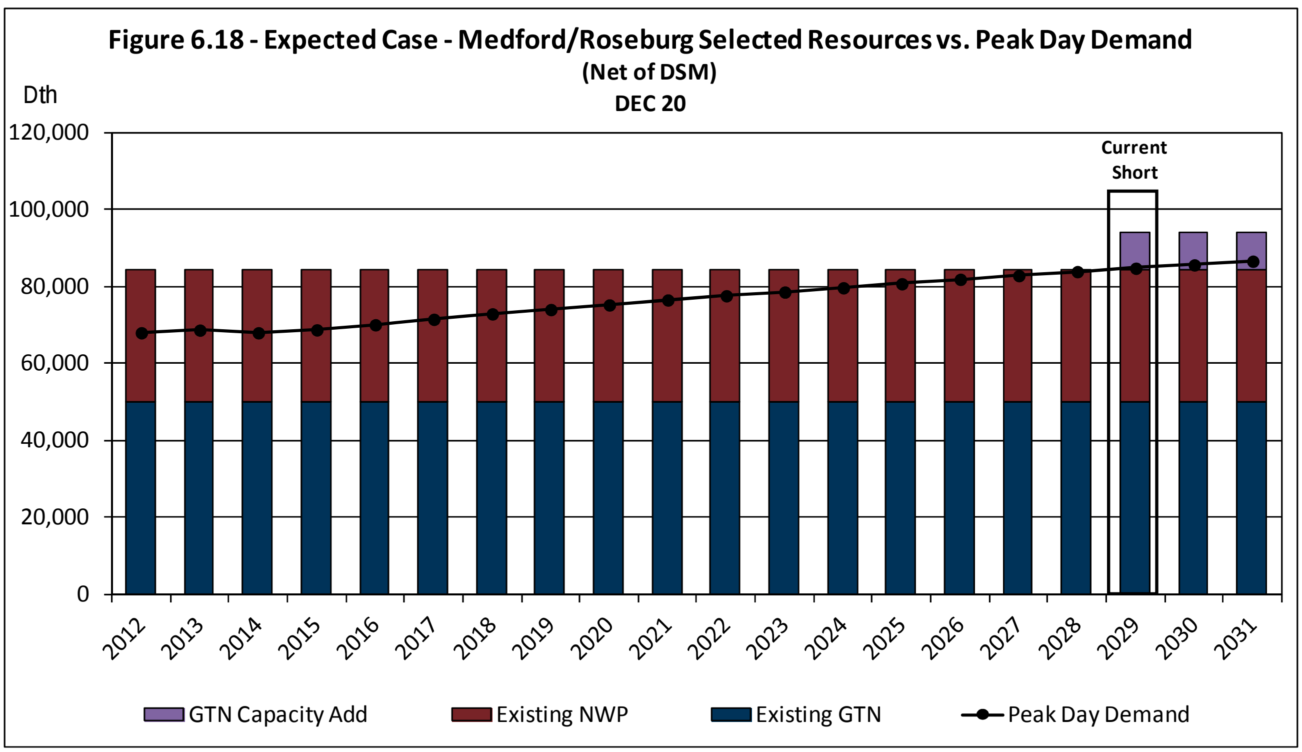
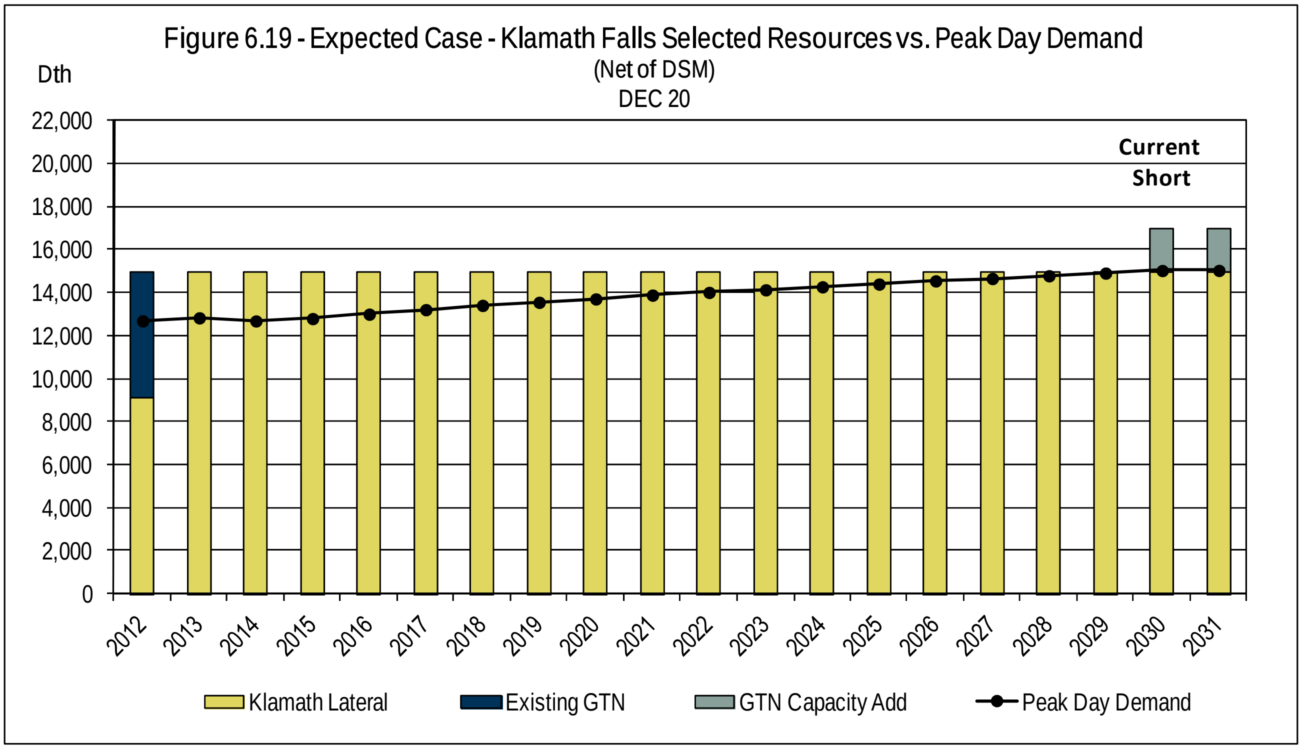


Figure 6.18 - Expected Case - Medford/Roseburg Selected Resources vs. Peak Day Demand
(Net of DSM)
DEC 20
Dth
120,000
100,000
80,000
60,000
40,000
20,000
0
Current Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
GTN Capacity Add
Existing NWP
Existing GTN
Peak Day Demand



As indicated in the figures, after DSM savings the model shows a general preference for incremental transportation resources from existing pipelines and supply basins to resolve capacity deficiencies.

RESOURCE UTILIZATION

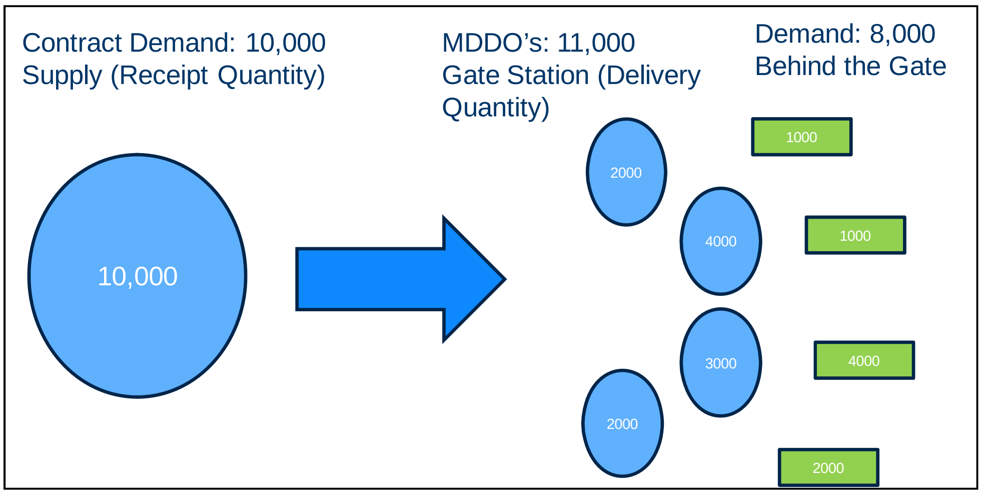
Our primary purpose is to meet our customer's demand needs in a cost effective manner. As the analysis indicates, we have ample resources to meet highly variable demand under multiple scenarios, including peak weather events, for the foreseeable future. With primary needs addressed, utilization of excess resource capacity is considered. There are many short term and long term opportunities to utilize and capture value for our customers using these resources. Each year a comprehensive evaluation of our demand forecasts and existing resource portfolio are reviewed. The following are some examples of how resources can be utilized:

- Serving interruptible demand
- Storage injections
- Storage optimization
- Capacity releases – short-term and long-term
- Basin optimization
- Transportation optimization
- Intra and/or inter-seasonal optimization

GATE STATION ANALYSIS

In previous IRP's we identified a risk associated with our aggregated methodology for supply and demand forecasting. Our forecasting methodology is consistent with operational practices which aggregate capacity at individual points for scheduling/nomination purposes. Typically, the amount of natural gas that can flow from a contract demand (CD) (i.e. receipt/supply quantity) is fixed and the amount that can be delivered (i.e. maximum daily delivery obligation (MDDO) or delivery quantity) to various gate stations is greater. (See Figure 6.20) However, aggregation could mask deficiencies at individual gate stations.

Figure 6.20 – Gate Station Modeling Challenge



In order to address this concern, a gate by gate analysis was developed outside of SENDOUT®. The analysis involved coordination between Gas Supply, Gas Engineering, and intrastate pipeline personnel. Utilizing historical gate station flow data and demand forecasting methodologies detailed in our IRP, forecasted peak day gate station demand was calculated. This demand was then compared to contracted and operational capacities at each gate station.

If forecasted demand exceeded contracted and/or operational capacities further analysis is completed. The additional analysis would involve assessing the most economic way to address the gate deficiency. This could involve a gate station expansion, re-assigning MDDO's, targeted DSM, or distribution system enhancements.

For example, the analysis identified a gate station on NWP's Coeur d'Alene Lateral where forecasted peak day demand exceeded both the gate station MDDO's and physical capacity. Working together with all parties, numerous solutions were examined. Current analysis indicates the optimal solution is to take advantage of a pre-existing plan to build a new gate station at Chase Road off of GTN's mainline (See Chapter 8 for further details). The project originally was designed to alleviate capacity constraints at GTN's Rathdrum gate, however, the new gate's location allows for the potential to displace gas on the NWP Coeur d'Alene Lateral.

‖ ACTION ITEM

With no immediate need to acquire incremental supply side resources to meet peak day demands Avista's focus in the near term will include the following:

- Continuing to coordinate analytic efforts between Gas Supply, Gas Engineering, and the intrastate pipelines to perform gate station analysis and if deficiencies are identified seek least cost solutions.

CONCLUSION

The integrated resource portfolio analysis process summarized in this chapter was first performed on our Average Case and then on the Expected Case demand scenario. We have chosen to utilize the Expected Case for our peak operational planning activities because this case is the most likely outcome given our experience, industry knowledge and our understanding of future natural gas markets. This case provides for reasonable demand growth given current expectations of natural gas prices over the planning horizon. If realized, this case is at a level that allows us to be well protected against resource shortages and does not over commit to additional long-term resources.

We fully recognize that there are numerous other potential outcomes. The process described in this chapter was applied to alternate demand and supply resource scenarios, which is covered in the Chapter 7 – Alternate Scenarios, Portfolios and Stochastic Analysis.

CHAPTER 7 ‖ ALTERNATE SCENARIOS, PORTFOLIOS AND STOCHASTIC ANALYSIS

OVERVIEW

The integrated resource portfolio analysis process described in Chapter 6 was applied to several alternate demand and supply resource scenarios to develop a sufficient range of possible alternate portfolios. This deterministic modeling approach considered a host of underlying assumptions which were vetted with significant discussion and recommendations from our TAC to develop a consensus number of cases to model and analyze.

We also performed stochastic modeling for estimating probability distributions of potential outcomes by allowing for random variation in natural gas prices and weather based on fluctuations observed in historical data. This statistical analysis, in conjunction with our deterministic analysis, enabled us to statistically quantify the risk from a reliability and cost perspective related to resource portfolios under varying price and weather environments.

ALTERNATE DEMAND SCENARIOS

As discussed in the Demand Forecasting section, we have identified several alternate scenarios for detailed analysis to capture a wide range of possible outcomes over the planning horizon. These scenarios are summarized in Table 7.1 and are described in detail in the Chapter 3 - Demand Forecasts and Appendices 3.6 and 3.7. These alternate scenarios consider different demand influencing factors as well as price elasticity effects for various price influencing factors.

Table 7.1 Demand Scenarios
Average Case
Expected Case
High Growth/Low Price
Low Growth/High Price
Alternate Weather Standard

Demand profiles over the planning horizon for each of the alternate scenarios shown in Figures 7.1 and 7.2 reflect the two winter peaks we model for the different service territories (Dec. 20 and Feb. 15).

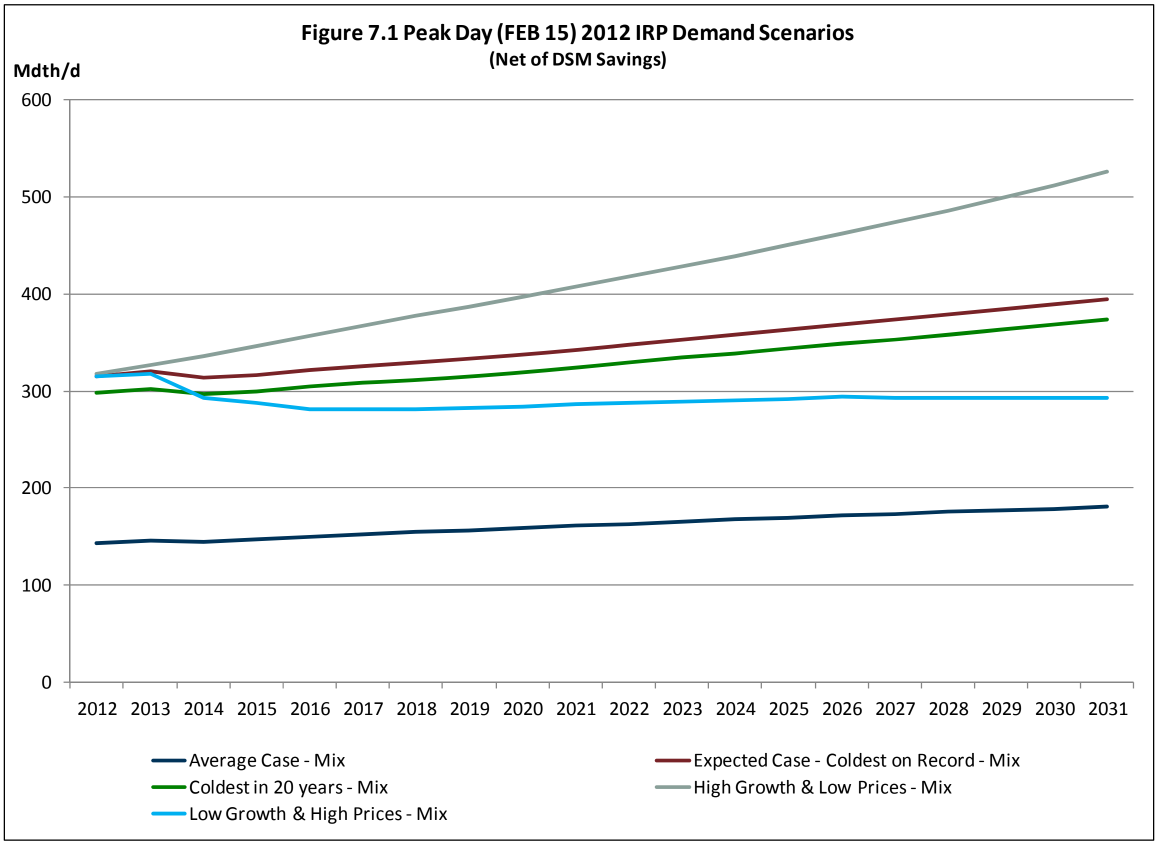


Figure 7.1 Peak Day (FEB 15) 2012 IRP Demand Scenarios
(Net of DSM Savings)
Mdth/d
600
500
400
300
200
100
0
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Average Case - Mix
Expected Case - Coldest on Record - Mix
Coldest in 20 years - Mix
High Growth & Low Prices - Mix
Low Growth & High Prices - Mix

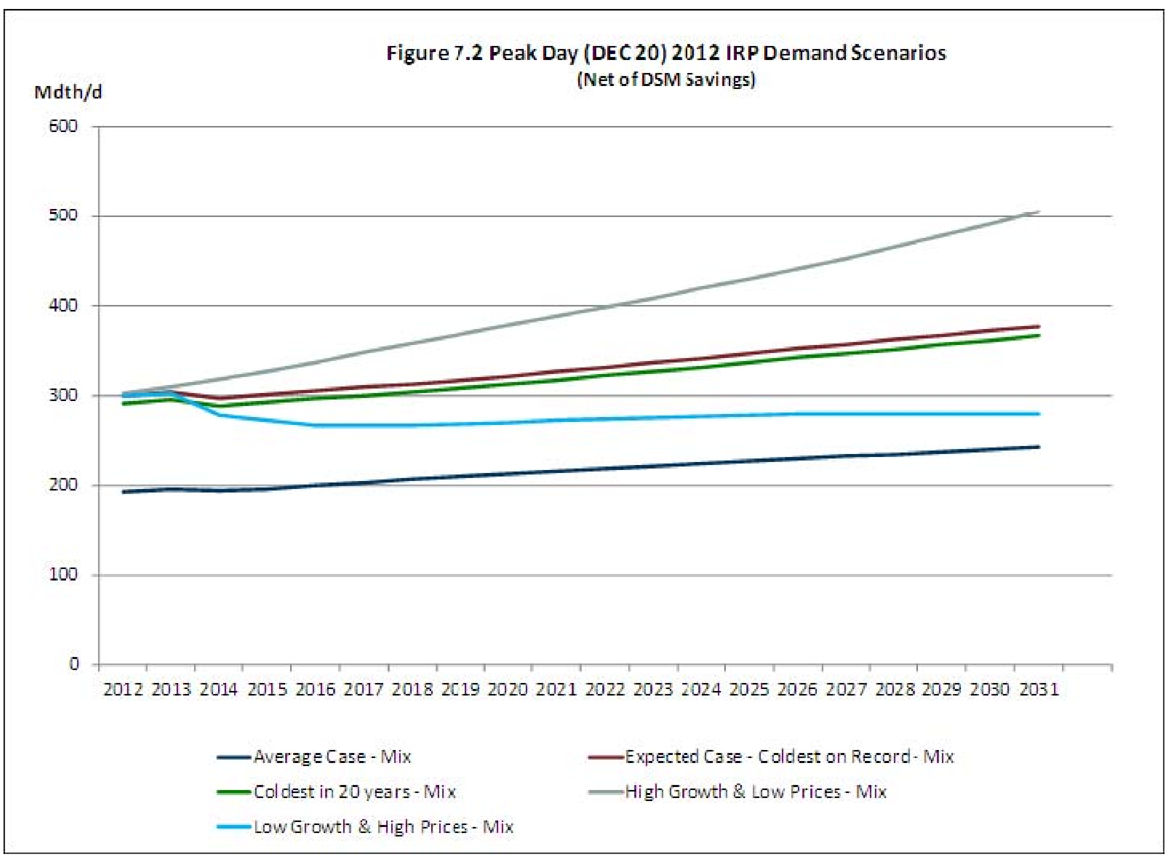
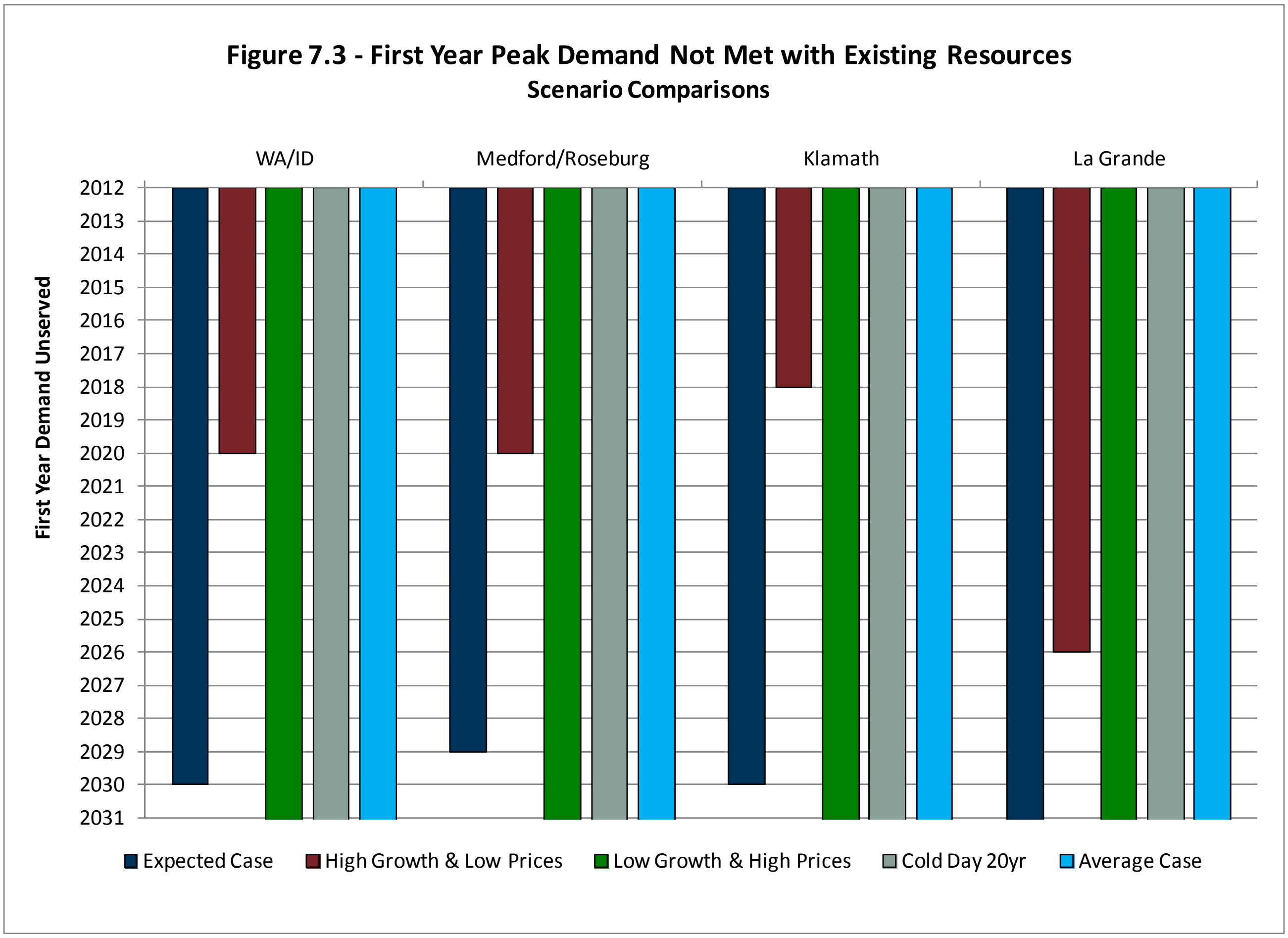


Figure 7.2 Peak Day (DEC 20) 2012 IRP Demand Scenarios
(Net of DSM Savings)
Mdth/d
600
500
400
300
200
100
0
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Average Case - Mix
Expected Case - Coldest on Record - Mix
Coldest in 20 years - Mix
High Growth & Low Prices - Mix
Low Growth & High Prices - Mix

As in the Expected Case, we modeled in SENDOUT® the same resource integration and optimization process described in this section for each of the other five demand scenarios (see Appendix 3.7 for a complete listing of all portfolios considered). This identified first year unserved dates for each scenario by service territory (Figure 7.3).



As anticipated, our High Growth, Low Price scenario has the most rapid growth and the earliest first year unserved dates. This scenario includes customer growth rates 60% higher than the Expected Case, incremental demand driven by NGV/CNG vehicles, and no adjustment for price elasticity. Even with these aggressive assumptions, resource shortages do not occur until late in the planning horizon.

- 2020 in Washington/Idaho
- 2020 in Medford/Roseburg
- 2018 in Klamath
- 2026 in La Grande

This "steeper" demand highlights the "flat demand risk" discussed earlier. The likelihood of this scenarios occurrence is remote; however any potential for accelerated unserved dates warrants close monitoring of demand trends and resource lead times.

The remaining scenarios do not identify any resource deficiencies in the planning horizon.

Detailed information on certain selected scenarios is included in the following appendices:

- Demand and Selected Resources graphs by service territory (High Growth Case only) – Appendix 7.1
- Peak Day Demand, Served and Unserved table (all cases) – Appendix 7.2
- Avoided cost curve detail and graphs for High Growth and Low Growth cases – Appendix 6.4

ALTERNATE SUPPLY SCENARIOS

We identified many supply-side resources which could be considered to meet resource deficiencies should they occur. Chapter 6 details available supply-side resource options that were considered for this IRP. The list includes resources we considered but did not input into SENDOUT® because of various restrictions.

For example, contracted city gate deliveries in the form of a structured purchase transaction could be a viable and desirable option to meet peak conditions. However, the market-based price and other terms are difficult to reliably determine until a formal agreement is negotiated. Exchange agreements also have market-based terms and are hard to reliably model especially when the resource is not needed in the near term.

Exported LNG was also a considered primarily as a price influencing factor. However, if one of the proposed export LNG terminals in Oregon were to be approved and a pipeline was to be built to supply that facility it potentially could bring supply through Avista's service territory. This scenario is interesting however; there is much uncertainty about export LNG. New pipeline builds are expensive and there are currently existing pipeline options that would be more cost effective. We will continue to monitor this situation and will consider inclusion of this supply scenario for future IRPs.

For our Washington/Idaho and Medford/Roseburg service territories unsubscribed firm capacity on GTN and/or firm backhaul plus lateral expansion is a preferred resource selection from our existing resources plus currently available supply scenario for most demand scenarios. However, assumptions on future availability could change over time. Therefore, we ran an additional alternate supply-side scenario with changed assumptions on GTN capacity as per Table 7.2.

Table 7.2 Supply Scenarios
Existing Resources
Existing + Expected Available
GTN Fully Subscribed

In our alternate supply scenario we assumed increased need for GTN capacity. This could be driven by power generators who require firm transportation to fuel combustion turbines or significant investments made by the transportation industry for fueling long haul trucks. The increased contracting leads to GTN becoming fully subscribed. The result of this scenario using our Expected Case demand profile is that in Washington and Idaho and Oregon recalls of existing capacity and satellite LNG is selected as the preferred resource portfolio. (Figures detailing the resources selected based on this scenario are included in Appendix 7.1.)

PORTFOLIO SELECTION

The alternate demand scenarios and supply scenarios are matched together to form portfolios. Each of these unique portfolios is run through SENDOUT® where the supply resources and demand-side resources are compared and selected on a least cost basis. Once the resources are determined, a net present value of the revenue requirement (PVRR) is calculated.

In the Expected Case, the Expected Demand with Existing Resources plus Expected Available portfolio has the lowest PVRR and was therefore selected as our preferred portfolio. In this portfolio, the supply-side resources selected to meet unserved demand include the acquisition of currently available pipeline capacity on GTN, additional compression and capacity on the GTN Medford Lateral. These resources are the least cost/risk adjusted options currently available to meet peak day demand.

Table 7.3 summarizes the PVRR of all the portfolios considered. Each of these portfolios is based on unique assumptions and therefore a simple comparison of PVRR cannot be made.

Table 7.3 Net Present Value of Revenue Requirement (PVRR) by Portfolio

	Portfolio	Unserved Demand	PVRR in (000's)
Average Case	Average Demand with Existing Resources (before resource additions)	No	$ 5,826,401
Expected Case			
	Expected Demand with Existing Resources (before resource additions)	Yes	$ 5,902,214
	Expected Demand with Existing Resources plus Expected Available	No	$ 5,972,641
	Expected Demand with GTN Fully Subscribed	No	$ 6,245,354
Additional Demand Scenarios			
	High Growth, Low Price Demand with Existing Resources	Yes	$ 6,315,432
	High Growth, Low Price Demand with Existing Resource plus Expected Available	No	$ 6,645,781
	High Growth, Low Price Demand with GTN Fully Subscribed	No	$ 6,954,112
	Alternate Weather Standard Demand with Existing Resources	No	$ 5,888,614
	Low Growth, High Price with Existing Resources	No	$ 8,281,177

STOCHASTIC ANALYSIS[1]

The scenario (deterministic) analysis described earlier in this document represents specific “what if” situations based on predetermined assumptions including price and weather. These two factors are an integral part of scenario analysis. To better understand a particular portfolio’s response to price and weather, we applied stochastic analysis to generate a wide variety of price and weather events.

Deterministic analysis is a valuable tool for selecting the optimal portfolio. The model selects resources to meet peak weather conditions in each of the 20 years. However, due to the recurrence of design conditions in each of the 20 years, total system costs over the planning horizon can be overstated because of annual recurrence of design conditions and the recurrence of price increases in the forward price curve. As a result, deterministic analysis does not provide a comprehensive look at future events. This type of analysis is only one piece of the puzzle. Utilizing Monte Carlo simulation in conjunction with deterministic analysis provides a more complete picture of how the portfolio performs under multiple weather and price profiles.

For this IRP, Monte Carlo analysis was employed in two ways. The first was to test our weather planning standard and the second was to assess the risk related to costs of our Expected portfolio under varying price environments.

[1] SENDOUT® uses Monte Carlo simulation to support stochastic analysis, which is a mathematical technique for evaluating risk and uncertainty. Monte Carlo simulation is a statistical modeling method used to imitate the many future possibilities that exist with a real-life system.

WEATHER

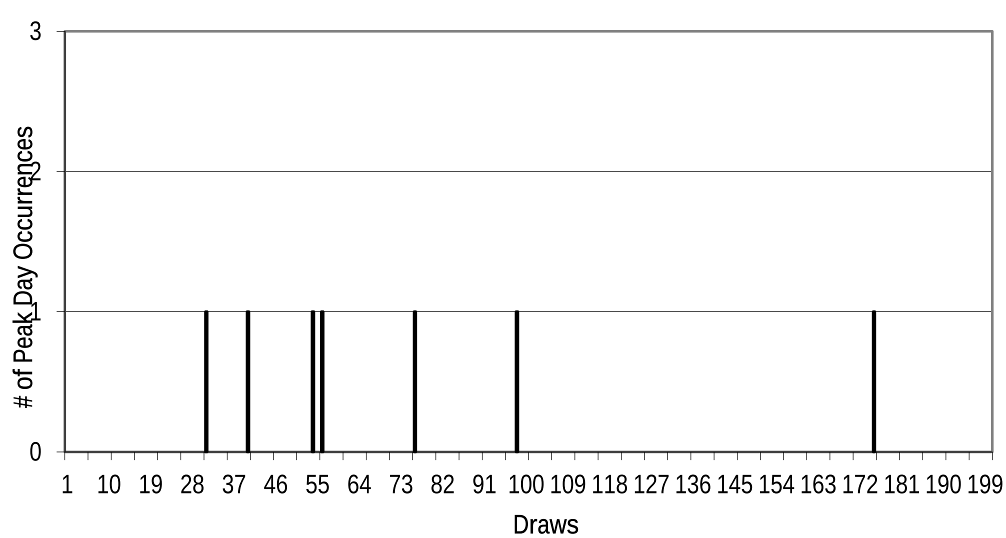
In order to evaluate weather and its effect on our portfolio we derived 200 simulations (draws) through the use of SENDOUT®'s Monte Carlo capabilities. Unlike deterministic scenarios or sensitivities the draws have more variability from month-to-month and year-to-year. In the model, random monthly total HDD draw values (subject to Monte Carlo parameters – see Table 7.4) are distributed on a daily basis for a month in history with similar HDD totals. The resulting draws provide a weather pattern with variability in the total HDD values, as well as variability in the shape of the weather pattern. This provides more robust basis for stress testing the deterministic analysis.

Table 7.4 Example of Monte Carlo Weather Inputs
Spokane

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
HDD Mean	895	1,152	1,145	913	781	546	331	143	37	37	191	544
HDD Std Dev	132	141	159	115	85	73	72	52	28	28	77	70
HDD Max	1,361	1,506	1,681	1,204	953	694	471	248	151	97	343	677
HDD Min	699	918	897	716	598	392	192	61	-	1	54	361

Avista models five weather areas: Spokane, Medford, Roseburg, Klamath Falls and La Grande. From the simulation data we were able to assess the frequency that the peak day occurs in each area. The stochastic analysis shows that in over 200 twenty-year simulations, while still remote, peak day (or more) does occur with enough frequency to maintain our current planning standard for this IRP though this topic remains a subject of continued analysis. For example, in our Medford weather pattern over the 200 twenty-year draws (i.e. 4000 years, HDDs at or above peak weather (61 HDD) occur 128 times. This equates to a peak day occurrence once every 31 years (4000 simulation years divided by 128 occurrences). The Spokane area has the least occurrences of peak day (or more) occurrences in our simulations while La Grande has the most occurrences. This is primarily due to the frequency in which each region's peak day HDD occurs within the historical data as well as near peak day HDDs. See Figures 7.9 through 7.13 for the number of peak day occurrences for a weather area.

Figure 7.4 - Frequency of Peak Day Occurrences
Spokane



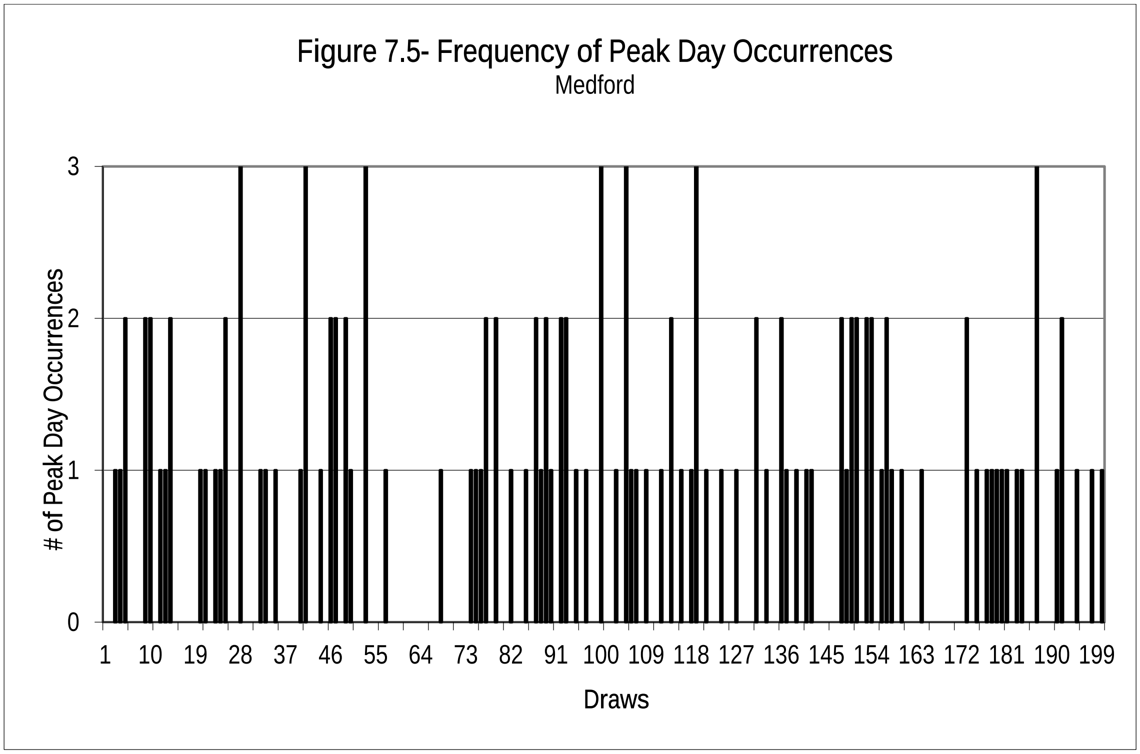


Figure 7.5- Frequency of Peak Day Occurrences
Medford
# of Peak Day Occurrences
0
1
2
3
1 10 19 28 37 46 55 64 73 82 91 100 109 118 127 136 145 154 163 172 181 190 199
Draws

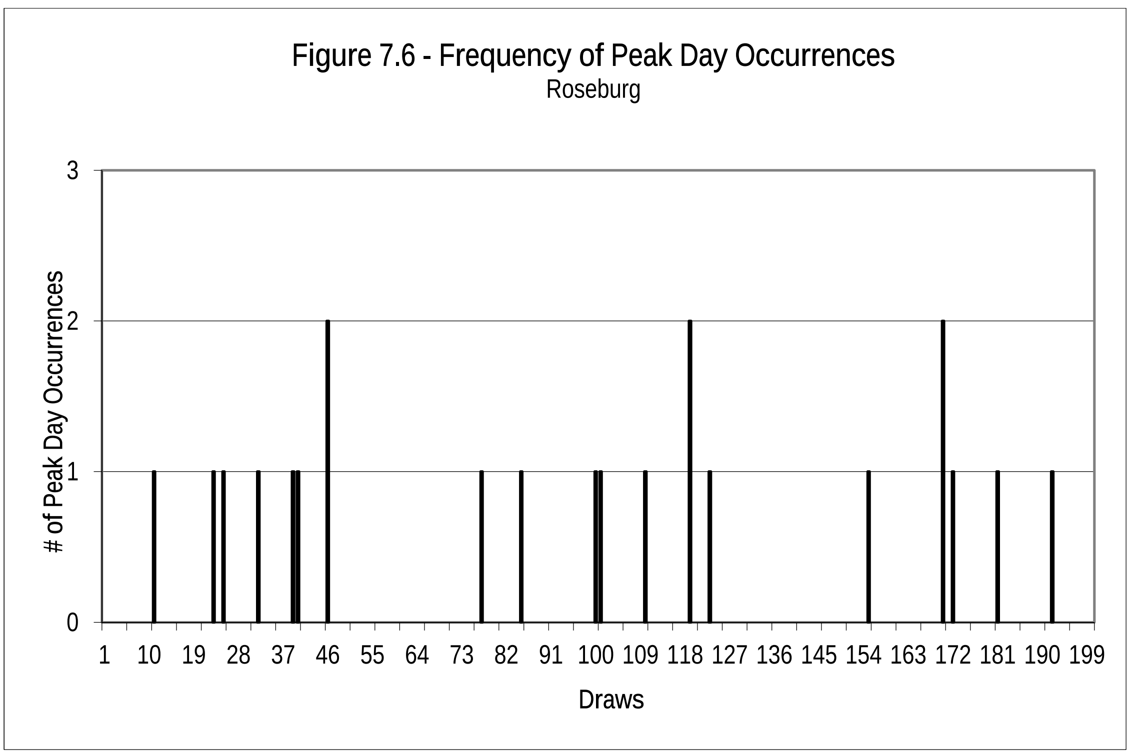
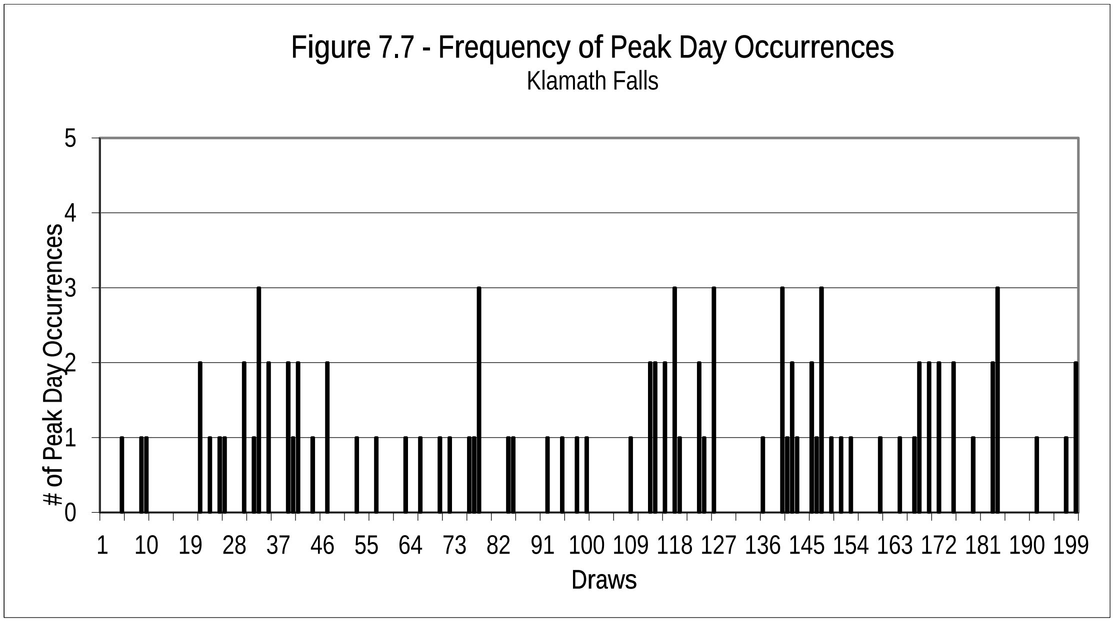
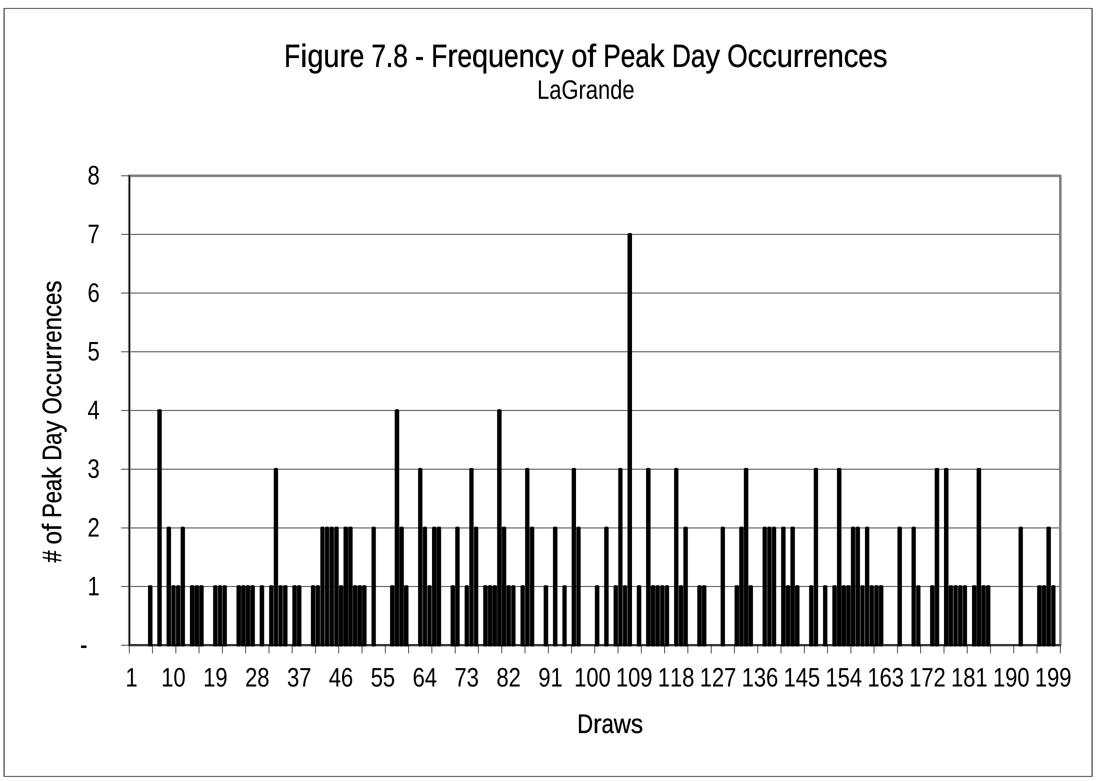


Figure 7.6 - Frequency of Peak Day Occurrences
Roseburg
# of Peak Day Occurrences
0
1
2
3
1 10 19 28 37 46 55 64 73 82 91 100 109 118 127 136 145 154 163 172 181 190 199
Draws



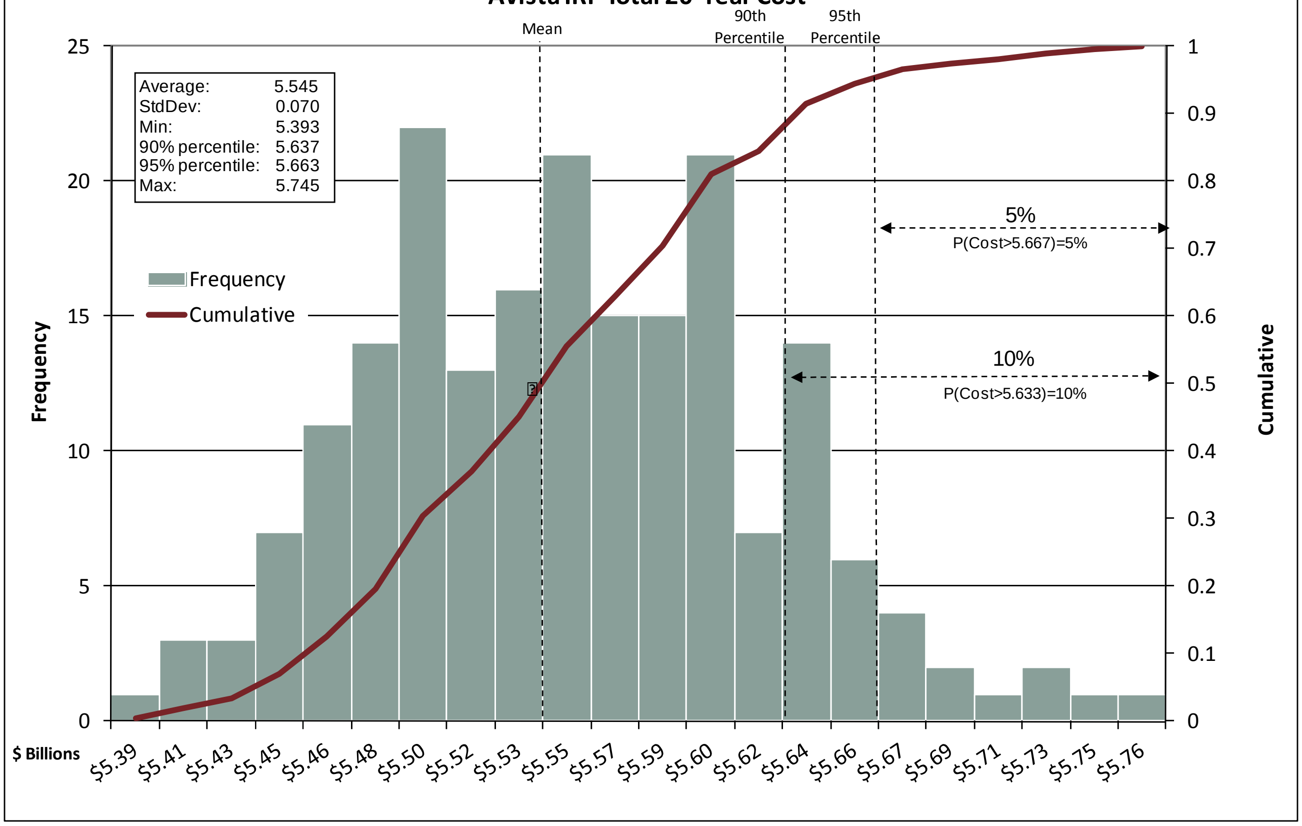


PRICE

While weather is an important driver for IRP planning price is also important. As seen in recent years, there can be significant price volatility that can affect the portfolio. In deterministic modeling a single price curve for each scenario is used to perform analysis. There is risk, however, that the price curve used in the scenario will not reflect actual results.

Through Monte Carlo simulation we are able to test our portfolio and quantify the risk to our customers when prices do not materialize as forecasted. We performed a simulation of 200 draws, varying prices, to investigate whether the Expected Case total portfolio costs from our deterministic analysis is within the range of occurrences in our stochastic analysis. Figure 7.9 shows a histogram of the total portfolio cost of all 200 draws plus the Expected Case results. This histogram depicts the frequency and the total cost of the portfolio among all the draws, the mean of the draws, the standard deviation of the total costs and the total costs from the Expected Case. The figure confirms that our Expected Case total portfolio cost is within an acceptable range of total portfolio costs based on 200 unique pricing scenarios.

Figure 7.9
Avista IRP Total 20-Year Cost



Performing stochastic analysis on two key variables of weather and price in our demand analysis provided a statistically supported approach to evaluate and confirm the findings reached from our scenario analysis with respect to adequacy and reasonableness of our weather planning standard and our selected natural gas price forecast. This alternative analytical perspective provides us better confidence in our conclusions and helps us stress test our assumption, thereby mitigating analytical risks.

REGULATORY REQUIREMENTS

IRP regulatory requirements in Washington, Oregon and Idaho call for several key components. The completed plan must demonstrate that we have:

- Examined a range of demand forecasts
- Examined feasible means of meeting demand with both supply-side and demand-side resources
- Treated supply-side and demand-side resources equally

- Described our long-term plan for meeting expected demand growth
- Described our plan for resource acquisitions between planning cycles
- Taken planning uncertainties into consideration
- Involved the public in the planning process
- We have addressed the applicable requirements throughout this document. Appendix 2.2 lists the specific requirements and guidelines of each jurisdiction and describes our compliance in detail

We are also required to consider risks and uncertainties throughout our planning and analysis. Our approach in addressing this requirement was to identify factors that could cause significant deviation from our Expected Case planning conclusions. We employed dynamic demand analytical methods and incorporated sensitivity analysis on various demand drivers that impacted demand forecast assumptions. From this, we created 14 demand sensitivities and modeled five demand scenario alternatives, which incorporated differing customer growth, use per customer, weather and price elasticity assumptions. We developed three supply scenarios to consider various risks of resource uncertainties. This resulted in nine distinct portfolios analyzed within SENDOUT®.

We performed analysis on our peak day weather planning standard, performing sensitivity on HDDs and modeling an alternate weather planning standard using coldest day in 20 years. We supplemented this analysis with stochastic analysis running Monte Carlo simulations in SENDOUT®. We also used simulations from SENDOUT® to analyze price uncertainty and the effect on total portfolio cost.

We examined risk factors and uncertainties that could impact expectations and assumptions with respect to DSM programs and supply-side scenarios. From this, we developed three supply-side scenarios and included potential DSM savings for evaluation.

This investigation, identification and assessment of risks and uncertainties in our IRP process should reasonably mitigate surprise outcomes.

▌▌ CONCLUSION

The High Growth and Low Growth Case demand analysis provides a sufficient range for evaluating possible demand trajectories relative to our Expected Case. Based on this analysis we feel comfortable that we have sufficient time to plan for forecasted resource needs. Even under a very extreme growth scenario our first forecasted deficiency does not occur until 2018. The analysis shows a preference to meet the forecasted demand needs with the purchase of existing incremental pipeline capacity. We recognize that many things could happen between now and when our resource needs occur, therefore we will carefully monitor our demand trends and continually updated and evaluate all demand side and supply side alternatives.

CHAPTER 8 || DISTRIBUTION PLANNING

OVERVIEW

Avista's integrated resource planning encompasses evaluation of safe, economical and reliable full-path delivery of natural gas from basin to burner tip. Securing adequate natural gas supply and ensuring sufficient pipeline transportation capacity to our city gates become secondary issues if the distribution system behind the city gates is not adequately planned and becomes severely constrained. An important part of the planning process is to forecast future local demand growth, determine potential areas of distribution system constraints, analyze possible solutions and estimate costs for eliminating constraints.

Analyzing our resource needs to this point has focused on ensuring adequate capacity to our city gates, especially during a peak event (i.e. "Is there adequate volume for a peak day?"). Distribution planning focuses on "Is there adequate pressure during a peak hour?" Despite this altered perspective distribution planning shares many of the same goals, objectives, risks and solutions.

Avista's natural gas distribution system consists of approximately 5,400 miles of distribution main pipelines in Washington, 3,000 miles in Idaho and 3,500 miles in Oregon as well as numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment. Currently, there are no storage facilities or compression systems within our distribution system. System pressure is maintained by pressure regulating stations that utilize pipeline pressures from the interstate transportation pipelines before natural gas enters our distribution networks.

DISTRIBUTION SYSTEM PLANNING

Avista conducts two primary types of evaluations in its distribution system planning efforts to determine the need for resource additions including distribution system reinforcements and expansions. Reinforcements are upgrades in existing infrastructure or new system additions that increase system capacity, reliability and safety. Expansions are new system additions to accommodate new demand. Collectively we refer to these as distribution enhancements.

Ongoing evaluations of each distribution network in our four primary service territories are conducted to identify strategies for addressing local distribution requirements resulting from customer growth. Customer growth assessments are made based on many factors including our IRP demand forecasts[1], monitoring of gate station flows and other system metering, ongoing communication with construction staff and local area management regarding new service requests, field personnel discussion and inquiries from major developers.

Additionally, Avista regularly conducts integrity assessments of its distribution systems. This type of ongoing system evaluation can also indicate distribution upgrading requirements, but as a result of system maintenance needs rather than customer and load growth. In some cases, however, the timing for system integrity upgrades can coincide with growth related expansion requirements.

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[1] Distribution Planning forecasts customer growth rates by town code to generate local demand growth projections in its forecasting model consistent with the broader IRP customer forecasting methodology facilitating consistent integrated planning efforts. A town code is an unincorporated area within a county or a municipality within a county.

These planning efforts provide a long-term planning and strategy outlook and are integrated into our capital planning and budgeting process which incorporates planning for other types of distribution capital expenditures and infrastructure upgrades.

NETWORK DESIGN FUNDAMENTALS

Natural gas distribution networks rely on pressure differentials to flow gas from one place to another. When pressures are the same on both ends of a pipe the gas does not move. When gas is removed from a point on the network the pressure at that point drops lower than the pressure upstream in the network. Gas then moves from the higher pressure in the network to the point of removal attempting to equalize the pressure throughout the network. If gas removed is not sufficiently replaced by new gas entering the network the pressure differential will decrease, flow will stall and the network could run out of pressure. Therefore, it is important to design a distribution network so that the intake pressure (from gate stations and/or regulator stations) within the network is high enough to maintain an adequate pressure differential when gas leaves the network.

Not all gas flows equally throughout a network. Certain points within the network can constrain flow and thus restrict overall network capacity. Network constraints can occur over time as demand requirements on the network evolve. Anticipating these demand requirements, identifying potential constraints and forming cost-effective solutions with sufficient lead times without overbuilding infrastructure are the key challenges in network design.

COMPUTER MODELING

Developing and maintaining effective network design is significantly aided by computer modeling to perform network demand studies. Demand studies have evolved with technology in the past decade to become a highly technical and powerful means for 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 modeling solutions produced closely resemble actual system behavior.

Avista conducts network load studies using GL Noble Denton's SynerGEE® 4.6.0 software. This computer-based modeling tool runs on a Windows operating system and allows users to analyze and interpret solutions graphically. Appendix 8.1 describes in detail our computer modeling methodology while Appendix 8.2 provides an example load study presentation including graphical interface and output examples.

DETERMINING PEAK DEMAND

For ease of maintenance and operation, safety to the public, reliable service and cost considerations, distribution networks operate at a relatively low pressure. Avista operates its distribution networks at a maximum operating pressure of 60 pounds per square inch (psig). Since distribution systems operate at pressure through relatively small diameter pipes there is essentially no line-pack capability for managing hourly demand fluctuations.

Core demand typically has a morning peaking period between 6 a.m. and 10 a.m. and an evening peaking period between 5 p.m. and 9 pm. The peak hour demand for these customers can be as much as 50% above the hourly average of the daily demand. Because of the importance of responding to hourly peaking in the distribution system, planning capacity requirements for our distribution systems are based on peak hour demand[2]. Included in Appendix 8.1 is the detailed methodology we use for determining peak demand.

DISTRIBUTION SYSTEM ENHANCEMENTS

Computer-aided demand studies facilitate modeling numerous "what if" demand forecasting scenarios, constraint identification and corresponding optimum combination of pipe modification and pressure modification solutions to maintain adequate pressures throughout the network over time.

Distribution system enhancements do not reduce demand nor do they create additional supply. However, they can increase the overall capacity of a distribution pipeline system while utilizing existing gate station supply points. The three broad categories of distribution enhancement solutions are pipelines, regulators and compression.

PIPELINES

Pipeline solutions consist of looping, upsizing and uprating.

- **PIPELINE LOOPING** is the most common method of increasing capacity within an existing distribution system. It involves constructing new pipe parallel to an existing pipeline that has, or may become, a constraint point. Constraint points inhibit pressure capacities downstream of the constraint creating inadequate pressure during periods of high demand. When the parallel line is connected to the system this second alternative path allows natural gas flow to bypass the original constraint point and bolster downstream pressure capacities. The feasibility of looping a pipeline is primarily dependent upon the location where the pipeline will be constructed. Installing gas pipelines through private easements, residential areas, existing asphalt and steep or rocky terrain can greatly increase the cost to amounts that are unjustifiable so that other alternative solutions offer a more cost effective solution.
- **PIPELINE UPSIZING** is simply replacing existing pipe with a larger size pipe. The increased pipe capacity relative to surface area of the pipe results in less friction and therefore a lower pressure drop. This option is usually pursued when there is damaged pipe or pipe integrity issues exist. If the existing pipe is otherwise in satisfactory condition looping is usually pursued, allowing the existing pipe to remain in use.
- **PIPELINE UPRATING** involves increasing the maximum allowable operating pressure of an existing pipeline. This enhancement can be a quick and relatively inexpensive method of increasing capacity in the existing distribution system before constructing more costly additional system facilities. However, safety considerations and pipe regulations may prohibit feasibility or lengthen the time before completion of this option. Also, increasing line pressure may produce leaks and other pipeline damage creating unanticipated costly repairs.

REGULATORS

Regulators or regulator stations are used to reduce pipeline pressure at various stages within the distribution. The primary purpose of regulation is to provide a specified and constant outlet pressure before gas continues its downstream travel to a city's distribution system, customer's property or gas appliance. Regulators also ensure that flow requirements are met at a desired pressure regardless of fluctuations upstream of the regulator. Regulators can be found at city gate stations, district regulators stations, farm taps and customer services.

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[2] This method differs from the approach that we use for broader IRP peak demand planning which focuses on peak day requirements to the city gate.

COMPRESSION

Compressor stations present a capacity enhancing option for pipelines with significant gas flow and the ability to operate at higher pressures. For pipelines experiencing a relatively high and constant flow of gas a single, large volume compressor can be installed in the optimal position along the pipeline to boost downstream pressure. However, this type of compressor configuration will not function effectively if the flow in the pipeline has high variability.

A second option is the installation of multiple, smaller compressors located close together or strategically placed in different locations along a pipeline. Multiple compressors accommodate a large flow range and the use of smaller and very reliable compressors. These smaller compressor stations are well suited for areas where gas demand is growing at a relatively slow and steady pace so that purchasing and installing these less expensive compressors can be done over time allowing a pipeline to serve growing customer demand for many years into the future.

Compressors can be a cost effective, feasible option to resolving constraint points; however, regulatory and environmental approvals to install a station along with engineering and construction time can be a significant deterrent. Also, adding compressor stations within a distribution system typically involves considerable capital expenditure. Based on our detailed knowledge of our distribution system, we do not currently envision or have any foreseeable plans to add compressors to our distribution network.

CONSERVATION RESOURCES

Included in our evaluation of distribution system constraints is consideration of targeted conservation resources that could reduce or delay distribution system enhancements. We are mindful; however, that the consumer is still the ultimate decision-maker regarding the purchase of a conservation measure. Because of this we attempt to influence these decisions but we do not depend on estimates of peak day demand reductions from conservation to eliminate near-term distribution system constraint areas. Over longer-term planning we do recognize that targeted conservation programs provide a cumulative benefit that offsets potential constraint areas and may be an effective strategy.

PLANNING RESULTS

Table 8.1 summarizes the cost of major distribution system enhancement projects which address future growth-related system constraints as well as system integrity issues and the anticipated timing of expenditures. These proposed projects are preliminary estimates of timing and costs of reinforcement solutions. The scope and needs of these projects can evolve over time with new information requiring ongoing reassessment. Actual solutions may be different due to differences in actual growth patterns and/or construction conditions from those assumed in the initial assessment.

The following discussion provides further information on our key near-term projects:

3203 - EAST MEDFORD REINFORCEMENT – Observed local growth and our IRP indicate increased gas deliveries will likely be needed from the TransCanada Pipeline source at Phoenix Road Gate Station in southeast Medford. To facilitate distribution receipt of the increased gas volumes, a new HP gas line encircling Medford to the east and tying into an existing high-pressure feeder in White City will improve delivery capacity and provide a much needed reinforcement in the East Medford area which is forecasting higher growth.

3237 – U.S. 2 NORTH SPOKANE REINFORCEMENT – This project will reinforce the area north of Spokane along U.S. Highway 2. This mixed-use area with residential, commercial and industrial demand experiences low pressure at unpredictable times given varied demand profiles of the diverse customer base. Completion of this reinforcement will improve pressures in the U.S. 2 north Kaiser area. Approximately 8,000 feet of HP steel will be installed in a newly established easement along U.S. Highway 2.

3296 – CHASE RD GATE STATION, POST FALLS, ID – This gate station will allow Avista to split the large load at the Rathdrum Gate Station. Approximately 18,000 feet of high-pressure line will be built to connect Chase Rd Gate Station to the existing high pressure. This gate station will also give Avista the opportunity to feed the growing the Post Falls and Coeur d'Alene areas from the north.

Table 8.1 Distribution Planning Capital Projects

				Estimated Budget and Timing					
	Ref #	Title	State	2012	2013	2014	2015	Beyond 2015	Total
	3000	Gas Reinfrc-Minor Blanket	ALL	800,002	1,050,000	1,050,000	1,050,000	1,050,000	5,000,002
	3001	Rep Deteriorating Gas Systems (Non-Aldyl-A)	ALL	800,006	1,000,000	1,000,000	1,000,000	1,000,000	4,800,006
	3002	Reg Reliable - Blanket	ALL	400,006	500,000	500,000	500,000	500,000	2,400,006
	3003	Gas Replc-St&Hwy	ALL	2,200,007	2,250,000	2,250,000	2,250,000	2,250,000	11,200,007
	3004	Cath Prot-Minor Blanket	ALL	500,003	500,000	500,000	500,000	500,000	2,500,003
	3005	Gas Dist Non-Rev Blanket	ALL	3,823,013	3,937,703	4,055,834	4,177,510	4,302,835	20,296,895
	3006	Overbuild Pipe Replacement	ALL	500,002	500,000	500,000	500,000	500,000	2,500,002
	3007	Isolated Steel Pipe Replacement, Various Locations	ALL	1,095,004	990,000	1,000,000	1,000,000	1,000,000	5,085,004
	3117	Gas Telemetry	ALL	370,801	100,000	100,000			570,801
	3296	Upgrade - YZ Odorizers, Various Locations (6ea.)	ALL	150,000					150,000
*	3246	Chase Rd Gate Station, Post Falls, ID	ID		2,100,000	2,164,000			4,264,000
	3275	Upgrade - Coeur d'Alene East Tap Upgrade, Coeur d'Alene, ID	ID						
	3279	Reinforcement - HP Main Extension south from CDA East Gate, CDA ID	ID						
	3292	Reinforcement - Sprit lake HP Main, Athol ID	ID						
	3297	Hwy 95 Relocation, CDA ID	ID	3,000,000					3,000,000
	3298	Old Hwy 95 Relocation, CDA ID	ID	1,250,000					1,250,000
	TBD	Post Falls HP Extension	ID			2,000,000	3,000,000	3,000,000	8,000,000
*	3203	East Medford	OR	550,000		4,100,000			4,650,000
	3242	Reinforce Talent OR Gate Station&Piping	OR						
	3257	Oakland Bridge Bore and Relocation, Oakland OR	OR	181,000					181,000
	3274	Reinforcement, Loop the existing 6" HP from Tolo to White City	OR						
	3112	Re-Rte Kettle Falls Feed & Gate Station	WA						
*	3237	US2 N Spo Gas HP Reinforce(Kaiser Prop)	WA		1,300,000				1,300,000
	3245	Cheney 8" HP Feeder Project	WA						
	3264	Appleway to Henry Reinforcement, Spokane Valley WA	WA						
*	Details of project described in IRP			**14,819,842**	**13,177,703**	**18,169,834**	**12,927,510**	**13,052,835**	**72,147,724**

‖ CONCLUSION

Avista's goal is to maintain its distribution systems reliably and cost effectively to deliver natural gas to every customer. This goal can be achieved with computer modeling, which increases the reliability of the distribution system by identifying specific areas within the system that may require changes.

The ability to meet our goal of reliable cost effective gas delivery is also enhanced through the recent integration of customer growth forecasting at the town code level and localized distribution planning enabling coordinated targeting of distribution projects that are responsive to detailed customer growth patterns.

CHAPTER 9 ‖ ACTION PLAN

2010-2011 ACTION PLAN REVIEW

The 2010-2011 Action Plan focused on the following areas:

- Integrated Resource Portfolio
- Demand Forecasting
- Demand-Side Management
- Supply-Side Resources

A discussion of the specific action items and the plan results follows.

ACTION ITEM

Monitor actual demand closely for indications of faster growth exceeding our forecasted growth to respond aggressively to address potential accelerated resource deficiencies arising from our exposure to "flat demand" risk. This includes researching and refining the evaluation of resource alternatives, including implementation risk factors and timelines, updated cost estimates and feasibility assessments targeting options for the service territories with nearer-term unserved demand exposure.

RESULTS

We continue to monitor demand and compare actual results to IRP forecasted demand. Trends so far indicate slower than anticipated customer growth and continued declines in weather normalized use-per-customer, which has delayed the need for resource acquisitions.

ACTION ITEM

Analyze actual use-per-customer data and DSM program results for indications of price elasticity response trends that may have been influenced by evolving economic conditions. Investigate contemporary analytical sources for information on natural gas price elasticity. Explore persuading the AGA to update their analytical work and/or consider hiring a third-party price elasticity study including assessing interest of other utilities in pursuing a regional project.

RESULTS

As part of our reconciliation of forecasted demand to actual demand we analyze weather normalized use – per customer. While rates have remained relatively stable over the last few years, customers have decreased their overall usage. Trying economic times, successful adoption of demand-side management initiatives and appliance and building code efficiencies have contributed to the lower use per customer. Long run price elasticity does not change much over time; however we did approach the AGA to update their analytic work. Like man, the AGA was managing a tight budget and did not have the dollars to undertake an updated study.

ACTION ITEM

Continue our pursuit of cost effective demand-side solutions to reduce demand. In Washington and Idaho conservation measures are targeted to reduce demand by approximately 2,193,000 therms in the first year. In Oregon conservation measures are targeted to reduce demand by approximately 303,000 therms in the first year. These goals represent increases of 54 percent in Washington and Idaho and 1 percent in Oregon from our prior 2007 IRP.

RESULTS

Avista actively pursues cost-effective demand-side management solutions to reduce demand. In 2010 and 2011 Washington and Idaho conservation measures reduced demand by approximately 1,850,000 therms and 1,730,000 therms. In Oregon demand was reduced by 312,000 therms and 313,000 therms.

ACTION ITEM

Research and engage a conservation consultant to perform an updated assessment of conservation technical and achievable potential in our service territories prior to the next IRP.

RESULTS

Global Energy Partners performed a conservation potential assessment for Avista's natural gas and electric demand-side management programs. Results from this analysis were used in the 2012 Natural Gas IRP and a copy of the assessment is included in Appendix 4.1.

ACTION ITEM

Continue to monitor the discussion around diminishing Canadian gas exports looking for signals that indicate increased risk of disrupted supply over the 20-year planning horizon. Since much of our supply comes from Canadian natural gas exports the notion that this supply could diminish significantly remains a concern.

RESULTS

During the 2009 IRP supplies available for import into the United States were showing signs of decline. Since then the supply picture for North America has changed dramatically. The widespread availability of shale gas throughout the U.S. and Canada has greatly reduced the concern that supplies will diminish.

ACTION ITEM

Explore and evaluate alternative and additional forecasting methodologies for potential inclusion in our next IRP. Methodologies to be evaluated include statistical, non-statistical, quantitative, qualitative and terrain overview approaches.

RESULTS

We continue to believe our forecasting methodology is sound, cost effective and adequate; however we have explored several alternative forecasting methodologies for possible consideration in our IRP planning. Our methodology allows the ability to vary the results of our statistical inputs by considering both qualitative and quantitative factors. These factors can be derived from data or surveys of market information, fundamental forecasters, and industry experts. We are always open to new methods of forecasting demand and are assessing which, if any, alternative methodologies to include in future IRPs.

❚❚ ACTION ITEM

Meet regularly with Commission Staff members to provide information on market activities, material changes to risk management programs, and significant changes in assumptions and/or status of company activity related to the IRP or procurement practices.

❚❚ RESULTS

We have met and will continue to meet no less than biannually with Commission Staff members to provide updates on market fundamentals, procurement planning initiatives, changes to risk management programs, and significant changes of assumptions related to the IRP.

2013-2014 ACTION PLAN

Since our 2009 IRP customer growth has slowed and it is not anticipated to rebound in the near term. We have also seen use per customer reductions as customers have become more household budget conscience, changed usage behavior, and over the last few years have invested in conservation measures. These factors have reduced overall and peak day demand when compared to our 2009 IRP.

Based on the analysis conducted for the 2012 IRP, under our Expected Case, we do not anticipate the need to acquire additional supply side resources in the next two to three years. Furthermore, even our most aggressive High Growth/Low Price scenario did not indicate supply side needs within the next few years. The Average, Alternate Planning Standard, and Low Growth/High Price scenarios do not indicate any resource deficiencies within the planning horizon. We will actively monitor our demand looking for indications of deviations away from our Expected Case.

The demand forecast was not the only thing that changed dramatically. The price of natural gas has dropped significantly since our last IRP. Robust North American supplies lead by shale gas developments coupled with lackluster demand due to the economy has pushed prices down to levels not seen in the last decade. These low prices, while good for our customers, challenge the cost-effectiveness of DSM at the program level. Since the drafting of this document, Avista has filed in Washington and Idaho to suspend natural gas DSM programs and is currently evaluating programs in Oregon.

Over the next two to three years, Avista will be watching natural gas prices as a sign post for the cost-effectiveness of DSM programs. Should prices move significantly Avista will again be proactive in seeking to reinstate a full complement of our natural gas DSM programs.

Continued enhancement of our gate station analysis will also be completed to assess if there are individual gate station deficiencies that are masked by our aggregated IRP analysis. Should any deficiencies be identified we will discuss findings and potential solutions with Commission Staff. We will continue to coordinate analytic efforts between Gas Supply, Gas Engineering, and the intrastate pipelines to perform gate station analysis and if deficiencies are identified seek least cost solutions.

❚❚ ONGOING ACTION ITEMS

- Monitor actual demand for indications of growth exceeding our forecast to respond aggressively to address potential accelerated resource deficiencies arising from exposure to “flat demand” risk. This will include providing commission staff with IRP demand forecast to actual variance analysis on customer growth and use per customer. This information will be provided in Avista's updates to each commission staff at least biannually.

- Pursue the possibility of a regional elasticity study through the Northwest Gas Association or possibly the American Gas Association.
- Assess potential demand impact from NGV/CNG vehicles and other new uses of natural gas to Avista.
- Continue to monitor supply resource trends including the availability and price of natural gas to the regions, exporting LNG, Canadian natural gas imports and interprovincial consumption, regional plans for gas-fired generation and its affect on pipeline availability, as well as regional pipeline and storage infrastructure plans.
- Monitor new resource lead time requirements relative to when resources are needed to preserve resource option flexibility.
- Regularly meet with Commission Staff members to provide information on market activities and significant changes in assumptions and/or status of Avista activities related to the IRP or natural gas procurement practices.

CHAPTER 10 GLOSSARY OF TERMS AND ACRONYMS

ACHIEVABLE POTENTIAL
Represents a realistic assessment of expected energy savings recognizing and accounting for economic and other constraints that preclude full installation of every identified conservation measure.

AGA
American Gas Association

ANNUAL MEASURES
Conservation measures that achieve generally uniform year round energy savings independent of weather temperature changes. Annual measures are also often called base load measures.

AVISTA
The regulated Operating Division of Avista Corp.; separated into north (Washington and Idaho) and south (Oregon) regions; 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.

BASE LOAD MEASURES
Conservation measures that achieve generally uniform year round energy savings independent of weather temperature changes. Base load measures are also often called annual measures.

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.

CD
Contract Demand

C&I
Commercial and Industrial

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.

CNG
Compressed Natural Gas

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

CONSERVATION MEASURES
Installations of appliances, products or facility upgrades that result in energy savings.

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.

COST EFFECTIVENESS
The determination of whether the present value of the therm savings for any given conservation measure is greater than the cost to achieve the savings.

CPA
Conservation Potential Assessment

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
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 MANAGEMENT (DSM)
The activity pursued by an energy utility to influence its customers to reduce their energy consumption or change their patterns of energy use away from peak consumption periods.

DEMAND-SIDE RESOURCES

Energy resources obtained through assisting customers to reduce their "demand" or use of natural gas. Also represents the aggregate energy savings attained from installation of conservation measures.

DSM

Demand-Side Management

DTH

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

EIA

Energy Information Administration

EXTERNAL ENERGY EFFICIENCY BOARD

Also known as the "Triple-E" board, this non-binding external oversight group was established in 1999 to provide Avista with input on DSM issues.

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.

FERC

Federal Energy Regulatory Commission

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 TRANSMISSION NORTHWEST (GTN)

A subsidiary of TransCanada Pipeline which owns and operates a natural gas pipeline that runs from the Canada/USA border to the Oregon/California border. One of the six natural gas pipelines Avista transacts with directly.

GEOGRAPHIC INFORMATION SYSTEM (GIS)
A system of computer software, hardware and spatially referenced data that allows information to be modeled and analyzed geographically.

GHG
Greenhouse Gas

GLOBAL INSIGHT, INC.
A national economic forecasting company.

GTN
Gas Transmission Northwest

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).

HP
High Pressure

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
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

IRP
Integrated Resource Plan; the document that explains Avista's plans and preparations to maintain sufficient resources to meet customer needs at a reasonable price.

JACKSON PRAIRIE
An underground storage project jointly owned by Avista Corp., Puget Sound Energy, and NWP; the project is a naturally occurring aquifer near Chehalis, Washington, 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 send outs observed that is sorted from highest send out 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 customer's 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.

MCF
A unit of volume equal to a thousand cubic feet.

MDDO
Maximum Daily Delivery Obligation

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
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 York Mercantile Exchange (NYMEX)
An organization that facilitates the trading of several commodities including natural gas.

NGV
Natural Gas Vehicles

NOAA
National Oceanic and Atmospheric Administration

Nominal
Discounting method that includes inflation.

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 peak day and one non-peak 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)
A principal interstate pipeline serving the Pacific Northwest and one of six natural gas pipelines Avista transacts with directly. NWP is a subsidiary of The Williams Companies and is headquartered in Salt Lake City, Utah.

NOVA Gas Transmission (NOVA)
See TransCanada Alberta System

Northwest Power and Conservation Council (NPCC)
A regional energy planning and analysis organization headquartered in Portland, Ore.

NPCC
Northwest Power and Conservation Council

NWP
Williams-Northwest Pipeline

NYMEX
New York Mercantile Exchange

OPUC
Oregon Public Utility Commission

PEAK DAY
The greatest total natural gas demand forecasted in a 24-hour period used as a basis for planning peak capacity requirements.

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.

PRESCRIPTIVE MEASURES
Avista's DSM tariffs require the application of a formula to determine customer incentives for natural gas-efficiency projects. For commonly encountered efficiency applications that are relatively uniform in their characteristics the utility has the option to define a standardized incentive based upon the typical application of the efficiency measure. This standardized incentive takes the place of a customized calculation for each individual customer. This streamlining reduces both the utility and customer administrative costs of program participation and enhances the marketability of the program.

PSIG
Pounds per square inch gauge – a measure of the pressure at which natural gas is delivered.

PVRR
Present Value Revenue Requirement

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.

REAL
Discounting method that excludes inflation.

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 Ventyx; 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.

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.

TAC
Technical Advisory Committee

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.

Technical Potential
An estimate of all energy savings that could theoretically be accomplished if every customer that could potentially install a conservation measure did so without consideration of market barriers such as cost and customer awareness.

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.

TOWN CODE

A town code is an unincorporated area within a county and a municipality within a county served by Avista natural gas retail services.

TRANSCANADA ALBERTA SYSTEM

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 transacts with directly.

TRANSCANADA BC SYSTEM

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 United States border; one of six natural gas pipelines Avista transacts 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.

TRC

Total Resource Cost

TRIPLE E

External Energy Efficiency Board

TUSCARORA GAS TRANSMISSION COMPANY

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

VAPORIZATION

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

WCSB

Western Canadian Sedimentary Basin

WEIGHTED AVERAGE COST OF GAS (WACOG)

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.

WEATHER SENSITIVE MEASURES

Conservation measures whose energy savings are influenced by weather temperature changes. Weather sensitive measures are also often referred to as winter measures.

WINTER MEASURES

Conservation measures whose energy savings are influenced by weather temperature changes. Winter measures are also often referred to as weather sensitive measures.

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