2012 Natural Gas Integrated Resource Plan

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www.avistautilities.com

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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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II 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 II 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.

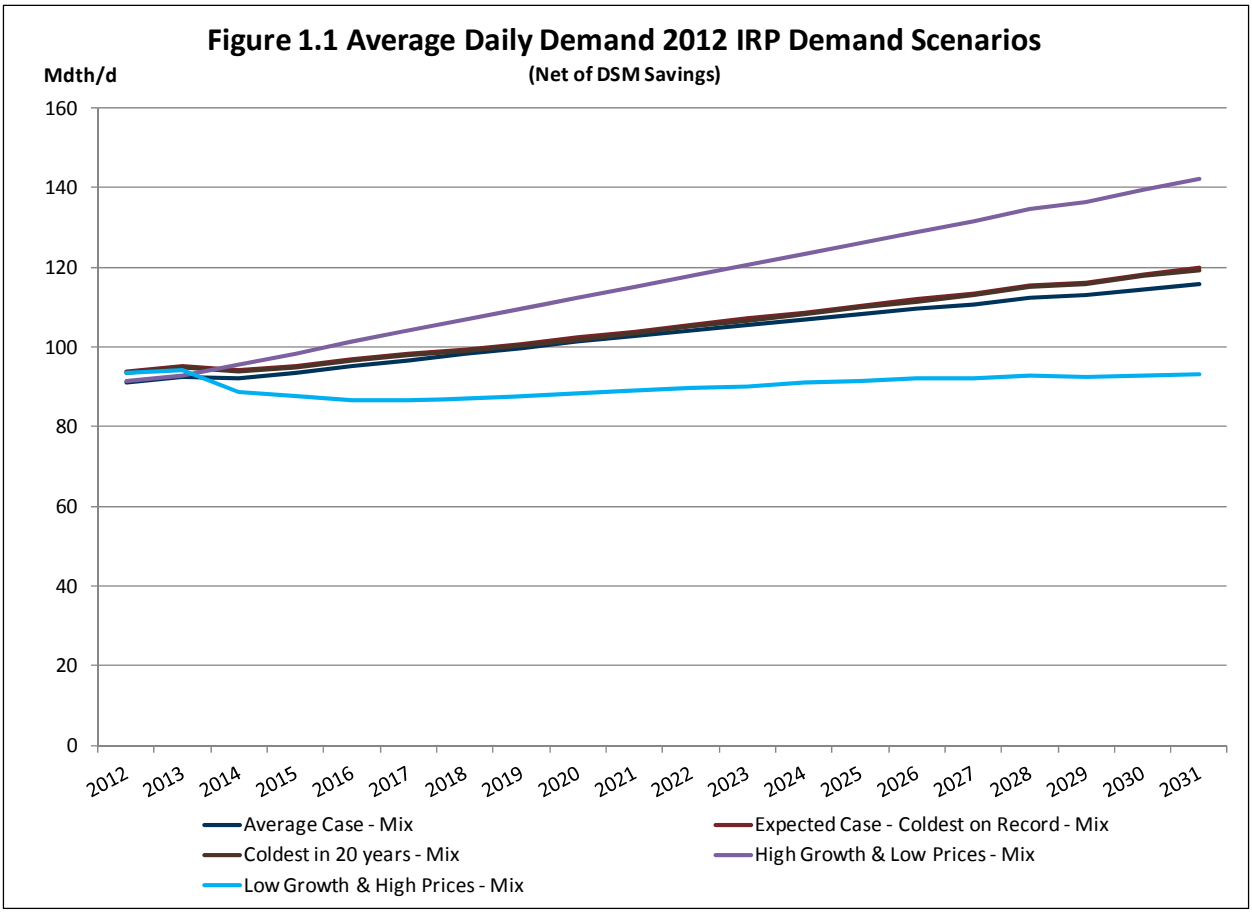
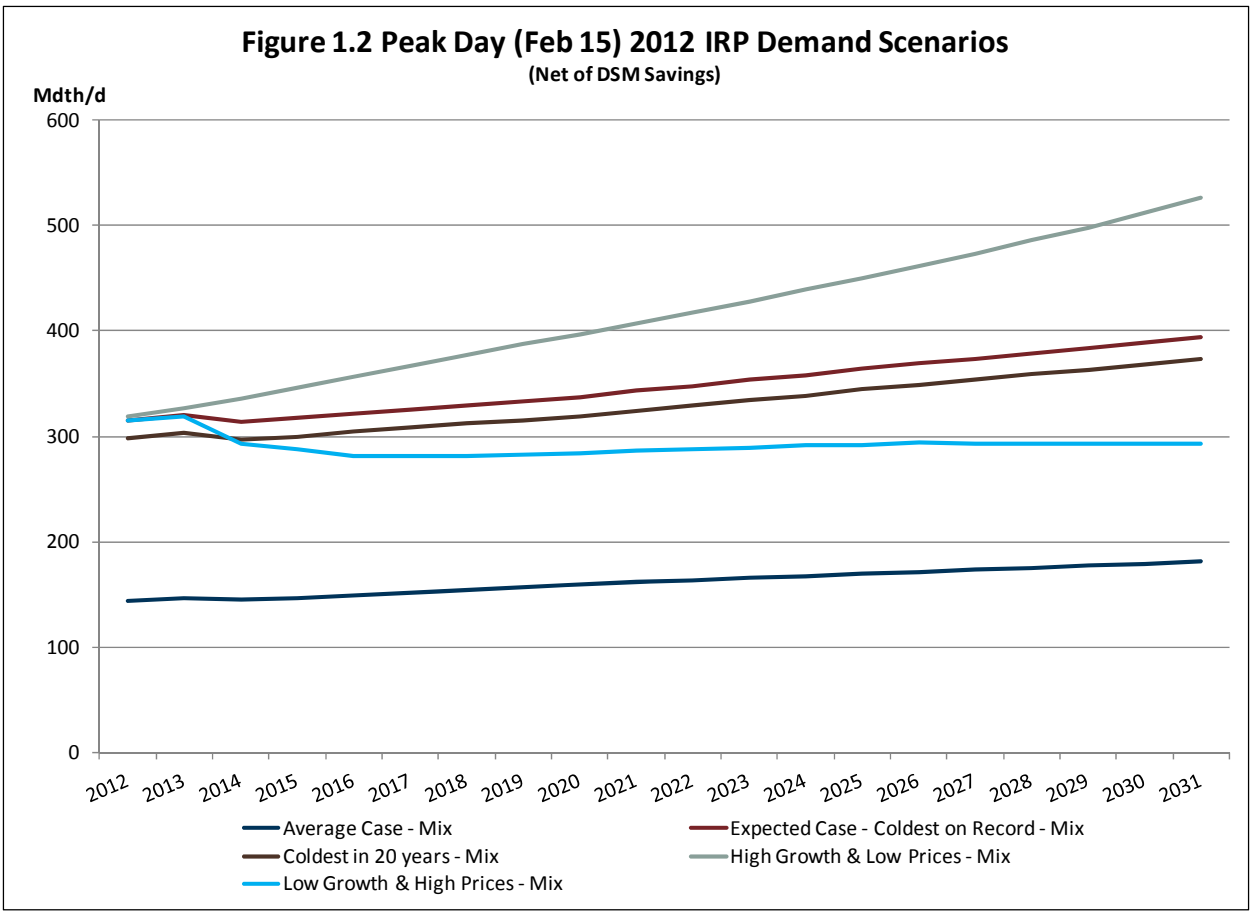


Figure 1.2 shows forecasted system-wide **peak day demand** for the five main demand scenarios modeled over the planning horizon.

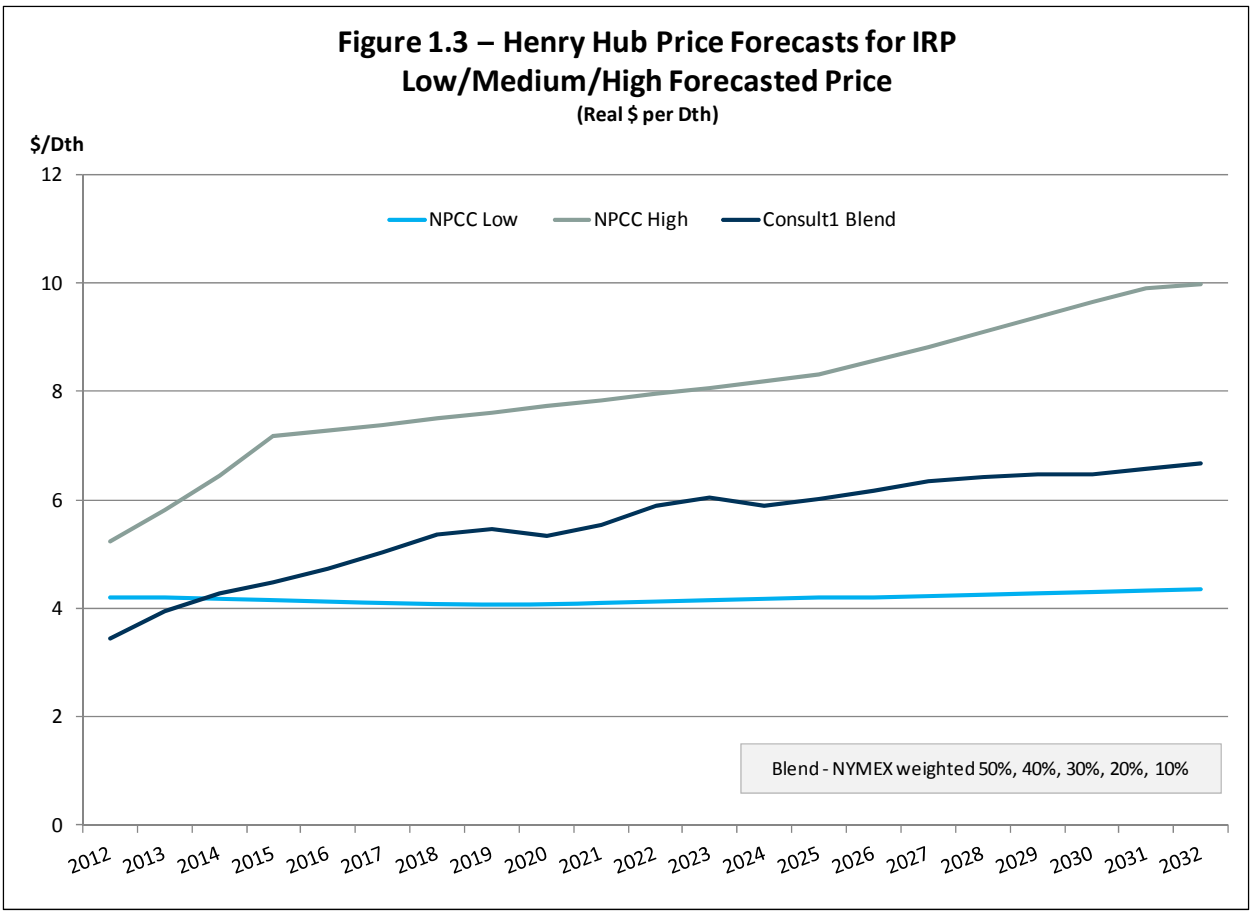


NATURAL GAS PRICE FORECASTS

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.



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

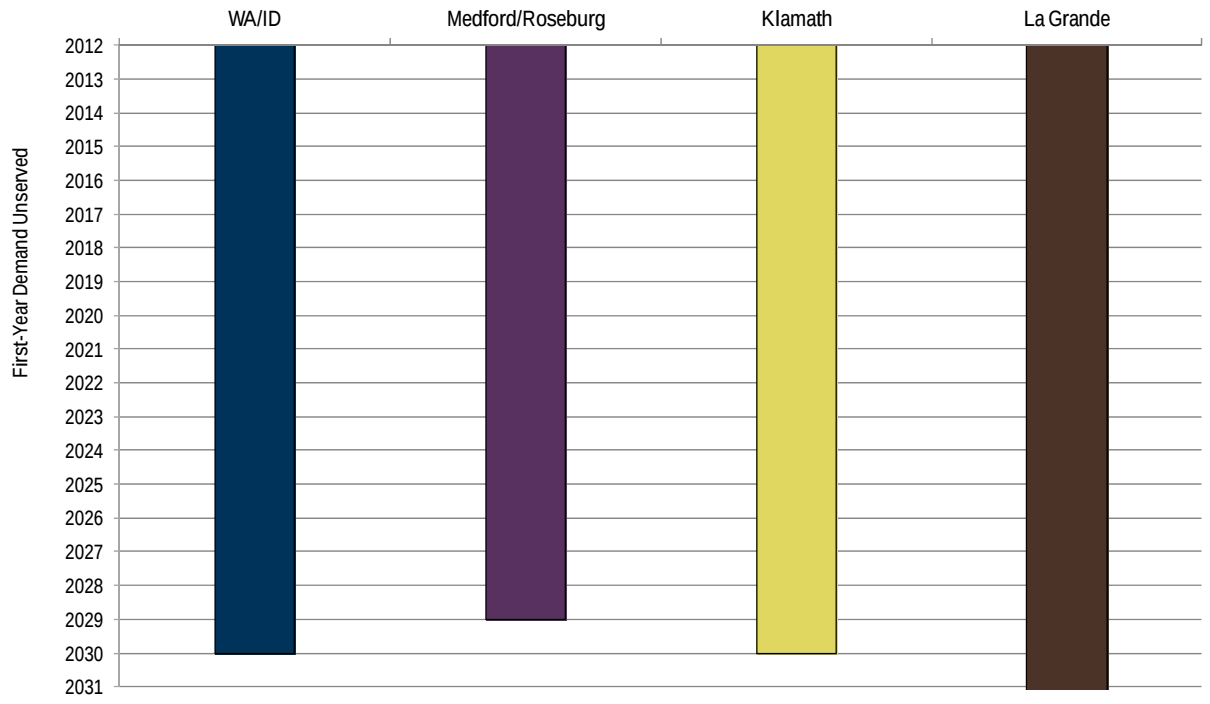
Avista has a diversified portfolio of natural gas supply resources, including contracts to purchase natural gas from several supply basins; owned and contracted storage providing flexibility of supply sources; and firm capacity rights on six pipelines diversifies delivery of supply to our service territory 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.

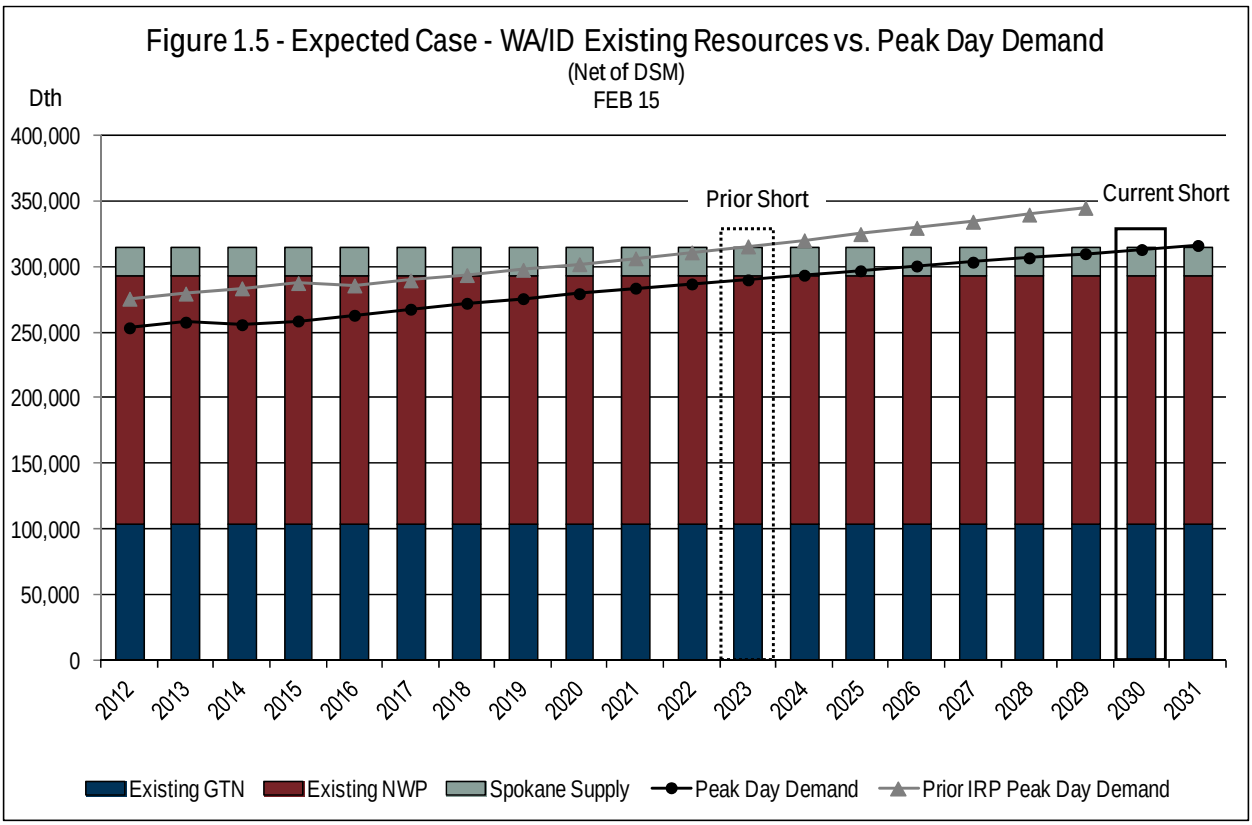


Figure 1.5 - Expected Case - WA/ID Existing Resources vs. Peak Day Demand
(Net of DSM)
FEB 15
Dth
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
Prior Short
Current Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Existing GTN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

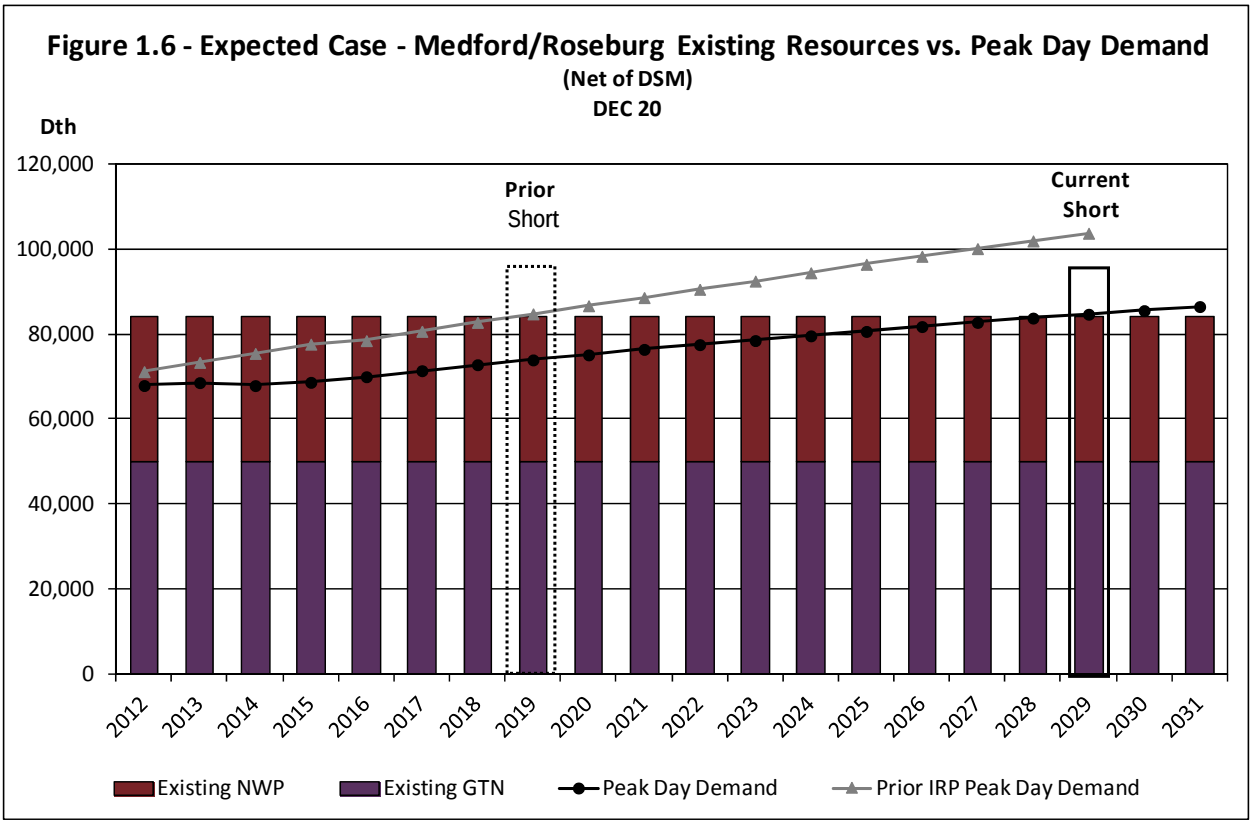


Figure 1.6 - Expected Case - Medford/Roseburg Existing Resources vs. Peak Day Demand
(Net of DSM)
DEC 20
Dth
120,000
100,000
80,000
60,000
40,000
20,000
0
Prior
Short
Current
Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Existing NWP
Existing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

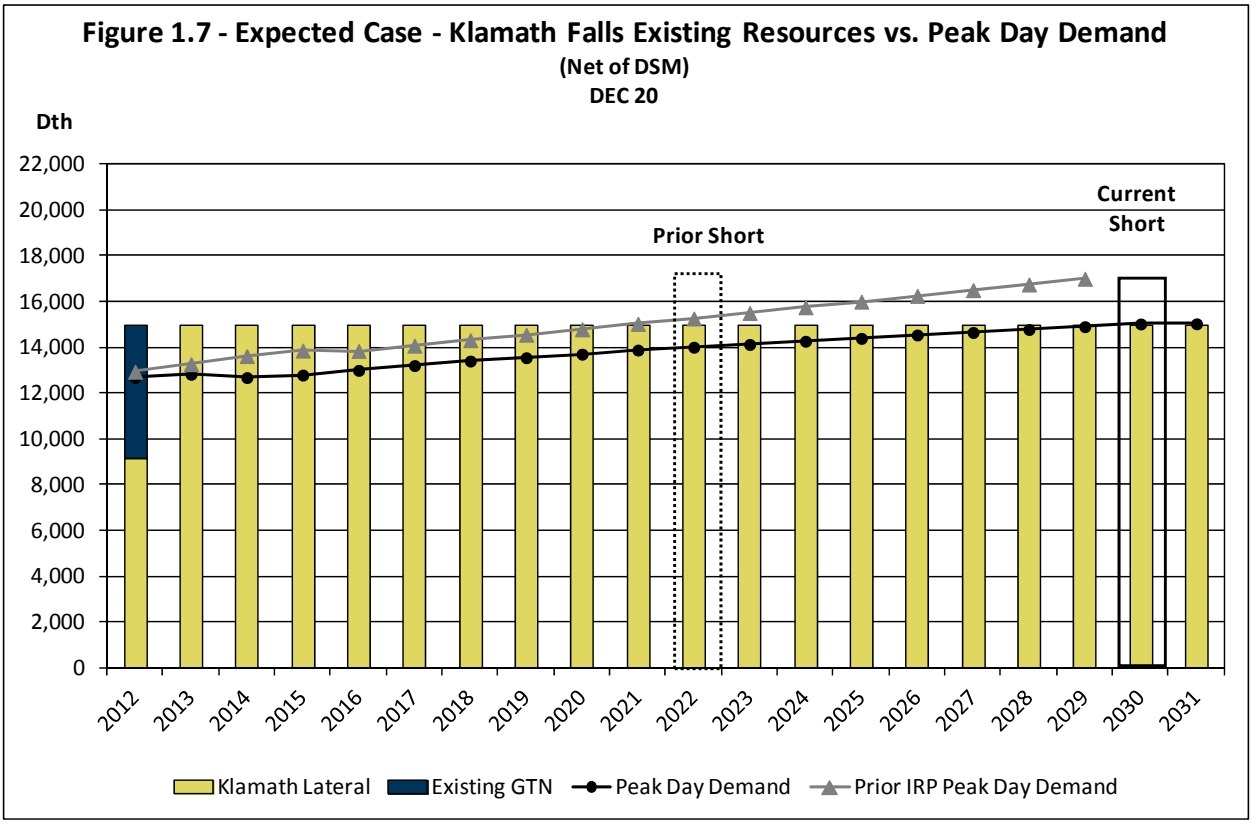


Figure 1.7 - Expected Case - Klamath Falls Existing Resources vs. Peak Day Demand
(Net of DSM)
DEC 20
Dth
22,000
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
Current Short
Prior Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030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

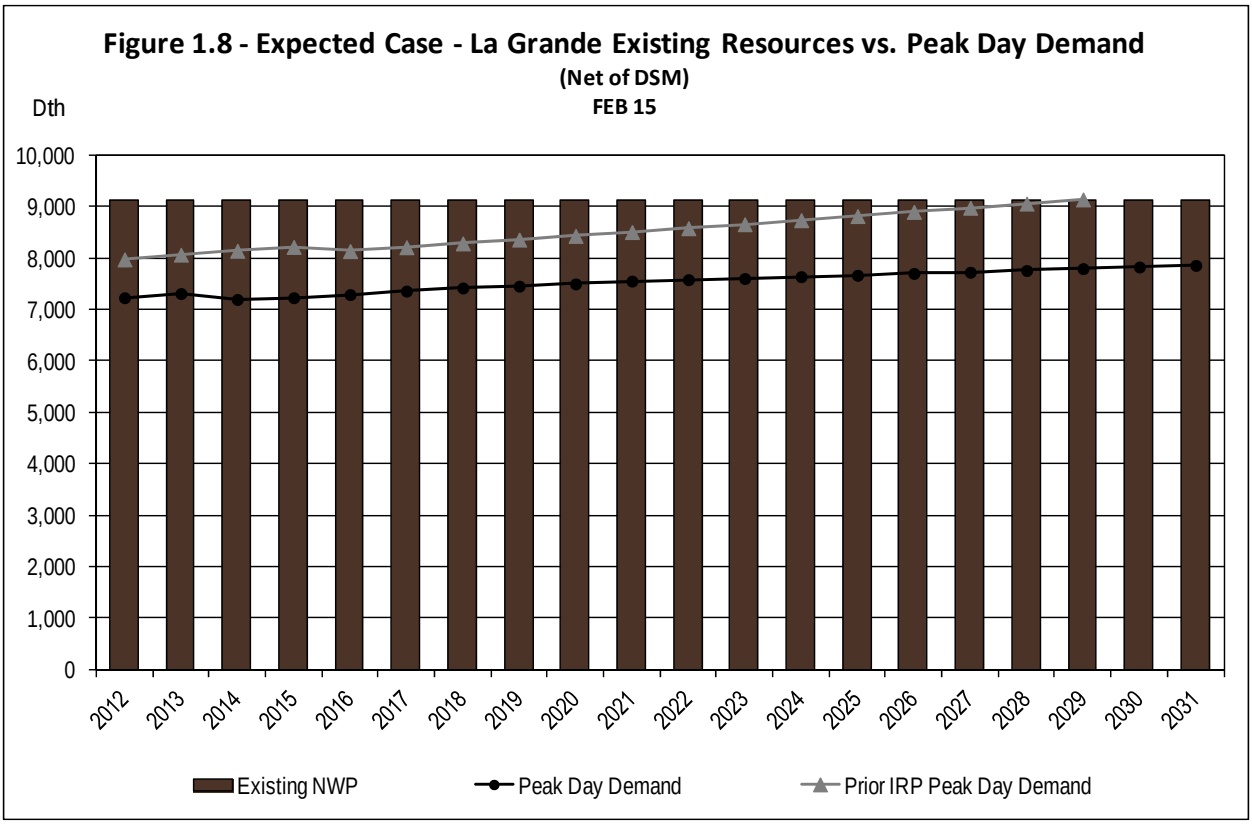
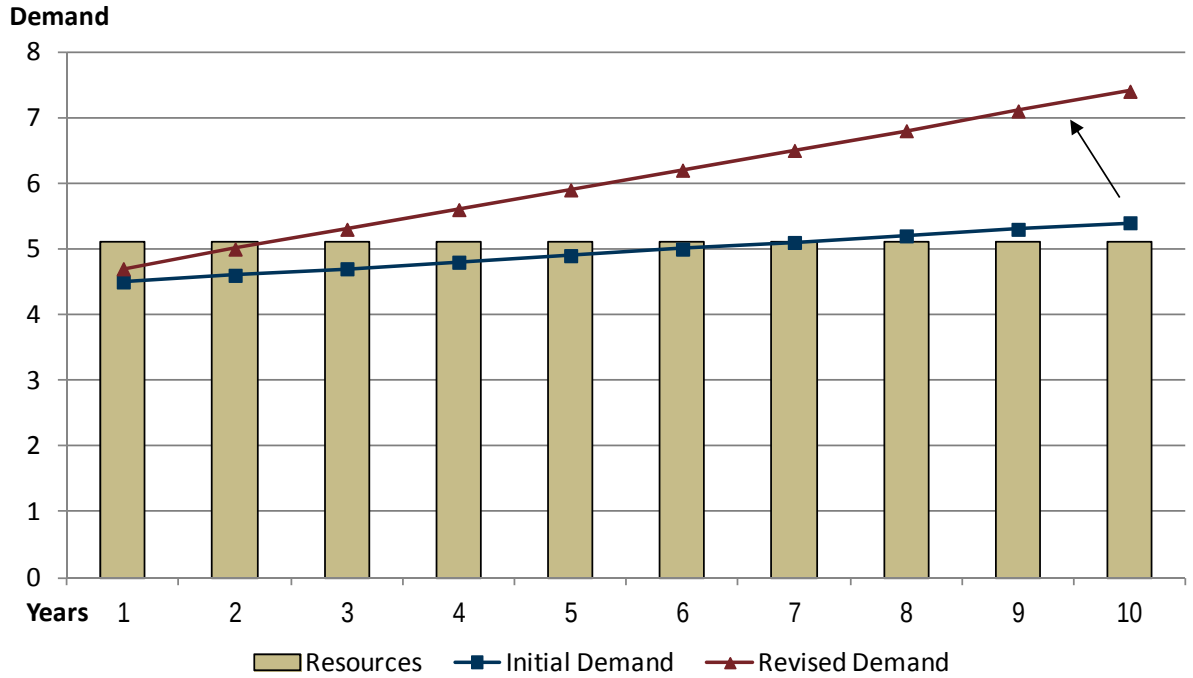


Figure 1.8 - Expected Case - La Grande Existing Resources vs. Peak Day Demand
(Net of DSM)
FEB 15
Dth
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Existing NWP
Peak Day Demand
Prior IRP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

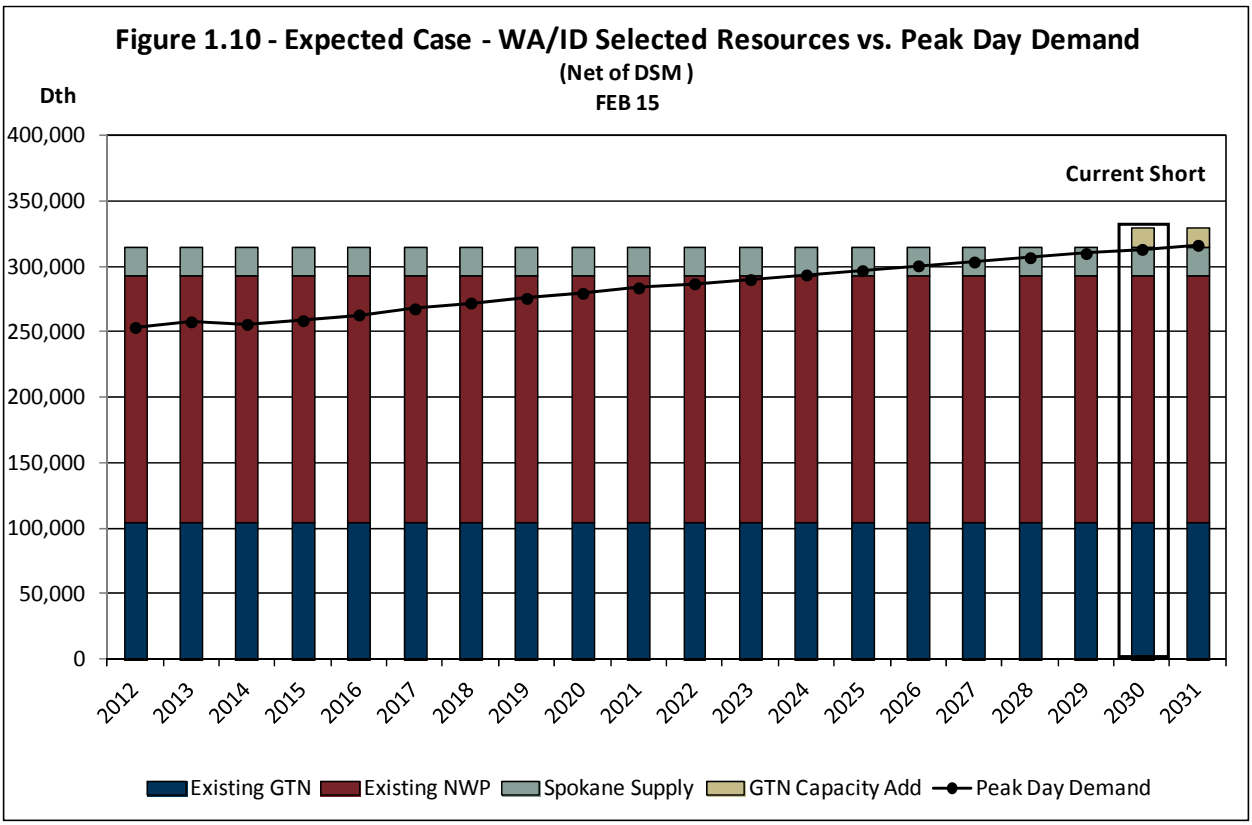


Figure 1.10 - Expected Case - WA/ID Selected Resources vs. Peak Day Demand
(Net of DSM)
FEB 15
Dth
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
Current Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Existing GTN
Existing NWP
Spokane Supply
GTN Capacity Add
Peak Day Demand

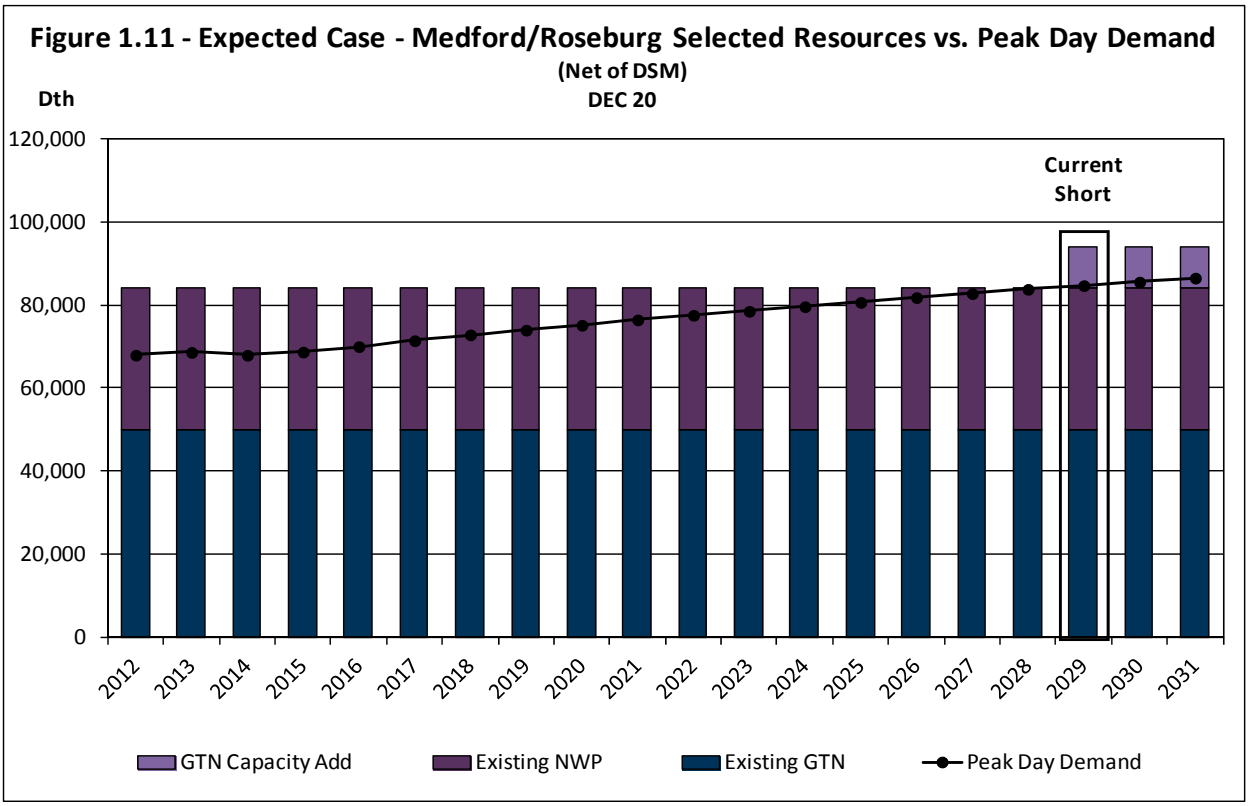
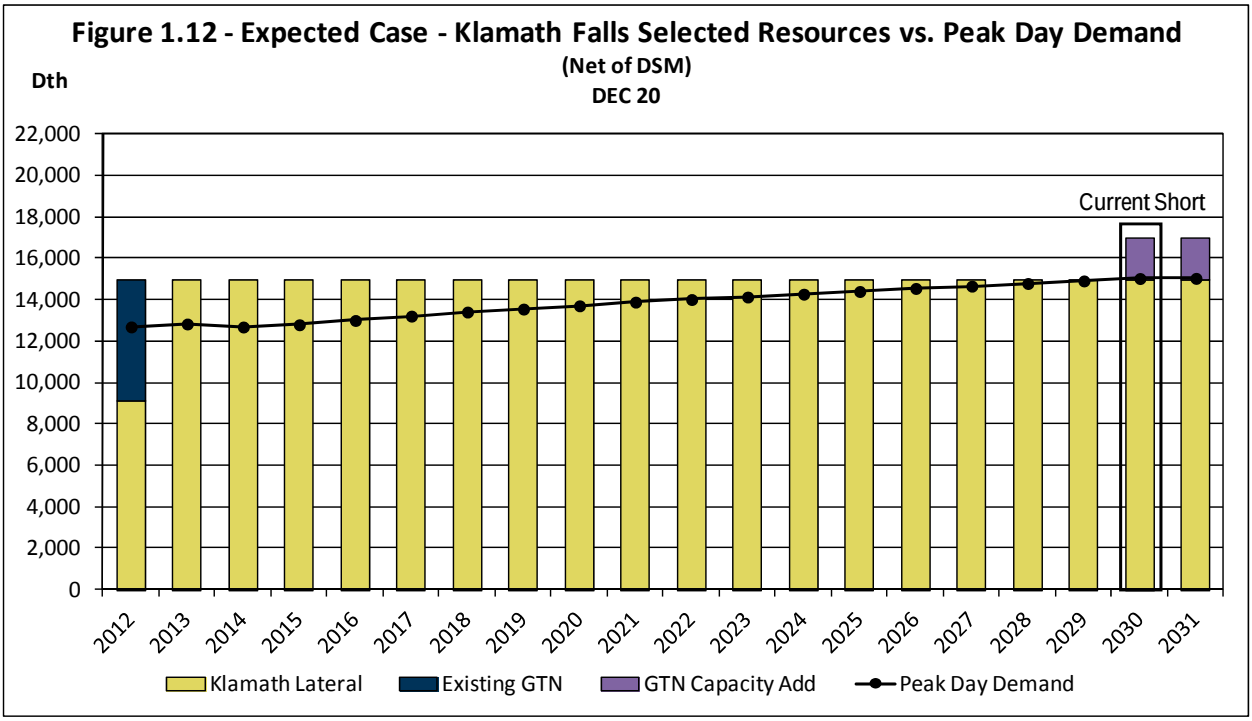


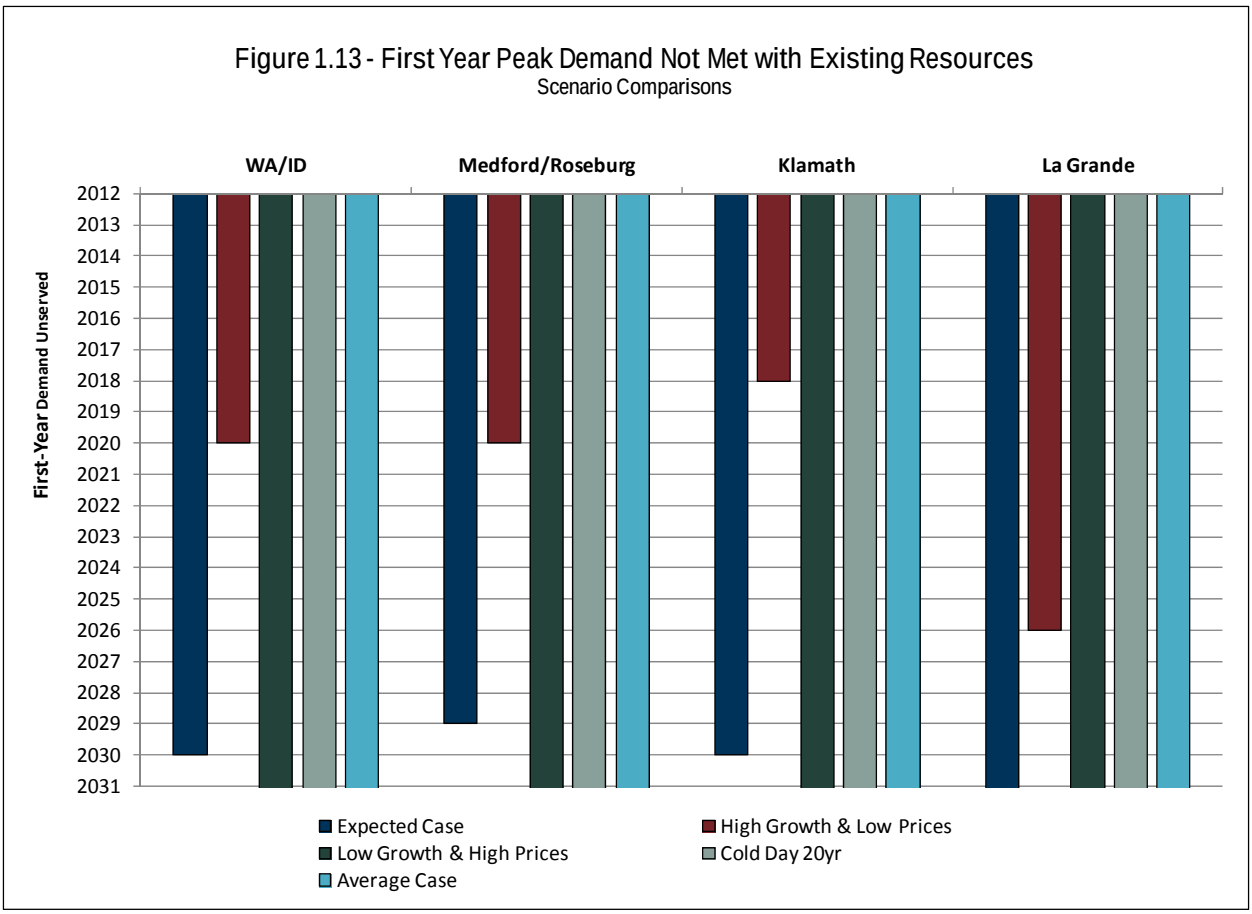
Figure 1.11 - Expected Case - Medford/Roseburg Selected Resources vs. Peak Day Demand
(Net of DSM)
DEC 20
Dth
120,000
100,000
80,000
60,000
40,000
20,000
0
Current
Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
GTN Capacity Add
Existing NWP
Existing 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 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.



II 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.

II 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.

II 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.

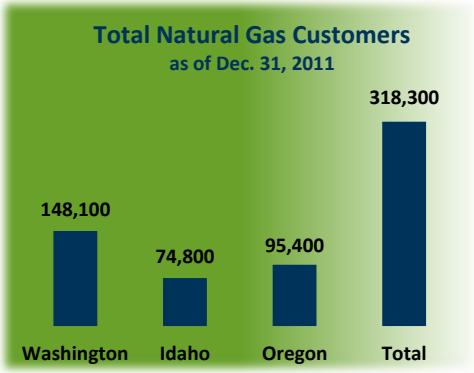
CHAPTER 2 II INTRODUCTION

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.

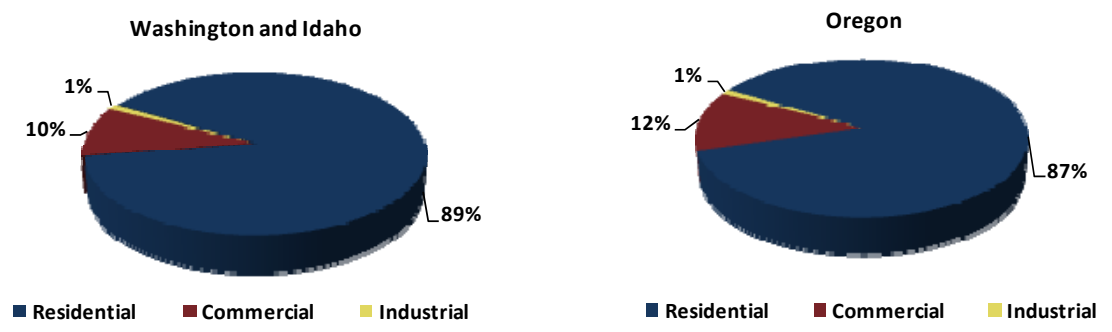
OUR CUSTOMERS

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.

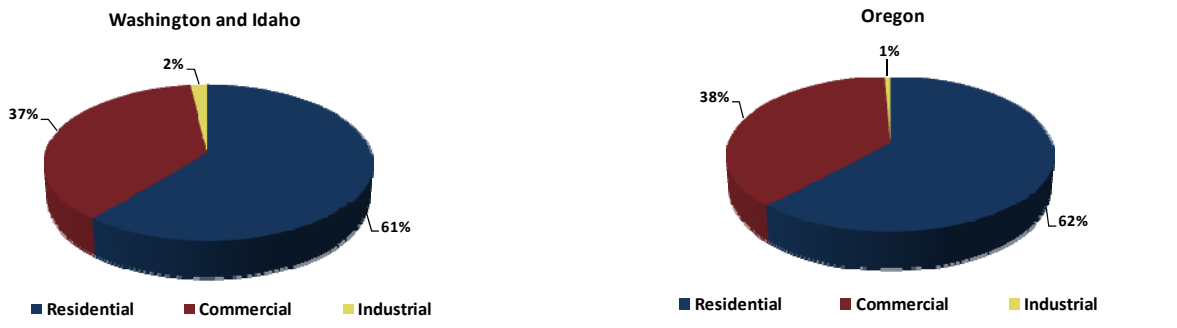
Our core or retail customers are further divided into three categories – residential, commercial and industrial. Most of our customers are residential, followed by commercial. Relatively few are industrial accounts (Figure 2.1).

Figure 2.1 Firm Customer Mix



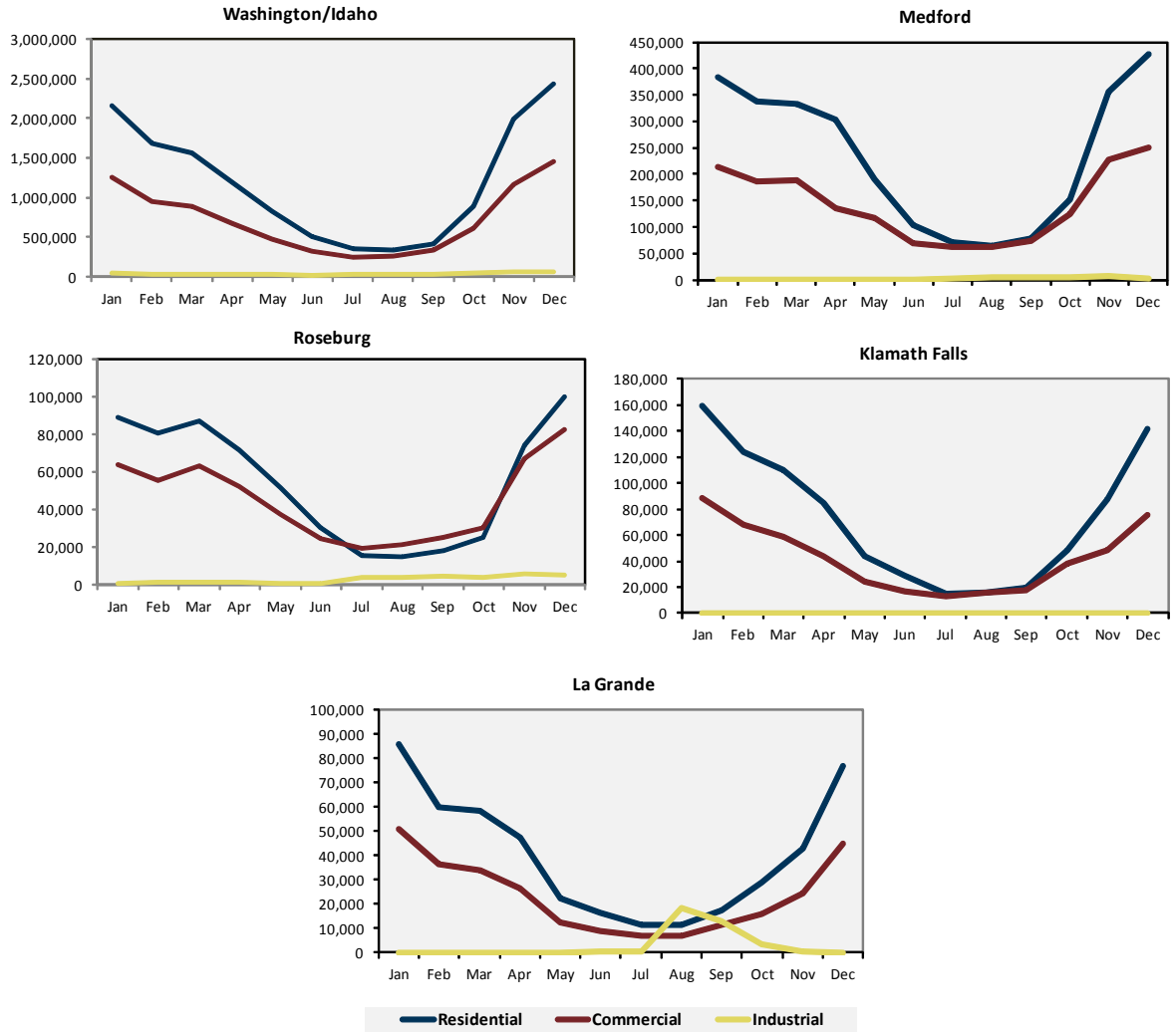
The mix is more balanced between residential and commercial accounts on an annual volume basis (Figure 2.2). Volume consumed by core industrial customers is not significant to the total, partly because most industrial customers in our service territories are transportation only customers.

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.

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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.”

II 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

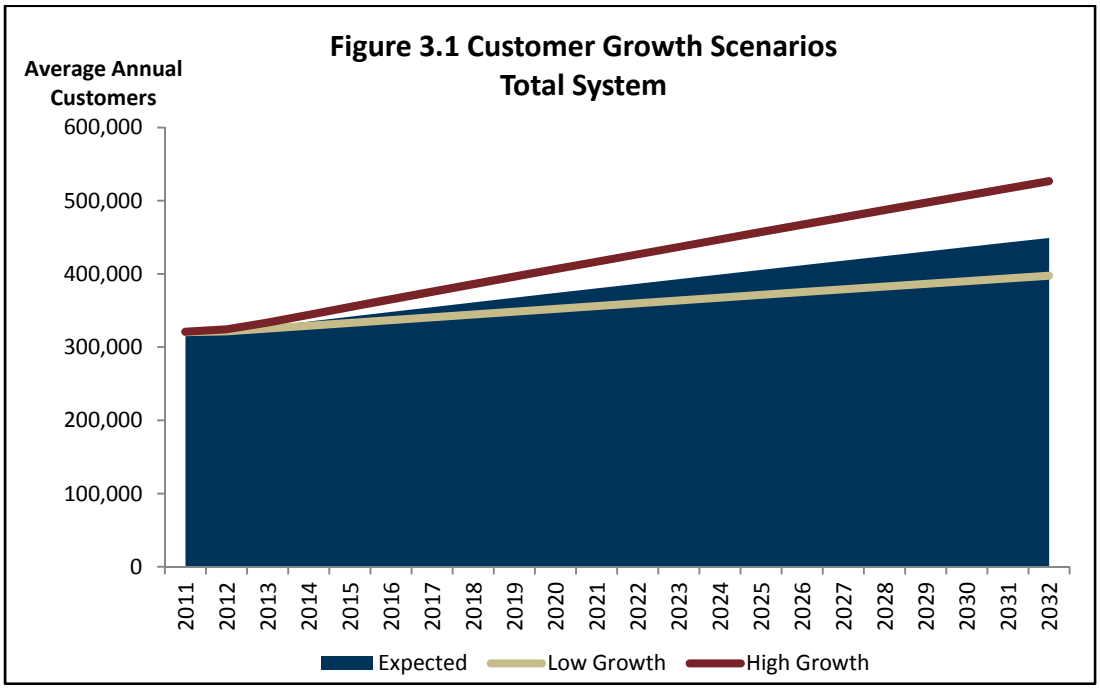
Avista's customer base is segregated into three categories: residential, commercial and industrial. For each of the customer categories we develop our customer forecasts by starting with national economic forecasts and then drilling down into regional economies. Population growth expectations and employment 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).

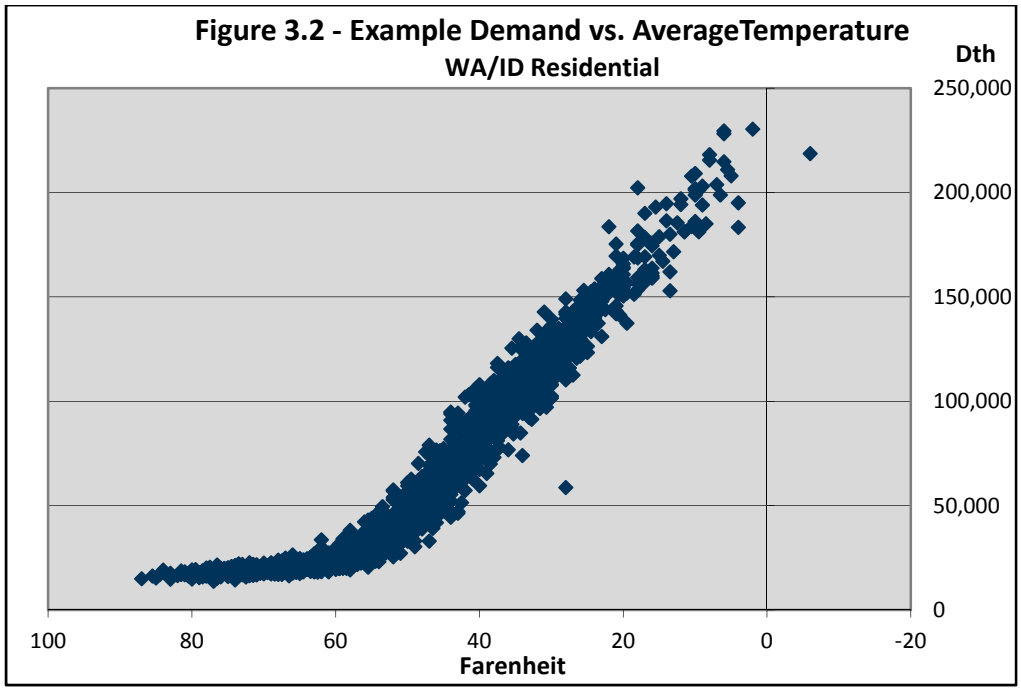
Forecasting customer growth is an inexact science so it is important to consider alternative forecasts. Two alternative growth forecasts were developed for consideration in this IRP. In past IRPs we have used 25 years of historical growth rates to derive our low and high growth sensitivities. This historical 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.



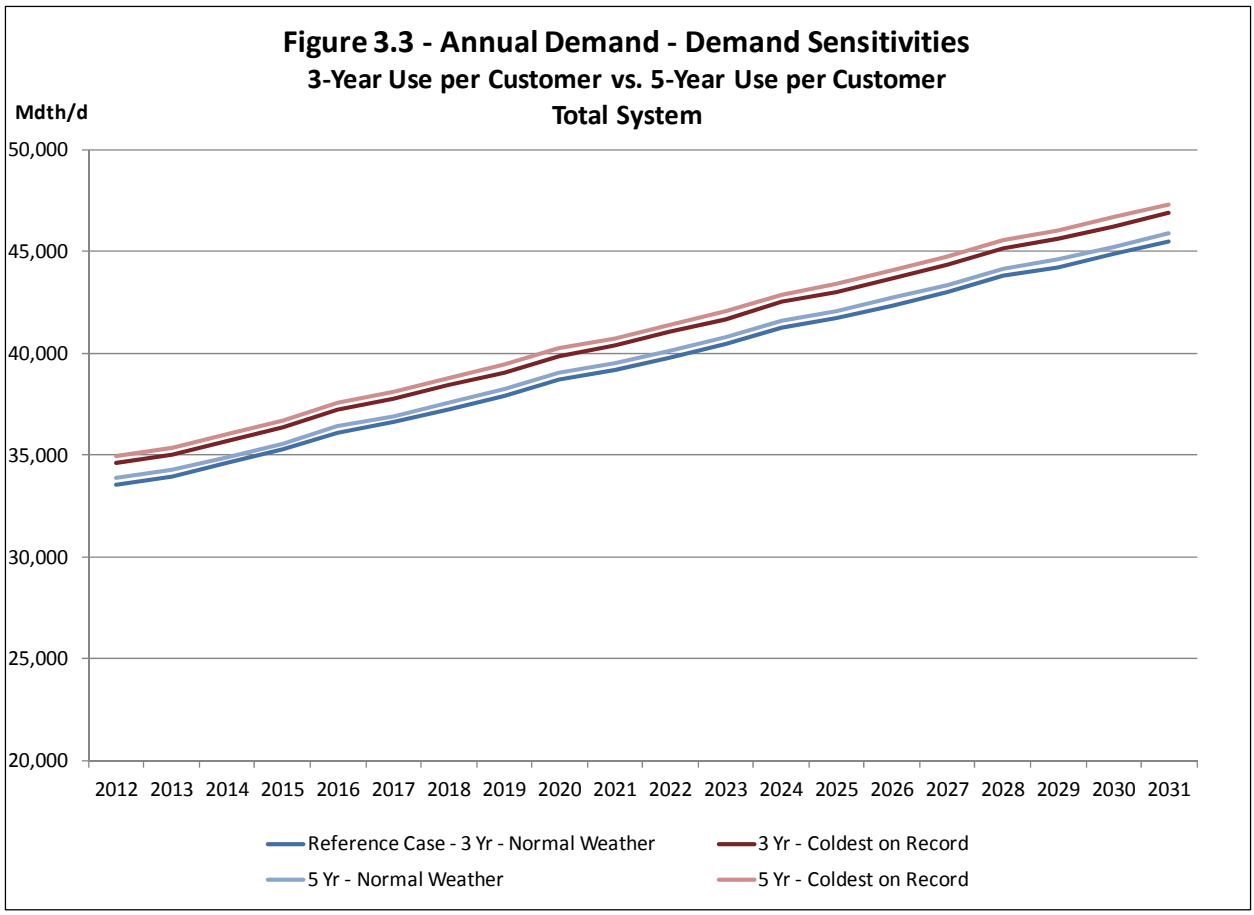
USE-PER-CUSTOMER FORECAST

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

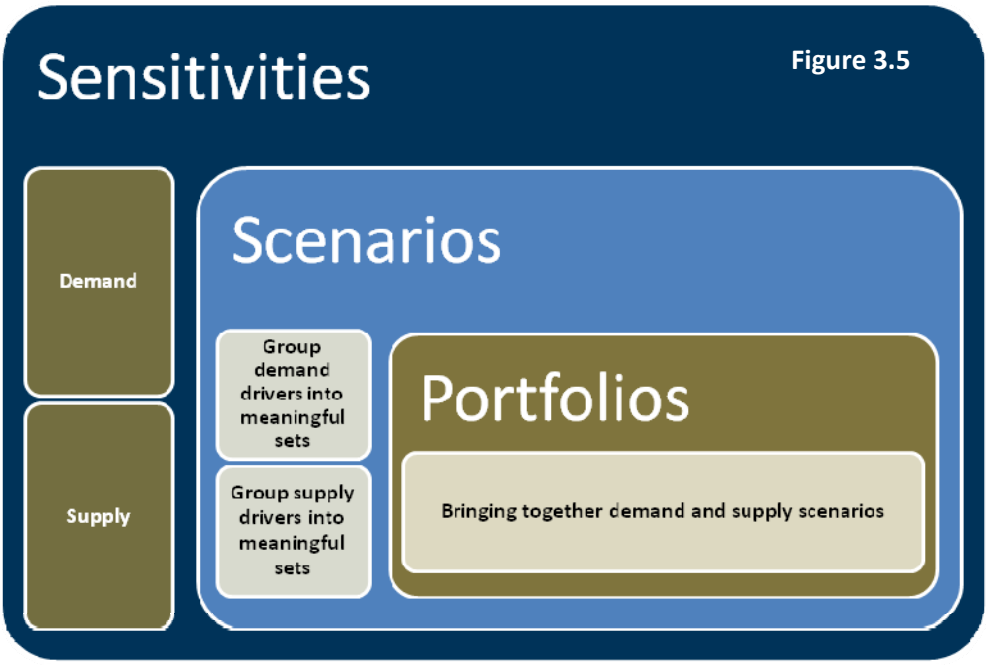
None

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

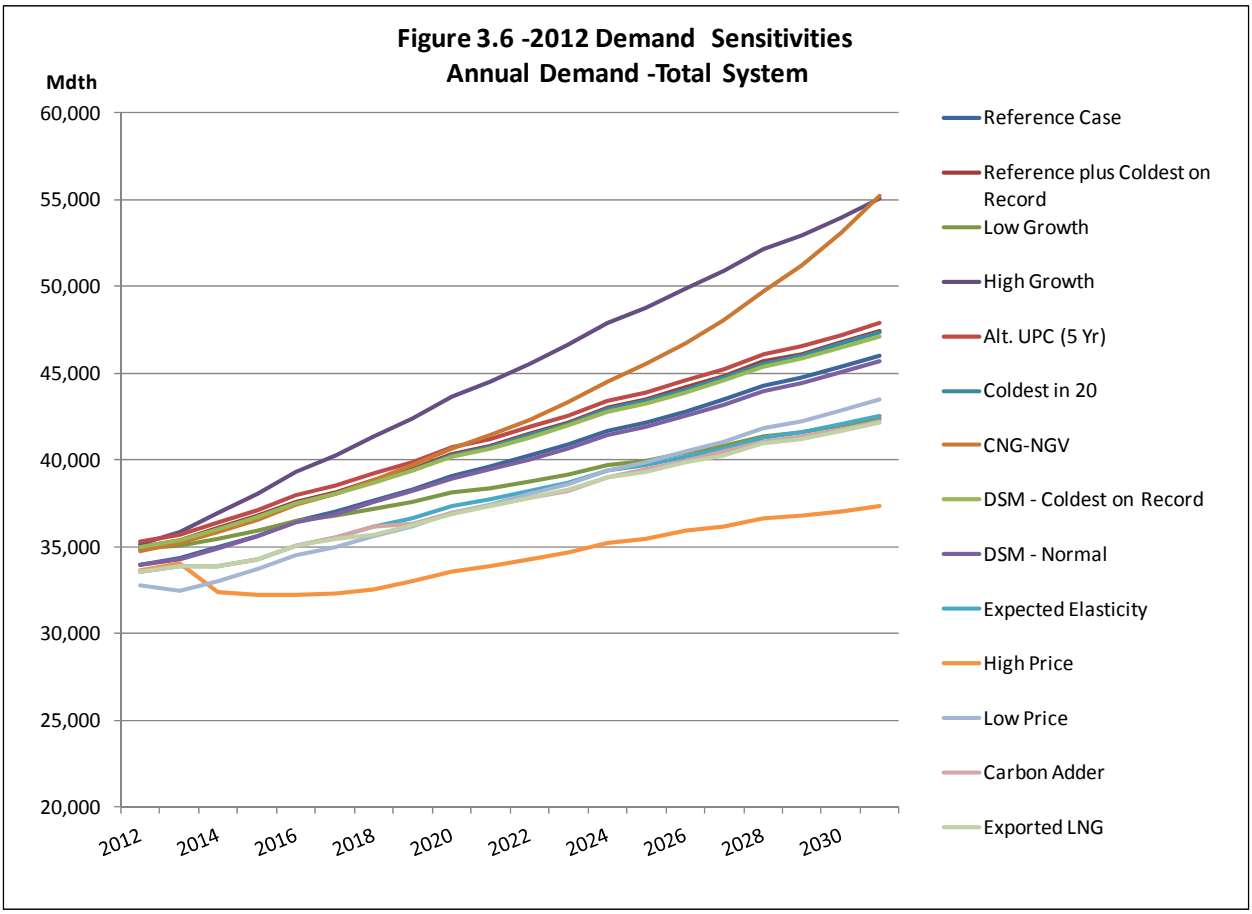
Once factors were identified, we developed sensitivities which we define as focused analysis of a specific natural gas demand driver and its impact on forecasted demand relative to our Reference Case when the underlying input assumptions are modified

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.

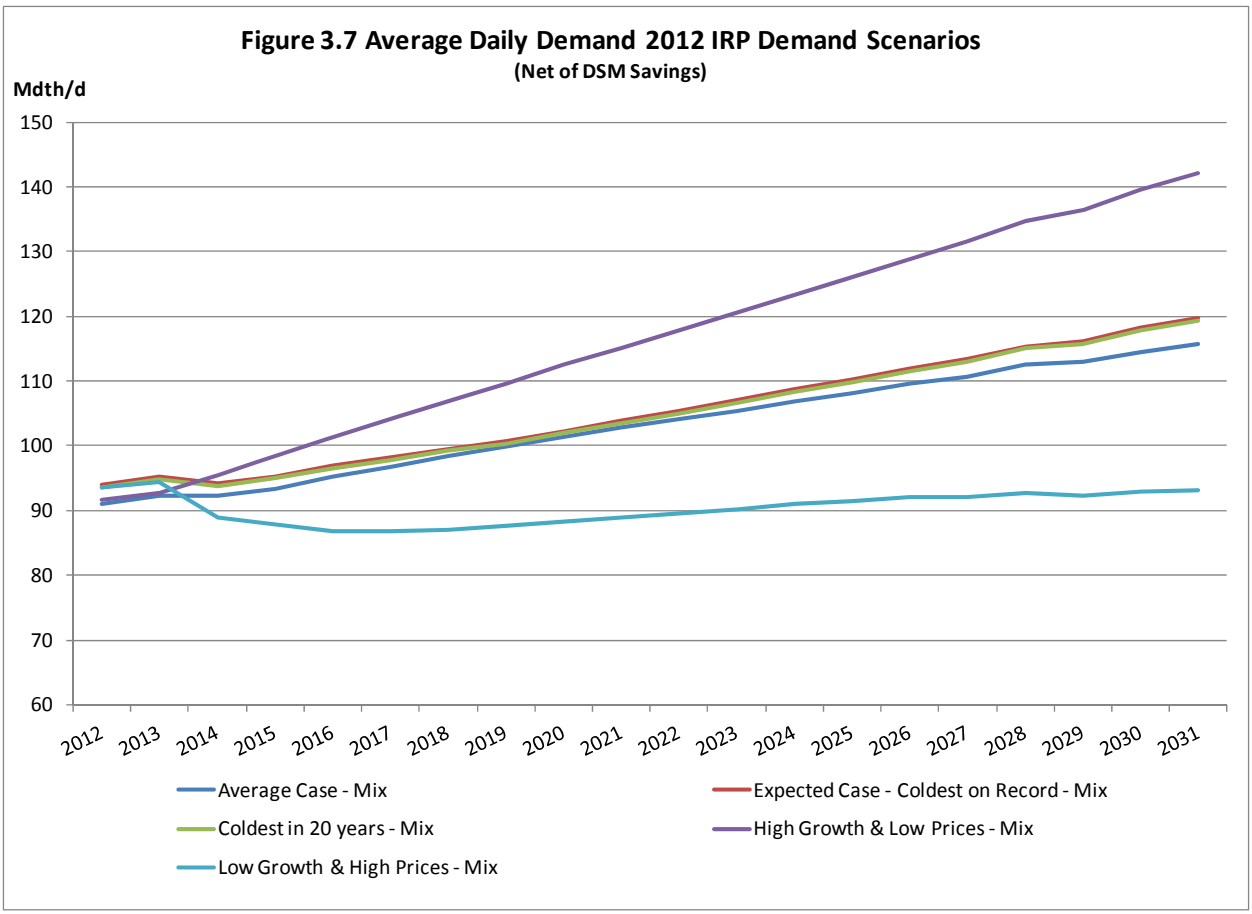
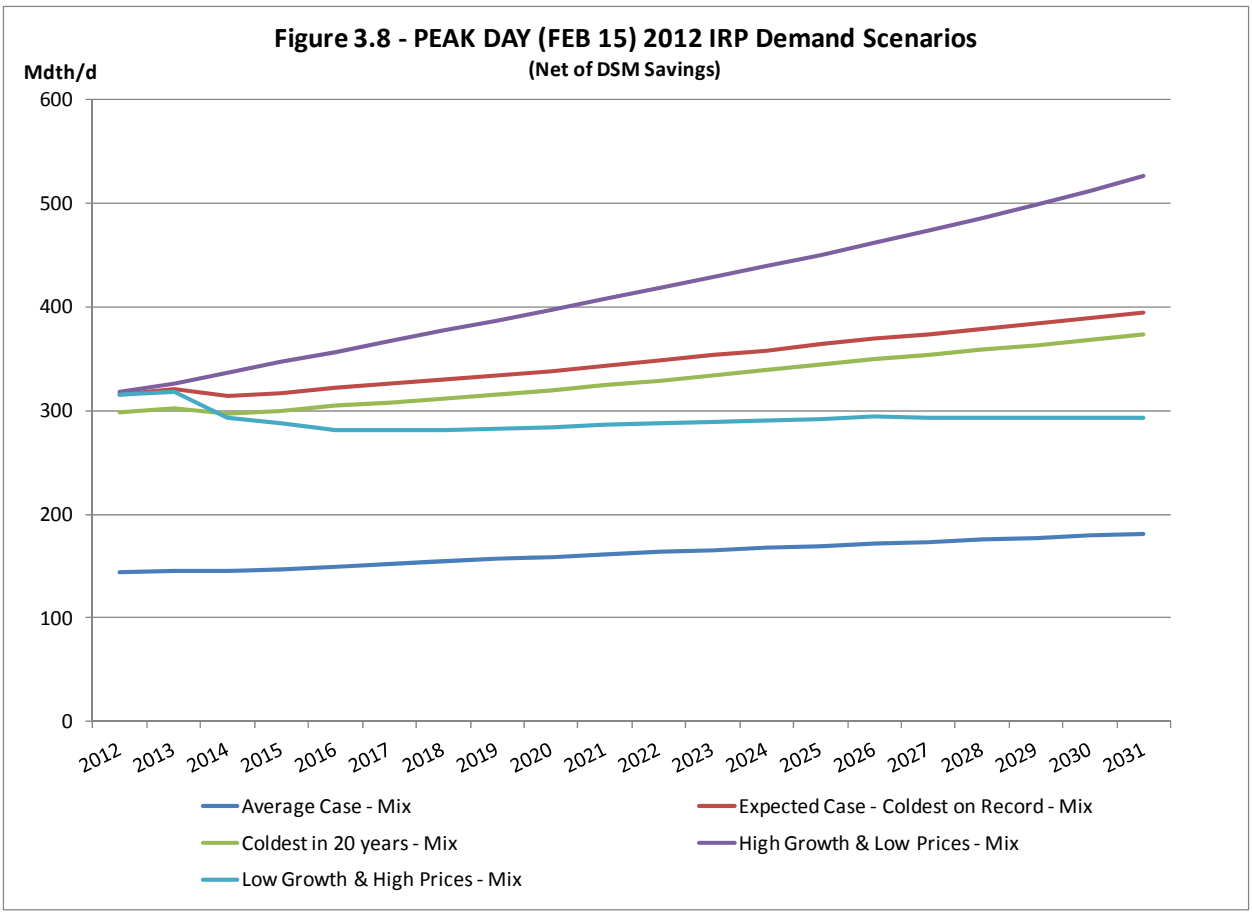


Figure 3.8 shows system forecasted demand for the Expected, High and Low Demand cases on a **peak day basis** for each year relative to the Average case average daily winter demand. Detailed data for all demand scenarios is in Appendix 3.8.



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.

II 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 II 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.

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[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.

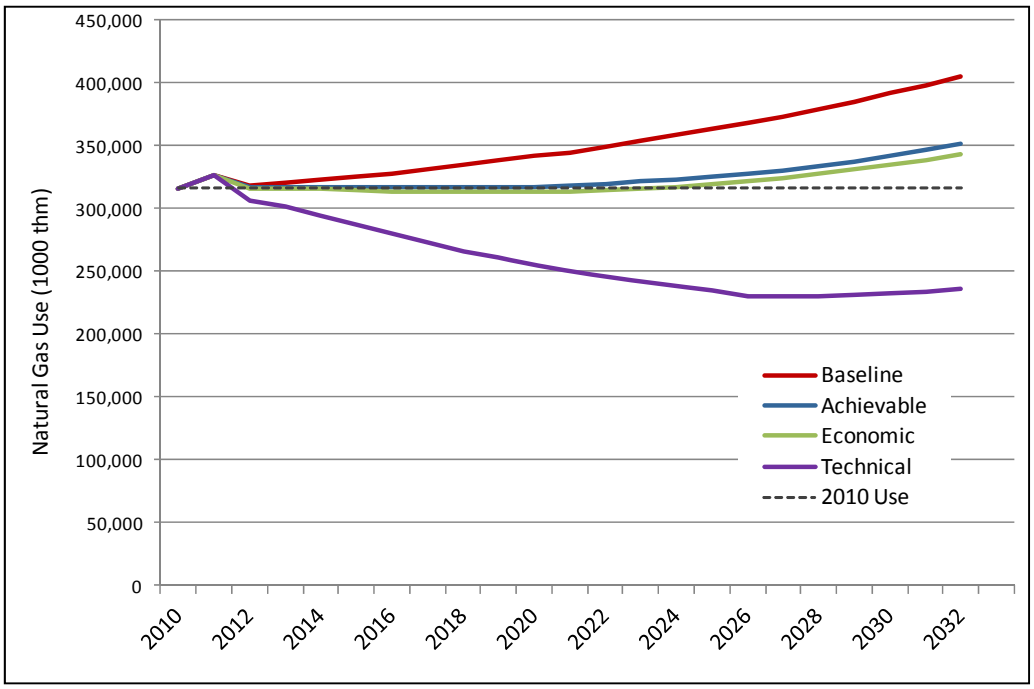
Table 4.4 Summary of Cumulative Achievable, Economic and Technical Conservation Potential by State and Sector

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.

II 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

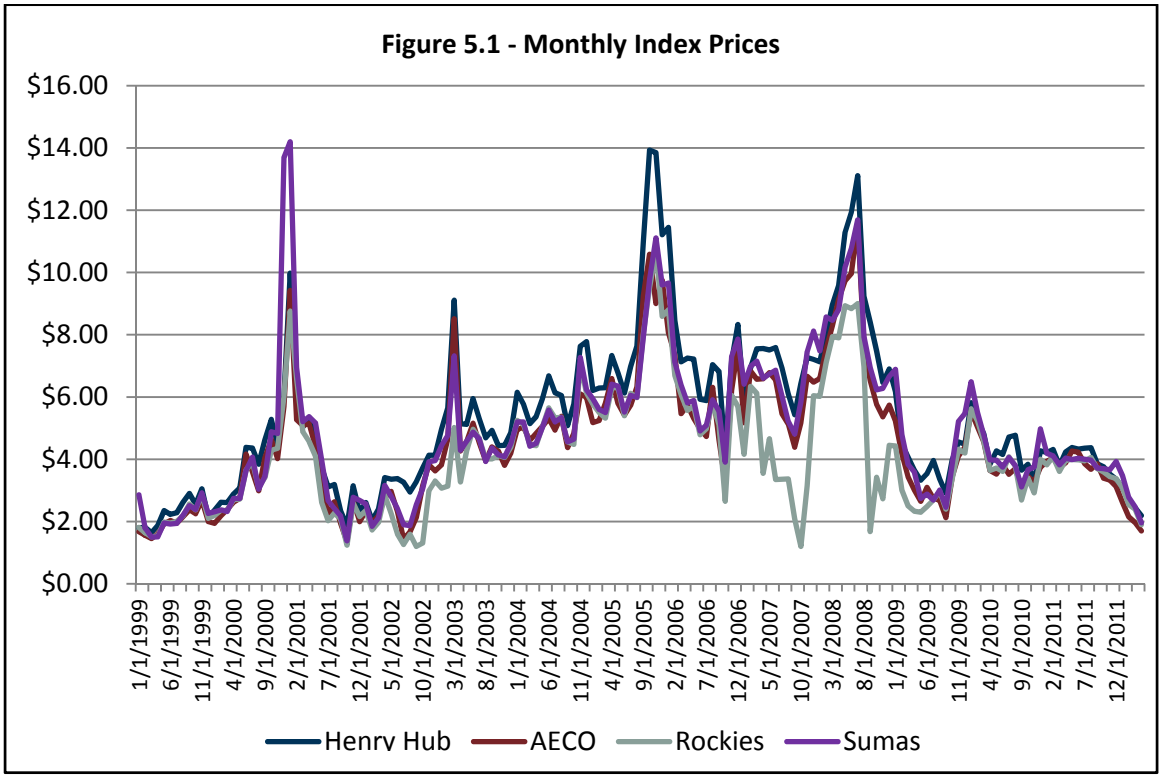
Extending out from the two primary basins are numerous regional market hubs where natural gas is traded. These typically are located at pipeline interconnects. Avista is located near and transacts at most of the Pacific Northwest regional market hubs, enabling flexible access to a diversity of supply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



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.

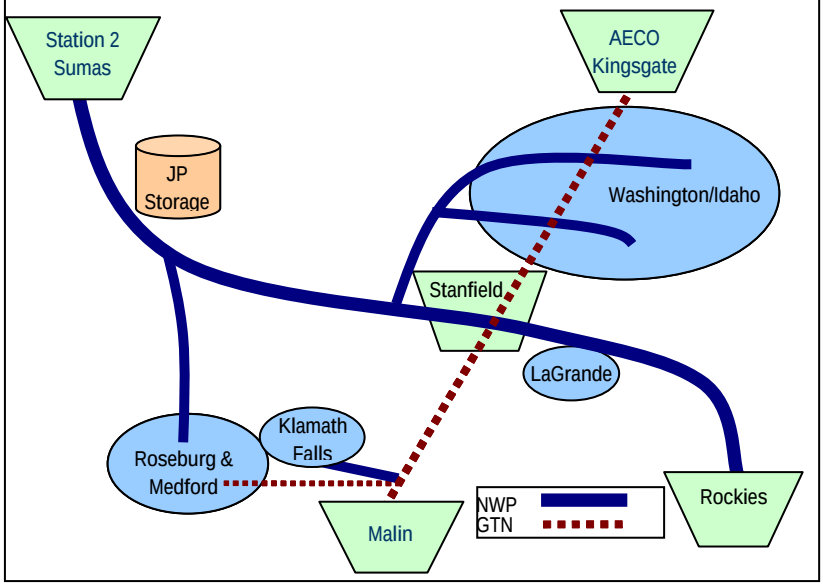
Table 5.1
Firm Transportation/Resources Contracted*
Dth/Day

	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).

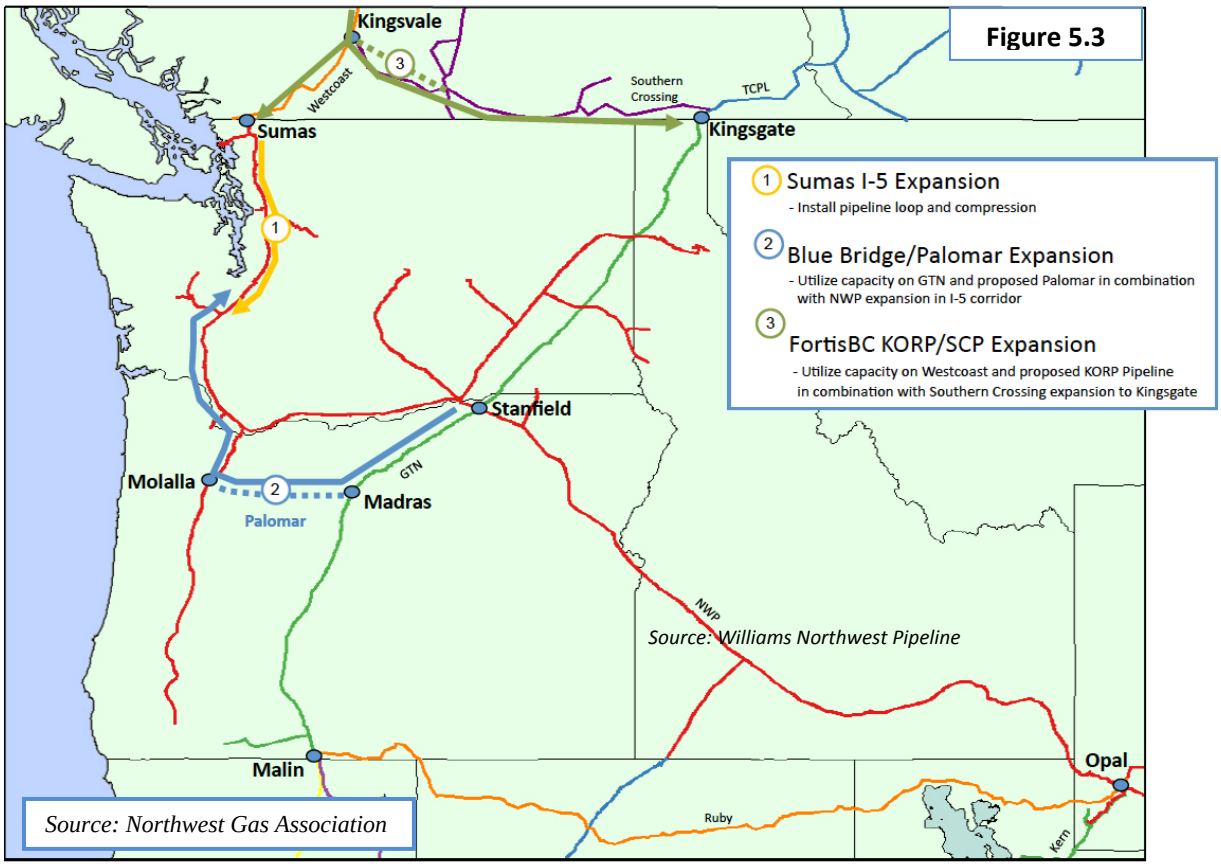
This service has the potential to be a particularly interesting solution for our Oregon customers. For example, Avista can purchase supplies at Malin, Ore. and transport those supplies to our service territory at either Klamath Falls or Medford. Malin-based natural gas supplies typically price at a premium 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:



II 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.

II 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.

II 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.

II 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.

II 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.

II 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.

II 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

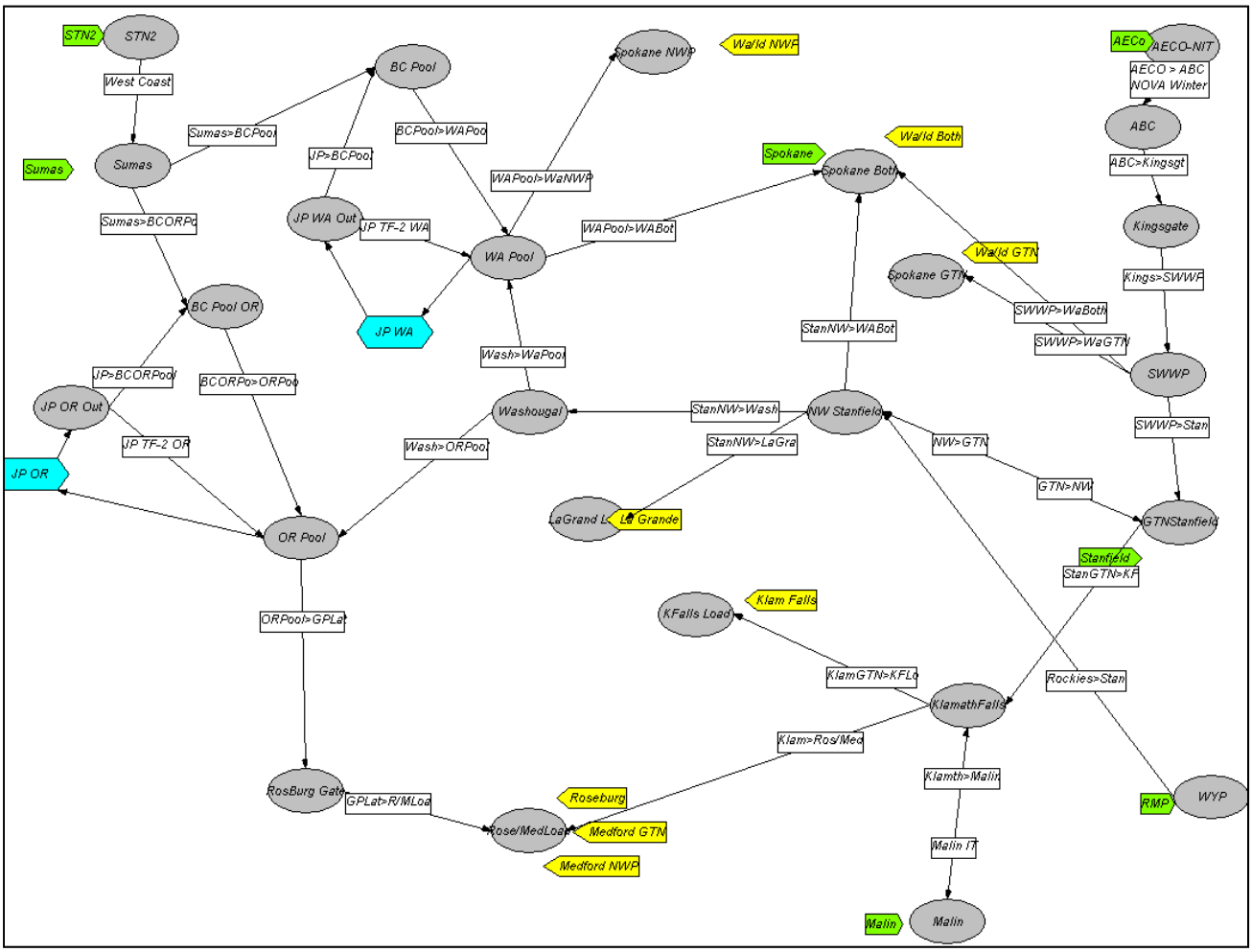
The software analyzes thousands of variables and evaluates possible solutions to generate a least cost solution. The model uses the following variables:

- 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

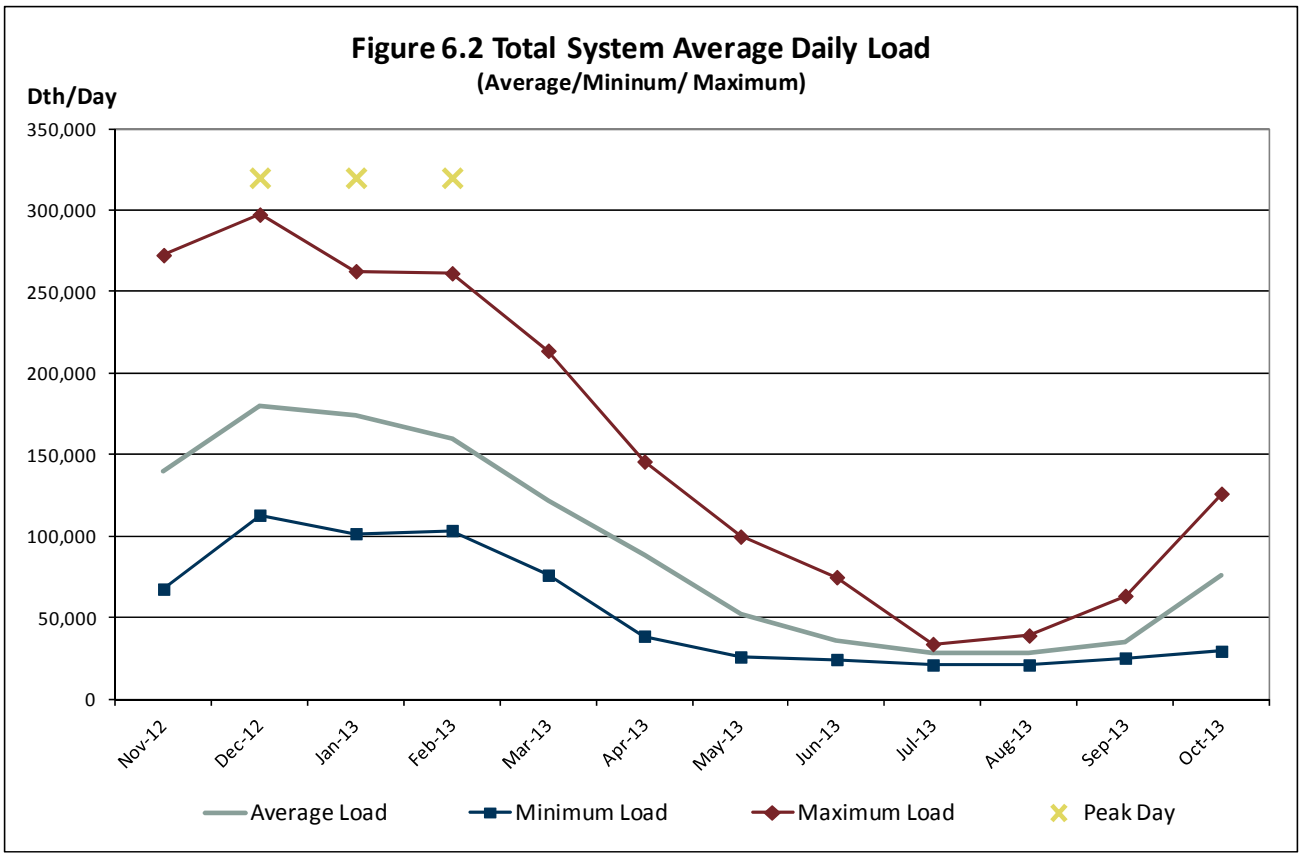
We have defined the planning methodologies, described the modeling tools and identified the existing and potential resources. The following summarizes the comprehensive analysis of bringing demand forecasting and existing and potential supply and demand-side resources together to form our 20-year, risk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



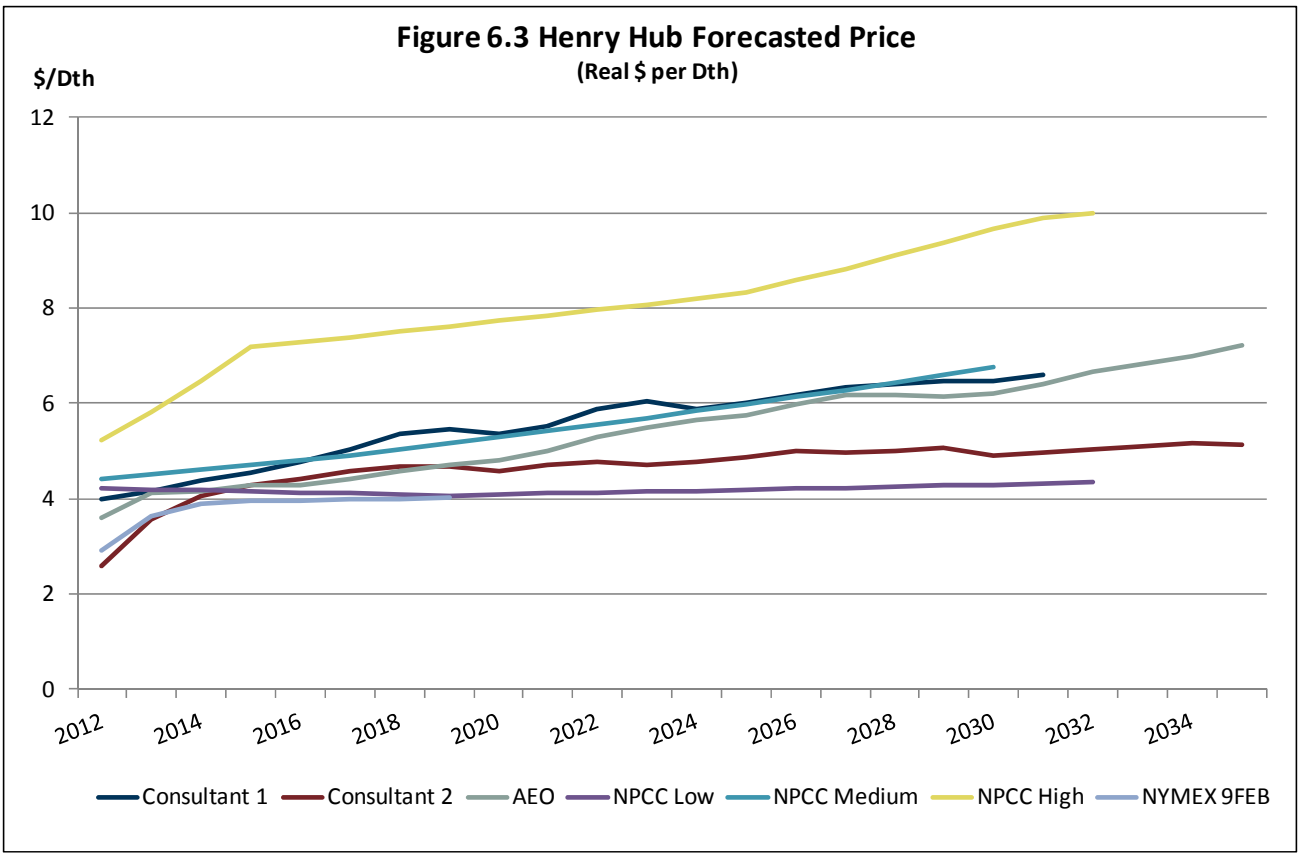
NATURAL GAS PRICE FORECASTS

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.

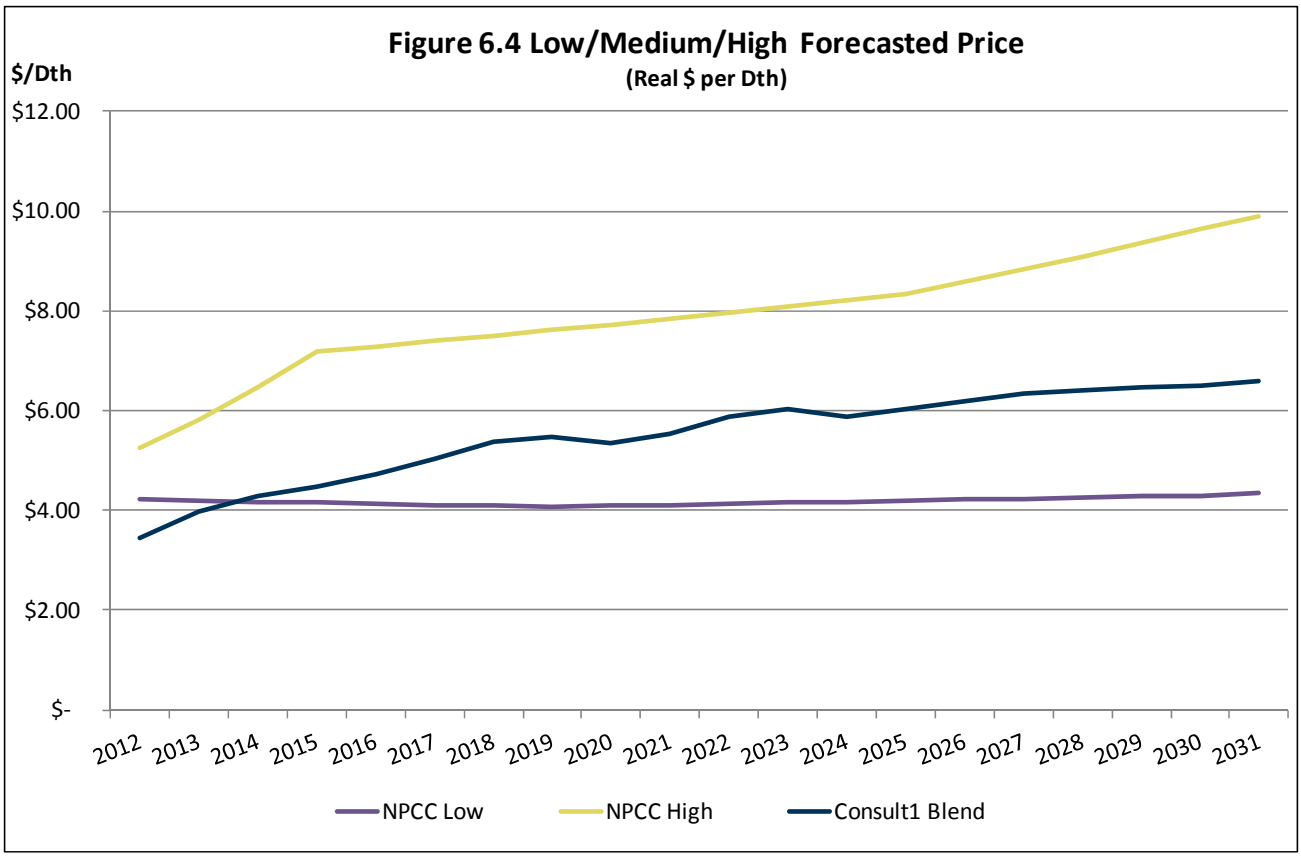


Figure 6.4 Low/Medium/High Forecasted Price
(Real $ per Dth)
$/Dth
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$-
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
NPCC Low
NPCC High
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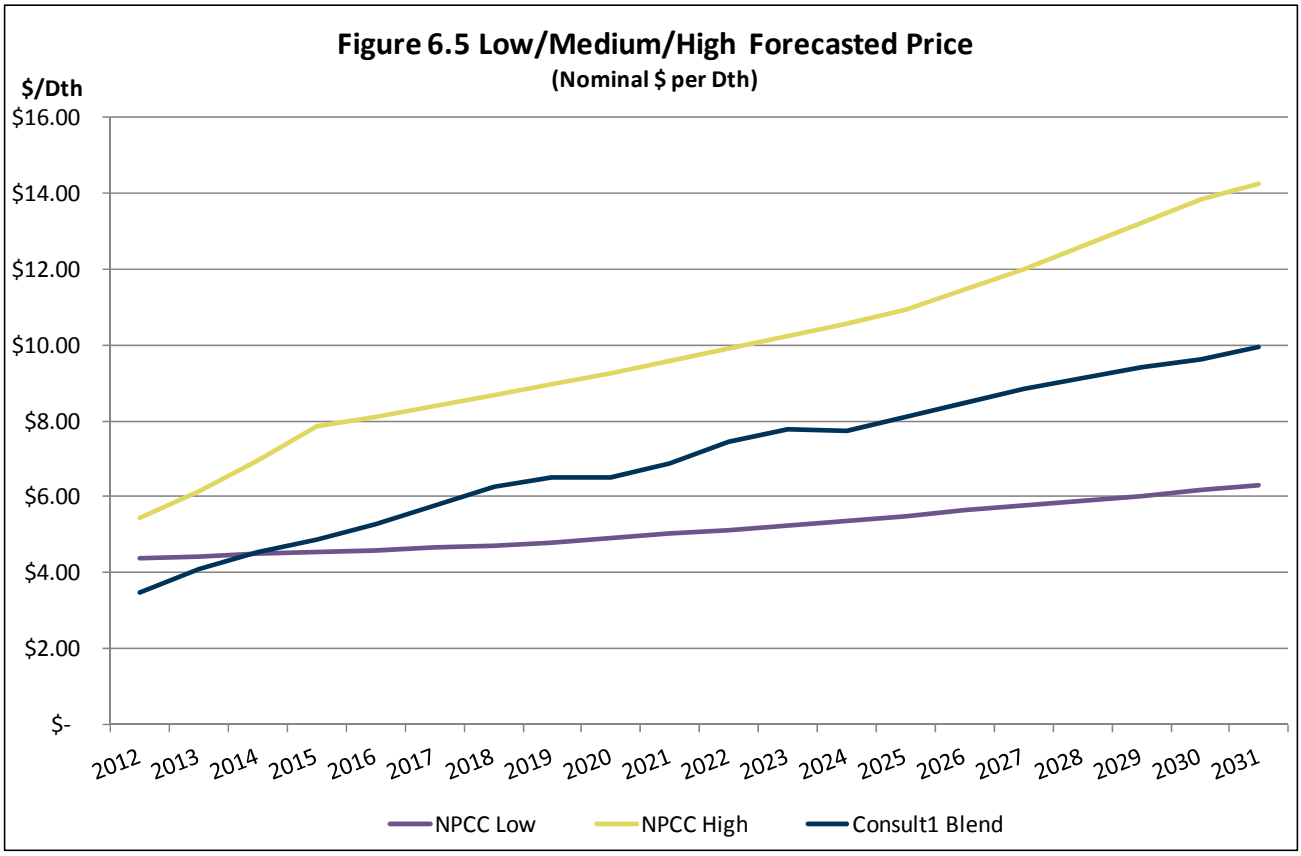


Figure 6.5 Low/Medium/High Forecasted Price
(Nominal $ per Dth)
$/Dth
$16.00
$14.00
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$-
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
NPCC Low
NPCC High
Consult1 Blend

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.

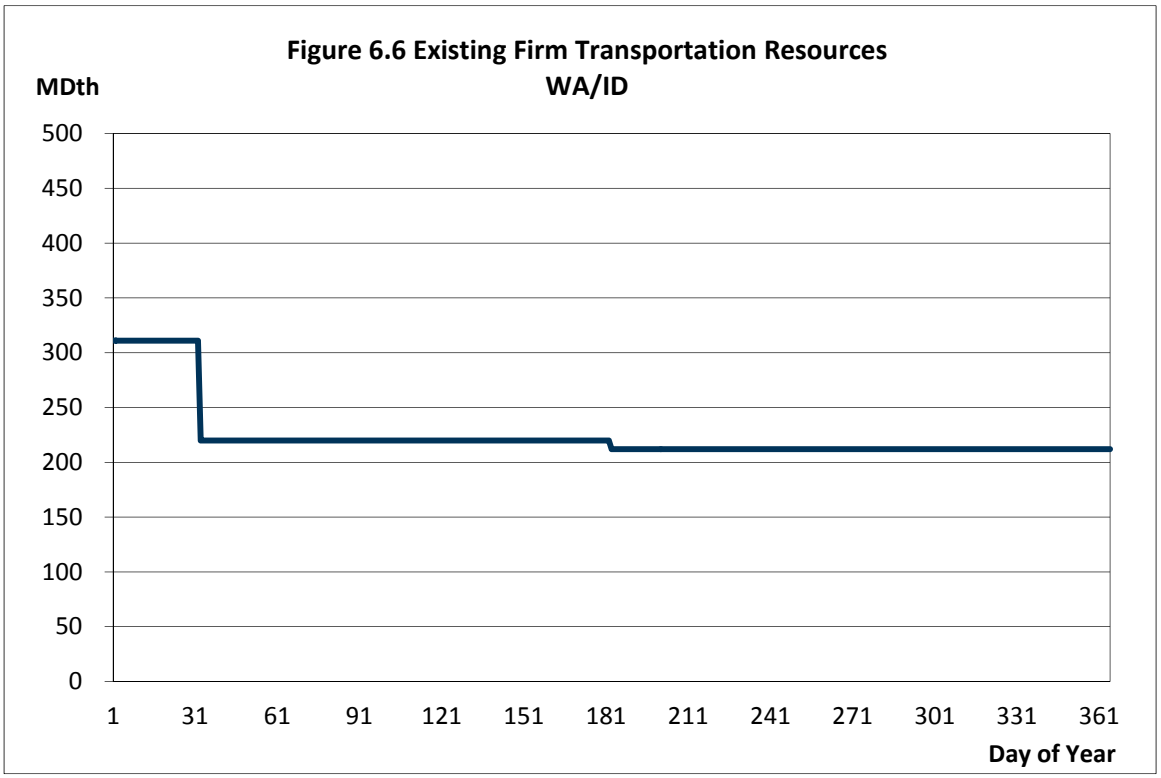
Table 6.2 Monthly Price as a Percent of Average Price

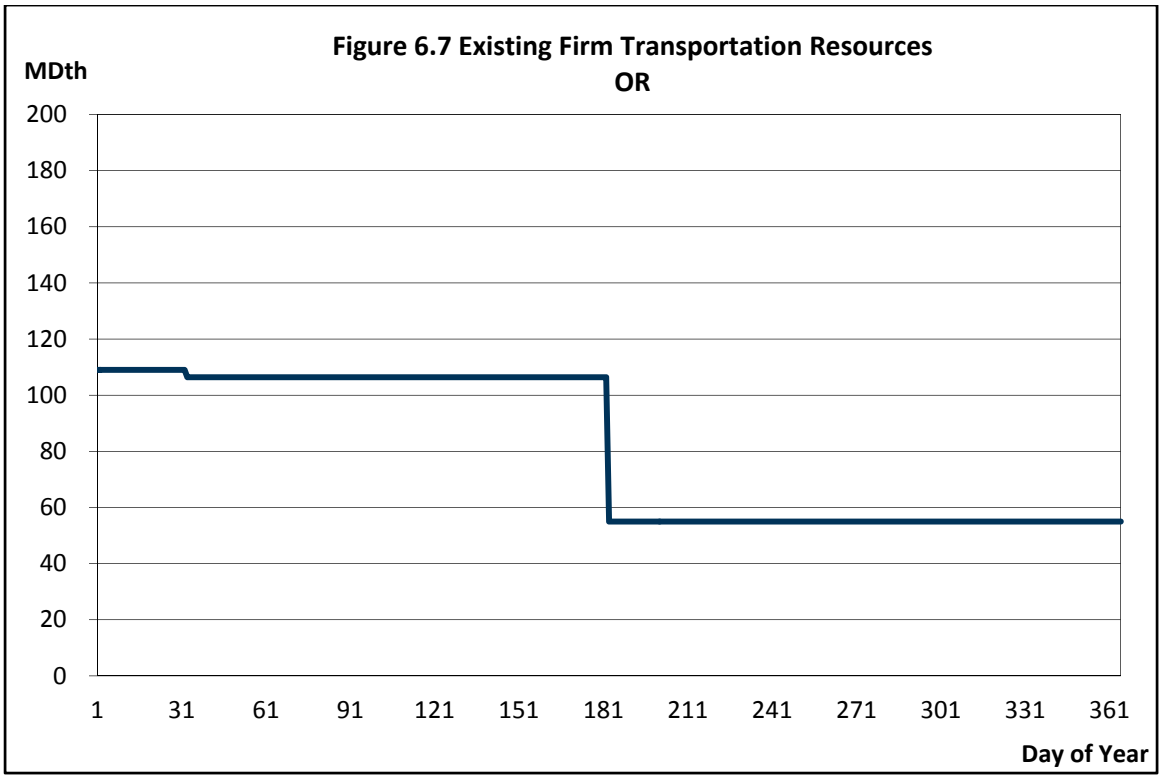
	Jan	Feb	Mar	Apr	May	Jun
Consult1	101%	101%	98%	98%	98%	100%
Consult2	103%	102%	99%	98%	99%	101%
Historic First of Month Index Three-Year Average	130%	113%	101%	94%	96%	96%
Prior IRP	107%	108%	103%	93%	93%	94%
	Jul	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Consult1	102%	103%	100%	100%	100%	102%
Consult2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





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.

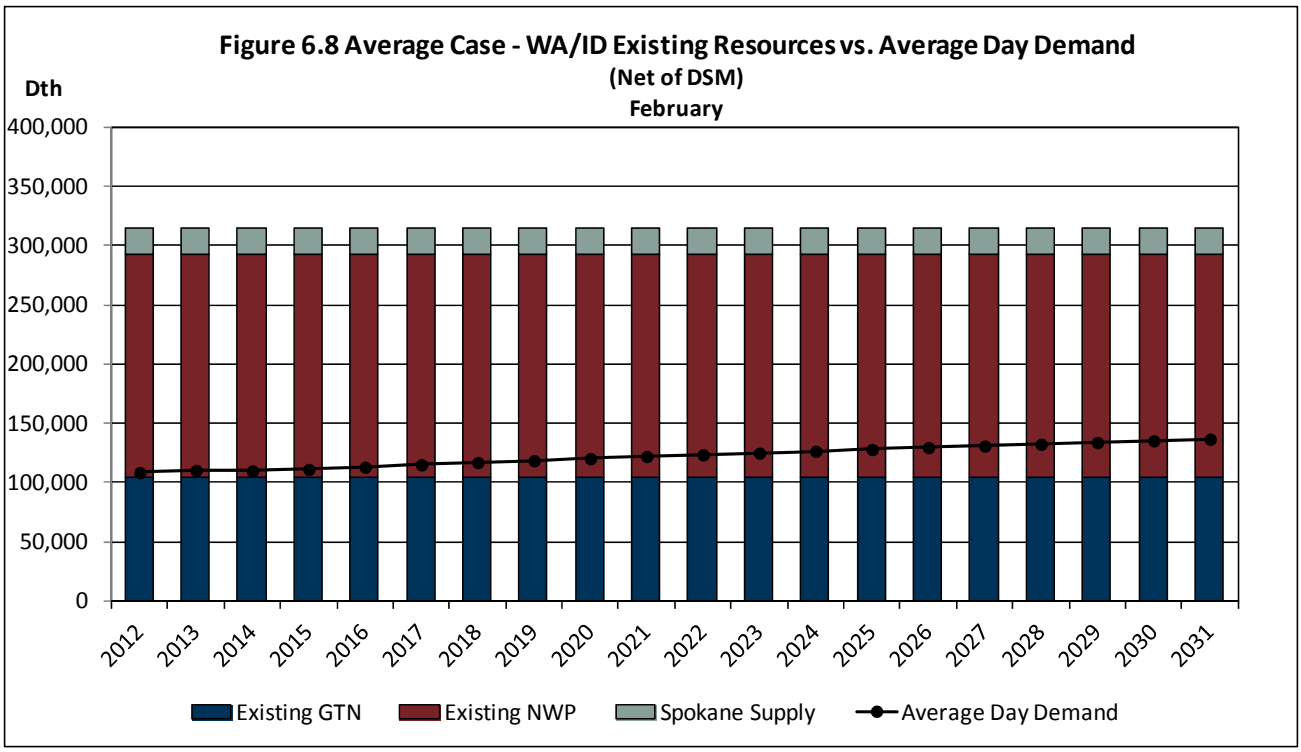


Figure 6.8 Average Case - WA/ID Existing Resources vs. Average Day Demand
(Net of DSM)
February
Dth
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Existing GTN
Existing NWP
Spokane Supply
Average Day Demand

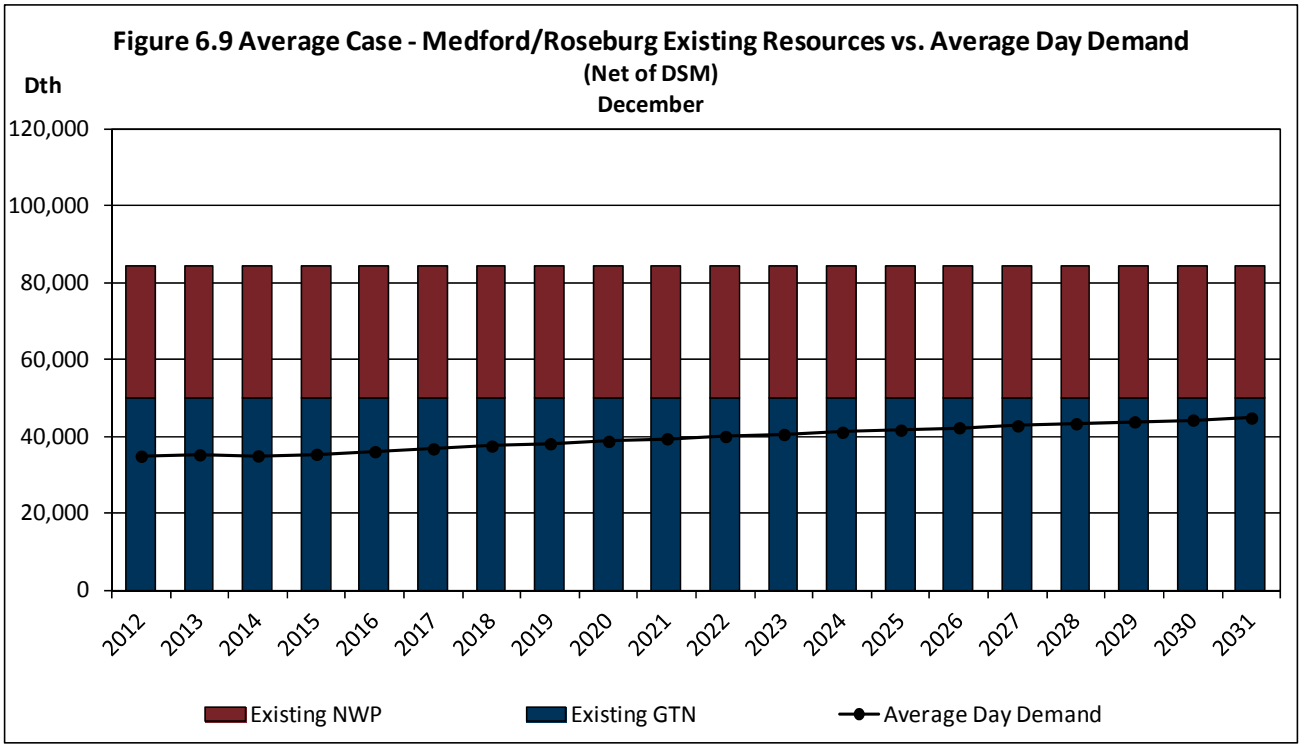
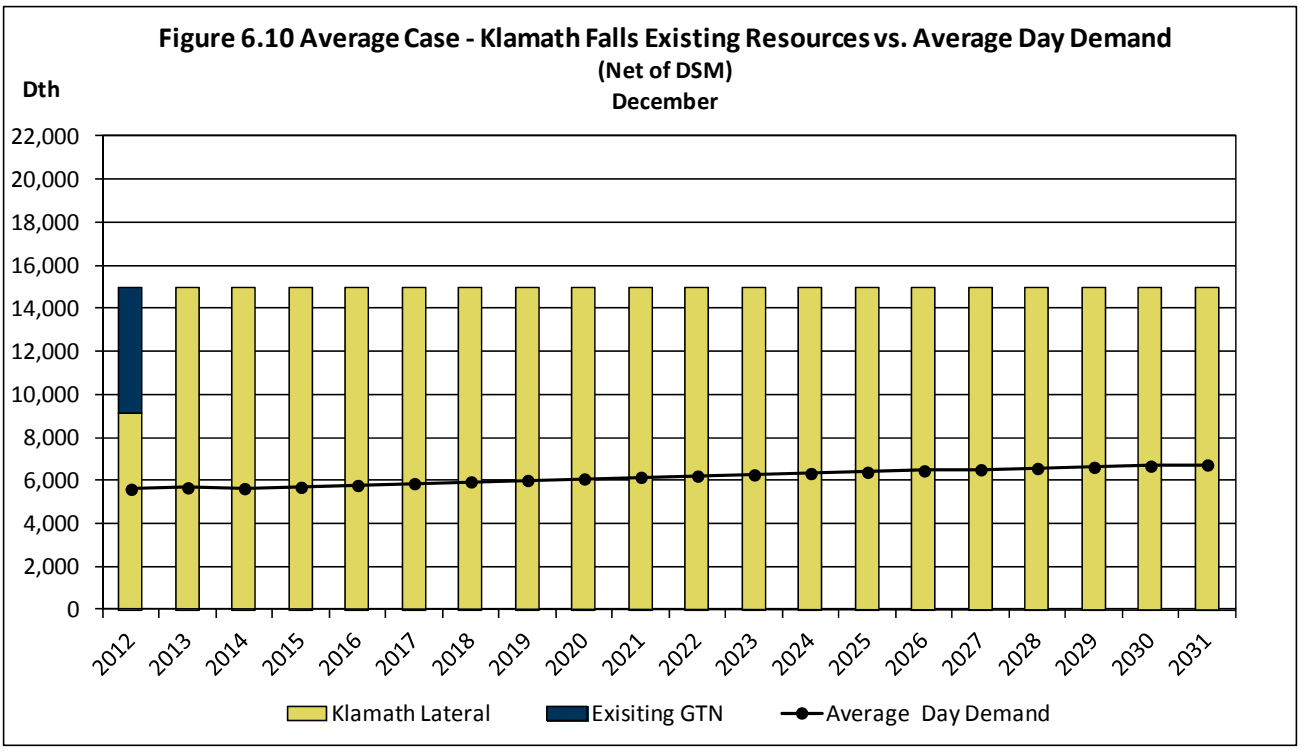
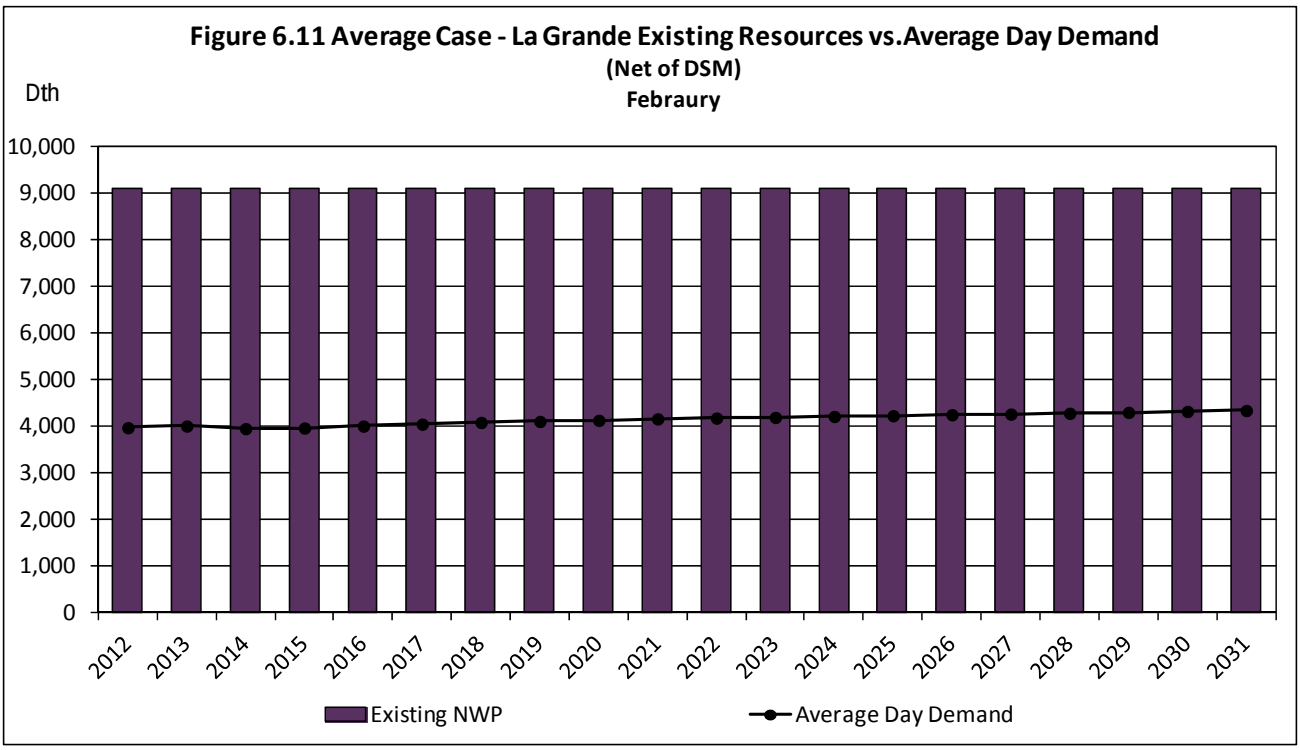


Figure 6.9 Average Case - Medford/Roseburg Existing Resources vs. Average Day Demand
(Net of DSM)
December
Dth
120,000
100,000
80,000
60,000
40,000
20,000
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Existing NWP
Existing GTN
Average Day Demand





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.

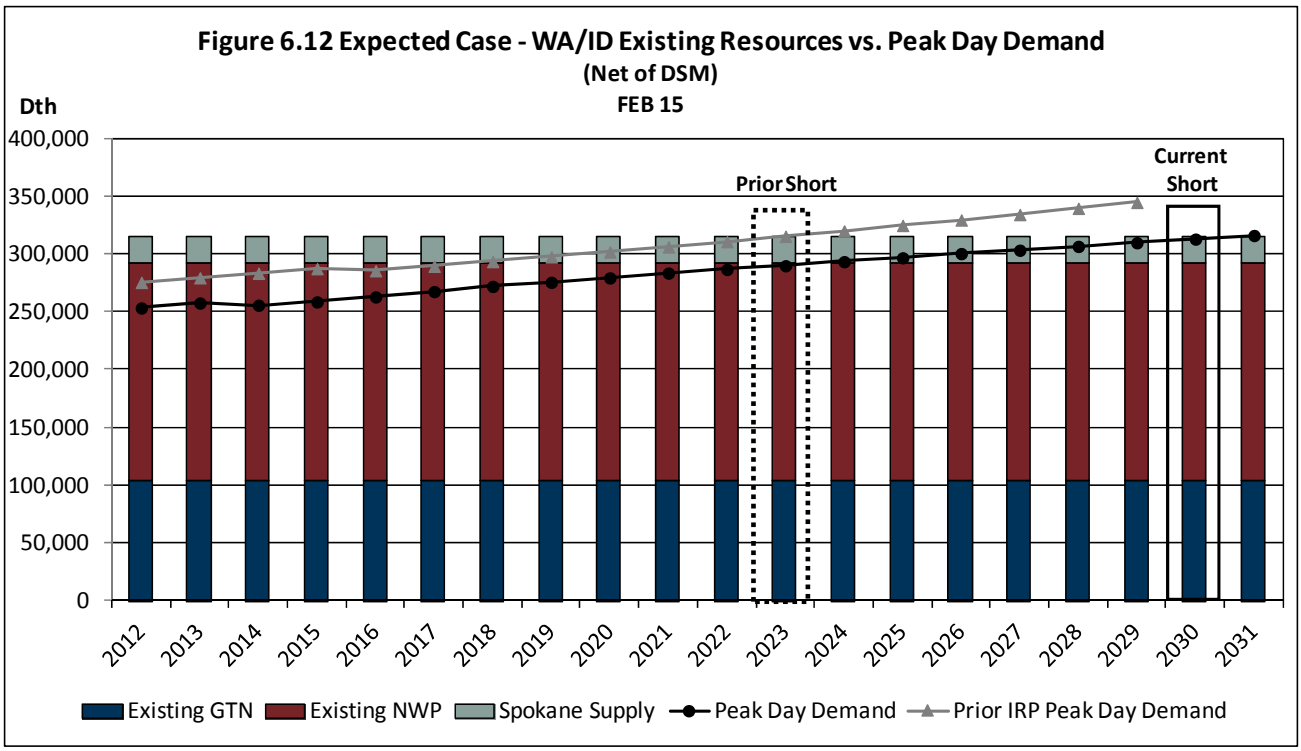


Figure 6.12 Expected Case - WA/ID Existing Resources vs. Peak Day Demand
(Net of DSM)
FEB 15
Dth
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
Prior Short
Current Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Existing GTN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

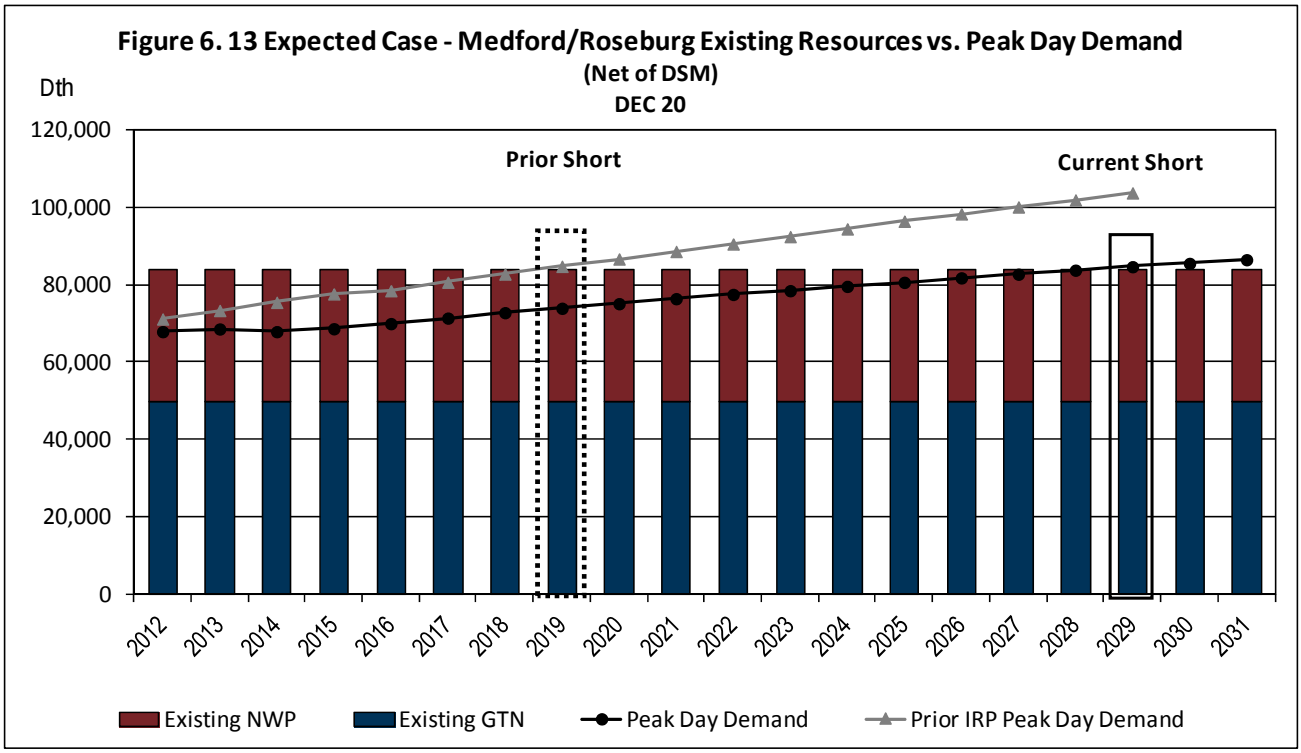
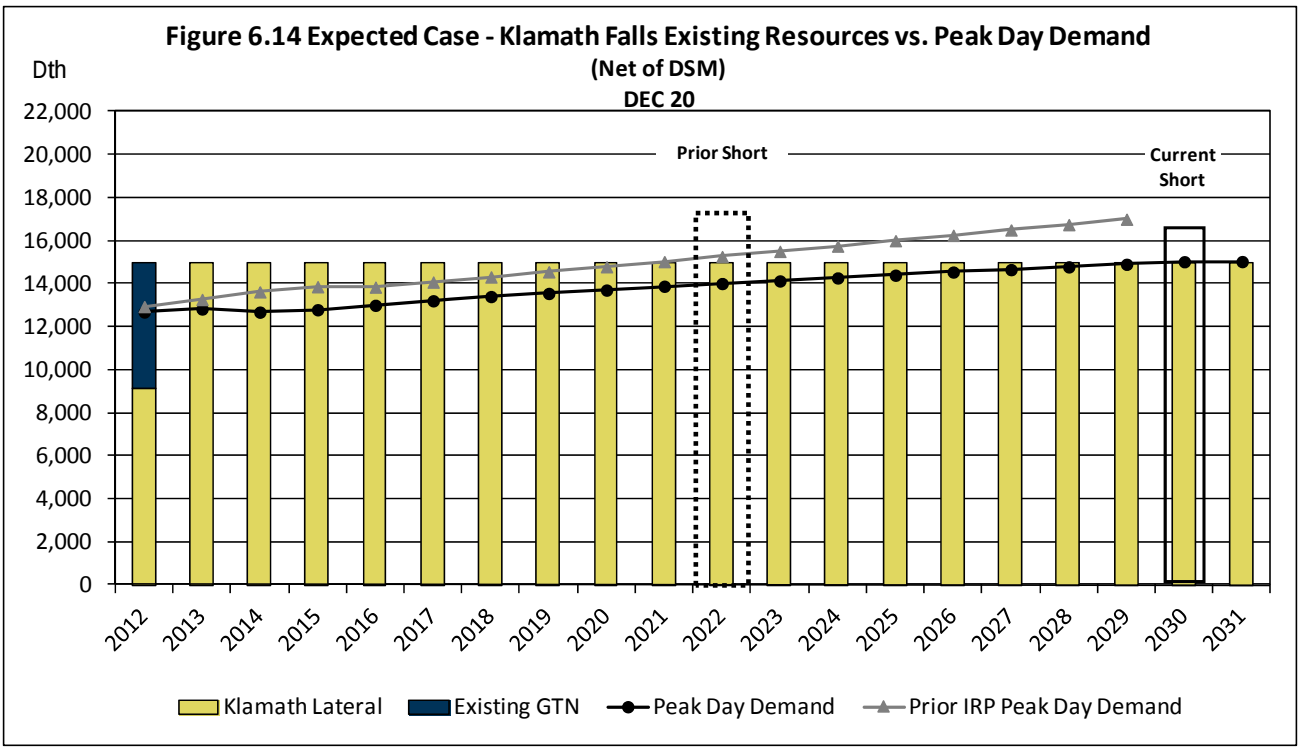
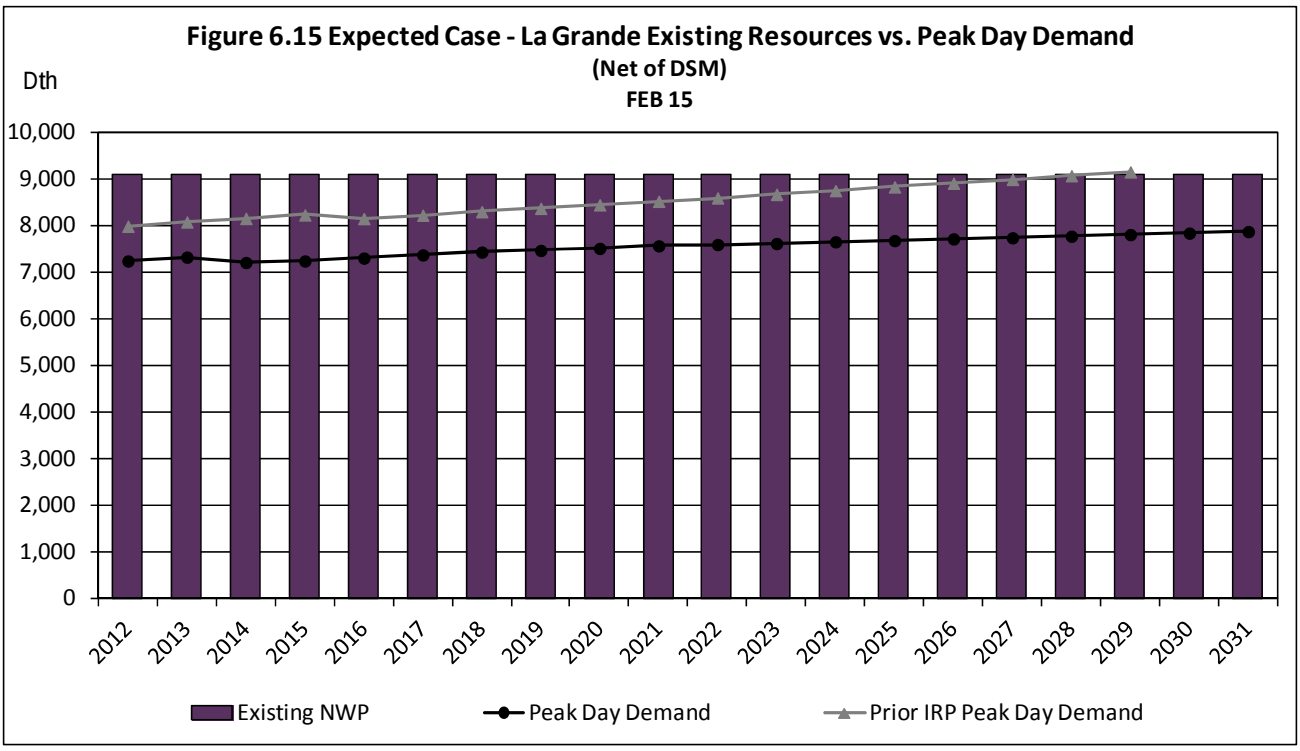


Figure 6. 13 Expected Case - Medford/Roseburg Existing Resources vs. Peak Day Demand
(Net of DSM)
DEC 20
Dth
120,000
100,000
80,000
60,000
40,000
20,000
0
Prior Short
Current Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Existing NWP
Existing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





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

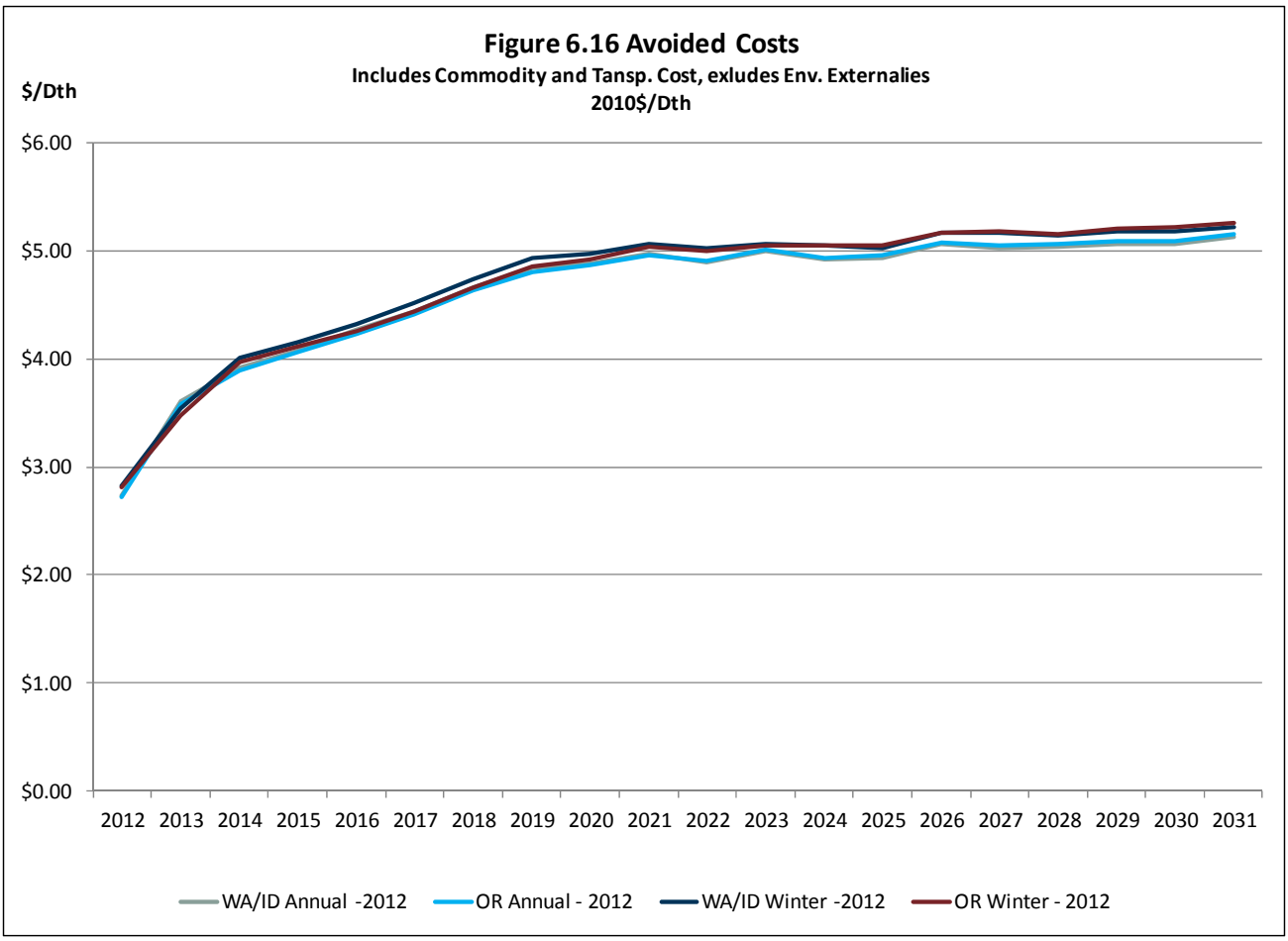
After identifying supply-side resource options and evaluating them based on the above considerations, we entered these supply-side scenarios (see Table 5.2) along with conservation measures (see Chapter 4 - Demand-side Resources) into the SENDOUT® model for it to select the least cost approach to meeting 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.

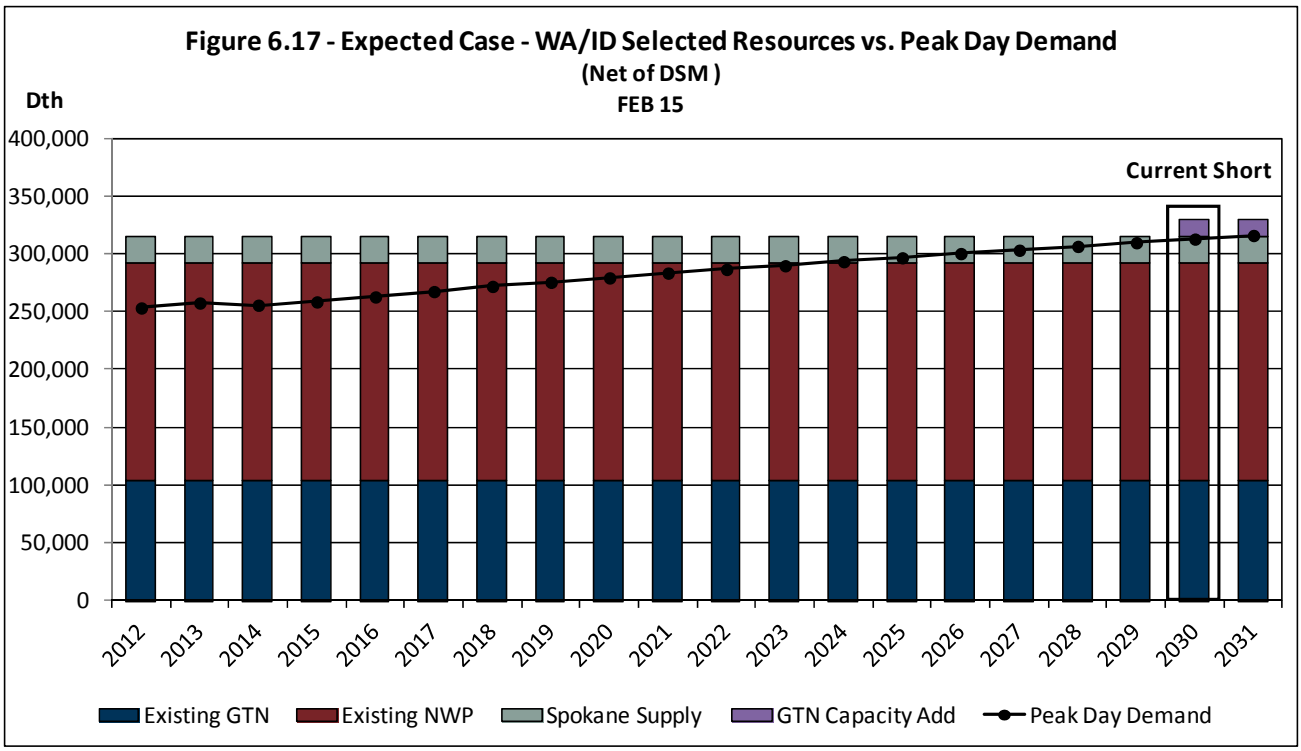


Figure 6.17 - Expected Case - WA/ID Selected Resources vs. Peak Day Demand
(Net of DSM)
FEB 15
Dth
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
Current Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Existing GTN
Existing NWP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

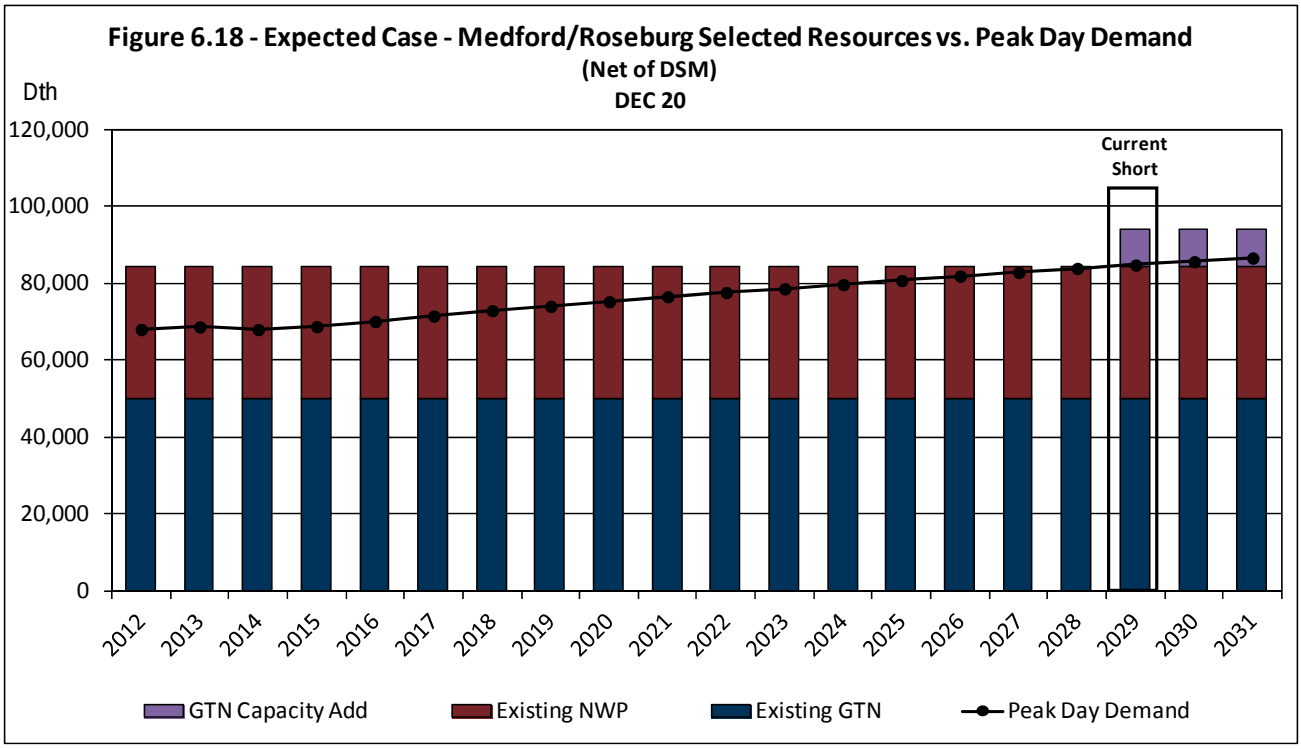
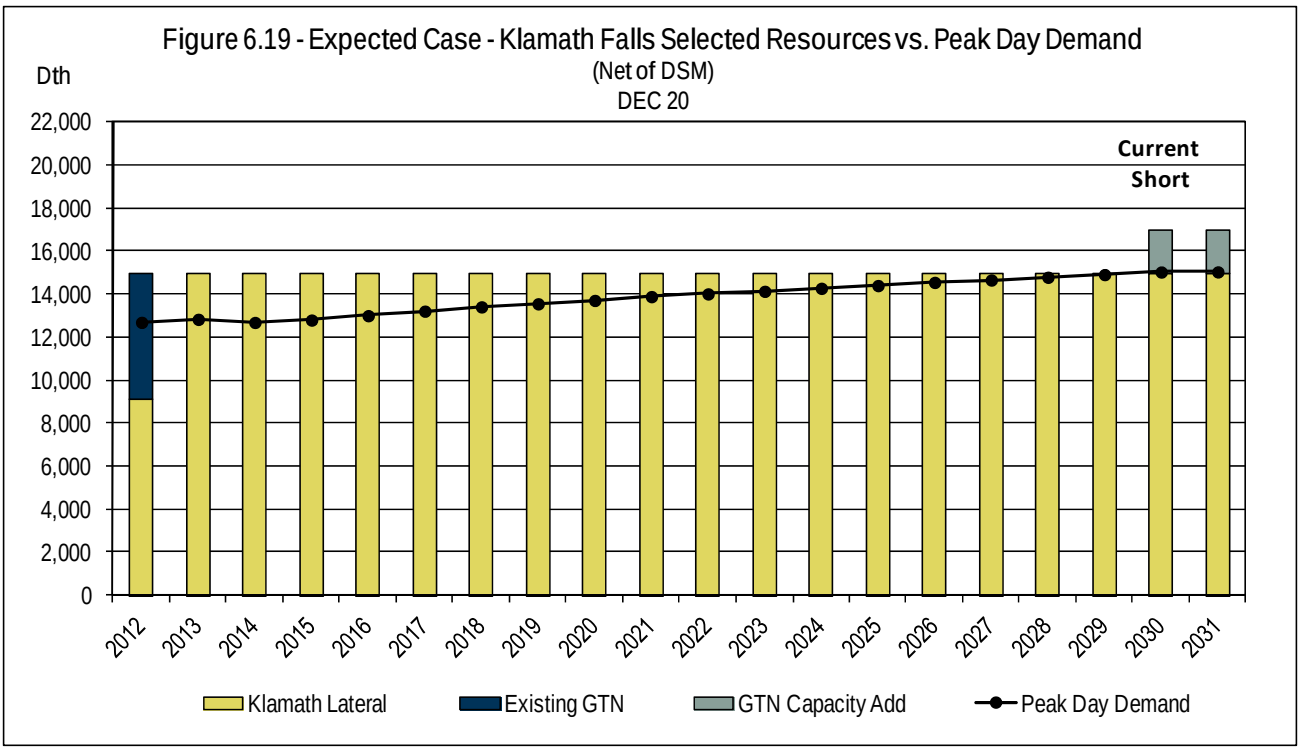


Figure 6.18 - Expected Case - Medford/Roseburg Selected Resources vs. Peak Day Demand
(Net of DSM)
DEC 20
Dth
120,000
100,000
80,000
60,000
40,000
20,000
0
Current Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
GTN Capacity Add
Existing NWP
Existing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

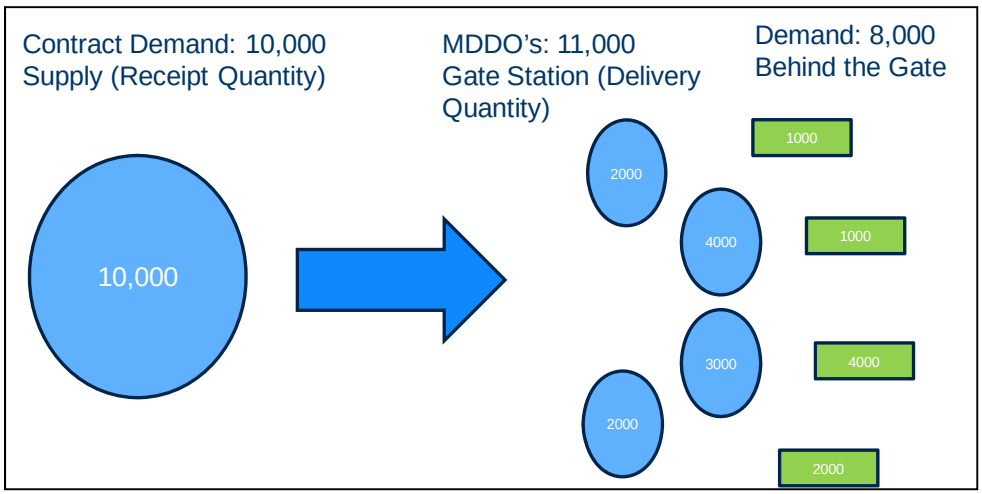
Our primary purpose is to meet our customer's demand needs in a cost effective manner. As the analysis indicates, we have ample resources to meet highly variable demand under multiple scenarios, including peak weather events, for the foreseeable future. With primary needs addressed, utilization of excess 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.

II 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 II 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).

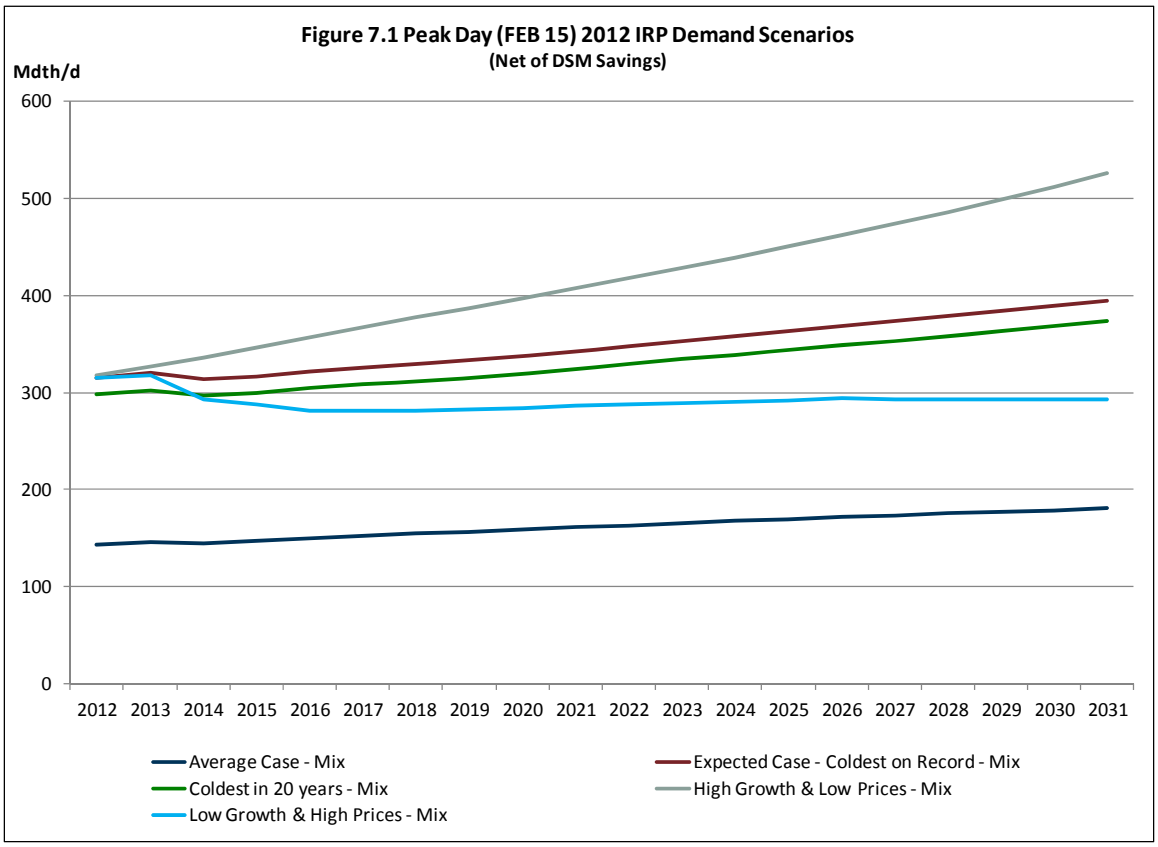


Figure 7.1 Peak Day (FEB 15) 2012 IRP Demand Scenarios
(Net of DSM Savings)
Mdth/d
600
500
400
300
200
100
0
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Average Case - Mix
Expected Case - Coldest on Record - Mix
Coldest in 20 years - Mix
High Growth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

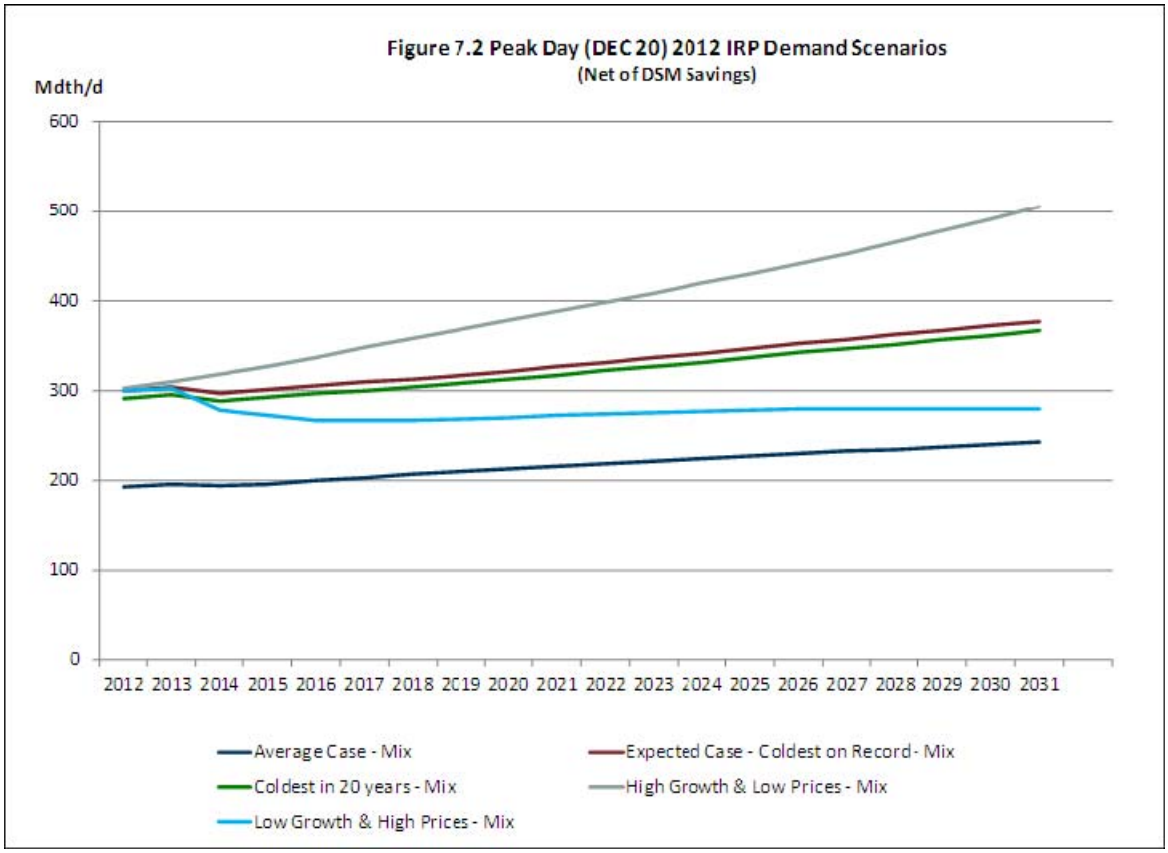
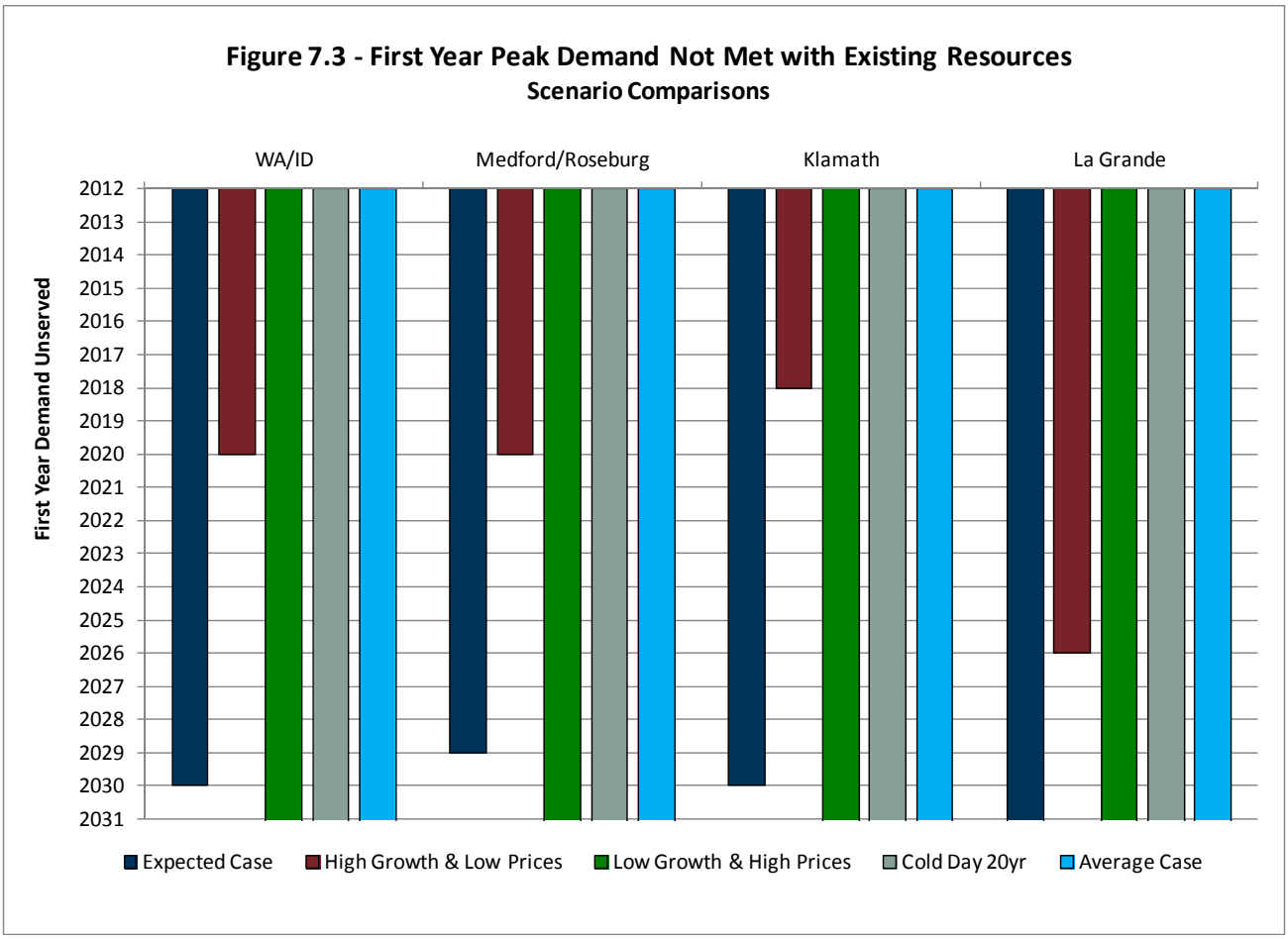


Figure 7.2 Peak Day (DEC 20) 2012 IRP Demand Scenarios
(Net of DSM Savings)
Mdth/d
600
500
400
300
200
100
0
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Average Case - Mix
Expected Case - Coldest on Record - Mix
Coldest in 20 years - Mix
High Growth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

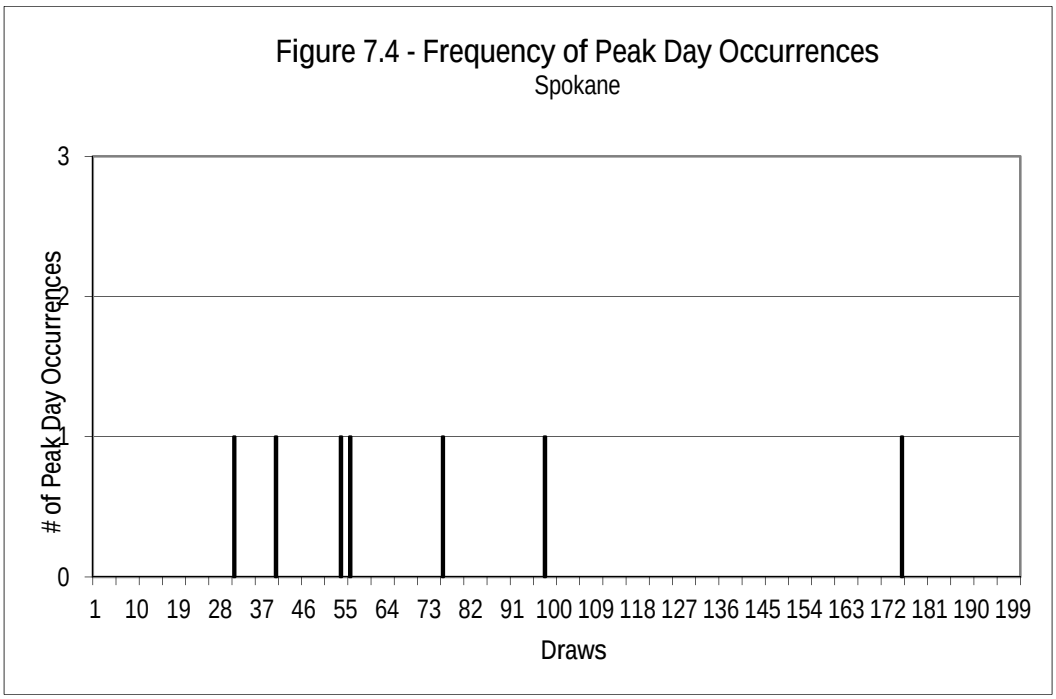
WEATHER

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.



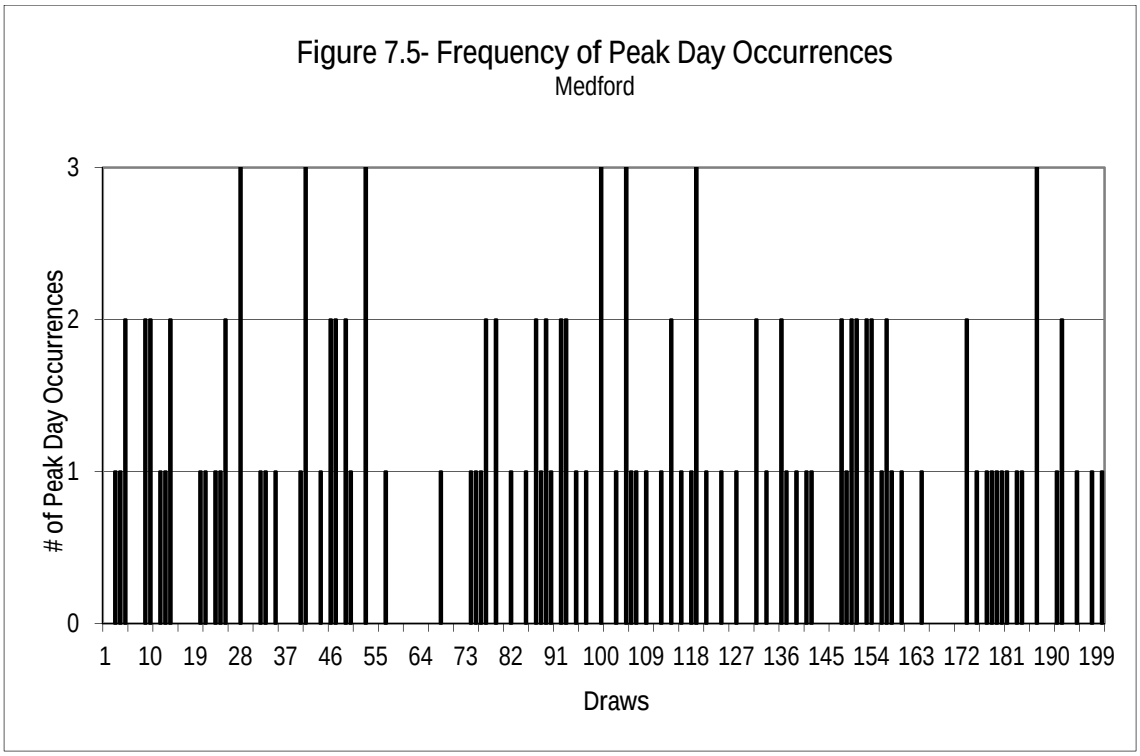


Figure 7.5- Frequency of Peak Day Occurrences
Medford
# of Peak Day Occurrences
0
1
2
3
1 10 19 28 37 46 55 64 73 82 91 100 109 118 127 136 145 154 163 172 181 190 199
Draws

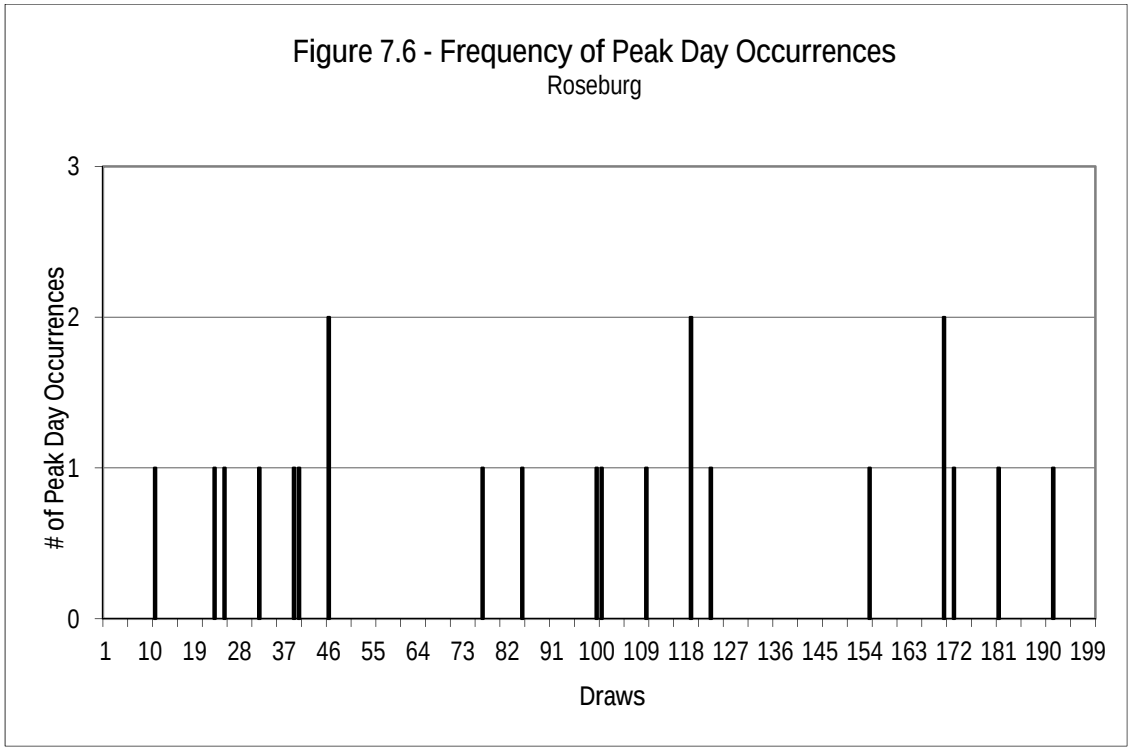
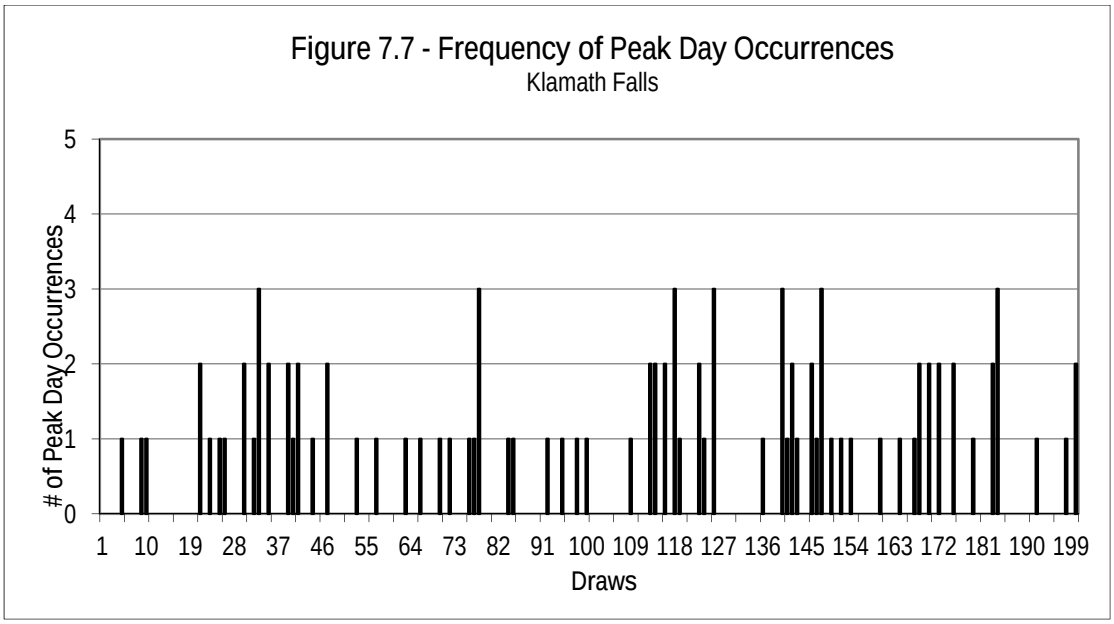
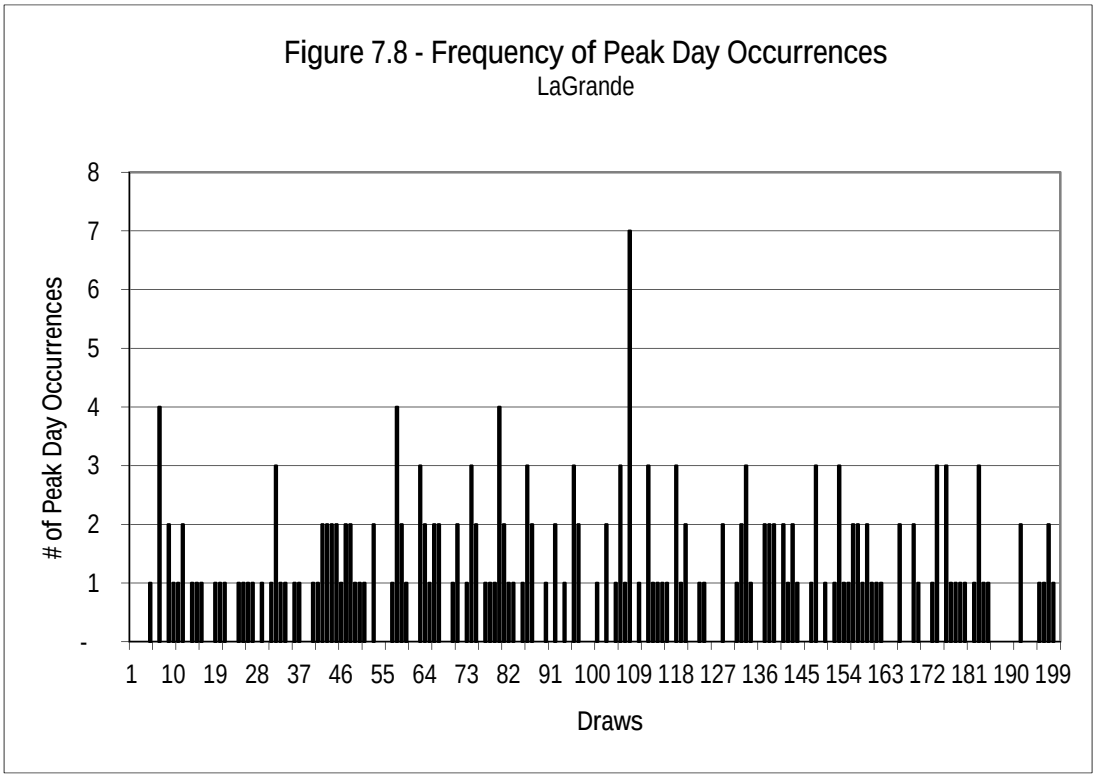


Figure 7.6 - Frequency of Peak Day Occurrences
Roseburg
# of Peak Day Occurrences
0
1
2
3
1 10 19 28 37 46 55 64 73 82 91 100 109 118 127 136 145 154 163 172 181 190 199
Draws

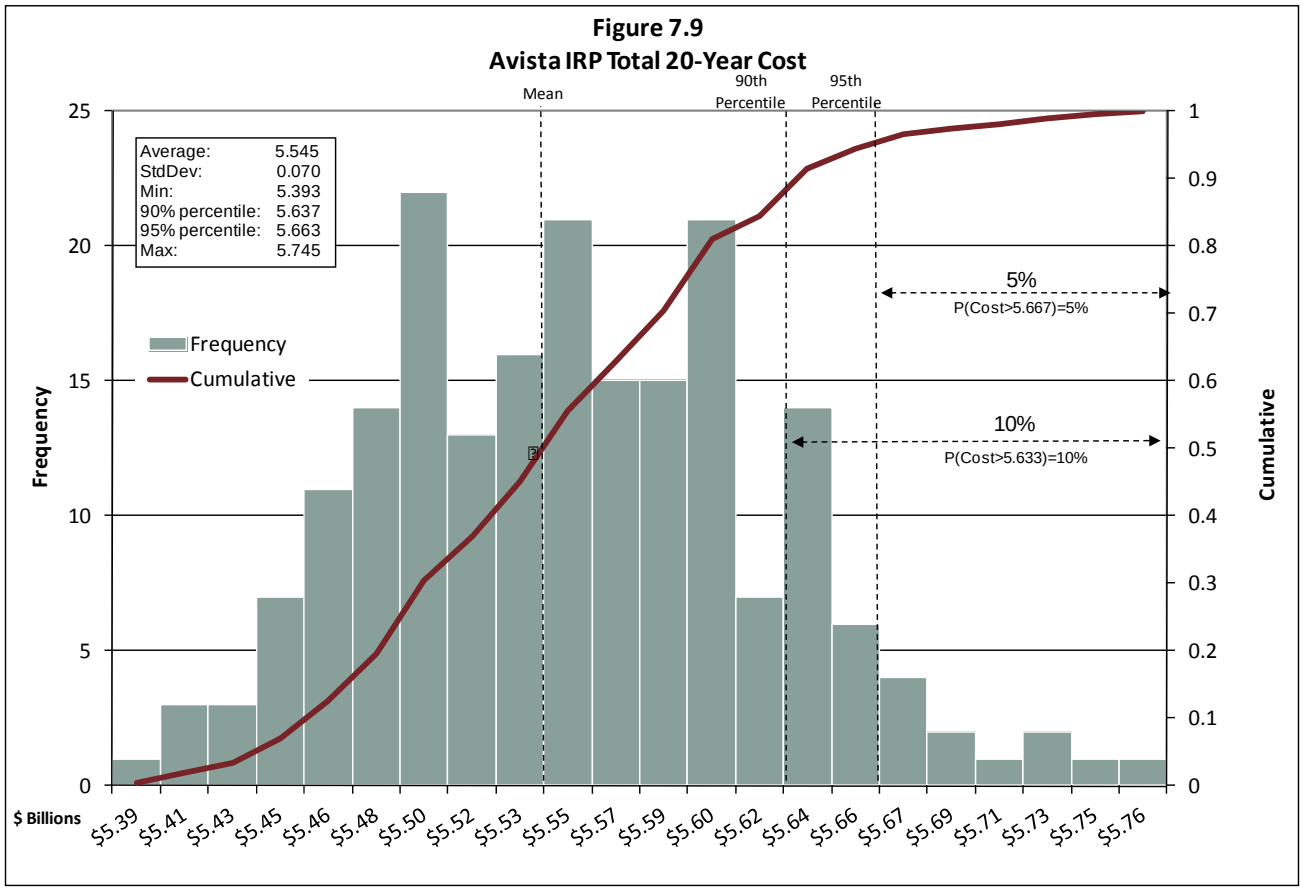




PRICE

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.



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.

II 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.

[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.

[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**

II 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 II 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.

II 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.

II 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.

II 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.

II 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.

II 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.

II 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.

II 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.

II 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.

II 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.

II 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.

II 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.

II 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.

II 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.

II 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.

II 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

2012 Natural Gas Integrated Resource Plan Appendices

August 31, 2012

www.avistautilities.com

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APPENDIX 1.1 II TAC MEMBER LIST

ORGANIZATION	REPRESENTATIVES	
Avista	Bruce Folsom Christopher Williams Greg Rahn Heather Rosentrater Jeff Webb John Lyons Jon Powell Kelly Irvine Kerry Shroy	Steve Harper Kris Ransom Linda Gervais Lori Hermanson Pat Ehrbar Randy Barcus Shawn Bonfield Tom Pardee
Cascade Natural Gas Company	Mark Sellers-Vaughn	Mike Parvinen
Fortis BC	Christina Lemire	Ken Ross
Intermountain Gas	Dave Swenson Mike McGrath	Shelli Chase
Idaho Public Utility Commission	Donn English Kathleen McHugh Matt Elam	Rick Sterling Terri Carlock
Northwest Gas Association	Ben Hemson	Dan Kirschner
Northwest Industrial Gas Users	Paula Pyron	
Northwest Natural Gas	John Sohl Mark Thompson	Sarah Dammen Jennifer Gross
Northwest Pipeline	Dave Allred Mike Rasmuson	Teresa Hagins
Northwest Power and Conservation Council	Terry Morlan	
Oregon Public Utility Commission	Ken Zimmerman	Lisa Gorsuch
Oregon CUB	Bob Jenks	
Puget Sound Energy	Gurvinder Singh	Phillip Popoff
TransCanada	Celeste Rudolph David White	Lee Bennett
Washington Attorney General's Office	Lea Daeschel	
Washington Utility and Transportation Commission	David Nightingale	Steven Johnson
	Deborah Reynolds Rick Applegate	Vonda Novak
WA Department of Commerce	Greg Nothstein	

APPENDIX 1.2 COMMENTS AND RESPONSES TO 2012 DRAFT INTEGRATED RESOURCE PLAN

The following table summarizes the significant comments on our DRAFT as submitted by TAC members and Avista's responses. The planning environment in this IRP cycle was especially challenging given some of the most challenging economic volatility seen in decades coupled with industry changing dynamics in natural gas production. We continued our robust, flexible demand forecasting methodology that captured a broad range of demand forecasts fully vetted with our TAC. This IRP produced reduced forecasted demand scenarios and no near term resource needs even in our most robust demand scenario. We appreciate the time and effort invested by all our TAC members throughout the IRP process. Many good suggestions have been made and we have incorporated those that enhance the document.

Document Reference[1]	Comment/Question	Avista Response
3.1 - DEMAND	Once again Staff requests that Avista Reverse this process. Evaluate need vs. resources in terms of annual average normal demand first and then move to need vs. resources in terms of peak demand. This builds demand and resources from the bottom up, which better represents how customer demand is actually built up and served.	We start with annual average demand and then do the peak demand forecast. We have enhanced the wording to make it clear that this is our process.
3.2 – DEMAND	Storage is a peak and near-peak resource only, correct?	Storage is to serve annual average demand as well as providing the delivery capacity to meet our peak or near-peak day requirements. Our plan is designed to ensure that there is sufficient gas available should a peak weather event occur.
3.2 - DEMAND	Do the analysis for each of these equations separately, and only later do the analysis for the two combined. See notes above.	The base usage factor is not annual average demand. Base usage is non-weather sensitive usage. This represents customer usage that is consistent throughout the year for applications like heating water in a residential home. The weather sensitive is usage that is dependent on temperature. When moving from annual average demand to peak the heating degree day assumption changes, thereby changing the amount of heat sensitive demand.

[1] All references are in reference to the DRAFT IRP submitted to the TAC on May 25, 2012.

Document Reference[1]	Comment/Question	Avista Response
3.2 - DEMAND	Basic questions to answer: Why would someone become a gas customer? After becoming a customer how much will that customer consume?	These questions are considered when developing the customer growth forecast. It is a combination of historical analysis and forward estimates driven primarily off of economics. The how much a customer will use is based initially on historical values but is altered for anticipated future issues. For example we adjust usage based on the change in natural gas prices through a price elasticity adjustment and demand side management measure adoption.
3.3 - DEMAND	So this average base and weather sensitive demand forecast, not design or extreme peak?	The use per customer coefficients is applied based on heating degree days. Base usage factors are multiplied by customers to develop base usage. Then heat sensitive coefficients are multiplied by customers and HDDs and are then added together. This methodology allows us to vary the weather assumption so we can do the build up from average load to peak load. Again we start by using the base and heat sensitive coefficients to develop an annual average demand forecast. We then change the weather assumption to incorporate peak weather and calculate the peak demand forecast.
3.6 - DEMAND	And these are ... ?	The worst case scenario would be the death or injury of a customer due to an outage at extremely cold temperatures. However, the potential cost due to appliance destruction, freezing pipes, etc. should also be a consideration.
3.12 - DEMAND	So the expected case for demand is that on average it will not grow over the next 20 years? Correct? Where is the expected case on this graph?	Total demand is expected to grow, but the elasticity adjustment and global warming also affect total annual demand. The difference between annual demand in the expected case and the alternate planning standard is minimal and so the lines lie almost on top of one another.

Document Reference[1]	Comment/Question	Avista Response
3.12 - DEMAND	Why is expected case peak demand growing? What are the primary and secondary elements underlying this growth?	Peak day demand is growing as customer counts grow. Additionally, we do not apply a price elastic adjustment to the peak factors, we assume that people are using at that level due to extreme temperatures not necessarily economically driven. Peak HDDs are also not adjusted for global warming.
3.13 - DEMAND	But you are still not checking your "statistical" or "stochastic" forecasting results with non-statistical approaches, so there is no cross verification?	We have researched many non-statistical forecasting methodologies and found them to be not relevant for our forecasting needs. Which non-statistical would provide proper verification? If we cannot find a valid non-statistical forecast then verification is not possible.
3.14 - DEMAND	But for IRP purposes you still need to focus on an "expected" case demand forecast and then integrate this into the expected case planning portfolio for the IRP.	We first do an average case, which shows that we are not resource deficient within the planning horizon. We then layer in the peak weather planning assumption which is our Expected case. The process is fully integrated.
4.1 - DSM	So potential estimates are not used? Isn't this contrary to the IRP guidelines?	Potential estimates are used. Before the DSM potential estimates were developed Global Energy Partners need to create a baseline demand forecast without any incremental DSM. From there Global developed its DSM potential which is used in the IRP.
5.8 – SUPPLY SIDE RESOURCES	But these must be included in the preferred portfolio and assessed in terms of cost and risk via that portfolio.	They are if the proposed enhancement solves a resource shortage in a particular region it is assessed in term of cost and risk in the same manner as other demand and supply side options. Many distribution projects are routine maintenance and reliability enhancements. These costs are not included in the IRP analysis.

Document Reference[1]	Comment/Question	Avista Response
6.21 – INTEGRATED PORTFOLIO	Highlighted conclusion statement	The sentence will be changed to reflect that the analysis is performed on the Average Demand case first and then the Expected Peak Demand case.
7.5 – ALTERNATE PORTFOLIO ANALYSIS	Does this include the $4.6M in distribution upgrades by 2014? See Table 8.1, Ref #3203.	Yes, the Medford project costs were included in the 2009 IRP and this IRP. However, it is important to understand that not all the capital projects detailed in Table 8.1 are included in the IRP analysis. Many of the capital projects are part of routine capital maintenance or are distribution system reliability/reinforcement issues and are not IRP issues. The IRP will include the costs necessary to facilitate additional interstate pipeline capacity takeaway when an area is resource deficient from a supply side, as was the case in Medford.

Document Reference[1]	Comment/Question	Avista Response
9.4 – ACTION PLAN	What supply-side resources does the IRP indicate are needed in the next two-three years? What demand-side resources does the IRP indicate are needed in the next two-three years? Which of those from #1 and #2 are included in the IRP for assessment? Any other resources shown in the IRP needed over next two-three years? Identify top 3-5 resource portfolios in terms of cost (NPVRR) and risk, and the portfolio chosen by the Company for this IRP (with all reasoning behind that choice laid out). Most of these values are included in Chapter 7, particularly the section called "Portfolio Selection" and in Table 7.3, as well as at the "Conclusion" section form Chapter 7. Also the chapter 7 analysis should be at least summarized in this chapter. Also, as noted on my notes for Table 7.3 an explanation needs to be included of whether the NPVRRs include the distribution resources and costs from Chapter 8, and summarized here.	The Action Plan was re-written to address these items.

Document Reference[1]	Comment/Question	Avista Response
Chapter 4 - DSM	Commission staff has some concerns that every one of the company's demand forecasts includes a Demand Side Management (DSM) effects adjustment on top of each forecast. Commission staff would like to see each one of the company's forecasts without this downward adjustment in load. This is due to current relative uncertainty of actual net effect that DSM has on load, and various off-setting factors that may be present and unaccounted for when calculating an estimated impact on the company's overall load. The company may include a forecast which incorporates this downward adjustment, but also alongside that forecast, have a picture of load without this adjustment. Commission staff would also like see the performance of these downward adjusted forecasts historically.	We show the graphs which will be included in Appendix 6 where we compare demand with and without DSM. The updated CPA provided less DSM potential than previous IRPs. There is not a material difference between the two which the graphs will show. Historic numbers which are used to generate the use per customer coefficients have embedded in them demand side management. A comparison of IRP use to actual is provided to staff each quarter as a part of our quarterly update.
Chapter 3 - DEMAND	In this current IRP, the company has developed Use Per Customer models for average use and for peak use, to better allow the company to depict (and predict) customer responses in terms of gas use in various temperature situations. For the company's super peak coefficients (which are utilized to model extreme occurrences, beyond typical annual peaks), it is necessary for the company to define what "very cold temperatures" were.	Very cold is defined as HDDs equal to or greater than 65.

Document Reference[1]	Comment/Question	Avista Response
Chapter 3 - DEMAND	Commission staff has concerns that the three years of data the Company used is not sufficient to establish its use per customer coefficients, and that Avista should consider using at least five years of data. The company has stated in its IRP that "five years incorporate some years of higher use per customer, which may overstate use due to changes in building codes and investments made in conservation initiatives[1]." Looking at figure 3.3[2] which shows a graph of the three-year Use Per Customer versus the five-year Use Per Customer on a total system basis, it appears the three-year and five-year lines lay relatively on top of one another. The speed of energy efficiency measure implementation and building code changes does not seem to commission staff to make such significant advances in a span of two years that these additional historical years must be excluded to prevent future bias in the company's Use Per Customer coefficients. Due to this observation, it makes sense to commission staff to utilize the five years of data points, to ensure that sufficient data points are used to allow development of a strong relationship.	The difference between 3 years and 5 years is not significantly different for Washington and Idaho. However, there is a significant difference for our Oregon service territory. In order to maintain consistency in our modeling and because the difference is insignificant in Washington and Idaho we utilized 3 years of data. There is a strong correlation, R-squared of over 90% with the three years of data.

[1] Chapter 3, Demand Forecasts, page 3.4

[2] Chapter 3, Demand Forecasts, page 3.5

Document Reference[1]	Comment/Question	Avista Response
Chapter 3 - DEMAND	Commission staff also has concerns about what seems to be a "conditional global warming" trend in its forecasts of future heating degree days in the planning period. The company claims that there has arisen from the analysis of historical weather data, a distinct warming trend in average weather data, yet the warming trend is absent, at least with any certainty, from the peak weather data. This caused the company to make adjustments downward in forecasts for future expected weather conditions, but not make any adjustments in future peak weather conditions. Commission staff is of the opinion that if a global warming trend exists, it should apply universally. At a minimum, the Company should explain in its next IRP why the trend is absent in the peak weather conditions.	We discussed the issue with the TAC at our first meeting. Consistent with our previous IRP we do not apply the global warming adjustment to our peak day weather planning assumption as we have not found evidence that global warming does in fact affect extreme events. If anything we have heard that volatility in weather may in fact be greater due to the overall global warming trend. To the extent we discover research counter to our current assumption we will assess it in our next IRP cycle.

Chapter 4 – DSM	The company has included in this overview of conservation, the low natural gas prices, and they have stated in their IRP that this is impacting the cost-effectiveness of measures due to the low avoided costs resulting from low natural gas prices. In WAC 480-90-238 (2) (b), the section titled "definitions", there is stated lowest reasonable cost mix of resources must, at a minimum, consider the following: Resource costs Market-volatility risks Demand-side resource uncertainties Risks imposed on ratepayers Resource effect on system operations Public policies regarding resource preference adopted by Washington state or the federal government Costs of risks associated with environmental effects including emissions of carbon dioxide Need for security of supply Commission staff has concerns that Avista's avoided costs calculation resulted in omitting many conservation measures, due to heavily emphasizing the relatively low cost of gas in this current time period, and the failure to consider appropriately the other variables which should play a larger role in the calculation. The nature of an IRP was meant to be utilized as a long-range planning tool, and commission staff considers the other variables mentioned in WAC 280-90-238 (2) (b) to be important, and not to be minimized. Specifically, commission staff would like the company to make a comparative avoided costs analysis to that shown in NW Natural's 2010 Natural Gas IRP, Docket UG-100245 in Chapter 6.2 and present the results in its revision of their draft plan. Commission staff notes that NW Natural included a 10% conservation adder to avoided costs to account for unquantifiable benefits of DSM as suggested by the NW Power and Conservation Council, as well as a CO2 emission adder. Commission staff would like to see these components added to Avista's avoided costs calculation.	The IRP selected essentially all the DSM that was given to the model. The avoided cost stream that comes from SENDOUT® does include a CO2 adder, as it is embedded in the expected price curve. The avoided costs also include variable charges (volumetric pipeline charges and fuel). This cost stream is provided to our DSM department for business planning purposes and program development/measurement, where they further incorporate the 10% conservation adder as well as a distribution system cost adder. Avista agrees with staff that the IRP is a long term plan and appropriately incorporates variables into the calculation. We agree that the low cost of gas in this current time period provides challenges for DSM programs; however the low cost is good for our customers. Additionally, we run a scenario with high prices to understand what implications that may have on our customer usage and portfolio costs and ultimately the avoided cost used to determine the cost effectiveness of DSM programs. Evaluation of the avoided costs will be ongoing. Should the price of natural gas rise rendering programs cost effective we will be proactive in requesting reinstatement our natural gas DSM programs.

APPENDIX 2.1 II AVISTA CORPORATION 2012 NATURAL GAS INTEGRATED RESOURCE PLAN WORK PLAN

IRP WORK PLAN REQUIREMENTS

Section 480-90-238 (4), of the natural gas Integrated Resource Plan ("IRP") rules, specify requirements for the IRP Work Plan:

> Not later than twelve months prior to the due date of a plan, the utility must provide a work plan for informal commission review. The work plan must outline the content of the integrated resource plan to be developed by the utility and the method for assessing potential resources.

Additionally, Section 480-90-238 (5) of the WAC states:

> The work plan must outline the timing and extent of public participation.

OVERVIEW

This Work Plan outlines the process Avista will follow to complete its 2012 Natural Gas IRP by Aug. 31, 2012. Avista uses a public process to obtain technical expertise and guidance throughout the planning period via Technical Advisory Committee (TAC) meetings. The TAC will be providing input into assumptions, scenarios, and modeling techniques.

PROCESS

The 2012 IRP process will be similar to that used to produce the previously published plan. Avista will use SENDOUT® (a PC based linear programming model widely used to solve natural gas supply and transportation optimization questions) to develop the risk adjusted least-cost resource mix for the 20 year planning period.

This plan will continue to include demand analysis, demand side management and avoided cost determination, existing and potential supply-side resource analysis, resource integration and alternative sensitivities and scenario analysis.

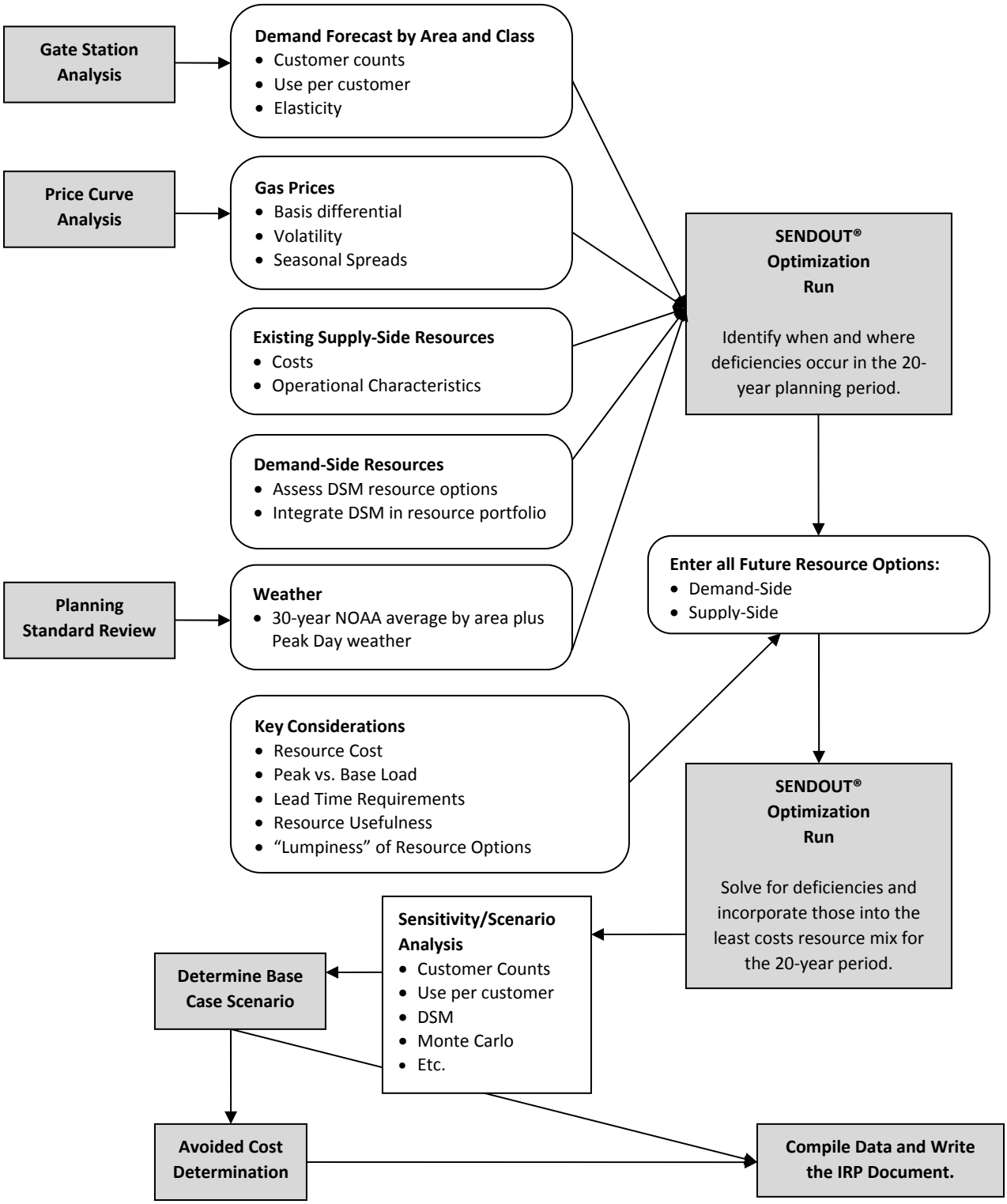
Additionally, Avista intends to incorporate action plan items identified in the 2009 Natural Gas IRP including more detailed demand analysis regarding use per customer, demand side management results and possible price elastic responses to evolving economic conditions, an updated assessment of conservation potential in our service territories, consideration of alternate forecasting methodologies, and the changing landscape of natural gas supply (i.e. shale gas, Canadian exports, and US LNG exports) and its implications to the planning process. Further details about Avista's process for determining the risk adjusted least-cost resource mix is shown in Exhibit 1.

TIMELINE

The following is Avista's TENTATIVE 2012 Natural Gas IRP timeline:

August 31, 2011	Work Plan filed with WUTC	
January through April 2012	Technical Advisory Committee meetings (exact meeting dates ***subject to change***). Meeting topics will include:	
	January 17	Demand Forecast & Demand-Side Management
	February 21	Distribution Planning & Supply/Infrastructure and Potential Case Discussion
	March 20	SENDOUT® Preliminary Output Results and Further Case Discussion
	April 17	SENDOUT® results
May 11, 2012	Draft of IRP document to TAC	
June 29, 2012	Comments on draft due back to Avista	
July 17, 2012	TAC final review meeting (if necessary)	
August 31, 2012	File finalized IRP document	

EXHIBIT 1: AVISTA'S 2012 NATURAL GAS IRP MODELING PROCESS



APPENDIX 2.2 II WASHINGTON PUBLIC UTILITY COMMISSION IRP POLICIES AND GUIDELINES – WAC 480-90-238

Avista Natural Gas IRP Review		
Rule	**Requirement**	**Plan Citation**
WAC 480-90-238(4)	Work plan filed no later than 12 months before next IRP due date.	Work plan submitted to the WUTC on August 31, 2011, See attachment to this Appendix 2.1.
WAC 480-90-238(4)	Work plan outlines content of IRP.	See workplan attached to this Appendix 2.1.
WAC 480-90-238(4)	Work plan outlines method for assessing potential resources. (See LRC analysis below)	See Appendix 2.1.
WAC 480-90-238(5)	Work plan outlines timing and extent of public participation.	See Appendix 2.1.
WAC 480-90-238(4)	Integrated resource plan submitted within two years of previous plan.	Last Integrated Resource Plan was submitted on December 31, 2009. In March 2011 the company asked to extend the deadline of filing to August 31, 2012 due to the lack of immediate resource needs and in order to alleviate resource burdens.
WAC 480-90-238(5)	Commission issues notice of public hearing after company files plan for review.	TBD
WAC 480-90-238(5)	Commission holds public hearing.	TBD
WAC 480-90-238(2)(a)	Plan describes mix of natural gas supply resources.	See Chapter 5 on Supply Side Resources
WAC 480-90-238(2)(a)	Plan describes conservation supply.	See Chapter 4 on Demand Side Resources
WAC 480-90-238(2)(a)	Plan addresses supply in terms of current and future needs of utility and ratepayers.	See Chapter 5 on Supply Side Resources and Chapter 6 Integrated Resource Portfolio
WAC 480-90-238(2)(a)&(b)	Plan uses lowest reasonable cost (LRC) analysis to select mix of resources.	See Chapters 4 and 5 for Demand and Supply Side Resources. Chapter 6 details how Demand and Supply come together to select the least cost/best risk portfolio for ratepayers.
WAC 480-90-238(2)(b)	LRC analysis considers resource costs.	See Chapters 4 and 5 for Demand and Supply Side Resources. Chapter 6 details how Demand and Supply come together to select the least cost/best risk portfolio for ratepayers.
WAC 480-90-238(2)(b)	LRC analysis considers market-volatility risks.	See Chapter 5 on Supply Side Resources
WAC 480-90-238(2)(b)	LRC analysis considers demand side uncertainties.	See Chapter 3 Demand Forecasting
WAC 480-90-238(2)(b)	LRC analysis considers resource effect on system operation.	See Chapter 5 and Chapter 6
WAC 480-90-238(2)(b)	LRC analysis considers risks imposed on ratepayers.	See Chapter 5 procurement plan section. We seek to minimize but cannot eliminate price risk for our customers.
WAC 480-90-238(2)(b)	LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government.	See Chapter 3 demand scenarios
WAC 480-90-238(2)(b)	LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	See Chapter 3 on demand scenarios
WAC 480-90-238(2)(b)	LRC analysis considers need for security of supply.	See Chapter 5 on Supply Side Resources

Rule	Requirement	Plan Citation
WAC 480-90-238(2)(c)	Plan defines conservation as any reduction in natural gas consumption that results from increases in the efficiency of energy use or distribution.	See Chapter 4 on Demand Side Resources
WAC 480-90-238(3)(a)	Plan includes a range of forecasts of future demand.	See Chapter 3 on Demand Forecast
WAC 480-90-238(3)(a)	Plan develops forecasts using methods that examine the effect of economic forces on the consumption of natural gas.	See Chapter 3 on Demand Forecast
WAC 480-90-238(3)(a)	Plan develops forecasts using methods that address changes in the number, type and efficiency of natural gas end-uses.	See Chapter 3 on Demand Forecast
WAC 480-90-238(3)(b)	Plan includes an assessment of commercially available conservation, including load management.	See Chapter 4 on Demand Side Management including demand response section.
WAC 480-90-238(3)(b)	Plan includes an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	See Chapter 4 and Appendix 4.1.
WAC 480-90-238(3)(c)	Plan includes an assessment of conventional and commercially available nonconventional gas supplies.	See Chapter 5 on Supply Side Resources
WAC 480-90-238(3)(d)	Plan includes an assessment of opportunities for using company-owned or contracted storage.	See Chapter 5 on Supply Side Resources
WAC 480-90-238(3)(e)	Plan includes an assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources.	See Chapter 5 on Supply Side Resources
WAC 480-90-238(3)(f)	Plan includes a comparative evaluation of the cost of natural gas purchasing strategies, storage options, delivery resources, and improvements in conservation using a consistent method to calculate cost-effectiveness.	See Chapter 4 on Demand Side Resources and Chapter 5 on Supply Side Resources
WAC 480-90-238(3)(g)	Plan includes at least a 10 year long-range planning horizon.	Our plan is a comprehensive 20 year plan.
WAC 480-90-238(3)(g)	Demand forecasts and resource evaluations are integrated into the long range plan for resource acquisition.	Chapter 6 Integrated Resource Portfolio details how demand and supply come together to form the least cost/best risk portfolio.
WAC 480-90-238(3)(h)	Plan includes a two-year action plan that implements the long range plan.	See Section 9 Action Plan
WAC 480-90-238(3)(i)	Plan includes a progress report on the implementation of the previously filed plan.	See Section 9 Action Plan
WAC 480-90-238(5)	Plan includes description of consultation with commission staff. (Description not required)	See Section 1 Introduction
WAC 480-90-238(5)	Plan includes description of completion of work plan. (Description not required)	See Appendix 2.1.

APPENDIX 2.2 II IDAHO PUBLIC UTILITY COMMISSION IRP POLICIES AND GUIDELINES – ORDER NO. 25342

	DESCRIPTION OF REQUIREMENT	FULLFILLMENT OF REQUIREMENT
1	Purpose and Process. Each gas utility regulated by the Idaho Public Utilities Commission with retail sales of more than 10,000,000,000 cubic feet in a calendar year (except gas utilities doing business in Idaho that are regulated by contract with a regulatory commission of another State) has the responsibility to meet system demand at least cost to the utility and its ratepayers. Therefore, an ''integrated resource plan'' shall be developed by each gas utility subject to this rule.	Avista prepares a comprehensive 20 year Integrated Resource Plan every two years. Avista will be filing its 2012 IRP on or before August 31, 2012.
2	Definition. Integrated resource planning. ''Integrated resource planning'' means planning by the use of any standard, regulation, practice, or policy to undertake a systematic comparison between demand-side management measures and the supply of gas by a gas utility to minimize life-cycle costs of adequate and reliable utility services to gas customers. Integrated resource planning shall take into account necessary features for system operation such as diversity, reliability, dispatchability, and other factors of risk and shall treat demand and supply to gas consumers on a consistent and integrated basis.	Avista's IRP brings together dynamic demand forecasts and matches them against demand-side and supply-side resources in order to evaluate the least cost/best risk portfoio for its core customers. While the primiary focus has been to ensure customer's needs are met under peak or design weather conditions, this process also evaluates the resource portfolio under normal/average operating conditions. The IRP provides the framework and methodology for evaluating Avista's natural gas demand and resources.
3	Elements of Plan. Each gas utility shall submit to the Commission on a biennial basis an integrated resource plan that shall include:	2012 IRP to be filed on or before August 31, 2012. The last IRP was filed on December 31, 2009. In March 2011 Avista asked for an extention in meeting the filing deadline. The lack of immediate resource needs coupled with better balancing of work load needs facilitated a change to the August 31, 2012 filing date.
a.	A range of forecasts of future gas demand in firm and interruptible markets for each customer class for one, five, and twenty years using methods that examine the effect of economic forces on the consumption of gas and that address changes in the number, type and e-fficiency of gas end-uses.	See **Chapter 3 - Demand Forecasts** and **Appendix 3 et. al.** for a detailed discussion of how demand was forecasted for this IRP.
b.	An assessment for each customer class of the technically feasible improvements in the efficient use of gas, including load management, as well as the policies and programs needed to obtain the efficiency improvements.	See **Chapter 4 - Demand Side Management** and **DSM Appendicies 4 et.al.** for detailed information on the DSM potential evaluated and selected for this IRP and the operational implementation process.
c.	An analysis for each customer class of gas supply options, including: (1) a projection of spot market versus long-term purchases for both firm and interruptible markets; (2) an evaluation of the opportunities for using company-owned or contracted storage or production; (3) an analysis of prospects for company participation in a gas futures market; and (4) an assessment of opportunities for access to multiple pipeline suppliers or direct purchases from producers.	See **Chapter 5 - Supply-Side Resources** for details about the market, storage, and pipeline transportation as well as other resource options considered in this IRP. See also the procurement plan section in this same chapter for supply procurement strategies.
d.	A comparative evaluation of gas purchasing options and improvements in the efficient use of gas based on a consistent method for calculating cost-effectiveness.	See Methodology section of **Chapter 4 - Demand-Side Resources** where we describe our process on how demand-side and supply-side resources are compared on par with each other in the SENDOUT® model. Chapter 4 also includes how results from the IRP are then utilized to create operational business plans. Operational implementation may differ from IRP results due to modeling assumptions.
e.	The integration of the demand forecast and resource evaluations into a long-range (e.g., twenty-year) integrated resource plan describing the strategies designed to meet current and future needs at the lowest cost to the utility and its ratepayers.	See **Chapter 6 - Integrated Resource Portfolio** for details on how we model demand and supply coming together to provide the least cost/best risk portfolio of resources.
f.	A short-term (e.g., two-year) plan outlining the specific actions to be taken by the utility in implementing the integrated resource plan.	See **Chapter 9 - Action Plan** for actions to be taken in implementing the IRP.
4	Relationship Between Plans. All plans following the initial integrated resource plan shall include a progress report that relates the new plan to the previously filed plan.	Avista strives to meet at least bi-annually with Staff and/or Commisioners to discuss the state of the market, procurement planning practices, and any other issues that may impact resource needs or other analysis within the IRP.
5	Plans to Be Considered in Rate Cases. The integrated resource plan will be considered with other available information to evaluate the performance of the utility in rate proceedings before the Commission.	We prepare and file our plan in part to establish a public record of our plan.
6	Public Participation. In formulating its plan, the gas utility must provide an opportunity for public participation and comment and must provide methods that will be available to the public of validating predicted performance.	Avista held four Technical Advisory Committee meetings beginning in January and ending in April. See **Chapter 1 - Introduction** for more detail about public participation in the IRP process.

7	Legal Effect of Plan. The plan constitutes the base line against which the utility's performance will ordinarily be measured. The requirement for implementation of a plan does not mean that the plan must be followed without deviation. The requirement of implementation of a plan means that a gas utility, having made an integrated resource plan to provide adequate and reliable service to its gas customers at the lowest system cost, may and should deviate from that plan when presented with responsible, reliable opportunities to further lower its planned system cost not anticipated or identified in existing or earlier plans and not undermining the utility's reliability.	See section titled "Avista's Procurement Plan" in **Chapter 5 - Supply-Side Resources**. Among other details we discuss plan revisions in response to changing market conditions.
	In order to encourage prudent planning and prudent deviation from past planning when presented with opportunities for improving upon a plan, a gas utility's plan must be on file with the Commission and available for public inspection. But the filing of a plan does not constitute approval or disa-pproval of the plan having the force and effect of law, and deviation from the plan would not constitute violation of the Commission's Orders or rules. The prudence of a utility's plan and the utility's prudence in following or not following a plan are matters that may be considered in a general rate proceeding or other proce-edings in which those issues have been noticed.	See also section titled "Alternate Supply-Side Scenarios" in **Chapter 6 - Integrated Resource Portfolio** where we discuss different supply portfolios that are resonsive to changing assumptions about resource alternatives.

APPENDIX 2.2 II OREGON PUBLIC UTILITY COMMISSION IRP STANDARD AND GUIDELINES – ORDER 07- 002

Guideline 1: Substantive Requirements		
1.a.1	All resources must be evaluated on a consistent and comparable basis.	All resource options considered, including demand-side and supply-side are modeled in SENDOUT® utilizing the same common general assumptions, approach and methodology.
1.a.2	All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	Avista considered a range of resources including demand-side management, distribution system enhancements, capacity release recalls, interstate pipeline transportation, interruptible customer supply, and storage options including liquefied natural gas. Chapter 4 and Appendix 4.1 documents Avista's demand-side management resources considered. Chapter 5 and Appendix 6.3 documents supply-side resources. Chapter 6 and 7 documents how Avista developed and assessed each of these resources.
1.a.3	Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	Avista considered various combinations of technologies, lead times, in-service dates, durations, and locations. Chapter 6 provides details about the modeling methodology and results. Chapter 5 describes resource attributes and Appendix 6.3 summarizes the resources' lead times, in-service dates and locations.
1.a.4	Consistent assumptions and methods should be used for evaluation of all resources.	Appendix 6.2 documents general assumptions used in Avista's SENDOUT® modeling software. All portfolio resources both demand and supply-side were evaluated within SENDOUT® using the same sets of inputs.
1.a.5	The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	Avista applied its after-tax WACC of 5.35% to discount all future resource costs. (See general assumptions at Appendix 6.2)
1.b.1	Risk and uncertainty must be considered. Electric utilities only	Not Applicable
1.b.2	Risk and uncertainty must be considered. Natural gas utilities should consider demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas (GHG) emissions.	Risk and uncertainty are key considerations in long term planning. In order to address risk and uncertainties a wide range of sensitivity, scenario and portfolio analysis is completed. A description of risk associated with each scenario is included in Appendix 3.6. One of the key risks is the "flat demand" risk as described in Chapter 2. Avista performed 14 sensitivities on demand. From there five demand scenarios were developed (Table 1.1) for SENDOUT® modeling purposes. Monthly demand coefficients were developed for base, heating demand while peak demand was contemplated through modeling a weather planning standard of the coldest day on record (see heating degree day data in Appendix 3.4). Avista evaluated several price forecasts and selected high, medium and low price scenarios for modeling purposes. The annual average prices are then weighted by month using fundamental forecast data. Additionally, the Henry Hub price forecasts are basis adjusted using the same fundamental forecast data.

		Four supply scenarios were also evaluated, see Table 5.3. These supply scenarios were combined with demand scenarios in order to establish portfolios for evaluation. Ultimately 9 portfolios were evaluated (See Table 7.3 for the PVRR results). Avista stochastic modeling techniques for price and weather variables to analyze weather sensitivity and to quantify the risk to customers under varying price environments. While there continues to be some uncertainty around GHG emission, Avista considered GHG emissions regulatory compliance costs in Appendix 4.2. As currently modeled, we include a carbon adder to our price curve to capture the costs of emission regulation.
	Utilities should identify in their plans any additional sources of risk and uncertainty.	Avista evaluated additional risks and uncertainties. Risks associated with the planning environment are detailed in Chapter 1 Introduction. Avista also analyzed demand risk which is detailed in Chapter 3. Chapter 4 discusses the uncertainty around how much DSM is achievable. Supply-side resource risks are discussed in Chapter 5. Chapter 6 and 7 discusses the variables modeled for scenario and stochastic risk analysis.
1c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.	Avista evaluated cost/risk tradeoffs for each of the risk analysis portfolios considered. See Chapter 6 and 7 plus supporting information in Appendix 3.6 for Avista's portfolio risk analysis and determination of the preferred portfolio.
	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	Avista used a 20-year study period for portfolio modeling. Avista contemplated possible costs beyond the planning period that could affect rates including end effects such as infrastructure decommission costs and concluded there were no significant costs reasonably likely to impact rates under different resource selection scenarios.
	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs of all long-lived resources such as power plants, gas storage facilities and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	Avista's SENDOUT® modeling software utilizes a PVRR cost metric methodology applied to both long and short-lived resources.
	To address risk, the plan should include at a minimum: 1) Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes. 2) Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	Avista, through its stochastic analysis, modeled 200 scenarios around varying gas price inputs via Monte Carlo iterations developing a distribution of Total 20 year cost estimates utilizing SENDOUT®'s PVRR methodology. Chapter 7 further describes this analysis. The variability of costs is plotted against the Expected Case while the scenarios beyond the 95th percentile capture the severity of outcomes. Chapter 5 discusses Avista's physical and financial hedging methodology.
	The utility should explain in its plan how its resource choices appropriately	Chapter 5, 6, and 7 describe various specific resource considerations and related risks, and describes what criteria

	balance cost and risk.	we used to determine what resource combinations provide an appropriate balance between cost and risk.
1d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	Avista considered current and expected state and federal energy policies in portfolio modeling. Chapter 6 describes the decision process used to derive portfolios, which includes consideration of state resource policy directions.
Guideline 2: Procedural Requirements		
2a	The public, including other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan.	Chapter 1 provides an overview of the public process and documents the details on public meetings held for the 2012 IRP. Avista encourages participation in the development of the plan, as each party brings a unique perspective and the ability to exchange information and ideas makes for a more robust plan.
	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan.	The entire IRP, as well as the TAC process, includes all of the non-confidential information the company used for portfolio evaluation and selection. Avista also provided stakeholders with non-confidential information to support public meeting discussions via email. The document and appendices will be available on the company website for viewing.
	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	Avista distributed a draft IRP document for external review to all TAC members on May 25, 2012 and requested comments by July 13, 2012.
Guideline 3: Plan Filing, Review and Updates		
3a	Utility must file an IRP within two years of its previous IRP acknowledgement order.	This Plan complies with this requirement as the 2009 Natural Gas IRP was acknowledged on 6/08/2010.
3b	Utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	Avista will work with Staff to fulfill this guideline following filing of the IRP.
3c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing	Pending
3d	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order	Pending
3e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	Pending
3f	Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility	An annual update was filed on May 9, 2011. No request for acknowledgement was required.

	anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update	
3g	Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that: ▪ Describes what actions the utility has taken to implement the plan; ▪ Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and ▪ Justifies any deviations from the acknowledged action plan.	The annual update filed on May 9, 2011 was an informational filing updating changes since acknowledgment of the 2009 IRP and an update of emerging planning issues. The update did not request acknowledgement of any changes. A request to present the information at a public meeting was not requested.
Guideline 4: Plan Components		
	At a minimum, the plan must include the following elements:	
4a	An explanation of how the utility met each of the substantive and procedural requirements.	This table summarizes guideline compliance by providing an overview of how Avista met each of the substantive and procedural requirements for a natural gas IRP.
4b	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions.	Avista developed five demand growth forecasts for scenario analysis. Stochastic variability of demand was also captured in the risk analysis. Chapter 2 describes the demand forecast data and Chapter 6 provides the scenario and risk analysis results. Appendix 6 details major assumptions.
4c	For electric utilities only	Not Applicable
4d	A determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources.	Figures 1.11 and 1.12 summarize graphically projected annual peak day demand and the existing and selected resources by year to meet demand for the expected case. Appendix 7.1 and 7.2 summarizes the peak day demand for the other demand scenarios.
4e	Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology	Chapter 4 and Appendix 4.1 identify the demand-side potential included in this IRP. Chapter 5 and 6 and Appendix 6.3 identify the supply-side resources.
4f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	Chapter 6, 7, and 8 discusses the modeling tools, customer growth forecasting and cost-risk considerations used to maintain and plan a reliable gas delivery system. These Chapters also captures a summary of the reliability analysis process demonstrated at the second TAC meeting.

		Chapter 5 discusses the diversified infrastructure and multiple supply basin approach that acts to mitigate certain reliability risks. Appendix 3.6 highlights key risks associated with each portfolio.
4g	Identification of key assumptions about the future (e.g. fuel prices and environmental compliance costs) and alternative scenarios considered.	Appendix 6 and Chapter 6 describe the key assumptions and alternative scenarios used in this IRP.
4h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations - system-wide or delivered to a specific portion of the system.	This Plan documents the development and results for portfolios evaluated in this IRP (see Table 5.3 for supply scenarios considered).
4i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties.	We evaluated our candidate portfolio by performing stochastic analysis using SENDOUT® varying price under 200 different scenarios. Additionally, we test the portfolio of options with the use of SENDOUT® under deterministic scenarios where demand and price vary. For resources selected, we assess other risk factors such as varying lead times required and potential for cost overruns outside of the amounts included in the modeling assumptions.
4j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Avista's four distinct geographic Oregon service territories limit many resource option synergies which inherently reduces available portfolio options. Feasibility uncertainty, lead time variability and uncertain cost escalation around certain resource options also reduce reasonably viable options. Chapter 5 describes resource options reviewed including discussion on uncertainties in lead times and costs as well as viability and resource availability (e.g. LNG). Appendix 6.3 summarizes the potential resource options identifying investment and variable costs, asset availability and lead time requirements while results of resources selected are identified in Table 6.5 as well as graphically presented in Figure 6.18 and 6.19 for the Expected Case and Appendix 7.1 for the High Growth case.
4k	Analysis of the uncertainties associated with each portfolio evaluated	See the responses to 1.b above.
4l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers	Avista evaluated cost/risk tradeoffs for each of the risk analysis portfolios considered. Chapter 6 and Appendix 3.6 show the company's portfolio risk analysis, as well as the process and determination of the preferred portfolio.
4m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation	This IRP is presumed to have no inconsistencies.
4n	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as	Chapter 9 presents the IRP Action Plan with focus on the following areas: II Modeling II Supply/capacity II Forecasting II Regulatory communication II DSM

	in portfolio testing.	
Guideline 5: Transmission		
5	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	Not applicable to Avista's gas utility operations.
Guideline 6: Conservation		
6a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	Global Energy Inc. performed a conservation potential assessment study for our 2012 IRP. A discussion of the study is included in Chapter 4. The full study document is in Appendix 4.1. Avista incorporates a comprehensive assessment of the potential for utility acquisition of energy-efficiency resources into the regularly-scheduled Integrated Resource Planning process.
6b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	A discussion on the treatment of conservation programs is included in Chapter 4 while selection methodology is documented in Chapter 6. The action plan details conservation targets, if any, as developed through the operational business planning process. These targets are updated annually, with the most current avoided costs. Given the challenge of the low cost environment, current operational planning and program evaluation is still underway and targets for Oregon have not yet been set.
6c	To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: 1) determine the amount of conservation resources in the best cost/ risk portfolio without regard to any limits on funding of conservation programs; and 2) identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	Not applicable. See the response for 6.b above.
Guideline 7: Demand Response		
7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	Avista has periodically evaluated conceptual approaches to meeting capacity constraints using demand-response and similar voluntary programs. Technology, customer characteristics and cost issues are hurdles for developing effective programs. See Chapter 4 Demand Response section for more discussion.
Guideline 8: Environmental Costs		
8	Utilities should include, in their base-case analyses, the regulatory	Avista's current direct gas distribution system infrastructure does not result in any CO2, NOx, SO2, or Hg emissions.

	compliance costs they expect for CO2, NOx, SO2, and Hg emissions. Utilities should analyze the range of potential CO2 regulatory costs in Order No. 93-695, from $0 - $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for NOx, SO2, and Hg, if applicable.	Upstream gas system infrastructure (pipelines, storage facilities, and gathering systems) do produce CO2 emissions via compressors used to pressurize and move gas throughout the system. The Environmental Externalities discussion in Appendix 4.2 describes our analysis performed. See also the guidelines addendum reflecting revised guidance for environmental costs per Order 08-339.
Guideline 9: Direct Access Loads		
9	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	Not applicable to Avista's gas utility operations.
Guideline 10: Multi-state utilities		
10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.	The 2012 IRP conforms to the multi-state planning approach.
Guideline 11: Reliability		
11	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	Avista's storage and transport resources while planned around meeting a peak day planning standard, also provides opportunities to capture off season pricing while providing system flexibility to meet swing and base-load requirements. Diversity in our transport options enables at least dual fuel source options in event of a transport disruption. For areas with only one fuel source option the cost of duplicative infrastructure is not feasible relative to the risk of generally high reliability infrastructure.
Guideline 12: Distributed Generation		
12	Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	Not applicable to Avista's gas utility operations.
Guideline 13: Resource Acquisition		
13a	An electric utility should: identify its proposed acquisition strategy for each resource in its action plan; Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party; identify any	Not applicable to Avista's gas utility operations.

	Benchmark Resources it plans to consider in competitive bidding.	
13b	Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.	A discussion of Avista's procurement practices is detailed in Chapter 5.
Guideline 8: Environmental Costs		
a.	BASE CASE AND OTHER COMPLIANCE SCENARIOS: The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. The utility also should develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Each compliance scenario should include a time profile of CO_2 compliance requirements. The utility should identify whether the basis of those requirements, or "costs", would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms such as allowance or credit trading or a safety valve). The analysis should recognize significant and important upstream emissions that would likely have a significant impact on its resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.	Avista's current direct gas distribution system infrastructure does not result in any CO2, NOx, SO2, or Hg emissions. Upstream gas system infrastructure (pipelines, storage facilities, and gathering systems) do produce CO2 emissions via compressors used to pressurize and move gas throughout the system. The Environmental Externalities discussion in Appendix 4.2 describes our process for addressing these costs.
b.	TESTING ALTERNATIVE PORTFOLIOS AGAINST THE COMPLIANCE SCENARIOS: The utility should estimate, under each of the compliance scenarios, the present value of revenue requirement (PVRR) costs and risk measures, over at least 20 years, for a set of reasonable alternative portfolios from which the preferred portfolio is selected. The utility should incorporate end-effect considerations in the analyses to allow for comparisons of portfolios containing resources with economic or physical lives that extend beyond the planning period. The utility should also modify projected lifetimes	The Environmental Externalities discussion in Appendix 4.2 describes our process for addressing these costs.

	as necessary to be consistent with the compliance scenario under analysis. In addition, the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection.	

APPENDIX 3.1 II ECONOMIC OUTLOOK AND CUSTOMER COUNT FORECAST

INTRODUCTION

For over twenty five years, Avista has produced natural gas customer forecasts which assume there is a direct relationship between economic growth and customer growth. This update of the Natural Gas Integrated Resource Plan continues this tradition. It would come as no surprise to readers that other utilities around the country use similar methods and procedures to produce customer forecasts. What follows is a narrative description of the methodology. A verbal description was provided at the 1st Technical Advisory Committee meeting held in Portland, Oregon, on January 17, 2012.

The Avista customer forecast is the primary driver of natural gas demand from firm natural gas customers. The forecast is produced by staff in the Finance Department, Financial Planning and Analysis group. These forecasts are produce annually in June of each calendar year and provide the basis for revenue forecasts, demand forecasts, purchased gas adjustments and general rate cases. The company employs the "one forecast" concept, wherein consistency across all parts of the business and regulatory environment is synchronized. However, the company does from time to time update forecasts when there is turbulence in the economy. This provides for flexibility as opposed to rigidity in terms of making good decisions for customers during unusual times. It would be accurate to say that between 2007 and 2010 the economy was moving downward as the recession evolved and the impacts on near term projections of customer growth were significant. The company updated their forecasts more frequently during this period, but now that the economy has settled down into a less volatile state forecast updates have returned to an annual update cycle. The forecast presented in this document was produced in June 2011 and relied on economic forecasts and actual customer data from May 2011. At this writing, an update to the customer forecast is being prepared for completion in June 2012. Early indications suggest the new forecast will not have material short term or long term adjustments from the base case.

In order to stress test the demand forecast, alternative customer forecasts have been prepared using publically available data from reliable sources. For at least the last five company natural gas plans, Avista has relied on high and low population forecasts from the State of Washington, Office of Financial Management, to provide alternative trajectories of customer growth. The principal economic drivers for the base case customer forecast are purchased from IHS Global Insight, Inc. As in previous plans, Avista's contract with Global Insight provides the company with a twenty five year forecast of economic drivers in the three metropolitan areas where we provide the bulk of our natural gas services (Spokane, Coeur d'Alene and Medford.) Avista also purchases limited economic forecasts from Global Insight on the other counties where we provide natural gas service. However, we rely on these metro-area forecasts as the primary drivers of customer forecasts in our Washington, Idaho and Oregon service areas.

What follows in order are discussions of the county-level forecasts, customer regressions and customer forecasts, with the final section addressing the alternative higher and lower forecasts.

SERVICE AREA ECONOMY

The service area economy in Washington includes ten mostly rural agriculture and resource extraction counties plus Spokane County, the regional metropolitan statistical area (MSA). Spokane County

(hereinafter referred to as Spokane) has a well diversified economy dominated by manufacturing, health care, retail and government. Spokane as well is a regional banking center and has a number of professional services firms (like architecture, engineering and information). One of the distinguishing characteristics of the company's Washington service area is the location of Washington State University roughly 75 miles south of downtown Spokane. But Spokane does have a large and growing public and private higher education sector. As the primary employment center for eastern Washington and northern Idaho, Spokane is also the largest area of customers and customer growth. In both 2010 and 2011, the Spokane area accounted for 45 percent of system customer growth, while Coeur d'Alene averaged 16 percent and Medford 14 percent. The remaining 25 percent of customer growth was widely spread between other counties in Washington, Idaho and Oregon. Subsequent paragraphs will detail information for Coeur d'Alene and Medford.

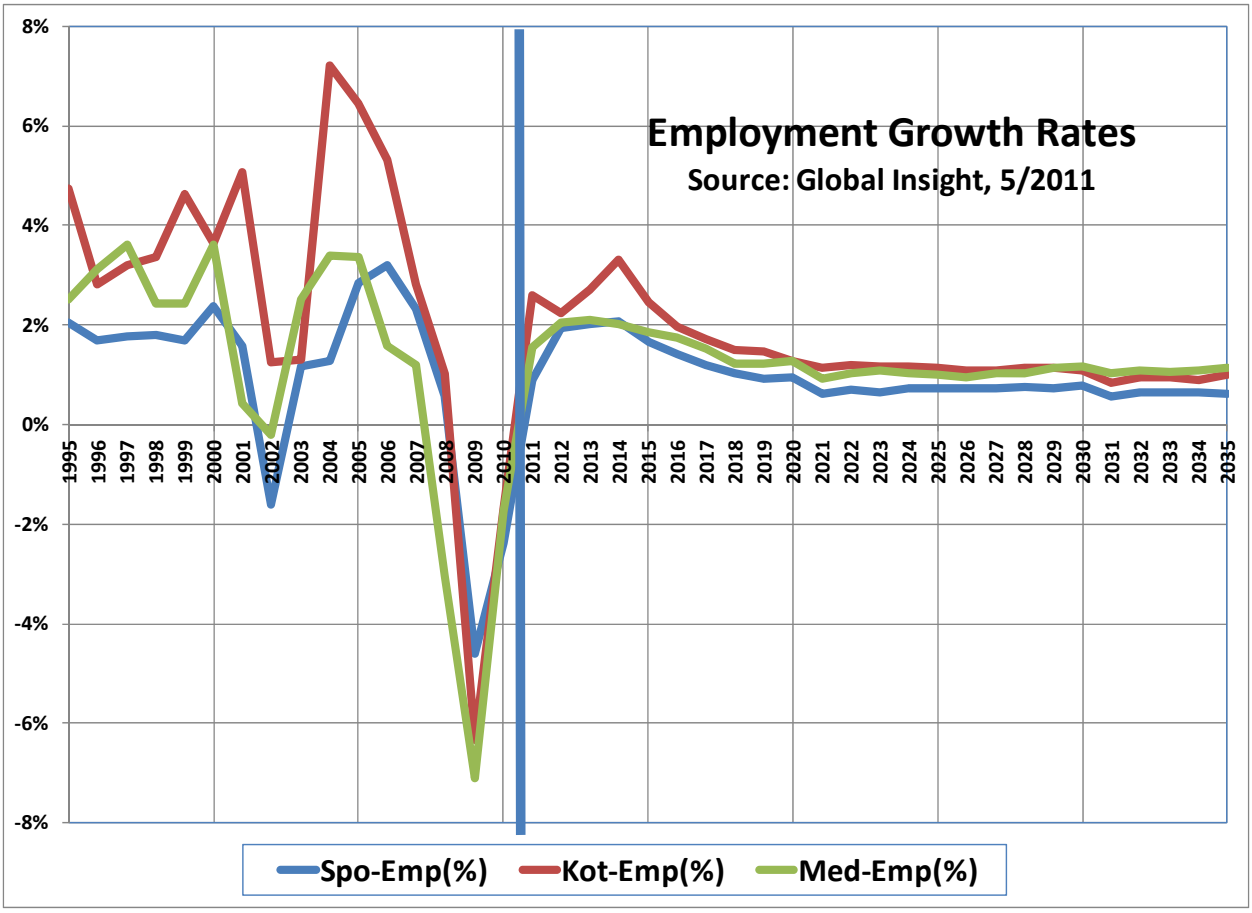
The service area in rural northern Idaho is similar to Washington but does substitute forestry for agriculture and Kootenai County (Coeur d'Alene) for Spokane. The metro area of Coeur d'Alene has been one of the faster growing parts of our service area and during the last census decade was one of the fastest growing counties in Idaho. Coeur d'Alene has an economic base that includes light manufacturing, health care and government services while its hospitality sector is a significant contributor to jobs. The remaining six counties have several notable large employers in the pulp and paper, mining and smelting and lumber and wood product industries. While Spokane has a very large higher education sector, Coeur d'Alene does not. In Idaho higher education is concentrated at the University of Idaho in Moscow, Idaho, and Lewis and Clark State in Lewiston, Idaho.

The company's Oregon service territory is made up of the urban areas of five counties, four of which are in southwestern Oregon and one small county in northeastern Oregon. Jackson County (with Medford as the largest city) is a metropolitan statistical area. Josephine County lies to the west of Jackson County and together the two counties, tied together by Interstate 5, comprise the Medford division of Avista. Due north of Josephine County is Douglas County, but the cities of Roseburg, Green, Winston, Sutherlin and Myrtle Creek lie in a different climate zone from Medford and the service area division of Roseburg is forecasted separately. The other geographic separation of the Oregon region occurs with Klamath County which lies due east of Jackson County but is separated by the Cascade mountain range not to mention being a few thousand feet higher elevation. For example, the Medford airport is at 1,335' elevation, while Klamath Falls airport is at 4,095' elevation. Due to the geographic separation and elevation differences, Klamath Falls and surrounding cities have a much colder climate than Medford and Roseburg. In order to accurately forecast customer demand, the Klamath Falls division is forecast separately. Last but not least, Union County (La Grande) is on Interstate 84 about 50 miles southeast of Pendleton, Oregon, represents less than 2 percent of customer growth but because of its climate and location isolation is forecast separately. Of the five counties, Jackson, Klamath Falls and La Grande are higher education centers with Southern Oregon, Oregon Institute of Technology and Eastern Oregon universities, respectively, located therein. With over 60 percent of Oregon customer growth, the Medford division of the company gets disproportionate scrutiny, but each of the four divisions employ the same customer forecast methodology.

The slides from Technical Advisory Committee #1 are available online. A brief summary of the forecasts follows. As mentioned previously, the company purchases county level forecasts from Global Insight. The charts provide a long term perspective, with historical data from 1995 to 2010 and forecasts from 2011 to 2035. Overall, it is clear from the slides that all three metro areas were briefly impacted by the brief recession in 2001 and were significantly impacted by the so-called "Great Recession" which began in 2007 and ended in 2009. Lackluster employment growth and slowly declining unemployment rates

have been the recent story. Global Insight forecasts a mild recovery in jobs begins during 2012 and gains steam in the 2013 to 2015 time period before settling back to its long term growth.

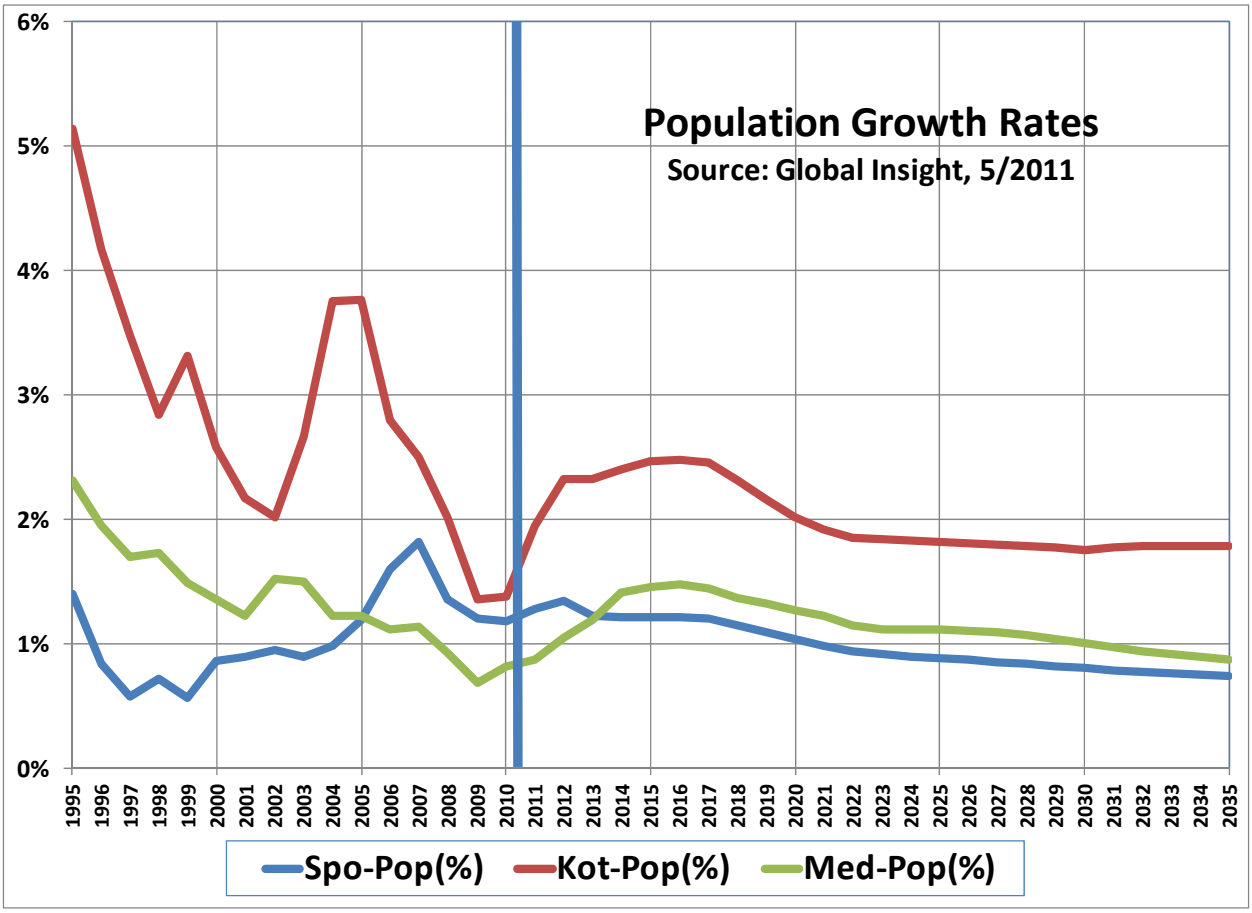
Chart F.1



It is clear from the chart above that employment growth rates which averaged over two percent in the prior fifteen years will be below two percent longer term in the next twenty-five years.

Global Insight largely drives their population forecast from their employment forecast although they do take into account changes in higher education enrollment and retirement and other migration impacts. The annual rates of growth of population in the three metro areas are shown on the following chart.

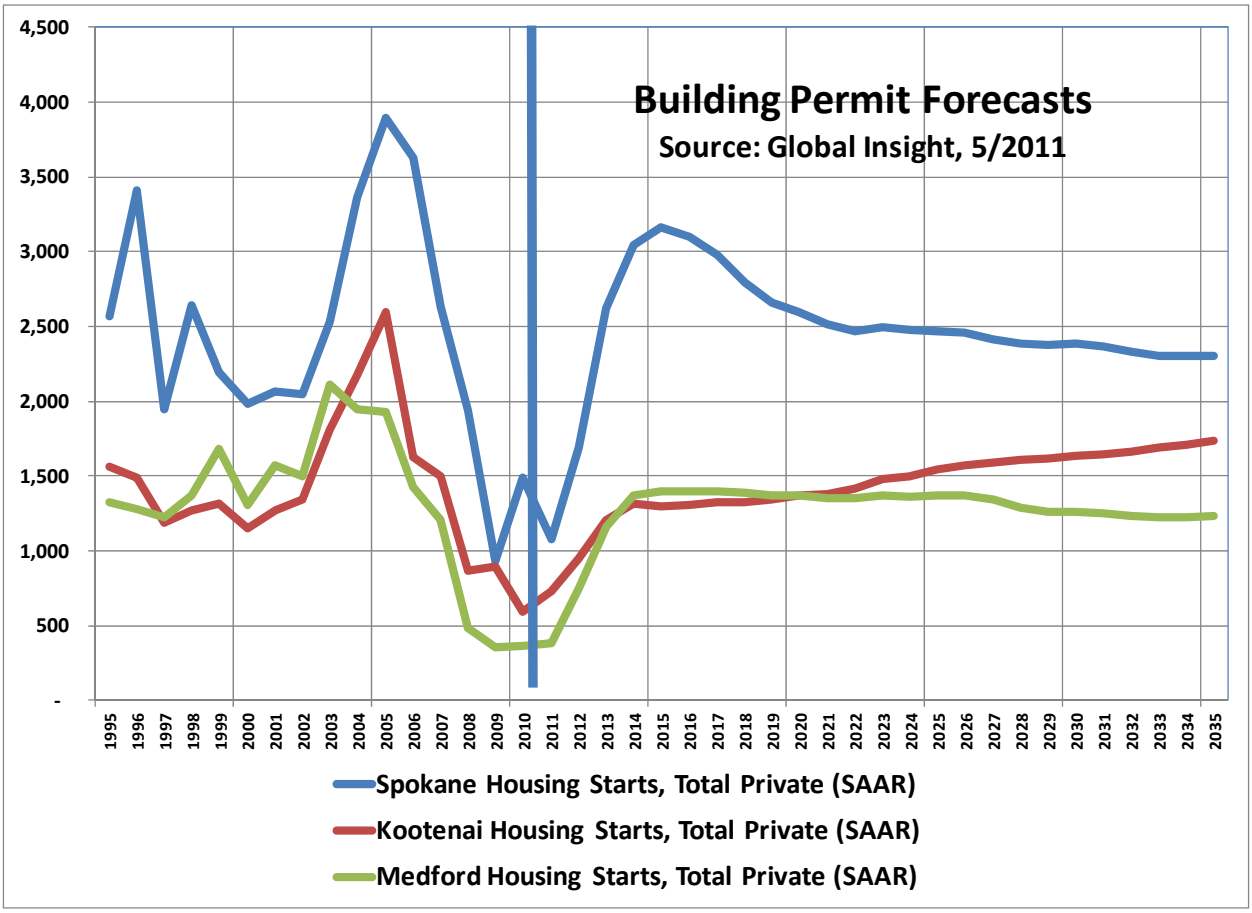
Chart F.2



Population growth rates have been highest in Kootenai County, Idaho as the "bedroom" effect of cross border commuting has been observed over the years. After a modest pause in population growth due to issues with labor mobility and recession –induced impacts, population growth is expected to rebound modestly consistent with the jobs forecast.

The population forecast becomes the key driver for the building permit forecasts for the three metro areas. After some recession induced absorption of foreclosures get worked out of the housing market and consistent with our observations and discussions locally with homebuilders and real estate professionals, the housing market forecasts shows a modest rebound.

Chart F.3



As we understand it, Global Insight has assumed banks and other financial institutions are expected to be more disciplined in lending practices such that the longer range forecasts do not include more housing bubbles or popped bubbles like we have observed in the recent history. Although we remain skeptical about this notion that housing cycles will be tempered, we do believe that these fundamentals based forecasts of housing are appropriate for long term natural gas customer forecasting. We have one additional observation about chart F.3; the apparent amplified rebound in Spokane housing permits is impacted by a large number of multi-family units being built to satisfy the growing higher education sector in Spokane which is largely absent in Coeur d'Alene. Although Medford has several higher education institutions, the growth there is expected to be muted due to state government policies and spending plans.

The final feature of economic data used to inform the customer forecast comes to us from using the State of Washington Office of Financial Management. In Washington, OFM's population forecasting division is the agency by law that produces population estimates for the Growth Management Act. At the time of the production of this Plan, OFM had produced a high, medium and low population forecast for Spokane County in 2007. At the 1st Technical Advisory Committee, we showed the members a table of population forecasts with these forecasts for 2010-2030. The high forecast in 2030 had 1.6 times the population growth of the medium forecast, and the low forecast during the same period had 0.6 times the population growth of the medium forecast. We proposed applying these ratios of population variation to our expected growth in residential customers because the logic of the building permit forecast ties to population

growth. We agreed it was a shortcut and represented to the committee this approach was reasonable and logical. We did not record any disagreement and have proceeded with this approach to scenarios.

CUSTOMER FORECAST REGRESSIONS

The process of customer forecasting employs regression analysis to utilize forecasts of building permits to produce forecasts of residential customer additions. We also use regression analysis to produce commercial customer additions as a function of residential customer additions. Indirectly, the logic and rationale is borrowed from Global Insight as follows. Employment drives population, population drives building permits, building permits drive residential customer growth, and residential customer growth drives commercial customer growth. Taking this full circle, employees have to work somewhere, and they largely work in commercial buildings. The forecasts for industrial employment are stable, and therefore we forecast firm industrial customers to grow slowly into the future. Important also is that firm industrial customers (and the therms they consume) are a very small portion of total firm sales.

CUSTOMER FORECASTS USED BY SENDOUT®

The company produces customer forecasts used by Sendout® in the following format. Monthly customer forecasts for residential, firm commercial and firm industrial for the combined Washington/Idaho service areas and the same customer forecasts for Oregon broken out by the four divisions, namely Medford, Roseburg, Klamath Falls and La Grande.

An annual summary for the Washington/Idaho region and for Oregon is shown in the table below. The term CGR is the compound growth rate from 2011-2031.

Table F.1

	Residential Customers	Commercial Customers	Industrial Customers
2006	185,897	20,884	247
2007	190,433	21,350	242
2008	194,316	21,844	238
2009	196,920	22,162	235
2010	198,604	22,344	230
2011	200,451	22,466	225
2012	203,404	22,621	228
2013	207,309	22,997	229
2014	211,420	23,442	231
2015	215,536	23,908	235
2016	219,611	24,370	237
2017	223,624	24,826	239
2018	227,540	25,267	241
2019	231,424	25,705	243
2020	235,300	26,141	244
2021	239,151	26,569	247
2022	243,002	26,998	248
2023	246,923	27,431	250
2024	250,835	27,864	251
2025	254,765	28,298	255
2026	258,699	28,732	256
2027	262,615	29,163	258
2028	266,515	29,593	259
2029	270,407	30,022	262
2030	274,312	30,446	263
2031	278,218	30,872	266
2032	282,115	31,295	267
2033	286,021	31,719	270
2034	289,943	32,145	271
2035	293,886	32,572	273
20 yr CGR 2011-31	1.65%	1.60%	0.84%

Table F.2

	Residential Medford Customers	Residential Roseburg Customers	Residential Klamath Falls Customers	Residential La Grande Customers	Commercial Medford Customers	Commercial Roseburg Customers	Commercial Klamath Falls Customers	Commercial La Grande Customers	Industrial Medford Customers	Industrial Roseburg Customers	Industrial Klamath Falls Customers	Industrial La Grande Customers
2006	49,002	12,726	13,424	6,296	6,263	2,134	1,585	878	1	2	0	3
2007	49,833	12,990	13,777	6,382	6,367	2,125	1,612	873	9	2	5	3
2008	50,239	13,037	13,859	6,441	6,427	2,120	1,624	886	10	2	5	3
2009	50,381	13,054	13,863	6,449	6,386	2,136	1,636	895	14	2	6	2
2010	50,682	13,077	13,886	6,473	6,433	2,124	1,635	895	13	2	7	2
2011	50,857	13,132	13,965	6,493	6,483	2,129	1,650	885	15	3	7	1
2012	51,282	13,250	14,090	6,528	6,513	2,149	1,670	895	15	3	7	1
2013	52,182	13,475	14,265	6,578	6,563	2,174	1,695	910	15	3	7	1
2014	53,432	13,775	14,515	6,628	6,643	2,204	1,725	925	15	3	7	1
2015	54,732	14,100	14,790	6,678	6,763	2,234	1,755	945	16	3	7	1
2016	56,027	14,434	15,059	6,737	6,886	2,258	1,780	958	16	3	7	1
2017	57,327	14,745	15,312	6,791	7,009	2,281	1,804	970	16	3	7	1
2018	58,616	15,034	15,553	6,842	7,131	2,303	1,827	981	16	3	7	1
2019	59,882	15,323	15,794	6,891	7,251	2,324	1,849	992	16	3	7	1
2020	61,139	15,614	16,034	6,940	7,369	2,346	1,872	1,002	17	3	7	1
2021	62,374	15,902	16,271	6,988	7,486	2,367	1,894	1,013	17	3	7	1
2022	63,608	16,189	16,506	7,036	7,603	2,388	1,916	1,023	17	3	7	1
2023	64,875	16,478	16,741	7,083	7,723	2,410	1,939	1,034	17	3	7	1
2024	66,137	16,771	16,977	7,130	7,842	2,431	1,961	1,044	17	3	7	1
2025	67,420	17,068	17,214	7,176	7,964	2,453	1,983	1,054	18	3	7	1
2026	68,698	17,368	17,452	7,223	8,085	2,476	2,006	1,064	18	3	7	1
2027	69,937	17,675	17,687	7,271	8,202	2,498	2,028	1,075	18	3	7	1
2028	71,120	17,906	17,919	7,321	8,314	2,515	2,050	1,086	18	3	7	1
2029	72,271	18,133	18,147	7,373	8,423	2,532	2,071	1,097	18	3	7	1
2030	73,426	18,361	18,375	7,424	8,532	2,549	2,093	1,108	19	3	7	1
2031	74,569	18,590	18,602	7,475	8,640	2,566	2,114	1,119	19	3	7	1
2032	75,684	18,814	18,828	7,525	8,746	2,583	2,135	1,131	19	3	7	1
2033	76,786	19,042	19,056	7,576	8,850	2,599	2,157	1,142	19	3	7	1
2034	77,893	19,272	19,285	7,627	8,955	2,616	2,178	1,153	19	3	7	1
2035	79,008	19,500	19,513	7,678	9,060	2,633	2,200	1,164	19	3	7	1
20 yr CGR 2011-2031	1.93%	1.75%	1.44%	0.71%	1.45%	0.94%	1.25%	1.18%	1.26%	0.14%	0.00%	-1.30%

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION WASHINGTON AND IDAHO

	Washington and Idaho - Expected Growth			Washington and Idaho - High Growth			Washington and Idaho - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Jan-12	202,574	22,501	228	203,572	22,510	228	201,908	22,495	228
Feb-12	202,563	22,523	227	203,555	22,545	227	201,902	22,508	227
Mar-12	202,688	22,547	227	203,755	22,584	227	201,977	22,523	227
Apr-12	202,517	22,561	227	203,481	22,606	227	201,874	22,531	227
May-12	202,633	22,564	227	203,667	22,611	227	201,944	22,533	227
Jun-12	202,521	22,612	227	203,488	22,688	227	201,877	22,562	227
Jul-12	202,830	22,623	228	203,982	22,705	228	202,062	22,568	228
Aug-12	203,492	22,641	228	205,041	22,734	228	202,459	22,579	228
Sep-12	203,900	22,676	228	205,694	22,790	228	202,704	22,600	228
Oct-12	204,313	22,699	228	206,355	22,827	228	202,952	22,614	228
Nov-12	204,999	22,735	228	207,452	22,884	228	203,363	22,635	228
Dec-12	205,820	22,764	228	208,766	22,931	228	203,856	22,653	228
Jan-13	206,379	22,812	229	209,660	23,008	229	204,191	22,682	229
Feb-13	206,368	22,839	228	209,643	23,051	228	204,185	22,698	228
Mar-13	206,493	22,868	228	209,843	23,097	228	204,260	22,715	228
Apr-13	206,322	22,902	228	209,569	23,152	228	204,157	22,736	228
May-13	206,538	22,930	228	209,915	23,196	228	204,287	22,752	228
Jun-13	206,426	22,993	228	209,736	23,297	228	204,220	22,790	228
Jul-13	206,735	23,019	229	210,230	23,339	229	204,405	22,806	229
Aug-13	207,397	23,042	229	211,289	23,376	229	204,802	22,820	229
Sep-13	207,905	23,092	229	212,102	23,456	229	205,107	22,850	229
Oct-13	208,318	23,120	229	212,763	23,500	229	205,355	22,866	229
Nov-13	209,004	23,156	229	213,860	23,558	229	205,766	22,888	229
Dec-13	209,825	23,185	229	215,174	23,604	229	206,259	22,905	229
Jan-14	210,490	23,257	232	216,238	23,720	232	206,658	22,949	232
Feb-14	210,479	23,284	231	216,220	23,763	231	206,651	22,965	231
Mar-14	210,604	23,313	231	216,420	23,809	231	206,726	22,982	231
Apr-14	210,433	23,347	231	216,147	23,864	231	206,624	23,003	231
May-14	210,649	23,375	231	216,492	23,908	231	206,753	23,019	231
Jun-14	210,537	23,438	231	216,313	24,009	231	206,686	23,057	231
Jul-14	210,846	23,464	231	216,808	24,051	231	206,872	23,073	231
Aug-14	211,508	23,487	231	217,867	24,088	231	207,269	23,087	231
Sep-14	212,016	23,537	231	218,680	24,168	231	207,574	23,117	231
Oct-14	212,429	23,565	231	219,340	24,212	231	207,821	23,133	231
Nov-14	213,115	23,601	231	220,438	24,270	231	208,233	23,155	231
Dec-14	213,936	23,630	231	221,752	24,316	231	208,726	23,172	231
Jan-15	214,606	23,723	235	222,824	24,465	235	209,128	23,228	235
Feb-15	214,595	23,750	234	222,806	24,508	234	209,121	23,244	234
Mar-15	214,720	23,779	234	223,006	24,555	234	209,196	23,262	234
Apr-15	214,549	23,813	234	222,732	24,609	234	209,093	23,282	234
May-15	214,765	23,841	234	223,078	24,654	234	209,223	23,299	234
Jun-15	214,653	23,904	234	222,899	24,755	234	209,156	23,337	234
Jul-15	214,962	23,930	235	223,393	24,796	235	209,341	23,352	235
Aug-15	215,624	23,953	235	224,452	24,833	235	209,738	23,366	235
Sep-15	216,132	24,003	235	225,265	24,913	235	210,043	23,396	235
Oct-15	216,545	24,031	235	225,926	24,958	235	210,291	23,413	235
Nov-15	217,231	24,067	235	227,024	25,016	235	210,703	23,435	235
Dec-15	218,052	24,096	235	228,337	25,062	235	211,195	23,452	235
Jan-16	218,664	24,182	237	229,316	25,200	237	211,562	23,504	237
Feb-16	218,652	24,210	236	229,298	25,244	236	211,555	23,520	236

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION WASHINGTON AND IDAHO

	Washington and Idaho - Expected Growth			Washington and Idaho - High Growth			Washington and Idaho - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Mar-16	218,780	24,239	236	229,502	25,291	236	211,632	23,538	236
Apr-16	218,606	24,274	236	229,223	25,347	236	211,527	23,559	236
May-16	218,826	24,303	236	229,575	25,393	236	211,659	23,576	236
Jun-16	218,712	24,367	236	229,393	25,495	236	211,591	23,614	236
Jul-16	219,026	24,393	237	229,896	25,538	237	211,780	23,630	237
Aug-16	219,701	24,417	237	230,975	25,575	237	212,185	23,644	237
Sep-16	220,219	24,468	237	231,804	25,657	237	212,495	23,675	237
Oct-16	220,639	24,496	237	232,477	25,702	237	212,748	23,692	237
Nov-16	221,338	24,533	237	233,595	25,761	237	213,167	23,714	237
Dec-16	222,175	24,563	237	234,934	25,808	237	213,669	23,732	237
Jan-17	222,659	24,634	239	235,708	25,923	239	213,959	23,775	239
Feb-17	222,647	24,662	238	235,689	25,968	238	213,952	23,792	238
Mar-17	222,777	24,693	238	235,897	26,016	238	214,030	23,810	238
Apr-17	222,599	24,728	238	235,613	26,073	238	213,924	23,831	238
May-17	222,823	24,757	238	235,972	26,119	238	214,058	23,849	238
Jun-17	222,707	24,822	238	235,786	26,224	238	213,988	23,888	238
Jul-17	223,028	24,849	239	236,299	26,267	239	214,181	23,904	239
Aug-17	223,715	24,873	239	237,398	26,306	239	214,593	23,918	239
Sep-17	224,242	24,925	239	238,241	26,389	239	214,909	23,949	239
Oct-17	224,670	24,954	239	238,926	26,435	239	215,166	23,967	239
Nov-17	225,382	24,992	239	240,065	26,495	239	215,593	23,989	239
Dec-17	226,234	25,022	239	241,428	26,543	239	216,104	24,007	239
Jan-18	226,558	25,072	241	241,946	26,623	241	216,299	24,038	241
Feb-18	226,546	25,100	240	241,928	26,669	240	216,292	24,055	240
Mar-18	226,678	25,131	240	242,139	26,718	240	216,371	24,073	240
Apr-18	226,498	25,167	240	241,850	26,776	240	216,263	24,095	240
May-18	226,726	25,197	240	242,215	26,823	240	216,399	24,112	240
Jun-18	226,607	25,263	240	242,026	26,930	240	216,328	24,152	240
Jul-18	226,934	25,291	241	242,548	26,974	241	216,524	24,169	241
Aug-18	227,632	25,315	241	243,666	27,012	241	216,943	24,183	241
Sep-18	228,169	25,368	241	244,524	27,097	241	217,265	24,215	241
Oct-18	228,605	25,397	241	245,222	27,144	241	217,527	24,233	241
Nov-18	229,329	25,435	241	246,380	27,205	241	217,961	24,256	241
Dec-18	230,196	25,466	241	247,767	27,254	241	218,481	24,274	241
Jan-19	230,425	25,507	243	248,134	27,319	243	218,619	24,298	243
Feb-19	230,413	25,536	242	248,115	27,366	242	218,612	24,316	242
Mar-19	230,547	25,567	242	248,330	27,415	242	218,692	24,335	242
Apr-19	230,364	25,603	242	248,036	27,474	242	218,582	24,356	242
May-19	230,596	25,634	242	248,407	27,522	242	218,721	24,375	242
Jun-19	230,475	25,701	242	248,215	27,630	242	218,649	24,415	242
Jul-19	230,807	25,729	243	248,745	27,675	243	218,848	24,432	243
Aug-19	231,518	25,754	243	249,883	27,715	243	219,275	24,447	243
Sep-19	232,063	25,808	243	250,755	27,801	243	219,602	24,479	243
Oct-19	232,507	25,838	243	251,465	27,849	243	219,868	24,497	243
Nov-19	233,243	25,877	243	252,643	27,911	243	220,310	24,520	243
Dec-19	234,125	25,908	243	254,054	27,961	243	220,839	24,539	243
Jan-20	234,284	25,939	244	254,309	28,011	244	220,935	24,558	244
Feb-20	234,272	25,969	243	254,290	28,058	243	220,927	24,576	243
Mar-20	234,409	26,000	243	254,508	28,109	243	221,009	24,595	243
Apr-20	234,222	26,038	243	254,210	28,169	243	220,897	24,617	243

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION WASHINGTON AND IDAHO

	Washington and Idaho - Expected Growth			Washington and Idaho - High Growth			Washington and Idaho - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
May-20	234,458	26,068	243	254,587	28,218	243	221,039	24,635	243
Jun-20	234,336	26,137	243	254,391	28,328	243	220,965	24,677	243
Jul-20	234,673	26,166	244	254,931	28,373	244	221,168	24,694	244
Aug-20	235,396	26,191	244	256,087	28,414	244	221,601	24,709	244
Sep-20	235,950	26,245	244	256,975	28,501	244	221,934	24,742	244
Oct-20	236,401	26,276	244	257,696	28,550	244	222,205	24,760	244
Nov-20	237,150	26,315	244	258,894	28,613	244	222,654	24,784	244
Dec-20	238,046	26,347	244	260,328	28,664	244	223,192	24,803	244
Jan-21	238,119	26,364	247	260,444	28,691	247	223,235	24,813	247
Feb-21	238,106	26,394	246	260,424	28,739	246	223,228	24,831	246
Mar-21	238,245	26,426	246	260,646	28,791	246	223,311	24,850	246
Apr-21	238,055	26,464	246	260,343	28,851	246	223,197	24,873	246
May-21	238,295	26,495	246	260,726	28,901	246	223,341	24,892	246
Jun-21	238,171	26,565	246	260,527	29,013	246	223,266	24,934	246
Jul-21	238,514	26,594	247	261,076	29,059	247	223,472	24,951	247
Aug-21	239,248	26,620	247	262,251	29,100	247	223,913	24,966	247
Sep-21	239,812	26,675	247	263,153	29,189	247	224,251	25,000	247
Oct-21	240,270	26,706	247	263,886	29,239	247	224,526	25,018	247
Nov-21	241,031	26,746	247	265,104	29,303	247	224,983	25,042	247
Dec-21	241,942	26,779	247	266,561	29,354	247	225,529	25,062	247
Jan-22	241,953	26,790	248	266,579	29,372	248	225,536	25,068	248
Feb-22	241,941	26,820	247	266,559	29,420	247	225,529	25,086	247
Mar-22	242,082	26,853	247	266,785	29,473	247	225,613	25,106	247
Apr-22	241,889	26,891	247	266,477	29,534	247	225,497	25,129	247
May-22	242,133	26,923	247	266,866	29,585	247	225,644	25,148	247
Jun-22	242,006	26,994	247	266,664	29,699	247	225,568	25,191	247
Jul-22	242,355	27,023	248	267,222	29,746	248	225,777	25,208	248
Aug-22	243,101	27,049	248	268,416	29,787	248	226,225	25,224	248
Sep-22	243,674	27,106	248	269,332	29,878	248	226,568	25,258	248
Oct-22	244,139	27,137	248	270,077	29,928	248	226,848	25,277	248
Nov-22	244,913	27,178	248	271,315	29,993	248	227,312	25,301	248
Dec-22	245,838	27,211	248	272,796	30,046	248	227,867	25,321	248
Jan-23	245,857	27,220	250	272,825	30,060	250	227,878	25,326	250
Feb-23	245,844	27,251	249	272,805	30,110	249	227,871	25,345	249
Mar-23	245,988	27,284	249	273,034	30,163	249	227,957	25,365	249
Apr-23	245,792	27,323	249	272,721	30,225	249	227,839	25,388	249
May-23	246,039	27,355	249	273,117	30,277	249	227,987	25,407	249
Jun-23	245,911	27,427	249	272,911	30,392	249	227,910	25,451	249
Jul-23	246,265	27,457	250	273,478	30,440	250	228,123	25,469	250
Aug-23	247,023	27,484	250	274,691	30,482	250	228,578	25,485	250
Sep-23	247,605	27,541	250	275,622	30,574	250	228,927	25,519	250
Oct-23	248,078	27,573	250	276,379	30,625	250	229,211	25,538	250
Nov-23	248,864	27,614	250	277,637	30,692	250	229,683	25,563	250
Dec-23	249,805	27,648	250	279,142	30,745	250	230,247	25,583	250
Jan-24	249,752	27,649	251	279,058	30,747	251	230,215	25,584	251
Feb-24	249,739	27,680	250	279,037	30,797	250	230,208	25,603	250
Mar-24	249,885	27,714	250	279,270	30,851	250	230,295	25,623	250
Apr-24	249,686	27,754	250	278,951	30,914	250	230,176	25,647	250
May-24	249,937	27,786	250	279,354	30,967	250	230,326	25,666	250
Jun-24	249,807	27,860	250	279,145	31,084	250	230,248	25,710	250

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION WASHINGTON AND IDAHO

	Washington and Idaho - Expected Growth			Washington and Idaho - High Growth			Washington and Idaho - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Jul-24	250,167	27,890	251	279,720	31,133	251	230,464	25,728	251
Aug-24	250,937	27,917	251	280,953	31,175	251	230,926	25,745	251
Sep-24	251,528	27,975	251	281,899	31,269	251	231,281	25,780	251
Oct-24	252,009	28,008	251	282,668	31,321	251	231,569	25,799	251
Nov-24	252,807	28,050	251	283,945	31,388	251	232,048	25,824	251
Dec-24	253,763	28,084	251	285,474	31,442	251	232,622	25,845	251
Jan-25	253,666	28,080	255	285,320	31,436	255	232,564	25,842	255
Feb-25	253,653	28,112	254	285,299	31,487	254	232,556	25,862	254
Mar-25	253,801	28,146	254	285,535	31,542	254	232,644	25,882	254
Apr-25	253,599	28,186	254	285,212	31,607	254	232,523	25,906	254
May-25	253,854	28,220	254	285,620	31,660	254	232,676	25,926	254
Jun-25	253,722	28,294	254	285,409	31,779	254	232,597	25,971	254
Jul-25	254,087	28,325	255	285,993	31,828	255	232,816	25,989	255
Aug-25	254,869	28,352	255	287,245	31,872	255	233,286	26,006	255
Sep-25	255,470	28,411	255	288,206	31,967	255	233,646	26,041	255
Oct-25	255,958	28,445	255	288,987	32,020	255	233,939	26,061	255
Nov-25	256,769	28,487	255	290,284	32,088	255	234,425	26,087	255
Dec-25	257,739	28,521	255	291,837	32,143	255	235,008	26,107	255
Jan-26	257,583	28,510	256	291,587	32,124	256	234,914	26,100	256
Feb-26	257,570	28,542	255	291,566	32,176	255	234,906	26,120	255
Mar-26	257,720	28,577	255	291,806	32,232	255	234,996	26,141	255
Apr-26	257,515	28,618	255	291,477	32,297	255	234,873	26,165	255
May-26	257,774	28,652	255	291,892	32,351		235,028	26,185	255
Jun-26	257,639	28,727	255	291,677	32,472	255	234,948	26,231	255
Jul-26	258,010	28,759	256	292,270	32,522	256	235,170	26,250	256
Aug-26	258,805	28,786	256	293,542	32,567	256	235,647	26,266	256
Sep-26	259,415	28,846	256	294,517	32,663	256	236,013	26,302	256
Oct-26	259,910	28,880	256	295,310	32,717	256	236,310	26,322	256
Nov-26	260,734	28,923	256	296,628	32,786	256	236,804	26,348	256
Dec-26	261,719	28,958	256	298,204	32,842	256	237,395	26,369	256
Jan-27	261,482	28,938	258	297,825	32,809	258	237,253	26,357	258
Feb-27	261,468	28,971	257	297,803	32,862	257	237,245	26,377	257
Mar-27	261,621	29,006	257	298,047	32,918	257	237,336	26,398	257
Apr-27	261,412	29,048	257	297,714	32,984	257	237,211	26,423	257
May-27	261,676	29,082	257	298,135	33,039	257	237,369	26,443	257
Jun-27	261,539	29,159	257	297,917	33,162	257	237,287	26,490	257
Jul-27	261,916	29,190	258	298,519	33,213	258	237,513	26,509	258
Aug-27	262,722	29,218	258	299,809	33,258	258	237,997	26,525	258
Sep-27	263,341	29,279	258	300,800	33,355	258	238,369	26,562	258
Oct-27	263,844	29,313	258	301,605	33,410	258	238,671	26,582	258
Nov-27	264,680	29,357	258	302,942	33,480	258	239,172	26,609	258
Dec-27	265,681	29,393	258	304,543	33,537	258	239,772	26,630	258
Jan-28	265,365	29,365	259	304,038	33,492	259	239,583	26,613	259
Feb-28	265,351	29,398	258	304,016	33,546	258	239,575	26,633	258
Mar-28	265,506	29,434	258	304,263	33,603	258	239,667	26,655	258
Apr-28	265,294	29,476	258	303,925	33,670	258	239,541	26,680	258
May-28	265,561	29,511	258	304,352	33,726	258	239,701	26,701	258
Jun-28	265,423	29,589	258	304,131	33,851	258	239,618	26,748	258
Jul-28	265,805	29,621	259	304,742	33,902	259	239,847	26,767	259
Aug-28	266,624	29,650	259	306,052	33,948	259	240,338	26,784	259

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION WASHINGTON AND IDAHO

	Washington and Idaho Expected Growth			Washington and Idaho - High Growth			Washington and Idaho - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Sep-28	267,252	29,711	259	307,057	34,047	259	240,715	26,821	259
Oct-28	267,762	29,746	259	307,874	34,102	259	241,021	26,842	259
Nov-28	268,611	29,791	259	309,231	34,173	259	241,530	26,869	259
Dec-28	269,626	29,827	259	310,855	34,231	259	242,140	26,890	259
Jan-29	269,240	29,790	262	310,237	34,172	262	241,908	26,868	262
Feb-29	269,226	29,824	261	310,215	34,227	261	241,900	26,889	261
Mar-29	269,383	29,860	261	310,466	34,285	261	241,994	26,911	261
Apr-29	269,168	29,903	261	310,123	34,353	261	241,865	26,936	261
May-29	269,439	29,938	261	310,557	34,409	261	242,027	26,957	261
Jun-29	269,299	30,017	261	310,332	34,536	261	241,943	27,005	261
Jul-29	269,686	30,050	262	310,952	34,588	262	242,176	27,024	262
Aug-29	270,517	30,079	262	312,281	34,634	262	242,674	27,042	262
Sep-29	271,154	30,142	262	313,301	34,735	262	243,056	27,079	262
Oct-29	271,672	30,177	262	314,130	34,791	262	243,367	27,100	262
Nov-29	272,533	30,222	262	315,507	34,863	262	243,884	27,128	262
Dec-29	273,563	30,258	262	317,155	34,922	262	244,502	27,149	262
Jan-30	273,128	30,211	263	316,459	34,846	263	244,241	27,121	263
Feb-30	273,114	30,246	262	316,436	34,901	262	244,232	27,142	262
Mar-30	273,273	30,283	262	316,691	34,961	262	244,328	27,164	262
Apr-30	273,055	30,326	262	316,343	35,030	262	244,197	27,190	262
May-30	273,330	30,362	262	316,783	35,087	262	244,362	27,211	262
Jun-30	273,188	30,442	262	316,554	35,215	262	244,277	27,259	262
Jul-30	273,581	30,475	263	317,184	35,268	263	244,513	27,279	263
Aug-30	274,424	30,504	263	318,532	35,315	263	245,018	27,297	263
Sep-30	275,070	30,568	263	319,566	35,417	263	245,406	27,335	263
Oct-30	275,596	30,604	263	320,407	35,474	263	245,721	27,357	263
Nov-30	276,469	30,649	263	321,804	35,547	263	246,245	27,384	263
Dec-30	277,514	30,686	263	323,476	35,606	263	246,872	27,406	263
Jan-31	277,018	30,633	266	322,682	35,522	266	246,575	27,374	266
Feb-31	277,004	30,668	265	322,660	35,578	265	246,566	27,395	265
Mar-31	277,165	30,706	265	322,918	35,638	265	246,663	27,418	265
Apr-31	276,944	30,750	265	322,565	35,708	265	246,530	27,444	265
May-31	277,223	30,786	265	323,011	35,766	265	246,698	27,466	265
Jun-31	277,078	30,867	265	322,779	35,896	265	246,611	27,515	265
Jul-31	277,477	30,901	266	323,418	35,950	266	246,850	27,535	266
Aug-31	278,332	30,930	266	324,785	35,997	266	247,363	27,553	266
Sep-31	278,988	30,995	266	325,834	36,100	266	247,757	27,591	266
Oct-31	279,521	31,031	266	326,687	36,158	266	248,076	27,613	266
Nov-31	280,406	31,078	266	328,104	36,233	266	248,608	27,641	266
Dec-31	281,466	31,115	266	329,799	36,293	266	249,244	27,663	266
Jan-32	280,897	31,053	267	328,890	36,194	267	248,902	27,626	267
Feb-32	280,883	31,089	266	328,867	36,251	266	248,894	27,648	266
Mar-32	281,047	31,127	266	329,129	36,311	266	248,992	27,670	266
Apr-32	280,823	31,171	266	328,771	36,382	266	248,858	27,697	266
May-32	281,106	31,208	266	329,223	36,441	266	249,027	27,719	266
Jun-32	280,959	31,290	266	328,988	36,573	266	248,939	27,769	266
Jul-32	281,363	31,324	267	329,635	36,628	267	249,182	27,789	267
Aug-32	282,230	31,355	267	331,022	36,676	267	249,702	27,807	267
Sep-32	282,895	31,420	267	332,086	36,780	267	250,101	27,846	267
Oct-32	283,435	31,457	267	332,951	36,839	267	250,425	27,868	267

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION WASHINGTON AND IDAHO

	Washington and Idaho - Expected Growth			Washington and Idaho - High Growth			Washington and Idaho - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Nov-32	284,333	31,504	267	334,387	36,914	267	250,964	27,897	267
Dec-32	285,408	31,542	267	336,107	36,975	267	251,609	27,919	267
Jan-33	284,787	31,474	270	335,113	36,867	270	251,236	27,879	270
Feb-33	284,772	31,510	269	335,090	36,924	269	251,227	27,900	269
Mar-33	284,938	31,548	269	335,355	36,986	269	251,327	27,923	269
Apr-33	284,711	31,593	269	334,992	37,058	269	251,191	27,950	269
May-33	284,998	31,631	269	335,451	37,117	269	251,363	27,973	269
Jun-33	284,849	31,714	269	335,213	37,251	269	251,274	28,023	269
Jul-33	285,259	31,749	270	335,869	37,306	270	251,520	28,044	270
Aug-33	286,138	31,779	270	337,274	37,355	270	252,047	28,062	270
Sep-33	286,812	31,846	270	338,353	37,461	270	252,451	28,102	270
Oct-33	287,360	31,883	270	339,230	37,521	270	252,780	28,124	270
Nov-33	288,270	31,930	270	340,686	37,597	270	253,326	28,153	270
Dec-33	289,360	31,969	270	342,430	37,659	270	253,980	28,176	270
Jan-34	288,692	31,897	271	341,361	37,544	271	253,579	28,133	271
Feb-34	288,677	31,933	270	341,338	37,602	270	253,570	28,154	270
Mar-34	288,846	31,972	270	341,607	37,664	270	253,671	28,178	270
Apr-34	288,615	32,018	270	341,239	37,737	270	253,533	28,205	270
May-34	288,906	32,056	270	341,704	37,798	270	253,708	28,228	270
Jun-34	288,755	32,140	270	341,463	37,933	270	253,617	28,279	270
Jul-34	289,171	32,175	271	342,128	37,989	271	253,867	28,300	271
Aug-34	290,062	32,206	271	343,553	38,038	271	254,401	28,318	271
Sep-34	290,745	32,274	271	344,646	38,146	271	254,811	28,359	271
Oct-34	291,301	32,311	271	345,535	38,206	271	255,144	28,381	271
Nov-34	292,223	32,360	271	347,011	38,284	271	255,698	28,410	271
Dec-34	293,328	32,399	271	348,778	38,346	271	256,361	28,434	271
Jan-35	292,617	32,321	273	347,642	38,221	273	255,934	28,387	273
Feb-35	292,602	32,357	272	347,618	38,280	272	255,925	28,409	272
Mar-35	292,773	32,397	272	347,890	38,343	272	256,028	28,433	272
Apr-35	292,540	32,443	272	347,517	38,418	272	255,888	28,460	272
May-35	292,834	32,481	272	347,989	38,479	272	256,064	28,483	272
Jun-35	292,681	32,567	272	347,744	38,616	272	255,973	28,535	272
Jul-35	293,103	32,603	273	348,418	38,673	273	256,226	28,556	273
Aug-35	294,005	32,634	273	349,863	38,723	273	256,767	28,575	273
Sep-35	294,698	32,702	273	350,971	38,832	273	257,183	28,616	273
Oct-35	295,261	32,740	273	351,872	38,893	273	257,521	28,639	273
Nov-35	296,196	32,789	273	353,368	38,971	273	258,082	28,668	273
Dec-35	297,316	32,829	273	355,160	39,034	273	258,754	28,692	273

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION MEDFORD

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Medford Customers	Commercial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commercial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commercia l Medford Customers	Industrial Medford Customers
Jan-12	51,338	6,544	15	51,762	6,581	15	51,056	6,520	15
Feb-12	51,254	6,553	15	51,627	6,595	15	51,005	6,525	15
Mar-12	51,297	6,489	15	51,696	6,493	15	51,031	6,487	15
Apr-12	51,214	6,510	15	51,563	6,526	15	50,981	6,499	15
May-12	51,264	6,505	18	51,643	6,518	18	51,011	6,496	18
Jun-12	51,177	6,500	15	51,504	6,510	15	50,959	6,493	15
Jul-12	51,096	6,494	15	51,374	6,501	15	50,910	6,490	15
Aug-12	51,095	6,492	15	51,373	6,497	15	50,910	6,488	15
Sep-12	51,027	6,502	15	51,264	6,513	15	50,869	6,494	15
Oct-12	51,232	6,513	15	51,592	6,531	15	50,992	6,501	15
Nov-12	51,508	6,527	15	52,034	6,553	15	51,158	6,509	15
Dec-12	51,884	6,531	15	52,635	6,560	15	51,383	6,512	15
Jan-13	52,038	6,594	15	52,882	6,661	15	51,476	6,550	15
Feb-13	51,954	6,603	15	52,747	6,675	15	51,425	6,555	15
Mar-13	51,997	6,539	15	52,816	6,573	15	51,451	6,517	15
Apr-13	52,014	6,560	15	52,843	6,606	15	51,461	6,529	15
May-13	52,064	6,555	18	52,923	6,598	18	51,491	6,526	18
Jun-13	52,077	6,550	15	52,944	6,590	15	51,499	6,523	15
Jul-13	51,996	6,544	15	52,814	6,581	15	51,450	6,520	15
Aug-13	52,095	6,542	15	52,973	6,577	15	51,510	6,518	15
Sep-13	52,027	6,552	15	52,864	6,593	15	51,469	6,524	15
Oct-13	52,332	6,563	15	53,352	6,611	15	51,652	6,531	15
Nov-13	52,608	6,577	15	53,794	6,633	15	51,818	6,539	15
Dec-13	52,984	6,581	15	54,395	6,640	15	52,043	6,542	15
Jan-14	53,138	6,674	15	54,642	6,789	15	52,136	6,598	15
Feb-14	53,054	6,683	15	54,507	6,803	15	52,085	6,603	15
Mar-14	53,197	6,619	15	54,736	6,701	15	52,171	6,565	15
Apr-14	53,214	6,640	15	54,763	6,734	15	52,181	6,577	15
May-14	53,364	6,635	18	55,003	6,726	18	52,271	6,574	18
Jun-14	53,377	6,630	15	55,024	6,718	15	52,279	6,571	15
Jul-14	53,296	6,624	15	54,894	6,709	15	52,230	6,568	15
Aug-14	53,395	6,622	15	55,053	6,705	15	52,290	6,566	15
Sep-14	53,327	6,632	15	54,944	6,721	15	52,249	6,572	15
Oct-14	53,632	6,643	15	55,432	6,739	15	52,432	6,579	15
Nov-14	53,908	6,657	15	55,874	6,761	15	52,598	6,587	15
Dec-14	54,284	6,661	15	56,475	6,768	15	52,823	6,590	15
Jan-15	54,438	6,794	16	56,722	6,981	16	52,916	6,670	16
Feb-15	54,354	6,803	16	56,587	6,995	16	52,865	6,675	16
Mar-15	54,497	6,739	16	56,816	6,893	16	52,951	6,637	16
Apr-15	54,514	6,760	16	56,843	6,926	16	52,961	6,649	16
May-15	54,664	6,755	19	57,083	6,918	19	53,051	6,646	19
Jun-15	54,677	6,750	16	57,104	6,910	16	53,059	6,643	16
Jul-15	54,596	6,744	16	56,974	6,901	16	53,010	6,640	16
Aug-15	54,695	6,742	16	57,133	6,897	16	53,070	6,638	16
Sep-15	54,627	6,752	16	57,024	6,913	16	53,029	6,644	16
Oct-15	54,932	6,763	16	57,512	6,931	16	53,212	6,651	16
Nov-15	55,208	6,777	16	57,954	6,953	16	53,378	6,659	16
Dec-15	55,584	6,781	16	58,555	6,960	16	53,603	6,662	16
Jan-16	55,726	6,917	16	58,782	7,177	16	53,688	6,743	16

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION MEDFORD

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Medford Customers	Commercial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commercial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commercia l Medford Customers	Industrial Medford Customers
Feb-16	55,640	6,926	16	58,644	7,192	16	53,637	6,749	16
Mar-16	55,786	6,861	16	58,879	7,088	16	53,724	6,710	16
Apr-16	55,803	6,882	16	58,906	7,122	16	53,735	6,723	16
May-16	55,957	6,877	19	59,152	7,114	19	53,827	6,720	19
Jun-16	55,970	6,872	16	59,173	7,106	16	53,835	6,717	16
Jul-16	55,887	6,866	16	59,041	7,096	16	53,785	6,713	16
Aug-16	55,989	6,864	16	59,203	7,093	16	53,846	6,712	16
Sep-16	55,919	6,874	16	59,091	7,109	16	53,804	6,718	16
Oct-16	56,231	6,885	16	59,591	7,127	16	53,992	6,724	16
Nov-16	56,514	6,900	16	60,043	7,150	16	54,161	6,733	16
Dec-16	56,899	6,904	16	60,659	7,156	16	54,392	6,735	16
Jan-17	57,018	7,041	17	60,850	7,375	17	54,464	6,818	17
Feb-17	56,930	7,050	17	60,710	7,390	17	54,411	6,823	17
Mar-17	57,080	6,984	17	60,949	7,284	17	54,501	6,783	17
Apr-17	57,098	7,005	17	60,978	7,319	17	54,512	6,796	17
May-17	57,255	7,000	20	61,229	7,310	20	54,606	6,793	20
Jun-17	57,269	6,995	17	61,251	7,302	17	54,614	6,790	17
Jul-17	57,184	6,989	17	61,115	7,292	17	54,563	6,786	17
Aug-17	57,288	6,987	17	61,281	7,289	17	54,625	6,785	17
Sep-17	57,216	6,997	17	61,167	7,305	17	54,583	6,791	17
Oct-17	57,536	7,008	17	61,678	7,324	17	54,774	6,798	17
Nov-17	57,825	7,023	17	62,141	7,347	17	54,948	6,807	17
Dec-17	58,219	7,027	17	62,771	7,354	17	55,184	6,809	17
Jan-18	58,301	7,163	17	62,903	7,571	17	55,234	6,891	17
Feb-18	58,211	7,173	17	62,759	7,586	17	55,180	6,897	17
Mar-18	58,365	7,105	17	63,004	7,478	17	55,272	6,856	17
Apr-18	58,383	7,127	17	63,033	7,514	17	55,282	6,870	17
May-18	58,543	7,122	20	63,290	7,505	20	55,379	6,866	20
Jun-18	58,557	7,117	17	63,312	7,497	17	55,387	6,863	17
Jul-18	58,471	7,110	17	63,174	7,487	17	55,335	6,859	17
Aug-18	58,577	7,108	17	63,343	7,484	17	55,399	6,858	17
Sep-18	58,504	7,119	17	63,227	7,500	17	55,355	6,865	17
Oct-18	58,830	7,130	17	63,749	7,519	17	55,551	6,871	17
Nov-18	59,126	7,145	17	64,222	7,543	17	55,728	6,880	17
Dec-18	59,529	7,149	17	64,867	7,549	17	55,970	6,883	17
Jan-19	59,560	7,283	17	64,917	7,764	17	55,989	6,963	17
Feb-19	59,469	7,293	17	64,770	7,779	17	55,934	6,969	17
Mar-19	59,625	7,224	17	65,021	7,669	17	56,028	6,928	17
Apr-19	59,644	7,247	17	65,051	7,705	17	56,039	6,941	17
May-19	59,808	7,242	20	65,313	7,697	20	56,137	6,938	20
Jun-19	59,822	7,236	17	65,336	7,688	17	56,146	6,935	17
Jul-19	59,733	7,230	17	65,194	7,678	17	56,093	6,931	17
Aug-19	59,842	7,228	17	65,367	7,675	17	56,158	6,930	17
Sep-19	59,767	7,238	17	65,248	7,692	17	56,113	6,936	17
Oct-19	60,101	7,250	17	65,782	7,711	17	56,313	6,943	17
Nov-19	60,403	7,265	17	66,265	7,735	17	56,495	6,952	17
Dec-19	60,814	7,270	17	66,924	7,741	17	56,741	6,955	17
Jan-20	60,811	7,403	17	66,918	7,955	17	56,739	7,035	17
Feb-20	60,717	7,413	17	66,768	7,971	17	56,683	7,041	17

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION MEDFORD

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Medford Customers	Commercial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commercial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commercial Medford Customers	Industrial Medford Customers
Mar-20	60,876	7,343	17	67,023	7,859	17	56,779	6,999	17
Apr-20	60,895	7,366	17	67,054	7,896	17	56,790	7,013	17
May-20	61,063	7,360	21	67,322	7,887	21	56,891	7,009	21
Jun-20	61,078	7,355	17	67,345	7,878	17	56,899	7,006	17
Jul-20	60,987	7,348	17	67,200	7,868	17	56,845	7,002	17
Aug-20	61,098	7,346	17	67,377	7,864	17	56,911	7,001	17
Sep-20	61,022	7,357	17	67,255	7,882	17	56,866	7,007	17
Oct-20	61,362	7,369	17	67,801	7,901	17	57,070	7,015	17
Nov-20	61,671	7,384	17	68,294	7,925	17	57,255	7,024	17
Dec-20	62,091	7,389	17	68,966	7,932	17	57,507	7,026	17
Jan-21	62,039	7,520	18	68,883	8,143	18	57,476	7,105	18
Feb-21	61,943	7,530	18	68,730	8,159	18	57,419	7,111	18
Mar-21	62,106	7,459	18	68,990	8,045	18	57,516	7,069	18
Apr-21	62,125	7,483	18	69,021	8,082	18	57,528	7,083	18
May-21	62,296	7,477	21	69,295	8,074	21	57,631	7,079	21
Jun-21	62,311	7,472	18	69,319	8,065	18	57,639	7,076	18
Jul-21	62,219	7,465	18	69,171	8,054	18	57,584	7,072	18
Aug-21	62,332	7,463	18	69,351	8,051	18	57,652	7,071	18
Sep-21	62,254	7,474	18	69,227	8,068	18	57,605	7,077	18
Oct-21	62,602	7,486	18	69,783	8,088	18	57,814	7,085	18
Nov-21	62,916	7,501	18	70,287	8,112	18	58,003	7,094	18
Dec-21	63,345	7,506	18	70,972	8,120	18	58,260	7,097	18
Jan-22	63,266	7,638	18	70,847	8,330	18	58,213	7,176	18
Feb-22	63,169	7,648	18	70,691	8,346	18	58,154	7,182	18
Mar-22	63,335	7,576	18	70,957	8,231	18	58,254	7,139	18
Apr-22	63,355	7,599	18	70,988	8,269	18	58,266	7,153	18
May-22	63,529	7,594	21	71,267	8,260	21	58,370	7,149	21
Jun-22	63,544	7,588	18	71,291	8,251	18	58,379	7,146	18
Jul-22	63,450	7,581	18	71,141	8,240	18	58,323	7,142	18
Aug-22	63,565	7,579	18	71,325	8,237	18	58,392	7,141	18
Sep-22	63,486	7,590	18	71,198	8,255	18	58,344	7,147	18
Oct-22	63,840	7,603	18	71,766	8,275	18	58,557	7,155	18
Nov-22	64,161	7,618	18	72,279	8,300	18	58,750	7,164	18
Dec-22	64,598	7,623	18	72,978	8,307	18	59,012	7,167	18
Jan-23	64,526	7,758	18	72,863	8,523	18	58,968	7,248	18
Feb-23	64,427	7,768	18	72,703	8,539	18	58,909	7,254	18
Mar-23	64,596	7,695	18	72,974	8,422	18	59,010	7,210	18
Apr-23	64,616	7,719	18	73,007	8,461	18	59,023	7,225	18
May-23	64,794	7,713	22	73,291	8,452	22	59,129	7,221	22
Jun-23	64,809	7,708	18	73,316	8,442	18	59,138	7,218	18
Jul-23	64,713	7,701	18	73,162	8,432	18	59,081	7,214	18
Aug-23	64,831	7,699	18	73,350	8,428	18	59,151	7,212	18
Sep-23	64,750	7,710	18	73,221	8,446	18	59,103	7,219	18
Oct-23	65,112	7,723	18	73,799	8,466	18	59,320	7,227	18
Nov-23	65,439	7,739	18	74,323	8,492	18	59,516	7,236	18
Dec-23	65,884	7,743	18	75,036	8,499	18	59,783	7,239	18
Jan-24	65,782	7,878	19	74,872	8,715	19	59,722	7,320	19
Feb-24	65,680	7,888	19	74,709	8,732	19	59,661	7,326	19
Mar-24	65,853	7,814	19	74,986	8,613	19	59,765	7,282	19

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION MEDFORD

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Medford Customers	Commercial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commercial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commercia l Medford Customers	Industrial Medford Customers
Apr-24	65,874	7,838	19	75,019	8,652	19	59,777	7,296	19
May-24	66,055	7,833	22	75,309	8,642	22	59,886	7,293	22
Jun-24	66,071	7,827	19	75,334	8,633	19	59,895	7,289	19
Jul-24	65,973	7,820	19	75,177	8,622	19	59,836	7,285	19
Aug-24	66,092	7,818	19	75,369	8,618	19	59,908	7,284	19
Sep-24	66,010	7,829	19	75,237	8,637	19	59,859	7,291	19
Oct-24	66,379	7,842	19	75,827	8,657	19	60,080	7,298	19
Nov-24	66,712	7,858	19	76,360	8,683	19	60,280	7,308	19
Dec-24	67,167	7,863	19	77,087	8,691	19	60,553	7,311	19
Jan-25	67,057	8,000	19	76,913	8,910	19	60,487	7,393	19
Feb-25	66,954	8,010	19	76,747	8,927	19	60,425	7,399	19
Mar-25	67,130	7,935	19	77,029	8,806	19	60,531	7,354	19
Apr-25	67,151	7,960	19	77,062	8,846	19	60,543	7,369	19
May-25	67,336	7,954	22	77,358	8,836	22	60,654	7,366	22
Jun-25	67,352	7,948	19	77,384	8,827	19	60,664	7,362	19
Jul-25	67,252	7,941	19	77,224	8,816	19	60,604	7,358	19
Aug-25	67,374	7,939	19	77,419	8,812	19	60,677	7,356	19
Sep-25	67,290	7,950	19	77,285	8,831	19	60,627	7,363	19
Oct-25	67,666	7,963	19	77,886	8,851	19	60,852	7,371	19
Nov-25	68,006	7,980	19	78,430	8,878	19	61,056	7,381	19
Dec-25	68,469	7,984	19	79,171	8,885	19	61,334	7,384	19
Jan-26	68,329	8,121	19	78,947	9,104	19	61,250	7,466	19
Feb-26	68,223	8,132	19	78,778	9,121	19	61,187	7,472	19
Mar-26	68,403	8,056	19	79,065	8,999	19	61,295	7,427	19
Apr-26	68,424	8,081	19	79,100	9,039	19	61,307	7,442	19
May-26	68,613	8,075	23	79,401	9,030	23	61,420	7,438	23
Jun-26	68,629	8,069	19	79,427	9,020	19	61,430	7,434	19
Jul-26	68,527	8,062	19	79,264	9,009	19	61,369	7,430	19
Aug-26	68,651	8,059	19	79,463	9,005	19	61,444	7,429	19
Sep-26	68,566	8,071	19	79,327	9,024	19	61,392	7,436	19
Oct-26	68,949	8,084	19	79,939	9,045	19	61,622	7,444	19
Nov-26	69,295	8,101	19	80,493	9,072	19	61,830	7,454	19
Dec-26	69,767	8,106	19	81,248	9,079	19	62,113	7,457	19
Jan-27	69,561	8,239	20	80,918	9,293	20	61,989	7,537	20
Feb-27	69,454	8,250	20	80,747	9,310	20	61,925	7,543	20
Mar-27	69,636	8,172	20	81,039	9,186	20	62,035	7,497	20
Apr-27	69,658	8,198	20	81,074	9,227	20	62,048	7,512	20
May-27	69,850	8,192	23	81,380	9,217	23	62,163	7,508	23
Jun-27	69,866	8,186	20	81,407	9,207	20	62,173	7,505	20
Jul-27	69,763	8,178	20	81,241	9,196	20	62,111	7,500	20
Aug-27	69,889	8,176	20	81,444	9,192	20	62,186	7,499	20
Sep-27	69,803	8,188	20	81,305	9,211	20	62,134	7,506	20
Oct-27	70,192	8,201	20	81,928	9,232	20	62,368	7,514	20
Nov-27	70,545	8,218	20	82,493	9,260	20	62,580	7,524	20
Dec-27	71,025	8,223	20	83,261	9,267	20	62,868	7,527	20
Jan-28	70,738	8,351	20	82,801	9,472	20	62,695	7,604	20
Feb-28	70,628	8,362	20	82,626	9,490	20	62,630	7,611	20
Mar-28	70,814	8,284	20	82,924	9,364	20	62,741	7,563	20
Apr-28	70,836	8,310	20	82,959	9,406	20	62,755	7,579	20

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION MEDFORD

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Medford Customers	Commercial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commercial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commercia l Medford Customers	Industrial Medford Customers
May-28	71,031	8,303	24	83,271	9,396	24	62,872	7,575	24
Jun-28	71,048	8,297	20	83,298	9,386	20	62,882	7,572	20
Jul-28	70,943	8,290	20	83,129	9,374	20	62,819	7,567	20
Aug-28	71,072	8,288	20	83,335	9,370	20	62,896	7,566	20
Sep-28	70,983	8,300	20	83,194	9,390	20	62,843	7,573	20
Oct-28	71,379	8,313	20	83,828	9,412	20	63,080	7,581	20
Nov-28	71,738	8,331	20	84,402	9,439	20	63,296	7,592	20
Dec-28	72,227	8,335	20	85,183	9,447	20	63,589	7,594	20
Jan-29	71,882	8,461	20	84,633	9,648	20	63,382	7,670	20
Feb-29	71,772	8,472	20	84,455	9,665	20	63,316	7,676	20
Mar-29	71,960	8,392	20	84,757	9,538	20	63,429	7,629	20
Apr-29	71,983	8,418	20	84,793	9,580	20	63,443	7,644	20
May-29	72,181	8,412	24	85,110	9,570	24	63,561	7,641	24
Jun-29	72,198	8,406	20	85,138	9,560	20	63,572	7,637	20
Jul-29	72,091	8,399	20	84,967	9,548	20	63,507	7,632	20
Aug-29	72,222	8,396	20	85,176	9,544	20	63,586	7,631	20
Sep-29	72,132	8,409	20	85,032	9,564	20	63,532	7,638	20
Oct-29	72,535	8,422	20	85,676	9,586	20	63,774	7,647	20
Nov-29	72,899	8,440	20	86,260	9,614	20	63,992	7,657	20
Dec-29	73,396	8,445	20	87,054	9,622	20	64,290	7,660	20
Jan-30	73,032	8,571	21	86,472	9,823	21	64,072	7,736	21
Feb-30	72,919	8,582	21	86,291	9,841	21	64,004	7,742	21
Mar-30	73,111	8,501	21	86,598	9,712	21	64,119	7,694	21
Apr-30	73,134	8,528	21	86,635	9,755	21	64,133	7,710	21
May-30	73,335	8,521	24	86,957	9,744	24	64,254	7,706	24
Jun-30	73,352	8,515	21	86,985	9,734	21	64,264	7,702	21
Jul-30	73,244	8,508	21	86,811	9,722	21	64,199	7,698	21
Aug-30	73,377	8,505	21	87,023	9,718	21	64,279	7,696	21
Sep-30	73,285	8,518	21	86,877	9,738	21	64,224	7,704	21
Oct-30	73,694	8,532	21	87,532	9,761	21	64,469	7,712	21
Nov-30	74,065	8,549	21	88,124	9,789	21	64,692	7,723	21
Dec-30	74,569	8,554	21	88,931	9,797	21	64,994	7,726	21
Jan-31	74,168	8,679	21	88,290	9,997	21	64,754	7,801	21
Feb-31	74,054	8,691	21	88,106	10,015	21	64,685	7,808	21
Mar-31	74,248	8,609	21	88,418	9,884	21	64,802	7,759	21
Apr-31	74,272	8,636	21	88,455	9,927	21	64,816	7,775	21
May-31	74,476	8,629	24	88,782	9,917	24	64,938	7,771	24
Jun-31	74,494	8,623	21	88,811	9,907	21	64,949	7,767	21
Jul-31	74,383	8,615	21	88,634	9,895	21	64,883	7,762	21
Aug-31	74,518	8,613	21	88,850	9,891	21	64,964	7,761	21
Sep-31	74,425	8,626	21	88,702	9,911	21	64,908	7,769	21
Oct-31	74,841	8,640	21	89,366	9,934	21	65,157	7,777	21
Nov-31	75,217	8,657	21	89,968	9,962	21	65,383	7,788	21
Dec-31	75,729	8,663	21	90,788	9,970	21	65,690	7,791	21
Jan-32	75,277	8,785	21	90,064	10,166	21	65,419	7,864	21
Feb-32	75,161	8,797	21	89,878	10,185	21	65,349	7,871	21
Mar-32	75,359	8,714	21	90,194	10,053	21	65,468	7,822	21
Apr-32	75,382	8,741	21	90,232	10,096	21	65,482	7,838	21
May-32	75,589	8,735	24	90,564	10,086	24	65,606	7,834	24

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION MEDFORD

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Medford Customers	Commercial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commercial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commercia l Medford Customers	Industrial Medford Customers
Jun-32	75,607	8,728	21	90,593	10,075	21	65,617	7,830	21
Jul-32	75,495	8,721	21	90,414	10,063	21	65,550	7,826	21
Aug-32	75,632	8,718	21	90,633	10,059	21	65,632	7,824	21
Sep-32	75,538	8,731	21	90,482	10,080	21	65,576	7,832	21
Oct-32	75,960	8,745	21	91,157	10,102	21	65,829	7,840	21
Nov-32	76,342	8,763	21	91,768	10,131	21	66,058	7,851	21
Dec-32	76,862	8,768	21	92,599	10,140	21	66,370	7,854	21
Jan-33	76,373	8,890	21	91,818	10,334	21	66,077	7,927	21
Feb-33	76,255	8,902	21	91,630	10,353	21	66,006	7,934	21
Mar-33	76,456	8,818	21	91,951	10,219	21	66,126	7,884	21
Apr-33	76,480	8,845	21	91,989	10,263	21	66,141	7,900	21
May-33	76,690	8,839	24	92,325	10,252	24	66,267	7,897	24
Jun-33	76,709	8,832	21	92,355	10,242	21	66,278	7,893	21
Jul-33	76,595	8,824	21	92,173	10,229	21	66,210	7,888	21
Aug-33	76,734	8,822	21	92,395	10,225	21	66,293	7,886	21
Sep-33	76,638	8,835	21	92,242	10,246	21	66,236	7,894	21
Oct-33	77,066	8,849	21	92,927	10,269	21	66,493	7,903	21
Nov-33	77,454	8,868	21	93,547	10,298	21	66,725	7,914	21
Dec-33	77,981	8,873	21	94,391	10,307	21	67,041	7,917	21
Jan-34	77,475	8,995	21	93,580	10,502	21	66,738	7,990	21
Feb-34	77,355	9,007	21	93,389	10,522	21	66,666	7,997	21
Mar-34	77,559	8,922	21	93,715	10,386	21	66,788	7,947	21
Apr-34	77,583	8,950	21	93,753	10,430	21	66,802	7,963	21
May-34	77,796	8,944	24	94,095	10,420	24	66,931	7,959	24
Jun-34	77,815	8,937	21	94,124	10,409	21	66,942	7,955	21
Jul-34	77,700	8,929	21	93,940	10,397	21	66,873	7,951	21
Aug-34	77,840	8,926	21	94,165	10,392	21	66,957	7,949	21
Sep-34	77,744	8,940	21	94,011	10,413	21	66,899	7,957	21
Oct-34	78,178	8,954	21	94,705	10,437	21	67,159	7,966	21
Nov-34	78,570	8,973	21	95,334	10,466	21	67,395	7,977	21
Dec-34	79,106	8,978	21	96,190	10,475	21	67,716	7,980	21
Jan-35	78,583	9,101	21	95,354	10,672	21	67,403	8,054	21
Feb-35	78,462	9,113	21	95,160	10,691	21	67,330	8,061	21
Mar-35	78,668	9,027	21	95,490	10,554	21	67,454	8,010	21
Apr-35	78,693	9,056	21	95,529	10,599	21	67,468	8,027	21
May-35	78,909	9,049	24	95,875	10,588	24	67,598	8,022	24
Jun-35	78,928	9,042	21	95,906	10,578	21	67,610	8,018	21
Jul-35	78,811	9,034	21	95,718	10,565	21	67,539	8,014	21
Aug-35	78,954	9,031	21	95,947	10,560	21	67,625	8,012	21
Sep-35	78,856	9,045	21	95,790	10,582	21	67,566	8,020	21
Oct-35	79,296	9,060	21	96,494	10,605	21	67,830	8,029	21
Nov-35	79,694	9,078	21	97,132	10,635	21	68,069	8,040	21
Dec-35	80,237	9,084	21	98,000	10,644	21	68,395	8,043	21

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION ROSEBURG

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Roseburg Customers	Commercial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commercial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commercial Roseburg Customers	Industrial Roseburg Customers
Jan-12	13,266	2,150	3	13,405	2,161	3	13,173	2,143	3
Feb-12	13,303	2,148	3	13,464	2,158	3	13,195	2,142	3
Mar-12	13,294	2,158	3	13,450	2,174	3	13,190	2,148	3
Apr-12	13,284	2,140	3	13,434	2,145	3	13,184	2,137	3
May-12	13,258	2,141	3	13,392	2,146	3	13,168	2,137	3
Jun-12	13,235	2,142	3	13,356	2,148	3	13,155	2,138	3
Jul-12	13,176	2,145	3	13,261	2,153	3	13,119	2,140	3
Aug-12	13,170	2,147	3	13,252	2,156	3	13,116	2,141	3
Sep-12	13,155	2,151	3	13,228	2,162	3	13,107	2,143	3
Oct-12	13,184	2,152	3	13,274	2,164	3	13,124	2,144	3
Nov-12	13,291	2,152	3	13,445	2,164	3	13,188	2,144	3
Dec-12	13,382	2,159	3	13,591	2,175	3	13,243	2,148	3
Jan-13	13,416	2,175	3	13,645	2,201	3	13,263	2,158	3
Feb-13	13,453	2,173	3	13,704	2,198	3	13,285	2,157	3
Mar-13	13,469	2,183	3	13,730	2,214	3	13,295	2,163	3
Apr-13	13,459	2,165	3	13,714	2,185	3	13,289	2,152	3
May-13	13,458	2,166	3	13,712	2,186	3	13,288	2,152	3
Jun-13	13,485	2,167	3	13,756	2,188	3	13,305	2,153	3
Jul-13	13,426	2,170	3	13,661	2,193	3	13,269	2,155	3
Aug-13	13,420	2,172	3	13,652	2,196	3	13,266	2,156	3
Sep-13	13,430	2,176	3	13,668	2,202	3	13,272	2,158	3
Oct-13	13,459	2,177	3	13,714	2,204	3	13,289	2,159	3
Nov-13	13,566	2,177	3	13,885	2,204	3	13,353	2,159	3
Dec-13	13,657	2,184	3	14,031	2,215	3	13,408	2,163	3
Jan-14	13,716	2,205	3	14,125	2,249	3	13,443	2,176	3
Feb-14	13,753	2,203	3	14,184	2,246	3	13,465	2,175	3
Mar-14	13,769	2,213	3	14,210	2,262	3	13,475	2,181	3
Apr-14	13,759	2,195	3	14,194	2,233	3	13,469	2,170	3
May-14	13,758	2,196	3	14,192	2,234	3	13,468	2,170	3
Jun-14	13,785	2,197	3	14,236	2,236	3	13,485	2,171	3
Jul-14	13,726	2,200	3	14,141	2,241	3	13,449	2,173	3
Aug-14	13,720	2,202	3	14,132	2,244	3	13,446	2,174	3
Sep-14	13,730	2,206	3	14,148	2,250	3	13,452	2,176	3
Oct-14	13,759	2,207	3	14,194	2,252	3	13,469	2,177	3
Nov-14	13,866	2,207	3	14,365	2,252	3	13,533	2,177	3
Dec-14	13,957	2,214	3	14,511	2,263	3	13,588	2,181	3
Jan-15	14,041	2,235	3	14,645	2,297	3	13,638	2,194	3
Feb-15	14,078	2,233	3	14,704	2,294	3	13,660	2,193	3
Mar-15	14,094	2,243	3	14,730	2,310	3	13,670	2,199	3
Apr-15	14,084	2,225	3	14,714	2,281	3	13,664	2,188	3
May-15	14,083	2,226	3	14,712	2,282	3	13,663	2,188	3
Jun-15	14,110	2,227	3	14,756	2,284	3	13,680	2,189	3
Jul-15	14,051	2,230	3	14,661	2,289	3	13,644	2,191	3
Aug-15	14,045	2,232	3	14,652	2,292	3	13,641	2,192	3
Sep-15	14,055	2,236	3	14,668	2,298	3	13,647	2,194	3
Oct-15	14,084	2,237	3	14,714	2,300	3	13,664	2,195	3
Nov-15	14,191	2,237	3	14,885	2,300	3	13,728	2,195	3
Dec-15	14,282	2,244	3	15,031	2,311	3	13,783	2,199	3
Jan-16	14,373	2,260	3	15,177	2,336	3	13,838	2,209	3

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION ROSEBURG

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Roseburg	Roseburg	Roseburg	Roseburg	Roseburg	Roseburg	Roseburg	Roseburg	Roseburg
Feb-16	14,411	2,258	3	15,238	2,333	3	13,860	2,207	3
Mar-16	14,428	2,268	3	15,264	2,349	3	13,870	2,213	3
Apr-16	14,417	2,250	3	15,247	2,320	3	13,864	2,203	3
May-16	14,416	2,251	3	15,246	2,322	3	13,863	2,203	3
Jun-16	14,444	2,252	3	15,290	2,323	3	13,880	2,204	3
Jul-16	14,384	2,255	3	15,193	2,328	3	13,844	2,206	3
Aug-16	14,377	2,257	3	15,183	2,331	3	13,840	2,207	3
Sep-16	14,388	2,261	3	15,200	2,338	3	13,846	2,209	3
Oct-16	14,417	2,262	3	15,247	2,340	3	13,864	2,210	3
Nov-16	14,527	2,262	3	15,423	2,340	3	13,930	2,210	3
Dec-16	14,620	2,269	3	15,572	2,351	3	13,986	2,214	3
Jan-17	14,683	2,283	3	15,673	2,373	3	14,023	2,222	3
Feb-17	14,722	2,281	3	15,735	2,370	3	14,047	2,221	3
Mar-17	14,739	2,291	3	15,761	2,386	3	14,057	2,227	3
Apr-17	14,728	2,273	3	15,745	2,357	3	14,050	2,216	3
May-17	14,727	2,274	3	15,743	2,358	3	14,050	2,217	3
Jun-17	14,755	2,275	3	15,788	2,360	3	14,067	2,218	3
Jul-17	14,694	2,278	3	15,689	2,365	3	14,030	2,219	3
Aug-17	14,687	2,280	3	15,679	2,368	3	14,026	2,221	3
Sep-17	14,698	2,284	3	15,696	2,375	3	14,032	2,223	3
Oct-17	14,728	2,285	3	15,745	2,376	3	14,050	2,224	3
Nov-17	14,840	2,285	3	15,924	2,376	3	14,118	2,224	3
Dec-17	14,935	2,292	3	16,076	2,388	3	14,175	2,228	3
Jan-18	14,971	2,304	3	16,133	2,407	3	14,196	2,235	3
Feb-18	15,010	2,302	3	16,196	2,404	3	14,220	2,234	3
Mar-18	15,027	2,312	3	16,224	2,421	3	14,230	2,240	3
Apr-18	15,017	2,294	3	16,206	2,391	3	14,224	2,229	3
May-18	15,016	2,295	3	16,205	2,393	3	14,223	2,230	3
Jun-18	15,045	2,296	3	16,251	2,394	3	14,240	2,230	3
Jul-18	14,982	2,299	3	16,150	2,399	3	14,203	2,232	3
Aug-18	14,975	2,301	3	16,140	2,402	3	14,199	2,233	3
Sep-18	14,986	2,305	3	16,157	2,409	3	14,205	2,236	3
Oct-18	15,017	2,306	3	16,206	2,411	3	14,224	2,237	3
Nov-18	15,131	2,306	3	16,389	2,411	3	14,292	2,237	3
Dec-18	15,228	2,313	3	16,544	2,422	3	14,350	2,241	3
Jan-19	15,259	2,326	3	16,594	2,442	3	14,369	2,248	3
Feb-19	15,299	2,323	3	16,658	2,438	3	14,393	2,247	3
Mar-19	15,317	2,334	3	16,686	2,455	3	14,404	2,253	3
Apr-19	15,306	2,315	3	16,669	2,425	3	14,397	2,242	3
May-19	15,305	2,316	3	16,667	2,427	3	14,396	2,243	3
Jun-19	15,334	2,317	3	16,714	2,428	3	14,414	2,243	3
Jul-19	15,270	2,320	3	16,611	2,433	3	14,376	2,245	3
Aug-19	15,263	2,322	3	16,601	2,437	3	14,372	2,246	3
Sep-19	15,274	2,327	3	16,618	2,443	3	14,378	2,249	3
Oct-19	15,306	2,328	3	16,669	2,445	3	14,397	2,249	3
Nov-19	15,422	2,328	3	16,855	2,445	3	14,467	2,249	3
Dec-19	15,521	2,335	3	17,013	2,457	3	14,526	2,254	3
Jan-20	15,549	2,347	3	17,058	2,476	3	14,543	2,261	3
Feb-20	15,590	2,345	3	17,124	2,473	3	14,568	2,260	3
Mar-20	15,608	2,356	3	17,152	2,490	3	14,578	2,266	3

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION ROSEBURG

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Roseburg Customers	Commercial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commercial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commercial Roseburg Customers	Industrial Roseburg Customers
Apr-20	15,597	2,337	3	17,134	2,459	3	14,572	2,255	3
May-20	15,596	2,338	3	17,133	2,461	3	14,571	2,255	3
Jun-20	15,626	2,339	3	17,181	2,463	3	14,589	2,256	3
Jul-20	15,560	2,342	3	17,076	2,468	3	14,550	2,258	3
Aug-20	15,554	2,344	3	17,065	2,471	3	14,546	2,259	3
Sep-20	15,565	2,348	3	17,083	2,478	3	14,552	2,262	3
Oct-20	15,597	2,349	3	17,134	2,480	3	14,572	2,262	3
Nov-20	15,715	2,349	3	17,324	2,480	3	14,643	2,262	3
Dec-20	15,816	2,357	3	17,485	2,491	3	14,703	2,267	3
Jan-21	15,836	2,368	4	17,517	2,510	4	14,715	2,274	4
Feb-21	15,878	2,366	4	17,584	2,507	4	14,740	2,273	4
Mar-21	15,896	2,377	4	17,613	2,524	4	14,751	2,279	4
Apr-21	15,884	2,358	4	17,595	2,493	4	14,744	2,268	4
May-21	15,883	2,359	4	17,593	2,495	4	14,744	2,268	4
Jun-21	15,914	2,360	4	17,642	2,497	4	14,762	2,269	4
Jul-21	15,847	2,363	4	17,535	2,502	4	14,722	2,271	4
Aug-21	15,840	2,365	4	17,524	2,505	4	14,718	2,272	4
Sep-21	15,852	2,369	4	17,542	2,512	4	14,725	2,274	4
Oct-21	15,884	2,371	4	17,595	2,514	4	14,744	2,275	4
Nov-21	16,005	2,371	4	17,788	2,514	4	14,817	2,275	4
Dec-21	16,108	2,378	4	17,952	2,526	4	14,878	2,280	4
Jan-22	16,121	2,390	4	17,974	2,544	4	14,886	2,287	4
Feb-22	16,164	2,388	4	18,042	2,541	4	14,912	2,285	4
Mar-22	16,182	2,398	4	18,071	2,558	4	14,923	2,292	4
Apr-22	16,171	2,379	4	18,053	2,527	4	14,916	2,280	4
May-22	16,170	2,380	4	18,051	2,529	4	14,915	2,281	4
Jun-22	16,201	2,381	4	18,101	2,531	4	14,934	2,281	4
Jul-22	16,133	2,384	4	17,992	2,536	4	14,893	2,283	4
Aug-22	16,126	2,386	4	17,981	2,539	4	14,889	2,285	4
Sep-22	16,137	2,391	4	18,000	2,546	4	14,896	2,287	4
Oct-22	16,171	2,392	4	18,053	2,548	4	14,916	2,288	4
Nov-22	16,294	2,392	4	18,249	2,548	4	14,990	2,288	4
Dec-22	16,398	2,399	4	18,417	2,560	4	15,052	2,292	4
Jan-23	16,409	2,411	4	18,434	2,578	4	15,059	2,299	4
Feb-23	16,452	2,409	4	18,503	2,575	4	15,085	2,298	4
Mar-23	16,471	2,420	4	18,533	2,592	4	15,096	2,305	4
Apr-23	16,459	2,400	4	18,514	2,561	4	15,089	2,293	4
May-23	16,458	2,401	4	18,512	2,563	4	15,088	2,294	4
Jun-23	16,490	2,402	4	18,563	2,565	4	15,107	2,294	4
Jul-23	16,421	2,406	4	18,453	2,570	4	15,066	2,296	4
Aug-23	16,414	2,408	4	18,441	2,573	4	15,062	2,297	4
Sep-23	16,425	2,412	4	18,460	2,580	4	15,069	2,300	4
Oct-23	16,459	2,413	4	18,514	2,582	4	15,089	2,301	4
Nov-23	16,584	2,413	4	18,714	2,582	4	15,164	2,301	4
Dec-23	16,691	2,421	4	18,885	2,594	4	15,228	2,305	4
Jan-24	16,701	2,433	4	18,902	2,613	4	15,234	2,312	4
Feb-24	16,745	2,431	4	18,972	2,610	4	15,261	2,311	4
Mar-24	16,764	2,441	4	19,002	2,627	4	15,272	2,318	4
Apr-24	16,752	2,422	4	18,983	2,596	4	15,265	2,306	4
May-24	16,751	2,423	4	18,982	2,598	4	15,264	2,307	4

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION ROSEBURG

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Roseburg Customers	Commercial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commercial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commercial Roseburg Customers	Industrial Roseburg Customers
Jun-24	16,783	2,424	4	19,033	2,599	4	15,284	2,307	4
Jul-24	16,713	2,427	4	18,921	2,605	4	15,241	2,309	4
Aug-24	16,706	2,429	4	18,909	2,608	4	15,237	2,310	4
Sep-24	16,718	2,434	4	18,928	2,615	4	15,244	2,313	4
Oct-24	16,752	2,435	4	18,983	2,617	4	15,265	2,314	4
Nov-24	16,880	2,435	4	19,187	2,617	4	15,341	2,314	4
Dec-24	16,988	2,443	4	19,360	2,629	4	15,406	2,318	4
Jan-25	16,996	2,455	4	19,374	2,648	4	15,411	2,326	4
Feb-25	17,041	2,453	4	19,445	2,645	4	15,438	2,324	4
Mar-25	17,061	2,463	4	19,476	2,662	4	15,450	2,331	4
Apr-25	17,048	2,444	4	19,457	2,631	4	15,443	2,319	4
May-25	17,047	2,445	4	19,455	2,633	4	15,442	2,320	4
Jun-25	17,080	2,446	4	19,507	2,634	4	15,462	2,320	4
Jul-25	17,008	2,449	4	19,393	2,640	4	15,419	2,322	4
Aug-25	17,001	2,451	4	19,382	2,643	4	15,414	2,324	4
Sep-25	17,013	2,456	4	19,401	2,650	4	15,422	2,326	4
Oct-25	17,048	2,457	4	19,457	2,652	4	15,443	2,327	4
Nov-25	17,178	2,457	4	19,664	2,652	4	15,520	2,327	4
Dec-25	17,288	2,465	4	19,841	2,664	4	15,586	2,332	4
Jan-26	17,296	2,477	4	19,853	2,684	4	15,591	2,339	4
Feb-26	17,341	2,475	4	19,926	2,680	4	15,618	2,338	4
Mar-26	17,361	2,486	4	19,957	2,698	4	15,630	2,344	4
Apr-26	17,349	2,466	4	19,938	2,666	4	15,623	2,332	4
May-26	17,347	2,467	4	19,936	2,668	4	15,622	2,333	4
Jun-26	17,381	2,468	4	19,989	2,670	4	15,642	2,334	4
Jul-26	17,308	2,471	4	19,872	2,675	4	15,598	2,336	4
Aug-26	17,301	2,474	4	19,861	2,679	4	15,594	2,337	4
Sep-26	17,313	2,478	4	19,880	2,686	4	15,601	2,340	4
Oct-26	17,349	2,479	4	19,938	2,687	4	15,623	2,340	4
Nov-26	17,480	2,479	4	20,148	2,687	4	15,702	2,340	4
Dec-26	17,593	2,487	4	20,328	2,700	4	15,769	2,345	4
Jan-27	17,602	2,500	4	20,342	2,720	4	15,775	2,353	4
Feb-27	17,648	2,497	4	20,416	2,717	4	15,802	2,351	4
Mar-27	17,668	2,509	4	20,448	2,735	4	15,814	2,358	4
Apr-27	17,656	2,489	4	20,428	2,702	4	15,807	2,346	4
May-27	17,654	2,490	4	20,426	2,704	4	15,806	2,347	4
Jun-27	17,688	2,491	4	20,481	2,706	4	15,826	2,347	4
Jul-27	17,614	2,494	4	20,362	2,711	4	15,782	2,349	4
Aug-27	17,607	2,496	4	20,350	2,715	4	15,778	2,351	4
Sep-27	17,619	2,501	4	20,370	2,722	4	15,785	2,353	4
Oct-27	17,656	2,502	4	20,428	2,724	4	15,807	2,354	4
Nov-27	17,790	2,502	4	20,643	2,724	4	15,887	2,354	4
Dec-27	17,904	2,510	4	20,826	2,736	4	15,956	2,359	4
Jan-28	17,832	2,517	4	20,710	2,748	4	15,913	2,363	4
Feb-28	17,879	2,515	4	20,785	2,744	4	15,941	2,362	4
Mar-28	17,899	2,526	4	20,818	2,762	4	15,953	2,368	4
Apr-28	17,886	2,506	4	20,797	2,730	4	15,945	2,356	4
May-28	17,885	2,507	4	20,795	2,731	4	15,945	2,357	4
Jun-28	17,919	2,508	4	20,850	2,733	4	15,965	2,357	4
Jul-28	17,844	2,511	4	20,730	2,739	4	15,920	2,359	4

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION ROSEBURG

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Roseburg Customers	Commercial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commercial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commercial Roseburg Customers	Industrial Roseburg Customers
Aug-28	17,837	2,513	4	20,718	2,742	4	15,916	2,361	4
Sep-28	17,849	2,518	4	20,739	2,749	4	15,923	2,364	4
Oct-28	17,886	2,519	4	20,797	2,751	4	15,945	2,364	4
Nov-28	18,022	2,519	4	21,015	2,751	4	16,027	2,364	4
Dec-28	18,138	2,527	4	21,200	2,764	4	16,096	2,369	4
Jan-29	18,058	2,534	4	21,072	2,775	4	16,048	2,373	4
Feb-29	18,105	2,531	4	21,148	2,771	4	16,077	2,372	4
Mar-29	18,126	2,543	4	21,181	2,789	4	16,089	2,378	4
Apr-29	18,113	2,522	4	21,160	2,756	4	16,081	2,366	4
May-29	18,112	2,523	4	21,158	2,758	4	16,081	2,367	4
Jun-29	18,146	2,525	4	21,214	2,760	4	16,101	2,368	4
Jul-29	18,070	2,528	4	21,092	2,765	4	16,056	2,370	4
Aug-29	18,063	2,530	4	21,080	2,769	4	16,051	2,371	4
Sep-29	18,076	2,535	4	21,101	2,776	4	16,059	2,374	4
Oct-29	18,113	2,536	4	21,160	2,778	4	16,081	2,374	4
Nov-29	18,250	2,536	4	21,380	2,778	4	16,164	2,374	4
Dec-29	18,368	2,544	4	21,568	2,791	4	16,234	2,379	4
Jan-30	18,285	2,550	5	21,435	2,802	5	16,184	2,383	5
Feb-30	18,333	2,548	5	21,512	2,798	5	16,213	2,382	5
Mar-30	18,354	2,560	5	21,545	2,816	5	16,226	2,389	5
Apr-30	18,341	2,539	5	21,525	2,783	5	16,218	2,376	5
May-30	18,339	2,540	5	21,523	2,785	5	16,217	2,377	5
Jun-30	18,375	2,541	5	21,579	2,787	5	16,238	2,378	5
Jul-30	18,298	2,545	5	21,456	2,792	5	16,192	2,380	5
Aug-30	18,290	2,547	5	21,443	2,796	5	16,188	2,381	5
Sep-30	18,303	2,552	5	21,464	2,803	5	16,195	2,384	5
Oct-30	18,341	2,553	5	21,525	2,805	5	16,218	2,384	5
Nov-30	18,480	2,553	5	21,748	2,805	5	16,302	2,384	5
Dec-30	18,599	2,561	5	21,937	2,818	5	16,373	2,389	5
Jan-31	18,512	2,567	5	21,799	2,829	5	16,321	2,393	5
Feb-31	18,561	2,565	5	21,877	2,825	5	16,350	2,392	5
Mar-31	18,582	2,577	5	21,911	2,843	5	16,363	2,399	5
Apr-31	18,569	2,556	5	21,890	2,810	5	16,355	2,386	5
May-31	18,567	2,557	5	21,887	2,812	5	16,354	2,387	5
Jun-31	18,603	2,558	5	21,944	2,814	5	16,375	2,388	5
Jul-31	18,525	2,562	5	21,820	2,819	5	16,329	2,390	5
Aug-31	18,517	2,564	5	21,807	2,823	5	16,324	2,391	5
Sep-31	18,530	2,569	5	21,828	2,830	5	16,332	2,394	5
Oct-31	18,569	2,570	5	21,890	2,832	5	16,355	2,395	5
Nov-31	18,710	2,570	5	22,115	2,832	5	16,439	2,395	5
Dec-31	18,830	2,578	5	22,307	2,845	5	16,511	2,399	5
Jan-32	18,735	2,584	5	22,156	2,855	5	16,455	2,403	5
Feb-32	18,785	2,582	5	22,235	2,851	5	16,484	2,402	5
Mar-32	18,806	2,593	5	22,269	2,870	5	16,497	2,409	5
Apr-32	18,793	2,572	5	22,248	2,837	5	16,489	2,396	5
May-32	18,791	2,574	5	22,246	2,838	5	16,488	2,397	5
Jun-32	18,827	2,575	5	22,303	2,840	5	16,510	2,398	5
Jul-32	18,749	2,578	5	22,177	2,846	5	16,463	2,400	5
Aug-32	18,740	2,580	5	22,164	2,850	5	16,458	2,401	5
Sep-32	18,754	2,585	5	22,186	2,857	5	16,466	2,404	5

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION ROSEBURG

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Roseburg Customers	Commercial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commercial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commercial Roseburg Customers	Industrial Roseburg Customers
Oct-32	18,793	2,586	5	22,248	2,859	5	16,489	2,405	5
Nov-32	18,935	2,586	5	22,476	2,859	5	16,575	2,405	5
Dec-32	19,057	2,594	5	22,670	2,872	5	16,648	2,409	5
Jan-33	18,963	2,601	5	22,520	2,882	5	16,591	2,413	5
Feb-33	19,013	2,599	5	22,600	2,878	5	16,621	2,412	5
Mar-33	19,034	2,610	5	22,635	2,897	5	16,634	2,419	5
Apr-33	19,021	2,589	5	22,613	2,864	5	16,626	2,406	5
May-33	19,019	2,590	5	22,611	2,865	5	16,625	2,407	5
Jun-33	19,056	2,592	5	22,669	2,867	5	16,647	2,408	5
Jul-33	18,976	2,595	5	22,542	2,873	5	16,599	2,410	5
Aug-33	18,968	2,597	5	22,529	2,877	5	16,594	2,411	5
Sep-33	18,982	2,602	5	22,550	2,884	5	16,603	2,414	5
Oct-33	19,021	2,603	5	22,613	2,886	5	16,626	2,415	5
Nov-33	19,165	2,603	5	22,844	2,886	5	16,713	2,415	5
Dec-33	19,288	2,611	5	23,041	2,899	5	16,787	2,420	5
Jan-34	19,191	2,618	5	22,885	2,909	5	16,728	2,424	5
Feb-34	19,242	2,616	5	22,966	2,906	5	16,759	2,422	5
Mar-34	19,264	2,627	5	23,001	2,924	5	16,772	2,429	5
Apr-34	19,250	2,606	5	22,979	2,891	5	16,764	2,416	5
May-34	19,249	2,607	5	22,977	2,893	5	16,763	2,417	5
Jun-34	19,285	2,608	5	23,036	2,894	5	16,785	2,418	5
Jul-34	19,205	2,612	5	22,907	2,900	5	16,736	2,420	5
Aug-34	19,197	2,614	5	22,894	2,904	5	16,732	2,421	5
Sep-34	19,210	2,619	5	22,916	2,911	5	16,740	2,424	5
Oct-34	19,250	2,620	5	22,979	2,913	5	16,764	2,425	5
Nov-34	19,396	2,620	5	23,213	2,913	5	16,851	2,425	5
Dec-34	19,521	2,628	5	23,412	2,926	5	16,926	2,430	5
Jan-35	19,418	2,635	5	23,249	2,936	5	16,865	2,434	5
Feb-35	19,469	2,632	5	23,331	2,933	5	16,895	2,432	5
Mar-35	19,492	2,644	5	23,366	2,951	5	16,909	2,439	5
Apr-35	19,478	2,623	5	23,344	2,918	5	16,900	2,427	5
May-35	19,476	2,624	5	23,342	2,919	5	16,899	2,427	5
Jun-35	19,514	2,625	5	23,401	2,921	5	16,922	2,428	5
Jul-35	19,432	2,629	5	23,271	2,927	5	16,873	2,430	5
Aug-35	19,424	2,631	5	23,258	2,931	5	16,868	2,432	5
Sep-35	19,438	2,636	5	23,280	2,938	5	16,876	2,434	5
Oct-35	19,478	2,637	5	23,344	2,940	5	16,900	2,435	5
Nov-35	19,626	2,637	5	23,581	2,940	5	16,989	2,435	5
Dec-35	19,752	2,645	5	23,782	2,953	5	17,065	2,440	5

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION KLAMATH FALLS

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industrial Klamath Falls Customers
Jan-12	14,147	1,668	7	14,317	1,678	7	14,034	1,662	7
Feb-12	14,137	1,675	8	14,301	1,689	8	14,028	1,666	8
Mar-12	14,169	1,666	6	14,352	1,674	6	14,047	1,660	6
Apr-12	14,126	1,671	7	14,283	1,682	7	14,021	1,663	7
May-12	14,139	1,669	7	14,304	1,679	7	14,029	1,662	7
Jun-12	14,054	1,663	7	14,168	1,670	7	13,978	1,659	7
Jul-12	14,008	1,663	7	14,094	1,670	7	13,950	1,659	7
Aug-12	13,904	1,665	7	13,928	1,673	7	13,888	1,660	7
Sep-12	13,910	1,671	7	13,938	1,682	7	13,892	1,663	7
Oct-12	14,014	1,672	7	14,104	1,684	7	13,954	1,664	7
Nov-12	14,179	1,675	7	14,368	1,689	7	14,053	1,666	7
Dec-12	14,296	1,679	7	14,555	1,695	7	14,123	1,668	7
Jan-13	14,297	1,693	7	14,557	1,718	7	14,124	1,677	7
Feb-13	14,287	1,700	8	14,541	1,729	8	14,118	1,681	8
Mar-13	14,319	1,691	6	14,592	1,714	6	14,137	1,675	6
Apr-13	14,276	1,696	7	14,523	1,722	7	14,111	1,678	7
May-13	14,289	1,694	7	14,544	1,719	7	14,119	1,677	7
Jun-13	14,229	1,688	7	14,448	1,710	7	14,083	1,674	7
Jul-13	14,183	1,688	7	14,374	1,710	7	14,055	1,674	7
Aug-13	14,079	1,690	7	14,208	1,713	7	13,993	1,675	7
Sep-13	14,085	1,696	7	14,218	1,722	7	13,997	1,678	7
Oct-13	14,214	1,697	7	14,424	1,724	7	14,074	1,679	7
Nov-13	14,404	1,700	7	14,728	1,729	7	14,188	1,681	7
Dec-13	14,521	1,704	7	14,915	1,735	7	14,258	1,683	7
Jan-14	14,547	1,723	7	14,957	1,766	7	14,274	1,695	7
Feb-14	14,537	1,730	8	14,941	1,777	8	14,268	1,699	8
Mar-14	14,569	1,721	6	14,992	1,762	6	14,287	1,693	6
Apr-14	14,526	1,726	7	14,923	1,770	7	14,261	1,696	7
May-14	14,539	1,724	7	14,944	1,767	7	14,269	1,695	7
Jun-14	14,479	1,718	7	14,848	1,758	7	14,233	1,692	7
Jul-14	14,433	1,718	7	14,774	1,758	7	14,205	1,692	7
Aug-14	14,329	1,720	7	14,608	1,761	7	14,143	1,693	7
Sep-14	14,335	1,726	7	14,618	1,770	7	14,147	1,696	7
Oct-14	14,464	1,727	7	14,824	1,772	7	14,224	1,697	7
Nov-14	14,654	1,730	7	15,128	1,777	7	14,338	1,699	7
Dec-14	14,771	1,734	7	15,315	1,783	7	14,408	1,701	7
Jan-15	14,822	1,753	7	15,397	1,814	7	14,439	1,713	7
Feb-15	14,812	1,760	8	15,381	1,825	8	14,433	1,717	8
Mar-15	14,844	1,751	6	15,432	1,810	6	14,452	1,711	6
Apr-15	14,801	1,756	7	15,363	1,818	7	14,426	1,714	7
May-15	14,814	1,754	7	15,384	1,815	7	14,434	1,713	7
Jun-15	14,754	1,748	7	15,288	1,806	7	14,398	1,710	7
Jul-15	14,708	1,748	7	15,214	1,806	7	14,370	1,710	7
Aug-15	14,604	1,750	7	15,048	1,809	7	14,308	1,711	7
Sep-15	14,610	1,756	7	15,058	1,818	7	14,312	1,714	7
Oct-15	14,739	1,757	7	15,264	1,820	7	14,389	1,715	7
Nov-15	14,929	1,760	7	15,568	1,825	7	14,503	1,717	7
Dec-15	15,046	1,764	7	15,755	1,831	7	14,573	1,719	7

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION KLAMATH FALLS

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industrial Klamath Falls Customers
Jan-16	15,091	1,778	7	15,827	1,854	7	14,600	1,728	7
Feb-16	15,081	1,785	8	15,811	1,865	8	14,594	1,732	8
Mar-16	15,113	1,776	6	15,863	1,851	6	14,614	1,727	6
Apr-16	15,070	1,781	7	15,793	1,859	7	14,587	1,730	7
May-16	15,083	1,779	7	15,814	1,856	7	14,595	1,728	7
Jun-16	15,022	1,773	7	15,716	1,846	7	14,559	1,725	7
Jul-16	14,975	1,773	7	15,641	1,846	7	14,531	1,725	7
Aug-16	14,869	1,775	7	15,472	1,849	7	14,467	1,726	7
Sep-16	14,875	1,781	7	15,482	1,859	7	14,471	1,730	7
Oct-16	15,006	1,782	7	15,692	1,861	7	14,549	1,730	7
Nov-16	15,200	1,785	7	16,001	1,865	7	14,666	1,732	7
Dec-16	15,319	1,789	7	16,192	1,872	7	14,737	1,734	7
Jan-17	15,345	1,802	7	16,234	1,892	7	14,753	1,742	7
Feb-17	15,335	1,809	8	16,217	1,904	8	14,746	1,746	8
Mar-17	15,368	1,800	6	16,270	1,889	6	14,766	1,741	6
Apr-17	15,323	1,805	7	16,199	1,897	7	14,740	1,744	7
May-17	15,337	1,803	7	16,220	1,894	7	14,748	1,743	7
Jun-17	15,275	1,797	7	16,121	1,884	7	14,710	1,739	7
Jul-17	15,227	1,797	7	16,045	1,884	7	14,682	1,739	7
Aug-17	15,119	1,799	7	15,873	1,887	7	14,617	1,740	7
Sep-17	15,126	1,805	7	15,882	1,897	7	14,621	1,744	7
Oct-17	15,259	1,806	7	16,096	1,899	7	14,701	1,745	7
Nov-17	15,456	1,809	7	16,411	1,904	7	14,819	1,746	7
Dec-17	15,577	1,813	7	16,605	1,910	7	14,892	1,749	7
Jan-18	15,587	1,825	7	16,620	1,929	7	14,898	1,756	7
Feb-18	15,576	1,832	8	16,604	1,940	8	14,891	1,760	8
Mar-18	15,610	1,823	6	16,657	1,925	6	14,912	1,754	6
Apr-18	15,565	1,828	7	16,585	1,934	7	14,884	1,758	7
May-18	15,578	1,826	7	16,607	1,930	7	14,893	1,756	7
Jun-18	15,515	1,820	7	16,506	1,920	7	14,855	1,753	7
Jul-18	15,467	1,820	7	16,429	1,920	7	14,826	1,753	7
Aug-18	15,358	1,822	7	16,254	1,924	7	14,760	1,754	7
Sep-18	15,364	1,828	7	16,264	1,934	7	14,764	1,758	7
Oct-18	15,499	1,829	7	16,481	1,935	7	14,845	1,758	7
Nov-18	15,699	1,832	7	16,800	1,940	7	14,965	1,760	7
Dec-18	15,822	1,836	7	16,997	1,947	7	15,039	1,763	7
Jan-19	15,828	1,847	7	17,006	1,965	7	15,042	1,769	7
Feb-19	15,817	1,855	8	16,989	1,977	8	15,036	1,774	8
Mar-19	15,851	1,845	6	17,044	1,961	6	15,056	1,768	6
Apr-19	15,806	1,851	7	16,970	1,970	7	15,029	1,771	7
May-19	15,819	1,849	7	16,993	1,966	7	15,037	1,770	7
Jun-19	15,755	1,842	7	16,890	1,956	7	14,999	1,766	7
Jul-19	15,706	1,842	7	16,812	1,956	7	14,969	1,766	7
Aug-19	15,595	1,844	7	16,634	1,960	7	14,903	1,767	7
Sep-19	15,602	1,851	7	16,644	1,970	7	14,907	1,771	7
Oct-19	15,739	1,852	7	16,865	1,972	7	14,989	1,772	7
Nov-19	15,942	1,855	7	17,189	1,977	7	15,111	1,774	7
Dec-19	16,067	1,859	7	17,389	1,983	7	15,186	1,776	7

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION KLAMATH FALLS

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industrial Klamath Falls Customers
Jan-20	16,068	1,870	7	17,391	2,001	7	15,186	1,783	7
Feb-20	16,057	1,878	8	17,373	2,013	8	15,180	1,787	8
Mar-20	16,092	1,868	6	17,429	1,997	6	15,201	1,782	6
Apr-20	16,045	1,873	7	17,354	2,006	7	15,173	1,785	7
May-20	16,059	1,871	7	17,377	2,003	7	15,181	1,783	7
Jun-20	15,994	1,865	7	17,273	1,992	7	15,142	1,780	7
Jul-20	15,945	1,865	7	17,193	1,992	7	15,112	1,780	7
Aug-20	15,832	1,867	7	17,012	1,996	7	15,045	1,781	7
Sep-20	15,838	1,873	7	17,023	2,006	7	15,049	1,785	7
Oct-20	15,978	1,874	7	17,247	2,008	7	15,132	1,785	7
Nov-20	16,184	1,878	7	17,576	2,013	7	15,256	1,787	7
Dec-20	16,311	1,882	7	17,779	2,020	7	15,332	1,790	7
Jan-21	16,306	1,892	7	17,771	2,037	7	15,329	1,796	7
Feb-21	16,295	1,900	8	17,753	2,049	8	15,323	1,801	8
Mar-21	16,330	1,890	6	17,810	2,033	6	15,344	1,795	6
Apr-21	16,283	1,896	7	17,734	2,042	7	15,315	1,798	7
May-21	16,297	1,893	7	17,757	2,038	7	15,324	1,797	7
Jun-21	16,231	1,887	7	17,651	2,028	7	15,284	1,793	7
Jul-21	16,180	1,887	7	17,570	2,028	7	15,254	1,793	7
Aug-21	16,066	1,889	7	17,387	2,031	7	15,185	1,794	7
Sep-21	16,073	1,896	7	17,398	2,042	7	15,189	1,798	7
Oct-21	16,215	1,897	7	17,625	2,044	7	15,274	1,799	7
Nov-21	16,424	1,900	7	17,959	2,049	7	15,400	1,801	7
Dec-21	16,552	1,904	7	18,165	2,056	7	15,477	1,803	7
Jan-22	16,542	1,915	7	18,148	2,072	7	15,471	1,810	7
Feb-22	16,530	1,922	8	18,130	2,084	8	15,464	1,814	8
Mar-22	16,566	1,912	6	18,187	2,069	6	15,485	1,808	6
Apr-22	16,518	1,918	7	18,111	2,077	7	15,456	1,811	7
May-22	16,533	1,916	7	18,134	2,074	7	15,465	1,810	7
Jun-22	16,466	1,909	7	18,027	2,063	7	15,425	1,806	7
Jul-22	16,414	1,909	7	17,945	2,063	7	15,394	1,806	7
Aug-22	16,298	1,911	7	17,759	2,067	7	15,325	1,808	7
Sep-22	16,305	1,918	7	17,770	2,077	7	15,329	1,811	7
Oct-22	16,449	1,919	7	18,000	2,079	7	15,415	1,812	7
Nov-22	16,661	1,922	7	18,339	2,084	7	15,542	1,814	7
Dec-22	16,792	1,927	7	18,548	2,091	7	15,621	1,817	7
Jan-23	16,777	1,937	7	18,525	2,107	7	15,612	1,823	7
Feb-23	16,766	1,944	8	18,507	2,120	8	15,605	1,827	8
Mar-23	16,802	1,934	6	18,565	2,104	6	15,627	1,821	6
Apr-23	16,753	1,940	7	18,487	2,113	7	15,598	1,825	7
May-23	16,768	1,938	7	18,510	2,109	7	15,606	1,823	7
Jun-23	16,700	1,931	7	18,402	2,099	7	15,566	1,819	7
Jul-23	16,648	1,931	7	18,318	2,099	7	15,534	1,819	7
Aug-23	16,530	1,933	7	18,130	2,102	7	15,464	1,821	7
Sep-23	16,537	1,940	7	18,141	2,113	7	15,468	1,825	7
Oct-23	16,683	1,941	7	18,375	2,115	7	15,555	1,825	7
Nov-23	16,898	1,944	7	18,719	2,120	7	15,684	1,827	7
Dec-23	17,031	1,949	7	18,931	2,127	7	15,764	1,830	7

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION KLAMATH FALLS

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industrial Klamath Falls Customers
Jan-24	17,014	1,959	7	18,904	2,143	7	15,754	1,836	7
Feb-24	17,002	1,967	8	18,885	2,156	8	15,747	1,841	8
Mar-24	17,039	1,957	6	18,944	2,139	6	15,769	1,835	6
Apr-24	16,990	1,962	7	18,865	2,148	7	15,739	1,838	7
May-24	17,005	1,960	7	18,889	2,145	7	15,748	1,837	7
Jun-24	16,936	1,953	7	18,779	2,134	7	15,707	1,833	7
Jul-24	16,883	1,953	7	18,694	2,134	7	15,675	1,833	7
Aug-24	16,764	1,956	7	18,503	2,138	7	15,604	1,834	7
Sep-24	16,770	1,962	7	18,514	2,148	7	15,608	1,838	7
Oct-24	16,918	1,963	7	18,751	2,150	7	15,697	1,839	7
Nov-24	17,137	1,967	7	19,100	2,156	7	15,828	1,841	7
Dec-24	17,271	1,971	7	19,315	2,163	7	15,908	1,844	7
Jan-25	17,251	1,981	7	19,284	2,179	7	15,896	1,850	7
Feb-25	17,240	1,989	8	19,265	2,191	8	15,889	1,854	8
Mar-25	17,277	1,979	6	19,325	2,175	6	15,912	1,848	6
Apr-25	17,227	1,985	7	19,245	2,184	7	15,882	1,852	7
May-25	17,242	1,982	7	19,269	2,181	7	15,891	1,850	7
Jun-25	17,172	1,976	7	19,157	2,170	7	15,849	1,846	7
Jul-25	17,119	1,976	7	19,071	2,170	7	15,817	1,846	7
Aug-25	16,998	1,978	7	18,878	2,173	7	15,744	1,847	7
Sep-25	17,005	1,985	7	18,889	2,184	7	15,748	1,852	7
Oct-25	17,155	1,986	7	19,129	2,186	7	15,838	1,852	7
Nov-25	17,376	1,989	7	19,483	2,191	7	15,971	1,854	7
Dec-25	17,512	1,994	7	19,701	2,199	7	16,053	1,857	7
Jan-26	17,489	2,004	7	19,664	2,214	7	16,039	1,863	7
Feb-26	17,477	2,012	8	19,645	2,227	8	16,032	1,868	8
Mar-26	17,515	2,001	6	19,706	2,211	6	16,055	1,862	6
Apr-26	17,464	2,007	7	19,624	2,220	7	16,024	1,865	7
May-26	17,480	2,005	7	19,649	2,216	7	16,033	1,864	7
Jun-26	17,409	1,998	7	19,536	2,205	7	15,991	1,859	7
Jul-26	17,355	1,998	7	19,449	2,205	7	15,958	1,859	7
Aug-26	17,232	2,000	7	19,253	2,209	7	15,885	1,861	7
Sep-26	17,239	2,007	7	19,264	2,220	7	15,889	1,865	7
Oct-26	17,391	2,008	7	19,507	2,222	7	15,980	1,866	7
Nov-26	17,615	2,012	7	19,866	2,227	7	16,115	1,868	7
Dec-26	17,753	2,016	7	20,087	2,235	7	16,198	1,870	7
Jan-27	17,725	2,026	7	20,042	2,250	7	16,181	1,876	7
Feb-27	17,713	2,034	8	20,023	2,263	8	16,174	1,881	8
Mar-27	17,752	2,023	6	20,084	2,246	6	16,197	1,875	6
Apr-27	17,700	2,029	7	20,002	2,256	7	16,166	1,878	7
May-27	17,716	2,027	7	20,027	2,252	7	16,175	1,877	7
Jun-27	17,644	2,020	7	19,912	2,241	7	16,132	1,873	7
Jul-27	17,589	2,020	7	19,824	2,241	7	16,099	1,873	7
Aug-27	17,465	2,022	7	19,625	2,244	7	16,024	1,874	7
Sep-27	17,472	2,029	7	19,636	2,256	7	16,029	1,878	7
Oct-27	17,626	2,030	7	19,883	2,257	7	16,121	1,879	7
Nov-27	17,853	2,034	7	20,247	2,263	7	16,258	1,881	7
Dec-27	17,993	2,038	7	20,471	2,270	7	16,342	1,884	7

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION KLAMATH FALLS

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industrial Klamath Falls Customers
Jan-28	17,958	2,048	7	20,414	2,285	7	16,320	1,889	7
Feb-28	17,945	2,056	8	20,394	2,298	8	16,313	1,894	8
Mar-28	17,984	2,045	6	20,456	2,281	6	16,336	1,888	6
Apr-28	17,932	2,051	7	20,373	2,290	7	16,305	1,891	7
May-28	17,948	2,049	7	20,398	2,287	7	16,314	1,890	7
Jun-28	17,875	2,042	7	20,282	2,276	7	16,271	1,886	7
Jul-28	17,819	2,042	7	20,193	2,276	7	16,237	1,886	7
Aug-28	17,693	2,044	7	19,991	2,279	7	16,162	1,887	7
Sep-28	17,701	2,051	7	20,003	2,290	7	16,166	1,891	7
Oct-28	17,857	2,052	7	20,253	2,292	7	16,260	1,892	7
Nov-28	18,087	2,056	7	20,621	2,298	7	16,398	1,894	7
Dec-28	18,229	2,060	7	20,848	2,305	7	16,483	1,897	7
Jan-29	18,186	2,069	7	20,780	2,319	7	16,457	1,902	7
Feb-29	18,174	2,077	8	20,760	2,332	8	16,450	1,907	8
Mar-29	18,213	2,067	6	20,823	2,315	6	16,474	1,901	6
Apr-29	18,160	2,073	7	20,738	2,325	7	16,442	1,904	7
May-29	18,176	2,070	7	20,764	2,321	7	16,451	1,903	7
Jun-29	18,103	2,063	7	20,646	2,310	7	16,407	1,899	7
Jul-29	18,046	2,063	7	20,556	2,310	7	16,373	1,899	7
Aug-29	17,919	2,065	7	20,352	2,314	7	16,297	1,900	7
Sep-29	17,926	2,073	7	20,363	2,325	7	16,301	1,904	7
Oct-29	18,084	2,074	7	20,617	2,327	7	16,396	1,905	7
Nov-29	18,317	2,077	7	20,990	2,332	7	16,536	1,907	7
Dec-29	18,461	2,082	7	21,219	2,340	7	16,622	1,910	7
Jan-30	18,414	2,090	7	21,144	2,353	7	16,594	1,915	7
Feb-30	18,402	2,099	8	21,124	2,367	8	16,587	1,920	8
Mar-30	18,441	2,088	6	21,188	2,350	6	16,610	1,914	6
Apr-30	18,388	2,094	7	21,102	2,359	7	16,578	1,917	7
May-30	18,404	2,092	7	21,128	2,355	7	16,588	1,916	7
Jun-30	18,330	2,084	7	21,009	2,344	7	16,543	1,911	7
Jul-30	18,272	2,084	7	20,917	2,344	7	16,509	1,911	7
Aug-30	18,143	2,087	7	20,711	2,348	7	16,432	1,913	7
Sep-30	18,151	2,094	7	20,723	2,359	7	16,436	1,917	7
Oct-30	18,311	2,095	7	20,979	2,361	7	16,532	1,918	7
Nov-30	18,547	2,099	7	21,357	2,367	7	16,674	1,920	7
Dec-30	18,692	2,104	7	21,589	2,374	7	16,761	1,923	7
Jan-31	18,642	2,112	7	21,509	2,388	7	16,731	1,928	7
Feb-31	18,630	2,120	8	21,489	2,401	8	16,723	1,933	8
Mar-31	18,670	2,109	6	21,554	2,384	6	16,748	1,926	6
Apr-31	18,616	2,115	7	21,467	2,394	7	16,715	1,930	7
May-31	18,632	2,113	7	21,493	2,390	7	16,725	1,929	7
Jun-31	18,557	2,106	7	21,373	2,378	7	16,680	1,924	7
Jul-31	18,499	2,106	7	21,280	2,378	7	16,645	1,924	7
Aug-31	18,368	2,108	7	21,071	2,382	7	16,567	1,926	7
Sep-31	18,376	2,115	7	21,083	2,394	7	16,571	1,930	7
Oct-31	18,538	2,117	7	21,342	2,396	7	16,668	1,931	7
Nov-31	18,777	2,120	7	21,725	2,401	7	16,812	1,933	7
Dec-31	18,924	2,125	7	21,960	2,409	7	16,900	1,936	7

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION KLAMATH FALLS

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industrial Klamath Falls Customers
Jan-32	18,868	2,133	7	21,871	2,422	7	16,867	1,941	7
Feb-32	18,856	2,142	8	21,851	2,435	8	16,859	1,946	8
Mar-32	18,896	2,131	6	21,916	2,418	6	16,883	1,939	6
Apr-32	18,842	2,137	7	21,828	2,428	7	16,851	1,943	7
May-32	18,858	2,134	7	21,855	2,424	7	16,861	1,941	7
Jun-32	18,782	2,127	7	21,732	2,412	7	16,815	1,937	7
Jul-32	18,723	2,127	7	21,639	2,412	7	16,780	1,937	7
Aug-32	18,591	2,129	7	21,427	2,416	7	16,700	1,938	7
Sep-32	18,598	2,137	7	21,439	2,428	7	16,705	1,943	7
Oct-32	18,763	2,138	7	21,702	2,430	7	16,803	1,944	7
Nov-32	19,005	2,142	7	22,089	2,435	7	16,948	1,946	7
Dec-32	19,154	2,146	7	22,327	2,443	7	17,038	1,949	7
Jan-33	19,097	2,155	7	22,237	2,456	7	17,004	1,954	7
Feb-33	19,084	2,163	8	22,216	2,470	8	16,996	1,959	8
Mar-33	19,125	2,152	6	22,282	2,452	6	17,021	1,952	6
Apr-33	19,070	2,158	7	22,193	2,462	7	16,988	1,956	7
May-33	19,087	2,156	7	22,220	2,458	7	16,998	1,954	7
Jun-33	19,009	2,148	7	22,097	2,446	7	16,951	1,950	7
Jul-33	18,950	2,148	7	22,002	2,446	7	16,916	1,950	7
Aug-33	18,816	2,151	7	21,787	2,450	7	16,835	1,951	7
Sep-33	18,824	2,158	7	21,800	2,462	7	16,840	1,956	7
Oct-33	18,990	2,159	7	22,066	2,464	7	16,940	1,956	7
Nov-33	19,235	2,163	7	22,457	2,470	7	17,087	1,959	7
Dec-33	19,386	2,168	7	22,699	2,478	7	17,177	1,962	7
Jan-34	19,326	2,176	7	22,604	2,491	7	17,141	1,966	7
Feb-34	19,313	2,185	8	22,583	2,505	8	17,134	1,972	8
Mar-34	19,355	2,174	6	22,650	2,487	6	17,159	1,965	6
Apr-34	19,299	2,180	7	22,560	2,497	7	17,125	1,969	7
May-34	19,316	2,177	7	22,587	2,493	7	17,135	1,967	7
Jun-34	19,238	2,170	7	22,462	2,481	7	17,088	1,963	7
Jul-34	19,178	2,170	7	22,366	2,481	7	17,052	1,963	7
Aug-34	19,042	2,172	7	22,149	2,485	7	16,971	1,964	7
Sep-34	19,050	2,180	7	22,162	2,497	7	16,976	1,969	7
Oct-34	19,218	2,181	7	22,431	2,499	7	17,076	1,969	7
Nov-34	19,466	2,185	7	22,827	2,505	7	17,225	1,972	7
Dec-34	19,618	2,190	7	23,071	2,512	7	17,317	1,975	7
Jan-35	19,555	2,198	7	22,970	2,525	7	17,279	1,979	7
Feb-35	19,542	2,206	8	22,948	2,539	8	17,271	1,985	8
Mar-35	19,584	2,195	6	23,016	2,521	6	17,296	1,978	6
Apr-35	19,527	2,201	7	22,925	2,531	7	17,262	1,982	7
May-35	19,544	2,199	7	22,953	2,527	7	17,272	1,980	7
Jun-35	19,465	2,191	7	22,826	2,515	7	17,225	1,976	7
Jul-35	19,405	2,191	7	22,729	2,515	7	17,188	1,976	7
Aug-35	19,267	2,194	7	22,509	2,519	7	17,106	1,977	7
Sep-35	19,275	2,201	7	22,522	2,531	7	17,111	1,982	7
Oct-35	19,445	2,203	7	22,794	2,533	7	17,213	1,982	7
Nov-35	19,696	2,206	7	23,195	2,539	7	17,363	1,985	7
Dec-35	19,851	2,211	7	23,442	2,547	7	17,456	1,988	7

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION
LA GRANDE

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential La Grande Customers	Commercial La Grande Customers	Industrial La Grande Customers	Residential La Grande Customers	Commercial La Grande Customers	Industrial La Grande Customers	Residential La Grande Customers	Commercial La Grande Customers	Industrial La Grande Customers
Jan-12	6,568	903	0	6,627	911	0	6,529	898	0
Feb-12	6,580	911	0	6,646	924	0	6,536	903	0
Mar-12	6,541	892	0	6,584	893	0	6,513	891	0
Apr-12	6,537	897	0	6,577	901	0	6,510	894	0
May-12	6,531	887	0	6,568	885	0	6,507	888	0
Jun-12	6,505	888	0	6,526	887	0	6,491	889	0
Jul-12	6,473	884	0	6,475	880	0	6,472	886	0
Aug-12	6,456	885	0	6,448	882	0	6,462	887	0
Sep-12	6,452	887	5	6,441	885	5	6,459	888	5
Oct-12	6,520	900	5	6,550	906	5	6,500	896	5
Nov-12	6,566	900	0	6,624	906	0	6,528	896	0
Dec-12	6,609	906	0	6,692	916	0	6,553	900	0
Jan-13	6,618	918	0	6,707	935	0	6,559	907	0
Feb-13	6,630	926	0	6,726	948	0	6,566	912	0
Mar-13	6,591	907	0	6,664	917	0	6,543	900	0
Apr-13	6,587	912	0	6,657	925	0	6,540	903	0
May-13	6,581	902	0	6,648	909	0	6,537	897	0
Jun-13	6,555	903	0	6,606	911	0	6,521	898	0
Jul-13	6,523	899	0	6,555	904	0	6,502	895	0
Aug-13	6,506	900	0	6,528	906	0	6,492	896	0
Sep-13	6,502	902	5	6,521	909	5	6,489	897	5
Oct-13	6,570	915	5	6,630	930	5	6,530	905	5
Nov-13	6,616	915	0	6,704	930	0	6,558	905	0
Dec-13	6,659	921	0	6,772	940	0	6,583	909	0
Jan-14	6,668	933	0	6,787	959	0	6,589	916	0
Feb-14	6,680	941	0	6,806	972	0	6,596	921	0
Mar-14	6,641	922	0	6,744	941	0	6,573	909	0
Apr-14	6,637	927	0	6,737	949	0	6,570	912	0
May-14	6,631	917	0	6,728	933	0	6,567	906	0
Jun-14	6,605	918	0	6,686	935	0	6,551	907	0
Jul-14	6,573	914	0	6,635	928	0	6,532	904	0
Aug-14	6,556	915	0	6,608	930	0	6,522	905	0
Sep-14	6,552	917	5	6,601	933	5	6,519	906	5
Oct-14	6,620	930	5	6,710	954	5	6,560	914	5
Nov-14	6,666	930	0	6,784	954	0	6,588	914	0
Dec-14	6,709	936	0	6,852	964	0	6,613	918	0
Jan-15	6,718	953	0	6,867	991	0	6,619	928	0
Feb-15	6,730	961	0	6,886	1,004	0	6,626	933	0
Mar-15	6,691	942	0	6,824	973	0	6,603	921	0
Apr-15	6,687	947	0	6,817	981	0	6,600	924	0
May-15	6,681	937	0	6,808	965	0	6,597	918	0
Jun-15	6,655	938	0	6,766	967	0	6,581	919	0
Jul-15	6,623	934	0	6,715	960	0	6,562	916	0
Aug-15	6,606	935	0	6,688	962	0	6,552	917	0
Sep-15	6,602	937	5	6,681	965	5	6,549	918	5
Oct-15	6,670	950	5	6,790	986	5	6,590	926	5
Nov-15	6,716	950	0	6,864	986	0	6,618	926	0
Dec-15	6,759	956	0	6,932	996	0	6,643	930	0
Jan-16	6,777	966	0	6,962	1,012	0	6,654	936	0

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION
LA GRANDE

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential La Grande Customers	Commercial La Grande Customers	Industrial La Grande Customers	Residential La Grande Customers	Commercial La Grande Customers	Industrial La Grande Customers	Residential La Grande Customers	Commercial La Grande Customers	Industrial La Grande Customers
Feb-16	6,789	974	0	6,981	1,025	0	6,662	940	0
Mar-16	6,750	955	0	6,918	994	0	6,638	929	0
Apr-16	6,746	960	0	6,912	1,002	0	6,636	932	0
May-16	6,740	950	0	6,902	986	0	6,632	926	0
Jun-16	6,714	951	0	6,860	987	0	6,616	926	0
Jul-16	6,681	947	0	6,808	981	0	6,597	924	0
Aug-16	6,664	948	0	6,781	982	0	6,587	925	0
Sep-16	6,660	950	5	6,775	986	5	6,584	926	5
Oct-16	6,729	963	5	6,884	1,007	5	6,625	934	5
Nov-16	6,775	963	0	6,959	1,007	0	6,653	934	0
Dec-16	6,819	969	0	7,028	1,017	0	6,679	937	0
Jan-17	6,832	978	0	7,049	1,031	0	6,687	943	0
Feb-17	6,844	986	0	7,069	1,044	0	6,694	948	0
Mar-17	6,804	967	0	7,005	1,013	0	6,671	936	0
Apr-17	6,800	972	0	6,999	1,021	0	6,668	939	0
May-17	6,794	962	0	6,989	1,005	0	6,665	933	0
Jun-17	6,768	963	0	6,946	1,006	0	6,649	934	0
Jul-17	6,735	959	0	6,894	1,000	0	6,629	931	0
Aug-17	6,718	960	0	6,867	1,001	0	6,619	932	0
Sep-17	6,714	962	5	6,860	1,005	5	6,616	933	5
Oct-17	6,783	975	5	6,971	1,026	5	6,658	941	5
Nov-17	6,830	975	0	7,046	1,026	0	6,686	941	0
Dec-17	6,874	981	0	7,116	1,036	0	6,712	945	0
Jan-18	6,883	989	0	7,130	1,049	0	6,718	950	0
Feb-18	6,895	997	0	7,150	1,062	0	6,725	954	0
Mar-18	6,855	978	0	7,086	1,030	0	6,701	943	0
Apr-18	6,851	983	0	7,080	1,039	0	6,699	946	0
May-18	6,845	973	0	7,070	1,022	0	6,695	940	0
Jun-18	6,818	974	0	7,027	1,024	0	6,679	940	0
Jul-18	6,785	969	0	6,975	1,017	0	6,659	938	0
Aug-18	6,768	970	0	6,947	1,019	0	6,649	938	0
Sep-18	6,764	973	5	6,940	1,022	5	6,646	940	5
Oct-18	6,834	986	5	7,052	1,044	5	6,688	948	5
Nov-18	6,881	986	0	7,127	1,044	0	6,716	948	0
Dec-18	6,925	992	0	7,198	1,054	0	6,743	951	0
Jan-19	6,932	1,000	0	7,210	1,066	0	6,747	956	0
Feb-19	6,945	1,008	0	7,230	1,080	0	6,755	961	0
Mar-19	6,905	989	0	7,165	1,048	0	6,731	949	0
Apr-19	6,900	994	0	7,159	1,056	0	6,728	952	0
May-19	6,894	983	0	7,149	1,039	0	6,725	946	0
Jun-19	6,867	984	0	7,106	1,041	0	6,708	947	0
Jul-19	6,834	980	0	7,053	1,034	0	6,689	944	0
Aug-19	6,817	981	0	7,025	1,036	0	6,678	945	0
Sep-19	6,813	983	5	7,018	1,039	5	6,676	946	5
Oct-19	6,883	997	5	7,131	1,061	5	6,718	954	5
Nov-19	6,930	997	0	7,207	1,061	0	6,746	954	0
Dec-19	6,975	1,003	0	7,278	1,071	0	6,773	958	0
Jan-20	6,982	1,011	0	7,289	1,083	0	6,777	963	0
Feb-20	6,994	1,019	0	7,309	1,097	0	6,785	968	0

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION
LA GRANDE

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential La Grande Customers	Commercial La Grande Customers	Industrial La Grande Customers	Residential La Grande Customers	Commercial La Grande Customers	Industrial La Grande Customers	Residential La Grande Customers	Commercial La Grande Customers	Industrial La Grande Customers
Mar-20	6,954	999	0	7,244	1,065	0	6,760	956	0
Apr-20	6,950	1,005	0	7,237	1,073	0	6,758	959	0
May-20	6,943	994	0	7,227	1,056	0	6,754	952	0
Jun-20	6,916	995	0	7,184	1,058	0	6,738	953	0
Jul-20	6,883	991	0	7,131	1,051	0	6,718	950	0
Aug-20	6,865	992	0	7,103	1,053	0	6,707	951	0
Sep-20	6,861	994	5	7,096	1,056	5	6,705	952	5
Oct-20	6,932	1,008	5	7,209	1,078	5	6,747	961	5
Nov-20	6,980	1,008	0	7,285	1,078	0	6,776	961	0
Dec-20	7,024	1,014	0	7,357	1,089	0	6,803	964	0
Jan-21	7,030	1,022	0	7,366	1,100	0	6,806	969	0
Feb-21	7,043	1,030	0	7,386	1,114	0	6,814	974	0
Mar-21	7,002	1,010	0	7,321	1,082	0	6,789	962	0
Apr-21	6,998	1,015	0	7,314	1,090	0	6,787	965	0
May-21	6,991	1,004	0	7,304	1,073	0	6,783	959	0
Jun-21	6,964	1,005	0	7,261	1,075	0	6,767	959	0
Jul-21	6,931	1,001	0	7,207	1,068	0	6,746	957	0
Aug-21	6,913	1,002	0	7,179	1,070	0	6,736	957	0
Sep-21	6,909	1,004	5	7,172	1,073	5	6,733	959	5
Oct-21	6,980	1,018	5	7,286	1,095	5	6,776	967	5
Nov-21	7,028	1,018	0	7,363	1,095	0	6,805	967	0
Dec-21	7,073	1,025	0	7,435	1,106	0	6,832	971	0
Jan-22	7,078	1,032	0	7,443	1,117	0	6,835	975	0
Feb-22	7,091	1,041	0	7,463	1,131	0	6,842	980	0
Mar-22	7,049	1,020	0	7,397	1,098	0	6,818	968	0
Apr-22	7,045	1,026	0	7,390	1,107	0	6,815	971	0
May-22	7,039	1,015	0	7,380	1,090	0	6,811	965	0
Jun-22	7,012	1,016	0	7,336	1,091	0	6,795	965	0
Jul-22	6,978	1,011	0	7,283	1,084	0	6,775	963	0
Aug-22	6,960	1,013	0	7,254	1,086	0	6,764	964	0
Sep-22	6,956	1,015	5	7,247	1,090	5	6,761	965	5
Oct-22	7,027	1,029	5	7,362	1,112	5	6,804	973	5
Nov-22	7,076	1,029	0	7,439	1,112	0	6,833	973	0
Dec-22	7,121	1,035	0	7,512	1,122	0	6,861	977	0
Jan-23	7,125	1,042	0	7,518	1,134	0	6,863	981	0
Feb-23	7,138	1,051	0	7,539	1,148	0	6,871	987	0
Mar-23	7,097	1,030	0	7,473	1,115	0	6,846	974	0
Apr-23	7,092	1,036	0	7,466	1,123	0	6,843	978	0
May-23	7,086	1,025	0	7,456	1,106	0	6,840	971	0
Jun-23	7,058	1,026	0	7,411	1,108	0	6,823	972	0
Jul-23	7,024	1,022	0	7,357	1,101	0	6,803	969	0
Aug-23	7,006	1,023	0	7,328	1,102	0	6,792	970	0
Sep-23	7,002	1,025	5	7,322	1,106	5	6,789	971	5
Oct-23	7,074	1,039	5	7,437	1,129	5	6,833	979	5
Nov-23	7,123	1,039	0	7,515	1,129	0	6,862	979	0
Dec-23	7,169	1,046	0	7,588	1,139	0	6,889	983	0
Jan-24	7,172	1,053	0	7,594	1,150	0	6,891	988	0
Feb-24	7,185	1,062	0	7,614	1,165	0	6,899	993	0
Mar-24	7,143	1,041	0	7,548	1,131	0	6,874	980	0

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION
LA GRANDE

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential La Grande Customers	Commercial La Grande Customers	Industrial La Grande Customers	Residential La Grande Customers	Commercial La Grande Customers	Industrial La Grande Customers	Residential La Grande Customers	Commercial La Grande Customers	Industrial La Grande Customers
Apr-24	7,139	1,046	0	7,541	1,140	0	6,872	984	0
May-24	7,133	1,035	0	7,530	1,122	0	6,868	977	0
Jun-24	7,105	1,036	0	7,486	1,124	0	6,851	978	0
Jul-24	7,071	1,032	0	7,431	1,117	0	6,831	975	0
Aug-24	7,053	1,033	0	7,402	1,119	0	6,820	976	0
Sep-24	7,048	1,035	5	7,395	1,122	5	6,817	977	5
Oct-24	7,121	1,049	5	7,512	1,145	5	6,861	986	5
Nov-24	7,170	1,049	0	7,590	1,145	0	6,890	986	0
Dec-24	7,216	1,056	0	7,664	1,156	0	6,918	990	0
Jan-25	7,219	1,063	0	7,669	1,167	0	6,919	994	0
Feb-25	7,232	1,072	0	7,689	1,181	0	6,927	999	0
Mar-25	7,190	1,051	0	7,622	1,147	0	6,902	986	0
Apr-25	7,186	1,056	0	7,615	1,156	0	6,900	990	0
May-25	7,179	1,045	0	7,605	1,138	0	6,896	983	0
Jun-25	7,151	1,046	0	7,560	1,140	0	6,879	984	0
Jul-25	7,117	1,042	0	7,505	1,133	0	6,858	981	0
Aug-25	7,099	1,043	0	7,476	1,135	0	6,847	982	0
Sep-25	7,095	1,045	5	7,469	1,138	5	6,845	983	5
Oct-25	7,168	1,060	5	7,586	1,162	5	6,889	992	5
Nov-25	7,217	1,060	0	7,665	1,162	0	6,918	992	0
Dec-25	7,263	1,066	0	7,739	1,172	0	6,946	996	0
Jan-26	7,266	1,073	0	7,743	1,183	0	6,947	1,000	0
Feb-26	7,279	1,082	0	7,764	1,198	0	6,955	1,005	0
Mar-26	7,237	1,061	0	7,697	1,163	0	6,930	993	0
Apr-26	7,232	1,067	0	7,690	1,172	0	6,927	996	0
May-26	7,226	1,055	0	7,679	1,154	0	6,923	989	0
Jun-26	7,198	1,056	0	7,634	1,156	0	6,907	990	0
Jul-26	7,163	1,052	0	7,579	1,149	0	6,886	987	0
Aug-26	7,145	1,053	0	7,549	1,151	0	6,875	988	0
Sep-26	7,140	1,055	5	7,542	1,154	5	6,872	989	5
Oct-26	7,214	1,070	5	7,660	1,178	5	6,916	998	5
Nov-26	7,264	1,070	0	7,740	1,178	0	6,946	998	0
Dec-26	7,310	1,077	0	7,814	1,189	0	6,974	1,002	0
Jan-27	7,314	1,084	0	7,820	1,200	0	6,976	1,006	0
Feb-27	7,327	1,093	0	7,841	1,215	0	6,984	1,012	0
Mar-27	7,285	1,071	0	7,773	1,180	0	6,959	999	0
Apr-27	7,280	1,077	0	7,766	1,189	0	6,956	1,002	0
May-27	7,274	1,066	0	7,756	1,171	0	6,952	995	0
Jun-27	7,245	1,067	0	7,711	1,173	0	6,935	996	0
Jul-27	7,211	1,062	0	7,655	1,166	0	6,914	993	0
Aug-27	7,192	1,063	0	7,625	1,167	0	6,903	994	0
Sep-27	7,188	1,066	5	7,618	1,171	5	6,901	995	5
Oct-27	7,262	1,080	5	7,737	1,195	5	6,945	1,004	5
Nov-27	7,312	1,080	0	7,817	1,195	0	6,975	1,004	0
Dec-27	7,359	1,087	0	7,892	1,206	0	7,003	1,008	0
Jan-28	7,365	1,095	0	7,901	1,218	0	7,007	1,013	0
Feb-28	7,378	1,104	0	7,922	1,233	0	7,015	1,019	0
Mar-28	7,335	1,082	0	7,854	1,198	0	6,989	1,005	0
Apr-28	7,331	1,088	0	7,847	1,207	0	6,986	1,009	0

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION
LA GRANDE

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential La Grande Customers	Commercial La Grande Customers	Industrial La Grande Customers	Residential La Grande Customers	Commercial La Grande Customers	Industrial La Grande Customers	Residential La Grande Customers	Commercial La Grande Customers	Industrial La Grande Customers
May-28	7,324	1,077	0	7,837	1,189	0	6,982	1,002	0
Jun-28	7,296	1,078	0	7,791	1,190	0	6,965	1,003	0
Jul-28	7,260	1,073	0	7,735	1,183	0	6,944	1,000	0
Aug-28	7,242	1,074	0	7,705	1,185	0	6,933	1,001	0
Sep-28	7,237	1,077	5	7,698	1,189	5	6,930	1,002	5
Oct-28	7,312	1,092	5	7,817	1,212	5	6,975	1,011	5
Nov-28	7,362	1,092	0	7,898	1,212	0	7,005	1,011	0
Dec-28	7,410	1,098	0	7,973	1,224	0	7,034	1,015	0
Jan-29	7,416	1,106	0	7,984	1,236	0	7,038	1,020	0
Feb-29	7,430	1,116	0	8,006	1,251	0	7,046	1,025	0
Mar-29	7,387	1,094	0	7,937	1,216	0	7,020	1,012	0
Apr-29	7,382	1,099	0	7,930	1,225	0	7,017	1,016	0
May-29	7,376	1,088	0	7,919	1,207	0	7,013	1,009	0
Jun-29	7,347	1,089	0	7,873	1,208	0	6,996	1,009	0
Jul-29	7,312	1,084	0	7,817	1,201	0	6,975	1,007	0
Aug-29	7,293	1,085	0	7,787	1,203	0	6,964	1,007	0
Sep-29	7,288	1,088	5	7,779	1,207	5	6,961	1,009	5
Oct-29	7,363	1,103	5	7,900	1,231	5	7,006	1,018	5
Nov-29	7,414	1,103	0	7,981	1,231	0	7,037	1,018	0
Dec-29	7,462	1,110	0	8,057	1,242	0	7,065	1,022	0
Jan-30	7,468	1,118	0	8,067	1,254	0	7,069	1,027	0
Feb-30	7,481	1,127	0	8,088	1,269	0	7,077	1,032	0
Mar-30	7,438	1,105	0	8,019	1,234	0	7,051	1,019	0
Apr-30	7,433	1,111	0	8,011	1,243	0	7,048	1,022	0
May-30	7,427	1,099	0	8,001	1,224	0	7,044	1,015	0
Jun-30	7,398	1,100	0	7,955	1,226	0	7,027	1,016	0
Jul-30	7,362	1,095	0	7,898	1,219	0	7,005	1,013	0
Aug-30	7,343	1,097	0	7,867	1,221	0	6,994	1,014	0
Sep-30	7,339	1,099	5	7,860	1,224	5	6,991	1,015	5
Oct-30	7,415	1,114	5	7,981	1,249	5	7,037	1,024	5
Nov-30	7,466	1,114	0	8,063	1,249	0	7,067	1,024	0
Dec-30	7,513	1,121	0	8,140	1,260	0	7,096	1,029	0
Jan-31	7,519	1,129	0	8,149	1,272	0	7,100	1,033	0
Feb-31	7,533	1,138	0	8,170	1,287	0	7,108	1,039	0
Mar-31	7,489	1,116	0	8,100	1,251	0	7,081	1,026	0
Apr-31	7,484	1,122	0	8,093	1,261	0	7,079	1,029	0
May-31	7,478	1,110	0	8,082	1,242	0	7,075	1,022	0
Jun-31	7,449	1,111	0	8,036	1,244	0	7,057	1,023	0
Jul-31	7,413	1,106	0	7,979	1,236	0	7,036	1,020	0
Aug-31	7,394	1,108	0	7,948	1,238	0	7,024	1,021	0
Sep-31	7,389	1,110	5	7,941	1,242	5	7,022	1,022	5
Oct-31	7,465	1,125	5	8,063	1,267	5	7,067	1,031	5
Nov-31	7,517	1,125	0	8,145	1,267	0	7,098	1,031	0
Dec-31	7,565	1,132	0	8,222	1,278	0	7,127	1,035	0
Jan-32	7,570	1,140	0	8,230	1,290	0	7,130	1,040	0
Feb-32	7,584	1,150	0	8,252	1,305	0	7,138	1,046	0
Mar-32	7,540	1,127	0	8,181	1,269	0	7,112	1,032	0
Apr-32	7,535	1,133	0	8,174	1,279	0	7,109	1,036	0
May-32	7,528	1,121	0	8,163	1,260	0	7,105	1,029	0

APPENDIX 3.2 II CUSTOMER FORECASTS BY REGION
LA GRANDE

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential La Grande Customers	Commercial La Grande Customers	Industrial La Grande Customers	Residential La Grande Customers	Commercial La Grande Customers	Industrial La Grande Customers	Residential La Grande Customers	Commercial La Grande Customers	Industrial La Grande Customers
Jun-32	7,499	1,122	0	8,116	1,261	0	7,087	1,029	0
Jul-32	7,463	1,117	0	8,059	1,254	0	7,066	1,026	0
Aug-32	7,444	1,119	0	8,028	1,256	0	7,054	1,027	0
Sep-32	7,439	1,121	5	8,021	1,260	5	7,052	1,029	5
Oct-32	7,516	1,137	5	8,143	1,284	5	7,098	1,038	5
Nov-32	7,568	1,137	0	8,226	1,284	0	7,129	1,038	0
Dec-32	7,616	1,144	0	8,304	1,296	0	7,158	1,042	0
Jan-33	7,621	1,151	0	8,312	1,308	0	7,161	1,047	0
Feb-33	7,635	1,161	0	8,334	1,324	0	7,169	1,053	0
Mar-33	7,591	1,138	0	8,263	1,287	0	7,142	1,039	0
Apr-33	7,586	1,144	0	8,256	1,297	0	7,140	1,042	0
May-33	7,579	1,132	0	8,245	1,277	0	7,136	1,035	0
Jun-33	7,550	1,133	0	8,198	1,279	0	7,118	1,036	0
Jul-33	7,514	1,128	0	8,140	1,271	0	7,096	1,033	0
Aug-33	7,494	1,130	0	8,109	1,273	0	7,085	1,034	0
Sep-33	7,490	1,132	5	8,102	1,277	5	7,082	1,035	5
Oct-33	7,567	1,148	5	8,225	1,302	5	7,128	1,045	5
Nov-33	7,619	1,148	0	8,308	1,302	0	7,159	1,045	0
Dec-33	7,668	1,155	0	8,387	1,314	0	7,189	1,049	0
Jan-34	7,673	1,163	0	8,394	1,326	0	7,192	1,054	0
Feb-34	7,686	1,172	0	8,416	1,342	0	7,200	1,059	0
Mar-34	7,642	1,149	0	8,345	1,305	0	7,173	1,046	0
Apr-34	7,637	1,155	0	8,337	1,314	0	7,170	1,049	0
May-34	7,630	1,143	0	8,327	1,295	0	7,166	1,042	0
Jun-34	7,601	1,144	0	8,279	1,297	0	7,148	1,043	0
Jul-34	7,564	1,139	0	8,221	1,289	0	7,126	1,040	0
Aug-34	7,545	1,141	0	8,189	1,291	0	7,115	1,040	0
Sep-34	7,540	1,143	5	8,182	1,295	5	7,112	1,042	5
Oct-34	7,618	1,159	5	8,306	1,320	5	7,159	1,051	5
Nov-34	7,670	1,159	0	8,390	1,320	0	7,190	1,051	0
Dec-34	7,719	1,166	0	8,469	1,332	0	7,220	1,056	0
Jan-35	7,724	1,174	0	8,476	1,344	0	7,222	1,060	0
Feb-35	7,738	1,184	0	8,498	1,360	0	7,231	1,066	0
Mar-35	7,693	1,160	0	8,426	1,322	0	7,204	1,052	0
Apr-35	7,688	1,166	0	8,419	1,332	0	7,201	1,056	0
May-35	7,681	1,154	0	8,408	1,313	0	7,197	1,048	0
Jun-35	7,651	1,155	0	8,360	1,315	0	7,179	1,049	0
Jul-35	7,614	1,150	0	8,301	1,307	0	7,157	1,046	0
Aug-35	7,595	1,152	0	8,270	1,309	0	7,145	1,047	0
Sep-35	7,590	1,154	5	8,263	1,313	5	7,142	1,048	5
Oct-35	7,669	1,170	5	8,388	1,338	5	7,189	1,058	5
Nov-35	7,721	1,170	0	8,472	1,338	0	7,221	1,058	0
Dec-35	7,771	1,178	0	8,551	1,350	0	7,251	1,063	0

APPENDIX 3.3 II DEMAND COEFFICIENTS

	January	February	March	April	May	June	July	August	September	October	November	December
HEAT COEFFICIENTS												
WA/ID Res	0.009844	0.008976	0.008870	0.008029	0.005690	0.003686	0.001174	0.000826	0.002388	0.006412	0.008695	0.009962
WA/ID Com	0.049978	0.045349	0.043363	0.037282	0.024076	0.016817	0.004930	0.007713	0.019781	0.036017	0.042431	0.050435
WA/ID Ind	0.129009	0.115248	0.094806	0.084501	0.041487	0.055783	0.044625	0.132057	0.198661	0.283820	0.164946	0.170180
Rose Res	0.010208	0.010184	0.009517	0.008514	0.006722	0.005038	0.000615	0.000049	0.001527	0.004756	0.008477	0.010124
Rose Com	0.041388	0.039173	0.037762	0.031763	0.022073	0.010826	0.003070	0.002933	0.020028	0.027221	0.036871	0.044178
Rose Ind	0.560088	0.639565	0.609582	1.794676	0.050434	0.307867	3.765089	4.759543	4.064708	1.476627	1.166407	0.839549
Medford Res	0.0103873	0.0100818	0.0100326	0.0089329	0.0066631	0.0046337	0.0021118	0.0009412	0.0029039	0.0064739	0.0090313	0.0105071
Medford Com	0.0404618	0.0406224	0.0364242	0.0292521	0.0221656	0.0144695	0.0106799	0.0095883	0.0213454	0.0383247	0.0390795	0.0420363
Medford Ind	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
LaGrande Res	0.0087736	0.0081353	0.0080601	0.0074661	0.0054241	0.0033964	0.0004897	0.0105253	0.0007420	0.0030466	0.0077767	0.0089209
LaGrande Com	0.0424449	0.0405465	0.0370305	0.0313249	0.0210792	0.0124668	0.0094054	0.0766325	0.0081499	0.0183217	0.0346280	0.0402809
LaGrande Ind	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
Klamath Res	0.008035	0.007601	0.007340	0.006312	0.004454	0.002573	0.000170	0.000560	0.001306	0.004338	0.006839	0.007861
Klamath Com	0.031883	0.030028	0.027044	0.021792	0.013740	0.004544	0.000226	0.006202	0.008292	0.023551	0.028058	0.031165
Klamath Ind	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
BASE COEFFICIENTS												
WA/ID Res	0.055491	0.055491	0.055491	0.055491	0.055491	0.055491	0.055491	0.055491	0.055491	0.055491	0.055491	0.055491
WA/ID Com	0.346420	0.346420	0.346420	0.346420	0.346420	0.346420	0.346420	0.346420	0.346420	0.346420	0.346420	0.346420
WA/ID Ind	3.651386	3.651386	3.651386	3.651386	3.651386	3.651386	3.651386	3.651386	3.651386	3.651386	3.651386	3.651386
Rose Res	0.045476	0.045476	0.045476	0.045476	0.045476	0.045476	0.045476	0.045476	0.045476	0.045476	0.045476	0.045476
Rose Com	0.327449	0.327449	0.327449	0.327449	0.327449	0.327449	0.327449	0.327449	0.327449	0.327449	0.327449	0.327449
Rose Ind	19.923195	19.923195	19.923195	19.923195	19.923195	19.923195	19.923195	19.923195	19.923195	19.923195	19.923195	19.923195
Medford Res	0.047121	0.047121	0.047121	0.047121	0.047121	0.047121	0.047121	0.047121	0.047121	0.047121	0.047121	0.047121
Medford Com	0.333897	0.333897	0.333897	0.333897	0.333897	0.333897	0.333897	0.333897	0.333897	0.333897	0.333897	0.333897
Medford Ind	3.762345	3.762345	3.762345	3.762345	3.762345	3.762345	3.762345	3.762345	3.762345	3.762345	3.762345	3.762345
LaGrande Res	0.053749	0.053749	0.053749	0.053749	0.053749	0.053749	0.053749	0.053749	0.053749	0.053749	0.053749	0.053749
LaGrande Com	0.252881	0.252881	0.252881	0.252881	0.252881	0.252881	0.252881	0.252881	0.252881	0.252881	0.252881	0.252881
LaGrande Ind	8.968306	8.968306	8.968306	8.968306	8.968306	8.968306	8.968306	8.968306	8.968306	8.968306	8.968306	8.968306
Klamath Res	0.041313	0.041313	0.041313	0.041313	0.041313	0.041313	0.041313	0.041313	0.041313	0.041313	0.041313	0.041313
Klamath Com	0.319781	0.319781	0.319781	0.319781	0.319781	0.319781	0.319781	0.319781	0.319781	0.319781	0.319781	0.319781
Klamath Ind	2.131761	2.131761	2.131761	2.131761	2.131761	2.131761	2.131761	2.131761	2.131761	2.131761	2.131761	2.131761
SUPER PEAK 1/												
WA/ID Res	0.009594	0.009594										0.009594
WA/ID Com	0.048587	0.048587										0.048587
WA/ID Ind	0.138145	0.138145										0.138145
Rose Res	0.010172	0.010172										0.010172
Rose Com	0.041580	0.041580										0.041580
Rose Ind	0.679734	0.679734										0.679734
Medford Res	0.010325	0.010325										0.010325
Medford Com	0.041040	0.041040										0.041040
Medford Ind	-	-										-
LaGrande Res	0.008610	0.008610										0.008610
LaGrande Com	0.041091	0.041091										0.041091
LaGrande Ind	-	-										-
Klamath Res	0.007832	0.007832										0.007832
Klamath Com	0.031025	0.031025										0.031025
Klamath Ind	-	-										-

1/ Average of DEC JAN FEB heat coefficients

	January	February	March	April	May	June	July	August	September	October	November	December
HEAT COEFFICIENTS												
WA/ID Res	0.009844	0.008976	0.008870	0.008029	0.005690	0.003686	0.001174	0.000826	0.002388	0.006412	0.008695	0.009962
WA/ID Com	0.049978	0.045349	0.043363	0.037282	0.024076	0.016817	0.004930	0.007713	0.019781	0.036017	0.042431	0.050435
WA/ID Ind	0.129009	0.115248	0.094806	0.084501	0.041487	0.055783	0.044625	0.132057	0.198661	0.283820	0.164946	0.170180
Rose Res	0.010208	0.010184	0.009517	0.008514	0.006722	0.005038	0.000615	0.000049	0.001527	0.004756	0.008477	0.010124
Rose Com	0.041388	0.039173	0.037762	0.031763	0.022073	0.010826	0.003070	0.002933	0.020028	0.027221	0.036871	0.044178
Rose Ind	0.560088	0.639565	0.609582	1.794676	0.050434	0.307867	3.765089	4.759543	4.064708	1.476627	1.166407	0.839549
Medford Res	0.0103873	0.0100818	0.0100326	0.0089329	0.0066631	0.0046337	0.0021118	0.0009412	0.0029039	0.0064739	0.0090313	0.0105071
Medford Com	0.0404618	0.0406224	0.0364242	0.0292521	0.0221656	0.0144695	0.0106799	0.0095883	0.0213454	0.0383247	0.0390795	0.0420363
Medford Ind	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
LaGrande Res	0.0087736	0.0081353	0.0080601	0.0074661	0.0054241	0.0033964	0.0004897	0.0105253	0.0007420	0.0030466	0.0077767	0.0089209
LaGrande Com	0.0424449	0.0405465	0.0370305	0.0313249	0.0210792	0.0124668	0.0094054	0.0766325	0.0081499	0.0183217	0.0346280	0.0402809
LaGrande Ind	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
Klamath Res	0.008035	0.007601	0.007340	0.006312	0.004454	0.002573	0.000170	0.000560	0.001306	0.004338	0.006839	0.007861
Klamath Com	0.031883	0.030028	0.027044	0.021792	0.013740	0.004544	0.000226	0.006202	0.008292	0.023551	0.028058	0.031165
Klamath Ind	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
BASE COEFFICIENTS												
WA/ID Res	0.055491	0.055491	0.055491	0.055491	0.055491	0.055491	0.055491	0.055491	0.055491	0.055491	0.055491	0.055491
WA/ID Com	0.346420	0.346420	0.346420	0.346420	0.346420	0.346420	0.346420	0.346420	0.346420	0.346420	0.346420	0.346420
WA/ID Ind	3.651386	3.651386	3.651386	3.651386	3.651386	3.651386	3.651386	3.651386	3.651386	3.651386	3.651386	3.651386
Rose Res	0.045476	0.045476	0.045476	0.045476	0.045476	0.045476	0.045476	0.045476	0.045476	0.045476	0.045476	0.045476
Rose Com	0.327449	0.327449	0.327449	0.327449	0.327449	0.327449	0.327449	0.327449	0.327449	0.327449	0.327449	0.327449
Rose Ind	19.923195	19.923195	19.923195	19.923195	19.923195	19.923195	19.923195	19.923195	19.923195	19.923195	19.923195	19.923195
Medford Res	0.047121	0.047121	0.047121	0.047121	0.047121	0.047121	0.047121	0.047121	0.047121	0.047121	0.047121	0.047121
Medford Com	0.333897	0.333897	0.333897	0.333897	0.333897	0.333897	0.333897	0.333897	0.333897	0.333897	0.333897	0.333897
Medford Ind	3.762345	3.762345	3.762345	3.762345	3.762345	3.762345	3.762345	3.762345	3.762345	3.762345	3.762345	3.762345
LaGrande Res	0.053749	0.053749	0.053749	0.053749	0.053749	0.053749	0.053749	0.053749	0.053749	0.053749	0.053749	0.053749
LaGrande Com	0.252881	0.252881	0.252881	0.252881	0.252881	0.252881	0.252881	0.252881	0.252881	0.252881	0.252881	0.252881
LaGrande Ind	8.968306	8.968306	8.968306	8.968306	8.968306	8.968306	8.968306	8.968306	8.968306	8.968306	8.968306	8.968306
Klamath Res	0.041313	0.041313	0.041313	0.041313	0.041313	0.041313	0.041313	0.041313	0.041313	0.041313	0.041313	0.041313
Klamath Com	0.319781	0.319781	0.319781	0.319781	0.319781	0.319781	0.319781	0.319781	0.319781	0.319781	0.319781	0.319781
Klamath Ind	2.131761	2.131761	2.131761	2.131761	2.131761	2.131761	2.131761	2.131761	2.131761	2.131761	2.131761	2.131761
SUPER PEAK 1/												
WA/ID Res	0.009594	0.009594										0.009594
WA/ID Com	0.048587	0.048587										0.048587
WA/ID Ind	0.138145	0.138145										0.138145
Rose Res	0.010172	0.010172										0.010172
Rose Com	0.041580	0.041580										0.041580
Rose Ind	0.679734	0.679734										0.679734
Medford Res	0.010325	0.010325										0.010325
Medford Com	0.041040	0.041040										0.041040
Medford Ind	-	-										-
LaGrande Res	0.008610	0.008610										0.008610
LaGrande Com	0.041091	0.041091										0.041091
LaGrande Ind	-	-										-
Klamath Res	0.007832	0.007832										0.007832
Klamath Com	0.031025	0.031025										0.031025
Klamath Ind	-	-										-

1/ Average of DEC JAN FEB heat coefficients

APPENDIX 3.3 II WA/ID BASE COEFFICIENT CALCULATION

Average Actual Demand by Class

Year	Data	Month 7	8	Grand Total
2005	Average of Res Demand	11,098	10,607	10,852
	Average of Com Demand	7,729	8,406	8,067
	Average of Ind Demand	991	1,001	996
2006	Average of Res Demand	9,988	10,513	10,250
	Average of Com Demand	6,956	8,331	7,643
	Average of Ind Demand	892	992	942
2007	Average of Res Demand	10,032	10,433	10,232
	Average of Com Demand	6,987	8,267	7,627
	Average of Ind Demand	896	984	940
2008	Average of Res Demand	10,684	10,495	10,590
	Average of Com Demand	7,441	8,317	7,879
	Average of Ind Demand	954	990	972
2009	Average of Res Demand	10,346	10,516	10,431
	Average of Com Demand	7,466	7,810	7,638
	Average of Ind Demand	756	797	777
2010	Average of Res Demand	11,208	10,733	10,971
	Average of Com Demand	8,030	8,435	8,232
	Average of Ind Demand	814	1,174	994
Total Average of Res Demand		10,559	10,549	10,554
Total Average of Com Demand		7,435	8,261	7,848
Total Average of Ind Demand		884	990	937

Average Actual Customer Count by Class

Year	Data	Month 7	8	Grand Total
2005	Average of Res Cust	179,140	179,447	179,294
	Average of Com Cust	20,450	20,427	20,439
	Average of Ind Cust	263	260	262
2006	Average of Res Cust	185,182	185,455	185,319
	Average of Com Cust	20,748	20,856	20,802
	Average of Ind Cust	246	242	244
2007	Average of Res Cust	189,577	190,087	189,832
	Average of Com Cust	21,291	21,336	21,314
	Average of Ind Cust	244	241	243
2008	Average of Res Cust	193,667	193,643	193,655
	Average of Com Cust	21,847	21,815	21,831
	Average of Ind Cust	239	240	240
2009	Average of Res Cust	196,121	196,276	196,199
	Average of Com Cust	22,087	21,928	22,008
	Average of Ind Cust	233	234	234
2010	Average of Res Cust	198,059	198,572	198,316
	Average of Com Cust	22,344	22,320	22,332
	Average of Ind Cust	227	229	228
Total Average of Res Cust		190,291	190,580	190,436
Total Average of Com Cust		21,461	21,447	21,454
Total Average of Ind Cust		242	241	242

Base Coefficients

(Actual Average Demand/Customer Count)

0.055491	Res Base Usage
0.346420	Com Base Usage
3.651386	Ind Base Usage

APPENDIX 3.3 II WA/ID REGRESSION STATS

WA/ID Residential	January	February	March	April	May	June	July	August	September	October	November	December
Regression Statistics												
Multiple R	0.997654206	0.997358913	0.99495305	0.981505937	0.978167166	0.971495302	0.9512495	0.820421448	0.905297943	0.980838934	0.996347984	0.998826781
R Square	0.995313916	0.994724801	0.989931572	0.963353905	0.956811005	0.943803121	0.904875612	0.673091352	0.819564366	0.962045014	0.992709306	0.997654938
Adjusted R Square	0.961980582	0.957687764	0.956598239	0.928871147	0.923477671	0.909320362	0.871542278	0.639758019	0.785081607	0.92871168	0.958226547	0.964321605
Standard Error	0.025319723	0.026597125	0.023849048	0.032003003	0.019326085	0.008778728	0.001506231	0.002405292	0.007547259	0.020314017	0.026682708	0.016880022
Observations	93	85	93	90	93	90	93	93	90	93	90	93
Coefficients												
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.009844497	0.008975558	0.008869664	0.008028585	0.005689813	0.003686459	0.001173698	0.000826461	0.00238834	0.006412228	0.008695213	0.009962245
Super Peak	0.009594											

WA/ID Commercial	January	February	March	April	May	June	July	August	September	October	November	December
Regression Statistics												
Multiple R	0.997535461	0.997292266	0.994399095	0.973845966	0.961984203	0.948589598	0.939986639	0.910976062	0.915358718	0.977449556	0.994645052	0.998846897
R Square	0.995076996	0.994591864	0.988829561	0.948375966	0.925413607	0.899822226	0.883574882	0.829877386	0.837881582	0.955407635	0.989318779	0.997695123
Adjusted R Square	0.961743663	0.957554827	0.955496228	0.913893207	0.892080274	0.865339467	0.850241548	0.796544053	0.803398823	0.922074302	0.954836021	0.96436179
Standard Error	0.132669245	0.14116655	0.126255346	0.17113869	0.110750203	0.049490372	0.008170014	0.015327701	0.058953352	0.129636092	0.162257455	0.085502566
Observations	93	85	93	90	93	90	93	93	90	93	90	93
Coefficients												
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.049978045	0.045348934	0.043362661	0.037282468	0.024075694	0.016816525	0.004929633	0.007712715	0.01978081	0.036017179	0.042430755	0.050434673
Super Peak	0.048587											

WA/ID Industrial	January	February	March	April	May	June	July	August	September	October	November	December
Regression Statistics												
Multiple R	0.976837619	0.985912283	0.965121396	0.812877595	0.747131231	0.713029296	0.866878204	0.97252247	0.917942089	0.963351152	0.979214675	0.991637888
R Square	0.954211734	0.972023031	0.93145931	0.660769984	0.558205076	0.508410777	0.751477821	0.945799954	0.842617678	0.928045441	0.958861379	0.983345701
Adjusted R Square	0.9208784	0.934985994	0.898125976	0.626287226	0.524871743	0.473928018	0.718144488	0.912466621	0.808134919	0.894712108	0.924378621	0.950012368
Standard Error	0.878794521	0.827132425	0.649592069	0.8391273	0.715597581	0.361846573	0.072274178	0.230399915	0.689125252	1.269881938	1.528875182	0.561757012
Observations	93	85	93	90	93	90	93	93	90	93	90	93
Coefficients												
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.129008542	0.115247756	0.0948062	0.084500696	0.041487475	0.055783015	0.044625063	0.132057167	0.198660758	0.283820092	0.164946307	0.170179963
Super Peak	0.138145											

APPENDIX 3.3 II MEDFORD BASE COEFFICIENT CALCULATION

Average Actual Demand by Class

Year	Data	Month 7	8	Grand Total
2005	Average of Res Demand	2,420	2,389	2,404
	Average of Com Demand	2,146	2,205	2,176
	Sum of Ind Demand	-	-	-
2006	Average of Res Demand	2,243	2,328	2,285
	Average of Com Demand	1,989	2,148	2,069
	Sum of Ind Demand	-	-	-
2007	Average of Res Demand	2,319	2,285	2,302
	Average of Com Demand	2,044	2,142	2,093
	Sum of Ind Demand	251	212	463
2008	Average of Res Demand	2,300	2,688	2,494
	Average of Com Demand	2,027	2,520	2,274
	Sum of Ind Demand	249	249	498
2009	Average of Res Demand	2,303	2,230	2,266
	Average of Com Demand	2,011	2,045	2,028
	Sum of Ind Demand	953	1,093	2,046
2010	Average of Res Demand	2,276	2,103	2,190
	Average of Com Demand	1,979	2,003	1,991
	Sum of Ind Demand	2,924	4,449	7,373
Total Average of Res Demand		2,310	2,337	2,324
Total Average of Com Demand		2,033	2,177	2,105
Total Sum of Ind Demand		4,377	6,003	10,380

Average Actual Customer Count by Class

Year	Data	Month 7	8	Grand Total
2005	Average of Res Customer	47,286	47,191	47,239
	Average of Com Customer	6,085	6,094	6,090
	Average of Ind Customer	-	-	-
2006	Average of Res Customer	48,666	48,531	48,599
	Average of Com Customer	6,225	6,229	6,227
	Average of Ind Customer	-	-	-
2007	Average of Res Customer	49,448	49,391	49,420
	Average of Com Customer	6,356	6,352	6,354
	Average of Ind Customer	9	9	9
2008	Average of Res Customer	49,930	49,734	49,832
	Average of Com Customer	6,395	6,391	6,393
	Average of Ind Customer	10	10	10
2009	Average of Res Customer	50,019	49,868	49,944
	Average of Com Customer	6,327	6,301	6,314
	Average of Ind Customer	12	13	13
2010	Average of Res Customer	50,824	50,824	50,824
	Average of Com Customer	6,449	6,449	6,449
	Average of Ind Customer	13	13	13
Total Average of Res Customer		49,362	49,257	49,309
Total Average of Com Customer		6,306	6,303	6,304
Total Average of Ind Customer		7	8	7

Base Coefficients

(Actual Average Demand/Customer Count)

0.047121	Res Base Usage
0.333897	Com Base Usage
3.762345	Ind Base Usage

APPENDIX 3.3 II MEDFORD REGRESSION STATS

Medford Residential

	January	February	March	April	May	June	July	August	September	October	November	December
Regression Statistics												
Multiple R	0.997413882	0.997067778	0.995768593	0.992944333	0.991228607	0.920024236	0.734018374	0.597421004	0.913447475	0.97528302	0.993329289	0.995999631
R Square	0.994834451	0.994144154	0.991555091	0.985938449	0.982534151	0.846444594	0.538782974	0.356911856	0.834386289	0.951176968	0.986703075	0.992015265
Adjusted R S	0.961501118	0.957107117	0.958221758	0.95145569	0.949200818	0.811961836	0.505449641	0.323578522	0.799903531	0.917843635	0.952220317	0.958681931
Standard Erro	0.02023568	0.01853198	0.01794617	0.019456396	0.010919646	0.008271836	0.000992949	0.001098302	0.00217479	0.013342662	0.023446397	0.020861739
Observations	93	85	93	90	93	90	93	93	90	93	90	93
Coefficients												
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.010387258	0.010081776	0.010032583	0.008932892	0.006663115	0.004633661	0.002111771	0.000941211	0.002903862	0.006473882	0.009031279	0.010507109
Super Peak	0.010325											

Medford Commercial

	January	February	March	April	May	June	July	August	September	October	November	December
Regression Statistics												
Multiple R	0.995602736	0.996276736	0.994485657	0.974882075	0.981370235	0.898112402	0.712055129	0.716686937	0.936128746	0.971201378	0.989751777	0.994448238
R Square	0.991224808	0.992567336	0.989001722	0.95039506	0.963087539	0.806605886	0.507022507	0.513640165	0.87633703	0.943232116	0.97960858	0.988927299
Adjusted R S	0.957891475	0.955530299	0.955668389	0.915912301	0.929754206	0.772123128	0.473689174	0.480306832	0.841854271	0.909898783	0.945125821	0.955593966
Standard Erro	0.10577674	0.098869555	0.07011104	0.093987061	0.058149805	0.022611663	0.005041153	0.01034255	0.017218831	0.089004979	0.132496693	0.101527957
Observations	93	85	93	90	93	90	93	93	90	93	90	93
Coefficients												
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.040461844	0.040622406	0.036424152	0.029252135	0.022165633	0.014469459	0.010679854	0.009588349	0.021345382	0.038324684	0.039079527	0.04203632
Super Peak	0.041040											

APPENDIX 3.3 II ROSEBURG BASE COEFFICIENT CALCULATION

Average Actual Demand by Class

Year	Data	Month 7	8	Grand Total
2005	Average of Res Demand	859	849	854
	Average of Com Demand	910	1,040	975
	Average of Ind Demand	32	46	39
2006	Average of Res Demand	702	611	657
	Average of Com Demand	744	748	746
	Average of Ind Demand	26	33	29
2007	Average of Res Demand	634	619	627
	Average of Com Demand	672	757	715
	Average of Ind Demand	24	33	28
2008	Average of Res Demand	632	585	609
	Average of Com Demand	670	716	693
	Average of Ind Demand	23	31	27
2009	Average of Res Demand	568	519	543
	Average of Com Demand	659	658	659
	Average of Ind Demand	21	31	26
2010	Average of Res Demand	497	488	492
	Average of Com Demand	631	688	659
	Average of Ind Demand	119	116	118
Total Average of Res Demand		649	612	630
Total Average of Com Demand		714	768	741
Total Average of Ind Demand		41	48	45

Average Actual Customer Count by Class

Year	Data	Month 7	8	Grand Total
2005	Average of Res Customer	12,311	12,257	12,284
	Average of Com Customer	2,093	2,093	2,093
	Average of Ind Customer	2	2	2
2006	Average of Res Customer	12,570	12,511	12,541
	Average of Com Customer	2,128	2,112	2,120
	Average of Ind Customer	3	4	4
2007	Average of Res Customer	12,900	12,777	12,839
	Average of Com Customer	2,126	2,105	2,116
	Average of Ind Customer	2	1	2
2008	Average of Res Customer	12,942	12,885	12,914
	Average of Com Customer	2,116	2,106	2,111
	Average of Ind Customer	2	2	2
2009	Average of Res Customer	12,920	12,874	12,897
	Average of Com Customer	2,123	2,120	2,122
	Average of Ind Customer	2	1	2
2010	Average of Res Customer	13,183	13,183	13,183
	Average of Com Customer	2,132	2,132	2,132
	Average of Ind Customer	3	3	3
Total Average of Res Customer		12,804	12,748	12,776
Total Average of Com Customer		2,120	2,111	2,116
Total Average of Ind Customer		2	2	2

Base Coefficients

(Actual Average Demand/Customer Count)

0.045476	Res Base Usage
0.327449	Com Base Usage
19.92319	Ind Base Usage

APPENDIX 3.3 II ROSEBRURG REGRESSION STATS

Roseburg Residential

	January	February	March	April	May	June	July	August	September	October	November	December
Regression Statistics												
Multiple R	0.995703207	0.996289735	0.995591731	0.990373703	0.989672191	0.961768478	1	1	0.337099931	0.76178275	0.981277194	0.995726522
R Square	0.991424876	0.992593235	0.991202896	0.980840072	0.979451046	0.924998606	1	1	0.113636364	0.580312959	0.962904931	0.991471306
Adjusted R S	0.958091542	0.955556198	0.957869562	0.946357313	0.946117713	0.890515847	0.966666667	0.966666667	0.079153605	0.546979626	0.928422173	0.958137973
Standard Erro	0.020189471	0.020546436	0.015516028	0.019450184	0.012207209	0.007791278	0	0	7.63152E-05	0.012083008	0.030766909	0.018667824
Observations	93	85	93	90	93	90	93	93	90	93	90	93
Coefficients												
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.010207961	0.01018421	0.00951694	0.008513573	0.006722065	0.00503812	0.000614775	4.93693E-05	0.001527313	0.004755629	0.00847663	0.010124057
Super Peak	0.010172											

Roseburg Commercial

	January	February	March	April	May	June	July	August	September	October	November	December
Regression Statistics												
Multiple R	0.994259965	0.995327341	0.994711326	0.982448921	0.966029275	0.888034969	0.760421488	0.707524379	0.855176459	0.788678508	0.97623698	0.995508486
R Square	0.988552879	0.990676515	0.989450621	0.965205882	0.933212559	0.788606107	0.578240839	0.500590747	0.731326775	0.622013789	0.953038641	0.991037146
Adjusted R S	0.955219545	0.953639478	0.956117288	0.930723123	0.899879226	0.754123348	0.544907506	0.467257413	0.696844017	0.588680456	0.918555882	0.957703813
Standard Erro	0.101619442	0.103566587	0.074606905	0.097003717	0.071132553	0.033976264	0.002411562	0.008759553	0.018320633	0.094215258	0.180655819	0.088740539
Observations	93	85	93	90	93	90	93	93	90	93	90	93
Coefficients												
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.041387999	0.039173031	0.037761981	0.031762565	0.022073058	0.010826	0.003070018	0.002933236	0.020028191	0.027221003	0.036871328	0.044178165
Super Peak	0.041580											

Roseburg Industrial

	January	February	March	April	May	June	July	August	September	October	November	December
Regression Statistics												
Multiple R	0.994038131	0.994751225	0.994750448	0.608177383	0.532904171	1	0.909561529	0.946941185	0.935096746	0.911034319	0.984317571	0.995636562
R Square	0.988111805	0.989529999	0.989528454	0.369879729	0.283986856	1	0.827302176	0.896697608	0.874405925	0.82998353	0.968881081	0.991292163
Adjusted R S	0.954778472	0.952492962	0.956195121	0.335396971	0.250653523	0.965517241	0.793968843	0.863364275	0.839923166	0.796650197	0.934398322	0.95795883
Standard Erro	3.965396109	3.82574582	2.993997033	0.986325539	0.535778415	0	4.895861812	3.485419118	8.945791539	12.11315329	10.57405988	3.838946443
Observations	93	85	93	90	93	90	93	93	90	93	90	93
Coefficients												
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.560088307	0.639564834	0.609581699	1.794675998	0.050433553	0.307866797	3.765089394	4.759542558	4.064707745	1.47662742	1.166406843	0.839548803
Super Peak	0.679734											

APPENDIX 3.3 II KLAMATH FALLS BASE COEFFICIENT CALCULATION

Average Actual Demand by Class

Year	Data	Month 7	8	Grand Total
2005	Average of Res Demand	752	684	718
	Average of Com Demand	641	684	662
	Average of Ind Demand	-	-	-
2006	Average of Res Demand	552	541	546
	Average of Com Demand	451	541	496
	Average of Ind Demand	-	-	-
2007	Average of Res Demand	576	540	558
	Average of Com Demand	484	547	515
	Average of Ind Demand	7	10	8
2008	Average of Res Demand	494	508	501
	Average of Com Demand	416	514	465
	Average of Ind Demand	6	9	8
2009	Average of Res Demand	459	499	479
	Average of Com Demand	428	464	446
	Average of Ind Demand	12	16	14
2010	Average of Res Demand	547	521	534
	Average of Com Demand	437	521	479
	Average of Ind Demand	16	22	19
Total Average of Res Demand		563	549	556
Total Average of Com Demand		476	545	511
Total Average of Ind Demand		7	10	8

Average Actual Customer Count by Class

Year	Data	Month 7	8	Grand Total
2005	Average of Res Customer	12,977	12,855	12,916
	Average of Com Customer	1,576	1,566	1,571
	Average of Ind Customer	-	-	-
2006	Average of Res Customer	13,240	13,135	13,188
	Average of Com Customer	1,582	1,576	1,579
	Average of Ind Customer	-	-	-
2007	Average of Res Customer	13,675	13,610	13,643
	Average of Com Customer	1,605	1,598	1,602
	Average of Ind Customer	5	5	5
2008	Average of Res Customer	13,703	13,576	13,640
	Average of Com Customer	1,603	1,590	1,597
	Average of Ind Customer	5	5	5
2009	Average of Res Customer	13,683	13,604	13,644
	Average of Com Customer	1,624	1,615	1,620
	Average of Ind Customer	6	6	6
2010	Average of Res Customer	13,783	13,679	13,731
	Average of Com Customer	1,620	1,610	1,615
	Average of Ind Customer	7	7	7
Total Average of Res Customer		13,510	13,410	13,460
Total Average of Com Customer		1,602	1,593	1,597
Total Average of Ind Customer		4	4	4

Base Coefficients

(Actual Average Demand/Customer Count)

0.041313	Res Base Usage
0.319781	Com Base Usage
2.131761	Ind Base Usage

APPENDIX 3.3 II KLAMATH FALLS REGRESSION STATS

Klamath Falls Residential												
	January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
						Regression Statistics						
Multiple R	0.99829776	0.994544536	0.992991253	0.983717594	0.966196571	0.950403906	0.868069678	0.791953474	0.811217624	0.957083956	0.993829215	0.996354859
R Square	0.996598417	0.989118833	0.986031629	0.967700304	0.933535813	0.903267585	0.753544966	0.627190306	0.658074033	0.916009699	0.987696508	0.992723005
Adjusted R S	0.963265084	0.952081796	0.952698296	0.933217545	0.90020248	0.868784827	0.720211632	0.593856972	0.623591274	0.882676366	0.95321375	0.959389671
Standard Erro	0.017001108	0.028351681	0.027273526	0.031901251	0.02817435	0.009303672	0.000969873	0.003637699	0.004936244	0.020286287	0.027067469	0.023112268
Observations	93	85	93	90	93	90	93	93	90	93	90	93
						Coefficients						
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.008035196	0.007601401	0.007340407	0.006311879	0.004454224	0.002572739	0.000169675	0.000560013	0.001305856	0.004338331	0.0068389	0.007860587
Super Peak	0.007832											

Klamath Falls Commercial												
	January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
						Regression Statistics						
Multiple R	0.997340356	0.993757996	0.989350597	0.966712005	0.925120201	0.603458962	0.602796287	0.834498042	0.793298581	0.935681771	0.990550238	0.995614497
R Square	0.994687786	0.987554955	0.978814603	0.934532101	0.855847385	0.364162718	0.363363363	0.696386983	0.629322638	0.875500377	0.981189773	0.991248227
Adjusted R S	0.961354452	0.950517917	0.94548127	0.900049343	0.822514052	0.32967996	0.33003003	0.663053649	0.594839879	0.842167044	0.946707014	0.957914893
Standard Erro	0.085213132	0.127752985	0.127404523	0.157638569	0.148601948	0.034214729	0.002984935	0.033287639	0.035625876	0.144022096	0.144170705	0.097840115
Observations	93	85	93	90	93	90	93	93	90	93	90	93
						Coefficients						
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.031882962	0.030028158	0.027044273	0.021792485	0.013739514	0.004543931	0.00022562	0.006201806	0.008292339	0.023550893	0.028057996	0.031164693
Super Peak	0.031025											

APPENDIX 3.3 II LA GRANDE BASE COEFFICIENT CALCULATION

Average Actual Demand by Class

Year	Data	Month 7	Grand Total
2005	Average of Res Demand	368	368
	Average of Com Demand	224	224
	Average of Ind Demand	17	17
2006	Average of Res Demand	360	360
	Average of Com Demand	219	219
	Average of Ind Demand	17	17
2007	Average of Res Demand	360	360
	Average of Com Demand	219	219
	Average of Ind Demand	17	17
2008	Average of Res Demand	365	365
	Average of Com Demand	222	222
	Average of Ind Demand	17	17
2009	Average of Res Demand	292	292
	Average of Com Demand	235	235
	Average of Ind Demand	3	3
2010	Average of Res Demand	300	300
	Average of Com Demand	235	235
	Average of Ind Demand	11	11
Total Average of Res Demand		341	341
Total Average of Com Demand		226	226
Total Average of Ind Demand		13	13

Average Actual Customer Count by Class

Year	Data	Month 7	Grand Total
2005	Average of Res Customers	6,475	6,475
	Average of Com Customers	949	949
	Average of Ind Customers	3	3
2006	Average of Res Customers	6,163	6,163
	Average of Com Customers	873	873
	Average of Ind Customers	2	2
2007	Average of Res Customers	6,259	6,259
	Average of Com Customers	868	868
	Average of Ind Customers	1	1
2008	Average of Res Customers	6,351	6,351
	Average of Com Customers	880	880
	Average of Ind Customers	1	1
2009	Average of Res Customers	6,386	6,386
	Average of Com Customers	891	891
	Average of Ind Customers	1	1
2010	Average of Res Customers	6,418	6,418
	Average of Com Customers	894	894
	Average of Ind Customers	1	1
Total Average of Res Customers		6,342	6,342
Total Average of Com Customers		893	893
Total Average of Ind Customers		2	2

Base Coefficients

(Actual Average Demand/Customer Count)

0.0537493	Res Base Usage
0.252881	Com Base Usage
8.9683057	Ind Base Usage

APPENDIX 3.3 II LA GRANDE REGRESSION STATS

LaGrande Residential												
	January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
						Regression Statistics						
Multiple R	0.996309419	0.99434025	0.994633514	0.981080712	0.950464084	0.928564142	0.594217046	0.973312551	0.353317	0.858301035	0.98932765	0.994761114
R Square	0.992632458	0.988712533	0.989295827	0.962519364	0.903381976	0.862231366	0.353093898	0.947337323	0.124832902	0.736680666	0.978769199	0.989549674
Adjusted R S	0.959299125	0.951675496	0.955962493	0.928036605	0.870048642	0.827748608	0.319760565	0.914003989	0.090350144	0.703347333	0.94428644	0.95621634
Standard Erro	0.025333762	0.028628557	0.022196244	0.02942289	0.0336419	0.011221729	0.001585687	0.01199327	0.002838372	0.015412471	0.036545557	0.027245655
Observations	93	85	93	90	93	90	93	93	90	93	90	93
						Coefficients						
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.008773593	0.008135275	0.00806009	0.007466051	0.005424053	0.003396429	0.000489695	0.010525255	0.000742044	0.003046619	0.007776698	0.008920865
Super Peak	0.008610											

LaGrande Commercial												
	January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
						Regression Statistics						
Multiple R	0.996207943	0.994427495	0.994652101	0.980673611	0.946830837	0.905913752	0.94890968	0.975588253	0.646135991	0.913700332	0.990307403	0.994680868
R Square	0.992430266	0.988886043	0.989332802	0.961720731	0.896488635	0.820679726	0.90042958	0.951772439	0.417491719	0.834848297	0.980708753	0.98939003
Adjusted R S	0.959096932	0.951849006	0.955999468	0.927237973	0.863155301	0.786196967	0.867096247	0.918439106	0.383008961	0.801514964	0.946225994	0.956056697
Standard Erro	0.132998566	0.168099669	0.099767818	0.125404814	0.139342004	0.04804627	0.011825828	0.086988832	0.062638627	0.091299821	0.177506477	0.140345357
Observations	93	85	93	90	93	90	93	93	90	93	90	93
						Coefficients						
Intercept	0	0	0	0	0	0	0	0	0	0	0	0
X Variable 1	0.042444919	0.04054651	0.03703053	0.031324856	0.021079166	0.012466839	0.009405361	0.076632518	0.008149919	0.018321714	0.034627962	0.040280918
Super Peak	0.041091											

APPENDIX 3.4 II HEATING DEGREE DAY DATA MONTHLY TABLES

Temp Pattern	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Klam Falls	2012	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2013	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2014	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2015	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2016	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2017	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2018	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2019	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2020	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2021	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2022	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2023	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2024	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2025	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2026	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2027	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2028	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2029	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2030	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2031	1032	847	780	595	391	181	38	55	184	505	836	1055	6499
Klam Falls	2032	1032	847	780	595	391	181	38	55	184	505	836	1055	6499

Temp Pattern	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
LaGrande	2012	1023	832	717	521	339	148	29	36	187	493	777	1024	6126
LaGrande	2013	1016	826	713	520	337	147	27	35	187	491	771	1021	6091
LaGrande	2014	1011	824	710	519	337	146	27	35	184	488	769	1020	6070
LaGrande	2015	1008	823	709	517	335	145	27	35	184	487	765	1016	6051
LaGrande	2016	1001	822	706	516	333	145	27	35	184	483	761	1015	6028
LaGrande	2017	1001	821	703	513	332	142	27	35	184	480	761	1008	6007
LaGrande	2018	997	817	700	512	332	142	27	35	183	477	757	1005	5984
LaGrande	2019	993	813	699	511	332	142	27	35	181	477	753	1002	5965
LaGrande	2020	993	812	698	509	331	142	26	35	181	476	753	996	5952
LaGrande	2021	991	806	694	505	331	140	26	35	180	475	751	993	5927
LaGrande	2022	989	804	694	505	330	140	26	35	180	474	750	992	5919
LaGrande	2023	987	802	693	503	330	140	26	35	180	473	749	991	5909
LaGrande	2024	983	801	693	502	329	140	26	35	180	473	749	989	5900
LaGrande	2025	982	801	693	502	329	139	26	35	180	472	747	989	5895
LaGrande	2026	981	801	691	501	329	139	26	35	180	472	746	989	5890
LaGrande	2027	980	800	691	501	329	139	26	35	180	471	746	989	5887
LaGrande	2028	979	800	689	499	328	139	26	35	180	471	745	989	5880
LaGrande	2029	979	798	689	498	328	138	26	35	180	471	745	987	5874
LaGrande	2030	975	797	687	498	327	137	26	35	179	471	744	984	5860
LaGrande	2031	972	797	687	498	326	137	26	35	179	470	744	984	5855
LaGrande	2032	971	796	686	497	325	137	26	35	178	470	743	984	5848

Temp Pattern	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Medford	2012	788	613	539	377	207	62	3	2	64	309	613	825	4402
Medford	2013	788	613	539	377	207	62	3	2	64	309	613	825	4402
Medford	2014	785	610	535	371	205	59	2	2	62	309	611	821	4372
Medford	2015	781	607	533	370	205	59	2	2	62	308	607	816	4352
Medford	2016	777	603	530	367	202	59	2	2	62	306	605	814	4329
Medford	2017	775	601	529	365	201	59	2	2	62	306	603	811	4316
Medford	2018	768	597	527	364	201	59	2	2	62	305	600	806	4293
Medford	2019	765	596	525	364	200	59	2	2	62	304	598	803	4280
Medford	2020	761	595	523	364	198	59	2	2	61	301	589	799	4254
Medford	2021	759	590	520	362	198	59	2	2	61	300	588	796	4237
Medford	2022	756	586	520	361	198	59	2	2	61	300	586	791	4222
Medford	2023	756	586	520	360	198	59	2	2	61	299	586	791	4220
Medford	2024	755	585	520	358	198	59	2	2	61	297	585	788	4210
Medford	2025	753	585	517	358	198	59	2	2	61	296	584	787	4202
Medford	2026	752	584	513	358	198	59	2	2	61	296	583	786	4194
Medford	2027	750	584	512	357	198	59	2	2	61	296	583	786	4190
Medford	2028	748	582	510	357	198	59	2	2	61	295	582	784	4180
Medford	2029	748	582	510	356	198	59	2	2	61	295	581	784	4178
Medford	2030	746	582	510	355	197	59	2	2	61	295	580	783	4172
Medford	2031	746	580	508	355	197	59	2	2	61	295	580	779	4164
Medford	2032	745	578	508	354	196	58	2	2	61	295	580	779	4158

APPENDIX 3.4 II HEATING DEGREE DAY DATA MONTHLY TABLES

Temp Pattern	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Roseburg	2012	677	551	495	361	219	82	9	3	62	274	497	692	3922
Roseburg	2013	677	551	495	361	219	82	9	3	62	274	497	692	3922
Roseburg	2014	672	550	492	359	219	81	9	3	61	272	495	692	3905
Roseburg	2015	666	547	491	358	217	81	9	3	61	271	492	688	3884
Roseburg	2016	664	544	487	357	217	81	9	3	61	270	490	685	3868
Roseburg	2017	657	544	486	356	216	80	9	3	61	270	488	683	3853
Roseburg	2018	655	544	485	355	216	79	9	3	60	269	488	681	3844
Roseburg	2019	653	539	481	353	215	78	9	3	59	269	486	678	3823
Roseburg	2020	652	539	480	351	214	78	9	3	59	268	483	675	3811
Roseburg	2021	652	538	479	350	213	78	9	3	59	268	482	674	3805
Roseburg	2022	651	533	477	349	212	78	9	3	59	267	477	669	3784
Roseburg	2023	651	533	475	349	212	78	9	3	59	267	476	667	3779
Roseburg	2024	650	533	475	349	212	78	9	3	59	267	475	666	3776
Roseburg	2025	649	533	475	349	212	78	9	3	59	267	475	666	3775
Roseburg	2026	648	532	475	347	211	78	9	3	59	267	474	664	3767
Roseburg	2027	648	531	475	347	211	78	9	3	59	267	474	664	3766
Roseburg	2028	647	530	475	347	211	78	9	3	59	267	474	664	3764
Roseburg	2029	646	528	474	346	210	78	9	3	59	267	472	663	3755
Roseburg	2030	646	527	474	346	209	77	9	3	59	267	472	662	3751
Roseburg	2031	646	527	474	346	209	77	9	3	59	266	472	660	3748
Roseburg	2032	641	527	474	346	208	77	9	3	59	264	471	658	3737

Temp Pattern	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
WA/ID	2012	1102	931	774	545	325	138	35	35	185	544	887	1174	6675
WA/ID	2013	1099	926	768	543	322	137	35	35	183	542	886	1168	6644
WA/ID	2014	1092	924	767	541	320	135	35	35	182	540	884	1165	6620
WA/ID	2015	1087	920	766	540	320	135	35	35	182	537	879	1163	6599
WA/ID	2016	1084	916	765	538	319	135	35	33	182	535	878	1159	6579
WA/ID	2017	1081	913	761	535	317	134	35	33	182	532	869	1153	6545
WA/ID	2018	1080	910	757	533	316	134	34	33	179	530	866	1148	6520
WA/ID	2019	1078	907	755	531	316	134	34	33	176	528	863	1142	6497
WA/ID	2020	1071	902	748	529	315	131	34	33	174	526	861	1138	6462
WA/ID	2021	1066	901	746	526	314	131	34	33	174	525	860	1134	6444
WA/ID	2022	1064	900	745	524	313	131	34	30	173	525	858	1134	6431
WA/ID	2023	1060	896	743	523	313	131	34	30	173	524	858	1132	6417
WA/ID	2024	1057	894	743	522	313	131	34	30	171	524	855	1130	6404
WA/ID	2025	1055	893	741	522	313	131	34	30	171	523	853	1129	6395
WA/ID	2026	1054	890	740	521	313	131	34	30	171	522	853	1128	6387
WA/ID	2027	1053	888	739	519	312	130	34	30	171	521	852	1124	6373
WA/ID	2028	1052	887	737	519	311	129	34	30	171	519	850	1122	6361
WA/ID	2029	1050	887	737	519	311	129	33	29	171	518	847	1120	6351
WA/ID	2030	1049	885	735	519	310	129	33	29	170	517	844	1117	6337
WA/ID	2031	1048	884	735	518	310	129	33	29	169	517	842	1114	6328
WA/ID	2032	1048	883	735	518	310	129	33	29	169	515	841	1109	6319

APPENDIX 3.4 II HEATING DEGREE DAILY MONTH BY AREA

Temp Pattern	Day	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
WA/ID	1	39	36	29	22	15	7	3	1	3	12	24	35
WA/ID	2	39	35	29	22	14	7	3	1	3	12	25	35
WA/ID	3	39	35	29	21	14	7	2	0	3	12	25	36
WA/ID	4	39	35	28	21	14	7	2	1	3	13	26	36
WA/ID	5	39	35	28	21	14	7	2	1	4	13	26	36
WA/ID	6	39	35	28	21	13	6	2	1	4	14	27	36
WA/ID	7	39	34	28	21	13	6	2	1	4	14	27	36
WA/ID	8	39	34	27	20	13	6	2	1	4	15	27	37
WA/ID	9	38	34	27	20	12	6	2	1	5	15	28	37
WA/ID	10	38	34	27	20	12	6	2	1	5	15	28	37
WA/ID	11	38	34	27	20	12	6	2	1	5	16	28	37
WA/ID	12	38	33	26	19	12	5	1	1	5	16	29	37
WA/ID	13	38	62	26	19	11	5	1	1	6	17	29	38
WA/ID	14	38	72	26	19	11	5	1	1	6	17	30	38
WA/ID	15	38	82	26	19	11	5	1	1	6	17	30	38
WA/ID	16	38	67	25	19	11	5	1	1	6	18	30	38
WA/ID	17	38	57	25	18	11	5	1	1	7	18	31	38
WA/ID	18	38	32	25	18	10	5	1	1	7	19	31	51
WA/ID	19	38	32	25	18	10	4	1	1	7	19	31	56
WA/ID	20	37	32	24	18	10	4	1	1	8	20	32	61
WA/ID	21	37	31	24	17	10	4	1	1	8	20	32	58
WA/ID	22	37	31	24	17	9	4	1	2	8	20	32	53
WA/ID	23	37	31	24	17	9	4	1	2	9	21	33	39
WA/ID	24	37	31	24	17	9	4	1	2	9	21	33	39
WA/ID	25	37	30	23	16	9	4	1	2	9	22	33	39
WA/ID	26	37	30	23	16	9	3	1	2	10	22	33	39
WA/ID	27	36	30	23	16	8	3	1	2	10	22	34	39
WA/ID	28	36	29	23	15	8	3	1	2	10	23	34	39
WA/ID	29	36		23	15	8	3	1	2	11	23	34	39
WA/ID	30	36		22	15	8	3	1	3	11	24	35	39
WA/ID	31	36		22		8		1	3		24		39

Temp Pattern	Day	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Medford	1	27	24	20	16	11	4	1	0	1	5	16	25
Medford	2	27	24	20	16	10	4	1	0	1	6	17	25
Medford	3	27	23	19	15	10	4	1	0	1	6	17	26
Medford	4	27	23	19	15	10	4	1	0	1	6	17	26
Medford	5	27	23	19	15	10	4	1	0	1	7	18	26
Medford	6	27	23	19	15	10	4	1	0	1	7	18	26
Medford	7	27	23	19	15	9	3	1	0	1	7	18	26
Medford	8	27	23	19	15	9	3	1	0	1	7	19	26
Medford	9	27	23	19	15	9	3	1	0	1	8	19	27
Medford	10	27	22	19	14	9	3	1	0	1	8	20	27
Medford	11	27	22	18	14	8	3	0	0	1	8	20	27
Medford	12	27	22	18	14	8	3	0	0	1	9	20	27
Medford	13	26	32	18	14	8	2	0	0	2	9	21	27
Medford	14	26	36	18	14	8	2	0	0	2	9	21	27
Medford	15	26	38	18	14	8	2	0	0	2	10	21	27
Medford	16	26	32	18	13	7	2	0	0	2	10	21	27
Medford	17	26	28	18	13	7	2	0	0	2	10	22	27
Medford	18	26	21	17	13	7	2	0	0	2	11	22	50
Medford	19	26	21	17	13	7	2	0	0	3	11	22	59
Medford	20	26	21	17	13	7	2	0	0	3	11	23	61
Medford	21	25	21	17	12	6	2	0	0	3	12	23	56
Medford	22	25	21	17	12	6	1	0	0	3	12	23	55
Medford	23	25	21	17	12	6	1	0	0	3	13	23	28
Medford	24	25	20	17	12	6	1	0	0	4	13	24	28
Medford	25	25	20	17	12	6	1	0	1	4	13	24	28
Medford	26	25	20	16	12	6	1	0	1	4	14	24	28
Medford	27	25	20	16	11	5	1	0	1	4	14	24	28
Medford	28	25	20	16	11	5	1	0	1	4	14	25	28
Medford	29	24		16	11	5	1	0	1	5	15	25	28
Medford	30	24		16	11	5	1	0	1	5	15	25	27
Medford	31	24		16		5		0	1		16		27

APPENDIX 3.4 II HEATING DEGREE DAILY MONTH BY AREA

Temp Pattern	Day	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Roseburg	1	24	21	18	14	10	5	1	0	1	5	13	21
Roseburg	2	24	21	17	14	10	4	1	0	1	5	14	21
Roseburg	3	24	21	17	14	9	4	1	0	1	5	14	21
Roseburg	4	23	21	17	14	9	4	1	0	1	6	14	22
Roseburg	5	23	20	17	14	9	4	1	0	1	6	14	22
Roseburg	6	23	20	17	14	9	4	1	0	1	6	15	22
Roseburg	7	23	20	17	14	9	4	1	0	1	6	15	22
Roseburg	8	23	20	17	14	9	4	1	0	1	7	15	22
Roseburg	9	23	20	17	13	8	3	1	0	1	7	16	22
Roseburg	10	23	20	17	13	8	3	1	0	2	7	16	23
Roseburg	11	23	20	17	13	8	3	1	0	2	7	16	23
Roseburg	12	23	20	16	13	8	3	1	0	2	7	17	23
Roseburg	13	23	32	16	13	8	3	1	0	2	8	17	23
Roseburg	14	23	37	16	13	7	3	1	0	2	8	17	23
Roseburg	15	23	42	16	13	7	3	1	0	2	8	17	23
Roseburg	16	23	34	16	13	7	3	1	0	2	9	18	23
Roseburg	17	23	28	16	12	7	3	1	0	2	9	18	23
Roseburg	18	23	19	16	12	7	2	1	0	3	9	18	40
Roseburg	19	22	19	16	12	7	2	1	0	3	9	18	53
Roseburg	20	22	19	16	12	6	2	0	0	3	10	19	55
Roseburg	21	22	18	15	12	6	2	0	1	3	10	19	46
Roseburg	22	22	18	15	12	6	2	0	1	3	10	19	48
Roseburg	23	22	18	15	11	6	2	0	1	3	10	19	24
Roseburg	24	22	18	15	11	6	2	0	1	4	11	20	24
Roseburg	25	22	18	15	11	6	2	0	1	4	11	20	24
Roseburg	26	22	18	15	11	5	2	0	1	4	11	20	24
Roseburg	27	22	18	15	11	5	2	0	1	4	12	20	24
Roseburg	28	21	18	15	10	5	2	0	1	4	12	20	24
Roseburg	29	21		15	10	5	2	0	1	4	12	21	24
Roseburg	30	21		15	10	5	1	0	1	5	13	21	24
Roseburg	31	21		14		5		0	1		13		24

Temp Pattern	Day	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Klamath Falls	1	35	32	27	22	16	8	3	1	3	10	22	32
Klamath Falls	2	35	32	27	22	15	8	3	1	3	10	22	32
Klamath Falls	3	35	31	27	22	15	8	3	1	4	11	23	33
Klamath Falls	4	35	31	27	22	15	7	3	1	4	11	23	33
Klamath Falls	5	35	31	26	21	15	7	2	1	4	11	24	33
Klamath Falls	6	35	31	26	21	14	7	2	1	4	12	24	33
Klamath Falls	7	35	31	26	21	14	7	2	1	4	12	25	33
Klamath Falls	8	35	31	26	21	14	7	2	1	5	12	25	33
Klamath Falls	9	35	30	26	21	13	6	2	1	5	13	25	34
Klamath Falls	10	35	30	26	20	13	6	2	1	5	13	26	34
Klamath Falls	11	35	30	26	20	13	6	2	1	5	13	26	34
Klamath Falls	12	35	30	25	20	13	6	2	1	5	14	26	34
Klamath Falls	13	35	42	25	20	12	6	2	1	6	14	27	34
Klamath Falls	14	35	51	25	20	12	5	2	1	6	14	27	34
Klamath Falls	15	34	54	25	19	12	5	1	1	6	15	28	34
Klamath Falls	16	34	53	25	19	12	5	1	1	6	15	28	34
Klamath Falls	17	34	47	25	19	12	5	1	1	7	15	28	35
Klamath Falls	18	34	29	24	19	11	5	1	1	7	16	29	54
Klamath Falls	19	34	29	24	19	11	5	1	1	7	16	29	66
Klamath Falls	20	34	28	24	18	11	4	1	1	7	17	29	72
Klamath Falls	21	34	28	24	18	11	4	1	2	7	17	30	68
Klamath Falls	22	34	28	24	18	10	4	1	2	8	17	30	58
Klamath Falls	23	34	28	24	18	10	4	1	2	8	18	30	35
Klamath Falls	24	33	28	23	17	10	4	1	2	8	18	30	35
Klamath Falls	25	33	28	23	17	10	4	1	2	9	19	31	35
Klamath Falls	26	33	27	23	17	9	3	1	2	9	19	31	35
Klamath Falls	27	33	27	23	17	9	3	1	2	9	20	31	35
Klamath Falls	28	33	27	23	16	9	3	1	3	9	20	31	35
Klamath Falls	29	32		23	16	9	3	1	3	10	20	32	35
Klamath Falls	30	32		22	16	8	3	1	3	10	21	32	35
Klamath Falls	31	32		22		8		1	3		21		35

APPENDIX 3.4 II HEATING DEGREE DAILY MONTH BY AREA

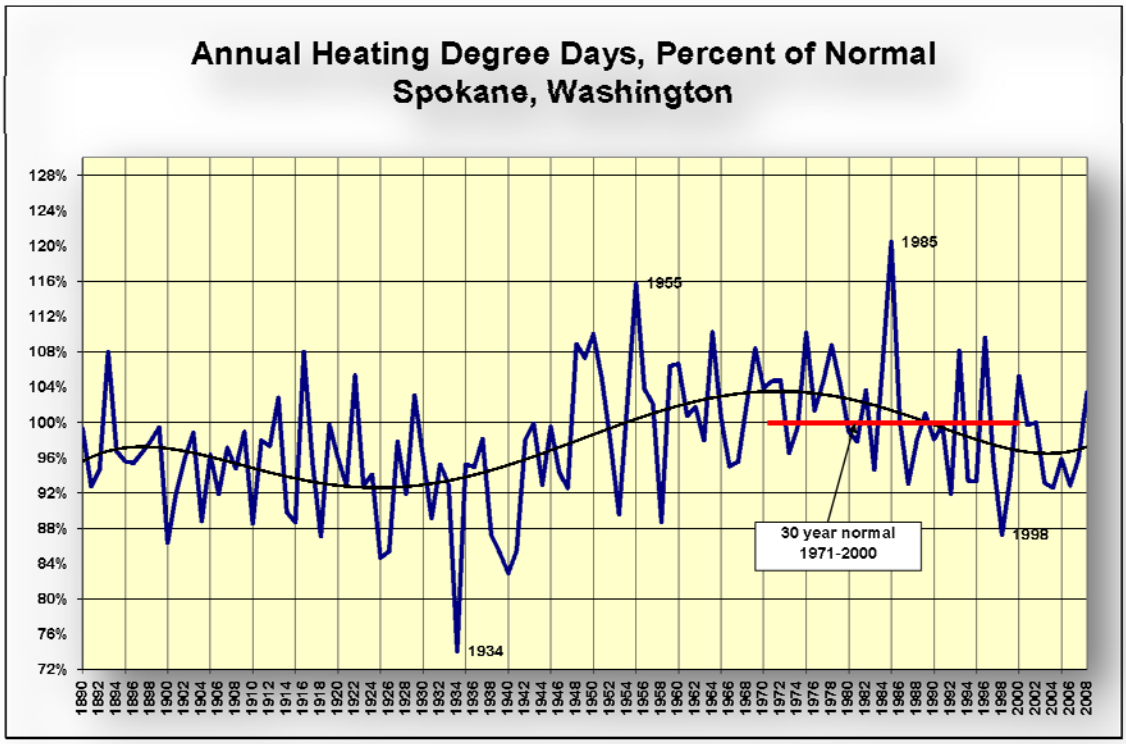
Temp Pattern	Day	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
LaGrande	1	35	33	28	22	15	8	3	1	4	11	22	32
LaGrande	2	35	33	27	21	15	7	2	1	4	11	23	32
LaGrande	3	35	33	27	21	14	7	2	1	4	12	23	32
LaGrande	4	35	32	27	21	14	7	2	1	4	12	23	32
LaGrande	5	36	32	27	21	14	7	2	1	5	12	24	32
LaGrande	6	36	32	26	21	13	7	2	1	5	13	24	33
LaGrande	7	36	32	26	21	13	6	2	1	5	13	25	33
LaGrande	8	36	32	26	20	13	6	2	1	5	13	25	33
LaGrande	9	35	31	26	20	13	6	2	1	6	13	25	33
LaGrande	10	35	31	26	20	12	6	2	1	6	14	26	33
LaGrande	11	35	31	26	20	12	6	1	1	6	14	26	33
LaGrande	12	35	31	25	20	12	5	1	1	6	14	26	34
LaGrande	13	35	61	25	19	12	5	1	1	6	15	27	34
LaGrande	14	35	68	25	19	11	5	1	1	7	15	27	34
LaGrande	15	35	74	25	19	11	5	1	1	7	15	28	34
LaGrande	16	35	61	25	19	11	5	1	1	7	16	28	34
LaGrande	17	35	60	24	18	11	5	1	1	7	16	28	34
LaGrande	18	35	30	24	18	11	4	1	2	8	17	28	51
LaGrande	19	35	30	24	18	10	4	1	2	8	17	29	58
LaGrande	20	35	29	24	18	10	4	1	2	8	17	29	64
LaGrande	21	35	29	24	17	10	4	1	2	8	18	29	58
LaGrande	22	35	29	23	17	10	4	1	2	9	18	30	51
LaGrande	23	34	29	23	17	9	4	1	2	9	18	30	35
LaGrande	24	34	29	23	17	9	4	1	2	9	19	30	35
LaGrande	25	34	28	23	16	9	3	1	3	9	19	30	35
LaGrande	26	34	28	23	16	9	3	1	3	10	20	31	35
LaGrande	27	34	28	22	16	9	3	1	3	10	20	31	35
LaGrande	28	34	28	22	16	8	3	1	3	10	20	31	35
LaGrande	29	34		22	15	8	3	1	3	10	21	31	35
LaGrande	30	33		22	15	8	3	1	3	11	21	31	35
LaGrande	31	33		22		8		1	4		22		35

APPENDIX 3.5 II GLOBAL WARMING

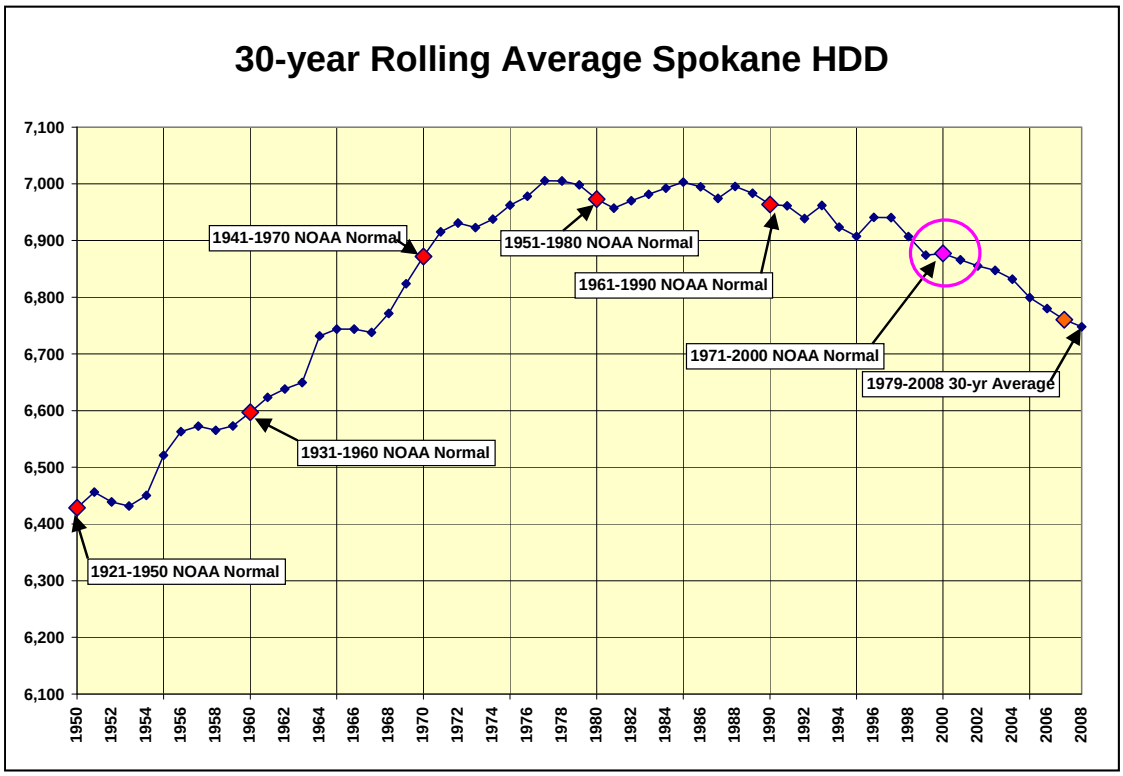
- Peak and trough weather appears more volatile
- Reduce annual consumption over time
- Decrease non peak HDDs over time to reflect warming trend

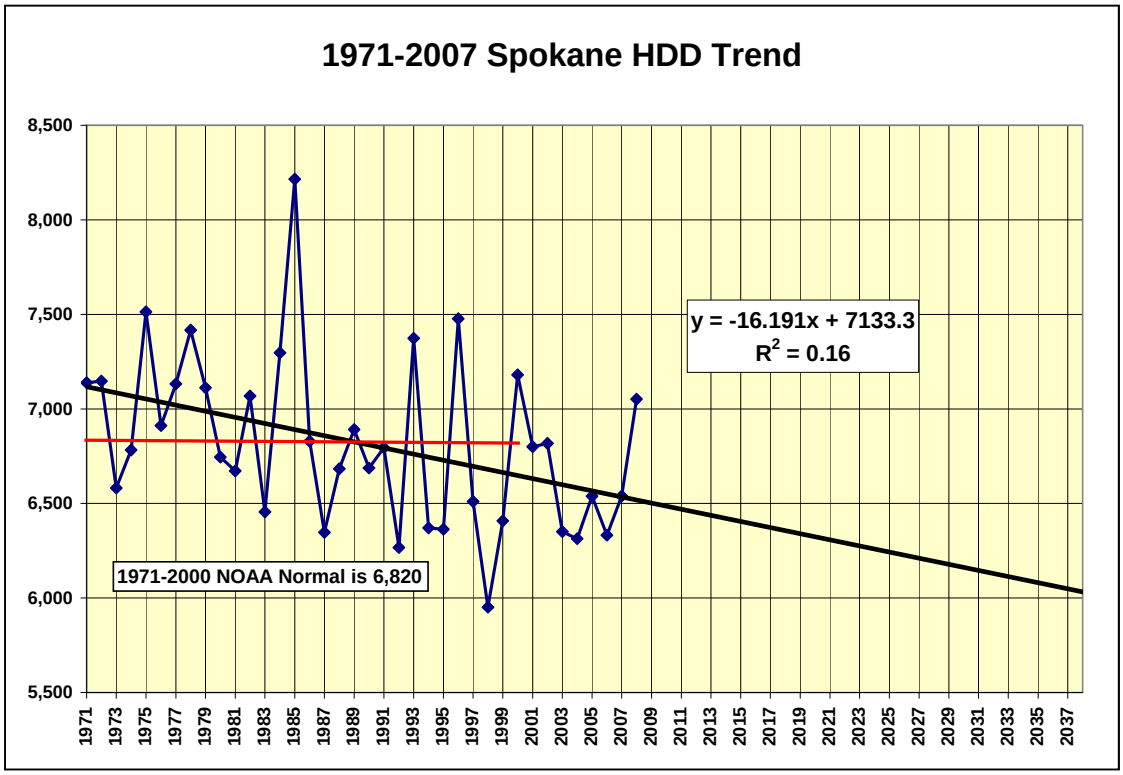
GLOBAL WARMING ADJUSTMENT

- Heating degree day data is obtained from the National Weather Service (NWS). Avista uses the most recent 30-year period, which goes from 1979-2008. For Oregon, Avista uses four weather stations as the weather basis, corresponding to the areas within which natural gas services are provided, all of which are official National Weather Service stations. Heating degree day weather patterns between these areas are uncorrelated.
- At the April 2009 Technical Advisory Committee meeting, Avista presented some data and information regarding trends in heating degree days for its service area. Avista has adopted a "Global Warming" baseline for forecasting which captures the modest warming trend (i.e. gradually declining heating degree days) expected through the 20 year forecast period.
- By 2030, as compared to the "official" NWS normal figures based on the 1971-2000 period, the number of annual heating degree days as a percentage of the official period are:
  - Spokane 93.9%
  - Medford 88.4%
  - Roseburg 86.8%
  - Klamath Falls 94.9%
  - La Grande 81.6%

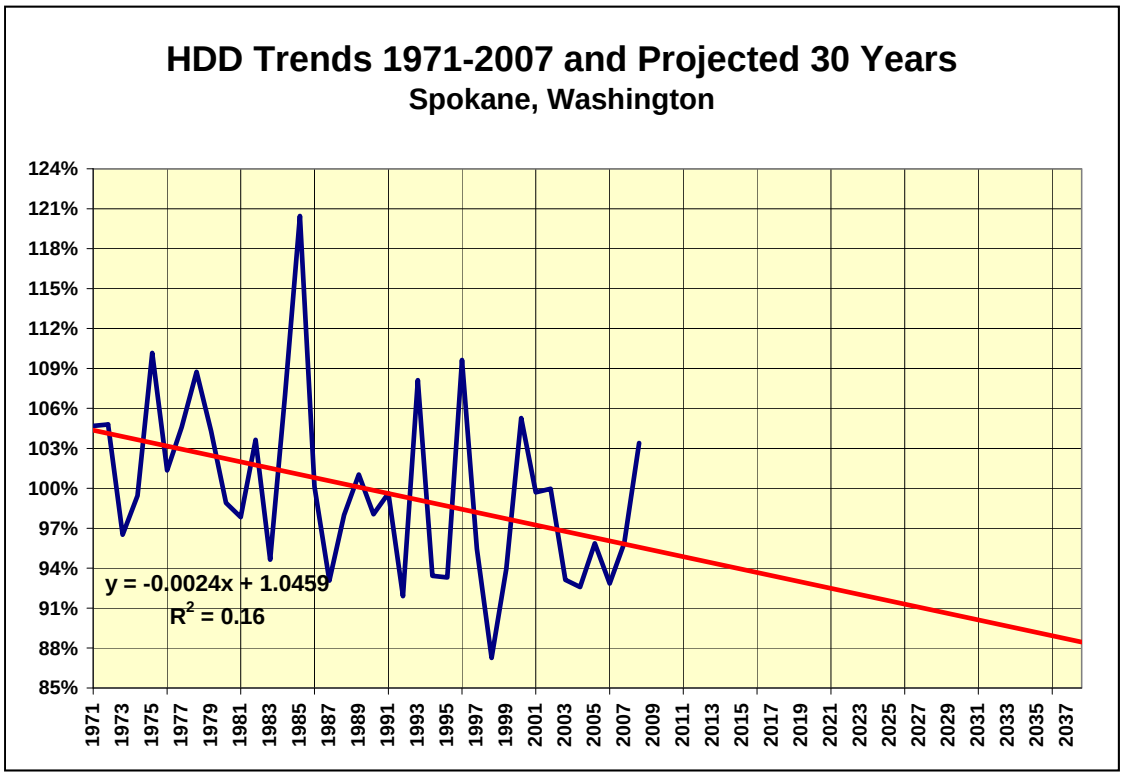


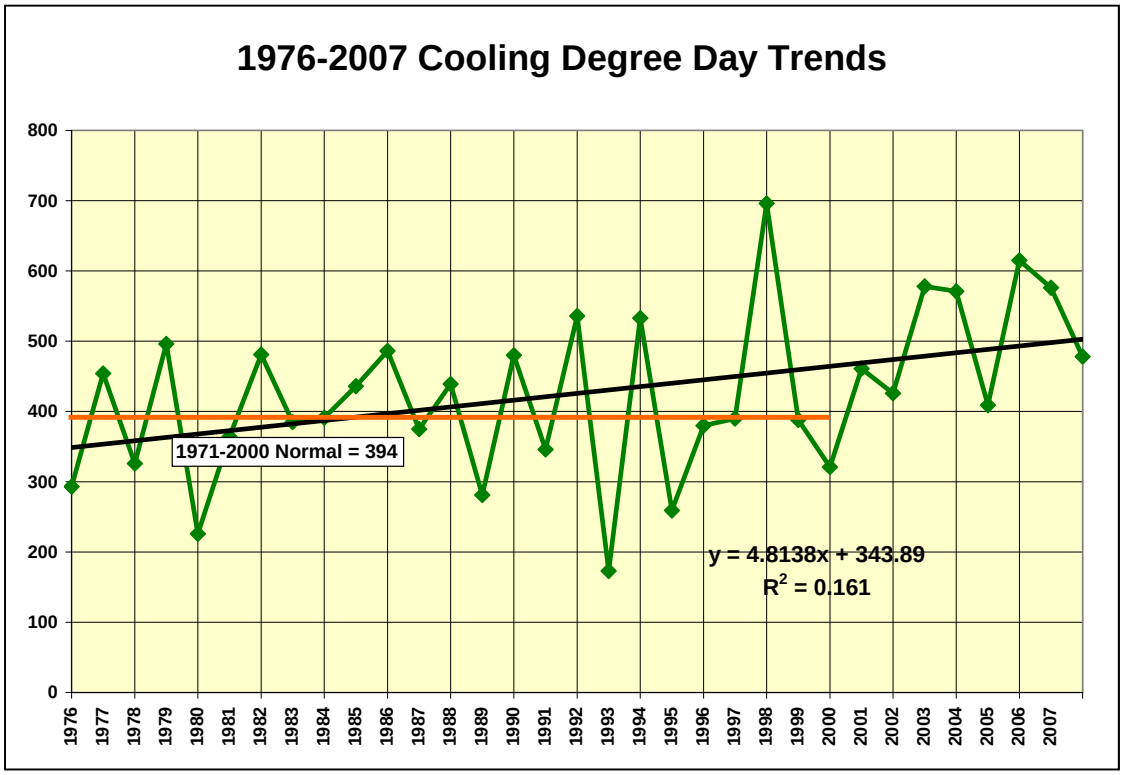
APPENDIX 3.5 II GLOBAL WARMING



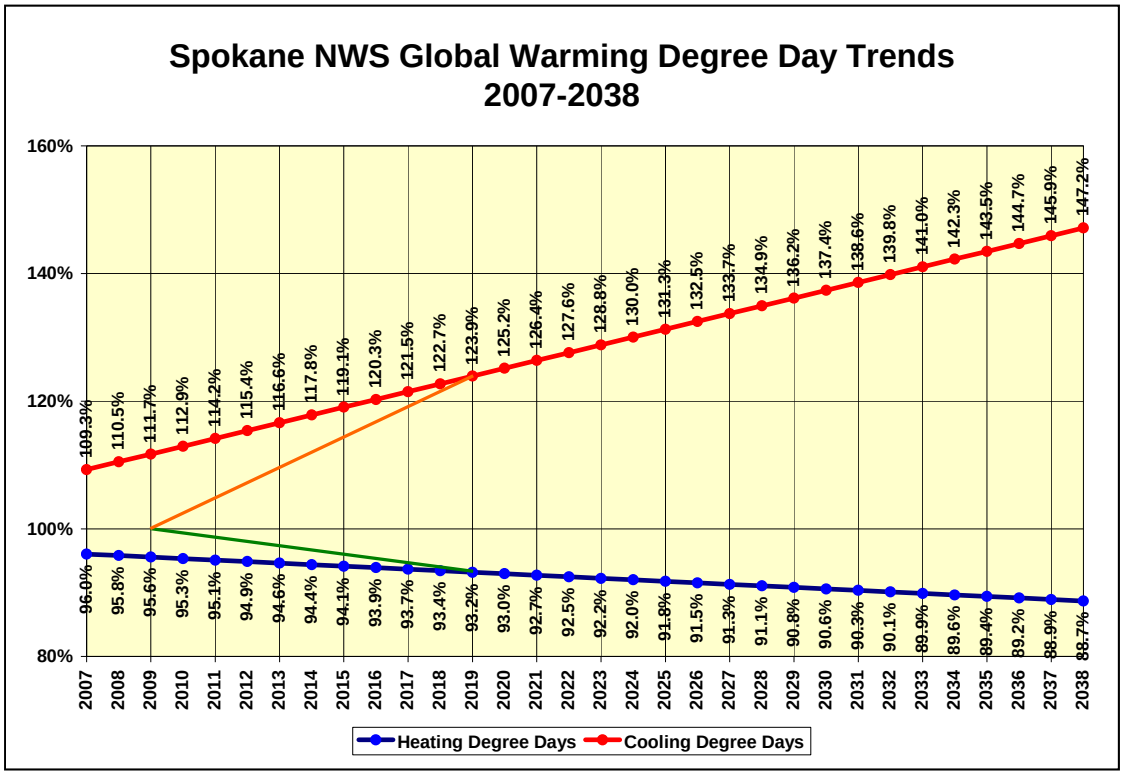


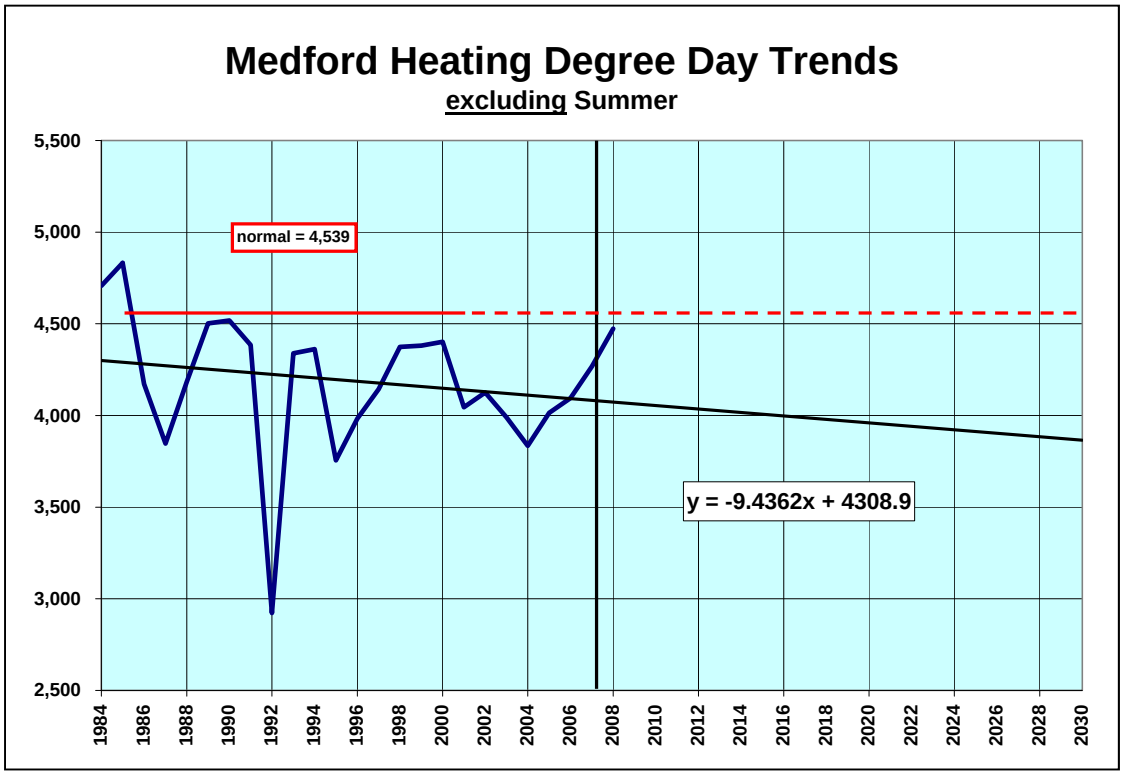
APPENDIX 3.5 II GLOBAL WARMING



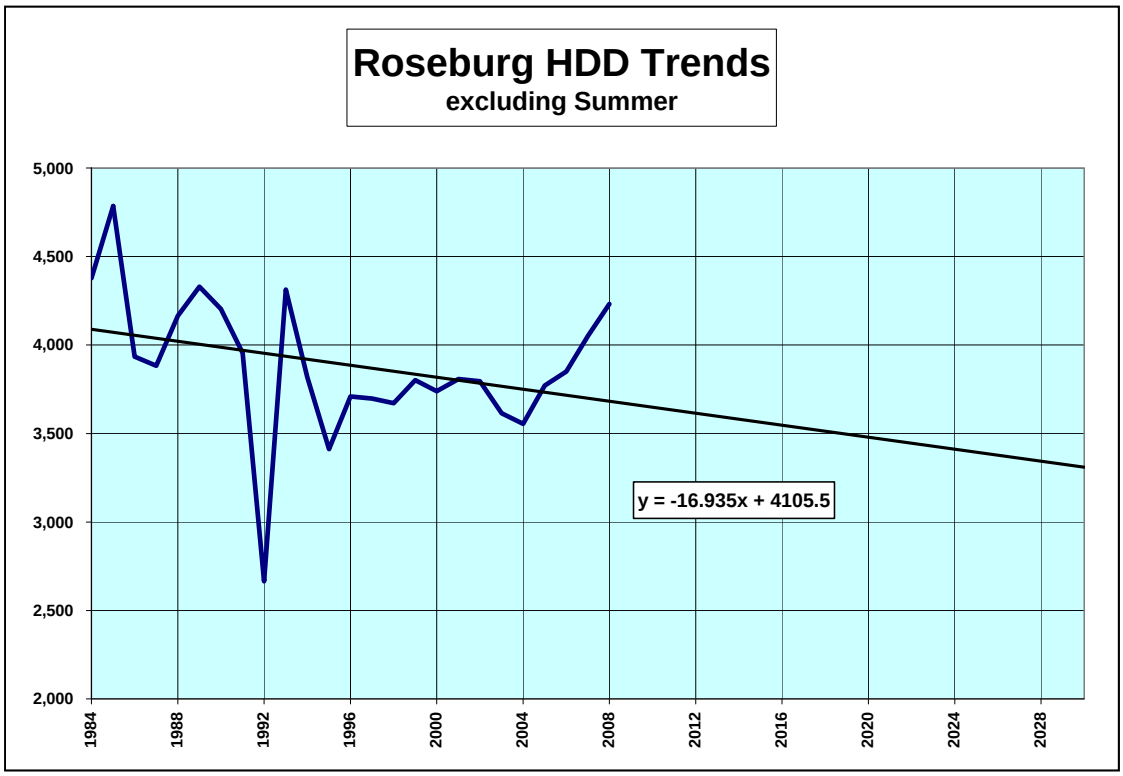


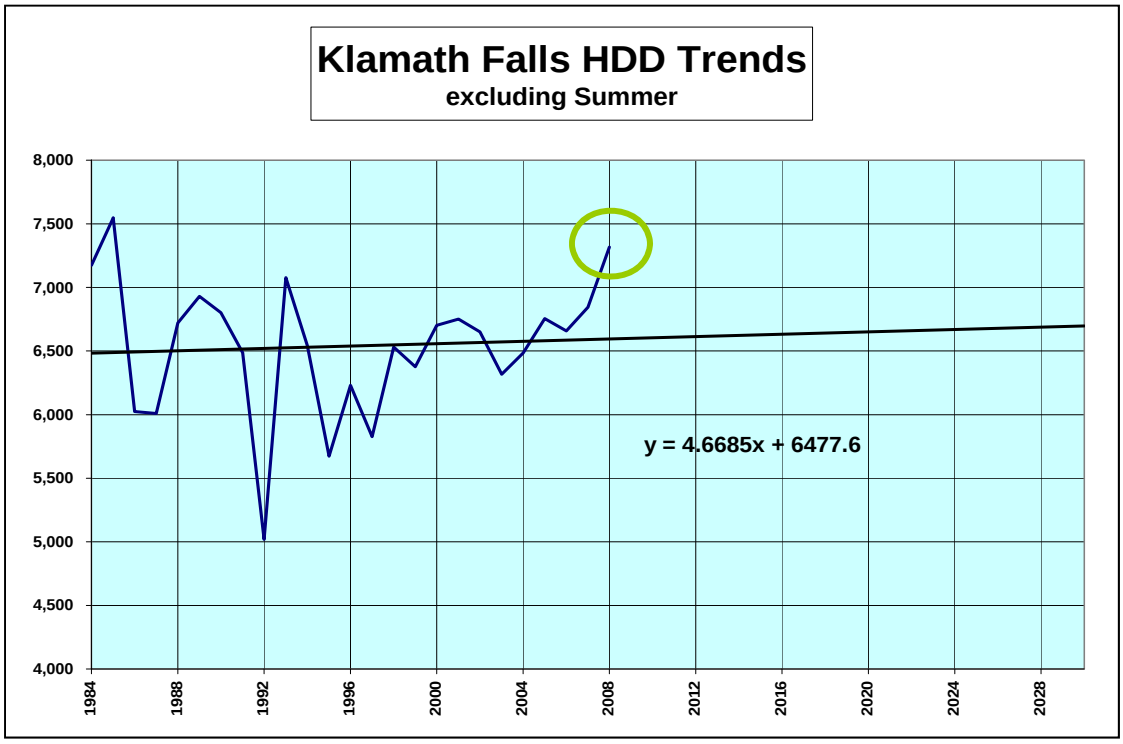
APPENDIX 3.5 II GLOBAL WARMING



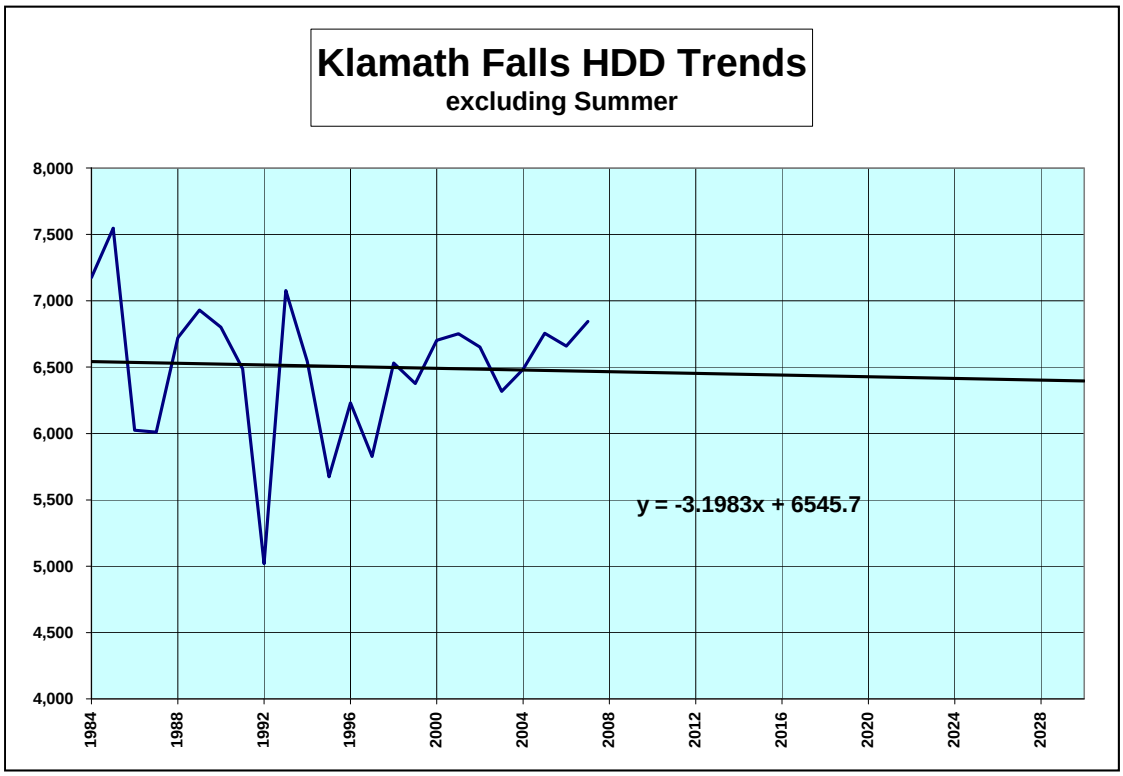


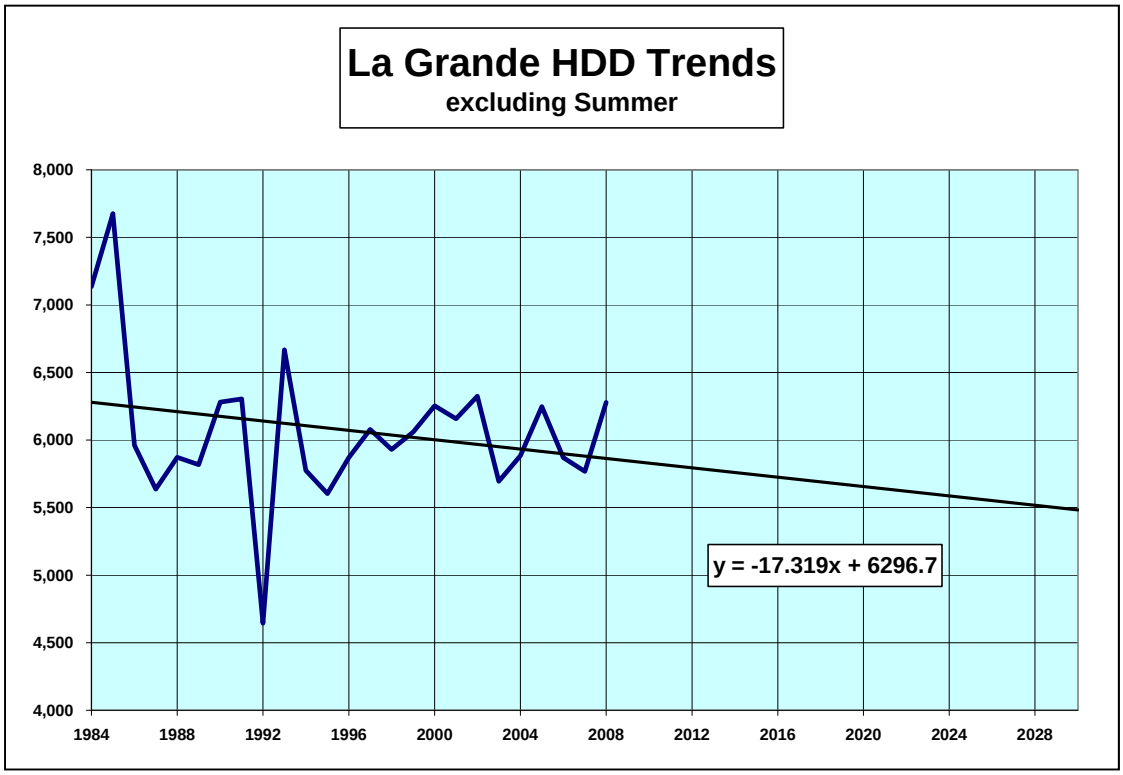
APPENDIX 3.5 II GLOBAL WARMING



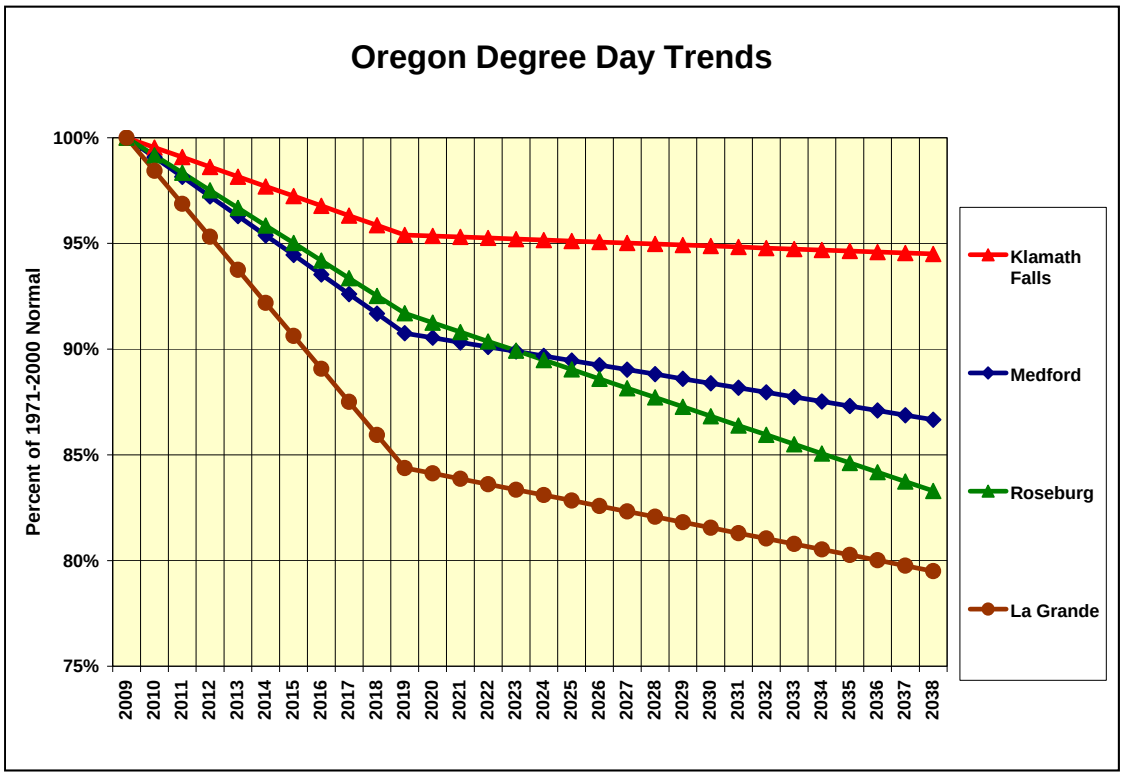


APPENDIX 3.5 II GLOBAL WARMING





APPENDIX 3.5 II GLOBAL WARMING



APPENDIX 3.6 II DEMAND SENSITIVITIES
SUMMARY OF ASSUMPTIONS – DEMAND SCENARIOS

			DEMAND INFLUENCING - DIRECT							PRICE INFLUENCING - INDIRECT				
INPUT ASSUMPTIONS	**Reference Case**	**Reference Plus Peak Case**	**Low Cust Growth**	**High Cust Growth**	**CNG/NGV Vehicles**	**Alternate Weather Std**	**DSM Case**	**Peak plus DSM Case**	**Alterante Historical UPC Case**	**Expect Elasticity**	**Low Prices**	**High Prices**	**Carbon Legistlation**	**Exported LNG**
Customer Growth Rate														
Residential WA/ID														
Residential Medford														
Residential Roseburg														
Residential Klamath			40% Decrease in Cust Growth Rates	60% Increase in Cust Growth Rates										
Residential La Grande														
Commercial WA/ID														
Commercial Medford														
Commercial Roseburg														
Commercial Klamath														
Commercial La Grande														
Use per Customer	3 Year Historical	3 Year Historical	3 Year Historical	3 Year Historical	15% Growth Cumulative	3 Year Historical	3 Year Historical	3 Year Historical	5 Year Historical	3 Year Historical	3 Year Historical	3 Year Historical	3 Year Historical	3 Year Historical
Weather														
Planning Standard	Normal plus GW Adj	Coldest on Record	Coldest on Record	Coldest on Record	Coldest on Record	Coldest 20yrs	Normal plus GW Adj	Coldest on Record	Coldest on Record	Coldest on Record	Coldest on Record	Coldest on Record	Coldest on Record	Coldest on Record
Demand Side Management														
Programs Included	No	No	No	No	No	No	Yes	Yes	No	No	No	No	No	No
Prices														
Price curve	Expected	Expected	Expected	Expected	Expected	Expected	Expected	Expected	Expected	Expected	Low	High	Expected	Expected
Price curve adder ($/Dth)	None	None	None	None	None	None	None	None	None					$.50 Adder After 5yrs
Elasticity	None	None	None	None	None	None	None	None	None	Expected	Expected	Expected	Expected	Expected
Carbon Adder ($/Ton)	None	None	None	None	None	None	None	None	None				$14-$22 starting in 2022	
RESULTS														
FIRST YEAR UNSERVED														
WA/ID	N/A	2023	N/A	2020	2024	2026	N/A	2023	2023	2031	2029	N/A	N/A	N/A
Medford	N/A	2023	N/A	2020	2023	N/A	N/A	2024	2023	2029	2028	N/A	2030	2030
Roseburg	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Klamath	N/A	2022	N/A	2019	2022	2023	N/A	2023	2022	2031	2028	N/A	2031	2031
La Grande	N/A	N/A	N/A	2027	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

APPENDIX 3.6 II DEMAND SCENARIOS
PROPOSED SCENARIOS

INPUT ASSUMPTIONS	Expected Case	High Growth & Low Prices	Low Growth & High Prices	Cold Day 20-yr Weather Std	Average Case
Customer Growth Rate	Reference Case Cust Growth Rates	60% Increase in Cust Growth Rates	40% Decrease in Cust Growth Rates	Reference Case Cust Growth Rates	Reference Case Cust Growth Rates
Use per Customer	3 yr Flat + Price Elast.	3 yr Flat + Price Elast. + CNG/NGV	3 yr Flat + Price Elast.	3 yr Flat + Price Elast.	3 yr Flat + Price Elast.
Demand Side Management	Yes	Yes	Yes	Yes	Yes
Weather Planning Standard	Coldest Day	Coldest Day	Coldest Day	Alternate Planning Standard	Normal
Prices					
Price curve	Expected	Low	High	Expected	Expected
Elasticity	Expected	None	Expected	Expected	Expected
Carbon Adder ($/Ton)	$14-$22	None	$14-$22	$14-$22	$14-$22
RESULTS					
First Gas Year Unserved					
WA/ID	2030	2020	N/A	N/A	N/A
Medford	2029	2020	N/A	N/A	N/A
Roseburg	N/A	N/A	N/A	N/A	N/A
Klamath	2030	2019	N/A	N/A	N/A
La Grande	N/A	N/A	N/A	N/A	N/A
SCENARIO SUMMARY					
	Most aggressive peak weather planning case utilizing Average Case assumptions as a starting point and layering in coldest weather on record. The liklihood of occurrence is low.	Aggressive growth assumptions in order to evaluate when our earliest resource shortage could occur. Not likely of occuring.	Stagnant growth assumptions in order to evaluate if a shortage does occur. Not likely to occur.	Evaluates adopting an alternate peak weather standard. Helps provide some bounds around our senstivity to weather.	Case most representative of our average (budget, PGA, rate case, procurement) planning criteria. Most likely to occur.
RISK ASSESSMENT					

Higher or lower customer growth rates, which are heavily based on economic recovery. Higher or lower growth rates will lead to accelerated or delayed unserved demand. Looking at various growth assumptions off the Expected Case allows us to capture the risk in terms of the change in demand linked to customer growth.

Higher or lower use per customer will also lead to accelerated or delayed unserved demand. Use per customer can differ in many ways. Direct use per customer influencers, such as demand side management, NGV/CNG usage, and derivation of the use per customer starting point (i.e. one year, three year, etc). Again, varying these assumptions under our forecasting methodology allows us to quantify the change each assumption has to our forecast.

Weather volatility and predictability are a key risk. As the most correlated direct demand influencer, varying weather assumptions is key to understanding the weather related risks.

Indirect influencers including elasticity and price are also important assumptions. The two go hand in hand, as price changes it will influence how much customers consume. If forecasted prices remain relatively stable over the planning horizon our current elasticity assumption will not provide much decreased usage. However, price adders or an overall steepening of the price curve will tirgger a greater decline in usage due to the price elastic response. The maginitude of the elasticity adjustment is also important. We are using a long run elasticity factor as calcuated by the AGA. We continue to evaluate this assumption and are looking to update the study as part of our Action Plan.

APPENDIX 3.7 II DEMAND FORECAST SENSITIVITIES AND SCENARIOS DESCRIPTIONS

DEFINITIONS

DYNAMIC DEMAND METHODOLOGY – Avista's demand forecasting approach wherein we 1) identify key demand drivers behind natural gas consumption, 2) perform sensitivity analysis on each demand driver, and 3) combine demand drivers under various scenarios to develop alternative potential outcomes for forecasted demand.

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.

REFERENCE CASE – A baseline point of reference that captures the basic inputs for determining a demand forecast in SENDOUT® which includes number of customers, use per customer, average daily weather temperatures (including an adjustment for global warming) and expected natural gas prices.

SENSITIVITIES – Focused analysis of a specific natural gas demand driver and its impact on forecasted demand relative to the Reference Case when underlying input assumptions are modified.

SCENARIOS – Combination of natural gas demand drivers that make up a demand forecast.

Avista evaluates each sensitivities impact.

SENSITIVITIES

The following Sensitivities were performed on identified demand drivers against the reference case for consideration in Scenario development. Note that Sensitivity assumptions reflect incremental adjustments we estimate are not captured in the underlying reference case forecast.

Following are the Demand Influencing (Direct) Sensitivities we evaluated:

REFERENCE CASE PLUS PEAK – Same assumptions as in the Reference Case with and adjustment made to normal weather to incorporate peak weather conditions. The peak weather data being the coldest day on record for each weather area.

LOW & HIGH CUSTOMER GROWTH – In our low customer growth Sensitivity, annual customer growth rates under perform the reference rate of growth by 40% over our 20 year planning horizon while annual customer growth rates exceed the reference rate by 60% in our high growth Sensitivity.

NATURAL GAS VEHICLES (NGV) AND/OR COMPRESSED NATURAL GAS (CNG) VEHICLES – NGV/CNG vehicles assumed to produce a 15% cumulative incremental demand over our 20 year planning horizon. Our assumption utilized market consumption estimates from an independent analysis on NGV/CNG vehicle viability. The analysis indicates significant challenges exist to widespread adoption but did provide a scenario for significant market penetration (10% in 10 years).

ALTERNATE WEATHER STANDARD (COLDEST DAY 20 YRS) – Peak Day weather temperature reduced to coldest average daily temperature (HDDs) experienced in the most recent 20 years in each region.

DSM – Reference case assumptions including the potential DSM identified by the Conservation Potential Assessment provided by Global Energy Partners. See Appendix 4.1 for full assessment report.

PEAK PLUS DSM – Reference plus peak weather assumptions including the potential DSM identified by the Conservation Potential Assessment provided by Global Energy Partners. See Appendix 4.1 for the full assessment report.

ALTERNATE USE PER CUSTOMER – Reference case use per customer was based upon 3 years of actual use per customer per heating degree day data. This sensitivity used five years of historical use per customer per heating degree day data.

Following are the Price Influencing (Indirect) Sensitivities we evaluated:

EXPECTED ELASTICITY – For our expected elasticity Sensitivity, we incorporate reduced consumption in response to higher natural gas prices utilizing a price elasticity study prepared by the American Gas Association.

LOW & HIGH PRICES – To capture a wide band of alternative prices forecasts, we use the Northwest Power and Conservation Council's "very low" and "very high" natural gas price forecast scenarios with first five years modified to include blend of recent market prices (Nymex forward prices) consistent with our Expected price forecast.

CARBON LEGISLATION– Utilizes carbon cost adders quantified by independent analysis from Consultant #1. They identify both an adder reflecting carbon allowances as well as an adder to capture the effect of increased natural gas demand as more gas turbines come online to replace coal plants and back up wind generation. The allowance adder escalates from $14/ton in 2022 to $22/ton by 2032.

EXPORTED LNG – Beginning in 2017, we apply an estimate of $.50/mmbtu *incremental* adder each year to regional natural gas prices to capture upward price pressure because of exports of LNG to Asian and European counties. There is much uncertainty about the region price impact LNG will have. It is highly dependent on many things including which export facilities get built and the pipeline infrastructure used to serve them. There are several analyses that have been conducted where the price impact can be minimal to $1.00/mmbtu.

SCENARIOS

After identifying the above demand drivers and analyzing the various Sensitivities, we have developed the following demand forecast Scenarios:

AVERAGE CASE – This Scenario we believe represents the most likely average demand forecast modeled. We assume service territory customer growth rates consistent with the reference case, rolling 30 year normal weather in each service territory, our expected natural gas price forecast (Consultant #1), expected price elasticity, and the CO2 cost adders from our **Carbon Legislation** Sensitivity, and DSM. The Scenario does not include incremental cost adders for declining Canadian imports or drilling restrictions beyond what is incorporated in the selected price forecast.

EXPECTED CASE – This Scenario represents the peak demand forecast. We assume service territory customer growth rates consistent with the reference case, a weather standard of coldest day on record in each service territory, our middle range natural gas price forecast (Consultant #1), expected price elasticity, and the CO2 cost adders from our **Carbon Legislation** Sensitivity, and DSM.

HIGH GROWTH, LOW PRICE – This Scenario models a rapid return to robust growth in part spurred on by low energy prices. We assume customer growth rates 60% higher than the reference case, coldest day on record weather standard, incremental demand from NGV/CNG, our low natural gas price forecast, no price elasticity, DSM, and no CO2 adders.

LOW GROWTH, HIGH PRICE – This Scenario models an extended period of slow economic growth in part resulting from high energy prices. We assume customer growth rates 40% lower than the reference case, coldest day on record weather standard, our high natural gas price forecast, expected price elasticity, and CO2 adders from our **Carbon Legislation Sensitivity**.

ALTERNATE WEATHER STANDARD – This Scenario models all the same assumptions as the **Expected Case** Scenario except for the change in the weather planning standard from coldest day on record to coldest day in 20 years for each service territory. As noted in the Sensitivity analysis, this change does not affect the Klamath Falls and La Grande service territories which have each experienced their coldest day on record within the last 20 years.

A case incorporating Exported LNG was not included in this IRP's scenario analysis. There is much uncertainty about the location and timing of exported LNG and its potential price impacts. The forecasters we subscribe to have incorporated some level of export LNG into their price forecasts and therefore our expected price curve does include an export LNG assumption. At this time the effects of LNG are minimal given the robust North American supply picture. Avista will closely monitor developments with export LNG for the potential price and infrastructure impacts.

APPENDIX 3.8 II ANNUAL DEMAND, AVERAGE DAY DEMAND AND PEAK DAY DEMAND (NET OF DSM – CASE AVERAGE

Case	Gas Year	Annual Demand Klamath (MDth)	Daily Demand Klamath (MDth/day)	Peak Day Klamath (MDth/day)	Annual Demand La Grande (MDth)	Daily Demand La Grande (MDth/day)	Peak Day La Grande (MDth/day)	Annual Demand Medford/Roseburg (MDth)	Daily Demand Medford/Roseburg (MDth/day)	Peak Day Medford/Roseburg (MDth/day)
Average	2012	1,277.85	3.501	12.482	719.60	1.972	7.083	6,163.95	16.888	65.99
Average	2013	1,288.18	3.529	12.513	723.97	1.983	7.100	6,210.64	17.015	66.04
Average	2014	1,284.04	3.518	12.817	717.67	1.966	7.224	6,205.13	17.000	67.76
Average	2015	1,298.94	3.559	13.164	721.86	1.978	7.372	6,298.05	17.255	69.87
Average	2016	1,324.25	3.628	13.534	731.58	2.004	7.496	6,445.07	17.658	72.18
Average	2017	1,339.27	3.669	13.884	735.37	2.015	7.610	6,547.54	17.938	74.51
Average	2018	1,358.38	3.722	14.215	741.47	2.031	7.716	6,671.57	18.278	76.82
Average	2019	1,373.79	3.764	14.529	745.61	2.043	7.820	6,777.80	18.569	79.08
Average	2020	1,395.83	3.824	14.843	753.35	2.064	7.923	6,915.81	18.947	81.32
Average	2021	1,408.12	3.858	15.156	755.72	2.070	8.024	7,016.72	19.224	83.54
Average	2022	1,422.13	3.896	15.466	759.18	2.080	8.123	7,120.21	19.507	85.72
Average	2023	1,435.69	3.933	15.772	762.30	2.089	8.222	7,218.04	19.775	87.91
Average	2024	1,456.62	3.991	16.079	769.45	2.108	8.320	7,354.80	20.150	90.14
Average	2025	1,465.16	4.014	16.387	769.77	2.109	8.418	7,428.59	20.352	92.38
Average	2026	1,480.81	4.057	16.696	773.92	2.120	8.515	7,537.43	20.650	94.64
Average	2027	1,493.82	4.093	17.006	776.99	2.129	8.616	7,634.26	20.916	96.91
Average	2028	1,513.95	4.148	17.313	784.11	2.148	8.722	7,759.19	21.258	99.13
Average	2029	1,521.43	4.168	17.616	784.99	2.151	8.830	7,815.12	21.411	101.17
Average	2030	1,534.70	4.205	17.913	789.06	2.162	8.937	7,914.29	21.683	103.16
Average	2031	1,547.94	4.241	18.210	792.95	2.172	9.044	8,004.53	21.930	105.15

Case	Gas Year	Annual Demand Oregon (MDth)	Daily Demand Oregon (MDth/day)	Peak Day Demand Oregon (MDth/day)	Annual Demand WA/ID (MDth)	Daily Demand WA/ID (MDth/day)	Peak Day WA/ID (MDth/day)	Annual Demand Total System (MDth)	Daily Demand Total System (MDth/day)	Peak Day Demand Total System (MDth/day)
Average	2012	8,161.406	22.360	85.551	25,163.851	68.942	245.972	33,325.258	91.302	331.523
Average	2013	8,222.780	22.528	85.654	25,480.238	69.809	248.812	33,703.019	92.337	334.466
Average	2014	8,206.842	22.484	87.804	25,445.489	69.714	256.521	33,652.331	92.198	344.326
Average	2015	8,318.857	22.791	90.406	25,773.110	70.611	264.366	34,091.967	93.403	354.772
Average	2016	8,500.904	23.290	93.208	26,327.094	72.129	272.090	34,827.998	95.419	365.298
Average	2017	8,622.183	23.622	96.002	26,690.777	73.125	279.693	35,312.961	96.748	375.695
Average	2018	8,771.422	24.031	98.748	27,146.080	74.373	287.093	35,917.502	98.404	385.840
Average	2019	8,897.202	24.376	101.434	27,527.058	75.417	294.436	36,424.260	99.792	395.869
Average	2020	9,064.991	24.836	104.083	28,039.888	76.822	301.744	37,104.879	101.657	405.827
Average	2021	9,180.559	25.152	106.719	28,355.733	77.687	308.999	37,536.292	102.839	415.718
Average	2022	9,301.523	25.484	109.314	28,706.582	78.648	316.234	38,008.105	104.132	425.548
Average	2023	9,416.028	25.797	111.903	29,053.598	79.599	323.594	38,469.626	105.396	435.497
Average	2024	9,580.870	26.249	114.541	29,552.166	80.965	330.924	39,133.036	107.214	445.465
Average	2025	9,663.522	26.475	117.181	29,797.373	81.637	338.326	39,460.895	108.112	455.507
Average	2026	9,792.160	26.828	119.855	30,186.012	82.701	345.687	39,978.173	109.529	465.542
Average	2027	9,905.070	27.137	122.532	30,520.477	83.618	353.026	40,425.547	110.755	475.558
Average	2028	10,057.255	27.554	125.162	31,004.570	84.944	360.329	41,061.825	112.498	485.491
Average	2029	10,121.537	27.730	127.612	31,232.440	85.568	367.636	41,353.977	113.299	495.248
Average	2030	10,238.048	28.049	130.006	31,580.327	86.521	374.910	41,818.376	114.571	504.916
Average	2031	10,345.422	28.344	132.406	31,928.321	87.475	382.216	42,273.743	115.818	514.622

APPENDIX 3.8 II ANNUAL DEMAND, AVERAGE DAY DEMAND AND PEAK DAY DEMAND (NET OF DSM) – CASE HIGH

Case	Gas Year	Annual Demand Klamath (MDth)	Daily Demand Klamath (MDth/day)	Peak Day Klamath (MDth/day)	Annual Demand La Grande (MDth)	Daily Demand La Grande (MDth/day)	Peak Day La Grande (MDth/day)	Annual Demand Medford/Roseburg (MDth)	Daily Demand Medford/Roseburg (MDth/day)	Peak Day Medford/Roseburg (MDth/day)
High	2012	1,312.83	3.597	12.482	705.92	1.934	7.083	6,222.40	17.048	65.99
High	2013	1,318.01	3.611	12.513	706.72	1.936	7.100	6,246.05	17.112	66.04
High	2014	1,353.14	3.707	12.817	719.05	1.970	7.224	6,421.81	17.594	67.76
High	2015	1,391.17	3.811	13.164	733.12	2.009	7.372	6,630.94	18.167	69.87
High	2016	1,433.48	3.927	13.534	749.12	2.052	7.496	6,871.78	18.827	72.18
High	2017	1,462.55	4.007	13.884	757.66	2.076	7.610	7,058.12	19.337	74.51
High	2018	1,495.45	4.097	14.215	768.42	2.105	7.716	7,268.03	19.912	76.82
High	2019	1,527.82	4.186	14.529	778.80	2.134	7.820	7,474.62	20.478	79.08
High	2020	1,566.17	4.291	14.843	792.26	2.171	7.923	7,709.62	21.122	81.32
High	2021	1,592.06	4.362	15.156	799.14	2.189	8.024	7,881.95	21.594	83.54
High	2022	1,623.76	4.449	15.466	809.08	2.217	8.123	8,083.19	22.146	85.72
High	2023	1,655.36	4.535	15.772	818.92	2.244	8.222	8,287.63	22.706	87.91
High	2024	1,693.65	4.640	16.079	832.07	2.280	8.320	8,526.67	23.361	90.14
High	2025	1,718.89	4.709	16.387	838.42	2.297	8.418	8,701.46	23.840	92.38
High	2026	1,750.78	4.797	16.696	848.10	2.324	8.515	8,910.37	24.412	94.64
High	2027	1,782.53	4.884	17.006	858.00	2.351	8.616	9,116.08	24.976	96.91
High	2028	1,820.93	4.989	17.313	871.91	2.389	8.722	9,345.33	25.604	99.13
High	2029	1,844.66	5.054	17.616	879.05	2.408	8.830	9,493.84	26.011	101.17
High	2030	1,875.25	5.138	17.913	889.74	2.438	8.937	9,677.82	26.515	103.16
High	2031	1,905.87	5.222	18.210	900.38	2.467	9.044	9,859.35	27.012	105.15

Case	Gas Year	Annual Demand Oregon (MDth)	Daily Demand Oregon (MDth/day)	Peak Day Demand Oregon (MDth/day)	Annual Demand WA/ID (MDth)	Daily Demand WA/ID (MDth/day)	Peak Day WA/ID (MDth/day)	Annual Demand Total System (MDth)	Daily Demand Total System (MDth/day)	Peak Day Demand Total System (MDth/day)
High	2012	8,241.152	22.578	85.551	26,676.459	73.086	245.972	34,917.611	95.665	331.523
High	2013	8,270.788	22.660	85.654	26,733.275	73.242	248.812	35,004.063	95.902	334.466
High	2014	8,494.001	23.271	87.804	27,127.241	74.321	256.521	35,621.241	97.592	344.326
High	2015	8,755.227	23.987	90.406	27,650.283	75.754	264.366	36,405.510	99.741	354.772
High	2016	9,054.378	24.807	93.208	28,293.395	77.516	272.090	37,347.773	102.323	365.298
High	2017	9,278.333	25.420	96.002	28,962.324	79.349	279.693	38,240.657	104.769	375.695
High	2018	9,531.905	26.115	98.748	29,516.994	80.868	287.093	39,048.899	106.983	385.840
High	2019	9,781.233	26.798	101.434	30,027.442	82.267	294.436	39,808.675	109.065	395.869
High	2020	10,068.045	27.584	104.083	30,622.956	83.899	301.744	40,691.001	111.482	405.827
High	2021	10,273.157	28.146	106.719	31,253.974	85.627	308.999	41,527.131	113.773	415.718
High	2022	10,516.037	28.811	109.314	31,976.453	87.607	316.234	42,492.490	116.418	425.548
High	2023	10,761.904	29.485	111.903	32,697.751	89.583	323.594	43,459.655	119.068	435.497
High	2024	11,052.396	30.281	114.541	33,441.452	91.620	330.924	44,493.848	121.901	445.465
High	2025	11,258.779	30.846	117.181	34,206.603	93.717	338.326	45,465.382	124.563	455.507
High	2026	11,509.257	31.532	119.855	35,016.400	95.935	345.687	46,525.656	127.468	465.542
High	2027	11,756.610	32.210	122.532	35,754.261	97.957	353.026	47,510.871	130.167	475.558
High	2028	12,038.173	32.981	125.162	36,578.506	100.215	360.329	48,616.679	133.196	485.491
High	2029	12,217.548	33.473	127.612	37,341.572	102.306	367.636	49,559.119	135.778	495.248
High	2030	12,442.813	34.090	130.006	38,196.855	104.649	374.910	50,639.668	138.739	504.916
High	2031	12,665.597	34.700	132.406	38,985.923	106.811	382.216	51,651.519	141.511	514.622

APPENDIX 3.8 II ANNUAL DEMAND, AVERAGE DAY DEMAND AND PEAK DAY DEMAND (NET OF DSM) – CASE LOW

Case	Gas Year	Annual Demand Klamath (MDth)	Daily Demand Klamath (MDth/day)	Peak Day Klamath (MDth/day)	Annual Demand La Grande (MDth)	Daily Demand La Grande (MDth/day)	Peak Day La Grande (MDth/day)	Annual Demand Medford/Roseburg (MDth)	Daily Demand Medford/Roseburg (MDth/day)	Peak Day Medford/Roseburg (MDth/day)
Low	2012	1,330.48	3.645	12.753	718.84	1.969	7.206	6,326.70	17.333	67.81
Low	2013	1,334.98	3.657	12.839	720.48	1.974	7.255	6,346.10	17.387	68.22
Low	2014	1,257.67	3.446	11.804	675.45	1.851	6.647	6,004.92	16.452	62.76
Low	2015	1,242.11	3.403	11.556	664.53	1.821	6.489	5,949.30	16.299	61.53
Low	2016	1,230.66	3.372	11.314	655.85	1.797	6.323	5,916.94	16.211	60.36
Low	2017	1,226.09	3.359	11.282	650.84	1.783	6.277	5,915.49	16.207	60.35
Low	2018	1,226.50	3.360	11.254	648.66	1.777	6.235	5,939.22	16.272	60.38
Low	2019	1,233.41	3.379	11.305	649.98	1.781	6.240	5,991.97	16.416	60.85
Low	2020	1,244.69	3.410	11.352	653.68	1.791	6.243	6,065.67	16.618	61.28
Low	2021	1,248.11	3.419	11.421	653.10	1.789	6.257	6,100.04	16.712	61.83
Low	2022	1,254.25	3.436	11.463	654.03	1.792	6.258	6,148.25	16.845	62.23
Low	2023	1,260.27	3.453	11.504	654.90	1.794	6.258	6,197.08	16.978	62.62
Low	2024	1,272.34	3.486	11.560	658.98	1.805	6.266	6,275.54	17.193	63.11
Low	2025	1,272.08	3.485	11.582	656.45	1.798	6.255	6,294.48	17.245	63.41
Low	2026	1,279.11	3.504	11.635	657.80	1.802	6.262	6,348.75	17.394	63.89
Low	2027	1,278.47	3.503	11.591	655.25	1.795	6.217	6,366.30	17.442	63.83
Low	2028	1,285.57	3.522	11.585	657.03	1.800	6.194	6,417.67	17.583	63.96
Low	2029	1,282.12	3.513	11.570	653.45	1.790	6.169	6,414.80	17.575	63.99
Low	2030	1,283.44	3.516	11.552	652.45	1.788	6.143	6,435.68	17.632	64.01
Low	2031	1,284.72	3.520	11.533	651.44	1.785	6.117	6,454.48	17.684	64.01

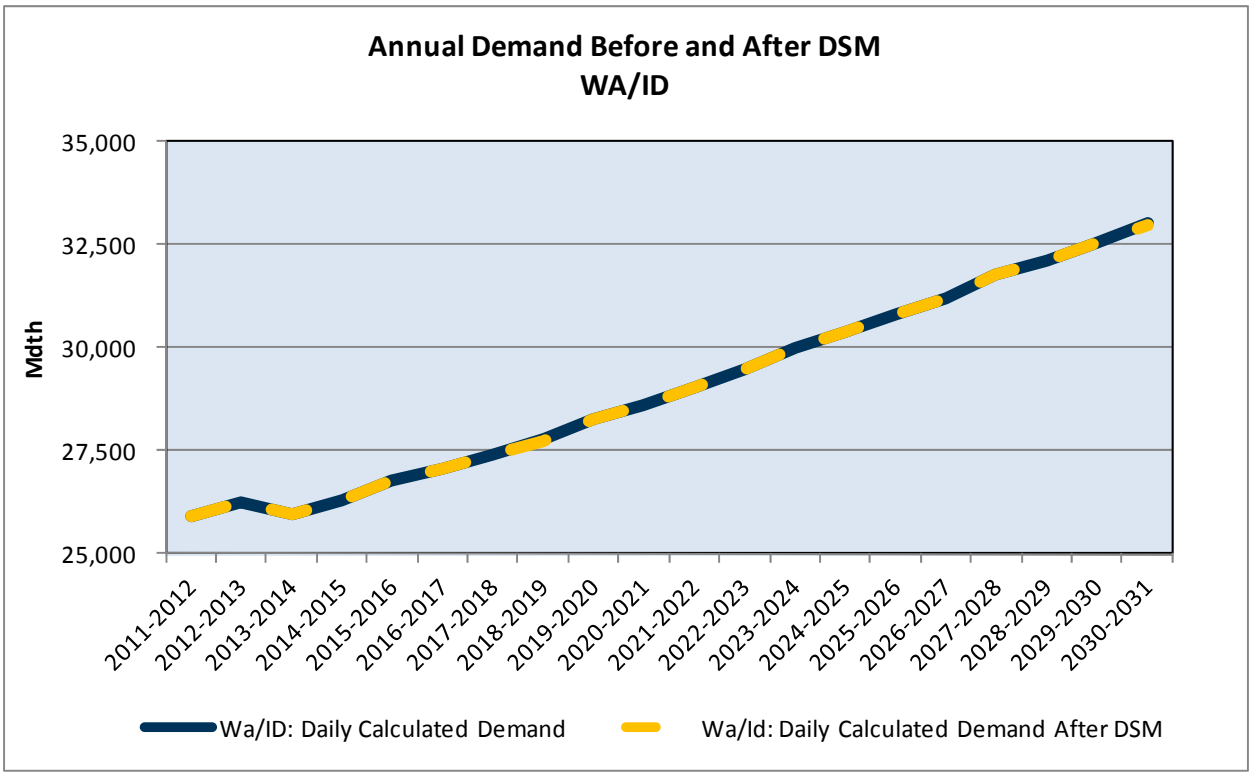
Case	Gas Year	Annual Demand Oregon (MDth)	Daily Demand Oregon (MDth/day)	Peak Day Demand Oregon (MDth/day)	Annual Demand WA/ID (MDth)	Daily Demand WA/ID (MDth/day)	Peak Day WA/ID (MDth/day)	Annual Demand Total System (MDth)	Daily Demand Total System (MDth/day)	Peak Day Demand Total System (MDth/day)
Low	2012	8,376.018	22.948	87.772	25,869.420	70.875	253.682	34,245.438	93.823	341.454
Low	2013	8,401.559	23.018	88.316	26,027.116	71.307	256.267	34,428.675	94.325	344.584
Low	2014	7,938.030	21.748	81.213	24,484.249	67.080	235.970	32,422.280	88.828	317.183
Low	2015	7,855.937	21.523	79.580	24,180.231	66.247	231.265	32,036.167	87.770	310.845
Low	2016	7,803.438	21.379	78.001	23,963.104	65.652	226.450	31,766.543	87.032	304.451
Low	2017	7,792.414	21.349	77.907	23,902.034	65.485	225.981	31,694.448	86.834	303.888
Low	2018	7,814.387	21.409	77.869	23,944.602	65.602	225.656	31,758.990	87.011	303.525
Low	2019	7,875.358	21.576	78.394	24,119.248	66.080	227.010	31,994.606	87.656	305.405
Low	2020	7,964.045	21.819	78.876	24,378.702	66.791	228.263	32,342.747	88.610	307.139
Low	2021	8,001.250	21.921	79.506	24,484.906	67.082	229.973	32,486.156	89.003	309.479
Low	2022	8,056.527	22.073	79.950	24,642.850	67.515	231.151	32,699.377	89.587	311.101
Low	2023	8,112.246	22.225	80.383	24,801.674	67.950	232.338	32,913.920	90.175	312.721
Low	2024	8,206.862	22.485	80.934	25,081.808	68.717	233.825	33,288.670	91.202	314.759
Low	2025	8,223.010	22.529	81.247	25,116.474	68.812	234.654	33,339.484	91.341	315.900
Low	2026	8,285.659	22.700	81.784	25,295.164	69.302	236.060	33,580.823	92.002	317.843
Low	2027	8,300.022	22.740	81.638	25,314.457	69.355	235.478	33,614.479	92.094	317.116
Low	2028	8,360.274	22.905	81.742	25,492.680	69.843	235.657	33,852.953	92.748	317.399
Low	2029	8,350.362	22.878	81.734	25,461.533	69.758	235.688	33,811.895	92.635	317.421
Low	2030	8,371.576	22.936	81.702	25,525.012	69.932	235.658	33,896.588	92.867	317.359
Low	2031	8,390.650	22.988	81.666	25,589.265	70.108	235.634	33,979.915	93.096	317.300

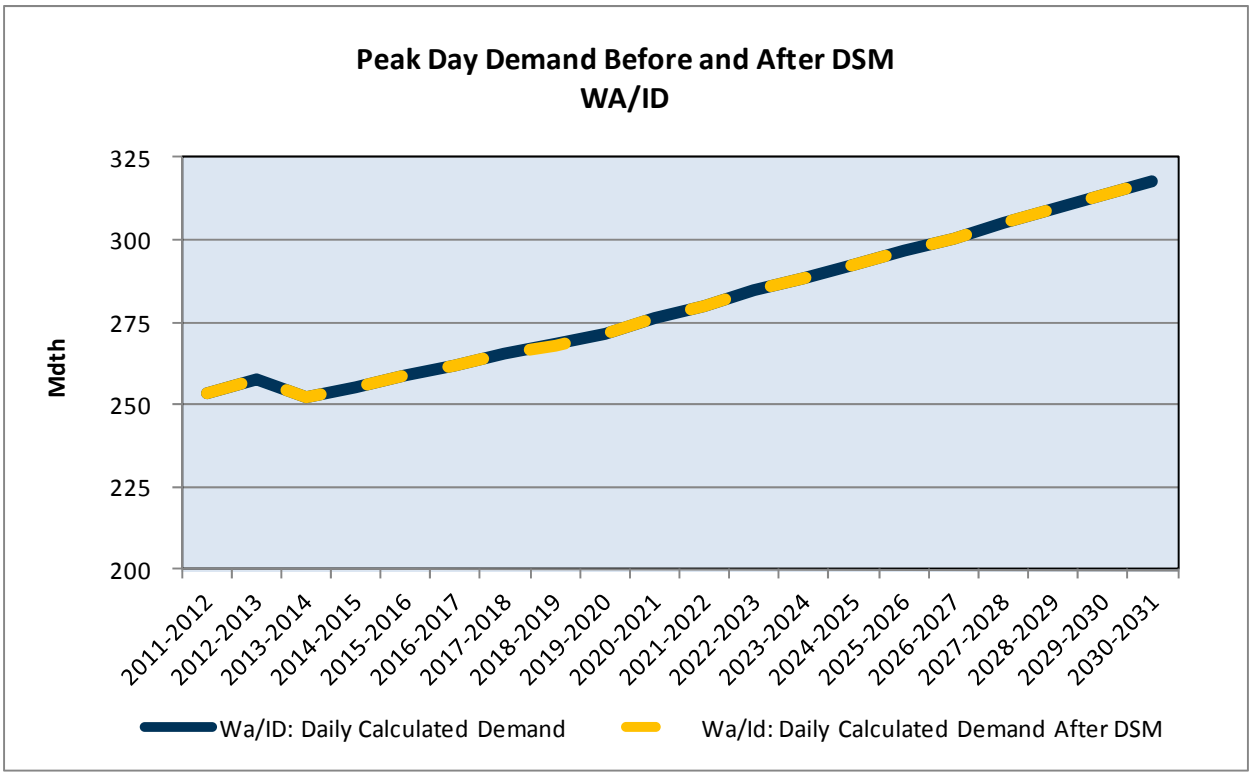
APPENDIX 3.8 II ANNUAL DEMAND, AVERAGE DAY DEMAND AND PEAK DAY DEMAND (NET OF DSM) – CASE COLDEST IN 20

Case	Gas Year	Annual Demand Klamath (MDth)	Daily Demand Klamath (MDth/day)	Peak Day Klamath (MDth/day)	Annual Demand La Grande (MDth)	Daily Demand La Grande (MDth/day)	Peak Day La Grande (MDth/day)	Annual Demand Medford/Roseburg (MDth)	Daily Demand Medford/Roseburg (MDth/day)	Peak Day Medford/Roseburg (MDth/day)
Coldest in 20	2012	1,310.62	3.591	11.393	745.86	2.043	7.231	6,324.53	17.327	60.67
Coldest in 20	2013	1,321.32	3.620	11.519	750.50	2.056	7.312	6,372.93	17.460	61.28
Coldest in 20	2014	1,304.32	3.573	11.251	736.89	2.019	7.108	6,309.85	17.287	59.94
Coldest in 20	2015	1,318.81	3.613	11.344	740.83	2.030	7.136	6,401.37	17.538	60.58
Coldest in 20	2016	1,341.98	3.677	11.498	749.39	2.053	7.180	6,539.28	17.916	61.60
Coldest in 20	2017	1,352.20	3.705	11.626	750.61	2.056	7.210	6,620.72	18.139	62.55
Coldest in 20	2018	1,366.76	3.745	11.746	754.30	2.067	7.236	6,724.60	18.424	63.49
Coldest in 20	2019	1,380.34	3.782	11.850	757.48	2.075	7.257	6,822.92	18.693	64.36
Coldest in 20	2020	1,401.25	3.839	11.976	764.64	2.095	7.292	6,956.07	19.058	65.33
Coldest in 20	2021	1,415.08	3.877	12.146	767.86	2.104	7.354	7,064.45	19.355	66.54
Coldest in 20	2022	1,432.40	3.924	12.293	773.08	2.118	7.404	7,183.63	19.681	67.71
Coldest in 20	2023	1,451.40	3.976	12.461	779.03	2.134	7.463	7,307.07	20.019	68.89
Coldest in 20	2024	1,473.50	4.037	12.596	786.77	2.156	7.505	7,449.79	20.410	69.93
Coldest in 20	2025	1,486.90	4.074	12.762	789.59	2.163	7.564	7,546.85	20.676	71.15
Coldest in 20	2026	1,505.28	4.124	12.922	795.12	2.178	7.617	7,669.18	21.011	72.32
Coldest in 20	2027	1,520.68	4.166	13.047	799.37	2.190	7.654	7,777.92	21.309	73.32
Coldest in 20	2028	1,545.42	4.234	13.212	808.81	2.216	7.717	7,925.26	21.713	74.52
Coldest in 20	2029	1,557.37	4.267	13.370	811.94	2.224	7.781	8,002.99	21.926	75.58
Coldest in 20	2030	1,575.18	4.316	13.525	818.26	2.242	7.841	8,124.26	22.258	76.62
Coldest in 20	2031	1,593.02	4.364	13.680	824.44	2.259	7.902	8,237.08	22.567	77.76

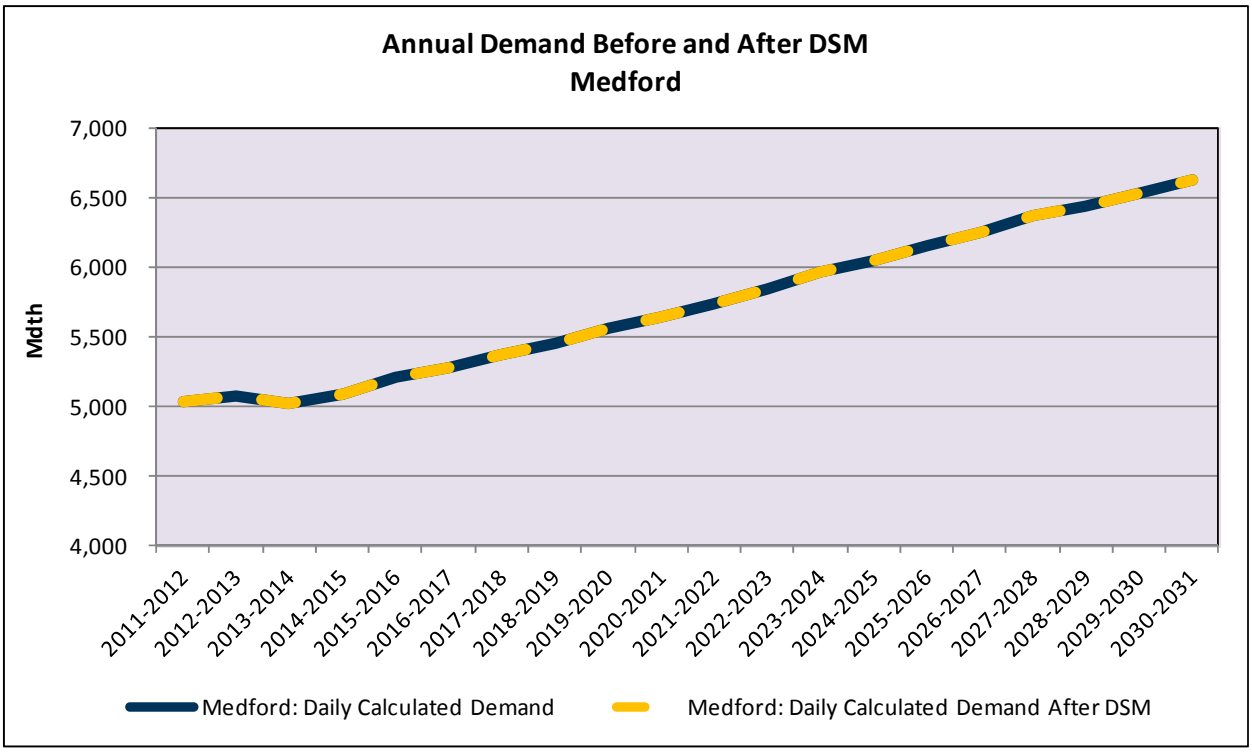
Case	Gas Year	Annual Demand Oregon (MDth)	Daily Demand Oregon (MDth/day)	Peak Day Demand Oregon (MDth/day)	Annual Demand WA/ID (MDth)	Daily Demand WA/ID (MDth/day)	Peak Day WA/ID (MDth/day)	Annual Demand Total System (MDth)	Daily Demand Total System (MDth/day)	Peak Day Demand Total System (MDth/day)
Coldest in 20	2012	8,381.005	22.962	79.297	25,850.890	70.824	236.316	34,231.896	93.786	315.614
Coldest in 20	2013	8,444.741	23.136	80.115	26,178.590	71.722	240.308	34,623.330	94.858	320.423
Coldest in 20	2014	8,351.060	22.880	78.294	25,883.372	70.913	235.606	34,234.432	93.793	313.900
Coldest in 20	2015	8,461.012	23.181	79.061	26,203.844	71.791	238.076	34,664.856	94.972	317.137
Coldest in 20	2016	8,630.650	23.646	80.280	26,714.961	73.192	241.508	35,345.611	96.837	321.789
Coldest in 20	2017	8,723.534	23.900	81.382	26,981.594	73.922	244.543	35,705.129	97.822	325.925
Coldest in 20	2018	8,845.665	24.235	82.470	27,344.674	74.917	247.489	36,190.340	99.152	329.959
Coldest in 20	2019	8,960.745	24.550	83.468	27,688.899	75.860	250.257	36,649.644	100.410	333.725
Coldest in 20	2020	9,121.955	24.992	84.598	28,178.988	77.203	253.448	37,300.943	102.194	338.046
Coldest in 20	2021	9,247.389	25.335	86.037	28,527.323	78.157	257.582	37,774.712	103.492	343.619
Coldest in 20	2022	9,389.109	25.724	87.407	28,946.999	79.307	261.267	38,336.108	105.030	348.674
Coldest in 20	2023	9,537.493	26.130	88.814	29,408.147	80.570	265.451	38,945.640	106.700	354.265
Coldest in 20	2024	9,710.063	26.603	90.034	29,932.043	82.006	268.955	39,642.107	108.609	358.988
Coldest in 20	2025	9,823.340	26.913	91.473	30,280.223	82.960	273.163	40,103.563	109.873	364.636
Coldest in 20	2026	9,969.582	27.314	92.859	30,727.329	84.184	277.147	40,696.911	111.498	370.006
Coldest in 20	2027	10,097.977	27.666	94.017	31,113.863	85.243	280.427	41,211.840	112.909	374.444
Coldest in 20	2028	10,279.493	28.163	95.444	31,696.310	86.839	284.546	41,975.803	115.002	379.990
Coldest in 20	2029	10,372.303	28.417	96.732	32,020.073	87.726	288.556	42,392.376	116.143	385.288
Coldest in 20	2030	10,517.702	28.816	97.987	32,465.913	88.948	292.555	42,983.616	117.763	390.542
Coldest in 20	2031	10,654.532	29.190	99.340	32,913.603	90.174	296.552	43,568.136	119.365	395.892

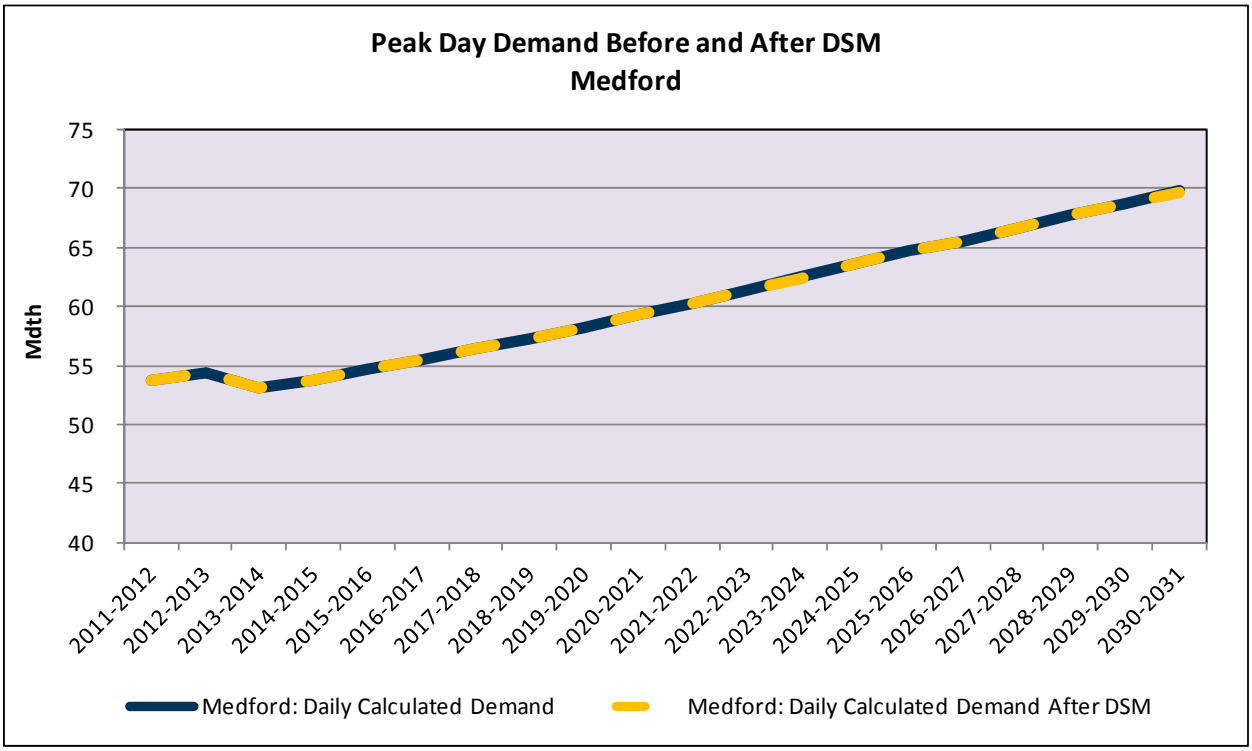
APPENDIX 3.9 II PEAK DAY DEMAND BEFORE AND AFTER DSM WA/ID



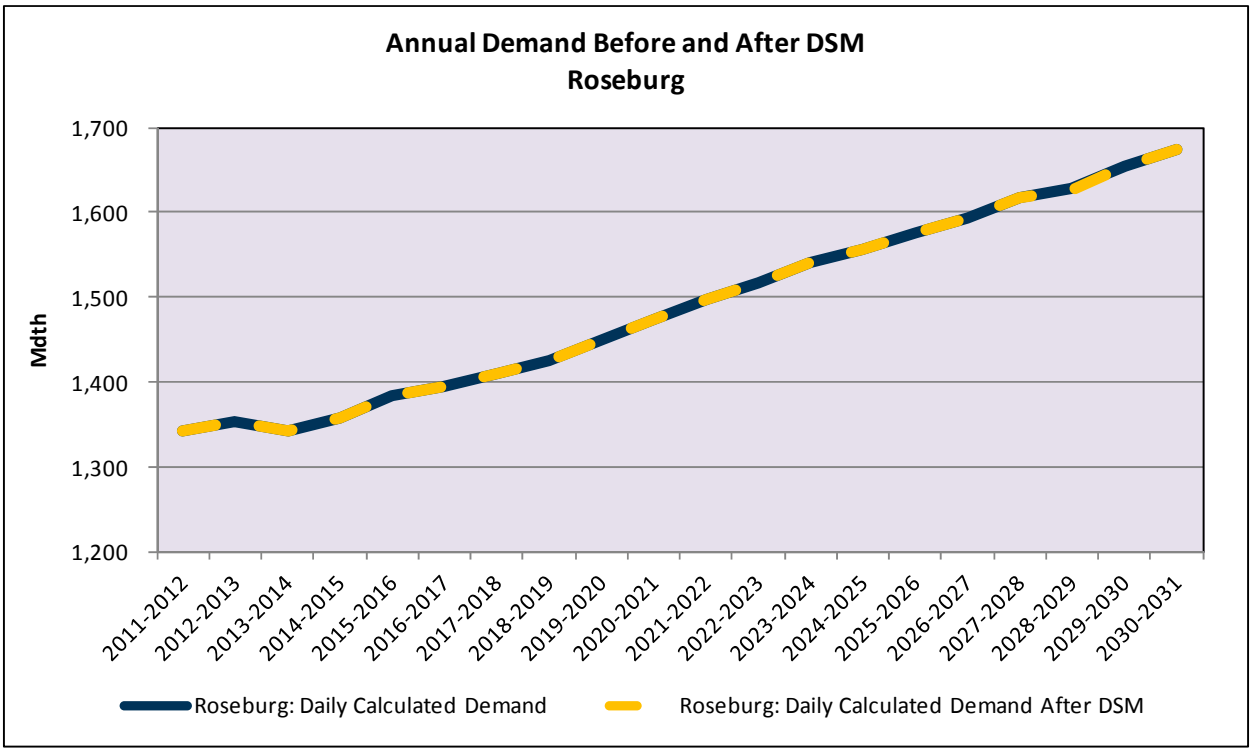


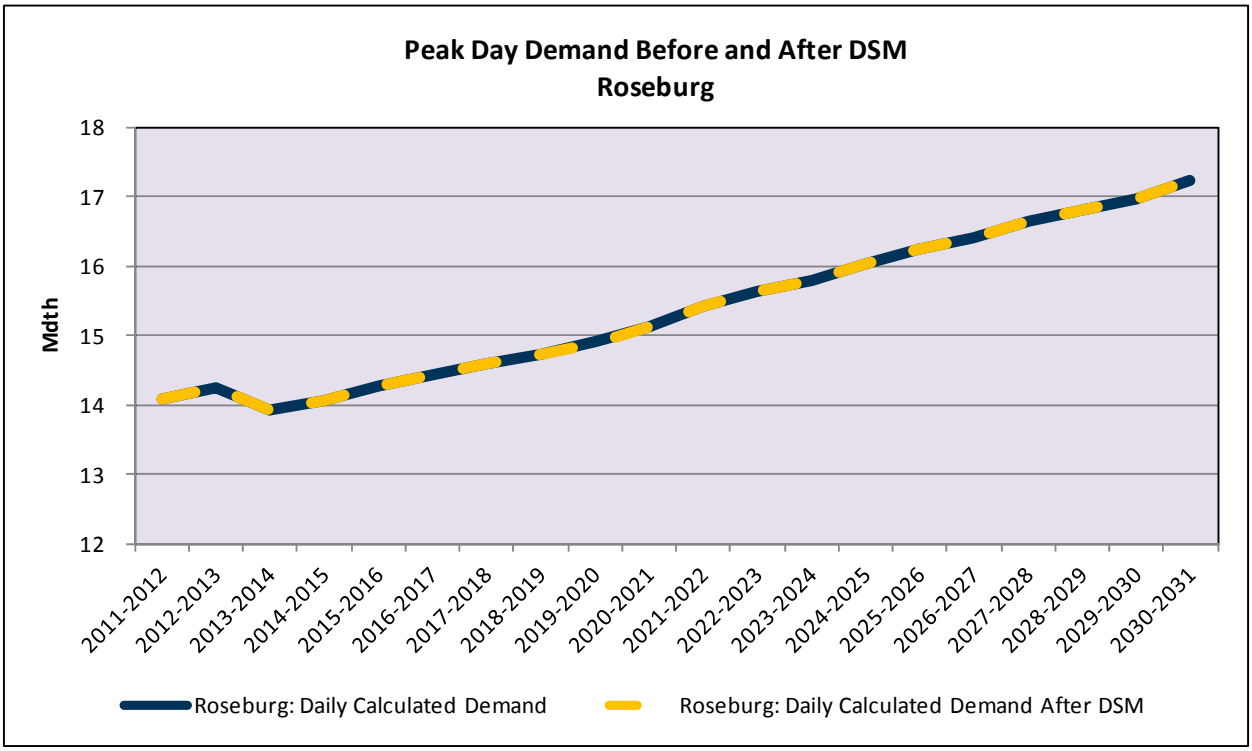
APPENDIX 3.9 II PEAK DAY DEMAND BEFORE AND AFTER DSM MEDFORD



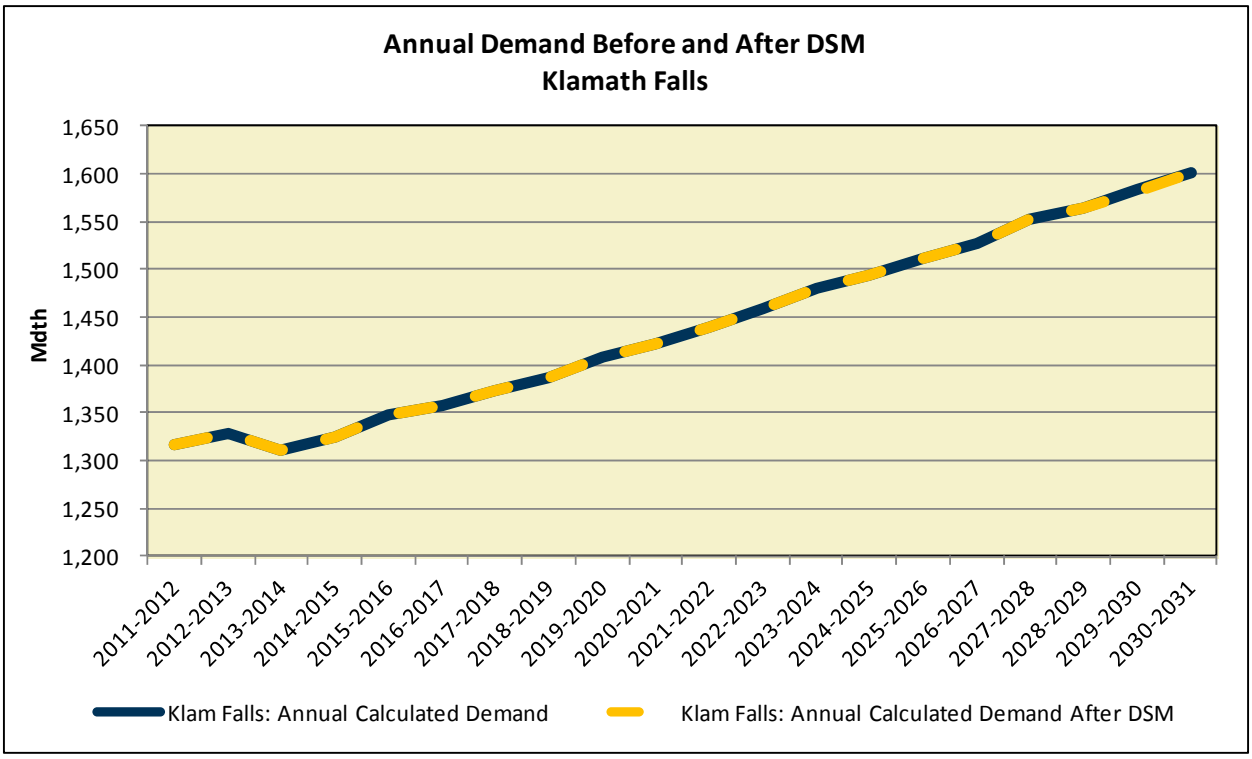


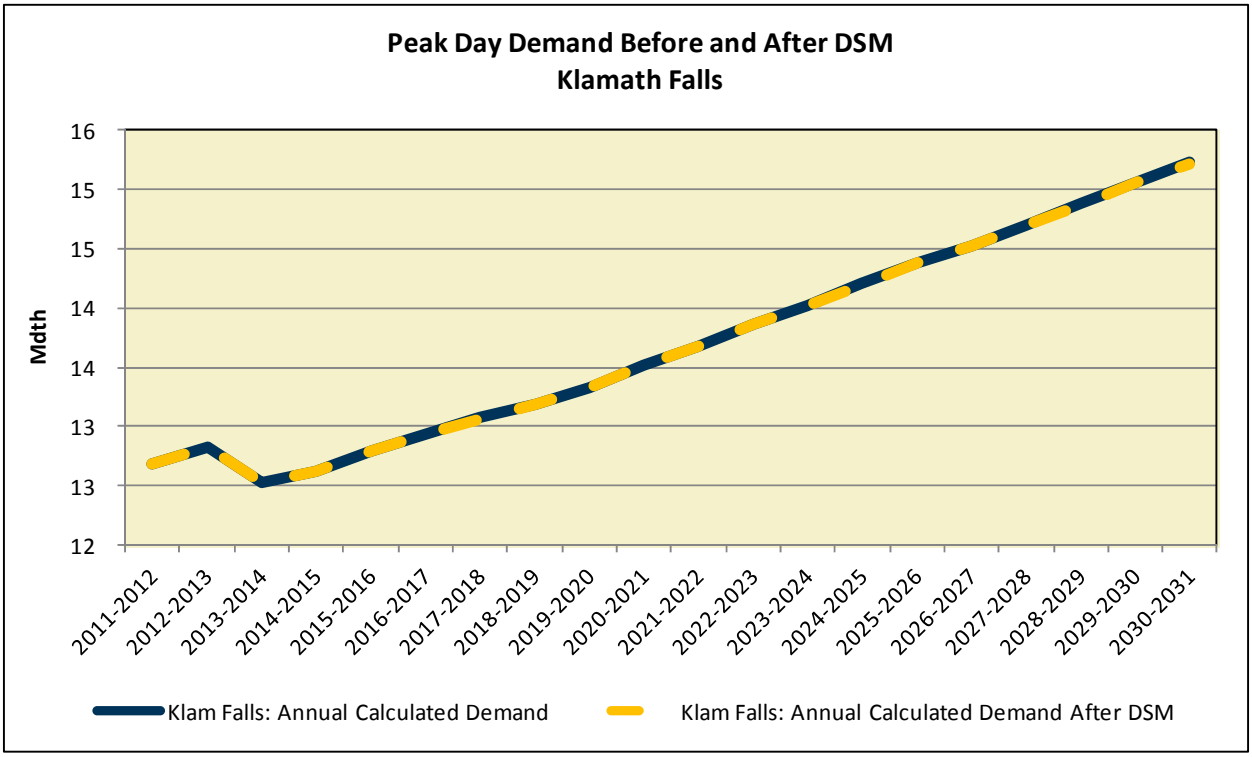
APPENDIX 3.9 II PEAK DAY DEMAND BEFORE AND AFTER DSM ROSEBURG



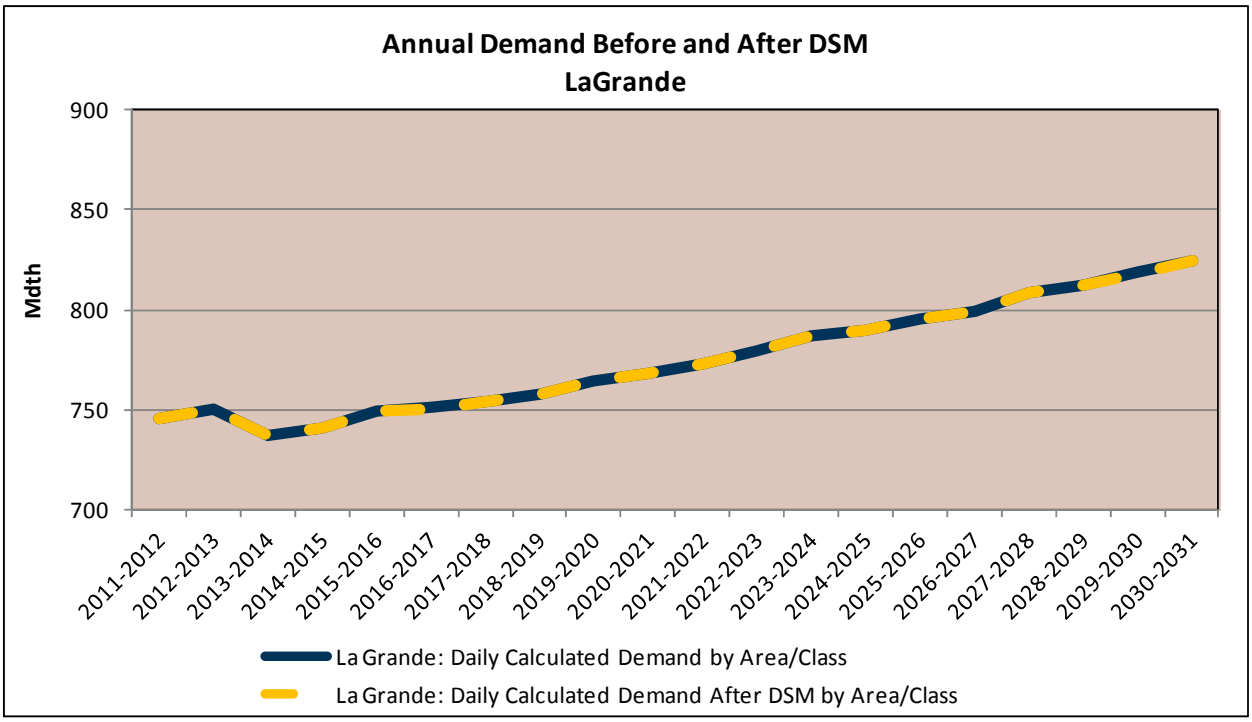


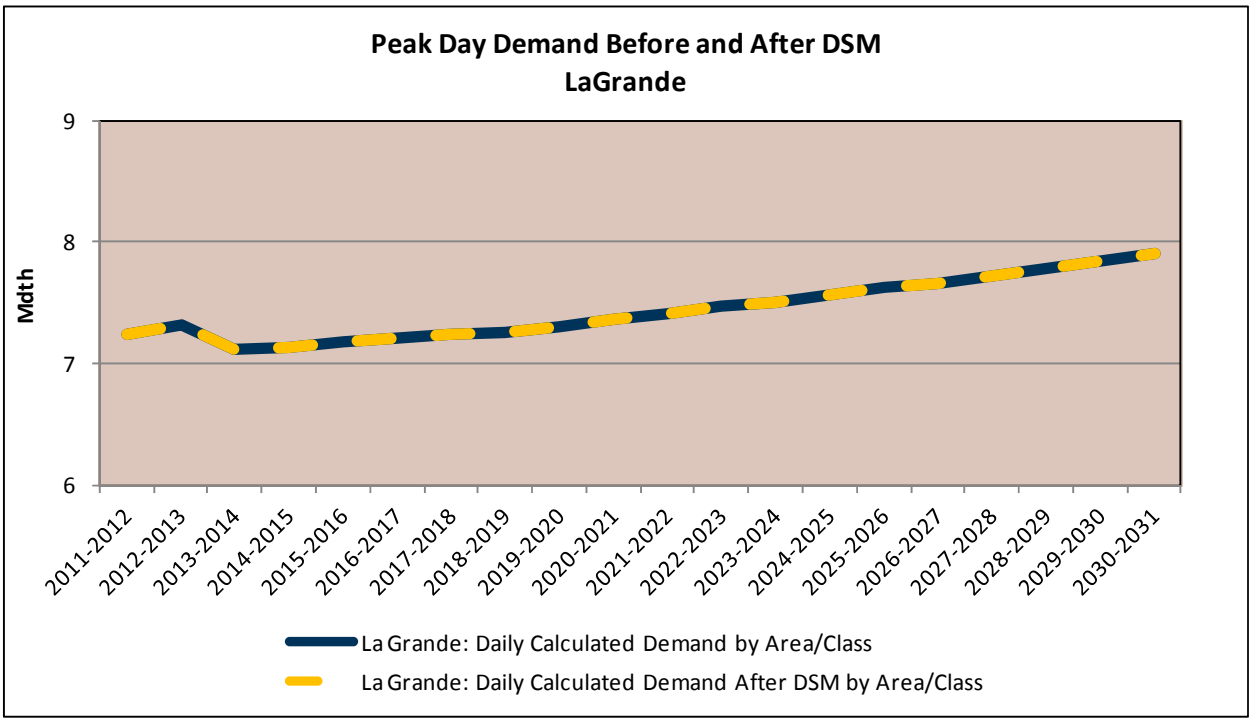
APPENDIX 3.9 II PEAK DAY DEMAND BEFORE AND AFTER DSM KLAMATH FALLS





APPENDIX 3.9 II PEAK DAY DEMAND BEFORE AND AFTER DSM LA GRANDE





APPENDIX 3.10 II DETAILED DEMAND DATA EXPECTED MIX

Area	2012: Residential	2012: Commercial	2012: Ind FirmSale	2012 Total	2013: Residential	2013: Commercial	2013: Ind FirmSale	2013 Total	2014: Residential	2014: Commercial	2014: Ind FirmSale	2014 Total
Klam Falls	832.29	479.61	5.02	1,316.92	838.10	484.58	5.01	1,327.69	825.31	480.20	5.01	1,310.52
La Grande	436.90	280.81	28.15	745.86	438.49	283.86	28.15	750.50	428.75	280.00	28.15	736.89
Medford GTN	2,122.77	1,319.53	27.83	3,470.13	2,144.95	1,323.48	28.25	3,496.68	2,127.21	1,305.07	28.25	3,460.54
Medford NWP	953.71	592.83	12.50	1,559.04	963.67	594.61	12.69	1,570.97	955.71	586.34	12.69	1,554.74
Roseburg	711.03	582.36	49.52	1,342.92	717.40	586.53	49.38	1,353.30	712.04	580.41	48.91	1,341.36
OR Sub-Total	**5,056.71**	**3,255.14**	**123.02**	**8,434.86**	**5,102.61**	**3,273.05**	**123.48**	**8,499.15**	**5,049.01**	**3,232.02**	**123.01**	**8,404.04**
WA/ID Both	9,207.42	5,521.06	306.24	15,034.72	9,342.29	5,576.39	306.80	15,225.48	9,230.37	5,518.49	304.41	15,053.27
WA/ID GTN	1,269.99	761.53	42.24	2,073.75	1,288.59	769.16	42.32	2,100.07	1,273.15	761.17	41.99	2,076.32
WA/ID NWP	5,397.45	3,236.49	179.52	8,813.46	5,476.52	3,268.93	179.85	8,925.29	5,410.91	3,234.99	178.45	8,824.35
WA/ID Sub-Total	**15,874.86**	**9,519.08**	**528.00**	**25,921.94**	**16,107.40**	**9,614.48**	**528.96**	**26,250.84**	**15,914.43**	**9,514.66**	**524.85**	**25,953.94**
Case Total	**20,931.57**	**12,774.21**	**651.02**	**34,356.80**	**21,210.01**	**12,887.54**	**652.44**	**34,749.99**	**20,963.44**	**12,746.67**	**647.86**	**34,357.98**

Area	2015: Residential	2015: Commercial	2015: Ind FirmSale	2015 Total	2016: Residential	2016: Commercial	2016: Ind FirmSale	2016 Total	2017: Residential	2017: Commercial	2017: Ind FirmSale	2017 Total
Klam Falls	834.34	485.71	5.01	1,325.06	849.85	493.43	5.02	1,348.30	857.10	496.48	5.01	1,358.59
La Grande	429.01	283.67	28.15	740.83	432.86	288.38	28.15	749.39	432.86	289.61	28.15	750.61
Medford GTN	2,164.16	1,318.96	29.61	3,512.74	2,216.60	1,344.06	30.22	3,590.88	2,249.64	1,358.28	31.49	3,639.41
Medford NWP	972.31	592.58	13.30	1,578.19	995.86	603.85	13.58	1,613.29	1,010.71	610.24	14.15	1,635.10
Roseburg	723.71	585.17	48.81	1,357.69	741.47	592.76	48.90	1,383.13	751.56	594.69	48.69	1,394.94
OR Sub-Total	**5,123.54**	**3,266.09**	**124.88**	**8,514.50**	**5,236.65**	**3,322.48**	**125.87**	**8,684.99**	**5,301.87**	**3,349.31**	**127.48**	**8,778.65**
WA/ID Both	9,342.69	5,589.65	307.19	15,239.53	9,523.97	5,701.77	310.81	15,536.55	9,617.59	5,762.39	311.72	15,691.70
WA/ID GTN	1,288.65	770.99	42.37	2,102.01	1,313.65	786.45	42.87	2,142.98	1,326.57	794.82	43.00	2,164.38
WA/ID NWP	5,476.76	3,276.71	180.08	8,933.55	5,583.03	3,342.44	182.20	9,107.68	5,637.92	3,377.98	182.73	9,198.63
WA/ID Sub-Total	**16,108.10**	**9,637.35**	**529.64**	**26,275.09**	**16,420.66**	**9,830.67**	**535.88**	**26,787.21**	**16,582.07**	**9,935.19**	**537.45**	**27,054.71**
Case Total	**21,231.64**	**12,903.44**	**654.52**	**34,789.59**	**21,657.31**	**13,153.14**	**661.75**	**35,472.20**	**21,883.94**	**13,284.50**	**664.92**	**35,833.36**

Area	2018: Residential	2018: Commercial	2018: Ind FirmSale	2018 Total	2019: Residential	2019: Commercial	2019: Ind FirmSale	2019 Total	2020: Residential	2020: Commercial	2020: Ind FirmSale	2020 Total
Klam Falls	867.06	501.15	5.01	1,373.21	876.37	505.47	5.01	1,386.85	890.47	512.33	5.02	1,407.82
La Grande	434.39	291.76	28.15	754.30	435.63	293.70	28.15	757.48	439.20	297.30	28.15	764.64
Medford GTN	2,291.24	1,377.44	32.00	3,700.68	2,330.95	1,395.74	32.00	3,758.69	2,382.58	1,420.77	32.15	3,835.50
Medford NWP	1,029.40	618.85	14.38	1,662.63	1,047.24	627.07	14.38	1,688.69	1,070.43	638.32	14.44	1,723.19
Roseburg	763.68	598.42	48.63	1,410.72	775.15	601.91	48.56	1,425.61	791.06	608.46	48.66	1,448.18
OR Sub-Total	**5,385.77**	**3,387.61**	**128.16**	**8,901.55**	**5,465.34**	**3,423.89**	**128.10**	**9,017.33**	**5,573.75**	**3,477.17**	**128.42**	**9,179.34**
WA/ID Both	9,746.28	5,842.88	313.60	15,902.77	9,868.05	5,919.40	315.42	16,102.86	10,043.33	6,026.84	317.48	16,387.65
WA/ID GTN	1,344.32	805.92	43.26	2,193.49	1,361.11	816.47	43.51	2,221.09	1,385.29	831.29	43.79	2,260.37
WA/ID NWP	5,713.37	3,425.17	183.84	9,322.37	5,784.75	3,470.03	184.90	9,439.69	5,887.51	3,533.02	186.11	9,606.64
WA/ID Sub-Total	**16,803.97**	**10,073.97**	**540.69**	**27,418.63**	**17,013.92**	**10,205.90**	**543.82**	**27,763.64**	**17,316.12**	**10,391.16**	**547.38**	**28,254.66**
Case Total	**22,189.74**	**13,461.59**	**668.85**	**36,320.18**	**22,479.26**	**13,629.79**	**671.92**	**36,780.97**	**22,889.87**	**13,868.33**	**675.79**	**37,434.00**

Area	2021: Residential	2021: Commercial	2021: Ind FirmSale	2021 Total	2022: Residential	2022: Commercial	2022: Ind FirmSale	2022 Total	2023: Residential	2023: Commercial	2023: Ind FirmSale	2023 Total
Klam Falls	900.18	516.56	5.01	1,421.75	912.06	522.08	5.01	1,439.15	925.10	528.13	5.01	1,458.24
La Grande	440.51	299.20	28.15	767.86	442.98	301.96	28.15	773.08	445.94	304.94	28.15	779.03
Medford GTN	2,421.76	1,438.08	33.36	3,893.20	2,466.89	1,459.16	33.88	3,959.92	2,515.90	1,482.06	33.92	4,031.89
Medford NWP	1,088.04	646.09	14.99	1,749.12	1,108.31	655.56	15.22	1,779.10	1,130.33	665.85	15.24	1,811.43
Roseburg	802.36	611.66	59.87	1,473.89	815.95	616.61	64.67	1,497.23	830.54	622.08	64.67	1,517.29
OR Sub-Total	**5,652.84**	**3,511.60**	**141.37**	**9,305.81**	**5,746.19**	**3,555.36**	**146.92**	**9,448.47**	**5,847.83**	**3,603.06**	**146.98**	**9,597.87**
WA/ID Both	10,168.21	6,102.41	319.77	16,590.39	10,319.06	6,193.88	321.49	16,834.43	10,485.41	6,293.44	323.76	17,102.61
WA/ID GTN	1,402.52	841.72	44.11	2,288.34	1,423.32	854.33	44.34	2,322.00	1,446.27	868.07	44.66	2,358.99
WA/ID NWP	5,960.72	3,577.33	187.45	9,725.50	6,049.15	3,630.95	188.46	9,868.57	6,146.67	3,689.32	189.79	10,025.79
WA/ID Sub-Total	**17,531.44**	**10,521.46**	**551.32**	**28,604.23**	**17,791.54**	**10,679.16**	**554.29**	**29,024.99**	**18,078.35**	**10,850.83**	**558.21**	**29,487.39**
Case Total	**23,184.28**	**14,033.06**	**692.70**	**37,910.03**	**23,537.73**	**14,234.53**	**701.21**	**38,473.47**	**23,926.17**	**14,453.89**	**705.20**	**39,085.26**

APPENDIX 3.10 II DETAILED DEMAND DATA EXPECTED MIX

Area	2024: Residential	2024: Commercial	2024: Ind FirmSale	2024 Total	2025: Residential	2025: Commercial	2025: Ind FirmSale	2025 Total	2026: Residential	2026: Commercial	2026: Ind FirmSale	2026 Total
Klam Falls	940.04	535.35	5.02	1,480.41	949.44	539.46	5.01	1,493.90	962.02	545.34	5.01	1,512.37
La Grande	449.85	308.78	28.15	786.77	451.01	310.44	28.15	789.59	453.70	313.27	28.15	795.12
Medford GTN	2,570.46	1,508.48	35.35	4,114.29	2,610.10	1,526.07	35.75	4,171.92	2,658.54	1,548.71	35.80	4,243.05
Medford NWP	1,154.84	677.72	15.88	1,848.45	1,172.65	685.63	16.06	1,874.34	1,194.42	695.80	16.08	1,906.30
Roseburg	847.41	629.16	64.82	1,541.40	858.76	632.47	64.63	1,555.87	873.47	637.93	64.62	1,576.02
OR Sub-Total	**5,962.61**	**3,659.49**	**149.22**	**9,771.31**	**6,041.96**	**3,694.06**	**149.60**	**9,885.62**	**6,142.16**	**3,741.06**	**149.65**	**10,032.87**
WA/ID Both	10,674.30	6,406.73	326.03	17,407.06	10,799.03	6,481.43	329.27	17,609.73	10,960.49	6,577.81	331.44	17,869.73
WA/ID GTN	1,472.32	883.69	44.97	2,400.99	1,489.53	894.00	45.42	2,428.94	1,511.80	907.29	45.72	2,464.80
WA/ID NWP	6,257.41	3,755.74	191.12	10,204.27	6,330.53	3,799.53	193.02	10,323.08	6,425.18	3,856.03	194.29	10,475.51
WA/ID Sub-Total	**18,404.03**	**11,046.16**	**562.13**	**30,012.32**	**18,619.09**	**11,174.95**	**567.71**	**30,361.75**	**18,897.46**	**11,341.14**	**571.44**	**30,810.04**
Case Total	**24,366.64**	**14,705.65**	**711.34**	**39,783.63**	**24,661.05**	**14,869.01**	**717.31**	**40,247.37**	**25,039.62**	**15,082.19**	**721.09**	**40,842.91**

Area	2027: Residential	2027: Commercial	2027: Ind FirmSale	2027 Total	2028: Residential	2028: Commercial	2028: Ind FirmSale	2028 Total	2029: Residential	2029: Commercial	2029: Ind FirmSale	2029 Total
Klam Falls	972.59	550.24	5.01	1,527.84	989.35	558.30	5.02	1,552.67	997.76	561.94	5.01	1,564.71
La Grande	455.60	315.63	28.15	799.37	460.54	320.12	28.15	808.81	461.78	322.02	28.15	811.94
Medford GTN	2,700.69	1,568.40	37.11	4,306.20	2,758.04	1,596.10	37.79	4,391.93	2,791.49	1,610.82	37.67	4,439.98
Medford NWP	1,213.35	704.64	16.67	1,934.67	1,239.12	717.09	16.98	1,973.19	1,254.15	723.70	16.93	1,994.77
Roseburg	886.86	642.56	64.57	1,593.99	903.43	649.83	64.76	1,618.02	910.82	651.55	64.57	1,626.94
OR Sub-Total	**6,229.10**	**3,781.48**	**151.51**	**10,162.08**	**6,350.49**	**3,841.44**	**152.70**	**10,344.62**	**6,416.00**	**3,870.03**	**152.32**	**10,438.34**
WA/ID Both	11,099.67	6,661.55	333.26	18,094.47	11,310.26	6,786.85	335.89	18,433.00	11,426.73	6,856.68	338.06	18,621.47
WA/ID GTN	1,530.99	918.84	45.97	2,495.80	1,560.04	936.12	46.33	2,542.50	1,576.11	945.76	46.63	2,568.49
WA/ID NWP	6,506.77	3,905.13	195.36	10,607.26	6,630.23	3,978.58	196.90	10,805.72	6,698.51	4,019.52	198.18	10,916.21
WA/ID Sub-Total	**19,137.43**	**11,485.51**	**574.58**	**31,197.53**	**19,500.53**	**11,701.55**	**579.13**	**31,781.21**	**19,701.34**	**11,821.96**	**582.87**	**32,106.17**
Case Total	**25,366.53**	**15,266.99**	**726.09**	**41,359.61**	**25,851.01**	**15,542.99**	**731.83**	**42,125.83**	**26,117.35**	**15,691.98**	**735.18**	**42,544.51**

Area	2030: Residential	2030: Commercial	2030: Ind FirmSale	2030 Total	2031: Residential	2031: Commercial	2031: Ind FirmSale	2031 Total
Klam Falls	1,009.99	567.60	5.01	1,582.60	1,022.21	573.31	5.01	1,600.52
La Grande	464.85	325.27	28.15	818.26	467.90	328.39	28.15	824.44
Medford GTN	2,835.39	1,631.42	38.99	4,505.80	2,878.97	1,651.77	39.50	4,570.25
Medford NWP	1,273.87	732.96	17.52	2,024.34	1,293.45	742.10	17.75	2,053.30
Roseburg	922.03	655.72	75.89	1,653.64	933.25	659.94	80.69	1,673.89
OR Sub-Total	**6,506.13**	**3,912.96**	**165.54**	**10,584.64**	**6,595.78**	**3,955.51**	**171.10**	**10,722.39**
WA/ID Both	11,588.62	6,952.18	339.94	18,880.74	11,750.46	7,047.50	343.12	19,141.09
WA/ID GTN	1,598.44	958.93	46.89	2,604.26	1,620.76	972.08	47.33	2,640.17
WA/ID NWP	6,793.42	4,075.51	199.28	11,068.20	6,888.30	4,131.38	201.14	11,220.82
WA/ID Sub-Total	**19,980.48**	**11,986.62**	**586.10**	**32,553.20**	**20,259.52**	**12,150.96**	**591.60**	**33,002.08**
Case Total	**26,486.61**	**15,899.58**	**751.65**	**43,137.83**	**26,855.31**	**16,106.47**	**762.69**	**43,724.47**

APPENDIX 3.10 II DETAILED DEMAND DATA
LOW GROWTH HIGH PRICE

Area	2012: Residential	2012: Commercial	2012: Ind FirmSale	2012 Total	2013: Residential	2013: Commercial	2013: Ind FirmSale	2013 Total	2014: Residential	2014: Commercial	2014: Ind FirmSale	2014 Total
Klam Falls	830.20	479.70	5.02	1,314.92	832.39	481.98	5.01	1,319.37	778.93	457.96	5.01	1,241.90
La Grande	436.78	281.08	28.15	746.01	437.05	282.46	28.15	747.65	408.85	265.63	28.15	702.63
Medford GTN	2,122.03	1,321.59	27.83	3,471.45	2,132.06	1,321.98	28.25	3,482.30	2,010.33	1,254.69	28.25	3,293.27
Medford NWP	953.38	593.76	12.50	1,559.64	957.88	593.93	12.69	1,564.51	903.19	563.70	12.69	1,479.58
Roseburg	709.37	582.82	49.59	1,341.78	711.99	584.45	49.44	1,345.89	673.31	557.11	48.35	1,278.77
OR Sub-Total	**5,051.76**	**3,258.95**	**123.08**	**8,433.79**	**5,071.38**	**3,264.80**	**123.55**	**8,459.72**	**4,774.62**	**3,099.09**	**122.45**	**7,996.16**
Wa/Id Both	9,217.51	5,568.18	309.22	15,094.90	9,284.07	5,593.04	309.79	15,186.89	8,714.68	5,278.14	300.26	14,293.07
Wa/Id GTN	1,271.38	768.02	42.65	2,082.06	1,280.56	771.45	42.73	2,094.74	1,202.02	728.02	41.41	1,971.46
Wa/Id NWP	5,403.37	3,264.11	181.27	8,848.74	5,442.39	3,278.68	181.60	8,902.67	5,108.61	3,094.09	176.01	8,378.72
Wa/Id Sub-Total	**15,892.25**	**9,600.31**	**533.13**	**26,025.70**	**16,007.02**	**9,643.17**	**534.11**	**26,184.30**	**15,025.31**	**9,100.25**	**517.69**	**24,643.25**
Case Total	**20,944.01**	**12,859.26**	**656.22**	**34,459.49**	**21,078.39**	**12,907.97**	**657.66**	**34,644.02**	**19,799.93**	**12,199.34**	**640.14**	**32,639.41**

Area	2015: Residential	2015: Commercial	2015: Ind FirmSale	2015 Total	2016: Residential	2016: Commercial	2016: Ind FirmSale	2016 Total	2017: Residential	2017: Commercial	2017: Ind FirmSale	2017 Total
Klam Falls	767.68	453.49	5.01	1,226.18	759.37	450.10	5.02	1,214.49	756.36	448.48	5.01	1,209.85
La Grande	401.03	262.54	28.15	691.73	395.06	259.86	28.15	683.06	391.64	258.27	28.15	678.06
Medford GTN	1,991.60	1,242.65	29.61	3,263.87	1,979.78	1,236.56	30.59	3,246.93	1,980.89	1,235.66	31.00	3,247.56
Medford NWP	894.78	558.29	13.30	1,466.38	889.46	555.56	13.74	1,458.76	889.97	555.15	13.93	1,459.05
Roseburg	667.29	551.43	48.00	1,266.72	664.25	547.20	48.76	1,260.21	664.25	544.53	49.86	1,258.63
OR Sub-Total	**4,722.38**	**3,068.41**	**124.07**	**7,914.86**	**4,687.92**	**3,049.28**	**126.26**	**7,863.46**	**4,683.11**	**3,042.09**	**127.94**	**7,853.14**
Wa/Id Both	8,598.84	5,218.85	300.16	14,117.85	8,513.98	5,179.09	300.23	13,993.30	8,488.77	5,169.66	300.23	13,958.67
Wa/Id GTN	1,186.05	719.84	41.40	1,947.29	1,174.34	714.36	41.41	1,930.11	1,170.87	713.06	41.41	1,925.34
Wa/Id NWP	5,040.71	3,059.34	175.96	8,276.01	4,990.97	3,036.04	176.00	8,203.01	4,976.20	3,030.52	176.00	8,182.72
Wa/Id Sub-Total	**14,825.60**	**8,998.03**	**517.52**	**24,341.16**	**14,679.29**	**8,929.49**	**517.64**	**24,126.42**	**14,635.84**	**8,913.24**	**517.65**	**24,066.72**
Case Total	**19,547.98**	**12,066.44**	**641.59**	**32,256.02**	**19,367.21**	**11,978.77**	**643.90**	**31,989.88**	**19,318.95**	**11,955.33**	**645.59**	**31,919.87**

Area	2018: Residential	2018: Commercial	2018: Ind FirmSale	2018 Total	2019: Residential	2019: Commercial	2019: Ind FirmSale	2019 Total	2020: Residential	2020: Commercial	2020: Ind FirmSale	2020 Total
Klam Falls	756.51	448.60	5.01	1,210.12	761.09	450.79	5.01	1,216.88	768.40	454.53	5.02	1,227.95
La Grande	389.93	257.81	28.15	675.89	390.35	258.72	28.15	677.22	392.17	260.62	28.15	680.94
Medford GTN	1,990.85	1,239.96	31.52	3,262.33	2,011.48	1,249.62	32.04	3,293.14	2,039.06	1,263.49	32.68	3,335.23
Medford NWP	894.44	557.08	14.16	1,465.68	903.71	561.42	14.40	1,479.53	916.10	567.65	14.68	1,498.44
Roseburg	666.82	543.97	51.15	1,261.94	672.77	545.69	52.56	1,271.02	681.42	549.34	54.16	1,284.93
OR Sub-Total	**4,698.54**	**3,047.43**	**129.98**	**7,875.96**	**4,739.40**	**3,066.24**	**132.15**	**7,937.79**	**4,797.16**	**3,095.63**	**134.69**	**8,027.48**
Wa/Id Both	8,501.12	5,182.02	301.26	13,984.40	8,562.06	5,221.46	303.20	14,086.72	8,653.99	5,279.45	305.07	14,238.50
Wa/Id GTN	1,172.57	714.76	41.55	1,928.89	1,180.98	720.20	41.82	1,943.00	1,193.66	728.20	42.08	1,963.94
Wa/Id NWP	4,983.44	3,037.77	176.60	8,197.81	5,019.17	3,060.90	177.74	8,257.81	5,073.06	3,094.90	178.83	8,346.80
Wa/Id Sub-Total	**14,657.14**	**8,934.55**	**519.41**	**24,111.10**	**14,762.21**	**9,002.56**	**522.77**	**24,287.53**	**14,920.71**	**9,102.55**	**525.98**	**24,549.24**
Case Total	**19,355.68**	**11,981.98**	**649.39**	**31,987.06**	**19,501.61**	**12,068.80**	**654.92**	**32,225.32**	**19,717.87**	**12,198.18**	**660.68**	**32,576.72**

Area	2021: Residential	2021: Commercial	2021: Ind FirmSale	2021 Total	2022: Residential	2022: Commercial	2022: Ind FirmSale	2022 Total	2023: Residential	2023: Commercial	2023: Ind FirmSale	2023 Total
Klam Falls	770.84	455.46	5.01	1,231.30	774.88	457.42	5.01	1,237.30	778.84	459.34	5.01	1,243.19
La Grande	391.49	260.72	28.15	680.35	391.70	261.45	28.15	681.29	391.87	262.15	28.15	682.17
Medford GTN	2,053.39	1,269.32	33.12	3,355.83	2,072.11	1,278.10	33.67	3,383.88	2,091.08	1,287.04	34.23	3,412.35
Medford NWP	922.54	570.27	14.88	1,507.69	930.95	574.22	15.13	1,520.29	939.47	578.23	15.38	1,533.08
Roseburg	685.26	549.52	55.51	1,290.29	690.82	551.05	57.04	1,298.91	696.37	552.57	58.61	1,307.55
OR Sub-Total	**4,823.52**	**3,105.28**	**136.67**	**8,065.47**	**4,860.45**	**3,122.23**	**138.99**	**8,121.67**	**4,897.64**	**3,139.33**	**141.37**	**8,178.34**
Wa/Id Both	8,690.67	5,303.22	306.94	14,300.83	8,746.42	5,338.85	308.17	14,393.43	8,802.28	5,374.55	309.73	14,486.57
Wa/Id GTN	1,198.72	731.48	42.34	1,972.54	1,206.41	736.40	42.51	1,985.31	1,214.11	741.32	42.72	1,998.16
Wa/Id NWP	5,094.58	3,108.84	179.93	8,383.35	5,127.26	3,129.73	180.65	8,437.64	5,160.01	3,150.66	181.57	8,492.24
Wa/Id Sub-Total	**14,983.96**	**9,143.55**	**529.21**	**24,656.72**	**15,080.09**	**9,204.97**	**531.33**	**24,816.38**	**15,176.40**	**9,266.53**	**534.03**	**24,976.96**
Case Total	**19,807.48**	**12,248.83**	**665.87**	**32,722.19**	**19,940.54**	**12,327.20**	**670.32**	**32,938.06**	**20,074.04**	**12,405.86**	**675.40**	**33,155.30**

APPENDIX 3.10 II DETAILED DEMAND DATA
LOW GROWTH HIGH PRICE

Area	2024: Residential	2024: Commercial	2024: Ind FirmSale	2024 Total	2025: Residential	2025: Commercial	2025: Ind FirmSale	2025 Total	2026: Residential	2026: Commercial	2026: Ind FirmSale	2026 Total
Klam Falls	786.69	463.33	5.02	1,255.04	786.59	463.12	5.01	1,254.72	791.24	465.37	5.01	1,261.61
La Grande	393.95	264.17	28.15	686.27	392.13	263.47	28.15	683.74	392.60	264.35	28.15	685.10
Medford GTN	2,120.33	1,301.78	34.91	3,457.02	2,128.80	1,304.84	35.38	3,469.02	2,149.65	1,314.74	35.97	3,500.36
Medford NWP	952.61	584.86	15.69	1,553.15	956.42	586.23	15.90	1,558.54	965.78	590.68	16.16	1,572.63
Roseburg	705.57	556.60	60.41	1,322.59	707.54	555.65	61.87	1,325.06	713.83	557.63	63.59	1,335.05
OR Sub-Total	**4,959.15**	**3,170.74**	**144.18**	**8,274.06**	**4,971.47**	**3,173.30**	**146.30**	**8,291.07**	**5,013.10**	**3,192.77**	**148.87**	**8,354.75**
Wa/Id Both	8,902.50	5,436.10	311.75	14,650.35	8,912.55	5,444.59	314.06	14,671.21	8,975.96	5,484.18	315.71	14,775.85
Wa/Id GTN	1,227.94	749.81	43.00	2,020.75	1,229.32	750.98	43.32	2,023.63	1,238.07	756.44	43.55	2,038.06
Wa/Id NWP	5,218.76	3,186.75	182.75	8,588.26	5,224.66	3,191.73	184.11	8,600.50	5,261.84	3,214.94	185.07	8,661.85
Wa/Id Sub-Total	**15,349.20**	**9,372.66**	**537.50**	**25,259.35**	**15,366.53**	**9,387.30**	**541.49**	**25,295.33**	**15,475.87**	**9,455.56**	**544.33**	**25,475.77**
Case Total	**20,308.34**	**12,543.39**	**681.68**	**33,533.42**	**20,338.00**	**12,560.61**	**687.80**	**33,586.41**	**20,488.97**	**12,648.33**	**693.21**	**33,830.51**

Area	2027: Residential	2027: Commercial	2027: Ind FirmSale	2027 Total	2028: Residential	2028: Commercial	2028: Ind FirmSale	2028 Total	2029: Residential	2029: Commercial	2029: Ind FirmSale	2029 Total
Klam Falls	790.61	465.22	5.01	1,260.84	795.02	467.67	5.02	1,267.71	792.73	466.48	5.01	1,264.21
La Grande	390.74	263.66	28.15	682.55	391.43	264.77	28.15	684.35	388.97	263.65	28.15	680.77
Medford GTN	2,156.50	1,317.88	36.57	3,510.95	2,175.76	1,327.87	37.30	3,540.93	2,176.32	1,327.25	37.80	3,541.37
Medford NWP	968.86	592.09	16.43	1,577.38	977.52	596.58	16.76	1,590.85	977.77	596.30	16.98	1,591.05
Roseburg	716.09	557.11	65.24	1,338.43	721.49	559.09	67.18	1,347.76	719.93	556.54	68.76	1,345.23
OR Sub-Total	**5,022.81**	**3,195.96**	**151.40**	**8,370.16**	**5,061.23**	**3,215.98**	**154.40**	**8,431.61**	**5,055.71**	**3,210.22**	**156.70**	**8,422.63**
Wa/Id Both	8,980.67	5,491.01	316.37	14,788.05	9,043.48	5,531.51	317.75	14,892.73	9,029.91	5,526.75	318.72	14,875.38
Wa/Id GTN	1,238.72	757.39	43.64	2,039.75	1,247.38	762.97	43.83	2,054.18	1,245.51	762.32	43.96	2,051.79
Wa/Id NWP	5,264.61	3,218.95	185.46	8,669.01	5,301.43	3,242.69	186.27	8,730.39	5,293.48	3,239.90	186.84	8,720.22
Wa/Id Sub-Total	**15,484.00**	**9,467.35**	**545.46**	**25,496.81**	**15,592.29**	**9,537.17**	**547.84**	**25,677.31**	**15,568.90**	**9,528.97**	**549.52**	**25,647.39**
Case Total	**20,506.80**	**12,663.31**	**696.86**	**33,866.97**	**20,653.52**	**12,753.15**	**702.24**	**34,108.92**	**20,624.61**	**12,739.19**	**706.22**	**34,070.02**

Area	2030: Residential	2030: Commercial	2030: Ind FirmSale	2030 Total	2031: Residential	2031: Commercial	2031: Ind FirmSale	2031 Total
Klam Falls	793.43	466.96	5.01	1,265.40	794.11	467.44	5.01	1,266.55
La Grande	388.03	263.61	28.15	679.79	387.09	263.55	28.15	678.79
Medford GTN	2,184.94	1,331.38	38.43	3,554.75	2,193.23	1,335.38	38.61	3,567.21
Medford NWP	981.64	598.15	17.27	1,597.06	985.36	599.95	17.34	1,602.66
Roseburg	721.32	556.04	70.59	1,347.95	722.67	555.56	71.04	1,349.27
OR Sub-Total	**5,069.36**	**3,216.14**	**159.44**	**8,444.95**	**5,082.46**	**3,221.88**	**160.15**	**8,464.48**
Wa/Id Both	9,051.35	5,542.48	319.36	14,913.18	9,072.44	5,557.76	321.27	14,951.47
Wa/Id GTN	1,248.47	764.49	44.05	2,057.01	1,251.38	766.60	44.31	2,062.29
Wa/Id NWP	5,306.05	3,249.13	187.21	8,742.39	5,318.42	3,258.09	188.33	8,764.84
Wa/Id Sub-Total	**15,605.87**	**9,556.09**	**550.62**	**25,712.58**	**15,642.23**	**9,582.45**	**553.91**	**25,778.59**
Case Total	**20,675.23**	**12,772.23**	**710.06**	**34,157.53**	**20,724.69**	**12,804.33**	**714.06**	**34,243.07**

APPENDIX 3.10 II DETAILED DEMAND DATA
HIGH GROWTH LOW PRICE

Area	2012: Residential	2012: Commercial	2012: Ind FirmSale	2012 Total	2013: Residential	2013: Commercial	2013: Ind FirmSale	2013 Total	2014: Residential	2014: Commercial	2014: Ind FirmSale	2014 Total
Klam Falls	854.74	491.34	5.46	1,351.53	866.16	500.53	5.44	1,372.13	889.34	513.91	5.44	1,408.69
La Grande	440.98	283.42	2.74	727.13	444.55	289.03	2.74	736.31	449.88	296.54	2.74	749.16
Medford GTN	2,149.26	1,328.84	14.34	3,492.44	2,189.93	1,338.15	14.45	3,542.54	2,267.06	1,361.28	14.45	3,642.79
Medford NWP	965.61	597.02	6.44	1,569.07	983.88	601.20	6.49	1,591.57	1,018.53	611.59	6.49	1,636.62
Roseburg	715.91	585.11	33.12	1,334.14	727.85	593.11	33.02	1,353.98	752.82	605.50	33.02	1,391.35
OR Sub-Total	**5,126.49**	**3,285.72**	**62.09**	**8,474.31**	**5,212.37**	**3,322.01**	**62.15**	**8,596.53**	**5,377.63**	**3,388.82**	**62.15**	**8,828.60**
WA/ID Both	9,309.49	5,508.24	303.40	15,121.14	9,548.68	5,609.43	303.96	15,462.07	9,846.00	5,779.62	306.90	15,932.52
WA/ID GTN	1,284.07	759.76	41.85	2,085.67	1,317.06	773.71	41.93	2,132.70	1,358.07	797.19	42.33	2,197.59
WA/ID NWP	5,457.29	3,228.97	177.86	8,864.12	5,597.50	3,288.29	178.18	9,063.98	5,771.80	3,388.06	179.91	9,339.77
WA/ID Sub-Total	**16,050.85**	**9,496.98**	**523.11**	**26,070.94**	**16,463.24**	**9,671.44**	**524.07**	**26,658.75**	**16,975.87**	**9,964.87**	**529.15**	**27,469.89**
High Case Total	**21,177.34**	**12,782.70**	**585.20**	**34,545.24**	**21,675.62**	**12,993.44**	**586.22**	**35,255.28**	**22,353.50**	**13,353.69**	**591.29**	**36,298.49**

Area	2015: Residential	2015: Commercial	2015: Ind FirmSale	2015 Total	2016: Residential	2016: Commercial	2016: Ind FirmSale	2016 Total	2017: Residential	2017: Commercial	2017: Ind FirmSale	2017 Total
Klam Falls	914.90	527.94	5.44	1,448.28	944.51	542.42	5.46	1,492.39	967.90	553.94	5.49	1,527.34
La Grande	455.21	305.86	2.74	763.81	463.09	314.68	2.74	780.50	468.56	320.41	2.76	791.72
Medford GTN	2,353.41	1,396.45	15.24	3,765.10	2,448.94	1,441.44	15.66	3,906.04	2,532.86	1,481.96	16.04	4,030.85
Medford NWP	1,057.33	627.39	6.85	1,691.57	1,100.25	647.60	7.04	1,754.89	1,137.95	665.81	7.20	1,810.96
Roseburg	779.93	618.49	33.02	1,431.44	811.62	632.23	33.85	1,477.70	837.87	642.83	34.95	1,515.65
OR Sub-Total	**5,560.78**	**3,476.13**	**63.29**	**9,100.20**	**5,768.41**	**3,578.38**	**64.74**	**9,411.52**	**5,945.15**	**3,664.93**	**66.44**	**9,676.52**
WA/ID Both	10,145.89	5,958.30	310.93	16,415.11	10,485.18	6,162.36	315.22	16,962.76	10,765.03	6,334.95	318.77	17,418.74
WA/ID GTN	1,399.43	821.84	42.89	2,264.16	1,446.23	849.98	43.48	2,339.69	1,484.83	873.79	43.97	2,402.59
WA/ID NWP	5,947.60	3,492.81	182.27	9,622.68	6,146.50	3,612.44	184.79	9,943.73	6,310.56	3,713.62	186.86	10,211.04
WA/ID Sub-Total	**17,492.92**	**10,272.94**	**536.09**	**28,301.95**	**18,077.91**	**10,624.78**	**543.49**	**29,246.18**	**18,560.42**	**10,922.35**	**549.60**	**30,032.37**
High Case Total	**23,053.70**	**13,749.07**	**599.38**	**37,402.15**	**23,846.32**	**14,203.16**	**608.22**	**38,657.70**	**24,505.57**	**14,587.28**	**616.04**	**39,708.90**

Area	2018: Residential	2018: Commercial	2018: Ind FirmSale	2018 Total	2019: Residential	2019: Commercial	2019: Ind FirmSale	2019 Total	2020: Residential	2020: Commercial	2020: Ind FirmSale	2020 Total
Klam Falls	994.34	567.38	5.56	1,567.28	1,021.01	581.19	5.63	1,607.83	1,052.51	597.83	5.73	1,656.08
La Grande	475.70	327.22	2.79	805.72	482.95	334.05	2.83	819.83	492.45	342.52	2.87	837.84
Medford GTN	2,627.80	1,529.13	16.49	4,173.42	2,723.43	1,577.30	16.99	4,317.72	2,831.70	1,633.14	17.58	4,482.41
Medford NWP	1,180.60	687.00	7.41	1,875.02	1,223.57	708.64	7.63	1,939.84	1,272.21	733.73	7.90	2,013.84
Roseburg	866.31	655.66	36.22	1,558.19	894.90	668.95	37.58	1,601.44	928.44	685.66	39.16	1,653.26
OR Sub-Total	**6,144.76**	**3,766.39**	**68.47**	**9,979.63**	**6,345.87**	**3,870.12**	**70.66**	**10,286.66**	**6,577.31**	**3,992.88**	**73.25**	**10,643.44**
WA/ID Both	11,086.65	6,531.21	323.60	17,941.46	11,411.79	6,730.05	328.82	18,470.66	11,791.41	6,961.29	334.50	19,087.20
WA/ID GTN	1,529.20	900.86	44.63	2,474.69	1,574.04	928.29	45.36	2,547.68	1,626.40	960.18	46.14	2,632.72
WA/ID NWP	6,499.10	3,828.68	189.70	10,517.47	6,689.70	3,945.24	192.76	10,827.70	6,912.24	4,080.81	196.09	11,189.13
WA/ID Sub-Total	**19,114.95**	**11,260.74**	**557.93**	**30,933.63**	**19,675.53**	**11,603.58**	**566.94**	**31,846.05**	**20,330.06**	**12,002.28**	**576.72**	**32,909.06**
High Case Total	**25,259.71**	**15,027.14**	**626.40**	**40,913.25**	**26,021.40**	**15,473.70**	**637.60**	**42,132.71**	**26,907.36**	**15,995.16**	**649.97**	**43,552.49**

Area	2021: Residential	2021: Commercial	2021: Ind FirmSale	2021 Total	2022: Residential	2022: Commercial	2022: Ind FirmSale	2022 Total	2023: Residential	2023: Commercial	2023: Ind FirmSale	2023 Total
Klam Falls	1,076.35	610.66	5.82	1,692.82	1,105.21	626.54	5.93	1,737.68	1,135.28	643.47	6.07	1,784.82
La Grande	498.38	348.32	2.92	849.63	506.70	355.87	2.98	865.55	515.56	363.81	3.05	882.43
Medford GTN	2,919.45	1,678.34	18.14	4,615.93	3,021.34	1,732.25	18.81	4,772.40	3,128.96	1,790.21	19.57	4,938.74
Medford NWP	1,311.64	754.04	8.15	2,073.82	1,357.41	778.26	8.45	2,144.12	1,405.76	804.30	8.79	2,218.85
Roseburg	954.91	698.04	40.64	1,693.59	986.39	714.04	42.37	1,742.80	1,019.44	731.40	44.27	1,795.11
OR Sub-Total	**6,760.73**	**4,089.39**	**75.67**	**10,925.79**	**6,977.05**	**4,206.95**	**78.55**	**11,262.55**	**7,205.00**	**4,333.20**	**81.75**	**11,619.95**
WA/ID Both	12,085.96	7,142.67	340.40	19,569.03	12,439.48	7,359.29	346.59	20,145.36	12,811.71	7,587.77	353.91	20,753.38
WA/ID GTN	1,667.03	985.20	46.95	2,699.18	1,715.79	1,015.08	47.81	2,778.68	1,767.14	1,046.59	48.81	2,862.55
WA/ID NWP	7,084.91	4,187.14	199.55	11,471.60	7,292.16	4,314.12	203.18	11,809.46	7,510.36	4,448.06	207.46	12,165.89
WA/ID Sub-Total	**20,837.91**	**12,315.01**	**586.90**	**33,739.81**	**21,447.43**	**12,688.49**	**597.57**	**34,733.50**	**22,089.21**	**13,082.43**	**610.18**	**35,781.82**
High Case Total	**27,598.64**	**16,404.39**	**662.57**	**44,665.60**	**28,424.48**	**16,895.44**	**676.12**	**45,996.04**	**29,294.21**	**17,415.63**	**691.93**	**47,401.76**

APPENDIX 3.10 II DETAILED DEMAND DATA
HIGH GROWTH LOW PRICE

Area	2024: Residential	2024: Commercial	2024: Ind FirmSale	2024 Total	2025: Residential	2025: Commercial	2025: Ind FirmSale	2025 Total	2026: Residential	2026: Commercial	2026: Ind FirmSale	2026 Total
Klam Falls	1,171.60	664.24	6.25	1,842.09	1,200.64	681.72	6.42	1,888.79	1,236.67	703.66	6.65	1,946.99
La Grande	527.20	373.82	3.13	904.16	535.55	381.34	3.23	920.12	547.03	391.20	3.34	941.57
Medford GTN	3,254.92	1,859.37	20.48	5,134.77	3,362.79	1,919.99	21.40	5,304.18	3,491.33	1,993.71	22.52	5,507.56
Medford NWP	1,462.36	835.37	9.20	2,306.93	1,510.82	862.60	9.61	2,383.04	1,568.57	895.73	10.12	2,474.41
Roseburg	1,059.09	753.31	46.49	1,858.90	1,092.31	771.64	48.70	1,912.64	1,133.04	795.29	51.32	1,979.64
OR Sub-Total	**7,475.17**	**4,486.12**	**85.56**	**12,046.84**	**7,702.12**	**4,617.30**	**89.36**	**12,408.77**	**7,976.64**	**4,779.59**	**93.94**	**12,850.17**
WA/ID Both	13,255.79	7,859.74	362.52	21,478.05	13,618.27	8,086.49	373.01	22,077.77	14,061.21	8,362.70	383.76	22,807.67
WA/ID GTN	1,828.39	1,084.11	50.00	2,962.50	1,878.39	1,115.38	51.45	3,045.22	1,939.48	1,153.48	52.93	3,145.90
WA/ID NWP	7,770.70	4,607.50	212.51	12,590.71	7,983.19	4,740.43	218.66	12,942.28	8,242.85	4,902.35	224.97	13,370.16
WA/ID Sub-Total	**22,854.88**	**13,551.34**	**625.03**	**37,031.26**	**23,479.84**	**13,942.30**	**643.12**	**38,065.26**	**24,243.54**	**14,418.53**	**661.67**	**39,323.73**
High Case Total	**30,330.05**	**18,037.46**	**710.59**	**49,078.10**	**31,181.96**	**18,559.60**	**732.48**	**50,474.03**	**32,220.18**	**19,198.12**	**755.61**	**52,173.91**

Area	2027: Residential	2027: Commercial	2027: Ind FirmSale	2027 Total	2028: Residential	2028: Commercial	2028: Ind FirmSale	2028 Total	2029: Residential	2029: Commercial	2029: Ind FirmSale	2029 Total
Klam Falls	1,275.45	727.97	6.92	2,010.34	1,322.58	757.88	7.26	2,087.72	1,363.42	785.81	7.63	2,156.85
La Grande	559.94	402.17	3.48	965.59	577.01	416.36	3.64	997.01	591.82	428.85	3.84	1,024.50
Medford GTN	3,627.46	2,073.90	23.82	5,725.17	3,786.30	2,169.48	25.41	5,981.19	3,928.07	2,259.25	27.14	6,214.47
Medford NWP	1,629.73	931.75	10.70	2,572.18	1,701.09	974.70	11.42	2,687.20	1,764.79	1,015.03	12.20	2,792.01
Roseburg	1,177.64	822.07	54.29	2,054.00	1,226.50	853.60	57.86	2,137.96	1,267.90	882.41	61.63	2,211.94
OR Sub-Total	**8,270.22**	**4,957.86**	**99.21**	**13,327.28**	**8,613.47**	**5,172.02**	**105.59**	**13,891.08**	**8,915.99**	**5,371.34**	**112.44**	**14,399.76**
WA/ID Both	14,537.11	8,661.52	396.24	23,594.87	15,112.69	9,023.46	411.20	24,547.34	15,622.26	9,351.98	428.34	25,402.58
WA/ID GTN	2,005.13	1,194.70	54.65	3,254.48	2,084.52	1,244.62	56.72	3,385.85	2,154.80	1,289.94	59.08	3,503.82
WA/ID NWP	8,521.83	5,077.52	232.28	13,831.63	8,859.24	5,289.70	241.05	14,389.99	9,157.96	5,482.28	251.10	14,891.34
WA/ID Sub-Total	**25,064.07**	**14,933.75**	**683.17**	**40,680.98**	**26,056.45**	**15,557.78**	**708.96**	**42,323.19**	**26,935.02**	**16,124.20**	**738.52**	**43,797.75**
High Case Total	**33,334.29**	**19,891.60**	**782.37**	**54,008.27**	**34,669.92**	**20,729.80**	**814.55**	**56,214.27**	**35,851.01**	**21,495.54**	**850.95**	**58,197.51**

Area	2030: Residential	2030: Commercial	2030: Ind FirmSale	2030 Total	2031: Residential	2031: Commercial	2031: Ind FirmSale	2031 Total
Klam Falls	1,414.80	821.12	8.10	2,244.02	1,473.29	862.45	8.67	2,344.41
La Grande	611.46	445.01	4.07	1,060.54	634.36	463.63	4.36	1,102.35
Medford GTN	4,102.52	2,371.21	29.29	6,503.02	4,300.14	2,501.24	31.45	6,832.84
Medford NWP	1,843.16	1,065.33	13.16	2,921.65	1,931.95	1,123.75	14.13	3,069.83
Roseburg	1,320.56	919.82	66.25	2,306.64	1,381.23	964.23	70.15	2,415.62
OR Sub-Total	**9,292.50**	**5,622.49**	**120.88**	**15,035.87**	**9,720.98**	**5,915.30**	**128.76**	**15,765.04**
WA/ID Both	16,257.92	9,759.54	448.26	26,465.72	16,978.99	10,225.50	474.16	27,678.65
WA/ID GTN	2,242.48	1,346.15	61.83	3,650.46	2,341.94	1,410.42	65.40	3,817.76
WA/ID NWP	9,530.59	5,721.20	262.78	15,514.57	9,953.29	5,994.35	277.96	16,225.60
WA/ID Sub-Total	**28,030.99**	**16,826.89**	**772.86**	**45,630.75**	**29,274.22**	**17,630.27**	**817.53**	**47,722.01**
High Case Total	**37,323.49**	**22,449.38**	**893.74**	**60,666.62**	**38,995.20**	**23,545.57**	**946.29**	**63,487.05**

APPENDIX 3.10 II DETAILED DEMAND DATA AVERAGE MIX

Area	2012: Residential	2012: Commercial	2012: Ind FirmSale	2012 Total	2013: Residential	2013: Commercial	2013: Ind FirmSale	2013 Total	2014: Residential	2014: Commercial	2014: Ind FirmSale	2014 Total
Klam Falls	805.65	467.19	5.02	1,277.85	811.18	471.99	5.01	1,288.18	807.27	471.76	5.01	1,284.04
La Grande	421.11	270.35	28.15	719.60	422.57	273.25	28.15	723.97	417.30	272.22	28.15	717.67
Medford GTN	2,048.56	1,281.69	27.83	3,358.08	2,069.78	1,285.43	28.25	3,383.46	2,073.41	1,278.15	28.25	3,379.82
Medford NWP	920.37	575.83	12.50	1,508.70	929.90	577.51	12.69	1,520.11	931.53	574.24	12.69	1,518.47
Roseburg	683.94	564.17	49.06	1,297.18	690.00	568.15	48.92	1,307.07	691.51	566.72	48.61	1,306.84
OR Sub-Total	**4,879.63**	**3,159.22**	**122.56**	**8,161.41**	**4,923.43**	**3,176.33**	**123.02**	**8,222.78**	**4,921.04**	**3,163.09**	**122.72**	**8,206.84**
Wa/Id Both	8,928.85	5,364.38	301.80	14,595.03	9,058.53	5,417.66	302.34	14,778.53	9,043.22	5,413.42	301.73	14,758.37
Wa/Id GTN	1,231.57	739.91	41.63	2,013.11	1,249.45	747.26	41.70	2,038.42	1,247.34	746.68	41.62	2,035.64
Wa/Id NWP	5,234.15	3,144.64	176.92	8,555.71	5,310.18	3,175.88	177.23	8,663.29	5,301.20	3,173.40	176.88	8,651.48
Wa/Id Sub-Total	**15,394.57**	**9,248.93**	**520.35**	**25,163.85**	**15,618.16**	**9,340.81**	**521.27**	**25,480.24**	**15,591.76**	**9,333.50**	**520.23**	**25,445.49**
Avg. Case Total	**20,274.20**	**12,408.15**	**642.91**	**33,325.26**	**20,541.59**	**12,517.14**	**644.29**	**33,703.02**	**20,512.80**	**12,496.59**	**642.95**	**33,652.33**

Area	2015: Residential	2015: Commercial	2015: Ind FirmSale	2015 Total	2016: Residential	2016: Commercial	2016: Ind FirmSale	2016 Total	2017: Residential	2017: Commercial	2017: Ind FirmSale	2017 Total
Klam Falls	816.55	477.38	5.01	1,298.94	833.47	485.77	5.02	1,324.25	843.93	490.33	5.01	1,339.27
La Grande	417.78	275.94	28.15	721.86	422.36	281.08	28.15	731.58	423.91	283.31	28.15	735.37
Medford GTN	2,110.51	1,292.41	29.61	3,432.54	2,165.94	1,319.14	30.22	3,515.30	2,206.45	1,337.16	31.49	3,575.10
Medford NWP	948.20	580.65	13.30	1,542.15	973.10	592.66	13.58	1,579.34	991.30	600.75	14.15	1,606.20
Roseburg	703.22	571.62	48.52	1,323.36	721.87	579.93	48.64	1,350.44	734.27	583.49	48.49	1,366.25
OR Sub-Total	**4,996.26**	**3,198.00**	**124.59**	**8,318.86**	**5,116.74**	**3,258.56**	**125.61**	**8,500.90**	**5,199.87**	**3,295.04**	**127.27**	**8,622.18**
Wa/Id Both	9,157.89	5,485.91	304.59	14,948.39	9,354.65	5,606.53	308.51	15,269.69	9,483.73	5,686.81	310.08	15,480.62
Wa/Id GTN	1,263.16	756.68	42.01	2,061.85	1,290.30	773.32	42.55	2,106.17	1,308.10	784.39	42.77	2,135.26
Wa/Id NWP	5,368.43	3,215.89	178.55	8,762.88	5,483.78	3,286.61	180.85	8,951.24	5,559.45	3,333.68	181.77	9,074.90
Wa/Id Sub-Total	**15,789.48**	**9,458.48**	**525.15**	**25,773.11**	**16,128.73**	**9,666.45**	**531.91**	**26,327.09**	**16,351.28**	**9,804.88**	**534.62**	**26,690.78**
Avg. Case Total	**20,785.75**	**12,656.48**	**649.74**	**34,091.97**	**21,245.47**	**12,925.01**	**657.52**	**34,828.00**	**21,551.15**	**13,099.92**	**661.89**	**35,312.96**

Area	2018: Residential	2018: Commercial	2018: Ind FirmSale	2018 Total	2019: Residential	2019: Commercial	2019: Ind FirmSale	2019 Total	2020: Residential	2020: Commercial	2020: Ind FirmSale	2020 Total
Klam Falls	856.95	496.43	5.01	1,358.38	867.46	501.32	5.01	1,373.79	882.29	508.52	5.02	1,395.83
La Grande	426.91	286.42	28.15	741.47	428.73	288.73	28.15	745.61	432.66	292.55	28.15	753.35
Medford GTN	2,255.22	1,359.92	32.00	3,647.14	2,297.58	1,379.59	32.00	3,709.17	2,350.69	1,405.41	32.15	3,788.25
Medford NWP	1,013.22	610.98	14.38	1,638.57	1,032.24	619.82	14.38	1,666.44	1,056.11	631.42	14.44	1,701.97
Roseburg	748.63	588.74	48.48	1,385.85	760.92	592.84	48.43	1,402.20	777.29	599.76	48.55	1,425.59
OR Sub-Total	**5,300.93**	**3,342.48**	**128.01**	**8,771.42**	**5,386.94**	**3,382.29**	**127.97**	**8,897.20**	**5,499.02**	**3,437.66**	**128.30**	**9,064.99**
Wa/Id Both	9,646.07	5,786.03	312.58	15,744.69	9,781.14	5,869.87	314.64	15,965.65	9,964.43	5,981.80	316.85	16,263.08
Wa/Id GTN	1,330.50	798.08	43.11	2,171.69	1,349.12	809.64	43.40	2,202.16	1,374.41	825.08	43.70	2,243.19
Wa/Id NWP	5,654.62	3,391.85	183.24	9,229.71	5,733.80	3,441.00	184.45	9,359.25	5,841.25	3,506.62	185.74	9,533.62
Wa/Id Sub-Total	**16,631.19**	**9,975.96**	**538.93**	**27,146.08**	**16,864.06**	**10,120.51**	**542.49**	**27,527.06**	**17,180.08**	**10,313.50**	**546.30**	**28,039.89**
Avg. Case Total	**21,932.12**	**13,318.44**	**666.94**	**35,917.50**	**22,251.00**	**13,502.80**	**670.46**	**36,424.26**	**22,679.11**	**13,751.16**	**674.61**	**37,104.88**

Area	2021: Residential	2021: Commercial	2021: Ind FirmSale	2021 Total	2022: Residential	2022: Commercial	2022: Ind FirmSale	2022 Total	2023: Residential	2023: Commercial	2023: Ind FirmSale	2023 Total
Klam Falls	890.86	512.25	5.01	1,408.12	900.41	516.71	5.01	1,422.13	909.64	521.04	5.01	1,435.69
La Grande	433.47	294.10	28.15	755.72	434.91	296.13	28.15	759.18	436.21	297.95	28.15	762.30
Medford GTN	2,386.67	1,421.25	33.36	3,841.28	2,425.54	1,439.41	33.88	3,898.83	2,464.49	1,457.60	33.92	3,956.00
Medford NWP	1,072.27	638.53	14.99	1,725.79	1,089.74	646.69	15.22	1,751.65	1,107.23	654.86	15.24	1,777.34
Roseburg	787.50	602.39	59.76	1,449.65	799.09	606.20	64.45	1,469.73	810.49	609.83	64.38	1,484.70
OR Sub-Total	**5,570.78**	**3,468.52**	**141.26**	**9,180.56**	**5,649.69**	**3,505.14**	**146.70**	**9,301.52**	**5,728.05**	**3,541.28**	**146.69**	**9,416.03**
Wa/Id Both	10,076.87	6,050.44	318.95	16,446.27	10,202.08	6,127.43	320.25	16,649.75	10,325.78	6,203.40	321.84	16,851.02
Wa/Id GTN	1,389.92	834.55	43.99	2,268.46	1,407.19	845.17	44.17	2,296.53	1,424.25	855.65	44.39	2,324.29
Wa/Id NWP	5,907.17	3,546.86	186.97	9,641.01	5,980.57	3,592.00	187.73	9,760.30	6,053.09	3,636.54	188.66	9,878.29
Wa/Id Sub-Total	**17,373.97**	**10,431.85**	**549.92**	**28,355.73**	**17,589.84**	**10,564.59**	**552.15**	**28,706.58**	**17,803.12**	**10,695.58**	**554.89**	**29,053.60**
Avg. Case Total	**22,944.74**	**13,900.37**	**691.18**	**37,536.29**	**23,239.52**	**14,069.73**	**698.85**	**38,008.11**	**23,531.18**	**14,236.87**	**701.58**	**38,469.63**

APPENDIX 3.10 II DETAILED DEMAND DATA AVERAGE MIX

Area	2024: Residential	2024: Commercial	2024: Ind FirmSale	2024 Total	2025: Residential	2025: Commercial	2025: Ind FirmSale	2025 Total	2026: Residential	2026: Commercial	2026: Ind FirmSale	2026 Total
Klam Falls	923.71	527.89	5.02	1,456.62	929.68	530.47	5.01	1,465.16	940.31	535.49	5.01	1,480.81
La Grande	439.77	301.53	28.15	769.45	439.47	302.16	28.15	769.77	441.36	304.41	28.15	773.92
Medford GTN	2,516.41	1,482.86	35.35	4,034.62	2,546.80	1,496.18	35.75	4,078.73	2,589.67	1,516.32	35.80	4,141.78
Medford NWP	1,130.56	666.21	15.88	1,812.65	1,144.21	672.19	16.06	1,832.47	1,163.48	681.24	16.08	1,860.80
Roseburg	826.51	616.51	64.52	1,507.53	834.94	618.18	64.26	1,517.39	847.89	622.73	64.22	1,534.84
OR Sub-Total	**5,836.96**	**3,595.00**	**148.91**	**9,580.87**	**5,895.10**	**3,619.18**	**149.23**	**9,663.52**	**5,982.71**	**3,660.19**	**149.26**	**9,792.16**
Wa/Id Both	10,504.97	6,311.23	323.97	17,140.18	10,591.22	6,364.58	326.60	17,282.39	10,730.68	6,448.70	328.43	17,507.80
Wa/Id GTN	1,448.97	870.52	44.69	2,364.17	1,460.86	877.88	45.05	2,383.79	1,480.10	889.48	45.30	2,414.88
Wa/Id NWP	6,158.14	3,699.75	189.91	10,047.81	6,208.71	3,731.03	191.45	10,131.19	6,290.46	3,780.34	192.53	10,263.33
Wa/Id Sub-Total	**18,112.09**	**10,881.51**	**558.57**	**29,552.17**	**18,260.79**	**10,973.49**	**563.10**	**29,797.37**	**18,501.24**	**11,118.52**	**566.26**	**30,186.01**
Avg. Case Total	**23,949.04**	**14,476.51**	**707.48**	**39,133.04**	**24,155.89**	**14,592.67**	**712.33**	**39,460.90**	**24,483.95**	**14,778.71**	**715.51**	**39,978.17**

Area	2027: Residential	2027: Commercial	2027: Ind FirmSale	2027 Total	2028: Residential	2028: Commercial	2028: Ind FirmSale	2028 Total	2029: Residential	2029: Commercial	2029: Ind FirmSale	2029 Total
Klam Falls	949.16	539.65	5.01	1,493.82	962.67	546.27	5.02	1,513.95	967.90	548.52	5.01	1,521.43
La Grande	442.58	306.27	28.15	776.99	446.17	309.79	28.15	784.11	446.11	310.74	28.15	784.99
Medford GTN	2,626.91	1,533.81	37.11	4,197.84	2,675.27	1,557.42	37.79	4,270.49	2,699.94	1,568.18	37.67	4,305.79
Medford NWP	1,180.21	689.10	16.67	1,885.99	1,201.93	699.71	16.98	1,918.63	1,213.02	704.54	16.93	1,934.49
Roseburg	859.71	626.58	64.15	1,550.44	873.47	632.33	64.28	1,570.08	878.19	632.62	64.03	1,574.84
OR Sub-Total	**6,058.58**	**3,695.41**	**151.08**	**9,905.07**	**6,159.51**	**3,745.53**	**152.22**	**10,057.26**	**6,205.16**	**3,764.59**	**151.79**	**10,121.54**
Wa/Id Both	10,850.16	6,521.66	329.97	17,701.78	11,023.98	6,626.52	332.05	17,982.55	11,104.69	6,676.35	333.68	18,114.71
Wa/Id GTN	1,496.58	899.55	45.51	2,441.64	1,520.56	914.01	45.80	2,480.37	1,531.69	920.88	46.02	2,498.60
Wa/Id NWP	6,360.51	3,823.12	193.43	10,377.06	6,462.41	3,884.59	194.65	10,541.65	6,509.72	3,913.80	195.61	10,619.13
Wa/Id Sub-Total	**18,707.25**	**11,244.32**	**568.91**	**30,520.48**	**19,006.95**	**11,425.12**	**572.51**	**31,004.57**	**19,146.10**	**11,511.04**	**575.31**	**31,232.44**
Avg. Case Total	**24,765.82**	**14,939.73**	**720.00**	**40,425.55**	**25,166.46**	**15,170.65**	**724.72**	**41,061.83**	**25,351.26**	**15,275.63**	**727.09**	**41,353.98**

Area	2030: Residential	2030: Commercial	2030: Ind FirmSale	2030 Total	2031: Residential	2031: Commercial	2031: Ind FirmSale	2031 Total
Klam Falls	976.92	552.77	5.01	1,534.70	985.88	557.06	5.01	1,547.94
La Grande	447.87	313.04	28.15	789.06	449.61	315.20	28.15	792.95
Medford GTN	2,734.96	1,584.77	38.99	4,358.71	2,769.46	1,601.05	39.50	4,410.01
Medford NWP	1,228.75	712.00	17.52	1,958.26	1,244.25	719.31	17.75	1,981.31
Roseburg	886.70	635.36	75.26	1,597.32	895.18	638.13	79.90	1,613.21
OR Sub-Total	**6,275.21**	**3,797.93**	**164.91**	**10,238.05**	**6,344.37**	**3,830.75**	**170.30**	**10,345.42**
Wa/Id Both	11,229.90	6,751.56	335.01	18,316.48	11,354.47	6,826.19	337.65	18,518.31
Wa/Id GTN	1,548.96	931.26	46.21	2,526.43	1,566.14	941.55	46.57	2,554.27
Wa/Id NWP	6,583.13	3,957.90	196.39	10,737.42	6,656.16	4,001.65	197.93	10,855.74
Wa/Id Sub-Total	**19,361.99**	**11,640.72**	**577.61**	**31,580.33**	**19,576.77**	**11,769.39**	**582.16**	**31,928.32**
Avg. Case Total	**25,637.20**	**15,438.65**	**742.52**	**41,818.38**	**25,921.15**	**15,600.14**	**752.46**	**42,273.74**

APPENDIX 3.10 II DETAILED DEMAND DATA COLDEST IN 20 YEARS

Area	2012: Residential	2012: Commercial	2012: Ind FirmSale	2012 Total	2013: Residential	2013: Commercial	2013: Ind FirmSale	2013 Total	2014: Residential	2014: Commercial	2014: Ind FirmSale	2014 Total
Klam Falls	827.99	477.61	5.02	1,310.62	833.75	482.56	5.01	1,321.32	821.08	478.23	5.01	1,304.32
La Grande	436.90	280.81	28.15	745.86	438.49	283.86	28.15	750.50	428.75	280.00	28.15	736.89
Medford GTN	2,105.83	1,310.93	27.83	3,444.58	2,127.79	1,314.84	28.25	3,470.88	2,110.43	1,296.73	28.25	3,435.42
Medford NWP	946.10	588.97	12.50	1,547.57	955.97	590.72	12.69	1,559.38	948.16	582.59	12.69	1,543.45
Roseburg	704.92	578.05	49.41	1,332.38	711.22	582.18	49.26	1,342.66	706.00	576.19	48.80	1,330.99
OR Sub-Total	**5,021.74**	**3,236.36**	**122.90**	**8,381.01**	**5,067.22**	**3,254.16**	**123.37**	**8,444.74**	**5,014.41**	**3,213.74**	**122.90**	**8,351.06**
WA/ID Both	9,181.27	5,506.37	305.87	14,993.51	9,315.65	5,561.50	306.42	15,183.57	9,204.35	5,503.95	304.05	15,012.34
WA/ID GTN	1,266.38	759.50	42.19	2,068.07	1,284.92	767.10	42.26	2,094.29	1,269.57	759.17	41.94	2,070.67
WA/ID NWP	5,382.13	3,227.88	179.30	8,789.31	5,460.90	3,260.20	179.62	8,900.73	5,395.66	3,226.47	178.23	8,800.36
WA/ID Sub-Total	**15,829.78**	**9,493.75**	**527.36**	**25,850.89**	**16,061.48**	**9,588.81**	**528.31**	**26,178.59**	**15,869.57**	**9,489.58**	**524.22**	**25,883.37**
Alt. Plan Case Total	**20,851.52**	**12,730.11**	**650.26**	**34,231.90**	**21,128.70**	**12,842.96**	**651.67**	**34,623.33**	**20,883.98**	**12,703.33**	**647.12**	**34,234.43**

Area	2015: Residential	2015: Commercial	2015: Ind FirmSale	2015 Total	2016: Residential	2016: Commercial	2016: Ind FirmSale	2016 Total	2017: Residential	2017: Commercial	2017: Ind FirmSale	2017 Total
Klam Falls	830.08	483.73	5.01	1,318.81	845.54	491.42	5.02	1,341.98	852.73	494.46	5.01	1,352.20
La Grande	429.01	283.67	28.15	740.83	432.86	288.38	28.15	749.39	432.86	289.61	28.15	750.61
Medford GTN	2,147.14	1,310.60	29.61	3,487.35	2,199.25	1,335.59	30.22	3,565.06	2,231.99	1,349.71	31.49	3,613.19
Medford NWP	964.66	588.82	13.30	1,566.78	988.07	600.05	13.58	1,601.69	1,002.78	606.39	14.15	1,623.32
Roseburg	717.60	580.94	48.70	1,347.24	735.25	588.49	48.79	1,372.53	745.23	590.41	48.58	1,384.21
OR Sub-Total	**5,088.49**	**3,247.76**	**124.77**	**8,461.01**	**5,200.96**	**3,303.93**	**125.76**	**8,630.65**	**5,265.59**	**3,330.58**	**127.37**	**8,723.53**
WA/ID Both	9,316.43	5,574.96	306.82	15,198.21	9,497.34	5,686.87	310.44	15,494.65	9,590.64	5,747.31	311.35	15,649.29
WA/ID GTN	1,285.03	768.96	42.32	2,096.31	1,309.98	784.40	42.82	2,137.20	1,322.85	792.73	42.94	2,158.53
WA/ID NWP	5,461.36	3,268.10	179.86	8,909.33	5,567.42	3,333.71	181.98	9,083.11	5,622.12	3,369.14	182.52	9,173.77
WA/ID Sub-Total	**16,062.81**	**9,612.02**	**529.01**	**26,203.84**	**16,374.74**	**9,804.98**	**535.24**	**26,714.96**	**16,535.60**	**9,909.18**	**536.81**	**26,981.59**
Alt. Plan Case Total	**21,151.30**	**12,859.78**	**653.77**	**34,664.86**	**21,575.70**	**13,108.91**	**661.00**	**35,345.61**	**21,801.19**	**13,239.76**	**664.18**	**35,705.13**

Area	2018: Residential	2018: Commercial	2018: Ind FirmSale	2018 Total	2019: Residential	2019: Commercial	2019: Ind FirmSale	2019 Total	2020: Residential	2020: Commercial	2020: Ind FirmSale	2020 Total
Klam Falls	862.64	499.11	5.01	1,366.76	871.92	503.42	5.01	1,380.34	885.96	510.27	5.02	1,401.25
La Grande	434.39	291.76	28.15	754.30	435.63	293.70	28.15	757.48	439.20	297.30	28.15	764.64
Medford GTN	2,273.29	1,368.77	32.00	3,674.06	2,312.71	1,386.97	32.00	3,731.69	2,364.03	1,411.90	32.15	3,808.07
Medford NWP	1,021.33	614.95	14.38	1,650.67	1,039.05	623.13	14.38	1,676.56	1,062.10	634.33	14.44	1,710.87
Roseburg	757.25	594.11	48.52	1,399.88	768.63	597.59	48.46	1,414.67	784.45	604.12	48.55	1,437.12
OR Sub-Total	**5,348.90**	**3,368.70**	**128.06**	**8,845.67**	**5,427.94**	**3,404.82**	**127.99**	**8,960.75**	**5,535.74**	**3,457.91**	**128.31**	**9,121.96**
WA/ID Both	9,719.02	5,827.62	313.23	15,859.87	9,840.50	5,903.97	315.05	16,059.51	10,015.43	6,011.22	317.11	16,343.76
WA/ID GTN	1,340.56	803.81	43.20	2,187.57	1,357.31	814.34	43.45	2,215.11	1,381.44	829.14	43.74	2,254.32
WA/ID NWP	5,697.38	3,416.23	183.62	9,297.23	5,768.60	3,460.99	184.68	9,414.27	5,871.15	3,523.87	185.89	9,580.91
WA/ID Sub-Total	**16,756.96**	**10,047.66**	**540.05**	**27,344.67**	**16,966.41**	**10,179.30**	**543.18**	**27,688.90**	**17,268.03**	**10,364.22**	**546.73**	**28,178.99**
Alt. Plan Case Total	**22,105.86**	**13,416.37**	**668.11**	**36,190.34**	**22,394.35**	**13,584.12**	**671.17**	**36,649.64**	**22,803.77**	**13,822.13**	**675.05**	**37,300.94**

Area	2021: Residential	2021: Commercial	2021: Ind FirmSale	2021 Total	2022: Residential	2022: Commercial	2022: Ind FirmSale	2022 Total	2023: Residential	2023: Commercial	2023: Ind FirmSale	2023 Total
Klam Falls	895.60	514.47	5.01	1,415.08	907.43	519.97	5.01	1,432.40	920.40	525.99	5.01	1,451.40
La Grande	440.51	299.20	28.15	767.86	442.98	301.96	28.15	773.08	445.94	304.94	28.15	779.03
Medford GTN	2,402.81	1,429.06	33.36	3,865.23	2,447.60	1,450.01	33.88	3,931.49	2,496.23	1,472.77	33.92	4,002.93
Medford NWP	1,079.52	642.04	14.99	1,736.55	1,099.65	651.45	15.22	1,766.32	1,121.49	661.68	15.24	1,798.42
Roseburg	795.62	607.28	59.76	1,462.66	809.10	612.20	64.52	1,485.82	823.57	617.63	64.52	1,505.73
OR Sub-Total	**5,614.07**	**3,492.05**	**141.27**	**9,247.39**	**5,706.75**	**3,535.58**	**146.78**	**9,389.11**	**5,807.64**	**3,583.01**	**146.84**	**9,537.49**
WA/ID Both	10,139.86	6,086.54	319.39	16,545.79	10,290.31	6,177.78	321.11	16,789.19	10,456.19	6,277.08	323.38	17,056.65
WA/ID GTN	1,398.60	839.53	44.05	2,282.19	1,419.36	852.11	44.29	2,315.76	1,442.24	865.81	44.60	2,352.65
WA/ID NWP	5,944.10	3,568.02	187.23	9,699.35	6,032.30	3,621.51	188.24	9,842.05	6,129.54	3,679.73	189.57	9,998.84
WA/ID Sub-Total	**17,482.56**	**10,494.09**	**550.68**	**28,527.32**	**17,741.96**	**10,651.40**	**553.64**	**28,947.00**	**18,027.97**	**10,822.62**	**557.56**	**29,408.15**
Alt. Plan Case Total	**23,096.63**	**13,986.14**	**691.94**	**37,774.71**	**23,448.71**	**14,186.98**	**700.41**	**38,336.11**	**23,835.61**	**14,405.63**	**704.40**	**38,945.64**

APPENDIX 3.10 II DETAILED DEMAND DATA COLDEST IN 20 YEARS

Area	2024: Residential	2024: Commercial	2024: Ind FirmSale	2024 Total	2025: Residential	2025: Commercial	2025: Ind FirmSale	2025 Total	2026: Residential	2026: Commercial	2026: Ind FirmSale	2026 Total
Klam Falls	935.29	533.19	5.02	1,473.50	944.61	537.27	5.01	1,486.90	957.14	543.14	5.01	1,505.28
La Grande	449.85	308.78	28.15	786.77	451.01	310.44	28.15	789.59	453.70	313.27	28.15	795.12
Medford GTN	2,550.45	1,499.07	35.35	4,084.87	2,589.70	1,516.51	35.75	4,141.97	2,637.76	1,539.02	35.80	4,212.58
Medford NWP	1,145.85	673.49	15.88	1,835.23	1,163.49	681.33	16.06	1,860.88	1,185.08	691.44	16.08	1,892.61
Roseburg	840.33	624.68	64.68	1,529.70	851.56	627.95	64.49	1,544.00	866.14	633.37	64.48	1,563.99
OR Sub-Total	**5,921.77**	**3,639.22**	**149.07**	**9,710.06**	**6,000.37**	**3,673.51**	**149.46**	**9,823.34**	**6,099.83**	**3,720.24**	**149.51**	**9,969.58**
WA/ID Both	10,644.70	6,390.16	325.65	17,360.51	10,768.97	6,464.59	328.88	17,562.44	10,929.98	6,560.73	331.05	17,821.76
WA/ID GTN	1,468.24	881.41	44.92	2,394.56	1,485.38	891.67	45.36	2,422.42	1,507.59	904.94	45.66	2,458.19
WA/ID NWP	6,240.05	3,746.02	190.90	10,176.97	6,312.91	3,789.66	192.80	10,295.36	6,407.30	3,846.02	194.06	10,447.38
WA/ID Sub-Total	**18,352.99**	**11,017.58**	**561.47**	**29,932.04**	**18,567.25**	**11,145.93**	**567.04**	**30,280.22**	**18,844.87**	**11,311.69**	**570.77**	**30,727.33**
Alt. Plan Case Total	**24,274.76**	**14,656.80**	**710.54**	**39,642.11**	**24,567.62**	**14,819.44**	**716.50**	**40,103.56**	**24,944.69**	**15,031.93**	**720.29**	**40,696.91**

Area	2027: Residential	2027: Commercial	2027: Ind FirmSale	2027 Total	2028: Residential	2028: Commercial	2028: Ind FirmSale	2028 Total	2029: Residential	2029: Commercial	2029: Ind FirmSale	2029 Total
Klam Falls	967.65	548.02	5.01	1,520.68	984.35	556.05	5.02	1,545.42	992.70	559.67	5.01	1,557.37
La Grande	455.60	315.63	28.15	799.37	460.54	320.12	28.15	808.81	461.78	322.02	28.15	811.94
Medford GTN	2,679.59	1,558.59	37.11	4,275.29	2,736.56	1,586.15	37.79	4,360.50	2,769.65	1,600.74	37.67	4,408.07
Medford NWP	1,203.87	700.24	16.67	1,920.78	1,229.47	712.62	16.98	1,959.07	1,244.34	719.17	16.93	1,980.44
Roseburg	879.43	637.98	64.43	1,581.84	895.87	645.21	64.62	1,605.70	903.17	646.89	64.43	1,614.49
OR Sub-Total	**6,186.15**	**3,760.46**	**151.37**	**10,097.98**	**6,306.79**	**3,820.14**	**152.56**	**10,279.49**	**6,371.64**	**3,848.49**	**152.18**	**10,372.30**
WA/ID Both	11,068.80	6,644.27	332.87	18,045.94	11,278.93	6,769.32	335.50	18,383.76	11,394.96	6,838.90	337.67	18,571.53
WA/ID GTN	1,526.74	916.46	45.91	2,489.11	1,555.72	933.71	46.28	2,535.70	1,571.73	943.30	46.57	2,561.61
WA/ID NWP	6,488.68	3,895.00	195.13	10,578.81	6,611.87	3,968.31	196.68	10,776.85	6,679.89	4,009.10	197.94	10,886.93
WA/ID Sub-Total	**19,084.22**	**11,455.73**	**573.91**	**31,113.86**	**19,446.52**	**11,671.33**	**578.45**	**31,696.31**	**19,646.58**	**11,791.31**	**582.18**	**32,020.07**
Alt. Plan Case Total	**25,270.37**	**15,216.19**	**725.28**	**41,211.84**	**25,753.32**	**15,491.48**	**731.01**	**41,975.80**	**26,018.22**	**15,639.80**	**734.36**	**42,392.38**

Area	2030: Residential	2030: Commercial	2030: Ind FirmSale	2030 Total	2031: Residential	2031: Commercial	2031: Ind FirmSale	2031 Total
Klam Falls	1,004.86	565.31	5.01	1,575.18	1,017.02	570.99	5.01	1,593.02
La Grande	464.85	325.27	28.15	818.26	467.90	328.39	28.15	824.44
Medford GTN	2,813.22	1,621.21	38.99	4,473.41	2,856.45	1,641.44	39.50	4,537.39
Medford NWP	1,263.91	728.37	17.52	2,009.79	1,283.33	737.46	17.75	2,038.54
Roseburg	914.27	651.04	75.75	1,641.06	925.41	655.23	80.52	1,661.15
OR Sub-Total	**6,461.11**	**3,891.19**	**165.40**	**10,517.70**	**6,550.11**	**3,933.50**	**170.92**	**10,654.53**
WA/ID Both	11,556.41	6,934.16	339.54	18,830.12	11,717.81	7,029.24	342.72	19,089.77
WA/ID GTN	1,594.00	956.44	46.83	2,597.27	1,616.26	969.56	47.27	2,633.09
WA/ID NWP	6,774.54	4,064.94	199.04	11,038.52	6,869.16	4,120.68	200.91	11,190.74
WA/ID Sub-Total	**19,924.94**	**11,955.55**	**585.42**	**32,465.91**	**20,203.22**	**12,119.47**	**590.90**	**32,913.60**
Alt. Plan Case Total	**26,386.05**	**15,846.74**	**750.82**	**42,983.62**	**26,753.33**	**16,052.98**	**761.83**	**43,568.14**

APPENDIX 4.1 II AVISTA GAS CPA REPORT 4/30/2012

AVISTA UTILITIES
GAS CONSERVATION
POTENTIAL ASSESSMENT

April 17, 2012
Revised April 30, 2012

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EXECUTIVE SUMMARY

Background

Avista Utilities (Avista) has contracted with Global Energy Partners (Global) to conduct a conservation potential assessment (CPA) to quantify the amount, the timing, and the cost of natural gas energy conservation resources available within the Avista service territory. The purpose of this study is to establish cost-effective and achievable energy conservation resources for the 2013–2032 period to support development of Avista's 2013 gas Integrated Resource Plan (IRP).

Key objectives for the study include:

- Determine the conservation potential for natural gas for Washington, Idaho, and Oregon, for the period 2013–2032, based on Avista's service territory characteristics.
- Develop energy conservation measure (ECM) data sets for each market sector and each appropriate market segment.
- Categorize the potential by market sector, segment, building type, and ECM.
- Using parameters provided by Avista, calculate the Total Resource Cost (TRC), and measure levelized cost of the ECMs.
- Provide supply curves of achievable potential.

Definitions of Potential

In this study, the conservation potential estimates represent gross savings[1] developed into three types of potential: technical potential, economic potential, and achievable potential. Technical and economic potential are both theoretical limits to efficiency savings. Achievable potential embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase, the maintenance activities they undertake, the controls they use for energy-consuming equipment, and the elements of building construction. These levels are described below.

Technical potential is defined as the theoretical upper limit of conservation potential. It assumes that customers adopt all feasible measures regardless of cost. At the time of equipment failure, customers replace equipment with the most efficient option available. In new construction, customers and developers also choose the most efficient equipment option. Examples of measures that make up technical potential in the residential sector include:

- High efficiency furnaces and boilers
- High efficiency water heaters
- High efficiency clothes dryers

Technical potential also assumes the adoption of every available non-equipment measure, where applicable. For example, it includes installation of high-efficiency windows in all new construction opportunities and furnace maintenance in all existing buildings with furnace systems. The retrofit measures are phased in over a number of years, which is longer for higher-cost measures.

Economic potential represents the adoption of all ***cost-effective*** conservation measures. In this analysis, the total resources cost (TRC) test, which compares lifetime energy and capacity benefits to the incremental cost of the measure, is applied. Economic potential assumes that

[1] Savings in "gross" terms instead of "net" terms means that the baseline forecast does not include naturally occurring efficiency. In other words, the baseline assumes that energy efficiency levels remain fixed as they are today. This rule holds true except in cases where future codes and standards were on the books before November 2011, e.g. the effects of the upcoming furnace and water heater standards.

customers purchase the most cost-effective option at the time of equipment failure and also adopt every other cost-effective and applicable measure.

Achievable potential takes into account market maturity, customer preferences for energy-efficient technologies, and expected program participation. Achievable potential establishes a realistic target for the conservation savings that a utility can hope to achieve through its programs. It is determined by applying a series of annual factors to the economic potential for each ECM. These factors represent the ramp rates at which technologies will penetrate the market and were based upon the Northwest Power and Conservation Council Sixth Plan (NWPCC) ramp rates. Although Avista is not required to use the Sixth Plan ramp rates for its gas CPA, the project team chose to use those ramp rates for consistency with the Avista 2011 electricity CPA. Also, these ramp rates have been widely vetted and are accepted by regional stakeholders. Details regarding the ramp rate development appear in Appendix E.

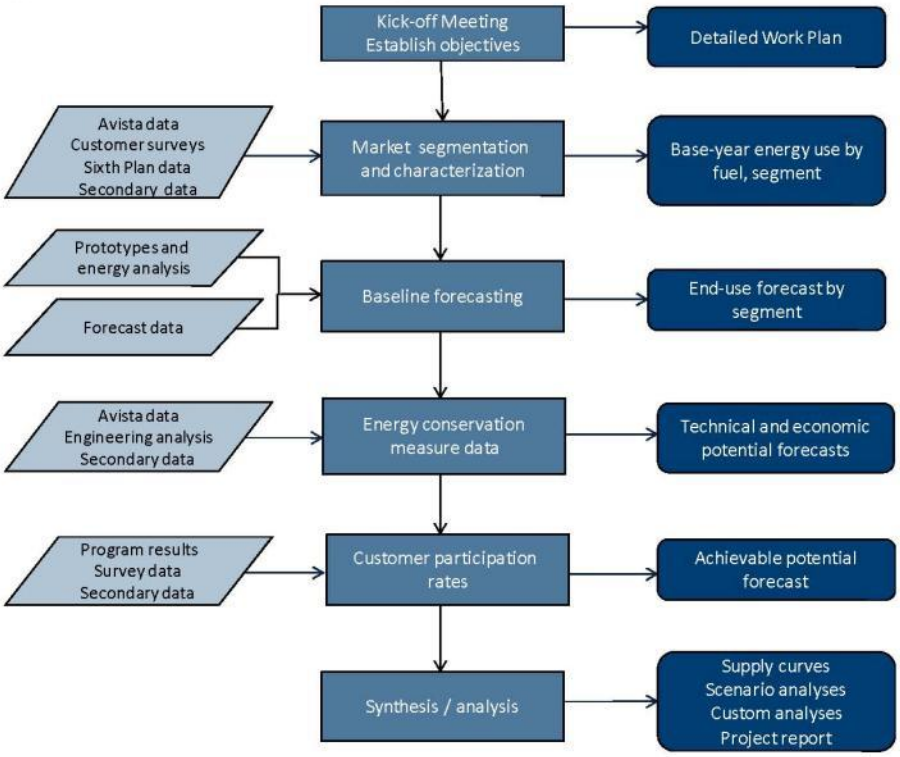
Analysis Approach

To perform the conservation analysis, Global used a bottom-up analysis approach as shown in Figure ES-1 and outlined below.

1. Met by phone with Avista staff to refine the objectives that were identified in the Avista RFP. This resulted in a work plan for the study.
2. Performed a market characterization to describe sector-level natural gas use for the residential, commercial, and industrial sectors for the base year, 2010. This included using utility data and secondary data from sources such as the American Community Survey (ACS), and the Energy Information Administration (EIA).
3. Utilized secondary sources including Northwest Energy Efficiency Alliance (NEAA) data and market reports to understand how customers in the Avista service territory currently use gas. Combining this information with the market characterization, we developed energy market profiles that describe energy use by sector, segment, and end use for 2010.
4. Developed a baseline gas forecast by sector, segment, and end use for 2013 through 2032.
5. Identified and analyzed energy conservations measures appropriate for the Avista service territory.
6. Estimated three levels of conservation potential, *Technical, Economic,* and *Achievable*.

The results from these steps are summarized below, with details provided in the body of the report.

Figure ES-1 Overview of Analysis Approach



Market Characterization

Avista Utilities, headquartered in Spokane, Washington is an investor-owned utility with annual revenues of more than $1.3 billion. Avista provides electric and natural gas service to about 481,000 customers in a service territory of more than 30,000 square miles. Avista uses a mix of hydro, natural gas, coal and biomass generation delivered over 2,100 miles of transmission line, 17,000 miles of distribution line, and 6,100 miles of natural gas distribution mains. Avista currently operates a portfolio of electric and natural gas conservation programs in Washington, Idaho, and Oregon for residential, low-income, and non-residential customers that is funded by a non-bypassable systems benefits charge.

Total natural gas use in 2010 for the residential, commercial, and industrial rate classes included in this potential assessment was 315,905,627 therms.[2] Table ES-1 shows detail by state and sector, including the rate classes included in each sector, number of meters, sales, and average use per meter. The largest sector is residential, accounting for 59.8% of system sales, followed by large commercial with 22.5% and small commercial with 16.0%. The gas transportation rate classes, which include relatively large commercial and industrial facilities, were excluded from the CPA analysis. Therefore, most of the remaining industrial customers, which represent only 1.6% of sales included in this CPA, are relatively small in terms of their gas usage per meter.

[2] Energy usage as measured "at-the-meter," i.e., does not include pipeline losses.

Table ES-1 2010 Gas Sales by State and Sector

All States Sector	Rate Class	Number of Meters	2010 Sales (1000 thm)	% of System Sales	Average Use per Meter (thm)
Residential	N/A	282,418	188,894	59.8%	669
Small Commercial	N/A	30,317	50,693	16.0%	1,672
Large Commercial	N/A	3,419	71,176	22.5%	20,818
Industrial	N/A	253	5,141	1.6%	20,322
Total		**316,407**	**315,906**	**100.0%**	**998**
Washington Sector	**Rate Class**	**Number of Meters**	**2010 Sales (1000 thm)**	**% of WA Sales**	**Average Use per Meter (thm)**
Residential	101	132,657	97,372	58.3%	734
Small Commercial	101	11,906	16,706	10.0%	1,403
Large Commercial	111, 112, 121, 122, 132	2,292	49,808	29.8%	21,731
Industrial	101, 111, 121, 122	132	3,135	1.9%	23,752
Washington total		**146,987**	**167,021**	**100.0%**	**1,136**
Idaho Sector	**Rate Class**	**Number of Meters**	**2010 Sales (1000 thm)**	**% of ID Sales**	**Average Use per Meter (thm)**
Residential	101	65,648	44,084	61.2%	672
Small Commercial	101	7,398	8,432	11.7%	1,140
Large Commercial	111, 132	1,050	17,820	24.7%	16,971
Industrial	101, 111, 112	99	1,681	2.3%	16,978
Idaho total		**74,195**	**72,017**	**100.0%**	**971**
Oregon Sector	**Rate Class**	**Number of Meters**	**2010 Sales (1000 thm)**	**% of OR Sales**	**Average Use per Meter (thm)**
Residential	410	84,114	47,438	61.7%	564
Small Commercial	420	11,013	25,556	33.2%	2,320
Large Commercial	424	77	3,548	4.6%	46,081
Industrial	420, 424	22	325	0.4%	14,787
Oregon total		**95,226**	**76,867**	**100.0%**	**807**

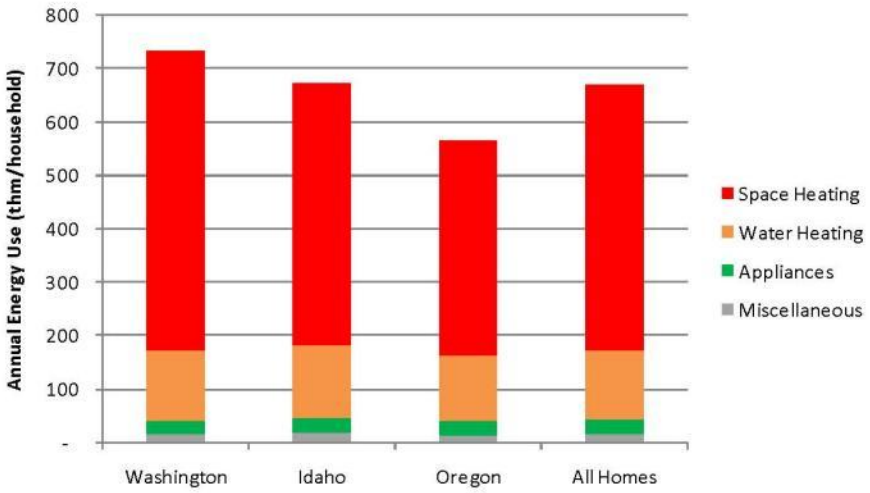
Total residential gas use in 2010 was 188.9 million therms. Customer information for each segment is shown in Table ES-2. System wide, the single-family segment consumed 84% of total residential sector gas in 2010 as a result of having the largest number of customers and the highest intensity.

Table ES-2 Residential Sector Gas Usage and Intensity by State and Segment Type

All States Residential Segment	Number of Meters	2010 Sales (1000 thm)	% of System Res. Sales	Intensity (thm/HH)
Single Family	222,934	157,830	84%	708
Multi Family	25,755	11,615	6%	451
Mobile Home	33,729	19,450	10%	577
Total	**282,418**	**188,894**	**100%**	**669**
WA Residential Segment	**Number of Meters**	**2010 Sales (1000 thm)**	**% of WA Res. Sales**	**Intensity (thm/HH)**
Single Family	107,230	83,143	85%	775
Multi Family	14,318	6,994	7%	488
Mobile Home	11,109	7,235	7%	651
Washington Total	**132,657**	**97,372**	**100%**	**734**
ID Residential Segment	**Number of Meters**	**2010 Sales (1000 thm)**	**% of ID Res. Sales**	**Intensity (thm/HH)**
Single Family	51,487	36,371	83%	706
Multi Family	4,648	2,068	5%	445
Mobile Home	9,513	5,645	13%	593
Idaho Total	**65,648**	**44,084**	**100%**	**672**
OR Residential Segment	**Number of Meters**	**2010 Sales (1000 thm)**	**% of OR Res. Sales**	**Intensity (thm/HH)**
Single Family	64,217	38,317	81%	597
Multi Family	6,789	2,552	5%	376
Mobile Home	13,107	6,570	14%	501
Oregon Total	**84,114**	**47,438**	**100%**	**564**

Figure ES-2 shows the breakdown of annual use by end use for the average home in each state and for the Avista residential sector as a whole. Space heating constitutes 77% of gas usage in Washington, 73% in Idaho, and from 71% in Oregon, reflecting the differences in climate among the states.

Figure ES-2 Annual Residential Natural Gas Use by End Use and State, 2010



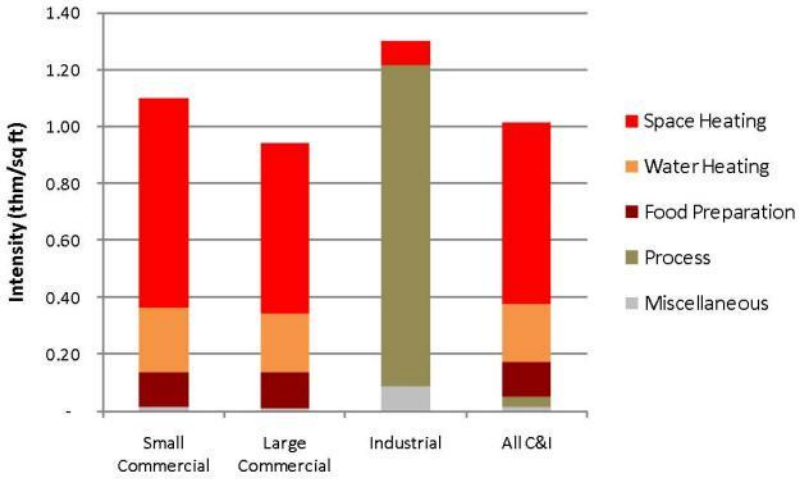
Total natural gas use in the commercial and industrial (C&I) sector in 2010 was 127.0 million therms. Avista rate classes were used to allocate this energy use to three segments per state. Intensity estimates in therms/sq. ft. were developed and then used to infer the segment size in floor space for each segment. Table ES-3 displays the resulting sales, intensity, and segment size. Due to the characteristics of the rate structures, a greater percentage of C&I customers in Oregon are classified as small commercial, as compared with Washington and Idaho.

Table ES-3 C&I Sector Gas Usage and Intensity by State and Segment, 2010

All States C&I		2010 Sales (1000 thm)	% of All C&I Sales	Intensity (thm/sq. ft.)	Segment Size (million sq. ft)
Small Commercial	N/A	50,693	40%	0.343	147.798
Large Commercial	N/A	71,176	56%	0.649	109.666
Industrial	N/A	5,141	4%	0.776	6.621
All States Total		**127,011**	**100%**	**0.481**	**264.085**
Washington Sector	**Rate Class**	**2010 Sales (1000 thm)**	**% of WA C&I Sales**	**Intensity (thm/sq. ft.)**	**Segment Size (million sq. ft)**
Small Commercial	101	16,706	24%	0.363	46.021
Large Commercial	111, 112, 121, 122, 132	49,808	72%	0.660	75.467
Industrial	101, 111, 121, 122	3,135	5%	0.792	3.959
Washington Total		**69,649**	**100%**	**0.555**	**125.447**
Idaho Sector	**Rate Class**	**2010 Sales (1000 thm)**	**% of ID C&I Sales**	**Intensity (thm/sq. ft.)**	**Segment Size (million sq. ft)**
Small Commercial	101	8,432	30%	0.347	24.335
Large Commercial	111, 132	17,820	64%	0.630	28.285
Industrial	101, 111, 112	1,681	6%	0.759	2.215
Idaho Total		**27,933**	**100%**	**0.509**	**54.835**
Oregon Sector	**Rate Class**	**2010 Sales (1000 thm)**	**% of OR C&I Sales**	**Intensity (thm/sq. ft.)**	**Segment Size (million sq. ft)**
Small Commercial	420	25,556	87%	0.330	77.441
Large Commercial	424	3,548	12%	0.600	5.914
Industrial	420, 424	325	1%	0.726	0.448
Oregon Total		**29,429**	**100%**	**0.351**	**83.803**

Figure ES-3 illustrates the distribution of gas consumption by end use for small commercial, large commercial, industrial, and C&I facilities as a whole. As one would expect, space heating is the predominant use, representing 63% of overall C&I gas consumption. For industrial facilities however, process heating represents the greatest share.

Figure ES-3 C&I End Use Intensities, 2010



Baseline Forecast

Prior to developing estimates of conservation potential, a baseline end-use forecast was developed to quantify how natural gas is used by end use in the base year and what the consumption is likely to be in the future in absence of new utility programs and naturally occurring conservation. The baseline forecast serves as the metric against which conservation potentials are measured.

Referring to Table ES-4, natural gas use across all three sectors is expected to increase by 28% between the base year 2010 and 2032, for an average annual growth rate of 1.1%. Overall, the forecast for the next 20 years grows steadily, dominated by growth in the residential sector.

Table ES-4 Baseline Forecast Summary (1000 therm)

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%**

Figure ES-4 and Figure ES-5 present the baseline end-use forecasts for the residential and C&I sectors respectively, while Figure ES-6 displays growth system wide.

Figure ES-4 Residential Baseline Forecast by End Use

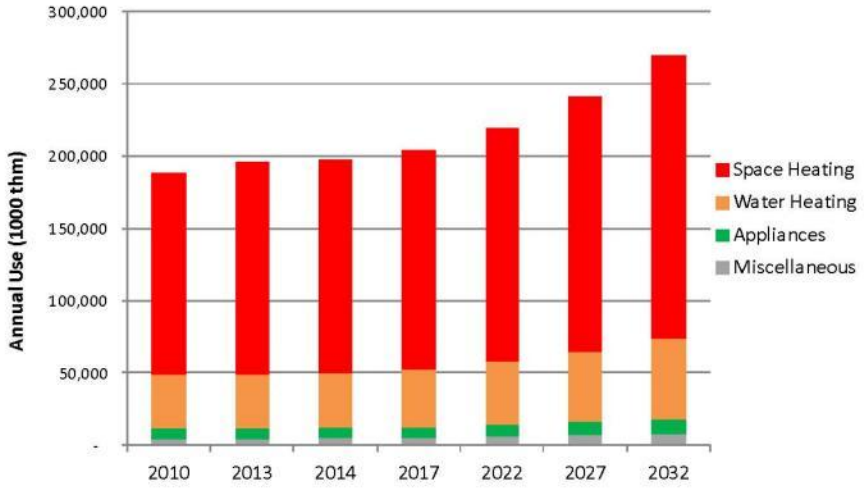


Figure ES-5 Commercial and Industrial Baseline Forecast by End Use

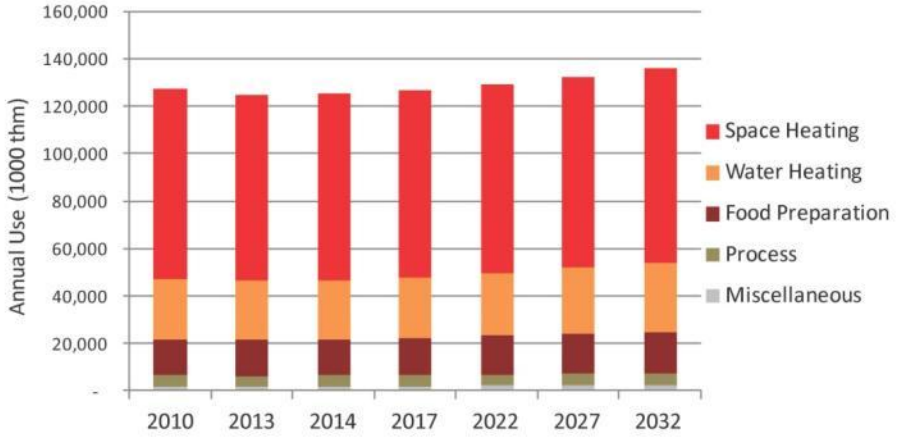
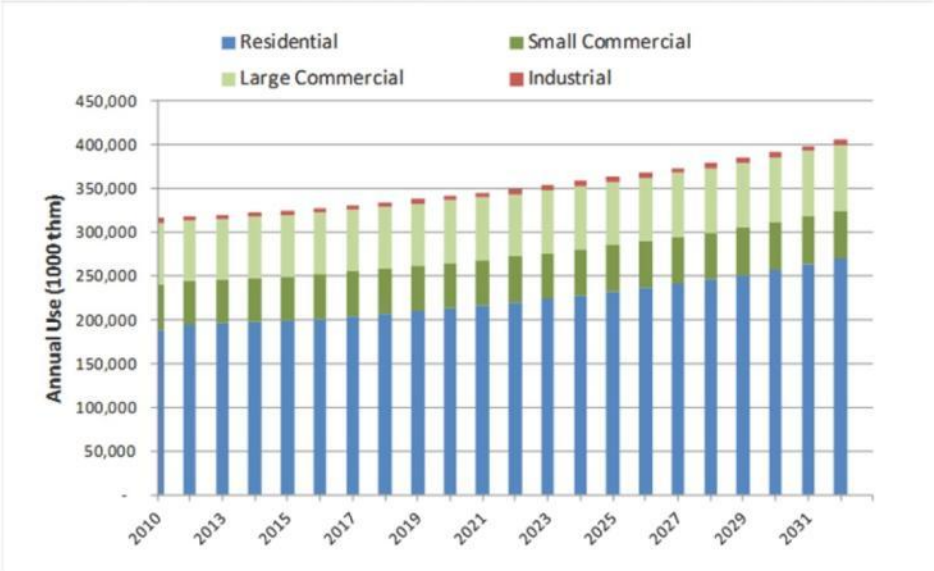


Figure ES-6 Baseline Forecast Summary (MWh)



Energy Conservation Measures

The first step of the energy conservation measure analysis is to identify the list of all relevant conservation measures that should be considered for the Avista CPA. The measures are categorized into two types according to the LoadMAP[3] taxonomy: equipment measures and non-equipment measures:

[3] Global's Load Management Analysis and Planning™ tool, which was used to perform the CPA analysis.

- ***Equipment measures,*** or efficient energy-consuming equipment, save energy by providing the same service with a lower energy requirement. For equipment measures, many efficiency levels are available for a specific technology that range from the baseline unit (often determined by code or standard) up to the most efficient product commercially available. For instance, in the case of residential furnaces, this list begins with the federal standard energy factor (EF) 0.78 unit and spans a broad spectrum of efficiency, with the highest efficiency level represented by an EF 0.96 unit.
- ***Non-equipment measures*** save energy by reducing the need for delivered energy but do not involve replacement or purchase of major end-use equipment (such as a furnace or water heater). An example would be a programmable thermostat that is pre-set to reduce the load on a furnace or boiler when the building is unoccupied. Non-equipment measures fall into one of the following categories:
    - Building shell (windows, insulation, roofing material)
    - Equipment controls (thermostat, occupancy sensors)
    - Equipment maintenance (cleaning filters, changing setpoints)
    - Whole-building design (natural ventilation, ENERGY STAR home)
    - Commissioning and retrocommissioning

Conservation Potential Results

Table ES-5 summarizes the achievable potential by state and by sector for selected years. As shown in Figure ES-7, 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 greatest, mainly due to growth in residential customer count.

Table ES-5 Cumulative Achievable Conservation Potential by State and by Sector

Cumulative Savings (1000 therm)	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 therm)	2013	2014	2017	2022	2027	2032
Residential	515	1,567	6,507	14,903	22,278	29,960
Small Comercial	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 ES-7 Cumulative Achievable Conservation Potential Savings by Sector

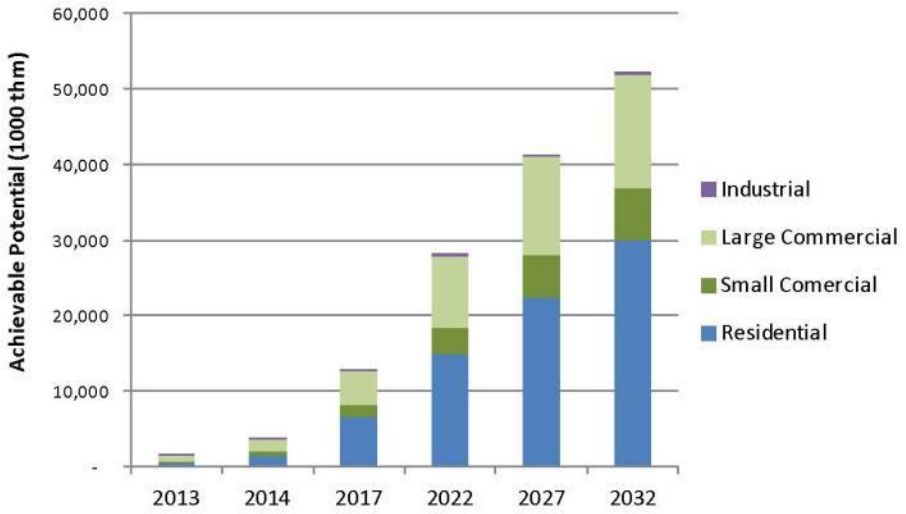


Table ES-6 and Figure ES-8 summarize the conservation savings for the different levels of potential relative to the baseline forecast. Figure ES-9 displays the baseline and potential forecasts.

- ***Achievable potential*** across the residential, commercial, and industrial sectors is 29.6 million therms in 2022 and increases to 53.8 million therms by 2032. These savings represent 8.5% of the baseline forecast in 2022 and 13.3% in 2032.
- ***Economic potential***, which reflects the savings when all cost-effective measures are taken, is 34.6 million therms in 2022. This represents 9.9% of the baseline energy forecast. By 2032, economic potential reaches 61.8 million therms, 15.3% of the baseline energy forecast. [4]
- ***Technical potential***, which reflects the adoption of all conservation measures regardless of cost-effectiveness, is a theoretical upper bound on savings. Technical potential is substantial, because measures such as solar thermal water heating could cut energy use dramatically. In 2022, energy savings are 103.5 million therms, equivalent to 29.7% of the baseline energy forecast. By 2032, technical potential reaches 169.4 million therms, 41.8% of the baseline energy forecast. The relatively wide gap between technical and economic potential reflects the low avoided costs, as well as the fact that Avista's long-running conservation programs have already achieved much of the cost-effective conservation. As a result, additional conservation measures are becoming relatively more costly, and many do not pass the cost-effectiveness screen based on Avista's current avoided costs.

[4] Note that economic and achievable potential for Oregon includes residential weatherization measures that are mandated to be included in utility DSM programs. Many of these measures did not pass the B/C test in the analysis model but were nonetheless included in economic and achievable potential.

Table ES-6 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%

Figure ES-8 Summary of Cumulative Conservation Potential Savings

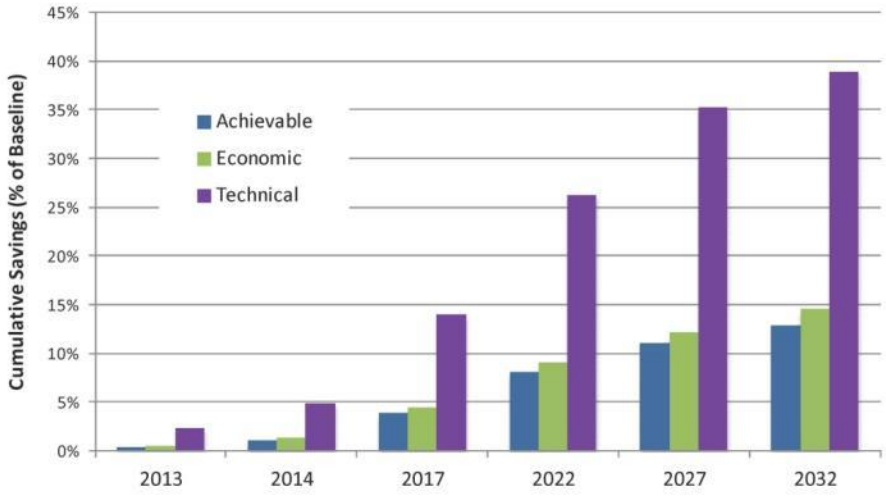
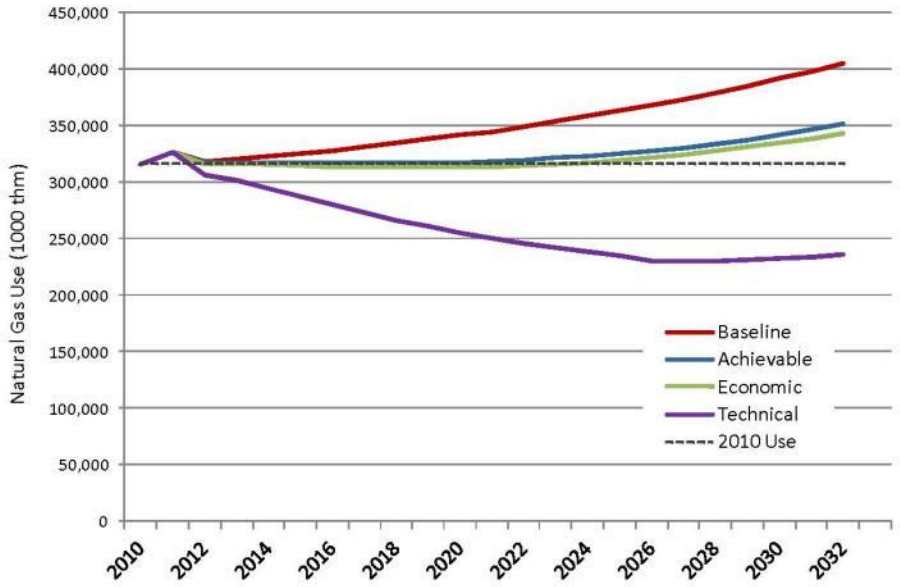


Figure ES-9 Conservation Potential Energy Forecasts (1000 therm)



The greatest sources of residential achievable potential in 2022, across all three states, are as follows:

- ***Shell measures and insulation***, which representing 6.4 million therms or 43% of all savings
- ***Thermostats and home energy monitoring systems***, which provide 3.5 million therms or 24% of all savings
- ***Water-saving devices***, including low-flow showerheads and faucet aerators, which combine for 3.2 million therms or 21% of achievable potential
- ***Water heater tank blankets and pipe insulation***, which provide an additional 1.3 million therms or nearly 9% of achievable potential

The primary sources of C&I achievable savings are as follows:

- ***Energy management systems and programmable thermostats***, because they can be readily installed, account for about 27% of achievable potential in 2014. These controls remain significant contributors to cumulative potential, with 2.5 million therms or 19% of potential in 2022.
- ***Boiler operating measures***, including maintenance, hot water reset, and efficient circulation, together can provide 4.3 million therms or about 29% of achievable potential in 2022.
- ***Equipment upgrades for furnaces, boilers, and unit heaters*** equal 2.0 million therms, or 15% of 2022 achievable potential.
- ***Foodservice equipment*** has an achievable potential by 2022 of 1.6 million therms, or 12% of achievable potential.

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CHAPTER | 1

INTRODUCTION

Background

Avista Utilities (Avista) has contracted with Global Energy Partners (Global) to conduct a conservation potential assessment (CPA) to quantify the amount, the timing, and the cost of natural gas energy conservation resources available within the Avista service territory. The purpose of this study is to establish cost-effective and achievable energy conservation resources for the 2013–2032 period to support development of Avista's 2013 gas Integrated Resource Plan (IRP).

Key objectives for the study include:

- Determine the conservation potential for natural gas for Washington, Idaho, and Oregon, for the period 2013–2032, based on Avista's service territory characteristics.
- Develop energy conservation measure (ECM) data sets for each market sector and each appropriate market segment.
- Categorize the potential by market sector, segment, building type, and ECM.
- Using parameters provided by Avista, calculate the Total Resource Cost (TRC), and measure levelized cost of the ECMs.
- Provide supply curves of achievable potential.

Report Organization

This report contains the following chapters:

1. Introduction
2. Analysis Approach and Data Development
3. Market Assessment and Market Profiles
4. Baseline Forecast
5. Conservation Potential

Definitions of Potential

In this study, the conservation potential estimates represent gross savings[5] developed into three types of potential: technical potential, economic potential, and achievable potential. Technical and economic potential are both theoretical limits to efficiency savings. Achievable potential embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase, the maintenance activities they undertake, the controls they use for energy-consuming equipment, and the elements of building construction. These levels are described below.

Technical potential is defined as the theoretical upper limit of conservation potential. It assumes that customers adopt all feasible measures regardless of cost. At the time of equipment failure, customers replace equipment with the most efficient option available. In new

[5] Savings in "gross" terms instead of "net" terms means that the baseline forecast does not include naturally occurring efficiency. In other words, the baseline assumes that energy efficiency levels remain fixed as they are today. This rule holds true except in cases where future codes and standards were on the books before November 2011, e.g. the effects of the upcoming furnace and water heater standards.

construction, customers and developers also choose the most efficient equipment option. Examples of measures that make up technical potential in the residential sector include:

- High efficiency furnaces and boilers
- High efficiency water heaters
- High efficiency clothes dryers

Technical potential also assumes the adoption of every available non-equipment measure, where applicable. For example, it includes installation of high-efficiency windows in all new construction opportunities and furnace maintenance in all existing buildings with furnace systems. The retrofit measures are phased in over a number of years, which is longer for higher-cost measures.

Economic potential represents the adoption of all ***cost-effective*** conservation measures. In this analysis, the TRC test, which compares lifetime energy and capacity benefits to the incremental cost of the measure, is applied. Economic potential assumes that customers \urchase the most cost-effective option at the time of equipment failure and also adopt every other cost-effective and applicable measure.

Achievable potential takes into account market maturity, customer preferences for energy-efficient technologies, and expected program participation. Achievable potential establishes a realistic target for the conservation savings that a utility can hope to achieve through its programs. It is determined by applying a series of annual factors to the economic potential for each ECM. These factors represent the ramp rates at which technologies will penetrate the market and were based upon the Northwest Power and Conservation Council Sixth Plan (NWPCC) ramp rates. Although Avista is not required to use the Sixth Plan ramp rates for its gas CPA, the project team chose to use those ramp rates for consistency with the Avista 2011 electricity CPA. Also, these ramp rates have been widely vetted and are accepted by regional stakeholders. Details regarding the ramp rate development appear in Appendix E.

Abbreviations and Acronyms

Throughout the report we make reference to several abbreviations and acronyms. Table 1-1 shows the abbreviation or acronym, along with what it stands for.

Table 1-1 Explanation of Abbreviations and Acronyms

Acronym	Explanation
ACS	American Community Survey
AEO	Annual Energy Outlook
B/C Ratio	Benefit to Cost Ratio
BEST	Global's Building Energy Simulation Tool
C&I	Commercial and Industrial
CBSA	Northwest Energy Efficiency Alliance Commercial Building Stock Assessment
CPA	Conservation Potential Assessment
DEEM	Global's Database of Energy Efficiency Measures
DEER	Database for Energy-Efficient Resources
DSM	Demand side management
EE	Energy Efficiency
EIA	Energy Information Administration
EISA	Energy Efficiency and Security Act of 2007
EPACT	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
EUEA	Efficient Use of Energy Act
EUI	Energy-use Index (energy use by end use)
HH	Household
I-937	Washington Initiative 937
LoadMAP	Global's Load Management Analysis and Planning™ tool
MAR	Market Acceptance Rate
NEEA	Northwest Energy Efficiency Alliance
NWPCC	Northwest Power and Conservation Council
RTF	Regional Technical Forum
Sq. ft.	Square feet
TRC	Total Resource Cost
UEC	Unit Energy Consumption

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CHAPTER | 2

ANALYSIS APPROACH AND DATA DEVELOPMENT

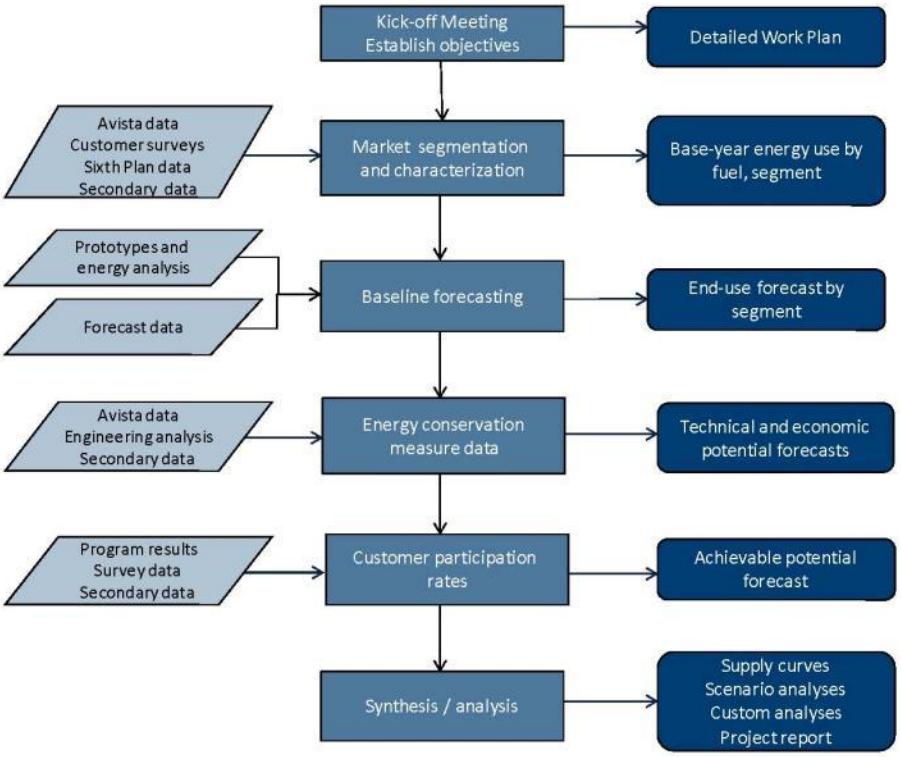
Introduction

To perform the conservation analysis, Global used a bottom-up analysis approach as shown in Figure 2-1 and summarized below.

1. Met by phone with Avista staff to refine the objectives that were identified in the Avista RFP. This resulted in a work plan for the study.
2. Performed a market characterization to describe sector-level natural gas use for the residential, commercial, and industrial sectors for the base year, 2010. This included using utility data and secondary data from sources such as the American Community Survey (ACS), and the Energy Information Administration (EIA).
3. Utilized secondary sources including Northwest Energy Efficiency Alliance (NEAA) data and market reports to understand how customers in the Avista service territory currently use gas. Combining this information with the market characterization, we developed energy market profiles that describe energy use by sector, segment, and end use for 2010.
4. Developed a baseline gas forecast by sector, segment, and end use for 2013 through 2032.
5. Identified and analyzed energy conservations measures appropriate for the Avista service territory.
6. Estimated three levels of conservation potential, *Technical, Economic,* and *Achievable*.

The steps are described in further detail throughout the remainder of this chapter.

Figure 2-1 Overview of Analysis Approach



LoadMAP Model

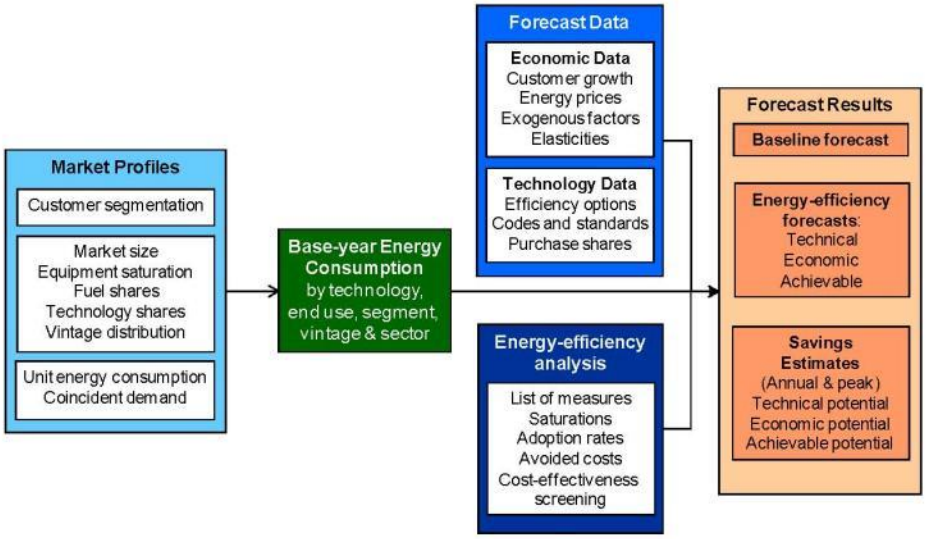
We used the Global Load Management Analysis and Planning tool (LoadMAP™) to develop the baseline forecast, as well as the estimates of conservation potential. Global developed LoadMAP in 2007 and has used it for the EPRI National Potential Study and numerous utility-specific forecasting and potential studies. Built in Excel, the LoadMAP framework (see Figure 2-2) is both accessible and transparent and has the following key features.

- Develops a bottom-up forecast based on energy use by end use of major energy-consuming equipment.
- Embodies the basic principles of rigorous end-use models (such as EPRI's REEPS and COMMEND) but in a more simplified, accessible form.
- Includes stock-accounting algorithms that treat older, less efficient appliance/equipment stock separately from newer, more efficient equipment. Equipment is replaced according to the measure life defined by the user.
- Balances the competing needs of simplicity and robustness by incorporating important modeling details related to equipment saturations, efficiencies, vintage, and the like, where market data are available, and treats end uses separately to account for varying importance and availability of data resources.
- Uses a simple logic for appliance and equipment decisions. Isolates new construction from existing equipment and buildings and treats purchase decisions for new construction and existing buildings separately.

- Includes appliance and equipment models customized by end use. For example, the logic for space heating is distinct from stoves and clothes dryers.
- Can accommodate various levels of segmentation. Analysis can be performed at the sector level (e.g., total residential) or for customized segments within sectors (e.g., housing type or income level).

Consistent with the segmentation scheme and the market profiles we describe below, the LoadMAP model provides forecasts of baseline natural gas use by sector, segment, end use and technology for existing and new buildings. It also provides forecasts of total natural gas use and conservation savings associated with the three types of potential.[6]

Figure 2-2 LoadMAP Analysis Framework



Market Characterization

Before assessing conservation potential, it is critical to develop a good understanding of where Avista is today in terms of natural gas use and customer behavior. The purpose of the market characterization is to develop market profiles that describe current natural gas use in terms of sector, customer segment, and end use. The base year for this study is 2010 because that was the most recent year for which utility sales data were available.

Segmentation for Modeling Purposes

The market assessment began by defining the market segments (building types, end uses, and other dimensions) that are relevant for Avista. The segmentation scheme employed for this project is presented in Table 2-1.

[6] The model computes energy and peak-demand forecasts for each type of potential for each end use as an intermediate calculation. Annual-energy and peak-demand savings are calculated as the difference between the value in the baseline forecast and the value in the potential forecast (e.g., technical potential).

Table 2-1 Overview of Segmentation Scheme for Potentials Modeling

Market Dimension	Segmentation Variable	Dimension Examples
Dimension 1	Sector	Residential, commercial, industrial
Dimension 2	Geographic Region	Washington, Idaho, Oregon
Dimension 3	Building type	Residential (Single family, Multi family, Mobile home) Commercial (Small commercial, Large commercial) Industrial (no further segmentation)
Dimension 4	Vintage	Existing and new construction (for residential and commercial sectors)
Dimension 5	End uses	Space heating, water heating, appliances, food preparation, etc. (as appropriate by sector)
Dimension 6	Appliances/end uses and technologies	Technologies such as space heating equipment, ovens, process equipment, etc.
Dimension 7	Equipment efficiency levels for new purchases	Baseline and higher-efficiency options as appropriate for each technology

For the residential sector, the CPA used the following segmentation.

- ***Single-family homes.*** This segment includes single-family detached homes, townhouses, and duplexes or row houses.
- ***Multi-family homes***. The multi-family segment includes apartments or condos in buildings with more than two units.
- ***Mobile homes***. This segment includes mobile homes and manufactured homes.

In addition to segmentation by housing type, we identified the set of end uses and technologies that are appropriate for Avista. These are shown in Table 2-2.

Table 2-2 Residential End Uses and Technologies

End Use	Technology
Space Heating	Furnace
Space Heating	Boiler
Space Heating	Other Heating
Water Heating	Water Heater
Appliances	Clothes Dryer
Appliances	Stove/Oven
Miscellaneous	Pool/Spa Heater
Miscellaneous	Miscellaneous

For the commercial sector, we used rate classes to identify the segments.

- ***Small Commercial.*** This segment includes commercial buildings under rate class 101 in Washington and Idaho, and 420 in Oregon.
- ***Large Commercial.*** This segment includes commercial buildings under rate classes 111, 112, 121, 122, and 132 in Washington and Idaho, and 424 in Oregon.

No further segmentation was applied to the industrial sector.

In addition to segmentation by rate class, we identified the set of commercial and industrial end uses and technologies that are appropriate for Avista's service territory, as shown in Table 2-3.

With the segmentation scheme defined, we then performed a high-level market characterization of natural gas sales in the base year to allocate sales to each customer segment. We used various data sources to identify the annual sales in each customer segment, as well as the number of customers for residential segments, and the square footage for the commercial and industrial segments. This information provided control totals (energy use and customers counts/square footage totals) for calibrating the LoadMAP model to known data for the base-year.

Table 2-3 Commercial & Industrial End Uses and Technologies

End Use	Technology
Space Heating	Furnace
Space Heating	Boiler
Space Heating	Other Heating
Water Heating	Water Heater
Food Preparation	Fryer
Food Preparation	Oven
Food Preparation	Broiler
Food Preparation	Griddle
Food Preparation	Range
Food Preparation	Steamer
Process	Process Heating
Process	Process Cooling
Process	Other Process
Miscellaneous	Pool/Spa Heater
Miscellaneous	Miscellaneous

Market Profiles

The next step was to develop market profiles for each sector, customer segment, end use, and technology. A market profile includes the following elements:

- ***Market size*** is a representation of the number of customers in the segment. For the residential sector, it is number of households. In the commercial and industrial sector, it is floor space measured in square feet.
- ***Saturations*** define the fraction of buildings with the natural gas technologies. (e.g., homes with natural gas water heating, commercial floor space with natural gas space heating, etc.).
- ***UEC (unit energy consumption) or EUI (energy-use index)*** describes the amount of natural gas consumed in 2010 by a specific technology in buildings that have the technology. We use UECs expressed in therms/household for the residential sector, and EUIs expressed in therms/square foot for the commercial and industrial sectors.
- ***Intensity*** for the residential sector represents the average use for the technology across all homes in 2010. It is computed as the product of the saturation and the UEC and is defined as therms/household. For the commercial and industrial sectors, intensity, computed as the product of the saturation and the EUI, represents the average use for the technology across all floor space in 2010.
- ***Usage*** is the annual gas use by a technology/end use in the segment. It is the product of the market size and intensity and is quantified in 1000 therm.

The market assessment results and the market profiles are presented in Chapter 3.

Baseline Forecast

The next step was to develop the baseline forecast of annual natural gas use for 2010 through 2032 by customer segment and end use without new utility programs or naturally occurring efficiency scenario. The end-use forecast does include 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 EE efforts as well as the metric against which potential savings are measured.

Inputs to the baseline forecast include:

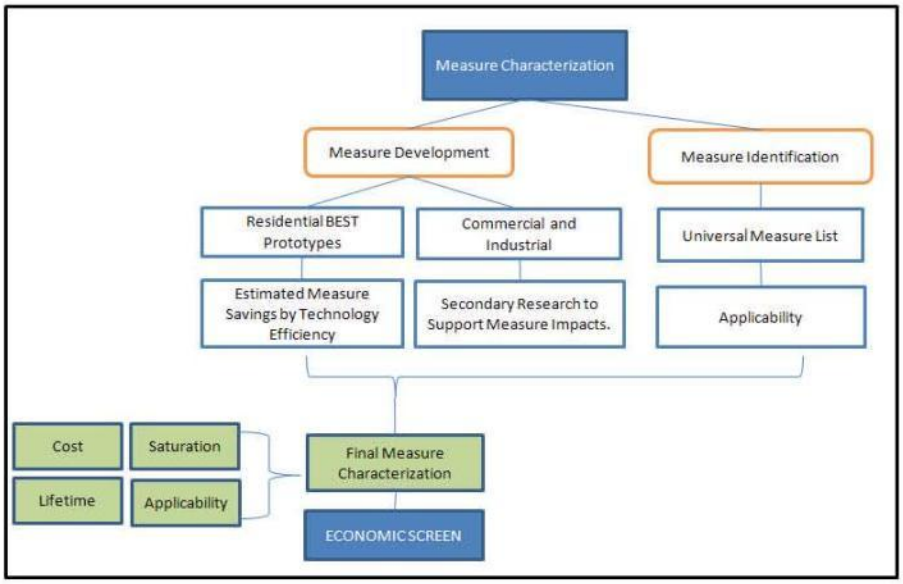
- Current economic growth forecasts (i.e., customer growth, income growth), provided by Avista
- Natural gas price forecasts, provided by Avista
- Trends in fuel shares and equipment saturations, developed by project team
- Existing and approved changes to building codes and equipment standards
- Avista's internally developed forecasts for natural gas sales

We present the results of the baseline forecast development in Chapter 4.

Conservation Measure Analysis

This section describes the framework used to assess the savings, costs, and other attributes of energy conservation measures. These characteristics form the basis for measure-level cost-effectiveness analyses as well as for determining measure-level savings. For all measures, Global assembled information to reflect equipment performance, incremental costs, and equipment lifetimes. We used this information, along with Avista's avoided costs, in the economic screen to determine economically feasible measures. Figure 2-3 outlines the framework for measure analysis.

Figure 2-3 Approach for Measure Assessment



The framework for assessing savings, costs, and other attributes of energy conservation measures involves identifying the list of conservation measures to include in the analysis, determining their applicability to each market sector and segment, fully characterizing each measure, and performing cost-effectiveness screening. Potential measures include the replacement of a unit that has failed or is at the end of its useful life with an efficient unit, retrofit/early replacement of equipment, improvements to the building envelope, the application of controls to optimize energy use, and other actions resulting in improved energy efficiency.

We compiled a robust list of conservation measures for each customer sector, drawing Avista's existing programs, as well as a variety of secondary sources. This universal list of energy conservation measures covers all major types of end-use equipment, as well as devices and actions to reduce energy consumption. If considered today, some of these measures would not pass the economic screens initially, but may pass in future years as a result of lower projected equipment costs or higher avoided costs.

The selected measures can be categorized into types, equipment measures and non-equipment measures, according to the LoadMAP taxonomy:

- ***Equipment measures,*** or efficient energy-consuming equipment, save energy by providing the same service with a lower energy requirement. For equipment measures, many efficiency levels are available for a specific technology that range from the baseline unit (often determined by code or standard) up to the most efficient product commercially available. For

instance, in the case of residential furnaces, this list begins with the federal standard energy factor (EF) 0.78 unit and spans a broad spectrum of efficiency, with the highest efficiency level represented by an EF 0.96 unit.

- ***Non-equipment measures*** save energy by reducing the need for delivered energy but do not involve replacement or purchase of major end-use equipment (such as a furnace or water heater). An example would be a programmable thermostat that is pre-set to reduce the load on a furnace or boiler when the building is unoccupied. Non-equipment measures fall into one of the following categories:
    - Building shell (windows, insulation, roofing material)
    - Equipment controls (thermostat, occupancy sensors)
    - Equipment maintenance (cleaning filters, changing setpoints)
    - Whole-building design (natural ventilation, ENERGY STAR home)
    - Commissioning and retrocommissioning

Global developed a preliminary list of energy conservation measures that included gas measures in Avista's existing DSM programs, as well as other measures that are typically included in gas utility conservation programs. The final list included in the study, which reflects feedback and additions from Avista, is presented in Appendices B, C, and D for the residential, commercial, and industrial sectors respectively.

Once we assembled the list of ECMs, the project team assessed their energy-saving characteristics. For each measure, we developed estimates of incremental cost, service life, and other performance factors, drawing upon data from Avista and from secondary sources. The project team also used data from Global's database of measure characteristics and simulation modeling. Following the measure characterization, we performed an economic screening of each measure, which serves as the basis for developing the economic potential.

Representative Measure Data Inputs

To provide an example of the measure data, Table 2-4 and Table 2-5 present samples of the detailed data inputs behind equipment and non-equipment measures, respectively, for the case of residential water heaters in single-family homes in Washington. Table 2-4 displays the various efficiency levels available as equipment measures, as well as the corresponding useful life, energy usage, and cost estimates. The columns labeled On Market and Off Market reflect equipment availability due to codes and standards or the entry of new products to the market.

Table 2-4 Sample Equipment Measures for Water Heaters – Single Family Home (WA)

Efficiency Level	Useful Life	Equipment Cost	Energy Usage(thm/yr)	On Market	Off Market
EF 0.59	15	$445	153.3	2010	2014
EF 0.62	15	$480	145.9	2010	2032
EF 0.64	15	$750	141.6	2010	2032
EF 0.67	15	$760	135.2	2010	2032
EF 0.70	15	$800	129.5	2010	2032
EF .86 (Condensing)	15	$2,500	105.3	2010	2032
Solar	15	$5,000	43.5	2010	2032

Table 2-5 lists some of the non-equipment measures affecting an existing single-family home in Washington with a gas water heater. These measures are also evaluated for cost effectiveness based on the lifetime benefits relative to the cost of the measure. The total savings are calculated for each year of the model and depend on the base year saturation of the measure, the applicability and feasibility[7] of the measure, and the savings as a percentage of the relevant energy end uses.

Table 2-5 Sample Non-Equipment Measures – Single Family Home (WA), Existing

End Use	Measure	Saturation in 2010[8]	Applica-bility	Lifetime (years)	Measure Installed Cost	Energy Savings (%)
Water Heating	Water Heating - Faucet Aerators	53%	90%	25	$24	3.70%
Water Heating	Water Heating - Low Flow Showerheads	42%	80%	10	$96	17.10%
Water Heating	Water Heating - Pipe Insulation	17%	75%	13	$10	2.00%
Water Heating	Water Heating - Tank Blanket/Insulation	54%	75%	10	$15	9.10%
Water Heating	Water Heating - Thermostat Setback	17%	75%	5	$40	9.10%
Water Heating	Water Heating - Timer	17%	40%	10	$194	8.00%
Water Heating	Water Heating - Hot Water Saver	5%	50%	5	$35	8.75%

Screening Measures for Cost-Effectiveness

Only measures that are cost-effective are included in economic and achievable potential. Therefore, for each individual measure, LoadMAP performs an economic screen. This study uses the total resource cost (TRC) test that compares the lifetime benefits (both energy and peak demand) of each applicable measure with its installed cost, which includes material, labor, and administration of a delivery mechanism, such as an energy efficiency program. The lifetime benefits are calculated by multiplying the annual energy and demand savings for each measure by all appropriate avoided costs for each year, and discounting the dollar savings to the present value equivalent. The analysis uses each measure's values for savings, costs, and lifetimes that were developed as part of the measure characterization process described above. For economic screening of measures, incentives are not included because they represent a simple transfer from one party to another, but have no effect on the overall measure cost.

The LoadMAP model performs this screening dynamically, taking into account changing savings and cost data over time. Thus, some measures pass the economic screen for some — but not all — of the years in the forecast.

It is important to note the following about the economic screen:

- The economic evaluation of every measure in the screen is conducted relative to a baseline condition. For instance, in order to determine the savings potential of a measure, consumption in therms with the measure applied must be compared to the consumption n therms of a baseline condition.

[7] The applicability factor takes into account whether the measure is applicable to a particular building type and whether it is feasible to install the measure. For instance, attic fans are not applicable to homes without attics, and in some homes with attics, it may not be feasible to install an attic fan because of lack of space.

[8] Note that saturation levels reflected for 2010 change over time as more measures are adopted.

- The economic screening was conducted only for measures that are applicable to each building type and vintage; thus if a measure is deemed to be irrelevant to a particular building type and vintage, it is excluded from the respective economic screen.

If the measure passes the screen (has a benefit-to-cost (B/C) ratio greater than or equal to 1.0), the measure is included in economic potential. Otherwise, it is screened out for that year. If multiple equipment measures have B/C ratios greater than or equal to 1.0, the most efficient technology with a B/C ration above 1.0 is selected by the economic screen.

Additional information on avoided costs appears later in this chapter, and detailed information on the measure analysis is presented in Appendices B, C, and D for the residential, commercial, and industrial sectors respectively.

Conservation Potential

The approach we used for this study adheres to the approaches and conventions outlined in the National Action Plan for Energy-Efficiency (NAPEE) Guide for Conducting Potential Studies (November 2007).[9] The NAPEE Guide represents the most credible and comprehensive industry practice for specifying energy-efficiency potential. Specifically, three types of potentials were developed as part of this study:

- ***Technical potential*** is a theoretical construct that assumes the highest efficiency measures that are technically feasible to install are adopted by customers, regardless of cost or customer preferences. Thus, determining the technical potential is relatively straightforward. LoadMAP "chooses" the most efficient equipment options for each technology at the time of equipment replacement. In addition, it installs all relevant non-equipment measures for each technology to calculate savings.

  For example, for water heating, as shown in Table 2-4, the most efficient option is solar water heating. The multiple non-equipment measures shown in Table 2-5 are then applied to the energy used by the solar water heater m to further reduce water heating energy use. LoadMAP applies the savings due to the non-equipment measures one-by-one to avoid double counting of savings. The measures are evaluated in order of their B/C ratio, with the measure with the highest B/C ratio applied first. Each time a measure is applied, the baseline energy use for the end use is reduced and the percentage savings for the next measure is applied to the revised (lower) usage.
- ***Economic potential*** results from the purchase of the most efficient *cost-effective* option available for a given equipment or non-equipment measure as determined in the cost-effectiveness screening process described above. As with technical potential, economic potential is a phased-in approach. Economic potential is still a hypothetical upper-boundary of savings potential as it represents only measures that are economic but does not yet consider customer acceptance and other factors.
- ***Achievable potential*** defines the range of savings that is very likely to occur. It accounts for customers' awareness of efficiency options, any barriers to customer adoption, limits to program design, and other factors that influence the rate at which conservation measures penetrate the market.

The calculation of technical and economic potential is straightforward as described above. To develop estimates for achievable potential, we specify adoption rates for each measure. For Avista, we began with the ramp rates specified in the Sixth Plan conservation workbooks. Although Avista is not required to use the Sixth Plan ramp rates for its gas CPA, the project team chose to use those ramp rates for consistency with the Avista 2011 electricity CPA. Also, these ramp rates have been widely vetted and are accepted by regional stakeholder. Details regarding the ramp rate development appear in Appendix E. Results of all the potentials analysis are presented in Chapter 5.

[9] National Action Plan for Energy Efficiency (2007). *National Action Plan for Energy Efficiency Vision for 2025: Developing a Framework for Change.* www.epa.gov/eeactionplan.

Data Development

This section begins with a description of the data sources used in this study, followed by a discussion of how these sources were applied.

Data Sources

The data sources are organized into the following categories:

- Utility-provided data
- Energy conservation measure data
- Global Energy Partners' databases and analysis tools
- Other secondary data and reports

Utility-provided Data

In order to enable the project team to appropriately characterize the market, Avista provide the following:

- Utility 2010 billing data — customers, usage, revenue
- Number of customers and gas sales by sector (residential, commercial, industrial)
- Energy and peak demand forecasts, at the sector level
- Forecasts of customer growth, persons per household, and income
- Price forecast
- Avoided costs forecast
- Discount rate
- Escalation rate
- Loss factors
- Description of existing conservation and demand side management programs and results from these programs
- Program administration expenses
- Recent conservation potential studies

Energy Conservation Measure Data

Several sources of data were used to characterize the energy conservation measures.

- ***Northwest Power and Conservation Council Sixth Plan Conservation Supply Curve Workbooks, 2010.*** To develop its Power Plan, the Council used workbooks with detailed information about measures, available at http://www.nwcouncil.org/energy/powerplan/6/supplycurves/default.htm. Although the Plan focuses on electricity and not gas conservation measures, it does provide useful information for a gas CPA, such as cost and savings estimates for weatherization measures.
- ***Regional Technical Forum Deemed Measures.*** The NWPCC Regional Technical Forum maintains databases of deemed measure savings data, available at http://www.nwcouncil.org/energy/rtf/measures/Default.asp . Although the Regional Technical Forum focuses on electricity and not gas conservation measures, it does provide useful information for a gas CPA, such as cost and savings estimates for weatherization measures.
- ***Database for Energy Efficient Resources (DEER).*** The California Energy Commission and California Public Utilities Commission (CPUC) sponsor this database, which is designed to

provide well-documented estimates of energy and peak demand savings values, measure costs, and effective useful life (EUL) for the state of California.

- ***Other cost data sources***
  - RS Means Facilities Maintenance and Repair Cost Data
  - RS Means Mechanical Construction Costs
  - RS Means Building Construction Cost Data
  - USGBC — LEED New Construction & Major Renovation (2008)
  - RS Means Green Buildings Project Planning & Cost Estimating Second Edition (2008)
  - Grainger Catalog Volume 398, (2007-2008)
  - EIA Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case, Navigant Consulting

Global Energy Partners Databases, Analysis Tools, and Reports

Global maintains several databases and modeling tools that we use for forecasting and potential studies.

- ***Energy Market Profiles Database.*** Since the late 1990s, Global staff has maintained a database of end-use profiles by sector, customer segment and region for electricity and natural gas. The database contains market size, fuel shares/saturations, UECs/EUIs, intensities, and total sales.
- ***Building Energy Simulation Tool (BEST)***. BEST is a derivative of the DOE 2.2 building simulation model, used to estimate base-year UECs and EUIs, as well as measure savings for the HVAC-related measures.
- ***Database of Energy Efficiency Measures (DEEM)***. Global maintains a database of energy efficiency measures for residential, commercial, and industrial segments across the U.S. This is analogous to the DEER database developed for California. Global updates the database on a regular basis as it conducts new conservation potential studies.
- ***EnergyShape™ Database***. This database contains end-use load shapes for residential and commercial segments for nine regions in the U.S. For the non-HVAC end uses, we used the EnergyShape data to develop the peak factors that represent the fraction of annual energy use that occurs during the peak hour. The peak factors were calibrated to available utility data for the system peak. The final peak factors were applied to annual energy savings to calculate the peak-demand savings from energy conservation measures.
- ***Recent Studies***. Global has conducted numerous studies of conservation potential in the last five years. We checked our input assumptions and analysis results against the results from these other studies which include AmerenUE, Los Angeles Department of Water and Power, Consolidated Edison of New York, State of New Mexico, and Tennessee Valley Authority. In addition, we used the information about impacts of building codes and appliance standards from a recent report for the Institute for Energy Efficiency.

Other Secondary Data and Reports

Finally, a variety of secondary data sources and reports were used for this study. The main sources are identified below.

- ***U.S. Census Data***:
  - The American Community Survey (ACS) is an ongoing survey that provides data every year on household characteristics. http://www.census.gov/acs/www/

- Census Bureau's Economic Census, which is conducted every five years, collects details on business characteristics. We used the 2007 version. http://www.census.gov/econ/census07/

- ***Northwest Energy Efficiency Alliance, Single-Family Residential Existing Construction Stock Assessment***, Market Research Report, E07-179 (10/2007), http://neea.org/research/reportdetail.aspx?ID=194
- ***Northwest Energy Efficiency Alliance, Assessment of Multifamily Building Stock in the Pacific Northwest***, Market Research Report, 05-146, August, 2005. http://neea.org/research/reports/146.pdf
- ***Northwest Energy Efficiency Alliance, Long-Term Northwest Residential Lighting Tracking and Monitoring Study***, Market Research Report, 11-228, August, 2011. http://neea.org/research/reports/E11-231_Combinedv2.pdf
- ***Northwest Energy Efficiency Alliance, Multifamily Residential New Construction characteristics and practices Study, Market*** Research Report, 07-173, June, 2007. http://neea.org/research/reports/07%20173.pdf
- ***Northwest Energy Efficiency Alliance, 2009 Northwest Commercial Building Stock Assessment*** (10-211), http://neea.org/research/reportdetail.aspx?ID=546.
- ***California Statewide Surveys***. The Residential Appliance Saturation Survey (RASS) and the Commercial End Use Survey (CEUS) are comprehensive market research studies conducted by the California Energy Commission. These databases provide a wealth of information on appliance use in homes and businesses. RASS is based on information from almost 25,000 homes and CEUS is based on information from a stratified random sample of almost 3,000 businesses in California.
- ***Annual Energy Outlook***. The Annual Energy Outlook (AEO), conducted each year by the U.S. Energy Information Administration (EIA), presents yearly projections and analysis of energy topics. For this study, we used data from the 2011 AEO.
- ***Electric Power Research Institute – Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.***, also known as the EPRI National Potential Study (2008). In 2008, Global conducted an assessment of the national potential for energy efficiency, with estimates derived for the four DOE regions (including the West region that includes Avista).
- ***EPRI End-Use Models (REEPS and COMMEND)***. These models provide the elasticities we apply to retail gas prices, household income, home size and heating and cooling.

Data Application

We now discuss how the data sources described above were used for each step of the study.

Data Application for Market Characterization

To construct the high-level market characterization of gas use and households/floor space for the residential, commercial, and industrial sectors, we applied sales data from Avista, the U.S. Census ACS, the NWPCC Sixth Plan, NEEA market characterization reports, and the Annual Energy Outlook.

To segment the residential customers into the three segments, we determined the housing type breakdown based on the U.S. Census ACS for and applied it to the number of customers reported in the 2010 Avista billing data. We then estimated the usage per household to calibrate total residential use for each state to the Avista sales data control totals. For commercial and industrial customers, we used the Sixth Plan, the NEEA CBSA, and our Energy Market Profiles to develop estimates of energy intensity. We then inferred the floor stock in square footage. As with the residential sector, total sales for C&I customers were calibrated to match to the Avista sales data control totals for each state.

Data Application for Market Profiles

To develop the market profiles for each segment, we used the following general approach:

1. Developed control totals for each segment as described above. These include market size, segment-level annual gas use, and annual intensity.
2. Used the Sixth Plan and NEEA studies to incorporate information on existing appliance and equipment saturations, appliance and equipment characteristics, building characteristics, customer behavior, operating characteristics, and energy-efficiency actions already taken.
3. Compared and cross-checked with secondary data sources, Energy Market Profiles, and other sources.
4. Ensured calibration to control totals for annual gas sales in each segment.
5. Worked with Avista staff to vet the data against their knowledge and experience.

The specific data elements for the market profiles, together with the key data sources, are shown in Table 2-6.

Table 2-6 Data Applied for the Market Profiles

Model Inputs	Description	Key Sources
Market size	Base-year residential dwellings and C&I floor space	• Utility billing data • American Community Survey • NWPCC Sixth Plan • NEEA Regional Surveys • Energy Market Profiles
Annual intensity	Residential: Annual energy use (kWh/household) C&I: Annual energy use (kWh/sq ft)	• Utility data • NWPCC Sixth Plan • NEEA CBSA • Energy Market Profiles • Previous studies
Appliance/equipment saturations	Fraction of dwellings with an appliance/technology Percentage of C&I floor space with equipment/technology	• NWPCC Sixth Plan • NEEA residential and commercial market studies • Energy Market Profiles
UEC/EUI for each end-use technology	UEC: Annual gas use for a technology in dwellings that have the technology EUI: Annual gas use per square foot for a technology in floor space that has the technology	• NWPCC Sixth Plan and RTF data • HVAC uses: BEST simulations using prototypes developed for Avista • Non HVAC uses: engineering analysis • Energy Market Profiles • California RASS and CEUS • Results from previous studies
Appliance/equipment vintage distribution	Age distribution for each technology	• NWPCC Sixth Plan and RTF data • NEEA regional survey data • Previous Global studies
Efficiency options for each technology	List of available efficiency options and annual energy use for each technology	• DEEM • DEER • Annual Energy Outlook • Previous studies
Peak factors	Share of technology energy use that occurs during the peak hour	• Utility data • EnergyShape database

Data Application for Baseline Forecast

Table 2-7 summarizes the LoadMAP model inputs required for the baseline forecast. These inputs are required for each segment within each sector, as well as for new construction and existing dwellings/buildings.

Table 2-7 Data Needs for the Baseline Forecast and Potentials Estimation in LoadMAP

Model Inputs	Description	Key Sources
Customer growth forecasts	Forecasts of residential customer growth and of C&I employment growth	• Data provided by Avista
Income growth forecasts	Forecast of per capita income	• Data provided by Avista
Equipment purchase shares for baseline forecast	For each equipment/technology, purchase shares for each efficiency level; specified separately for equipment replacement (replace-on-burnout) and new construction	• Shipments data • AEO 2011 forecast assumptions Appliance/efficiency standards analysis • NEEA studies
Gas prices	Forecast of average gas prices	• Avista price forecasts
Utilization model parameters	Price elasticities, elasticities for other variables (income, weather)	• EPRI's REEPS and COMMEND models

We developed initial baseline purchase shares based on the Energy Information Agency's *Annual Energy Outlook* report (2011). Beyond 2011, we assumed a frozen efficiency case in which the purchase shares for efficient equipment do not change during the study period, unless equipment standards remove a technology option from the market. Table 2-8 and Table 2-9 show the assumptions regarding upcoming standards, based on known standards as of January 2011. This approach removes any effects of naturally occurring conservation or effects of future conservation programs that may be embedded in the AEO forecasts. Thus the CPA's resulting forecasts of potential compared to this baseline are gross forecasts because naturally occurring conservation effects have been removed.

Table 2-8 Residential Gas Equipment Standards (Northern)

Today's Efficiency or Standard Assumption
Next Standard (relative to today's standard)
2nd Standard (relative to today's standard)

End Use	Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heating	Furnace	AFUE 80%		AFUE 90% -Non-weatherized		AFUE 90% -Weatherized										
	Boiler	EF 0.81		EF 0.82												
Water Heating	Water Heater (<=55 gallons)	EF 0.59				EF 0.62										
	Water Heater (>55 gallons)	EF 0.59				Condensing Technology										
Appliances	Clothes Dryer	Conventional				5% more efficient										
	Range/Oven	Conventional	No Standing Pilot Light													
Miscellaneous	Pool Heater	Conventional		EF 0.82												

Table 2-9 Commercial and Industrial Gas Equipment Standards

Today's Efficiency or Standard Assumption
Next Standard (relative to today's standard)

End Use	Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heating	Furnace	AFUE 76%														
	Boiler	EF 0.76	EF 0.82													
Water Heating	Water Heater	EF 0.80														
Miscellaneous	Pool Heater	Conventional		EF 0.82												

Energy Conservation Measure Data Application

Table 2-10 details the data sources used for measure characterization.

Table 2-10 Data Needs for the Measure Characteristics in LoadMAP

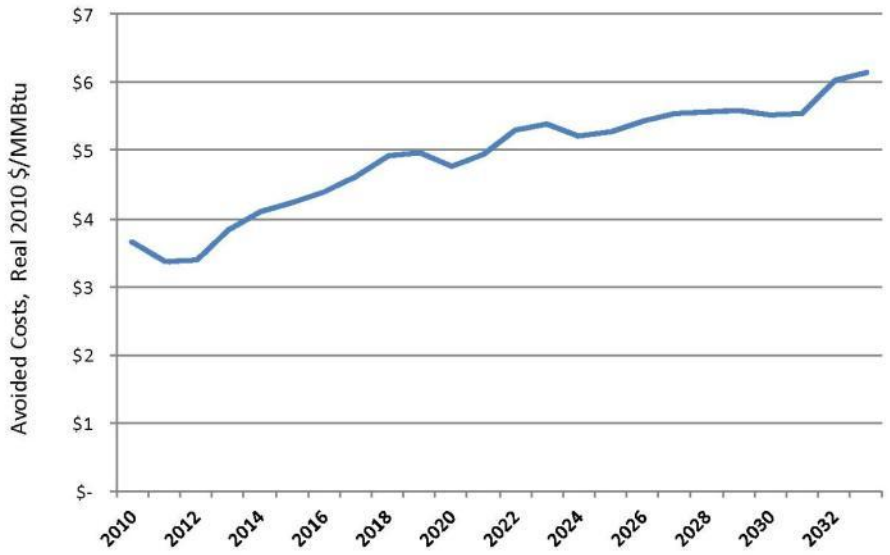
Model Inputs	Description	Key Sources
Energy Impacts	The annual reduction in consumption attributable to each specific measure. Savings were developed as a percentage of the energy end use that the measure affects.	• NWPCC Sixth Plan conservation workbooks • RTF deemed measure databases • BEST • EPRI National Study • DEEM • DEER • Other secondary sources
Costs	Equipment Measures: Includes the full cost of purchasing and installing the equipment on a per-unit or per-square-foot basis for the residential and C&I sectors, respectively Non-equipment measures: Existing buildings – full installed cost. New Construction - the costs may be either the full cost of the measure, or as appropriate, it may be the incremental cost of upgrading from a standard level to a higher efficiency level.	• NWPCC Sixth Plan conservation workbooks • RTF deemed measure databases • DEEM • DEER • Other secondary sources
Measure Lifetimes	Estimates derived from the technical data and secondary data sources that support the measure demand and energy savings analysis	• NWPCC Sixth Plan conservation workbooks • RTF deemed measure databases • DEEM • DEER • Other secondary sources
Applicability	Estimate of the percentage of either dwellings in the residential sector or square feet in the C&I sectors where the measures is applicable and where it is technically feasible to implement	• NWPCC Sixth Plan conservation workbooks • RTF deemed measure databases • DEEM • DEER • Other secondary sources
On Market and Off Market Availability	Expressed as years for equipment measures to reflect when the equipment technology is available or no longer available in the market	• Appliance, building codes, and standards analysis

Data Application for Cost-effectiveness Screening

To perform the cost-effectiveness screening, the following information was needed:

- Avoided cost of energy provided by Avista, as shown in Figure 2-4. The avoided costs are based on forecasted Henry Hub market costs.
- Line (pipeline) losses of 1.9%, provided by Avista
- Discount rate of 4%, provided by Avista
- Program administration costs. For this study, we used a value of 6% provided by Avista.

Figure 2-4 Avoided Costs of Energy Forecast



Potentials Estimation

To estimate potentials, two sets of parameters were required.

- ***Adoption rates for non-equipment measures***. Equipment is assumed to be replaced at the end of its useful life, but for non-equipment measures, a set of factors is required to model the gradual implementation over time. Rather than installing all non-equipment measures in the first year of the forecast (instantaneous potential), they are phased in according to adoption schedules that vary based on equipment cost and measure complexity. The adoption rates for the Avista study were bases on ramp rate curves specified in the NWPCC Sixth Power Plan. These adoption rates are used within LoadMAP to generate the technical and economic potentials.
- ***Market acceptance rates (MARs)***. These factors are applied to Economic potential to estimate Achievable potential. These rates were developed using the Council ramp rates. In some cases, the rates were adjusted to reflect Avista DSM program history.

Ramp rates and MARs are discussed in Appendix E.

CHAPTER | 3

MARKET CHARACTERIZATION AND MARKET PROFILES

Avista Utilities, headquartered in Spokane, Washington is an investor-owned utility with annual revenues of more than $1.3 billion. Avista provides electric and natural gas service to about 481,000 customers in a service territory of more than 30,000 square miles. Avista uses a mix of hydro, natural gas, coal and biomass generation delivered over 2,100 miles of transmission line, 17,000 miles of distribution line, and 6,100 miles of natural gas distribution mains. Avista currently operates a portfolio of electric and natural gas conservation programs in Washington, Idaho, and Oregon for residential, low-income, and non-residential customers that is funded by a non-bypassable systems benefits charge.

Total natural gas use in 2010 for the residential, commercial, and industrial rate classes included in this potential assessment was 315,905,627 therms.[10] As shown in Figure 3-1, the largest sector is residential, accounting for 59.8% of sales, followed by large commercial, with 22.5% of sales.

Figure 3-1 Sector-Level Gas Use, 2010 (percentage of sales)

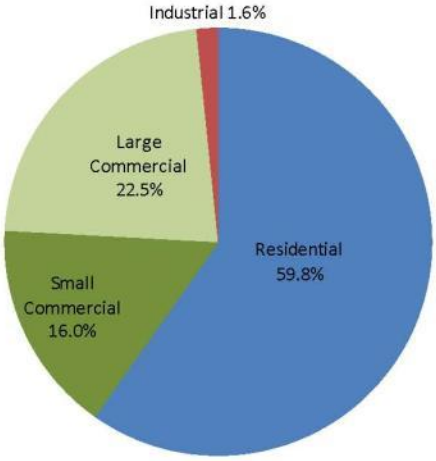


Table 3-1 shows additional detail by state and sector, including the rate classes included in each sector, number of meters, sales, and average use per meter. The gas transportation rate classes, which include relatively large commercial and industrial facilities, were excluded from the CPA analysis. Therefore, most of the remaining industrial customers are relatively small in terms of their gas usage per meter, especially in Oregon.

[10] Energy usage as measured "at-the-meter," i.e., does not include line losses.

Table 3-1 2010 Gas Sales by State and Sector

All States Sector	Rate Class	Number of Meters	2010 Sales (1000 thm)	% of System Sales	Average Use per Meter (thm)
Residential	N/A	282,418	188,894	59.8%	669
Small Commercial	N/A	30,317	50,693	16.0%	1,672
Large Commercial	N/A	3,419	71,176	22.5%	20,818
Industrial	N/A	253	5,141	1.6%	20,322
Total		**316,407**	**315,906**	**100.0%**	**998**
Washington Sector	**Rate Class**	**Number of Meters**	**2010 Sales (1000 thm)**	**% of WA Sales**	**Average Use per Meter (thm)**
Residential	101	132,657	97,372	58.3%	734
Small Commercial	101	11,906	16,706	10.0%	1,403
Large Commercial	111, 112, 121, 122, 132	2,292	49,808	29.8%	21,731
Industrial	101, 111, 121, 122	132	3,135	1.9%	23,752
Washington total		**146,987**	**167,021**	**100.0%**	**1,136**
Idaho Sector	**Rate Class**	**Number of Meters**	**2010 Sales (1000 thm)**	**% of ID Sales**	**Average Use per Meter (thm)**
Residential	101	65,648	44,084	61.2%	672
Small Commercial	101	7,398	8,432	11.7%	1,140
Large Commercial	111, 132	1,050	17,820	24.7%	16,971
Industrial	101, 111, 112	99	1,681	2.3%	16,978
Idaho total		**74,195**	**72,017**	**100.0%**	**971**
Oregon Sector	**Rate Class**	**Number of Meters**	**2010 Sales (1000 thm)**	**% of OR Sales**	**Average Use per Meter (thm)**
Residential	410	84,114	47,438	61.7%	564
Small Commercial	420	11,013	25,556	33.2%	2,320
Large Commercial	424	77	3,548	4.6%	46,081
Industrial	420, 424	22	325	0.4%	14,787
Oregon total		**95,226**	**76,867**	**100.0%**	**807**

Residential Sector

This section characterizes the residential market at a high level, and then provides a profile of how customers in each segment use gas by end use. Total residential gas use in 2010 was 188.9 million therms. Customer information for each segment is shown in Table 3-2. System wide, the single-family segment consumed 84% of total residential sector gas in 2010 as a result of having the largest number of customers and the highest intensity.

Table 3-2 Residential Sector Gas Usage and Intensity by State and Segment Type

All States Residential Segment	Number of Meters	2010 Sales (1000 thm)	% of System Res. Sales	Intensity (thm/HH)
Single Family	222,934	157,830	84%	708
Multi Family	25,755	11,615	6%	451
Mobile Home	33,729	19,450	10%	577
Total	**282,418**	**188,894**	**100%**	**669**
WA Residential Segment	**Number of Meters**	**2010 Sales (1000 thm)**	**% of WA Res. Sales**	**Intensity (thm/HH)**
Single Family	107,230	83,143	85%	775
Multi Family	14,318	6,994	7%	488
Mobile Home	11,109	7,235	7%	651
Washington Total	**132,657**	**97,372**	**100%**	**734**
ID Residential Segment	**Number of Meters**	**2010 Sales (1000 thm)**	**% of ID Res. Sales**	**Intensity (thm/HH)**
Single Family	51,487	36,371	83%	706
Multi Family	4,648	2,068	5%	445
Mobile Home	9,513	5,645	13%	593
Idaho Total	**65,648**	**44,084**	**100%**	**672**
OR Residential Segment	**Number of Meters**	**2010 Sales (1000 thm)**	**% of OR Res. Sales**	**Intensity (thm/HH)**
Single Family	64,217	38,317	81%	597
Multi Family	6,789	2,552	5%	376
Mobile Home	13,107	6,570	14%	501
Oregon Total	**84,114**	**47,438**	**100%**	**564**

As we describe in the previous chapter, the market profiles provide the foundation upon which we develop the baseline forecast. The market profile for the residential sector as a whole for the base year 2010 is presented in Table 3-3. The residential market profiles for each housing segment and state are presented in Appendix A. Bear in mind that the Avista residential customers included in this analysis all have natural gas service, and thus the percentages with

gas space heating and gas water heating, 96% and 77% respectively, are higher than they would be in the general population of all Avista residential customers.

Table 3-3 Market Profile for the Residential Sector

Average Market Profiles

End Use	Technology	Saturation	UEC (Thrm)	Intensity (Thrm/HH)	Usage (mmThrm)
Space Heating	Furnace	83%	535	446.08	125.98
Space Heating	Boiler	2%	415	10.15	2.87
Space Heating	Other Heating	9%	472	40.29	11.38
Water Heating	Water Heater	77%	170	130.41	36.83
Appliances	Clothes Dryer	24%	23	5.59	1.58
Appliances	Stove/Oven	56%	37	20.63	5.83
Miscellaneous	Pool Heater	4%	205	7.95	2.25
Miscellaneous	Miscellaneous	100%	8	7.75	2.19
Total				**668.85**	**188.89**

Figure 3-2 presents the end-use breakout for the average residential household, displaying both annual usage per household and percentage of use. Space heating accounts for the lion's share, with 74% of residential sector gas sales or about 497 therms for the average household in 2010.

Figure 3-2 Residential Gas Use by End Use, Average Therms/Household and Percentage of Sales, 2010

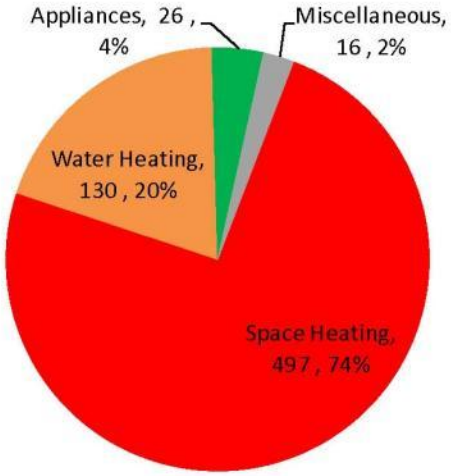
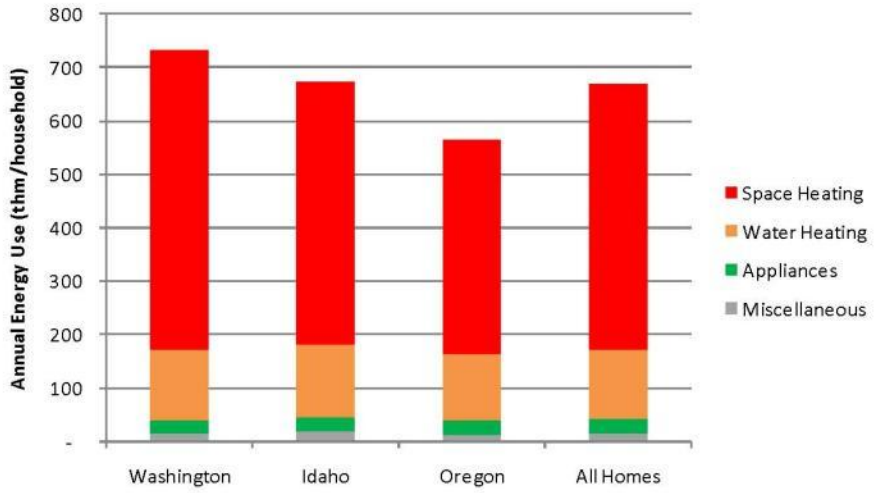


Figure 3-3 shows the breakdown of annual use by end use for the average home in each state and for the Avista residential sector as a whole. Space heating constitutes 77% of gas usage in Washington, 73% in Idaho, and from 71% in Oregon, reflecting the differences in climate among the states.

Figure 3-3 Annual Residential Natural Gas Use by End Use and State, 2010



Commercial and Industrial Sector

Total natural gas use in the commercial and industrial (C&I) sector in 2010 was 127.0 million therms. Avista rate classes were used to allocate this energy use to three segments per state. Intensity estimates in therms/sq. ft. were developed and then used to infer the segment size in floor space for each segment. Table 3-4 displays the resulting sales, intensity, and segment size. Due to the characteristics of the rate structures, a greater percentage of C&I customers in Oregon are classified as small commercial, as compared with Washington and Idaho.

Table 3-4 C&I Sector Gas Usage and Intensity by State and Segment, 2010

All States C&I		2010 Sales (1000 thm)	% of All C&I Sales	Intensity (thm/sq. ft.)	Segment Size (million sq. ft)
Small Commercial	N/A	50,693	40%	0.343	147.798
Large Commercial	N/A	71,176	56%	0.649	109.666
Industrial	N/A	5,141	4%	0.776	6.621
All States Total		**127,011**	**100%**	**0.481**	**264.085**
Washington Sector	**Rate Class**	**2010 Sales (1000 thm)**	**% of WA C&I Sales**	**Intensity (thm/sq. ft.)**	**Segment Size (million sq. ft)**
Small Commercial	101	16,706	24%	0.363	46.021
Large Commercial	111, 112, 121, 122, 132	49,808	72%	0.660	75.467
Industrial	101, 111, 121, 122	3,135	5%	0.792	3.959
Washington Total		**69,649**	**100%**	**0.555**	**125.447**
Idaho Sector	**Rate Class**	**2010 Sales (1000 thm)**	**% of ID C&I Sales**	**Intensity (thm/sq. ft.)**	**Segment Size (million sq. ft)**
Small Commercial	101	8,432	30%	0.347	24.335
Large Commercial	111, 132	17,820	64%	0.630	28.285
Industrial	101, 111, 112	1,681	6%	0.759	2.215
Idaho Total		**27,933**	**100%**	**0.509**	**54.835**
Oregon Sector	**Rate Class**	**2010 Sales (1000 thm)**	**% of OR C&I Sales**	**Intensity (thm/sq. ft.)**	**Segment Size (million sq. ft)**
Small Commercial	420	25,556	87%	0.330	77.441
Large Commercial	424	3,548	12%	0.600	5.914
Industrial	420, 424	325	1%	0.726	0.448
Oregon Total		**29,429**	**100%**	**0.351**	**83.803**

Table 3-5 shows the market profile for C&I customers as a whole, representing a composite of small commercial, large commercial, and industrial. Overall, about 94% of the floor space for these gas customers is heated with natural gas. Market profiles for each segment and state are presented in Appendix A.

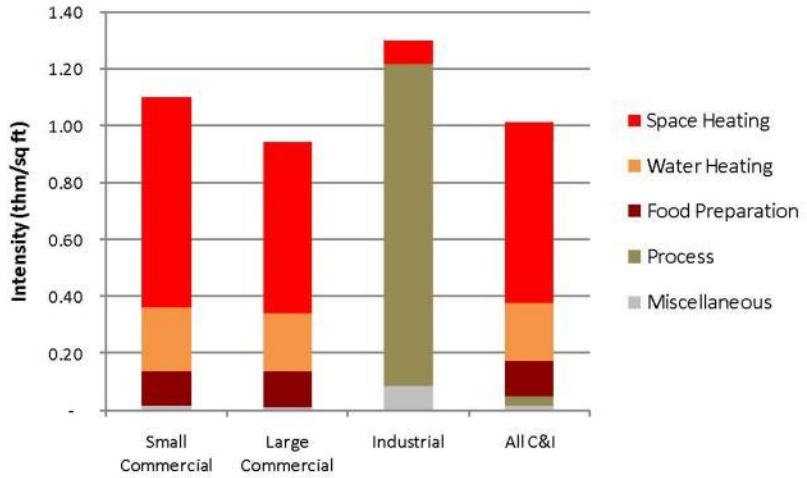
Table 3-5 Commercial Sector Composite Market Profile, 2010

Average Market Profiles

End Use	Technology	Saturation	EUI (Thrm)	Intensity (Thrm/Sqft.)	Usage (mmThrm)
Space Heating	Furnace	60%	0.222	0.133	35.103
Space Heating	Boiler	20%	0.697	0.140	37.098
Space Heating	Other Heating	14%	0.198	0.028	7.379
Water Heating	Water Heater	37%	0.264	0.098	25.816
Food Preparation	Oven	16%	0.042	0.007	1.734
Food Preparation	Fryer	16%	0.064	0.010	2.682
Food Preparation	Broiler	16%	0.064	0.010	2.679
Food Preparation	Griddle	16%	0.064	0.010	2.679
Food Preparation	Range	16%	0.047	0.007	1.978
Food Preparation	Steamer	16%	0.080	0.013	3.342
Process	Process Heating	3%	0.671	0.017	4.446
Process	Process Cooling	3%	0.001	0.000	0.008
Process	Other Process	3%	0.005	0.000	0.030
Miscellaneous	Pool Heater	1%	0.137	0.002	0.409
Miscellaneous	Miscellaneous	100%	0.006	0.006	1.627
	Total			**0.481**	**127.011**

Figure 3-4 illustrates the distribution of gas consumption by end use for small commercial, large commercial, industrial, and C&I facilities as a whole. As one would expect, space heating is the predominant use, representing 63% of overall C&I gas consumption. For industrial facilities however, process heating represents the greatest share.

Figure 3-4 C&I End Use Intensities, 2010



CHAPTER | 4

BASELINE FORECAST

Prior to developing estimates of conservation potential, a baseline end-use forecast was developed to quantify how natural gas is used by end use in the base year and what the consumption is likely to be in the future in absence of new utility programs and naturally occurring conservation. The baseline forecast serves as the metric against which conservation potentials are measured.

Residential Sector

The baseline forecast incorporates assumptions about customer growth, economic growth, natural gas prices, and appliance/equipment standards and building codes already mandated. Figure 4-1 and Table 4-1 present the baseline forecast at the end-use level for the residential sector. Overall, residential use increases, from about 188.9 million therms in 2010 to 269.3 million therms in 2032, a 43% increase, translating to an average annual growth rate of 1.6%.

Figure 4-1 Residential Baseline Forecast by End Use

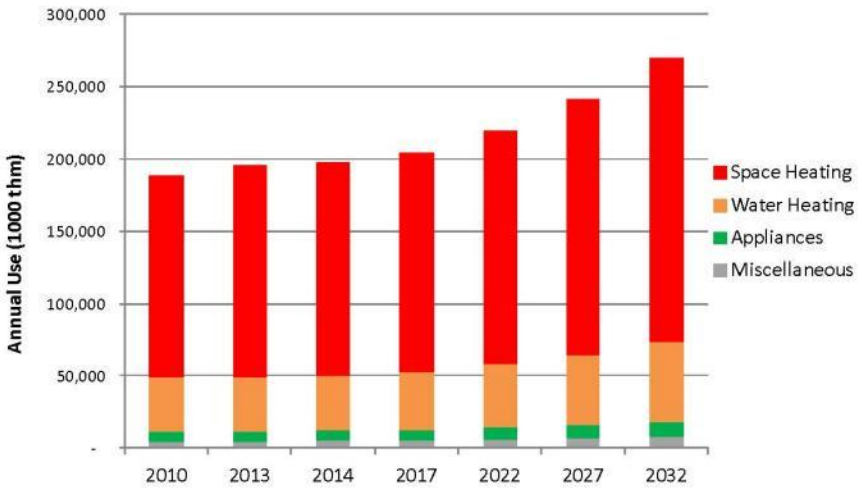


Table 4-1 Residential Baseline Forecast by End Use (1000 therm)

End Use	2010	2013	2014	2017	2022	2027	2032	% Change (2010-2032)	Avg. Growth Rate (2010-2032)
Space Heating	140,227	147,112	147,684	151,812	162,067	176,430	196,022	40%	1.5%
Water Heating	36,830	36,943	37,540	39,382	43,315	48,652	55,025	49%	1.8%
Appliances	7,404	7,313	7,388	7,649	8,319	9,234	10,233	38%	1.5%
Miscellaneous	4,433	4,705	4,837	5,269	6,077	6,975	7,995	80%	2.7%
Total	**188,894**	**196,073**	**197,449**	**204,112**	**219,778**	**241,292**	**269,274**	**43%**	**1.6%**

Table 4-2 shows the end-use forecast at the technology level.

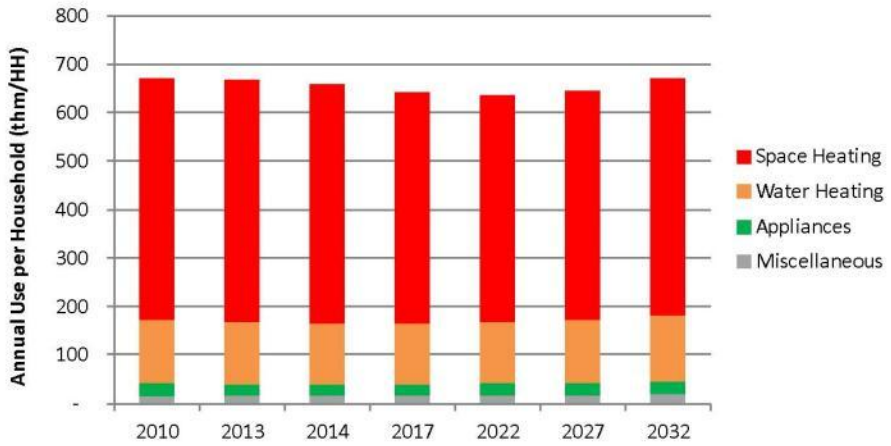
Table 4-2 Residential Baseline Forecast by End Use and Technology (1000 therm)

End Use	Technology	2010	2013	2014	2017	2022	2027	2032	% Change (2010-2032)	Avg. Growth Rate (2010-2032)
Space Heating	Furnace	125,981	131,500	131,729	134,695	142,731	154,426	170,969	36%	1.4%
	Boiler	2,866	3,062	3,106	3,242	3,526	3,912	4,377	53%	1.9%
	Other Heating	11,380	12,549	12,849	13,876	15,810	18,093	20,677	82%	2.7%
Water Heating	Water Heater	36,830	36,943	37,540	39,382	43,315	48,652	55,025	49%	1.8%
Appliances	Clothes Dryer	1,579	1,363	1,328	1,199	1,113	1,180	1,294	-18%	-0.9%
	Stove/Oven	5,825	5,950	6,060	6,451	7,206	8,054	8,939	53%	1.9%
Miscellaneous	Miscellaneous	2,187	2,330	2,399	2,628	3,055	3,530	4,054	85%	2.8%
	Pool Heater	2,246	2,376	2,438	2,642	3,022	3,445	3,941	75%	2.6%
Grand Total		**188,894**	**196,073**	**197,449**	**204,112**	**219,778**	**241,292**	**269,274**	**43%**	**1.6%**

Gas consumption for all end uses and technologies increases, mainly due to the projected 1.7% annual growth in the number of households, but also due to slight increases in the average home physical size. Other heating, which includes unit wall heaters, and miscellaneous loads have a relatively high growth rate compared to other loads, but at the end of the study period these loads are still constitute only a small part of overall use.

Figure 4-2 presents the forecast of use per household. Most noticeable is that space heating, water heating, and appliance use all decrease slightly, due to new equipment standards that come into effect between 2014 and 2015. After 2022, however, total use begins to grow again, due to the assumption that average home size continues to grow slightly as older housing stock is replaced.

Figure 4-2 Residential Baseline Use per Household by End Use



Commercial and Industrial Sector

Natural gas use in the C&I sector continues to grow, albeit slowly, during the forecast horizon, as new C&I construction increases overall square footage in the commercial sector. In addition, existing buildings are renovated to incorporate additional amenities, such as full-scale kitchens. Consumption starts at 127 million therms in 2010 and increases to nearly 136 million therms in 2032, an overall growth of 7.1%.

Figure 4-3 and Table 4-3 present the baseline forecast at the end-use level for the C&I sector as a whole. All end uses show growth over the forecast period, with the exception of space heating with only 2% growth, which is attributed to upcoming equipment standards.

Figure 4-3 Commercial and Industrial Baseline Forecast by End Use

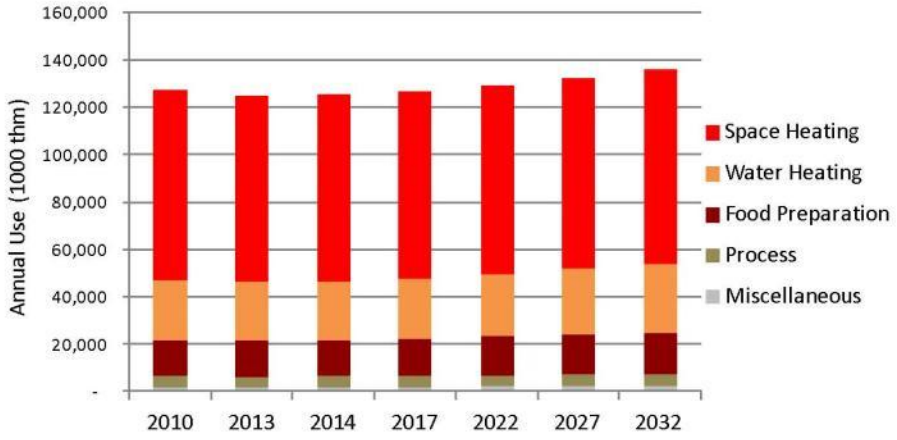


Table 4-3 Commercial Natural Gas Consumption by End Use (1000-therm)

End Use	2010	2013	2014	2017	2022	2027	2032	% Change (2010-2032)	Avg. Growth Rate (2010-2032)
Space Heating	79,580	78,184	78,553	79,021	79,488	80,114	81,826	2.8%	0.1%
Water Heating	25,816	24,685	24,873	25,412	26,574	27,892	29,251	13.3%	0.6%
Food Preparation	15,095	15,122	15,312	15,724	16,374	16,969	17,527	16.1%	0.7%
Process	4,484	4,391	4,430	4,517	4,632	4,759	4,898	9.2%	0.4%
Miscellaneous	2,036	2,047	2,077	2,146	2,251	2,359	2,473	21.5%	0.9%
Total	**127,011**	**124,429**	**125,244**	**126,819**	**129,319**	**132,094**	**135,976**	**7.1%**	**0.3%**

Table 4-4 presents the commercial sector forecast by technology. Specific observations include:

- Growth in the HVAC and water heating end uses is moderate, commensurate with projected growth in floor space and employment, the two principal drivers of commercial sector consumption.
- Food preparation, though remaining a small percentage of total usage, grows at a higher rate than other end uses. This reflects the addition of kitchen facilities to commercial office buildings during new construction or renovation, as well as the expansion of food service offerings in other building types as well.
- Consumption by miscellaneous equipment also increases. This reflects the assumption that buildings in the commercial sector will increase use.
- Growth in process heating is also commensurate with projected industrial growth.

Table 4-4 C&I Baseline Natural Gas Forecast by End Use and Technology (MWh)

End Use	Technology	2010	2013	2014	2017	2022	2027	2032	% Change (2010-2032)	Avg. Growth Rate (2010-2032)
Space Heating	Furnace	35,103	35,003	35,302	35,791	36,092	36,193	37,071	5.6%	0.2%
	Boiler	37,098	35,899	35,918	35,864	36,180	36,810	37,762	1.8%	0.1%
	Other Heating	7,379	7,282	7,332	7,366	7,216	7,111	6,993	-5.2%	-0.2%
Water Heating	Water Heater	25,816	24,685	24,873	25,412	26,574	27,892	29,251	13.3%	0.6%
Food Preparation	Fryer	2,682	2,695	2,732	2,814	2,942	3,062	3,178	18.5%	0.8%
	Oven	1,734	1,744	1,769	1,825	1,917	2,006	2,086	20.3%	0.8%
	Broiler	2,679	2,712	2,758	2,864	3,035	3,206	3,376	26.0%	1.1%
	Griddle	2,679	2,712	2,757	2,862	3,027	3,190	3,352	25.1%	1.0%
	Range	1,978	2,002	2,035	2,111	2,227	2,336	2,438	23.2%	0.9%
	Steamer	3,342	3,257	3,262	3,249	3,225	3,169	3,097	-7.3%	-0.3%
Process	Process Heating	4,446	4,353	4,392	4,478	4,593	4,719	4,857	9.2%	0.4%
	Process Cooling	8	8	8	8	8	8	9	9.2%	0.4%
	Other Process	30	30	30	30	31	32	33	9.2%	0.4%
Miscellaneous	Pool Heater	409	412	417	428	442	459	480	17.4%	0.7%
	Miscellaneous	1,627	1,635	1,660	1,718	1,809	1,900	1,993	22.5%	0.9%
Grand Total		**127,011**	**124,429**	**125,244**	**126,819**	**129,319**	**132,094**	**135,976**	**7.1%**	**0.3%**

System-wide Baseline Forecast

Table 4-5 and Figure 4-4 provide an overall summary of the baseline forecast by sector for Avista as a whole. Overall, the forecast for the next 20 years grows steadily, dominated by growth in the residential sector, as discussed above.

Table 4-5 Baseline Forecast Summary (1000 therm)

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%**
Small Commercial	50,693	50,130	50,530	51,271	52,378	53,494	55,120	9%	**0.4%**
Large 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%**

Figure 4-4 Baseline Forecast Summary, by Sector

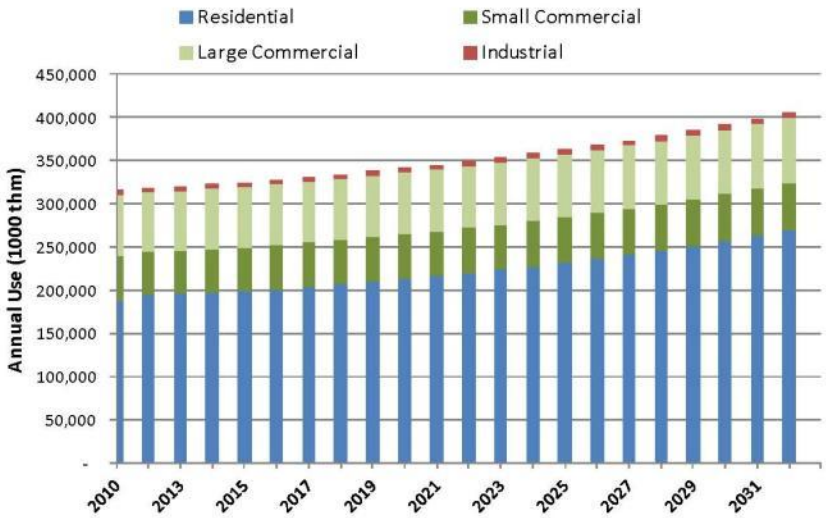


Table 4-6 and Figure 4-5 provide an overall summary of the baseline forecast by state. Growth is projected to be highest in Idaho, based on assumptions regarding customer growth, followed by Oregon.

Table 4-6 Baseline Forecast Summary, by State (1000-therm)

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%**

Figure 4-5 Baseline Forecast Summary, By State

CHAPTER | 5

CONSERVATION POTENTIAL

This chapter presents the results of the potential analysis, with overall potential presented first, followed by results for each sector. All results show cumulative potential. Additional details for all years and incremental annual results appear in Appendix F.

Table 5-1 summarizes achievable potential by state and sector for selected years.

Table 5-1 Cumulative Achievable Conservation Potential by State and by Sector

Cumulative Savings (1000 therm)	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 therm)	2013	2014	2017	2022	2027	2032
Residential	515	1,567	6,507	14,903	22,278	29,960
Small Comercial	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**

As shown in Figure 5-2, 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 changes, so that the residential sector's share of savings is greatest, mainly due to growth in residential customer count.

Figure 5-1 Cumulative Achievable Conservation Potential Savings by Sector

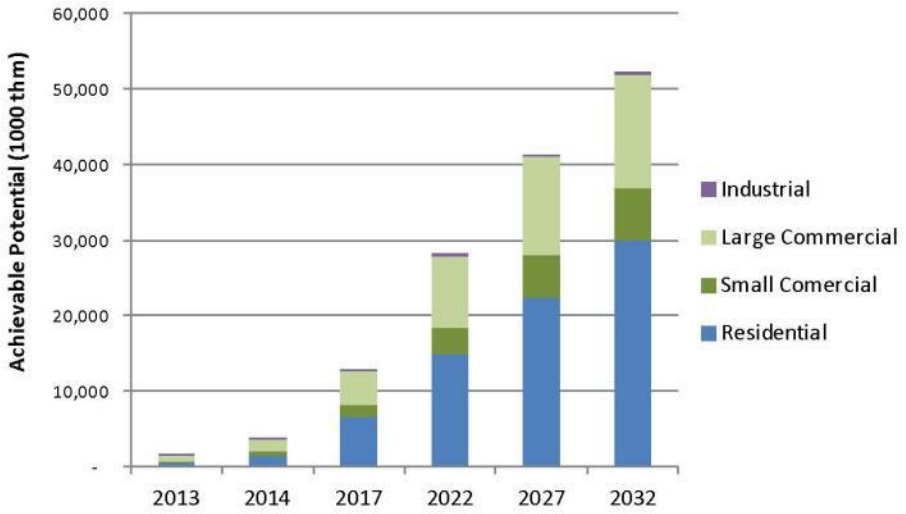


Table 5-2 presents the baseline forecasts of energy consumption, as well as the three levels of conservation potential for the residential, commercial, and industrial sectors. As discussed in detail in Chapter 4, the baseline forecast across all sectors increases over the 20-year time period. This is due largely to the growth in the residential sector, which is tempered somewhat due to appliance and equipment standards, building codes, and a sluggish economy in the initial years. Key findings related to potentials are summarized below.

- ***Achievable potential*** across the residential, commercial, and industrial sectors is 28.2 million therms in 2022 and increases to 52.4 million therms by 2032. These savings represent 8.1% of the baseline forecast in 2022 and 12.9% in 2032.
- ***Economic potential***, which reflects the savings when all cost-effective measures are taken, is 31.8 million therms in 2022. This represents 9.1% of the baseline energy forecast. By 2032, economic potential reaches 59.0 million therms, 14.6% of the baseline energy forecast.
- ***Technical potential***, which reflects the adoption of all conservation measures regardless of cost-effectiveness, is a theoretical upper bound on savings. Technical potential is substantial, because measures such as solar thermal water heating could cut energy use dramatically. In 2022, energy savings are 91.7 million therms, equivalent to 26.3% of the baseline energy forecast. By 2032, technical potential reaches 157.5 million therms, 38.9% of the baseline energy forecast. The relatively wide gap between technical and economic potential reflects the low avoided costs, as well as the fact that Avista's long-running conservation programs have already achieved much of the cost-effective conservation. As a result, additional conservation measures are becoming relatively more costly, and many do not pass the cost-effectiveness screen based on Avista's current avoided costs.

Table 5-2 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%

Figure 5-2 summarizes the energy-efficiency savings for the three levels of potential relative to the baseline forecast. Figure 5-3 displays the baseline and conservation potential forecasts. The dotted black line depicts the 2010 usage level. In 2022, Achievable potential, indicated by the blue line, offsets 89% of the growth in the baseline forecast since 2012. By 2032, Achievable potential offsets 60% of that growth.

Figure 5-2 Summary of Cumulative Conservation Potential Savings

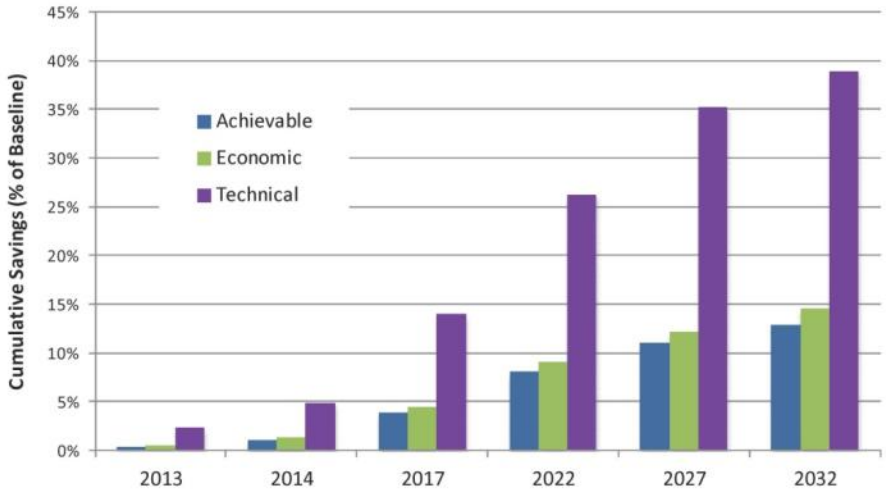
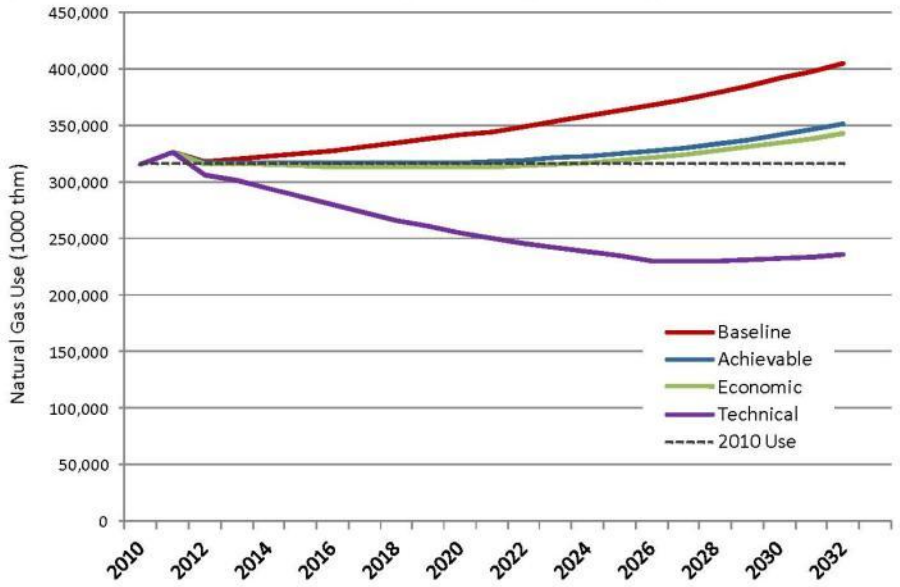


Figure 5-3 Conservation Potential Energy Forecasts (1000 therm)



Residential Sector

Table 5-3 presents estimates for the three types of potential for the residential sector. Note that we have included in the achievable and economic potential specific weatherization measures in Oregon, which although not cost-effective, are mandated to be included in residential DSM programs.

- ***Achievable potential*** is 14.9 million therms in 2022. This level of potential is equivalent to 6.8% of the residential baseline forecast for that year. By 2032, the cumulative achievable conservation savings are 30.0 million therms, 11.1% of the baseline forecast.
- ***Economic potential,*** which reflects the savings when all cost-effective measures are taken, is 16.8 million therms in 2022, or 7.6% of the baseline energy forecast. By 2032, economic potential reaches 34.4 million therms, 12.8% of the baseline energy forecast.
- ***Technical potential,*** which reflects the adoption of all energy conservation measures regardless of cost, is a theoretical upper bound on savings. The 10-year technical potential is 55.2 million therms, or 25.1% of the baseline energy forecast. By 2032, technical potential reaches 101.4 million therms, 37.6% of the baseline energy forecast.

Table 5-3 Residential Sector Cumulative Conservation Potential Summary

	2013	2014	2017	2022	2027	2032
Baseline Forecast (1000 thm)						
	196,073	197,449	204,112	219,778	241,292	269,274
Cumulative Natural Gas Savings (1000 thm)						
Achievable	515	1,567	6,507	14,903	22,278	29,960
Economic	732	2,034	7,839	16,771	25,105	34,439
Technical	4,757	9,491	28,678	55,233	80,721	101,352
Cumulative Natural Gas Savings (% of Baseline)						
Achievable	0.3%	0.8%	3.2%	6.8%	9.2%	11.1%
Economic	0.4%	1.0%	3.8%	7.6%	10.4%	12.8%
Technical	2.4%	4.8%	14.0%	25.1%	33.5%	37.6%

Figure 5-4 summarizes the energy-efficiency savings for the three levels of potential relative to the baseline forecast. Figure 5-5 displays the baseline and conservation potential forecasts. The dotted black line depicts the 2010 usage level. In 2022, Achievable potential, indicated by the blue line, offsets 50% of the growth in the residential baseline forecast since 2012. By 2032, Achievable potential offsets 38% of that growth.

Figure 5-4 Residential Cumulative Conservation Potential Savings

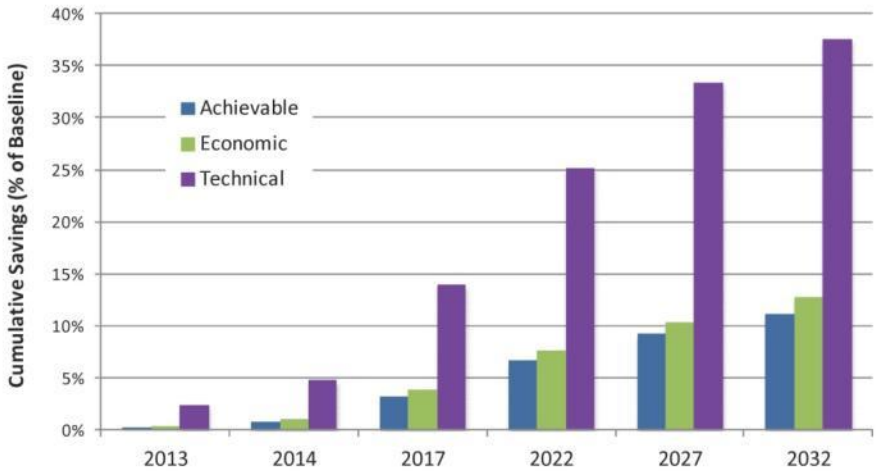
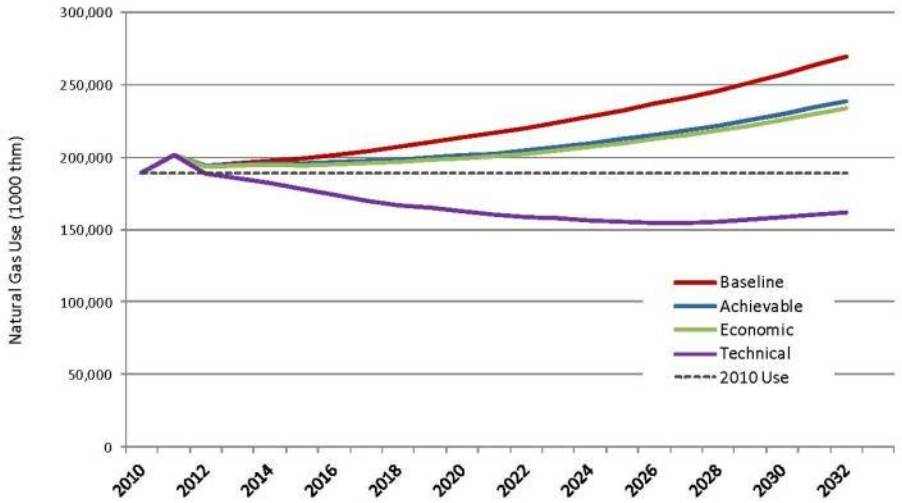


Figure 5-5 Residential Conservation Potential Forecast



Residential Potential by Housing Type and State

Single-family homes represent about 79% of Avista's residential gas customers, but accounted for 84% of the sector's consumption in 2010. The distribution of potential savings by segment is nearly the same as the distribution of consumption among the sectors, as shown in Table 5-4.

Table 5-4 Residential Cumulative Achievable Potential by Housing Type, Selected Years

	2013	2014	2017	2022	2027	2032
Baseline Forecast (1000 therm)						
Single Family	163,823	164,914	170,332	183,163	200,847	223,978
Multi Family	12,108	12,234	12,736	13,824	15,255	17,033
Mobile Home	20,143	20,300	21,045	22,791	25,189	28,263
Total	**196,073**	**197,449**	**204,112**	**219,778**	**241,292**	**269,274**
Natural Gas Savings (1000 therm)						
Single Family	427	1,343	5,472	12,713	18,853	24,847
Multi Family	26	65	310	750	1,265	2,041
Mobile Home	61	158	724	1,441	2,161	3,072
Total	**515**	**1,567**	**6,507**	**14,903**	**22,278**	**29,960**
% of Total Residential Savings						
Single Family	83.0%	85.7%	84.1%	85.3%	84.6%	82.9%
Multi Family	5.1%	4.2%	4.8%	5.0%	5.7%	6.8%
Mobile Home	11.9%	10.1%	11.1%	9.7%	9.7%	10.3%

The distribution of achievable savings by state is shown in Table 5-5. Whereas Oregon represents only about one-quarter of the baseline forecast, it makes up between 28 and 35% of the achievable potential savings. This is due to the inclusion of mandated weatherization and insulation measures within Oregon's achievable potential.

Table 5-5 Residential Cumulative Achievable Potential by State, Selected Years

	2013	2014	2017	2022	2027	2032
Baseline Forecast (1000 therm)						
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 therm)						
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%

Table 5-6 shows additional detail by state for 2022, including the cumulative economic and technical potential, as well as achievable potential. We note that technical potential savings as a percentage of baseline is roughly the same across the states. However, economic and achievable potential as a percentage of baseline use is highest in Oregon, again because of the inclusion of mandated weatherization and insulation measures.

Table 5-6 Residential Cumulative Potential Summary by State, 2022

	Washington	Idaho	Oregon[1]	All States
Baseline Forecast	110,964	52,647	56,167	219,778
Energy Savings (1000 thm)				
Achievable	7,268	2,337	5,298	14,903
Economic	8,322	2,723	5,726	16,771
Technical	27,441	13,235	14,557	55,233
Energy Savings (% of Baseline)				
Achievable	6.6%	4.4%	9.4%	6.8%
Economic	7.5%	5.2%	10.2%	7.6%
Technical	24.7%	25.1%	25.9%	25.1%

1. Oregon potential includes mandated residential weatherization and insulation measures.

Residential Potential by End Use, Technology and Measure Type

Table 5-7 provides estimates of savings for each end use and type of potential. Focusing first on technical potential, there are significant savings possible; however, due to low avoided costs, many of these measures are cost-ineffective and thus economic and achievable potential are much lower.

- ***Space heating***, which is the highest use in the residential sector, offers between 53% and 59% of the technical potential, depending on the year. This potential would be achieved if all furnaces, boilers, and unit heaters were replaced with the most efficient units available, and all insulation, weatherization, and controls measures were installed as well. However, in most cases, with the exception of boilers and unit heaters in selected housing types, the higher-efficiency units are not cost-effective compared with standard efficiency units. And many of the weatherization measures are likewise cost-ineffective, especially in the earlier years of the forecast. In 2022, space heating represents 69% of economic potential and 70% of achievable potential.
- ***Water Heating*** offers between 40% and 46% of technical potential depending on the year. This potential reflects the across the board-installation of solar water heating. However, solar water heating is not cost-effective, particularly in the Northwestern climate. In addition, higher-efficiency conventional equipment is not cost-effective compared with standard efficiency models. However, many of the water heating non-equipment measures, such as insulating tanks and pipes or flow-reducing devices, are cost-effective and thus do contribute to economic and achievable potential. In 2022, water heating represents 31% of economic potential and 30% of achievable potential.
- ***Appliances and Miscellaneous*** represent a small percentage of the technical potential in any given year — so small that even when combined they constitute less than 1% of the total technical potential. In any case, equipment upgrades were not found to be cost-effective, so economic and achievable potential for these two end uses are zero.

Table 5-7 Residential Cumulative Savings by End Use and Potential Type (1000-therm)

		2013	2014	2017	2022	2027	2032
Space Heating	Achievable	291	991	3,922	10,416	15,924	21,100
	Economic	455	1,314	4,808	11,535	17,696	24,187
	Technical	2,666	5,061	16,073	31,492	46,405	59,916
Water Heating	Achievable	223	576	2,585	4,488	6,354	8,859
	Economic	277	721	3,032	5,235	7,409	10,252
	Technical	2,042	4,332	12,396	23,354	33,787	40,830
Appliances	Achievable	0	0	0	0	0	0
	Economic	0	0	0	0	0	0
	Technical	32	63	114	182	221	240
Misc.	Achievable	0	0	0	0	0	0
	Economic	0	0	0	0	0	0
	Technical	17	36	95	205	308	365
Total	**Achievable**	**515**	**1,567**	**6,507**	**14,903**	**22,278**	**29,960**
	Economic	**732**	**2,034**	**7,839**	**16,771**	**25,105**	**34,439**
	Technical	**4,757**	**9,491**	**28,678**	**55,233**	**80,721**	**101,352**

As described in Chapter 2, using our LoadMAP model, we develop separate estimates of potential for equipment and non-equipment measures. Table 5-8 presents results for equipment at the technology level and Table 5-9 presents non-equipment measures in 2022. In any given year, at least 94% of the savings come from the non-equipment measures.

Table 5-8 Residential Cumulative Achievable Potential, Equipment Measures (1000 thm)

End Use	Technology	2012	2013	2014	2017	2022	2027	2032
Space Heating	Furnace	-	-	-	-	-	-	-
	Boiler	3	6	16	78	244	448	682
	Other Heating	12	20	34	91	257	506	748
Water Heating	Water Heater	7	10	24	24	26	24	-
Total Equipment Savings		22	**36**	**73**	**193**	**527**	**979**	**1,430**

Table 5-9 Residential Cumulative Achievable Potential, Non-equip. Measures (1000 thm)

Non-Equipment Measure	2012	2013	2014	2017	2022	2027	2032
Advanced New Construction Designs	-	-	-	-	-	-	-
Home Energy Management System	109	45	126	446	1,655	2,565	3,626
Doors - Storm and Thermal	-	-	-	-	-	-	-
Insulation - Ceiling	3	3	7	28	102	187	231
Insulation - Ducting	14	11	25	112	396	654	738
Insulation - Foundation	-	-	-	-	-	-	-
Insulation - Infiltration Control	36	46	139	918	3,035	4,227	5,784
Insulation - Wall Cavity	13	10	24	107	397	690	824
Thermostat - Clock/Programmable	96	125	320	1,377	1,875	1,953	2,164
ENERGY STAR Homes	-	-	-	-	-	-	-
Furnace - Maintenance	-	-	-	-	-	-	-
Boiler - Pipe Insulation	0	0	1	6	16	33	45
Insulation - Attic Hatch	1	1	2	8	30	54	80
Ducting - Repair and Sealing	33	25	297	750	2,409	4,607	6,178
Fireplace - Damper Control	-	-	-	-	-	-	-
Windows - ENERGY STAR	-	-	-	-	-	-	-
Water Heating - Faucet Aerators	18	25	66	302	474	541	610
Water Heating - Low Flow Showerheads	73	116	295	1,406	2,409	2,821	3,166
Water Heating - Pipe Insulation	30	40	107	497	794	895	1,000
Water Heating - Tank Blanket/Insulation	26	33	85	355	477	470	469
Water Heating - Thermostat Setback	-	-	-	-	-	374	1,953
Water Heating - Timer	-	-	-	-	-	-	-
Water Heating - Hot Water Saver	-	-	-	-	308	1,228	1,662
Water Heating - Drainwater Heat Recovery	-	-	-	-	-	-	-
Total, Non-equipment Measures	**452**	**478**	**1,493**	**6,314**	**14,376**	**21,299**	**28,531**
Total, All Measures	**475**	**515**	**1,567**	**6,507**	**14,903**	**22,278**	**29,960**

Based on the above measure-by measure findings, the greatest sources of residential achievable potential in 2022, across all three states, are as follows:

- ***Shell measures and insulation***, which representing 6.4 million therms or 43% of all savings
- ***Thermostats and home energy monitoring systems***, which provide 3.5 million therms or 24% of all savings
- ***Water-saving devices***, including low-flow showerheads and faucet aerators, which combine for 3.2 million therms or 21% of achievable potential
- ***Water heater tank blankets and pipe insulation***, which provide an additional 1.3 million therms or nearly 9% of achievable potential

Commercial and Industrial Sector Potential

The baseline forecast for the C&I sector grows steadily during the forecast period as the region emerges from the economic downturn. As a result, opportunities for energy-efficiency savings are significant for the commercial sector. However, as with the residential sector, many conservation opportunities are cost-ineffective, given current projections of gas avoided costs.

- ***Achievable potential*** projects 13.3 million therms of energy savings in 2022 and 22.4 million therms in 2032. This corresponds to 10.3% of the baseline forecast in 2022 and 16.5% in 2032.
- ***Economic potential,*** which reflects the savings when all cost-effective measures are taken, is 15.0 million therms in 2022. This represents 11.6% of the baseline energy forecast. By 2032, economic potential reaches 24.5 million therms, 18.0% of the baseline energy forecast.
- ***Technical potential,*** which reflects the adoption of all energy conservation measures regardless of cost, is a theoretical upper bound on savings. In 2022, technical potential energy savings are 36.4 million therms, or 28.2% of the baseline energy forecast. By 2032, technical potential reaches 56.1 million therms, 41.3% of the baseline energy forecast.

Table 5-10 and Figure 5-6 present the savings associated with each level of potential. Figure 5-7 shows the C&I sector baseline forecast and the three potential level forecasts, as well as the 2010 usage level.

Table 5-10 C&I Sector Cumulative Conservation Potential Summary

	2013	2014	2017	2022	2027	2032
Baseline Forecast (1000 thm)						
	124,429	125,244	126,819	129,319	132,094	135,976
Cumulative Natural Gas Savings (1000 thm)						
Achievable	1,031	2,172	6,287	13,312	19,071	22,422
Economic	1,065	2,299	6,945	14,986	20,704	24,526
Technical	2,865	6,353	17,511	36,422	50,702	56,169
Cumulative Natural Gas Savings (% of Baseline)						
Achievable	0.8%	1.7%	5.0%	10.3%	14.4%	16.5%
Economic	0.9%	1.8%	5.5%	11.6%	15.7%	18.0%
Technical	2.3%	5.1%	13.8%	28.2%	38.4%	41.3%

Figure 5-6 C&I Cumulative Conservation Potential Savings

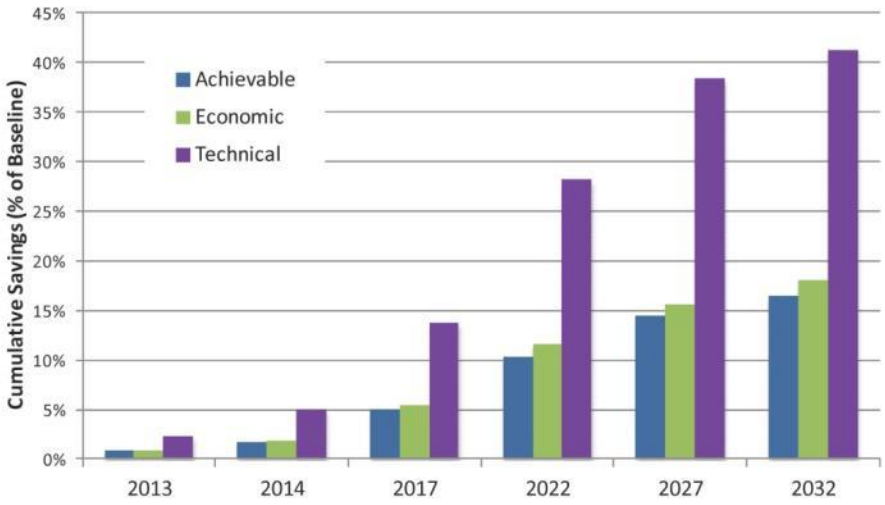
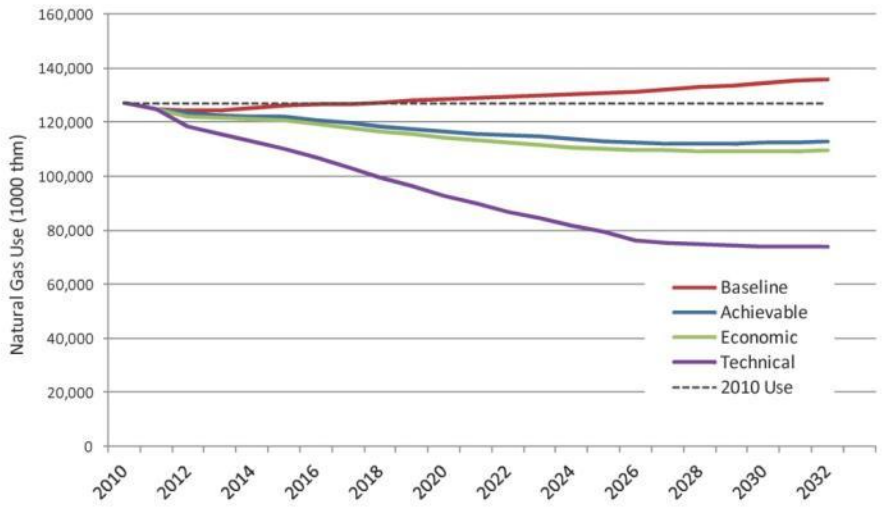


Figure 5-7 C&I Energy Efficiency Potential Forecast



C&I Potential by Segment and State

Table 5-11 and Table 5-12 provide additional detail on the cumulative achievable potential for selected years. As expected, the large commercial segment provides the greatest savings.

Table 5-11 C&I Cumulative Achievable Potential by Sector, Selected Years

	2013	2014	2017	2022	2027	2032
Baseline Forecast (1000 therm)						
Sm. Commercial	50,130	50,530	51,271	52,378	53,494	55,120
Lg. Commercial	69,274	69,647	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 therm)						
Sm. Commercial	206	469	1,588	3,557	5,709	7,018
Lg. 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						
Sm. Commercial	20.0%	21.6%	25.3%	26.7%	29.9%	31.3%
Lg. 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%

Table 5-12 C&I Cumulative Achievable Potential by State, Selected Years

	2013	2014	2017	2022	2027	2032
Baseline Forecast (1000 therm)						
Washington	67,722	68,107	68,790	69,944	71,299	73,259
Idaho	27,702	28,002	28,700	29,780	30,910	32,239
Oregon	29,006	29,135	29,329	29,595	29,885	30,477
Total	**124,429**	**125,244**	**126,819**	**129,319**	**132,094**	**135,976**
Natural Gas Savings (1000 therm)						
Washington	655	1,365	3,906	8,096	11,251	13,015
Idaho	243	514	1,486	3,264	4,756	5,668
Oregon	133	293	895	1,953	3,064	3,739
Total	**1,031**	**2,172**	**6,287**	**13,312**	**19,071**	**22,422**
% of Total C&I Savings						
Washington	63.5%	62.8%	62.1%	60.8%	59.0%	58.0%
Idaho	23.6%	23.7%	23.6%	24.5%	24.9%	25.3%
Oregon	12.9%	13.5%	14.2%	14.7%	16.1%	16.7%

Table 5-13 shows additional detail by state and sector for 2022, including the cumulative economic and technical potential, as well as achievable potential. We note that although potential as a percentage of baseline use varies from one sector to the next, results do not vary greatly among the three states.

Table 5-13 C&I Cumulative Potential Summary by Sector and State, 2022

	Washington			Idaho			Oregon			Total C&I
	Small Comm.	Large Comm.	Ind.	Small Comm.	Large Comm.	Ind.	Small Comm.	Large Comm.	Ind.	
Baseline (1000 therm)										
	17,589	49,101	3,255	8,690	19,407	1,683	26,099	3,159	337	129,319
Cumulative Natural Gas Savings (1000 therm)										
Achievable	1,425	6,477	193	581	2,578	105	1,550	382	21	13,312
Economic	1,693	7,062	203	711	2,843	110	1,924	418	22	14,986
Technical	4,824	14,796	379	2,330	6,036	197	6,927	894	39	36,422
Cumulative Savings (% of Baseline)										
Achievable	8.1%	13.2%	5.9%	6.7%	13.3%	6.2%	5.9%	12.1%	6.1%	10.3%
Economic	9.6%	14.4%	6.2%	8.2%	14.7%	6.6%	7.4%	13.2%	6.4%	11.6%
Technical	27.4%	30.1%	11.6%	26.8%	31.1%	11.7%	26.5%	28.3%	11.7%	28.2%

Potential by End Use, Technology, and Measure Type

Table 5-14 presents the C&I sector savings by end use and potential type.

- ***Space heating*** has the highest savings for technical potential at 20.0 million therms in 2022. These savings would result from installation of high-efficiency equipment and numerous thermal shell measures, HVAC control strategies, and retrocommissioning. Many of these measures are cost-effective, resulting in economic potential savings of 10.7 million therms in 2022, or 53% of technical potential savings.
- ***Food service equipment*** offers technical potential savings at 2.9 million therms in 2022, and because these equipment upgrades are mostly cost-effective, economic potential in that year is 2.7 million therms.
- ***Water heating***, including equipment upgrades, hot water saving fixtures, and controls, has 2022 technical potential of 12.9 million therms, but because the equipment upgrades are cost-ineffective, economic potential of 1.3 million therms is only 10% of the technical potential.
- ***Process equipment*** for industrial uses has technical potential savings of 0.5 million therms in 2022, and economic potential in that year is 0.3 million therms.

Table 5-14 C&I Cumulative Potential by End Use and Potential Type (1000 therm)

		2013	2014	2017	2022	2027	2032
Space Heating	Achievable	859	1,752	4,896	10,328	14,766	17,424
	Economic	662	1,442	4,636	10,728	15,579	18,895
	Technical	1,306	2,877	8,952	20,071	27,393	31,405
Water Heating	Achievable	88	221	675	1,113	1,647	2,133
	Economic	75	193	699	1,257	1,821	2,398
	Technical	1,210	2,766	6,795	12,917	19,307	20,723
Food Preparation	Achievable	63	158	583	1,585	2,351	2,540
	Economic	314	629	1,479	2,697	2,953	2,859
	Technical	321	646	1,540	2,879	3,277	3,253
Process	Achievable	21	41	133	286	307	325
	Economic	14	34	131	304	351	374
	Technical	25	57	211	518	671	731
Miscellaneous	Achievable	0	0	0	0	0	0
	Economic	1	1	1	1	0	0
	Technical	3	6	13	36	54	57
Total	**Achievable**	**1,031**	**1,279**	**6,287**	**13,312**	**19,071**	**22,422**
	Economic	**1,065**	**2,299**	**6,945**	**14,986**	**20,704**	**24,527**
	Technical	**2,865**	**6,353**	**17,511**	**36,422**	**50,702**	**56,169**

Table 5-15 and Table 5-16 present achievable potential savings for equipment measures and non-equipment measures, respectively.

Table 5-15 C&I Cumulative Achievable Potential, Equipment Measures (1000 thm)

End Use	Technology	2013	2014	2017	2022	2027	2032
Space Heating	Furnace	32	84	361	1,031	1,959	2,385
	Boiler	60	149	472	928	1,419	2,114
	Other Heating	4	4	4	4	12	48
Water Heating	Water Heater	-	-	-	-	-	-
Food Preparation	Fryer	15	37	137	381	583	654
	Oven	9	23	88	250	387	436
	Broiler	-	-	-	-	-	-
	Griddle	6	16	59	168	264	306
	Range	8	20	75	212	328	370
	Steamer	25	62	223	574	789	758
Total Equipment Savings		**158**	**395**	**1,419**	**3,548**	**5,741**	**7,071**

Table 5-16 C&I Cumulative Achievable Potential, Non-equip. Measures (1000 thm)

Non-Equipment Measure	2013	2014	2017	2022	2027	2032
Advanced New Construction Designs	17	52	234	971	2,338	3,456
Custom Measures	-	-	-	-	-	133
Energy Management System	252	497	1,100	2,056	2,812	2,927
Insulation - Ceiling	8	23	89	286	589	854
Insulation - Ducting	-	-	-	-	-	-
Insulation - Wall Cavity	4	8	135	326	703	959
Thermostat - Clock/Programmable	50	98	218	412	564	592
Windows - High Efficiency	-	-	-	-	-	-
Furnace - Maintenance	-	-	-	-	-	52
Ducting - Repair and Sealing	-	-	-	-	-	-
Water Heating - Faucet Aerators	75	184	540	701	740	774
Water Heating - Pipe Insulation	-	-	-	-	-	-
Water Heating - Tank Blanket/Insulation	8	19	54	69	73	76
Water Heating - Hot Water Saver	-	-	-	-	-	-
Boiler - Maintenance	140	273	876	1,832	1,898	1,876
Boiler - Hot Water Reset	122	235	729	1,428	1,428	1,384
Boiler - High Eff. Hot Water Circulation	65	127	276	507	683	699
Space Heating - Heat Recovery Vent.	112	220	484	888	1,193	1,243
Comprehensive Retrocommissioning	-	-	-	-	-	-
Comprehensive Commissioning	-	-	-	-	-	-
Process - Boiler Hot Water Reset	21	41	133	286	307	325
Total, Non-equipment Measures	**873**	**1,777**	**4,868**	**9,764**	**13,329**	**15,350**
Total, All Measures	**1,031**	**2,172**	**6,287**	**13,312**	**19,071**	**22,422**

Based on the above, the primary sources of commercial sector achievable savings are as follows:

- ***Energy management systems and programmable thermostats***, because they can be readily installed, account for about 27% of achievable potential in 2014. These controls remain significant contributors to cumulative potential, with 2.5 million therms or 19% of potential in 2022.
- ***Boiler operating measures***, including maintenance, hot water reset, and efficient circulation, together can provide 4.3 million therms or about 29% of achievable potential in 2022.
- ***Equipment upgrades for furnaces, boilers, and unit heaters*** equal 2.0 million therms, or 15% of 2022 achievable potential.
- ***Foodservice equipment*** has an achievable potential by 2022 of 1.6 million therms, or 12% of achievable potential.

ABOUT GLOBAL

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APPENDIX 4.2 II ENVIRONMENTAL EXTERNALITIES OVERVIEW (OREGON JURISDICTION ONLY)

The methodology for determining avoided costs from reduced incremental natural gas usage considers commodity and variable transportation costs only. These avoided cost streams do not include environmental externality costs related to the gathering, transmission, distribution or end-use of natural gas.

Per traditional economic theory and industry practice, an environmental externality factor is typically added to the avoided cost when there is an opportunity to displace traditional supply-side resources with an alternative resource with no adverse environmental impact.

REGULATORY GUIDANCE

The Oregon Public Utility Commission (OPUC) issued Order 93-965 (UM-424) to address how utilities should consider the impact of environmental externalities in planning for future energy resources. The Order required analysis on the potential natural gas cost impacts from emitting carbon dioxide (CO_2) and nitric-oxide (NOx).

The OPUC's Order No. 07-002 in Docket UM 1056 (Investigation Into Integrated Resource Planning) established the following guideline for the treatment of environmental costs used by energy utilities that evaluate demand-side and supply-side energy choices:

> UM 1056, Guideline 8 - Environmental Costs
>
> *"Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides (NOx), sulfur oxides (SO_2), and mercury (Hg) emissions. Utilities should analyze the range of potential CO2 regulatory costs in Order No. 93-695, from $0 - $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides (NOx), sulfur dioxide (SO2), and mercury (Hg), if applicable.*

In June 2008, the OPUC issued Order 08-338 (UM1302) which revised UM1056, Guideline 8. The revised guideline requires the utility should construct a base case portfolio to reflect what it considers to be the most likely regulatory compliance future for the various emissions. Additionally the guideline requires the utility to develop several compliance scenarios ranging from the present CO2 regulatory level to the upper reaches of credible proposals and each scenario should include a time profile of CO2 costs. The utility is also required to include a "trigger point" analysis in which the utility must determine at what level of carbon costs its selection of portfolio resources would be significantly different.

ANALYSIS

Unlike electric utilities, environmental cost issues rarely impact a natural gas utility's supply-side resource options. This is because the only supply-side energy resource is natural gas. The utility cannot choose between say "dirty" coal-fired generation and "clean" wind energy sources. The supply-side implication of environmental externalities generally relates to combustion of fuel to move or compress natural gas. Avista's direct gas distribution system infrastructure relies solely on the upstream line pressure of the

interstate pipeline transportation network to distribute natural gas to its customers and thus does not directly combust fuels that result in any CO_2, NOx, SO2, or Hg emissions.

Upstream gas system infrastructure (pipelines, storage facilities, and gathering systems), however, do produce CO_2 emissions via compressors used to pressurize and move natural gas. Accessing CO_2 emissions data on these upstream activities to perform detailed meaningful analysis is challenging. In the 2009 Natural Gas IRP there was significant momentum regarding GHG legislation and the movement towards the creation of carbon cap and trade markets or tax structure. Since then, the momentum has slowed significantly. Where there is still a focus on reducing GHG emissions and improving the nation's carbon footprint, the timing of implementing a carbon cap and trade/tax framework has been delayed. Additionally, the pricing level of the framework has been greatly reduced.. Whichever structure ultimately gets implemented, Avista believes the cost pass through mechanisms for upstream gas system infrastructure will not make a difference in supply-side resource selection although the amount of cost pass through could differ widely.

Table 4.2.1 summarizes a range of environmental cost adders we believe capture several compliance futures including our expected scenario. The CO2 cost adders reflect outlooks we obtained from one of our consultants, and following discussion and feedback from the TAC, have been incorporated into our Expected, Low Growth/High Price, and Alternate Planning Standard portfolios.

The guidelines also call for a trigger point analysis that reflects a "turning point" at which an alternate resource portfolio would be selected at different carbon cost adders levels. Because natural gas is the only supply resource applicable to LDC's any alternate resource portfolio selection would be a result of delivery methods of natural gas to customers. Conceptually, there could be differing levels of cost adders applicable to pipeline transported supply versus in service territory LNG storage gas. From a practical standpoint however, the differences in these relative cost adders would be very minor and would not change supply-side resource selection regardless of various carbon cost adder levels. We do acknowledge there is influence to the avoided costs which would impact the cost effectiveness of demand-side measures in the DSM business planning process.

CONSERVATON COST ADVANTAGE

For this IRP, we also incorporated a 10 percent environmental externality factor into our assessment of the cost-effectiveness of existing demand-side management programs. Our assessment of prospective demand-side management opportunities is based on an avoided cost stream that includes this 10 percent factor.

Environmental externalities were evaluated in the IRP by adding the cost per therm equivalent of the externality cost values to supply-side resources as described in OPUC Order No. 93-965. Avista found that the environmental cost adders had no impact on the company's supply-side choices, although they did impact the level of demand-side measures that could be cost-effective to acquire.

REGULATORY FILING

Avista will file revised cost-effectiveness limits (CELs) based upon the updated avoided costs available from this IRP process within the prescribed regulatory timetable.

Table 4.2.1 Environmental Externalities Cost Adder Analysis (2010$)

			2020	2025	2030	2035
Expected Carbon Case	NOx	$/ton	$ 2,500	$ 2,500	$ 2,500	$ 2,500
		$/lb	$ 1.25	$ 1.25	$ 1.25	$ 1.25
		lbs/therm	0.008	0.008	0.008	0.008
		NOx Adder $/therm	$ 0.01	$ 0.01	$ 0.01	$ 0.01
	CO2	$/ton	$ -	$ 16.67	$ 21.05	$ 22.31
		$/lb	$ -	$ 0.0079	$ 0.0105	$ 0.0112
		lbs/therm	11.64	11.64	11.64	11.64
		CO2 Adder $/therm	$ -	$ 0.10	$ 0.12	$ 0.13
	Total	**Total Adders $/therm**	**$ 0.01**	**$ 0.10**	**$ 0.13**	**$ 0.14**
			2020	**2025**	**2030**	**2035**
High Carbon Case	NOx	$/ton	$ 2,500	$ 2,500	$ 2,500	$ 2,500
		$/lb	$ 1.25	$ 1.25	$ 1.25	$ 1.25
		lbs/therm	0.008	0.008	0.008	0.008
		NOx Adder $/therm	$ 0.01	$ 0.01	$ 0.01	$ 0.01
	CO2	$/ton	$ 40.00	$ 60.00	$ 85.00	$ 100.00
		$/lb	$ 0.0200	$ 0.0300	$ 0.0425	$ 0.0500
		lbs/therm	11.64	11.64	11.64	11.64
		CO2 Adder $/therm	$ 0.23	$ 0.35	$ 0.49	$ 0.58
	Total	**Total Adders $/therm**	**$ 0.24**	**$ 0.36**	**$ 0.50**	**$ 0.59**
			2020	**2025**	**2030**	**2035**
Expected Carbon Low Nox	NOx	$/ton	$ 500	$ 500	$ 500	$ 500
		$/lb	$ 0.25	$ 0.25	$ 0.25	$ 0.25
		lbs/therm	0.008	0.008	0.008	0.008
		NOx Adder $/therm	$ 0.00	$ 0.00	$ 0.00	$ 0.00
	CO2	$/ton	$ -	$ 15.73	$ 21.05	$ 22.31
		$/lb	$ -	$ 0.0079	$ 0.0105	$ 0.0112
		lbs/therm	11.64	11.64	11.64	11.64
		CO2 Adder $/therm	$ -	$ 0.09	$ 0.12	$ 0.13
	Total	**Total Adders $/therm**	**$ 0.00**	**$ 0.09**	**$ 0.12**	**$ 0.13**

APPENDIX 5.1 II CURRENT TRANSPORTATION/STORAGE RATES AND ASSUMPTIONS

Rates in US$/Dth/Day

	Reservation	Commodity	Fuel Rate 3/	Rate Change Assumptions
TransCanada Alberta System Firm Rates -				
Postage Stamp Rates				
AECo/NIT to ABC	0.1910	-	0.00%	Changes every three years
AECo/NIT to ABC Winter Only	0.2388	-	0.00%	Changes every three years
TransCanada BC System Firm Rates -				
Postage Stamp Rates				
ABC to Kingsgate	0.0990	0.0300	1.10%	Changes every three years
GTN FTS-1 Rates				
Mileage Based - Representative Example				
Kingsgate to Spokane	0.0931	0.0017	0.25%	Changes every five years
Kingsgate to Medford	0.3376	0.0096	1.38%	Changes every five years
Meford Lateral	0.8244	-	0.00%	Changes every five years
Spectra Energy/Westcoast System Firm Rates -				
Postage Stamp Rates				
Station 2 to Huntington/Sumas	0.4112	-	0.80%	Changes every three years
Williams NWP 4/				
Postage Stamp Rates				
TF-1 1/	0.4100	0.03000	1.30%	Changes every five years
TF-2 1/	0.4100	0.03000	1.30%	Changes every five years
SGS-2F 2/	0.4751	0.01734	0.52%	Changes every five years

1/ TF-1 based upon annual delivery capability. TF-2 based upon approximately 32 days of delivery capability
2/ Not applicable for WA/ID Customers
3/ Fuel retained in-kind
4/ New rate effective January 2013

APPENDIX 5.2 II ALTERNATE SUPPLY SCENARIOS

	Existing Resources	Existing + Expected Available	GTN Fully Subscribed
INPUT ASSUMPTIONS			
Resources	Currently contracted capacity net of long term releases	Currently contracted capacity net of long term releases Currently available GTN Capacity Release Recalls NWP Expansions Satellite LNG	Currently contracted capacity net of long term releases Capacity Release Recalls NWP Expansions Satellite LNG
Rates	Current Rates	Current Rates	Current Rates

APPENDIX 6.1 II MONTHLY PRICE DATA BY BASIN

EXPECTED PRICE

			2010$											
Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Expected Case	AECo	2011-2012	$ 2.90	$ 2.73	$ 2.29	$ 2.82	$ 2.88	$ 2.38	$ 2.49	$ 2.63	$ 2.69	$ 2.57	$ 2.47	$ 2.59
Expected Case	AECo	2012-2013	$ 3.04	$ 3.13	$ 3.37	$ 3.51	$ 3.58	$ 3.52	$ 3.50	$ 3.51	$ 3.54	$ 3.54	$ 3.54	$ 3.57
Expected Case	AECo	2013-2014	$ 3.76	$ 3.84	$ 3.85	$ 3.85	$ 3.86	$ 3.70	$ 3.65	$ 3.68	$ 3.71	$ 3.71	$ 3.72	$ 3.74
Expected Case	AECo	2014-2015	$ 3.93	$ 3.93	$ 3.97	$ 3.98	$ 3.99	$ 3.85	$ 3.84	$ 3.89	$ 3.92	$ 3.91	$ 3.88	$ 3.89
Expected Case	AECo	2015-2016	$ 4.06	$ 4.06	$ 4.09	$ 4.10	$ 4.16	$ 4.01	$ 4.02	$ 4.06	$ 4.08	$ 4.08	$ 4.07	$ 4.08
Expected Case	AECo	2016-2017	$ 4.25	$ 4.24	$ 4.27	$ 4.29	$ 4.31	$ 4.14	$ 4.19	$ 4.22	$ 4.25	$ 4.25	$ 4.25	$ 4.26
Expected Case	AECo	2017-2018	$ 4.40	$ 4.44	$ 4.49	$ 4.52	$ 4.52	$ 4.35	$ 4.39	$ 4.43	$ 4.46	$ 4.47	$ 4.46	$ 4.47
Expected Case	AECo	2018-2019	$ 4.58	$ 4.65	$ 4.67	$ 4.70	$ 4.69	$ 4.52	$ 4.56	$ 4.59	$ 4.63	$ 4.64	$ 4.57	$ 4.58
Expected Case	AECo	2019-2020	$ 4.67	$ 4.72	$ 4.78	$ 4.81	$ 4.75	$ 4.61	$ 4.64	$ 4.68	$ 4.72	$ 4.73	$ 4.66	$ 4.67
Expected Case	AECo	2020-2021	$ 4.79	$ 4.85	$ 4.88	$ 4.91	$ 4.89	$ 4.73	$ 4.77	$ 4.81	$ 4.85	$ 4.87	$ 4.68	$ 4.69
Expected Case	AECo	2021-2022	$ 4.80	$ 4.84	$ 4.87	$ 4.90	$ 4.74	$ 4.62	$ 4.66	$ 4.69	$ 4.72	$ 4.74	$ 4.70	$ 4.69
Expected Case	AECo	2022-2023	$ 4.84	$ 4.87	$ 4.89	$ 4.92	$ 4.91	$ 4.79	$ 4.84	$ 4.89	$ 4.92	$ 4.94	$ 4.78	$ 4.78
Expected Case	AECo	2023-2024	$ 4.89	$ 4.92	$ 4.94	$ 4.97	$ 4.77	$ 4.65	$ 4.67	$ 4.74	$ 4.77	$ 4.79	$ 4.74	$ 4.75
Expected Case	AECo	2024-2025	$ 4.86	$ 4.89	$ 4.91	$ 4.94	$ 4.87	$ 4.74	$ 4.76	$ 4.81	$ 4.87	$ 4.89	$ 4.79	$ 4.80
Expected Case	AECo	2025-2026	$ 4.98	$ 5.00	$ 5.03	$ 5.06	$ 4.90	$ 4.77	$ 4.80	$ 4.86	$ 4.89	$ 4.91	$ 4.87	$ 4.87
Expected Case	AECo	2026-2027	$ 5.00	$ 5.03	$ 5.05	$ 5.08	$ 4.85	$ 4.71	$ 4.74	$ 4.79	$ 4.82	$ 4.84	$ 4.82	$ 4.82
Expected Case	AECo	2027-2028	$ 4.97	$ 5.00	$ 5.03	$ 5.06	$ 4.89	$ 4.75	$ 4.80	$ 4.83	$ 4.87	$ 4.89	$ 4.85	$ 4.86
Expected Case	AECo	2028-2029	$ 5.02	$ 5.05	$ 5.08	$ 5.11	$ 4.96	$ 4.79	$ 4.82	$ 4.86	$ 4.90	$ 4.92	$ 4.91	$ 4.91
Expected Case	AECo	2029-2030	$ 5.06	$ 5.10	$ 5.13	$ 5.15	$ 4.91	$ 4.76	$ 4.79	$ 4.84	$ 4.90	$ 4.91	$ 4.91	$ 4.92
Expected Case	AECo	2030-2031	$ 5.06	$ 5.13	$ 5.16	$ 5.19	$ 5.01	$ 4.86	$ 4.89	$ 4.96	$ 5.00	$ 5.02	$ 5.01	$ 5.02
Expected Case	Malin	2011-2012	$ 3.01	$ 2.97	$ 2.48	$ 3.00	$ 3.06	$ 2.52	$ 2.80	$ 2.94	$ 3.01	$ 2.89	$ 2.78	$ 2.91
Expected Case	Malin	2012-2013	$ 3.34	$ 3.45	$ 3.69	$ 3.83	$ 3.87	$ 3.79	$ 3.82	$ 3.82	$ 3.86	$ 3.87	$ 3.86	$ 3.89
Expected Case	Malin	2013-2014	$ 4.06	$ 4.18	$ 4.18	$ 4.19	$ 4.15	$ 3.98	$ 3.99	$ 4.02	$ 4.05	$ 4.07	$ 4.09	$ 4.12
Expected Case	Malin	2014-2015	$ 4.28	$ 4.31	$ 4.34	$ 4.34	$ 4.29	$ 4.15	$ 4.17	$ 4.19	$ 4.21	$ 4.24	$ 4.26	$ 4.29
Expected Case	Malin	2015-2016	$ 4.44	$ 4.48	$ 4.51	$ 4.52	$ 4.47	$ 4.37	$ 4.38	$ 4.40	$ 4.45	$ 4.47	$ 4.48	$ 4.51
Expected Case	Malin	2016-2017	$ 4.67	$ 4.69	$ 4.71	$ 4.74	$ 4.62	$ 4.55	$ 4.58	$ 4.61	$ 4.64	$ 4.66	$ 4.69	$ 4.71
Expected Case	Malin	2017-2018	$ 4.88	$ 4.93	$ 4.95	$ 4.98	$ 4.87	$ 4.80	$ 4.82	$ 4.85	$ 4.90	$ 4.92	$ 4.94	$ 4.97
Expected Case	Malin	2018-2019	$ 5.08	$ 5.15	$ 5.15	$ 5.18	$ 5.05	$ 4.95	$ 4.95	$ 4.98	$ 5.07	$ 5.10	$ 5.07	$ 5.09
Expected Case	Malin	2019-2020	$ 5.15	$ 5.24	$ 5.19	$ 5.22	$ 5.10	$ 4.97	$ 5.01	$ 5.04	$ 5.13	$ 5.16	$ 5.13	$ 5.15
Expected Case	Malin	2020-2021	$ 5.25	$ 5.32	$ 5.33	$ 5.36	$ 5.23	$ 5.07	$ 5.12	$ 5.15	$ 5.23	$ 5.26	$ 5.19	$ 5.21
Expected Case	Malin	2021-2022	$ 5.30	$ 5.36	$ 5.33	$ 5.36	$ 5.09	$ 5.01	$ 5.05	$ 5.08	$ 5.12	$ 5.16	$ 5.17	$ 5.19
Expected Case	Malin	2022-2023	$ 5.32	$ 5.36	$ 5.38	$ 5.41	$ 5.26	$ 5.19	$ 5.22	$ 5.25	$ 5.31	$ 5.33	$ 5.26	$ 5.29
Expected Case	Malin	2023-2024	$ 5.44	$ 5.48	$ 5.44	$ 5.47	$ 5.16	$ 5.10	$ 5.05	$ 5.12	$ 5.19	$ 5.23	$ 5.18	$ 5.24
Expected Case	Malin	2024-2025	$ 5.40	$ 5.46	$ 5.44	$ 5.47	$ 5.30	$ 5.20	$ 5.14	$ 5.19	$ 5.28	$ 5.31	$ 5.26	$ 5.31
Expected Case	Malin	2025-2026	$ 5.52	$ 5.57	$ 5.55	$ 5.58	$ 5.31	$ 5.22	$ 5.23	$ 5.28	$ 5.32	$ 5.35	$ 5.37	$ 5.40
Expected Case	Malin	2026-2027	$ 5.54	$ 5.59	$ 5.57	$ 5.61	$ 5.26	$ 5.17	$ 5.18	$ 5.23	$ 5.27	$ 5.29	$ 5.32	$ 5.35
Expected Case	Malin	2027-2028	$ 5.49	$ 5.55	$ 5.53	$ 5.56	$ 5.30	$ 5.20	$ 5.23	$ 5.27	$ 5.31	$ 5.34	$ 5.37	$ 5.40
Expected Case	Malin	2028-2029	$ 5.55	$ 5.60	$ 5.59	$ 5.63	$ 5.37	$ 5.24	$ 5.26	$ 5.30	$ 5.35	$ 5.38	$ 5.41	$ 5.44
Expected Case	Malin	2029-2030	$ 5.56	$ 5.64	$ 5.62	$ 5.66	$ 5.33	$ 5.24	$ 5.26	$ 5.30	$ 5.35	$ 5.38	$ 5.41	$ 5.47
Expected Case	Malin	2030-2031	$ 5.60	$ 5.66	$ 5.68	$ 5.72	$ 5.42	$ 5.33	$ 5.36	$ 5.41	$ 5.46	$ 5.49	$ 5.52	$ 5.57
Expected Case	Rockies	2011-2012	$ 2.92	$ 2.94	$ 2.44	$ 2.96	$ 3.03	$ 2.49	$ 2.73	$ 2.86	$ 2.93	$ 2.81	$ 2.71	$ 2.83
Expected Case	Rockies	2012-2013	$ 3.25	$ 3.36	$ 3.61	$ 3.75	$ 3.79	$ 3.71	$ 3.74	$ 3.75	$ 3.79	$ 3.79	$ 3.79	$ 3.81
Expected Case	Rockies	2013-2014	$ 3.98	$ 4.09	$ 4.09	$ 4.10	$ 4.07	$ 3.90	$ 3.92	$ 3.94	$ 3.97	$ 3.99	$ 4.01	$ 4.04
Expected Case	Rockies	2014-2015	$ 4.19	$ 4.22	$ 4.25	$ 4.26	$ 4.21	$ 4.07	$ 4.09	$ 4.11	$ 4.13	$ 4.16	$ 4.18	$ 4.21
Expected Case	Rockies	2015-2016	$ 4.35	$ 4.39	$ 4.42	$ 4.43	$ 4.38	$ 4.29	$ 4.30	$ 4.32	$ 4.37	$ 4.39	$ 4.39	$ 4.42
Expected Case	Rockies	2016-2017	$ 4.58	$ 4.59	$ 4.62	$ 4.64	$ 4.53	$ 4.47	$ 4.50	$ 4.52	$ 4.56	$ 4.58	$ 4.60	$ 4.63
Expected Case	Rockies	2017-2018	$ 4.79	$ 4.84	$ 4.86	$ 4.89	$ 4.77	$ 4.72	$ 4.74	$ 4.76	$ 4.81	$ 4.84	$ 4.85	$ 4.88
Expected Case	Rockies	2018-2019	$ 4.98	$ 5.05	$ 5.06	$ 5.08	$ 4.96	$ 4.87	$ 4.87	$ 4.90	$ 4.97	$ 4.99	$ 4.98	$ 5.00
Expected Case	Rockies	2019-2020	$ 5.01	$ 5.07	$ 5.06	$ 5.09	$ 4.98	$ 4.86	$ 4.84	$ 4.86	$ 4.91	$ 4.93	$ 4.91	$ 4.96
Expected Case	Rockies	2020-2021	$ 5.08	$ 5.16	$ 5.15	$ 5.18	$ 5.09	$ 4.95	$ 4.94	$ 4.97	$ 5.04	$ 5.05	$ 4.90	$ 4.94
Expected Case	Rockies	2021-2022	$ 5.06	$ 5.13	$ 5.11	$ 5.14	$ 4.92	$ 4.79	$ 4.80	$ 4.83	$ 4.88	$ 4.90	$ 4.86	$ 4.89
Expected Case	Rockies	2022-2023	$ 5.04	$ 5.11	$ 5.11	$ 5.14	$ 5.04	$ 4.89	$ 4.91	$ 4.93	$ 4.98	$ 5.01	$ 4.90	$ 4.93
Expected Case	Rockies	2023-2024	$ 5.04	$ 5.11	$ 5.06	$ 5.09	$ 4.81	$ 4.74	$ 4.69	$ 4.71	$ 4.80	$ 4.83	$ 4.80	$ 4.85
Expected Case	Rockies	2024-2025	$ 4.95	$ 5.05	$ 5.05	$ 5.08	$ 4.89	$ 4.70	$ 4.64	$ 4.66	$ 4.76	$ 4.79	$ 4.78	$ 4.84
Expected Case	Rockies	2025-2026	$ 5.17	$ 5.27	$ 5.29	$ 5.32	$ 5.06	$ 4.96	$ 4.97	$ 5.00	$ 5.07	$ 5.10	$ 5.08	$ 5.10
Expected Case	Rockies	2026-2027	$ 5.21	$ 5.29	$ 5.28	$ 5.30	$ 4.98	$ 4.87	$ 4.90	$ 4.92	$ 4.99	$ 5.01	$ 5.00	$ 5.02
Expected Case	Rockies	2027-2028	$ 5.14	$ 5.22	$ 5.22	$ 5.23	$ 4.96	$ 4.88	$ 4.90	$ 4.93	$ 5.00	$ 5.03	$ 4.99	$ 5.01
Expected Case	Rockies	2028-2029	$ 5.13	$ 5.23	$ 5.22	$ 5.25	$ 4.97	$ 4.89	$ 4.89	$ 4.92	$ 5.01	$ 5.04	$ 5.02	$ 5.04
Expected Case	Rockies	2029-2030	$ 5.13	$ 5.22	$ 5.21	$ 5.24	$ 4.89	$ 4.83	$ 4.85	$ 4.88	$ 4.95	$ 4.97	$ 4.99	$ 5.02
Expected Case	Rockies	2030-2031	$ 5.10	$ 5.21	$ 5.21	$ 5.25	$ 4.94	$ 4.90	$ 4.93	$ 4.96	$ 5.03	$ 5.05	$ 5.05	$ 5.08

APPENDIX 6.1 II MONTHLY PRICE DATA BY BASIN
EXPECTED PRICE

			2010$											
Scenario	**Index**	**Gas Year**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**
Expected Case	Stanfield	2011-2012	$ 2.95	$ 2.97	$ 2.45	$ 2.97	$ 2.95	$ 2.48	$ 2.72	$ 2.86	$ 2.93	$ 2.81	$ 2.67	$ 2.79
Expected Case	Stanfield	2012-2013	$ 3.24	$ 3.34	$ 3.58	$ 3.72	$ 3.78	$ 3.71	$ 3.74	$ 3.74	$ 3.78	$ 3.79	$ 3.75	$ 3.77
Expected Case	Stanfield	2013-2014	$ 3.97	$ 4.07	$ 4.07	$ 4.08	$ 4.06	$ 3.89	$ 3.89	$ 3.92	$ 3.95	$ 3.97	$ 3.97	$ 3.99
Expected Case	Stanfield	2014-2015	$ 4.16	$ 4.18	$ 4.22	$ 4.23	$ 4.20	$ 4.04	$ 4.04	$ 4.08	$ 4.11	$ 4.12	$ 4.13	$ 4.16
Expected Case	Stanfield	2015-2016	$ 4.31	$ 4.34	$ 4.37	$ 4.39	$ 4.37	$ 4.23	$ 4.24	$ 4.27	$ 4.31	$ 4.33	$ 4.34	$ 4.37
Expected Case	Stanfield	2016-2017	$ 4.54	$ 4.54	$ 4.57	$ 4.60	$ 4.53	$ 4.41	$ 4.44	$ 4.47	$ 4.50	$ 4.52	$ 4.54	$ 4.56
Expected Case	Stanfield	2017-2018	$ 4.73	$ 4.77	$ 4.80	$ 4.83	$ 4.74	$ 4.64	$ 4.67	$ 4.70	$ 4.74	$ 4.77	$ 4.77	$ 4.80
Expected Case	Stanfield	2018-2019	$ 4.92	$ 4.98	$ 5.12	$ 5.15	$ 4.92	$ 4.80	$ 4.81	$ 4.83	$ 4.90	$ 4.92	$ 4.90	$ 5.04
Expected Case	Stanfield	2019-2020	$ 5.11	$ 5.07	$ 5.18	$ 5.21	$ 4.98	$ 4.84	$ 4.86	$ 4.90	$ 4.96	$ 4.98	$ 4.95	$ 4.97
Expected Case	Stanfield	2020-2021	$ 5.11	$ 5.30	$ 5.33	$ 5.36	$ 5.12	$ 4.96	$ 4.98	$ 5.02	$ 5.08	$ 5.10	$ 5.00	$ 5.03
Expected Case	Stanfield	2021-2022	$ 5.27	$ 5.34	$ 5.32	$ 5.36	$ 4.98	$ 4.86	$ 4.89	$ 4.92	$ 4.96	$ 4.99	$ 4.98	$ 5.01
Expected Case	Stanfield	2022-2023	$ 5.30	$ 5.33	$ 5.37	$ 5.40	$ 5.15	$ 5.04	$ 5.07	$ 5.10	$ 5.13	$ 5.16	$ 5.07	$ 5.10
Expected Case	Stanfield	2023-2024	$ 5.39	$ 5.43	$ 5.44	$ 5.47	$ 5.03	$ 4.93	$ 4.90	$ 4.96	$ 5.02	$ 5.05	$ 5.00	$ 5.05
Expected Case	Stanfield	2024-2025	$ 5.35	$ 5.41	$ 5.42	$ 5.45	$ 5.16	$ 5.04	$ 4.99	$ 5.04	$ 5.11	$ 5.14	$ 5.08	$ 5.11
Expected Case	Stanfield	2025-2026	$ 5.47	$ 5.52	$ 5.54	$ 5.57	$ 5.30	$ 5.06	$ 5.06	$ 5.11	$ 5.15	$ 5.17	$ 5.18	$ 5.21
Expected Case	Stanfield	2026-2027	$ 5.51	$ 5.56	$ 5.57	$ 5.60	$ 5.25	$ 5.01	$ 5.01	$ 5.06	$ 5.09	$ 5.11	$ 5.13	$ 5.16
Expected Case	Stanfield	2027-2028	$ 5.46	$ 5.53	$ 5.52	$ 5.56	$ 5.29	$ 5.05	$ 5.06	$ 5.10	$ 5.14	$ 5.16	$ 5.18	$ 5.20
Expected Case	Stanfield	2028-2029	$ 5.52	$ 5.58	$ 5.59	$ 5.62	$ 5.37	$ 5.09	$ 5.10	$ 5.13	$ 5.17	$ 5.20	$ 5.22	$ 5.25
Expected Case	Stanfield	2029-2030	$ 5.55	$ 5.62	$ 5.62	$ 5.65	$ 5.32	$ 5.08	$ 5.09	$ 5.13	$ 5.17	$ 5.20	$ 5.22	$ 5.28
Expected Case	Stanfield	2030-2031	$ 5.58	$ 5.65	$ 5.67	$ 5.71	$ 5.42	$ 5.17	$ 5.31	$ 5.24	$ 5.28	$ 5.31	$ 5.33	$ 5.38
Expected Case	Sumas	2011-2012	$ 3.10	$ 2.97	$ 2.48	$ 3.00	$ 2.95	$ 2.43	$ 2.59	$ 2.69	$ 2.79	$ 2.67	$ 2.53	$ 2.73
Expected Case	Sumas	2012-2013	$ 3.44	$ 3.55	$ 3.79	$ 3.93	$ 3.87	$ 3.62	$ 3.58	$ 3.59	$ 3.63	$ 3.64	$ 3.61	$ 3.68
Expected Case	Sumas	2013-2014	$ 4.17	$ 4.28	$ 4.29	$ 4.30	$ 4.15	$ 3.75	$ 3.73	$ 3.77	$ 3.79	$ 3.80	$ 3.76	$ 3.80
Expected Case	Sumas	2014-2015	$ 4.38	$ 4.41	$ 4.45	$ 4.46	$ 4.29	$ 3.89	$ 3.88	$ 3.93	$ 3.96	$ 3.95	$ 3.92	$ 3.94
Expected Case	Sumas	2015-2016	$ 4.54	$ 4.57	$ 4.61	$ 4.63	$ 4.46	$ 4.06	$ 4.06	$ 4.10	$ 4.13	$ 4.13	$ 4.12	$ 4.13
Expected Case	Sumas	2016-2017	$ 4.77	$ 4.78	$ 4.81	$ 4.84	$ 4.62	$ 4.20	$ 4.24	$ 4.27	$ 4.30	$ 4.31	$ 4.31	$ 4.32
Expected Case	Sumas	2017-2018	$ 4.98	$ 5.02	$ 5.05	$ 5.08	$ 4.59	$ 4.41	$ 4.45	$ 4.49	$ 4.52	$ 4.54	$ 4.53	$ 4.54
Expected Case	Sumas	2018-2019	$ 4.94	$ 5.24	$ 5.27	$ 5.30	$ 4.88	$ 4.69	$ 4.70	$ 4.66	$ 4.69	$ 4.69	$ 4.62	$ 4.65
Expected Case	Sumas	2019-2020	$ 4.77	$ 4.83	$ 5.33	$ 5.36	$ 4.98	$ 4.75	$ 4.73	$ 4.74	$ 4.81	$ 4.82	$ 4.76	$ 4.78
Expected Case	Sumas	2020-2021	$ 5.14	$ 5.34	$ 5.38	$ 5.41	$ 5.26	$ 4.85	$ 4.78	$ 4.80	$ 4.93	$ 4.90	$ 4.70	$ 4.81
Expected Case	Sumas	2021-2022	$ 5.32	$ 5.39	$ 5.42	$ 5.46	$ 5.13	$ 4.74	$ 4.68	$ 4.68	$ 4.79	$ 4.79	$ 4.71	$ 4.84
Expected Case	Sumas	2022-2023	$ 5.35	$ 5.38	$ 5.42	$ 5.45	$ 5.30	$ 4.92	$ 4.87	$ 4.88	$ 4.99	$ 4.96	$ 4.78	$ 4.88
Expected Case	Sumas	2023-2024	$ 5.44	$ 5.48	$ 5.51	$ 5.52	$ 5.18	$ 4.79	$ 4.70	$ 4.73	$ 4.84	$ 4.82	$ 4.74	$ 4.87
Expected Case	Sumas	2024-2025	$ 5.40	$ 5.46	$ 5.49	$ 5.53	$ 5.31	$ 4.89	$ 4.79	$ 4.80	$ 4.99	$ 4.92	$ 4.81	$ 4.94
Expected Case	Sumas	2025-2026	$ 5.52	$ 5.57	$ 5.61	$ 5.64	$ 5.35	$ 4.92	$ 4.84	$ 4.74	$ 5.02	$ 4.96	$ 4.90	$ 5.04
Expected Case	Sumas	2026-2027	$ 5.56	$ 5.63	$ 5.67	$ 5.70	$ 5.30	$ 4.86	$ 4.80	$ 4.67	$ 4.96	$ 4.91	$ 4.86	$ 4.98
Expected Case	Sumas	2027-2028	$ 5.51	$ 5.59	$ 5.62	$ 5.66	$ 5.34	$ 4.90	$ 4.86	$ 4.71	$ 5.01	$ 4.97	$ 4.88	$ 5.03
Expected Case	Sumas	2028-2029	$ 5.57	$ 5.76	$ 5.80	$ 5.83	$ 5.42	$ 4.94	$ 4.89	$ 4.74	$ 5.04	$ 5.06	$ 4.97	$ 5.08
Expected Case	Sumas	2029-2030	$ 5.60	$ 5.81	$ 5.84	$ 5.87	$ 5.37	$ 4.92	$ 4.86	$ 4.72	$ 5.04	$ 5.05	$ 5.03	$ 5.09
Expected Case	Sumas	2030-2031	$ 5.63	$ 5.97	$ 6.01	$ 6.04	$ 5.47	$ 5.02	$ 4.96	$ 4.84	$ 5.15	$ 5.16	$ 5.13	$ 5.20

APPENDIX 6.1 II MONTHLY PRICE DATA BY BASIN
HIGH GROWTH LOW PRICE

			2010$											
Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
High Growth Low Price	AECo	2011-2012	$ 2.90	$ 2.73	$ 2.29	$ 2.82	$ 2.88	$ 2.38	$ 2.49	$ 2.63	$ 2.69	$ 2.57	$ 2.47	$ 2.59
High Growth Low Price	AECo	2012-2013	$ 3.04	$ 3.13	$ 3.37	$ 3.51	$ 3.58	$ 3.52	$ 3.50	$ 3.51	$ 3.54	$ 3.54	$ 3.54	$ 3.57
High Growth Low Price	AECo	2013-2014	$ 3.76	$ 3.84	$ 3.85	$ 3.85	$ 3.86	$ 3.70	$ 3.65	$ 3.68	$ 3.71	$ 3.71	$ 3.72	$ 3.74
High Growth Low Price	AECo	2014-2015	$ 3.93	$ 3.93	$ 3.97	$ 3.98	$ 3.99	$ 3.85	$ 3.84	$ 3.89	$ 3.92	$ 3.91	$ 3.88	$ 3.89
High Growth Low Price	AECo	2015-2016	$ 4.06	$ 4.06	$ 4.09	$ 4.10	$ 4.16	$ 4.01	$ 4.02	$ 4.06	$ 4.08	$ 4.08	$ 4.07	$ 4.08
High Growth Low Price	AECo	2016-2017	$ 4.25	$ 4.24	$ 4.27	$ 4.29	$ 4.31	$ 4.14	$ 4.19	$ 4.22	$ 4.25	$ 4.25	$ 4.25	$ 4.26
High Growth Low Price	AECo	2017-2018	$ 4.40	$ 4.44	$ 4.49	$ 4.52	$ 4.52	$ 4.35	$ 4.39	$ 4.43	$ 4.46	$ 4.47	$ 4.46	$ 4.47
High Growth Low Price	AECo	2018-2019	$ 4.58	$ 4.65	$ 4.67	$ 4.70	$ 4.69	$ 4.52	$ 4.56	$ 4.59	$ 4.63	$ 4.64	$ 4.57	$ 4.58
High Growth Low Price	AECo	2019-2020	$ 4.67	$ 4.72	$ 4.78	$ 4.81	$ 4.75	$ 4.61	$ 4.64	$ 4.68	$ 4.72	$ 4.73	$ 4.66	$ 4.67
High Growth Low Price	AECo	2020-2021	$ 4.79	$ 4.85	$ 4.88	$ 4.91	$ 4.89	$ 4.73	$ 4.77	$ 4.81	$ 4.85	$ 4.87	$ 4.68	$ 4.69
High Growth Low Price	AECo	2021-2022	$ 4.80	$ 4.84	$ 4.87	$ 4.90	$ 4.74	$ 4.62	$ 4.66	$ 4.69	$ 4.72	$ 4.74	$ 4.70	$ 4.69
High Growth Low Price	AECo	2022-2023	$ 4.84	$ 4.87	$ 4.89	$ 4.92	$ 4.91	$ 4.79	$ 4.84	$ 4.89	$ 4.92	$ 4.94	$ 4.78	$ 4.78
High Growth Low Price	AECo	2023-2024	$ 4.89	$ 4.92	$ 4.94	$ 4.97	$ 4.77	$ 4.65	$ 4.67	$ 4.74	$ 4.77	$ 4.79	$ 4.74	$ 4.75
High Growth Low Price	AECo	2024-2025	$ 4.86	$ 4.89	$ 4.91	$ 4.94	$ 4.87	$ 4.74	$ 4.76	$ 4.81	$ 4.87	$ 4.89	$ 4.79	$ 4.80
High Growth Low Price	AECo	2025-2026	$ 4.98	$ 5.00	$ 5.03	$ 5.06	$ 4.90	$ 4.77	$ 4.80	$ 4.86	$ 4.89	$ 4.91	$ 4.87	$ 4.87
High Growth Low Price	AECo	2026-2027	$ 5.00	$ 5.03	$ 5.05	$ 5.08	$ 4.85	$ 4.71	$ 4.74	$ 4.79	$ 4.82	$ 4.84	$ 4.82	$ 4.82
High Growth Low Price	AECo	2027-2028	$ 4.97	$ 5.00	$ 5.03	$ 5.06	$ 4.89	$ 4.75	$ 4.80	$ 4.83	$ 4.87	$ 4.89	$ 4.85	$ 4.86
High Growth Low Price	AECo	2028-2029	$ 5.02	$ 5.05	$ 5.08	$ 5.11	$ 4.96	$ 4.79	$ 4.82	$ 4.86	$ 4.90	$ 4.92	$ 4.91	$ 4.91
High Growth Low Price	AECo	2029-2030	$ 5.06	$ 5.10	$ 5.13	$ 5.15	$ 4.91	$ 4.76	$ 4.79	$ 4.84	$ 4.90	$ 4.91	$ 4.91	$ 4.92
High Growth Low Price	AECo	2030-2031	$ 5.06	$ 5.13	$ 5.16	$ 5.19	$ 5.01	$ 4.86	$ 4.89	$ 4.96	$ 5.00	$ 5.02	$ 5.01	$ 5.02
High Growth Low Price	Malin	2011-2012	$ 3.01	$ 2.97	$ 2.48	$ 3.00	$ 3.06	$ 2.52	$ 2.80	$ 2.94	$ 3.01	$ 2.89	$ 2.78	$ 2.91
High Growth Low Price	Malin	2012-2013	$ 3.34	$ 3.45	$ 3.69	$ 3.83	$ 3.87	$ 3.79	$ 3.82	$ 3.82	$ 3.86	$ 3.87	$ 3.86	$ 3.89
High Growth Low Price	Malin	2013-2014	$ 4.06	$ 4.18	$ 4.18	$ 4.19	$ 4.15	$ 3.98	$ 3.99	$ 4.02	$ 4.05	$ 4.07	$ 4.09	$ 4.12
High Growth Low Price	Malin	2014-2015	$ 4.28	$ 4.31	$ 4.34	$ 4.34	$ 4.29	$ 4.15	$ 4.17	$ 4.19	$ 4.21	$ 4.24	$ 4.26	$ 4.29
High Growth Low Price	Malin	2015-2016	$ 4.44	$ 4.48	$ 4.51	$ 4.52	$ 4.47	$ 4.37	$ 4.38	$ 4.40	$ 4.45	$ 4.47	$ 4.48	$ 4.51
High Growth Low Price	Malin	2016-2017	$ 4.67	$ 4.69	$ 4.71	$ 4.74	$ 4.62	$ 4.55	$ 4.58	$ 4.61	$ 4.64	$ 4.66	$ 4.69	$ 4.71
High Growth Low Price	Malin	2017-2018	$ 4.88	$ 4.93	$ 4.95	$ 4.98	$ 4.87	$ 4.80	$ 4.82	$ 4.85	$ 4.90	$ 4.92	$ 4.94	$ 4.97
High Growth Low Price	Malin	2018-2019	$ 5.08	$ 5.15	$ 5.15	$ 5.18	$ 5.05	$ 4.95	$ 4.95	$ 4.98	$ 5.07	$ 5.10	$ 5.07	$ 5.09
High Growth Low Price	Malin	2019-2020	$ 5.15	$ 5.24	$ 5.19	$ 5.22	$ 5.10	$ 4.97	$ 5.01	$ 5.04	$ 5.13	$ 5.16	$ 5.13	$ 5.15
High Growth Low Price	Malin	2020-2021	$ 5.25	$ 5.32	$ 5.33	$ 5.36	$ 5.23	$ 5.07	$ 5.12	$ 5.15	$ 5.23	$ 5.26	$ 5.19	$ 5.21
High Growth Low Price	Malin	2021-2022	$ 5.30	$ 5.36	$ 5.33	$ 5.36	$ 5.09	$ 5.01	$ 5.05	$ 5.08	$ 5.12	$ 5.16	$ 5.17	$ 5.19
High Growth Low Price	Malin	2022-2023	$ 5.32	$ 5.36	$ 5.38	$ 5.41	$ 5.26	$ 5.19	$ 5.22	$ 5.25	$ 5.31	$ 5.33	$ 5.26	$ 5.29
High Growth Low Price	Malin	2023-2024	$ 5.44	$ 5.48	$ 5.44	$ 5.47	$ 5.16	$ 5.10	$ 5.05	$ 5.12	$ 5.19	$ 5.23	$ 5.18	$ 5.24
High Growth Low Price	Malin	2024-2025	$ 5.40	$ 5.46	$ 5.44	$ 5.47	$ 5.30	$ 5.20	$ 5.14	$ 5.19	$ 5.28	$ 5.31	$ 5.26	$ 5.31
High Growth Low Price	Malin	2025-2026	$ 5.52	$ 5.57	$ 5.55	$ 5.58	$ 5.31	$ 5.22	$ 5.23	$ 5.28	$ 5.32	$ 5.35	$ 5.37	$ 5.40
High Growth Low Price	Malin	2026-2027	$ 5.54	$ 5.59	$ 5.57	$ 5.61	$ 5.26	$ 5.17	$ 5.18	$ 5.23	$ 5.27	$ 5.29	$ 5.32	$ 5.35
High Growth Low Price	Malin	2027-2028	$ 5.49	$ 5.55	$ 5.53	$ 5.56	$ 5.30	$ 5.20	$ 5.23	$ 5.27	$ 5.31	$ 5.34	$ 5.37	$ 5.40
High Growth Low Price	Malin	2028-2029	$ 5.55	$ 5.60	$ 5.59	$ 5.63	$ 5.37	$ 5.24	$ 5.26	$ 5.30	$ 5.35	$ 5.38	$ 5.41	$ 5.44
High Growth Low Price	Malin	2029-2030	$ 5.56	$ 5.64	$ 5.62	$ 5.66	$ 5.33	$ 5.24	$ 5.26	$ 5.30	$ 5.35	$ 5.38	$ 5.41	$ 5.47
High Growth Low Price	Malin	2030-2031	$ 5.60	$ 5.66	$ 5.68	$ 5.72	$ 5.42	$ 5.33	$ 5.36	$ 5.41	$ 5.46	$ 5.49	$ 5.52	$ 5.57
High Growth Low Price	Rockies	2011-2012	$ 2.92	$ 2.94	$ 2.44	$ 2.96	$ 3.03	$ 2.49	$ 2.73	$ 2.86	$ 2.93	$ 2.81	$ 2.71	$ 2.83
High Growth Low Price	Rockies	2012-2013	$ 3.25	$ 3.36	$ 3.61	$ 3.75	$ 3.79	$ 3.71	$ 3.74	$ 3.75	$ 3.79	$ 3.79	$ 3.79	$ 3.81
High Growth Low Price	Rockies	2013-2014	$ 3.98	$ 4.09	$ 4.09	$ 4.10	$ 4.07	$ 3.90	$ 3.92	$ 3.94	$ 3.97	$ 3.99	$ 4.01	$ 4.04
High Growth Low Price	Rockies	2014-2015	$ 4.19	$ 4.22	$ 4.25	$ 4.26	$ 4.21	$ 4.07	$ 4.09	$ 4.11	$ 4.13	$ 4.16	$ 4.18	$ 4.21
High Growth Low Price	Rockies	2015-2016	$ 4.35	$ 4.39	$ 4.42	$ 4.43	$ 4.38	$ 4.29	$ 4.30	$ 4.32	$ 4.37	$ 4.39	$ 4.39	$ 4.42
High Growth Low Price	Rockies	2016-2017	$ 4.58	$ 4.59	$ 4.62	$ 4.64	$ 4.53	$ 4.47	$ 4.50	$ 4.52	$ 4.56	$ 4.58	$ 4.60	$ 4.63
High Growth Low Price	Rockies	2017-2018	$ 4.79	$ 4.84	$ 4.86	$ 4.89	$ 4.77	$ 4.72	$ 4.74	$ 4.76	$ 4.81	$ 4.84	$ 4.85	$ 4.88
High Growth Low Price	Rockies	2018-2019	$ 4.98	$ 5.05	$ 5.06	$ 5.08	$ 4.96	$ 4.87	$ 4.87	$ 4.90	$ 4.97	$ 4.99	$ 4.98	$ 5.00
High Growth Low Price	Rockies	2019-2020	$ 5.01	$ 5.07	$ 5.06	$ 5.09	$ 4.98	$ 4.86	$ 4.84	$ 4.86	$ 4.91	$ 4.93	$ 4.91	$ 4.96
High Growth Low Price	Rockies	2020-2021	$ 5.08	$ 5.16	$ 5.15	$ 5.18	$ 5.09	$ 4.95	$ 4.94	$ 4.97	$ 5.04	$ 5.05	$ 4.90	$ 4.94
High Growth Low Price	Rockies	2021-2022	$ 5.06	$ 5.13	$ 5.11	$ 5.14	$ 4.92	$ 4.79	$ 4.80	$ 4.83	$ 4.88	$ 4.90	$ 4.86	$ 4.89
High Growth Low Price	Rockies	2022-2023	$ 5.04	$ 5.11	$ 5.11	$ 5.14	$ 5.04	$ 4.89	$ 4.91	$ 4.93	$ 4.98	$ 5.01	$ 4.90	$ 4.93
High Growth Low Price	Rockies	2023-2024	$ 5.04	$ 5.11	$ 5.06	$ 5.09	$ 4.81	$ 4.74	$ 4.69	$ 4.71	$ 4.80	$ 4.83	$ 4.80	$ 4.85
High Growth Low Price	Rockies	2024-2025	$ 4.95	$ 5.05	$ 5.05	$ 5.08	$ 4.89	$ 4.70	$ 4.64	$ 4.66	$ 4.76	$ 4.79	$ 4.78	$ 4.84
High Growth Low Price	Rockies	2025-2026	$ 5.17	$ 5.27	$ 5.29	$ 5.32	$ 5.06	$ 4.96	$ 4.97	$ 5.00	$ 5.07	$ 5.10	$ 5.08	$ 5.10
High Growth Low Price	Rockies	2026-2027	$ 5.21	$ 5.29	$ 5.28	$ 5.30	$ 4.98	$ 4.87	$ 4.90	$ 4.92	$ 4.99	$ 5.01	$ 5.00	$ 5.02
High Growth Low Price	Rockies	2027-2028	$ 5.14	$ 5.22	$ 5.22	$ 5.23	$ 4.96	$ 4.88	$ 4.90	$ 4.93	$ 5.00	$ 5.03	$ 4.99	$ 5.01
High Growth Low Price	Rockies	2028-2029	$ 5.13	$ 5.23	$ 5.22	$ 5.25	$ 4.97	$ 4.89	$ 4.89	$ 4.92	$ 5.01	$ 5.04	$ 5.02	$ 5.04
High Growth Low Price	Rockies	2029-2030	$ 5.13	$ 5.22	$ 5.21	$ 5.24	$ 4.89	$ 4.83	$ 4.85	$ 4.88	$ 4.95	$ 4.97	$ 4.99	$ 5.02
High Growth Low Price	Rockies	2030-2031	$ 5.10	$ 5.21	$ 5.21	$ 5.25	$ 4.94	$ 4.90	$ 4.93	$ 4.96	$ 5.03	$ 5.05	$ 5.05	$ 5.08

APPENDIX 6.1 II MONTHLY PRICE DATA BY BASIN
HIGH GROWTH LOW PRICE

			2010$											
Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
High Growth Low Price	Stanfield	2011-2012	$ 2.95	$ 2.97	$ 2.45	$ 2.97	$ 2.95	$ 2.48	$ 2.72	$ 2.86	$ 2.93	$ 2.81	$ 2.67	$ 2.79
High Growth Low Price	Stanfield	2012-2013	$ 3.24	$ 3.34	$ 3.58	$ 3.72	$ 3.78	$ 3.71	$ 3.74	$ 3.74	$ 3.78	$ 3.79	$ 3.75	$ 3.77
High Growth Low Price	Stanfield	2013-2014	$ 3.97	$ 4.07	$ 4.07	$ 4.08	$ 4.06	$ 3.89	$ 3.89	$ 3.92	$ 3.95	$ 3.97	$ 3.97	$ 3.99
High Growth Low Price	Stanfield	2014-2015	$ 4.16	$ 4.18	$ 4.22	$ 4.23	$ 4.20	$ 4.04	$ 4.04	$ 4.08	$ 4.11	$ 4.12	$ 4.13	$ 4.16
High Growth Low Price	Stanfield	2015-2016	$ 4.31	$ 4.34	$ 4.37	$ 4.39	$ 4.37	$ 4.23	$ 4.24	$ 4.27	$ 4.31	$ 4.33	$ 4.34	$ 4.37
High Growth Low Price	Stanfield	2016-2017	$ 4.54	$ 4.54	$ 4.57	$ 4.60	$ 4.53	$ 4.41	$ 4.44	$ 4.47	$ 4.50	$ 4.52	$ 4.54	$ 4.56
High Growth Low Price	Stanfield	2017-2018	$ 4.73	$ 4.77	$ 4.80	$ 4.83	$ 4.74	$ 4.64	$ 4.67	$ 4.70	$ 4.74	$ 4.77	$ 4.77	$ 4.80
High Growth Low Price	Stanfield	2018-2019	$ 4.92	$ 4.98	$ 5.12	$ 5.15	$ 4.92	$ 4.80	$ 4.81	$ 4.83	$ 4.90	$ 4.92	$ 4.90	$ 5.04
High Growth Low Price	Stanfield	2019-2020	$ 5.11	$ 5.07	$ 5.18	$ 5.21	$ 4.98	$ 4.84	$ 4.86	$ 4.90	$ 4.96	$ 4.98	$ 4.95	$ 4.97
High Growth Low Price	Stanfield	2020-2021	$ 5.11	$ 5.30	$ 5.33	$ 5.36	$ 5.12	$ 4.96	$ 4.98	$ 5.02	$ 5.08	$ 5.10	$ 5.00	$ 5.03
High Growth Low Price	Stanfield	2021-2022	$ 5.27	$ 5.34	$ 5.32	$ 5.36	$ 4.98	$ 4.86	$ 4.89	$ 4.92	$ 4.96	$ 4.99	$ 4.98	$ 5.01
High Growth Low Price	Stanfield	2022-2023	$ 5.30	$ 5.33	$ 5.37	$ 5.40	$ 5.15	$ 5.04	$ 5.07	$ 5.10	$ 5.13	$ 5.16	$ 5.07	$ 5.10
High Growth Low Price	Stanfield	2023-2024	$ 5.39	$ 5.43	$ 5.44	$ 5.47	$ 5.03	$ 4.93	$ 4.90	$ 4.96	$ 5.02	$ 5.05	$ 5.00	$ 5.05
High Growth Low Price	Stanfield	2024-2025	$ 5.35	$ 5.41	$ 5.42	$ 5.45	$ 5.16	$ 5.04	$ 4.99	$ 5.04	$ 5.11	$ 5.14	$ 5.08	$ 5.11
High Growth Low Price	Stanfield	2025-2026	$ 5.47	$ 5.52	$ 5.54	$ 5.57	$ 5.30	$ 5.06	$ 5.06	$ 5.11	$ 5.15	$ 5.17	$ 5.18	$ 5.21
High Growth Low Price	Stanfield	2026-2027	$ 5.51	$ 5.56	$ 5.57	$ 5.60	$ 5.25	$ 5.01	$ 5.01	$ 5.06	$ 5.09	$ 5.11	$ 5.13	$ 5.16
High Growth Low Price	Stanfield	2027-2028	$ 5.46	$ 5.53	$ 5.52	$ 5.56	$ 5.29	$ 5.05	$ 5.06	$ 5.10	$ 5.14	$ 5.16	$ 5.18	$ 5.20
High Growth Low Price	Stanfield	2028-2029	$ 5.52	$ 5.58	$ 5.59	$ 5.62	$ 5.37	$ 5.09	$ 5.10	$ 5.13	$ 5.17	$ 5.20	$ 5.22	$ 5.25
High Growth Low Price	Stanfield	2029-2030	$ 5.55	$ 5.62	$ 5.62	$ 5.65	$ 5.32	$ 5.08	$ 5.09	$ 5.13	$ 5.17	$ 5.20	$ 5.22	$ 5.28
High Growth Low Price	Stanfield	2030-2031	$ 5.58	$ 5.65	$ 5.67	$ 5.71	$ 5.42	$ 5.17	$ 5.31	$ 5.24	$ 5.28	$ 5.31	$ 5.33	$ 5.38
High Growth Low Price	Sumas	2011-2012	$ 3.10	$ 2.97	$ 2.48	$ 3.00	$ 2.95	$ 2.43	$ 2.59	$ 2.69	$ 2.79	$ 2.67	$ 2.53	$ 2.73
High Growth Low Price	Sumas	2012-2013	$ 3.44	$ 3.55	$ 3.79	$ 3.93	$ 3.87	$ 3.62	$ 3.58	$ 3.59	$ 3.63	$ 3.64	$ 3.61	$ 3.68
High Growth Low Price	Sumas	2013-2014	$ 4.17	$ 4.28	$ 4.29	$ 4.30	$ 4.15	$ 3.75	$ 3.73	$ 3.77	$ 3.79	$ 3.80	$ 3.76	$ 3.80
High Growth Low Price	Sumas	2014-2015	$ 4.38	$ 4.41	$ 4.45	$ 4.46	$ 4.29	$ 3.89	$ 3.88	$ 3.93	$ 3.96	$ 3.95	$ 3.92	$ 3.94
High Growth Low Price	Sumas	2015-2016	$ 4.54	$ 4.57	$ 4.61	$ 4.63	$ 4.46	$ 4.06	$ 4.06	$ 4.10	$ 4.13	$ 4.13	$ 4.12	$ 4.13
High Growth Low Price	Sumas	2016-2017	$ 4.77	$ 4.78	$ 4.81	$ 4.84	$ 4.62	$ 4.20	$ 4.24	$ 4.27	$ 4.30	$ 4.31	$ 4.31	$ 4.32
High Growth Low Price	Sumas	2017-2018	$ 4.98	$ 5.02	$ 5.05	$ 5.08	$ 4.59	$ 4.41	$ 4.45	$ 4.49	$ 4.52	$ 4.54	$ 4.53	$ 4.54
High Growth Low Price	Sumas	2018-2019	$ 4.94	$ 5.24	$ 5.27	$ 5.30	$ 4.88	$ 4.69	$ 4.70	$ 4.66	$ 4.69	$ 4.69	$ 4.62	$ 4.65
High Growth Low Price	Sumas	2019-2020	$ 4.77	$ 4.83	$ 5.33	$ 5.36	$ 4.98	$ 4.75	$ 4.73	$ 4.74	$ 4.81	$ 4.82	$ 4.76	$ 4.78
High Growth Low Price	Sumas	2020-2021	$ 5.14	$ 5.34	$ 5.38	$ 5.41	$ 5.26	$ 4.85	$ 4.78	$ 4.80	$ 4.93	$ 4.90	$ 4.70	$ 4.81
High Growth Low Price	Sumas	2021-2022	$ 5.32	$ 5.39	$ 5.42	$ 5.46	$ 5.13	$ 4.74	$ 4.68	$ 4.68	$ 4.79	$ 4.79	$ 4.71	$ 4.84
High Growth Low Price	Sumas	2022-2023	$ 5.35	$ 5.38	$ 5.42	$ 5.45	$ 5.30	$ 4.92	$ 4.87	$ 4.88	$ 4.99	$ 4.96	$ 4.78	$ 4.88
High Growth Low Price	Sumas	2023-2024	$ 5.44	$ 5.48	$ 5.51	$ 5.52	$ 5.18	$ 4.79	$ 4.70	$ 4.73	$ 4.84	$ 4.82	$ 4.74	$ 4.87
High Growth Low Price	Sumas	2024-2025	$ 5.40	$ 5.46	$ 5.49	$ 5.53	$ 5.31	$ 4.89	$ 4.79	$ 4.80	$ 4.99	$ 4.92	$ 4.81	$ 4.94
High Growth Low Price	Sumas	2025-2026	$ 5.52	$ 5.57	$ 5.61	$ 5.64	$ 5.35	$ 4.92	$ 4.84	$ 4.74	$ 5.02	$ 4.96	$ 4.90	$ 5.04
High Growth Low Price	Sumas	2026-2027	$ 5.56	$ 5.63	$ 5.67	$ 5.70	$ 5.30	$ 4.86	$ 4.80	$ 4.67	$ 4.96	$ 4.91	$ 4.86	$ 4.98
High Growth Low Price	Sumas	2027-2028	$ 5.51	$ 5.59	$ 5.62	$ 5.66	$ 5.34	$ 4.90	$ 4.86	$ 4.71	$ 5.01	$ 4.97	$ 4.88	$ 5.03
High Growth Low Price	Sumas	2028-2029	$ 5.57	$ 5.76	$ 5.80	$ 5.83	$ 5.42	$ 4.94	$ 4.89	$ 4.74	$ 5.04	$ 5.06	$ 4.97	$ 5.08
High Growth Low Price	Sumas	2029-2030	$ 5.60	$ 5.81	$ 5.84	$ 5.87	$ 5.37	$ 4.92	$ 4.86	$ 4.72	$ 5.04	$ 5.05	$ 5.03	$ 5.09
High Growth Low Price	Sumas	2030-2031	$ 5.63	$ 5.97	$ 6.01	$ 6.04	$ 5.47	$ 5.02	$ 4.96	$ 4.84	$ 5.15	$ 5.16	$ 5.13	$ 5.20

APPENDIX 6.1 II MONTHLY PRICE DATA BY BASIN
LOW GROWTH HIGH PRICE

								2010$						
Scenario	**Index**	**Gas Year**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**
Low Growth High Price	AECo	2011-2012	$ 3.13	$ 2.97	$ 2.49	$ 2.59	$ 3.99	$ 3.92	$ 3.87	$ 3.94	$ 3.98	$ 3.99	$ 4.04	$ 4.08
Low Growth High Price	AECo	2012-2013	$ 4.39	$ 4.63	$ 5.08	$ 5.05	$ 5.04	$ 4.81	$ 4.78	$ 4.80	$ 4.83	$ 4.86	$ 4.89	$ 4.94
Low Growth High Price	AECo	2013-2014	$ 5.24	$ 5.46	$ 6.02	$ 5.99	$ 6.00	$ 5.66	$ 5.60	$ 5.65	$ 5.67	$ 5.69	$ 5.71	$ 5.76
Low Growth High Price	AECo	2014-2015	$ 6.11	$ 6.36	$ 7.14	$ 7.10	$ 7.05	$ 6.69	$ 6.67	$ 6.73	$ 6.76	$ 6.77	$ 6.76	$ 6.80
Low Growth High Price	AECo	2015-2016	$ 7.21	$ 7.46	$ 7.57	$ 7.53	$ 7.50	$ 7.10	$ 7.10	$ 7.12	$ 7.15	$ 7.17	$ 7.21	$ 7.26
Low Growth High Price	AECo	2016-2017	$ 7.63	$ 7.93	$ 8.15	$ 8.10	$ 8.06	$ 7.58	$ 7.60	$ 7.61	$ 7.62	$ 7.64	$ 7.73	$ 7.78
Low Growth High Price	AECo	2017-2018	$ 7.79	$ 8.11	$ 8.35	$ 8.30	$ 8.25	$ 7.78	$ 7.80	$ 7.83	$ 7.79	$ 7.83	$ 7.91	$ 7.99
Low Growth High Price	AECo	2018-2019	$ 8.00	$ 8.37	$ 8.58	$ 8.54	$ 8.51	$ 8.00	$ 8.02	$ 8.05	$ 7.99	$ 8.03	$ 8.11	$ 8.25
Low Growth High Price	AECo	2019-2020	$ 8.23	$ 8.61	$ 8.85	$ 8.80	$ 8.73	$ 8.23	$ 8.24	$ 8.24	$ 8.21	$ 8.25	$ 8.37	$ 8.49
Low Growth High Price	AECo	2020-2021	$ 8.48	$ 8.89	$ 9.10	$ 9.05	$ 9.00	$ 8.50	$ 8.51	$ 8.49	$ 8.48	$ 8.52	$ 8.66	$ 8.78
Low Growth High Price	AECo	2021-2022	$ 8.77	$ 9.16	$ 9.36	$ 9.31	$ 9.22	$ 8.72	$ 8.74	$ 8.76	$ 8.73	$ 8.78	$ 8.94	$ 9.02
Low Growth High Price	AECo	2022-2023	$ 9.05	$ 9.35	$ 9.55	$ 9.49	$ 9.44	$ 8.95	$ 8.98	$ 8.96	$ 8.95	$ 9.01	$ 9.15	$ 9.23
Low Growth High Price	AECo	2023-2024	$ 9.21	$ 9.61	$ 9.90	$ 9.84	$ 9.82	$ 9.33	$ 9.33	$ 9.36	$ 9.32	$ 9.38	$ 9.46	$ 9.59
Low Growth High Price	AECo	2024-2025	$ 9.58	$ 9.94	$ 10.13	$ 10.07	$ 10.06	$ 9.54	$ 9.53	$ 9.56	$ 9.55	$ 9.60	$ 9.68	$ 9.82
Low Growth High Price	AECo	2025-2026	$ 9.89	$ 10.28	$ 10.78	$ 10.71	$ 10.67	$ 10.13	$ 10.15	$ 10.15	$ 10.14	$ 10.20	$ 10.35	$ 10.48
Low Growth High Price	AECo	2026-2027	$ 10.48	$ 10.91	$ 11.29	$ 11.24	$ 11.19	$ 10.64	$ 10.65	$ 10.65	$ 10.62	$ 10.69	$ 10.88	$ 10.99
Low Growth High Price	AECo	2027-2028	$ 11.00	$ 11.45	$ 11.93	$ 11.88	$ 11.81	$ 11.20	$ 11.22	$ 11.23	$ 11.19	$ 11.26	$ 11.51	$ 11.60
Low Growth High Price	AECo	2028-2029	$ 11.62	$ 12.08	$ 12.56	$ 12.48	$ 12.46	$ 11.80	$ 11.81	$ 11.81	$ 11.80	$ 11.87	$ 12.00	$ 12.18
Low Growth High Price	AECo	2029-2030	$ 12.20	$ 12.69	$ 13.27	$ 13.20	$ 13.16	$ 12.50	$ 12.51	$ 12.51	$ 12.50	$ 12.57	$ 12.73	$ 12.89
Low Growth High Price	AECo	2030-2031	$ 12.90	$ 13.45	$ 13.30	$ 13.23	$ 13.17	$ 12.50	$ 12.51	$ 12.55	$ 12.51	$ 12.59	$ 12.76	$ 12.94
Low Growth High Price	Malin	2011-2012	$ 3.24	$ 3.22	$ 2.67	$ 2.77	$ 4.16	$ 4.06	$ 4.17	$ 4.25	$ 4.29	$ 4.31	$ 4.36	$ 4.40
Low Growth High Price	Malin	2012-2013	$ 4.69	$ 4.95	$ 5.39	$ 5.37	$ 5.33	$ 5.09	$ 5.09	$ 5.12	$ 5.15	$ 5.18	$ 5.21	$ 5.27
Low Growth High Price	Malin	2013-2014	$ 5.54	$ 5.80	$ 6.36	$ 6.33	$ 6.29	$ 5.95	$ 5.95	$ 5.98	$ 6.01	$ 6.05	$ 6.08	$ 6.14
Low Growth High Price	Malin	2014-2015	$ 6.46	$ 6.73	$ 7.51	$ 7.46	$ 7.35	$ 7.00	$ 7.00	$ 7.03	$ 7.05	$ 7.10	$ 7.14	$ 7.21
Low Growth High Price	Malin	2015-2016	$ 7.58	$ 7.88	$ 7.99	$ 7.95	$ 7.81	$ 7.47	$ 7.46	$ 7.46	$ 7.51	$ 7.56	$ 7.62	$ 7.69
Low Growth High Price	Malin	2016-2017	$ 8.05	$ 8.37	$ 8.59	$ 8.55	$ 8.38	$ 7.99	$ 7.99	$ 8.00	$ 8.01	$ 8.06	$ 8.16	$ 8.23
Low Growth High Price	Malin	2017-2018	$ 8.27	$ 8.60	$ 8.81	$ 8.77	$ 8.60	$ 8.23	$ 8.23	$ 8.24	$ 8.23	$ 8.28	$ 8.39	$ 8.49
Low Growth High Price	Malin	2018-2019	$ 8.49	$ 8.87	$ 9.06	$ 9.01	$ 8.87	$ 8.44	$ 8.41	$ 8.44	$ 8.44	$ 8.49	$ 8.61	$ 8.76
Low Growth High Price	Malin	2019-2020	$ 8.72	$ 9.12	$ 9.25	$ 9.21	$ 9.07	$ 8.59	$ 8.61	$ 8.59	$ 8.62	$ 8.68	$ 8.84	$ 8.97
Low Growth High Price	Malin	2020-2021	$ 8.95	$ 9.35	$ 9.54	$ 9.49	$ 9.34	$ 8.84	$ 8.86	$ 8.83	$ 8.86	$ 8.91	$ 9.17	$ 9.31
Low Growth High Price	Malin	2021-2022	$ 9.26	$ 9.68	$ 9.82	$ 9.77	$ 9.57	$ 9.11	$ 9.13	$ 9.14	$ 9.12	$ 9.20	$ 9.41	$ 9.52
Low Growth High Price	Malin	2022-2023	$ 9.53	$ 9.85	$ 10.03	$ 9.98	$ 9.79	$ 9.35	$ 9.35	$ 9.32	$ 9.34	$ 9.40	$ 9.63	$ 9.75
Low Growth High Price	Malin	2023-2024	$ 9.76	$ 10.17	$ 10.40	$ 10.35	$ 10.21	$ 9.78	$ 9.71	$ 9.74	$ 9.75	$ 9.81	$ 9.90	$ 10.08
Low Growth High Price	Malin	2024-2025	$ 10.12	$ 10.51	$ 10.65	$ 10.60	$ 10.48	$ 10.00	$ 9.92	$ 9.94	$ 9.96	$ 10.02	$ 10.15	$ 10.33
Low Growth High Price	Malin	2025-2026	$ 10.43	$ 10.84	$ 11.29	$ 11.23	$ 11.08	$ 10.58	$ 10.58	$ 10.56	$ 10.57	$ 10.64	$ 10.84	$ 11.00
Low Growth High Price	Malin	2026-2027	$ 11.02	$ 11.47	$ 11.81	$ 11.76	$ 11.61	$ 11.10	$ 11.09	$ 11.08	$ 11.07	$ 11.14	$ 11.38	$ 11.52
Low Growth High Price	Malin	2027-2028	$ 11.52	$ 12.00	$ 12.43	$ 12.38	$ 12.21	$ 11.64	$ 11.65	$ 11.66	$ 11.62	$ 11.70	$ 12.03	$ 12.14
Low Growth High Price	Malin	2028-2029	$ 12.14	$ 12.62	$ 13.07	$ 13.00	$ 12.87	$ 12.26	$ 12.26	$ 12.26	$ 12.25	$ 12.33	$ 12.50	$ 12.71
Low Growth High Price	Malin	2029-2030	$ 12.70	$ 13.24	$ 13.77	$ 13.71	$ 13.58	$ 12.98	$ 12.98	$ 12.97	$ 12.95	$ 13.04	$ 13.23	$ 13.44
Low Growth High Price	Malin	2030-2031	$ 13.43	$ 13.98	$ 13.82	$ 13.75	$ 13.58	$ 12.97	$ 12.98	$ 12.99	$ 12.98	$ 13.06	$ 13.28	$ 13.48
Low Growth High Price	Rockies	2011-2012	$ 3.14	$ 3.18	$ 2.63	$ 2.73	$ 4.13	$ 4.03	$ 4.10	$ 4.18	$ 4.21	$ 4.24	$ 4.28	$ 4.33
Low Growth High Price	Rockies	2012-2013	$ 4.61	$ 4.86	$ 5.31	$ 5.29	$ 5.24	$ 5.01	$ 5.02	$ 5.04	$ 5.08	$ 5.10	$ 5.13	$ 5.19
Low Growth High Price	Rockies	2013-2014	$ 5.46	$ 5.72	$ 6.27	$ 6.24	$ 6.21	$ 5.87	$ 5.87	$ 5.91	$ 5.93	$ 5.97	$ 6.00	$ 6.05
Low Growth High Price	Rockies	2014-2015	$ 6.37	$ 6.64	$ 7.42	$ 7.37	$ 7.26	$ 6.92	$ 6.92	$ 6.95	$ 6.97	$ 7.02	$ 7.06	$ 7.12
Low Growth High Price	Rockies	2015-2016	$ 7.49	$ 7.79	$ 7.90	$ 7.86	$ 7.72	$ 7.38	$ 7.38	$ 7.38	$ 7.43	$ 7.48	$ 7.53	$ 7.61
Low Growth High Price	Rockies	2016-2017	$ 7.96	$ 8.28	$ 8.50	$ 8.46	$ 8.29	$ 7.91	$ 7.91	$ 7.92	$ 7.93	$ 7.97	$ 8.08	$ 8.15
Low Growth High Price	Rockies	2017-2018	$ 8.18	$ 8.51	$ 8.72	$ 8.67	$ 8.51	$ 8.15	$ 8.14	$ 8.16	$ 8.14	$ 8.19	$ 8.30	$ 8.40
Low Growth High Price	Rockies	2018-2019	$ 8.40	$ 8.77	$ 8.96	$ 8.91	$ 8.78	$ 8.35	$ 8.33	$ 8.35	$ 8.33	$ 8.39	$ 8.52	$ 8.67
Low Growth High Price	Rockies	2019-2020	$ 8.57	$ 8.96	$ 9.13	$ 9.07	$ 8.95	$ 8.48	$ 8.44	$ 8.42	$ 8.41	$ 8.45	$ 8.62	$ 8.78
Low Growth High Price	Rockies	2020-2021	$ 8.77	$ 9.20	$ 9.37	$ 9.31	$ 9.21	$ 8.72	$ 8.69	$ 8.65	$ 8.67	$ 8.71	$ 8.89	$ 9.03
Low Growth High Price	Rockies	2021-2022	$ 9.03	$ 9.45	$ 9.61	$ 9.55	$ 9.39	$ 8.89	$ 8.88	$ 8.89	$ 8.88	$ 8.94	$ 9.10	$ 9.22
Low Growth High Price	Rockies	2022-2023	$ 9.25	$ 9.60	$ 9.77	$ 9.71	$ 9.57	$ 9.05	$ 9.05	$ 9.00	$ 9.01	$ 9.07	$ 9.27	$ 9.38
Low Growth High Price	Rockies	2023-2024	$ 9.36	$ 9.80	$ 10.02	$ 9.96	$ 9.86	$ 9.42	$ 9.35	$ 9.33	$ 9.36	$ 9.42	$ 9.51	$ 9.69
Low Growth High Price	Rockies	2024-2025	$ 9.67	$ 10.10	$ 10.27	$ 10.21	$ 10.07	$ 9.50	$ 9.41	$ 9.41	$ 9.44	$ 9.50	$ 9.67	$ 9.87
Low Growth High Price	Rockies	2025-2026	$ 10.08	$ 10.55	$ 11.04	$ 10.97	$ 10.83	$ 10.32	$ 10.32	$ 10.28	$ 10.32	$ 10.39	$ 10.55	$ 10.71
Low Growth High Price	Rockies	2026-2027	$ 10.70	$ 11.17	$ 11.52	$ 11.46	$ 11.33	$ 10.80	$ 10.81	$ 10.78	$ 10.79	$ 10.86	$ 11.06	$ 11.20
Low Growth High Price	Rockies	2027-2028	$ 11.16	$ 11.67	$ 12.12	$ 12.05	$ 11.87	$ 11.33	$ 11.33	$ 11.32	$ 11.32	$ 11.39	$ 11.64	$ 11.75
Low Growth High Price	Rockies	2028-2029	$ 11.73	$ 12.25	$ 12.70	$ 12.62	$ 12.47	$ 11.91	$ 11.88	$ 11.88	$ 11.91	$ 11.98	$ 12.11	$ 12.31
Low Growth High Price	Rockies	2029-2030	$ 12.27	$ 12.82	$ 13.35	$ 13.29	$ 13.13	$ 12.56	$ 12.57	$ 12.55	$ 12.55	$ 12.63	$ 12.81	$ 12.99
Low Growth High Price	Rockies	2030-2031	$ 12.93	$ 13.53	$ 13.35	$ 13.28	$ 13.10	$ 12.54	$ 12.55	$ 12.54	$ 12.54	$ 12.62	$ 12.80	$ 13.00

APPENDIX 6.1 II MONTHLY PRICE DATA BY BASIN
LOW GROWTH HIGH PRICE

			2010$											
Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Low Growth High Price	Stanfield	2011-2012	$ 3.18	$ 3.22	$ 2.64	$ 2.74	$ 4.05	$ 4.03	$ 4.10	$ 4.17	$ 4.21	$ 4.23	$ 4.25	$ 4.29
Low Growth High Price	Stanfield	2012-2013	$ 4.59	$ 4.85	$ 5.28	$ 5.26	$ 5.24	$ 5.00	$ 5.01	$ 5.04	$ 5.07	$ 5.10	$ 5.10	$ 5.15
Low Growth High Price	Stanfield	2013-2014	$ 5.45	$ 5.69	$ 6.25	$ 6.22	$ 6.20	$ 5.86	$ 5.84	$ 5.89	$ 5.91	$ 5.95	$ 5.95	$ 6.01
Low Growth High Price	Stanfield	2014-2015	$ 6.34	$ 6.60	$ 7.39	$ 7.35	$ 7.26	$ 6.89	$ 6.88	$ 6.92	$ 6.95	$ 6.98	$ 7.01	$ 7.07
Low Growth High Price	Stanfield	2015-2016	$ 7.45	$ 7.74	$ 7.86	$ 7.82	$ 7.72	$ 7.33	$ 7.33	$ 7.33	$ 7.38	$ 7.42	$ 7.48	$ 7.55
Low Growth High Price	Stanfield	2016-2017	$ 7.91	$ 8.23	$ 8.45	$ 8.41	$ 8.28	$ 7.85	$ 7.85	$ 7.86	$ 7.87	$ 7.91	$ 8.01	$ 8.08
Low Growth High Price	Stanfield	2017-2018	$ 8.12	$ 8.44	$ 8.66	$ 8.62	$ 8.48	$ 8.07	$ 8.07	$ 8.09	$ 8.07	$ 8.12	$ 8.22	$ 8.31
Low Growth High Price	Stanfield	2018-2019	$ 8.33	$ 8.71	$ 9.03	$ 8.99	$ 8.74	$ 8.28	$ 8.27	$ 8.29	$ 8.27	$ 8.32	$ 8.43	$ 8.70
Low Growth High Price	Stanfield	2019-2020	$ 8.67	$ 8.95	$ 9.24	$ 9.20	$ 8.95	$ 8.46	$ 8.46	$ 8.45	$ 8.46	$ 8.50	$ 8.66	$ 8.79
Low Growth High Price	Stanfield	2020-2021	$ 8.80	$ 9.33	$ 9.54	$ 9.49	$ 9.23	$ 8.72	$ 8.73	$ 8.70	$ 8.71	$ 8.75	$ 8.99	$ 9.12
Low Growth High Price	Stanfield	2021-2022	$ 9.24	$ 9.66	$ 9.82	$ 9.77	$ 9.46	$ 8.96	$ 8.97	$ 8.99	$ 8.97	$ 9.03	$ 9.23	$ 9.34
Low Growth High Price	Stanfield	2022-2023	$ 9.51	$ 9.82	$ 10.02	$ 9.97	$ 9.67	$ 9.20	$ 9.20	$ 9.17	$ 9.17	$ 9.22	$ 9.44	$ 9.56
Low Growth High Price	Stanfield	2023-2024	$ 9.71	$ 10.11	$ 10.39	$ 10.34	$ 10.08	$ 9.61	$ 9.56	$ 9.58	$ 9.58	$ 9.64	$ 9.72	$ 9.89
Low Growth High Price	Stanfield	2024-2025	$ 10.07	$ 10.46	$ 10.64	$ 10.58	$ 10.35	$ 9.83	$ 9.76	$ 9.79	$ 9.79	$ 9.85	$ 9.96	$ 10.14
Low Growth High Price	Stanfield	2025-2026	$ 10.38	$ 10.80	$ 11.28	$ 11.22	$ 11.07	$ 10.43	$ 10.41	$ 10.40	$ 10.40	$ 10.46	$ 10.65	$ 10.81
Low Growth High Price	Stanfield	2026-2027	$ 10.99	$ 11.44	$ 11.81	$ 11.76	$ 11.60	$ 10.94	$ 10.92	$ 10.91	$ 10.89	$ 10.96	$ 11.19	$ 11.33
Low Growth High Price	Stanfield	2027-2028	$ 11.49	$ 11.97	$ 12.43	$ 12.37	$ 12.20	$ 11.49	$ 11.48	$ 11.49	$ 11.45	$ 11.52	$ 11.84	$ 11.95
Low Growth High Price	Stanfield	2028-2029	$ 12.11	$ 12.60	$ 13.06	$ 12.99	$ 12.87	$ 12.10	$ 12.09	$ 12.09	$ 12.07	$ 12.15	$ 12.31	$ 12.52
Low Growth High Price	Stanfield	2029-2030	$ 12.69	$ 13.22	$ 13.76	$ 13.70	$ 13.57	$ 12.82	$ 12.81	$ 12.80	$ 12.77	$ 12.85	$ 13.04	$ 13.25
Low Growth High Price	Stanfield	2030-2031	$ 13.41	$ 13.97	$ 13.81	$ 13.74	$ 13.58	$ 12.81	$ 12.93	$ 12.83	$ 12.80	$ 12.88	$ 13.08	$ 13.29
Low Growth High Price	Sumas	2011-2012	$ 3.32	$ 3.21	$ 2.67	$ 2.77	$ 4.06	$ 3.97	$ 3.97	$ 4.01	$ 4.08	$ 4.09	$ 4.10	$ 4.22
Low Growth High Price	Sumas	2012-2013	$ 4.79	$ 5.05	$ 5.49	$ 5.47	$ 5.32	$ 4.92	$ 4.86	$ 4.88	$ 4.92	$ 4.95	$ 4.96	$ 5.06
Low Growth High Price	Sumas	2013-2014	$ 5.64	$ 5.90	$ 6.47	$ 6.44	$ 6.29	$ 5.72	$ 5.69	$ 5.73	$ 5.76	$ 5.78	$ 5.74	$ 5.82
Low Growth High Price	Sumas	2014-2015	$ 6.56	$ 6.83	$ 7.62	$ 7.58	$ 7.35	$ 6.74	$ 6.71	$ 6.77	$ 6.80	$ 6.82	$ 6.80	$ 6.85
Low Growth High Price	Sumas	2015-2016	$ 7.68	$ 7.97	$ 8.09	$ 8.05	$ 7.81	$ 7.16	$ 7.14	$ 7.17	$ 7.20	$ 7.22	$ 7.26	$ 7.32
Low Growth High Price	Sumas	2016-2017	$ 8.15	$ 8.47	$ 8.69	$ 8.65	$ 8.37	$ 7.64	$ 7.65	$ 7.67	$ 7.67	$ 7.70	$ 7.78	$ 7.84
Low Growth High Price	Sumas	2017-2018	$ 8.37	$ 8.69	$ 8.91	$ 8.87	$ 8.33	$ 7.84	$ 7.86	$ 7.88	$ 7.85	$ 7.89	$ 7.98	$ 8.06
Low Growth High Price	Sumas	2018-2019	$ 8.36	$ 8.96	$ 9.18	$ 9.13	$ 8.70	$ 8.17	$ 8.16	$ 8.11	$ 8.05	$ 8.08	$ 8.16	$ 8.32
Low Growth High Price	Sumas	2019-2020	$ 8.34	$ 8.72	$ 9.39	$ 9.35	$ 8.95	$ 8.37	$ 8.33	$ 8.30	$ 8.31	$ 8.34	$ 8.47	$ 8.61
Low Growth High Price	Sumas	2020-2021	$ 8.83	$ 9.38	$ 9.59	$ 9.54	$ 9.38	$ 8.62	$ 8.52	$ 8.48	$ 8.56	$ 8.56	$ 8.68	$ 8.91
Low Growth High Price	Sumas	2021-2022	$ 9.29	$ 9.71	$ 9.92	$ 9.87	$ 9.61	$ 8.85	$ 8.77	$ 8.75	$ 8.80	$ 8.83	$ 8.96	$ 9.18
Low Growth High Price	Sumas	2022-2023	$ 9.56	$ 9.87	$ 10.07	$ 10.02	$ 9.82	$ 9.08	$ 9.01	$ 8.95	$ 9.02	$ 9.02	$ 9.14	$ 9.34
Low Growth High Price	Sumas	2023-2024	$ 9.76	$ 10.16	$ 10.47	$ 10.39	$ 10.23	$ 9.47	$ 9.36	$ 9.35	$ 9.40	$ 9.41	$ 9.46	$ 9.71
Low Growth High Price	Sumas	2024-2025	$ 10.12	$ 10.51	$ 10.71	$ 10.65	$ 10.50	$ 9.69	$ 9.57	$ 9.55	$ 9.66	$ 9.63	$ 9.70	$ 9.97
Low Growth High Price	Sumas	2025-2026	$ 10.43	$ 10.85	$ 11.35	$ 11.29	$ 11.12	$ 10.28	$ 10.19	$ 10.03	$ 10.27	$ 10.25	$ 10.38	$ 10.64
Low Growth High Price	Sumas	2026-2027	$ 11.04	$ 11.51	$ 11.91	$ 11.85	$ 11.65	$ 10.79	$ 10.71	$ 10.52	$ 10.76	$ 10.76	$ 10.92	$ 11.16
Low Growth High Price	Sumas	2027-2028	$ 11.54	$ 12.03	$ 12.52	$ 12.47	$ 12.25	$ 11.35	$ 11.28	$ 11.11	$ 11.33	$ 11.33	$ 11.54	$ 11.77
Low Growth High Price	Sumas	2028-2029	$ 12.16	$ 12.79	$ 13.27	$ 13.21	$ 12.92	$ 11.95	$ 11.88	$ 11.69	$ 11.94	$ 12.00	$ 12.06	$ 12.35
Low Growth High Price	Sumas	2029-2030	$ 12.74	$ 13.40	$ 13.98	$ 13.92	$ 13.62	$ 12.66	$ 12.58	$ 12.39	$ 12.64	$ 12.70	$ 12.85	$ 13.07
Low Growth High Price	Sumas	2030-2031	$ 13.46	$ 14.29	$ 14.15	$ 14.08	$ 13.63	$ 12.66	$ 12.58	$ 12.43	$ 12.66	$ 12.73	$ 12.88	$ 13.11

APPENDIX 6.2 II WEIGHTED AVERAGE COST OF CAPITAL

Avista Corporation Capital Structure and Overall Rate of Return

OREGON

Cost of Capital as of	Amount	Percent of Total	Cost	Component	After Tax Component
L/T Debt		50.00%	5.90%	2.95%	1.92%
Trust Preferred Securities		0.00%	0.00%	0.00%	
Common Equity		50.00%	10.10%	5.05%	5.05%
TOTAL		**100.00%**		**8.00%**	**6.97%**

WASHINGTON

Agreed-upon Cost of Capital		Percent of Total Capital	Cost	Component	After Tax Component
L/T Debt		53.50%	5.93%	3.17%	2.06%
Trust Preferred Securities				0.00%	
Common Equity		46.50%	10.20%	4.74%	4.74%
TOTAL		**100.00%**		**7.92%**	**6.81%**

IDAHO

Agreed-upon Cost of Capital	Amount	Percent of Total Capital	Cost	Component	After Tax Component
L/T Debt (1)		50.00%	6.60%	3.30%	2.15%
Trust Preferred Securities				0.00%	
Preferred Stock				0.00%	0.00%
Common Equity		50.00%	10.50%	5.25%	5.25%
TOTAL		**100.00%**		**8.55%**	**7.40%**

Rate Base from Commission Basis Reports			
OR	$	141,728,000	31%
WA	$	205,507,000	45%
ID	$	107,759,000	24%
	$	454,994,000	

System Weighted Average Cost of Capital (Nominal$)*	8.09%	7.00%
GDP price deflator	1.56%	1.56%
After Tax WACC	6.43%	**5.35%**

*Weighting based on Commission Basis Reports
**Tax rate applied to L/T Debt 35%

APPENDIX 6.2 II AUTHORIZED RATES OF RETURN

Washington Electric
General Case Settlement in 2008 (UE-080416)
effective 1/1/2009

Component	Capital Structure	ProForma Cost	ProForma Weighted Cost
L/T Debt (1)	53.70%	6.51%	3.50%
Pref Trust			0.00%
Common	46.30%	10.20%	4.72%
Total	100.00%		8.22%

(1) includes short-term debt

Washington Gas
General Case Settlement in 2008 (UG-080417)
effective 1/1/2009

Component	Capital Structure	ProForma Cost	ProForma Weighted Cost
L/T Debt (1)	53.70%	6.51%	3.50%
Pref Trust			0.00%
Common	46.30%	10.20%	4.72%
Total	100.00%		8.22%

(1) includes short-term debt

Idaho Electric
Case Decided in 2008-AVU-E-08-01
effective 10/1/2008

Component	Capital Structure	ProForma Cost	ProForma Weighted Cost
L/T Debt	52.06%	6.84%	3.56%
Pref Trust			0.00%
Pref Stock			0.00%
Common	47.94%	10.20%	4.89%
Total	100.00%		8.45%

(excludes short-term debt)

Idaho Gas
Case Decided in 2008-AVU-G-08-01
effective 10/1/2008

Component	Capital Structure	ProForma Cost	ProForma Weighted Cost
L/T Debt	52.06%	6.84%	3.56%
Pref Trust			0.00%
Pref Stock			0.00%
Common	47.94%	10.20%	4.89%
Total	100.00%		8.45%

(excludes short-term debt)

Oregon Gas
General Case Settlement in 2007 (UG-181)
effective 4/1/2008

Component	Capital Structure	ProForma Cost	ProForma Weighted Cost
L/T Debt	45.00%	6.40%	2.88%
Pref Trust	5.00%	6.57%	0.33%
Common	50.00%	10.00%	5.00%
Total	100.00%		8.21%

(excludes short-term debt)

APPENDIX 6.2 II ESCALATION/INFLATION FORECASTS

Implicit Price Deflators — U. S. Average 5/20/2011
Source: Randy Barcus, Finance--Analysis, Budget & Forecasting
Discount Rate: Levelizing is Not Applicable to Escalation Rates

Year	E1 Gross Domestic Product (% change)	E2 Personal Consumption Expenditures (% change)	E3 Power Equipment Investment (% change)	E4 Consumer Price Index-Urban (% change)
1996	1.9	2.2	1.6	2.9
1997	1.7	1.7	2.1	2.3
1998	1.1	0.9	1.9	1.5
1999	1.4	1.7	1.6	2.2
2000	2.2	2.5	4.1	3.4
2001	2.3	1.9	2.8	2.8
2002	1.6	1.4	2.7	1.6
2003	2.2	2.0	2.3	2.3
2004	2.8	2.6	8.3	2.7
2005	3.3	3.0	9.3	3.4
2006	3.3	2.7	6.1	3.2
2007	2.9	2.7	4.7	2.9
2008	2.2	3.3	9.4	3.8
2009	0.9	0.2	-0.7	-0.3
2010	1.0	1.7	1.0	1.6
2011	1.3	1.4	3.5	1.9
2012	1.3	1.5	1.6	1.7
2013	1.6	1.7	2.2	1.9
2014	1.8	2.0	3.0	2.2
2015	1.8	2.1	3.0	2.2
2016	1.8	2.0	2.8	2.1
2017	1.8	2.0	2.9	2.1
2018	1.8	2.1	2.9	2.1
2019	1.8	1.9	2.8	2.0
2020	1.8	1.9	2.8	1.9
2021	1.8	1.9	2.7	1.9
2022	1.7	1.8	2.6	1.9
2023	1.7	1.8	2.4	1.9
2024	1.7	1.9	2.5	2.0
2025	1.7	1.9	2.5	2.0
2026	1.8	2.0	2.5	2.0
2027	1.8	2.0	2.6	2.1
2028	1.8	2.0	2.6	2.1
2029	1.8	2.0	2.6	2.1
2030	1.8	2.0	2.5	2.1
2031	1.8	2.0	2.6	2.0
2032	1.8	2.0	2.6	2.0
2033	1.8	2.0	2.6	2.0
2034	1.8	2.0	2.5	2.0
2035	1.7	2.0	2.5	1.9
2036	1.7	2.0	2.4	2.0
2037	1.8	2.0	2.5	2.0
2038	1.8	2.1	2.6	2.1
2039	1.9	2.1	2.6	2.1
2040	1.8	2.1	2.5	2.1
2010-2040 Avg.	1.7	1.9	2.6	2.0
5 Year Avg.	1.6	1.7	2.6	2.0
10 Year Avg.	1.7	1.9	2.7	2.0
20 Year Avg.	1.7	1.9	2.6	2.0
25 Year Avg.	1.7	1.9	2.6	2.0
30 Year Avg.	1.7	1.9	2.6	2.0
Std. Dev.	1.0	1.0	1.5	1.0
	0.5	0.5	1.9	0.6

E1 Applies to inflation of all good & services produced & consumed in the U.S.
E2 Applies to inflation of goods & services consumed by individuals.
E3 Applies to inflation of non-residential power equipment
E4 For all urban consumers, applies to inflation of a fixed market basket of typical goods & services.

Reference: Global Insight's Review of the U.S. Economy First Quarter 2011

APPENDIX 6.2 II COST OF CAPITAL

Source: Damien Lysiak, Treasury Department 6/20/2011

Projected Long-Term Cost of Capital – Avista Utilities for Net Present Value Analysis

	Target Capital Structure	Component Cost		
Debt	50%	5.85%		2.93%
Common Equity	50%	10.90%	1	5.45%
Weighted Cost of Capital				8.38%

1: Based on Avista's WUTC 2011 rate case

Authorized Cost of Capital – Avista Utilities for Revenue Requirements Analysis Washington Elec/Gas Decided 2010

	Authorized Capital Structure	Component Cost	Component Return
Debt	53.50%	5.92%	3.17%
Common Equity	46.50%	10.20%	4.74%
Rate of Return			7.91%

Authorized Cost of Capital – Avista Utilities for Revenue Requirements Analysis Idaho Elec/Gas Decided

	Authorized Capital Structure	Component Cost	Component Return
Debt	50.00%	6.60%	3.30%
Common Equity	50.00%	10.50%	5.25%
Rate of Return			8.55%

APPENDIX 6.3 II POTENTIAL SUPPLY SIDE RESOURCE ADDITIONS

Additional Resources	Jurisdiction	Size	Cost/Rates	Availability	Modeled	Case(s)	Notes
Pipeline							
Capacity Release Recalls	WA/ID	28,000 Dth/d	NWPL fixed rate	2018	Yes	Expected/High	Recall previously released capacity
GTN Capacity	WA/ID	25,000 - 75,000 Dth/d	GTN rate	2013	Yes	Expected/High	Currently available unsubscribed capacity from Kingsgate to Spokane
GTN Capacity	OR	25,000 - 50,000 Dth/d	GTN rate	2013	Yes	Expected/High	Currently available unsubscribed capacity; requires expansion of Medford Lateral
GTN Medford Lateral Expansion	OR	25,000 - 50,000 Dth/d	GTN rate	2014	Yes	Expected/High	Additional compression to allow more gas to flow from GTN mailine to the lateral
NWP Expansion	WA/ID	75,000 Dth/d	NWPL fixed rate x 3	2018	Yes	Expected/High	Transport expansion from Sumas/JP to WA/ID
NWP Expansion	OR	50,000 Dth/d	NWPL fixed rate x 5	2018	Yes	Expected/High	Transport expansion from Sumas/JP to Oregon
Statellite LNG							
WA/ID Satellite LNG	WA/ID	270,000 capacity; 90,000 delivery for 3 days	$132 million capital cost $1 million annual O&M	November 2018	Yes	Expected/High	
Medford/Roseburg Satellite LNG	OR	135,000 capacity; 45,000 delivery for 3 days	$66 million capital cost $850,000 annual O&M	November 2018	Yes	Expected/High	
Klamath Falls Satellite LNG	OR	45,000 capacity; 15,000 delivery for 3 days	$22 million capital cost $850,000 annual O&M	November 2018	Yes	Expected/High	
La Grande Satellite LNG	OR	45,000 capacity; 15,000 delivery for 3 days	$22 million capital cost $850,000 annual O&M	November 2018	Yes	Expected/High	
Company Owned Liquifaction LNG							
WA/ID	WA	600 MMcf capacity; 150,000 delivery for 4 days	$75 million capital cost, $2 million annual O&M	November 2018	No		Considered and discussed but not taken to full cycle modeling.
Export LNG							
An Oregon Export LNG Facility plus pipeline build through Avista service territory.	OR	25,000 Dth/d	Pipeline charge $1.00/Dth/d	November 2018	No		Considered and discussed but not taken to full cycle modeling.
Other Resources Considered							
Citygate deliveries	WA/ID/OR				No		Represents the ability to buy a delivered product fron another utility or marketer. Limited counterparties to structure transaction
Inground Storage							
California					No		Dependent on GTN backhaul or convert to bidirectional pipeline
JP Expansion					No		Dependent on NWP Expansion or other Tport arrangements back to service territory
Mist					No		Dependent on NWP Expansion or other Tport arrangements back to service territory; Long term subscription may not be available

APPENDIX 6.4 II EXPECTED CASE AVOIDED COST

Annual Avoided Costs 1/
2010$

Scenario	Gas Year	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA/ID Both	WA/ID GTN	WA/ID NWP	WA/ID Annual	OR Annual
Expected	2011-2012	$ 2.69	$ 2.84	$ 2.69	$ 2.69	$ 2.69	$ 2.69	$ 2.65	$ 2.87	$ 2.74	$ 2.72
Expected	2012-2013	$ 3.54	$ 3.77	$ 3.54	$ 3.54	$ 3.54	$ 3.58	$ 3.48	$ 3.77	$ 3.61	$ 3.58
Expected	2013-2014	$ 3.85	$ 4.07	$ 3.85	$ 3.85	$ 3.85	$ 3.86	$ 3.80	$ 4.08	$ 3.91	$ 3.90
Expected	2014-2015	$ 4.01	$ 4.24	$ 4.01	$ 4.01	$ 4.01	$ 4.03	$ 3.96	$ 4.25	$ 4.08	$ 4.06
Expected	2015-2016	$ 4.18	$ 4.45	$ 4.18	$ 4.18	$ 4.18	$ 4.21	$ 4.12	$ 4.47	$ 4.26	$ 4.23
Expected	2016-2017	$ 4.35	$ 4.64	$ 4.35	$ 4.35	$ 4.35	$ 4.39	$ 4.29	$ 4.65	$ 4.44	$ 4.41
Expected	2017-2018	$ 4.56	$ 4.88	$ 4.56	$ 4.56	$ 4.56	$ 4.60	$ 4.50	$ 4.89	$ 4.67	$ 4.63
Expected	2018-2019	$ 4.73	$ 5.06	$ 4.73	$ 4.73	$ 4.73	$ 4.78	$ 4.67	$ 5.08	$ 4.84	$ 4.80
Expected	2019-2020	$ 4.82	$ 5.03	$ 4.83	$ 4.83	$ 4.83	$ 4.84	$ 4.76	$ 5.05	$ 4.88	$ 4.87
Expected	2020-2021	$ 4.93	$ 5.10	$ 4.93	$ 4.93	$ 4.93	$ 4.94	$ 4.86	$ 5.11	$ 4.97	$ 4.96
Expected	2021-2022	$ 4.87	$ 5.01	$ 4.88	$ 4.88	$ 4.88	$ 4.87	$ 4.80	$ 5.02	$ 4.90	$ 4.90
Expected	2022-2023	$ 4.99	$ 5.08	$ 4.99	$ 4.99	$ 4.99	$ 4.99	$ 4.92	$ 5.09	$ 5.00	$ 5.01
Expected	2023-2024	$ 4.92	$ 4.98	$ 4.93	$ 4.93	$ 4.93	$ 4.91	$ 4.85	$ 4.99	$ 4.92	$ 4.94
Expected	2024-2025	$ 4.96	$ 4.98	$ 4.95	$ 4.95	$ 4.95	$ 4.94	$ 4.90	$ 4.97	$ 4.94	$ 4.96
Expected	2025-2026	$ 5.04	$ 5.20	$ 5.05	$ 5.05	$ 5.05	$ 5.01	$ 4.98	$ 5.22	$ 5.07	$ 5.08
Expected	2026-2027	$ 5.01	$ 5.15	$ 5.02	$ 5.02	$ 5.02	$ 4.97	$ 4.94	$ 5.16	$ 5.03	$ 5.04
Expected	2027-2028	$ 5.03	$ 5.13	$ 5.04	$ 5.04	$ 5.04	$ 5.00	$ 4.96	$ 5.14	$ 5.04	$ 5.06
Expected	2028-2029	$ 5.07	$ 5.14	$ 5.08	$ 5.08	$ 5.08	$ 5.04	$ 5.00	$ 5.16	$ 5.07	$ 5.09
Expected	2029-2030	$ 5.08	$ 5.12	$ 5.08	$ 5.08	$ 5.08	$ 5.03	$ 5.00	$ 5.14	$ 5.06	$ 5.09
Expected	2030-2031	$ 5.15	$ 5.17	$ 5.16	$ 5.16	$ 5.16	$ 5.11	$ 5.08	$ 5.19	$ 5.13	$ 5.16

Winter Avoided Costs 1/
2010$

Scenario	Gas Year	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA/ID Both	WA/ID GTN	WA/ID NWP	WA/ID Winter	OR Winter
Expected	2011-2012	$ 2.80	$ 2.88	$ 2.80	$ 2.80	$ 2.80	$ 2.86	$ 2.75	$ 2.87	$ 2.83	$ 2.81
Expected	2012-2013	$ 3.42	$ 3.68	$ 3.43	$ 3.43	$ 3.43	$ 3.59	$ 3.36	$ 3.68	$ 3.55	$ 3.48
Expected	2013-2014	$ 3.94	$ 4.11	$ 3.94	$ 3.94	$ 3.94	$ 4.03	$ 3.88	$ 4.11	$ 4.00	$ 3.97
Expected	2014-2015	$ 4.07	$ 4.28	$ 4.07	$ 4.07	$ 4.07	$ 4.19	$ 4.00	$ 4.27	$ 4.15	$ 4.11
Expected	2015-2016	$ 4.21	$ 4.47	$ 4.21	$ 4.21	$ 4.21	$ 4.36	$ 4.14	$ 4.47	$ 4.32	$ 4.26
Expected	2016-2017	$ 4.39	$ 4.67	$ 4.39	$ 4.39	$ 4.39	$ 4.55	$ 4.32	$ 4.67	$ 4.51	$ 4.44
Expected	2017-2018	$ 4.60	$ 4.91	$ 4.60	$ 4.60	$ 4.60	$ 4.77	$ 4.52	$ 4.91	$ 4.73	$ 4.66
Expected	2018-2019	$ 4.79	$ 5.11	$ 4.79	$ 4.79	$ 4.79	$ 4.97	$ 4.71	$ 5.11	$ 4.93	$ 4.85
Expected	2019-2020	$ 4.88	$ 5.10	$ 4.88	$ 4.88	$ 4.88	$ 5.00	$ 4.80	$ 5.10	$ 4.97	$ 4.92
Expected	2020-2021	$ 5.00	$ 5.18	$ 5.00	$ 5.00	$ 5.00	$ 5.11	$ 4.92	$ 5.18	$ 5.07	$ 5.03
Expected	2021-2022	$ 4.97	$ 5.12	$ 4.97	$ 4.97	$ 4.97	$ 5.05	$ 4.88	$ 5.12	$ 5.02	$ 5.00
Expected	2022-2023	$ 5.02	$ 5.15	$ 5.02	$ 5.02	$ 5.02	$ 5.10	$ 4.94	$ 5.15	$ 5.06	$ 5.05
Expected	2023-2024	$ 5.04	$ 5.13	$ 5.04	$ 5.04	$ 5.04	$ 5.08	$ 4.95	$ 5.11	$ 5.05	$ 5.06
Expected	2024-2025	$ 5.03	$ 5.09	$ 5.03	$ 5.03	$ 5.03	$ 5.06	$ 4.95	$ 5.07	$ 5.02	$ 5.04
Expected	2025-2026	$ 5.14	$ 5.29	$ 5.14	$ 5.14	$ 5.14	$ 5.15	$ 5.07	$ 5.28	$ 5.17	$ 5.17
Expected	2026-2027	$ 5.15	$ 5.28	$ 5.15	$ 5.15	$ 5.15	$ 5.16	$ 5.08	$ 5.27	$ 5.17	$ 5.18
Expected	2027-2028	$ 5.14	$ 5.23	$ 5.14	$ 5.14	$ 5.14	$ 5.15	$ 5.07	$ 5.22	$ 5.15	$ 5.16
Expected	2028-2029	$ 5.19	$ 5.24	$ 5.19	$ 5.19	$ 5.19	$ 5.19	$ 5.10	$ 5.23	$ 5.18	$ 5.20
Expected	2029-2030	$ 5.21	$ 5.24	$ 5.22	$ 5.22	$ 5.22	$ 5.20	$ 5.13	$ 5.23	$ 5.18	$ 5.22
Expected	2030-2031	$ 5.25	$ 5.26	$ 5.26	$ 5.26	$ 5.26	$ 5.23	$ 5.17	$ 5.26	$ 5.22	$ 5.26

1/ Avoided costs are before Environmental Externalities adder.

APPENDIX 6.4 II LOW GROWTH CASE AVOIDED COST

Annual Avoided Costs 1/
2010$

Scenario	Gas Year	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA/ID Both	WA/ID GTN	WA/ID NWP	WA/ID Annual	OR Annual
Low Growth	2011-2012	$ 3.68	$ 3.82	$ 3.68	$ 3.68	$ 3.68	$ 3.71	$ 3.63	$ 3.82	$ 3.72	$ 3.71
Low Growth	2012-2013	$ 4.96	$ 5.13	$ 4.96	$ 4.96	$ 4.96	$ 4.95	$ 4.90	$ 5.13	$ 4.99	$ 5.00
Low Growth	2013-2014	$ 5.84	$ 6.02	$ 5.84	$ 5.84	$ 5.84	$ 5.80	$ 5.77	$ 6.01	$ 5.86	$ 5.88
Low Growth	2014-2015	$ 6.91	$ 7.07	$ 6.91	$ 6.91	$ 6.91	$ 6.85	$ 6.82	$ 7.05	$ 6.91	$ 6.94
Low Growth	2015-2016	$ 7.45	$ 7.65	$ 7.45	$ 7.45	$ 7.45	$ 7.42	$ 7.36	$ 7.65	$ 7.48	$ 7.49
Low Growth	2016-2017	$ 7.97	$ 8.18	$ 7.97	$ 7.97	$ 7.97	$ 7.92	$ 7.87	$ 8.16	$ 7.99	$ 8.01
Low Growth	2017-2018	$ 8.17	$ 8.41	$ 8.17	$ 8.17	$ 8.17	$ 8.12	$ 8.06	$ 8.39	$ 8.19	$ 8.21
Low Growth	2018-2019	$ 8.40	$ 8.64	$ 8.40	$ 8.40	$ 8.40	$ 8.35	$ 8.29	$ 8.62	$ 8.42	$ 8.45
Low Growth	2019-2020	$ 8.64	$ 8.78	$ 8.64	$ 8.64	$ 8.64	$ 8.58	$ 8.53	$ 8.78	$ 8.63	$ 8.67
Low Growth	2020-2021	$ 8.91	$ 9.03	$ 8.90	$ 8.90	$ 8.90	$ 8.84	$ 8.80	$ 9.02	$ 8.89	$ 8.93
Low Growth	2021-2022	$ 9.17	$ 9.26	$ 9.16	$ 9.16	$ 9.16	$ 9.10	$ 9.06	$ 9.25	$ 9.13	$ 9.18
Low Growth	2022-2023	$ 9.39	$ 9.43	$ 9.38	$ 9.38	$ 9.38	$ 9.31	$ 9.28	$ 9.42	$ 9.34	$ 9.39
Low Growth	2023-2024	$ 9.74	$ 9.75	$ 9.72	$ 9.72	$ 9.72	$ 9.64	$ 9.62	$ 9.75	$ 9.67	$ 9.73
Low Growth	2024-2025	$ 9.98	$ 9.97	$ 9.96	$ 9.96	$ 9.96	$ 9.89	$ 9.86	$ 9.98	$ 9.91	$ 9.97
Low Growth	2025-2026	$ 10.57	$ 10.65	$ 10.56	$ 10.56	$ 10.56	$ 10.47	$ 10.44	$ 10.64	$ 10.52	$ 10.58
Low Growth	2026-2027	$ 11.10	$ 11.18	$ 11.10	$ 11.10	$ 11.10	$ 11.00	$ 10.97	$ 11.16	$ 11.04	$ 11.12
Low Growth	2027-2028	$ 11.71	$ 11.74	$ 11.70	$ 11.70	$ 11.70	$ 11.59	$ 11.57	$ 11.72	$ 11.63	$ 11.71
Low Growth	2028-2029	$ 12.32	$ 12.33	$ 12.31	$ 12.31	$ 12.31	$ 12.19	$ 12.17	$ 12.33	$ 12.23	$ 12.32
Low Growth	2029-2030	$ 13.02	$ 13.01	$ 13.01	$ 13.01	$ 13.01	$ 12.89	$ 12.87	$ 13.02	$ 12.93	$ 13.01
Low Growth	2030-2031	$ 13.16	$ 13.12	$ 13.14	$ 13.14	$ 13.14	$ 13.03	$ 13.01	$ 13.16	$ 13.06	$ 13.14

Winter Avoided Costs 1/
2010$

Scenario	Gas Year	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA/ID Both	WA/ID GTN	WA/ID NWP	WA/ID Winter	OR Winter
Low Growth	2011-2012	$ 3.13	$ 3.32	$ 3.13	$ 3.13	$ 3.13	$ 3.28	$ 3.07	$ 3.32	$ 3.23	$ 3.17
Low Growth	2012-2013	$ 4.96	$ 5.09	$ 4.97	$ 4.97	$ 4.97	$ 5.03	$ 4.89	$ 5.07	$ 5.00	$ 4.99
Low Growth	2013-2014	$ 5.88	$ 5.99	$ 5.89	$ 5.89	$ 5.89	$ 5.89	$ 5.80	$ 5.94	$ 5.88	$ 5.91
Low Growth	2014-2015	$ 6.92	$ 7.03	$ 6.92	$ 6.92	$ 6.92	$ 6.91	$ 6.82	$ 6.97	$ 6.90	$ 6.94
Low Growth	2015-2016	$ 7.64	$ 7.78	$ 7.64	$ 7.64	$ 7.64	$ 7.68	$ 7.54	$ 7.74	$ 7.65	$ 7.67
Low Growth	2016-2017	$ 8.17	$ 8.31	$ 8.17	$ 8.17	$ 8.17	$ 8.19	$ 8.06	$ 8.26	$ 8.17	$ 8.20
Low Growth	2017-2018	$ 8.36	$ 8.53	$ 8.36	$ 8.36	$ 8.36	$ 8.38	$ 8.25	$ 8.48	$ 8.37	$ 8.39
Low Growth	2018-2019	$ 8.60	$ 8.78	$ 8.60	$ 8.60	$ 8.60	$ 8.63	$ 8.49	$ 8.73	$ 8.62	$ 8.64
Low Growth	2019-2020	$ 8.85	$ 8.99	$ 8.85	$ 8.85	$ 8.85	$ 8.85	$ 8.74	$ 8.93	$ 8.84	$ 8.88
Low Growth	2020-2021	$ 9.12	$ 9.23	$ 9.12	$ 9.12	$ 9.12	$ 9.11	$ 9.00	$ 9.17	$ 9.09	$ 9.14
Low Growth	2021-2022	$ 9.38	$ 9.48	$ 9.38	$ 9.38	$ 9.38	$ 9.36	$ 9.26	$ 9.42	$ 9.35	$ 9.40
Low Growth	2022-2023	$ 9.60	$ 9.67	$ 9.60	$ 9.60	$ 9.60	$ 9.57	$ 9.48	$ 9.62	$ 9.55	$ 9.62
Low Growth	2023-2024	$ 9.91	$ 9.94	$ 9.91	$ 9.91	$ 9.91	$ 9.84	$ 9.78	$ 9.88	$ 9.83	$ 9.92
Low Growth	2024-2025	$ 10.19	$ 10.21	$ 10.19	$ 10.19	$ 10.19	$ 10.13	$ 10.07	$ 10.16	$ 10.12	$ 10.20
Low Growth	2025-2026	$ 10.72	$ 10.78	$ 10.72	$ 10.72	$ 10.72	$ 10.65	$ 10.58	$ 10.70	$ 10.64	$ 10.73
Low Growth	2026-2027	$ 11.28	$ 11.35	$ 11.28	$ 11.28	$ 11.28	$ 11.22	$ 11.14	$ 11.27	$ 11.21	$ 11.30
Low Growth	2027-2028	$ 11.89	$ 11.93	$ 11.89	$ 11.89	$ 11.89	$ 11.79	$ 11.74	$ 11.84	$ 11.79	$ 11.90
Low Growth	2028-2029	$ 12.53	$ 12.54	$ 12.53	$ 12.53	$ 12.53	$ 12.43	$ 12.37	$ 12.46	$ 12.42	$ 12.53
Low Growth	2029-2030	$ 13.20	$ 13.19	$ 13.20	$ 13.20	$ 13.20	$ 13.10	$ 13.04	$ 13.13	$ 13.09	$ 13.20
Low Growth	2030-2031	$ 13.51	$ 13.45	$ 13.50	$ 13.50	$ 13.50	$ 13.40	$ 13.36	$ 13.42	$ 13.39	$ 13.49

1/ Avoided costs are before Environmental Externalities adder.

APPENDIX 6.4 II HIGH GROWTH CASE AVOIDED COST

Annual Avoided Costs 1/
2010$

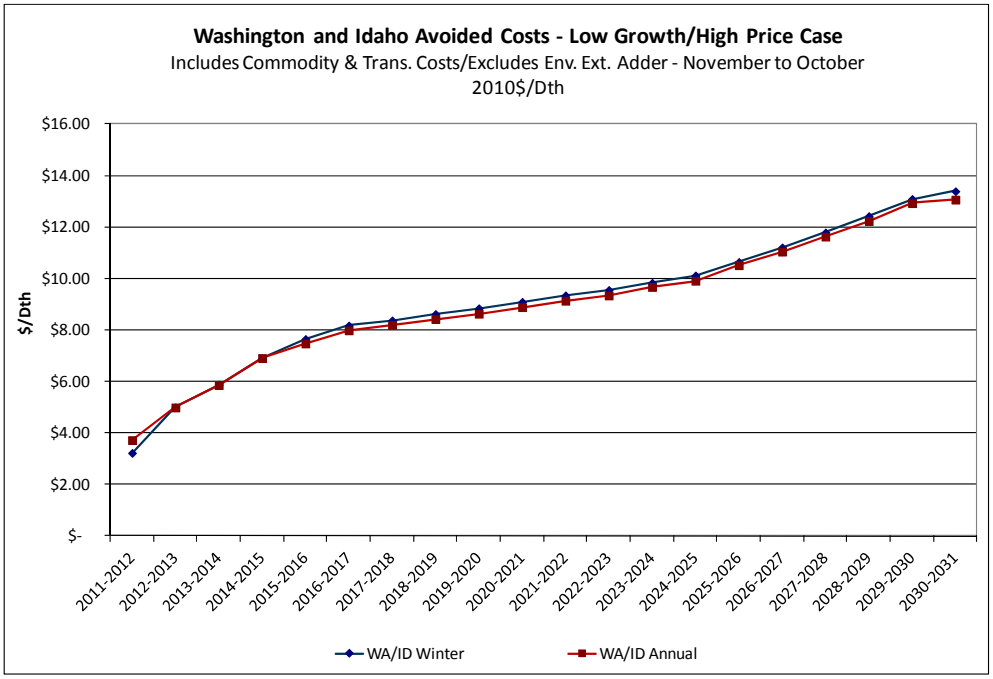
Scenario	Gas Year	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA/ID Both	WA/ID GTN	WA/ID NWP	WA/ID Annual	OR Annual
High Growth	2011-2012	$ 2.69	$ 2.84	$ 2.69	$ 2.69	$ 2.69	$ 2.65	$ 2.65	$ 2.87	$ 2.72	$ 2.72
High Growth	2012-2013	$ 3.54	$ 3.74	$ 3.54	$ 3.54	$ 3.54	$ 3.49	$ 3.49	$ 3.76	$ 3.58	$ 3.58
High Growth	2013-2014	$ 3.85	$ 4.07	$ 3.85	$ 3.85	$ 3.85	$ 3.80	$ 3.80	$ 4.08	$ 3.89	$ 3.90
High Growth	2014-2015	$ 4.02	$ 4.23	$ 4.02	$ 4.02	$ 4.02	$ 3.96	$ 3.96	$ 4.24	$ 4.05	$ 4.06
High Growth	2015-2016	$ 4.18	$ 4.45	$ 4.18	$ 4.18	$ 4.18	$ 4.12	$ 4.12	$ 4.46	$ 4.23	$ 4.23
High Growth	2016-2017	$ 4.87	$ 5.15	$ 4.87	$ 4.87	$ 4.87	$ 4.80	$ 4.80	$ 5.16	$ 4.92	$ 4.93
High Growth	2017-2018	$ 5.08	$ 5.39	$ 5.09	$ 5.09	$ 5.09	$ 5.01	$ 5.01	$ 5.40	$ 5.14	$ 5.15
High Growth	2018-2019	$ 5.25	$ 5.57	$ 5.25	$ 5.25	$ 5.25	$ 5.18	$ 5.18	$ 5.59	$ 5.31	$ 5.32
High Growth	2019-2020	$ 5.34	$ 5.54	$ 5.35	$ 5.35	$ 5.35	$ 5.27	$ 5.27	$ 5.55	$ 5.36	$ 5.39
High Growth	2020-2021	$ 5.45	$ 5.63	$ 5.46	$ 5.46	$ 5.46	$ 5.38	$ 5.38	$ 5.66	$ 5.47	$ 5.49
High Growth	2021-2022	$ 5.39	$ 5.53	$ 5.40	$ 5.40	$ 5.40	$ 5.31	$ 5.31	$ 5.54	$ 5.39	$ 5.42
High Growth	2022-2023	$ 5.52	$ 5.59	$ 5.52	$ 5.52	$ 5.52	$ 5.43	$ 5.43	$ 5.61	$ 5.49	$ 5.53
High Growth	2023-2024	$ 5.44	$ 5.48	$ 5.45	$ 5.45	$ 5.45	$ 5.36	$ 5.36	$ 5.50	$ 5.41	$ 5.45
High Growth	2024-2025	$ 5.50	$ 5.50	$ 5.50	$ 5.50	$ 5.50	$ 5.41	$ 5.41	$ 5.50	$ 5.44	$ 5.50
High Growth	2025-2026	$ 5.62	$ 5.72	$ 5.63	$ 5.63	$ 5.63	$ 5.48	$ 5.48	$ 5.74	$ 5.57	$ 5.65
High Growth	2026-2027	$ 5.58	$ 5.67	$ 5.60	$ 5.60	$ 5.60	$ 5.45	$ 5.45	$ 5.68	$ 5.52	$ 5.61
High Growth	2027-2028	$ 5.59	$ 5.65	$ 5.61	$ 5.61	$ 5.61	$ 5.47	$ 5.47	$ 5.67	$ 5.54	$ 5.61
High Growth	2028-2029	$ 5.65	$ 5.68	$ 5.66	$ 5.66	$ 5.66	$ 5.52	$ 5.52	$ 5.71	$ 5.59	$ 5.66
High Growth	2029-2030	$ 5.69	$ 5.70	$ 5.70	$ 5.70	$ 5.70	$ 5.54	$ 5.54	$ 5.76	$ 5.61	$ 5.70
High Growth	2030-2031	$ 5.78	$ 5.78	$ 5.79	$ 5.79	$ 5.79	$ 5.62	$ 5.62	$ 5.82	$ 5.69	$ 5.79

Winter Avoided Costs 1/
2010$

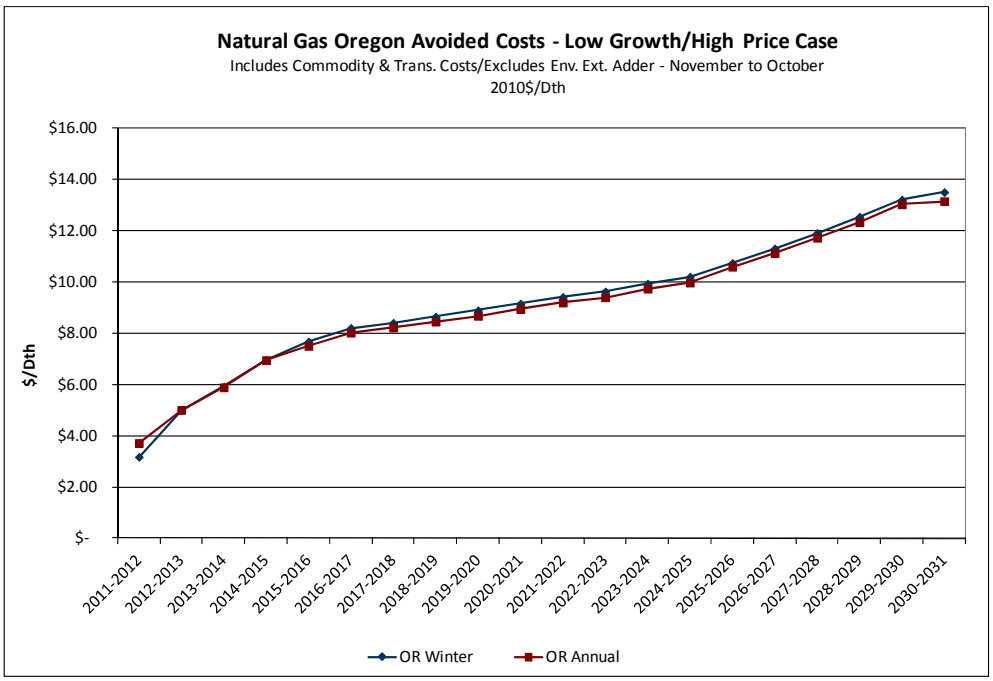
Scenario	Gas Year	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA/ID Both	WA/ID GTN	WA/ID NWP	WA/ID Winter	OR Winter
High Growth	2011-2012	$ 2.80	$ 2.87	$ 2.80	$ 2.80	$ 2.80	$ 2.75	$ 2.75	$ 2.85	$ 2.79	$ 2.81
High Growth	2012-2013	$ 3.42	$ 3.61	$ 3.42	$ 3.42	$ 3.42	$ 3.36	$ 3.36	$ 3.65	$ 3.46	$ 3.46
High Growth	2013-2014	$ 3.94	$ 4.11	$ 3.94	$ 3.94	$ 3.94	$ 3.88	$ 3.88	$ 4.10	$ 3.95	$ 3.97
High Growth	2014-2015	$ 4.07	$ 4.27	$ 4.07	$ 4.07	$ 4.07	$ 4.01	$ 4.01	$ 4.27	$ 4.09	$ 4.11
High Growth	2015-2016	$ 4.21	$ 4.46	$ 4.21	$ 4.21	$ 4.21	$ 4.14	$ 4.14	$ 4.46	$ 4.25	$ 4.26
High Growth	2016-2017	$ 4.91	$ 5.17	$ 4.91	$ 4.91	$ 4.91	$ 4.83	$ 4.83	$ 5.17	$ 4.94	$ 4.96
High Growth	2017-2018	$ 5.12	$ 5.41	$ 5.12	$ 5.12	$ 5.12	$ 5.04	$ 5.04	$ 5.41	$ 5.16	$ 5.18
High Growth	2018-2019	$ 5.31	$ 5.61	$ 5.31	$ 5.31	$ 5.31	$ 5.23	$ 5.23	$ 5.61	$ 5.36	$ 5.37
High Growth	2019-2020	$ 5.41	$ 5.60	$ 5.41	$ 5.41	$ 5.41	$ 5.32	$ 5.32	$ 5.60	$ 5.41	$ 5.45
High Growth	2020-2021	$ 5.53	$ 5.71	$ 5.53	$ 5.53	$ 5.53	$ 5.44	$ 5.44	$ 5.71	$ 5.53	$ 5.57
High Growth	2021-2022	$ 5.49	$ 5.64	$ 5.49	$ 5.49	$ 5.49	$ 5.41	$ 5.41	$ 5.63	$ 5.48	$ 5.52
High Growth	2022-2023	$ 5.58	$ 5.67	$ 5.58	$ 5.58	$ 5.58	$ 5.47	$ 5.47	$ 5.67	$ 5.53	$ 5.60
High Growth	2023-2024	$ 5.57	$ 5.61	$ 5.57	$ 5.57	$ 5.57	$ 5.47	$ 5.47	$ 5.60	$ 5.51	$ 5.58
High Growth	2024-2025	$ 5.61	$ 5.60	$ 5.61	$ 5.61	$ 5.61	$ 5.47	$ 5.47	$ 5.59	$ 5.51	$ 5.61
High Growth	2025-2026	$ 5.81	$ 5.84	$ 5.81	$ 5.81	$ 5.81	$ 5.58	$ 5.58	$ 5.82	$ 5.66	$ 5.81
High Growth	2026-2027	$ 5.81	$ 5.82	$ 5.81	$ 5.81	$ 5.81	$ 5.58	$ 5.58	$ 5.80	$ 5.65	$ 5.81
High Growth	2027-2028	$ 5.77	$ 5.77	$ 5.77	$ 5.77	$ 5.77	$ 5.57	$ 5.57	$ 5.76	$ 5.63	$ 5.77
High Growth	2028-2029	$ 5.84	$ 5.84	$ 5.84	$ 5.84	$ 5.84	$ 5.63	$ 5.63	$ 5.84	$ 5.70	$ 5.84
High Growth	2029-2030	$ 5.94	$ 5.93	$ 5.94	$ 5.94	$ 5.94	$ 5.68	$ 5.68	$ 5.95	$ 5.77	$ 5.94
High Growth	2030-2031	$ 6.01	$ 5.99	$ 6.01	$ 6.01	$ 6.01	$ 5.73	$ 5.73	$ 6.04	$ 5.84	$ 6.01

1/ Avoided costs are before Environmental Externalities adder.

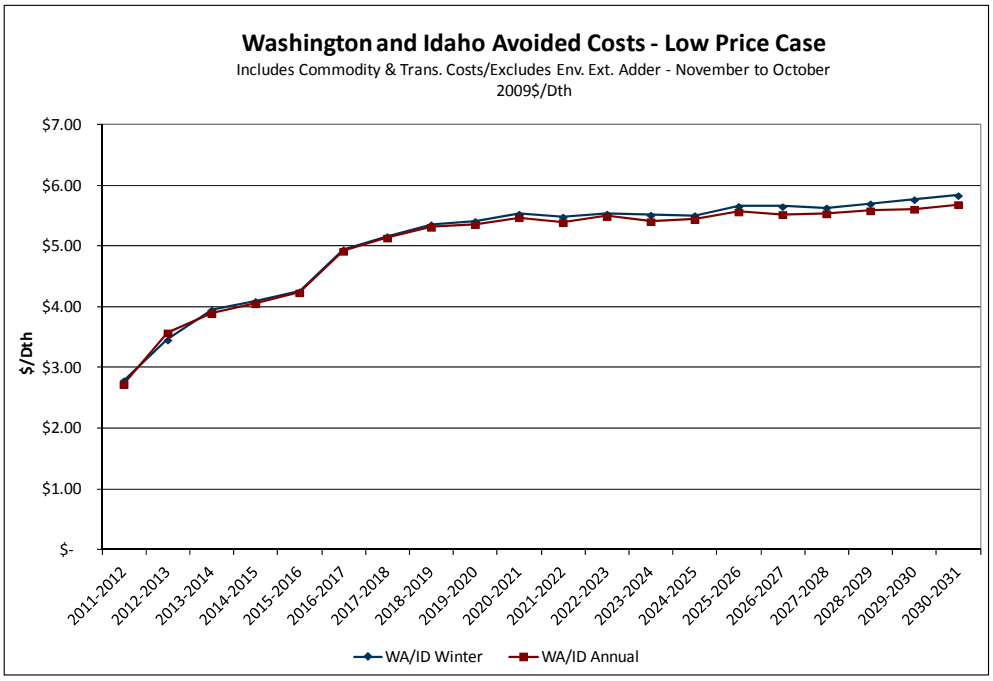
APPENDIX 6.4 II WASHINGTON AND IDAHO AVOIDED COSTS - LOW GROWTH/HIGH PRICE CASE



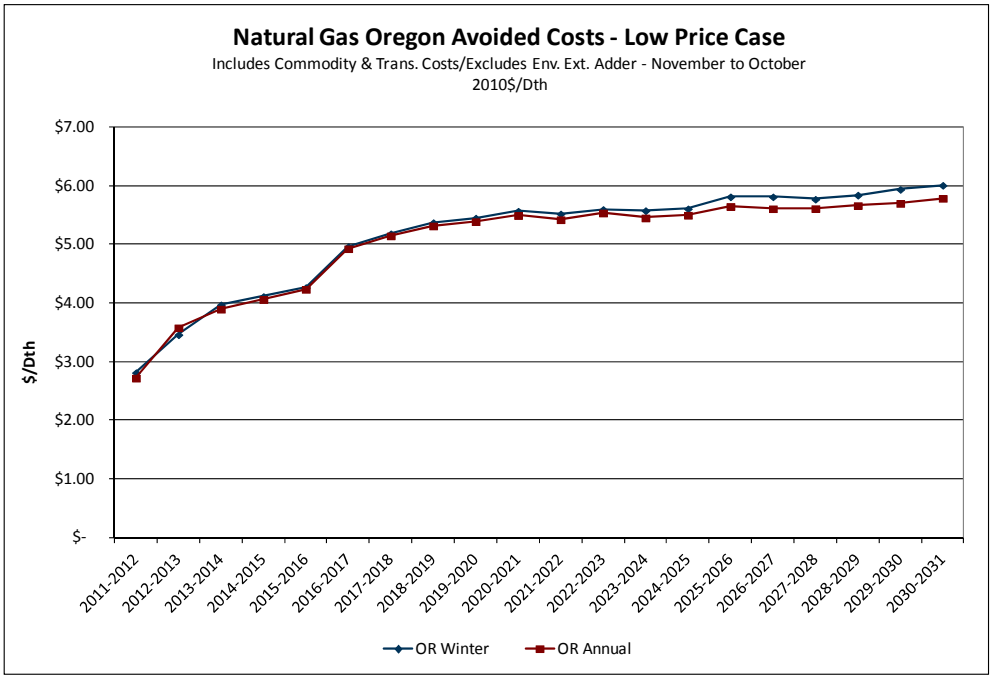
APPENDIX 6.4 II NATURAL GAS OREGON AVOIDED COSTS - LOW GROWTH/HIGH PRICE CASE



APPENDIX 6.4 II WASHINGTON AND IDAHO AVOIDED COSTS - LOW PRICE CASE



APPENDIX 6.4 II NATURAL GAS OREGON AVOIDED COSTS - LOW PRICE CASE



APPENDIX 6.4 II LOW GROWTH – HIGH PRICE MONTHLY DETAIL

Monthly Avoided Cost Detail 1/
2010$

Scenario	Gas Year	Month	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA/ID Both	WA/ID GTN	WA/ID NWP	WA/ID Annual	OR Annual
Low Growth & High Price	2011-2012	Nov	$ 3.21	$ 3.21	$ 3.21	$ 3.21	$ 3.21	$ 3.18	$ 3.17	$ 3.21	$ 3.19	$ 3.21
Low Growth & High Price	2011-2012	Dec	$ 3.07	$ 3.48	$ 3.11	$ 3.11	$ 3.11	$ 3.48	$ 3.00	$ 3.48	$ 3.32	$ 3.18
Low Growth & High Price	2011-2012	Jan	$ 2.55	$ 2.74	$ 2.55	$ 2.55	$ 2.55	$ 2.74	$ 2.52	$ 2.75	$ 2.67	$ 2.59
Low Growth & High Price	2011-2012	Feb	$ 2.68	$ 3.03	$ 2.68	$ 2.68	$ 2.68	$ 2.95	$ 2.62	$ 3.03	$ 2.87	$ 2.75
Low Growth & High Price	2011-2012	Mar	$ 4.09	$ 4.11	$ 4.09	$ 4.09	$ 4.09	$ 4.03	$ 4.03	$ 4.11	$ 4.06	$ 4.09
Low Growth & High Price	2011-2012	Apr	$ 4.02	$ 4.11	$ 4.02	$ 4.02	$ 4.02	$ 3.96	$ 3.96	$ 4.11	$ 4.01	$ 4.04
Low Growth & High Price	2011-2012	May	$ 3.97	$ 4.12	$ 3.97	$ 3.97	$ 3.97	$ 3.91	$ 3.91	$ 4.12	$ 3.98	$ 4.00
Low Growth & High Price	2011-2012	Jun	$ 4.04	$ 4.12	$ 4.04	$ 4.04	$ 4.04	$ 3.98	$ 3.98	$ 4.12	$ 4.03	$ 4.05
Low Growth & High Price	2011-2012	Jul	$ 4.08	$ 4.16	$ 4.08	$ 4.08	$ 4.08	$ 4.02	$ 4.02	$ 4.16	$ 4.07	$ 4.09
Low Growth & High Price	2011-2012	Aug	$ 4.09	$ 4.17	$ 4.09	$ 4.09	$ 4.09	$ 4.03	$ 4.03	$ 4.17	$ 4.08	$ 4.10
Low Growth & High Price	2011-2012	Sep	$ 4.14	$ 4.18	$ 4.14	$ 4.14	$ 4.14	$ 4.09	$ 4.09	$ 4.18	$ 4.12	$ 4.15
Low Growth & High Price	2011-2012	Oct	$ 4.18	$ 4.42	$ 4.18	$ 4.18	$ 4.18	$ 4.13	$ 4.13	$ 4.42	$ 4.22	$ 4.23
Low Growth & High Price	2012-2013	Nov	$ 4.50	$ 4.70	$ 4.50	$ 4.50	$ 4.50	$ 4.52	$ 4.44	$ 4.70	$ 4.55	$ 4.54
Low Growth & High Price	2012-2013	Dec	$ 4.78	$ 5.13	$ 4.82	$ 4.82	$ 4.82	$ 5.13	$ 4.68	$ 5.13	$ 4.98	$ 4.87
Low Growth & High Price	2012-2013	Jan	$ 5.20	$ 5.23	$ 5.20	$ 5.20	$ 5.20	$ 5.23	$ 5.14	$ 5.23	$ 5.20	$ 5.21
Low Growth & High Price	2012-2013	Feb	$ 5.17	$ 5.21	$ 5.17	$ 5.17	$ 5.17	$ 5.15	$ 5.11	$ 5.16	$ 5.14	$ 5.18
Low Growth & High Price	2012-2013	Mar	$ 5.16	$ 5.16	$ 5.16	$ 5.16	$ 5.16	$ 5.10	$ 5.10	$ 5.14	$ 5.11	$ 5.16
Low Growth & High Price	2012-2013	Apr	$ 4.93	$ 5.11	$ 4.93	$ 4.93	$ 4.93	$ 4.86	$ 4.86	$ 5.14	$ 4.95	$ 4.96
Low Growth & High Price	2012-2013	May	$ 4.90	$ 5.12	$ 4.90	$ 4.90	$ 4.90	$ 4.83	$ 4.83	$ 5.14	$ 4.94	$ 4.94
Low Growth & High Price	2012-2013	Jun	$ 4.92	$ 5.14	$ 4.92	$ 4.92	$ 4.92	$ 4.85	$ 4.85	$ 5.14	$ 4.95	$ 4.96
Low Growth & High Price	2012-2013	Jul	$ 4.95	$ 5.14	$ 4.95	$ 4.95	$ 4.95	$ 4.88	$ 4.88	$ 5.14	$ 4.97	$ 4.99
Low Growth & High Price	2012-2013	Aug	$ 4.98	$ 5.15	$ 4.98	$ 4.98	$ 4.98	$ 4.91	$ 4.91	$ 5.15	$ 4.99	$ 5.01
Low Growth & High Price	2012-2013	Sep	$ 5.01	$ 5.15	$ 5.01	$ 5.01	$ 5.01	$ 4.94	$ 4.94	$ 5.15	$ 5.01	$ 5.04
Low Growth & High Price	2012-2013	Oct	$ 5.06	$ 5.29	$ 5.06	$ 5.06	$ 5.06	$ 5.00	$ 5.00	$ 5.29	$ 5.09	$ 5.10
Low Growth & High Price	2013-2014	Nov	$ 5.37	$ 5.56	$ 5.37	$ 5.37	$ 5.37	$ 5.30	$ 5.30	$ 5.56	$ 5.39	$ 5.40
Low Growth & High Price	2013-2014	Dec	$ 5.62	$ 5.90	$ 5.66	$ 5.66	$ 5.66	$ 5.90	$ 5.52	$ 5.90	$ 5.77	$ 5.70
Low Growth & High Price	2013-2014	Jan	$ 6.16	$ 6.16	$ 6.16	$ 6.16	$ 6.16	$ 6.10	$ 6.09	$ 6.10	$ 6.09	$ 6.16
Low Growth & High Price	2013-2014	Feb	$ 6.13	$ 6.17	$ 6.13	$ 6.13	$ 6.13	$ 6.08	$ 6.06	$ 6.08	$ 6.07	$ 6.14
Low Growth & High Price	2013-2014	Mar	$ 6.14	$ 6.14	$ 6.14	$ 6.14	$ 6.14	$ 6.07	$ 6.07	$ 6.07	$ 6.07	$ 6.14
Low Growth & High Price	2013-2014	Apr	$ 5.79	$ 5.98	$ 5.79	$ 5.79	$ 5.79	$ 5.72	$ 5.72	$ 6.03	$ 5.83	$ 5.83
Low Growth & High Price	2013-2014	May	$ 5.73	$ 5.98	$ 5.73	$ 5.73	$ 5.73	$ 5.66	$ 5.66	$ 6.03	$ 5.79	$ 5.78
Low Growth & High Price	2013-2014	Jun	$ 5.78	$ 6.02	$ 5.78	$ 5.78	$ 5.78	$ 5.71	$ 5.71	$ 6.04	$ 5.82	$ 5.83
Low Growth & High Price	2013-2014	Jul	$ 5.80	$ 6.04	$ 5.80	$ 5.80	$ 5.80	$ 5.73	$ 5.73	$ 6.04	$ 5.83	$ 5.85
Low Growth & High Price	2013-2014	Aug	$ 5.83	$ 6.04	$ 5.83	$ 5.83	$ 5.83	$ 5.75	$ 5.75	$ 6.04	$ 5.85	$ 5.87
Low Growth & High Price	2013-2014	Sep	$ 5.85	$ 6.04	$ 5.85	$ 5.85	$ 5.85	$ 5.77	$ 5.77	$ 6.04	$ 5.86	$ 5.88
Low Growth & High Price	2013-2014	Oct	$ 5.90	$ 6.16	$ 5.90	$ 5.90	$ 5.90	$ 5.82	$ 5.82	$ 6.16	$ 5.94	$ 5.95
Low Growth & High Price	2014-2015	Nov	$ 6.25	$ 6.48	$ 6.25	$ 6.25	$ 6.25	$ 6.18	$ 6.18	$ 6.48	$ 6.28	$ 6.30
Low Growth & High Price	2014-2015	Dec	$ 6.55	$ 6.83	$ 6.58	$ 6.58	$ 6.58	$ 6.83	$ 6.43	$ 6.84	$ 6.70	$ 6.62
Low Growth & High Price	2014-2015	Jan	$ 7.31	$ 7.31	$ 7.31	$ 7.31	$ 7.31	$ 7.22	$ 7.22	$ 7.22	$ 7.22	$ 7.31
Low Growth & High Price	2014-2015	Feb	$ 7.27	$ 7.31	$ 7.27	$ 7.27	$ 7.27	$ 7.19	$ 7.18	$ 7.19	$ 7.19	$ 7.27
Low Growth & High Price	2014-2015	Mar	$ 7.22	$ 7.22	$ 7.22	$ 7.22	$ 7.22	$ 7.13	$ 7.13	$ 7.13	$ 7.13	$ 7.22
Low Growth & High Price	2014-2015	Apr	$ 6.85	$ 7.04	$ 6.85	$ 6.85	$ 6.85	$ 6.76	$ 6.76	$ 7.09	$ 6.87	$ 6.89
Low Growth & High Price	2014-2015	May	$ 6.83	$ 7.04	$ 6.83	$ 6.83	$ 6.83	$ 6.74	$ 6.74	$ 7.09	$ 6.86	$ 6.87
Low Growth & High Price	2014-2015	Jun	$ 6.89	$ 7.07	$ 6.89	$ 6.89	$ 6.89	$ 6.80	$ 6.80	$ 7.09	$ 6.90	$ 6.92
Low Growth & High Price	2014-2015	Jul	$ 6.92	$ 7.09	$ 6.92	$ 6.92	$ 6.92	$ 6.83	$ 6.83	$ 7.09	$ 6.92	$ 6.95
Low Growth & High Price	2014-2015	Aug	$ 6.93	$ 7.09	$ 6.93	$ 6.93	$ 6.93	$ 6.84	$ 6.84	$ 7.09	$ 6.93	$ 6.96
Low Growth & High Price	2014-2015	Sep	$ 6.92	$ 7.10	$ 6.92	$ 6.92	$ 6.92	$ 6.83	$ 6.83	$ 7.10	$ 6.92	$ 6.95
Low Growth & High Price	2014-2015	Oct	$ 6.96	$ 7.24	$ 6.96	$ 6.96	$ 6.96	$ 6.88	$ 6.88	$ 7.24	$ 7.00	$ 7.02
Low Growth & High Price	2015-2016	Nov	$ 7.38	$ 7.62	$ 7.38	$ 7.38	$ 7.38	$ 7.29	$ 7.29	$ 7.62	$ 7.40	$ 7.43
Low Growth & High Price	2015-2016	Dec	$ 7.67	$ 7.93	$ 7.67	$ 7.67	$ 7.67	$ 7.93	$ 7.54	$ 7.93	$ 7.80	$ 7.72
Low Growth & High Price	2015-2016	Jan	$ 7.75	$ 7.93	$ 7.75	$ 7.75	$ 7.75	$ 7.93	$ 7.65	$ 7.93	$ 7.84	$ 7.78
Low Growth & High Price	2015-2016	Feb	$ 7.71	$ 7.76	$ 7.71	$ 7.71	$ 7.71	$ 7.64	$ 7.61	$ 7.64	$ 7.63	$ 7.72
Low Growth & High Price	2015-2016	Mar	$ 7.68	$ 7.68	$ 7.68	$ 7.68	$ 7.68	$ 7.58	$ 7.58	$ 7.58	$ 7.58	$ 7.68
Low Growth & High Price	2015-2016	Apr	$ 7.27	$ 7.51	$ 7.27	$ 7.27	$ 7.27	$ 7.18	$ 7.18	$ 7.55	$ 7.30	$ 7.31
Low Growth & High Price	2015-2016	May	$ 7.27	$ 7.51	$ 7.27	$ 7.27	$ 7.27	$ 7.18	$ 7.18	$ 7.55	$ 7.30	$ 7.31
Low Growth & High Price	2015-2016	Jun	$ 7.29	$ 7.51	$ 7.29	$ 7.29	$ 7.29	$ 7.20	$ 7.20	$ 7.56	$ 7.32	$ 7.33
Low Growth & High Price	2015-2016	Jul	$ 7.32	$ 7.56	$ 7.32	$ 7.32	$ 7.32	$ 7.23	$ 7.23	$ 7.56	$ 7.34	$ 7.37
Low Growth & High Price	2015-2016	Aug	$ 7.34	$ 7.56	$ 7.34	$ 7.34	$ 7.34	$ 7.25	$ 7.25	$ 7.56	$ 7.35	$ 7.38
Low Growth & High Price	2015-2016	Sep	$ 7.38	$ 7.56	$ 7.38	$ 7.38	$ 7.38	$ 7.29	$ 7.29	$ 7.56	$ 7.38	$ 7.42
Low Growth & High Price	2015-2016	Oct	$ 7.43	$ 7.74	$ 7.43	$ 7.43	$ 7.43	$ 7.34	$ 7.34	$ 7.74	$ 7.47	$ 7.49
Low Growth & High Price	2016-2017	Nov	$ 7.81	$ 8.09	$ 7.81	$ 7.81	$ 7.81	$ 7.71	$ 7.71	$ 8.09	$ 7.84	$ 7.87
Low Growth & High Price	2016-2017	Dec	$ 8.15	$ 8.42	$ 8.15	$ 8.15	$ 8.15	$ 8.42	$ 8.02	$ 8.42	$ 8.29	$ 8.21
Low Growth & High Price	2016-2017	Jan	$ 8.34	$ 8.43	$ 8.34	$ 8.34	$ 8.34	$ 8.43	$ 8.24	$ 8.43	$ 8.37	$ 8.36
Low Growth & High Price	2016-2017	Feb	$ 8.29	$ 8.34	$ 8.29	$ 8.29	$ 8.29	$ 8.20	$ 8.19	$ 8.20	$ 8.20	$ 8.30
Low Growth & High Price	2016-2017	Mar	$ 8.25	$ 8.25	$ 8.25	$ 8.25	$ 8.25	$ 8.15	$ 8.15	$ 8.15	$ 8.15	$ 8.25
Low Growth & High Price	2016-2017	Apr	$ 7.76	$ 8.04	$ 7.76	$ 7.76	$ 7.76	$ 7.66	$ 7.66	$ 8.06	$ 7.80	$ 7.81
Low Growth & High Price	2016-2017	May	$ 7.78	$ 8.04	$ 7.78	$ 7.78	$ 7.78	$ 7.68	$ 7.68	$ 8.06	$ 7.81	$ 7.83
Low Growth & High Price	2016-2017	Jun	$ 7.79	$ 8.05	$ 7.79	$ 7.79	$ 7.79	$ 7.69	$ 7.69	$ 8.06	$ 7.82	$ 7.84
Low Growth & High Price	2016-2017	Jul	$ 7.80	$ 8.06	$ 7.80	$ 7.80	$ 7.80	$ 7.70	$ 7.70	$ 8.06	$ 7.82	$ 7.85
Low Growth & High Price	2016-2017	Aug	$ 7.82	$ 8.07	$ 7.82	$ 7.82	$ 7.82	$ 7.72	$ 7.72	$ 8.07	$ 7.84	$ 7.87
Low Growth & High Price	2016-2017	Sep	$ 7.91	$ 8.07	$ 7.91	$ 7.91	$ 7.91	$ 7.82	$ 7.82	$ 8.07	$ 7.90	$ 7.94
Low Growth & High Price	2016-2017	Oct	$ 7.96	$ 8.29	$ 7.96	$ 7.96	$ 7.96	$ 7.87	$ 7.87	$ 8.29	$ 8.01	$ 8.03
Low Growth & High Price	2017-2018	Nov	$ 7.97	$ 8.32	$ 7.97	$ 7.97	$ 7.97	$ 7.88	$ 7.88	$ 8.32	$ 8.02	$ 8.04
Low Growth & High Price	2017-2018	Dec	$ 8.34	$ 8.65	$ 8.34	$ 8.34	$ 8.34	$ 8.62	$ 8.20	$ 8.65	$ 8.49	$ 8.40
Low Growth & High Price	2017-2018	Jan	$ 8.54	$ 8.66	$ 8.54	$ 8.54	$ 8.54	$ 8.66	$ 8.44	$ 8.66	$ 8.59	$ 8.57
Low Growth & High Price	2017-2018	Feb	$ 8.49	$ 8.55	$ 8.49	$ 8.49	$ 8.49	$ 8.41	$ 8.39	$ 8.41	$ 8.40	$ 8.50
Low Growth & High Price	2017-2018	Mar	$ 8.44	$ 8.44	$ 8.44	$ 8.44	$ 8.44	$ 8.34	$ 8.34	$ 8.34	$ 8.34	$ 8.44
Low Growth & High Price	2017-2018	Apr	$ 7.96	$ 8.29	$ 7.96	$ 7.96	$ 7.96	$ 7.87	$ 7.87	$ 8.29	$ 8.01	$ 8.03
Low Growth & High Price	2017-2018	May	$ 7.98	$ 8.28	$ 7.98	$ 7.98	$ 7.98	$ 7.89	$ 7.89	$ 8.30	$ 8.02	$ 8.04
Low Growth & High Price	2017-2018	Jun	$ 8.01	$ 8.30	$ 8.01	$ 8.01	$ 8.01	$ 7.92	$ 7.92	$ 8.30	$ 8.04	$ 8.07
Low Growth & High Price	2017-2018	Jul	$ 7.97	$ 8.28	$ 7.97	$ 7.97	$ 7.97	$ 7.88	$ 7.88	$ 8.30	$ 8.02	$ 8.03
Low Growth & High Price	2017-2018	Aug	$ 8.01	$ 8.30	$ 8.01	$ 8.01	$ 8.01	$ 7.92	$ 7.92	$ 8.30	$ 8.04	$ 8.07
Low Growth & High Price	2017-2018	Sep	$ 8.09	$ 8.30	$ 8.09	$ 8.09	$ 8.09	$ 8.00	$ 8.00	$ 8.30	$ 8.10	$ 8.14
Low Growth & High Price	2017-2018	Oct	$ 8.18	$ 8.54	$ 8.18	$ 8.18	$ 8.18	$ 8.08	$ 8.08	$ 8.54	$ 8.23	$ 8.25
Low Growth & High Price	2018-2019	Nov	$ 8.19	$ 8.54	$ 8.19	$ 8.19	$ 8.19	$ 8.09	$ 8.09	$ 8.54	$ 8.24	$ 8.26
Low Growth & High Price	2018-2019	Dec	$ 8.61	$ 8.92	$ 8.61	$ 8.61	$ 8.61	$ 8.88	$ 8.46	$ 8.92	$ 8.75	$ 8.67
Low Growth & High Price	2018-2019	Jan	$ 8.78	$ 8.94	$ 8.78	$ 8.78	$ 8.78	$ 8.94	$ 8.67	$ 8.94	$ 8.85	$ 8.81
Low Growth & High Price	2018-2019	Feb	$ 8.74	$ 8.80	$ 8.74	$ 8.74	$ 8.74	$ 8.65	$ 8.63	$ 8.65	$ 8.64	$ 8.75
Low Growth & High Price	2018-2019	Mar	$ 8.71	$ 8.71	$ 8.71	$ 8.71	$ 8.71	$ 8.60	$ 8.60	$ 8.60	$ 8.60	$ 8.71
Low Growth & High Price	2018-2019	Apr	$ 8.19	$ 8.49	$ 8.19	$ 8.19	$ 8.19	$ 8.09	$ 8.09	$ 8.50	$ 8.22	$ 8.25
Low Growth & High Price	2018-2019	May	$ 8.21	$ 8.47	$ 8.21	$ 8.21	$ 8.21	$ 8.11	$ 8.11	$ 8.50	$ 8.24	$ 8.26
Low Growth & High Price	2018-2019	Jun	$ 8.24	$ 8.49	$ 8.24	$ 8.24	$ 8.24	$ 8.14	$ 8.14	$ 8.50	$ 8.26	$ 8.29
Low Growth & High Price	2018-2019	Jul	$ 8.18	$ 8.47	$ 8.18	$ 8.18	$ 8.18	$ 8.08	$ 8.08	$ 8.50	$ 8.22	$ 8.23
Low Growth & High Price	2018-2019	Aug	$ 8.22	$ 8.50	$ 8.22	$ 8.22	$ 8.22	$ 8.12	$ 8.12	$ 8.50	$ 8.25	$ 8.27

APPENDIX 6.4 II LOW GROWTH – HIGH PRICE MONTHLY DETAIL

Monthly Avoided Cost Detail 1/
2010$

Scenario	Gas Year	Month	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA/ID Both	WA/ID GTN	WA/ID NWP	WA/ID Annual	OR Annual
Low Growth & High Price	2018-2019	Sep	$ 8.30	$ 8.51	$ 8.30	$ 8.30	$ 8.30	$ 8.20	$ 8.20	$ 8.51	$ 8.30	$ 8.34
Low Growth & High Price	2018-2019	Oct	$ 8.44	$ 8.81	$ 8.44	$ 8.44	$ 8.44	$ 8.34	$ 8.34	$ 8.81	$ 8.50	$ 8.52
Low Growth & High Price	2019-2020	Nov	$ 8.42	$ 8.71	$ 8.42	$ 8.42	$ 8.42	$ 8.32	$ 8.32	$ 8.71	$ 8.45	$ 8.48
Low Growth & High Price	2019-2020	Dec	$ 8.86	$ 9.11	$ 8.86	$ 8.86	$ 8.86	$ 9.11	$ 8.70	$ 9.11	$ 8.97	$ 8.91
Low Growth & High Price	2019-2020	Jan	$ 9.06	$ 9.13	$ 9.06	$ 9.06	$ 9.06	$ 9.13	$ 8.95	$ 9.13	$ 9.07	$ 9.07
Low Growth & High Price	2019-2020	Feb	$ 9.00	$ 9.04	$ 9.00	$ 9.00	$ 9.00	$ 8.87	$ 8.90	$ 8.87	$ 8.88	$ 9.01
Low Growth & High Price	2019-2020	Mar	$ 8.93	$ 8.93	$ 8.93	$ 8.93	$ 8.93	$ 8.83	$ 8.83	$ 8.83	$ 8.83	$ 8.93
Low Growth & High Price	2019-2020	Apr	$ 8.42	$ 8.62	$ 8.42	$ 8.42	$ 8.42	$ 8.32	$ 8.32	$ 8.62	$ 8.42	$ 8.46
Low Growth & High Price	2019-2020	May	$ 8.43	$ 8.58	$ 8.43	$ 8.43	$ 8.43	$ 8.33	$ 8.33	$ 8.62	$ 8.43	$ 8.46
Low Growth & High Price	2019-2020	Jun	$ 8.43	$ 8.56	$ 8.43	$ 8.43	$ 8.43	$ 8.33	$ 8.33	$ 8.63	$ 8.43	$ 8.46
Low Growth & High Price	2019-2020	Jul	$ 8.40	$ 8.55	$ 8.40	$ 8.40	$ 8.40	$ 8.30	$ 8.30	$ 8.63	$ 8.41	$ 8.43
Low Growth & High Price	2019-2020	Aug	$ 8.44	$ 8.59	$ 8.44	$ 8.44	$ 8.44	$ 8.34	$ 8.34	$ 8.63	$ 8.44	$ 8.47
Low Growth & High Price	2019-2020	Sep	$ 8.56	$ 8.63	$ 8.56	$ 8.56	$ 8.56	$ 8.46	$ 8.46	$ 8.63	$ 8.52	$ 8.58
Low Growth & High Price	2019-2020	Oct	$ 8.69	$ 8.93	$ 8.69	$ 8.69	$ 8.69	$ 8.58	$ 8.58	$ 8.93	$ 8.70	$ 8.73
Low Growth & High Price	2020-2021	Nov	$ 8.68	$ 8.92	$ 8.68	$ 8.68	$ 8.68	$ 8.57	$ 8.57	$ 8.92	$ 8.69	$ 8.72
Low Growth & High Price	2020-2021	Dec	$ 9.14	$ 9.35	$ 9.14	$ 9.14	$ 9.14	$ 9.35	$ 8.99	$ 9.35	$ 9.23	$ 9.18
Low Growth & High Price	2020-2021	Jan	$ 9.31	$ 9.37	$ 9.31	$ 9.31	$ 9.31	$ 9.37	$ 9.20	$ 9.37	$ 9.32	$ 9.32
Low Growth & High Price	2020-2021	Feb	$ 9.26	$ 9.30	$ 9.26	$ 9.26	$ 9.26	$ 9.12	$ 9.15	$ 9.12	$ 9.13	$ 9.27
Low Growth & High Price	2020-2021	Mar	$ 9.21	$ 9.21	$ 9.21	$ 9.21	$ 9.21	$ 9.10	$ 9.10	$ 9.10	$ 9.10	$ 9.21
Low Growth & High Price	2020-2021	Apr	$ 8.70	$ 8.86	$ 8.70	$ 8.70	$ 8.70	$ 8.59	$ 8.59	$ 8.86	$ 8.68	$ 8.73
Low Growth & High Price	2020-2021	May	$ 8.71	$ 8.83	$ 8.70	$ 8.70	$ 8.70	$ 8.60	$ 8.60	$ 8.87	$ 8.69	$ 8.73
Low Growth & High Price	2020-2021	Jun	$ 8.69	$ 8.79	$ 8.69	$ 8.69	$ 8.69	$ 8.58	$ 8.58	$ 8.87	$ 8.68	$ 8.71
Low Growth & High Price	2020-2021	Jul	$ 8.68	$ 8.81	$ 8.68	$ 8.68	$ 8.68	$ 8.57	$ 8.57	$ 8.87	$ 8.67	$ 8.70
Low Growth & High Price	2020-2021	Aug	$ 8.72	$ 8.85	$ 8.71	$ 8.71	$ 8.71	$ 8.61	$ 8.61	$ 8.87	$ 8.70	$ 8.74
Low Growth & High Price	2020-2021	Sep	$ 8.86	$ 8.88	$ 8.82	$ 8.82	$ 8.82	$ 8.76	$ 8.76	$ 8.88	$ 8.80	$ 8.84
Low Growth & High Price	2020-2021	Oct	$ 8.98	$ 9.18	$ 8.98	$ 8.98	$ 8.98	$ 8.88	$ 8.88	$ 9.18	$ 8.98	$ 9.02
Low Growth & High Price	2021-2022	Nov	$ 8.97	$ 9.18	$ 8.97	$ 8.97	$ 8.97	$ 8.87	$ 8.87	$ 9.18	$ 8.97	$ 9.01
Low Growth & High Price	2021-2022	Dec	$ 9.41	$ 9.61	$ 9.41	$ 9.41	$ 9.41	$ 9.61	$ 9.26	$ 9.61	$ 9.49	$ 9.45
Low Growth & High Price	2021-2022	Jan	$ 9.58	$ 9.63	$ 9.58	$ 9.58	$ 9.58	$ 9.63	$ 9.46	$ 9.63	$ 9.58	$ 9.59
Low Growth & High Price	2021-2022	Feb	$ 9.53	$ 9.56	$ 9.53	$ 9.53	$ 9.53	$ 9.35	$ 9.41	$ 9.35	$ 9.37	$ 9.53
Low Growth & High Price	2021-2022	Mar	$ 9.43	$ 9.43	$ 9.43	$ 9.43	$ 9.43	$ 9.32	$ 9.32	$ 9.32	$ 9.32	$ 9.43
Low Growth & High Price	2021-2022	Apr	$ 8.92	$ 9.04	$ 8.92	$ 8.92	$ 8.92	$ 8.82	$ 8.82	$ 9.08	$ 8.90	$ 8.95
Low Growth & High Price	2021-2022	May	$ 8.94	$ 9.03	$ 8.94	$ 8.94	$ 8.94	$ 8.84	$ 8.84	$ 9.08	$ 8.92	$ 8.96
Low Growth & High Price	2021-2022	Jun	$ 8.96	$ 9.04	$ 8.95	$ 8.95	$ 8.95	$ 8.86	$ 8.86	$ 9.08	$ 8.93	$ 8.97
Low Growth & High Price	2021-2022	Jul	$ 8.93	$ 9.03	$ 8.93	$ 8.93	$ 8.93	$ 8.83	$ 8.83	$ 9.09	$ 8.91	$ 8.95
Low Growth & High Price	2021-2022	Aug	$ 8.98	$ 9.09	$ 8.98	$ 8.98	$ 8.98	$ 8.88	$ 8.88	$ 9.09	$ 8.95	$ 9.00
Low Growth & High Price	2021-2022	Sep	$ 9.15	$ 9.11	$ 9.11	$ 9.11	$ 9.11	$ 9.04	$ 9.04	$ 9.11	$ 9.06	$ 9.12
Low Growth & High Price	2021-2022	Oct	$ 9.23	$ 9.37	$ 9.23	$ 9.23	$ 9.23	$ 9.12	$ 9.12	$ 9.37	$ 9.20	$ 9.26
Low Growth & High Price	2022-2023	Nov	$ 9.26	$ 9.40	$ 9.26	$ 9.26	$ 9.26	$ 9.15	$ 9.15	$ 9.40	$ 9.23	$ 9.29
Low Growth & High Price	2022-2023	Dec	$ 9.61	$ 9.77	$ 9.61	$ 9.61	$ 9.61	$ 9.77	$ 9.45	$ 9.77	$ 9.66	$ 9.64
Low Growth & High Price	2022-2023	Jan	$ 9.77	$ 9.80	$ 9.77	$ 9.77	$ 9.77	$ 9.79	$ 9.65	$ 9.79	$ 9.75	$ 9.78
Low Growth & High Price	2022-2023	Feb	$ 9.71	$ 9.74	$ 9.71	$ 9.71	$ 9.71	$ 9.56	$ 9.59	$ 9.56	$ 9.57	$ 9.71
Low Growth & High Price	2022-2023	Mar	$ 9.66	$ 9.66	$ 9.66	$ 9.66	$ 9.66	$ 9.54	$ 9.54	$ 9.55	$ 9.54	$ 9.66
Low Growth & High Price	2022-2023	Apr	$ 9.16	$ 9.20	$ 9.16	$ 9.16	$ 9.16	$ 9.05	$ 9.05	$ 9.23	$ 9.11	$ 9.17
Low Growth & High Price	2022-2023	May	$ 9.19	$ 9.20	$ 9.16	$ 9.16	$ 9.16	$ 9.08	$ 9.08	$ 9.23	$ 9.13	$ 9.17
Low Growth & High Price	2022-2023	Jun	$ 9.17	$ 9.16	$ 9.16	$ 9.16	$ 9.16	$ 9.06	$ 9.06	$ 9.23	$ 9.12	$ 9.16
Low Growth & High Price	2022-2023	Jul	$ 9.16	$ 9.17	$ 9.16	$ 9.16	$ 9.16	$ 9.05	$ 9.05	$ 9.24	$ 9.11	$ 9.16
Low Growth & High Price	2022-2023	Aug	$ 9.22	$ 9.22	$ 9.17	$ 9.17	$ 9.17	$ 9.11	$ 9.11	$ 9.24	$ 9.15	$ 9.19
Low Growth & High Price	2022-2023	Sep	$ 9.36	$ 9.29	$ 9.29	$ 9.29	$ 9.29	$ 9.25	$ 9.25	$ 9.29	$ 9.26	$ 9.30
Low Growth & High Price	2022-2023	Oct	$ 9.44	$ 9.53	$ 9.44	$ 9.44	$ 9.44	$ 9.33	$ 9.33	$ 9.53	$ 9.40	$ 9.46
Low Growth & High Price	2023-2024	Nov	$ 9.42	$ 9.51	$ 9.42	$ 9.42	$ 9.42	$ 9.31	$ 9.31	$ 9.51	$ 9.38	$ 9.44
Low Growth & High Price	2023-2024	Dec	$ 9.88	$ 9.98	$ 9.88	$ 9.88	$ 9.88	$ 9.98	$ 9.72	$ 9.98	$ 9.89	$ 9.90
Low Growth & High Price	2023-2024	Jan	$ 10.13	$ 10.13	$ 10.13	$ 10.13	$ 10.13	$ 10.03	$ 10.01	$ 10.03	$ 10.03	$ 10.13
Low Growth & High Price	2023-2024	Feb	$ 10.07	$ 10.08	$ 10.07	$ 10.07	$ 10.07	$ 9.94	$ 9.95	$ 9.94	$ 9.94	$ 10.07
Low Growth & High Price	2023-2024	Mar	$ 10.05	$ 10.02	$ 10.05	$ 10.05	$ 10.05	$ 9.93	$ 9.93	$ 9.93	$ 9.93	$ 10.04
Low Growth & High Price	2023-2024	Apr	$ 9.55	$ 9.57	$ 9.55	$ 9.55	$ 9.55	$ 9.43	$ 9.43	$ 9.62	$ 9.50	$ 9.55
Low Growth & High Price	2023-2024	May	$ 9.55	$ 9.53	$ 9.53	$ 9.53	$ 9.53	$ 9.43	$ 9.43	$ 9.63	$ 9.50	$ 9.53
Low Growth & High Price	2023-2024	Jun	$ 9.58	$ 9.53	$ 9.53	$ 9.53	$ 9.53	$ 9.46	$ 9.46	$ 9.63	$ 9.52	$ 9.54
Low Growth & High Price	2023-2024	Jul	$ 9.54	$ 9.54	$ 9.54	$ 9.54	$ 9.54	$ 9.42	$ 9.42	$ 9.63	$ 9.49	$ 9.54
Low Growth & High Price	2023-2024	Aug	$ 9.60	$ 9.57	$ 9.56	$ 9.56	$ 9.56	$ 9.48	$ 9.48	$ 9.63	$ 9.53	$ 9.57
Low Growth & High Price	2023-2024	Sep	$ 9.68	$ 9.64	$ 9.61	$ 9.61	$ 9.61	$ 9.56	$ 9.56	$ 9.64	$ 9.59	$ 9.63
Low Growth & High Price	2023-2024	Oct	$ 9.81	$ 9.85	$ 9.81	$ 9.81	$ 9.81	$ 9.70	$ 9.70	$ 9.85	$ 9.75	$ 9.82
Low Growth & High Price	2024-2025	Nov	$ 9.80	$ 9.83	$ 9.80	$ 9.80	$ 9.80	$ 9.69	$ 9.69	$ 9.83	$ 9.73	$ 9.81
Low Growth & High Price	2024-2025	Dec	$ 10.21	$ 10.28	$ 10.21	$ 10.21	$ 10.21	$ 10.28	$ 10.05	$ 10.28	$ 10.21	$ 10.22
Low Growth & High Price	2024-2025	Jan	$ 10.36	$ 10.38	$ 10.36	$ 10.36	$ 10.36	$ 10.32	$ 10.24	$ 10.32	$ 10.30	$ 10.37
Low Growth & High Price	2024-2025	Feb	$ 10.30	$ 10.31	$ 10.30	$ 10.30	$ 10.30	$ 10.18	$ 10.18	$ 10.18	$ 10.18	$ 10.30
Low Growth & High Price	2024-2025	Mar	$ 10.29	$ 10.23	$ 10.29	$ 10.29	$ 10.29	$ 10.17	$ 10.17	$ 10.18	$ 10.17	$ 10.28
Low Growth & High Price	2024-2025	Apr	$ 9.76	$ 9.76	$ 9.76	$ 9.76	$ 9.76	$ 9.64	$ 9.64	$ 9.82	$ 9.70	$ 9.76
Low Growth & High Price	2024-2025	May	$ 9.75	$ 9.74	$ 9.74	$ 9.74	$ 9.74	$ 9.63	$ 9.63	$ 9.82	$ 9.70	$ 9.74
Low Growth & High Price	2024-2025	Jun	$ 9.78	$ 9.74	$ 9.74	$ 9.74	$ 9.74	$ 9.66	$ 9.66	$ 9.82	$ 9.72	$ 9.75
Low Growth & High Price	2024-2025	Jul	$ 9.77	$ 9.74	$ 9.74	$ 9.74	$ 9.74	$ 9.65	$ 9.65	$ 9.82	$ 9.71	$ 9.75
Low Growth & High Price	2024-2025	Aug	$ 9.82	$ 9.74	$ 9.74	$ 9.74	$ 9.74	$ 9.71	$ 9.71	$ 9.83	$ 9.75	$ 9.76
Low Growth & High Price	2024-2025	Sep	$ 9.90	$ 9.83	$ 9.83	$ 9.83	$ 9.83	$ 9.79	$ 9.79	$ 9.83	$ 9.80	$ 9.84
Low Growth & High Price	2024-2025	Oct	$ 10.05	$ 10.03	$ 10.03	$ 10.03	$ 10.03	$ 9.93	$ 9.93	$ 10.03	$ 9.96	$ 10.03
Low Growth & High Price	2025-2026	Nov	$ 10.12	$ 10.24	$ 10.12	$ 10.12	$ 10.12	$ 10.00	$ 10.00	$ 10.24	$ 10.08	$ 10.14
Low Growth & High Price	2025-2026	Dec	$ 10.57	$ 10.73	$ 10.57	$ 10.57	$ 10.57	$ 10.73	$ 10.39	$ 10.73	$ 10.62	$ 10.60
Low Growth & High Price	2025-2026	Jan	$ 11.03	$ 11.03	$ 11.03	$ 11.03	$ 11.03	$ 10.90	$ 10.90	$ 10.90	$ 10.90	$ 11.03
Low Growth & High Price	2025-2026	Feb	$ 10.96	$ 10.99	$ 10.96	$ 10.96	$ 10.96	$ 10.83	$ 10.83	$ 10.83	$ 10.83	$ 10.96
Low Growth & High Price	2025-2026	Mar	$ 10.92	$ 10.92	$ 10.92	$ 10.92	$ 10.92	$ 10.79	$ 10.79	$ 10.79	$ 10.79	$ 10.92
Low Growth & High Price	2025-2026	Apr	$ 10.36	$ 10.49	$ 10.36	$ 10.36	$ 10.36	$ 10.24	$ 10.24	$ 10.55	$ 10.34	$ 10.39
Low Growth & High Price	2025-2026	May	$ 10.38	$ 10.49	$ 10.38	$ 10.38	$ 10.38	$ 10.26	$ 10.26	$ 10.55	$ 10.36	$ 10.40
Low Growth & High Price	2025-2026	Jun	$ 10.38	$ 10.45	$ 10.38	$ 10.38	$ 10.38	$ 10.26	$ 10.26	$ 10.55	$ 10.36	$ 10.40
Low Growth & High Price	2025-2026	Jul	$ 10.37	$ 10.49	$ 10.37	$ 10.37	$ 10.37	$ 10.25	$ 10.25	$ 10.55	$ 10.35	$ 10.40
Low Growth & High Price	2025-2026	Aug	$ 10.43	$ 10.56	$ 10.42	$ 10.42	$ 10.42	$ 10.31	$ 10.31	$ 10.56	$ 10.39	$ 10.45
Low Growth & High Price	2025-2026	Sep	$ 10.59	$ 10.56	$ 10.55	$ 10.55	$ 10.55	$ 10.46	$ 10.46	$ 10.56	$ 10.50	$ 10.56
Low Growth & High Price	2025-2026	Oct	$ 10.72	$ 10.88	$ 10.72	$ 10.72	$ 10.72	$ 10.59	$ 10.59	$ 10.88	$ 10.69	$ 10.75
Low Growth & High Price	2026-2027	Nov	$ 10.72	$ 10.87	$ 10.72	$ 10.72	$ 10.72	$ 10.59	$ 10.59	$ 10.87	$ 10.69	$ 10.75
Low Growth & High Price	2026-2027	Dec	$ 11.21	$ 11.36	$ 11.21	$ 11.21	$ 11.21	$ 11.36	$ 11.03	$ 11.36	$ 11.25	$ 11.24
Low Growth & High Price	2026-2027	Jan	$ 11.55	$ 11.55	$ 11.55	$ 11.55	$ 11.55	$ 11.47	$ 11.41	$ 11.47	$ 11.45	$ 11.55

APPENDIX 6.4 II LOW GROWTH – HIGH PRICE MONTHLY DETAIL

Monthly Avoided Cost Detail 1/
2010$

Scenario	Gas Year	Month	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA/ID Both	WA/ID GTN	WA/ID NWP	WA/ID Annual	OR Annual
Low Growth & High Price	2026-2027	Feb	$ 11.50	$ 11.52	$ 11.50	$ 11.50	$ 11.50	$ 11.34	$ 11.36	$ 11.34	$ 11.35	$ 11.50
Low Growth & High Price	2026-2027	Mar	$ 11.45	$ 11.45	$ 11.45	$ 11.45	$ 11.45	$ 11.31	$ 11.31	$ 11.31	$ 11.31	$ 11.45
Low Growth & High Price	2026-2027	Apr	$ 10.88	$ 10.97	$ 10.88	$ 10.88	$ 10.88	$ 10.76	$ 10.76	$ 11.02	$ 10.85	$ 10.90
Low Growth & High Price	2026-2027	May	$ 10.89	$ 10.98	$ 10.89	$ 10.89	$ 10.89	$ 10.77	$ 10.77	$ 11.03	$ 10.85	$ 10.91
Low Growth & High Price	2026-2027	Jun	$ 10.89	$ 10.95	$ 10.89	$ 10.89	$ 10.89	$ 10.77	$ 10.77	$ 11.03	$ 10.85	$ 10.91
Low Growth & High Price	2026-2027	Jul	$ 10.86	$ 10.96	$ 10.86	$ 10.86	$ 10.86	$ 10.74	$ 10.74	$ 11.03	$ 10.83	$ 10.88
Low Growth & High Price	2026-2027	Aug	$ 10.94	$ 11.03	$ 10.93	$ 10.93	$ 10.93	$ 10.81	$ 10.81	$ 11.03	$ 10.88	$ 10.95
Low Growth & High Price	2026-2027	Sep	$ 11.13	$ 11.09	$ 11.09	$ 11.09	$ 11.09	$ 11.00	$ 11.00	$ 11.09	$ 11.03	$ 11.10
Low Growth & High Price	2026-2027	Oct	$ 11.24	$ 11.38	$ 11.24	$ 11.24	$ 11.24	$ 11.11	$ 11.11	$ 11.38	$ 11.20	$ 11.27
Low Growth & High Price	2027-2028	Nov	$ 11.25	$ 11.34	$ 11.25	$ 11.25	$ 11.25	$ 11.12	$ 11.12	$ 11.34	$ 11.19	$ 11.27
Low Growth & High Price	2027-2028	Dec	$ 11.76	$ 11.88	$ 11.76	$ 11.76	$ 11.76	$ 11.88	$ 11.58	$ 11.88	$ 11.78	$ 11.78
Low Growth & High Price	2027-2028	Jan	$ 12.20	$ 12.20	$ 12.20	$ 12.20	$ 12.20	$ 12.06	$ 12.06	$ 12.06	$ 12.06	$ 12.20
Low Growth & High Price	2027-2028	Feb	$ 12.15	$ 12.17	$ 12.15	$ 12.15	$ 12.15	$ 11.96	$ 12.01	$ 11.96	$ 11.98	$ 12.16
Low Growth & High Price	2027-2028	Mar	$ 12.08	$ 12.06	$ 12.08	$ 12.08	$ 12.08	$ 11.94	$ 11.94	$ 11.95	$ 11.94	$ 12.08
Low Growth & High Price	2027-2028	Apr	$ 11.46	$ 11.51	$ 11.46	$ 11.46	$ 11.46	$ 11.32	$ 11.32	$ 11.56	$ 11.40	$ 11.47
Low Growth & High Price	2027-2028	May	$ 11.48	$ 11.51	$ 11.48	$ 11.48	$ 11.48	$ 11.34	$ 11.34	$ 11.56	$ 11.42	$ 11.48
Low Growth & High Price	2027-2028	Jun	$ 11.49	$ 11.50	$ 11.49	$ 11.49	$ 11.49	$ 11.35	$ 11.35	$ 11.57	$ 11.42	$ 11.49
Low Growth & High Price	2027-2028	Jul	$ 11.45	$ 11.50	$ 11.45	$ 11.45	$ 11.45	$ 11.31	$ 11.31	$ 11.57	$ 11.40	$ 11.46
Low Growth & High Price	2027-2028	Aug	$ 11.52	$ 11.57	$ 11.51	$ 11.51	$ 11.51	$ 11.38	$ 11.38	$ 11.57	$ 11.45	$ 11.52
Low Growth & High Price	2027-2028	Sep	$ 11.77	$ 11.72	$ 11.72	$ 11.72	$ 11.72	$ 11.64	$ 11.64	$ 11.72	$ 11.66	$ 11.73
Low Growth & High Price	2027-2028	Oct	$ 11.87	$ 11.93	$ 11.87	$ 11.87	$ 11.87	$ 11.73	$ 11.73	$ 11.93	$ 11.80	$ 11.88
Low Growth & High Price	2028-2029	Nov	$ 11.89	$ 11.91	$ 11.89	$ 11.89	$ 11.89	$ 11.75	$ 11.75	$ 11.91	$ 11.80	$ 11.89
Low Growth & High Price	2028-2029	Dec	$ 12.40	$ 12.49	$ 12.40	$ 12.40	$ 12.40	$ 12.49	$ 12.21	$ 12.49	$ 12.40	$ 12.42
Low Growth & High Price	2028-2029	Jan	$ 12.85	$ 12.85	$ 12.85	$ 12.85	$ 12.85	$ 12.70	$ 12.70	$ 12.70	$ 12.70	$ 12.85
Low Growth & High Price	2028-2029	Feb	$ 12.77	$ 12.77	$ 12.77	$ 12.77	$ 12.77	$ 12.61	$ 12.62	$ 12.61	$ 12.61	$ 12.77
Low Growth & High Price	2028-2029	Mar	$ 12.74	$ 12.66	$ 12.74	$ 12.74	$ 12.74	$ 12.60	$ 12.60	$ 12.61	$ 12.60	$ 12.73
Low Growth & High Price	2028-2029	Apr	$ 12.07	$ 12.10	$ 12.07	$ 12.07	$ 12.07	$ 11.93	$ 11.93	$ 12.18	$ 12.01	$ 12.08
Low Growth & High Price	2028-2029	May	$ 12.08	$ 12.08	$ 12.08	$ 12.08	$ 12.08	$ 11.94	$ 11.94	$ 12.18	$ 12.02	$ 12.08
Low Growth & High Price	2028-2029	Jun	$ 12.08	$ 12.08	$ 12.08	$ 12.08	$ 12.08	$ 11.94	$ 11.94	$ 12.18	$ 12.02	$ 12.08
Low Growth & High Price	2028-2029	Jul	$ 12.07	$ 12.10	$ 12.07	$ 12.07	$ 12.07	$ 11.93	$ 11.93	$ 12.19	$ 12.01	$ 12.08
Low Growth & High Price	2028-2029	Aug	$ 12.14	$ 12.17	$ 12.14	$ 12.14	$ 12.14	$ 12.00	$ 12.00	$ 12.19	$ 12.06	$ 12.15
Low Growth & High Price	2028-2029	Sep	$ 12.27	$ 12.25	$ 12.25	$ 12.25	$ 12.25	$ 12.13	$ 12.13	$ 12.25	$ 12.17	$ 12.25
Low Growth & High Price	2028-2029	Oct	$ 12.46	$ 12.50	$ 12.46	$ 12.46	$ 12.46	$ 12.31	$ 12.31	$ 12.50	$ 12.38	$ 12.47
Low Growth & High Price	2029-2030	Nov	$ 12.48	$ 12.46	$ 12.48	$ 12.48	$ 12.48	$ 12.33	$ 12.33	$ 12.46	$ 12.38	$ 12.48
Low Growth & High Price	2029-2030	Dec	$ 13.02	$ 13.13	$ 13.02	$ 13.02	$ 13.02	$ 13.13	$ 12.83	$ 13.13	$ 13.03	$ 13.04
Low Growth & High Price	2029-2030	Jan	$ 13.57	$ 13.56	$ 13.56	$ 13.56	$ 13.56	$ 13.41	$ 13.41	$ 13.41	$ 13.41	$ 13.56
Low Growth & High Price	2029-2030	Feb	$ 13.50	$ 13.50	$ 13.50	$ 13.50	$ 13.50	$ 13.31	$ 13.34	$ 13.31	$ 13.32	$ 13.50
Low Growth & High Price	2029-2030	Mar	$ 13.44	$ 13.33	$ 13.44	$ 13.44	$ 13.44	$ 13.30	$ 13.30	$ 13.31	$ 13.30	$ 13.42
Low Growth & High Price	2029-2030	Apr	$ 12.79	$ 12.79	$ 12.79	$ 12.79	$ 12.79	$ 12.64	$ 12.64	$ 12.89	$ 12.72	$ 12.79
Low Growth & High Price	2029-2030	May	$ 12.80	$ 12.78	$ 12.78	$ 12.78	$ 12.78	$ 12.65	$ 12.65	$ 12.89	$ 12.73	$ 12.78
Low Growth & High Price	2029-2030	Jun	$ 12.80	$ 12.78	$ 12.78	$ 12.78	$ 12.78	$ 12.65	$ 12.65	$ 12.89	$ 12.73	$ 12.79
Low Growth & High Price	2029-2030	Jul	$ 12.79	$ 12.79	$ 12.79	$ 12.79	$ 12.79	$ 12.64	$ 12.64	$ 12.90	$ 12.72	$ 12.79
Low Growth & High Price	2029-2030	Aug	$ 12.86	$ 12.83	$ 12.83	$ 12.83	$ 12.83	$ 12.71	$ 12.71	$ 12.90	$ 12.77	$ 12.83
Low Growth & High Price	2029-2030	Sep	$ 13.02	$ 13.01	$ 13.01	$ 13.01	$ 13.01	$ 12.87	$ 12.87	$ 13.01	$ 12.92	$ 13.01
Low Growth & High Price	2029-2030	Oct	$ 13.18	$ 13.19	$ 13.18	$ 13.18	$ 13.18	$ 13.03	$ 13.03	$ 13.19	$ 13.08	$ 13.19
Low Growth & High Price	2030-2031	Nov	$ 13.19	$ 13.13	$ 13.19	$ 13.19	$ 13.19	$ 13.04	$ 13.04	$ 13.13	$ 13.07	$ 13.18
Low Growth & High Price	2030-2031	Dec	$ 13.76	$ 13.74	$ 13.75	$ 13.75	$ 13.75	$ 13.74	$ 13.60	$ 13.74	$ 13.69	$ 13.75
Low Growth & High Price	2030-2031	Jan	$ 13.60	$ 13.56	$ 13.59	$ 13.59	$ 13.59	$ 13.56	$ 13.45	$ 13.56	$ 13.52	$ 13.58
Low Growth & High Price	2030-2031	Feb	$ 13.53	$ 13.48	$ 13.53	$ 13.53	$ 13.53	$ 13.33	$ 13.37	$ 13.33	$ 13.34	$ 13.52
Low Growth & High Price	2030-2031	Mar	$ 13.43	$ 13.31	$ 13.43	$ 13.43	$ 13.43	$ 13.31	$ 13.31	$ 13.31	$ 13.31	$ 13.41
Low Growth & High Price	2030-2031	Apr	$ 12.79	$ 12.79	$ 12.79	$ 12.79	$ 12.79	$ 12.64	$ 12.64	$ 12.92	$ 12.73	$ 12.79
Low Growth & High Price	2030-2031	May	$ 12.80	$ 12.79	$ 12.79	$ 12.79	$ 12.79	$ 12.65	$ 12.65	$ 12.92	$ 12.74	$ 12.79
Low Growth & High Price	2030-2031	Jun	$ 12.84	$ 12.79	$ 12.79	$ 12.79	$ 12.79	$ 12.69	$ 12.69	$ 12.92	$ 12.77	$ 12.80
Low Growth & High Price	2030-2031	Jul	$ 12.80	$ 12.79	$ 12.79	$ 12.79	$ 12.79	$ 12.65	$ 12.65	$ 12.93	$ 12.74	$ 12.79
Low Growth & High Price	2030-2031	Aug	$ 12.88	$ 12.82	$ 12.82	$ 12.82	$ 12.82	$ 12.73	$ 12.73	$ 12.93	$ 12.79	$ 12.83
Low Growth & High Price	2030-2031	Sep	$ 13.05	$ 13.00	$ 13.00	$ 13.00	$ 13.00	$ 12.90	$ 12.90	$ 13.00	$ 12.93	$ 13.01
Low Growth & High Price	2030-2031	Oct	$ 13.24	$ 13.20	$ 13.20	$ 13.20	$ 13.20	$ 13.08	$ 13.08	$ 13.20	$ 13.12	$ 13.21

1/ Avoided costs shown before Environmental Externalities adder.

APPENDIX 6.4 II EXPECTED MONTHLY DETAIL

Appendix 6.4 - Monthly Avoided Cost Detail 1/
2010$

Scenario	Gas Year	Month	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA/ID Both	WA/ID GTN	WA/ID NWP	WA/ID Annual	OR Annual
Expected	2011-2012	Nov	$ 2.97	$ 2.99	$ 2.97	$ 2.97	$ 2.97	$ 2.95	$ 2.93	$ 2.99	$ 2.96	$ 2.98
Expected	2011-2012	Dec	$ 2.83	$ 3.02	$ 2.83	$ 2.83	$ 2.83	$ 3.02	$ 2.76	$ 3.02	$ 2.93	$ 2.87
Expected	2011-2012	Jan	$ 2.35	$ 2.55	$ 2.35	$ 2.35	$ 2.35	$ 2.55	$ 2.32	$ 2.55	$ 2.47	$ 2.39
Expected	2011-2012	Feb	$ 2.89	$ 2.92	$ 2.89	$ 2.89	$ 2.89	$ 2.88	$ 2.85	$ 2.89	$ 2.87	$ 2.90
Expected	2011-2012	Mar	$ 2.95	$ 2.95	$ 2.95	$ 2.95	$ 2.95	$ 2.91	$ 2.91	$ 2.91	$ 2.91	$ 2.95
Expected	2011-2012	Apr	$ 2.44	$ 2.59	$ 2.44	$ 2.44	$ 2.44	$ 2.41	$ 2.41	$ 2.87	$ 2.56	$ 2.47
Expected	2011-2012	May	$ 2.55	$ 2.80	$ 2.55	$ 2.55	$ 2.55	$ 2.52	$ 2.52	$ 2.87	$ 2.64	$ 2.60
Expected	2011-2012	Jun	$ 2.70	$ 2.87	$ 2.70	$ 2.70	$ 2.70	$ 2.66	$ 2.66	$ 2.87	$ 2.73	$ 2.73
Expected	2011-2012	Jul	$ 2.76	$ 2.88	$ 2.76	$ 2.76	$ 2.76	$ 2.72	$ 2.72	$ 2.88	$ 2.77	$ 2.78
Expected	2011-2012	Aug	$ 2.64	$ 2.88	$ 2.64	$ 2.64	$ 2.64	$ 2.60	$ 2.60	$ 2.88	$ 2.69	$ 2.68
Expected	2011-2012	Sep	$ 2.53	$ 2.78	$ 2.53	$ 2.53	$ 2.53	$ 2.50	$ 2.50	$ 2.88	$ 2.63	$ 2.58
Expected	2011-2012	Oct	$ 2.66	$ 2.90	$ 2.66	$ 2.66	$ 2.66	$ 2.62	$ 2.62	$ 2.90	$ 2.71	$ 2.70
Expected	2012-2013	Nov	$ 3.12	$ 3.32	$ 3.12	$ 3.12	$ 3.12	$ 3.15	$ 3.07	$ 3.32	$ 3.18	$ 3.16
Expected	2012-2013	Dec	$ 3.26	$ 3.66	$ 3.29	$ 3.29	$ 3.29	$ 3.66	$ 3.17	$ 3.66	$ 3.50	$ 3.36
Expected	2012-2013	Jan	$ 3.45	$ 3.79	$ 3.45	$ 3.45	$ 3.45	$ 3.79	$ 3.41	$ 3.79	$ 3.67	$ 3.52
Expected	2012-2013	Feb	$ 3.61	$ 3.83	$ 3.61	$ 3.61	$ 3.61	$ 3.74	$ 3.55	$ 3.83	$ 3.71	$ 3.65
Expected	2012-2013	Mar	$ 3.67	$ 3.82	$ 3.67	$ 3.67	$ 3.67	$ 3.62	$ 3.62	$ 3.82	$ 3.69	$ 3.70
Expected	2012-2013	Apr	$ 3.61	$ 3.79	$ 3.61	$ 3.61	$ 3.61	$ 3.56	$ 3.56	$ 3.82	$ 3.65	$ 3.64
Expected	2012-2013	May	$ 3.59	$ 3.82	$ 3.59	$ 3.59	$ 3.59	$ 3.54	$ 3.54	$ 3.82	$ 3.63	$ 3.63
Expected	2012-2013	Jun	$ 3.60	$ 3.82	$ 3.60	$ 3.60	$ 3.60	$ 3.55	$ 3.55	$ 3.82	$ 3.64	$ 3.64
Expected	2012-2013	Jul	$ 3.63	$ 3.82	$ 3.63	$ 3.63	$ 3.63	$ 3.58	$ 3.58	$ 3.82	$ 3.66	$ 3.67
Expected	2012-2013	Aug	$ 3.63	$ 3.82	$ 3.63	$ 3.63	$ 3.63	$ 3.58	$ 3.58	$ 3.82	$ 3.66	$ 3.67
Expected	2012-2013	Sep	$ 3.63	$ 3.83	$ 3.63	$ 3.63	$ 3.63	$ 3.58	$ 3.58	$ 3.83	$ 3.66	$ 3.67
Expected	2012-2013	Oct	$ 3.66	$ 3.89	$ 3.66	$ 3.66	$ 3.66	$ 3.61	$ 3.61	$ 3.89	$ 3.70	$ 3.70
Expected	2013-2014	Nov	$ 3.85	$ 4.06	$ 3.85	$ 3.85	$ 3.85	$ 3.88	$ 3.80	$ 4.06	$ 3.92	$ 3.89
Expected	2013-2014	Dec	$ 3.97	$ 4.18	$ 3.97	$ 3.97	$ 3.97	$ 4.18	$ 3.88	$ 4.18	$ 4.08	$ 4.02
Expected	2013-2014	Jan	$ 3.94	$ 4.17	$ 3.94	$ 3.94	$ 3.94	$ 4.17	$ 3.89	$ 4.17	$ 4.08	$ 3.99
Expected	2013-2014	Feb	$ 3.95	$ 4.07	$ 3.95	$ 3.95	$ 3.95	$ 4.00	$ 3.89	$ 4.06	$ 3.99	$ 3.98
Expected	2013-2014	Mar	$ 3.95	$ 4.05	$ 3.95	$ 3.95	$ 3.95	$ 3.90	$ 3.90	$ 4.05	$ 3.95	$ 3.97
Expected	2013-2014	Apr	$ 3.79	$ 3.98	$ 3.79	$ 3.79	$ 3.79	$ 3.74	$ 3.74	$ 4.05	$ 3.84	$ 3.83
Expected	2013-2014	May	$ 3.74	$ 4.00	$ 3.74	$ 3.74	$ 3.74	$ 3.69	$ 3.69	$ 4.05	$ 3.81	$ 3.79
Expected	2013-2014	Jun	$ 3.77	$ 4.02	$ 3.77	$ 3.77	$ 3.77	$ 3.72	$ 3.72	$ 4.05	$ 3.83	$ 3.82
Expected	2013-2014	Jul	$ 3.80	$ 4.05	$ 3.80	$ 3.80	$ 3.80	$ 3.75	$ 3.75	$ 4.05	$ 3.85	$ 3.85
Expected	2013-2014	Aug	$ 3.80	$ 4.05	$ 3.80	$ 3.80	$ 3.80	$ 3.75	$ 3.75	$ 4.05	$ 3.85	$ 3.85
Expected	2013-2014	Sep	$ 3.81	$ 4.06	$ 3.81	$ 3.81	$ 3.81	$ 3.76	$ 3.76	$ 4.06	$ 3.86	$ 3.86
Expected	2013-2014	Oct	$ 3.83	$ 4.12	$ 3.83	$ 3.83	$ 3.83	$ 3.78	$ 3.78	$ 4.12	$ 3.90	$ 3.89
Expected	2014-2015	Nov	$ 4.03	$ 4.28	$ 4.03	$ 4.03	$ 4.03	$ 4.06	$ 3.97	$ 4.28	$ 4.10	$ 4.08
Expected	2014-2015	Dec	$ 4.07	$ 4.32	$ 4.07	$ 4.07	$ 4.07	$ 4.32	$ 3.97	$ 4.32	$ 4.20	$ 4.12
Expected	2014-2015	Jan	$ 4.07	$ 4.34	$ 4.07	$ 4.07	$ 4.07	$ 4.34	$ 4.01	$ 4.34	$ 4.23	$ 4.12
Expected	2014-2015	Feb	$ 4.08	$ 4.23	$ 4.08	$ 4.08	$ 4.08	$ 4.17	$ 4.02	$ 4.23	$ 4.14	$ 4.11
Expected	2014-2015	Mar	$ 4.09	$ 4.21	$ 4.09	$ 4.09	$ 4.09	$ 4.03	$ 4.03	$ 4.21	$ 4.09	$ 4.11
Expected	2014-2015	Apr	$ 3.94	$ 4.15	$ 3.94	$ 3.94	$ 3.94	$ 3.89	$ 3.89	$ 4.21	$ 4.00	$ 3.99
Expected	2014-2015	May	$ 3.93	$ 4.17	$ 3.93	$ 3.93	$ 3.93	$ 3.88	$ 3.88	$ 4.21	$ 3.99	$ 3.98
Expected	2014-2015	Jun	$ 3.99	$ 4.19	$ 3.99	$ 3.99	$ 3.99	$ 3.93	$ 3.93	$ 4.21	$ 4.03	$ 4.03
Expected	2014-2015	Jul	$ 4.02	$ 4.21	$ 4.02	$ 4.02	$ 4.02	$ 3.96	$ 3.96	$ 4.21	$ 4.05	$ 4.06
Expected	2014-2015	Aug	$ 4.01	$ 4.22	$ 4.01	$ 4.01	$ 4.01	$ 3.95	$ 3.95	$ 4.22	$ 4.04	$ 4.05
Expected	2014-2015	Sep	$ 3.98	$ 4.22	$ 3.98	$ 3.98	$ 3.98	$ 3.92	$ 3.92	$ 4.22	$ 4.02	$ 4.02
Expected	2014-2015	Oct	$ 3.99	$ 4.30	$ 3.99	$ 3.99	$ 3.99	$ 3.93	$ 3.93	$ 4.30	$ 4.05	$ 4.05
Expected	2015-2016	Nov	$ 4.16	$ 4.44	$ 4.16	$ 4.16	$ 4.16	$ 4.21	$ 4.11	$ 4.44	$ 4.25	$ 4.21
Expected	2015-2016	Dec	$ 4.21	$ 4.49	$ 4.21	$ 4.21	$ 4.21	$ 4.49	$ 4.11	$ 4.49	$ 4.36	$ 4.27
Expected	2015-2016	Jan	$ 4.19	$ 4.51	$ 4.19	$ 4.19	$ 4.19	$ 4.51	$ 4.14	$ 4.51	$ 4.38	$ 4.25
Expected	2015-2016	Feb	$ 4.20	$ 4.47	$ 4.20	$ 4.20	$ 4.20	$ 4.37	$ 4.15	$ 4.47	$ 4.33	$ 4.25
Expected	2015-2016	Mar	$ 4.26	$ 4.45	$ 4.26	$ 4.26	$ 4.26	$ 4.21	$ 4.21	$ 4.45	$ 4.29	$ 4.30
Expected	2015-2016	Apr	$ 4.11	$ 4.38	$ 4.11	$ 4.11	$ 4.11	$ 4.06	$ 4.06	$ 4.45	$ 4.19	$ 4.16
Expected	2015-2016	May	$ 4.12	$ 4.39	$ 4.12	$ 4.12	$ 4.12	$ 4.07	$ 4.07	$ 4.45	$ 4.19	$ 4.17
Expected	2015-2016	Jun	$ 4.16	$ 4.41	$ 4.16	$ 4.16	$ 4.16	$ 4.11	$ 4.11	$ 4.46	$ 4.22	$ 4.21
Expected	2015-2016	Jul	$ 4.18	$ 4.46	$ 4.18	$ 4.18	$ 4.18	$ 4.13	$ 4.13	$ 4.46	$ 4.24	$ 4.24
Expected	2015-2016	Aug	$ 4.18	$ 4.46	$ 4.18	$ 4.18	$ 4.18	$ 4.13	$ 4.13	$ 4.46	$ 4.24	$ 4.24
Expected	2015-2016	Sep	$ 4.17	$ 4.46	$ 4.17	$ 4.17	$ 4.17	$ 4.12	$ 4.12	$ 4.46	$ 4.23	$ 4.23
Expected	2015-2016	Oct	$ 4.18	$ 4.51	$ 4.18	$ 4.18	$ 4.18	$ 4.13	$ 4.13	$ 4.51	$ 4.25	$ 4.25
Expected	2016-2017	Nov	$ 4.35	$ 4.67	$ 4.35	$ 4.35	$ 4.35	$ 4.41	$ 4.30	$ 4.67	$ 4.46	$ 4.42
Expected	2016-2017	Dec	$ 4.40	$ 4.69	$ 4.40	$ 4.40	$ 4.40	$ 4.69	$ 4.29	$ 4.69	$ 4.56	$ 4.46
Expected	2016-2017	Jan	$ 4.37	$ 4.71	$ 4.37	$ 4.37	$ 4.37	$ 4.71	$ 4.32	$ 4.71	$ 4.58	$ 4.44
Expected	2016-2017	Feb	$ 4.39	$ 4.64	$ 4.39	$ 4.39	$ 4.39	$ 4.58	$ 4.34	$ 4.64	$ 4.52	$ 4.44
Expected	2016-2017	Mar	$ 4.41	$ 4.62	$ 4.41	$ 4.41	$ 4.41	$ 4.36	$ 4.36	$ 4.62	$ 4.45	$ 4.46
Expected	2016-2017	Apr	$ 4.24	$ 4.56	$ 4.24	$ 4.24	$ 4.24	$ 4.19	$ 4.19	$ 4.62	$ 4.33	$ 4.30
Expected	2016-2017	May	$ 4.29	$ 4.59	$ 4.29	$ 4.29	$ 4.29	$ 4.24	$ 4.24	$ 4.62	$ 4.37	$ 4.35
Expected	2016-2017	Jun	$ 4.32	$ 4.61	$ 4.32	$ 4.32	$ 4.32	$ 4.27	$ 4.27	$ 4.62	$ 4.39	$ 4.38
Expected	2016-2017	Jul	$ 4.35	$ 4.63	$ 4.35	$ 4.35	$ 4.35	$ 4.30	$ 4.30	$ 4.63	$ 4.41	$ 4.41
Expected	2016-2017	Aug	$ 4.35	$ 4.63	$ 4.35	$ 4.35	$ 4.35	$ 4.30	$ 4.30	$ 4.63	$ 4.41	$ 4.41
Expected	2016-2017	Sep	$ 4.35	$ 4.63	$ 4.35	$ 4.35	$ 4.35	$ 4.30	$ 4.30	$ 4.63	$ 4.41	$ 4.41
Expected	2016-2017	Oct	$ 4.36	$ 4.72	$ 4.36	$ 4.36	$ 4.36	$ 4.31	$ 4.31	$ 4.72	$ 4.45	$ 4.44
Expected	2017-2018	Nov	$ 4.51	$ 4.88	$ 4.51	$ 4.51	$ 4.51	$ 4.58	$ 4.45	$ 4.88	$ 4.64	$ 4.58
Expected	2017-2018	Dec	$ 4.62	$ 4.94	$ 4.62	$ 4.62	$ 4.62	$ 4.94	$ 4.49	$ 4.94	$ 4.79	$ 4.68
Expected	2017-2018	Jan	$ 4.60	$ 4.95	$ 4.60	$ 4.60	$ 4.60	$ 4.95	$ 4.54	$ 4.95	$ 4.82	$ 4.67
Expected	2017-2018	Feb	$ 4.63	$ 4.89	$ 4.63	$ 4.63	$ 4.63	$ 4.83	$ 4.57	$ 4.89	$ 4.76	$ 4.68
Expected	2017-2018	Mar	$ 4.63	$ 4.86	$ 4.63	$ 4.63	$ 4.63	$ 4.57	$ 4.57	$ 4.86	$ 4.67	$ 4.68
Expected	2017-2018	Apr	$ 4.46	$ 4.81	$ 4.46	$ 4.46	$ 4.46	$ 4.40	$ 4.40	$ 4.86	$ 4.55	$ 4.53
Expected	2017-2018	May	$ 4.50	$ 4.83	$ 4.50	$ 4.50	$ 4.50	$ 4.44	$ 4.44	$ 4.87	$ 4.58	$ 4.56
Expected	2017-2018	Jun	$ 4.54	$ 4.85	$ 4.54	$ 4.54	$ 4.54	$ 4.48	$ 4.48	$ 4.87	$ 4.61	$ 4.60
Expected	2017-2018	Jul	$ 4.57	$ 4.87	$ 4.57	$ 4.57	$ 4.57	$ 4.51	$ 4.51	$ 4.87	$ 4.63	$ 4.63
Expected	2017-2018	Aug	$ 4.58	$ 4.87	$ 4.58	$ 4.58	$ 4.58	$ 4.52	$ 4.52	$ 4.87	$ 4.64	$ 4.64
Expected	2017-2018	Sep	$ 4.57	$ 4.87	$ 4.57	$ 4.57	$ 4.57	$ 4.51	$ 4.51	$ 4.87	$ 4.63	$ 4.63

APPENDIX 6.4 II EXPECTED MONTHLY DETAIL

Appendix 6.4 - Monthly Avoided Cost Detail 1/
2010$

Scenario	Gas Year	Month	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA/ID Both	WA/ID GTN	WA/ID NWP	WA/ID Annual	OR Annual
Expected	2017-2018	Oct	$ 4.58	$ 4.97	$ 4.58	$ 4.58	$ 4.58	$ 4.52	$ 4.52	$ 4.97	$ 4.67	$ 4.66
Expected	2018-2019	Nov	$ 4.69	$ 5.08	$ 4.69	$ 4.69	$ 4.69	$ 4.76	$ 4.63	$ 5.08	$ 4.82	$ 4.77
Expected	2018-2019	Dec	$ 4.84	$ 5.15	$ 4.84	$ 4.84	$ 4.84	$ 5.15	$ 4.70	$ 5.15	$ 5.00	$ 4.90
Expected	2018-2019	Jan	$ 4.78	$ 5.16	$ 4.78	$ 4.78	$ 4.78	$ 5.16	$ 4.72	$ 5.16	$ 5.01	$ 4.86
Expected	2018-2019	Feb	$ 4.81	$ 5.09	$ 4.81	$ 4.81	$ 4.81	$ 5.05	$ 4.75	$ 5.08	$ 4.96	$ 4.87
Expected	2018-2019	Mar	$ 4.80	$ 5.06	$ 4.80	$ 4.80	$ 4.80	$ 4.74	$ 4.74	$ 5.06	$ 4.85	$ 4.85
Expected	2018-2019	Apr	$ 4.63	$ 4.96	$ 4.63	$ 4.63	$ 4.63	$ 4.57	$ 4.57	$ 5.06	$ 4.73	$ 4.70
Expected	2018-2019	May	$ 4.67	$ 4.96	$ 4.67	$ 4.67	$ 4.67	$ 4.61	$ 4.61	$ 5.06	$ 4.76	$ 4.73
Expected	2018-2019	Jun	$ 4.70	$ 4.99	$ 4.70	$ 4.70	$ 4.70	$ 4.64	$ 4.64	$ 5.06	$ 4.78	$ 4.76
Expected	2018-2019	Jul	$ 4.74	$ 5.06	$ 4.74	$ 4.74	$ 4.74	$ 4.68	$ 4.68	$ 5.06	$ 4.81	$ 4.81
Expected	2018-2019	Aug	$ 4.75	$ 5.06	$ 4.75	$ 4.75	$ 4.75	$ 4.69	$ 4.69	$ 5.06	$ 4.82	$ 4.81
Expected	2018-2019	Sep	$ 4.68	$ 5.06	$ 4.68	$ 4.68	$ 4.68	$ 4.62	$ 4.62	$ 5.06	$ 4.77	$ 4.76
Expected	2018-2019	Oct	$ 4.69	$ 5.10	$ 4.69	$ 4.69	$ 4.69	$ 4.63	$ 4.63	$ 5.10	$ 4.79	$ 4.77
Expected	2019-2020	Nov	$ 4.78	$ 5.11	$ 4.78	$ 4.78	$ 4.78	$ 4.84	$ 4.72	$ 5.11	$ 4.89	$ 4.85
Expected	2019-2020	Dec	$ 4.92	$ 5.18	$ 4.92	$ 4.92	$ 4.92	$ 5.18	$ 4.77	$ 5.18	$ 5.04	$ 4.97
Expected	2019-2020	Jan	$ 4.90	$ 5.16	$ 4.90	$ 4.90	$ 4.90	$ 5.16	$ 4.83	$ 5.16	$ 5.05	$ 4.95
Expected	2019-2020	Feb	$ 4.93	$ 5.06	$ 4.93	$ 4.93	$ 4.93	$ 5.04	$ 4.86	$ 5.05	$ 4.98	$ 4.96
Expected	2019-2020	Mar	$ 4.86	$ 5.00	$ 4.86	$ 4.86	$ 4.86	$ 4.80	$ 4.80	$ 5.00	$ 4.87	$ 4.89
Expected	2019-2020	Apr	$ 4.72	$ 4.95	$ 4.72	$ 4.72	$ 4.72	$ 4.66	$ 4.66	$ 5.00	$ 4.77	$ 4.77
Expected	2019-2020	May	$ 4.75	$ 4.93	$ 4.75	$ 4.75	$ 4.75	$ 4.69	$ 4.69	$ 5.00	$ 4.79	$ 4.79
Expected	2019-2020	Jun	$ 4.79	$ 4.95	$ 4.79	$ 4.79	$ 4.79	$ 4.73	$ 4.73	$ 5.00	$ 4.82	$ 4.83
Expected	2019-2020	Jul	$ 4.83	$ 5.00	$ 4.83	$ 4.83	$ 4.83	$ 4.77	$ 4.77	$ 5.00	$ 4.85	$ 4.87
Expected	2019-2020	Aug	$ 4.84	$ 5.00	$ 4.84	$ 4.84	$ 4.84	$ 4.78	$ 4.78	$ 5.00	$ 4.86	$ 4.88
Expected	2019-2020	Sep	$ 4.77	$ 5.00	$ 4.77	$ 4.77	$ 4.77	$ 4.71	$ 4.71	$ 5.00	$ 4.81	$ 4.82
Expected	2019-2020	Oct	$ 4.78	$ 5.06	$ 4.78	$ 4.78	$ 4.78	$ 4.72	$ 4.72	$ 5.06	$ 4.83	$ 4.84
Expected	2020-2021	Nov	$ 4.91	$ 5.18	$ 4.91	$ 4.91	$ 4.91	$ 4.94	$ 4.84	$ 5.18	$ 4.99	$ 4.96
Expected	2020-2021	Dec	$ 5.04	$ 5.27	$ 5.04	$ 5.04	$ 5.04	$ 5.27	$ 4.90	$ 5.27	$ 5.15	$ 5.09
Expected	2020-2021	Jan	$ 5.00	$ 5.25	$ 5.00	$ 5.00	$ 5.00	$ 5.25	$ 4.93	$ 5.25	$ 5.14	$ 5.05
Expected	2020-2021	Feb	$ 5.03	$ 5.13	$ 5.03	$ 5.03	$ 5.03	$ 5.12	$ 4.96	$ 5.12	$ 5.07	$ 5.05
Expected	2020-2021	Mar	$ 5.01	$ 5.06	$ 5.01	$ 5.01	$ 5.01	$ 4.94	$ 4.94	$ 5.06	$ 4.98	$ 5.02
Expected	2020-2021	Apr	$ 4.84	$ 5.05	$ 4.84	$ 4.84	$ 4.84	$ 4.78	$ 4.78	$ 5.06	$ 4.88	$ 4.88
Expected	2020-2021	May	$ 4.88	$ 5.04	$ 4.88	$ 4.88	$ 4.88	$ 4.82	$ 4.82	$ 5.06	$ 4.90	$ 4.92
Expected	2020-2021	Jun	$ 4.93	$ 5.07	$ 4.89	$ 4.89	$ 4.89	$ 4.86	$ 4.86	$ 5.07	$ 4.93	$ 4.93
Expected	2020-2021	Jul	$ 4.97	$ 5.07	$ 4.97	$ 4.97	$ 4.97	$ 4.90	$ 4.90	$ 5.07	$ 4.96	$ 4.99
Expected	2020-2021	Aug	$ 4.99	$ 5.07	$ 4.99	$ 4.99	$ 4.99	$ 4.92	$ 4.92	$ 5.07	$ 4.97	$ 5.00
Expected	2020-2021	Sep	$ 4.79	$ 4.99	$ 4.79	$ 4.79	$ 4.79	$ 4.73	$ 4.73	$ 5.07	$ 4.85	$ 4.83
Expected	2020-2021	Oct	$ 4.80	$ 5.04	$ 4.80	$ 4.80	$ 4.80	$ 4.74	$ 4.74	$ 5.04	$ 4.84	$ 4.85
Expected	2021-2022	Nov	$ 4.92	$ 5.16	$ 4.92	$ 4.92	$ 4.92	$ 4.97	$ 4.85	$ 5.16	$ 5.00	$ 4.96
Expected	2021-2022	Dec	$ 5.02	$ 5.24	$ 5.02	$ 5.02	$ 5.02	$ 5.24	$ 4.89	$ 5.24	$ 5.12	$ 5.06
Expected	2021-2022	Jan	$ 4.99	$ 5.21	$ 4.99	$ 4.99	$ 4.99	$ 5.21	$ 4.92	$ 5.21	$ 5.11	$ 5.03
Expected	2021-2022	Feb	$ 5.06	$ 5.07	$ 5.06	$ 5.06	$ 5.06	$ 5.03	$ 4.95	$ 5.03	$ 5.00	$ 5.06
Expected	2021-2022	Mar	$ 4.85	$ 4.95	$ 4.85	$ 4.85	$ 4.85	$ 4.80	$ 4.79	$ 4.95	$ 4.85	$ 4.87
Expected	2021-2022	Apr	$ 4.73	$ 4.88	$ 4.73	$ 4.73	$ 4.73	$ 4.67	$ 4.67	$ 4.95	$ 4.76	$ 4.76
Expected	2021-2022	May	$ 4.77	$ 4.89	$ 4.77	$ 4.77	$ 4.77	$ 4.71	$ 4.71	$ 4.95	$ 4.79	$ 4.80
Expected	2021-2022	Jun	$ 4.80	$ 4.92	$ 4.80	$ 4.80	$ 4.80	$ 4.74	$ 4.74	$ 4.95	$ 4.81	$ 4.82
Expected	2021-2022	Jul	$ 4.83	$ 4.95	$ 4.83	$ 4.83	$ 4.83	$ 4.77	$ 4.77	$ 4.95	$ 4.83	$ 4.86
Expected	2021-2022	Aug	$ 4.85	$ 4.95	$ 4.85	$ 4.85	$ 4.85	$ 4.79	$ 4.79	$ 4.95	$ 4.85	$ 4.87
Expected	2021-2022	Sep	$ 4.81	$ 4.95	$ 4.80	$ 4.80	$ 4.80	$ 4.75	$ 4.75	$ 4.95	$ 4.82	$ 4.83
Expected	2021-2022	Oct	$ 4.80	$ 4.98	$ 4.93	$ 4.93	$ 4.93	$ 4.74	$ 4.74	$ 4.98	$ 4.82	$ 4.92
Expected	2022-2023	Nov	$ 4.96	$ 5.14	$ 4.96	$ 4.96	$ 4.96	$ 5.00	$ 4.89	$ 5.14	$ 5.01	$ 4.99
Expected	2022-2023	Dec	$ 5.06	$ 5.22	$ 5.06	$ 5.06	$ 5.06	$ 5.22	$ 4.92	$ 5.22	$ 5.12	$ 5.09
Expected	2022-2023	Jan	$ 5.01	$ 5.21	$ 5.01	$ 5.01	$ 5.01	$ 5.21	$ 4.94	$ 5.21	$ 5.12	$ 5.05
Expected	2022-2023	Feb	$ 5.05	$ 5.13	$ 5.05	$ 5.05	$ 5.05	$ 5.13	$ 4.97	$ 5.13	$ 5.08	$ 5.07
Expected	2022-2023	Mar	$ 5.03	$ 5.05	$ 5.03	$ 5.03	$ 5.03	$ 4.97	$ 4.96	$ 5.05	$ 4.99	$ 5.03
Expected	2022-2023	Apr	$ 4.91	$ 4.98	$ 4.91	$ 4.91	$ 4.91	$ 4.84	$ 4.84	$ 5.05	$ 4.91	$ 4.92
Expected	2022-2023	May	$ 4.96	$ 5.00	$ 4.96	$ 4.96	$ 4.96	$ 4.89	$ 4.89	$ 5.05	$ 4.95	$ 4.97
Expected	2022-2023	Jun	$ 5.01	$ 5.02	$ 4.97	$ 4.97	$ 4.97	$ 4.94	$ 4.94	$ 5.05	$ 4.98	$ 4.99
Expected	2022-2023	Jul	$ 5.04	$ 5.08	$ 5.04	$ 5.04	$ 5.04	$ 4.97	$ 4.97	$ 5.08	$ 5.01	$ 5.05
Expected	2022-2023	Aug	$ 5.06	$ 5.06	$ 5.06	$ 5.06	$ 5.06	$ 5.00	$ 5.00	$ 5.06	$ 5.02	$ 5.06
Expected	2022-2023	Sep	$ 4.90	$ 4.99	$ 4.87	$ 4.87	$ 4.87	$ 4.83	$ 4.83	$ 5.06	$ 4.91	$ 4.90
Expected	2022-2023	Oct	$ 4.90	$ 5.02	$ 4.97	$ 4.97	$ 4.97	$ 4.83	$ 4.83	$ 5.03	$ 4.90	$ 4.97
Expected	2023-2024	Nov	$ 5.01	$ 5.16	$ 5.01	$ 5.01	$ 5.01	$ 5.06	$ 4.94	$ 5.16	$ 5.05	$ 5.04
Expected	2023-2024	Dec	$ 5.10	$ 5.22	$ 5.10	$ 5.10	$ 5.10	$ 5.22	$ 4.97	$ 5.22	$ 5.14	$ 5.13
Expected	2023-2024	Jan	$ 5.06	$ 5.21	$ 5.06	$ 5.06	$ 5.06	$ 5.21	$ 5.00	$ 5.21	$ 5.14	$ 5.09
Expected	2023-2024	Feb	$ 5.14	$ 5.15	$ 5.14	$ 5.14	$ 5.14	$ 5.08	$ 5.03	$ 5.08	$ 5.06	$ 5.14
Expected	2023-2024	Mar	$ 4.88	$ 4.89	$ 4.88	$ 4.88	$ 4.88	$ 4.83	$ 4.82	$ 4.89	$ 4.85	$ 4.89
Expected	2023-2024	Apr	$ 4.76	$ 4.83	$ 4.76	$ 4.76	$ 4.76	$ 4.70	$ 4.70	$ 4.89	$ 4.76	$ 4.78
Expected	2023-2024	May	$ 4.78	$ 4.82	$ 4.78	$ 4.78	$ 4.78	$ 4.72	$ 4.72	$ 4.89	$ 4.78	$ 4.79
Expected	2023-2024	Jun	$ 4.85	$ 4.82	$ 4.82	$ 4.82	$ 4.82	$ 4.79	$ 4.79	$ 4.89	$ 4.83	$ 4.83
Expected	2023-2024	Jul	$ 4.88	$ 4.89	$ 4.88	$ 4.88	$ 4.88	$ 4.82	$ 4.82	$ 4.89	$ 4.85	$ 4.89
Expected	2023-2024	Aug	$ 4.91	$ 4.91	$ 4.91	$ 4.91	$ 4.91	$ 4.84	$ 4.84	$ 4.91	$ 4.87	$ 4.91
Expected	2023-2024	Sep	$ 4.85	$ 4.89	$ 4.83	$ 4.83	$ 4.83	$ 4.79	$ 4.79	$ 4.90	$ 4.83	$ 4.85
Expected	2023-2024	Oct	$ 4.86	$ 4.94	$ 4.94	$ 4.94	$ 4.94	$ 4.80	$ 4.80	$ 4.94	$ 4.85	$ 4.93
Expected	2024-2025	Nov	$ 4.98	$ 5.08	$ 4.98	$ 4.98	$ 4.98	$ 5.01	$ 4.91	$ 5.08	$ 5.00	$ 5.00
Expected	2024-2025	Dec	$ 5.09	$ 5.16	$ 5.09	$ 5.09	$ 5.09	$ 5.16	$ 4.94	$ 5.16	$ 5.09	$ 5.10
Expected	2024-2025	Jan	$ 5.03	$ 5.15	$ 5.03	$ 5.03	$ 5.03	$ 5.15	$ 4.96	$ 5.15	$ 5.09	$ 5.05
Expected	2024-2025	Feb	$ 5.08	$ 5.09	$ 5.08	$ 5.08	$ 5.08	$ 5.03	$ 5.00	$ 5.03	$ 5.02	$ 5.08
Expected	2024-2025	Mar	$ 4.99	$ 4.98	$ 4.99	$ 4.99	$ 4.99	$ 4.92	$ 4.92	$ 4.92	$ 4.92	$ 4.99
Expected	2024-2025	Apr	$ 4.85	$ 4.88	$ 4.85	$ 4.85	$ 4.85	$ 4.79	$ 4.79	$ 4.90	$ 4.83	$ 4.86

APPENDIX 6.4 II EXPECTED MONTHLY DETAIL

Appendix 6.4 - Monthly Avoided Cost Detail 1/
2010$

Scenario	Gas Year	Month	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA/ID Both	WA/ID GTN	WA/ID NWP	WA/ID Annual	OR Annual
Expected	2024-2025	May	$ 4.87	$ 4.88	$ 4.87	$ 4.87	$ 4.87	$ 4.81	$ 4.81	$ 4.90	$ 4.84	$ 4.88
Expected	2024-2025	Jun	$ 4.93	$ 4.89	$ 4.89	$ 4.89	$ 4.89	$ 4.86	$ 4.86	$ 4.90	$ 4.88	$ 4.90
Expected	2024-2025	Jul	$ 4.94	$ 4.90	$ 4.90	$ 4.90	$ 4.90	$ 4.90	$ 4.92	$ 4.90	$ 4.91	$ 4.91
Expected	2024-2025	Aug	$ 4.94	$ 4.90	$ 4.90	$ 4.90	$ 4.90	$ 4.90	$ 4.94	$ 4.90	$ 4.92	$ 4.91
Expected	2024-2025	Sep	$ 4.91	$ 4.90	$ 4.90	$ 4.90	$ 4.90	$ 4.84	$ 4.84	$ 4.90	$ 4.86	$ 4.90
Expected	2024-2025	Oct	$ 4.92	$ 4.93	$ 4.93	$ 4.93	$ 4.93	$ 4.85	$ 4.85	$ 4.93	$ 4.88	$ 4.93
Expected	2025-2026	Nov	$ 5.10	$ 5.27	$ 5.10	$ 5.10	$ 5.10	$ 5.04	$ 5.04	$ 5.27	$ 5.11	$ 5.13
Expected	2025-2026	Dec	$ 5.22	$ 5.39	$ 5.22	$ 5.22	$ 5.22	$ 5.35	$ 5.14	$ 5.39	$ 5.29	$ 5.25
Expected	2025-2026	Jan	$ 5.15	$ 5.39	$ 5.15	$ 5.15	$ 5.15	$ 5.22	$ 5.09	$ 5.39	$ 5.23	$ 5.20
Expected	2025-2026	Feb	$ 5.23	$ 5.23	$ 5.23	$ 5.23	$ 5.23	$ 5.16	$ 5.16	$ 5.20	$ 5.17	$ 5.23
Expected	2025-2026	Mar	$ 5.02	$ 5.16	$ 5.02	$ 5.02	$ 5.02	$ 4.95	$ 4.95	$ 5.16	$ 5.02	$ 5.05
Expected	2025-2026	Apr	$ 4.88	$ 5.06	$ 4.88	$ 4.88	$ 4.88	$ 4.82	$ 4.82	$ 5.16	$ 4.94	$ 4.92
Expected	2025-2026	May	$ 4.92	$ 5.07	$ 4.92	$ 4.92	$ 4.92	$ 4.85	$ 4.85	$ 5.16	$ 4.96	$ 4.95
Expected	2025-2026	Jun	$ 4.98	$ 5.10	$ 4.98	$ 4.98	$ 4.98	$ 4.91	$ 4.91	$ 5.17	$ 5.00	$ 5.00
Expected	2025-2026	Jul	$ 5.01	$ 5.17	$ 5.01	$ 5.01	$ 5.01	$ 4.94	$ 4.94	$ 5.17	$ 5.02	$ 5.04
Expected	2025-2026	Aug	$ 5.03	$ 5.17	$ 5.03	$ 5.03	$ 5.03	$ 4.96	$ 4.96	$ 5.17	$ 5.03	$ 5.06
Expected	2025-2026	Sep	$ 4.99	$ 5.17	$ 4.99	$ 4.99	$ 4.99	$ 4.92	$ 4.92	$ 5.17	$ 5.01	$ 5.02
Expected	2025-2026	Oct	$ 4.99	$ 5.20	$ 5.14	$ 5.14	$ 5.14	$ 4.92	$ 4.92	$ 5.20	$ 5.02	$ 5.12
Expected	2026-2027	Nov	$ 5.12	$ 5.31	$ 5.12	$ 5.12	$ 5.12	$ 5.06	$ 5.06	$ 5.31	$ 5.14	$ 5.16
Expected	2026-2027	Dec	$ 5.23	$ 5.40	$ 5.23	$ 5.23	$ 5.23	$ 5.40	$ 5.15	$ 5.40	$ 5.32	$ 5.26
Expected	2026-2027	Jan	$ 5.20	$ 5.38	$ 5.20	$ 5.20	$ 5.20	$ 5.25	$ 5.14	$ 5.38	$ 5.26	$ 5.24
Expected	2026-2027	Feb	$ 5.25	$ 5.24	$ 5.25	$ 5.25	$ 5.25	$ 5.17	$ 5.17	$ 5.18	$ 5.17	$ 5.25
Expected	2026-2027	Mar	$ 4.97	$ 5.08	$ 4.97	$ 4.97	$ 4.97	$ 4.90	$ 4.90	$ 5.08	$ 4.96	$ 4.99
Expected	2026-2027	Apr	$ 4.82	$ 4.96	$ 4.82	$ 4.82	$ 4.82	$ 4.76	$ 4.76	$ 5.08	$ 4.87	$ 4.85
Expected	2026-2027	May	$ 4.85	$ 4.99	$ 4.85	$ 4.85	$ 4.85	$ 4.79	$ 4.79	$ 5.08	$ 4.89	$ 4.88
Expected	2026-2027	Jun	$ 4.91	$ 5.01	$ 4.91	$ 4.91	$ 4.91	$ 4.84	$ 4.84	$ 5.08	$ 4.92	$ 4.93
Expected	2026-2027	Jul	$ 4.94	$ 5.09	$ 4.94	$ 4.94	$ 4.94	$ 4.87	$ 4.87	$ 5.09	$ 4.94	$ 4.97
Expected	2026-2027	Aug	$ 4.96	$ 5.09	$ 4.96	$ 4.96	$ 4.96	$ 4.89	$ 4.89	$ 5.09	$ 4.96	$ 4.98
Expected	2026-2027	Sep	$ 4.94	$ 5.09	$ 4.94	$ 4.94	$ 4.94	$ 4.87	$ 4.87	$ 5.09	$ 4.95	$ 4.97
Expected	2026-2027	Oct	$ 4.94	$ 5.12	$ 5.08	$ 5.08	$ 5.08	$ 4.87	$ 4.87	$ 5.12	$ 4.95	$ 5.06
Expected	2027-2028	Nov	$ 5.09	$ 5.24	$ 5.09	$ 5.09	$ 5.09	$ 5.03	$ 5.03	$ 5.24	$ 5.10	$ 5.12
Expected	2027-2028	Dec	$ 5.22	$ 5.33	$ 5.22	$ 5.22	$ 5.22	$ 5.33	$ 5.14	$ 5.33	$ 5.27	$ 5.24
Expected	2027-2028	Jan	$ 5.16	$ 5.32	$ 5.16	$ 5.16	$ 5.16	$ 5.28	$ 5.09	$ 5.32	$ 5.23	$ 5.19
Expected	2027-2028	Feb	$ 5.22	$ 5.21	$ 5.22	$ 5.22	$ 5.22	$ 5.15	$ 5.15	$ 5.16	$ 5.15	$ 5.22
Expected	2027-2028	Mar	$ 5.01	$ 5.06	$ 5.01	$ 5.01	$ 5.01	$ 4.94	$ 4.94	$ 5.06	$ 4.98	$ 5.02
Expected	2027-2028	Apr	$ 4.86	$ 4.97	$ 4.86	$ 4.86	$ 4.86	$ 4.80	$ 4.80	$ 5.08	$ 4.89	$ 4.89
Expected	2027-2028	May	$ 4.92	$ 4.99	$ 4.92	$ 4.92	$ 4.92	$ 4.85	$ 4.85	$ 5.08	$ 4.93	$ 4.93
Expected	2027-2028	Jun	$ 4.95	$ 5.02	$ 4.95	$ 4.95	$ 4.95	$ 4.88	$ 4.88	$ 5.08	$ 4.95	$ 4.96
Expected	2027-2028	Jul	$ 4.99	$ 5.10	$ 4.99	$ 4.99	$ 4.99	$ 4.92	$ 4.92	$ 5.10	$ 4.98	$ 5.01
Expected	2027-2028	Aug	$ 5.01	$ 5.08	$ 5.01	$ 5.01	$ 5.01	$ 4.94	$ 4.94	$ 5.08	$ 4.99	$ 5.02
Expected	2027-2028	Sep	$ 4.97	$ 5.09	$ 4.97	$ 4.97	$ 4.97	$ 4.90	$ 4.90	$ 5.09	$ 4.96	$ 4.99
Expected	2027-2028	Oct	$ 4.98	$ 5.11	$ 5.11	$ 5.11	$ 5.11	$ 4.91	$ 4.91	$ 5.11	$ 4.98	$ 5.08
Expected	2028-2029	Nov	$ 5.14	$ 5.23	$ 5.14	$ 5.14	$ 5.14	$ 5.08	$ 5.08	$ 5.24	$ 5.13	$ 5.16
Expected	2028-2029	Dec	$ 5.27	$ 5.34	$ 5.27	$ 5.27	$ 5.27	$ 5.34	$ 5.11	$ 5.34	$ 5.26	$ 5.28
Expected	2028-2029	Jan	$ 5.20	$ 5.32	$ 5.20	$ 5.20	$ 5.20	$ 5.32	$ 5.14	$ 5.32	$ 5.26	$ 5.23
Expected	2028-2029	Feb	$ 5.26	$ 5.26	$ 5.26	$ 5.26	$ 5.26	$ 5.20	$ 5.18	$ 5.20	$ 5.19	$ 5.26
Expected	2028-2029	Mar	$ 5.08	$ 5.07	$ 5.08	$ 5.08	$ 5.08	$ 5.02	$ 5.02	$ 5.07	$ 5.03	$ 5.08
Expected	2028-2029	Apr	$ 4.91	$ 4.98	$ 4.91	$ 4.91	$ 4.91	$ 4.84	$ 4.84	$ 5.10	$ 4.93	$ 4.92
Expected	2028-2029	May	$ 4.94	$ 4.98	$ 4.94	$ 4.94	$ 4.94	$ 4.87	$ 4.87	$ 5.10	$ 4.95	$ 4.95
Expected	2028-2029	Jun	$ 4.98	$ 5.01	$ 4.98	$ 4.98	$ 4.98	$ 4.91	$ 4.91	$ 5.10	$ 4.98	$ 4.98
Expected	2028-2029	Jul	$ 5.02	$ 5.11	$ 5.02	$ 5.02	$ 5.02	$ 4.95	$ 4.95	$ 5.11	$ 5.01	$ 5.04
Expected	2028-2029	Aug	$ 5.04	$ 5.14	$ 5.04	$ 5.04	$ 5.04	$ 4.97	$ 4.97	$ 5.14	$ 5.03	$ 5.06
Expected	2028-2029	Sep	$ 5.03	$ 5.11	$ 5.03	$ 5.03	$ 5.03	$ 4.96	$ 4.96	$ 5.11	$ 5.01	$ 5.04
Expected	2028-2029	Oct	$ 5.03	$ 5.14	$ 5.14	$ 5.14	$ 5.14	$ 4.96	$ 4.96	$ 5.14	$ 5.02	$ 5.11
Expected	2029-2030	Nov	$ 5.19	$ 5.23	$ 5.19	$ 5.19	$ 5.19	$ 5.12	$ 5.12	$ 5.25	$ 5.16	$ 5.19
Expected	2029-2030	Dec	$ 5.29	$ 5.33	$ 5.29	$ 5.29	$ 5.29	$ 5.33	$ 5.16	$ 5.33	$ 5.27	$ 5.30
Expected	2029-2030	Jan	$ 5.25	$ 5.31	$ 5.25	$ 5.25	$ 5.25	$ 5.31	$ 5.19	$ 5.31	$ 5.27	$ 5.26
Expected	2029-2030	Feb	$ 5.32	$ 5.34	$ 5.33	$ 5.33	$ 5.33	$ 5.26	$ 5.22	$ 5.27	$ 5.25	$ 5.33
Expected	2029-2030	Mar	$ 5.03	$ 5.00	$ 5.03	$ 5.03	$ 5.03	$ 4.96	$ 4.96	$ 5.00	$ 4.98	$ 5.02
Expected	2029-2030	Apr	$ 4.87	$ 4.95	$ 4.87	$ 4.87	$ 4.87	$ 4.81	$ 4.81	$ 5.06	$ 4.90	$ 4.89
Expected	2029-2030	May	$ 4.91	$ 4.95	$ 4.91	$ 4.91	$ 4.91	$ 4.84	$ 4.84	$ 5.06	$ 4.92	$ 4.92
Expected	2029-2030	Jun	$ 4.96	$ 4.97	$ 4.96	$ 4.96	$ 4.96	$ 4.89	$ 4.89	$ 5.06	$ 4.95	$ 4.96
Expected	2029-2030	Jul	$ 5.02	$ 5.05	$ 5.02	$ 5.02	$ 5.02	$ 4.95	$ 4.95	$ 5.06	$ 4.99	$ 5.02
Expected	2029-2030	Aug	$ 5.03	$ 5.07	$ 5.03	$ 5.03	$ 5.03	$ 4.96	$ 4.96	$ 5.07	$ 5.00	$ 5.04
Expected	2029-2030	Sep	$ 5.03	$ 5.09	$ 5.03	$ 5.03	$ 5.03	$ 4.96	$ 4.96	$ 5.09	$ 5.01	$ 5.04
Expected	2029-2030	Oct	$ 5.04	$ 5.12	$ 5.12	$ 5.12	$ 5.12	$ 4.97	$ 4.97	$ 5.12	$ 5.02	$ 5.10
Expected	2030-2031	Nov	$ 5.18	$ 5.20	$ 5.18	$ 5.18	$ 5.18	$ 5.12	$ 5.12	$ 5.23	$ 5.15	$ 5.19
Expected	2030-2031	Dec	$ 5.32	$ 5.32	$ 5.32	$ 5.32	$ 5.32	$ 5.32	$ 5.19	$ 5.32	$ 5.28	$ 5.32
Expected	2030-2031	Jan	$ 5.28	$ 5.31	$ 5.28	$ 5.28	$ 5.28	$ 5.31	$ 5.22	$ 5.31	$ 5.28	$ 5.29
Expected	2030-2031	Feb	$ 5.36	$ 5.38	$ 5.38	$ 5.38	$ 5.38	$ 5.32	$ 5.28	$ 5.32	$ 5.31	$ 5.37
Expected	2030-2031	Mar	$ 5.13	$ 5.10	$ 5.13	$ 5.13	$ 5.13	$ 5.07	$ 5.07	$ 5.10	$ 5.08	$ 5.12
Expected	2030-2031	Apr	$ 4.98	$ 5.05	$ 4.98	$ 4.98	$ 4.98	$ 4.91	$ 4.91	$ 5.14	$ 4.99	$ 4.99
Expected	2030-2031	May	$ 5.01	$ 5.06	$ 5.01	$ 5.01	$ 5.01	$ 4.94	$ 4.94	$ 5.14	$ 5.01	$ 5.02
Expected	2030-2031	Jun	$ 5.08	$ 5.06	$ 5.06	$ 5.06	$ 5.06	$ 5.02	$ 5.02	$ 5.14	$ 5.06	$ 5.06
Expected	2030-2031	Jul	$ 5.12	$ 5.13	$ 5.12	$ 5.12	$ 5.12	$ 5.06	$ 5.06	$ 5.14	$ 5.08	$ 5.12
Expected	2030-2031	Aug	$ 5.14	$ 5.15	$ 5.14	$ 5.14	$ 5.14	$ 5.08	$ 5.08	$ 5.15	$ 5.10	$ 5.14
Expected	2030-2031	Sep	$ 5.13	$ 5.15	$ 5.13	$ 5.13	$ 5.13	$ 5.07	$ 5.07	$ 5.15	$ 5.09	$ 5.13
Expected	2030-2031	Oct	$ 5.14	$ 5.18	$ 5.18	$ 5.18	$ 5.18	$ 5.08	$ 5.08	$ 5.18	$ 5.11	$ 5.17

1/ Avoided costs shown before Environmental Externalities adder.

APPENDIX 6.4 II HIGH GROWTH – LOW PRICE MONTHLY DETAIL

Appendix 6.4 - Monthly Avoided Cost Detail 1/
2010$

Scenario	Gas Year	Month	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA/ID Both	WA/ID GTN	WA/ID NWP	WA/ID Annual	OR Annual
High Growth & Low Price	2011-2012	Nov	$ 2.97	$ 2.99	$ 2.97	$ 2.97	$ 2.97	$ 2.93	$ 2.93	$ 2.99	$ 2.95	$ 2.98
High Growth & Low Price	2011-2012	Dec	$ 2.83	$ 3.00	$ 2.83	$ 2.83	$ 2.83	$ 2.76	$ 2.76	$ 3.00	$ 2.84	$ 2.87
High Growth & Low Price	2011-2012	Jan	$ 2.35	$ 2.50	$ 2.35	$ 2.35	$ 2.35	$ 2.32	$ 2.32	$ 2.50	$ 2.38	$ 2.38
High Growth & Low Price	2011-2012	Feb	$ 2.89	$ 2.92	$ 2.89	$ 2.89	$ 2.89	$ 2.86	$ 2.86	$ 2.88	$ 2.86	$ 2.90
High Growth & Low Price	2011-2012	Mar	$ 2.95	$ 2.95	$ 2.95	$ 2.95	$ 2.95	$ 2.91	$ 2.91	$ 2.91	$ 2.91	$ 2.95
High Growth & Low Price	2011-2012	Apr	$ 2.44	$ 2.65	$ 2.44	$ 2.44	$ 2.44	$ 2.41	$ 2.41	$ 2.87	$ 2.56	$ 2.48
High Growth & Low Price	2011-2012	May	$ 2.55	$ 2.80	$ 2.55	$ 2.55	$ 2.55	$ 2.52	$ 2.52	$ 2.87	$ 2.64	$ 2.60
High Growth & Low Price	2011-2012	Jun	$ 2.70	$ 2.87	$ 2.70	$ 2.70	$ 2.70	$ 2.66	$ 2.66	$ 2.87	$ 2.73	$ 2.73
High Growth & Low Price	2011-2012	Jul	$ 2.76	$ 2.87	$ 2.76	$ 2.76	$ 2.76	$ 2.72	$ 2.72	$ 2.88	$ 2.77	$ 2.78
High Growth & Low Price	2011-2012	Aug	$ 2.64	$ 2.88	$ 2.64	$ 2.64	$ 2.64	$ 2.60	$ 2.60	$ 2.88	$ 2.69	$ 2.68
High Growth & Low Price	2011-2012	Sep	$ 2.53	$ 2.78	$ 2.53	$ 2.53	$ 2.53	$ 2.50	$ 2.50	$ 2.88	$ 2.63	$ 2.58
High Growth & Low Price	2011-2012	Oct	$ 2.66	$ 2.90	$ 2.66	$ 2.66	$ 2.66	$ 2.62	$ 2.62	$ 2.90	$ 2.71	$ 2.70
High Growth & Low Price	2012-2013	Nov	$ 3.12	$ 3.32	$ 3.12	$ 3.12	$ 3.12	$ 3.07	$ 3.07	$ 3.32	$ 3.16	$ 3.16
High Growth & Low Price	2012-2013	Dec	$ 3.26	$ 3.44	$ 3.26	$ 3.26	$ 3.26	$ 3.17	$ 3.17	$ 3.58	$ 3.30	$ 3.30
High Growth & Low Price	2012-2013	Jan	$ 3.45	$ 3.69	$ 3.45	$ 3.45	$ 3.45	$ 3.41	$ 3.41	$ 3.70	$ 3.51	$ 3.50
High Growth & Low Price	2012-2013	Feb	$ 3.61	$ 3.82	$ 3.61	$ 3.61	$ 3.61	$ 3.56	$ 3.56	$ 3.82	$ 3.64	$ 3.65
High Growth & Low Price	2012-2013	Mar	$ 3.67	$ 3.82	$ 3.67	$ 3.67	$ 3.67	$ 3.62	$ 3.62	$ 3.82	$ 3.69	$ 3.70
High Growth & Low Price	2012-2013	Apr	$ 3.61	$ 3.79	$ 3.61	$ 3.61	$ 3.61	$ 3.56	$ 3.56	$ 3.82	$ 3.65	$ 3.64
High Growth & Low Price	2012-2013	May	$ 3.59	$ 3.82	$ 3.59	$ 3.59	$ 3.59	$ 3.54	$ 3.54	$ 3.82	$ 3.63	$ 3.63
High Growth & Low Price	2012-2013	Jun	$ 3.60	$ 3.82	$ 3.60	$ 3.60	$ 3.60	$ 3.55	$ 3.55	$ 3.82	$ 3.64	$ 3.64
High Growth & Low Price	2012-2013	Jul	$ 3.63	$ 3.82	$ 3.63	$ 3.63	$ 3.63	$ 3.58	$ 3.58	$ 3.82	$ 3.66	$ 3.67
High Growth & Low Price	2012-2013	Aug	$ 3.63	$ 3.83	$ 3.63	$ 3.63	$ 3.63	$ 3.58	$ 3.58	$ 3.83	$ 3.66	$ 3.67
High Growth & Low Price	2012-2013	Sep	$ 3.63	$ 3.83	$ 3.63	$ 3.63	$ 3.63	$ 3.58	$ 3.58	$ 3.83	$ 3.66	$ 3.67
High Growth & Low Price	2012-2013	Oct	$ 3.66	$ 3.89	$ 3.66	$ 3.66	$ 3.66	$ 3.61	$ 3.61	$ 3.89	$ 3.70	$ 3.70
High Growth & Low Price	2013-2014	Nov	$ 3.85	$ 4.06	$ 3.85	$ 3.85	$ 3.85	$ 3.80	$ 3.80	$ 4.06	$ 3.89	$ 3.89
High Growth & Low Price	2013-2014	Dec	$ 3.97	$ 4.17	$ 3.97	$ 3.97	$ 3.97	$ 3.88	$ 3.88	$ 4.17	$ 3.98	$ 4.01
High Growth & Low Price	2013-2014	Jan	$ 3.94	$ 4.17	$ 3.94	$ 3.94	$ 3.94	$ 3.89	$ 3.89	$ 4.17	$ 3.99	$ 3.99
High Growth & Low Price	2013-2014	Feb	$ 3.95	$ 4.07	$ 3.95	$ 3.95	$ 3.95	$ 3.90	$ 3.90	$ 4.06	$ 3.95	$ 3.97
High Growth & Low Price	2013-2014	Mar	$ 3.95	$ 4.04	$ 3.95	$ 3.95	$ 3.95	$ 3.90	$ 3.90	$ 4.04	$ 3.95	$ 3.97
High Growth & Low Price	2013-2014	Apr	$ 3.79	$ 3.98	$ 3.79	$ 3.79	$ 3.79	$ 3.74	$ 3.74	$ 4.05	$ 3.84	$ 3.83
High Growth & Low Price	2013-2014	May	$ 3.74	$ 4.00	$ 3.74	$ 3.74	$ 3.74	$ 3.69	$ 3.69	$ 4.05	$ 3.81	$ 3.79
High Growth & Low Price	2013-2014	Jun	$ 3.77	$ 4.02	$ 3.77	$ 3.77	$ 3.77	$ 3.72	$ 3.72	$ 4.05	$ 3.83	$ 3.82
High Growth & Low Price	2013-2014	Jul	$ 3.80	$ 4.05	$ 3.80	$ 3.80	$ 3.80	$ 3.75	$ 3.75	$ 4.05	$ 3.85	$ 3.85
High Growth & Low Price	2013-2014	Aug	$ 3.80	$ 4.05	$ 3.80	$ 3.80	$ 3.80	$ 3.75	$ 3.75	$ 4.05	$ 3.85	$ 3.85
High Growth & Low Price	2013-2014	Sep	$ 3.81	$ 4.06	$ 3.81	$ 3.81	$ 3.81	$ 3.76	$ 3.76	$ 4.06	$ 3.86	$ 3.86
High Growth & Low Price	2013-2014	Oct	$ 3.83	$ 4.12	$ 3.83	$ 3.83	$ 3.83	$ 3.78	$ 3.78	$ 4.12	$ 3.90	$ 3.89
High Growth & Low Price	2014-2015	Nov	$ 4.03	$ 4.28	$ 4.03	$ 4.03	$ 4.03	$ 3.97	$ 3.97	$ 4.28	$ 4.07	$ 4.08
High Growth & Low Price	2014-2015	Dec	$ 4.09	$ 4.31	$ 4.09	$ 4.09	$ 4.09	$ 3.97	$ 3.97	$ 4.31	$ 4.08	$ 4.13
High Growth & Low Price	2014-2015	Jan	$ 4.07	$ 4.31	$ 4.07	$ 4.07	$ 4.07	$ 4.01	$ 4.01	$ 4.31	$ 4.11	$ 4.12
High Growth & Low Price	2014-2015	Feb	$ 4.09	$ 4.23	$ 4.09	$ 4.09	$ 4.09	$ 4.04	$ 4.04	$ 4.22	$ 4.10	$ 4.12
High Growth & Low Price	2014-2015	Mar	$ 4.09	$ 4.21	$ 4.09	$ 4.09	$ 4.09	$ 4.03	$ 4.03	$ 4.21	$ 4.09	$ 4.11
High Growth & Low Price	2014-2015	Apr	$ 3.94	$ 4.15	$ 3.94	$ 3.94	$ 3.94	$ 3.89	$ 3.89	$ 4.21	$ 4.00	$ 3.99
High Growth & Low Price	2014-2015	May	$ 3.93	$ 4.17	$ 3.93	$ 3.93	$ 3.93	$ 3.88	$ 3.88	$ 4.21	$ 3.99	$ 3.98
High Growth & Low Price	2014-2015	Jun	$ 3.99	$ 4.19	$ 3.99	$ 3.99	$ 3.99	$ 3.93	$ 3.93	$ 4.21	$ 4.03	$ 4.03
High Growth & Low Price	2014-2015	Jul	$ 4.02	$ 4.21	$ 4.02	$ 4.02	$ 4.02	$ 3.96	$ 3.96	$ 4.21	$ 4.05	$ 4.06
High Growth & Low Price	2014-2015	Aug	$ 4.01	$ 4.22	$ 4.01	$ 4.01	$ 4.01	$ 3.95	$ 3.95	$ 4.22	$ 4.04	$ 4.05
High Growth & Low Price	2014-2015	Sep	$ 3.98	$ 4.22	$ 3.98	$ 3.98	$ 3.98	$ 3.92	$ 3.92	$ 4.22	$ 4.02	$ 4.02
High Growth & Low Price	2014-2015	Oct	$ 3.99	$ 4.30	$ 3.99	$ 3.99	$ 3.99	$ 3.93	$ 3.93	$ 4.30	$ 4.05	$ 4.05
High Growth & Low Price	2015-2016	Nov	$ 4.16	$ 4.44	$ 4.16	$ 4.16	$ 4.16	$ 4.11	$ 4.11	$ 4.44	$ 4.22	$ 4.21
High Growth & Low Price	2015-2016	Dec	$ 4.23	$ 4.48	$ 4.23	$ 4.23	$ 4.23	$ 4.11	$ 4.11	$ 4.48	$ 4.23	$ 4.28
High Growth & Low Price	2015-2016	Jan	$ 4.19	$ 4.49	$ 4.19	$ 4.19	$ 4.19	$ 4.14	$ 4.14	$ 4.49	$ 4.25	$ 4.25
High Growth & Low Price	2015-2016	Feb	$ 4.22	$ 4.46	$ 4.22	$ 4.22	$ 4.22	$ 4.16	$ 4.16	$ 4.46	$ 4.26	$ 4.26
High Growth & Low Price	2015-2016	Mar	$ 4.26	$ 4.45	$ 4.26	$ 4.26	$ 4.26	$ 4.21	$ 4.21	$ 4.45	$ 4.29	$ 4.30
High Growth & Low Price	2015-2016	Apr	$ 4.11	$ 4.38	$ 4.11	$ 4.11	$ 4.11	$ 4.06	$ 4.06	$ 4.45	$ 4.19	$ 4.16
High Growth & Low Price	2015-2016	May	$ 4.12	$ 4.39	$ 4.12	$ 4.12	$ 4.12	$ 4.07	$ 4.07	$ 4.45	$ 4.19	$ 4.17
High Growth & Low Price	2015-2016	Jun	$ 4.16	$ 4.41	$ 4.16	$ 4.16	$ 4.16	$ 4.11	$ 4.11	$ 4.46	$ 4.22	$ 4.21
High Growth & Low Price	2015-2016	Jul	$ 4.18	$ 4.46	$ 4.18	$ 4.18	$ 4.18	$ 4.13	$ 4.13	$ 4.46	$ 4.24	$ 4.24
High Growth & Low Price	2015-2016	Aug	$ 4.18	$ 4.46	$ 4.18	$ 4.18	$ 4.18	$ 4.13	$ 4.13	$ 4.46	$ 4.24	$ 4.24
High Growth & Low Price	2015-2016	Sep	$ 4.17	$ 4.46	$ 4.17	$ 4.17	$ 4.17	$ 4.12	$ 4.12	$ 4.46	$ 4.23	$ 4.23
High Growth & Low Price	2015-2016	Oct	$ 4.18	$ 4.51	$ 4.18	$ 4.18	$ 4.18	$ 4.13	$ 4.13	$ 4.51	$ 4.25	$ 4.25
High Growth & Low Price	2016-2017	Nov	$ 4.86	$ 5.18	$ 4.86	$ 4.86	$ 4.86	$ 4.80	$ 4.80	$ 5.18	$ 4.93	$ 4.93
High Growth & Low Price	2016-2017	Dec	$ 4.94	$ 5.19	$ 4.94	$ 4.94	$ 4.94	$ 4.80	$ 4.80	$ 5.19	$ 4.93	$ 4.99
High Growth & Low Price	2016-2017	Jan	$ 4.90	$ 5.22	$ 4.90	$ 4.90	$ 4.90	$ 4.82	$ 4.82	$ 5.22	$ 4.95	$ 4.96
High Growth & Low Price	2016-2017	Feb	$ 4.93	$ 5.14	$ 4.93	$ 4.93	$ 4.93	$ 4.87	$ 4.86	$ 5.14	$ 4.96	$ 4.97
High Growth & Low Price	2016-2017	Mar	$ 4.93	$ 5.13	$ 4.93	$ 4.93	$ 4.93	$ 4.86	$ 4.86	$ 5.13	$ 4.95	$ 4.97
High Growth & Low Price	2016-2017	Apr	$ 4.75	$ 5.07	$ 4.75	$ 4.75	$ 4.75	$ 4.69	$ 4.69	$ 5.13	$ 4.84	$ 4.81
High Growth & Low Price	2016-2017	May	$ 4.80	$ 5.10	$ 4.80	$ 4.80	$ 4.80	$ 4.74	$ 4.74	$ 5.13	$ 4.87	$ 4.86
High Growth & Low Price	2016-2017	Jun	$ 4.83	$ 5.12	$ 4.83	$ 4.83	$ 4.83	$ 4.77	$ 4.77	$ 5.13	$ 4.89	$ 4.89
High Growth & Low Price	2016-2017	Jul	$ 4.86	$ 5.13	$ 4.86	$ 4.86	$ 4.86	$ 4.80	$ 4.80	$ 5.13	$ 4.91	$ 4.92
High Growth & Low Price	2016-2017	Aug	$ 4.86	$ 5.14	$ 4.86	$ 4.86	$ 4.86	$ 4.80	$ 4.80	$ 5.14	$ 4.91	$ 4.92
High Growth & Low Price	2016-2017	Sep	$ 4.86	$ 5.14	$ 4.86	$ 4.86	$ 4.86	$ 4.80	$ 4.80	$ 5.14	$ 4.91	$ 4.92
High Growth & Low Price	2016-2017	Oct	$ 4.87	$ 5.23	$ 4.91	$ 4.91	$ 4.91	$ 4.81	$ 4.81	$ 5.23	$ 4.95	$ 4.97
High Growth & Low Price	2017-2018	Nov	$ 5.02	$ 5.39	$ 5.02	$ 5.02	$ 5.02	$ 4.95	$ 4.95	$ 5.39	$ 5.10	$ 5.09
High Growth & Low Price	2017-2018	Dec	$ 5.17	$ 5.44	$ 5.17	$ 5.17	$ 5.17	$ 5.01	$ 5.01	$ 5.44	$ 5.15	$ 5.22
High Growth & Low Price	2017-2018	Jan	$ 5.12	$ 5.46	$ 5.12	$ 5.12	$ 5.12	$ 5.05	$ 5.05	$ 5.46	$ 5.18	$ 5.19
High Growth & Low Price	2017-2018	Feb	$ 5.17	$ 5.39	$ 5.17	$ 5.17	$ 5.17	$ 5.11	$ 5.10	$ 5.39	$ 5.20	$ 5.22
High Growth & Low Price	2017-2018	Mar	$ 5.14	$ 5.37	$ 5.14	$ 5.14	$ 5.14	$ 5.08	$ 5.08	$ 5.37	$ 5.17	$ 5.19
High Growth & Low Price	2017-2018	Apr	$ 4.97	$ 5.32	$ 4.97	$ 4.97	$ 4.97	$ 4.90	$ 4.90	$ 5.37	$ 5.06	$ 5.04
High Growth & Low Price	2017-2018	May	$ 5.01	$ 5.34	$ 5.01	$ 5.01	$ 5.01	$ 4.94	$ 4.94	$ 5.37	$ 5.09	$ 5.07
High Growth & Low Price	2017-2018	Jun	$ 5.05	$ 5.36	$ 5.05	$ 5.05	$ 5.05	$ 4.99	$ 4.99	$ 5.37	$ 5.11	$ 5.11
High Growth & Low Price	2017-2018	Jul	$ 5.08	$ 5.38	$ 5.08	$ 5.08	$ 5.08	$ 5.02	$ 5.02	$ 5.38	$ 5.14	$ 5.14
High Growth & Low Price	2017-2018	Aug	$ 5.09	$ 5.38	$ 5.09	$ 5.09	$ 5.09	$ 5.03	$ 5.03	$ 5.38	$ 5.14	$ 5.15
High Growth & Low Price	2017-2018	Sep	$ 5.08	$ 5.38	$ 5.08	$ 5.08	$ 5.08	$ 5.02	$ 5.02	$ 5.38	$ 5.14	$ 5.14
High Growth & Low Price	2017-2018	Oct	$ 5.09	$ 5.48	$ 5.14	$ 5.14	$ 5.14	$ 5.03	$ 5.03	$ 5.48	$ 5.18	$ 5.20
High Growth & Low Price	2018-2019	Nov	$ 5.20	$ 5.58	$ 5.20	$ 5.20	$ 5.20	$ 5.14	$ 5.14	$ 5.58	$ 5.29	$ 5.28
High Growth & Low Price	2018-2019	Dec	$ 5.36	$ 5.65	$ 5.36	$ 5.36	$ 5.36	$ 5.23	$ 5.23	$ 5.65	$ 5.37	$ 5.42
High Growth & Low Price	2018-2019	Jan	$ 5.31	$ 5.66	$ 5.31	$ 5.31	$ 5.31	$ 5.23	$ 5.23	$ 5.66	$ 5.37	$ 5.38
High Growth & Low Price	2018-2019	Feb	$ 5.37	$ 5.59	$ 5.37	$ 5.37	$ 5.37	$ 5.30	$ 5.30	$ 5.59	$ 5.40	$ 5.41
High Growth & Low Price	2018-2019	Mar	$ 5.31	$ 5.56	$ 5.31	$ 5.31	$ 5.31	$ 5.25	$ 5.25	$ 5.56	$ 5.35	$ 5.36
High Growth & Low Price	2018-2019	Apr	$ 5.14	$ 5.47	$ 5.14	$ 5.14	$ 5.14	$ 5.08	$ 5.08	$ 5.56	$ 5.24	$ 5.21
High Growth & Low Price	2018-2019	May	$ 5.18	$ 5.47	$ 5.18	$ 5.18	$ 5.18	$ 5.12	$ 5.12	$ 5.57	$ 5.27	$ 5.24
High Growth & Low Price	2018-2019	Jun	$ 5.21	$ 5.50	$ 5.21	$ 5.21	$ 5.21	$ 5.15	$ 5.15	$ 5.57	$ 5.29	$ 5.27
High Growth & Low Price	2018-2019	Jul	$ 5.25	$ 5.57	$ 5.25	$ 5.25	$ 5.25	$ 5.19	$ 5.19	$ 5.57	$ 5.31	$ 5.32
High Growth & Low Price	2018-2019	Aug	$ 5.26	$ 5.57	$ 5.26	$ 5.26	$ 5.26	$ 5.20	$ 5.20	$ 5.57	$ 5.32	$ 5.32

APPENDIX 6.4 II HIGH GROWTH – LOW PRICE MONTHLY DETAIL

Appendix 6.4 - Monthly Avoided Cost Detail 1/
2010$

Scenario	Gas Year	Month	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA/ID Both	WA/ID GTN	WA/ID NWP	WA/ID Annual	OR Annual
High Growth & Low Price	2018-2019	Sep	$ 5.19	$ 5.57	$ 5.19	$ 5.19	$ 5.19	$ 5.13	$ 5.13	$ 5.57	$ 5.28	$ 5.27
High Growth & Low Price	2018-2019	Oct	$ 5.20	$ 5.60	$ 5.25	$ 5.25	$ 5.25	$ 5.14	$ 5.14	$ 5.60	$ 5.29	$ 5.31
High Growth & Low Price	2019-2020	Nov	$ 5.29	$ 5.61	$ 5.29	$ 5.29	$ 5.29	$ 5.23	$ 5.23	$ 5.61	$ 5.36	$ 5.36
High Growth & Low Price	2019-2020	Dec	$ 5.48	$ 5.68	$ 5.48	$ 5.48	$ 5.48	$ 5.30	$ 5.30	$ 5.68	$ 5.43	$ 5.52
High Growth & Low Price	2019-2020	Jan	$ 5.43	$ 5.66	$ 5.43	$ 5.43	$ 5.43	$ 5.34	$ 5.34	$ 5.66	$ 5.45	$ 5.48
High Growth & Low Price	2019-2020	Feb	$ 5.47	$ 5.57	$ 5.47	$ 5.47	$ 5.47	$ 5.40	$ 5.40	$ 5.55	$ 5.45	$ 5.49
High Growth & Low Price	2019-2020	Mar	$ 5.38	$ 5.50	$ 5.38	$ 5.38	$ 5.38	$ 5.31	$ 5.31	$ 5.50	$ 5.37	$ 5.40
High Growth & Low Price	2019-2020	Apr	$ 5.23	$ 5.46	$ 5.23	$ 5.23	$ 5.23	$ 5.17	$ 5.17	$ 5.50	$ 5.28	$ 5.28
High Growth & Low Price	2019-2020	May	$ 5.26	$ 5.44	$ 5.26	$ 5.26	$ 5.26	$ 5.20	$ 5.20	$ 5.50	$ 5.30	$ 5.30
High Growth & Low Price	2019-2020	Jun	$ 5.30	$ 5.46	$ 5.30	$ 5.30	$ 5.30	$ 5.24	$ 5.24	$ 5.51	$ 5.33	$ 5.34
High Growth & Low Price	2019-2020	Jul	$ 5.34	$ 5.51	$ 5.34	$ 5.34	$ 5.34	$ 5.28	$ 5.28	$ 5.51	$ 5.35	$ 5.38
High Growth & Low Price	2019-2020	Aug	$ 5.36	$ 5.51	$ 5.36	$ 5.36	$ 5.36	$ 5.29	$ 5.29	$ 5.51	$ 5.36	$ 5.39
High Growth & Low Price	2019-2020	Sep	$ 5.28	$ 5.51	$ 5.28	$ 5.28	$ 5.28	$ 5.22	$ 5.22	$ 5.51	$ 5.32	$ 5.33
High Growth & Low Price	2019-2020	Oct	$ 5.29	$ 5.56	$ 5.38	$ 5.38	$ 5.38	$ 5.23	$ 5.23	$ 5.56	$ 5.34	$ 5.40
High Growth & Low Price	2020-2021	Nov	$ 5.44	$ 5.68	$ 5.44	$ 5.44	$ 5.44	$ 5.35	$ 5.35	$ 5.70	$ 5.47	$ 5.49
High Growth & Low Price	2020-2021	Dec	$ 5.58	$ 5.77	$ 5.58	$ 5.58	$ 5.58	$ 5.45	$ 5.45	$ 5.77	$ 5.56	$ 5.62
High Growth & Low Price	2020-2021	Jan	$ 5.54	$ 5.75	$ 5.54	$ 5.54	$ 5.54	$ 5.44	$ 5.44	$ 5.75	$ 5.54	$ 5.58
High Growth & Low Price	2020-2021	Feb	$ 5.58	$ 5.70	$ 5.58	$ 5.58	$ 5.58	$ 5.51	$ 5.51	$ 5.69	$ 5.57	$ 5.60
High Growth & Low Price	2020-2021	Mar	$ 5.52	$ 5.64	$ 5.52	$ 5.52	$ 5.52	$ 5.45	$ 5.45	$ 5.64	$ 5.51	$ 5.54
High Growth & Low Price	2020-2021	Apr	$ 5.36	$ 5.55	$ 5.36	$ 5.36	$ 5.36	$ 5.29	$ 5.29	$ 5.64	$ 5.40	$ 5.39
High Growth & Low Price	2020-2021	May	$ 5.40	$ 5.54	$ 5.40	$ 5.40	$ 5.40	$ 5.33	$ 5.33	$ 5.64	$ 5.43	$ 5.43
High Growth & Low Price	2020-2021	Jun	$ 5.44	$ 5.57	$ 5.44	$ 5.44	$ 5.44	$ 5.37	$ 5.37	$ 5.64	$ 5.46	$ 5.46
High Growth & Low Price	2020-2021	Jul	$ 5.48	$ 5.64	$ 5.48	$ 5.48	$ 5.48	$ 5.41	$ 5.41	$ 5.64	$ 5.49	$ 5.51
High Growth & Low Price	2020-2021	Aug	$ 5.50	$ 5.65	$ 5.50	$ 5.50	$ 5.50	$ 5.43	$ 5.43	$ 5.65	$ 5.50	$ 5.53
High Growth & Low Price	2020-2021	Sep	$ 5.30	$ 5.50	$ 5.30	$ 5.30	$ 5.30	$ 5.24	$ 5.24	$ 5.65	$ 5.37	$ 5.34
High Growth & Low Price	2020-2021	Oct	$ 5.31	$ 5.54	$ 5.41	$ 5.41	$ 5.41	$ 5.25	$ 5.25	$ 5.54	$ 5.35	$ 5.42
High Growth & Low Price	2021-2022	Nov	$ 5.45	$ 5.66	$ 5.45	$ 5.45	$ 5.45	$ 5.36	$ 5.36	$ 5.68	$ 5.47	$ 5.49
High Growth & Low Price	2021-2022	Dec	$ 5.56	$ 5.74	$ 5.56	$ 5.56	$ 5.56	$ 5.46	$ 5.46	$ 5.74	$ 5.55	$ 5.60
High Growth & Low Price	2021-2022	Jan	$ 5.51	$ 5.71	$ 5.51	$ 5.51	$ 5.51	$ 5.43	$ 5.43	$ 5.71	$ 5.52	$ 5.55
High Growth & Low Price	2021-2022	Feb	$ 5.58	$ 5.59	$ 5.58	$ 5.58	$ 5.58	$ 5.49	$ 5.49	$ 5.55	$ 5.51	$ 5.58
High Growth & Low Price	2021-2022	Mar	$ 5.37	$ 5.47	$ 5.37	$ 5.37	$ 5.37	$ 5.30	$ 5.30	$ 5.47	$ 5.36	$ 5.39
High Growth & Low Price	2021-2022	Apr	$ 5.24	$ 5.39	$ 5.24	$ 5.24	$ 5.24	$ 5.18	$ 5.18	$ 5.47	$ 5.28	$ 5.27
High Growth & Low Price	2021-2022	May	$ 5.28	$ 5.40	$ 5.28	$ 5.28	$ 5.28	$ 5.22	$ 5.22	$ 5.48	$ 5.30	$ 5.31
High Growth & Low Price	2021-2022	Jun	$ 5.31	$ 5.43	$ 5.31	$ 5.31	$ 5.31	$ 5.25	$ 5.25	$ 5.48	$ 5.32	$ 5.34
High Growth & Low Price	2021-2022	Jul	$ 5.34	$ 5.48	$ 5.34	$ 5.34	$ 5.34	$ 5.28	$ 5.28	$ 5.48	$ 5.35	$ 5.37
High Growth & Low Price	2021-2022	Aug	$ 5.37	$ 5.48	$ 5.37	$ 5.37	$ 5.37	$ 5.30	$ 5.30	$ 5.48	$ 5.36	$ 5.39
High Growth & Low Price	2021-2022	Sep	$ 5.32	$ 5.46	$ 5.32	$ 5.32	$ 5.32	$ 5.26	$ 5.26	$ 5.49	$ 5.33	$ 5.35
High Growth & Low Price	2021-2022	Oct	$ 5.31	$ 5.49	$ 5.44	$ 5.44	$ 5.44	$ 5.25	$ 5.25	$ 5.49	$ 5.33	$ 5.43
High Growth & Low Price	2022-2023	Nov	$ 5.50	$ 5.64	$ 5.50	$ 5.50	$ 5.50	$ 5.40	$ 5.40	$ 5.66	$ 5.49	$ 5.53
High Growth & Low Price	2022-2023	Dec	$ 5.64	$ 5.73	$ 5.64	$ 5.64	$ 5.64	$ 5.49	$ 5.49	$ 5.73	$ 5.57	$ 5.65
High Growth & Low Price	2022-2023	Jan	$ 5.59	$ 5.71	$ 5.59	$ 5.59	$ 5.59	$ 5.45	$ 5.45	$ 5.71	$ 5.54	$ 5.62
High Growth & Low Price	2022-2023	Feb	$ 5.62	$ 5.67	$ 5.62	$ 5.62	$ 5.62	$ 5.52	$ 5.52	$ 5.66	$ 5.57	$ 5.63
High Growth & Low Price	2022-2023	Mar	$ 5.54	$ 5.57	$ 5.54	$ 5.54	$ 5.54	$ 5.47	$ 5.47	$ 5.57	$ 5.51	$ 5.55
High Growth & Low Price	2022-2023	Apr	$ 5.42	$ 5.49	$ 5.42	$ 5.42	$ 5.42	$ 5.35	$ 5.35	$ 5.58	$ 5.42	$ 5.43
High Growth & Low Price	2022-2023	May	$ 5.47	$ 5.51	$ 5.47	$ 5.47	$ 5.47	$ 5.40	$ 5.40	$ 5.58	$ 5.46	$ 5.48
High Growth & Low Price	2022-2023	Jun	$ 5.52	$ 5.53	$ 5.50	$ 5.50	$ 5.50	$ 5.45	$ 5.45	$ 5.58	$ 5.49	$ 5.51
High Growth & Low Price	2022-2023	Jul	$ 5.55	$ 5.58	$ 5.55	$ 5.55	$ 5.55	$ 5.48	$ 5.48	$ 5.58	$ 5.51	$ 5.56
High Growth & Low Price	2022-2023	Aug	$ 5.57	$ 5.58	$ 5.56	$ 5.56	$ 5.56	$ 5.50	$ 5.50	$ 5.58	$ 5.53	$ 5.57
High Growth & Low Price	2022-2023	Sep	$ 5.41	$ 5.50	$ 5.41	$ 5.41	$ 5.41	$ 5.34	$ 5.34	$ 5.59	$ 5.42	$ 5.43
High Growth & Low Price	2022-2023	Oct	$ 5.41	$ 5.53	$ 5.48	$ 5.48	$ 5.48	$ 5.34	$ 5.34	$ 5.53	$ 5.40	$ 5.48
High Growth & Low Price	2023-2024	Nov	$ 5.54	$ 5.64	$ 5.54	$ 5.54	$ 5.54	$ 5.45	$ 5.45	$ 5.65	$ 5.52	$ 5.56
High Growth & Low Price	2023-2024	Dec	$ 5.65	$ 5.72	$ 5.65	$ 5.65	$ 5.65	$ 5.53	$ 5.53	$ 5.72	$ 5.59	$ 5.67
High Growth & Low Price	2023-2024	Jan	$ 5.59	$ 5.66	$ 5.59	$ 5.59	$ 5.59	$ 5.50	$ 5.50	$ 5.66	$ 5.55	$ 5.60
High Growth & Low Price	2023-2024	Feb	$ 5.66	$ 5.63	$ 5.66	$ 5.66	$ 5.66	$ 5.55	$ 5.55	$ 5.55	$ 5.55	$ 5.65
High Growth & Low Price	2023-2024	Mar	$ 5.40	$ 5.41	$ 5.40	$ 5.40	$ 5.40	$ 5.33	$ 5.33	$ 5.41	$ 5.36	$ 5.40
High Growth & Low Price	2023-2024	Apr	$ 5.27	$ 5.34	$ 5.27	$ 5.27	$ 5.27	$ 5.21	$ 5.21	$ 5.41	$ 5.28	$ 5.29
High Growth & Low Price	2023-2024	May	$ 5.29	$ 5.33	$ 5.33	$ 5.33	$ 5.33	$ 5.23	$ 5.23	$ 5.41	$ 5.29	$ 5.32
High Growth & Low Price	2023-2024	Jun	$ 5.37	$ 5.33	$ 5.33	$ 5.33	$ 5.33	$ 5.30	$ 5.30	$ 5.42	$ 5.34	$ 5.34
High Growth & Low Price	2023-2024	Jul	$ 5.40	$ 5.40	$ 5.40	$ 5.40	$ 5.40	$ 5.33	$ 5.33	$ 5.42	$ 5.36	$ 5.40
High Growth & Low Price	2023-2024	Aug	$ 5.42	$ 5.42	$ 5.42	$ 5.42	$ 5.42	$ 5.35	$ 5.35	$ 5.42	$ 5.37	$ 5.42
High Growth & Low Price	2023-2024	Sep	$ 5.37	$ 5.40	$ 5.34	$ 5.34	$ 5.34	$ 5.30	$ 5.30	$ 5.42	$ 5.34	$ 5.36
High Growth & Low Price	2023-2024	Oct	$ 5.38	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.31	$ 5.31	$ 5.45	$ 5.36	$ 5.44
High Growth & Low Price	2024-2025	Nov	$ 5.52	$ 5.56	$ 5.52	$ 5.52	$ 5.52	$ 5.42	$ 5.42	$ 5.60	$ 5.48	$ 5.53
High Growth & Low Price	2024-2025	Dec	$ 5.69	$ 5.67	$ 5.69	$ 5.69	$ 5.69	$ 5.50	$ 5.50	$ 5.67	$ 5.56	$ 5.69
High Growth & Low Price	2024-2025	Jan	$ 5.64	$ 5.65	$ 5.64	$ 5.64	$ 5.64	$ 5.47	$ 5.47	$ 5.65	$ 5.53	$ 5.65
High Growth & Low Price	2024-2025	Feb	$ 5.69	$ 5.65	$ 5.69	$ 5.69	$ 5.69	$ 5.53	$ 5.53	$ 5.56	$ 5.54	$ 5.68
High Growth & Low Price	2024-2025	Mar	$ 5.50	$ 5.49	$ 5.50	$ 5.50	$ 5.50	$ 5.43	$ 5.43	$ 5.44	$ 5.43	$ 5.50
High Growth & Low Price	2024-2025	Apr	$ 5.37	$ 5.39	$ 5.37	$ 5.37	$ 5.37	$ 5.30	$ 5.30	$ 5.44	$ 5.35	$ 5.37
High Growth & Low Price	2024-2025	May	$ 5.39	$ 5.40	$ 5.40	$ 5.40	$ 5.40	$ 5.32	$ 5.32	$ 5.44	$ 5.36	$ 5.39
High Growth & Low Price	2024-2025	Jun	$ 5.44	$ 5.40	$ 5.40	$ 5.40	$ 5.40	$ 5.37	$ 5.37	$ 5.45	$ 5.39	$ 5.41
High Growth & Low Price	2024-2025	Jul	$ 5.49	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.43	$ 5.43	$ 5.45	$ 5.44	$ 5.46
High Growth & Low Price	2024-2025	Aug	$ 5.50	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.46
High Growth & Low Price	2024-2025	Sep	$ 5.42	$ 5.41	$ 5.41	$ 5.41	$ 5.41	$ 5.35	$ 5.35	$ 5.45	$ 5.38	$ 5.41
High Growth & Low Price	2024-2025	Oct	$ 5.43	$ 5.44	$ 5.44	$ 5.44	$ 5.44	$ 5.36	$ 5.36	$ 5.44	$ 5.39	$ 5.44
High Growth & Low Price	2025-2026	Nov	$ 5.74	$ 5.80	$ 5.74	$ 5.74	$ 5.74	$ 5.54	$ 5.54	$ 5.85	$ 5.64	$ 5.75
High Growth & Low Price	2025-2026	Dec	$ 5.91	$ 5.90	$ 5.91	$ 5.91	$ 5.91	$ 5.63	$ 5.63	$ 5.91	$ 5.72	$ 5.90
High Growth & Low Price	2025-2026	Jan	$ 5.89	$ 5.90	$ 5.89	$ 5.89	$ 5.89	$ 5.59	$ 5.59	$ 5.90	$ 5.69	$ 5.89
High Growth & Low Price	2025-2026	Feb	$ 5.95	$ 5.92	$ 5.95	$ 5.95	$ 5.95	$ 5.67	$ 5.67	$ 5.79	$ 5.71	$ 5.94
High Growth & Low Price	2025-2026	Mar	$ 5.56	$ 5.66	$ 5.56	$ 5.56	$ 5.56	$ 5.46	$ 5.46	$ 5.66	$ 5.53	$ 5.58
High Growth & Low Price	2025-2026	Apr	$ 5.40	$ 5.56	$ 5.40	$ 5.40	$ 5.40	$ 5.33	$ 5.33	$ 5.67	$ 5.44	$ 5.43
High Growth & Low Price	2025-2026	May	$ 5.43	$ 5.57	$ 5.49	$ 5.49	$ 5.49	$ 5.36	$ 5.36	$ 5.67	$ 5.46	$ 5.49
High Growth & Low Price	2025-2026	Jun	$ 5.49	$ 5.60	$ 5.49	$ 5.49	$ 5.49	$ 5.42	$ 5.42	$ 5.67	$ 5.50	$ 5.51
High Growth & Low Price	2025-2026	Jul	$ 5.52	$ 5.67	$ 5.52	$ 5.52	$ 5.52	$ 5.45	$ 5.45	$ 5.67	$ 5.52	$ 5.55
High Growth & Low Price	2025-2026	Aug	$ 5.54	$ 5.68	$ 5.54	$ 5.54	$ 5.54	$ 5.47	$ 5.47	$ 5.68	$ 5.54	$ 5.57
High Growth & Low Price	2025-2026	Sep	$ 5.50	$ 5.68	$ 5.50	$ 5.50	$ 5.50	$ 5.43	$ 5.43	$ 5.68	$ 5.51	$ 5.54
High Growth & Low Price	2025-2026	Oct	$ 5.50	$ 5.70	$ 5.64	$ 5.64	$ 5.64	$ 5.43	$ 5.43	$ 5.70	$ 5.52	$ 5.63
High Growth & Low Price	2026-2027	Nov	$ 5.77	$ 5.83	$ 5.77	$ 5.77	$ 5.77	$ 5.56	$ 5.56	$ 5.87	$ 5.66	$ 5.79
High Growth & Low Price	2026-2027	Dec	$ 5.92	$ 5.91	$ 5.92	$ 5.92	$ 5.92	$ 5.66	$ 5.66	$ 5.91	$ 5.74	$ 5.92
High Growth & Low Price	2026-2027	Jan	$ 5.89	$ 5.89	$ 5.89	$ 5.89	$ 5.89	$ 5.61	$ 5.61	$ 5.90	$ 5.71	$ 5.89
High Growth & Low Price	2026-2027	Feb	$ 5.94	$ 5.92	$ 5.94	$ 5.94	$ 5.94	$ 5.68	$ 5.68	$ 5.72	$ 5.70	$ 5.94

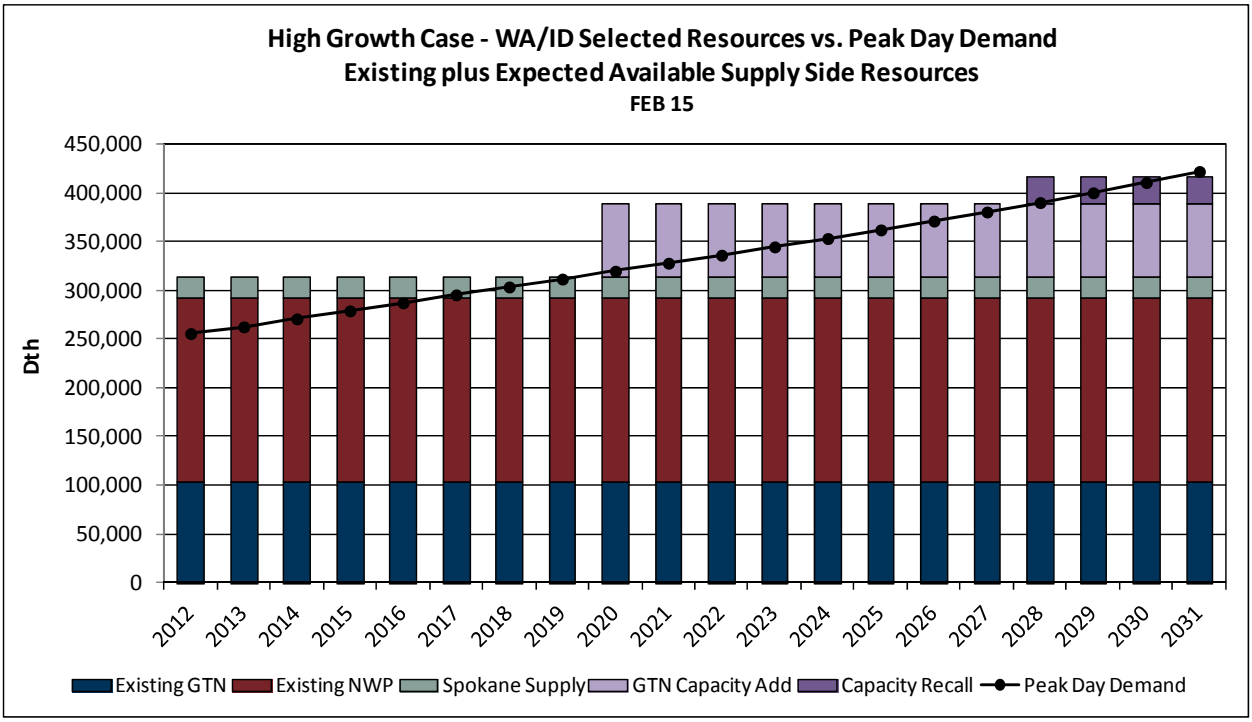
APPENDIX 6.4 II HIGH GROWTH – LOW PRICE MONTHLY DETAIL

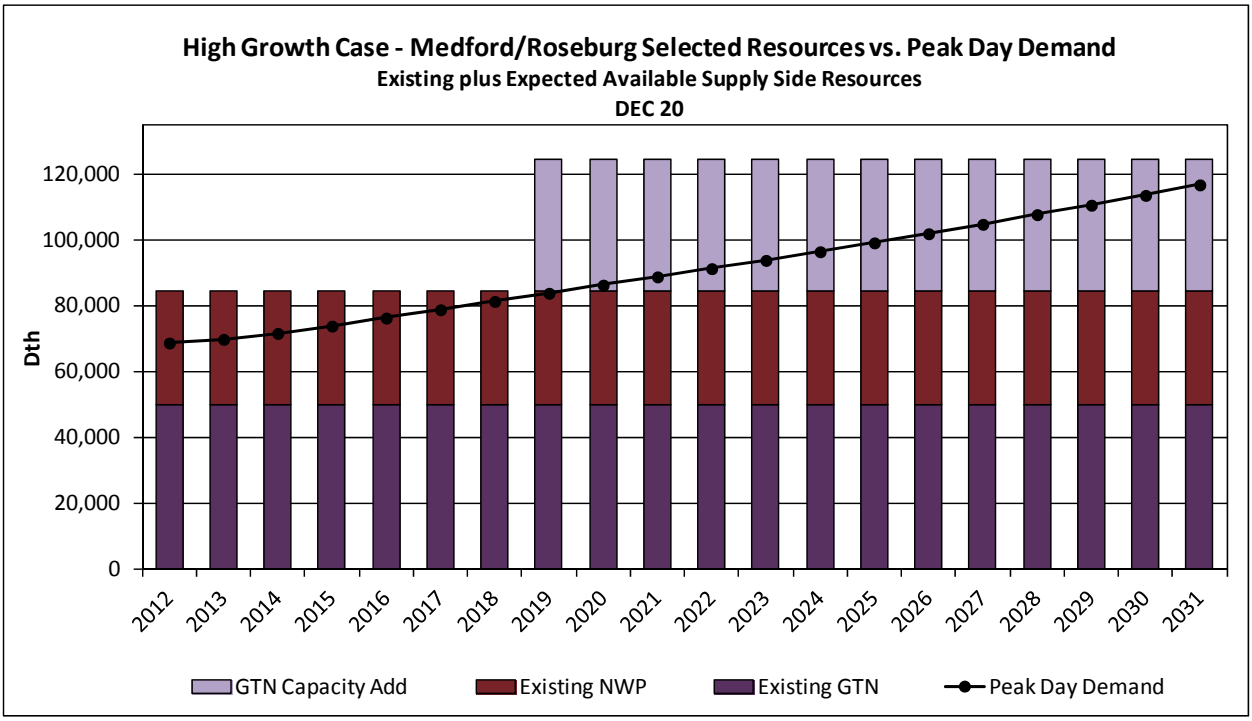
Appendix 6.4 - Monthly Avoided Cost Detail 1/
2010$

Scenario	Gas Year	Month	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA/ID Both	WA/ID GTN	WA/ID NWP	WA/ID Annual	OR Annual
High Growth & Low Price	2026-2027	Mar	$ 5.52	$ 5.58	$ 5.52	$ 5.52	$ 5.52	$ 5.41	$ 5.41	$ 5.58	$ 5.47	$ 5.53
High Growth & Low Price	2026-2027	Apr	$ 5.33	$ 5.47	$ 5.33	$ 5.33	$ 5.33	$ 5.27	$ 5.27	$ 5.59	$ 5.37	$ 5.36
High Growth & Low Price	2026-2027	May	$ 5.37	$ 5.50	$ 5.45	$ 5.45	$ 5.45	$ 5.30	$ 5.30	$ 5.59	$ 5.39	$ 5.44
High Growth & Low Price	2026-2027	Jun	$ 5.42	$ 5.52	$ 5.42	$ 5.42	$ 5.42	$ 5.35	$ 5.35	$ 5.59	$ 5.43	$ 5.44
High Growth & Low Price	2026-2027	Jul	$ 5.45	$ 5.59	$ 5.45	$ 5.45	$ 5.45	$ 5.38	$ 5.38	$ 5.59	$ 5.45	$ 5.48
High Growth & Low Price	2026-2027	Aug	$ 5.47	$ 5.59	$ 5.47	$ 5.47	$ 5.47	$ 5.40	$ 5.40	$ 5.59	$ 5.46	$ 5.49
High Growth & Low Price	2026-2027	Sep	$ 5.45	$ 5.60	$ 5.45	$ 5.45	$ 5.45	$ 5.38	$ 5.38	$ 5.60	$ 5.45	$ 5.48
High Growth & Low Price	2026-2027	Oct	$ 5.45	$ 5.62	$ 5.58	$ 5.58	$ 5.58	$ 5.38	$ 5.38	$ 5.62	$ 5.46	$ 5.56
High Growth & Low Price	2027-2028	Nov	$ 5.74	$ 5.77	$ 5.74	$ 5.74	$ 5.74	$ 5.53	$ 5.53	$ 5.82	$ 5.63	$ 5.75
High Growth & Low Price	2027-2028	Dec	$ 5.86	$ 5.84	$ 5.86	$ 5.86	$ 5.86	$ 5.62	$ 5.62	$ 5.84	$ 5.69	$ 5.86
High Growth & Low Price	2027-2028	Jan	$ 5.83	$ 5.83	$ 5.83	$ 5.83	$ 5.83	$ 5.59	$ 5.59	$ 5.83	$ 5.67	$ 5.83
High Growth & Low Price	2027-2028	Feb	$ 5.87	$ 5.85	$ 5.87	$ 5.87	$ 5.87	$ 5.67	$ 5.67	$ 5.73	$ 5.69	$ 5.87
High Growth & Low Price	2027-2028	Mar	$ 5.55	$ 5.56	$ 5.55	$ 5.55	$ 5.55	$ 5.45	$ 5.45	$ 5.58	$ 5.49	$ 5.56
High Growth & Low Price	2027-2028	Apr	$ 5.38	$ 5.48	$ 5.38	$ 5.38	$ 5.38	$ 5.31	$ 5.31	$ 5.60	$ 5.40	$ 5.40
High Growth & Low Price	2027-2028	May	$ 5.43	$ 5.50	$ 5.47	$ 5.47	$ 5.47	$ 5.36	$ 5.36	$ 5.60	$ 5.44	$ 5.47
High Growth & Low Price	2027-2028	Jun	$ 5.46	$ 5.53	$ 5.46	$ 5.46	$ 5.46	$ 5.39	$ 5.39	$ 5.60	$ 5.46	$ 5.47
High Growth & Low Price	2027-2028	Jul	$ 5.50	$ 5.60	$ 5.50	$ 5.50	$ 5.50	$ 5.43	$ 5.43	$ 5.60	$ 5.49	$ 5.52
High Growth & Low Price	2027-2028	Aug	$ 5.52	$ 5.63	$ 5.52	$ 5.52	$ 5.52	$ 5.45	$ 5.45	$ 5.63	$ 5.51	$ 5.54
High Growth & Low Price	2027-2028	Sep	$ 5.48	$ 5.59	$ 5.48	$ 5.48	$ 5.48	$ 5.41	$ 5.41	$ 5.61	$ 5.48	$ 5.50
High Growth & Low Price	2027-2028	Oct	$ 5.49	$ 5.61	$ 5.61	$ 5.61	$ 5.61	$ 5.42	$ 5.42	$ 5.61	$ 5.48	$ 5.59
High Growth & Low Price	2028-2029	Nov	$ 5.82	$ 5.83	$ 5.82	$ 5.82	$ 5.82	$ 5.58	$ 5.58	$ 5.94	$ 5.70	$ 5.82
High Growth & Low Price	2028-2029	Dec	$ 5.95	$ 5.95	$ 5.95	$ 5.95	$ 5.95	$ 5.69	$ 5.69	$ 5.96	$ 5.78	$ 5.95
High Growth & Low Price	2028-2029	Jan	$ 5.94	$ 5.94	$ 5.94	$ 5.94	$ 5.94	$ 5.64	$ 5.64	$ 5.94	$ 5.74	$ 5.94
High Growth & Low Price	2028-2029	Feb	$ 5.91	$ 5.88	$ 5.91	$ 5.91	$ 5.91	$ 5.72	$ 5.72	$ 5.76	$ 5.73	$ 5.90
High Growth & Low Price	2028-2029	Mar	$ 5.59	$ 5.59	$ 5.59	$ 5.59	$ 5.59	$ 5.52	$ 5.52	$ 5.61	$ 5.55	$ 5.59
High Growth & Low Price	2028-2029	Apr	$ 5.49	$ 5.49	$ 5.49	$ 5.49	$ 5.49	$ 5.42	$ 5.42	$ 5.61	$ 5.49	$ 5.49
High Growth & Low Price	2028-2029	May	$ 5.45	$ 5.49	$ 5.49	$ 5.49	$ 5.49	$ 5.38	$ 5.38	$ 5.61	$ 5.46	$ 5.48
High Growth & Low Price	2028-2029	Jun	$ 5.49	$ 5.52	$ 5.49	$ 5.49	$ 5.49	$ 5.42	$ 5.42	$ 5.62	$ 5.49	$ 5.49
High Growth & Low Price	2028-2029	Jul	$ 5.53	$ 5.61	$ 5.53	$ 5.53	$ 5.53	$ 5.46	$ 5.46	$ 5.62	$ 5.51	$ 5.55
High Growth & Low Price	2028-2029	Aug	$ 5.55	$ 5.64	$ 5.55	$ 5.55	$ 5.55	$ 5.48	$ 5.48	$ 5.64	$ 5.53	$ 5.57
High Growth & Low Price	2028-2029	Sep	$ 5.54	$ 5.62	$ 5.54	$ 5.54	$ 5.54	$ 5.47	$ 5.47	$ 5.62	$ 5.52	$ 5.56
High Growth & Low Price	2028-2029	Oct	$ 5.54	$ 5.64	$ 5.64	$ 5.64	$ 5.64	$ 5.47	$ 5.47	$ 5.64	$ 5.53	$ 5.62
High Growth & Low Price	2029-2030	Nov	$ 5.96	$ 5.96	$ 5.96	$ 5.96	$ 5.96	$ 5.62	$ 5.62	$ 6.12	$ 5.79	$ 5.96
High Growth & Low Price	2029-2030	Dec	$ 6.12	$ 6.12	$ 6.12	$ 6.12	$ 6.12	$ 5.85	$ 5.84	$ 6.14	$ 5.94	$ 6.12
High Growth & Low Price	2029-2030	Jan	$ 6.12	$ 6.12	$ 6.12	$ 6.12	$ 6.12	$ 5.69	$ 5.69	$ 6.12	$ 5.84	$ 6.12
High Growth & Low Price	2029-2030	Feb	$ 5.93	$ 5.88	$ 5.93	$ 5.93	$ 5.93	$ 5.77	$ 5.76	$ 5.77	$ 5.77	$ 5.92
High Growth & Low Price	2029-2030	Mar	$ 5.56	$ 5.56	$ 5.56	$ 5.56	$ 5.56	$ 5.47	$ 5.47	$ 5.61	$ 5.52	$ 5.56
High Growth & Low Price	2029-2030	Apr	$ 5.52	$ 5.52	$ 5.52	$ 5.52	$ 5.52	$ 5.45	$ 5.45	$ 5.61	$ 5.51	$ 5.52
High Growth & Low Price	2029-2030	May	$ 5.42	$ 5.48	$ 5.48	$ 5.48	$ 5.48	$ 5.35	$ 5.35	$ 5.61	$ 5.44	$ 5.47
High Growth & Low Price	2029-2030	Jun	$ 5.47	$ 5.48	$ 5.48	$ 5.48	$ 5.48	$ 5.40	$ 5.40	$ 5.62	$ 5.47	$ 5.48
High Growth & Low Price	2029-2030	Jul	$ 5.53	$ 5.55	$ 5.53	$ 5.53	$ 5.53	$ 5.46	$ 5.46	$ 5.62	$ 5.51	$ 5.53
High Growth & Low Price	2029-2030	Aug	$ 5.54	$ 5.57	$ 5.54	$ 5.54	$ 5.54	$ 5.47	$ 5.47	$ 5.62	$ 5.52	$ 5.55
High Growth & Low Price	2029-2030	Sep	$ 5.54	$ 5.59	$ 5.59	$ 5.59	$ 5.59	$ 5.47	$ 5.47	$ 5.62	$ 5.52	$ 5.58
High Growth & Low Price	2029-2030	Oct	$ 5.55	$ 5.62	$ 5.62	$ 5.62	$ 5.62	$ 5.48	$ 5.48	$ 5.62	$ 5.53	$ 5.61
High Growth & Low Price	2030-2031	Nov	$ 6.02	$ 6.02	$ 6.02	$ 6.02	$ 6.02	$ 5.62	$ 5.62	$ 6.24	$ 5.83	$ 6.02
High Growth & Low Price	2030-2031	Dec	$ 6.17	$ 6.18	$ 6.18	$ 6.18	$ 6.18	$ 5.90	$ 5.89	$ 6.26	$ 6.02	$ 6.18
High Growth & Low Price	2030-2031	Jan	$ 6.18	$ 6.18	$ 6.18	$ 6.18	$ 6.18	$ 5.77	$ 5.77	$ 6.24	$ 5.93	$ 6.18
High Growth & Low Price	2030-2031	Feb	$ 6.03	$ 5.89	$ 6.03	$ 6.03	$ 6.03	$ 5.81	$ 5.81	$ 5.81	$ 5.81	$ 6.00
High Growth & Low Price	2030-2031	Mar	$ 5.65	$ 5.65	$ 5.65	$ 5.65	$ 5.65	$ 5.57	$ 5.57	$ 5.65	$ 5.60	$ 5.65
High Growth & Low Price	2030-2031	Apr	$ 5.62	$ 5.62	$ 5.62	$ 5.62	$ 5.62	$ 5.55	$ 5.55	$ 5.65	$ 5.59	$ 5.62
High Growth & Low Price	2030-2031	May	$ 5.52	$ 5.59	$ 5.59	$ 5.59	$ 5.59	$ 5.45	$ 5.45	$ 5.65	$ 5.52	$ 5.57
High Growth & Low Price	2030-2031	Jun	$ 5.59	$ 5.59	$ 5.59	$ 5.59	$ 5.59	$ 5.52	$ 5.52	$ 5.66	$ 5.57	$ 5.59
High Growth & Low Price	2030-2031	Jul	$ 5.63	$ 5.63	$ 5.63	$ 5.63	$ 5.63	$ 5.56	$ 5.56	$ 5.66	$ 5.59	$ 5.63
High Growth & Low Price	2030-2031	Aug	$ 5.65	$ 5.65	$ 5.65	$ 5.65	$ 5.65	$ 5.58	$ 5.58	$ 5.66	$ 5.61	$ 5.65
High Growth & Low Price	2030-2031	Sep	$ 5.64	$ 5.65	$ 5.65	$ 5.65	$ 5.65	$ 5.57	$ 5.57	$ 5.66	$ 5.60	$ 5.65
High Growth & Low Price	2030-2031	Oct	$ 5.65	$ 5.68	$ 5.68	$ 5.68	$ 5.68	$ 5.58	$ 5.58	$ 5.68	$ 5.62	$ 5.68

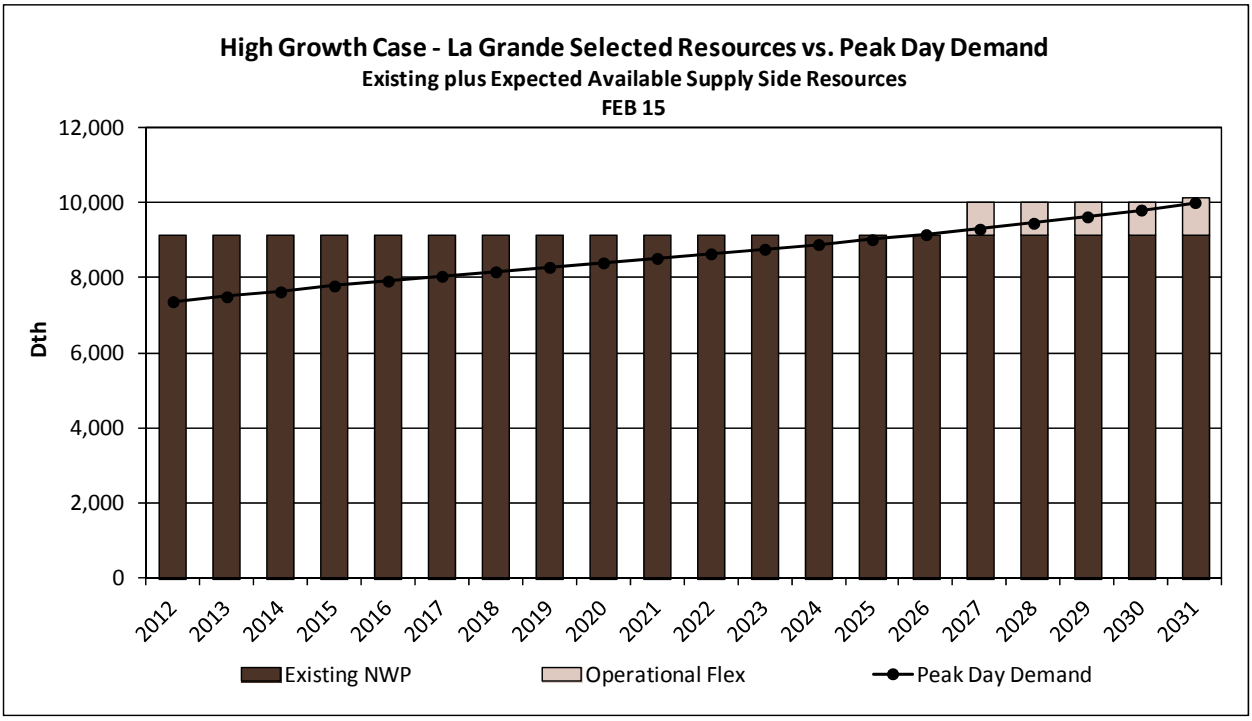
1/ Avoided costs shown before Environmental Externalities adder.

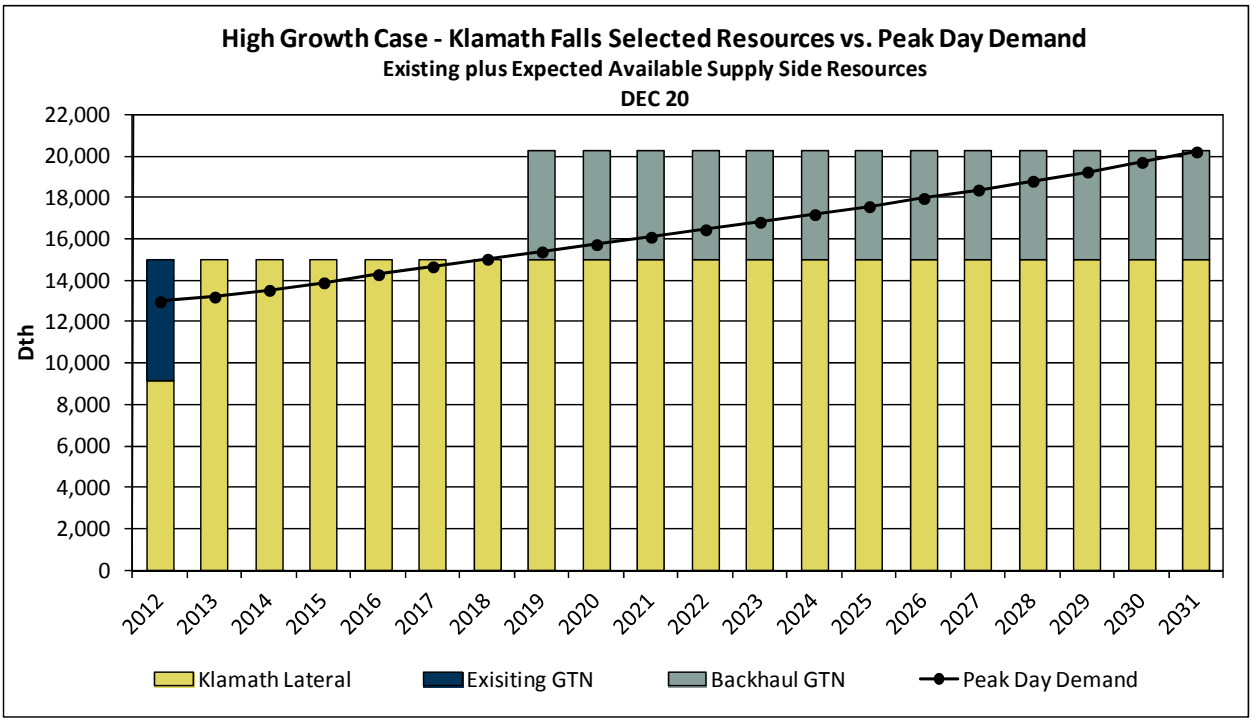
APPENDIX 7.1 II HIGH GROWTH CASES
SELECTED RESOURCES VS. PEAK DAY DEMAND
EXISTING PLUS EXPECTED AVAILABLE



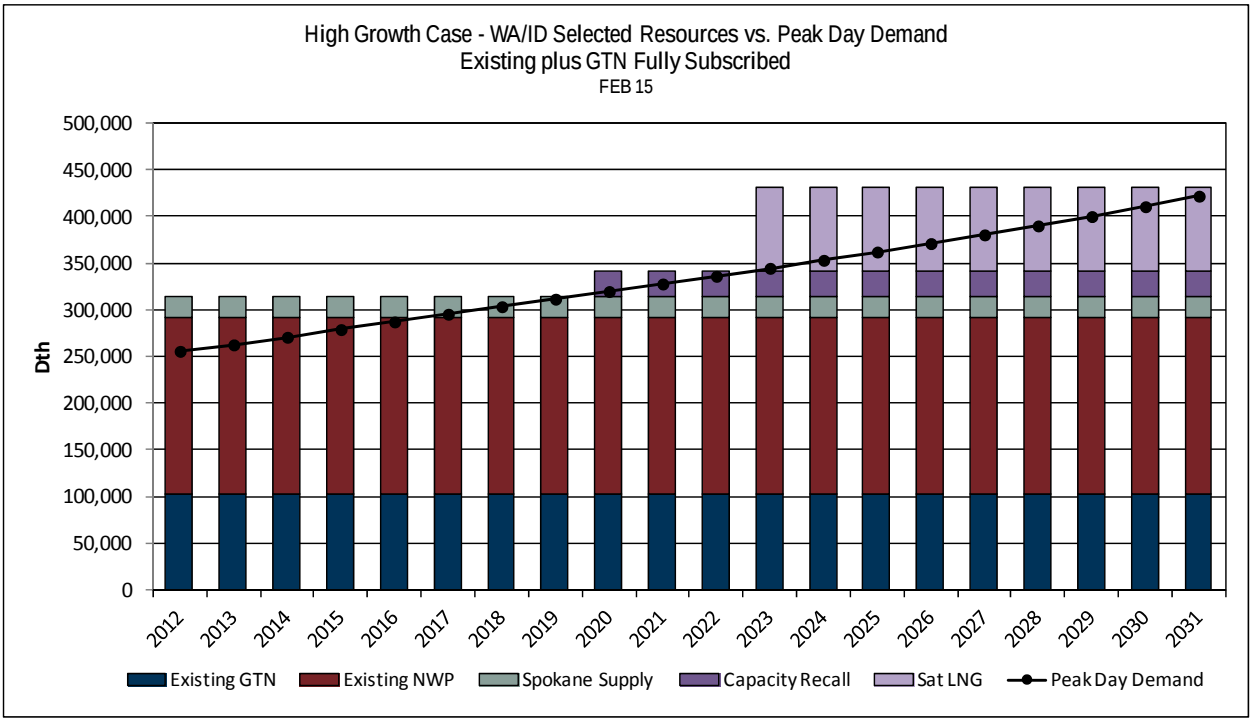


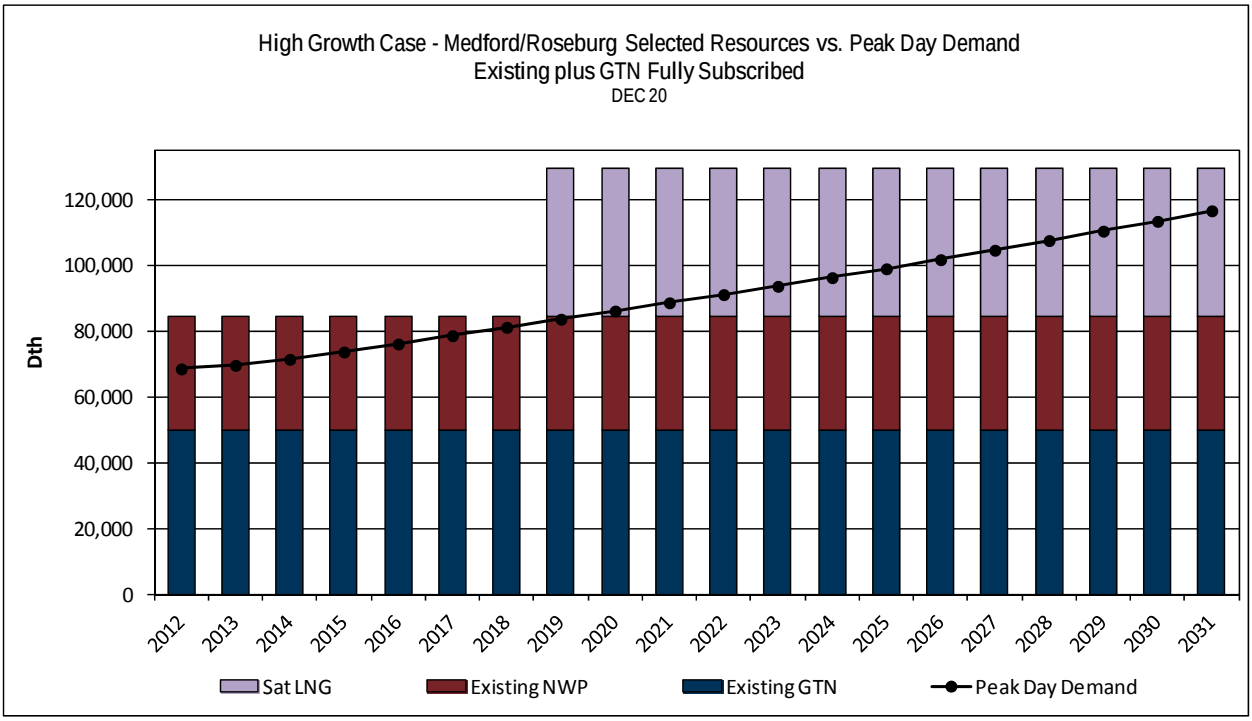
APPENDIX 7.1 II HIGH GROWTH CASES
SELECTED RESOURCES VS. PEAK DAY DEMAND
EXISTING PLUS EXPECTED AVAILABLE



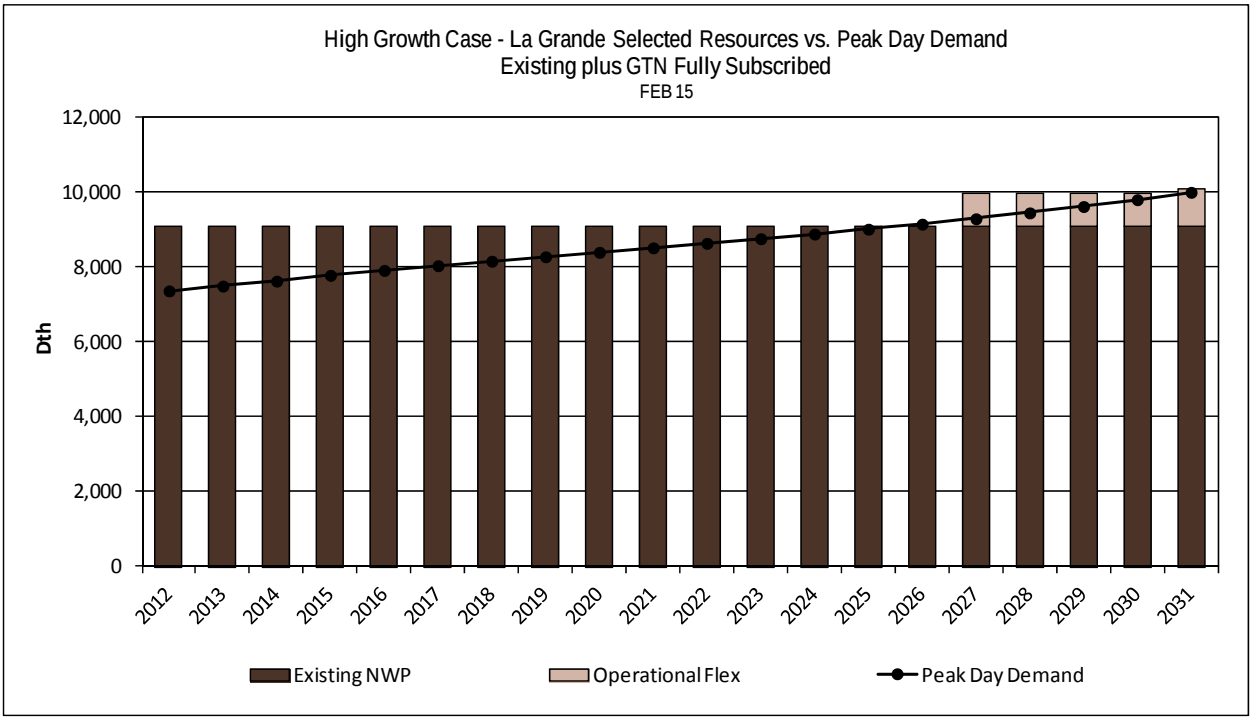


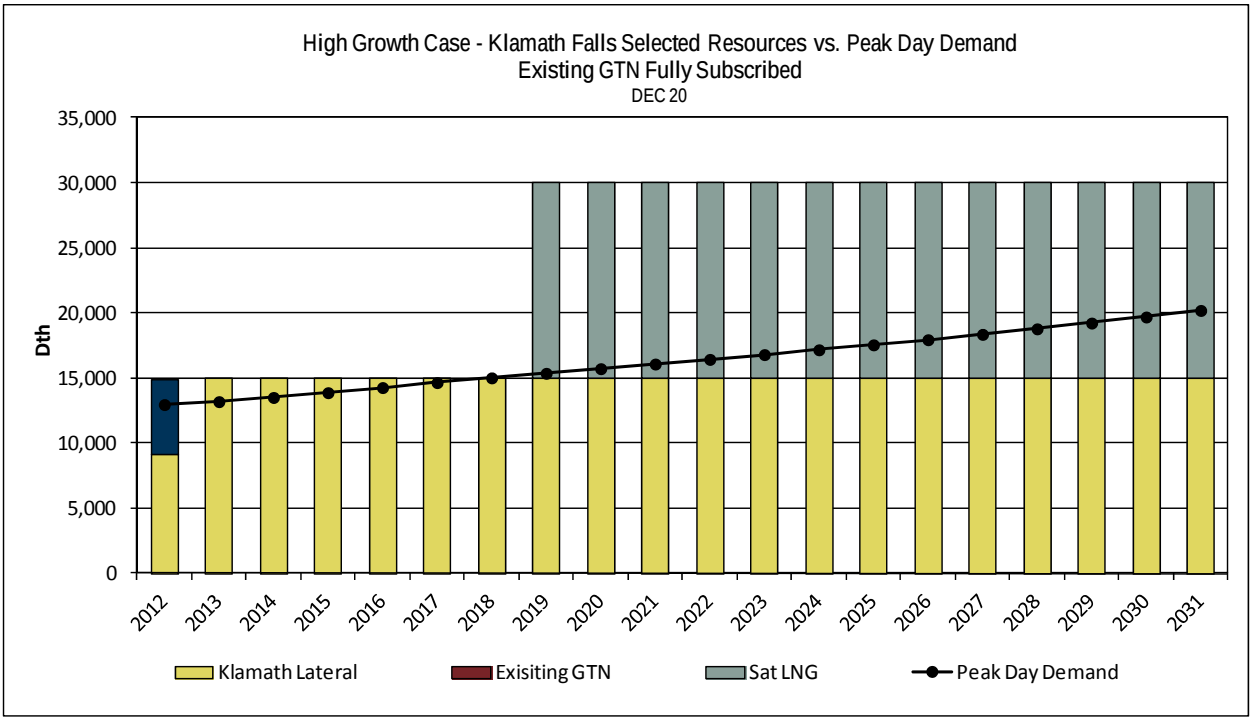
APPENDIX 7.1 II HIGH GROWTH CASES
SELECTED RESOURCES VS. PEAK DAY DEMAND
EXISTING PLUS GTN FULLY SUBSCRIBED





APPENDIX 7.1 II HIGH GROWTH CASES
SELECTED RESOURCES VS. PEAK DAY DEMAND
EXISTING PLUS GTN FULLY SUBSCRIBED





APPENDIX 7.2 II PEAK DAY DEMAND TABLE
HIGH GROWTH

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
High Growth	2012	7.36	-	7.36	100%	255.74	-	255.74	100%
High Growth	2013	7.49	-	7.49	100%	262.63	-	262.63	100%
High Growth	2014	7.62	-	7.62	100%	270.77	-	270.77	100%
High Growth	2015	7.78	-	7.78	100%	279.05	-	279.05	100%
High Growth	2016	7.91	-	7.91	100%	287.20	-	287.20	100%
High Growth	2017	8.04	-	8.04	100%	295.46	-	295.46	100%
High Growth	2018	8.16	-	8.16	100%	303.56	-	303.56	100%
High Growth	2019	8.28	-	8.28	100%	311.65	-	311.65	100%
High Growth	2020	8.40	-	8.40	100%	314.09	5.68	319.78	98%
High Growth	2021	8.52	-	8.52	100%	314.09	13.84	327.93	96%
High Growth	2022	8.64	-	8.64	100%	314.09	22.08	336.17	93%
High Growth	2023	8.76	-	8.76	100%	314.09	30.57	344.66	91%
High Growth	2024	8.88	-	8.88	100%	314.09	39.18	353.27	89%
High Growth	2025	9.01	-	9.01	100%	314.09	48.05	362.15	87%
High Growth	2026	9.10	0.05	9.15	99%	314.09	57.11	371.20	85%
High Growth	2027	9.10	0.19	9.29	98%	314.09	66.41	380.51	83%
High Growth	2028	9.10	0.35	9.45	96%	314.09	76.03	390.12	81%
High Growth	2029	9.10	0.52	9.62	95%	314.09	86.07	400.17	78%
High Growth	2030	9.10	0.70	9.80	93%	314.09	96.63	410.72	76%
High Growth	2031	9.10	0.90	10.00	91%	314.09	107.92	422.01	74%

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
High Growth	2012	12.97	-	12.97	100%	68.57	-	68.57	100%
High Growth	2013	13.20	-	13.20	100%	69.66	-	69.66	100%
High Growth	2014	13.52	-	13.52	100%	71.48	-	71.48	100%
High Growth	2015	13.89	-	13.89	100%	73.71	-	73.71	100%
High Growth	2016	14.28	-	14.28	100%	76.14	-	76.14	100%
High Growth	2017	14.66	-	14.66	100%	78.67	-	78.67	100%
High Growth	2018	15.00	0.02	15.02	100%	81.19	-	81.19	100%
High Growth	2019	15.00	0.38	15.38	98%	83.69	-	83.69	100%
High Growth	2020	15.00	0.73	15.73	95%	84.12	2.05	86.17	98%
High Growth	2021	15.00	1.09	16.09	93%	84.12	4.55	88.66	95%
High Growth	2022	15.00	1.45	16.45	91%	84.12	7.04	91.15	92%
High Growth	2023	15.00	1.81	16.81	89%	84.12	9.56	93.68	90%
High Growth	2024	15.00	2.18	17.18	87%	84.12	12.19	96.30	87%
High Growth	2025	15.00	2.56	17.56	85%	84.12	14.87	98.98	85%
High Growth	2026	15.00	2.96	17.96	84%	84.12	17.65	101.77	83%
High Growth	2027	15.00	3.37	18.37	82%	84.12	20.53	104.64	80%
High Growth	2028	15.00	3.79	18.79	80%	84.12	23.45	107.57	78%
High Growth	2029	15.00	4.23	19.23	78%	84.12	26.32	110.44	76%
High Growth	2030	15.00	4.70	19.70	76%	84.12	29.30	113.42	74%
High Growth	2031	15.00	5.20	20.20	74%	84.12	32.50	116.61	72%

APPENDIX 7.2 II PEAK DAY DEMAND TABLE
LOW GROWTH

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
Low Growth	2012	7.23	-	7.23	100%	254.74	-	254.74	100%
Low Growth	2013	7.28	-	7.28	100%	257.33	-	257.33	100%
Low Growth	2014	7.33	-	7.33	100%	260.42	-	260.42	100%
Low Growth	2015	7.39	-	7.39	100%	263.55	-	263.55	100%
Low Growth	2016	7.44	-	7.44	100%	266.63	-	266.63	100%
Low Growth	2017	7.48	-	7.48	100%	269.67	-	269.67	100%
Low Growth	2018	7.52	-	7.52	100%	272.62	-	272.62	100%
Low Growth	2019	7.56	-	7.56	100%	275.55	-	275.55	100%
Low Growth	2020	7.61	-	7.61	100%	278.45	-	278.45	100%
Low Growth	2021	7.65	-	7.65	100%	281.36	-	281.36	100%
Low Growth	2022	7.69	-	7.69	100%	284.23	-	284.23	100%
Low Growth	2023	7.72	-	7.72	100%	287.17	-	287.17	100%
Low Growth	2024	7.76	-	7.76	100%	290.09	-	290.09	100%
Low Growth	2025	7.80	-	7.80	100%	293.06	-	293.06	100%
Low Growth	2026	7.84	-	7.84	100%	295.98	-	295.98	100%
Low Growth	2027	7.88	-	7.88	100%	298.91	-	298.91	100%
Low Growth	2028	7.92	-	7.92	100%	301.81	-	301.81	100%
Low Growth	2029	7.97	-	7.97	100%	304.74	-	304.74	100%
Low Growth	2030	8.01	-	8.01	100%	307.63	-	307.63	100%
Low Growth	2031	8.05	-	8.05	100%	310.55	-	310.55	100%

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
Low Growth	2012	9.51	-	9.51	100%	68.19	-	68.19	100%
Low Growth	2013	9.58	-	9.58	100%	68.60	-	68.60	100%
Low Growth	2014	9.68	-	9.68	100%	69.28	-	69.28	100%
Low Growth	2015	9.79	-	9.79	100%	70.12	-	70.12	100%
Low Growth	2016	9.90	-	9.90	100%	71.04	-	71.04	100%
Low Growth	2017	9.99	-	9.99	100%	71.97	-	71.97	100%
Low Growth	2018	10.08	-	10.08	100%	72.90	-	72.90	100%
Low Growth	2019	10.17	-	10.17	100%	73.80	-	73.80	100%
Low Growth	2020	10.26	-	10.26	100%	74.70	-	74.70	100%
Low Growth	2021	10.35	-	10.35	100%	75.58	-	75.58	100%
Low Growth	2022	10.44	-	10.44	100%	76.46	-	76.46	100%
Low Growth	2023	10.53	-	10.53	100%	77.33	-	77.33	100%
Low Growth	2024	10.62	-	10.62	100%	78.23	-	78.23	100%
Low Growth	2025	10.71	-	10.71	100%	79.12	-	79.12	100%
Low Growth	2026	10.80	-	10.80	100%	80.03	-	80.03	100%
Low Growth	2027	10.89	-	10.89	100%	80.94	-	80.94	100%
Low Growth	2028	10.98	-	10.98	100%	81.83	-	81.83	100%
Low Growth	2029	11.07	-	11.07	100%	82.65	-	82.65	100%
Low Growth	2030	11.15	-	11.15	100%	83.45	-	83.45	100%
Low Growth	2031	11.24	-	11.24	100%	84.09	-	84.09	100%

APPENDIX 7.2 II PEAK DAY DEMAND TABLE COLDEST IN 20 YEARS

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
Coldest in 20	2012	7.23	-	7.23	100%	230.63	-	230.63	100%
Coldest in 20	2013	7.31	-	7.31	100%	234.53	-	234.53	100%
Coldest in 20	2014	7.20	-	7.20	100%	232.87	-	232.87	100%
Coldest in 20	2015	7.23	-	7.23	100%	235.45	-	235.45	100%
Coldest in 20	2016	7.29	-	7.29	100%	239.40	-	239.40	100%
Coldest in 20	2017	7.36	-	7.36	100%	243.63	-	243.63	100%
Coldest in 20	2018	7.42	-	7.42	100%	247.71	-	247.71	100%
Coldest in 20	2019	7.46	-	7.46	100%	250.95	-	250.95	100%
Coldest in 20	2020	7.50	-	7.50	100%	254.42	-	254.42	100%
Coldest in 20	2021	7.56	-	7.56	100%	258.24	-	258.24	100%
Coldest in 20	2022	7.58	-	7.58	100%	261.16	-	261.16	100%
Coldest in 20	2023	7.61	-	7.61	100%	264.03	-	264.03	100%
Coldest in 20	2024	7.64	-	7.64	100%	267.26	-	267.26	100%
Coldest in 20	2025	7.67	-	7.67	100%	270.30	-	270.30	100%
Coldest in 20	2026	7.70	-	7.70	100%	273.64	-	273.64	100%
Coldest in 20	2027	7.73	-	7.73	100%	276.33	-	276.33	100%
Coldest in 20	2028	7.76	-	7.76	100%	279.33	-	279.33	100%
Coldest in 20	2029	7.80	-	7.80	100%	282.24	-	282.24	100%
Coldest in 20	2030	7.83	-	7.83	100%	285.11	-	285.11	100%
Coldest in 20	2031	7.86	-	7.86	100%	287.97	-	287.97	100%

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
Coldest in 20	2012	12.69	-	12.69	100%	59.07	-	59.07	100%
Coldest in 20	2013	12.83	-	12.83	100%	59.66	-	59.66	100%
Coldest in 20	2014	12.68	-	12.68	100%	59.08	-	59.08	100%
Coldest in 20	2015	12.79	-	12.79	100%	59.75	-	59.75	100%
Coldest in 20	2016	13.00	-	13.00	100%	60.91	-	60.91	100%
Coldest in 20	2017	13.21	-	13.21	100%	62.15	-	62.15	100%
Coldest in 20	2018	13.40	-	13.40	100%	63.38	-	63.38	100%
Coldest in 20	2019	13.55	-	13.55	100%	64.38	-	64.38	100%
Coldest in 20	2020	13.70	-	13.70	100%	65.42	-	65.42	100%
Coldest in 20	2021	13.88	-	13.88	100%	66.55	-	66.55	100%
Coldest in 20	2022	14.01	-	14.01	100%	67.53	-	67.53	100%
Coldest in 20	2023	14.13	-	14.13	100%	68.38	-	68.38	100%
Coldest in 20	2024	14.27	-	14.27	100%	69.35	-	69.35	100%
Coldest in 20	2025	14.40	-	14.40	100%	70.28	-	70.28	100%
Coldest in 20	2026	14.54	-	14.54	100%	71.28	-	71.28	100%
Coldest in 20	2027	14.65	-	14.65	100%	72.13	-	72.13	100%
Coldest in 20	2028	14.78	-	14.78	100%	73.04	-	73.04	100%
Coldest in 20	2029	14.91	-	14.91	100%	73.83	-	73.83	100%
Coldest in 20	2030	15.02	-	15.02	100%	74.59	-	74.59	100%
Coldest in 20	2031	15.14	-	15.14	100%	75.44	-	75.44	100%

APPENDIX 8.1 II DISTRIBUTION SYSTEM MODELING

OVERVIEW

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

COMPUTER MODELING

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

THEORY AND APPLICATION OF STUDY

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

CREATING A MODEL

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

Nodes are placed at all pipe intersections, beginnings and ends of mains, changes in pipe diameter/material and to identify all large customers. A model element connects two nodes together. Therefore, a "to node" and a "from node" will represent an element between those two nodes. Almost all of the elements in a model are pipes.

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

FLUID MECHANICS OF THE MODEL

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

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

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

LOAD DATA

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

Customer loads are obtained from Avista's customer billing system and converted to an algebraic format so loads can be generated for various conditions. Customer Management Module (CMM), a new add-on application for SynerGEE processes customer usage history and generates a base load (non-temperature dependent) and heat load (varying with temperature) for each customer.

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

DETERMINING NATURAL GAS CUSTOMERS' MAXIMUM HOURLY USAGE

DETERMINING DESIGN PEAK HOURLY LOAD

The design peak hourly load for a customer is estimated by adding the hourly base load and the hourly heat load for a design temperature. This estimate reflects highest system hourly demands, as shown in Table 1:

Table 1 - Determining Peak* Hourly Load

Peak Hourly Base Load	+	Peak Hourly Heat Load	=	Peak Hourly Load

This method differs from the approach that we use for IRP peak day load planning. The primary reason for this difference is due to the importance of responding to hourly peaking in the distribution system, while IRP resource planning focuses on peak day requirements to the city gate.

APPLYING LOADS

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

GENERATING LOADS

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

GEOGRAPHIC INFORMATION SYSTEM (GIS)

Several years ago we converted our natural gas facility maps to GIS. While the GIS can provide a variety of map products, its power lies in its analytical capability. A GIS consists of three components: spatial operations, data association and map representation.

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

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

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

Finally, the GIS provides a means to create maps of existing facilities in different scales, projections and displays. In addition, the results of a comparative or spatial analysis can be presented pictorially. This allows users to present complex analyses rapidly and in an easy-to-understand method.

BUILDING SYNERGEE® MODELS FROM A GIS

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

MAINTENANCE USING A GIS

The GIS helps maintain the existing distribution facility by allowing a design to be initiated on a GIS. Currently, design jobs for the company's natural gas system are managed through Avista's Facility Management (AFM) tool. Once jobs are completed, the as-built information is automatically updated on GIS, eliminating the need to convert physical maps to a GIS at a later date. Because the facility is updated , load studies can remain current by refreshing the analysis.

DEVELOPING A PRESENT CASE LOAD STUDY

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

Pressure charts plot pressure (some include temperature) versus time over several days. Various locations recording simultaneously are used to validate the model. Customer loads on SynerGEE® are generated to correspond with actual temperatures recorded on the pressure charts. An accurate model's downstream

pressures will match the corresponding location's field pressure chart. Efficiency factors are fine-tuned to further refine the model's pressures.

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

DEVELOPING A PEAK CASE LOAD STUDY

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

ANALYZING RESULTS

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

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

PLANNING CRITERIA

In most instances, models resulting in node pressures below 15 psig indicate a likelihood of distribution low pressure and therefore necessitate reinforcements. For most Avista distribution systems, a minimum of 15 psig will ensure deliverability as natural gas exits the distribution mains and travels through service pipelines to a customer's meter. Some Avista distribution areas operate at lower pressures and are assigned a minimum pressure of 5 psig for model results. Given a lower operating pressure, service pipelines in such areas are sized accordingly to maintain reliability.

DETERMINING MAXIMUM CAPACITY FOR A SYSTEM

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

Since the approximate natural gas usage for the average customer is known, it can be determined how many new customers can be added to the distribution system before necessitating system reinforcements. The above models and procedures are utilized with new construction proposals or pipe reinforcements to determine the potential increase in capacity.

FIVE-YEAR FORECASTING

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

By combining information from Avista's demand forecast, IRP planning efforts, regional growth plans and area developments, proposals for pipeline reinforcements and expansions can be evaluated with SynerGEE®.