AVISTA

Avista Corp.
1411 East Mission P.O. Box 3727
Spokane. Washington 99220-0500
Telephone 509-489-0500
Toll Free 800-727-9170

August 29, 2014

Oregon Public Utility Commission
Attn: Vikie Bailey-Goggins
Administrative Regulatory Operations
550 Capitol St. N.E. Suite 215
Salem, OR 97308-2551

Attention: Filing Center

RE: Avista Utilities 2014 Natural Gas Integrated Resource Plan (IRP)

Filing Center:

Per Commission Order No. 89-507, 07-002 and UM 1056, Avista Corporation d/b/a/ Avista Utilities, hereby submits for filing an original and five (5) copies of its 2014 Natural Gas Integrated Resource Plan. An electronic copy of the IRP and appendices are also enclosed. Also enclosed and in compliance with Order No. 13-159, in No. Docket LC 55, is the completed Action Plan for 2013 and 2014 specific to the Company's Oregon service territory.

The Company submits the IRP to Public Utility Commissions in Oregon, Idaho, and Washington every two years as required by state regulation. The Company has a statutory obligation to provide reliable natural gas service to customers at rates, terms and conditions that are fair, just, reasonable and sufficient. The IRP, by identifying and evaluating various resource options and establishing a plan of action for resource decisions, is a significant component in meeting this obligation.

The 2014 Plan highlights the following:

- Avista reliably provides natural gas to our customers with an appropriate balance of price stability and prudent cost using our portfolio of purchase contracts, storage and firm pipeline capacity rights;

- The Company forecasts sufficient natural gas resources well into the future with resource needs not occurring during the 20 year planning horizon;

- Expected customer growth has continued to slow since the 2012 IRP with expected customer growth now 1% annually compared to 1.8% in the 2012 IRP and it is not anticipated to rebound in the near term and also use per customer has declined;

- The price of natural gas has remained low and Avista expects it to remain low for quite some time even with increased incremental demand for LNG exports, transportation fuels, and increased industrial consumption; and

- As forecasted demand is relatively flat, the Company will continue to monitor actual demand for signs of increased growth which could accelerate resource needs.

Please direct any questions regarding this report to Tom Pardee at (509) 495-2159 or myself at (509)-495-4975.

Sincerely,

Linda Gervais

Linda Gervais
Manager, Regulatory Policy
State and Federal Regulation
Avista Utilities
509-495-4975
linda.gervais@avistacorp.com

Attachment

cc: Ms. Lisa Gorsuch
Mr. Erik Colville

2013-2014 ACTION PLAN RESULTS – OREGON SPECIFIC ITEMS

Per Order No. 13-159 in Docket LC 55, the following provides an explanation of the results of the Action Items included within the Commission's Order acknowledging Avista's 2012 Natural Gas IRP.

Action Item
The Company will continue DSM programs in Oregon and achieve a minimum savings of 225,000 therms in 2013 and 250,000 therms in 2014.

Results
Avista continued its DSM program in Oregon during 2013 and 2014. Savings for all programs in 2013 totaled 217,177 therms or 97% of the 2013 minimum goal.

Action Item
Two years from the date of acknowledgement of this IRP, Avista will provide the results of the following:

- Savings and cost effectiveness of the DSM program.
- Actions taken to reduce delivery costs, including administration costs and audit costs.
- Actions taken to increase the number of cost effective efficiency measures in the portfolio.
- An analysis of non-natural gas benefits of existing and proposed DSM measures.
- An analysis of measure lives for all measures.

Results
We have taken many steps to increase the cost effectiveness of the DSM program. Specifically, measure lives were extended for numerous measures, certain tariff changes were implemented to reduce administration costs, audit costs were separated from other program costs, a new software program is being implemented for calculating project savings, and a separate low-income energy efficiency program was created. We are continuing to evaluate additional changes to increase the cost effectiveness of individual measures and the entire program.

Action Item
Within six months of the date of acknowledgement of this IRP, Avista will develop a potential mechanism for allocating funding for a separate low-income energy efficiency program, and will submit a report to Staff outlining the mechanism.

Results
Avista worked with Staff and other stakeholders on the development of a low-income energy efficiency program and submitted a report to Staff outlining a proposed mechanism on October 30, 2013. Pursuant to the proposal the Company filed tariffs to implement the Avista Oregon

Low-Income Energy Efficiency (AOLIEE) Program on January 8, 2014. The tariffs were approved and the AOLIEE Program commenced on March 1, 2014.

Action Item

Pursue the possibility of a regional elasticity study through the Northwest Gas Association or possibly the American Gas Association.

Results

Price elasticity theory predicts that energy consumers will reduce consumption as prices rise. The amount of a response is debatable. Avista has reviewed historic research on price elasticity. The analysis shows a wide range of results from statistically significant to statistically insignificant and even positive in some cases.

Avista contacted the NGA and they are still willing to help facilitate a process if a regional price elasticity study moves forward. At this time, Avista is assessing the costs and benefits of such an undertaking. A regional natural gas price elasticity study will commence if enough interest develops in the project.

Action Item

Assess potential demand impact from NGV/CNG vehicles and other new uses of natural gas.

Results

In our assessment of potential demand impact due to NGV/CNG vehicles, our model results show a direct sensitivity to NGV/CNG vehicles. This results in an increase of 9 MDT on a February 20th peak day as compared to the reference case. In the case of Exported LNG, our price elasticity sensitivity shows a decrease in usage in direct response to higher pricing. The analysis timeframe is over the IRP's 20 year horizon with no shortages on a peak day in either case.

2014 Natural Gas Integrated Resource Plan

August 31, 2014

Safe Harbor Statement

This document contains forward-looking statements. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond the Company's control, and many of which could have a significant impact on the Company's operations, results of operations and financial condition, and could cause actual results to differ materially from those anticipated.

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. The forward-looking statements contained in this document speak only as of the date hereof. The Company undertakes 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 the Company's 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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Executive Summary

Avista Corporation's 2014 Natural Gas Integrated Resource Plan (IRP) identifies a strategic natural gas resource portfolio to meet customer demand requirements over the next 20 years. While the primary focus of the IRP is meeting customers' 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 agencies, 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, modeling tools, and distribution planning. The process results in a resource portfolio designed to serve our customers' natural gas needs while balancing cost and risk.

Avista's collaborative planning process results in a resource portfolio that meets customers' long-term needs considering cost and risk.

Planning Environment

A long- term resource plan must address the uncertainties inherent in any planning exercise. Compared to prior planning cycles, there is more certainty about the availability of natural gas and that much of it can be extracted at favorable prices for consumers. However, some of the uses of this plentiful and economic energy resource are unknown. There are questions concerning an industrial renaissance, the amount of liquefied natural gas (LNG) exports, the market for natural gas vehicles, and power generation. We continue to challenge key assumptions by evaluating multiple scenarios over a range of possible outcomes to address the uncertainties.

Demand Forecasts

Avista defines eight distinct demand areas in this IRP structured around the pipeline transportation and storage resources that serve them. Demand areas include four large Avista 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 includes areas served only by Northwest Pipeline (NWP), only by Gas Transmission Northwest (GTN), and by both pipelines. The Medford service territory includes an area 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. Avista recognizes and accounts for weather as the most significant direct demand-influencing factor. Other demand influencing factors studied include population, employment trends, age and income demographics, construction trends, conservation technology, new uses (e.g. natural gas vehicles), and use-per-customer trends.

Recognizing that customers may adjust consumption in response to price, Avista 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).

Avista 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, Avista created several alternate demand scenarios for detailed analysis. Table 1 summarizes these scenarios, which represent a range of potential outcomes. The Average Case represents Avista's demand forecast for normal planning purposes. The Expected Case is the most likely scenario for peak day planning purposes.

Table 1: Demand Scenarios

2014 IRP Demand Scenarios
Average Case
Expected Case
High Growth, Low Price
Low Growth, High Price
Alternate Weather Standard

The IRP process defines the methodology for the development of two primary types of demand forecasts – annual average daily and peak day. The annual average daily demand forecast is useful for preparing revenue budgets, developing natural gas procurement plans, and preparing purchased gas adjustment filings. Forecasts of peak day demand 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 as shown in Table 2:

Annual Average Daily Demand – Expected average day, system-wide core demand increases from an average of 91,352 dekatherms per day (Dth/day) in 2014 to 102,937 Dth/day in 2033. This is an annual average growth rate of 0.7 percent and is net of projected conservation savings from DSM programs. Appendix 3.9 shows gross demand, DSM savings and net demand.

Peak Day Demand – Expected coincidental peak day, system-wide core demand increases from a peak of 358,736 Dth/day in 2014 to 404,122 Dth/day in 2033. Forecasted non-coincidental peak day demand peaks at 333,129 Dth/day in 2014 and increases to 375,747 Dth/day in 2033 a 0.6 percent compounded growth rate in peak day requirements. This is also net of projected conservation savings from DSM programs.

Table 2: Annual Average and Peak Day Demand Cases (Dth/day)

Year	Annual Average Daily Demand	Peak Day Demand	Non-coincidental Peak Day Demand
2014	91,352	358,736	333,129
2033	102,937	404,122	375,747

Figure 1 shows forecasted average daily demand for the five main demand scenarios modeled over the IRP planning horizon.

Figure 1: Average Daily Demand

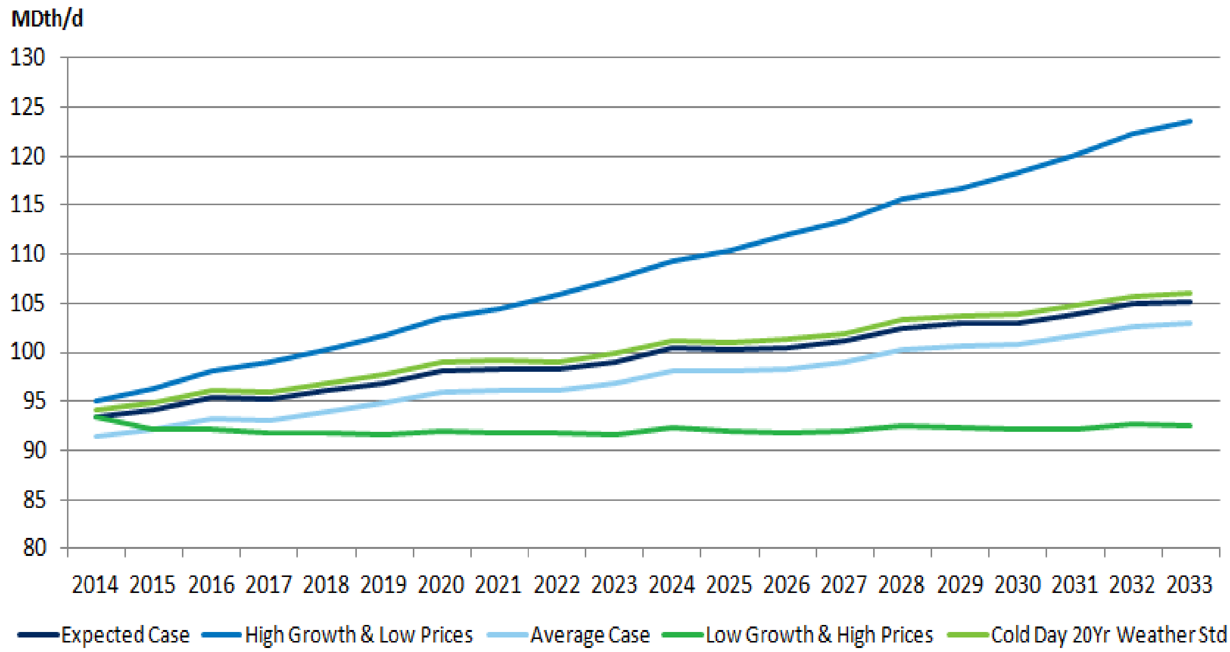
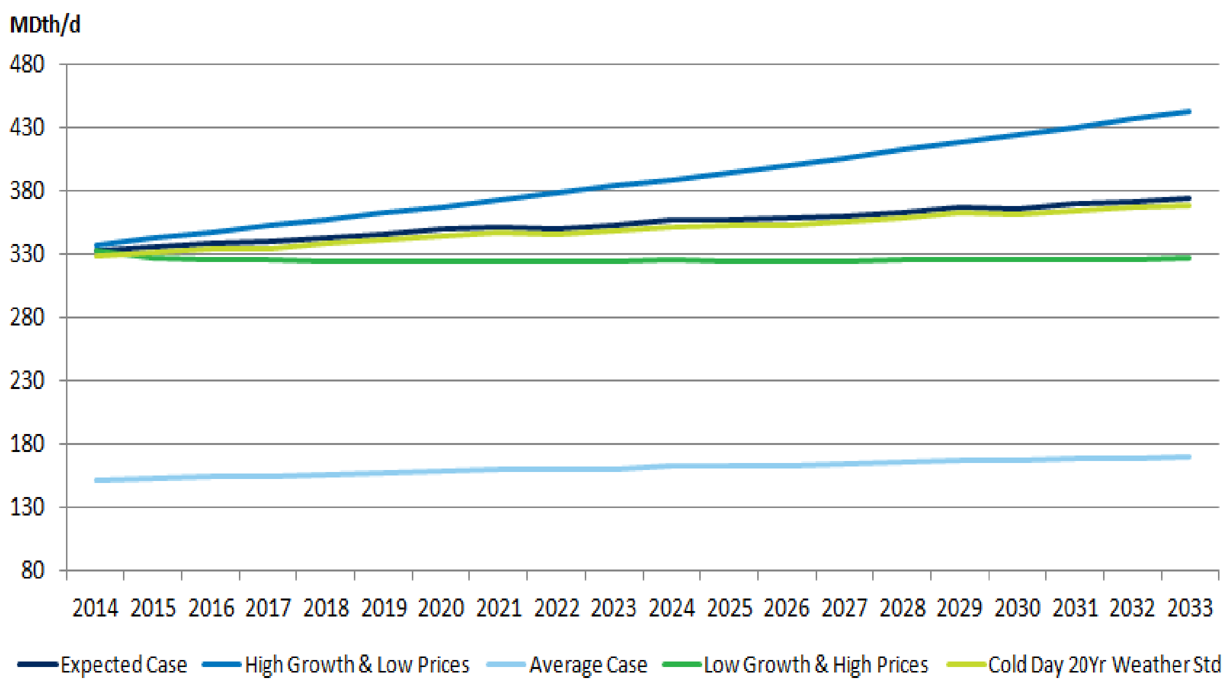


Figure 2 shows forecasted system-wide peak day demand for the five main demand scenarios modeled over the IRP planning horizon.

Figure 2: Peak Day Demand Scenarios (Net of DSM Savings)



Natural Gas Price Forecasts

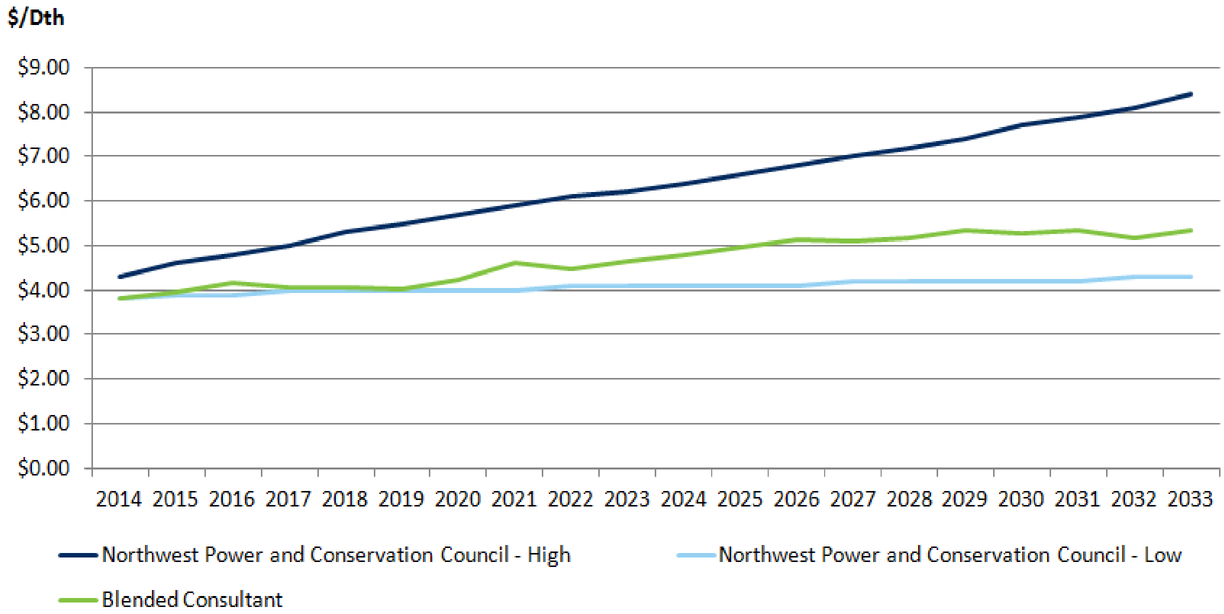
Natural gas prices are a fundamental component of integrated resource planning because the commodity price is a significant component of the total cost of a resource option. This affects the avoided cost threshold for determining cost-effectiveness of conservation measures. The price of natural gas also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

With more information known about the costs and volumes produced by shale gas there appears to be consensus that production costs will continue to stay low for quite some time. Avista expects continued low prices even with increased incremental demand for LNG exports, transportation fuels, and increased industrial consumption.

The carbon legislation debate continues. Avista's current thinking is that carbon legislation at the federal level may not occur, but will occur at the state level or in a regulatory setting like the Environmental Protection Agency's (EPA) recent proposals to regulate carbon emissions from electric generation. Current IRP price forecasts include a lower federal carbon tax that occurs later than prior IRPs. To address the uncertainty about carbon legislation, Avista analyzed three carbon sensitivities and their impact to the demand forecasts.

Avista reviewed several price forecasts from credible sources and selected high, medium, and low price forecasts to represent a reasonable range of pricing possibilities for the IRP analysis. The range of prices provides necessary variation for addressing uncertainty of future prices. Figure 1.3 depicts the price forecasts used in this IRP.

Figure 3: Low/Medium/High Henry Hub Forecasts (Real $/Dth)



Historical statistical analysis shows a long run consumption response to price changes. In order to model consumption response to these price curves, Avista utilized an expected elasticity response factor that was applied under various scenarios. Avista will continue to monitor and research this assumption and make any necessary adjustments as described in the Ongoing Activities section of Chapter 8 – Action Items.

Existing and Potential Resources

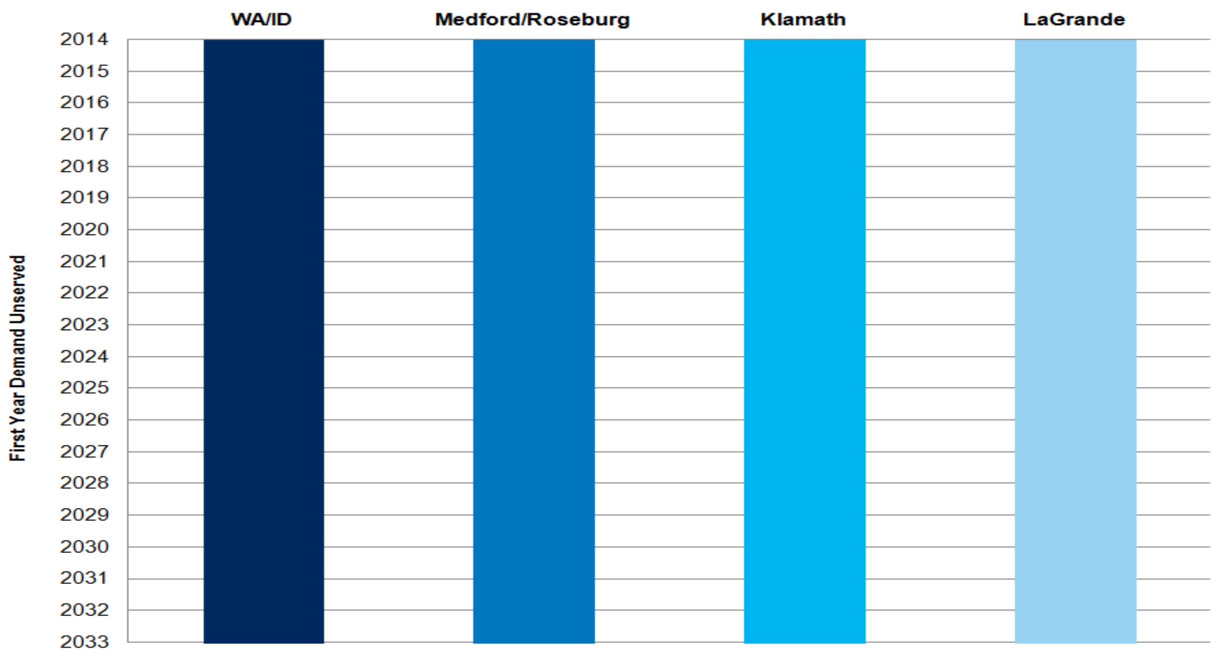
Avista has a diversified portfolio of natural gas supply resources, including access to and contracts for the purchase of natural gas from several supply basins; owned and contracted storage providing supply source flexibility; and firm capacity rights on six pipelines. For potential resource additions, Avista considers incremental pipeline transportation, storage options, distribution enhancements, and various forms of LNG storage or service.

Avista models aggregated conservation potential that reduces demand if the conservation programs are cost-effective over the planning horizon. The identification and incorporation of conservation savings into the SENDOUT® model utilize projected natural gas prices and the estimated cost of alternative supply resources. The operational business planning process starts with IRP identified savings and ultimately determines the near term program offerings. Given current avoided costs, a limited number of programs are cost effective in Idaho, Oregon, and Washington. Currently, Avista is not running natural gas DSM programs in Idaho. Avista actively promotes cost-effective efficiency measures to our customers as one component of a comprehensive strategy to arrive at mix of best cost/risk adjusted resources.

Resource Needs

In the Average Case demand scenario, using Avista's existing supply resources, the analysis showed no resource deficiencies in the 20-year planning horizon. The Expected Case demand scenario, using the existing resources, determined when the first year peak day demand would not be fully served. Figure 4 summarizes the results of this portfolio. Avista is not resource deficient in the Expected Case in the 20-year planning horizon.

Figure 4: Expected Case – First Year Demand Not Met with Existing Resources



Figures 5 through 8 illustrate Avista's peak day demand by service territory for both this and the prior IRP. These charts compare existing peak day resources to expected peak day demand by year and show the timing and extent of resource deficiencies, if any, for the Expected Case. Based on this information, Avista has time to carefully monitor, plan and take action on potential resource additions as described in Chapter 8 – Ongoing Activities.

Figure 5: Expected Case – WA/ID Existing Resources vs. Peak Day Demand (Net of DSM)

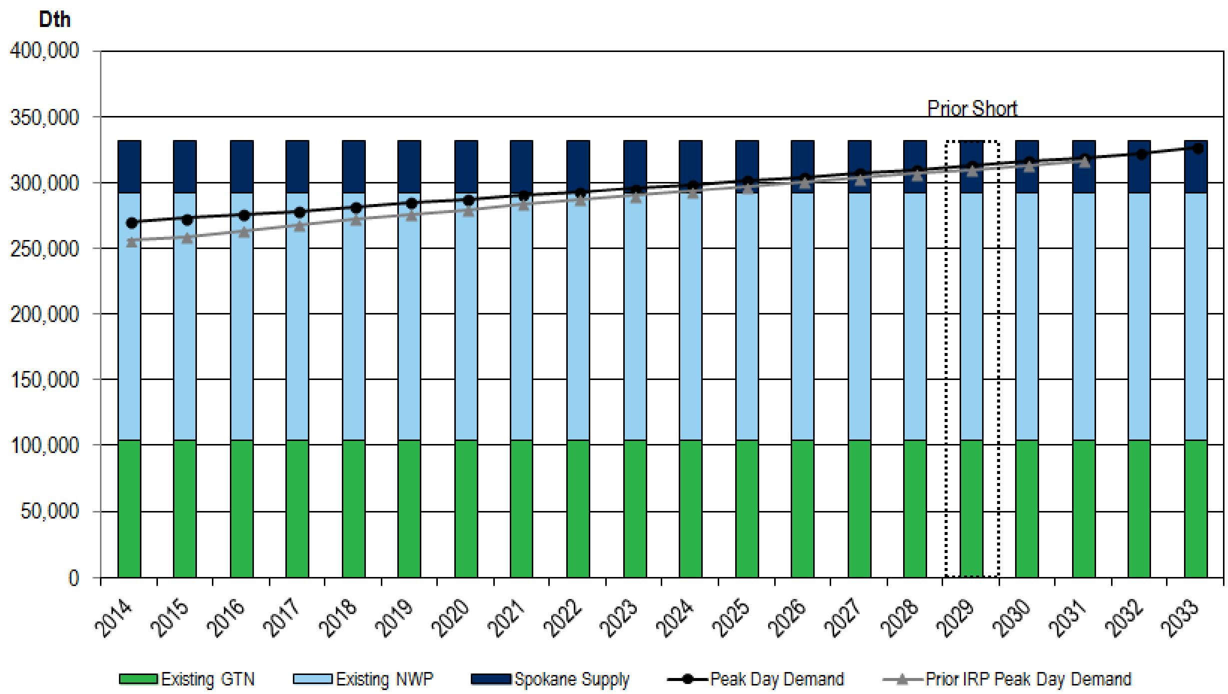


Figure 6: Expected Case – Medford/Roseburg Existing Resources vs. Peak Day Demand (Net of DSM)

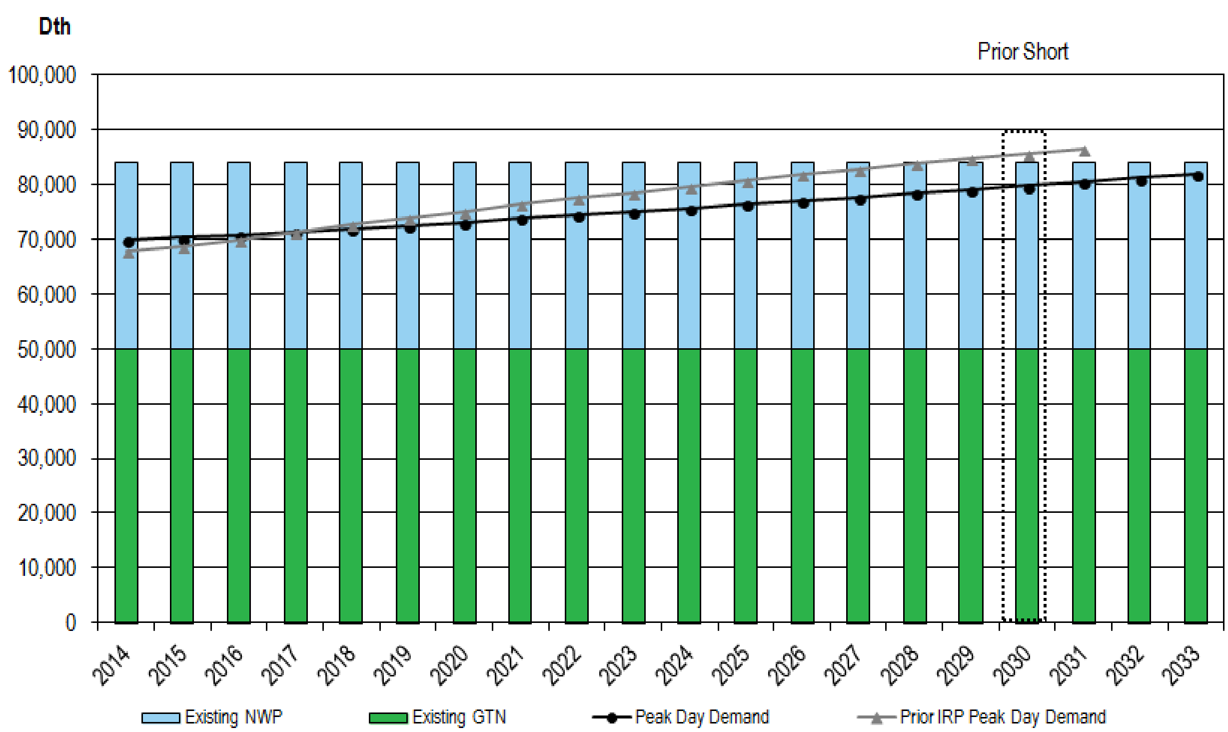


Figure 7: Expected Case – Klamath Falls Existing Resources vs. Peak Day Demand (Net of DSM)

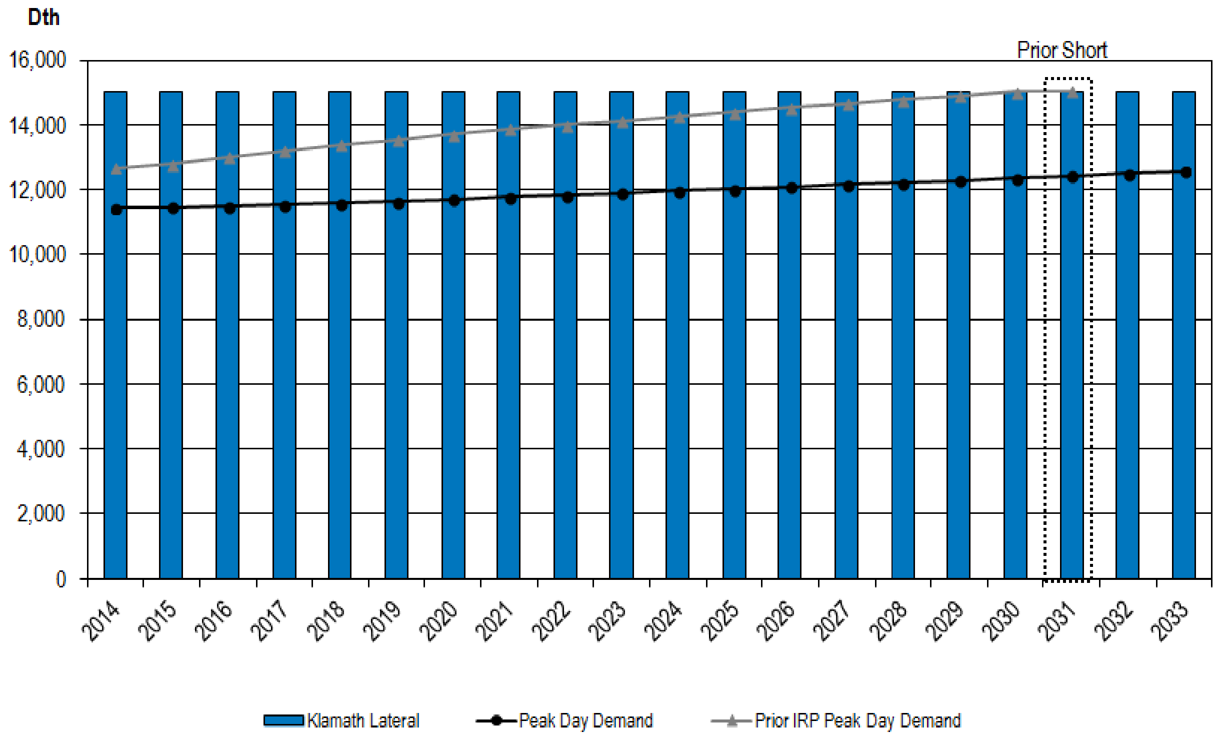
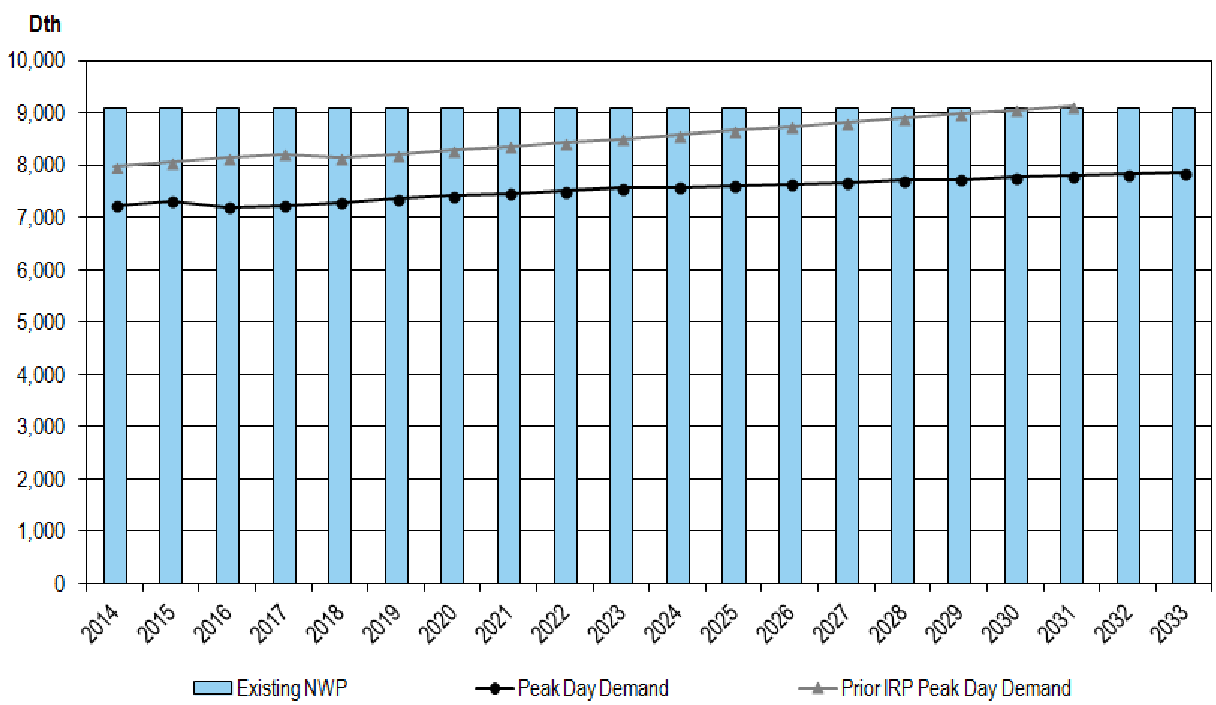
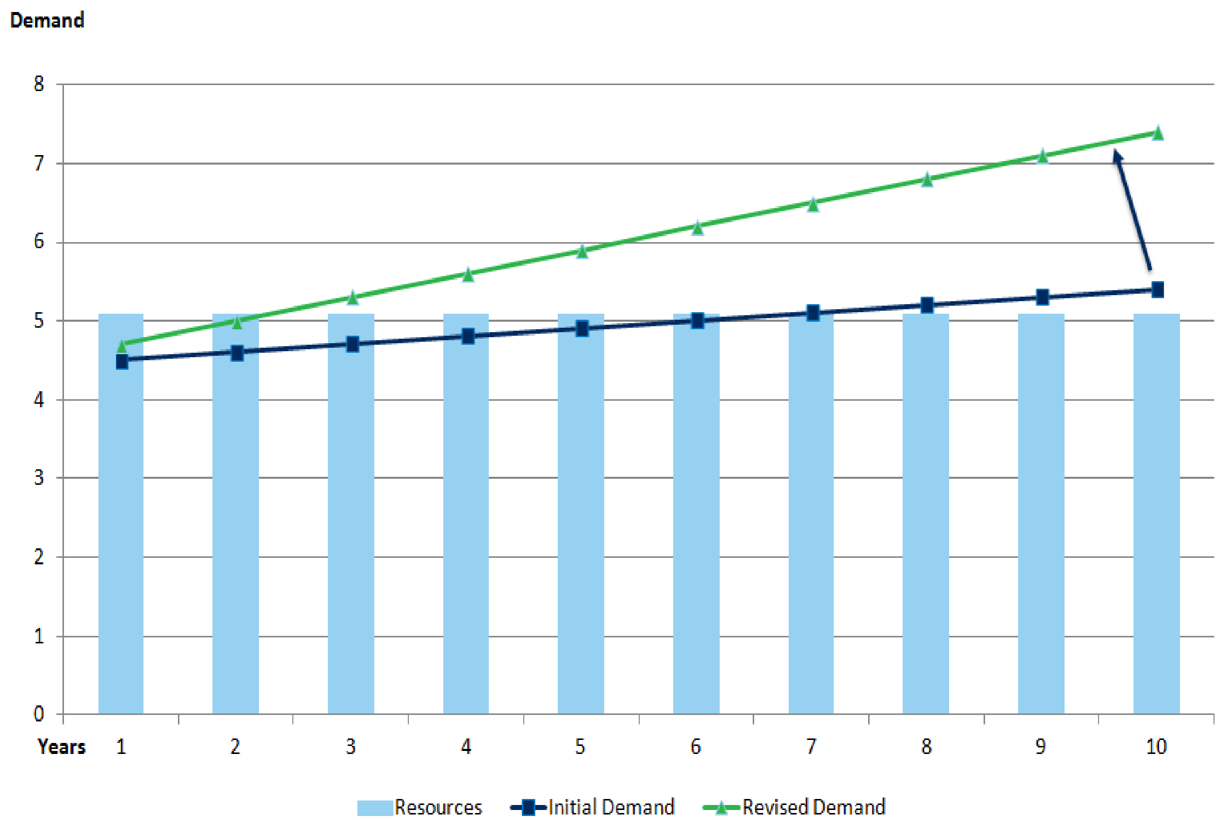


Figure 8: Expected Case – La Grande Existing Resources vs. Peak Day Demand (Net of DSM)



A critical risk is the slope of forecasted demand growth, which is almost flat in Avista's current projections. This outlook implies that existing resources will be sufficient within the planning horizon 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.

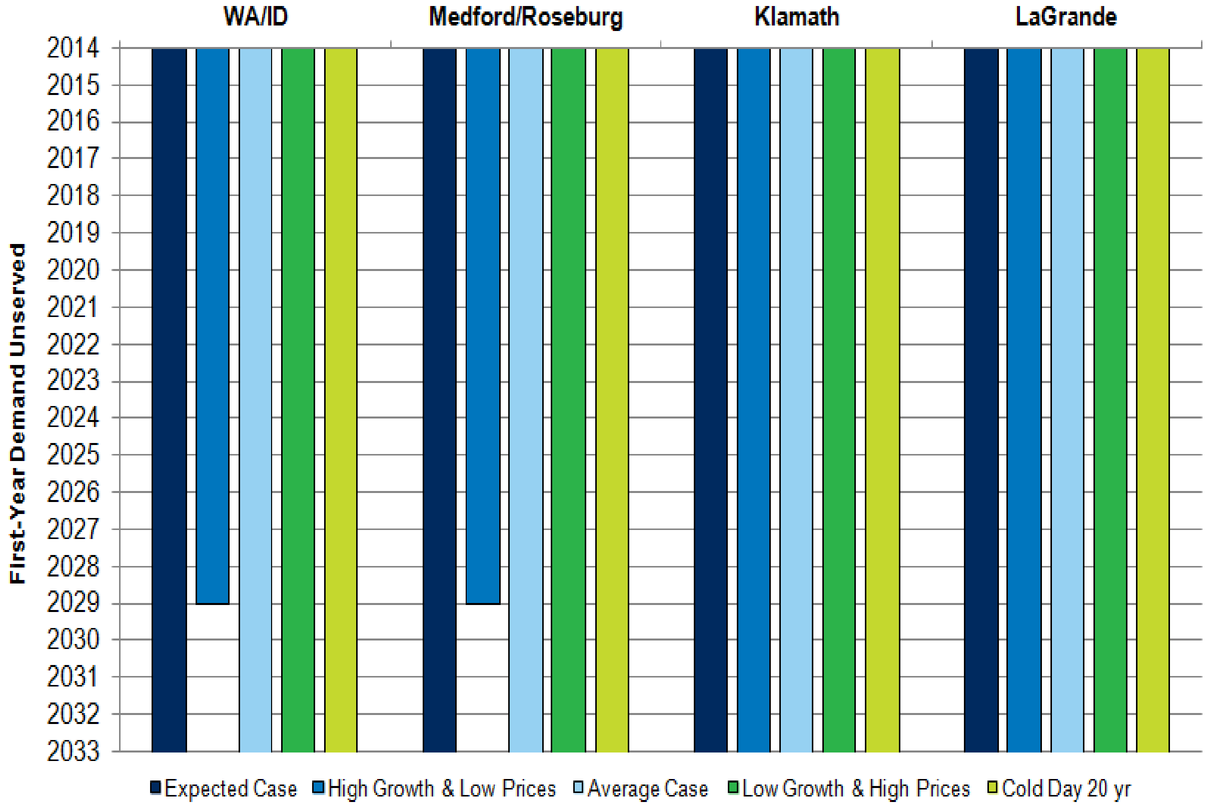
Figure 9: Flat Demand Risk Example



Alternate Demand Scenarios

Avista performed the same analysis for four other demand scenarios- Average, High Growth/Low Price, Low Growth/High Price, and Coldest in 20 years. As expected, the High Growth/Low Price scenario has the most rapid growth and is the only scenario with unserved demand. This "steeper" demand lessens the "flat demand risk" discussed above, yet resource deficiencies occur very late in the planning horizon. Figure 10 shows first year resource deficiencies under each scenario.

Figure 10: Scenario Comparisons of First Year Peak Demand Not Met with Existing Resources



Issues and Challenges

Even with the planning, analysis, and conclusions reached in this IRP, there is still uncertainty requiring diligent monitoring of the following issues and challenges.

Demand Issues

The recent recession had a significant impact on the future customer growth trajectory in Avista's service territory leading to a declining use per customer. Because of this the long-term forecast for natural gas demand has declined dramatically. Considering a broad range of demand scenarios provides insight into how quickly resource needs can change if demand varies from the Expected Case.

With an increase in natural supply and subsequent low costs, there is increasing interest in using natural gas. Avista does not anticipate that traditional residential and commercial customers will provide growth in demand. There is potential for increased natural gas usage in other markets, such as transportation fuel and power generation, or as an industrial feedstock. Most of these emerging markets will not be core customers of the LDC, however they will affect regional gas infrastructure and could affect natural gas pricing.

Price Issues
Shale gas has changed the face of North American gas supply. The abundance of shale along with lagging demand has created a near-term supply glut that kept prices at low levels. The winter of 2013-2014 brought increased demand and rebalanced the market, reversing the downward pricing trend. However, the relatively higher prices are a short-term phenomenon and forecasters anticipate a return to lower prices. This would be beneficial for customers, but experience has shown that markets can change quickly and dramatically. To address this uncertainty, this plan includes high and low price scenarios along with stochastic price analysis to capture a range of possible prices.

LNG Exports
The availability of plentiful amounts of natural gas in North America has changed global LNG dynamics. Existing and new LNG facilities are looking to export low cost North American gas to the higher priced Asian and European markets. In Canada, 16 LNG export projects are in various stages of the permitting process. In the Northwest, there are 2 proposed terminals in Oregon. How many of these terminals actually get approval and ultimately built is yet to be determined. However, LNG exporting has the potential to alter the price, constrain existing pipeline networks, stimulate development of new pipeline resources, and change flows of natural gas across North America.

Action Plan
Avista's 2015-2016 Action Plan outlines activities identified by the IRP team, with input 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 highlights key analytical needs 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 (Chapter 8 – Action Items).

The IRP analysis indicates there is no near term needs to acquire additional supply side resources to meet customer demand. Therefore, appropriate management of existing resources is paramount. Optimizing underutilized resources reduces costs to customers while providing reliability if customers' needs exceed forecasted expectations.

Avista also pursues cost-effective demand-side solutions, but recognizes the challenges of the current low cost environment. Within the IRP, Washington and Idaho conservation measures aim to reduce demand by approximately 151,500 dekatherms in 2015. In Oregon, conservation measures aim to reduce demand by approximately 16,100 dekatherms in 2015.

Avista will comply with Commission findings to try to increase the cost effectiveness of measures within the portfolio by reducing administration and audit costs, analyzing non-natural gas benefits, and increasing measure lives. Natural gas prices will be monitored as a leading indicator for increasing avoided costs. If avoided costs increase, DSM programs will be evaluated for cost-effectiveness and Avista will be proactive in submitting to the Commissions to resume natural gas DSM options.

Completion of the gate station analysis to assess any resource deficiencies masked by Avista's aggregated IRP analysis. Should deficiencies be identified we will discuss findings and potential solutions with Commission Staff. Avista will continue to coordinate analytic efforts between Gas Supply, Gas Engineering, and the intrastate pipelines to perform gate station analysis and develop least cost solutions for any future deficiencies.

Key ongoing components of the Action Plan include:

- Monitor actual demand for growth exceeding the 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. Avista will provide these updates to each Commission Staff at least bi-annually.
- Continue to monitor supply resource trends including the availability and price of natural gas to the region, LNG exports, Canadian natural gas supply availability and interprovincial consumption, and pipeline and storage infrastructure availability.
- Monitor availability of current resource options and assess new resource lead-time requirements relative to resource need to preserve flexibility.
- Meet regularly with Commission Staff to provide information on market activities and significant changes in assumptions and/or status of Avista activities related to the IRP or natural gas procurement practices.

CONCLUSION

Anticipated low customer growth has eliminated the need for Avista to acquire additional supply-side resources, therefore appropriate management of underutilized resources to reduce costs until resources are needed is essential. Additionally, the lower cost of natural gas continues to challenge the cost-effectiveness of DSM programs. While Avista believes adoption of conservation is the best strategy for minimizing costs to customers and promoting a cleaner environment, this IRP shows a lower conservation potential than previous IRP's because of the relatively low avoided cost of natural gas. The IRP has many objectives, but foremost is to ensure that proper planning will enable

Avista to continue delivering safe, reliable, and economic natural gas service to our customers.

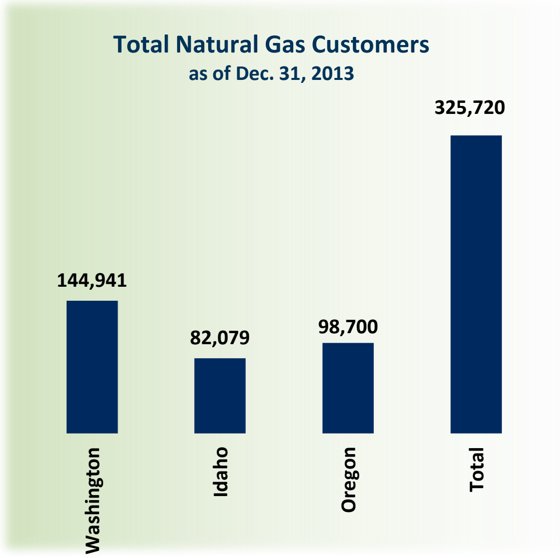
1: Introduction

Avista is involved in the production, transmission and distribution of natural gas and electricity, 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 125 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 NWP) to develop the Jackson Prairie natural gas underground storage facility in Chehalis, Wash. In 1991, Avista 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. Figure 1.1 shows where Avista currently provides natural gas service to approximately 325,000 customers in eastern Washington, northern Idaho and several communities in northeast and southwest Oregon. Figure 1.2 shows the number of natural gas customers by state.

Figure 1.1: Avista Service Territory

Figure 1.2: Avista's Natural Gas Customer Counts



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 470,000 followed by the Lewiston, Idaho/Clarkston, Washington and Coeur d'Alene, Idaho areas. The North Division has about 74 miles of natural gas distribution mains and 5,000 miles of distribution lines. The North Division receives natural gas at more than 40 points along interstate pipelines and distributes it to over 227,000 customers.
- The South Division serves four counties in southwest Oregon and one county in northeast Oregon. The combined population of these 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 290,000 residents. The South Division consists of about 67 miles of natural gas distribution mains and 2,000 miles of distribution lines. Avista receives natural gas at more than 20 points along interstate pipelines and distributes it to almost 96,000 customers.

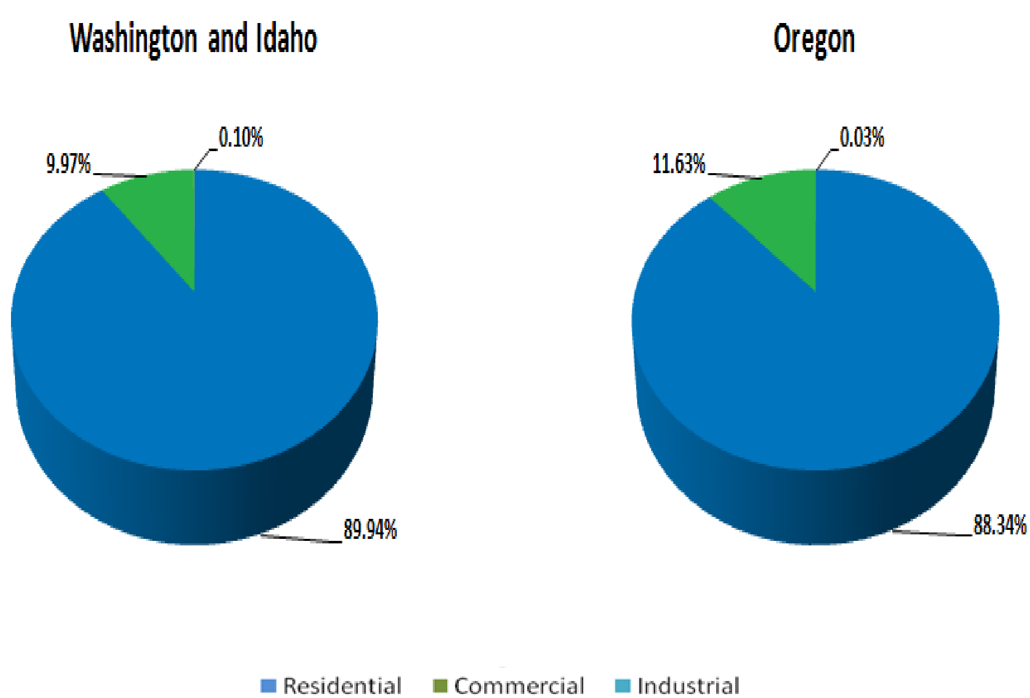
Customers

Avista provides natural gas services to “core” and “transportation-only” customer classes. Core or retail customers purchase natural gas directly from Avista with delivery to their home or business under a bundled rate. Core customers on firm rate schedules are entitled to receive any volume of gas they require. Some core customers are on interruptible rate schedules. These customers pay a lesser rate than firm customers since their service can be interrupted. Interruptible customers are not considered in peak day IRP planning.

Transportation-only customers purchase natural gas from third parties who deliver the purchased gas to our distribution system. Avista delivers this gas to their business charging a distribution rate only. Avista can interrupt the delivery service when following the priority of service tariff. The long-term resource planning exercise excludes transportation-only customers because they purchase their own gas and utilize their own interstate pipeline transportation contracts. However, distribution planning exercises include these customers.

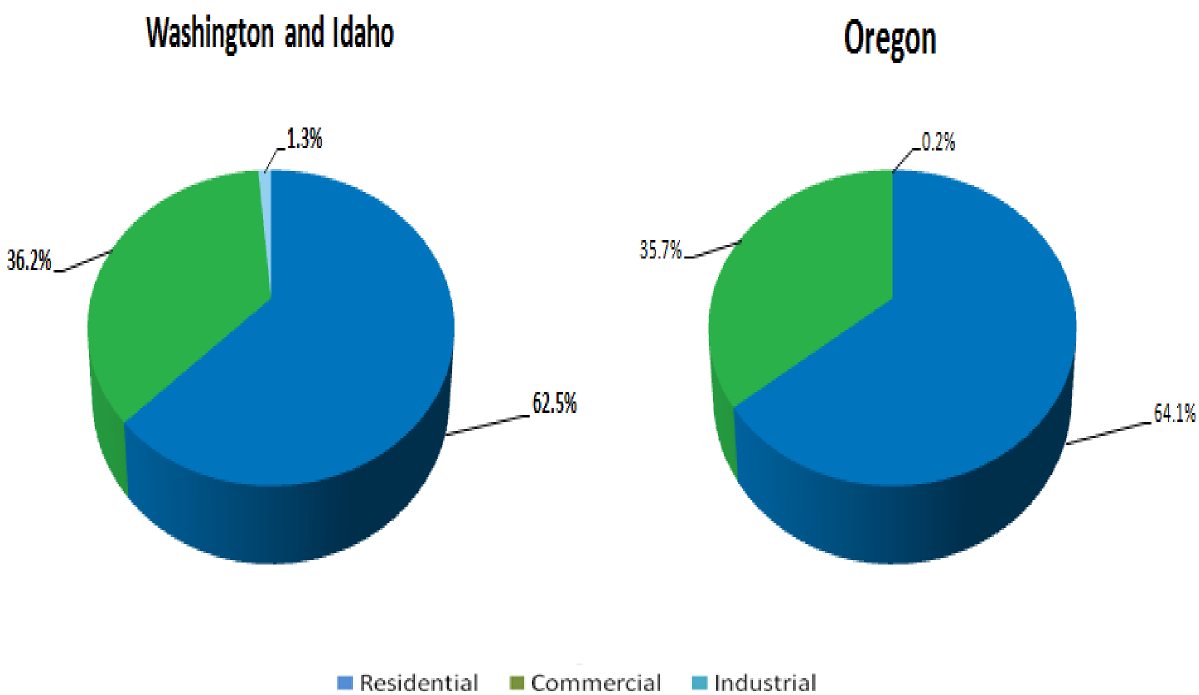
Avista’s core or retail customers include residential, commercial and industrial categories. Most of Avista’s customers are residential, followed by commercial and relatively few industrial accounts (Figure 1.3).

Figure 1.3 Firm Customer Mix



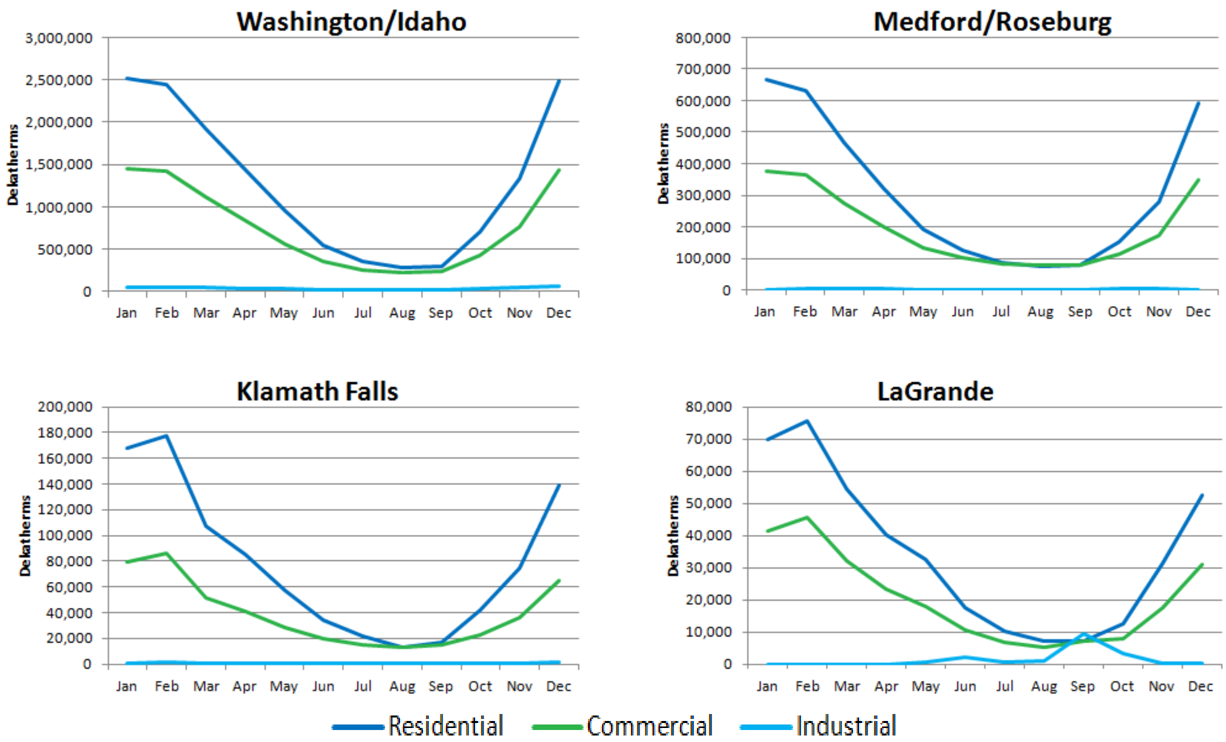
The mix is more balanced between residential and commercial accounts on an annual volume basis (Figure 1.4). Volume consumed by core industrial customers is not significant to the total, partly because most industrial customers in Avista's service territories are transportation-only customers.

Figure 1.4 Therms by Class



Core customer demand is seasonal, especially residential accounts in service territories with colder winters (Figure 1.5). Industrial demand, which is typically not weather sensitive, has very little seasonality. However, the La Grande service territory has several industrially classified agricultural processing facilities that produce a late summer seasonal demand spike.

Figure 1.5: Customer Demand by Service Territory



Integrated Resource Planning

Avista's IRP involves a comprehensive analytical process to ensure that core firm customers receive long-term reliable natural gas service at a competitive price. The IRP includes evaluation, identification, and planning for the acquisition of an optimal combination of expected costs and associated risk 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

Avista's 2014 Natural Gas IRP:

- 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 future demand requirements.
- Responds to Washington, Idaho and Oregon rules, orders, and guidelines.

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

Avista's TAC members 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. 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 2014 IRP. The first meeting convened on January 24, 2014, and the last meeting occurred on April 23, 2014. Meetings are at a variety of locations convenient for stakeholders and are electronically available for those unable to attend in person. Each meeting included a broad spectrum of stakeholders. The meetings focused on specific planning topics, reviewing the progress of planning activities, and soliciting input on IRP development. TAC members received a draft of this IRP on May 30, 2014, for their review. Avista addressed the comments and concerns about that draft, and they enhanced this document. Avista appreciates all of the time and effort TAC members gave to the IRP process; they provided valuable input through their participation in the TAC process.

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

Regulatory Requirements

Avista submits an IRP to the public utility commissions in Idaho, Oregon and Washington on or before August 31 every two years as required by state regulation.[1] There is a statutory obligation to provide reliable natural gas service to customers at rates, terms and conditions that are fair, just, reasonable and sufficient. Avista regards

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1 The Washington IRP requirements are in WAC 480-90-238 on Integrated Resource Planning.
Case No. GNR-G-93-2, Order No. 25342 outlines the Idaho IRP requirements. Order Nos. 07-002, 07-047 and 08-339 outline the Oregon IRP requirements. Appendix 2.2 provides details of these requirements and how this IRP meets those requirements.

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 Avista to determine that alternative resources are more cost effective than resources reviewed and selected in this IRP. Avista 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, Avista used the SENDOUT® planning model to perform comprehensive natural gas supply planning and analysis for this IRP. SENDOUT® is a linear programming-based model that is widely used 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 the following:

- 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.

Avista incorporated stochastic modeling by utilizing a SENDOUT® module to simulate weather and price uncertainty. The module generates Monte Carlo weather and price simulations, running concurrently to account for events and to provide a probability distribution of results that aid resource decisions. Some examples of the types of stochastic analysis provided 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 competing resources).

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

Planning Environment

Even though Avista publishes an IRP biannually, the process is ongoing with new information and developments. In normal circumstances, the process can become complex as underlying assumptions evolve, impacting previously completed analyses. Every planning cycle has challenges and uncertainties; this cycle was no different. For example, the recession greatly impacted Avista's forecasted demand growth and has significantly reduced long-term natural gas needs. Widespread agreement on the availability of shale gas and the ability to produce it at lower prices has increased interest in the use of natural gas for LNG exports and for more transportation and industrial uses. However, there is uncertainty about the timing and size of those markets.

IRP Planning Strategy

Planning for an uncertain future requires robust analysis that encompasses a wide range of possibilities. Avista has determined that the planning approach needs to:

- Recognize that 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, Avista developed a strategy encompassing all required planning criteria. This produced a complete IRP that effectively analyzes risks and resource options, which sufficiently ensures customers will receive safe and reliable energy delivery services with the best-risk, lease-cost, long-term solutions.

Summary of changes from the 2012 IRP

Chapter	Issue	2014 Natural Gas IRP	2012 Natural Gas IRP
Demand	Expected Customer Growth	Expected Case customer growth is 1% compounded annually.	Expected Case customer growth of 1.8% compounded annually.
	High/Low Growth	High and low growth based on forecasted long run employment growth.	Based on Washington State Office of Financial Management, 40% below and 60% above expected growth.
	Price Elasticity	Utilized a -0.15 response based on multiple historic analysis. Incorporated mechanism to	Utilized a -0.13 response based on AGA survey. Applied to change year-over-

		represent existing rate mechanisms that shield customers from timely price signals (i.e. comfort level billing, PGA mechanisms, deferrals, etc.)	year on commodity price.
	Weather	Rolling 20-year average with no adjustment for global warming.	Rolling 30-year average with an adjustment for global warming.
Demand Side Management	SENDOUT® modeling methodology	Integrated by price. SENDOUT® will be run without DSM and the resulting avoided costs will be calculated. Those costs will be given to ENERNOC to determine cost effective programs and savings. Resultant savings and costs will be incorporated into SENDOUT® and avoided costs will be re-evaluated until there is not a material change.	Utilized SENDOUT® DSM module, aggregated program bundles by demand area and type. Modeling at this level can mask individual cost effectiveness of programs and results in more DSM selected than might otherwise be selected.
Environmental Issues	Carbon Dioxide Emission (Carbon)	Three sensitivities on level of carbon tax ($/ton) were compared. The base carbon case is the medium case. The high and low cases help bracket the base case results.	Analyzed one carbon sensitivity case.
Supply Side Resources	Spokane Supply	Increased the amount of supply available to take from GTN onto NWP to serve WA/ID that was not included in the 2012 IRP.	Resource not included in this IRP.
	Resource Deficiency	Not resource deficient in the Expected Case.	Resource deficient in 2029 in Oregon and 2030 in Washington and Idaho in the Expected Case.
	Supply Side Scenarios	The only case that identifies a resource deficiency is the High Growth/Low Price scenario. Avista utilized only the existing resource scenario and existing plus expected available resource scenario for modeling purposes.	Evaluated three supply side scenarios on cases with resource deficiencies. Existing resources, Existing plus Expected Available, and GTN fully subscribed.

2: 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 forecasts is vital to the planning process. Utilization of historical data provides a reliable baseline, however past trends may not be indicative of future trends. This IRP mitigates the uncertainty by considering a range of scenarios to evaluate and prepare for a broad spectrum of outcomes.

Demand Areas

Avista defined eight demand areas, structured around the pipeline transportation resources that serve them, within the SENDOUT® model (Table 2.1). These demand areas are aggregated into four service territories and further summarized into two divisions for presentation throughout this IRP.

Table 2.1 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 customers' natural gas needs in extreme weather conditions.

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, natural gas demand is a function of customer base usage (non-weather sensitive usage) plus customer weather sensitive usage. Basic demand takes the formula in Table 2.2:

Table 2.2: Basic Demand Formula

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

SENDOUT® requires inputs as expressed in the Table 2.3 format to compute daily demand in dekatherms (Dth):

Table 2.3: 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

SENDOUT® performs this calculation daily for each customer class and each demand area. The base and weather sensitive usage (heating degree day usage) factors use customer demand coefficients developed outside the SENDOUT® model, and the coefficients 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

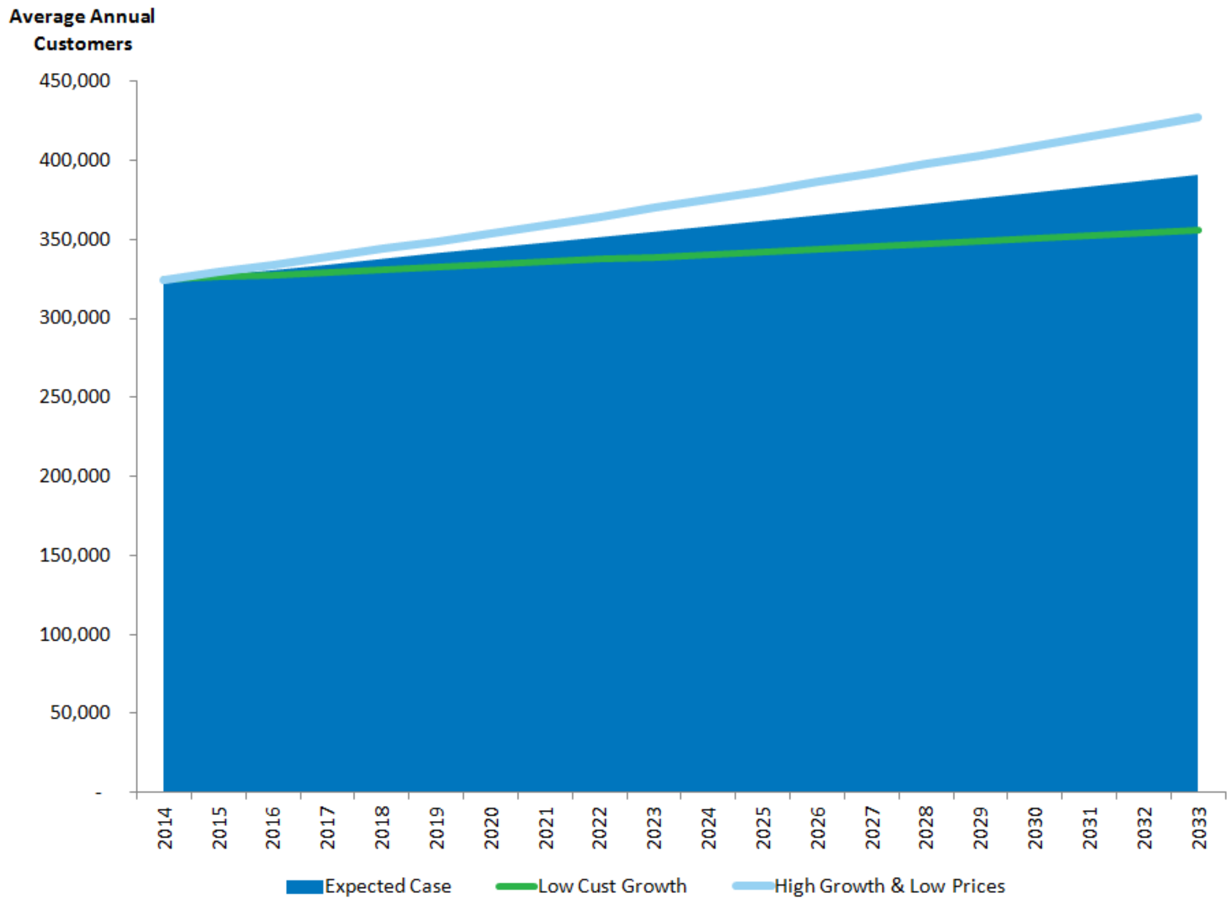
Avista's customer base includes residential, commercial and industrial categories. For each of the customer categories, Avista develops customer forecasts incorporating national economic forecasts and then drilling down into regional economies. U.S. GDP growth, U.S. and regional employment growth, and regional population growth expectations are key drivers in regional economic forecasts and are useful in estimating the number of natural gas customers. A detailed description of the customer forecast is found in Appendix 2.1. Avista combines this data with local knowledge about sub-regional construction activity, age and other demographic trends, and historical data to develop the 20-year customer forecasts.

Several departments within Avista use these forecasts, but Finance, Accounting, Rates, and Gas Supply are the primary users of these forecasts. Additionally, the distribution engineering group utilizes the forecast data for system optimization and planning purposes (see further discussion in Chapter 7 – 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. Avista developed High and Low growth forecasts to provide potential paths and test resource adequacy. Appendix 2.1 contains a description of how these alternatives were developed.

Figure 2.1 shows these three customer growth forecasts. Due to a change in forecasting customer growth, the expected case customer counts are lower than the last IRP. This has impacted forecasted demand from both and average and peak day perspective. Detailed customer count data by region and class for all three scenarios is in Appendix. 2.2.

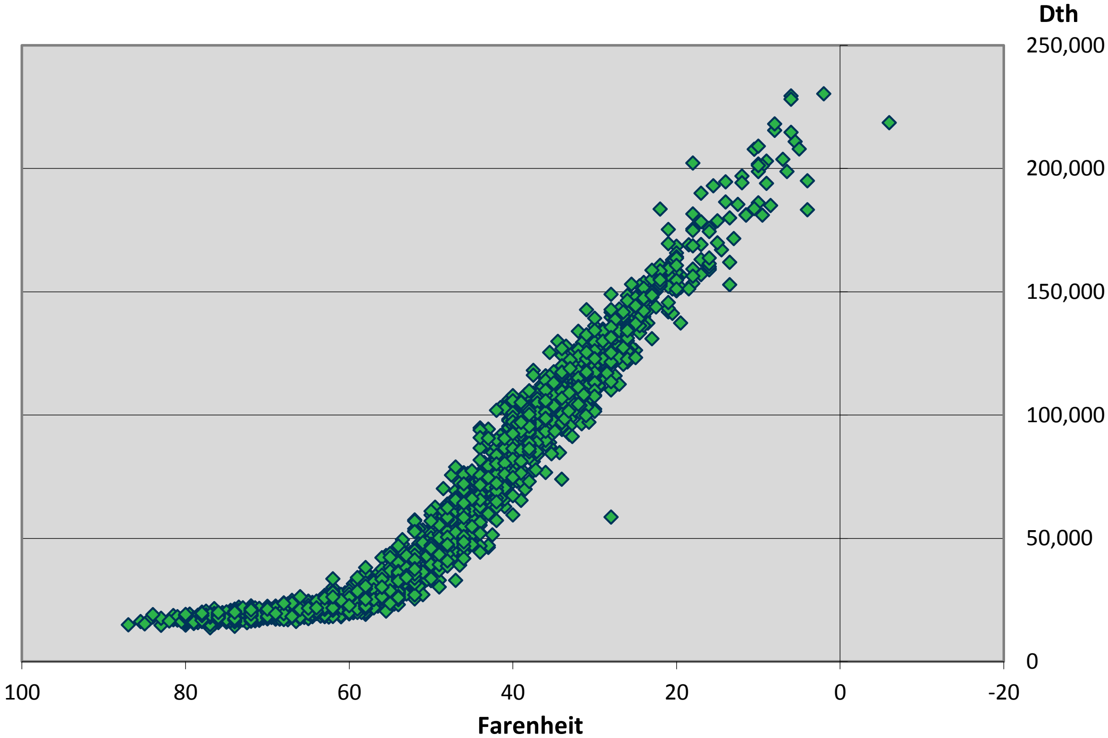
Figure 2.1: Customer Growth Scenarios



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 reliable forecast because of the high correlation between usage and temperature as depicted in the example scatter plot in Figure 2.2.

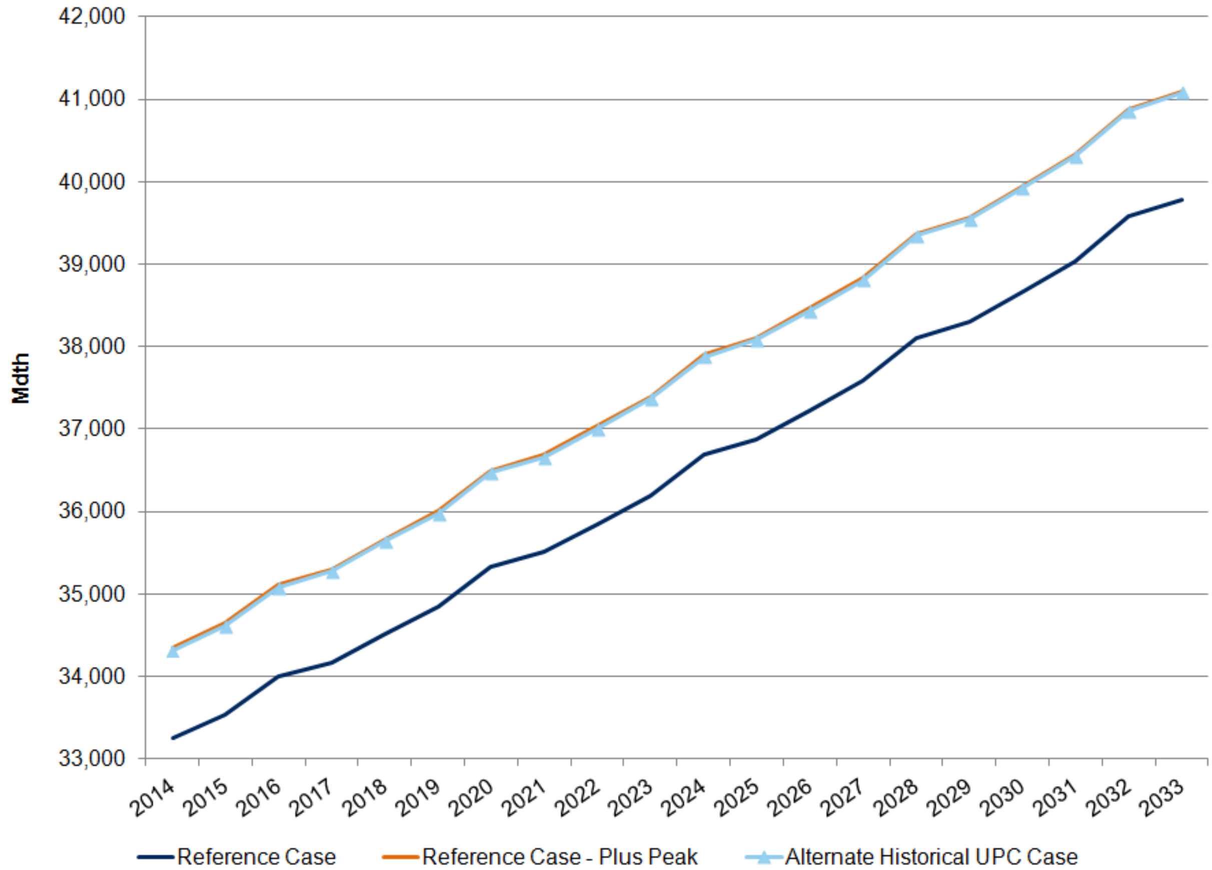
Figure 2.2: Example Demand vs. Average Temperature – WA/ID



The first step in developing demand coefficients was gathering daily historical gas flow data for all of Avista's city gates. The use of city gate data over revenue data is due to the tight correlation between weather and demand. The revenue system does not capture data on a daily basis and, therefore, makes a statistical analysis with tight correlations on a daily basis virtually impossible. Avista reconciles city gate flow data to revenue data to ensure that total demand is properly captured.

The historical city gate data was gathered, sorted by service territory/temperature zone, and then by month. As in the last IRP, Avista used three years of historical data to derive the use-per-customer coefficients, but also considered varying the number of years of historical data. When comparing five years of historical use-per-customer to the three years of data, the five-year data had slightly lower use-per-customer, which may understate use as the economy moderately recovers and customers' usage patterns return to pre-recession patterns. Three years struck a balance between historical and current customer usage patterns. Figure 2.3 illustrates the annual demand differences between the three and five-year use-per-customer with normal and peak weather conditions.

Figure 2.3: Annual Demand – Demand Sensitivities 3-Year vs. 5-Year Use-per-Customer



The base usage calculation used three years of July data to derive coefficients. Average usage in these months divided by the 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, Avista removed base demand from the total and plotted usage by HDD in a scatter plot chart to verify correlation visually. The process included the application of a 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 begin to flatten out relative to the linear relationships at less extreme temperatures. This occurs, for example, when furnaces reach maximum output and do not consume any more natural gas, regardless of how much colder temperatures get. Avista sought to capture this phenomenon through development of super peak coefficients.

The methodology for deriving super peak coefficients was derived by averaging the heat coefficients for December, January and February. One inherent drawback to this methodology is the lack of sufficient data points to develop a strong linear relationship. Avista will continue to test this theory and monitor trends as described in Chapter 8 - Ongoing Activities.

As a final step, coefficient reasonableness was checked by applying the coefficients to actual customer count and weather data to backcast demand. This was compared to actual demand with satisfactory results.

Weather Forecast

The last input in the demand modeling equation is weather (specifically HDDs). This started with the most current 20 years of daily weather data from the National Oceanic Atmospheric Administration (NOAA), converted to HDDs, and used to compute an average for each day to develop the weather forecast. The Oregon weather input used four weather stations, corresponding to the areas where Avista provides natural gas services. HDD weather patterns between these areas are uncorrelated. Weather data for the Spokane Airport is used for the eastern Washington and northern Idaho portions of the service area, as HDD weather patterns within that region are correlated.

The NOAA 20-year average weather serves as the base weather forecast to prepare the annual average demand forecast. The peak day demand forecast includes adjustments to 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 on either side of the coldest day to temperatures slightly warmer than the coldest day. For the Washington/Idaho and La Grande service territories, the model assumes this event on and around February 15 each year. For the southwestern Oregon service territories (Medford, Roseburg, Klamath Falls), the model assumes this event on and around December 20 each year.

The following section provides details about the coldest days on record for each service territory.

The Washington/Idaho service areas coldest day on record was an 82 HDD for Spokane and occurred on Dec. 30, 1968. 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 Jan. 5, 2004, respectively.

Medford experienced the coldest day on record, a 61 HDD, on Dec. 9, 1972. 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. 8, 2013; 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 the peak day weather standard for modeling purposes.

Utilizing a peak planning standard of the coldest temperature on record may seem aggressive given a temperature experienced rarely, or only once. Given the potential impacts of an extreme weather event on customers' personal safety and property damage to customer appliances and Avista's infrastructure, it is a prudent planning standard. While remote, peak days do occur, as on Dec. 8, 2014, when Avista matched the previous peak HDD in Klamath Falls.

Avista analyzes an alternate planning standard using the coldest temperature in the last twenty years the Washington/Idaho service area uses a 76 HDD, which is equal to an average daily temperature of -11 degrees Fahrenheit. In Medford, the coldest day in 20 years is a 54 HDD, equivalent to a temperature of 11 degrees Fahrenheit. In Roseburg, the coldest day in 20 years is a 48 HDD, equivalent to a temperature of 17 degrees Fahrenheit. In Klamath Falls, the coldest day in 20 years is a 72 HDD, equivalent to a temperature of -7 degree Fahrenheit. In La Grande, the coldest day in 20 years is a 64 HDD, equivalent to a temperature of 1 degree Fahrenheit.

The HDDs by area, class and day entered into SENDOUT® are in Appendix 2.4.

Global Warming

In previous IRP's, an adjustment has been made to NOAA weather data to incorporate estimates for global warming. This adjustment was based on analysis of historical weather data in each of the areas served. In this IRP, Avista moved away from adjusting the weather data in favor of moving from a rolling 30-year average to a 20-year average.

Avista chose a 20-year average for several reasons. First, NASA climate studies indicate that the distribution of temperatures in North America began to shift upwards significantly about 20 years ago.[1] In this case, a 20-year average coincides with the period when the temperature shift occurred. Second, there is a tradeoff between the length of the normal weather definition and its volatility.[2] For example, although a 10-year moving average captures turning points in climate trends more quickly than 15, 20 or 30-year averages, it will do so at the cost of larger year-to-year changes in the measurement of normal weather. That is, short-term weather variations not necessarily related to climate change will play a larger role in the defining normal weather as the number of years used for calculating the moving average declines. This can lead to excessive forecast volatility for each update to the 10-year average. In this respect, the 20-year average is a compromise between the traditional 30-year average, which may not capture climate trends, and the 10-year average, which greatly increases the volatility of year-to-year normal weather.

Avista was unable to find any definitive evidence to support a peak day warming trend. After discussion with the TAC, Avista decided to discontinue global warming trend adjustments to the peak day weather events in the HDD forecast. Therefore, the modeling and analysis with respect to peak day planning is unaffected by global warming.

Developing a Reference Case

To adjust for uncertainty, Avista developed a dynamic demand forecasting methodology that is flexible to changing assumptions. To understand how various alternative assumptions influence forecasted demand Avista needed a reference point for comparative analysis. For this, Avista defined the reference case demand forecast shown in Figure 2.4. This case is only a starting point to compare other cases.

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[1] See Hansen, J.; M. Sato; and R. Ruedy, "Global Temperature Update Through 2012," *Science Summary of NASA's 2012 Temperature Summary* January 2013, http://www.nasa.gov/topics/earth/features/2012-temps.html

[2] For a detailed discussion of this issue, see Livezey, R. E., and P. Q. Hanser, "Redefining Normal Temperatures: Resource Planning and Forecasting in a Changing Environment," *Public Utilities Fortnightly*, May 2013, 151(5), pp. 28-33,56.

Figure 2.4: Reference Case Assumptions

1. Customer Annual Average Growth Rates

Area	Residential	Commercial	Industrial
Washington - Idaho	1.0%	1.0%	-0.53%
Klamath Falls	0.66%	0.66%	0.0%
LaGrande	0.40%	0.40%	0.0%
Medford	1.1%	1.1%	0.0%
Roseburg	0.8%	0.02%	0.0%

2. Use Per Customer Coefficients

Flat Across All Classes

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

3. Weather

20-year Normal - NOAA (1994-2013)

4. Elasticity

None

5. Demand Side Management

None

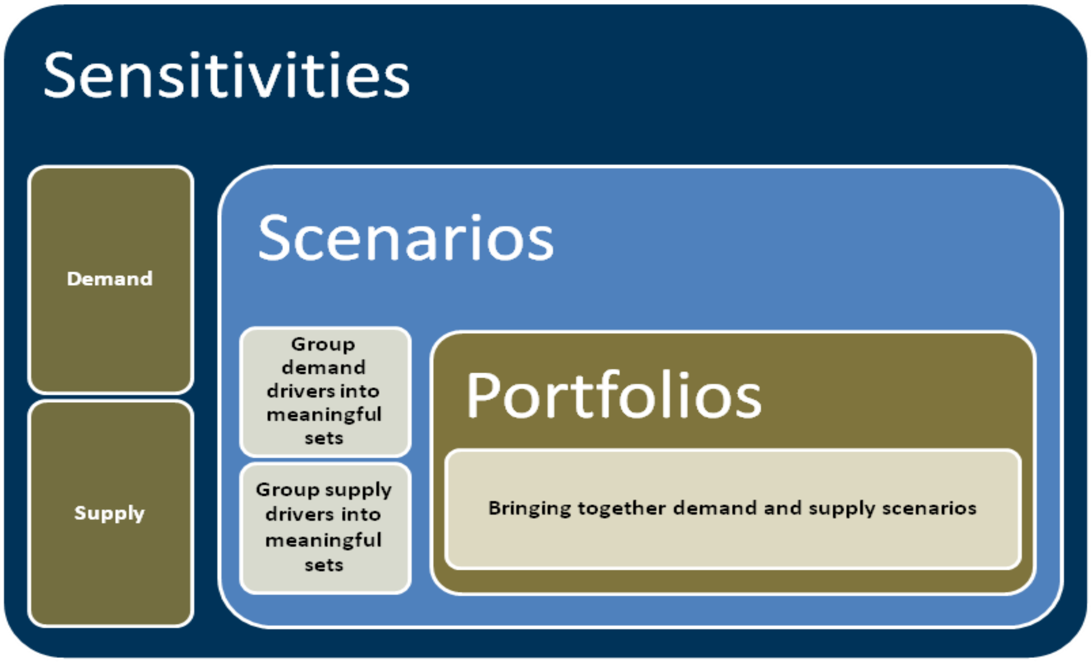
Dynamic Demand Methodology

The dynamic demand planning strategy examines a range of potential outcomes. The approach 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 2.5 represents our methodology of starting with sensitivities, progressing to scenarios, and ultimately creating portfolios.

Figure 2.5: Sensitivities, Scenarios and Portfolios



Sensitivity Analysis

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

- Demand Influencing Factors directly influencing the volume of natural gas consumed by core customers.

- Price Influencing Factors indirectly influencing the volume of natural gas consumed by core customers through a price elasticity response.

After identifying demand and price influencing factors, Avista developed sensitivities to focus on the analysis of a specific natural gas demand driver and its impact on forecasted demand relative to the Reference Case when modifying the underlying input assumptions.

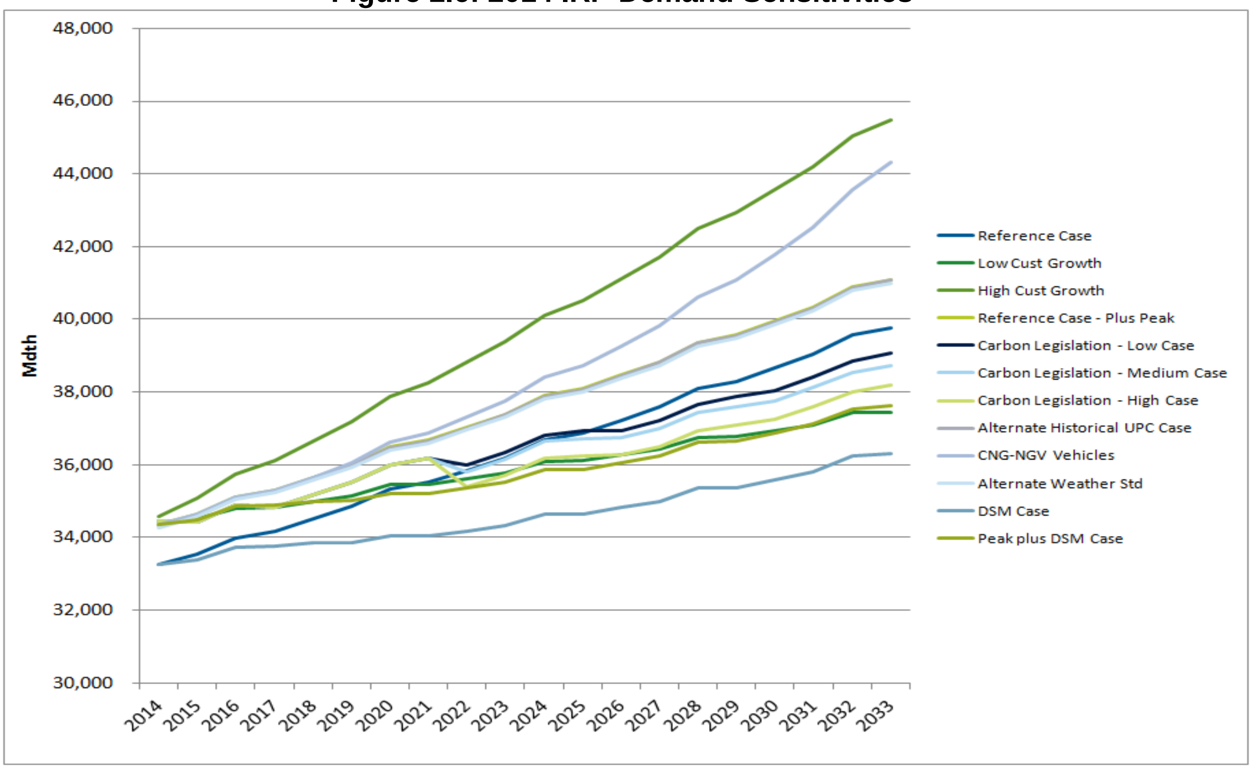
Sensitivity assumptions reflect incremental adjustments not captured in the underlying Reference Case forecast. Avista analyzed 17 demand sensitivities to determine the results relative to the reference case. Table 2.4 lists these sensitivities. Detailed information about these sensitivities is in Appendix 3.6.

Table 2.4: Demand Sensitivities

Scenario	Influence	Weather	Growth	Use per Customer	Price Curve	Carbon Adder	LNG Adder	DSM	New Markets	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
New Markets 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 - Low	Indirect	Peak	Expected	3 year	Expected	Yes	No	No	No	No
Carbon Legislation - Medium	Indirect	Peak	Expected	3 year	Expected	Yes	No	No	No	No
Carbon Legislation - High	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 2.6 shows the annual demand from each of the sensitivities modeled for this IRP.

Figure 2.6: 2014 IRP Demand Sensitivities



Scenario Analysis

After testing the sensitivities, Avista grouped them into meaningful combinations of demand drivers to develop demand forecasts representing scenarios. Table 2.5

identifies the scenarios developed. The Average Demand Case represents the case used for normal planning purposes, such as corporate budgeting, procurement planning, and PGA/General Rate Cases. The Expected Case reflects the demand forecast Avista believes is most likely given peak weather conditions. The High Growth/Low Price and Low Growth/High Price cases represent a range of possibilities for customer growth and future prices. The Alternate Weather Standard case utilizes the coldest day in Avista's service territories in the last 20 years. Each of these scenarios provides a "what if" analysis given the volatile nature of key assumptions, including weather and price. Appendix 2.6 lists the specific assumptions within the scenarios while Appendix 2.7 contains a detailed description of each scenario.

Table 2.5: Demand Scenarios

2014 IRP Demand Scenarios
Average Case
Expected Case
High Growth, Low Price
Low Growth, High Price
Alternate Weather Standard

Price Elasticity

The economic theory of price elasticity states that the quantity demanded for a good or service will change with its price. Price elasticity is a numerical factor that identifies the relationship of a consumer's consumption change in response to a 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 0.15 for a particular good or service means a 10 percent price increase will prompt a 1.5 percent consumption decrease and a 10 percent price decrease will prompt a 1.5 percent consumption increase.

Complex relationships influence price elasticity and given the current economic environment, Avista questions whether current behavior will become normal or if customers will return to historic usage patterns. Furthermore, complex regulatory pricing mechanisms shield customers from price volatility, thereby dampening price signals and affecting price elastic responses. For example, budget billing averages a customer's bills into equal payments throughout the year. This popular program helps customers manage household budgets, but does not send a timely price signal. Additionally, natural gas cost adjustments, such as the Purchased Gas Adjustment (PGA), annually adjusts the commodity cost which shields customers from daily gas price volatility. These mechanisms do not completely remove price signals, but they can significantly dampen the potential demand impact.

When considering a variety of studies on energy price elasticity, a range of potential outcomes was identified, including the existence of positive price elastic adjustments to demand. One study looking at the regional differences in price elasticity of demand for energy found that the statistical significance of price becomes more uncertain as the geographic area of measurement shrinks.[3] This is particularly important given Avista's geographically diverse and relatively small service territories.

Avista acknowledges changing price levels can and do influence natural gas usage, so this IRP includes a price elasticity of demand factor of -0.15 into the modeling assumptions to allow use-per-customer to vary into the future as the natural gas price forecast changes.

Recent usage data indicates that even with declines in the retail rate for natural gas, long run use-per-customer continues to decline. This likely includes a confluence of factors including high unemployment, increased investments in energy efficiency measures, building code improvements, behavioral changes, and heightened focus of consumers' household budgets.

Results

During 2014, the Average Case demand forecast indicates Avista will serve an average of 324,606 core natural gas customers with 33,343,423 dekatherms of natural gas. By 2033, Avista projects 391,203 core natural gas customers with an annual demand of over 38,069,627 dekatherms. In Washington/Idaho, the projected number of customers increases at an average annual rate of 0.99 percent with demand growing at a compounded average annual rate of 1.03 percent. In Oregon, the projected number of customers increases at an average annual rate of 1.7percent, with demand growing 1.3 percent per year.

During 2014, the Expected Case demand forecast indicates Avista will serve an average of 324,606 core natural gas customers with 34,095,766 dekatherms of natural gas. By 2033, Avista projects 391,203 core natural gas customers with an annual demand of over 38,889,977 dekatherms.

[3] Bernstein, M.A. and J. Griffin (2005). Regional Differences in Price-Elasticity of Demand for Energy, Rand Corporation.

Figure 2.7 shows system forecasted demand for the demand scenarios on an average daily basis for each year.[4]

Figure 2.7: Average Daily Demand – 2014 IRP Scenarios

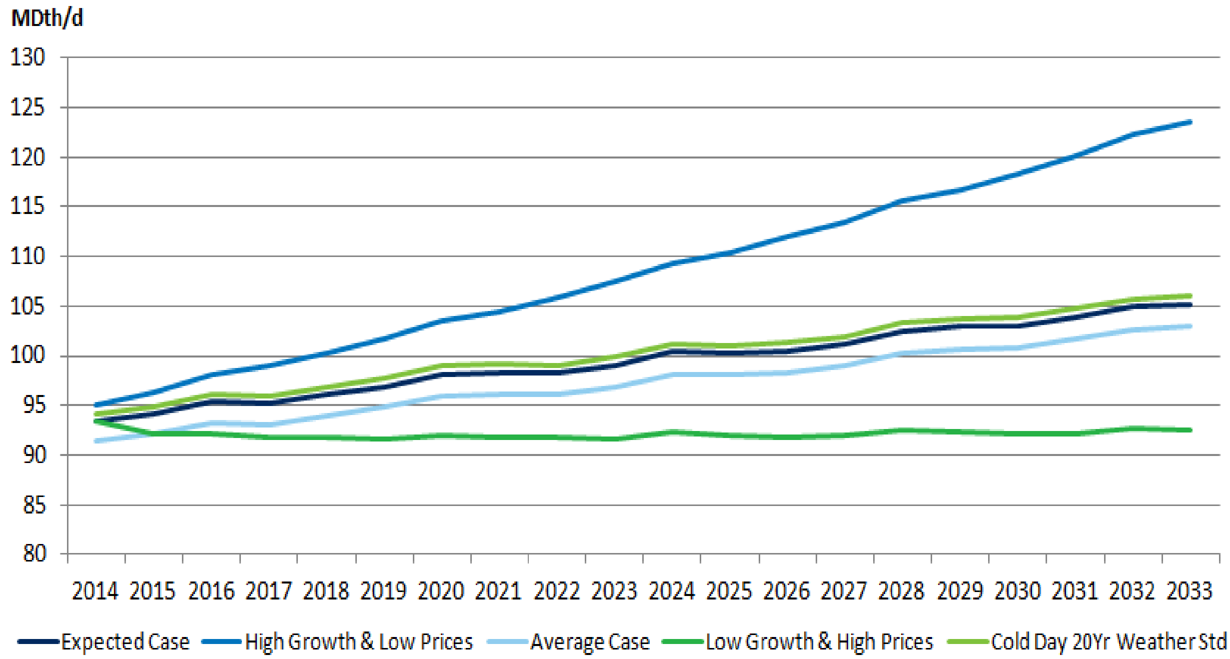
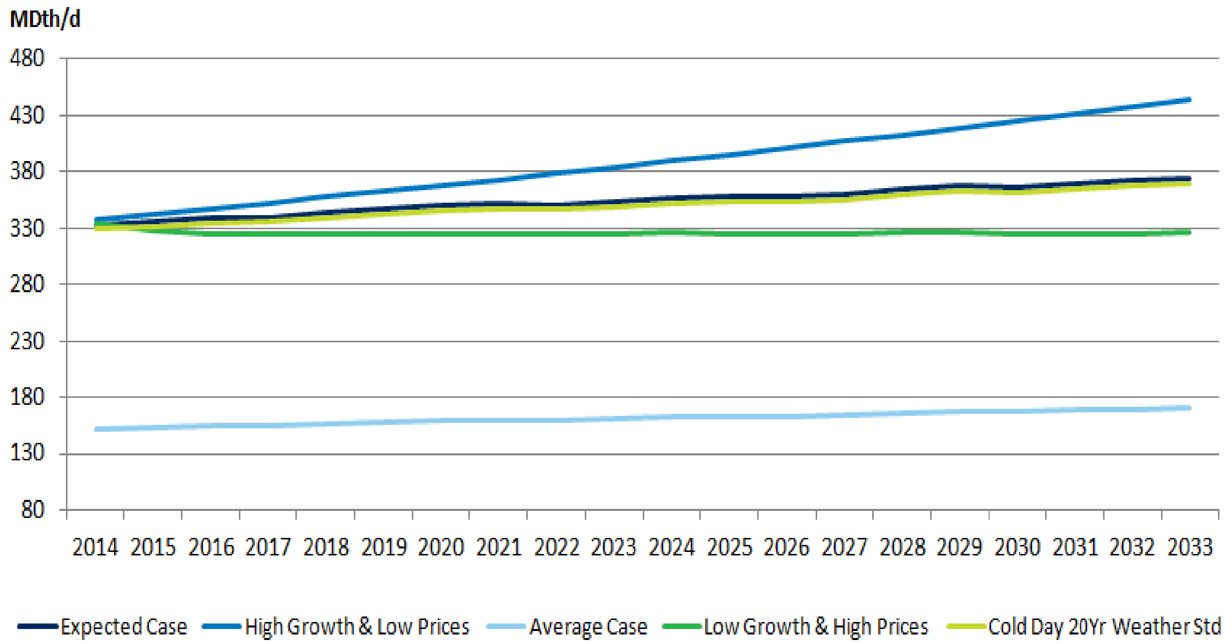


Figure 2.8 shows system forecasted demand for the Expected, High and Low Demand cases on a peak day basis for each year relative to the Average case average daily winter demand. Detailed data for all demand scenarios is in Appendix 2.8.

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

Figure 2.8: February 15th – Peak Day – 2014 IRP Demand Scenarios



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 DSM initiatives is in Chapter 3 – Demand-Side Resources.

Alternative Forecasting Methodologies

There are many forecasting methods available and used throughout different industries. Avista strives to use methods that enhance forecast accuracy, facilitate meaningful variance analysis, and allows for modeling flexibility to incorporate different assumptions. Avista believes the statistical methodology to be sound and provides a robust range of demand considerations. The methodology allows for the analysis of different statistical inputs by considering both qualitative and quantitative factors. These factors can come from data, surveys of market information, fundamental forecasts, and industry experts. Avista is always open to new methods of forecasting natural gas demand and will continue to assess which, if any, alternative methodologies to include in the dynamic demand forecasting methodology.

Key Issues
Demand forecasting is a critical component of the IRP requiring careful evaluation of the current methodology and use of sufficient scenario planning to understand how changes to the underlying assumptions will affect the results. The evolution of demand forecasting 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. However, Avista is mindful of the importance of the assumptions driving current forecasts and understands that these can and will change over time. Therefore, monitoring key assumptions driving the demand forecast is an ongoing effort that will be shared with the TAC as they develop.

Price Elasticity

Avista continues to study how to incorporate a price elastic response to demand given the complex cross commodity relationships, regulatory pricing mechanisms, flat forward price curve and changing technologies in energy efficiency that make discerning how much demand response to expect over the long term.

An action item from the previous IRP was to explore the possibility of a regional elasticity study facilitated by Avista in conjunction with a third-party such as the NWGA or the AGA. Avista approached the NWGA and they are willing to assess regional interest and facilitate the process. Avista is developing the scope, assessing who is best to conduct a study, and determining the associated costs. Avista will assess the interest level of regional stakeholders before deciding to proceed with the study.

Flat Demand Risk

Forecasting customer usage is a complex process because of the number of underlying assumptions and the relative uncertainty of future patterns of usage with a goal of increasing forecast accuracy. There are many factors that can be incorporated into these models, assessing which ones are significant and improving the accuracy are key. Avista continues to evaluate economic and non-economic drivers to determine which factors improve forecasting accuracy. The forecasting process will continue to review research on climate change and the best way to incorporate the results of that research into the forecasting process.

For the last few planning cycles, the TAC has discussed the changing slope of forecasted demand. Growth has slowed due to the recent recession and declining use-per-customer. This is primarily driven by energy efficiency and responses to higher commodity costs and general inflation. Use-per-customer seems to have stabilized, but customer growth in Avista's service territory may not return to pre-recession levels.

This reduced demand pushes the need for resources beyond the planning horizon, which means no new investment in resources is necessary. However, should assumptions about lower customer growth prove to be inaccurate and there is a rebound in demand, new resource needs will occur sooner than expected. Therefore, careful monitoring of demand trends in order to identify signposts of accelerated demand growth is critical to the identification of new resource needs coming earlier.

Emerging Natural Gas Demand

The shale gas revolution has fundamentally changed the long-term availability and price of natural gas. This revolution prompts an evolution in the increased use of natural gas. From fertilizer plants to food processors, interest in industrial processes that use natural gas as a feedstock is growing. Another likely demand growth area is in the transportation sector; both land-based and marine fleets are turning to natural gas for their fuel supply due to its low price and better environmental footprint when compared to diesel. It remains to be seen if these new customers are served by an LDC, in all likelihood they will not be firm sales customers. , However, their demands will have an impact on regional supply which could trigger price movement.

Conclusion

Recessionary impacts have significantly reduced Avista's outlook for customer growth and reduced the long-term demand forecasts. Avista's dynamic demand methodology provides a means to assess the individual and collective demand impact of a variety of economic and non-economic drivers. The results of this comprehensive analysis provides a better understanding of the possible outcomes with respect to core consumption of natural gas and helps drive resource decisions based on changing consumer needs.

Chapter 3: Demand-Side Resources

Overview

Avista is committed to offering natural gas DSM portfolios to residential, commercial and industrial customers when it is feasible to do so in a cost-effective manner as prescribed within each jurisdiction. In recent years, customers have benefitted from precipitous declines in natural gas avoided costs. At the same time, these falling avoided costs have made it more challenging to design a cost effective DSM portfolio as well as limiting the cost incentives that efficiency programs have with retail customers. The Avista continues to work with regulators and key external stakeholders on potential natural gas DSM opportunities to achieve a cost effective portfolio in each of its jurisdictions. Currently, the status of the Avista's natural gas DSM programs differs significantly in each of its three jurisdictions.

Avista manages the Washington and Idaho DSM programs, to the extent possible, as a single portfolio due to the geography and communications inherent within that portion of the service territory. Previous analysis, using the then-prevailing avoided cost that were more favorable to DSM resources, led Avista to the conclusion that it was not possible to field a Washington and Idaho natural gas DSM portfolio that would be cost-effective under the traditional Total Resource Cost (TRC) test. The TRC cost-benefit test is a measurement of the success that a portfolio has in reducing the customer's total energy cost for providing end-use services. As a result, in May 2012 Avista proposed revisions to its natural gas energy efficiency tariffs in Washington and Idaho that would have, if adopted as filed, suspended all incentives and direct marketing of natural gas efficiency programs. As happened with the Company's previous experience of suspending natural gas programs in 1997, Avista committed to reinstitute natural gas programs when and if natural gas avoided costs increased to a level sufficient to field a cost-effective portfolio. Due to the inability to offer a TRC cost-effective portfolio, in Idaho, Avista received approval for the suspension of the natural gas DSM portfolio.

The Washington Utilities and Transportation Commission responded to Avista's request to suspend its natural gas DSM portfolio by initiating a rulemaking proceeding.[1] After much discussion and process, at the direction of the Commission, the Company withdrew its filing and applied the Program Administrator Cost (PAC) test (also known as the Utility Cost Test) in place of the TRC test. The PAC cost-effectiveness test takes the perspective of managing only the customer's utility bill through efficiency programs

[1] Docket No. UG-121207 - The result of this rulemaking was a Policy Statement on the "Evaluation of the Cost-Effectiveness of Natural Gas Conservations Programs."

and not the customers total cost of energy. It does this by excluding from consideration the customer's incremental investment in purchasing efficiency beyond incentives paid by the utility. Since incentives are almost invariably only part of the incremental cost associated with efficiency measures, the restricted cost definition of the PAC test leads to higher benefit-to-cost ratios. Avista found it necessary to reduce financial incentives, but was able to design a DSM portfolio anticipated to be cost-effective under the more narrowly defined PAC test.

Avista's Oregon DSM portfolio is distinctly separate from the portfolios offered in the Washington and Idaho jurisdictions. In September of 2012, Avista filed to suspend certain programs and modify many others within its Oregon DSM portfolio for the same reasons it did so in Washington and Idaho. However, on April 30, 2013 the Oregon Public Utility Commission granted a two-year exception period for Avista to identify and implement strategies that could potentially have a significant impact on the cost-effectiveness of the DSM portfolio in a low avoided cost environment. Many of these strategies have been completed and more are in-progress with favorable impacts upon the cost-effectiveness performance to date.

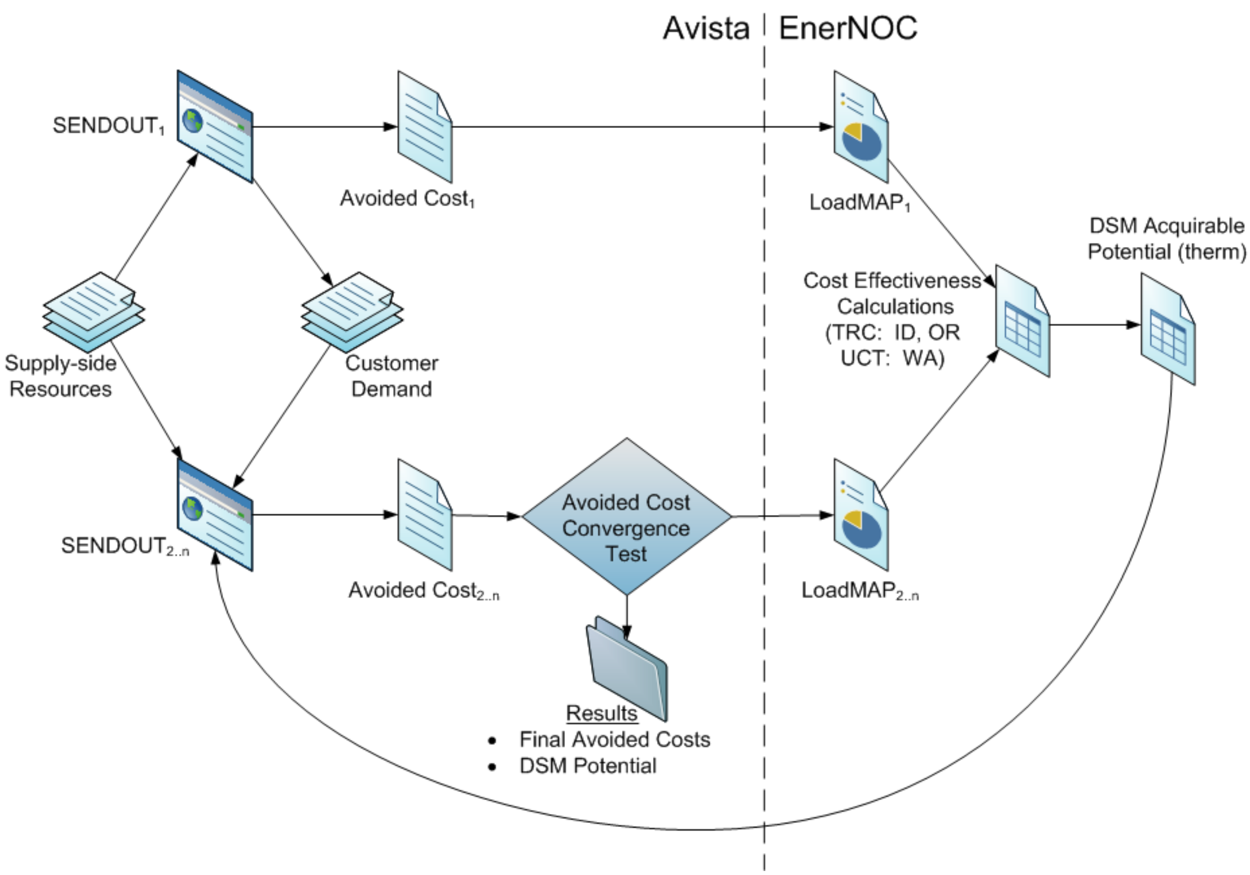
Conservation Potential Assessment Methodology

Avista engaged EnerNOC (now Applied Energy Group) to perform an independent evaluation of the technical, economic and achievable DSM potential within each of Avista's three jurisdictions over a 20-year planning horizon. This process involves indexing existing nationally recognized Conservation Potential Assessment (CPA) models to the Avista service territory load forecast, housing stock, end-use saturations and other key characteristics. Additional consideration of the impact of energy codes and appliance standards for end-use equipment at both the state and national level are incorporated into the projection of energy use and the baseline for the evaluation of efficiency options. The modeling process also utilizes ramp rates for the acquisition of efficiency resources over time in a manner generally consistent with the assumptions used by the Northwest Power Planning Council. This includes adjusted ramp rates to better align with Avista's recent program accomplishments and adjusted in the later years for some measures.

The process described above defines an Avista-specific supply curve for conservation resources. Simultaneously, the avoided cost of natural gas consistent with serving the full forecasted demand was defined as part of the SENDOUT® modeling of the Avista system. The preliminary cost-effective conservation potential is determined by applying the stream of annual natural gas avoided costs to the Avista-specific supply curve for conservation resources. This quantity of conservation acquisition is then decremented from the load, which the utility must serve, and the SENDOUT® model run against the modified (reduced) load requirements. The resulting avoided costs are compared to those obtained from the previous iteration of SENDOUT® avoided costs. This reiteration process continues until the differential between the avoided cost streams of the most recent and the immediately previous iteration becomes immaterial. At that point both supply and demand side options are functioning from comparable (including a 10 percent preference for DSM resources) avoided costs and the resulting load is meeting all load requirements.

Figure 3.1 is a graphical depiction of the previously described methodology used in the presentation of this methodology to the TAC.

Figure 3.1 – Integration of DSM into the IRP Process



Integrating the DSM portfolio into the IRP process by equilibrating the avoided costs in this iterative process is useful since Avista's DSM acquisition is small relative to the total western natural gas market used to establish the commodity prices driving the avoided cost stream. Therefore, few iterations are necessary to reach a stable avoided cost. Additionally it provides some assurance, at least at the aggregate level, that the quantity of DSM resource selected will be cost-effective when the final avoided cost stream is used in retrospective portfolio evaluation.

It should be noted that, based upon guidance provided by the Washington Commission, and as previously explained, the cost-effectiveness metric applied in developing the Washington DSM supply curve was the PAC test rather than the TRC test used in past IRP evaluations of Washington and continues to be used in the Idaho and Oregon jurisdictions. The PAC tests narrower definition of costs led to proportionately higher DSM acquisition targets within the Washington jurisdiction.

Environmental Externalities

The gathering, transmission, distribution and end-use of natural gas involve some inherent environmental costs that are not necessarily borne by the parties to the transaction or the user of the resource. These costs are externalities since they represent those costs that are external to the parties involved in the transaction. It is difficult to quantify the value of these externalities since they are borne by individuals within society who may drastically differ on the value that they place on the absence of these impacts. Furthermore, there are no well-defined markets for measuring the economic impact of these externalities.

This IRP intends to consider the full cost of the resources acquired by the utility and used by customers in the resource selection process. Towards that end, Avista incorporates a DSM preference in recognition of the lower environmental externality cost incurred when efficiency resources meet customer end-use needs rather than supply resources. The CPA incorporates this preference by increasing the avoided cost used to determine if DSM resources are within 10 percent of being cost-effective. By artificially increasing the avoided cost price signal, DSM measures that would not otherwise pass the cost-effectiveness test are accepted into the optimized DSM portfolio and incorporated within the acquisition target. This preference for DSM resources is separate from, and in addition to, any quantifiable non-energy impacts (generally benefits) that Avista is able to quantify for inclusion as an efficiency resource option benefit within the TRC cost-effectiveness test.

Conservation Potential Assessment Findings

Prior to the development of potential estimates, EnerNOC created 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 2013 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, natural gas price forecasts, trends in fuel shares and equipment saturations developed by EnerNOC, existing and approved changes to building codes and equipment standards, and Avista's internally developed load forecast.

According to the CPA completed for Avista, the residential sector natural gas consumption for all end uses and technologies increases primarily due to the projected 1.0 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 natural gas use.

For the commercial and industrial sectors, natural gas use continues to grow slowly over the 20-year planning horizon as new construction increases the overall square footage in this sector. Growth in heating, ventilation and air conditioning (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 3.1 illustrates the system-wide baseline forecast of natural gas use across all sectors for selected years to include the baseline year, annually for the years to the next IRP cycle, and selected years thereafter. This baseline increases by 11 percent over the 20-year planning horizon corresponding to an annualized growth of 0.5 percent. Overall, the forecast projects steady growth over the next 20 years with growth in the residential sector making up for the decrease in industrial sector sales. Idaho is projected to experience the highest level of growth, with Oregon having the next highest level of growth.

Table 3.1 Baseline Forecast Summary (1,000's of therms)

Sector	2013	2015	2016	2019	2024	2034	% Change (2013-2034)	Avg. Growth Rate (2013-2034)
Residential	199,115	197,496	199,264	204,876	206,391	232,976	17%	0.7%
Commercial	126,489	126,009	127,191	129,099	127,577	129,402	2%	0.1%
Industrial	5,015	5,252	5,524	5,867	5,477	4,491	-10%	-0.5%
Total	**330,619**	**328,757**	**331,980**	**339,842**	**339,444**	**366,869**	**11%**	**0.5%**

State	2013	2015	2016	2019	2024	2034	% Change (2013-2034)	Avg. Growth Rate (2013-2034)
Washington	173,409	171,422	172,719	176,166	175,134	183,693	6%	0.3%
Idaho	76,250	77,988	79,291	82,207	82,739	91,603	20%	0.9%
Oregon	80,960	79,346	79,969	81,469	81,571	91,574	13%	0.6%
Total	**330,619**	**328,757**	**331,980**	**339,842**	**339,444**	**366,869**	**11%**	**0.5%**

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 and adopt the most efficient energy use practices possible at every opportunity without regard to cost-effectiveness. Economic potential represents the adoption of all cost-effective conservation measures based on the TRC test in Idaho and Oregon and the PAC test in Washington. The 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 efficiency 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 HDD 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 often referred to as winter load shape measures and are typically valued using a higher avoided cost (due to summer to winter pricing differentials) while base load measures (often called annual load shape measures) are valued at a lower avoided cost.

Avista offers conservation measures to residential, non-residential and low-income customers.[2] Measures offered to residential customers are almost universally on a prescriptive basis, meaning they have a fixed incentive for all customers and do not require individual pre-project analysis by the utility. Low income customers are treated with a more flexible approach through cooperative arrangements with participating Community Action Agency partnerships. Non-residential customers have access to prescriptive and site-specific conservation measures. Site-specific measures customized to specific applications have cost and therm savings unique to the individual facility.

In Oregon, some conservation measures are legally required and therefore their costs and benefits become part of the portfolio without being subject to cost-effectiveness testing. These measures, for example, include energy audits that do not in and of themselves generate energy savings absent customer action and the timing and cost-effectiveness of the action(s) taken by the customer are uncertain.

See Table 3.2 for residential, commercial and industrial measures evaluated in this study for all three states.

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

Table 3.2 Conservation Measures

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

Commercial and Industrial Measures
Furnace – Maintenance
Boiler – Maintenance
Boiler – Hot Water Reset
Boiler – High Efficiency Hot Water Circulation
Space Heating – Heat Recovery Ventilator
Insulation – Ducting
Insulation – Ceiling
Insulation – Wall Cavity
Ducting – Repair and Sealing
Windows – High Efficiency
Energy Management System
Thermostat – Clock/Programmable
Water Heating – Faucet Aerators
Water Heating – Pipe Insulation
Water Heating – Tank Blanket/Insulation
Water Heating – Hot Water Saver
Advanced New Construction Designs (new only)
Comprehensive Commissioning
Process – Boiler Hot Water Reset (industrial only)

Conservation Potential Assessment Results

Based upon the previously described methodology and baseline forecasts, EnerNOC developed technical, economic and achievable potentials by jurisdiction and segment over a 20-year horizon.

The technical potential for Avista’s service territory for the 20-year IRP period reaches 46.5 percent of the baseline end-use forecast. This would be the full DSM potential without regard for cost effectiveness.

Economic potential applies the cost-effectiveness metric appropriate to each jurisdiction to measures identified within the technical potential and quantifies the impact of the adoption of cost-effective DSM measures. By the end of the 20-year timeframe, this represents 13.5 percent of the baseline energy forecast. The significant difference between the technical and economic potential is a reflection of the economic impact of falling natural gas avoided costs as well as the market saturation achieved in previous years with higher prevailing natural gas avoided costs. Past adoption of the most cost-effective measures leads to progressively higher costs for the remaining measures. At the same time the avoided cost value of these future adoptions is falling.

The achievable potential across the residential, commercial and industrial sectors, incorporating ramp rates derived from the Northwest Power and Conservation Council, is 10.1 percent of the baseline energy forecast by the end of 2034.

Tables 3.3 and 3.4 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 this situation reverses so the residential sector's share of savings is the greatest due to growth in residential customer count. Please refer to the natural gas CPA provided in Appendix 3.1 for more details.

Table 3.3 Summary of Cumulative Achievable, Economic and Conservation Potential

	2015	2016	2019	2024	2034
Baseline projection (1,000's of Therms)	328,757	331,980	339,842	339,444	366,869
Cumulative Natural Gas Savings (1,000's of Therms)					
Achievable Potential	1,677	2,639	9,890	20,615	36,887
Economic Potential	4,152	5,877	17,371	32,580	49,566
Technical Potential	12,512	19,298	53,433	100,103	170,543
Cumulative Natural Gas as a percentage of Baseline					
Achievable Potential	0.5%	0.8%	2.9%	6.1%	10.1%
Economic Potential	1.3%	1.8%	5.1%	9.6%	13.5%
Technical Potential	3.8%	5.8%	15.7%	29.5%	46.5%

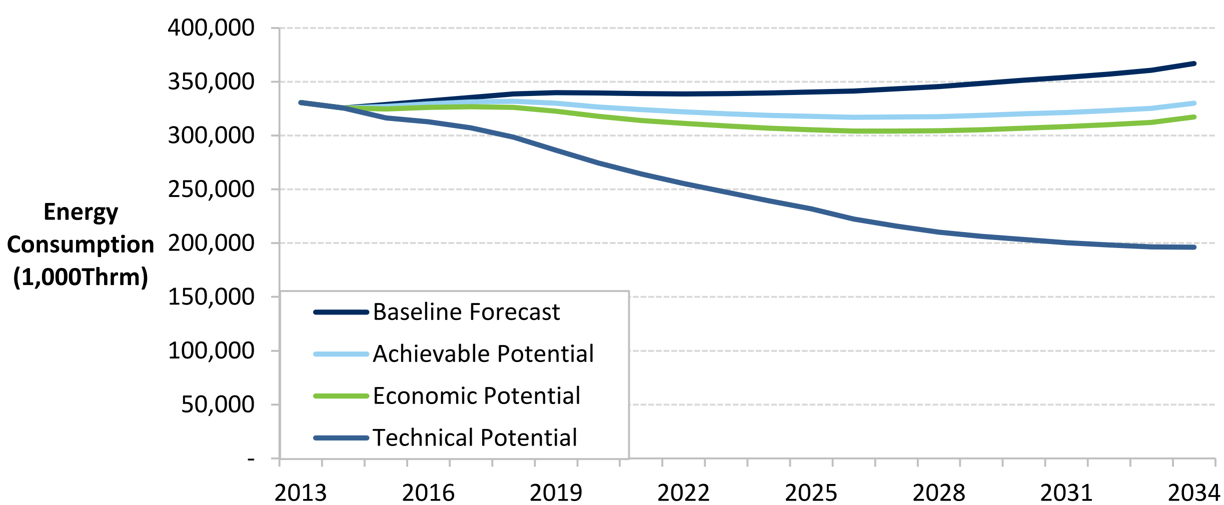
The overall achievable potential is presented first by state and then by sector in Table 3.4.

Table 3.4 Summary of Cumulative Achievable Potential by State and Sector

Cumulative Savings (1,000's of Therms)	2015	2016	2019	2024	2034
Washington	1,287	2,024	7,781	15,822	26,997
Idaho	228	342	1,029	2,316	4,504
Oregon	161	272	1,080	2,477	5,386
Total	**1,677**	**2,639**	**9,890**	**20,615**	**36,887**
Cumulative Savings (1,000's of Therms)	**2015**	**2016**	**2019**	**2024**	**2034**
Residential	384	727	5,279	10,154	15,957
Small Commercial	296	480	1,400	3,286	6,924
Large Commercial	969	1,390	3,085	6,907	13,599
Industrial	27	42	126	268	407
Total	**1,677**	**2,639**	**9,890**	**20,615**	**36,887**

Figure 3.1 illustrates the impact of the DSM potential forecast upon the end-use baseline absent any DSM acquisition. By the end of the 20-year period, the achievable potential (indicated by the light blue line) offsets 102 percent of the growth in the baseline forecast for the Avista service territory. This is in part the consequence of low load growth as well as the higher level of achievable DSM identified within Washington (Avista's largest jurisdiction) using the more generous PAC cost-effectiveness test metric.

Figure 3.1 - Conservation Potential Energy Forecast (1000's of therms)



Residential Potential Results

Single-family homes represent 78 percent of Avista's residential natural gas customers, but account for 83 percent of the sector's consumption in the study base year 2013. The state of Washington is a disproportionate quantity of the savings since the target acquisition relies on the PAC test while Oregon and Idaho relies on the TRC test.

Table 3.5 provides a distribution of achievable potential by state for the residential sector.

Table 3.5 – Residential Cumulative Achievable Potential by State, Selected Years

	2015	2016	2019	2024	2034
Baseline Projection (1,000's of Therms)					
Washington	101,488	102,205	105,064	105,708	116,970
Idaho	46,978	47,633	49,224	49,670	58,109
Oregon	49,029	49,426	50,589	51,012	57,897
Total	**197,496**	**199,264**	**204,876**	**206,391**	**232,976**
Natural Gas Cumulative Savings (1,000's of Therms)					
Washington	370	682	4,643	8,898	13,676
Idaho	6	18	261	493	875
Oregon	8	27	375	763	1,405
Total	**384**	**727**	**5,279**	**10,154**	**15,957**
% of Total Residential Savings					
Washington	96%	94%	88%	88%	86%
Idaho	1%	3%	5%	5%	5%
Oregon	2%	4%	7%	8%	9%

Most residential potential exists in space heating end-uses and water heating applications. Appliances and miscellaneous end-use loads 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 jurisdictions 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.

Commercial and Industrial Potential Results

The baseline forecast for the commercial and industrial sector grows steadily during the forecast period. Consequently, energy efficiency opportunities are significant for this sector. However, similar to the residential sector, the historically low avoided cost projections limit the achievable potential.

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 under the TRC test; Washington has higher savings due to using the PAC cost effectiveness test. Tables 3.6 and 3.7 show the commercial and industrial achievable potential by sector for selected years.

Table 3.6 – Commercial and Industrial Cumulative Achievable Potential by Selected Years

	2015	2016	2019	2024	2034
Baseline projection (1,000's of Therms)					
Small Commercial	51,170	51,514	51,931	50,861	52,475
Large Commercial	74,839	75,677	77,168	76,716	76,927
Industrial	5,252	5,524	5,867	5,477	4,491
Total	**178,239**	**180,349**	**184,098**	**182,156**	**189,882**
Natural Gas Savings (1,000's of Therms)					
Small Commercial	296	480	1,400	3,286	6,924
Large Commercial	969	1,390	3,085	6,907	13,599
Industrial	27	42	126	268	407
Total	**1,292**	**1,912**	**4,611**	**10,461**	**20,930**
% of Total Commercial and Industrial Savings					
Small Commercial	23%	25%	30%	31%	33%
Large Commercial	75%	73%	67%	66%	65%
Industrial	2%	2%	3%	3%	2%

Table 3.7 – Commercial and Industrial Cumulative Achievable Potential by State, Selected Years

Cumulative Savings (1,000's of Therms)	2015	2016	2019	2024	2034
Washington	917	1,343	3,138	6,924	13,321
Idaho	223	324	768	1,824	3,629
Oregon	153	245	705	1,714	3,981
Total	**1,292**	**1,912**	**4,611**	**10,461**	**20,930**
Cumulative Natural Gas Savings (% of Statewide Baseline)					
Washington	1.3%	1.9%	4.4%	10.0%	20.0%
Idaho	0.7%	1.0%	2.3%	5.5%	10.8%
Oregon	0.5%	0.8%	2.3%	5.6%	11.8%
Total	**1.0%**	**1.4%**	**3.4%**	**7.9%**	**15.6%**

Similar to residential sector, most of the commercial and industrial potential exists in space and water heating applications. Food preparation, process and miscellaneous represents a smaller proportion of potential. Primary sources of commercial and industrial sector 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.

Aggregate Potential Results

The following three tables provide the 2015-2016 CPA identified DSM opportunities for Idaho, Oregon and Washington, respectively.

Table 3.8 – Idaho Natural Gas Savings Target (2015-2016)

Incremental Annual Savings (1,000's of Therms)	2015	2016
Residential	6	13
Commercial & Industrial	223	101
Total	**228**	**114**

Table 3.9 – Oregon Natural Gas Savings Target (2015-2016)

Incremental Annual Savings (1,000's of Therms)	2015	2016
Residential	8	19
Commercial & Industrial	153	92
Total	**161**	**111**

Table 3.10 – Washington Natural Gas Savings Target (2015-2016)

Incremental Annual Savings (1,000's of Therms)	2015	2016
Residential	370	311
Commercial & Industrial	917	426
Total	**1,287**	**737**

CPA Uses and Applications

It is useful to place the IRP process, and the CPA component of that process, into the larger perspective of Avista's efforts to acquire all available cost-effective DSM resources. Those activities outside the immediate scope of the IRP process include the formal annual business planning and annual cost-effectiveness and acquisition reporting processes, in addition to the ongoing management of the DSM portfolio.

The IRP process establishes a 20-year avoided cost stream that is essential not only to determining the quantity of DSM resources that are cost-effective when compared to the CPA-identified DSM supply curve, but also and perhaps more importantly the management of the DSM portfolio between the two-year IRP cycles. The avoided costs are critical to the selection and optimization of DSM delivery options on a real-time basis and as part of a comprehensive annual business planning process. The IRP-identified avoided costs also serve as the foundation for calculating the portfolios actual cost-effectiveness performance as part of Avista's retrospective DSM Annual Report.

These related and coordinated processes contribute to the planning and management of the DSM portfolio towards meeting its cost-effectiveness and acquisition goals.

The relationship between the CPA and the annual business planning process is of particular note. The CPA is a high-level tool useful for establishing aggregate targets and identifying general target markets and target measures. However, the CPA must make certain broad assumptions regarding key characteristics that are fine-tuned in the operational business plan. Some of the most frequently modified assumptions include market segmentation, customer eligibility, measure definition, incentive level, interaction between measures and opportunities for packaging measures or coordinating the delivery of measures.

The increased level of detail in the operational business planning process generally improves the cost-effectiveness of the individual measures and the overall portfolio. Eligibility and measure definitions can be fine-tuned to target the most cost-effective elements of a measure in such a way that marginally cost-ineffective measures can be become cost-effective contributors to the portfolio. However, it can also be true that the high-level assumptions made as part of the CPA may be overly optimistic when applied to individual programs.

One issue that inevitably arises when moving from the CPA to the business planning process is the treatment of market segments. The CPA defines market segments (e.g. by residential building type or vintage) to appropriately define the cost-effective potential for efficiency options and to ensure consistency with system loads and load forecasts. However, it is often infeasible to recognize these distinctions on an operational basis. This may result in aggregations of market segments into programs that could lead to more or less operationally achievable savings.

The continuation of the downward trend in natural gas avoided cost expectations is causing a growing deviation between the CPA and business planning process. CPA processes generally make the simplifying assumption that non-incentive utility costs are a constant percentage of the customer's incremental cost or of the offered incentive. Operationally there may be fixed and incremental components to these non-incentive costs and there may be economies of scale when enlarging the size of the portfolio (or conversely diseconomies of scale when the portfolio decreases due to lower avoided costs). CPA processes often function at too high of a level to recognize these operational details and are unable to predict the point at which the quantity of cost-effective DSM and the cost-effectiveness margin associated with those measures are insufficient to offset fixed portfolio costs and diseconomies of scale. These challenges are more appropriately left to the operational business planning processes.

Conclusion

Avista has a long-term commitment to responsibly pursuing all available and cost-effective efficiency options as an important means to reduce customer's energy costs. Cost-effective DSM options are a key element in Avista's strategy to meet those commitments. Falling avoided costs and low growth in customer demand have led to a reduced role for DSM in the natural gas portfolio, although as a consequence of the lower growth and the change in the cost-effectiveness metric applicable to the Washington jurisdiction, DSM greatly offset future load growth.

Avista is working to optimize how natural gas efficiency resource acquisition under this radically different economic environment. Important factors that must be considered within this optimization include:

- The criteria for adopting measures within the portfolio.
- The nature of Avista's non-incentive utility cost.
- The level of incentives established with particular attention to their implications upon the PAC test performance.
- Alternative means of moving cost-effective efficiency options forward.

In June 2014, Avista will begin developing the Washington and Idaho 2015 DSM Business Plan. This process is an opportunity to review the electric and natural gas DSM portfolios and perform the optimizations noted above. Within Washington, where the PAC test is being applied to this optimization process, there will be a review of the customer financial incentives to determine if the lower avoided costs are sufficient to support existing incentive levels. The Idaho portfolio review will determine if there are new opportunities that would allow a TRC cost-effective portfolio offering.

In Oregon the on-going optimization of the DSM portfolio has led to significant improvements in TRC cost-effectiveness performance in 2013, though revised unit energy savings may make it difficult to deliver the same level of performance in 2014. Nevertheless, there is a favorable trend occurring in the cost-effectiveness of the non-mandated portfolio components.

Perhaps of most importance in the long-term are Avista's ongoing efforts to work with others to develop a regional natural gas market transformation organization and portfolio. This concept has been developing for nearly a decade, but current circumstances have moved the discussion closer to the realization of such an organization. Regional natural gas utilities are actively working with the Northwest Energy Efficiency Alliance (NEEA) to develop a proposal for a natural gas market transformation entity similar to the electric market transformation efforts. The viability of market transformation efforts are likely to be less impacted by falling avoided costs since they focus upon technologies and markets where strategically selected market transformation interventions can have a disproportionate impact upon markets for efficient products and services. This makes market transformation a valuable tool in a lower avoided cost environment.

The CPA does not specify market transformation since it focuses on conservation potential without regard to how that potential is achieved. The prospect for a regional market transformation entity will potentially bring a valuable tool in working towards the achievement of the cost-effective conservation opportunities identified in the CPA.

Avista is also working with regional natural gas utilities on an ad hoc natural gas heat pump water heater technology pilot in anticipation of a future market transformation portfolio. The progress and prospective funding of this venture is a favorable indication that a cooperative regional market transformation effort is viable.

Avista anticipates that a proposal for a permanent natural gas market transformation organization will advance for regional discussion by the end of 2014. It is hoped that successes in this area will augment cost-effective local efforts and create additional local programmatic DSM opportunities.

4: Supply-Side Resources

Overview

Avista analyzed a range of future demand scenarios and possible cost-effective conservation measures to reduce demand. This chapter discusses supply options to meet net demand. Avista's objective is to provide reliable natural gas to customers with an appropriate balance of price stability and prudent cost under changing market conditions. To achieve this objective, Avista evaluates a variety of supply-side resources and attempts to build a diversified natural gas supply portfolio. The resource acquisition and commodity procurement programs resulting from the evaluation consider physical and financial risks, market-related risks, and procurement execution risks; and identify the methods to mitigate these risks.

Avista manages natural gas procurement and related activities on a system-wide basis with several regional supply options available to serve core customers. Supply options 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. This chapter discusses the available regional commodity resources and Avista's procurement plan strategies, the regional pipeline resource options available to deliver the commodity to customers, and the storage resource options available to provide additional supply diversity, enhanced reliability, favorable price opportunities, and flexibility to meet a varied demand profile. Non-traditional resources are also considered.

Commodity Resources

Supply Basins

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

Several large pipelines connect the WCSB and Rockies gas basins to the Pacific Northwest, Southwest, Midwest and Northeast sections of the continent. Historically, natural gas supplies from the WCSB and Rockies cost less relative to other parts of the country. Shale gas production from the Northeast has altered flow dynamics and helped sustain the regional pricing discount. Forecasts show a long-term regional price advantage for WCSB and Rockies basins as the need for these supplies in the East diminishes as more shale gas supply develops in the East.

Increased availability of North American natural gas has prompted a change in the global LNG landscape. Excess supply has prompted LNG developers to consider exporting natural gas to capture higher prices in the Asian and European markets. Regionally, there are two proposed projects in Oregon - Jordan Cove and Oregon LNG. Jordan Cove and Oregon LNG have each received their FERC export authorization. There are 16 announced export LNG projects in British Columbia. While there is much uncertainty about the number of completed facilities, the bigger question is the impact of exports on regional infrastructure and prices.

Regional Market Hubs

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

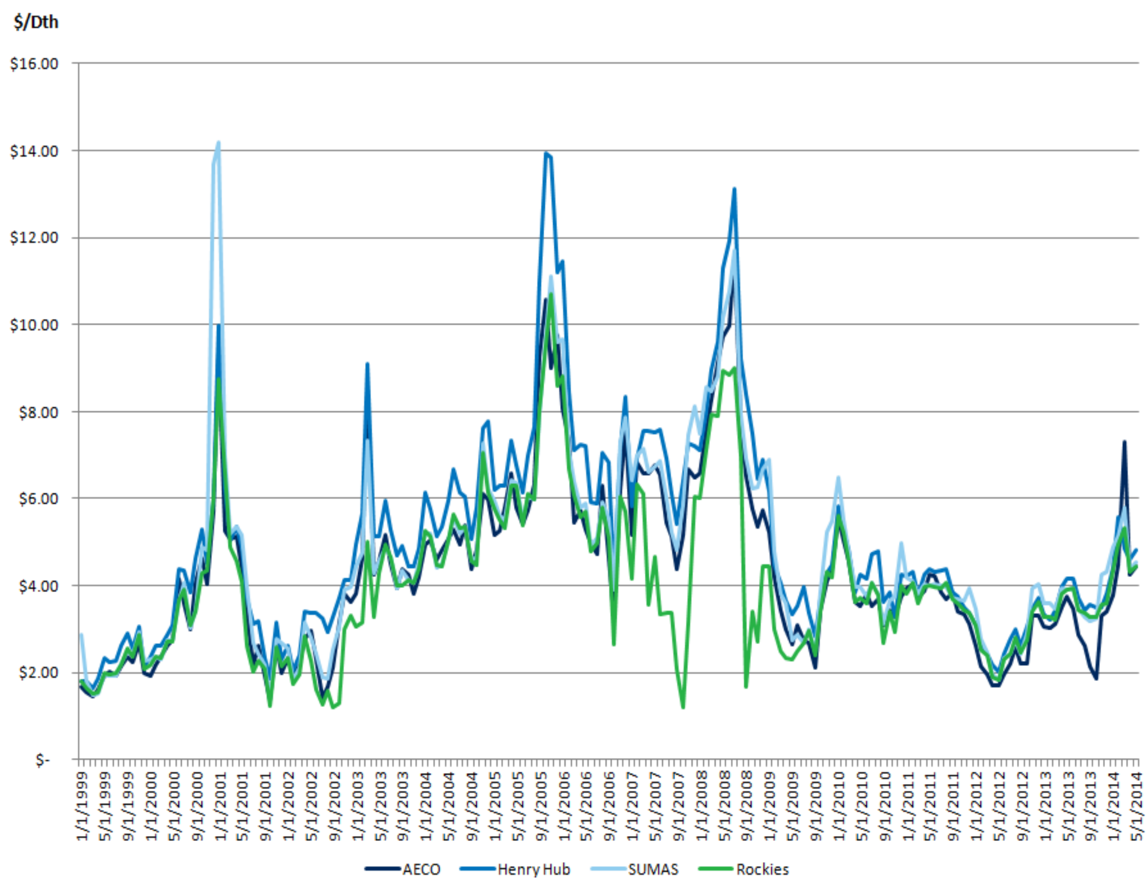
- **AECO** – The AECO-C/Nova Inventory Transfer market center located in Alberta is a major connection region to long-distance transportation systems, which take natural gas to points throughout Canada and the United States. Alberta is the major Canadian exporter of natural gas to the U.S. and historically produced 90 percent of Canada's natural gas.
- **Rockies** – This pricing point represents several locations on the southern end of the NWP system in the Rocky Mountain region. The system draws on Rocky Mountain natural gas-producing areas clustered in areas of Colorado, Utah and Wyoming.
- **Sumas/Huntingdon** – This pricing point at Sumas, Washington, is on the U.S./Canadian border where the northern end of the NWP system connects with Spectra Energy’s Westcoast Pipeline and predominantly markets Canadian gas from Northern British Columbia.
- **Malin** – This pricing point is at Malin, Oregon, on the California/Oregon border where the pipelines of TransCanada Gas Transmission Northwest (GTN) and Pacific Gas & Electric Company connect.

- **Station 2** – Located at the center of the Spectra Energy/Westcoast Pipeline system connecting to northern British Columbia natural gas 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 across North America, natural gas pricing is often compared to the Henry Hub price for natural gas. Henry Hub, located in Louisiana, is the primary natural gas pricing point in the U.S. and is the trading point used in NYMEX futures contracts.

Figure 4.1 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 regional market hubs; however, there have been periods where one or more price points have disconnected.

Figure 4.1: Monthly Index Prices



Northwest regional natural gas prices typically move together; however, the basis differential can change depending on market or operational factors. This includes differences in weather patterns, pipeline constraints, and the ability to shift supplies to higher-priced delivery points in the U.S. or Canada. By monitoring these price shifts, Avista can often 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 and Malin). This illiquidity contributes to generally higher relative prices in the high demand winter months.

Avista procures natural gas via contracts. Contract specifics vary from transaction-to-transaction, and many of those terms or conditions affect commodity pricing. Some of the 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 on 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 natural gas purchases under a firm, physical, fixed-price contract, regardless of contract execution date and type of contract. Avista pursues a variety of contractual terms and conditions to capture the most value for customers. Avista‘s natural gas buyers actively assess the most cost-effective way to meet customer demand and optimize unutilized resources.

Avista's Procurement Plan

No company can accurately predict future natural gas prices, but market conditions and experience help shape the overall approach. Avista's natural gas procurement plan process seeks to acquire natural gas supplies while reducing exposure to short-term price volatility. The procurement strategy includes hedging, storage utilization and index purchases. Although the specific provisions of the procurement plan will change based on ongoing analysis and experience, the following principles guide Avista's procurement plan.

Avista employs a time, location and counterparty diversified hedging strategy. It is appropriate to hedge over a period and establish hedge periods when portions of future demand are physically and/or financially hedged. Avista views hedging as an appropriate part of a diversified procurement plan and provides a level of known pricing and stability to customers. Hedges may not be at the lowest possible price, but they still protect customers from price volatility. With access to multiple supply basins, Avista transacts with the lowest priced basin at the time of the hedge. Furthermore, Avista transacts with a range of counterparties to spread supply among a wider range of market participants.

Avista uses a disciplined, but flexible hedging approach. In addition to establishing periods when hedges are to be completed, Avista also sets upper and lower pricing points. This reduces Avista's exposure to extreme price spikes in a rising market and 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 procurement plan assumptions. Even though the initial plan establishes various targets, policies provide flexibility to exercise judgment to revise targets in response to changing conditions.

Avista utilizes a number of tools to help mitigate financial risks. Avista purchases gas in the spot market and forward markets. Spot purchases are for the next day or weekend. Forward purchases are for future delivery. Many of these tools are financial instruments or derivatives that can provide fixed prices or dampen price volatility. Avista continues to evaluate how to manage daily demand volatility, whether through option tools from counterparties or through access to additional storage capacity and/or transportation.

Market-Related Risks and Risk Management

There are several definitions of risk management. The IRP focuses on two areas of risk: the financial risk where the cost to supply customers will be unreasonably high or volatile, and the physical risk that there may not be enough natural gas resources (either transportation capacity or the commodity) to serve core customers.

Avista's Risk Management Policy describes the policies and procedures associated with financial and physical risk management. The Risk Management Policy addresses issues related to management oversight and responsibilities, internal reporting requirements, documentation and transaction tracking, and credit risk.

Two internal organizations 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 includes 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 coordinates natural gas matters among internal natural gas-related stakeholders and serves 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 Strategic Oversight Group provides input and advice.

Transportation Resources

Although proximity to liquid market hubs is important from a cost perspective, supplies are only as reliable 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. Avista contracts for a sufficient amount of diversified firm pipeline capacity from various receipt and delivery points (including storage facilities), so that firm deliveries will meet peak day demand. This combination of firm transportation rights to Avista's service territory, storage facilities and access to liquid supply basins ensure peak supplies are available to serve core customers.

The major pipelines servicing the region include:

- **Williams - Northwest Pipeline (NWP)**
  A natural gas transmission pipeline serving the Pacific Northwest moving natural

gas from the U.S./Canadian border in Washington and from the Rocky Mountain region of the U.S.

- **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, Oregon.
- **TransCanada Alberta System:** This natural gas gathering and transmission pipeline in Alberta, Canada, delivers natural gas into the TransCanada Foothills pipeline at the Alberta/British Columbia border.
- **TransCanada Foothills System:** This natural gas transmission pipeline delivers natural gas between the Alberta, British Columbia, border and the Canadian/U.S. border at Kingsgate, Idaho.
- **TransCanada Tuscarora Gas Transmission:** This natural gas transmission pipeline originates at Malin, Oregon, and terminates at Wadsworth, Nevada.
- **Spectra Energy - Westcoast Pipeline:** This natural gas transmission pipeline originates at Fort Nelson, British Columbia, and terminates at the Canadian/U.S. border at Huntington, British Columbia/Sumas, Washington.
- **El Paso Natural Gas– Ruby pipeline:** This natural gas transmission pipeline brings supplies from the Rocky Mountain region of the U.S. to interconnections near Malin, Oregon.

Avista has contracts with all of the above pipelines (with the exception of Ruby Pipeline) for firm transportation to serve our core customers. Table 4.1 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 4.1: Firm Transportation Resources Contracted (Dth/Day)

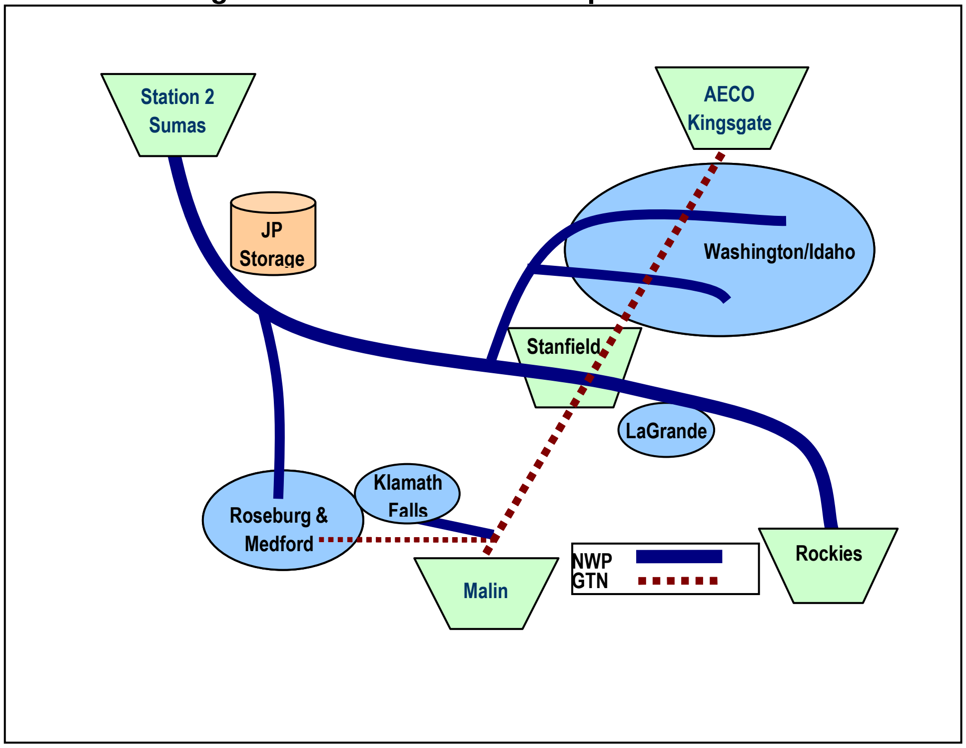
Firm Transportation	Avista North Winter	Avista North Summer	Avista South Winter	Avista South Summer
NWP TF-1	157,869	157,869	42,699	42,699
GTN T-1	100,605	75,782	42,260	20,640
NWP TF-2	91,200		2,623	
Total	**349,674**	**233,651**	**87,582**	**63,339**
Firm Storage Resources - Max Deliverability				
Jackson 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 Avista’s 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 4.2 illustrates the direct-connect pipeline network relative to Avista’s supply sources and service territories.[1]

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

Figure 4.2: Direct-Connect Pipelines



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.

The NWP system, for the most part, is a fully-contracted system. With the exception of La Grande, Avista's service territories lie at the end of NWP pipeline laterals. The Spokane, Coeur d'Alene and Lewiston laterals serve Washington/Idaho load, and the Grants Pass lateral serves Roseburg and Medford. Capacity expansions of these laterals would be lengthy and costly endeavors which Avista would likely bear most of the incremental costs.

The GTN system currently has ample unsubscribed capacity. This pipeline runs directly through or near most of Avista's service territories. Mileage based rates provides an attractive option for securing incremental resource needs.

Peak day planning aside, both pipelines provide an array of options to flexibly manage daily operations. The NWP and GTN pipelines directly serve Avista's two largest service territories, providing diversification and risk mitigation 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 Columbia supply and facilitates optionality for storage facility management. The Stanfield interconnect of the two lines is also geographically well situated to Avista's service territories.

The rates used in the planning model start with filed rates currently in effect (See Appendix 4.1). Forecasting future pipeline rates is challenging. Assumptions for future rate changes are the result of market information on comparable pipeline projects, prior rate case experience, and informal discussions with regional pipeline owners. 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. 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. Avista does 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 on a peak day in the planning horizon. Since contracts for pipeline capacity are often lengthy and core customer demand needs can vary over time, determining the appropriate level of firm transportation is a complex analysis. 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 upstream supplies. This analysis is 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 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 (See Chapter 5 for a more detailed description of the management of underutilized pipeline resources).

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 several 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), of 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, Washington approximately 30 miles south of Olympia, Washington. 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. Besides ownership rights, Avista 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

Avista's existing portfolio of supply-side resources provides a mix of assets to manage demand requirements for average and peak day events. Avista monitors the following potential resource options to meet future requirements in anticipation of changing demand requirements. When considering or selecting a transportation resource, the appropriate natural gas supply pairs with the transportation resource and the SENDOUT® model prices the resources accordingly.

System Enhancements

Distribution planning plays a role in the IRP, but is not the primary focus. Distribution works with supply to meet customer demand on average and peak days. Modifications, enhancements or upgrades occur on the distribution system that are routine projects, enhancing system reliability. However, in certain instances, Avista can facilitate additional peak and base load-serving capabilities through a modification or upgrade of distribution facilities. These projects would enable more takeaway capacity from the interstate pipelines. When resource deficiencies are identified, Gas Supply works with distribution engineering to assess if the distribution system can facilitate additional take away. 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) are in Chapter 7 – Distribution Planning.

Capacity Release Recall

As discussed earlier, pipeline capacity not utilized to serve core customer demand is available to sell to other parties or optimized through daily or term transactions. Released capacity is generally marketed through a competitive bidding process and can be on a short-term (month-to-month) or long-term basis. Avista actively participates in the capacity release market with short-term and long-term capacity releases.

Avista assesses 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 to recall some or all long-term releases.

Existing Available Capacity

In some instances, there is currently available capacity on existing pipelines. NWP's mainline is 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. Avista models access to the GTN capacity as an option to meet our future demand needs.

GTN Backhauls

The GTN interconnection with the Ruby Pipeline has enabled GTN the physical capability to provide a limited amount of firm back-haul service from Malin with minor modifications to their system. Fees for utilizing this service are under the existing Firm Rate Schedule (FTS-1) and currently include no fuel charges. Additional requests for back-haul service may require additional facilities and compression (i.e., fuel).

This service can provide an interesting solution for Oregon customers. For example, Avista can purchase supplies at Malin, Oregon and transport those supplies to Klamath

Falls or Medford. Malin-based natural gas supplies typically include a higher basis differential to AECO supplies, but are generally less expensive than the cost of forward-haul transporting those traditional supplies south and paying the associated demand charges. The GTN system is a mileage-based system, so Avista pays only a fraction of the 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.

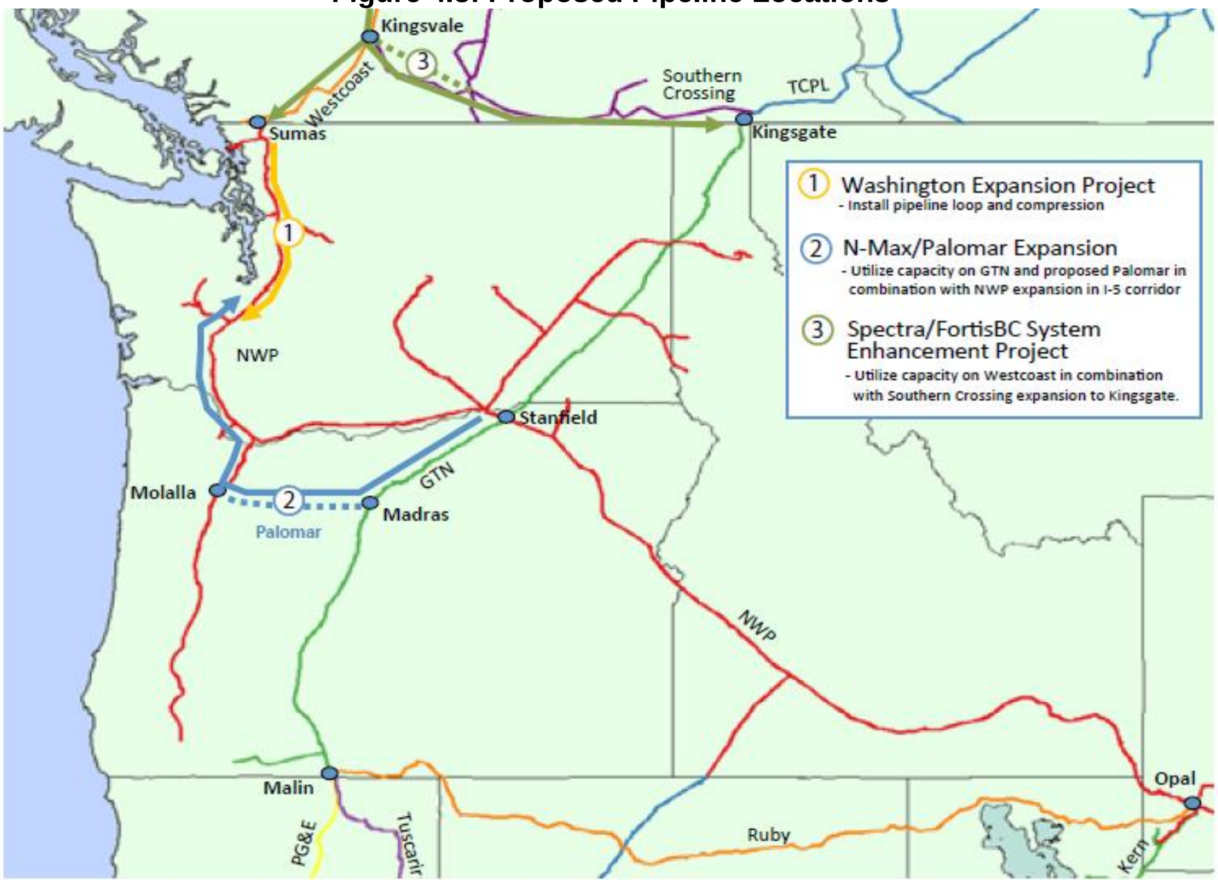
New Pipeline Transportation

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 if existing resources will be available at the appropriate time, make this resource difficult to analyze. Firm pipeline transportation 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 transportation 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 contracts. Even though expansions may be more expensive than existing capacity, this approach may still provide the best option given that some of the other options discussed in this section require matching pipeline transportation. Expansions may also provide reliability or access to supply that cannot be obtained through existing pipelines.

Several specific projects have been proposed for the region. The following summaries describe these projects while Figure 4.3 illustrates their location.

Figure 4.3: Proposed Pipeline Locations



Source: Northwest Gas

- **NWP Washington Expansion**

  NWP continues to explore options to expand service from Sumas, Wash., to markets along the Interstate-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 it can scale to meet market demand. This project is currently under FERC review.

- **Northwest Market Access Expansion (N-MAX)/Palomar Expansion**

  NWP began working with Palomar Gas Transmission (a partnership between NW Natural and TransCanada) to develop the Cascade (eastern) section of the previously proposed Palomar gas transmission line 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, Oregon. It would be a bi-directional pipeline with an initial capacity of up to 300 MMcf/d expandable up to 750 MMcf/d. In 2011, Palomar Gas Transmission withdrew its application for this pipeline, yet remains prepared if natural gas demand rebounds.

- **Spectra/FortisBC System Enhancement**

  FortisBC 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. Expanding 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. Currently, there is no plan to construct this pipeline, but it would be available if demand was sufficient.

Avista supports proposals that bring supply diversity and reliability to the region. Avista engages in discussions and analysis of the potential impact of each regional proposal from a demand serving and reliability/supply diversity perspective. None of the above projects provides direct delivery connection to any of the service territories. For Avista to consider them a viable incremental resource to meet demand needs would require combining them with additional capacity on existing pipeline resources. Given this situation, Avista did not model these specific projects. However, the IRP considers a generic expansion that represents a new pipeline build to Avista's service territories.

In-Ground Storage

In-ground storage provides advantages when gas from storage can be delivered to Avista's service territory city-gates. It enables deliveries of natural gas to customers during peak cold weather events. It also facilitates potentially lower-cost supply for 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 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, Avista will continue to look for exchange and transportation release opportunities that could fully utilize these additional resource options. When an opportunity presents itself, Avista assesses if it makes sense from a financial impact to customers, as well as reliability. Even without deliverability, 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.

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, Wyo., and northern California storage are all possibilities. Transportation to and from these facilities to Avista’s service territories continues to be the largest impediment to these options. Avista will continue to look for exchange and transportation release opportunities while monitoring daily metrics of load, transport and market environment.

LNG and CNG

LNG is another resource option in Avista’s service territories and is suited for meeting peak day or cold weather events. Satellite LNG uses natural gas that is trucked to the facilities in liquid form from an offsite liquefaction facility. Alternatively, small-scale liquefaction and storage may also be an effective resource option if gas supply during non-peak times is sufficient to build adequate inventory for peak events. Permitting issues notwithstanding, facilities could be located in optimal locations within the distribution system.

CNG is another resource option for meeting demand peaks and is operationally similar to LNG. Natural gas could be compressed offsite and delivered to a distribution supply point or compressed locally at the distribution supply point if sufficient natural gas supply and power for compression is available during non-peak times.

LNG and CNG supply resource options for LDCs are becoming more attractive as the market for LNG and CNG as alternative transportation fuels develops. The combined demand for peaking and transportation fuels can increase the volume and utilization of these resource assets thus lowering unit costs for the benefit of both market segments.

Estimates for LNG and CNG resources vary because of sizing and location issues. This IRP uses estimates from other facilities constructed in the area and from informal conversations with experts in the industry. Avista will monitor and refine the costs of developing LNG and CNG resources while considering lead time requirements and environmental issues.

Plymouth LNG

NWP owns and operates an LNG storage facility at Plymouth, Wash., which provides gas liquefaction, storage and vaporization service under its LS-1 and LS-2F tariffs. An example ratio of injection and withdrawal rates show 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 Avista's service territories would have to be obtained in order for it to be an effective peaking resource.

This peaking resource is fully contracted and not available at this time. Given this situation, this option is not modeled in SENDOUT® for this IRP. However, because many of the current capacity holders are on one-year rolling evergreen contracts, it is possible this option will become viable in the future. As with other storage options, firm transportation from the facility would be required.

Avista-Owned Liquefaction LNG

Avista could construct a liquefaction LNG facility in the service area. Doing so could use excess transportation during off-peak periods to fill the facility, avoid tying up transportation during peak weather events, and it may avoid additional annual pipeline charges.

Construction would depend 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, Avista did not include this resource in the IRP modeling.

Biogas

Biogas typically refers to a gas produced by the biological breakdown of organic matter in the absence of oxygen. Biogas can be 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 is primarily methane and carbon dioxide.

Biogas is a renewable fuel, so it may qualify for renewable energy subsidies. Avista is not aware of any current subsidies, but future stimulus or energy policies could lead to some form of financial incentives.

Biogas projects are unique, so reliable cost estimates are 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. Avista did not consider biogas as a resource in this planning cycle, since they are small and insignificant compared to demand, but remains receptive to such projects as they are proposed.

Supply Scenarios

This IRP includes two supply scenarios. Table 4.2 lists the supply scenarios and Appendix 4.2 provides the details on what is included in each of these scenarios. Additional details about the results of the supply scenarios are in Chapters 5 and 6.

Table 4.2: Supply Scenarios

Supply Scenarios
Existing Resources
Existing + Expected Available

- **Existing Resources:** This scenario represents all resources currently owned or contracted by Avista.
- **Existing + Expected Available:** In this scenario, existing resources plus supply resource options expected to be available when resource needs are identified. This includes currently available south and north bound GTN, capacity release recalls, NWP expansions and satellite LNG.

Supply Issues

The abundance and accessibility of shale gas has fundamentally altered North American natural gas supply and the outlook for future natural gas prices. Even though the supply is available and the technology exists to access it, there are issues that can affect the cost and availability of natural gas.

Hydraulic Fracturing

Improvements in hydraulic fracturing, a 60-year-old technique used to extract oil and natural gas from shale rock formations, coupled with horizontal drilling has enabled access to previously uneconomic resources. However, the process does not come without challenges. The publicity caused by movies, documentaries and articles in national newspapers about “fracking” has plagued the natural gas and oil industry. There is worry that hydraulic fracturing is contaminating aquifers, increasing air pollution and 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.

Government, industry and universities engaged in studies to understand the actual and potential impacts of hydraulic fracturing. 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 hydraulic fracturing processing, and implementing “green completions” for wells. State governments are participating in independent audits of their regulations to ensure that proper oversight is in place. The outcome of these audits, studies and research could greatly affect the cost and availability of natural gas and oil.

Pipeline Availability

The Pacific Northwest has efficiently utilized its relatively sparse network of pipeline infrastructure to meet the regions needs. As the amount of renewable energy increases, future demand for natural gas-fired generation will increase. Pipeline capacity is the link between natural gas and power.

Adding additional pressure to existing pipeline resources is the announcement of three methanol plants in the region. The plants use large amounts of natural gas as a feedstock for creating methanol, which is used to make other chemicals and as a fuel.

LDCs will have to compete with power generators, LNG exporters and other large end users for limited pipeline capacity. The new mix could alter current pipeline operations and the potential availability of infrastructure to the region.

Action Items

Without resource deficiencies or a need to acquire incremental supply-side resources to meet peak day demands, Avista’s focus will only include normal activities in the near term, including:

- Continue to monitor supply resource trends including the availability and price of natural gas to the region, exporting LNG (specifically on the Oregon coast) Canadian natural gas imports, regional plans for natural gas-fired generation and its affect on pipeline availability, and regional pipeline and storage infrastructure plans
- Avista will also monitor new resource lead-time requirements relative to when resources are needed to preserve resource option flexibility

Conclusion

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

5: Integrated Resource Portfolio

Overview

This chapter combines the previously discussed IRP components and the model used to determine resource deficiencies during the 20-year planning horizon. Although not the case in this IRP, this chapter also provides an analysis of potential resource options to meet resource deficiencies when they exist.

The foundation for integrated resource planning is the criteria used for developing demand forecasts. Avista uses the coldest day on record as its weather-planning standard for determining peak-day demand. This is consistent with past IRPs and as described in Chapter 2 – Demand Forecasts. This IRP utilizes coldest day on record and average weather data for each demand region for this IRP. Avista plans to serve expected peak day in each demand region with firm resources. Firm resources include natural gas supplies, firm pipeline transportation and storage resources. In addition to peak requirements, Avista also plans for non-peak periods such as winter, shoulder and summer demand. The modeling process includes running a daily 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. It is Avista's belief that using coldest day on record weather criteria, a blended price curve developed by industry experts, and an academically backed customer forecast all work together to develop stringent planning criteria.

Forecasted demand represents the amount of natural gas supply needed. In order to deliver the forecasted demand, the supply forecast needs to be 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 1.0 percent to 3.0 percent, known as fuel, varies depending on the pipeline. The FERC and National Energy Board approved tariffs govern the percentage of required additional fuel supply.

SENDOUT® Planning Model

The SENDOUT® Gas Planning System from Ventyx performs 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 for software updates and enhancements. Enhancements include software corrections and improvements brought on by industry needs.

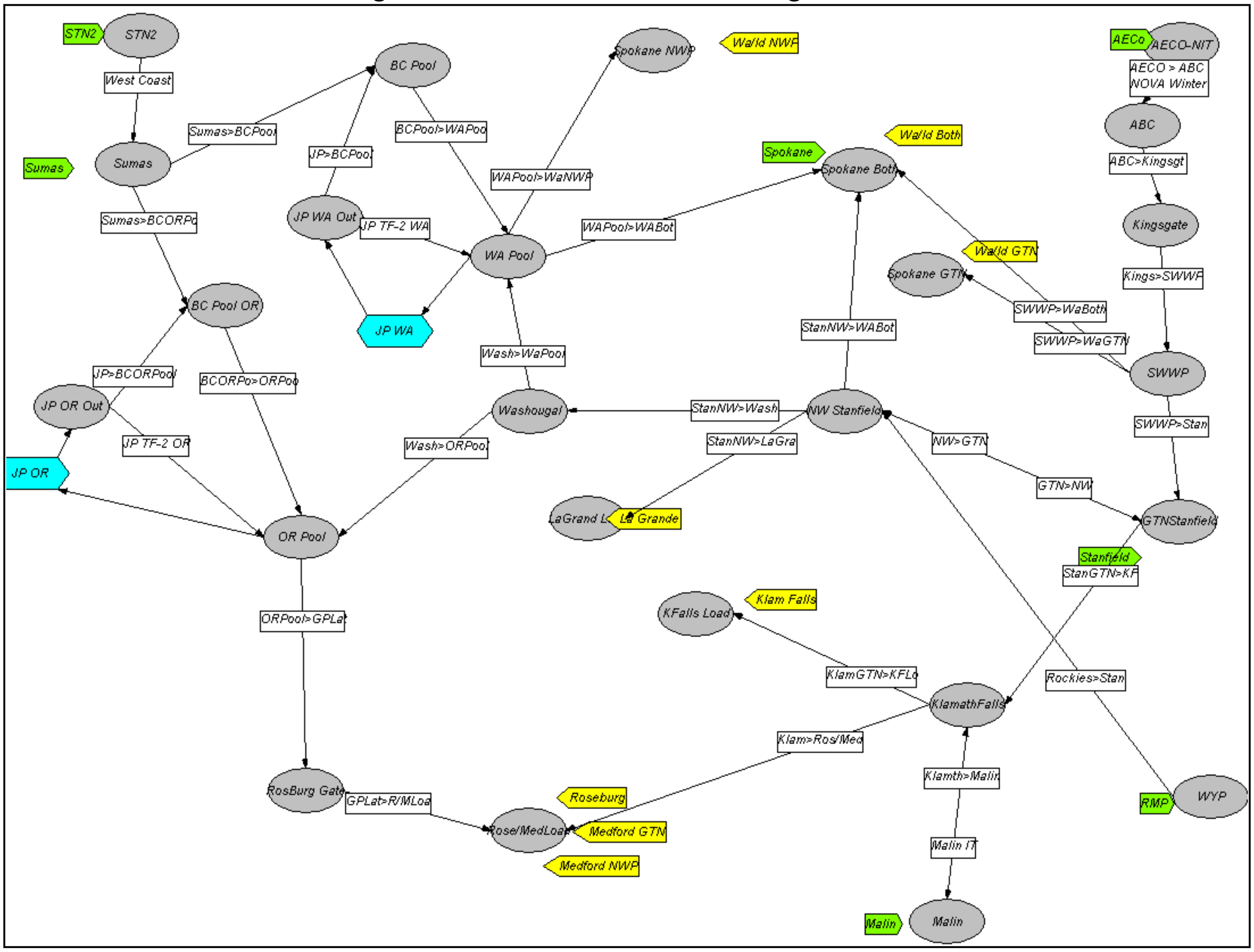
SENDOUT® is a linear programming model widely used to solve natural gas supply and transportation optimization questions. Linear programming is a proven technique used to solve minimization/maximization problems. SENDOUT® analyzes the complete problem at one time within the study horizon, while accounting for 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, including minimum, maximum and average temperatures.
- Existing and potential transportation data which describes the network for physical movement of 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 5.1 is a SENDOUT® network diagram of Avista's demand centers and resources. This diagram illustrates current transportation and storage assets, flow paths and constraint points.

Figure 5.1 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 6 – Alternate Scenarios, Portfolios and Stochastic Analysis.

Resource Integration

This IRP defines the planning methodologies, describes the modeling tools and identifies existing and potential resources. The following summarizes the comprehensive analysis bringing demand forecasting and existing and potential supply and demand-side resources together to form the 20-year, least-cost plan.

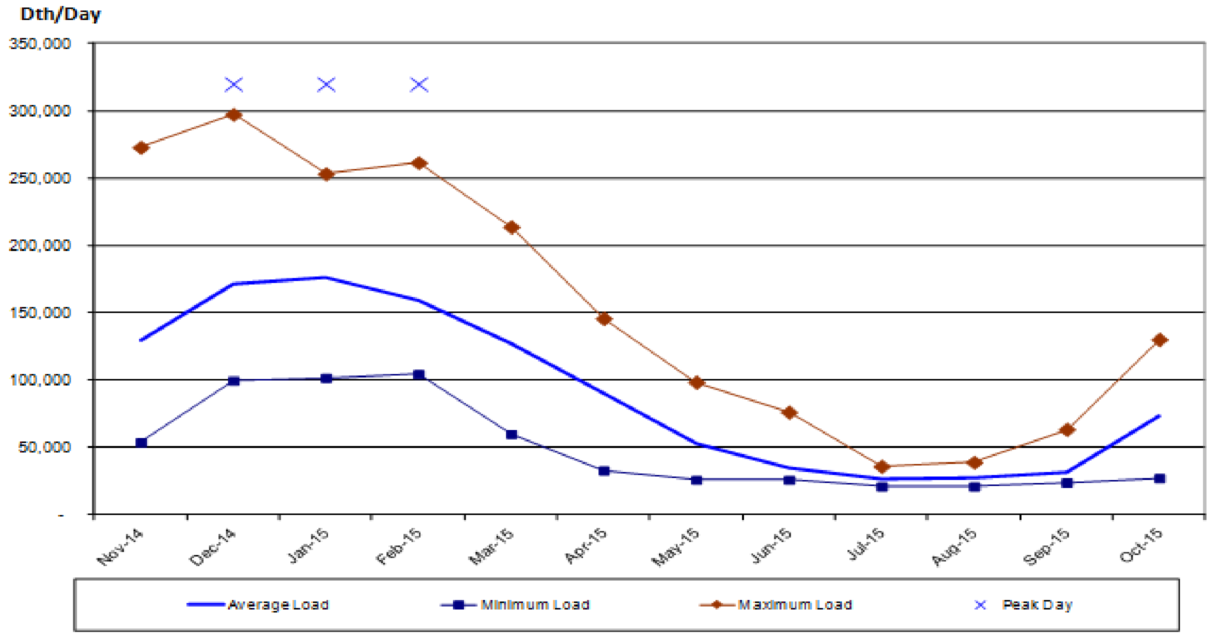
Demand Forecasting

Chapter 2 - Demand Forecasts describes Avista's demand forecasting approach.

Avista forecasts 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, Avista also models demand by customer class within each area. The relevant customer classes are residential, commercial and firm industrial customers.

Customer demand is highly weather-sensitive. Avista's customer demand is not only highly seasonable, but also highly variable. Figure 5.2 captures this variability showing monthly system-wide average demand, minimum demand day observed by month, maximum demand day observed in each month, and winter projected peak day demand for the first year of the Expected Case forecast as determined in SENDOUT®.

Figure 5.2: Total System Average Daily Load (Average, Minimum, Maximum)



Natural Gas Price Forecasts

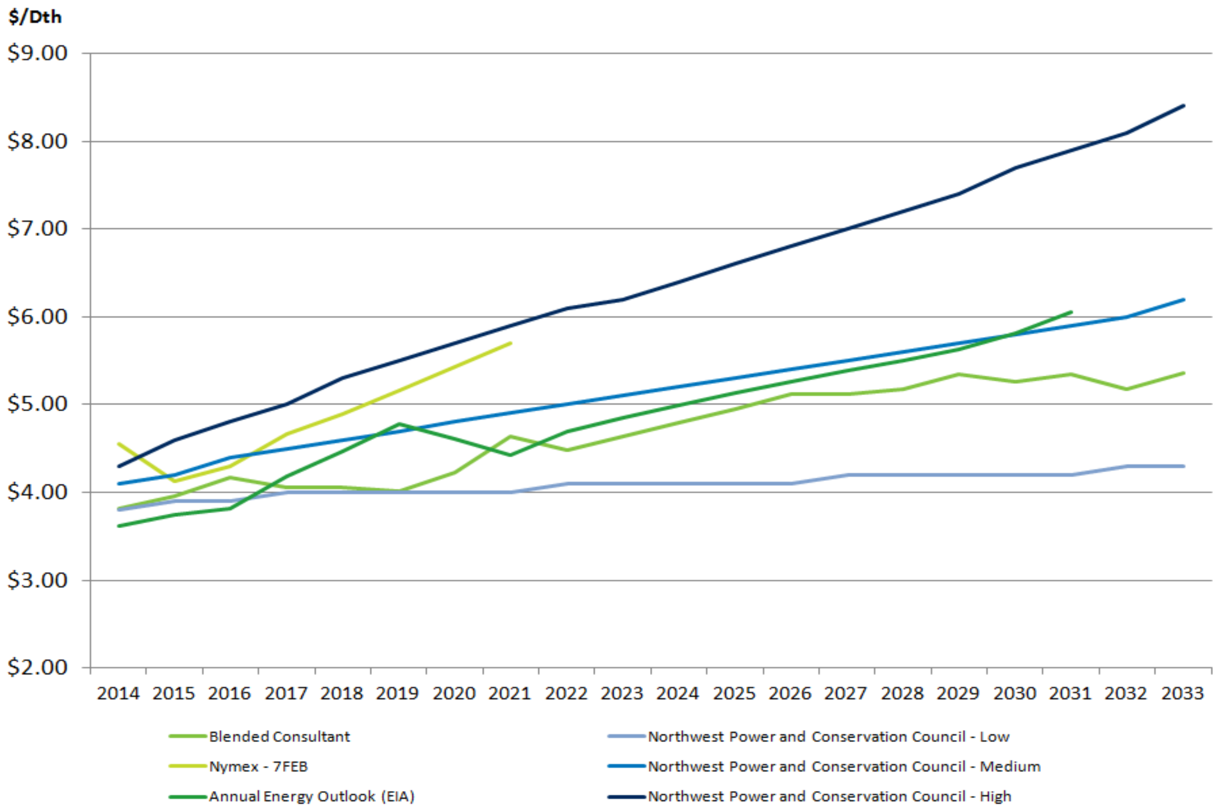
Natural gas prices are a fundamental component of the IRP. The commodity price is a significant component of the total cost of a resource option. This affects the avoided cost threshold for determining cost-effectiveness of conservation measures. The price of natural gas influences consumption, so price elasticity is part of the demand evaluation (see Chapter 2 – 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 recent recession, shale gas production, green house gas issues, and renewable energy standards creating the potential for more natural gas-fired generation impact the natural gas outlook. 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, natural gas-fired generation, infrastructure disruptions, and infrastructure additions (e.g. new pipelines and LNG terminals).

Even though Avista continually monitors these factors, we cannot accurately predict future prices for the 20-year horizon of this IRP. This IRP reviewed several price forecasts from credible sources. Figure 5.3 depicts the price forecasts considered in the IRP analyses.

Figure 5.3: Henry Hub Forecasted Price (Real $/Dth)



Selecting the price curves can be more art than science. With the assistance of the TAC, Avista selected high, expected and low price curves to consider possible outcomes and their impact on resource planning. The expected curve was a 50 / 50 blended price derived from consulting services subscriptions with the high and low bounding the expected curve with industry experts' opinions. The selected price curves have variation and provide reasonable upper and lower bounds, consistent with stretching modeling assumptions to address uncertainty in the planning environment. These curves are in real dollars in Figure 5.4 and nominal dollars in Figure 5.5. Additionally, stochastic modeling of natural gas prices is also completed. The results from that analysis are in Chapter 6 – Alternate Scenarios, Portfolios and Stochastic Analysis.

Figure 5.4 Henry Hub Forecasts for IRP Low/ Medium/ High Forecasted Price – Real $/Dth

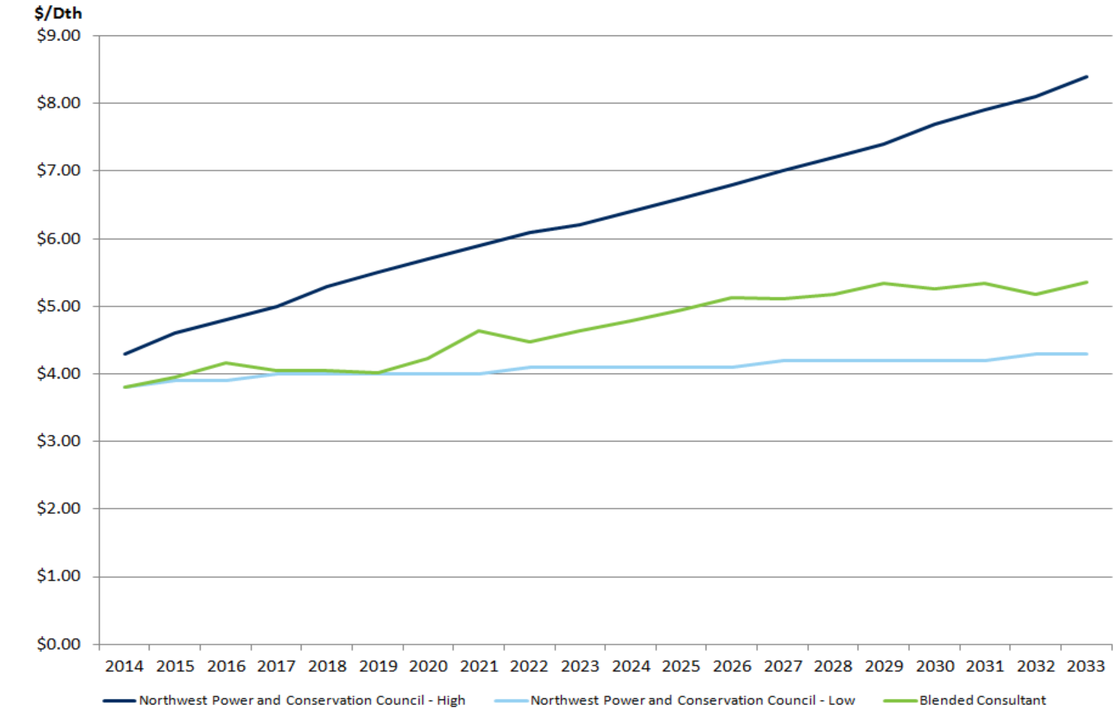
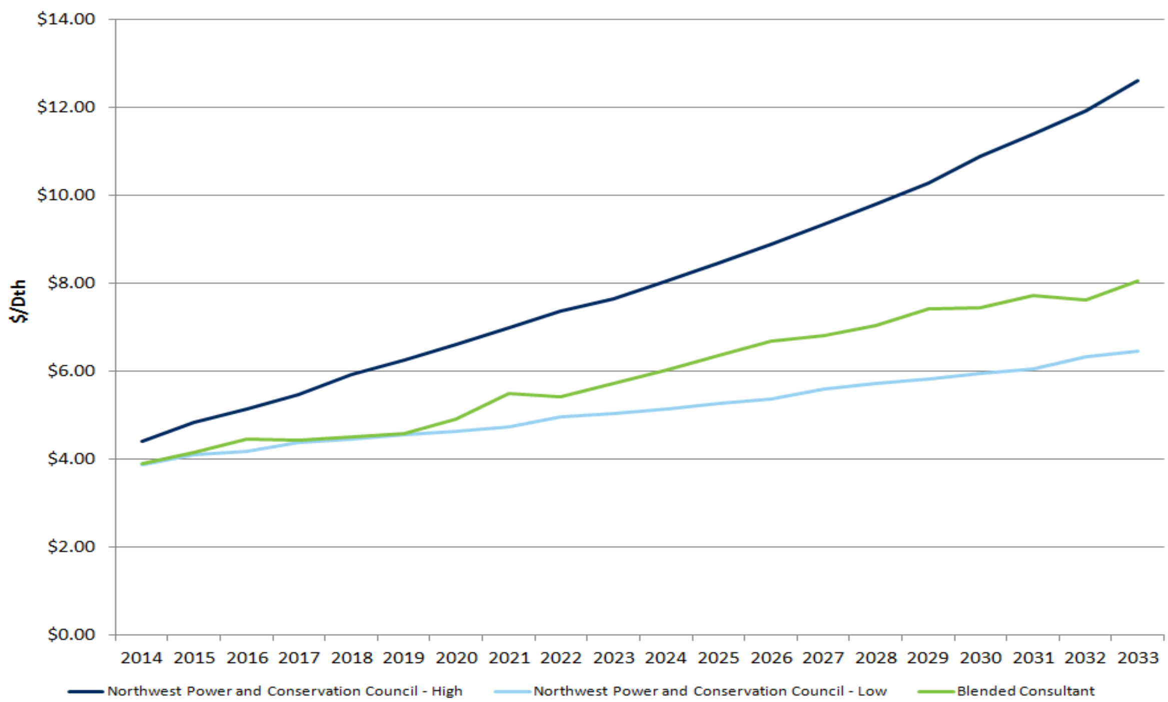


Figure 5.5: Low / Medium / High Forecasted Price – Nominal $/Dth



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 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) determine Avista's costs. Prices at these points typically trade at a discount, or negative basis differential, to Henry Hub because of their proximity to the two largest natural gas basins in North America (the WCSB and the Rockies).

Table 5.1 shows the Pacific Northwest regional prices from the consultants, historic averages and the prior IRP as a percent of Henry Hub price, along with three-year historical comparisons.

Table 5.1: Regional Price as a Percent of Henry Hub Price

	AECO	Sumas	Rockies	Malin	Stanfield
Consultant1 Forecast Average	91.9%	101.4%	99.2%	105.3%	102.7%
Consultant2 Forecast Average	84.9%	93.6%	91.6%	97.3%	94.8%
Historic Cash Three-Year Average	87.4%	98.4%	116.4%	99.2%	97.5%
2012 IRP	88.60%	89.90%	90.80%	92.30%	91.40%

This IRP used monthly prices for modeling purposes because of Avista's winter-weighted demand profile. Table 5.2 depicts the monthly price shape used in this IRP. A slight change to the shape of the pricing curve 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 5.2: Monthly Price as a Percent of Average Price

	Jan	Feb	Mar	Apr	May	Jun
Consult 1	101%	102%	102%	99%	99%	99%
Consult 2	104%	104%	97%	96%	97%	98%
Prior IRP	101%	101%	98%	98%	98%	100%
	Jul	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Consult 1	99%	100%	101%	100%	100%	100%
Consult 2	99%	100%	99%	99%	102%	106%
Prior IRP	102%	103%	100%	100%	100%	102%

Avista selected a blend of Consultant 1 and Consultant 2's forecast of regional prices and monthly shapes. Appendix 5.1 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 natural gas to customers. Daily capacity of existing transportation resources (described in Chapter 4 – Supply-Side Resources) is represented by the firm resource duration curves depicted in Figures 5.6 and 5.7.

Figure 5.6: Existing Firm Transportation Resources – Washington/Idaho

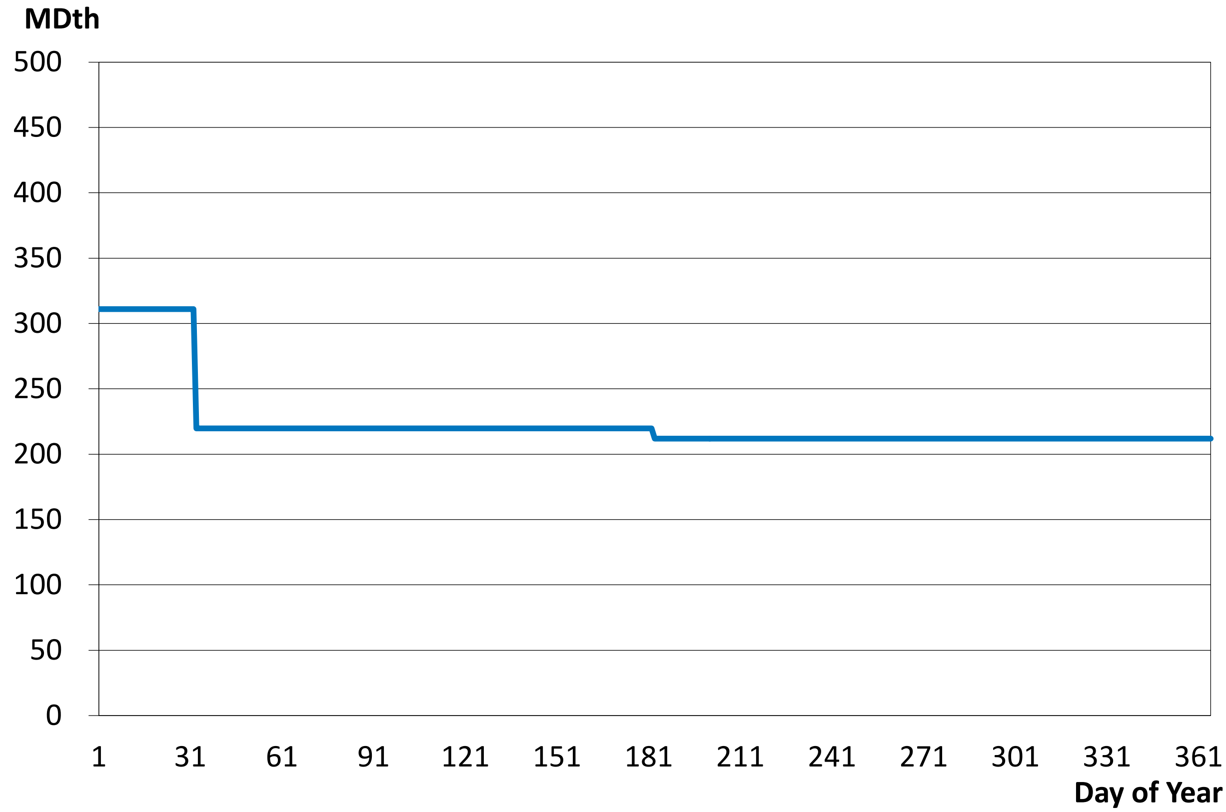
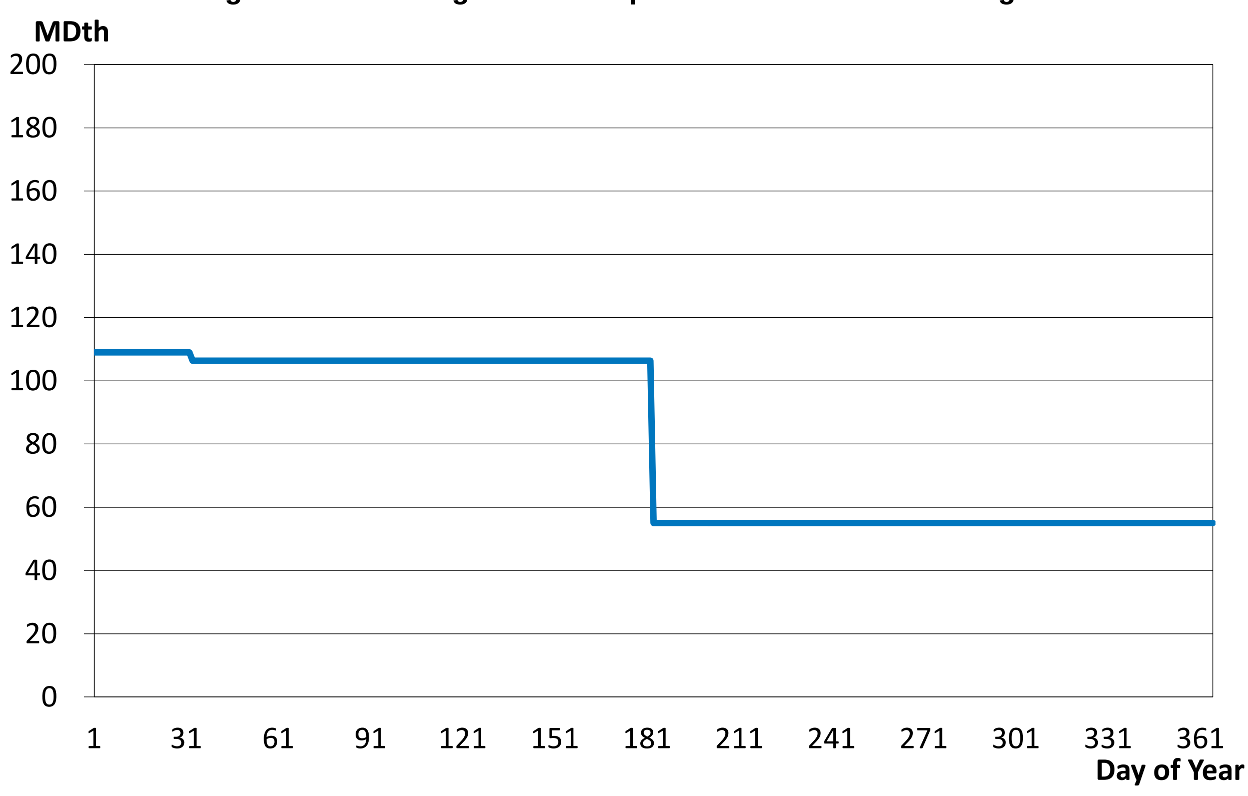


Figure 5.7: Existing Firm Transportation Resources – Oregon



Current rates for capacity are in Appendix 5.1. Forecasting future pipeline rates can be a challenge because of the need to estimate the amount and timing of rate changes. Avista's estimates and timing of future pipeline 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 5.2 – General Assumptions).

Demand-Side Management

Chapter 3 – Demand-Side Resources describes the methodology used to identify conservation potential and the interactive process that utilizes avoided cost thresholds for determining the cost effectiveness of conservation measures on an equivalent basis with supply-side resources.

Preliminary Results

After incorporating the above data into the SENDOUT® model, Avista generated an assessment of demand compared to existing resources for several scenarios. Chapter 2 – Demand Forecasts discusses the demand results from these cases, with additional details in Appendices 2.1 through 2.10.

Figures 5.8 through 5.11 provide graphic summaries of Average Case demand compared to existing resources. This demand is net of DSM savings and shows the adequacy of Avista's resources under normal weather conditions. For this case, current resources meet demand needs over the planning horizon.

Figure 5.8: Average Case – Washington/Idaho Existing Resources vs. Peak Day Demand – February 15th

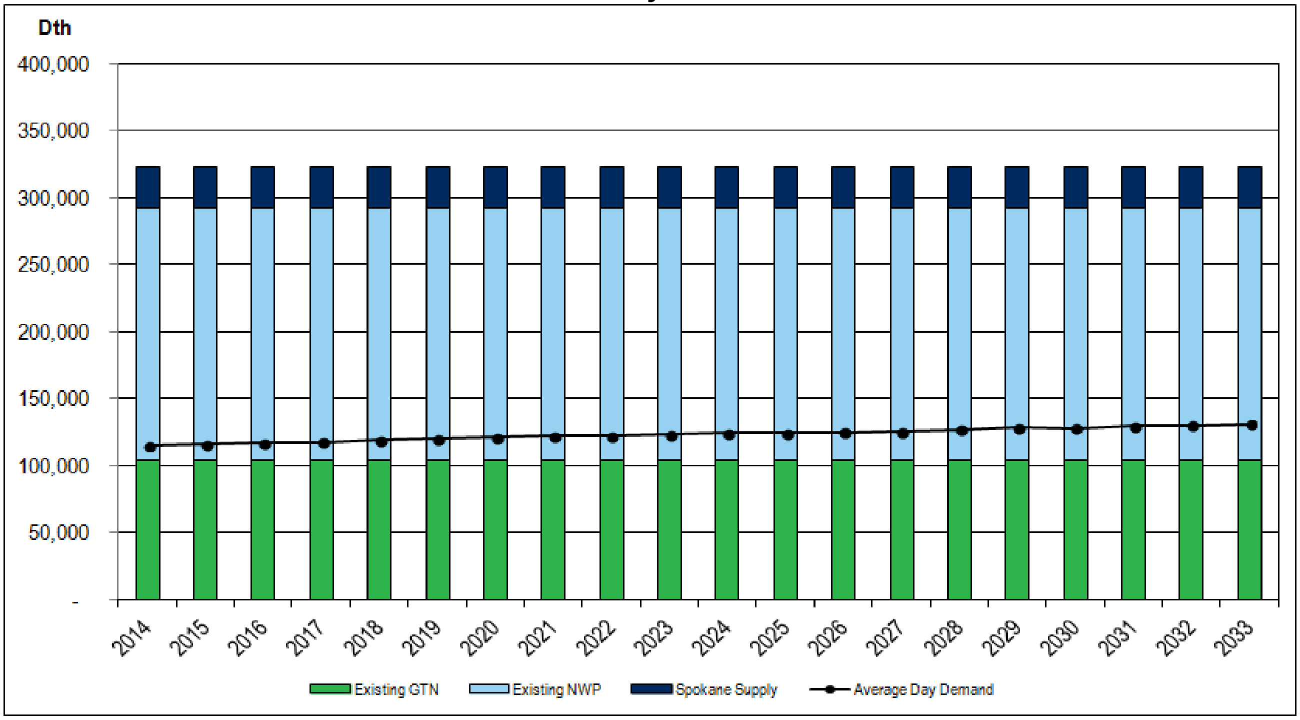


Figure 5.9: Average Case – Medford / Roseburg Existing Resources vs. Peak Day Demand – December 20th

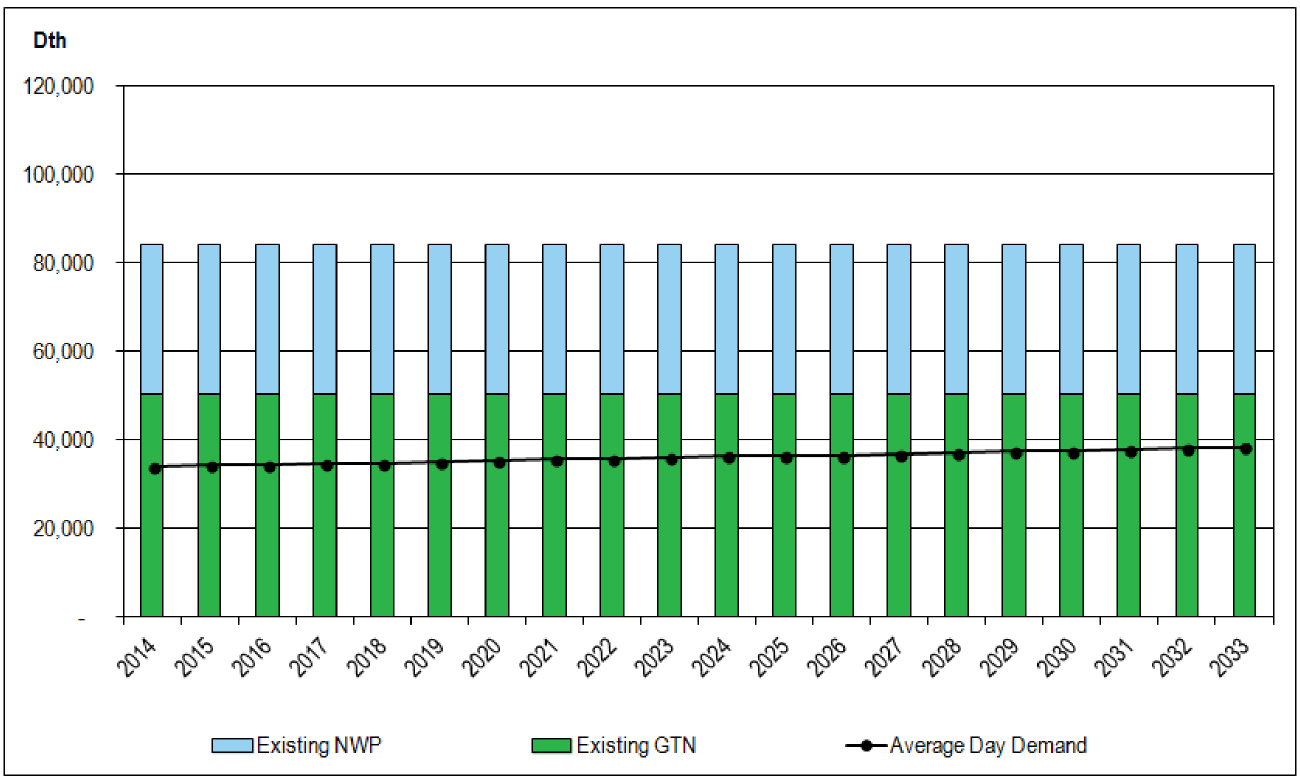


Figure 5.10: Average Case – Klamath Falls Existing Resources vs. Peak Day Demand – December 20th

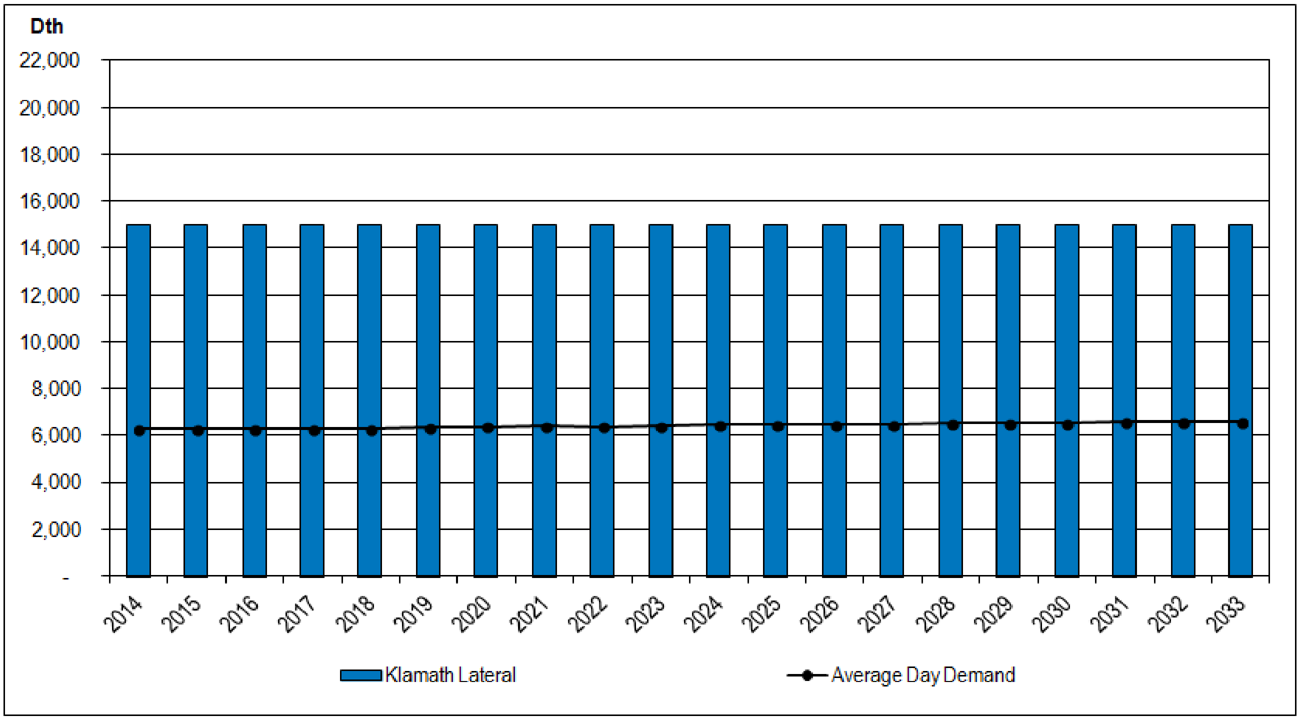
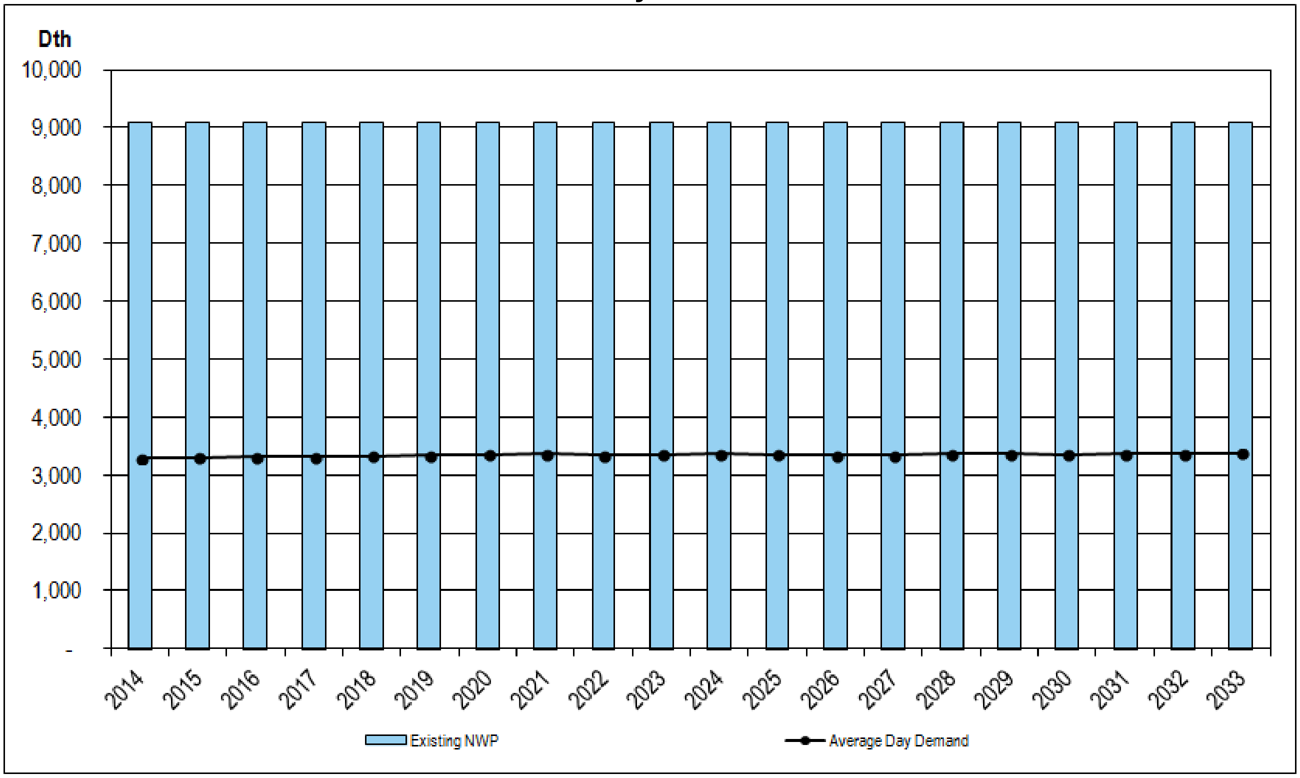


Figure 5.11: Average Case – La Grande Existing Resources vs. Peak Day Demand – February 15th



Figures 5.12 through 5.15 provide graphic summaries of Expected Case peak day demand compared to existing resources, as well as demand comparisons to the 2012 IRP. This demand is net of DSM savings. For this case, existing resources meet peak day demand needs over the planning horizon. This surplus resource situation provides ample time to carefully monitor, plan and act on potential resource additions.

Figure 5.12: Expected Case – Washington/Idaho Existing Resources vs. Peak Day Demand – February 15th

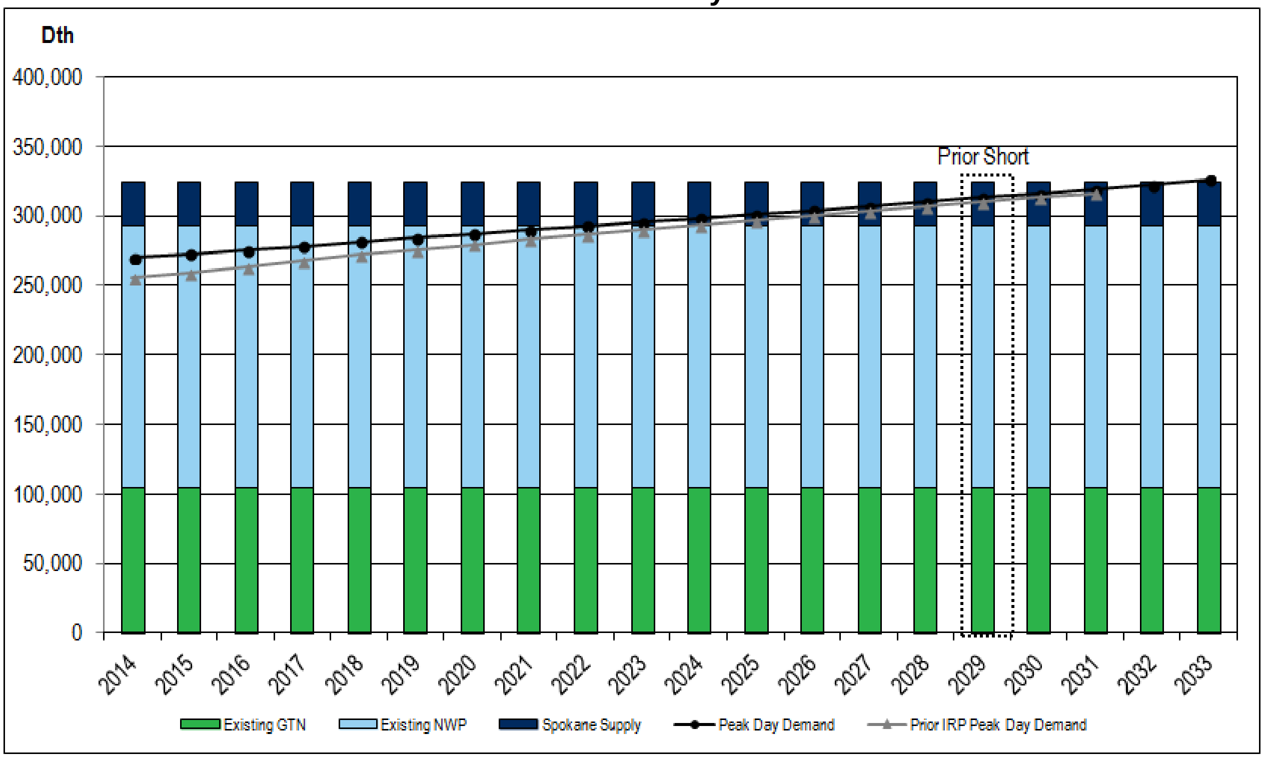


Figure 5.13: Expected Case – Medford / Roseburg Existing Resources vs. Peak Day Demand – December 20th

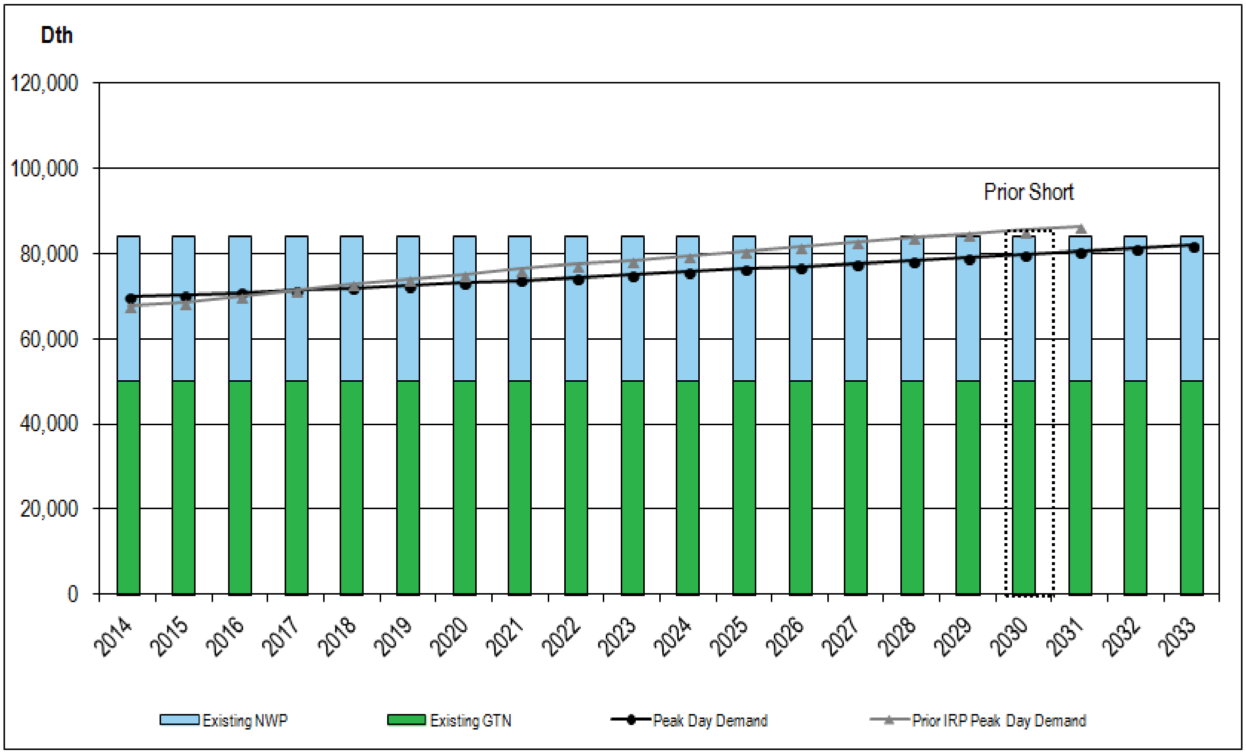


Figure 5.14: Expected Case – Klamath Falls Existing Resources vs. Peak Day Demand – December 20th

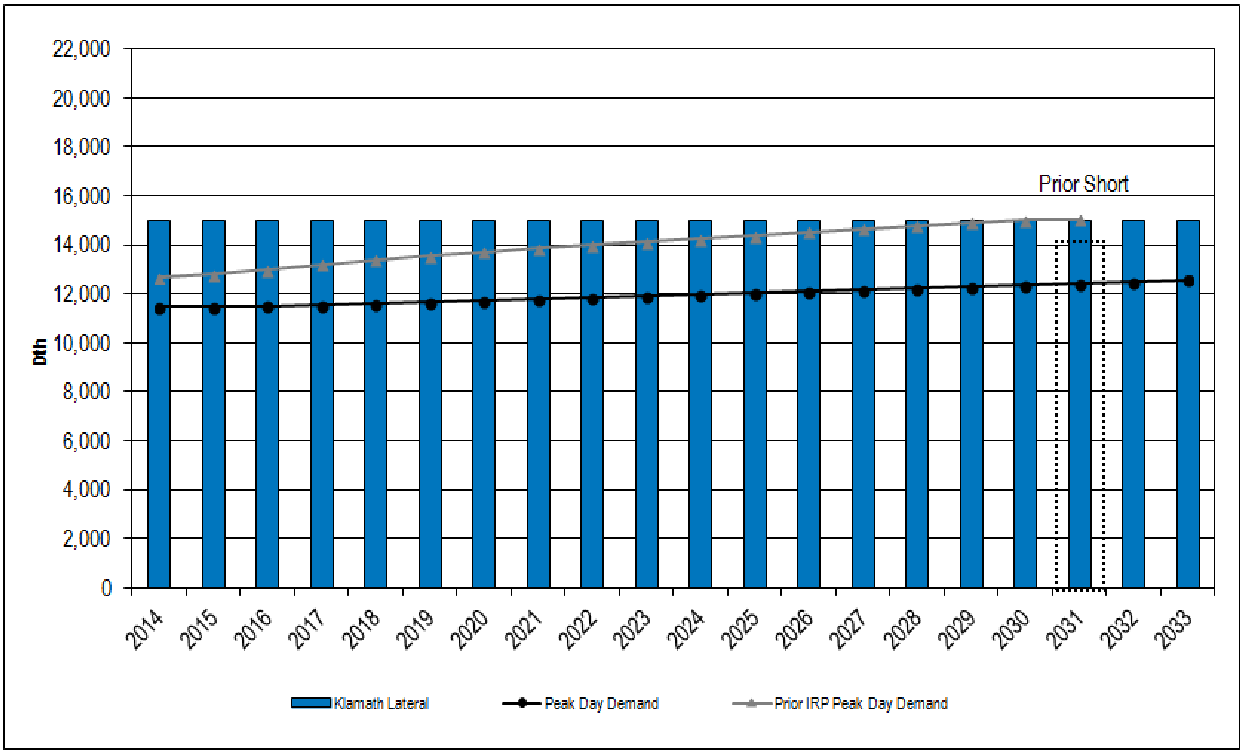
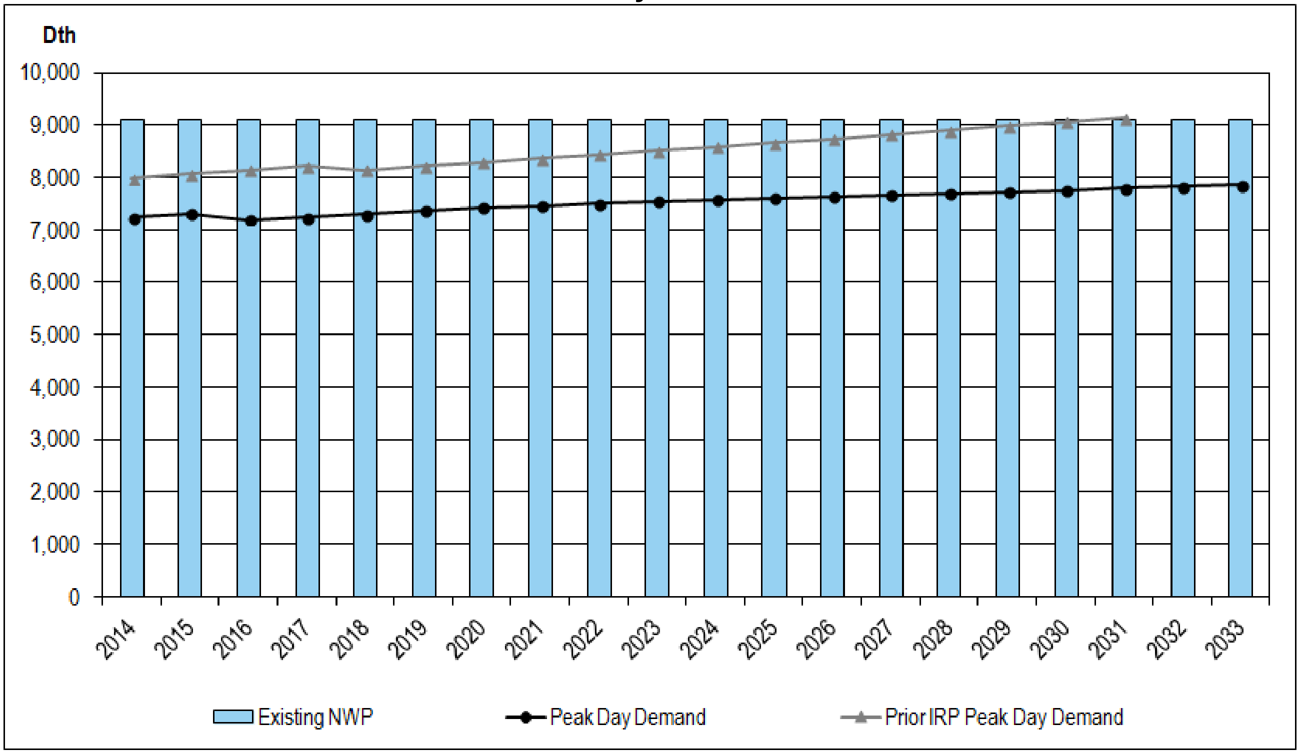


Figure 5.15: Expected Case – La Grande Existing Resources vs. Peak Day Demand – February 15th



If demand grows faster than expected, the need for new resources will come earlier. “Flat demand risk” requires close monitoring for signs of increasing demand and evaluation of lead times to acquire preferred incremental resources. Monitoring of “flat demand risk” includes a reconciliation of forecasted demand to actual demand on a monthly basis. This reconciliation helps identify customer growth trends and use-per-customer trends. If they meaningfully differ compared to forecasted trends, Avista will assess the impacts on planning from procurement and resource sufficiency standing.

Table 5.3 quantifies the forecasted total demand net of DSM savings and un-served demand from the above charts.

Table 5.3: Peak Day Demand – Served and Unserved (MDth/d)

Case	Year	LaGrande Served	LaGrande Unserved	LaGrande Total	LaGrande % of Peak Day Served	WA/ID Served	WA/ID Unserved	WA/ID Total	WA/ID % of Peak Day Served
Expected	2014	7.36	-	7.36	100%	270.11	0	270.11	100%
Expected	2015	7.39	-	7.39	100%	272.87	0	272.87	100%
Expected	2016	7.43	-	7.43	100%	275.55	0	275.55	100%
Expected	2017	7.40	-	7.40	100%	276.08	0	276.08	100%
Expected	2018	7.44	-	7.44	100%	279.16	0	279.16	100%
Expected	2019	7.47	-	7.47	100%	281.91	0	281.91	100%
Expected	2020	7.50	-	7.50	100%	284.69	0	284.69	100%
Expected	2021	7.51	-	7.51	100%	286.61	0	286.61	100%
Expected	2022	7.45	-	7.45	100%	285.97	0	285.97	100%
Expected	2023	7.47	-	7.47	100%	288.42	0	288.42	100%
Expected	2024	7.50	-	7.50	100%	291.26	0	291.26	100%
Expected	2025	7.47	-	7.47	100%	291.84	0	291.84	100%
Expected	2026	7.44	-	7.44	100%	292.39	0	292.39	100%
Expected	2027	7.45	-	7.45	100%	294.28	0	294.28	100%
Expected	2028	7.48	-	7.48	100%	297.18	0	297.18	100%
Expected	2029	7.51	-	7.51	100%	300.11	0	300.11	100%
Expected	2030	7.45	-	7.45	100%	299.63	0	299.63	100%
Expected	2031	7.48	-	7.48	100%	302.58	0	302.58	100%
Expected	2032	7.48	-	7.48	100%	304.17	0	304.17	100%
Expected	2033	7.49	-	7.49	100%	306.36	0	306.36	100%

Case	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	2014	11.45		11.45	100%	69.82	0	69.82	100%
Expected	2015	11.46		11.46	100%	70.38	0	70.38	100%
Expected	2016	11.50		11.50	100%	70.92	0	70.92	100%
Expected	2017	11.46		11.46	100%	70.90	0	70.90	100%
Expected	2018	11.52		11.52	100%	71.49	0	71.49	100%
Expected	2019	11.58		11.58	100%	72.10	0	72.10	100%
Expected	2020	11.66		11.66	100%	72.79	0	72.79	100%
Expected	2021	11.70		11.70	100%	73.27	0	73.27	100%
Expected	2022	11.64		11.64	100%	73.10	0	73.10	100%
Expected	2023	11.70		11.70	100%	73.72	0	73.72	100%
Expected	2024	11.78		11.78	100%	74.43	0	74.43	100%
Expected	2025	11.76		11.76	100%	74.58	0	74.58	100%
Expected	2026	11.75		11.75	100%	74.71	0	74.71	100%
Expected	2027	11.79		11.79	100%	75.19	0	75.19	100%
Expected	2028	11.87		11.87	100%	75.92	0	75.92	100%
Expected	2029	11.94		11.94	100%	76.66	0	76.66	100%
Expected	2030	11.89		11.89	100%	76.54	0	76.54	100%
Expected	2031	11.96		11.96	100%	77.28	0	77.28	100%
Expected	2032	11.99		11.99	100%	77.68	0	77.68	100%
Expected	2033	12.04		12.04	100%	78.24	0	78.24	100%

New Resource Options

When existing resources are not sufficient to meet expected demand, there are many important considerations in determining the appropriateness of potential resources. Interruptible customers' transportation may be cut, as needed, when existing resources are not sufficient to meet firm customers demand.

Resource Cost

Resource cost is the primary consideration when evaluating resource options, although other factors mentioned below also influence resource decisions. 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 facilities. Recalls of released pipeline capacity typically require advance notice of up to one year. Even DSM programs can require significant time from program development and rollout to the realization of natural gas savings.

Peak versus Base Load

Avista's planning efforts include the ability to serve firm natural loads on 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

Available resource must effectively deliver natural gas to the intended 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 resources increases 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), they 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, where 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. Economies of scale for pipeline construction afford the opportunity to secure resources to serve future demand increases.

Competition

LDCs, end-users and marketers compete for regional resources. The Northwest has been efficient in the utilization of existing resources and has an appropriately sized system. Currently, the region can accommodate the regional demand needs. However, future needs vary, and regional LDCs may find they are competing with each other and other parties 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 are subject to degrees of estimation, partly influenced by the expected timeframe of the resource need and 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 underground storage (low certainty).

Resource Selection

After identifying supply-side resource options and evaluating them based on the above considerations, Avista entered the supply-side scenarios (see Table 5.2) and conservation measures (see Chapter 3 – Demand-Side Resources) into the SENDOUT® model for it to select the least cost approach to meeting resource deficiencies, if they exist. SENDOUT® compares demand-side and supply-side resources (see Appendix 5.3 for a list of supply-side resource options) using PVRR analysis to determine which resource is a best option/least cost resource.

Demand-Side Resources

Integration by Price

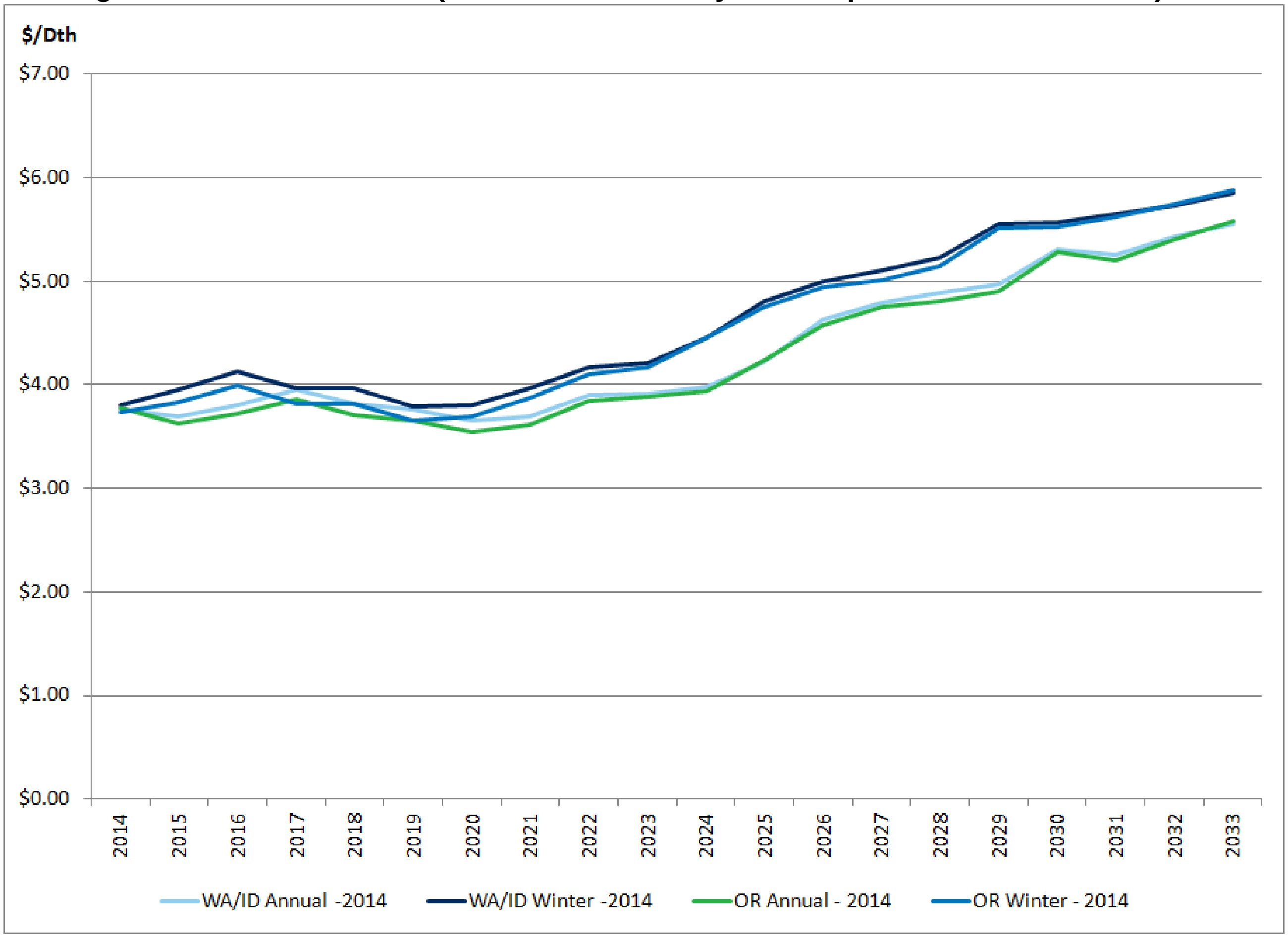
As described in Chapter 3, the model runs without future DSM programs. This preliminary run provides an avoided cost curve for EnerNOC. EnerNOC then evaluates the cost effectiveness of DSM programs against the initial avoided cost curve using the appropriate resource cost tests. The therm savings and associated program costs are incorporated into the SENDOUT® model. After incorporation, the avoided costs are re-evaluated. This process continues until the change in avoided cost curve is immaterial.

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 (for Idaho and Oregon), or utility cost (for Washington), is less than this avoided cost, it will be cost effective to reduce customer demand and Avista can avoid commodity, storage, transportation and other supply resource costs.

SENDOUT® calculates marginal cost data by day, month and year for each demand area. A summary graphical depiction of avoided annual and winter costs for the Washington/Idaho and Oregon areas is in Figure 5.16. The detailed data is in Appendix 5.4. Other than the carbon tax adder embedded in the expected price curve, avoided costs do not include additional environmental externality adders for adverse environmental impacts. Appendix 3.2 discusses this concept more fully and includes specific requirements required in the Oregon service territory.

Figure 5.16: Avoided Cost (Includes Commodity & Transport Cost – 2012 $/Dth)



DSM Potential

Using the avoided cost thresholds, EnerNOC selected all potential cost effective DSM. Table 5.4 shows potential DSM savings in each region from the selected conservation potential for the Expected Case. The DSM potential includes anticipated annual acquisition and is cumulative.

Table 5.4: Annual and Average Daily Demand Served by DSM

Case	Year	Annual Klamath DSM (MDth)	Daily Klamath/DSM (MDth/day)	Annual LaGrande DSM (MDth)	Daily LaGrande DSM (MDth)	Annual Medford/ Roseburg DSM (MDth)	Daily Medford/ Roseburg DSM (MDth)
Expected	2014	-	-	-	-	-	-
Expected	2015	0.23	0.00	0.14	0.00	1.24	0.00
Expected	2016	0.40	0.00	0.23	0.00	2.09	0.01
Expected	2017	0.67	0.00	0.39	0.00	3.46	0.01
Expected	2018	1.10	0.00	0.63	0.00	5.59	0.02
Expected	2019	1.64	0.00	0.93	0.00	8.24	0.02
Expected	2020	2.12	0.01	1.21	0.00	10.65	0.03
Expected	2021	2.48	0.01	1.41	0.00	12.49	0.03
Expected	2022	2.84	0.01	1.64	0.00	14.36	0.04
Expected	2023	3.20	0.01	1.85	0.01	16.24	0.04
Expected	2024	3.59	0.01	2.09	0.01	18.25	0.05
Expected	2025	4.12	0.01	2.41	0.01	20.98	0.06
Expected	2026	4.54	0.01	2.67	0.01	23.13	0.06
Expected	2027	4.96	0.01	2.93	0.01	25.32	0.07
Expected	2028	5.39	0.01	3.19	0.01	27.56	0.08
Expected	2029	5.84	0.02	3.46	0.01	29.84	0.08
Expected	2030	6.27	0.02	3.72	0.01	32.06	0.09
Expected	2031	6.69	0.02	3.97	0.01	34.23	0.09
Expected	2032	7.11	0.02	4.22	0.01	36.41	0.10
Expected	2033	7.54	0.02	4.46	0.01	38.58	0.11

Case	Year	Annual Oregon DSM (MDth)	Daily Oregon DSM (MDth/day)	Annual WA/ID DSM (MDth)	Daily WA/ID DSM (MDth/day)	Annual Total System DSM (MDth)	Daily Total System DSM (MDth/day)
Expected	2014	-	-	-	-	-	0.00
Expected	2015	1.61	0.00	15.15	0.04	16.77	0.05
Expected	2016	2.73	0.01	23.67	0.06	26.39	0.07
Expected	2017	4.51	0.01	37.04	0.10	41.55	0.11
Expected	2018	7.32	0.02	59.02	0.16	66.34	0.18
Expected	2019	10.81	0.03	87.72	0.24	98.54	0.27
Expected	2020	13.98	0.04	113.70	0.31	127.69	0.35
Expected	2021	16.39	0.04	130.99	0.36	147.37	0.40
Expected	2022	18.84	0.05	147.61	0.40	166.45	0.46
Expected	2023	21.30	0.06	163.70	0.45	185.00	0.51
Expected	2024	23.93	0.07	179.76	0.49	203.69	0.56
Expected	2025	27.51	0.08	195.92	0.54	223.43	0.61
Expected	2026	30.34	0.08	210.77	0.58	241.11	0.66
Expected	2027	33.21	0.09	225.16	0.62	258.37	0.71
Expected	2028	36.14	0.10	239.20	0.66	275.34	0.75
Expected	2029	39.14	0.11	252.89	0.69	292.02	0.80
Expected	2030	42.05	0.12	265.48	0.73	307.52	0.84
Expected	2031	44.90	0.12	276.62	0.76	321.51	0.88
Expected	2032	47.74	0.13	287.06	0.79	334.80	0.92
Expected	2033	50.59	0.14	296.88	0.81	347.47	0.95

DSM Acquisition Goals
The avoided cost established in SENDOUT®, the DSM potential selected, and the amount of therm savings is the basis for determining DSM acquisition goals and subsequent program implementation planning. Chapter 3 – Demand-Side Resources has additional details on this process.

Supply-Side Resources
SENDOUT® considers all options entered into the model, determines when and what resources are needed, and which options are cost effective. Selected resources represent the best cost/risk solution, within given constraints, to serve anticipated customer requirements. Since the Expected Case has no resource additions in the planning horizon, Avista will continue to review and refine knowledge of resource options and will act to secure best cost/risk options when necessary or advantageous.

Resource Utilization
Avista's plans to meet firm customers' demand requirements in a cost-effective manner. This goal encompasses a range of activities from meeting peak day requirements in the winter to acting as a responsible steward of resources during periods of lower resource utilization. As the analysis presented in this IRP indicates, Avista has ample resources to meet highly variable demand under multiple scenarios, including peak weather events.

Avista acquired the majority of its upstream pipeline capacity during the deregulation or "unbundling" of the natural gas industry. Pipelines were required to allocate capacity and costs to their existing customers as they transitioned to transportation only service providers. The FERC allowed a rate structure for pipelines to recover costs through a Straight Fixed Variable rate design. This structure is based on a higher reservation charge to cover pipeline costs whether gas is transported or not, and a much smaller variable charge which is incurred only when gas is transported. An additional fuel charge is assessed to account for the compressors required to move the gas to customers. Avista maintains enough firm capacity to meet peak day requirements under the Expected Case in this IRP. This requires pipeline capacity contracts at levels in excess of the average and above minimum load requirements. Given this load profile and the Straight Fixed Variable rate design, Avista incurs ongoing pipeline costs during non-peak periods.

Avista chooses to have an active, hands-on management of resources to mitigate upstream pipeline and commodity costs for customers when the capacity is not utilized for system load requirements. This management simultaneously deploys multiple long and short-term strategies to meet firm demand requirements in a cost effective manner. The resource strategies addressed are:

- Pipeline contract terms.
- Pipeline capacity.
- Storage.
- Commodity and transport optimization.
- Combination of available resources.

Pipeline Contract Terms

Pipeline costs are incurred whether the capacity is utilized or not. Winter demand must be satisfied and peak days must be met. Ideally, capacity could be contracted from pipelines for the time and days it is required. Unfortunately, this is not how pipelines are contracted or built. Long-term agreements at fixed volumes are the usual requirements for building or acquiring firm transport. This assures the pipeline of long-term, reasonable cost recovery.

Avista has negotiated and contracted for several seasonal transportation agreements. These agreements allow volumes to increase during the demand intensive winter months and decrease over the lower demand summer period. This is a preferred contracting strategy because it eliminates costs when demand is low. Avista refers to this as a front line strategy because it attempts to mitigate costs prior to contracting the resource. Not all pipelines offer this option. Avista seeks this type of arrangement when available. Avista currently has some seasonal transportation contracts on TransCanada GTN, TransCanada BC and TransCanada Alberta. These pipelines match up to move natural gas from Alberta (AECO) to Avista's service territories. Avista also contracted for TF2 on NWP. This is a storage specific contract and matches up to some of the Jackson Prairie storage capacity. TF2 is a firm service and allows for contracting a daily amount of transportation for a specified number of days rather than a daily amount on an annual basis as is usually required. For example, one of the TF2 agreements allows Avista to transport 91,200 Dth/day for 31 days. This is a more cost effective strategy for storage transport than contracting for an annual amount. Through NWP's tariff, Avista maintains an option to increase and decrease the number of days this transportation option is available. More days correspond to more costs, so balancing storage, transport and demand is important to ensure an optimal blend of cost and reliability.

Pipeline Capacity

After contracting for pipeline capacity, its management and utilization determine the actual costs. The worst-case economic scenario is to do nothing and simply incur the costs associated with this transport contract over a long term to meet current and future peak demand requirements. Avista develops strategies to ensure this does not happen on a regular basis.

Capacity Release

Through the pipeline unbundling of transportation, the FERC establishes rules and procedures to ensure a fair market developed to manage pipeline capacity as a commodity. This evolved into the capacity release market and is governed by FERC regulations through individual pipelines. The pipelines implement the FERC's posting requirements to ensure a transparent and fair market is maintained for the capacity. All capacity releases are posted on the pipelines Bulletin Boards and, depending on the terms, may be subject to bidding in an open market. This provides the transparency sought by FERC in establishing the release requirements. Avista utilizes the capacity release market to manage both long-term and short-term transportation capacity.

For capacity under contract that may exceed current demand, Avista seeks other parties that may need it and arranges for capacity releases to transfer rights, obligations and costs. This shifts all or a portion of the costs away from customers to a third party until it is needed to meet customers' demand.

There are many variables in determining the value of transportation. Certain pipeline paths are more valuable and this can vary by year, season, month and day. The term, volume and conditions precedent also contribute to the value recoverable through a capacity release. For example, a release of winter capacity to a third party may allow for full cost recovery; while a release for the same period that allows Avista to recall the capacity for up to 10 days during the winter may not be as valuable to the third party, but of high value to us. Avista may be willing to offer a discount to retain the recall rights during high demand periods. This turns a seasonal-for-annual cost into a peaking-only cost. These are market terms and conditions that are negotiated to determine the value or discount required by both parties.

Avista has several long-term releases, some extending through 2025 providing full recovery of all the pipeline costs. These releases maintain Avista's long-term rights to the transportation capacity without incurring the costs of waiting until demand increases. As the end of these release terms near, Avista surveys the market against the IRP to determine if these contracts should be reclaimed or released, and for what duration. Avista has releases to third parties that terminate in 2016. Results of this IRP show that this capacity is not needed in 2016 as originally anticipated, and Avista is negotiating new terms and conditions to continue full cost recovery until it is required. Through this process, Avista retains the rights to vintage capacity without incurring the costs or having to participate in future pipeline expansions that will cost more than current capacity.

On a shorter term, excess capacity not fully utilized on a seasonal, monthly or daily basis can also be released. Market conditions often dictate less than full cost recovery for shorter-term requirements. Mitigating some costs for an unutilized, but required resource reduces costs to our customers.

Segmentation

Through a process called segmentation, Avista creates new firm pipeline capacity for the service territory. This doubles some of the capacity volumes at no additional cost to customers. With increased firm capacity, Avista can continue some long-term releases, or even reduce some contract levels, if the release market does not provide adequate recovery.

Storage

As a one-third owner of the Jackson Prairie Storage facility, Avista holds an equal share of capacity (space available to store gas) and delivery (the amount of natural gas that can be withdrawn on a daily basis).

Storage allows lower summer-priced gas to be stored and used in the winter during high demand or peak day events. Similar to transportation, unneeded capacity and delivery can be optimized by selling into a higher priced market. This allows Avista to manage storage capacity and delivery to meet growing peak day requirements when needed.

The injection of gas into storage during the summer utilizes existing pipeline transport and helps increase the utilization factor of pipeline agreements. Avista employs several storage optimization strategies to mitigate costs. Revenue from this activity flows through the annual PGA/Deferral process.

Commodity and Transportation Optimization

Another strategy to mitigate transportation costs is to participate in the daily market to assess if unutilized capacity has value. Avista seeks daily opportunities to purchase gas, transport it on existing unutilized capacity, and sell it into a higher priced market to capture the cost of the gas purchased and recover some pipeline charges. The recovery is market dependent and may or may not recover all pipeline costs, but mitigates pipeline costs to customers.

Combination of Resources

Unutilized resources like supply, transportation, storage and capacity can combine to create products that capture more value than the individual pieces. Avista has structured long-term arrangements with other utilities that allow available resources utilization and provide products that no individual component can satisfy. These products provide more cost recovery of the fixed charges incurred for the resources.

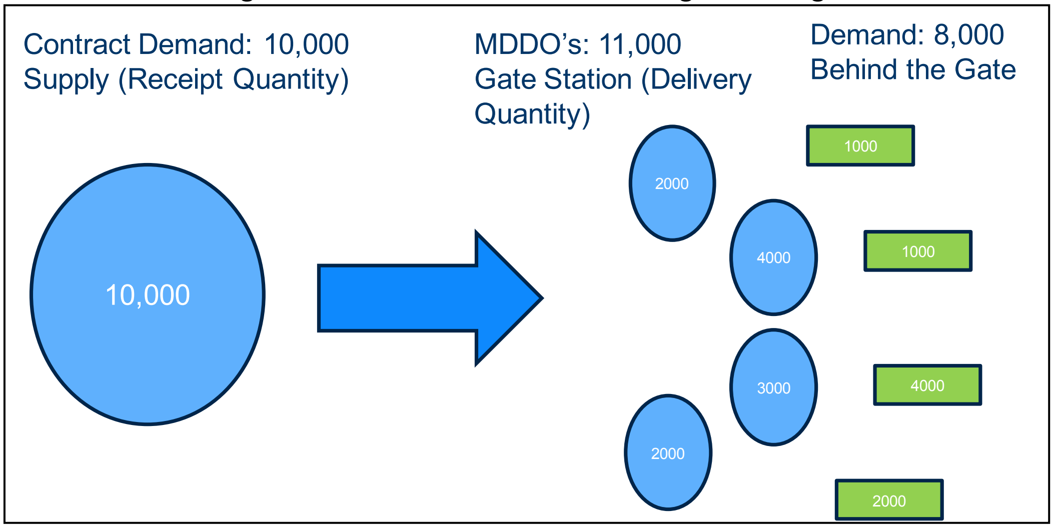
Resource Utilization Summary

As determined through the IRP modeling of demand and existing resources, new resources under the Expected Case are not required. Avista manages the existing resources to mitigate the costs incurred by customers until the resource is required to meet demand. The recovery of costs is often market based with rules governed by the FERC. Avista is recovering full costs on some resources and partial costs on others. The management of long and short-term resources ensures the goal to meet firm customer demand in a reliable and cost-effective manner.

Gate Station Analysis

Avista identified a risk associated with the aggregated methodology for supply and demand forecasting in previous IRPs. The 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 (i.e., receipt/supply quantity) is fixed and the deliverable amount (i.e., maximum daily delivery obligation or delivery quantity) to gate stations is greater. (See Figure 5.17) However, aggregation could mask deficiencies at individual gate stations.

Figure 5.17: Gate Station Modeling Challenge



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 the IRP, forecasted peak-day gate station demand was calculated. This demand was compared to contracted and operational capacities at each gate station.

If forecasted demand exceeded contracted and/or operational capacities, further analysis was completed. The additional analysis involved assessing the economic way to address the gate deficiency. This could involve a gate station expansion, re-assigning maximum daily delivery obligations, targeted DSM, or distribution system enhancements.

For example, analysis in the last IRP identified a gate station on NWP's Coeur d'Alene Lateral where forecasted peak day demand exceeded the gate station maximum daily delivery obligation and the physical capacity. Numerous solutions were examined with all parties. The analysis indicated the optimal solution is a pre-existing plan to build a new gate station at Chase Road off GTN's mainline. The project originally was designed to alleviate capacity constraints at GTN's Rathdrum gate; however, the new gate's location could displace natural gas on the NWP Coeur d'Alene Lateral.

Avista is working on the gate station analysis on NWP's system serving Oregon customers. Any deficiencies identified will be communicated to Commission Staff with proposed least cost solutions. After the analysis of the NWP gates is complete, Avista will analyze the GTN system gates.

Action Items

With no resource deficiencies in the planning horizon, there are no specific and measurable near-term action items for gate station analysis.

Conclusion

The IRP portfolio analysis summarized in this chapter was performed on the Average Case and then on the Expected Case demand scenario. Although the results show no resource deficiencies during the 20-year forecasted term, Avista has chosen to utilize the Expected Case for peak operational planning activities because this case is the most likely outcome given experience, industry knowledge and understanding of future natural gas markets. This case provides reasonable demand growth given current expectations of natural gas prices over the planning horizon. If realized, this case allows Avista protection against resource shortages and does not over commit to additional long-term resources.

Avista recognizes that there are other potential outcomes. The process described in this chapter applies to the alternate demand and supply resource scenarios covered in Chapter 6 – Alternate Scenarios, Portfolios and Stochastic Analysis.

6: Alternate Scenarios, Portfolios and Stochastic Analysis

Overview

Avista applied the IRP analysis in Chapter 5 to several alternate demand and supply resource scenarios to develop a range of alternate portfolios. This deterministic modeling approach considered different underlying assumptions vetted with the TAC members to develop a consensus about the number of cases to model.

Avista 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 in historical data. This statistical analysis, in conjunction with the deterministic analysis, enabled statistical quantification of risk from reliability and cost perspectives related to resource portfolios under varying price and weather environments.

Alternate Demand Scenarios

As discussed in the Demand Forecasting section, Avista identified alternate scenarios for detailed analysis to capture a range of possible outcomes over the planning horizon. Table 6.1 summarizes these scenarios and Chapter 2 – Demand Forecasts and Appendices 2.6 and 2.7 describes them in more detail. The scenarios consider different demand influencing factors and price elasticity effects for various price influencing factors.

Table 6.1: Scenarios

Proposed Scenarios INPUT ASSUMPTIONS	**Expected Case**	**High Growth & Low Prices**	**Low Growth & High Prices**	**Cold Day 20yr 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 Legislation ($/Ton)	$8.32 - $14.83	None	$8.32 - $14.83	$8.32 - $14.83	$8.32 - $14.83
RESULTS					
First Gas Year Unserved					
WA/ID	N/A	2029	N/A	N/A	N/A
Medford	N/A	2029	N/A	N/A	N/A
Roseburg	N/A	N/A	N/A	N/A	N/A
Klamath	N/A	N/A	N/A	N/A	N/A
La Grande	N/A	N/A	N/A	N/A	N/A

Demand profiles over the planning horizon for each of the scenarios shown in Figures 6.1 and 6.2 reflect the two winter peaks modeled for the different service territories (Dec. 20 and Feb. 15).

Figure 6.1 Peak Day (Feb 15) – 2014 IRP Demand Scenarios

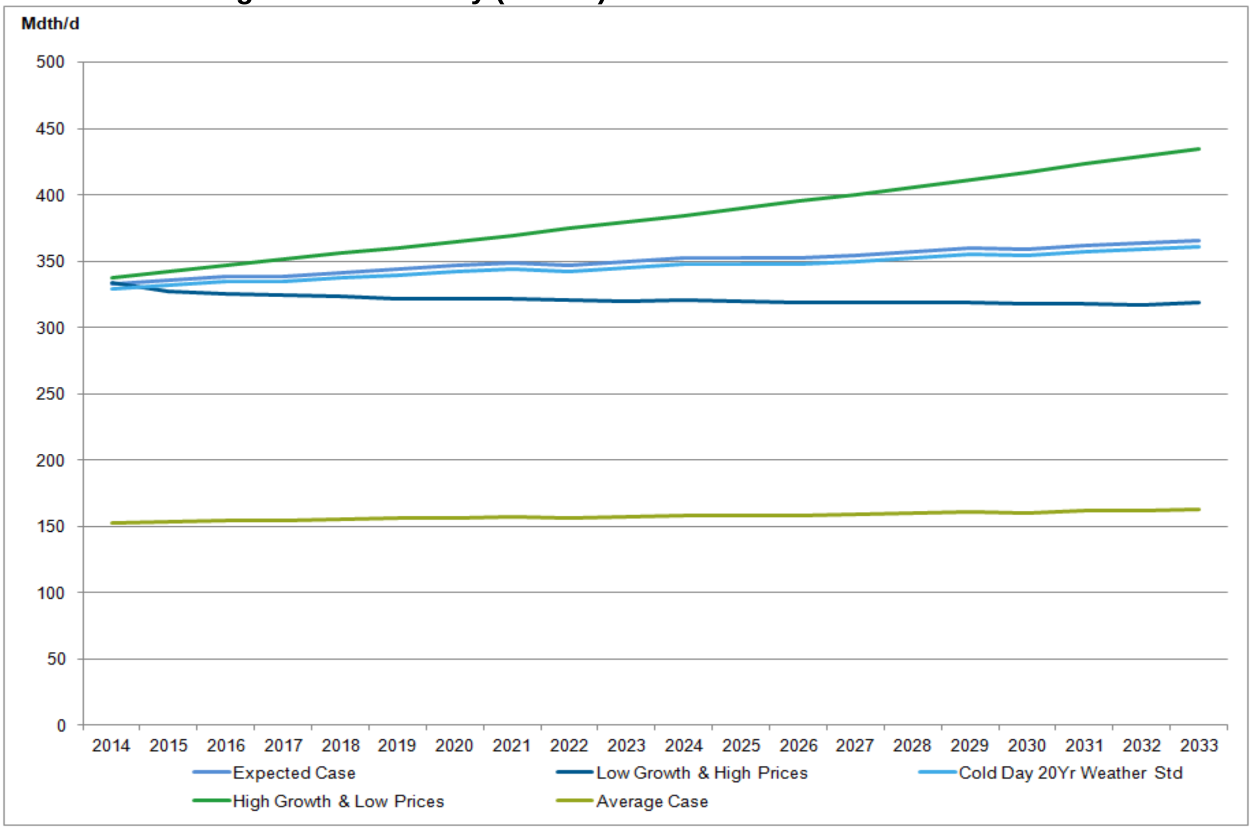
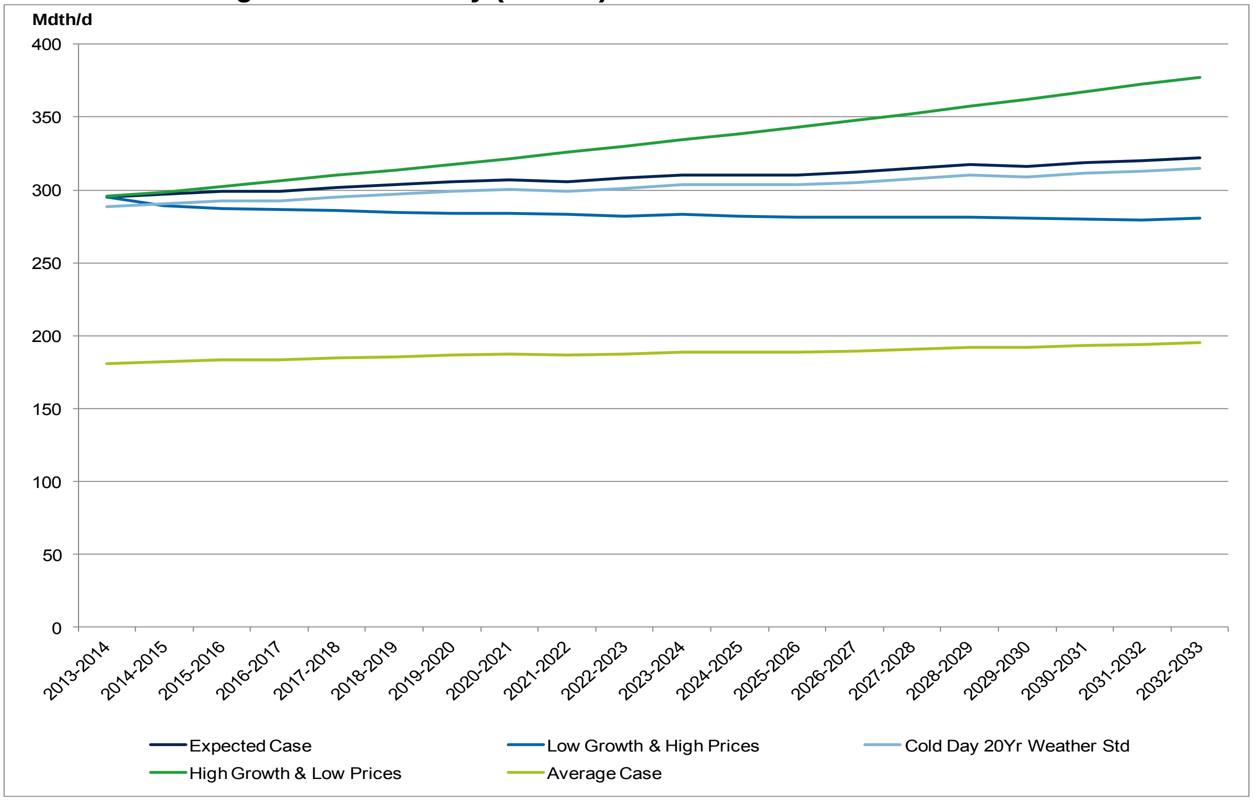
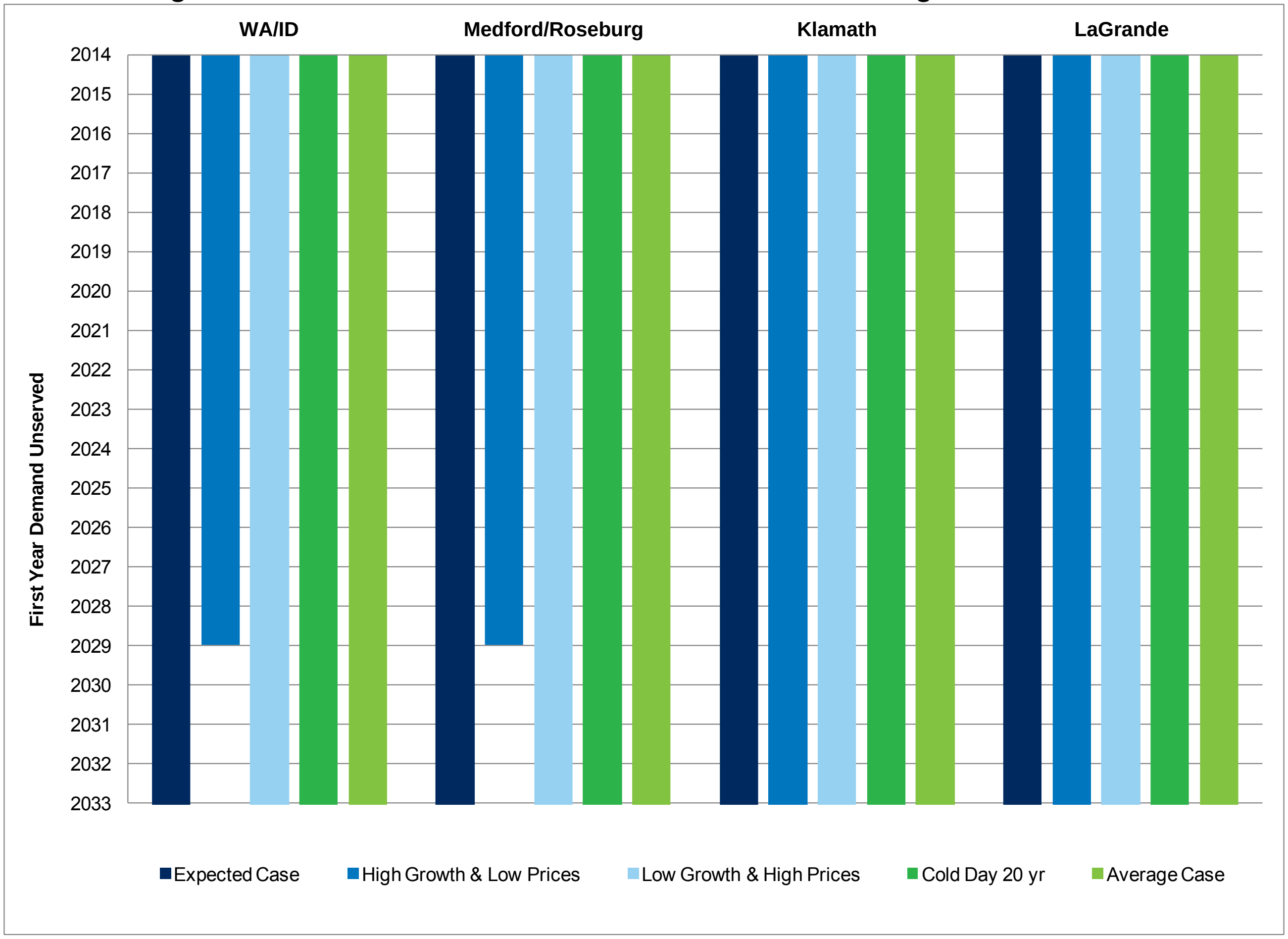


Figure 6.2 Peak Day (Dec 20) – 2014 IRP Demand Scenarios



As in the Expected Case, Avista used SENDOUT® to model the same resource integration and optimization process described in this section for each of the five demand scenarios (see Appendix 2.7 for a complete listing of portfolios considered). This identified first year unserved dates for each scenario by service territory (Figure 6.3).

Figure 6.3: First Year Peak Demand Not Met with Existing Resources



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

- 2029 in Washington/Idaho.
- 2029 in Medford/Roseburg.

Steeper demand highlights the flat demand risk discussed earlier. The likelihood of this scenario occurring is remote due to a yearly recurrence of coldest day on record weather paired with a much steeper growth of customer population; however, any potential for accelerated unserved dates warrants close monitoring of demand trends and resource lead times as described in the Ongoing Activities section of Chapter 8 –

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

Due to their importance and connection with the IRP process, additional detailed information on certain selected scenarios is included in the following appendices:

- Demand and Existing Resources graphs by service territory (High Growth Case only) – Appendix 6.1.
- Peak Day Demand, Served and Unserved table (all cases) – Appendix 6.2.
- Avoided cost curve detail and graphs for High Growth and Low Growth cases – Appendix 6.4.

Alternate Supply Resources

Avista identified supply-side resources that could meet resource deficiencies. Table 6.2 shows available supply-side scenarios considered for this IRP. There are many other options; however, Avista excluded them from SENDOUT® modeling for this IRP given the lack of need in the near term and the speculative nature of many of these resources.

For example, contracted city gate deliveries in the form of a structured purchase transaction could 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 when the resource need is later in the planning horizon.

Many of the potential resources are not yet commercially available or well tested technically making them speculative. Resources such as coal-bed methane, LNG imports and absorbed natural gas (ANG) would fall into this category. Avista will continue to monitor all resources and assess their appropriateness for inclusion in future IRPs as described in Chapter 8 – Ongoing Activities.

One resource which will be closely observed is exported LNG. While Avista considered LNG exports, it was primarily as a price-influencing factor. However, if one of the proposed export LNG terminals in Oregon were approved and a pipeline was to be built to supply that facility, it potentially could bring supply through Avista’s service territory. However, there is much uncertainty about export LNG because new pipelines are expensive and there are currently existing pipeline options that are more cost effective. Avista will monitor (Chapter 8 – Ongoing Activities) this situation through industry publications and daily operations to consider inclusion of this supply scenario for future IRPs.

Table 6.2: Supply Scenarios

Existing Resources
Existing + Expected Available

Portfolio Evaluation

There is no resource deficiency identified in the planning period and the existing resource portfolio is adequate to meet forecasted demand. The alternate demand scenarios and supply scenarios are matched together to form portfolios. This creates bounds for analyzing the expected case by creating a high and low for customer count, weather and pricing. Each portfolio runs through SENDOUT® where the supply resources and demand-side resources are compared and selected on a least cost basis. Supply resources include AECO, Sumas, Malin, Rockies, Stanfield trading hubs and Jackson Prairie storage. Once resources are determined, a net present value of the revenue requirement (PVRR) is calculated.

Table 6.3 summarizes the PVRR of the portfolios considered. Each portfolio is based on unique assumptions and therefore a simple comparison of PVRR cannot be made.

Table 6.3: 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	$ 4,463,055
Expected Case			
	Expected Demand with Existing Resources (before resource additions)	No	$ 4,717,654
Additional Demand Scenarios			
	High Growth, Low Price Demand with Existing Resources	Yes	$ 4,491,462
	Alternate Weather Standard Demand with Existing Resources	No	$ 4,557,367
	Low Growth, High Price with Existing Resources	No	$ 5,455,336

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 factors are an integral part of scenario analysis. To understand a

[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 future possibilities that exist with a real-life system.

particular portfolio's response to price and weather, Avista applied stochastic analysis to generate a variety of price and weather events.

Deterministic analysis is a valuable tool for selecting an 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. Utilizing Monte Carlo simulation in conjunction with deterministic analysis provides a more complete picture of portfolio performance under multiple weather and price profiles.

This IRP employs stochastic analysis in two ways. The first tested the weather-planning standard and the second assessed risk related to costs of our Expected case (existing portfolio) under varying price environments. The Monte Carlo simulation in SENDOUT® can vary index price and weather simultaneously. This simulates the effects each have on one another.

Weather

In order to evaluate weather and its effect on the portfolio, Avista derived 200 simulations (draws) through SENDOUT®'s stochastic 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 6.4) 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 a more robust basis for stress testing the deterministic analysis.

Table 6.4: 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. Avista assessed the frequency that the peak day occurs in each area from the simulation data. The stochastic analysis shows that in over 200, 20-year simulations, peak day (or more) occurs with enough frequency to maintain the current planning standard for this IRP. This topic remains a subject of continued analysis. For example, the Medford weather pattern over the 200 20-year draws (i.e., 4,000 years). HDDs at or above peak weather (61 HDDs) occur 128 times. This equates to a peak day occurrence once every 31 years (4,000 simulation years divided by 128 occurrences). The Spokane area has the least occurrences of peak day (or more) occurrences and 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 6.4 through 6.8 for the number of peak day occurrences by weather area.

Figure 6.4: Frequency of Peak Day Occurrences – Spokane

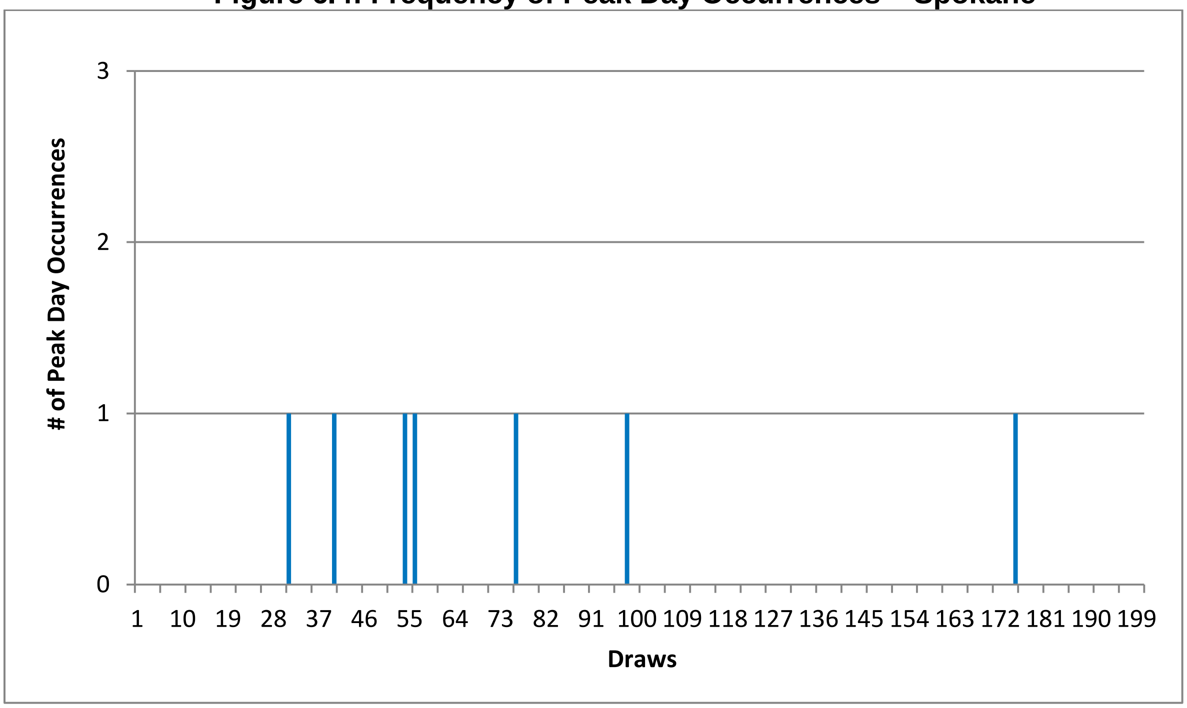


Figure 6.5: Frequency of Peak Day Occurrences – Medford

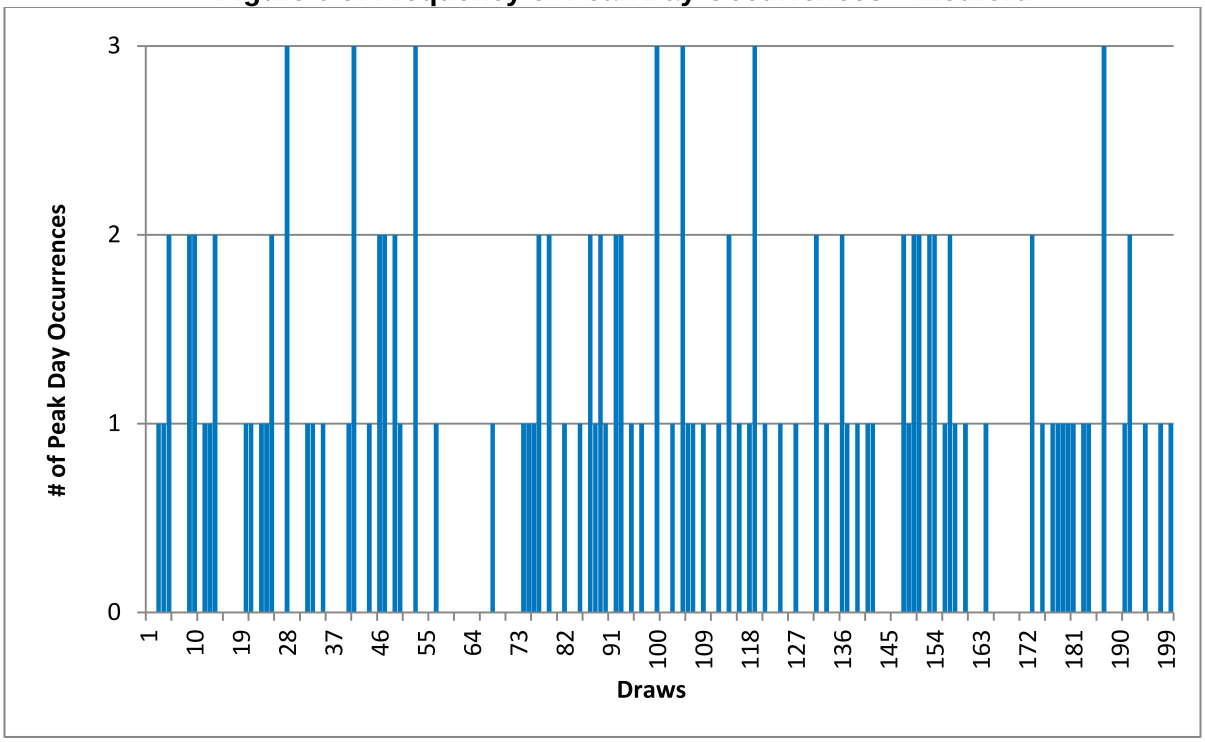


Figure 6.6: Frequency of Peak Day Occurrences – Roseburg

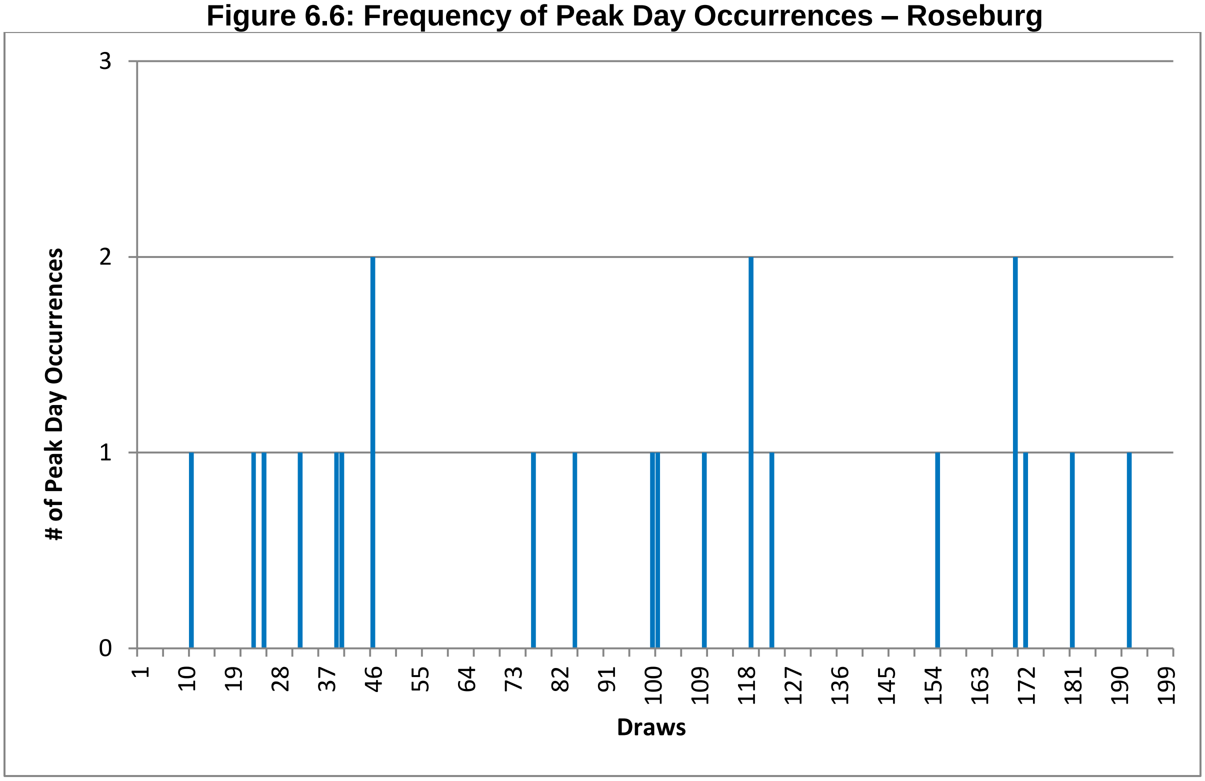


Figure 6.7: Frequency of Peak Day Occurrences – Klamath Falls

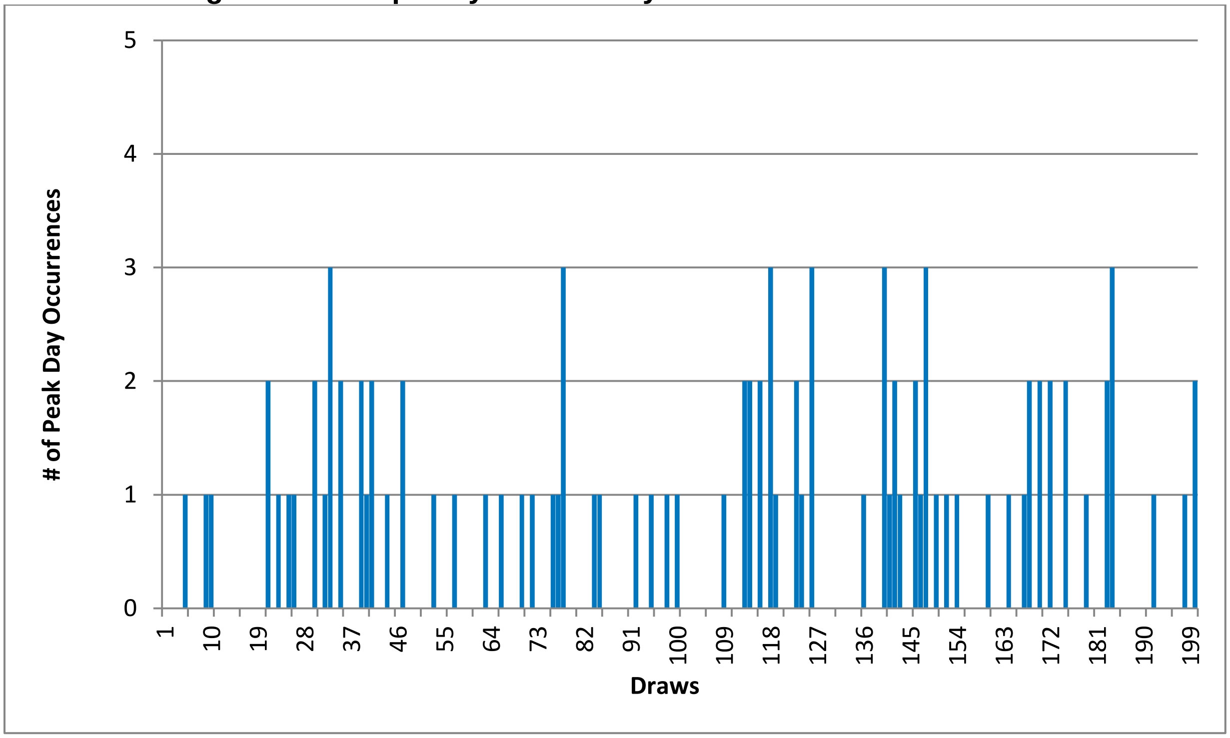
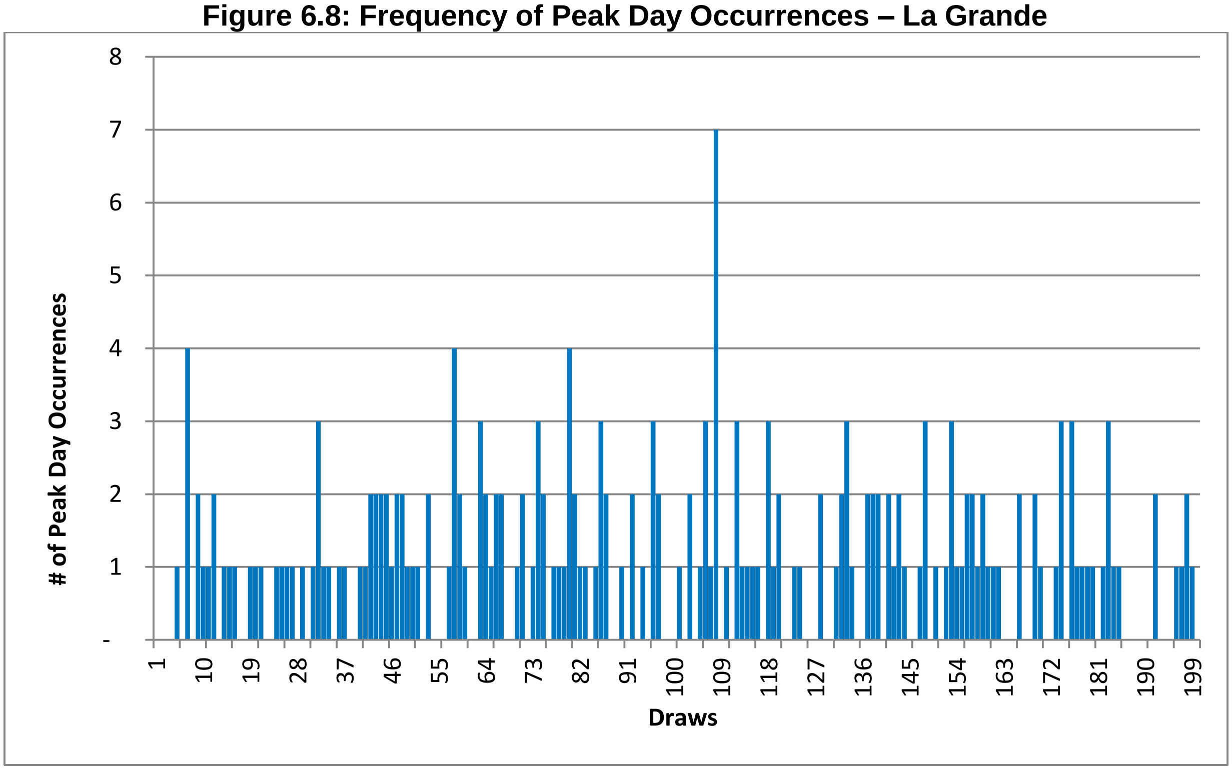


Figure 6.8: Frequency of Peak Day Occurrences – La Grande

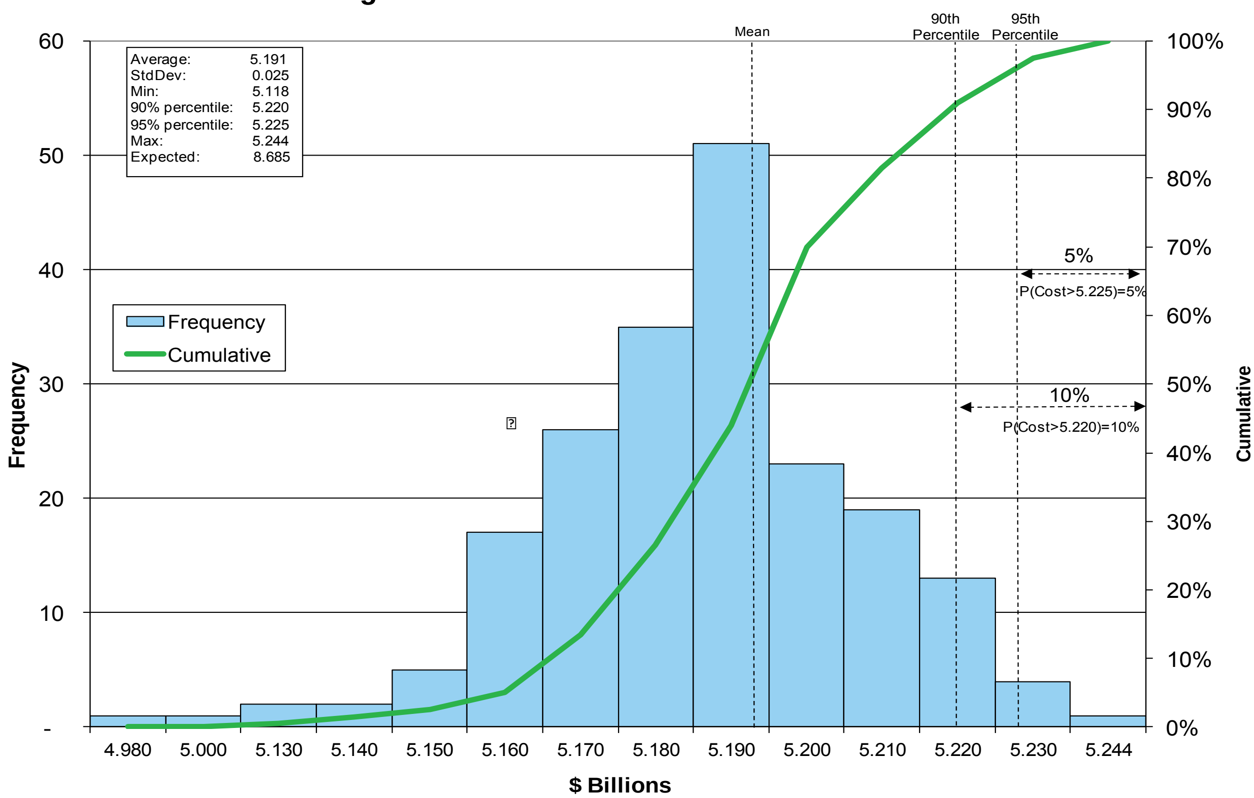


Price

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

Avista used Monte Carlo simulation to test the portfolio and quantify the risk to customers when prices do not materialize as forecast. Avista performed a simulation of 200 draws, varying prices, to investigate whether the Expected Case total portfolio costs from the deterministic analysis is within the range of occurrences in the stochastic analysis. Figure 6.9 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 Expected Case total portfolio cost is within an acceptable range of total portfolio costs based on 200 unique pricing scenarios.

Figure 6.9: 2014 IRP Total 20-Year Cost



Performing stochastic analysis on weather and price in the demand analysis provided a statistical approach to evaluate and confirm the findings in the scenario analysis with respect to adequacy and reasonableness of the weather-planning standard and the natural gas price forecast. This analytical perspective provides more confidence in the conclusions and stress tests the robustness of the selected portfolio of resources, thereby mitigating analytical risks.

Regulatory Requirements

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

- Examines a range of demand forecasts.
- Examines feasible means of meeting demand with both supply-side and demand-side resources.
- Treats supply-side and demand-side resources equally.
- Describes the long-term plan for meeting expected demand growth.
- Describes the plan for resource acquisitions between planning cycles.
- Takes planning uncertainties into consideration.
- Involves the public in the planning process.

Avista addressed the applicable requirements throughout this document. Appendix 1.2 lists the specific requirements and guidelines of each jurisdiction and describes Avista's compliance.

The IRP is also required to consider risks and uncertainties throughout the planning and analysis. Avista's approach in addressing this requirement was to identify factors that could cause significant deviation from the Expected Case planning conclusions. This included dynamic demand analytical methods and sensitivity analysis on demand drivers that impacted demand forecast assumptions. From this, Avista created 17 demand sensitivities and modeled five demand scenario alternatives, which incorporated different customer growth, use-per-customer, weather, and price elasticity assumptions.

Avista analyzed peak day weather planning standard, performing sensitivity on HDDs and modeling an alternate weather-planning standard using the coldest day in 20 years.

Stochastic analysis using Monte Carlo simulations in SENDOUT® supplemented this analysis. Avista also used simulations from SENDOUT® to analyze price uncertainty and the effect on total portfolio cost.

Avista examined risk factors and uncertainties that could affect expectations and assumptions with respect to DSM programs and supply-side scenarios. From this, Avista assessed the expected available supply-side resources and potential DSM savings for evaluation.

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

Conclusion

The High Growth and Low Growth Case demand analyses provide a range for evaluating demand trajectories relative to the Expected Case. Based on this analysis there appears to be sufficient time to plan for forecasted resource needs. Even under an extreme growth scenario, the first forecasted deficiency does not occur until 2029. Many things could happen between now and when the first resource needs occur, so Avista we will carefully monitor (Chapter 8 – Action Items) demand trends through reconciling and comparing forecast to actual customer counts and continually update and evaluate all demand-side and supply-side alternatives.

7: Distribution Planning

Overview

Avista's integrated resource planning encompasses evaluation of safe, economical and reliable full-path delivery of natural gas from basin to the customer meter. Securing adequate natural gas supply and ensuring sufficient pipeline transportation capacity to city gates become secondary issues if distribution system growth behind the city gates becomes severely constrained. Important parts of the planning process include forecasting local demand growth, determining potential distribution system constraints, analyzing possible solutions, and estimating costs for eliminating constraints.

Analyzing resource needs to this point has focused on ensuring adequate capacity to the city gates, especially during a peak event. Distribution planning focuses on determining if there will be adequate pressure during a peak hour. Despite this altered perspective, distribution planning shares many of the same goals, objectives, risks and solutions as resource planning.

Avista's natural gas distribution system consists of approximately 3,000 miles of distribution main pipelines in Idaho, 3,500 miles in Oregon and 5,400 miles in Washington, 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 Avista's distribution system. Pressure regulating stations that utilize pipeline pressures from the interstate transportation pipelines before natural gas enters our distribution networks maintains system pressure.

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 to existing infrastructure, or new system additions, which increase system capacity, reliability and safety. Expansions are new system additions to accommodate new demand. Collectively, these are distribution enhancements.

Ongoing evaluations of each distribution network in the four primary service territories identify strategies for addressing local distribution requirements resulting from customer growth. Customer growth assessments are made based on factors including IRP demand forecasts, monitoring gate station flows and other system metering, ongoing communication about new service requests, field personnel discussion, and inquiries from major developers.

Additionally, Avista regularly conducts integrity assessments of its distribution systems. Ongoing system evaluation can also indicate distribution-upgrading requirements for system maintenance needs rather than customer and load growth. In some cases, the timing for system integrity upgrades coincides with growth-related expansion requirements.

These planning efforts provide a long-term planning and strategy outlook and integrate into the 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 natural gas from one place to another. When pressures are the same on both ends of a pipe, the natural gas does not move. When natural gas is removed from a point on the network, the pressure at that point drops below the pressure upstream in the network and moves from the higher pressure area in the network to the point of removal to equalize pressure throughout the network. If the amount of natural gas removed is not replaced, the pressure differential decreases, flow stalls and the network could run out of pressure. Therefore, it is important to design a distribution network so that intake pressure (from gate stations and/or regulator stations) within the network is high enough to maintain an adequate pressure differential when natural gas leaves the network.

Not all natural gas flows equally throughout a network. Certain points within the network constrain flow and restrict overall network capacity. Network constraints can occur as demand requirements 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 aided by computer modeling for network demand studies. Demand studies have evolved with technology in the past decade to become a highly technical and powerful means of analyzing distribution system performance. Using a pipeline fluid flow formula, a specified parameter for each pipe element can be simultaneously solved. Many 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® software. This computer-based modeling tool allows users to analyze and interpret solutions graphically. Appendix 7.1 describes the computer modeling methodology while

Appendix 7.2 provides an example load study including graphical interface and output examples.

Determining Peak Demand

Avista's distribution network is comprised of high pressure (90-500 psig) and intermediate pressure (5-60 psig) mains. Avista operates its intermediate networks at a relatively low maximum pressure of 60 psig or less for ease of maintenance and operation, public safety, reliable service, and cost considerations. Since the majority of distribution systems operate 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 p.m. The peak hour demand for these customers can be as much as 50 percent above the hourly average of daily demand. Because of the importance of responding to hourly peaking in the distribution system, planning capacity requirements for distribution systems uses peak hour demand.[1] Appendix 7.1 shows the methodology Avista uses for determining peak demand.

Distribution System Enhancements

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

Distribution system enhancements do not reduce demand nor do they create additional supply. Enhancements 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 in 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 flow capacities downstream of the constraint creating inadequate pressures during periods of high demand. When the parallel line connects to the system, this alternative path allows natural gas flow to bypass the original constraint and bolsters downstream pressures. Looping can also involve

[1] This method differs from the approach that Avista uses for IRP peak demand planning, which focuses on peak day requirements to the city gate.

connecting previously unconnected mains. The feasibility of looping a pipeline depends 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 a point where alternative solutions are more cost effective.

Pipeline upsizing involves replacing existing pipe with a larger size pipe. The increased pipe capacity relative to surface area 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 augments existing pipe, which remains in use.

Pipeline uprating increases 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 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 costly repairs. A thorough review is conducted to ensure integrity before pressure is increased.

Regulators

Regulators, or regulator stations, reduce pipeline pressure at various stages in the distribution system. Regulation provides a specified and constant outlet pressure before natural 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 pressure fluctuations upstream of the regulator. Regulators are at city gate stations, district regulators stations, farm taps and customer services.

Compression

Compressor stations present a capacity enhancing option for pipelines with significant natural gas flow and the ability to operate at higher pressures. For pipelines experiencing a relatively high and constant flow of natural gas, a large volume compressor installation along the pipeline boosts downstream pressure.

A second option is the installation of smaller compressors located close together or strategically placed along a pipeline. Multiple compressors accommodate a large flow range and use 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 over time allows a pipeline to serve growing customer demand for into the future.

Compressors can be a cost effective option to resolving system constraints; however, regulatory and environmental approvals to install a station, along with engineering and construction time can be a significant deterrent. Adding compressor stations typically involves considerable capital expenditure. Based on Avista's detailed knowledge of the distribution system, there are no foreseeable plans to add compressors to the distribution network.

Conservation Resources

Included in the evaluation of distribution system constraints is the consideration of targeted conservation resources to reduce or delay distribution system enhancements. The consumer is still the ultimate decision-maker regarding the purchase of a conservation measure. Because of this, Avista attempts to influence conservation through the DSM measures discussed in Chapter 3 – Demand-Side Resources, but does not depend on estimates of peak day demand reductions from conservation to eliminate near-term distribution system constraints. Over longer-term, targeted conservation programs provide a cumulative benefit that offsets potential constraint areas and may be an effective strategy.

Planning Results

Table 7.1 summarizes the cost of major distribution system enhancements addressing growth-related system constraints, system integrity issues and the timing of these expenditures. These projects are preliminary estimates of timing and costs of major reinforcement solutions. The scope and needs of these projects generally evolves with new information requiring ongoing reassessment. Actual solutions may differ due to differences in actual growth patterns and/or construction conditions from the initial assessment.

The following discussion provides information about key near-term projects:

East Medford Reinforcement: Previous IRP and distribution planning analysis identified a near-term resource deficiency driven by forecasted local growth. Increased natural gas deliveries from the TransCanada Pipeline source at Phoenix Road Gate Station in southeast Medford will remedy this deficiency. To facilitate distribution receipt of the increased natural gas volumes, a new high-pressure (HP) line encircling Medford to the east and tying into an existing high-pressure line in White City will improve delivery capacity and provide reinforcement in the East Medford area.

This has been a multi-phase project spanning several years. As forecasted, needs have changed over time, and with no immediate resource need, completing the final phase of the project has been delayed. Other factors may drive completion of the project including reliability needs, flexibility of natural gas supply management and optimizing synergies of other construction projects to reduce project cost. Avista will continue to evaluate forecasts and assess the most appropriate timing for completion of this project.

U.S. Highway 2 North Spokane Reinforcement: This project will reinforce the area north of Spokane along U.S. Highway 2. This mixed-use area experiences low pressure during winter at unpredictable times given 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 gas main will be installed in a newly established easement along U.S. Highway 2.

Chase Road Gate Station, Post Falls, Idaho: This gate station will allow Avista to split the large load at the Rathdrum Gate Station. Approximately 18,000 feet of new HP line will connect the Chase Road Gate Station to the existing HP line. This gate station will give Avista the opportunity to feed the growing Post Falls and Coeur d'Alene areas from the north.

Table 7.1 Distribution Planning Capital Projects

		2015	2016	2017	2018
Projects	*East Medford Reinforcement	$0	$0	$0	$5,000,000
	Goldendale HP	$3,500,000	$0	$0	$0
	NSC Greene ST HP	$0	$0	$0	$1,500,000
	Rathdrum Prairie HP Gas Reinforcement	$100,000	$4,900,000	$5,000,000	$0
	*Reinforcement, Hwy 2 Kaiser	$1,300,000	$0	$0	$0
	Spokane St Bridge Gas	$1,000,000	$0	$0	$0

*Details of project described in IRP

Table 7.2 shows city gate stations identified as over utilized or under capacity. Estimated cost, year and the plan to remediate the capacity concern are shown.

Table 7.2 City Gate Station Upgrades

Location	Gate Stn	Project to Remediate	Cost	Year
Athol, ID	Athol #219	TBD	-	2019+
Genesee, ID	Genesee #320	TBD	-	2019+
Rathdrum, ID	*Chase Rd	Chase Rd Gate Stn & Hayden Ave HP Main	$5.4M	2014
CDA (East), ID	CDA East #221	Rathdrum Prairie HP Gas Reinforcement	$10M	2016-17
Post Falls, ID	McGuire #213			
CDA (West), ID	Post Falls & CDA West			
Colton, WA	Colton #316	TBD	-	2019+
Sutherlin, OR	Sutherlin #2626	TBD	-	2019+
La Grande, OR	La Grande #815 & Union #817	Union HP Connector	$3M	2019+

*Details of project described in IRP

CONCLUSION

Avista’s goal is to maintain its distribution systems reliably and cost effectively to deliver natural gas to every customer. This goal relies on computer modeling to increase the capacity and reliability of the distribution system by identifying specific areas that may require changes.

The ability to meet the goal of reliable and cost effective gas delivery is enhanced through localized distribution planning, which enables coordinated targeting of distribution projects responsive to customer growth patterns.

8: Action Plan

2013-2014 Action Plan Review

Action Item
Avista will monitor actual demand for indications of deviations away from the Expected Case.

Results
Forecast to actual analysis reveals that the modeling techniques are producing forecasts that track actual demand. Recent natural gas demand does not show significant deviation away from expected results.

Action Item
Continued enhancement of the gate station analysis will assess if the aggregated IRP analysis masks any individual gate station deficiencies. Any deficiencies identified and potential solutions will be discussed with Commission Staff. Avista will continue to coordinate analytic efforts between Gas Supply, Gas Engineering and the intrastate pipelines to perform gate station analysis and seek least cost solutions for any identified deficiencies.

Results
Avista is completing the gate analysis in Oregon on the NWP system. Any deficiencies will be communicated along with solutions for rectifying the deficiencies to Commission Staff. The gates along the GTN system will be reviewed next.

Action Item
Avista filed in Idaho, Oregon and Washington to suspend natural gas DSM programs due to the low avoided costs in the 2012 IRP. Over the next two to three years, Avista will review natural gas prices as a signpost for the cost-effectiveness of DSM programs. If natural gas prices increase enough, Avista will seek to reinstate a full complement of natural gas DSM programs.

Results
Idaho approved the filing, and natural gas DSM programs were suspended. In Oregon, DSM programs will continue for a two-year period. During that time, Avista will evaluate program costs and develop a separate program for low-income participants. In Washington, DSM programs were also allowed to continue for a limited period and the test for evaluating cost effectiveness was changed from the total resource cost to the utility cost test.

Action Item
Pursue the possibility of a regional elasticity study through the NGA or the AGA.

Results
Price elasticity theory predicts that energy consumers will reduce consumption as prices rise. The amount of a response is debatable. Avista has reviewed historic research on price elasticity. The analysis shows a wide range of results from statistically significant to statistically insignificant and even positive in some cases.

Avista contacted the NGA and they are still willing to help facilitate a process if a regional price elasticity study moves forward. At this time, Avista is assessing the costs and benefits of such an undertaking. A regional natural gas price elasticity study will commence if enough interest develops in the project.

2015-2016 Action Plan

The recent recession significantly affected the expected long-term customer growth in Avista's service territory. This natural gas demand reduction has created no resource needs in the Expected Case within the 20-year planning horizon. Scenario analysis shows that even in the most robust growth case, Avista will not have a resource deficiency until very late in the 20-year forecast.

With no immediate resource needs, Avista can evaluate current resources and potential future resources. Avista will continue to optimize underutilized resource to recover value for customers and reduce their costs until resources are required to meet changing demand needs.

Avista remains committed to offering cost-effective conservation measures as a way for customers to reduce their energy bills and promote a cleaner environment. Like the 2012 IRP, the low price of natural gas has reduced the amount of cost-effective DSM measures. Based on the latest CPA, incorporating the lower avoided costs, Avista estimates 22,800 Dth of first year savings in Idaho, 16,100 Dth of savings in Oregon and 128,700 Dth of savings in Washington. .

Avista will comply with Commission findings to try to increase the cost effectiveness of DSM measures by reducing administration and audit costs, analyzing non-natural gas benefits and increasing measure lives. Avista will monitor natural gas prices as signpost for increasing avoided costs. If avoided costs increase, Avista will evaluate DSM programs for cost effectiveness and submit to resume natural gas DSM options.

Complete the gate station analysis to assess resource deficiencies masked by aggregated IRP analysis. Any identified deficiencies and potential solutions will be discussed with Commission Staff. Avista will continue to coordinate analytic efforts between Gas Supply, Gas Engineering and the intrastate pipelines to perform gate station analysis and develop least cost solutions should deficiencies exist.

Ongoing Activities

- Monitor actual demand for indications of growth exceeding the forecast to respond aggressively to address accelerated resource deficiencies arising from flat demand risk. This will include providing Commission Staff with IRP demand forecast to actual variance analysis on customer growth and use-per-customer. Avista will provide this information in updates to Commission Staff at least biannually.
- Continue to monitor supply resource trends, including the availability and price of natural gas to the regions, LNG exports, Canadian natural gas imports and interprovincial consumption trends, regional plans for natural 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 resource need 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's activities related to the IRP and natural gas procurement practices.

9: 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.

Average Case
Represents Avista's demand forecast for normal planning purposes. This case uses a 20 year rolling average NOAA weather for the five major areas (Spokane, WA., Medford, OR. Klamath Falls, OR, Roseburg, OR. La Grande, OR.).

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.

Capacity
The sum amount of natural gas transportation contracts or storage available in Avista's current portfolio.

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

Demand-Side 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

Expected Case
The most likely scenario for peak day planning purposes. This case uses a 20 year rolling average NOAA weather for the five major areas (Spokane, WA., Medford, OR. Klamath Falls, OR, Roseburg, OR. La Grande, OR.). Combined with this 20 year rolling average weather is the coldest day on record.

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
Costs and benefits borne by a third party 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 Haul
A transaction where gas is transported the normal direction of normal flow on a unidirectional pipeline.

Forward Market
An over-the-counter marketplace that sets the price of a financial instrument or physical asset for future delivery.

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 in Louisiana that is widely recognized as the most important natural gas pricing point in the U.S., as well as 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 customers' natural gas needs at a reasonable price.

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

Liquefaction
Any process converting natural gas 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 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, sorted from highest send out day to lowest to demonstrate 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. 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 supplement firm contracts during times of high demand or to displace other volumes when cost-effective. 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, 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 who 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, Nev.; 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

2014 Natural Gas Integrated Resource Plan Appendices

August 31, 2014

Safe Harbor Statement

This document contains forward-looking statements. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond the Company's control, and many of which could have a significant impact on the Company's operations, results of operations and financial condition, and could cause actual results to differ materially from those anticipated.

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. The forward-looking statements contained in this document speak only as of the date hereof. The Company undertakes 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 the Company's 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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APPENDIX 0.1: TAC MEMBER LIST

ORGANIZATION	REPRESENTATIVES	
Avista	John Lyons Jon Powell Jason Thackston Kerry Shroy Terrence Brown Annette Brandon Shawn Bonfield Laura Pendergraft	Linda Gervais Lori Hermanson Pat Ehrbar Grant Forsyth Tom Pardee Mike Diedesch Clint Kalich
Cascade Natural Gas Company	Brian Robertson	Jon Whiting
Fortis BC	Dana Wong	Ken Ross
Intermountain Gas	Mike McGrath	Shelli Chase
Idaho Public Utility Commission	Matt Elam	Rick Sterling Terri Carlock
Northwest Gas Association	Ben Hemson	Dan Kirschner
Northwest Industrial Gas Users	Ed Finklea	
Northwest Natural Gas	Tammy Linver	Mark Thompson
Northwest Pipeline	Teresa Hagins	Ray Warner
Oregon Public Utility Commission	Ryan Bracken Erik Colville	Lisa Gorsuch
Oregon CUB	Nadine Hanhan	
Puget Sound Energy	Gurvinder Singh	Phillip Popoff
TransCanada	David White	Jay Story
Washington Attorney General's Office	Lea Daeschel	Mary Kimball
Washington Utility and Transportation Commission	David Nightingale Brad Cebulko	Chris McGuire
WA Department of Commerce	Greg Nothstein	

APPENDIX 0.2: COMMENTS AND RESPONSES TO 2014 DRAFT INTEGRATED RESOURCE PLAN

The following table summarizes the significant comments on our DRAFT as submitted by TAC members and Avista's responses. These comments are those not directly incorporated into the primary document. 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 – DEMAND SIDE MANAGEMENT	Avista has a DSM preference adder, but does not quantify many natural gas non-energy benefits (NEBs). In chapter 9 the company has committed to analyzing "non-natural gas benefits" as an action item. Perhaps this is an area the company could work with the Energy Trust of Oregon, the advisory group and other regional actors to quantify NEBs. The Commission's Policy Statement on the Evaluation of the Cost-Effectiveness of Natural Gas Conservation Programs in Docket UG-121207 has a preference for a fully developed Total Resource Cost test, and staff would like to see the company works towards that end.	It is Avista's policy to include all non-natural gas impacts that can be quantified in a manner that is sufficiently rigorous and reasonable to defend to a critical but reasonable audience. Where such degrees of rigor cannot be met the Company is committed to measuring the presence of non-natural gas impacts to the extent possible so as to facilitate the discussion of non-quantifiable non-natural gas impacts. The primary non-natural gas impacts currently quantified by the Company are non-natural gas energy savings (electric, propane and other non-natural gas fuels), water and sewage savings. Additionally, for low-income programs, the Company has a valuation of health and human safety investments and provision of baseline end-use services. The Company treats the importation of funding from outside of the Avista ratepayer population as offsetting the customer incremental cost and not as a non-natural gas impact, but the consequences to the Total Resource Cost test is similar. The Company has a mechanism with the site-specific program to capturing unusual and unique non-natural gas impacts and incorporating them into the cost-effectiveness analysis.

3 – DEMAND SIDE MANAGEMENT	As staff asked in its acknowledgment letter in Docket UG-111588, Avista should include an analysis and narrative describing the “trigger point” avoided cost value, where the conservation programs of the company become cost-effective.	The Company has committed to monitoring the weighted average cost of gas (WACOG) as a proxy for the avoided cost between Integrated Resource Plans. Though the WACOG and the avoided cost differ in some significant and important ways, a significant upward movement in the WACOG would tend to indicate a similar movement in the avoided cost. This could then trigger an immediate re-evaluation of the potential between IRP cycles. Earlier analysis indicated that an increase of approximately 90% in the avoided cost would be necessary to deliver a portfolio that was cost-effective under the Total Resource Cost test.
3.10 – DEMAND SIDE MANAGEMENT	The targets for 2015 and 2016 for Oregon are substantially lower than 2013 and 2014 (161 and 111 versus 225 and 250). Please provide more information about why there is such a large reduction. OPUC may be interested in the Company continuing current levels of acquisition. Please present a case where that can happen and what measures could fall within the exception criteria in Order 94-590, Docket No. UM 551.	Incremental economic potential in the 2015 and 2016 biennium is 454 and 235 dekatherms. In the previous study, incremental economic potential for 2013 and 2014 was 486 and 642 dekatherms. The lower economic potential in the current study reflects lower avoided cost projections. This flows through to achievable potential and the targets for 2015 and 2016 are lower than they were for 2013 and 2014. See the comparison of avoided costs in the separate tab.
3.12– DEMAND SIDE MANAGEMENT	Good discussion on developing a regional natural gas market transformation organization. Does Avista have a timeline? Can this conversation be expanded? Please update the final draft with the most current information.	The interested regional natural gas utilities are continuing the process of developing a proposal for review by the full Northwest Energy Efficiency Alliance (NEEA) board. The deadline for completing that proposal is the end of the calendar year, but every attempt is being made to expedite that process. The best opportunity for interested parties to contribute to that discussion will be as part of the NEEA board review.
3.2 – DEMAND SIDE MANAGEMENT	Please provide more details about how ramp rates were calculated and how they were or weren’t consistent with assumptions used by the Northwest Power Planning Council. Also, please include a side by side comparison with explanation of differences.	EnerNOC Consulting Services (now AEG) used the Council's Sixth Plan ramp rates as a starting point for the Avista study. Then, we made adjustments to the ramp rates in the early years of the projection to better align with Avista's recent program accomplishments. The ramp rates were also adjusted in the out years for some measures. The resulting Avista ramp rates are presented in the two tabs: Equip_Ramp Rates and Non_Equip_Ramp Rates.

3.4 – DEMAND SIDE MANAGEMENT	More details are needed about how achievable potential was calculated and how each of the elements mentioned were incorporated in practice.	In each year of the forecast, some number of appliances fail and need to be replaced. If a measure is cost effective, then the ramp rate is applied to determine what fraction of the market installs the cost-effective option. For example, the ramp rate in 2015 for furnaces in the commercial sector, a cost-effective measure, is 20%. Therefore, 20% of the furnaces that fail in 2015 are replaced with the energy-conservation measure (high efficiency furnace) and the remaining furnaces are replaced with the baseline option.
3.6 – DEMAND SIDE MANAGEMENT	Please describe why only 74 percent of economic potential is achievable by 2034. Provide details regarding underlying assumptions and data files.	This 74% is actually a very high share of economic potential and reflects the combination of lost-opportunity and non lost opportunity measures, with ramp rates in the out years of up to 65% and 85% respectively.
3.8 – DEMAND SIDE MANAGEMENT	In the Oregon achievable potential numbers; please explain what assumptions are made about which measures are included. Are only TRC cost effective measures (and those measures required by law) included in projections? How is low income handled relative to cost effectiveness? Please include a sensitivity case and numbers for the occasion where current exceptions to cost effectiveness are continued beyond the current two year window.	A comprehensive measure list was included in the analysis. The total resource cost test (TRC) was used for cost-effectiveness screening with a minimum threshold of 1.0. Only measures that are considered cost-effective are included in economic, and therefore acheivable potential. The residential sector was segmented by housing type. Low income was not specifically considered as part of the CPA. However, the low-income segment is considered in the development of programs.
4.4 – SUPPLY SIDE RESOURCES	The last sentence of first full paragraph mentions a process to acquire value from each transaction. Please identify how that process is carried out and identify who is involved.	The value of a transaction for the purchase of natural gas can encompass many different aspects both financial and non-financial and is assessed at the time the transaction is executed. Our natural gas buyers are actively assessing the most cost effective way to meet customer demand and optimize unutilized resources. Therefore value cannot be necessarily measured from a single transaction. It may be a series of transactions that span across timeframes of a day, week, month or season.

4.11 – SUPPLY SIDE RESOURCES	Jackson Prairie paragraph mentions that Avista will look for exchange and transportation release opportunities. Please discuss how the opportunities will be monitored and what will be done with the intelligence gathered through such monitoring.	These opportunities can be discovered in a number of ways. For example, buyers may be contacted from marketers or other utility counterparts. When the opportunity presents itself we assess if it makes sense from a financial impact to customers as well as a reliability concerns.
5.20 – INTEGRATED RESOURCE PORTFOLIO	Avista has TF-2 service for its storage at Jackson Prairie. Presumably the company draws down JP during cold events when demand is high. Is TF-2 firm capacity? If not, please explain why the company feels it can rely upon the service for meeting peak demand.	TF2 is a firm service as noted on NWP website: "TF2 allows for contracting a daily amount of firm service for a specified number of days rather than a daily amount on an annual basis as is usually required."
5.23 – INTEGRATED RESOURCE PORTFOLIO	ACTION ITEM discusses routine LDC activities. The action items should not include actions that are "normal" utility activities. The action plan items should be specific and measurable.	With no resource deficiency in our expected case, there are no specific and measurable near term action items.
6.5 – ALTERNATE SCENARIOS	The last paragraph highlights a structural problem with the IRP analysis. The point of calculating PVRR is to be able to compare alternate portfolios (different ways of meeting forecast demand). See Guideline 1.c. Please expand the discussion to explain the intended PVRR calculation value and why in this IRP the value is not there.	Using PVRR analysis to compare various scenarios where some of the assumptions are similar is a very useful analysis. However, looking strictly at PVRR calculations without considering the assumptions of each scenario is not appropriate. For example the PVRR of our Expected scenario is higher than the PVRR of the High Growth scenario. However, there are lower supply costs and demand that remains unserved in the High Growth Scenario so selecting the lowest PVRR scenarios is not applicable. There are also non-economic factors that may make the selection of one scenario over the other based on pure PVRR analysis undesirable.
7 – DISTRIBUTION PLANNING	Will you be describing all projects on Table 7.1 and 7.2?	We only provide detail on specific projects that were driven from IRP analysis. We have provided major capital expenditures for informational purposes only.

8.2 – ACTION PLAN	There is no action item that speaks to the exception period for non-cost effective measures that will sunset in April 2015, and what action will be taken to address this ongoing situation.	Ongoing situation of Oegon DSM program will be addressed outside of the IRP through its Annual Plan, Year-End Reporting, and tariff filings. IRP Action Plan was updated to reflect the progress made on the 2013/2014 Action Items Ordered by the Commission.

APPENDIX 1.1: AVISTA CORPORATION 2014 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 2014 Natural Gas IRP by Aug. 31, 2014. 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 2014 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.

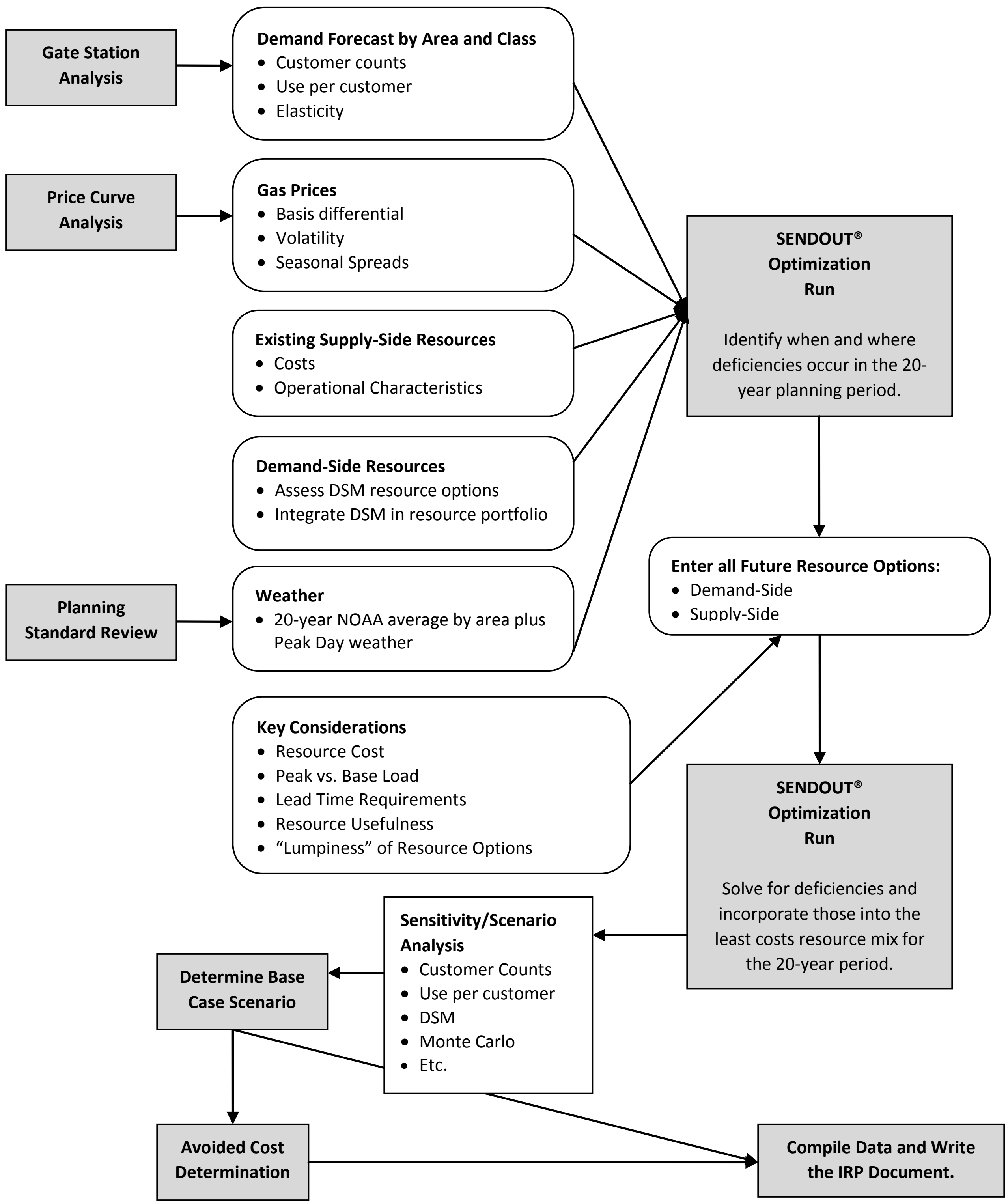
Additionally, Avista intends to incorporate action plan items identified in the 2012 Natural Gas IRP including more detailed demand analysis regarding use per customer, demand side management results and possible price elastic responses to evolving economic conditions, an updated assessment of conservation 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 2014 Natural Gas IRP timeline:

August 30, 2013	Work Plan filed with WUTC	
January through April 2014	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, 2014	Draft of IRP document to TAC	
June 29, 2014	Comments on draft due back to Avista	
July 17, 2014	TAC final review meeting (if necessary)	
August 31, 2014	File finalized IRP document	

EXHIBIT 1: AVISTA'S 2014 NATURAL GAS IRP MODELING PROCESS



APPENDIX 1.2: WASHINGTON PUBLIC UTILITY COMMISSION IRP POLICIES AND GUIDELINES – WAC 480-90-238

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 1.1.
WAC 480-90-238(4)	Work plan outlines content of IRP.	See workplan attached to this Appendix 0.1.
WAC 480-90-238(4)	Work plan outlines method for assessing potential resources. (See LRC analysis below)	See Appendix 1.1.
WAC 480-90-238(5)	Work plan outlines timing and extent of public participation.	See Appendix 1.1.
WAC 480-90-238(4)	Integrated resource plan submitted within two years of previous plan.	Last Integrated Resource Plan was submitted on August 31, 2012
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 4 on Supply Side Resources
WAC 480-90-238(2)(a)	Plan describes conservation supply.	See Chapter 3 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 4 on Supply Side Resources and Chapter 5 Integrated Resource Portfolio
WAC 480-90-238(2)(a)&(b)	Plan uses lowest reasonable cost (LRC) analysis to select mix of resources.	See Chapters 3 and 4 for Demand and Supply Side Resources. Chapter 5 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 3 and 4 for Demand and Supply Side Resources. Chapter 5 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 4 on Supply Side Resources
WAC 480-90-238(2)(b)	LRC analysis considers demand side uncertainties.	See Chapter 2 Demand Forecasting
WAC 480-90-238(2)(b)	LRC analysis considers resource effect on system operation.	See Chapter 4 and Chapter 5
WAC 480-90-238(2)(b)	LRC analysis considers risks imposed on ratepayers.	See Chapter 4 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 2 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 2 on demand scenarios
WAC 480-90-238(2)(b)	LRC analysis considers need for security of supply.	See Chapter 4 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 3 on Demand Side Resources
WAC 480-90-238(3)(a)	Plan includes a range of forecasts of future demand.	See Chapter 2 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 2 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 2 on Demand Forecast
WAC 480-90-238(3)(b)	Plan includes an assessment of commercially available conservation, including load management.	See Chapter 3 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 3 and Appendix 3.1.
WAC 480-90-238(3)(c)	Plan includes an assessment of conventional and commercially available nonconventional gas supplies.	See Chapter 4 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 4 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 4 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 3 on Demand Side Resources and Chapter 4 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 5 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 8 Action Plan
WAC 480-90-238(3)(i)	Plan includes a progress report on the implementation of the previously filed plan.	See Section 8 Action Plan

WAC 480-90-238(5)	Plan includes description of consultation with commission staff. (Description not required)	See Section 0 Introduction
WAC 480-90-238(5)	Plan includes description of completion of work plan. (Description not required)	See Appendix 1.1.

APPENDIX 1.2: IDAHO PUBLIC UTILITY COMMISSION IRP POLICIES AND GUIDELINES – ORDER NO. 2534

	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 2014 IRP on or before August 31, 2014.
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 portfolio for its core customers. While the primary 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:	2014 IRP to be filed on or before August 31, 2014. The last IRP was filed on August 31, 2012.
	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 efficiency of gas end-uses.	See **Chapter 2 - Demand Forecasts** and **Appendix 2 et. al.** for a detailed discussion of how demand was forecasted for this IRP.
	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 3 - Demand Side Management** and **DSM Appendices 3 et.al.** for detailed information on the DSM potential evaluated and selected for this IRP and the operational implementation process.

	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 4 - 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.
	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 3 - 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 3 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.
	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 5 - Integrated Resource Portfolio** for details on how we model demand and supply coming together to provide the least cost/best risk portfolio of resources.
	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 8 - 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 Commissioners 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 0 - 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 4 - 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 disapproval 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 proceedings in which those issues have been noticed.	See also section titled "Alternate Supply-Side Scenarios" in **Chapter 5 - Integrated Resource Portfolio** where we discuss different supply portfolios that are resonsive to changing assumptions about resource alternatives.

APPENDIX 1.2: 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 3 and Appendix 3.1 documents Avista's demand-side management resources considered. Chapter 4 and Appendix 5.3 documents supply-side resources. Chapter 5 and 6 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 5 provides details about the modeling methodology and results. Chapter 4 describes resource attributes and Appendix 5.3 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 5.2 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 4.93% to discount all future resource costs. (See general assumptions at Appendix 5.2)
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 2.6. One of the key risks is the "flat demand" risk as described in Chapter 1. Avista performed 15 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 2.4).

		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 4.3. These supply scenarios were combined with demand scenarios in order to establish portfolios for evaluation. Ultimately 9 portfolios were evaluated (See Table 6.3 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 3.2. 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 0 Introduction. Avista also analyzed demand risk which is detailed in Chapter 2. Chapter 3 discusses the uncertainty around how much DSM is achievable. Supply-side resource risks are discussed in Chapter 4. Chapter 5 and 6 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 5 and 6 plus supporting information in Appendix 2.6 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	Avista's SENDOUT® modeling software utilizes a PVRR cost metric methodology applied to both long and short-lived resources.

	short-term power purchases.	
	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 6 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 4 discusses Avista's physical and financial hedging methodology.
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Chapter 4, 5, and 6 describe various specific resource considerations and related risks, and describes what criteria 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 5 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 0 provides an overview of the public process and documents the details on public meetings held for the 2014 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, 2014 and requested comments by July 13, 2014.
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 2012 Natural Gas IRP was acknowledged on 4/30/2013.
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 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	Because the 2012 IRP was not acknowledged until April 30, 2013 the Company did not submit an annual update as the 2014 IRP process was well underway by the anniversary date of the acknowledgement. The Company provided updates and comparisons to its 2012 IRP during its 2014 IRP TAC meetings held on January 24, 2014, February 25, 2014, March 26, 2014, and April 23, 2014, in which Commission Staff and other TAC members were present. In addition the Company provided an update during its Natural Gas Quarterly update meeting held on April 17, 2014. No request for acknowledgement was required as no significant deviation from the 2012 IRP was anticipated.
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 updates described in 3f above explained changes since acknowledgment of the 2012 IRP and an update of emerging planning issues. The updates did not request acknowledgement of any changes. Also, as directed in Order No. 13-159, per the 2013-2014 Action Plan, the Company continued its DSM programs in Oregon with a minimum savings goal of 225,000 therms in 2013 and 250,000 therms in 2014. On April 30, 2014, the Company submitted its 2013 DSM Annual Report to Commission Staff which included updates and progress in meeting the DSM Action Items contained in Order No. 13-159. Lastly, as ordered the Company developed a potential mechanism for allocating funding for a separate low-income energy efficiency program and submitted a report to Commission Staff outlining the mechanism on October 30, 2013. On January 8, 2014 the Company filed a tariff to implement the low-income energy efficiency program, which was approved with an effective date of March 1, 2014.
Guideline 4: Plan Components		
	At a minimum, the plan must include the following elements:	
4a	An explanation of how the utility met	This table summarizes guideline compliance by

	each of the substantive and procedural requirements.	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 1 describes the demand forecast data and Chapter 5 provides the scenario and risk analysis results. Appendix 5 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 0.6 and 0.7summarize graphically projected annual peak day demand and the existing and selected resources by year to meet demand for the expected case. Appendix 6.1 and 6.2 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 3 and Appendix 3.1 identify the demand-side potential included in this IRP. Chapter 4 and 5 and Appendix 5.3 identify the supply-side resources.
4f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	Chapter 5, 6, and 7 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 4 discusses the diversified infrastructure and multiple supply basin approach that acts to mitigate certain reliability risks. Appendix 2.6 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 5 and Chapter 5 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 4.3 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 4 describes resource options reviewed including discussion on uncertainties in lead times and costs as well as viability and resource availability (e.g. LNG). Appendix 5.3 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 5.5 as well as graphically presented in Figure 5.18 and 5.19 for the Expected Case and Appendix 6.1 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 5 and Appendix 2.6 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 in portfolio testing.	Chapter 8 presents the IRP Action Plan with focus on the following areas: • Modeling • Supply/capacity • Forecasting • Regulatory communication • DSM
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.	EnerNOC performed a conservation potential assessment study for our 2014 IRP. A discussion of the study is included in Chapter 3. The full study document is in Appendix 3.1. 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 3 while selection methodology is documented in Chapter 5. 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 5.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 3 Demand Response section for more discussion.
Guideline 8: Environmental Costs		
8	Utilities should include, in their base-case analyses, the regulatory 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.	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 3.2 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 2014 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 Benchmark Resources it plans to consider in competitive bidding.	Not applicable to Avista's gas utility operations.

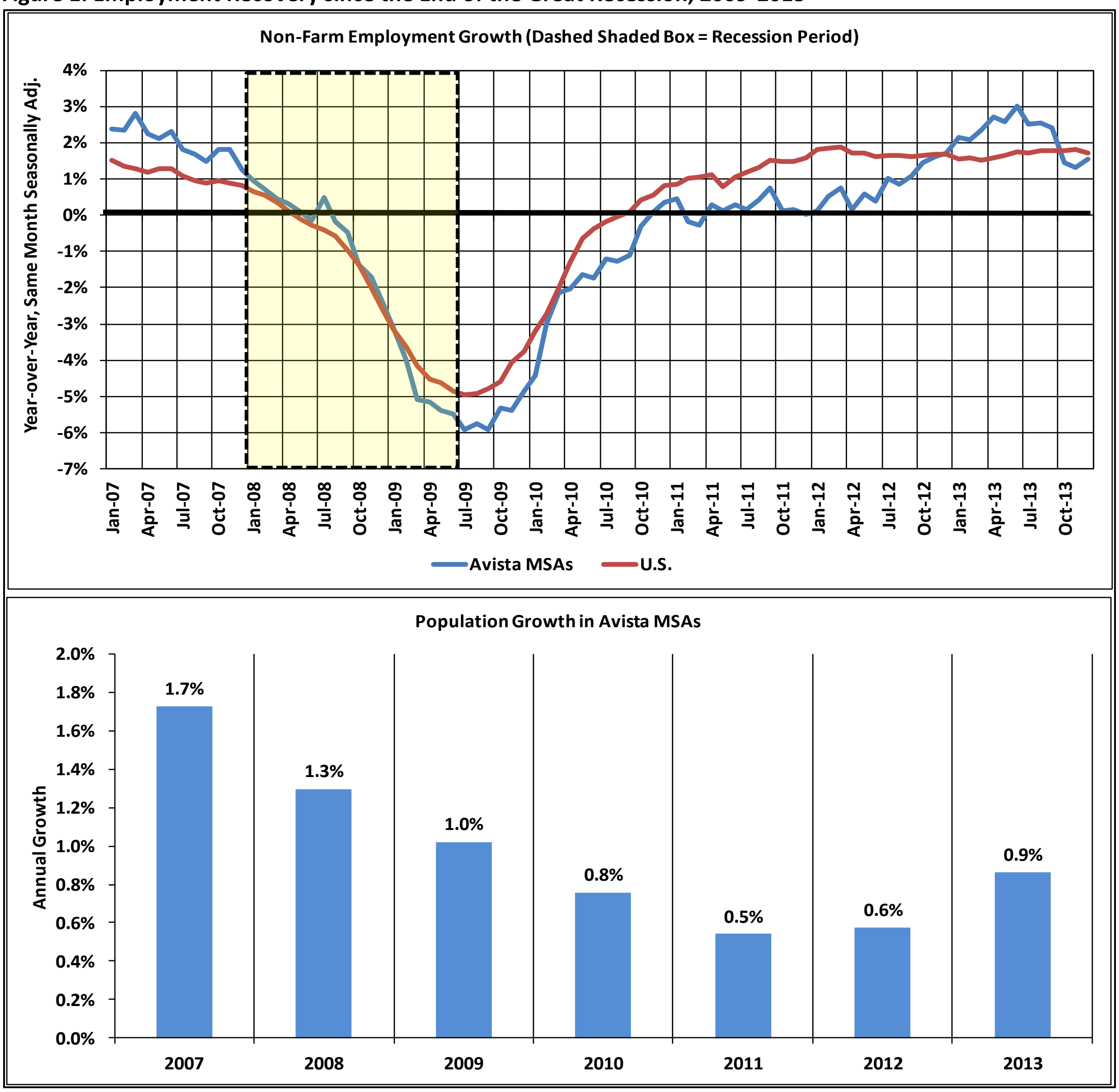
13b	Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.	A discussion of Avista's procurement practices is detailed in Chapter 4.
Guideline 8: Environmental Costs		
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 3.2 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 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.	The Environmental Externalities discussion in Appendix 3.2 describes our process for addressing these costs.

APPENDIX 2.1: ECONOMIC OUTLOOK AND CUSTOMER COUNT FORECAST

I. Service Area Economic Performance and Outlook

Avista's core service area for natural gas includes Eastern Washington, Northern Idaho, and Southwest Oregon. Smaller service islands are also located in rural South-Central Washington and Northeast Oregon. Our service area is dominated by four metropolitan statistical areas (MSAs): the Spokane-Spokane Valley, WA MSA (Spokane-Stevens counties); the Coeur d'Alene, ID MSA (Kootenai County); the Lewiston-Clarkson ID-WA, MSA (Nez Perce-Asotin counties); and the Medford, OR MSA (Jackson County). These four MSAs represent the primary demand for Avista's natural gas and account for 75% of both customers (i.e., meters) and load. The remaining 25% of customers and load are spread over low density rural areas in all three states.

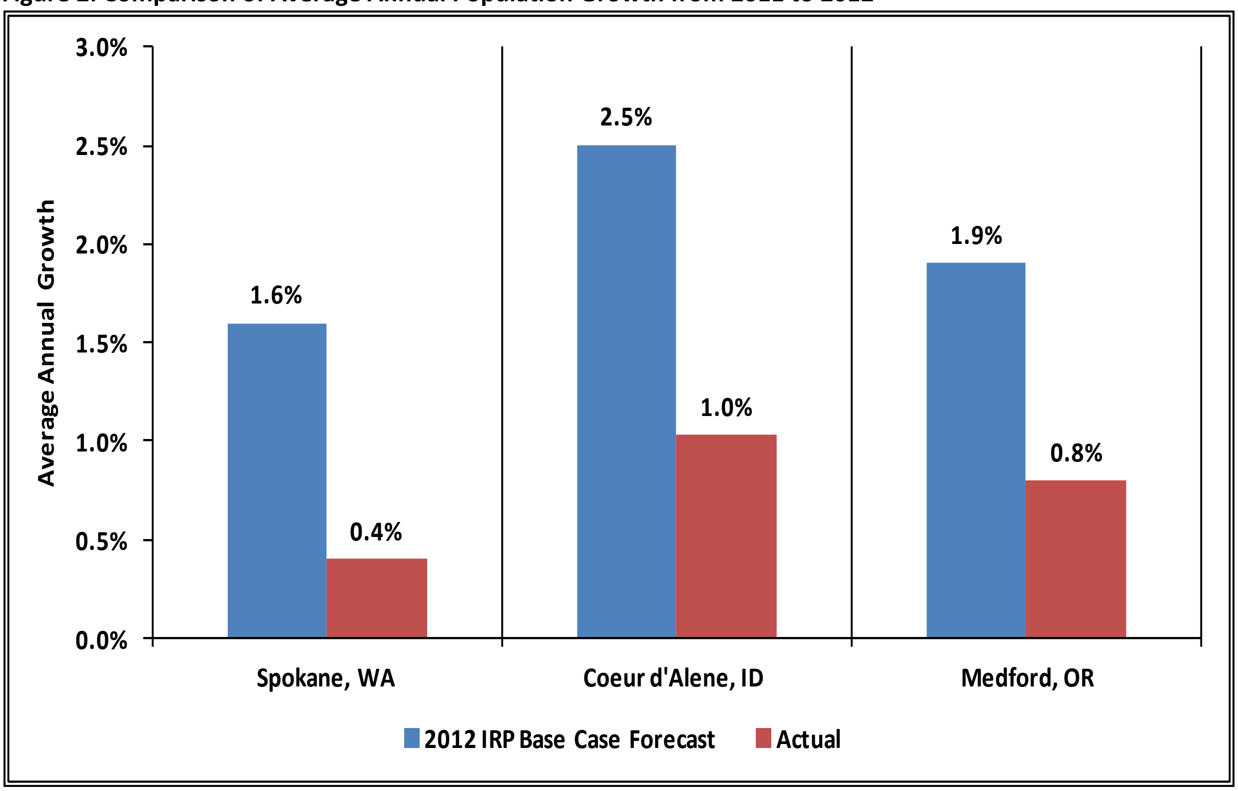
Figure 1: Employment Recovery since the End of the Great Recession, 2009-2013



Data source: Employment from the BLS; population from the U.S. Census.

Compared to the U.S. as a whole, our service area has been slow to recover from the Great Recession. Although the U.S. recession officially ended in June 2009 (dated by the National Bureau of Economic Research), our service area did not start a significant employment recovery until the second half of 2012 (Figure 1, top graph). As a result, service area population growth, which is significantly influenced by in-migration through employment opportunities, remains much lower than pre-recession levels (Figure 1, bottom graph) and has recovered at a much slower rate than anticipated in the 2012 IRP (Figure 2). In 2011, Avista's MSA population growth fell to around 0.5%, the lowest since the late 1980s. Since population growth is a long-run proxy for residential and commercial customer growth, this IRP shows a significant downward revision in total forecasted customers in WA-ID and OR compared to the 2012 IRP (Figure 3). Industrial customer growth, which is not significantly correlated with population growth, has been close to zero since the end of Great Recession. Over the same time period, our rural service areas have seen very little growth in total customers.

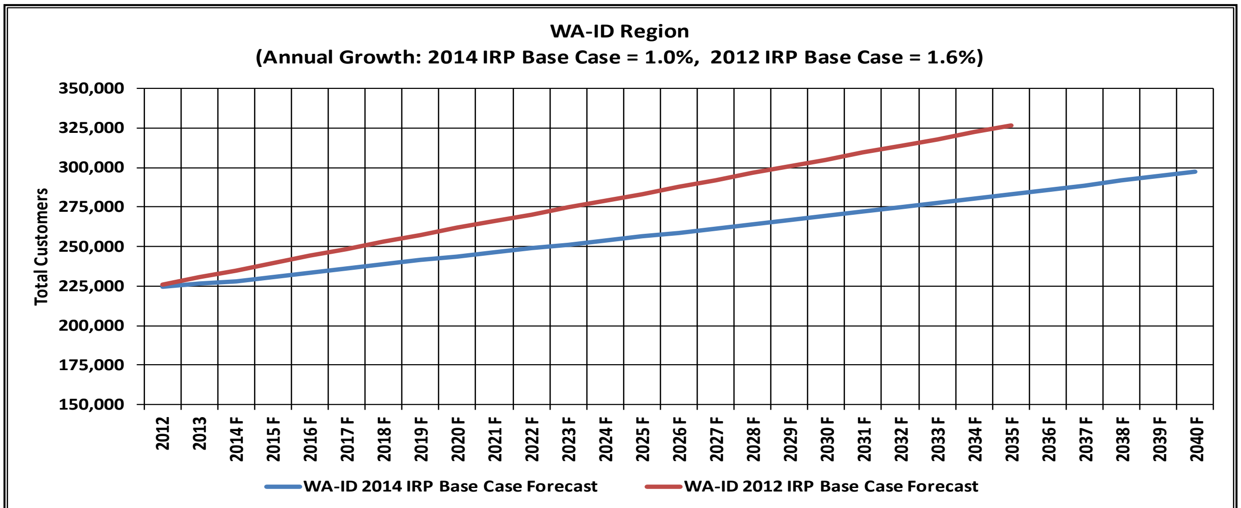
Figure 2: Comparison of Average Annual Population Growth from 2011 to 2012

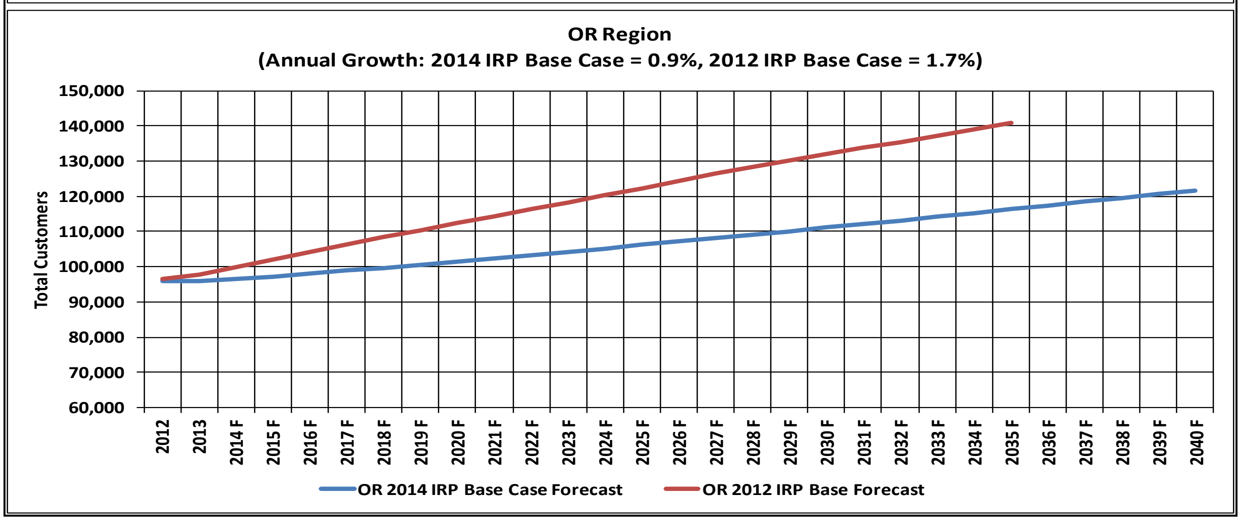


Data source: Actual population growth calculated U.S. Census data.

In large part, the downward revision in this IRP reflects an assumed lower long-run GDP growth in the U.S., which filters down to our service area as lower employment growth relative to the U.S. In turn, this translates into lower population growth due to slower in-migration. The current assumption for long-run GDP growth is 2.5%, significantly lower than the to 3% assumption in the 2012 IRP. Based on demographic and productivity trends, the 2.5% growth assumption is consistent with a growing consensus that long-run GDP growth with be in the 2.2-2.7% range. For example, the Energy Information Administration's (EIA) 2014 Annual Energy Outlook forecast assumes a 2.4% annual average growth rate out to 2040. Finally, since GDP is both a measure of output and income, the lower GDP growth assumption also implies slower industrial production growth and household income growth compared to the 2012 IRP.

Figure 3: Comparison of Forecasted Customer Growth WA-ID and OR, 2014-2040



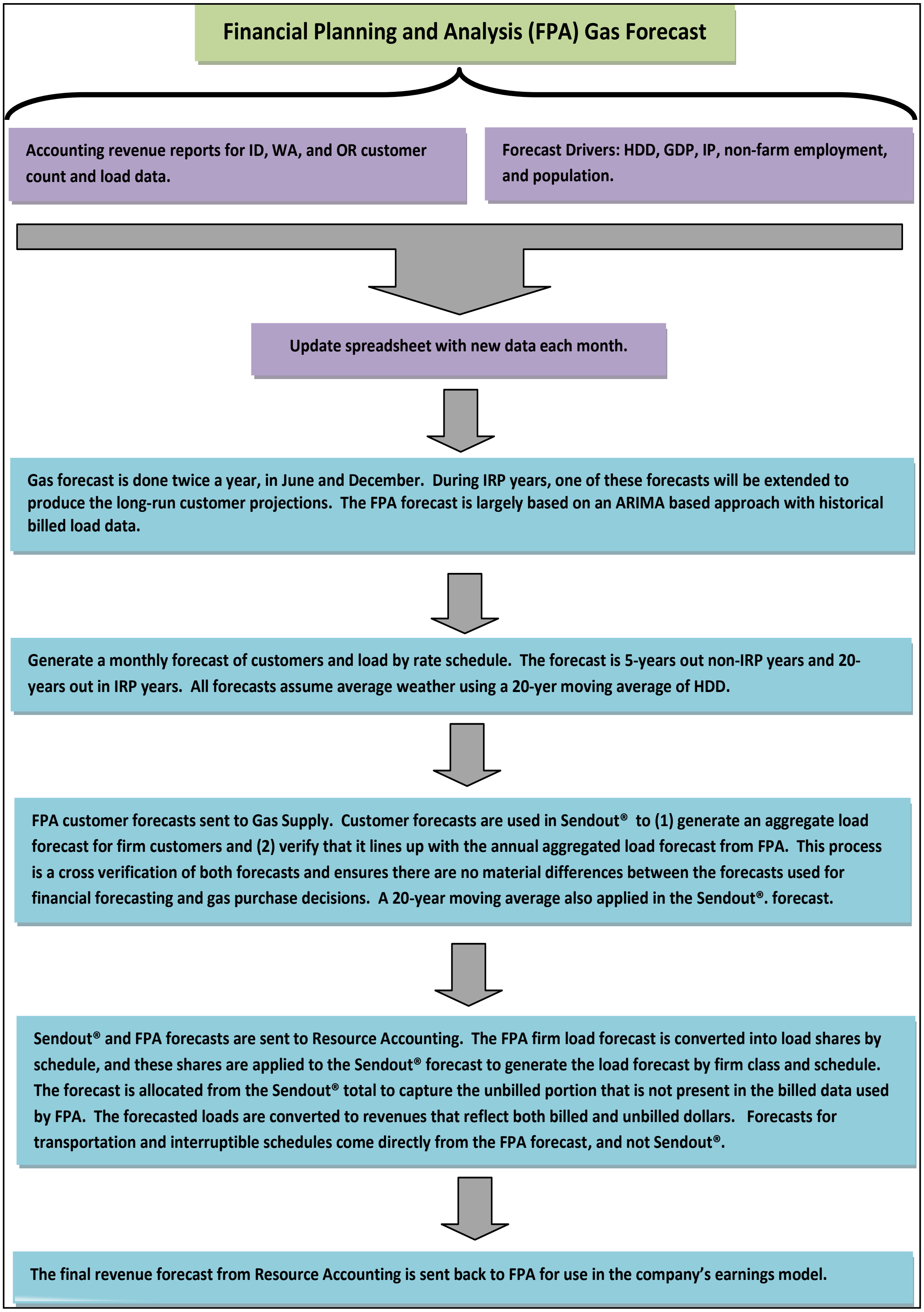


II. Forecast Process and Methodology

Figure 4 summarizes the forecast process for natural gas. In non-IRP periods, the forecast from Financial Planning and Analysis (FPA) is generated by schedule for each class (residential, commercial, and industrial) out five years. For schedules with the most load and customers, forecasts are generated from regression models that are either pure ARIMA models or ARIMA transfer function models. Pure ARIMA models use only past values of therm use per customer (UPC) or customers to forecast future UPC or customers. ARIMA transfer function models are based on weather, non-weather seasonal factors, long-run time trends, economic drivers, and ARIMA error correction terms. These are standard time-series models that are estimated using SAS/ETS software.

The FPA customer forecasts are used as input into Sendout® to generate the IRP load forecasts for gas purchase decisions. Sendout® forecasts are compared against FRP forecasts to ensure that there are no significant deviations between the two forecasts. Over five year forecast horizon, the deviations are not typically material on an aggregate annual basis.

Figure 4: Avista's Forecast Process for Natural Gas

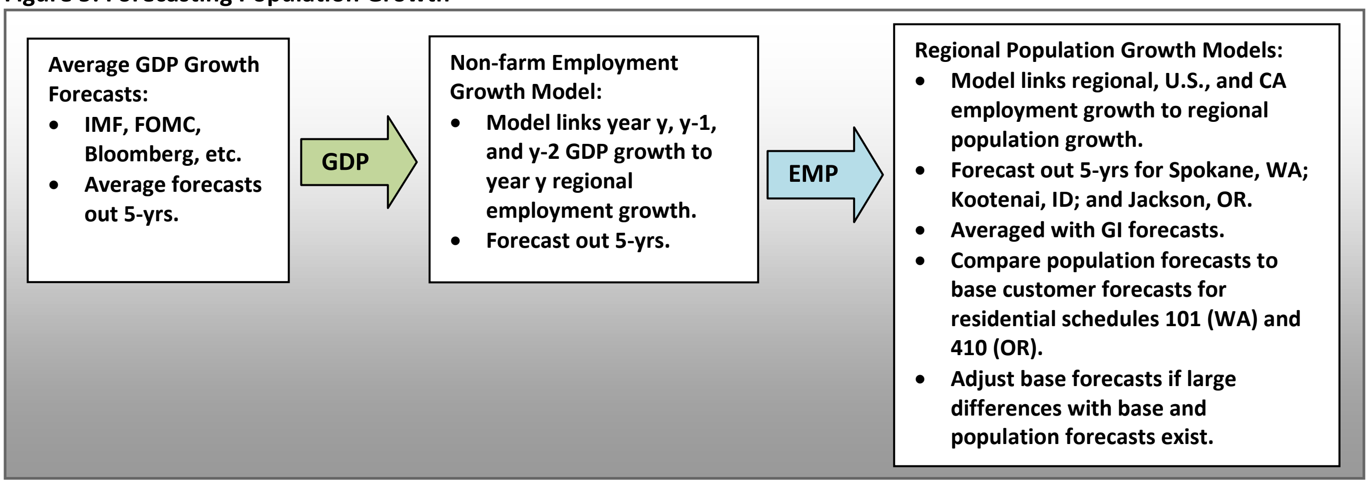


Economic Drivers in Five Year Customer Forecasts

Population growth is the key driver for the residential customer forecast. Because of the high historic correlation between residential and customer forecasts, population is also an indirect driver in forecast for commercial customers. As will be discussed below, the implicit assumption is that commercial customer growth tends to follow along with residential growth.

Population growth forecast is one of the key drivers behind the customer forecast for residential schedules 101 in WA-ID and 410 in OR. These two schedules represent the majority of customers and, therefore, drive overall residential customer growth. Because of their size and growth potential, a multi-step forecasting process has been developed for the Spokane-Spokane Valley-Coeur d'Alene combined MSAs and the Medford MSA. Figure 5 describes the forecasting process for population growth for these MSAs.

Figure 5: Forecasting Population Growth



The forecasting models for regional employment growth are:

[1] $GEMP_{y,SPK+KOOT} = \vartheta_0 + \vartheta_1 GGDP_{y,US} + \vartheta_2 GGDP_{y-1,US} + \vartheta_3 GGDP_{y-2,US} + \omega_{SC} D_{KC,1998-2000=1} + \omega_{SC} D_{HB,2005-2007=1} + \epsilon_{t,y}$

[2] $GEMP_{y,JACK} = \phi_0 + \phi_1 GGDP_{y,US} + \phi_2 GGDP_{y-1,US} + \phi_3 GGDP_{y-2,US} + \omega_{SC} D_{HB,2004-2005=1} + ARIMA\epsilon_{t,y}\,(1,0,0)(0,0,0)_{12}$

SPK+KOOT is for the combined area of Spokane, WA (Spokane MSA) and Kootenai, ID (Coeur d'Alene MSA), and JACK is for Jackson County, OR (Medford MSA). $GEMP_y$ is employment growth in year y, $GGDP_{y,US}$ is U.S. real GDP growth in year y. D_{KC} is a dummy variable for the collapse of Kaiser Aluminum in Spokane, and D_{HB} is a dummy for the housing bubble, specific to each region. The average GDP forecasts are used in the estimated model to generate five-year employment growth forecasts. Averaging the GDP forecasts reduces the systematic errors of a single-source forecast. Discussed below, employment growth forecasts are then used to generate population growth forecasts.

The major MSA forecasting models for regional population growth are:

[3] $GPOP_{y,SPK+KOOT} = \kappa_0 + \kappa_1 GEMP_{y-1,SPK+KOOT} + \kappa_2 GEMP_{y-1,US} + \omega_{OL} D_{2001=1} + \epsilon_{t,y}$

[4] $GPOP_{y,JACK} = \psi_0 + \psi_1 GEMP_{y-1,JACK} + \psi_2 GEMP_{y-1,CA} + \omega_{OL} D_{1991=1} + \omega_{SC} D_{HB,2004-2006=1} + \epsilon_{t,y}$

$D_{2001=1}$ and $D_{1991=1}$ are outlier dummy variables for recession impacts. $GEMP_{y-1,US}$ is U.S. employment growth in year y-1 and $GEMP_{y-1}$,CA is California Employment growth in year y-1. Because of its close proximity to CA, CA employment growth is better predictor of Medford's population growth than U.S. growth.

Forecasts generated from [3] and [4] are combined with GI's population (GIPOP) forecasts for the same areas in the form of a simple average. As with the GDP forecasts, averaging with GI's population forecast reduces the systematic errors of a single-source forecast. In the case of Spokane-Kootenai, the forecasted growth rate is broken apart by to generate an individual rate for each MSA:

[5] $F_{Avg}(POP_{y,SPK+KOOT}) = \frac{F(POP_{y,SPK+KOOT})+F(GIPOP_{y,SPK+KOOT})}{2}$

[6] $F_{Avg}(GPOP_{y,JACK}) = \frac{F(POP_{y,JACK})+F(GIPOP_{y,JACK})}{2}$

Forecasts [5] and [6] are applied to base-line residential schedule 101 (WA-ID) and 410 (OR) customer forecasts generated by ARIMA models. If the base-line forecast appears are in line with the population growth forecasts from [5] and [6], then no direct adjustment is made to the base-line ARIMA forecasts. However, if the base-line ARIMA forecasts appear to be too low or too high relative to the population forecast, [5] and [6] are applied to adjust the base-line forecasts so that the final annual growth rate of forecasted customers matches the forecasted population growth rate, $F_{Avg}(GPOP_y)$ for each major MSA.
For La Grande, OR (Union County); Klamath Falls, OR (Klamath County); and Roseburg, OR (Douglas County), GI's forecasts are used in lieu of in-house forecasts. Because of their small size, the WA service areas around Stevenson, WA (Skamania County) and Goldendale, WA (Klickitat County) are not broken out for forecasting purposes. The Lewiston-Clarkston area is aggregated into the Spokane and Kootenai customer count used for forecasting; therefore, it is not considered separately. Given its close proximity to the Medford area, this is also the case for Grants Pass, OR (Josephine County).

The residential customer forecasts, generated from the process described above, are then used as a driver in the forecasts for commercial schedule 101 (WA-ID) and schedule 420 (OR). The exception is Roseburg, OR, where there is little correlation between residential and commercial customer growth. As with residential schedules 101 and 410, commercial schedules 101 (WA) and 420 (OR) are the main drivers of overall commercial customer growth. This is a three step process. First, historical residential customers are used as an explanatory variable in an ARIMA model for forecasting commercial customers. Second, commercial ARIMA models for WA, ID, and OR are estimated from historical commercial and residential customer data. Third, five year commercial forecasts for schedules 101 or 420 are generated using the 101 or 410 residential customer forecasts in the commercial ARIMA models estimated with historical data. This method assumes this historical high correlation between residential and commercial customer growth continues in the future.

Long-Run IRP Forecasts after the Five Year Forecast Horizon

Forecasts for IRP years are extend out from the five year forecasts by first assuming long-run values as inputs into [1] and [2]. As discussed above, the current assumption is a long-run GDP growth rate of 2.5%. This assumption generates long-run growth rate for employment growth, which is used in [3] and [4]. Finally, GI's long-range forecasts are combined with [3] and [4] to produce a base-line residential growth rate for the largest MSAs. As with the 5-year out forecast, the smaller service areas in OR rely on GI's forecasts as a proxy for residential customer growth, which currently extend to the early 2040s.
With the exception of Roseburg, OR, commercial customer growth is assumed to be equal to residential customer growth. This assumption is based on long-run relationship between residential and commercial customer growth after 2018. Figure 6 shows system wide same month, year-over-year residential and commercial customer growth (top graph) and industrial customer growth (bottom graph) for the 2007-2013 period.

Figure 6: Year-over-Year Customer Growth for the Three Rate Classes, 2007-2013

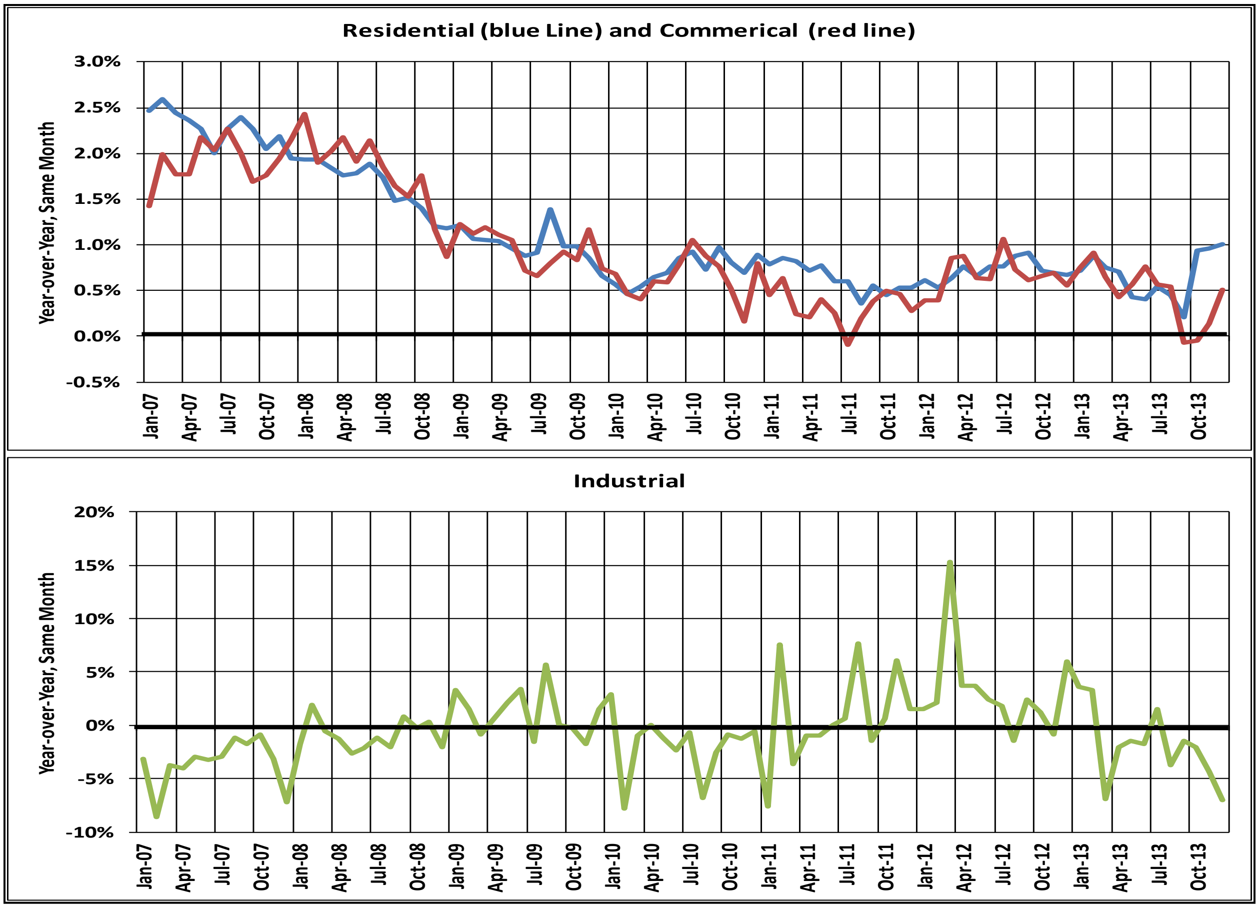


Figure 6 demonstrates that residential and commercial growth rates are highly correlated and maintain similar levels over the long-run—both classes' growth rates averaged about 1% over this period. This growth is slightly higher than population growth because of the housing boom and existing households retrofitting with natural gas. However, by the end of 2009, with the collapse of the housing bubble and increased natural gas saturation, customer growth moved in line with population growth. For Roseburg, OR, it is assumed commercial customer growth will continue at an annual rate 0.02% after 2018, which reflects average commercial growth since 2008.
In contrast, the behavior of Industrial customer growth looks quite different. Customer growth is both lower and more volatile. The average growth rate over this period is -0.4%, reflecting a trend of nearly flat or slowly declining customers, depending on the service area region. In addition, the standard deviation of growth is 3.7% compared to 0.6% for both residential and commercial growth—over five times higher. The current IRP forecast reflects this historical trend of weak growth. Some energy industry analysts believe the U.S.'s increased supply of natural gas and oil will attract industrial production back from overseas locations. However, in this IRP, we do not assume plentiful energy supplies in the U.S. will alter long-run trends in industrial customer growth in our service area.

Establishing High-Low Cases for IRP Customer Forecast

The customer forecasts for this IRP include high and low cases that set the expected bounds around the base-case. In the WA-ID area, the high and low cases were set by altering base case assumptions about U.S. and regional employment growth in equation [3] for the Spokane-Coeur d'Alene region. In particular, the high-case reflects more optimistic assumptions about long-run growth and the low case reflects more pessimistic assumptions. The WA-ID high case effectively assumes long-run employment growth of over 2.0% (compared to a base-case of around 1.7%), while the low-case assumes growth under 0.5%.
In the OR area, a similar approach was used for the Medford area using equation [4]. The Medford area high case also assumes long-run employment growth of over 2.0% (compared to a base-case of around 1.5%), while the low-case assumes growth under 0.5%. The range for employment growth was obtained by looking at different scenarios of U.S. GDP growth, as was well as the historical distribution of employment growth rates since the early 1990s for our service area, U.S., and California. The areas of Klamath Falls, Roseburg, and La Grande were

considered separately by looking the historical distributions population growth rates since the 1980s. Since the early 1980s, annual population growth as averaged less than 1% in these three areas.

Table F.1

Year	Residential Customers	Commercial Customers	Industrial Customers
2013	203,503	22,712	229
2014	205,332	22,747	228
2015	207,565	22,969	227
2016	209,966	23,142	226
2017	212,602	23,344	225
2018	215,266	23,551	223
2019	217,419	23,787	222
2020	219,593	24,025	221
2021	221,789	24,265	220
2022	224,007	24,507	219
2023	226,247	24,753	218
2024	228,509	25,000	217
2025	230,794	25,250	216
2026	233,102	25,503	215
2027	235,433	25,758	214
2028	237,787	26,015	213
2029	240,165	26,275	212
2030	242,567	26,538	211
2031	244,993	26,803	210
2032	247,443	27,071	209
2033	249,917	27,342	208
20 yr CGR 2013-2033	1.03%	0.93%	-0.47%

Table F.2

Year	Residential Medford Customers	Commercial Medford Customers	Industiral Medford Customers	Residential Roseburg Customers	Commercial Roseburg Customers	Industiral Roseburg Customers	Residential Klamath Falls Customers	Commercial Klamath Falls Customers	Industiral Klamath Falls Customers	Residential LaGrande Customers	Commercial LaGrande Customers	Industiral LaGrande Customers
2013	51,102	6,522	16	13,140	2,129	3	13,999	1,652	8	6,542	897	4
2014	51,486	6,528	16	13,181	2,131	3	14,041	1,651	8	6,590	898	3
2015	51,950	6,577	16	13,256	2,133	3	14,094	1,660	8	6,626	901	3
2016	52,470	6,629	16	13,347	2,135	3	14,165	1,665	8	6,664	904	3
2017	52,996	6,684	16	13,449	2,137	3	14,249	1,673	8	6,702	906	3
2018	53,527	6,739	16	13,559	2,138	3	14,343	1,678	8	6,740	909	3
2019	54,116	6,813	16	13,662	2,139	3	14,438	1,689	8	6,767	913	3
2020	54,711	6,888	16	13,766	2,139	3	14,533	1,700	8	6,794	917	3
2021	55,313	6,963	16	13,871	2,140	3	14,629	1,712	8	6,821	920	3
2022	55,921	7,040	16	13,976	2,140	3	14,726	1,723	8	6,848	924	3
2023	56,536	7,118	16	14,082	2,141	3	14,823	1,734	8	6,876	928	3
2024	57,158	7,196	16	14,189	2,141	3	14,921	1,746	8	6,903	931	3
2025	57,787	7,275	16	14,297	2,141	3	15,019	1,757	8	6,931	935	3
2026	58,423	7,355	16	14,406	2,142	3	15,118	1,769	8	6,959	939	3
2027	59,065	7,436	16	14,515	2,142	3	15,218	1,780	8	6,986	943	3
2028	59,715	7,518	16	14,625	2,143	3	15,319	1,792	8	7,014	946	3
2029	60,372	7,600	16	14,737	2,143	3	15,420	1,804	8	7,042	950	3
2030	61,036	7,684	16	14,849	2,144	3	15,521	1,816	8	7,071	954	3
2031	61,707	7,769	16	14,961	2,144	3	15,624	1,828	8	7,099	958	3
2032	62,386	7,854	16	15,075	2,144	3	15,727	1,840	8	7,127	962	3
2033	63,072	7,940	16	15,190	2,145	3	15,831	1,852	8	7,156	965	3
20 yr CGR 2013-2033	1.06%	0.99%	-0.10%	0.73%	0.04%	0.00%	0.62%	0.57%	0.03%	0.45%	0.37%	-1.24%

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION WASHINGTON AND IDAHO

	Washington and Idaho - Expected Growth			Washington and Idaho - High Growth			Washington and Idaho - Low Growth		
	Residential Customers	Commericial Customers	Industrial Customers	Residential Customers	Commericial Customers	Industrial Customers	Residential Customers	Commericial Customers	Industrial Customers
Jan-12	201,902	22,585	231	201,902	22,585	231	201,902	22,585	231
Feb-12	201,632	22,629	232	201,632	22,629	232	201,632	22,629	232
Mar-12	201,664	22,599	259	201,664	22,599	259	201,664	22,599	259
Apr-12	201,613	22,649	230	201,613	22,649	230	201,613	22,649	230
May-12	201,428	22,589	235	201,428	22,589	235	201,428	22,589	235
Jun-12	201,187	22,579	234	201,187	22,579	234	201,187	22,579	234
Jul-12	201,420	22,615	230	201,420	22,615	230	201,420	22,615	230
Aug-12	201,615	22,573	233	201,615	22,573	233	201,615	22,573	233
Sep-12	202,443	22,568	231	202,443	22,568	231	202,443	22,568	231
Oct-12	202,130	22,584	231	202,130	22,584	231	202,130	22,584	231
Nov-12	202,592	22,645	229	202,592	22,645	229	202,592	22,645	229
Dec-12	203,155	22,711	231	203,155	22,711	231	203,155	22,711	231
Jan-13	203,490	22,779	231	203,490	22,779	231	203,490	22,779	231
Feb-13	203,527	22,834	230	203,527	22,834	230	203,527	22,834	230
Mar-13	203,401	22,768	231	203,401	22,768	231	203,401	22,768	231
Apr-13	203,331	22,739	229	203,331	22,739	229	203,331	22,739	229
May-13	203,011	22,743	230	203,011	22,743	230	203,011	22,743	230
Jun-13	202,672	22,756	229	202,672	22,756	229	202,672	22,756	229
Jul-13	203,193	22,753	228	203,193	22,753	228	203,193	22,753	228
Aug-13	203,095	22,698	227	203,095	22,698	227	203,095	22,698	227
Sep-13	203,205	22,535	228	203,205	22,535	228	203,205	22,535	228
Oct-13	203,842	22,529	226	203,842	22,529	226	203,842	22,529	226
Nov-13	204,286	22,665	229	204,286	22,665	229	204,286	22,665	229
Dec-13	204,989	22,740	229	204,989	22,740	229	204,989	22,740	229
Jan-14	205,228	22,772	229	206,542	23,121	234	204,507	22,893	228
Feb-14	205,168	22,760	229	206,580	23,177	233	204,545	22,948	227
Mar-14	205,104	22,713	229	206,452	23,110	234	204,418	22,882	228
Apr-14	204,985	22,741	229	206,381	23,080	232	204,348	22,853	226
May-14	204,850	22,701	228	206,056	23,084	233	204,026	22,857	227
Jun-14	204,605	22,730	228	205,712	23,097	232	203,685	22,870	226
Jul-14	204,672	22,694	228	206,241	23,094	231	204,209	22,867	225
Aug-14	204,908	22,711	228	206,141	23,038	230	204,110	22,811	224
Sep-14	205,340	22,736	228	206,253	22,873	231	204,221	22,648	225
Oct-14	205,703	22,733	228	206,900	22,867	229	204,861	22,642	223
Nov-14	206,342	22,791	228	207,350	23,005	232	205,307	22,779	226
Dec-14	207,078	22,880	228	208,064	23,082	232	206,014	22,854	226
Jan-15	207,418	22,919	228	209,640	23,467	237	205,530	23,007	225
Feb-15	207,380	22,982	228	209,679	23,524	236	205,567	23,063	224
Mar-15	207,335	22,956	228	209,549	23,456	237	205,440	22,996	225
Apr-15	207,208	22,960	228	209,477	23,426	235	205,369	22,967	223
May-15	206,938	22,936	228	209,147	23,430	236	205,046	22,971	224
Jun-15	206,781	22,952	227	208,798	23,444	235	204,704	22,984	223
Jul-15	206,897	22,943	227	209,335	23,441	234	205,230	22,981	222
Aug-15	207,184	22,952	227	209,234	23,384	233	205,131	22,926	221

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION WASHINGTON AND IDAHO

	Washington and Idaho - Expected Growth			Washington and Idaho - High Growth			Washington and Idaho - Low Growth		
	Residential Customers	Commericial Customers	Industrial Customers	Residential Customers	Commericial Customers	Industrial Customers	Residential Customers	Commericial Customers	Industrial Customers
Sep-15	207,592	22,953	227	209,347	23,216	234	205,242	22,761	222
Oct-15	207,971	22,967	227	210,003	23,210	232	205,886	22,755	220
Nov-15	208,668	23,014	227	210,461	23,351	235	206,334	22,893	223
Dec-15	209,404	23,092	227	211,185	23,428	235	207,044	22,968	223
Jan-16	209,744	23,125	227	212,785	23,820	240	206,558	23,122	222
Feb-16	209,711	23,158	227	212,824	23,877	239	206,595	23,178	221
Mar-16	209,668	23,132	227	212,692	23,808	240	206,467	23,111	222
Apr-16	209,567	23,142	226	212,619	23,778	238	206,396	23,082	220
May-16	209,333	23,116	226	212,284	23,782	239	206,071	23,086	221
Jun-16	209,202	23,121	226	211,930	23,795	238	205,727	23,099	220
Jul-16	209,313	23,098	226	212,475	23,792	237	206,256	23,096	219
Aug-16	209,611	23,113	226	212,372	23,735	236	206,157	23,040	218
Sep-16	210,040	23,115	226	212,487	23,564	237	206,268	22,875	219
Oct-16	210,421	23,134	226	213,153	23,558	235	206,915	22,869	217
Nov-16	211,124	23,188	226	213,617	23,701	238	207,366	23,007	220
Dec-16	211,861	23,259	226	214,353	23,779	238	208,079	23,083	220
Jan-17	212,344	23,303	225	215,977	24,177	243	207,590	23,238	219
Feb-17	212,322	23,339	225	216,016	24,235	242	207,628	23,294	218
Mar-17	212,285	23,321	225	215,882	24,165	243	207,500	23,227	219
Apr-17	212,194	23,333	225	215,808	24,134	241	207,428	23,197	217
May-17	211,961	23,311	225	215,468	24,139	242	207,102	23,201	218
Jun-17	211,837	23,332	225	215,109	24,152	241	206,756	23,215	217
Jul-17	211,956	23,307	225	215,662	24,149	240	207,287	23,211	216
Aug-17	212,258	23,322	225	215,558	24,091	239	207,187	23,155	215
Sep-17	212,692	23,331	225	215,674	23,918	240	207,300	22,989	216
Oct-17	213,075	23,341	224	216,350	23,911	238	207,950	22,983	214
Nov-17	213,781	23,402	224	216,822	24,056	241	208,402	23,122	217
Dec-17	214,524	23,479	224	217,568	24,136	241	209,120	23,199	217
Jan-18	214,990	23,515	224	219,217	24,539	246	208,628	23,354	216
Feb-18	214,974	23,556	224	219,256	24,599	245	208,666	23,411	215
Mar-18	214,939	23,529	224	219,121	24,528	246	208,537	23,343	216
Apr-18	214,853	23,543	224	219,045	24,496	244	208,465	23,313	214
May-18	214,621	23,524	224	218,701	24,501	245	208,137	23,317	215
Jun-18	214,500	23,537	223	218,335	24,515	244	207,790	23,331	214
Jul-18	214,622	23,518	223	218,897	24,511	243	208,324	23,328	213
Aug-18	214,925	23,525	223	218,791	24,452	242	208,223	23,271	212
Sep-18	215,362	23,532	223	218,909	24,277	243	208,336	23,104	213
Oct-18	215,748	23,549	223	219,596	24,270	241	208,989	23,098	211
Nov-18	216,456	23,602	223	220,074	24,417	244	209,444	23,238	214
Dec-18	217,203	23,680	223	220,831	24,498	244	210,165	23,315	214
Jan-19	217,140	23,750	223	222,505	24,908	249	209,672	23,471	213
Feb-19	217,123	23,792	223	222,545	24,968	248	209,710	23,528	212
Mar-19	217,088	23,765	223	222,407	24,896	249	209,580	23,460	213
Apr-19	217,001	23,779	223	222,331	24,864	247	209,508	23,430	211

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION WASHINGTON AND IDAHO

	Washington and Idaho - Expected Growth			Washington and Idaho - High Growth			Washington and Idaho - Low Growth		
	Residential Customers	Commericial Customers	Industrial Customers	Residential Customers	Commericial Customers	Industrial Customers	Residential Customers	Commericial Customers	Industrial Customers
May-19	216,768	23,760	223	221,981	24,868	248	209,178	23,434	212
Jun-19	216,645	23,773	222	221,610	24,882	247	208,829	23,447	211
Jul-19	216,768	23,754	222	222,180	24,879	246	209,365	23,444	210
Aug-19	217,074	23,761	222	222,073	24,819	245	209,265	23,388	209
Sep-19	217,515	23,768	222	222,193	24,641	246	209,378	23,220	210
Oct-19	217,905	23,785	222	222,890	24,634	244	210,034	23,213	208
Nov-19	218,620	23,838	222	223,375	24,783	247	210,492	23,354	211
Dec-19	219,375	23,917	222	224,144	24,865	247	211,216	23,431	211
Jan-20	219,311	23,988	222	225,842	25,281	252	210,720	23,588	210
Feb-20	219,295	24,030	222	225,883	25,342	251	210,758	23,645	209
Mar-20	219,259	24,002	222	225,744	25,269	252	210,628	23,577	210
Apr-20	219,171	24,017	222	225,666	25,237	250	210,555	23,547	208
May-20	218,935	23,997	222	225,311	25,241	251	210,224	23,551	209
Jun-20	218,811	24,010	221	224,934	25,256	250	209,873	23,565	208
Jul-20	218,936	23,991	221	225,513	25,252	249	210,412	23,561	207
Aug-20	219,245	23,998	221	225,404	25,191	248	210,311	23,504	206
Sep-20	219,691	24,005	221	225,526	25,010	249	210,425	23,336	207
Oct-20	220,084	24,023	221	226,233	25,004	247	211,084	23,329	205
Nov-20	220,806	24,077	221	226,726	25,155	250	211,544	23,471	208
Dec-20	221,568	24,156	221	227,506	25,238	250	212,272	23,548	208
Jan-21	221,504	24,228	221	229,230	25,660	255	211,773	23,706	207
Feb-21	221,488	24,270	221	229,272	25,722	254	211,812	23,764	206
Mar-21	221,452	24,242	221	229,130	25,648	255	211,681	23,695	207
Apr-21	221,363	24,257	221	229,051	25,615	253	211,608	23,665	205
May-21	221,125	24,237	221	228,690	25,620	254	211,275	23,669	206
Jun-21	220,999	24,251	220	228,309	25,634	253	210,922	23,682	205
Jul-21	221,125	24,231	220	228,895	25,631	252	211,464	23,679	204
Aug-21	221,437	24,238	220	228,785	25,569	251	211,362	23,622	203
Sep-21	221,887	24,245	220	228,909	25,386	252	211,477	23,452	204
Oct-21	222,285	24,263	220	229,627	25,379	250	212,140	23,446	202
Nov-21	223,014	24,318	220	230,127	25,532	253	212,602	23,588	205
Dec-21	223,784	24,398	220	230,919	25,617	253	213,334	23,666	205
Jan-22	223,719	24,470	220	232,668	26,045	258	212,832	23,825	204
Feb-22	223,703	24,513	220	232,711	26,108	257	212,871	23,882	203
Mar-22	223,666	24,485	220	232,567	26,033	258	212,739	23,813	204
Apr-22	223,577	24,499	220	232,487	26,000	256	212,666	23,783	202
May-22	223,336	24,480	220	232,121	26,004	257	212,331	23,787	203
Jun-22	223,209	24,493	219	231,733	26,019	256	211,977	23,801	202
Jul-22	223,336	24,473	219	232,329	26,016	255	212,522	23,798	201
Aug-22	223,652	24,481	219	232,217	25,953	254	212,419	23,740	200
Sep-22	224,106	24,488	219	232,343	25,766	255	212,534	23,570	201
Oct-22	224,508	24,506	219	233,071	25,759	253	213,201	23,563	199
Nov-22	225,244	24,561	219	233,579	25,915	256	213,665	23,706	202
Dec-22	226,022	24,642	219	234,382	26,001	256	214,400	23,784	202

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	Washington and Idaho - Expected Growth			Washington and Idaho - High Growth			Washington and Idaho - Low Growth		
	Residential Customers	Commericial Customers	Industrial Customers	Residential Customers	Commericial Customers	Industrial Customers	Residential Customers	Commericial Customers	Industrial Customers
Jan-23	225,956	24,715	219	236,158	26,436	261	213,897	23,944	201
Feb-23	225,940	24,758	219	236,201	26,500	260	213,935	24,002	200
Mar-23	225,903	24,730	219	236,055	26,423	261	213,803	23,932	201
Apr-23	225,812	24,744	219	235,974	26,390	259	213,729	23,902	199
May-23	225,569	24,724	219	235,603	26,394	260	213,393	23,906	200
Jun-23	225,441	24,738	218	235,209	26,409	259	213,037	23,920	199
Jul-23	225,570	24,718	218	235,814	26,406	258	213,584	23,917	198
Aug-23	225,888	24,725	218	235,700	26,342	257	213,481	23,859	197
Sep-23	226,347	24,733	218	235,828	26,153	258	213,597	23,687	198
Oct-23	226,753	24,751	218	236,567	26,146	256	214,267	23,681	196
Nov-23	227,497	24,806	218	237,082	26,304	259	214,733	23,825	199
Dec-23	228,282	24,888	218	237,898	26,391	259	215,472	23,903	199
Jan-24	228,216	24,962	218	239,701	26,832	264	214,966	24,064	198
Feb-24	228,199	25,006	218	239,744	26,897	263	215,005	24,122	197
Mar-24	228,162	24,977	218	239,596	26,820	264	214,872	24,052	198
Apr-24	228,071	24,992	218	239,514	26,785	262	214,798	24,021	196
May-24	227,825	24,972	218	239,137	26,790	263	214,460	24,026	197
Jun-24	227,696	24,985	217	238,737	26,805	262	214,102	24,039	196
Jul-24	227,825	24,965	217	239,351	26,802	261	214,652	24,036	195
Aug-24	228,147	24,973	217	239,236	26,737	260	214,549	23,978	194
Sep-24	228,611	24,980	217	239,365	26,545	261	214,665	23,806	195
Oct-24	229,021	24,998	217	240,115	26,538	259	215,338	23,800	193
Nov-24	229,772	25,054	217	240,638	26,699	262	215,807	23,944	196
Dec-24	230,565	25,137	217	241,467	26,787	262	216,550	24,023	196
Jan-25	230,498	25,212	217	243,296	27,235	267	216,041	24,184	195
Feb-25	230,481	25,256	217	243,341	27,301	266	216,080	24,242	194
Mar-25	230,443	25,227	217	243,190	27,222	267	215,946	24,172	195
Apr-25	230,351	25,242	217	243,106	27,187	265	215,872	24,141	193
May-25	230,103	25,221	217	242,724	27,192	266	215,532	24,146	194
Jun-25	229,973	25,235	216	242,318	27,207	265	215,172	24,160	193
Jul-25	230,104	25,215	216	242,941	27,204	264	215,725	24,156	192
Aug-25	230,429	25,222	216	242,824	27,138	263	215,621	24,098	191
Sep-25	230,897	25,230	216	242,956	26,943	264	215,738	23,925	192
Oct-25	231,311	25,248	216	243,717	26,936	262	216,415	23,919	190
Nov-25	232,070	25,305	216	244,248	27,099	265	216,886	24,063	193
Dec-25	232,871	25,389	216	245,089	27,189	265	217,632	24,143	193
Jan-26	232,803	25,464	216	246,946	27,644	270	217,121	24,305	192
Feb-26	232,786	25,508	216	246,991	27,710	269	217,161	24,364	191
Mar-26	232,748	25,479	216	246,838	27,630	270	217,026	24,293	192
Apr-26	232,655	25,494	216	246,753	27,595	268	216,951	24,262	190
May-26	232,404	25,473	216	246,364	27,600	269	216,610	24,266	191
Jun-26	232,273	25,488	215	245,953	27,616	268	216,248	24,280	190
Jul-26	232,405	25,467	215	246,585	27,612	267	216,804	24,277	189
Aug-26	232,733	25,475	215	246,466	27,545	266	216,700	24,218	188

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION WASHINGTON AND IDAHO

	Washington and Idaho - Expected Growth			Washington and Idaho - High Growth			Washington and Idaho - Low Growth		
	Residential Customers	Commericial Customers	Industrial Customers	Residential Customers	Commericial Customers	Industrial Customers	Residential Customers	Commericial Customers	Industrial Customers
Sep-26	233,206	25,482	215	246,600	27,347	267	216,817	24,045	189
Oct-26	233,624	25,501	215	247,373	27,340	265	217,497	24,038	187
Nov-26	234,390	25,558	215	247,912	27,506	268	217,970	24,184	190
Dec-26	235,199	25,642	215	248,765	27,597	268	218,720	24,264	190
Jan-27	235,131	25,718	215	250,650	28,058	273	218,207	24,426	189
Feb-27	235,114	25,763	215	250,696	28,126	272	218,246	24,485	188
Mar-27	235,075	25,734	215	250,540	28,045	273	218,111	24,415	189
Apr-27	234,981	25,749	215	250,454	28,009	271	218,036	24,384	187
May-27	234,728	25,728	215	250,060	28,014	272	217,693	24,388	188
Jun-27	234,595	25,742	214	249,642	28,030	271	217,329	24,402	187
Jul-27	234,729	25,722	214	250,284	28,026	270	217,888	24,399	186
Aug-27	235,060	25,729	214	250,163	27,958	269	217,783	24,340	185
Sep-27	235,538	25,737	214	250,299	27,758	270	217,901	24,165	186
Oct-27	235,960	25,756	214	251,084	27,750	268	218,584	24,158	184
Nov-27	236,734	25,814	214	251,630	27,918	271	219,060	24,305	187
Dec-27	237,551	25,899	214	252,496	28,011	271	219,814	24,385	187
Jan-28	237,482	25,976	214	254,410	28,479	276	219,298	24,549	186
Feb-28	237,465	26,021	214	254,456	28,548	275	219,338	24,608	185
Mar-28	237,426	25,991	214	254,298	28,465	276	219,202	24,537	186
Apr-28	237,331	26,006	214	254,211	28,429	274	219,126	24,505	184
May-28	237,076	25,985	214	253,811	28,434	275	218,781	24,510	185
Jun-28	236,941	26,000	213	253,387	28,450	274	218,416	24,524	184
Jul-28	237,076	25,979	213	254,038	28,447	273	218,978	24,521	183
Aug-28	237,411	25,987	213	253,916	28,378	272	218,872	24,461	182
Sep-28	237,893	25,994	213	254,053	28,174	273	218,991	24,286	183
Oct-28	238,320	26,013	213	254,850	28,166	271	219,677	24,279	181
Nov-28	239,102	26,072	213	255,405	28,337	274	220,155	24,426	184
Dec-28	239,927	26,158	213	256,284	28,431	274	220,913	24,507	184
Jan-29	239,857	26,235	213	258,226	28,906	279	220,394	24,671	183
Feb-29	239,839	26,281	213	258,273	28,976	278	220,434	24,731	182
Mar-29	239,800	26,251	213	258,113	28,892	279	220,298	24,659	183
Apr-29	239,704	26,267	213	258,024	28,855	277	220,222	24,628	181
May-29	239,446	26,245	213	257,618	28,861	278	219,875	24,632	182
Jun-29	239,311	26,260	212	257,188	28,877	277	219,508	24,646	181
Jul-29	239,447	26,239	212	257,849	28,873	276	220,072	24,643	180
Aug-29	239,785	26,246	212	257,725	28,803	275	219,966	24,584	179
Sep-29	240,272	26,254	212	257,864	28,597	276	220,085	24,407	180
Oct-29	240,703	26,273	212	258,673	28,589	274	220,775	24,401	178
Nov-29	241,493	26,332	212	259,236	28,762	277	221,256	24,548	181
Dec-29	242,326	26,419	212	260,128	28,857	277	222,018	24,629	181
Jan-30	242,256	26,498	212	262,099	29,340	282	221,496	24,795	180
Feb-30	242,238	26,544	212	262,147	29,411	281	221,536	24,855	179
Mar-30	242,198	26,513	212	261,985	29,326	282	221,399	24,783	180
Apr-30	242,101	26,529	212	261,894	29,288	280	221,323	24,751	178

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION WASHINGTON AND IDAHO

	Washington and Idaho - Expected Growth			Washington and Idaho - High Growth			Washington and Idaho - Low Growth		
	Residential Customers	Commericial Customers	Industrial Customers	Residential Customers	Commericial Customers	Industrial Customers	Residential Customers	Commericial Customers	Industrial Customers
May-30	241,841	26,508	212	261,482	29,293	281	220,975	24,755	179
Jun-30	241,704	26,522	211	261,046	29,310	280	220,606	24,770	178
Jul-30	241,841	26,501	211	261,717	29,306	279	221,173	24,766	177
Aug-30	242,183	26,509	211	261,590	29,235	278	221,066	24,706	176
Sep-30	242,675	26,517	211	261,732	29,026	279	221,186	24,529	177
Oct-30	243,110	26,536	211	262,553	29,018	277	221,879	24,523	175
Nov-30	243,907	26,596	211	263,124	29,194	280	222,363	24,671	178
Dec-30	244,749	26,684	211	264,030	29,290	280	223,128	24,753	178
Jan-31	244,678	26,763	211	266,031	29,780	285	222,604	24,919	177
Feb-31	244,660	26,809	211	266,079	29,852	284	222,644	24,979	176
Mar-31	244,620	26,779	211	265,914	29,766	285	222,506	24,907	177
Apr-31	244,522	26,795	211	265,823	29,728	283	222,430	24,875	175
May-31	244,259	26,773	211	265,405	29,733	284	222,080	24,879	176
Jun-31	244,121	26,788	210	264,961	29,750	283	221,709	24,893	175
Jul-31	244,260	26,766	210	265,642	29,746	282	222,279	24,890	174
Aug-31	244,605	26,774	210	265,514	29,674	281	222,171	24,830	173
Sep-31	245,102	26,782	210	265,658	29,461	282	222,292	24,652	174
Oct-31	245,541	26,801	210	266,491	29,453	280	222,989	24,645	172
Nov-31	246,347	26,862	210	267,071	29,631	283	223,474	24,794	175
Dec-31	247,197	26,950	210	267,990	29,729	283	224,243	24,876	175
Jan-32	247,125	27,030	210	270,021	30,227	288	223,717	25,043	174
Feb-32	247,107	27,077	210	270,070	30,300	287	223,757	25,104	173
Mar-32	247,067	27,046	210	269,903	30,212	288	223,619	25,031	174
Apr-32	246,968	27,062	210	269,810	30,174	286	223,542	24,999	172
May-32	246,702	27,041	210	269,386	30,179	287	223,190	25,004	173
Jun-32	246,562	27,056	209	268,936	30,196	286	222,817	25,018	172
Jul-32	246,702	27,034	209	269,627	30,192	285	223,390	25,015	171
Aug-32	247,051	27,042	209	269,497	30,119	284	223,282	24,954	170
Sep-32	247,553	27,050	209	269,643	29,903	285	223,403	24,775	171
Oct-32	247,997	27,069	209	270,488	29,895	283	224,104	24,768	169
Nov-32	248,810	27,130	209	271,077	30,076	286	224,592	24,918	172
Dec-32	249,669	27,220	209	272,010	30,175	286	225,365	25,001	172
Jan-33	249,596	27,301	209	274,072	30,680	291	224,835	25,168	171
Feb-33	249,578	27,348	209	274,121	30,754	290	224,876	25,229	170
Mar-33	249,537	27,317	209	273,952	30,665	291	224,737	25,156	171
Apr-33	249,437	27,333	209	273,857	30,626	289	224,660	25,124	169
May-33	249,169	27,311	209	273,426	30,632	290	224,306	25,129	170
Jun-33	249,028	27,326	208	272,970	30,649	289	223,931	25,143	169
Jul-33	249,169	27,304	208	273,672	30,645	288	224,507	25,140	168
Aug-33	249,521	27,312	208	273,540	30,571	287	224,399	25,079	167
Sep-33	250,028	27,320	208	273,688	30,351	288	224,520	24,899	168
Oct-33	250,477	27,340	208	274,546	30,343	286	225,224	24,892	166
Nov-33	251,298	27,402	208	275,144	30,527	289	225,715	25,043	169
Dec-33	252,166	27,492	208	276,090	30,628	289	226,491	25,126	169

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION
MEDFORD

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Medford Customers	Commericial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commericial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commericial Medford Customers	Industrial Medford Customers
Jan-12	51,331	6,513	18	51,331	6,513	18	51,331	6,513	18
Feb-12	51,255	6,532	18	51,255	6,532	18	51,255	6,532	18
Mar-12	51,317	6,549	18	51,317	6,549	18	51,317	6,549	18
Apr-12	51,292	6,508	18	51,292	6,508	18	51,292	6,508	18
May-12	51,111	6,499	18	51,111	6,499	18	51,111	6,499	18
Jun-12	51,028	6,475	18	51,028	6,475	18	51,028	6,475	18
Jul-12	50,836	6,463	18	50,836	6,463	18	50,836	6,463	18
Aug-12	50,727	6,445	17	50,727	6,445	17	50,727	6,445	17
Sep-12	50,650	6,447	16	50,650	6,447	16	50,650	6,447	16
Oct-12	50,690	6,462	18	50,690	6,462	18	50,690	6,462	18
Nov-12	51,079	6,502	17	51,079	6,502	17	51,079	6,502	17
Dec-12	51,500	6,534	17	51,500	6,534	17	51,500	6,534	17
Jan-13	51,740	6,559	17	51,740	6,559	17	51,740	6,559	17
Feb-13	51,700	6,589	17	51,700	6,589	17	51,700	6,589	17
Mar-13	51,645	6,582	17	51,645	6,582	17	51,645	6,582	17
Apr-13	51,602	6,565	17	51,602	6,565	17	51,602	6,565	17
May-13	50,798	6,517	16	50,798	6,517	16	50,798	6,517	16
Jun-13	50,658	6,524	16	50,658	6,524	16	50,658	6,524	16
Jul-13	50,499	6,493	16	50,499	6,493	16	50,499	6,493	16
Aug-13	50,451	6,479	16	50,451	6,479	16	50,451	6,479	16
Sep-13	50,413	6,448	16	50,413	6,448	16	50,413	6,448	16
Oct-13	51,350	6,487	16	51,350	6,487	16	51,350	6,487	16
Nov-13	51,025	6,488	16	51,025	6,488	16	51,025	6,488	16
Dec-13	51,339	6,532	16	51,339	6,532	16	51,339	6,532	16
Jan-14	51,845	6,589	16	52,594	6,667	17	52,025	6,595	16
Feb-14	51,794	6,593	16	52,553	6,698	17	51,984	6,625	16
Mar-14	51,751	6,579	16	52,497	6,691	17	51,929	6,618	16
Apr-14	51,713	6,556	16	52,453	6,673	17	51,886	6,601	16
May-14	51,491	6,536	16	51,636	6,625	17	51,077	6,553	16
Jun-14	51,333	6,518	16	51,494	6,632	17	50,937	6,560	16
Jul-14	51,141	6,484	16	51,332	6,600	17	50,777	6,529	16
Aug-14	51,032	6,474	16	51,283	6,586	17	50,728	6,515	16
Sep-14	50,982	6,456	16	51,245	6,554	17	50,690	6,483	16
Oct-14	51,234	6,470	16	52,197	6,594	17	51,632	6,523	16
Nov-14	51,598	6,519	16	51,867	6,595	17	51,306	6,524	16
Dec-14	51,914	6,562	16	52,186	6,640	17	51,621	6,568	16
Jan-15	52,311	6,610	16	53,462	6,777	17	52,311	6,631	16
Feb-15	52,260	6,625	16	53,420	6,808	17	52,270	6,662	16
Mar-15	52,217	6,616	16	53,363	6,801	17	52,215	6,655	16
Apr-15	52,178	6,598	16	53,319	6,783	17	52,171	6,637	16
May-15	51,956	6,589	16	52,488	6,734	17	51,358	6,589	16
Jun-15	51,797	6,579	16	52,344	6,741	17	51,217	6,596	16
Jul-15	51,603	6,547	16	52,179	6,709	17	51,056	6,565	16
Aug-15	51,494	6,535	16	52,130	6,695	17	51,007	6,550	16

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION MEDFORD

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Medford Customers	Commericial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commericial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commericial Medford Customers	Industrial Medford Customers
Sep-15	51,443	6,514	16	52,090	6,663	17	50,969	6,519	16
Oct-15	51,696	6,524	16	53,059	6,703	17	51,916	6,559	16
Nov-15	52,064	6,572	16	52,723	6,704	17	51,588	6,560	16
Dec-15	52,381	6,616	16	53,047	6,749	17	51,905	6,604	16
Jan-16	52,834	6,670	16	54,344	6,889	18	52,598	6,668	15
Feb-16	52,782	6,682	16	54,302	6,921	18	52,558	6,698	15
Mar-16	52,738	6,671	16	54,244	6,913	18	52,502	6,691	15
Apr-16	52,700	6,652	16	54,199	6,895	18	52,458	6,674	15
May-16	52,476	6,640	16	53,354	6,845	18	51,641	6,625	15
Jun-16	52,317	6,628	16	53,207	6,852	18	51,498	6,632	15
Jul-16	52,122	6,595	16	53,040	6,820	18	51,337	6,601	15
Aug-16	52,011	6,584	16	52,990	6,805	18	51,288	6,586	15
Sep-16	51,961	6,564	16	52,950	6,772	18	51,249	6,555	15
Oct-16	52,215	6,575	16	53,934	6,813	18	52,202	6,595	15
Nov-16	52,585	6,624	16	53,593	6,814	18	51,872	6,596	15
Dec-16	52,904	6,668	16	53,922	6,861	18	52,191	6,640	15
Jan-17	53,361	6,722	16	55,240	7,003	18	52,888	6,704	15
Feb-17	53,310	6,735	16	55,198	7,035	18	52,847	6,735	15
Mar-17	53,266	6,725	16	55,139	7,027	18	52,791	6,728	15
Apr-17	53,227	6,706	16	55,093	7,009	18	52,747	6,711	15
May-17	53,002	6,695	16	54,235	6,958	18	51,925	6,662	15
Jun-17	52,841	6,684	16	54,085	6,965	18	51,782	6,669	15
Jul-17	52,645	6,651	16	53,915	6,932	18	51,619	6,637	15
Aug-17	52,535	6,639	16	53,864	6,917	18	51,570	6,623	15
Sep-17	52,483	6,618	16	53,824	6,884	18	51,531	6,591	15
Oct-17	52,739	6,630	16	54,824	6,926	18	52,489	6,631	15
Nov-17	53,111	6,679	16	54,477	6,927	18	52,157	6,632	15
Dec-17	53,432	6,723	16	54,812	6,974	18	52,478	6,677	15
Jan-18	53,894	6,778	16	56,152	7,118	19	53,179	6,741	14
Feb-18	53,842	6,791	16	56,108	7,151	19	53,137	6,772	14
Mar-18	53,798	6,780	16	56,049	7,143	19	53,081	6,765	14
Apr-18	53,759	6,761	16	56,002	7,125	19	53,037	6,748	14
May-18	53,532	6,749	16	55,129	7,073	19	52,210	6,698	14
Jun-18	53,372	6,738	16	54,977	7,080	19	52,067	6,705	14
Jul-18	53,175	6,705	16	54,805	7,047	19	51,903	6,674	14
Aug-18	53,062	6,693	16	54,753	7,031	19	51,854	6,659	14
Sep-18	53,012	6,673	16	54,712	6,998	19	51,815	6,627	14
Oct-18	53,268	6,684	16	55,729	7,040	19	52,778	6,667	14
Nov-18	53,643	6,734	16	55,376	7,041	19	52,444	6,668	14
Dec-18	53,966	6,778	16	55,717	7,089	19	52,766	6,714	14
Jan-19	54,487	6,853	16	57,078	7,236	19	53,471	6,778	14
Feb-19	54,435	6,866	16	57,034	7,269	19	53,430	6,809	14
Mar-19	54,390	6,855	16	56,973	7,261	19	53,373	6,802	14
Apr-19	54,350	6,835	16	56,926	7,242	19	53,328	6,785	14

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION
MEDFORD

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Medford Customers	Commericial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commericial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commericial Medford Customers	Industrial Medford Customers
May-19	54,121	6,823	16	56,039	7,189	19	52,498	6,735	14
Jun-19	53,959	6,812	16	55,885	7,197	19	52,353	6,742	14
Jul-19	53,760	6,779	16	55,709	7,163	19	52,189	6,710	14
Aug-19	53,646	6,767	16	55,656	7,147	19	52,139	6,696	14
Sep-19	53,595	6,746	16	55,614	7,113	19	52,100	6,664	14
Oct-19	53,854	6,758	16	56,648	7,156	19	53,068	6,704	14
Nov-19	54,233	6,808	16	56,289	7,157	19	52,732	6,705	14
Dec-19	54,560	6,853	16	56,636	7,206	19	53,057	6,751	14
Jan-20	55,086	6,928	16	58,020	7,355	20	53,765	6,816	13
Feb-20	55,033	6,941	16	57,975	7,389	20	53,724	6,847	13
Mar-20	54,988	6,930	16	57,914	7,381	20	53,666	6,840	13
Apr-20	54,948	6,911	16	57,865	7,362	20	53,622	6,822	13
May-20	54,716	6,898	16	56,964	7,308	20	52,786	6,772	13
Jun-20	54,552	6,887	16	56,807	7,316	20	52,641	6,779	13
Jul-20	54,351	6,853	16	56,628	7,281	20	52,476	6,747	13
Aug-20	54,236	6,841	16	56,575	7,265	20	52,426	6,733	13
Sep-20	54,185	6,821	16	56,532	7,231	20	52,386	6,700	13
Oct-20	54,447	6,832	16	57,583	7,274	20	53,360	6,741	13
Nov-20	54,829	6,883	16	57,218	7,275	20	53,022	6,742	13
Dec-20	55,160	6,928	16	57,570	7,325	20	53,348	6,788	13
Jan-21	55,692	7,004	16	58,977	7,476	20	54,061	6,853	13
Feb-21	55,639	7,018	16	58,932	7,511	20	54,019	6,885	13
Mar-21	55,593	7,006	16	58,869	7,503	20	53,962	6,877	13
Apr-21	55,553	6,987	16	58,820	7,483	20	53,917	6,859	13
May-21	55,318	6,974	16	57,904	7,429	20	53,077	6,809	13
Jun-21	55,152	6,963	16	57,744	7,437	20	52,930	6,817	13
Jul-21	54,949	6,929	16	57,563	7,401	20	52,764	6,784	13
Aug-21	54,833	6,916	16	57,508	7,385	20	52,714	6,770	13
Sep-21	54,781	6,896	16	57,465	7,350	20	52,674	6,737	13
Oct-21	55,046	6,907	16	58,533	7,394	20	53,653	6,778	13
Nov-21	55,432	6,959	16	58,162	7,396	20	53,314	6,779	13
Dec-21	55,767	7,004	16	58,520	7,446	20	53,642	6,825	13
Jan-22	56,305	7,081	16	59,951	7,600	21	54,358	6,891	12
Feb-22	56,251	7,095	16	59,904	7,635	21	54,316	6,922	12
Mar-22	56,205	7,083	16	59,840	7,626	21	54,258	6,915	12
Apr-22	56,164	7,063	16	59,791	7,607	21	54,213	6,897	12
May-22	55,927	7,051	16	58,859	7,551	21	53,369	6,847	12
Jun-22	55,759	7,039	16	58,697	7,559	21	53,221	6,854	12
Jul-22	55,553	7,005	16	58,513	7,523	21	53,054	6,822	12
Aug-22	55,436	6,992	16	58,457	7,507	21	53,004	6,807	12
Sep-22	55,383	6,971	16	58,413	7,471	21	52,964	6,774	12
Oct-22	55,651	6,983	16	59,499	7,516	21	53,948	6,815	12
Nov-22	56,042	7,035	16	59,122	7,518	21	53,607	6,816	12
Dec-22	56,380	7,081	16	59,486	7,569	21	53,937	6,863	12

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION MEDFORD

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Medford Customers	Commericial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commericial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commericial Medford Customers	Industrial Medford Customers
Jan-23	56,924	7,159	16	60,940	7,725	21	54,657	6,929	12
Feb-23	56,870	7,173	16	60,893	7,761	21	54,615	6,960	12
Mar-23	56,823	7,161	16	60,828	7,752	21	54,557	6,953	12
Apr-23	56,781	7,141	16	60,777	7,732	21	54,511	6,935	12
May-23	56,542	7,128	16	59,830	7,676	21	53,662	6,884	12
Jun-23	56,372	7,117	16	59,665	7,684	21	53,514	6,892	12
Jul-23	56,164	7,082	16	59,478	7,647	21	53,346	6,859	12
Aug-23	56,046	7,069	16	59,421	7,631	21	53,295	6,844	12
Sep-23	55,992	7,048	16	59,377	7,594	21	53,255	6,812	12
Oct-23	56,263	7,060	16	60,480	7,640	21	54,245	6,853	12
Nov-23	56,658	7,113	16	60,098	7,642	21	53,902	6,854	12
Dec-23	57,000	7,159	16	60,467	7,693	21	54,234	6,900	12
Jan-24	57,550	7,238	16	61,945	7,853	22	54,958	6,967	11
Feb-24	57,495	7,252	16	61,897	7,889	22	54,915	6,999	11
Mar-24	57,448	7,240	16	61,831	7,880	22	54,857	6,991	11
Apr-24	57,406	7,220	16	61,780	7,860	22	54,811	6,973	11
May-24	57,164	7,207	16	60,817	7,802	22	53,957	6,922	11
Jun-24	56,992	7,195	16	60,650	7,811	22	53,808	6,930	11
Jul-24	56,782	7,160	16	60,459	7,774	22	53,640	6,897	11
Aug-24	56,662	7,147	16	60,402	7,757	22	53,589	6,882	11
Sep-24	56,608	7,126	16	60,356	7,720	22	53,548	6,849	11
Oct-24	56,882	7,137	16	61,478	7,766	22	54,544	6,890	11
Nov-24	57,282	7,191	16	61,089	7,768	22	54,198	6,891	11
Dec-24	57,627	7,238	16	61,465	7,820	22	54,532	6,938	11
Jan-25	58,183	7,317	16	62,967	7,982	22	55,260	7,005	11
Feb-25	58,128	7,331	16	62,919	8,019	22	55,217	7,037	11
Mar-25	58,080	7,320	16	62,852	8,010	22	55,159	7,030	11
Apr-25	58,038	7,299	16	62,799	7,990	22	55,113	7,012	11
May-25	57,793	7,286	16	61,821	7,931	22	54,254	6,960	11
Jun-25	57,619	7,274	16	61,651	7,940	22	54,104	6,968	11
Jul-25	57,407	7,239	16	61,457	7,902	22	53,935	6,935	11
Aug-25	57,286	7,226	16	61,399	7,885	22	53,883	6,920	11
Sep-25	57,231	7,204	16	61,352	7,847	22	53,843	6,887	11
Oct-25	57,508	7,216	16	62,493	7,895	22	54,844	6,928	11
Nov-25	57,912	7,270	16	62,097	7,896	22	54,496	6,929	11
Dec-25	58,261	7,317	16	62,479	7,949	22	54,832	6,976	11
Jan-26	58,823	7,398	16	64,006	8,114	23	55,564	7,044	10
Feb-26	58,767	7,412	16	63,957	8,151	23	55,521	7,076	10
Mar-26	58,719	7,400	16	63,889	8,142	23	55,462	7,068	10
Apr-26	58,676	7,379	16	63,836	8,121	23	55,416	7,050	10
May-26	58,429	7,366	16	62,841	8,062	23	54,552	6,999	10
Jun-26	58,253	7,354	16	62,668	8,071	23	54,402	7,006	10
Jul-26	58,038	7,318	16	62,471	8,032	23	54,231	6,973	10
Aug-26	57,916	7,305	16	62,412	8,015	23	54,180	6,958	10

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION MEDFORD

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Medford Customers	Commericial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commericial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commericial Medford Customers	Industrial Medford Customers
Sep-26	57,861	7,283	16	62,365	7,977	23	54,139	6,925	10
Oct-26	58,141	7,295	16	63,524	8,025	23	55,145	6,966	10
Nov-26	58,549	7,350	16	63,122	8,026	23	54,796	6,968	10
Dec-26	58,902	7,398	16	63,510	8,081	23	55,133	7,015	10
Jan-27	59,470	7,479	16	65,062	8,248	23	55,870	7,083	10
Feb-27	59,413	7,494	16	65,012	8,286	23	55,826	7,115	10
Mar-27	59,365	7,482	16	64,943	8,277	23	55,767	7,107	10
Apr-27	59,321	7,461	16	64,889	8,255	23	55,721	7,089	10
May-27	59,071	7,447	16	63,878	8,195	23	54,852	7,037	10
Jun-27	58,894	7,435	16	63,702	8,204	23	54,701	7,045	10
Jul-27	58,677	7,399	16	63,502	8,165	23	54,530	7,011	10
Aug-27	58,553	7,386	16	63,441	8,147	23	54,478	6,996	10
Sep-27	58,497	7,363	16	63,394	8,108	23	54,437	6,963	10
Oct-27	58,780	7,376	16	64,572	8,157	23	55,448	7,005	10
Nov-27	59,193	7,431	16	64,163	8,159	23	55,098	7,006	10
Dec-27	59,550	7,479	16	64,558	8,214	23	55,437	7,053	10
Jan-28	60,125	7,562	16	66,136	8,384	24	56,177	7,121	9
Feb-28	60,067	7,576	16	66,085	8,422	24	56,133	7,154	9
Mar-28	60,018	7,564	16	66,014	8,413	24	56,074	7,146	9
Apr-28	59,974	7,543	16	65,959	8,392	24	56,027	7,128	9
May-28	59,721	7,529	16	64,932	8,330	24	55,154	7,076	9
Jun-28	59,542	7,517	16	64,753	8,339	24	55,002	7,083	9
Jul-28	59,322	7,480	16	64,550	8,300	24	54,829	7,050	9
Aug-28	59,197	7,467	16	64,488	8,282	24	54,777	7,035	9
Sep-28	59,141	7,444	16	64,440	8,242	24	54,736	7,001	9
Oct-28	59,427	7,457	16	65,637	8,292	24	55,753	7,043	9
Nov-28	59,844	7,513	16	65,222	8,293	24	55,401	7,044	9
Dec-28	60,205	7,562	16	65,623	8,349	24	55,741	7,092	9
Jan-29	60,786	7,645	16	67,227	8,522	24	56,486	7,161	9
Feb-29	60,728	7,659	16	67,175	8,561	24	56,442	7,193	9
Mar-29	60,678	7,647	16	67,104	8,552	24	56,382	7,186	9
Apr-29	60,634	7,626	16	67,048	8,530	24	56,335	7,167	9
May-29	60,378	7,612	16	66,003	8,468	24	55,457	7,115	9
Jun-29	60,197	7,600	16	65,821	8,477	24	55,305	7,122	9
Jul-29	59,975	7,562	16	65,615	8,437	24	55,131	7,089	9
Aug-29	59,848	7,549	16	65,552	8,418	24	55,079	7,073	9
Sep-29	59,791	7,526	16	65,503	8,378	24	55,037	7,039	9
Oct-29	60,080	7,539	16	66,720	8,429	24	56,060	7,082	9
Nov-29	60,502	7,595	16	66,298	8,430	24	55,705	7,083	9
Dec-29	60,867	7,645	16	66,706	8,487	24	56,048	7,131	9
Jan-30	61,455	7,729	16	68,336	8,663	25	56,797	7,200	8
Feb-30	61,396	7,744	16	68,284	8,703	25	56,753	7,233	8
Mar-30	61,345	7,731	16	68,211	8,693	25	56,692	7,225	8
Apr-30	61,301	7,709	16	68,154	8,671	25	56,645	7,207	8

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION MEDFORD

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Medford Customers	Commericial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commericial Medford Customers	Industrial Medford Customers	Residential Medford Customers	Commericial Medford Customers	Industrial Medford Customers
May-30	61,042	7,696	16	67,092	8,607	25	55,762	7,154	8
Jun-30	60,859	7,683	16	66,907	8,617	25	55,609	7,162	8
Jul-30	60,634	7,646	16	66,697	8,576	25	55,434	7,128	8
Aug-30	60,506	7,632	16	66,634	8,557	25	55,382	7,112	8
Sep-30	60,449	7,609	16	66,584	8,516	25	55,340	7,078	8
Oct-30	60,741	7,622	16	67,821	8,568	25	56,368	7,121	8
Nov-30	61,168	7,679	16	67,392	8,569	25	56,012	7,122	8
Dec-30	61,537	7,729	16	67,807	8,627	25	56,356	7,170	8
Jan-31	62,131	7,814	16	69,464	8,806	25	57,109	7,240	8
Feb-31	62,071	7,829	16	69,410	8,846	25	57,065	7,273	8
Mar-31	62,020	7,816	16	69,336	8,837	25	57,004	7,265	8
Apr-31	61,975	7,794	16	69,279	8,814	25	56,957	7,246	8
May-31	61,714	7,780	16	68,199	8,749	25	56,069	7,193	8
Jun-31	61,528	7,768	16	68,011	8,759	25	55,915	7,201	8
Jul-31	61,301	7,730	16	67,798	8,717	25	55,739	7,167	8
Aug-31	61,172	7,716	16	67,733	8,698	25	55,686	7,151	8
Sep-31	61,114	7,693	16	67,682	8,657	25	55,644	7,117	8
Oct-31	61,409	7,706	16	68,940	8,709	25	56,678	7,160	8
Nov-31	61,841	7,763	16	68,504	8,711	25	56,320	7,161	8
Dec-31	62,214	7,814	16	68,926	8,770	25	56,666	7,210	8
Jan-32	62,814	7,900	16	70,610	8,951	26	57,423	7,279	7
Feb-32	62,754	7,915	16	70,555	8,992	26	57,379	7,313	7
Mar-32	62,702	7,902	16	70,480	8,983	26	57,318	7,305	7
Apr-32	62,657	7,880	16	70,422	8,959	26	57,270	7,286	7
May-32	62,392	7,866	16	69,325	8,894	26	56,378	7,233	7
Jun-32	62,205	7,853	16	69,133	8,903	26	56,222	7,241	7
Jul-32	61,976	7,815	16	68,916	8,861	26	56,046	7,206	7
Aug-32	61,845	7,801	16	68,851	8,842	26	55,992	7,191	7
Sep-32	61,786	7,777	16	68,799	8,800	26	55,950	7,156	7
Oct-32	62,085	7,790	16	70,078	8,853	26	56,990	7,200	7
Nov-32	62,521	7,849	16	69,634	8,854	26	56,629	7,201	7
Dec-32	62,898	7,900	16	70,063	8,914	26	56,978	7,249	7
Jan-33	63,505	7,987	16	71,775	9,099	26	57,739	7,319	7
Feb-33	63,444	8,002	16	71,720	9,140	26	57,694	7,353	7
Mar-33	63,392	7,989	16	71,643	9,131	26	57,633	7,345	7
Apr-33	63,346	7,967	16	71,584	9,107	26	57,585	7,326	7
May-33	63,079	7,953	16	70,468	9,041	26	56,688	7,273	7
Jun-33	62,889	7,940	16	70,274	9,050	26	56,531	7,280	7
Jul-33	62,657	7,901	16	70,054	9,007	26	56,354	7,246	7
Aug-33	62,525	7,887	16	69,987	8,988	26	56,300	7,230	7
Sep-33	62,466	7,863	16	69,934	8,945	26	56,258	7,196	7
Oct-33	62,768	7,876	16	71,234	8,999	26	57,304	7,239	7
Nov-33	63,209	7,935	16	70,783	9,000	26	56,941	7,240	7
Dec-33	63,590	7,987	16	71,219	9,061	26	57,291	7,289	7

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION
ROSEBURG

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Roseburg Customers	Commericial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commericial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commericial Roseburg Customers	Industrial Roseburg Customers
Jan-12	13,221	2,155	2	13,221	2,155	2	13,221	2,155	2
Feb-12	13,186	2,145	2	13,186	2,145	2	13,186	2,145	2
Mar-12	13,217	2,151	2	13,217	2,151	2	13,217	2,151	2
Apr-12	13,221	2,149	3	13,221	2,149	3	13,221	2,149	3
May-12	13,137	2,145	2	13,137	2,145	2	13,137	2,145	2
Jun-12	13,080	2,132	2	13,080	2,132	2	13,080	2,132	2
Jul-12	13,037	2,125	2	13,037	2,125	2	13,037	2,125	2
Aug-12	12,928	2,112	2	12,928	2,112	2	12,928	2,112	2
Sep-12	12,976	2,120	2	12,976	2,120	2	12,976	2,120	2
Oct-12	12,964	2,116	3	12,964	2,116	3	12,964	2,116	3
Nov-12	13,086	2,130	3	13,086	2,130	3	13,086	2,130	3
Dec-12	13,200	2,133	3	13,200	2,133	3	13,200	2,133	3
Jan-13	13,233	2,133	3	13,233	2,133	3	13,233	2,133	3
Feb-13	13,266	2,141	3	13,266	2,141	3	13,266	2,141	3
Mar-13	13,227	2,146	3	13,227	2,146	3	13,227	2,146	3
Apr-13	13,191	2,138	3	13,191	2,138	3	13,191	2,138	3
May-13	13,150	2,140	3	13,150	2,140	3	13,150	2,140	3
Jun-13	13,093	2,135	3	13,093	2,135	3	13,093	2,135	3
Jul-13	13,059	2,128	3	13,059	2,128	3	13,059	2,128	3
Aug-13	12,981	2,111	3	12,981	2,111	3	12,981	2,111	3
Sep-13	12,981	2,104	3	12,981	2,104	3	12,981	2,104	3
Oct-13	13,064	2,114	3	13,064	2,114	3	13,064	2,114	3
Nov-13	13,144	2,119	3	13,144	2,119	3	13,144	2,119	3
Dec-13	13,293	2,136	3	13,293	2,136	3	13,293	2,136	3
Jan-14	13,270	2,134	3	13,384	2,137	3	13,283	2,133	3
Feb-14	13,294	2,140	3	13,417	2,145	3	13,316	2,141	3
Mar-14	13,286	2,144	3	13,378	2,150	3	13,277	2,146	3
Apr-14	13,255	2,140	3	13,341	2,142	3	13,241	2,138	3
May-14	13,212	2,138	3	13,300	2,144	3	13,200	2,140	3
Jun-14	13,135	2,132	3	13,242	2,139	3	13,143	2,135	3
Jul-14	13,085	2,126	3	13,208	2,132	3	13,109	2,128	3
Aug-14	13,012	2,115	3	13,129	2,115	3	13,030	2,111	3
Sep-14	13,011	2,117	3	13,129	2,108	3	13,030	2,104	3
Oct-14	13,060	2,116	3	13,213	2,118	3	13,114	2,114	3
Nov-14	13,179	2,130	3	13,294	2,123	3	13,194	2,118	3
Dec-14	13,370	2,144	3	13,445	2,140	3	13,344	2,135	3
Jan-15	13,347	2,138	3	13,536	2,142	3	13,334	2,132	3
Feb-15	13,369	2,144	3	13,570	2,150	3	13,367	2,140	3
Mar-15	13,362	2,146	3	13,530	2,155	3	13,328	2,145	3
Apr-15	13,331	2,142	3	13,493	2,147	3	13,291	2,137	3
May-15	13,287	2,139	3	13,452	2,149	3	13,250	2,139	3
Jun-15	13,210	2,132	3	13,393	2,144	3	13,193	2,134	3
Jul-15	13,160	2,127	3	13,358	2,137	3	13,158	2,127	3
Aug-15	13,087	2,116	3	13,279	2,119	3	13,080	2,110	3

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION ROSEBURG

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Roseburg Customers	Commericial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commericial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commericial Roseburg Customers	Industrial Roseburg Customers
Sep-15	13,085	2,118	3	13,279	2,112	3	13,080	2,103	3
Oct-15	13,135	2,118	3	13,364	2,122	3	13,163	2,113	3
Nov-15	13,253	2,132	3	13,445	2,127	3	13,244	2,118	3
Dec-15	13,445	2,146	3	13,598	2,144	3	13,394	2,135	3
Jan-16	13,439	2,140	3	13,691	2,146	3	13,384	2,132	3
Feb-16	13,461	2,146	3	13,725	2,154	3	13,418	2,140	3
Mar-16	13,454	2,148	3	13,685	2,159	3	13,378	2,145	3
Apr-16	13,423	2,143	3	13,647	2,151	3	13,342	2,137	3
May-16	13,378	2,141	3	13,605	2,153	3	13,300	2,139	3
Jun-16	13,302	2,134	3	13,546	2,148	3	13,243	2,134	3
Jul-16	13,250	2,129	3	13,511	2,141	3	13,208	2,127	3
Aug-16	13,178	2,118	3	13,430	2,124	3	13,130	2,110	3
Sep-16	13,176	2,120	3	13,430	2,117	3	13,130	2,103	3
Oct-16	13,225	2,119	3	13,516	2,127	3	13,213	2,113	3
Nov-16	13,345	2,133	3	13,599	2,132	3	13,294	2,118	3
Dec-16	13,538	2,147	3	13,753	2,149	3	13,445	2,135	3
Jan-17	13,540	2,142	3	13,847	2,150	3	13,435	2,131	3
Feb-17	13,562	2,148	3	13,881	2,158	3	13,469	2,139	3
Mar-17	13,556	2,149	3	13,841	2,163	3	13,429	2,144	3
Apr-17	13,524	2,145	3	13,803	2,155	3	13,393	2,136	3
May-17	13,479	2,143	3	13,760	2,157	3	13,351	2,138	3
Jun-17	13,402	2,136	3	13,700	2,152	3	13,293	2,133	3
Jul-17	13,352	2,130	3	13,665	2,145	3	13,259	2,126	3
Aug-17	13,279	2,119	3	13,583	2,128	3	13,179	2,109	3
Sep-17	13,277	2,122	3	13,583	2,121	3	13,179	2,102	3
Oct-17	13,326	2,121	3	13,670	2,131	3	13,264	2,112	3
Nov-17	13,447	2,135	3	13,754	2,136	3	13,345	2,117	3
Dec-17	13,640	2,149	3	13,910	2,153	3	13,496	2,134	3
Jan-18	13,651	2,144	3	14,005	2,154	3	13,486	2,131	3
Feb-18	13,674	2,150	3	14,040	2,162	3	13,520	2,139	3
Mar-18	13,666	2,151	3	13,998	2,168	3	13,480	2,144	3
Apr-18	13,635	2,147	3	13,960	2,159	3	13,444	2,136	3
May-18	13,590	2,145	3	13,917	2,161	3	13,402	2,138	3
Jun-18	13,513	2,137	3	13,857	2,156	3	13,344	2,133	3
Jul-18	13,462	2,132	3	13,821	2,149	3	13,309	2,126	3
Aug-18	13,387	2,121	3	13,738	2,132	3	13,230	2,109	3
Sep-18	13,385	2,124	3	13,738	2,125	3	13,230	2,102	3
Oct-18	13,436	2,123	3	13,826	2,135	3	13,314	2,112	3
Nov-18	13,557	2,137	3	13,910	2,140	3	13,396	2,117	3
Dec-18	13,752	2,151	3	14,068	2,157	3	13,548	2,134	3
Jan-19	13,755	2,144	3	14,164	2,159	3	13,538	2,130	3
Feb-19	13,778	2,150	3	14,200	2,167	3	13,571	2,138	3
Mar-19	13,770	2,151	3	14,158	2,172	3	13,531	2,143	3
Apr-19	13,739	2,147	3	14,119	2,164	3	13,495	2,135	3

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION ROSEBURG

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Roseburg Customers	Commericial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commericial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commericial Roseburg Customers	Industrial Roseburg Customers
May-19	13,693	2,145	3	14,075	2,166	3	13,453	2,137	3
Jun-19	13,615	2,137	3	14,014	2,161	3	13,394	2,132	3
Jul-19	13,564	2,132	3	13,978	2,154	3	13,360	2,125	3
Aug-19	13,489	2,121	3	13,895	2,136	3	13,280	2,108	3
Sep-19	13,487	2,124	3	13,895	2,129	3	13,280	2,101	3
Oct-19	13,538	2,123	3	13,983	2,139	3	13,365	2,111	3
Nov-19	13,660	2,137	3	14,069	2,144	3	13,447	2,116	3
Dec-19	13,856	2,151	3	14,229	2,162	3	13,599	2,133	3
Jan-20	13,860	2,145	3	14,326	2,163	3	13,589	2,130	3
Feb-20	13,882	2,151	3	14,362	2,171	3	13,623	2,138	3
Mar-20	13,875	2,152	3	14,319	2,176	3	13,583	2,143	3
Apr-20	13,843	2,148	3	14,280	2,168	3	13,546	2,135	3
May-20	13,797	2,146	3	14,236	2,170	3	13,504	2,137	3
Jun-20	13,719	2,138	3	14,174	2,165	3	13,445	2,132	3
Jul-20	13,667	2,133	3	14,137	2,158	3	13,410	2,125	3
Aug-20	13,592	2,122	3	14,053	2,141	3	13,330	2,108	3
Sep-20	13,590	2,125	3	14,053	2,134	3	13,330	2,101	3
Oct-20	13,641	2,124	3	14,143	2,144	3	13,415	2,111	3
Nov-20	13,763	2,138	3	14,229	2,149	3	13,498	2,116	3
Dec-20	13,961	2,152	3	14,391	2,166	3	13,651	2,133	3
Jan-21	13,965	2,145	3	14,489	2,167	3	13,641	2,130	3
Feb-21	13,988	2,151	3	14,525	2,175	3	13,675	2,138	3
Mar-21	13,980	2,152	3	14,483	2,181	3	13,634	2,143	3
Apr-21	13,948	2,148	3	14,443	2,172	3	13,597	2,135	3
May-21	13,902	2,146	3	14,398	2,174	3	13,555	2,137	3
Jun-21	13,823	2,138	3	14,336	2,169	3	13,496	2,132	3
Jul-21	13,771	2,133	3	14,299	2,162	3	13,461	2,125	3
Aug-21	13,695	2,122	3	14,213	2,145	3	13,381	2,108	3
Sep-21	13,693	2,125	3	14,213	2,138	3	13,381	2,101	3
Oct-21	13,745	2,124	3	14,304	2,148	3	13,466	2,111	3
Nov-21	13,868	2,138	3	14,392	2,153	3	13,549	2,116	3
Dec-21	14,068	2,152	3	14,555	2,170	3	13,703	2,132	3
Jan-22	14,071	2,146	3	14,654	2,172	3	13,693	2,129	3
Feb-22	14,094	2,152	3	14,691	2,180	3	13,727	2,137	3
Mar-22	14,087	2,153	3	14,648	2,185	3	13,686	2,142	3
Apr-22	14,054	2,149	3	14,608	2,177	3	13,649	2,134	3
May-22	14,008	2,147	3	14,562	2,179	3	13,607	2,136	3
Jun-22	13,928	2,139	3	14,499	2,174	3	13,548	2,131	3
Jul-22	13,876	2,134	3	14,462	2,167	3	13,512	2,124	3
Aug-22	13,799	2,123	3	14,375	2,149	3	13,432	2,107	3
Sep-22	13,797	2,126	3	14,375	2,142	3	13,432	2,100	3
Oct-22	13,850	2,125	3	14,467	2,152	3	13,518	2,110	3
Nov-22	13,973	2,139	3	14,556	2,157	3	13,600	2,115	3
Dec-22	14,175	2,153	3	14,721	2,175	3	13,755	2,132	3

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION
ROSEBURG

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Roseburg Customers	Commericial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commericial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commericial Roseburg Customers	Industrial Roseburg Customers
Jan-23	14,178	2,146	3	14,821	2,176	3	13,745	2,129	3
Feb-23	14,201	2,152	3	14,858	2,184	3	13,779	2,137	3
Mar-23	14,194	2,153	3	14,815	2,189	3	13,738	2,142	3
Apr-23	14,161	2,149	3	14,774	2,181	3	13,701	2,134	3
May-23	14,114	2,147	3	14,728	2,183	3	13,658	2,136	3
Jun-23	14,034	2,139	3	14,665	2,178	3	13,599	2,131	3
Jul-23	13,981	2,134	3	14,626	2,171	3	13,564	2,124	3
Aug-23	13,904	2,123	3	14,539	2,154	3	13,483	2,107	3
Sep-23	13,902	2,126	3	14,539	2,146	3	13,483	2,100	3
Oct-23	13,955	2,125	3	14,632	2,157	3	13,569	2,110	3
Nov-23	14,080	2,139	3	14,722	2,162	3	13,652	2,115	3
Dec-23	14,282	2,153	3	14,889	2,179	3	13,807	2,132	3
Jan-24	14,286	2,147	3	14,990	2,180	3	13,797	2,128	3
Feb-24	14,309	2,153	3	15,028	2,189	3	13,831	2,136	3
Mar-24	14,302	2,154	3	14,984	2,194	3	13,791	2,141	3
Apr-24	14,269	2,150	3	14,943	2,186	3	13,753	2,133	3
May-24	14,222	2,148	3	14,896	2,188	3	13,710	2,135	3
Jun-24	14,141	2,140	3	14,832	2,182	3	13,651	2,130	3
Jul-24	14,087	2,135	3	14,793	2,175	3	13,615	2,123	3
Aug-24	14,010	2,123	3	14,705	2,158	3	13,534	2,106	3
Sep-24	14,008	2,126	3	14,705	2,151	3	13,534	2,099	3
Oct-24	14,061	2,125	3	14,799	2,161	3	13,621	2,109	3
Nov-24	14,187	2,140	3	14,889	2,166	3	13,704	2,114	3
Dec-24	14,391	2,154	3	15,058	2,183	3	13,859	2,131	3
Jan-25	14,394	2,147	3	15,161	2,185	3	13,849	2,128	3
Feb-25	14,418	2,153	3	15,199	2,193	3	13,884	2,136	3
Mar-25	14,410	2,154	3	15,154	2,198	3	13,843	2,141	3
Apr-25	14,377	2,150	3	15,113	2,190	3	13,805	2,133	3
May-25	14,330	2,148	3	15,066	2,192	3	13,762	2,135	3
Jun-25	14,248	2,140	3	15,001	2,187	3	13,703	2,130	3
Jul-25	14,195	2,135	3	14,962	2,180	3	13,667	2,123	3
Aug-25	14,116	2,124	3	14,872	2,162	3	13,585	2,106	3
Sep-25	14,114	2,127	3	14,872	2,155	3	13,585	2,099	3
Oct-25	14,168	2,126	3	14,968	2,165	3	13,672	2,109	3
Nov-25	14,294	2,140	3	15,059	2,170	3	13,756	2,114	3
Dec-25	14,500	2,154	3	15,230	2,188	3	13,912	2,131	3
Jan-26	14,504	2,147	3	15,334	2,189	3	13,902	2,127	3
Feb-26	14,527	2,153	3	15,372	2,197	3	13,936	2,135	3
Mar-26	14,520	2,154	3	15,327	2,202	3	13,896	2,140	3
Apr-26	14,486	2,150	3	15,285	2,194	3	13,858	2,132	3
May-26	14,439	2,148	3	15,238	2,196	3	13,815	2,134	3
Jun-26	14,356	2,140	3	15,172	2,191	3	13,755	2,129	3
Jul-26	14,302	2,135	3	15,132	2,184	3	13,719	2,122	3
Aug-26	14,223	2,124	3	15,042	2,167	3	13,637	2,106	3

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION
ROSEBURG

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Roseburg Customers	Commericial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commericial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commericial Roseburg Customers	Industrial Roseburg Customers
Sep-26	14,221	2,127	3	15,042	2,159	3	13,637	2,099	3
Oct-26	14,275	2,126	3	15,138	2,170	3	13,724	2,109	3
Nov-26	14,403	2,140	3	15,231	2,175	3	13,808	2,113	3
Dec-26	14,610	2,154	3	15,404	2,192	3	13,965	2,130	3
Jan-27	14,614	2,148	3	15,509	2,194	3	13,955	2,127	3
Feb-27	14,638	2,154	3	15,548	2,202	3	13,989	2,135	3
Mar-27	14,630	2,155	3	15,502	2,207	3	13,948	2,140	3
Apr-27	14,596	2,151	3	15,460	2,199	3	13,910	2,132	3
May-27	14,548	2,149	3	15,412	2,201	3	13,867	2,134	3
Jun-27	14,466	2,141	3	15,345	2,196	3	13,807	2,129	3
Jul-27	14,411	2,136	3	15,305	2,188	3	13,771	2,122	3
Aug-27	14,332	2,125	3	15,214	2,171	3	13,689	2,105	3
Sep-27	14,329	2,128	3	15,214	2,164	3	13,689	2,098	3
Oct-27	14,384	2,127	3	15,311	2,174	3	13,776	2,108	3
Nov-27	14,512	2,141	3	15,405	2,179	3	13,861	2,113	3
Dec-27	14,721	2,155	3	15,579	2,196	3	14,018	2,130	3
Jan-28	14,725	2,148	3	15,686	2,198	3	14,008	2,127	3
Feb-28	14,749	2,154	3	15,725	2,206	3	14,043	2,135	3
Mar-28	14,741	2,155	3	15,679	2,211	3	14,001	2,140	3
Apr-28	14,707	2,151	3	15,636	2,203	3	13,963	2,132	3
May-28	14,659	2,149	3	15,587	2,205	3	13,920	2,134	3
Jun-28	14,576	2,141	3	15,520	2,200	3	13,859	2,129	3
Jul-28	14,521	2,136	3	15,479	2,193	3	13,823	2,122	3
Aug-28	14,440	2,125	3	15,387	2,175	3	13,741	2,105	3
Sep-28	14,438	2,128	3	15,387	2,168	3	13,741	2,098	3
Oct-28	14,493	2,127	3	15,485	2,178	3	13,829	2,108	3
Nov-28	14,623	2,141	3	15,580	2,183	3	13,913	2,113	3
Dec-28	14,833	2,155	3	15,757	2,201	3	14,071	2,130	3
Jan-29	14,837	2,149	3	15,864	2,202	3	14,061	2,126	3
Feb-29	14,861	2,155	3	15,904	2,211	3	14,096	2,134	3
Mar-29	14,853	2,156	3	15,857	2,216	3	14,055	2,139	3
Apr-29	14,819	2,152	3	15,814	2,207	3	14,016	2,131	3
May-29	14,770	2,150	3	15,765	2,210	3	13,973	2,133	3
Jun-29	14,686	2,142	3	15,697	2,204	3	13,912	2,128	3
Jul-29	14,631	2,137	3	15,656	2,197	3	13,876	2,121	3
Aug-29	14,550	2,126	3	15,562	2,180	3	13,793	2,104	3
Sep-29	14,548	2,129	3	15,562	2,172	3	13,793	2,097	3
Oct-29	14,603	2,128	3	15,662	2,183	3	13,881	2,107	3
Nov-29	14,734	2,142	3	15,758	2,188	3	13,966	2,112	3
Dec-29	14,946	2,156	3	15,937	2,205	3	14,125	2,129	3
Jan-30	14,950	2,149	3	16,045	2,207	3	14,114	2,126	3
Feb-30	14,974	2,155	3	16,085	2,215	3	14,150	2,134	3
Mar-30	14,966	2,156	3	16,038	2,220	3	14,108	2,139	3
Apr-30	14,932	2,152	3	15,994	2,212	3	14,070	2,131	3

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION
ROSEBURG

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Roseburg Customers	Commericial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commericial Roseburg Customers	Industrial Roseburg Customers	Residential Roseburg Customers	Commericial Roseburg Customers	Industrial Roseburg Customers
May-30	14,883	2,150	3	15,945	2,214	3	14,026	2,133	3
Jun-30	14,798	2,142	3	15,876	2,209	3	13,965	2,128	3
Jul-30	14,742	2,137	3	15,834	2,202	3	13,929	2,121	3
Aug-30	14,661	2,126	3	15,740	2,184	3	13,846	2,104	3
Sep-30	14,659	2,129	3	15,740	2,177	3	13,846	2,097	3
Oct-30	14,714	2,128	3	15,840	2,187	3	13,934	2,107	3
Nov-30	14,846	2,142	3	15,937	2,192	3	14,019	2,112	3
Dec-30	15,060	2,156	3	16,118	2,210	3	14,178	2,129	3
Jan-31	15,063	2,150	3	16,228	2,211	3	14,168	2,125	3
Feb-31	15,088	2,156	3	16,269	2,219	3	14,203	2,133	3
Mar-31	15,080	2,157	3	16,221	2,225	3	14,162	2,138	3
Apr-31	15,045	2,153	3	16,177	2,216	3	14,123	2,130	3
May-31	14,996	2,151	3	16,126	2,218	3	14,079	2,132	3
Jun-31	14,910	2,143	3	16,057	2,213	3	14,018	2,127	3
Jul-31	14,854	2,137	3	16,015	2,206	3	13,982	2,120	3
Aug-31	14,772	2,126	3	15,919	2,188	3	13,898	2,103	3
Sep-31	14,770	2,129	3	15,919	2,181	3	13,898	2,096	3
Oct-31	14,826	2,128	3	16,021	2,191	3	13,987	2,106	3
Nov-31	14,959	2,143	3	16,119	2,197	3	14,073	2,111	3
Dec-31	15,174	2,157	3	16,302	2,214	3	14,232	2,128	3
Jan-32	15,178	2,150	3	16,413	2,216	3	14,222	2,125	3
Feb-32	15,203	2,156	3	16,454	2,224	3	14,257	2,133	3
Mar-32	15,195	2,157	3	16,406	2,229	3	14,215	2,138	3
Apr-32	15,160	2,153	3	16,361	2,221	3	14,177	2,130	3
May-32	15,110	2,151	3	16,310	2,223	3	14,133	2,132	3
Jun-32	15,024	2,143	3	16,240	2,218	3	14,071	2,127	3
Jul-32	14,967	2,138	3	16,197	2,210	3	14,035	2,120	3
Aug-32	14,884	2,127	3	16,101	2,193	3	13,951	2,103	3
Sep-32	14,882	2,130	3	16,101	2,185	3	13,951	2,096	3
Oct-32	14,939	2,129	3	16,204	2,196	3	14,040	2,106	3
Nov-32	15,072	2,143	3	16,303	2,201	3	14,126	2,111	3
Dec-32	15,289	2,157	3	16,488	2,219	3	14,286	2,128	3
Jan-33	15,293	2,150	3	16,600	2,220	3	14,276	2,124	3
Feb-33	15,318	2,156	3	16,642	2,228	3	14,311	2,132	3
Mar-33	15,310	2,157	3	16,593	2,233	3	14,269	2,137	3
Apr-33	15,275	2,153	3	16,548	2,225	3	14,231	2,129	3
May-33	15,225	2,151	3	16,496	2,227	3	14,186	2,131	3
Jun-33	15,138	2,143	3	16,425	2,222	3	14,125	2,126	3
Jul-33	15,081	2,138	3	16,382	2,215	3	14,088	2,120	3
Aug-33	14,998	2,127	3	16,284	2,197	3	14,004	2,103	3
Sep-33	14,995	2,130	3	16,284	2,190	3	14,004	2,096	3
Oct-33	15,052	2,129	3	16,388	2,200	3	14,094	2,106	3
Nov-33	15,187	2,143	3	16,489	2,205	3	14,180	2,110	3
Dec-33	15,406	2,157	3	16,676	2,223	3	14,341	2,127	3

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION
KLAMATH FALLS

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Klamath Falls Customers	Commericial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commericial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commericial Klamath Falls Customers	Industrial Klamath Falls Customers
Jan-12	14,067	1,636	7	14,067	1,636	7	14,067	1,636	7
Feb-12	14,047	1,635	7	14,047	1,635	7	14,047	1,635	7
Mar-12	14,044	1,643	7	14,044	1,643	7	14,044	1,643	7
Apr-12	14,063	1,640	7	14,063	1,640	7	14,063	1,640	7
May-12	14,002	1,643	7	14,002	1,643	7	14,002	1,643	7
Jun-12	13,927	1,632	7	13,927	1,632	7	13,927	1,632	7
Jul-12	13,796	1,626	7	13,796	1,626	7	13,796	1,626	7
Aug-12	13,770	1,625	7	13,770	1,625	7	13,770	1,625	7
Sep-12	13,766	1,621	8	13,766	1,621	8	13,766	1,621	8
Oct-12	13,802	1,625	7	13,802	1,625	7	13,802	1,625	7
Nov-12	14,010	1,631	7	14,010	1,631	7	14,010	1,631	7
Dec-12	14,044	1,636	11	14,044	1,636	11	14,044	1,636	11
Jan-13	14,099	1,661	8	14,099	1,661	8	14,099	1,661	8
Feb-13	14,116	1,673	8	14,116	1,673	8	14,116	1,673	8
Mar-13	14,077	1,659	8	14,077	1,659	8	14,077	1,659	8
Apr-13	14,053	1,649	8	14,053	1,649	8	14,053	1,649	8
May-13	13,964	1,655	8	13,964	1,655	8	13,964	1,655	8
Jun-13	13,933	1,652	8	13,933	1,652	8	13,933	1,652	8
Jul-13	13,885	1,648	8	13,885	1,648	8	13,885	1,648	8
Aug-13	13,828	1,643	8	13,828	1,643	8	13,828	1,643	8
Sep-13	13,821	1,636	7	13,821	1,636	7	13,821	1,636	7
Oct-13	14,009	1,635	9	14,009	1,635	9	14,009	1,635	9
Nov-13	14,070	1,649	8	14,070	1,649	8	14,070	1,649	8
Dec-13	14,134	1,662	8	14,134	1,662	8	14,134	1,662	8
Jan-14	14,152	1,671	8	14,239	1,677	8	14,146	1,666	8
Feb-14	14,160	1,663	8	14,256	1,690	8	14,163	1,679	8
Mar-14	14,144	1,660	8	14,216	1,675	8	14,123	1,664	8
Apr-14	14,130	1,663	8	14,192	1,665	8	14,099	1,654	8
May-14	14,078	1,657	8	14,102	1,671	8	14,010	1,660	8
Jun-14	14,004	1,652	8	14,071	1,668	8	13,979	1,657	8
Jul-14	13,929	1,641	8	14,022	1,664	8	13,931	1,653	8
Aug-14	13,846	1,630	8	13,965	1,659	8	13,874	1,648	8
Sep-14	13,847	1,629	8	13,958	1,652	8	13,867	1,641	8
Oct-14	13,936	1,638	8	14,148	1,651	8	14,055	1,640	8
Nov-14	14,095	1,651	8	14,209	1,665	8	14,116	1,654	8
Dec-14	14,175	1,656	8	14,274	1,678	8	14,181	1,667	8
Jan-15	14,207	1,665	8	14,380	1,694	8	14,192	1,672	8
Feb-15	14,222	1,675	8	14,397	1,706	8	14,209	1,684	8
Mar-15	14,200	1,678	8	14,357	1,692	8	14,170	1,670	8
Apr-15	14,171	1,671	8	14,333	1,682	8	14,146	1,660	8
May-15	14,137	1,667	8	14,242	1,688	8	14,056	1,666	8
Jun-15	14,057	1,661	8	14,210	1,685	8	14,025	1,663	8
Jul-15	13,981	1,652	8	14,161	1,681	8	13,977	1,659	8
Aug-15	13,894	1,646	8	14,103	1,676	8	13,919	1,654	8

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION
KLAMATH FALLS

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Klamath Falls Customers	Commericial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commericial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commericial Klamath Falls Customers	Industrial Klamath Falls Customers
Sep-15	13,897	1,645	8	14,096	1,669	8	13,912	1,647	8
Oct-15	13,996	1,647	8	14,288	1,668	8	14,102	1,646	8
Nov-15	14,144	1,654	8	14,350	1,682	8	14,163	1,660	8
Dec-15	14,226	1,662	8	14,415	1,695	8	14,227	1,673	8
Jan-16	14,278	1,680	8	14,522	1,711	8	14,239	1,677	8
Feb-16	14,295	1,686	8	14,539	1,723	8	14,256	1,690	8
Mar-16	14,273	1,679	8	14,499	1,709	8	14,217	1,675	8
Apr-16	14,236	1,672	8	14,475	1,698	8	14,193	1,665	8
May-16	14,209	1,669	8	14,383	1,705	8	14,103	1,671	8
Jun-16	14,128	1,665	8	14,351	1,702	8	14,071	1,668	8
Jul-16	14,051	1,657	8	14,301	1,697	8	14,023	1,664	8
Aug-16	13,964	1,647	8	14,243	1,692	8	13,965	1,659	8
Sep-16	13,965	1,642	8	14,236	1,685	8	13,958	1,652	8
Oct-16	14,070	1,646	8	14,429	1,684	8	14,148	1,651	8
Nov-16	14,213	1,659	8	14,492	1,698	8	14,210	1,665	8
Dec-16	14,296	1,672	8	14,558	1,712	8	14,274	1,679	8
Jan-17	14,363	1,686	8	14,666	1,728	9	14,286	1,683	7
Feb-17	14,379	1,688	8	14,683	1,740	9	14,303	1,695	7
Mar-17	14,359	1,686	8	14,643	1,726	9	14,264	1,681	7
Apr-17	14,319	1,683	8	14,618	1,715	9	14,239	1,671	7
May-17	14,295	1,680	8	14,525	1,722	9	14,149	1,677	7
Jun-17	14,213	1,674	8	14,493	1,718	9	14,118	1,674	7
Jul-17	14,135	1,663	8	14,443	1,714	9	14,069	1,670	7
Aug-17	14,047	1,653	8	14,384	1,709	9	14,011	1,665	7
Sep-17	14,047	1,652	8	14,376	1,702	9	14,004	1,658	7
Oct-17	14,155	1,659	8	14,572	1,701	9	14,195	1,657	7
Nov-17	14,299	1,670	8	14,636	1,715	9	14,257	1,671	7
Dec-17	14,380	1,677	8	14,702	1,729	9	14,321	1,684	7
Jan-18	14,457	1,690	8	14,811	1,745	9	14,333	1,689	7
Feb-18	14,474	1,697	8	14,829	1,757	9	14,350	1,701	7
Mar-18	14,454	1,695	8	14,788	1,743	9	14,311	1,687	7
Apr-18	14,413	1,689	8	14,763	1,732	9	14,286	1,676	7
May-18	14,388	1,684	8	14,669	1,739	9	14,196	1,682	7
Jun-18	14,307	1,677	8	14,636	1,735	9	14,164	1,679	7
Jul-18	14,229	1,668	8	14,586	1,731	9	14,116	1,675	7
Aug-18	14,141	1,661	8	14,526	1,726	9	14,058	1,670	7
Sep-18	14,140	1,659	8	14,519	1,719	9	14,051	1,663	7
Oct-18	14,249	1,663	8	14,716	1,718	9	14,242	1,662	7
Nov-18	14,393	1,672	8	14,780	1,732	9	14,304	1,676	7
Dec-18	14,474	1,682	8	14,848	1,746	9	14,369	1,690	7
Jan-19	14,553	1,701	8	14,957	1,762	9	14,380	1,694	7
Feb-19	14,570	1,708	8	14,976	1,775	9	14,398	1,706	7
Mar-19	14,549	1,706	8	14,934	1,760	9	14,358	1,692	7
Apr-19	14,508	1,700	8	14,909	1,749	9	14,334	1,682	7

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION
KLAMATH FALLS

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Klamath Falls Customers	Commericial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commericial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commericial Klamath Falls Customers	Industrial Klamath Falls Customers
May-19	14,483	1,695	8	14,814	1,756	9	14,243	1,688	7
Jun-19	14,401	1,688	8	14,781	1,753	9	14,211	1,685	7
Jul-19	14,323	1,679	8	14,730	1,748	9	14,162	1,681	7
Aug-19	14,235	1,672	8	14,670	1,743	9	14,104	1,676	7
Sep-19	14,233	1,670	8	14,663	1,736	9	14,097	1,669	7
Oct-19	14,343	1,674	8	14,862	1,735	9	14,289	1,668	7
Nov-19	14,488	1,683	8	14,927	1,749	9	14,351	1,682	7
Dec-19	14,570	1,693	8	14,995	1,763	9	14,416	1,695	7
Jan-20	14,649	1,712	8	15,106	1,780	10	14,428	1,700	6
Feb-20	14,666	1,719	8	15,124	1,792	10	14,445	1,712	6
Mar-20	14,646	1,717	8	15,082	1,777	10	14,405	1,698	6
Apr-20	14,604	1,711	8	15,056	1,767	10	14,381	1,687	6
May-20	14,579	1,706	8	14,961	1,773	10	14,290	1,694	6
Jun-20	14,496	1,699	8	14,928	1,770	10	14,258	1,691	6
Jul-20	14,417	1,690	8	14,876	1,766	10	14,209	1,686	6
Aug-20	14,328	1,683	8	14,815	1,760	10	14,151	1,681	6
Sep-20	14,327	1,681	8	14,808	1,753	10	14,143	1,674	6
Oct-20	14,438	1,685	8	15,009	1,752	10	14,336	1,673	6
Nov-20	14,583	1,694	8	15,074	1,767	10	14,398	1,687	6
Dec-20	14,666	1,704	8	15,143	1,781	10	14,464	1,701	6
Jan-21	14,745	1,724	8	15,255	1,797	10	14,476	1,705	6
Feb-21	14,763	1,731	8	15,274	1,810	10	14,493	1,718	6
Mar-21	14,742	1,729	8	15,231	1,795	10	14,453	1,703	6
Apr-21	14,700	1,723	8	15,205	1,784	10	14,428	1,693	6
May-21	14,675	1,718	8	15,109	1,791	10	14,337	1,699	6
Jun-21	14,592	1,710	8	15,075	1,787	10	14,305	1,696	6
Jul-21	14,513	1,701	8	15,024	1,783	10	14,256	1,692	6
Aug-21	14,423	1,694	8	14,962	1,778	10	14,197	1,687	6
Sep-21	14,422	1,692	8	14,954	1,770	10	14,190	1,680	6
Oct-21	14,533	1,696	8	15,158	1,769	10	14,383	1,679	6
Nov-21	14,679	1,705	8	15,224	1,784	10	14,446	1,693	6
Dec-21	14,763	1,716	8	15,293	1,798	10	14,511	1,706	6
Jan-22	14,843	1,735	8	15,406	1,815	10	14,523	1,711	6
Feb-22	14,860	1,742	8	15,425	1,828	10	14,541	1,723	6
Mar-22	14,839	1,740	8	15,382	1,813	10	14,501	1,709	6
Apr-22	14,797	1,734	8	15,356	1,802	10	14,476	1,699	6
May-22	14,772	1,729	8	15,259	1,808	10	14,384	1,705	6
Jun-22	14,688	1,722	8	15,225	1,805	10	14,352	1,702	6
Jul-22	14,608	1,712	8	15,172	1,801	10	14,303	1,698	6
Aug-22	14,518	1,705	8	15,110	1,795	10	14,244	1,692	6
Sep-22	14,517	1,703	8	15,102	1,788	10	14,237	1,685	6
Oct-22	14,629	1,707	8	15,308	1,787	10	14,431	1,684	6
Nov-22	14,776	1,717	8	15,374	1,802	10	14,493	1,699	6
Dec-22	14,860	1,727	8	15,444	1,816	10	14,559	1,712	6

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KLAMATH FALLS

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Klamath Falls Customers	Commericial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commericial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commericial Klamath Falls Customers	Industrial Klamath Falls Customers
Jan-23	14,941	1,747	8	15,559	1,833	11	14,571	1,717	5
Feb-23	14,958	1,754	8	15,577	1,846	11	14,589	1,729	5
Mar-23	14,937	1,752	8	15,534	1,831	11	14,549	1,715	5
Apr-23	14,895	1,745	8	15,508	1,820	11	14,524	1,704	5
May-23	14,870	1,740	8	15,410	1,826	11	14,432	1,710	5
Jun-23	14,785	1,733	8	15,375	1,823	11	14,400	1,707	5
Jul-23	14,705	1,724	8	15,322	1,819	11	14,350	1,703	5
Aug-23	14,614	1,717	8	15,260	1,813	11	14,291	1,698	5
Sep-23	14,613	1,714	8	15,252	1,805	11	14,284	1,691	5
Oct-23	14,726	1,719	8	15,459	1,804	11	14,478	1,690	5
Nov-23	14,874	1,728	8	15,527	1,820	11	14,541	1,704	5
Dec-23	14,958	1,738	8	15,597	1,834	11	14,607	1,718	5
Jan-24	15,039	1,758	8	15,713	1,851	11	14,619	1,722	5
Feb-24	15,057	1,765	8	15,732	1,864	11	14,637	1,735	5
Mar-24	15,036	1,763	8	15,688	1,849	11	14,597	1,720	5
Apr-24	14,993	1,757	8	15,661	1,838	11	14,572	1,710	5
May-24	14,968	1,752	8	15,562	1,844	11	14,479	1,716	5
Jun-24	14,883	1,745	8	15,528	1,841	11	14,447	1,713	5
Jul-24	14,802	1,735	8	15,474	1,837	11	14,397	1,709	5
Aug-24	14,710	1,728	8	15,411	1,831	11	14,338	1,704	5
Sep-24	14,709	1,726	8	15,403	1,823	11	14,331	1,696	5
Oct-24	14,823	1,730	8	15,612	1,822	11	14,526	1,695	5
Nov-24	14,972	1,739	8	15,680	1,838	11	14,589	1,710	5
Dec-24	15,057	1,750	8	15,752	1,852	11	14,656	1,723	5
Jan-25	15,138	1,770	8	15,868	1,869	11	14,668	1,728	5
Feb-25	15,156	1,777	8	15,887	1,883	11	14,685	1,740	5
Mar-25	15,135	1,775	8	15,843	1,867	11	14,645	1,726	5
Apr-25	15,092	1,769	8	15,816	1,856	11	14,620	1,715	5
May-25	15,067	1,763	8	15,716	1,863	11	14,527	1,722	5
Jun-25	14,981	1,756	8	15,681	1,859	11	14,495	1,719	5
Jul-25	14,900	1,747	8	15,627	1,855	11	14,445	1,714	5
Aug-25	14,808	1,739	8	15,563	1,849	11	14,386	1,709	5
Sep-25	14,807	1,737	8	15,555	1,841	11	14,378	1,702	5
Oct-25	14,921	1,741	8	15,767	1,840	11	14,574	1,701	5
Nov-25	15,071	1,751	8	15,836	1,856	11	14,637	1,715	5
Dec-25	15,156	1,761	8	15,908	1,871	11	14,704	1,729	5
Jan-26	15,238	1,781	8	16,025	1,888	12	14,716	1,734	4
Feb-26	15,256	1,789	8	16,045	1,902	12	14,734	1,746	4
Mar-26	15,235	1,787	8	16,000	1,886	12	14,693	1,732	4
Apr-26	15,192	1,780	8	15,973	1,874	12	14,668	1,721	4
May-26	15,166	1,775	8	15,872	1,881	12	14,575	1,727	4
Jun-26	15,080	1,768	8	15,837	1,878	12	14,543	1,724	4
Jul-26	14,998	1,758	8	15,782	1,873	12	14,493	1,720	4
Aug-26	14,905	1,751	8	15,717	1,867	12	14,433	1,715	4

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Sep-26	14,904	1,749	8	15,709	1,860	12	14,426	1,708	4
Oct-26	15,019	1,753	8	15,923	1,858	12	14,622	1,707	4
Nov-26	15,170	1,762	8	15,992	1,874	12	14,686	1,721	4
Dec-26	15,256	1,773	8	16,065	1,889	12	14,753	1,735	4
Jan-27	15,339	1,793	8	16,184	1,907	12	14,765	1,739	4
Feb-27	15,357	1,801	8	16,204	1,920	12	14,782	1,752	4
Mar-27	15,336	1,798	8	16,159	1,904	12	14,741	1,737	4
Apr-27	15,292	1,792	8	16,131	1,893	12	14,716	1,727	4
May-27	15,266	1,787	8	16,029	1,900	12	14,623	1,733	4
Jun-27	15,179	1,779	8	15,993	1,896	12	14,591	1,730	4
Jul-27	15,097	1,770	8	15,938	1,892	12	14,540	1,726	4
Aug-27	15,004	1,762	8	15,873	1,886	12	14,481	1,721	4
Sep-27	15,003	1,760	8	15,865	1,878	12	14,473	1,713	4
Oct-27	15,118	1,764	8	16,081	1,877	12	14,670	1,712	4
Nov-27	15,270	1,774	8	16,151	1,893	12	14,734	1,727	4
Dec-27	15,357	1,785	8	16,224	1,908	12	14,801	1,740	4
Jan-28	15,440	1,805	8	16,344	1,926	12	14,813	1,745	4
Feb-28	15,458	1,812	8	16,364	1,939	12	14,831	1,758	4
Mar-28	15,437	1,810	8	16,319	1,923	12	14,790	1,743	4
Apr-28	15,393	1,804	8	16,291	1,912	12	14,765	1,733	4
May-28	15,367	1,799	8	16,188	1,919	12	14,671	1,739	4
Jun-28	15,280	1,791	8	16,152	1,915	12	14,639	1,736	4
Jul-28	15,196	1,781	8	16,096	1,910	12	14,588	1,731	4
Aug-28	15,103	1,774	8	16,030	1,905	12	14,529	1,726	4
Sep-28	15,102	1,772	8	16,022	1,897	12	14,521	1,719	4
Oct-28	15,218	1,776	8	16,240	1,895	12	14,719	1,718	4
Nov-28	15,371	1,786	8	16,311	1,912	12	14,783	1,733	4
Dec-28	15,458	1,796	8	16,385	1,927	12	14,850	1,746	4
Jan-29	15,542	1,817	8	16,506	1,945	13	14,862	1,751	3
Feb-29	15,560	1,824	8	16,526	1,959	13	14,880	1,764	3
Mar-29	15,539	1,822	8	16,480	1,942	13	14,839	1,749	3
Apr-29	15,494	1,816	8	16,452	1,931	13	14,814	1,738	3
May-29	15,468	1,810	8	16,348	1,938	13	14,720	1,745	3
Jun-29	15,380	1,803	8	16,312	1,934	13	14,687	1,741	3
Jul-29	15,297	1,793	8	16,255	1,929	13	14,637	1,737	3
Aug-29	15,202	1,786	8	16,189	1,923	13	14,576	1,732	3
Sep-29	15,201	1,783	8	16,181	1,915	13	14,569	1,725	3
Oct-29	15,318	1,788	8	16,401	1,914	13	14,767	1,723	3
Nov-29	15,473	1,797	8	16,472	1,931	13	14,832	1,738	3
Dec-29	15,560	1,808	8	16,547	1,946	13	14,899	1,752	3
Jan-30	15,645	1,829	8	16,669	1,964	13	14,911	1,757	3
Feb-30	15,663	1,836	8	16,690	1,978	13	14,929	1,769	3
Mar-30	15,641	1,834	8	16,643	1,961	13	14,888	1,755	3
Apr-30	15,597	1,828	8	16,615	1,950	13	14,863	1,744	3

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION
KLAMATH FALLS

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential Klamath Falls Customers	Commericial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commericial Klamath Falls Customers	Industrial Klamath Falls Customers	Residential Klamath Falls Customers	Commericial Klamath Falls Customers	Industrial Klamath Falls Customers
May-30	15,570	1,822	8	16,510	1,957	13	14,768	1,750	3
Jun-30	15,482	1,815	8	16,473	1,953	13	14,736	1,747	3
Jul-30	15,398	1,805	8	16,416	1,948	13	14,685	1,743	3
Aug-30	15,303	1,797	8	16,349	1,943	13	14,625	1,738	3
Sep-30	15,302	1,795	8	16,341	1,934	13	14,617	1,730	3
Oct-30	15,420	1,800	8	16,563	1,933	13	14,816	1,729	3
Nov-30	15,575	1,809	8	16,635	1,950	13	14,881	1,744	3
Dec-30	15,663	1,820	8	16,711	1,965	13	14,948	1,758	3
Jan-31	15,748	1,841	8	16,834	1,983	13	14,960	1,762	3
Feb-31	15,767	1,849	8	16,855	1,998	13	14,978	1,775	3
Mar-31	15,745	1,846	8	16,808	1,981	13	14,937	1,760	3
Apr-31	15,699	1,840	8	16,780	1,969	13	14,912	1,750	3
May-31	15,673	1,834	8	16,673	1,976	13	14,817	1,756	3
Jun-31	15,584	1,827	8	16,636	1,973	13	14,784	1,753	3
Jul-31	15,499	1,817	8	16,579	1,968	13	14,733	1,749	3
Aug-31	15,404	1,809	8	16,511	1,962	13	14,673	1,743	3
Sep-31	15,403	1,807	8	16,503	1,953	13	14,665	1,736	3
Oct-31	15,521	1,811	8	16,727	1,952	13	14,865	1,735	3
Nov-31	15,678	1,821	8	16,800	1,969	13	14,930	1,750	3
Dec-31	15,767	1,832	8	16,876	1,984	13	14,998	1,764	3
Jan-32	15,852	1,853	8	17,001	2,003	14	15,010	1,768	2
Feb-32	15,871	1,861	8	17,022	2,017	14	15,028	1,781	2
Mar-32	15,848	1,859	8	16,975	2,000	14	14,986	1,766	2
Apr-32	15,803	1,852	8	16,946	1,988	14	14,961	1,756	2
May-32	15,777	1,846	8	16,838	1,996	14	14,866	1,762	2
Jun-32	15,687	1,839	8	16,801	1,992	14	14,833	1,759	2
Jul-32	15,602	1,829	8	16,743	1,987	14	14,782	1,754	2
Aug-32	15,505	1,821	8	16,674	1,981	14	14,721	1,749	2
Sep-32	15,504	1,819	8	16,666	1,973	14	14,714	1,742	2
Oct-32	15,624	1,823	8	16,893	1,972	14	14,914	1,741	2
Nov-32	15,781	1,833	8	16,966	1,988	14	14,979	1,756	2
Dec-32	15,871	1,844	8	17,043	2,004	14	15,047	1,769	2
Jan-33	15,956	1,865	8	17,169	2,023	14	15,059	1,774	2
Feb-33	15,975	1,873	8	17,190	2,037	14	15,077	1,787	2
Mar-33	15,953	1,871	8	17,143	2,020	14	15,036	1,772	2
Apr-33	15,907	1,864	8	17,113	2,008	14	15,010	1,761	2
May-33	15,881	1,859	8	17,005	2,015	14	14,915	1,768	2
Jun-33	15,790	1,851	8	16,967	2,012	14	14,882	1,765	2
Jul-33	15,705	1,841	8	16,909	2,007	14	14,831	1,760	2
Aug-33	15,608	1,833	8	16,839	2,001	14	14,770	1,755	2
Sep-33	15,607	1,831	8	16,831	1,992	14	14,762	1,747	2
Oct-33	15,727	1,835	8	17,060	1,991	14	14,963	1,746	2
Nov-33	15,885	1,845	8	17,134	2,008	14	15,028	1,761	2
Dec-33	15,975	1,856	8	17,212	2,024	14	15,097	1,775	2

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION
LA GRANDE

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential LaGrande Customers	Commericial LaGrande Customers	Industrial LaGrande Customers	Residential LaGrande Customers	Commericial LaGrande Customers	Industrial LaGrande Customers	Residential LaGrande Customers	Commericial LaGrande Customers	Industrial LaGrande Customers
Jan-12	6,562	892	1	6,562	892	1	6,562	892	1
Feb-12	6,578	893	1	6,578	893	1	6,578	893	1
Mar-12	6,562	899	1	6,562	899	1	6,562	899	1
Apr-12	6,555	898	2	6,555	898	2	6,555	898	2
May-12	6,559	894	1	6,559	894	1	6,559	894	1
Jun-12	6,492	892	1	6,492	892	1	6,492	892	1
Jul-12	6,479	890	1	6,479	890	1	6,479	890	1
Aug-12	6,478	888	8	6,478	888	8	6,478	888	8
Sep-12	6,452	883	5	6,452	883	5	6,452	883	5
Oct-12	6,465	882	7	6,465	882	7	6,465	882	7
Nov-12	6,557	883	7	6,557	883	7	6,557	883	7
Dec-12	6,585	894	7	6,585	894	7	6,585	894	7
Jan-13	6,595	898	7	6,595	898	7	6,595	898	7
Feb-13	6,607	903	7	6,607	903	7	6,607	903	7
Mar-13	6,602	899	1	6,602	899	1	6,602	899	1
Apr-13	6,589	899	1	6,589	899	1	6,589	899	1
May-13	6,544	901	1	6,544	901	1	6,544	901	1
Jun-13	6,503	896	3	6,503	896	3	6,503	896	3
Jul-13	6,468	892	3	6,468	892	3	6,468	892	3
Aug-13	6,443	896	5	6,443	896	5	6,443	896	5
Sep-13	6,461	889	7	6,461	889	7	6,461	889	7
Oct-13	6,472	887	6	6,472	887	6	6,472	887	6
Nov-13	6,595	900	4	6,595	900	4	6,595	900	4
Dec-13	6,621	903	2	6,621	903	2	6,621	903	2
Jan-14	6,644	902	4	6,635	903	4	6,608	900	4
Feb-14	6,646	903	2	6,647	908	2	6,620	905	2
Mar-14	6,633	902	1	6,642	904	1	6,615	901	1
Apr-14	6,617	900	1	6,629	904	1	6,602	901	1
May-14	6,603	899	1	6,583	906	1	6,557	903	1
Jun-14	6,566	896	1	6,542	901	1	6,516	898	1
Jul-14	6,532	894	1	6,507	897	1	6,481	894	1
Aug-14	6,522	893	5	6,482	901	5	6,456	898	5
Sep-14	6,506	893	7	6,500	894	7	6,474	891	7
Oct-14	6,543	895	7	6,511	892	7	6,485	889	7
Nov-14	6,621	900	4	6,635	905	4	6,608	902	4
Dec-14	6,649	902	2	6,661	908	2	6,634	904	2
Jan-15	6,677	904	4	6,674	909	4	6,621	902	4
Feb-15	6,686	905	2	6,687	914	2	6,633	907	2
Mar-15	6,666	904	1	6,681	910	1	6,628	903	1
Apr-15	6,654	903	1	6,668	910	1	6,615	903	1
May-15	6,637	901	1	6,623	912	1	6,570	905	1
Jun-15	6,603	899	1	6,581	907	1	6,529	900	1
Jul-15	6,568	896	1	6,546	903	1	6,494	896	1
Aug-15	6,556	895	5	6,521	907	5	6,469	900	5

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION
LA GRANDE

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential LaGrande Customers	Commericial LaGrande Customers	Industrial LaGrande Customers	Residential LaGrande Customers	Commericial LaGrande Customers	Industrial LaGrande Customers	Residential LaGrande Customers	Commericial LaGrande Customers	Industrial LaGrande Customers
Sep-15	6,543	895	7	6,539	900	7	6,487	893	7
Oct-15	6,578	898	7	6,550	898	7	6,498	891	7
Nov-15	6,657	903	4	6,674	911	4	6,621	903	4
Dec-15	6,683	905	2	6,701	913	2	6,648	906	2
Jan-16	6,716	907	4	6,714	914	4	6,635	903	4
Feb-16	6,724	908	2	6,727	919	2	6,647	908	2
Mar-16	6,705	907	1	6,722	915	1	6,642	904	1
Apr-16	6,693	906	1	6,708	915	1	6,629	904	1
May-16	6,675	904	1	6,663	917	1	6,583	906	1
Jun-16	6,642	902	1	6,621	912	1	6,542	901	1
Jul-16	6,605	899	1	6,585	908	1	6,507	897	1
Aug-16	6,596	898	5	6,560	912	5	6,482	901	5
Sep-16	6,581	898	7	6,578	905	7	6,500	894	7
Oct-16	6,616	901	7	6,589	903	7	6,511	892	7
Nov-16	6,696	906	4	6,714	916	4	6,635	905	4
Dec-16	6,722	908	2	6,741	919	2	6,661	908	2
Jan-17	6,755	910	4	6,755	920	4	6,648	905	4
Feb-17	6,762	911	2	6,767	925	2	6,660	910	2
Mar-17	6,744	909	1	6,762	921	1	6,655	906	1
Apr-17	6,731	908	1	6,749	921	1	6,642	906	1
May-17	6,714	907	1	6,702	923	1	6,597	908	1
Jun-17	6,679	905	1	6,660	918	1	6,555	903	1
Jul-17	6,643	902	1	6,625	914	1	6,520	899	1
Aug-17	6,633	901	5	6,599	918	5	6,495	903	5
Sep-17	6,619	901	7	6,617	911	7	6,513	896	7
Oct-17	6,654	904	7	6,629	908	7	6,524	894	7
Nov-17	6,734	909	4	6,755	922	4	6,648	907	4
Dec-17	6,760	911	2	6,781	924	2	6,674	910	2
Jan-18	6,803	914	4	6,795	925	4	6,661	907	4
Feb-18	6,810	914	2	6,808	930	2	6,673	912	2
Mar-18	6,792	913	1	6,802	926	1	6,668	908	1
Apr-18	6,780	912	1	6,789	926	1	6,655	908	1
May-18	6,762	911	1	6,743	928	1	6,610	910	1
Jun-18	6,728	908	1	6,700	923	1	6,568	905	1
Jul-18	6,692	906	1	6,664	919	1	6,533	901	1
Aug-18	6,681	905	5	6,639	923	5	6,508	905	5
Sep-18	6,667	905	7	6,657	916	7	6,526	898	7
Oct-18	6,664	904	7	6,669	914	7	6,537	896	7
Nov-18	6,734	909	4	6,795	927	4	6,661	909	4
Dec-18	6,766	911	2	6,822	930	2	6,687	912	2
Jan-19	6,830	918	4	6,836	931	4	6,675	909	4
Feb-19	6,837	918	2	6,848	936	2	6,687	914	2
Mar-19	6,819	917	1	6,843	932	1	6,682	910	1
Apr-19	6,807	916	1	6,830	932	1	6,668	910	1

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION
LA GRANDE

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential LaGrande Customers	Commericial LaGrande Customers	Industrial LaGrande Customers	Residential LaGrande Customers	Commericial LaGrande Customers	Industrial LaGrande Customers	Residential LaGrande Customers	Commericial LaGrande Customers	Industrial LaGrande Customers
May-19	6,789	914	1	6,783	934	1	6,623	912	1
Jun-19	6,755	912	1	6,741	929	1	6,581	907	1
Jul-19	6,719	909	1	6,704	925	1	6,546	903	1
Aug-19	6,708	908	5	6,678	929	5	6,521	907	5
Sep-19	6,694	908	7	6,697	921	7	6,539	900	7
Oct-19	6,691	908	7	6,709	919	7	6,550	898	7
Nov-19	6,761	912	4	6,836	933	4	6,675	911	4
Dec-19	6,793	915	2	6,863	936	2	6,701	913	2
Jan-20	6,858	921	4	6,877	936	4	6,688	911	4
Feb-20	6,865	922	2	6,890	942	2	6,700	916	2
Mar-20	6,846	920	1	6,884	937	1	6,695	912	1
Apr-20	6,834	919	1	6,871	937	1	6,682	912	1
May-20	6,816	918	1	6,824	940	1	6,636	914	1
Jun-20	6,782	916	1	6,781	934	1	6,595	909	1
Jul-20	6,746	913	1	6,745	930	1	6,559	905	1
Aug-20	6,735	912	5	6,719	934	5	6,534	909	5
Sep-20	6,720	912	7	6,737	927	7	6,552	902	7
Oct-20	6,717	912	7	6,749	925	7	6,563	899	7
Nov-20	6,788	916	4	6,877	938	4	6,688	912	4
Dec-20	6,820	918	2	6,904	941	2	6,714	915	2
Jan-21	6,885	925	4	6,918	942	4	6,701	912	4
Feb-21	6,892	925	2	6,931	947	2	6,713	918	2
Mar-21	6,874	924	1	6,926	943	1	6,708	913	1
Apr-21	6,862	923	1	6,912	943	1	6,695	913	1
May-21	6,843	922	1	6,865	945	1	6,649	916	1
Jun-21	6,809	919	1	6,822	940	1	6,608	910	1
Jul-21	6,773	916	1	6,785	936	1	6,572	906	1
Aug-21	6,762	916	5	6,759	940	5	6,547	910	5
Sep-21	6,747	916	7	6,778	933	7	6,565	903	7
Oct-21	6,744	915	7	6,789	930	7	6,576	901	7
Nov-21	6,816	920	4	6,918	944	4	6,701	914	4
Dec-21	6,847	922	2	6,946	947	2	6,728	917	2
Jan-22	6,913	929	4	6,960	948	4	6,715	914	4
Feb-22	6,920	929	2	6,972	953	2	6,727	919	2
Mar-22	6,901	928	1	6,967	949	1	6,722	915	1
Apr-22	6,889	927	1	6,953	949	1	6,709	915	1
May-22	6,871	925	1	6,906	951	1	6,663	917	1
Jun-22	6,837	923	1	6,863	946	1	6,621	912	1
Jul-22	6,800	920	1	6,826	941	1	6,585	908	1
Aug-22	6,789	919	5	6,799	946	5	6,560	912	5
Sep-22	6,774	919	7	6,818	938	7	6,578	905	7
Oct-22	6,771	919	7	6,830	936	7	6,589	903	7
Nov-22	6,843	923	4	6,960	950	4	6,715	916	4
Dec-22	6,875	926	2	6,987	953	2	6,741	919	2

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION
LA GRANDE

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential LaGrande Customers	Commericial LaGrande Customers	Industrial LaGrande Customers	Residential LaGrande Customers	Commericial LaGrande Customers	Industrial LaGrande Customers	Residential LaGrande Customers	Commericial LaGrande Customers	Industrial LaGrande Customers
Jan-23	6,940	932	4	7,002	953	4	6,728	916	4
Feb-23	6,947	933	2	7,014	959	2	6,740	921	2
Mar-23	6,929	931	1	7,009	954	1	6,735	917	1
Apr-23	6,917	931	1	6,995	954	1	6,722	917	1
May-23	6,898	929	1	6,947	957	1	6,676	919	1
Jun-23	6,864	927	1	6,904	951	1	6,634	914	1
Jul-23	6,827	924	1	6,867	947	1	6,599	910	1
Aug-23	6,816	923	5	6,840	951	5	6,573	914	5
Sep-23	6,801	923	7	6,859	944	7	6,591	907	7
Oct-23	6,798	923	7	6,871	942	7	6,603	905	7
Nov-23	6,870	927	4	7,002	955	4	6,728	918	4
Dec-23	6,902	929	2	7,029	958	2	6,755	921	2
Jan-24	6,968	936	4	7,044	959	4	6,742	918	4
Feb-24	6,975	937	2	7,056	964	2	6,754	923	2
Mar-24	6,957	935	1	7,051	960	1	6,749	919	1
Apr-24	6,944	934	1	7,037	960	1	6,735	919	1
May-24	6,926	933	1	6,989	962	1	6,689	921	1
Jun-24	6,892	930	1	6,945	957	1	6,648	916	1
Jul-24	6,854	928	1	6,908	953	1	6,612	912	1
Aug-24	6,843	927	5	6,881	957	5	6,586	916	5
Sep-24	6,829	927	7	6,900	949	7	6,605	909	7
Oct-24	6,825	926	7	6,912	947	7	6,616	907	7
Nov-24	6,898	931	4	7,044	961	4	6,742	920	4
Dec-24	6,930	933	2	7,071	964	2	6,768	923	2
Jan-25	6,996	940	4	7,086	965	4	6,755	920	4
Feb-25	7,003	940	2	7,099	970	2	6,767	925	2
Mar-25	6,984	939	1	7,093	966	1	6,762	921	1
Apr-25	6,972	938	1	7,079	966	1	6,749	921	1
May-25	6,953	937	1	7,031	968	1	6,703	923	1
Jun-25	6,919	934	1	6,987	963	1	6,661	918	1
Jul-25	6,882	931	1	6,949	958	1	6,625	914	1
Aug-25	6,870	930	5	6,923	963	5	6,599	918	5
Sep-25	6,856	930	7	6,942	955	7	6,618	911	7
Oct-25	6,853	930	7	6,954	953	7	6,629	909	7
Nov-25	6,925	934	4	7,086	967	4	6,755	922	4
Dec-25	6,957	937	2	7,114	970	2	6,782	924	2
Jan-26	7,024	944	4	7,128	971	4	6,769	922	4
Feb-26	7,031	944	2	7,141	976	2	6,781	927	2
Mar-26	7,012	943	1	7,136	972	1	6,776	923	1
Apr-26	7,000	942	1	7,122	972	1	6,762	923	1
May-26	6,981	940	1	7,073	974	1	6,716	925	1
Jun-26	6,947	938	1	7,029	968	1	6,674	920	1
Jul-26	6,909	935	1	6,991	964	1	6,638	915	1
Aug-26	6,898	934	5	6,964	968	5	6,613	920	5

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION
LA GRANDE

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential LaGrande Customers	Commericial LaGrande Customers	Industrial LaGrande Customers	Residential LaGrande Customers	Commericial LaGrande Customers	Industrial LaGrande Customers	Residential LaGrande Customers	Commericial LaGrande Customers	Industrial LaGrande Customers
Sep-26	6,883	934	7	6,984	961	7	6,631	912	7
Oct-26	6,880	934	7	6,995	959	7	6,642	910	7
Nov-26	6,953	938	4	7,128	972	4	6,769	923	4
Dec-26	6,985	941	2	7,156	976	2	6,795	926	2
Jan-27	7,052	947	4	7,171	976	4	6,782	923	4
Feb-27	7,059	948	2	7,184	982	2	6,794	929	2
Mar-27	7,040	946	1	7,179	978	1	6,789	925	1
Apr-27	7,028	945	1	7,165	978	1	6,776	925	1
May-27	7,009	944	1	7,116	980	1	6,730	927	1
Jun-27	6,975	942	1	7,071	974	1	6,687	921	1
Jul-27	6,937	939	1	7,033	970	1	6,651	917	1
Aug-27	6,925	938	5	7,006	974	5	6,626	921	5
Sep-27	6,911	938	7	7,025	967	7	6,644	914	7
Oct-27	6,908	938	7	7,037	964	7	6,656	912	7
Nov-27	6,981	942	4	7,171	978	4	6,782	925	4
Dec-27	7,013	944	2	7,199	981	2	6,809	928	2
Jan-28	7,080	951	4	7,214	982	4	6,796	925	4
Feb-28	7,087	952	2	7,227	988	2	6,808	930	2
Mar-28	7,069	950	1	7,222	983	1	6,803	926	1
Apr-28	7,056	949	1	7,208	983	1	6,789	926	1
May-28	7,037	948	1	7,158	986	1	6,743	928	1
Jun-28	7,002	945	1	7,114	980	1	6,701	923	1
Jul-28	6,965	942	1	7,075	976	1	6,665	919	1
Aug-28	6,953	942	5	7,048	980	5	6,639	923	5
Sep-28	6,938	942	7	7,068	972	7	6,658	916	7
Oct-28	6,935	941	7	7,080	970	7	6,669	914	7
Nov-28	7,009	946	4	7,214	984	4	6,796	927	4
Dec-28	7,041	948	2	7,243	987	2	6,822	930	2
Jan-29	7,108	955	4	7,257	988	4	6,809	927	4
Feb-29	7,116	955	2	7,271	994	2	6,822	932	2
Mar-29	7,097	954	1	7,265	989	1	6,816	928	1
Apr-29	7,084	953	1	7,251	989	1	6,803	928	1
May-29	7,065	952	1	7,201	991	1	6,757	930	1
Jun-29	7,030	949	1	7,156	986	1	6,714	925	1
Jul-29	6,993	946	1	7,118	982	1	6,678	921	1
Aug-29	6,981	945	5	7,090	986	5	6,652	925	5
Sep-29	6,966	945	7	7,110	978	7	6,671	918	7
Oct-29	6,963	945	7	7,122	976	7	6,682	916	7
Nov-29	7,037	950	4	7,257	990	4	6,809	929	4
Dec-29	7,069	952	2	7,286	993	2	6,836	932	2
Jan-30	7,137	959	4	7,301	994	4	6,823	929	4
Feb-30	7,144	959	2	7,314	1,000	2	6,835	934	2
Mar-30	7,125	958	1	7,309	995	1	6,830	930	1
Apr-30	7,113	957	1	7,294	995	1	6,817	930	1

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION
LA GRANDE

	Oregon - Expected Growth			Oregon - High Growth			Oregon - Low Growth		
	Residential LaGrande Customers	Commericial LaGrande Customers	Industrial LaGrande Customers	Residential LaGrande Customers	Commericial LaGrande Customers	Industrial LaGrande Customers	Residential LaGrande Customers	Commericial LaGrande Customers	Industrial LaGrande Customers
May-30	7,093	955	1	7,245	997	1	6,770	932	1
Jun-30	7,059	953	1	7,199	992	1	6,728	927	1
Jul-30	7,021	950	1	7,160	987	1	6,691	923	1
Aug-30	7,009	949	5	7,133	992	5	6,666	927	5
Sep-30	6,994	949	7	7,153	984	7	6,684	920	7
Oct-30	6,991	949	7	7,165	982	7	6,696	918	7
Nov-30	7,065	953	4	7,301	996	4	6,823	931	4
Dec-30	7,098	956	2	7,330	999	2	6,850	934	2
Jan-31	7,165	963	4	7,345	1,000	4	6,836	931	4
Feb-31	7,173	963	2	7,358	1,006	2	6,849	936	2
Mar-31	7,154	962	1	7,353	1,001	1	6,844	932	1
Apr-31	7,141	961	1	7,338	1,001	1	6,830	932	1
May-31	7,122	959	1	7,288	1,003	1	6,784	934	1
Jun-31	7,087	957	1	7,242	998	1	6,741	929	1
Jul-31	7,049	954	1	7,203	993	1	6,705	925	1
Aug-31	7,037	953	5	7,175	998	5	6,679	929	5
Sep-31	7,022	953	7	7,196	990	7	6,698	922	7
Oct-31	7,019	953	7	7,208	988	7	6,709	919	7
Nov-31	7,093	957	4	7,345	1,002	4	6,836	933	4
Dec-31	7,126	960	2	7,374	1,005	2	6,863	936	2
Jan-32	7,194	966	4	7,389	1,006	4	6,850	933	4
Feb-32	7,202	967	2	7,402	1,012	2	6,863	938	2
Mar-32	7,182	966	1	7,397	1,007	1	6,857	934	1
Apr-32	7,170	965	1	7,382	1,007	1	6,844	934	1
May-32	7,150	963	1	7,332	1,009	1	6,797	936	1
Jun-32	7,115	960	1	7,286	1,004	1	6,755	931	1
Jul-32	7,077	958	1	7,247	999	1	6,718	927	1
Aug-32	7,065	957	5	7,219	1,004	5	6,692	931	5
Sep-32	7,050	957	7	7,239	996	7	6,711	923	7
Oct-32	7,047	956	7	7,251	994	7	6,722	921	7
Nov-32	7,122	961	4	7,389	1,008	4	6,850	935	4
Dec-32	7,155	963	2	7,418	1,011	2	6,877	938	2
Jan-33	7,223	970	4	7,433	1,012	4	6,864	935	4
Feb-33	7,230	971	2	7,447	1,018	2	6,876	940	2
Mar-33	7,211	969	1	7,441	1,013	1	6,871	936	1
Apr-33	7,198	968	1	7,426	1,013	1	6,858	936	1
May-33	7,179	967	1	7,376	1,016	1	6,811	938	1
Jun-33	7,144	964	1	7,329	1,010	1	6,768	933	1
Jul-33	7,105	961	1	7,290	1,005	1	6,732	928	1
Aug-33	7,093	961	5	7,262	1,010	5	6,706	933	5
Sep-33	7,078	961	7	7,282	1,002	7	6,724	925	7
Oct-33	7,075	960	7	7,295	1,000	7	6,736	923	7
Nov-33	7,150	965	4	7,433	1,014	4	6,864	936	4
Dec-33	7,183	967	2	7,462	1,017	2	6,891	939	2

APPENDIX 2.3: DEMAND COEFFICIENTS

	January	February	March	April	May	June	July	August	September	October	November	December
HEAT COEFFICIENTS												
WA/ID Residential	0.009653	0.009544	0.009042	0.007642	0.005096	0.003866	0.000691	0.000768	0.002725	0.006970	0.008833	0.009620
WA/ID Commercial	0.048562	0.047053	0.043468	0.035557	0.023406	0.020180	0.006577	0.008521	0.016160	0.032551	0.042232	0.047461
WA/ID Industrial	0.117333	0.112057	0.105316	0.098644	0.097972	0.136265	0.130544	0.067139	0.119601	0.134183	0.114920	0.126836
Roseburg Residential	0.010687	0.010367	0.009721	0.007918	0.005406	0.004600	0.001486	0.003424	0.002799	0.006260	0.007701	0.010748
Roseburg Commercial	0.042045	0.039664	0.035551	0.030689	0.020086	0.021323	0.010073	0.030308	0.016645	0.032359	0.029985	0.045113
Roseburg Industrial	0.134944	0.128278	0.193123	0.250720	0.244527	0.365646	0.871099	1.458261	1.572231	0.765100	0.154081	0.102736
Medford Residential	0.011011	0.010571	0.009769	0.008484	0.006075	0.004465	0.000000	0.000229	0.003441	0.007392	0.009451	0.010665
Medford Commercial	0.043468	0.039906	0.036884	0.033342	0.024208	0.021766	0.000000	0.001982	0.021539	0.030094	0.036756	0.043289
Medford Industrial	0.048846	0.022250	0.039482	0.065815	0.068050	0.127835	0.000000	0.000000	0.318489	0.085234	0.056711	0.079292
LaGrande Residential	0.009396	0.008731	0.008246	0.006698	0.006580	0.003782	0.001318	0.003200	0.000622	0.005574	0.007952	0.008383
LaGrande Commercial	0.039780	0.036526	0.033212	0.023394	0.021045	0.012020	0.007462	0.036060	0.005256	0.019711	0.031028	0.035610
LaGrande Industrial	0.000000	0.000000	0.014191	0.156925	0.225875	2.103282	0.762568	18.064739	3.936633	0.839843	0.025550	0.007093
Klamath Residential	0.008051	0.007645	0.007361	0.006111	0.003960	0.002162	0.000125	0.000024	0.001179	0.004770	0.006925	0.007151
Klamath Commercial	0.031553	0.029541	0.027199	0.021085	0.012997	0.012421	0.003716	0.005496	0.009214	0.017109	0.025669	0.026212
Klamath Industrial	0.033503	0.029395	0.035901	0.044675	0.026656	0.073581	0.043124	0.050675	0.116683	0.043722	0.029335	0.053690
BASE COEFFICIENTS												
WA/ID Residential	0.051899	0.051899	0.051899	0.051899	0.051899	0.051899	0.051899	0.051899	0.051899	0.051899	0.051899	0.051899
WA/ID Commercial	0.354193	0.354193	0.354193	0.354193	0.354193	0.354193	0.354193	0.354193	0.354193	0.354193	0.354193	0.354193
WA/ID Industrial	3.941451	3.941451	3.941451	3.941451	3.941451	3.941451	3.941451	3.941451	3.941451	3.941451	3.941451	3.941451
Roseburg Residential	0.053418	0.053418	0.053418	0.053418	0.053418	0.053418	0.053418	0.053418	0.053418	0.053418	0.053418	0.053418
Roseburg Commercial	0.378016	0.378016	0.378016	0.378016	0.378016	0.378016	0.378016	0.378016	0.378016	0.378016	0.378016	0.378016
Roseburg Industrial	16.187912	16.187912	16.187912	16.187912	16.187912	16.187912	16.187912	16.187912	16.187912	16.187912	16.187912	16.187912
Medford Residential	0.044191	0.044191	0.044191	0.044191	0.044191	0.044191	0.044191	0.044191	0.044191	0.044191	0.044191	0.044191
Medford Commercial	0.314099	0.314099	0.314099	0.314099	0.314099	0.314099	0.314099	0.314099	0.314099	0.314099	0.314099	0.314099
Medford Industrial	2.135537	2.135537	2.135537	2.135537	2.135537	2.135537	2.135537	2.135537	2.135537	2.135537	2.135537	2.135537
LaGrande Residential	0.054280	0.054280	0.054280	0.054280	0.054280	0.054280	0.054280	0.054280	0.054280	0.054280	0.054280	0.054280
LaGrande Commercial	0.287460	0.287460	0.287460	0.287460	0.287460	0.287460	0.287460	0.287460	0.287460	0.287460	0.287460	0.287460
LaGrande Industrial	0.869065	0.869065	0.869065	0.869065	0.869065	0.869065	0.869065	0.869065	0.869065	0.869065	0.869065	0.869065
Klamath Residential	0.038598	0.038598	0.038598	0.038598	0.038598	0.038598	0.038598	0.038598	0.038598	0.038598	0.038598	0.038598
Klamath Commercial	0.262845	0.262845	0.262845	0.262845	0.262845	0.262845	0.262845	0.262845	0.262845	0.262845	0.262845	0.262845
Klamath Industrial	2.919956	2.919956	2.919956	2.919956	2.919956	2.919956	2.919956	2.919956	2.919956	2.919956	2.919956	2.919956
SUPER PEAK 1/												
WA/ID Res	0.009605614	0.009605614										0.009605614
WA/ID Com	0.047692046	0.047692046										0.047692046
WA/ID Ind	0.118742005	0.118742005										0.118742005
Rose Res	0.010600643	0.010600643										0.010600643
Rose Com	0.042273836	0.042273836										0.042273836
Rose Ind	0.121986166	0.121986166										0.121986166
Medford Res	0.010749125	0.010749125										0.010749125
Medford Com	0.042220865	0.042220865										0.042220865
Medford Ind	0.050129224	0.050129224										0.050129224
LaGrande Res	0.008836594	0.008836594										0.008836594
LaGrande Com	0.037305148	0.037305148										0.037305148
LaGrande Ind	0.002364178	0.002364178										0.002364178
Klamath Res	0.007615622	0.007615622										0.007615622
Klamath Com	0.029101928	0.029101928										0.029101928
Klamath Ind	0.038862569	0.038862569										0.038862569

1/ Average of DEC JAN FEB heat coefficients

APPENDIX 2.3: WA/ID BASE COEFFICIENT CALCULATION

WA-ID

Average Actual Demand by Class

Year		Month 7
2009	Average of Res Demand	10,211
	Average of Com Demand	7,583
	Average of Ind Demand	774
2010	Average of Res Demand	10,717
	Average of Com Demand	8,158
	Average of Ind Demand	1,177
2011	Average of Res Demand	10,772
	Average of Com Demand	8,383
	Average of Ind Demand	1,146
2012	Average of Res Demand	10,027
	Average of Com Demand	8,124
	Average of Ind Demand	941
2013	Average of Res Demand	10,259
	Average of Com Demand	7,204
	Average of Ind Demand	636
Total Average of Res Demand		10,397
Total Average of Com Demand		7,890
Total Average of Ind Demand		935

Average Actual Customer Count by Class

Year		Month 7
2009	Average of Res Cust	196,276
	Average of Com Cust	21,928
	Average of Ind Cust	234
2010	Average of Res Cust	197,541
	Average of Com Cust	22,126
	Average of Ind Cust	229
2011	Average of Res Cust	198,492
	Average of Com Cust	22,218
	Average of Ind Cust	232
2012	Average of Res Cust	200,290
	Average of Com Cust	22,315
	Average of Ind Cust	233
2013	Average of Res Cust	199,628
	Average of Com Cust	22,410
	Average of Ind Cust	226
Total Average of Res Cust		198,445
Total Average of Com Cust		22,199
Total Average of Ind Cust		231

Base Coefficients

(Actual Average Demand/Customer Count)

0.051899	Res Base Usage
0.354193	Com Base Usage
3.941451	Ind Base Usage

APPENDIX 2.3: MEDFORD BASE COEFFICIENT CALCULATION

Medford
Average Actual Demand by Class

Year		Month 7
2009	Average of Res Demand	2,248
	Average of Com Demand	2,061
	Average of Ind Demand	36
2010	Average of Res Demand	2,265
	Average of Com Demand	2,047
	Average of Ind Demand	38
2011	Average of Res Demand	2,123
	Average of Com Demand	1,935
	Average of Ind Demand	37
2012	Average of Res Demand	2,278
	Average of Com Demand	2,057
	Average of Ind Demand	31
2013	Average of Res Demand	2,297
	Average of Com Demand	2,083
	Average of Ind Demand	40
Total Average of Res Demand		2,242
Total Average of Com Demand		2,037
Total Average of Ind Demand		36

Average Actual Customer Count by Class

Year		Month 7
2009	Average of Res Cust	49,868
	Average of Com Cust	6,301
	Average of Ind Cust	13
2010	Average of Res Cust	50,420
	Average of Com Cust	6,417
	Average of Ind Cust	13
2011	Average of Res Cust	50,367
	Average of Com Cust	6,403
	Average of Ind Cust	17
2012	Average of Res Cust	50,727
	Average of Com Cust	6,445
	Average of Ind Cust	17
2013	Average of Res Cust	50,499
	Average of Com Cust	6,493
	Average of Ind Cust	16
Total Average of Res Cust		50,376
Total Average of Com Cust		6,412
Total Average of Ind Cust		15

Base Coefficients

(Actual Average Demand/Customer Count)

0.044191	Res Base Usage
0.314099	Com Base Usage
2.135537	Ind Base Usage

APPENDIX 2.3: ROSEBURG BASE COEFFICIENT CALCULATION

Roseburg
Average Actual Demand by Class

		Month
Year		7
2009	Average of Res Demand	536
	Average of Com Demand	680
	Average of Ind Demand	32
2010	Average of Res Demand	565
	Average of Com Demand	644
	Average of Ind Demand	38
2011	Average of Res Demand	841
	Average of Com Demand	953
	Average of Ind Demand	33
2012	Average of Res Demand	680
	Average of Com Demand	820
	Average of Ind Demand	48
2013	Average of Res Demand	559
	Average of Com Demand	622
	Average of Ind Demand	32
Total Average of Res Demand		636
Total Average of Com Demand		744
Total Average of Ind Demand		37

Average Actual Customer Count by Class

		Month
Year		7
2009	Average of Res Cust	12,874
	Average of Com Cust	2,120
	Average of Ind Cust	1
2010	Average of Res Cust	12,960
	Average of Com Cust	2,107
	Average of Ind Cust	2
2011	Average of Res Cust	12,961
	Average of Com Cust	2,096
	Average of Ind Cust	2
2012	Average of Res Cust	12,928
	Average of Com Cust	2,112
	Average of Ind Cust	2
2013	Average of Res Cust	13,059
	Average of Com Cust	2,128
	Average of Ind Cust	3
Total Average of Res Cust		12,956
Total Average of Com Cust		2,113
Total Average of Ind Cust		2

Base Coefficients

(Actual Average Demand/Customer Count)

0.053418	Res Base Usage
0.378016	Com Base Usage
16.187912	Ind Base Usage

APPENDIX 2.3: KLAMATH FALLS BASE COEFFICIENT CALCULATION

Klamath Falls

Average Actual Demand by Class

Year		Month 7
2009	Average of Res Demand	458
	Average of Com Demand	426
	Average of Ind Demand	15
2010	Average of Res Demand	503
	Average of Com Demand	475
	Average of Ind Demand	21
2011	Average of Res Demand	531
	Average of Com Demand	480
	Average of Ind Demand	21
2012	Average of Res Demand	507
	Average of Com Demand	424
	Average of Ind Demand	22
2013	Average of Res Demand	559
	Average of Com Demand	383
	Average of Ind Demand	21
Total Average of Res Demand		512
Total Average of Com Demand		438
Total Average of Ind Demand		20

Average Actual Customer Count by Class

Year		Month 7
2009	Average of Res Cust	13,604
	Average of Com Cust	1,615
	Average of Ind Cust	6
2010	Average of Res Cust	13,679
	Average of Com Cust	1,610
	Average of Ind Cust	7
2011	Average of Res Cust	13,725
	Average of Com Cust	1,621
	Average of Ind Cust	7
2012	Average of Res Cust	13,770
	Average of Com Cust	1,625
	Average of Ind Cust	7
2013	Average of Res Cust	13,885
	Average of Com Cust	1,648
	Average of Ind Cust	8
Total Average of Res Cust		13,733
Total Average of Com Cust		1,624
Total Average of Ind Cust		7

Base Coefficients

(Actual Average Demand/Customer Count)

0.038598	Res Base Usage
0.262845	Com Base Usage
2.919956	Ind Base Usage

APPENDIX 2.3: LA GRANDE BASE COEFFICIENT CALCULATION

LaGrande

Average Actual Demand by Class

Year	Values	Month 7	8	Grand Total
2009	Average of Res Demand	286	409	347
	Average of Com Demand	234	323	279
	Average of Ind Demand	9	665	337
2010	Average of Res Demand	299	477	388
	Average of Com Demand	225	357	291
	Average of Ind Demand	21	557	289
2011	Average of Res Demand	310	384	347
	Average of Com Demand	237	380	308
	Average of Ind Demand	13	659	336
2012	Average of Res Demand	416	413	414
	Average of Com Demand	307	404	356
	Average of Ind Demand	(6)	691	343
2013	Average of Res Demand	326	734	530
	Average of Com Demand	219	541	380
	Average of Ind Demand	14	113	63
Total Average of Res Demand		327	483	405
Total Average of Com Demand		244	401	323
Total Average of Ind Demand		10	537	274

Average Actual Customer Count by Class

Year	Values	Month 7	8	Grand Total
2009	Average of Res Cust	6,362	6,338	6,350
	Average of Com Cust	891	887	889
	Average of Ind Cust	2	7	5
2010	Average of Res Cust	6,401	6,392	6,397
	Average of Com Cust	885	882	884
	Average of Ind Cust	1	6	4
2011	Average of Res Cust	6,427	6,400	6,414
	Average of Com Cust	873	875	874
	Average of Ind Cust	13	7	10
2012	Average of Res Cust	6,478	6,452	6,465
	Average of Com Cust	888	883	886
	Average of Ind Cust	8	7	8
2013	Average of Res Cust	6,468	6,443	6,456
	Average of Com Cust	892	896	894
	Average of Ind Cust	3	5	4
Total Average of Res Cust		6,427	6,405	6,416
Total Average of Com Cust		886	885	885
Total Average of Ind Cust		5	6	6

Base Coefficients

(Actual Average Demand/Customer Count)

0.054280	Res Base Usage
0.287460	Com Base Usage
0.869065	Ind Base Usage

APPENDIX 2.4: HEATING DEGREE DAY DATA MONTHLY TABLES

Temp Pattern	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
WA/ID	2014	1,122	844	777	490	280	138	-	49	82	558	1,132	1,210	6,681
WA/ID	2015	1,346	1,008	769	570	224	206	88	2	147	692	1,011	1,158	7,221
WA/ID	2016	1,128	918	871	512	311	142	7	34	218	507	1,039	1,163	6,849
WA/ID	2017	1,164	1,085	735	530	322	162	31	36	124	648	805	1,050	6,692
WA/ID	2018	1,102	930	861	584	346	195	38	46	272	490	1,132	1,131	7,128
WA/ID	2019	1,250	965	903	598	285	155	45	21	237	470	779	1,191	6,899
WA/ID	2020	1,219	857	959	581	361	128	25	28	139	685	859	1,190	7,031
WA/ID	2021	1,141	901	861	547	486	161	83	2	200	603	887	1,221	7,094
WA/ID	2022	1,111	784	871	599	399	95	38	19	219	692	709	1,313	6,847
WA/ID	2023	1,034	887	738	607	244	123	29	24	247	482	821	1,190	6,426
WA/ID	2024	1,187	859	862	518	352	126	90	8	228	535	915	1,119	6,800
WA/ID	2025	1,072	962	821	529	275	95	57	13	296	511	937	1,313	6,881
WA/ID	2026	1,230	1,008	794	541	270	105	4	6	77	642	833	1,203	6,712
WA/ID	2027	1,303	999	783	472	435	179	3	2	105	512	1,020	1,089	6,902
WA/ID	2028	1,197	951	680	557	422	164	-	44	178	644	1,132	1,015	6,985
WA/ID	2029	1,055	806	886	658	258	153	33	47	139	547	800	1,170	6,552
WA/ID	2030	1,194	1,116	698	558	331	124	8	19	199	545	712	1,246	6,749
WA/ID	2031	1,127	995	871	477	445	121	28	40	251	594	893	1,097	6,938
WA/ID	2032	1,296	1,024	875	515	416	174	-	2	167	522	873	1,177	7,039
WA/ID	2033	1,118	849	934	581	372	203	9	4	127	655	910	1,171	6,933

Temp Pattern	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Klamath Falls	2014	978	910	825	780	478	178	3	91	120	497	914	1,294	7,068
Klamath Falls	2015	918	635	933	497	405	340	67	43	136	400	722	1,175	6,270
Klamath Falls	2016	1,072	940	830	479	362	158	19	59	219	429	917	1,083	6,568
Klamath Falls	2017	1,259	826	892	459	510	255	47	83	81	604	836	908	6,760
Klamath Falls	2018	1,044	788	776	682	620	232	-	125	232	575	946	1,074	7,094
Klamath Falls	2019	1,107	878	595	691	472	164	39	29	148	463	732	973	6,290
Klamath Falls	2020	776	925	694	780	364	228	25	13	70	605	926	975	6,380
Klamath Falls	2021	973	833	896	664	519	233	80	70	259	440	643	1,018	6,626
Klamath Falls	2022	1,169	898	816	478	620	205	39	40	393	451	1,051	999	7,158
Klamath Falls	2023	914	860	933	702	419	102	76	83	220	356	856	1,149	6,670
Klamath Falls	2024	1,103	872	988	654	384	219	68	50	251	566	779	1,154	7,086
Klamath Falls	2025	1,238	1,091	780	550	400	206	103	61	276	322	812	956	6,795
Klamath Falls	2026	1,163	836	711	561	554	241	13	70	230	510	801	1,248	6,939
Klamath Falls	2027	892	846	779	577	309	324	89	13	36	609	1,079	1,077	6,629
Klamath Falls	2028	1,151	801	922	735	259	142	-	98	146	419	706	989	6,369
Klamath Falls	2029	1,012	811	719	646	392	164	52	31	166	624	848	1,132	6,598
Klamath Falls	2030	1,042	690	848	656	419	154	53	46	301	636	750	921	6,518
Klamath Falls	2031	998	961	896	605	462	82	19	79	55	324	906	1,046	6,432
Klamath Falls	2032	1,211	748	791	540	336	152	80	29	393	599	1,122	1,166	7,167
Klamath Falls	2033	1,068	707	719	561	333	272	104	30	187	517	860	1,070	6,429

Temp Pattern	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Medford	2014	743	650	580	527	254	51	-	33	26	300	652	1,111	4,927
Medford	2015	704	490	691	316	199	139	8	-	32	224	524	919	4,248
Medford	2016	804	669	585	304	167	41	-	9	66	235	654	821	4,354
Medford	2017	923	596	649	290	278	92	4	27	11	401	600	693	4,565
Medford	2018	785	572	531	445	343	80	-	59	71	374	673	811	4,743
Medford	2019	826	629	393	451	249	44	3	-	37	267	531	703	4,133
Medford	2020	602	660	447	519	168	77	-	-	6	402	660	705	4,245
Medford	2021	740	601	653	433	285	80	11	17	81	245	465	751	4,361
Medford	2022	865	642	571	303	343	65	3	-	139	256	743	731	4,662
Medford	2023	702	618	691	459	210	19	10	27	66	224	614	891	4,530
Medford	2024	823	625	773	426	184	72	8	2	78	365	562	897	4,816
Medford	2025	910	765	535	353	196	66	15	10	88	224	584	693	4,440
Medford	2026	862	602	464	361	312	84	-	18	70	312	577	998	4,659
Medford	2027	688	609	533	372	127	128	13	-	3	406	761	814	4,454
Medford	2028	854	580	679	482	89	32	-	39	36	226	514	719	4,252
Medford	2029	765	586	473	420	190	44	5	-	44	420	608	873	4,429
Medford	2030	784	510	604	427	210	39	5	-	98	431	543	693	4,345
Medford	2031	756	682	653	392	242	19	-	24	3	224	647	781	4,422
Medford	2032	893	546	546	346	147	37	11	-	145	397	761	910	4,739
Medford	2033	801	520	472	361	145	100	16	-	53	319	614	817	4,218

APPENDIX 2.4: HEATING DEGREE DAY DATA MONTHLY TABLES

Temp Pattern	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Roseburg	2014	684	492	487	277	153	58	-	9	26	289	654	740	3,868
Roseburg	2015	862	606	479	369	99	131	19	-	49	356	608	707	4,285
Roseburg	2016	688	543	581	302	184	61	2	4	74	256	627	710	4,032
Roseburg	2017	717	645	445	323	195	83	7	5	41	348	473	638	3,919
Roseburg	2018	668	552	571	385	218	119	8	8	93	245	654	690	4,211
Roseburg	2019	784	576	613	400	159	76	10	-	80	232	456	728	4,113
Roseburg	2020	760	501	622	381	232	46	6	2	46	356	508	727	4,187
Roseburg	2021	699	531	571	342	339	82	18	-	67	319	527	747	4,243
Roseburg	2022	675	449	581	402	269	12	8	-	74	356	405	806	4,037
Roseburg	2023	615	521	448	411	119	41	7	1	84	240	484	727	3,696
Roseburg	2024	735	502	572	309	224	44	20	-	77	275	545	683	3,985
Roseburg	2025	645	574	531	322	149	12	13	-	106	259	560	806	3,975
Roseburg	2026	768	606	504	335	144	21	1	-	21	345	491	736	3,971
Roseburg	2027	825	600	493	234	304	101	1	-	34	259	615	663	4,129
Roseburg	2028	742	566	388	354	292	85	-	7	60	346	654	616	4,110
Roseburg	2029	632	465	596	469	132	73	7	8	46	282	470	715	3,895
Roseburg	2030	740	645	408	355	203	42	2	-	67	281	412	763	3,917
Roseburg	2031	688	597	581	263	314	38	6	6	85	313	531	668	4,090
Roseburg	2032	819	617	585	305	286	96	-	-	56	266	517	719	4,266
Roseburg	2033	681	495	622	380	243	127	2	-	41	353	536	715	4,197

Temp Pattern	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
LaGrande	2014	881	847	604	486	478	119	52	74	258	478	935	995	6,206
LaGrande	2015	909	848	792	563	227	123	24	37	244	505	744	990	6,006
LaGrande	2016	1,105	799	624	574	284	162	13	75	297	613	650	866	6,061
LaGrande	2017	1,015	812	685	518	396	158	28	20	231	537	656	1,166	6,222
LaGrande	2018	1,113	712	781	619	324	202	74	42	151	448	781	1,082	6,329
LaGrande	2019	973	711	755	458	396	120	49	56	206	485	633	1,156	5,997
LaGrande	2020	1,018	807	636	674	466	196	55	59	251	487	755	1,023	6,427
LaGrande	2021	840	825	727	563	346	84	17	61	190	490	622	1,162	5,927
LaGrande	2022	882	933	843	599	337	121	63	36	169	491	831	910	6,215
LaGrande	2023	1,030	915	748	459	345	172	69	9	97	492	952	1,039	6,327
LaGrande	2024	908	874	764	547	290	167	-	56	219	488	899	978	6,191
LaGrande	2025	913	806	767	513	313	138	59	49	231	560	756	1,083	6,187
LaGrande	2026	965	848	805	502	368	156	-	42	174	524	803	1,043	6,231
LaGrande	2027	1,058	925	718	589	219	151	53	80	246	614	585	935	6,172
LaGrande	2028	1,003	797	843	637	340	174	44	20	109	581	726	1,078	6,352
LaGrande	2029	1,021	788	740	488	362	167	14	57	103	591	695	1,012	6,037
LaGrande	2030	1,032	884	777	441	327	158	81	105	181	459	842	1,016	6,304
LaGrande	2031	1,030	801	696	496	429	213	39	39	297	584	805	895	6,324
LaGrande	2032	840	737	744	409	294	101	-	26	229	515	760	1,121	5,775
LaGrande	2033	1,085	710	811	654	245	154	4	91	209	391	759	1,029	6,141

APPENDIX 2.4: HEATING DEGREE DAILY MONTH BY AREA

Temp Pattern	Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
WA/ID	1	36	35	29	23	16	4	0	0	0	8	28	32
WA/ID	2	37	35	28	24	15	6	0	0	0	13	27	33
WA/ID	3	38	35	29	23	15	4	0	0	0	13	27	36
WA/ID	4	36	32	29	22	16	4	0	0	0	13	27	37
WA/ID	5	37	33	29	22	15	7	0	0	2	15	28	37
WA/ID	6	36	32	29	20	15	9	0	0	3	14	26	38
WA/ID	7	34	33	28	20	14	8	0	0	3	14	25	39
WA/ID	8	34	34	29	20	13	9	0	0	2	15	25	39
WA/ID	9	34	34	27	21	13	8	0	0	3	16	27	39
WA/ID	10	34	35	27	20	12	7	0	0	3	17	27	37
WA/ID	11	37	35	25	19	11	7	0	0	2	18	27	36
WA/ID	12	36	33	25	20	10	5	0	0	1	18	26	35
WA/ID	13	35	62	24	20	11	4	0	0	1	16	26	35
WA/ID	14	33	72	24	22	8	5	0	0	0	16	28	35
WA/ID	15	36	82	24	21	8	4	0	0	1	18	27	35
WA/ID	16	37	67	24	18	8	3	0	0	3	17	27	35
WA/ID	17	36	57	25	19	9	4	0	0	5	17	27	36
WA/ID	18	35	31	25	19	9	5	0	0	5	18	29	51
WA/ID	19	35	30	25	19	8	6	0	0	6	18	29	56
WA/ID	20	34	30	24	16	11	4	0	0	9	18	29	61
WA/ID	21	35	29	25	16	11	1	0	0	10	19	32	58
WA/ID	22	36	29	24	16	11	1	0	0	8	19	34	53
WA/ID	23	35	30	24	16	10	2	0	0	6	21	33	38
WA/ID	24	35	33	24	17	7	2	0	0	6	22	32	38
WA/ID	25	34	34	24	16	8	1	0	0	5	23	32	37
WA/ID	26	35	34	24	16	8	1	0	0	7	23	33	37
WA/ID	27	36	33	24	15	7	0	0	0	7	23	34	36
WA/ID	28	36	32	24	16	8	0	0	0	7	23	34	35
WA/ID	29	34	30	23	16	8	0	0	0	7	25	33	36
WA/ID	30	33		21	16	7	0	0	0	8	26	32	38
WA/ID	31	33		22		5		0	0		26		37

Temp Pattern	Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LaGrande	1	33	32	27	21	16	5	0	0	2	9	26	29
LaGrande	2	32	32	25	22	16	5	0	0	3	12	24	31
LaGrande	3	35	31	27	21	15	6	0	0	2	12	24	33
LaGrande	4	34	28	27	21	15	4	0	0	0	14	23	34
LaGrande	5	34	29	26	22	15	7	0	0	2	15	23	36
LaGrande	6	33	29	26	20	14	8	0	0	3	14	21	34
LaGrande	7	30	29	25	20	13	7	0	0	5	13	22	35
LaGrande	8	30	30	26	20	13	7	0	0	4	15	22	35
LaGrande	9	30	30	23	20	14	8	0	0	5	14	24	36
LaGrande	10	30	31	23	20	14	8	0	0	3	16	24	32
LaGrande	11	32	29	23	19	11	7	0	0	3	17	25	33
LaGrande	12	33	29	22	18	11	6	0	0	1	17	24	31
LaGrande	13	31	61	21	18	10	4	0	0	3	15	24	29
LaGrande	14	31	68	22	21	9	4	0	0	3	14	25	31
LaGrande	15	35	74	22	21	9	4	0	0	3	17	24	31
LaGrande	16	33	61	22	18	9	4	0	0	5	16	23	33
LaGrande	17	33	60	23	18	8	4	0	0	6	16	24	34
LaGrande	18	31	27	22	19	8	6	0	0	7	17	26	51
LaGrande	19	30	28	22	19	9	7	0	0	6	16	24	58
LaGrande	20	30	27	22	17	10	4	0	0	9	17	26	64
LaGrande	21	32	27	23	17	12	3	0	0	10	19	27	58
LaGrande	22	34	25	22	15	12	1	0	0	10	18	29	51
LaGrande	23	32	27	22	16	10	2	0	0	8	18	30	34
LaGrande	24	31	29	22	18	8	2	0	1	7	20	29	34
LaGrande	25	30	29	22	15	9	2	0	0	8	21	29	34
LaGrande	26	32	29	23	14	9	1	0	0	10	21	30	34
LaGrande	27	34	29	24	13	8	1	0	0	9	21	30	33
LaGrande	28	32	27	23	16	9	0	0	0	9	20	30	31
LaGrande	29	32	25	22	17	8	0	0	0	8	22	28	32
LaGrande	30	30		21	15	7	0	0	1	6	22	27	34
LaGrande	31	31		20		6		0	1		24		32

APPENDIX 2.4: HEATING DEGREE DAILY MONTH BY AREA

Temp Pattern	Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Medford	1	26	24	20	16	10	0	0	0	0	3	17	25
Medford	2	26	23	21	16	9	1	0	0	0	6	18	24
Medford	3	28	22	22	16	9	1	0	0	0	6	17	26
Medford	4	27	22	21	15	9	0	0	0	0	7	18	26
Medford	5	26	22	21	16	8	2	0	0	0	7	17	27
Medford	6	27	21	20	14	8	2	0	0	0	6	16	27
Medford	7	24	21	20	15	6	2	0	0	0	7	17	29
Medford	8	25	24	19	15	7	3	0	0	0	7	19	28
Medford	9	26	22	18	15	9	2	0	0	0	9	21	27
Medford	10	25	22	17	14	8	2	0	0	0	9	19	27
Medford	11	25	22	17	13	6	2	0	0	0	10	19	27
Medford	12	26	21	17	14	6	1	0	0	0	10	18	25
Medford	13	27	32	16	15	5	0	0	0	0	8	19	23
Medford	14	27	36	17	16	4	0	0	0	0	8	19	25
Medford	15	26	38	16	15	3	0	0	0	0	10	18	28
Medford	16	26	32	17	14	3	0	0	0	0	8	19	28
Medford	17	25	28	18	14	3	0	0	0	0	9	20	27
Medford	18	24	20	16	15	4	0	0	0	0	10	21	50
Medford	19	23	20	15	13	5	0	0	0	0	9	20	59
Medford	20	25	20	16	12	6	0	0	0	0	11	22	61
Medford	21	26	20	15	12	6	0	0	0	0	12	24	56
Medford	22	25	21	16	11	6	0	0	0	0	11	23	55
Medford	23	25	22	16	11	4	0	0	0	0	12	23	28
Medford	24	24	21	15	10	4	0	0	0	0	13	23	29
Medford	25	23	21	17	9	4	0	0	0	1	14	21	28
Medford	26	24	22	17	8	2	0	0	0	1	14	23	28
Medford	27	25	21	18	9	4	0	0	0	0	15	24	27
Medford	28	24	21	17	10	4	0	0	0	0	15	23	26
Medford	29	24	19	16	10	3	0	0	0	1	15	24	26
Medford	30	23		16	10	0	0	0	0	1	16	24	27
Medford	31	23		15		0		0	0		16		27

Temp Pattern	Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Klamath Falls	1	34	32	29	24	18	7	0	0	3	10	25	31
Klamath Falls	2	34	32	29	24	17	8	0	0	2	13	26	32
Klamath Falls	3	36	30	30	24	17	8	0	0	3	15	25	35
Klamath Falls	4	36	30	30	24	17	8	1	0	4	16	26	35
Klamath Falls	5	35	30	29	24	16	10	0	0	6	15	25	35
Klamath Falls	6	33	29	28	23	15	10	0	0	6	14	24	34
Klamath Falls	7	31	30	28	23	15	10	0	0	5	14	25	36
Klamath Falls	8	32	32	27	24	16	11	0	0	4	15	28	36
Klamath Falls	9	33	31	27	24	18	10	0	0	5	16	30	35
Klamath Falls	10	33	30	27	24	16	10	0	0	5	17	28	36
Klamath Falls	11	33	30	25	22	14	10	0	0	4	18	27	36
Klamath Falls	12	34	29	25	22	14	9	0	0	3	17	24	34
Klamath Falls	13	34	42	25	24	13	8	0	0	4	15	26	33
Klamath Falls	14	34	51	25	25	11	6	0	0	6	15	27	36
Klamath Falls	15	34	54	24	24	11	6	0	0	6	16	26	37
Klamath Falls	16	34	53	25	23	12	6	0	0	9	17	25	35
Klamath Falls	17	33	47	26	23	12	6	0	0	10	17	28	37
Klamath Falls	18	32	29	25	24	13	7	0	0	9	17	28	36
Klamath Falls	19	32	30	24	22	13	8	0	0	8	17	27	63
Klamath Falls	20	33	30	23	21	13	6	0	0	8	18	28	72
Klamath Falls	21	35	28	23	20	13	5	0	1	8	20	29	67
Klamath Falls	22	35	29	24	19	13	6	0	1	8	19	30	58
Klamath Falls	23	34	31	26	19	13	5	0	1	8	20	32	53.5
Klamath Falls	24	33	29	24	18	11	4	0	1	8	21	32	37
Klamath Falls	25	32	31	25	17	11	4	0	1	10	22	31	36
Klamath Falls	26	32	31	26	17	10	3	0	2	10	22	33	36
Klamath Falls	27	33	30	26	17	10	1	0	1	8	23	32	34
Klamath Falls	28	33	29	25	19	11	0	0	1	8	21	32	32
Klamath Falls	29	31	30	25	18	10	1	0	0	8	22	33	33
Klamath Falls	30	31		24	18	9	1	0	3	9	23	31	35
Klamath Falls	31	32		24		6		0	2		24		35

APPENDIX 2.4: HEATING DEGREE DAILY MONTH BY AREA

Temp Pattern	Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Roseburg	1	21	20	18	16	9	1	0	0	0	3	14	21
Roseburg	2	22	20	18	15	9	2	0	0	0	5	14	21
Roseburg	3	22	20	19	14	9	2	0	0	0	6	15	22
Roseburg	4	22	19	18	14	9	1	0	0	0	7	15	21
Roseburg	5	22	19	19	15	8	3	0	0	0	5	15	22
Roseburg	6	21	18	18	14	8	3	0	0	0	4	13	23
Roseburg	7	19	20	18	14	7	3	0	0	0	5	15	24
Roseburg	8	20	21	17	15	8	3	0	0	0	6	17	23
Roseburg	9	21	21	16	14	10	3	0	0	0	7	17	22
Roseburg	10	21	20	16	13	9	4	0	0	0	9	17	22
Roseburg	11	22	19	14	12	7	3	0	0	0	9	16	22
Roseburg	12	21	18	15	13	7	1	0	0	0	9	14	21
Roseburg	13	23	32	15	13	6	0	0	0	0	7	14	21
Roseburg	14	23	37	15	15	4	1	0	0	0	8	15	22
Roseburg	15	23	42	15	14	5	0	0	0	0	9	15	23
Roseburg	16	22	34	17	13	5	1	0	0	0	8	16	22
Roseburg	17	22	28	17	13	4	0	0	0	1	9	17	23
Roseburg	18	21	18	14	14	4	2	0	0	0	9	17	40
Roseburg	19	21	18	15	13	5	1	0	0	0	8	16	53
Roseburg	20	21	19	15	12	6	0	0	0	0	10	20	55
Roseburg	21	22	18	16	11	7	0	0	0	1	10	21	46
Roseburg	22	22	18	16	10	6	1	0	0	0	10	20	48
Roseburg	23	21	19	15	10	5	0	0	0	0	11	21	22
Roseburg	24	21	19	15	9	4	0	0	0	0	12	19	23
Roseburg	25	21	20	16	8	3	0	0	0	2	13	20	23
Roseburg	26	23	19	17	8	2	0	0	0	2	13	20	23
Roseburg	27	23	18	16	9	4	0	0	0	1	14	21	23
Roseburg	28	20	18	16	9	5	0	0	0	0	12	20	22
Roseburg	29	19	18	15	8	3	0	0	0	1	13	20	22
Roseburg	30	19		15	8	2	0	0	0	1	13	20	23
Roseburg	31	20		15		1		0	0		14		22

APPENDIX 2.5: 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	Carbon Legistlation	Carbon Legistlation	Exported LNG
Customer Growth Rate																
Residential WA/ID			40% Decrease in Cust Growth Rates	60% Increase in Cust Growth Rates												
Residential Medford																
Residential Roseburg																
Residential Klamath																
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	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	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	No	No
Prices																
Price curve	Expected	Expected	Expected	Expected	Expected	Expected	Expected	Expected	Expected	Expected	Low	High	Low	Medium	High	Expected
Price curve adder ($/Dth)	None	None	None	None	None	None	None	None	None							$.50 Adder After 5yrs
Elasticity	None	None	None	None	None	None	None	None	None	Expected	Expected	Expected	Expected	Expected	Expected	Expected
Carbon Adder ($/Ton)	None	None	None	None	None	None	None	None	None				$5 starting in 2021	$8.32-$14.83 starting in 2021	$16-$28 starting in 2021	
RESULTS																
FIRST YEAR UNSERVED																
WA/ID	N/A	N/A	N/A	2029	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		N/A		N/A
Medford	N/A	N/A	N/A	2029	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		N/A		N/A
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	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
La Grande	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

APPENDIX 2.5: 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)	$8.32-$14.83	None	$8.32-$14.83	$8.32-$14.83	$8.32-$14.83
RESULTS					
First Gas Year Unserved					
WA/ID	N/A	2029	N/A	N/A	N/A
Medford	N/A	2029	N/A	N/A	N/A
Roseburg	N/A	N/A	N/A	N/A	N/A
Klamath	N/A	N/A	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 2.6: 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 LOW CASE – 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 2033.

CARBON LEGISLATION MEDIUM CASE –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 $8.32/ton in 2021 to $14.83/ton by 2033. This is the expected carbon adder utilized in our carbon case sensitivities.

CARBON LEGISLATION HIGH CASE – 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 $16/ton in 2021 to $28/ton by 2033.

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 Medium Case** 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 Medium Case** 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 Medium Case** 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 2.7: ANNUAL DEMAND, AVERAGE DAY DEMAND AND PEAK DAY DEMAND (NET OF DSM – CASE AVERAGE

Scenario	Gas Year	Annual Demand Klam Falls (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 Case	2013-2014	1,257.66	3.45	6.27	720.60	1.97	3.29	6,207.32	17.01	33.85
Average Case	2014-2015	1,261.98	3.46	6.27	723.27	1.98	3.31	6,252.06	17.13	34.12
Average Case	2015-2016	1,272.99	3.49	6.29	729.63	2.00	3.32	6,328.05	17.34	34.38
Average Case	2016-2017	1,265.52	3.47	6.28	725.57	1.99	3.31	6,315.96	17.30	34.40
Average Case	2017-2018	1,272.48	3.49	6.31	729.40	2.00	3.33	6,368.55	17.45	34.69
Average Case	2018-2019	1,280.28	3.51	6.34	731.59	2.00	3.35	6,427.02	17.61	34.99
Average Case	2019-2020	1,294.56	3.55	6.38	737.44	2.02	3.36	6,515.10	17.85	35.32
Average Case	2020-2021	1,294.13	3.55	6.41	735.69	2.02	3.36	6,536.37	17.91	35.57
Average Case	2021-2022	1,290.82	3.54	6.38	732.27	2.01	3.34	6,544.39	17.93	35.53
Average Case	2022-2023	1,298.09	3.56	6.41	734.46	2.01	3.35	6,601.11	18.09	35.84
Average Case	2023-2024	1,312.52	3.60	6.46	740.33	2.03	3.37	6,691.81	18.33	36.18
Average Case	2024-2025	1,307.44	3.58	6.45	736.13	2.02	3.36	6,692.29	18.34	36.29
Average Case	2025-2026	1,308.20	3.58	6.45	734.86	2.01	3.35	6,719.70	18.41	36.38
Average Case	2026-2027	1,313.43	3.60	6.47	735.96	2.02	3.35	6,768.76	18.54	36.63
Average Case	2027-2028	1,328.10	3.64	6.52	741.84	2.03	3.37	6,861.81	18.80	36.98
Average Case	2028-2029	1,330.67	3.65	6.56	741.76	2.03	3.38	6,899.62	18.90	37.34
Average Case	2029-2030	1,328.02	3.64	6.53	738.69	2.02	3.36	6,911.87	18.94	37.33
Average Case	2030-2031	1,336.73	3.66	6.58	741.63	2.03	3.37	6,978.53	19.12	37.69
Average Case	2031-2032	1,347.05	3.69	6.59	745.11	2.04	3.37	7,052.70	19.32	37.91
Average Case	2032-2033	1,347.00	3.69	6.62	743.57	2.04	3.38	7,078.88	19.39	38.19

Scenario	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 Case	2013-2014	8,185.58	22.43	43.41	25,157.85	68.93	114.99	33,343.42	91.35	158.40
Average Case	2014-2015	8,237.30	22.57	43.70	25,396.41	69.58	116.16	33,633.72	92.15	159.86
Average Case	2015-2016	8,330.67	22.82	44.00	25,762.27	70.58	117.29	34,092.94	93.41	161.29
Average Case	2016-2017	8,307.06	22.76	43.99	25,744.70	70.53	117.61	34,051.75	93.29	161.61
Average Case	2017-2018	8,370.42	22.93	44.33	26,025.73	71.30	118.92	34,396.15	94.24	163.25
Average Case	2018-2019	8,438.90	23.12	44.67	26,286.70	72.02	120.08	34,725.60	95.14	164.76
Average Case	2019-2020	8,547.10	23.42	45.07	26,660.40	73.04	121.26	35,207.49	96.46	166.33
Average Case	2020-2021	8,566.19	23.47	45.34	26,738.05	73.25	122.11	35,304.24	96.72	167.45
Average Case	2021-2022	8,567.49	23.47	45.26	26,752.36	73.29	122.00	35,319.85	96.77	167.26
Average Case	2022-2023	8,633.66	23.65	45.60	26,986.60	73.94	123.06	35,620.26	97.59	168.66
Average Case	2023-2024	8,744.67	23.96	46.01	27,370.34	74.99	124.26	36,115.01	98.95	170.27
Average Case	2024-2025	8,735.86	23.93	46.10	27,352.57	74.94	124.62	36,088.43	98.87	170.71
Average Case	2025-2026	8,762.76	24.01	46.18	27,453.85	75.22	124.96	36,216.61	99.22	171.14
Average Case	2026-2027	8,818.15	24.16	46.45	27,650.79	75.76	125.81	36,468.94	99.91	172.26
Average Case	2027-2028	8,931.74	24.47	46.86	28,044.14	76.83	127.04	36,975.89	101.30	173.91
Average Case	2028-2029	8,972.05	24.58	47.28	28,192.71	77.24	128.29	37,164.76	101.82	175.57
Average Case	2029-2030	8,978.58	24.60	47.22	28,223.36	77.32	128.25	37,201.94	101.92	175.47
Average Case	2030-2031	9,056.89	24.81	47.64	28,498.85	78.08	129.50	37,555.74	102.89	177.15
Average Case	2031-2032	9,144.86	25.05	47.88	28,804.79	78.92	130.25	37,949.65	103.97	178.13
Average Case	2032-2033	9,169.44	25.12	48.19	28,900.19	79.18	131.22	38,069.63	104.30	179.41

APPENDIX 2.7: ANNUAL DEMAND, AVERAGE DAY DEMAND AND PEAK DAY DEMAND (NET OF DSM) – CASE HIGH

Scenario	Gas Year	Annual Demand Klam Falls (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 Growth & Low Prices	2013-2014	1,299.14	3.56	11.49	746.65	2.05	7.40	6,478.36	17.75	70.03
High Growth & Low Prices	2014-2015	1,310.90	3.59	11.54	750.58	2.06	7.45	6,566.28	17.99	70.69
High Growth & Low Prices	2015-2016	1,329.72	3.64	11.65	757.88	2.08	7.49	6,688.55	18.32	71.72
High Growth & Low Prices	2016-2017	1,337.90	3.67	11.77	759.49	2.08	7.54	6,758.43	18.52	72.77
High Growth & Low Prices	2017-2018	1,351.30	3.70	11.89	763.87	2.09	7.58	6,857.04	18.79	73.84
High Growth & Low Prices	2018-2019	1,364.54	3.74	12.01	768.46	2.11	7.63	6,956.69	19.06	74.92
High Growth & Low Prices	2019-2020	1,385.22	3.80	12.13	776.06	2.13	7.68	7,086.78	19.42	76.02
High Growth & Low Prices	2020-2021	1,392.83	3.82	12.25	777.54	2.13	7.72	7,161.25	19.62	77.14
High Growth & Low Prices	2021-2022	1,406.48	3.85	12.37	782.23	2.14	7.77	7,266.36	19.91	78.28
High Growth & Low Prices	2022-2023	1,421.38	3.89	12.50	786.84	2.16	7.81	7,372.42	20.20	79.44
High Growth & Low Prices	2023-2024	1,442.01	3.95	12.63	794.53	2.18	7.86	7,510.78	20.58	80.60
High Growth & Low Prices	2024-2025	1,449.61	3.97	12.75	796.17	2.18	7.91	7,590.23	20.80	81.79
High Growth & Low Prices	2025-2026	1,465.00	4.01	12.88	800.92	2.19	7.96	7,701.96	21.10	83.00
High Growth & Low Prices	2026-2027	1,479.57	4.05	13.01	805.62	2.21	8.00	7,815.11	21.41	84.24
High Growth & Low Prices	2027-2028	1,500.79	4.11	13.14	813.51	2.23	8.05	7,962.11	21.81	85.48
High Growth & Low Prices	2028-2029	1,509.86	4.14	13.27	815.15	2.23	8.10	8,046.90	22.05	86.75
High Growth & Low Prices	2029-2030	1,524.87	4.18	13.40	819.98	2.25	8.15	8,165.97	22.37	88.03
High Growth & Low Prices	2030-2031	1,539.79	4.22	13.54	824.86	2.26	8.20	8,286.24	22.70	89.35
High Growth & Low Prices	2031-2032	1,562.89	4.28	13.67	833.02	2.28	8.25	8,442.87	23.13	90.67
High Growth & Low Prices	2032-2033	1,571.39	4.31	13.81	834.67	2.29	8.30	8,533.22	23.38	92.03

Scenario	Gas Year	Annual Demand Klam Falls (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 Growth & Low Prices	2013-2014	8,524.15	23.35	88.92	26,163.75	71.68	273.78	34,687.90	95.04	362.70
High Growth & Low Prices	2014-2015	8,627.75	23.64	89.68	26,533.25	72.69	277.88	35,161.01	96.33	367.55
High Growth & Low Prices	2015-2016	8,776.16	24.04	90.86	27,046.80	74.10	282.04	35,822.96	98.15	372.90
High Growth & Low Prices	2016-2017	8,855.81	24.26	92.08	27,332.78	74.88	286.26	36,188.59	99.15	378.34
High Growth & Low Prices	2017-2018	8,972.21	24.58	93.31	27,741.43	76.00	290.55	36,713.64	100.59	383.86
High Growth & Low Prices	2018-2019	9,089.69	24.90	94.56	28,156.12	77.14	294.90	37,245.82	102.04	389.46
High Growth & Low Prices	2019-2020	9,248.07	25.34	95.83	28,700.50	78.63	299.31	37,948.57	103.97	395.13
High Growth & Low Prices	2020-2021	9,331.63	25.57	97.12	29,003.73	79.46	303.79	38,335.36	105.03	400.91
High Growth & Low Prices	2021-2022	9,455.07	25.90	98.42	29,437.06	80.65	308.33	38,892.13	106.55	406.75
High Growth & Low Prices	2022-2023	9,580.64	26.25	99.75	29,876.72	81.85	312.95	39,457.36	108.10	412.69
High Growth & Low Prices	2023-2024	9,747.32	26.70	101.09	30,454.12	83.44	317.63	40,201.45	110.14	418.71
High Growth & Low Prices	2024-2025	9,836.00	26.95	102.45	30,775.67	84.32	322.38	40,611.68	111.26	424.84
High Growth & Low Prices	2025-2026	9,967.89	27.31	103.83	31,235.11	85.58	327.20	41,203.00	112.88	431.04
High Growth & Low Prices	2026-2027	10,100.30	27.67	105.25	31,701.38	86.85	332.10	41,801.68	114.53	437.35
High Growth & Low Prices	2027-2028	10,276.42	28.15	106.67	32,313.76	88.53	337.07	42,590.18	116.69	443.73
High Growth & Low Prices	2028-2029	10,371.91	28.42	108.12	32,654.55	89.46	342.11	43,026.46	117.88	450.23
High Growth & Low Prices	2029-2030	10,510.83	28.80	109.59	33,141.79	90.80	347.22	43,652.62	119.60	456.81
High Growth & Low Prices	2030-2031	10,650.89	29.18	111.08	33,636.27	92.15	352.42	44,287.16	121.33	463.50
High Growth & Low Prices	2031-2032	10,838.78	29.70	112.59	34,285.78	93.93	357.69	45,124.57	123.63	470.28
High Growth & Low Prices	2032-2033	10,939.29	29.97	114.13	34,647.06	94.92	363.03	45,586.34	124.89	477.17

APPENDIX 2.7: ANNUAL DEMAND, AVERAGE DAY DEMAND AND PEAK DAY DEMAND (NET OF DSM) – CASE LOW

Scenario	Gas Year	Annual Demand Klam Falls (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 Growth & High Prices	2013-2014	1,279.53	3.51	11.45	733.03	2.01	7.34	6,357.51	17.42	69.82
Low Growth & High Prices	2014-2015	1,261.30	3.46	11.23	722.02	1.98	7.19	6,284.24	17.22	68.58
Low Growth & High Prices	2015-2016	1,260.82	3.45	11.15	720.46	1.97	7.13	6,291.26	17.24	68.20
Low Growth & High Prices	2016-2017	1,253.20	3.43	11.13	716.29	1.96	7.11	6,272.07	17.18	68.16
Low Growth & High Prices	2017-2018	1,252.46	3.43	11.11	715.22	1.96	7.09	6,279.85	17.21	68.16
Low Growth & High Prices	2018-2019	1,250.05	3.42	11.07	713.10	1.95	7.06	6,279.14	17.20	68.03
Low Growth & High Prices	2019-2020	1,255.22	3.44	11.07	715.40	1.96	7.05	6,317.30	17.31	68.11
Low Growth & High Prices	2020-2021	1,251.02	3.43	11.07	712.53	1.95	7.04	6,310.55	17.29	68.26
Low Growth & High Prices	2021-2022	1,250.34	3.43	11.05	711.33	1.95	7.02	6,317.39	17.31	68.24
Low Growth & High Prices	2022-2023	1,246.58	3.42	11.01	709.02	1.94	6.99	6,315.35	17.30	68.08
Low Growth & High Prices	2023-2024	1,255.95	3.44	11.04	713.27	1.95	7.00	6,369.69	17.45	68.41
Low Growth & High Prices	2024-2025	1,248.44	3.42	11.01	708.62	1.94	6.97	6,346.22	17.39	68.30
Low Growth & High Prices	2025-2026	1,246.11	3.41	10.98	707.04	1.94	6.95	6,350.36	17.40	68.25
Low Growth & High Prices	2026-2027	1,246.22	3.41	10.97	706.35	1.94	6.93	6,363.01	17.43	68.30
Low Growth & High Prices	2027-2028	1,253.71	3.43	10.98	709.27	1.94	6.93	6,407.67	17.56	68.48
Low Growth & High Prices	2028-2029	1,248.76	3.42	10.99	706.60	1.94	6.93	6,400.89	17.54	68.63
Low Growth & High Prices	2029-2030	1,246.03	3.41	10.94	704.47	1.93	6.89	6,399.78	17.53	68.49
Low Growth & High Prices	2030-2031	1,245.70	3.41	10.93	703.48	1.93	6.88	6,409.12	17.56	68.49
Low Growth & High Prices	2031-2032	1,249.84	3.42	10.91	705.19	1.93	6.86	6,443.20	17.65	68.50
Low Growth & High Prices	2032-2033	1,248.09	3.42	10.94	703.88	1.93	6.87	6,448.10	17.67	68.82

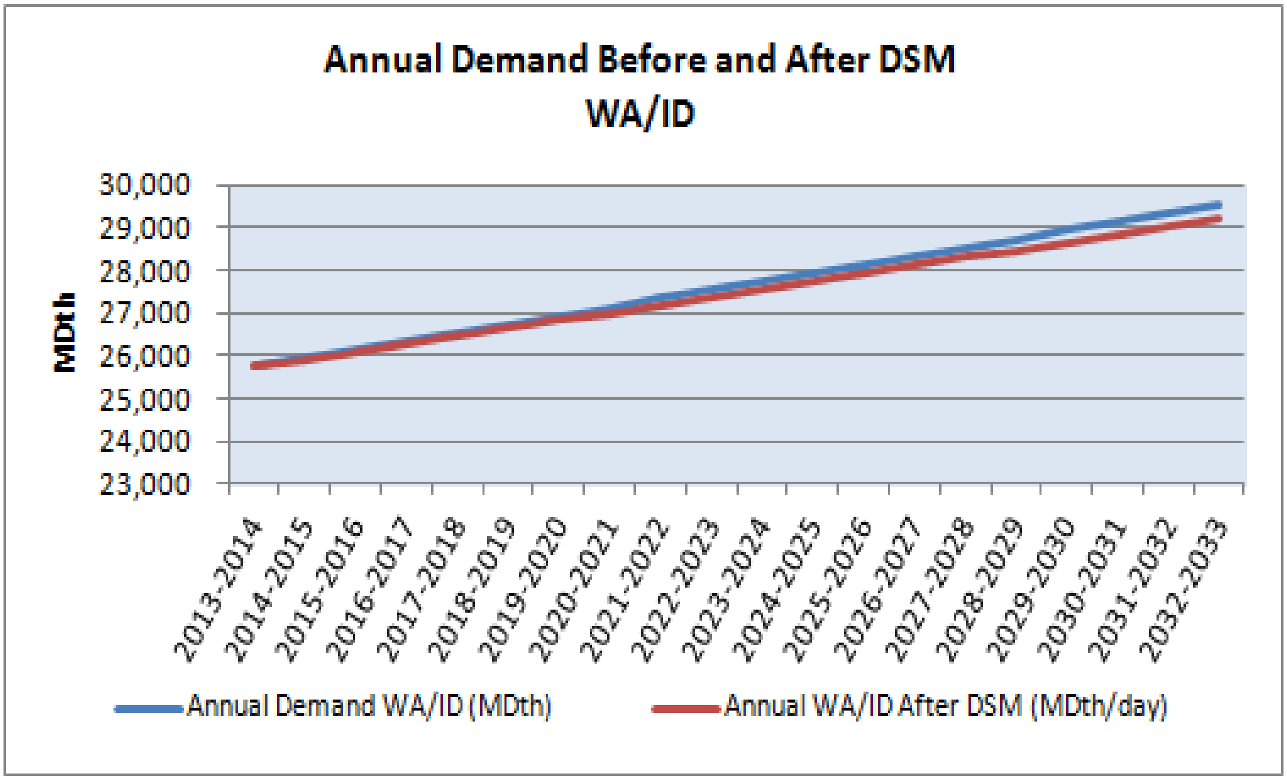
Scenario	Gas Year	Annual Demand Klam Falls (MDth)	Daily Demand Klamath (MDth/day)	Peak Day Klamath (MDth/day)	Annual Demand La Grande (MDth)	Daily Demand La Grande (MDth/day)	Peak Day La Grande (MDth/day)	Annual Demand Medford/Roseburg (MDth)	Daily Demand Medford/Roseburg (MDth/day)	Peak Day Medford/Roseburg (MDth/day)
Low Growth & High Prices	2013-2014	8,370.06	22.93	88.62	25,726.26	70.48	270.35	34,096.32	93.41	358.97
Low Growth & High Prices	2014-2015	8,267.56	22.65	87.01	25,388.96	69.56	265.49	33,656.52	92.21	352.50
Low Growth & High Prices	2015-2016	8,272.54	22.66	86.48	25,407.96	69.61	263.95	33,680.50	92.28	350.43
Low Growth & High Prices	2016-2017	8,241.57	22.58	86.40	25,312.42	69.35	263.82	33,553.98	91.93	350.22
Low Growth & High Prices	2017-2018	8,247.53	22.60	86.36	25,336.53	69.42	263.83	33,584.07	92.01	350.19
Low Growth & High Prices	2018-2019	8,242.29	22.58	86.16	25,321.10	69.37	263.29	33,563.39	91.95	349.45
Low Growth & High Prices	2019-2020	8,287.92	22.71	86.22	25,477.26	69.80	263.60	33,765.18	92.51	349.83
Low Growth & High Prices	2020-2021	8,274.10	22.67	86.37	25,435.94	69.69	264.20	33,710.04	92.36	350.57
Low Growth & High Prices	2021-2022	8,279.07	22.68	86.32	25,456.30	69.74	264.14	33,735.37	92.43	350.46
Low Growth & High Prices	2022-2023	8,270.95	22.66	86.08	25,433.76	69.68	263.51	33,704.70	92.34	349.59
Low Growth & High Prices	2023-2024	8,338.91	22.85	86.45	25,662.18	70.31	264.78	34,001.08	93.15	351.23
Low Growth & High Prices	2024-2025	8,303.29	22.75	86.28	25,546.84	69.99	264.37	33,850.12	92.74	350.65
Low Growth & High Prices	2025-2026	8,303.52	22.75	86.18	25,554.41	70.01	264.14	33,857.92	92.76	350.31
Low Growth & High Prices	2026-2027	8,315.59	22.78	86.21	25,596.74	70.13	264.37	33,912.33	92.91	350.57
Low Growth & High Prices	2027-2028	8,370.66	22.93	86.39	25,781.25	70.63	265.03	34,151.91	93.57	351.42
Low Growth & High Prices	2028-2029	8,356.25	22.89	86.54	25,739.84	70.52	265.62	34,096.09	93.41	352.16
Low Growth & High Prices	2029-2030	8,350.28	22.88	86.32	25,723.42	70.48	265.05	34,073.70	93.35	351.38
Low Growth & High Prices	2030-2031	8,358.30	22.90	86.30	25,751.57	70.55	265.09	34,109.87	93.45	351.39
Low Growth & High Prices	2031-2032	8,398.23	23.01	86.27	25,888.48	70.93	265.10	34,286.71	93.94	351.37
Low Growth & High Prices	2032-2033	8,400.07	23.01	86.64	25,898.70	70.96	266.38	34,298.77	93.97	353.01

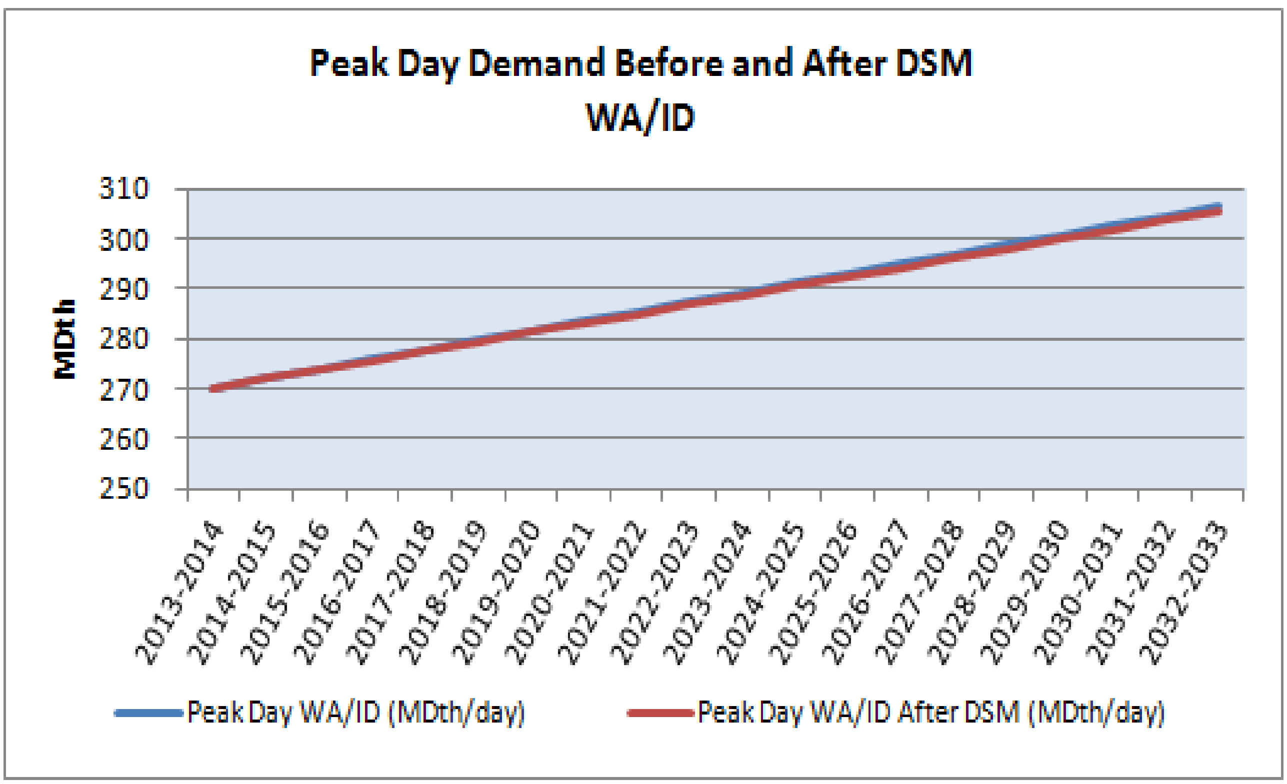
APPENDIX 2.7: ANNUAL DEMAND, AVERAGE DAY DEMAND AND PEAK DAY DEMAND (NET OF DSM) – CASE COLDEST IN 20

Scenario	Gas Year	Annual Demand Klam Falls (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)
Cold Day 20Yr Weather Std	2013-2014	1,290.24	3.53	11.49	746.36	2.04	7.39	6,424.46	17.60	62.53
Cold Day 20Yr Weather Std	2014-2015	1,294.65	3.55	11.50	749.13	2.05	7.42	6,470.83	17.73	63.04
Cold Day 20Yr Weather Std	2015-2016	1,305.81	3.58	11.54	755.61	2.07	7.46	6,548.62	17.94	63.52
Cold Day 20Yr Weather Std	2016-2017	1,298.20	3.56	11.50	751.44	2.06	7.43	6,536.32	17.91	63.50
Cold Day 20Yr Weather Std	2017-2018	1,305.33	3.58	11.56	755.41	2.07	7.47	6,590.81	18.06	64.04
Cold Day 20Yr Weather Std	2018-2019	1,313.33	3.60	11.62	757.67	2.08	7.50	6,651.33	18.22	64.58
Cold Day 20Yr Weather Std	2019-2020	1,327.82	3.64	11.70	763.63	2.09	7.53	6,741.61	18.47	65.20
Cold Day 20Yr Weather Std	2020-2021	1,327.50	3.64	11.74	761.88	2.09	7.54	6,764.35	18.53	65.64
Cold Day 20Yr Weather Std	2021-2022	1,323.98	3.63	11.68	758.24	2.08	7.48	6,771.62	18.55	65.50
Cold Day 20Yr Weather Std	2022-2023	1,331.43	3.65	11.74	760.49	2.08	7.50	6,830.26	18.71	66.05
Cold Day 20Yr Weather Std	2023-2024	1,346.08	3.69	11.82	766.47	2.10	7.53	6,923.21	18.97	66.69
Cold Day 20Yr Weather Std	2024-2025	1,340.93	3.67	11.80	762.15	2.09	7.50	6,924.00	18.97	66.83
Cold Day 20Yr Weather Std	2025-2026	1,341.62	3.68	11.79	760.76	2.08	7.48	6,951.68	19.05	66.95
Cold Day 20Yr Weather Std	2026-2027	1,346.95	3.69	11.83	761.87	2.09	7.48	7,002.18	19.18	67.38
Cold Day 20Yr Weather Std	2027-2028	1,361.84	3.73	11.91	767.86	2.10	7.51	7,097.53	19.45	68.04
Cold Day 20Yr Weather Std	2028-2029	1,364.63	3.74	11.98	767.88	2.10	7.54	7,137.67	19.56	68.70
Cold Day 20Yr Weather Std	2029-2030	1,361.78	3.73	11.93	764.59	2.09	7.49	7,149.31	19.59	68.61
Cold Day 20Yr Weather Std	2030-2031	1,370.71	3.76	12.01	767.64	2.10	7.52	7,218.33	19.78	69.27
Cold Day 20Yr Weather Std	2031-2032	1,381.09	3.78	12.03	771.09	2.11	7.51	7,293.67	19.98	69.64
Cold Day 20Yr Weather Std	2032-2033	1,381.16	3.78	12.08	769.58	2.11	7.52	7,321.52	20.06	70.14

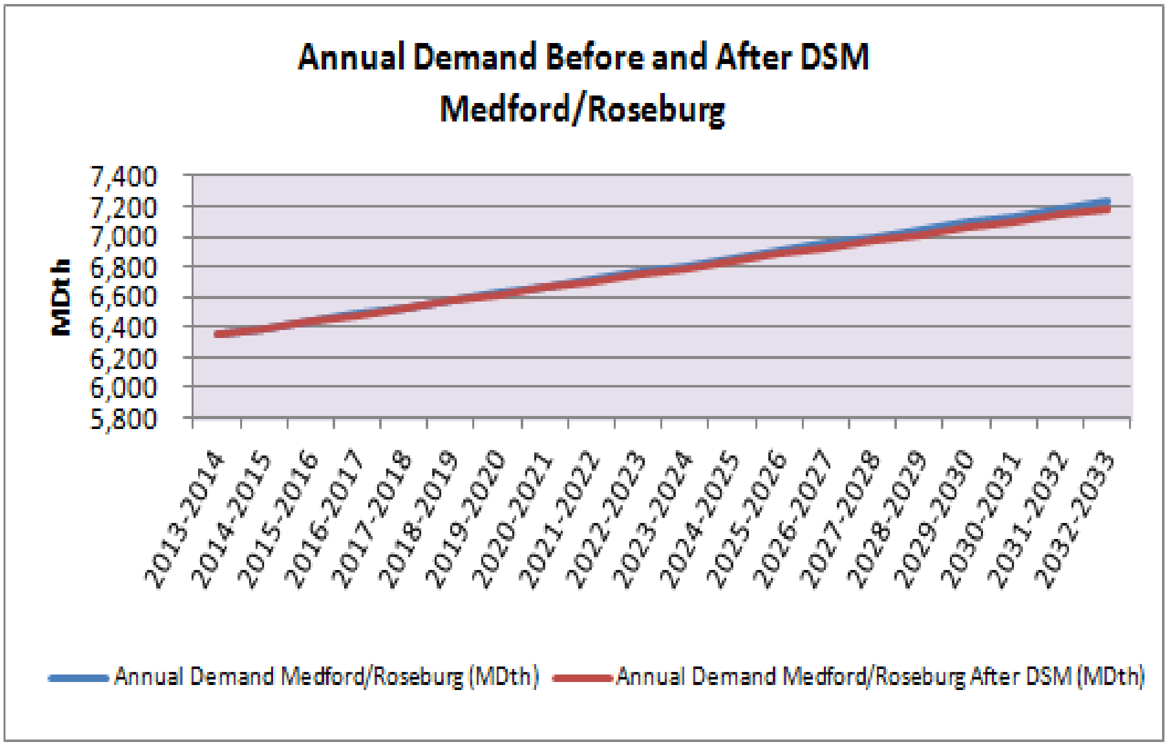
Scenario	Gas Year	Annual Demand Klam Falls (MDth)	Daily Demand Klamath (MDth/day)	Peak Day Klamath (MDth/day)	Annual Demand La Grande (MDth)	Daily Demand La Grande (MDth/day)	Peak Day La Grande (MDth/day)	Annual Demand Medford/Roseburg (MDth)	Daily Demand Medford/Roseburg (MDth/day)	Peak Day Medford/Roseburg (MDth/day)
Cold Day 20Yr Weather Std	2013-2014	8,461.06	23.18	81.41	25,905.48	70.97	252.45	34,366.54	94.15	333.86
Cold Day 20Yr Weather Std	2014-2015	8,514.61	23.33	81.96	26,151.29	71.65	255.04	34,665.90	94.98	337.00
Cold Day 20Yr Weather Std	2015-2016	8,610.04	23.59	82.51	26,524.74	72.67	257.54	35,134.78	96.26	340.05
Cold Day 20Yr Weather Std	2016-2017	8,585.96	23.52	82.44	26,507.99	72.62	258.05	35,093.95	96.15	340.48
Cold Day 20Yr Weather Std	2017-2018	8,651.54	23.70	83.07	26,797.62	73.42	260.93	35,449.16	97.12	344.00
Cold Day 20Yr Weather Std	2018-2019	8,722.34	23.90	83.70	27,066.53	74.15	263.50	35,788.87	98.05	347.21
Cold Day 20Yr Weather Std	2019-2020	8,833.06	24.20	84.44	27,447.93	75.20	266.10	36,281.00	99.40	350.53
Cold Day 20Yr Weather Std	2020-2021	8,853.73	24.26	84.92	27,530.74	75.43	267.90	36,384.47	99.68	352.81
Cold Day 20Yr Weather Std	2021-2022	8,853.85	24.26	84.66	27,542.53	75.46	267.32	36,396.38	99.72	351.98
Cold Day 20Yr Weather Std	2022-2023	8,922.18	24.44	85.29	27,783.48	76.12	269.61	36,705.65	100.56	354.91
Cold Day 20Yr Weather Std	2023-2024	9,035.76	24.76	86.04	28,175.10	77.19	272.27	37,210.86	101.95	358.31
Cold Day 20Yr Weather Std	2024-2025	9,027.08	24.73	86.14	28,158.46	77.15	272.83	37,185.54	101.88	358.97
Cold Day 20Yr Weather Std	2025-2026	9,054.06	24.81	86.22	28,260.75	77.43	273.36	37,314.82	102.23	359.58
Cold Day 20Yr Weather Std	2026-2027	9,111.01	24.96	86.69	28,462.70	77.98	275.13	37,573.71	102.94	361.82
Cold Day 20Yr Weather Std	2027-2028	9,227.22	25.28	87.46	28,864.09	79.08	277.85	38,091.31	104.36	365.30
Cold Day 20Yr Weather Std	2028-2029	9,270.18	25.40	88.22	29,020.77	79.51	280.58	38,290.95	104.91	368.81
Cold Day 20Yr Weather Std	2029-2030	9,275.68	25.41	88.02	29,049.33	79.59	280.16	38,325.02	105.00	368.18
Cold Day 20Yr Weather Std	2030-2031	9,356.68	25.63	88.80	29,332.99	80.36	282.92	38,689.67	106.00	371.72
Cold Day 20Yr Weather Std	2031-2032	9,445.85	25.88	89.18	29,643.02	81.21	284.42	39,088.87	107.09	373.60
Cold Day 20Yr Weather Std	2032-2033	9,472.27	25.95	89.74	29,744.29	81.49	286.47	39,216.55	107.44	376.21

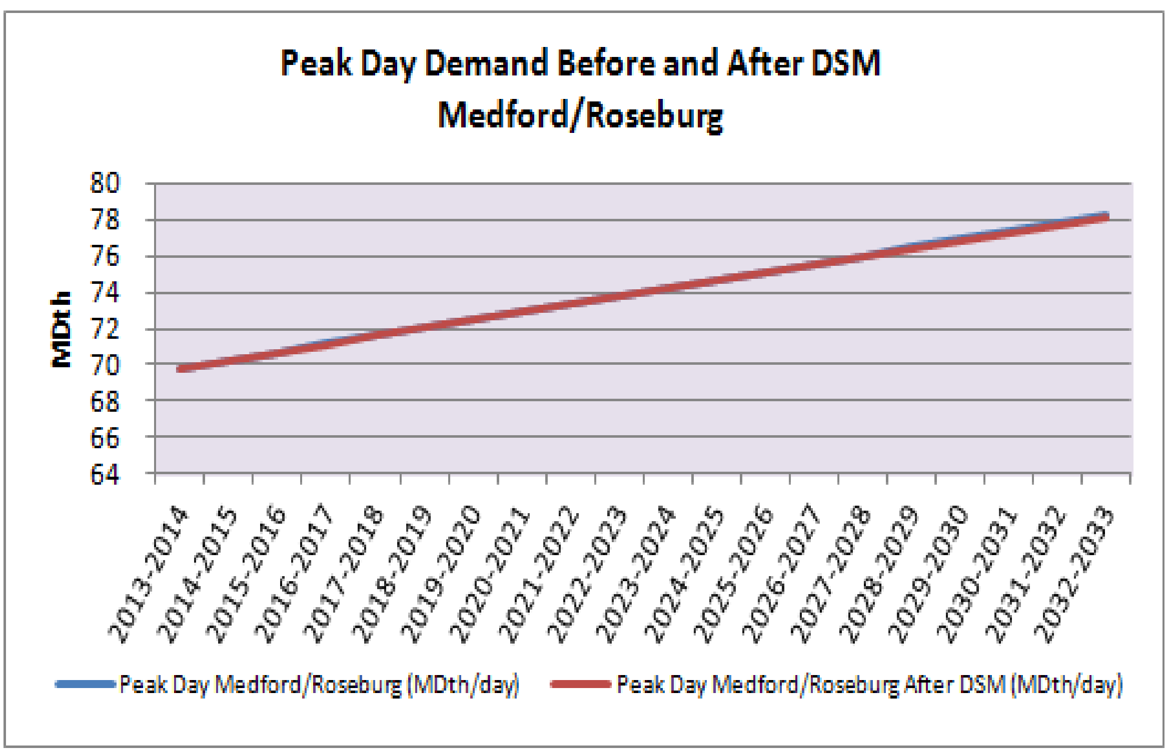
APPENDIX 2.8: PEAK DAY DEMAND BEFORE AND AFTER DSM WA/ID



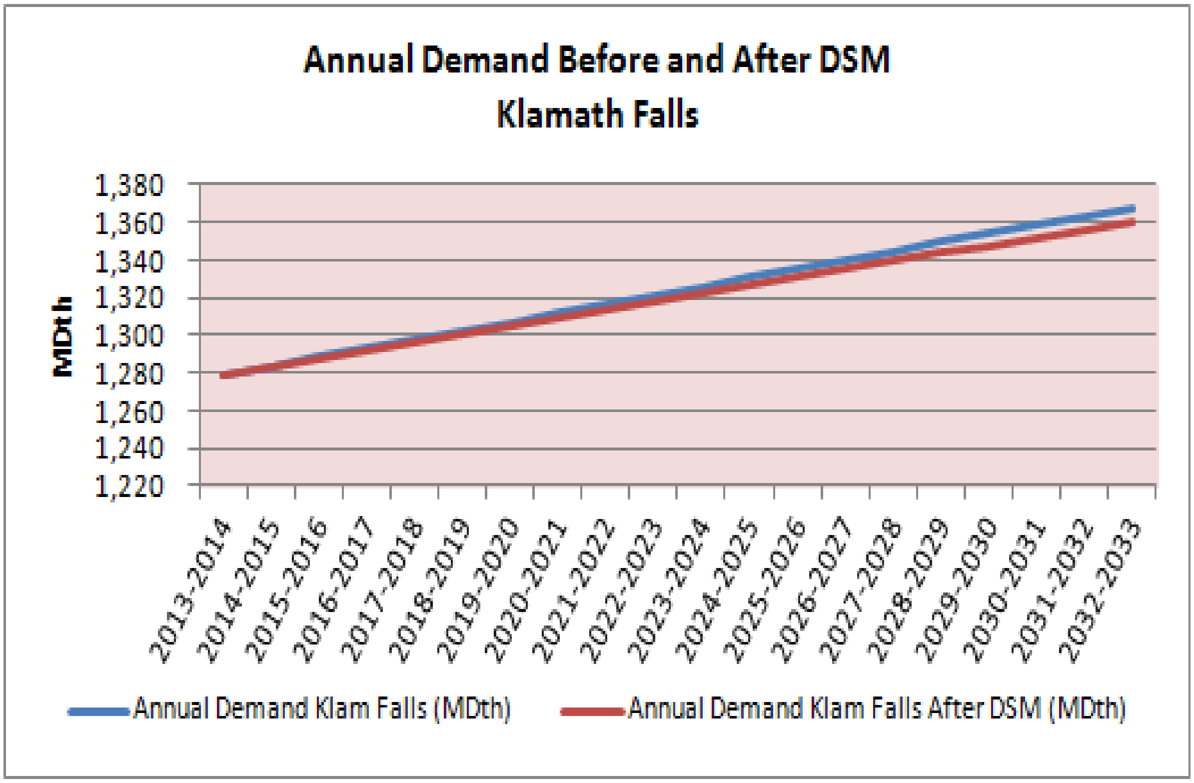


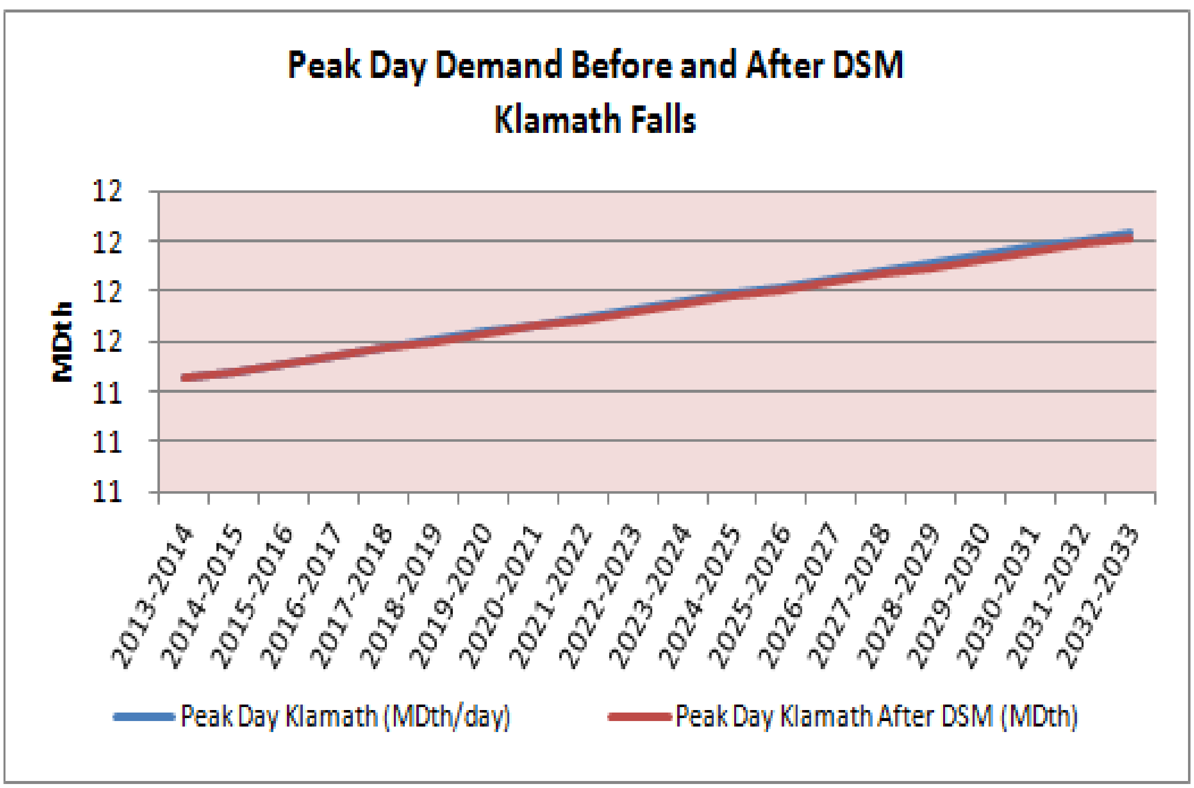
APPENDIX 2.8: PEAK DAY DEMAND BEFORE AND AFTER DSM MEDFORD/ROSEBURG



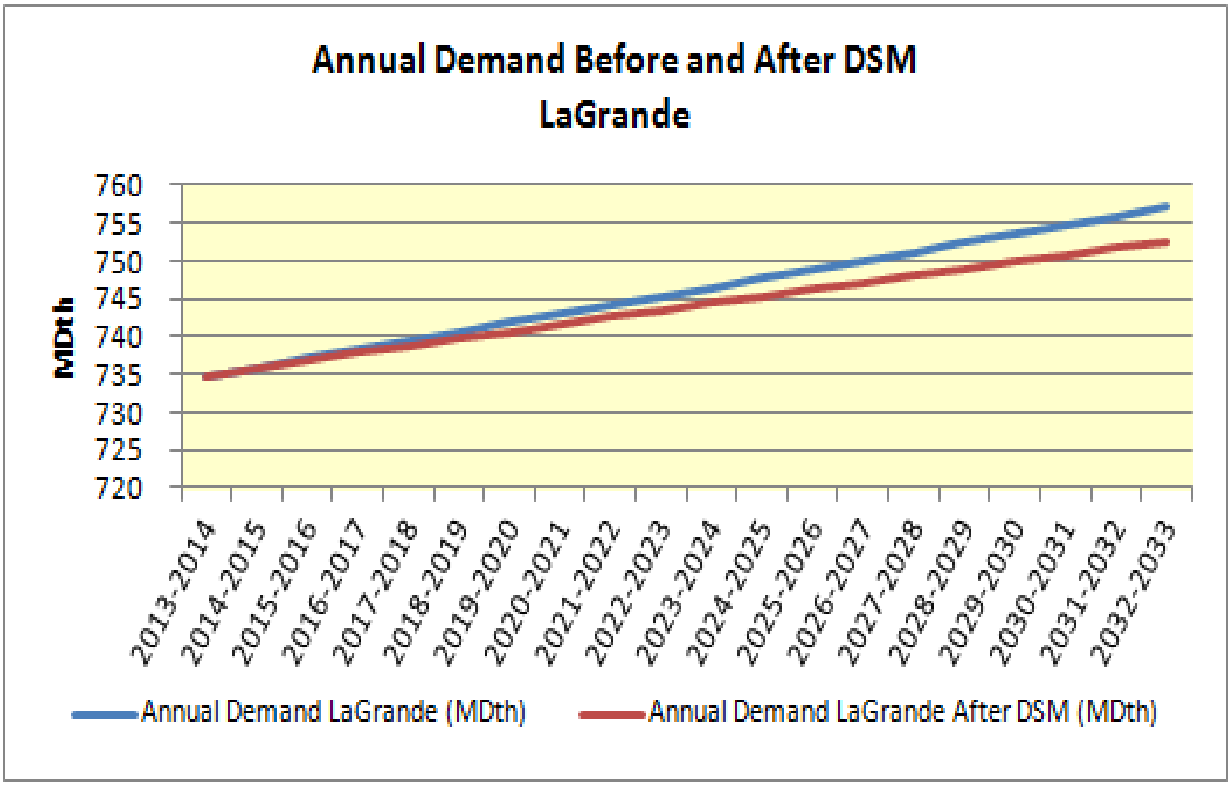


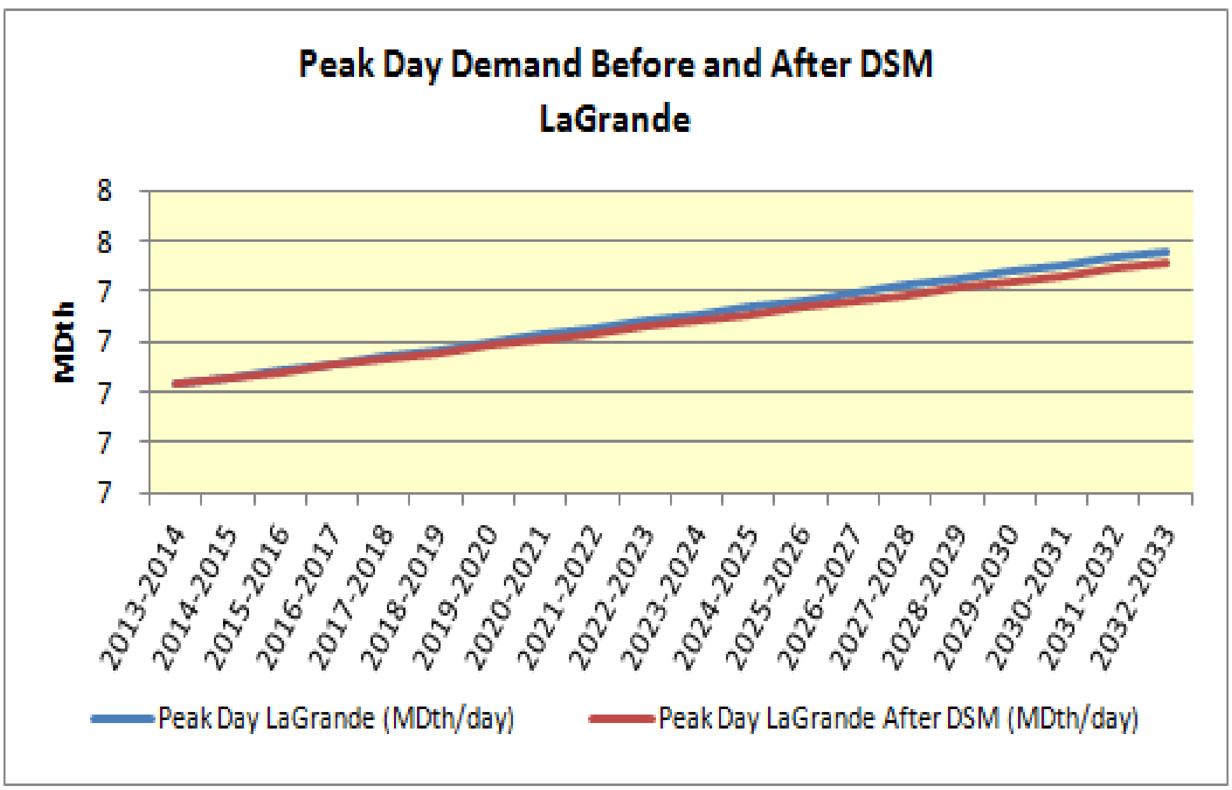
APPENDIX 2.8: PEAK DAY DEMAND BEFORE AND AFTER DSM KLAMATH FALLS





APPENDIX 2.8: PEAK DAY DEMAND BEFORE AND AFTER DSM LA GRANDE





APPENDIX 2.9: DETAILED DEMAND DATA EXPECTED MIX

Area	2014: Residential	2014: Commercial	2014: Ind FirmSale	2014 Total	2015: Residential	2015: Commercial	2015: Ind FirmSale	2015 Total	2016: Residential	2016: Commercial	2016: Ind FirmSale	2016 Total
Klam Falls	830.12	437.90	10.79	1,278.81	833.01	439.37	10.79	1,283.17	840.67	442.76	10.82	1,294.25
La Grande	454.22	271.28	9.24	734.73	456.50	271.72	9.24	737.46	460.91	273.71	9.24	743.86
Medford GTN	2,128.03	1,292.49	11.40	3,431.92	2,148.66	1,299.90	11.40	3,459.97	2,178.41	1,315.57	11.43	3,505.41
Medford NWP	956.07	580.68	5.12	1,541.88	965.34	584.02	5.12	1,554.48	978.71	591.05	5.14	1,574.90
Roseburg	745.28	607.72	20.14	1,373.14	749.33	608.89	20.14	1,378.36	757.46	611.76	20.19	1,389.41
OR Sub-Total	**5,113.72**	**3,190.07**	**56.69**	**8,360.47**	**5,152.85**	**3,203.91**	**56.69**	**8,413.44**	**5,216.16**	**3,234.86**	**56.81**	**8,507.84**
Wa/Id Both	9,182.14	5,449.74	294.60	14,926.47	9,279.41	5,495.35	293.40	15,068.15	9,425.86	5,564.72	292.88	15,283.46
Wa/Id GTN	1,266.50	751.69	40.63	2,058.82	1,279.92	757.98	40.47	2,078.37	1,300.12	767.55	40.40	2,108.06
Wa/Id NWP	5,382.63	3,194.67	172.69	8,750.00	5,439.65	3,221.41	171.99	8,833.06	5,525.50	3,262.08	171.69	8,959.27
WA/ID Sub-Total	**15,831.27**	**9,396.10**	**507.93**	**25,735.30**	**15,998.98**	**9,474.74**	**505.86**	**25,979.58**	**16,251.48**	**9,594.35**	**504.97**	**26,350.79**
Case Total	**20,944.99**	**12,586.17**	**564.61**	**34,095.77**	**21,151.82**	**12,678.64**	**562.54**	**34,393.01**	**21,467.64**	**12,829.21**	**561.78**	**34,858.63**

Area	2017: Residential	2017: Commercial	2017: Ind FirmSale	2017 Total	2018: Residential	2018: Commercial	2018: Ind FirmSale	2018 Total	2019: Residential	2019: Commercial	2019: Ind FirmSale	2019 Total
Klam Falls	835.65	440.18	10.77	1,286.60	841.00	441.91	10.77	1,293.68	846.55	444.29	10.77	1,301.61
La Grande	458.69	271.82	9.16	739.67	461.61	272.81	9.16	743.58	463.01	273.64	9.16	745.81
Medford GTN	2,176.38	1,313.83	11.38	3,501.58	2,198.14	1,324.65	11.38	3,534.16	2,221.64	1,338.17	11.38	3,571.18
Medford NWP	977.79	590.27	5.11	1,573.17	987.57	595.13	5.11	1,587.81	998.13	601.21	5.11	1,604.44
Roseburg	755.19	606.95	20.11	1,382.25	761.25	607.50	20.11	1,388.87	767.17	607.65	20.11	1,394.94
OR Sub-Total	**5,203.70**	**3,223.05**	**56.53**	**8,483.28**	**5,249.57**	**3,242.00**	**56.53**	**8,548.10**	**5,296.49**	**3,264.97**	**56.53**	**8,617.99**
Wa/Id Both	9,433.69	5,549.89	289.17	15,272.75	9,551.88	5,600.55	287.30	15,439.74	9,654.37	5,654.36	286.02	15,594.74
Wa/Id GTN	1,301.20	765.50	39.89	2,106.59	1,317.50	772.49	39.63	2,129.62	1,331.64	779.91	39.45	2,151.00
Wa/Id NWP	5,530.10	3,253.38	169.51	8,952.99	5,599.38	3,283.08	168.42	9,050.88	5,659.46	3,314.62	167.67	9,141.75
WA/ID Sub-Total	**16,264.99**	**9,568.77**	**498.57**	**26,332.33**	**16,468.77**	**9,656.12**	**495.35**	**26,620.23**	**16,645.46**	**9,748.89**	**493.14**	**26,887.49**
Case Total	**21,468.69**	**12,791.83**	**555.10**	**34,815.61**	**21,718.33**	**12,898.12**	**551.88**	**35,168.33**	**21,941.95**	**13,013.86**	**549.67**	**35,505.47**

Area	2020: Residential	2020: Commercial	2020: Ind FirmSale	2020 Total	2021: Residential	2021: Commercial	2021: Ind FirmSale	2021 Total	2022: Residential	2022: Commercial	2022: Ind FirmSale	2022 Total
Klam Falls	856.04	449.14	10.80	1,315.99	855.60	449.27	10.76	1,315.62	852.78	448.49	10.73	1,312.00
La Grande	466.73	275.80	9.16	751.69	465.63	275.18	9.13	749.94	463.21	274.02	9.03	746.25
Medford GTN	2,255.30	1,357.98	11.40	3,624.69	2,265.30	1,365.05	11.37	3,641.71	2,268.63	1,369.37	11.33	3,649.33
Medford NWP	1,013.25	610.11	5.12	1,628.48	1,017.74	613.28	5.11	1,636.13	1,019.24	615.23	5.09	1,639.56
Roseburg	776.30	610.20	20.17	1,406.67	777.17	606.90	20.11	1,404.18	776.49	603.08	20.08	1,399.64
OR Sub-Total	**5,367.63**	**3,303.24**	**56.66**	**8,727.52**	**5,381.43**	**3,309.68**	**56.47**	**8,747.59**	**5,380.34**	**3,310.18**	**56.26**	**8,746.78**
Wa/Id Both	9,793.59	5,735.32	285.67	15,814.59	9,823.86	5,754.92	283.12	15,861.91	9,825.54	5,761.06	280.56	15,867.16
Wa/Id GTN	1,350.84	791.08	39.40	2,181.32	1,355.02	793.78	39.05	2,187.85	1,355.25	794.63	38.70	2,188.57
Wa/Id NWP	5,741.07	3,362.08	167.46	9,270.62	5,758.82	3,373.58	165.97	9,298.36	5,759.80	3,377.17	164.47	9,301.44
WA/ID Sub-Total	**16,885.51**	**9,888.48**	**492.54**	**27,266.53**	**16,937.70**	**9,922.28**	**488.14**	**27,348.12**	**16,940.58**	**9,932.86**	**483.73**	**27,357.17**
Case Total	**22,253.14**	**13,191.72**	**549.19**	**35,994.05**	**22,319.13**	**13,231.96**	**544.61**	**36,095.70**	**22,320.93**	**13,243.04**	**539.98**	**36,103.95**

Area	2023: Residential	2023: Commercial	2023: Ind FirmSale	2023 Total	2024: Residential	2024: Commercial	2024: Ind FirmSale	2024 Total	2025: Residential	2025: Commercial	2025: Ind FirmSale	2025 Total
Klam Falls	857.52	451.12	10.73	1,319.36	867.12	456.02	10.76	1,333.89	863.34	454.64	10.71	1,328.69
La Grande	464.60	274.85	9.02	748.46	468.32	277.03	9.02	754.37	465.54	275.54	8.95	750.03
Medford GTN	2,291.28	1,383.30	11.33	3,685.90	2,325.98	1,403.82	11.36	3,741.16	2,327.68	1,406.85	11.30	3,745.84
Medford NWP	1,029.41	621.48	5.09	1,655.98	1,045.01	630.70	5.10	1,680.81	1,045.77	632.07	5.08	1,682.91
Roseburg	781.68	602.73	20.07	1,404.48	790.99	605.20	20.13	1,416.32	789.28	600.42	20.05	1,409.75
OR Sub-Total	**5,424.49**	**3,333.47**	**56.23**	**8,814.19**	**5,497.41**	**3,372.77**	**56.36**	**8,926.54**	**5,491.61**	**3,369.52**	**56.09**	**8,917.22**
Wa/Id Both	9,913.51	5,813.19	279.15	16,005.85	10,056.41	5,896.36	278.79	16,231.56	10,049.06	5,896.07	275.79	16,220.92
Wa/Id GTN	1,367.38	801.82	38.50	2,207.70	1,387.09	813.29	38.45	2,238.84	1,386.08	813.25	38.04	2,237.37
Wa/Id NWP	5,811.37	3,407.73	163.64	9,382.74	5,895.14	3,456.49	163.43	9,515.05	5,890.83	3,456.32	161.67	9,508.82
WA/ID Sub-Total	**17,092.26**	**10,022.74**	**481.30**	**27,596.29**	**17,338.64**	**10,166.14**	**480.67**	**27,985.45**	**17,325.97**	**10,165.64**	**475.50**	**27,967.11**
Case Total	**22,516.75**	**13,356.21**	**537.53**	**36,410.49**	**22,836.05**	**13,538.91**	**537.03**	**36,911.99**	**22,817.58**	**13,535.16**	**531.60**	**36,884.33**

APPENDIX 2.9: DETAILED DEMAND DATA EXPECTED MIX

Area	2026: Residential	2026: Commercial	2026: Ind FirmSale	2026 Total	2027: Residential	2027: Commercial	2027: Ind FirmSale	2027 Total	2028: Residential	2028: Commercial	2028: Ind FirmSale	2028 Total
Klam Falls	863.43	455.17	10.69	1,329.28	866.74	457.10	10.68	1,334.53	876.44	462.14	10.71	1,349.29
La Grande	464.57	275.15	8.88	748.60	465.24	275.57	8.85	749.67	468.96	277.76	8.85	755.57
Medford GTN	2,338.71	1,415.10	11.28	3,765.10	2,358.21	1,427.66	11.27	3,797.14	2,393.93	1,448.77	11.30	3,854.00
Medford NWP	1,050.72	635.77	5.07	1,691.56	1,059.48	641.41	5.06	1,705.96	1,075.53	650.90	5.08	1,731.51
Roseburg	790.87	597.82	20.03	1,408.71	795.01	596.92	20.02	1,411.95	804.45	599.27	20.08	1,423.81
OR Sub-Total	**5,508.30**	**3,379.01**	**55.95**	**8,943.26**	**5,544.68**	**3,398.66**	**55.89**	**8,999.24**	**5,619.31**	**3,438.85**	**56.02**	**9,114.18**
Wa/Id Both	10,084.65	5,920.45	273.71	16,278.81	10,157.79	5,964.84	272.10	16,394.73	10,304.11	6,050.20	271.72	16,626.03
Wa/Id GTN	1,390.99	816.61	37.75	2,245.35	1,401.07	822.74	37.53	2,261.34	1,421.26	834.51	37.48	2,293.25
Wa/Id NWP	5,911.69	3,470.61	160.45	9,542.75	5,954.56	3,496.63	159.51	9,610.70	6,040.34	3,546.67	159.28	9,746.29
WA/ID Sub-Total	**17,387.33**	**10,207.68**	**471.92**	**28,066.92**	**17,513.42**	**10,284.21**	**469.14**	**28,266.77**	**17,765.71**	**10,431.37**	**468.48**	**28,665.57**
Case Total	**22,895.63**	**13,586.68**	**527.87**	**37,010.18**	**23,058.11**	**13,682.87**	**525.03**	**37,266.01**	**23,385.03**	**13,870.22**	**524.51**	**37,779.75**

Area	2029: Residential	2029: Commercial	2029: Ind FirmSale	2029 Total	2030: Residential	2030: Commercial	2030: Ind FirmSale	2030 Total	2031: Residential	2031: Commercial	2031: Ind FirmSale	2031 Total
Klam Falls	878.21	463.15	10.68	1,352.05	875.84	462.60	10.66	1,349.09	881.62	465.67	10.66	1,357.94
La Grande	468.97	277.76	8.85	755.59	466.78	276.72	8.75	752.25	468.65	277.84	8.75	755.25
Medford GTN	2,410.38	1,459.25	11.27	3,880.90	2,415.26	1,464.60	11.24	3,891.09	2,441.83	1,480.71	11.24	3,933.78
Medford NWP	1,082.92	655.60	5.06	1,743.59	1,085.12	658.01	5.05	1,748.17	1,097.05	665.25	5.05	1,767.35
Roseburg	807.13	597.20	20.02	1,424.36	806.83	593.56	20.00	1,420.39	812.96	593.71	20.00	1,426.67
OR Sub-Total	**5,647.62**	**3,452.96**	**55.89**	**9,156.48**	**5,649.82**	**3,455.48**	**55.69**	**9,160.99**	**5,702.11**	**3,483.19**	**55.69**	**9,240.99**
Wa/Id Both	10,361.96	6,084.76	269.57	16,716.29	10,369.58	6,094.42	267.17	16,731.17	10,473.26	6,155.43	265.91	16,894.60
Wa/Id GTN	1,429.24	839.28	37.18	2,305.69	1,430.29	840.61	36.85	2,307.75	1,444.59	849.03	36.68	2,330.29
Wa/Id NWP	6,074.25	3,566.93	158.02	9,799.20	6,078.72	3,572.59	156.62	9,807.93	6,139.50	3,608.36	155.88	9,903.73
WA/ID Sub-Total	**17,865.45**	**10,490.97**	**464.77**	**28,821.18**	**17,878.58**	**10,507.63**	**460.64**	**28,846.85**	**18,057.35**	**10,612.81**	**458.46**	**29,128.62**
Case Total	**23,513.07**	**13,943.93**	**520.66**	**37,977.66**	**23,528.40**	**13,963.11**	**516.33**	**38,007.84**	**23,759.46**	**14,096.00**	**514.16**	**38,369.62**

Area	2032: Residential	2032: Commercial	2032: Ind FirmSale	2032 Total	2033: Residential	2033: Commercial	2033: Ind FirmSale	2033 Total
Klam Falls	888.17	469.34	10.68	1,368.19	888.05	469.52	10.64	1,368.21
La Grande	470.76	279.15	8.72	758.63	469.83	278.59	8.69	757.11
Medford GTN	2,469.97	1,498.24	11.25	3,979.47	2,481.83	1,506.57	11.22	3,999.61
Medford NWP	1,109.70	673.12	5.06	1,787.88	1,115.02	676.86	5.04	1,796.93
Roseburg	820.02	594.62	20.04	1,434.68	821.22	591.51	19.98	1,432.71
OR Sub-Total	**5,758.62**	**3,514.48**	**55.74**	**9,328.84**	**5,775.95**	**3,523.05**	**55.57**	**9,354.57**
Wa/Id Both	10,585.02	6,222.52	265.07	17,072.60	10,621.78	6,246.07	262.69	17,130.54
Wa/Id GTN	1,460.00	858.28	36.56	2,354.84	1,465.07	861.53	36.23	2,362.83
Wa/Id NWP	6,205.01	3,647.68	155.38	10,008.08	6,226.56	3,661.49	153.99	10,042.04
WA/ID Sub-Total	**18,250.03**	**10,728.48**	**457.01**	**29,435.52**	**18,313.41**	**10,769.09**	**452.91**	**29,535.41**
Case Total	**24,008.65**	**14,242.96**	**512.75**	**38,764.36**	**24,089.36**	**14,292.14**	**508.48**	**38,889.98**

APPENDIX 2.9: DETAILED DEMAND DATA
LOW GROWTH HIGH PRICE

Area	2014: Residential	2014: Commercial	2014: Ind FirmSale	2014 Total	2015: Residential	2015: Commercial	2015: Ind FirmSale	2015 Total	2016: Residential	2016: Commercial	2016: Ind FirmSale	2016 Total
Klam Falls	830.06	438.68	10.79	1,279.53	817.28	433.29	10.73	1,261.30	816.62	433.46	10.74	1,260.82
La Grande	452.54	271.25	9.24	733.03	445.52	267.47	9.03	722.02	444.61	266.91	8.94	720.46
Medford GTN	2,130.77	1,296.84	11.40	3,439.01	2,104.13	1,284.85	11.33	3,400.31	2,106.85	1,288.01	10.79	3,405.64
Medford NWP	957.30	582.64	5.12	1,545.06	945.33	577.25	5.09	1,527.67	946.55	578.67	4.85	1,530.07
Roseburg	745.71	607.58	20.14	1,373.43	736.56	599.62	20.08	1,356.25	737.02	598.42	20.11	1,355.55
OR Sub-Total	**5,116.38**	**3,196.99**	**56.69**	**8,370.06**	**5,048.81**	**3,162.47**	**56.27**	**8,267.56**	**5,051.65**	**3,165.47**	**55.42**	**8,272.54**
Wa/Id Both	9,159.37	5,469.65	292.21	14,921.23	9,035.18	5,404.56	285.85	14,725.60	9,042.25	5,412.54	281.83	14,736.62
Wa/Id GTN	1,263.36	754.43	40.31	2,058.10	1,246.23	745.46	39.43	2,031.12	1,247.21	746.56	38.87	2,032.64
Wa/Id NWP	5,369.29	3,206.34	171.30	8,746.93	5,296.48	3,168.19	167.57	8,632.25	5,300.63	3,172.87	165.21	8,638.71
WA/ID Sub-Total	**15,792.02**	**9,430.42**	**503.82**	**25,726.26**	**15,577.90**	**9,318.21**	**492.85**	**25,388.96**	**15,590.08**	**9,331.97**	**485.91**	**25,407.96**
Case Total	**20,908.40**	**12,627.42**	**560.50**	**34,096.32**	**20,626.71**	**12,480.69**	**549.12**	**33,656.52**	**20,641.73**	**12,497.43**	**541.33**	**33,680.50**

Area	2017: Residential	2017: Commercial	2017: Ind FirmSale	2017 Total	2018: Residential	2018: Commercial	2018: Ind FirmSale	2018 Total	2019: Residential	2019: Commercial	2019: Ind FirmSale	2019 Total
Klam Falls	812.08	431.50	9.62	1,253.20	811.59	431.52	9.35	1,252.46	809.78	430.94	9.34	1,250.05
La Grande	441.94	265.45	8.90	716.29	441.20	265.16	8.86	715.22	439.81	264.49	8.80	713.10
Medford GTN	2,101.03	1,285.86	10.58	3,397.47	2,104.71	1,289.00	10.03	3,403.74	2,105.06	1,290.48	9.85	3,405.38
Medford NWP	943.94	577.70	4.75	1,526.40	945.59	579.11	4.51	1,529.21	945.75	579.78	4.42	1,529.95
Roseburg	733.95	594.21	20.04	1,348.20	734.29	592.58	20.03	1,346.90	733.61	590.18	20.01	1,343.80
OR Sub-Total	**5,032.95**	**3,154.72**	**53.89**	**8,241.57**	**5,037.40**	**3,157.37**	**52.76**	**8,247.53**	**5,034.01**	**3,155.87**	**52.41**	**8,242.29**
Wa/Id Both	9,009.27	5,395.39	276.54	14,681.20	9,019.48	5,403.46	272.25	14,695.19	9,014.95	5,403.52	267.77	14,686.24
Wa/Id GTN	1,242.66	744.19	38.14	2,024.99	1,244.07	745.31	37.55	2,026.92	1,243.44	745.31	36.93	2,025.69
Wa/Id NWP	5,281.30	3,162.82	162.11	8,606.22	5,287.28	3,167.55	159.59	8,614.42	5,284.62	3,167.58	156.97	8,609.17
WA/ID Sub-Total	**15,533.22**	**9,302.40**	**476.80**	**25,312.42**	**15,550.82**	**9,316.32**	**469.40**	**25,336.53**	**15,543.01**	**9,316.41**	**461.67**	**25,321.10**
Case Total	**20,566.17**	**12,457.12**	**530.69**	**33,553.98**	**20,588.22**	**12,473.69**	**522.16**	**33,584.07**	**20,577.02**	**12,472.28**	**514.09**	**33,563.39**

Area	2020: Residential	2020: Commercial	2020: Ind FirmSale	2020 Total	2021: Residential	2021: Commercial	2021: Ind FirmSale	2021 Total	2022: Residential	2022: Commercial	2022: Ind FirmSale	2022 Total
Klam Falls	813.75	433.19	8.28	1,255.22	811.05	431.97	7.99	1,251.02	810.43	431.93	7.98	1,250.34
La Grande	441.23	265.40	8.77	715.40	439.49	264.29	8.75	712.53	438.73	263.90	8.70	711.33
Medford GTN	2,119.35	1,299.51	9.32	3,428.18	2,118.06	1,299.63	9.13	3,426.82	2,121.43	1,302.63	8.58	3,432.64
Medford NWP	952.17	583.84	4.19	1,540.20	951.59	583.89	4.10	1,539.58	953.11	585.24	3.85	1,542.20
Roseburg	737.67	591.20	20.05	1,348.92	736.02	588.13	19.99	1,344.15	736.27	586.29	19.98	1,342.55
OR Sub-Total	**5,064.16**	**3,173.14**	**50.61**	**8,287.92**	**5,056.22**	**3,167.92**	**49.96**	**8,274.10**	**5,059.97**	**3,170.00**	**49.10**	**8,279.07**
Wa/Id Both	9,073.06	5,439.26	264.49	14,776.81	9,060.16	5,433.10	259.59	14,752.85	9,068.94	5,440.38	255.34	14,764.65
Wa/Id GTN	1,251.46	750.24	36.48	2,038.18	1,249.68	749.39	35.81	2,034.88	1,250.89	750.40	35.22	2,036.50
Wa/Id NWP	5,318.69	3,188.53	155.04	8,662.27	5,311.13	3,184.92	152.17	8,648.22	5,316.27	3,189.19	149.68	8,655.14
WA/ID Sub-Total	**15,643.20**	**9,378.04**	**456.01**	**25,477.26**	**15,620.96**	**9,367.41**	**447.57**	**25,435.94**	**15,636.10**	**9,379.96**	**440.24**	**25,456.30**
Case Total	**20,707.36**	**12,551.19**	**506.63**	**33,765.18**	**20,677.18**	**12,535.33**	**497.53**	**33,710.04**	**20,696.07**	**12,549.96**	**489.34**	**33,735.37**

Area	2023: Residential	2023: Commercial	2023: Ind FirmSale	2023 Total	2024: Residential	2024: Commercial	2024: Ind FirmSale	2024 Total	2025: Residential	2025: Commercial	2025: Ind FirmSale	2025 Total
Klam Falls	808.37	431.31	6.90	1,246.58	814.71	434.58	6.66	1,255.95	809.55	432.26	6.63	1,248.44
La Grande	437.21	263.17	8.64	709.02	439.83	264.79	8.64	713.27	436.86	263.17	8.59	708.62
Medford GTN	2,121.19	1,303.86	8.40	3,433.45	2,141.60	1,315.93	7.88	3,465.42	2,134.06	1,312.96	7.69	3,454.71
Medford NWP	953.00	585.79	3.77	1,542.56	962.17	591.22	3.54	1,556.93	958.78	589.88	3.45	1,552.11
Roseburg	735.38	583.99	19.96	1,339.34	741.31	586.01	20.02	1,347.34	737.73	581.72	19.95	1,339.40
OR Sub-Total	**5,055.14**	**3,168.12**	**47.69**	**8,270.95**	**5,099.63**	**3,192.53**	**46.75**	**8,338.91**	**5,076.98**	**3,179.99**	**46.31**	**8,303.29**
Wa/Id Both	9,061.69	5,438.99	250.90	14,751.58	9,146.62	5,489.51	247.94	14,884.06	9,106.09	5,468.27	242.80	14,817.17
Wa/Id GTN	1,249.89	750.21	34.61	2,034.70	1,261.60	757.17	34.20	2,052.97	1,256.01	754.24	33.49	2,043.75
Wa/Id NWP	5,312.03	3,188.37	147.08	8,647.48	5,361.81	3,217.99	145.34	8,725.14	5,338.06	3,205.54	142.33	8,685.93
WA/ID Sub-Total	**15,623.61**	**9,377.56**	**432.58**	**25,433.76**	**15,770.04**	**9,464.66**	**427.48**	**25,662.18**	**15,700.16**	**9,428.05**	**418.62**	**25,546.84**
Case Total	**20,678.76**	**12,545.68**	**480.27**	**33,704.70**	**20,869.66**	**12,657.20**	**474.22**	**34,001.08**	**20,777.14**	**12,608.05**	**464.94**	**33,850.12**

APPENDIX 2.9: DETAILED DEMAND DATA LOW GROWTH HIGH PRICE

Area	2026: Residential	2026: Commercial	2026: Ind FirmSale	2026 Total	2027: Residential	2027: Commercial	2027: Ind FirmSale	2027 Total	2028: Residential	2028: Commercial	2028: Ind FirmSale	2028 Total
Klam Falls	808.49	432.06	5.56	1,246.11	808.59	432.34	5.30	1,246.22	813.41	434.99	5.31	1,253.71
La Grande	435.87	262.63	8.54	707.04	435.44	262.40	8.51	706.35	437.29	263.49	8.49	709.27
Medford GTN	2,136.35	1,315.47	7.14	3,458.96	2,141.59	1,319.51	6.97	3,468.07	2,158.33	1,329.75	6.45	3,494.53
Medford NWP	959.81	591.01	3.21	1,554.03	962.16	592.82	3.13	1,558.12	969.69	597.42	2.90	1,570.01
Roseburg	737.65	579.79	19.93	1,337.37	738.44	578.46	19.93	1,336.83	743.22	579.94	19.97	1,343.14
OR Sub-Total	**5,078.17**	**3,180.96**	**44.39**	**8,303.52**	**5,086.23**	**3,185.52**	**43.84**	**8,315.59**	**5,121.94**	**3,205.59**	**43.12**	**8,370.66**
Wa/Id Both	9,110.02	5,472.99	238.55	14,821.56	9,126.87	5,484.77	234.46	14,846.11	9,195.41	5,526.44	231.28	14,953.12
Wa/Id GTN	1,256.55	754.89	32.90	2,044.35	1,258.88	756.52	32.34	2,047.74	1,268.33	762.27	31.90	2,062.50
Wa/Id NWP	5,340.36	3,208.30	139.84	8,688.50	5,350.24	3,215.21	137.44	8,702.89	5,390.41	3,239.64	135.58	8,765.63
WA/ID Sub-Total	**15,706.94**	**9,436.18**	**411.29**	**25,554.41**	**15,735.99**	**9,456.50**	**404.25**	**25,596.74**	**15,854.15**	**9,528.35**	**398.75**	**25,781.25**
Case Total	**20,785.11**	**12,617.14**	**455.68**	**33,857.92**	**20,822.21**	**12,642.03**	**448.08**	**33,912.33**	**20,976.10**	**12,733.94**	**441.87**	**34,151.91**

Area	2029: Residential	2029: Commercial	2029: Ind FirmSale	2029 Total	2030: Residential	2030: Commercial	2030: Ind FirmSale	2030 Total	2031: Residential	2031: Commercial	2031: Ind FirmSale	2031 Total
Klam Falls	810.73	433.81	4.23	1,248.76	808.86	433.21	3.96	1,246.03	808.47	433.27	3.96	1,245.70
La Grande	435.58	262.55	8.47	706.60	434.18	261.87	8.41	704.47	433.53	261.58	8.38	703.48
Medford GTN	2,157.03	1,329.94	6.27	3,493.24	2,157.30	1,331.47	5.72	3,494.49	2,161.34	1,334.88	5.56	3,501.78
Medford NWP	969.10	597.51	2.82	1,569.42	969.22	598.20	2.57	1,569.99	971.04	599.73	2.50	1,573.26
Roseburg	741.57	576.75	19.91	1,338.23	740.86	574.54	19.90	1,335.30	741.28	572.91	19.89	1,334.08
OR Sub-Total	**5,114.01**	**3,200.55**	**41.70**	**8,356.25**	**5,110.43**	**3,199.29**	**40.57**	**8,350.28**	**5,115.65**	**3,202.37**	**40.27**	**8,358.30**
Wa/Id Both	9,182.38	5,520.16	226.57	14,929.11	9,177.27	5,520.04	222.27	14,919.58	9,188.77	5,528.96	218.18	14,935.91
Wa/Id GTN	1,266.53	761.40	31.25	2,059.19	1,265.83	761.38	30.66	2,057.87	1,267.42	762.62	30.09	2,060.13
Wa/Id NWP	5,382.77	3,235.96	132.82	8,751.54	5,379.78	3,235.88	130.30	8,745.96	5,386.52	3,241.12	127.90	8,755.53
WA/ID Sub-Total	**15,831.68**	**9,517.52**	**390.64**	**25,739.84**	**15,822.88**	**9,517.31**	**383.23**	**25,723.42**	**15,842.71**	**9,532.69**	**376.17**	**25,751.57**
Case Total	**20,945.69**	**12,718.06**	**432.33**	**34,096.09**	**20,933.31**	**12,716.60**	**423.80**	**34,073.70**	**20,958.36**	**12,735.07**	**416.44**	**34,109.87**

Area	2032: Residential	2032: Commercial	2032: Ind FirmSale	2032 Total	2033: Residential	2033: Commercial	2033: Ind FirmSale	2033 Total
Klam Falls	811.70	435.24	2.90	1,249.84	810.69	434.76	2.64	1,248.09
La Grande	434.54	262.31	8.34	705.19	433.71	261.83	8.34	703.88
Medford GTN	2,174.10	1,343.25	5.03	3,522.38	2,177.17	1,345.59	4.86	3,527.61
Medford NWP	976.77	603.49	2.26	1,582.52	978.15	604.54	2.18	1,584.87
Roseburg	744.81	573.56	19.93	1,338.30	744.49	571.25	19.88	1,335.62
OR Sub-Total	**5,141.92**	**3,217.86**	**38.46**	**8,398.23**	**5,144.21**	**3,217.97**	**37.89**	**8,400.07**
Wa/Id Both	9,239.55	5,560.98	214.78	15,015.32	9,245.69	5,565.19	210.37	15,021.24
Wa/Id GTN	1,274.42	767.03	29.63	2,071.08	1,275.27	767.61	29.02	2,071.90
Wa/Id NWP	5,416.29	3,259.89	125.91	8,802.08	5,419.89	3,262.35	123.32	8,805.56
WA/ID Sub-Total	**15,930.26**	**9,587.90**	**370.32**	**25,888.48**	**15,940.84**	**9,595.15**	**362.71**	**25,898.70**
Case Total	**21,072.18**	**12,805.76**	**408.77**	**34,286.71**	**21,085.05**	**12,813.12**	**400.59**	**34,298.77**

APPENDIX 2.9: DETAILED DEMAND DATA
HIGH GROWTH LOW PRICE

Area	2014: Residential	2014: Commercial	2014: Ind FirmSale	2014 Total	2015: Residential	2015: Commercial	2015: Ind FirmSale	2015 Total	2016: Residential	2016: Commercial	2016: Ind FirmSale	2016 Total
Klam Falls	841.21	446.80	11.13	1,299.14	848.83	450.94	11.13	1,310.90	861.14	457.42	11.16	1,329.72
La Grande	459.92	276.32	10.40	746.65	462.31	277.87	10.40	750.58	466.93	280.55	10.40	757.88
Medford GTN	2,167.72	1,325.88	12.31	3,505.91	2,201.35	1,346.64	12.48	3,560.47	2,246.92	1,374.02	13.07	3,634.01
Medford NWP	973.90	595.68	5.53	1,575.12	989.01	605.01	5.61	1,599.63	1,009.49	617.31	5.87	1,632.67
Roseburg	757.88	617.79	21.68	1,397.34	765.84	618.66	21.67	1,406.17	777.90	622.24	21.73	1,421.87
OR Sub-Total	**5,200.63**	**3,262.47**	**61.05**	**8,524.15**	**5,267.34**	**3,299.12**	**61.28**	**8,627.75**	**5,362.37**	**3,351.54**	**62.24**	**8,776.16**
Wa/Id Both	9,301.50	5,568.80	304.67	15,174.98	9,432.92	5,647.87	308.50	15,389.29	9,616.39	5,757.28	313.48	15,687.14
Wa/Id GTN	1,282.97	768.11	42.02	2,093.10	1,301.09	779.02	42.55	2,122.66	1,326.40	794.11	43.24	2,163.74
Wa/Id NWP	5,452.60	3,264.47	178.60	8,895.68	5,529.64	3,310.82	180.85	9,021.31	5,637.19	3,374.96	183.76	9,195.91
WA/ID Sub-Total	**16,037.07**	**9,601.38**	**525.30**	**26,163.75**	**16,263.65**	**9,737.70**	**531.90**	**26,533.25**	**16,579.98**	**9,926.34**	**540.48**	**27,046.80**
Case Total	**21,237.70**	**12,863.85**	**586.35**	**34,687.90**	**21,531.00**	**13,036.82**	**593.19**	**35,161.01**	**21,942.35**	**13,277.88**	**602.73**	**35,822.96**

Area	2017: Residential	2017: Commercial	2017: Ind FirmSale	2017 Total	2018: Residential	2018: Commercial	2018: Ind FirmSale	2018 Total	2019: Residential	2019: Commercial	2019: Ind FirmSale	2019 Total
Klam Falls	865.71	459.94	12.24	1,337.90	874.29	464.49	12.52	1,351.30	882.94	469.09	12.52	1,364.54
La Grande	467.87	281.21	10.40	759.49	470.67	282.80	10.40	763.87	473.49	284.57	10.40	768.46
Medford GTN	2,274.60	1,391.45	13.21	3,679.26	2,312.13	1,414.41	13.77	3,740.31	2,350.28	1,437.73	13.94	3,801.95
Medford NWP	1,021.92	625.14	5.93	1,653.00	1,038.78	635.46	6.19	1,680.43	1,055.92	645.94	6.26	1,708.12
Roseburg	783.41	621.09	21.67	1,426.18	792.34	622.28	21.67	1,436.30	801.36	623.58	21.67	1,446.61
OR Sub-Total	**5,413.51**	**3,378.84**	**63.46**	**8,855.81**	**5,488.22**	**3,419.43**	**64.56**	**8,972.21**	**5,563.98**	**3,460.91**	**64.80**	**9,089.69**
Wa/Id Both	9,718.02	5,818.59	316.40	15,853.01	9,863.80	5,905.88	320.35	16,090.03	10,011.75	5,994.51	324.29	16,330.55
Wa/Id GTN	1,340.42	802.56	43.64	2,186.62	1,360.52	814.60	44.19	2,219.31	1,380.93	826.83	44.73	2,252.49
Wa/Id NWP	5,696.77	3,410.90	185.48	9,293.14	5,782.23	3,462.07	187.79	9,432.09	5,868.96	3,514.02	190.10	9,573.08
WA/ID Sub-Total	**16,755.21**	**10,032.05**	**545.51**	**27,332.78**	**17,006.56**	**10,182.55**	**552.32**	**27,741.43**	**17,261.64**	**10,335.36**	**559.13**	**28,156.12**
Case Total	**22,168.72**	**13,410.89**	**608.98**	**36,188.59**	**22,494.77**	**13,601.98**	**616.88**	**36,713.64**	**22,825.62**	**13,796.26**	**623.93**	**37,245.82**

Area	2020: Residential	2020: Commercial	2020: Ind FirmSale	2020 Total	2021: Residential	2021: Commercial	2021: Ind FirmSale	2021 Total	2022: Residential	2022: Commercial	2022: Ind FirmSale	2022 Total
Klam Falls	895.76	475.79	13.67	1,385.22	900.50	478.42	13.91	1,392.83	909.43	483.14	13.91	1,406.48
La Grande	478.24	287.42	10.40	776.06	479.20	287.95	10.40	777.54	482.07	289.76	10.40	782.23
Medford GTN	2,398.92	1,466.99	14.54	3,880.46	2,428.47	1,485.57	14.68	3,928.72	2,468.54	1,510.11	15.24	3,993.90
Medford NWP	1,077.78	659.08	6.53	1,743.39	1,091.05	667.43	6.59	1,765.08	1,109.06	678.46	6.85	1,794.36
Roseburg	813.98	627.22	21.73	1,462.94	819.74	626.04	21.67	1,467.45	829.09	627.34	21.67	1,478.10
OR Sub-Total	**5,664.68**	**3,516.50**	**66.89**	**9,248.07**	**5,718.96**	**3,545.41**	**67.26**	**9,331.63**	**5,798.19**	**3,588.81**	**68.07**	**9,455.07**
Wa/Id Both	10,206.47	6,110.49	329.33	16,646.29	10,314.37	6,175.61	332.19	16,822.16	10,469.08	6,268.27	336.14	17,073.49
Wa/Id GTN	1,407.79	842.83	45.42	2,296.04	1,422.67	851.81	45.82	2,320.30	1,444.01	864.59	46.36	2,354.96
Wa/Id NWP	5,983.11	3,582.01	193.05	9,758.17	6,046.35	3,620.18	194.73	9,861.27	6,137.05	3,674.50	197.05	10,008.60
WA/ID Sub-Total	**17,597.37**	**10,535.32**	**567.80**	**28,700.50**	**17,783.39**	**10,647.60**	**572.74**	**29,003.73**	**18,050.14**	**10,807.36**	**579.55**	**29,437.06**
Case Total	**23,262.05**	**14,051.82**	**634.69**	**37,948.57**	**23,502.35**	**14,193.01**	**640.00**	**38,335.36**	**23,848.33**	**14,396.17**	**647.62**	**38,892.13**

Area	2023: Residential	2023: Commercial	2023: Ind FirmSale	2023 Total	2024: Residential	2024: Commercial	2024: Ind FirmSale	2024 Total	2025: Residential	2025: Commercial	2025: Ind FirmSale	2025 Total
Klam Falls	918.41	487.94	15.03	1,421.38	931.75	494.92	15.35	1,442.01	936.69	497.62	15.30	1,449.61
La Grande	484.96	291.47	10.40	786.84	489.82	294.31	10.40	794.53	490.80	294.96	10.40	796.17
Medford GTN	2,509.28	1,535.02	15.41	4,059.71	2,561.21	1,566.24	16.02	4,143.46	2,592.77	1,586.08	16.15	4,194.99
Medford NWP	1,127.36	689.65	6.92	1,823.93	1,150.69	703.67	7.20	1,861.56	1,164.87	712.59	7.25	1,884.71
Roseburg	838.54	628.58	21.67	1,488.78	851.74	632.29	21.73	1,505.76	857.76	631.10	21.67	1,510.52
OR Sub-Total	**5,878.55**	**3,632.65**	**69.44**	**9,580.64**	**5,985.20**	**3,691.43**	**70.69**	**9,747.32**	**6,042.88**	**3,722.35**	**70.78**	**9,836.00**
Wa/Id Both	10,626.10	6,362.31	340.09	17,328.50	10,832.78	6,485.44	345.17	17,663.39	10,947.29	6,554.62	347.98	17,849.89
Wa/Id GTN	1,465.67	877.56	46.91	2,390.14	1,494.18	894.54	47.61	2,436.33	1,509.97	904.09	48.00	2,462.05
Wa/Id NWP	6,229.10	3,729.63	199.36	10,158.08	6,350.25	3,801.81	202.34	10,354.40	6,417.37	3,842.36	203.99	10,463.73
WA/ID Sub-Total	**18,320.87**	**10,969.49**	**586.36**	**29,876.72**	**18,677.20**	**11,181.80**	**595.12**	**30,454.12**	**18,874.63**	**11,301.07**	**599.97**	**30,775.67**
Case Total	**24,199.42**	**14,602.14**	**655.79**	**39,457.36**	**24,662.41**	**14,873.23**	**665.81**	**40,201.45**	**24,917.51**	**15,023.42**	**670.75**	**40,611.68**

APPENDIX 2.9: DETAILED DEMAND DATA HIGH GROWTH LOW PRICE

Area	2026: Residential	2026: Commercial	2026: Ind FirmSale	2026 Total	2027: Residential	2027: Commercial	2027: Ind FirmSale	2027 Total	2028: Residential	2028: Commercial	2028: Ind FirmSale	2028 Total
Klam Falls	945.97	502.61	16.42	1,465.00	955.34	507.54	16.69	1,479.57	969.21	514.85	16.74	1,500.79
La Grande	493.74	296.78	10.40	800.92	496.70	298.51	10.40	805.62	501.68	301.43	10.40	813.51
Medford GTN	2,635.55	1,612.23	16.71	4,264.49	2,679.03	1,638.88	16.88	4,334.79	2,734.48	1,672.20	17.49	4,424.17
Medford NWP	1,184.09	724.34	7.51	1,915.93	1,203.62	736.31	7.58	1,947.51	1,228.53	751.28	7.86	1,987.67
Roseburg	867.54	632.33	21.67	1,521.55	877.45	633.69	21.67	1,532.81	891.24	637.29	21.73	1,550.27
OR Sub-Total	**6,126.89**	**3,768.29**	**72.71**	**9,967.89**	**6,212.15**	**3,814.92**	**73.23**	**10,100.30**	**6,325.14**	**3,877.06**	**74.22**	**10,276.42**
Wa/Id Both	11,111.50	6,652.93	351.93	18,116.37	11,278.17	6,752.75	355.88	18,386.80	11,497.51	6,883.46	361.01	18,741.98
Wa/Id GTN	1,532.62	917.65	48.54	2,498.81	1,555.61	931.41	49.09	2,536.11	1,585.86	949.44	49.79	2,585.10
Wa/Id NWP	6,513.64	3,900.00	206.30	10,619.94	6,611.34	3,958.51	208.62	10,778.47	6,739.92	4,035.13	211.63	10,986.68
WA/ID Sub-Total	**19,157.76**	**11,470.58**	**606.78**	**31,235.11**	**19,445.12**	**11,642.68**	**613.58**	**31,701.38**	**19,823.30**	**11,868.03**	**622.44**	**32,313.76**
Case Total	**25,284.65**	**15,238.86**	**679.49**	**41,203.00**	**25,657.27**	**15,457.60**	**686.81**	**41,801.68**	**26,148.44**	**15,745.08**	**696.66**	**42,590.18**

Area	2029: Residential	2029: Commercial	2029: Ind FirmSale	2029 Total	2030: Residential	2030: Commercial	2030: Ind FirmSale	2030 Total	2031: Residential	2031: Commercial	2031: Ind FirmSale	2031 Total
Klam Falls	974.35	517.70	17.81	1,509.86	983.99	522.80	18.08	1,524.87	993.73	527.97	18.08	1,539.79
La Grande	502.69	302.05	10.40	815.15	505.70	303.88	10.40	819.98	508.75	305.72	10.40	824.86
Medford GTN	2,768.17	1,693.35	17.61	4,479.14	2,813.84	1,721.33	18.18	4,553.35	2,860.27	1,749.72	18.35	4,628.34
Medford NWP	1,243.67	760.78	7.91	2,012.37	1,264.19	773.35	8.17	2,045.71	1,285.05	786.11	8.24	2,079.40
Roseburg	897.55	636.18	21.67	1,555.40	907.79	637.46	21.67	1,566.92	918.13	638.69	21.67	1,578.50
OR Sub-Total	**6,386.43**	**3,910.07**	**75.41**	**10,371.91**	**6,475.51**	**3,958.82**	**76.50**	**10,510.83**	**6,565.93**	**4,008.20**	**76.75**	**10,650.89**
Wa/Id Both	11,619.05	6,956.81	363.77	18,939.64	11,793.33	7,061.18	367.72	19,222.24	11,970.23	7,167.13	371.67	19,509.04
Wa/Id GTN	1,602.63	959.56	50.18	2,612.36	1,626.67	973.96	50.72	2,651.34	1,651.07	988.57	51.26	2,690.90
Wa/Id NWP	6,811.17	4,078.13	213.25	11,102.55	6,913.33	4,139.31	215.56	11,268.21	7,017.03	4,201.42	217.88	11,436.33
WA/ID Sub-Total	**20,032.85**	**11,994.50**	**627.20**	**32,654.55**	**20,333.33**	**12,174.45**	**634.00**	**33,141.79**	**20,638.33**	**12,357.13**	**640.81**	**33,636.27**
Case Total	**26,419.28**	**15,904.57**	**702.61**	**43,026.46**	**26,808.84**	**16,133.27**	**710.51**	**43,652.62**	**27,204.26**	**16,365.33**	**717.56**	**44,287.16**

Area	2032: Residential	2032: Commercial	2032: Ind FirmSale	2032 Total	2033: Residential	2033: Commercial	2033: Ind FirmSale	2033 Total
Klam Falls	1,008.16	535.48	19.25	1,562.89	1,013.50	538.42	19.48	1,571.39
La Grande	513.84	308.78	10.40	833.02	514.86	309.40	10.40	834.67
Medford GTN	2,919.48	1,785.35	18.96	4,723.78	2,955.44	1,807.93	19.08	4,782.45
Medford NWP	1,311.65	802.11	8.52	2,122.28	1,327.81	812.26	8.57	2,148.64
Roseburg	932.58	642.49	21.73	1,596.80	939.19	641.27	21.67	1,602.13
OR Sub-Total	**6,685.70**	**4,074.21**	**78.87**	**10,838.78**	**6,750.80**	**4,109.28**	**79.20**	**10,939.29**
Wa/Id Both	12,203.04	7,305.86	376.86	19,885.75	12,332.03	7,383.69	379.57	20,095.29
Wa/Id GTN	1,683.18	1,007.70	51.98	2,742.86	1,700.97	1,018.44	52.35	2,771.76
Wa/Id NWP	7,153.50	4,282.74	220.92	11,657.17	7,229.12	4,328.37	222.50	11,780.00
WA/ID Sub-Total	**21,039.72**	**12,596.31**	**649.75**	**34,285.78**	**21,262.13**	**12,730.51**	**654.43**	**34,647.06**
Case Total	**27,725.42**	**16,670.52**	**728.62**	**45,124.57**	**28,012.93**	**16,839.79**	**733.63**	**45,586.34**

APPENDIX 2.9: DETAILED DEMAND DATA AVERAGE MIX

Area	2014: Residential	2014: Commercial	2014: Ind FirmSale	2014 Total	2015: Residential	2015: Commercial	2015: Ind FirmSale	2015 Total	2016: Residential	2016: Commercial	2016: Ind FirmSale	2016 Total
Klam Falls	813.35	433.25	11.05	1,257.66	816.19	434.74	11.05	1,261.98	823.80	438.10	11.08	1,272.99
La Grande	443.90	266.30	10.40	720.60	446.13	266.74	10.40	723.27	450.50	268.73	10.40	729.63
Medford GTN	2,071.71	1,272.19	11.61	3,355.51	2,091.73	1,279.56	11.61	3,382.89	2,121.02	1,295.10	11.64	3,427.76
Medford NWP	930.77	571.56	5.21	1,507.55	939.76	574.87	5.21	1,519.85	952.92	581.86	5.23	1,540.01
Roseburg	724.44	598.21	21.61	1,344.26	728.37	599.34	21.61	1,349.32	736.40	602.22	21.67	1,360.29
OR Sub-Total	**4,984.18**	**3,141.51**	**59.88**	**8,185.58**	**5,022.18**	**3,155.25**	**59.88**	**8,237.30**	**5,084.64**	**3,186.01**	**60.02**	**8,330.67**
Wa/Id Both	8,953.25	5,341.51	296.79	14,591.55	9,048.11	5,386.23	295.58	14,729.92	9,192.20	5,454.85	295.07	14,942.12
Wa/Id GTN	1,234.93	736.76	40.94	2,012.63	1,248.02	742.93	40.77	2,031.71	1,267.89	752.39	40.70	2,060.98
Wa/Id NWP	5,248.46	3,131.23	173.98	8,553.67	5,304.06	3,157.44	173.27	8,634.78	5,388.53	3,197.67	172.97	8,759.17
WA/ID Sub-Total	**15,436.64**	**9,209.50**	**511.71**	**25,157.85**	**15,600.19**	**9,286.60**	**509.63**	**25,396.41**	**15,848.61**	**9,404.92**	**508.74**	**25,762.27**
Case Total	**20,420.83**	**12,351.01**	**571.58**	**33,343.42**	**20,622.37**	**12,441.84**	**569.50**	**33,633.72**	**20,933.26**	**12,590.93**	**568.75**	**34,092.94**

Area	2017: Residential	2017: Commercial	2017: Ind FirmSale	2017 Total	2018: Residential	2018: Commercial	2018: Ind FirmSale	2018 Total	2019: Residential	2019: Commercial	2019: Ind FirmSale	2019 Total
Klam Falls	818.89	435.60	11.03	1,265.52	824.15	437.30	11.03	1,272.48	829.58	439.67	11.03	1,280.28
La Grande	448.35	266.90	10.32	725.57	451.21	267.87	10.32	729.40	452.58	268.69	10.32	731.59
Medford GTN	2,119.09	1,293.52	11.58	3,424.19	2,140.28	1,304.17	11.58	3,456.03	2,163.19	1,317.54	11.58	3,492.31
Medford NWP	952.06	581.14	5.20	1,538.40	961.57	585.93	5.20	1,552.71	971.87	591.94	5.20	1,569.01
Roseburg	734.23	597.55	21.58	1,353.37	740.13	598.10	21.58	1,359.81	745.88	598.24	21.58	1,365.70
OR Sub-Total	**5,072.62**	**3,174.71**	**59.72**	**8,307.06**	**5,117.33**	**3,193.37**	**59.72**	**8,370.42**	**5,163.10**	**3,216.07**	**59.72**	**8,438.90**
Wa/Id Both	9,199.90	5,440.65	291.37	14,931.92	9,315.17	5,490.27	289.49	15,094.92	9,415.06	5,543.04	288.19	15,246.29
Wa/Id GTN	1,268.95	750.43	40.19	2,059.58	1,284.85	757.28	39.93	2,082.06	1,298.63	764.56	39.75	2,102.94
Wa/Id NWP	5,393.05	3,189.35	170.80	8,753.20	5,460.62	3,218.43	169.70	8,848.75	5,519.17	3,249.37	168.94	8,937.48
WA/ID Sub-Total	**15,861.90**	**9,380.43**	**502.37**	**25,744.70**	**16,060.64**	**9,465.98**	**499.12**	**26,025.73**	**16,232.86**	**9,556.96**	**496.89**	**26,286.70**
Case Total	**20,934.52**	**12,555.14**	**562.09**	**34,051.75**	**21,177.97**	**12,659.34**	**558.84**	**34,396.15**	**21,395.96**	**12,773.03**	**556.61**	**34,725.60**

Area	2020: Residential	2020: Commercial	2020: Ind FirmSale	2020 Total	2021: Residential	2021: Commercial	2021: Ind FirmSale	2021 Total	2022: Residential	2022: Commercial	2022: Ind FirmSale	2022 Total
Klam Falls	838.99	444.51	11.06	1,294.56	838.48	444.62	11.03	1,294.13	835.88	443.95	11.00	1,290.82
La Grande	456.27	270.84	10.33	737.44	455.17	270.22	10.30	735.69	452.93	269.16	10.19	732.27
Medford GTN	2,196.28	1,337.17	11.61	3,545.06	2,205.83	1,344.09	11.57	3,561.50	2,209.58	1,348.72	11.54	3,569.84
Medford NWP	986.73	600.76	5.22	1,592.71	991.03	603.87	5.20	1,600.09	992.71	605.95	5.18	1,603.84
Roseburg	754.87	600.81	21.64	1,377.33	755.66	597.55	21.58	1,374.78	755.20	593.97	21.55	1,370.71
OR Sub-Total	**5,233.14**	**3,254.09**	**59.86**	**8,547.10**	**5,246.17**	**3,260.35**	**59.67**	**8,566.19**	**5,246.29**	**3,261.74**	**59.46**	**8,567.49**
Wa/Id Both	9,552.12	5,623.06	287.85	15,463.03	9,580.83	5,641.95	285.29	15,508.07	9,584.34	5,649.26	282.77	15,516.37
Wa/Id GTN	1,317.53	775.59	39.70	2,132.83	1,321.49	778.20	39.35	2,139.04	1,321.98	779.21	39.00	2,140.19
Wa/Id NWP	5,599.52	3,296.28	168.74	9,064.53	5,616.35	3,307.35	167.24	9,090.94	5,618.40	3,311.63	165.76	9,095.80
WA/ID Sub-Total	**16,469.17**	**9,694.93**	**496.30**	**26,660.40**	**16,518.67**	**9,727.51**	**491.88**	**26,738.05**	**16,524.72**	**9,740.10**	**487.54**	**26,752.36**
Case Total	**21,702.31**	**12,949.02**	**556.16**	**35,207.49**	**21,764.84**	**12,987.85**	**551.55**	**35,304.24**	**21,771.01**	**13,001.84**	**547.00**	**35,319.85**

Area	2023: Residential	2023: Commercial	2023: Ind FirmSale	2023 Total	2024: Residential	2024: Commercial	2024: Ind FirmSale	2024 Total	2025: Residential	2025: Commercial	2025: Ind FirmSale	2025 Total
Klam Falls	840.54	446.56	10.99	1,298.09	850.05	451.45	11.03	1,312.52	846.35	450.11	10.98	1,307.44
La Grande	454.30	269.98	10.18	734.46	457.99	272.16	10.18	740.33	455.30	270.72	10.11	736.13
Medford GTN	2,231.69	1,362.48	11.54	3,605.70	2,265.81	1,382.83	11.56	3,660.20	2,267.48	1,385.93	11.51	3,664.92
Medford NWP	1,002.64	612.13	5.18	1,619.95	1,017.97	621.27	5.20	1,644.44	1,018.72	622.66	5.17	1,646.56
Roseburg	760.27	593.63	21.54	1,375.45	769.44	596.13	21.60	1,387.18	767.80	591.48	21.52	1,380.81
OR Sub-Total	**5,289.44**	**3,284.78**	**59.43**	**8,633.66**	**5,361.26**	**3,323.84**	**59.57**	**8,744.67**	**5,355.65**	**3,320.90**	**59.30**	**8,735.86**
Wa/Id Both	9,670.35	5,700.51	281.36	15,652.23	9,811.06	5,782.74	281.00	15,874.80	9,803.83	5,782.65	278.01	15,864.49
Wa/Id GTN	1,333.84	786.28	38.81	2,158.93	1,353.25	797.62	38.76	2,189.63	1,352.25	797.61	38.35	2,188.21
Wa/Id NWP	5,668.83	3,341.68	164.93	9,175.44	5,751.31	3,389.88	164.72	9,305.91	5,747.07	3,389.83	162.97	9,299.87
WA/ID Sub-Total	**16,673.02**	**9,828.47**	**485.10**	**26,986.60**	**16,915.62**	**9,970.24**	**484.48**	**27,370.34**	**16,903.16**	**9,970.09**	**479.33**	**27,352.57**
Case Total	**21,962.47**	**13,113.26**	**544.53**	**35,620.26**	**22,276.88**	**13,294.08**	**544.05**	**36,115.01**	**22,258.81**	**13,290.99**	**538.63**	**36,088.43**

APPENDIX 2.9: DETAILED DEMAND DATA AVERAGE MIX

Area	2026: Residential	2026: Commercial	2026: Ind FirmSale	2026 Total	2027: Residential	2027: Commercial	2027: Ind FirmSale	2027 Total	2028: Residential	2028: Commercial	2028: Ind FirmSale	2028 Total
Klam Falls	846.53	450.71	10.96	1,308.20	849.83	452.65	10.95	1,313.43	859.43	457.68	10.98	1,328.10
La Grande	454.43	270.38	10.04	734.86	455.12	270.82	10.01	735.96	458.82	273.00	10.02	741.84
Medford GTN	2,278.57	1,394.31	11.49	3,684.38	2,297.72	1,406.79	11.48	3,715.99	2,332.84	1,427.73	11.51	3,772.09
Medford NWP	1,023.71	626.43	5.16	1,655.30	1,032.31	632.03	5.16	1,669.50	1,048.09	641.45	5.17	1,694.71
Roseburg	769.48	589.03	21.51	1,380.02	773.57	588.20	21.50	1,383.27	782.88	590.58	21.56	1,395.02
OR Sub-Total	**5,372.73**	**3,330.86**	**59.16**	**8,762.76**	**5,408.55**	**3,350.50**	**59.10**	**8,818.15**	**5,482.06**	**3,390.44**	**59.24**	**8,931.74**
Wa/Id Both	9,839.83	5,807.45	275.95	15,923.23	9,911.75	5,851.37	274.34	16,037.46	10,055.86	5,935.77	273.97	16,265.60
Wa/Id GTN	1,357.22	801.03	38.06	2,196.31	1,367.14	807.09	37.84	2,212.06	1,387.02	818.73	37.79	2,243.53
Wa/Id NWP	5,768.18	3,404.37	161.76	9,334.31	5,810.33	3,430.11	160.82	9,401.27	5,894.81	3,479.59	160.60	9,535.01
WA/ID Sub-Total	**16,965.23**	**10,012.84**	**475.78**	**27,453.85**	**17,089.22**	**10,088.56**	**473.01**	**27,650.79**	**17,337.69**	**10,234.09**	**472.36**	**28,044.14**
Case Total	**22,337.96**	**13,343.70**	**534.94**	**36,216.61**	**22,497.77**	**13,439.06**	**532.11**	**36,468.94**	**22,819.75**	**13,624.53**	**531.60**	**36,975.89**

Area	2029: Residential	2029: Commercial	2029: Ind FirmSale	2029 Total	2030: Residential	2030: Commercial	2030: Ind FirmSale	2030 Total	2031: Residential	2031: Commercial	2031: Ind FirmSale	2031 Total
Klam Falls	861.07	458.65	10.95	1,330.67	858.89	458.20	10.93	1,328.02	864.56	461.24	10.93	1,336.73
La Grande	458.77	272.98	10.01	741.76	456.74	272.03	9.92	738.69	458.58	273.14	9.92	741.63
Medford GTN	2,348.55	1,437.91	11.48	3,797.95	2,353.82	1,443.56	11.45	3,808.84	2,379.72	1,459.45	11.45	3,850.62
Medford NWP	1,055.15	646.02	5.16	1,706.32	1,057.51	648.56	5.14	1,711.22	1,069.15	655.69	5.14	1,729.99
Roseburg	785.37	588.48	21.50	1,395.35	785.29	585.06	21.47	1,391.82	791.25	585.21	21.47	1,397.93
OR Sub-Total	**5,508.92**	**3,404.03**	**59.10**	**8,972.05**	**5,512.26**	**3,407.41**	**58.91**	**8,978.58**	**5,563.26**	**3,434.73**	**58.91**	**9,056.89**
Wa/Id Both	10,110.98	5,969.00	271.79	16,351.77	10,120.33	5,979.80	269.43	16,369.55	10,221.52	6,039.66	268.15	16,529.33
Wa/Id GTN	1,394.62	823.31	37.49	2,255.42	1,395.91	824.80	37.16	2,257.87	1,409.86	833.06	36.99	2,279.91
Wa/Id NWP	5,927.12	3,499.07	159.32	9,585.52	5,932.60	3,505.40	157.94	9,595.94	5,991.92	3,540.49	157.19	9,689.61
WA/ID Sub-Total	**17,432.72**	**10,291.39**	**468.60**	**28,192.71**	**17,448.84**	**10,310.00**	**464.53**	**28,223.36**	**17,623.30**	**10,413.21**	**462.33**	**28,498.85**
Case Total	**22,941.63**	**13,695.42**	**527.70**	**37,164.76**	**22,961.09**	**13,717.41**	**523.44**	**37,201.94**	**23,186.56**	**13,847.94**	**521.24**	**37,555.74**

Area	2032: Residential	2032: Commercial	2032: Ind FirmSale	2032 Total	2033: Residential	2033: Commercial	2033: Ind FirmSale	2033 Total
Klam Falls	871.15	464.95	10.95	1,347.05	870.97	465.12	10.91	1,347.00
La Grande	460.74	274.49	9.88	745.11	459.80	273.91	9.86	743.57
Medford GTN	2,407.68	1,477.02	11.47	3,896.17	2,419.03	1,485.18	11.43	3,915.65
Medford NWP	1,081.71	663.59	5.15	1,750.45	1,086.81	667.25	5.14	1,759.20
Roseburg	798.33	586.23	21.52	1,406.08	799.43	583.15	21.45	1,404.03
OR Sub-Total	**5,619.61**	**3,466.28**	**58.97**	**9,144.86**	**5,636.04**	**3,474.61**	**58.79**	**9,169.44**
Wa/Id Both	10,332.73	6,106.71	267.33	16,706.78	10,367.71	6,129.46	264.94	16,762.11
Wa/Id GTN	1,425.20	842.31	36.87	2,304.38	1,430.03	845.44	36.54	2,312.01
Wa/Id NWP	6,057.12	3,579.80	156.71	9,793.63	6,077.63	3,593.13	155.31	9,826.06
WA/ID Sub-Total	**17,815.05**	**10,528.81**	**460.92**	**28,804.79**	**17,875.37**	**10,568.03**	**456.79**	**28,900.19**
Case Total	**23,434.66**	**13,995.09**	**519.89**	**37,949.65**	**23,511.41**	**14,042.64**	**515.58**	**38,069.63**

APPENDIX 2.9: DETAILED DEMAND DATA COLDEST IN 20 YEARS

Area	2014: Residential	2014: Commercial	2014: Ind FirmSale	2014 Total	2015: Residential	2015: Commercial	2015: Ind FirmSale	2015 Total	2016: Residential	2016: Commercial	2016: Ind FirmSale	2016 Total
Klam Falls	835.92	443.20	11.13	1,290.24	838.83	444.69	11.13	1,294.65	846.54	448.10	11.16	1,305.81
La Grande	460.28	275.68	10.40	746.36	462.60	276.13	10.40	749.13	467.06	278.15	10.40	755.61
Medford GTN	2,152.19	1,312.19	11.72	3,476.10	2,173.01	1,319.74	11.72	3,504.47	2,203.07	1,335.63	11.75	3,550.45
Medford NWP	966.92	589.53	5.27	1,561.72	976.28	592.93	5.27	1,574.47	989.79	600.06	5.28	1,595.13
Roseburg	750.21	614.75	21.67	1,386.64	754.29	615.93	21.67	1,391.89	762.47	618.83	21.73	1,403.04
OR Sub-Total	**5,165.53**	**3,235.35**	**60.19**	**8,461.06**	**5,205.00**	**3,249.42**	**60.19**	**8,514.61**	**5,268.94**	**3,280.77**	**60.32**	**8,610.04**
Wa/Id Both	9,231.09	5,493.50	300.60	15,025.18	9,328.88	5,539.50	299.37	15,167.75	9,476.12	5,609.39	298.84	15,384.35
Wa/Id GTN	1,273.25	757.72	41.46	2,072.44	1,286.74	764.07	41.29	2,092.10	1,307.05	773.71	41.22	2,121.98
Wa/Id NWP	5,411.33	3,220.33	176.21	8,807.86	5,468.65	3,247.29	175.49	8,891.44	5,554.97	3,288.26	175.18	9,018.41
WA/ID Sub-Total	**15,915.66**	**9,471.55**	**518.27**	**25,905.48**	**16,084.27**	**9,550.86**	**516.16**	**26,151.29**	**16,338.14**	**9,671.36**	**515.24**	**26,524.74**
Case Total	**21,081.19**	**12,706.90**	**578.45**	**34,366.54**	**21,289.28**	**12,800.28**	**576.35**	**34,665.90**	**21,607.08**	**12,952.13**	**575.57**	**35,134.78**

Area	2017: Residential	2017: Commercial	2017: Ind FirmSale	2017 Total	2018: Residential	2018: Commercial	2018: Ind FirmSale	2018 Total	2019: Residential	2019: Commercial	2019: Ind FirmSale	2019 Total
Klam Falls	841.54	445.55	11.11	1,298.20	846.94	447.29	11.11	1,305.33	852.52	449.70	11.11	1,313.33
La Grande	464.86	276.26	10.32	751.44	467.82	277.26	10.32	755.41	469.24	278.11	10.32	757.67
Medford GTN	2,201.20	1,333.98	11.69	3,546.88	2,223.20	1,344.97	11.69	3,579.87	2,246.99	1,358.74	11.69	3,617.42
Medford NWP	988.94	599.33	5.25	1,593.52	998.83	604.26	5.25	1,608.35	1,009.52	610.45	5.25	1,625.22
Roseburg	760.25	614.02	21.65	1,395.92	766.36	614.58	21.65	1,402.59	772.31	614.73	21.65	1,408.69
OR Sub-Total	**5,256.80**	**3,269.14**	**60.03**	**8,585.96**	**5,303.15**	**3,288.36**	**60.03**	**8,651.54**	**5,350.59**	**3,311.72**	**60.03**	**8,722.34**
Wa/Id Both	9,484.63	5,594.92	295.08	15,374.64	9,603.46	5,645.98	293.18	15,542.62	9,706.49	5,700.23	291.87	15,698.59
Wa/Id GTN	1,308.23	771.71	40.70	2,120.64	1,324.62	778.76	40.44	2,143.81	1,338.83	786.24	40.26	2,165.32
Wa/Id NWP	5,559.96	3,279.78	172.98	9,012.72	5,629.62	3,309.71	171.86	9,111.19	5,690.01	3,341.51	171.09	9,202.62
WA/ID Sub-Total	**16,352.81**	**9,646.41**	**508.77**	**26,507.99**	**16,557.70**	**9,734.45**	**505.48**	**26,797.62**	**16,735.34**	**9,827.98**	**503.22**	**27,066.53**
Case Total	**21,609.61**	**12,915.55**	**568.80**	**35,093.95**	**21,860.84**	**13,022.81**	**565.51**	**35,449.16**	**22,085.92**	**13,139.70**	**563.25**	**35,788.87**

Area	2020: Residential	2020: Commercial	2020: Ind FirmSale	2020 Total	2021: Residential	2021: Commercial	2021: Ind FirmSale	2021 Total	2022: Residential	2022: Commercial	2022: Ind FirmSale	2022 Total
Klam Falls	862.08	454.61	11.14	1,327.82	861.65	454.75	11.10	1,327.50	858.90	454.02	11.07	1,323.98
La Grande	473.00	280.30	10.33	763.63	471.91	279.68	10.30	761.88	469.51	278.54	10.19	758.24
Medford GTN	2,281.00	1,378.82	11.72	3,671.55	2,291.20	1,386.06	11.69	3,688.95	2,294.77	1,390.60	11.65	3,697.03
Medford NWP	1,024.80	619.47	5.27	1,649.54	1,029.38	622.72	5.25	1,657.36	1,030.98	624.76	5.23	1,660.98
Roseburg	781.51	617.30	21.71	1,420.52	782.41	613.99	21.64	1,418.04	781.80	610.20	21.61	1,413.61
OR Sub-Total	**5,422.39**	**3,350.51**	**60.17**	**8,833.06**	**5,436.55**	**3,357.21**	**59.97**	**8,853.73**	**5,435.97**	**3,358.12**	**59.76**	**8,853.85**
Wa/Id Both	9,846.47	5,781.82	291.51	15,919.80	9,877.14	5,801.77	288.92	15,967.83	9,879.74	5,808.59	286.34	15,974.67
Wa/Id GTN	1,358.13	797.49	40.21	2,195.83	1,362.36	800.24	39.85	2,202.46	1,362.72	801.18	39.49	2,203.40
Wa/Id NWP	5,772.07	3,389.35	170.88	9,332.30	5,790.05	3,401.04	169.36	9,360.45	5,791.57	3,405.04	167.85	9,364.46
WA/ID Sub-Total	**16,976.67**	**9,968.66**	**502.60**	**27,447.93**	**17,029.55**	**10,003.05**	**498.13**	**27,530.74**	**17,034.04**	**10,014.81**	**493.68**	**27,542.53**
Case Total	**22,399.06**	**13,319.17**	**562.77**	**36,281.00**	**22,466.10**	**13,360.26**	**558.11**	**36,384.47**	**22,470.01**	**13,372.93**	**553.44**	**36,396.38**

Area	2023: Residential	2023: Commercial	2023: Ind FirmSale	2023 Total	2024: Residential	2024: Commercial	2024: Ind FirmSale	2024 Total	2025: Residential	2025: Commercial	2025: Ind FirmSale	2025 Total
Klam Falls	863.67	456.69	11.07	1,331.43	873.34	461.64	11.10	1,346.08	869.59	460.28	11.05	1,340.93
La Grande	470.93	279.38	10.18	760.49	474.69	281.60	10.18	766.47	471.92	280.11	10.11	762.15
Medford GTN	2,317.70	1,404.76	11.65	3,734.11	2,352.76	1,425.58	11.68	3,790.01	2,354.66	1,428.78	11.62	3,795.06
Medford NWP	1,041.29	631.13	5.23	1,677.64	1,057.04	640.48	5.25	1,702.76	1,057.89	641.92	5.22	1,705.03
Roseburg	787.05	609.85	21.61	1,418.50	796.42	612.35	21.67	1,430.44	794.75	607.57	21.59	1,423.91
OR Sub-Total	**5,480.64**	**3,381.81**	**59.73**	**8,922.18**	**5,554.24**	**3,421.65**	**59.87**	**9,035.76**	**5,548.82**	**3,418.66**	**59.60**	**9,027.08**
Wa/Id Both	9,968.30	5,861.22	284.90	16,114.42	10,111.98	5,945.05	284.53	16,341.56	10,105.21	5,945.21	281.49	16,331.91
Wa/Id GTN	1,374.94	808.44	39.30	2,222.68	1,394.76	820.01	39.24	2,254.01	1,393.82	820.03	38.83	2,252.68
Wa/Id NWP	5,843.49	3,435.89	167.01	9,446.38	5,927.71	3,485.03	166.79	9,579.53	5,923.74	3,485.12	165.01	9,573.88
WA/ID Sub-Total	**17,186.73**	**10,105.54**	**491.21**	**27,783.48**	**17,434.46**	**10,250.08**	**490.56**	**28,175.10**	**17,422.78**	**10,250.35**	**485.33**	**28,158.46**
Case Total	**22,667.36**	**13,487.35**	**550.94**	**36,705.65**	**22,988.70**	**13,671.73**	**550.43**	**37,210.86**	**22,971.59**	**13,669.02**	**544.92**	**37,185.54**

APPENDIX 2.9: DETAILED DEMAND DATA COLDEST IN 20 YEARS

Area	2026: Residential	2026: Commercial	2026: Ind FirmSale	2026 Total	2027: Residential	2027: Commercial	2027: Ind FirmSale	2027 Total	2028: Residential	2028: Commercial	2028: Ind FirmSale	2028 Total
Klam Falls	869.73	460.86	11.03	1,341.62	873.10	462.83	11.02	1,346.95	882.85	467.93	11.05	1,361.84
La Grande	470.98	279.74	10.04	760.76	471.67	280.18	10.02	761.87	475.44	282.40	10.02	767.86
Medford GTN	2,365.95	1,437.26	11.60	3,814.82	2,385.74	1,450.06	11.59	3,847.39	2,421.83	1,471.48	11.62	3,904.93
Medford NWP	1,062.97	645.73	5.21	1,713.90	1,071.85	651.48	5.21	1,728.54	1,088.07	661.10	5.22	1,754.39
Roseburg	796.41	604.98	21.57	1,422.96	800.60	604.10	21.56	1,426.26	810.12	606.48	21.62	1,438.21
OR Sub-Total	**5,566.04**	**3,428.57**	**59.46**	**9,054.06**	**5,602.96**	**3,448.65**	**59.40**	**9,111.01**	**5,678.30**	**3,489.38**	**59.53**	**9,227.22**
Wa/Id Both	10,141.63	5,970.22	279.39	16,391.24	10,215.45	6,015.17	277.75	16,508.37	10,362.60	6,101.22	277.36	16,741.17
Wa/Id GTN	1,398.85	823.48	38.54	2,260.86	1,409.03	829.68	38.31	2,277.02	1,429.32	841.55	38.26	2,309.13
Wa/Id NWP	5,945.09	3,499.79	163.78	9,608.66	5,988.37	3,526.13	162.82	9,677.32	6,074.63	3,576.57	162.59	9,813.79
WA/ID Sub-Total	**17,485.56**	**10,293.49**	**481.70**	**28,260.75**	**17,612.84**	**10,370.98**	**478.88**	**28,462.70**	**17,866.55**	**10,519.34**	**478.21**	**28,864.09**
Case Total	**23,051.60**	**13,722.06**	**541.15**	**37,314.82**	**23,215.80**	**13,819.63**	**538.28**	**37,573.71**	**23,544.85**	**14,008.72**	**537.74**	**38,091.31**

Area	2029: Residential	2029: Commercial	2029: Ind FirmSale	2029 Total	2030: Residential	2030: Commercial	2030: Ind FirmSale	2030 Total	2031: Residential	2031: Commercial	2031: Ind FirmSale	2031 Total
Klam Falls	884.65	468.96	11.02	1,364.63	882.33	468.45	11.00	1,361.78	888.16	471.56	11.00	1,370.71
La Grande	475.45	282.41	10.02	767.88	473.29	281.38	9.92	764.59	475.19	282.53	9.92	767.64
Medford GTN	2,438.52	1,482.14	11.59	3,932.25	2,443.66	1,487.73	11.56	3,942.95	2,470.54	1,504.10	11.56	3,986.20
Medford NWP	1,095.57	665.89	5.21	1,766.66	1,097.88	668.40	5.19	1,771.47	1,109.95	675.76	5.19	1,790.90
Roseburg	812.81	604.38	21.56	1,438.75	812.60	600.77	21.53	1,434.90	818.77	600.92	21.53	1,441.22
OR Sub-Total	**5,707.01**	**3,503.78**	**59.40**	**9,270.18**	**5,709.75**	**3,506.73**	**59.20**	**9,275.68**	**5,762.62**	**3,534.87**	**59.20**	**9,356.68**
Wa/Id Both	10,420.78	6,136.10	275.16	16,832.04	10,429.38	6,146.49	272.75	16,848.61	10,533.66	6,208.02	271.46	17,013.14
Wa/Id GTN	1,437.35	846.36	37.95	2,321.66	1,438.53	847.79	37.62	2,323.95	1,452.92	856.28	37.44	2,346.64
Wa/Id NWP	6,108.73	3,597.03	161.30	9,867.06	6,113.77	3,603.11	159.89	9,876.77	6,174.90	3,639.18	159.13	9,973.22
WA/ID Sub-Total	**17,966.86**	**10,579.49**	**474.42**	**29,020.77**	**17,981.69**	**10,597.39**	**470.25**	**29,049.33**	**18,161.48**	**10,703.48**	**468.03**	**29,332.99**
Case Total	**23,673.87**	**14,083.26**	**533.82**	**38,290.95**	**23,691.44**	**14,104.13**	**529.45**	**38,325.02**	**23,924.10**	**14,238.35**	**527.23**	**38,689.67**

Area	2032: Residential	2032: Commercial	2032: Ind FirmSale	2032 Total	2033: Residential	2033: Commercial	2033: Ind FirmSale	2033 Total
Klam Falls	894.79	475.29	11.02	1,381.09	894.69	475.49	10.98	1,381.16
La Grande	477.34	283.87	9.88	771.09	476.41	283.31	9.86	769.58
Medford GTN	2,499.05	1,521.94	11.57	4,032.57	2,511.14	1,530.46	11.54	4,053.14
Medford NWP	1,122.76	683.77	5.20	1,811.73	1,128.20	687.60	5.18	1,820.98
Roseburg	825.92	601.87	21.58	1,449.37	827.15	598.74	21.51	1,447.40
OR Sub-Total	**5,819.85**	**3,566.74**	**59.25**	**9,445.85**	**5,837.59**	**3,575.60**	**59.07**	**9,472.27**
Wa/Id Both	10,646.44	6,275.91	270.61	17,192.95	10,683.64	6,299.86	268.18	17,251.69
Wa/Id GTN	1,468.47	865.64	37.32	2,371.44	1,473.61	868.95	36.99	2,379.54
Wa/Id NWP	6,241.01	3,678.98	158.63	10,078.63	6,262.83	3,693.02	157.21	10,113.06
WA/ID Sub-Total	**18,355.93**	**10,820.53**	**466.56**	**29,643.02**	**18,420.08**	**10,861.82**	**462.39**	**29,744.29**
Case Total	**24,175.78**	**14,387.28**	**525.82**	**39,088.87**	**24,257.67**	**14,437.42**	**521.46**	**39,216.55**

APPENDIX 3.1: AVISTA GAS CPA REPORT 4/23/2014

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Avista Natural Gas Conservation Potential Assessment Results

April 23, 2014

Topics

- Overview of analysis approach
- Market characterization
- Energy market profile
- Baseline projection
- Conservation potential

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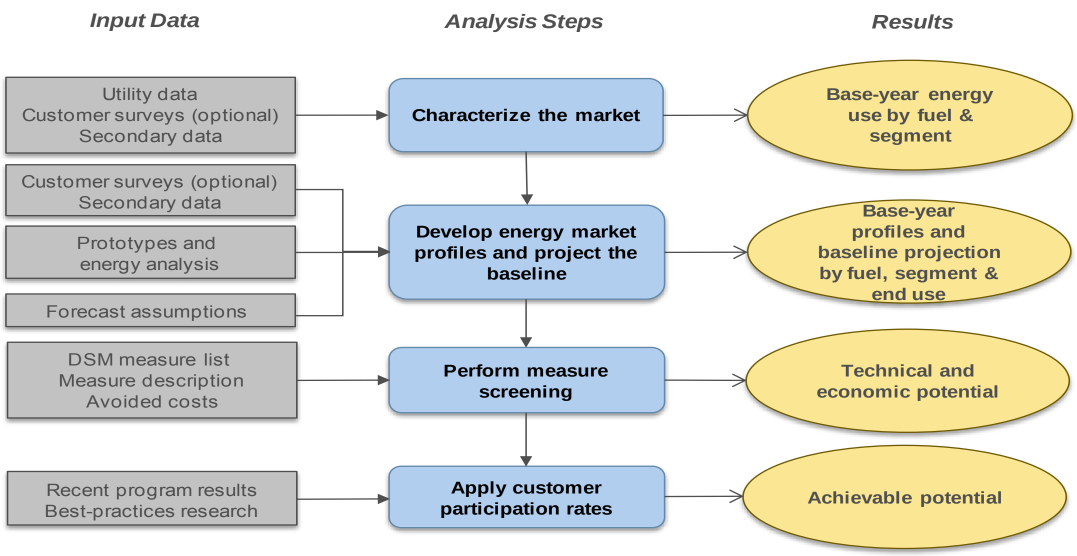
Approach



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Approach

Market Dimension	Segmentation Variable	Dimension Examples
1	State	Washington, Idaho, and Oregon
2	Sector	Residential, Commercial, and Industrial
3	Building type	**Residential**: Single family, Multi Family, and Mobile Home **Commercial**: Small Commercial and Large Commercial **Industrial**: All sectors combined
4	Vintage	Existing and new construction
5	End uses	Space heating, water heating, appliances, process, etc. (as appropriate by sector)
6	Appliances/end uses and technologies	Technologies such as furnaces, boilers, ovens, fryers, etc
7	Equipment efficiency levels for new purchases	Baseline and higher-efficiency options as appropriate for each technology

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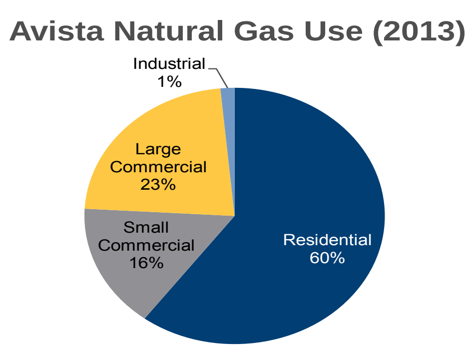
Market Characterization

Avista market characterization (All states, 2013)

- Based on 2013 Avista gas sales data
- Excludes transport and Oregon 444

Avista Total	2013 Sales (1,000Thrm)	# of Meters	Average Use per Meter (Thrm)
Residential	199,115	288,088	691
Small Commercial	51,825	30,410	1,704
Large Commercial	74,664	3,875	19,266
Industrial	5,015	255	19,649
Total	**330,619**	**322,628**	**1,025**



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Avista market characterization (2013)

Washington	Rate Class	2013 Sales (1,000Thrm)	% of Sales	# of Meters	% of Meters	Average Use/Meter (Thrm)
Residential	101	102,680	59%	135,792	90%	756
Small Commercial	101	17,267	10%	11,971	8%	1,442
Large Commercial	111,132	51,078	29%	2,469	2%	20,687
Industrial	101,111,112	2,384	1%	134	0%	17,756
Washington total		**173,409**	**100%**	**150,366**	**100%**	**1,153**

Idaho	Rate Class	2013 Sales (1,000Thrm)	% of Sales	# of Meters	% of Meters	Average Use/Meter (Thrm)
Residential	101	46,336	61%	67,415	89%	687
Small Commercial	101	7,725	10%	7,292	10%	1,059
Large Commercial	111,132	19,968	26%	1,335	2%	14,961
Industrial	101,111,112	2,222	3%	94	0%	23,698
Idaho total		**76,250**	**100%**	**76,136**	**100%**	**1,001**

Oregon	Rate Class	2013 Sales (1,000Thrm)	% of Sales	# of Meters	% of Meters	Average Use/Meter (Thrm)
Residential	410	50,099	62%	84,881	88%	590
Small Commercial	420	26,833	33%	11,146	12%	2,407
Large Commercial	424	3,618	4%	72	0%	50,484
Industrial	420,424	410	1%	27	0%	15,044
Oregon total		**80,960**	**100%**	**96,126**	**100%**	**842**

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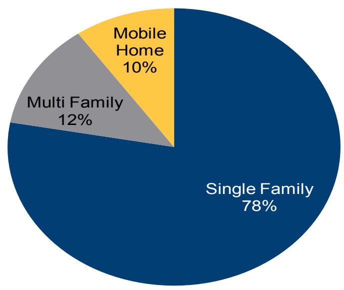
Residential Sector

Avista residential market characterization (All states, 2013)

All States Residential	2013 Sales (1,000 Therms)	# of Meters	Average Use per Household (Therms/HH)
Single Family	165,435	224,253	738
Multi Family	16,935	35,706	474
Mobile Home	16,745	28,128	595
Total	**199,115**	**288,088**	**691**

Avista Residential Natural Gas Use (2013)



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Avista residential market characterization (2013)

Washington	2013 Sales (1,000 Therms)	% of Sales	# of Meters	% of Meters	Average Use/Meter (Therms)
Single Family	86,211	84%	106,732	79%	808
Multi Family	9,743	9%	19,147	14%	509
Mobile Home	6,726	7%	9,913	7%	678
Washington total	**102,680**	**100%**	**135,792**	**100%**	**756**

Idaho	2013 Sales (1,000 Therms)	% of Sales	# of Meters	% of Meters	Average Use/Meter (Therms)
Single Family	38,758	84%	52,719	78%	735
Multi Family	4,496	10%	9,708	14%	463
Mobile Home	3,081	7%	4,989	7%	618
Idaho total	**46,336**	**100%**	**67,415**	**100%**	**687**

Oregon	2013 Sales (1,000 Therms)	% of Sales	# of Meters	% of Meters	Average Use/Meter (Therms)
Single Family	40,466	81%	64,803	76%	624
Multi Family	2,695	5%	6,851	8%	393
Mobile Home	6,938	14%	13,227	16%	525
Oregon total	**50,099**	**100%**	**84,881**	**100%**	**590**

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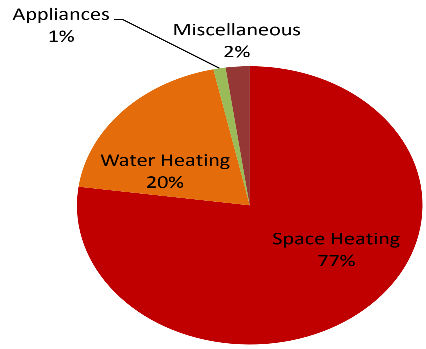
Avista residential market characterization (2013)

- Energy Market Profiles
  - Characterize energy use by sector, segment, end use, and technology
  - Existing, replacement, and new construction
- Accounts for
  - Codes and standards
  - Previous DSM results
  - Equipment saturation and fuel shares



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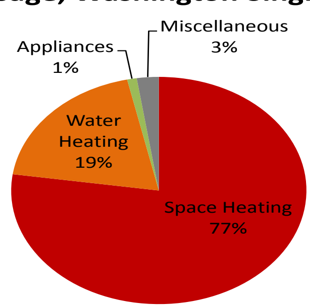
Energy market profile for Washington, single family

End Use	Technology	Saturation	UEC (Therms)	Intensity (Therms/HH)	Usage (MMThrm)
Space Heating	Furnace	87.8%	623.3	547.1	58.4
Space Heating	Boiler	3.6%	705.8	25.5	2.7
Space Heating	Other Heating	8.6%	600.0	51.7	5.5
Water Heating	Water Heater	60.8%	256.1	155.6	16.6
Appliances	Clothes Dryer	8.3%	30.8	2.5	0.3
Appliances	Stove/Oven	10.3%	57.4	5.9	0.6
Miscellaneous	Pool Heater	1.1%	219.0	2.5	0.3
Miscellaneous	Miscellaneous	100.0%	16.9	16.9	1.8
Total				**807.7**	**86.2**

Energy Usage, Washington Single Family



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Assumptions in the residential baseline projection

- Projection of growth without conservation programs
- Incorporates
  - Customer growth, about 1.5% per year
  - Differences in new homes (i.e., larger than average dwellings)
  - Per capita income growth, about 2.1% per year
  - Retail price forecast
  - Trends in end-use/technology saturations
  - Equipment purchase decisions

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

End Use	Technology	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heating	Furnace	AFUE 90% -Non-weatherized		AFUE 90% -Weatherized										
	Boiler	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	No Standing Pilot Light												
Miscellaneous	Pool Heater	EF 0.82												

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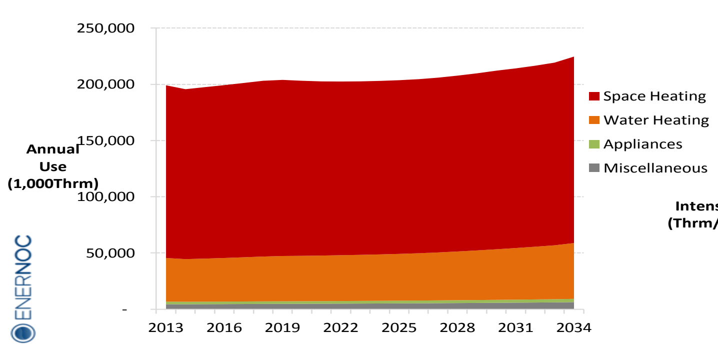
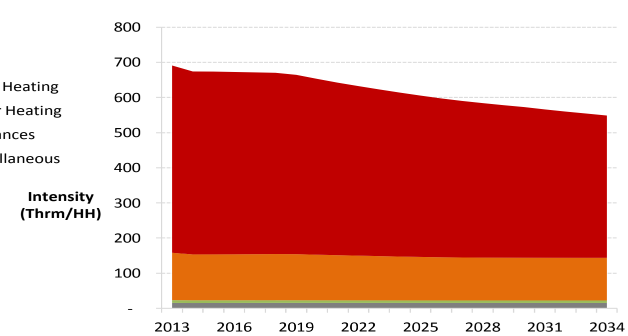
Residential baseline projection results

- Residential sector use increases 13% from 199 million therms to 224 million therms
- Use per household decreases by 21%
  - Larger home size and income effects are offset by efficiency standards





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Commercial Sector

Avista commercial market characterization (2013)

Washington	2013 Sales (1,000Thrm)	% of Sales	SqFt	Average Use/SqFt (Thrm)
Small Commercial	17,267	25%	47,567,634	0.36
Large Commercial	51,078	75%	77,391,189	0.66
Washington total	**68,345**	**100%**	**124,958,823**	**0.55**

Idaho	2013 Sales (1,000Thrm)	% of Sales	SqFt	Average Use/SqFt (Thrm)
Small Commercial	7,725	28%	22,293,951	0.35
Large Commercial	19,968	72%	31,695,198	0.63
Idaho total	**27,693**	**100%**	**53,989,149**	**0.51**

Oregon	2013 Sales (1,000Thrm)	% of Sales	SqFt	Average Use/SqFt (Thrm)
Small Commercial	26,833	88%	81,311,800	0.33
Large Commercial	3,618	12%	6,030,062	0.60
Oregon total	**30,451**	**100%**	**87,341,862**	**0.35**

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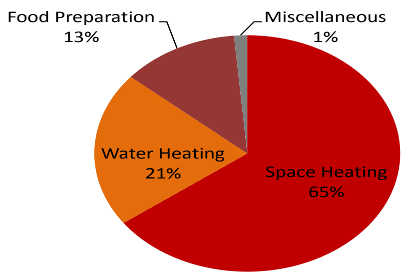
Avista commercial market characterization (2013)

- Energy Market Profiles
  - Characterize energy use by sector, segment, end use, and technology
  - Existing, replacement, and new construction
- Accounts for
  - Codes and standards
  - Previous DSM results
  - Equipment saturation and fuel shares



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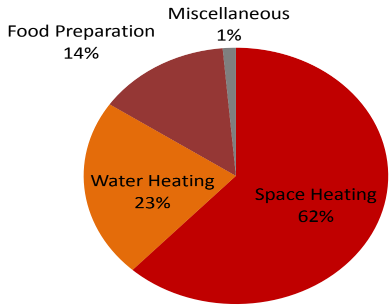
Energy market profile for Oregon, large commercial

End Use	Technology	Saturation	EUI (Therms)	Intensity (Therms/sqf	Usage (MMThrm)
Space Heating	Furnace	45.2%	0.24	0.11	0.6
Space Heating	Boiler	29.8%	0.77	0.23	1.4
Space Heating	Other Heating	16.6%	0.21	0.04	0.2
Water Heating	Water Heater	42.5%	0.32	0.14	0.8
Food Preparation	Oven	16.2%	0.06	0.01	0.1
Food Preparation	Fryer	16.2%	0.09	0.02	0.1
Food Preparation	Broiler	16.2%	0.09	0.02	0.1
Food Preparation	Griddle	16.2%	0.07	0.01	0.1
Food Preparation	Range	16.2%	0.07	0.01	0.1
Food Preparation	Steamer	16.2%	0.12	0.02	0.1
Miscellaneous	Pool Heater	1.2%	0.09	0.00	0.0
Miscellaneous	Miscellaneous	100.0%	0.01	0.01	0.1
Total				**0.600**	**3.6**



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Assumptions in the commercial baseline projection

- Projection of growth without conservation programs
- Incorporates
  - Floor space growth, about 1.1% per year
  - Differences in new construction
  - Retail price forecast
  - Trends in end-use/technology saturations
  - Equipment purchase decisions
  - Building codes and appliance standards

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

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

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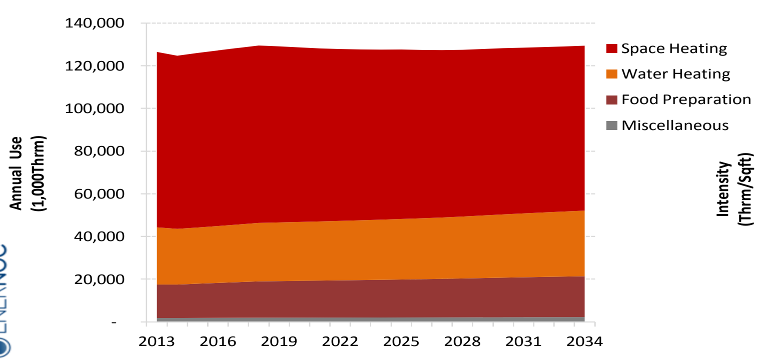
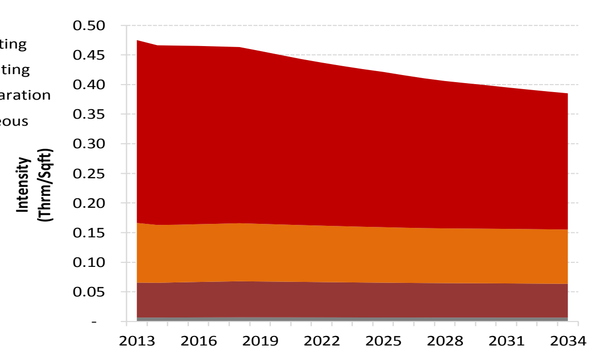
Commercial baseline projection results

- Commercial sector use increases 2% from 127 million therms to 130 million therms
- Use per square footage decreases by 19%
  - Energy consumption stays relatively flat while floor space increases





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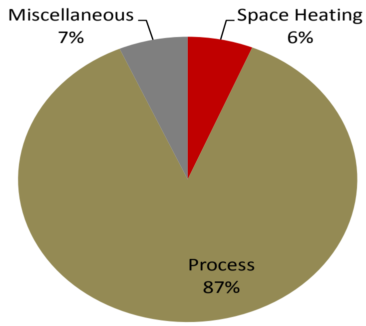
Industrial Sector

Avista industrial market characterization (2013)

State	2013 Sales (1,000 Therms)	Square Feet	Average Use/SqFt (Therms)
Washington	2,384	3,009,759	0.79
Idaho	2,222	2,927,137	0.76
Oregon	410	564,683	0.73
All states total	**5,015**	**6,501,579**	**0.77**

Avista industrial market characterization (2013)

- Energy Market Profiles
  - Characterize energy use by sector, segment, end use, and technology
  - Existing, replacement, and new construction
- Accounts for
  - Codes and standards
  - Previous DSM results
  - Equipment saturation and fuel shares



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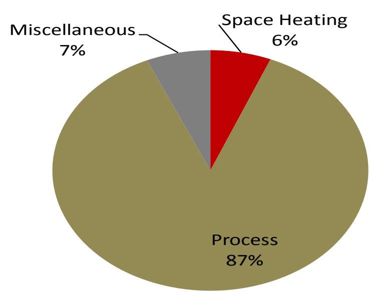
Energy market profile for Idaho, industrial

End Use	Technology	Saturation	EUI (Therms)	Intensity (Therms/sqft)	Usage (MMThrm)
Space Heating	Furnace	9.6%	0.017	0.00	0.00
Space Heating	Boiler	81.3%	0.055	0.04	0.13
Space Heating	Other Heating	4.8%	0.015	0.00	0.00
Process	Process Heating	100.0%	0.656	0.66	1.92
Process	Process Cooling	100.0%	0.001	0.00	0.00
Process	Other Process	100.0%	0.004	0.00	0.01
Other	Other Uses	100.0%	0.050	0.05	0.15
Total				**0.76**	**2.22**

Energy Usage, Idaho Industrial



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Assumptions in the industrial baseline projection

- Projection of growth without conservation programs
- Incorporates
  - Floor space decline, about 0.5% per year (space consolidation)
  - Differences in new construction
  - Retail price forecast
  - Trends in end-use/technology saturations
  - Equipment purchase decisions
  - Building codes and appliance standards

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

End Use	Technology	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heating	Furnace	AFUE 76%												
	Boiler	EF 0.82												

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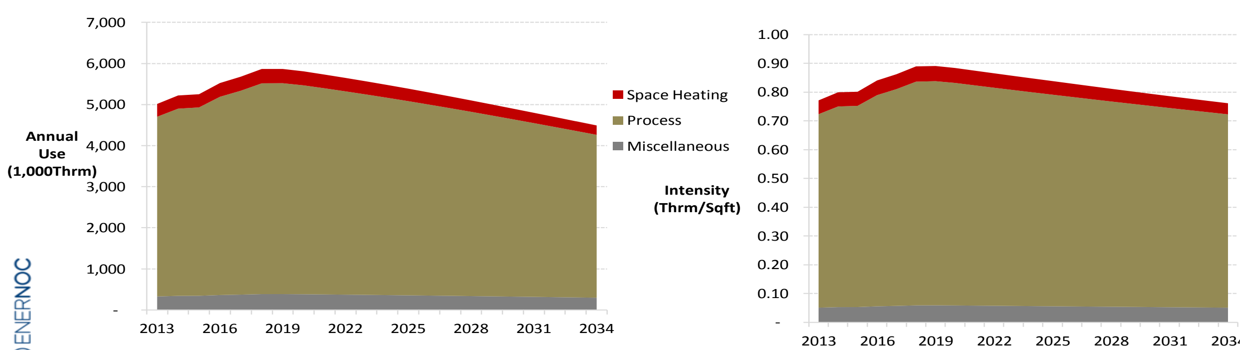
Industrial baseline projection results

- Industrial sector use decreases 10% from 5 million therms to 4.5 million therms
- Use per square footage slightly decreases by 1%



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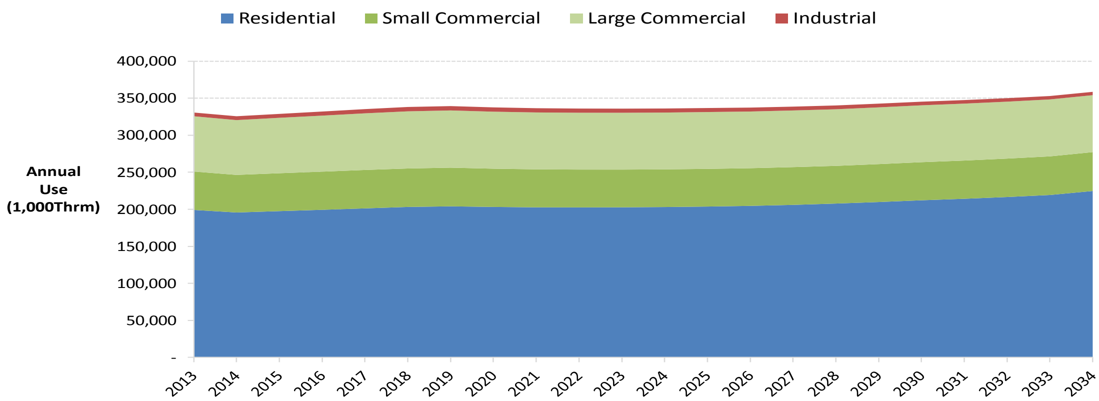
Baseline projection – all sectors

- Overall increase in use 8%
- Average annual growth 0.4%



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Energy conservation measures

- Assessed 1,785 measures
- Measure attributes
  - Average lifetime
  - Energy savings
  - Cost
  - Timing of standards
  - Base-year saturation
  - Applicability / feasibility
- Example: Washington, Single Family, Existing

Technology	Efficiency Level	Lifetime	Equipment Cost	Energy Usage (Therms/year)	Off Market
Furnace	100.0%	20	$3,651	565	2014
Furnace	97.5%	20	$4,056	551	2014
Furnace	94.0%	20	$4,259	531	2014
Furnace	87.7%	20	$4,462	495	2034
Furnace	81.6%	20	$6,084	461	2034

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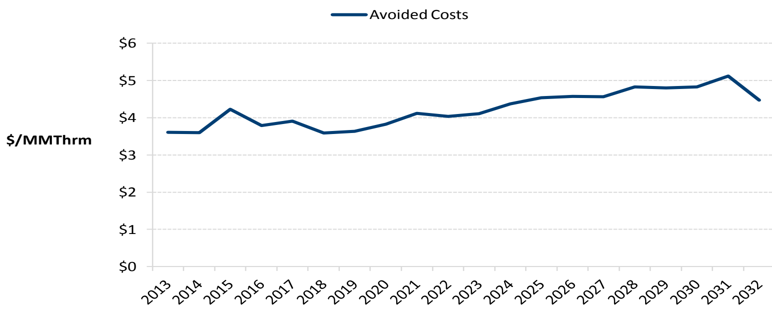
Conservation potential assumptions

- Three levels of potential
  - *Technical potential* – all applicable measures are implemented, regardless of cost
  - *Economic potential* – all cost-effective measures
    - TRC test with B/C ratio ≥ 1.0 (Idaho and Oregon)
    - UCT test with B/C ratio ≥ 1.0 (Washington)
  - *Achievable potential* – accounts for market acceptance and rates at which programs can realistically be implemented
    - Based on Sixth Plan ramp rates



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Summary of CPA results (across all states)

- Achievable potential begins at 40% of economic potential in 2015 and reaches 74% by 2034

	2015	2016	2019	2024	2034
Baseline Forecast	328,757	331,980	338,917	336,073	358,562
Cumulative Natural Gas Savings (1,000Thrm)					
Achievable Potential	1,677	2,639	9,854	20,369	36,110
Economic Potential	4,153	5,877	17,317	32,220	48,528
Technical Potential	12,207	18,677	51,810	96,562	162,236
Cumulative Natural Gas Savings (% of Baseline)					
Achievable Potential	0.5%	0.8%	2.9%	6.1%	10.1%
Economic Potential	1.3%	1.8%	5.1%	9.6%	13.5%
Technical Potential	3.7%	5.6%	15.3%	28.7%	45.2%

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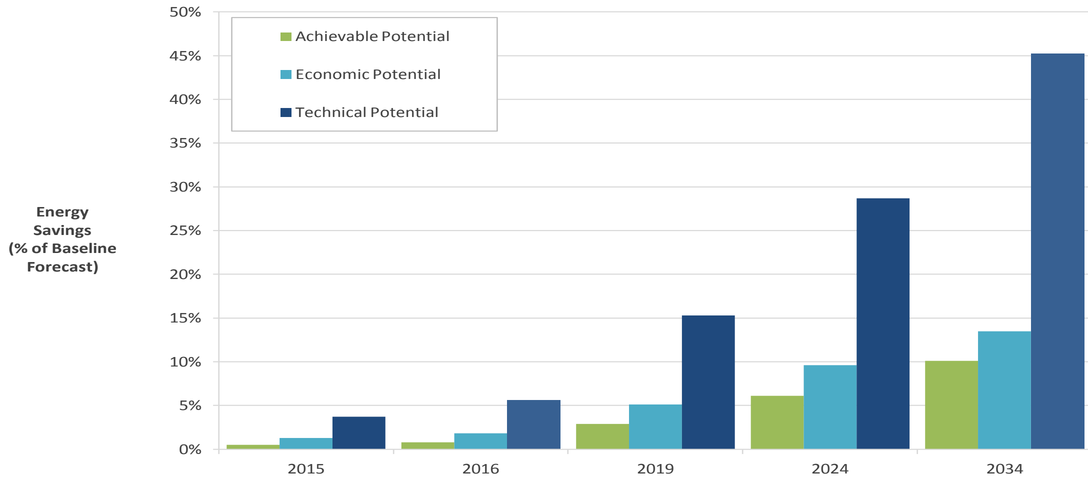
Summary of CPA results (continued)



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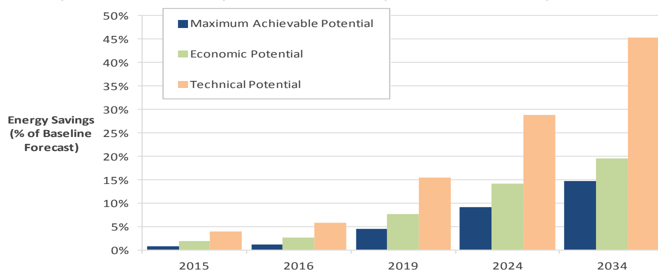
Savings by State - Washington

Total potential results, Washington

	2015	2016	2019	2024	2034
Baseline Forecast	171,422	172,719	175,548	173,273	179,456
Cumulative Natural Gas Savings (1,000Thrm)					
Achievable Potential	1,287	2,024	7,742	15,656	26,259
Economic Potential	3,127	4,385	13,330	24,445	35,042
Technical Potential	6,620	9,963	26,953	50,035	81,431
Cumulative Natural Gas Savings (% of Baseline)					
Achievable Potential	0.8%	1.2%	4.4%	9.0%	14.6%
Economic Potential	1.8%	2.5%	7.6%	14.1%	19.5%
Technical Potential	3.9%	5.8%	15.4%	28.9%	45.4%



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Residential potential results, Washington

	2015	2016	2019	2024	2034
Baseline Forecast	101,488	102,205	104,445	103,847	112,733
Cumulative Natural Gas Savings (1,000Thrm)					
Achievable Potential	370	682	4,604	8,733	12,938
Economic Potential	964	1,471	7,571	13,180	16,955
Technical Potential	3,017	4,832	15,965	28,899	49,110
Cumulative Natural Gas Savings (% of Baseline)					
Achievable Potential	0.4%	0.7%	4.4%	8.4%	11.5%
Economic Potential	1.0%	1.4%	7.2%	12.7%	15.0%
Technical Potential	3.0%	4.7%	15.3%	27.8%	43.6%

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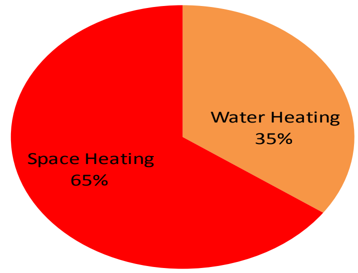
Residential results – Key measures, Washington

Measure / Technology	2024 Cumulative Savings (1,000Thrm)
Insulation - Infiltration Control	
Water Heating - Low Flow Showerheads	
Ducting - Repair and Sealing	
Home Energy Management System	
Thermostat - Clock/Programmable	
Water Heating - Thermostat Setback	
Water Heating - Hot Water Saver	
Water Heating - Tank Blanket/Insulation	
Water Heating - Faucet Aerators	
Water Heating - Pipe Insulation	
Insulation - Ceiling	61
Boiler - Pipe Insulation	58
Insulation - Attic Hatch	49
Insulation - Wall Cavity	5
Total	**8,733**



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Commercial potential results, Washington

	2015	2016	2019	2024	2034
Baseline Forecast	67,462	67,947	68,368	66,870	64,746
Cumulative Natural Gas Savings (1,000Thrm)					
Achievable Potential	893	1,305	3,020	6,704	13,100
Economic Potential	2,138	2,874	5,635	11,012	17,839
Technical Potential	3,555	5,061	10,803	20,762	31,923
Cumulative Natural Gas Savings (% of Baseline)					
Achievable Potential	1.3%	1.9%	4.4%	10.0%	20.2%
Economic Potential	3.2%	4.2%	8.2%	16.5%	27.6%
Technical Potential	5.3%	7.4%	15.8%	31.0%	49.3%

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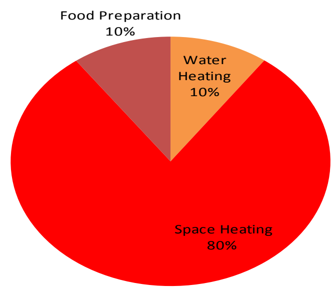
Commercial results – Key measures, Washington

Measure / Technology	2024 Cumulative Savings (1,000Thrm)
Space Heating - Heat Recovery Ventilator	1,545
Energy Management System	[illegible]
Custom Measures	[illegible]
Boiler - Hot Water Reset	[illegible]
Water Heating - Faucet Aerators	[illegible]
Furnace - Maintenance	[illegible]
Boiler - Maintenance	[illegible]
Space Heating - Furnace	[illegible]
Thermostat - Clock/Programmable	[illegible]
Insulation - Ceiling	[illegible]
Advanced New Construction Designs	[illegible]
Insulation - Wall Cavity	[illegible]
Boiler - High Efficiency Hot Water Circulation	[illegible]
Food Preparation - Fryer	[illegible]
Food Preparation - Oven	129
Food Preparation - Steamer	113
Food Preparation - Range	101
Food Preparation - Griddle	81
Water Heating - Tank Blanket/Insulation	53
Space Heating - Boiler	34
Water Heating - Hot Water Saver	4
Total	**6,704**



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Industrial potential results, Washington

	2015	2016	2019	2024	2034
Baseline Forecast	2,472	2,567	2,735	2,555	1,977
Cumulative Natural Gas Savings (1,000Thrm)					
Achievable Potential	24	38	118	220	220
Economic Potential	25	39	124	253	248
Technical Potential	48	69	184	374	398
Cumulative Natural Gas Savings (% of Baseline)					
Achievable Potential	1.0%	1.5%	4.3%	8.6%	11.1%
Economic Potential	1.0%	1.5%	4.5%	9.9%	12.6%
Technical Potential	1.9%	2.7%	6.7%	14.6%	20.1%

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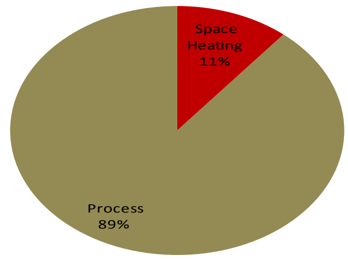
Industrial results – Key measures, Washington

Measure / Technology	202 (1
Process - Boiler Hot Water Reset	
Insulation - Wall Cavity	
Space Heating - Heat Recovery Ventilator	
Total	



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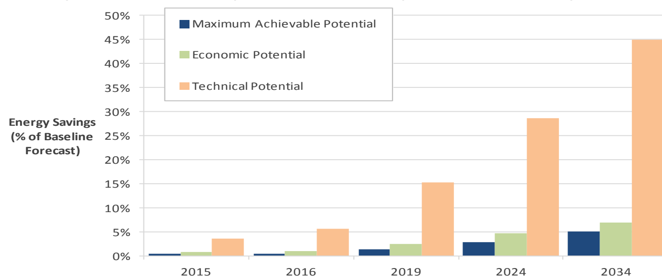
Savings by State - Idaho

Total potential results, Idaho

	2015	2016	2019	2024	2034
Baseline Forecast	77,988	79,291	82,115	82,171	89,483
Cumulative Natural Gas Savings (1,000Thrm)					
Achievable Potential	228	342	1,031	2,320	4,503
Economic Potential	571	803	1,984	3,881	6,209
Technical Potential	2,818	4,387	12,471	23,483	40,252
Cumulative Natural Gas Savings (% of Baseline)					
Achievable Potential	0.3%	0.4%	1.3%	2.8%	5.0%
Economic Potential	0.7%	1.0%	2.4%	4.7%	6.9%
Technical Potential	3.6%	5.5%	15.2%	28.6%	45.0%



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Residential potential results, Idaho

	2015	2016	2019	2024	2034
Baseline Forecast	46,978	47,633	49,132	49,102	55,990
Cumulative Natural Gas Savings (1,000Thrm)					
Achievable Potential	6	18	263	496	874
Economic Potential	10	31	434	756	1,117
Technical Potential	1,239	2,065	7,276	13,308	24,129
Cumulative Natural Gas Savings (% of Baseline)					
Achievable Potential	0.0%	0.0%	0.5%	1.0%	1.6%
Economic Potential	0.0%	0.1%	0.9%	1.5%	2.0%
Technical Potential	2.6%	4.3%	14.8%	27.1%	43.1%

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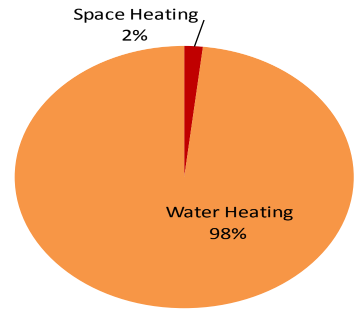
Residential results – Key measures, Idaho

Measure / Technology	202 (
Water Heating - Pipe Insulation	
Water Heating - Tank Blanket/Insulation	
Water Heating - Low Flow Showerheads	
Boiler - Pipe Insulation	
Insulation - Ceiling	
Total	



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Commercial potential results, Idaho

	2015	2016	2019	2024	2034
Baseline Forecast	28,645	29,129	30,299	30,572	31,360
Cumulative Natural Gas Savings (1,000Thrm)					
Achievable Potential	220	320	760	1,786	3,478
Economic Potential	559	768	1,543	3,083	4,921
Technical Potential	1,533	2,253	5,014	9,808	15,689
Cumulative Natural Gas Savings (% of Baseline)					
Achievable Potential	0.8%	1.1%	2.5%	5.8%	11.1%
Economic Potential	2.0%	2.6%	5.1%	10.1%	15.7%
Technical Potential	5.4%	7.7%	16.5%	32.1%	50.0%

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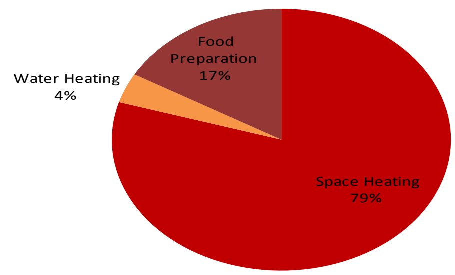
Commercial results – Key measures, Idaho

Measure / Technology	2024 Cumulative S (1,0
Space Heating - Heat Recovery Ventilator	
Energy Management System	
Boiler - Hot Water Reset	
Boiler - Maintenance	
Space Heating - Furnace	
Food Preparation - Fryer	
Boiler - High Efficiency Hot Water Circulation	
Food Preparation - Oven	
Food Preparation - Steamer	
Food Preparation - Range	[illegible]
Water Heating - Faucet Aerators	40
Food Preparation - Griddle	40
Water Heating - Tank Blanket/Insulation	26
Insulation - Ceiling	8
Total	**1,786**



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Industrial potential results, Idaho

	2015	2016	2019	2024	2034
Baseline Forecast	2,365	2,530	2,684	2,497	2,133
Cumulative Natural Gas Savings (1,000Thrm)					
Achievable Potential	3	4	7	38	151
Economic Potential	3	4	8	43	172
Technical Potential	46	69	181	368	434
Cumulative Natural Gas Savings (% of Baseline)					
Achievable Potential	0.1%	0.1%	0.3%	1.5%	7.1%
Economic Potential	0.1%	0.1%	0.3%	1.7%	8.1%
Technical Potential	1.9%	2.7%	6.8%	14.7%	20.3%

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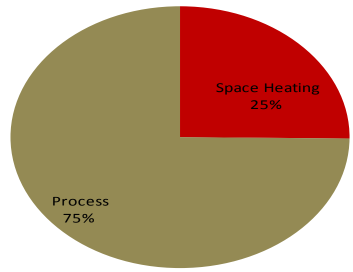
Industrial results – Key measures, Idaho

Measure / Technology
Process - Boiler Hot Water Reset
Insulation - Wall Cavity
Total



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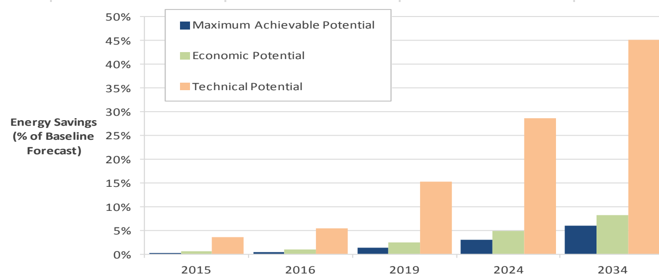
Savings by State - Oregon

Total potential results, Oregon

	2015	2016	2019	2024	2034
Baseline Forecast	79,346	79,969	81,255	80,629	89,623
Cumulative Natural Gas Savings (1,000Thrm)					
Achievable Potential	161	273	1,081	2,393	5,349
Economic Potential	454	690	2,004	3,894	7,276
Technical Potential	2,769	4,327	12,387	23,043	40,553
Cumulative Natural Gas Savings (% of Baseline)					
Achievable Potential	0.2%	0.3%	1.3%	3.0%	6.0%
Economic Potential	0.6%	0.9%	2.5%	4.8%	8.1%
Technical Potential	3.5%	5.4%	15.2%	28.6%	45.2%



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Residential potential results, Oregon

	2015	2016	2019	2024	2034
Baseline Forecast	49,029	49,426	50,374	50,070	55,947
Cumulative Natural Gas Savings (1,000Thrm)					
Achievable Potential	8	27	376	679	1,368
Economic Potential	14	44	595	1,006	1,690
Technical Potential	1,326	2,218	7,699	13,823	24,244
Cumulative Natural Gas Savings (% of Baseline)					
Achievable Potential	0.0%	0.1%	0.7%	1.4%	2.4%
Economic Potential	0.0%	0.1%	1.2%	2.0%	3.0%
Technical Potential	2.7%	4.5%	15.3%	27.6%	43.3%

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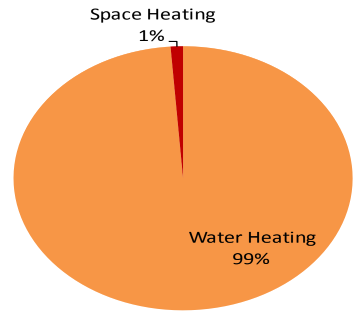
Residential results – Key measures, Oregon

Measure / Technology	202 (1
Water Heating - Pipe Insulation	
Water Heating - Tank Blanket/Insulation	
Water Heating - Faucet Aerators	
Water Heating - Low Flow Showerheads	
Insulation - Ceiling	
Boiler - Pipe Insulation	
Total	



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Commercial potential results, Oregon

	2015	2016	2019	2024	2034
Baseline Forecast	29,902	30,115	30,433	30,134	33,296
Cumulative Natural Gas Savings (1,000Thrm)					
Achievable Potential	153	245	704	1,704	3,944
Economic Potential	440	645	1,407	2,876	5,545
Technical Potential	1,434	2,097	4,657	9,158	16,232
Cumulative Natural Gas Savings (% of Baseline)					
Achievable Potential	0.5%	0.8%	2.3%	5.7%	11.8%
Economic Potential	1.5%	2.1%	4.6%	9.5%	16.7%
Technical Potential	4.8%	7.0%	15.3%	30.4%	48.7%

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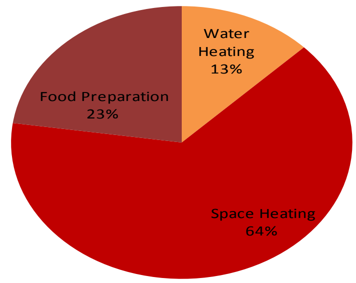
Commercial results – Key measures, Oregon

Measure / Technology	202[illegible]
Space Heating - Heat Recovery Ventilator	
Space Heating - Furnace	
Water Heating - Faucet Aerators	
Water Heating - Tank Blanket/Insulation	
Food Preparation - Fryer	
Food Preparation - Oven	
Boiler - Maintenance	
Food Preparation - Steamer	
Food Preparation - Range	
Energy Management System	37
Food Preparation - Griddle	34
Insulation - Ceiling	30
Boiler - Hot Water Reset	29
Boiler - High Efficiency Hot Water Circulation	13
Total	**1,704**



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Industrial potential results, Oregon

	2015	2016	2019	2024	2034
Baseline Forecast	415	427	448	425	380
Cumulative Natural Gas Savings (1,000Thrm)					
Achievable Potential	0	1	1	10	36
Economic Potential	0	1	1	11	41
Technical Potential	8	12	30	63	77
Cumulative Natural Gas Savings (% of Baseline)					
Achievable Potential	0.1%	0.1%	0.3%	2.4%	9.6%
Economic Potential	0.1%	0.1%	0.3%	2.7%	10.9%
Technical Potential	1.9%	2.7%	6.8%	14.7%	20.3%

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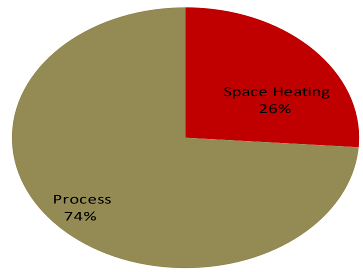
Industrial results – Key measures, Oregon

Measure / Technology	Cu (1,
Process - Boiler Hot Water Reset	
Insulation - Wall Cavity	
Total	



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Ingrid Rohmund
irohmund@enernoc.com
Bridget Kester
bkester@enernoc.com
Sogol Kananizadeh
skananizadeh@enernoc.com
Sharon Yoshida
Syoshida@enernoc.com

APPENDIX 3.2: 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 3.2.1 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 3.2.1: ENVIRONMENTAL EXTERNALITIES COST ADDER ANALYSIS (2012$)

			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	$ 8.32	$ 10.59	$ 12.85	$ 14.83
		$/lb	$ 0.0042	$ 0.0051	$ 0.0064	$ 0.0074
		lbs/therm	11.64	11.64	11.64	11.64
		CO2 Adder $/therm	$ 0.05	$ 0.06	$ 0.07	$ 0.09
	Total	**Total Adders $/therm**	**$ 0.06**	**$ 0.07**	**$ 0.08**	**$ 0.10**
			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	$ 16.00	$ 20.00	$ 25.00	$ 27.00
		$/lb	$ 0.0080	$ 0.0100	$ 0.0125	$ 0.0135
		lbs/therm	11.64	11.64	11.64	11.64
		CO2 Adder $/therm	$ 0.09	$ 0.12	$ 0.15	$ 0.16
	Total	**Total Adders $/therm**	**$ 0.10**	**$ 0.13**	**$ 0.16**	**$ 0.17**
			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	$ -	$ 5.00	$ 5.00	$ 5.00
		$/lb	$ -	$ 0.0025	$ 0.0025	$ 0.0025
		lbs/therm	11.64	11.64	11.64	11.64
		CO2 Adder $/therm	$ -	$ 0.03	$ 0.03	$ 0.03
	Total	**Total Adders $/therm**	**$ 0.00**	**$ 0.03**	**$ 0.03**	**$ 0.03**

APPENDIX 4.1: 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	0.0897	0.0300	0.38%	Changes every three years
GTN FTS-1 Rates				
Mileage Based - Representative Example				
Kingsgate to Spokane	0.0949	0.0017	0.31%	Changes every five years
Kingsgate to Medford	0.3471	0.0096	1.38%	Changes every five years
Meford Lateral	0.2953	-	0.00%	Changes every five years
Spectra Energy/Westcoast System Firm Rates -				
Postage Stamp Rates				
Station 2 to Huntington/Sumas	0.5444	-	2.13%	Changes every three years
Williams NWP				
Postage Stamp Rates				
TF-1 1/	0.4100	0.03370	1.45%	Changes every five years
TF-2 1/	0.4100	0.03370	1.45%	Changes every five years
SGS-2F 2/	0.0156	0.03370	1.60%	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

APPENDIX 4.2: 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 contracted capacity net of long term releases
		Currently available GTN	
		Capacity Release Recalls	Capacity Release Recalls
		NWP Expansions	NWP Expansions
		Satellite LNG	Satellite LNG
Rates	Current Rates	Current Rates	Current Rates

APPENDIX 5.1: MONTHLY PRICE DATA BY BASIN
EXPECTED PRICE

							2012$							
Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Expected Case	AECO	2013-2014	$ 3.26	$ 3.65	$ 4.18	$ 3.34	$ 3.44	$ 3.42	$ 3.37	$ 3.38	$ 3.37	$ 3.30	$ 3.33	$ 3.18
Expected Case	AECO	2014-2015	$ 3.28	$ 3.26	$ 3.34	$ 3.38	$ 3.48	$ 3.36	$ 3.35	$ 3.39	$ 3.45	$ 3.49	$ 3.54	$ 3.61
Expected Case	AECO	2015-2016	$ 3.78	$ 3.91	$ 3.96	$ 3.88	$ 3.93	$ 3.73	$ 3.60	$ 3.61	$ 3.62	$ 3.45	$ 3.36	$ 3.38
Expected Case	AECO	2016-2017	$ 3.52	$ 3.45	$ 3.45	$ 3.49	$ 3.54	$ 3.40	$ 3.37	$ 3.39	$ 3.40	$ 3.40	$ 3.42	$ 3.46
Expected Case	AECO	2017-2018	$ 3.60	$ 3.61	$ 3.62	$ 3.62	$ 3.59	$ 3.38	$ 3.31	$ 3.28	$ 3.25	$ 3.23	$ 3.25	$ 3.27
Expected Case	AECO	2018-2019	$ 3.48	$ 3.40	$ 3.25	$ 3.28	$ 3.36	$ 3.22	$ 3.18	$ 3.16	$ 3.19	$ 3.18	$ 3.21	$ 3.25
Expected Case	AECO	2019-2020	$ 3.46	$ 3.46	$ 3.24	$ 3.32	$ 3.45	$ 3.32	$ 3.28	$ 3.30	$ 3.31	$ 3.32	$ 3.32	$ 3.39
Expected Case	AECO	2020-2021	$ 3.53	$ 3.47	$ 3.33	$ 3.40	$ 3.57	$ 3.57	$ 3.57	$ 3.60	$ 3.59	$ 3.62	$ 3.67	$ 3.72
Expected Case	AECO	2021-2022	$ 3.84	$ 3.89	$ 3.96	$ 3.95	$ 3.85	$ 3.60	$ 3.54	$ 3.52	$ 3.52	$ 3.52	$ 3.63	$ 3.68
Expected Case	AECO	2022-2023	$ 3.95	$ 3.97	$ 3.94	$ 3.93	$ 3.91	$ 3.71	$ 3.58	$ 3.55	$ 3.55	$ 3.56	$ 3.65	$ 3.71
Expected Case	AECO	2023-2024	$ 4.02	$ 4.11	$ 4.22	$ 4.26	$ 4.26	$ 4.04	$ 3.92	$ 3.89	$ 3.88	$ 3.90	$ 3.99	$ 4.05
Expected Case	AECO	2024-2025	$ 4.34	$ 4.43	$ 4.50	$ 4.48	$ 4.45	$ 4.26	$ 4.23	$ 4.22	$ 4.21	$ 4.23	$ 4.30	$ 4.37
Expected Case	AECO	2025-2026	$ 4.61	$ 4.69	$ 4.67	$ 4.70	$ 4.70	$ 4.47	$ 4.40	$ 4.37	$ 4.36	$ 4.38	$ 4.45	$ 4.50
Expected Case	AECO	2026-2027	$ 4.79	$ 4.85	$ 4.73	$ 4.67	$ 4.76	$ 4.45	$ 4.39	$ 4.36	$ 4.36	$ 4.38	$ 4.44	$ 4.49
Expected Case	AECO	2027-2028	$ 4.83	$ 4.86	$ 4.71	$ 4.67	$ 4.71	$ 4.48	$ 4.44	$ 4.42	$ 4.42	$ 4.44	$ 4.52	$ 4.58
Expected Case	AECO	2028-2029	$ 5.05	$ 5.12	$ 5.24	$ 5.32	$ 5.30	$ 4.98	$ 4.92	$ 4.88	$ 4.86	$ 4.87	$ 4.93	$ 4.98
Expected Case	AECO	2029-2030	$ 5.32	$ 5.37	$ 5.36	$ 5.24	$ 5.21	$ 4.84	$ 4.72	$ 4.69	$ 4.68	$ 4.69	$ 4.78	$ 4.85
Expected Case	AECO	2030-2031	$ 5.42	$ 5.50	$ 5.40	$ 5.27	$ 5.30	$ 5.04	$ 5.01	$ 4.98	$ 5.02	$ 5.04	$ 5.12	$ 5.20
Expected Case	AECO	2031-2032	$ 5.67	$ 5.39	$ 5.45	$ 5.47	$ 5.65	$ 5.42	$ 5.39	$ 5.31	$ 5.20	$ 5.20	$ 5.39	$ 5.44
Expected Case	AECO	2032-2033	$ 5.73	$ 5.59	$ 5.70	$ 5.73	$ 5.87	$ 5.67	$ 5.66	$ 5.61	$ 5.53	$ 5.53	$ 5.75	$ 5.80
Expected Case	Malin	2013-2014	$ 3.62	$ 4.53	$ 4.69	$ 3.81	$ 3.83	$ 3.82	$ 3.78	$ 3.77	$ 3.77	$ 3.71	$ 3.74	$ 3.61
Expected Case	Malin	2014-2015	$ 3.71	$ 3.75	$ 3.79	$ 3.83	$ 3.82	$ 3.76	$ 3.74	$ 3.79	$ 3.86	$ 3.90	$ 3.96	$ 4.03
Expected Case	Malin	2015-2016	$ 4.25	$ 4.43	$ 4.49	$ 4.39	$ 4.30	$ 4.16	$ 4.04	$ 4.01	$ 4.03	$ 3.89	$ 3.85	$ 3.83
Expected Case	Malin	2016-2017	$ 4.04	$ 3.99	$ 3.97	$ 3.97	$ 3.93	$ 3.88	$ 3.91	$ 3.92	$ 3.93	$ 3.96	$ 4.00	$ 4.00
Expected Case	Malin	2017-2018	$ 4.17	$ 4.17	$ 4.16	$ 4.12	$ 4.02	$ 3.92	$ 3.91	$ 3.85	$ 3.83	$ 3.87	$ 3.92	$ 3.90
Expected Case	Malin	2018-2019	$ 4.08	$ 4.00	$ 3.85	$ 3.82	$ 3.83	$ 3.81	$ 3.82	$ 3.81	$ 3.84	$ 3.86	$ 3.92	$ 3.96
Expected Case	Malin	2019-2020	$ 4.09	$ 4.05	$ 3.79	$ 3.79	$ 3.91	$ 3.93	$ 3.89	$ 3.91	$ 3.94	$ 3.98	$ 4.00	$ 4.04
Expected Case	Malin	2020-2021	$ 4.20	$ 4.14	$ 3.83	$ 3.88	$ 4.06	$ 4.22	$ 4.15	$ 4.19	$ 4.24	$ 4.27	$ 4.35	$ 4.40
Expected Case	Malin	2021-2022	$ 4.55	$ 4.49	$ 4.41	$ 4.30	$ 4.27	$ 4.16	$ 4.13	$ 4.11	$ 4.11	$ 4.15	$ 4.29	$ 4.34
Expected Case	Malin	2022-2023	$ 4.63	$ 4.54	$ 4.45	$ 4.45	$ 4.45	$ 4.35	$ 4.21	$ 4.13	$ 4.14	$ 4.15	$ 4.36	$ 4.42
Expected Case	Malin	2023-2024	$ 4.76	$ 4.68	$ 4.72	$ 4.64	$ 4.79	$ 4.69	$ 4.51	$ 4.49	$ 4.51	$ 4.56	$ 4.66	$ 4.72
Expected Case	Malin	2024-2025	$ 5.05	$ 5.02	$ 5.00	$ 4.83	$ 4.93	$ 4.90	$ 4.86	$ 4.83	$ 4.90	$ 4.92	$ 5.01	$ 5.05
Expected Case	Malin	2025-2026	$ 5.33	$ 5.27	$ 5.22	$ 5.20	$ 5.28	$ 5.14	$ 5.05	$ 5.02	$ 5.08	$ 5.10	$ 5.21	$ 5.24
Expected Case	Malin	2026-2027	$ 5.52	$ 5.53	$ 5.28	$ 5.09	$ 5.24	$ 5.11	$ 5.05	$ 5.03	$ 5.04	$ 5.08	$ 5.15	$ 5.22
Expected Case	Malin	2027-2028	$ 5.56	$ 5.48	$ 5.26	$ 5.16	$ 5.26	$ 5.14	$ 5.08	$ 5.08	$ 5.10	$ 5.17	$ 5.25	$ 5.31
Expected Case	Malin	2028-2029	$ 5.78	$ 5.69	$ 5.80	$ 5.72	$ 5.68	$ 5.54	$ 5.51	$ 5.47	$ 5.52	$ 5.55	$ 5.63	$ 5.68
Expected Case	Malin	2029-2030	$ 6.01	$ 5.94	$ 5.88	$ 5.68	$ 5.64	$ 5.47	$ 5.37	$ 5.34	$ 5.36	$ 5.42	$ 5.52	$ 5.58
Expected Case	Malin	2030-2031	$ 6.14	$ 6.08	$ 5.98	$ 5.75	$ 5.73	$ 5.65	$ 5.64	$ 5.62	$ 5.69	$ 5.75	$ 5.85	$ 5.91
Expected Case	Malin	2031-2032	$ 6.37	$ 6.02	$ 5.95	$ 5.97	$ 6.07	$ 5.90	$ 5.85	$ 5.77	$ 5.65	$ 5.67	$ 5.89	$ 5.99
Expected Case	Malin	2032-2033	$ 6.26	$ 6.12	$ 6.23	$ 6.25	$ 6.29	$ 6.14	$ 6.13	$ 6.06	$ 5.99	$ 6.01	$ 6.26	$ 6.35
Expected Case	Rockies	2013-2014	$ 3.53	$ 4.56	$ 4.66	$ 3.77	$ 3.79	$ 3.77	$ 3.75	$ 3.74	$ 3.73	$ 3.67	$ 3.70	$ 3.57
Expected Case	Rockies	2014-2015	$ 3.67	$ 3.72	$ 3.76	$ 3.80	$ 3.78	$ 3.71	$ 3.71	$ 3.76	$ 3.82	$ 3.86	$ 3.91	$ 3.96
Expected Case	Rockies	2015-2016	$ 4.17	$ 4.39	$ 4.45	$ 4.36	$ 4.26	$ 4.12	$ 4.01	$ 3.98	$ 3.99	$ 3.85	$ 3.80	$ 3.78
Expected Case	Rockies	2016-2017	$ 3.95	$ 3.95	$ 3.93	$ 3.93	$ 3.89	$ 3.83	$ 3.83	$ 3.82	$ 3.83	$ 3.85	$ 3.88	$ 3.89
Expected Case	Rockies	2017-2018	$ 4.07	$ 4.13	$ 4.12	$ 4.08	$ 3.98	$ 3.84	$ 3.81	$ 3.75	$ 3.73	$ 3.72	$ 3.77	$ 3.75
Expected Case	Rockies	2018-2019	$ 3.92	$ 3.95	$ 3.81	$ 3.77	$ 3.78	$ 3.72	$ 3.69	$ 3.68	$ 3.68	$ 3.71	$ 3.76	$ 3.76
Expected Case	Rockies	2019-2020	$ 3.84	$ 3.91	$ 3.75	$ 3.75	$ 3.77	$ 3.71	$ 3.70	$ 3.72	$ 3.73	$ 3.75	$ 3.78	$ 3.81
Expected Case	Rockies	2020-2021	$ 3.90	$ 3.98	$ 3.78	$ 3.80	$ 3.82	$ 3.87	$ 3.94	$ 3.92	$ 4.00	$ 4.03	$ 4.09	$ 4.11
Expected Case	Rockies	2021-2022	$ 4.15	$ 4.25	$ 4.21	$ 4.12	$ 3.92	$ 3.78	$ 3.75	$ 3.73	$ 3.73	$ 3.75	$ 3.85	$ 3.88
Expected Case	Rockies	2022-2023	$ 4.13	$ 4.14	$ 4.15	$ 4.11	$ 4.04	$ 3.94	$ 3.83	$ 3.80	$ 3.82	$ 3.84	$ 3.93	$ 3.99
Expected Case	Rockies	2023-2024	$ 4.22	$ 4.29	$ 4.32	$ 4.30	$ 4.25	$ 4.15	$ 4.03	$ 3.98	$ 4.00	$ 4.01	$ 4.10	$ 4.21
Expected Case	Rockies	2024-2025	$ 4.43	$ 4.50	$ 4.72	$ 4.72	$ 4.61	$ 4.52	$ 4.53	$ 4.50	$ 4.55	$ 4.57	$ 4.62	$ 4.66
Expected Case	Rockies	2025-2026	$ 4.85	$ 4.88	$ 4.90	$ 4.90	$ 4.84	$ 4.73	$ 4.67	$ 4.64	$ 4.67	$ 4.69	$ 4.75	$ 4.83
Expected Case	Rockies	2026-2027	$ 4.97	$ 5.02	$ 5.10	$ 5.00	$ 4.96	$ 4.86	$ 4.83	$ 4.81	$ 4.84	$ 4.85	$ 4.92	$ 4.97
Expected Case	Rockies	2027-2028	$ 5.19	$ 5.24	$ 5.10	$ 5.07	$ 4.99	$ 4.89	$ 4.88	$ 4.85	$ 4.88	$ 4.91	$ 4.99	$ 5.05
Expected Case	Rockies	2028-2029	$ 5.39	$ 5.45	$ 5.50	$ 5.43	$ 5.36	$ 5.24	$ 5.22	$ 5.15	$ 5.18	$ 5.21	$ 5.27	$ 5.29
Expected Case	Rockies	2029-2030	$ 5.54	$ 5.56	$ 5.55	$ 5.44	$ 5.28	$ 5.16	$ 5.05	$ 5.02	$ 5.05	$ 5.08	$ 5.17	$ 5.24
Expected Case	Rockies	2030-2031	$ 5.58	$ 5.65	$ 5.61	$ 5.52	$ 5.36	$ 5.27	$ 5.26	$ 5.24	$ 5.31	$ 5.36	$ 5.44	$ 5.47
Expected Case	Rockies	2031-2032	$ 5.81	$ 5.64	$ 5.53	$ 5.55	$ 5.62	$ 5.49	$ 5.44	$ 5.35	$ 5.25	$ 5.26	$ 5.47	$ 5.54
Expected Case	Rockies	2032-2033	$ 5.76	$ 5.67	$ 5.76	$ 5.78	$ 5.81	$ 5.71	$ 5.69	$ 5.61	$ 5.55	$ 5.56	$ 5.79	$ 5.86

APPENDIX 5.1: MONTHLY PRICE DATA BY BASIN
EXPECTED PRICE

2012$														
Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Expected Case	Stanfield	2013-2014	$ 3.60	$ 4.56	$ 4.66	$ 3.72	$ 3.76	$ 3.73	$ 3.72	$ 3.73	$ 3.73	$ 3.67	$ 3.69	$ 3.53
Expected Case	Stanfield	2014-2015	$ 3.67	$ 3.66	$ 3.72	$ 3.76	$ 3.78	$ 3.67	$ 3.71	$ 3.75	$ 3.81	$ 3.85	$ 3.90	$ 3.94
Expected Case	Stanfield	2015-2016	$ 4.17	$ 4.43	$ 4.49	$ 4.39	$ 4.24	$ 4.08	$ 3.96	$ 3.97	$ 3.99	$ 3.82	$ 3.77	$ 3.74
Expected Case	Stanfield	2016-2017	$ 3.95	$ 3.99	$ 3.97	$ 3.88	$ 3.85	$ 3.78	$ 3.78	$ 3.78	$ 3.79	$ 3.81	$ 3.85	$ 3.87
Expected Case	Stanfield	2017-2018	$ 4.15	$ 4.18	$ 4.17	$ 4.03	$ 3.94	$ 3.79	$ 3.76	$ 3.69	$ 3.68	$ 3.69	$ 3.73	$ 3.71
Expected Case	Stanfield	2018-2019	$ 4.04	$ 4.00	$ 3.85	$ 3.83	$ 3.75	$ 3.76	$ 3.64	$ 3.62	$ 3.65	$ 3.66	$ 3.71	$ 3.85
Expected Case	Stanfield	2019-2020	$ 3.91	$ 4.04	$ 3.79	$ 3.70	$ 3.82	$ 3.75	$ 3.71	$ 3.72	$ 3.76	$ 3.78	$ 3.80	$ 3.84
Expected Case	Stanfield	2020-2021	$ 4.01	$ 4.07	$ 3.84	$ 3.79	$ 3.96	$ 4.02	$ 3.98	$ 4.01	$ 4.04	$ 4.07	$ 4.15	$ 4.19
Expected Case	Stanfield	2021-2022	$ 4.45	$ 4.48	$ 4.46	$ 4.36	$ 4.17	$ 4.00	$ 3.96	$ 3.93	$ 3.93	$ 3.95	$ 4.09	$ 4.13
Expected Case	Stanfield	2022-2023	$ 4.56	$ 4.54	$ 4.35	$ 4.35	$ 4.28	$ 4.15	$ 4.03	$ 4.01	$ 4.01	$ 4.02	$ 4.13	$ 4.18
Expected Case	Stanfield	2023-2024	$ 4.65	$ 4.68	$ 4.74	$ 4.57	$ 4.64	$ 4.48	$ 4.34	$ 4.31	$ 4.30	$ 4.32	$ 4.45	$ 4.51
Expected Case	Stanfield	2024-2025	$ 4.97	$ 5.02	$ 4.90	$ 4.78	$ 4.81	$ 4.70	$ 4.69	$ 4.65	$ 4.67	$ 4.69	$ 4.78	$ 4.83
Expected Case	Stanfield	2025-2026	$ 5.24	$ 5.27	$ 5.24	$ 5.10	$ 5.10	$ 4.93	$ 4.85	$ 4.82	$ 4.85	$ 4.86	$ 4.96	$ 5.11
Expected Case	Stanfield	2026-2027	$ 5.42	$ 5.47	$ 5.30	$ 5.05	$ 5.13	$ 5.02	$ 4.86	$ 4.83	$ 4.84	$ 4.86	$ 4.92	$ 5.12
Expected Case	Stanfield	2027-2028	$ 5.45	$ 5.48	$ 5.27	$ 5.06	$ 5.11	$ 5.05	$ 4.89	$ 4.88	$ 4.90	$ 4.93	$ 5.01	$ 5.20
Expected Case	Stanfield	2028-2029	$ 5.67	$ 5.69	$ 5.82	$ 5.79	$ 5.61	$ 5.39	$ 5.34	$ 5.29	$ 5.32	$ 5.34	$ 5.42	$ 5.46
Expected Case	Stanfield	2029-2030	$ 5.95	$ 5.96	$ 5.94	$ 5.74	$ 5.54	$ 5.41	$ 5.17	$ 5.14	$ 5.14	$ 5.18	$ 5.28	$ 5.48
Expected Case	Stanfield	2030-2031	$ 6.06	$ 6.11	$ 6.00	$ 5.82	$ 5.66	$ 5.59	$ 5.46	$ 5.44	$ 5.48	$ 5.53	$ 5.61	$ 5.68
Expected Case	Stanfield	2031-2032	$ 6.31	$ 6.02	$ 5.94	$ 5.97	$ 6.06	$ 5.74	$ 5.69	$ 5.60	$ 5.48	$ 5.48	$ 5.69	$ 5.80
Expected Case	Stanfield	2032-2033	$ 6.25	$ 6.11	$ 6.22	$ 6.24	$ 6.29	$ 5.98	$ 6.08	$ 5.89	$ 5.81	$ 5.82	$ 6.07	$ 6.16
Expected Case	Sumas	2013-2014	$ 3.93	$ 5.31	$ 4.68	$ 3.87	$ 3.83	$ 3.60	$ 3.66	$ 3.60	$ 3.63	$ 3.50	$ 3.56	$ 3.40
Expected Case	Sumas	2014-2015	$ 3.82	$ 3.97	$ 3.98	$ 3.91	$ 3.82	$ 3.55	$ 3.65	$ 3.61	$ 3.67	$ 3.67	$ 3.78	$ 3.84
Expected Case	Sumas	2015-2016	$ 4.33	$ 4.65	$ 4.66	$ 4.46	$ 4.30	$ 3.92	$ 3.91	$ 3.83	$ 3.84	$ 3.64	$ 3.61	$ 3.62
Expected Case	Sumas	2016-2017	$ 4.11	$ 4.21	$ 4.14	$ 4.04	$ 3.93	$ 3.59	$ 3.68	$ 3.64	$ 3.65	$ 3.59	$ 3.67	$ 3.75
Expected Case	Sumas	2017-2018	$ 4.22	$ 4.39	$ 4.34	$ 4.20	$ 4.03	$ 3.65	$ 3.63	$ 3.54	$ 3.51	$ 3.43	$ 3.50	$ 3.58
Expected Case	Sumas	2018-2019	$ 4.11	$ 4.22	$ 4.02	$ 3.90	$ 3.84	$ 3.50	$ 3.48	$ 3.43	$ 3.46	$ 3.42	$ 3.45	$ 3.47
Expected Case	Sumas	2019-2020	$ 3.94	$ 4.26	$ 3.96	$ 3.86	$ 3.79	$ 3.50	$ 3.58	$ 3.56	$ 3.58	$ 3.56	$ 3.56	$ 3.60
Expected Case	Sumas	2020-2021	$ 4.01	$ 4.29	$ 4.00	$ 3.95	$ 3.95	$ 3.75	$ 3.86	$ 3.86	$ 3.85	$ 3.85	$ 3.90	$ 3.92
Expected Case	Sumas	2021-2022	$ 4.52	$ 4.70	$ 4.63	$ 4.43	$ 4.22	$ 3.80	$ 3.85	$ 3.79	$ 3.79	$ 3.77	$ 3.88	$ 3.91
Expected Case	Sumas	2022-2023	$ 4.63	$ 4.76	$ 4.62	$ 4.37	$ 4.18	$ 3.92	$ 3.86	$ 3.79	$ 3.84	$ 3.78	$ 3.90	$ 3.95
Expected Case	Sumas	2023-2024	$ 4.50	$ 4.90	$ 4.91	$ 4.65	$ 4.58	$ 4.29	$ 4.22	$ 4.16	$ 4.19	$ 4.13	$ 4.26	$ 4.33
Expected Case	Sumas	2024-2025	$ 4.81	$ 5.23	$ 5.18	$ 4.87	$ 4.76	$ 4.51	$ 4.53	$ 4.48	$ 4.51	$ 4.46	$ 4.57	$ 4.65
Expected Case	Sumas	2025-2026	$ 5.08	$ 5.49	$ 5.41	$ 5.27	$ 5.05	$ 4.72	$ 4.69	$ 4.63	$ 4.66	$ 4.61	$ 4.72	$ 4.74
Expected Case	Sumas	2026-2027	$ 5.26	$ 5.69	$ 5.47	$ 5.22	$ 5.07	$ 4.68	$ 4.70	$ 4.63	$ 4.67	$ 4.63	$ 4.72	$ 4.75
Expected Case	Sumas	2027-2028	$ 5.31	$ 5.70	$ 5.44	$ 5.23	$ 5.05	$ 4.71	$ 4.72	$ 4.67	$ 4.71	$ 4.70	$ 4.78	$ 4.81
Expected Case	Sumas	2028-2029	$ 5.74	$ 5.91	$ 5.99	$ 5.86	$ 5.68	$ 5.23	$ 5.24	$ 5.14	$ 5.19	$ 5.18	$ 5.24	$ 5.26
Expected Case	Sumas	2029-2030	$ 6.02	$ 6.25	$ 6.31	$ 5.81	$ 5.64	$ 5.08	$ 5.02	$ 4.94	$ 4.99	$ 4.97	$ 5.06	$ 5.12
Expected Case	Sumas	2030-2031	$ 6.13	$ 6.39	$ 6.47	$ 5.89	$ 5.76	$ 5.28	$ 5.32	$ 5.24	$ 5.35	$ 5.34	$ 5.42	$ 5.47
Expected Case	Sumas	2031-2032	$ 6.38	$ 6.41	$ 6.16	$ 6.19	$ 6.11	$ 5.58	$ 5.45	$ 5.19	$ 5.34	$ 5.33	$ 5.50	$ 5.62
Expected Case	Sumas	2032-2033	$ 6.30	$ 6.43	$ 6.55	$ 6.58	$ 6.34	$ 5.83	$ 5.73	$ 5.49	$ 5.67	$ 5.67	$ 5.87	$ 5.98

Appendix 5.1: Monthly Price Data by Basin
High Growth Low Price

								2012$						
Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
High Growth & Low Prices	AECo	2013-2014	$ 3.44	$ 3.35	$ 3.36	$ 3.38	$ 3.50	$ 3.48	$ 3.44	$ 3.45	$ 3.43	$ 3.42	$ 3.45	$ 3.47
High Growth & Low Prices	AECo	2014-2015	$ 3.50	$ 3.43	$ 3.55	$ 3.56	$ 3.70	$ 3.63	$ 3.56	$ 3.55	$ 3.52	$ 3.51	$ 3.55	$ 3.61
High Growth & Low Prices	AECo	2015-2016	$ 3.63	$ 3.54	$ 3.45	$ 3.46	$ 3.62	$ 3.55	$ 3.49	$ 3.51	$ 3.48	$ 3.45	$ 3.46	$ 3.50
High Growth & Low Prices	AECo	2016-2017	$ 3.54	$ 3.45	$ 3.41	$ 3.43	$ 3.54	$ 3.44	$ 3.37	$ 3.37	$ 3.35	$ 3.34	$ 3.36	$ 3.41
High Growth & Low Prices	AECo	2017-2018	$ 3.42	$ 3.31	$ 3.30	$ 3.29	$ 3.40	$ 3.33	$ 3.28	$ 3.28	$ 3.26	$ 3.24	$ 3.25	$ 3.29
High Growth & Low Prices	AECo	2018-2019	$ 3.40	$ 3.27	$ 3.11	$ 3.12	$ 3.31	$ 3.22	$ 3.17	$ 3.14	$ 3.12	$ 3.10	$ 3.12	$ 3.17
High Growth & Low Prices	AECo	2019-2020	$ 3.30	$ 3.18	$ 3.06	$ 3.11	$ 3.37	$ 3.28	$ 3.21	$ 3.18	$ 3.14	$ 3.13	$ 3.15	$ 3.20
High Growth & Low Prices	AECo	2020-2021	$ 3.28	$ 3.13	$ 3.12	$ 3.16	$ 3.38	$ 3.28	$ 3.20	$ 3.16	$ 3.08	$ 3.07	$ 3.13	$ 3.18
High Growth & Low Prices	AECo	2021-2022	$ 3.27	$ 3.24	$ 3.32	$ 3.36	$ 3.48	$ 3.38	$ 3.31	$ 3.25	$ 3.22	$ 3.21	$ 3.29	$ 3.34
High Growth & Low Prices	AECo	2022-2023	$ 3.39	$ 3.32	$ 3.20	$ 3.19	$ 3.32	$ 3.19	$ 3.05	$ 2.99	$ 2.96	$ 2.94	$ 3.01	$ 3.06
High Growth & Low Prices	AECo	2023-2024	$ 3.27	$ 3.25	$ 3.24	$ 3.27	$ 3.43	$ 3.31	$ 3.18	$ 3.11	$ 3.06	$ 3.05	$ 3.14	$ 3.18
High Growth & Low Prices	AECo	2024-2025	$ 3.29	$ 3.31	$ 3.39	$ 3.37	$ 3.50	$ 3.39	$ 3.33	$ 3.28	$ 3.22	$ 3.22	$ 3.30	$ 3.35
High Growth & Low Prices	AECo	2025-2026	$ 3.44	$ 3.42	$ 3.31	$ 3.33	$ 3.48	$ 3.35	$ 3.24	$ 3.17	$ 3.13	$ 3.12	$ 3.20	$ 3.25
High Growth & Low Prices	AECo	2026-2027	$ 3.40	$ 3.39	$ 3.23	$ 3.15	$ 3.45	$ 3.24	$ 3.16	$ 3.08	$ 3.05	$ 3.04	$ 3.13	$ 3.18
High Growth & Low Prices	AECo	2027-2028	$ 3.35	$ 3.32	$ 3.07	$ 3.04	$ 3.32	$ 3.16	$ 3.09	$ 3.03	$ 2.98	$ 2.98	$ 3.05	$ 3.11
High Growth & Low Prices	AECo	2028-2029	$ 3.33	$ 3.30	$ 3.30	$ 3.36	$ 3.58	$ 3.37	$ 3.31	$ 3.24	$ 3.20	$ 3.18	$ 3.24	$ 3.28
High Growth & Low Prices	AECo	2029-2030	$ 3.44	$ 3.44	$ 3.42	$ 3.31	$ 3.63	$ 3.34	$ 3.26	$ 3.19	$ 3.15	$ 3.13	$ 3.19	$ 3.26
High Growth & Low Prices	AECo	2030-2031	$ 3.57	$ 3.52	$ 3.32	$ 3.22	$ 3.61	$ 3.41	$ 3.36	$ 3.29	$ 3.28	$ 3.27	$ 3.34	$ 3.39
High Growth & Low Prices	AECo	2031-2032	$ 3.55	$ 3.31	$ 3.27	$ 3.28	$ 3.44	$ 3.28	$ 3.27	$ 3.19	$ 3.08	$ 3.07	$ 3.21	$ 3.26
High Growth & Low Prices	AECo	2032-2033	$ 3.37	$ 3.31	$ 3.31	$ 3.30	$ 3.45	$ 3.28	$ 3.27	$ 3.22	$ 3.10	$ 3.08	$ 3.24	$ 3.31
High Growth & Low Prices	Malin	2013-2014	$ 3.90	$ 3.87	$ 3.85	$ 3.85	$ 3.88	$ 3.88	$ 3.85	$ 3.84	$ 3.84	$ 3.83	$ 3.86	$ 3.91
High Growth & Low Prices	Malin	2014-2015	$ 3.93	$ 3.93	$ 4.00	$ 4.01	$ 4.04	$ 4.03	$ 3.96	$ 3.95	$ 3.93	$ 3.92	$ 3.97	$ 4.02
High Growth & Low Prices	Malin	2015-2016	$ 4.09	$ 4.06	$ 3.98	$ 3.97	$ 3.99	$ 3.99	$ 3.93	$ 3.90	$ 3.89	$ 3.89	$ 3.94	$ 3.96
High Growth & Low Prices	Malin	2016-2017	$ 4.07	$ 3.98	$ 3.92	$ 3.91	$ 3.93	$ 3.91	$ 3.91	$ 3.89	$ 3.89	$ 3.89	$ 3.94	$ 3.94
High Growth & Low Prices	Malin	2017-2018	$ 3.99	$ 3.88	$ 3.84	$ 3.80	$ 3.83	$ 3.87	$ 3.87	$ 3.85	$ 3.84	$ 3.87	$ 3.92	$ 3.92
High Growth & Low Prices	Malin	2018-2019	$ 4.01	$ 3.86	$ 3.70	$ 3.66	$ 3.78	$ 3.81	$ 3.81	$ 3.79	$ 3.77	$ 3.79	$ 3.82	$ 3.87
High Growth & Low Prices	Malin	2019-2020	$ 3.93	$ 3.77	$ 3.61	$ 3.59	$ 3.83	$ 3.89	$ 3.82	$ 3.79	$ 3.78	$ 3.78	$ 3.82	$ 3.86
High Growth & Low Prices	Malin	2020-2021	$ 3.95	$ 3.80	$ 3.63	$ 3.63	$ 3.87	$ 3.93	$ 3.78	$ 3.74	$ 3.73	$ 3.73	$ 3.81	$ 3.86
High Growth & Low Prices	Malin	2021-2022	$ 3.98	$ 3.84	$ 3.76	$ 3.71	$ 3.89	$ 3.95	$ 3.90	$ 3.84	$ 3.82	$ 3.84	$ 3.95	$ 4.00
High Growth & Low Prices	Malin	2022-2023	$ 4.06	$ 3.88	$ 3.71	$ 3.71	$ 3.86	$ 3.83	$ 3.69	$ 3.57	$ 3.55	$ 3.53	$ 3.72	$ 3.76
High Growth & Low Prices	Malin	2023-2024	$ 4.00	$ 3.82	$ 3.75	$ 3.66	$ 3.96	$ 3.96	$ 3.77	$ 3.71	$ 3.69	$ 3.71	$ 3.82	$ 3.85
High Growth & Low Prices	Malin	2024-2025	$ 4.01	$ 3.89	$ 3.89	$ 3.72	$ 3.98	$ 4.03	$ 3.96	$ 3.89	$ 3.91	$ 3.91	$ 4.01	$ 4.03
High Growth & Low Prices	Malin	2025-2026	$ 4.16	$ 4.00	$ 3.86	$ 3.83	$ 4.06	$ 4.01	$ 3.89	$ 3.83	$ 3.84	$ 3.84	$ 3.96	$ 4.00
High Growth & Low Prices	Malin	2026-2027	$ 4.14	$ 4.07	$ 3.77	$ 3.58	$ 3.94	$ 3.90	$ 3.82	$ 3.74	$ 3.74	$ 3.75	$ 3.84	$ 3.91
High Growth & Low Prices	Malin	2027-2028	$ 4.09	$ 3.94	$ 3.62	$ 3.52	$ 3.87	$ 3.82	$ 3.74	$ 3.69	$ 3.66	$ 3.70	$ 3.78	$ 3.84
High Growth & Low Prices	Malin	2028-2029	$ 4.06	$ 3.88	$ 3.86	$ 3.77	$ 3.97	$ 3.93	$ 3.90	$ 3.84	$ 3.87	$ 3.85	$ 3.93	$ 3.98
High Growth & Low Prices	Malin	2029-2030	$ 4.13	$ 4.00	$ 3.94	$ 3.75	$ 4.06	$ 3.97	$ 3.91	$ 3.84	$ 3.83	$ 3.87	$ 3.94	$ 3.98
High Growth & Low Prices	Malin	2030-2031	$ 4.29	$ 4.11	$ 3.90	$ 3.70	$ 4.04	$ 4.02	$ 4.00	$ 3.93	$ 3.94	$ 3.98	$ 4.06	$ 4.09
High Growth & Low Prices	Malin	2031-2032	$ 4.25	$ 3.95	$ 3.77	$ 3.78	$ 3.86	$ 3.76	$ 3.73	$ 3.65	$ 3.54	$ 3.53	$ 3.71	$ 3.82
High Growth & Low Prices	Malin	2032-2033	$ 3.90	$ 3.85	$ 3.83	$ 3.83	$ 3.87	$ 3.75	$ 3.74	$ 3.67	$ 3.56	$ 3.56	$ 3.76	$ 3.86
High Growth & Low Prices	Rockies	2013-2014	$ 3.86	$ 3.84	$ 3.82	$ 3.81	$ 3.85	$ 3.83	$ 3.82	$ 3.81	$ 3.80	$ 3.79	$ 3.81	$ 3.86
High Growth & Low Prices	Rockies	2014-2015	$ 3.89	$ 3.89	$ 3.97	$ 3.97	$ 4.01	$ 3.97	$ 3.93	$ 3.92	$ 3.89	$ 3.88	$ 3.93	$ 3.95
High Growth & Low Prices	Rockies	2015-2016	$ 4.02	$ 4.02	$ 3.94	$ 3.94	$ 3.95	$ 3.95	$ 3.90	$ 3.87	$ 3.84	$ 3.84	$ 3.89	$ 3.91
High Growth & Low Prices	Rockies	2016-2017	$ 3.98	$ 3.94	$ 3.89	$ 3.87	$ 3.90	$ 3.86	$ 3.83	$ 3.80	$ 3.79	$ 3.78	$ 3.82	$ 3.84
High Growth & Low Prices	Rockies	2017-2018	$ 3.89	$ 3.83	$ 3.80	$ 3.76	$ 3.79	$ 3.79	$ 3.78	$ 3.75	$ 3.74	$ 3.73	$ 3.77	$ 3.77
High Growth & Low Prices	Rockies	2018-2019	$ 3.85	$ 3.81	$ 3.66	$ 3.61	$ 3.73	$ 3.73	$ 3.68	$ 3.65	$ 3.61	$ 3.64	$ 3.67	$ 3.68
High Growth & Low Prices	Rockies	2019-2020	$ 3.68	$ 3.63	$ 3.57	$ 3.54	$ 3.69	$ 3.67	$ 3.62	$ 3.60	$ 3.57	$ 3.56	$ 3.60	$ 3.62
High Growth & Low Prices	Rockies	2020-2021	$ 3.65	$ 3.65	$ 3.57	$ 3.55	$ 3.63	$ 3.58	$ 3.57	$ 3.48	$ 3.49	$ 3.48	$ 3.54	$ 3.57
High Growth & Low Prices	Rockies	2021-2022	$ 3.58	$ 3.61	$ 3.57	$ 3.52	$ 3.54	$ 3.57	$ 3.52	$ 3.46	$ 3.44	$ 3.44	$ 3.52	$ 3.54
High Growth & Low Prices	Rockies	2022-2023	$ 3.56	$ 3.49	$ 3.41	$ 3.37	$ 3.45	$ 3.41	$ 3.30	$ 3.24	$ 3.23	$ 3.22	$ 3.29	$ 3.33
High Growth & Low Prices	Rockies	2023-2024	$ 3.46	$ 3.43	$ 3.35	$ 3.31	$ 3.42	$ 3.42	$ 3.29	$ 3.20	$ 3.18	$ 3.17	$ 3.26	$ 3.34
High Growth & Low Prices	Rockies	2024-2025	$ 3.38	$ 3.38	$ 3.61	$ 3.62	$ 3.66	$ 3.65	$ 3.63	$ 3.56	$ 3.56	$ 3.56	$ 3.62	$ 3.64
High Growth & Low Prices	Rockies	2025-2026	$ 3.68	$ 3.61	$ 3.53	$ 3.52	$ 3.61	$ 3.60	$ 3.51	$ 3.44	$ 3.44	$ 3.43	$ 3.50	$ 3.58
High Growth & Low Prices	Rockies	2026-2027	$ 3.59	$ 3.57	$ 3.59	$ 3.48	$ 3.66	$ 3.65	$ 3.60	$ 3.52	$ 3.53	$ 3.52	$ 3.61	$ 3.65
High Growth & Low Prices	Rockies	2027-2028	$ 3.71	$ 3.70	$ 3.47	$ 3.43	$ 3.60	$ 3.57	$ 3.53	$ 3.45	$ 3.45	$ 3.45	$ 3.52	$ 3.58
High Growth & Low Prices	Rockies	2028-2029	$ 3.67	$ 3.63	$ 3.56	$ 3.47	$ 3.65	$ 3.64	$ 3.61	$ 3.51	$ 3.52	$ 3.52	$ 3.58	$ 3.59
High Growth & Low Prices	Rockies	2029-2030	$ 3.66	$ 3.63	$ 3.61	$ 3.51	$ 3.70	$ 3.66	$ 3.59	$ 3.52	$ 3.52	$ 3.52	$ 3.58	$ 3.64
High Growth & Low Prices	Rockies	2030-2031	$ 3.73	$ 3.67	$ 3.53	$ 3.46	$ 3.67	$ 3.64	$ 3.61	$ 3.54	$ 3.56	$ 3.59	$ 3.65	$ 3.66
High Growth & Low Prices	Rockies	2031-2032	$ 3.68	$ 3.56	$ 3.36	$ 3.36	$ 3.42	$ 3.35	$ 3.32	$ 3.23	$ 3.13	$ 3.12	$ 3.29	$ 3.36
High Growth & Low Prices	Rockies	2032-2033	$ 3.40	$ 3.39	$ 3.36	$ 3.36	$ 3.38	$ 3.32	$ 3.30	$ 3.22	$ 3.13	$ 3.11	$ 3.29	$ 3.37

Appendix 5.1: Monthly Price Data by Basin
High Growth Low Price

							2012$							
Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
High Growth & Low Prices	Stanfield	2013-2014	$ 3.82	$ 3.87	$ 3.85	$ 3.76	$ 3.81	$ 3.79	$ 3.80	$ 3.81	$ 3.79	$ 3.79	$ 3.81	$ 3.82
High Growth & Low Prices	Stanfield	2014-2015	$ 3.89	$ 3.83	$ 3.93	$ 3.94	$ 4.01	$ 3.94	$ 3.92	$ 3.91	$ 3.89	$ 3.87	$ 3.91	$ 3.93
High Growth & Low Prices	Stanfield	2015-2016	$ 4.02	$ 4.06	$ 3.98	$ 3.98	$ 3.93	$ 3.90	$ 3.85	$ 3.87	$ 3.84	$ 3.81	$ 3.86	$ 3.87
High Growth & Low Prices	Stanfield	2016-2017	$ 3.97	$ 3.99	$ 3.93	$ 3.82	$ 3.86	$ 3.82	$ 3.77	$ 3.75	$ 3.75	$ 3.75	$ 3.78	$ 3.81
High Growth & Low Prices	Stanfield	2017-2018	$ 3.97	$ 3.88	$ 3.85	$ 3.70	$ 3.75	$ 3.74	$ 3.73	$ 3.70	$ 3.69	$ 3.69	$ 3.73	$ 3.73
High Growth & Low Prices	Stanfield	2018-2019	$ 3.97	$ 3.86	$ 3.70	$ 3.67	$ 3.69	$ 3.77	$ 3.63	$ 3.60	$ 3.58	$ 3.59	$ 3.62	$ 3.77
High Growth & Low Prices	Stanfield	2019-2020	$ 3.75	$ 3.75	$ 3.61	$ 3.50	$ 3.74	$ 3.71	$ 3.63	$ 3.60	$ 3.60	$ 3.58	$ 3.62	$ 3.65
High Growth & Low Prices	Stanfield	2020-2021	$ 3.76	$ 3.73	$ 3.63	$ 3.54	$ 3.77	$ 3.73	$ 3.61	$ 3.57	$ 3.53	$ 3.53	$ 3.61	$ 3.65
High Growth & Low Prices	Stanfield	2021-2022	$ 3.88	$ 3.84	$ 3.82	$ 3.76	$ 3.80	$ 3.79	$ 3.73	$ 3.67	$ 3.64	$ 3.63	$ 3.75	$ 3.80
High Growth & Low Prices	Stanfield	2022-2023	$ 4.00	$ 3.88	$ 3.61	$ 3.61	$ 3.70	$ 3.63	$ 3.51	$ 3.45	$ 3.42	$ 3.41	$ 3.49	$ 3.52
High Growth & Low Prices	Stanfield	2023-2024	$ 3.89	$ 3.82	$ 3.76	$ 3.59	$ 3.80	$ 3.75	$ 3.59	$ 3.53	$ 3.49	$ 3.48	$ 3.60	$ 3.64
High Growth & Low Prices	Stanfield	2024-2025	$ 3.92	$ 3.89	$ 3.79	$ 3.68	$ 3.86	$ 3.82	$ 3.79	$ 3.71	$ 3.68	$ 3.68	$ 3.77	$ 3.81
High Growth & Low Prices	Stanfield	2025-2026	$ 4.07	$ 4.00	$ 3.88	$ 3.72	$ 3.88	$ 3.81	$ 3.69	$ 3.63	$ 3.61	$ 3.60	$ 3.71	$ 3.86
High Growth & Low Prices	Stanfield	2026-2027	$ 4.03	$ 4.02	$ 3.79	$ 3.53	$ 3.82	$ 3.82	$ 3.63	$ 3.55	$ 3.53	$ 3.53	$ 3.62	$ 3.81
High Growth & Low Prices	Stanfield	2027-2028	$ 3.98	$ 3.94	$ 3.63	$ 3.43	$ 3.72	$ 3.73	$ 3.55	$ 3.49	$ 3.46	$ 3.46	$ 3.54	$ 3.73
High Growth & Low Prices	Stanfield	2028-2029	$ 3.95	$ 3.88	$ 3.88	$ 3.83	$ 3.90	$ 3.78	$ 3.73	$ 3.66	$ 3.66	$ 3.65	$ 3.73	$ 3.76
High Growth & Low Prices	Stanfield	2029-2030	$ 4.07	$ 4.02	$ 4.00	$ 3.81	$ 3.97	$ 3.91	$ 3.72	$ 3.64	$ 3.61	$ 3.63	$ 3.70	$ 3.88
High Growth & Low Prices	Stanfield	2030-2031	$ 4.21	$ 4.13	$ 3.92	$ 3.76	$ 3.98	$ 3.96	$ 3.81	$ 3.75	$ 3.74	$ 3.75	$ 3.82	$ 3.87
High Growth & Low Prices	Stanfield	2031-2032	$ 4.18	$ 3.94	$ 3.77	$ 3.78	$ 3.86	$ 3.60	$ 3.56	$ 3.48	$ 3.36	$ 3.35	$ 3.52	$ 3.62
High Growth & Low Prices	Stanfield	2032-2033	$ 3.88	$ 3.83	$ 3.82	$ 3.82	$ 3.87	$ 3.59	$ 3.69	$ 3.51	$ 3.38	$ 3.37	$ 3.56	$ 3.67
High Growth & Low Prices	Sumas	2013-2014	$ 3.97	$ 4.09	$ 4.02	$ 3.91	$ 3.88	$ 3.66	$ 3.73	$ 3.68	$ 3.70	$ 3.62	$ 3.68	$ 3.70
High Growth & Low Prices	Sumas	2014-2015	$ 4.04	$ 4.15	$ 4.19	$ 4.09	$ 4.04	$ 3.82	$ 3.87	$ 3.77	$ 3.74	$ 3.69	$ 3.79	$ 3.83
High Growth & Low Prices	Sumas	2015-2016	$ 4.18	$ 4.28	$ 4.15	$ 4.05	$ 3.99	$ 3.74	$ 3.80	$ 3.72	$ 3.69	$ 3.63	$ 3.70	$ 3.75
High Growth & Low Prices	Sumas	2016-2017	$ 4.14	$ 4.21	$ 4.10	$ 3.98	$ 3.93	$ 3.63	$ 3.68	$ 3.62	$ 3.61	$ 3.53	$ 3.60	$ 3.69
High Growth & Low Prices	Sumas	2017-2018	$ 4.04	$ 4.10	$ 4.01	$ 3.87	$ 3.84	$ 3.60	$ 3.59	$ 3.54	$ 3.52	$ 3.43	$ 3.50	$ 3.60
High Growth & Low Prices	Sumas	2018-2019	$ 4.04	$ 4.08	$ 3.87	$ 3.74	$ 3.78	$ 3.50	$ 3.47	$ 3.40	$ 3.39	$ 3.34	$ 3.36	$ 3.39
High Growth & Low Prices	Sumas	2019-2020	$ 3.79	$ 3.97	$ 3.78	$ 3.66	$ 3.71	$ 3.46	$ 3.50	$ 3.44	$ 3.41	$ 3.36	$ 3.38	$ 3.41
High Growth & Low Prices	Sumas	2020-2021	$ 3.76	$ 3.95	$ 3.80	$ 3.71	$ 3.75	$ 3.46	$ 3.49	$ 3.42	$ 3.34	$ 3.30	$ 3.36	$ 3.38
High Growth & Low Prices	Sumas	2021-2022	$ 3.95	$ 4.06	$ 3.99	$ 3.83	$ 3.84	$ 3.59	$ 3.62	$ 3.53	$ 3.50	$ 3.46	$ 3.54	$ 3.57
High Growth & Low Prices	Sumas	2022-2023	$ 4.07	$ 4.10	$ 3.88	$ 3.63	$ 3.60	$ 3.40	$ 3.33	$ 3.23	$ 3.25	$ 3.16	$ 3.27	$ 3.29
High Growth & Low Prices	Sumas	2023-2024	$ 3.74	$ 4.04	$ 3.93	$ 3.66	$ 3.75	$ 3.57	$ 3.48	$ 3.38	$ 3.37	$ 3.29	$ 3.41	$ 3.46
High Growth & Low Prices	Sumas	2024-2025	$ 3.77	$ 4.11	$ 4.07	$ 3.76	$ 3.82	$ 3.63	$ 3.63	$ 3.54	$ 3.53	$ 3.45	$ 3.57	$ 3.62
High Growth & Low Prices	Sumas	2025-2026	$ 3.91	$ 4.22	$ 4.05	$ 3.90	$ 3.82	$ 3.60	$ 3.53	$ 3.43	$ 3.43	$ 3.35	$ 3.47	$ 3.50
High Growth & Low Prices	Sumas	2026-2027	$ 3.88	$ 4.24	$ 3.96	$ 3.70	$ 3.76	$ 3.47	$ 3.47	$ 3.35	$ 3.37	$ 3.29	$ 3.41	$ 3.44
High Growth & Low Prices	Sumas	2027-2028	$ 3.83	$ 4.16	$ 3.80	$ 3.59	$ 3.65	$ 3.39	$ 3.38	$ 3.28	$ 3.27	$ 3.24	$ 3.31	$ 3.34
High Growth & Low Prices	Sumas	2028-2029	$ 4.02	$ 4.10	$ 4.05	$ 3.90	$ 3.97	$ 3.62	$ 3.63	$ 3.50	$ 3.53	$ 3.48	$ 3.54	$ 3.56
High Growth & Low Prices	Sumas	2029-2030	$ 4.14	$ 4.32	$ 4.38	$ 3.88	$ 4.06	$ 3.58	$ 3.56	$ 3.44	$ 3.46	$ 3.41	$ 3.48	$ 3.52
High Growth & Low Prices	Sumas	2030-2031	$ 4.27	$ 4.42	$ 4.39	$ 3.83	$ 4.08	$ 3.65	$ 3.67	$ 3.55	$ 3.60	$ 3.56	$ 3.63	$ 3.66
High Growth & Low Prices	Sumas	2031-2032	$ 4.25	$ 4.34	$ 3.99	$ 4.00	$ 3.90	$ 3.44	$ 3.33	$ 3.07	$ 3.23	$ 3.20	$ 3.33	$ 3.44
High Growth & Low Prices	Sumas	2032-2033	$ 3.93	$ 4.16	$ 4.15	$ 4.16	$ 3.92	$ 3.44	$ 3.33	$ 3.10	$ 3.25	$ 3.22	$ 3.36	$ 3.49

APPENDIX 5.1: MONTHLY PRICE DATA BY BASIN
LOW GROWTH HIGH PRICE

2012$

Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Low Growth & High Prices	AECo	2013-2014	$ 3.26	$ 3.65	$ 4.18	$ 3.34	$ 3.90	$ 3.88	$ 3.84	$ 3.85	$ 3.83	$ 3.82	$ 3.85	$ 3.87
Low Growth & High Prices	AECo	2014-2015	$ 3.90	$ 3.83	$ 4.15	$ 4.16	$ 4.30	$ 4.23	$ 4.16	$ 4.15	$ 4.12	$ 4.11	$ 4.15	$ 4.21
Low Growth & High Prices	AECo	2015-2016	$ 4.23	$ 4.14	$ 4.25	$ 4.26	$ 4.42	$ 4.35	$ 4.29	$ 4.31	$ 4.28	$ 4.25	$ 4.26	$ 4.30
Low Growth & High Prices	AECo	2016-2017	$ 4.34	$ 4.25	$ 4.41	$ 4.43	$ 4.54	$ 4.44	$ 4.37	$ 4.37	$ 4.35	$ 4.34	$ 4.36	$ 4.41
Low Growth & High Prices	AECo	2017-2018	$ 4.42	$ 4.31	$ 4.60	$ 4.59	$ 4.70	$ 4.63	$ 4.58	$ 4.58	$ 4.56	$ 4.54	$ 4.55	$ 4.59
Low Growth & High Prices	AECo	2018-2019	$ 4.70	$ 4.57	$ 4.61	$ 4.62	$ 4.81	$ 4.72	$ 4.67	$ 4.64	$ 4.62	$ 4.60	$ 4.62	$ 4.67
Low Growth & High Prices	AECo	2019-2020	$ 4.80	$ 4.68	$ 4.66	$ 4.71	$ 4.97	$ 4.88	$ 4.81	$ 4.78	$ 4.74	$ 4.73	$ 4.75	$ 4.80
Low Growth & High Prices	AECo	2020-2021	$ 4.88	$ 4.73	$ 4.84	$ 4.87	$ 5.09	$ 5.00	$ 4.91	$ 4.87	$ 4.79	$ 4.78	$ 4.84	$ 4.89
Low Growth & High Prices	AECo	2021-2022	$ 4.99	$ 4.95	$ 5.32	$ 5.36	$ 5.48	$ 5.38	$ 5.31	$ 5.25	$ 5.23	$ 5.21	$ 5.30	$ 5.34
Low Growth & High Prices	AECo	2022-2023	$ 5.39	$ 5.32	$ 5.39	$ 5.38	$ 5.51	$ 5.38	$ 5.24	$ 5.18	$ 5.15	$ 5.13	$ 5.20	$ 5.24
Low Growth & High Prices	AECo	2023-2024	$ 5.45	$ 5.43	$ 5.71	$ 5.74	$ 5.90	$ 5.78	$ 5.65	$ 5.59	$ 5.54	$ 5.53	$ 5.61	$ 5.66
Low Growth & High Prices	AECo	2024-2025	$ 5.76	$ 5.78	$ 6.04	$ 6.03	$ 6.16	$ 6.04	$ 5.99	$ 5.93	$ 5.88	$ 5.87	$ 5.95	$ 6.00
Low Growth & High Prices	AECo	2025-2026	$ 6.09	$ 6.08	$ 6.25	$ 6.27	$ 6.42	$ 6.29	$ 6.18	$ 6.11	$ 6.06	$ 6.05	$ 6.14	$ 6.19
Low Growth & High Prices	AECo	2026-2027	$ 6.34	$ 6.33	$ 6.45	$ 6.37	$ 6.67	$ 6.46	$ 6.38	$ 6.30	$ 6.27	$ 6.26	$ 6.35	$ 6.40
Low Growth & High Prices	AECo	2027-2028	$ 6.57	$ 6.54	$ 6.57	$ 6.54	$ 6.82	$ 6.66	$ 6.59	$ 6.53	$ 6.48	$ 6.48	$ 6.55	$ 6.61
Low Growth & High Prices	AECo	2028-2029	$ 6.82	$ 6.80	$ 7.07	$ 7.14	$ 7.36	$ 7.15	$ 7.09	$ 7.02	$ 6.98	$ 6.95	$ 7.02	$ 7.06
Low Growth & High Prices	AECo	2029-2030	$ 7.21	$ 7.21	$ 7.47	$ 7.36	$ 7.68	$ 7.39	$ 7.31	$ 7.24	$ 7.20	$ 7.18	$ 7.24	$ 7.31
Low Growth & High Prices	AECo	2030-2031	$ 7.62	$ 7.57	$ 7.64	$ 7.54	$ 7.94	$ 7.73	$ 7.68	$ 7.62	$ 7.60	$ 7.59	$ 7.66	$ 7.71
Low Growth & High Prices	AECo	2031-2032	$ 7.87	$ 7.64	$ 7.87	$ 7.88	$ 8.04	$ 7.88	$ 7.86	$ 7.79	$ 7.68	$ 7.66	$ 7.81	$ 7.86
Low Growth & High Prices	AECo	2032-2033	$ 7.96	$ 7.91	$ 8.28	$ 8.27	$ 8.42	$ 8.25	$ 8.24	$ 8.19	$ 8.07	$ 8.05	$ 8.21	$ 8.28
Low Growth & High Prices	Malin	2013-2014	$ 3.62	$ 4.53	$ 4.69	$ 3.81	$ 4.28	$ 4.28	$ 4.25	$ 4.24	$ 4.24	$ 4.23	$ 4.26	$ 4.31
Low Growth & High Prices	Malin	2014-2015	$ 4.33	$ 4.33	$ 4.60	$ 4.61	$ 4.64	$ 4.63	$ 4.56	$ 4.55	$ 4.53	$ 4.52	$ 4.57	$ 4.62
Low Growth & High Prices	Malin	2015-2016	$ 4.69	$ 4.66	$ 4.78	$ 4.77	$ 4.79	$ 4.79	$ 4.73	$ 4.70	$ 4.69	$ 4.69	$ 4.74	$ 4.76
Low Growth & High Prices	Malin	2016-2017	$ 4.87	$ 4.78	$ 4.92	$ 4.91	$ 4.93	$ 4.91	$ 4.91	$ 4.89	$ 4.89	$ 4.89	$ 4.94	$ 4.94
Low Growth & High Prices	Malin	2017-2018	$ 4.99	$ 4.88	$ 5.14	$ 5.10	$ 5.13	$ 5.17	$ 5.17	$ 5.15	$ 5.14	$ 5.17	$ 5.22	$ 5.22
Low Growth & High Prices	Malin	2018-2019	$ 5.31	$ 5.16	$ 5.20	$ 5.16	$ 5.28	$ 5.31	$ 5.31	$ 5.29	$ 5.27	$ 5.29	$ 5.32	$ 5.37
Low Growth & High Prices	Malin	2019-2020	$ 5.43	$ 5.27	$ 5.21	$ 5.19	$ 5.43	$ 5.49	$ 5.42	$ 5.39	$ 5.38	$ 5.38	$ 5.42	$ 5.46
Low Growth & High Prices	Malin	2020-2021	$ 5.55	$ 5.40	$ 5.34	$ 5.35	$ 5.58	$ 5.65	$ 5.50	$ 5.46	$ 5.44	$ 5.44	$ 5.52	$ 5.58
Low Growth & High Prices	Malin	2021-2022	$ 5.70	$ 5.55	$ 5.76	$ 5.71	$ 5.90	$ 5.95	$ 5.90	$ 5.84	$ 5.82	$ 5.84	$ 5.95	$ 6.00
Low Growth & High Prices	Malin	2022-2023	$ 6.07	$ 5.88	$ 5.90	$ 5.89	$ 6.05	$ 6.02	$ 5.87	$ 5.75	$ 5.74	$ 5.72	$ 5.91	$ 5.95
Low Growth & High Prices	Malin	2023-2024	$ 6.19	$ 6.01	$ 6.22	$ 6.13	$ 6.43	$ 6.43	$ 6.24	$ 6.18	$ 6.16	$ 6.19	$ 6.29	$ 6.33
Low Growth & High Prices	Malin	2024-2025	$ 6.48	$ 6.37	$ 6.55	$ 6.38	$ 6.64	$ 6.68	$ 6.62	$ 6.54	$ 6.57	$ 6.57	$ 6.66	$ 6.68
Low Growth & High Prices	Malin	2025-2026	$ 6.82	$ 6.66	$ 6.80	$ 6.76	$ 6.99	$ 6.95	$ 6.83	$ 6.77	$ 6.78	$ 6.78	$ 6.89	$ 6.93
Low Growth & High Prices	Malin	2026-2027	$ 7.08	$ 7.01	$ 6.99	$ 6.79	$ 7.16	$ 7.12	$ 7.04	$ 6.96	$ 6.95	$ 6.97	$ 7.06	$ 7.13
Low Growth & High Prices	Malin	2027-2028	$ 7.31	$ 7.16	$ 7.12	$ 7.02	$ 7.37	$ 7.32	$ 7.23	$ 7.18	$ 7.16	$ 7.20	$ 7.28	$ 7.33
Low Growth & High Prices	Malin	2028-2029	$ 7.56	$ 7.38	$ 7.63	$ 7.54	$ 7.74	$ 7.71	$ 7.67	$ 7.61	$ 7.64	$ 7.63	$ 7.71	$ 7.76
Low Growth & High Prices	Malin	2029-2030	$ 7.91	$ 7.78	$ 8.00	$ 7.80	$ 8.11	$ 8.03	$ 7.96	$ 7.89	$ 7.88	$ 7.92	$ 7.99	$ 8.04
Low Growth & High Prices	Malin	2030-2031	$ 8.34	$ 8.16	$ 8.23	$ 8.03	$ 8.37	$ 8.34	$ 8.32	$ 8.26	$ 8.27	$ 8.30	$ 8.39	$ 8.42
Low Growth & High Prices	Malin	2031-2032	$ 8.57	$ 8.27	$ 8.37	$ 8.38	$ 8.46	$ 8.36	$ 8.33	$ 8.24	$ 8.13	$ 8.13	$ 8.31	$ 8.41
Low Growth & High Prices	Malin	2032-2033	$ 8.50	$ 8.44	$ 8.80	$ 8.79	$ 8.83	$ 8.72	$ 8.70	$ 8.64	$ 8.53	$ 8.52	$ 8.72	$ 8.83
Low Growth & High Prices	Rockies	2013-2014	$ 3.53	$ 4.56	$ 4.66	$ 3.77	$ 4.25	$ 4.23	$ 4.22	$ 4.21	$ 4.20	$ 4.19	$ 4.21	$ 4.26
Low Growth & High Prices	Rockies	2014-2015	$ 4.29	$ 4.29	$ 4.57	$ 4.57	$ 4.61	$ 4.57	$ 4.53	$ 4.52	$ 4.49	$ 4.48	$ 4.53	$ 4.55
Low Growth & High Prices	Rockies	2015-2016	$ 4.62	$ 4.62	$ 4.74	$ 4.74	$ 4.75	$ 4.75	$ 4.70	$ 4.67	$ 4.64	$ 4.64	$ 4.69	$ 4.71
Low Growth & High Prices	Rockies	2016-2017	$ 4.78	$ 4.74	$ 4.89	$ 4.87	$ 4.90	$ 4.86	$ 4.83	$ 4.80	$ 4.79	$ 4.78	$ 4.82	$ 4.84
Low Growth & High Prices	Rockies	2017-2018	$ 4.89	$ 4.83	$ 5.10	$ 5.06	$ 5.09	$ 5.09	$ 5.08	$ 5.05	$ 5.04	$ 5.03	$ 5.07	$ 5.07
Low Growth & High Prices	Rockies	2018-2019	$ 5.15	$ 5.11	$ 5.16	$ 5.11	$ 5.23	$ 5.23	$ 5.18	$ 5.15	$ 5.11	$ 5.14	$ 5.17	$ 5.18
Low Growth & High Prices	Rockies	2019-2020	$ 5.18	$ 5.13	$ 5.17	$ 5.14	$ 5.29	$ 5.27	$ 5.22	$ 5.20	$ 5.17	$ 5.16	$ 5.20	$ 5.22
Low Growth & High Prices	Rockies	2020-2021	$ 5.25	$ 5.25	$ 5.28	$ 5.27	$ 5.34	$ 5.29	$ 5.28	$ 5.19	$ 5.21	$ 5.20	$ 5.25	$ 5.28
Low Growth & High Prices	Rockies	2021-2022	$ 5.29	$ 5.32	$ 5.57	$ 5.52	$ 5.55	$ 5.57	$ 5.52	$ 5.47	$ 5.44	$ 5.44	$ 5.52	$ 5.54
Low Growth & High Prices	Rockies	2022-2023	$ 5.57	$ 5.49	$ 5.59	$ 5.56	$ 5.64	$ 5.60	$ 5.49	$ 5.43	$ 5.41	$ 5.41	$ 5.48	$ 5.52
Low Growth & High Prices	Rockies	2023-2024	$ 5.65	$ 5.61	$ 5.82	$ 5.79	$ 5.89	$ 5.89	$ 5.76	$ 5.67	$ 5.65	$ 5.64	$ 5.73	$ 5.81
Low Growth & High Prices	Rockies	2024-2025	$ 5.86	$ 5.85	$ 6.27	$ 6.28	$ 6.32	$ 6.31	$ 6.28	$ 6.21	$ 6.22	$ 6.21	$ 6.28	$ 6.29
Low Growth & High Prices	Rockies	2025-2026	$ 6.33	$ 6.27	$ 6.47	$ 6.46	$ 6.55	$ 6.54	$ 6.45	$ 6.38	$ 6.38	$ 6.37	$ 6.44	$ 6.52
Low Growth & High Prices	Rockies	2026-2027	$ 6.53	$ 6.50	$ 6.81	$ 6.70	$ 6.88	$ 6.87	$ 6.82	$ 6.74	$ 6.75	$ 6.74	$ 6.83	$ 6.87
Low Growth & High Prices	Rockies	2027-2028	$ 6.93	$ 6.92	$ 6.96	$ 6.93	$ 7.09	$ 7.07	$ 7.03	$ 6.95	$ 6.95	$ 6.94	$ 7.02	$ 7.08
Low Growth & High Prices	Rockies	2028-2029	$ 7.17	$ 7.13	$ 7.34	$ 7.25	$ 7.42	$ 7.41	$ 7.38	$ 7.29	$ 7.30	$ 7.30	$ 7.35	$ 7.37
Low Growth & High Prices	Rockies	2029-2030	$ 7.43	$ 7.40	$ 7.66	$ 7.56	$ 7.75	$ 7.72	$ 7.64	$ 7.57	$ 7.57	$ 7.57	$ 7.64	$ 7.70
Low Growth & High Prices	Rockies	2030-2031	$ 7.78	$ 7.72	$ 7.86	$ 7.79	$ 8.00	$ 7.97	$ 7.93	$ 7.87	$ 7.89	$ 7.91	$ 7.98	$ 7.99
Low Growth & High Prices	Rockies	2031-2032	$ 8.01	$ 7.89	$ 7.96	$ 7.96	$ 8.01	$ 7.95	$ 7.92	$ 7.83	$ 7.73	$ 7.72	$ 7.89	$ 7.96
Low Growth & High Prices	Rockies	2032-2033	$ 8.00	$ 7.99	$ 8.33	$ 8.33	$ 8.35	$ 8.29	$ 8.27	$ 8.19	$ 8.09	$ 8.08	$ 8.25	$ 8.34

APPENDIX 5.1: MONTHLY PRICE DATA BY BASIN
LOW GROWTH HIGH PRICE

2012$														
Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Low Growth & High Prices	Stanfield	2013-2014	$ 3.60	$ 4.56	$ 4.66	$ 3.72	$ 4.21	$ 4.19	$ 4.20	$ 4.21	$ 4.19	$ 4.19	$ 4.21	$ 4.22
Low Growth & High Prices	Stanfield	2014-2015	$ 4.29	$ 4.23	$ 4.53	$ 4.54	$ 4.61	$ 4.54	$ 4.52	$ 4.51	$ 4.49	$ 4.47	$ 4.51	$ 4.53
Low Growth & High Prices	Stanfield	2015-2016	$ 4.62	$ 4.66	$ 4.78	$ 4.78	$ 4.73	$ 4.70	$ 4.65	$ 4.67	$ 4.64	$ 4.61	$ 4.66	$ 4.67
Low Growth & High Prices	Stanfield	2016-2017	$ 4.77	$ 4.79	$ 4.93	$ 4.82	$ 4.86	$ 4.82	$ 4.77	$ 4.75	$ 4.75	$ 4.75	$ 4.78	$ 4.81
Low Growth & High Prices	Stanfield	2017-2018	$ 4.97	$ 4.88	$ 5.15	$ 5.00	$ 5.05	$ 5.04	$ 5.03	$ 5.00	$ 4.99	$ 4.99	$ 5.03	$ 5.03
Low Growth & High Prices	Stanfield	2018-2019	$ 5.27	$ 5.16	$ 5.20	$ 5.17	$ 5.19	$ 5.27	$ 5.13	$ 5.10	$ 5.08	$ 5.09	$ 5.12	$ 5.27
Low Growth & High Prices	Stanfield	2019-2020	$ 5.25	$ 5.25	$ 5.21	$ 5.10	$ 5.34	$ 5.31	$ 5.23	$ 5.20	$ 5.20	$ 5.18	$ 5.22	$ 5.25
Low Growth & High Prices	Stanfield	2020-2021	$ 5.36	$ 5.33	$ 5.34	$ 5.25	$ 5.48	$ 5.44	$ 5.32	$ 5.28	$ 5.25	$ 5.24	$ 5.32	$ 5.37
Low Growth & High Prices	Stanfield	2021-2022	$ 5.59	$ 5.55	$ 5.82	$ 5.76	$ 5.80	$ 5.79	$ 5.73	$ 5.67	$ 5.64	$ 5.64	$ 5.75	$ 5.80
Low Growth & High Prices	Stanfield	2022-2023	$ 6.00	$ 5.89	$ 5.79	$ 5.79	$ 5.88	$ 5.81	$ 5.69	$ 5.63	$ 5.60	$ 5.59	$ 5.68	$ 5.71
Low Growth & High Prices	Stanfield	2023-2024	$ 6.08	$ 6.01	$ 6.24	$ 6.06	$ 6.27	$ 6.22	$ 6.07	$ 6.00	$ 5.96	$ 5.95	$ 6.07	$ 6.12
Low Growth & High Prices	Stanfield	2024-2025	$ 6.39	$ 6.36	$ 6.44	$ 6.33	$ 6.52	$ 6.48	$ 6.44	$ 6.36	$ 6.34	$ 6.33	$ 6.43	$ 6.46
Low Growth & High Prices	Stanfield	2025-2026	$ 6.72	$ 6.66	$ 6.81	$ 6.66	$ 6.82	$ 6.75	$ 6.63	$ 6.56	$ 6.55	$ 6.54	$ 6.65	$ 6.80
Low Growth & High Prices	Stanfield	2026-2027	$ 6.97	$ 6.96	$ 7.01	$ 6.75	$ 7.04	$ 7.03	$ 6.85	$ 6.77	$ 6.75	$ 6.75	$ 6.83	$ 7.02
Low Growth & High Prices	Stanfield	2027-2028	$ 7.20	$ 7.16	$ 7.13	$ 6.93	$ 7.22	$ 7.23	$ 7.05	$ 6.99	$ 6.96	$ 6.96	$ 7.04	$ 7.23
Low Growth & High Prices	Stanfield	2028-2029	$ 7.45	$ 7.38	$ 7.65	$ 7.60	$ 7.67	$ 7.56	$ 7.50	$ 7.43	$ 7.44	$ 7.42	$ 7.50	$ 7.54
Low Growth & High Prices	Stanfield	2029-2030	$ 7.85	$ 7.80	$ 8.06	$ 7.86	$ 8.02	$ 7.97	$ 7.77	$ 7.69	$ 7.66	$ 7.68	$ 7.75	$ 7.93
Low Growth & High Prices	Stanfield	2030-2031	$ 8.26	$ 8.18	$ 8.25	$ 8.09	$ 8.30	$ 8.29	$ 8.14	$ 8.07	$ 8.06	$ 8.08	$ 8.15	$ 8.19
Low Growth & High Prices	Stanfield	2031-2032	$ 8.51	$ 8.27	$ 8.37	$ 8.37	$ 8.45	$ 8.20	$ 8.16	$ 8.08	$ 7.96	$ 7.94	$ 8.12	$ 8.22
Low Growth & High Prices	Stanfield	2032-2033	$ 8.48	$ 8.43	$ 8.79	$ 8.78	$ 8.83	$ 8.56	$ 8.66	$ 8.47	$ 8.35	$ 8.34	$ 8.53	$ 8.63
Low Growth & High Prices	Sumas	2013-2014	$ 3.93	$ 5.31	$ 4.68	$ 3.87	$ 4.28	$ 4.06	$ 4.13	$ 4.08	$ 4.10	$ 4.02	$ 4.08	$ 4.10
Low Growth & High Prices	Sumas	2014-2015	$ 4.44	$ 4.55	$ 4.79	$ 4.69	$ 4.64	$ 4.42	$ 4.47	$ 4.37	$ 4.34	$ 4.29	$ 4.39	$ 4.43
Low Growth & High Prices	Sumas	2015-2016	$ 4.78	$ 4.88	$ 4.95	$ 4.85	$ 4.79	$ 4.54	$ 4.60	$ 4.52	$ 4.49	$ 4.43	$ 4.50	$ 4.55
Low Growth & High Prices	Sumas	2016-2017	$ 4.94	$ 5.01	$ 5.10	$ 4.98	$ 4.93	$ 4.63	$ 4.68	$ 4.62	$ 4.61	$ 4.53	$ 4.60	$ 4.69
Low Growth & High Prices	Sumas	2017-2018	$ 5.04	$ 5.10	$ 5.31	$ 5.17	$ 5.14	$ 4.90	$ 4.89	$ 4.84	$ 4.82	$ 4.73	$ 4.80	$ 4.90
Low Growth & High Prices	Sumas	2018-2019	$ 5.34	$ 5.38	$ 5.37	$ 5.24	$ 5.28	$ 5.00	$ 4.97	$ 4.90	$ 4.89	$ 4.84	$ 4.86	$ 4.89
Low Growth & High Prices	Sumas	2019-2020	$ 5.29	$ 5.47	$ 5.38	$ 5.26	$ 5.31	$ 5.06	$ 5.10	$ 5.04	$ 5.01	$ 4.96	$ 4.98	$ 5.01
Low Growth & High Prices	Sumas	2020-2021	$ 5.36	$ 5.55	$ 5.51	$ 5.42	$ 5.47	$ 5.18	$ 5.21	$ 5.13	$ 5.05	$ 5.02	$ 5.07	$ 5.10
Low Growth & High Prices	Sumas	2021-2022	$ 5.66	$ 5.77	$ 5.99	$ 5.83	$ 5.84	$ 5.59	$ 5.62	$ 5.53	$ 5.50	$ 5.46	$ 5.54	$ 5.57
Low Growth & High Prices	Sumas	2022-2023	$ 6.07	$ 6.10	$ 6.07	$ 5.82	$ 5.78	$ 5.59	$ 5.52	$ 5.41	$ 5.43	$ 5.35	$ 5.45	$ 5.48
Low Growth & High Prices	Sumas	2023-2024	$ 5.93	$ 6.23	$ 6.41	$ 6.14	$ 6.22	$ 6.04	$ 5.95	$ 5.85	$ 5.84	$ 5.76	$ 5.89	$ 5.94
Low Growth & High Prices	Sumas	2024-2025	$ 6.24	$ 6.58	$ 6.72	$ 6.42	$ 6.47	$ 6.29	$ 6.28	$ 6.19	$ 6.18	$ 6.11	$ 6.22	$ 6.28
Low Growth & High Prices	Sumas	2025-2026	$ 6.57	$ 6.88	$ 6.98	$ 6.83	$ 6.76	$ 6.54	$ 6.47	$ 6.37	$ 6.36	$ 6.29	$ 6.41	$ 6.43
Low Growth & High Prices	Sumas	2026-2027	$ 6.82	$ 7.18	$ 7.18	$ 6.92	$ 6.98	$ 6.69	$ 6.69	$ 6.57	$ 6.59	$ 6.51	$ 6.63	$ 6.66
Low Growth & High Prices	Sumas	2027-2028	$ 7.05	$ 7.38	$ 7.30	$ 7.09	$ 7.15	$ 6.89	$ 6.87	$ 6.78	$ 6.77	$ 6.74	$ 6.81	$ 6.84
Low Growth & High Prices	Sumas	2028-2029	$ 7.52	$ 7.60	$ 7.82	$ 7.67	$ 7.74	$ 7.40	$ 7.41	$ 7.28	$ 7.31	$ 7.26	$ 7.32	$ 7.34
Low Growth & High Prices	Sumas	2029-2030	$ 7.92	$ 8.09	$ 8.43	$ 7.93	$ 8.12	$ 7.64	$ 7.62	$ 7.49	$ 7.51	$ 7.47	$ 7.53	$ 7.58
Low Growth & High Prices	Sumas	2030-2031	$ 8.33	$ 8.47	$ 8.72	$ 8.16	$ 8.40	$ 7.98	$ 8.00	$ 7.88	$ 7.93	$ 7.89	$ 7.96	$ 7.99
Low Growth & High Prices	Sumas	2031-2032	$ 8.58	$ 8.66	$ 8.59	$ 8.59	$ 8.50	$ 8.04	$ 7.93	$ 7.67	$ 7.82	$ 7.79	$ 7.92	$ 8.04
Low Growth & High Prices	Sumas	2032-2033	$ 8.53	$ 8.75	$ 9.12	$ 9.12	$ 8.88	$ 8.41	$ 8.30	$ 8.07	$ 8.21	$ 8.19	$ 8.33	$ 8.45

APPENDIX 5.2: WEIGHTED AVERAGE COST OF CAPITAL

Avista Corporation Capital Structure and Overall Rate of Return

WASHINGTON

From 2012 Rate Case Settlement Cost of Capital	Percent of Total Capital	Cost	Component	After Tax
L/T Debt	53.00%	5.72%	3.03%	1.97%
Common Equity	47.00%	9.80%	4.61%	4.61%
TOTAL	100.00%		7.64%	6.58%

IDAHO

Agreed-upon Cost of Capital	Percent of Total Capital	Cost	Component	
L/T Debt (1)	50.00%	6.60%	3.30%	2.15%
Common Equity	50.00%	10.50%	5.25%	5.25%
TOTAL	100.00%		8.55%	7.40%

OREGON

Agreed-upon Cost of Capital	Percent of Total Capital	Cost	Component	
L/T Debt	50.00%	5.90%	2.95%	1.92%
Common Equity	50.00%	10.10%	5.05%	5.05%
TOTAL	100.00%		8.00%	6.97%

11/13 Gas Net Rate Base AMA		
WA	$ 217,600	45%
ID	$ 110,739	23%
OR	$ 151,627	32%
	$ 479,966	

System Weighted Average Cost of Capital (Nominal)*	6.93%
GDP price deflator	1.90%
Real After Tax WACC	4.93%

APPENDIX 5.3: POTENTIAL SUPPLY SIDE RESOURCE OPTIONS

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 5.4: EXPECTED CASE AVOIDED COST

Annual Avoided Costs 1/
2012$

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 Case	2013-2014	$ 3.54	$ 4.12	$ 3.54	$ 3.54	$ 3.54	$ 3.53	$ 3.45	$ 4.12	$ 3.70	$ 3.65
Expected Case	2014-2015	$ 3.50	$ 4.16	$ 3.50	$ 3.50	$ 3.50	$ 3.56	$ 3.42	$ 4.17	$ 3.72	$ 3.63
Expected Case	2015-2016	$ 3.77	$ 4.46	$ 3.77	$ 3.77	$ 3.77	$ 3.84	$ 3.70	$ 4.48	$ 4.01	$ 3.91
Expected Case	2016-2017	$ 3.53	$ 4.34	$ 3.53	$ 3.53	$ 3.53	$ 3.60	$ 3.45	$ 4.35	$ 3.80	$ 3.69
Expected Case	2017-2018	$ 3.50	$ 4.38	$ 3.50	$ 3.50	$ 3.50	$ 3.58	$ 3.43	$ 4.38	$ 3.80	$ 3.68
Expected Case	2018-2019	$ 3.36	$ 4.26	$ 3.36	$ 3.36	$ 3.36	$ 3.42	$ 3.28	$ 4.27	$ 3.65	$ 3.54
Expected Case	2019-2020	$ 3.44	$ 4.20	$ 3.44	$ 3.44	$ 3.44	$ 3.51	$ 3.36	$ 4.20	$ 3.69	$ 3.59
Expected Case	2020-2021	$ 3.67	$ 4.28	$ 3.67	$ 3.67	$ 3.67	$ 3.71	$ 3.57	$ 4.28	$ 3.85	$ 3.79
Expected Case	2021-2022	$ 3.80	$ 4.16	$ 3.80	$ 3.80	$ 3.80	$ 3.85	$ 3.72	$ 4.17	$ 3.92	$ 3.87
Expected Case	2022-2023	$ 3.84	$ 4.23	$ 3.84	$ 3.84	$ 3.84	$ 3.87	$ 3.76	$ 4.24	$ 3.96	$ 3.92
Expected Case	2023-2024	$ 4.14	$ 4.30	$ 4.14	$ 4.14	$ 4.14	$ 4.13	$ 4.06	$ 4.33	$ 4.17	$ 4.17
Expected Case	2024-2025	$ 4.45	$ 4.86	$ 4.45	$ 4.45	$ 4.45	$ 4.46	$ 4.35	$ 4.88	$ 4.56	$ 4.53
Expected Case	2025-2026	$ 4.64	$ 5.06	$ 4.64	$ 4.64	$ 4.64	$ 4.66	$ 4.54	$ 5.07	$ 4.76	$ 4.72
Expected Case	2026-2027	$ 4.67	$ 5.30	$ 4.67	$ 4.67	$ 4.67	$ 4.71	$ 4.57	$ 5.30	$ 4.86	$ 4.79
Expected Case	2027-2028	$ 4.71	$ 5.42	$ 4.71	$ 4.71	$ 4.71	$ 4.76	$ 4.61	$ 5.43	$ 4.93	$ 4.85
Expected Case	2028-2029	$ 5.17	$ 5.61	$ 5.17	$ 5.17	$ 5.17	$ 5.19	$ 5.06	$ 5.62	$ 5.29	$ 5.25
Expected Case	2029-2030	$ 5.09	$ 5.57	$ 5.09	$ 5.09	$ 5.09	$ 5.12	$ 5.00	$ 5.59	$ 5.24	$ 5.18
Expected Case	2030-2031	$ 5.31	$ 5.68	$ 5.31	$ 5.31	$ 5.31	$ 5.33	$ 5.21	$ 5.71	$ 5.42	$ 5.39
Expected Case	2031-2032	$ 5.54	$ 5.63	$ 5.53	$ 5.53	$ 5.53	$ 5.54	$ 5.43	$ 5.67	$ 5.55	$ 5.55
Expected Case	2032-2033	$ 5.81	$ 5.79	$ 5.79	$ 5.79	$ 5.79	$ 5.74	$ 5.70	$ 5.79	$ 5.75	$ 5.80

Annual Avoided Costs 1/
2012$

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 Case	2013-2014	$ 3.72	$ 4.16	$ 3.72	$ 3.72	$ 3.72	$ 3.78	$ 3.59	$ 4.10	$ 3.83	$ 3.81
Expected Case	2014-2015	$ 3.47	$ 4.14	$ 3.47	$ 3.47	$ 3.47	$ 3.70	$ 3.36	$ 4.14	$ 3.73	$ 3.60
Expected Case	2015-2016	$ 4.00	$ 4.61	$ 4.00	$ 4.00	$ 4.00	$ 4.24	$ 3.91	$ 4.60	$ 4.25	$ 4.13
Expected Case	2016-2017	$ 3.61	$ 4.38	$ 3.61	$ 3.61	$ 3.61	$ 3.85	$ 3.50	$ 4.37	$ 3.91	$ 3.76
Expected Case	2017-2018	$ 3.71	$ 4.54	$ 3.71	$ 3.71	$ 3.71	$ 3.98	$ 3.62	$ 4.54	$ 4.04	$ 3.88
Expected Case	2018-2019	$ 3.49	$ 4.29	$ 3.49	$ 3.49	$ 3.49	$ 3.72	$ 3.37	$ 4.28	$ 3.79	$ 3.65
Expected Case	2019-2020	$ 3.52	$ 4.23	$ 3.52	$ 3.52	$ 3.52	$ 3.75	$ 3.40	$ 4.22	$ 3.79	$ 3.66
Expected Case	2020-2021	$ 3.63	$ 4.23	$ 3.63	$ 3.63	$ 3.63	$ 3.82	$ 3.47	$ 4.23	$ 3.84	$ 3.75
Expected Case	2021-2022	$ 4.01	$ 4.37	$ 4.01	$ 4.01	$ 4.01	$ 4.23	$ 3.91	$ 4.36	$ 4.17	$ 4.08
Expected Case	2022-2023	$ 4.05	$ 4.32	$ 4.05	$ 4.05	$ 4.05	$ 4.21	$ 3.96	$ 4.32	$ 4.16	$ 4.10
Expected Case	2023-2024	$ 4.29	$ 4.42	$ 4.29	$ 4.29	$ 4.29	$ 4.36	$ 4.19	$ 4.42	$ 4.32	$ 4.32
Expected Case	2024-2025	$ 4.60	$ 4.82	$ 4.60	$ 4.60	$ 4.60	$ 4.72	$ 4.46	$ 4.82	$ 4.67	$ 4.65
Expected Case	2025-2026	$ 4.82	$ 5.11	$ 4.82	$ 4.82	$ 4.82	$ 4.99	$ 4.69	$ 5.11	$ 4.93	$ 4.88
Expected Case	2026-2027	$ 4.91	$ 5.26	$ 4.91	$ 4.91	$ 4.91	$ 5.11	$ 4.78	$ 5.25	$ 5.05	$ 4.98
Expected Case	2027-2028	$ 4.91	$ 5.48	$ 4.91	$ 4.91	$ 4.91	$ 5.15	$ 4.77	$ 5.47	$ 5.13	$ 5.03
Expected Case	2028-2029	$ 5.38	$ 5.70	$ 5.38	$ 5.38	$ 5.38	$ 5.54	$ 5.22	$ 5.70	$ 5.49	$ 5.45
Expected Case	2029-2030	$ 5.43	$ 5.69	$ 5.43	$ 5.43	$ 5.43	$ 5.61	$ 5.32	$ 5.69	$ 5.54	$ 5.49
Expected Case	2030-2031	$ 5.53	$ 5.74	$ 5.53	$ 5.53	$ 5.53	$ 5.68	$ 5.40	$ 5.74	$ 5.61	$ 5.57
Expected Case	2031-2032	$ 5.67	$ 5.83	$ 5.67	$ 5.67	$ 5.67	$ 5.80	$ 5.55	$ 5.82	$ 5.73	$ 5.70
Expected Case	2032-2033	$ 5.88	$ 5.86	$ 5.87	$ 5.87	$ 5.87	$ 5.85	$ 5.75	$ 5.86	$ 5.82	$ 5.87

1/ Avoided costs are before Environmental Externalities adder.

APPENDIX 5.4: LOW GROWTH CASE AVOIDED COST

Annual Avoided Costs 1/
2012$

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 & High Prices	2013-2014	$ 3.89	$ 4.53	$ 3.89	$ 3.89	$ 3.89	$ 3.91	$ 3.79	$ 4.52	$ 4.07	$ 4.02
Low Growth & High Prices	2014-2015	$ 4.22	$ 4.89	$ 4.22	$ 4.22	$ 4.22	$ 4.26	$ 4.14	$ 4.90	$ 4.43	$ 4.36
Low Growth & High Prices	2015-2016	$ 4.38	$ 5.08	$ 4.38	$ 4.38	$ 4.38	$ 4.42	$ 4.30	$ 5.08	$ 4.60	$ 4.52
Low Growth & High Prices	2016-2017	$ 4.49	$ 5.27	$ 4.49	$ 4.49	$ 4.49	$ 4.52	$ 4.40	$ 5.28	$ 4.73	$ 4.64
Low Growth & High Prices	2017-2018	$ 4.66	$ 5.53	$ 4.66	$ 4.66	$ 4.66	$ 4.70	$ 4.57	$ 5.53	$ 4.93	$ 4.83
Low Growth & High Prices	2018-2019	$ 4.77	$ 5.65	$ 4.77	$ 4.77	$ 4.77	$ 4.80	$ 4.67	$ 5.65	$ 5.04	$ 4.94
Low Growth & High Prices	2019-2020	$ 4.89	$ 5.64	$ 4.89	$ 4.89	$ 4.89	$ 4.92	$ 4.79	$ 5.64	$ 5.12	$ 5.04
Low Growth & High Prices	2020-2021	$ 4.99	$ 5.64	$ 4.99	$ 4.99	$ 4.99	$ 5.01	$ 4.89	$ 5.65	$ 5.19	$ 5.12
Low Growth & High Prices	2021-2022	$ 5.38	$ 5.72	$ 5.38	$ 5.38	$ 5.38	$ 5.38	$ 5.28	$ 5.72	$ 5.46	$ 5.45
Low Growth & High Prices	2022-2023	$ 5.40	$ 5.77	$ 5.40	$ 5.40	$ 5.40	$ 5.40	$ 5.31	$ 5.78	$ 5.50	$ 5.48
Low Growth & High Prices	2023-2024	$ 5.74	$ 5.88	$ 5.74	$ 5.74	$ 5.74	$ 5.71	$ 5.65	$ 5.90	$ 5.75	$ 5.77
Low Growth & High Prices	2024-2025	$ 6.08	$ 6.46	$ 6.08	$ 6.08	$ 6.08	$ 6.07	$ 5.97	$ 6.46	$ 6.17	$ 6.16
Low Growth & High Prices	2025-2026	$ 6.31	$ 6.71	$ 6.31	$ 6.31	$ 6.31	$ 6.30	$ 6.20	$ 6.71	$ 6.40	$ 6.39
Low Growth & High Prices	2026-2027	$ 6.52	$ 7.14	$ 6.52	$ 6.52	$ 6.52	$ 6.52	$ 6.41	$ 7.14	$ 6.69	$ 6.64
Low Growth & High Prices	2027-2028	$ 6.72	$ 7.41	$ 6.72	$ 6.72	$ 6.72	$ 6.72	$ 6.60	$ 7.41	$ 6.91	$ 6.86
Low Growth & High Prices	2028-2029	$ 7.19	$ 7.61	$ 7.19	$ 7.19	$ 7.19	$ 7.17	$ 7.06	$ 7.61	$ 7.28	$ 7.27
Low Growth & High Prices	2029-2030	$ 7.47	$ 7.88	$ 7.47	$ 7.47	$ 7.47	$ 7.44	$ 7.34	$ 7.88	$ 7.56	$ 7.55
Low Growth & High Prices	2030-2031	$ 7.82	$ 8.15	$ 7.82	$ 7.82	$ 7.82	$ 7.79	$ 7.69	$ 8.15	$ 7.88	$ 7.88
Low Growth & High Prices	2031-2032	$ 7.97	$ 8.01	$ 7.95	$ 7.95	$ 7.95	$ 7.92	$ 7.85	$ 8.05	$ 7.94	$ 7.97
Low Growth & High Prices	2032-2033	$ 8.33	$ 8.29	$ 8.29	$ 8.29	$ 8.29	$ 8.23	$ 8.21	$ 8.28	$ 8.24	$ 8.30

Annual Avoided Costs 1/
2012$

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 & High Prices	2013-2014	$ 3.84	$ 4.42	$ 3.84	$ 3.84	$ 3.84	$ 3.99	$ 3.69	$ 4.39	$ 4.02	$ 3.95
Low Growth & High Prices	2014-2015	$ 4.19	$ 4.85	$ 4.19	$ 4.19	$ 4.19	$ 4.38	$ 4.08	$ 4.85	$ 4.44	$ 4.32
Low Growth & High Prices	2015-2016	$ 4.39	$ 5.07	$ 4.39	$ 4.39	$ 4.39	$ 4.57	$ 4.28	$ 5.06	$ 4.64	$ 4.52
Low Growth & High Prices	2016-2017	$ 4.52	$ 5.27	$ 4.52	$ 4.52	$ 4.52	$ 4.71	$ 4.41	$ 5.27	$ 4.80	$ 4.67
Low Growth & High Prices	2017-2018	$ 4.66	$ 5.48	$ 4.66	$ 4.66	$ 4.66	$ 4.85	$ 4.54	$ 5.48	$ 4.96	$ 4.82
Low Growth & High Prices	2018-2019	$ 4.80	$ 5.63	$ 4.80	$ 4.80	$ 4.80	$ 4.98	$ 4.68	$ 5.63	$ 5.10	$ 4.97
Low Growth & High Prices	2019-2020	$ 4.90	$ 5.62	$ 4.90	$ 4.90	$ 4.90	$ 5.08	$ 4.78	$ 5.62	$ 5.16	$ 5.05
Low Growth & High Prices	2020-2021	$ 5.03	$ 5.65	$ 5.03	$ 5.03	$ 5.03	$ 5.19	$ 4.90	$ 5.65	$ 5.25	$ 5.15
Low Growth & High Prices	2021-2022	$ 5.36	$ 5.69	$ 5.36	$ 5.36	$ 5.36	$ 5.48	$ 5.24	$ 5.69	$ 5.47	$ 5.42
Low Growth & High Prices	2022-2023	$ 5.52	$ 5.76	$ 5.52	$ 5.52	$ 5.52	$ 5.63	$ 5.42	$ 5.76	$ 5.60	$ 5.57
Low Growth & High Prices	2023-2024	$ 5.76	$ 5.88	$ 5.75	$ 5.75	$ 5.75	$ 5.80	$ 5.67	$ 5.88	$ 5.78	$ 5.78
Low Growth & High Prices	2024-2025	$ 6.10	$ 6.32	$ 6.10	$ 6.10	$ 6.10	$ 6.20	$ 5.98	$ 6.32	$ 6.16	$ 6.14
Low Growth & High Prices	2025-2026	$ 6.37	$ 6.65	$ 6.37	$ 6.37	$ 6.37	$ 6.49	$ 6.25	$ 6.65	$ 6.46	$ 6.42
Low Growth & High Prices	2026-2027	$ 6.59	$ 6.99	$ 6.59	$ 6.59	$ 6.59	$ 6.73	$ 6.46	$ 6.99	$ 6.72	$ 6.67
Low Growth & High Prices	2027-2028	$ 6.78	$ 7.36	$ 6.78	$ 6.78	$ 6.78	$ 6.92	$ 6.63	$ 7.36	$ 6.97	$ 6.89
Low Growth & High Prices	2028-2029	$ 7.21	$ 7.53	$ 7.21	$ 7.21	$ 7.21	$ 7.31	$ 7.06	$ 7.53	$ 7.30	$ 7.27
Low Growth & High Prices	2029-2030	$ 7.56	$ 7.78	$ 7.56	$ 7.56	$ 7.56	$ 7.65	$ 7.42	$ 7.78	$ 7.61	$ 7.60
Low Growth & High Prices	2030-2031	$ 7.84	$ 8.04	$ 7.84	$ 7.84	$ 7.84	$ 7.93	$ 7.69	$ 8.04	$ 7.89	$ 7.88
Low Growth & High Prices	2031-2032	$ 8.02	$ 8.10	$ 8.01	$ 8.01	$ 8.01	$ 8.05	$ 7.89	$ 8.10	$ 8.01	$ 8.03
Low Growth & High Prices	2032-2033	$ 8.33	$ 8.31	$ 8.32	$ 8.32	$ 8.32	$ 8.26	$ 8.20	$ 8.27	$ 8.24	$ 8.32

1/ Avoided costs are before Environmental Externalities adder.

APPENDIX 5.4: HIGH GROWTH CASE AVOIDED COST

Annual Avoided Costs 1/
2012$

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 & Low Prices	2013-2014	$ 3.53	$ 3.90	$ 3.53	$ 3.53	$ 3.53	$ 3.56	$ 3.44	$ 3.89	$ 3.63	$ 3.60
High Growth & Low Prices	2014-2015	$ 3.65	$ 4.04	$ 3.65	$ 3.65	$ 3.65	$ 3.68	$ 3.57	$ 4.03	$ 3.76	$ 3.73
High Growth & Low Prices	2015-2016	$ 3.61	$ 4.01	$ 3.61	$ 3.61	$ 3.61	$ 3.65	$ 3.53	$ 4.00	$ 3.72	$ 3.69
High Growth & Low Prices	2016-2017	$ 3.52	$ 4.08	$ 3.52	$ 3.52	$ 3.52	$ 3.57	$ 3.43	$ 4.08	$ 3.69	$ 3.63
High Growth & Low Prices	2017-2018	$ 3.41	$ 4.01	$ 3.41	$ 3.41	$ 3.41	$ 3.46	$ 3.32	$ 4.01	$ 3.60	$ 3.53
High Growth & Low Prices	2018-2019	$ 3.31	$ 3.92	$ 3.31	$ 3.31	$ 3.31	$ 3.35	$ 3.20	$ 3.91	$ 3.49	$ 3.43
High Growth & Low Prices	2019-2020	$ 3.33	$ 3.84	$ 3.33	$ 3.33	$ 3.33	$ 3.35	$ 3.21	$ 3.84	$ 3.47	$ 3.43
High Growth & Low Prices	2020-2021	$ 3.32	$ 3.81	$ 3.32	$ 3.32	$ 3.32	$ 3.34	$ 3.19	$ 3.81	$ 3.45	$ 3.42
High Growth & Low Prices	2021-2022	$ 3.46	$ 3.77	$ 3.49	$ 3.49	$ 3.49	$ 3.46	$ 3.32	$ 3.77	$ 3.51	$ 3.54
High Growth & Low Prices	2022-2023	$ 3.27	$ 3.61	$ 3.31	$ 3.31	$ 3.31	$ 3.27	$ 3.15	$ 3.61	$ 3.34	$ 3.36
High Growth & Low Prices	2023-2024	$ 3.34	$ 3.49	$ 3.36	$ 3.36	$ 3.36	$ 3.32	$ 3.22	$ 3.49	$ 3.34	$ 3.38
High Growth & Low Prices	2024-2025	$ 3.48	$ 3.84	$ 3.52	$ 3.52	$ 3.52	$ 3.48	$ 3.34	$ 3.84	$ 3.56	$ 3.58
High Growth & Low Prices	2025-2026	$ 3.43	$ 3.80	$ 3.47	$ 3.47	$ 3.47	$ 3.44	$ 3.30	$ 3.80	$ 3.51	$ 3.53
High Growth & Low Prices	2026-2027	$ 3.38	$ 3.79	$ 3.42	$ 3.42	$ 3.42	$ 3.38	$ 3.22	$ 3.79	$ 3.46	$ 3.49
High Growth & Low Prices	2027-2028	$ 3.32	$ 9.20	$ 3.36	$ 3.36	$ 3.36	$ 8.77	$ 3.14	$ 9.20	$ 7.04	$ 4.52
High Growth & Low Prices	2028-2029	$ 3.49	$ 9.34	$ 3.54	$ 3.54	$ 3.54	$ 8.96	$ 3.32	$ 9.34	$ 7.21	$ 4.69
High Growth & Low Prices	2029-2030	$ 3.48	$ 9.32	$ 8.99	$ 8.99	$ 8.99	$ 8.96	$ 3.33	$ 9.32	$ 7.20	$ 7.96
High Growth & Low Prices	2030-2031	$ 3.56	$ 9.35	$ 9.07	$ 9.07	$ 9.07	$ 9.02	$ 8.87	$ 9.36	$ 9.08	$ 8.02
High Growth & Low Prices	2031-2032	$ 3.44	$ 8.96	$ 14.35	$ 14.35	$ 14.35	$ 8.88	$ 8.74	$ 8.96	$ 8.86	$ 11.09
High Growth & Low Prices	2032-2033	$ 3.43	$ 8.93	$ 14.36	$ 14.36	$ 14.36	$ 8.87	$ 8.75	$ 8.91	$ 8.84	$ 11.09

Annual Avoided Costs 1/
2012$

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 & Low Prices	2013-2014	$ 3.54	$ 3.92	$ 3.54	$ 3.54	$ 3.54	$ 3.70	$ 3.42	$ 3.88	$ 3.67	$ 3.61
High Growth & Low Prices	2014-2015	$ 3.67	$ 4.04	$ 3.67	$ 3.67	$ 3.67	$ 3.83	$ 3.56	$ 4.02	$ 3.81	$ 3.75
High Growth & Low Prices	2015-2016	$ 3.67	$ 4.05	$ 3.67	$ 3.67	$ 3.67	$ 3.84	$ 3.55	$ 4.03	$ 3.81	$ 3.75
High Growth & Low Prices	2016-2017	$ 3.61	$ 4.34	$ 3.61	$ 3.61	$ 3.61	$ 3.83	$ 3.49	$ 4.33	$ 3.88	$ 3.76
High Growth & Low Prices	2017-2018	$ 3.50	$ 4.25	$ 3.50	$ 3.50	$ 3.50	$ 3.71	$ 3.36	$ 4.25	$ 3.77	$ 3.65
High Growth & Low Prices	2018-2019	$ 3.45	$ 4.23	$ 3.45	$ 3.45	$ 3.45	$ 3.62	$ 3.26	$ 4.23	$ 3.70	$ 3.61
High Growth & Low Prices	2019-2020	$ 3.44	$ 4.07	$ 3.44	$ 3.44	$ 3.44	$ 3.57	$ 3.22	$ 4.07	$ 3.62	$ 3.57
High Growth & Low Prices	2020-2021	$ 3.45	$ 4.03	$ 3.45	$ 3.45	$ 3.45	$ 3.59	$ 3.23	$ 4.03	$ 3.61	$ 3.57
High Growth & Low Prices	2021-2022	$ 3.61	$ 3.81	$ 3.61	$ 3.61	$ 3.61	$ 3.68	$ 3.35	$ 3.81	$ 3.61	$ 3.65
High Growth & Low Prices	2022-2023	$ 3.52	$ 3.68	$ 3.52	$ 3.52	$ 3.52	$ 3.60	$ 3.30	$ 3.68	$ 3.52	$ 3.55
High Growth & Low Prices	2023-2024	$ 3.51	$ 3.59	$ 3.51	$ 3.51	$ 3.51	$ 3.55	$ 3.31	$ 3.59	$ 3.48	$ 3.53
High Growth & Low Prices	2024-2025	$ 3.63	$ 3.79	$ 3.63	$ 3.63	$ 3.63	$ 3.71	$ 3.39	$ 3.79	$ 3.63	$ 3.66
High Growth & Low Prices	2025-2026	$ 3.66	$ 3.83	$ 3.66	$ 3.66	$ 3.66	$ 3.75	$ 3.41	$ 3.83	$ 3.66	$ 3.69
High Growth & Low Prices	2026-2027	$ 3.64	$ 3.86	$ 3.64	$ 3.64	$ 3.64	$ 3.71	$ 3.34	$ 3.86	$ 3.64	$ 3.69
High Growth & Low Prices	2027-2028	$ 3.60	$ 17.04	$ 3.60	$ 3.60	$ 3.60	$ 16.79	$ 3.24	$ 17.04	$ 12.36	$ 6.29
High Growth & Low Prices	2028-2029	$ 3.73	$ 17.11	$ 3.73	$ 3.73	$ 3.73	$ 17.01	$ 3.39	$ 17.11	$ 12.50	$ 6.40
High Growth & Low Prices	2029-2030	$ 3.76	$ 17.10	$ 16.98	$ 16.98	$ 16.98	$ 17.09	$ 3.47	$ 17.10	$ 12.55	$ 14.36
High Growth & Low Prices	2030-2031	$ 3.78	$ 17.08	$ 16.99	$ 16.99	$ 16.99	$ 17.06	$ 16.69	$ 17.10	$ 16.95	$ 14.37
High Growth & Low Prices	2031-2032	$ 3.69	$ 16.88	$ 29.94	$ 29.94	$ 29.94	$ 16.87	$ 16.52	$ 16.88	$ 16.76	$ 22.08
High Growth & Low Prices	2032-2033	$ 3.64	$ 16.90	$ 30.07	$ 30.07	$ 30.07	$ 16.90	$ 16.59	$ 16.90	$ 16.79	$ 22.15

1/ Avoided costs are before Environmental Externalities adder.

APPENDIX 5.4: CARBON LEGISLATION – MEDIUM CASE AVOIDED COST

Annual Avoided Costs 1/
2012$

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
Carbon Legislation - Medium Case	2013-2014	$ 3.52	$ 3.71	$ 3.52	$ 3.52	$ 3.52	$ 3.45	$ 3.45	$ 3.66	$ 3.52	$ 3.56
Carbon Legislation - Medium Case	2014-2015	$ 3.49	$ 3.72	$ 3.49	$ 3.49	$ 3.49	$ 3.51	$ 3.43	$ 3.72	$ 3.55	$ 3.53
Carbon Legislation - Medium Case	2015-2016	$ 3.76	$ 3.92	$ 3.76	$ 3.76	$ 3.76	$ 3.77	$ 3.70	$ 3.92	$ 3.79	$ 3.79
Carbon Legislation - Medium Case	2016-2017	$ 3.52	$ 3.80	$ 3.52	$ 3.52	$ 3.52	$ 3.57	$ 3.45	$ 3.80	$ 3.61	$ 3.57
Carbon Legislation - Medium Case	2017-2018	$ 3.49	$ 3.79	$ 3.49	$ 3.49	$ 3.49	$ 3.54	$ 3.43	$ 3.79	$ 3.59	$ 3.55
Carbon Legislation - Medium Case	2018-2019	$ 3.34	$ 3.64	$ 3.34	$ 3.34	$ 3.34	$ 3.39	$ 3.28	$ 3.63	$ 3.43	$ 3.40
Carbon Legislation - Medium Case	2019-2020	$ 3.43	$ 3.68	$ 3.43	$ 3.43	$ 3.43	$ 3.47	$ 3.36	$ 3.68	$ 3.50	$ 3.48
Carbon Legislation - Medium Case	2020-2021	$ 4.14	$ 4.34	$ 4.14	$ 4.14	$ 4.14	$ 4.17	$ 4.05	$ 4.34	$ 4.19	$ 4.18
Carbon Legislation - Medium Case	2021-2022	$ 4.32	$ 4.47	$ 4.32	$ 4.32	$ 4.32	$ 4.32	$ 4.24	$ 4.47	$ 4.34	$ 4.35
Carbon Legislation - Medium Case	2022-2023	$ 4.30	$ 4.44	$ 4.30	$ 4.30	$ 4.30	$ 4.28	$ 4.23	$ 4.44	$ 4.32	$ 4.33
Carbon Legislation - Medium Case	2023-2024	$ 4.53	$ 4.58	$ 4.53	$ 4.53	$ 4.53	$ 4.50	$ 4.46	$ 4.58	$ 4.51	$ 4.54
Carbon Legislation - Medium Case	2024-2025	$ 4.77	$ 4.93	$ 4.77	$ 4.77	$ 4.77	$ 4.75	$ 4.69	$ 4.93	$ 4.79	$ 4.80
Carbon Legislation - Medium Case	2025-2026	$ 4.91	$ 5.08	$ 4.91	$ 4.91	$ 4.91	$ 4.89	$ 4.83	$ 5.08	$ 4.93	$ 4.95
Carbon Legislation - Medium Case	2026-2027	$ 4.90	$ 5.10	$ 4.90	$ 4.90	$ 4.90	$ 4.90	$ 4.81	$ 5.10	$ 4.93	$ 4.94
Carbon Legislation - Medium Case	2027-2028	$ 4.89	$ 5.09	$ 4.89	$ 4.89	$ 4.89	$ 4.90	$ 4.80	$ 5.09	$ 4.93	$ 4.93
Carbon Legislation - Medium Case	2028-2029	$ 5.30	$ 5.47	$ 5.30	$ 5.30	$ 5.30	$ 5.28	$ 5.20	$ 5.48	$ 5.32	$ 5.33
Carbon Legislation - Medium Case	2029-2030	$ 5.19	$ 5.36	$ 5.19	$ 5.19	$ 5.19	$ 5.17	$ 5.10	$ 5.36	$ 5.21	$ 5.22
Carbon Legislation - Medium Case	2030-2031	$ 5.37	$ 5.50	$ 5.37	$ 5.37	$ 5.37	$ 5.34	$ 5.28	$ 5.50	$ 5.37	$ 5.40
Carbon Legislation - Medium Case	2031-2032	$ 5.57	$ 5.57	$ 5.55	$ 5.55	$ 5.55	$ 5.52	$ 5.47	$ 5.57	$ 5.52	$ 5.56
Carbon Legislation - Medium Case	2032-2033	$ 5.80	$ 5.77	$ 5.76	$ 5.76	$ 5.76	$ 5.73	$ 5.71	$ 5.76	$ 5.73	$ 5.77

Winter Avoided Costs 1/
2012$

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
Carbon Legislation - Medium Case	2013-2014	$ 3.69	$ 3.87	$ 3.69	$ 3.69	$ 3.69	$ 3.60	$ 3.60	$ 3.74	$ 3.65	$ 3.72
Carbon Legislation - Medium Case	2014-2015	$ 3.44	$ 3.71	$ 3.44	$ 3.44	$ 3.44	$ 3.57	$ 3.36	$ 3.71	$ 3.55	$ 3.49
Carbon Legislation - Medium Case	2015-2016	$ 3.98	$ 4.22	$ 3.98	$ 3.98	$ 3.98	$ 4.07	$ 3.91	$ 4.21	$ 4.06	$ 4.03
Carbon Legislation - Medium Case	2016-2017	$ 3.58	$ 3.95	$ 3.58	$ 3.58	$ 3.58	$ 3.77	$ 3.50	$ 3.95	$ 3.74	$ 3.65
Carbon Legislation - Medium Case	2017-2018	$ 3.69	$ 4.09	$ 3.69	$ 3.69	$ 3.69	$ 3.89	$ 3.62	$ 4.09	$ 3.87	$ 3.77
Carbon Legislation - Medium Case	2018-2019	$ 3.44	$ 3.84	$ 3.44	$ 3.44	$ 3.44	$ 3.64	$ 3.37	$ 3.83	$ 3.61	$ 3.52
Carbon Legislation - Medium Case	2019-2020	$ 3.48	$ 3.79	$ 3.48	$ 3.48	$ 3.48	$ 3.67	$ 3.40	$ 3.79	$ 3.62	$ 3.54
Carbon Legislation - Medium Case	2020-2021	$ 3.95	$ 4.24	$ 3.95	$ 3.95	$ 3.95	$ 4.12	$ 3.82	$ 4.24	$ 4.06	$ 4.01
Carbon Legislation - Medium Case	2021-2022	$ 4.53	$ 4.69	$ 4.53	$ 4.53	$ 4.53	$ 4.63	$ 4.45	$ 4.69	$ 4.59	$ 4.56
Carbon Legislation - Medium Case	2022-2023	$ 4.51	$ 4.62	$ 4.51	$ 4.51	$ 4.51	$ 4.56	$ 4.43	$ 4.62	$ 4.54	$ 4.53
Carbon Legislation - Medium Case	2023-2024	$ 4.68	$ 4.73	$ 4.67	$ 4.67	$ 4.67	$ 4.69	$ 4.60	$ 4.72	$ 4.67	$ 4.68
Carbon Legislation - Medium Case	2024-2025	$ 4.90	$ 4.99	$ 4.90	$ 4.90	$ 4.90	$ 4.94	$ 4.81	$ 4.99	$ 4.91	$ 4.92
Carbon Legislation - Medium Case	2025-2026	$ 5.09	$ 5.21	$ 5.09	$ 5.09	$ 5.09	$ 5.14	$ 5.00	$ 5.21	$ 5.11	$ 5.11
Carbon Legislation - Medium Case	2026-2027	$ 5.13	$ 5.30	$ 5.13	$ 5.13	$ 5.13	$ 5.23	$ 5.03	$ 5.30	$ 5.19	$ 5.17
Carbon Legislation - Medium Case	2027-2028	$ 5.09	$ 5.30	$ 5.08	$ 5.08	$ 5.08	$ 5.21	$ 4.98	$ 5.30	$ 5.16	$ 5.13
Carbon Legislation - Medium Case	2028-2029	$ 5.50	$ 5.62	$ 5.49	$ 5.49	$ 5.49	$ 5.56	$ 5.38	$ 5.62	$ 5.52	$ 5.52
Carbon Legislation - Medium Case	2029-2030	$ 5.54	$ 5.64	$ 5.54	$ 5.54	$ 5.54	$ 5.59	$ 5.44	$ 5.64	$ 5.56	$ 5.56
Carbon Legislation - Medium Case	2030-2031	$ 5.59	$ 5.66	$ 5.59	$ 5.59	$ 5.59	$ 5.62	$ 5.48	$ 5.66	$ 5.59	$ 5.60
Carbon Legislation - Medium Case	2031-2032	$ 5.71	$ 5.74	$ 5.70	$ 5.70	$ 5.70	$ 5.72	$ 5.59	$ 5.72	$ 5.68	$ 5.71
Carbon Legislation - Medium Case	2032-2033	$ 5.86	$ 5.84	$ 5.85	$ 5.85	$ 5.85	$ 5.84	$ 5.76	$ 5.84	$ 5.81	$ 5.85

1/Avoided costs are before Environmental Externalities adder.

APPENDIX 5.4: COLD DAY 20 YR WEATHER STANDARD AVOIDED COST

Annual Avoided Costs 1/
2012$

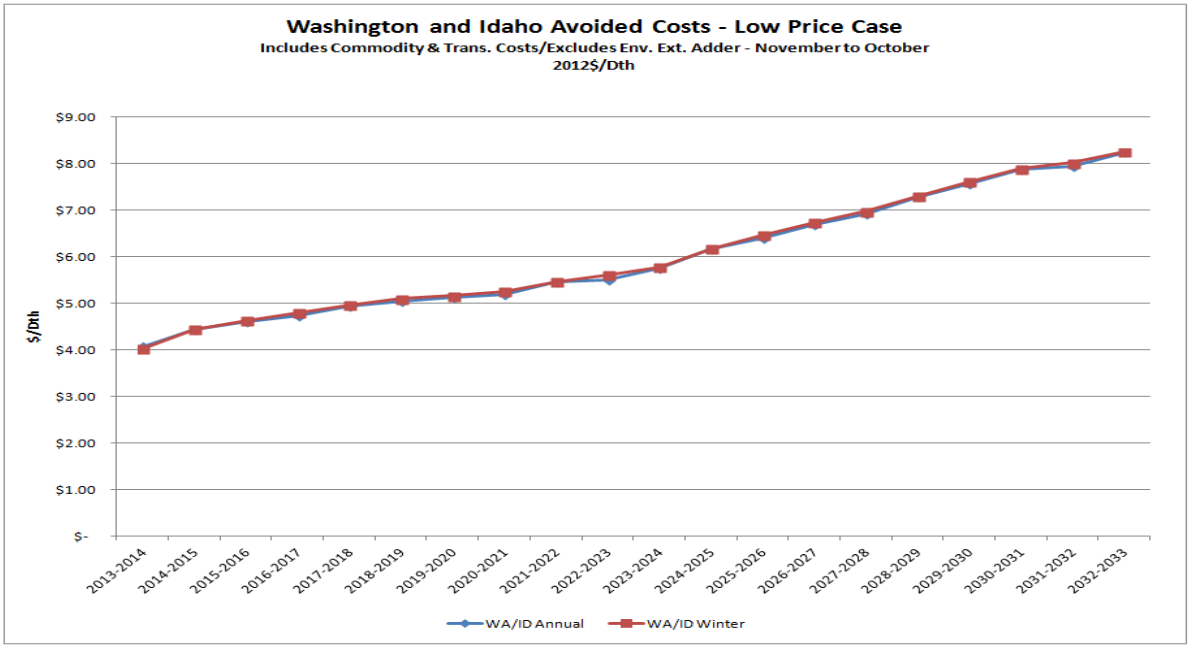
Scenario	Gas Year	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	Wa/Id Both	Wa/Id GTN	Wa/Id NWP	WA/ID Annual	OR Annual
Cold Day 20 Yr Weather Std	2013-2014	$ 3.53	$ 4.12	$ 3.53	$ 3.53	$ 3.53	$ 3.54	$ 3.45	$ 4.12	$ 3.70	$ 3.65
Cold Day 20 Yr Weather Std	2014-2015	$ 3.50	$ 4.16	$ 3.50	$ 3.50	$ 3.50	$ 3.56	$ 3.42	$ 4.17	$ 3.72	$ 3.63
Cold Day 20 Yr Weather Std	2015-2016	$ 3.77	$ 4.46	$ 3.77	$ 3.77	$ 3.77	$ 3.84	$ 3.70	$ 4.48	$ 4.01	$ 3.91
Cold Day 20 Yr Weather Std	2016-2017	$ 3.53	$ 4.34	$ 3.53	$ 3.53	$ 3.53	$ 3.60	$ 3.45	$ 4.34	$ 3.80	$ 3.69
Cold Day 20 Yr Weather Std	2017-2018	$ 3.50	$ 4.38	$ 3.50	$ 3.50	$ 3.50	$ 3.58	$ 3.43	$ 4.38	$ 3.80	$ 3.67
Cold Day 20 Yr Weather Std	2018-2019	$ 3.36	$ 4.26	$ 3.36	$ 3.36	$ 3.36	$ 3.42	$ 3.28	$ 4.27	$ 3.65	$ 3.54
Cold Day 20 Yr Weather Std	2019-2020	$ 3.44	$ 4.20	$ 3.44	$ 3.44	$ 3.44	$ 3.51	$ 3.36	$ 4.21	$ 3.69	$ 3.59
Cold Day 20 Yr Weather Std	2020-2021	$ 3.75	$ 4.36	$ 3.75	$ 3.75	$ 3.75	$ 3.78	$ 3.64	$ 4.37	$ 3.93	$ 3.87
Cold Day 20 Yr Weather Std	2021-2022	$ 3.81	$ 4.17	$ 3.81	$ 3.81	$ 3.81	$ 3.87	$ 3.74	$ 4.17	$ 3.93	$ 3.88
Cold Day 20 Yr Weather Std	2022-2023	$ 3.77	$ 4.15	$ 3.77	$ 3.77	$ 3.77	$ 3.80	$ 3.69	$ 4.17	$ 3.89	$ 3.84
Cold Day 20 Yr Weather Std	2023-2024	$ 3.97	$ 4.13	$ 3.97	$ 3.97	$ 3.97	$ 3.97	$ 3.90	$ 4.16	$ 4.01	$ 4.00
Cold Day 20 Yr Weather Std	2024-2025	$ 4.19	$ 4.61	$ 4.19	$ 4.19	$ 4.19	$ 4.22	$ 4.11	$ 4.64	$ 4.32	$ 4.28
Cold Day 20 Yr Weather Std	2025-2026	$ 4.30	$ 4.73	$ 4.30	$ 4.30	$ 4.30	$ 4.34	$ 4.22	$ 4.74	$ 4.44	$ 4.39
Cold Day 20 Yr Weather Std	2026-2027	$ 4.25	$ 4.89	$ 4.25	$ 4.25	$ 4.25	$ 4.30	$ 4.17	$ 4.89	$ 4.45	$ 4.38
Cold Day 20 Yr Weather Std	2027-2028	$ 4.22	$ 4.92	$ 4.22	$ 4.22	$ 4.22	$ 4.27	$ 4.12	$ 4.93	$ 4.44	$ 4.36
Cold Day 20 Yr Weather Std	2028-2029	$ 4.59	$ 5.04	$ 4.59	$ 4.59	$ 4.59	$ 4.63	$ 4.49	$ 5.05	$ 4.72	$ 4.68
Cold Day 20 Yr Weather Std	2029-2030	$ 4.44	$ 4.92	$ 4.44	$ 4.44	$ 4.44	$ 4.47	$ 4.36	$ 4.94	$ 4.59	$ 4.54
Cold Day 20 Yr Weather Std	2030-2031	$ 4.59	$ 4.96	$ 4.59	$ 4.59	$ 4.59	$ 4.61	$ 4.50	$ 5.00	$ 4.70	$ 4.67
Cold Day 20 Yr Weather Std	2031-2032	$ 4.73	$ 4.86	$ 4.74	$ 4.74	$ 4.74	$ 4.76	$ 4.64	$ 4.90	$ 4.77	$ 4.76
Cold Day 20 Yr Weather Std	2032-2033	$ 4.94	$ 4.93	$ 4.93	$ 4.93	$ 4.93	$ 4.88	$ 4.84	$ 4.93	$ 4.89	$ 4.93

Winter Avoided Costs 1/
2012$

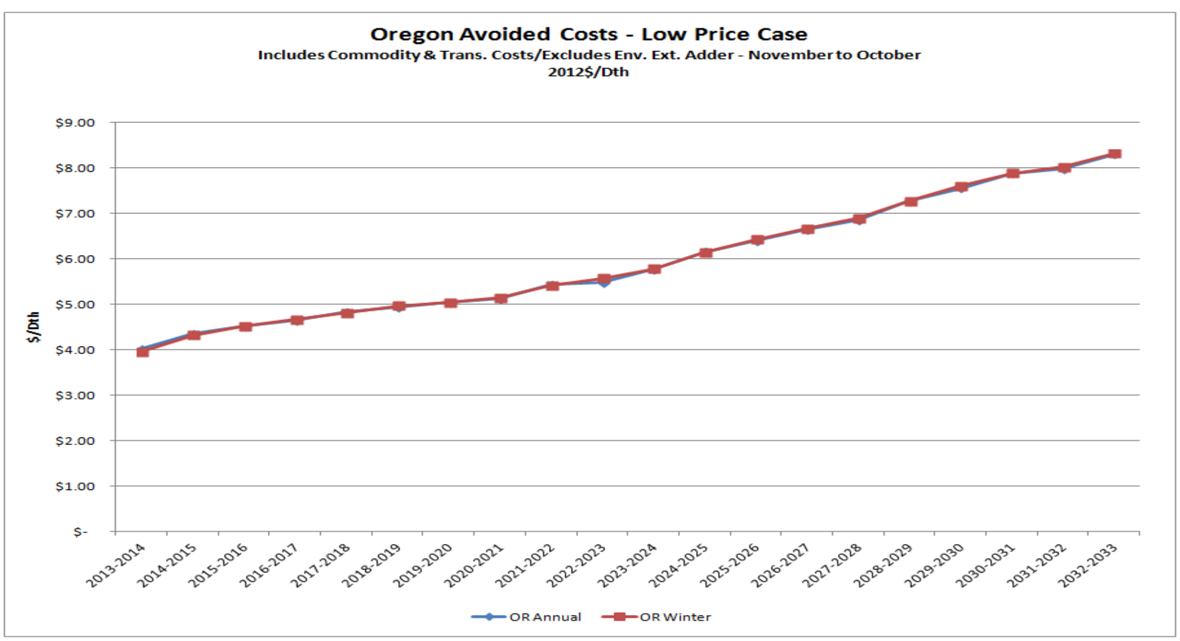
Scenario	Gas Year	Klam Falls	La Grande	Medford GTN	Medford NWP	Roseburg	Wa/Id Both	Wa/Id GTN	Wa/Id NWP	WA/ID Annual	OR Annual
Cold Day 20 Yr Weather Std	2013-2014	$ 3.72	$ 4.16	$ 3.72	$ 3.72	$ 3.72	$ 3.81	$ 3.59	$ 4.10	$ 3.84	$ 3.81
Cold Day 20 Yr Weather Std	2014-2015	$ 3.47	$ 4.14	$ 3.47	$ 3.47	$ 3.47	$ 3.70	$ 3.36	$ 4.14	$ 3.73	$ 3.60
Cold Day 20 Yr Weather Std	2015-2016	$ 4.00	$ 4.61	$ 4.00	$ 4.00	$ 4.00	$ 4.24	$ 3.91	$ 4.60	$ 4.25	$ 4.13
Cold Day 20 Yr Weather Std	2016-2017	$ 3.61	$ 4.37	$ 3.61	$ 3.61	$ 3.61	$ 3.85	$ 3.50	$ 4.37	$ 3.91	$ 3.76
Cold Day 20 Yr Weather Std	2017-2018	$ 3.71	$ 4.54	$ 3.71	$ 3.71	$ 3.71	$ 3.98	$ 3.62	$ 4.54	$ 4.05	$ 3.88
Cold Day 20 Yr Weather Std	2018-2019	$ 3.49	$ 4.29	$ 3.49	$ 3.49	$ 3.49	$ 3.72	$ 3.37	$ 4.28	$ 3.79	$ 3.65
Cold Day 20 Yr Weather Std	2019-2020	$ 3.52	$ 4.23	$ 3.52	$ 3.52	$ 3.52	$ 3.75	$ 3.40	$ 4.22	$ 3.79	$ 3.66
Cold Day 20 Yr Weather Std	2020-2021	$ 3.70	$ 4.31	$ 3.70	$ 3.70	$ 3.70	$ 3.87	$ 3.53	$ 4.31	$ 3.90	$ 3.82
Cold Day 20 Yr Weather Std	2021-2022	$ 4.04	$ 4.38	$ 4.04	$ 4.04	$ 4.04	$ 4.26	$ 3.95	$ 4.37	$ 4.19	$ 4.11
Cold Day 20 Yr Weather Std	2022-2023	$ 4.00	$ 4.27	$ 4.00	$ 4.00	$ 4.00	$ 4.16	$ 3.90	$ 4.27	$ 4.11	$ 4.05
Cold Day 20 Yr Weather Std	2023-2024	$ 4.13	$ 4.25	$ 4.13	$ 4.13	$ 4.13	$ 4.21	$ 4.05	$ 4.25	$ 4.17	$ 4.16
Cold Day 20 Yr Weather Std	2024-2025	$ 4.35	$ 4.59	$ 4.35	$ 4.35	$ 4.35	$ 4.51	$ 4.23	$ 4.59	$ 4.44	$ 4.40
Cold Day 20 Yr Weather Std	2025-2026	$ 4.50	$ 4.80	$ 4.50	$ 4.50	$ 4.50	$ 4.69	$ 4.39	$ 4.80	$ 4.63	$ 4.56
Cold Day 20 Yr Weather Std	2026-2027	$ 4.51	$ 4.85	$ 4.51	$ 4.51	$ 4.51	$ 4.71	$ 4.39	$ 4.85	$ 4.65	$ 4.58
Cold Day 20 Yr Weather Std	2027-2028	$ 4.45	$ 4.98	$ 4.45	$ 4.45	$ 4.45	$ 4.68	$ 4.31	$ 4.98	$ 4.65	$ 4.55
Cold Day 20 Yr Weather Std	2028-2029	$ 4.82	$ 5.15	$ 4.82	$ 4.82	$ 4.82	$ 5.01	$ 4.68	$ 5.15	$ 4.94	$ 4.89
Cold Day 20 Yr Weather Std	2029-2030	$ 4.81	$ 5.05	$ 4.81	$ 4.81	$ 4.81	$ 4.98	$ 4.70	$ 5.05	$ 4.91	$ 4.86
Cold Day 20 Yr Weather Std	2030-2031	$ 4.84	$ 5.04	$ 4.84	$ 4.84	$ 4.84	$ 4.98	$ 4.70	$ 5.05	$ 4.91	$ 4.88
Cold Day 20 Yr Weather Std	2031-2032	$ 4.89	$ 5.08	$ 4.88	$ 4.88	$ 4.88	$ 5.06	$ 4.77	$ 5.08	$ 4.97	$ 4.92
Cold Day 20 Yr Weather Std	2032-2033	$ 5.03	$ 5.01	$ 5.02	$ 5.02	$ 5.02	$ 5.00	$ 4.90	$ 5.00	$ 4.97	$ 5.02

1/Avoided costs are before Environmental Externalities adder.

APPENDIX 5.4: WASHINGTON AND IDAHO AVOIDED COSTS - LOW GROWTH/HIGH PRICE CASE



APPENDIX 5.4: NATURAL GAS OREGON AVOIDED COSTS - LOW GROWTH/HIGH PRICE CASE



APPENDIX 5.4: LOW GROWTH – HIGH PRICE MONTHLY DETAIL

Monthly Avoided Cost Detail 1/
2012$

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 Prices	2013-2014	Nov	$ 3.33	$ 3.83	$ 3.33	$ 3.33	$ 3.33	$ 3.27	$ 3.27	$ 3.83	$ 3.46	$ 3.43
Low Growth & High Prices	2013-2014	Dec	$ 4.01	$ 4.73	$ 4.02	$ 4.02	$ 4.02	$ 4.21	$ 3.66	$ 4.59	$ 4.15	$ 4.16
Low Growth & High Prices	2013-2014	Jan	$ 4.26	$ 4.61	$ 4.26	$ 4.26	$ 4.26	$ 4.61	$ 4.20	$ 4.61	$ 4.47	$ 4.33
Low Growth & High Prices	2013-2014	Feb	$ 3.56	$ 4.30	$ 3.56	$ 3.56	$ 3.56	$ 3.89	$ 3.35	$ 4.30	$ 3.85	$ 3.71
Low Growth & High Prices	2013-2014	Mar	$ 3.98	$ 4.59	$ 3.98	$ 3.98	$ 3.98	$ 3.92	$ 3.92	$ 4.59	$ 4.14	$ 4.10
Low Growth & High Prices	2013-2014	Apr	$ 3.96	$ 4.61	$ 3.96	$ 3.96	$ 3.96	$ 3.90	$ 3.90	$ 4.61	$ 4.13	$ 4.09
Low Growth & High Prices	2013-2014	May	$ 3.92	$ 4.59	$ 3.92	$ 3.92	$ 3.92	$ 3.86	$ 3.86	$ 4.59	$ 4.10	$ 4.05
Low Growth & High Prices	2013-2014	Jun	$ 3.93	$ 4.59	$ 3.93	$ 3.93	$ 3.93	$ 3.87	$ 3.87	$ 4.59	$ 4.11	$ 4.06
Low Growth & High Prices	2013-2014	Jul	$ 3.91	$ 4.59	$ 3.91	$ 3.91	$ 3.91	$ 3.85	$ 3.85	$ 4.59	$ 4.09	$ 4.04
Low Growth & High Prices	2013-2014	Aug	$ 3.90	$ 4.59	$ 3.90	$ 3.90	$ 3.90	$ 3.84	$ 3.84	$ 4.59	$ 4.09	$ 4.04
Low Growth & High Prices	2013-2014	Sep	$ 3.93	$ 4.59	$ 3.93	$ 3.93	$ 3.93	$ 3.87	$ 3.87	$ 4.59	$ 4.11	$ 4.06
Low Growth & High Prices	2013-2014	Oct	$ 3.95	$ 4.68	$ 3.95	$ 3.95	$ 3.95	$ 3.89	$ 3.89	$ 4.68	$ 4.15	$ 4.09
Low Growth & High Prices	2014-2015	Nov	$ 3.98	$ 4.71	$ 3.98	$ 3.98	$ 3.98	$ 3.92	$ 3.92	$ 4.71	$ 4.18	$ 4.12
Low Growth & High Prices	2014-2015	Dec	$ 4.07	$ 4.79	$ 4.07	$ 4.07	$ 4.07	$ 4.40	$ 3.84	$ 4.80	$ 4.35	$ 4.22
Low Growth & High Prices	2014-2015	Jan	$ 4.23	$ 4.92	$ 4.23	$ 4.23	$ 4.23	$ 4.65	$ 4.17	$ 4.92	$ 4.58	$ 4.37
Low Growth & High Prices	2014-2015	Feb	$ 4.29	$ 4.94	$ 4.29	$ 4.29	$ 4.29	$ 4.63	$ 4.18	$ 4.93	$ 4.58	$ 4.42
Low Growth & High Prices	2014-2015	Mar	$ 4.38	$ 4.92	$ 4.38	$ 4.38	$ 4.38	$ 4.32	$ 4.32	$ 4.92	$ 4.52	$ 4.49
Low Growth & High Prices	2014-2015	Apr	$ 4.31	$ 4.95	$ 4.31	$ 4.31	$ 4.31	$ 4.25	$ 4.25	$ 4.95	$ 4.48	$ 4.44
Low Growth & High Prices	2014-2015	May	$ 4.24	$ 4.92	$ 4.24	$ 4.24	$ 4.24	$ 4.18	$ 4.18	$ 4.92	$ 4.42	$ 4.38
Low Growth & High Prices	2014-2015	Jun	$ 4.23	$ 4.92	$ 4.23	$ 4.23	$ 4.23	$ 4.17	$ 4.17	$ 4.92	$ 4.42	$ 4.37
Low Growth & High Prices	2014-2015	Jul	$ 4.20	$ 4.89	$ 4.20	$ 4.20	$ 4.20	$ 4.14	$ 4.14	$ 4.92	$ 4.40	$ 4.34
Low Growth & High Prices	2014-2015	Aug	$ 4.19	$ 4.88	$ 4.19	$ 4.19	$ 4.19	$ 4.13	$ 4.13	$ 4.92	$ 4.39	$ 4.33
Low Growth & High Prices	2014-2015	Sep	$ 4.23	$ 4.92	$ 4.23	$ 4.23	$ 4.23	$ 4.17	$ 4.17	$ 4.92	$ 4.42	$ 4.37
Low Growth & High Prices	2014-2015	Oct	$ 4.29	$ 4.93	$ 4.29	$ 4.29	$ 4.29	$ 4.23	$ 4.23	$ 4.93	$ 4.46	$ 4.42
Low Growth & High Prices	2015-2016	Nov	$ 4.31	$ 5.04	$ 4.31	$ 4.31	$ 4.31	$ 4.25	$ 4.25	$ 5.04	$ 4.51	$ 4.46
Low Growth & High Prices	2015-2016	Dec	$ 4.37	$ 5.08	$ 4.37	$ 4.37	$ 4.37	$ 4.70	$ 4.16	$ 5.07	$ 4.64	$ 4.51
Low Growth & High Prices	2015-2016	Jan	$ 4.33	$ 5.07	$ 4.33	$ 4.33	$ 4.33	$ 4.75	$ 4.27	$ 5.07	$ 4.69	$ 4.48
Low Growth & High Prices	2015-2016	Feb	$ 4.40	$ 5.10	$ 4.40	$ 4.40	$ 4.40	$ 4.72	$ 4.28	$ 5.07	$ 4.69	$ 4.54
Low Growth & High Prices	2015-2016	Mar	$ 4.51	$ 5.07	$ 4.51	$ 4.51	$ 4.51	$ 4.44	$ 4.44	$ 5.07	$ 4.65	$ 4.62
Low Growth & High Prices	2015-2016	Apr	$ 4.44	$ 5.17	$ 4.44	$ 4.44	$ 4.44	$ 4.37	$ 4.37	$ 5.17	$ 4.63	$ 4.58
Low Growth & High Prices	2015-2016	May	$ 4.37	$ 5.07	$ 4.37	$ 4.37	$ 4.37	$ 4.31	$ 4.31	$ 5.07	$ 4.56	$ 4.51
Low Growth & High Prices	2015-2016	Jun	$ 4.40	$ 5.07	$ 4.40	$ 4.40	$ 4.40	$ 4.33	$ 4.33	$ 5.07	$ 4.57	$ 4.53
Low Growth & High Prices	2015-2016	Jul	$ 4.36	$ 5.04	$ 4.36	$ 4.36	$ 4.36	$ 4.30	$ 4.30	$ 5.07	$ 4.56	$ 4.50
Low Growth & High Prices	2015-2016	Aug	$ 4.33	$ 5.07	$ 4.33	$ 4.33	$ 4.33	$ 4.27	$ 4.27	$ 5.07	$ 4.54	$ 4.48
Low Growth & High Prices	2015-2016	Sep	$ 4.34	$ 5.07	$ 4.34	$ 4.34	$ 4.34	$ 4.28	$ 4.28	$ 5.07	$ 4.54	$ 4.49
Low Growth & High Prices	2015-2016	Oct	$ 4.39	$ 5.14	$ 4.39	$ 4.39	$ 4.39	$ 4.32	$ 4.32	$ 5.14	$ 4.59	$ 4.54
Low Growth & High Prices	2016-2017	Nov	$ 4.43	$ 5.24	$ 4.43	$ 4.43	$ 4.43	$ 4.36	$ 4.36	$ 5.24	$ 4.65	$ 4.59
Low Growth & High Prices	2016-2017	Dec	$ 4.49	$ 5.27	$ 4.49	$ 4.49	$ 4.49	$ 4.82	$ 4.27	$ 5.27	$ 4.78	$ 4.64
Low Growth & High Prices	2016-2017	Jan	$ 4.50	$ 5.27	$ 4.50	$ 4.50	$ 4.50	$ 4.91	$ 4.43	$ 5.27	$ 4.87	$ 4.65
Low Growth & High Prices	2016-2017	Feb	$ 4.56	$ 5.28	$ 4.56	$ 4.56	$ 4.56	$ 4.91	$ 4.45	$ 5.28	$ 4.88	$ 4.71
Low Growth & High Prices	2016-2017	Mar	$ 4.63	$ 5.27	$ 4.63	$ 4.63	$ 4.63	$ 4.56	$ 4.56	$ 5.27	$ 4.80	$ 4.76
Low Growth & High Prices	2016-2017	Apr	$ 4.53	$ 5.32	$ 4.53	$ 4.53	$ 4.53	$ 4.46	$ 4.46	$ 5.32	$ 4.75	$ 4.69
Low Growth & High Prices	2016-2017	May	$ 4.46	$ 5.28	$ 4.46	$ 4.46	$ 4.46	$ 4.39	$ 4.39	$ 5.28	$ 4.68	$ 4.62
Low Growth & High Prices	2016-2017	Jun	$ 4.46	$ 5.26	$ 4.46	$ 4.46	$ 4.46	$ 4.39	$ 4.39	$ 5.28	$ 4.68	$ 4.62
Low Growth & High Prices	2016-2017	Jul	$ 4.44	$ 5.25	$ 4.44	$ 4.44	$ 4.44	$ 4.37	$ 4.37	$ 5.28	$ 4.67	$ 4.60
Low Growth & High Prices	2016-2017	Aug	$ 4.43	$ 5.26	$ 4.43	$ 4.43	$ 4.43	$ 4.36	$ 4.36	$ 5.28	$ 4.66	$ 4.59
Low Growth & High Prices	2016-2017	Sep	$ 4.45	$ 5.28	$ 4.45	$ 4.45	$ 4.45	$ 4.38	$ 4.38	$ 5.28	$ 4.68	$ 4.61
Low Growth & High Prices	2016-2017	Oct	$ 4.50	$ 5.30	$ 4.50	$ 4.50	$ 4.50	$ 4.43	$ 4.43	$ 5.30	$ 4.72	$ 4.66
Low Growth & High Prices	2017-2018	Nov	$ 4.51	$ 5.39	$ 4.51	$ 4.51	$ 4.51	$ 4.44	$ 4.44	$ 5.39	$ 4.76	$ 4.68
Low Growth & High Prices	2017-2018	Dec	$ 4.56	$ 5.40	$ 4.56	$ 4.56	$ 4.56	$ 4.90	$ 4.33	$ 5.41	$ 4.88	$ 4.73
Low Growth & High Prices	2017-2018	Jan	$ 4.69	$ 5.55	$ 4.69	$ 4.69	$ 4.69	$ 5.10	$ 4.62	$ 5.55	$ 5.09	$ 4.86
Low Growth & High Prices	2017-2018	Feb	$ 4.73	$ 5.55	$ 4.73	$ 4.73	$ 4.73	$ 5.09	$ 4.61	$ 5.55	$ 5.08	$ 4.90
Low Growth & High Prices	2017-2018	Mar	$ 4.79	$ 5.51	$ 4.79	$ 4.79	$ 4.79	$ 4.72	$ 4.72	$ 5.51	$ 4.98	$ 4.94
Low Growth & High Prices	2017-2018	Apr	$ 4.72	$ 5.58	$ 4.72	$ 4.72	$ 4.72	$ 4.65	$ 4.65	$ 5.58	$ 4.96	$ 4.89
Low Growth & High Prices	2017-2018	May	$ 4.67	$ 5.55	$ 4.67	$ 4.67	$ 4.67	$ 4.60	$ 4.60	$ 5.55	$ 4.91	$ 4.85
Low Growth & High Prices	2017-2018	Jun	$ 4.67	$ 5.55	$ 4.67	$ 4.67	$ 4.67	$ 4.60	$ 4.60	$ 5.55	$ 4.92	$ 4.85
Low Growth & High Prices	2017-2018	Jul	$ 4.65	$ 5.55	$ 4.65	$ 4.65	$ 4.65	$ 4.58	$ 4.58	$ 5.55	$ 4.90	$ 4.83
Low Growth & High Prices	2017-2018	Aug	$ 4.63	$ 5.55	$ 4.63	$ 4.63	$ 4.63	$ 4.56	$ 4.56	$ 5.55	$ 4.89	$ 4.81
Low Growth & High Prices	2017-2018	Sep	$ 4.64	$ 5.55	$ 4.64	$ 4.64	$ 4.64	$ 4.57	$ 4.57	$ 5.55	$ 4.90	$ 4.82
Low Growth & High Prices	2017-2018	Oct	$ 4.68	$ 5.58	$ 4.68	$ 4.68	$ 4.68	$ 4.61	$ 4.61	$ 5.58	$ 4.93	$ 4.86
Low Growth & High Prices	2018-2019	Nov	$ 4.79	$ 5.62	$ 4.79	$ 4.79	$ 4.79	$ 4.72	$ 4.72	$ 5.62	$ 5.02	$ 4.96
Low Growth & High Prices	2018-2019	Dec	$ 4.83	$ 5.64	$ 4.83	$ 4.83	$ 4.83	$ 5.15	$ 4.59	$ 5.63	$ 5.12	$ 4.99
Low Growth & High Prices	2018-2019	Jan	$ 4.70	$ 5.63	$ 4.70	$ 4.70	$ 4.70	$ 5.11	$ 4.63	$ 5.63	$ 5.12	$ 4.89
Low Growth & High Prices	2018-2019	Feb	$ 4.79	$ 5.63	$ 4.79	$ 4.79	$ 4.79	$ 5.11	$ 4.64	$ 5.63	$ 5.13	$ 4.96
Low Growth & High Prices	2018-2019	Mar	$ 4.90	$ 5.63	$ 4.90	$ 4.90	$ 4.90	$ 4.83	$ 4.83	$ 5.63	$ 5.10	$ 5.05
Low Growth & High Prices	2018-2019	Apr	$ 4.81	$ 5.76	$ 4.81	$ 4.81	$ 4.81	$ 4.74	$ 4.74	$ 5.76	$ 5.08	$ 5.00
Low Growth & High Prices	2018-2019	May	$ 4.76	$ 5.63	$ 4.76	$ 4.76	$ 4.76	$ 4.69	$ 4.69	$ 5.63	$ 5.00	$ 4.94
Low Growth & High Prices	2018-2019	Jun	$ 4.73	$ 5.63	$ 4.73	$ 4.73	$ 4.73	$ 4.66	$ 4.66	$ 5.63	$ 4.98	$ 4.91
Low Growth & High Prices	2018-2019	Jul	$ 4.71	$ 5.63	$ 4.71	$ 4.71	$ 4.71	$ 4.64	$ 4.64	$ 5.64	$ 4.97	$ 4.89
Low Growth & High Prices	2018-2019	Aug	$ 4.69	$ 5.64	$ 4.69	$ 4.69	$ 4.69	$ 4.62	$ 4.62	$ 5.64	$ 4.96	$ 4.88
Low Growth & High Prices	2018-2019	Sep	$ 4.71	$ 5.64	$ 4.71	$ 4.71	$ 4.71	$ 4.64	$ 4.64	$ 5.64	$ 4.97	$ 4.90
Low Growth & High Prices	2018-2019	Oct	$ 4.76	$ 5.72	$ 4.76	$ 4.76	$ 4.76	$ 4.69	$ 4.69	$ 5.72	$ 5.03	$ 4.95
Low Growth & High Prices	2019-2020	Nov	$ 4.89	$ 5.59	$ 4.89	$ 4.89	$ 4.89	$ 4.82	$ 4.82	$ 5.59	$ 5.08	$ 5.03
Low Growth & High Prices	2019-2020	Dec	$ 4.92	$ 5.61	$ 4.92	$ 4.92	$ 4.92	$ 5.24	$ 4.70	$ 5.62	$ 5.18	$ 5.06
Low Growth & High Prices	2019-2020	Jan	$ 4.75	$ 5.64	$ 4.75	$ 4.75	$ 4.75	$ 5.16	$ 4.68	$ 5.64	$ 5.16	$ 4.93
Low Growth & High Prices	2019-2020	Feb	$ 4.88	$ 5.61	$ 4.88	$ 4.88	$ 4.88	$ 5.19	$ 4.73	$ 5.61	$ 5.17	$ 5.03
Low Growth & High Prices	2019-2020	Mar	$ 5.07	$ 5.64	$ 5.07	$ 5.07	$ 5.07	$ 4.99	$ 4.99	$ 5.64	$ 5.21	$ 5.18
Low Growth & High Prices	2019-2020	Apr	$ 4.98	$ 5.69	$ 4.98	$ 4.98	$ 4.98	$ 4.90	$ 4.90	$ 5.69	$ 5.16	$ 5.12
Low Growth & High Prices	2019-2020	May	$ 4.90	$ 5.65	$ 4.90	$ 4.90	$ 4.90	$ 4.83	$ 4.83	$ 5.65	$ 5.10	$ 5.05
Low Growth & High Prices	2019-2020	Jun	$ 4.87	$ 5.65	$ 4.87	$ 4.87	$ 4.87	$ 4.80	$ 4.80	$ 5.65	$ 5.08	$ 5.03
Low Growth & High Prices	2019-2020	Jul	$ 4.83	$ 5.62	$ 4.83	$ 4.83	$ 4.83	$ 4.76	$ 4.76	$ 5.65	$ 5.05	$ 4.99
Low Growth & High Prices	2019-2020	Aug	$ 4.82	$ 5.62	$ 4.82	$ 4.82	$ 4.82	$ 4.75	$ 4.75	$ 5.65	$ 5.05	$ 4.98
Low Growth & High Prices	2019-2020	Sep	$ 4.84	$ 5.65	$ 4.84	$ 4.84	$ 4.84	$ 4.77	$ 4.77	$ 5.65	$ 5.06	$ 5.00
Low Growth & High Prices	2019-2020	Oct	$ 4.89	$ 5.67	$ 4.89	$ 4.89	$ 4.89	$ 4.82	$ 4.82	$ 5.67	$ 5.10	$ 5.05

1/ Avoided costs are before Environmental Externalities adder.

APPENDIX 5.4: LOW GROWTH – HIGH PRICE MONTHLY DETAIL

Monthly Avoided Cost Detail 1/
2012$

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 Prices	2020-2021	Nov	$ 4.98	$ 5.65	$ 4.98	$ 4.98	$ 4.98	$ 4.90	$ 4.90	$ 5.65	$ 5.15	$ 5.11
Low Growth & High Prices	2020-2021	Dec	$ 5.00	$ 5.67	$ 5.00	$ 5.00	$ 5.00	$ 5.29	$ 4.75	$ 5.66	$ 5.23	$ 5.14
Low Growth & High Prices	2020-2021	Jan	$ 4.93	$ 5.65	$ 4.93	$ 4.93	$ 4.93	$ 5.34	$ 4.86	$ 5.65	$ 5.28	$ 5.08
Low Growth & High Prices	2020-2021	Feb	$ 5.03	$ 5.66	$ 5.03	$ 5.03	$ 5.03	$ 5.34	$ 4.89	$ 5.66	$ 5.30	$ 5.15
Low Growth & High Prices	2020-2021	Mar	$ 5.19	$ 5.62	$ 5.19	$ 5.19	$ 5.19	$ 5.11	$ 5.11	$ 5.62	$ 5.28	$ 5.28
Low Growth & High Prices	2020-2021	Apr	$ 5.10	$ 5.62	$ 5.10	$ 5.10	$ 5.10	$ 5.02	$ 5.02	$ 5.65	$ 5.23	$ 5.20
Low Growth & High Prices	2020-2021	May	$ 5.01	$ 5.65	$ 5.01	$ 5.01	$ 5.01	$ 4.93	$ 4.93	$ 5.65	$ 5.17	$ 5.13
Low Growth & High Prices	2020-2021	Jun	$ 4.96	$ 5.54	$ 4.96	$ 4.96	$ 4.96	$ 4.89	$ 4.89	$ 5.65	$ 5.14	$ 5.08
Low Growth & High Prices	2020-2021	Jul	$ 4.88	$ 5.65	$ 4.88	$ 4.88	$ 4.88	$ 4.81	$ 4.81	$ 5.65	$ 5.09	$ 5.04
Low Growth & High Prices	2020-2021	Aug	$ 4.87	$ 5.64	$ 4.87	$ 4.87	$ 4.87	$ 4.80	$ 4.80	$ 5.65	$ 5.08	$ 5.03
Low Growth & High Prices	2020-2021	Sep	$ 4.93	$ 5.65	$ 4.93	$ 4.93	$ 4.93	$ 4.86	$ 4.86	$ 5.65	$ 5.12	$ 5.08
Low Growth & High Prices	2020-2021	Oct	$ 4.99	$ 5.70	$ 4.99	$ 4.99	$ 4.99	$ 4.91	$ 4.91	$ 5.70	$ 5.17	$ 5.13
Low Growth & High Prices	2021-2022	Nov	$ 5.09	$ 5.63	$ 5.09	$ 5.09	$ 5.09	$ 5.01	$ 5.01	$ 5.63	$ 5.22	$ 5.20
Low Growth & High Prices	2021-2022	Dec	$ 5.19	$ 5.71	$ 5.19	$ 5.19	$ 5.19	$ 5.48	$ 4.97	$ 5.71	$ 5.39	$ 5.29
Low Growth & High Prices	2021-2022	Jan	$ 5.42	$ 5.73	$ 5.42	$ 5.42	$ 5.42	$ 5.73	$ 5.34	$ 5.73	$ 5.60	$ 5.48
Low Growth & High Prices	2021-2022	Feb	$ 5.51	$ 5.72	$ 5.51	$ 5.51	$ 5.51	$ 5.66	$ 5.38	$ 5.72	$ 5.59	$ 5.55
Low Growth & High Prices	2021-2022	Mar	$ 5.59	$ 5.65	$ 5.59	$ 5.59	$ 5.59	$ 5.50	$ 5.50	$ 5.65	$ 5.55	$ 5.60
Low Growth & High Prices	2021-2022	Apr	$ 5.48	$ 5.78	$ 5.48	$ 5.48	$ 5.48	$ 5.40	$ 5.40	$ 5.78	$ 5.53	$ 5.54
Low Growth & High Prices	2021-2022	May	$ 5.41	$ 5.76	$ 5.41	$ 5.41	$ 5.41	$ 5.33	$ 5.33	$ 5.76	$ 5.47	$ 5.48
Low Growth & High Prices	2021-2022	Jun	$ 5.35	$ 5.71	$ 5.35	$ 5.35	$ 5.35	$ 5.27	$ 5.27	$ 5.72	$ 5.42	$ 5.42
Low Growth & High Prices	2021-2022	Jul	$ 5.33	$ 5.68	$ 5.33	$ 5.33	$ 5.33	$ 5.25	$ 5.25	$ 5.72	$ 5.41	$ 5.40
Low Growth & High Prices	2021-2022	Aug	$ 5.31	$ 5.70	$ 5.31	$ 5.31	$ 5.31	$ 5.23	$ 5.23	$ 5.72	$ 5.39	$ 5.39
Low Growth & High Prices	2021-2022	Sep	$ 5.40	$ 5.77	$ 5.40	$ 5.40	$ 5.40	$ 5.32	$ 5.32	$ 5.77	$ 5.47	$ 5.48
Low Growth & High Prices	2021-2022	Oct	$ 5.44	$ 5.77	$ 5.44	$ 5.44	$ 5.44	$ 5.36	$ 5.36	$ 5.77	$ 5.50	$ 5.51
Low Growth & High Prices	2022-2023	Nov	$ 5.49	$ 5.77	$ 5.49	$ 5.49	$ 5.49	$ 5.41	$ 5.41	$ 5.77	$ 5.53	$ 5.55
Low Growth & High Prices	2022-2023	Dec	$ 5.50	$ 5.71	$ 5.50	$ 5.50	$ 5.50	$ 5.71	$ 5.34	$ 5.71	$ 5.59	$ 5.55
Low Growth & High Prices	2022-2023	Jan	$ 5.49	$ 5.79	$ 5.49	$ 5.49	$ 5.49	$ 5.79	$ 5.41	$ 5.79	$ 5.66	$ 5.55
Low Growth & High Prices	2022-2023	Feb	$ 5.51	$ 5.77	$ 5.51	$ 5.51	$ 5.51	$ 5.71	$ 5.40	$ 5.77	$ 5.63	$ 5.56
Low Growth & High Prices	2022-2023	Mar	$ 5.62	$ 5.77	$ 5.62	$ 5.62	$ 5.62	$ 5.53	$ 5.53	$ 5.77	$ 5.61	$ 5.65
Low Growth & High Prices	2022-2023	Apr	$ 5.48	$ 5.86	$ 5.48	$ 5.48	$ 5.48	$ 5.40	$ 5.40	$ 5.86	$ 5.55	$ 5.56
Low Growth & High Prices	2022-2023	May	$ 5.34	$ 5.77	$ 5.34	$ 5.34	$ 5.34	$ 5.26	$ 5.26	$ 5.77	$ 5.43	$ 5.43
Low Growth & High Prices	2022-2023	Jun	$ 5.28	$ 5.71	$ 5.28	$ 5.28	$ 5.28	$ 5.20	$ 5.20	$ 5.77	$ 5.39	$ 5.37
Low Growth & High Prices	2022-2023	Jul	$ 5.25	$ 5.71	$ 5.25	$ 5.25	$ 5.25	$ 5.17	$ 5.17	$ 5.77	$ 5.37	$ 5.34
Low Growth & High Prices	2022-2023	Aug	$ 5.23	$ 5.72	$ 5.23	$ 5.23	$ 5.23	$ 5.15	$ 5.15	$ 5.77	$ 5.36	$ 5.33
Low Growth & High Prices	2022-2023	Sep	$ 5.30	$ 5.77	$ 5.30	$ 5.30	$ 5.30	$ 5.22	$ 5.22	$ 5.77	$ 5.41	$ 5.40
Low Growth & High Prices	2022-2023	Oct	$ 5.34	$ 5.83	$ 5.34	$ 5.34	$ 5.34	$ 5.26	$ 5.26	$ 5.83	$ 5.45	$ 5.44
Low Growth & High Prices	2023-2024	Nov	$ 5.56	$ 5.88	$ 5.56	$ 5.56	$ 5.56	$ 5.47	$ 5.47	$ 5.88	$ 5.61	$ 5.62
Low Growth & High Prices	2023-2024	Dec	$ 5.62	$ 5.84	$ 5.62	$ 5.62	$ 5.62	$ 5.84	$ 5.45	$ 5.84	$ 5.71	$ 5.67
Low Growth & High Prices	2023-2024	Jan	$ 5.82	$ 5.90	$ 5.82	$ 5.82	$ 5.82	$ 5.90	$ 5.73	$ 5.90	$ 5.84	$ 5.84
Low Growth & High Prices	2023-2024	Feb	$ 5.85	$ 5.87	$ 5.85	$ 5.85	$ 5.85	$ 5.85	$ 5.76	$ 5.87	$ 5.83	$ 5.85
Low Growth & High Prices	2023-2024	Mar	$ 5.97	$ 5.91	$ 5.92	$ 5.92	$ 5.92	$ 5.91	$ 5.92	$ 5.91	$ 5.91	$ 5.93
Low Growth & High Prices	2023-2024	Apr	$ 5.89	$ 6.03	$ 5.89	$ 5.89	$ 5.89	$ 5.80	$ 5.80	$ 6.03	$ 5.88	$ 5.92
Low Growth & High Prices	2023-2024	May	$ 5.76	$ 5.90	$ 5.76	$ 5.76	$ 5.76	$ 5.67	$ 5.67	$ 5.90	$ 5.75	$ 5.79
Low Growth & High Prices	2023-2024	Jun	$ 5.70	$ 5.79	$ 5.70	$ 5.70	$ 5.70	$ 5.61	$ 5.61	$ 5.88	$ 5.70	$ 5.72
Low Growth & High Prices	2023-2024	Jul	$ 5.65	$ 5.80	$ 5.65	$ 5.65	$ 5.65	$ 5.56	$ 5.56	$ 5.88	$ 5.67	$ 5.68
Low Growth & High Prices	2023-2024	Aug	$ 5.64	$ 5.79	$ 5.64	$ 5.64	$ 5.64	$ 5.55	$ 5.55	$ 5.88	$ 5.66	$ 5.67
Low Growth & High Prices	2023-2024	Sep	$ 5.72	$ 5.87	$ 5.72	$ 5.72	$ 5.72	$ 5.63	$ 5.63	$ 5.88	$ 5.72	$ 5.75
Low Growth & High Prices	2023-2024	Oct	$ 5.77	$ 6.00	$ 5.77	$ 5.77	$ 5.77	$ 5.68	$ 5.68	$ 6.00	$ 5.79	$ 5.82
Low Growth & High Prices	2024-2025	Nov	$ 5.87	$ 5.98	$ 5.87	$ 5.87	$ 5.87	$ 5.78	$ 5.78	$ 5.98	$ 5.85	$ 5.89
Low Growth & High Prices	2024-2025	Dec	$ 6.00	$ 6.07	$ 6.00	$ 6.00	$ 6.00	$ 6.07	$ 5.80	$ 6.07	$ 5.98	$ 6.02
Low Growth & High Prices	2024-2025	Jan	$ 6.16	$ 6.52	$ 6.16	$ 6.16	$ 6.16	$ 6.52	$ 6.06	$ 6.52	$ 6.37	$ 6.23
Low Growth & High Prices	2024-2025	Feb	$ 6.19	$ 6.53	$ 6.19	$ 6.19	$ 6.19	$ 6.44	$ 6.05	$ 6.53	$ 6.34	$ 6.26
Low Growth & High Prices	2024-2025	Mar	$ 6.28	$ 6.51	$ 6.28	$ 6.28	$ 6.28	$ 6.18	$ 6.18	$ 6.51	$ 6.29	$ 6.32
Low Growth & High Prices	2024-2025	Apr	$ 6.16	$ 6.60	$ 6.16	$ 6.16	$ 6.16	$ 6.06	$ 6.06	$ 6.60	$ 6.24	$ 6.24
Low Growth & High Prices	2024-2025	May	$ 6.10	$ 6.61	$ 6.10	$ 6.10	$ 6.10	$ 6.01	$ 6.01	$ 6.61	$ 6.21	$ 6.21
Low Growth & High Prices	2024-2025	Jun	$ 6.04	$ 6.52	$ 6.04	$ 6.04	$ 6.04	$ 5.95	$ 5.95	$ 6.53	$ 6.14	$ 6.14
Low Growth & High Prices	2024-2025	Jul	$ 5.99	$ 6.53	$ 5.99	$ 5.99	$ 5.99	$ 5.90	$ 5.90	$ 6.53	$ 6.11	$ 6.10
Low Growth & High Prices	2024-2025	Aug	$ 5.98	$ 6.53	$ 5.98	$ 5.98	$ 5.98	$ 5.89	$ 5.89	$ 6.53	$ 6.10	$ 6.09
Low Growth & High Prices	2024-2025	Sep	$ 6.06	$ 6.53	$ 6.06	$ 6.06	$ 6.06	$ 5.97	$ 5.97	$ 6.53	$ 6.16	$ 6.16
Low Growth & High Prices	2024-2025	Oct	$ 6.12	$ 6.61	$ 6.12	$ 6.12	$ 6.12	$ 6.02	$ 6.02	$ 6.61	$ 6.22	$ 6.21
Low Growth & High Prices	2025-2026	Nov	$ 6.21	$ 6.60	$ 6.21	$ 6.21	$ 6.21	$ 6.11	$ 6.11	$ 6.60	$ 6.28	$ 6.29
Low Growth & High Prices	2025-2026	Dec	$ 6.30	$ 6.53	$ 6.30	$ 6.30	$ 6.30	$ 6.53	$ 6.10	$ 6.53	$ 6.39	$ 6.35
Low Growth & High Prices	2025-2026	Jan	$ 6.37	$ 6.72	$ 6.37	$ 6.37	$ 6.37	$ 6.72	$ 6.27	$ 6.72	$ 6.57	$ 6.44
Low Growth & High Prices	2025-2026	Feb	$ 6.42	$ 6.70	$ 6.42	$ 6.42	$ 6.42	$ 6.63	$ 6.29	$ 6.70	$ 6.54	$ 6.48
Low Growth & High Prices	2025-2026	Mar	$ 6.54	$ 6.71	$ 6.54	$ 6.54	$ 6.54	$ 6.44	$ 6.44	$ 6.71	$ 6.53	$ 6.57
Low Growth & High Prices	2025-2026	Apr	$ 6.41	$ 6.83	$ 6.41	$ 6.41	$ 6.41	$ 6.31	$ 6.31	$ 6.83	$ 6.49	$ 6.49
Low Growth & High Prices	2025-2026	May	$ 6.30	$ 6.75	$ 6.30	$ 6.30	$ 6.30	$ 6.20	$ 6.20	$ 6.75	$ 6.39	$ 6.39
Low Growth & High Prices	2025-2026	Jun	$ 6.23	$ 6.68	$ 6.23	$ 6.23	$ 6.23	$ 6.13	$ 6.13	$ 6.71	$ 6.33	$ 6.32
Low Growth & High Prices	2025-2026	Jul	$ 6.18	$ 6.71	$ 6.18	$ 6.18	$ 6.18	$ 6.08	$ 6.08	$ 6.71	$ 6.29	$ 6.28
Low Growth & High Prices	2025-2026	Aug	$ 6.17	$ 6.71	$ 6.17	$ 6.17	$ 6.17	$ 6.07	$ 6.07	$ 6.71	$ 6.29	$ 6.27
Low Growth & High Prices	2025-2026	Sep	$ 6.26	$ 6.71	$ 6.26	$ 6.26	$ 6.26	$ 6.16	$ 6.16	$ 6.71	$ 6.35	$ 6.35
Low Growth & High Prices	2025-2026	Oct	$ 6.31	$ 6.88	$ 6.31	$ 6.31	$ 6.31	$ 6.21	$ 6.21	$ 6.88	$ 6.44	$ 6.42
Low Growth & High Prices	2026-2027	Nov	$ 6.46	$ 6.74	$ 6.46	$ 6.46	$ 6.46	$ 6.36	$ 6.36	$ 6.74	$ 6.49	$ 6.52
Low Growth & High Prices	2026-2027	Dec	$ 6.58	$ 6.78	$ 6.58	$ 6.58	$ 6.58	$ 6.78	$ 6.35	$ 6.80	$ 6.64	$ 6.62
Low Growth & High Prices	2026-2027	Jan	$ 6.57	$ 7.21	$ 6.57	$ 6.57	$ 6.57	$ 6.95	$ 6.47	$ 7.21	$ 6.88	$ 6.70
Low Growth & High Prices	2026-2027	Feb	$ 6.55	$ 7.08	$ 6.55	$ 6.55	$ 6.55	$ 6.84	$ 6.39	$ 7.09	$ 6.78	$ 6.66
Low Growth & High Prices	2026-2027	Mar	$ 6.80	$ 7.11	$ 6.80	$ 6.80	$ 6.80	$ 6.69	$ 6.69	$ 7.11	$ 6.83	$ 6.86
Low Growth & High Prices	2026-2027	Apr	$ 6.58	$ 7.31	$ 6.58	$ 6.58	$ 6.58	$ 6.48	$ 6.48	$ 7.31	$ 6.76	$ 6.73
Low Growth & High Prices	2026-2027	May	$ 6.50	$ 7.22	$ 6.50	$ 6.50	$ 6.50	$ 6.40	$ 6.40	$ 7.22	$ 6.67	$ 6.64
Low Growth & High Prices	2026-2027	Jun	$ 6.42	$ 7.22	$ 6.42	$ 6.42	$ 6.42	$ 6.32	$ 6.32	$ 7.22	$ 6.62	$ 6.58
Low Growth & High Prices	2026-2027	Jul	$ 6.39	$ 7.22	$ 6.39	$ 6.39	$ 6.39	$ 6.29	$ 6.29	$ 7.22	$ 6.60	$ 6.56
Low Growth & High Prices	2026-2027	Aug	$ 6.38	$ 7.22	$ 6.38	$ 6.38	$ 6.38	$ 6.28	$ 6.28	$ 7.22	$ 6.60	$ 6.55
Low Growth & High Prices	2026-2027	Sep	$ 6.47	$ 7.22	$ 6.47	$ 6.47	$ 6.47	$ 6.37	$ 6.37	$ 7.22	$ 6.66	$ 6.62
Low Growth & High Prices	2026-2027	Oct	$ 6.52	$ 7.38	$ 6.52	$ 6.52	$ 6.52	$ 6.42	$ 6.42	$ 7.38	$ 6.74	$ 6.69
Low Growth & High Prices	2027-2028	Nov	$ 6.69	$ 7.32	$ 6.69	$ 6.69	$ 6.69	$ 6.59	$ 6.59	$ 7.32	$ 6.84	$ 6.82
Low Growth & High Prices	2027-2028	Dec	$ 6.81	$ 7.34	$ 6.81	$ 6.81	$ 6.81	$ 7.09	$ 6.56	$ 7.34	$ 7.00	$ 6.91
Low Growth & High Prices	2027-2028	Jan	$ 6.69	$ 7.38	$ 6.69	$ 6.69	$ 6.69	$ 7.07	$ 6.59	$ 7.38	$ 7.02	$ 6.83
Low Growth & High Prices	2027-2028	Feb	$ 6.73	$ 7.37	$ 6.73	$ 6.73	$ 6.73	$ 7.00	$ 6.56	$ 7.37	$ 6.98	$ 6.86
Low Growth & High Prices	2027-2028	Mar	$ 6.95	$ 7.40	$ 6.95	$ 6.95	$ 6.95	$ 6.85	$ 6.85	$ 7.40	$ 7.03	$ 7.04
Low Growth & High Prices	2027-2028	Apr	$ 6.79	$ 7.51	$ 6.79	$ 6.79	$ 6.79	$ 6.68	$ 6.68	$ 7.51	$ 6.96	$ 6.93
Low Growth & High Prices	2027-2028	May	$ 6.72	$ 7.40	$ 6.72	$ 6.72	$ 6.72	$ 6.61	$ 6.61	$ 7.40	$ 6.88	$ 6.85
Low Growth & High Prices	2027-2028	Jun	$ 6.65	$ 7.40	$ 6.65	$ 6.65	$ 6.65	$ 6.55	$ 6.55	$ 7.40	$ 6.84	$ 6.80
Low Growth & High Prices	2027-2028	Jul	$ 6.60	$ 7.40	$ 6.60	$ 6.60	$ 6.60	$ 6.50	$ 6.50	$ 7.41	$ 6.80	$ 6.76
Low Growth & High Prices	2027-2028	Aug	$ 6.60	$ 7.41	$ 6.60	$ 6.60	$ 6.60	$ 6.50	$ 6.50	$ 7.41	$ 6.81	$ 6.76
Low Growth & High Prices	2027-2028	Sep	$ 6.67	$ 7.41	$ 6.67	$ 6.67	$ 6.67	$ 6.57	$ 6.57	$ 7.41	$ 6.85	$ 6.82
Low Growth & High Prices	2027-2028	Oct	$ 6.74	$ 7.58	$ 6.74	$ 6.74	$ 6.74	$ 6.64	$ 6.64	$ 7.58	$ 6.95	$ 6.90

1/ Avoided costs are before Environmental Externalities adder.

APPENDIX 5.4: LOW GROWTH – HIGH PRICE MONTHLY DETAIL

Monthly Avoided Cost Detail 1/
2012$

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 Prices	2028-2029	Nov	$ 6.95	$ 7.54	$ 6.95	$ 6.95	$ 6.95	$ 6.85	$ 6.85	$ 7.54	$ 7.08	$ 7.07
Low Growth & High Prices	2028-2029	Dec	$ 7.07	$ 7.51	$ 7.07	$ 7.07	$ 7.07	$ 7.34	$ 6.83	$ 7.51	$ 7.23	$ 7.16
Low Growth & High Prices	2028-2029	Jan	$ 7.20	$ 7.63	$ 7.20	$ 7.20	$ 7.20	$ 7.57	$ 7.10	$ 7.63	$ 7.43	$ 7.29
Low Growth & High Prices	2028-2029	Feb	$ 7.33	$ 7.44	$ 7.33	$ 7.33	$ 7.33	$ 7.40	$ 7.17	$ 7.44	$ 7.33	$ 7.35
Low Growth & High Prices	2028-2029	Mar	$ 7.50	$ 7.51	$ 7.50	$ 7.50	$ 7.50	$ 7.39	$ 7.39	$ 7.51	$ 7.43	$ 7.50
Low Growth & High Prices	2028-2029	Apr	$ 7.28	$ 7.70	$ 7.28	$ 7.28	$ 7.28	$ 7.18	$ 7.18	$ 7.70	$ 7.35	$ 7.37
Low Growth & High Prices	2028-2029	May	$ 7.22	$ 7.71	$ 7.22	$ 7.22	$ 7.22	$ 7.12	$ 7.12	$ 7.71	$ 7.31	$ 7.32
Low Growth & High Prices	2028-2029	Jun	$ 7.15	$ 7.59	$ 7.15	$ 7.15	$ 7.15	$ 7.05	$ 7.05	$ 7.64	$ 7.24	$ 7.24
Low Growth & High Prices	2028-2029	Jul	$ 7.11	$ 7.65	$ 7.11	$ 7.11	$ 7.11	$ 7.01	$ 7.01	$ 7.65	$ 7.22	$ 7.22
Low Growth & High Prices	2028-2029	Aug	$ 7.08	$ 7.64	$ 7.08	$ 7.08	$ 7.08	$ 6.98	$ 6.98	$ 7.64	$ 7.20	$ 7.19
Low Growth & High Prices	2028-2029	Sep	$ 7.15	$ 7.66	$ 7.15	$ 7.15	$ 7.15	$ 7.05	$ 7.05	$ 7.66	$ 7.25	$ 7.25
Low Growth & High Prices	2028-2029	Oct	$ 7.19	$ 7.71	$ 7.19	$ 7.19	$ 7.19	$ 7.09	$ 7.09	$ 7.71	$ 7.29	$ 7.30
Low Growth & High Prices	2029-2030	Nov	$ 7.35	$ 7.68	$ 7.35	$ 7.35	$ 7.35	$ 7.24	$ 7.24	$ 7.68	$ 7.39	$ 7.41
Low Growth & High Prices	2029-2030	Dec	$ 7.46	$ 7.67	$ 7.46	$ 7.46	$ 7.46	$ 7.67	$ 7.24	$ 7.67	$ 7.53	$ 7.50
Low Growth & High Prices	2029-2030	Jan	$ 7.61	$ 7.88	$ 7.61	$ 7.61	$ 7.61	$ 7.88	$ 7.50	$ 7.88	$ 7.75	$ 7.66
Low Growth & High Prices	2029-2030	Feb	$ 7.56	$ 7.81	$ 7.56	$ 7.56	$ 7.56	$ 7.74	$ 7.39	$ 7.81	$ 7.64	$ 7.61
Low Growth & High Prices	2029-2030	Mar	$ 7.82	$ 7.85	$ 7.82	$ 7.82	$ 7.82	$ 7.71	$ 7.71	$ 7.85	$ 7.76	$ 7.83
Low Growth & High Prices	2029-2030	Apr	$ 7.53	$ 8.07	$ 7.53	$ 7.53	$ 7.53	$ 7.42	$ 7.42	$ 8.07	$ 7.64	$ 7.64
Low Growth & High Prices	2029-2030	May	$ 7.45	$ 7.95	$ 7.45	$ 7.45	$ 7.45	$ 7.34	$ 7.34	$ 7.95	$ 7.54	$ 7.55
Low Growth & High Prices	2029-2030	Jun	$ 7.38	$ 7.89	$ 7.38	$ 7.38	$ 7.38	$ 7.27	$ 7.27	$ 7.89	$ 7.47	$ 7.48
Low Growth & High Prices	2029-2030	Jul	$ 7.34	$ 7.89	$ 7.34	$ 7.34	$ 7.34	$ 7.23	$ 7.23	$ 7.89	$ 7.45	$ 7.45
Low Growth & High Prices	2029-2030	Aug	$ 7.32	$ 7.89	$ 7.32	$ 7.32	$ 7.32	$ 7.21	$ 7.21	$ 7.89	$ 7.43	$ 7.43
Low Growth & High Prices	2029-2030	Sep	$ 7.38	$ 7.89	$ 7.38	$ 7.38	$ 7.38	$ 7.27	$ 7.27	$ 7.89	$ 7.47	$ 7.48
Low Growth & High Prices	2029-2030	Oct	$ 7.45	$ 8.12	$ 7.45	$ 7.45	$ 7.45	$ 7.34	$ 7.34	$ 8.12	$ 7.60	$ 7.58
Low Growth & High Prices	2030-2031	Nov	$ 7.76	$ 7.97	$ 7.76	$ 7.76	$ 7.76	$ 7.65	$ 7.65	$ 7.97	$ 7.76	$ 7.80
Low Growth & High Prices	2030-2031	Dec	$ 7.82	$ 7.96	$ 7.82	$ 7.82	$ 7.82	$ 7.95	$ 7.60	$ 7.96	$ 7.84	$ 7.85
Low Growth & High Prices	2030-2031	Jan	$ 7.78	$ 8.10	$ 7.78	$ 7.78	$ 7.78	$ 8.10	$ 7.67	$ 8.10	$ 7.96	$ 7.85
Low Growth & High Prices	2030-2031	Feb	$ 7.76	$ 8.08	$ 7.76	$ 7.76	$ 7.76	$ 7.97	$ 7.57	$ 8.08	$ 7.87	$ 7.82
Low Growth & High Prices	2030-2031	Mar	$ 8.09	$ 8.09	$ 8.09	$ 8.09	$ 8.09	$ 7.97	$ 7.97	$ 8.09	$ 8.01	$ 8.09
Low Growth & High Prices	2030-2031	Apr	$ 7.88	$ 8.23	$ 7.88	$ 7.88	$ 7.88	$ 7.76	$ 7.76	$ 8.23	$ 7.92	$ 7.95
Low Growth & High Prices	2030-2031	May	$ 7.82	$ 8.21	$ 7.82	$ 7.82	$ 7.82	$ 7.71	$ 7.71	$ 8.21	$ 7.88	$ 7.90
Low Growth & High Prices	2030-2031	Jun	$ 7.76	$ 8.16	$ 7.76	$ 7.76	$ 7.76	$ 7.65	$ 7.65	$ 8.16	$ 7.82	$ 7.84
Low Growth & High Prices	2030-2031	Jul	$ 7.74	$ 8.21	$ 7.74	$ 7.74	$ 7.74	$ 7.63	$ 7.63	$ 8.21	$ 7.82	$ 7.84
Low Growth & High Prices	2030-2031	Aug	$ 7.73	$ 8.22	$ 7.73	$ 7.73	$ 7.73	$ 7.62	$ 7.62	$ 8.22	$ 7.82	$ 7.83
Low Growth & High Prices	2030-2031	Sep	$ 7.80	$ 8.29	$ 7.80	$ 7.80	$ 7.80	$ 7.69	$ 7.69	$ 8.29	$ 7.89	$ 7.90
Low Growth & High Prices	2030-2031	Oct	$ 7.86	$ 8.29	$ 7.86	$ 7.86	$ 7.86	$ 7.74	$ 7.74	$ 8.29	$ 7.92	$ 7.94
Low Growth & High Prices	2031-2032	Nov	$ 8.02	$ 8.11	$ 8.02	$ 8.02	$ 8.02	$ 7.90	$ 7.90	$ 8.11	$ 7.97	$ 8.04
Low Growth & High Prices	2031-2032	Dec	$ 7.88	$ 8.14	$ 7.88	$ 7.88	$ 7.88	$ 8.14	$ 7.67	$ 8.14	$ 7.98	$ 7.93
Low Growth & High Prices	2031-2032	Jan	$ 8.02	$ 8.07	$ 8.02	$ 8.02	$ 8.02	$ 8.07	$ 7.90	$ 8.07	$ 8.01	$ 8.03
Low Growth & High Prices	2031-2032	Feb	$ 8.03	$ 8.10	$ 8.03	$ 8.03	$ 8.03	$ 8.07	$ 7.91	$ 8.10	$ 8.02	$ 8.04
Low Growth & High Prices	2031-2032	Mar	$ 8.15	$ 8.07	$ 8.10	$ 8.10	$ 8.10	$ 8.07	$ 8.07	$ 8.07	$ 8.07	$ 8.10
Low Growth & High Prices	2031-2032	Apr	$ 8.03	$ 8.05	$ 8.03	$ 8.03	$ 8.03	$ 7.91	$ 7.91	$ 8.05	$ 7.96	$ 8.03
Low Growth & High Prices	2031-2032	May	$ 8.01	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 7.89	$ 7.89	$ 8.00	$ 7.93	$ 8.00
Low Growth & High Prices	2031-2032	Jun	$ 7.94	$ 7.90	$ 7.81	$ 7.81	$ 7.81	$ 7.82	$ 7.82	$ 8.00	$ 7.88	$ 7.85
Low Growth & High Prices	2031-2032	Jul	$ 7.82	$ 7.81	$ 7.81	$ 7.81	$ 7.81	$ 7.71	$ 7.71	$ 8.00	$ 7.81	$ 7.81
Low Growth & High Prices	2031-2032	Aug	$ 7.80	$ 7.81	$ 7.80	$ 7.80	$ 7.80	$ 7.69	$ 7.69	$ 8.00	$ 7.79	$ 7.81
Low Growth & High Prices	2031-2032	Sep	$ 7.96	$ 8.00	$ 7.96	$ 7.96	$ 7.96	$ 7.84	$ 7.84	$ 8.00	$ 7.89	$ 7.97
Low Growth & High Prices	2031-2032	Oct	$ 8.01	$ 8.09	$ 8.01	$ 8.01	$ 8.01	$ 7.89	$ 7.89	$ 8.09	$ 7.96	$ 8.02
Low Growth & High Prices	2032-2033	Nov	$ 8.11	$ 8.06	$ 8.11	$ 8.11	$ 8.11	$ 7.99	$ 7.99	$ 8.06	$ 8.01	$ 8.10
Low Growth & High Prices	2032-2033	Dec	$ 8.14	$ 8.17	$ 8.14	$ 8.14	$ 8.14	$ 8.17	$ 7.94	$ 8.17	$ 8.10	$ 8.15
Low Growth & High Prices	2032-2033	Jan	$ 8.43	$ 8.42	$ 8.43	$ 8.43	$ 8.43	$ 8.31	$ 8.31	$ 8.31	$ 8.31	$ 8.43
Low Growth & High Prices	2032-2033	Feb	$ 8.42	$ 8.44	$ 8.42	$ 8.42	$ 8.42	$ 8.38	$ 8.30	$ 8.38	$ 8.35	$ 8.43
Low Growth & High Prices	2032-2033	Mar	$ 8.54	$ 8.45	$ 8.49	$ 8.49	$ 8.49	$ 8.45	$ 8.45	$ 8.45	$ 8.45	$ 8.49
Low Growth & High Prices	2032-2033	Apr	$ 8.40	$ 8.36	$ 8.40	$ 8.40	$ 8.40	$ 8.28	$ 8.28	$ 8.36	$ 8.31	$ 8.40
Low Growth & High Prices	2032-2033	May	$ 8.39	$ 8.33	$ 8.33	$ 8.33	$ 8.33	$ 8.27	$ 8.27	$ 8.33	$ 8.29	$ 8.34
Low Growth & High Prices	2032-2033	Jun	$ 8.30	$ 8.22	$ 8.14	$ 8.14	$ 8.14	$ 8.22	$ 8.22	$ 8.22	$ 8.22	$ 8.19
Low Growth & High Prices	2032-2033	Jul	$ 8.22	$ 8.14	$ 8.14	$ 8.14	$ 8.14	$ 8.10	$ 8.10	$ 8.14	$ 8.11	$ 8.16
Low Growth & High Prices	2032-2033	Aug	$ 8.20	$ 8.14	$ 8.14	$ 8.14	$ 8.14	$ 8.08	$ 8.08	$ 8.14	$ 8.10	$ 8.15
Low Growth & High Prices	2032-2033	Sep	$ 8.36	$ 8.32	$ 8.32	$ 8.32	$ 8.32	$ 8.24	$ 8.24	$ 8.32	$ 8.27	$ 8.33
Low Growth & High Prices	2032-2033	Oct	$ 8.44	$ 8.43	$ 8.43	$ 8.43	$ 8.43	$ 8.31	$ 8.31	$ 8.43	$ 8.35	$ 8.43

1/ Avoided costs are before Environmental Externalities adder.

APPENDIX 5.4: EXPECTED MONTHLY DETAIL

Monthly Avoided Cost Detail 1/
2012$

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 Case	2013-2014	Nov	$ 3.33	$ 3.83	$ 3.33	$ 3.33	$ 3.33	$ 3.27	$ 3.27	$ 3.83	$ 3.46	$ 3.43
Expected Case	2013-2014	Dec	$ 4.01	$ 4.38	$ 4.02	$ 4.02	$ 4.02	$ 4.16	$ 3.66	$ 4.16	$ 3.99	$ 4.09
Expected Case	2013-2014	Jan	$ 4.26	$ 4.26	$ 4.26	$ 4.26	$ 4.26	$ 4.19	$ 4.20	$ 4.19	$ 4.19	$ 4.26
Expected Case	2013-2014	Feb	$ 3.47	$ 4.17	$ 3.47	$ 3.47	$ 3.47	$ 3.82	$ 3.35	$ 4.17	$ 3.78	$ 3.61
Expected Case	2013-2014	Mar	$ 3.51	$ 4.16	$ 3.51	$ 3.51	$ 3.51	$ 3.45	$ 3.45	$ 4.17	$ 3.69	$ 3.64
Expected Case	2013-2014	Apr	$ 3.49	$ 4.15	$ 3.49	$ 3.49	$ 3.49	$ 3.43	$ 3.43	$ 4.15	$ 3.67	$ 3.62
Expected Case	2013-2014	May	$ 3.44	$ 4.12	$ 3.44	$ 3.44	$ 3.44	$ 3.38	$ 3.38	$ 4.12	$ 3.63	$ 3.57
Expected Case	2013-2014	Jun	$ 3.45	$ 4.12	$ 3.45	$ 3.45	$ 3.45	$ 3.39	$ 3.39	$ 4.12	$ 3.64	$ 3.58
Expected Case	2013-2014	Jul	$ 3.44	$ 4.12	$ 3.44	$ 3.44	$ 3.44	$ 3.38	$ 3.38	$ 4.12	$ 3.63	$ 3.58
Expected Case	2013-2014	Aug	$ 3.37	$ 4.07	$ 3.37	$ 3.37	$ 3.37	$ 3.31	$ 3.31	$ 4.12	$ 3.58	$ 3.51
Expected Case	2013-2014	Sep	$ 3.40	$ 4.10	$ 3.40	$ 3.40	$ 3.40	$ 3.34	$ 3.34	$ 4.12	$ 3.60	$ 3.54
Expected Case	2013-2014	Oct	$ 3.25	$ 3.99	$ 3.25	$ 3.25	$ 3.25	$ 3.19	$ 3.19	$ 4.12	$ 3.50	$ 3.39
Expected Case	2014-2015	Nov	$ 3.35	$ 4.09	$ 3.35	$ 3.35	$ 3.35	$ 3.44	$ 3.29	$ 4.09	$ 3.61	$ 3.50
Expected Case	2014-2015	Dec	$ 3.50	$ 4.16	$ 3.50	$ 3.50	$ 3.50	$ 3.83	$ 3.27	$ 4.16	$ 3.75	$ 3.63
Expected Case	2014-2015	Jan	$ 3.42	$ 4.16	$ 3.42	$ 3.42	$ 3.42	$ 3.84	$ 3.35	$ 4.16	$ 3.78	$ 3.57
Expected Case	2014-2015	Feb	$ 3.51	$ 4.17	$ 3.51	$ 3.51	$ 3.51	$ 3.90	$ 3.39	$ 4.16	$ 3.82	$ 3.64
Expected Case	2014-2015	Mar	$ 3.55	$ 4.11	$ 3.55	$ 3.55	$ 3.55	$ 3.49	$ 3.49	$ 4.11	$ 3.70	$ 3.66
Expected Case	2014-2015	Apr	$ 3.43	$ 4.09	$ 3.43	$ 3.43	$ 3.43	$ 3.37	$ 3.37	$ 4.16	$ 3.64	$ 3.56
Expected Case	2014-2015	May	$ 3.42	$ 4.10	$ 3.42	$ 3.42	$ 3.42	$ 3.36	$ 3.36	$ 4.16	$ 3.63	$ 3.55
Expected Case	2014-2015	Jun	$ 3.46	$ 4.16	$ 3.46	$ 3.46	$ 3.46	$ 3.40	$ 3.40	$ 4.16	$ 3.66	$ 3.60
Expected Case	2014-2015	Jul	$ 3.52	$ 4.16	$ 3.52	$ 3.52	$ 3.52	$ 3.46	$ 3.46	$ 4.16	$ 3.70	$ 3.65
Expected Case	2014-2015	Aug	$ 3.56	$ 4.16	$ 3.56	$ 3.56	$ 3.56	$ 3.50	$ 3.50	$ 4.16	$ 3.72	$ 3.68
Expected Case	2014-2015	Sep	$ 3.61	$ 4.16	$ 3.61	$ 3.61	$ 3.61	$ 3.55	$ 3.55	$ 4.16	$ 3.76	$ 3.72
Expected Case	2014-2015	Oct	$ 3.68	$ 4.34	$ 3.68	$ 3.68	$ 3.68	$ 3.62	$ 3.62	$ 4.34	$ 3.86	$ 3.81
Expected Case	2015-2016	Nov	$ 3.86	$ 4.59	$ 3.86	$ 3.86	$ 3.86	$ 3.94	$ 3.79	$ 4.59	$ 4.11	$ 4.00
Expected Case	2015-2016	Dec	$ 4.14	$ 4.64	$ 4.14	$ 4.14	$ 4.14	$ 4.44	$ 3.93	$ 4.60	$ 4.32	$ 4.24
Expected Case	2015-2016	Jan	$ 4.04	$ 4.59	$ 4.04	$ 4.04	$ 4.04	$ 4.46	$ 3.98	$ 4.59	$ 4.34	$ 4.15
Expected Case	2015-2016	Feb	$ 3.97	$ 4.63	$ 3.97	$ 3.97	$ 3.97	$ 4.40	$ 3.90	$ 4.60	$ 4.30	$ 4.10
Expected Case	2015-2016	Mar	$ 4.01	$ 4.60	$ 4.01	$ 4.01	$ 4.01	$ 3.95	$ 3.95	$ 4.60	$ 4.16	$ 4.13
Expected Case	2015-2016	Apr	$ 3.80	$ 4.54	$ 3.80	$ 3.80	$ 3.80	$ 3.74	$ 3.74	$ 4.54	$ 4.01	$ 3.95
Expected Case	2015-2016	May	$ 3.67	$ 4.38	$ 3.67	$ 3.67	$ 3.67	$ 3.61	$ 3.61	$ 4.38	$ 3.87	$ 3.81
Expected Case	2015-2016	Jun	$ 3.68	$ 4.38	$ 3.68	$ 3.68	$ 3.68	$ 3.62	$ 3.62	$ 4.38	$ 3.88	$ 3.82
Expected Case	2015-2016	Jul	$ 3.69	$ 4.38	$ 3.69	$ 3.69	$ 3.69	$ 3.63	$ 3.63	$ 4.38	$ 3.88	$ 3.83
Expected Case	2015-2016	Aug	$ 3.52	$ 4.28	$ 3.52	$ 3.52	$ 3.52	$ 3.46	$ 3.46	$ 4.38	$ 3.77	$ 3.67
Expected Case	2015-2016	Sep	$ 3.43	$ 4.27	$ 3.43	$ 3.43	$ 3.43	$ 3.37	$ 3.37	$ 4.38	$ 3.71	$ 3.60
Expected Case	2015-2016	Oct	$ 3.45	$ 4.21	$ 3.45	$ 3.45	$ 3.45	$ 3.39	$ 3.39	$ 4.38	$ 3.72	$ 3.60
Expected Case	2016-2017	Nov	$ 3.59	$ 4.40	$ 3.59	$ 3.59	$ 3.59	$ 3.68	$ 3.53	$ 4.40	$ 3.87	$ 3.75
Expected Case	2016-2017	Dec	$ 3.71	$ 4.41	$ 3.71	$ 3.71	$ 3.71	$ 4.03	$ 3.46	$ 4.40	$ 3.96	$ 3.85
Expected Case	2016-2017	Jan	$ 3.53	$ 4.40	$ 3.53	$ 3.53	$ 3.53	$ 3.95	$ 3.46	$ 4.40	$ 3.94	$ 3.70
Expected Case	2016-2017	Feb	$ 3.61	$ 4.41	$ 3.61	$ 3.61	$ 3.61	$ 4.06	$ 3.50	$ 4.41	$ 3.99	$ 3.77
Expected Case	2016-2017	Mar	$ 3.61	$ 4.27	$ 3.61	$ 3.61	$ 3.61	$ 3.55	$ 3.55	$ 4.27	$ 3.79	$ 3.74
Expected Case	2016-2017	Apr	$ 3.47	$ 4.29	$ 3.47	$ 3.47	$ 3.47	$ 3.41	$ 3.41	$ 4.32	$ 3.72	$ 3.63
Expected Case	2016-2017	May	$ 3.44	$ 4.32	$ 3.44	$ 3.44	$ 3.44	$ 3.38	$ 3.38	$ 4.32	$ 3.70	$ 3.62
Expected Case	2016-2017	Jun	$ 3.46	$ 4.28	$ 3.46	$ 3.46	$ 3.46	$ 3.40	$ 3.40	$ 4.32	$ 3.71	$ 3.62
Expected Case	2016-2017	Jul	$ 3.47	$ 4.29	$ 3.47	$ 3.47	$ 3.47	$ 3.41	$ 3.41	$ 4.32	$ 3.72	$ 3.63
Expected Case	2016-2017	Aug	$ 3.47	$ 4.32	$ 3.47	$ 3.47	$ 3.47	$ 3.41	$ 3.41	$ 4.32	$ 3.72	$ 3.64
Expected Case	2016-2017	Sep	$ 3.49	$ 4.32	$ 3.49	$ 3.49	$ 3.49	$ 3.43	$ 3.43	$ 4.32	$ 3.73	$ 3.66
Expected Case	2016-2017	Oct	$ 3.53	$ 4.35	$ 3.53	$ 3.53	$ 3.53	$ 3.47	$ 3.47	$ 4.35	$ 3.77	$ 3.69
Expected Case	2017-2018	Nov	$ 3.67	$ 4.57	$ 3.67	$ 3.67	$ 3.67	$ 3.76	$ 3.61	$ 4.57	$ 3.98	$ 3.85
Expected Case	2017-2018	Dec	$ 3.85	$ 4.59	$ 3.85	$ 3.85	$ 3.85	$ 4.19	$ 3.62	$ 4.57	$ 4.13	$ 4.00
Expected Case	2017-2018	Jan	$ 3.69	$ 4.57	$ 3.69	$ 3.69	$ 3.69	$ 4.12	$ 3.63	$ 4.57	$ 4.11	$ 3.87
Expected Case	2017-2018	Feb	$ 3.69	$ 4.58	$ 3.69	$ 3.69	$ 3.69	$ 4.22	$ 3.63	$ 4.58	$ 4.14	$ 3.87
Expected Case	2017-2018	Mar	$ 3.66	$ 4.40	$ 3.66	$ 3.66	$ 3.66	$ 3.60	$ 3.60	$ 4.40	$ 3.87	$ 3.81
Expected Case	2017-2018	Apr	$ 3.45	$ 4.33	$ 3.45	$ 3.45	$ 3.45	$ 3.39	$ 3.39	$ 4.33	$ 3.71	$ 3.63
Expected Case	2017-2018	May	$ 3.38	$ 4.26	$ 3.38	$ 3.38	$ 3.38	$ 3.32	$ 3.32	$ 4.26	$ 3.63	$ 3.55
Expected Case	2017-2018	Jun	$ 3.35	$ 4.25	$ 3.35	$ 3.35	$ 3.35	$ 3.29	$ 3.29	$ 4.26	$ 3.61	$ 3.53
Expected Case	2017-2018	Jul	$ 3.32	$ 4.24	$ 3.32	$ 3.32	$ 3.32	$ 3.26	$ 3.26	$ 4.26	$ 3.59	$ 3.50
Expected Case	2017-2018	Aug	$ 3.30	$ 4.24	$ 3.30	$ 3.30	$ 3.30	$ 3.24	$ 3.24	$ 4.26	$ 3.58	$ 3.49
Expected Case	2017-2018	Sep	$ 3.32	$ 4.26	$ 3.32	$ 3.32	$ 3.32	$ 3.26	$ 3.26	$ 4.26	$ 3.60	$ 3.51
Expected Case	2017-2018	Oct	$ 3.34	$ 4.26	$ 3.34	$ 3.34	$ 3.34	$ 3.28	$ 3.28	$ 4.26	$ 3.61	$ 3.52
Expected Case	2018-2019	Nov	$ 3.55	$ 4.29	$ 3.55	$ 3.55	$ 3.55	$ 3.64	$ 3.49	$ 4.29	$ 3.81	$ 3.70
Expected Case	2018-2019	Dec	$ 3.68	$ 4.33	$ 3.68	$ 3.68	$ 3.68	$ 3.97	$ 3.41	$ 4.29	$ 3.89	$ 3.81
Expected Case	2018-2019	Jan	$ 3.37	$ 4.29	$ 3.37	$ 3.37	$ 3.37	$ 3.75	$ 3.26	$ 4.29	$ 3.77	$ 3.55
Expected Case	2018-2019	Feb	$ 3.41	$ 4.29	$ 3.41	$ 3.41	$ 3.41	$ 3.89	$ 3.29	$ 4.29	$ 3.83	$ 3.59
Expected Case	2018-2019	Mar	$ 3.43	$ 4.23	$ 3.43	$ 3.43	$ 3.43	$ 3.37	$ 3.37	$ 4.23	$ 3.66	$ 3.59
Expected Case	2018-2019	Apr	$ 3.29	$ 4.25	$ 3.29	$ 3.29	$ 3.29	$ 3.23	$ 3.23	$ 4.25	$ 3.57	$ 3.48
Expected Case	2018-2019	May	$ 3.25	$ 4.23	$ 3.25	$ 3.25	$ 3.25	$ 3.19	$ 3.19	$ 4.24	$ 3.54	$ 3.44
Expected Case	2018-2019	Jun	$ 3.23	$ 4.23	$ 3.23	$ 3.23	$ 3.23	$ 3.17	$ 3.17	$ 4.25	$ 3.53	$ 3.43
Expected Case	2018-2019	Jul	$ 3.26	$ 4.20	$ 3.26	$ 3.26	$ 3.26	$ 3.20	$ 3.20	$ 4.25	$ 3.55	$ 3.44
Expected Case	2018-2019	Aug	$ 3.25	$ 4.25	$ 3.25	$ 3.25	$ 3.25	$ 3.19	$ 3.19	$ 4.25	$ 3.54	$ 3.45
Expected Case	2018-2019	Sep	$ 3.28	$ 4.25	$ 3.28	$ 3.28	$ 3.28	$ 3.22	$ 3.22	$ 4.25	$ 3.57	$ 3.47
Expected Case	2018-2019	Oct	$ 3.32	$ 4.30	$ 3.32	$ 3.32	$ 3.32	$ 3.26	$ 3.26	$ 4.30	$ 3.61	$ 3.51
Expected Case	2019-2020	Nov	$ 3.53	$ 4.25	$ 3.53	$ 3.53	$ 3.53	$ 3.62	$ 3.47	$ 4.25	$ 3.78	$ 3.67
Expected Case	2019-2020	Dec	$ 3.74	$ 4.27	$ 3.74	$ 3.74	$ 3.74	$ 4.01	$ 3.47	$ 4.26	$ 3.91	$ 3.84
Expected Case	2019-2020	Jan	$ 3.36	$ 4.25	$ 3.36	$ 3.36	$ 3.36	$ 3.74	$ 3.25	$ 4.25	$ 3.75	$ 3.54
Expected Case	2019-2020	Feb	$ 3.45	$ 4.23	$ 3.45	$ 3.45	$ 3.45	$ 3.92	$ 3.33	$ 4.23	$ 3.83	$ 3.60
Expected Case	2019-2020	Mar	$ 3.52	$ 4.12	$ 3.52	$ 3.52	$ 3.52	$ 3.46	$ 3.46	$ 4.12	$ 3.68	$ 3.64
Expected Case	2019-2020	Apr	$ 3.39	$ 4.13	$ 3.39	$ 3.39	$ 3.39	$ 3.33	$ 3.33	$ 4.18	$ 3.61	$ 3.54
Expected Case	2019-2020	May	$ 3.35	$ 4.15	$ 3.35	$ 3.35	$ 3.35	$ 3.29	$ 3.29	$ 4.18	$ 3.59	$ 3.51
Expected Case	2019-2020	Jun	$ 3.37	$ 4.17	$ 3.37	$ 3.37	$ 3.37	$ 3.31	$ 3.31	$ 4.18	$ 3.60	$ 3.53
Expected Case	2019-2020	Jul	$ 3.38	$ 4.18	$ 3.38	$ 3.38	$ 3.38	$ 3.32	$ 3.32	$ 4.18	$ 3.61	$ 3.54
Expected Case	2019-2020	Aug	$ 3.39	$ 4.18	$ 3.39	$ 3.39	$ 3.39	$ 3.33	$ 3.33	$ 4.18	$ 3.62	$ 3.55
Expected Case	2019-2020	Sep	$ 3.39	$ 4.18	$ 3.39	$ 3.39	$ 3.39	$ 3.33	$ 3.33	$ 4.18	$ 3.62	$ 3.55
Expected Case	2019-2020	Oct	$ 3.46	$ 4.26	$ 3.46	$ 3.46	$ 3.46	$ 3.40	$ 3.40	$ 4.26	$ 3.69	$ 3.62

1/ Avoided costs are before Environmental Externalities adder.

APPENDIX 5.4: EXPECTED MONTHLY DETAIL

Monthly Avoided Cost Detail 1/
2012$

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 Case	2020-2021	Nov	$ 3.60	$ 4.26	$ 3.60	$ 3.60	$ 3.60	$ 3.69	$ 3.54	$ 4.26	$ 3.83	$ 3.73
Expected Case	2020-2021	Dec	$ 3.84	$ 4.31	$ 3.84	$ 3.84	$ 3.84	$ 4.02	$ 3.48	$ 4.27	$ 3.93	$ 3.93
Expected Case	2020-2021	Jan	$ 3.49	$ 4.26	$ 3.49	$ 3.49	$ 3.49	$ 3.83	$ 3.34	$ 4.26	$ 3.81	$ 3.65
Expected Case	2020-2021	Feb	$ 3.56	$ 4.24	$ 3.56	$ 3.56	$ 3.56	$ 3.97	$ 3.41	$ 4.24	$ 3.87	$ 3.70
Expected Case	2020-2021	Mar	$ 3.64	$ 4.10	$ 3.64	$ 3.64	$ 3.64	$ 3.58	$ 3.58	$ 4.10	$ 3.76	$ 3.73
Expected Case	2020-2021	Apr	$ 3.64	$ 4.20	$ 3.64	$ 3.64	$ 3.64	$ 3.58	$ 3.58	$ 4.27	$ 3.81	$ 3.75
Expected Case	2020-2021	May	$ 3.64	$ 4.34	$ 3.64	$ 3.64	$ 3.64	$ 3.58	$ 3.58	$ 4.34	$ 3.84	$ 3.78
Expected Case	2020-2021	Jun	$ 3.67	$ 4.27	$ 3.67	$ 3.67	$ 3.67	$ 3.61	$ 3.61	$ 4.27	$ 3.83	$ 3.79
Expected Case	2020-2021	Jul	$ 3.66	$ 4.27	$ 3.66	$ 3.66	$ 3.66	$ 3.60	$ 3.60	$ 4.27	$ 3.83	$ 3.78
Expected Case	2020-2021	Aug	$ 3.69	$ 4.27	$ 3.69	$ 3.69	$ 3.69	$ 3.63	$ 3.63	$ 4.27	$ 3.85	$ 3.81
Expected Case	2020-2021	Sep	$ 3.74	$ 4.27	$ 3.74	$ 3.74	$ 3.74	$ 3.68	$ 3.68	$ 4.27	$ 3.88	$ 3.85
Expected Case	2020-2021	Oct	$ 3.79	$ 4.53	$ 3.79	$ 3.79	$ 3.79	$ 3.73	$ 3.73	$ 4.53	$ 4.00	$ 3.94
Expected Case	2021-2022	Nov	$ 3.92	$ 4.46	$ 3.92	$ 3.92	$ 3.92	$ 4.00	$ 3.86	$ 4.46	$ 4.10	$ 4.03
Expected Case	2021-2022	Dec	$ 4.14	$ 4.49	$ 4.14	$ 4.14	$ 4.14	$ 4.41	$ 3.91	$ 4.47	$ 4.26	$ 4.21
Expected Case	2021-2022	Jan	$ 4.04	$ 4.46	$ 4.04	$ 4.04	$ 4.04	$ 4.46	$ 3.98	$ 4.46	$ 4.30	$ 4.12
Expected Case	2021-2022	Feb	$ 4.03	$ 4.42	$ 4.03	$ 4.03	$ 4.03	$ 4.42	$ 3.97	$ 4.42	$ 4.27	$ 4.11
Expected Case	2021-2022	Mar	$ 3.93	$ 4.02	$ 3.93	$ 3.93	$ 3.93	$ 3.87	$ 3.87	$ 4.02	$ 3.92	$ 3.95
Expected Case	2021-2022	Apr	$ 3.67	$ 3.99	$ 3.67	$ 3.67	$ 3.67	$ 3.61	$ 3.61	$ 4.01	$ 3.75	$ 3.74
Expected Case	2021-2022	May	$ 3.61	$ 3.99	$ 3.61	$ 3.61	$ 3.61	$ 3.55	$ 3.55	$ 4.01	$ 3.71	$ 3.69
Expected Case	2021-2022	Jun	$ 3.59	$ 3.97	$ 3.59	$ 3.59	$ 3.59	$ 3.53	$ 3.53	$ 4.01	$ 3.69	$ 3.67
Expected Case	2021-2022	Jul	$ 3.59	$ 3.97	$ 3.59	$ 3.59	$ 3.59	$ 3.53	$ 3.53	$ 4.01	$ 3.69	$ 3.67
Expected Case	2021-2022	Aug	$ 3.59	$ 4.01	$ 3.59	$ 3.59	$ 3.59	$ 3.53	$ 3.53	$ 4.01	$ 3.69	$ 3.68
Expected Case	2021-2022	Sep	$ 3.70	$ 4.10	$ 3.70	$ 3.70	$ 3.70	$ 3.64	$ 3.64	$ 4.10	$ 3.80	$ 3.78
Expected Case	2021-2022	Oct	$ 3.75	$ 4.11	$ 3.75	$ 3.75	$ 3.75	$ 3.69	$ 3.69	$ 4.11	$ 3.83	$ 3.83
Expected Case	2022-2023	Nov	$ 4.03	$ 4.34	$ 4.03	$ 4.03	$ 4.03	$ 4.08	$ 3.97	$ 4.34	$ 4.13	$ 4.09
Expected Case	2022-2023	Dec	$ 4.17	$ 4.35	$ 4.17	$ 4.17	$ 4.17	$ 4.35	$ 3.99	$ 4.35	$ 4.23	$ 4.21
Expected Case	2022-2023	Jan	$ 4.03	$ 4.37	$ 4.03	$ 4.03	$ 4.03	$ 4.37	$ 3.96	$ 4.37	$ 4.23	$ 4.10
Expected Case	2022-2023	Feb	$ 4.02	$ 4.35	$ 4.02	$ 4.02	$ 4.02	$ 4.35	$ 3.95	$ 4.35	$ 4.22	$ 4.08
Expected Case	2022-2023	Mar	$ 3.99	$ 4.20	$ 3.99	$ 3.99	$ 3.99	$ 3.93	$ 3.93	$ 4.20	$ 4.02	$ 4.03
Expected Case	2022-2023	Apr	$ 3.78	$ 4.20	$ 3.78	$ 3.78	$ 3.78	$ 3.72	$ 3.72	$ 4.20	$ 3.88	$ 3.87
Expected Case	2022-2023	May	$ 3.65	$ 4.11	$ 3.65	$ 3.65	$ 3.65	$ 3.59	$ 3.59	$ 4.16	$ 3.78	$ 3.74
Expected Case	2022-2023	Jun	$ 3.62	$ 4.08	$ 3.62	$ 3.62	$ 3.62	$ 3.56	$ 3.56	$ 4.16	$ 3.76	$ 3.71
Expected Case	2022-2023	Jul	$ 3.62	$ 4.12	$ 3.62	$ 3.62	$ 3.62	$ 3.56	$ 3.56	$ 4.16	$ 3.76	$ 3.72
Expected Case	2022-2023	Aug	$ 3.63	$ 4.15	$ 3.63	$ 3.63	$ 3.63	$ 3.57	$ 3.57	$ 4.16	$ 3.77	$ 3.74
Expected Case	2022-2023	Sep	$ 3.72	$ 4.18	$ 3.72	$ 3.72	$ 3.72	$ 3.66	$ 3.66	$ 4.18	$ 3.84	$ 3.82
Expected Case	2022-2023	Oct	$ 3.78	$ 4.30	$ 3.78	$ 3.78	$ 3.78	$ 3.72	$ 3.72	$ 4.30	$ 3.92	$ 3.89
Expected Case	2023-2024	Nov	$ 4.10	$ 4.45	$ 4.10	$ 4.10	$ 4.10	$ 4.16	$ 4.04	$ 4.45	$ 4.21	$ 4.17
Expected Case	2023-2024	Dec	$ 4.39	$ 4.48	$ 4.39	$ 4.39	$ 4.39	$ 4.48	$ 4.13	$ 4.48	$ 4.36	$ 4.41
Expected Case	2023-2024	Jan	$ 4.31	$ 4.45	$ 4.31	$ 4.31	$ 4.31	$ 4.45	$ 4.24	$ 4.45	$ 4.38	$ 4.34
Expected Case	2023-2024	Feb	$ 4.34	$ 4.45	$ 4.34	$ 4.34	$ 4.34	$ 4.44	$ 4.28	$ 4.44	$ 4.38	$ 4.36
Expected Case	2023-2024	Mar	$ 4.32	$ 4.28	$ 4.32	$ 4.32	$ 4.32	$ 4.28	$ 4.28	$ 4.28	$ 4.28	$ 4.31
Expected Case	2023-2024	Apr	$ 4.12	$ 4.29	$ 4.12	$ 4.12	$ 4.12	$ 4.06	$ 4.06	$ 4.29	$ 4.13	$ 4.15
Expected Case	2023-2024	May	$ 4.00	$ 4.17	$ 4.00	$ 4.00	$ 4.00	$ 3.94	$ 3.94	$ 4.24	$ 4.04	$ 4.03
Expected Case	2023-2024	Jun	$ 3.97	$ 4.15	$ 3.97	$ 3.97	$ 3.97	$ 3.91	$ 3.91	$ 4.24	$ 4.02	$ 4.00
Expected Case	2023-2024	Jul	$ 3.96	$ 4.15	$ 3.96	$ 3.96	$ 3.96	$ 3.90	$ 3.90	$ 4.24	$ 4.01	$ 4.00
Expected Case	2023-2024	Aug	$ 3.98	$ 4.15	$ 3.98	$ 3.98	$ 3.98	$ 3.92	$ 3.92	$ 4.24	$ 4.02	$ 4.01
Expected Case	2023-2024	Sep	$ 4.07	$ 4.24	$ 4.07	$ 4.07	$ 4.07	$ 4.01	$ 4.01	$ 4.24	$ 4.08	$ 4.10
Expected Case	2023-2024	Oct	$ 4.13	$ 4.40	$ 4.13	$ 4.13	$ 4.13	$ 4.07	$ 4.07	$ 4.40	$ 4.18	$ 4.18
Expected Case	2024-2025	Nov	$ 4.43	$ 4.55	$ 4.43	$ 4.43	$ 4.43	$ 4.42	$ 4.36	$ 4.55	$ 4.44	$ 4.45
Expected Case	2024-2025	Dec	$ 4.79	$ 4.88	$ 4.79	$ 4.79	$ 4.79	$ 4.88	$ 4.45	$ 4.88	$ 4.74	$ 4.81
Expected Case	2024-2025	Jan	$ 4.65	$ 4.93	$ 4.65	$ 4.65	$ 4.65	$ 4.93	$ 4.52	$ 4.93	$ 4.79	$ 4.71
Expected Case	2024-2025	Feb	$ 4.60	$ 4.94	$ 4.60	$ 4.60	$ 4.60	$ 4.93	$ 4.50	$ 4.93	$ 4.79	$ 4.67
Expected Case	2024-2025	Mar	$ 4.54	$ 4.80	$ 4.54	$ 4.54	$ 4.54	$ 4.47	$ 4.47	$ 4.80	$ 4.58	$ 4.59
Expected Case	2024-2025	Apr	$ 4.34	$ 4.81	$ 4.34	$ 4.34	$ 4.34	$ 4.28	$ 4.28	$ 4.90	$ 4.49	$ 4.44
Expected Case	2024-2025	May	$ 4.31	$ 4.86	$ 4.31	$ 4.31	$ 4.31	$ 4.25	$ 4.25	$ 4.90	$ 4.47	$ 4.42
Expected Case	2024-2025	Jun	$ 4.30	$ 4.81	$ 4.30	$ 4.30	$ 4.30	$ 4.24	$ 4.24	$ 4.91	$ 4.46	$ 4.41
Expected Case	2024-2025	Jul	$ 4.29	$ 4.91	$ 4.29	$ 4.29	$ 4.29	$ 4.23	$ 4.23	$ 4.91	$ 4.45	$ 4.42
Expected Case	2024-2025	Aug	$ 4.31	$ 4.91	$ 4.31	$ 4.31	$ 4.31	$ 4.25	$ 4.25	$ 4.91	$ 4.47	$ 4.43
Expected Case	2024-2025	Sep	$ 4.39	$ 4.91	$ 4.39	$ 4.39	$ 4.39	$ 4.32	$ 4.32	$ 4.91	$ 4.51	$ 4.49
Expected Case	2024-2025	Oct	$ 4.46	$ 4.98	$ 4.46	$ 4.46	$ 4.46	$ 4.39	$ 4.39	$ 4.98	$ 4.59	$ 4.56
Expected Case	2025-2026	Nov	$ 4.70	$ 5.12	$ 4.70	$ 4.70	$ 4.70	$ 4.82	$ 4.63	$ 5.12	$ 4.86	$ 4.78
Expected Case	2025-2026	Dec	$ 4.99	$ 5.13	$ 4.99	$ 4.99	$ 4.99	$ 5.13	$ 4.71	$ 5.13	$ 4.99	$ 5.02
Expected Case	2025-2026	Jan	$ 4.82	$ 5.15	$ 4.82	$ 4.82	$ 4.82	$ 5.15	$ 4.69	$ 5.15	$ 5.00	$ 4.88
Expected Case	2025-2026	Feb	$ 4.81	$ 5.14	$ 4.81	$ 4.81	$ 4.81	$ 5.14	$ 4.72	$ 5.14	$ 5.00	$ 4.88
Expected Case	2025-2026	Mar	$ 4.79	$ 5.01	$ 4.79	$ 4.79	$ 4.79	$ 4.72	$ 4.72	$ 5.01	$ 4.82	$ 4.84
Expected Case	2025-2026	Apr	$ 4.56	$ 5.02	$ 4.56	$ 4.56	$ 4.56	$ 4.49	$ 4.49	$ 5.02	$ 4.67	$ 4.65
Expected Case	2025-2026	May	$ 4.49	$ 4.97	$ 4.49	$ 4.49	$ 4.49	$ 4.42	$ 4.42	$ 5.02	$ 4.62	$ 4.58
Expected Case	2025-2026	Jun	$ 4.46	$ 4.94	$ 4.46	$ 4.46	$ 4.46	$ 4.39	$ 4.39	$ 5.02	$ 4.60	$ 4.55
Expected Case	2025-2026	Jul	$ 4.45	$ 5.01	$ 4.45	$ 4.45	$ 4.45	$ 4.38	$ 4.38	$ 5.02	$ 4.59	$ 4.56
Expected Case	2025-2026	Aug	$ 4.47	$ 5.02	$ 4.47	$ 4.47	$ 4.47	$ 4.40	$ 4.40	$ 5.02	$ 4.61	$ 4.58
Expected Case	2025-2026	Sep	$ 4.54	$ 5.03	$ 4.54	$ 4.54	$ 4.54	$ 4.47	$ 4.47	$ 5.03	$ 4.65	$ 4.64
Expected Case	2025-2026	Oct	$ 4.59	$ 5.19	$ 4.59	$ 4.59	$ 4.59	$ 4.52	$ 4.52	$ 5.19	$ 4.74	$ 4.71
Expected Case	2026-2027	Nov	$ 4.88	$ 5.18	$ 4.88	$ 4.88	$ 4.88	$ 4.96	$ 4.81	$ 5.18	$ 4.98	$ 4.94
Expected Case	2026-2027	Dec	$ 5.12	$ 5.30	$ 5.12	$ 5.12	$ 5.12	$ 5.30	$ 4.87	$ 5.30	$ 5.15	$ 5.16
Expected Case	2026-2027	Jan	$ 4.88	$ 5.30	$ 4.88	$ 4.88	$ 4.88	$ 5.23	$ 4.75	$ 5.30	$ 5.09	$ 4.96
Expected Case	2026-2027	Feb	$ 4.79	$ 5.31	$ 4.79	$ 4.79	$ 4.79	$ 5.20	$ 4.69	$ 5.31	$ 5.06	$ 4.90
Expected Case	2026-2027	Mar	$ 4.85	$ 5.19	$ 4.85	$ 4.85	$ 4.85	$ 4.86	$ 4.78	$ 5.19	$ 4.94	$ 4.92
Expected Case	2026-2027	Apr	$ 4.54	$ 5.30	$ 4.54	$ 4.54	$ 4.54	$ 4.47	$ 4.47	$ 5.30	$ 4.75	$ 4.69
Expected Case	2026-2027	May	$ 4.48	$ 5.30	$ 4.48	$ 4.48	$ 4.48	$ 4.41	$ 4.41	$ 5.30	$ 4.71	$ 4.64
Expected Case	2026-2027	Jun	$ 4.45	$ 5.29	$ 4.45	$ 4.45	$ 4.45	$ 4.38	$ 4.38	$ 5.30	$ 4.69	$ 4.62
Expected Case	2026-2027	Jul	$ 4.45	$ 5.30	$ 4.45	$ 4.45	$ 4.45	$ 4.38	$ 4.38	$ 5.30	$ 4.69	$ 4.62
Expected Case	2026-2027	Aug	$ 4.47	$ 5.30	$ 4.47	$ 4.47	$ 4.47	$ 4.40	$ 4.40	$ 5.30	$ 4.70	$ 4.63
Expected Case	2026-2027	Sep	$ 4.53	$ 5.31	$ 4.53	$ 4.53	$ 4.53	$ 4.46	$ 4.46	$ 5.31	$ 4.74	$ 4.68
Expected Case	2026-2027	Oct	$ 4.58	$ 5.48	$ 4.58	$ 4.58	$ 4.58	$ 4.51	$ 4.51	$ 5.48	$ 4.83	$ 4.76
Expected Case	2027-2028	Nov	$ 4.92	$ 5.52	$ 4.92	$ 4.92	$ 4.92	$ 5.04	$ 4.85	$ 5.52	$ 5.14	$ 5.04
Expected Case	2027-2028	Dec	$ 5.13	$ 5.55	$ 5.13	$ 5.13	$ 5.13	$ 5.39	$ 4.88	$ 5.53	$ 5.27	$ 5.22
Expected Case	2027-2028	Jan	$ 4.90	$ 5.52	$ 4.90	$ 4.90	$ 4.90	$ 5.21	$ 4.73	$ 5.52	$ 5.15	$ 5.03
Expected Case	2027-2028	Feb	$ 4.80	$ 5.51	$ 4.80	$ 4.80	$ 4.80	$ 5.29	$ 4.69	$ 5.51	$ 5.16	$ 4.94
Expected Case	2027-2028	Mar	$ 4.80	$ 5.30	$ 4.80	$ 4.80	$ 4.80	$ 4.82	$ 4.73	$ 5.30	$ 4.95	$ 4.90
Expected Case	2027-2028	Apr	$ 4.57	$ 5.33	$ 4.57	$ 4.57	$ 4.57	$ 4.50	$ 4.50	$ 5.37	$ 4.79	$ 4.72
Expected Case	2027-2028	May	$ 4.53	$ 5.35	$ 4.53	$ 4.53	$ 4.53	$ 4.46	$ 4.46	$ 5.37	$ 4.76	$ 4.69
Expected Case	2027-2028	Jun	$ 4.51	$ 5.31	$ 4.51	$ 4.51	$ 4.51	$ 4.44	$ 4.44	$ 5.37	$ 4.75	$ 4.67
Expected Case	2027-2028	Jul	$ 4.51	$ 5.37	$ 4.51	$ 4.51	$ 4.51	$ 4.44	$ 4.44	$ 5.37	$ 4.75	$ 4.68
Expected Case	2027-2028	Aug	$ 4.53	$ 5.37	$ 4.53	$ 4.53	$ 4.53	$ 4.46	$ 4.46	$ 5.37	$ 4.76	$ 4.70
Expected Case	2027-2028	Sep	$ 4.61	$ 5.37	$ 4.61	$ 4.61	$ 4.61	$ 4.54	$ 4.54	$ 5.37	$ 4.82	$ 4.76
Expected Case	2027-2028	Oct	$ 4.67	$ 5.55	$ 4.67	$ 4.67	$ 4.67	$ 4.60	$ 4.60	$ 5.55	$ 4.92	$ 4.85

1/ Avoided costs are before Environmental Externalities adder.

APPENDIX 5.4: EXPECTED MONTHLY DETAIL

Monthly Avoided Cost Detail 1/
2012$

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 Case	2028-2029	Nov	$ 5.15	$ 5.76	$ 5.15	$ 5.15	$ 5.15	$ 5.26	$ 5.07	$ 5.76	$ 5.36	$ 5.27
Expected Case	2028-2029	Dec	$ 5.52	$ 5.78	$ 5.52	$ 5.52	$ 5.52	$ 5.65	$ 5.14	$ 5.78	$ 5.52	$ 5.57
Expected Case	2028-2029	Jan	$ 5.41	$ 5.77	$ 5.41	$ 5.41	$ 5.41	$ 5.74	$ 5.26	$ 5.77	$ 5.59	$ 5.49
Expected Case	2028-2029	Feb	$ 5.43	$ 5.73	$ 5.43	$ 5.43	$ 5.43	$ 5.73	$ 5.34	$ 5.73	$ 5.60	$ 5.49
Expected Case	2028-2029	Mar	$ 5.40	$ 5.45	$ 5.40	$ 5.40	$ 5.40	$ 5.35	$ 5.32	$ 5.45	$ 5.37	$ 5.41
Expected Case	2028-2029	Apr	$ 5.08	$ 5.53	$ 5.08	$ 5.08	$ 5.08	$ 5.00	$ 5.00	$ 5.55	$ 5.18	$ 5.17
Expected Case	2028-2029	May	$ 5.02	$ 5.55	$ 5.02	$ 5.02	$ 5.02	$ 4.94	$ 4.94	$ 5.55	$ 5.14	$ 5.12
Expected Case	2028-2029	Jun	$ 4.98	$ 5.45	$ 4.98	$ 4.98	$ 4.98	$ 4.90	$ 4.90	$ 5.55	$ 5.12	$ 5.07
Expected Case	2028-2029	Jul	$ 4.95	$ 5.53	$ 4.95	$ 4.95	$ 4.95	$ 4.88	$ 4.88	$ 5.55	$ 5.10	$ 5.07
Expected Case	2028-2029	Aug	$ 4.97	$ 5.55	$ 4.97	$ 4.97	$ 4.97	$ 4.89	$ 4.89	$ 5.55	$ 5.11	$ 5.08
Expected Case	2028-2029	Sep	$ 5.03	$ 5.58	$ 5.03	$ 5.03	$ 5.03	$ 4.95	$ 4.95	$ 5.58	$ 5.16	$ 5.14
Expected Case	2028-2029	Oct	$ 5.08	$ 5.63	$ 5.08	$ 5.08	$ 5.08	$ 5.00	$ 5.00	$ 5.63	$ 5.21	$ 5.19
Expected Case	2029-2030	Nov	$ 5.42	$ 5.77	$ 5.42	$ 5.42	$ 5.42	$ 5.51	$ 5.34	$ 5.77	$ 5.54	$ 5.49
Expected Case	2029-2030	Dec	$ 5.62	$ 5.78	$ 5.62	$ 5.62	$ 5.62	$ 5.78	$ 5.39	$ 5.78	$ 5.65	$ 5.65
Expected Case	2029-2030	Jan	$ 5.47	$ 5.77	$ 5.47	$ 5.47	$ 5.47	$ 5.77	$ 5.38	$ 5.77	$ 5.64	$ 5.53
Expected Case	2029-2030	Feb	$ 5.34	$ 5.76	$ 5.34	$ 5.34	$ 5.34	$ 5.76	$ 5.26	$ 5.76	$ 5.59	$ 5.43
Expected Case	2029-2030	Mar	$ 5.31	$ 5.38	$ 5.31	$ 5.31	$ 5.31	$ 5.26	$ 5.23	$ 5.38	$ 5.29	$ 5.32
Expected Case	2029-2030	Apr	$ 4.93	$ 5.51	$ 4.93	$ 4.93	$ 4.93	$ 4.86	$ 4.86	$ 5.51	$ 5.08	$ 5.05
Expected Case	2029-2030	May	$ 4.81	$ 5.41	$ 4.81	$ 4.81	$ 4.81	$ 4.74	$ 4.74	$ 5.50	$ 4.99	$ 4.93
Expected Case	2029-2030	Jun	$ 4.78	$ 5.38	$ 4.78	$ 4.78	$ 4.78	$ 4.71	$ 4.71	$ 5.50	$ 4.97	$ 4.90
Expected Case	2029-2030	Jul	$ 4.77	$ 5.45	$ 4.77	$ 4.77	$ 4.77	$ 4.70	$ 4.70	$ 5.50	$ 4.97	$ 4.91
Expected Case	2029-2030	Aug	$ 4.78	$ 5.50	$ 4.78	$ 4.78	$ 4.78	$ 4.71	$ 4.71	$ 5.50	$ 4.97	$ 4.93
Expected Case	2029-2030	Sep	$ 4.87	$ 5.50	$ 4.87	$ 4.87	$ 4.87	$ 4.80	$ 4.80	$ 5.50	$ 5.03	$ 5.00
Expected Case	2029-2030	Oct	$ 4.94	$ 5.66	$ 4.94	$ 4.94	$ 4.94	$ 4.87	$ 4.87	$ 5.66	$ 5.13	$ 5.09
Expected Case	2030-2031	Nov	$ 5.52	$ 5.77	$ 5.52	$ 5.52	$ 5.52	$ 5.57	$ 5.44	$ 5.77	$ 5.59	$ 5.57
Expected Case	2030-2031	Dec	$ 5.75	$ 5.83	$ 5.75	$ 5.75	$ 5.75	$ 5.83	$ 5.52	$ 5.83	$ 5.73	$ 5.77
Expected Case	2030-2031	Jan	$ 5.57	$ 5.83	$ 5.57	$ 5.57	$ 5.57	$ 5.83	$ 5.42	$ 5.83	$ 5.69	$ 5.63
Expected Case	2030-2031	Feb	$ 5.41	$ 5.82	$ 5.41	$ 5.41	$ 5.41	$ 5.80	$ 5.29	$ 5.82	$ 5.64	$ 5.49
Expected Case	2030-2031	Mar	$ 5.40	$ 5.45	$ 5.40	$ 5.40	$ 5.40	$ 5.35	$ 5.32	$ 5.45	$ 5.37	$ 5.41
Expected Case	2030-2031	Apr	$ 5.14	$ 5.53	$ 5.14	$ 5.14	$ 5.14	$ 5.06	$ 5.06	$ 5.66	$ 5.26	$ 5.22
Expected Case	2030-2031	May	$ 5.11	$ 5.54	$ 5.11	$ 5.11	$ 5.11	$ 5.03	$ 5.03	$ 5.66	$ 5.24	$ 5.19
Expected Case	2030-2031	Jun	$ 5.08	$ 5.53	$ 5.08	$ 5.08	$ 5.08	$ 5.00	$ 5.00	$ 5.66	$ 5.22	$ 5.17
Expected Case	2030-2031	Jul	$ 5.12	$ 5.63	$ 5.12	$ 5.12	$ 5.12	$ 5.04	$ 5.04	$ 5.66	$ 5.25	$ 5.22
Expected Case	2030-2031	Aug	$ 5.14	$ 5.67	$ 5.14	$ 5.14	$ 5.14	$ 5.06	$ 5.06	$ 5.67	$ 5.26	$ 5.24
Expected Case	2030-2031	Sep	$ 5.22	$ 5.75	$ 5.22	$ 5.22	$ 5.22	$ 5.14	$ 5.14	$ 5.75	$ 5.34	$ 5.33
Expected Case	2030-2031	Oct	$ 5.30	$ 5.77	$ 5.30	$ 5.30	$ 5.30	$ 5.22	$ 5.22	$ 5.77	$ 5.40	$ 5.39
Expected Case	2031-2032	Nov	$ 5.78	$ 5.87	$ 5.78	$ 5.78	$ 5.78	$ 5.77	$ 5.69	$ 5.87	$ 5.78	$ 5.80
Expected Case	2031-2032	Dec	$ 5.71	$ 5.89	$ 5.71	$ 5.71	$ 5.71	$ 5.89	$ 5.41	$ 5.89	$ 5.73	$ 5.75
Expected Case	2031-2032	Jan	$ 5.57	$ 5.86	$ 5.57	$ 5.57	$ 5.57	$ 5.86	$ 5.47	$ 5.86	$ 5.73	$ 5.63
Expected Case	2031-2032	Feb	$ 5.58	$ 5.83	$ 5.58	$ 5.58	$ 5.58	$ 5.84	$ 5.49	$ 5.84	$ 5.72	$ 5.63
Expected Case	2031-2032	Mar	$ 5.73	$ 5.67	$ 5.69	$ 5.69	$ 5.69	$ 5.67	$ 5.67	$ 5.67	$ 5.67	$ 5.70
Expected Case	2031-2032	Apr	$ 5.52	$ 5.59	$ 5.52	$ 5.52	$ 5.52	$ 5.44	$ 5.44	$ 5.59	$ 5.49	$ 5.54
Expected Case	2031-2032	May	$ 5.49	$ 5.52	$ 5.49	$ 5.49	$ 5.49	$ 5.41	$ 5.41	$ 5.52	$ 5.45	$ 5.50
Expected Case	2031-2032	Jun	$ 5.41	$ 5.42	$ 5.33	$ 5.33	$ 5.33	$ 5.33	$ 5.33	$ 5.52	$ 5.39	$ 5.36
Expected Case	2031-2032	Jul	$ 5.30	$ 5.33	$ 5.30	$ 5.30	$ 5.30	$ 5.22	$ 5.22	$ 5.52	$ 5.32	$ 5.31
Expected Case	2031-2032	Aug	$ 5.30	$ 5.35	$ 5.30	$ 5.30	$ 5.30	$ 5.22	$ 5.22	$ 5.52	$ 5.32	$ 5.31
Expected Case	2031-2032	Sep	$ 5.49	$ 5.58	$ 5.49	$ 5.49	$ 5.49	$ 5.41	$ 5.41	$ 5.58	$ 5.47	$ 5.51
Expected Case	2031-2032	Oct	$ 5.55	$ 5.67	$ 5.55	$ 5.55	$ 5.55	$ 5.46	$ 5.46	$ 5.67	$ 5.53	$ 5.57
Expected Case	2032-2033	Nov	$ 5.84	$ 5.82	$ 5.84	$ 5.84	$ 5.84	$ 5.78	$ 5.75	$ 5.82	$ 5.78	$ 5.84
Expected Case	2032-2033	Dec	$ 5.91	$ 5.83	$ 5.91	$ 5.91	$ 5.91	$ 5.83	$ 5.61	$ 5.83	$ 5.75	$ 5.90
Expected Case	2032-2033	Jan	$ 5.83	$ 5.85	$ 5.83	$ 5.83	$ 5.83	$ 5.85	$ 5.72	$ 5.85	$ 5.81	$ 5.84
Expected Case	2032-2033	Feb	$ 5.87	$ 5.91	$ 5.87	$ 5.87	$ 5.87	$ 5.90	$ 5.75	$ 5.90	$ 5.85	$ 5.88
Expected Case	2032-2033	Mar	$ 5.95	$ 5.89	$ 5.91	$ 5.91	$ 5.91	$ 5.89	$ 5.89	$ 5.89	$ 5.89	$ 5.92
Expected Case	2032-2033	Apr	$ 5.78	$ 5.78	$ 5.78	$ 5.78	$ 5.78	$ 5.69	$ 5.69	$ 5.78	$ 5.72	$ 5.78
Expected Case	2032-2033	May	$ 5.77	$ 5.75	$ 5.75	$ 5.75	$ 5.75	$ 5.68	$ 5.68	$ 5.75	$ 5.70	$ 5.75
Expected Case	2032-2033	Jun	$ 5.70	$ 5.64	$ 5.62	$ 5.62	$ 5.62	$ 5.63	$ 5.63	$ 5.63	$ 5.63	$ 5.64
Expected Case	2032-2033	Jul	$ 5.64	$ 5.60	$ 5.62	$ 5.62	$ 5.62	$ 5.55	$ 5.55	$ 5.60	$ 5.57	$ 5.62
Expected Case	2032-2033	Aug	$ 5.64	$ 5.62	$ 5.62	$ 5.62	$ 5.62	$ 5.55	$ 5.55	$ 5.62	$ 5.57	$ 5.62
Expected Case	2032-2033	Sep	$ 5.86	$ 5.86	$ 5.86	$ 5.86	$ 5.86	$ 5.77	$ 5.77	$ 5.86	$ 5.80	$ 5.86
Expected Case	2032-2033	Oct	$ 5.91	$ 5.95	$ 5.91	$ 5.91	$ 5.91	$ 5.82	$ 5.82	$ 5.95	$ 5.87	$ 5.92

1/ Avoided costs are before Environmental Externalities adder.

APPENDIX 5.4: HIGH GROWTH – LOW PRICE MONTHLY DETAIL

Monthly Avoided Cost Detail 1/
2012$

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 Prices	2013-2014	Nov	$ 3.51	$ 3.88	$ 3.51	$ 3.51	$ 3.51	$ 3.45	$ 3.45	$ 3.88	$ 3.59	$ 3.58
High Growth & Low Prices	2013-2014	Dec	$ 3.63	$ 4.02	$ 3.63	$ 3.63	$ 3.63	$ 3.86	$ 3.36	$ 3.88	$ 3.70	$ 3.71
High Growth & Low Prices	2013-2014	Jan	$ 3.44	$ 3.88	$ 3.44	$ 3.44	$ 3.44	$ 3.86	$ 3.37	$ 3.88	$ 3.70	$ 3.53
High Growth & Low Prices	2013-2014	Feb	$ 3.52	$ 3.95	$ 3.52	$ 3.52	$ 3.52	$ 3.81	$ 3.39	$ 3.90	$ 3.70	$ 3.61
High Growth & Low Prices	2013-2014	Mar	$ 3.57	$ 3.88	$ 3.57	$ 3.57	$ 3.57	$ 3.51	$ 3.51	$ 3.88	$ 3.64	$ 3.63
High Growth & Low Prices	2013-2014	Apr	$ 3.55	$ 3.88	$ 3.55	$ 3.55	$ 3.55	$ 3.49	$ 3.49	$ 3.88	$ 3.62	$ 3.62
High Growth & Low Prices	2013-2014	May	$ 3.51	$ 3.88	$ 3.51	$ 3.51	$ 3.51	$ 3.45	$ 3.45	$ 3.88	$ 3.60	$ 3.58
High Growth & Low Prices	2013-2014	Jun	$ 3.52	$ 3.88	$ 3.52	$ 3.52	$ 3.52	$ 3.46	$ 3.46	$ 3.88	$ 3.60	$ 3.59
High Growth & Low Prices	2013-2014	Jul	$ 3.50	$ 3.88	$ 3.50	$ 3.50	$ 3.50	$ 3.44	$ 3.44	$ 3.88	$ 3.59	$ 3.58
High Growth & Low Prices	2013-2014	Aug	$ 3.49	$ 3.88	$ 3.49	$ 3.49	$ 3.49	$ 3.43	$ 3.43	$ 3.88	$ 3.58	$ 3.57
High Growth & Low Prices	2013-2014	Sep	$ 3.52	$ 3.89	$ 3.52	$ 3.52	$ 3.52	$ 3.46	$ 3.46	$ 3.89	$ 3.60	$ 3.59
High Growth & Low Prices	2013-2014	Oct	$ 3.54	$ 3.95	$ 3.54	$ 3.54	$ 3.54	$ 3.48	$ 3.48	$ 3.95	$ 3.64	$ 3.62
High Growth & Low Prices	2014-2015	Nov	$ 3.57	$ 4.01	$ 3.57	$ 3.57	$ 3.57	$ 3.51	$ 3.51	$ 4.01	$ 3.68	$ 3.66
High Growth & Low Prices	2014-2015	Dec	$ 3.67	$ 4.07	$ 3.67	$ 3.67	$ 3.67	$ 3.95	$ 3.44	$ 4.02	$ 3.80	$ 3.75
High Growth & Low Prices	2014-2015	Jan	$ 3.66	$ 4.03	$ 3.66	$ 3.66	$ 3.66	$ 4.03	$ 3.56	$ 4.03	$ 3.88	$ 3.73
High Growth & Low Prices	2014-2015	Feb	$ 3.68	$ 4.09	$ 3.68	$ 3.68	$ 3.68	$ 3.96	$ 3.57	$ 4.04	$ 3.86	$ 3.76
High Growth & Low Prices	2014-2015	Mar	$ 3.77	$ 4.02	$ 3.77	$ 3.77	$ 3.77	$ 3.71	$ 3.71	$ 4.02	$ 3.82	$ 3.82
High Growth & Low Prices	2014-2015	Apr	$ 3.70	$ 4.04	$ 3.70	$ 3.70	$ 3.70	$ 3.64	$ 3.64	$ 4.04	$ 3.78	$ 3.77
High Growth & Low Prices	2014-2015	May	$ 3.63	$ 4.02	$ 3.63	$ 3.63	$ 3.63	$ 3.57	$ 3.57	$ 4.02	$ 3.72	$ 3.71
High Growth & Low Prices	2014-2015	Jun	$ 3.62	$ 4.02	$ 3.62	$ 3.62	$ 3.62	$ 3.56	$ 3.56	$ 4.02	$ 3.72	$ 3.70
High Growth & Low Prices	2014-2015	Jul	$ 3.59	$ 4.02	$ 3.59	$ 3.59	$ 3.59	$ 3.53	$ 3.53	$ 4.02	$ 3.70	$ 3.68
High Growth & Low Prices	2014-2015	Aug	$ 3.58	$ 4.02	$ 3.58	$ 3.58	$ 3.58	$ 3.52	$ 3.52	$ 4.02	$ 3.69	$ 3.67
High Growth & Low Prices	2014-2015	Sep	$ 3.62	$ 4.02	$ 3.62	$ 3.62	$ 3.62	$ 3.56	$ 3.56	$ 4.02	$ 3.72	$ 3.70
High Growth & Low Prices	2014-2015	Oct	$ 3.68	$ 4.09	$ 3.68	$ 3.68	$ 3.68	$ 3.62	$ 3.62	$ 4.09	$ 3.78	$ 3.76
High Growth & Low Prices	2015-2016	Nov	$ 3.70	$ 4.03	$ 3.70	$ 3.70	$ 3.70	$ 3.64	$ 3.64	$ 4.03	$ 3.77	$ 3.77
High Growth & Low Prices	2015-2016	Dec	$ 3.77	$ 4.12	$ 3.77	$ 3.77	$ 3.77	$ 4.04	$ 3.55	$ 4.04	$ 3.88	$ 3.84
High Growth & Low Prices	2015-2016	Jan	$ 3.58	$ 4.03	$ 3.58	$ 3.58	$ 3.58	$ 3.95	$ 3.46	$ 4.03	$ 3.81	$ 3.67
High Growth & Low Prices	2015-2016	Feb	$ 3.59	$ 4.09	$ 3.59	$ 3.59	$ 3.59	$ 3.96	$ 3.47	$ 4.03	$ 3.82	$ 3.69
High Growth & Low Prices	2015-2016	Mar	$ 3.69	$ 4.01	$ 3.69	$ 3.69	$ 3.69	$ 3.63	$ 3.63	$ 4.01	$ 3.76	$ 3.76
High Growth & Low Prices	2015-2016	Apr	$ 3.62	$ 3.96	$ 3.62	$ 3.62	$ 3.62	$ 3.56	$ 3.56	$ 3.96	$ 3.70	$ 3.69
High Growth & Low Prices	2015-2016	May	$ 3.56	$ 3.96	$ 3.56	$ 3.56	$ 3.56	$ 3.50	$ 3.50	$ 3.96	$ 3.66	$ 3.64
High Growth & Low Prices	2015-2016	Jun	$ 3.58	$ 3.96	$ 3.58	$ 3.58	$ 3.58	$ 3.52	$ 3.52	$ 3.96	$ 3.67	$ 3.66
High Growth & Low Prices	2015-2016	Jul	$ 3.55	$ 3.97	$ 3.55	$ 3.55	$ 3.55	$ 3.49	$ 3.49	$ 3.97	$ 3.65	$ 3.63
High Growth & Low Prices	2015-2016	Aug	$ 3.52	$ 3.97	$ 3.52	$ 3.52	$ 3.52	$ 3.46	$ 3.46	$ 3.97	$ 3.63	$ 3.61
High Growth & Low Prices	2015-2016	Sep	$ 3.53	$ 3.97	$ 3.53	$ 3.53	$ 3.53	$ 3.47	$ 3.47	$ 3.97	$ 3.64	$ 3.62
High Growth & Low Prices	2015-2016	Oct	$ 3.57	$ 4.02	$ 3.57	$ 3.57	$ 3.57	$ 3.51	$ 3.51	$ 4.02	$ 3.68	$ 3.66
High Growth & Low Prices	2016-2017	Nov	$ 3.61	$ 4.34	$ 3.61	$ 3.61	$ 3.61	$ 3.70	$ 3.55	$ 4.34	$ 3.86	$ 3.76
High Growth & Low Prices	2016-2017	Dec	$ 3.72	$ 4.36	$ 3.72	$ 3.72	$ 3.72	$ 4.02	$ 3.46	$ 4.35	$ 3.94	$ 3.85
High Growth & Low Prices	2016-2017	Jan	$ 3.57	$ 4.34	$ 3.57	$ 3.57	$ 3.57	$ 3.91	$ 3.42	$ 4.34	$ 3.89	$ 3.73
High Growth & Low Prices	2016-2017	Feb	$ 3.55	$ 4.36	$ 3.55	$ 3.55	$ 3.55	$ 3.99	$ 3.44	$ 4.36	$ 3.93	$ 3.71
High Growth & Low Prices	2016-2017	Mar	$ 3.61	$ 4.28	$ 3.61	$ 3.61	$ 3.61	$ 3.55	$ 3.55	$ 4.28	$ 3.80	$ 3.75
High Growth & Low Prices	2016-2017	Apr	$ 3.51	$ 3.88	$ 3.51	$ 3.51	$ 3.51	$ 3.45	$ 3.45	$ 3.88	$ 3.60	$ 3.58
High Growth & Low Prices	2016-2017	May	$ 3.44	$ 3.88	$ 3.44	$ 3.44	$ 3.44	$ 3.38	$ 3.38	$ 3.88	$ 3.55	$ 3.53
High Growth & Low Prices	2016-2017	Jun	$ 3.44	$ 3.88	$ 3.44	$ 3.44	$ 3.44	$ 3.38	$ 3.38	$ 3.88	$ 3.55	$ 3.53
High Growth & Low Prices	2016-2017	Jul	$ 3.42	$ 3.88	$ 3.42	$ 3.42	$ 3.42	$ 3.36	$ 3.36	$ 3.88	$ 3.54	$ 3.51
High Growth & Low Prices	2016-2017	Aug	$ 3.41	$ 3.88	$ 3.41	$ 3.41	$ 3.41	$ 3.35	$ 3.35	$ 3.88	$ 3.53	$ 3.50
High Growth & Low Prices	2016-2017	Sep	$ 3.43	$ 3.88	$ 3.43	$ 3.43	$ 3.43	$ 3.37	$ 3.37	$ 3.88	$ 3.54	$ 3.52
High Growth & Low Prices	2016-2017	Oct	$ 3.48	$ 4.01	$ 3.48	$ 3.48	$ 3.48	$ 3.42	$ 3.42	$ 4.01	$ 3.62	$ 3.59
High Growth & Low Prices	2017-2018	Nov	$ 3.49	$ 4.25	$ 3.49	$ 3.49	$ 3.49	$ 3.58	$ 3.43	$ 4.25	$ 3.76	$ 3.64
High Growth & Low Prices	2017-2018	Dec	$ 3.62	$ 4.27	$ 3.62	$ 3.62	$ 3.62	$ 3.89	$ 3.32	$ 4.26	$ 3.82	$ 3.75
High Growth & Low Prices	2017-2018	Jan	$ 3.51	$ 4.25	$ 3.51	$ 3.51	$ 3.51	$ 3.80	$ 3.31	$ 4.25	$ 3.79	$ 3.66
High Growth & Low Prices	2017-2018	Feb	$ 3.42	$ 4.26	$ 3.42	$ 3.42	$ 3.42	$ 3.89	$ 3.30	$ 4.26	$ 3.82	$ 3.59
High Growth & Low Prices	2017-2018	Mar	$ 3.47	$ 4.21	$ 3.47	$ 3.47	$ 3.47	$ 3.41	$ 3.41	$ 4.21	$ 3.68	$ 3.62
High Growth & Low Prices	2017-2018	Apr	$ 3.40	$ 3.90	$ 3.40	$ 3.40	$ 3.40	$ 3.34	$ 3.34	$ 3.90	$ 3.53	$ 3.50
High Growth & Low Prices	2017-2018	May	$ 3.35	$ 3.81	$ 3.35	$ 3.35	$ 3.35	$ 3.29	$ 3.29	$ 3.81	$ 3.47	$ 3.44
High Growth & Low Prices	2017-2018	Jun	$ 3.35	$ 3.81	$ 3.35	$ 3.35	$ 3.35	$ 3.29	$ 3.29	$ 3.81	$ 3.47	$ 3.44
High Growth & Low Prices	2017-2018	Jul	$ 3.33	$ 3.81	$ 3.33	$ 3.33	$ 3.33	$ 3.27	$ 3.27	$ 3.81	$ 3.45	$ 3.43
High Growth & Low Prices	2017-2018	Aug	$ 3.31	$ 3.82	$ 3.31	$ 3.31	$ 3.31	$ 3.25	$ 3.25	$ 3.82	$ 3.44	$ 3.41
High Growth & Low Prices	2017-2018	Sep	$ 3.32	$ 3.82	$ 3.32	$ 3.32	$ 3.32	$ 3.26	$ 3.26	$ 3.82	$ 3.45	$ 3.42
High Growth & Low Prices	2017-2018	Oct	$ 3.36	$ 3.94	$ 3.36	$ 3.36	$ 3.36	$ 3.30	$ 3.30	$ 3.94	$ 3.52	$ 3.48
High Growth & Low Prices	2018-2019	Nov	$ 3.47	$ 4.25	$ 3.47	$ 3.47	$ 3.47	$ 3.56	$ 3.41	$ 4.25	$ 3.74	$ 3.63
High Growth & Low Prices	2018-2019	Dec	$ 3.65	$ 4.28	$ 3.65	$ 3.65	$ 3.65	$ 3.85	$ 3.28	$ 4.26	$ 3.80	$ 3.78
High Growth & Low Prices	2018-2019	Jan	$ 3.47	$ 4.26	$ 3.47	$ 3.47	$ 3.47	$ 3.61	$ 3.12	$ 4.26	$ 3.66	$ 3.62
High Growth & Low Prices	2018-2019	Feb	$ 3.26	$ 4.20	$ 3.26	$ 3.26	$ 3.26	$ 3.78	$ 3.13	$ 4.20	$ 3.70	$ 3.45
High Growth & Low Prices	2018-2019	Mar	$ 3.38	$ 4.18	$ 3.38	$ 3.38	$ 3.38	$ 3.32	$ 3.32	$ 4.18	$ 3.61	$ 3.54
High Growth & Low Prices	2018-2019	Apr	$ 3.29	$ 3.82	$ 3.29	$ 3.29	$ 3.29	$ 3.23	$ 3.23	$ 3.82	$ 3.43	$ 3.39
High Growth & Low Prices	2018-2019	May	$ 3.24	$ 3.81	$ 3.24	$ 3.24	$ 3.24	$ 3.18	$ 3.18	$ 3.81	$ 3.39	$ 3.35
High Growth & Low Prices	2018-2019	Jun	$ 3.21	$ 3.64	$ 3.21	$ 3.21	$ 3.21	$ 3.15	$ 3.15	$ 3.64	$ 3.32	$ 3.29
High Growth & Low Prices	2018-2019	Jul	$ 3.19	$ 3.64	$ 3.19	$ 3.19	$ 3.19	$ 3.13	$ 3.13	$ 3.64	$ 3.30	$ 3.28
High Growth & Low Prices	2018-2019	Aug	$ 3.17	$ 3.64	$ 3.17	$ 3.17	$ 3.17	$ 3.11	$ 3.11	$ 3.64	$ 3.29	$ 3.26
High Growth & Low Prices	2018-2019	Sep	$ 3.19	$ 3.64	$ 3.19	$ 3.19	$ 3.19	$ 3.13	$ 3.13	$ 3.64	$ 3.30	$ 3.28
High Growth & Low Prices	2018-2019	Oct	$ 3.24	$ 3.64	$ 3.24	$ 3.24	$ 3.24	$ 3.18	$ 3.18	$ 3.65	$ 3.34	$ 3.32
High Growth & Low Prices	2019-2020	Nov	$ 3.37	$ 4.08	$ 3.37	$ 3.37	$ 3.37	$ 3.46	$ 3.31	$ 4.08	$ 3.62	$ 3.51
High Growth & Low Prices	2019-2020	Dec	$ 3.64	$ 4.09	$ 3.64	$ 3.64	$ 3.64	$ 3.75	$ 3.19	$ 4.09	$ 3.68	$ 3.73
High Growth & Low Prices	2019-2020	Jan	$ 3.48	$ 4.08	$ 3.48	$ 3.48	$ 3.48	$ 3.56	$ 3.07	$ 4.08	$ 3.57	$ 3.60
High Growth & Low Prices	2019-2020	Feb	$ 3.26	$ 4.05	$ 3.26	$ 3.26	$ 3.26	$ 3.72	$ 3.12	$ 4.05	$ 3.63	$ 3.42
High Growth & Low Prices	2019-2020	Mar	$ 3.44	$ 4.04	$ 3.44	$ 3.44	$ 3.44	$ 3.38	$ 3.38	$ 4.04	$ 3.60	$ 3.56
High Growth & Low Prices	2019-2020	Apr	$ 3.35	$ 3.68	$ 3.35	$ 3.35	$ 3.35	$ 3.29	$ 3.29	$ 3.68	$ 3.42	$ 3.41
High Growth & Low Prices	2019-2020	May	$ 3.28	$ 3.84	$ 3.28	$ 3.28	$ 3.28	$ 3.22	$ 3.22	$ 3.84	$ 3.43	$ 3.39
High Growth & Low Prices	2019-2020	Jun	$ 3.25	$ 3.65	$ 3.25	$ 3.25	$ 3.25	$ 3.19	$ 3.19	$ 3.65	$ 3.35	$ 3.33
High Growth & Low Prices	2019-2020	Jul	$ 3.21	$ 3.65	$ 3.21	$ 3.21	$ 3.21	$ 3.15	$ 3.15	$ 3.65	$ 3.32	$ 3.30
High Growth & Low Prices	2019-2020	Aug	$ 3.20	$ 3.66	$ 3.20	$ 3.20	$ 3.20	$ 3.14	$ 3.14	$ 3.66	$ 3.31	$ 3.29
High Growth & Low Prices	2019-2020	Sep	$ 3.22	$ 3.66	$ 3.22	$ 3.22	$ 3.22	$ 3.16	$ 3.16	$ 3.66	$ 3.33	$ 3.30
High Growth & Low Prices	2019-2020	Oct	$ 3.27	$ 3.66	$ 3.27	$ 3.27	$ 3.27	$ 3.21	$ 3.21	$ 3.66	$ 3.36	$ 3.35

1/ Avoided costs are before Environmental Externalities adder.

APPENDIX 5.4: HIGH GROWTH – LOW PRICE MONTHLY DETAIL

Monthly Avoided Cost Detail 1/
2012$

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 Prices	2020-2021	Nov	$ 3.35	$ 4.06	$ 3.35	$ 3.35	$ 3.35	$ 3.44	$ 3.29	$ 4.06	$ 3.60	$ 3.49
High Growth & Low Prices	2020-2021	Dec	$ 3.65	$ 4.08	$ 3.65	$ 3.65	$ 3.65	$ 3.70	$ 3.14	$ 4.06	$ 3.64	$ 3.74
High Growth & Low Prices	2020-2021	Jan	$ 3.50	$ 4.06	$ 3.50	$ 3.50	$ 3.50	$ 3.62	$ 3.13	$ 4.06	$ 3.60	$ 3.61
High Growth & Low Prices	2020-2021	Feb	$ 3.29	$ 4.04	$ 3.29	$ 3.29	$ 3.29	$ 3.78	$ 3.17	$ 4.04	$ 3.66	$ 3.44
High Growth & Low Prices	2020-2021	Mar	$ 3.45	$ 3.92	$ 3.45	$ 3.45	$ 3.45	$ 3.39	$ 3.39	$ 3.92	$ 3.57	$ 3.54
High Growth & Low Prices	2020-2021	Apr	$ 3.35	$ 3.68	$ 3.35	$ 3.35	$ 3.35	$ 3.29	$ 3.29	$ 3.68	$ 3.42	$ 3.41
High Growth & Low Prices	2020-2021	May	$ 3.27	$ 3.82	$ 3.27	$ 3.27	$ 3.27	$ 3.21	$ 3.21	$ 3.82	$ 3.41	$ 3.38
High Growth & Low Prices	2020-2021	Jun	$ 3.23	$ 3.62	$ 3.23	$ 3.23	$ 3.23	$ 3.17	$ 3.17	$ 3.62	$ 3.32	$ 3.31
High Growth & Low Prices	2020-2021	Jul	$ 3.15	$ 3.62	$ 3.15	$ 3.15	$ 3.15	$ 3.09	$ 3.09	$ 3.63	$ 3.27	$ 3.24
High Growth & Low Prices	2020-2021	Aug	$ 3.14	$ 3.63	$ 3.14	$ 3.14	$ 3.14	$ 3.08	$ 3.08	$ 3.63	$ 3.26	$ 3.23
High Growth & Low Prices	2020-2021	Sep	$ 3.20	$ 3.63	$ 3.20	$ 3.20	$ 3.20	$ 3.14	$ 3.14	$ 3.63	$ 3.30	$ 3.28
High Growth & Low Prices	2020-2021	Oct	$ 3.25	$ 3.63	$ 3.25	$ 3.25	$ 3.25	$ 3.19	$ 3.19	$ 3.63	$ 3.34	$ 3.32
High Growth & Low Prices	2021-2022	Nov	$ 3.34	$ 3.86	$ 3.34	$ 3.34	$ 3.34	$ 3.48	$ 3.28	$ 3.86	$ 3.54	$ 3.44
High Growth & Low Prices	2021-2022	Dec	$ 3.87	$ 3.88	$ 3.87	$ 3.87	$ 3.87	$ 3.77	$ 3.25	$ 3.86	$ 3.63	$ 3.87
High Growth & Low Prices	2021-2022	Jan	$ 3.77	$ 3.86	$ 3.77	$ 3.77	$ 3.77	$ 3.82	$ 3.33	$ 3.86	$ 3.67	$ 3.79
High Growth & Low Prices	2021-2022	Feb	$ 3.48	$ 3.80	$ 3.48	$ 3.48	$ 3.48	$ 3.80	$ 3.37	$ 3.80	$ 3.66	$ 3.54
High Growth & Low Prices	2021-2022	Mar	$ 3.55	$ 3.65	$ 3.55	$ 3.55	$ 3.55	$ 3.52	$ 3.49	$ 3.65	$ 3.56	$ 3.57
High Growth & Low Prices	2021-2022	Apr	$ 3.45	$ 3.79	$ 3.45	$ 3.45	$ 3.45	$ 3.39	$ 3.39	$ 3.79	$ 3.53	$ 3.52
High Growth & Low Prices	2021-2022	May	$ 3.38	$ 3.77	$ 3.38	$ 3.38	$ 3.38	$ 3.32	$ 3.32	$ 3.77	$ 3.47	$ 3.46
High Growth & Low Prices	2021-2022	Jun	$ 3.32	$ 3.71	$ 3.32	$ 3.32	$ 3.32	$ 3.26	$ 3.26	$ 3.71	$ 3.41	$ 3.40
High Growth & Low Prices	2021-2022	Jul	$ 3.29	$ 3.69	$ 3.29	$ 3.29	$ 3.29	$ 3.23	$ 3.23	$ 3.71	$ 3.39	$ 3.37
High Growth & Low Prices	2021-2022	Aug	$ 3.28	$ 3.71	$ 3.28	$ 3.28	$ 3.28	$ 3.22	$ 3.22	$ 3.71	$ 3.39	$ 3.36
High Growth & Low Prices	2021-2022	Sep	$ 3.36	$ 3.71	$ 3.36	$ 3.36	$ 3.36	$ 3.30	$ 3.30	$ 3.71	$ 3.44	$ 3.43
High Growth & Low Prices	2021-2022	Oct	$ 3.41	$ 3.78	$ 3.78	$ 3.78	$ 3.78	$ 3.35	$ 3.35	$ 3.78	$ 3.50	$ 3.70
High Growth & Low Prices	2022-2023	Nov	$ 3.46	$ 3.71	$ 3.46	$ 3.46	$ 3.46	$ 3.53	$ 3.40	$ 3.71	$ 3.55	$ 3.51
High Growth & Low Prices	2022-2023	Dec	$ 3.78	$ 3.72	$ 3.78	$ 3.78	$ 3.78	$ 3.72	$ 3.33	$ 3.72	$ 3.59	$ 3.77
High Growth & Low Prices	2022-2023	Jan	$ 3.68	$ 3.69	$ 3.68	$ 3.68	$ 3.68	$ 3.69	$ 3.21	$ 3.69	$ 3.53	$ 3.68
High Growth & Low Prices	2022-2023	Feb	$ 3.29	$ 3.66	$ 3.29	$ 3.29	$ 3.29	$ 3.66	$ 3.20	$ 3.66	$ 3.51	$ 3.36
High Growth & Low Prices	2022-2023	Mar	$ 3.39	$ 3.61	$ 3.39	$ 3.39	$ 3.39	$ 3.40	$ 3.33	$ 3.61	$ 3.45	$ 3.43
High Growth & Low Prices	2022-2023	Apr	$ 3.26	$ 3.65	$ 3.26	$ 3.26	$ 3.26	$ 3.20	$ 3.20	$ 3.65	$ 3.35	$ 3.34
High Growth & Low Prices	2022-2023	May	$ 3.12	$ 3.59	$ 3.12	$ 3.12	$ 3.12	$ 3.06	$ 3.06	$ 3.59	$ 3.24	$ 3.21
High Growth & Low Prices	2022-2023	Jun	$ 3.05	$ 3.53	$ 3.05	$ 3.05	$ 3.05	$ 3.00	$ 3.00	$ 3.53	$ 3.18	$ 3.15
High Growth & Low Prices	2022-2023	Jul	$ 3.02	$ 3.53	$ 3.02	$ 3.02	$ 3.02	$ 2.97	$ 2.97	$ 3.53	$ 3.16	$ 3.13
High Growth & Low Prices	2022-2023	Aug	$ 3.00	$ 3.53	$ 3.00	$ 3.00	$ 3.00	$ 2.95	$ 2.95	$ 3.53	$ 3.15	$ 3.11
High Growth & Low Prices	2022-2023	Sep	$ 3.08	$ 3.53	$ 3.08	$ 3.08	$ 3.08	$ 3.02	$ 3.02	$ 3.53	$ 3.19	$ 3.17
High Growth & Low Prices	2022-2023	Oct	$ 3.13	$ 3.57	$ 3.57	$ 3.57	$ 3.57	$ 3.07	$ 3.07	$ 3.57	$ 3.24	$ 3.48
High Growth & Low Prices	2023-2024	Nov	$ 3.34	$ 3.65	$ 3.34	$ 3.34	$ 3.34	$ 3.43	$ 3.28	$ 3.65	$ 3.45	$ 3.40
High Growth & Low Prices	2023-2024	Dec	$ 3.73	$ 3.66	$ 3.73	$ 3.73	$ 3.73	$ 3.66	$ 3.26	$ 3.66	$ 3.53	$ 3.71
High Growth & Low Prices	2023-2024	Jan	$ 3.64	$ 3.64	$ 3.64	$ 3.64	$ 3.64	$ 3.64	$ 3.25	$ 3.64	$ 3.51	$ 3.64
High Growth & Low Prices	2023-2024	Feb	$ 3.36	$ 3.56	$ 3.36	$ 3.36	$ 3.36	$ 3.56	$ 3.28	$ 3.56	$ 3.47	$ 3.40
High Growth & Low Prices	2023-2024	Mar	$ 3.49	$ 3.45	$ 3.45	$ 3.45	$ 3.45	$ 3.44	$ 3.44	$ 3.45	$ 3.45	$ 3.46
High Growth & Low Prices	2023-2024	Apr	$ 3.38	$ 3.57	$ 3.38	$ 3.38	$ 3.38	$ 3.32	$ 3.32	$ 3.57	$ 3.41	$ 3.42
High Growth & Low Prices	2023-2024	May	$ 3.25	$ 3.44	$ 3.25	$ 3.25	$ 3.25	$ 3.19	$ 3.19	$ 3.44	$ 3.28	$ 3.29
High Growth & Low Prices	2023-2024	Jun	$ 3.18	$ 3.33	$ 3.18	$ 3.18	$ 3.18	$ 3.12	$ 3.12	$ 3.34	$ 3.20	$ 3.21
High Growth & Low Prices	2023-2024	Jul	$ 3.13	$ 3.34	$ 3.13	$ 3.13	$ 3.13	$ 3.07	$ 3.07	$ 3.34	$ 3.16	$ 3.17
High Growth & Low Prices	2023-2024	Aug	$ 3.12	$ 3.33	$ 3.12	$ 3.12	$ 3.12	$ 3.06	$ 3.06	$ 3.34	$ 3.16	$ 3.16
High Growth & Low Prices	2023-2024	Sep	$ 3.21	$ 3.34	$ 3.21	$ 3.21	$ 3.21	$ 3.15	$ 3.15	$ 3.34	$ 3.22	$ 3.23
High Growth & Low Prices	2023-2024	Oct	$ 3.25	$ 3.54	$ 3.54	$ 3.54	$ 3.54	$ 3.19	$ 3.19	$ 3.54	$ 3.31	$ 3.48
High Growth & Low Prices	2024-2025	Nov	$ 3.36	$ 3.51	$ 3.36	$ 3.36	$ 3.36	$ 3.39	$ 3.30	$ 3.51	$ 3.40	$ 3.39
High Growth & Low Prices	2024-2025	Dec	$ 3.88	$ 3.82	$ 3.88	$ 3.88	$ 3.88	$ 3.82	$ 3.32	$ 3.82	$ 3.65	$ 3.87
High Growth & Low Prices	2024-2025	Jan	$ 3.81	$ 3.87	$ 3.81	$ 3.81	$ 3.81	$ 3.87	$ 3.40	$ 3.87	$ 3.72	$ 3.82
High Growth & Low Prices	2024-2025	Feb	$ 3.52	$ 3.87	$ 3.52	$ 3.52	$ 3.52	$ 3.87	$ 3.38	$ 3.87	$ 3.71	$ 3.59
High Growth & Low Prices	2024-2025	Mar	$ 3.57	$ 3.86	$ 3.57	$ 3.57	$ 3.57	$ 3.62	$ 3.51	$ 3.86	$ 3.67	$ 3.63
High Growth & Low Prices	2024-2025	Apr	$ 3.46	$ 3.92	$ 3.46	$ 3.46	$ 3.46	$ 3.40	$ 3.40	$ 3.92	$ 3.58	$ 3.55
High Growth & Low Prices	2024-2025	May	$ 3.40	$ 3.97	$ 3.40	$ 3.40	$ 3.40	$ 3.34	$ 3.34	$ 3.97	$ 3.55	$ 3.52
High Growth & Low Prices	2024-2025	Jun	$ 3.35	$ 3.84	$ 3.35	$ 3.35	$ 3.35	$ 3.29	$ 3.29	$ 3.84	$ 3.48	$ 3.45
High Growth & Low Prices	2024-2025	Jul	$ 3.29	$ 3.84	$ 3.29	$ 3.29	$ 3.29	$ 3.23	$ 3.23	$ 3.84	$ 3.44	$ 3.40
High Growth & Low Prices	2024-2025	Aug	$ 3.29	$ 3.84	$ 3.29	$ 3.29	$ 3.29	$ 3.23	$ 3.23	$ 3.84	$ 3.44	$ 3.40
High Growth & Low Prices	2024-2025	Sep	$ 3.37	$ 3.84	$ 3.37	$ 3.37	$ 3.37	$ 3.31	$ 3.31	$ 3.84	$ 3.49	$ 3.47
High Growth & Low Prices	2024-2025	Oct	$ 3.42	$ 3.94	$ 3.94	$ 3.94	$ 3.94	$ 3.36	$ 3.36	$ 3.94	$ 3.56	$ 3.84
High Growth & Low Prices	2025-2026	Nov	$ 3.51	$ 3.86	$ 3.51	$ 3.51	$ 3.51	$ 3.66	$ 3.45	$ 3.86	$ 3.66	$ 3.58
High Growth & Low Prices	2025-2026	Dec	$ 3.91	$ 3.85	$ 3.91	$ 3.91	$ 3.91	$ 3.85	$ 3.43	$ 3.85	$ 3.71	$ 3.90
High Growth & Low Prices	2025-2026	Jan	$ 3.81	$ 3.81	$ 3.81	$ 3.81	$ 3.81	$ 3.81	$ 3.32	$ 3.81	$ 3.65	$ 3.81
High Growth & Low Prices	2025-2026	Feb	$ 3.47	$ 3.83	$ 3.47	$ 3.47	$ 3.47	$ 3.83	$ 3.34	$ 3.83	$ 3.67	$ 3.54
High Growth & Low Prices	2025-2026	Mar	$ 3.55	$ 3.78	$ 3.55	$ 3.55	$ 3.55	$ 3.59	$ 3.49	$ 3.78	$ 3.62	$ 3.60
High Growth & Low Prices	2025-2026	Apr	$ 3.42	$ 3.89	$ 3.42	$ 3.42	$ 3.42	$ 3.36	$ 3.36	$ 3.89	$ 3.54	$ 3.52
High Growth & Low Prices	2025-2026	May	$ 3.31	$ 3.82	$ 3.31	$ 3.31	$ 3.31	$ 3.25	$ 3.25	$ 3.82	$ 3.44	$ 3.41
High Growth & Low Prices	2025-2026	Jun	$ 3.24	$ 3.75	$ 3.24	$ 3.24	$ 3.24	$ 3.18	$ 3.18	$ 3.75	$ 3.37	$ 3.34
High Growth & Low Prices	2025-2026	Jul	$ 3.20	$ 3.75	$ 3.20	$ 3.20	$ 3.20	$ 3.14	$ 3.14	$ 3.75	$ 3.35	$ 3.31
High Growth & Low Prices	2025-2026	Aug	$ 3.19	$ 3.75	$ 3.19	$ 3.19	$ 3.19	$ 3.13	$ 3.13	$ 3.75	$ 3.34	$ 3.30
High Growth & Low Prices	2025-2026	Sep	$ 3.27	$ 3.75	$ 3.27	$ 3.27	$ 3.27	$ 3.21	$ 3.21	$ 3.75	$ 3.39	$ 3.37
High Growth & Low Prices	2025-2026	Oct	$ 3.32	$ 3.78	$ 3.78	$ 3.78	$ 3.78	$ 3.26	$ 3.26	$ 3.78	$ 3.44	$ 3.69
High Growth & Low Prices	2026-2027	Nov	$ 3.47	$ 3.81	$ 3.47	$ 3.47	$ 3.47	$ 3.65	$ 3.41	$ 3.81	$ 3.63	$ 3.54
High Growth & Low Prices	2026-2027	Dec	$ 3.98	$ 3.87	$ 3.98	$ 3.98	$ 3.98	$ 3.87	$ 3.40	$ 3.87	$ 3.72	$ 3.96
High Growth & Low Prices	2026-2027	Jan	$ 3.87	$ 3.89	$ 3.87	$ 3.87	$ 3.87	$ 3.73	$ 3.24	$ 3.89	$ 3.62	$ 3.87
High Growth & Low Prices	2026-2027	Feb	$ 3.33	$ 3.87	$ 3.33	$ 3.33	$ 3.33	$ 3.71	$ 3.16	$ 3.87	$ 3.58	$ 3.44
High Growth & Low Prices	2026-2027	Mar	$ 3.52	$ 3.86	$ 3.52	$ 3.52	$ 3.52	$ 3.58	$ 3.46	$ 3.86	$ 3.64	$ 3.59
High Growth & Low Prices	2026-2027	Apr	$ 3.31	$ 3.74	$ 3.31	$ 3.31	$ 3.31	$ 3.25	$ 3.25	$ 3.74	$ 3.42	$ 3.40
High Growth & Low Prices	2026-2027	May	$ 3.23	$ 3.82	$ 3.23	$ 3.23	$ 3.23	$ 3.17	$ 3.17	$ 3.82	$ 3.39	$ 3.35
High Growth & Low Prices	2026-2027	Jun	$ 3.15	$ 3.72	$ 3.15	$ 3.15	$ 3.15	$ 3.09	$ 3.09	$ 3.72	$ 3.30	$ 3.26
High Growth & Low Prices	2026-2027	Jul	$ 3.12	$ 3.72	$ 3.12	$ 3.12	$ 3.12	$ 3.06	$ 3.06	$ 3.72	$ 3.28	$ 3.24
High Growth & Low Prices	2026-2027	Aug	$ 3.11	$ 3.72	$ 3.11	$ 3.11	$ 3.11	$ 3.05	$ 3.05	$ 3.72	$ 3.28	$ 3.23
High Growth & Low Prices	2026-2027	Sep	$ 3.20	$ 3.72	$ 3.20	$ 3.20	$ 3.20	$ 3.14	$ 3.14	$ 3.72	$ 3.34	$ 3.30
High Growth & Low Prices	2026-2027	Oct	$ 3.25	$ 3.74	$ 3.74	$ 3.74	$ 3.74	$ 3.19	$ 3.19	$ 3.74	$ 3.38	$ 3.64
High Growth & Low Prices	2027-2028	Nov	$ 3.42	$ 3.90	$ 3.42	$ 3.42	$ 3.42	$ 3.80	$ 3.36	$ 3.90	$ 3.69	$ 3.52
High Growth & Low Prices	2027-2028	Dec	$ 4.00	$ 3.96	$ 4.00	$ 4.00	$ 4.00	$ 3.84	$ 3.33	$ 3.93	$ 3.70	$ 3.99
High Growth & Low Prices	2027-2028	Jan	$ 3.90	$ 3.90	$ 3.90	$ 3.90	$ 3.90	$ 3.57	$ 3.08	$ 3.90	$ 3.52	$ 3.90
High Growth & Low Prices	2027-2028	Feb	$ 3.26	$ 72.72	$ 3.26	$ 3.26	$ 3.26	$ 72.44	$ 3.05	$ 72.72	$ 49.40	$ 17.15
High Growth & Low Prices	2027-2028	Mar	$ 3.39	$ 3.91	$ 3.39	$ 3.39	$ 3.39	$ 3.49	$ 3.33	$ 3.91	$ 3.58	$ 3.50
High Growth & Low Prices	2027-2028	Apr	$ 3.23	$ 3.66	$ 3.23	$ 3.23	$ 3.23	$ 3.17	$ 3.17	$ 3.66	$ 3.34	$ 3.32
High Growth & Low Prices	2027-2028	May	$ 3.16	$ 3.70	$ 3.16	$ 3.16	$ 3.16	$ 3.10	$ 3.10	$ 3.70	$ 3.30	$ 3.27
High Growth & Low Prices	2027-2028	Jun	$ 3.10	$ 3.60	$ 3.10	$ 3.10	$ 3.10	$ 3.04	$ 3.04	$ 3.60	$ 3.23	$ 3.20
High Growth & Low Prices	2027-2028	Jul	$ 3.05	$ 3.60	$ 3.05	$ 3.05	$ 3.05	$ 2.99	$ 2.99	$ 3.60	$ 3.20	$ 3.16
High Growth & Low Prices	2027-2028	Aug	$ 3.05	$ 3.60	$ 3.05	$ 3.05	$ 3.05	$ 2.99	$ 2.99	$ 3.60	$ 3.20	$ 3.16
High Growth & Low Prices	2027-2028	Sep	$ 3.12	$ 3.61	$ 3.12	$ 3.12	$ 3.12	$ 3.06	$ 3.06	$ 3.61	$ 3.24	$ 3.22
High Growth & Low Prices	2027-2028	Oct	$ 3.18	$ 3.61	$ 3.61	$ 3.61	$ 3.61	$ 3.12	$ 3.12	$ 3.61	$ 3.29	$ 3.53

1/ Avoided costs are before Environmental Externalities adder.

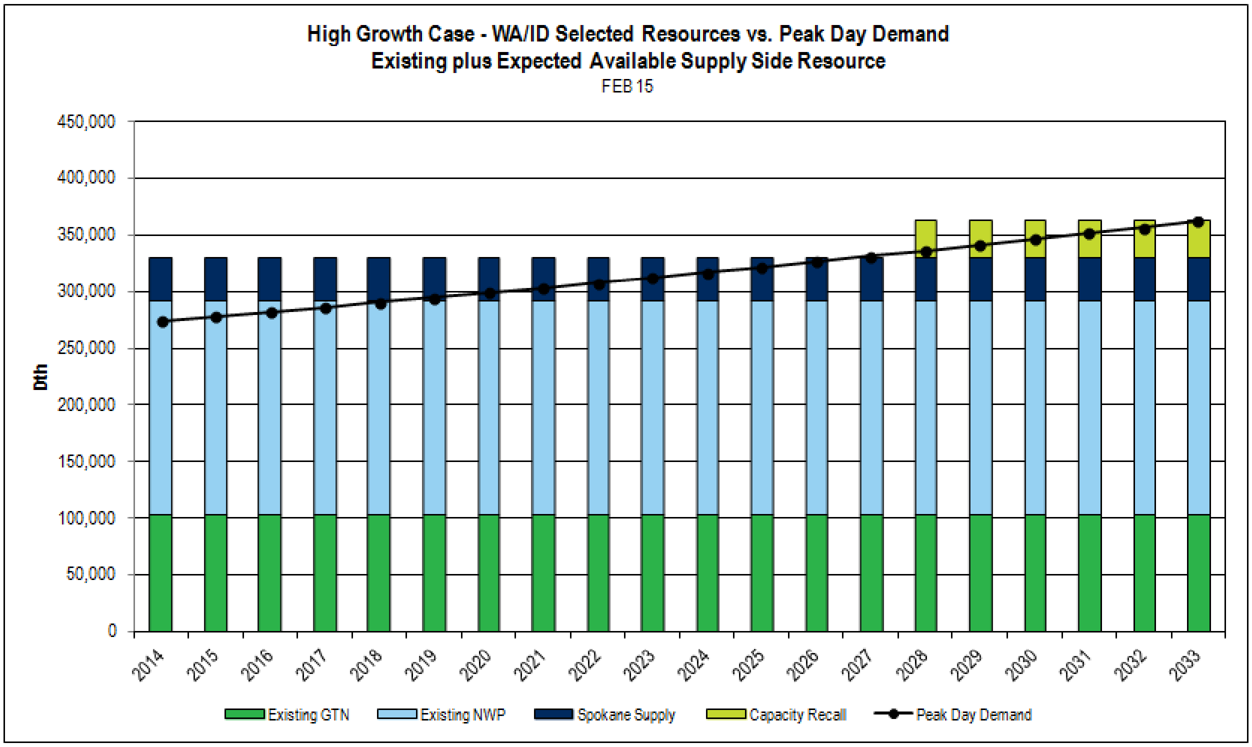
APPENDIX 5.4: HIGH GROWTH – LOW PRICE MONTHLY DETAIL

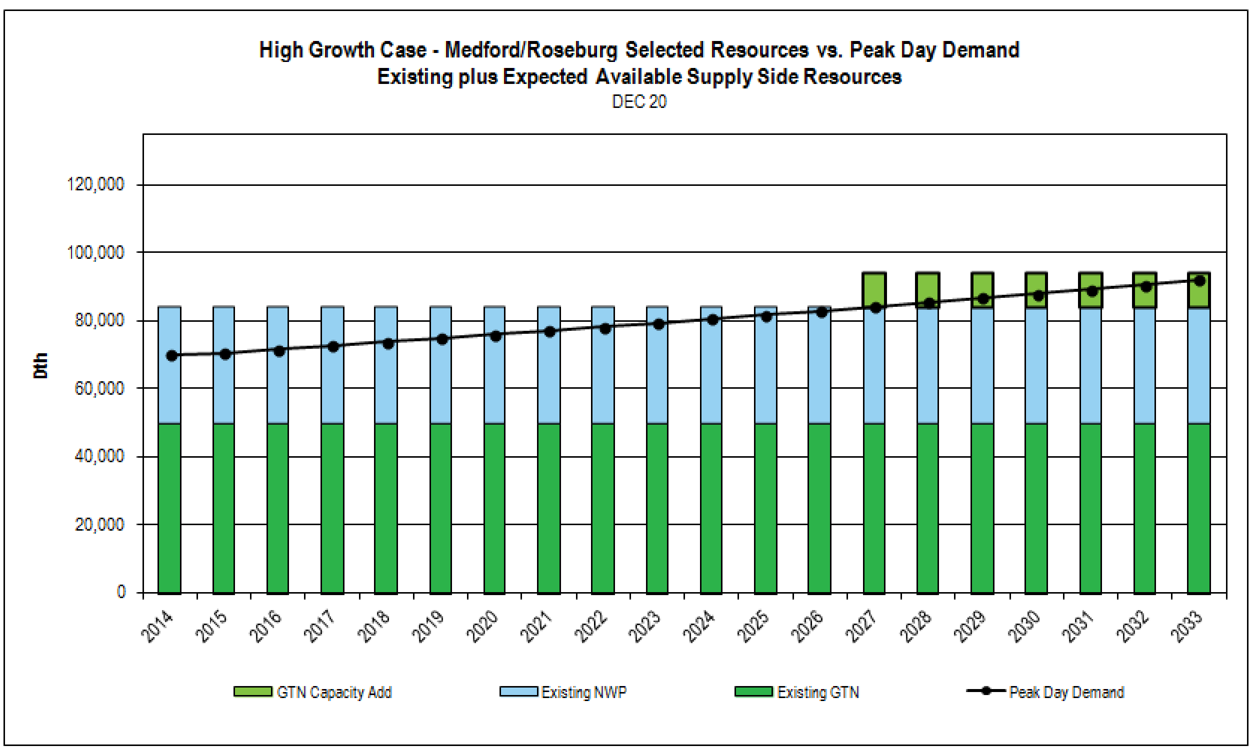
Monthly Avoided Cost Detail 1/
2012$

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 Prices	2028-2029	Nov	$ 3.40	$ 3.96	$ 3.40	$ 3.40	$ 3.40	$ 3.78	$ 3.34	$ 3.96	$ 3.69	$ 3.51
High Growth & Low Prices	2028-2029	Dec	$ 4.02	$ 3.99	$ 4.02	$ 4.02	$ 4.02	$ 3.83	$ 3.31	$ 3.99	$ 3.71	$ 4.02
High Growth & Low Prices	2028-2029	Jan	$ 3.87	$ 3.87	$ 3.87	$ 3.87	$ 3.87	$ 3.80	$ 3.31	$ 3.87	$ 3.66	$ 3.87
High Growth & Low Prices	2028-2029	Feb	$ 3.66	$ 75.14	$ 3.66	$ 3.66	$ 3.66	$ 75.14	$ 3.37	$ 75.14	$ 51.22	$ 17.96
High Growth & Low Prices	2028-2029	Mar	$ 3.66	$ 3.75	$ 3.66	$ 3.66	$ 3.66	$ 3.68	$ 3.60	$ 3.76	$ 3.68	$ 3.68
High Growth & Low Prices	2028-2029	Apr	$ 3.44	$ 3.91	$ 3.44	$ 3.44	$ 3.44	$ 3.38	$ 3.38	$ 3.92	$ 3.56	$ 3.54
High Growth & Low Prices	2028-2029	May	$ 3.38	$ 3.96	$ 3.38	$ 3.38	$ 3.38	$ 3.32	$ 3.32	$ 3.96	$ 3.53	$ 3.50
High Growth & Low Prices	2028-2029	Jun	$ 3.31	$ 3.82	$ 3.31	$ 3.31	$ 3.31	$ 3.25	$ 3.25	$ 3.83	$ 3.44	$ 3.41
High Growth & Low Prices	2028-2029	Jul	$ 3.27	$ 3.83	$ 3.27	$ 3.27	$ 3.27	$ 3.21	$ 3.21	$ 3.83	$ 3.42	$ 3.38
High Growth & Low Prices	2028-2029	Aug	$ 3.25	$ 3.83	$ 3.25	$ 3.25	$ 3.25	$ 3.19	$ 3.19	$ 3.83	$ 3.40	$ 3.37
High Growth & Low Prices	2028-2029	Sep	$ 3.31	$ 3.83	$ 3.31	$ 3.31	$ 3.31	$ 3.25	$ 3.25	$ 3.83	$ 3.45	$ 3.41
High Growth & Low Prices	2028-2029	Oct	$ 3.35	$ 3.88	$ 3.88	$ 3.88	$ 3.88	$ 3.29	$ 3.29	$ 3.88	$ 3.49	$ 3.78
High Growth & Low Prices	2029-2030	Nov	$ 3.51	$ 3.92	$ 3.51	$ 3.51	$ 3.51	$ 3.92	$ 3.45	$ 3.92	$ 3.77	$ 3.60
High Growth & Low Prices	2029-2030	Dec	$ 4.02	$ 3.93	$ 68.39	$ 68.39	$ 68.39	$ 3.93	$ 3.45	$ 3.93	$ 3.77	$ 42.63
High Growth & Low Prices	2029-2030	Jan	$ 3.92	$ 3.92	$ 3.92	$ 3.92	$ 3.92	$ 3.92	$ 3.43	$ 3.92	$ 3.76	$ 3.92
High Growth & Low Prices	2029-2030	Feb	$ 3.62	$ 75.13	$ 3.62	$ 3.62	$ 3.62	$ 75.13	$ 3.32	$ 75.13	$ 51.19	$ 17.92
High Growth & Low Prices	2029-2030	Mar	$ 3.71	$ 3.81	$ 3.71	$ 3.71	$ 3.71	$ 3.73	$ 3.65	$ 3.81	$ 3.73	$ 3.73
High Growth & Low Prices	2029-2030	Apr	$ 3.41	$ 3.87	$ 3.41	$ 3.41	$ 3.41	$ 3.35	$ 3.35	$ 3.87	$ 3.52	$ 3.50
High Growth & Low Prices	2029-2030	May	$ 3.33	$ 3.91	$ 3.33	$ 3.33	$ 3.33	$ 3.27	$ 3.27	$ 3.91	$ 3.48	$ 3.45
High Growth & Low Prices	2029-2030	Jun	$ 3.26	$ 3.80	$ 3.26	$ 3.26	$ 3.26	$ 3.20	$ 3.20	$ 3.80	$ 3.40	$ 3.37
High Growth & Low Prices	2029-2030	Jul	$ 3.22	$ 3.80	$ 3.22	$ 3.22	$ 3.22	$ 3.16	$ 3.16	$ 3.80	$ 3.38	$ 3.34
High Growth & Low Prices	2029-2030	Aug	$ 3.20	$ 3.80	$ 3.20	$ 3.20	$ 3.20	$ 3.14	$ 3.14	$ 3.81	$ 3.36	$ 3.32
High Growth & Low Prices	2029-2030	Sep	$ 3.26	$ 3.81	$ 3.26	$ 3.26	$ 3.26	$ 3.20	$ 3.20	$ 3.81	$ 3.40	$ 3.37
High Growth & Low Prices	2029-2030	Oct	$ 3.33	$ 3.84	$ 3.84	$ 3.84	$ 3.84	$ 3.27	$ 3.27	$ 3.84	$ 3.46	$ 3.74
High Growth & Low Prices	2030-2031	Nov	$ 3.65	$ 3.94	$ 3.65	$ 3.65	$ 3.65	$ 3.94	$ 3.59	$ 3.94	$ 3.82	$ 3.71
High Growth & Low Prices	2030-2031	Dec	$ 4.06	$ 3.95	$ 68.42	$ 68.42	$ 68.42	$ 3.95	$ 3.53	$ 3.95	$ 3.81	$ 42.66
High Growth & Low Prices	2030-2031	Jan	$ 3.84	$ 3.84	$ 3.84	$ 3.84	$ 3.84	$ 3.82	$ 3.33	$ 3.94	$ 3.70	$ 3.84
High Growth & Low Prices	2030-2031	Feb	$ 3.66	$ 75.09	$ 3.66	$ 3.66	$ 3.66	$ 75.06	$ 74.55	$ 75.09	$ 74.90	$ 17.94
High Growth & Low Prices	2030-2031	Mar	$ 3.69	$ 3.78	$ 3.69	$ 3.69	$ 3.69	$ 3.70	$ 3.63	$ 3.78	$ 3.70	$ 3.71
High Growth & Low Prices	2030-2031	Apr	$ 3.48	$ 3.92	$ 3.48	$ 3.48	$ 3.48	$ 3.42	$ 3.42	$ 3.92	$ 3.59	$ 3.57
High Growth & Low Prices	2030-2031	May	$ 3.43	$ 3.91	$ 3.43	$ 3.43	$ 3.43	$ 3.37	$ 3.37	$ 3.91	$ 3.55	$ 3.53
High Growth & Low Prices	2030-2031	Jun	$ 3.36	$ 3.85	$ 3.36	$ 3.36	$ 3.36	$ 3.30	$ 3.30	$ 3.86	$ 3.49	$ 3.46
High Growth & Low Prices	2030-2031	Jul	$ 3.35	$ 3.86	$ 3.35	$ 3.35	$ 3.35	$ 3.29	$ 3.29	$ 3.86	$ 3.48	$ 3.45
High Growth & Low Prices	2030-2031	Aug	$ 3.34	$ 3.86	$ 3.34	$ 3.34	$ 3.34	$ 3.28	$ 3.28	$ 3.86	$ 3.48	$ 3.45
High Growth & Low Prices	2030-2031	Sep	$ 3.41	$ 3.86	$ 3.41	$ 3.41	$ 3.41	$ 3.35	$ 3.35	$ 3.86	$ 3.52	$ 3.50
High Growth & Low Prices	2030-2031	Oct	$ 3.46	$ 3.98	$ 3.98	$ 3.98	$ 3.98	$ 3.40	$ 3.40	$ 3.98	$ 3.60	$ 3.87
High Growth & Low Prices	2031-2032	Nov	$ 3.63	$ 3.86	$ 3.63	$ 3.63	$ 3.63	$ 3.86	$ 3.57	$ 3.86	$ 3.76	$ 3.67
High Growth & Low Prices	2031-2032	Dec	$ 3.98	$ 3.87	$ 132.71	$ 132.71	$ 132.71	$ 3.83	$ 3.32	$ 3.87	$ 3.68	$ 81.20
High Growth & Low Prices	2031-2032	Jan	$ 3.79	$ 3.79	$ 3.79	$ 3.79	$ 3.79	$ 3.77	$ 3.28	$ 3.82	$ 3.62	$ 3.79
High Growth & Low Prices	2031-2032	Feb	$ 3.51	$ 72.57	$ 3.51	$ 3.51	$ 3.51	$ 72.57	$ 72.15	$ 72.57	$ 72.43	$ 17.32
High Growth & Low Prices	2031-2032	Mar	$ 3.51	$ 3.47	$ 3.50	$ 3.50	$ 3.50	$ 3.47	$ 3.45	$ 3.47	$ 3.47	$ 3.50
High Growth & Low Prices	2031-2032	Apr	$ 3.35	$ 3.47	$ 3.35	$ 3.35	$ 3.35	$ 3.29	$ 3.29	$ 3.47	$ 3.35	$ 3.38
High Growth & Low Prices	2031-2032	May	$ 3.34	$ 3.42	$ 3.34	$ 3.34	$ 3.34	$ 3.28	$ 3.28	$ 3.42	$ 3.33	$ 3.36
High Growth & Low Prices	2031-2032	Jun	$ 3.26	$ 3.23	$ 3.23	$ 3.23	$ 3.23	$ 3.20	$ 3.20	$ 3.23	$ 3.21	$ 3.23
High Growth & Low Prices	2031-2032	Jul	$ 3.15	$ 3.23	$ 3.15	$ 3.15	$ 3.15	$ 3.09	$ 3.09	$ 3.23	$ 3.14	$ 3.17
High Growth & Low Prices	2031-2032	Aug	$ 3.14	$ 3.23	$ 3.14	$ 3.14	$ 3.14	$ 3.08	$ 3.08	$ 3.23	$ 3.13	$ 3.16
High Growth & Low Prices	2031-2032	Sep	$ 3.28	$ 3.28	$ 3.28	$ 3.28	$ 3.28	$ 3.22	$ 3.22	$ 3.28	$ 3.24	$ 3.28
High Growth & Low Prices	2031-2032	Oct	$ 3.33	$ 3.51	$ 3.51	$ 3.51	$ 3.51	$ 3.27	$ 3.27	$ 3.51	$ 3.35	$ 3.47
High Growth & Low Prices	2032-2033	Nov	$ 3.44	$ 3.55	$ 3.44	$ 3.44	$ 3.44	$ 3.55	$ 3.38	$ 3.55	$ 3.49	$ 3.47
High Growth & Low Prices	2032-2033	Dec	$ 3.89	$ 3.80	$ 132.64	$ 132.64	$ 132.64	$ 3.80	$ 3.32	$ 3.80	$ 3.64	$ 81.12
High Growth & Low Prices	2032-2033	Jan	$ 3.79	$ 3.79	$ 3.79	$ 3.79	$ 3.79	$ 3.79	$ 3.32	$ 3.79	$ 3.64	$ 3.79
High Growth & Low Prices	2032-2033	Feb	$ 3.52	$ 75.05	$ 3.52	$ 3.52	$ 3.52	$ 75.05	$ 74.62	$ 75.05	$ 74.91	$ 17.82
High Growth & Low Prices	2032-2033	Mar	$ 3.52	$ 3.48	$ 3.51	$ 3.51	$ 3.51	$ 3.48	$ 3.46	$ 3.48	$ 3.48	$ 3.51
High Growth & Low Prices	2032-2033	Apr	$ 3.35	$ 3.41	$ 3.35	$ 3.35	$ 3.35	$ 3.29	$ 3.29	$ 3.41	$ 3.33	$ 3.36
High Growth & Low Prices	2032-2033	May	$ 3.34	$ 3.38	$ 3.34	$ 3.34	$ 3.34	$ 3.28	$ 3.28	$ 3.38	$ 3.32	$ 3.35
High Growth & Low Prices	2032-2033	Jun	$ 3.29	$ 3.25	$ 3.17	$ 3.17	$ 3.17	$ 3.03	$ 3.23	$ 3.03	$ 3.10	$ 3.21
High Growth & Low Prices	2032-2033	Jul	$ 3.17	$ 3.17	$ 3.17	$ 3.17	$ 3.17	$ 3.11	$ 3.11	$ 3.17	$ 3.13	$ 3.17
High Growth & Low Prices	2032-2033	Aug	$ 3.15	$ 3.17	$ 3.15	$ 3.15	$ 3.15	$ 3.09	$ 3.09	$ 3.17	$ 3.12	$ 3.15
High Growth & Low Prices	2032-2033	Sep	$ 3.31	$ 3.31	$ 3.31	$ 3.31	$ 3.31	$ 3.25	$ 3.25	$ 3.31	$ 3.27	$ 3.31
High Growth & Low Prices	2032-2033	Oct	$ 3.38	$ 3.48	$ 3.48	$ 3.48	$ 3.48	$ 3.32	$ 3.32	$ 3.48	$ 3.38	$ 3.46

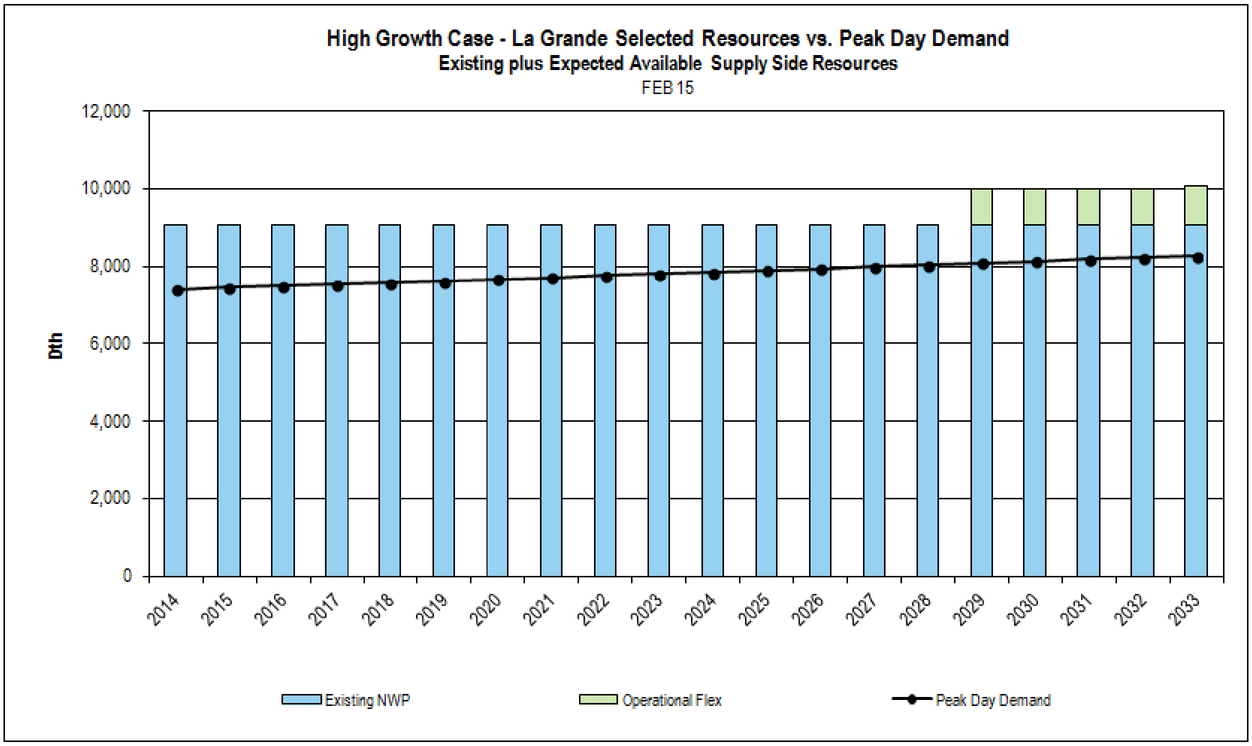
1/ Avoided costs are before Environmental Externalities adder.

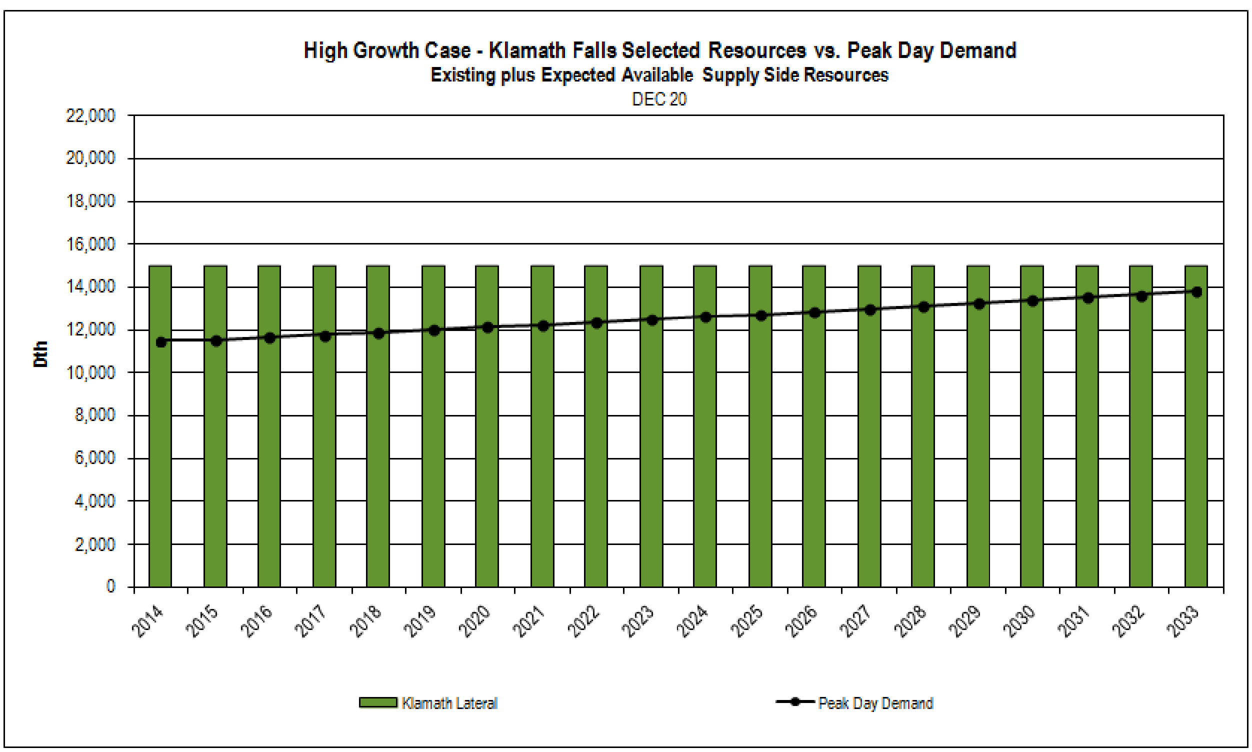
Appendix 6.1: High Growth Cases
Selected Resources vs. Peak Day Demand
Existing plus Expected Available





APPENDIX 6.1: HIGH GROWTH CASES
SELECTED RESOURCES VS. PEAK DAY DEMAND
EXISTING PLUS EXPECTED AVAILABLE





APPENDIX 6.2: PEAK DAY DEMAND TABLE
HIGH GROWTH

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

Case	Gas Year	LaGrande Served	LaGrande Unserved	LaGrande Total	LaGrande % of Peak Day Served	WA/ID Served	WA/ID Unserved	WA/ID Total	WA/ID % of Peak Day Served
High Growth & Low Prices	2014	7,404	-	7,404	100%	273,778	-	273,778	100%
High Growth & Low Prices	2015	7,449	-	7,449	100%	277,834	-	277,834	100%
High Growth & Low Prices	2016	7,492	-	7,492	100%	281,972	-	281,972	100%
High Growth & Low Prices	2017	7,538	-	7,538	100%	286,157	-	286,157	100%
High Growth & Low Prices	2018	7,581	-	7,581	100%	290,384	-	290,384	100%
High Growth & Low Prices	2019	7,626	-	7,626	100%	294,655	-	294,655	100%
High Growth & Low Prices	2020	7,673	-	7,673	100%	298,996	-	298,996	100%
High Growth & Low Prices	2021	7,717	-	7,717	100%	303,428	-	303,428	100%
High Growth & Low Prices	2022	7,763	-	7,763	100%	307,929	-	307,929	100%
High Growth & Low Prices	2023	7,810	-	7,810	100%	312,500	-	312,500	100%
High Growth & Low Prices	2024	7,854	-	7,854	100%	317,136	-	317,136	100%
High Growth & Low Prices	2025	7,901	-	7,901	100%	321,846	-	321,846	100%
High Growth & Low Prices	2026	7,948	-	7,948	100%	326,626	-	326,626	100%
High Growth & Low Prices	2027	7,995	-	7,995	100%	331,483	-	331,483	100%
High Growth & Low Prices	2028	8,043	-	8,043	100%	331,804	4,607	336,411	99%
High Growth & Low Prices	2029	8,091	-	8,091	100%	332,121	9,293	341,414	97%
High Growth & Low Prices	2030	8,139	-	8,139	100%	332,447	14,050	346,497	96%
High Growth & Low Prices	2031	8,187	-	8,187	100%	332,391	19,267	351,658	95%
High Growth & Low Prices	2032	8,235	-	8,235	100%	332,314	24,586	356,900	93%
High Growth & Low Prices	2033	8,284	-	8,284	100%	332,237	29,982	362,219	92%

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 & Low Prices	2014	11,488	-	11,488	100%	70,032	-	70,032	100%
High Growth & Low Prices	2015	11,539	-	11,539	100%	70,686	-	70,686	100%
High Growth & Low Prices	2016	11,653	-	11,653	100%	71,711	-	71,711	100%
High Growth & Low Prices	2017	11,768	-	11,768	100%	72,765	-	72,765	100%
High Growth & Low Prices	2018	11,890	-	11,890	100%	73,822	-	73,822	100%
High Growth & Low Prices	2019	12,005	-	12,005	100%	74,901	-	74,901	100%
High Growth & Low Prices	2020	12,122	-	12,122	100%	75,994	-	75,994	100%
High Growth & Low Prices	2021	12,248	-	12,248	100%	77,109	-	77,109	100%
High Growth & Low Prices	2022	12,366	-	12,366	100%	78,236	-	78,236	100%
High Growth & Low Prices	2023	12,487	-	12,487	100%	79,391	-	79,391	100%
High Growth & Low Prices	2024	12,616	-	12,616	100%	80,551	-	80,551	100%
High Growth & Low Prices	2025	12,739	-	12,739	100%	81,736	-	81,736	100%
High Growth & Low Prices	2026	12,865	-	12,865	100%	82,938	-	82,938	100%
High Growth & Low Prices	2027	12,996	-	12,996	100%	84,166	-	84,166	100%
High Growth & Low Prices	2028	13,123	-	13,123	100%	85,403	-	85,403	100%
High Growth & Low Prices	2029	13,252	-	13,252	100%	86,668	-	86,668	100%
High Growth & Low Prices	2030	13,388	-	13,388	100%	87,097	849	87,947	99%
High Growth & Low Prices	2031	13,518	-	13,518	100%	87,091	2,163	89,254	98%
High Growth & Low Prices	2032	13,649	-	13,649	100%	87,085	3,490	90,575	96%
High Growth & Low Prices	2033	13,790	-	13,790	100%	87,079	4,843	91,922	95%

APPENDIX 6.2: PEAK DAY DEMAND TABLE
LOW GROWTH

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

Case	Gas Year	LaGrande Served	LaGrande Unserved	LaGrande Total	LaGrande % of Peak Day Served	WA/ID Served	WA/ID Unserved	WA/ID Total	WA/ID % of Peak Day Served
Low Growth & High Prices	2014	7,345	-	7,345	100%	270,352	-	270,352	100%
Low Growth & High Prices	2015	7,195	-	7,195	100%	265,445	-	265,445	100%
Low Growth & High Prices	2016	7,132	-	7,132	100%	263,889	-	263,889	100%
Low Growth & High Prices	2017	7,109	-	7,109	100%	263,718	-	263,718	100%
Low Growth & High Prices	2018	7,089	-	7,089	100%	263,664	-	263,664	100%
Low Growth & High Prices	2019	7,056	-	7,056	100%	263,054	-	263,054	100%
Low Growth & High Prices	2020	7,045	-	7,045	100%	263,292	-	263,292	100%
Low Growth & High Prices	2021	7,040	-	7,040	100%	263,837	-	263,837	100%
Low Growth & High Prices	2022	7,017	-	7,017	100%	263,736	-	263,736	100%
Low Growth & High Prices	2023	6,981	-	6,981	100%	263,060	-	263,060	100%
Low Growth & High Prices	2024	6,995	-	6,995	100%	264,284	-	264,284	100%
Low Growth & High Prices	2025	6,965	-	6,965	100%	263,830	-	263,830	100%
Low Growth & High Prices	2026	6,940	-	6,940	100%	263,559	-	263,559	100%
Low Growth & High Prices	2027	6,926	-	6,926	100%	263,749	-	263,749	100%
Low Growth & High Prices	2028	6,921	-	6,921	100%	264,377	-	264,377	100%
Low Growth & High Prices	2029	6,917	-	6,917	100%	264,926	-	264,926	100%
Low Growth & High Prices	2030	6,883	-	6,883	100%	264,327	-	264,327	100%
Low Growth & High Prices	2031	6,865	-	6,865	100%	264,329	-	264,329	100%
Low Growth & High Prices	2032	6,846	-	6,846	100%	264,312	-	264,312	100%
Low Growth & High Prices	2033	6,859	-	6,859	100%	265,562	-	265,562	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 & High Prices	2014	11,451	-	11,451	100%	69,822	-	69,822	100%
Low Growth & High Prices	2015	11,230	-	11,230	100%	68,580	-	68,580	100%
Low Growth & High Prices	2016	11,151	-	11,151	100%	68,191	-	68,191	100%
Low Growth & High Prices	2017	11,130	-	11,130	100%	68,150	-	68,150	100%
Low Growth & High Prices	2018	11,105	-	11,105	100%	68,148	-	68,148	100%
Low Growth & High Prices	2019	11,067	-	11,067	100%	68,004	-	68,004	100%
Low Growth & High Prices	2020	11,061	-	11,061	100%	68,080	-	68,080	100%
Low Growth & High Prices	2021	11,063	-	11,063	100%	68,222	-	68,222	100%
Low Growth & High Prices	2022	11,043	-	11,043	100%	68,206	-	68,206	100%
Low Growth & High Prices	2023	11,001	-	11,001	100%	68,039	-	68,039	100%
Low Growth & High Prices	2024	11,030	-	11,030	100%	68,359	-	68,359	100%
Low Growth & High Prices	2025	10,995	-	10,995	100%	68,244	-	68,244	100%
Low Growth & High Prices	2026	10,969	-	10,969	100%	68,184	-	68,184	100%
Low Growth & High Prices	2027	10,956	-	10,956	100%	68,235	-	68,235	100%
Low Growth & High Prices	2028	10,965	-	10,965	100%	68,402	-	68,402	100%
Low Growth & High Prices	2029	10,972	-	10,972	100%	68,545	-	68,545	100%
Low Growth & High Prices	2030	10,926	-	10,926	100%	68,398	-	68,398	100%
Low Growth & High Prices	2031	10,911	-	10,911	100%	68,399	-	68,399	100%
Low Growth & High Prices	2032	10,895	-	10,895	100%	68,401	-	68,401	100%
Low Growth & High Prices	2033	10,922	-	10,922	100%	68,719	-	68,719	100%

APPENDIX 6.2: 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	LaGrande Served	LaGrande Unserved	LaGrande Total	LaGrande % of Peak Day Served	WA/ID Served	WA/ID Unserved	WA/ID Total	WA/ID % of Peak Day Served
Coldest in 20	2014	7,388	-	7,388	100%	252,453	-	252,453	100%
Coldest in 20	2015	7,422	-	7,422	100%	254,998	-	254,998	100%
Coldest in 20	2016	7,457	-	7,457	100%	257,472	-	257,472	100%
Coldest in 20	2017	7,429	-	7,429	100%	257,946	-	257,946	100%
Coldest in 20	2018	7,471	-	7,471	100%	260,769	-	260,769	100%
Coldest in 20	2019	7,501	-	7,501	100%	263,261	-	263,261	100%
Coldest in 20	2020	7,532	-	7,532	100%	265,785	-	265,785	100%
Coldest in 20	2021	7,536	-	7,536	100%	267,539	-	267,539	100%
Coldest in 20	2022	7,478	-	7,478	100%	266,917	-	266,917	100%
Coldest in 20	2023	7,498	-	7,498	100%	269,164	-	269,164	100%
Coldest in 20	2024	7,528	-	7,528	100%	271,778	-	271,778	100%
Coldest in 20	2025	7,497	-	7,497	100%	272,296	-	272,296	100%
Coldest in 20	2026	7,469	-	7,469	100%	272,781	-	272,781	100%
Coldest in 20	2027	7,474	-	7,474	100%	274,514	-	274,514	100%
Coldest in 20	2028	7,503	-	7,503	100%	277,190	-	277,190	100%
Coldest in 20	2029	7,531	-	7,531	100%	279,891	-	279,891	100%
Coldest in 20	2030	7,476	-	7,476	100%	279,431	-	279,431	100%
Coldest in 20	2031	7,506	-	7,506	100%	282,162	-	282,162	100%
Coldest in 20	2032	7,502	-	7,502	100%	283,631	-	283,631	100%
Coldest in 20	2033	7,512	-	7,512	100%	285,655	-	285,655	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	2014	11,488	-	11,488	100%	62,534	-	62,534	100%
Coldest in 20	2015	11,497	-	11,497	100%	63,033	-	63,033	100%
Coldest in 20	2016	11,538	-	11,538	100%	63,512	-	63,512	100%
Coldest in 20	2017	11,500	-	11,500	100%	63,494	-	63,494	100%
Coldest in 20	2018	11,556	-	11,556	100%	64,022	-	64,022	100%
Coldest in 20	2019	11,617	-	11,617	100%	64,557	-	64,557	100%
Coldest in 20	2020	11,692	-	11,692	100%	65,174	-	65,174	100%
Coldest in 20	2021	11,732	-	11,732	100%	65,602	-	65,602	100%
Coldest in 20	2022	11,671	-	11,671	100%	65,458	-	65,458	100%
Coldest in 20	2023	11,731	-	11,731	100%	66,006	-	66,006	100%
Coldest in 20	2024	11,806	-	11,806	100%	66,639	-	66,639	100%
Coldest in 20	2025	11,793	-	11,793	100%	66,771	-	66,771	100%
Coldest in 20	2026	11,776	-	11,776	100%	66,891	-	66,891	100%
Coldest in 20	2027	11,814	-	11,814	100%	67,315	-	67,315	100%
Coldest in 20	2028	11,891	-	11,891	100%	67,964	-	67,964	100%
Coldest in 20	2029	11,966	-	11,966	100%	68,621	-	68,621	100%
Coldest in 20	2030	11,910	-	11,910	100%	68,518	-	68,518	100%
Coldest in 20	2031	11,987	-	11,987	100%	69,180	-	69,180	100%
Coldest in 20	2032	12,011	-	12,011	100%	69,540	-	69,540	100%
Coldest in 20	2033	12,057	-	12,057	100%	70,032	-	70,032	100%

APPENDIX 7.1: 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 Avista converted its 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®.

2014 Avista Natural Gas IRP

Technical Advisory Committee Meeting 1

January 24, 2014

Portland, Oregon

Agenda

- Introductions & Logistics
- Purpose of IRP and Avista's IRP Process
- Avista's Demand Overview and 2012 IRP Revisited
- Economic Outlook and Customer Count Forecast
- Demand Forecast Methodology
- Dynamic Demand Forecasting
- Demand Side Management
- Questions/Wrap Up

2014 IRP Timeline

- **August 31, 2013** – Work Plan filed with WUTC
- **January through April 2014** – Technical Advisory Committee meetings. Meeting topics will include:
  – Demand Forecast and Demand Side Management – January 24
  – Supply/Infrastructure, Natural Gas Pricing, and Potential Case Discussion– *February 25*
  – Distribution Planning, SENDOUT® Preliminary Output Results and Further Case Discussion – *March 26*
  – SENDOUT® results – *April 23*
- **May 30, 2014 –** Draft of IRP document to TAC
- **June 30, 2014 –** Comments on draft due back to Avista
- **July 2014 –** TAC final review meeting (if necessary)
- **August 31, 2014 –** File finalized IRP document

Purpose of Gas Integrated Resource Planning

- Comprehensive long-range resource planning tool
- Fully integrates forecasted demand requirements with potential demand side and supply side resources
- Process determines the least cost, risk adjusted means for meeting demand requirements for our firm residential, commercial and industrial customers
- Responsive to Idaho, Oregon and Washington rules and/or orders

Avista's IRP Process

- Comprehensive analysis bringing demand forecasting and existing and potential supply-side and demand-side resources together into a 20-year, risk adjusted least-cost plan
- Considers:
  - Customer growth and usage
  - Weather planning standard
  - Demand-side management opportunities
  - Existing and potential supply-side resource options
  - Risk
  - Public participation through Technical Advisory Committee meetings (TAC)
- 2012 IRP completed and filed in all three jurisdictions on August 31, 2012 and acknowledged

Avista's Demand Overview and 2012 IRP Re-Visited

Avista's Demand Overview

Service Territory and Customer Overview

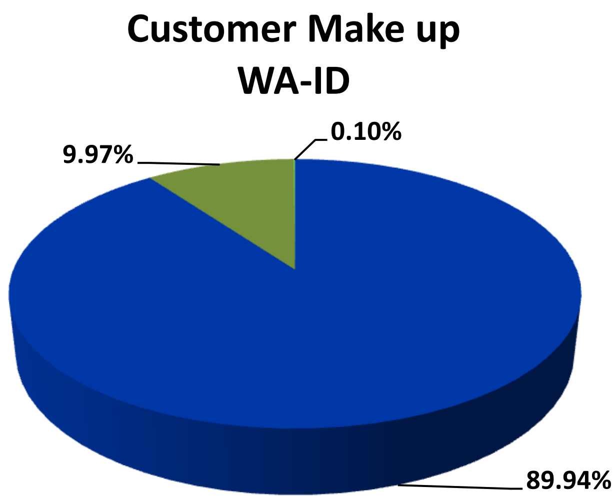
- Serves electric and natural gas customers in eastern Washington and northern Idaho, and natural gas customers in southern and eastern Oregon
  - Population of service area 1,590,341
    - 365,000 electric customers
    - 331,000 natural gas customers

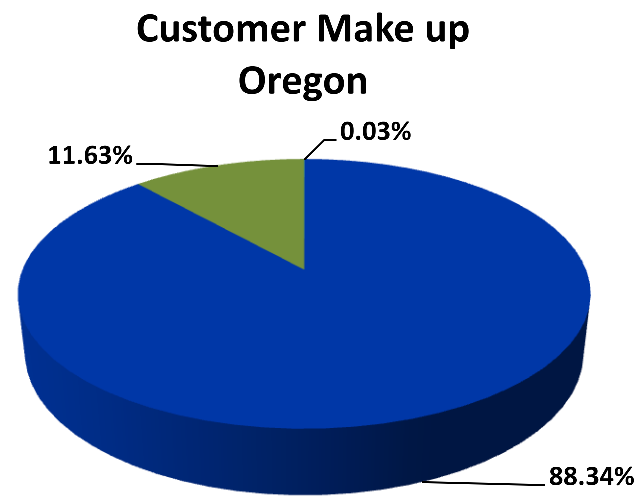
- Have one of the smallest carbon footprints among America's 100 largest investor-owned utilities

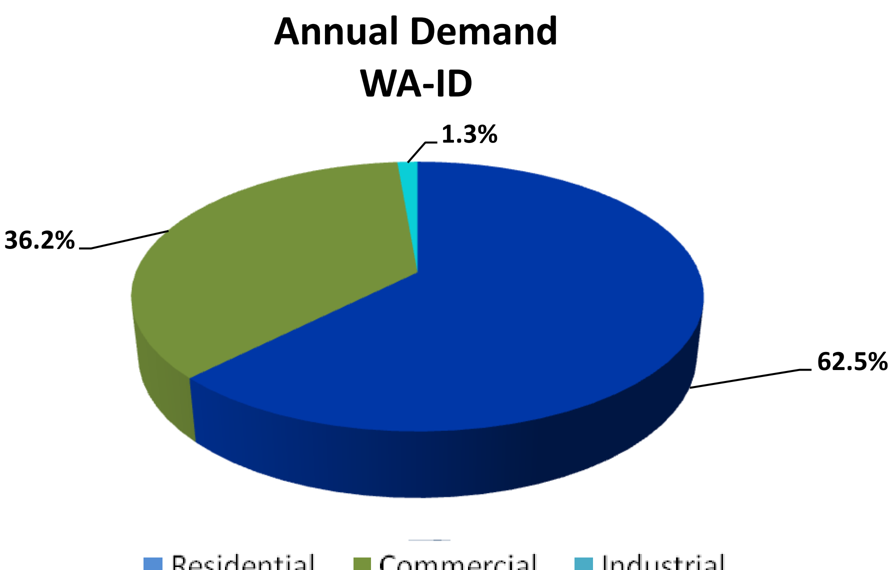
- Committed to environmental stewardship and efficient use of resources

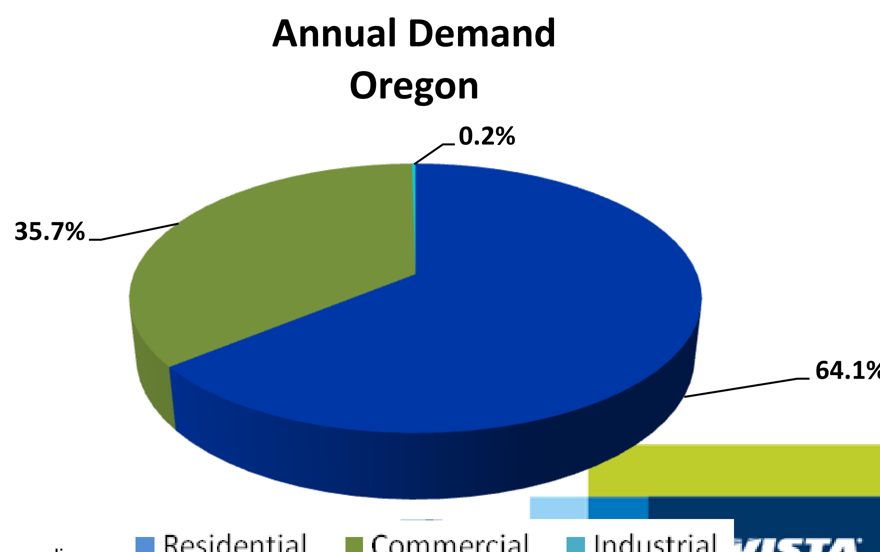
State	Total Customers	% of Total
Washington	157,557	47%
Oregon	97,404	29%
Idaho	76,739	23%
Total	331,700	100%

2013 Customer Make Up and Demand Mix



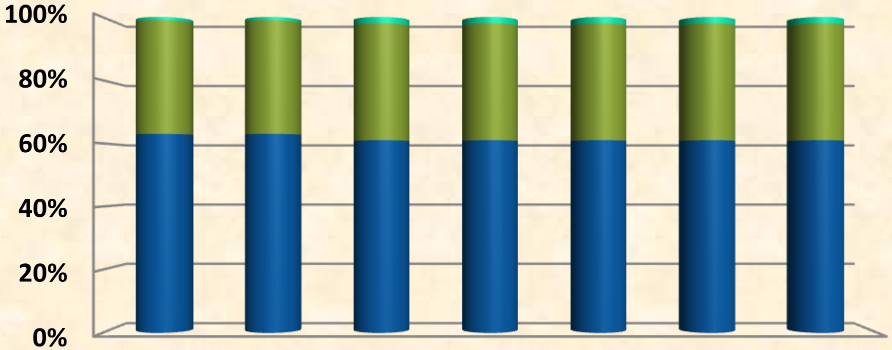






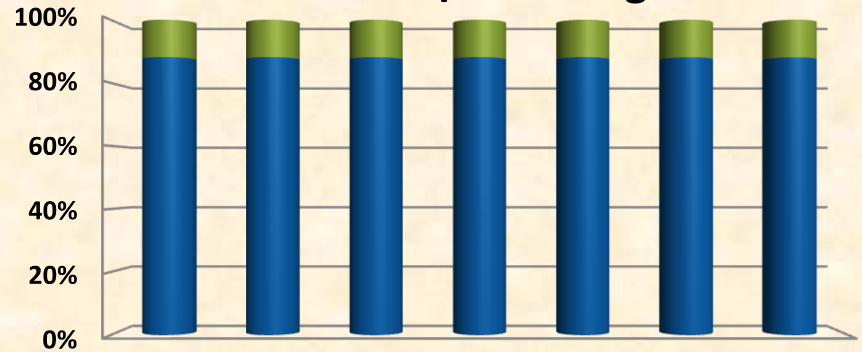
Historical Demand Mix

WA-ID



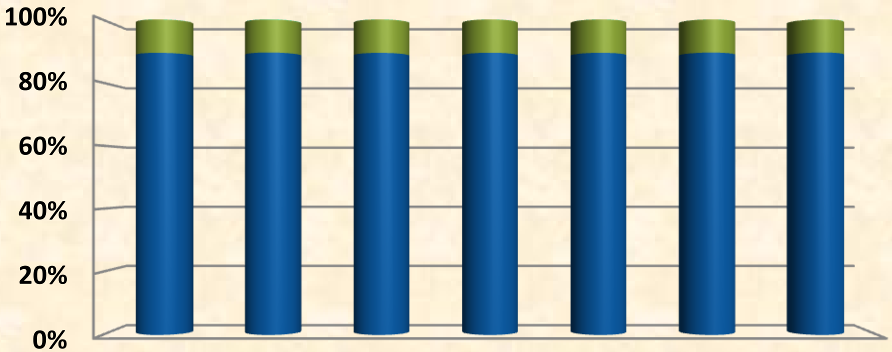
	2013	2012	2011	2010	2009	2008	2007
Industrial	1%	1%	2%	2%	2%	2%	2%
Commercial	36%	36%	37%	37%	37%	37%	37%
Residential	63%	63%	61%	61%	61%	61%	61%

Medford/Roseburg



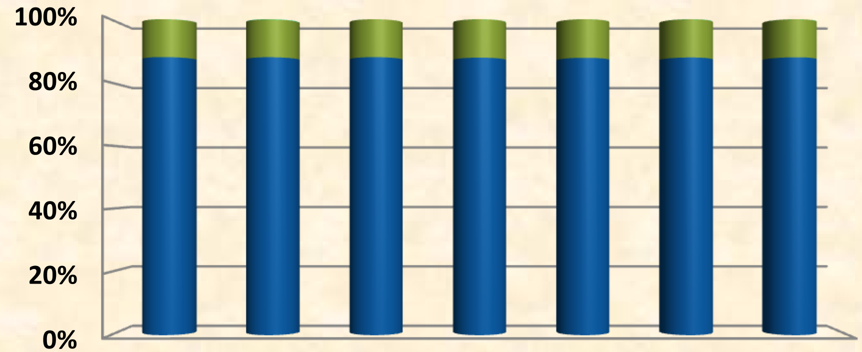
	2013	2012	2011	2010	2009	2008	2007
Industrial	0%	0%	0%	0%	0%	0%	0%
Commercial	12%	12%	12%	12%	12%	12%	12%
Residential	88%	88%	88%	88%	88%	88%	88%

Klamath Falls



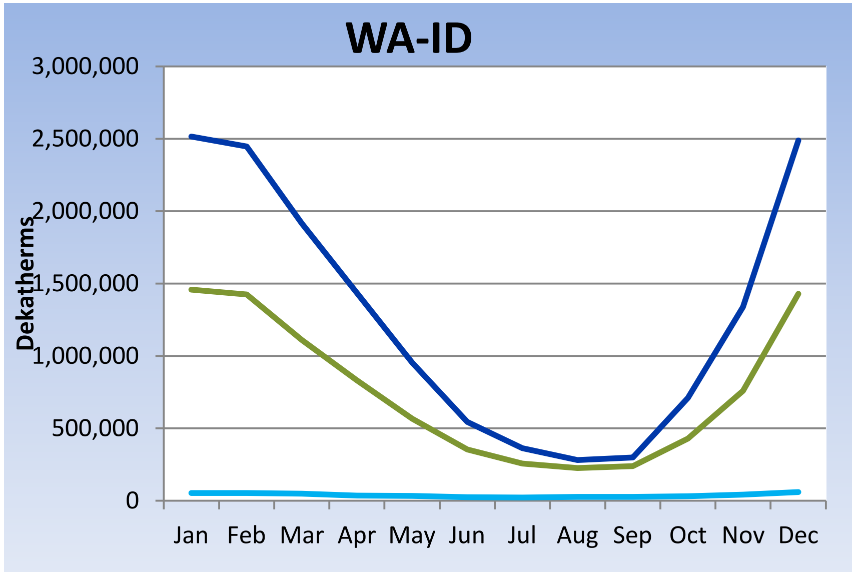
	2013	2012	2011	2010	2009	2008	2007
Industrial	0%	0%	0%	0%	0%	0%	0%
Commercial	11%	10%	11%	11%	11%	10%	10%
Residential	89%	90%	89%	89%	89%	89%	90%

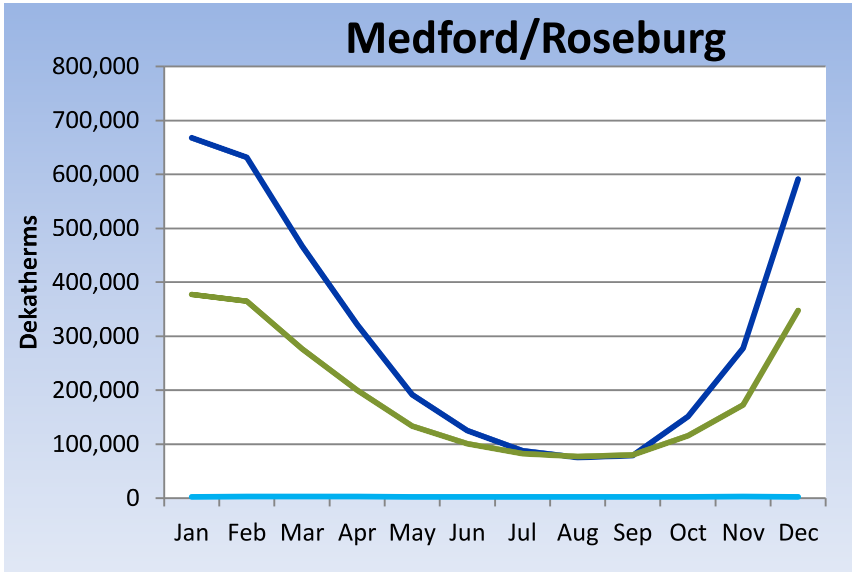
LaGrande

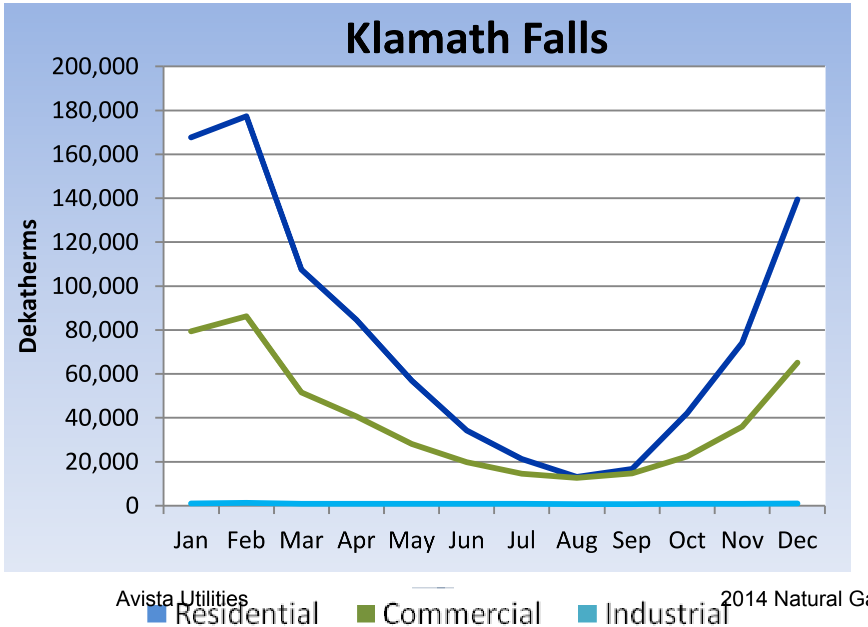


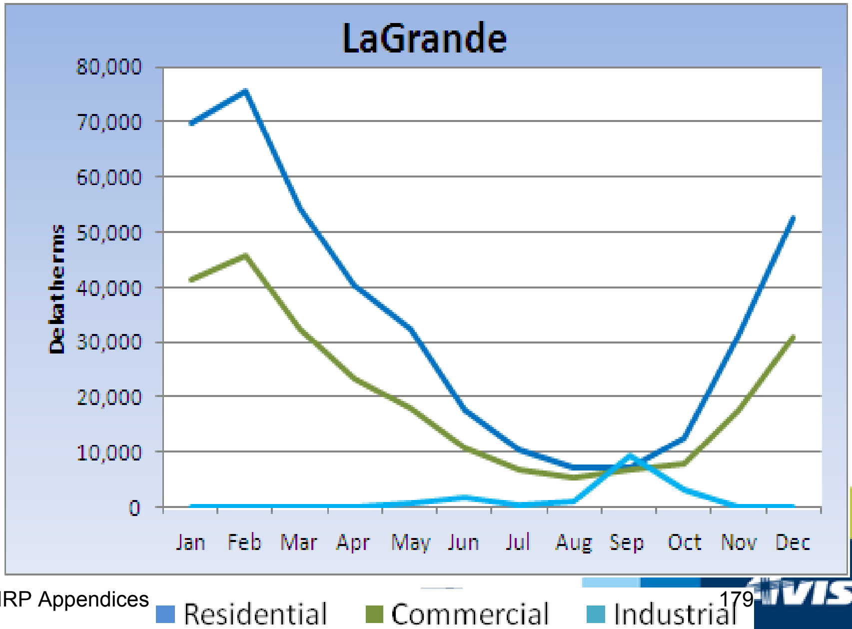
	2013	2012	2011	2010	2009	2008	2007
Industrial	0%	0%	0%	0%	0%	0%	0%
Commercial	12%	12%	12%	12%	12%	12%	12%
Residential	88%	88%	88%	88%	88%	88%	88%

Seasonal Demand Profiles

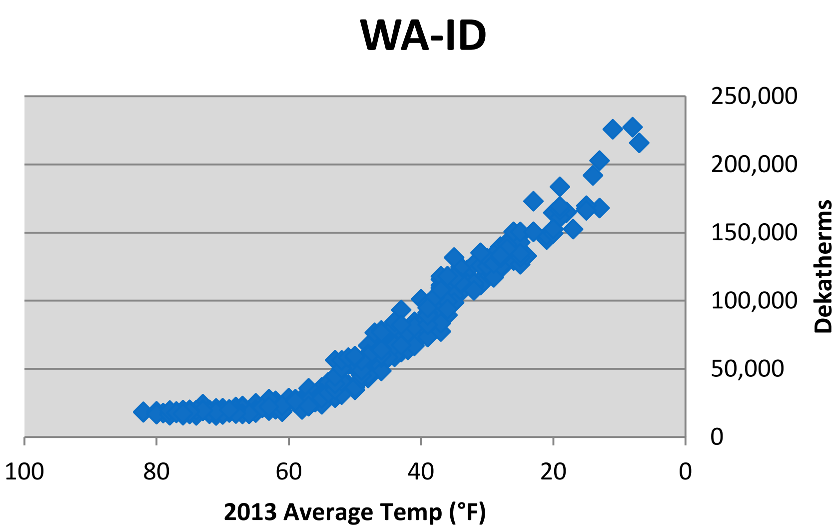


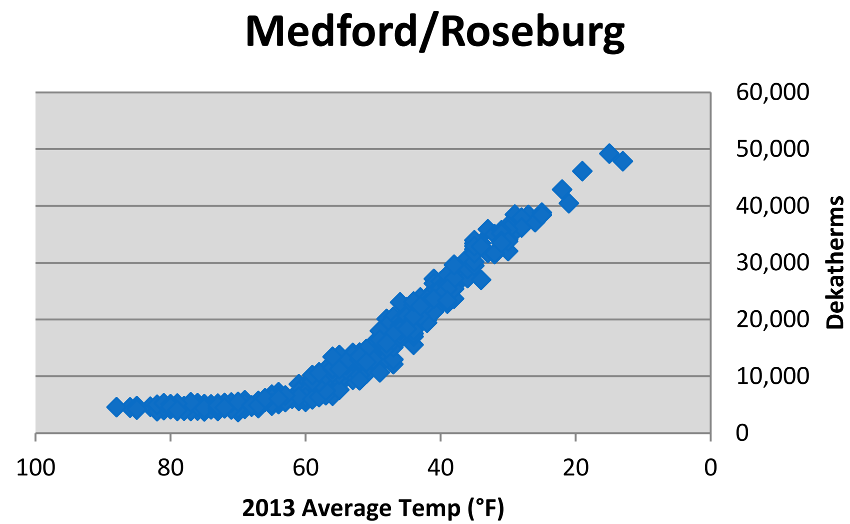


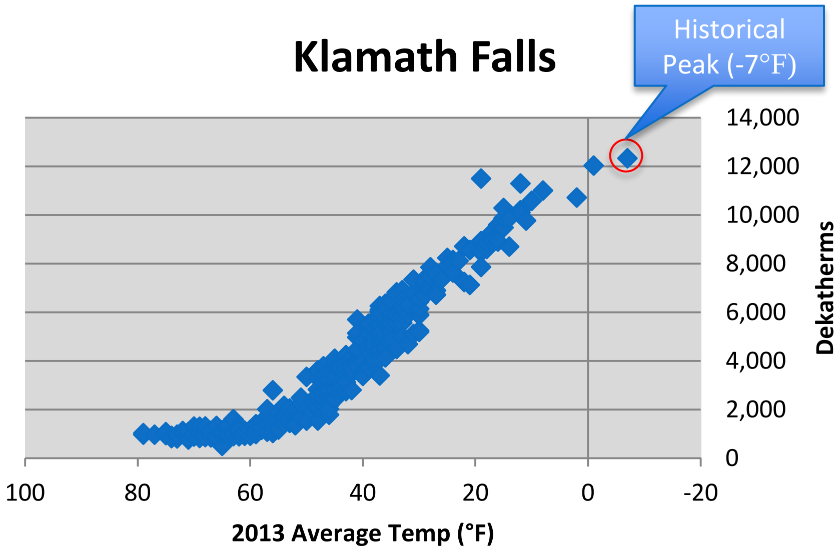


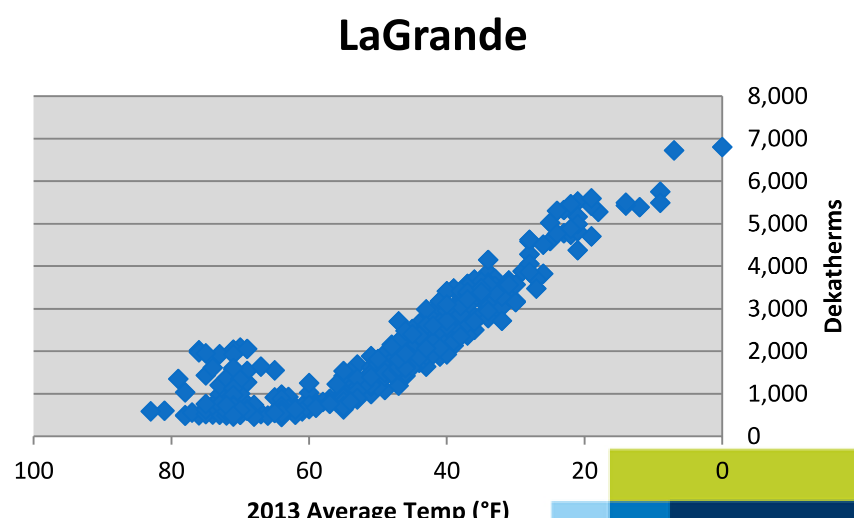


Daily Demand Profiles

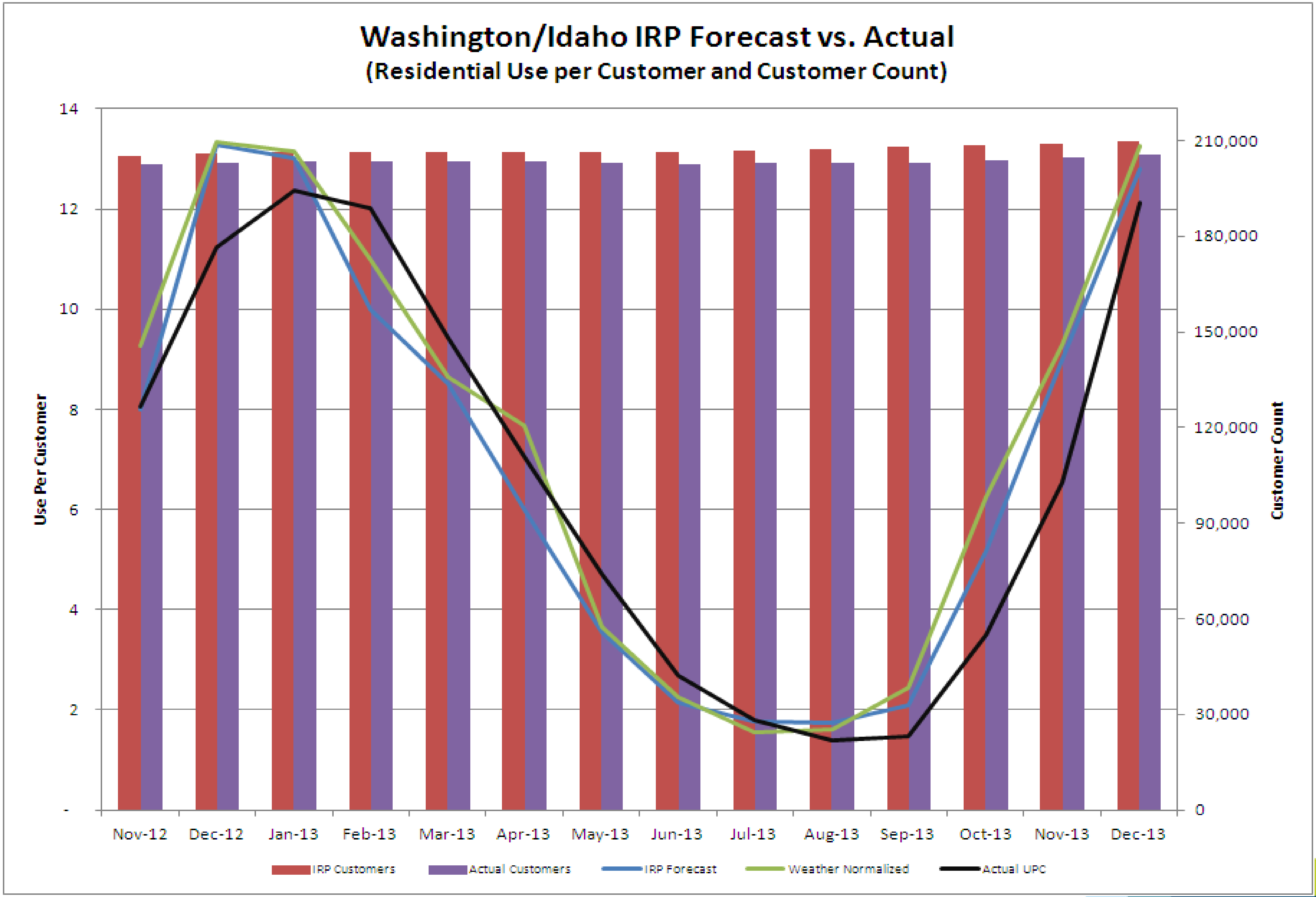


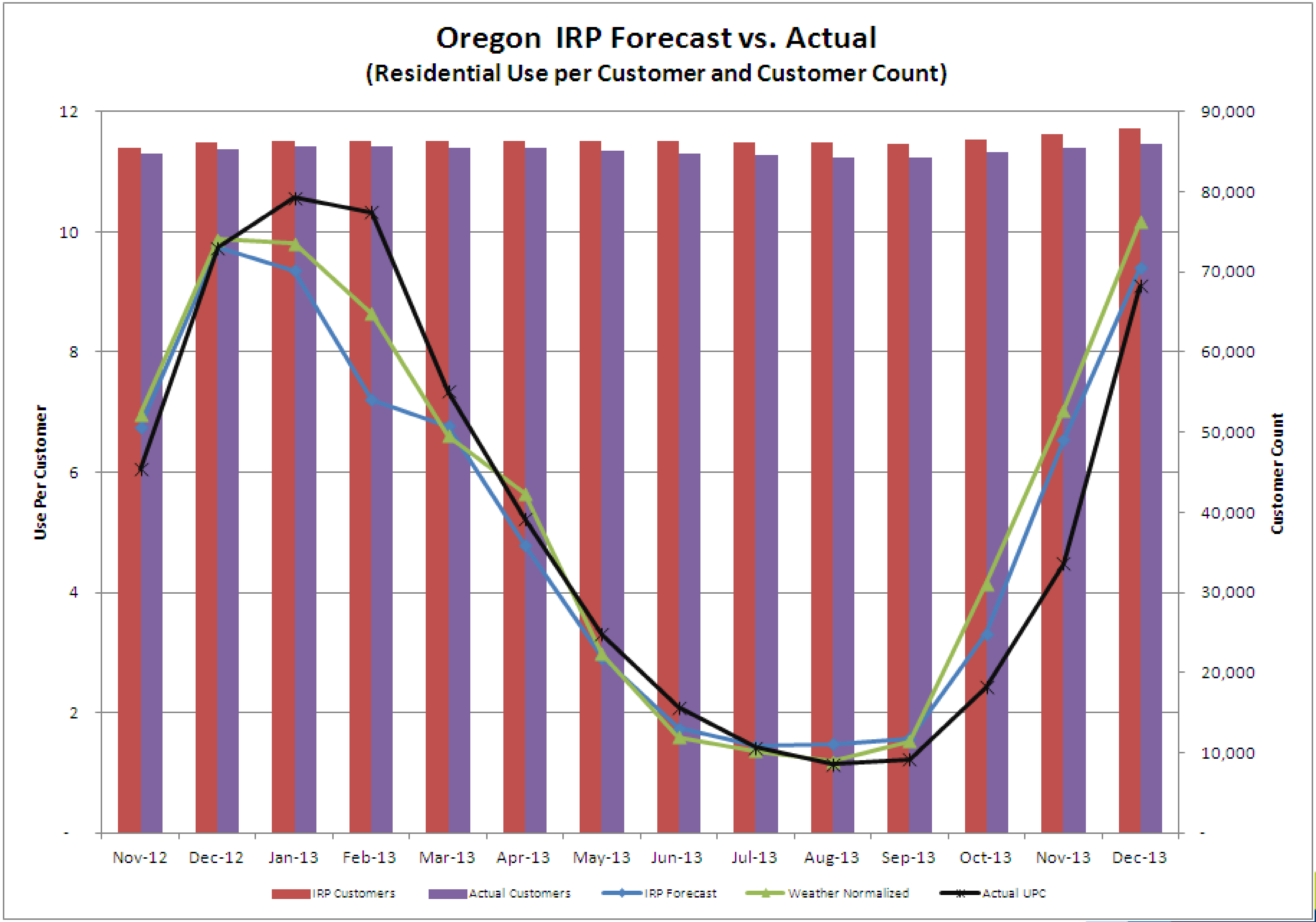


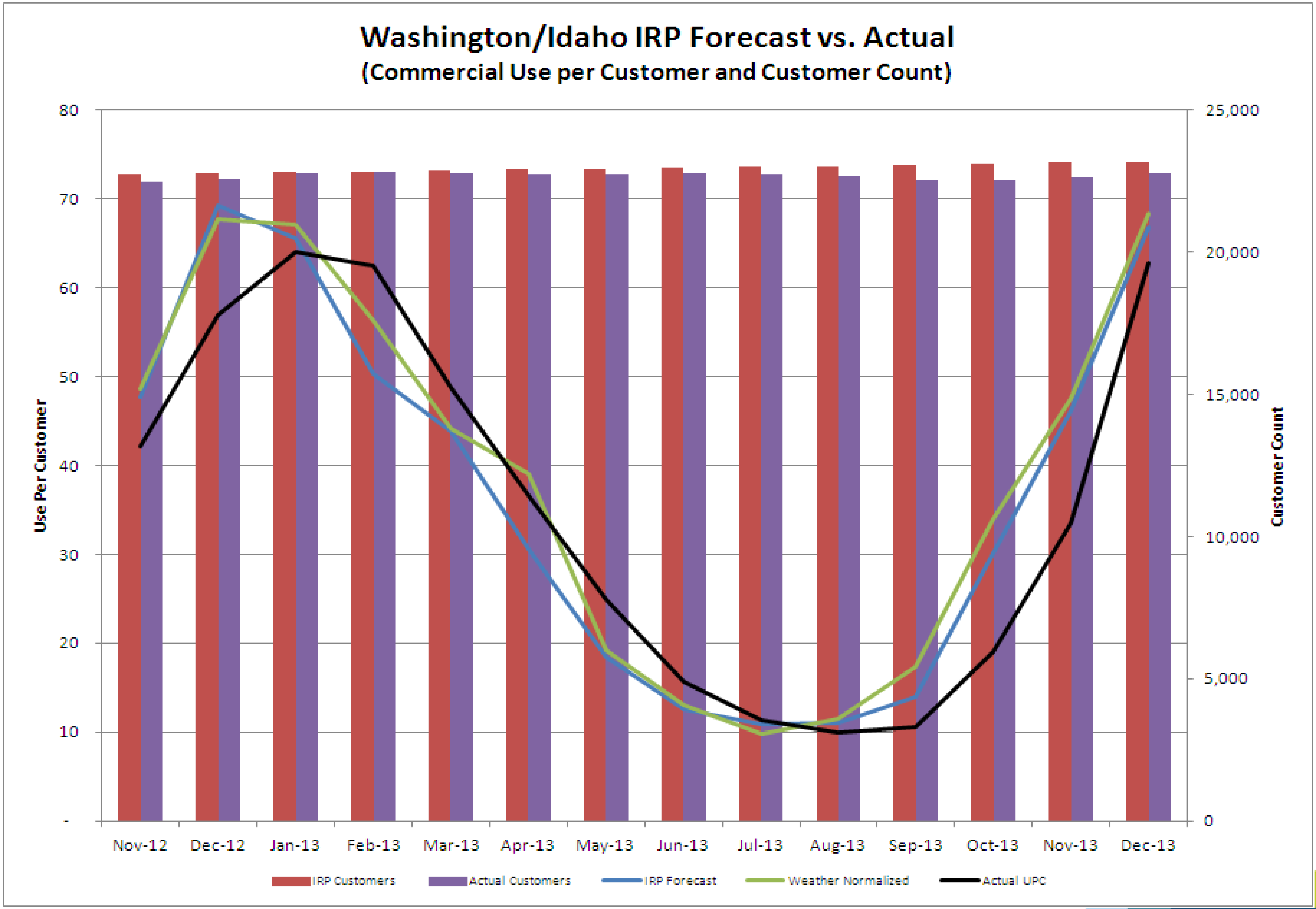




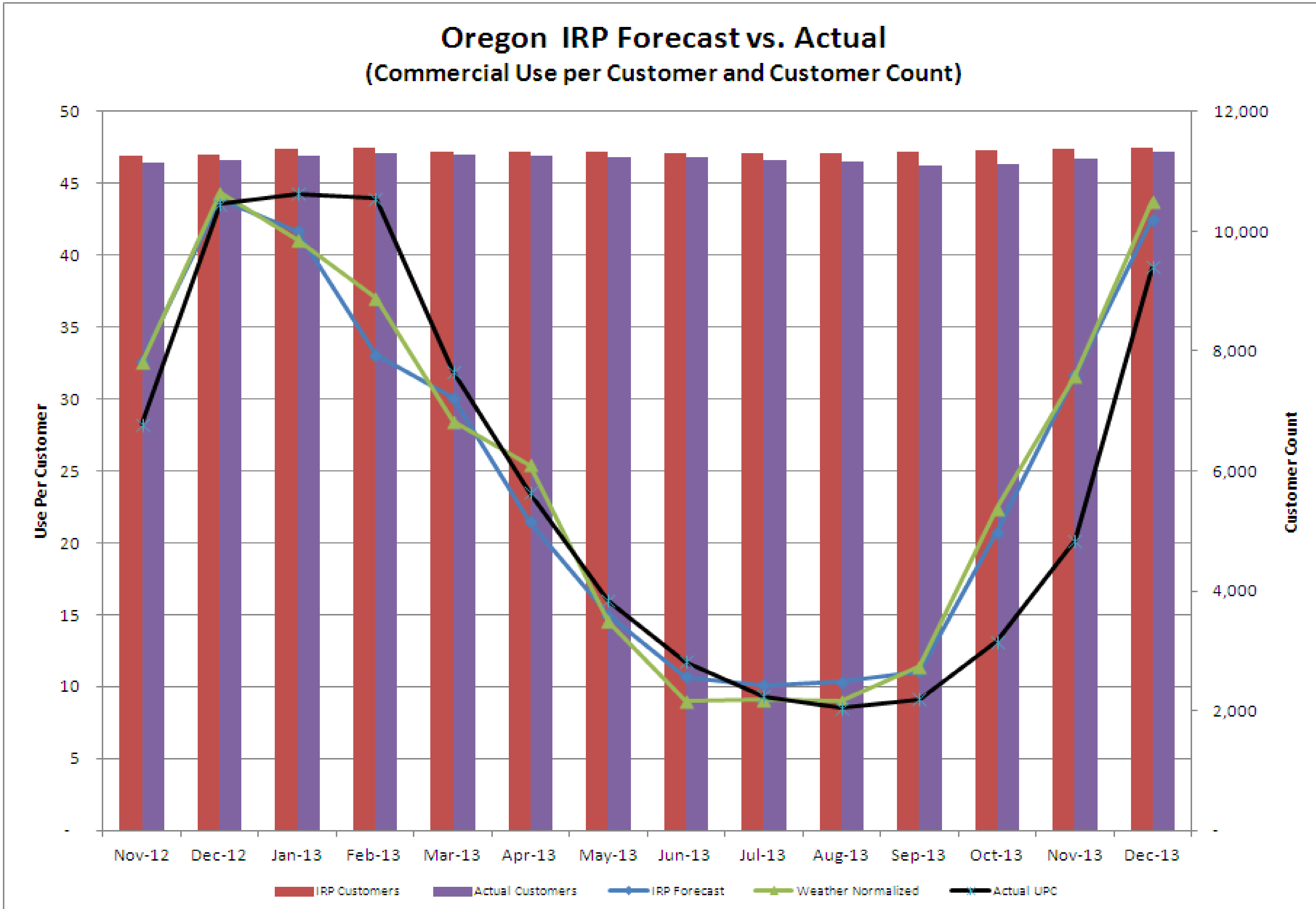
Avista's 2012 Natural Gas IRP Re-Visited


Washington/Idaho IRP Forecast vs. Actual
(Residential Use per Customer and Customer Count)
Use Per Customer
Customer Count
14
12
10
8
6
4
2
-
210,000
180,000
150,000
120,000
90,000
60,000
30,000
0
Nov-12
Dec-12
Jan-13
Feb-13
Mar-13
Apr-13
May-13
Jun-13
Jul-13
Aug-13
Sep-13
Oct-13
Nov-13
Dec-13
IRP Customers
Actual Customers
IRP Forecast
Weather Normalized
Actual UPC

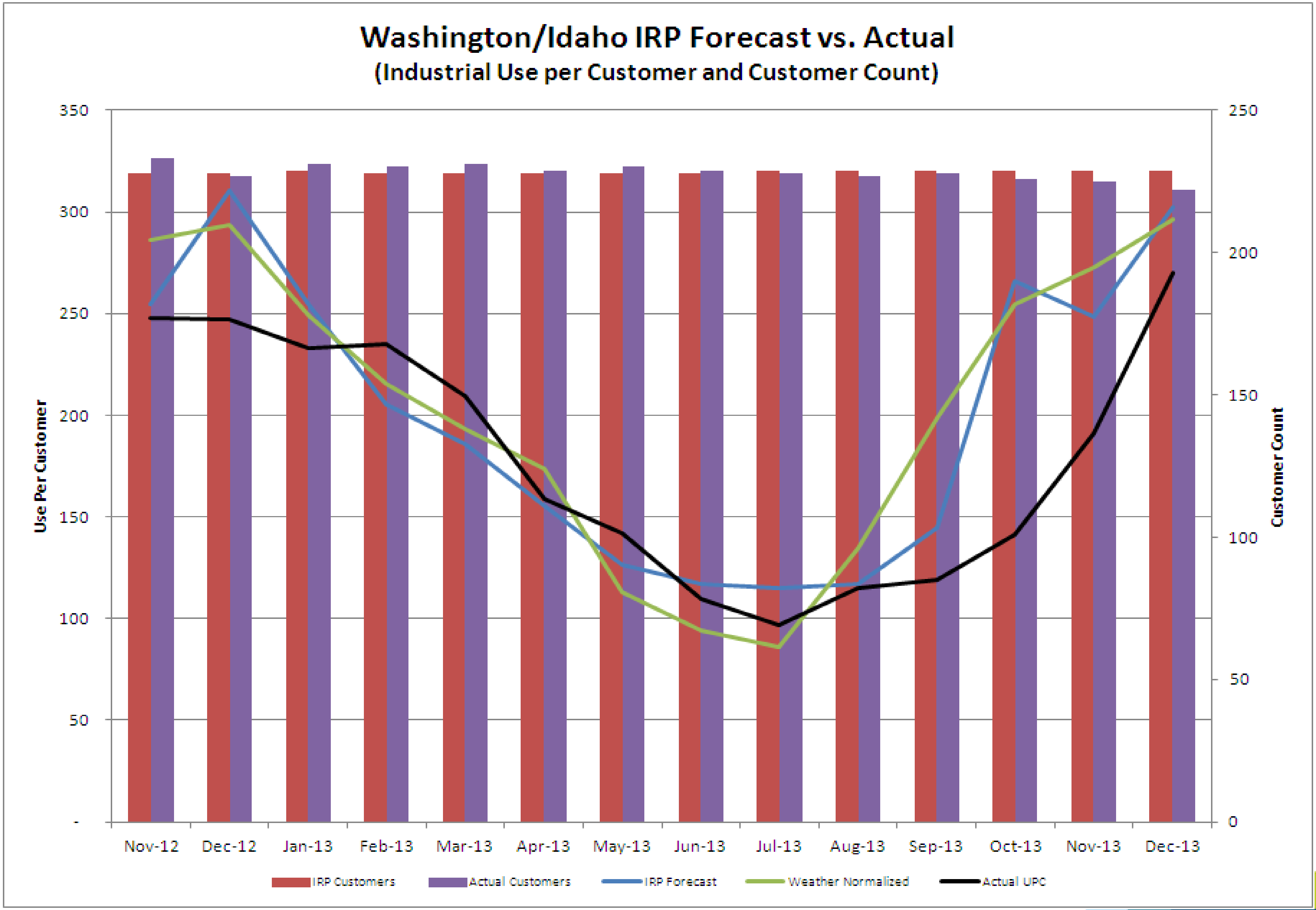

Oregon IRP Forecast vs. Actual
(Residential Use per Customer and Customer Count)
Use Per Customer
Customer Count
12
10
8
6
4
2
-
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
Nov-12
Dec-12
Jan-13
Feb-13
Mar-13
Apr-13
May-13
Jun-13
Jul-13
Aug-13
Sep-13
Oct-13
Nov-13
Dec-13
IRP Customers
Actual Customers
IRP Forecast
Weather Normalized
Actual UPC



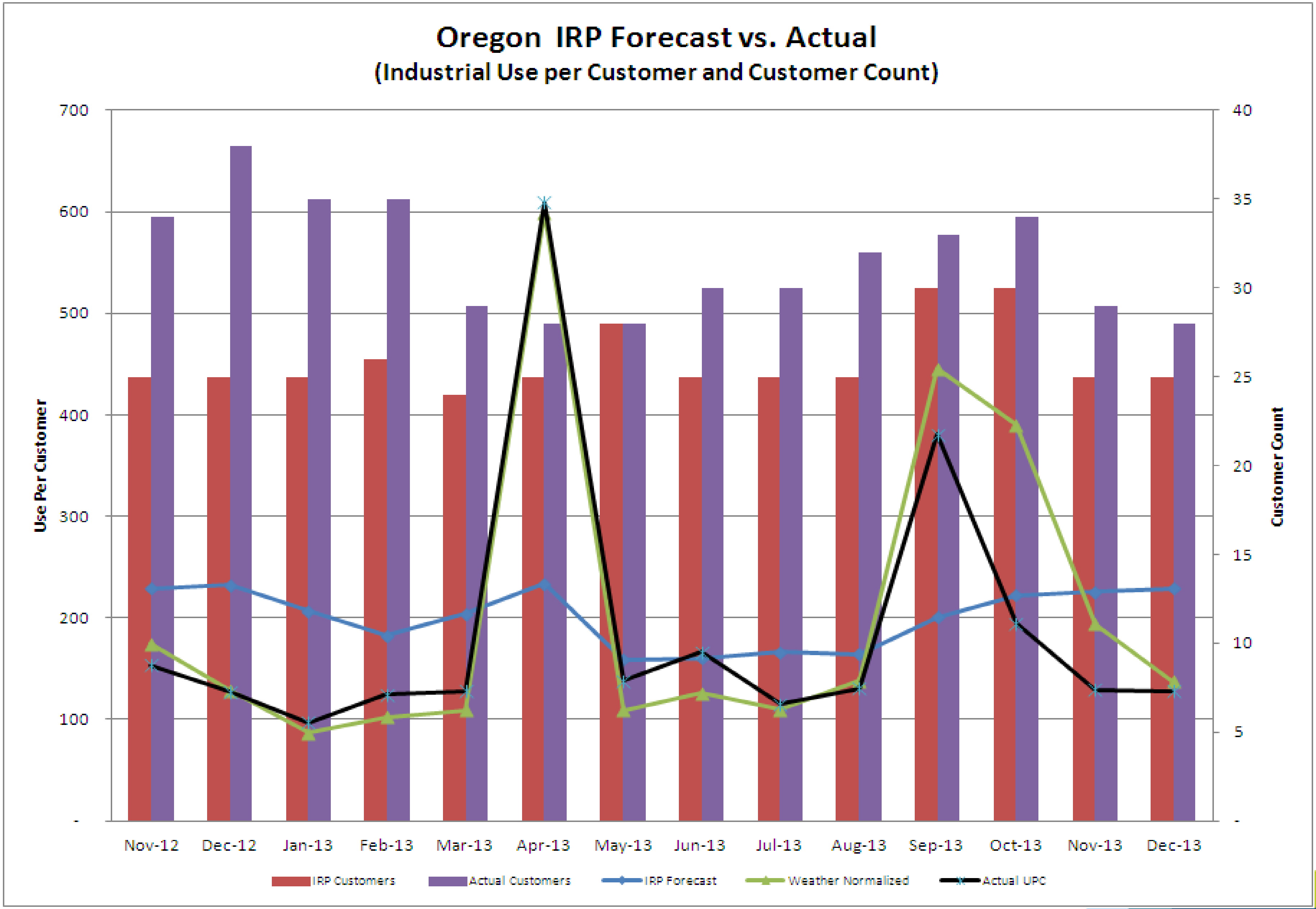
Washington/Idaho IRP Forecast vs. Actual
(Commercial Use per Customer and Customer Count)
Use Per Customer
Customer Count
80
70
60
50
40
30
20
10
-
25,000
20,000
15,000
10,000
5,000
0
Nov-12
Dec-12
Jan-13
Feb-13
Mar-13
Apr-13
May-13
Jun-13
Jul-13
Aug-13
Sep-13
Oct-13
Nov-13
Dec-13
IRP Customers
Actual Customers
IRP Forecast
Weather Normalized
Actual UPC



Oregon IRP Forecast vs. Actual
(Commercial Use per Customer and Customer Count)
Use Per Customer
Customer Count
50
45
40
35
30
25
20
15
10
5
-
12,000
10,000
8,000
6,000
4,000
2,000
-
Nov-12
Dec-12
Jan-13
Feb-13
Mar-13
Apr-13
May-13
Jun-13
Jul-13
Aug-13
Sep-13
Oct-13
Nov-13
Dec-13
IRP Customers
Actual Customers
IRP Forecast
Weather Normalized
Actual UPC



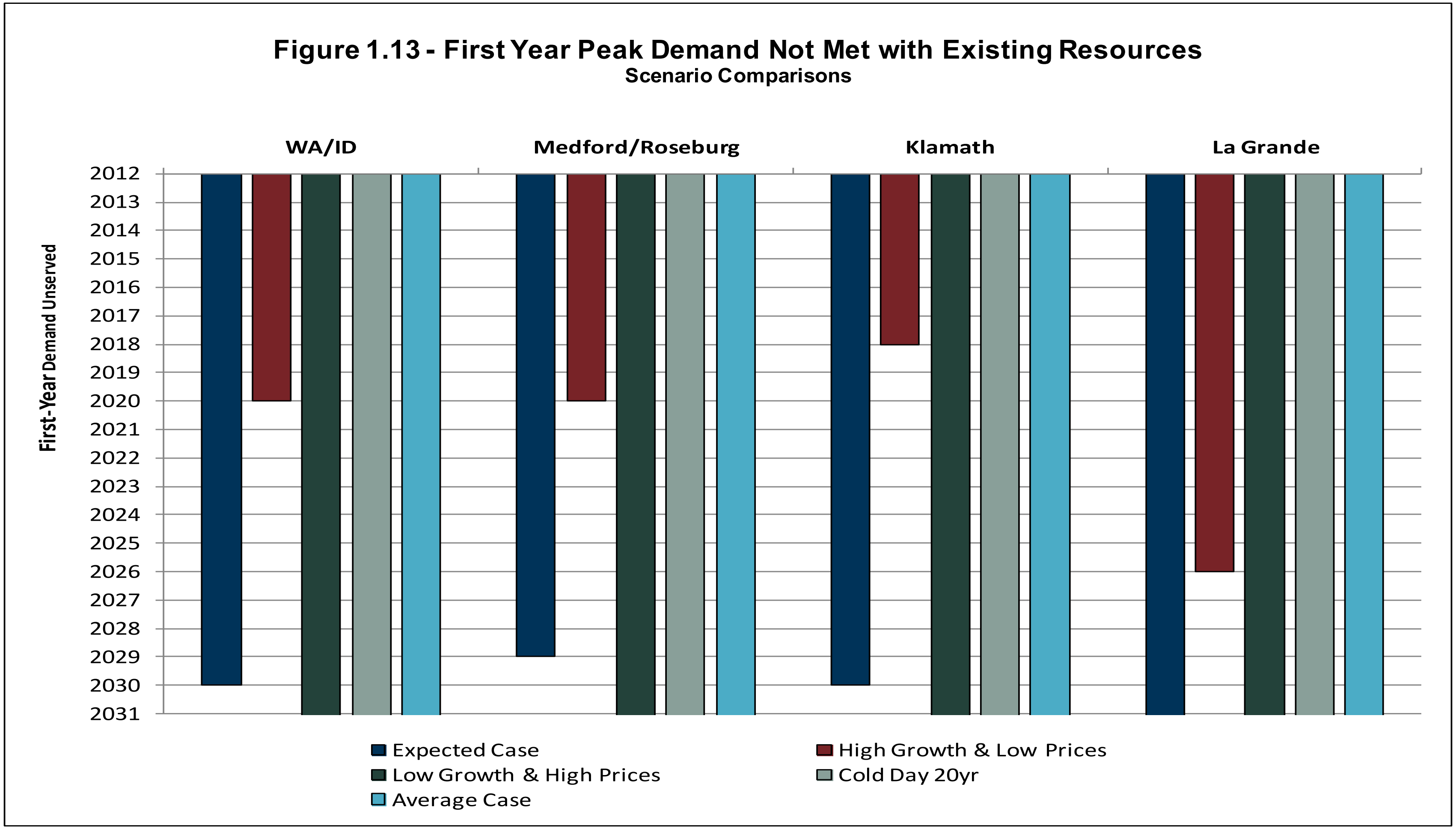
Washington/Idaho IRP Forecast vs. Actual
(Industrial Use per Customer and Customer Count)
350
300
250
200
150
100
50
-
Use Per Customer
250
200
150
100
50
0
Customer Count
Nov-12
Dec-12
Jan-13
Feb-13
Mar-13
Apr-13
May-13
Jun-13
Jul-13
Aug-13
Sep-13
Oct-13
Nov-13
Dec-13
IRP Customers
Actual Customers
IRP Forecast
Weather Normalized
Actual UPC



Oregon IRP Forecast vs. Actual
(Industrial Use per Customer and Customer Count)
Use Per Customer
Customer Count
700
600
500
400
300
200
100
-
40
35
30
25
20
15
10
5
-
Nov-12
Dec-12
Jan-13
Feb-13
Mar-13
Apr-13
May-13
Jun-13
Jul-13
Aug-13
Sep-13
Oct-13
Nov-13
Dec-13
IRP Customers
Actual Customers
IRP Forecast
Weather Normalized
Actual UPC

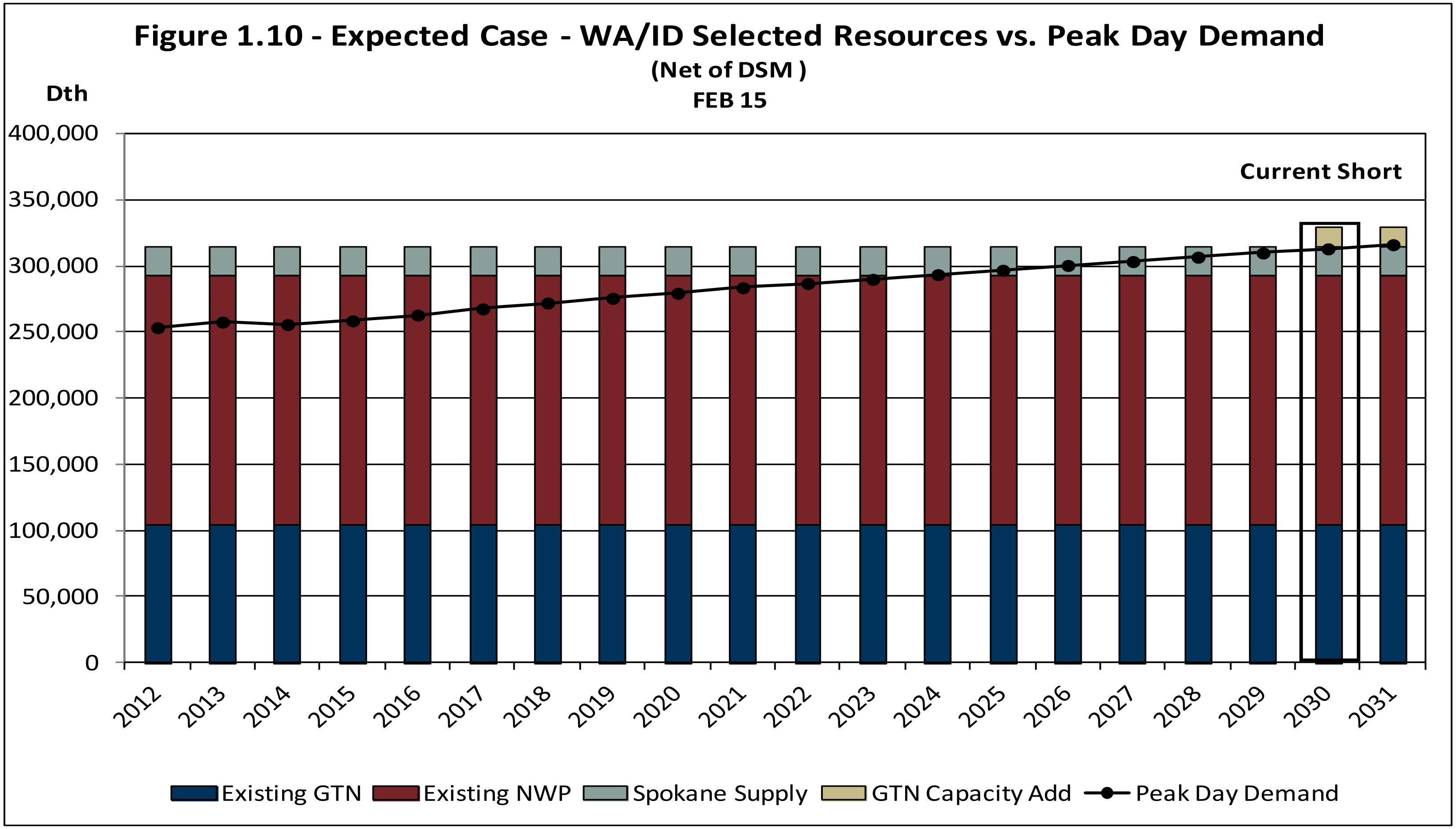
Year First Unserved

Scenario Comparisons



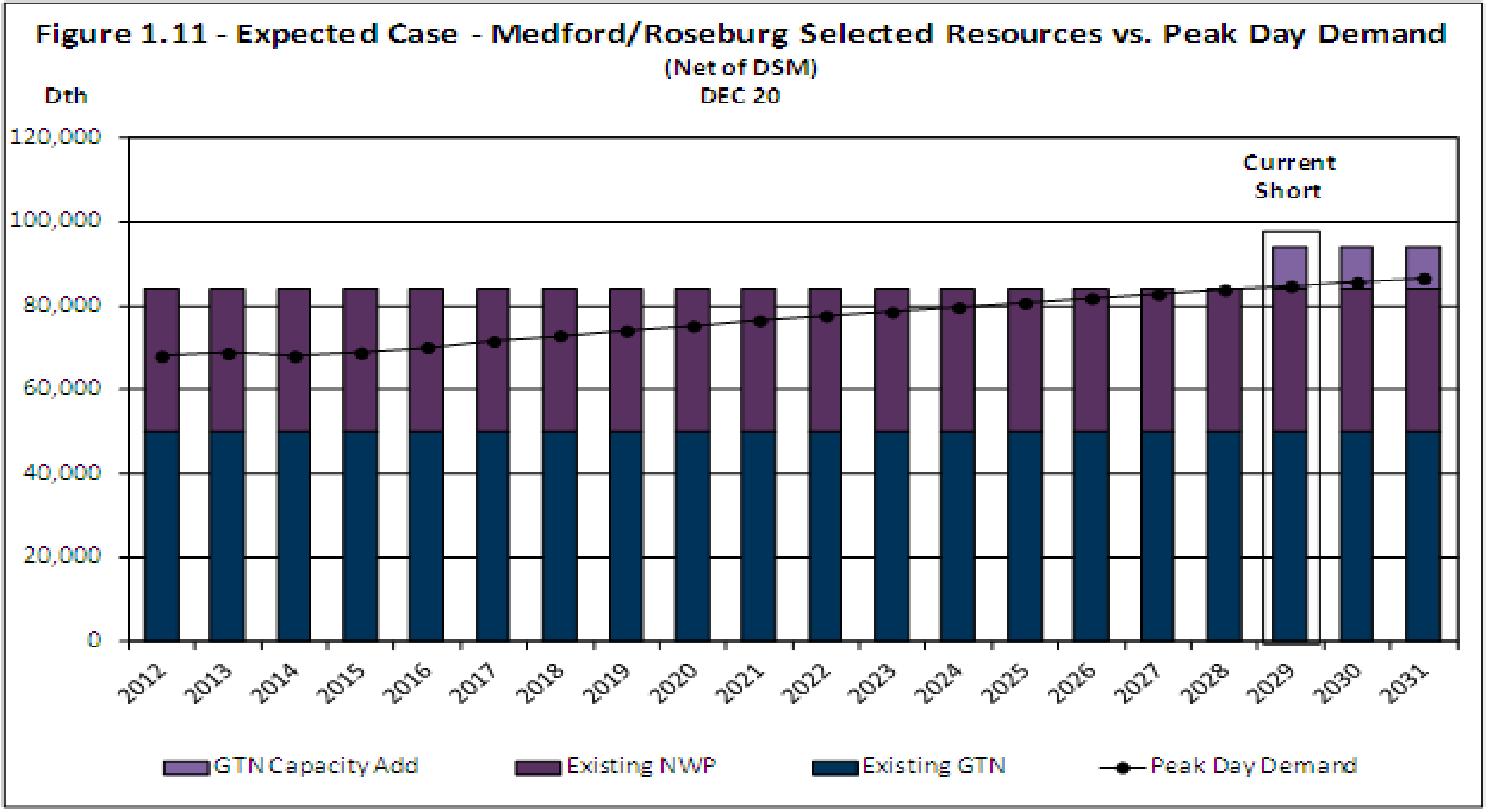
Best Cost/Risk Resources

Expected Case – WA/ID



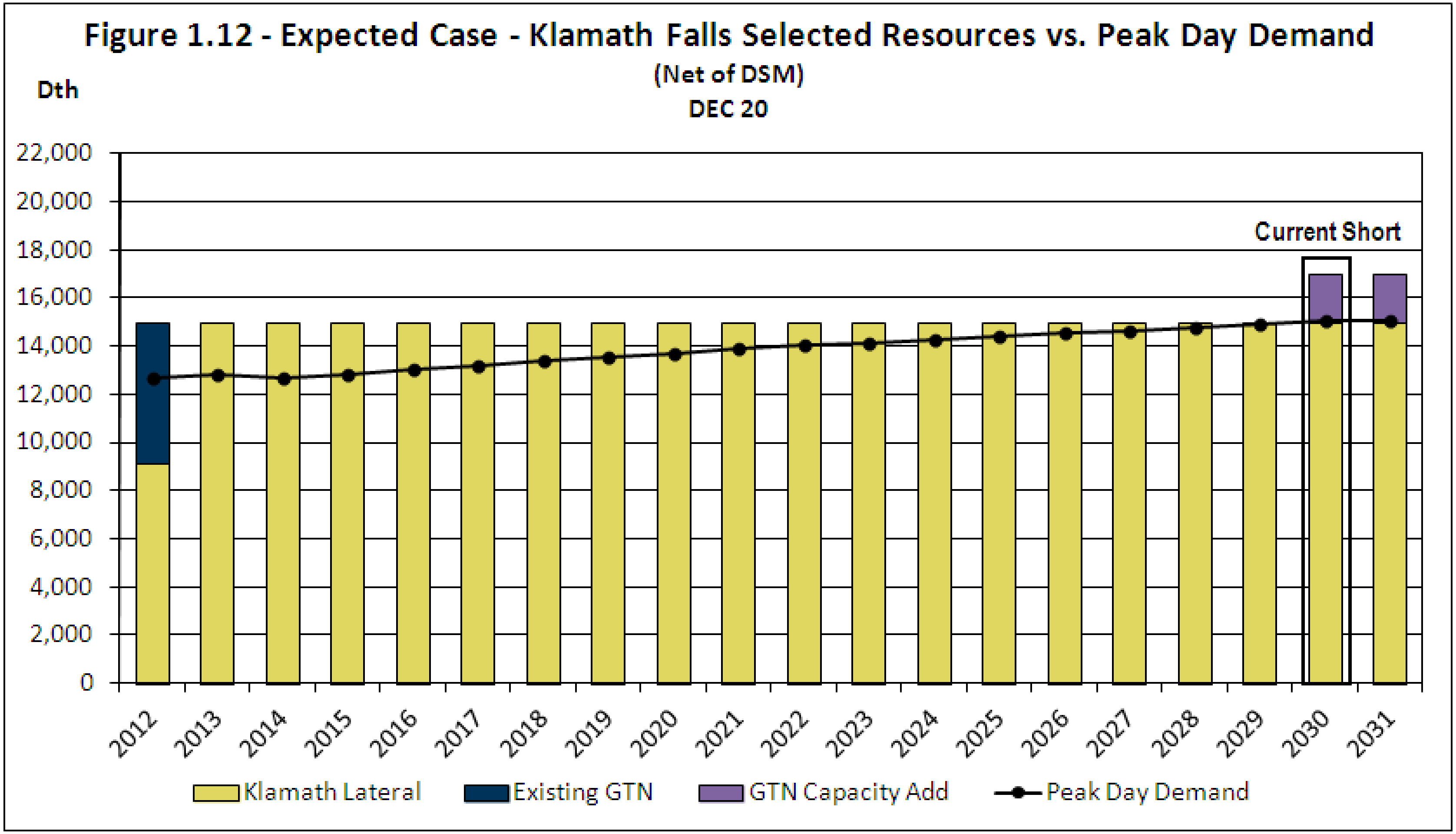
Best Cost/Risk Resources

Expected Case – Medford/Roseburg

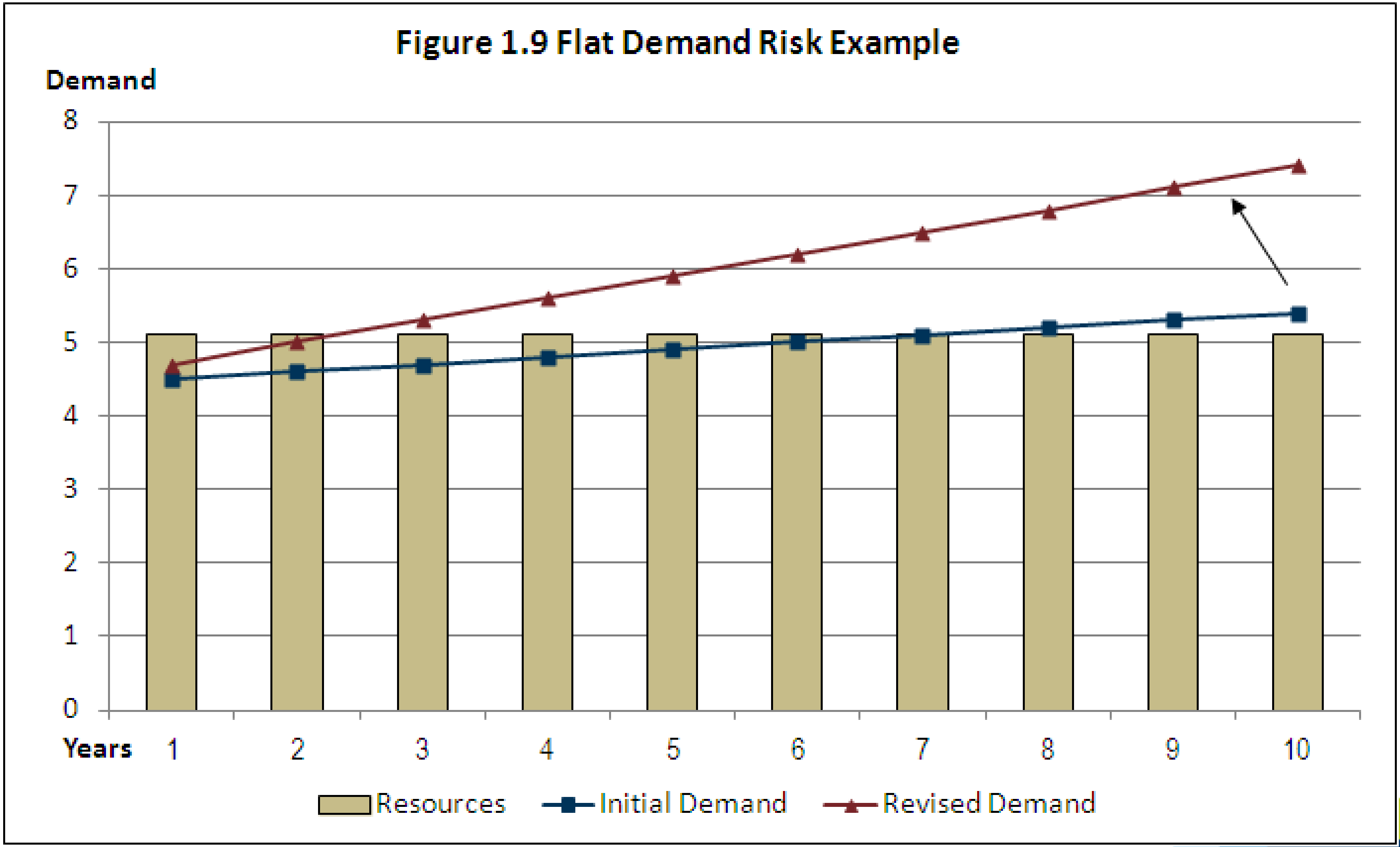


Best Cost/Risk Resources

Expected Case – Klamath Falls



Our Biggest Risk Last IRP
"Flat Demand" Risk



December 8, 2013 Cold Weather Stats

Area	Actual HDD	Peak HDD	Actual Demand (Dth/d)	Forecasted Peak Demand (Dth/d)
Klamath Falls	72	72	12,656	12,830
LaGrande	65	74	6,709	7,310
Medford	52	61	48,060	53,120
Roseburg	44	55	13,058	13,930
Washington/Idaho	57	82	218,178	257,650

Note: Klamath Falls and Medford set record high loads. LaGrande and Roseburg had second highest demand days.

Near Term Action Items

- Demand trend monitoring
- Demand side management cost effectiveness and targets
- Gate station analysis

On-going Action Items

- Price elasticity study inquiry
- NGV/CNG and other demand potential
- Supply side resource trends/availability
- Meet regularly with Commission Staff

Economic Outlook and Customer Forecast Development

Grant D. Forsyth, Ph.D.
Chief Economist
Grant.Forsyth@avistacorp.com

Load Forecasts-Two Step Process

- First, forecast customers (C) by month by schedule (s) by residential (r), commercial (c), industrial (i)—for example, $C_{t,y,s.r}$
- Forecast use per customer (U) by month by schedule by class—for example, $U_{t,y,s.r}$
- Load forecast (L) is the product of the two:

$$L_{t,y,s.r} = \boxed{C_{t,y,s.r}} \times U_{t,y,s.r}$$

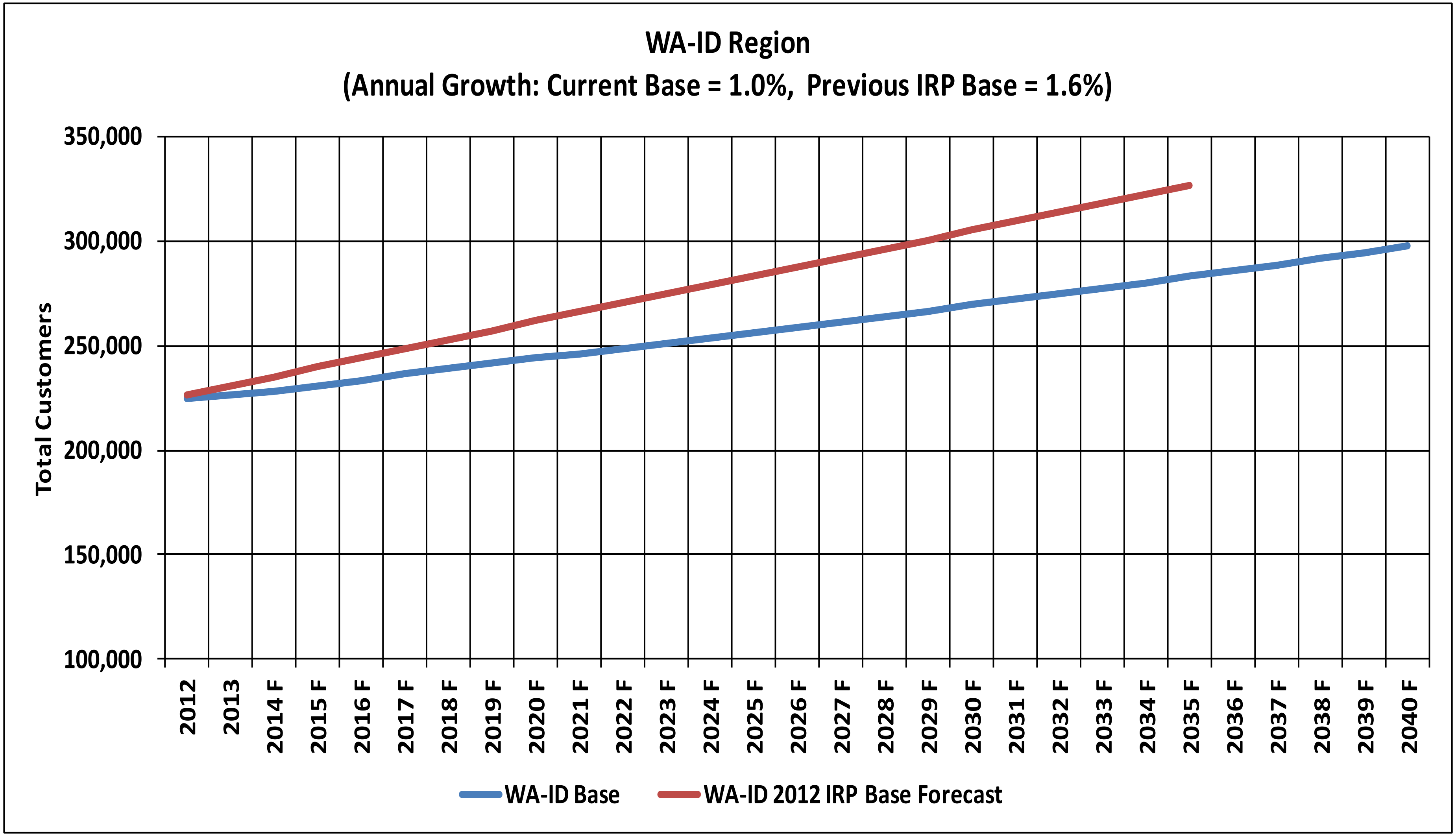
For non-IRP years, forecast is run out 5-yrs.

For weather sensitive schedules a 20-yr MA defines normal weather.

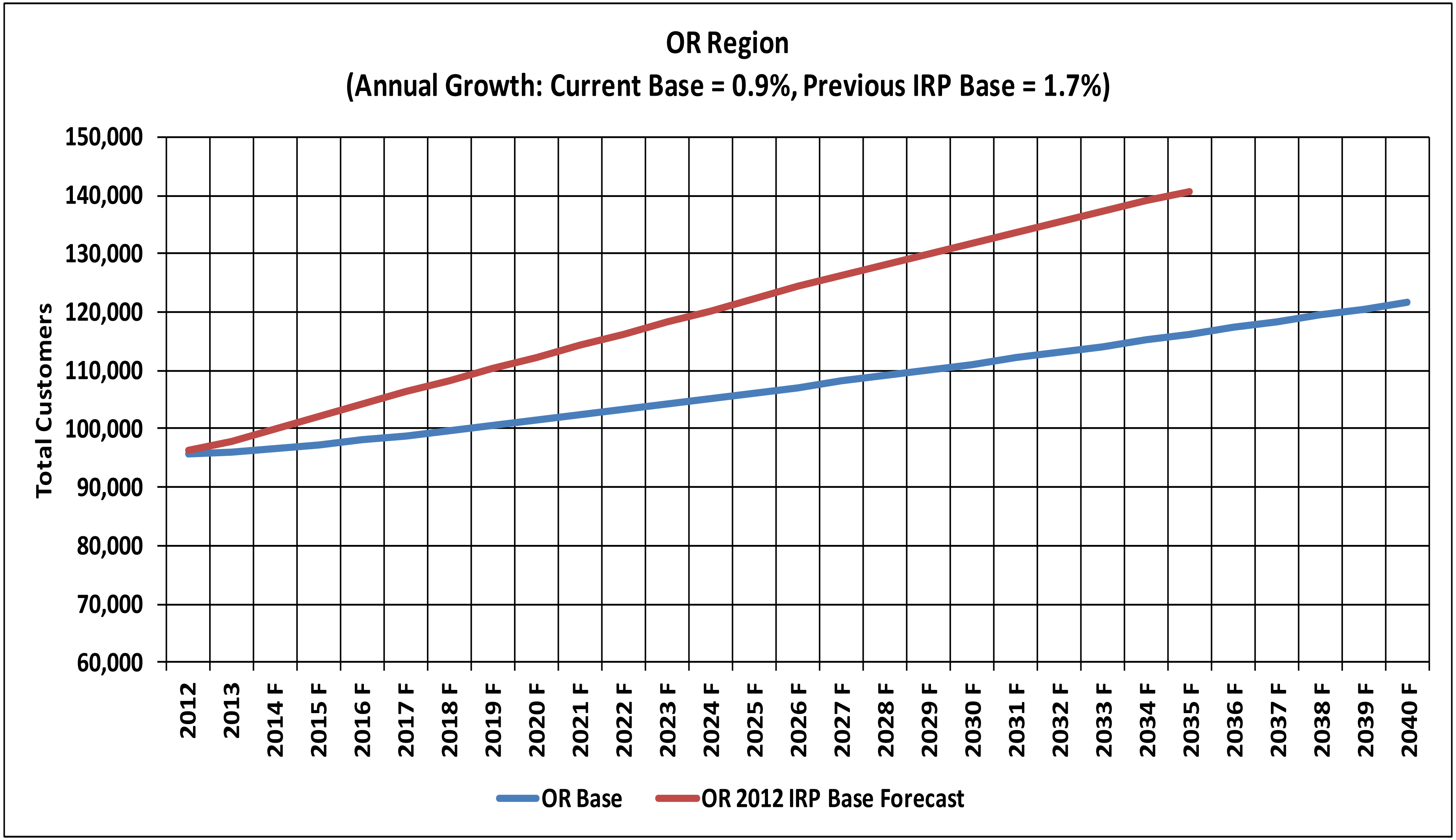
Forecast Method—Methodology Change

- 5-year out forecasts: ARIMA based models with economic drivers and traditional smoothing models.
- For IRP years, will push out 5-year forecasts based on longer-run growth assumptions and historical relationships.
- SAS/ETS software.
- Also consider external analysis such as the University of Oregon's Regional Economic Indexes. Framing forecast in a broader economic context.
- Model building is dynamic and model improvements/changes constant.
- Forecast is lower than last IRP…Why?

WA-ID Region: 2014 IRP and 2012 IRP



OR Region: 2014 IRP and 2012 IRP



The Relationship Between Classes

Residential customer growth is approximately equal to population growth in the long-run.

Commercial customer growth is highly correlated with and approximately equal to residential growth in the long-run.

Year-over-year Growth, Gas Correlations by Class, Jan. 2006-May 2013

Customers	Residential	Commercial	Industrial		Load	Residential	Commercial	Industrial
Residential	1.00				**Residential**	1.00		
Commercial	**0.83**	1.00			**Commercial**	**0.94**	1.00	
Industrial	**-0.44**	**-0.35**	1.00		**Industrial**	**0.33**	**0.34**	1.00

Industrial's correlation to residential is lower and negative. Customer numbers stable or slightly declining.

(1) Estimate with historical data: $C_{t,y,WA101.r} = \alpha_0 + \boldsymbol{\omega_{SD}D_{t,y}} + ARIMA\epsilon_{t,y}(10,1,0)(0,0,0)_{12}$

(2) 5-yr forecasts of $C_{t,y,WA101.r}$ adjusted (post-forecast) for forecasted population growth to get $C^*_{t,y,WA101.r}$

(3) Estimate with historical data: $C_{t,y,WA101.c} = \alpha_0 + \alpha_1 C_{t,y,WA101.r} + \boldsymbol{\omega_{SD}D_{t,y}} + ARIMA\epsilon_{t,y}(12,1,0)(0,0,0)_{12}$

(4) 5-yr forecasts of $C_{t,y,WA101.c}$ are generated by using $C^*_{t,y,WA101.r}$ in the estimate of (3).

Getting to Population as a Driver

Average GDP Growth Forecasts:

- IMF, FOMC, Bloomberg, etc.
- Average forecasts out 5-yrs.

GDP

Non-farm Employment Growth Model:

- Model links year y, y-1, and y-2 GDP growth to year y regional employment growth.
- Forecast out 5-yrs.

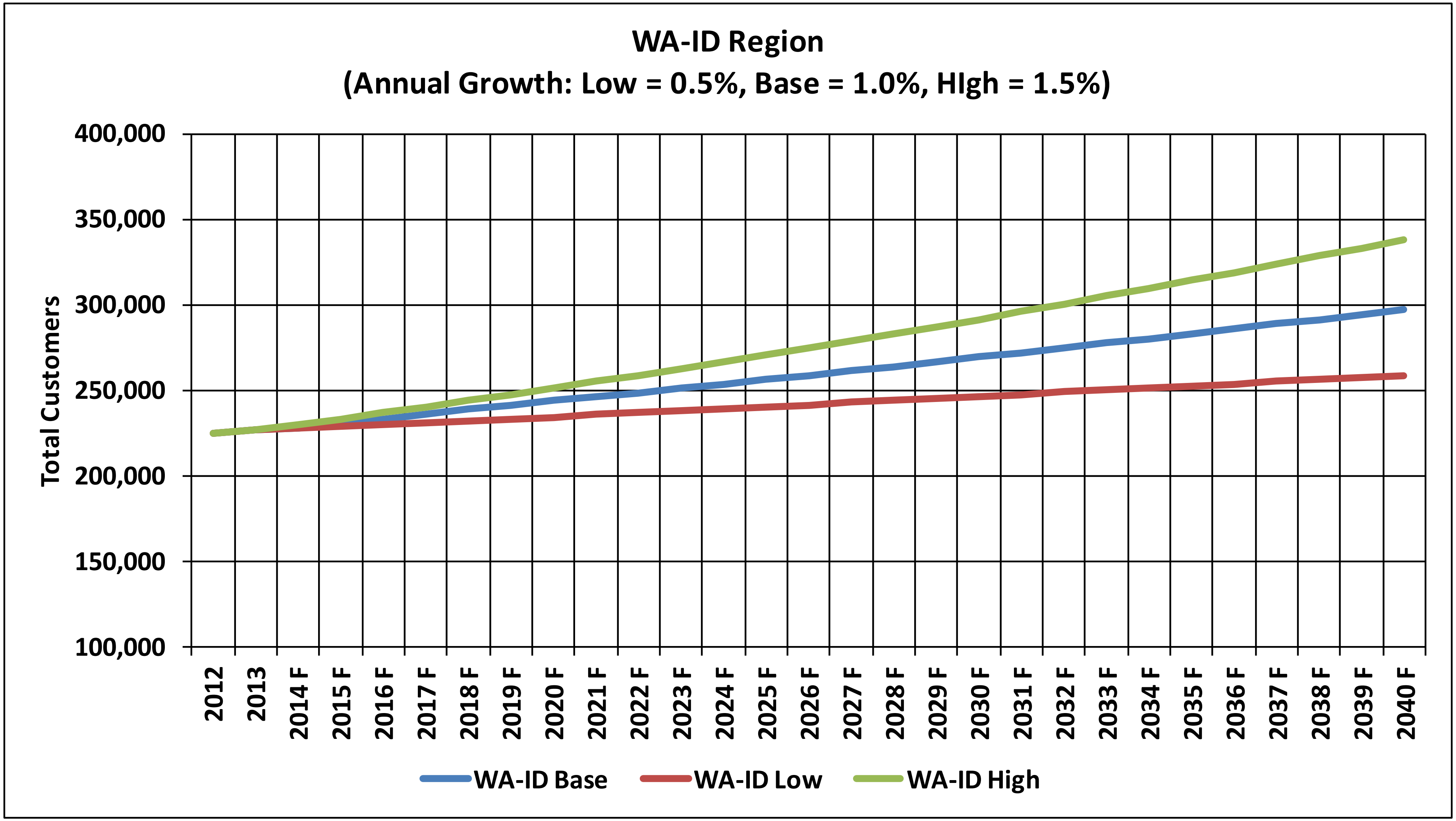
EMP

Regional Population Growth Models:

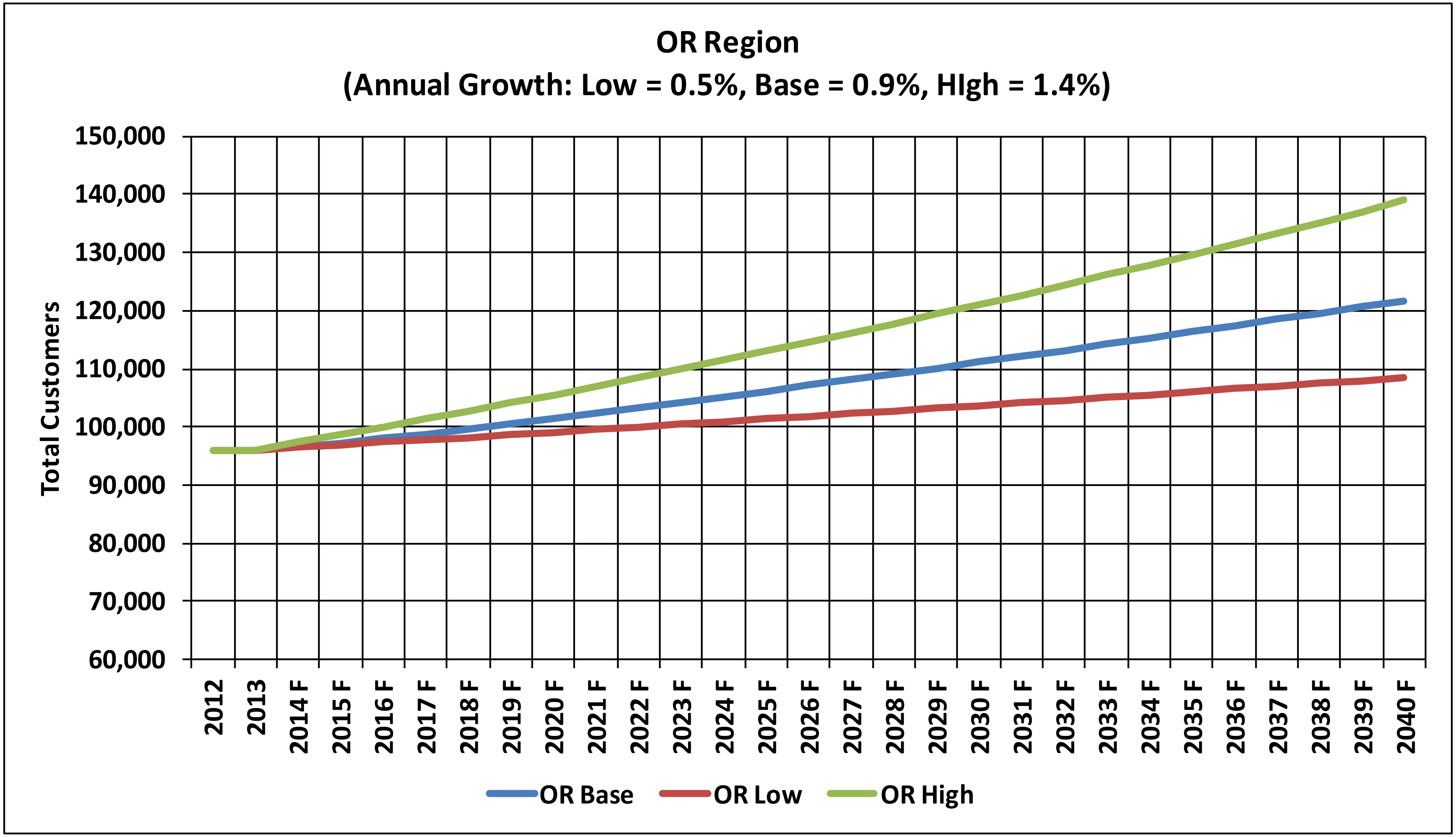
- Model links regional, U.S., and CA employment growth to regional population growth.
- Forecast out 5-yrs for Spokane, WA; Kootenai, ID; and Jackson, OR.
- Averaged with GI forecasts.
- Compare population forecasts to base customer forecasts for residential schedules 1, 101, and 410.
- Adjust base forecasts if large differences with base and population forecasts exist.

By assuming different long-run values for regional employment growth, we can obtain long-run residential and commercial customer growth rates for base, low, and high cases.

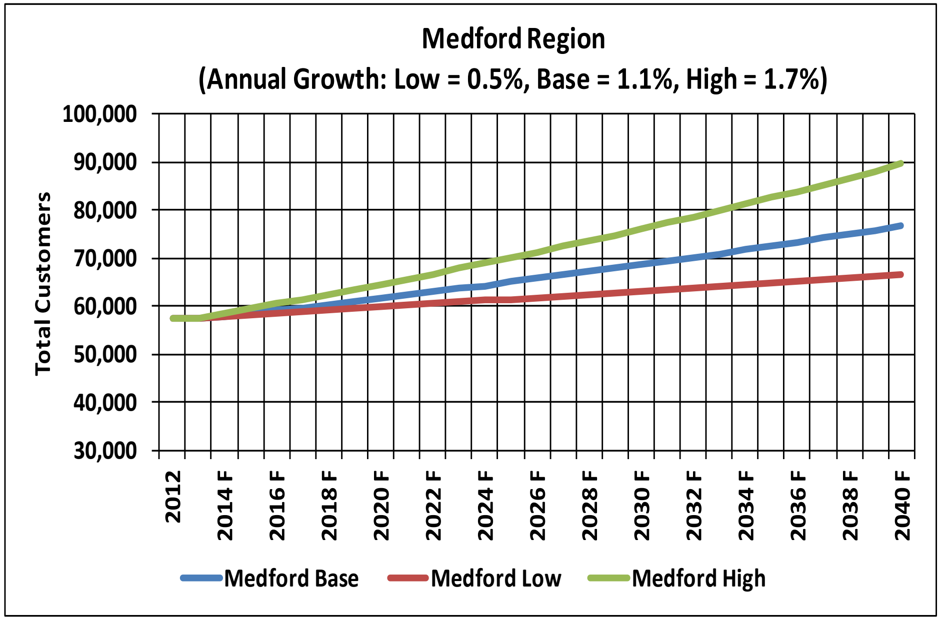
WA-ID Region, 2012-2040

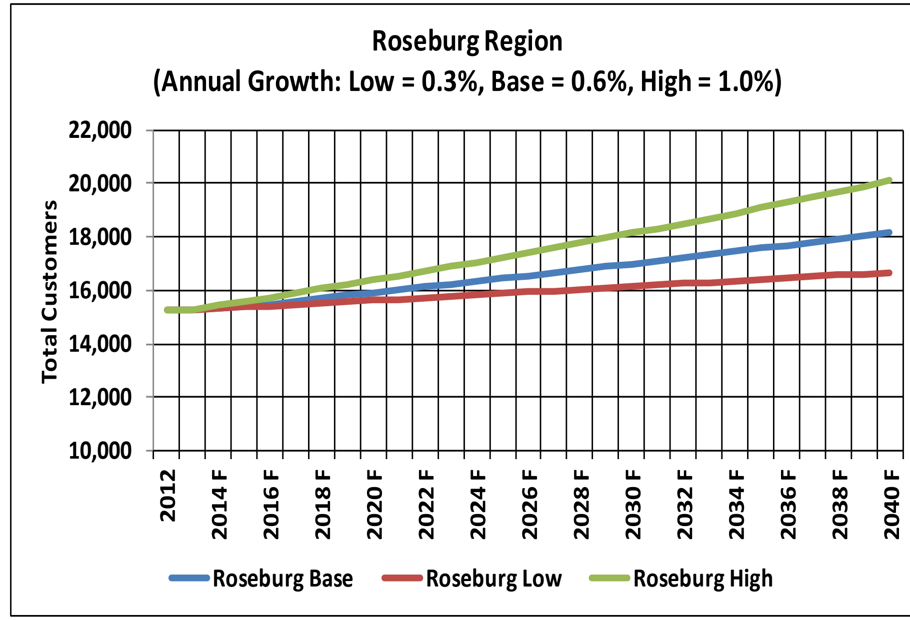


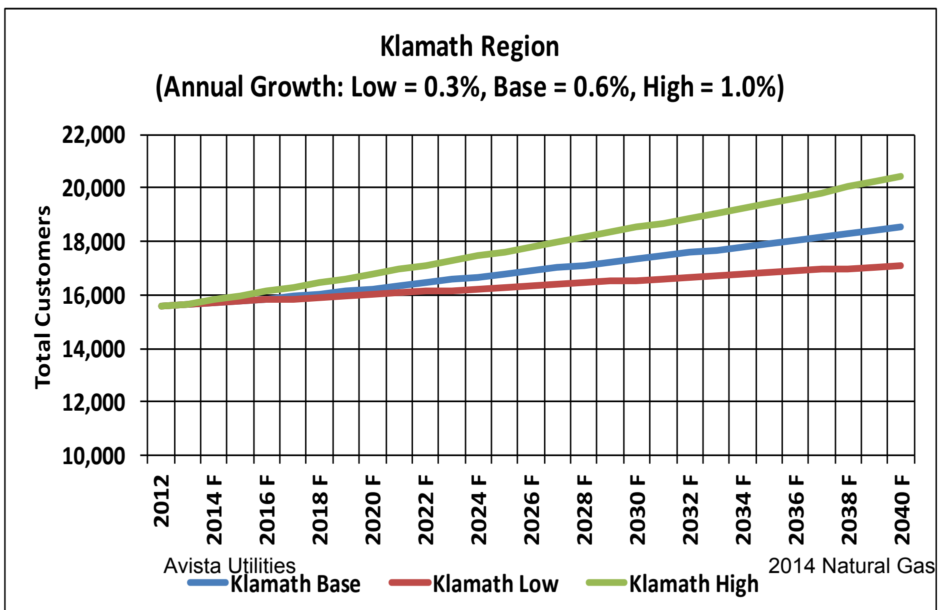
OR Region, 2012-2040

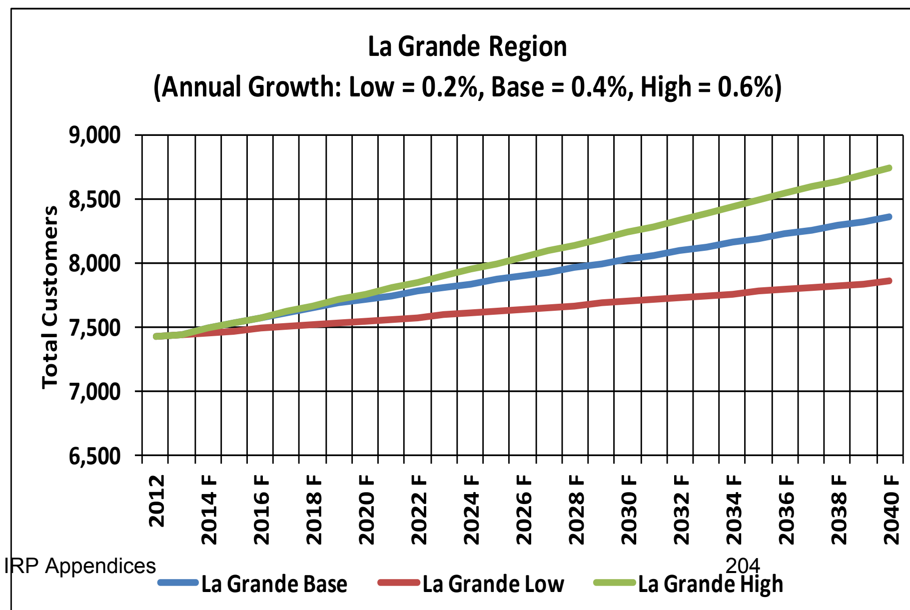


OR by Individual Region, 2012-2040







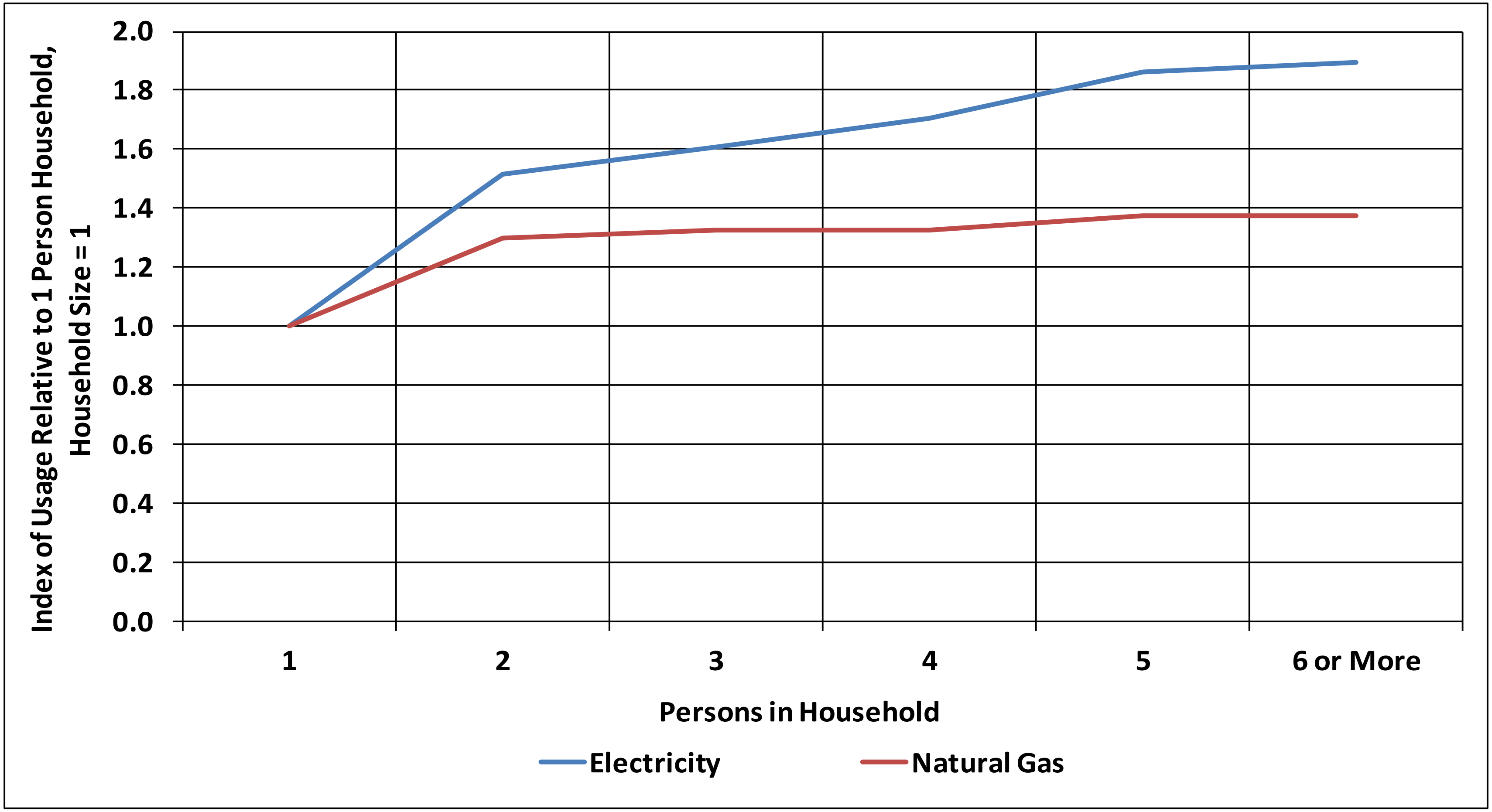


Future Modeling

- Attempt to integrate employment and/or population directly into the residential customer model.

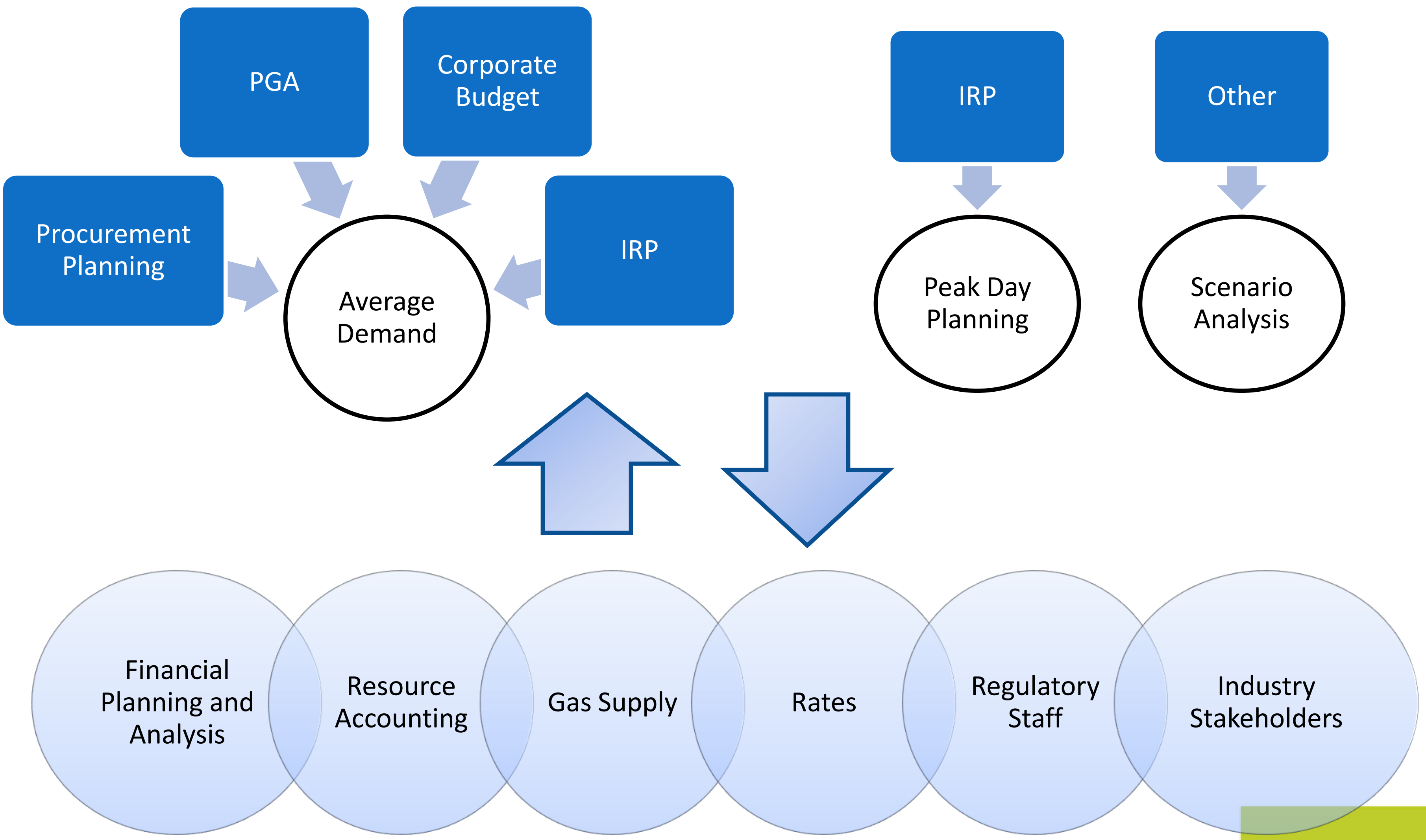
- Continue to explore the best way to model price, household income, and household size.

Example: West Household Size and Usage, 2009 RECS

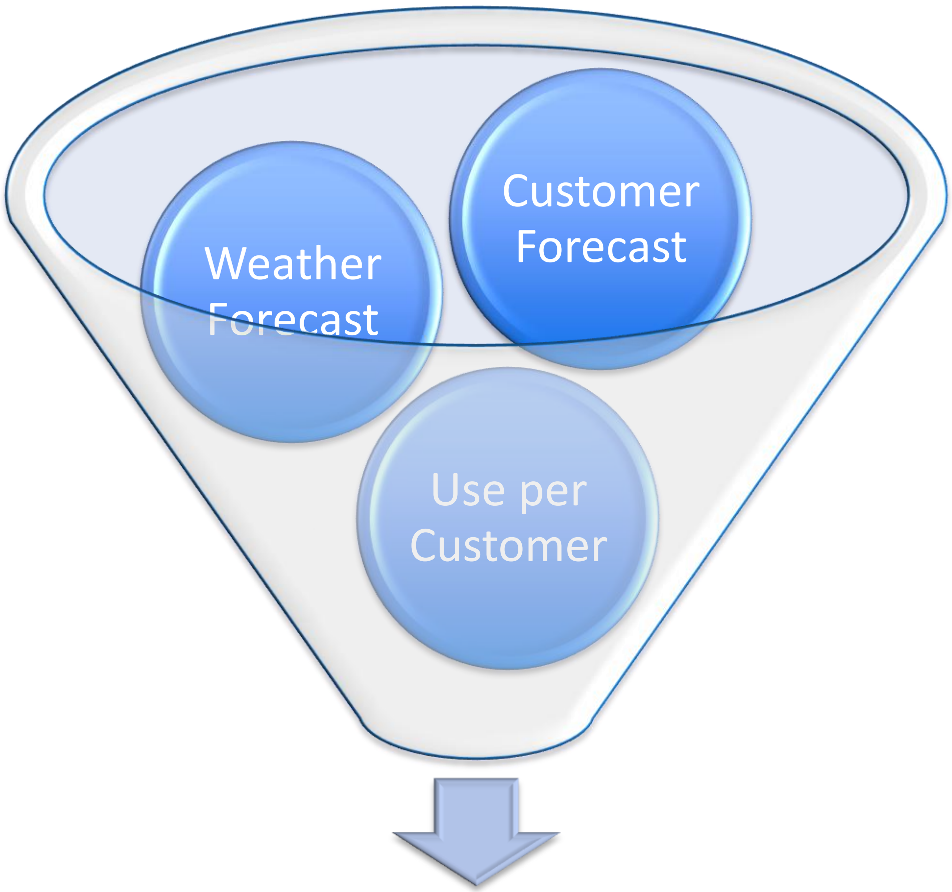


Demand Forecast Methodology

Natural Gas Demand Forecasting

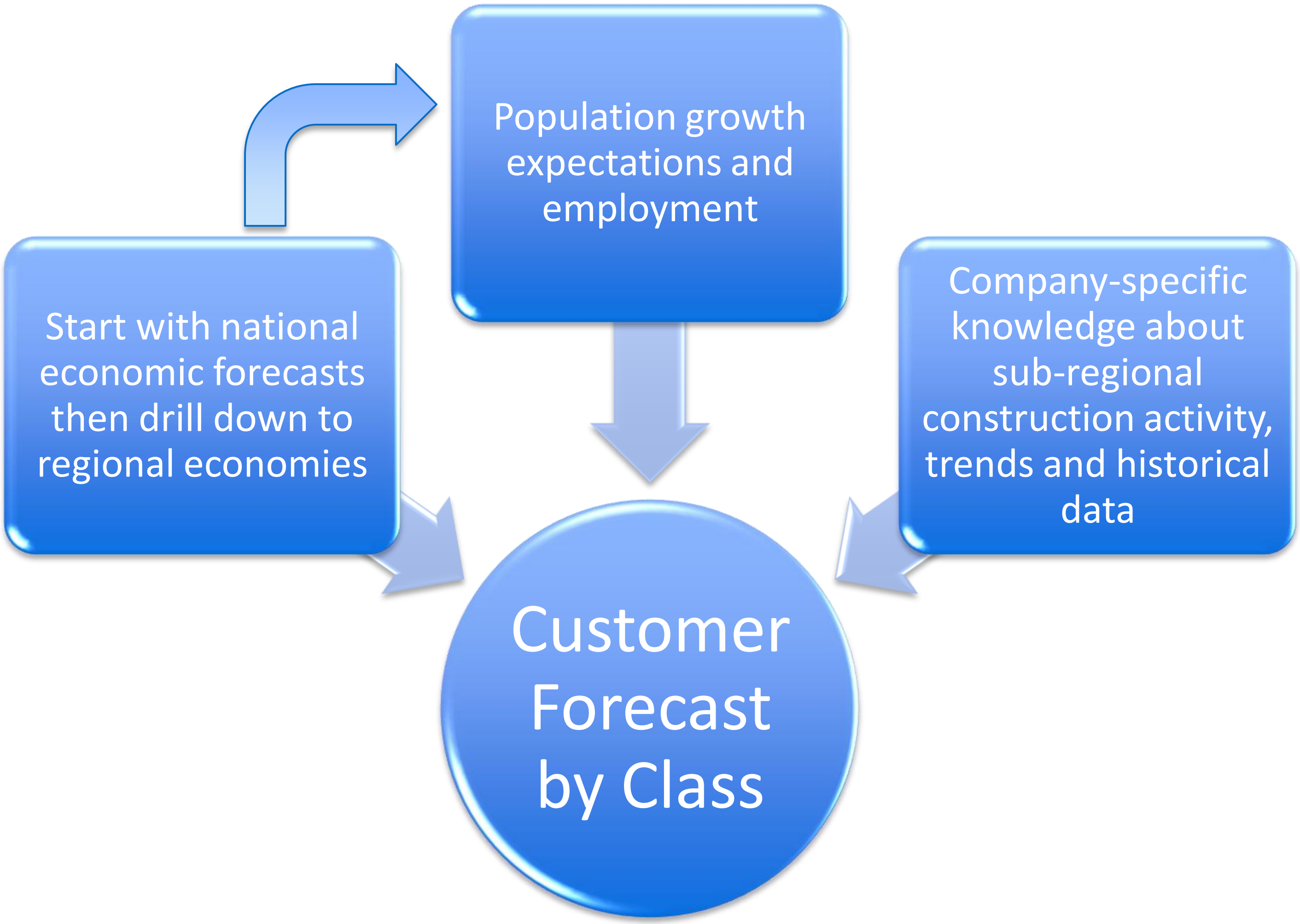


What goes into the Natural Gas Demand Forecast?

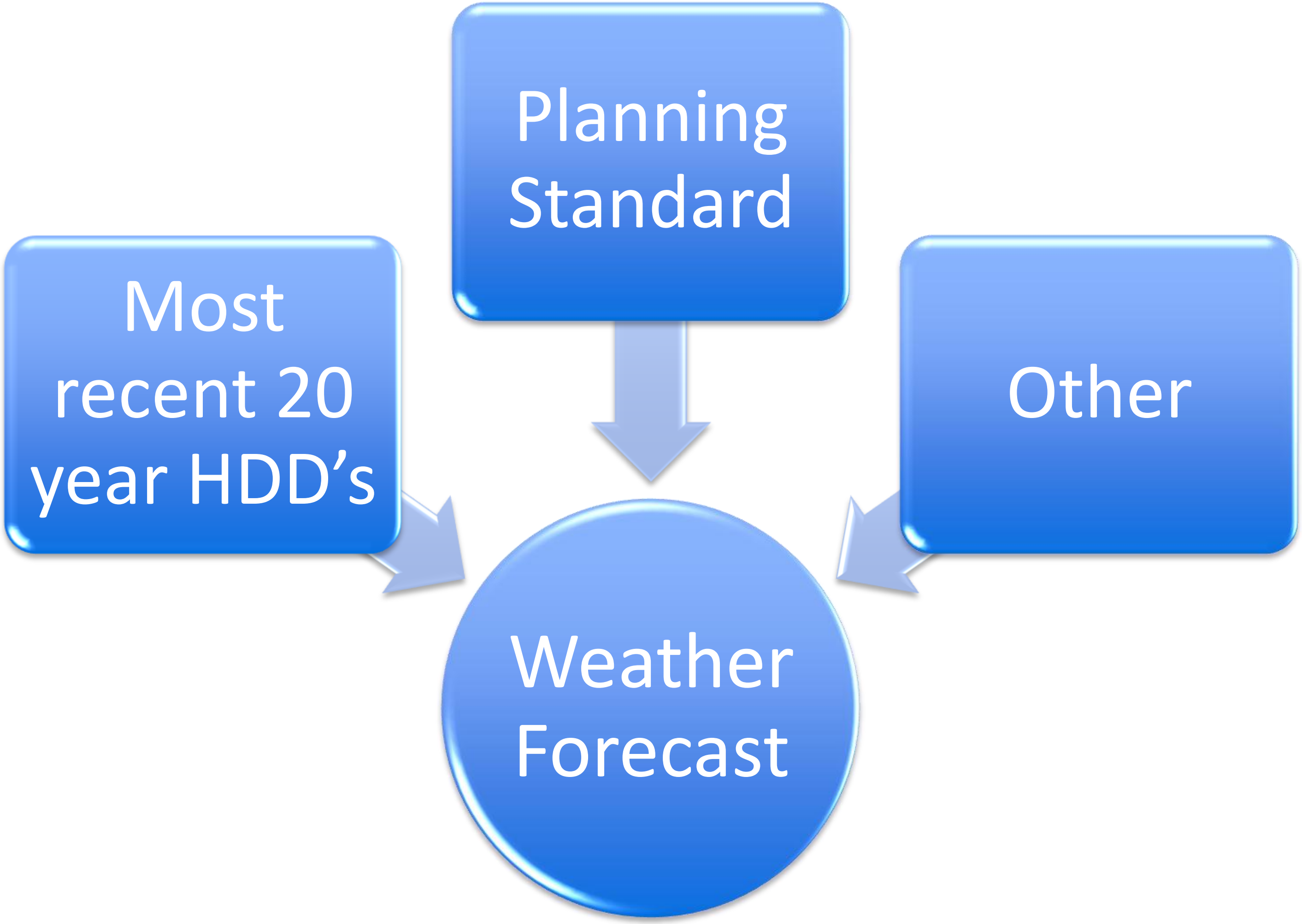


Natural Gas Demand Forecast

The Customer Forecast



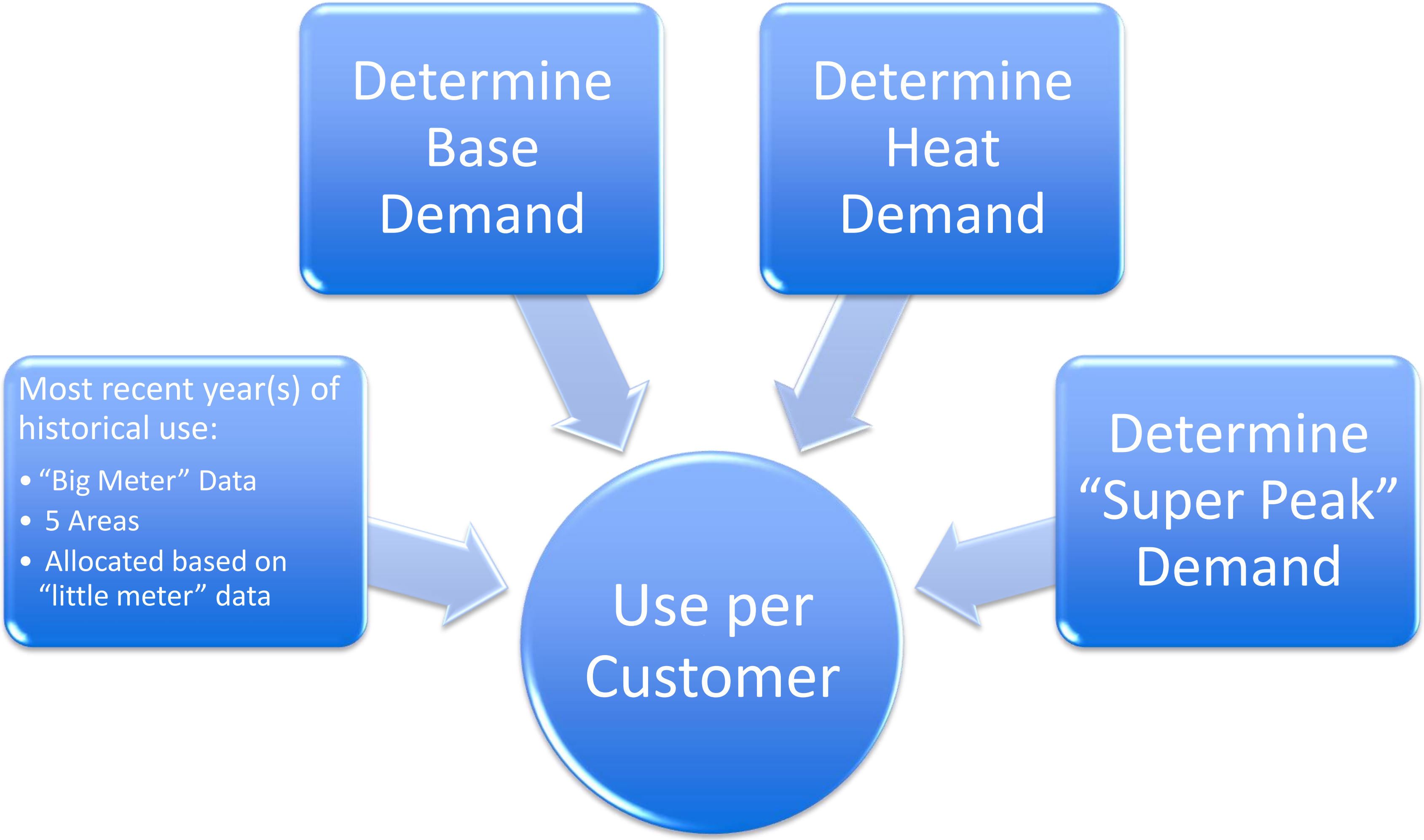
The Weather Forecast



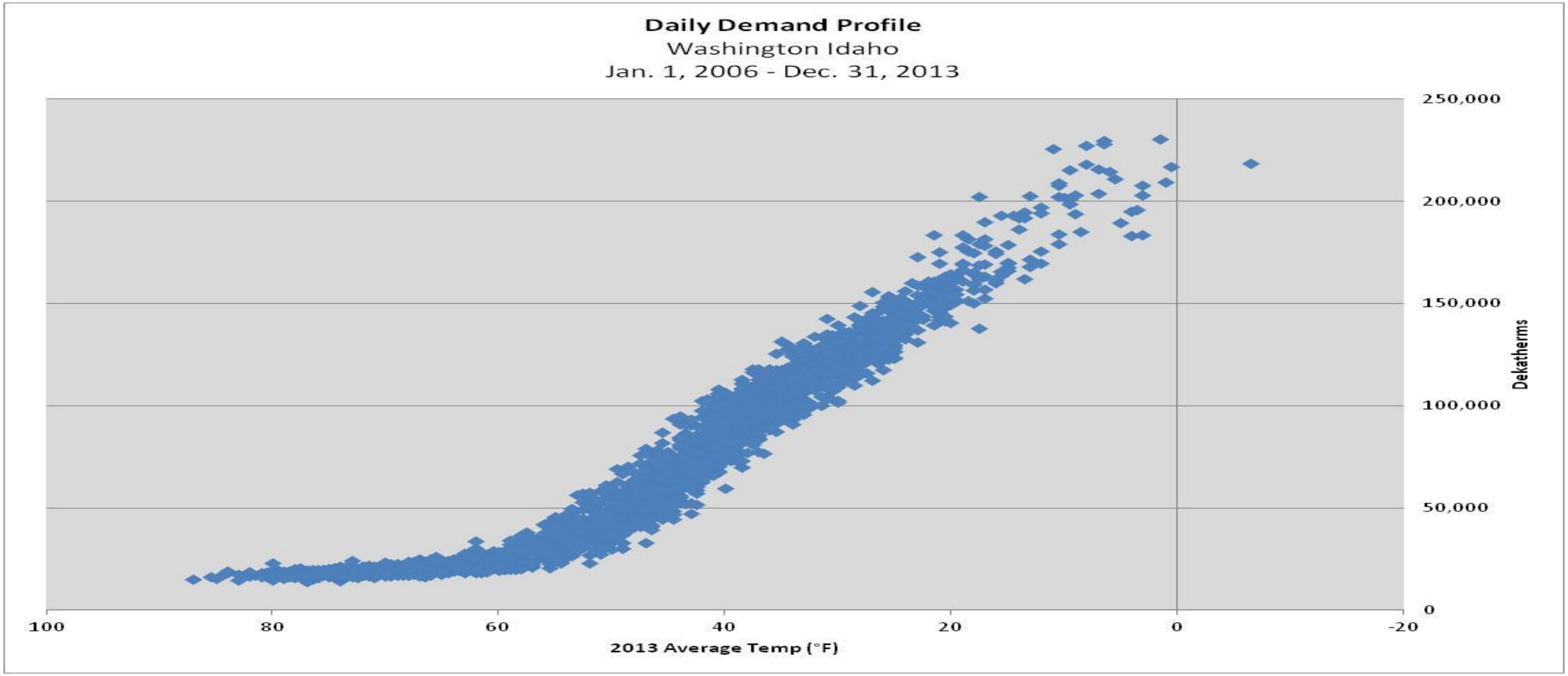
Weather

- NOAA 20 year actual average daily HDD's (1994-2013)
- Peak weather includes two winter storms (5 day durration), one in December and one in February
- Planning Standard – coldest day on record
- Sensitivity around planning standard including
  - Normal/Average
  - Coincidental vs. Non-coincidental
  - Coldest in 20 years
  - Monte Carlo simulation

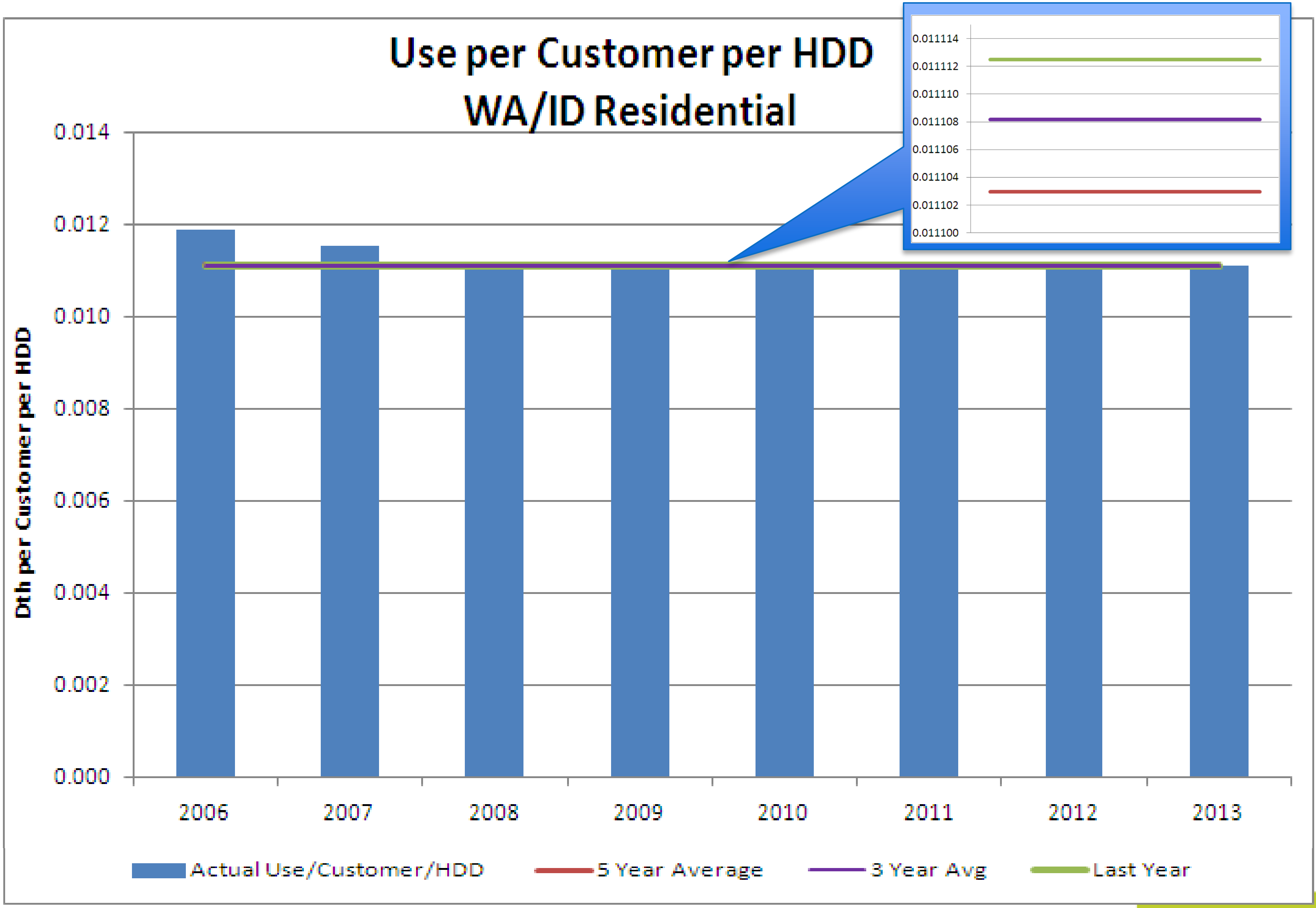
The Use per Customer Forecast

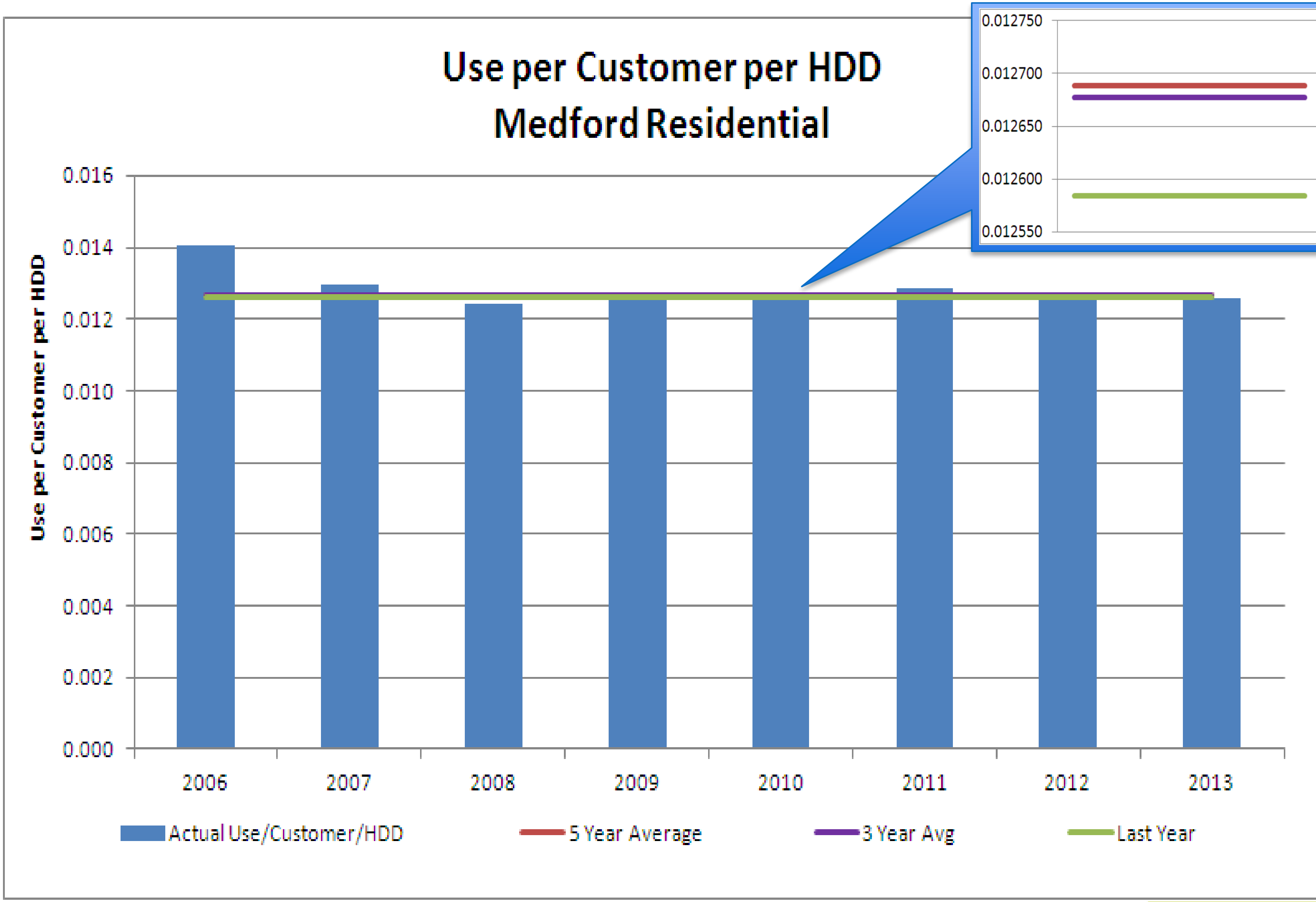


The Use per Customer Forecast cont.

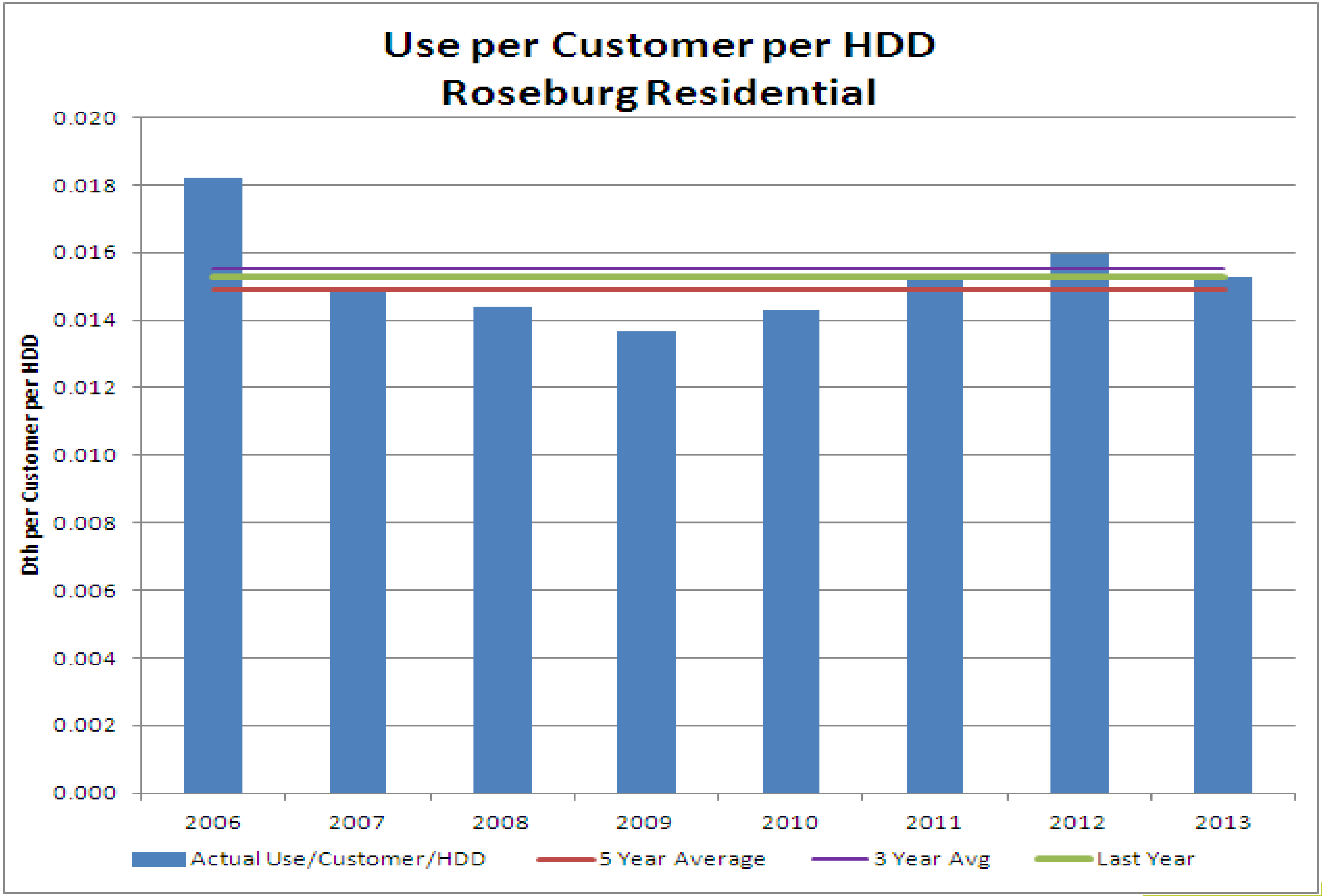


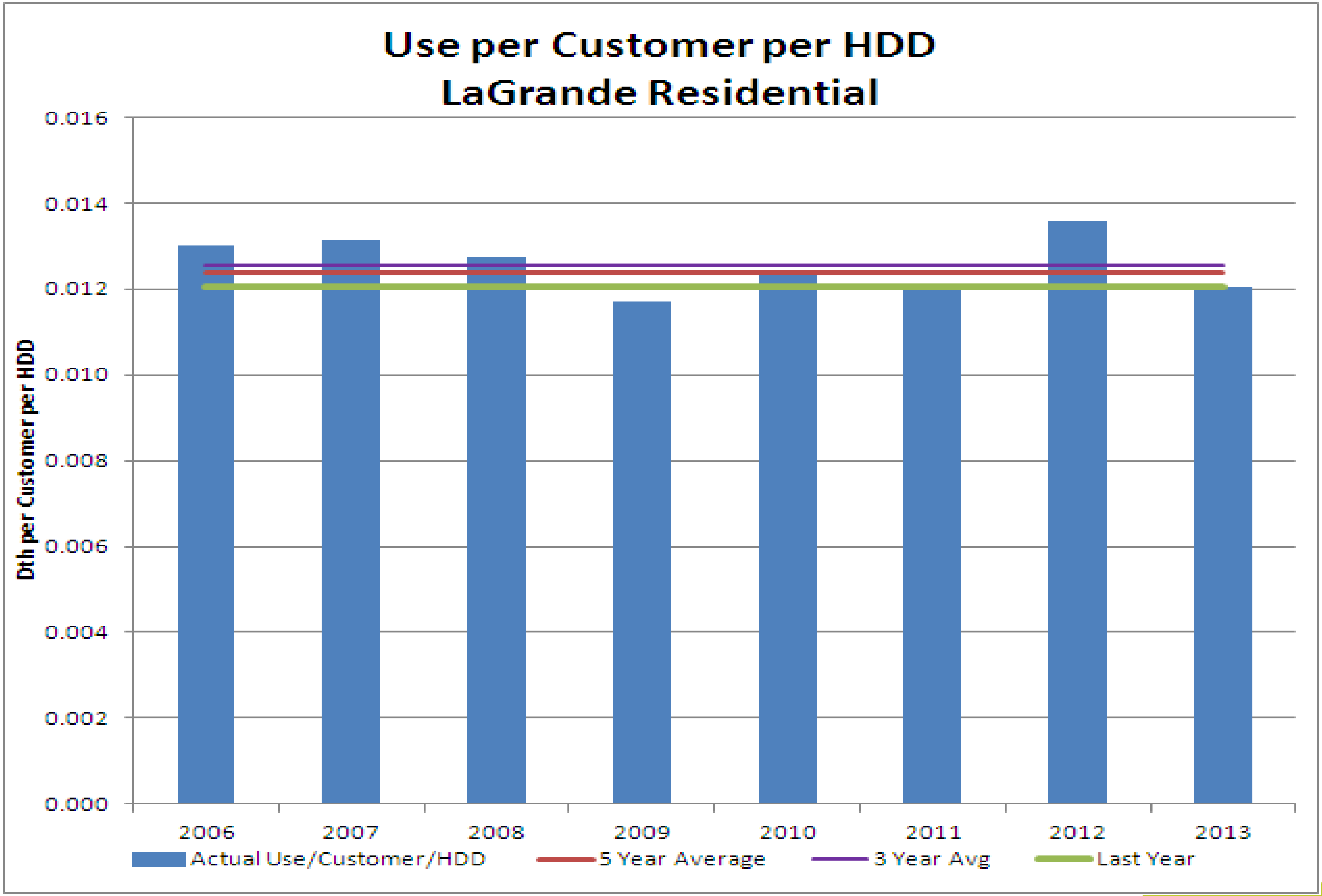
- Historical data is used to determine initial base and heat coefficients.
- Adjustments are made to incorporate DSM and price elastic responses.


Use per Customer per HDD
WA/ID Residential
Dth per Customer per HDD
0.014
0.012
0.010
0.008
0.006
0.004
0.002
0.000
2006
2007
2008
2009
2010
2011
2012
2013
0.011114
0.011112
0.011110
0.011108
0.011106
0.011104
0.011102
0.011100
Actual Use/Customer/HDD
5 Year Average
3 Year Avg
Last Year

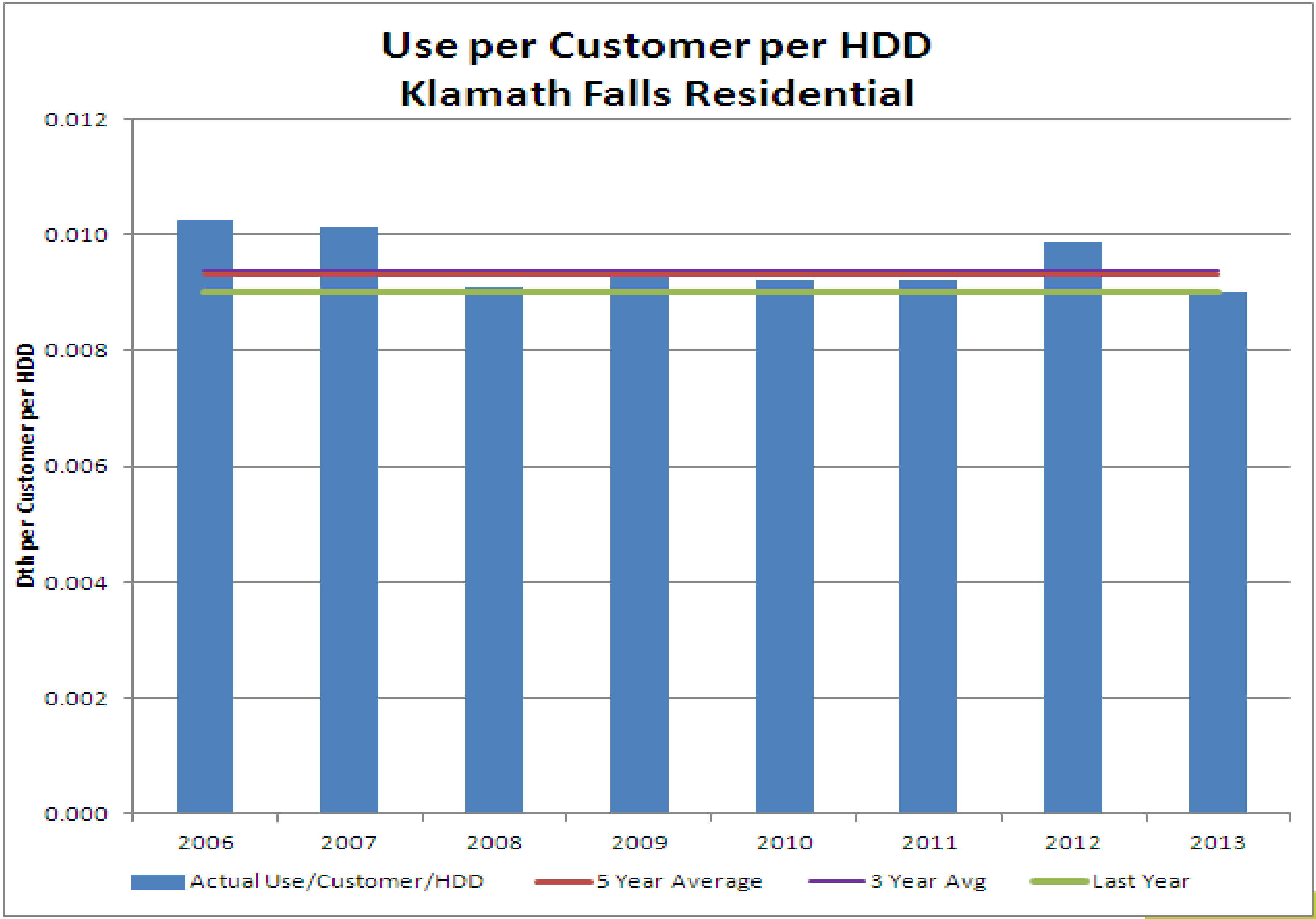


Use per Customer per HDD
Medford Residential
Use per Customer per HDD
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
0.000
2006
2007
2008
2009
2010
2011
2012
2013
Actual Use/Customer/HDD
5 Year Average
3 Year Avg
Last Year
0.012750
0.012700
0.012650
0.012600
0.012550


Use per Customer per HDD
Roseburg Residential
Dth per Customer per HDD
0.020
0.018
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
0.000
2006
2007
2008
2009
2010
2011
2012
2013
Actual Use/Customer/HDD
5 Year Average
3 Year Avg
Last Year



Use per Customer per HDD
LaGrande Residential
Dth per Customer per HDD
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
0.000
2006
2007
2008
2009
2010
2011
2012
2013
Actual Use/Customer/HDD
5 Year Average
3 Year Avg
Last Year


Use per Customer per HDD
Klamath Falls Residential
0.012
0.010
0.008
0.006
0.004
0.002
0.000
Dth per Customer per HDD
2006
2007
2008
2009
2010
2011
2012
2013
Actual Use/Customer/HDD
5 Year Average
3 Year Avg
Last Year

Demand Modeling Equation – a closer look

SENDOUT® requires inputs expressed in the below format to compute daily demand in dekatherms. The **base** and **weather sensitive** usage (degree-day usage) factors are developed outside the model and capture a variety of demand usage assumptions.

Table 3.2 Basic Demand Formula

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

Developing a Reference Case

Customer count forecast + Use per customer coefficients + Weather = Reference Case Demand

1. Customer annual growth rates:

	Residential	Commercial	Industrial
Washington - Idaho	1.0%	1.0%	-0.53%
Klamath Falls	0.66%	0.66%	0.0%
LaGrande	0.40%	0.40%	0.0%
Medford	1.1%	1.1%	0.0%
Roseburg	0.8%	0.02%	0.0%

2. Use per customer coefficients – Flat all classes, 5 year, 3 year or last year average use per HDD per customer
3. Weather planning standard – coldest day on record
   - WA/ID 82; Medford 61; Roseburg 55; Klamath 72; La Grande 74

Dynamic Demand Methodology

Dynamic Demand Methodology

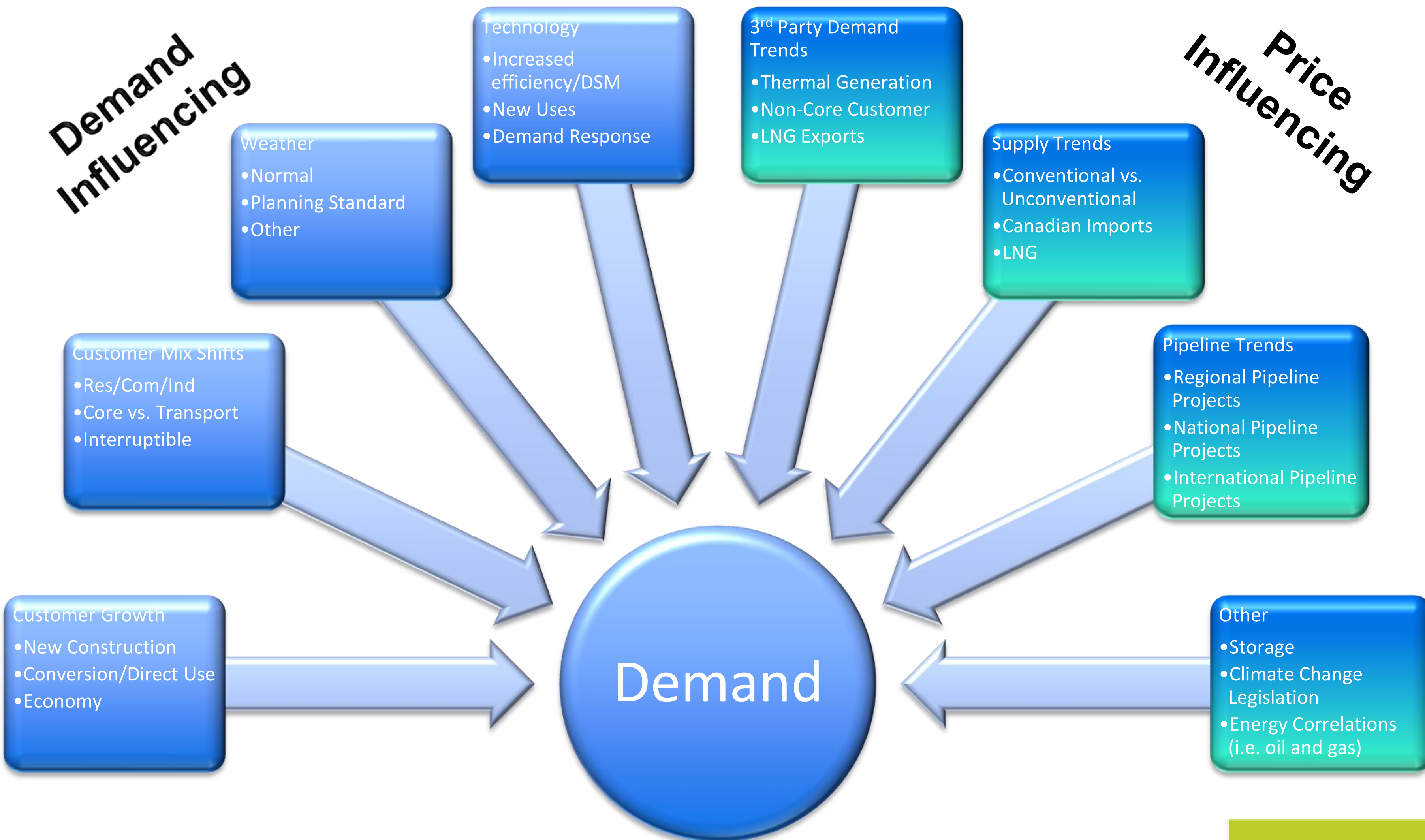
Demand Influencing

– Conditions that **DIRECTLY** affect core customer volume consumed

Price Influencing

– *PRICE SENSITIV*E conditions that, through price elasticity, **INDIRECTLY** affect core customer volume consumed

Demand Drivers



Customer Growth and Mix – Demand Influencing

- Key driver in demand growth
- Can change the timing and/or location of resource needs
- Currently we model expected, high, and low growth scenarios
- New construction vs. conversions
- Residential/Commercial/Industrial vs. Transportation
- New uses – CNG/NGV

Weather Standard – Demand Influencing

- Has the potential to significantly change timing of resource needs
- Significant qualitative considerations
  - No infrastructure response time if standard exceeded
  - Significant safety and property damage risks
- Current Peak HDD Planning Standards
  - WA/ID 82
  - Medford 61
  - Roseburg 55
  - Klamath 72
  - LaGrande 74

Global Warming – Demand Influencing

- There is a lack of studies or information on the affect global warming has on peak weather conditions
- Uncertain whether any change in timing of resource needs
- Peak and trough weather appears more volatile – does not influence the peak
- Will reduce annual consumption over time for LDC but could increase consumption for thermal generation
- Proposing to remove global warming adjustment

Technology – Demand Influencing

- Demand side management initiatives will reduce demand **HOWEVER**, it is dependent upon customers willingness/ability to participate.
- Development of new uses for natural gas
  - CNG
  - NGV
  - LNG
  - ???NG
- Demand response (Smart Grid)
- New technologies in Demand Side Management

Price Elasticity Factors Defined

- 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 -0.13 means:
  – A 10% price **increase** will prompt a 1.3% consumption **decrease**
  – A 10% price **decrease** will prompt a 1.3% consumption **increase**

Price Elasticity

- Establishes factors for use in other price influencing scenarios
- Very complex relationship – we use historical data however……
    - Historical data has DSM, rate changes (PGA, general rate, etc.), economic conditions, technological changes, etc.
    - History is not necessarily the best predictor of future behavior

2007 AGA Study Results

- **American Gas Assn Study**
  - National results
    - Short-run -0.09
    - Long-run -0.18
  - Pacific & Mtn Region results
    - Short-run -0.07 & -0.07
    - long-run -0.12 & -0.10
  - Min-Max range
    - Short-run +0.01 to -0.13
    - Long-run -.01 to -.29

- **Avista Specific Results**
  - Oregon
    - Short-run -0.08
    - long-run -0.13
  - Idaho
    - Short-run -0.05
    - long-run -0.10
  - Washington
    - Short-run -0.12
    - long-run -0.14

Price Elasticity Assumptions From 2012 IRP

Elasticity Assumption	Real Price annual increase within 30%
High	Negative .20
Expected	Negative .13
Low	No response

3rd Party Demand Trends – Price Influencing

- Gas fired generation – the largest contributor to future growth
- Coal plant retirements driving gas for power
- CNG/NGV Transportation Fleets
- Export LNG
- Non-firm customer trends

Supply Trends – Price Influencing

- Not all its “Frack-ed” up to be or “Fracking” Awesome
- Shale is Everywhere
- O’ Canada vs. Canada Dry
- LNG Export
- Basis - Location, location, location

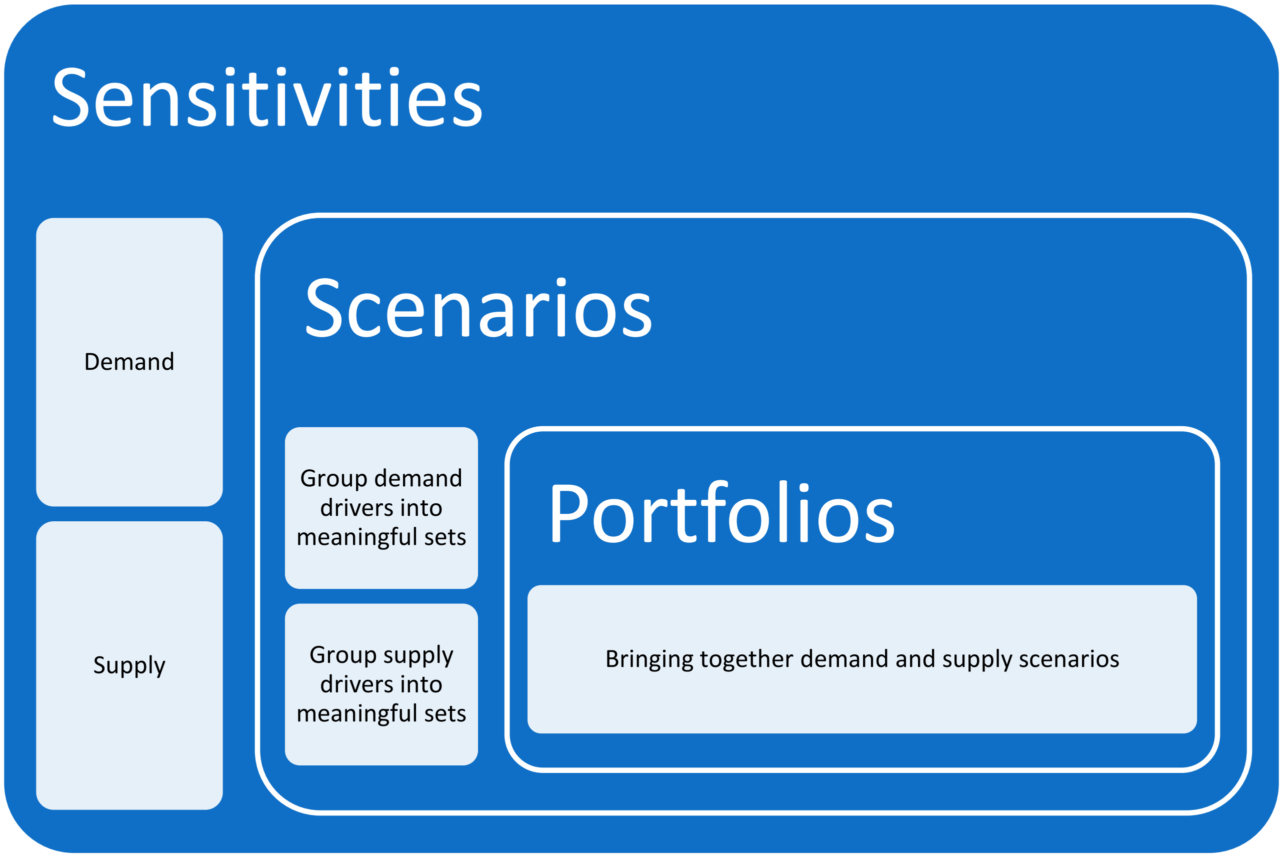
Pipeline Trends – Price Influencing

- Regional Pipeline Proposals
  - N-Max/Palomar – cross Cascades pipeline (NWN, GTN and NWP)
  - Pacific Connector – from Jordan Cove LNG to various interconnects in the Pacific Northwest (Williams, Fort Chicago Energy Partners, and PG&E)
- National Pipeline Proposals
- International Pipeline Proposals

Other Supply Issues – Price Influencing

- Storage
- Climate Change and Carbon Legislation
- Energy Correlations

Sensitivities, Scenarios, Portfolios



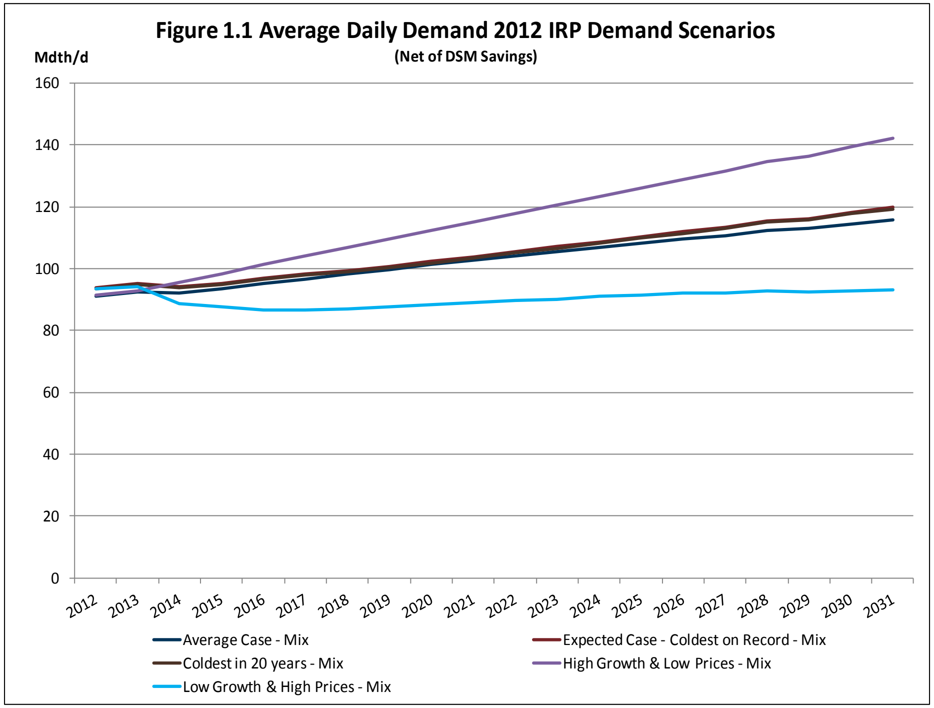
Demand Sensitivities from 2012 IRP

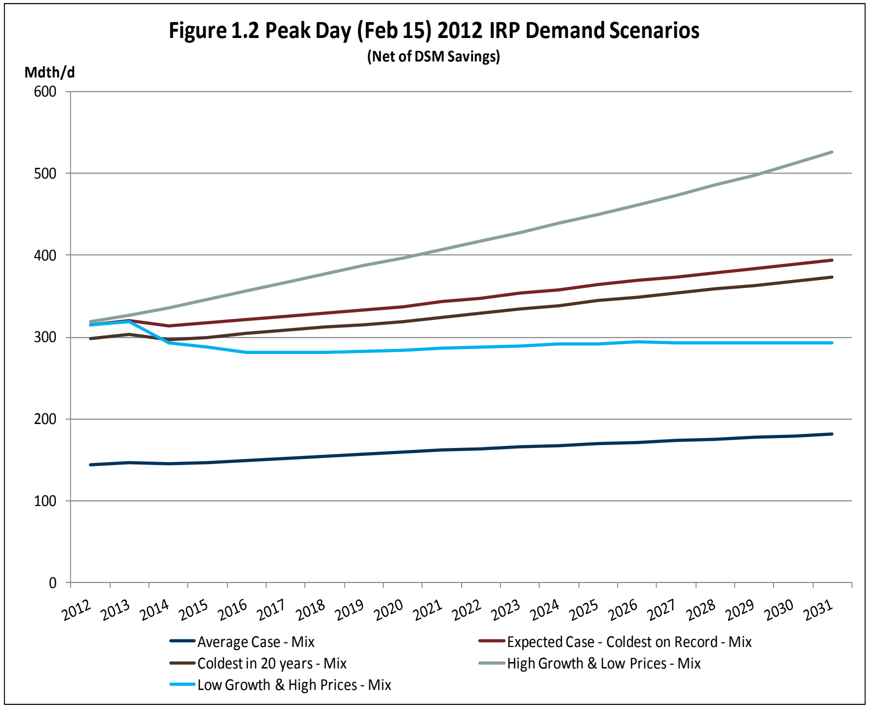
				DEMAND INFLUENCING - DIRECT							PRICE INFLUENCING - INDIRECT				
INPUT ASSUMPTIONS		Reference Case	Reference Plus Peak Case	Low Cust Growth	High Cust Growth	CNG/NGV Vehicles	Alternate Weather Std	DSM Case	Peak plus DSM Case	Alterante Historical UPC Case	Expect Elasticity	Low Prices	High Prices	Carbon Legislation	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

What do we want to consider for 2014?

Mix and Match to Make Scenarios

The Goal – A Bunch of Meaningful Lines





Forecast Methodology Considerations

- Know the goal – what is the purpose of the forecast?
- Know your data – what you have, what you need
- Is there sufficient quantitative data available?
- Is the change small or large?
- Is their conflict among decision makers?
- Are the relationships among variable complicated?
- Have there been similar situations?

Demand Side Management

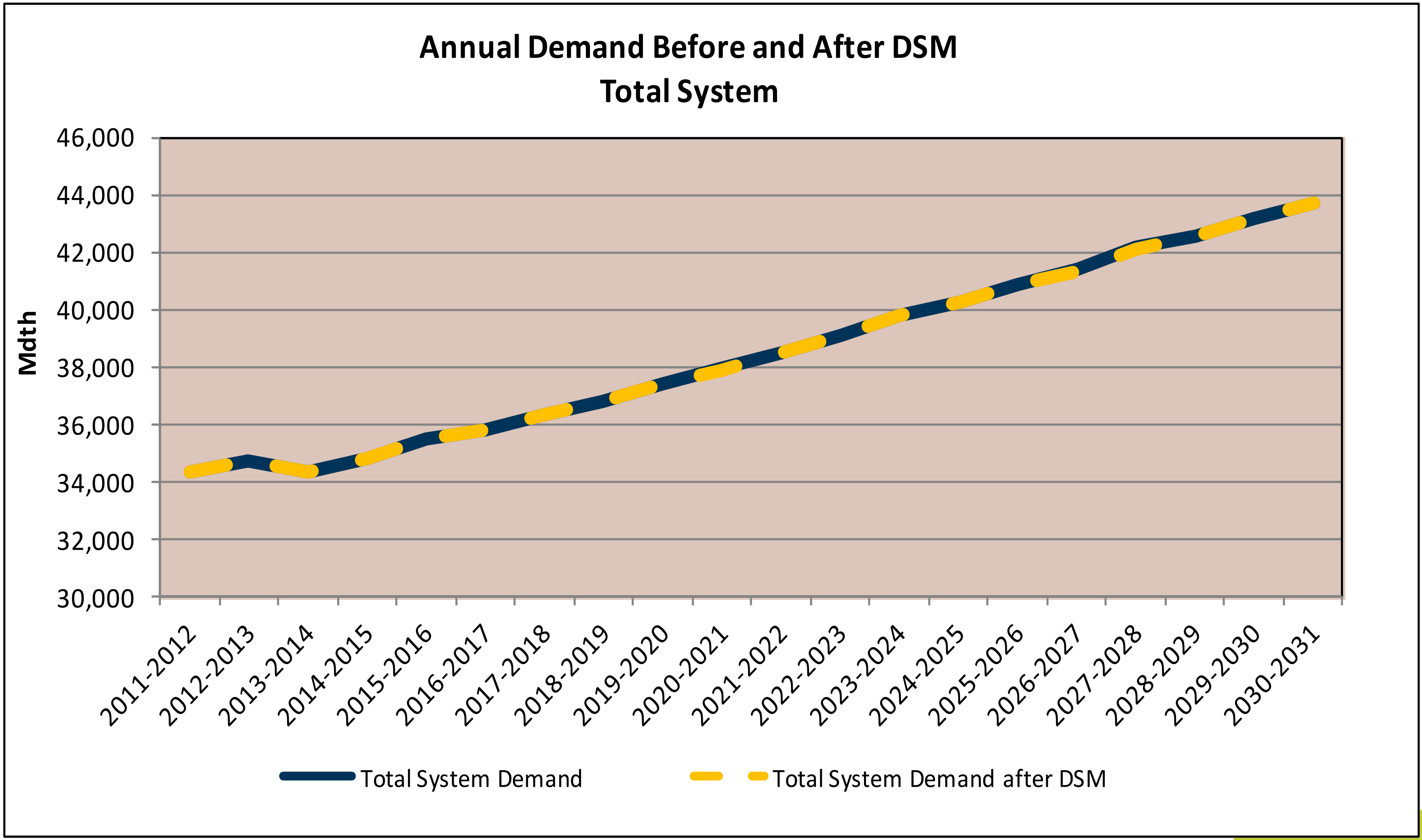
Lori Hermanson

Utility Resource Analyst

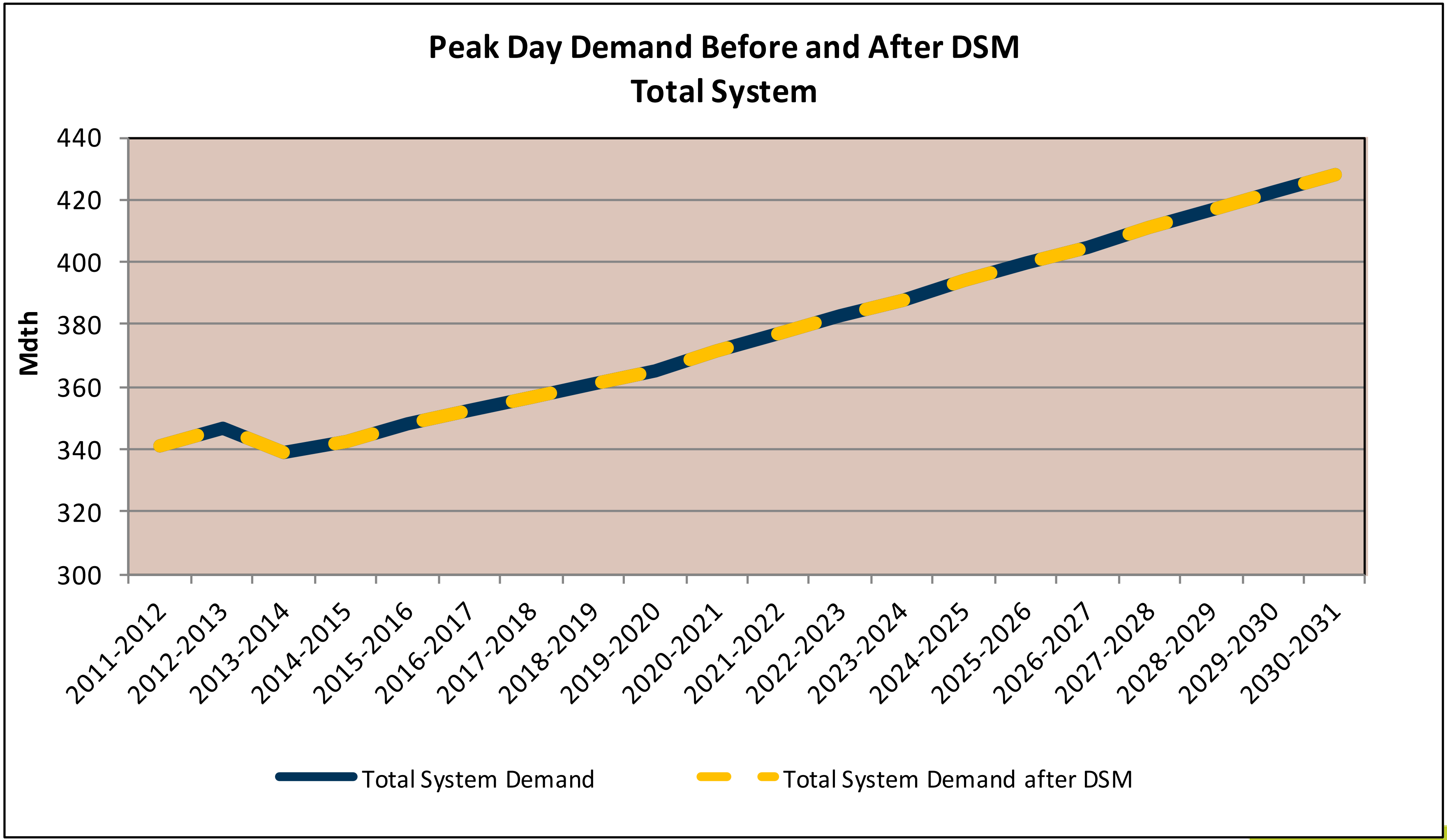
Agenda

- DSM in the last IRP
  - Target/Acquisition
- What's happened since the last IRP
  - Cost-effectiveness comparison
- What's different with avoided costs?
- Proposed DSM modeling methodology
- Business planning process

DSM in the 2012 IRP - Annual



DSM in the 2012 IRP – Peak Day



2012 IRP DSM Targets

- 2013 targets & (Unverified) acquisition (achievable potential)

State	Therms	Target	% Achieved
Idaho	18,804	364,000	5.17
Oregon	217,177	289,000	75.14
Washington	595,614	893,000	66.70

- OPUC established “minimum” target

Therms	Target	% Achieved
217,177	225,000	96.52

Recap of Recent History

- Idaho – Schedule 190 suspended effective 10/1/12
- Oregon – two year cost-effectiveness pass and revised savings expectation for 2013-2014
- Washington – WUTC adopted the gross UCT as the cost-effectiveness test for natural gas DSM

Cost-effective Test Comparison

- Total Resource Cost (TRC) =

  (avoided costs + non-energy benefits)

  ____

  (customer incremental cost + non-incentive utility costs)

- Utility Cost Test (UCT) =

  avoided costs

  ____

  incentives + non-incentive utility costs

TRC vs UCT

TRC

- Traditional cost-effectiveness metric
- Includes non-energy benefits
- Results in programs that influence customer decisions

UCT

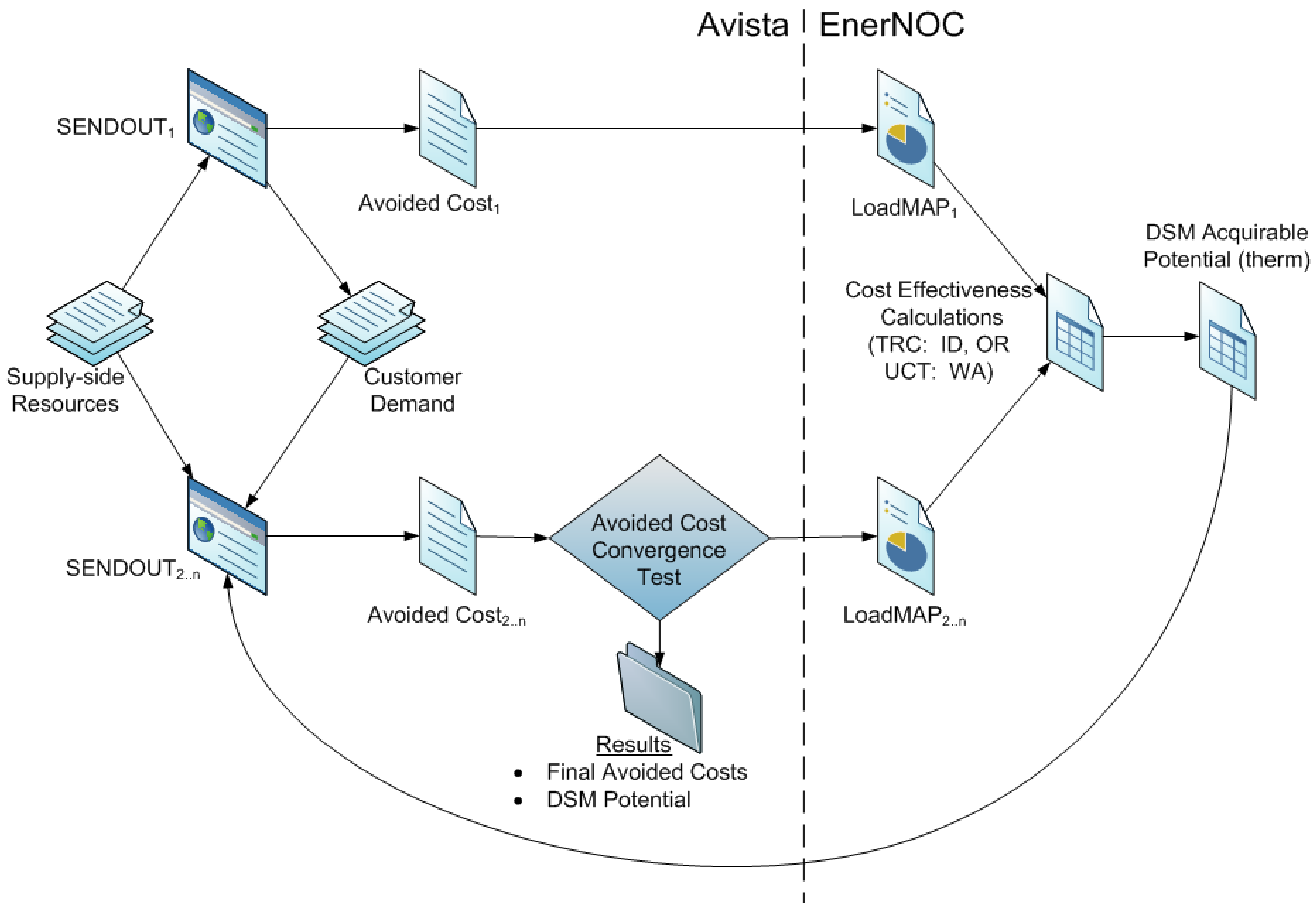
- Customer costs are ignored
- Incentives are reduced in order to offer programs below avoided costs
- Ignore free-riders in order to be cost-effective

Avoided Costs (2013 $)

	2009 IRP		2012 IRP		2014 IRP*	
	Annual	Winter	Annual	Winter	Annual	Winter
WA/ID	$12.56	$12.88	$5.31	$5.40	??	??
OR	$12.74	$13.18	$5.34	$5.45	??	??

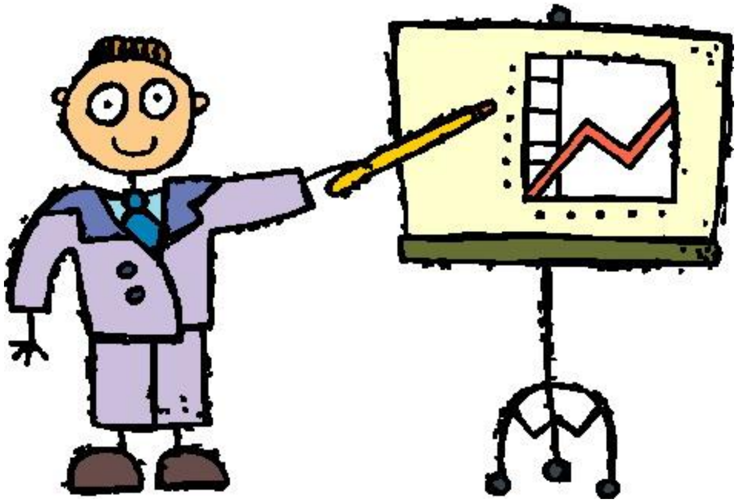
*Similar avoided costs levels anticipated from the upcoming IRP

Proposed DSM Modeling Methodology



Business Planning Process

- IRP generated target (CPA achievable potential)
- Bottom-up evaluation of all measures regardless of cost-effectiveness
- Add in non-incentive utility costs
- Evaluate with final avoided costs
- Process results in updated operational plan



Questions?

2014 IRP Timeline

- **August 31, 2013** – Work Plan filed with WUTC
- **January through April 2014** – Technical Advisory Committee meetings. Meeting topics will include:
  - Demand Forecast and Demand Side Management – January 24
  - Supply/Infrastructure, Natural Gas Pricing, and Potential Case Discussion– *February 25*
  - Distribution Planning, SENDOUT® Preliminary Output Results and Further Case Discussion – *March 26*
  - SENDOUT® results – *April 23*
- **May 30, 2014 –** Draft of IRP document to TAC
- **June 30, 2014 –** Comments on draft due back to Avista
- **July 2014 –** TAC final review meeting (if necessary)
- **August 31, 2014 –** File finalized IRP document

Tentative Agenda for the Next TAC Meeting

- Natural Gas Prices
- Supply Side Resources (Current and Future)
  - Transportation
  - Storage
  - Other
- Gate Station Analysis

2014 Avista Natural Gas IRP

Technical Advisory Committee Meeting 2

February 25, 2014

Portland, Oregon

Agenda

- Introductions & Logistics
- Update from NWP and GTN
- Regional and Avista's Supply Side Resources/Resource Optimization
- Gate Station Analysis
- Solving Unserved Demand

2014 IRP Timeline

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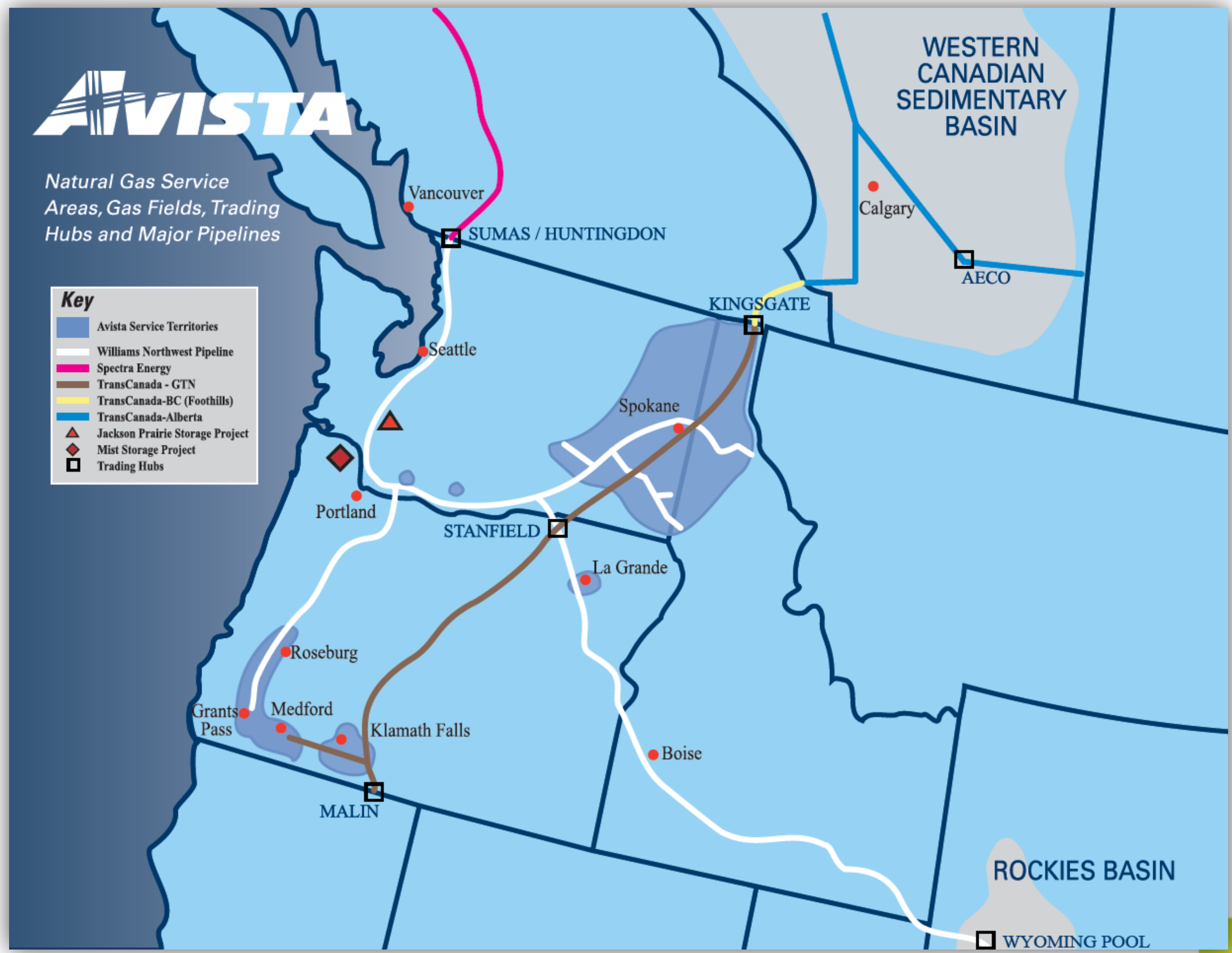
Regional and Avista's Supply and Infrastructure

NWP Presentation

GTN Presentation

Connecting Supply and Storage with Customers



Storage – A valuable asset

- Peaking resource
- Improves reliability
- Enables capture of price spreads between time periods
  - Inter seasonal spreads
  - Intra seasonal spreads
- Enables efficient counter cyclical utilization of transportation (i.e. summer injections)
- May require transportation to service territory
- In-service territory storage offers most flexibility

Regional Natural Gas Storage Resources

Jackson Prairie Natural Gas Facility
Chehalis, Washington

Facility	Owner	Type	Capacity[1] (MDth)	Max Withdrawal (MDth/day)
Jackson Prairie, WA	Avista, PSE, NW Pipeline	Underground	25,448	1,196[2]
Mist, OR	NW Natural	Underground	16,100	520[2]
	Underground Subtotal		**41,548**	**1,716**
Plymouth, WA	NW Pipeline	LNG	2,388	305
Newport, OR	NW Natural	LNG	1,000	60
Portland, OR	NW Natural	LNG	600	120
Tilbury, B.C.	FortisBC Energy	LNG	591	155
Nampa, ID	Intermountain Gas	LNG	588	60
Gig Harbor, WA	PSE	LNG	13	3
Swarr Station, WA	PSE	LPG[3]	130	10
Mt. Hayes, B.C.	FortisBC Energy	LNG	1,530	153
	LNG/LPG Subtotal		**6,858**	**866**
	Total Storage		**48,406**	**2,582**

[1]Working gas capacity; gas that can be used to serve the market.
[2]Start of season or full rate; storage withdrawal rates decline as working gas volumes decline below certain levels.
[3]LPG= Liquid Propane Gas and Air mixture.

Avista's Storage Resources

Washington and Idaho
Owned Jackson Prairie

- 7.7 Bcf of Capacity with approximately 346,000 Dth/d of deliverability

Oregon

Owned Jackson Prairie

- 823,000 Dth of Capacity with approximately 52,000 Dth/d of deliverability

Leased Jackson Prairie

- 95,565 Dth of Capacity with approximately 2,654 Dth/d of deliverability

Interstate Pipeline Resources

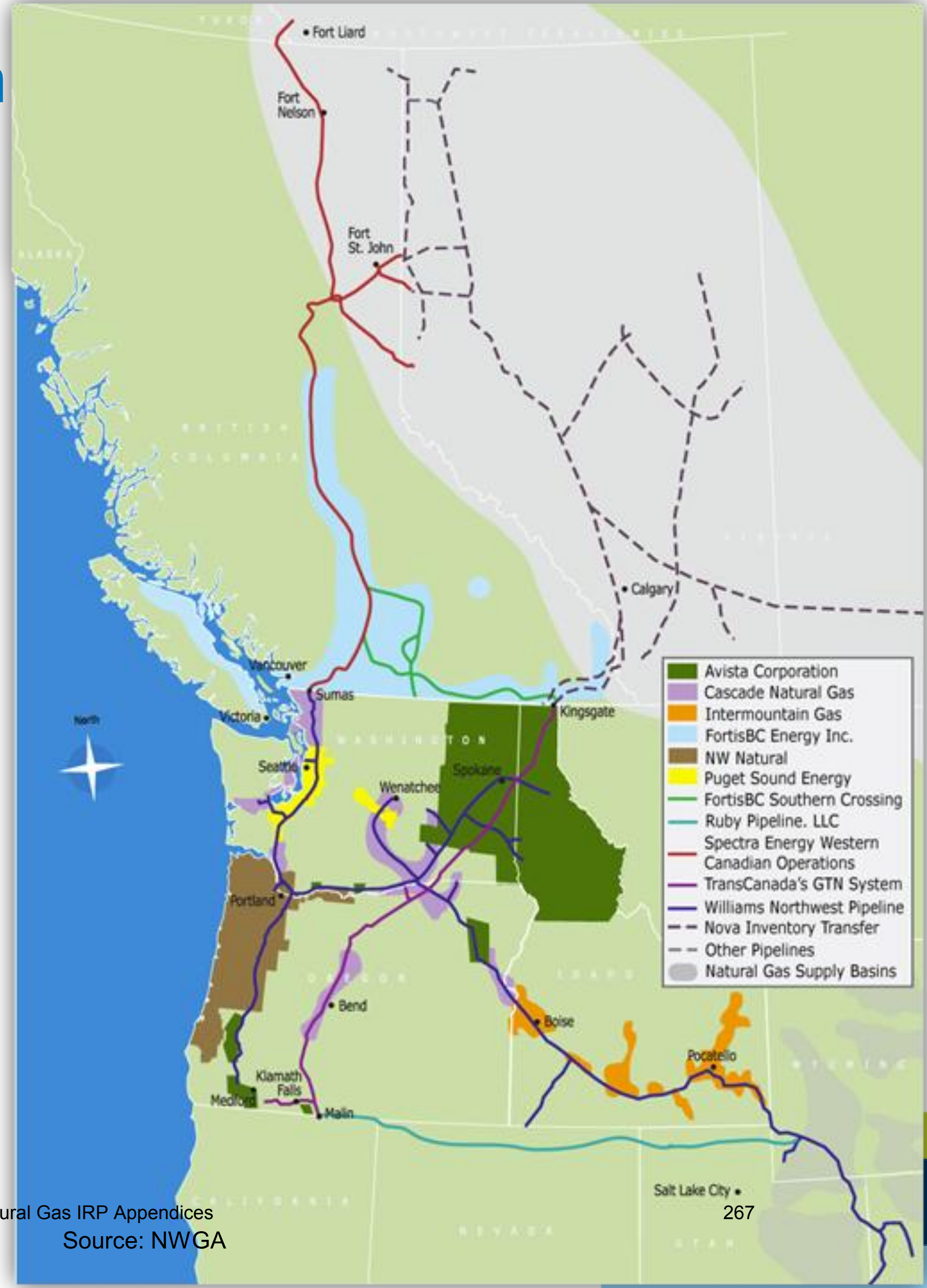
- The Integrated Resource Plan (IRP) brings together the various components necessary to ensure proper resource planning for reliable service to utility customers.

- One of the key components for natural gas service is interstate pipeline transportation. Low prices, firm supply and storage resources are rendered meaningless to a utility customer without the ability to transport the gas reliably during cold weather events.

- Acquiring firm interstate pipeline transportation provides the most reliable delivery of supply.

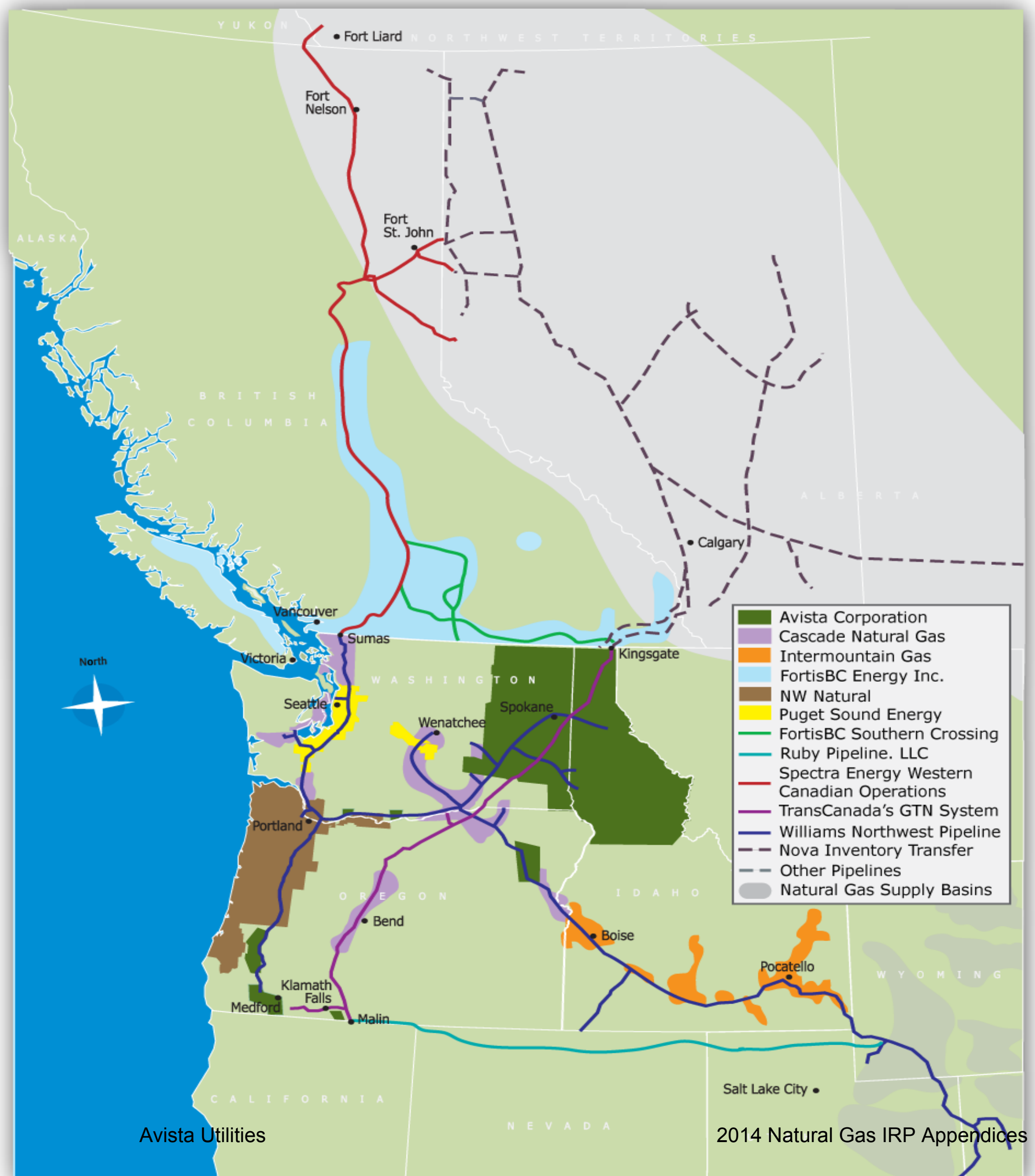
Regional Transportation Resources

- **TransCanada Alberta (NOVA)**
  - Transporting gas out of Alberta, Canada
- **TransCanada BC (ANG)**
  - Transporting gas through BC, Canada to US
- **Spectra Energy (WestCoast)**
  - Transporting gas from western BC Canada to US
- **Gas Transmission Northwest (GTN)**
  - Transporting gas from Canada/US border to CA
- **Williams Pipeline West (NWP)**
  - Transporting gas from western BC and US Rockies
- **El Paso Ruby Pipeline**
  - Transporting gas from the Rockies to Malin



Source: NWGA

Overview of Transportation



AECO
Station 2
Sumas
Stanfield
Rockies
Jackson Prairie
Malin
Starr Rd
Kingsgate

Proposed Pipeline Infrastructure

- Pacific Connector/Jordan Cove
- N-Max/Palomar
- Washington Expansion
- Oregon LNG

Pipeline Contracting

Simply stated: The right to move (transport) a specified amount of gas from Point A to Point B

Rate Structure

Straight Fixed Variable (SFV)	• Pipeline charges a higher demand charge and a lower variable or commodity charge
Enhanced fixed variable	• Pipeline charges a lower demand charge and a higher variable or commodity charge
Postage Stamp Rate	• Pay the same demand and variable costs regardless of how far the gas is transported
Mileage Based	• Pay a variable and demand charge based on how far the gas is transported

Types of Pipeline Contracts

Firm Transport

- Contractual rights to:
  - Receive
  - Transport
  - Deliver
- From point A to point B

Interruptible Transport

- Contractual rights to:
- Receive
- Transport
- Deliver
- From point A to Point B *AFTER FIRM TRANSPORT HAS BEEN SCHEDULED – and can be BUMPED later!*

Seasonal Transport

- Firm service available for limited periods (Nov-Mar) or for a limited amount (TF2 on NWP)
  - Usually matched, paired or utilized with storage.

Alternate Firm Transport

- The use of firm transport outside of the primary path
- Priority rights below firm
- Priority rights above interruptible

Postage Stamp Rate

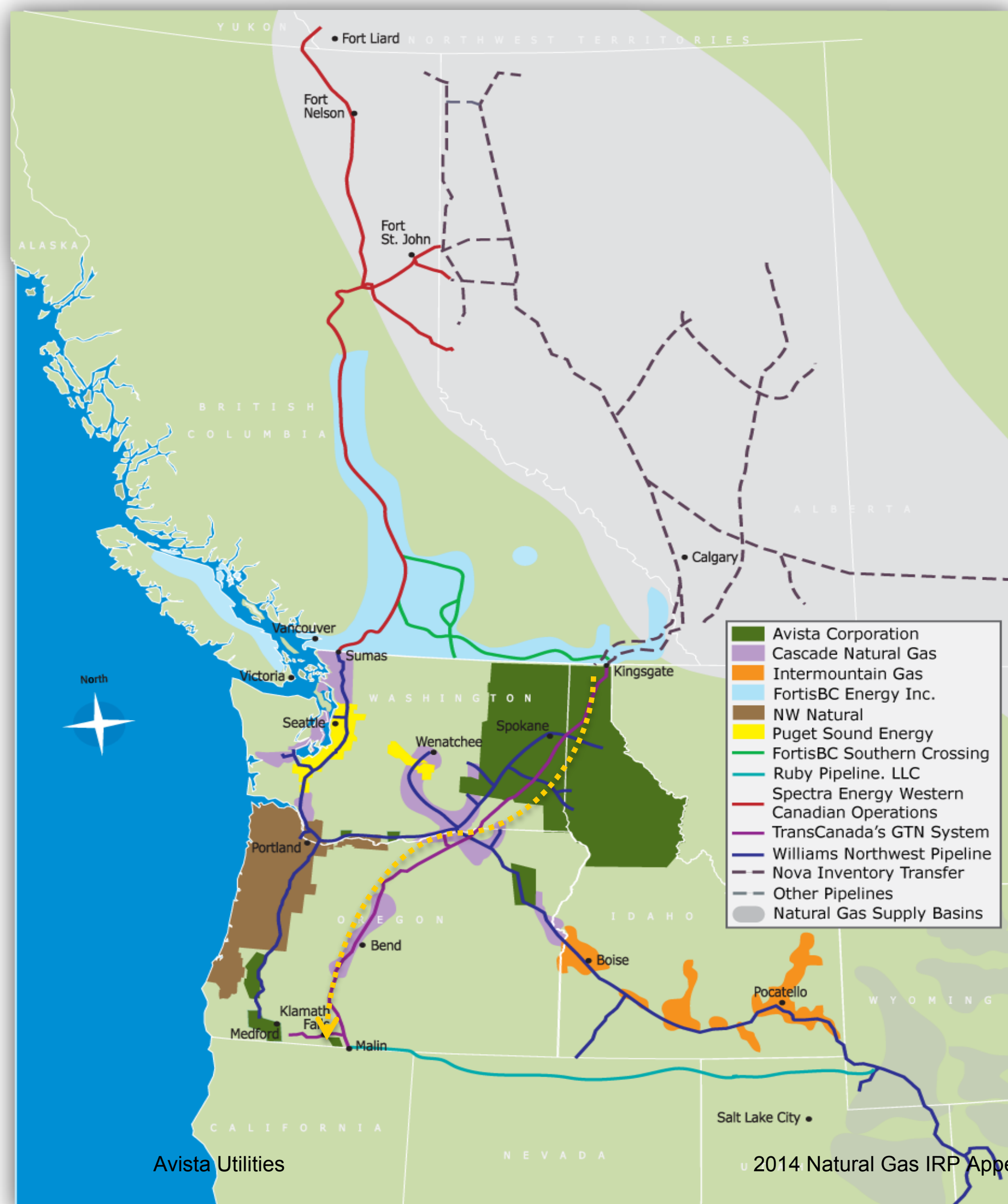
Postage Stamp:

Same costs regardless of distance or locations

Pipeline Revenue
NWP Example: Postage Stamp

- Postage Stamp (NWP)
  - Pay $0.37 to reserve the space
    - Whether you use it or not
  - Pay $0.03 when used
    - Only when you use it
  - Net $0.40
- Demand Charge = $0.37
- Commodity Charge = $0.03

Mileage Rate



Mileage Base:

Pay based on how far you move the gas

Pipeline Revenue

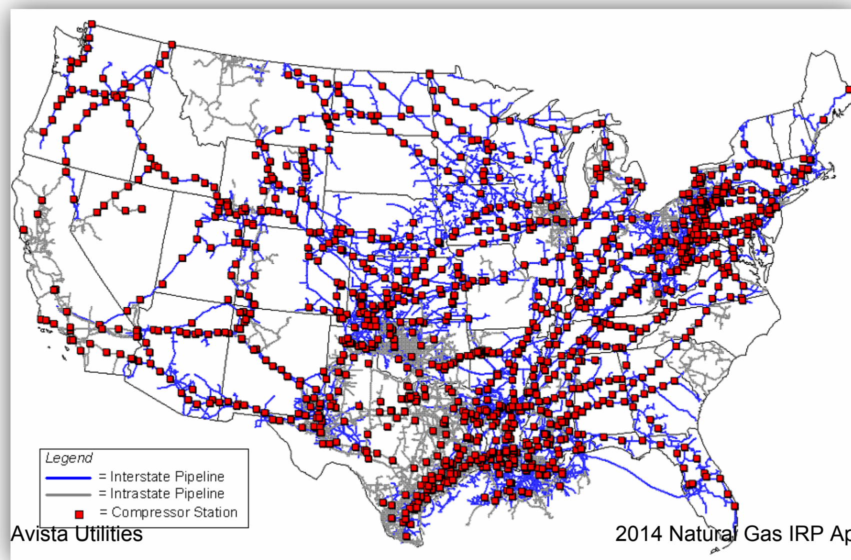
GTN Example: Mileage Based

- Mileage Based (GTN)
  - Pay $0.01 per mile to reserve the space
    - Whether you use it or not
  - Pay $0.002 per mile when used
    - Only when you use it
  - $0.021 per mile when used
- Demand Charge = $0.01
- Commodity Charge = $0.002

Interruptible Rates

- Pay as you go!
- Pay full firm rate for any gas transported (may be discounted)
  - Pay $0.37 equivalent to cost to reserve the space
  - Pay $0.03 variable charge when used
  - Net $0.40 for all gas transported
    - So IT rate is $0.40
- NO GUARANTEE it will flow.
- Can be “BUMPED” by Firm Shippers

Fuel Rates



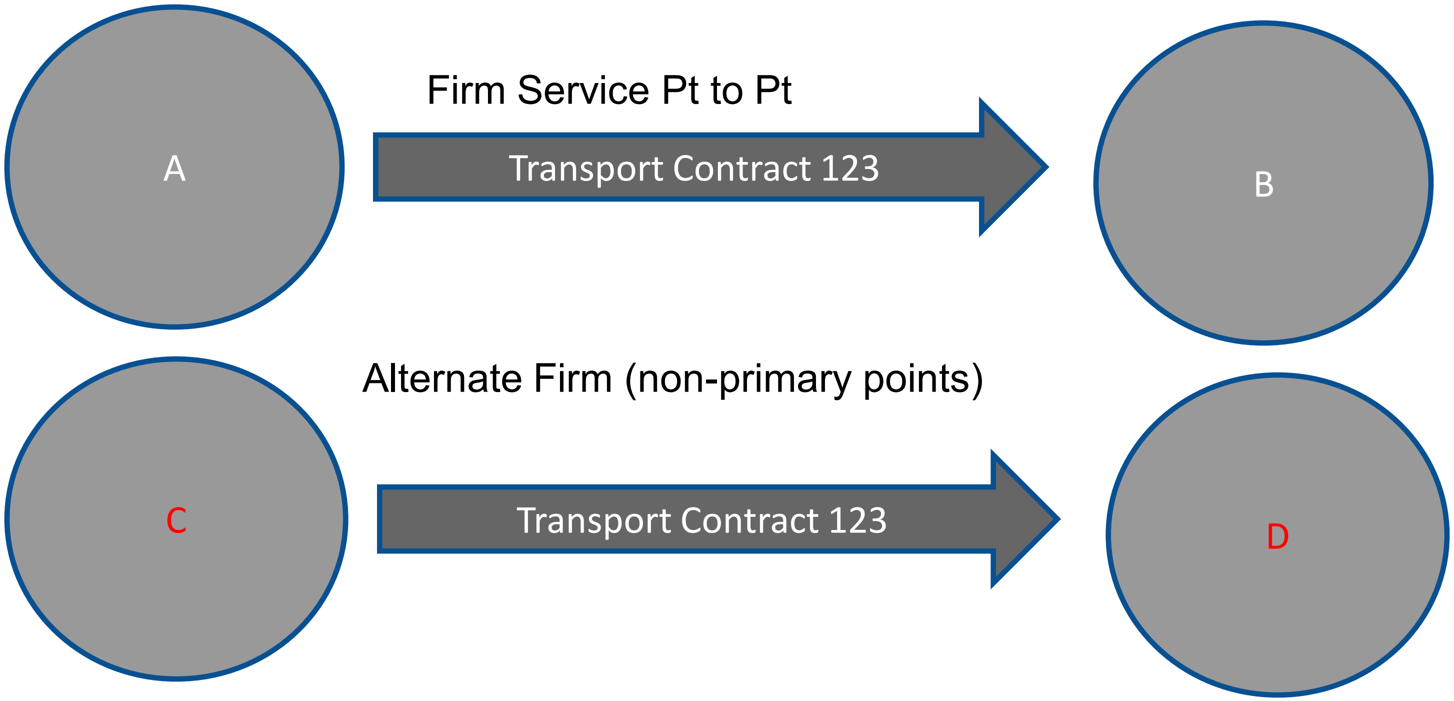
To move gas through the pipelines the gas is compressed to a higher pressure.

To run the compressors, the pipeline takes some of your gas – this is referred to as pipeline fuel. It is a percent of what you are transporting.

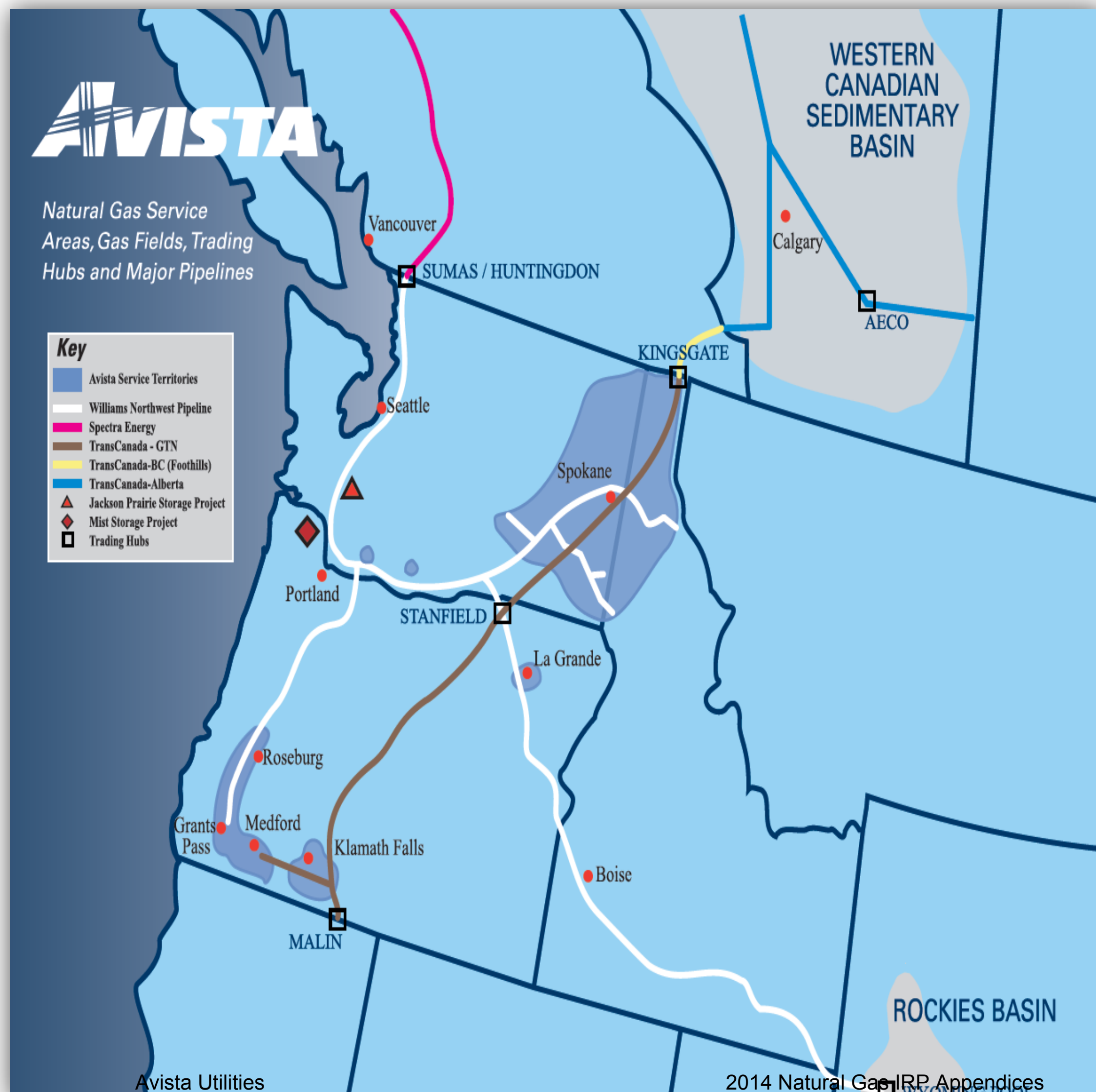
For example, if we purchase 1000 Dth in a supply basin, we will only receive 975 Dth at our gate station for the customers.

Pipeline Contracting

Transport contract #123 with "primary" points A to B



Capacity Firm or Not?

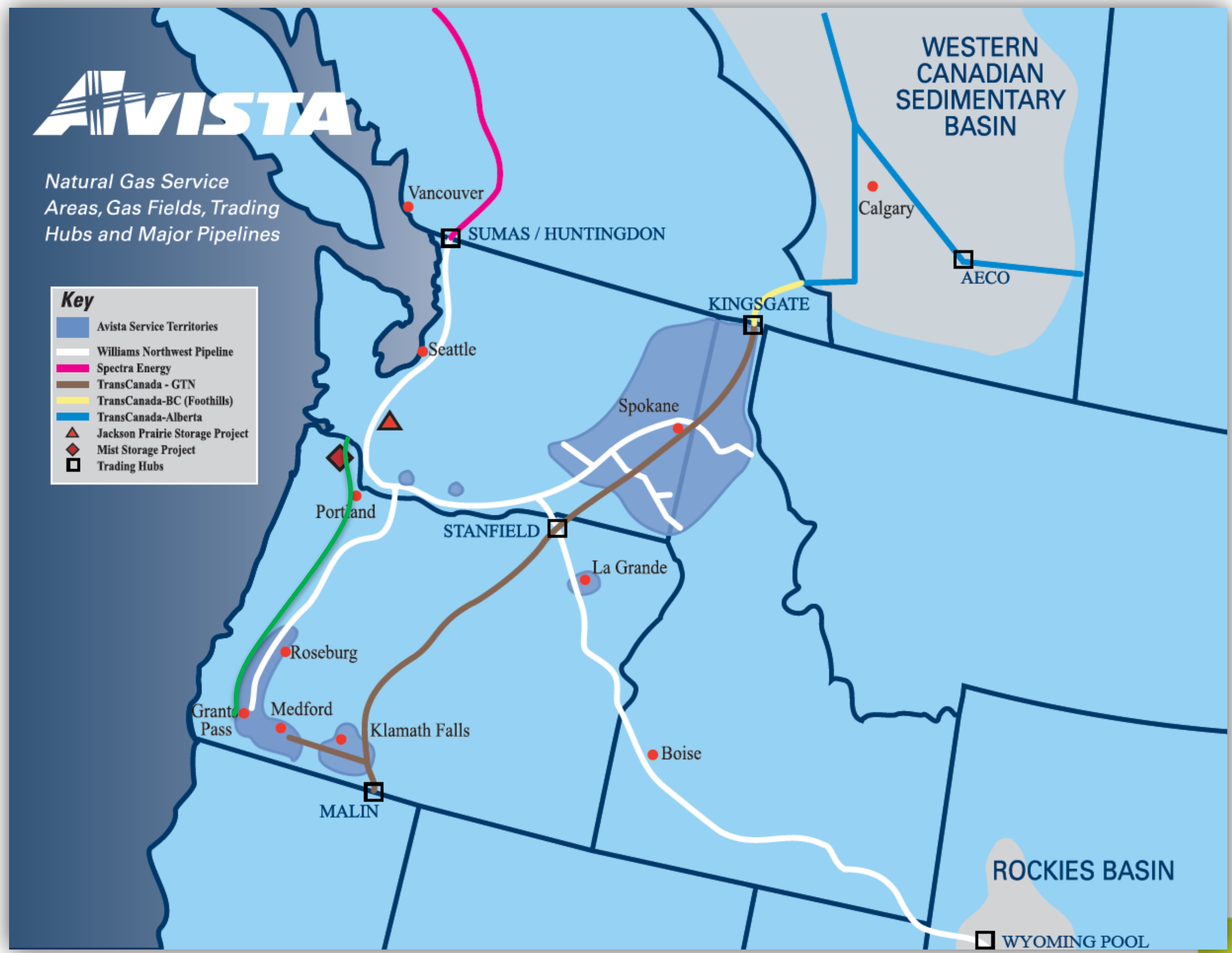


Firm:
- Primary Receipt
- Delivery Path

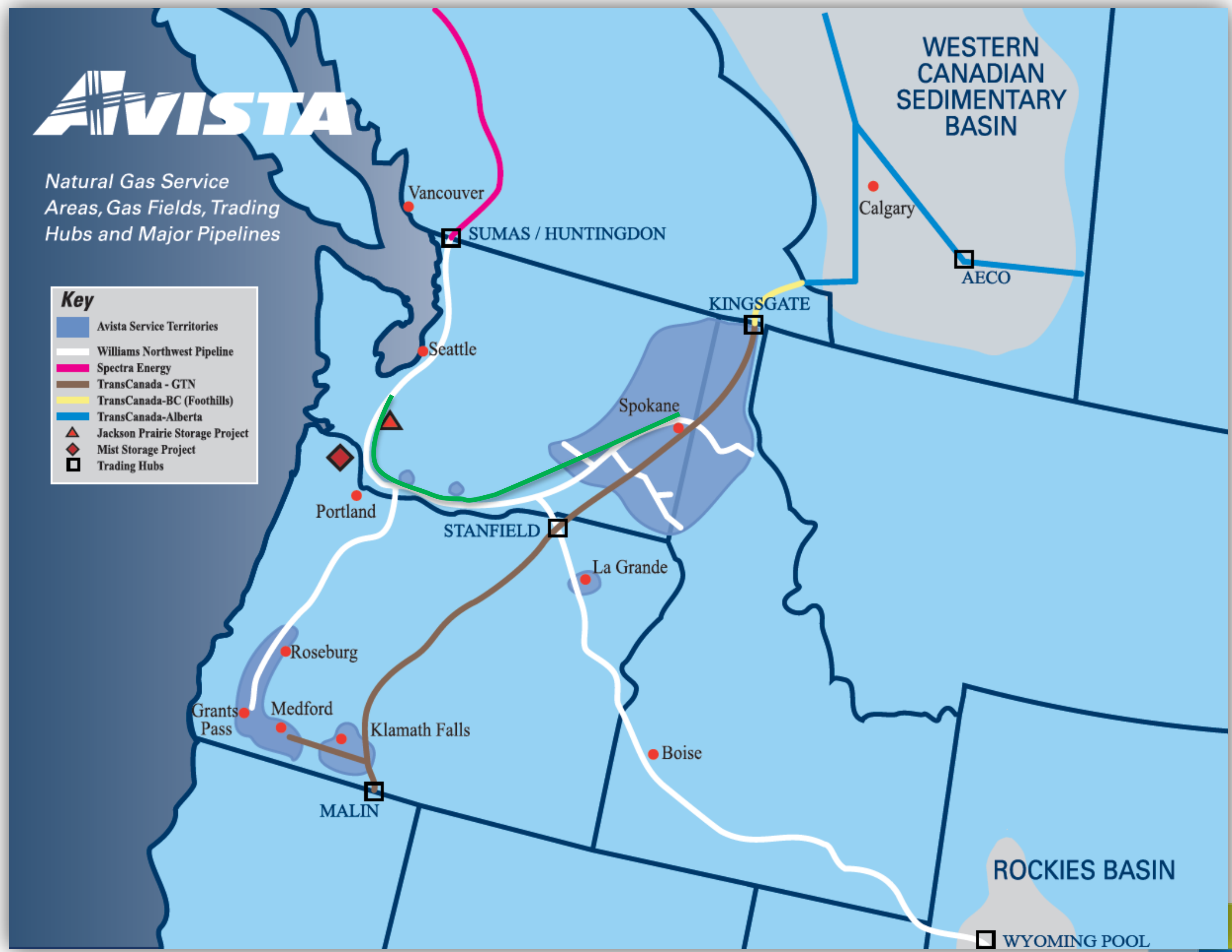
Secondary:
- Any part not firm
- Requires knowledge and experience to rely on interruptible

No on NWP
Yes on GTN

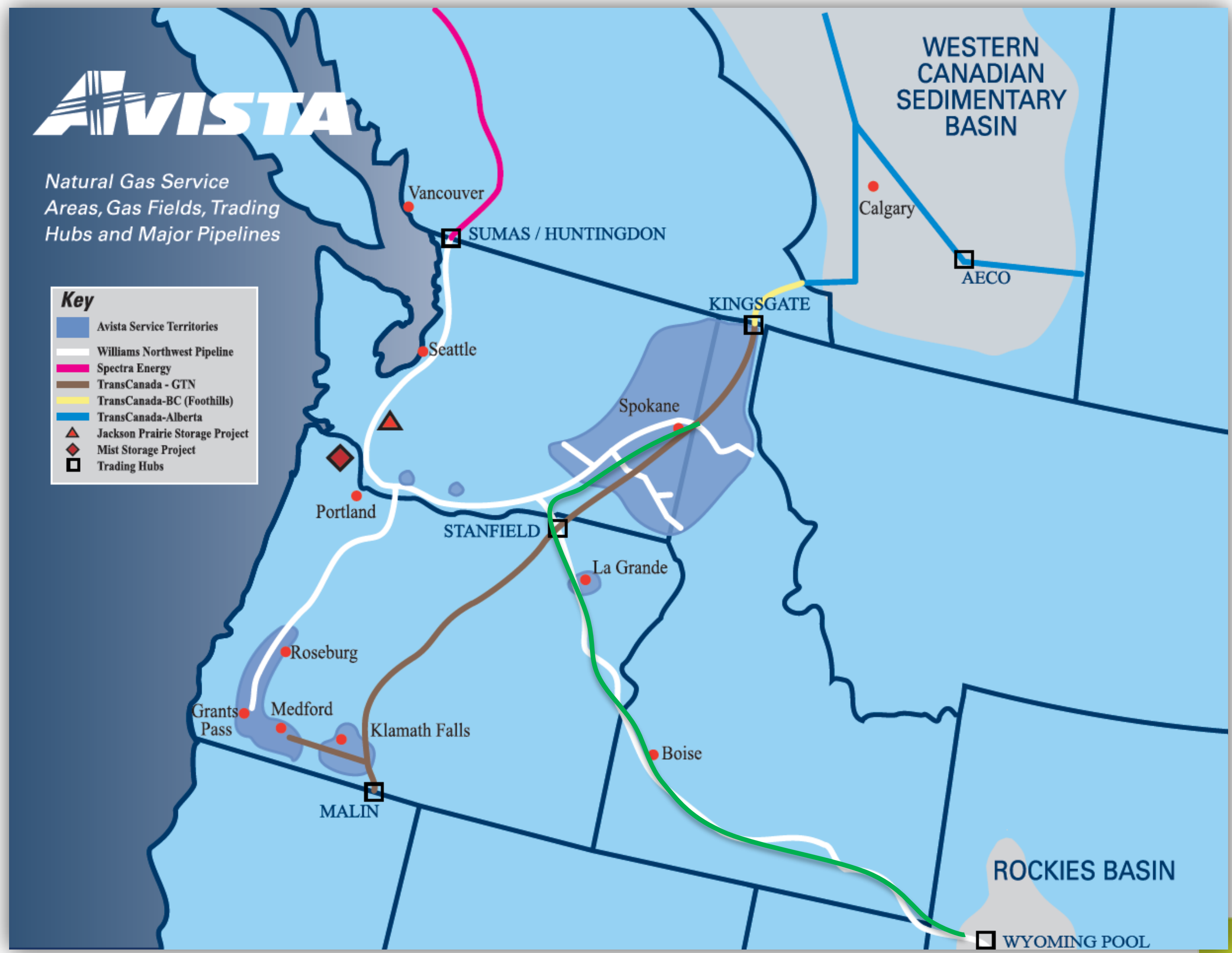
Capacity Firm or Not?



Capacity Firm or Not?

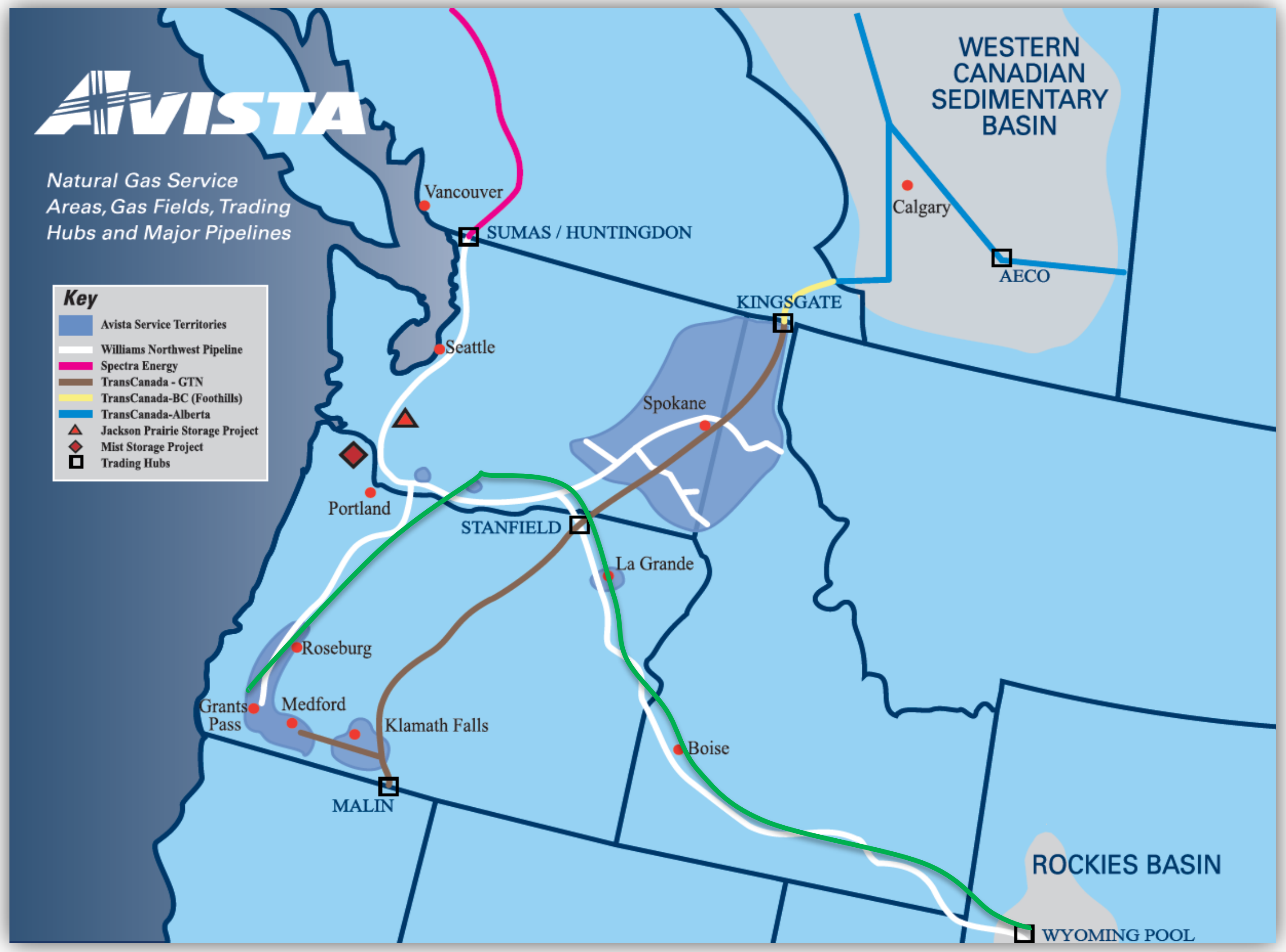


Capacity Firm or Not?



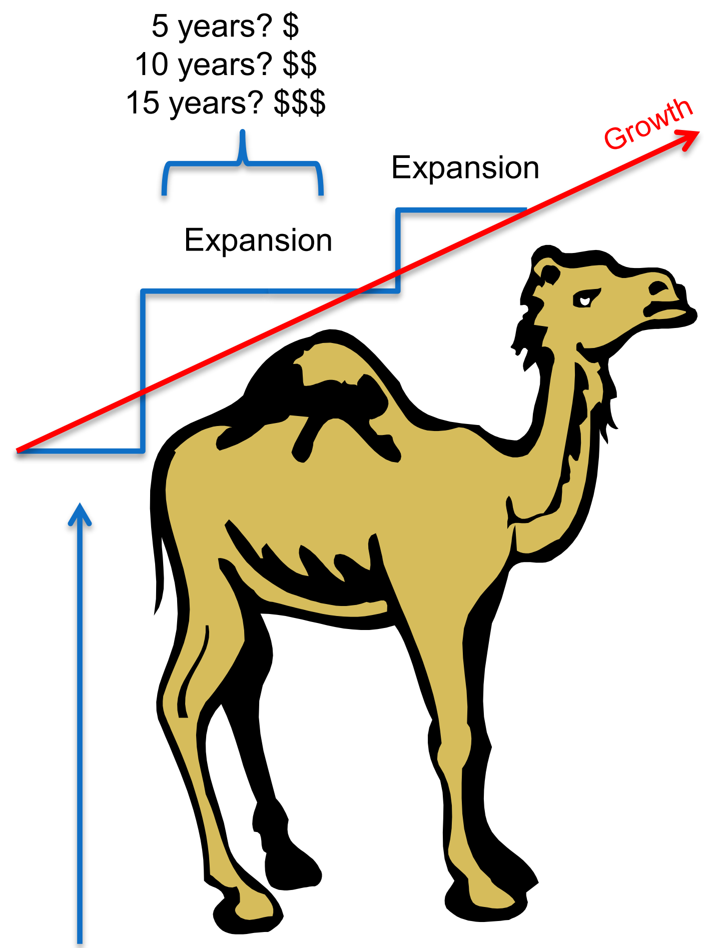
Firm Point to Point

Capacity Firm or Not?



Alternate capacity – flex delivery point
- Subject to cuts through constraints

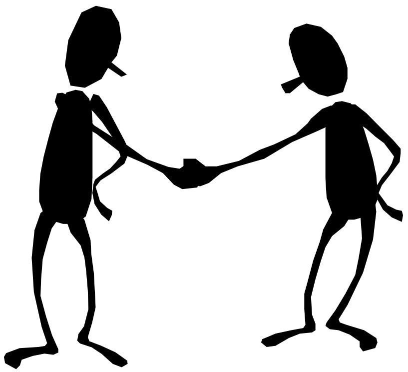
Pipeline Capacity can be "lumpy"



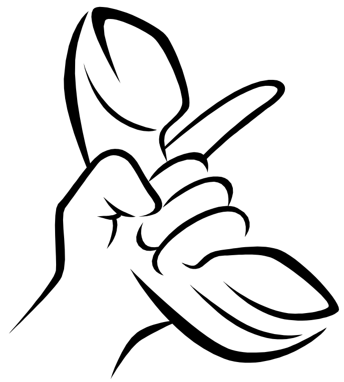
Alternatives can be expensive and timing unknown

How to Manage the “LUMPS”

- Transport Optimization
  - Contract Terms (seasonal)
  - Long term releases
  - Short term releases
  - Daily Optimization
  - Segmentation

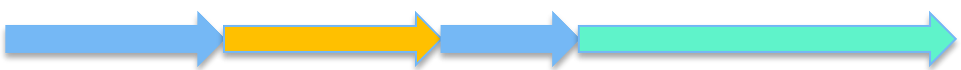


Long Term



Short Term

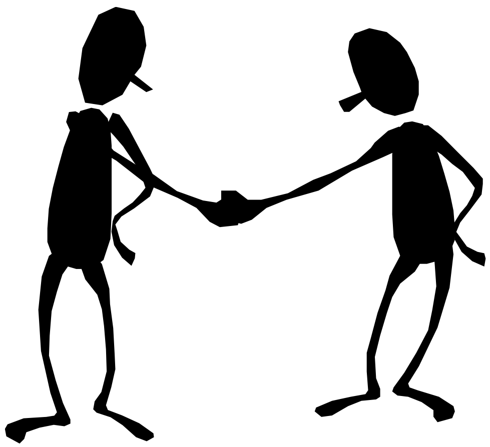
Daily basin spread arbitrage



Segmentation

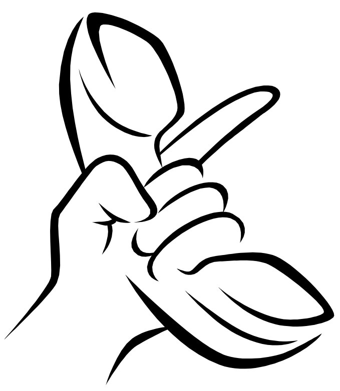
Long Term Releases

- 1 year – 20 plus years
- Negotiated – but subject to bidding
- Can be subject to recall
- Cannot exceed Maximum Rate

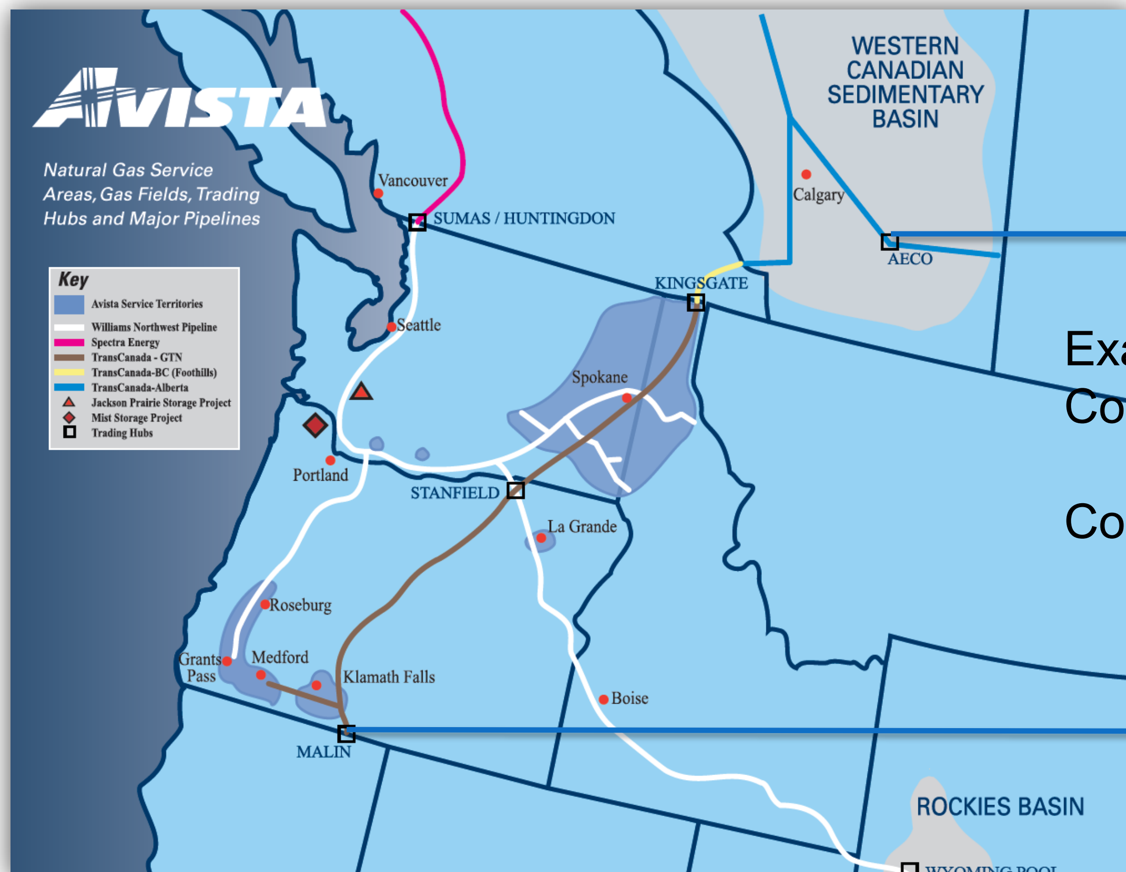


Short Term Releases

- Less than 1 year (can be for 1 day)
- Negotiated – but subject to bidding
- Can be posted for bidding only
- “Sweet Heart” rules prevent rolling from term to term
- Can be higher than Max Rate



Daily Transportation Optimization



AECO

Example:

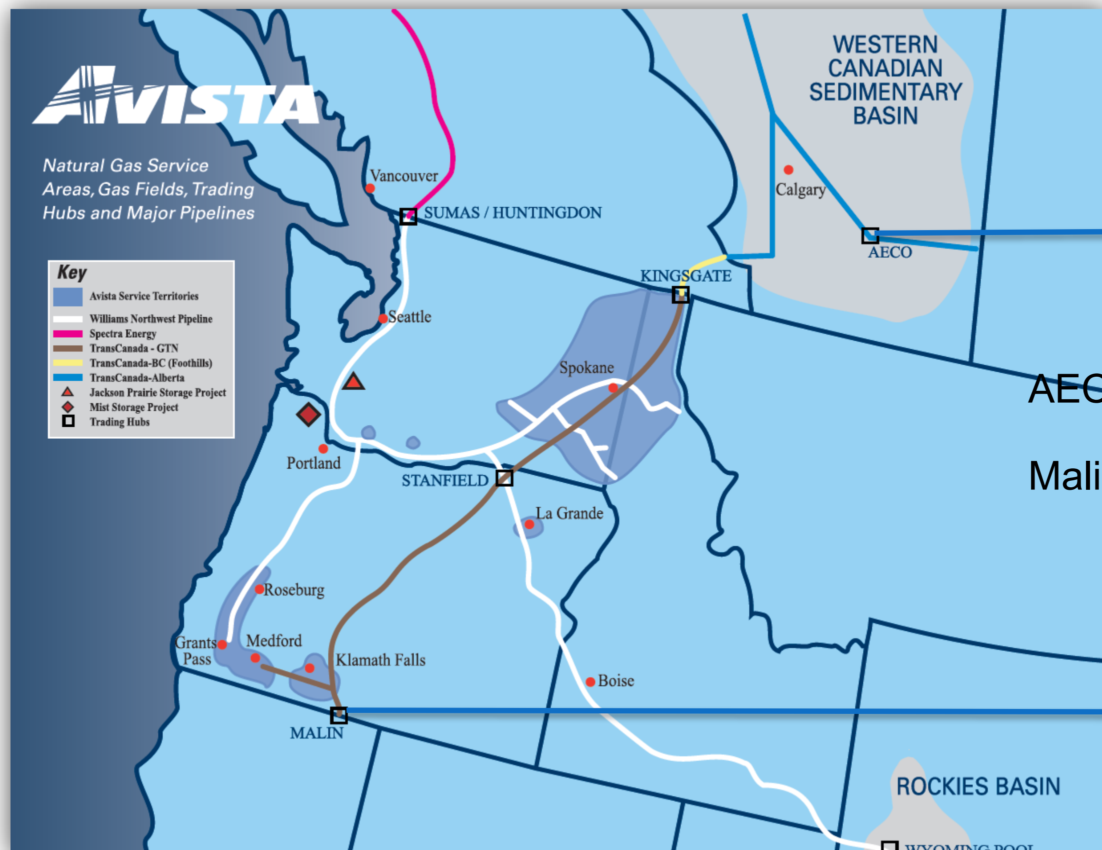
Cost to own transport is $0.70

- Whether used or not (demand)

Cost to actually move gas is $0.10

Malin

Daily Transportation Optimization



AECO

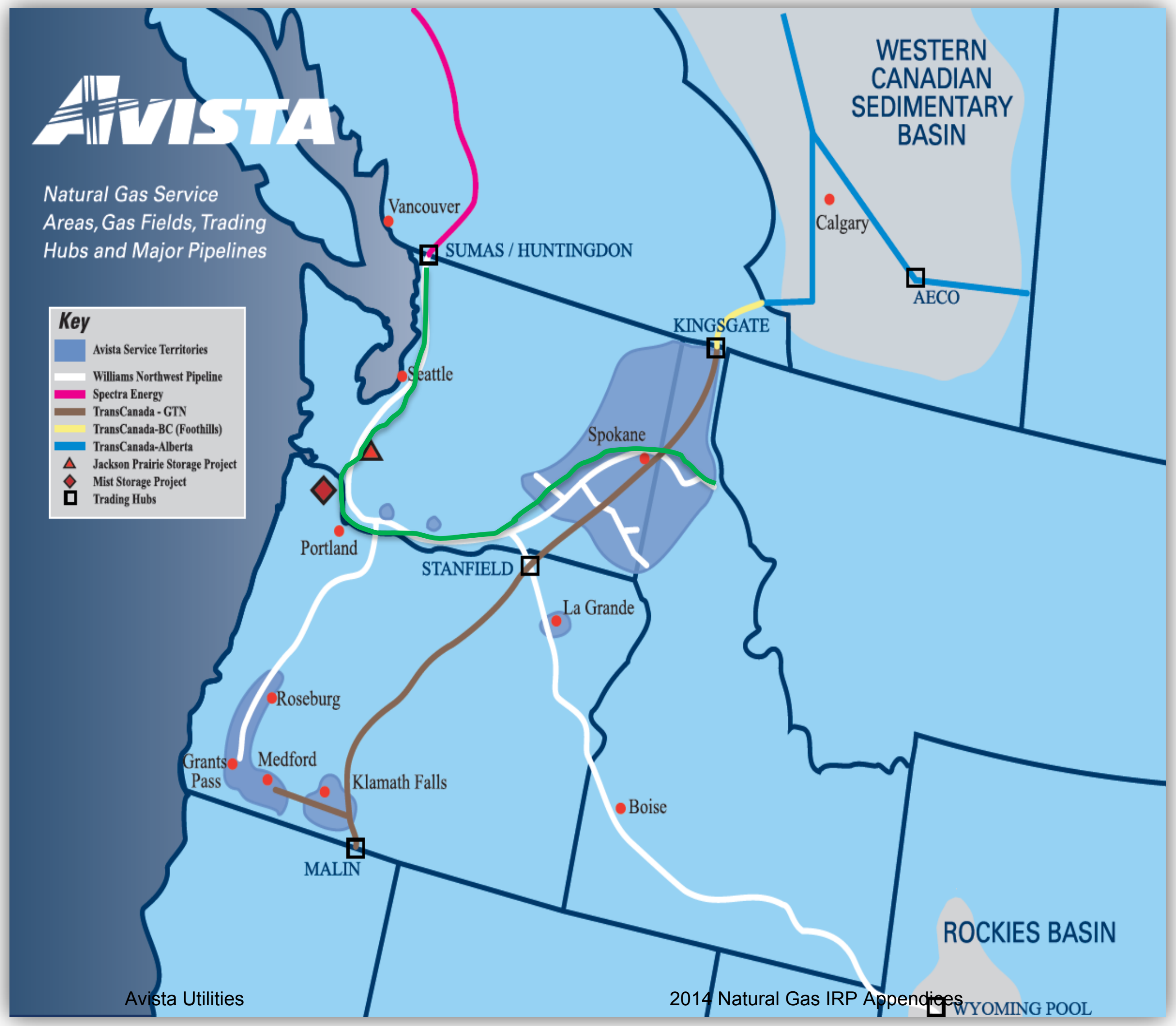
AECO Price is $4.00

Malin Price is $4.50

Malin

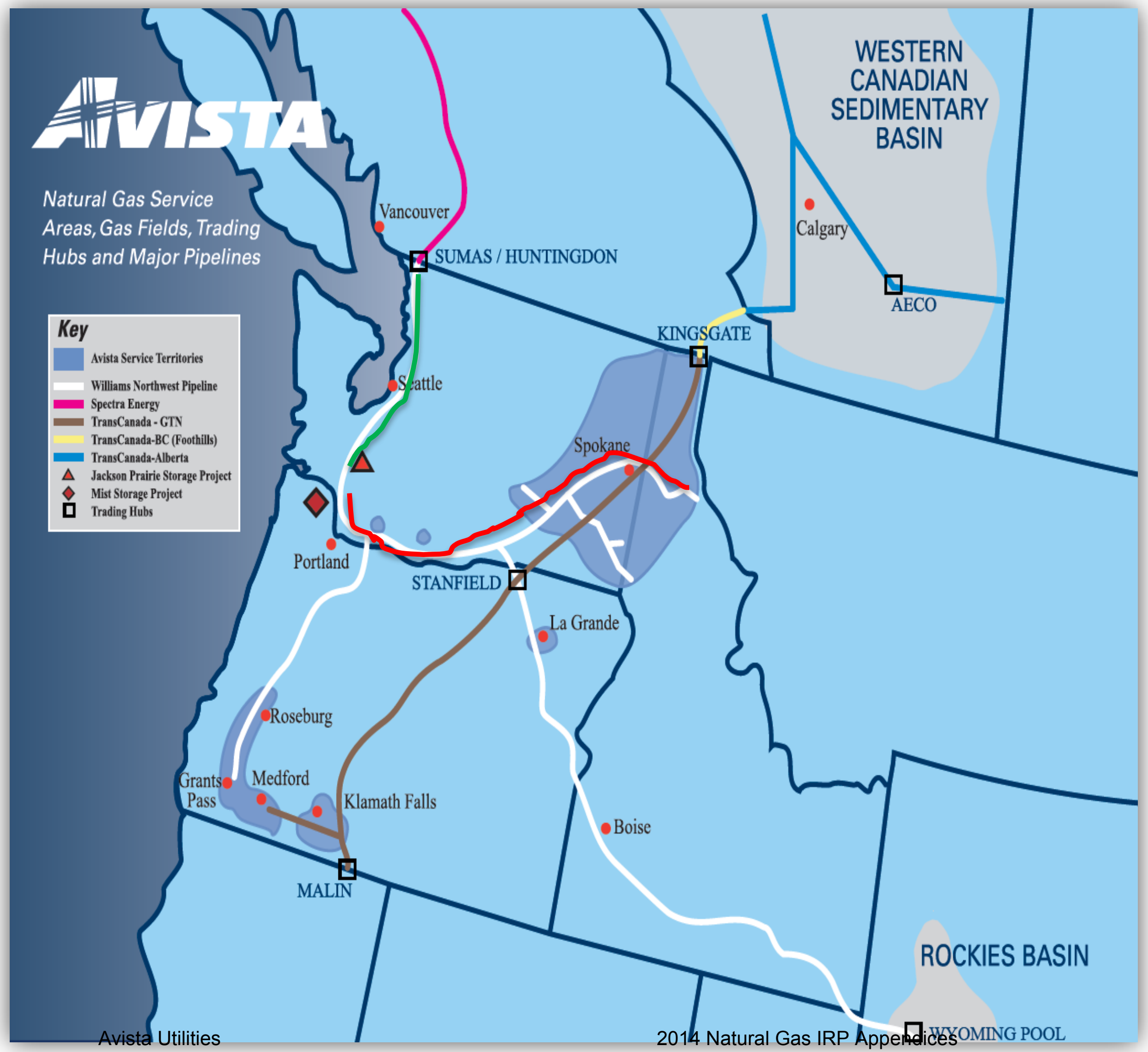
Buy AECO gas at $4.00
Pay $0.10 to transport it (fuel costs)
Sell Malin gas at $4.50
Net is $4.50-$4.00 is $0.50; less $0.10 to transport yields $0.40
We have reduced customer’s costs by $0.40

Segmentation



Primary Path:
Sumas to CDA
10,000 Dth/day
Guaranteed Delivery

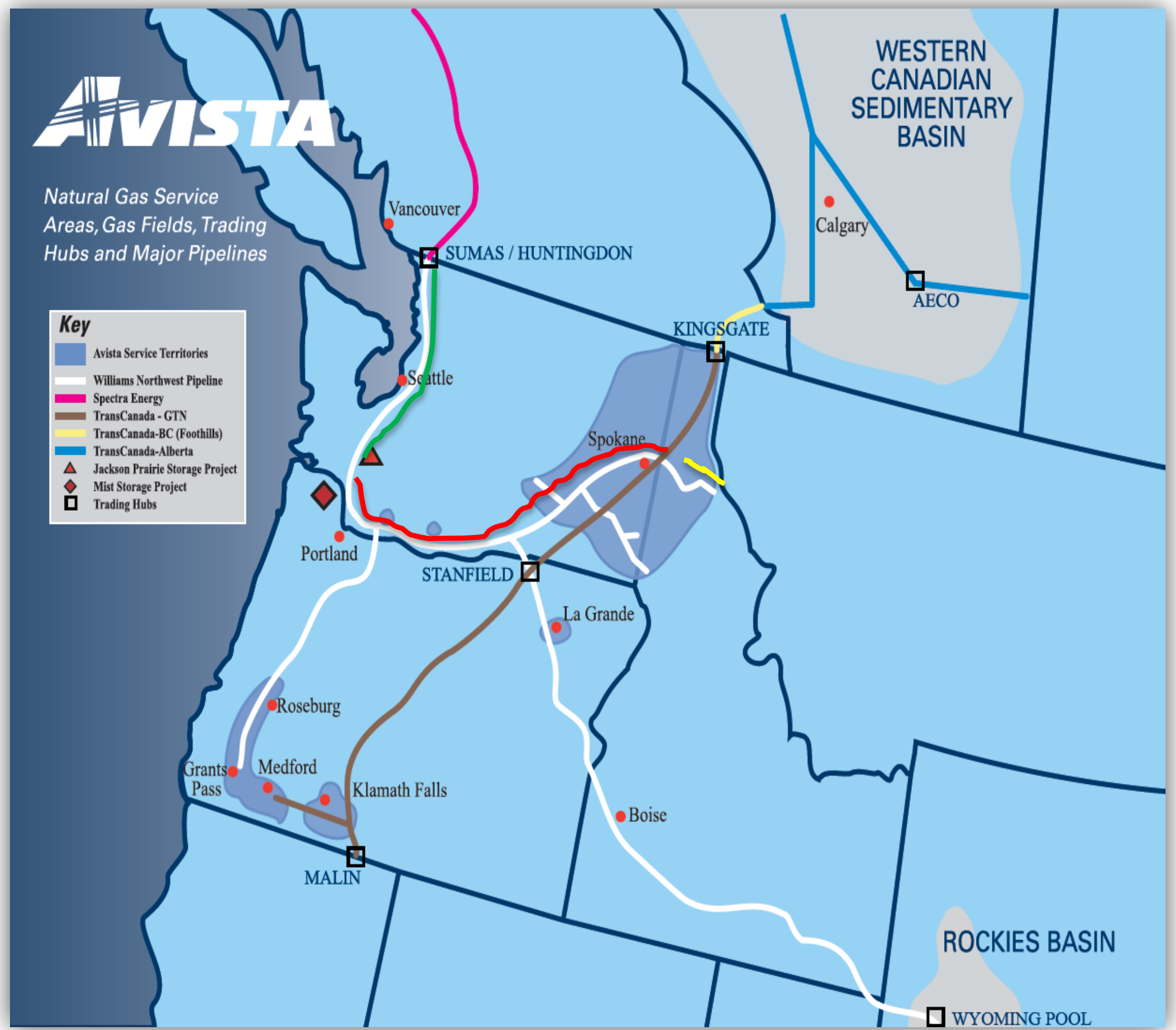
Segmentation



Segment:
Sumas to JP – FIRM
10,000 Dth/day

JP to CDA – FIRM
10,000 Dth/day

Segmentation



Segment:

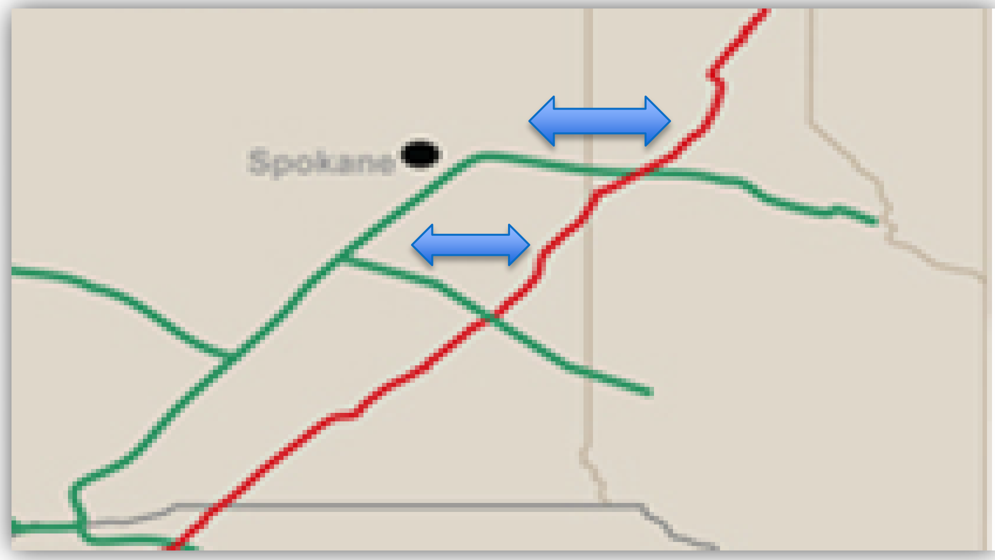
Sumas to JP – FIRM
10,000 Dth/day

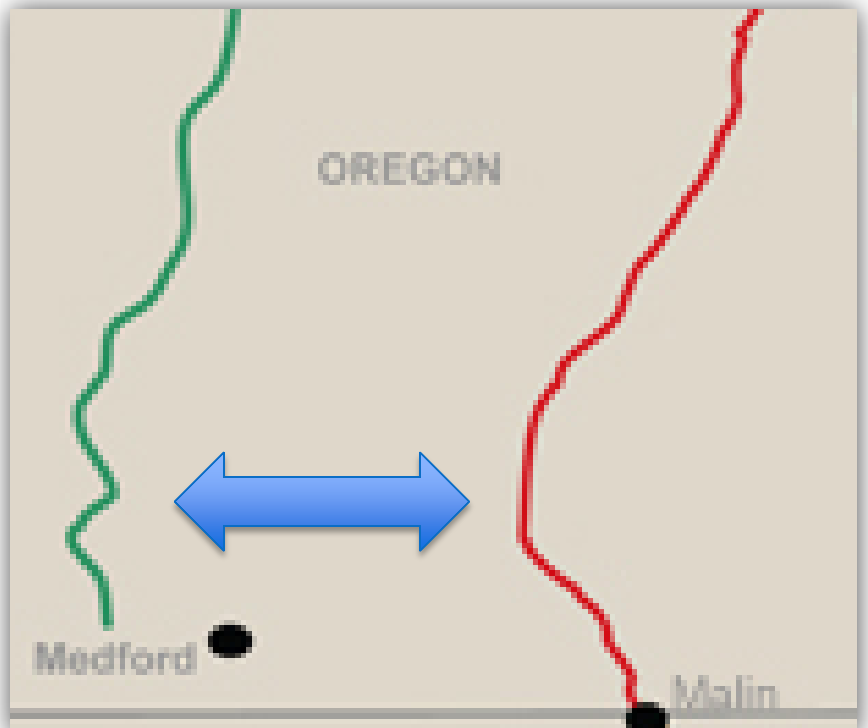
JP to Spokane – FIRM
10,000 Dth/day

Starr Rd to CDA – FIRM
10,000 Dth/day

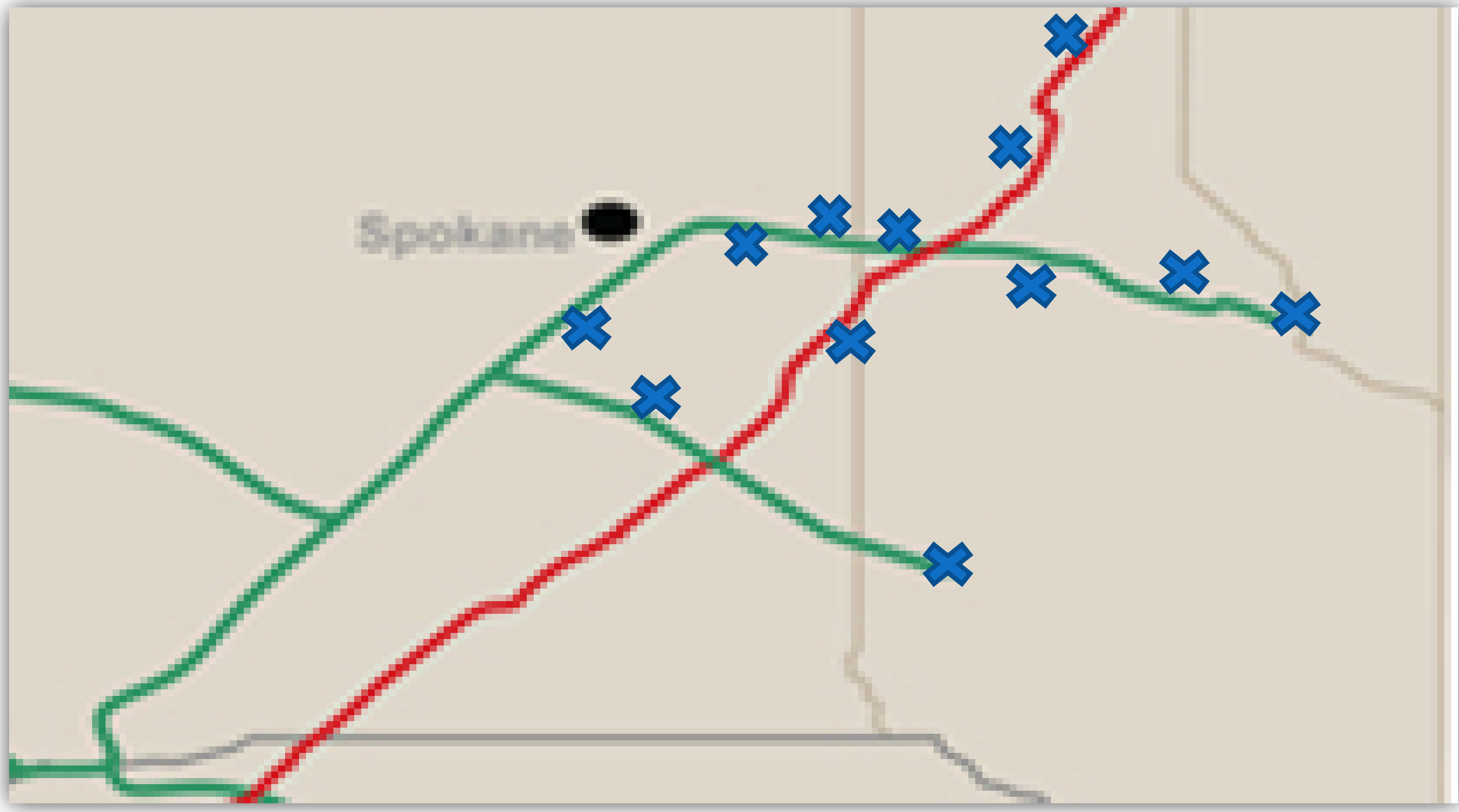
One payment
3 x capacity

Pipeline Optimization





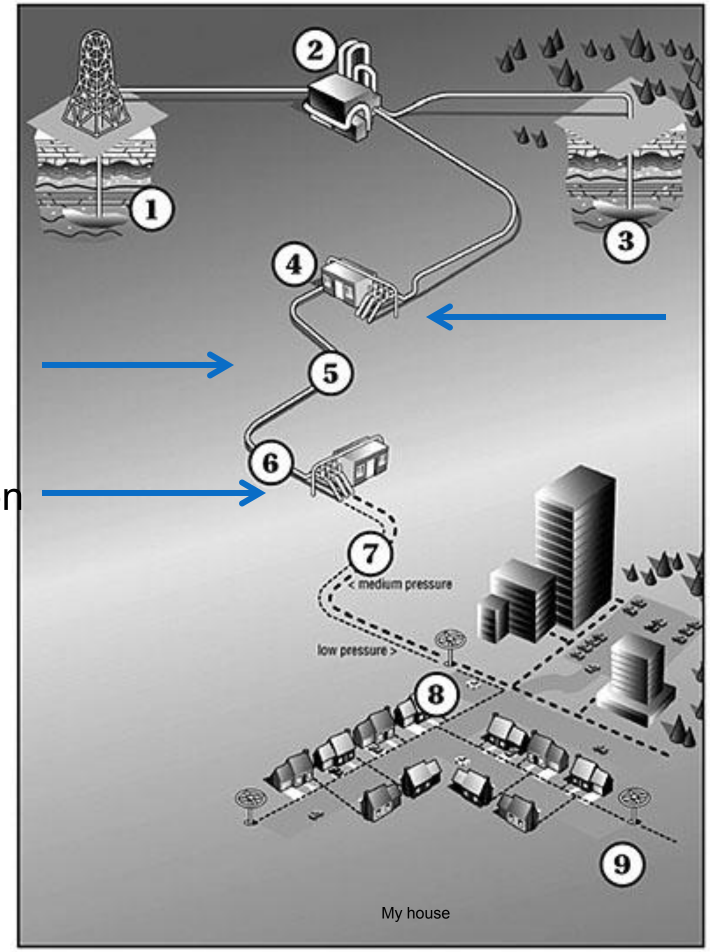
Points Along the Pipe



Gate Stations

Pipeline

Delivery Pt/Gate Station



Receipt Pt

Pipeline Contracting

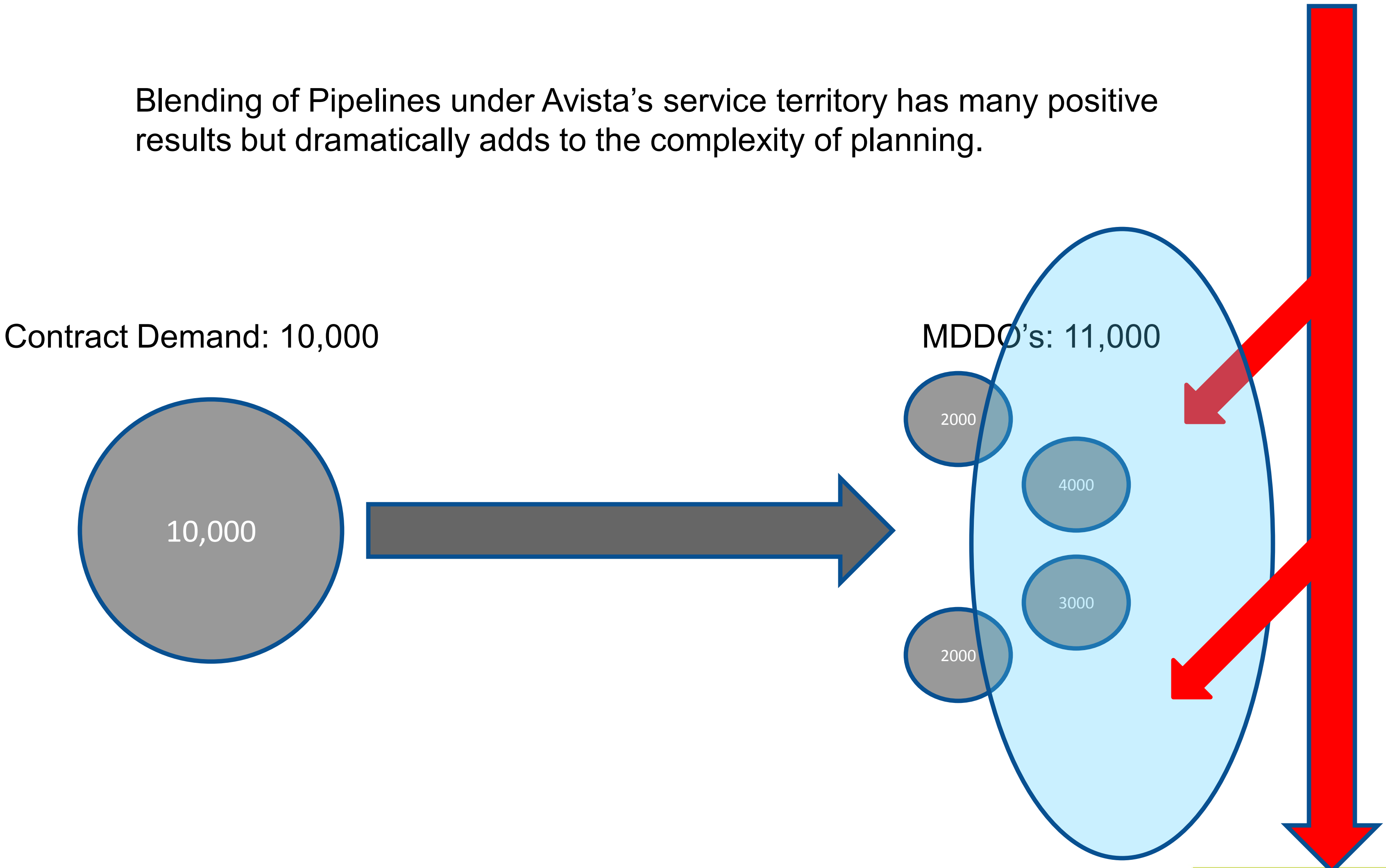
Gate stations may have the ability to deliver volume in excess of contract demand. This may be a result for future growth and construction efficiencies.

Contract Demand: 10,000

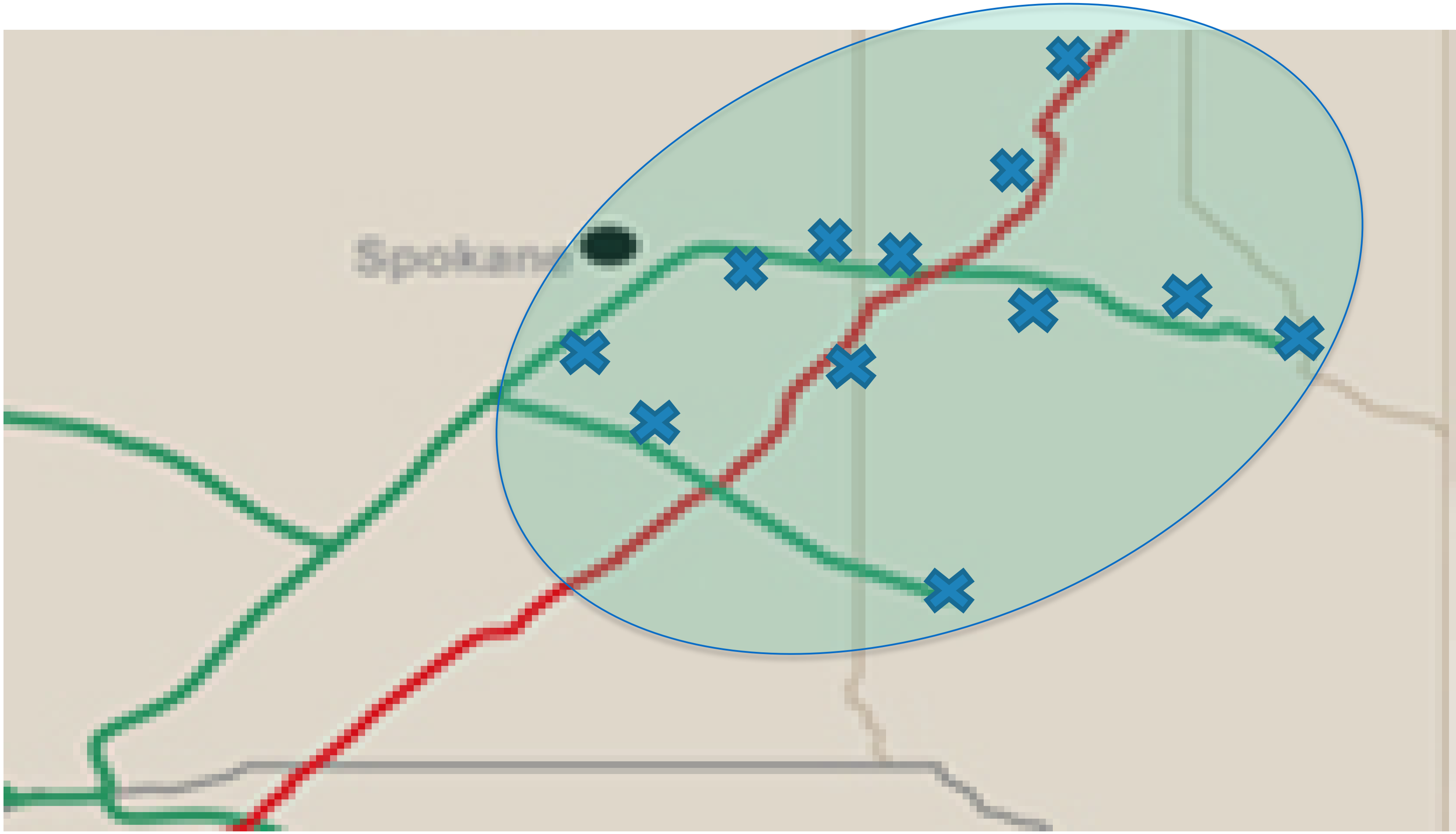
MDDO's: 11,000

Pipeline Contracting

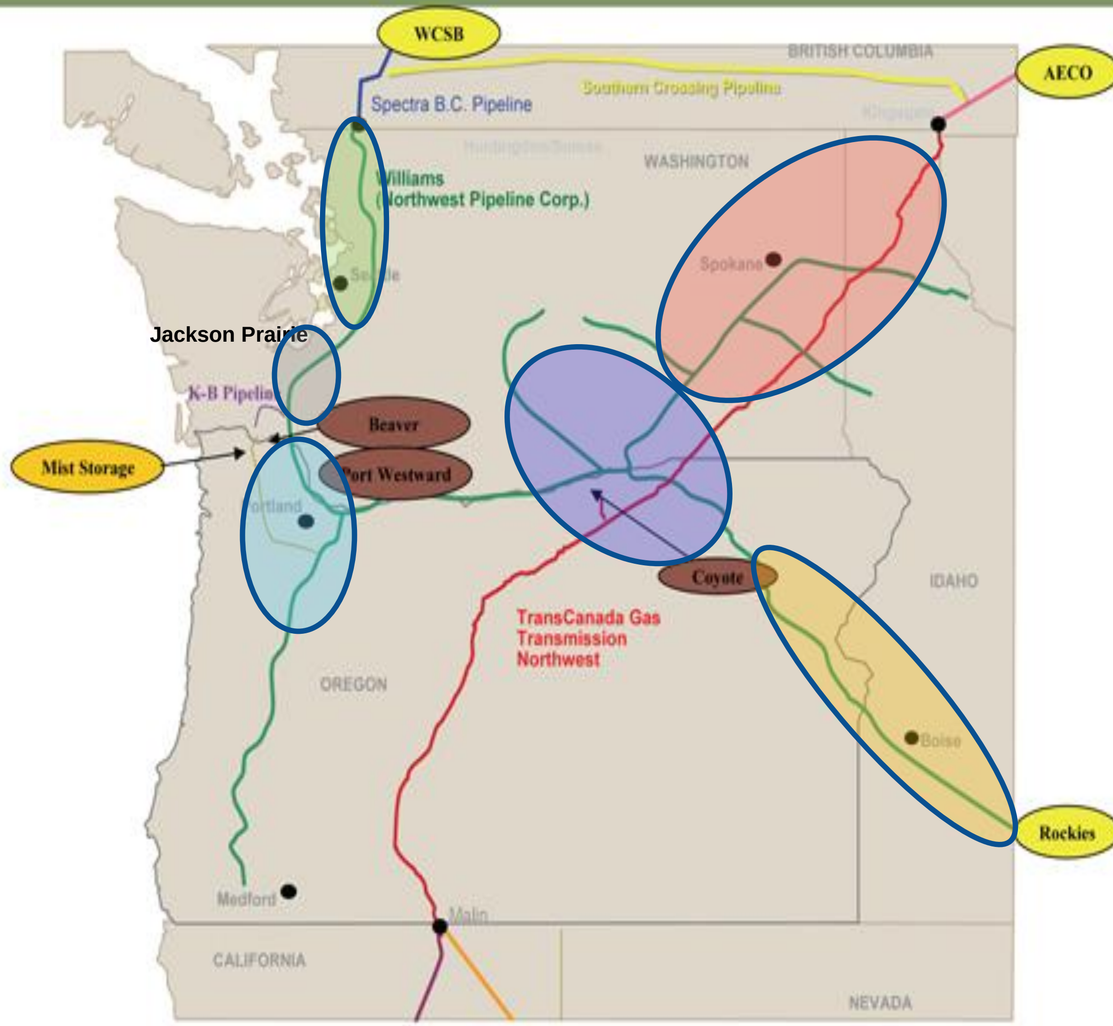
Blending of Pipelines under Avista's service territory has many positive results but dramatically adds to the complexity of planning.



Zones Along the Pipe



Natural Gas Transportation



Modeling Transportation In SENDOUT®

- Start with a point in time look at each jurisdiction's resources
  - Contracts – Receipt and Delivery Points
  - Rates
- Contractual vs. Operational
  - Contractual can be overly restrictive
  - Operational can be overly flexible
- Incorporating operational realities into our modeling can defer the need to acquire new resources.
- Gas Supply's job is to get gas from the supply basin to the pipeline citygate.
- Gas Engineering/Distribution's job is to take gas from the pipeline gate to our customers.
- The **major** limiting factor is receipt quantity – how much can you bring into the system?

Modeling Challenges

- Supply needs to get gas to the gate.
- Contracts were created years ago, based on demand projections at that point in time.
- Stuff happens (i.e. growth differs from forecast).
- Sum of receipt quantity and aggregated delivery quantity don't identify resource deficiency for quite some time however…..
- The aggregated look can mask individual city gate issues, and the disaggregated look can create deficiencies where they don't exist.
- In many cases operational capacity is greater than contracted.
- Transportation resources are interconnected (two pipes can serve one area).
- WARNING – we need to mindful of the modeling limitations.

What is in SENDOUT® ?

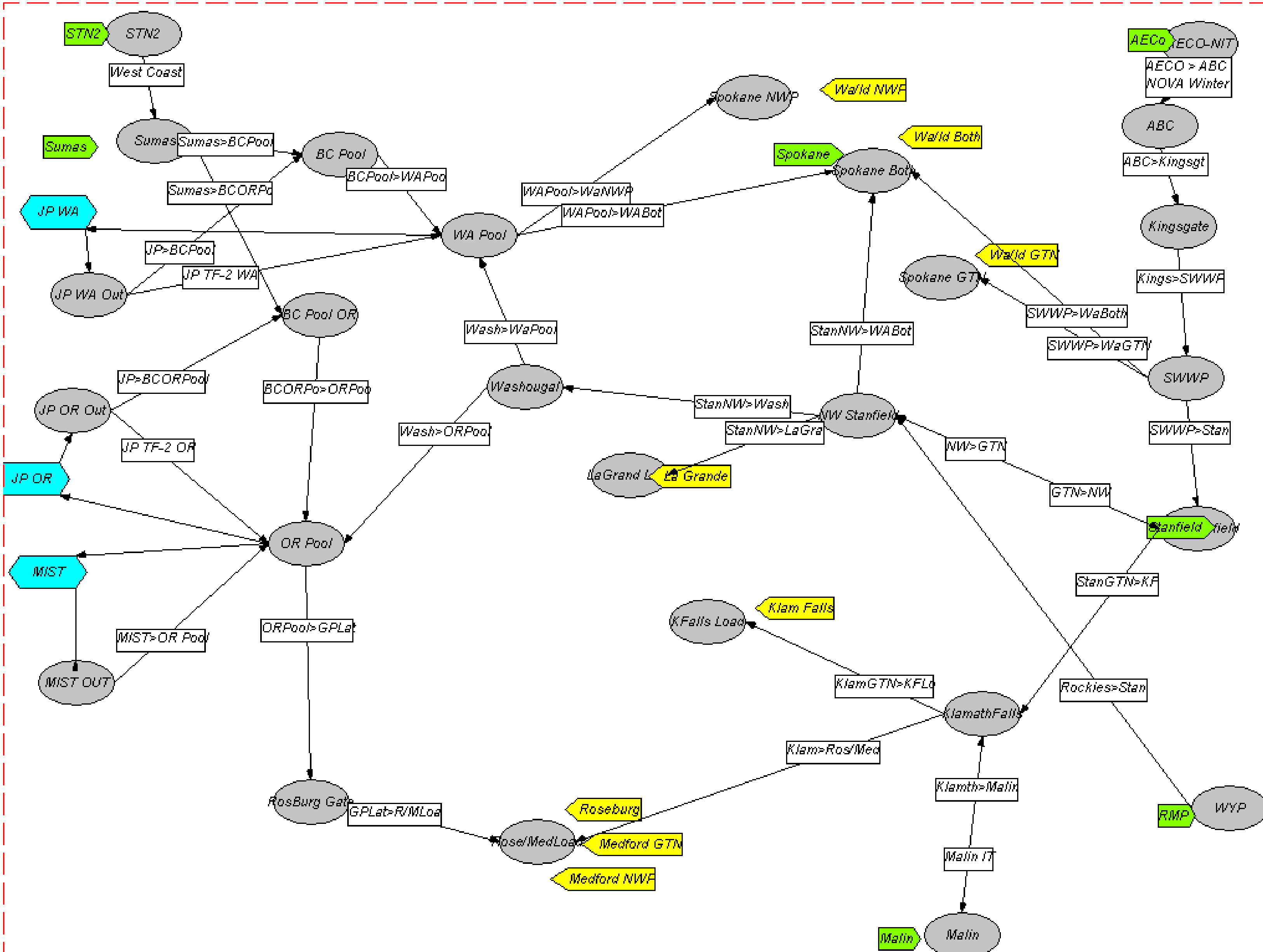
Inside:

- Demand forecasts at an aggregated level
- Existing transportation resources and current rates
  - Receipt point to aggregated delivery points/“zone”
  - Jurisdictional considerations
  - Long term capacity releases
- Potential resources, both supply and demand side

What is outside SENDOUT®?

Outside:

- Gate station analysis
  - Forecasted demand behind the gate
    - Growth rates consistent with IRP assumptions
    - Actual hourly/daily city gate flow data
  - Gate station MDDO's
  - Gate station operational capacities


STN2
STN2
West Coast
Sumas
Sumas
Sumas>BCPool
BC Pool
Sumas>BCORPo
BCPool>WAPoo
JP WA
JP>BCPool
JP TF-2 WA
JP WA Out
WA Pool
WAPool>WaNWP
WAPool>WABot
Spokane NWP
Wa/ld NWP
Wa/ld Both
Spokane
Spokane Both
BC Pool OR
JP>BCORPool
BCORPo>ORPoo
Wash>WaPool
Washougal
Wash>ORPool
JP OR Out
JP TF-2 OR
JP OR
OR Pool
MIST
MIST>OR Pool
MIST OUT
ORPool>GPLat
RosBurg Gate
GPLat>R/MLoa
Rose/MedLoad
Roseburg
Medford GTN
Medford NWP
AECo
AECO-NIT
AECO > ABC
NOVA Winter
ABC
ABC>Kingsgt
Kingsgate
Kings>SWWP
Wa/ld GTN
Spokane GTN
SWWP>WaBoth
SWWP>WaGTN
StanNW>WABot
SWWP
StanNW>Wash
NW Stanfield
StanNW>LaGra
LaGrand L
La Grande
NW>GTN
GTN>NW
SWWP>Stan
Stanfield
Stanfield
StanGTN>KF
Klam Falls
KFalls Load
KlamGTN>KFLo
KlamathFalls
Klam>Ros/Med
Rockies>Stan
Klamth>Malin
Malin IT
Malin
Malin
RMP
WYP

City Gate Analysis

City Gate Analysis Issues to Address

- MDQ vs. MDDO
- Our gate vs. Pipeline gate
- Operational capacity vs. contracted capacity
- Pipeline differences
  - Zonal vs. Point Specific
  - Laterals and Mainlines

Forecasting Demand Behind the Gate

- Our IRP desire has always been to forecast to as granular a level as possible using the available data.

- Attempts to forecast demand behind the gate using existing forecasting methodology has been challenging.
    - Revenue data does not have daily meter reads for core customers making regression analysis on a use per HDD per customer difficult.
    - DSM would become more burdensome than it already is.
    - Some towns can be served by multiple pipelines and the mix can change over time.

Forecasting Demand Behind the Gate cont.

While there are challenges, there is modeling that we can do to help identify more granular city gate deficiencies.

- Utilize daily/hourly pipeline flow data from each meter station to estimate what demand could be on a peak day or any heating degree day.
- Apply growth factors to estimate what the demand could grow to consistent with IRP assumptions/methodology.

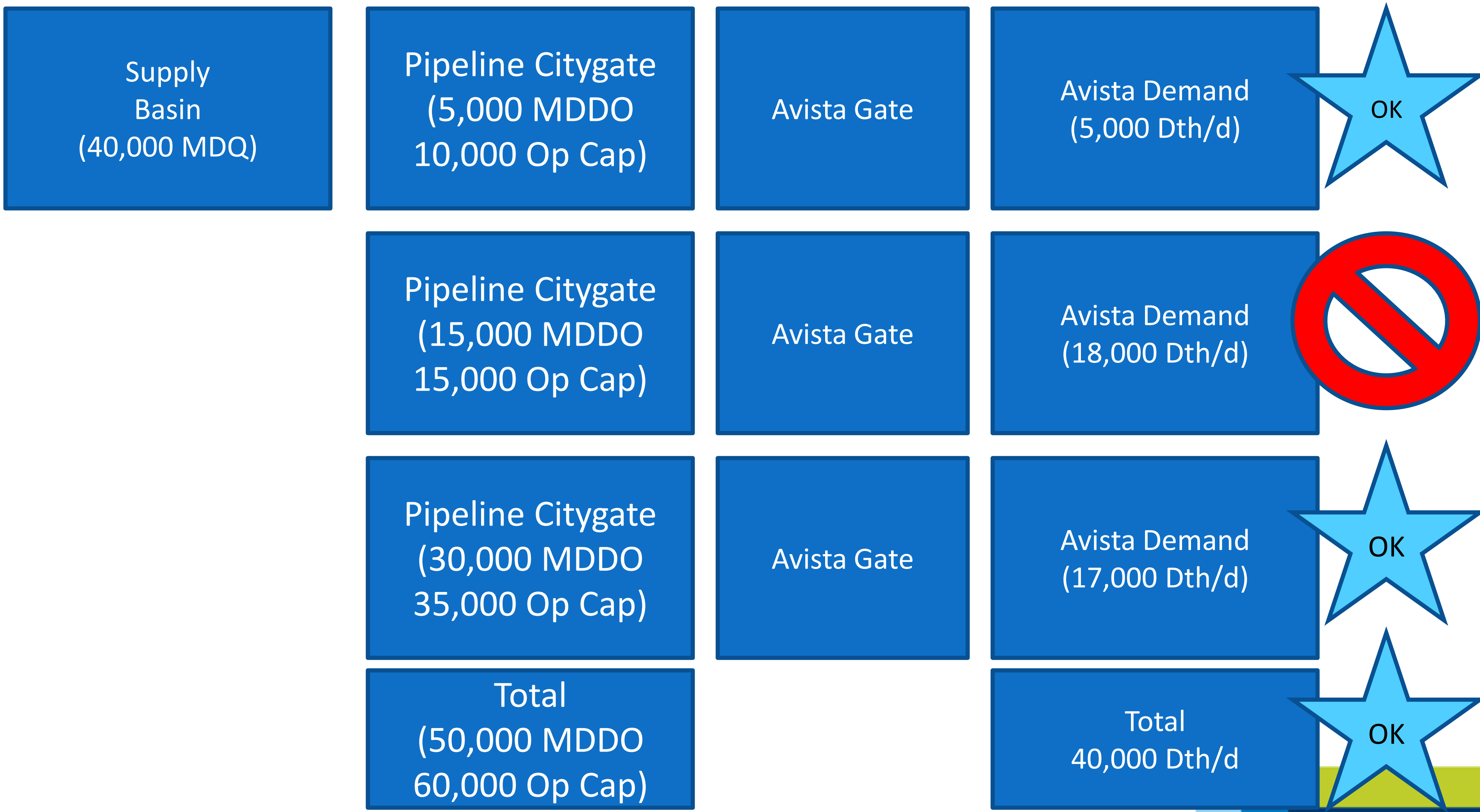
The Pieces and Parts

Supply Basin (40,000 MDQ)	• Contracted MDQ • Basis for billing (i.e. what we pay for)
Pipeline Citygate (15,000 MDDO 18,000 Op Cap)	• Contracted MDDO • Operational Capacity • Not always the same volumes, provides flexibility on the system
Avista Gate	• Point where the gas enters the LDC's system
Avista Demand (5,000 Dth/d)	• What's behind the gate?

From Supply Basin to Meet Demand

Supply Basin (40,000 MDQ)	Pipeline Citygate (5,000 MDDO 10,000 Op Cap)	Avista Gate	Avista Demand (5,000 Dth/d)
	Pipeline Citygate (15,000 MDDO 15,000 Op Cap)	Avista Gate	Avista Demand (18,000 Dth/d)
	Pipeline Citygate (30,000 MDDO 35,000 Op Cap)	Avista Gate	Avista Demand (17,000 Dth/d)
	Total (50,000 MDDO 60,000 Op Cap)		Total 40,000 Dth/d

Not all gates are created equal



Where is the deficiency?

Interstate Pipeline Issue		Avista Distribution Issue	
Supply Basin (40,000 MDQ)	Pipeline Citygate (5,000 MDDO 10,000 Op Cap)	Avista Gate	Avista Demand (5,000 Dth/d)
	Pipeline Citygate (15,000 MDDO 15,000 Op Cap)	Avista Gate	Avista Demand (18,000 Dth/d)
	Pipeline Citygate (30,000 MDDO 35,000 Op Cap)	Avista Gate	Avista Demand (17,000 Dth/d)
	Total (50,000 MDDO 60,000 Op Cap)		Total 40,000 Dth/d

Where is the deficiency?

Pipeline Issue

Supply Basin (40,000 MDQ)	Pipeline Citygate (5,000 MDDO 10,000 Op Cap)
	Pipeline Citygate (15,000 MDDO 15,000 Op Cap)
	Pipeline Citygate (30,000 MDDO 35,000 Op Cap)
	Total (50,000 MDDO 60,000 Op Cap)

- Can they get you the supply you have contracted for?
- Can they get it through the gate?

Solutions

- Mainline expansion
- Upgrade the meter station
- Realignment of MDDO

Where is the deficiency?

- Do you have enough mainline capacity?
- Is it a gate station design issue?
- What is your demand behind the gate?

Solutions

- Distribution system enhancements
  - High pressure looping
  - New gate station
- Recall capacity releases
- Acquire additional pipeline capacity
  - Existing
  - Expansion
- Storage
  - On system vs. Off System
- Peaking agreements

Avista Issue

Avista Gate	Avista Demand (5,000 Dth/d)
Avista Gate	Avista Demand (18,000 Dth/d)
Avista Gate	Avista Demand (17,000 Dth/d)
	Total 40,000 Dth/d

Solving Unserved Demand

When unserved demand does show up……

There are few questions we need to ask:

1. Why is the demand unserved?
2. What is the magnitude of the short? (i.e Are we 1 Dth or 1000 Dth's short?)
3. What are my options to meet it?

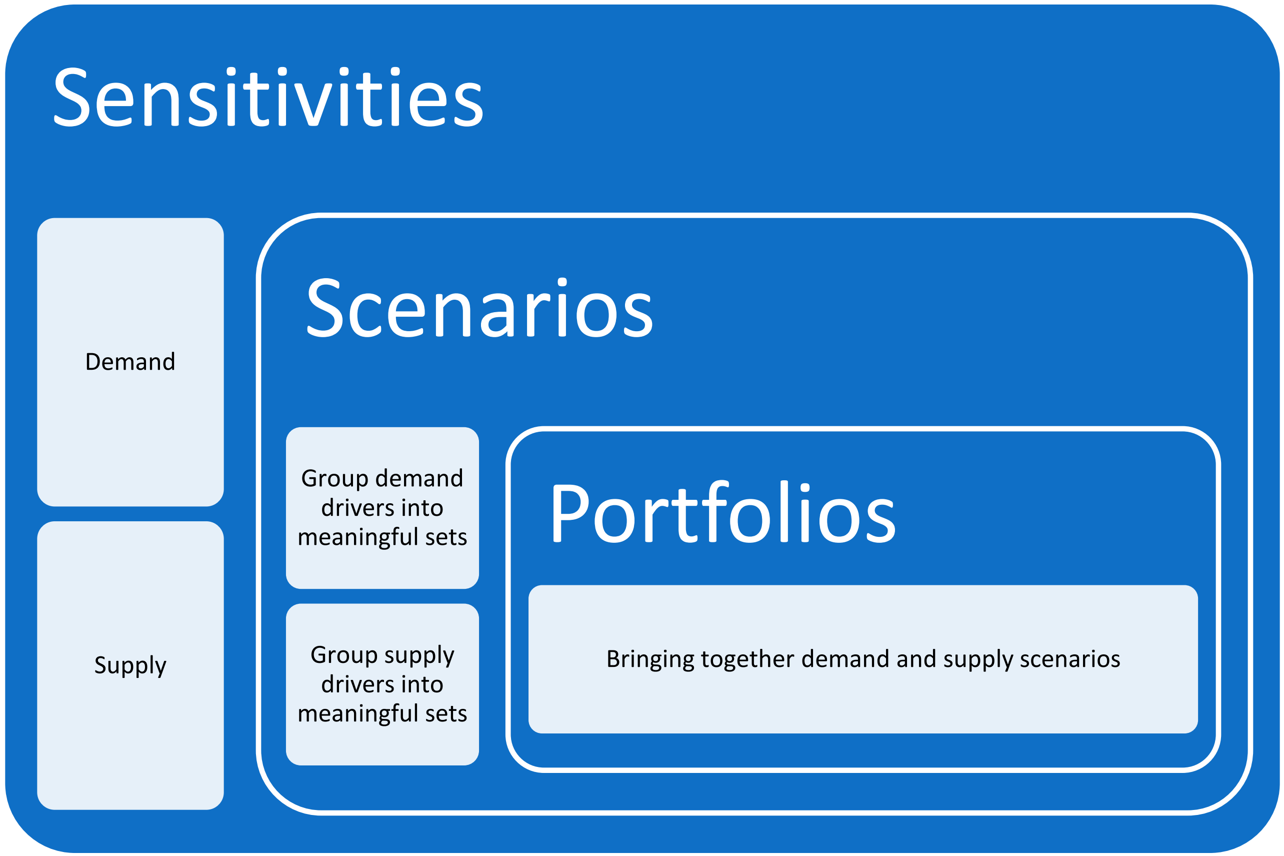
When current resources don't meet demand what do we consider?

- Transport capacity release recalls
- "Firm" backhauls
- Contract for existing available transportation
- Expansions of current pipelines
- Peaking arrangements with other utilities (swaps/mutual assistance agreements) or marketers
- In-service territory storage
- Satellite/Micro LNG (storage inside service territory)
- Large scale LNG with corresponding pipeline build into our service territory
- Structured products/exchange agreements delivered to city gates
- Biogas
- Avista distribution system enhancements
- Demand side management

New Resource Risk Considerations

- Does is get supply to the gate?
- Is it reliable/firm?
- Does it have a long lead time?
- How much does it cost?
    - New build vs. depreciated cost
    - The rate pancake
- Is it a base load resource or peaking?
- How many dekatherms do I need?
- What is the “shape” of resource?
- Is it tried and true technology, new technology, or yet to be discovered?
- Who else will be competing for the resource?

Sensitivities, Scenarios, Portfolios



Supply Scenarios from the 2012 IRP

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

Supply Scenarios for the 2014 IRP

Supply Scenarios
?????
?????
?????
?????

- Do they get gas to the gate?
- Does this affect pricing at the basins?
- Rank the risk of these scenarios.

Questions?

2014 IRP Timeline

- **August 31, 2013** – Work Plan filed with WUTC
- **January through April 2014** – Technical Advisory Committee meetings. Meeting topics will include:
  - Demand Forecast and Demand Side Management – January 24
  - Supply and Infrastructure, Gate Station Analysis, Supply Side Resources, Resource Optimization – *February 25*
  - **Distribution Planning, Natural Gas Pricing, CNG/NGV, SENDOUT® Preliminary Results and Further Case Discussion – *March 26***
  - SENDOUT® results – *April 23*
- **May 30, 2014 –** Draft of IRP document to TAC
- **June 30, 2014 –** Comments on draft due back to Avista
- **July 2014 –** TAC final review meeting (if necessary)
- **August 31, 2014 –** File finalized IRP document

2014 Avista Natural Gas IRP

Technical Advisory Committee Meeting 3

March 26, 2014

Coeur d’Alene, ID

Agenda

- Introductions & Logistics
- Distribution System Planning
- CNG/NGV Initiatives
- Natural Gas Prices
- Procurement Planning
- Preliminary Results and Scenario Discussion

2014 IRP Timeline

- **August 31, 2013** – Work Plan filed with WUTC
- **January through April 2014** – Technical Advisory Committee meetings. Meeting topics will include:
  - Demand Forecast and Demand Side Management – January 24
  - Supply and Infrastructure, Gate Station Analysis, Supply Side Resources, Resource Optimization – *February 25*
  - **Distribution Planning, Natural Gas Pricing, CNG/NGV, SENDOUT® Preliminary Results and Further Case Discussion –** ***March 26***
  - DSM CPA results, further SENDOUT® results and Stochastic analysis – *April 23*
- **May 30, 2014 –** Draft of IRP document to TAC
- **June 30, 2014 –** Comments on draft due back to Avista
- **July 2014 –** TAC final review meeting (if necessary)
- **August 31, 2014 –** File finalized IRP document

Distribution System Planning

Terrence Browne, Senior Gas Planning Engineer

Natural Gas Technical Advisory Committee
March 26, 2014

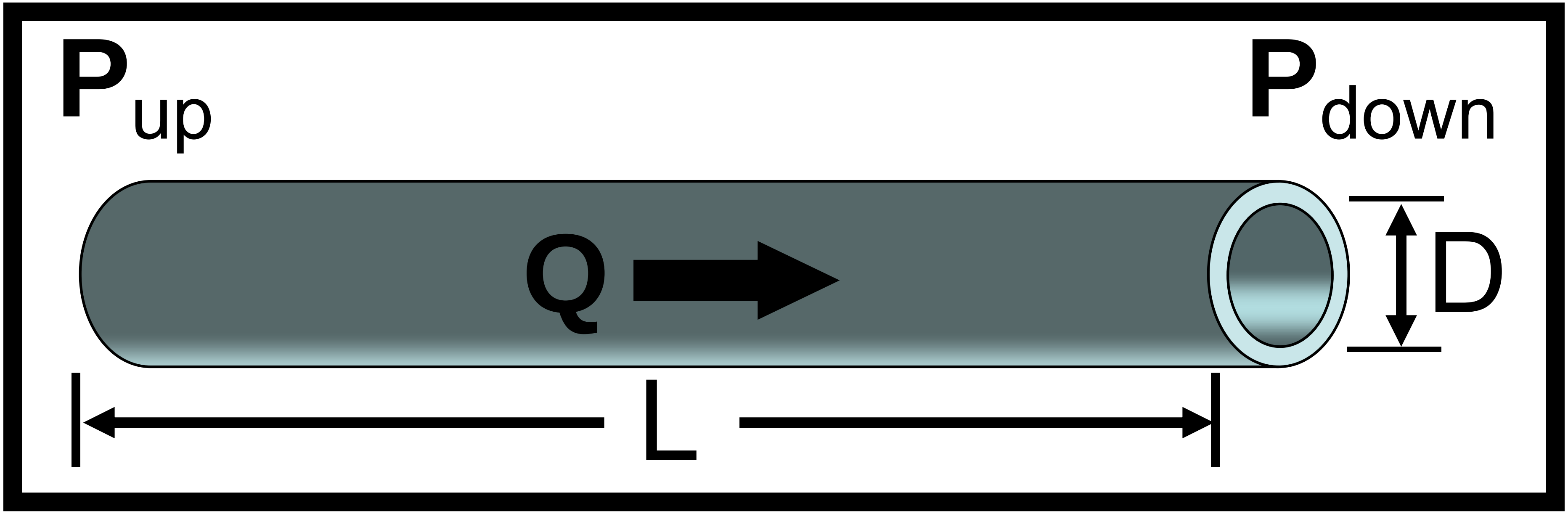
Mission

- Using technology to plan and design a safe, reliable, and economical distribution system

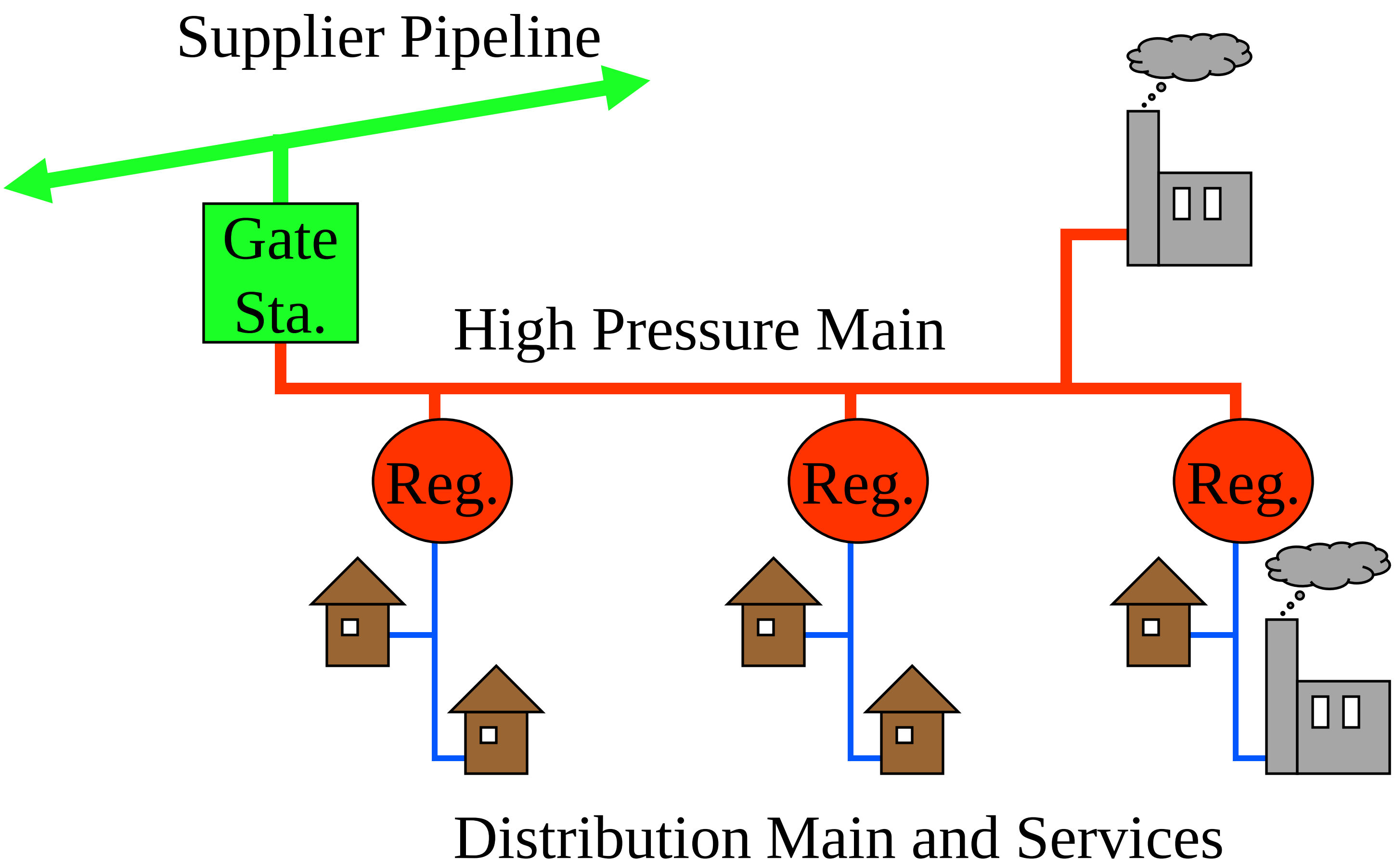
Gas Distribution Planning Overview

- Scope of Gas Distribution Planning
- SynerGEE Load Study
  - Preparing a Load Study
  - Balancing Model
  - Validating Model
- Planning Criteria
- Interpreting Results
- Long-term Planning Objectives
- Sharing Load Study Results
- Electronic Pressure Recorders
- Project Examples

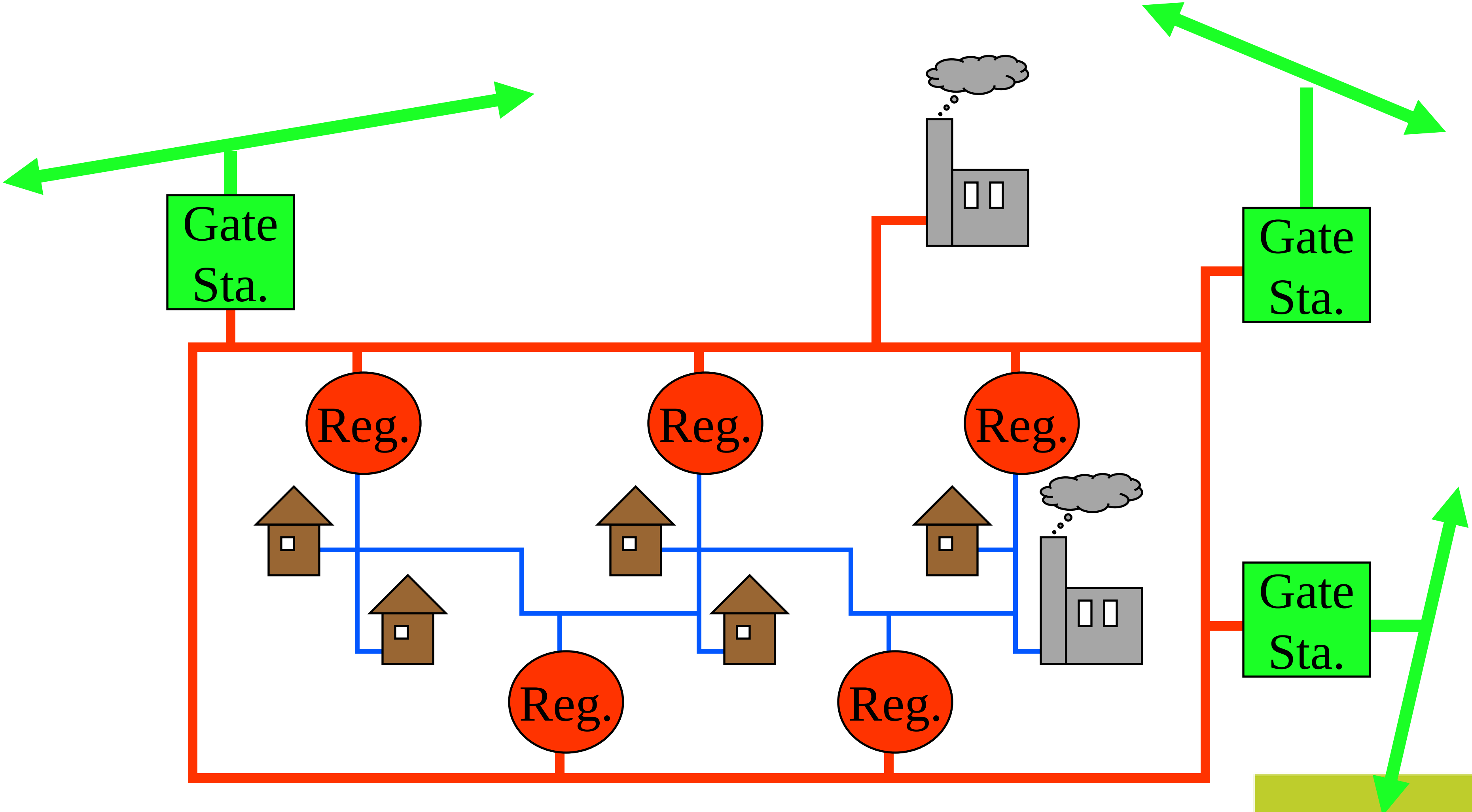
5 Variables for Any Given Pipe



Scope of Gas Distribution Planning

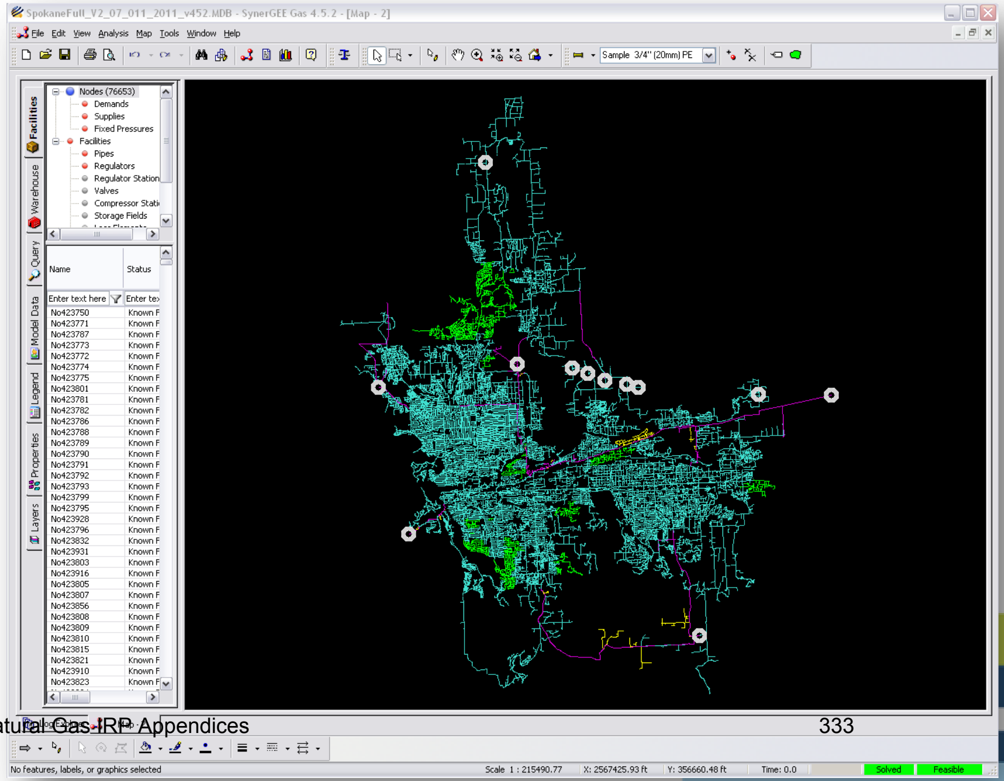


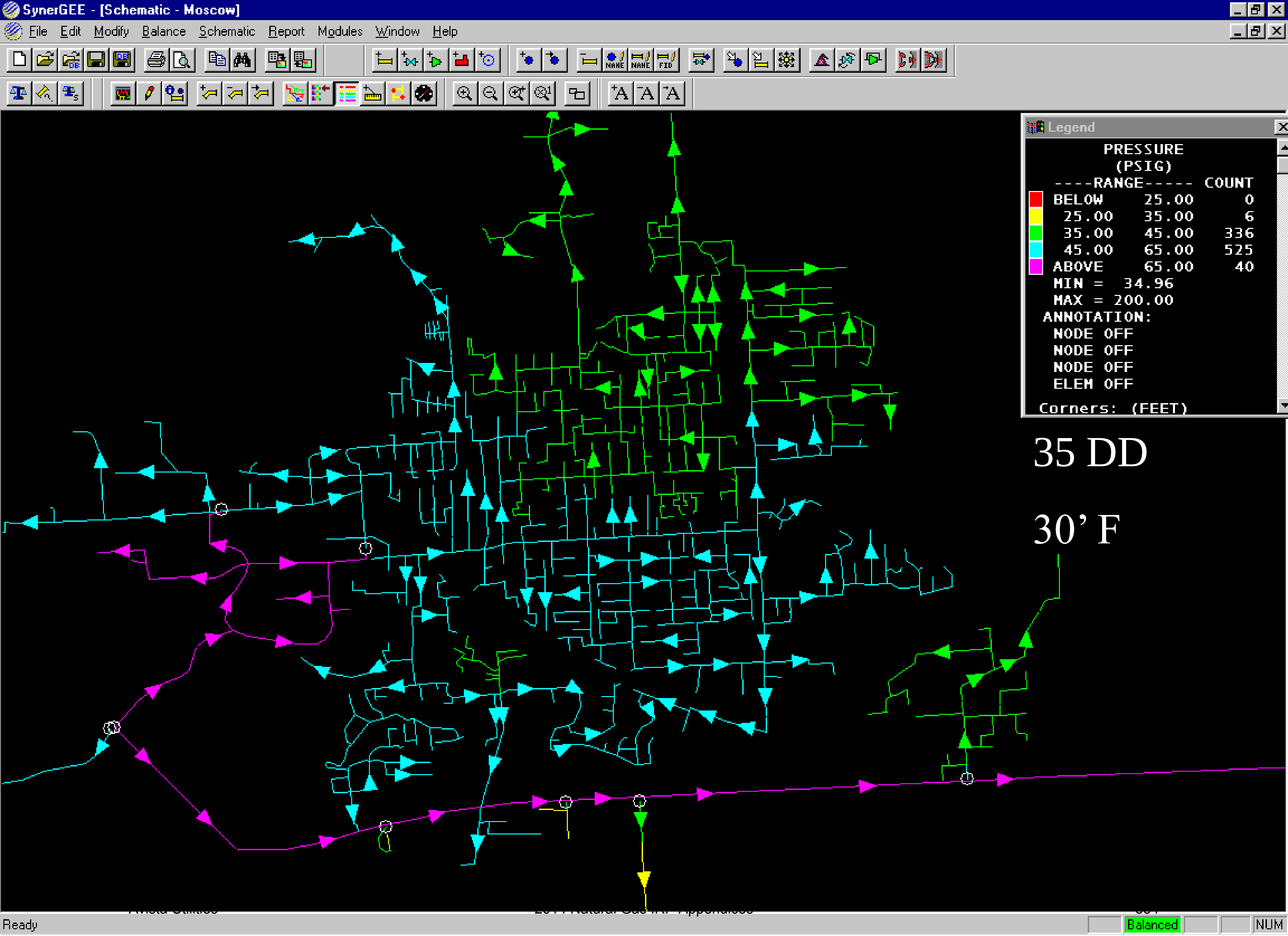
Scope of Gas Distrib. Planning cont.



SynerGEE Load Study

- Simulate distribution behavior
- Identify low pressure areas
- Coordinate reinforcements with expansions
- Measure reliability




SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
Legend
PRESSURE
(PSIG)
----RANGE----- COUNT
BELOW 25.00 0
25.00 35.00 6
35.00 45.00 336
45.00 65.00 525
ABOVE 65.00 40
MIN = 34.96
MAX = 200.00
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Corners: (FEET)
35 DD
30' F
Ready
Balanced
NUM

Preparing a Load Study

- Estimating Customer Usage
- Creating a Pipeline Network
- Join Customer Loads to Pipes
- Convert to Load Study

Estimating Customer Usage

- Gathering Data
  - Days of service
  - Degree Days
  - Usage
  - Name, Address, Revenue Class, Rate Schedule…

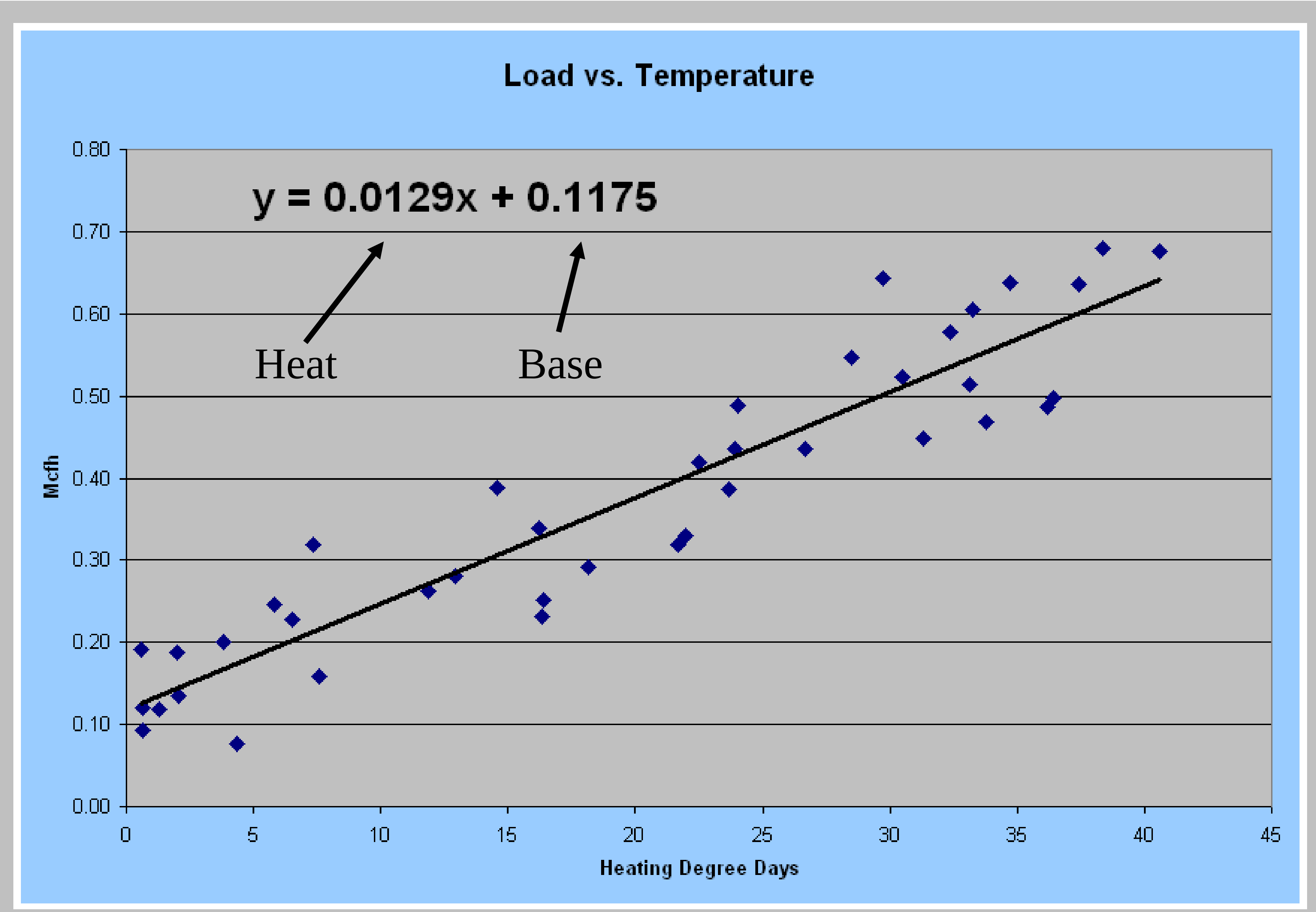
Estimating Customer Usage cont.

- Degree Days
  - Heating (HDD)
  - Cooling (CDD)
- Temperature - Usage Relationship
  - Load vs. HDD's
  - Base Load (constant)
  - Heat Load (variable)
  - High correlation with residential

Avg. Daily Temperature ('Fahrenheit)	Heating Degree Days (HDD)	Cooling Degree Days (CDD)
85		20
80		15
75		10
70		5
65	***0***	***0***
60	5	
55	10	
50	15	
45	20	
40	25	
35	30	
30	35	
25	40	
20	45	
15	50	
10	55	
5	60	
4	61	
0	65	
-5	70	
-10	75	
-15	80	
-17	82	

Begin Date	Read Date	RBC	Dys Svc	Deg Dys	Usage	Therm/Day	*DD/day	mcfh/day
01-23-2002	02-22-2002	RR	30	971	2775	92.5	32.36667	0.58
12-21-2001	01-23-2002	RR	33	1195	2567	77.78788	36.21212	0.49
11-20-2001	12-21-2001	RR	31	1028	2547	82.16129	33.16129	0.51
10-24-2001	11-20-2001	RR	27	586	1379	51.07407	21.7037	0.32
09-24-2001	10-24-2001	RR	30	491	1208	40.26667	16.36667	0.25
08-22-2001	09-24-2001	RR	33	67	715	21.66667	2.030303	0.14
07-24-2001	08-22-2001	RY	29	19	432	14.89655	0.655172	0.09
06-22-2001	07-24-2001	RR	32	41	611	19.09375	1.28125	0.12
05-24-2001	06-22-2001	RR	29	219	736	25.37931	7.551724	0.16
04-23-2001	05-24-2001	RY	31	368	1301	41.96774	11.87097	0.26
03-23-2001	04-23-2001	RR	31	734	1913	61.70968	23.67742	0.39
02-22-2001	03-23-2001	RR	29	826	2538	87.51724	28.48276	0.55
01-24-2001	02-22-2001	RY	29	1113	3153	108.7241	38.37931	0.68
12-19-2000	01-24-2001	RY	36	1347	3668	101.8889	37.41667	0.64
11-16-2000	12-19-2000	RY	33	1340	3573	108.2727	40.60606	0.68
10-18-2000	11-16-2000	RR	29	884	2424	83.58621	30.48276	0.52
09-20-2000	10-18-2000	RR	28	408	1738	62.07143	14.57143	0.39
08-22-2000	09-20-2000	RY	29	169	1139	39.27586	5.827586	0.25

Summary / 109735 / 103678 / 114268 / 114279 / Chart1 / **133049** / 156920 / 161549 / 208478

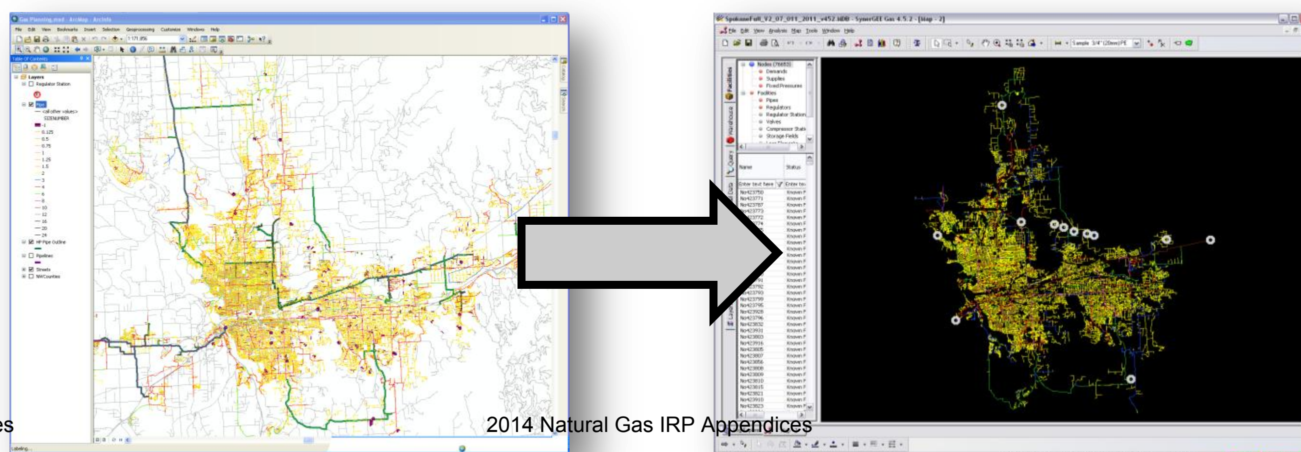

Load vs. Temperature
y = 0.0129x + 0.1175
Heat
Base
Mcfh
Heating Degree Days
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0
5
10
15
20
25
30
35
40
45
Summary
109735
103678
114268
114279
Chart1
133049
156920
161549
208478

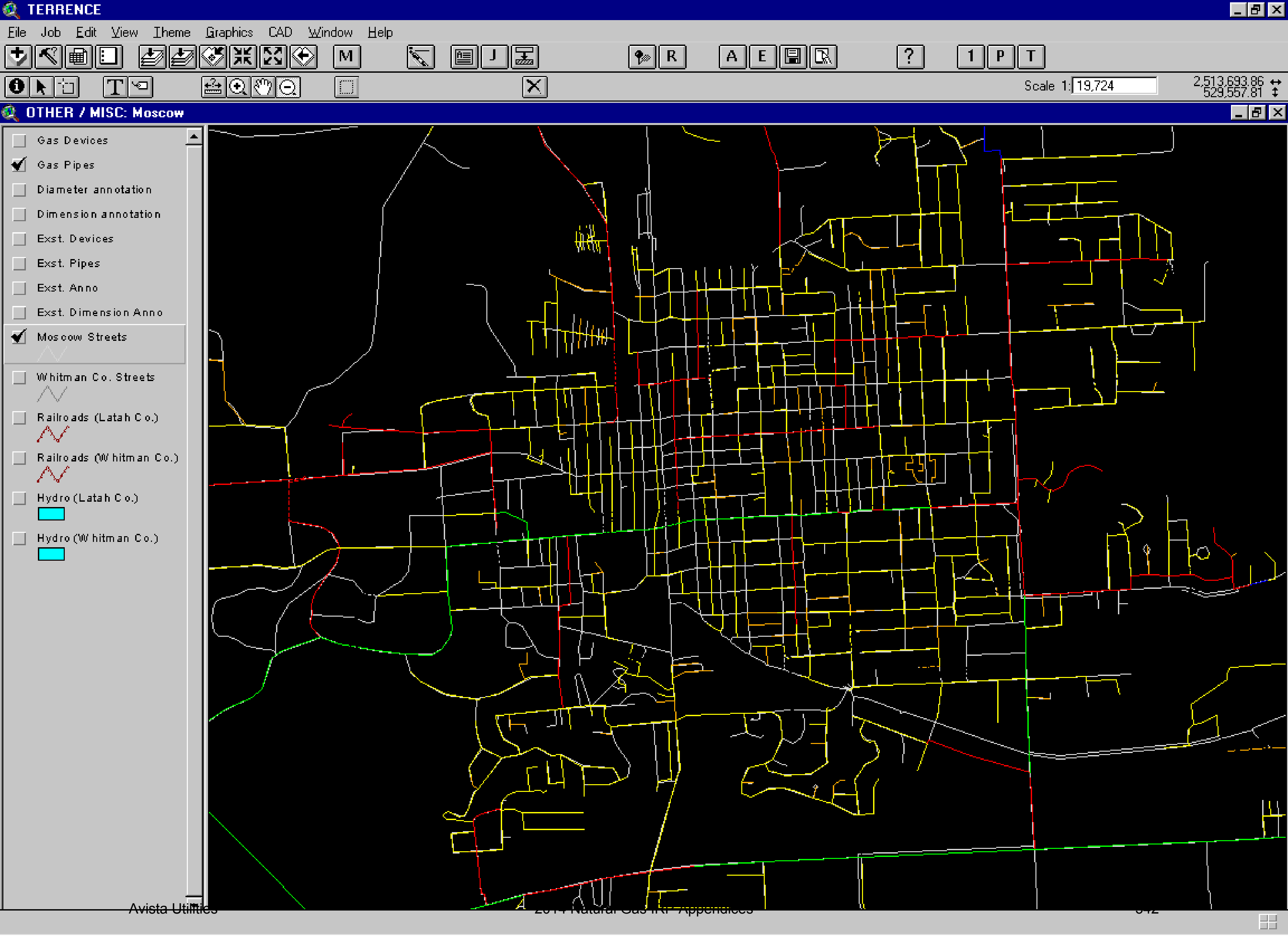
Estimating Customer Usage cont.

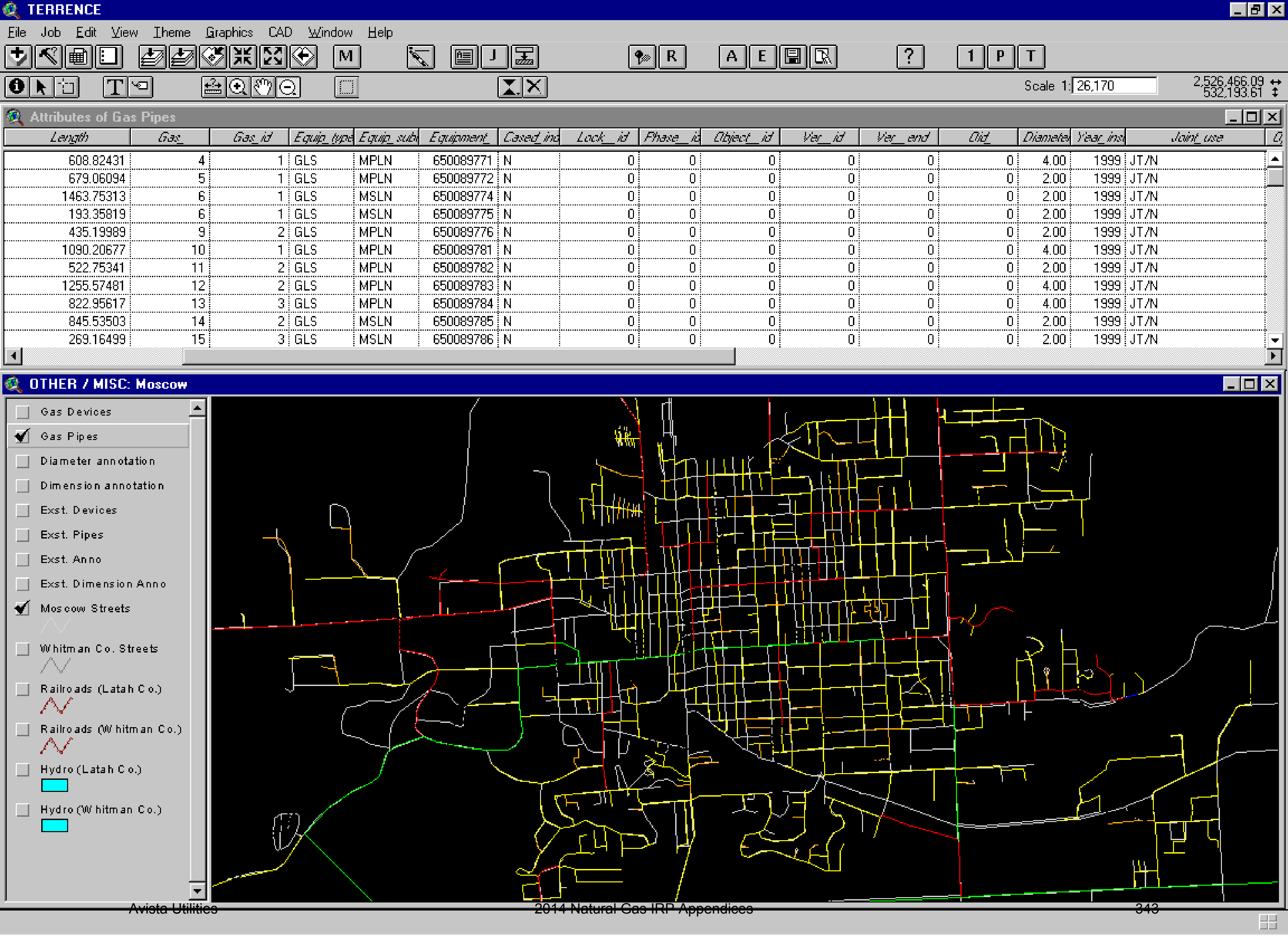
- Peaking Factor
  - Peaking Factor = 6.25% of daily load
  - "Observed ratio" of greatest hourly flow to total daily flow at Gate Stations
- Industrial Customers
  - Model maximum hourly usage per Contractual Agreement
  - Firm Transportation customers only
  - Low Temperature-Usage correlation

Creating a Pipeline Network

- Elements
  - Pipes, regulators, valves
  - Attributes: Length, internal diameter, roughness
- Nodes
  - Sources, usage points, pipe ends
  - Attributes: Flow, pressure



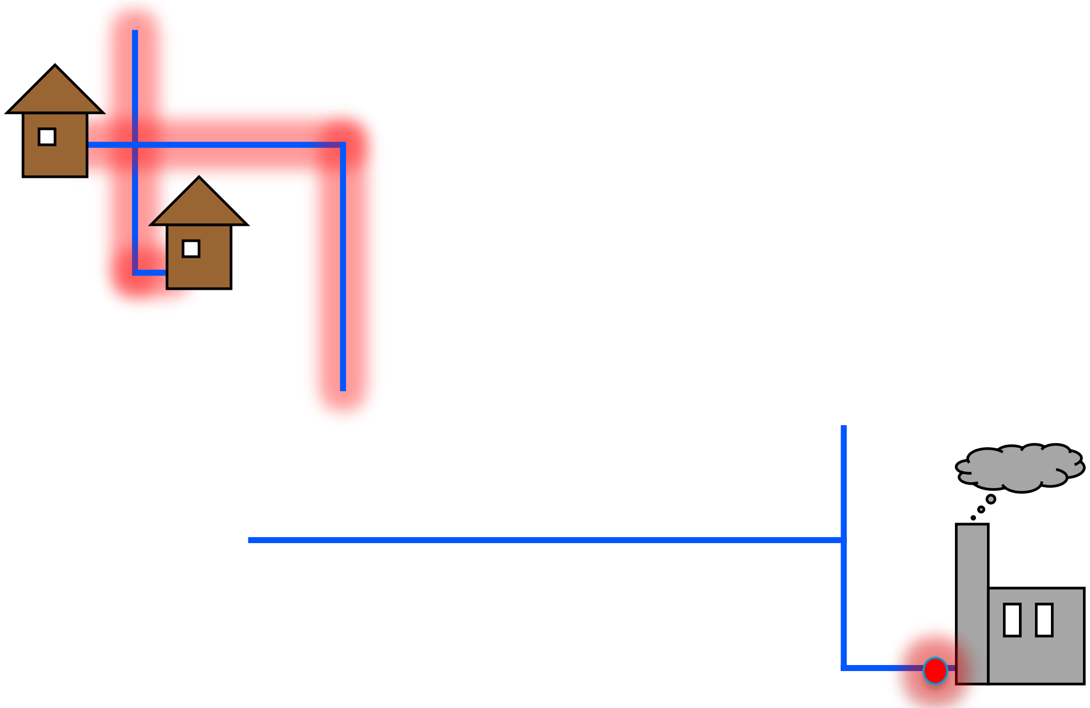

TERRENCE
File Job Edit View Theme Graphics CAD Window Help
M
R
A E
?
1 P T
Scale 1: 19,724
2,513,693.86
529,557.81
OTHER / MISC: Moscow
Gas Devices
Gas Pipes
Diameter annotation
Dimension annotation
Exst. Devices
Exst. Pipes
Exst. Anno
Exst. Dimension Anno
Moscow Streets
Whitman Co. Streets
Railroads (Latah Co.)
Railroads (Whitman Co.)
Hydro (Latah Co.)
Hydro (Whitman Co.)

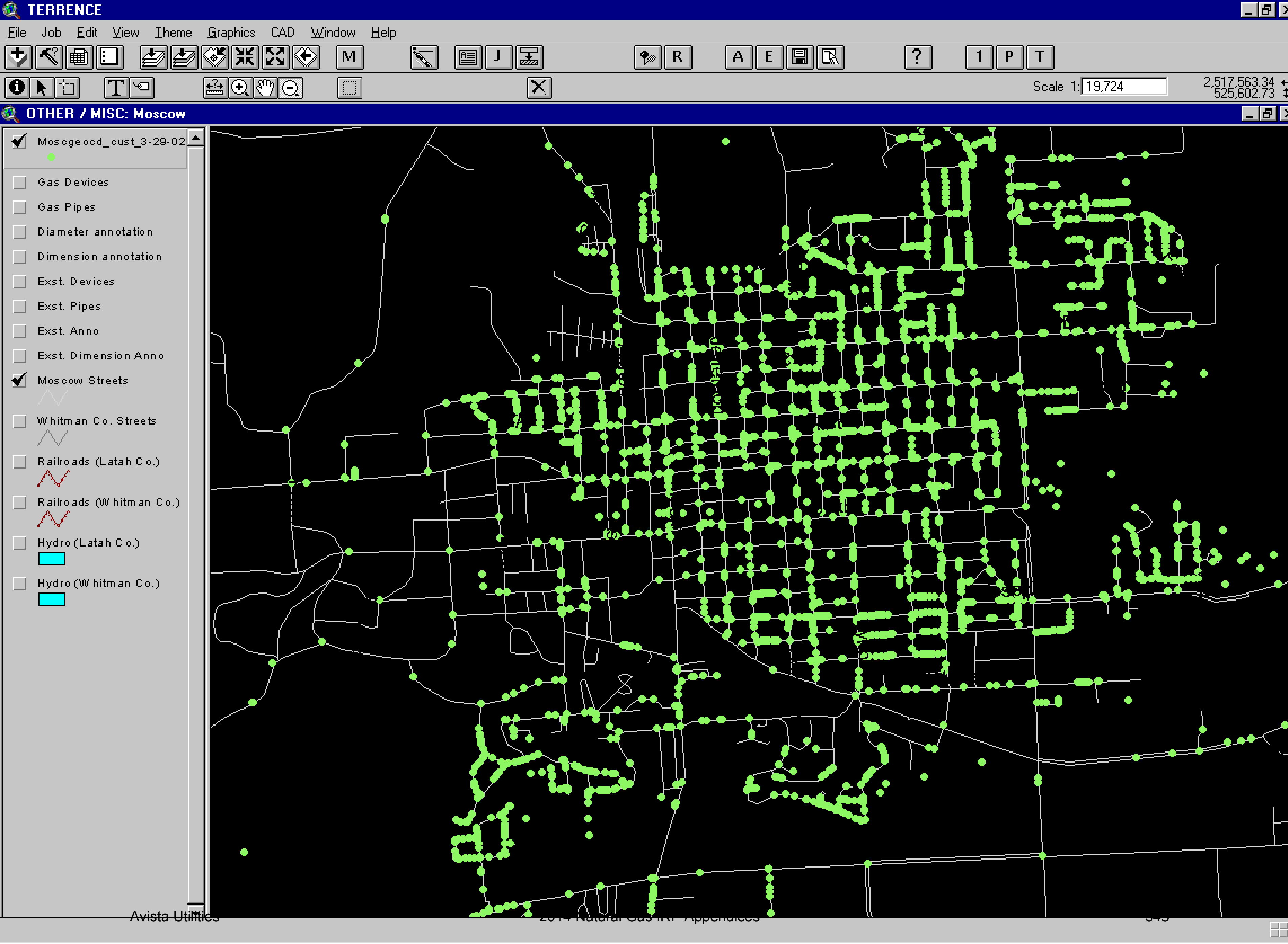


Length	Gas_	Gas_id	Equip_type	Equip_sub	Equipment_	Cased_ind	Lock_id	Phase_id	Object_id	Ver_id	Ver_end	Oid	Diameter	Year_ins	Joint_use
608.82431	4	1	GLS	MPLN	650089771	N	0	0	0	0	0	0	4.00	1999	JT/N
679.06094	5	1	GLS	MPLN	650089772	N	0	0	0	0	0	0	2.00	1999	JT/N
1463.75313	6	1	GLS	MSLN	650089774	N	0	0	0	0	0	0	2.00	1999	JT/N
193.35819	6	1	GLS	MSLN	650089775	N	0	0	0	0	0	0	2.00	1999	JT/N
435.19989	9	2	GLS	MPLN	650089776	N	0	0	0	0	0	0	2.00	1999	JT/N
1090.20677	10	1	GLS	MPLN	650089781	N	0	0	0	0	0	0	4.00	1999	JT/N
522.75341	11	2	GLS	MPLN	650089782	N	0	0	0	0	0	0	2.00	1999	JT/N
1255.57481	12	2	GLS	MPLN	650089783	N	0	0	0	0	0	0	4.00	1999	JT/N
822.95617	13	3	GLS	MPLN	650089784	N	0	0	0	0	0	0	4.00	1999	JT/N
845.53503	14	2	GLS	MSLN	650089785	N	0	0	0	0	0	0	2.00	1999	JT/N
269.16499	15	3	GLS	MSLN	650089786	N	0	0	0	0	0	0	2.00	1999	JT/N

Join Customer Loads to a Model

- Residential and commercial loads are assigned to ***pipes***
- Industrial or other large loads are assigned to ***nodes***

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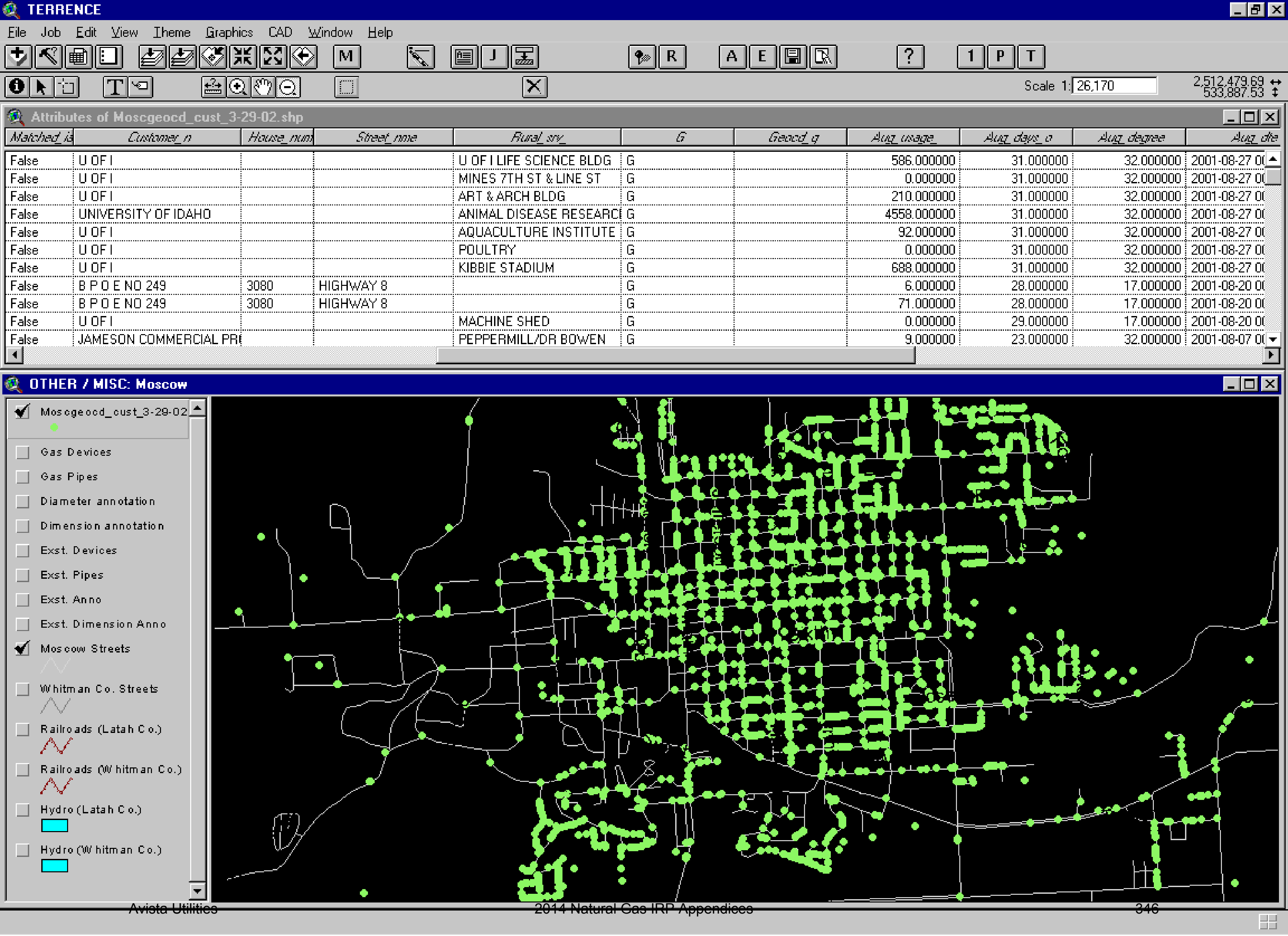
525,602.73
OTHER / MISC: Moscow
Moscgeocd_cust_3-29-02
Gas Devices
Gas Pipes
Diameter annotation
Dimension annotation
Exst. Devices
Exst. Pipes
Exst. Anno
Exst. Dimension Anno
Moscow Streets
Whitman Co. Streets
Railroads (Latah Co.)
Railroads (Whitman Co.)
Hydro (Latah Co.)
Hydro (Whitman Co.)



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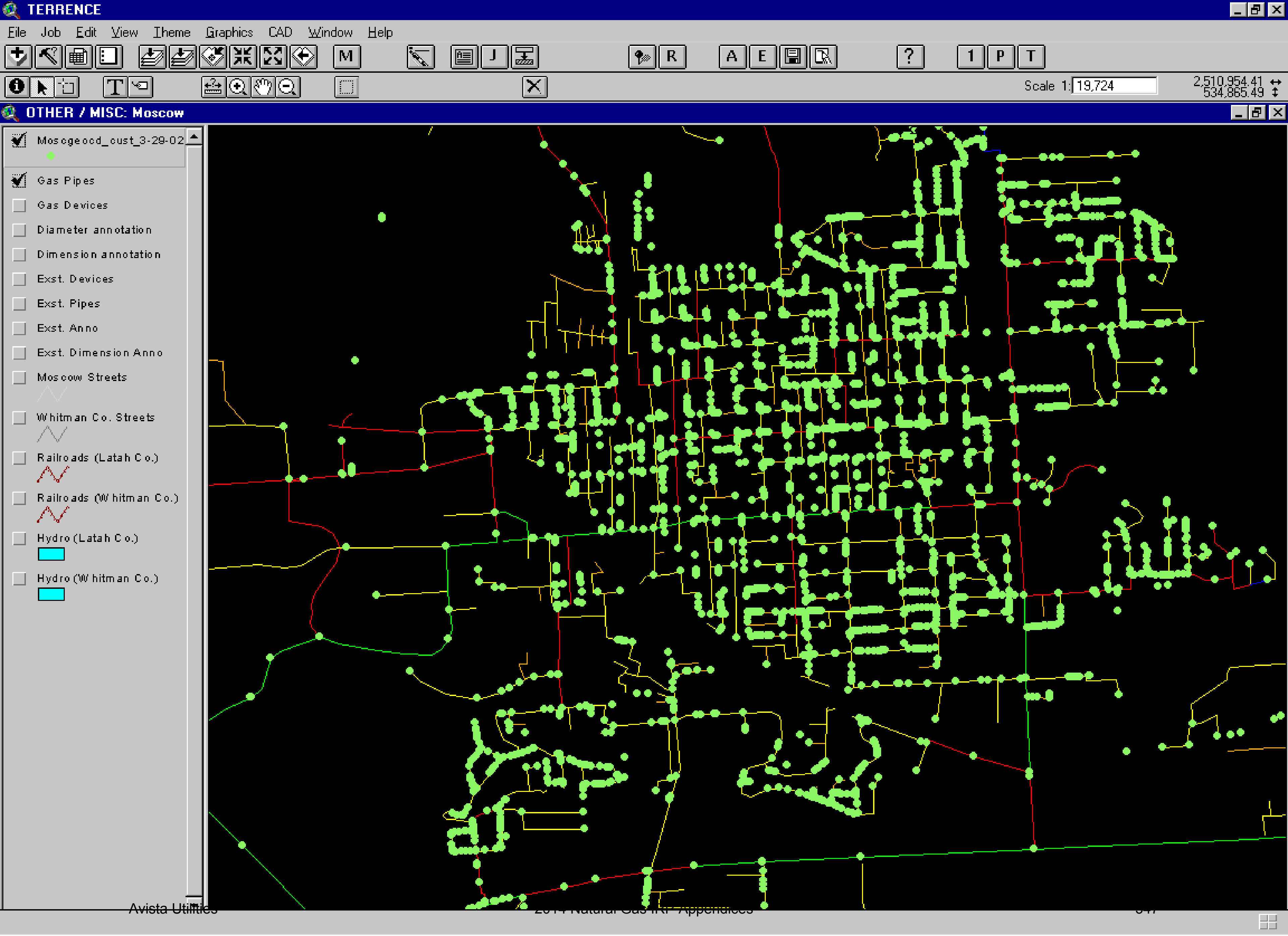
Attributes of Moscgeocd_cust_3-29-02.shp

Matched_is	Customer_n	House_num	Street_nme	Rural_srv_	G	Geocd_q	Avg_usage_	Avg_days_o	Avg_degree	Avg_dte
False	U OF I			U OF I LIFE SCIENCE BLDG	G		586.000000	31.000000	32.000000	2001-08-27 0
False	U OF I			MINES 7TH ST & LINE ST	G		0.000000	31.000000	32.000000	2001-08-27 0
False	U OF I			ART & ARCH BLDG	G		210.000000	31.000000	32.000000	2001-08-27 0
False	UNIVERSITY OF IDAHO			ANIMAL DISEASE RESEARCI	G		4558.000000	31.000000	32.000000	2001-08-27 0
False	U OF I			AQUACULTURE INSTITUTE	G		92.000000	31.000000	32.000000	2001-08-27 0
False	U OF I			POULTRY	G		0.000000	31.000000	32.000000	2001-08-27 0
False	U OF I			KIBBIE STADIUM	G		688.000000	31.000000	32.000000	2001-08-27 0
False	B P O E NO 249	3080	HIGHWAY 8		G		6.000000	28.000000	17.000000	2001-08-20 0
False	B P O E NO 249	3080	HIGHWAY 8		G		71.000000	28.000000	17.000000	2001-08-20 0
False	U OF I			MACHINE SHED	G		0.000000	29.000000	17.000000	2001-08-20 0
False	JAMESON COMMERCIAL PRI			PEPPERMILL/DR BOWEN	G		9.000000	23.000000	32.000000	2001-08-07 0

OTHER / MISC: Moscow
Moscgeocd_cust_3-29-02
Gas Devices
Gas Pipes
Diameter annotation
Dimension annotation
Exst. Devices
Exst. Pipes
Exst. Anno
Exst. Dimension Anno
Moscow Streets
Whitman Co. Streets
Railroads (Latah Co.)
Railroads (Whitman Co.)
Hydro (Latah Co.)
Hydro (Whitman Co.)



TERRENCE
File Job Edit View Theme Graphics CAD Window Help
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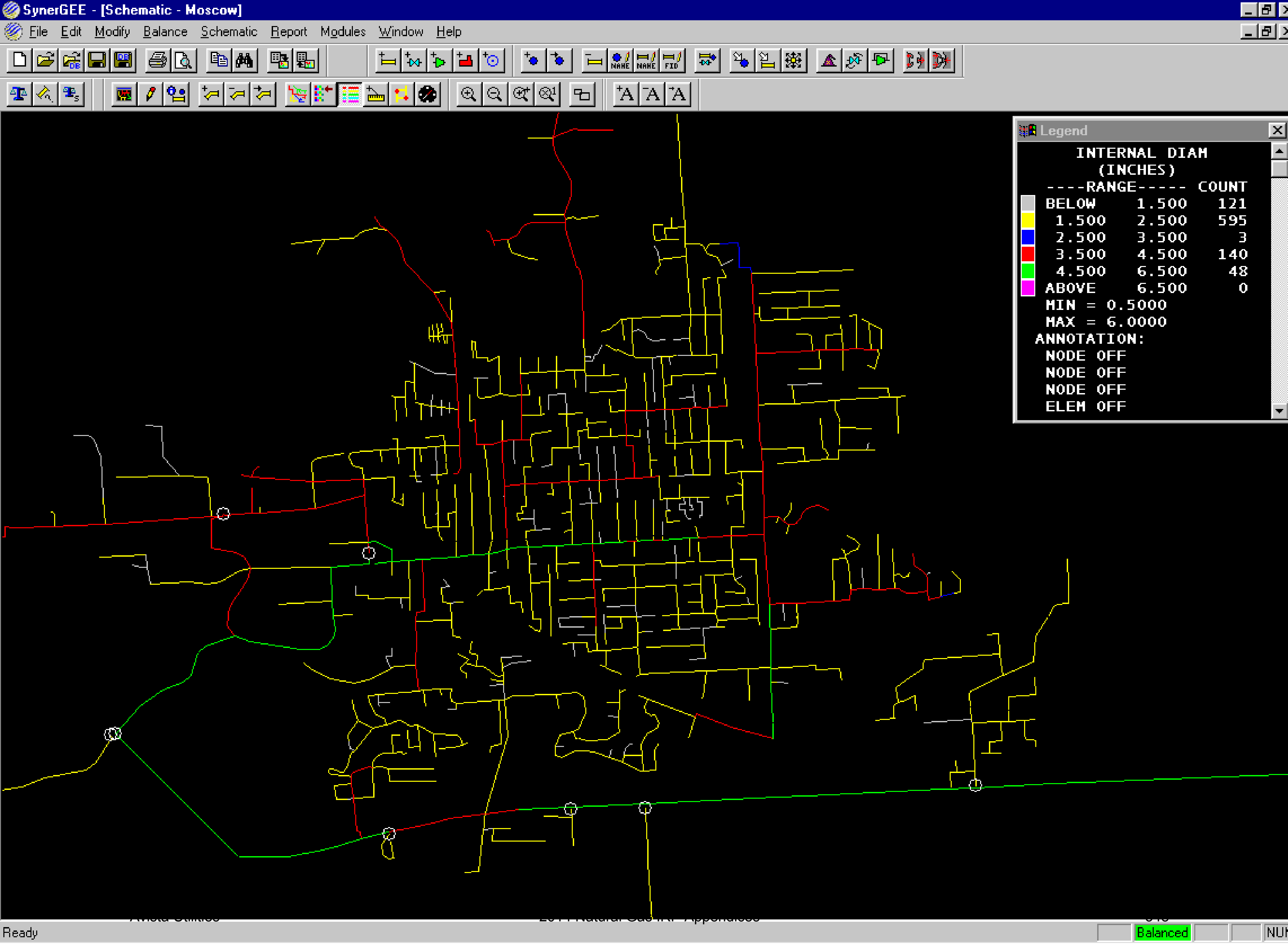
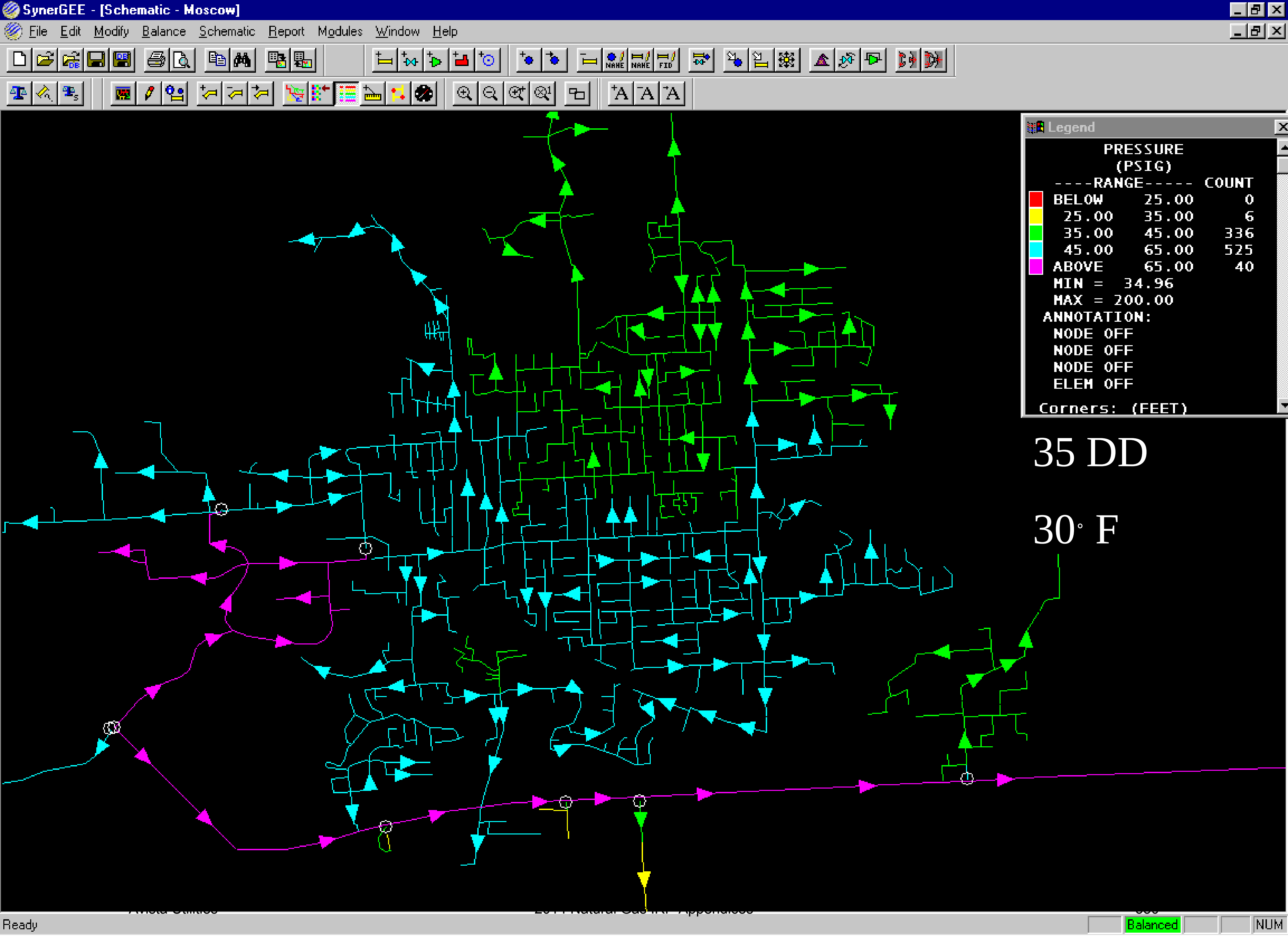
OTHER / MISC: Moscow
Moscgeocd_cust_3-29-02
Gas Pipes
Gas Devices
Diameter annotation
Dimension annotation
Exst. Devices
Exst. Pipes
Exst. Anno
Exst. Dimension Anno
Moscow Streets
Whitman Co. Streets
Railroads (Latah Co.)
Railroads (Whitman Co.)
Hydro (Latah Co.)
Hydro (Whitman Co.)



SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
Legend
INTERNAL DIAM
(INCHES)
----RANGE----- COUNT
BELOW 1.500 121
1.500 2.500 595
2.500 3.500 3
3.500 4.500 140
4.500 6.500 48
ABOVE 6.500 0
MIN = 0.5000
MAX = 6.0000
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Ready
Balanced
NUM

Balancing Model

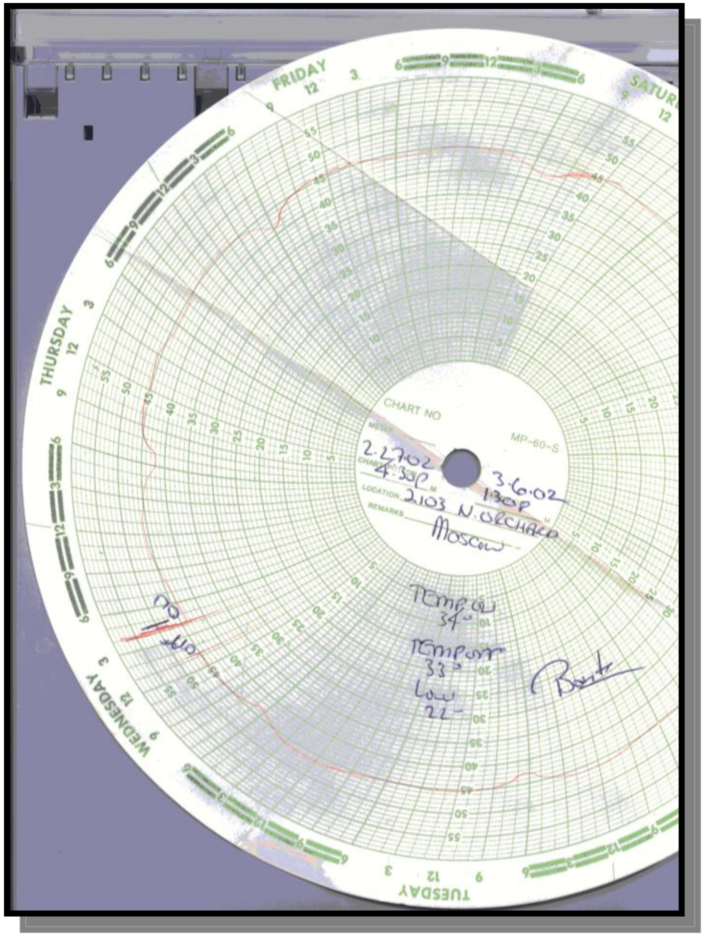
- Simulate system for any temperature
  - HDD's
- Solve for pressure at all nodes

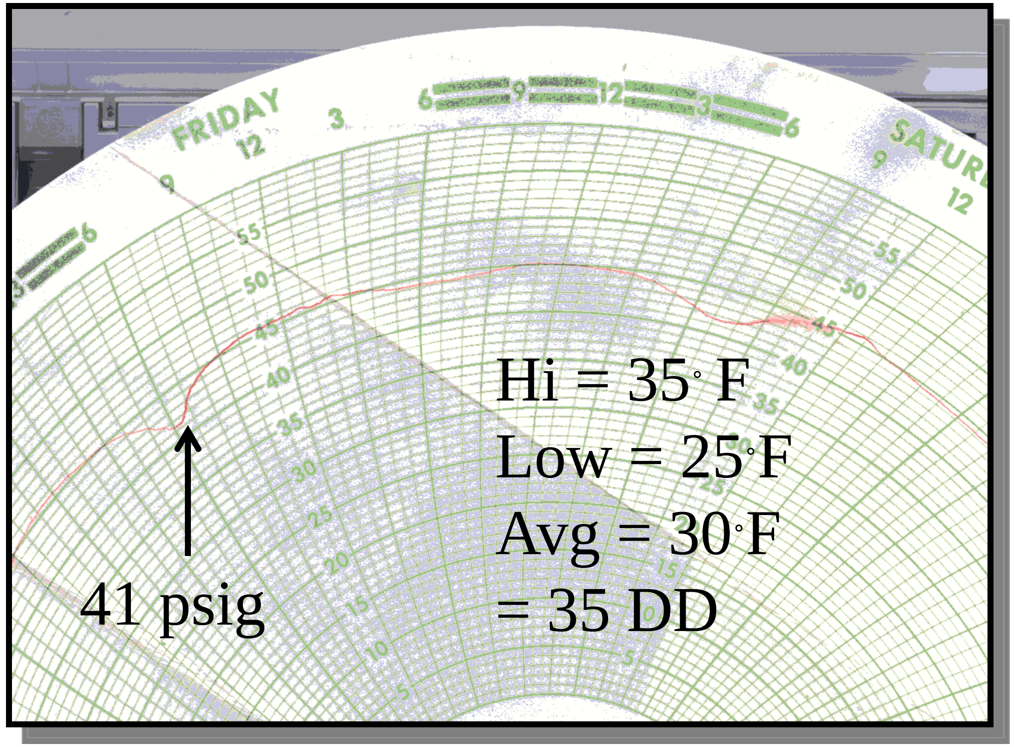

SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
Legend
PRESSURE
(PSIG)
----RANGE----- COUNT
BELOW 25.00 0
25.00 35.00 6
35.00 45.00 336
45.00 65.00 525
ABOVE 65.00 40
MIN = 34.96
MAX = 200.00
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Corners: (FEET)
35 DD
30° F
Ready
Balanced
NUM

Validating Model

- Simulate recorded condition
- Pressure Recorders
  - Do calculated results match *field* data?
- Gate Station Telemetry
  - Do calculated results match *source* data?
- Possible Errors
  - Missing pipe
  - Source pressure changed
  - Industrial loads

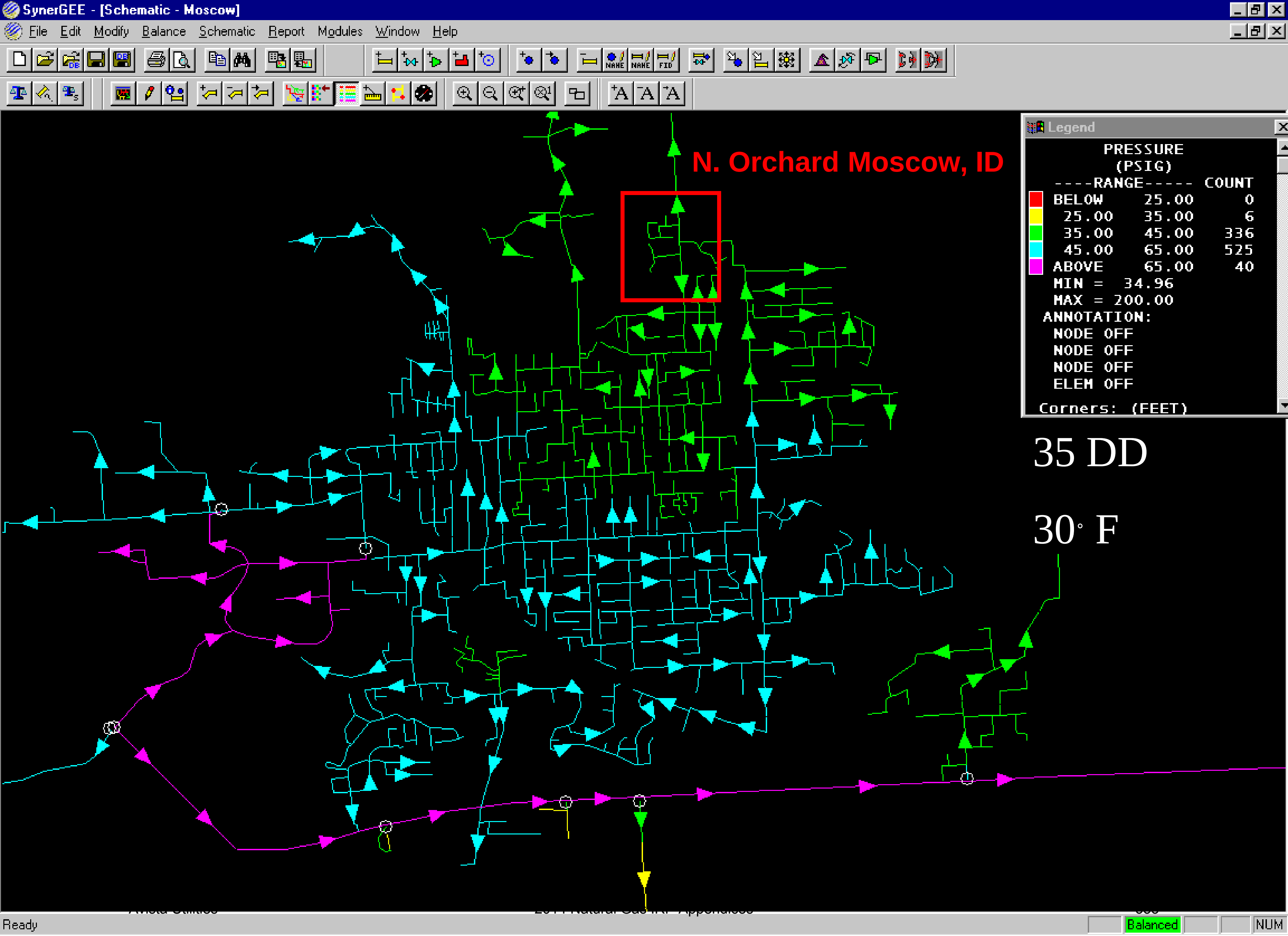
Validating Model cont.





Location: N. Orchard, Moscow ID

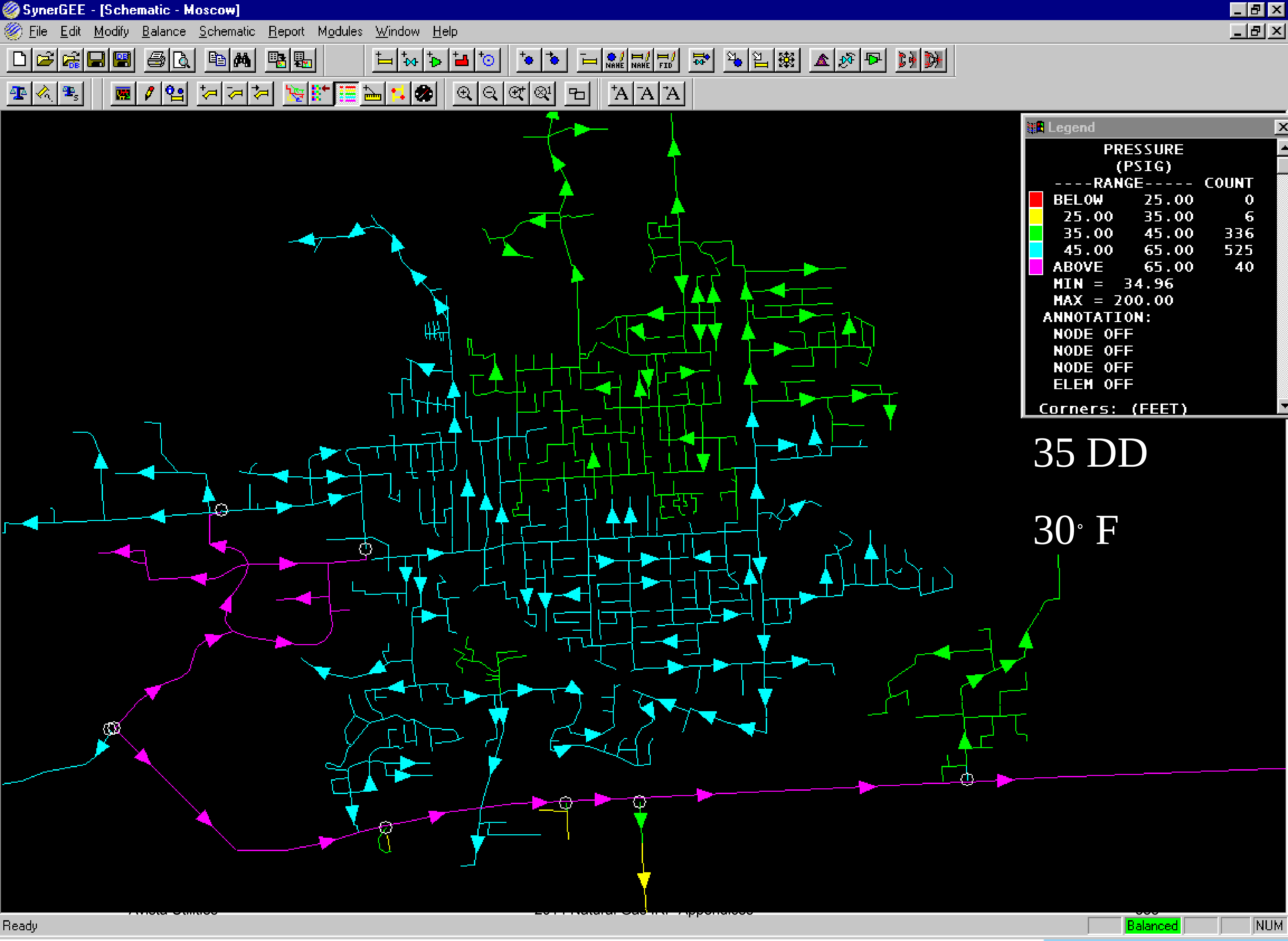
Observation Date: Friday, March 1st

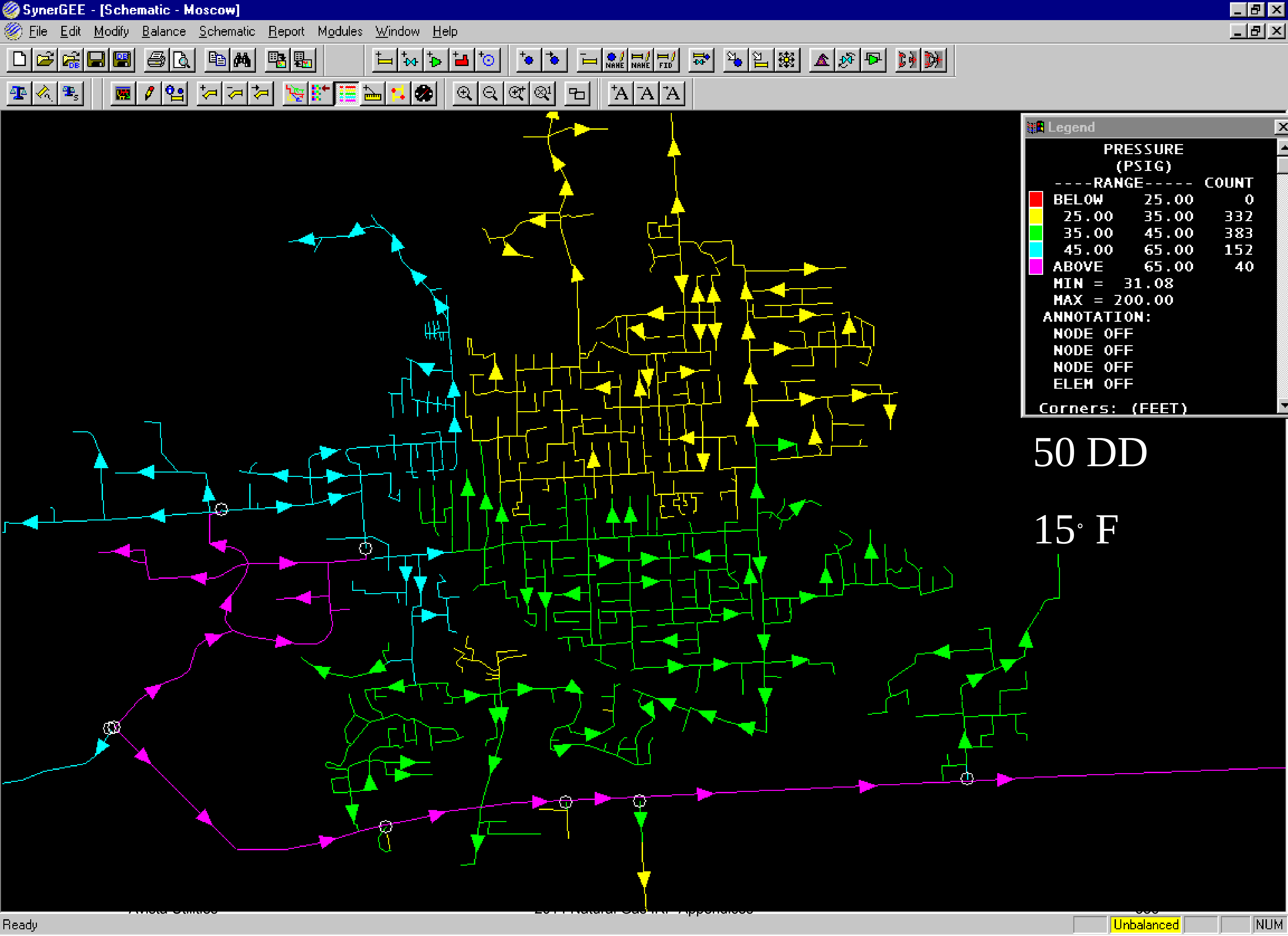

SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
N. Orchard Moscow, ID
Legend
PRESSURE
(PSIG)
----RANGE----- COUNT
BELOW 25.00 0
25.00 35.00 6
35.00 45.00 336
45.00 65.00 525
ABOVE 65.00 40
MIN = 34.96
MAX = 200.00
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Corners: (FEET)
35 DD
30° F
Ready
Balanced
NUM

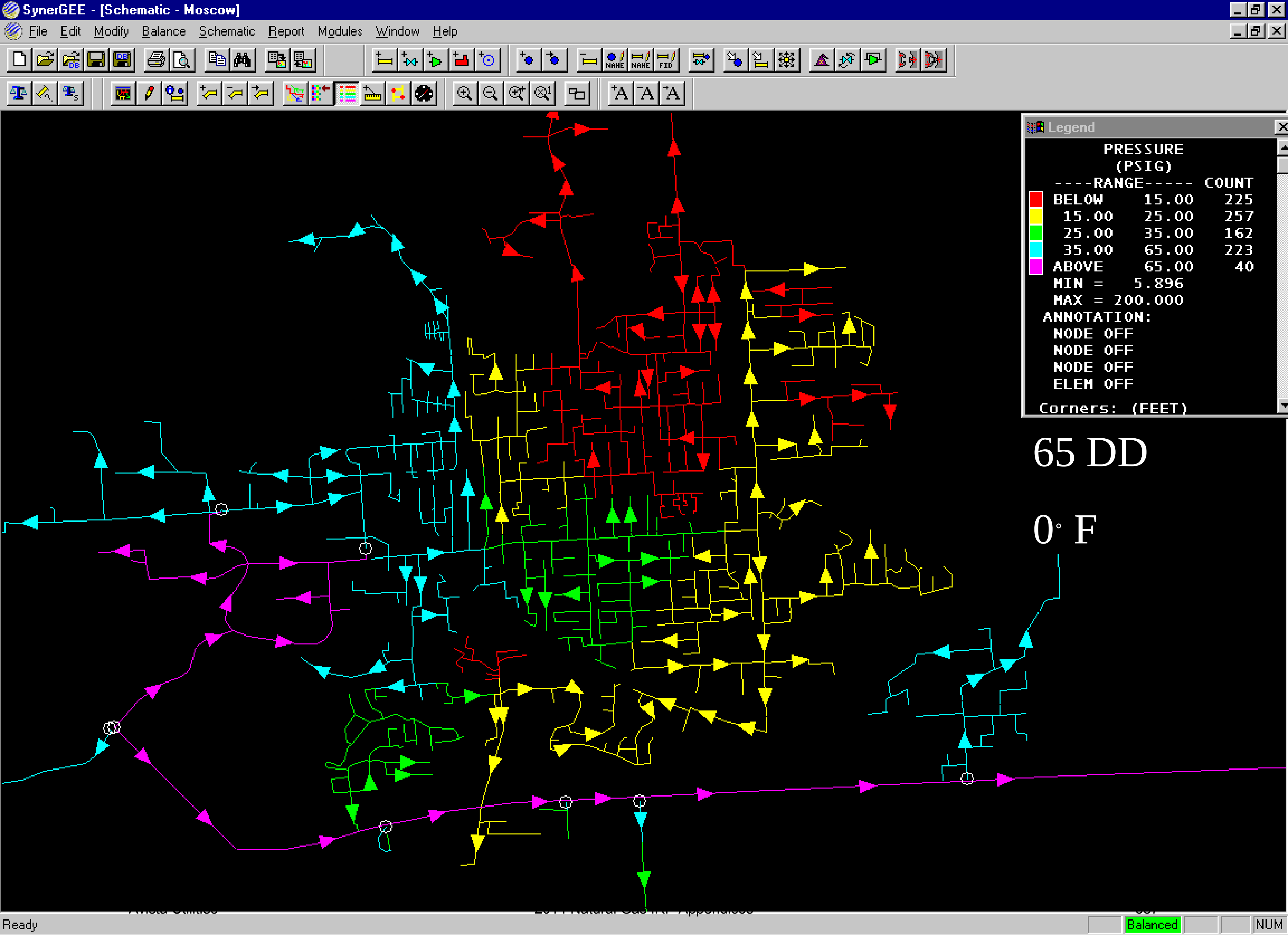
Planning Criteria

- Reliability during design HDD
  - Spokane 82 HDD
  - Medford 61 HDD
  - Klamath Falls 72 HDD
  - La Grande 74 HDD
  - Roseburg 55 HDD

- Maintain minimum of 15 psig in system at all times
  - 5 psig in lower MAOP areas


SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
Legend
PRESSURE
(PSIG)
----RANGE----- COUNT
BELOW 25.00 0
25.00 35.00 6
35.00 45.00 336
45.00 65.00 525
ABOVE 65.00 40
MIN = 34.96
MAX = 200.00
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Corners: (FEET)
35 DD
30° F
Ready
Balanced
NUM

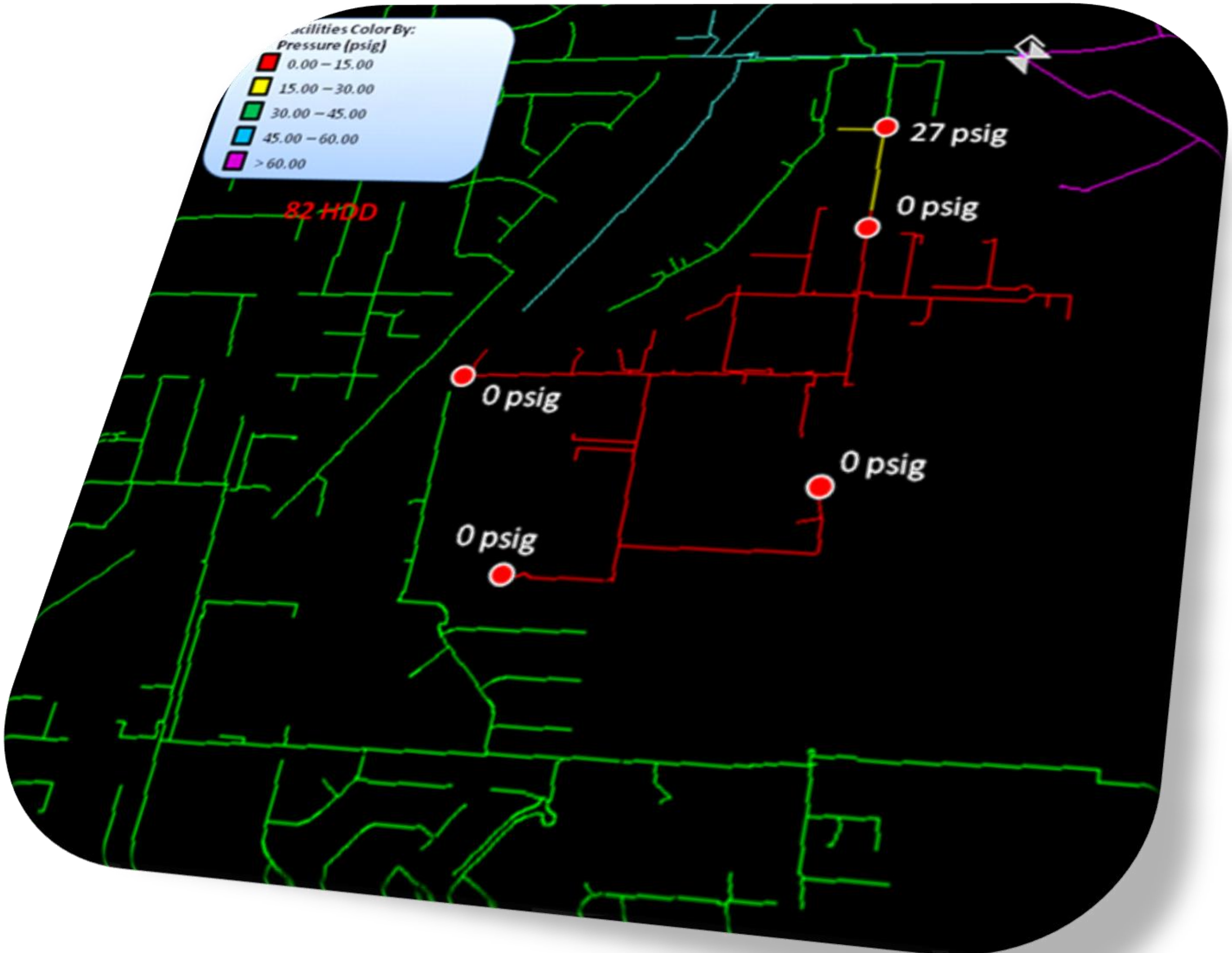

SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
Legend
PRESSURE
(PSIG)
----RANGE----- COUNT
BELOW 25.00 0
25.00 35.00 332
35.00 45.00 383
45.00 65.00 152
ABOVE 65.00 40
MIN = 31.08
MAX = 200.00
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Corners: (FEET)
50 DD
15° F
Ready
Unbalanced
NUM

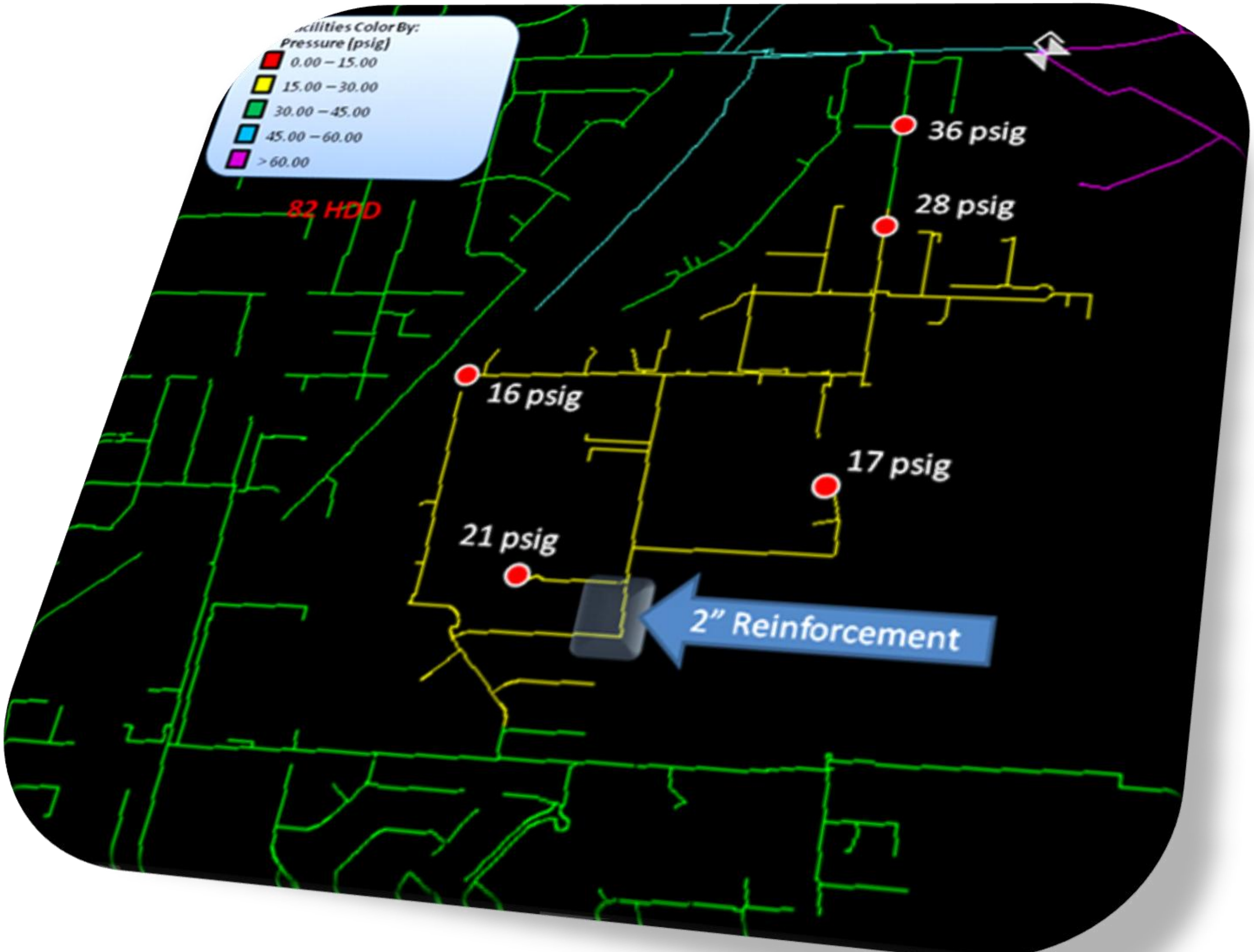


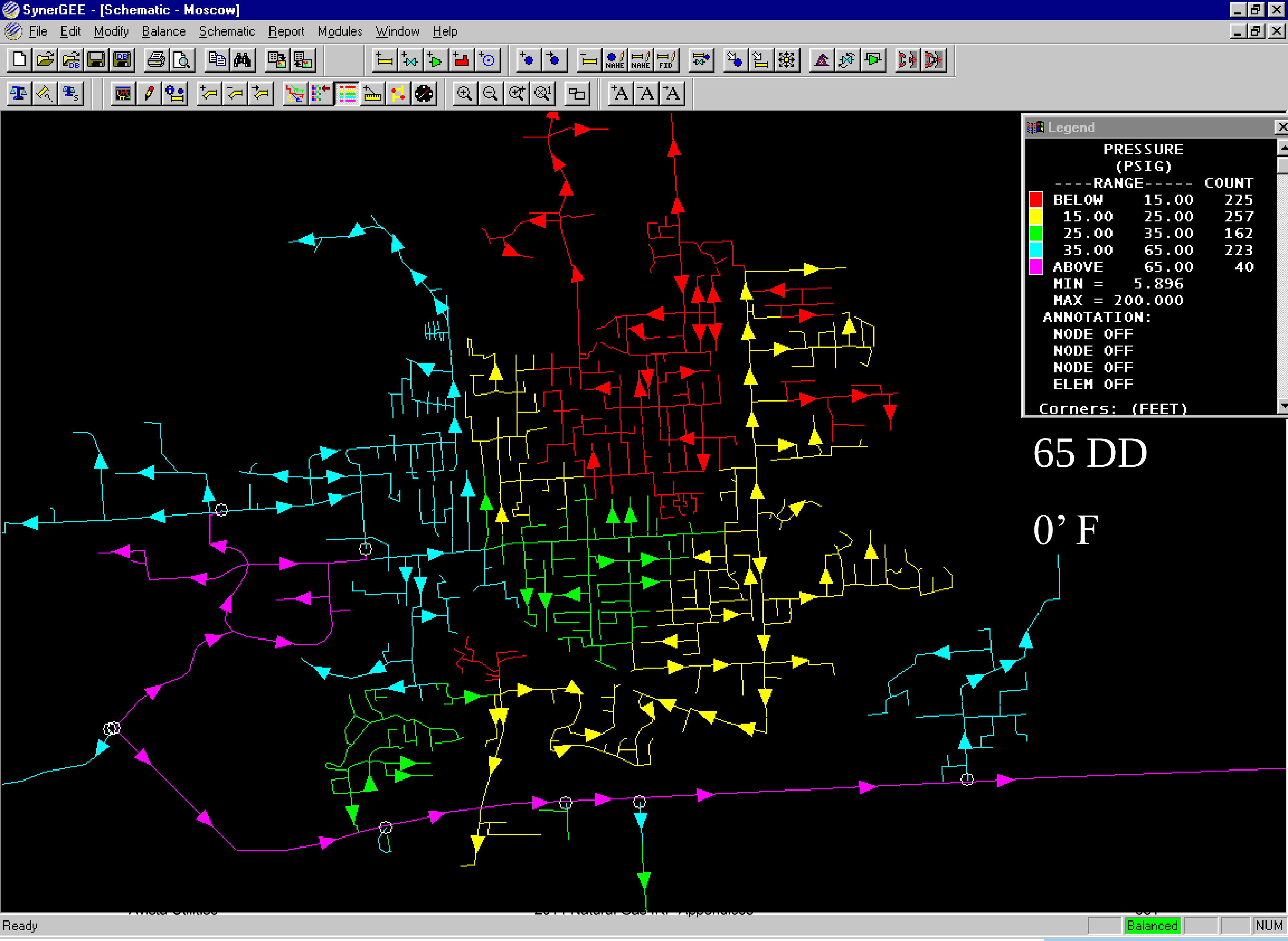
SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
Legend
PRESSURE
(PSIG)
----RANGE----- COUNT
BELOW 15.00 225
15.00 25.00 257
25.00 35.00 162
35.00 65.00 223
ABOVE 65.00 40
MIN = 5.896
MAX = 200.000
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Corners: (FEET)
65 DD
0° F
Ready
Balanced
NUM

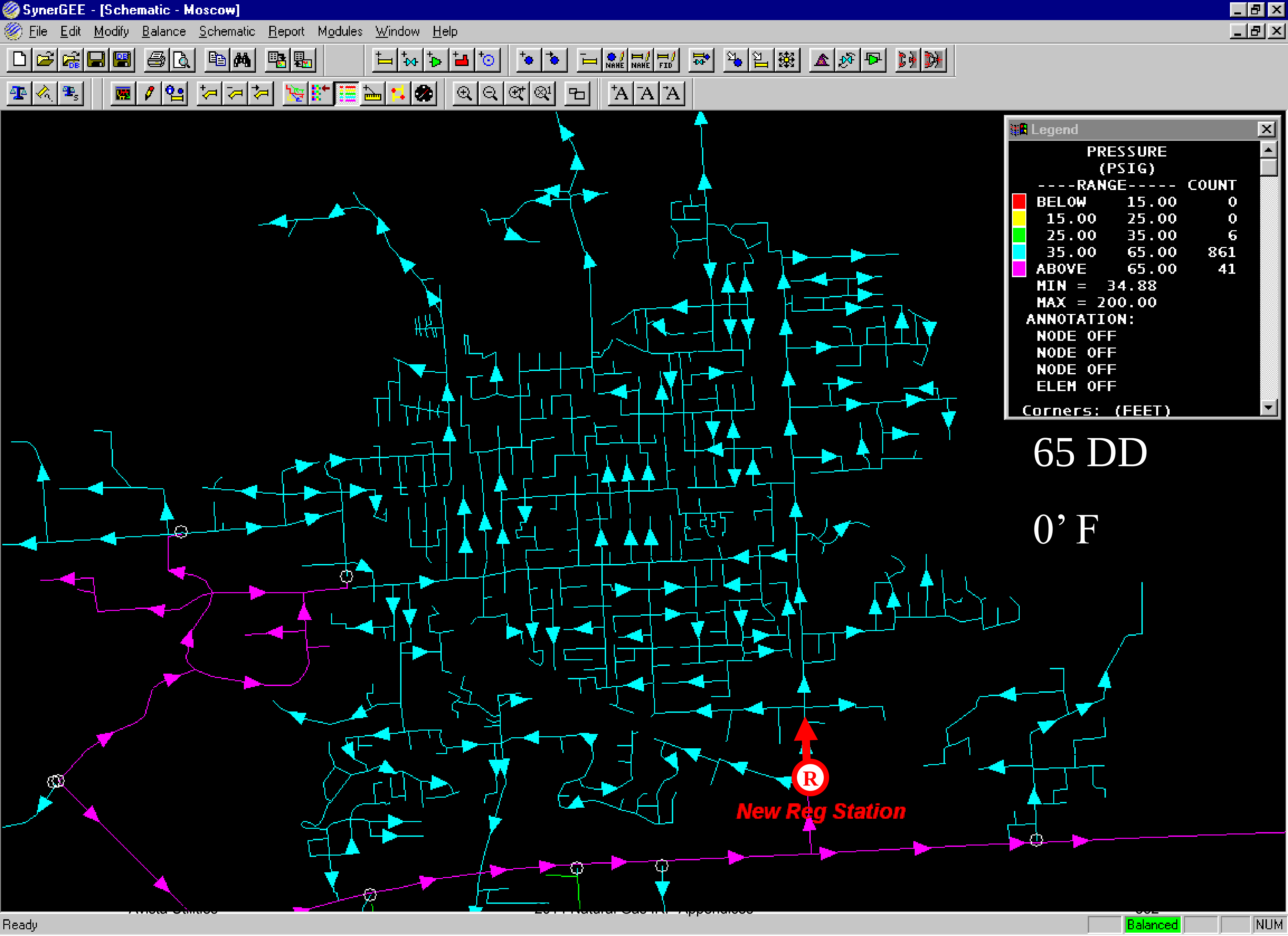
Interpreting Results

- Identify Low Pressure Areas
  - Number of feeds
  - Proximity to source
- Looking for Most Economical Solution
  - Length (minimize)
  - Construction obstacles (minimize)
  - Customer growth (maximize)

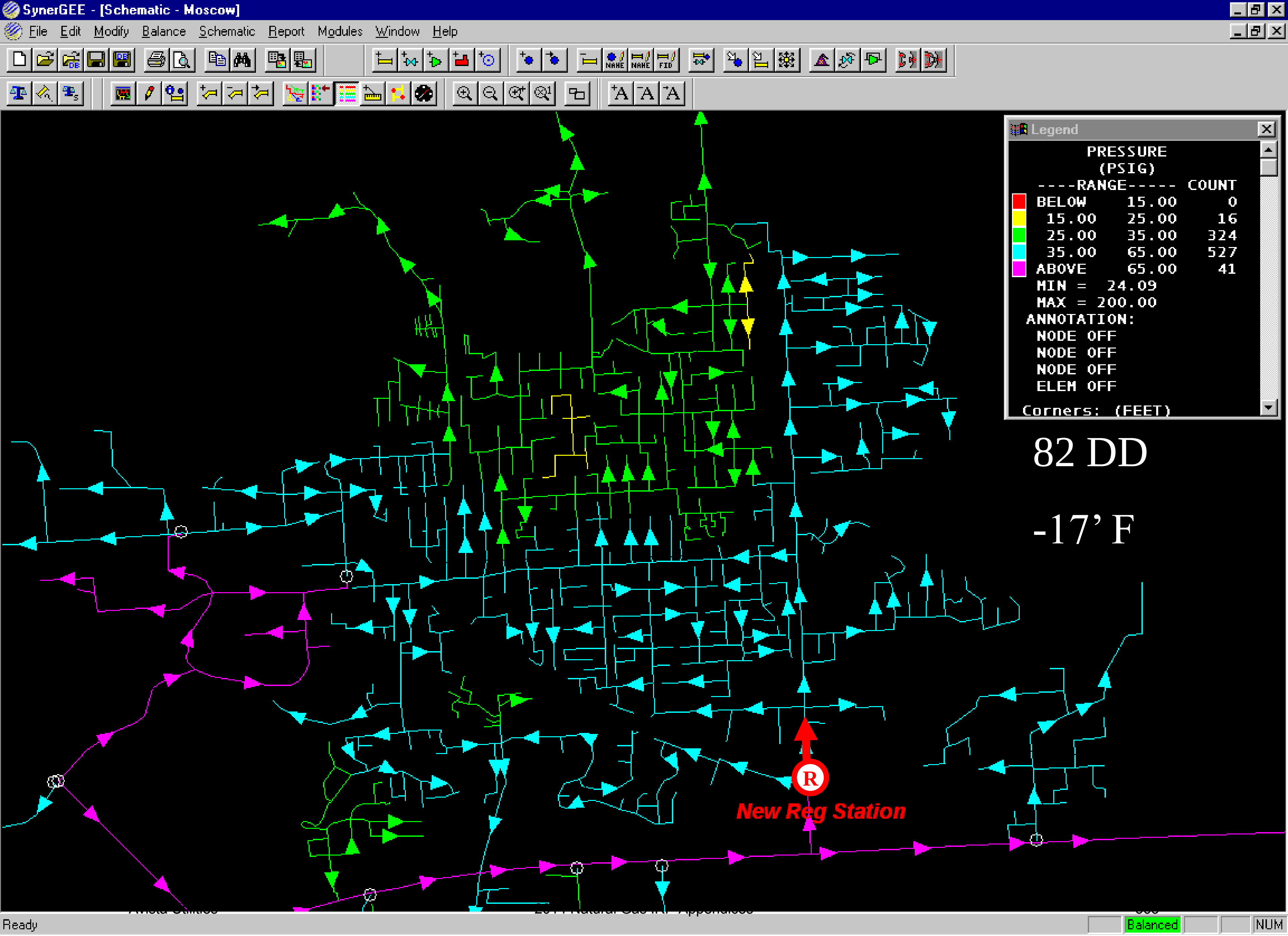

acilities Color By:
Pressure (psig)
0.00 – 15.00
15.00 – 30.00
30.00 – 45.00
45.00 – 60.00
> 60.00
82 HDD
27 psig
0 psig
0 psig
0 psig
0 psig


acilities Color By:
Pressure (psig)
0.00 – 15.00
15.00 – 30.00
30.00 – 45.00
45.00 – 60.00
> 60.00
82 HDD
36 psig
28 psig
16 psig
17 psig
21 psig
2" Reinforcement


SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
Legend
PRESSURE
(PSIG)
----RANGE----- COUNT
BELOW 15.00 225
15.00 25.00 257
25.00 35.00 162
35.00 65.00 223
ABOVE 65.00 40
MIN = 5.896
MAX = 200.000
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Corners: (FEET)
65 DD
0' F
Ready
Balanced
NUM



SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
Legend
PRESSURE
(PSIG)
----RANGE----- COUNT
BELOW 15.00 0
15.00 25.00 0
25.00 35.00 6
35.00 65.00 861
ABOVE 65.00 41
MIN = 34.88
MAX = 200.00
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Corners: (FEET)
65 DD
0' F
R
New Reg Station
Ready
Balanced
NUM

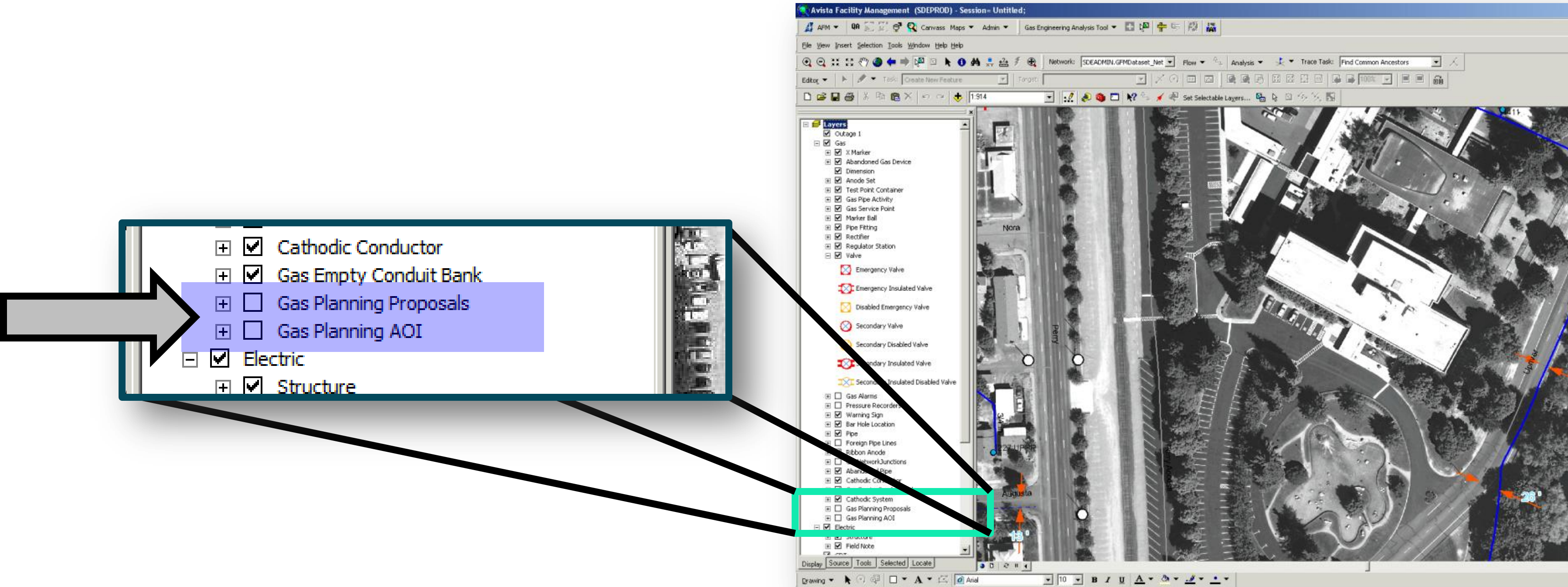

SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
Legend
PRESSURE
(PSIG)
----RANGE----- COUNT
BELOW 15.00 0
15.00 25.00 16
25.00 35.00 324
35.00 65.00 527
ABOVE 65.00 41
MIN = 24.09
MAX = 200.00
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Corners: (FEET)
82 DD
-17' F
R
New Reg Station
Ready
Balanced
NUM

Long-term Planning Objectives

- Future Growth/Expansion
- Design Day Conditions
- Facilitate Customer Installation Targets

Sharing Load Study Results

- Gas Planning Proposals
- Gas Planning AOI



Gas Planning Proposals

- Proposed pipe - dashed line

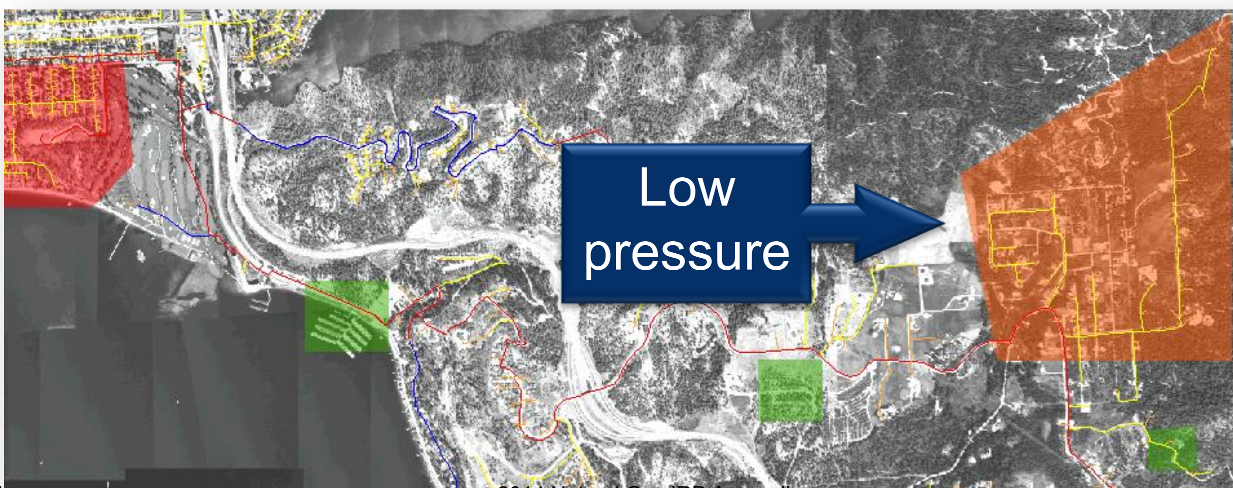
- Gas Planning recommendations for main extensions

Gas Planning AOI

- Different colors to show the types of areas

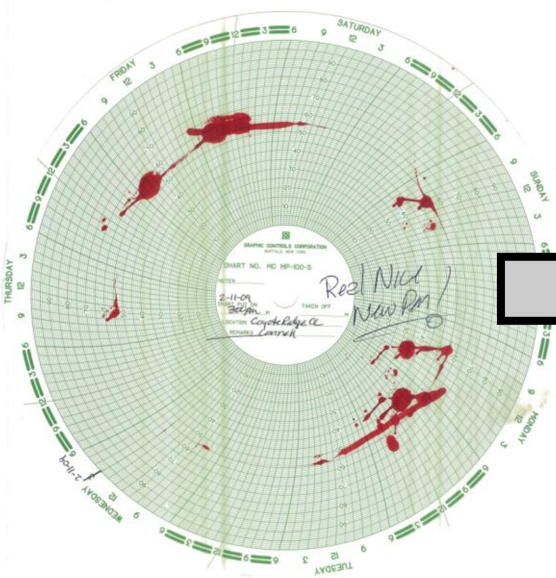
Gas Planning AOI
Area Type
Critical Pressure
Low Pressure
Miscellaneous
New Developments

- Geographic-specific information to help make decisions

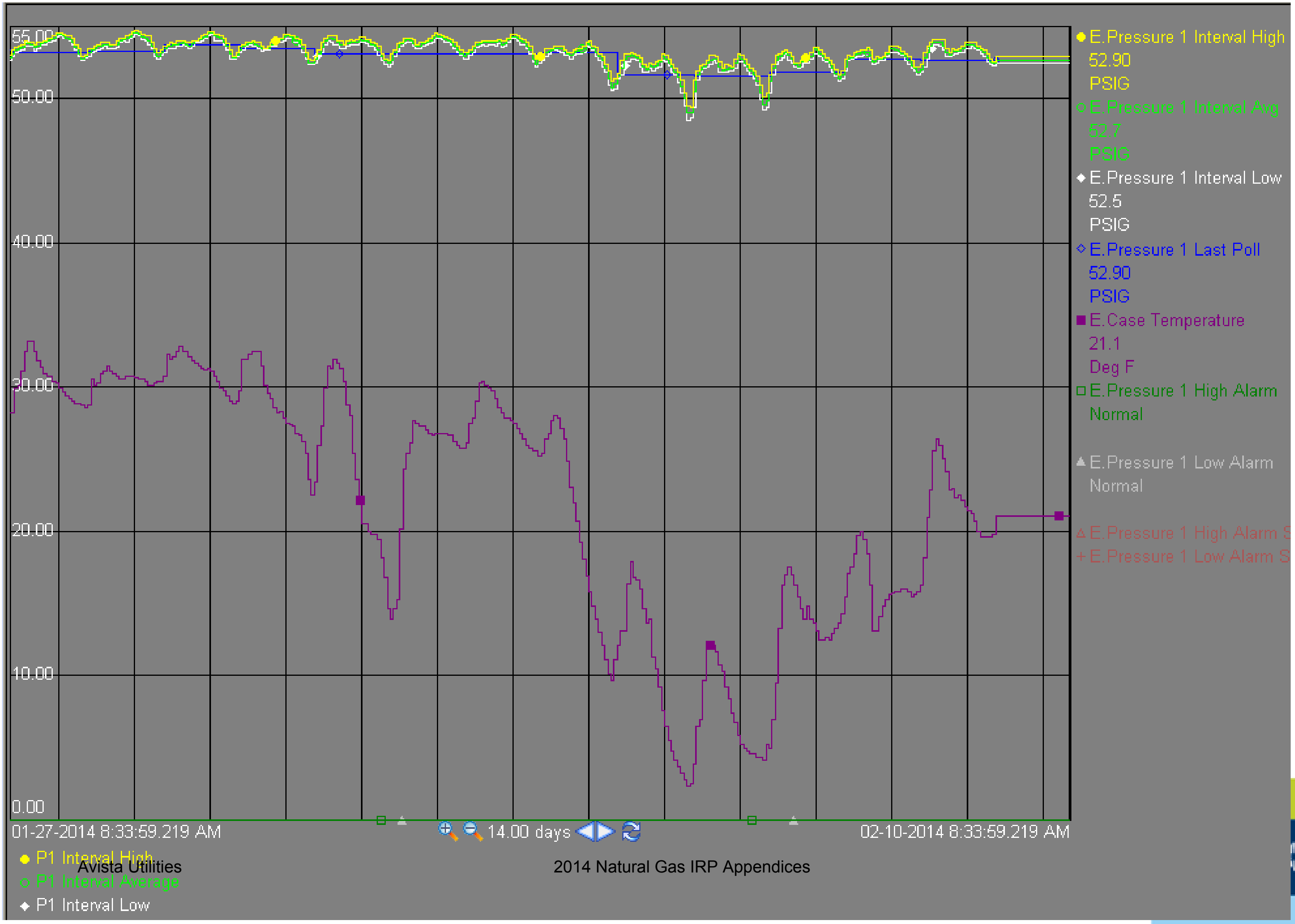


Electronic Pressure Recorders

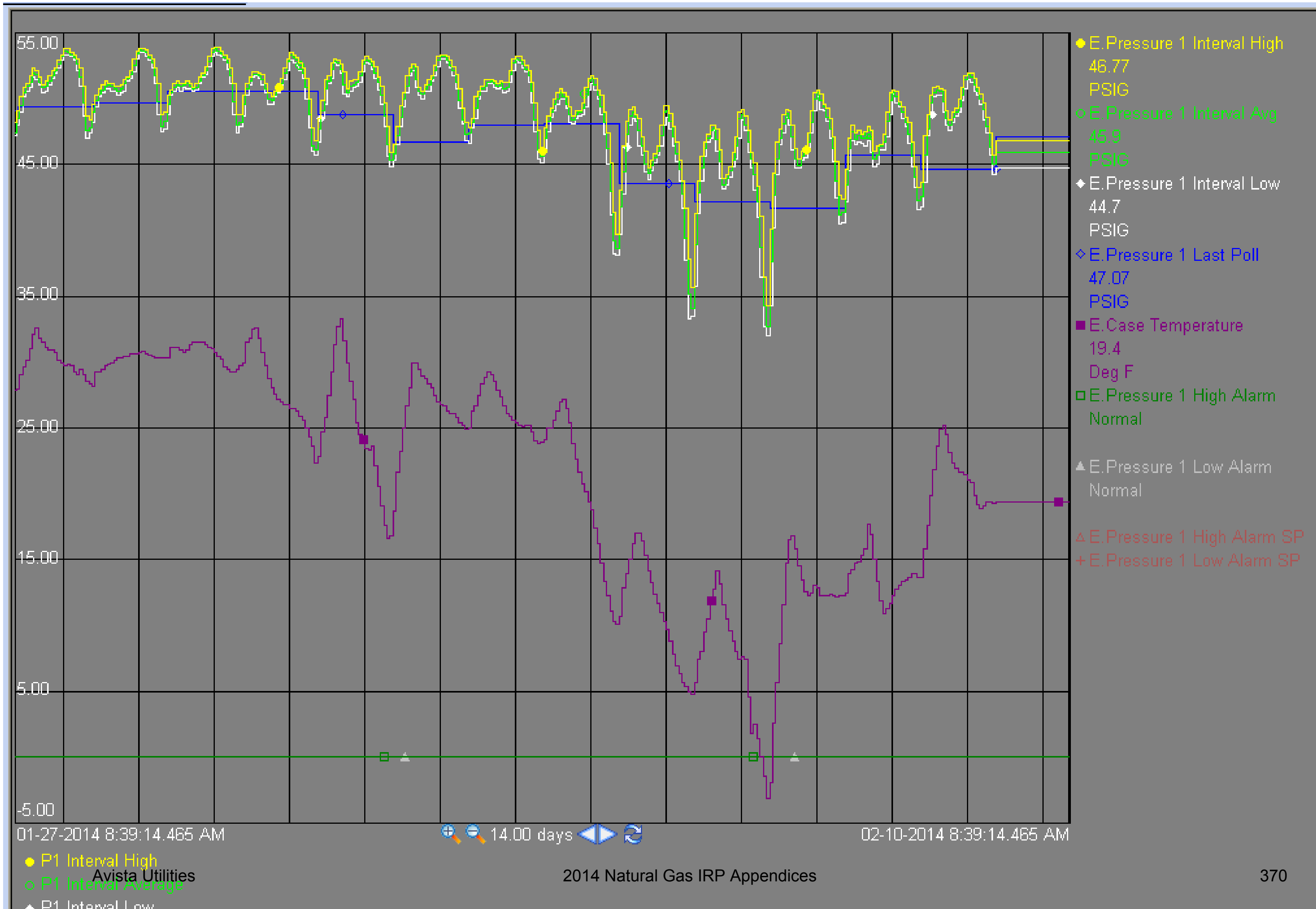
- Daily Feedback
- Real time if necessary



Post Falls State Line

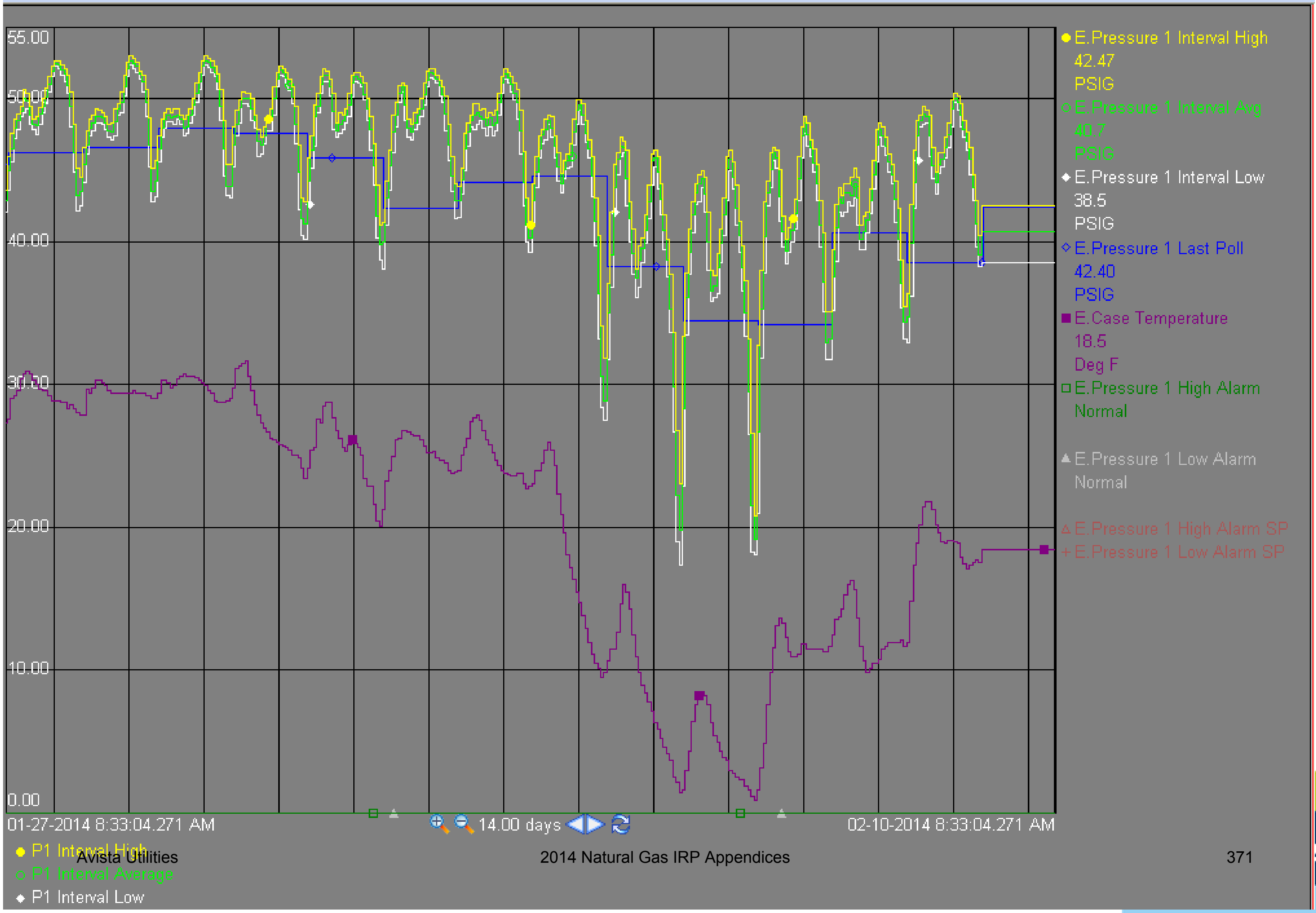


Hayden Lake



55.00
45.00
35.00
25.00
15.00
5.00
-5.00
E.Pressure 1 Interval High
46.77
PSIG
E.Pressure 1 Interval Avg
45.9
PSIG
E.Pressure 1 Interval Low
44.7
PSIG
E.Pressure 1 Last Poll
47.07
PSIG
E.Case Temperature
19.4
Deg F
E.Pressure 1 High Alarm
Normal
E.Pressure 1 Low Alarm
Normal
E.Pressure 1 High Alarm SP
E.Pressure 1 Low Alarm SP
01-27-2014 8:39:14.465 AM
14.00 days
02-10-2014 8:39:14.465 AM
P1 Interval High
P1 Interval Average
P1 Interval Low

South Hayden Lake



Compressed Natural Gas Services

Marc Schaffner, Strategic Initiatives Manager

Natural Gas Technical Advisory Committee
March 26, 2014

Natural Gas Reserves and Utilization

U.S. Natural Gas Reserves

- The U.S.'s total recoverable resource base at 2,384 trillion cubic feet
- Projected to meet total domestic demand over the next 100 years
- This year's estimates rose significantly at 22.1 percent since 2010

Source: Potential Gas Committee (PGC)

Natural Gas Vehicles (NGV) Worldwide

- Estimated 15 million natural gas vehicles (NGVs)
- Asia and Middle East 8.8M, South America 4.3 M, Africa .16M and North America .14M

NGVs on U.S. Highways

- Estimated 120,000 NGVs on U.S. highways
- Estimated 15,000 NGVs were added to U.S. highways in 2012

Source: American Clean Skies

The Future of NGVs

- Since 2003, the use of natural gas for vehicles has doubled in the U.S.
- The number of natural gas fueling stations is expected to more than double by 2015
- Natural gas is projected to overtake oil as the most-used fuel in the U.S. by 2030

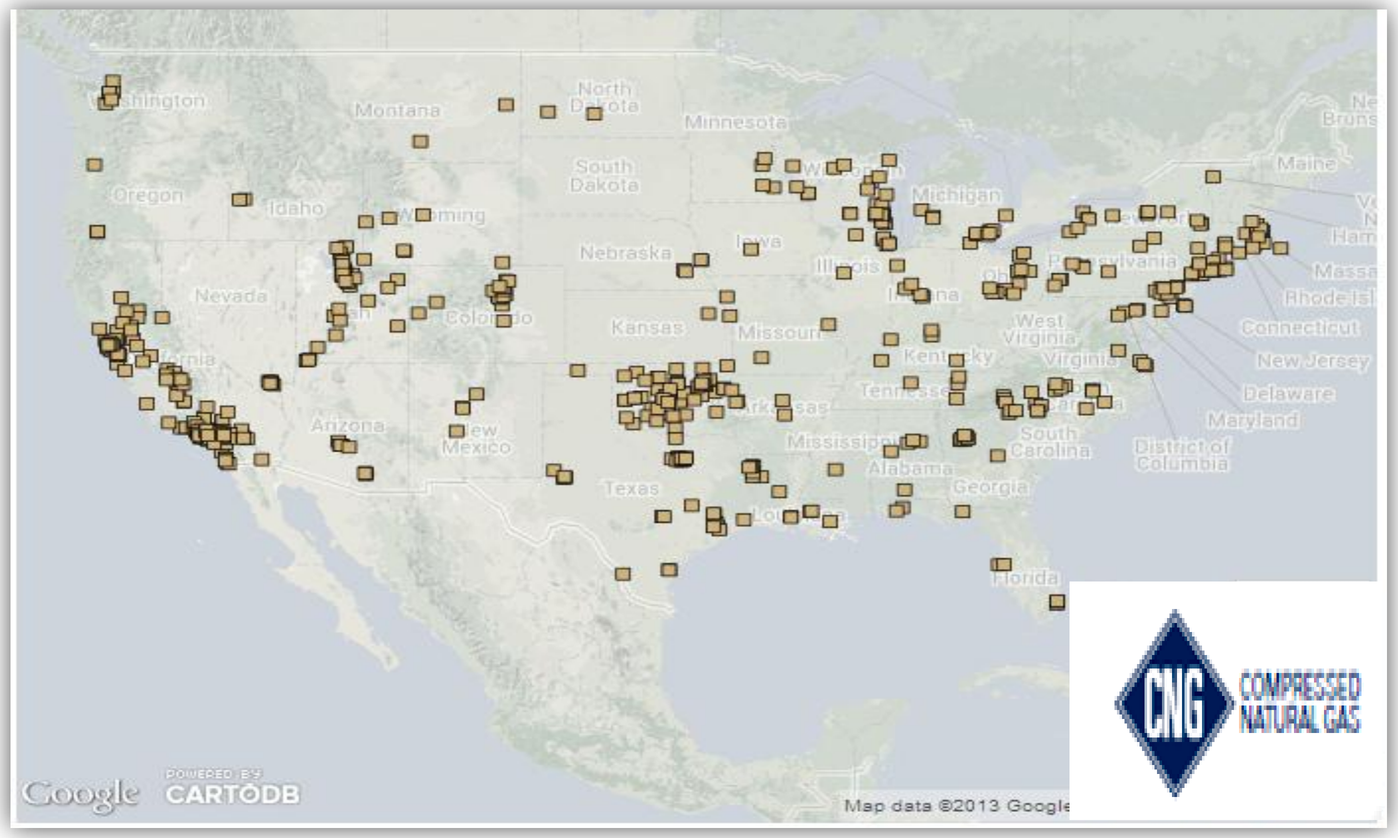
Source: IEA World Outlook Report

U.S. CNG Infrastructure
1,334 Private and Public Refueling Stations

<5% in Oregon, Washington and Idaho

Source: U.S. Department of Energy, February 2014

U.S. CNG Infrastructure
585 Public Refueling Stations



Source: U.S. Department of Energy, March 2013

Avista's Investment in Compressed Natural Gas

Environmentally responsible

- It's clean and efficient
- 25% less CO_2 emissions than gasoline or diesel
- A vital part of an alternative transportation portfolio

Cost effective

- Lowers fuel costs
- Tax credits and incentives

Reduces dependency on imported fuel sources

- Natural gas is an abundant, domestic resource

A clean fueling solution across an increasing range of NGV classes

- Extends benefits to commercial fleets and private operators

Mobilizes safe and reliable CNG equipment

- Vehicles
- Public fueling infrastructure

Avista CNG – Yesterday and Today

- Over the past 25 years Avista has fueled light duty vehicles, service continuity equipment and fork lifts with CNG
- Ten of our gas operating centers have maintained private CNG refueling infrastructure over that time period
- 2011, we began devising plans to upgrade CNG infrastructure at our highest volume service centers in Idaho, Oregon and Washington
- 2012, we completed construction of a new refueling station at our Mission Avenue service center in Spokane, WA
- 2013, we completed a second Spokane refueling station at our Dollar Road gas service center
- Q2 of 2014 we intend to start on construction of a new refueling station at our Coeur d' Alene, ID and begin upgrading an existing station at Klamath Falls, OR
- Q4 of 2014 construction of a new refueling station at White City, OR is projected to begin

Spokane Refueling Stations
Mission Avenue (top)
Dollar Road (bottom)

Avista's CNG Station Schedule

CNG Refueling Location	Project Status	Compression Capability	Storage Capacity	Public Access *
Mission Avenue SC Spokane, Wash.	Completed 2012	125 HP Compressor 202 SCFM	280 GGE at 4500 psi	
Dollar Road SC Spokane, Wash.	Completed 2013	125 HP Compressor 202 SCFM	280 GGE at 4500 psi	X
Coeur d'Alene SC Coeur d'Alene, Idaho	Construction 2014	(2) 50 HP Compressors 75 SCFM	280 GGE at 4500 psi	X
Klamath Falls SC Klamath Falls, Ore.	Upgrade 2013-14	30 HP Compressor 60 SCFM	90 GGE at 4500 psi	
White City Industrial Medford, Ore.	Construction 2014-15	200 HP Dual Compressor 300 SCFM	450 GGE at 4500 psi	X

* Public access subject to regulatory approval

CNG Investment Recovery

CNG fueling equipment can be effectively treated like conventional utility infrastructure

- gas pipe and regulators, power poles and transformers
- compressors, storage vessels and dispensers

The financial tests and investment recovery mechanisms are familiar

- standard service agreements may be offered to anchor fleet operators with special provisions that define annual consumption minimum, schedule and deficiency requirements

However…

CNG fueling infrastructure offers an average operating life of 20 years

The service life of commercial grade NGVs ranges from 5 to 10 years

Investment Recovery Illustration

Avista's Investment	$1M capital to fund a turn key CNG station
Consumption minimum annually*	350k gas gallon equivalents (GGE)
Consumption schedule	10 years
CNG Rate	$2.00 per GGE

Dollar Road
CNG Fuel Dispenser

* eq... ...ste hauling vehicles

Natural Gas Vehicle Investment Recovery

Waste Hauling NGV

Customer Investment	$35,000 per vehicle
Miles per gallon	3
Annual mileage	25,000
CNG per gallon	$2.00
Diesel per gallon	$4.00
Estimated payback	25 months
Annual fuel savings	$16,800
Five–year ROI	238%

Make or Buy Decisions

CNG Station Maintenance and Service Continuity

- Technical expertise and equipment monitoring systems
- Planned maintenance - resources and costs
- Unplanned repairs and restoration - resources and costs
- Outage response and service continuity

Point of Sale Customer Billing

- Availability of full service providers
- Transaction processors
- Billing cost per unit of measure
- Required menu of services

Avista Contributors

Energy Solutions Account Executives

Customer Solutions
Regional Business Managers

Government Relations
Lobbyists

Legal Counsel Risk
Real Estate

Contract Administration

Real Estate
Legal
Property Acquisition

Regulatory
Rates & Tariffs

Treasury
Billing Analysis

Financial Planning & Analysis

Facilities
Project Management

Fleet
NGV Management
CNG Infrastructure Maintenance

Distribution Infrastructure
Gas Engineering

Organizational Capability

What are we learning?

- The value of broad-based collaboration occurring across a dynamic natural gas for transportation marketplace. Private & public sector customers, industry associations, government, contractors and vendors

What skills are we developing?

- NGV acquisition and maintenance
- CNG fueling infrastructure planning, construction and maintenance
- CNG/NGV consultation

What value does Avista's CNG capability provide our employees, customers and business community?

- A more robust portfolio of energy offerings
- Enhanced revenue and cost saving opportunities for regional businesses
- An innovative, sustainable way to positively affect environmental quality and energy independence

Thank You

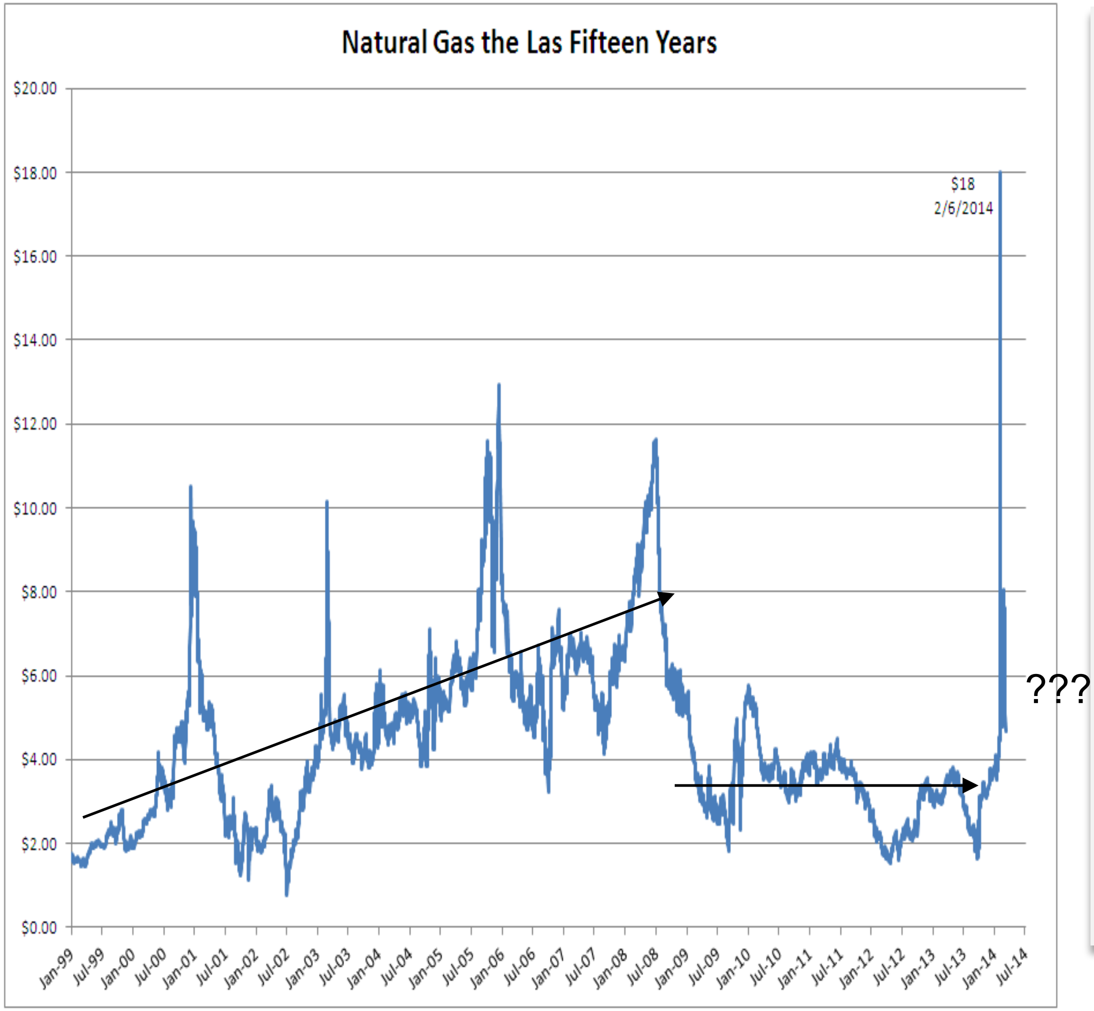
Natural Gas Prices

Kelly Fukai, Manager of Natural Gas Planning

Natural Gas Technical Advisory Committee
March 26, 2014

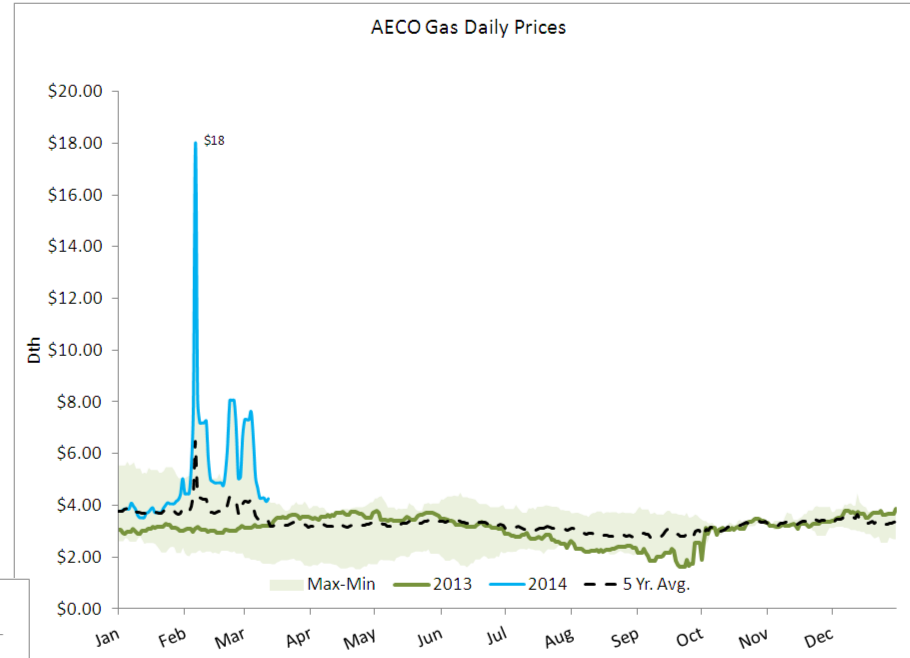
What Drives the Natural Gas Market?

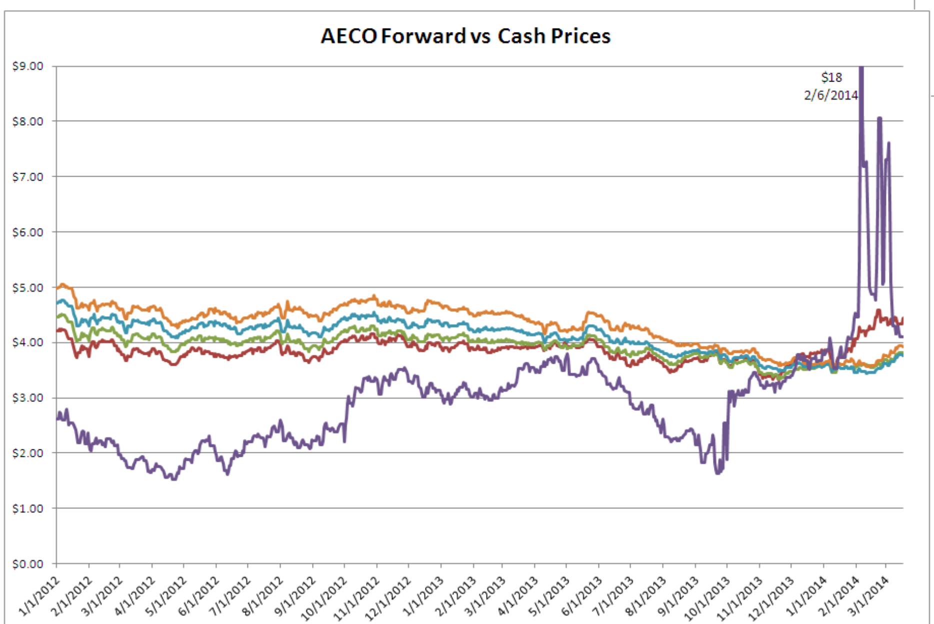
Natural Gas Spot Prices (Henry Hub)



- **Supply**
  - Type: Conventional vs. Non-conventional
  - Location
  - Cost
- **Demand**
  - Residential/Commercial/Industrial
  - Power Generation
  - Natural Gas Vehicles
- **Legislation**
  - Environmental
- **Energy Correlations**
  - Oil vs. Gas
  - Coal vs. Gas
  - Natural Gas Liquids
- **Weather**
- **Storage**

Short Term Market Perspective





The Long Term Fundamentals

Demand

- Economy (Recession, Depression, Inflation, etc.)
- Industrial Demand
- Power Generation
- Any NG (LNG, NGV, CNG)

US Natural Gas Supply and Production

- Resource Base
- Drilling Efficiency
- Associated Gas

Global Dynamics – LNG Imports and Exports

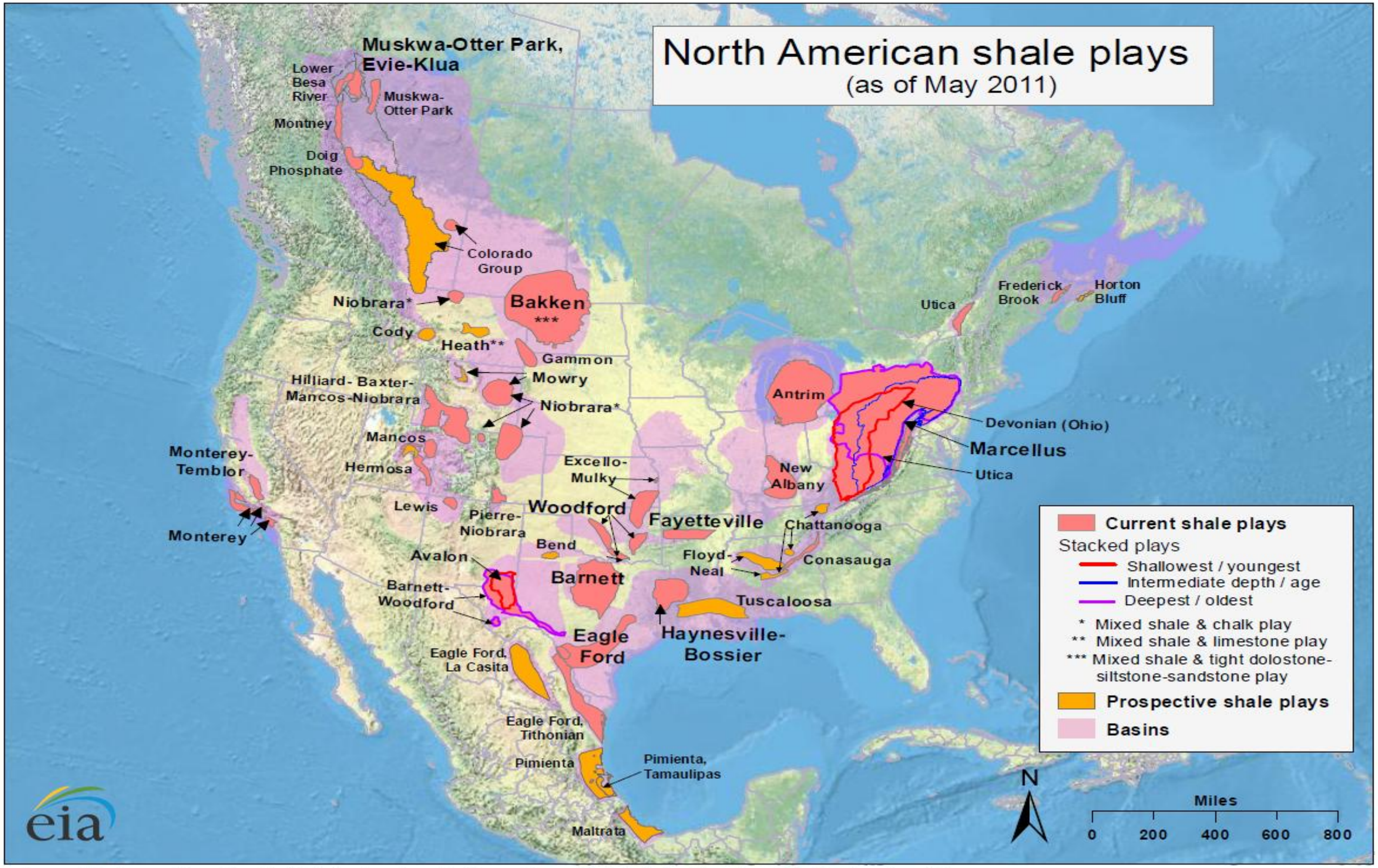
North American Storage Capacity

Correlation (or lack thereof) with other energy products

The Environment

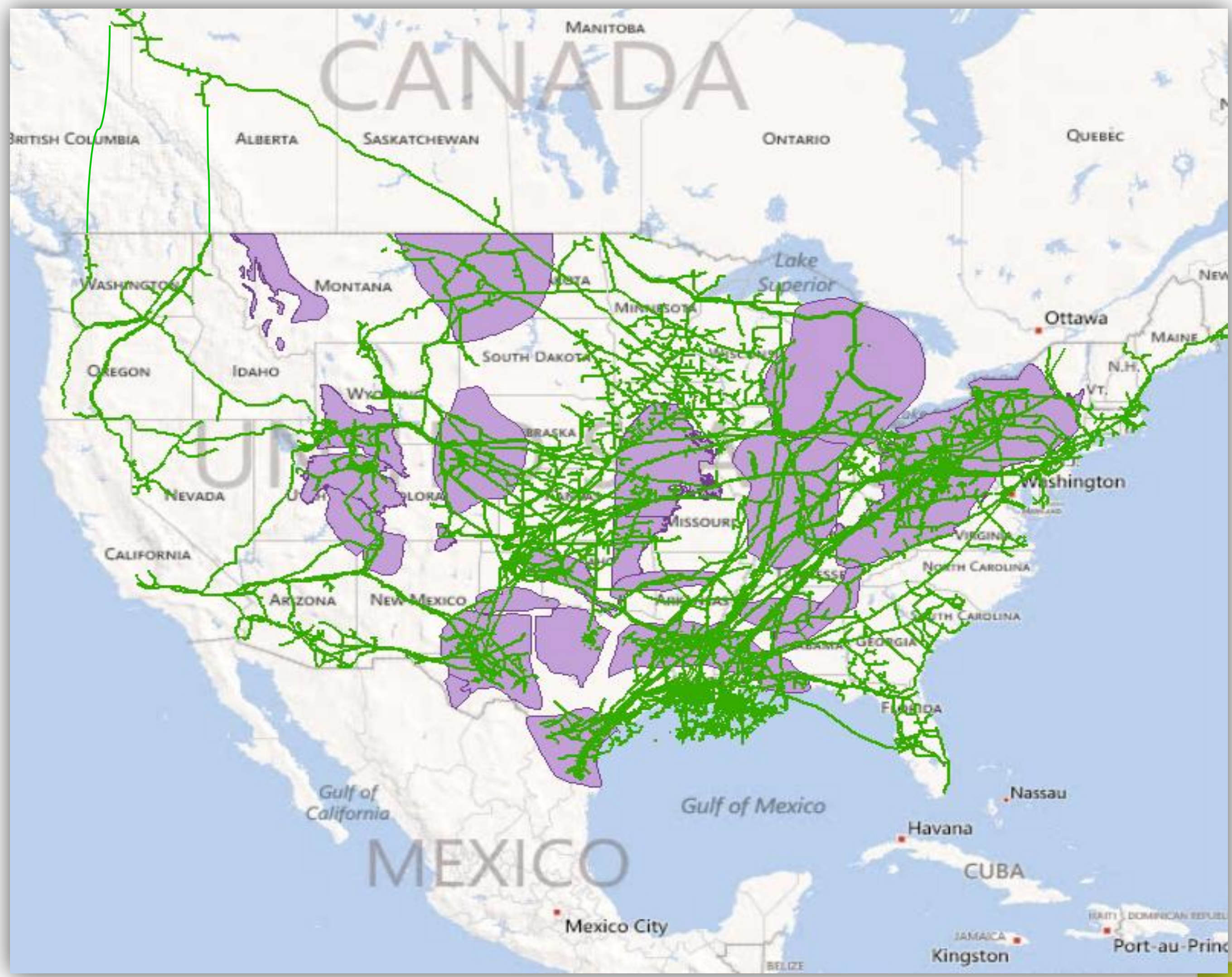
- Carbon Legislation
- The "F" Word – FRACKING
- Renewable Portfolio Standards

Shale is almost EVERYWHERE



Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Changing the Flow Dynamics



NGL's Impact on the Cost to Produce

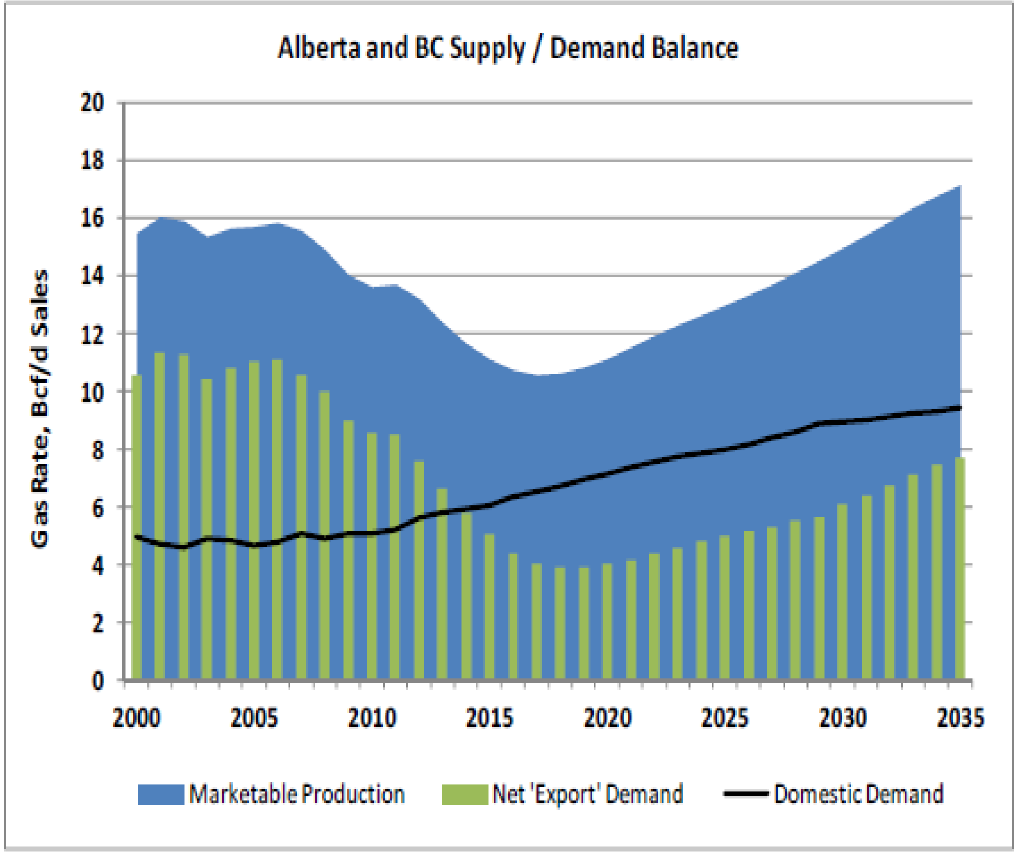
NGL's enhance the production economics for producers. NGL's are a main contributor to understanding why gas production companies continue to produce even with gas prices at very low levels.

The following table illustrates how the economics can improve with a credit for NGL's.

Shale Play	Cost to Produce without NGL's Credit	Cost to Produce including NGL's Credit
Marcellus	$4.81	$2.83
Montney	$3.85	$0.57
Barnett	$5.39	$2.41

Note: These costs are indicative of the historical impact. The costs can vary from play to play and company to company and will change as market conditions change.

Canada Dry vs. Canada Not Dry

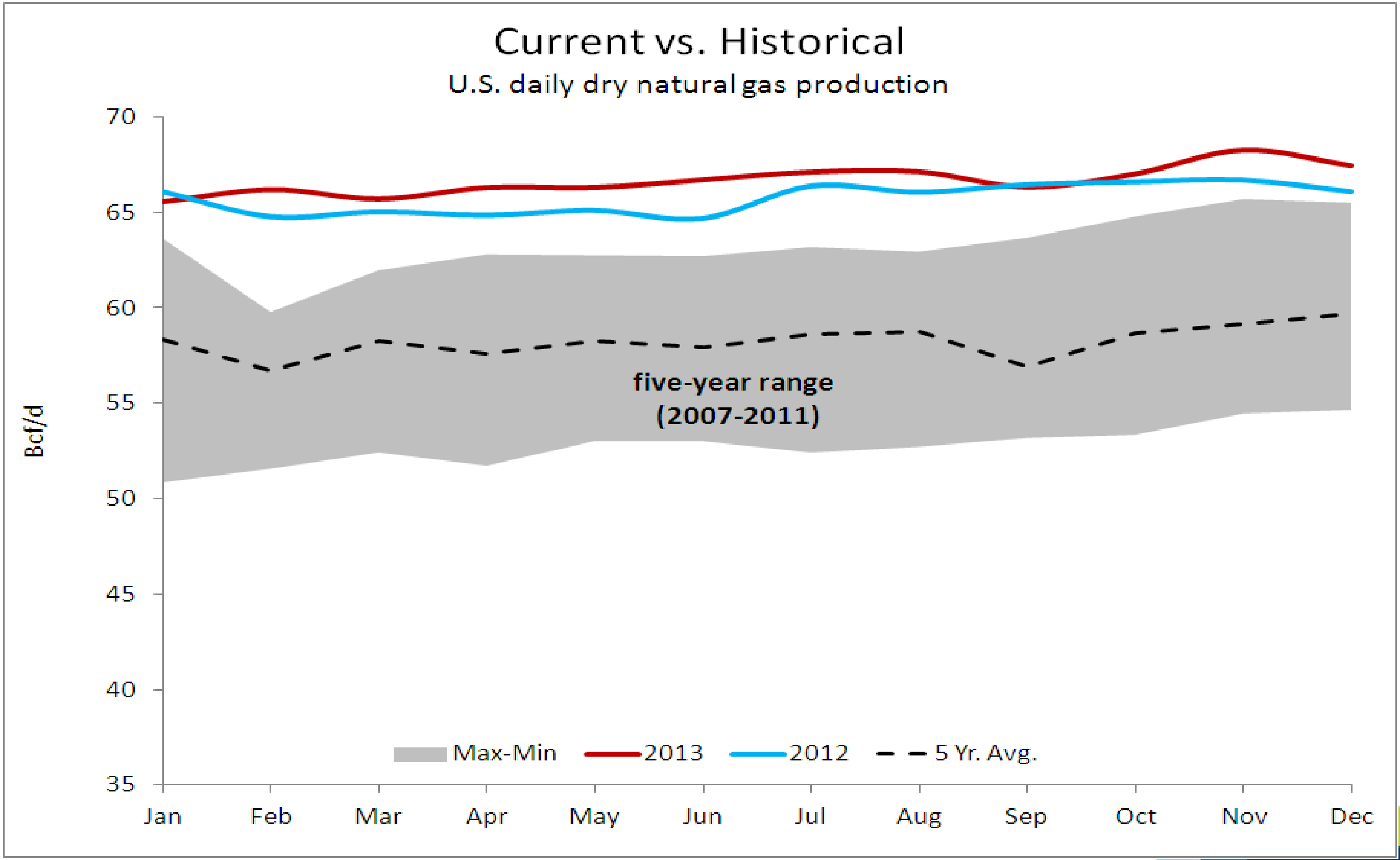


Source: NEB Canada's Energy Future 2013

Why won't Canada be dry?

- Tons of JV money
- IP rates are proving to be better than anticipated.
  - Horn River IP rates have increased 150%
- Economics are pretty good too.
  - Duverney in particular is liquids rich.

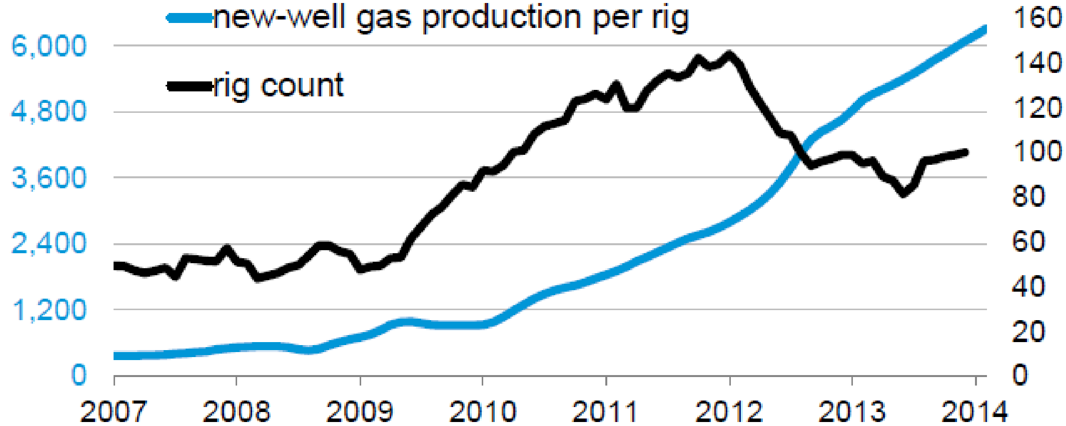
Current vs. Historical US Dry Gas Production



The Learning Curve

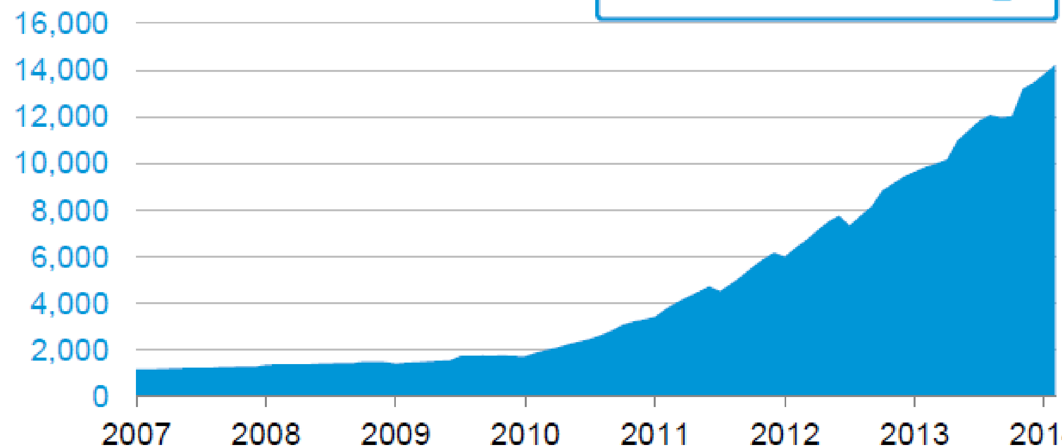
Marcellus
New-well gas production per rig
thousand cubic feet/day

Rig count
rigs



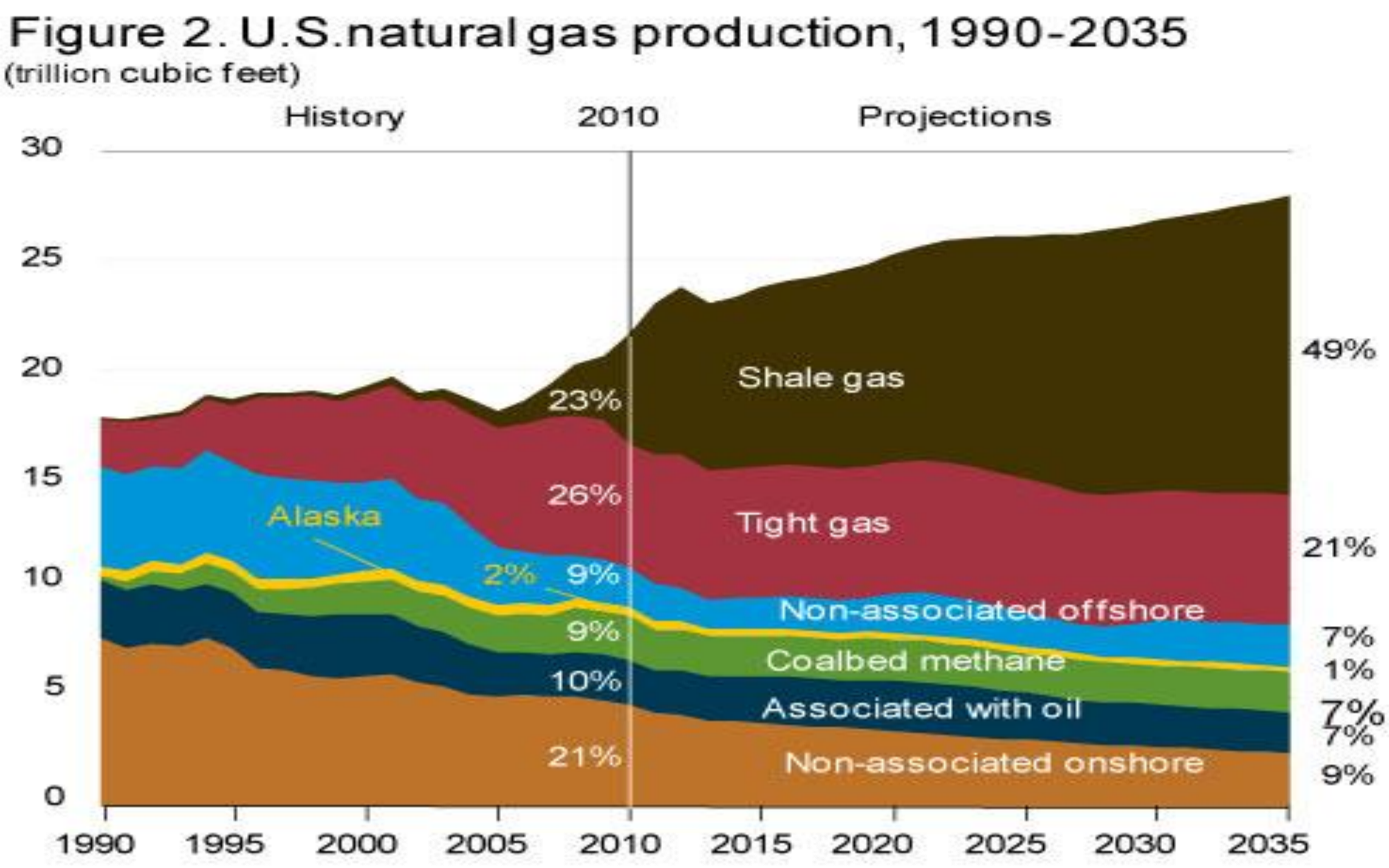
Marcellus
Natural gas production
million cubic feet/day

Gas +388
million cubic feet/day
month over month

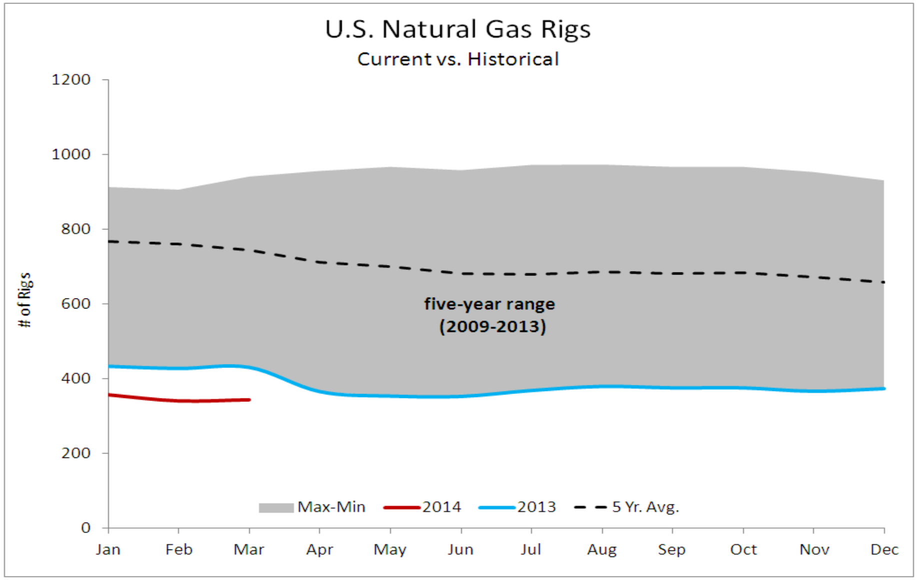


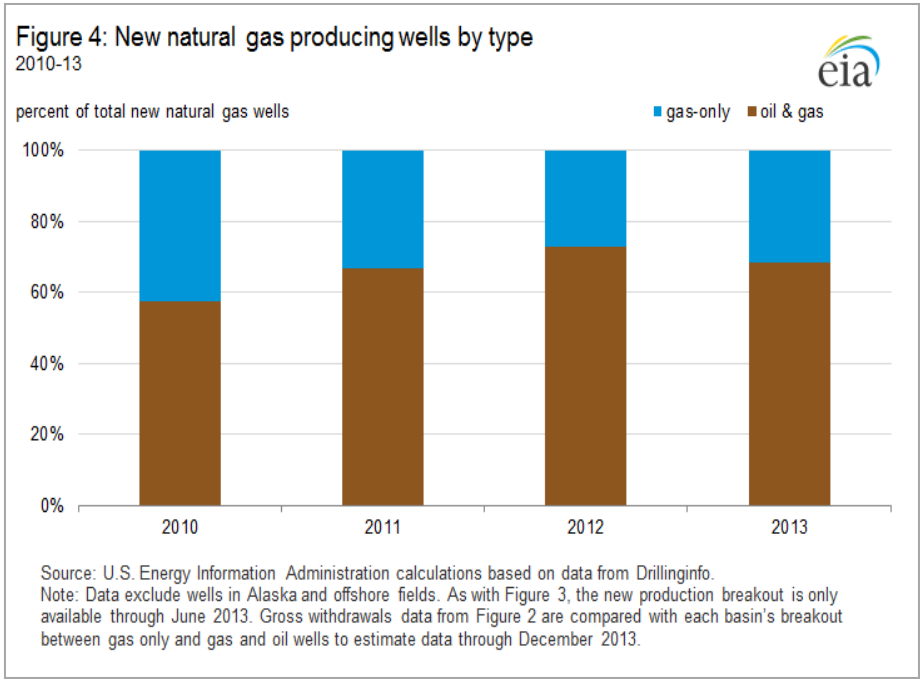
Source: EIA January Drilling Productivity Report

Forecasted Natural Gas Production

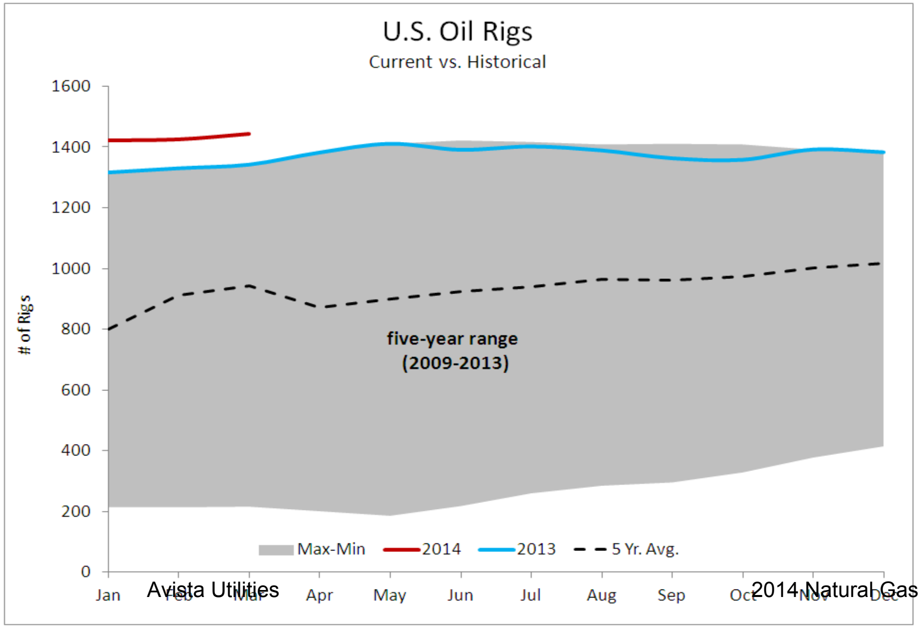


Oil and Gas Production are like Peas and Carrots





More oil = More gas



Carbon Prices

- Currently our consultant forecasts include carbon tax adders to the Henry Hub gas price.
    - Adders start in early 2020's
    - Modest adders
- One will drop carbon in next long term forecast.
- Primarily a demand effect
    - Can result in demand change due to price elastic response, however tax must be significant enough to trigger.
    - Could possibly trigger increased usage due to fuel switching.
    - May increase the DSM potential.
- Changes total portfolio costs but does not necessarily change the resource mix.

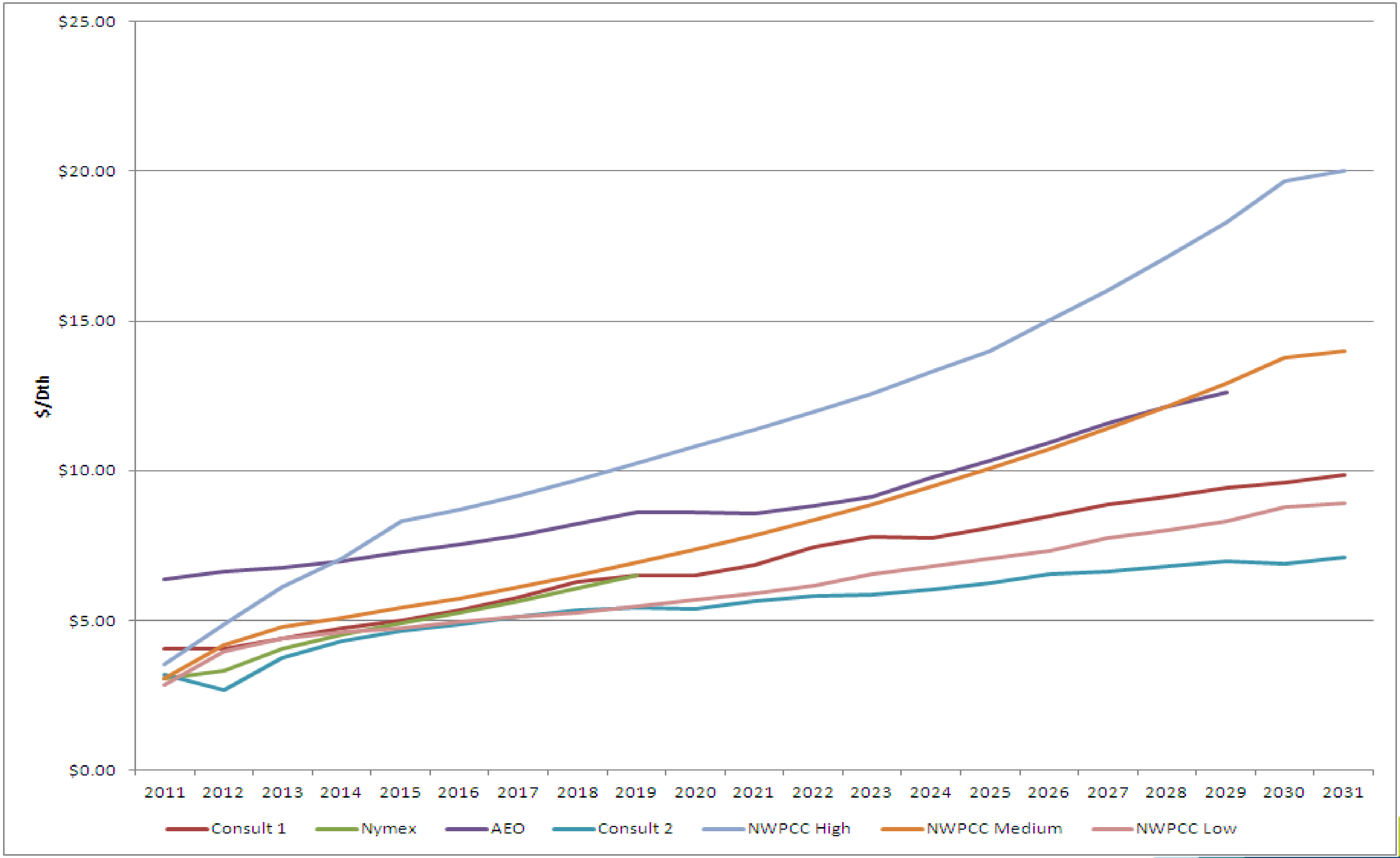
How prices affect IRP Planning?

- Major component of the total cost
- Change in price **can** trigger price elastic response
- **THE** major piece of avoided costs and therefore cost effectiveness of DSM
- Can change resource selection based on basin differentials
- Storage utilization

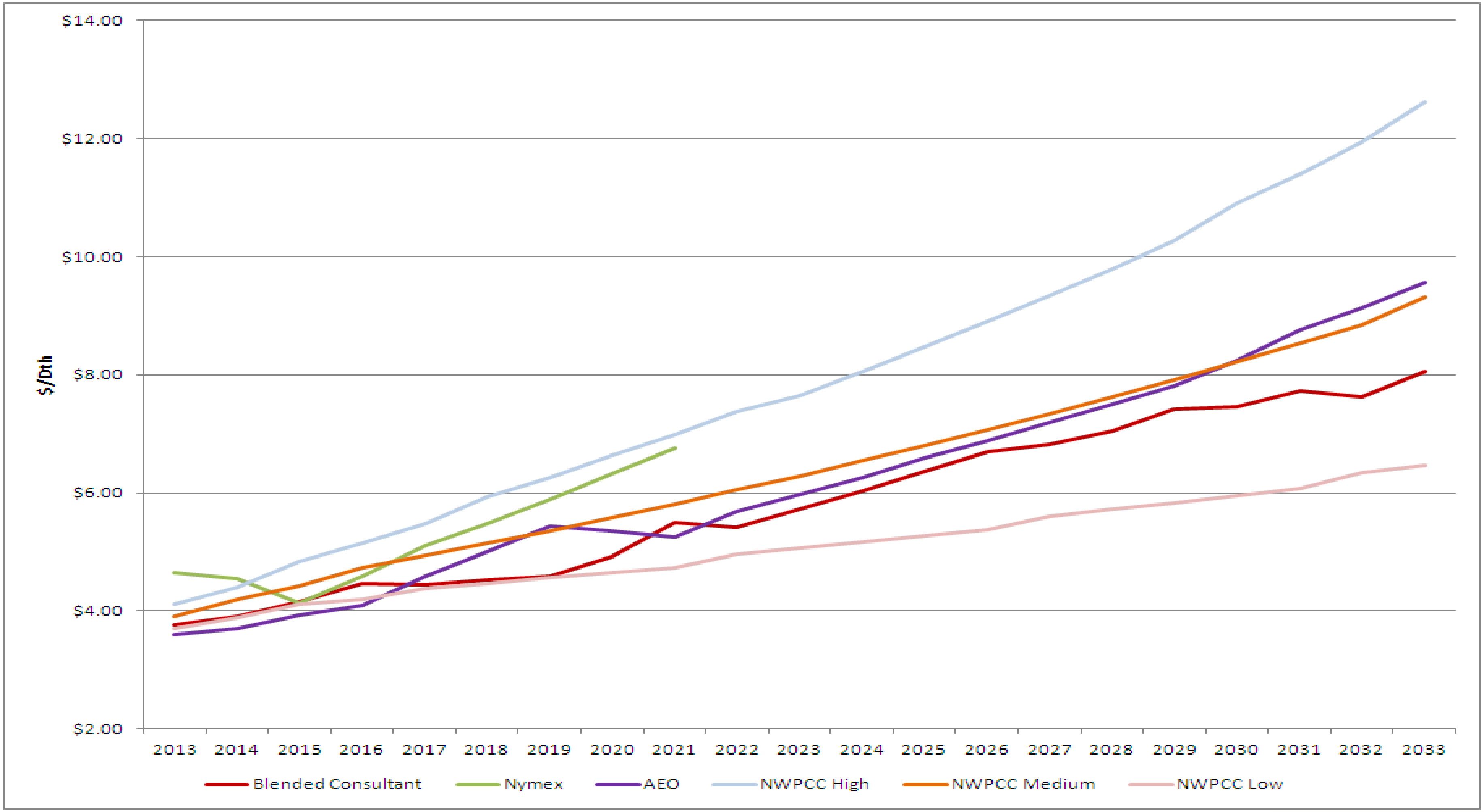
IRP Natural Gas Price Forecast Methodology

1. Examine fundamental forecasts (Consultant #1, Consultant #2, EIA, etc.)
2. Forward prices
3. Carbon legislation adder beginning in 2022 ($8.49/ton grows to $15.24/ton)
4. Basin adjusted based on forecasted
5. Monthly shape set based on forecasted
6. 50% Nymex, 50% blended Consultants Year 1
7. 40% Nymex, 60% blended Consultants Year 2
8. 30% Nymex, 70% blended Consultants Year 3
9. 20% Nymex, 80% blended Consultants Year 4
10. 10% Nymex, 90% blended Consultants Year 5
11. 100% blended Consultants Year 6 – 18
12. 100% Consultant #1 year 18 - 20

2012 IRP Forecasted Prices

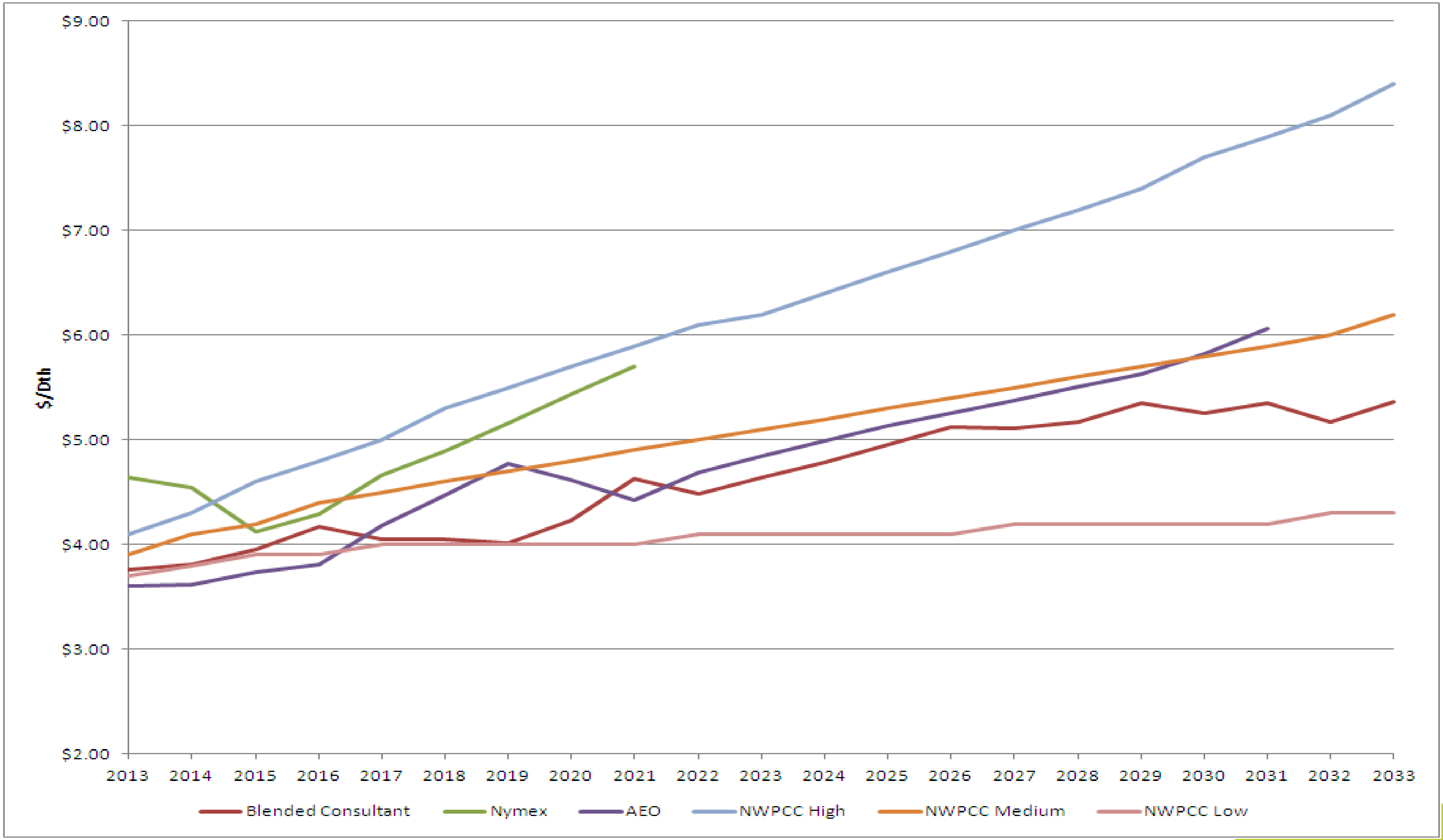


Current Long Term Henry Hub Forecasts NOMINAL



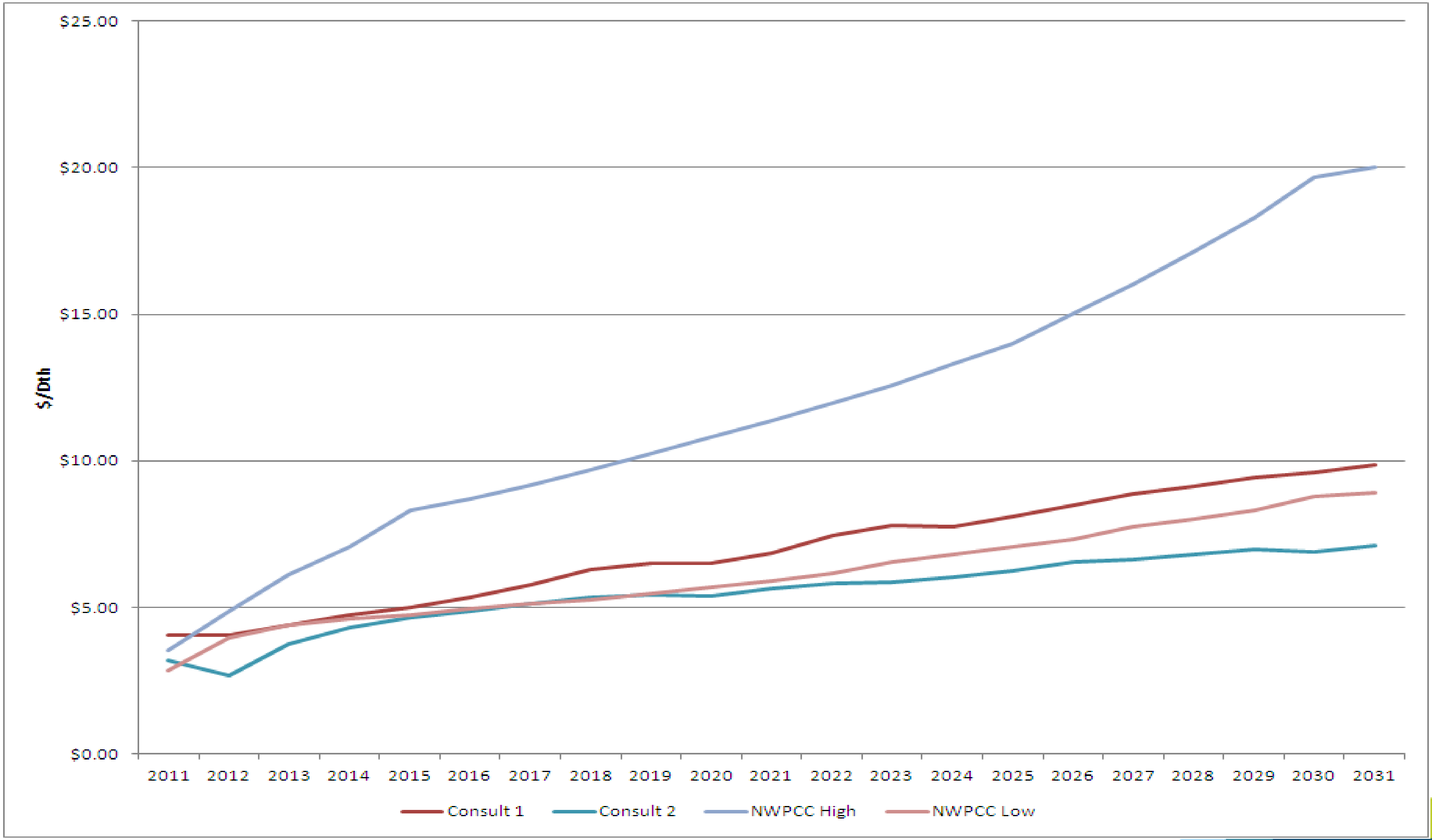
Current Long Term Henry Hub Forecasts

REAL



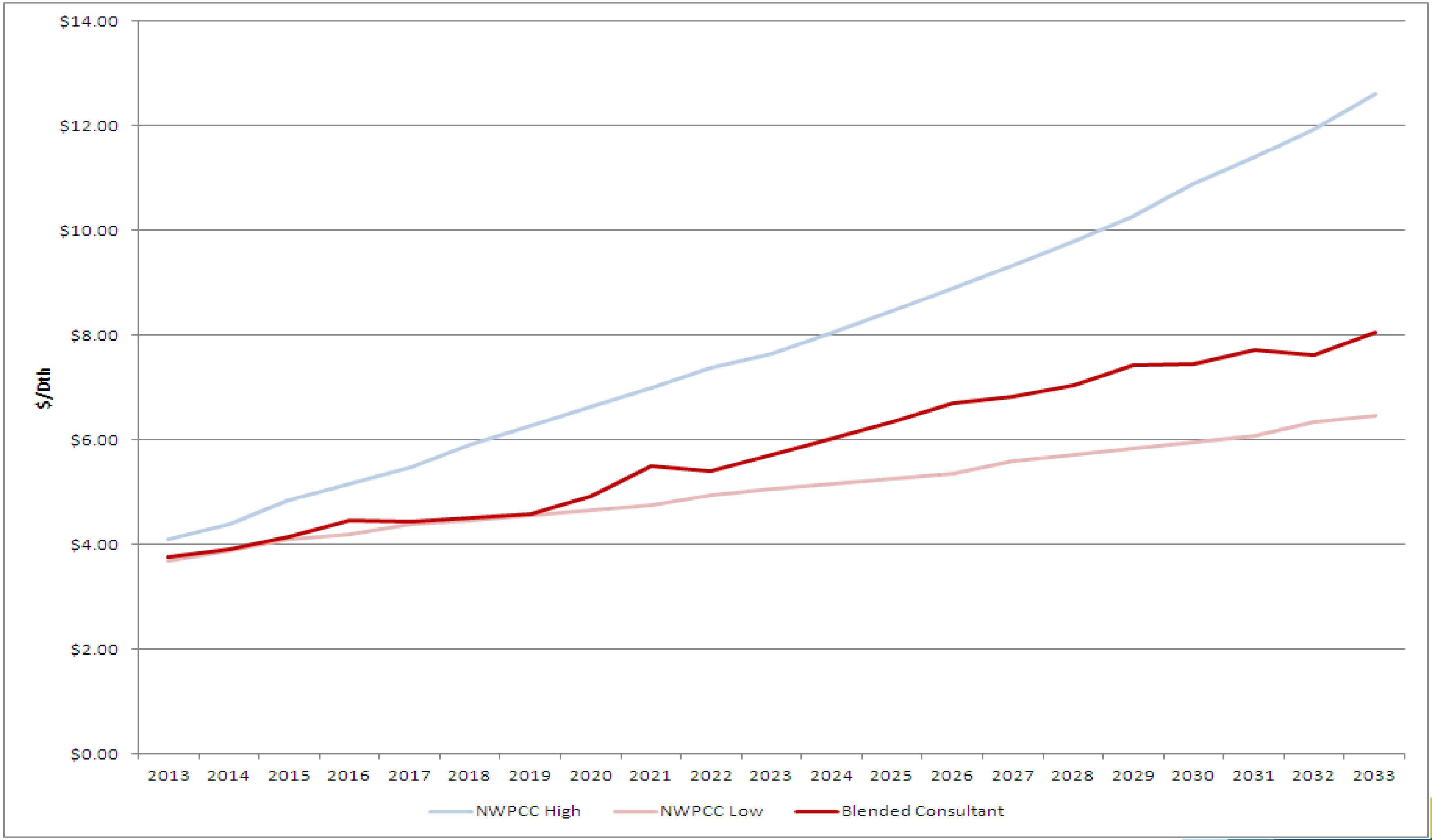
Low – Med – High from 2012 IRP

NOMINAL

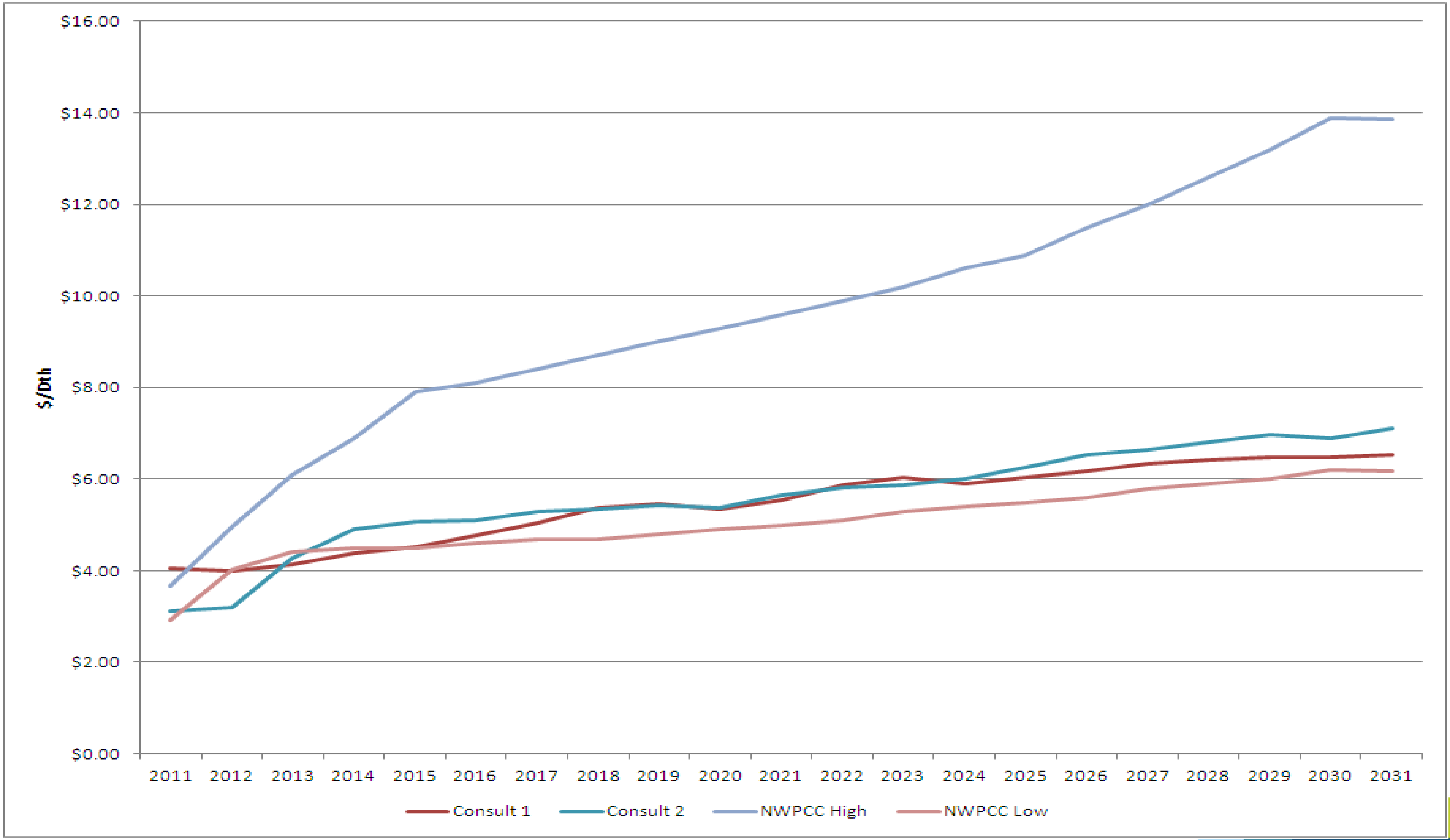


Proposed Price Forecasts

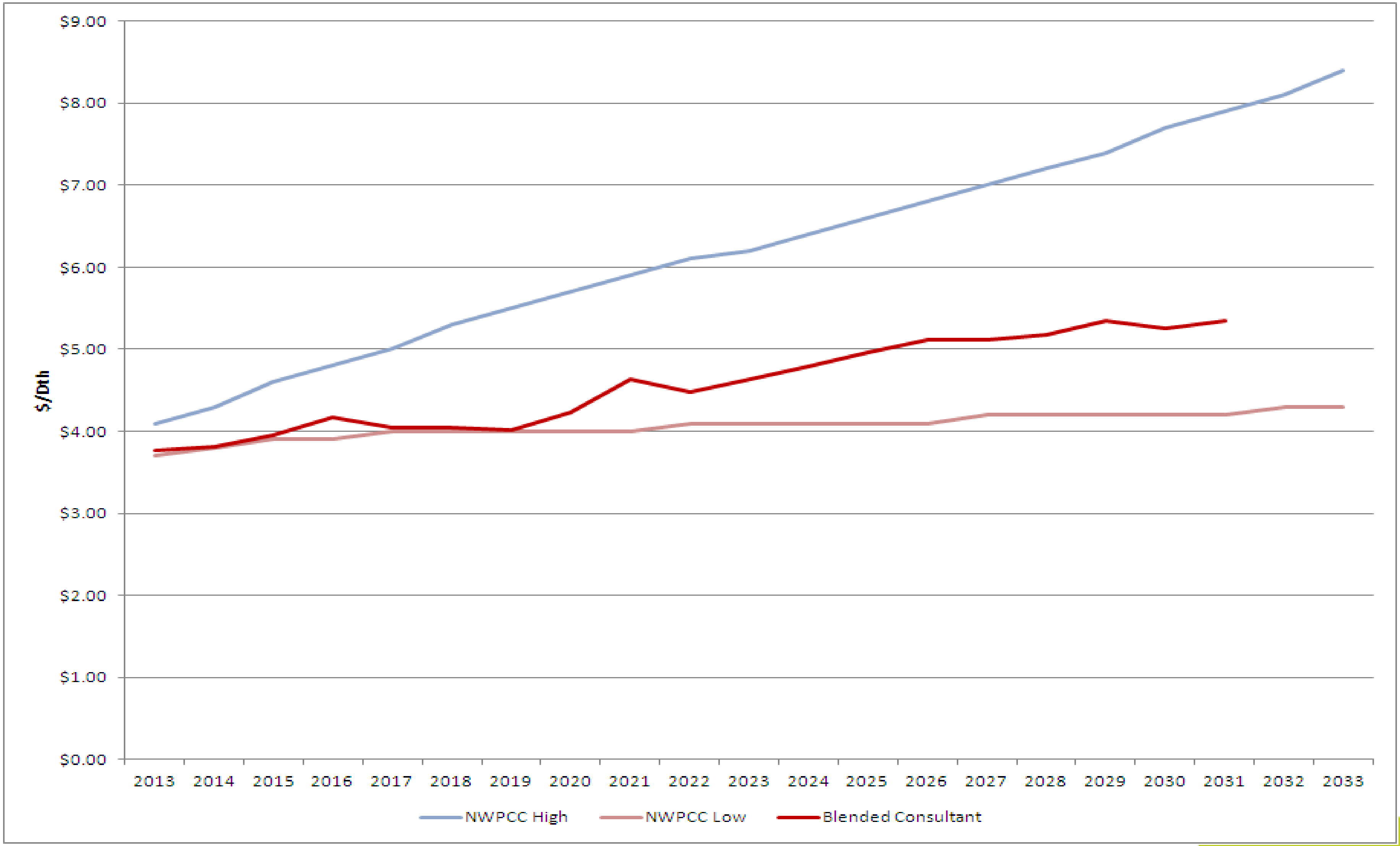
NOMINAL



Low – Med - High from 2012 IRP
REAL



Proposed Price Forecasts
REAL



Regional Price Assumptions

Regional Price as a percent of Henry Hub Price					
	AECO	Sumas	Rockies	Malin	Stanfield
Consultant1 Forecast Average	84.0%	92.0%	90.6%	95.4%	93.2%
Consultant2 Forecast Average	88.5%	94.4%	95.1%	97.0%	95.0%
Historic Cash Three Yr Average	87.4%	98.4%	96.9%	99.2%	97.5%
Prior IRP	87.0%	88.3%	89.4%	91.1%	90.2%

Monthly Price Shape

Monthly Price as a percent of Average Price						
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**
Consult1	104.7%	104.2%	96.8%	95.9%	96.6%	98.2%
Consult2	101%	101.6%	101.5%	98.9%	98.8%	98.5%
Prior IRP	102%	101.5%	98.5%	98.0%	98.5%	100.5%
	Jul	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Consult1	99.2%	99.7%	98.9%	99.4%	101%	105.2%
Consult2	99.3%	99.3%	100.3%	99.3%	100.5%	101.1%
Prior IRP	101.5%	102.0%	98.5%	98.5%	99.0%	103%

Procurement Planning

Kelly Fukai, Manager of Natural Gas Planning

Natural Gas Technical Advisory Committee
March 26, 2014

Procurement Plan Philosophy

Mission

To provide a diversified portfolio of reliable supply and a level of price certainty in volatile markets.

We cannot accurately predict what natural gas prices will do, however we can use experience, market intelligence, and fundamental market analysis to structure and guide our procurement strategies.

Our goal is to develop a plan that utilizes customer resources (storage and transportation), layers in pricing over time for stability (time averaging), allows discretion to take advantage of pricing opportunities should they arise, and appropriately manages risk.

Comprehensive Review of Previous Plan

Review conducted with SOG includes:

- Mission statement and approach
- Current and future market dynamics
- Hedge percentage
- Resources available (i.e. storage and transportation)
- Hedge windows (how many, how long)
- Long term hedging approach
- Storage utilization
- Analysis (volatility, past performance, scenarios, etc.)

A Thorough Evaluation of Risks

Procurement Plan Structure

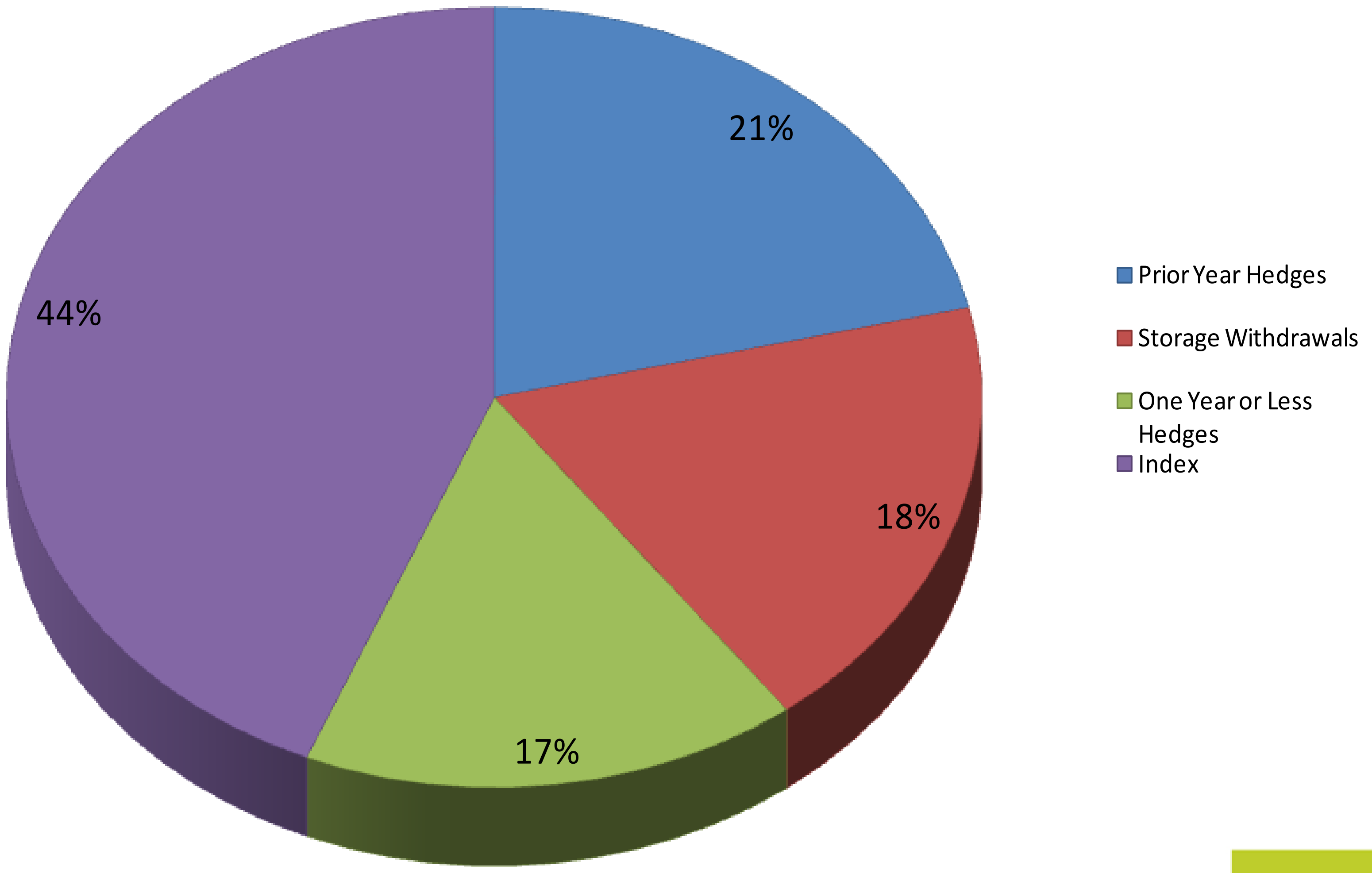
The procurement plan incorporates a portfolio approach that is diversified in terms of:

- **Components:** The plan utilizes a mix of index, fixed price, and storage transactions.
- **Transaction Dates:** Hedge windows are developed to distribute the transactions throughout the plan.
- **Supply Basins:** Plan to primarily utilize AECO, execute at lowest price basis at the time.
- **Delivery Periods:** Hedges are completed in annual and/or seasonal timeframes. Long-term hedges may be executed.

Transactions are executed pursuant to a plan and process; however, the procurement plan allows Avista to be flexible to market conditions and opportunistic when appropriate.

2014-2015 Procurement Plan Components

All Jurisdictions



Preliminary Modeling Results

Kelly Fukai, Manager of Natural Gas Planning

Natural Gas Technical Advisory Committee
March 26, 2014

Developing a Reference Case

Customer count forecast + Use per customer coefficients + Weather = Reference Case Demand

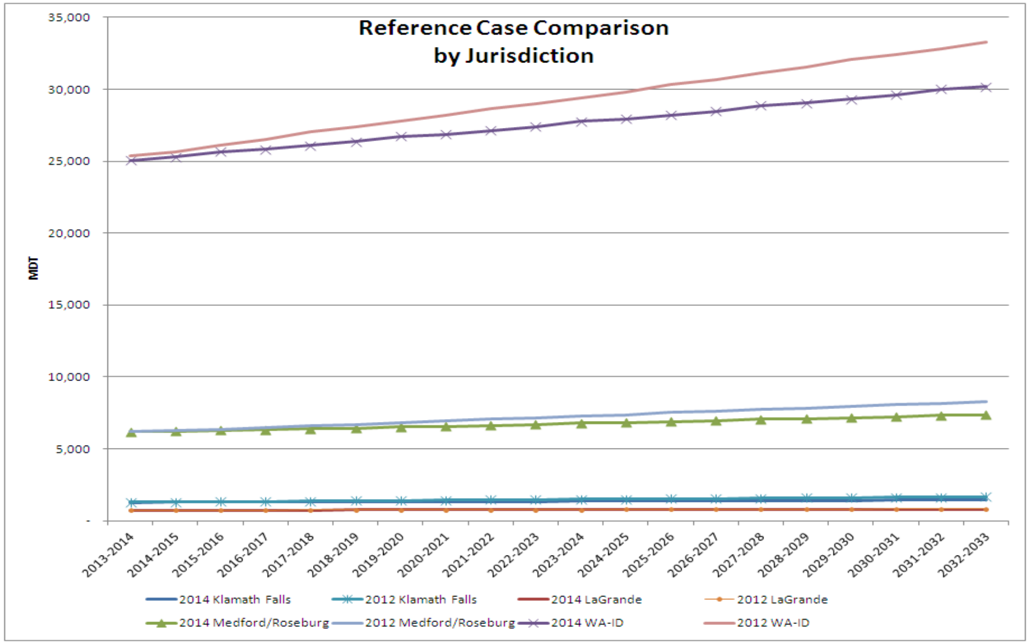
1. Customer annual growth rates:

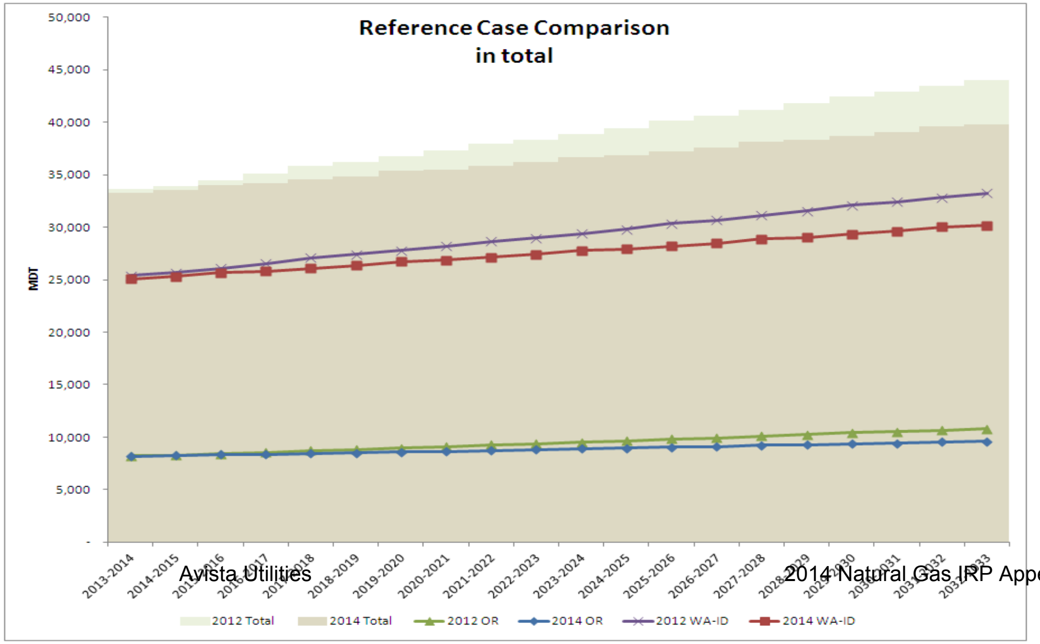
	Residential	Commercial	Industrial
Washington - Idaho	1.0%	1.0%	-0.53%
Klamath Falls	0.66%	0.66%	0.0%
LaGrande	0.40%	0.40%	0.0%
Medford	1.1%	1.1%	0.0%
Roseburg	0.8%	0.02%	0.0%

2. Use per customer coefficients –3 year average use per HDD per customer
3. Weather planning standard – coldest day on record
   - WA/ID 82; Medford 61; Roseburg 55; Klamath 72; La Grande 74

Reference Demand Case

Year	2012	2014	Delta
1	33,603	33,249	-1%
2	33,929	33,538	-1%
3	34,475	33,996	-1%
4	35,074	34,174	-3%
5	35,796	34,520	-4%
6	36,235	34,850	-4%
7	36,765	35,335	-4%
8	37,311	35,513	-5%
9	37,948	35,849	-6%
10	38,342	36,189	-6%
11	38,902	36,693	-6%
12	39,460	36,878	-7%
13	40,198	37,228	-8%
14	40,617	37,582	-8%
15	41,195	38,106	-8%
16	41,775	38,300	-9%
17	42,495	38,664	-10%
18	42,897	39,032	-10%
19	43,456	39,577	-10%
20	44,015	39,779	-11%

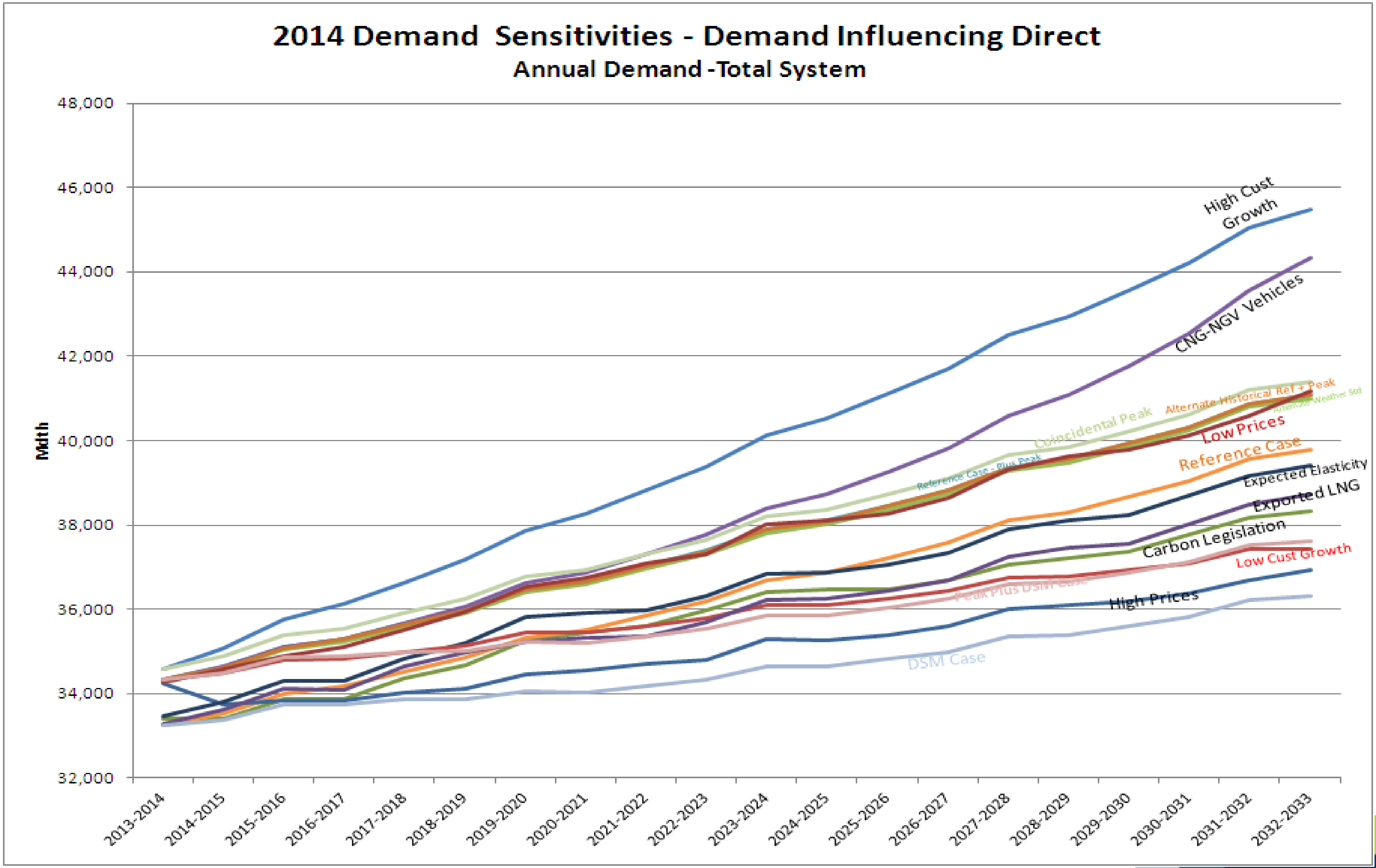




Demand Sensitivities

Model Sensitivities				DEMAND INFLUENCING - DIRECT							PRICE INFLUENCING - INDIRECT				
		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 Legislation	Exported LNG
INPUT ASSUMPTIONS															
Customer Growth Rate															
Residential	WA/ID			40% Decrease in Cust Growth Rates	60% Increase in Cust Growth Rates										
Residential	Medford														
Residential	Roseburg														
Residential	Klamath														
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		20 Year Normal	Coldest on Record	Coldest on Record	Coldest on Record	Coldest on Record	Coldest 20yrs	Normal	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	Expected	Expected	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				$5 starting in 2022	

Demand Sensitivities- Preliminary Results

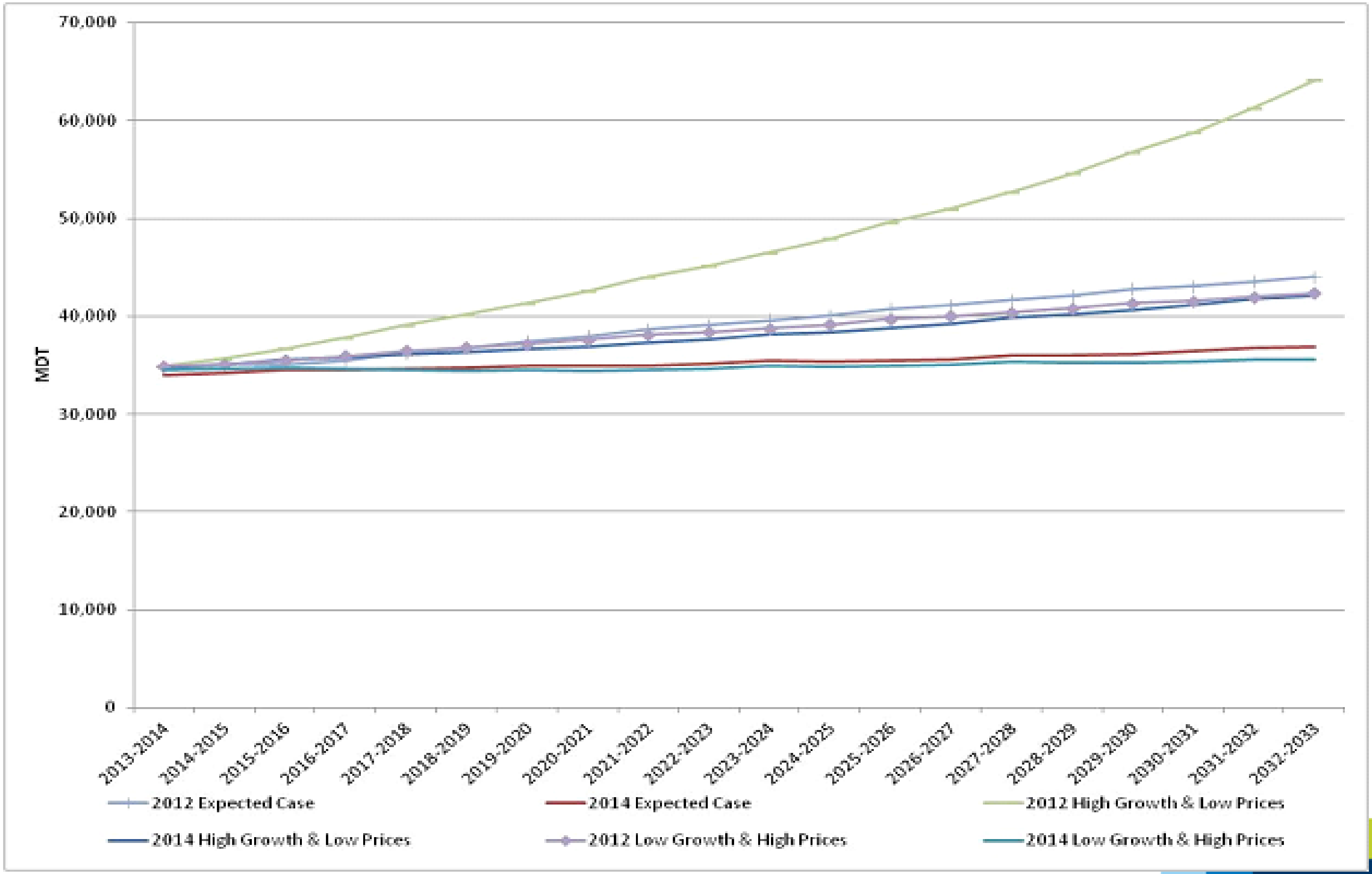


Mix and Match to Make Scenarios

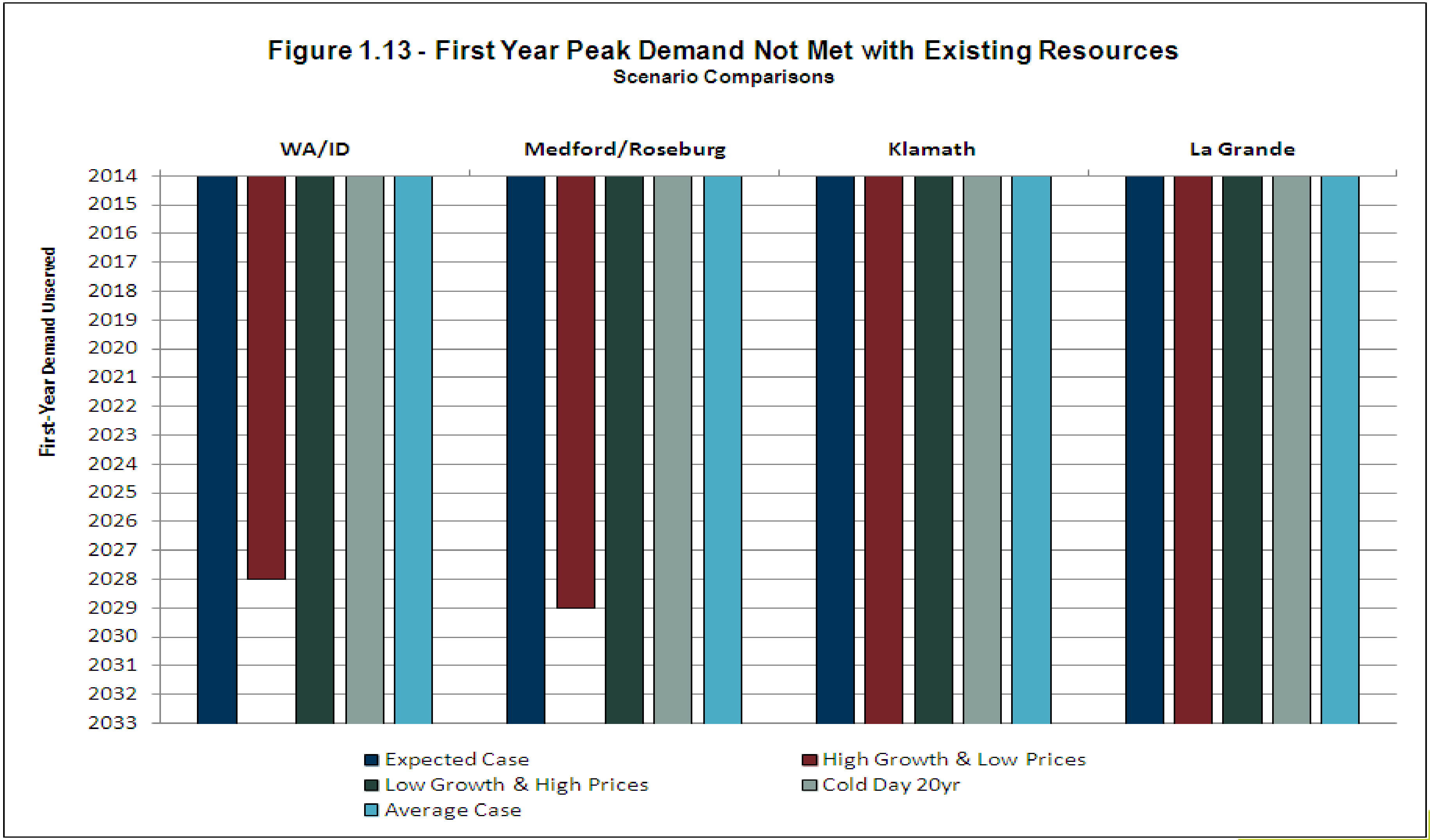
Demand Scenarios – Proposed

Proposed Scenarios		Expected Case	High Growth & Low Prices	Low Growth & High Prices	Cold Day 20yr Weather Std	Average Case
INPUT ASSUMPTIONS						
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)		$5	None	$5	$5	$5
RESULTS						
First Gas Year Unserved						
	WA/ID	N/A	2027	N/A	N/A	N/A
	Medford	N/A	2029	N/A	N/A	N/A
	Roseburg	N/A	N/A	N/A	N/A	N/A
	Klamath	N/A	N/A	N/A	N/A	N/A
	La Grande	N/A	N/A	N/A	N/A	N/A

Demand Scenarios – Preliminary Results



First Year Unserved – Preliminary Results



2014 IRP Timeline

- **August 31, 2013** – Work Plan filed with WUTC
- **January through April 2014** – Technical Advisory Committee meetings. Meeting topics will include:
  - Demand Forecast and Demand Side Management – January 24
  - Supply and Infrastructure, Gate Station Analysis, Supply Side Resources, Resource Optimization – *February 25*
  - Distribution Planning, Natural Gas Pricing, CNG/NGV, SENDOUT® Preliminary Results and Further Case Discussion – *March 26*
  - **DSM CPA results, further SENDOUT® results and Stochastic analysis – *April 23***
- **May 30, 2014 –** Draft of IRP document to TAC
- **June 30, 2014 –** Comments on draft due back to Avista
- **July 2014 –** TAC final review meeting (if necessary)
- **August 31, 2014 –** File finalized IRP document

2014 Avista Natural Gas IRP

Technical Advisory Committee Meeting 4

April 23, 2014

Spokane, WA

Agenda

- Introductions & Logistics
- Demand Side Management Potential
- Assumptions Review
- Demand Sensitivities and Scenarios Updates
- Supply Side Resource Options
- Stochastic Analysis
- Key Issues & Document Discussion

2014 IRP Timeline

- **August 31, 2013** – Work Plan filed with WUTC
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Demand Side Management CPA Results

Assumptions Review

Developing a Reference Case

Customer count forecast + Use per customer coefficients + Weather = Reference Case Demand

1. Customer annual growth rates:

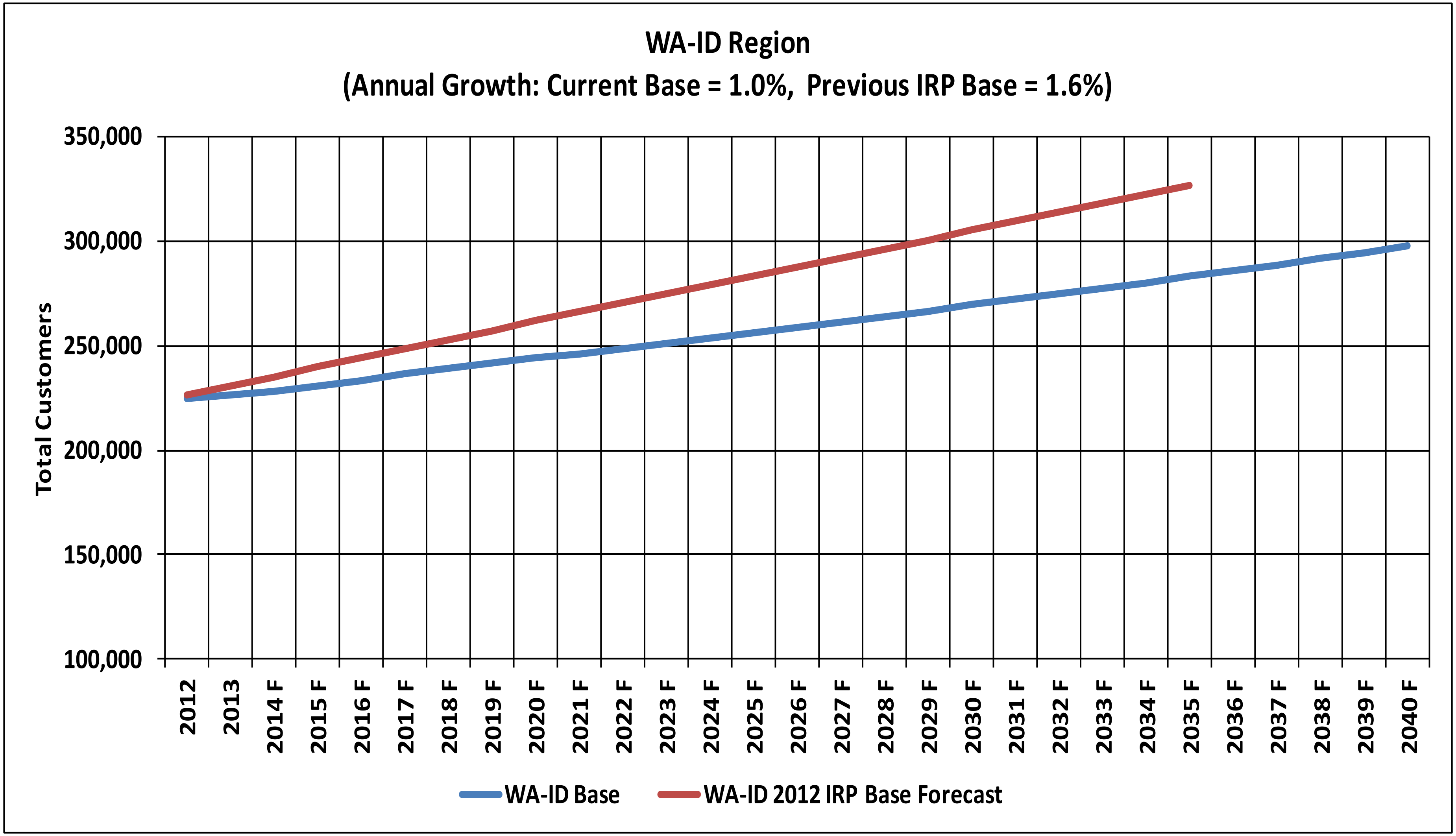
	Residential	Commercial	Industrial
Washington - Idaho	1.0%	1.0%	-0.53%
Klamath Falls	0.66%	0.66%	0.0%
LaGrande	0.40%	0.40%	0.0%
Medford	1.1%	1.1%	0.0%
Roseburg	0.8%	0.02%	0.0%

2. Use per customer coefficients – 3 year historical use per customer by class

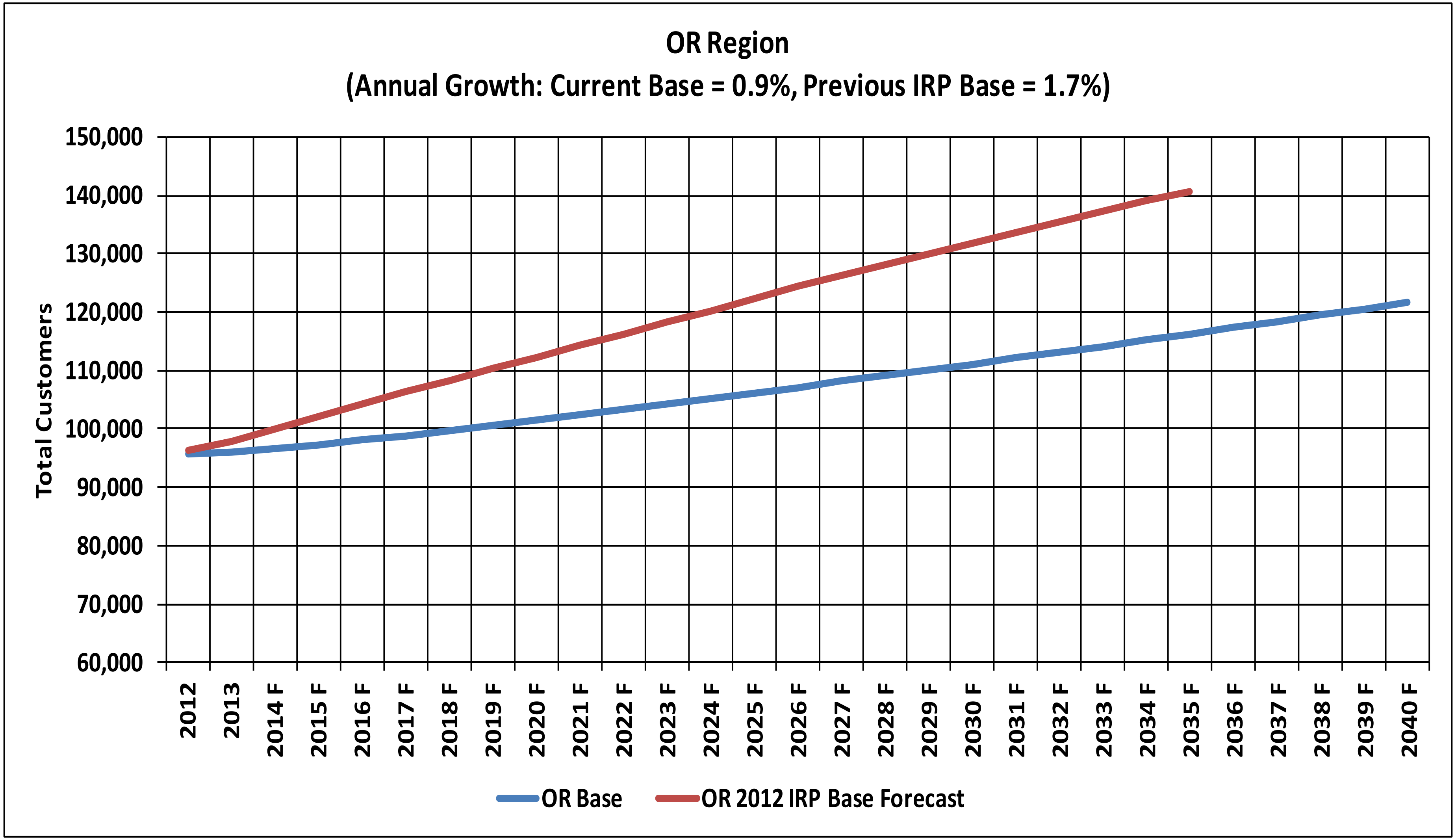
3. Weather planning standard – coldest day on record

   - WA/ID 82; Medford 61; Roseburg 55; Klamath 72; La Grande 74

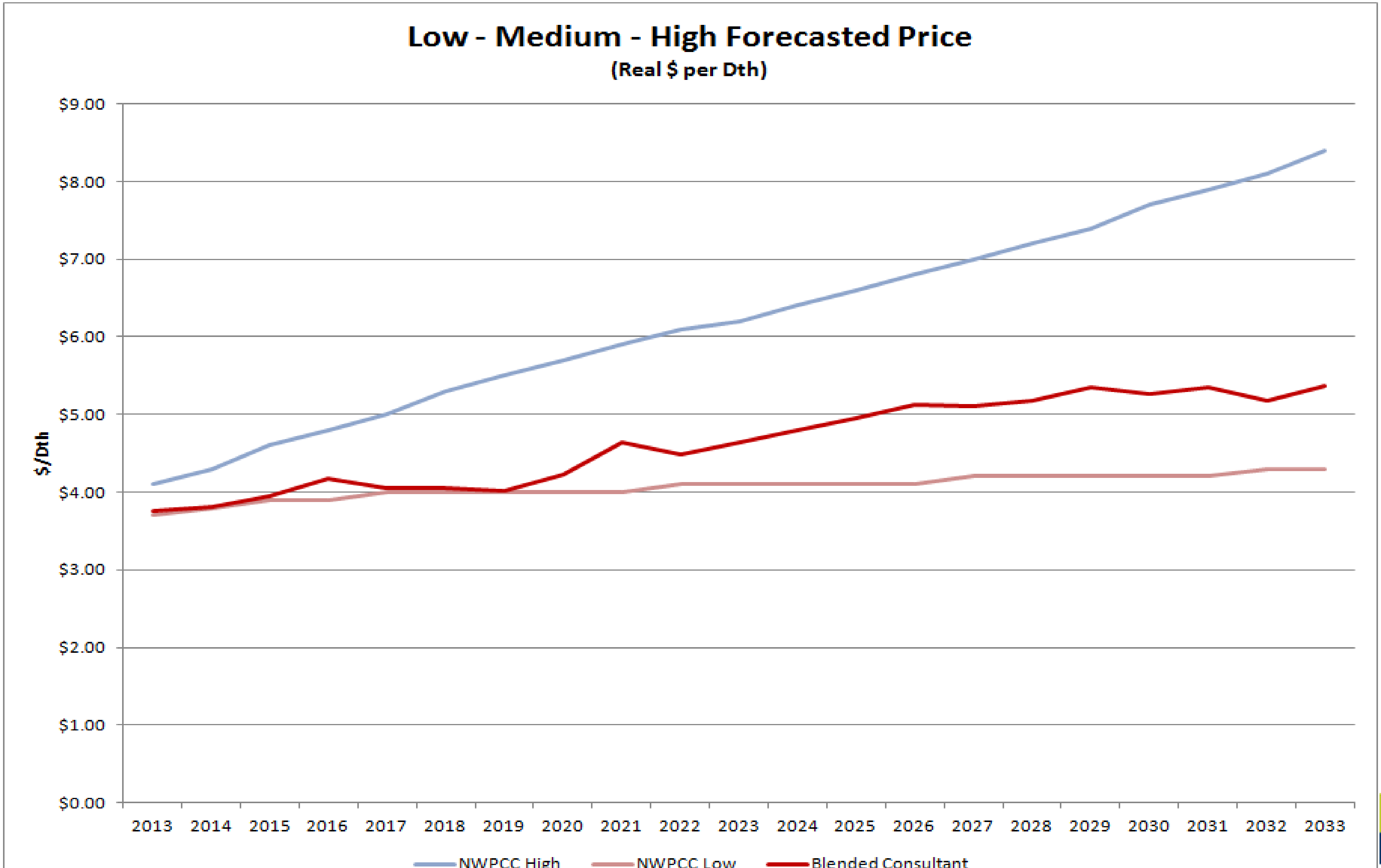
WA-ID Region: 2014 IRP and 2012 IRP



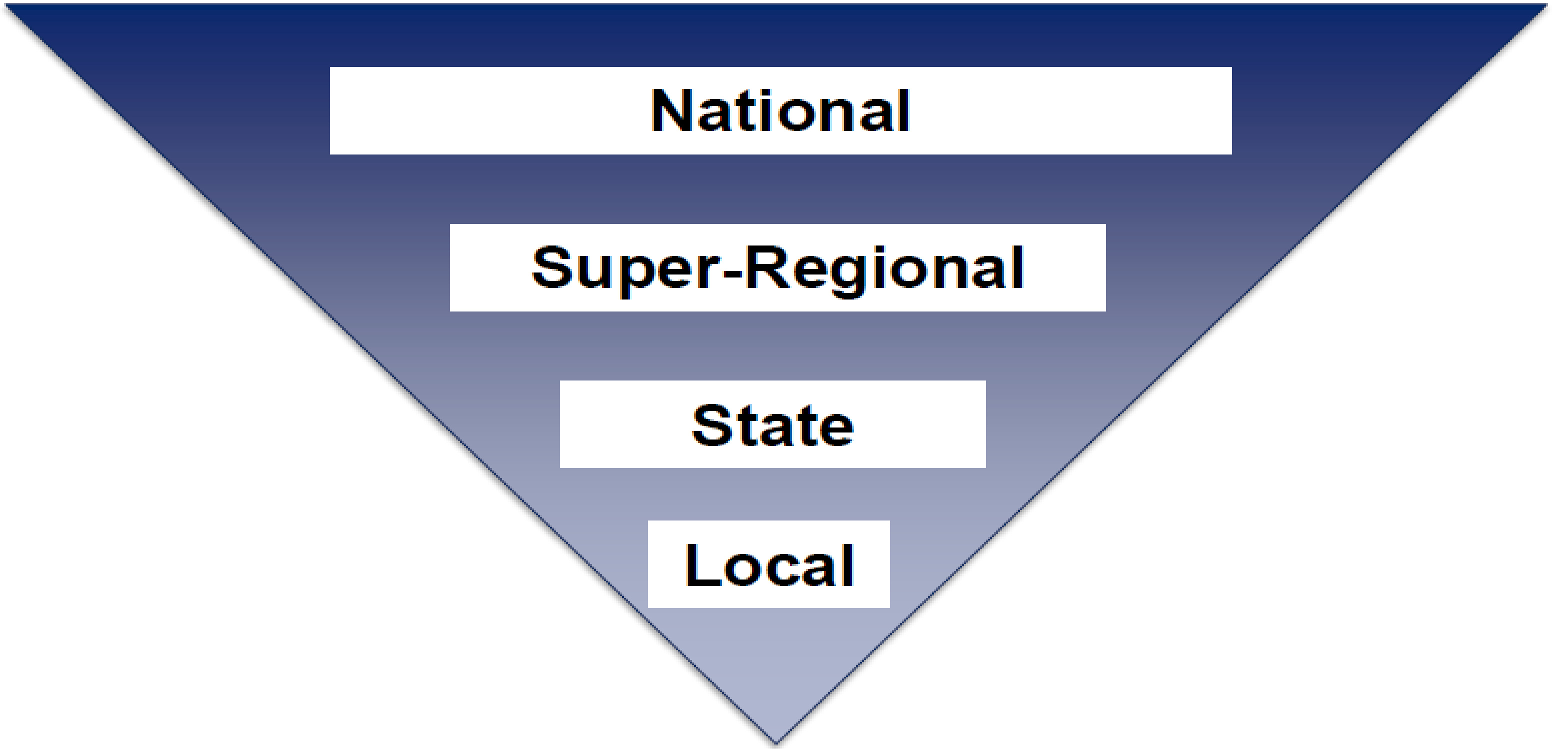
OR Region: 2014 IRP and 2012 IRP



Natural Gas Prices



Price Elasticity: What does the research show?



Statistical significance of own-price becomes more uncertain as geographic area of measurement shrinks.*

*Bernstein, M.A. and J. Griffin (2005). *Regional Differences in Price-Elasticity of Demand for Energy*, Rand Corporation

Price Elasticity Proposed Assumptions

- The data is a mixed bag at best:
  - 8 of 9 super regions have statistically significant short and long run elasticities.
  - At a state level only 10 of 50 show statistical significant elasticities.
  - In some cases, the estimated elasticities are positive.

We incorporated a -.15 price elastic response for our expected elasticity assumption.

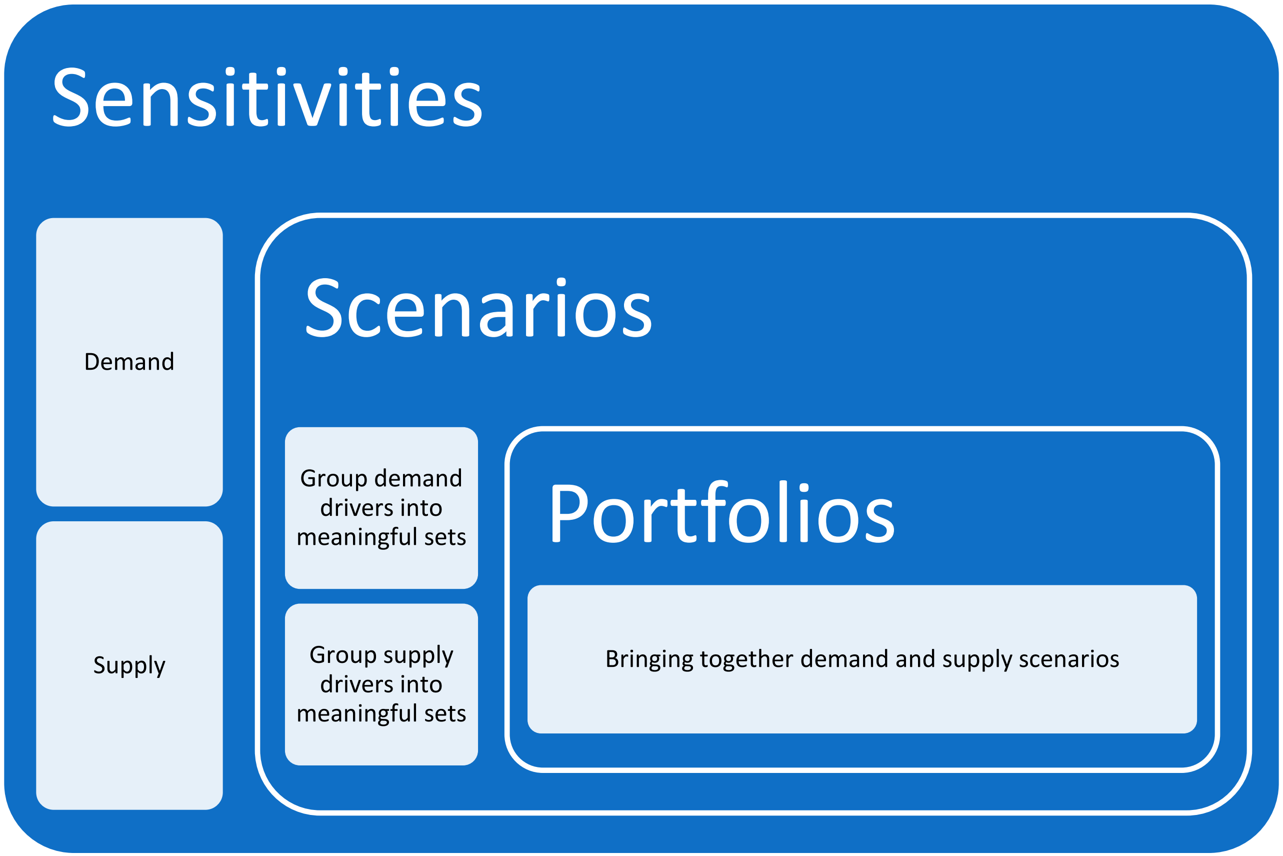
Carbon Legislation Sensitivities

Carbon Legislation Case	2013	2033
Low	$ 5.00	$ 5.00
Medium	$ 8.32	$ 14.83
High	$ 16.00	$ 28.00

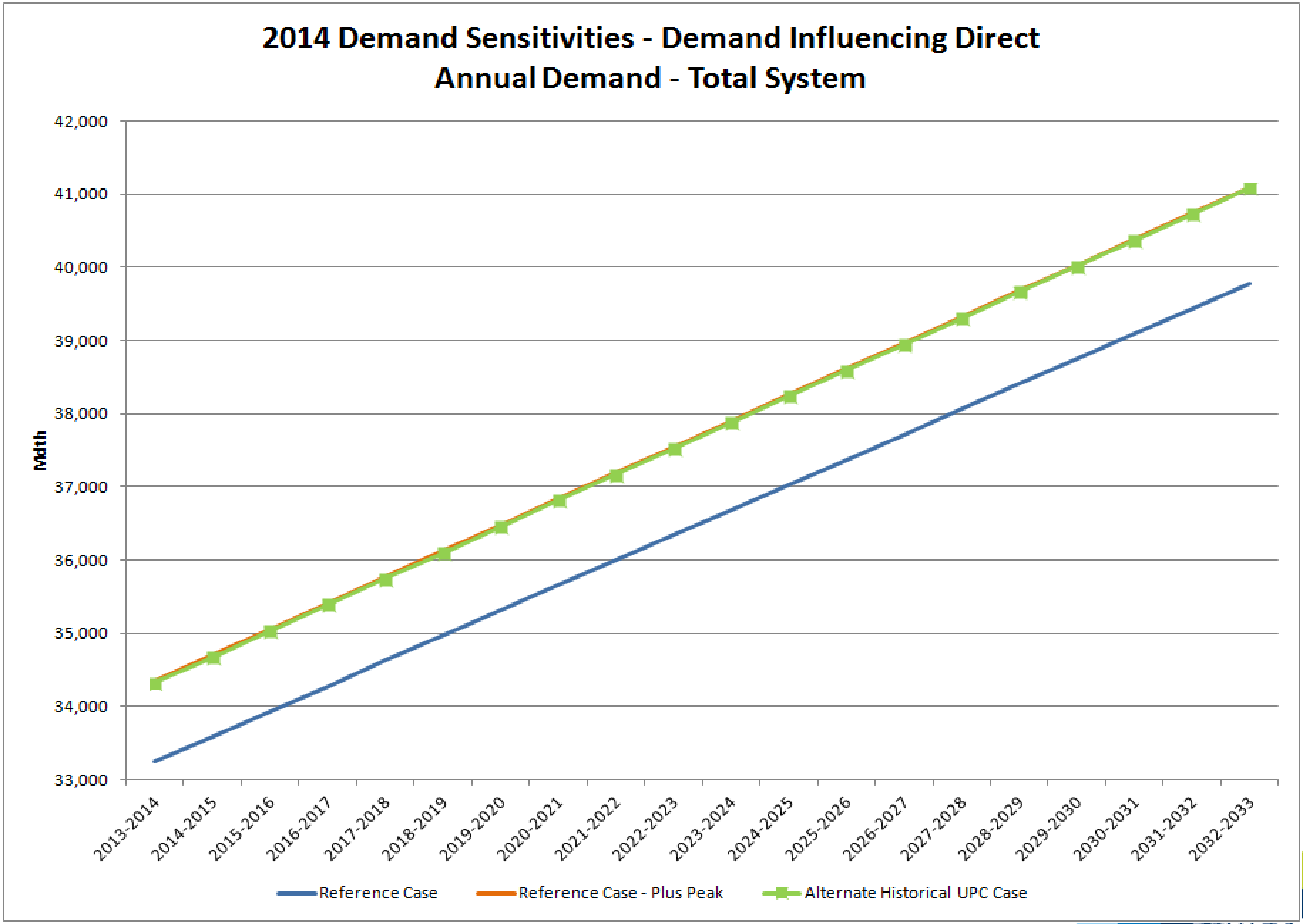
*Real Dollars per Ton of CO2

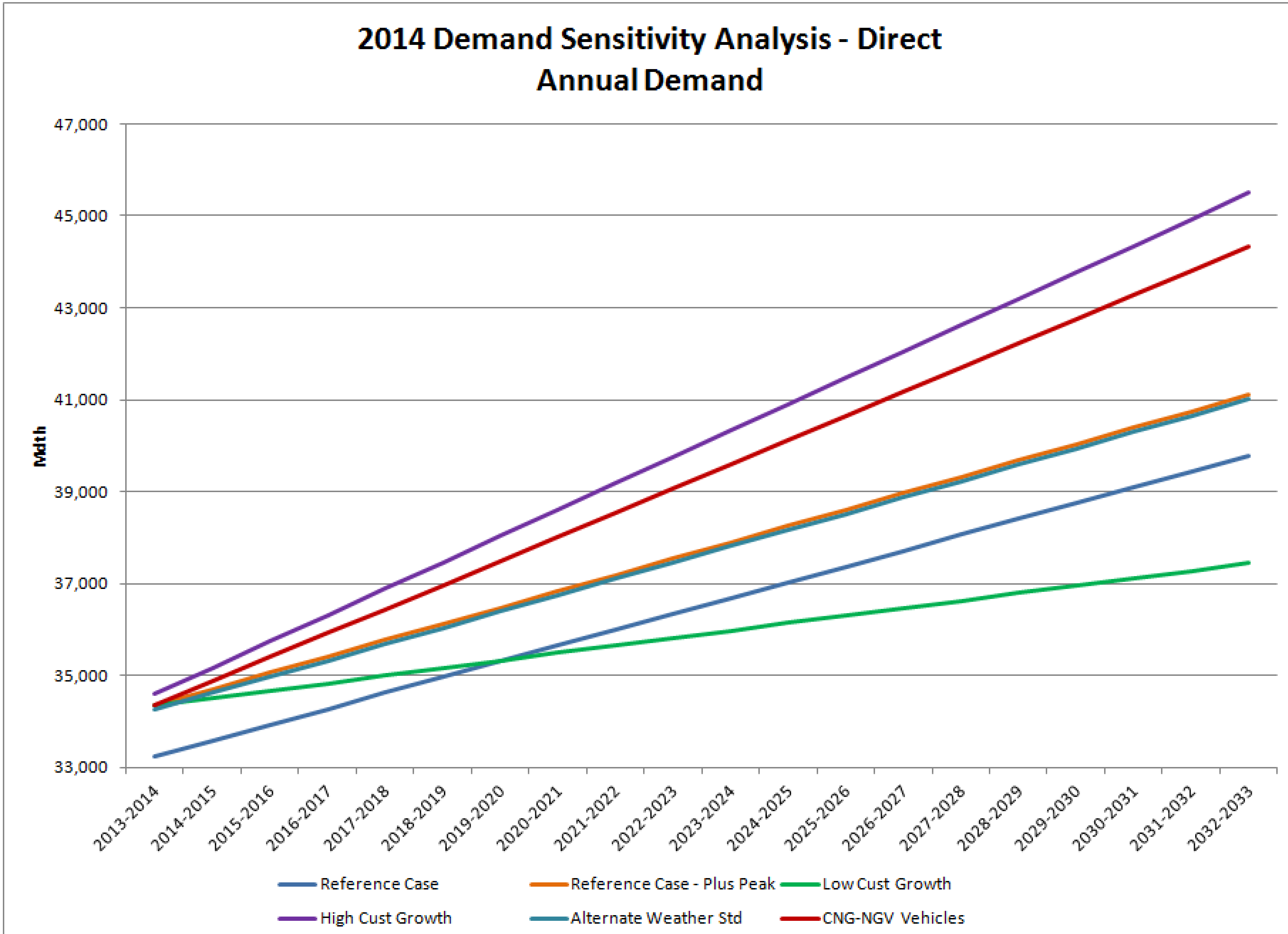
Demand Sensitivities & Scenarios Update

Sensitivities, Scenarios, Portfolios

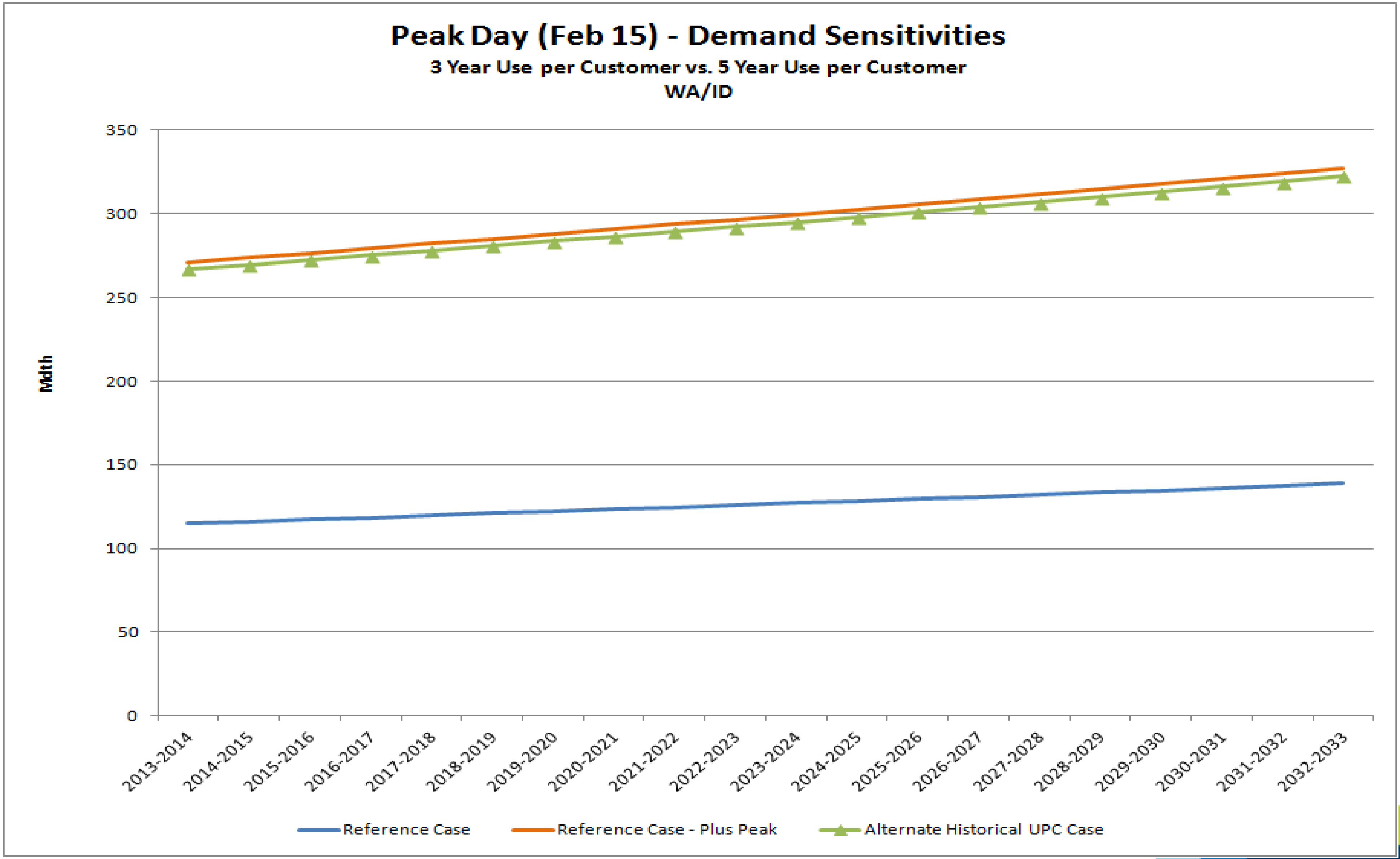


Sensitivity Analysis

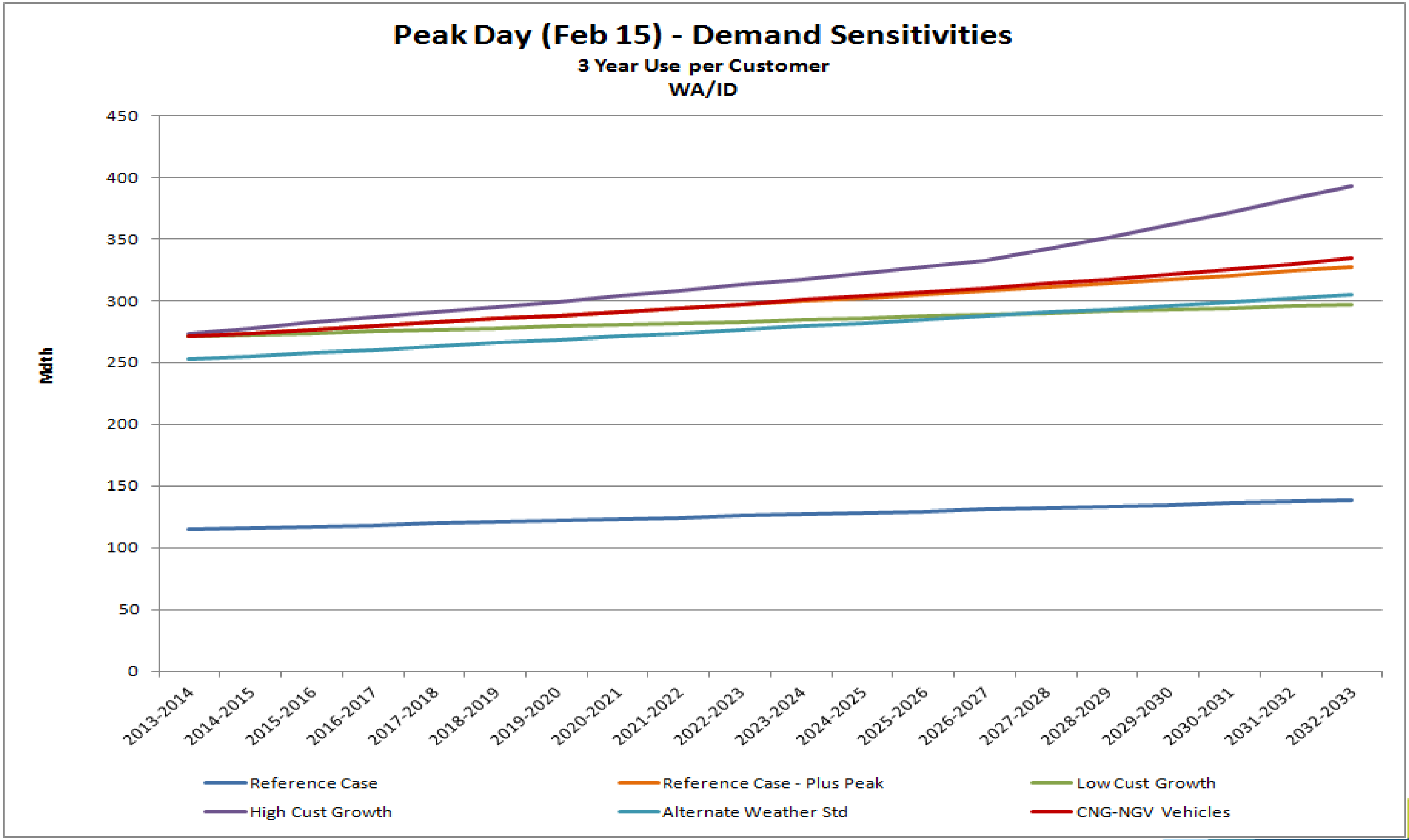

2014 Demand Sensitivities - Demand Influencing Direct
Annual Demand - Total System
Mdth
42,000
41,000
40,000
39,000
38,000
37,000
36,000
35,000
34,000
33,000
2013-2014
2014-2015
2015-2016
2016-2017
2017-2018
2018-2019
2019-2020
2020-2021
2021-2022
2022-2023
2023-2024
2024-2025
2025-2026
2026-2027
2027-2028
2028-2029
2029-2030
2030-2031
2031-2032
2032-2033
Reference Case
Reference Case - Plus Peak
Alternate Historical UPC Case


2014 Demand Sensitivity Analysis - Direct
Annual Demand
Mdth
47,000
45,000
43,000
41,000
39,000
37,000
35,000
33,000
2013-2014
2014-2015
2015-2016
2016-2017
2017-2018
2018-2019
2019-2020
2020-2021
2021-2022
2022-2023
2023-2024
2024-2025
2025-2026
2026-2027
2027-2028
2028-2029
2029-2030
2030-2031
2031-2032
2032-2033
Reference Case
Reference Case - Plus Peak
Low Cust Growth
High Cust Growth
Alternate Weather Std
CNG-NGV Vehicles

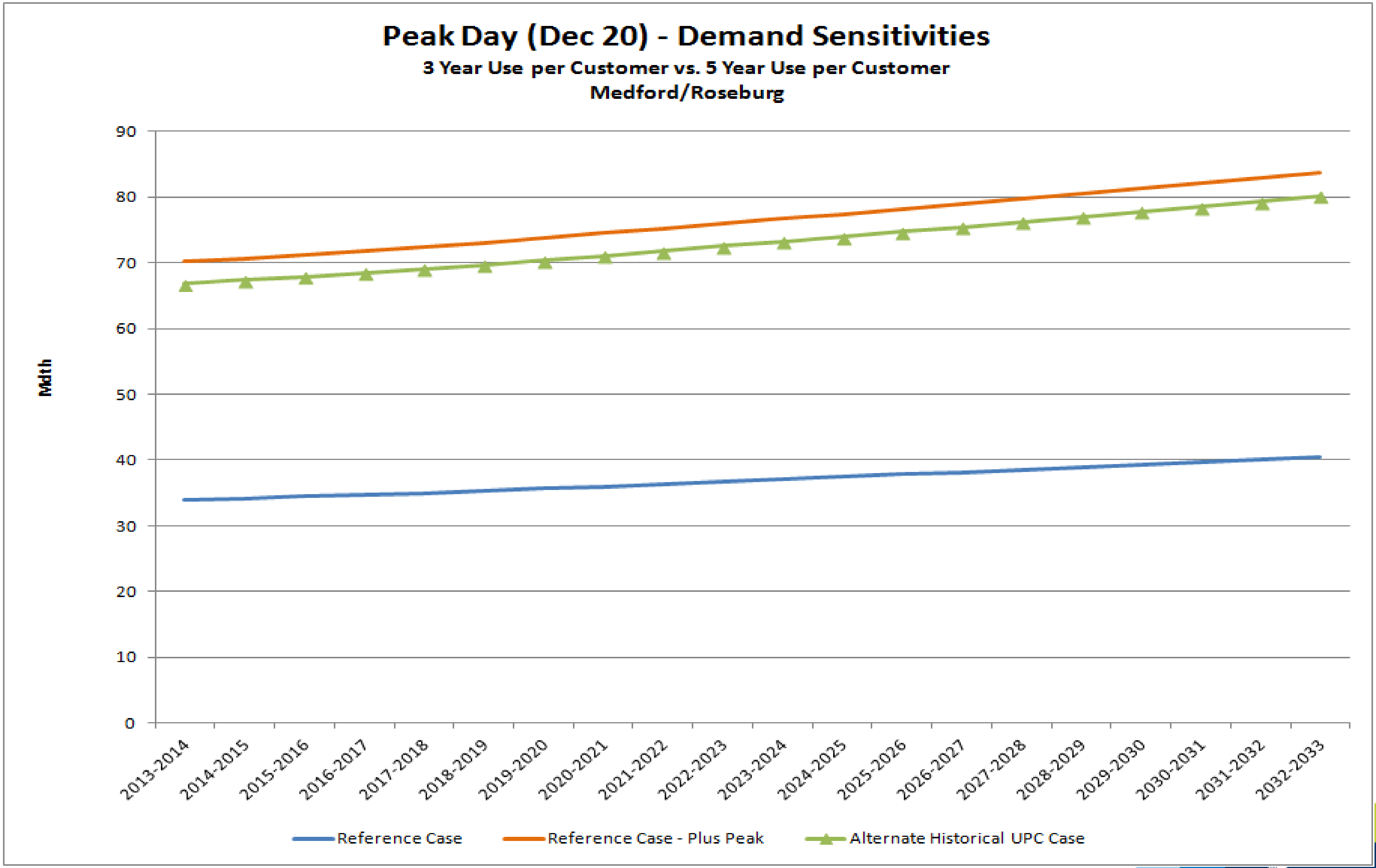
Demand Sensitivity Analysis – DIRECT
Peak Day Demand



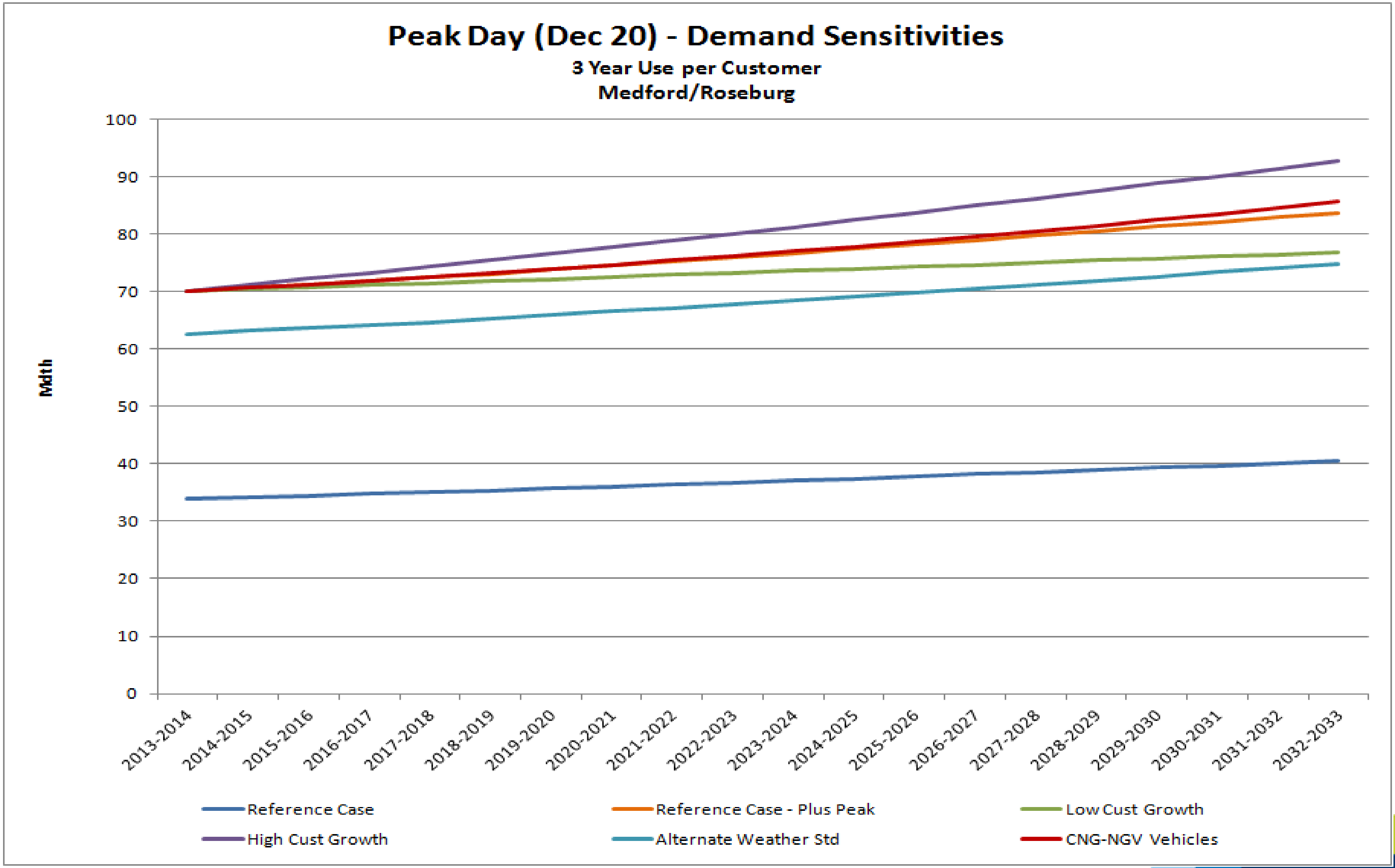
Demand Sensitivity Analysis – DIRECT
Peak Day Demand



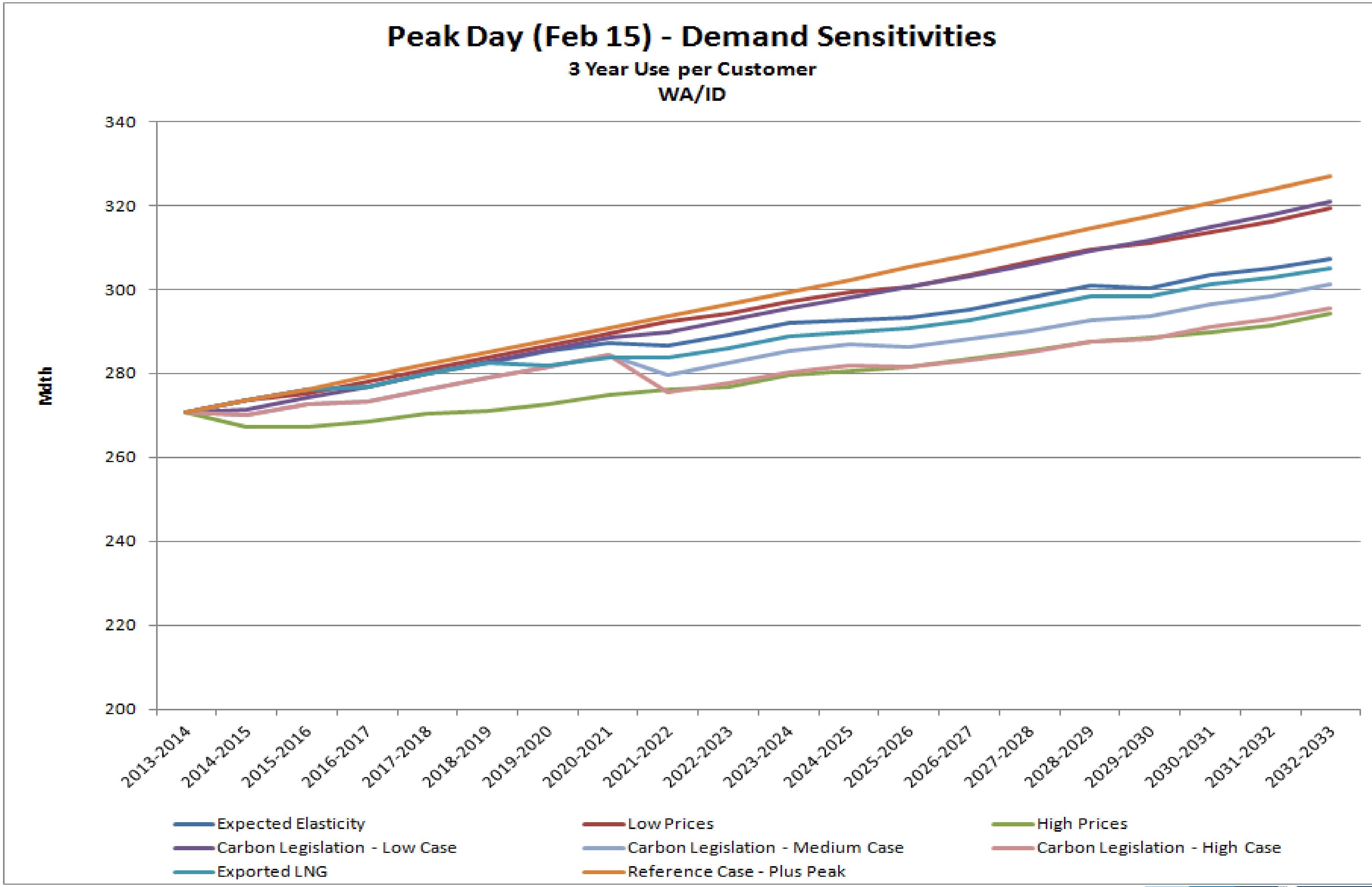
Demand Sensitivity Analysis – DIRECT
Peak Day Demand



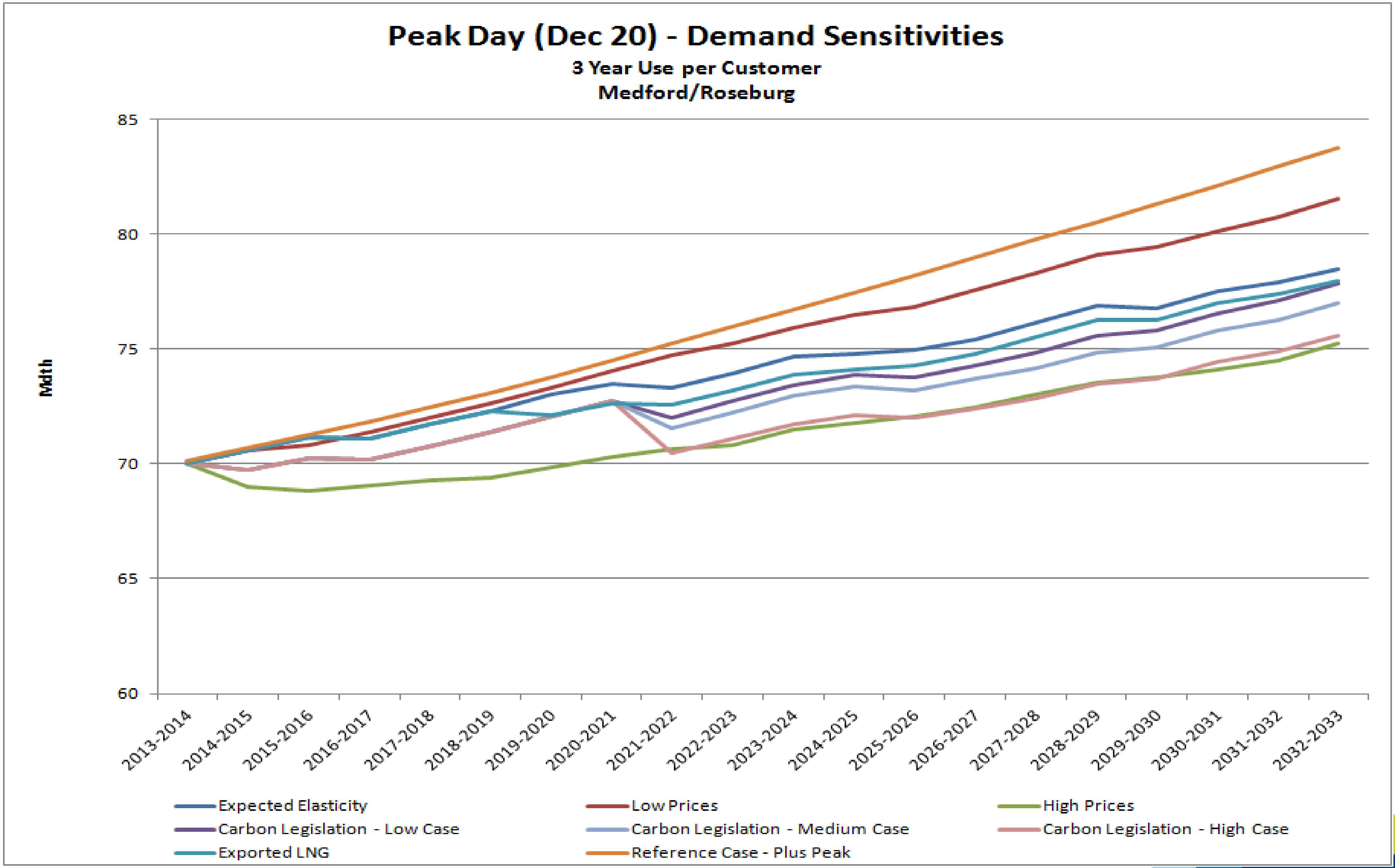
Demand Sensitivity Analysis – DIRECT
Peak Day Demand

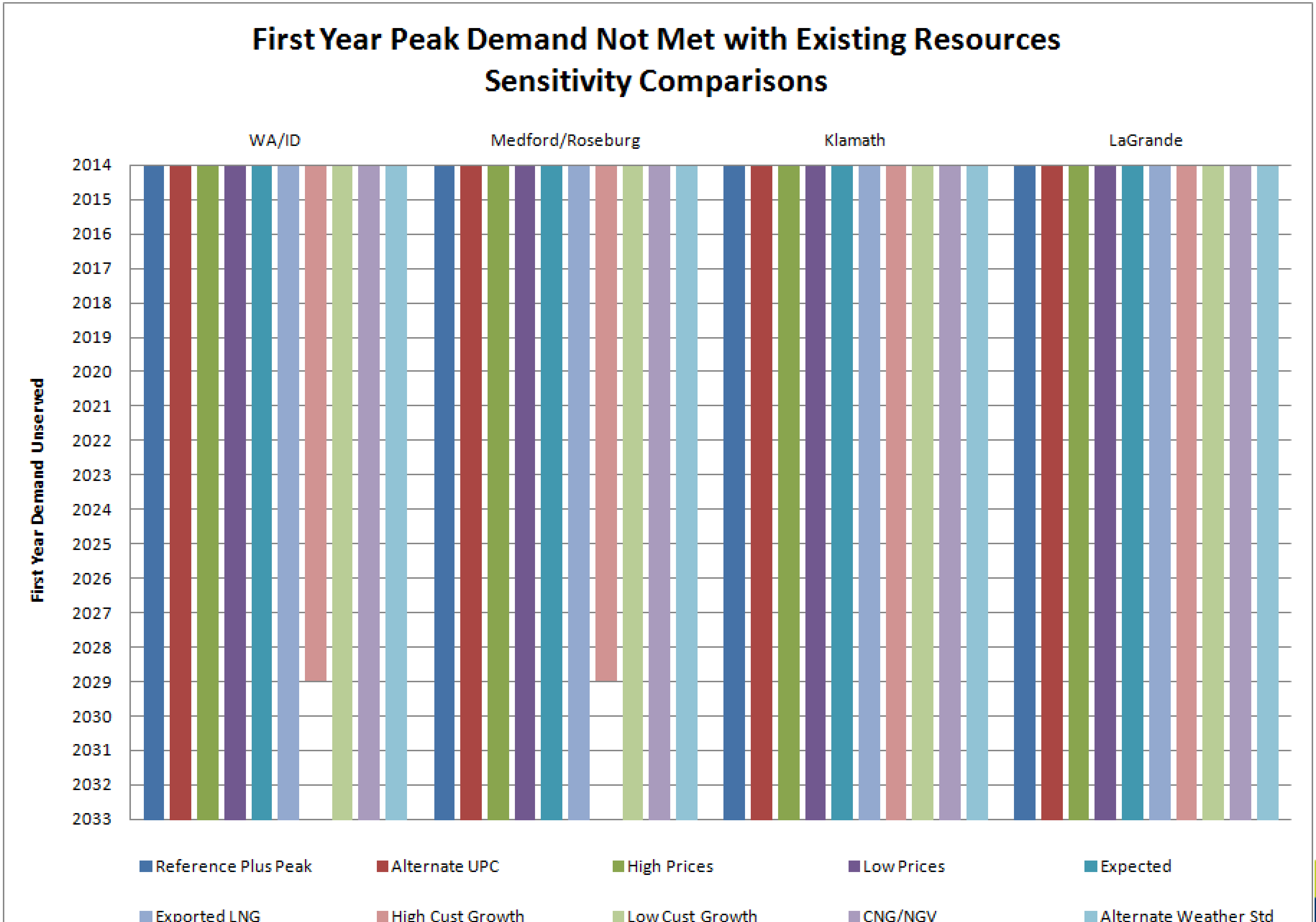


Demand Sensitivity Analysis – INDIRECT
Peak Day Demand



Demand Sensitivity Analysis – INDIRECT
Peak Day Demand





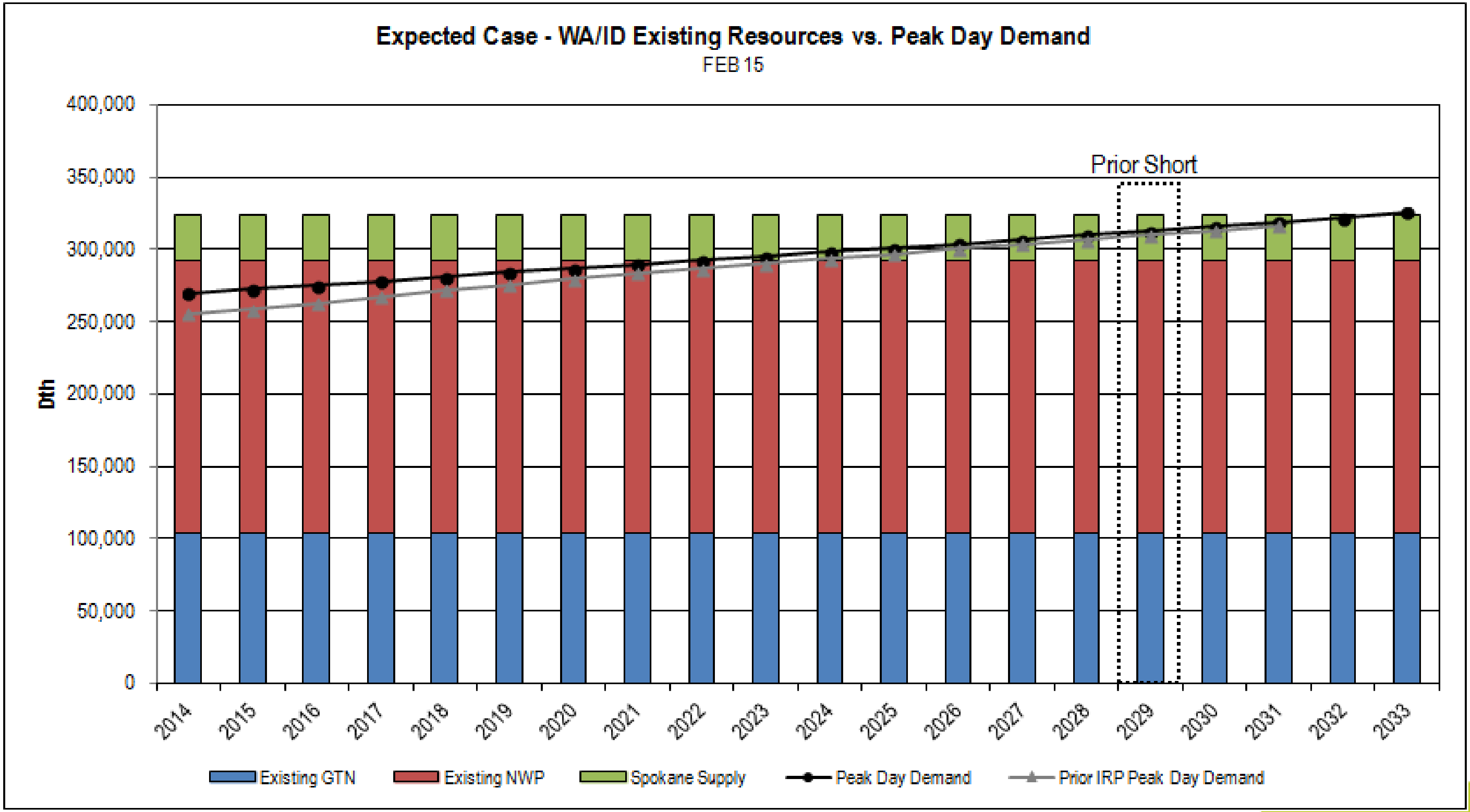
First Year Peak Demand Not Met with Existing Resources
Sensitivity Comparisons
WA/ID
Medford/Roseburg
Klamath
LaGrande
First Year Demand Unserved
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Reference Plus Peak
Alternate UPC
High Prices
Low Prices
Expected
Exported LNG
High Cust Growth
Low Cust Growth
CNG/NGV
Alternate Weather Std

Scenario Analysis

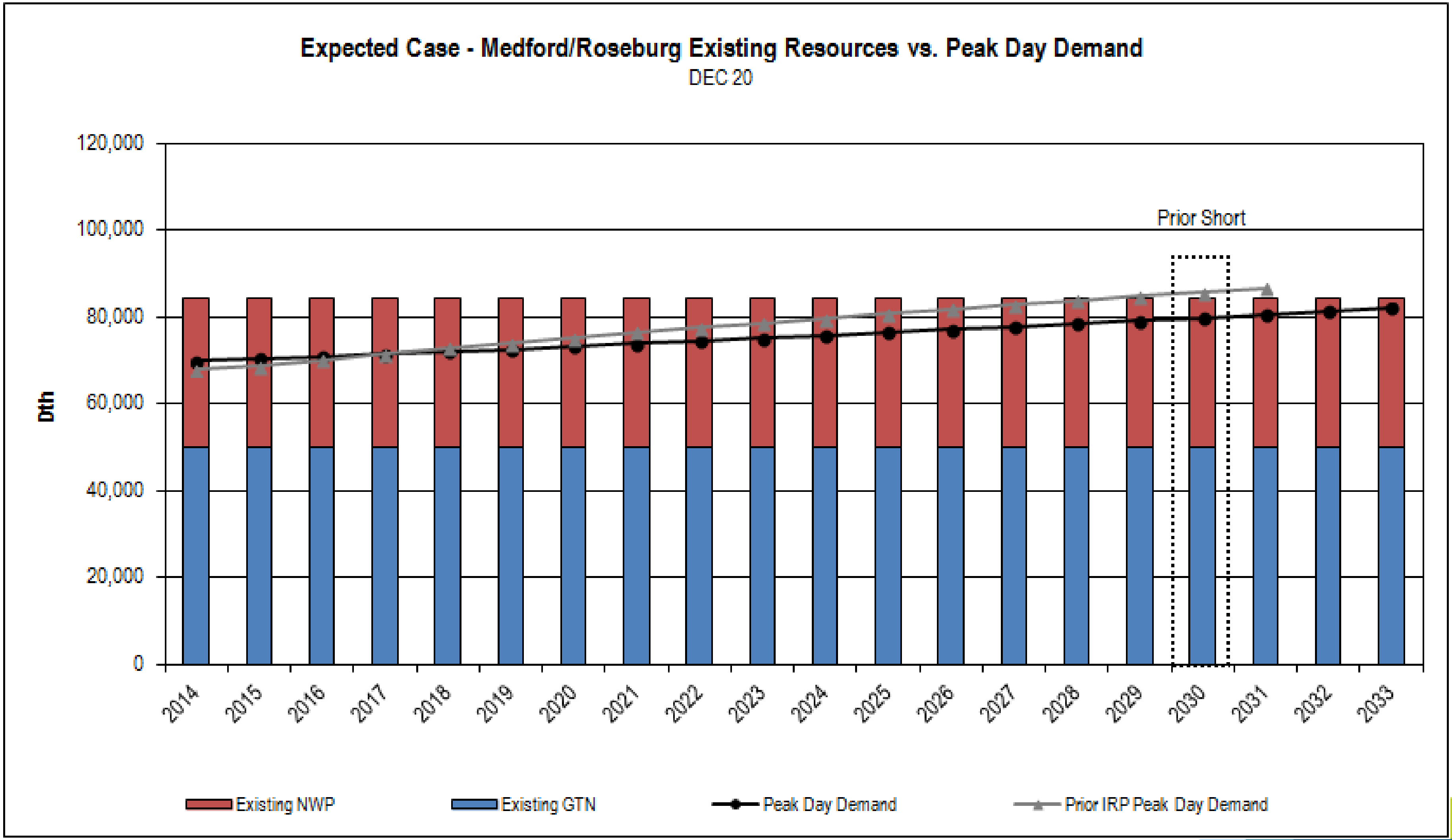
Proposed Scenarios

Proposed Scenarios	Expected Case	High Growth & Low Prices	Low Growth & High Prices	Cold Day 20yr Weather Std	Average Case
Input Assumptions					
Customer Growth Rate	Reference Case Cust Growth Rates	High Growth Rate	Low Growth Rate	Reference Case Growth Rate	Reference Case Growth Rate
Use Per Customer	3 Yr Flat + Price Elast.	3 Yr Flat + Price Elast. + CNG/LNG	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 Std.	Normal
Prices					
Price curve	Expected	Low	High	Expected	Expected
Price curve adder ($/Dth)	None	None	None	None	None
Elasticity	Expected	None	Expected	Expected	Expected
Carbon Adder ($/Ton)	$14-$22		$14-$22	$14-$22	

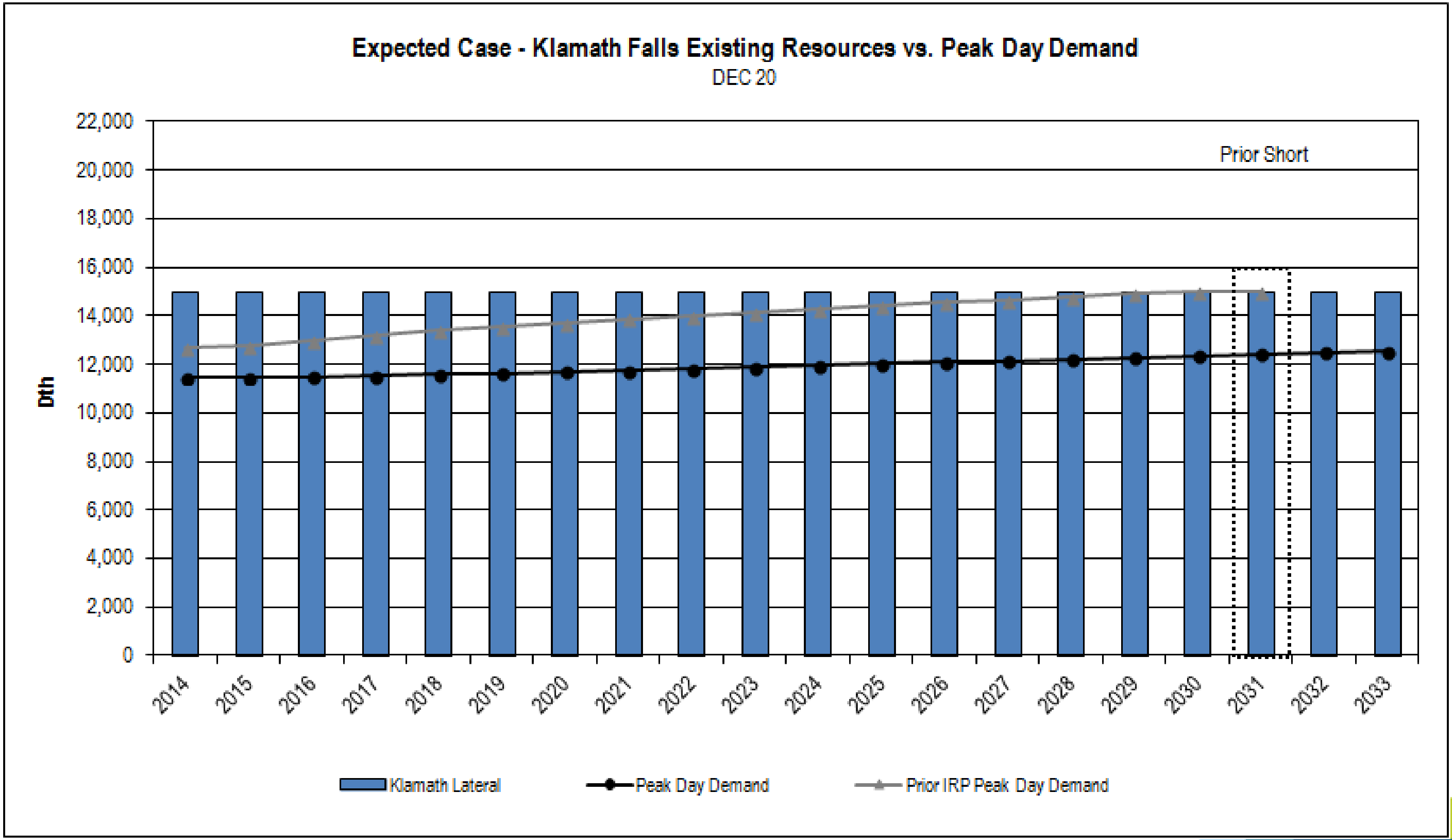
Existing Resources vs. Peak Day Demand



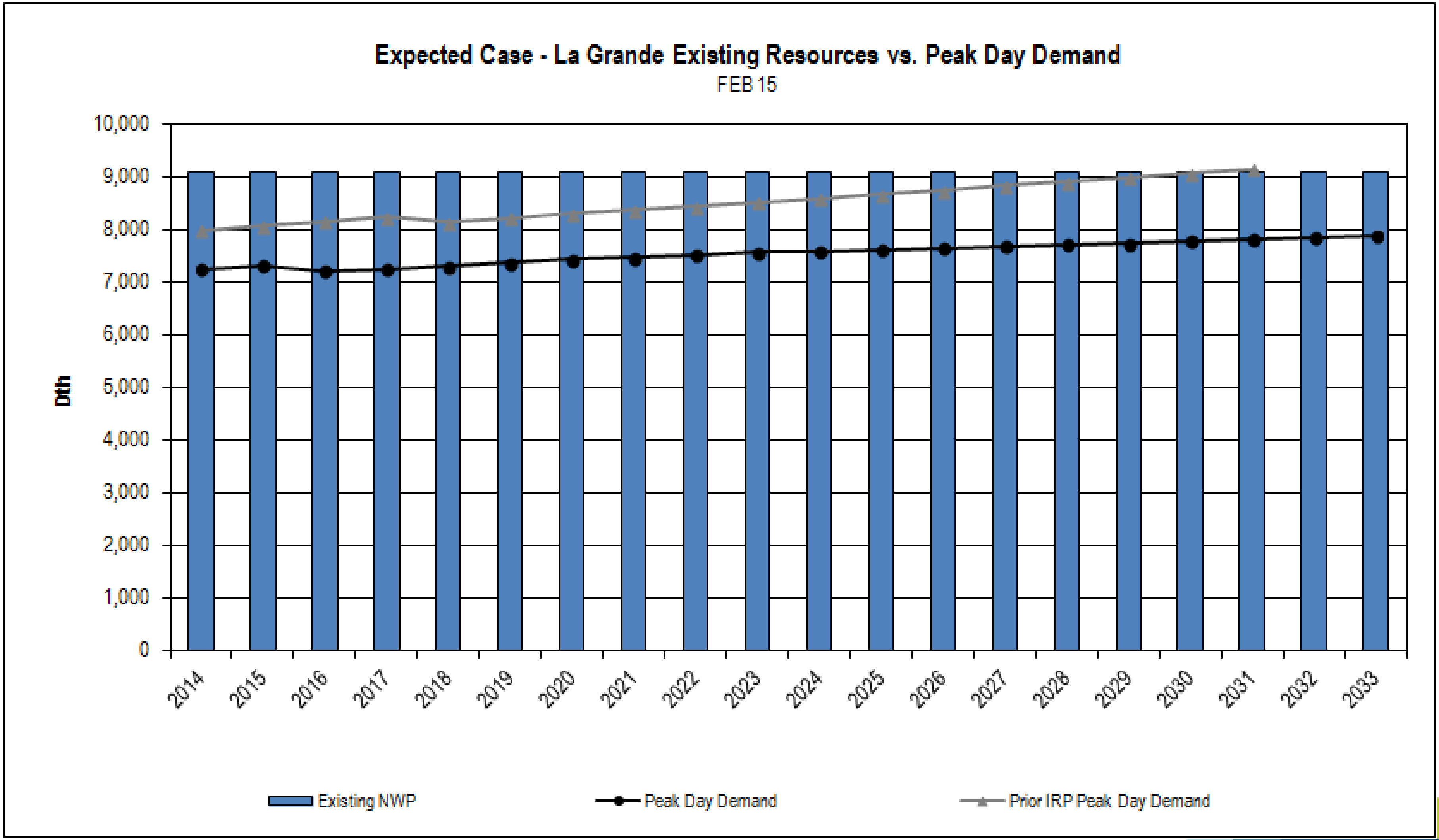
Existing Resources vs. Peak Day Demand

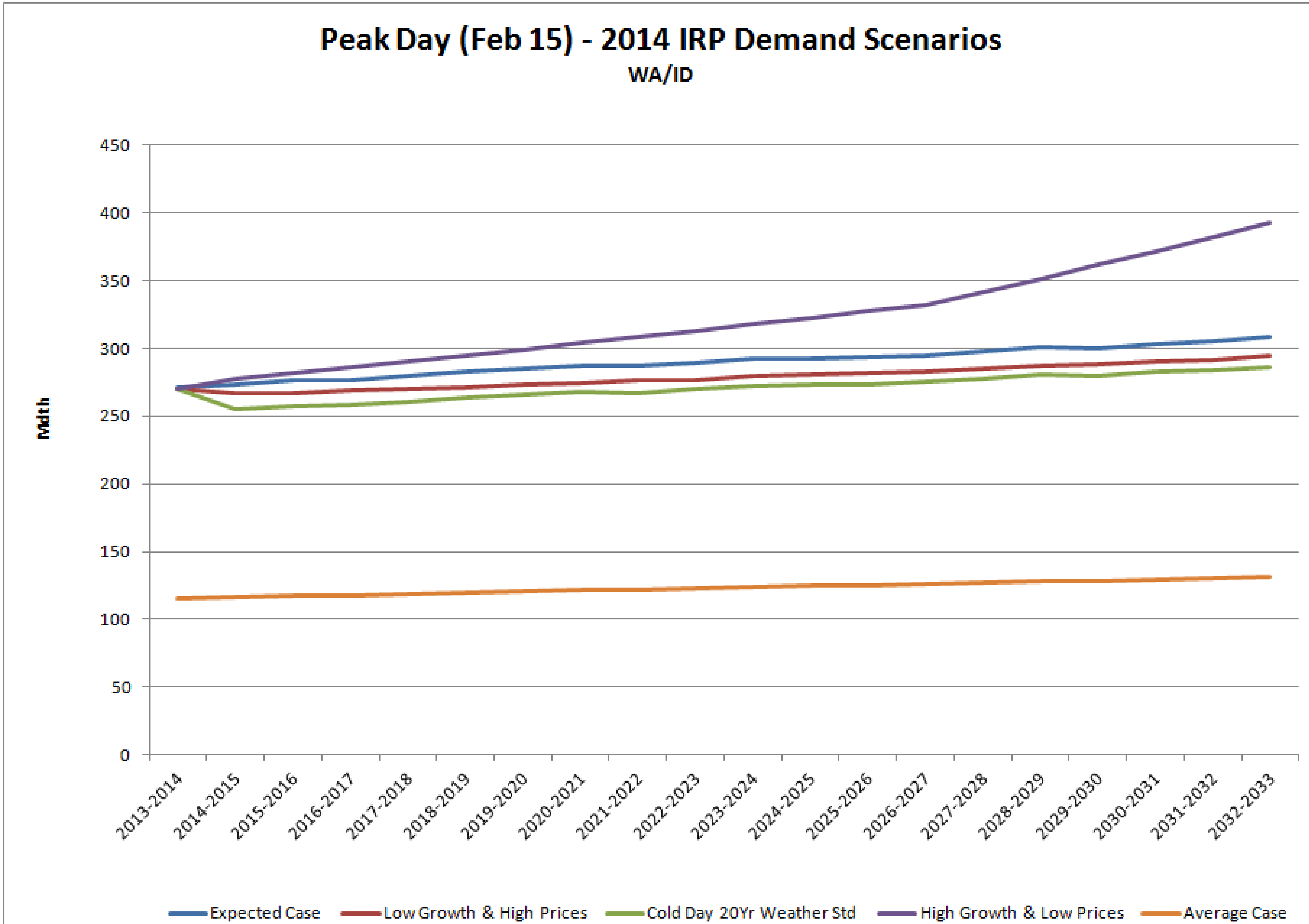


Existing Resources vs. Peak Day Demand

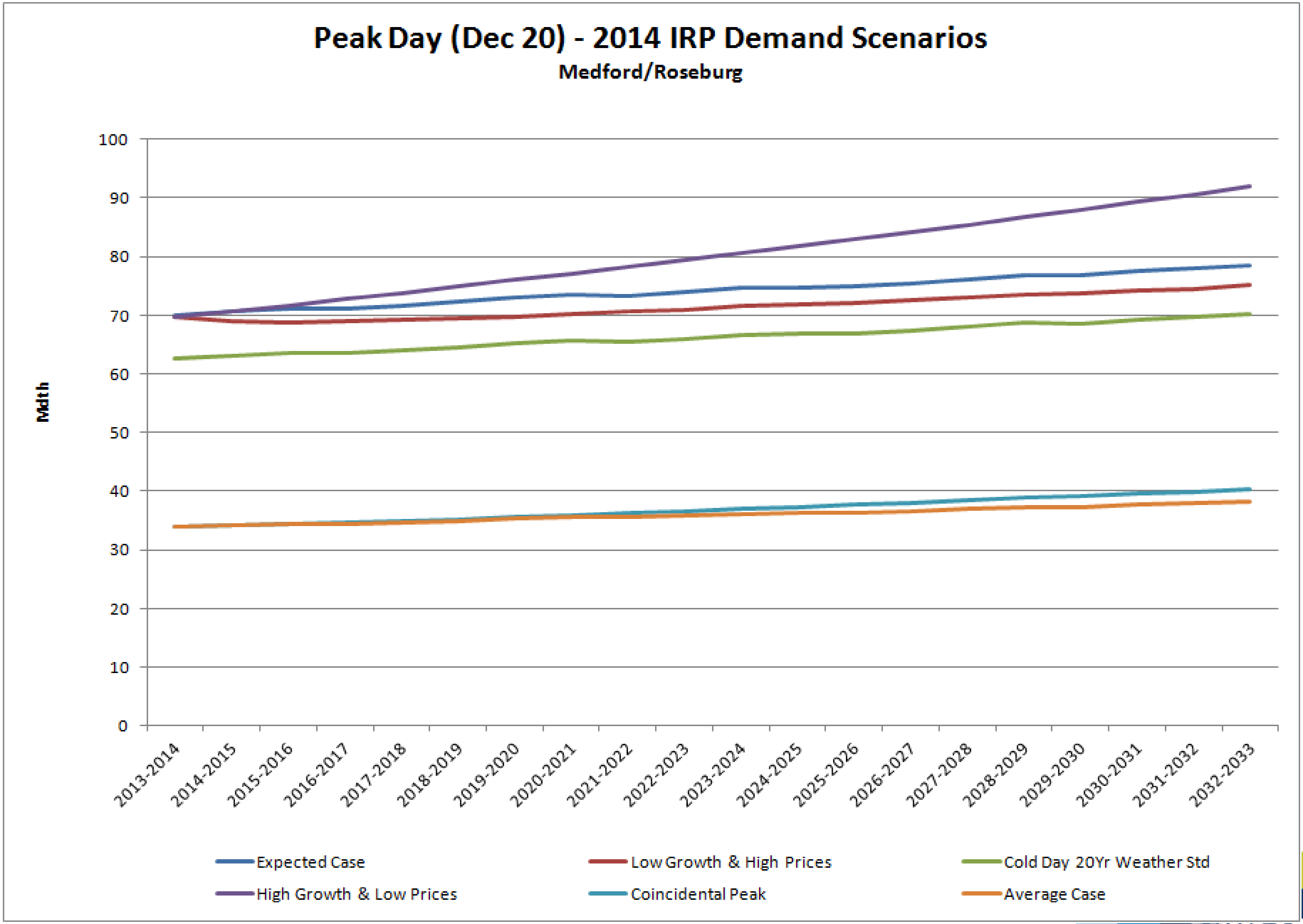


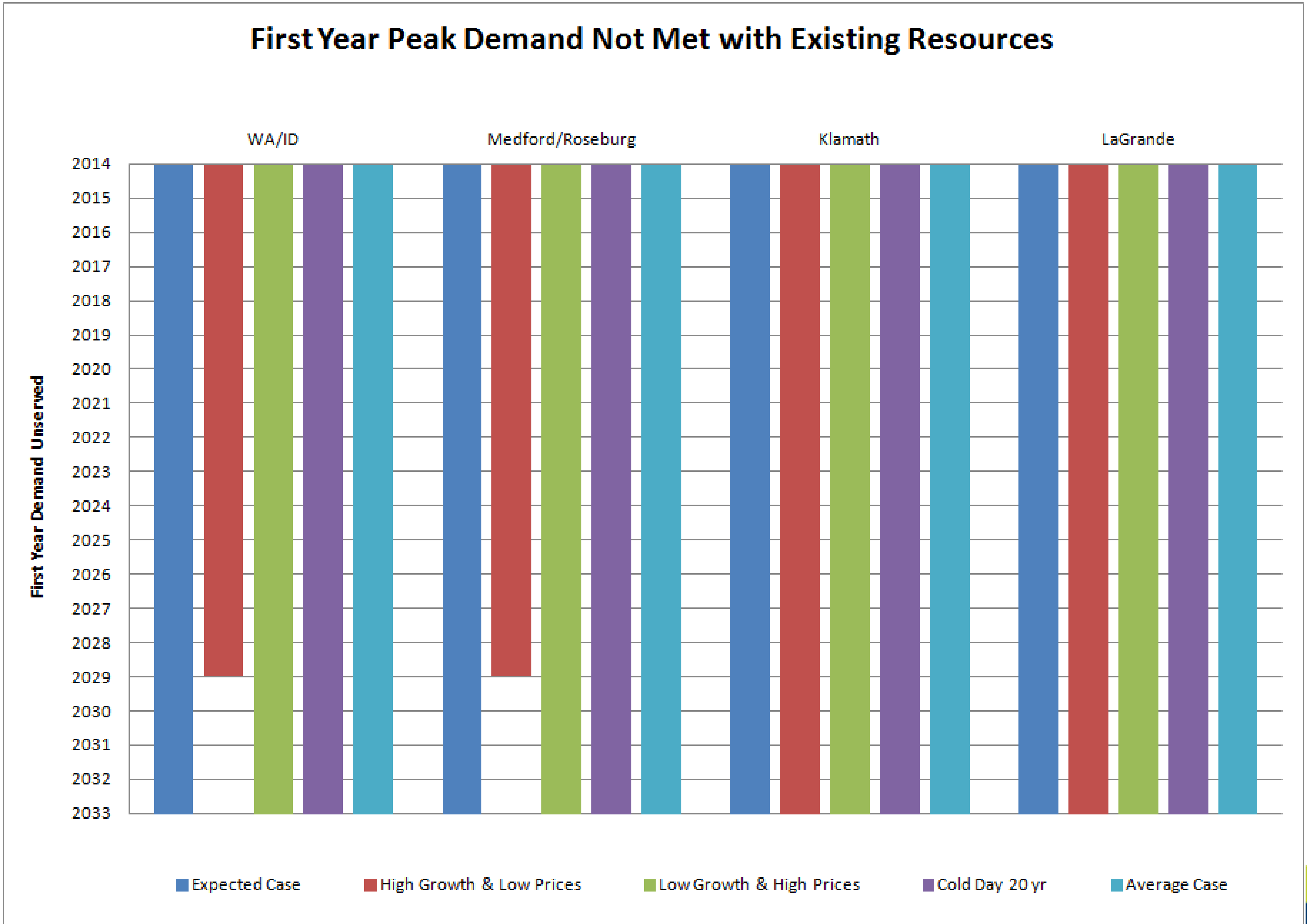
Existing Resources vs. Peak Day Demand





Peak Day (Feb 15) - 2014 IRP Demand Scenarios
WA/ID
Mdth
450
400
350
300
250
200
150
100
50
0
2013-2014
2014-2015
2015-2016
2016-2017
2017-2018
2018-2019
2019-2020
2020-2021
2021-2022
2022-2023
2023-2024
2024-2025
2025-2026
2026-2027
2027-2028
2028-2029
2029-2030
2030-2031
2031-2032
2032-2033
Expected Case
Low Growth & High Prices
Cold Day 20Yr Weather Std
High Growth & Low Prices
Average Case


Peak Day (Dec 20) - 2014 IRP Demand Scenarios
Medford/Roseburg
Mdth
100
90
80
70
60
50
40
30
20
10
0
2013-2014
2014-2015
2015-2016
2016-2017
2017-2018
2018-2019
2019-2020
2020-2021
2021-2022
2022-2023
2023-2024
2024-2025
2025-2026
2026-2027
2027-2028
2028-2029
2029-2030
2030-2031
2031-2032
2032-2033
Expected Case
Low Growth & High Prices
Cold Day 20Yr Weather Std
High Growth & Low Prices
Coincidental Peak
Average Case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LaGrande
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2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Expected Case
High Growth & Low Prices
Low Growth & High Prices
Cold Day 20 yr
Average Case

Resource Options for Meeting Unserved Demand

Potential New Supply Resources Considerations

- Availability
  - By Region – which region(s) can the resource be utilized?
  - Lead time considerations – when will it be available?
- Type of Resource
  - Peak vs. Baseload
  - Firm or Non-Firm
  - “Lumpiness”
- Usefulness
  - Does it get the gas where we need it to be?
  - Last mile issues
- Cost

Supply Resources Available

Additional Resource	Size	Cost/Rates	Availability	Notes
Capacity Release Recall	30,000 Dth	NWPL Rate	2018	Recall of previously released capacity
Unsubscribed GTN Capacity	Up to 50,000 Dth	GTN Rate plus Upstream TCPL	Now	Currently available unsubscribed capacity from Kingsgate to Stanfield or Malin plus associated Alberta transport
NWP Expansion	Up to 50,000 Dth	NWPL Rate x 4	2016	Expansion from Sumas/JP to WA/ID or Sumas/JP to OR
Citygate Deliveries	Variable	Varies	Now	Represents the ability to buy a delivered product from another utility or marketer. Limited counterparties
Satellite LNG	90,000 Dth w/30,000 Dth deliverability	$6.5 Million capital cost plus $350K O&M	2016	Provides for peaking services and alleviates the need for costly pipeline expansions.

Supply Resources Available

Additional Resource	Size	Cost/Rates	Availability	Notes
Medford Lateral Exp	25,000 Dth	GTN Rate	2016	Additional compression to facilitate more gas to flow from mainline GTN to Medford.
Malin Backhauls	25,000	GTN Rate	Now	Currently available

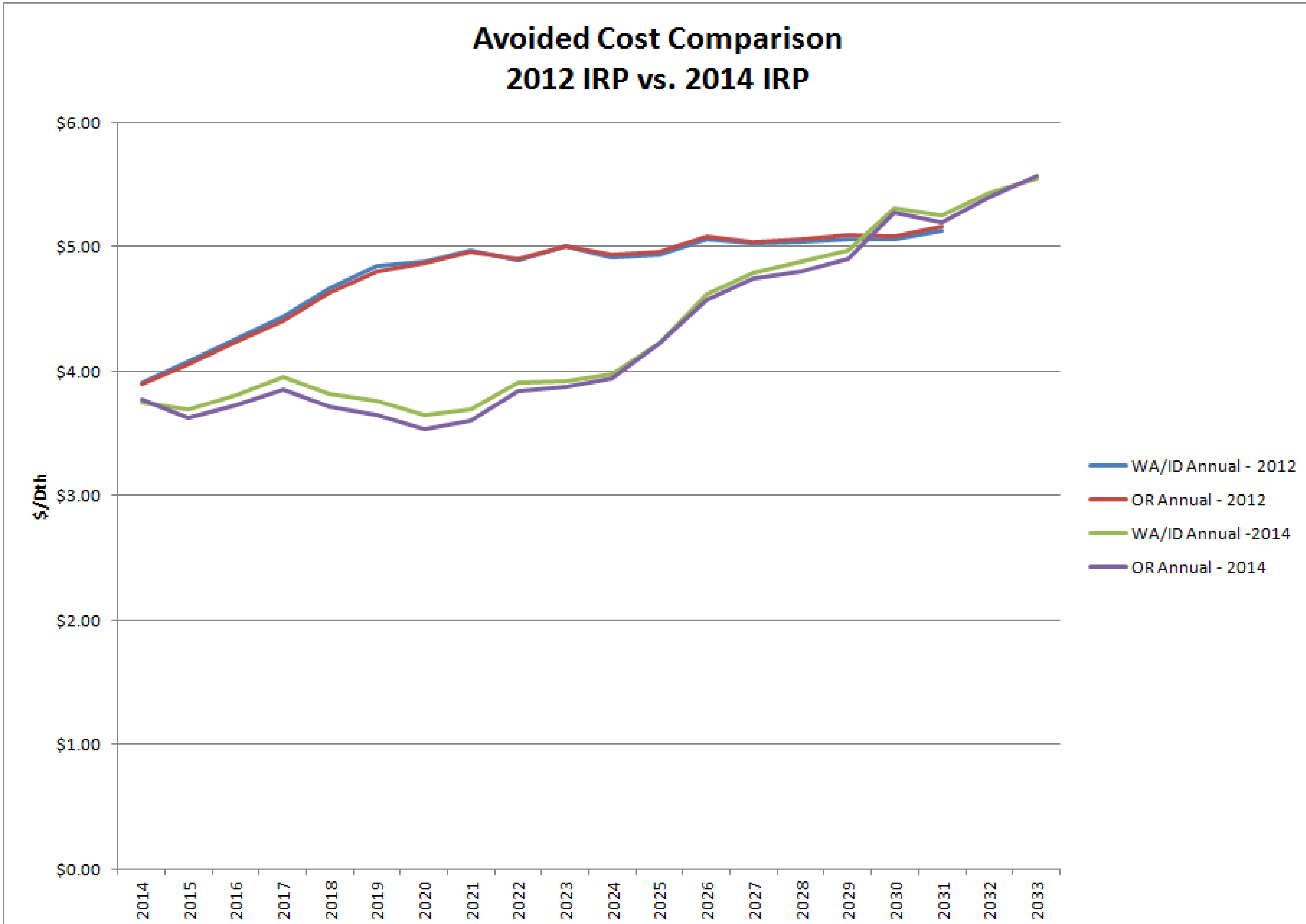
Future Supply Resources

Other Resources Considered

Additional Resource	Size	Cost/Rates	Availability	Notes
Co. Owned LNG	600,000 Dth w/ 150,000 of deliverability	$75 Million plus $2 Million annual O&M	2020	On site, in service territory liquefaction and vaporization facility
Various pipelines – Pacific Connector, Cross-Cascades, etc.	Varies	Precedent Agreement Rates	2018	Requires additional mainline capacity on NWPL or GTN to get to service territory
Large Scale LNG	Varies	Commodity less Fuel	2018	Speculative, needs pipeline transport
In Ground Storage	Varies	Varies	Varies	Requires additional mainline transport to get to service territory

DSM Avoided Cost

- Avoided cost determined by comparison to the marginal supply side resources to meet incremental demand, primarily commodity costs.
- Preliminary avoided costs were provided to Enernoc for cost effectiveness testing and development of the DSM acquirable potential.
- Potential is then input into SENDOUT® and avoided costs are re-evaluated.



Avoided Cost Comparison
2012 IRP vs. 2014 IRP
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
$/Dth
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
WA/ID Annual - 2012
OR Annual - 2012
WA/ID Annual -2014
OR Annual - 2014

Stochastic Analysis

What is it?

- Stochastic vs. Deterministic
- Facilitates a statistical approach to analysis
- Reiterative runs of SENDOUT (e.g. 200 “Draws”)
- Utilizes statistically generated price curves and weather patterns derived from historical data
- Develops a distribution of the “draws” results
  - Normal and lognormal distribution

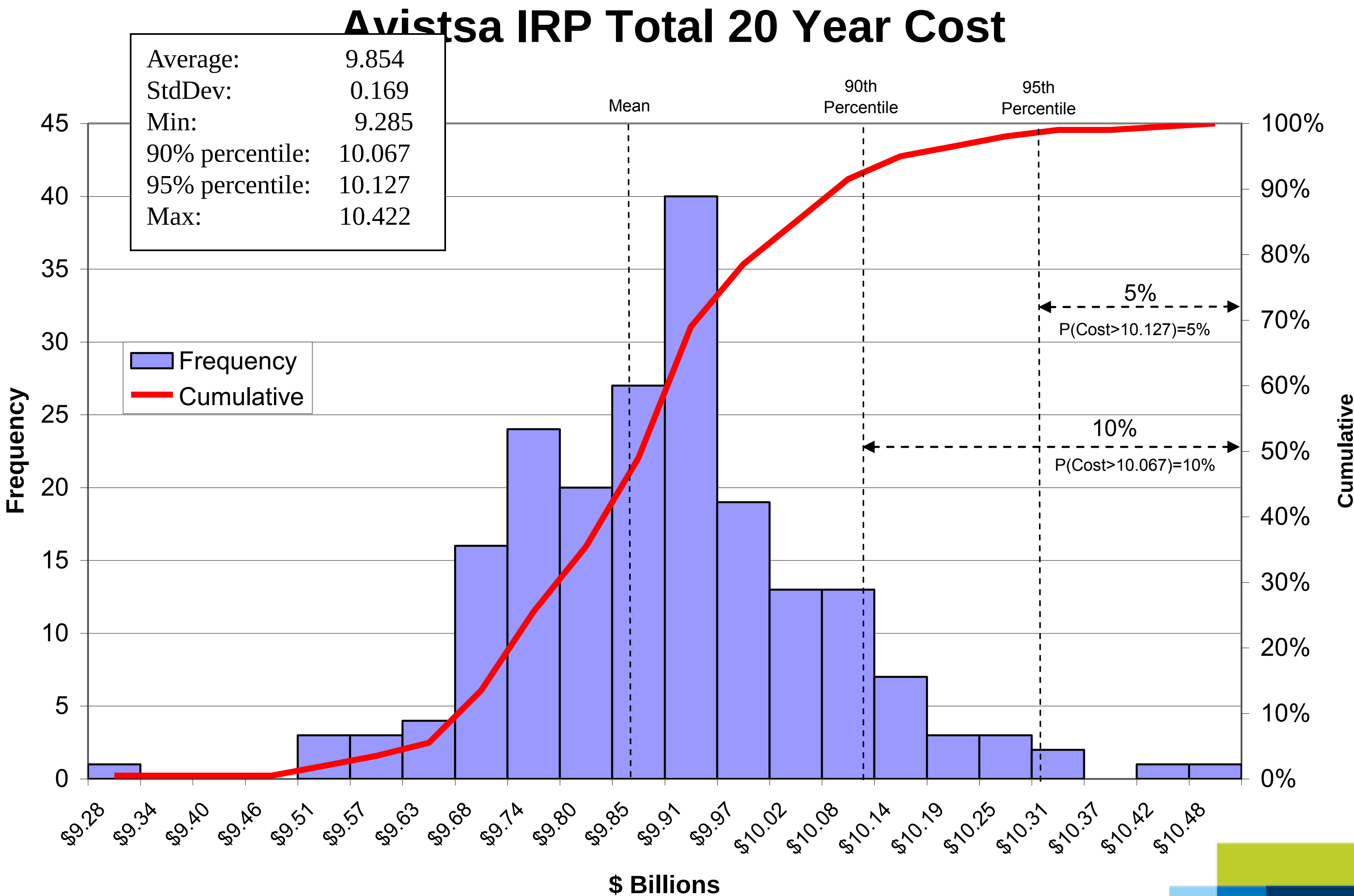
Analytical Objectives

- Weather
  - Validate reasonableness of our weather planning standard
  - Compare demand and unserved results
  - Quantify potential alternate weather planning standards via comparison of alternate aggregate NPV portfolio costs

- Price
  - Substantiate preferred portfolio selection (commodity cost perspective)
  - Compare distribution of aggregate NPV cost to preferred portfolio

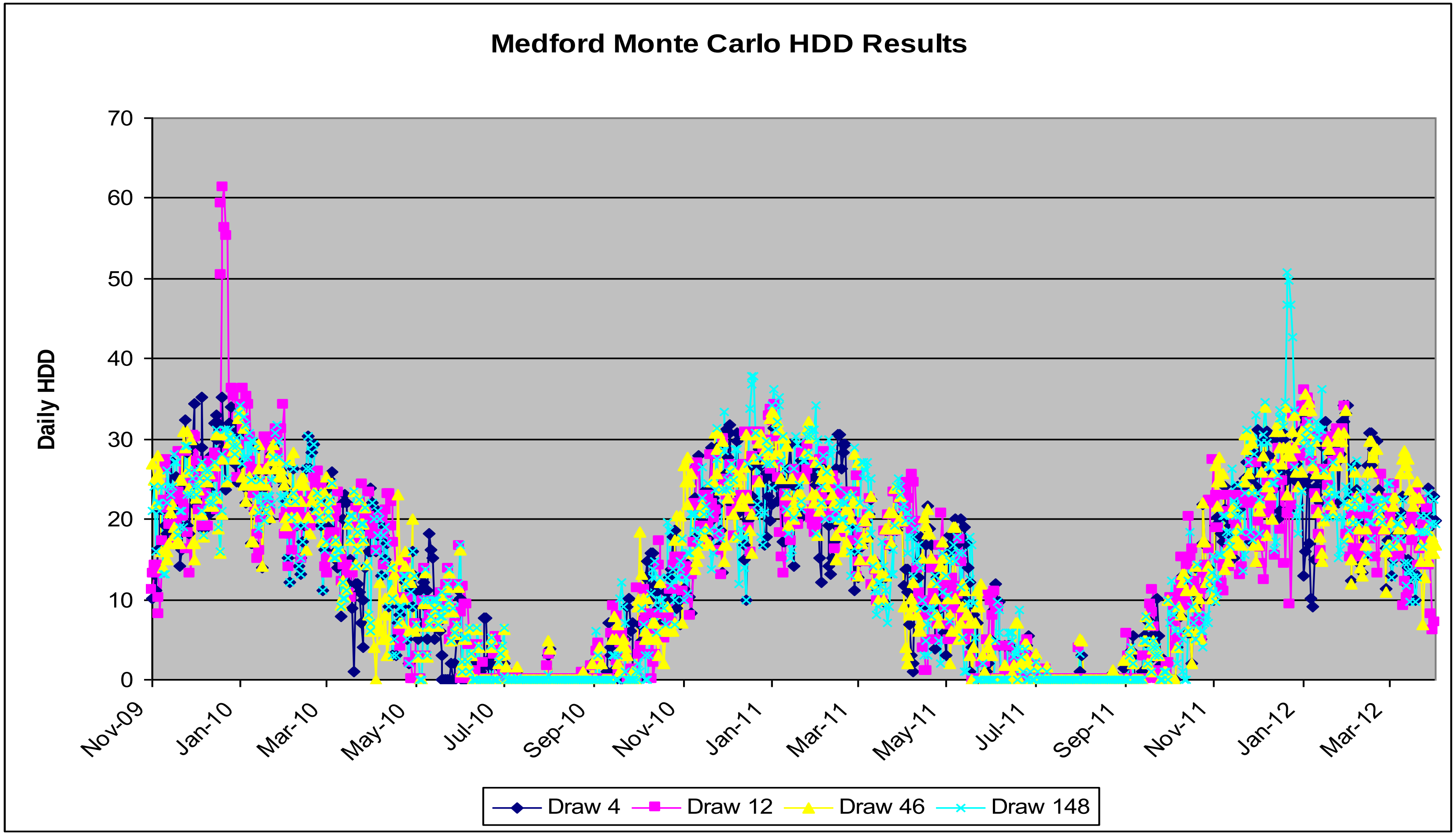
VectorGas™ Reports

EXAMPLE ONLY



Sample Weather Pattern

Medford HDDs - Four example draws



AVISTA

Key Issues / Document Discussion

Highlights of the 2014 IRP

- No near-term resource needs under most scenarios.
- Lower long term customer growth rates.
- 20 year rolling average is the new “normal”.
- No global warming adjustment.
- Updated DSM potential and resultant avoided costs.

2012 IRP Acknowledgement Comments

- Describe more clearly derivation of growth scenarios, including high and low in demand forecasting chapter.
- Use 5 year use per customer data set
- Provide a comparative avoided cost analysis in future IRP’s
- Do an analysis and/or narrative describing the “trigger point” avoided cost value where conservation programs become cost-effective.
- Between IRP’s compare modeling assumptions with actual demand.
- Include a Washington specific city gate analysis, including a narrative of its conclusions as a result of such analysis.

2012 IRP Acknowledgement Comments

- Include an easily identifiable progress report that relates new plan to previous plan.
- Reconcile inconsistencies between models used in demand forecasting and implementation and description of these models.
- Hold public outreach meetings in locations convenient for customers.

2012 IRP Acknowledgement Comments

- Continue DSM programs in Oregon to achieve minimum savings of 225,000 therms in 2013 and 250,000 therms in 2014.
- Provide results of the following:
    - Savings and cost effectiveness of DSM program.
    - Actions taken to reduce delivery costs, including admin and audit costs.
    - Actions taken to increase cost effective efficiency measures in the portfolio.
    - Analysis of non-natural gas benefits of existing and proposed measures.
    - Analysis of measure lives for all measures.
- Develop mechanism for allocating funding for a separate low-income energy efficiency program.
- Pursue possibility of regional elasticity study through NWGA or AGA.
- Assess potential demand impact from NGV/CNG vehicles and other new uses of natural gas.

Key Issues

- Where's the Demand?
  - Even flatter demand – How long does this trend continue?
  - What impacts on consumption? Temporary or permanent change?
  - What is the demand boost?
- Resource Management
  - Prudent management of resource length
- "The Price is Right"
  - $5 gas forever?
- Environmental Impacts
  - Carbon Tax?
  - Hydraulic Fracturing Bans

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